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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Public Service Electric and Gas Company,	)	
	)	
Complainant,	)	
	)	
v.	)	Docket No. EL15-___-000
	)	
PJM Interconnection, L.L.C.,	)	
	)	
Respondent.	)	

COMPLAINT OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY AGAINST PJM INTERCONNECTION, L.L.C.

Public Service Electric and Gas Company ("PSE&G") hereby submits this complaint ("Complaint") against PJM Interconnection, L.L.C. ("PJM") pursuant to section 206 of the Federal Power Act ("FPA"), 16 U.S.C. § 824e, and Rule 206 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.206. PSE&G is submitting this Complaint because PJM did not follow its rules when conducting a competitive transmission solicitation to resolve operational performance issues at Artificial Island. PSE&G requests that the Commission order PJM to comply with its rules in this and all future transmission solicitations under Order No. 1000.[1]

SUMMARY

Artificial Island is PJM's first major competitive solicitation for transmission under its Order No. 1000 rules. "Artificial Island" refers to the transmission and generation infrastructure associated with the second largest nuclear complex in the United States, including the Salem 1

[1] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Utils.*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *affirmed sub. nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

and 2 and Hope Creek nuclear generating units that have a total generating capacity of 3818 MW. Artificial Island has historically been stability-constrained and special operating procedures have been used to maintain stability in the area. PJM proposed to mitigate these limitations through a competitive transmission solicitation that commenced in April 2013.

PJM's Order No. 1000 rules for transmission solicitations use a "sponsorship model" under which potential transmission solutions are proposed by sponsors, not by PJM. The process begins when PJM posts information on the transmission problem and requests proposals to address it. Prospective transmission developers then have the opportunity to submit proposals during a defined "proposal window" (ranging from 30 to 120 days). After the window closes, PJM can request additional information from the project sponsors. The sponsors must respond within ten days if they want to remain in the solicitation, but they cannot modify their proposal in response to PJM's request (or at any time after the window closes). PJM staff then evaluates and compares the proposals and, after seeking stakeholder input, PJM selects the more efficient and cost-effective proposal. If, however, none of the proposals represents the more efficient or cost-effective solution, PJM re-posts the solicitation or, if there is insufficient time to do that, PJM proposes its own solution and designates the incumbent transmission owner to build it. This is the only situation in which PJM may craft its own solution under its rules.

PJM did not, however, follow this process when conducting the Artificial Island solicitation. Rather than evaluating and comparing the proposals and selecting the best one, PJM unilaterally modified all of them. PJM removed major line segments from several proposals. It added static VAR compensators to many of them. It fixed the proposals that failed to meet its posted criteria so they would pass the criteria. After making all these changes, PJM sought stakeholder comment on a short list of four PJM-modified proposals and then recommended one

of the proposals to the PJM Board. The Board did not accept that recommendation, but rather allowed one sponsor to modify its proposal to include a cost cap. The Board then invited the other short-listed sponsors to submit cost caps as well. PJM then conducted more evaluations and requested more information. That process continues today, nearly two years after it started, with no conclusion or even a recommendation.

The competitive transmission process envisioned by Order No. 1000 cannot succeed if the regions do not follow their solicitation rules. The Commission gave each region significant flexibility in implementing the reforms associated with removing federal rights of first refusal, but it required each of them to have clear and transparent rules for conducting solicitations and selecting a winner from among the competing proposals. PJM emphasized the clarity and transparency of its rules when it complied with Order No. 1000. Additionally, PJM emphasized the limitations on its role in the process—specifically, its role as an independent evaluator of competing solutions, not the entity crafting those solutions. PJM also emphasized the importance of not allowing bidders to modify their proposals after the proposal window closed. PJM said this would "chill" the competitive process and give one bidder an "unfair advantage" over the others.

Because PJM did not adhere to this process, the Commission should grant the Complaint and order PJM to follow its rules in this solicitation and all future ones. If PJM believes that no proposal submitted during the proposal window represents the more efficient or cost-effective solution, it can re-post the solicitation. When doing so, it can provide more guidance to potential sponsors based on the experience of its first major solicitation.

PSE&G appreciates that there are growing pains with implementing any significant new process. PSE&G also believes that PJM has acted in good faith and is no doubt trying to achieve

an end result that it believes reasonable. But it is the competitive process that is relied upon to produce reasonable results in this area and that process can succeed only if the rules are clear and they are followed. If PJM believes its rules need improvement, it can discuss its concerns with stakeholders and, as appropriate, file proposed amendments with the Commission. But in the meantime it must follow the rules. Artificial Island was lauded as the initial test of those rules and that test will fail if the rules continue to be abandoned.

BACKGROUND

I. THE PARTIES

PSE&G is a public utility organized under the laws of New Jersey. PSE&G transmits and distributes electricity and distributes natural gas in its franchise service territory in northern and central New Jersey. PSE&G owns electric transmission facilities in New Jersey that are under the operational control of PJM, including ownership—either sole or joint—of facilities interconnected to the Salem and Hope Creek nuclear generation facilities in southern New Jersey.

PJM is a Commission-approved Regional Transmission Organization ("RTO"). PJM is a transmission provider under, and the administrator of, the PJM Open Access Transmission Tariff ("Tariff"). Also, through the Tariff and the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("PJM OA"), PJM operates energy and capacity markets, plans regional transmission expansion improvements to maintain grid reliability and relieve congestion, and conducts the day-to-day operations of the transmission system in the PJM region. Under Schedule 6 of the OA, PJM is responsible for developing PJM's transmission expansion plan in accordance with Commission-approved requirements.

II. COMPETITIVE TRANSMISSION FRAMEWORK UNDER ORDER NO. 1000

In Order No. 1000, the Commission ordered public utility transmission providers to reform their existing transmission planning and cost allocation practices. The reforms included

the elimination of federal rights of first refusal ("ROFRs") for incumbent transmission owners and a requirement to adopt a framework for the submission and evaluation of regional transmission projects proposed by incumbent and nonincumbent transmission owners. Order No. 1000 at P 7. The Commission found that federal ROFRs discourage nonincumbent transmission owners from participating in the planning process because, among other reasons, projects they propose could be taken by the incumbents once the benefits are identified. *Id.* at PP 229, 257. The Commission stated that the framework for submitting and evaluating transmission projects could include a competitive solicitation process to solicit projects or project developers. *Id.* at P 259.

The Commission did not mandate a specific framework, but allowed regional flexibility in developing the processes. *Id.* at P 322. The Commission, however, provided guidance on features of the framework. For example, the Commission required the framework to include (1) appropriate qualification criteria for determining an entity's eligibility to propose a project; (2) a form by which a prospective sponsor would provide information in sufficient detail to allow the proposed project to be evaluated in the regional transmission planning process, including a specific date by which proposals must be submitted; and (3) a transparent and not unduly discriminatory process for evaluating the proposals. *Id.* at P 293.

With respect to the obligation for the framework to require a specific date by which proposals must be submitted, the Commission disagreed with arguments that this would undermine the "iterative nature" of the planning process and stated that "[w]ithout some reasonable limitation on the submission of new information, public utility transmission providers would never be able to complete the analysis needed to complete their region's transmission

plan." *Id.* at P 327. But the Commission allowed each region to propose rolling or flexible dates if it could support such a proposal. *Id.*

The Commission ruled that the Order No. 1000 revisions—including the framework for submitting and evaluating projects—would apply to new transmission facilities, which the Commission defined as "those transmission facilities that are subject to evaluation, *or reevaluation as the case may be*, within a public utility transmission provider's local or regional transmission planning process" after the effective date of the Order No. 1000 compliance filing. *Id.* at P 65 (emphasis added). The Commission recognized that transitional issues could arise regarding which projects are subject to Order No. 1000 and directed transmission providers to explain in their compliance filings how they will determine which projects are subject to the requirements of Order No. 1000. *Id.* The Commission required the Order No. 1000 compliance filings establishing the framework to be submitted within twelve months after the effective date of Order No. 1000. *Id.* at P 792.

III. PJM'S ORDER NO. 1000 COMPLIANCE FILINGS

On October 25, 2012, PJM submitted its Order No. 1000 compliance filing. *PJM Interconnection, L.L.C.*, Docket No. ER13-198-000, PJM Compliance Filing (Oct. 25, 2012) ("October 2012 Compliance Filing"). A key component of this filing was a solicitation process for new transmission facilities ("Solicitation Process") to comply with the Order No. 1000's directives regarding nonincumbent transmission providers. This process adopted a "sponsorship model" under which pre-qualified entities—both incumbents and nonincumbents—would propose transmission solutions during a "proposal window" and PJM would evaluate the proposals and select the project and the entity to construct the project. *Id.* at 13-14, 22-23. This competitive transmission process applied to three broad categories of new transmission facilities, including long- and short-term reliability projects and market efficiency projects. *Id.* at 54-59.

The Commission accepted PJM's proposal window process with an effective date of January 1, 2014. *See PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 (2013) ("March 2013 Compliance Order"), *order on reh'g*, 147 FERC ¶ 61,128 (2014).

The proposal window process was established primarily through the addition of Section 1.5.8 to Schedule 6 of the PJM OA. In a nutshell, under this process:

- Entities must first pre-qualify with PJM for the right to submit proposals under specific pre-qualification requirements, PJM OA, Schedule 6, § 1.5.8(a);

- PJM then posts a request for proposals that (1) identifies and explains the existing transmission limitations that need to be resolved; and (2) establishes the window of time in which pre-qualified entities are allowed to submit their proposals, *id.*, §§ 1.5.8(b) & (c);

- Any proposals submitted during the window must contain specified technical and other relevant information about the proposed project, including cost estimates, projected construction and in-service date, and the proposing entities' ability to construct the project, *id.*, § 1.5.8(c)(1)-(3);

- After the window closes, PJM staff must post a description of the proposals on the PJM website, *id.*, § 1.5.8(d);

- PJM staff must then evaluate the proposals submitted during the window in accordance with the criteria set forth in Sections 1.5.8(e) and (f) and, after consultation with PJM's Transmission Expansion and Advisory Committee ("TEAC"), present to the PJM Board its recommendation of the "more efficient or cost-effective transmission enhancements and expansions" to be included in the transmission expansion plan, *id.*;

- If PJM staff determines that none of the solutions would be the more efficient or cost-effective approach, PJM staff has two options: (1) repost a new request for proposals and start a new open window process; or (2) if there is insufficient time for a new proposal process, propose a specific project to resolve the problem and assign construction of the project to the incumbent transmission owner, *id.*, § 1.5.8(g); and

- Finally, the PJM Board must approve PJM's staff's recommendations based on the studies and analyses performed by PJM staff, *id.*, § 1.6(a).[2]

[2] PJM indicated that it would provide further details about its evaluation process in the PJM Manuals, *see PJM Interconnection, L.L.C.*, Docket No. ER13-198-000, Motion for Leave to Answer and Answer of PJM *(cont'd)*

PJM emphasized certain limitations on its role in the Solicitation Process when describing these tariff provisions. PJM emphasized that sponsors, not PJM, were responsible for crafting the solutions. PJM's role was to "evaluate and compare all proposals" and then "select the projects . . . for PJM Board review and approval," not create its own proposals. October 2012 Compliance Filing at 54-56; *see also id.* at 67-68. PJM stated that its "'sponsorship' proposal is designed to give both incumbent transmission owners and nonincumbent developers an opportunity to propose new and innovative projects. It is not designed, nor intended, to award bid-based contracts based on PJM-proposed solutions." *PJM Interconnection, L.L.C.*, Docket No. ER13-198-000, Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. at 9 (Sept. 5, 2013) ("September 2013 Answer"); *see also id.* at 13 ("PJM's sponsorship model is based on incumbent transmission owners and nonincumbent developers proposing a project based on identified violations. It is not intended to designate a PJM-proposed solution on a bid-based model.").

The one exception to PJM's limited role is triggered where no proposal is deemed the more efficient or cost-effective approach *and* there is no time for PJM to re-post the project. In that limited situation, PJM can fashion its own proposal and award it to the incumbent. PJM OA, Schedule 6, Section 1.5.8(g) sets forth the process as follows:

> If the Office of the Interconnection determines that none of the proposed Long-lead Projects received during the Long-lead Project proposal window would be the more efficient or cost-effective solution to resolve a posted violation, *or* system condition, the Office of the Interconnection may re-evaluate and re-post on the PJM website the unresolved violations, *or* system conditions pursuant to Section 1.5.8(b), provided such re-evaluation and re-posting would not affect the ability of the Office of the Interconnection to timely address the identified reliability need. In the event that re-posting and conducting such re-evaluation

Interconnection, L.L.C. at 54 (Jan. 29, 2013) ("January 2013 Answer"), but no significant details, pertinent to this Complaint, were added.

> would prevent the Office of the Interconnection from timely addressing the existing and projected limitations on the Transmission System that give rise to the need for an enhancement or expansion, the Office of the Interconnection shall propose a project to solve the posted violation, *or* system condition for inclusion in the recommended plan and shall present such project to the Transmission Expansion Advisory Committee for review and comment. The Transmission Owner(s) in the Zone(s) where the project is to be located shall be the Designated Entity(ies) for such project.

PJM OA, Schedule 6, § 1.5.8(g) (emphasis in original); *see also* January 2013 Answer at 57 ("PJM only will propose 'unsponsored' projects when required to *timely* meet reliability needs").

In addition to the limitations on PJM's role, PJM also proposed material limitations on the rights of bidders. One critical limitation is that bidders are prohibited from submitting "a new project proposal or modifications to a proposed project once the proposal window is closed." PJM OA, Schedule 6, § 1.5.8(c)(4). PJM stated that this limitation was designed to "prevent proposers from having a second bite at the apple after a proposal window has closed" because that "would provide an unfair advantage to those entities . . . and would chill PJM's ability to gather additional information that would enable it to make a better evaluation." January 2013 Answer at 55. PJM further underscored the importance of this limitation, stating: "This is the very reason why the *stakeholders were insistent* that proposers not be permitted to modify or change their proposal after the close of the proposal window." *Id.* (emphasis added). The Commission agreed with PJM and accepted this limitation. *See* March 2013 Compliance Order at P 297.

When submitting its amended compliance filing on July 22, 2013, PJM again stressed the importance of this limitation:

> Once the proposal window closes, no additional proposals or amendments to proposals by the proposer may be submitted or considered for inclusion in the recommended plan. Given the highly competitive nature of the proposal window process, if entities were permitted to submit proposals outside the proposal window, they potentially could have access to additional information, including proposals submitted during a proposal window, which would give them an undue

> advantage over entities that submitted timely proposals. Such a practice would be unfair to the entities that submitted proposals during the proposal windows and undermine the proposal process.

PJM Interconnection, L.L.C., Docket No. ER13-198-000, Second Compliance Filing Letter at 8-9 (July 22, 2013) ("July 2013 Compliance Filing") (footnote omitted).

IV. THE ARTIFICIAL ISLAND SOLICITATION

A. Operational Issues at Artificial Island

Artificial Island is a nuclear generation and transmission complex located in Salem County in southern New Jersey, along the Delaware River. Artificial Island has three nuclear generating units—Salem 1 and 2 and Hope Creek—with a total generating capacity of 3818 MW. It is the second largest nuclear generating complex in the United States. The two Salem units are owned jointly by subsidiaries of PSEG Power LLC and Exelon Corp., and the Hope Creek plant is owned by a subsidiary of PSEG Power LLC, specifically, PSEG Nuclear LLC. All three units are operated by PSEG Nuclear LLC. Although the nuclear generating facilities are owned by PSE&G and Exelon, they are located in the PJM transmission zone of Atlantic City Electric Company.

The three nuclear generating units at Artificial Island are connected to the PJM 500 kV transmission system through one 500 kV circuit to PECO's Peach Bottom substation in Pennsylvania and three 500 kV circuits to PSE&G's New Freedom substation in New Jersey, which continues from New Freedom through one 500 kV circuit to PSE&G's Dean substation. The first substation on the 500 kV circuit to Peach Bottom is the 500 kV Red Lion substation across the Delaware River, which is owned by Delmarva Power & Light Co. ("DPL"). The Red Lion substation connects to the PJM 230 kV system in Delaware, which includes DPL's Cedar Creek and Cartanza substations. A diagram depicting the Artificial Island complex and a map showing the location of Artificial Island are attached as Attachments 1 and 2.

PJM is experiencing operational performance challenges in the Artificial Island area. Artificial Island has historically been stability-constrained, and special operating procedures have been used to maintain stability in the area for the past several years. Also, scheduled or forced outages on the 500 kV transmission circuits at Artificial Island can require a significant reduction in the output of the generating units and potentially cause 500 kV voltage criteria to be violated. There are, however, no identified reliability violations to date. PJM's planning studies through 2022 do not show reliability violations associated with Artificial Island.

B. The Artificial Island Proposal Window

To mitigate these operational limitations, PJM selected Artificial Island as the first test of its Solicitation Process. PJM opened the proposal window for Artificial Island in April 2013, one month after the Commission accepted the Solicitation Process in its March 2013 Compliance Order. Although PJM's compliance tariff would not take effect until January 1, 2014, PJM stated that existing transmission projects would comply with these revisions "to the extent feasible and practicable" and identified Artificial Island as "a good opportunity to implement a proposal window consistent with the revisions proposed in its October 25 [Order No. 1000 Compliance] Filing." July 2013 Compliance Filing at 3-4; *see also* October 2012 Compliance Filing at 81-82 (stating that projects in the planning cycle when the Commission issues its order "will be evaluated under the new rules to the extent feasible."); Order No. 1000 at P 65 (requiring transmission providers to specify which projects would be subject to the new rules).

In anticipation of applying the Order No. 1000 processes to Artificial Island, in March 2013 PJM announced that it would use the window proposal competitive solicitation process proposed in its October 2012 Compliance Filing to identify projects to resolve the operational issues at Artificial Island. Attachment 3, TEAC 3/7/13, slide 52. Consistent with the Order No. 1000 process, pre-qualified bidders—both incumbents and nonincumbents—were informed

that they would be allowed to propose projects within a 60-day window, and PJM would evaluate those proposals for inclusion in its transmission expansion plan. *Id.* PJM later determined that the window for Artificial Island proposals would open on April 29, 2013 and close on June 28, 2013. Attachment 4, TEAC 4/11/13, slide 20.

On April 29, 2013, PJM posted a Problem Statement and Requirements Document for the Artificial Island Proposal Window ("Artificial Island RFP"). Attachment 5. The Artificial Island RFP stated that its purpose was to seek technical solutions to improve PJM's operational performance in the Artificial Island area under a range of anticipated system conditions. *Id.* at 1. The Artificial Island RFP identified the following five objectives for the Artificial Island Proposal Window:

1. Generate maximum power (3818 MW total) from all AI Units (Salem1: 1253MW, Salem-2: 1245MW, Hope Creek: 1320MW) without a minimum MVAr requirement from the AI. Full maximum power must be maintained under both the baseline and all N-1 outage conditions of 500kV transmission lines in the AI area. For both the baseline and N-1 outage conditions, AI voltage must be maintained within operating limits and stable for all NERC Category B and C contingencies. NERC Category C3 contingencies "N-1-1 contingencies" do not need to be run on top of the N-1 outage condition.
2. Maximum MW output from AI should not be affected by the simultaneous outage of Power System Stabilizers (PSS) of Artificial Island units Hope Creek and Salem-2. The Salem-1 PSS is assumed to be on for all scenarios.
3. Reduce operational complexity.
4. Improve Artificial Island stability.
5. Maintain PJM System Operating Limits (SOLs)

Id. at 2.

The Artificial Island RFP also required the following timeline for the Artificial Island Proposal Window:

- Monday, 4/29/2013, Opening of the Artificial Island Proposal Window.

- Friday, 6/28/2013, Close of the Artificial Island Proposal Window.
- All proposals and pre-qualification documentation due by 6/28.

Id. at 3. Consistent with PJM's filings in its Order No. 1000 compliance proceeding, the Artificial Island RFP informed bidders that "[a]ny proposals received after close of the proposal will not be accepted." *Id.* at 4.

In response to the Artificial Island RFP, twenty-six timely proposals were submitted by seven entities—VEPCo/Dominion Power, Transource, FirstEnergy, PHI/Exelon, Northeast Development/LS Power, Atlantic Wind, and PSE&G. The proposed projects mostly included new 500 kV or 230 kV transmission lines and improvements, but one entity (Dominion) proposed to add a new switching station including eight breakers, two Thyristor Controlled Series Compensation ("TCSC") devices, and a Static VAR Compensator ("SVC"). Dominion's TCSC/SVC proposal is referred to as the "Dominion 1A" project.[3] A slide describing each of the 26 proposals is attached hereto as Attachment 6.

C. PJM's Initial Evaluation of Artificial Island Proposals

After the proposal window closed, PJM posted on its website all of the proposals submitted during the open window, consistent with the process established in the October 2012 Compliance Filing. PJM staff, in consultation with PJM's TEAC, began reviewing and evaluating the proposals in accordance with the criteria stated in the Artificial Island RFP and Sections 1.5.8(e) and (f) of Schedule 6 of the PJM OA.

PJM staff then deviated from evaluating the projects and modified them instead. Attachment 7, TEAC 5/19/14, slides 40-42. Rather than rejecting proposals that did not satisfy

[3] PJM developed a taxonomy for referring to the proposals, in which the proposing party was designated by a number and its proposals were designated with letters. For example, Dominion's three proposals were labeled 1A, 1B, and 1C, and Transource's two proposals were labeled 2A and 2B.

the technical criteria, PJM staff modified them so they would pass the criteria. For example, PJM staff increased the capacity of the SVC in Dominion's 1A proposal from 500 MVAR to 750 MVAR because the 500 MVAR SVC failed to resolve the reliability problem. *Id.*, slides 44 & 45. Similarly, staff added the SVC component to the 500 kV and 230 kV transmission line proposals because the proposals—after being modified by PJM staff—failed to pass the criteria without an SVC. Attachment 7, TEAC 5/19/14, slides 65-66, 74-75, 83-84, 94-95, 103-04, 114-15, 123-24, 132-33, 142-43, 151-52, 160-61, 169-70; Attachment 8, TEAC 12/11/13, slide 56.

PJM staff made other major modifications as well. Staff also added an SVC to all of the transmission line proposals. Attachment 7, TEAC 5/19/14, slides 65-66, 74-75, 83-84, 94-95, 103-04, 114-15, 123-24, 132-33, 142-43, 151-52, 160-61, 169-70. PJM staff also modified most of the transmission line proposals to remove line segments that PJM staff did not consider necessary. *Id.* Staff made other less significant modifications to the proposals, *e.g.*, to add or remove breakers and to add dead-end structures. *Id.*

PJM staff presented its evaluation of the proposals at the May 19, 2014 TEAC meeting. PJM staff was candid about the fact that it had modified each of the proposals and specifically listed the modifications it made to each proposal. *Id.*, slides 40-42. PJM staff short-listed two general categories of proposals among the modified proposals, both of which involved transmission lines to increase Artificial Island's connections across the Delaware River to the Delmarva Peninsula: (1) the addition of a new 500 kV transmission line from Artificial Island to DPL's Red Lion substation, and (2) the addition of a new 230 kV transmission line from the Salem substation to DPL's 230 kV system in Delaware—sometimes called the "Southern Crossing" proposal. *Id.*, slides 181 & 197. Both of these short-listed proposals involved two options. The 500 kV line proposals included either (a) a line from the Hope Creek substation to

Red Lion or (b) a line from Salem to Red Lion. *Id.* Also, the Southern Crossing 230 kV lines included either an aerial or a submarine crossing of the Delaware River. *Id.* The 500 kV line proposals included Dominion's 1C proposal and PSE&G's 7K proposal (Hope Creek to Red Lion), as well as PHI/Exelon's 4A proposal, LS Power's 5B proposal, and Transource's 2C proposal (Salem to Red Lion). *Id.* The Southern Crossing 230 kV proposals included LS Power 5A, Transource 2B, and Transource 2A (submarine), as well as LS Power 5A and Dominion 1B (aerial). *Id.*

PJM staff did not short-list Dominion's 1A proposal to add TCSCs and an SVC at 500 kV substations in New Jersey. *Id.* PJM staff concluded that there were stability concerns and Nuclear Regulatory Commission ("NRC") concerns with this proposal. *Id.*, slide 45. PSEG Nuclear has argued that the proposal would increase (not reduce) operating complexity and would not eliminate the need for operating guides in the Artificial Island area—the primary objective of the Artificial Island RFP. Attachment 9, PSEG Nuclear Comments. Furthermore, as PSEG Nuclear stated, the proposal relies on an untested technology in the switchyard of the second largest nuclear generation complex in the United States. To PSE&G's knowledge, there are few, if any, SVCs with a capacity of 750 MVAR in use in the United States and the integrated TCSC/SVC solution proposed by Dominion has never been used anywhere else in the United States, making it a poor candidate to test at Artificial Island. *Id.*

After receiving feedback from the TEAC, PJM staff recommended PSE&G's 7K proposal, which (as modified) was a new 500 kV transmission line from Hope Creek to Red Lion and a 650MVAR SVC at New Freedom. Attachment 10, 6/16/14 TEAC, slides 30-36. PJM staff explained that it had short-listed four projects: Southern Crossing – submarine; Southern Crossing – overhead; Salem to Red Lion 500 kV; and Hope Creek to Red Lion 500 kV. *Id.* PJM

determined that the 500 kV line proposals were "more robust" than the 230 kV Southern Crossing proposals. *Id.*, slide 28. PJM also recommended the Hope Creek to Red Lion 500 kV line proposal over the Salem to Red Lion proposals. *Id.*, slide 30. PJM staff then recommended that PSE&G be designated the responsibility to construct the Hope Creek to Red Lion 500 kV line (except for upgrades to the Red Lion substation, which were assigned to PHI) and that PSE&G construct the new SVC at the New Freedom substation. *Id.*, slides 31-36.

PJM allowed interested parties to submit comments to the proposed recommendation and announced that the PJM staff's recommendation of the PSE&G project would be presented to the PJM Board at its July 22, 2014 meeting. *Id.*, slide 36.

D. Comments on Staff's Recommendation and the PJM Board's Response

Several parties submitted comments in response to PJM staff's recommendation. Two in particular are worth noting here.

First, PHI/Exelon focused its comments on the concern that PJM did not follow its Solicitation Process. Attachment 11, PHI/Exelon July 14, 2014 Letter. PHI/Exelon stated that PJM "did not follow the process that was laid out in their October 25, 2012 and July 22, 2013 Order No. 1000 Compliance filings" but instead resorted to "different processes" that "are not transparent to participants and could be problematic in the future if they are not corrected." *Id.* at 1. According to PHI/Exelon, rather than applying its Order No. 1000 "sponsorship" model, PJM instead "chose to modify all project submittals and, at the end of the day, selected the project closest to the one created by PJM." *Id.* at 1-2. Although PHI/Exelon commended PJM for "tr[ying] very hard to distinguish all short listed proposals," PHI/Exelon stated that "it is particularly difficult to distinguish amongst these plans [because they] were essentially all developed by PJM." *Id.* at 2.

Second, LS Power submitted comments that modified its own proposal and also criticized PJM staff's decision to recommend PSE&G's 500 kV proposal. Attachment 12, July 8, 2014 Letter. Although PJM staff expressly found that the 500 kV solution was "more robust," LS Power asserted that PJM staff had erred in concluding that the 500 kV line proposal and the Southern Crossing 230 kV proposal were equivalent in cost and further asserted that it could build its Southern Crossing proposal at a lower cost than PJM staff estimated. *Id.* LS Power then proposed to modify its Southern Crossing proposal by adopting a $171 million construction cost cap, despite the fact that the proposal window closed more than a year earlier. *Id.*

The PJM Board did not approve the staff's recommendation at its July 22, 2014 meeting, but rather reopened the process. Attachment 13, PJM's July 23, 2014 Letter. The Board explained that LS Power "has *modified* its proposal to place a fixed cap on the costs associated with the project" and stated that, although this cap should have been "presented to PJM in a more timely fashion," the Board invited the four "finalist" bidders—PSE&G, Transource, LS Power, and Dominion—to "supplement their proposals in light of LS Power's proposal." *Id.* at 1 (emphasis added). The Board did not mention the Dominion 1A proposal (which had not been short-listed), but stated that it would be "reaching out to the Nuclear Regulatory Commission to discuss technical issues associated with certain proposals impacting nuclear switchyards." *Id.* at 2. The Board also stated that "Order 1000, which guided our competitive bidding initiative on this project, has created entirely new processes which are especially challenging when evaluating transmission solicitations as complex as those required for the Artificial Island stability issues." *Id.*

Subsequently, on August 12, 2014, PJM sent a letter to the four "finalist bidders" inviting them to "supplement" their proposals "to submit final terms of project costs." Attachment 14,

PJM's August 12, 2014 Letter at 1-2. The letter also added the previously-rejected Dominion 1A proposal to the short list without explaining why it was being added. *Id.* The letter stated that, if the finalists wanted to supplement their (now five) proposals in terms of cost, they "must include sufficient detail for PJM to evaluate the details of its cost proposal, including the specific details surrounding any costs cap that a proposer wishes to submit." *Id.* at 2. PJM stated that the supplemental proposals were due on September 12, 2014. *Id.* PJM identified the following five projects as the finalists: (1) Dominion 1A (TCSC/SVC); (2) Dominion Project 1C (Hope Creek to Red Lion 500 kV line); (3) Transource 2B (Southern Crossing 230 kV – submarine); (4) LS Power 5A (Southern Crossing 230 kV – submarine); and (5) PSE&G 7K (Hope Creek to Red Lion 500 kV line). *Id.* at 1.

In addition, on August 29, 2014, PJM sent a letter to Chief Judge Wagner asking Judge Wagner to engage the Commission's Alternative Dispute Resolution ("ADR") process and appoint Judge Sterner to be present as a "neutral, non-decisional observer" at PJM's discussions with the four finalist bidders. Attachment 15, August 29, 2014 Letter at 1. The letter outlined the process that PJM intended to follow in discussions with the four finalists, Judge Sterner's expected role in that process, and guidelines for PJM governing the conduct of the discussions. Among other things, the letter asked Judge Sterner to provide a final report on the discussions and publish the report in Docket No. MD14-1. *Id.* at 3. Although the purpose of the ADR process was "to ensure fairness and due process," Judge Sterner was not asked to examine or ensure that PJM complied with the rules for its Order No. 1000 competitive solicitation processes.

E. Evaluation of the Supplemental Proposals and Further PJM Modifications

The four finalists resubmitted their five proposals on September 12, 2014. LS Power, Transource, and PSE&G all modified their proposals to add a cost cap, but Dominion declined to

add a cost cap to either of its two remaining proposals. Attachment 16, TEAC 12/9/14, slide 22. Commencing on October 22nd and lasting through November 3rd, four "fact-finding" sessions were convened at FERC before Administrative Law Judge Sterner. During these sessions, PJM probed each finalist regarding its re-submitted proposal. Judge Sterner observed these discussions and, on December 3, 2014, he published his report on the discussions as requested in PJM's August 29, 2014 letter to Chief Judge Wagner. *See Artificial Island Order 1000 Transmission Solicitation*, 149 FERC ¶ 63,017 (2014).

PJM staff then proceeded to conduct further evaluation of the finalist proposals, much of which focused on examining Dominion's previously-rejected 1A proposal. PJM conducted several studies and inquiries directed solely to this proposal, including discussions with the NRC, as well as an examination of the performance of the TCSC under several scenarios, the engagement of a consultant to study Sub Synchronous Resonance ("SSR"), and an examination of the flexible alternating current transmission system ("FACTS") used in Dominion's 1A proposal. Attachment 17, TEAC 10/9/14, slides 42-46; Attachment 16, 12/9/14, slides 8-12.

On December 9, 2014, the four finalist bidders made additional presentations regarding their supplemental proposals. At this meeting, PSE&G, along with PSEG Nuclear and Transource, presented their concerns regarding the Dominion 1A proposal**.**

The timeline for final PJM decision on the Artificial Island Transmission Solicitation has continued to slip. At the November TEAC meeting, PJM stated that it would make its recommendation on the finalist proposals in January 2015. Attachment 18, TEAC 11/11/14, slide 63. However, at the January TEAC meeting, PJM cancelled a January 21, 2015 meeting scheduled for PJM staff to submit its recommendation, and has not indicated when its staff will be in a position to make a recommendation. Attachment 19, TEAC 1/7/15, slide 102. Instead,

PJM is conducting multiple further evaluations. These evaluations include: (i) finalizing a relay clearing time study associated with Fiber Optic Ground wire ("FOG wire") installation for shorter clearing times, (ii) receiving and finalizing Sub Synchronous Resonance ("SSR") Study, and (iii) engaging a third party to review studies associated with the Dominion 1A proposal. *Id.*, slides 101-02.

In addition to these further evaluations, PJM may be contemplating further unilateral modifications to the proposals. It is PSE&G's understanding from statements made by PJM staff that it is considering taking two important features from PSE&G's 7K proposal—FOG wire installation and optimization of generator step up ("GSU") tap adjustments—and adding those features to the remaining proposals to make them more attractive. *See id.*, slides 101-02. PJM staff has indicated that adding these two features to the line proposals would eliminate the need for an SVC, which is a feature PJM itself proposed yet was criticized by several entities as undermining the central purpose of the solicitation (to increase operational flexibility). We are hopeful that our understanding is incorrect, but, if not, it represents another departure from the rules and a troubling example in which key aspects of one sponsor's proposal are appropriated and given to other sponsors.

ARGUMENT

I. PJM DID NOT COMPLY WITH ITS TARIFF SOLICITATION PROCESS

PJM did not follow its Solicitation Process in two fundamental respects. First, PJM unilaterally modified each proposal, rather than, as required, evaluating them and selecting the best proposal or, if none qualified as such, reposting the solicitation. Second, PJM allowed LS Power to modify its proposal more than one year after the proposal window closed and after PJM staff had recommended another proposal. Each violation is significant standing alone and, when taken together, created a process with no discernible standards.

A. PJM Exceeded Its Authority by Unilaterally Modifying All the Proposals

PJM's role is to "evaluate and compare all proposals" and then "select the projects . . . for PJM Board review and approval." October 2012 Compliance Filing at 54-56; *see also id.* at 67-68. PJM's role is not to modify those proposals as PJM deems appropriate. "PJM's 'sponsorship' proposal is designed to give both incumbent transmission owners and nonincumbent developers an opportunity to propose new and innovative projects. It is not designed, nor intended, to award bid-based contracts based on PJM-proposed solutions." September 2013 Answer at 9. PJM OA, Schedule 6, Section 1.5.8(d) says this quite clearly: "The Office of the Interconnection shall *review* all proposals submitted during a proposal window and determine and *present* to the Transmission Expansion Advisory Committee the proposals that merit further consideration for inclusion in the recommended plan" (emphasis added).

PJM did not do this. It unilaterally modified all the proposals. It added SVCs to all the transmission line projects. It changed the configuration of several projects by deleting major line segments. It considered proposals that did not satisfy its own criteria and, instead of rejecting them, changed them to remedy their deficiencies. This extra-tariff process continues to date and, as indicated, may include appropriating key elements of one sponsor's proposal and giving it to the other sponsors.

This is not the Solicitation Process that the Commission approved. PJM proposed one, and only one, exception to its "sponsorship model." If PJM determines that none of the proposals are "the more efficient or cost-effective solution to a posted violation or system condition," then PJM may repost the violation and open a new window or—if time does not allow for a new window—craft the optimal solution itself and designate the incumbent Transmission Owner to build it. *Id.*, § 1.5.8(g). But the tariff does not authorize PJM to change

the proposals that it is evaluating. "PJM only will propose 'unsponsored' projects when required to *timely* meet reliability needs." January 2013 Answer at 57 (emphasis added).

PJM has not explained why it believes it has the right to unilaterally modify all the proposals, but it is possible that PJM is relying on the following passage of Section 1.5.8(d): "Based on review and comment by the Transmission Expansion Advisory Committee, the Office of Interconnection may, if necessary conduct further study and evaluation. The Office of the Interconnection shall post on the PJM website and present to the Transmission Expansion Advisory Committee the revised enhancements and expansions for review and comment." PJM OA, Schedule 6, § 1.5.8(d). The word "revised" in this sentence does not, however, give PJM authority to do what it did here. It merely gives PJM the right to consider the views of the TEAC on "the proposals that merit further consideration," *id.*,—i.e., the short list initially proposed by PJM—and then revise that short list in response to the concerns of the TEAC. It does not give PJM authority to modify all of those proposals unilaterally. If it did, there would be no point in requiring PJM to "re-evaluate and re-post" the solicitation if none of the proposals were efficient and cost effective. *Id.*, § 1.5.8(g). PJM could just change them all, as it did here. As PHI/Exelon stated, PJM "chose to modify all project submittals and, at the end of the day, selected the project closest to the one created by PJM." Attachment 11, Exelon/PHI Letter at 2.

PJM represented to the Commission that the Solicitation Process "is sufficiently detailed from start to finish for stakeholders to understand why a particular transmission is selected or not selected in the RTEP for cost allocation purposes." October 2012 Compliance Filing at 71. It is "not a 'black box' selection process," PJM claimed. January 2013 Answer at 51. Those statements were true of the process accepted by the Commission, but not of the process that PJM actually implemented. The "different processes" actually used by PJM were "not transparent to

participants" and "did not follow the process that was laid out in [PJM's compliance filings]." Attachment 11, Exelon-PHI Letter at 1.

B. PJM Violated the Tariff by Allowing LS Power to Modify Its Bid

The Solicitation Process prohibits bidders from modifying their proposals after the proposal window closes. Although PJM can request additional information after the window closes, "[i]n response to the Office of the Information's request for additional reports or information, the proposing entity *(whether an existing Transmission Owner or Nonincumbent Developer)* may *not* submit a new project proposal or modifications to a proposed project once the proposal window is closed." PJM OA, Schedule 6, § 1.5.8(c)(4) (emphasis added). The Artificial Island RFP complied with this limitation, expressly informing all potential bidders that there was a 60-day window in which to submit proposals and that "[a]ny proposals received after close of the proposal *will not be accepted*." Attachment 5, Artificial Island RFP at 4 (emphasis added).

The reason for this restriction is, as explained by PJM, to protect the integrity of the competitive process:

> Given the highly competitive nature of the proposal window process, if entities were permitted to submit proposals outside the proposal window, they potentially could have access to additional information, including proposals submitted during a proposal window, which would give them an undue advantage over entities that submitted timely proposals. Such a practice would be unfair to the entities that submitted proposals during the proposal windows and undermine the proposal process.

July 2013 Compliance Filing at 9. It would also "adversely impact the planning process as well as reliability," "provide an unfair advantage to those entities" submitting untimely modifications, and "chill PJM's ability to gather additional information that would enable it to make a better evaluation." January 2013 Answer at 54-55. The Commission agreed with PJM and approved the limitation. *See* March 2013 Compliance Order at P 297; *see also Sw. Power Pool, Inc.*, 144

FERC ¶ 61,059 at P 294 (2013) ("Order No. 1000 does not require a public utility transmission provider to provide an opportunity to potential transmission developers to remedy deficiencies in project proposals" and "extending the cure period beyond the bidding window could significantly delay the Transmission Owner Selection Process."); *ISO New England Inc.*, 143 FERC ¶ 61,150 at PP 297, 307-12 (2013) (approving requirement that transmission proposals must be submitted by the deadline specified in the posting by the ISO).

LS Power's addition of a cost cap to its Southern Crossing 230 kV proposal—which LS Power made more than one year after the window closed—was a clear modification to LS Power's proposal. The PJM Board recognized this, stating that "LS Power *has modified its proposal* to place a fixed cap on the costs associated with the project." Attachment 13, July 23, 2013 Letter at 1 (emphasis added). The Board did not, however, explain why it permitted this modification. All bidders were aware that PJM would give "special emphasis" to cost caps offered by proposing entities. PJM so stated in its January 2013 Answer—two months before the Artificial Island window—in direct response to an LS Power protest. January 2013 Answer at 52 ("special emphasis" will be "given by PJM should a cost cap be voluntarily offered by the developer").

II. THE COMPETITIVE TRANSMISSION REGIME ESTABLISHED BY ORDER NO. 1000 WILL NOT SUCCEED IF THE REGIONS DO NOT FOLLOW THEIR RULES

The filed rate doctrine requires RTOs, like all public utilities, to follow the requirements of their own tariffs. *E.g.*, *City of Vernon*, 109 FERC ¶ 61,369 at P 27 (2004) ("[T]he CAISO is required to follow its tariff."). The Commission "expect[s] transmission providers . . . to know what is in a tariff and to follow its rates, terms and conditions." *Midwest Indep. Transmission Sys. Operator, Inc.*, 118 FERC ¶ 61,212 at P 90 (2007). The Commission "expect[s] [an RTO] to rely on the filed rate and to ensure that its Business Practice Manuals are consistent with the

[MISO Tariff]." *Id.*; *see also Shetek Wind Inc. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 138 FERC ¶ 61,250 at PP 48, 52 (2012) (explaining that, "[t]o the extent that MISO did not follow its interconnection study approach according to the Tariff, it violated those Tariff provisions" and finding "a clear violation of the Tariff"). The Commission has encouraged market participants to bring tariff violations to the Commission's attention. *See Preventing Undue Discrimination and Preference in Transmission Serv.*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 806 (2007) ("Once the tariff language is in place, transmission customers can, and should, bring to the Commission's attention any failure by the transmission provider to follow its tariff."). The Commission will fashion an appropriate remedy for any such tariff violations. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 118 FERC ¶ 61,212 at P 95 ("[F]aced with a public utility's violation of its own tariff, the Commission must examine the factual situation, balance the equities, and craft an appropriate remedy.").

The obligation of RTOs to follow their own tariff rules is particularly critical to the success of Order No. 1000's efforts to remove barriers to transmission development. A central goal of these reforms—remedying undue discrimination—cannot be achieved unless transmission development solicitation rules are clear and are followed by the transmission provider. *See* Order No. 1000 at P 162. The Commission has explained that "inadequate transparency requirements" can "increase[] the opportunities for undue discrimination . . . and make[] instances of undue discrimination more difficult to detect." Order No. 890, *Preventing Undue Discrimination and Preference in Transmission Serv.*, 118 FERC ¶ 61,119 at P 51 (2007).

In evaluating PJM's initial Order No. 1000 compliance filing, the Commission held that it was unacceptable that PJM's proposed tariff revisions did not specify what factors PJM would consider when selecting transmission projects. *See* March 2013 Compliance Order at P 312.

The Commission explained that "[t]his lack of specificity may permit PJM to use an unduly discriminatory evaluation process to select transmission projects in the regional transmission plan for purposes of cost allocation" and therefore required PJM to specify the factors it would consider. *Id.* The Commission has also recognized in other contexts that clear tariff rules prevent RTOs from unduly discriminating among market participants. *See Shetek Wind Inc.*, 138 FERC ¶ 61,250 at PP 30, 49, 102-03 (finding that MISO violated its tariff's rules governing interconnection requests and that "a lack of transparency and fairness" may have resulted in undue discrimination).

Ensuring that RTOs follow their own tariff rules is also essential to facilitating the construction of new infrastructure. The transmission planning and siting process has enough uncertainty and conflict without enduring challenges to solicitation outcomes because the rules are not followed. Transmission infrastructure cannot be financed and built on a timely basis with that uncertainty. That is why the Commission has insisted on clear tariff rules that "balance the goal of limiting opportunities for undue discrimination while fostering the development of . . . needed investment." *See id.* at P 101.

PSE&G is sympathetic to the fact that the Artificial Island solicitation was PJM's first major solicitation and that PJM may believe that, in retrospect, some of its existing tariff rules could be improved. But there is an established process for that: the changes should be discussed with stakeholders and, consistent with PJM's FPA section 205 filing rights, submitted to the Commission as proposed amendments to take effect *prospectively*. *See, e.g.*, *Tenaska Power Servs. Co. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,230 at P 53 (2004) ("[I]f Midwest ISO were to find that its methodology . . . is inadequate and needs to be changed, it should vet any changes through its stakeholder process and, if necessary, file proposed tariff

language with the Commission."); *accord Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,129 at P 5 (2004).

III. THE TIMING OF THE ARTIFICIAL ISLAND SOLICITATION DOES NOT EXCUSE PJM'S FAILURE TO FOLLOW ITS OWN RULES

PJM's Order No. 1000 compliance filing stated that "PJM *commits* herein that depending upon the stage of the planning cycle, PJM will implement whatever provisions proposed herein can be implemented without restarting a planning cycle" and that proposals received prior to the effective date of the new rules "will be evaluated under the new rules to the extent feasible." October 2012 Compliance Filing at 81-82 (emphasis added). PJM made this commitment before it solicited proposals to address the Artificial Island reliability problems. Then, in the July 2013 Compliance Filing, PJM reaffirmed this commitment: "as PJM indicated in the October 25 Filing, PJM is implementing the new proposal window process to the extent feasible and practicable under its current process." July 2013 Compliance Filing at 3. PJM then committed to apply the new process to Artificial Island. "PJM determined that [Artificial Island] offered a good opportunity to implement a proposal window consistent with the revisions proposed in [PJM's Order No. 1000 compliance filing]." *Id.* at 3-4; *see also PJM Interconnection, L.L.C.*, Docket No. ER15-639-000, FPA Section 205 Filing at 7 (Dec. 16, 2014) (explaining that the Artificial Island proposal window "utilized the study process proposed under Order No. 1000"). PJM described the Artificial Island solicitation as a "pilot" of the new proposal window rules. September 2013 Answer at 17.

The Commission accepted PJM's representations in approving PJM's transition proposal and PJM is therefore bound to them. *See, e.g.*, *Linden VFT, LLC v. N.Y. Indep. Sys. Operator, Inc.*, 141 FERC ¶ 61,008 at P 28 (2012) (evaluating whether New York ISO fulfilled its promise to provide a type of grandfathered treatment to certain generators and concluding that it had);

Cal. Indep. Sys. Operator Corp., 119 FERC ¶ 61,076 at P 149 (2007) (evaluating whether CAISO had honored a promise to address seams issues in a particular filing and concluding that it had); *Cal. Indep. Sys. Operator Corp*., 106 FERC ¶ 61,179 at P 167 (2004) ("[W]e direct the ISO to honor its commitment to post an updated, conformed tariff on its website within 30 days following the acceptance of its subsequent compliance filing in this proceeding."). PJM's commitment to follow the tariff process was particularly important here because there were no pre-existing tariff rules to follow regarding competitive transmission solicitations. An RTO is "not authorized to implement whatever policies or procedures that it chooses as long as they are not specifically prohibited." *Shetek Wind Inc.*, 138 FERC ¶ 61,250 at P 49.

In addition to these commitments, the formal tariff process was triggered when PJM reevaluated the proposals in 2014. Order No. 1000 held that its new rules would apply to new projects and pre-existing projects that were reevaluated after the effective date of the RTO's proposal. *See* Order No. 1000 at P 65 (holding that the new rules would apply to "those transmission facilities that are subject to evaluation, *or reevaluation* as the case may be, within a public utility transmission provider's local or regional transmission planning process" after the effective date of an RTO's compliance filing) (emphasis added). PJM's consideration of Artificial Island proposals extended well past the January 1, 2014 effective date of its Order No. 1000 compliance filing and, importantly, after January 1, 2014 PJM made numerous material modifications to the proposals it had received. PJM then reevaluated the proposals, as modified. This reevaluation continues today.

IV. RELIEF REQUESTED

The Commission should grant the Complaint and direct PJM to follow its rules in the Artificial Island solicitation and all future solicitations. If PJM believes that none of the proposals submitted in 2013 represents the more efficient or cost-effective solution, PJM can re-

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post the Artificial Island solicitation and provide any additional guidance to prospective sponsors that PJM deems appropriate based on the experience it has gained over the last two years. PSE&G understands that granting this relief will delay the process somewhat, but the process has already languished for nearly two years, there is no other tariff-based remedy for the violations that have occurred, and the remedy is nondiscriminatory because it does not favor one bidder over another.

ADDITIONAL INFORMATION REQUIRED BY COMMISSION REGULATIONS

I. CORRESPONDENCE AND COMMUNICATIONS

PSE&G requests that all communications and correspondence with respect to the Complaint be directed to the following individuals and that these individuals be included on the Commission's official service list for this proceeding.

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II. OTHER PROCEEDINGS

The issues presented in this proceeding are not pending in any other forum in which PSE&G is a party.

III. DOCUMENTS AND OTHER THINGS SUPPORTING THE COMPLAINT

In accordance with Rule 206(b)(8) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.206(b)(8), all documents supporting the facts in the Complaint are attached to the Complaint.

IV. NEGOTIATIONS AMONG THE PARTIES

In accordance with Rule 206(b)(9) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.206(b)(9), PSE&G states that it has not initiated any formal dispute resolution procedures prior to filing the complaint. However, PSE&G participated in the proceedings before Administrative Law Judge Sterner in Docket No. MD14-1-000 and PSE&G recently informed PJM of its intent to file this Complaint. PSE&G does not believe that alternative dispute resolution would be effective at resolving the dispute in this proceeding.

V. FINANCIAL IMPACT

PSE&G is unable to quantify the aggregate dollar impact of PJM's violations because the primary harm from the violations is to the Solicitation Process and the resulting impact on transmission investment. PSE&G may also suffer financial harm if its proposal is not ultimately selected due to tariff violations committed when PJM reopened the process to consider proposal modifications after its staff had already recommended that the Board adopt PSE&G's proposal; however, this financial harm cannot be precisely quantified at this time.

VI. SERVICE AND FORM OF NOTICE

In accordance with Rule 206(c) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.206(c), PSE&G is simultaneously serving a copy of this filing on PJM Interconnection, L.L.C.:

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A Form of Notice suitable for publication in the *Federal Register* in accordance with 18 C.F.R. § 385.206(b)(10) is attached hereto.

CONCLUSION

PSE&G respectfully requests that the Commission grant the Complaint and direct PJM to follow its rules in the Artificial Island solicitation and all future solicitations.

Respectfully submitted,

/s/

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Counsel for Public Service Electric and Gas Company

Dated: January 29, 2015

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing Complaint on the persons listed below via email and overnight delivery:

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Counsel for PJM Interconnection, L.L.C.

Dated in Washington, D.C., this twenty-ninth day of January, 2015.

/s/
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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Public Service Electric and Gas Company	)	
	)	
v.	)	Docket No. EL15-___-000
	)	
PJM Interconnection, L.L.C.	)	
	)	

NOTICE OF COMPLAINT
(January __, 2015)

Take notice that on January __, 2015, Public Service Electric and Gas Company ("PSE&G") filed a formal complaint against PJM Interconnection, L.L.C. ("PJM") pursuant to section 206 of the Federal Power Act, 16 U.S.C. § 824e, and Rule 206 of the Commission's Rules of Practice and Procedure, 18 U.S.C. § 385.206, alleging that PJM has violated its rules governing competitive transmission solicitations.

PSE&G certifies that copies of the complaint were served on PJM and on the contacts for PJM, as listed on the Commission's list of Corporate Officials.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible online at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the website that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).

Kimberly D. Bose
Secretary

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Table of Attachments

No.	Description
1	Diagram depicting the Artificial Island complex (excerpt from 6/16/14 TEAC Presentation)
2	Map showing the location of Artificial Island (excerpt from 10/8/13 PJM Presentation)
3	TEAC 3/7/13 Presentation (excerpt)
4	TEAC 4/11/13 Presentation (excerpt)
5	PJM RTEP – Artificial Island Area Proposal Window Problem Statement & Requirements Document, PJM Interconnection Presentation (Original: 4/29/13; Version 14.0: 5/16/13)
6	Slides describing each of the 26 timely proposals submitted in response to the Artificial Island RFP (excerpt from 6/16/14 TEAC Presentation)
7	TEAC 5/19/14 Presentation
8	TEAC 12/11/13 Presentation (excerpt)
9	PSEG Nuclear Comments to PJM re: Artificial Island Open Window (12/8/14)
10	6/16/14 TEAC Presentation (excerpt)
11	PHI/Exelon Letter to PJM re: PJM Process for Evaluating Competitive Artificial Island Proposals (7/14/14)
12	Northeast Transmission Development Letter to PJM re: PJM Artificial Island Project Selection (7/8/14)
13	PJM Letter to TEAC Members (7/23/14)
14	PJM Letter re: Artificial Island Supplemental Proposal Request (8/12/14)
15	PJM Letter to FERC re: Artificial Island Solicitation Appointment of Facilitator, Docket No. MD14-1 (8/29/14)
16	TEAC 12/9/14 Presentation
17	TEAC 10/9/14 Presentation (excerpt)
18	TEAC 11/11/14 Presentation (excerpt)
19	TEAC 1/7/15 Presentation (excerpt)

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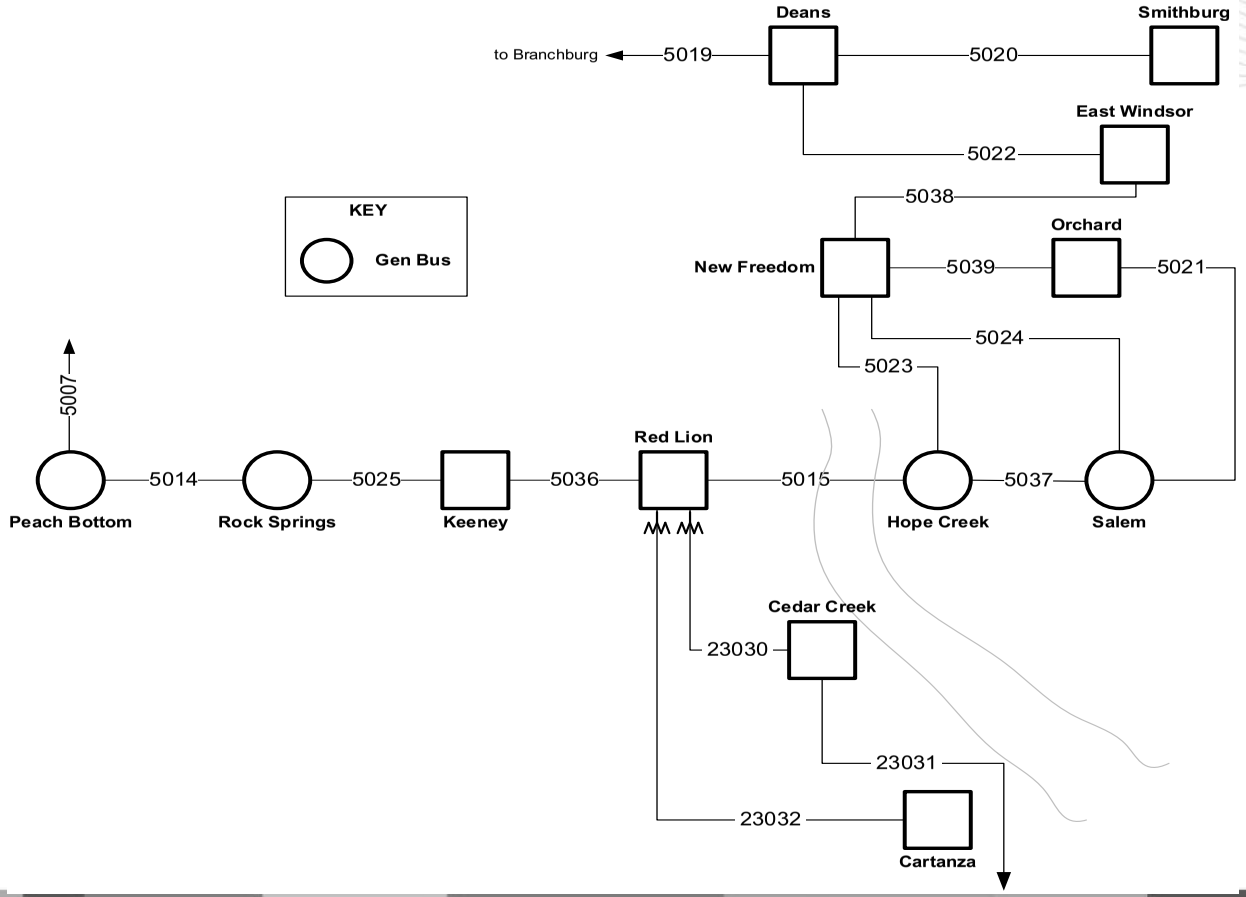
Attachment 1

Artificial Island Area Network



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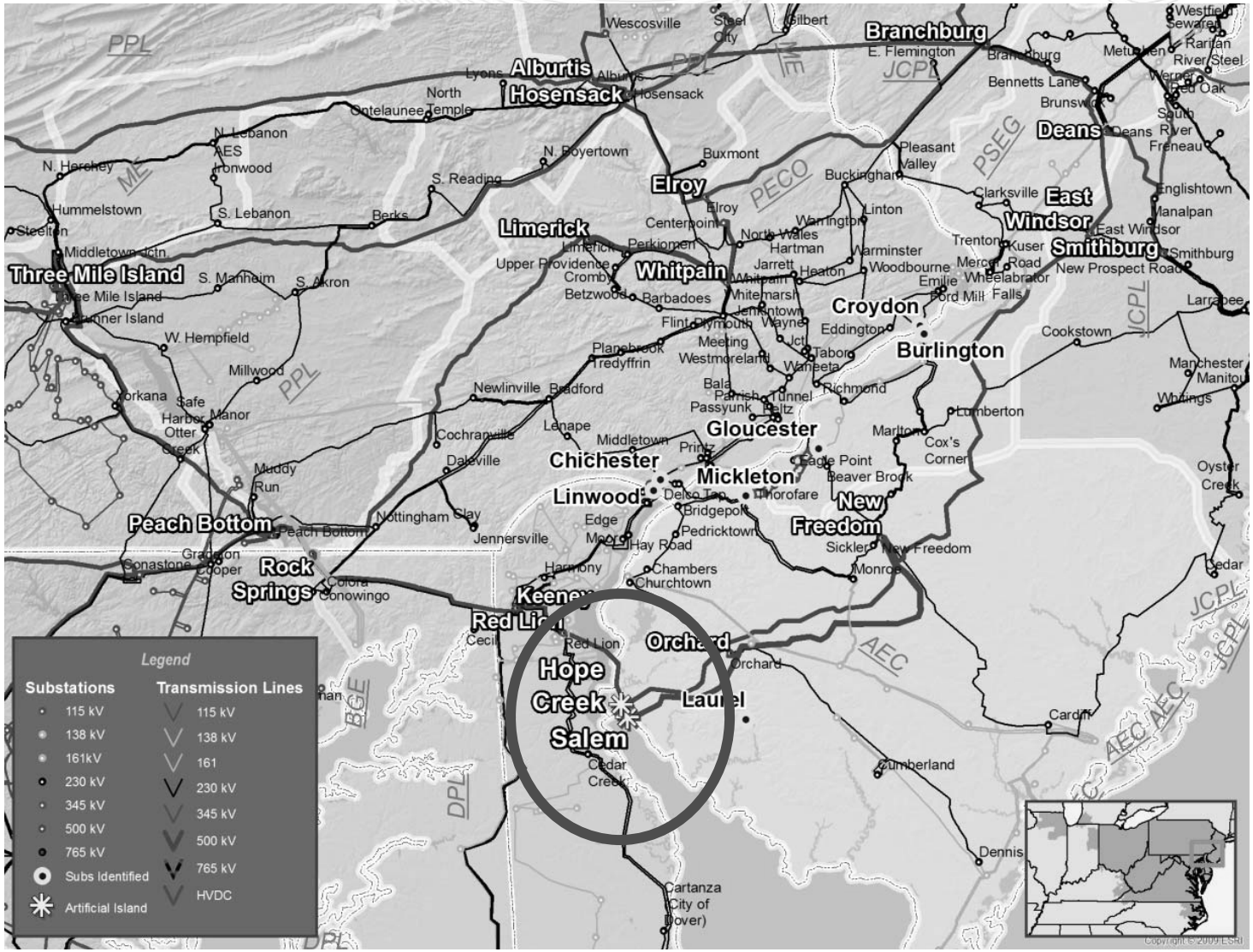
Attachment 2

Artificial Island



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Attachment 3

Transmission Expansion Advisory Committee

March 7, 2013

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intervening pages intentionally omitted

Artificial Island

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Artificial Island Stability Background

Max generation power output for stable operation is expressed as:

$$P_{max} = (V_t \times E_i) / X_d$$

- V_t is system voltage
  - More is theoretically better, but has operational limits
- E_i is internal machine voltage
- X_d is system impedance
  - Smaller is better

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Artificial Island Stability

- Stability Requirements
  - Artificial Island Operating Guide (AIOG)
  - Minimum MVAR output requirements from Hope Creek, Salem 1&2

- Reliability Issues
  - High voltage

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Artificial Island Proposal Window

- Goals
  1. System Performance
     - Outage conditions - improve system performance and AI stability margin under N-1 (forced or unforced)
     - Normal conditions - Improve system performance and stability margin under normal system conditions
  2. AIOG
     - Eliminate the AIOG

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Pre-Qualification & Timeline

- See Today's Planning Committee Presentations
  - Pre-Qualification Submittal
  - CEII & NDA Requirements
  - Possible window timeline

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Artificial Island Proposal Requirements

- Sponsoring entity information
  - Company name, contact information etc.
- Project Description
  - Include scope, interconnection points, configurtion (e.g. overhead, underground, AC/DC etc>), ROW, high level project schedule including CPCN, engineering, construction start, and in-service date
  - Project cost estimate

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Artificial Island Proposal Requirements

- Technical Report
  - Include assumptions and calculations demonstrating the efficacy of the project
    - Report should include information about the origin of power flow case and any modifications, station single line drawings and results of any sensitivity studies
    - Modeling information such as conductor type, calculated impedances, contingency files, *.idev files and dynamic files

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Artificial Island Case Development

- PJM coordinating development and benchmark of critical system condition cases to the current case
  - Cases will be available in PSS/E v32.1.1 (*.sav format)
  - Power flow case and dynamics data file
  - Other environment files (.snp, .dll and .rsp)

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Artificial Island Proposal Window Timeline

Announcement

Today (3/7/2013)

- Announce window and potential timeline
- Request CEII/NDA submittals from anticipated participants
- Request Designated Entity Pre-Qualification

→

Case Development

Estimated 3/8/2013 through 4/5/2013

- Develop and benchmark critical system condition cases

→

Open Window

(60 Day Duration)

- Open the "Artificial Island" RTEP Proposal Window
- Analytical files available

↓

Coordinate with Window Participants and Receive Solution Proposals

- Coordination VIA www.pjm.com
- Data, Information
- Questions & Answers

→

Close Proposal Window (Estimated 6/7/2013)

→

PJM Evaluates Solution Proposals

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Next Steps

- Update Artificial Island Proposal window progress
- Finalize 2013 RTEP base case development (2018)
- Finalize 2013 RTEP scenario scope
- Recommend solution package for High Voltage in PJM Operations

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Questions?

Email: RTEP@pjm.com

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Attachment 4

Transmission Expansion Advisory Committee

April 11, 2013

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SI-SSA-0010-0054

intervening pages intentionally omitted

Artificial Island RTEP Proposal Window

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Artificial Island Window – Information Communication

- Communication
  - PJM.com
    - http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000.aspx
  - Currently all communication through email to RTEP@pjm.com
  - Upon the opening of the Artificial Island window, an email will be sent to the PC and TEAC email distribution lists and also posted to PJM.com
  - PJM will distribute information to the registered Artificial Island RTEP Window participants VIA email or posting to the secure PJM.com page with an email notification to go retrieve the information

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Artificial Island Window – Security

- Security
  - All CEII will be encrypted using PGP encryption
  - CEII will be distributed using a self extracting (*.exe) encrypted file
    - From a user perspective, this is similar to the familiar self extracting ZIP file, but the user will be asked for a security code.
      - E.g. PJM posts the files to the secure Artificial Island window section of PJM.com. Users download “Artificial Island Information (CEII).exe” to their local environment
      - Once downloaded, the user will be prompted for a security code
    - Security codes, per PJM Policy, are required to be distributed through a contextless email message.
      - E.g. PJM distributes the security code that will be used to access the CEII by the Artificial Island Window participants in the “Artificial Island Information (CEII).exe” file.

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Artificial Island Proposal Window Timeline
Updated for 4/11/2013 TEAC

Announcement
(Presented at 3/7/2013 TEAC)
- Announce window and potential timeline
- Request CEII/NDA submittals from anticipated participants
- Request Designated Entity Pre-Qualification

→

PSS/E v32 Case Development
(Initial case complete, pending benchmarking)
- Initial PSS/E v32 case created
- Benchmarking in Progress
- Develop and benchmark critical system condition cases

→

Open Window
(Anticipated 4/29/2013
60 Day Duration)
- Open the "Artificial Island" RTEP Proposal Window
- Complete problem statement available
- Analytical files available

↓

Coordinate with Window Participants and Receive Solution Proposals
- Coordination VIA www.pjm.com
- Data, Information
- Questions & Answers

→

Close Proposal Window (Estimated 6/28/2013)
- Dependant on timing of window opening

→

PJM Evaluates Solution Proposals

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Critical Path to Window Opening

- PSS/E v32 Model development
- Model benchmarking
- Problem Statement Parameters

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Artificial Island Submittal Requirement Preview

- Problem statement status: Under development
  - To be released on PJM.com with Artificial Island CEII

- Anticipated Parameters
  - System voltage limits
  - Stability
  - Minimize / eliminate the Artificial Island Operating Guide

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Artificial Island Submittal Requirement Preview

- Technical Report
  - Include assumptions and calculations demonstrating the efficacy of the project
    - Report should include information about the origin of power flow case and any modifications, station single line drawings and results of any sensitivity studies
    - Modeling information such as conductor type, calculated impedances, contingency files, *.idev files and dynamic files

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Artificial Island Submittal Requirement Preview

- Proposal shall include:
  - Modeling information, including solved power flow models and description of solution
  - Documentation of performance
    - Voltage, Angle
    - Need for additional operating guide
  - Estimated schedule
  - Estimated cost

PJM©2013

Artificial Island Submittal Requirement Preview

- Sponsoring entity information
  - Company name, contact information etc.
- Project Description
  - Include scope, interconnection points, configurtion (e.g. overhead, underground, AC/DC etc>), ROW, high level project schedule including CPCN, engineering, construction start, and in-service date
  - Project cost estimate

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Pre-Qualification & Timeline

- See Today's Planning Committee Presentations
  - Pre-Qualification Submittal
  - CEII & NDA Requirements
  - Window timeline

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Artificial Island Case Development

- PJM coordinating development and benchmark of critical system condition cases to the current case
  - Cases will be available in PSS/E v32.1.1 (*.sav format)
  - Power flow case and dynamics data file
  - Other environment files (.snp, .dll and .rsp)

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Next Steps

- Complete Artificial Island RTEP Windows models and open window
- Finalize 2013 RTEP scenario scope
- Recommend solution package for High Voltage in PJM Operations

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remaining pages intentionally omitted

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Attachment 5

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PJM RTEP – Artificial Island Area Proposal Window
Problem Statement & Requirements Document

PJM Interconnection

Original Document: April 29, 2013

Version 14.0

Revised: May 16, 2013

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Email: RTEP@pjm.com with any questions or clarifications and include a reference to Artificial Island Window

REQUEST FOR PROPOSAL - Improve Artificial Island Area System Performance

I. Purpose of Proposal

PJM seeks technical solution alternatives (hereinafter referred to as "Proposals") to improve PJM Operational Performance in the Artificial Island area under a range of anticipated system conditions and to eliminate potential planning criteria (PJM, NERC, RFC, and Local Transmission Owner criteria) violations in the Artificial Island area.

II. Terminology

Artificial Island Area = "AI"
The system consisting of the transmission and generation facilities as depicted in Figure 1- Artificial Island 500 kV network. The Artificial Island includes the Salem #1, Salem #2, and Hope Creek #1 nuclear generation facilities

System Operating Limit = "SOL"
A System Operating Limit (SOL) is defined as:
The value (such as MW, MVAr, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within applicable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Thermal Ratings (Applicable pre- and post-Contingency equipment or facility ratings)
- Transient Stability Ratings or Limits (Applicable pre- and post-Contingency Stability Limits)
- Voltage Stability Ratings or Limits (Applicable pre- and post-Contingency Voltage Stability)
- System Voltage Ratings or Limits (Applicable pre- and post-Contingency Voltage Limits)

Critical Contingency:
The most limiting (i.e. the "worst") contingency.

III. Scope of Work

Objectives

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1. Generate maximum power (3818 MW total) from all AI Units (Salem1: 1253MW, Salem-2: 1245MW, Hope Creek: 1320MW) without a minimum MVAr requirement from the AI. Full maximum power must be maintained under both the baseline and all N-1 outage conditions of 500kV transmission lines in the AI area. For both the baseline and N-1 outage conditions, AI voltage must be maintained within operating limits and stable for all NERC Category B and C contingencies. NERC Category C3 contingencies "N-1-1 contingencies" do not need to be run on top of the N-1 outage condition.
2. Maximum MW output from AI should not be affected by the simultaneous outage of Power System Stabilizers (PSS) of Artificial Island units Hope Creek and Salem-2. The Salem-1 PSS is assumed to be on for all scenarios.
3. Reduce operational complexity.
4. Improve Artificial Island stability.
5. Maintain PJM System Operating Limits (SOLs)

What PJM Provides:

The following data and related information is required for this project and is expected to be available from PJM:

Modeling Data:

The following data is provided:

1. **Base power flow case.** This case has all lines in service with AI units at maximum real power output. This case has been developed based on the NERC MMWG 2011 Series 2017 Summer Light Load case in PSS/E version 32 (separate file).
2. **Dynamic Case.** This case has been developed based on the NERC SSDWG 2011 Series 2017 Summer Light Load case in PSS/E version 32 (separate files)
3. **Short Circuit Case.** This case has a 2017 short circuit model in PSS/E version 32 and ASPEN *.olr format. (separate file)
4. **Contingency list** to ensure stability in Table 2 – Fault List.
5. **Fault clearing times** for buses at/near the Artificial Island are provided in Tables 3 and 4. Examples of fault clearing time calculation using Tables 3 and 4 are also provided for contingency creation.
6. **Machine Capability Curves** ("D Curves") of the AI Units in Figures 2~4 for reactive power capability at the target MW output.
7. **Description of Salem unit 1 user-defined exciter model (USAC6AU).**

Other Supporting Data:

1. One-line diagram of Artificial Island Area in Fig. 1.
2. Applicable stability criteria (system performance criteria).

3. AI case description (separate file: "Artificial Island Dynamics Case.docx")

Response back to PJM (Deliverables)

1. Description of the proposed solution.
2. Detailed analysis report on proposed solutions, including:
    a) Response plots (e.g. Machine angles over time)
    b) Breaker one-line diagrams to illustrate system topology
    c) Spreadsheets (e.g. Table of system voltages)
    d) High level estimate of:
        i. Time to construct the proposed solutions
        ii. Cost estimates with a description of assumptions (e.g. base cost, risk and contingency (R&C) costs, and total cost)
        iii. Availability of right of ways
3. Equipment parameters and assumptions
    a) All parameters (Ratings, impedances, mileage, etc.)
    b) For reactive devices, settings and outputs
    c) For synchronous machines, MW and MVAR output assumptions
4. Complete set of power flow and dynamic cases containing proposed solutions. If possible, also provide a PSS/E IDEV file so that the modeling of the proposal may be easily applied to other models. This may be difficult for non PSS/E users, please contact PJM with any questions. Provide any other necessary data including critical contingency files to reproduce the proposed solutions. All cases and data files for dynamic simulations should be in PSS/E ver. 32 format.
5. Any other supporting documentation required for the proposal performance validation by PJM.
6. Submission of Deliverables
    a) Preferred - VIA electronic mail to RTEP@pjm.com
    b) Alternate - VIA FedEx to Nancy Muhl, PJM Interconnection, 955 Jefferson Avenue, Norristown, PA 19403

Timeline

Monday, 4/29/2013, Opening of Artificial Island RTEP Proposal window
Friday, 6/28/2013, Close of Artificial Island RTEP Proposal window

- All proposals and pre-qualification documentation due by 6/28

Action	Target Date
PJM distributes RFP to Artificial Island RTEP proposal window participants	4/29/2013
RFP recipients submit questions to PJM	4/29/2013 – 6/28/2013

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PJM distributes answers to questions to all recipients*	4/29/2013 – 6/28/2013
Recipients submit proposals to PJM**	On or before 6/28/2013
Recipients submit pre-qualification packages to PJM**	On or before 6/28/2013

*PJM will maintain confidentiality of individual proposals for the duration of the window, but will distribute general information to the Artificial Island RTEP proposal window participants

**Any proposals received after close of the proposal will not be accepted.

Stability Performance Criteria

PJM Manual 14B, Attachment G.
http://www.pjm.com/~/media/documents/manuals/m14b.ashx

(a) *Steady state voltage*: pre-fault voltages at selected 500 kV buses should be within operating range in Table 1. This pre-fault voltage must be noted for the following buses:

Table 1 – Steady State Voltage Limits

Bus Name	Bus Voltage	Bus # Identifier	Steady state pre-fault Voltage
Branchburg	500 kV	200002	1.0 – 1.1 p.u.
Deans	500 kV	200006	1.0 – 1.1 p.u.
Keeney	500 kV	200010	1.0 – 1.1 p.u.
New Freedom	500 kV	200012	1.0 – 1.1 p.u.
Peach Bottom	500 kV	200013	1.0 – 1.1 p.u.
Salem	500 kV	200014	1.0 – 1.1 p.u.
Red Lion	500 kV	200027	1.0 – 1.1 p.u.
East Windsor	500 kV	200028	1.0 – 1.1 p.u.
Hope Creek	500 kV	200029	1.0 – 1.1 p.u.
Orchard	500 kV	200063	1.0 – 1.1 p.u.

1. Post-fault steady state voltage shall not be below 0.986 pu at the Salem and Hope Creek 500kV buses.
2. The voltage drop magnitude from pre-trip to post-trip conditions for any of the Artificial Island Units shall not exceed:
    a) 2% - Salem Unit 1 and Unit 2
    b) 2.5% - Hope Creek
3. The operating voltage range of AI generator terminal (25kV bus) is from 0.95 pu to 1.05 pu.

(b) *Transient stability*: PJM's transient stability criteria are applied:

1. Monitored Facilities:
    a) All machines in Artificial Island and neighboring areas. Area numbers in the power flow case to monitor include areas 225, 227, 228, 229, 230, 231, 232, 234, 235, 201 (please refer to the area information embedded in the power flow case to map the area numbers to area names).
    b) PJM 500kV bus voltages (500kV bus voltages in area 225) and Deans, New Freedom, Red Lion and Keeney 230kV bus voltages.
2. Monitored Data Channels
    a) Rotor angles of all machines in the monitored areas. Real and reactive power output, EFD (generator field voltage), speed and terminal voltage of machines in area 225 (PJM) must be monitored in the simulation.
    b) PJM 500kV bus voltages (500kV bus voltages in area 225) and Deans, New Freedom, Red Lion and Keeney 230kV bus voltages are also monitored.
    c) Monitored facilities and data channel information for the given cases are stored in the snap shot file (.snp) in dynamics case. If proposed solutions include new dynamic devices and/or topology, proper data channels need to be included in the snap shot file to monitor stability.
3. Fault List
    a) See “Fault List” section below.
4. Overall test procedure:
    a) A minimum of fifteen (15) seconds time domain simulation shall be conducted for each contingency.
    b) The system must be stable for all faults considered.
    c) Rotor angles should be represented in relative quantities with respect to a reference machine’s rotor angle. In the dynamics case, a reference machine shall be set to Sea Brook unit 1 (bus 105568)
    d) If the system performance simulation is stable but the maximum angle swing of any unit (relative to the reference generator) exceeds 120 degrees, a safety margin test is performed.
    e) Safety margin test procedure: Delay fault clearance by a half cycle and re-run the simulation. The case is not considered secure if the system is unstable for the delayed fault clearance.
    f) Post-fault transient voltages at AI 500 kV buses shall not be below 0.7 pu after fault clearing.

(c) *Damping*:

1. Monitored Facilities:
    a) Same facilities to those in transient stability.
2. Monitored Data Channels:
    a) Rotor angles.
3. Fault List
    a) See “Fault List” section below.
4. Overall test procedure

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a) Fifteen (15) seconds time domain simulation shall be conducted for each contingency.
b) Damping ratio of rotor angle is calculated for the period of 10~15 seconds using a modal analysis tool (e.g. PSSPLT modal analysis tool).
c) Damping ratio shall be above 3% and remains above 3% until the end of the simulation.
d) If nonlinearity is significant for the period of 10 to 15 seconds, it is necessary to extend the time domain simulation to longer time to capture system linear characteristics.

Fault List

All of the following faults, at a minimum, must be simulated whenever "Fault List" is referenced in the procedure above. If proposed solutions require modification of existing contingencies and/or creation of new contingencies due to topology changes, the modified and/or new contingencies should be added in the fault list with proper fault IDs.

Table 2 - Fault List

Fault ID	Fault Description
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

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[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

*SLG: Single-Line-to-Ground
**SB: Stuck Breaker

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Artificial Island One-line Diagram

Figure 1 - Artificial Island Area 500 kV Network

Fault Clearing Times

All fault clearing times are in cycles.

Table 3 - Fault Clearing Times

Station	Faulted Line /Transformer	Fault Clearing Times (cycles)			
		Three phase or SLG fault on Line/Transformer with Normal Clearing	Delayed Clearing Due to Stuck Breaker		Three phase or SLG fault on Bus with Normal Clearing
			Local Station Clearing	Remote Station Clearing	
Hope Creek	5037	[redacted]			
	5015, 5023				
Salem*	5024, 5021				
Orchard	5039, 230kV Transformer				
Red Lion	5015, 230kV Transformer				
East Windsor	5022				
	5038				
New Freedom	5038				

*Note: for a fault on 5037 near Salem (e.g., contingency IDs 5a and 5b), please use the information for Hope Creek station related to 5037.

Table 4 – Transfer Trip Delay

Line	From	To	Transfer Trip Delay (cycles)*
5037	Hope Creek	Salem	[redacted]
5015	Hope Creek	Red Lion	
5023	Hope Creek	New Freedom	
5024	Salem	New Freedom	
5021	Salem	Orchard	
5039	Orchard	New Freedom	
5015	Red Lion	Hope Creek	
5038	New Freedom	East Windsor	

5022	East Windsor	Deans	[redacted]

*Note: it is assumed that the transfer trip delay is the same at both ends of the line unless both cases are specified in the table.

Examples of fault clearing time calculation using Tables 3 and 4 for contingency creation

Three Phase Bus Fault

Suppose a bus fault occurs at Salem bus [redacted] with no outages. The fault will clear in [redacted] cycles by opening breakers [redacted]

Line Fault and Transfer Trip

Suppose a line fault occurs on 5024 near Salem. The fault will clear at Salem by opening breakers [redacted] and [redacted] in [redacted] cycles. The transfer trip delay for 5024 is [redacted] cycles. Therefore, the fault at New Freedom will clear in [redacted] cycles [redacted]).

Line Fault with Breaker Failure

Suppose a line fault occurs on 5024 near Salem. Breaker [redacted] opens in [redacted] cycles but [redacted] fails to open. To clear the fault, breakers [redacted] and [redacted] will open after [redacted] cycles. At New Freedom, the fault clears in [redacted] cycles.

Line Fault with Breaker Failure involving remote station clearing

Suppose a line fault occurs on 5038 near New Freedom. Breaker [redacted] and [redacted] at New Freedom open in [redacted] cycles and breaker [redacted] at East Windsor opens in [redacted] cycles but breaker [redacted] at East Windsor fails to open. To clear the fault, breakers [redacted] will open after [redacted] cycles. At Deans, the fault clears in [redacted] cycles.

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Generator Capability Curves

SALEM 1:

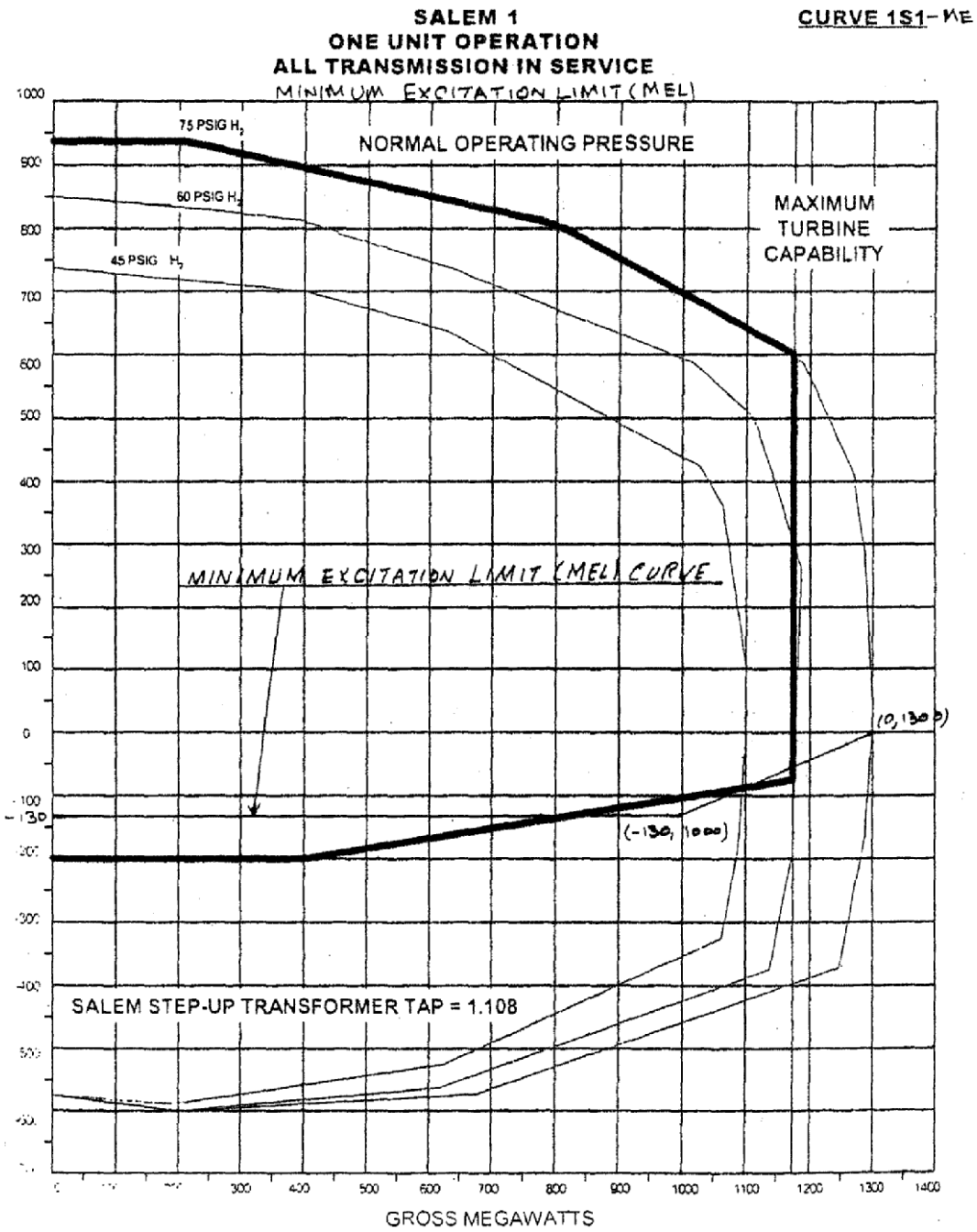

Figure 2 – Salem unit 1 capability curve

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SALEM 2:

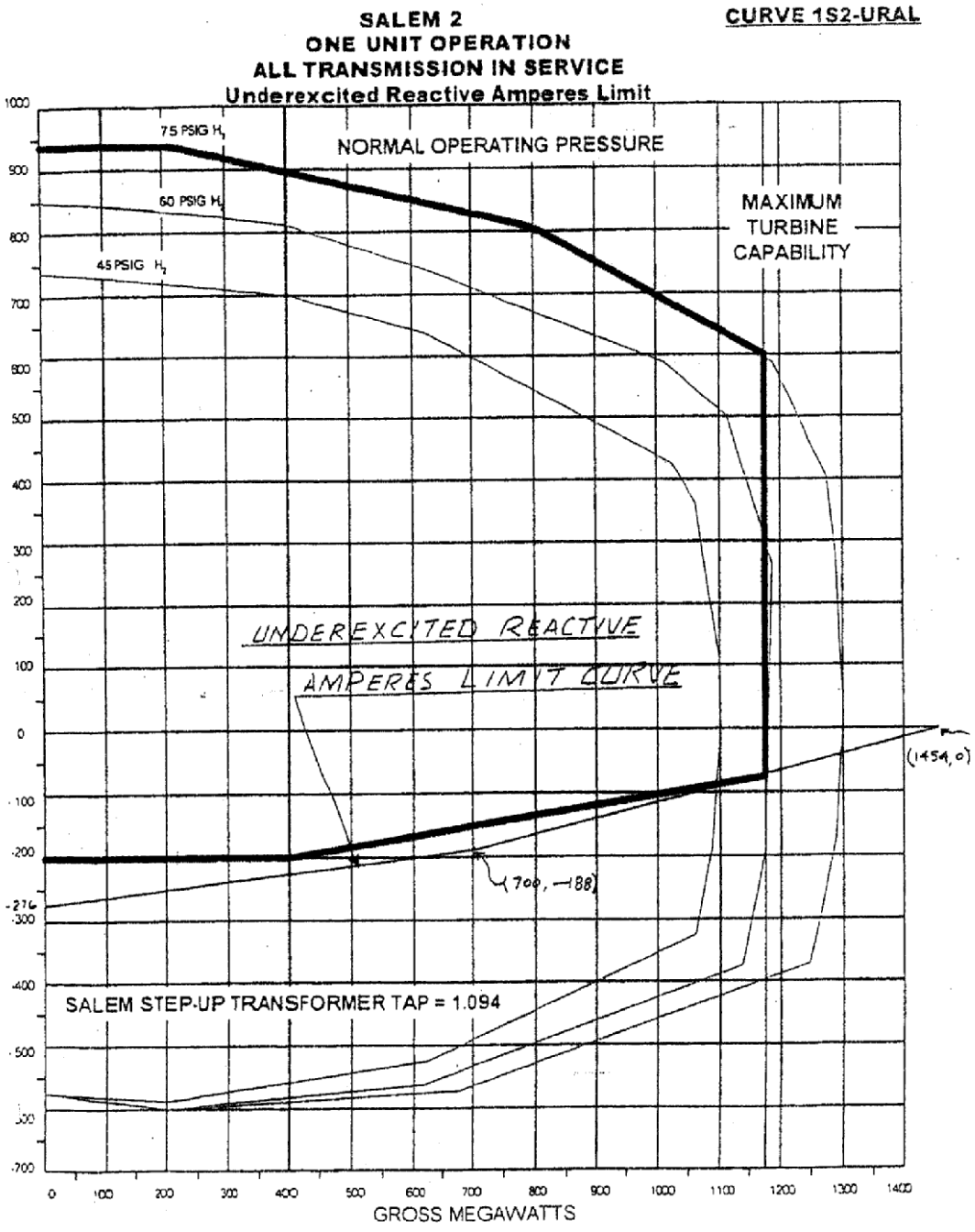

Figure 3 – Salem unit 2 capability curve

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HOPE CREEK:

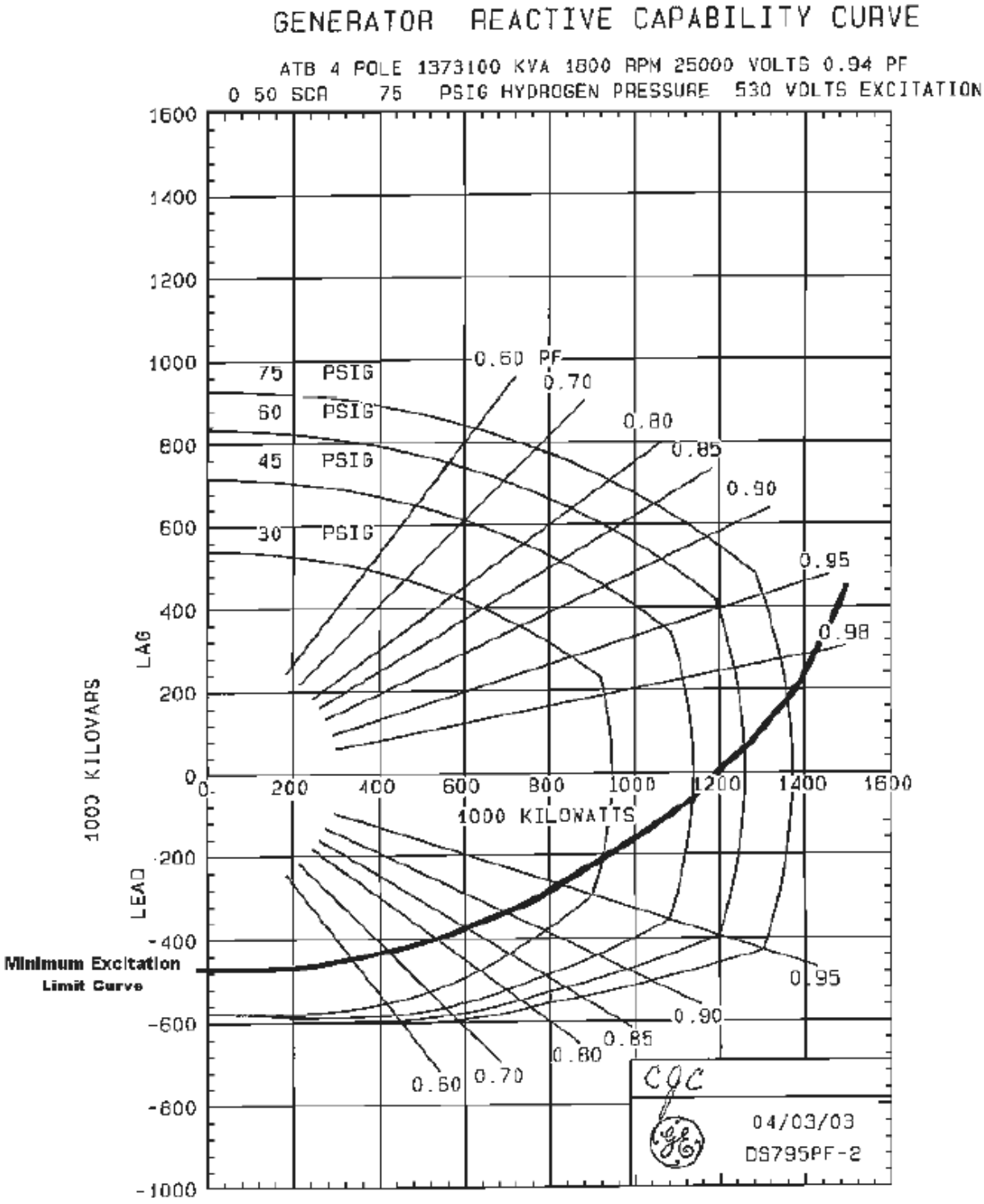

Figure 4 – Hope Creek unit capability curve

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Salem unit 1 User-defined Exciter Model (USAC6AU – Modified ESAC6A)

The user-written model USAC6A is a modified version of the PSSE standard model ESAC6A. The difference between the USAC6A and ESAC6A is in the way the non-windup limit is applied on the lead-lag block (STATE(K+2)). In the USAC6A model, the implementation of the non-wind up limit on STATE(K+2) is consistent with the recommendation as given in the IEEE 421.5 2005 standard.

Table 5 – USAC6AU model parameter description

CONs	#	Value	Description

Data format in the dyr file:
IBUS, 'USRMDL', ID, 'USAC6AU', 4, 0, 0, 23, 5, 0, CON(J) to CON(J+22) /

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Table 6 – USAC6AU model dynamic states description

STATEs	#	Value	Description
[redacted]			

Figure 5 – Block Diagram of USAC6AU exciter model

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Document Revision History

April 29, 2013
Original File Posted

April 30, 2013
Table 2 – Fault List updated
Table 3 – Fault Clearing Times updated
Table 4 – Transfer Trip Delay updated
Figure 1- Updated Deans bus number in the Figure from 20006 to 200006

May 3, 2013
Added a short circuit model in Aspen *.olr format
Added a Description of Salem unit 1 user-defined exciter model (USAC6AU), which includes a new Table 5 and Table 6
Described the operating voltage range of AI generator terminal (25kV bus) - from 0.95 pu to 1.05 pu

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Attachment 6

Project ID	TO	Cost ($)	Major Components	Supporting info
P2013_1-1A	Virginia Electric and Power Com	$ 133	500 MVAR SVC near New Freedom	Two (2) Thyristor Controlled Series Compensation (TCSC) Devices near New Freedom
P2013_1-1B	Virginia Electric and Power Com	$ 126	New 500 kV from Salem - a new station in Delaware	New 500/230 kV station in Delaware that taps existing Cedar Creek - Red Lion 230kV and Catanza - Red Lion 230kV
P2013_1-1C	Virginia Electric and Power Com	$ 202	New 500 kV from Hope Creek - a new Station in Delaware	Install a new 500kV line from Hope Creek - Red Lion; New Salem - Hope Creek 500 kV line
P2013_1-2A	Transource	$213 - $269	Salem - Cedar Creek 230 kV	Two (2) 500/230 Transformers near Salem; Loop in Red Lion - Cartanza 230 to Cedar Creek
P2013_1-2B	Transource	$165 - $208	Salem - North Cedar Creek (new) 230 kV	Two (2) 500/230 transformers near Salem and loop in Red Lion - Cartanza 230 and Red Lion - Cedar Creek 230 kV
P2013_1-2C	Transource	$123 - $156	Salem - Red Lion 500 kV	
P2013_1-2D	Transource	$788 - $994	New Freedom - Lumberton - North Smithburg (New) 500 kV line	New Salem - Hope Creek 500 kV line and new 500/230 station east of Lumberton
P2013_1-3A	First Energy	$410.7 (Only FirstEnergy portion)	New Freedom-Smithburg 500 kV line with a loop into Larrabee	Hope Creek - Red Lion 500 kV line
P2013_1-4A	PHI Exelon	$ 475	Peach Bottom - Keeney - Red Lion - Salem 500 kV	Remove Keeney - Red Lion 230 kV; Reconfigure 230 around Hay Road; Reconductor Harmony-Chapel St 138 kV
P2013_1-5A	LS Power	$116.3M - $148.3M	Salem - Silver Run (new) 230 kV; Salem 500/230 kV Transformer	New 230 kV station that taps existing Cedar Creek - Red Lion 230kV and Catanza - Red Lion 230kV
P2013_1-5B	LS Power	$ 170	Salem - Red Lion 500 kV	
P2013_1-6A	Atlantic Wind	$ 1,012	320 kV HVDC Salem/Hope Creek - Cardiff	SVC at Salem/Hope Creek; New HVDC Stations at Cardiff and Salem
P2013_1-7A	PSE&G	$ 1,371	Salem-Hope Creek to Peach Bottom 500 kV	Existing ROW
P2013_1-7B	PSE&G	$ 1,372	Salem-Hope Creek to Peach Bottom 500 kV	Same as 7A with Loop into Keeney
P2013_1-7C	PSE&G	$ 1,372	Salem-Hope Creek to Peach Bottom 500 kV	Same at 7A with Loop into Red Lion
P2013_1-7D	PSE&G	$ 831	Salem-Hope Creek to Peach Bottom 500 kV	Same as 7A with New ROW
P2013_1-7E	PSE&G	$ 692	New Freedom - Deans 500 & Salem - Hope Creek 500 kV lines	
P2013_1-7F	PSE&G	$ 879	New Freedom - Smithburg and Salem-Hope Creek 500 kV lines	Existing ROW
P2013_1-7G	PSE&G	$ 1,034	New Freedom - Smithburg and Salem-Hope Creek 500 kV lines	Same as 7F with a Loop into a new Larrabee 500 kV station
P2013_1-7H	PSE&G	$ 1,177	New Freedom - Whitpain and Salem - Hope Creek 500 kV lines	Northern Route
P2013_1-7I	PSE&G	$ 1,353	New Freedom - Whitpain and Salem - Hope Creek 500 kV lines	Same as 7H with the Southern Route
P2013_1-7J	PSE&G	$ 915	New Freedom - New Station on Branchburg-Elroy 500 kV line ("5017 Junction") and Salem - Hope Creek 500 kV line	Existing ROW
P2013_1-7K	PSE&G	$ 1,066	New Freedom - Deans & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7E with Hope Creek - Red Lion
P2013_1-7L	PSE&G	$ 1,250	New Freedom - Smithburg & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7F with Hope Creek - Red Lion
P2013_1-7M	PSE&G	$ 1,548	New Freedom - Whitpain (North) & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7H with Hope Creek - Red Lion
P2013_1-7N	PSE&G	$ 1,289	New Freedom - a new Station on the Branchburg-Elroy 500 kV line ("5017 Junction") & Salem-Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	

SLSSA-0010-0089

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Attachment 7

Artificial Island Proposal Window

PJM Special TEAC

Artificial Island Review

05/19/2014

Version 2

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Artificial Island Problem Statement Summary

- Generate maximum power from the AI under both the baseline (N-0) and maintenance (N-1) assumptions

- Satisfy applicable planning criteria

  – http://pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/redacted-artificial-island-problem-statement.ashx

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Artificial Island Proposal Window Timeline

Announcement

- Announce window and potential timeline
- Request CEII/NDA submittals from anticipated participants
- Request Designated Entity Pre-Qualification

PSS/E v32 Case Development

Initial PSS/E v32 case created

- Benchmarking in Progress
- Develop and benchmark critical system condition cases

Window Opened

(4/29/2013 - 60 Day Duration)

- Open the "Artificial Island" RTEP Proposal Window
- Complete problem statement available
- Analytical files available

Coordinate with Window Participants and Receive Solution Proposals

- Coordination VIA www.pjm.com
- Data, Information
- Questions & Answers

Proposal Window Closed on 6/28/2013

PJM Evaluates Solution Proposals

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Past Timeline

- 9/13/2012 – PJM discusses the Artificial Island with PJM Stakeholders
- March 2013 - TEAC Previewed conceptual timeline and next steps for an Artificial Island Proposal Window
- 4/29/2013 – Artificial Island Proposal Window Opened
- 6/28/2013 – Artificial Island Proposal Window Closed
- July 2013 through April 2014 – PJM discusses the details of project performance, cost and constructability

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Proposals Overview

- 26 Proposals received from 7 individual entities
- **Cost Estimates:** Approximate range of $100 M to $1.5 B
- **Technology:** Static Var Compensator (SVC), Thyristor Controlled Series Compensation (TCSC), High Voltage Direct Current (HVDC) transmission line, (AC) transformers, (AC) overhead transmission line, underground/underwater cable transmission line, circuit breakers and associated protection equipment
- **Voltages:** 230 and 500kV
- **Station Connections:** Broad diversity of proposed methods to connect to existing stations or construct new stations as needed
- **Routing:** Wide variety of proposed methods to route new transmission over/under existing rights of way (ROW) or through new ROW

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Artificial Island Project Proposal Overviews

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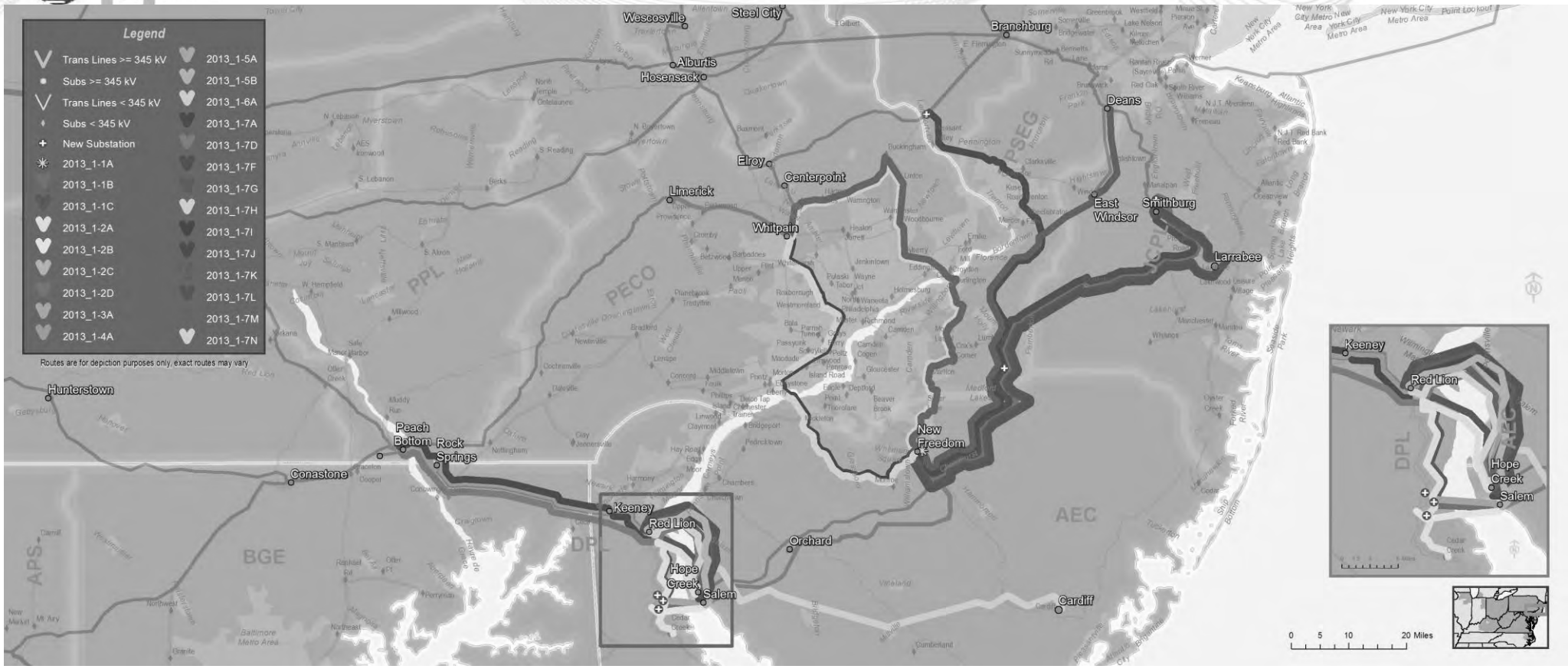
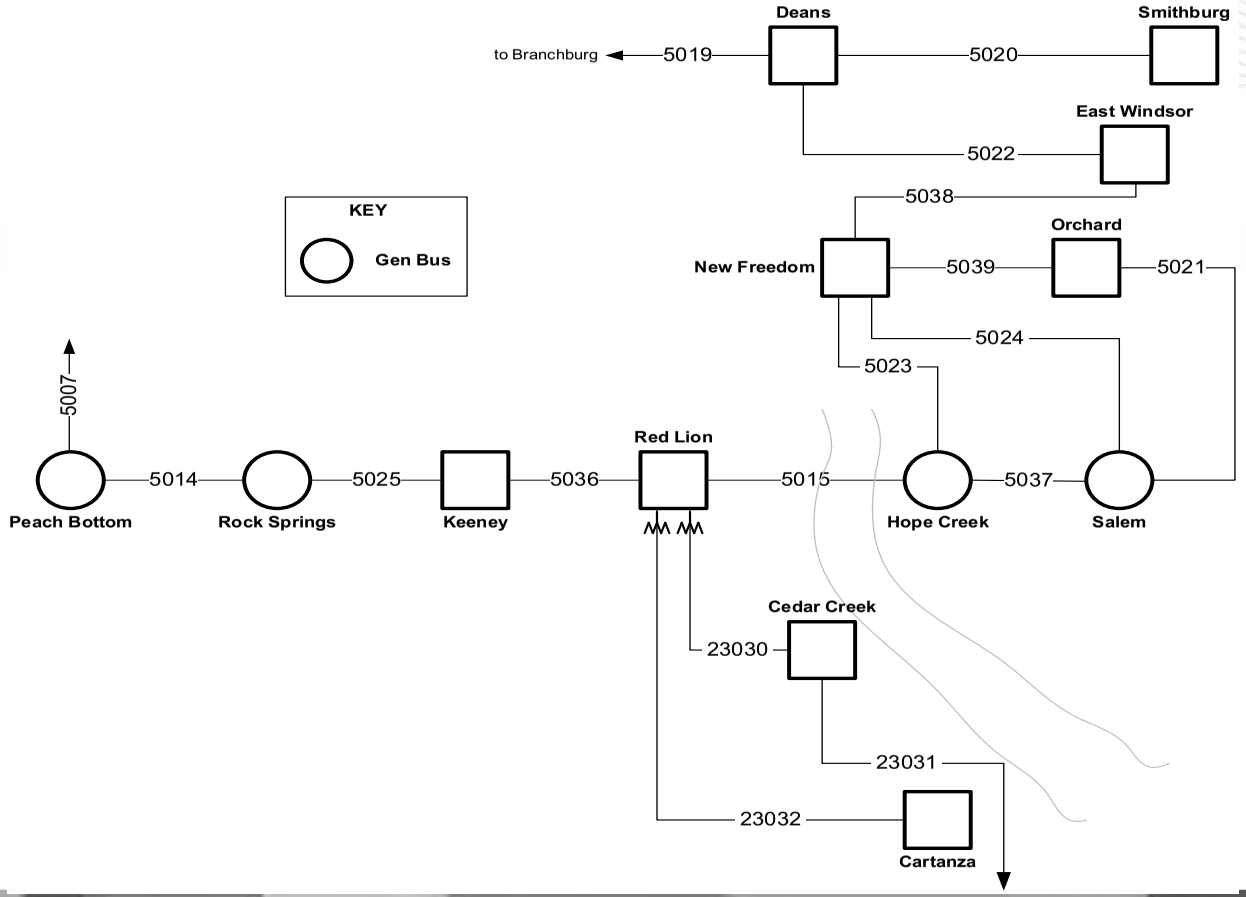
Project ID	TO	Cost ($)	Major Components	Supporting info
P2013_1-1A	Virginia Electric and Power Com	$ 133	500 MVAR SVC near New Freedom	Two (2) Thyristor Controlled Series Compensation (TCSC) Devices near New Freedom
P2013_1-1B	Virginia Electric and Power Com	$ 126	New 500 kV from Salem - a new station in Delaware	New 500/230 kV station in Delaware that taps existing Cedar Creek - Red Lion 230kV and Catanza - Red Lion 230kV
P2013_1-1C	Virginia Electric and Power Com	$ 202	New 500 kV from Hope Creek - a new Station in Delaware	Install a new 500kV line from Hope Creek - Red Lion; New Salem - Hope Creek 500 kV line
P2013_1-2A	Transource	$213 - $269	Salem - Cedar Creek 230 kV	Two (2) 500/230 Transformers near Salem; Loop in Red Lion - Cartanza 230 to Cedar Creek
P2013_1-2B	Transource	$165 - $208	Salem - North Cedar Creek (new) 230 kV	Two (2) 500/230 transformers near Salem and loop in Red Lion - Cartanza 230 and Red Lion - Cedar Creek 230 kV
P2013_1-2C	Transource	$123 - $156	Salem - Red Lion 500 kV	
P2013_1-2D	Transource	$788 - $994	New Freedom - Lumberton - North Smithburg (New) 500 kV line	New Salem - Hope Creek 500 kV line and new 500/230 station east of Lumberton
P2013_1-3A	First Energy	$410.7 (Only FirstEnergy portion)	New Freedom-Smithburg 500 kV line with a loop into Larrabee	Hope Creek - Red Lion 500 kV line
P2013_1-4A	PHI Exelon	$ 475	Peach Bottom - Keeney - Red Lion - Salem 500 kV	Remove Keeney - Red Lion 230 kV; Reconfigure 230 around Hay Road; Reconductor Harmony-Chapel St 138 kV
P2013_1-5A	LS Power	$116.3M - $148.3M	Salem - Silver Run (new) 230 kV; Salem 500/230 kV Transformer	New 230 kV station that taps existing Cedar Creek - Red Lion 230kV and Catanza - Red Lion 230kV
P2013_1-5B	LS Power	$ 170	Salem - Red Lion 500 kV	
P2013_1-6A	Atlantic Wind	$ 1,012	320 kV HVDC Salem/Hope Creek - Cardiff	SVC at Salem/Hope Creek; New HVDC Stations at Cardiff and Salem
P2013_1-7A	PSE&G	$ 1,371	Salem-Hope Creek to Peach Bottom 500 kV	Existing ROW
P2013_1-7B	PSE&G	$ 1,372	Salem-Hope Creek to Peach Bottom 500 kV	Same as 7A with Loop into Keeney
P2013_1-7C	PSE&G	$ 1,372	Salem-Hope Creek to Peach Bottom 500 kV	Same at 7A with Loop into Red Lion
P2013_1-7D	PSE&G	$ 831	Salem-Hope Creek to Peach Bottom 500 kV	Same as 7A with New ROW
P2013_1-7E	PSE&G	$ 692	New Freedom - Deans 500 & Salem - Hope Creek 500 kV lines	
P2013_1-7F	PSE&G	$ 879	New Freedom - Smithburg and Salem-Hope Creek 500 kV lines	Existing ROW
P2013_1-7G	PSE&G	$ 1,034	New Freedom - Smithburg and Salem-Hope Creek 500 kV lines	Same as 7F with a Loop into a new Larrabee 500 kV station
P2013_1-7H	PSE&G	$ 1,177	New Freedom - Whitpain and Salem - Hope Creek 500 kV lines	Northern Route
P2013_1-7I	PSE&G	$ 1,353	New Freedom - Whitpain and Salem - Hope Creek 500 kV lines	Same as 7H with the Southern Route
P2013_1-7J	PSE&G	$ 915	New Freedom - New Station on Branchburg-Elroy 500 kV line ("5017 Junction") and Salem - Hope Creek 500 kV line	Existing ROW
P2013_1-7K	PSE&G	$ 1,066	New Freedom - Deans & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7E with Hope Creek - Red Lion
P2013_1-7L	PSE&G	$ 1,250	New Freedom - Smithburg & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7F with Hope Creek - Red Lion
P2013_1-7M	PSE&G	$ 1,548	New Freedom - Whitpain (North) & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7H with Hope Creek - Red Lion
P2013_1-7N	PSE&G	$ 1,289	New Freedom - a new Station on the Branchburg-Elroy 500 kV line ("5017 Junction") & Salem-Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	

Artificial Island Proposals



Artificial Island Area Network



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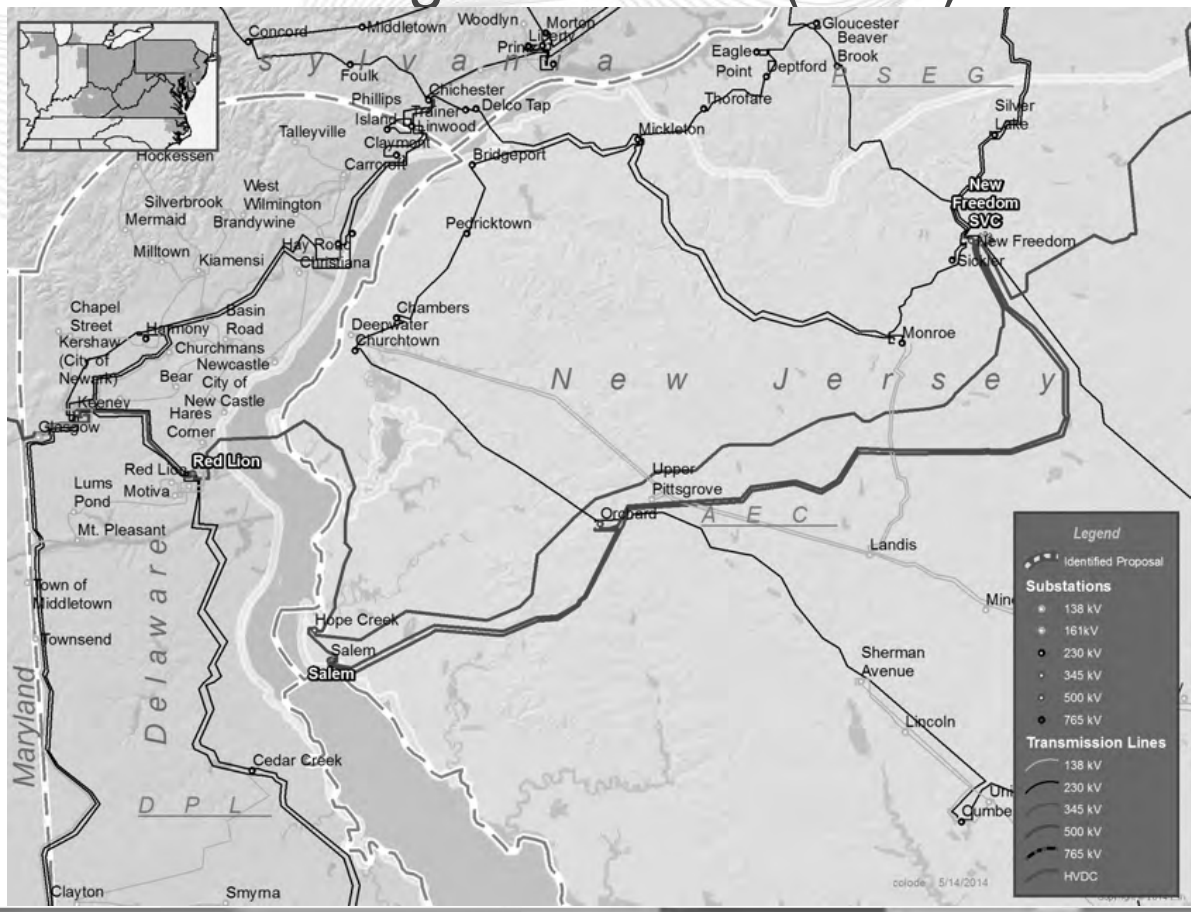
Dominion Virginia Power (DVP) 1A

- New switching station cutting the 5023 and 5024 lines near New Freedom substation that includes
  - a 500kV SVC (+500 to -300 MVAr)
  - Two Thyristor Controlled Series Compensation (TCSC) devices
- Proposed Cost Estimate: $130MM



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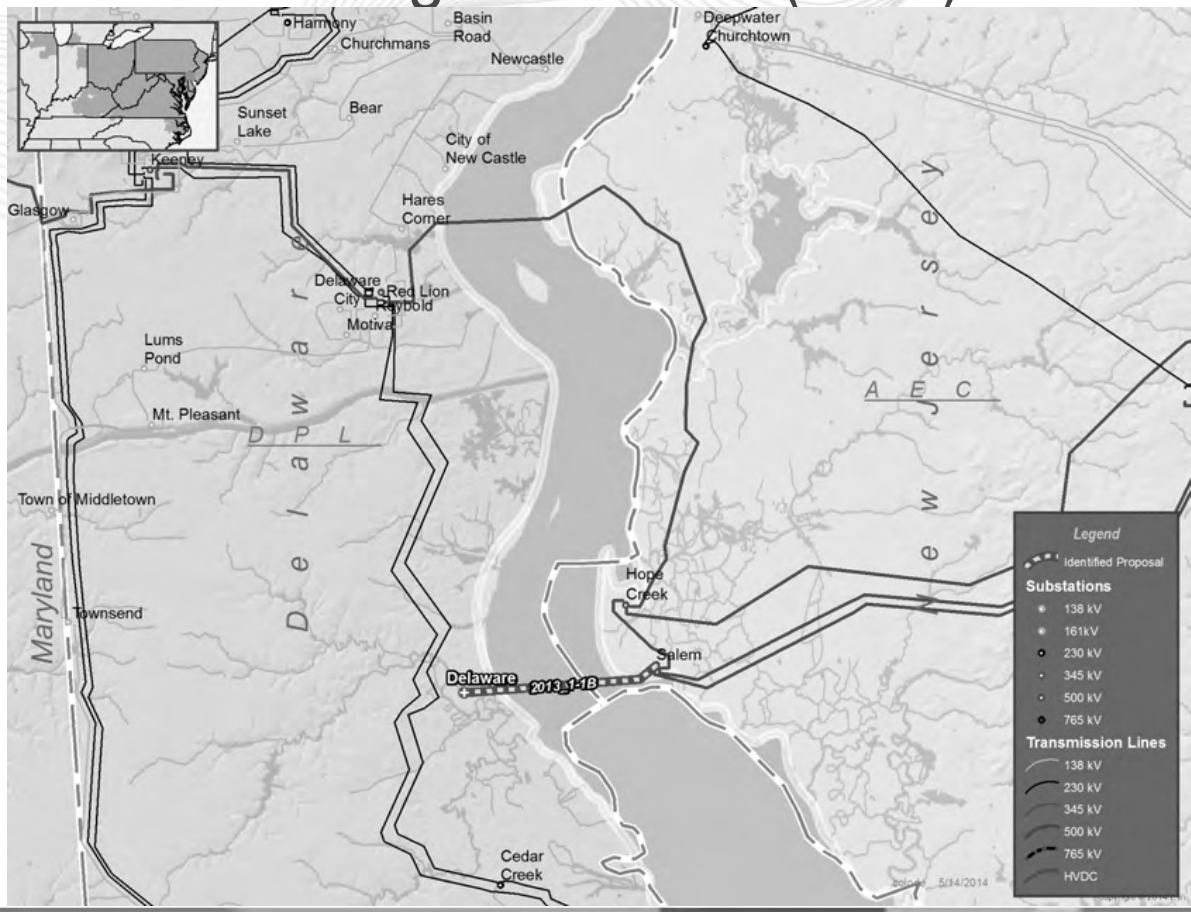
Dominion Virginia Power (DVP) 1B

- Install a new 500kV line from Salem 500kV to a new station in Delaware
- Aerial crossing of the Delaware river
- New substation in Delaware that taps the existing Red Lion to Cartanza 230kV and Red Lion to Cedar Creek 230kV lines
- Proposed Cost Estimate: $133MM



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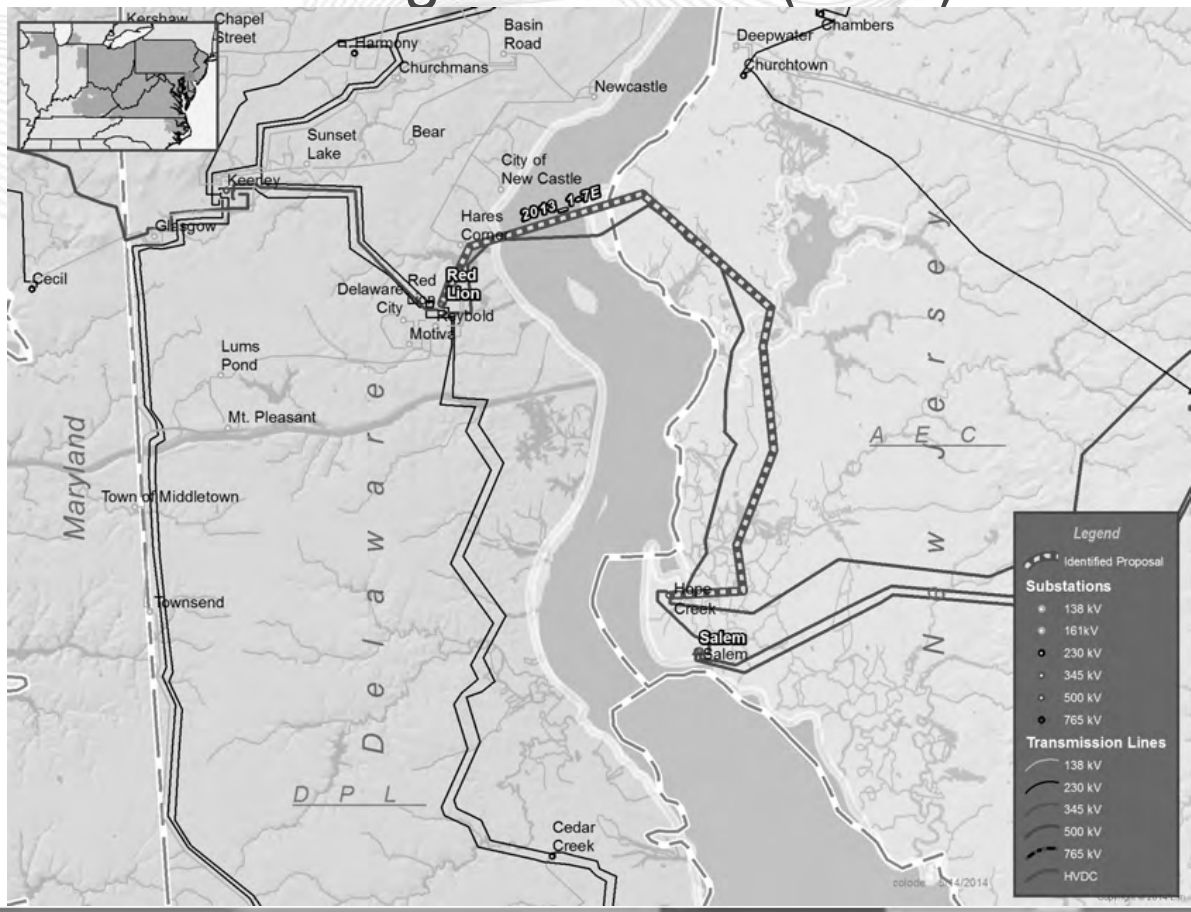
Dominion Virginia Power (DVP) 1C

- Expansion of Hope Creek substation
- 17 mile 500kV line from Hope Creek to Red Lion
  - Parallels existing 5015 Red Lion to Hope Creek 500 kV line
- Second Hope Creek to Salem tie line
- Reconfiguration of Red Lion substation into a breaker and a half scheme
- Proposed Cost Estimate: $199MM



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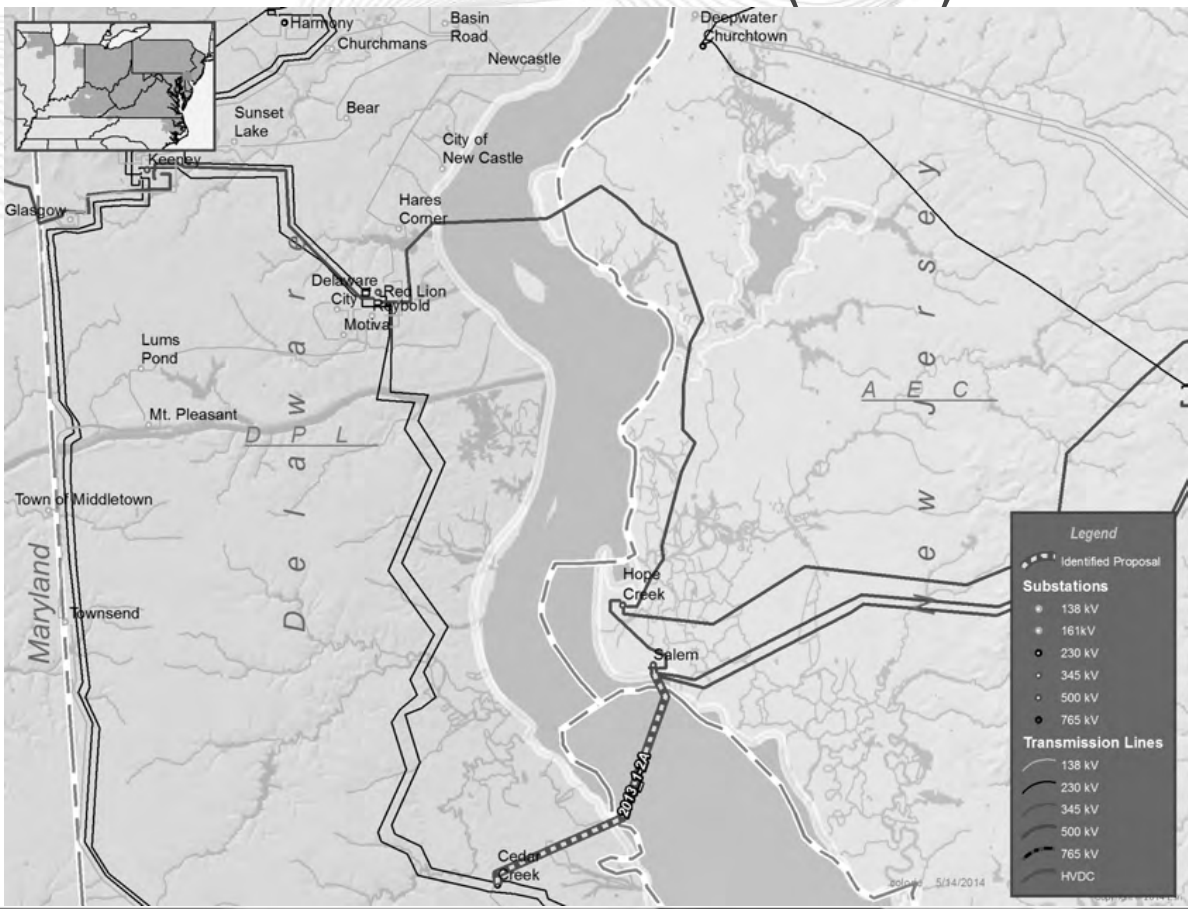
SI-SSA-0010-0102

Transource (AEP) 2A

- Expansion of the Salem substation
- New substation near Artificial Island with two 500/230 kV autotransformers
- Submarine line under the Delaware river
- Expand existing Cedar Creek substation to accept the new line and to loop in the Red Lion – Cartanza 230kV line
- Proposed Cost Estimate: $213-$269MM



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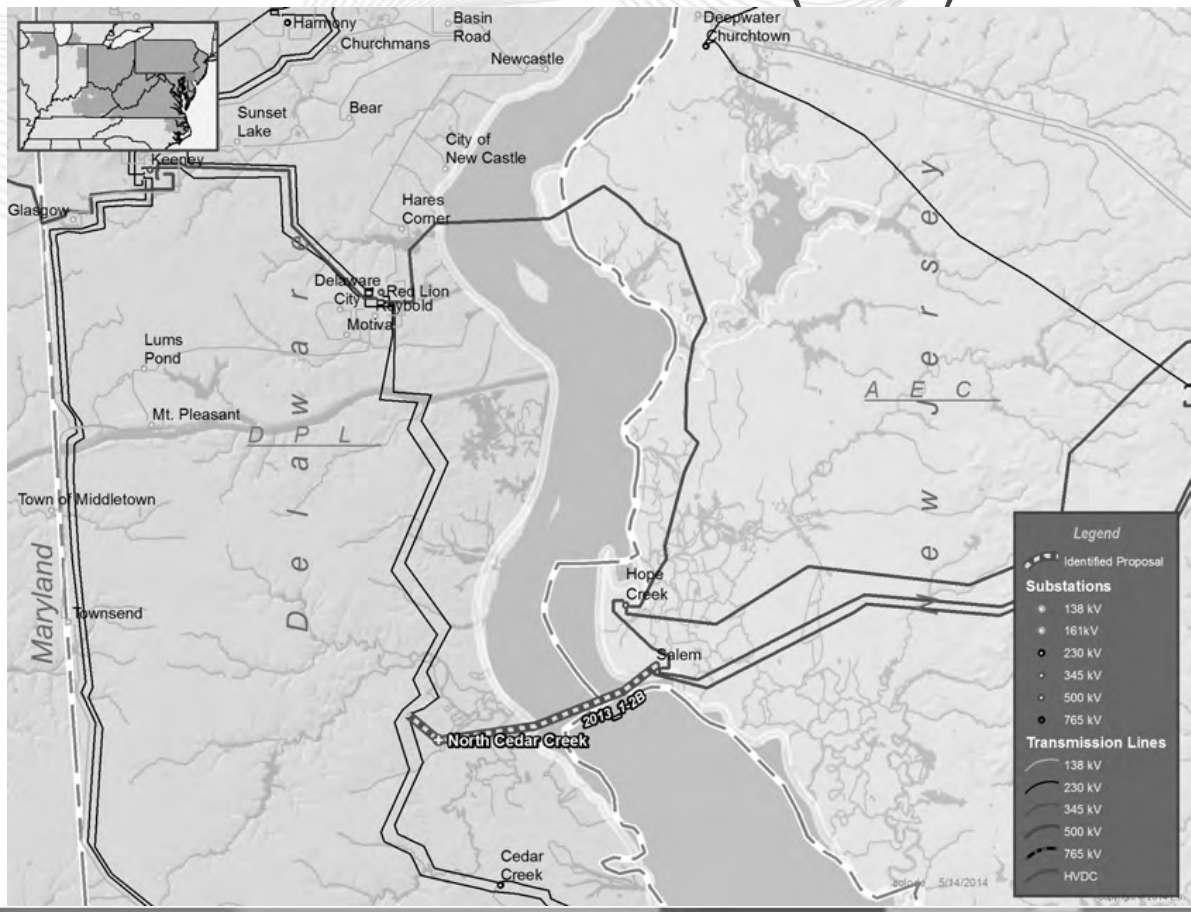
SI-SSA-0010-0103

Transource (AEP) 2B

- Expansion of the Salem substation
- New substation near Artificial Island with two 500/230 kV autotransformers
- Submarine line under the Delaware river
- New substation in Delaware that taps the existing Red Lion to Cartanza 230 kV and Red Lion to Cedar Creek 230 kV lines
- Proposed Cost Estimate: $165-$208MM



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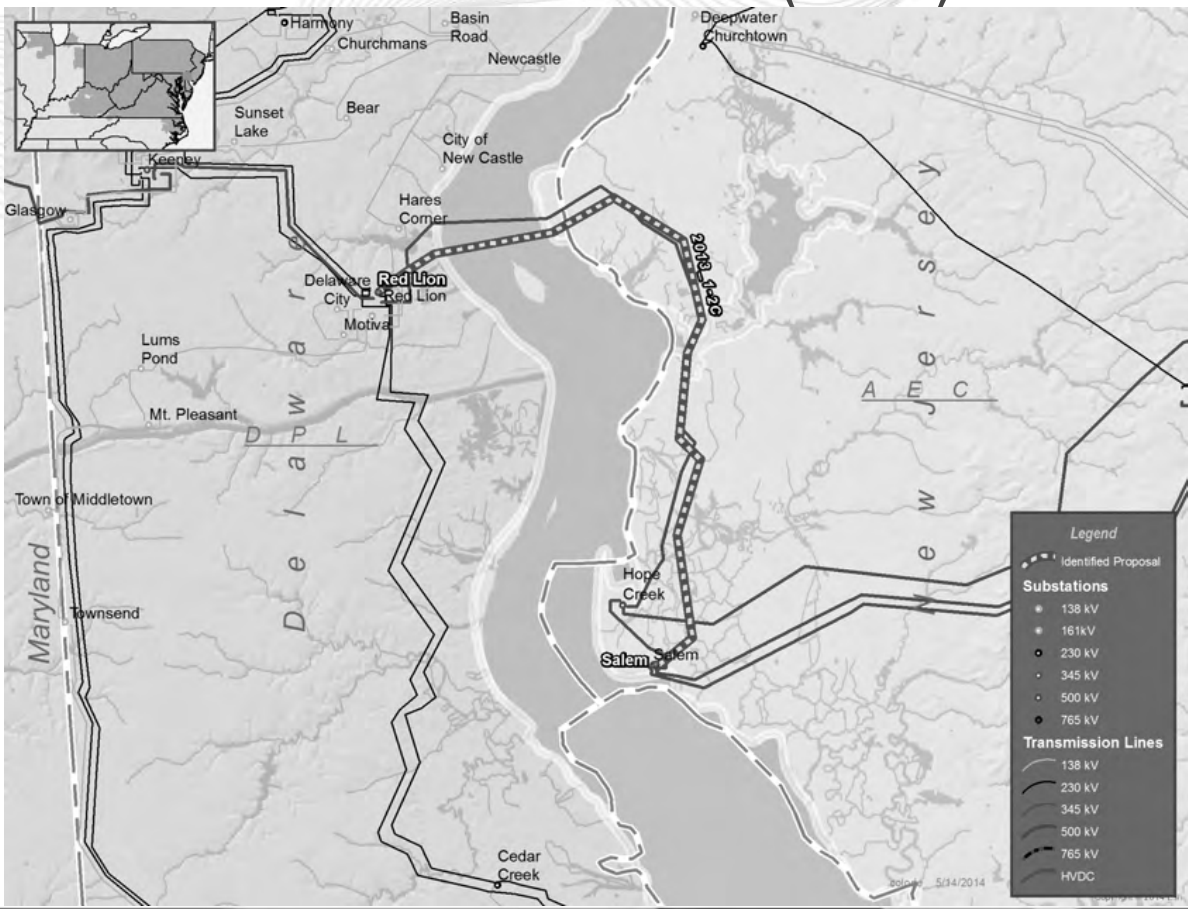
Transource (AEP) 2C

- Expansion of Salem substation
- Move 5024 and 5021 line bays within Salem substation
- 17 mile 500kV line from Red Lion to Salem
  - Parallels existing 5015 Red Lion to Hope Creek 500 kV line
- Reconfiguration of Red Lion substation into a breaker and a half scheme
- Proposed Cost Estimate: $123-$156MM



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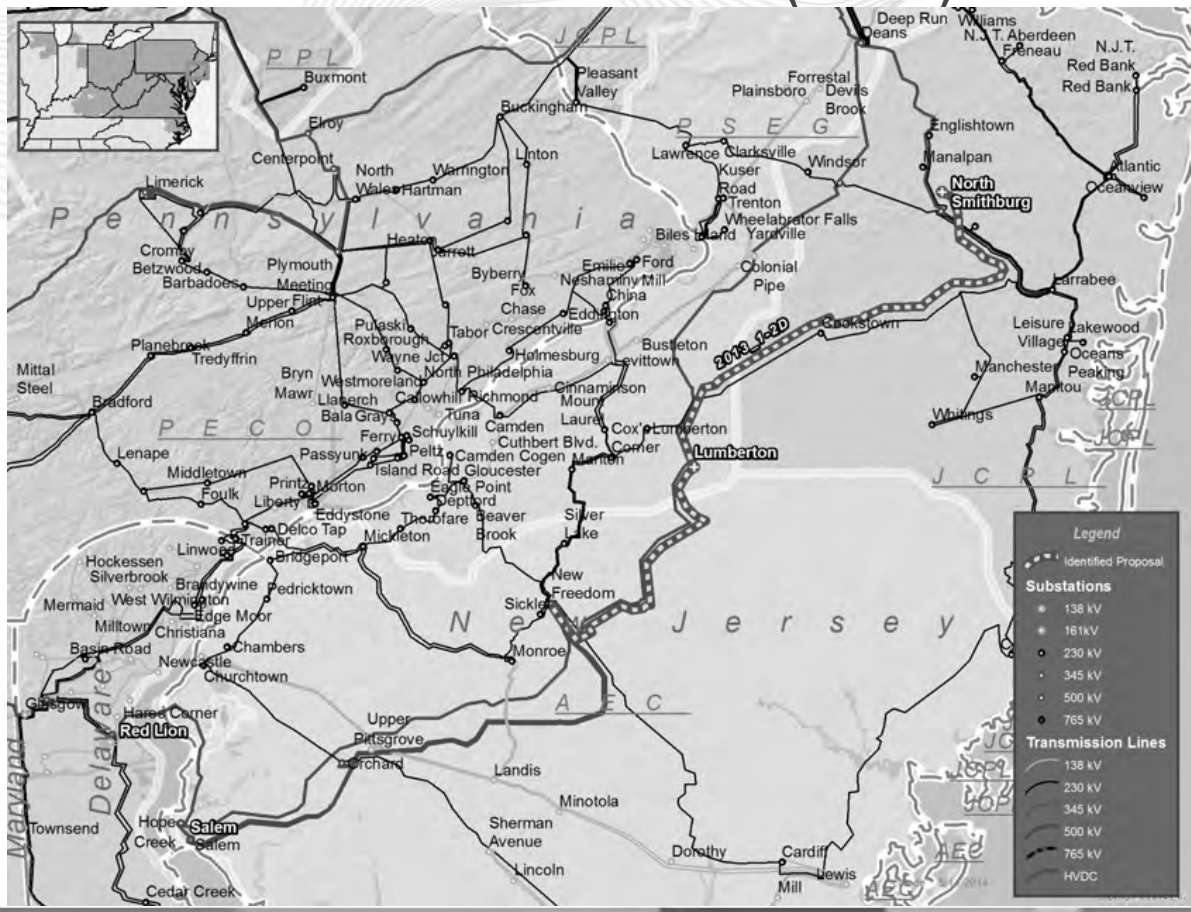
Transource (AEP) 2D

- Install a new 500kV line from New Freedom to Lumberton to North Smithburg
- New 500/230 substation east of Lumberton
- Second Hope Creek to Salem 500kV tie line
- Proposed Cost Estimate: $788-$994MM



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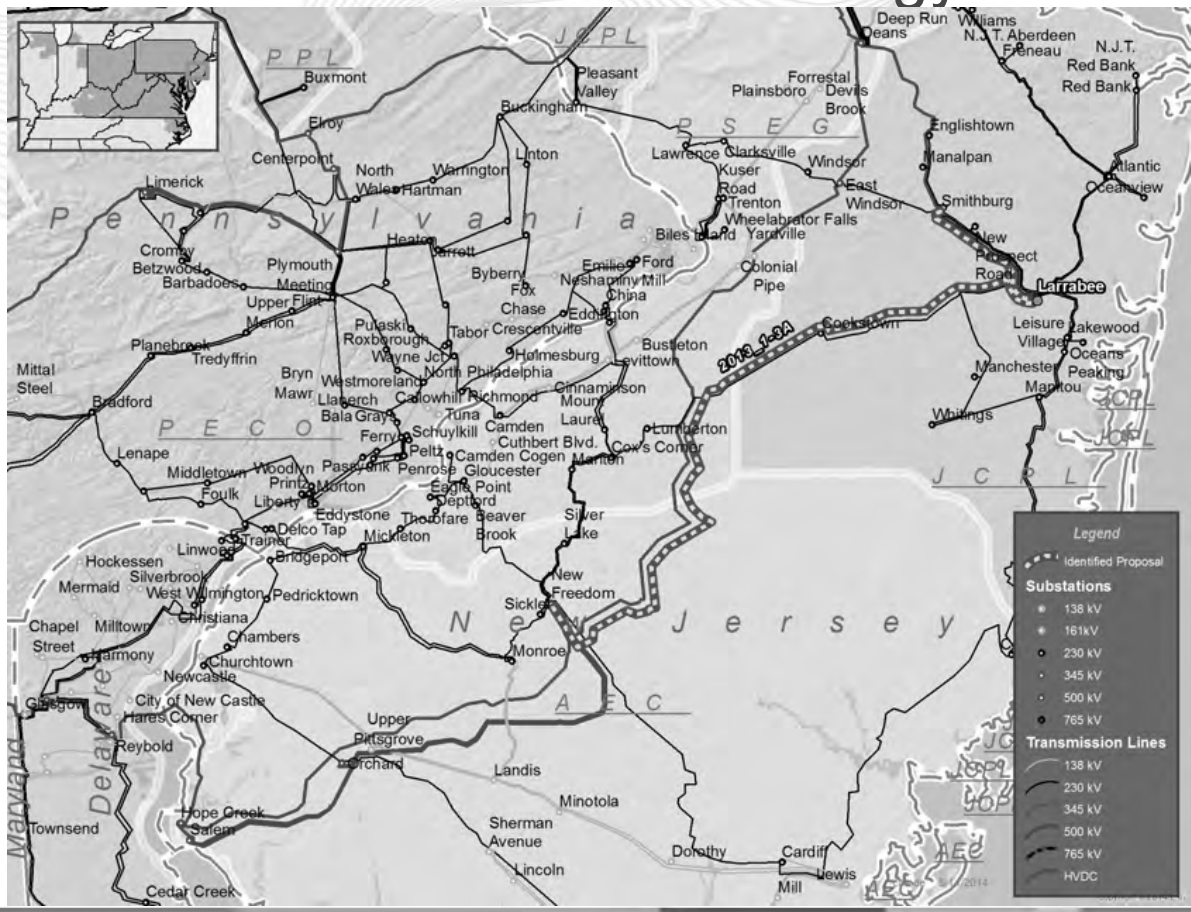
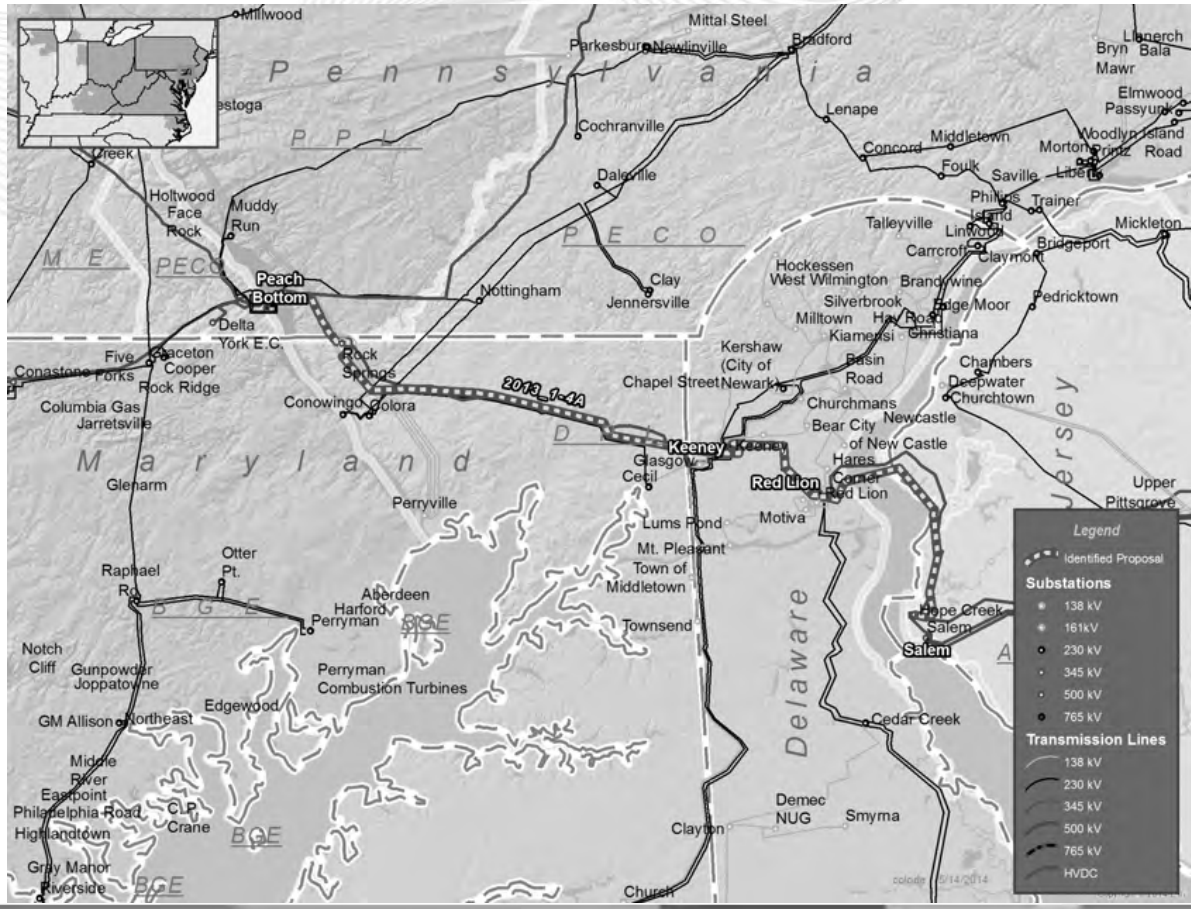
FirstEnergy 3A

- Install a new, New Freedom to Smithburg 500kV line with a loop into Larrabee substation
- Install two new 500/230 auto-transformers at Larrabee
- 17 mile 500kV line from Hope Creek to Red Lion
  - Parallels existing 5015 Red Lion to Hope Creek 500 kV line
- Proposed Cost Estimate: $452MM



PHI / Exelon 4A

- Install a new Peach Bottom to Keeney to Red Lion to Salem 500kV line
- Remove existing Keeney to Red Lion 230 kV circuit
- Reconfigure the existing 230 kV line from Hay Road to Red Lion to terminate at Keeney instead of Red Lion
- Re-conductor the Harmony to Chapel Street 138 kV line
- Proposed Cost Estimate: $475MM



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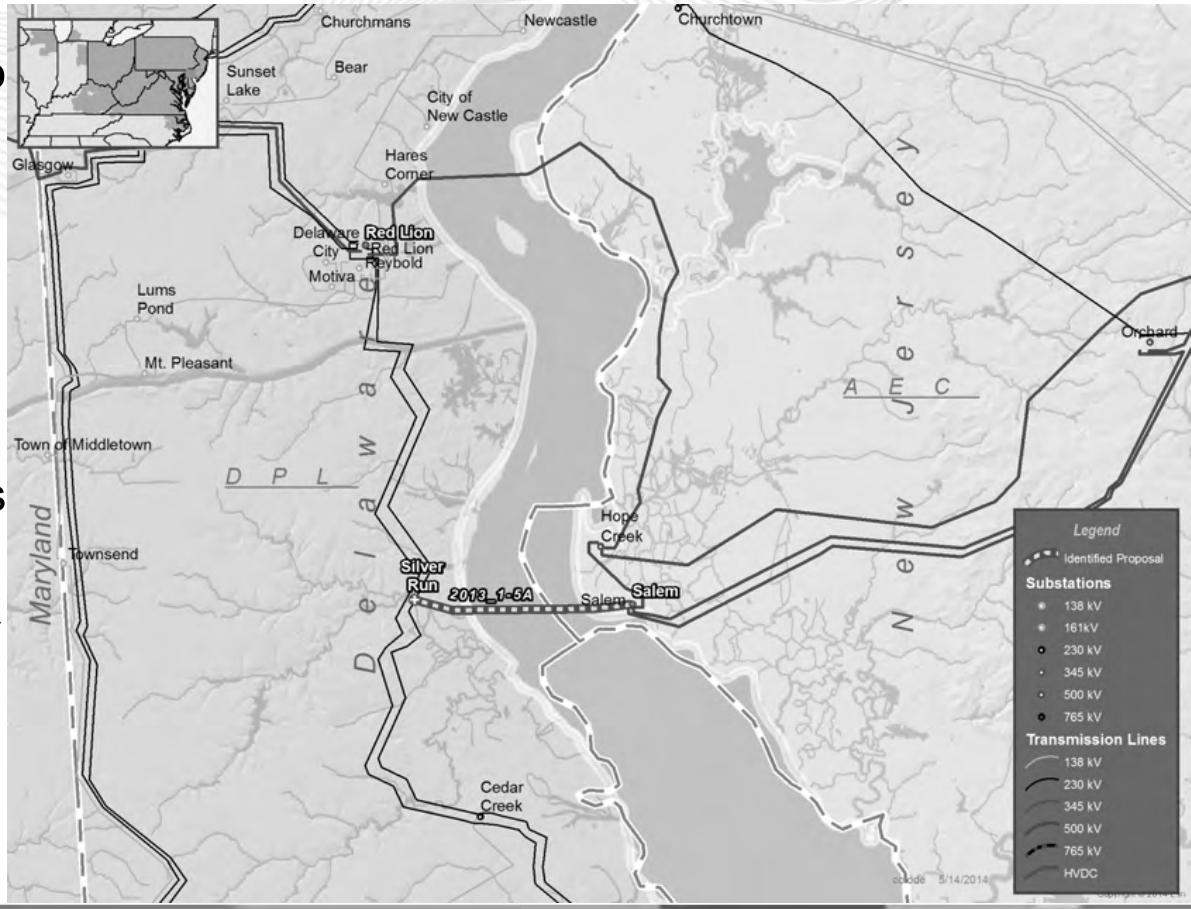
LS Power 5A

- Expansion of the Salem substation to the south to include a new 500/230kV auto-transformer
- Submarine or aerial line over the Delaware
- New substation in Delaware that taps the existing Red Lion to Cartanza 230 kV and Red Lion to Cedar Creek 230 kV lines
- Proposed Cost Estimate: $116 - $148MM



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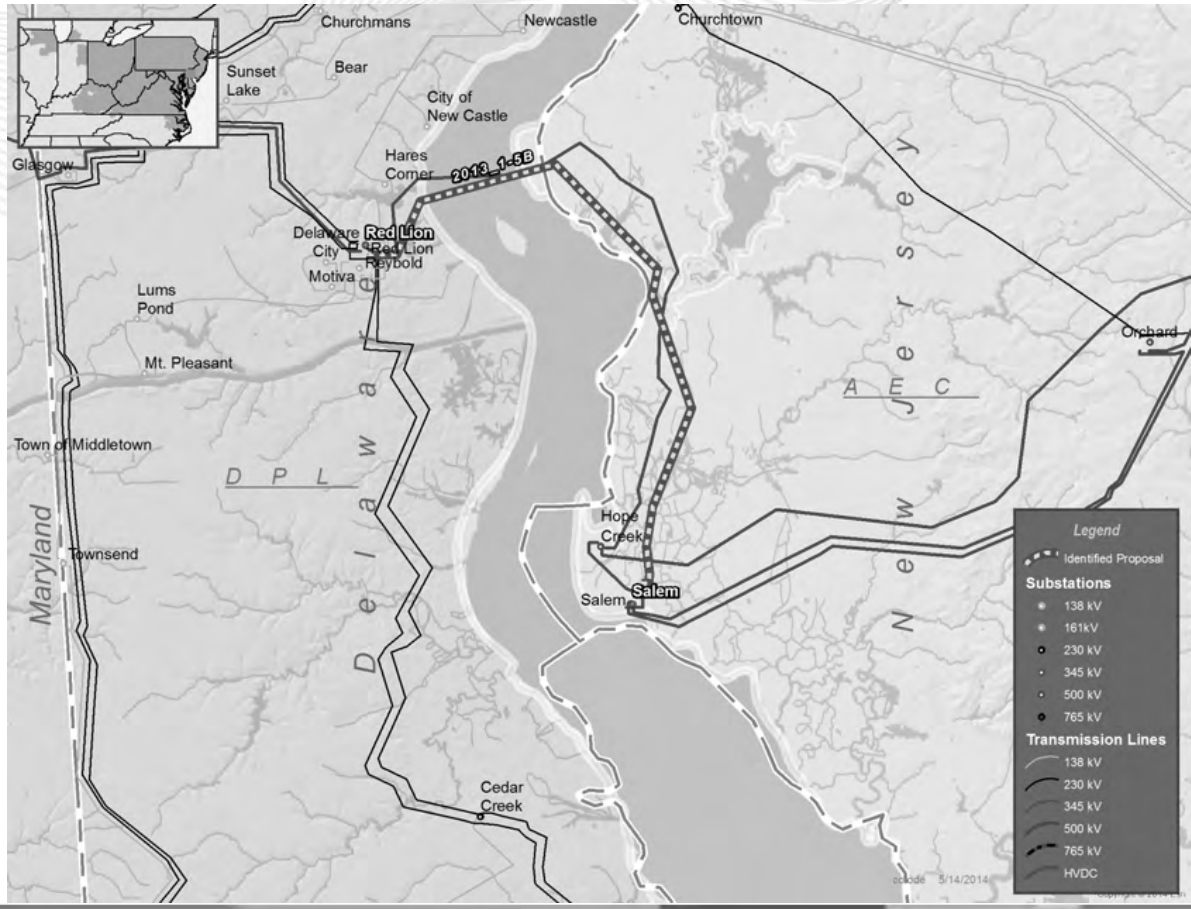
LS Power 5B

- Expansion of Salem substation
- 17 mile 500kV line from Red Lion to Salem
  - Parallels existing 5015 Red Lion to Hope Creek 500 kV line
- Expansion of Red Lion substation ring-bus
- Proposed Cost Estimate: $170MM



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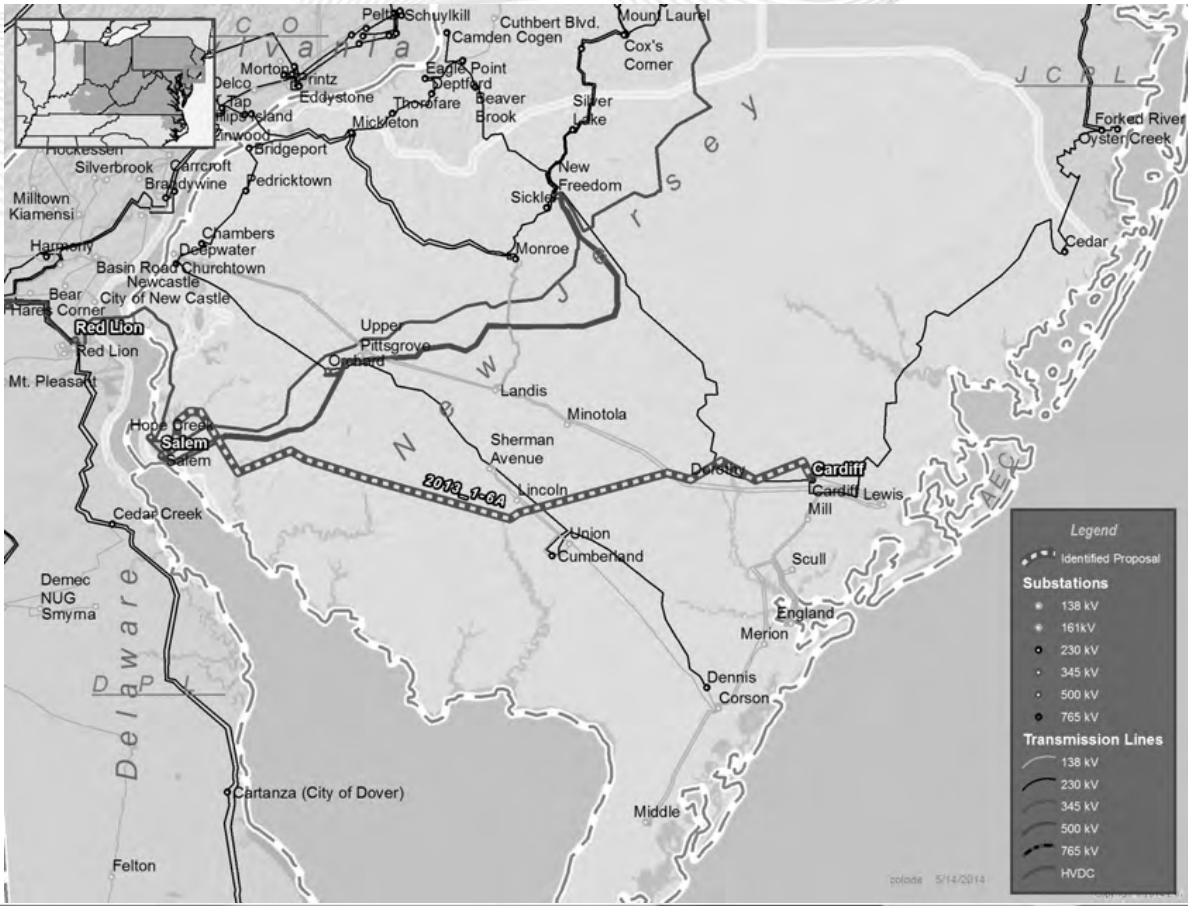
SI-SSA-0010-0110

Atlantic Wind 6A

- Install a HVDC converter station near the Artificial Island
  - Install a SVC at the new Artificial Island HVDC station
- Install a HVDC converter station near the existing Cardiff 230 kV
- Install a 320kV HVDC line from the new Artificial Island HVDC station and the new HVDC station near Cardiff 230kV
- Proposed Cost Estimate : $1,012MM



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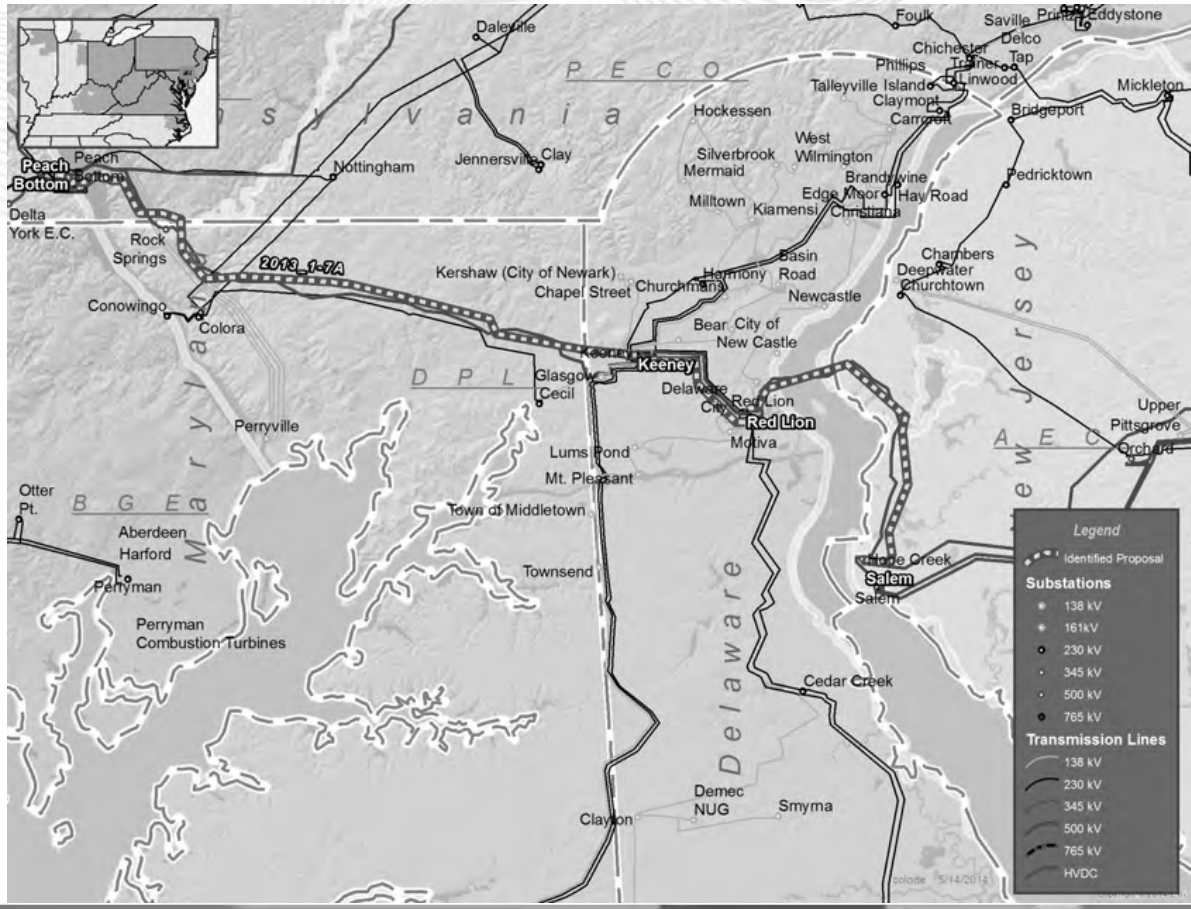
PSE&G 7A

- Second Salem to Hope Creek tie line
- Install a new Hope Creek to Peach Bottom 500 kV line on existing right of way
- Proposed Cost Estimate: $1,371MM



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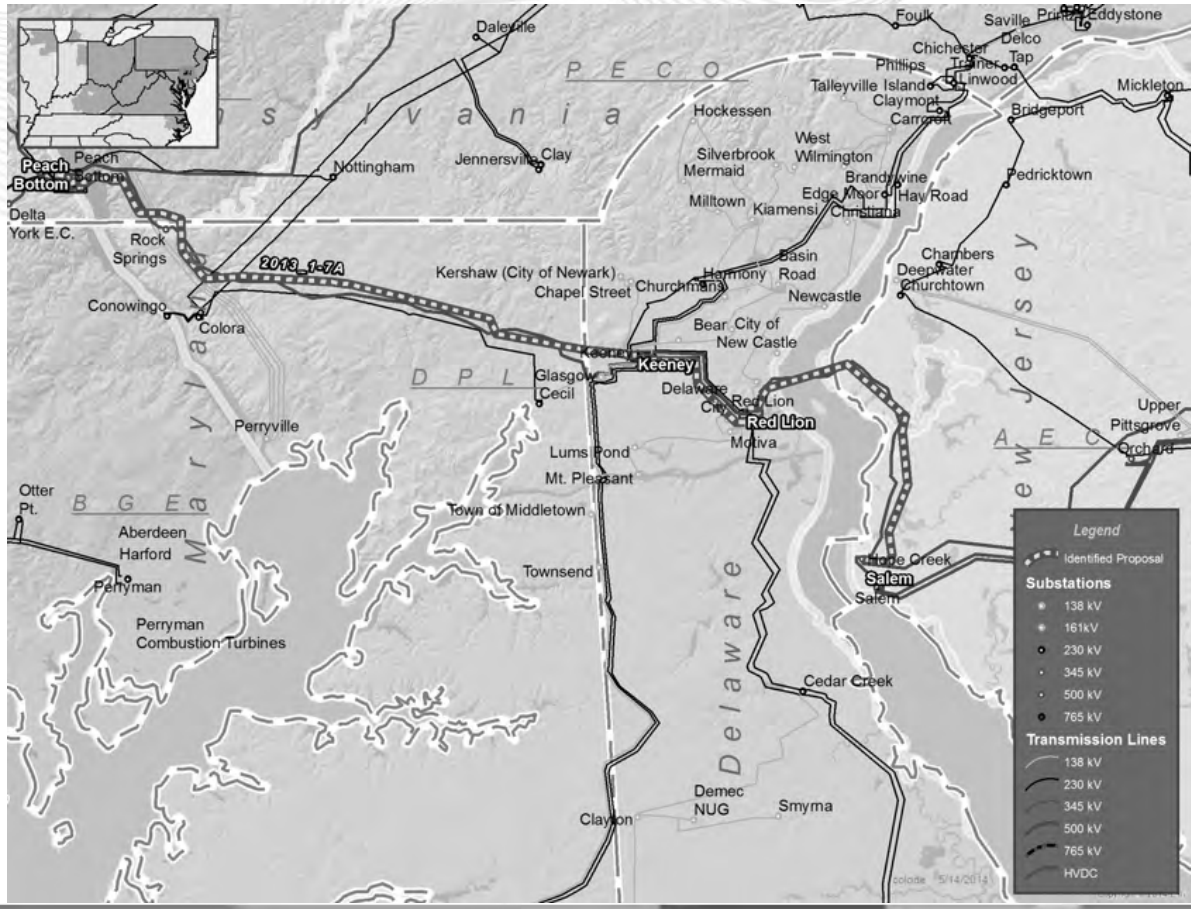
PSE&G 7B

- Second Salem to Hope Creek tie line
- Install a new Hope Creek to Keeney to Peach Bottom 500 kV line on existing right of way
- Tie 5036 and 5025 lines together to open a bay position at Keeney substation
- Proposed Cost Estimate: $1,372MM



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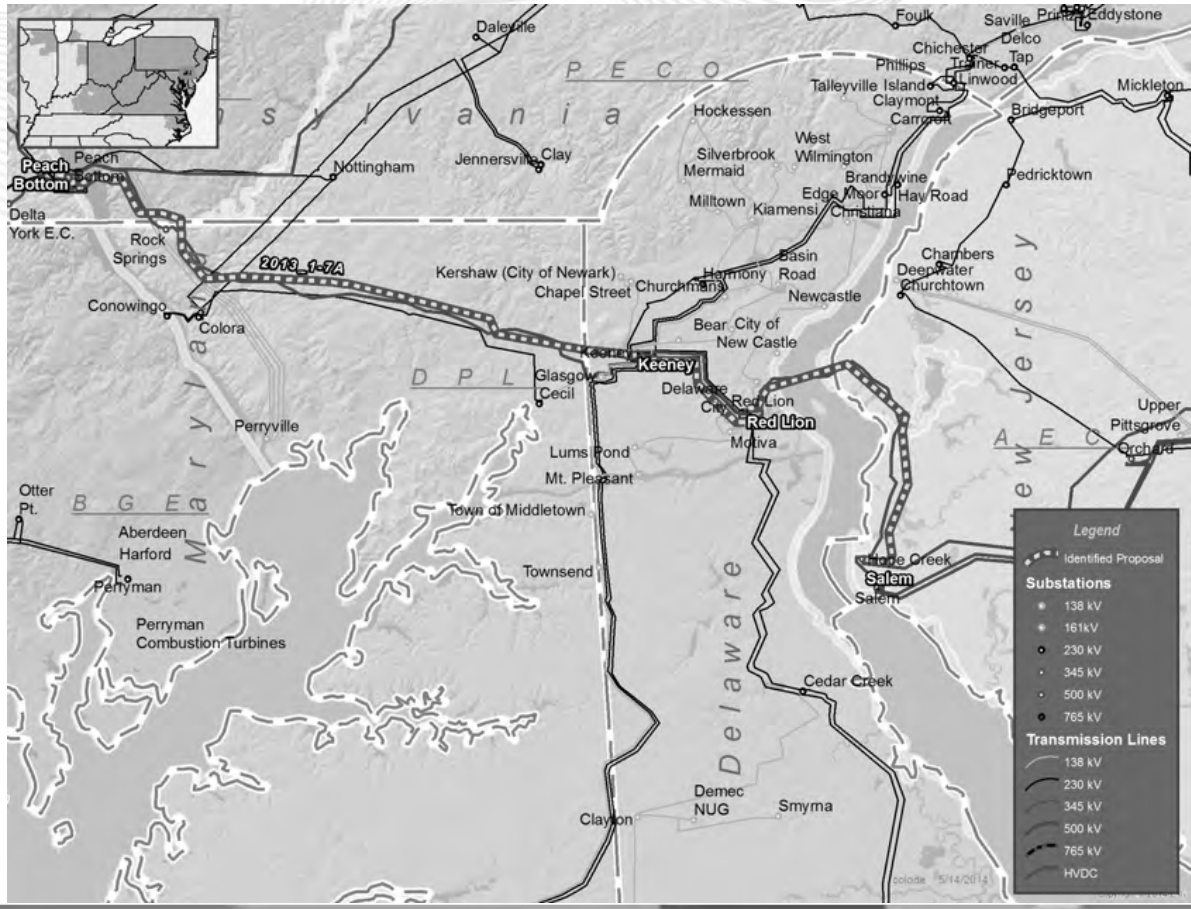
PSE&G 7C

- Second Salem to Hope Creek tie line
- Install a new Hope Creek to Red Lion to Peach Bottom 500 kV line on existing right of way
- Tie 5036 and 5015 lines together to open a bay position at Red Lion substation
- Proposed Cost Estimate: $1,372MM



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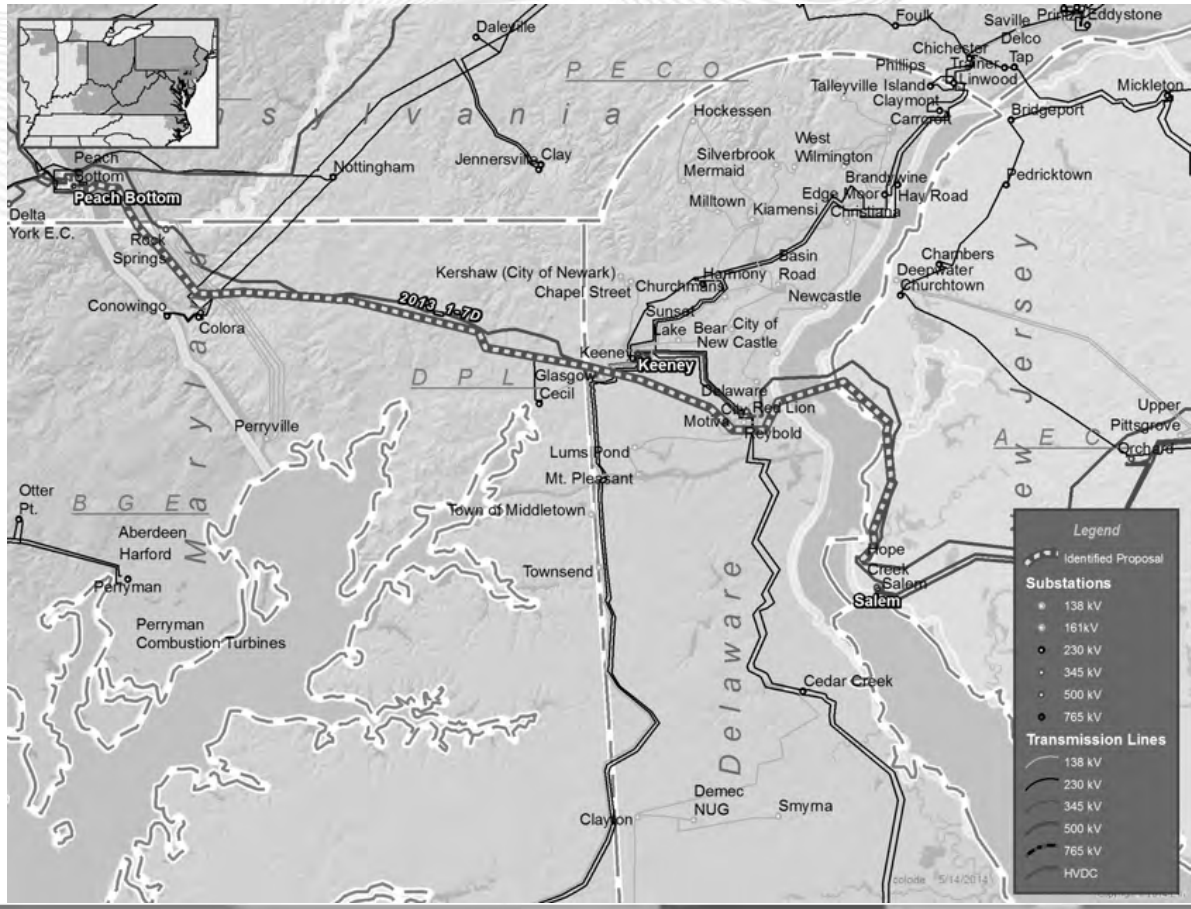
PSE&G 7D

- Second Salem to Hope Creek tie line
- Install a new Hope Creek to Peach Bottom 500 kV line on new right of way
- Proposed Cost Estimate: $831MM



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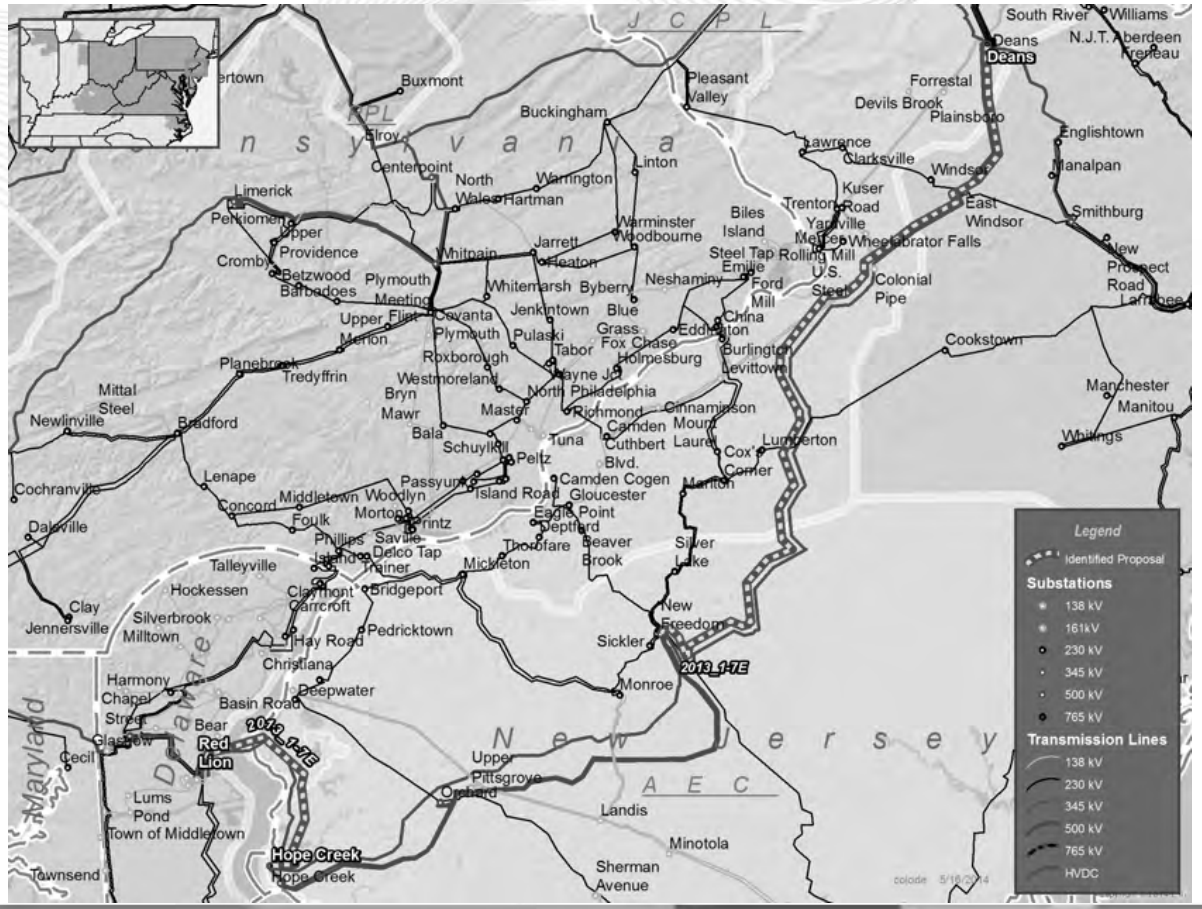
SI-SSA-0010-0115

PSE&G 7E

- Second Salem to Hope Creek tie line
- Install a new 500kV line Deans to New Freedom
- Proposed Cost Estimate: $692MM



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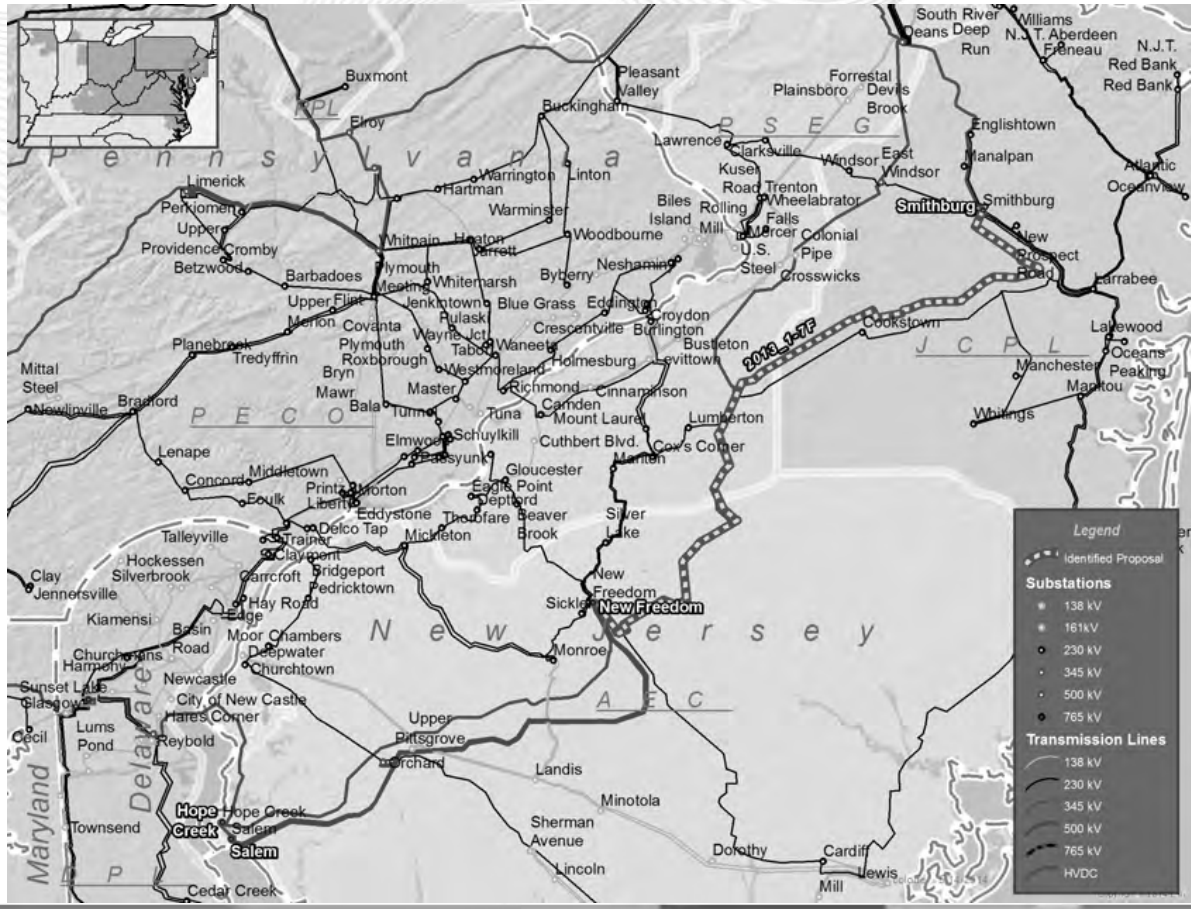
PSE&G 7F

- Second Salem to Hope Creek tie line
- Install a new Smithburg to New Freedom 500kV line
- Proposed Cost Estimate: $879MM



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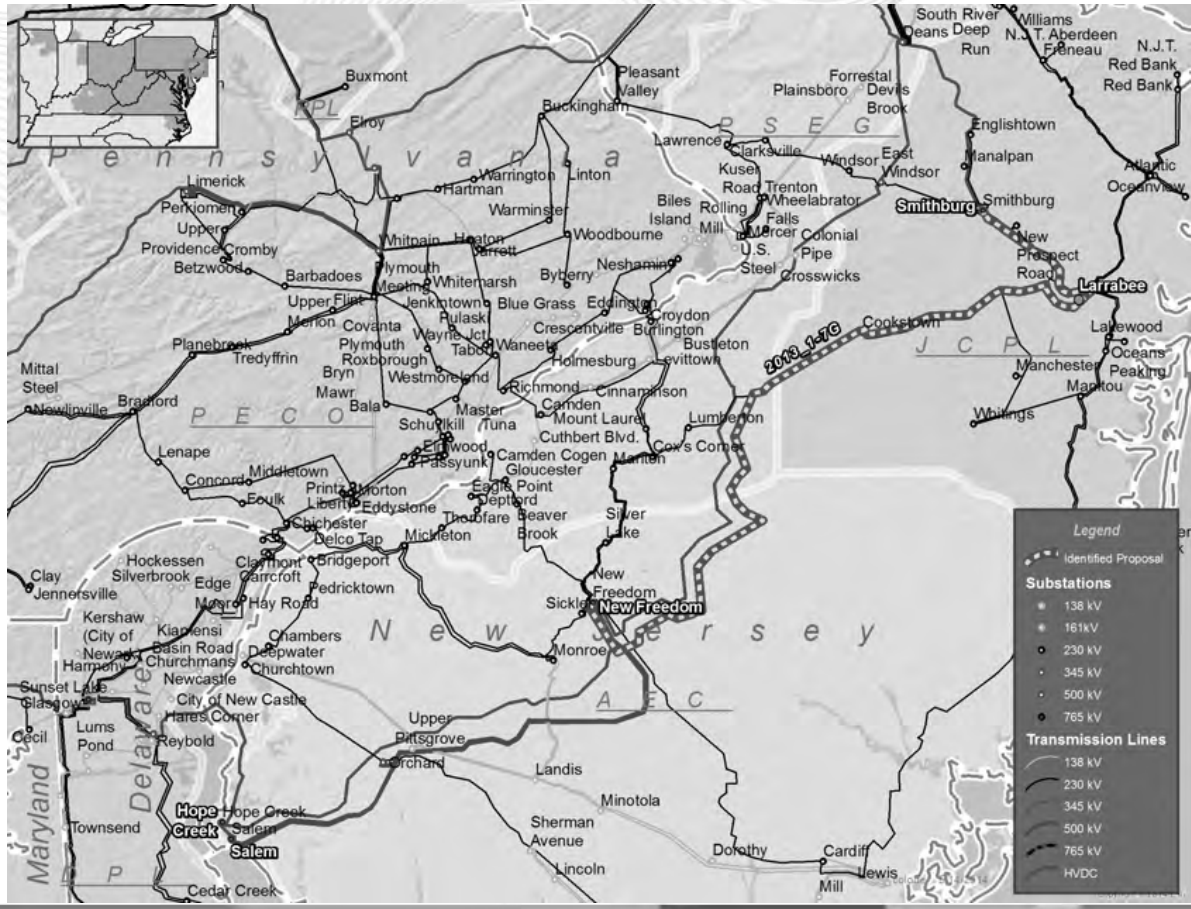
PSE&G 7G

- Second Salem to Hope Creek tie line
- Install a new Smithburg to Larrabee to New Freedom 500kV line
- Expand Larrabee substation to accept the new 500kV connection
- Proposed Cost Estimate: $1,034MM



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PSE&G 7H

- Second Salem to Hope Creek tie line
- Install a new Whitpain to New Freedom 500kV line using a northern route
- Proposed Cost Estimate: $1,177MM

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PSE&G 7I

- Second Salem to Hope Creek tie line
- Install a new Whitpain to New Freedom 500kV line using a southern route
- Proposed Cost Estimate: $1,353MM

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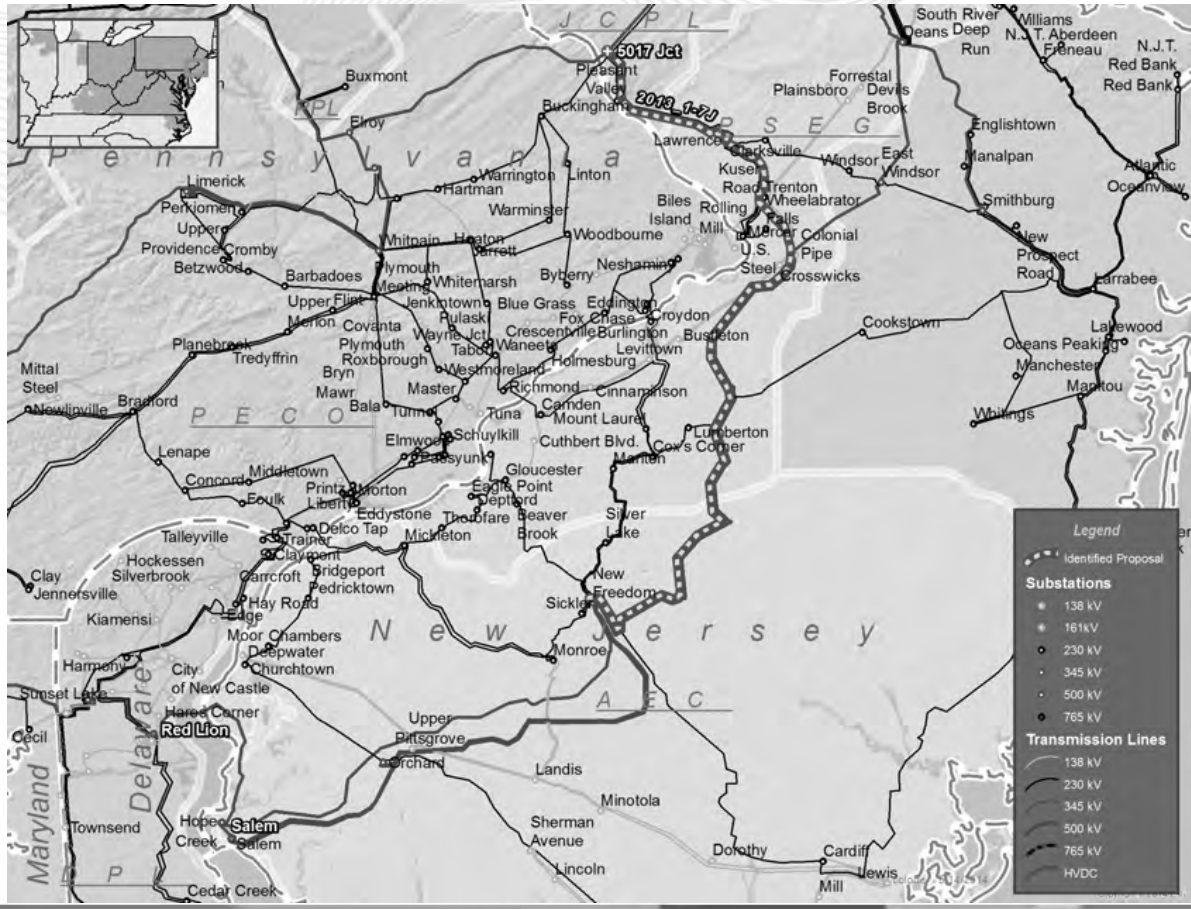
PSE&G 7J

- Second Salem to Hope Creek tie line
- New substation at the 5017 junction site cutting the 5017 Elroy to Branchburg line
- Install a new 5017 Junction to New Freedom 500kV line
- Proposed Cost Estimate: $915MM



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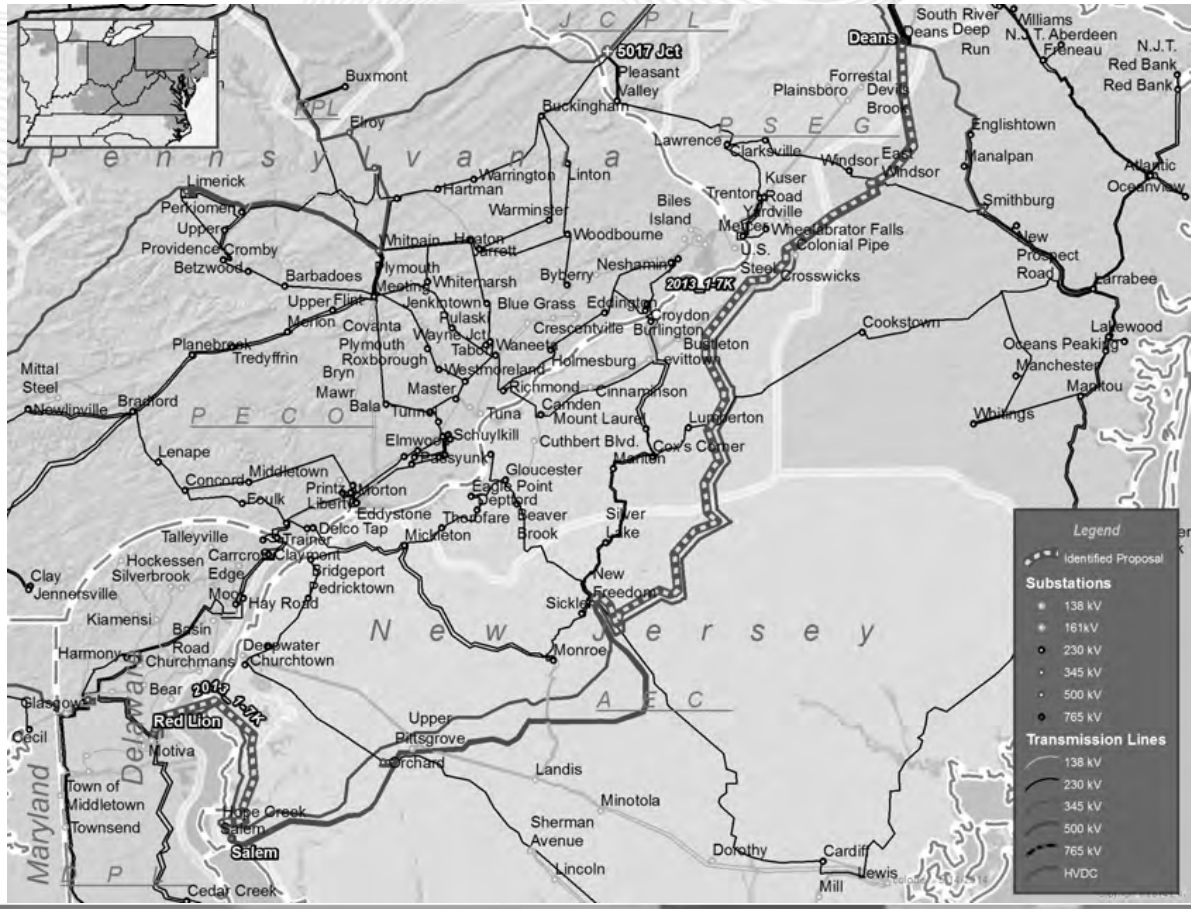
PSE&G 7K

- Second Salem to Hope Creek tie line
- 17 mile 500kV line from Hope Creek to Red Lion
  - Parallels existing 5015 Red Lion to Hope Creek 500 kV line
- Install a new Deans to New Freedom 500kV line
- Proposed Cost Estimate: $1,066MM



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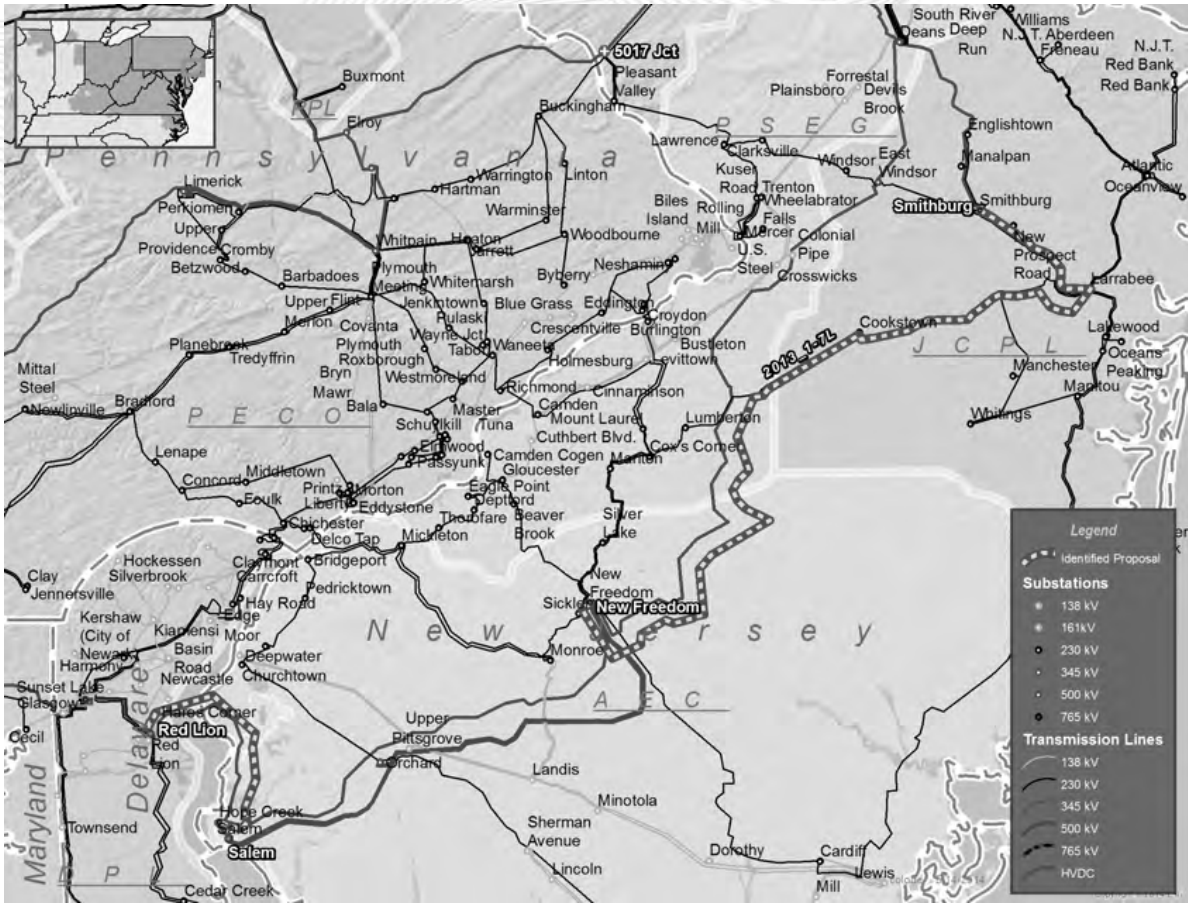
PSE&G 7L

- Second Salem to Hope Creek tie line
- 17 mile 500kV line from Hope Creek to Red Lion
  - Parallels existing 5015 Red Lion to Hope Creek 500 kV line
- Install a new Smithburg to New Freedom 500kV line
- Proposed Cost Estimate: $1,250MM



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PSE&G 7M

- Second Salem to Hope Creek tie line
- 17 mile 500kV line from Hope Creek to Red Lion
  - Parallels existing 5015 Red Lion to Hope Creek 500 kV line
- Install a new Whitpain to New Freedom 500kV line using a northern route
- Proposed Cost Estimate: $1,548MM

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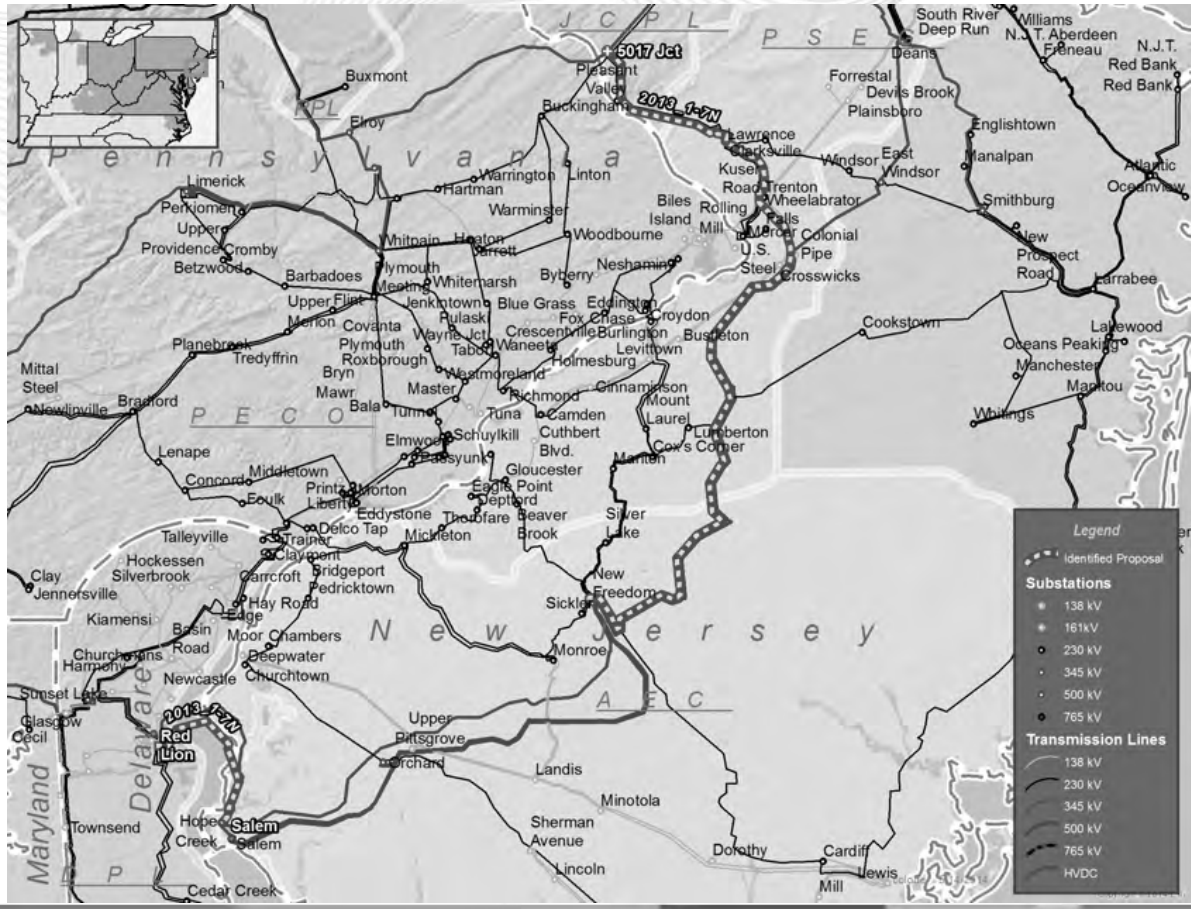
PSE&G 7N

- Second Salem to Hope Creek tie line
- 17 mile 500kV line from Hope Creek to Red Lion
  - Parallels existing 5015 Red Lion to Hope Creek 500 kV line
- New substation at the 5017 junction site cutting the 5017 Elroy to Branchburg line
- Install a new 5017 Junction to New Freedom 500kV line
- Proposed Cost Estimate: $1,289MM



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Artificial Island Project Evaluation

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Evaluation of Proposals

Objectives

- ✓ Achieve desired system performance
- ✓ Minimize initial project cost
- ✓ Assess risk factors to minimize impact to cost and schedule
- ✓ Minimize impact to transmission operations
- ✓ No adverse impact to nuclear licensing

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Evaluation of Proposals – PJM Approach

- Performed extensive technical analysis
  - Stability, thermal, voltage, short circuit, market efficiency
  - Studied all solutions as is and with modifications

    Initial analysis showed only two of the highest cost solutions worked as submitted
- Engage outside engineers to perform constructability review
  - *focus on physical, cost, schedule, RoW, siting, permitting*
- Met with all proposers for clarification as needed
- Met with AI nuclear plant representatives
- PJM Operations review
- PJM independent cost evaluation
- Met with equipment manufacturers

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Artificial Island Evaluation Considerations

- Primary Considerations
  - Technical Analysis
    - Thermal
    - Stability
    - Short-circuit
    - Voltage
    - NERC Cat-D Contingencies
  - Cost Factors
    - Cost effectiveness
    - Market efficiency
    - PJM estimated costs
- Secondary Considerations
  - Schedule
    - Permitting
    - Construction
    - Long lead time equipment
  - Project Complexity
    - Line crossings
    - Outage requirements
    - Modifications to other transmission facilities
    - Modification to Artificial Island substations
    - Modifications to Red Lion substation
  - Right of Way and Land Acquisition
    - No eminent domain in Delaware
    - New right of way required
    - Substation land required
  - Siting and Permitting
    - Wetlands impact
    - Public opposition risk
    - Delaware river crossing
    - Land permitting
    - Historic and scenic highway
  - Operational Impact
    - Artificial island facility requirements
    - Ongoing maintenance
    - Blackstart
    - Route diversity

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Project Modifications

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Project Modifications

- Identified and implemented by PJM
- Modification Examples to Improve Performance
  - Move connection point to eliminate a critical fault
  - Add SVC to improve stability performance
- Modification Examples to reduce cost and improve constructability
  - Remove proposed new breakers that aren't needed to pass applicable criteria testing
  - Remove proposed transmission that isn't needed to pass applicable criteria testing

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Modification Summary

		Southern Crossing Lines (Submarine)			Southern Crossing Lines (Overhead)		Red Lion to Artificial Island Lines						
							From Salem			From Hope Creek			
		LS Power 5A - Submarine Option	Transource 2B - North Cedar Creek	Transource 2A - Cedar Creek Expansion	LS Power 5A - Overhead	Dominion 1B - 500kV Overhead	PHI/Exelon 4A - Red Lion to Salem	LS Power 5B - Red Lion to Salem	Transource 2C - Red Lion to Salem	Dominion 1C - Red Lion to Hope Creek	PSE&G 7K- Red Lion to Hope Creek	Dominion 1C - Red Lion to Hope Creek (Remove RL - HK)	PSE&G 7K- Red Lion to Hope Creek (Remove RL - HK)
Modifications	**SVC Additions at Orchard, NF, AI**	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓*	✓*
	Moved Connection At Salem or Hope Creek						✓						✓
	Removed proposed breakers					✓				✓		✓	✓
	Removed proposed Transmission										✓	✓	✓

* SVC option at AI is excluded.

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PJM Evaluation of Potential Solutions

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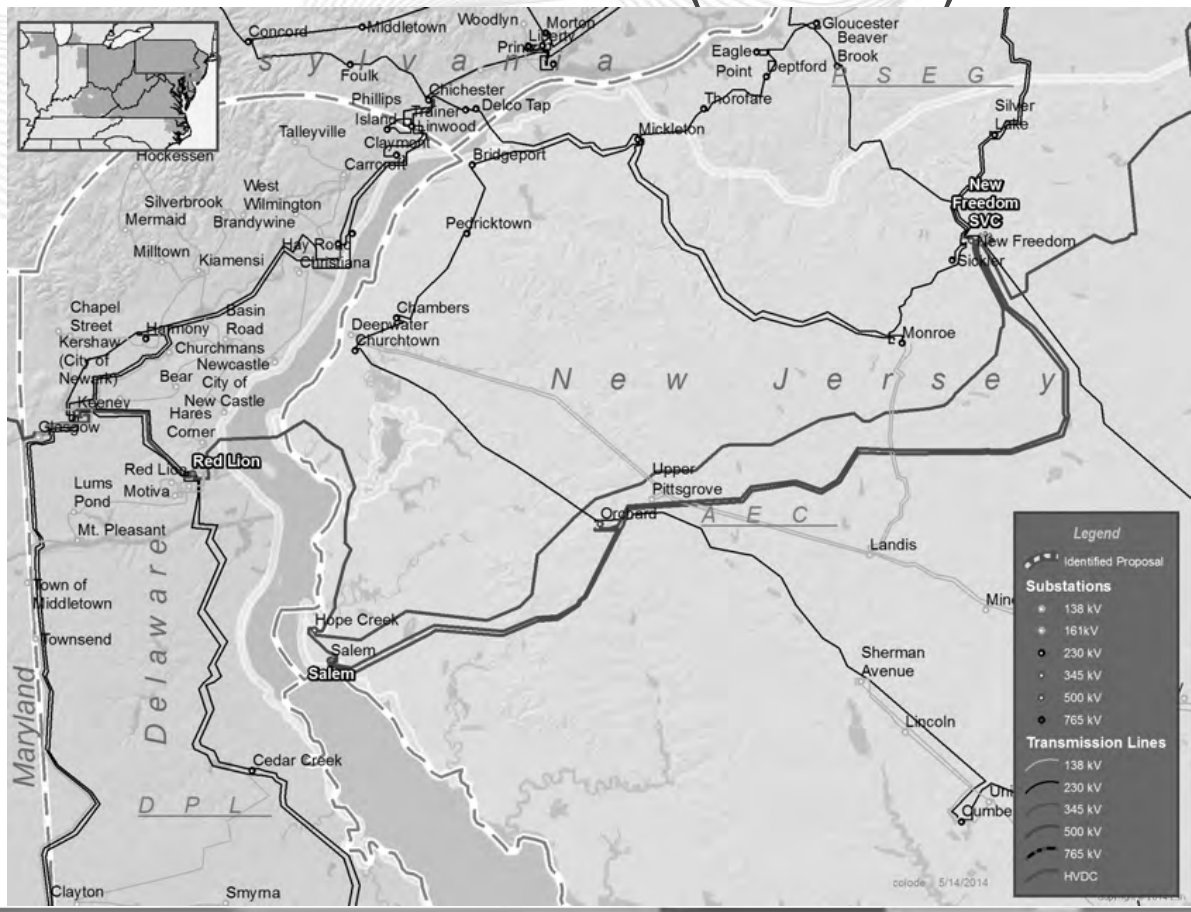
Dominion (VEPCO) 1A

- New switching station cutting New Freedom to Hope Creek and New Freedom to Salem (5023 and 5024) lines. Two Thyristor Controlled Series Compensation (TCSC) devices at the new station.

- PJM modifications
  - Changed SVC size



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DVP 1A – Technical Analysis

- Stability Performance
  - Failed required performance
    - Failed as proposed by project sponsor. Did not satisfy stability criteria for a three phase fault with normal clearing with AI units at unity power factor under 5038 maintenance outage condition
  - Passed required performance when SVC size increased to 750MVAr to achieve acceptable performance.
  - Stability performance is not as good as 230kV options + SVC or as good as 500kV options + SVC.
  - Anticipate nuclear regulatory concerns in approving this configuration.

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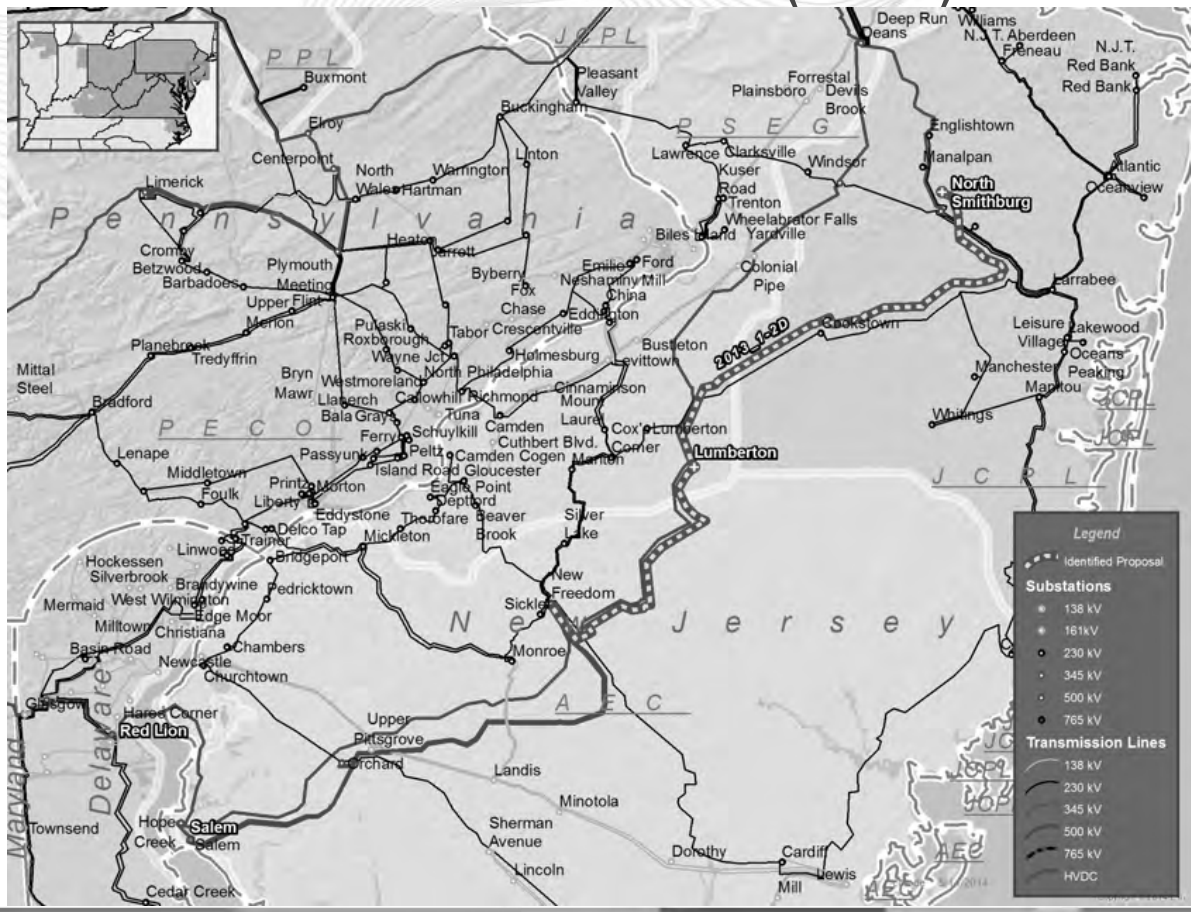
Transource (AEP) 2D

- Lines between:
  - New Freedom to Lumberton
  - Lumberton to North Smithburg
  - Hope Creek to Salem tie
- Estimated costs higher than other proposals



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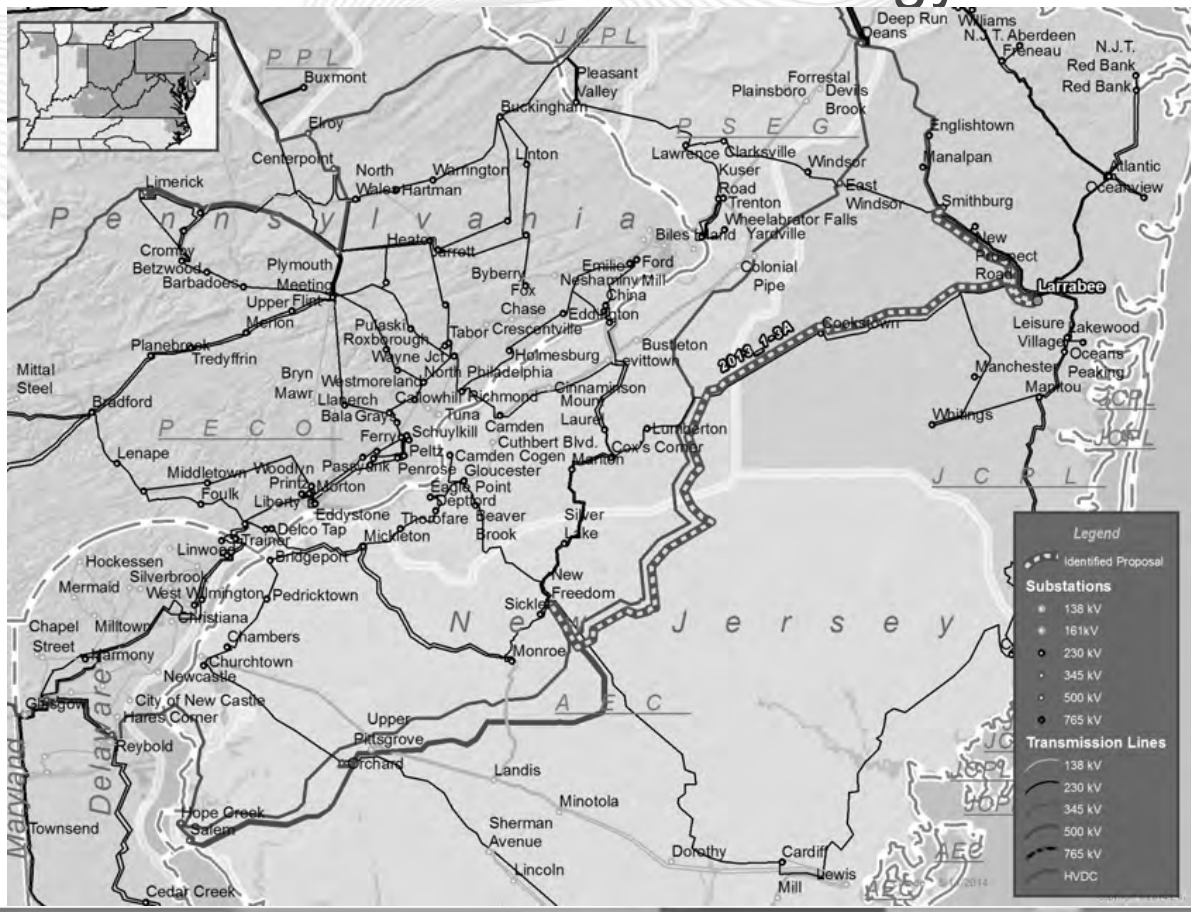
FirstEnergy 3A

- Lines between:
  - Smithburg to Larrabee
  - Larrabee to New Freedom
  - Hope Creek to Red Lion
- Estimated costs higher than other proposals



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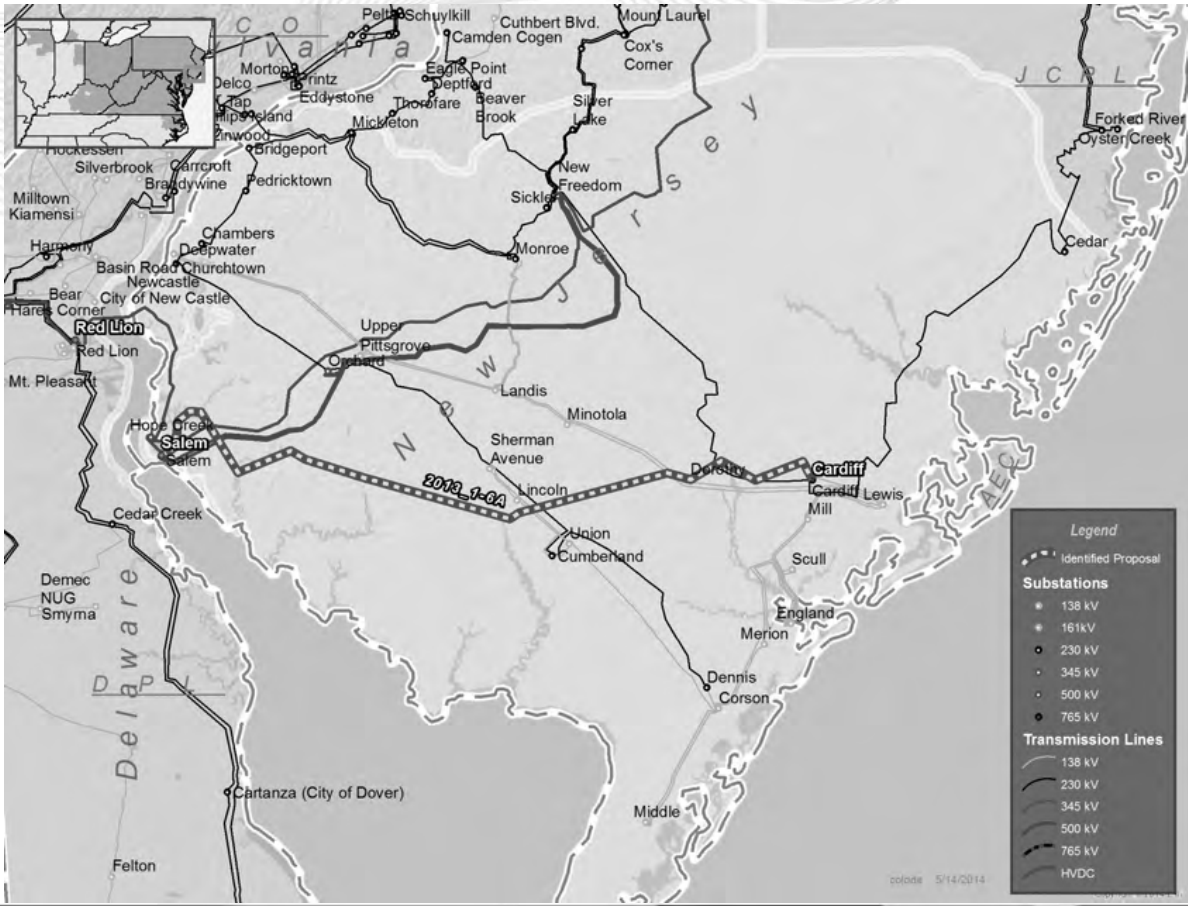
Atlantic Wind 6A

- HVDC line between Artificial Island and Cardiff
- SVC at Artificial Island converter station
- Estimated costs higher than other proposals



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- Stability Performance

  – Failed required performance
    - Failed as proposed by project sponsor.
    - Did not satisfy stability criteria for a SLG fault with stuck breaker with AI units at unity power factor under 5015 maintenance outage condition without significant MW flow on the proposed HVDC facility from the AI to Cardiff.

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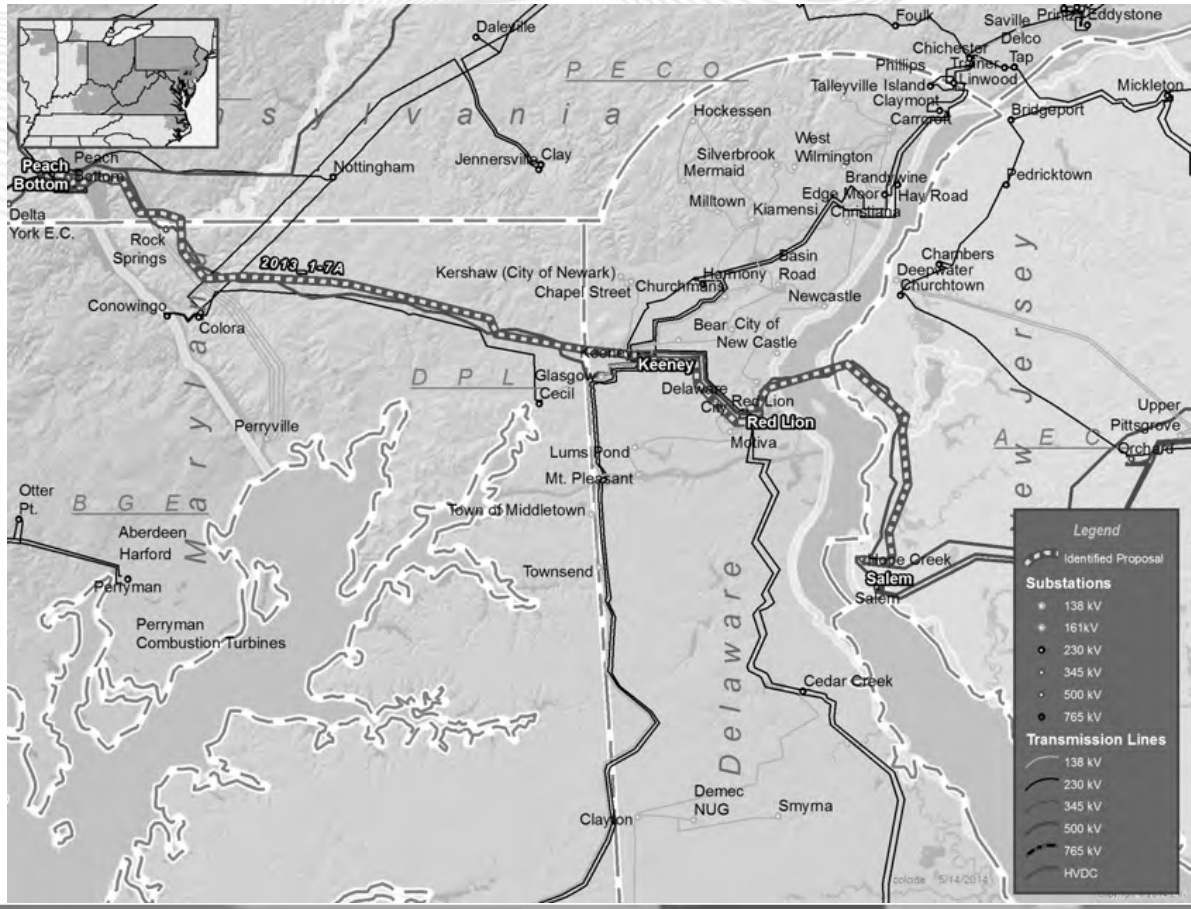
PSE&G 7A

- Lines between:
  - Salem to Hope Creek tie
  - Hope Creek to Peach Bottom (existing right of way)
- Estimated costs higher than other proposals



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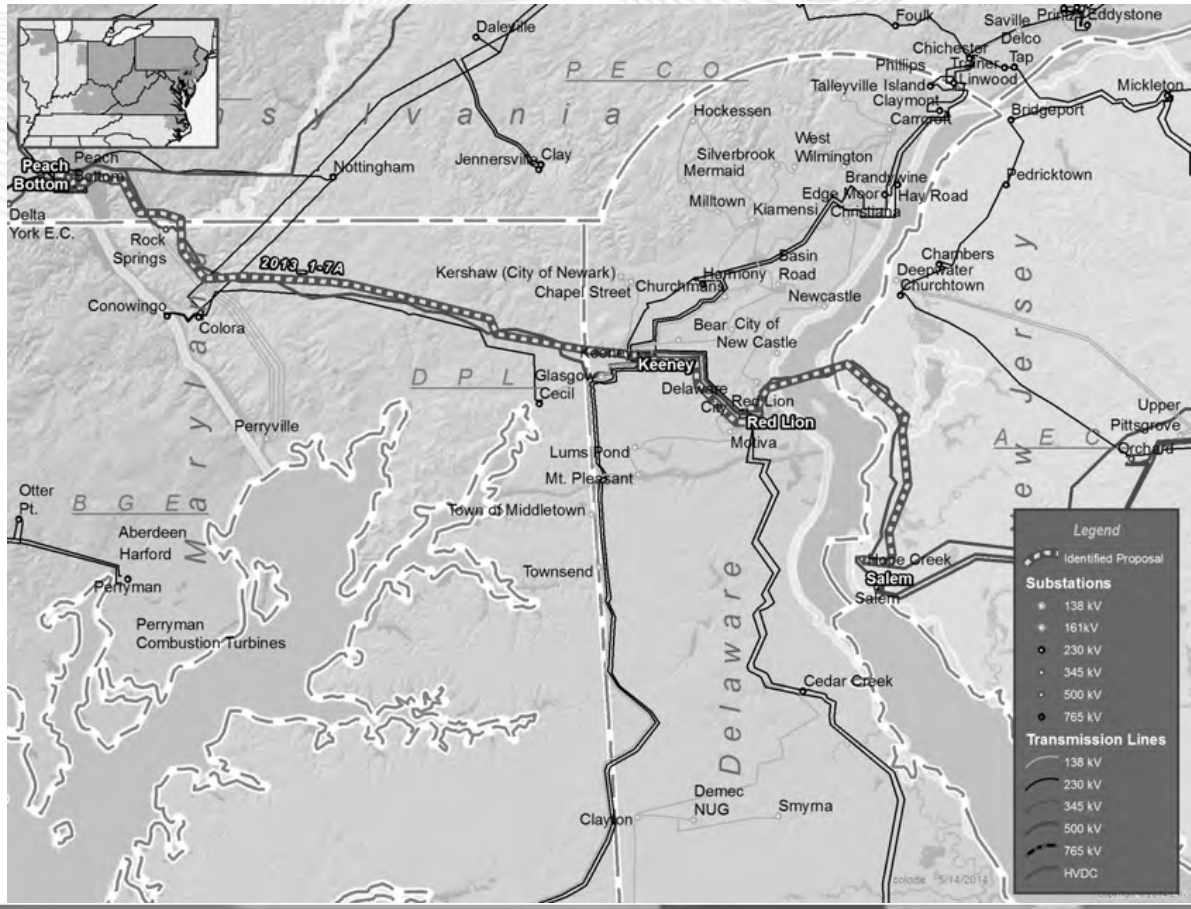
PSE&G 7B

- Lines between:
  - Salem to Hope Creek tie
  - Hope Creek to Keeney
  - Keeney to Peach Bottom
  - Remove Keeney from existing Rock Springs to Keeney to Red Lion lines (5025 and 5036)

- Estimated costs higher than other proposals



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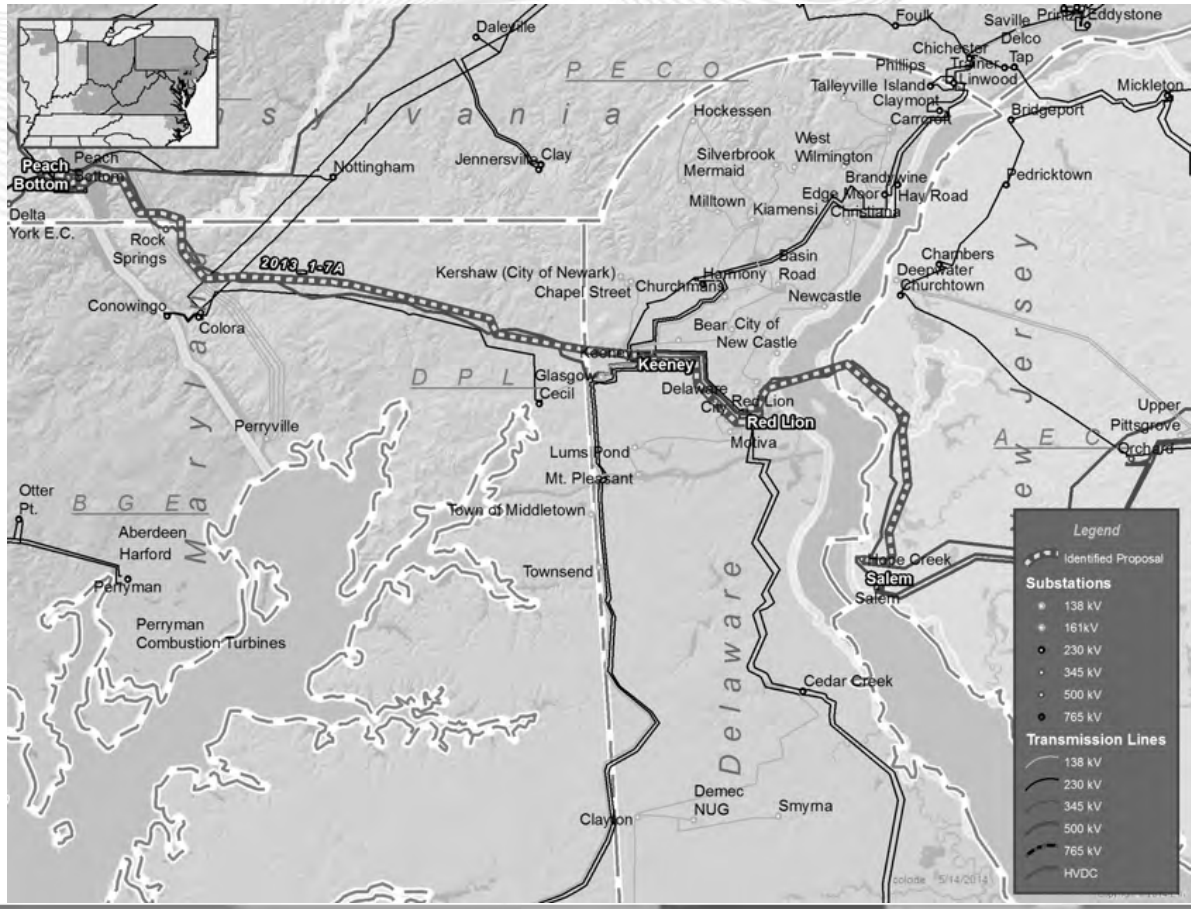
PSE&G 7C

- Lines between:
  - Salem to Hope Creek tie
  - Hope Creek to Red Lion
  - Red Lion to Peach Bottom
  - Remove Red Lion from existing Keeney to Red Lion to Hope Creek lines (5036 and 5015)

- Estimated costs higher than other proposals



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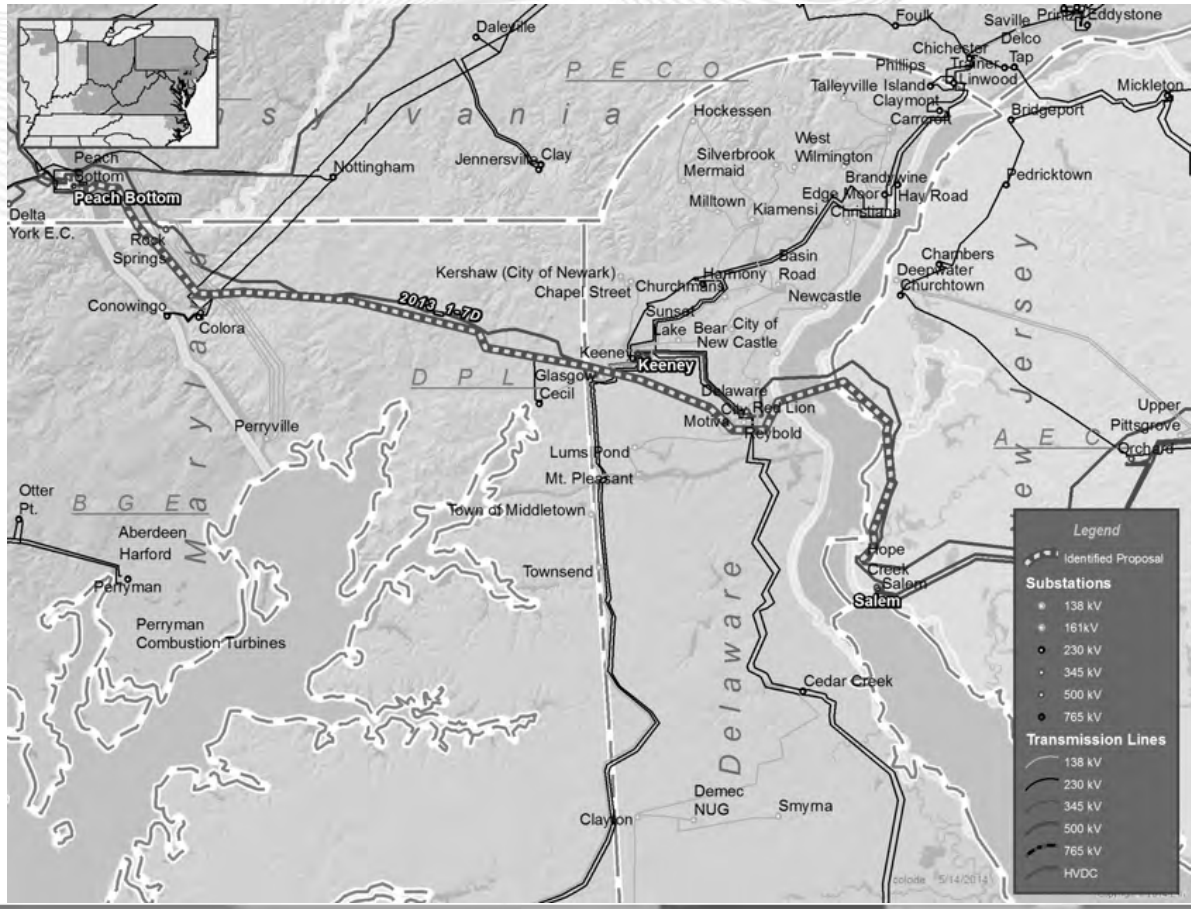
PSE&G 7D

- Lines between:
  - Salem to Hope Creek tie
  - Hope Creek to Peach Bottom (new right of way)
- Estimated costs higher than other proposals



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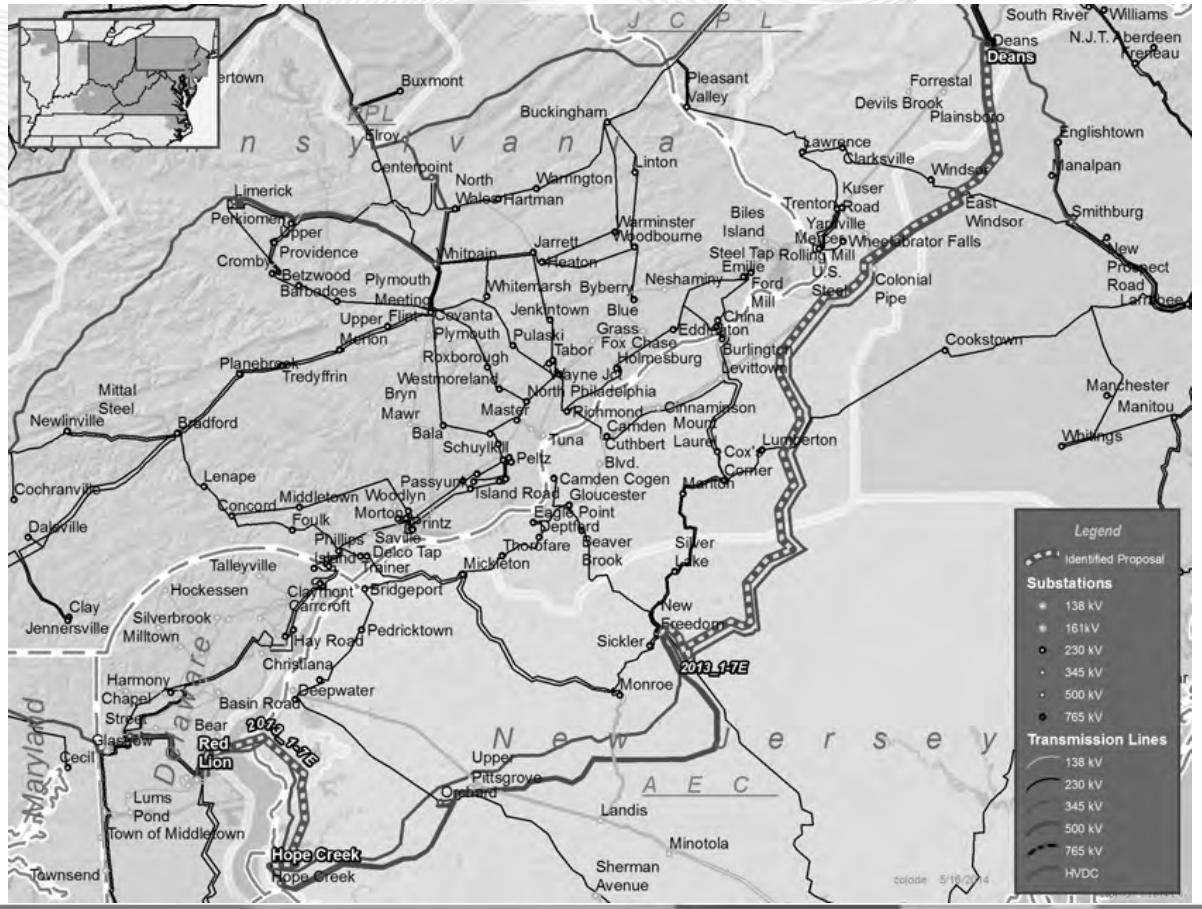
PSE&G 7E

- Lines between:
  - Salem to Hope Creek tie
  - Deans to New Freedom
- Estimated costs higher than other proposals



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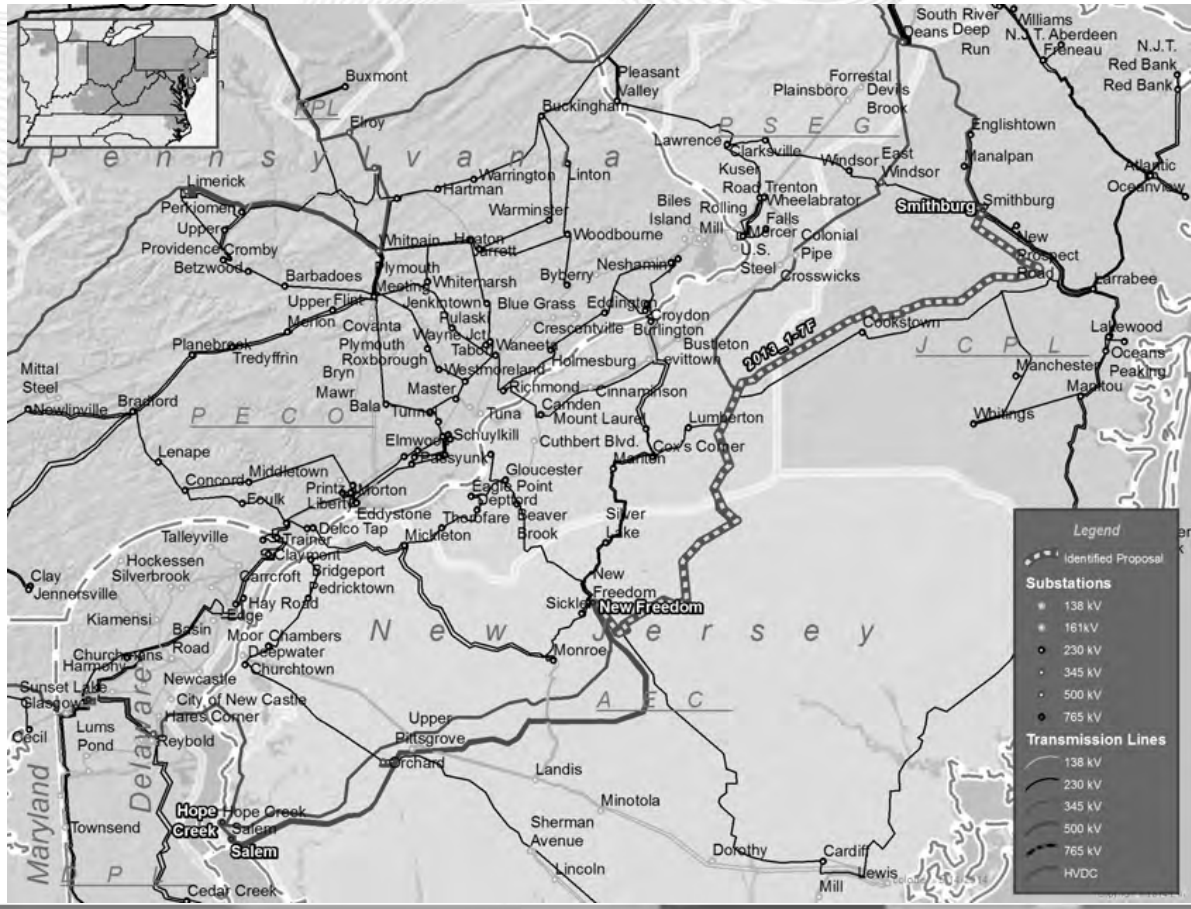
PSE&G 7F

- Lines between:
  - Salem to Hope Creek tie
  - Smithburg to New Freedom
- Estimated costs higher than other proposals



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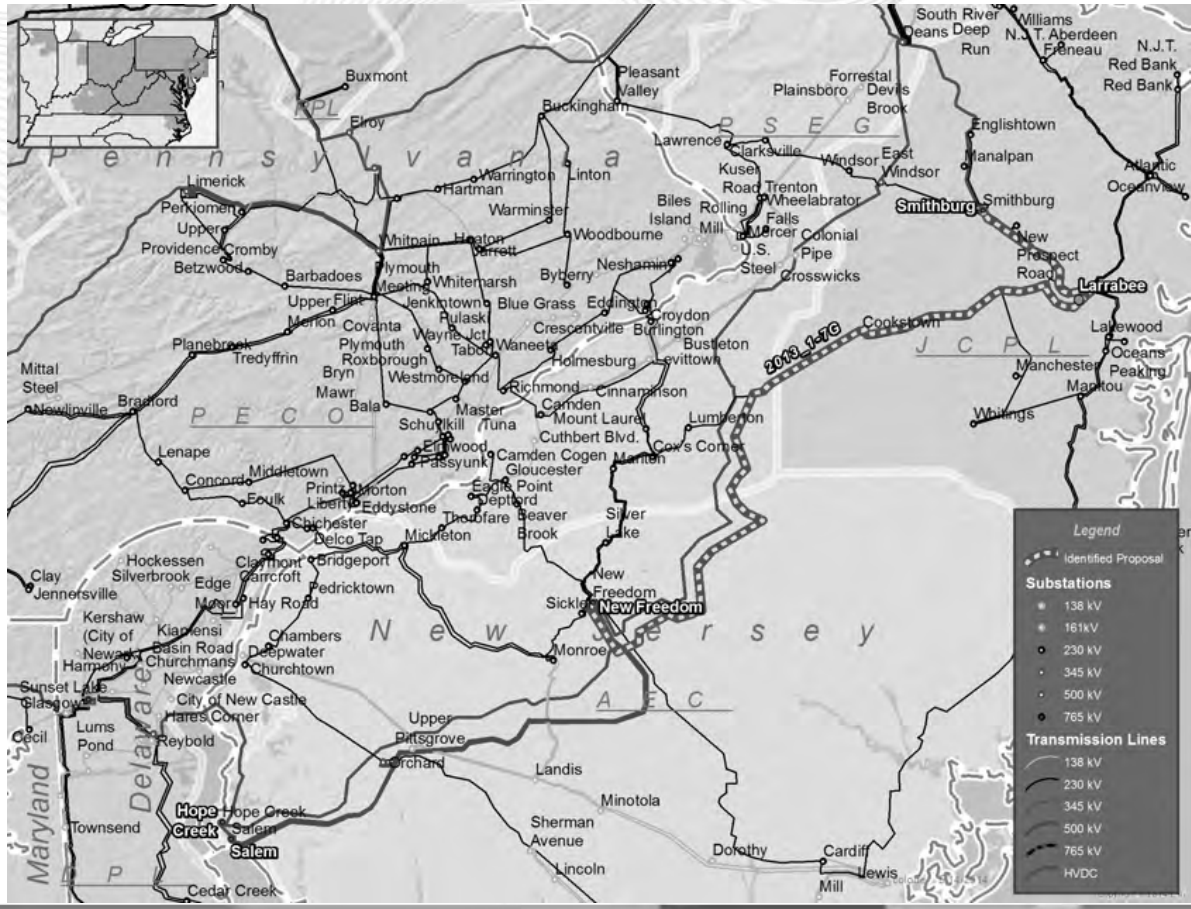
PSE&G 7G

- Lines between:
  - Salem to Hope Creek tie
  - Smithburg to Larrabee
  - Larrabee to New Freedom

- Estimated costs higher than other proposals



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PSE&G 7H

- Lines between:
  - Salem to Hope Creek tie
  - Whitpain to New Freedom (northern route)
- Estimated costs higher than other proposals

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PSE&G 7H

- Lines between:
  - Salem to Hope Creek tie
  - Whitpain to New Freedom (northern route)
- Estimated costs higher than other proposals

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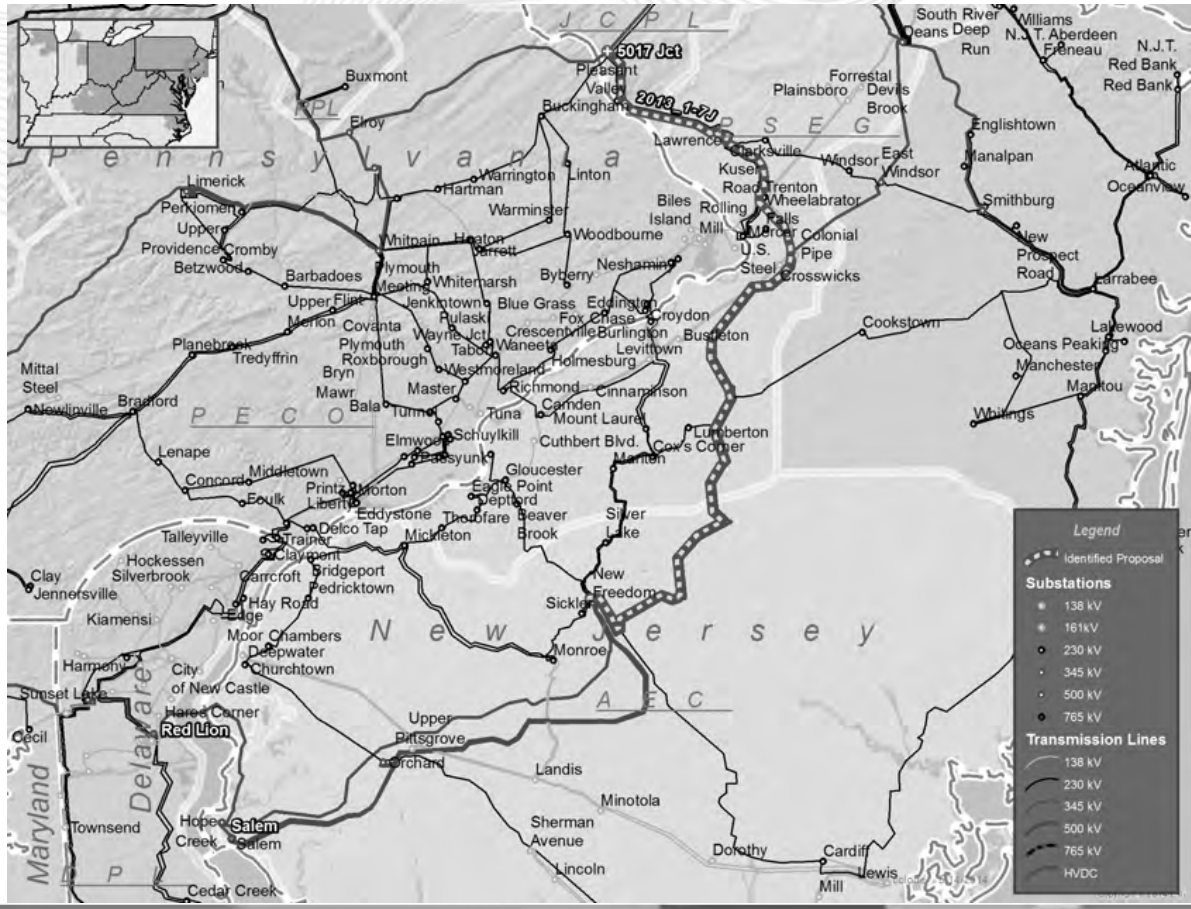
PSE&G 7l

- Lines between:
  - Salem to Hope Creek tie
  - Whitpain to New Freedom (southern route)
- Estimated costs higher than other proposals

PSE&G 7J

- Lines between:
  - Salem to Hope Creek tie
  - 5017 Junction (cutting the 5017 Elroy to Branchburg line) to New Freedom

- Estimated costs higher than other proposals



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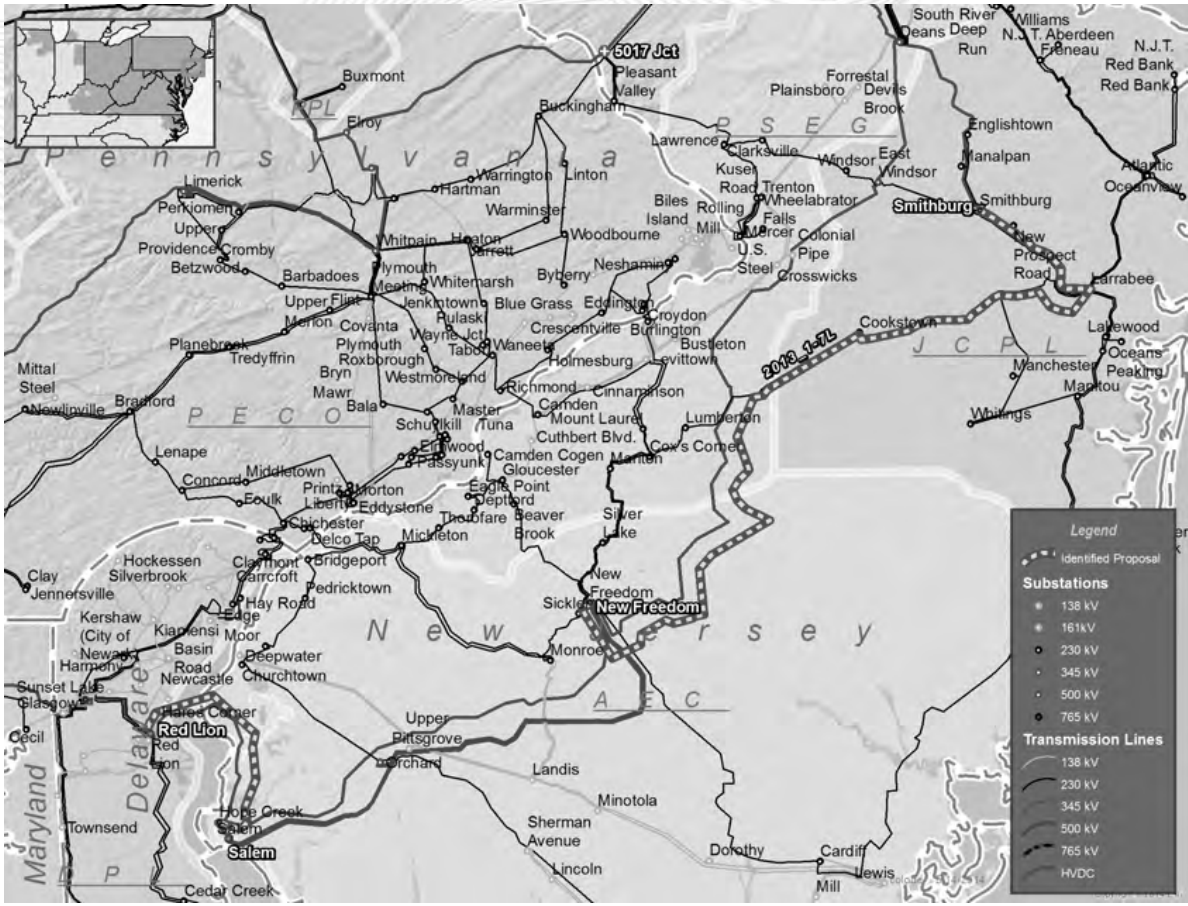
PSE&G 7L

- Lines between:
  - Salem to Hope Creek tie
  - Hope Creek to Red Lion
  - New Smithburg to New Freedom
- Estimated costs higher than other proposals



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PSE&G 7M

- Lines between:
  - Salem to Hope Creek tie
  - Hope Creek to Red Lion
  - Whitpain to New Freedom (northern route)

- Estimated costs higher than other proposals

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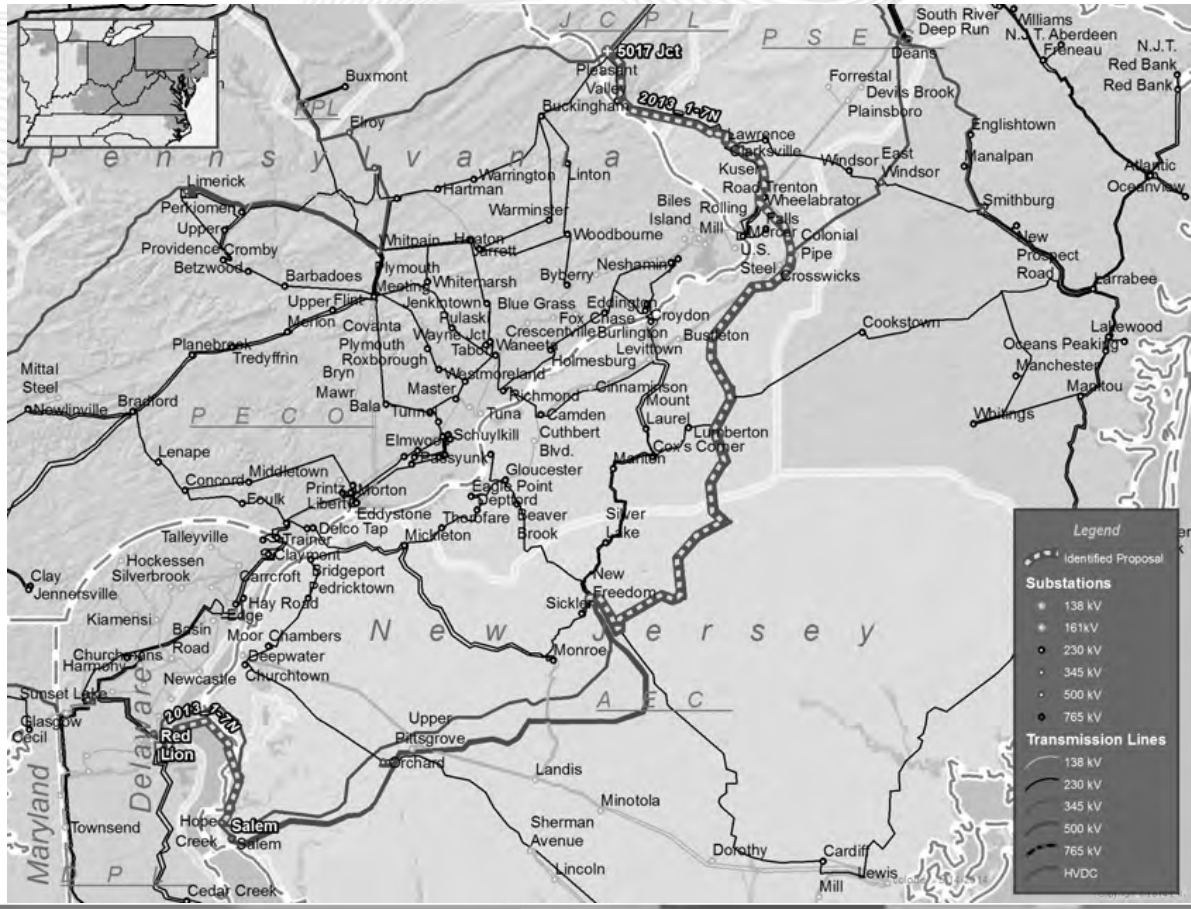
PSE&G 7N

- Lines between:
  - Salem to Hope Creek tie
  - Hope Creek to Red Lion
  - 5017 Junction (cutting the 5017 Elroy to Branchburg line) to New Freedom

- Estimated costs higher than other proposals



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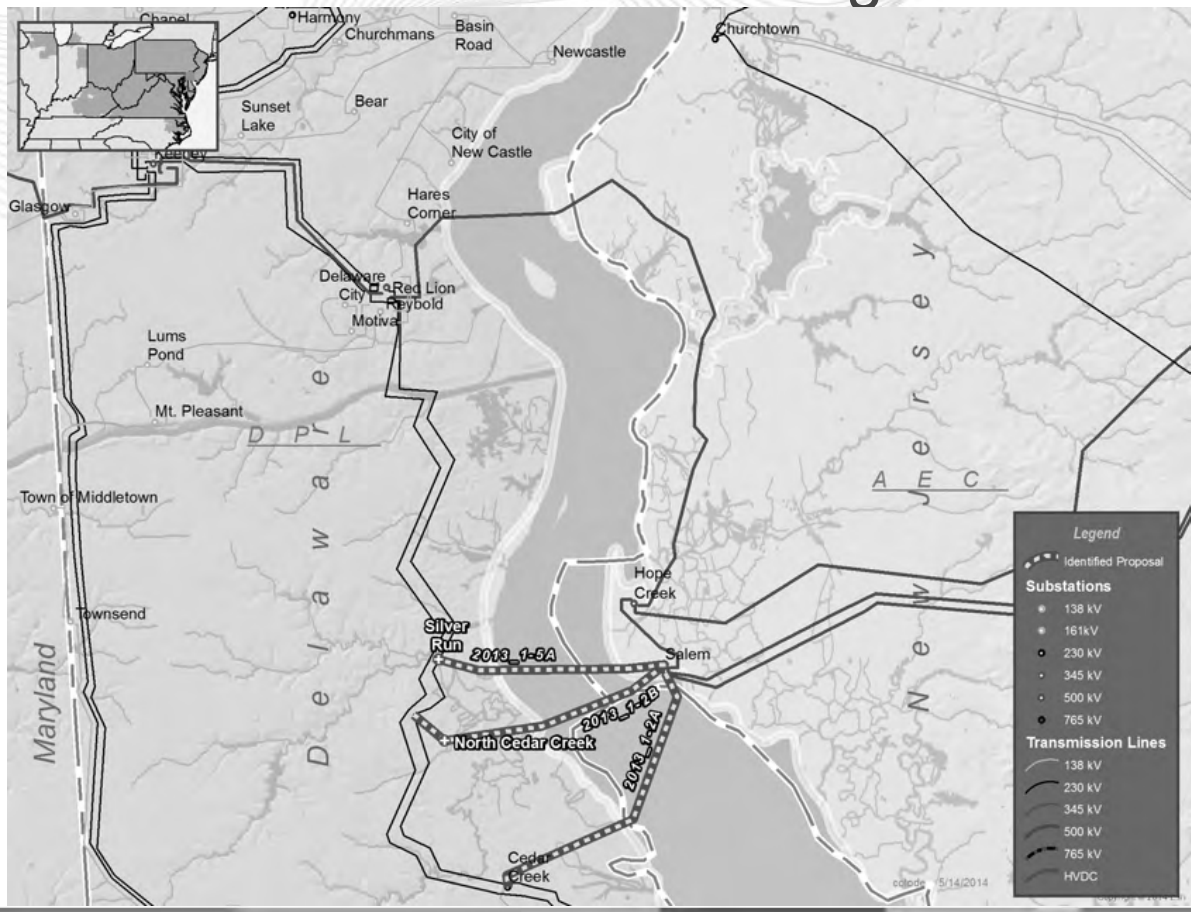
Submarine Southern Delaware Crossing Lines

- Expansion of the Salem substation to the south
- Submarine line under the Delaware river
- New or expansion of existing substation in Delaware
- Proposing Entities:

Transource
LS Power



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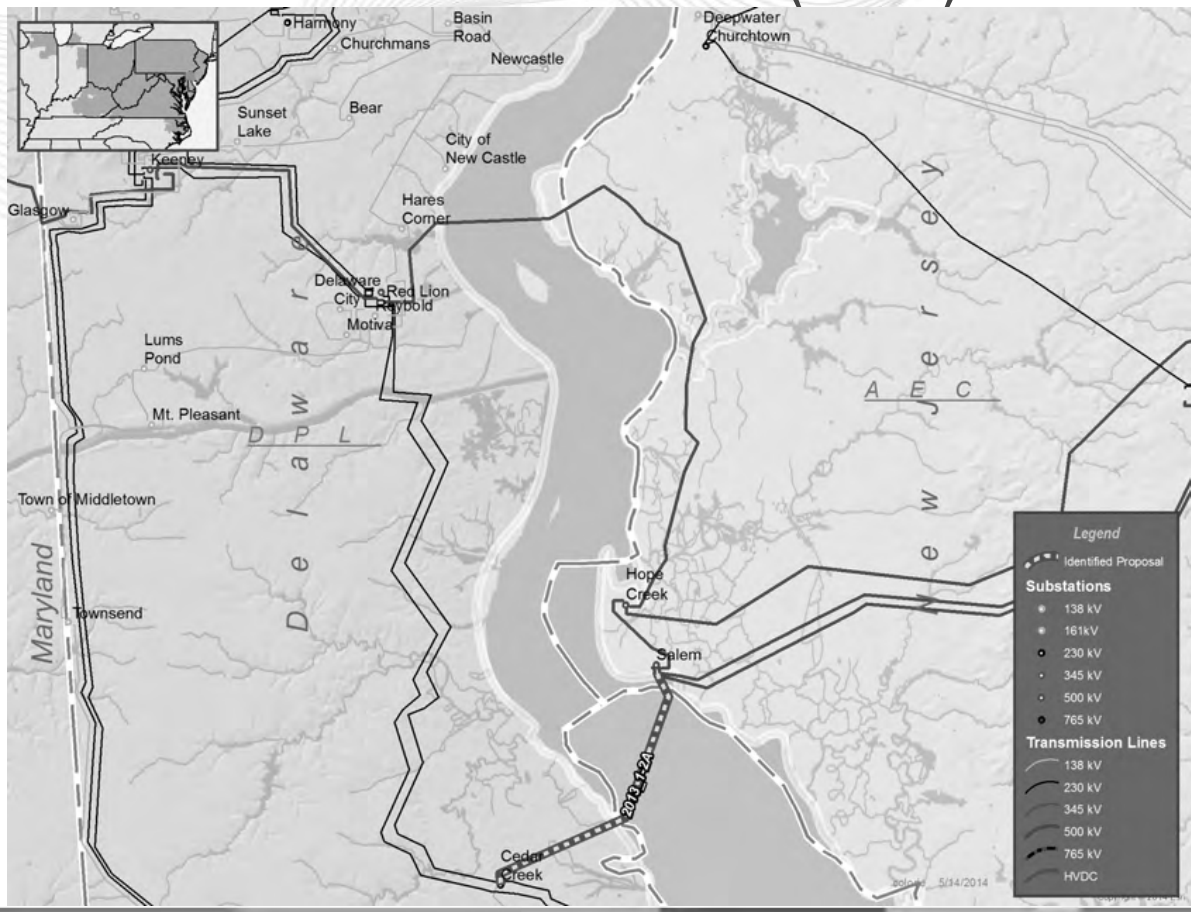
Transource (AEP) 2A

- Line between new substation near Artificial Island and Cedar Creek substation
- Submarine under the Delaware river
- PJM modifications
  - Technical:
    - Added SVC
  - Constructability:
    - Spare submarine cable added
    - New Salem connection as a full bay



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Transource (AEP) 2A – Technical Analysis

- Stability Performance
  - Failed required performance
    - Failed as proposed by project sponsor
    - Did not satisfy stability criteria for a single line to ground fault with stuck breaker with AI units at unity power factor under 5015 maintenance outage condition.
  - Passed required performance
    - Passed when modified with the addition of an SVC at Orchard, New Freedom or Artificial Island

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Artificial Island
Transource (AEP) 2A
Salem Expansion
Proposed new 500/230kV substation
• Two 500/230kV auto-transformers
New bay for 5024 line
• No aerial line crossings
• Outages for final tie in
Red Lion (5015)
New Freedom (5023)
Hope Creek (5037)
Orchard (5021)
New Freedom (5024)
Hope Creek Generating Station
Hope Creek Rd
Salem Rd
Salem Rd
Salem Rd

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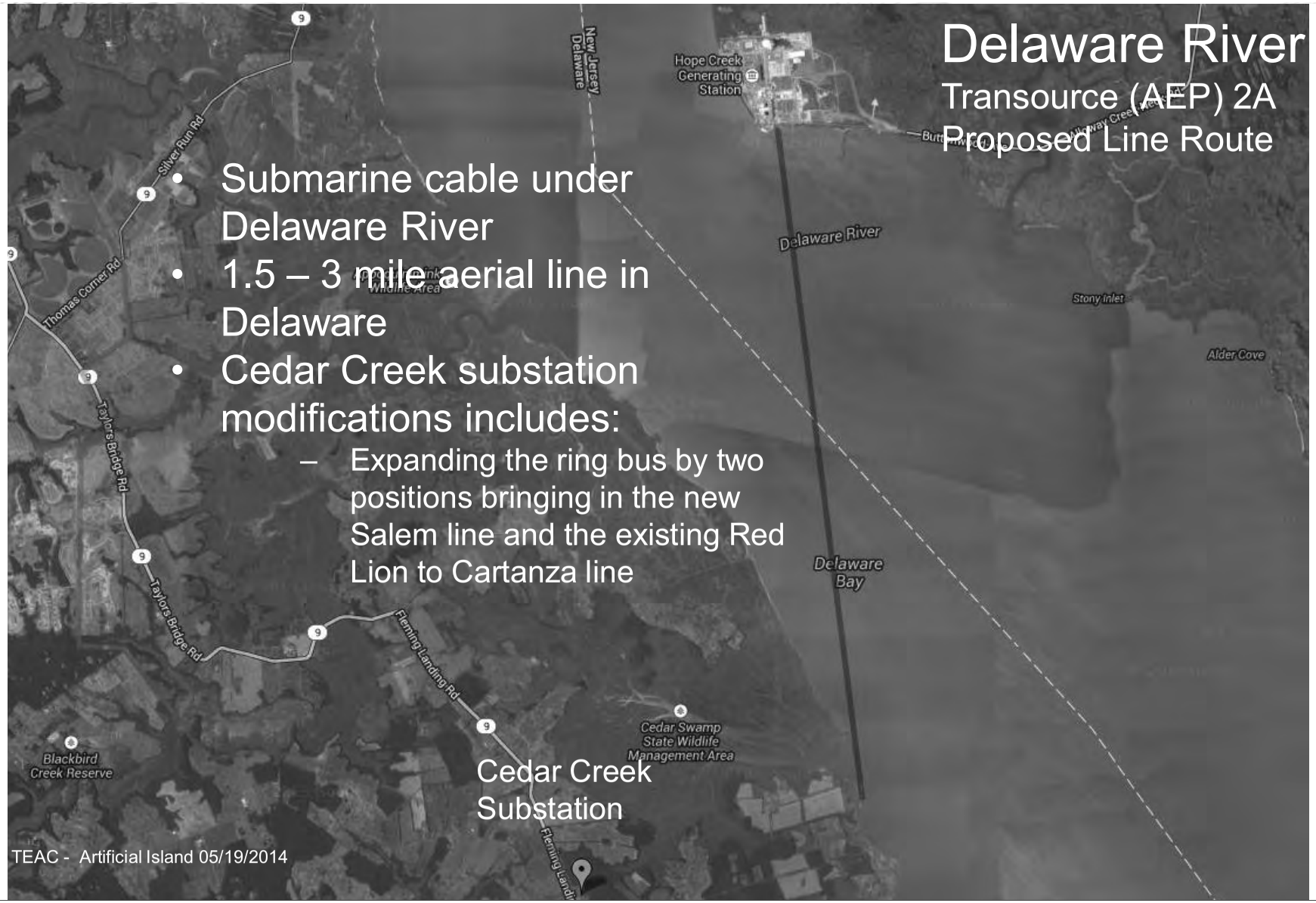
Delaware River

Transource (AEP) 2A Proposed Line Route



- Submarine cable under Delaware River
- 1.5 – 3 mile aerial line in Delaware
- Cedar Creek substation modifications includes:
  - Expanding the ring bus by two positions bringing in the new Salem line and the existing Red Lion to Cartanza line

Transource (AEP) 2A - Cost Factors

PJM Estimated Cost: $366-$446 (million)

- 5.7 circuit miles of submarine cable (two cables per phase plus one spare cable)
- Six 500/230kV auto-transformers

Proposed Cost Estimate: $213-269 (million)

Market Efficiency Analysis Sensitivity Study

- Scenario:
  - New path from the AI to Delaware (on the Cedar Creek - Catanza / Red Lion – Catanza path)
- Results:
  - Approximate benefit to cost ratio of 0.25
  - Approximately $92 million over 15 years

Outage Cost

- 230kV outage during substation cut-in

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Transource (AEP) 2A - Project Schedule

Proposed Schedule 42 months (items run concurrent)

- Permitting: 24 months
- RoW acquisition: 12 months

Schedule Criteria

- Permitting
  - CPCNs in two states and Army Corps of Engineers
- Long Lead Time Materials
  - Auto-transformers and submarine cable
- Construction
  - Specialized equipment needed for submarine cable installation
  - Could be impacted by restrictions due to endangered species and shipping traffic

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Transource (AEP) 2A - RoW and Land Acquisition

Right of Way and Land Acquisition Criteria

- No Eminent Domain in Delaware
  - Approximately 3 miles of right of way needs to be acquired in Delaware
- New Right of Way Required
  - Approximately 3 miles of right of way needs to be acquired in Delaware
- Substation Land Required
  - Land in New Jersey will need to be acquired for the new substations

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Transource (AEP) 2A - Siting and Permitting

Siting and Permitting Criteria

- Wetlands Impact
  - Permits required to cross the Delaware state lands on the river coast
  - Impacts approximately 10 acres of forested wetlands
- Public Opposition Risk
  - Submarine crossing of the Delaware river does not incur any new view-shed impact
  - Some opposition to any river crossing is expected
- Historic and Scenic Highway
  - Not applicable
- Delaware River Crossing
  - Numerous approvals and permits required:
    (a few major permits are listed below)
    - Delaware River Basin Commission approval required
    - Delaware and New Jersey CPCNs required
    - US Army Corps of Engineers Section 404 and 10 authorizations
    - Multiple US Fish and Wildlife permits required
    - National Marine Fisheries Service

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Transource (AEP) 2A - Operational Impact

Operational Impact Criteria

- Artificial Island Facility Requirements
  - PJM Operations Review
    - Request to minimize impact to existing transmission facilities
  - Salem/Hope Creek Facility Owner Feedback
    - Request to minimize outage and physical impacts to existing transmission facilities
    - Salem is space constrained so expansion needs to incorporate maintenance access to substation equipment
    - Salem control house is a part of plant facilities and access is constrained
- Blackstart
  - 230kV connection may provide additional benefit
- Route Diversity
  - Project route is new and does not parallel an existing line
- Ongoing Maintenance
  - Auto-transformers as line component may increase outage frequency
  - Salt spray concern with proximity to Delaware river

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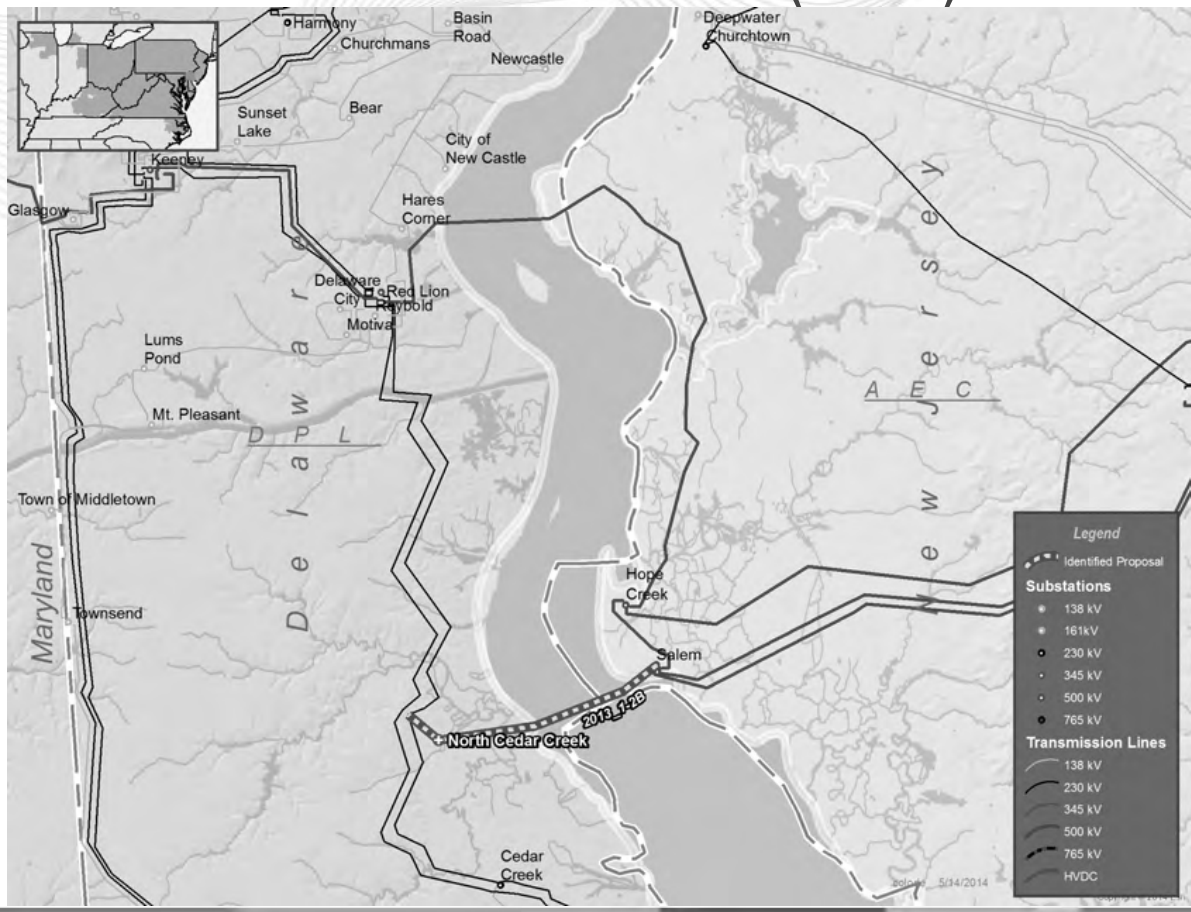
Transource (AEP) 2B

- Line between new substation near Artificial Island and new substation in Delaware
- Submarine under the Delaware river
- PJM modifications
  - Technical:
    - Added SVC
  - Constructability:
    - Spare submarine cable added
    - New Salem connection as a full bay



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Transource (AEP) 2B – Technical Analysis

- Stability Performance

  – Failed required performance
    - Failed as proposed by project sponsor.
    - Did not satisfy stability criteria for a single line to ground fault with stuck breaker with AI units at unity power factor under 5015 maintenance outage condition.

  – Passed required performance
    - Passed as proposed with the addition of an SVC at Orchard, New Freedom or Artificial Island

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Artificial Island

Transource (AEP) 2B
Salem Expansion

Proposed new 500/230kV substation

- Two 500/230kV auto-transformers

New bay for 5024 line

- No aerial line crossings
- Outages for final tie in

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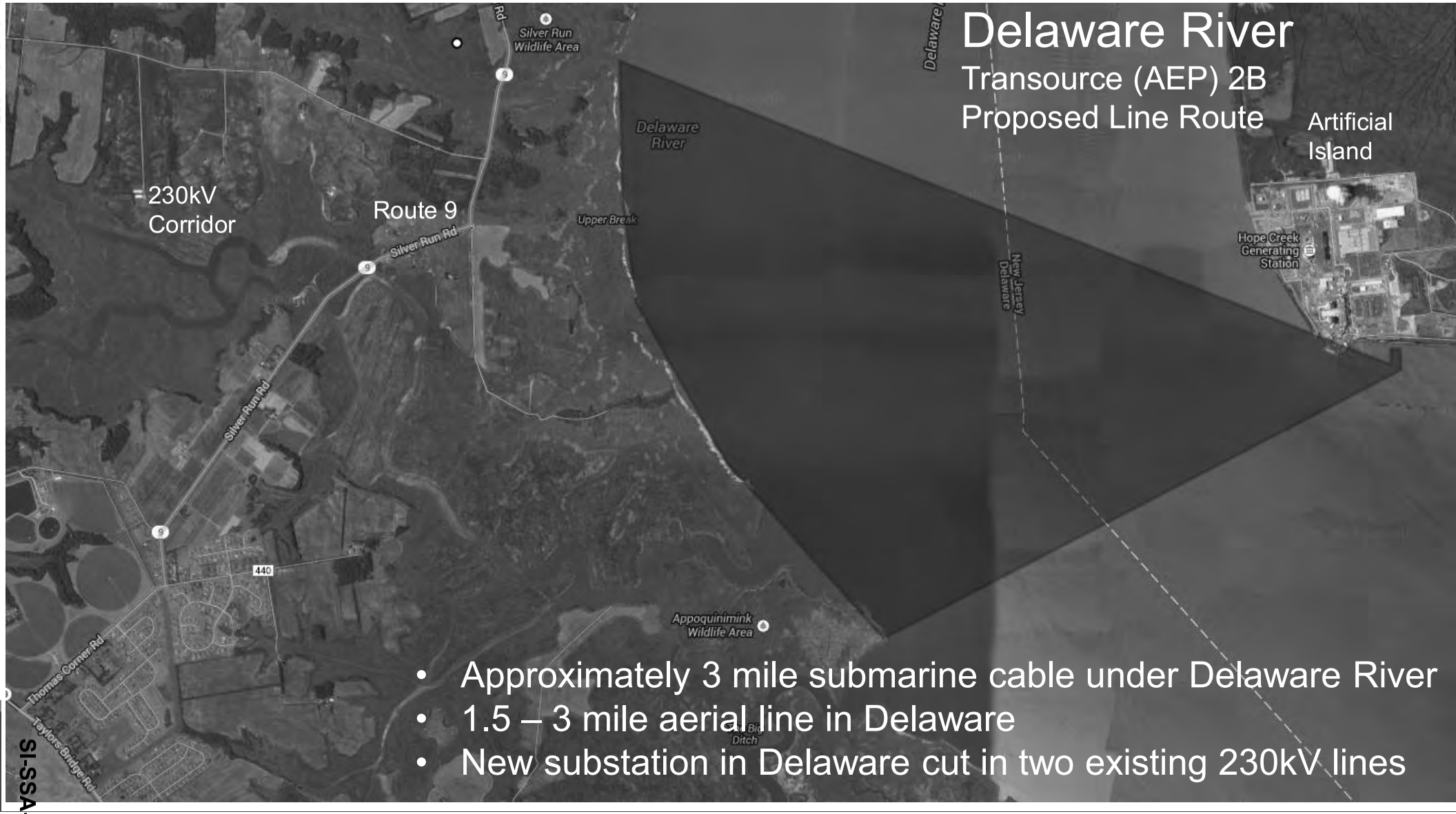

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Transource (AEP) 2B - Cost Factors

PJM Estimated Cost: $257-$313 (million)

- Approximately 3 miles of submarine cable (two cables per phase plus one spare cable)
- Six 500/230kV auto-transformers

Proposed Cost Estimate: $165-$208 (million)

Market Efficiency Analysis Sensitivity Study

- Scenario:
  - New path from the AI to Delaware (on the Cedar Creek - Catanza / Red Lion – Catanza path)
- Results:
  - Approximate benefit to cost ratio of 0.25
  - Approximately $92 million over 15 years

Outage Cost

- 230kV outage during substation cut-in

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Transource (AEP) 2B - Project Schedule

Proposed Schedule 42 months (items run concurrent)

- Permitting: 30 months
- RoW acquisition: 9 months

Schedule Criteria

- Permitting
  - CPCNs in two states and Army Corps of Engineers
- Long Lead Time Materials
  - Auto-transformers and submarine cable
- Construction
  - Specialized equipment needed for submarine cable installation
  - Could be impacted by restrictions due to endangered species and shipping traffic

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Transource (AEP) 2B - RoW and Land Acquisition

Right of Way and Land Acquisition Criteria

- No Eminent Domain in Delaware
  - 1.5 to 3 miles of right of way needs to be acquired in Delaware
- New Right of Way Required
  - 1.5 to 3 miles of right of way needs to be acquired in Delaware
- Substation Land Required
  - Land in Delaware and New Jersey will need to be acquired for the new substations

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Transource (AEP) 2B - Siting and Permitting

Siting and Permitting Criteria

- Wetlands Impact
  - Permits required to cross the Delaware state lands on the river coast
  - New route will allow flexibility
- Public Opposition Risk
  - Submarine crossing of the Delaware river does not incur any new view-shed impact
  - Some opposition to any river crossing is expected
- Historic and Scenic Highway
  - Proposed line route crosses Delaware state route 9, which is classified as a 'Scenic and Historic" highway which may impact permitting
- Delaware River Crossing
  - Numerous approvals and permits required:

    (a few major permits are listed below)
    - Delaware River Basin Commission approval required
    - Delaware and New Jersey CPCNs required
    - US Army Corps of Engineers Section 404 and 10 authorizations
    - Multiple US Fish and Wildlife permits required
    - National Marine Fisheries Service

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Transource (AEP) 2B - Operational Impact

Operational Impact Criteria

- Artificial Island Facility Requirements
  - PJM Operations Review
    - Request to minimize impact to existing transmission facilities
  - Salem/Hope Creek Facility Owner Feedback
    - Request to minimize outage and physical impacts to existing transmission facilities
    - Salem is space constrained so expansion needs to incorporate maintenance access to substation equipment
    - Salem control house is a part of plant facilities and access is constrained
- Blackstart
  - 230kV connection may provide additional benefit
- Route Diversity
  - Project route is new and does not parallel an existing line
- Ongoing Maintenance
  - Auto-transformers as line component may increase outage frequency
  - Salt spray concern with proximity to Delaware river

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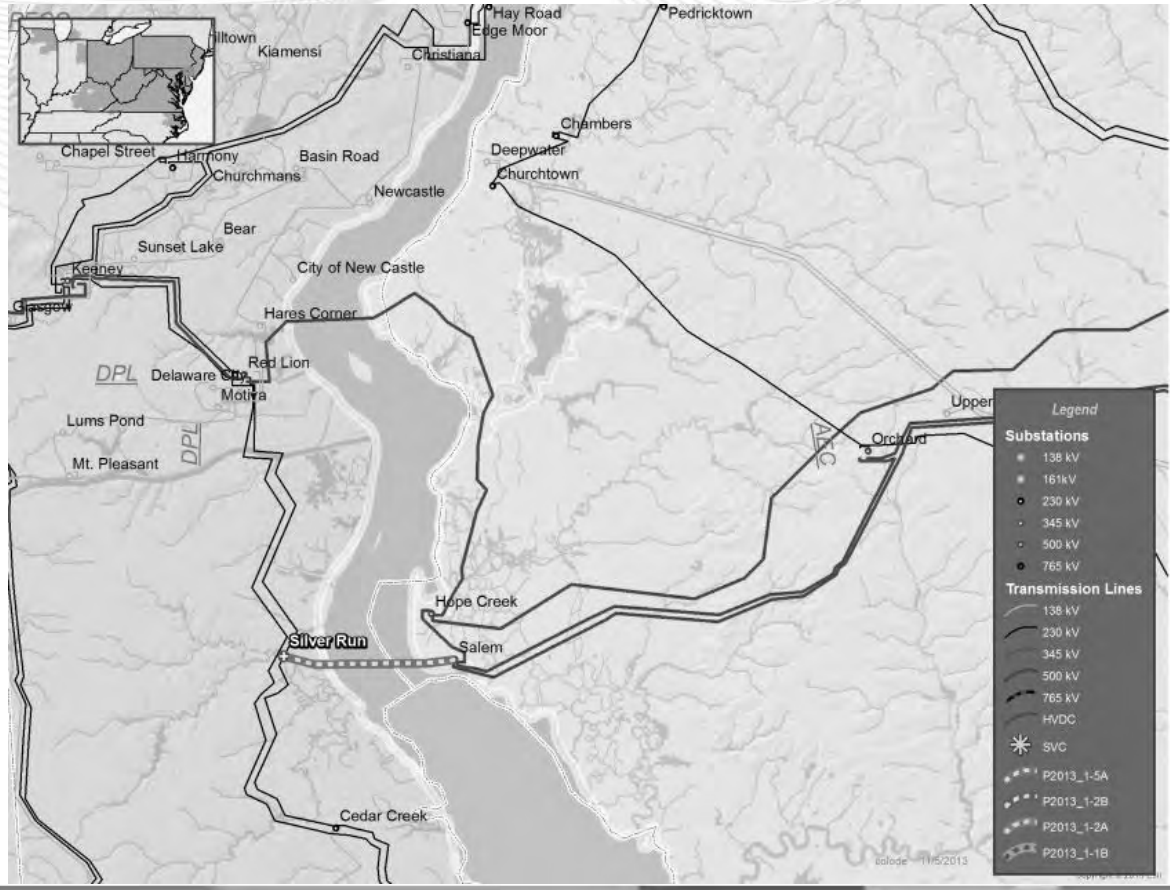
LS Power 5A (Submarine)

- Line between Salem and new substation in Delaware
- Submarine under the Delaware river
- PJM modifications
  - Technical:
    - Added SVC
  - Constructability:
    - Spare transformer phase added
    - Spare submarine cable added



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LS Power 5A (Submarine) – Technical Analysis

- Stability Performance

  – Failed required performance
    - Failed as proposed by project sponsor.
    - Did not satisfy stability criteria for a three phase fault with AI units at unity power factor under 5015 maintenance outage condition.

  – Passed required performance
    - Passed as proposed with the addition of an SVC at Orchard, New Freedom or Artificial Island

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Artificial Island

LS Power – Proposal 5A
Salem Expansion

New 500kV bay and 500/230kV autotransformer in Salem substation

- No aerial line crossings
- Outages for final tie in

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Salem Substation

LS Power – Proposal 5A
Salem Expansion

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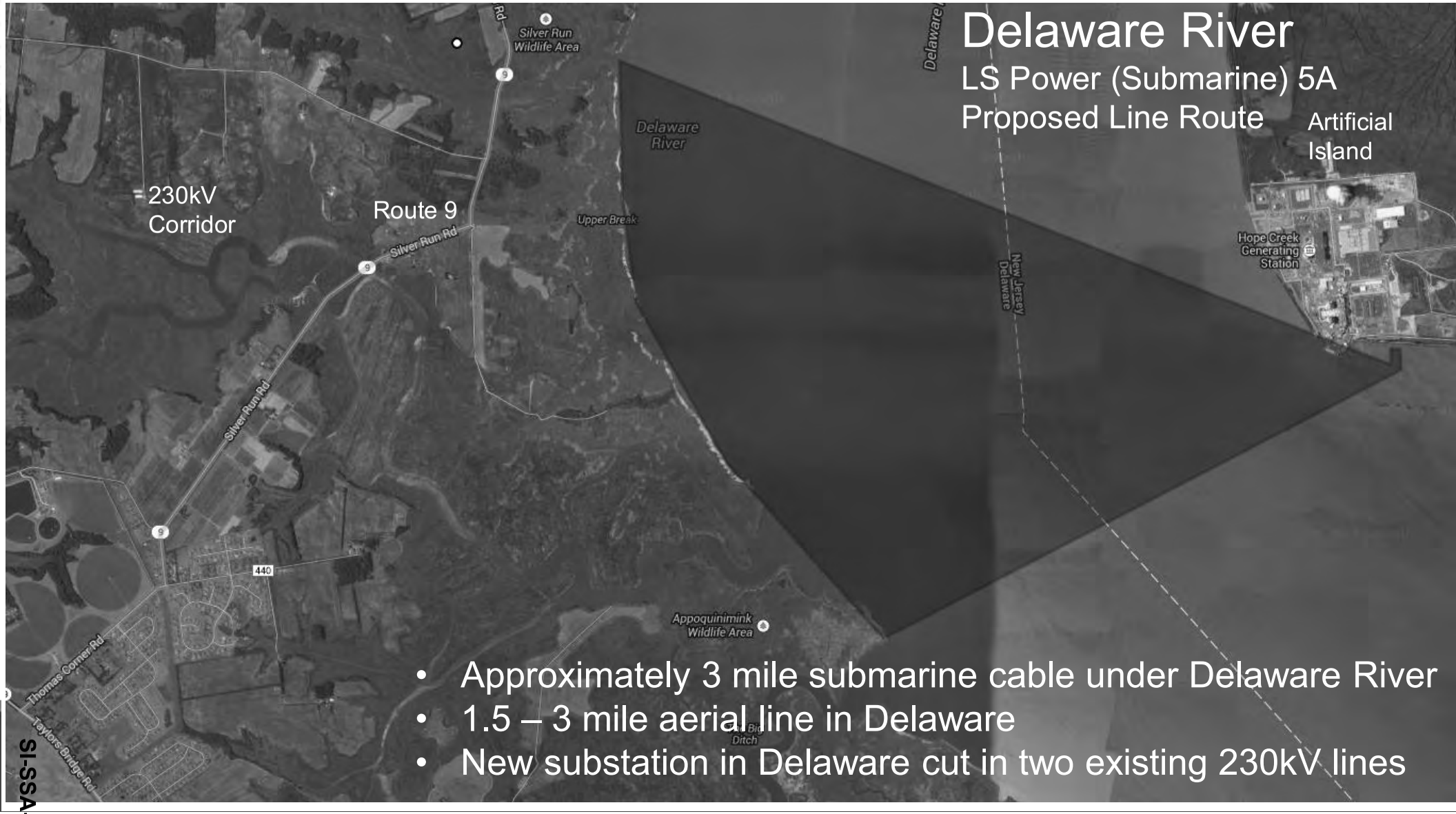

SI-SSA-0010-0177

LS Power 5A (Submarine) - Cost Factors

PJM Estimated Cost: $248 - $311 (million)

- 3.3 circuit miles of submarine cable (two cables per phase plus one spare cable)
- Four 500/230kV auto-transformers

Proposed Cost Estimate: $148 (million)

Market Efficiency Analysis Sensitivity Study

- Scenario:
  - New path from the AI to Delaware (on the Cedar Creek - Catanza / Red Lion – Catanza path)
- Results:
  - Approximate benefit to cost ratio of 0.25
  - Approximately $92 million over 15 years

Outage Cost

- 230kV outage during substation cut-in

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LS Power 5A (Submarine) - Project Schedule

Proposed Schedule 42 months (items run concurrent)

- Permitting: 30 months
- RoW acquisition: 9 months

Schedule Criteria

- Permitting
  - CPCNs in two states and Army Corps of Engineers
- Long Lead Time Materials
  - Auto-transformers and submarine cable
- Construction
  - Specialized equipment needed for submarine cable installation
  - Could be impacted by restrictions due to endangered species and shipping traffic

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LS Power 5A (Submarine) - RoW and Land Acquisition

Right of Way and Land Acquisition Criteria

- No Eminent Domain in Delaware
  - 1.5 to 3 miles of right of way needs to be acquired in Delaware
- New Right of Way Required
  - 1.5 to 3 miles of right of way needs to be acquired in Delaware
- Substation Land Required
  - Has acquired an option on a site for the proposed new switching station in Delaware

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LS Power 5A (Submarine) - Siting and Permitting

Siting and Permitting Criteria

- Wetlands Impact
  - Permits required to cross the Delaware state lands on the river coast
  - New route will allow flexibility
- Public Opposition Risk
  - Submarine crossing of the Delaware river does not incur any new view-shed impact
  - Some opposition to any river crossing is expected
- Historic and Scenic Highway
  - Proposed line route parallels Delaware state route 9, which is classified as a 'Scenic and Historic" highway which may impact permitting
- Delaware River Crossing
  - Numerous approvals and permits required:

    (a few major permits are listed below)
    - Delaware River Basin Commission approval required
    - Delaware and New Jersey CPCNs required
    - US Army Corps of Engineers Section 404 and 10 authorizations
    - Multiple US Fish and Wildlife permits required
    - National Marine Fisheries Service

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LS Power 5A (Submarine) - Operational Impact

Operational Impact Criteria

- Artificial Island Facility Requirements
  - PJM Operations Review
    - Request to minimize impact to existing transmission facilities
  - Salem/Hope Creek Facility Owner Feedback
    - Request to minimize outage and physical impacts to existing transmission facilities
    - Salem is space constrained so expansion needs to incorporate maintenance access to substation equipment
    - Salem control house is a part of plant facilities and access is constrained
- Blackstart
  - 230kV connection may provide additional benefit
- Route Diversity
  - Project route is new and does not parallel an existing line
- Ongoing Maintenance
  - Auto-transformers as line component may increase outage frequency
  - Salt spray concern with proximity to Delaware river

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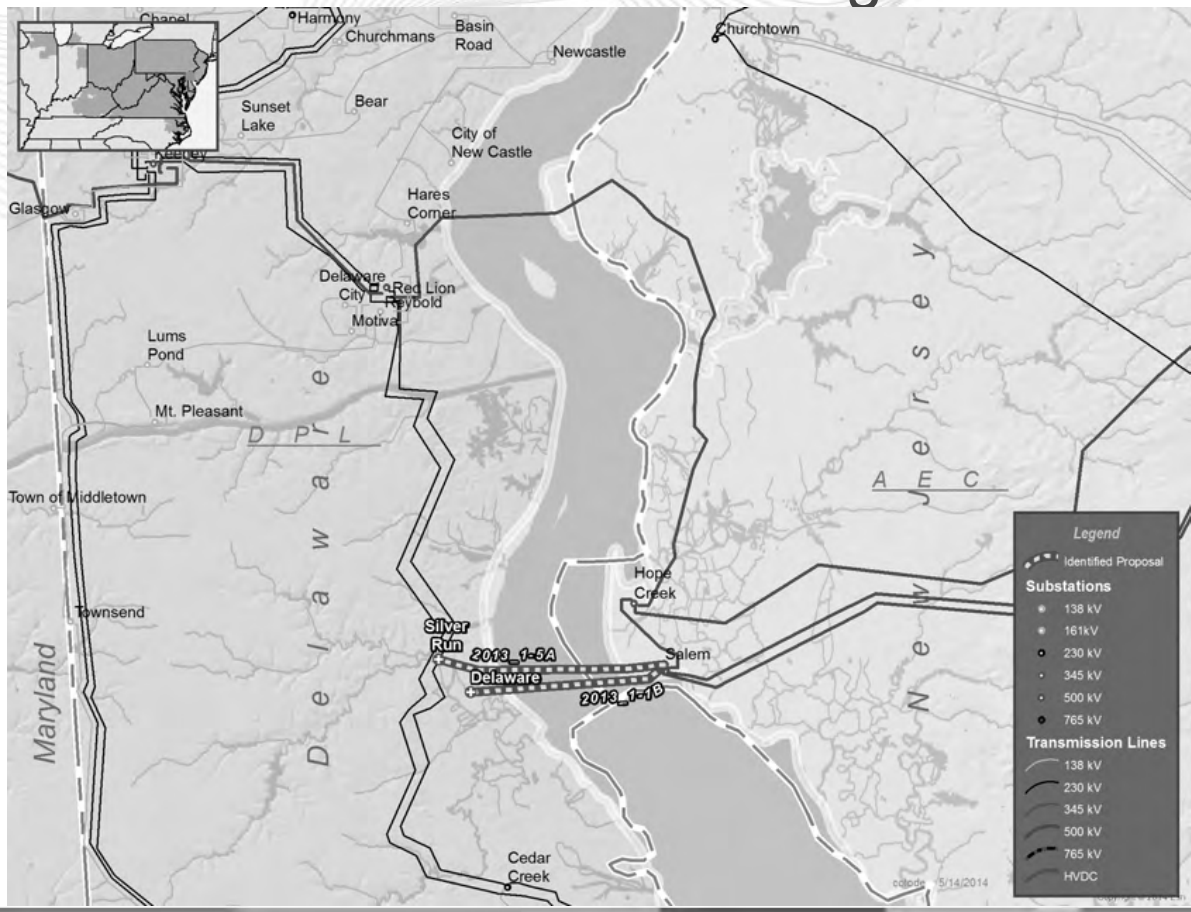
Overhead Southern Delaware Crossing Lines

- Expansion of the Salem substation to the south
- Aerial line over the Delaware river
- New substation in Delaware
- Proposing Entities:

Dominion
LS Power



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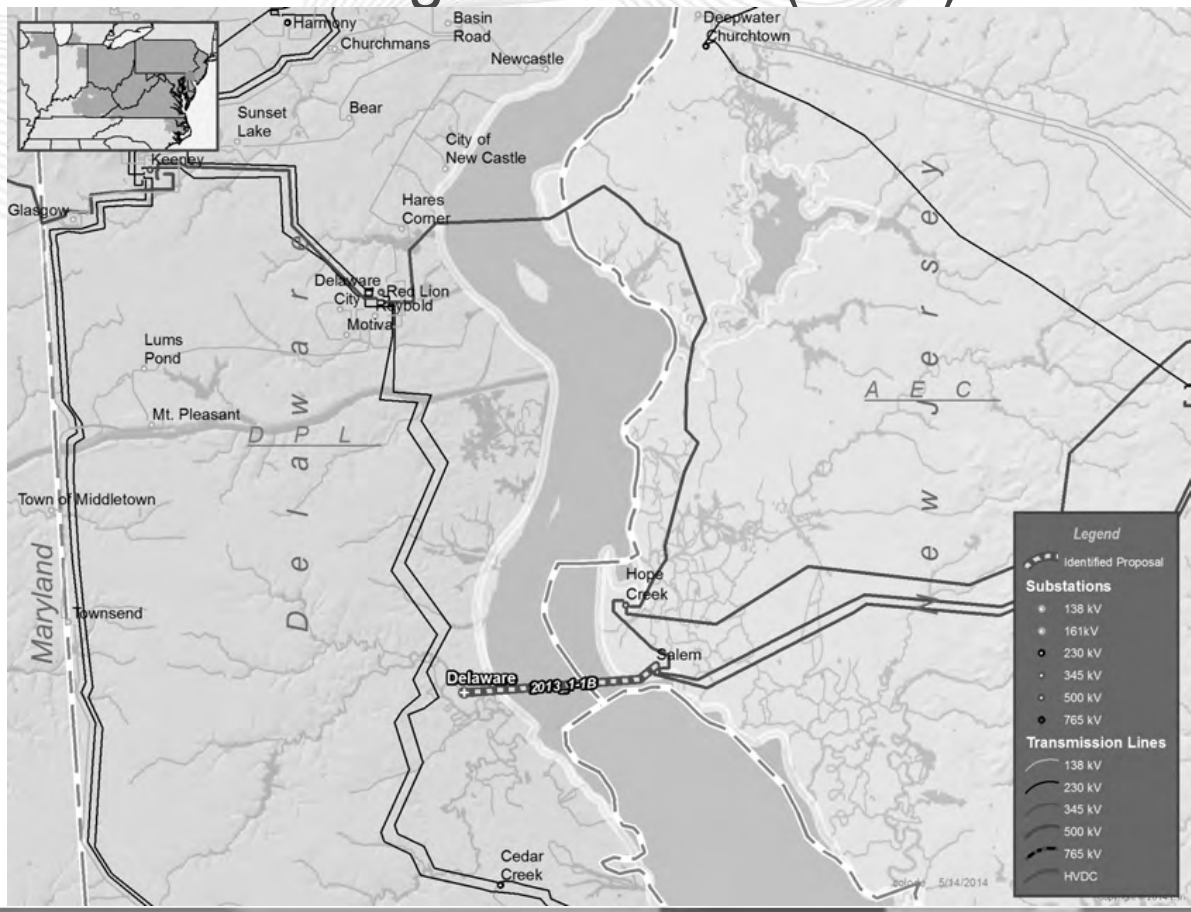
Dominion Virginia Power (DVP) 1B

- Line between Salem and new substation in Delaware
- Aerial crossing of the Delaware river
- PJM modifications
  - Technical:
    - Added SVC
  - Constructability:



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Dominion Virginia Power (DVP) 1B – Technical Analysis

- Stability Performance

  – Failed required performance
    - Failed as proposed by project sponsor.
    - Failed with modification to remove proposed breakers.
    - Did not satisfy stability criteria for a three phase fault with AI units at unity power factor under 5015 maintenance outage condition.
    - Did not satisfy stability criteria for a three phase fault with AI units at unity power factor under 5015 maintenance outage condition with modification to remove proposed breakers.

  – Passed required performance
    - Passed as modified with the addition of an SVC at Orchard, New Freedom or Artificial Island.

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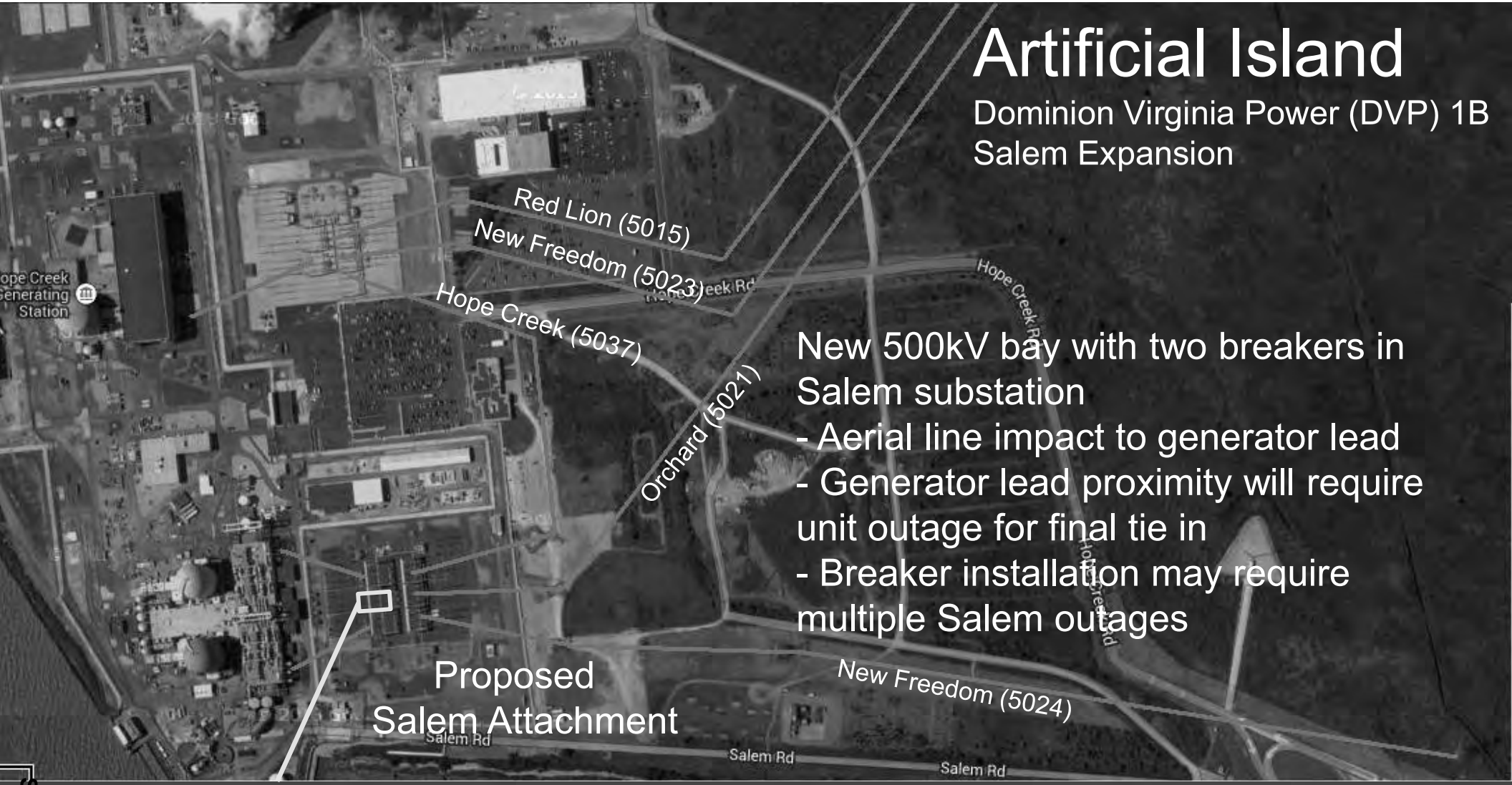
Artificial Island

Dominion Virginia Power (DVP) 1B
Salem Expansion



New 500kV bay with two breakers in Salem substation
- Aerial line impact to generator lead
- Generator lead proximity will require unit outage for final tie in
- Breaker installation may require multiple Salem outages

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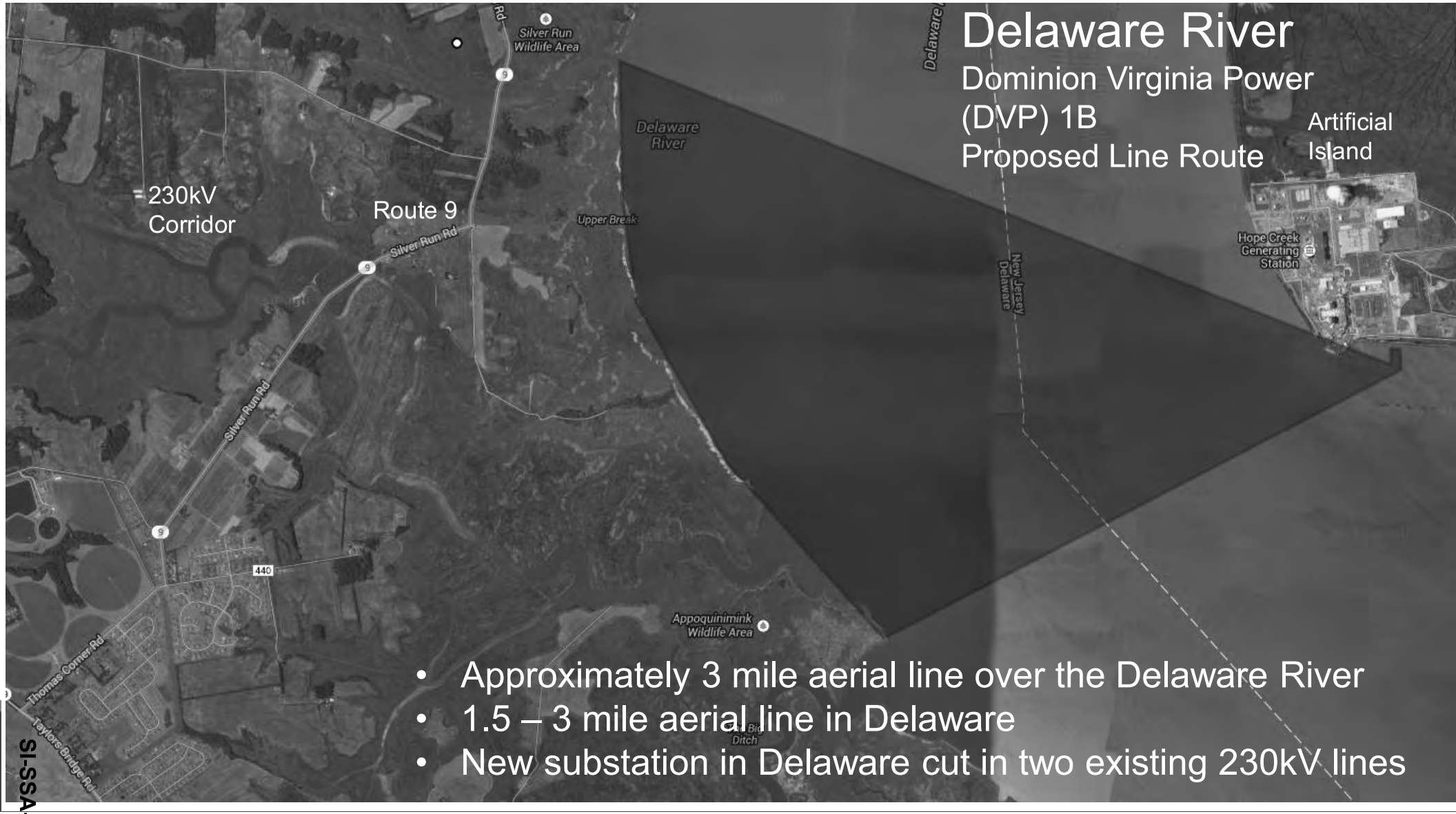

SI-SSA-0010-0187

Dominion Virginia Power (DVP) 1B- Cost Factors

PJM Estimated Cost: $233 - $283 (million)

- Six 500/230kV auto-transformers
- Aerial crossing of the Delaware River

Proposed Cost Estimate: $133 (million)

Market Efficiency Analysis Sensitivity Study

- Scenario:
  - New path from the AI to Delaware (on the Cedar Creek - Catanza / Red Lion – Catanza path)
- Results:
  - Approximate benefit to cost ratio of 0.25
  - Approximately $92 million over 15 years

Outage Cost

- 230kV outage during substation cut-in

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Dominion Virginia Power (DVP) 1B - Project Schedule

Proposed Schedule 93 months (items run concurrent)

- Permitting: 50 months
- RoW acquisition: 56 months

Schedule Criteria

- Permitting
  - CPCNs in two states and Army Corps of Engineers
- Long Lead Time Materials
  - Auto-transformers
- Construction
  - Could be impacted by restrictions due to endangered species and shipping traffic

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Dominion Virginia Power (DVP) 1B RoW and Land Acquisition

Right of Way and Land Acquisition Criteria

- No Eminent Domain in Delaware
  - 1.5 to 3 miles of right of way needs to be acquired in Delaware
- New Right of Way Required
  - 1.5 to 3 miles of right of way needs to be acquired in Delaware
- Substation Land Required
  - Land in Delaware will need to be acquired for the new substation

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Dominion Virginia Power (DVP) 1B - Siting and Permitting

Siting and Permitting Criteria

- Wetlands Impact
  - Permits required to cross the Delaware state lands on the river coast
  - New route will allow flexibility
- Public Opposition Risk
  - Aerial crossing of the Delaware river would create a new view-shed impact
  - Some opposition to any river crossing is expected
- Historic and Scenic Highway
  - Proposed line route parallels Delaware state route 9, which is classified as a 'Scenic and Historic" highway which may impact permitting
- Delaware River Crossing
  - Numerous approvals and permits required:

    (a few major permits are listed below)
    - Delaware River Basin Commission approval required
    - Delaware and New Jersey CPCNs required
    - US Army Corps of Engineers Section 404 and 10 authorizations
    - Multiple US Fish and Wildlife permits required
    - National Marine Fisheries Service

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Dominion Virginia Power (DVP) 1B - Operational Impact

Operational Impact Criteria

- Artificial Island Facility Requirements
  - PJM Operations Review
    - Request to minimize impact to existing transmission facilities
  - Salem/Hope Creek Facility Owner Feedback
    - Request to minimize outage and physical impacts to existing transmission facilities
    - Salem is space constrained so expansion needs to incorporate maintenance access to substation equipment
    - Salem control house is a part of plant facilities and access is constrained
- Blackstart
  - 500kV connection may provide additional benefit
- Route Diversity
  - Project route is new and does not parallel an existing line
- Ongoing Maintenance
  - Auto-transformers as line component may increase outage frequency

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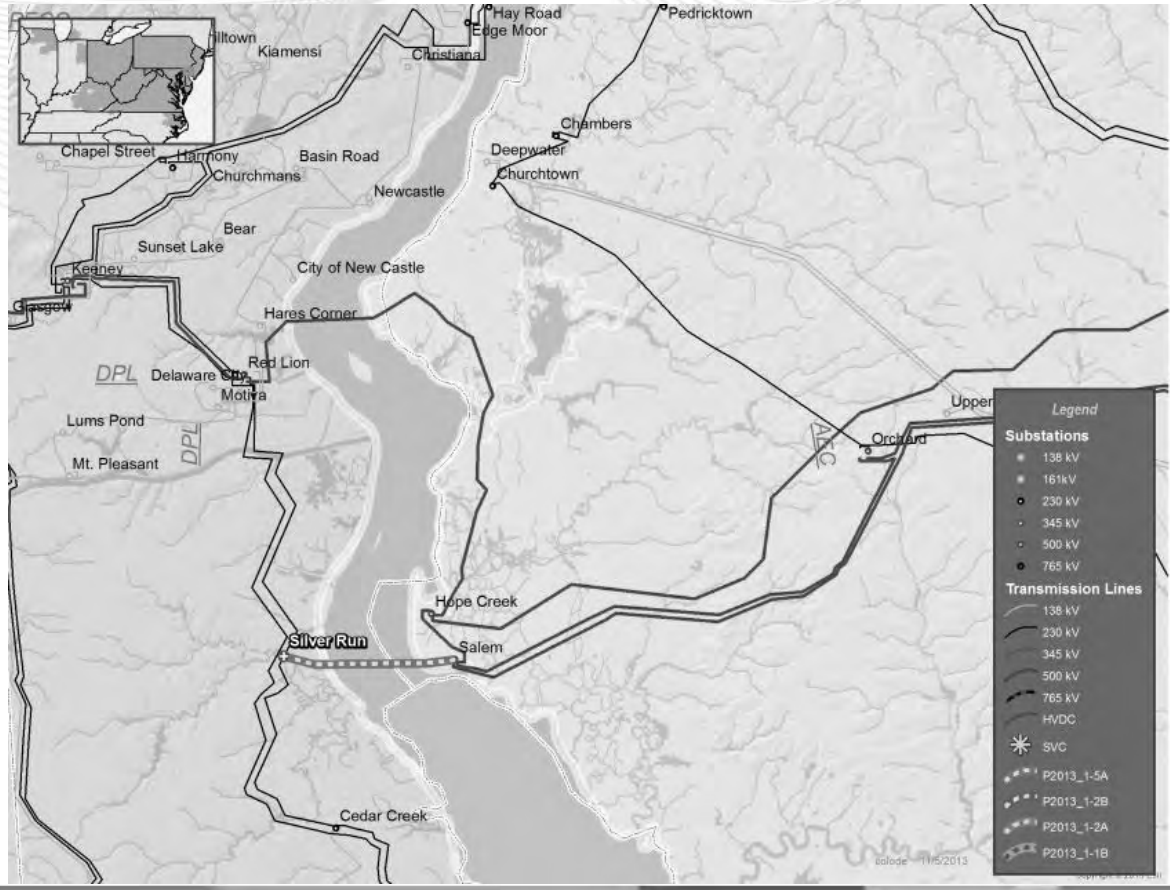
LS Power 5A (Aerial)

- Line between Salem and new substation in Delaware
- Aerial crossing of the Delaware river
- PJM modifications
  - Technical:
    - Added SVC
  - Constructability:
    - Spare transformer phase added



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LS Power 5A (Overhead) – Technical Analysis

- Stability Performance

  – Failed required performance
    - Failed as proposed by project sponsor.
    - Did not satisfy stability criteria for a three phase fault with AI units at unity power factor under 5015 maintenance outage condition.

  – Passed required performance
    - Passed as proposed with the addition of an SVC at Orchard, New Freedom or Artificial Island.

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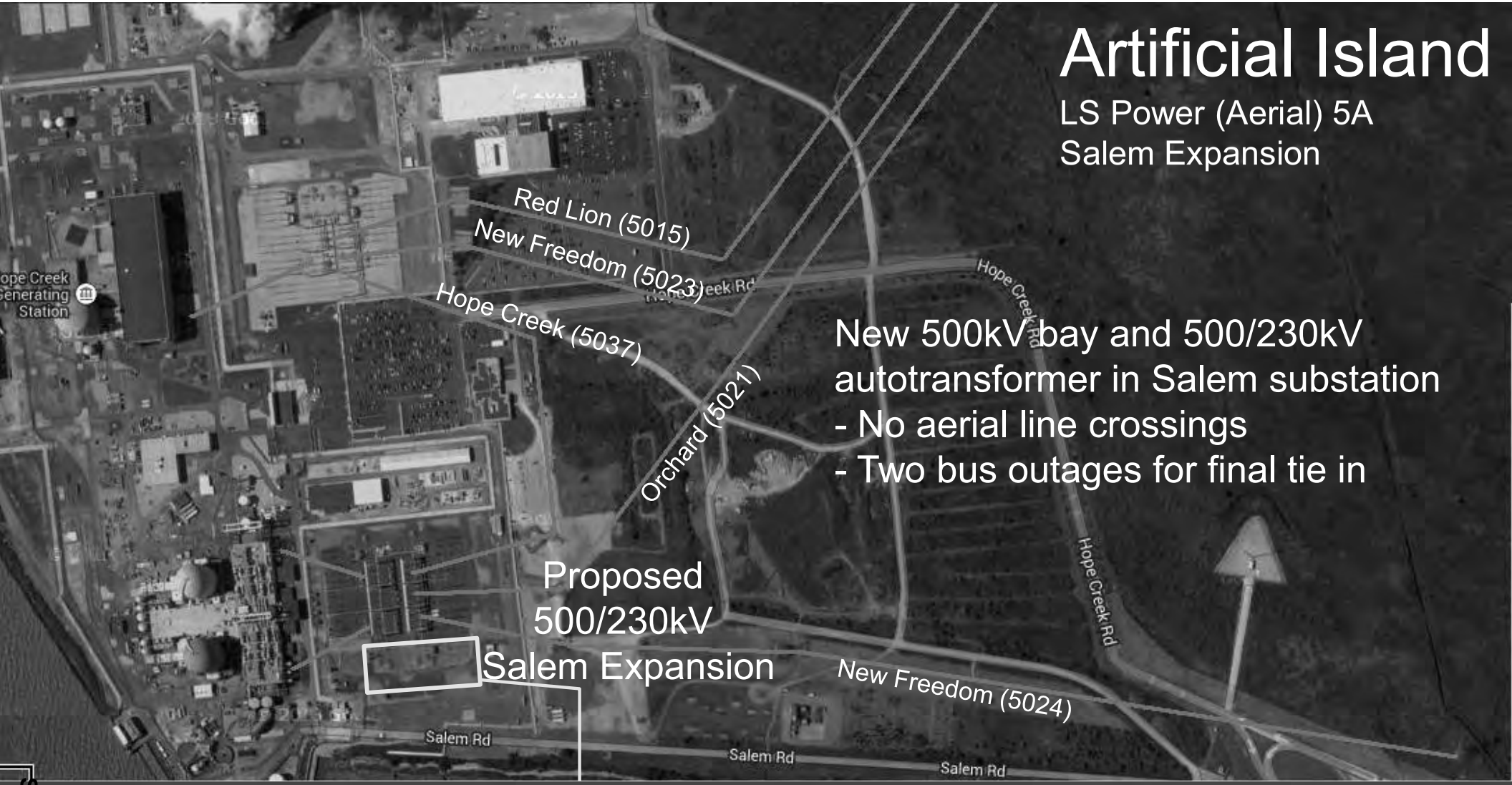
Artificial Island

LS Power (Aerial) 5A
Salem Expansion



New 500kV bay and 500/230kV autotransformer in Salem substation
- No aerial line crossings
- Two bus outages for final tie in

SI-SSA-0010-0195

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Salem Substation

LS Power (Aerial) 5A
Salem Expansion

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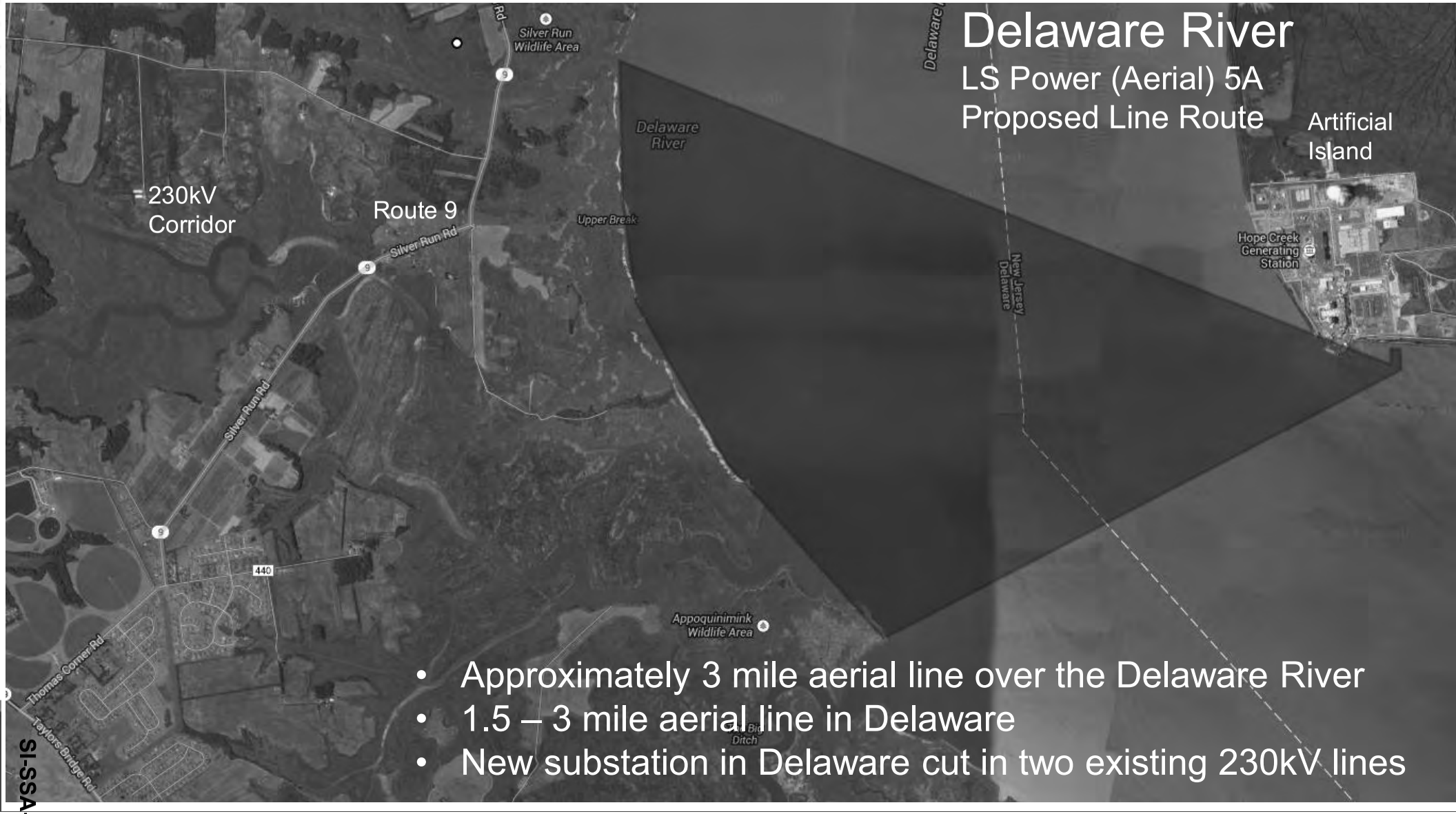

SI-SSA-0010-0197

LS Power 5A (Aerial) - Cost Factors

PJM Estimated Cost: $211 - $257 (million)

- Four 500/230kV auto-transformers
- Aerial Delaware river crossing

Proposed Cost Estimate: $116 (million)

Market Efficiency Analysis Sensitivity Study

- Scenario:
  - New path from the AI to Delaware (on the Cedar Creek - Catanza / Red Lion – Catanza path)
- Results:
  - Approximate benefit to cost ratio of 0.25
  - Approximately $92 million over 15 years

Outage Cost

- 230kV outage during substation cut-in

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LS Power 5A (Aerial) - Project Schedule

Proposed Schedule 42 months (items run concurrent)

- Permitting: 30 months
- RoW acquisition: 9 months

Schedule Criteria

- Permitting
  - CPCNs in two states and Army Corps of Engineers
- Long Lead Time Materials
  - Auto-transformers
- Construction
  - Could be impacted by restrictions due to endangered species and shipping traffic

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LS Power 5A (Aerial) - RoW and Land Acquisition

Right of Way and Land Acquisition Criteria

- No Eminent Domain in Delaware
  - Has acquired an option on a site for the proposed new switching station in Delaware
  - 1.5 to 3 miles of right of way needs to be acquired in Delaware
- New Right of Way Required
  - 1.5 to 3 miles of right of way needs to be acquired in Delaware
- Substation Land Required
  - Has acquired an option on a site for the proposed new switching station in Delaware

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LS Power 5A (Aerial) - Siting and Permitting

Siting and Permitting Criteria

- Wetlands Impact
  - Permits required to cross the Delaware state lands on the river coast
  - New route will allow flexibility
- Public Opposition Risk
  - Aerial crossing of the Delaware river would create a new view-shed impact
  - Some opposition to any river crossing is expected
- Historic and Scenic Highway
  - Proposed line route parallels Delaware state route 9, which is classified as a 'Scenic and Historic" highway which may impact permitting
- Delaware River Crossing
  - Numerous approvals and permits required:

    (a few major permits are listed below)
    - Delaware River Basin Commission approval required
    - Delaware and New Jersey CPCNs required
    - US Army Corps of Engineers Section 404 and 10 authorizations
    - Multiple US Fish and Wildlife permits required
    - National Marine Fisheries Service

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LS Power 5A (Aerial) - Operational Impact

Operational Impact Criteria

- Artificial Island Facility Requirements
  - PJM Operations Review
    - Request to minimize impact to existing transmission facilities
  - Salem/Hope Creek Facility Owner Feedback
    - Request to minimize outage and physical impacts to existing transmission facilities
    - Salem is space constrained so expansion needs to incorporate maintenance access to substation equipment
    - Salem control house is a part of plant facilities and access is constrained
- Blackstart
  - 230kV connection may provide additional benefit
- Route Diversity
  - Project route is new and does not parallel an existing line
- Ongoing Maintenance
  - Auto-transformers as line component may increase outage frequency
  - Salt spray concern with proximity to Delaware river

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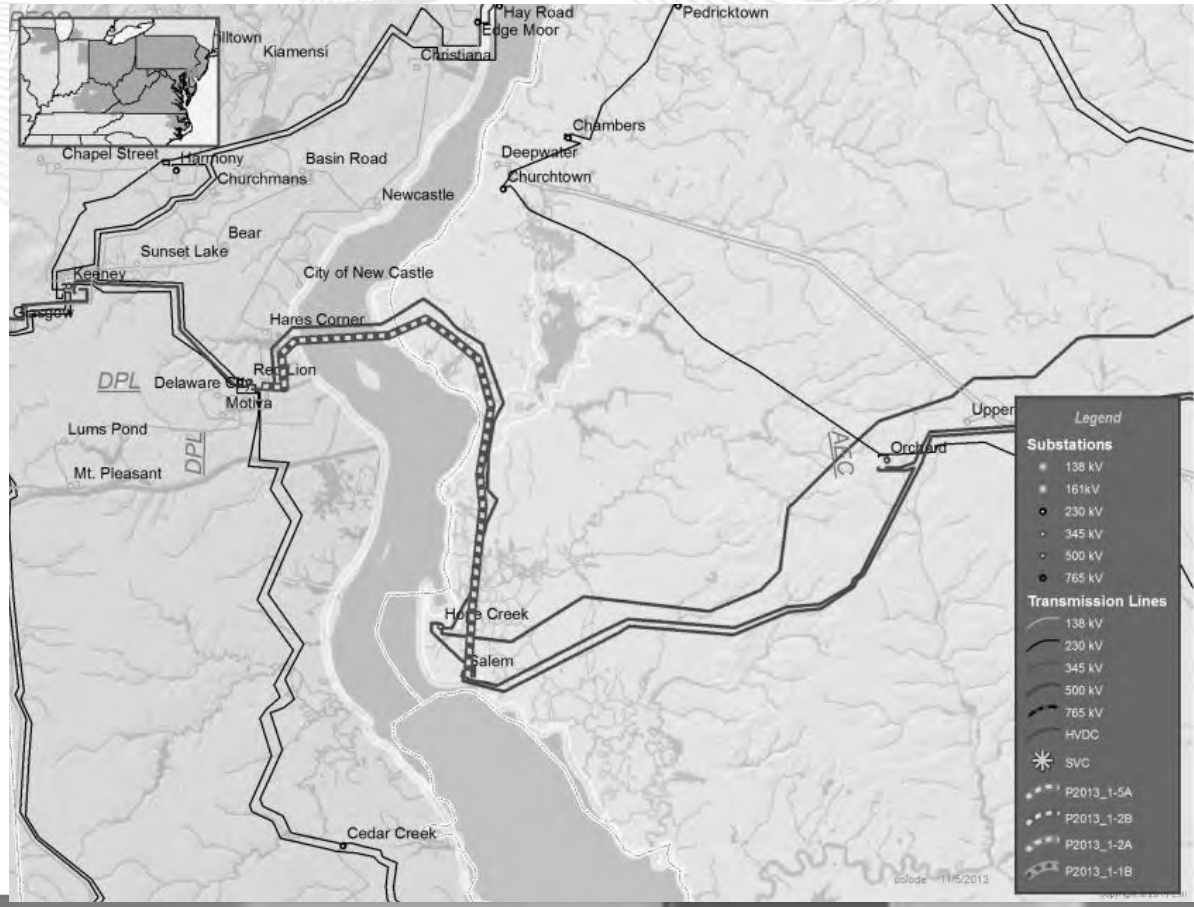
Salem to Red Lion Lines

- Expansion of Salem substation
- 17 mile 500kV line
- Parallels 5015 (Existing Red Lion – Hope Creek 500 kV)
- Proposing Entities:

PHI/Exelon
LS Power
Transource



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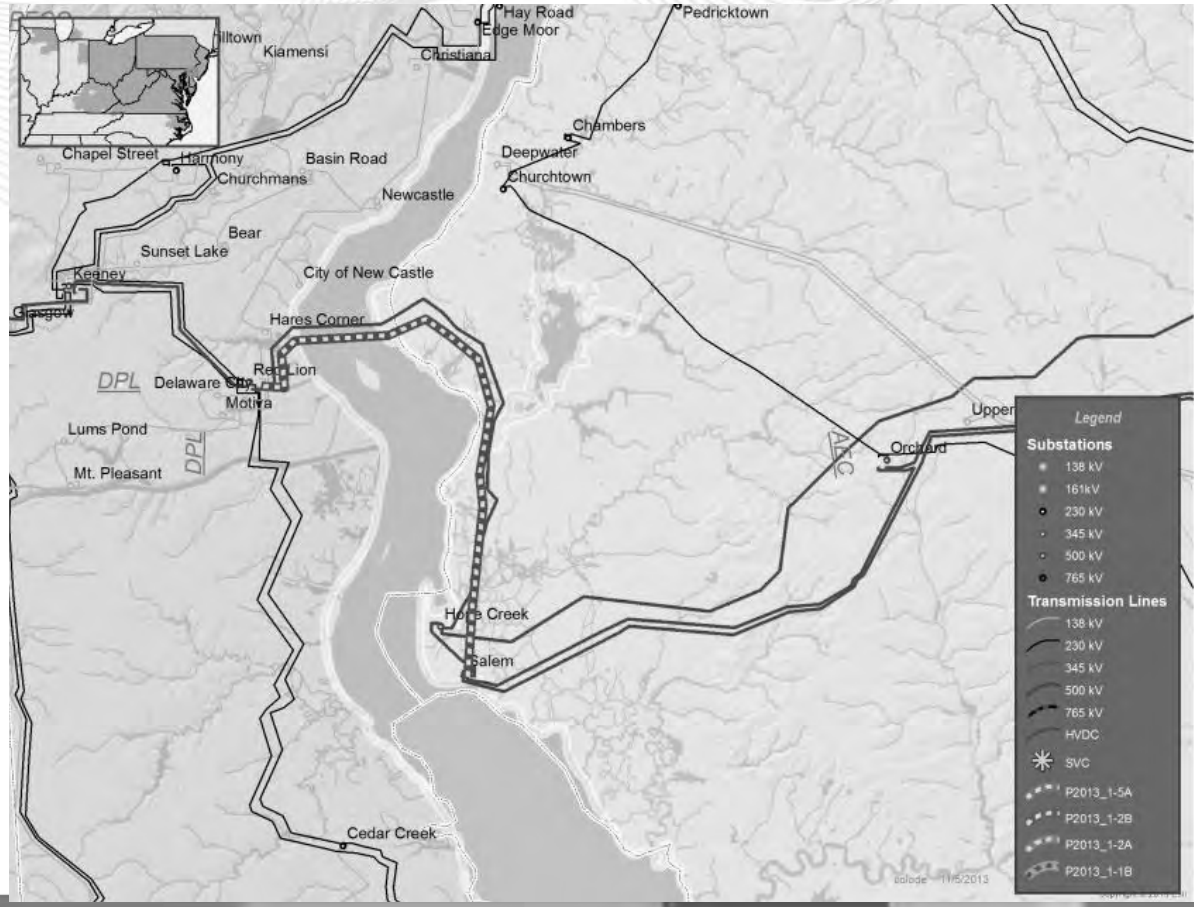
PHI / Exelon 4A

- New 500kV Line between Salem and Red Lion substations

- PJM modifications
  - Technical:
    - Analysis based on building only the Salem to Red Lion segment of proposed Salem to Peach Bottom proposal
    - Added SVC
  - Constructability:
    - Dead-end towers added around line crossing
    - New Salem connection as a full bay



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PHI/Exelon 4A – Technical Analysis

- Stability Performance
  - Failed required performance
    - Failed as proposed by project sponsor.
    - Failed with modification to change connection point at Salem to bus bar #1 from #2.
    - Did not satisfy stability criteria for a single line to ground fault with stuck breaker with AI units at unity power factor under 5015 maintenance outage condition.
    - Did not satisfy stability criteria for a single line to ground fault with stuck breaker with AI units at unity power factor under 5015 maintenance outage condition with modification to change connection point at Salem to bus bar #1 from #2.
  - Passed required performance
    - Passed as modified with the addition of an SVC at Orchard, New Freedom or Artificial Island.

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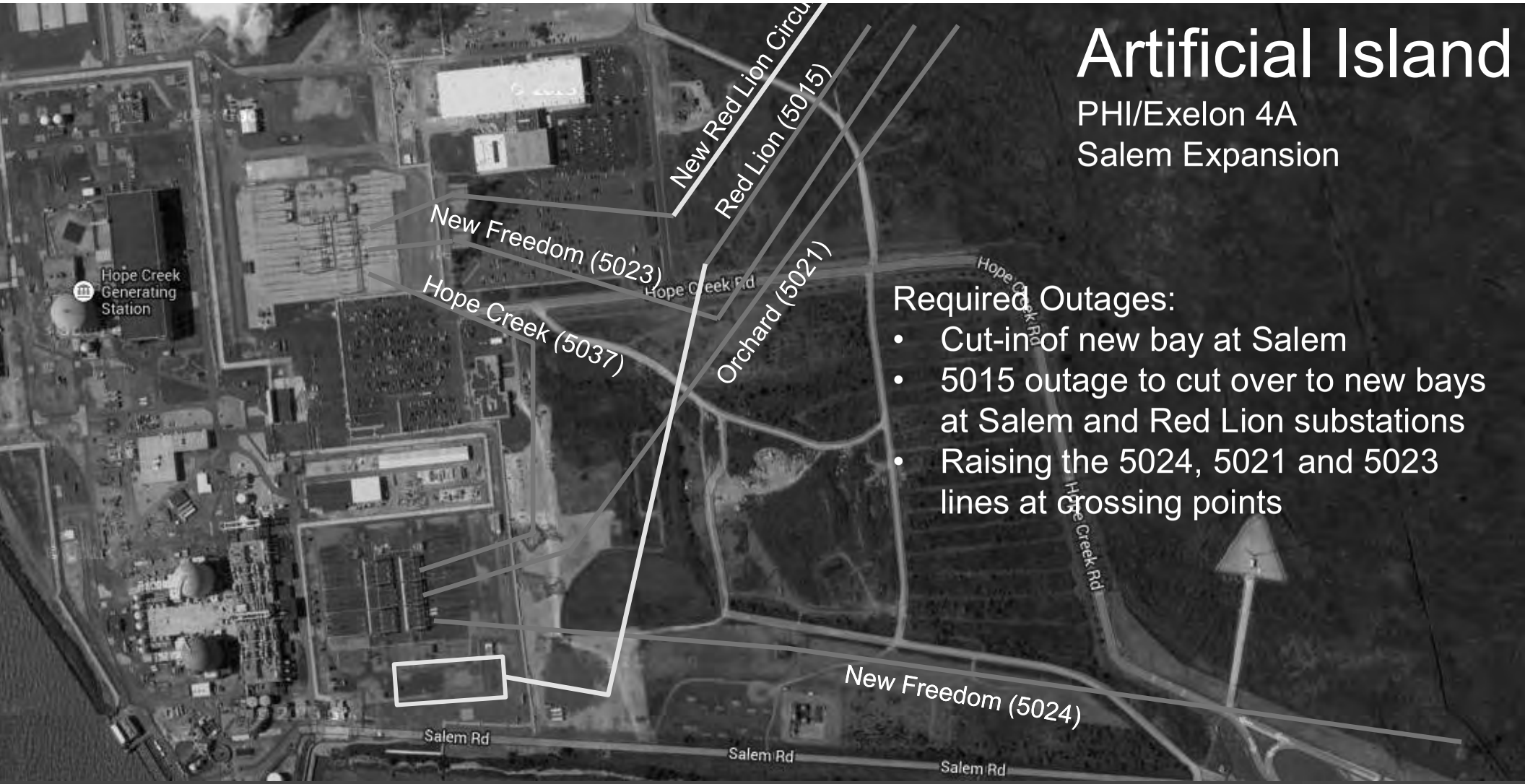
Artificial Island

PHI/Exelon 4A
Salem Expansion



Required Outages:

- Cut-in of new bay at Salem
- 5015 outage to cut over to new bays at Salem and Red Lion substations
- Raising the 5024, 5021 and 5023 lines at crossing points

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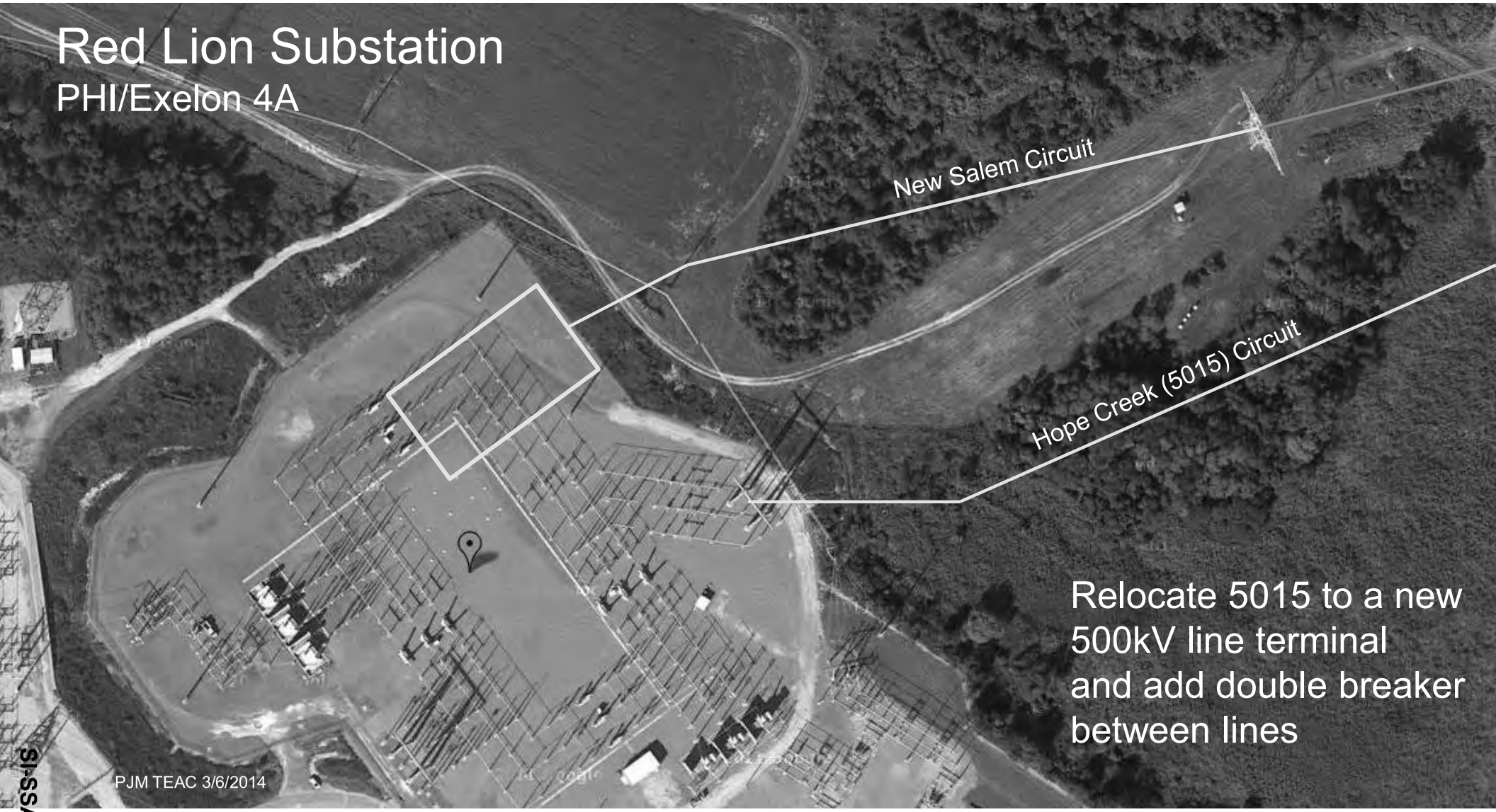
SI-SSA-0010-0206

Red Lion Substation

PHI/Exelon 4A



Relocate 5015 to a new 500kV line terminal and add double breaker between lines

PHI / Exelon 4A - Cost Factors

PJM Estimated Cost: $216-$263 (million)

- New 17 mile 500kV line
- Aerial Delaware river crossing

Proposed Cost Estimate: $181 (million)

Market Efficiency Analysis Sensitivity Study

- Scenario:
  - New 500 kV path from the AI to Red Lion
- Results:
  - Approximate benefit to cost ratio of 0.15
  - Approximately $57 million over 15 years

Outage Cost

- 5015 outage estimated at 30 days

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PHI / Exelon 4A - Project Schedule

Proposed Schedule 60 months (items run concurrent)

- Permitting: 34 months
- Design and Construction: 50 months
- Property Acquisition: 0 months

Schedule Criteria

- Permitting
  - CPCNs in two states and Army Corps of Engineers
- Long Lead Time Materials
  - No significant long lead time equipment required
- Construction
  - Could be impacted by restrictions due to endangered species and shipping traffic

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PHI / Exelon 4A - RoW and Land Acquisition

Right of Way and Land Acquisition Criteria

- No Eminent Domain in Delaware
  - All project have approximately 0.5 miles of right of way to either expand or acquire in Delaware
    - Land is coastal and under state jurisdiction
  - Red Lion substation expansion is on land currently owned by PHI
- New Right of Way Required
  - As participants in the LDV agreement, party has a right of way agreement for the new line
- Substation Land Required
  - Red Lion substation expansion will be done on land currently owned by PHI.

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PHI / Exelon 4A - Siting and Permitting

Siting and Permitting Criteria

- Wetlands Impact
  - Permits required to cross the Delaware state lands on the river coast
  - Impacts approximately 350 acres of forested wetland
- Public Opposition Risk
  - View-shed impacts minimal as this is adjacent to the existing 5015
  - Some opposition to any river crossing is expected
- Historic and Scenic Highway
  - No impact
- Land Permitting
  - USFWS right of way permit to cross Supawna National Wildlife Refuge required
- Delaware River Crossing
  - Numerous approvals and permits required:

  (a few major permits are listed below)
  - Delaware River Basin Commission approval required
  - Delaware and New Jersey CPCNs required
  - US Army Corps of Engineers Section 404 and 10 authorizations
  - Multiple US Fish and Wildlife permits required
  - National Marine Fisheries Service

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PHI / Exelon 4A - Operational Impact

Operational Impact Criteria

- Artificial Island Facility Requirements
  - PJM Operations Review
    - Request to minimize impact to existing transmission facilities
  - Salem/Hope Creek Facility Owner Feedback
    - Request to minimize outage and physical impacts to existing transmission facilities
    - Salem is space constrained so expansion needs to incorporate maintenance access to substation equipment
    - Salem control house is a part of plant facilities and access is constrained
- Blackstart
  - No blackstart advantage
- Route Diversity
  - Project route is parallels the existing 5015 line
- Ongoing Maintenance
  - Salt spray concern with proximity to Delaware river

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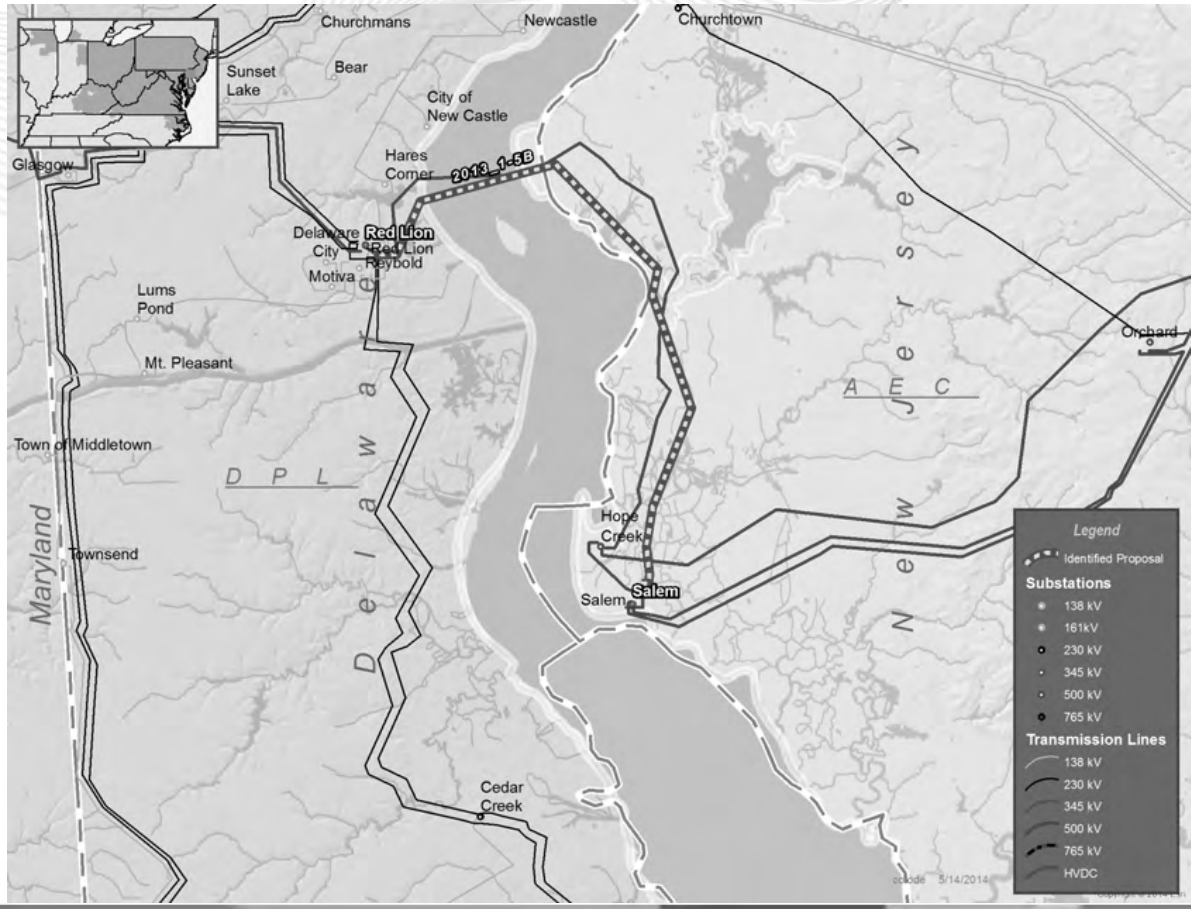
LS Power 5B

- New 500kV Line between Salem and Red Lion substations

- PJM modifications
  - Technical:
    - Added SVC
  - Constructability:
    - Dead-end towers added around line crossing
    - New Salem connection as a full bay



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LS Power 5B – Technical Analysis

- Stability Performance

  – Failed required performance
    - Failed as proposed by project sponsor.
    - Did not satisfy stability criteria for a three phase fault with AI units at unity power factor under 5015 maintenance outage condition.

  – Passed required performance
    - Passed as proposed with the addition of an SVC at Orchard, New Freedom or Artificial Island.

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Artificial Island

LS Power 5B
Salem Expansion

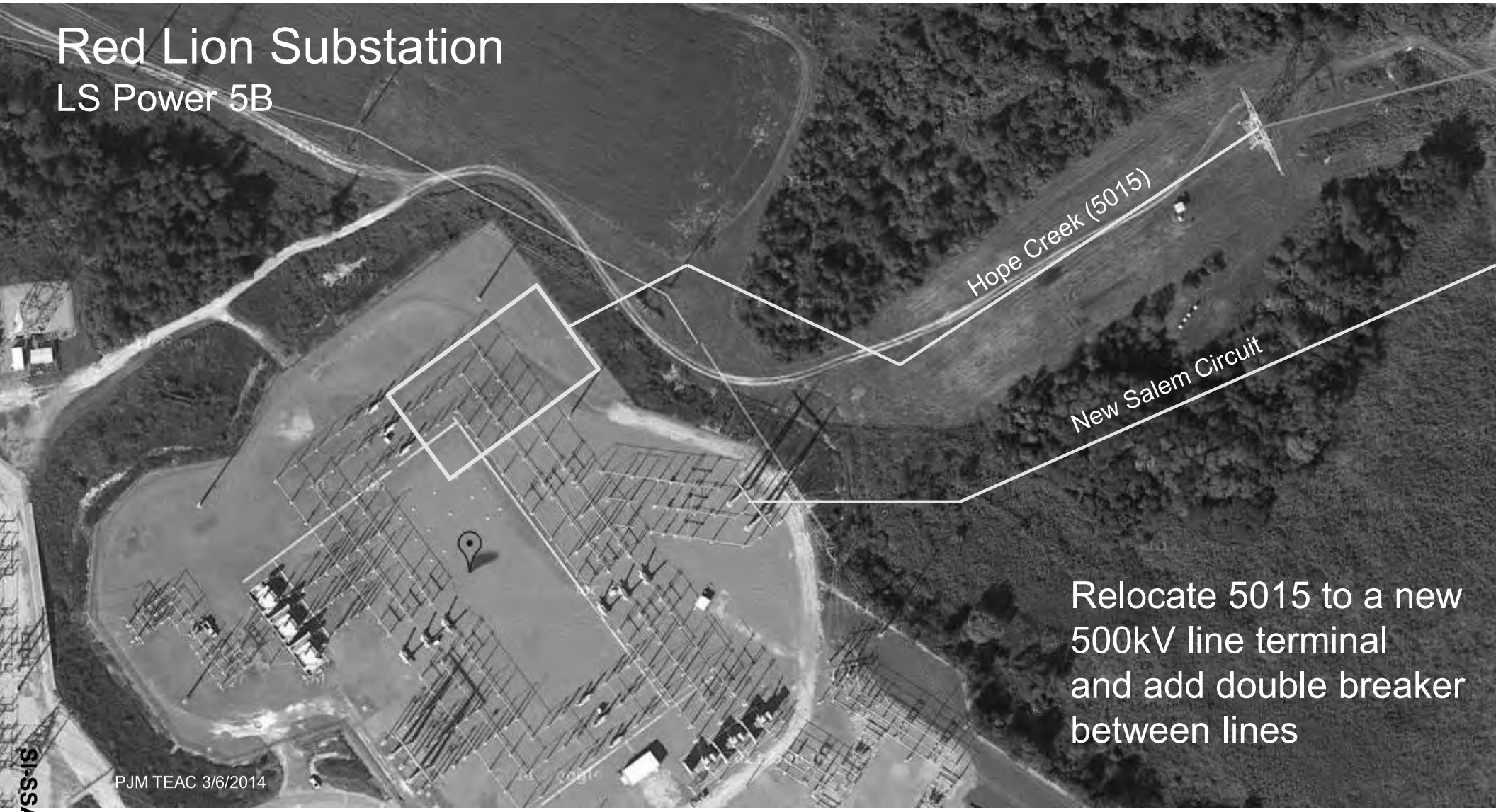
Required Outages:

- Cut-in of new bay at Salem
- 5037 outage to cut over to new bay
- Raising the 5015 and 5023 lines at crossing points

SI-SSA-0010-0215

Red Lion Substation

LS Power 5B



Relocate 5015 to a new 500kV line terminal and add double breaker between lines

LS Power 5B - Cost Factors

PJM Estimated Cost: $221-$269 (million)

- New 17 mile 500kV line
- Aerial Delaware river crossing

Proposed Cost Estimate: $171 (million)

Market Efficiency Analysis Sensitivity Study

- Scenario:
  - New 500 kV path from the AI to Red Lion
- Results:
  - Approximate benefit to cost ratio of 0.15
  - Approximately $57 million over 15 years

Outage Cost

- 5015 outage estimated at 30 days

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LS Power 5B - Project Schedule

Proposed Schedule 60 months (items run concurrent)

- Permitting: 27 months
- Design and Construction: 60 months
- Property Acquisition: 18 months

Schedule Criteria

- Permitting
  - CPCNs in two states and Army Corps of Engineers
- Long Lead Time Materials
  - No significant long lead time equipment required
- Construction
  - Could be impacted by restrictions due to endangered species and shipping traffic

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LS Power 5B - RoW and Land Acquisition

Right of Way and Land Acquisition Criteria

- No Eminent Domain in Delaware
  - All project have approximately 0.5 miles of right of way to either expand or acquire in Delaware
    - Land is coastal and under state jurisdiction
  - Red Lion substation expansion is on land currently owned by PHI
- New Right of Way Required
  - Will need to either negotiate with the LDV parties or negotiate with individual land owners and public entities
- Substation Land Required
  - Red Lion substation expansion will be done on land currently owned by PHI.

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LS Power 5B - Siting and Permitting

Siting and Permitting Criteria

- Wetlands Impact
  - Permits required to cross the Delaware state lands on the river coast
  - Impacts approximately 350 acres of forested wetland
- Public Opposition Risk
  - View-shed impacts minimal as this is adjacent to the existing 5015
  - Some opposition to any river crossing is expected
- Historic and Scenic Highway
  - No impact
- Land Permitting
  - USFWS right of way permit to cross Supawna National Wildlife Refuge required
- Delaware River Crossing
  - Numerous approvals and permits required:

  (a few major permits are listed below)
  - Delaware River Basin Commission approval required
  - Delaware and New Jersey CPCNs required
  - US Army Corps of Engineers Section 404 and 10 authorizations
  - Multiple US Fish and Wildlife permits required
  - National Marine Fisheries Service

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LS Power 5B - Operational Impact

Operational Impact Criteria

- Artificial Island Facility Requirements
  - PJM Operations Review
    - Request to minimize impact to existing transmission facilities
  - Salem/Hope Creek Facility Owner Feedback
    - Request to minimize outage and physical impacts to existing transmission facilities
    - Salem is space constrained so expansion needs to incorporate maintenance access to substation equipment
    - Salem control house is a part of plant facilities and access is constrained
- Blackstart
  - No blackstart advantage
- Route Diversity
  - Project route is parallels the existing 5015 line
- Ongoing Maintenance
  - No impact

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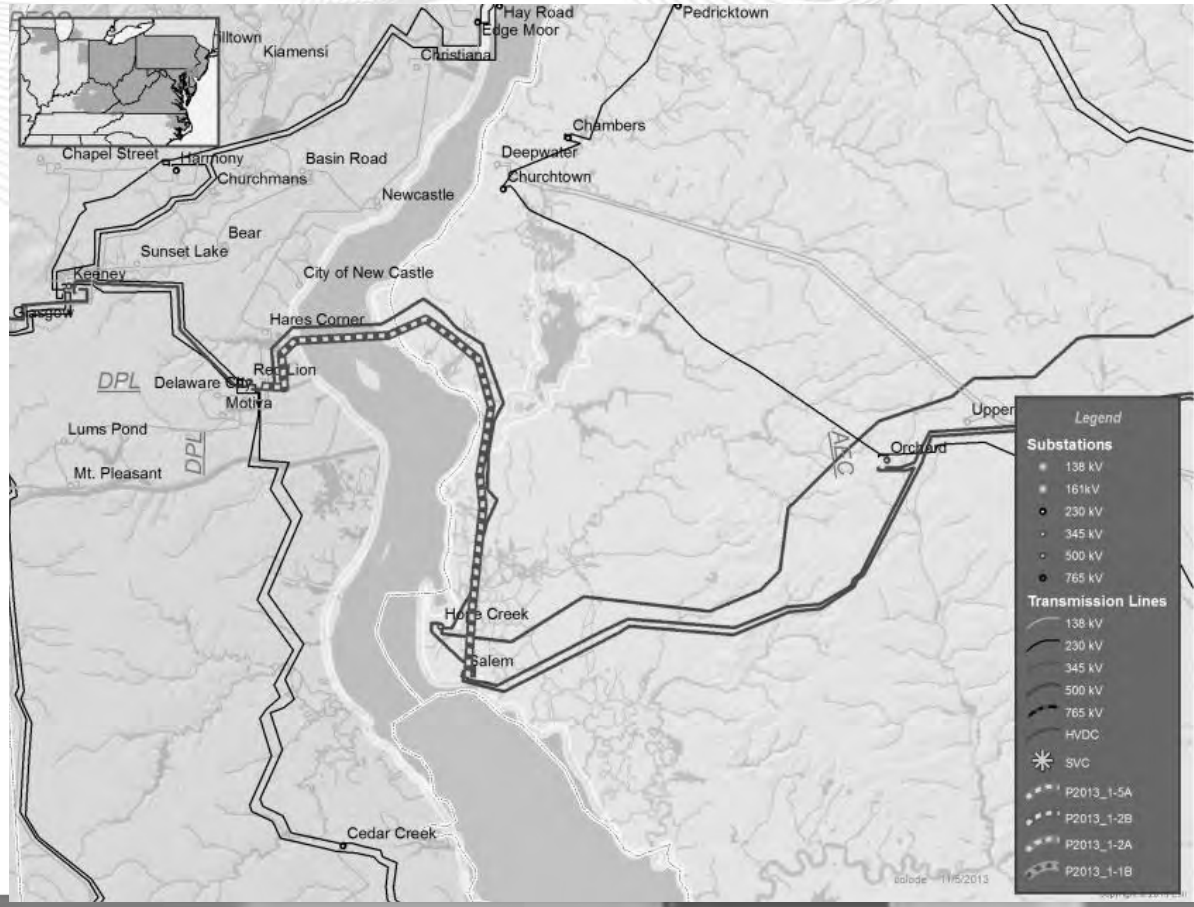
Transource (AEP) 2C

- New 500kV Line between Salem and Red Lion substations

- PJM modifications
  - Technical:
    - Added SVC
  - Constructability:
    - Dead-end towers added around line crossing
    - New Salem connection as a full bay



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Transource (AEP) 2C – Technical Analysis

- Stability Performance

  – Failed required performance
    - Failed as proposed by project sponsor.
    - Did not satisfy stability criteria for a single line to ground fault with stuck breaker with AI units at unity power factor under 5015 maintenance outage condition.

  – Passed required performance
    - Passed as proposed with the addition of an SVC at Orchard, New Freedom or Artificial Island.

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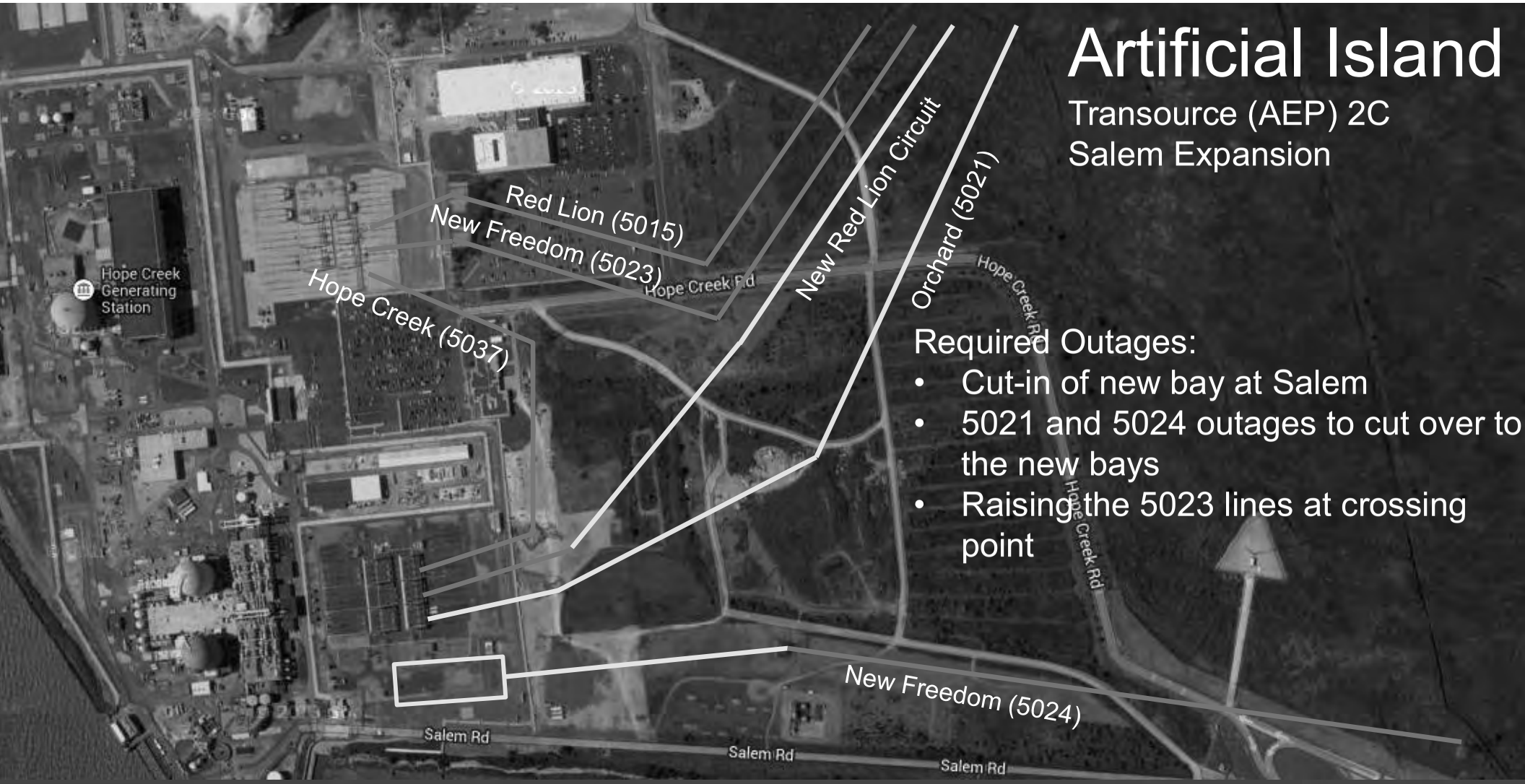


Artificial Island

Transource (AEP) 2C
Salem Expansion

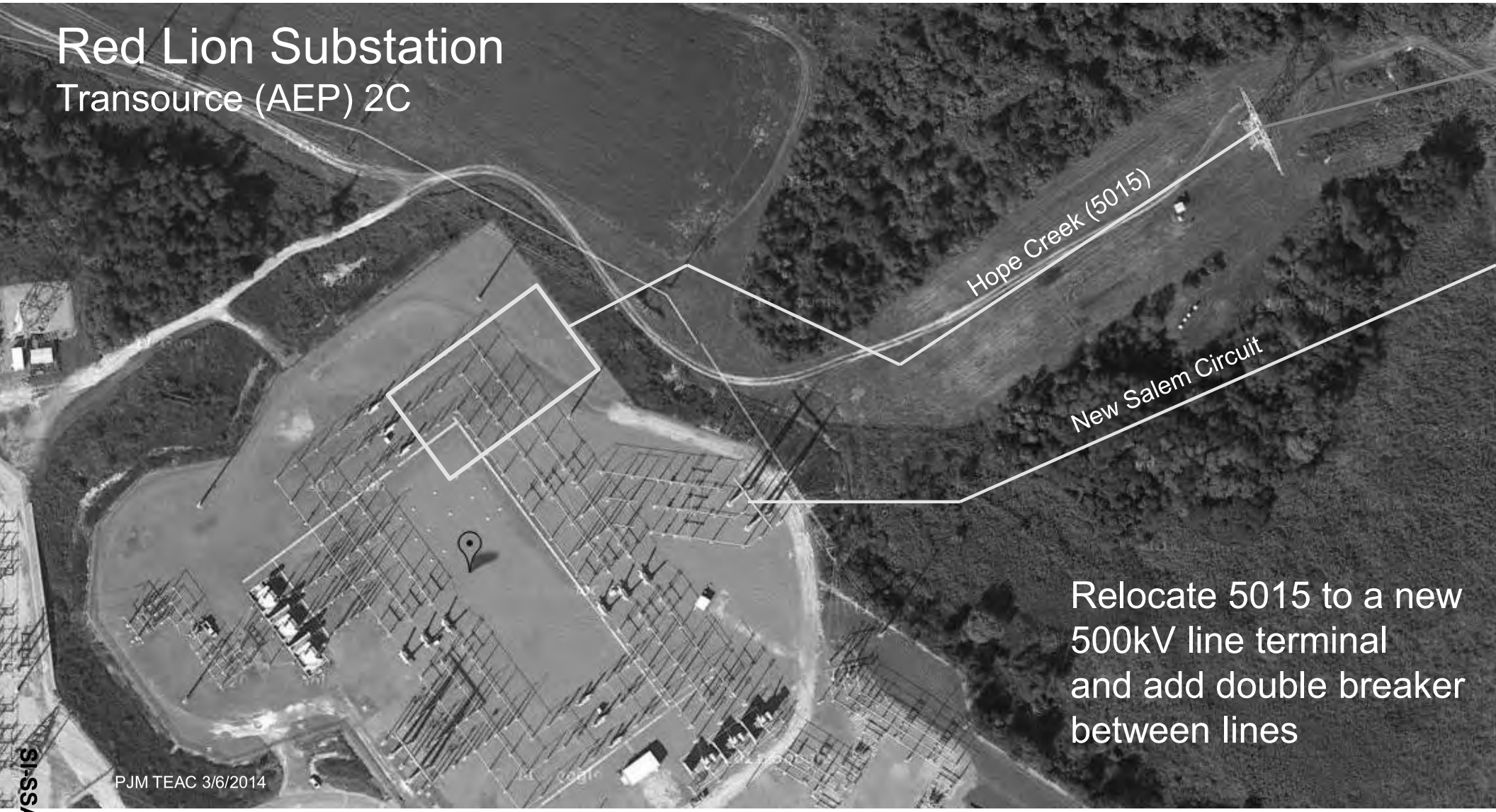
Required Outages:

- Cut-in of new bay at Salem
- 5021 and 5024 outages to cut over to the new bays
- Raising the 5023 lines at crossing point

SI-SSA-0010-0224

Red Lion Substation

Transource (AEP) 2C



Relocate 5015 to a new 500kV line terminal and add double breaker between lines

Transource (AEP) 2C - Cost Factors

PJM Estimated Cost: $232-$282 (million)

- New 17 mile 500kV line
- Aerial Delaware river crossing

Proposed Cost Estimate: $123-156 (million)

Market Efficiency Analysis Sensitivity Study

- Scenario:
  - New 500 kV path from the AI to Red Lion
- Results:
  - Approximate benefit to cost ratio of 0.15
  - Approximately $57 million over 15 years

Outage Cost

- 5015 outage estimated at 30 days

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Transource (AEP) 2C - Project Schedule

Proposed Schedule 48 months (items run concurrent)

- Permitting: 27 months
- Design and Construction: 30 months
- Property Acquisition: 15 months

Schedule Criteria

- Permitting
  - CPCNs in two states and Army Corps of Engineers
- Long Lead Time Materials
  - No significant long lead time equipment required
- Construction
  - Could be impacted by restrictions due to endangered species and shipping traffic

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Transource (AEP) 2C - RoW and Land Acquisition

Right of Way and Land Acquisition Criteria

- No Eminent Domain in Delaware
  - All project have approximately 0.5 miles of right of way to either expand or acquire in Delaware
    - Land is coastal and under state jurisdiction
  - Red Lion substation expansion is on land currently owned by PHI
- New Right of Way Required
  - Will need to either negotiate with the LDV parties or negotiate with individual land owners and public entities
- Substation Land Required
  - Red Lion substation expansion will be done on land currently owned by PHI.

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Transource (AEP) 2C - Siting and Permitting

Siting and Permitting Criteria

- Wetlands Impact
  - Permits required to cross the Delaware state lands on the river coast
  - Impacts approximately 350 acres of forested wetland
- Public Opposition Risk
  - View-shed impacts minimal as this is adjacent to the existing 5015
  - Some opposition to any river crossing is expected
- Historic and Scenic Highway
  - No impact
- Land Permitting
  - USFWS right of way permit to cross Supawna National Wildlife Refuge required
- Delaware River Crossing
  - Numerous approvals and permits required:

  (a few major permits are listed below)
  - Delaware River Basin Commission approval required
  - Delaware and New Jersey CPCNs required
  - US Army Corps of Engineers Section 404 and 10 authorizations
  - Multiple US Fish and Wildlife permits required
  - National Marine Fisheries Service

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Transource (AEP) 2C - Operational Impact

Operational Impact Criteria

- Artificial Island Facility Requirements
  - PJM Operations Review
    - Request to minimize impact to existing transmission facilities
  - Salem/Hope Creek Facility Owner Feedback
    - Request to minimize outage and physical impacts to existing transmission facilities
    - Salem is space constrained so expansion needs to incorporate maintenance access to substation equipment
    - Salem control house is a part of plant facilities and access is constrained
- Blackstart
  - No blackstart advantage
- Route Diversity
  - Project route is parallels the existing 5015 line
- Ongoing Maintenance
  - Salt spray concern with proximity to Delaware river

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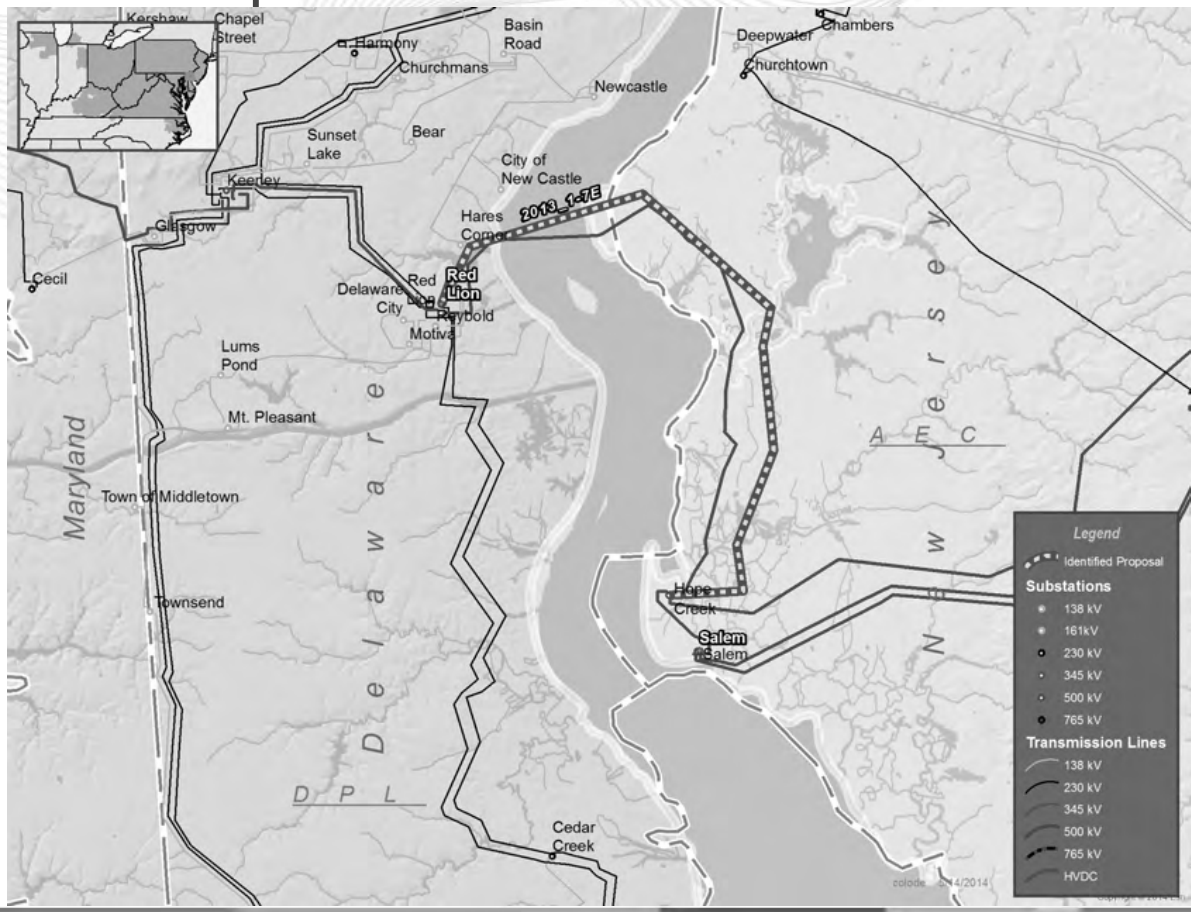
Hope Creek to Red Lion Lines

- Expansion of Hope Creek substation
- 17 mile 500kV line
- Parallels 5015 (Existing Red Lion – Hope Creek 500 kV)
- Proposing Entities:

Dominion
PSE&G



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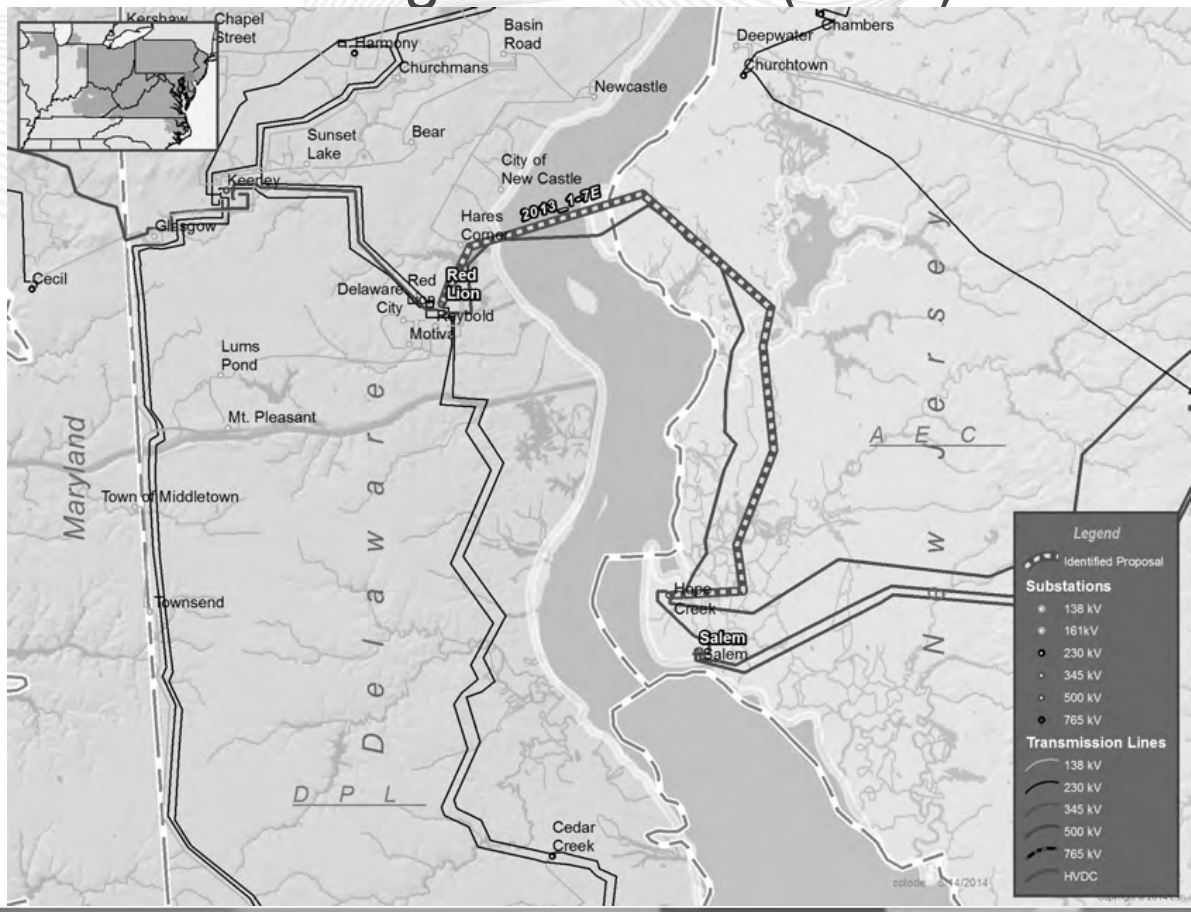
Dominion Virginia Power (DVP) 1C

- New 500kV Line between Hope Creek and Red Lion substations
- New bus tie between Hope Creek and Salem substations
- PJM modifications
  - Technical:
    - Added SVC
  - Constructability:
    - Dead-end towers added around line crossing



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Dominion Virginia Power (DVP) 1C – Technical Analysis

- Stability Performance

  – Failed required performance
    - Failed as proposed by project sponsor.
    - Failed with modification to remove proposed breakers.
    - Did not satisfy stability criteria for a SLG fault with stuck breaker with AI units at unity power factor under new Hope Creek – Red Lion line maintenance outage condition.
    - Did not satisfy stability criteria for a SLG fault with stuck breaker with AI units at unity power factor under new Hope Creek – Red Lion line maintenance outage condition with modification to remove proposed breakers.

  – Passed required performance
    - Passed as modified with the addition of an SVC at Orchard, New Freedom or Artificial Island.

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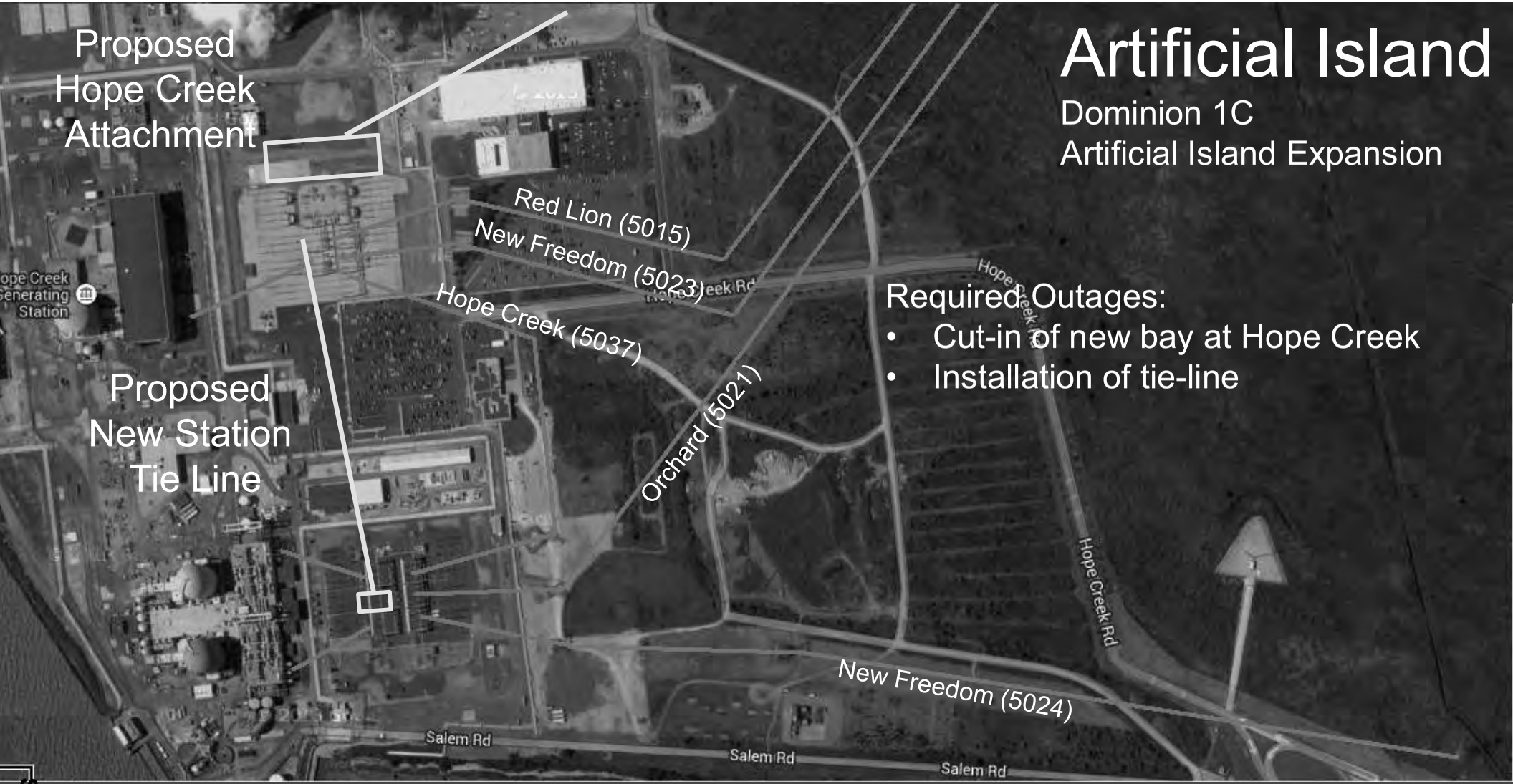
Proposed
Hope Creek
Attachment
Proposed
New Station
Tie Line
Red Lion (5015)
New Freedom (5023)
Hope Creek (5037)
Orchard (5021)
Hope Creek Rd
New Freedom (5024)
Salem Rd
Salem Rd
Salem Rd
Artificial Island
Dominion 1C
Artificial Island Expansion
Required Outages:
• Cut-in of new bay at Hope Creek
• Installation of tie-line

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Red Lion Substation

Dominion 1C

- Substation proposed to be rebuilt as a double bus – double breaker scheme
- New line crosses the 5015 line

Dominion Virginia Power (DVP) 1C - Cost Factors

PJM Estimated Cost: $242-$294 (million)

- New 17 mile 500kV line
- Aerial Delaware river crossing

Proposed Cost Estimate: $199 (million)

Market Efficiency Analysis Sensitivity Study

- Scenario:
  - New 500 kV path from the AI to Red Lion
- Results:
  - Approximate benefit to cost ratio of 0.15
  - Approximately $57 million over 15 years

Outage Cost

- 5015 outage estimated at 40 days

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Dominion Virginia Power (DVP) 1C - Project Schedule

Proposed Schedule 111 months (items run concurrent)

- Permitting: 24 months
- Design and Construction: 38 months
- Property Acquisition: 78 months

Schedule Criteria

- Permitting
  - CPCNs in two states and Army Corps of Engineers
- Long Lead Time Materials
  - No significant long lead time equipment required
- Construction
  - Could be impacted by restrictions due to endangered species and shipping traffic

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Dominion Virginia Power (DVP) 1C - RoW and Land Acquisition

Right of Way and Land Acquisition Criteria

- No Eminent Domain in Delaware
  - All project have approximately 0.5 miles of right of way to either expand or acquire in Delaware
    - Land is coastal and under state jurisdiction
  - Red Lion substation expansion is on land currently owned by PHI

- New Right of Way Required
  - Will need to either negotiate with the LDV parties or negotiate with individual land owners and public entities

- Substation Land Required
  - Red Lion substation expansion will be done on land currently owned by PHI.

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Dominion Virginia Power (DVP) 1C - Siting and Permitting

Siting and Permitting Criteria

- Wetlands Impact
  - Permits required to cross the Delaware state lands on the river coast
  - Impacts approximately 350 acres of forested wetland
- Public Opposition Risk
  - View-shed impacts minimal as this is adjacent to the existing 5015
  - Some opposition to any river crossing is expected
- Historic and Scenic Highway
  - No impact
- Land Permitting
  - USFWS right of way permit to cross Supawna National Wildlife Refuge required
- Delaware River Crossing
  - Numerous approvals and permits required:

  (a few major permits are listed below)
  - Delaware River Basin Commission approval required
  - Delaware and New Jersey CPCNs required
  - US Army Corps of Engineers Section 404 and 10 authorizations
  - Multiple US Fish and Wildlife permits required
  - National Marine Fisheries Service

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Dominion Virginia Power (DVP) 1C - Operational Impact

Operational Impact Criteria

- Artificial Island Facility Requirements
  - PJM Operations Review
    - Request to minimize impact to existing transmission facilities
  - Salem/Hope Creek Facility Owner Feedback
    - Request to minimize outage and physical impacts to existing transmission facilities
    - Salem is space constrained so expansion needs to incorporate maintenance access to substation equipment
    - Salem control house is a part of plant facilities and access is constrained
- Blackstart
  - No blackstart advantage
- Route Diversity
  - Project route parallels the existing 5015 line
- Ongoing Maintenance
  - Limited physical access could lead to maintenance issues on the new tie line between Salem and Hope Creek

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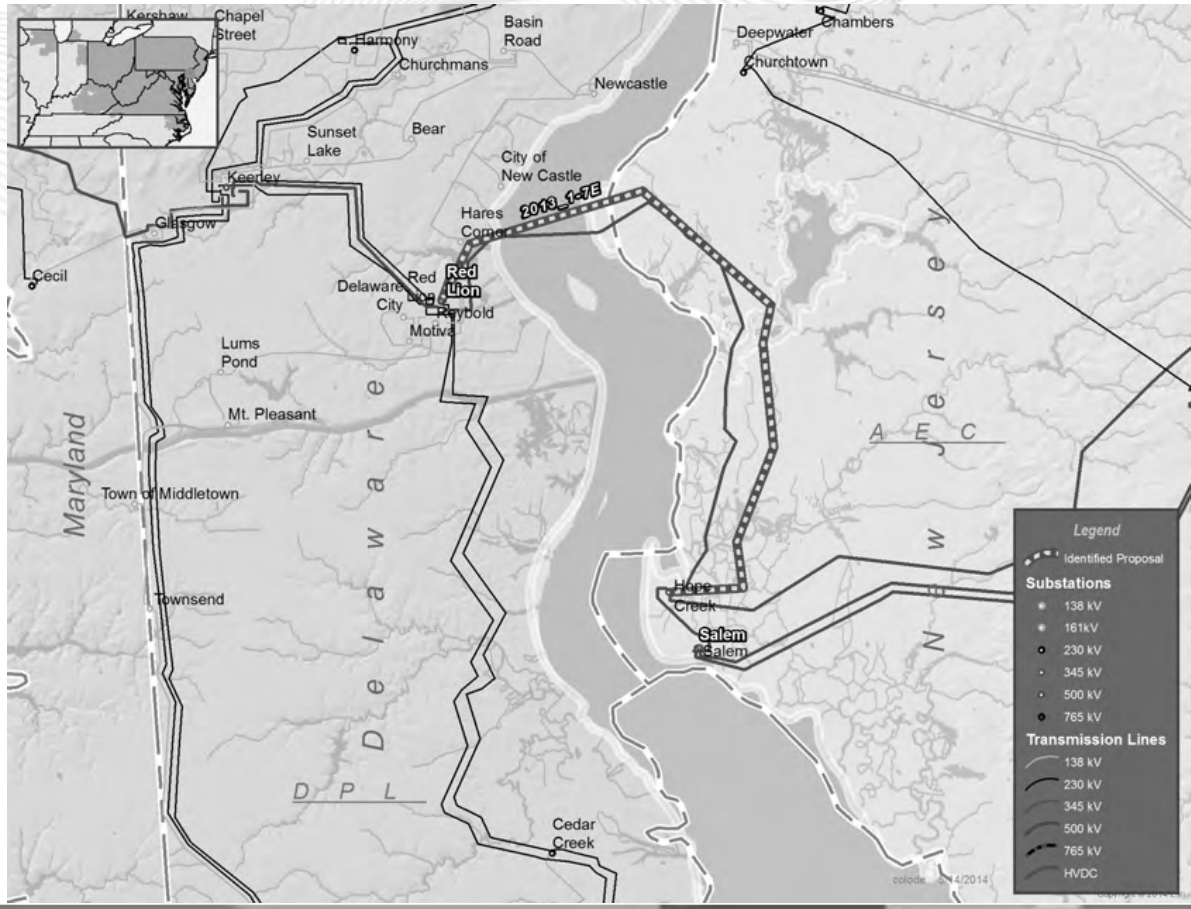
PSE&G 7K

- New 500kV Line between Hope Creek and Red Lion substations
- New bus tie between Hope Creek and Salem substations
- PJM modifications
  - Technical:
    - Removed the New Freedom to Deans portion of the project
    - Added SVC
  - Constructability:
    - Dead-end towers added around line crossing



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PSE&G 7K – Technical Analysis

- Stability Performance

  – Failed required performance
    - Failed as proposed by project sponsor.
    - Did not satisfy stability criteria for a single line to ground fault with stuck breaker with AI units at unity power factor under 5037 maintenance outage condition.

  – Passed required performance
    - Passed as modified with the addition of an SVC at Orchard, New Freedom or Artificial Island.

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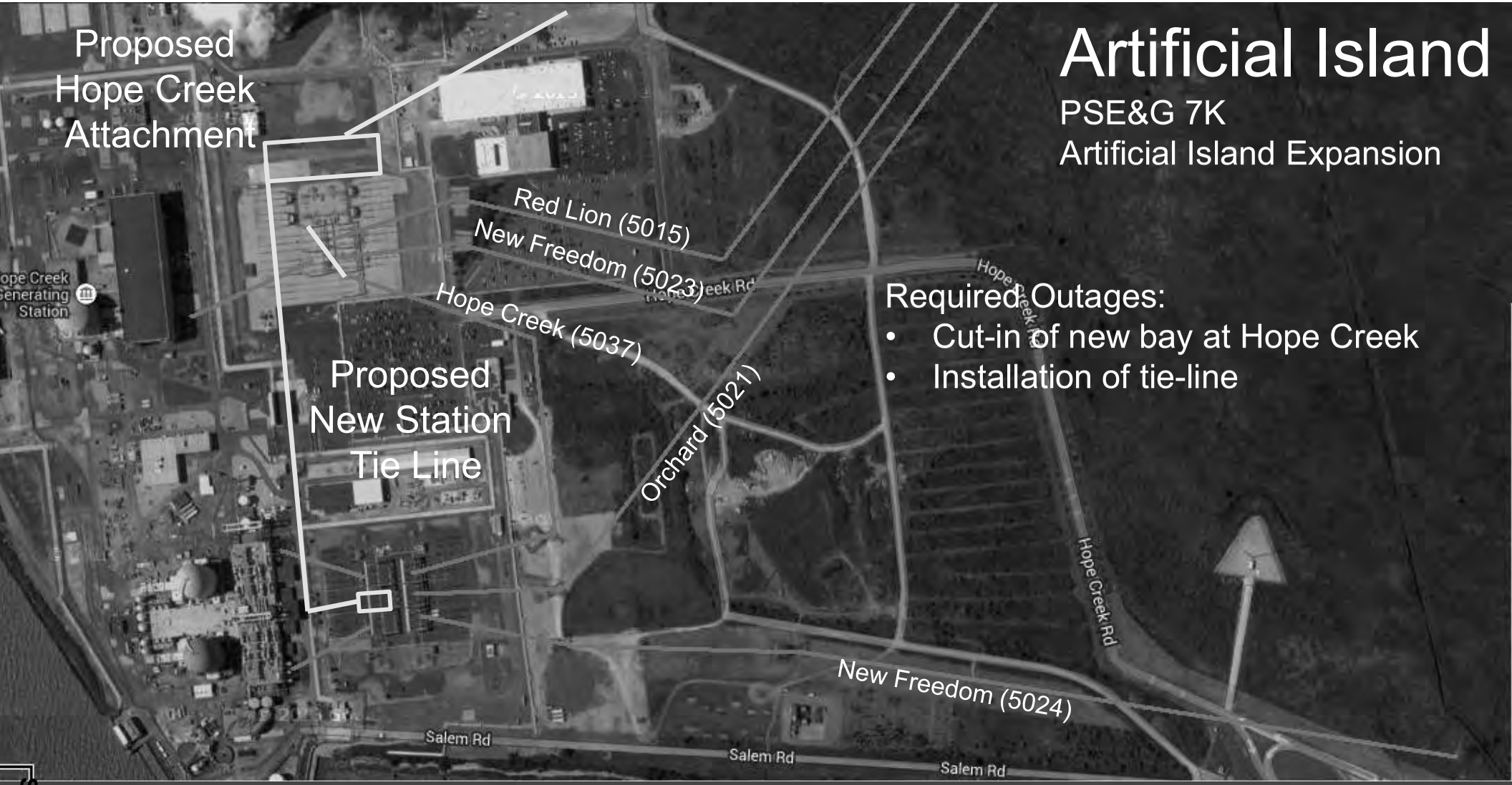

Artificial Island

PSE&G 7K
Artificial Island Expansion

Required Outages:

- Cut-in of new bay at Hope Creek
- Installation of tie-line

SI-SSA-0010-0243

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New Hope Creek Circuit
Hope Creek (5015)
• Substation proposed to be rebuilt as a breaker and a half scheme
• New line crosses the 5015 line
Red Lion Substation
PSE&G 7K

PSE&G 7K - Cost Factors

PJM Estimated Cost: $249-$304 (million)

- New 17 mile 500kV line
- Aerial Delaware river crossing

Proposed Cost Estimate: $297 (million)

Market Efficiency Analysis Sensitivity Study

- Scenario:
  - New 500 kV path from the AI to Red Lion
- Results:
  - Approximate benefit to cost ratio of 0.15
  - Approximately $57 million over 15 years

Outage Cost

- 5015 outage estimated at 40 days

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PSE&G 7K - Project Schedule

Proposed Schedule 51 months (items run concurrent)

- Permitting: 51 months
- Design and Construction: 48 months
- Property Acquisition: 0 months

Schedule Criteria

- Permitting
  - CPCNs in two states and Army Corps of Engineers
- Long Lead Time Materials
  - No significant long lead time equipment required
- Construction
  - Could be impacted by restrictions due to endangered species and shipping traffic

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PSE&G 7K - RoW and Land Acquisition

Right of Way and Land Acquisition Criteria

- No Eminent Domain in Delaware
  - All project have approximately 0.5 miles of right of way to either expand or acquire in Delaware
    - Land is coastal and under state jurisdiction
  - Red Lion substation expansion is on land currently owned by PHI
- New Right of Way Required
  - As participants in the LDV agreement, party has a right of way agreement for the new line
- Substation Land Required
  - Red Lion substation expansion will be done on land currently owned by PHI.

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PSE&G 7K - Siting and Permitting

Siting and Permitting Criteria

- Wetlands Impact
  - Permits required to cross the Delaware state lands on the river coast
  - Impacts approximately 350 acres of forested wetland
- Public Opposition Risk
  - View-shed impacts minimal as this is adjacent to the existing 5015
  - Some opposition to any river crossing is expected
- Historic and Scenic Highway
  - No impact
- Land Permitting
  - USFWS right of way permit to cross Supawna National Wildlife Refuge required
- Delaware River Crossing
  - Numerous approvals and permits required:

  (a few major permits are listed below)
  - Delaware River Basin Commission approval required
  - Delaware and New Jersey CPCNs required
  - US Army Corps of Engineers Section 404 and 10 authorizations
  - Multiple US Fish and Wildlife permits required
  - National Marine Fisheries Service

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PSE&G 7K - Operational Impact

Operational Impact Criteria

- Artificial Island Facility Requirements
  - PJM Operations Review
    - Request to minimize impact to existing transmission facilities
  - Salem/Hope Creek Facility Owner Feedback
    - Request to minimize outage and physical impacts to existing transmission facilities
    - Salem is space constrained so expansion needs to incorporate maintenance access to substation equipment
    - Salem control house is a part of plant facilities and access is constrained
- Blackstart
  - No blackstart advantage
- Route Diversity
  - Project route is parallels the existing 5015 line
- Ongoing Maintenance
  - The new gas-insulated bus tie line between Salem and Hope Creek may require more frequent maintenance

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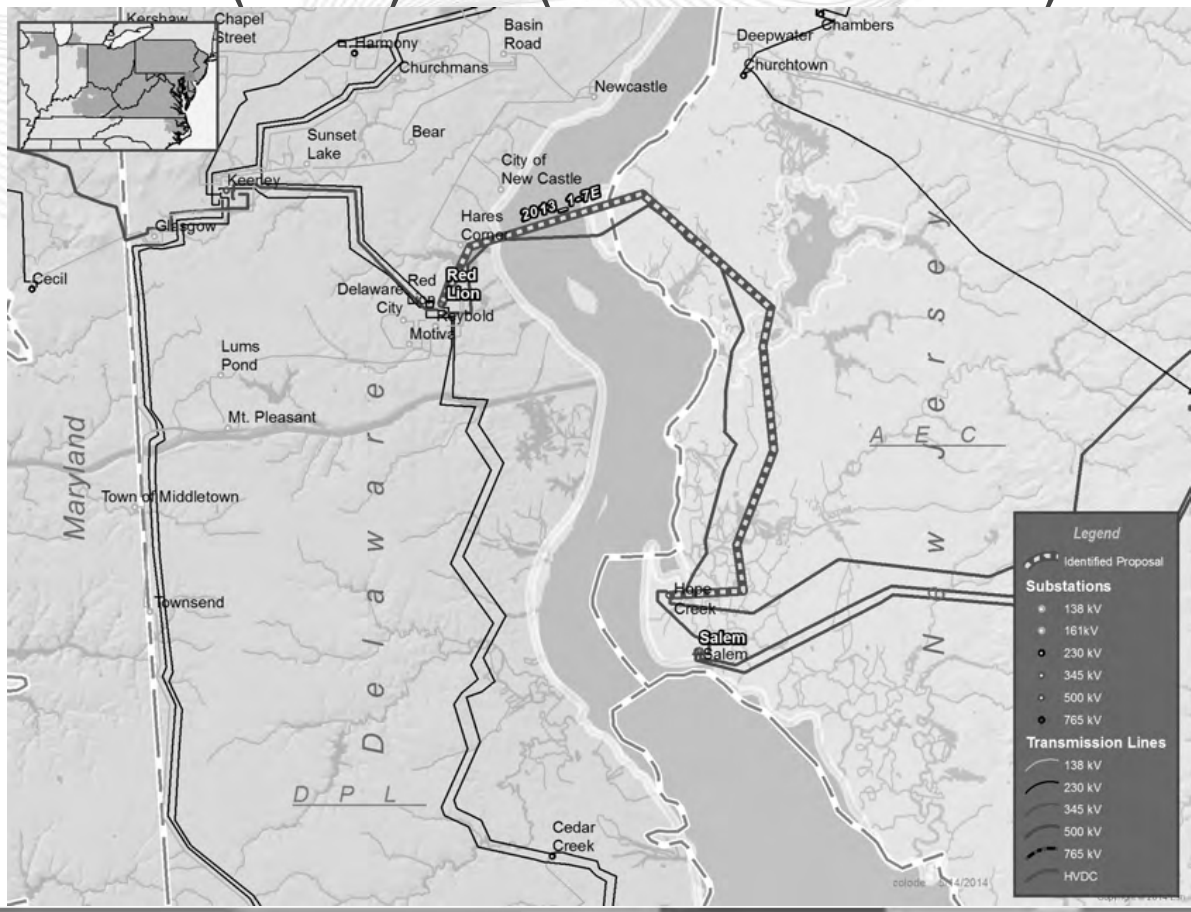
Dominion Virginia Power (DVP) 1C (No New Bus Tie)

- New 500kV Line between Hope Creek and Red Lion substations
- PJM modifications
  - Technical:
    - Removed the new tie between Salem and Hope Creek substations
    - Added SVC
  - Constructability:
    - Red Lion expansion changed from a breaker and a half to an expansion of the existing ring-bus



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Dominion Virginia Power (DVP) 1C (No New Bus Tie) Technical Analysis

- Stability Performance
  - Failed required performance
    - Failed as proposed by project sponsor.
    - Failed with modification to remove proposed breakers and transmission line.
    - Did not satisfy stability criteria for a SLG fault with stuck breaker with AI units at unity power factor under Hope Creek – Red Lion line maintenance outage condition.
    - Did not satisfy stability criteria for a SLG fault with stuck breaker with AI units at unity power factor under Hope Creek – Red Lion line maintenance outage condition with modification to remove proposed breakers and transmission line.
  - Passed required performance
    - Passed as modified with the addition of an SVC at Orchard or New Freedom.

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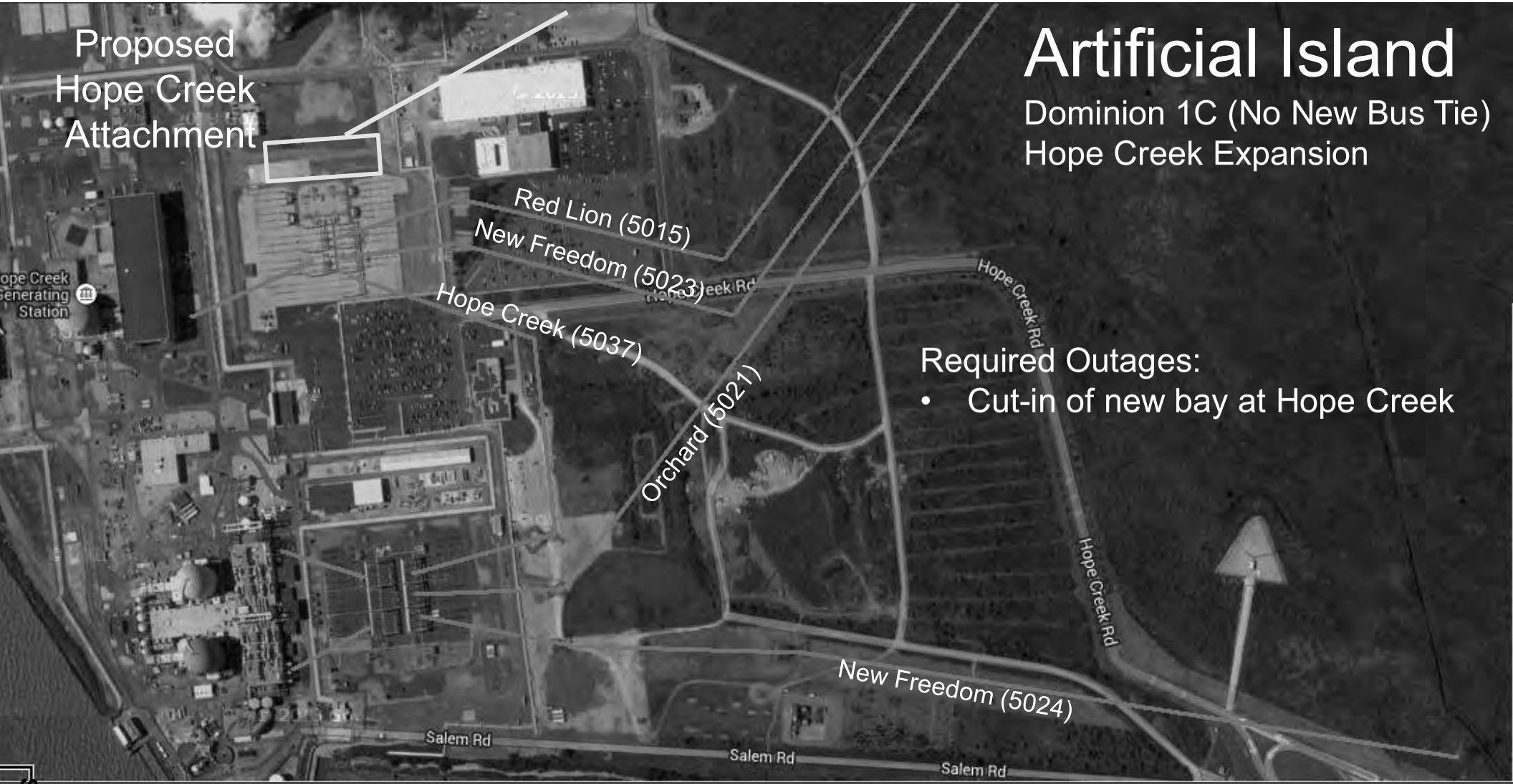
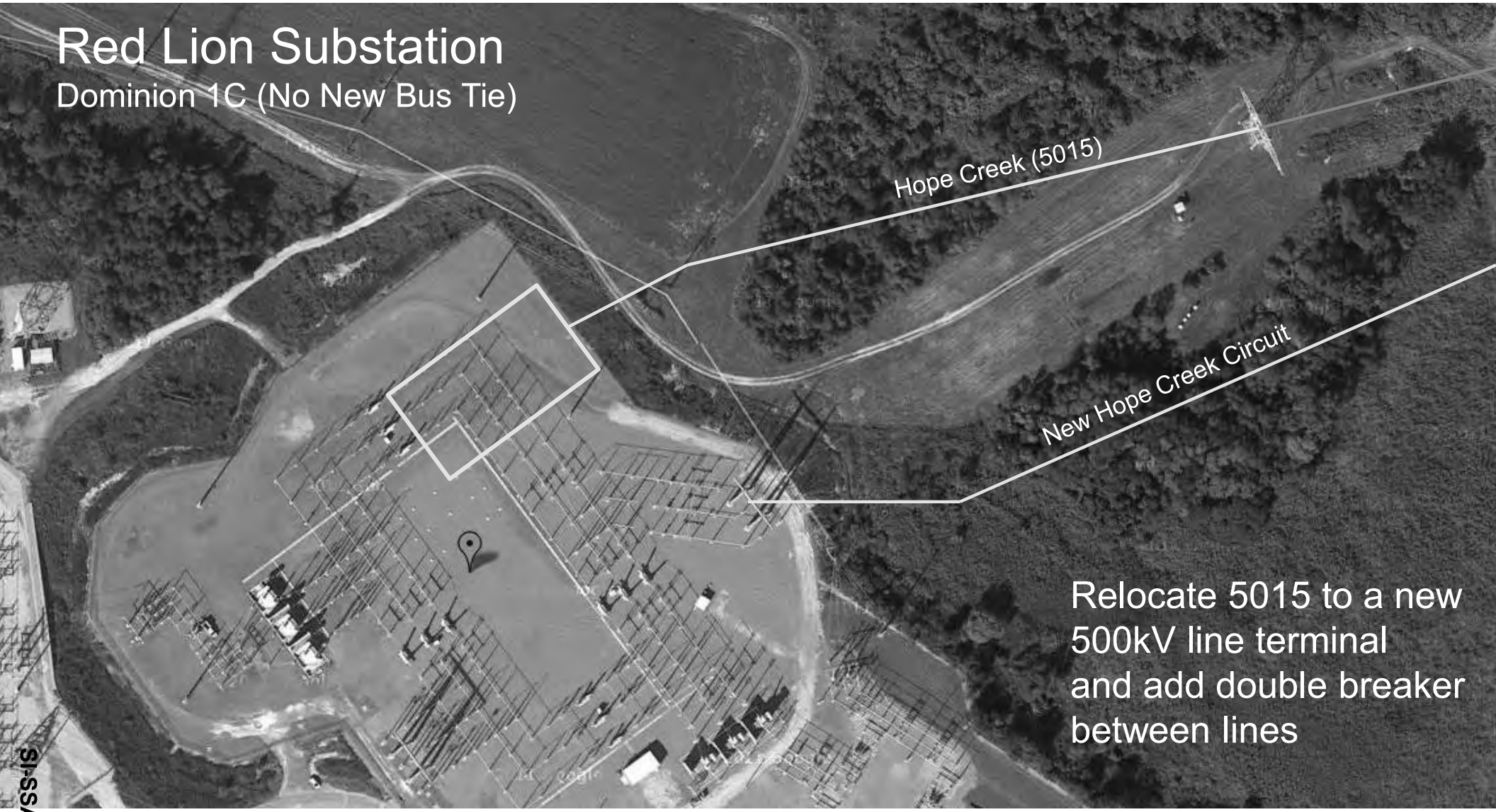
Artificial Island

Dominion 1C (No New Bus Tie)
Hope Creek Expansion



Required Outages:

- Cut-in of new bay at Hope Creek


Red Lion Substation
Dominion 1C (No New Bus Tie)
Hope Creek (5015)
New Hope Creek Circuit
Relocate 5015 to a new 500kV line terminal and add double breaker between lines

Dominion Virginia Power (DVP) 1C (No New Bus Tie) Cost Factors

PJM Estimated Cost: $211-$257 (million)

- New 17 mile 500kV line
- Aerial Delaware river crossing

Market Efficiency Analysis Sensitivity Study

- Scenario:
  - New 500 kV path from the AI to Red Lion
- Results:
  - Approximate benefit to cost ratio of 0.15
  - Approximately $57 million over 15 years

Outage Cost

- 5015 outage estimated at 14 days

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Dominion Virginia Power (DVP) 1C (No New Bus Tie) Project Schedule

Proposed Schedule 111 months (items run concurrent)

- Permitting: 24 months
- Design and Construction: 38 months
- Property Acquisition: 78 months

Schedule Criteria

- Permitting
  - CPCNs in two states and Army Corps of Engineers
- Long Lead Time Materials
  - No significant long lead time equipment required
- Construction
  - Could be impacted by restrictions due to endangered species and shipping traffic

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Dominion Virginia Power (DVP) 1C (No New Bus Tie) RoW and Land Acquisition

Right of Way and Land Acquisition Criteria

- No Eminent Domain in Delaware
  - All project have approximately 0.5 miles of right of way to either expand or acquire in Delaware
    - Land is coastal and under state jurisdiction
  - Red Lion substation expansion is on land currently owned by PHI

- New Right of Way Required
  - Will need to either negotiate with the LDV parties or negotiate with individual land owners and public entities

- Substation Land Required
  - Red Lion substation expansion will be done on land currently owned by PHI.

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Dominion Virginia Power (DVP) 1C (No New Bus Tie) Siting and Permitting

Siting and Permitting Criteria

- Wetlands Impact
  - Permits required to cross the Delaware state lands on the river coast
  - Impacts approximately 350 acres of forested wetland
- Public Opposition Risk
  - View-shed impacts minimal as this is adjacent to the existing 5015
  - Some opposition to any river crossing is expected
- Historic and Scenic Highway
  - No impact
- Land Permitting
  - USFWS right of way permit to cross Supawna National Wildlife Refuge required
- Delaware River Crossing
  - Numerous approvals and permits required:

  (a few major permits are listed below)
  - Delaware River Basin Commission approval required
  - Delaware and New Jersey CPCNs required
  - US Army Corps of Engineers Section 404 and 10 authorizations
  - Multiple US Fish and Wildlife permits required
  - National Marine Fisheries Service

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Dominion Virginia Power (DVP) 1C (No New Bus Tie) Operational Impact

Operational Impact Criteria

- Artificial Island Facility Requirements
  - PJM Operations Review
    - Request to minimize impact to existing transmission facilities
  - Salem/Hope Creek Facility Owner Feedback
    - Request to minimize outage and physical impacts to existing transmission facilities
    - Hope Creek north has available land for expansion
    - Hope Creek control house has adequate space and access for expansion
- Blackstart
  - No blackstart advantage
- Route Diversity
  - Project route is parallels the existing 5015 line
- Ongoing Maintenance
  - No impact

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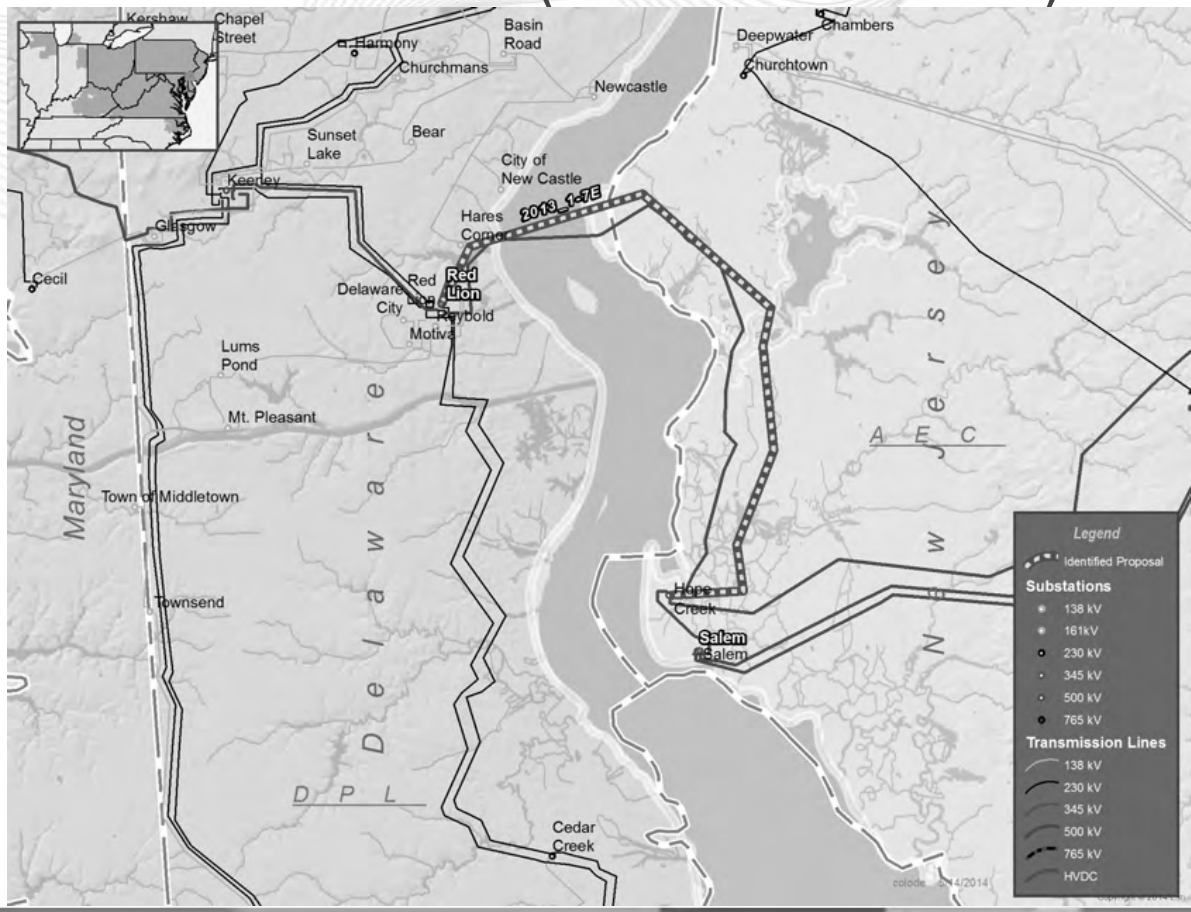
PSE&G 7K (No New Bus Tie)

- New 500kV Line between Hope Creek and Red Lion substations
- PJM modifications
  - Technical:
    - Removed the New Freedom to Deans portion of the project
    - Removed the new tie between Salem and Hope Creek substations
    - Added SVC
  - Constructability:
    - Red Lion expansion changed from a breaker and a half to an expansion of the existing ring-bus



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- Stability Performance

  – Failed required performance
    - Failed as proposed by project sponsor.
    - Did not satisfy stability criteria for a single line to ground fault with stuck breaker with AI units at unity power factor under new Hope Creek – Red Lion 500kV line maintenance outage condition with modification to remove Salem – Hope Creek 2nd tie and proposed breakers.

  – Passed required performance
    - Passed as modified with the addition of an SVC at Orchard or New Freedom.

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Artificial Island

PSE&G 7K (No New Bus Tie)
Hope Creek Expansion

Required Outages:

- Cut-in of new bay at Hope Creek

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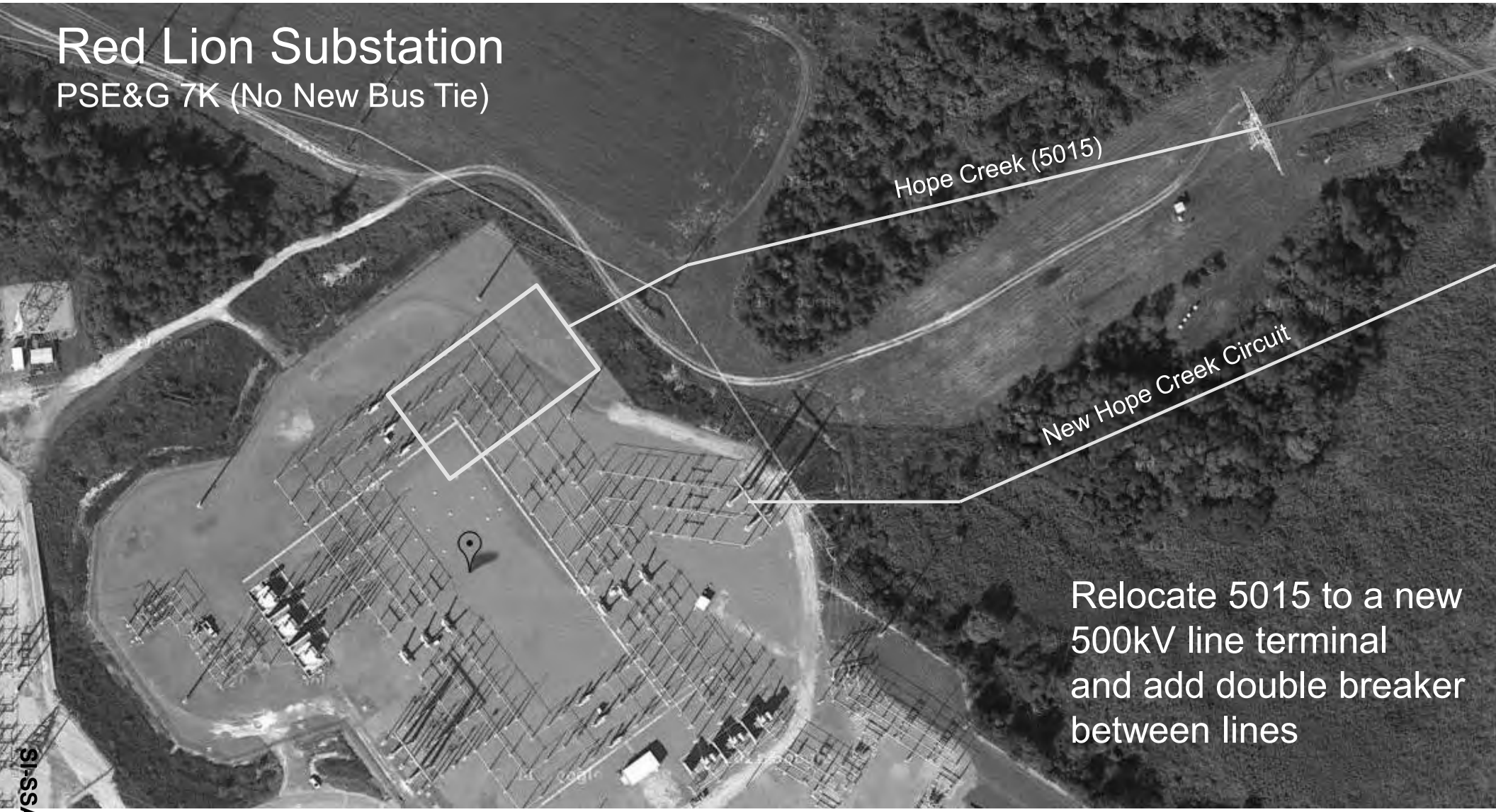
Red Lion Substation

PSE&G 7K (No New Bus Tie)



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PSE&G 7K (No New Bus Tie) - Cost Factors

PJM Estimated Cost: $211-$257 (million)

- New 17 mile 500kV line
- Aerial Delaware river crossing

Market Efficiency Analysis Sensitivity Study

- Scenario:
  - New 500 kV path from the AI to Red Lion
- Results:
  - Approximate benefit to cost ratio of 0.15
  - Approximately $57 million over 15 years

Outage Cost

- 5015 outage estimated at 14 days

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PSE&G 7K (No New Bus Tie) - Project Schedule

Proposed Schedule: 51 months (items run concurrent)

- Permitting: 51 months
- Design and Construction: 48 months
- Property Acquisition: 0 months

Schedule Criteria

- Permitting
  - CPCNs in two states and Army Corps of Engineers
- Long Lead Time Materials
  - No significant long lead time equipment required
- Construction
  - Could be impacted by restrictions due to endangered species and shipping traffic

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PSE&G 7K (No New Bus Tie) - RoW and Land Acquisition

Right of Way and Land Acquisition Criteria

- No Eminent Domain in Delaware
  - All project have approximately 0.5 miles of right of way to either expand or acquire in Delaware
    - Land is coastal and under state jurisdiction
  - Red Lion substation expansion is on land currently owned by PHI
- New Right of Way Required
  - As participants in the LDV agreement, party has a right of way agreement for the new line
- Substation Land Required
  - Red Lion substation expansion will be done on land currently owned by PHI.

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PSE&G 7K (No New Bus Tie) - Siting and Permitting

Siting and Permitting Criteria

- Wetlands Impact
  - Permits required to cross the Delaware state lands on the river coast
  - Impacts approximately 350 acres of forested wetland
- Public Opposition Risk
  - View-shed impacts minimal as this is adjacent to the existing 5015
  - Some opposition to any river crossing is expected
- Historic and Scenic Highway
  - No impact
- Land Permitting
  - USFWS right of way permit to cross Supawna National Wildlife Refuge required
- Delaware River Crossing
  - Numerous approvals and permits required:

  (a few major permits are listed below)
  - Delaware River Basin Commission approval required
  - Delaware and New Jersey CPCNs required
  - US Army Corps of Engineers Section 404 and 10 authorizations
  - Multiple US Fish and Wildlife permits required
  - National Marine Fisheries Service

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PSE&G 7K (No New Bus Tie) - Operational Impact

Operational Impact Criteria

- Artificial Island Facility Requirements
  - PJM Operations Review
    - Request to minimize impact to existing transmission facilities
  - Salem/Hope Creek Facility Owner Feedback
    - Request to minimize outage and physical impacts to existing transmission facilities
    - Hope Creek north has available land for expansion
    - Hope Creek control house has adequate space and access for expansion
- Blackstart
  - No blackstart advantage
- Route Diversity
  - Project route is parallels the existing 5015 line
- Ongoing Maintenance
  - No impact

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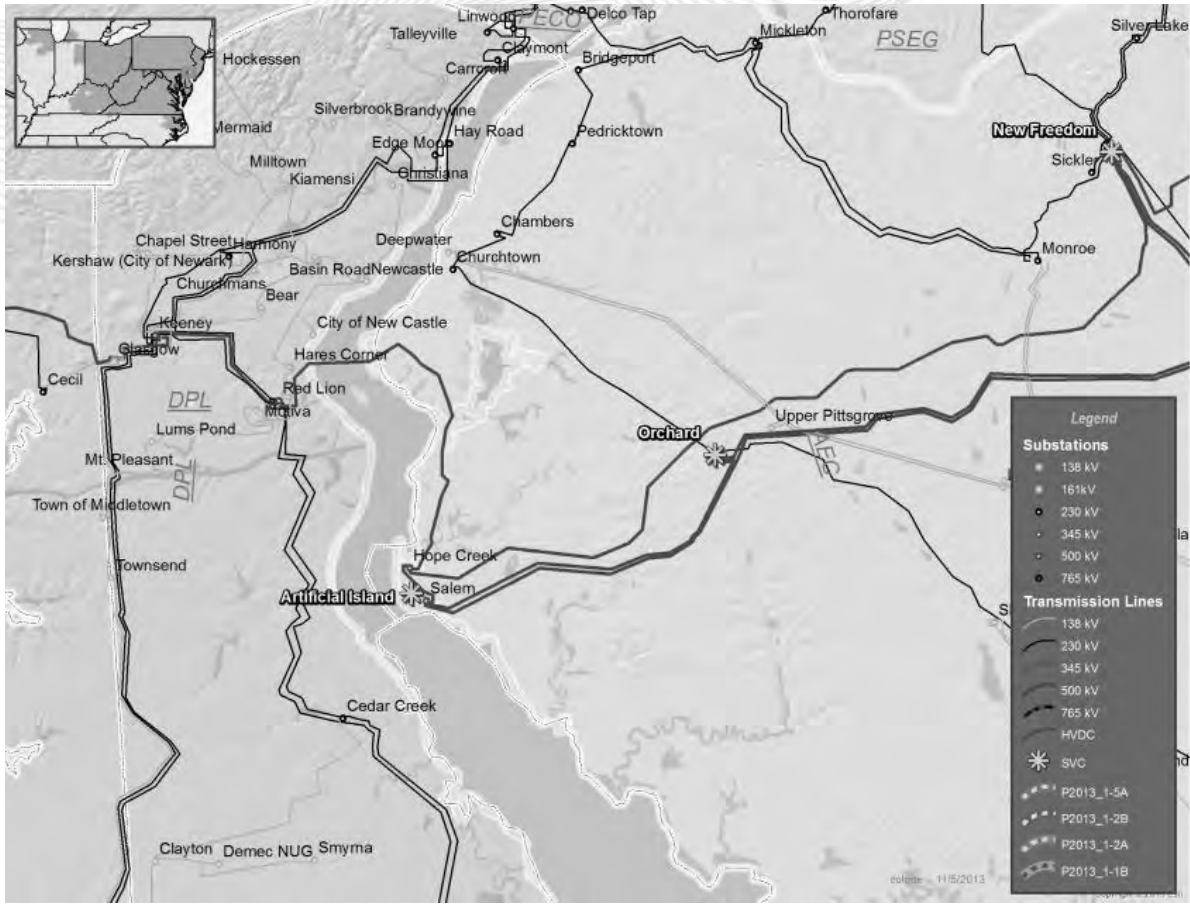
SVCs

- SVC Locations Considered:
  - New Freedom
  - Orchard
  - Artificial Island
- Schedule Estimate 36 months
  - SVC lead time of 24 months
  - Permitting and land acquisition 6 months
- Cost Estimate $80 million
  - SVC $60 million



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SVC Constructability Analysis

- No determining factor difference between the Orchard or New Freedom SVC
  - Project complexity
    - Expansion of existing substations at either Orchard or New Freedom
  - Land acquisition
    - New land purchase at Orchard
    - PSE&G owns adjacent land at New Freedom
  - Siting and permitting will be similar between the two projects
  - Cost and schedule estimates are the same

- Artificial Island
  - Anticipated nuclear regulatory concerns in approving this device at Artificial Island

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Consolidated Summary

SI-SSA-0010-0270

Artificial Island Technical Summary

		Southern Crossing Lines (Submarine)			Southern Crossing Lines (Overhead)		Red Lion to Artificial Island Lines						
							From Salem			From Hope Creek			
		LS Power 5A - Submarine Option	Transource 2B - North Cedar Creek	Transource 2A - Cedar Creek Expansion	LS Power 5A - Overhead	Dominion 1B - 500kV Overhead	PHI/Exelon 4A - Red Lion to Salem	LS Power 5B - Red Lion to Salem	Transource 2C - Red Lion to Salem	Dominion 1C - Red Lion to Hope Creek	PSE&G 7K- Red Lion to Hope Creek	Dominion 1C - Red Lion to Hope Creek (Remove HC-S 2nd Tie)	PSE&G 7K- Red Lion to Hope Creek (Remove HC-S 2nd Tie)
Technical Analysis Criteria	**Stability**	Maximum angle swing range of 80 - 112 degrees, dependent on solution and SVC location			Maximum angle swing range of 80 - 110 degrees, dependent on solution and SVC location		Maximum angle swing range of 77 - 102 degrees, dependent on solution and SVC location						
	Thermal	Preliminary analysis indicates no thermal overloads			Preliminary analysis indicates no thermal overloads		Preliminary analysis indicates no thermal overloads						
	Market Efficiency Results	Approximate $92 M cost savings over 15 Years			Approximate $92 M cost savings over 15 Years		Approximate $57 M cost savings over 15 Years						
	Short Circuit	Three overdutied 230 kV breakers		No overdutied breakers	Three overdutied 230 kV breakers		No overdutied breakers						

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Criteria Evaluation

- The following slides provide a summary review of PJM's assessment of the modified proposals in terms of technical performance, cost, constructability and other factors, which are covered in greater detail in the preceding slides.

- Legend:

Positive or limited impact	
Some impact	
Negative impact	
Does not apply	

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Southern Crossing Lines – Project Complexity

Criteria	Project Class	Southern Crossing 230kV Lines (Submarine)			Southern Crossing Lines (Overhead)	
	Proposal	LS Power 5A - Submarine Option	Transource 2B - North Cedar Creek	Transource 2A - Cedar Creek Expansion	LS Power 5A - 230kV Overhead	Dominion 1B - 500kV Overhead
	Sub-Criteria					
Project Complexity	Line Crossings	None	None	None	None	Generator lead line
	Outage Requirements	New bay tie-in at Salem	Relocation of 5024 line at Salem	Relocation of 5024 line at Salem; Cedar Creek ring-bus expansion	New bay tie-in at Salem	New tie-in at Salem will necessitate a unit outage; Breaker installation may require multiple Salem outages.
	Modification to other Transmission Facilities	Cutting the two 230kV lines into the new Delaware substation	Cutting the two 230kV lines into the new Delaware substation; installing one new span on the 5024 line.	Expanding the Cedar Creek ring bus by two positions to bring in the new Salem line and the existing Red Lion to Cartanza line; installing one new span on the 5024 line.	Cutting the two 230kV lines into the new Delaware substation	Cutting the two 230kV lines into the new Delaware substation

Southern Crossing Lines – Project Complexity

	Project Class	Southern Crossing 230kV Lines (Submarine)			Southern Crossing Lines (Overhead)	
Criteria	Proposal	LS Power 5A - Submarine Option	Transource 2B - North Cedar Creek	Transource 2A - Cedar Creek Expansion	LS Power 5A - 230kV Overhead	Dominion 1B - 500kV Overhead
	Sub-Criteria					
Project Complexity	Modification of Artificial Island Substations	New bay and auto-transformer to the south in Salem	New bay for 5024 line to the south in Salem	New bay for 5024 line to the south in Salem	New bay and auto-transformer to the south in Salem	Installing two breakers into the open middle bay in Salem
	Modification of Red Lion Substation	Not applicable	Not applicable	Not applicable	Not applicable	Not applicable

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AI to Red Lion Lines – Project Complexity

Criteria	Project Class	Red Lion to Salem 500kV Lines			Red Lion to Hope Creek 500kV Lines			
	Proposal	PHI/Exelon 4A - Red Lion to Salem	LS Power 5B - Red Lion to Salem	Transource 2C - Red Lion to Salem	Dominion 1C - Red Lion to Hope Creek	PSE&G 7K- Red Lion to Hope Creek	Dominion Red Lion to Hope Creek w/ 2nd tie removed	PSE&G Red Lion to Hope Creek w/ 2nd tie removed
Project Complexity	Line Crossings	5023, 5021, 5024 lines	5015 and 5023 lines	5023 line	5015 line; aerial tie has multiple crossings	5015 line	None	None
	Outage Requirements	5015 line position changing at both ends; Raising the three 500kV lines	Raising 5015 line and moving it to the new position at Red Lion. Relocation of 5037 line at Salem; Raising the 5023 line	Relocating the 5024 and 5021 lines at Salem; New line crosses the 5023 line.	Multple 500kV outages to convert the Red Lion ring bus to a breaker and a half scheme; New line crosses the 5015 line; Outages to suppor the new Hope Creek to Salem tie	Multple 500kV outages to convert the Red Lion ring bus to a breaker and a half scheme; New line crosses the 5015 line; Outages to suppor the new Hope Creek to Salem tie; 5037 into new position at Hope Creek	5015 line position changing at Red Lion. New bay tie-in at Hope Creek	5015 line position changing at Red Lion. New bay tie-in at Hope Creek
	Modification to other Facilities	Impacts detailed in other sub-criteria	Installing one new span on the 5037 line.	Use of the existing 5021 for a number of spans and build a new portion of 5021 along that length; installing one new span for the 5024 line	Impacts detailed in other sub-criteria	Impacts detailed in other sub-criteria	Impacts detailed in other sub-criteria	Impacts detailed in other sub-criteria

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AI to Red Lion Lines – Project Complexity

Criteria	Project Class	Red Lion to Salem 500kV Lines			Red Lion to Hope Creek 500kV Lines			
	Proposal	PHI/Exelon 4A - Red Lion to Salem	LS Power 5B - Red Lion to Salem	Transource 2C - Red Lion to Salem	Dominion 1C - Red Lion to Hope Creek	PSE&G 7K- Red Lion to Hope Creek	Dominion Red Lion to Hope Creek w/ 2nd tie removed	PSE&G Red Lion to Hope Creek w/ 2nd tie removed
Project Complexity	Modification of AI Subs	New bay to the south in Salem	New bay for 5037 line to the north in Salem	New bay for 5024 line to the south and relocate 5021 line in Salem	New bay in Hope Creek and a new tie between Hope Creek and Salem	New bay in Hope Creek and a new tie between Hope Creek and Salem; moving the 5037 into the existing open bay at Hope Creek	New bay in Hope Creek	New bay in Hope Creek
	Modification of Red Lion Sub	Moving 5015 line into new ring-bus position	Moving 5015 line into new ring-bus position	Moving 5015 line into new ring-bus position	Rebuilding the substation as a double bus - double breaker scheme	Rebuilding the substation as a breaker and a half scheme	Moving 5015 line into new ring-bus position	Moving 5015 line into new ring-bus position

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Southern Crossing Lines – Cost Factors

Criteria	Project Class	Southern Crossing 230kV Lines (Submarine)			Southern Crossing Lines (Overhead)	
	Proposal	LS Power 5A - Submarine Option	Transource 2B - North Cedar Creek	Transource 2A - Cedar Creek Expansion	LS Power 5A - 230kV Overhead	Dominion 1B - 500kV Overhead
	Sub-Criteria					
Cost Factors	PJM Estimated Project	$248-$302	$257-$313	$366-$446	$211-$257	$233-$283
	Proposed Project Costs	$148	$165-$208	$213-269	$116	$133
	Market Efficiency	Approximately $92 over 15 years			Approximately $92 over 15 years	
	Outage Cost	230kV outage during substation cut-in	230kV outage during substation cut-in	230kV outage during substation cut-in	230kV outage during substation cut-in	230kV outage during substation cut-in

Note: Costs are for the line project only; SVC costs are not included.

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AI to Red Lion Lines – Cost Factors

	Project Class	Red Lion to Salem 500kV Lines			Red Lion to Hope Creek 500kV Lines			
Criteria	Proposal	PHI/Exelon 4A - Red Lion to Salem	LS Power 5B - Red Lion to Salem	Transource 2C - Red Lion to Salem	Dominion 1C - Red Lion to Hope Creek	PSE&G 7K- Red Lion to Hope Creek	Dominion Red Lion to Hope Creek w/ 2nd tie removed	PSE&G Red Lion to Hope Creek w/ 2nd tie removed
	Sub-Criteria							
Cost Factors	PJM Estimated Project	$216-$263	$221-$269	$232-$282	$242-$294	$249-$304	$211-$257	$211-$257
	Proposed Project Costs	$181	$171	$123-156	$199	$297		
	Market Efficiency	Approximately $57 over 15 years			Approximately $57 over 15 years			
	Outage Cost	5015 outage estimated at 30 days	5015 outage estimated at 30 days	5015 outage estimated at 14 days	5015 outage estimated at 40 days	5015 outage estimated at 40 days	5015 outage estimated at 14 days	5015 outage estimated at 14 days

Note: Costs are for the line project only; SVC costs are not included.

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Southern Crossing Lines – Operational Impact

Criteria	Project Class	Southern Crossing 230kV Lines (Submarine)			Southern Crossing Lines (Overhead)	
	Proposal	LS Power 5A - Submarine Option	Transource 2B - North Cedar Creek	Transource 2A - Cedar Creek Expansion	LS Power 5A - 230kV Overhead	Dominion 1B - 500kV Overhead
	Sub-Criteria					
Operational Impact	Artificial Island Facility Requirements	Expansion at Salem needs to incorporate maintenance access to substation equipment; Salem is space constrained; Control house access is also constrained	Expansion at Salem needs to incorporate maintenance access to substation equipment; Salem is space constrained; Control house access is also constrained	Expansion at Salem needs to incorporate maintenance access to substation equipment; Salem is space constrained; Control house access is also constrained	Expansion at Salem needs to incorporate maintenance access to substation equipment; Salem is space constrained; Control house access is also constrained	Expansion at Salem needs to incorporate maintenance access to substation equipment; Salem is space constrained; Control house access is also constrained
	Blackstart	Additional access to blackstart resources	Additional access to blackstart resources	Additional access to blackstart resources	Additional access to blackstart resources	Additional access to blackstart resources
	Route Diversity	New route	New route	New route	New route	New route
	Ongoing Maintenance	Salt spray concern with proximity to Delaware river; auto-transformer maintenance may increase line outage frequency	Salt spray concern with proximity to Delaware river; auto-transformer maintenance may increase line outage frequency	Salt spray concern with proximity to Delaware river; auto-transformer maintenance may increase line outage frequency	Salt spray concern with proximity to Delaware river; auto-transformer maintenance may increase line outage frequency	Auto-transformer maintenance may increase line outage frequency

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AI to Red Lion Lines – Operational Impact

Criteria	Project Class	Red Lion to Salem 500kV Lines			Red Lion to Hope Creek 500kV Lines			
	Proposal	PHI/Exelon 4A - Red Lion to Salem	LS Power 5B - Red Lion to Salem	Transource 2C - Red Lion to Salem	Dominion 1C - Red Lion to Hope Creek	PSE&G 7K- Red Lion to Hope Creek	Dominion Red Lion to Hope Creek w/ 2nd tie removed	PSE&G Red Lion to Hope Creek w/ 2nd tie removed
	Sub-Criteria							
Operational Impact	Artificial Island Facility Requirements	Expansion at Salem needs to incorporate maintenance access to substation equipment; Salem is space constrained; Control house access is also constrained	Expansion at Salem needs to incorporate maintenance access to substation equipment; Salem is space constrained; Control house access is also constrained	Expansion at Salem needs to incorporate maintenance access to substation equipment; Salem is space constrained; Control house access is also constrained	Expansion at Salem needs to incorporate maintenance access to substation equipment; Salem is space constrained; Control house access is also constrained	Expansion at Salem needs to incorporate maintenance access to substation equipment; Salem is space constrained; Control house access is also constrained	Land available to the north of Hope Creek for expansion and control house has adequate space and access for expansion	Land available to the north of Hope Creek for expansion and control house has adequate space and access for expansion
	Blackstart	No blackstart advantage	No blackstart advantage	No blackstart advantage	No blackstart advantage	No blackstart advantage	No blackstart advantage	No blackstart advantage
	Route Diversity	Parallels existing 5015 line	Parallels existing 5015 line	Parallels existing 5015 line	Parallels existing 5015 line	Parallels existing 5015 line	Parallels existing 5015 line	Parallels existing 5015 line
	Ongoing Maintenance	Salt spray concern with proximity to Delaware river	No impact	Salt spray concern with proximity to Delaware river	The new gas-insulated bus tie line between Salem and Hope Creek may require more frequent maintenance	Limited physical access could lead to maintenance issues on the new tie line between Salem and Hope Creek	No impact	No impact

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Southern Crossing Lines
Right of Way and Land Acquisition

Criteria	Project Class	Southern Crossing 230kV Lines (Submarine)			Southern Crossing Lines (Overhead)	
	Proposal	LS Power 5A - Submarine Option	Transource 2B - North Cedar Creek	Transource 2A - Cedar Creek Expansion	LS Power 5A - 230kV Overhead	Dominion 1B - 500kV Overhead
	Sub-Criteria					
Right of Way and Land Acquisition	No Eminent Domain in Delaware	1.5-3 miles of new RoW to acquire in Delaware	1.5-3 miles of new RoW to acquire in Delaware	3 miles of new RoW to acquire in Delaware	1.5-3 miles of new RoW to acquire in Delaware	1.5-3 miles of new RoW to acquire in Delaware
	New Right of Way Required	1.5-3 miles of new RoW to acquire in Delaware	1.5-3 miles of new RoW to acquire in Delaware	3 miles of new RoW to acquire in Delaware	1.5-3 miles of new RoW to acquire in Delaware	1.5-3 miles of new RoW to acquire in Delaware
	Substation Land Required	Acquired an option on a substation location in Delaware	New substation land required in Delaware and New Jersey	New substation land required in Delaware and New Jersey	Acquired an option on a substation location in Delaware	New substation land required in Delaware

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AI to Red Lion Lines
Right of Way and Land Acquisition

Criteria	Project Class	Red Lion to Salem 500kV Lines			Red Lion to Hope Creek 500kV Lines			
	Proposal	PHI/Exelon 4A - Red Lion to Salem	LS Power 5B - Red Lion to Salem	Transource 2C - Red Lion to Salem	Dominion 1C - Red Lion to Hope Creek	PSE&G 7K- Red Lion to Hope Creek	Dominion Red Lion to Hope Creek w/ 2nd tie removed	PSE&G Red Lion to Hope Creek w/ 2nd tie removed
	Sub-Criteria							
Right of Way and Land Acquisition	No Eminent Domain in Delaware	0.5 miles of right of way to expand in Delaware; land is coastal and under state jurisdiction	0.5 miles of right of way to expand in Delaware; land is coastal and under state jurisdiction	0.5 miles of right of way to expand in Delaware; land is coastal and under state jurisdiction	0.5 miles of right of way to expand in Delaware; land is coastal and under state jurisdiction	0.5 miles of right of way to expand in Delaware; land is coastal and under state jurisdiction	0.5 miles of right of way to expand in Delaware; land is coastal and under state jurisdiction	0.5 miles of right of way to expand in Delaware; land is coastal and under state jurisdiction
	New Right of Way Required	Participant in the LDV agreement which governs 5015 RoW	Negotiate with LDV parties or individual land owners	Negotiate with LDV parties or individual land owners	Negotiate with LDV parties or individual land owners	Participant in the LDV agreement which governs 5015 RoW	Negotiate with LDV parties or individual land owners	Participant in the LDV agreement which governs 5015 RoW
	Substation Land Required	None	None	None	None	None	None	None

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Southern Crossing Lines - Siting and Permitting

Criteria	Project Class	Southern Crossing 230kV Lines (Submarine)			Southern Crossing Lines (Overhead)	
	Proposal	LS Power 5A - Submarine Option	Transource 2B - North Cedar Creek	Transource 2A - Cedar Creek Expansion	LS Power 5A - 230kV Overhead	Dominion 1B - 500kV Overhead
	Sub-Criteria					
Siting and Permitting	Wetlands Impact	New route will allow flexibility	New route will allow flexibility	Impacts approximately 10 acres of forested wetland	New route will allow flexibility	New route will allow flexibility
	Land Permitting	No major permit identified	No major permit identified	No major permit identified	No major permit identified	No major permit identified
	Public Opposition Risk	No view-shed impact; some opposition to any river crossing is expected	No view-shed impact; some opposition to any river crossing is expected	No view-shed impact; some opposition to any river crossing is expected	Creates a new view-shed impact and would become the southern-most aerial infrastructure on the Delaware Rive	Creates a new view-shed impact and would become the southern-most aerial infrastructure on the Delaware Rive
	Historic and Scenic Highway	New line parallels Delaware state route 9	New line crosses Delaware state route 9	Not applicable	New line parallels Delaware state route 9	New line crosses Delaware state route 9
	Delaware River Crossing	Numerous approvals and permits will be required for any Delaware river crossing	Numerous approvals and permits will be required for any Delaware river crossing	Numerous approvals and permits will be required for any Delaware river crossing	Numerous approvals and permits will be required for any Delaware river crossing	Numerous approvals and permits will be required for any Delaware river crossing

AI to Red Lion Lines - Siting and Permitting

Criteria	Project Class	Red Lion to Salem 500kV Lines			Red Lion to Hope Creek 500kV Lines			
	Proposal	PHI/Exelon 4A - Red Lion to Salem	LS Power 5B - Red Lion to Salem	Transource 2C - Red Lion to Salem	Dominion 1C - Red Lion to Hope Creek	PSE&G 7K- Red Lion to Hope Creek	Dominion Red Lion to Hope Creek w/ 2nd tie removed	PSE&G Red Lion to Hope Creek w/ 2nd tie removed
	Sub-Criteria							
Siting and Permitting	Wetlands Impact	Impacts approximately 350 acres of forested wetland	Impacts approximately 350 acres of forested wetland	Impacts approximately 350 acres of forested wetland	Impacts approximately 350 acres of forested wetland	Impacts approximately 350 acres of forested wetland	Impacts approximately 350 acres of forested wetland	Impacts approximately 350 acres of forested wetland
	Land Permitting	USFWS RoW permit to cross Supawna National Wildlife Refuge required	USFWS RoW permit to cross Supawna National Wildlife Refuge required	USFWS RoW permit to cross Supawna National Wildlife Refuge required	USFWS RoW permit to cross Supawna National Wildlife Refuge required	USFWS RoW permit to cross Supawna National Wildlife Refuge required	USFWS RoW permit to cross Supawna National Wildlife Refuge required	USFWS RoW permit to cross Supawna National Wildlife Refuge required
	Public Opposition Risk	View-shed impacts minimized by proximity to the existing 5015; some opposition to any river crossing is expected	View-shed impacts minimized by proximity to the existing 5015; some opposition to any river crossing is expected	View-shed impacts minimized by proximity to the existing 5015; some opposition to any river crossing is expected	View-shed impacts minimized by proximity to the existing 5015; some opposition to any river crossing is expected	View-shed impacts minimized by proximity to the existing 5015; some opposition to any river crossing is expected	View-shed impacts minimized by proximity to the existing 5015; some opposition to any river crossing is expected	View-shed impacts minimized by proximity to the existing 5015; some opposition to any river crossing is expected
	Historic and Scenic Highway	Not applicable	Not applicable	Not applicable	Not applicable	Not applicable	Not applicable	Not applicable
	Delaware River Crossing	Numerous approvals and permits will be required for any Delaware river crossing	Numerous approvals and permits will be required for any Delaware river crossing	Numerous approvals and permits will be required for any Delaware river crossing	Numerous approvals and permits will be required for any Delaware river crossing	Numerous approvals and permits will be required for any Delaware river crossing	Numerous approvals and permits will be required for any Delaware river crossing	Numerous approvals and permits will be required for any Delaware river crossing

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Southern Crossing Lines – Project Schedule

Criteria	Project Class	Southern Crossing 230kV Lines (Submarine)			Southern Crossing Lines (Overhead)	
	Proposal	LS Power 5A - Submarine Option	Transource 2B - North Cedar Creek	Transource 2A - Cedar Creek Expansion	LS Power 5A - 230kV Overhead	Dominion 1B - 500kV Overhead
	Sub-Criteria					
Project Schedule	Permitting	Multiple permits required including CPCNs from two states and Army Corp of Engineers permits	Multiple permits required including CPCNs from two states and Army Corp of Engineers permits	Multiple permits required including CPCNs from two states and Army Corp of Engineers permits	Multiple permits required including CPCNs from two states and Army Corp of Engineers permits	Multiple permits required including CPCNs from two states and Army Corp of Engineers permits
	Construction	Submarine cable installation requires specialized equipment; Spawning/nesting seasons of endagered species may impact construction timeframes	Submarine cable installation requires specialized equipment; Spawning/nesting seasons of endagered species may impact construction timeframes	Submarine cable installation requires specialized equipment; Spawning/nesting seasons of endagered species may impact construction timeframes	Spawning/nesting seasons of endagered species may impact construction timeframes	Spawning/nesting seasons of endagered species may impact construction timeframes
	Long Lead Time Materials	Submarine cable and auto-transformers	Submarine cable and auto-transformers	Submarine cable and auto-transformers	Auto-transformers	Auto-transformers

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AI to Red Lion Lines – Project Schedule

Criteria	Project Class	Red Lion to Salem 500kV Lines			Red Lion to Hope Creek 500kV Lines			
	Proposal	PHI/Exelon 4A - Red Lion to Salem	LS Power 5B - Red Lion to Salem	Transource 2C - Red Lion to Salem	Dominion 1C - Red Lion to Hope Creek	PSE&G 7K- Red Lion to Hope Creek	Dominion Red Lion to Hope Creek w/ 2nd tie removed	PSE&G Red Lion to Hope Creek w/ 2nd tie removed
	Sub-Criteria							
Project Schedule	Permitting	Multiple permits required including CPCNs from two states and Army Corp of Engineers permits	Multiple permits required including CPCNs from two states and Army Corp of Engineers permits	Multiple permits required including CPCNs from two states and Army Corp of Engineers permits	Multiple permits required including CPCNs from two states and Army Corp of Engineers permits	Multiple permits required including CPCNs from two states and Army Corp of Engineers permits	Multiple permits required including CPCNs from two states and Army Corp of Engineers permits	Multiple permits required including CPCNs from two states and Army Corp of Engineers permits
	Construction	Spawning/nesting seasons of endagered species may impact construction timeframes	Spawning/nesting seasons of endagered species may impact construction timeframes	Spawning/nesting seasons of endagered species may impact construction timeframes	Spawning/nesting seasons of endagered species may impact construction timeframes	Spawning/nesting seasons of endagered species may impact construction timeframes	Spawning/nesting seasons of endagered species may impact construction timeframes	Spawning/nesting seasons of endagered species may impact construction timeframes
	Long Lead Time Materials	None	None	None	None	None	None	None

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Criteria	Project Class	Southern Crossing 230kV Lines (Submarine)			Southern Crossing Lines (Overhead)		Red Lion to Salem 500kV Lines			Red Lion to Hope Creek 500kV Lines			
	Proposal	LS Power 5A - Submarine Option	Transource 2B - North Cedar Creek	Transource 2A - Cedar Creek Expansion	LS Power 5A - 230kV Overhead	Dominion 1B - 500kV Overhead	PHI/Exelon 4A - Red Lion to Salem	LS Power 5B - Red Lion to Salem	Transource 2C - Red Lion to Salem	Dominion 1C - Red Lion to Hope Creek	PSE&G 7K- Red Lion to Hope Creek	Dominion Red Lion to Hope Creek w/ 2nd tie removed	PSE&G Red Lion to Hope Creek w/ 2nd tie removed
Technical Analysis	Stability												
	Thermal												
	Market Efficiency Results	Approximate 0.15 Benefit to Cost Ratio			Approximate 0.15 Benefit to Cost Ratio		Approximate 0.2 Benefit to Cost Ratio			Approximate 0.2 Benefit to Cost Ratio			
	Short Circuit												
	NERC Cat-D Contingencies												
Cost Factors	PJM Estimated Project Cost	$248-$302	$257-$313	$366-$446	$211-$257	$233-$283	$216-$263	$221-$269	$232-$282	$242-$294	$249-$304	$211-$257	$211-$257
	Project Costs as Proposed	$148	$165-$208	$213-269	$116	$133	$181	$171	$123-156	$199	$297		
	Market Efficiency	Approximately $92 over 15 years			Approximately $92 over 15 years		Approximately $57 over 15 years			Approximately $57 over 15 years			
	Outage Cost												
Project Schedule	Permitting												
	Construction												
	Long Lead Time Materials												
Risks to Cost and Schedule													
Project Complexity	Line Crossings												
	Outage Requirements												
	Modification to other Facilities												
	Modification of AI Subs												
	Modification of Red Lion Sub												
RoW and Land Acquisition	No Eminent Domain in Delaware												
	New Right of Way Required												
	Substation Land Required												
Siting and Permitting	Wetlands Impact												
	Land Permitting												
	Public Opposition Risk												
	Historic and Scenic Highway												
	Delaware River Crossing												
Operational Impact	Artificial Island Facility Requirements												
	Blackstart												
	Route Diversity												
	Ongoing Maintenance												

SI-SSA-0010-0287

Artificial Island Timeline

- **Today - Monday, May 19th Special TEAC**
  - **3 hour stakeholder technical meeting**
  - **In-person at PJM CTC**
- Monday, June 2nd – Due date for stakeholder comment/feedback (14 day comment period)
- June 5th TEAC
- **Monday, June 16th – PJM review of stakeholder comment/feedback and final decision meeting**
  - **Special TEAC Webex / Teleconference**
- Comment Period to the PJM Board (36 days for comment period)
- July 10th TEAC
- **Tuesday, July 22nd – PJM Board meeting**
  - **Artificial Island solution recommendation to the PJM Board**

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Appendix

SI-SSA-0010-0289

Technical Overview

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Minimum AI voltage for 230kV proposals

Comparison Method:
Assume 1.065 p.u. at the AI (unstable below 1.065), solve the power flow for the corresponding Salem and Hope Creek MVAr output. Simulate the combination of the most critical fault and outage. Do not assume the addition of an SVC.
Result:
Measure the maximum machine angle swing.
All 230 kV proposals pass the stability criteria.

Group	Project ID	230 kV Transmission Solution	AI 500kV bus voltage	AI MVAr output	Critical Outage	Critical Contingency	Maximum Angle Swing (deg.)
1.1	**P2013_1-5A**	LS Power	**1.065 pu**	1044	5015*	14b**	**102**
1.1	**P2013_1-2B**	Transource (AEP)	**1.065 pu**	965	5015	14b	**105**
1.1	**P2013_1-2A**	Transource (AEP)	**1.065 pu**	940	5015	14b	**110**
1.2	**P2013_1-1B**	DVP	**1.065 pu**	926	5015	14b	**115**

5015*: Hope Creek – Red Lion 500kV line
14b**: single-line-to-ground fault on the new line from Salem w/ delayed clearing due to stuck breaker

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230kV proposal comparison - 5015 outage

Comparison Method:
For each proposal, assume a fixed MVAr output at the Artificial Island, solve the power flow for the corresponding Artificial Island bus voltages. Simulate the combination of the most critical fault and outage. Do not assume the addition of an SVC.
Result:
Measure the maximum machine angle swing.
All 230 kV proposal pass the stability criteria.

Group	Project ID	230 kV Transmission Solution	AI 500kV bus voltage	AI MVAr output	Critical Outage	Critical Contingency	Maximum Angle Swing (deg)
1.1	**P2013_1-5A**	LS Power	1.065	1044	5015	14b	**102**
1.1	**P2013_1-2B**	Transource (AEP)	1.071	1044	5015	14b	**95**
1.1	**P2013_1-2A**	Transource (AEP)	1.074	1044	5015	14b	**95**
1.2	**P2013_1-1B**	DVP	1.074	1044	5015	14b	**97**

5015*: Hope Creek – Red Lion 500kV line
14b**: single-line-to-ground fault on the new line from Salem w/ delayed clearing due to stuck breaker

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230kV proposal comparison – 5038 outage

Comparison Method:
For each proposal, assume a fixed MVAr output at the Artificial Island, solve the power flow for the corresponding Artificial Island bus voltages. Simulate the combination of the most critical fault and outage. Do not assume the addition of an SVC.
Result:
Measure the maximum machine angle swing.
All 230 kV proposal pass the stability criteria.

Group	Project ID	230 kV Transmission Solution	AI 500kV bus voltage	AI MVAr output	Critical Outage	Critical Contingency	Maximum Angle Swing (deg)
1.1	**P2013_1-5A**	LS Power	1.044	832	5038*	2b**	**121**
1.1	**P2013_1-2B**	Transource (AEP)	1.052	832	5038	2b	**89**
1.1	**P2013_1-2A**	Transource (AEP)	1.053	832	5038	2b	**93**
1.2	**P2013_1-1B**	DVP	1.049	832	5038	2b	**87**

5038*: New Freedom – East Windsor 500kV line
2b**: single-line-to-ground fault on Hope Creek-Red Lion 500kV line w/ delayed clearing due to stuck breaker

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230kV+ SVC proposal comparison

Comparison Method:
For each proposal, assume the addition of an SVC at each of three locations. Simulate the combination of the most critical fault and outage.
Result:
Measure the maximum machine angle swing.
All 230 kV proposals with SVC additions pass the stability criteria with greater margin than without SVCs.

Project ID	230 kV Transmission Solution	SVC option	AI 500kV Bus Voltage	AI MVAr Output	Critical Outage	Critical Contingency	Maximum Angle Swing
P2013_1-5A-SVC	LS Power	Artificial Island	1.042	728	5015	14b	80
		Orchard	1.041	724	5015	14b	108
		New Freedom	1.041	721	5015	14b	112
P2013_1-2B-SVC	Transource (AEP)	Artificial Island	1.042	664	5015	14b	81
		Orchard	1.042	662	5015	14b	105
		New Freedom	1.042	662	5015	14b	109
P2013_1-2A-SVC	Transource (AEP)	Artificial Island	1.043	655	5015	14b	82
		Orchard	1.042	658	5015	14b	107
		New Freedom	1.042	658	5015	14b	112
P2013_1-1B-SVC	DVP	Artificial Island	1.042	672	5015	14b	85
		Orchard	1.041	670	5015	14b	106
		New Freedom	1.041	674	5015	14b	110

Note: The study results are obtained under the assumption of unity power factor at the high side of GSU.

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TCSC+SVC vs. 230kV+SVC

Compare TCSC + SVC (assumes +750 MVAR) alternative to 230 kV + SVC alternatives

Project	Project ID	TO	SVC location	AI 500kV bus voltage	AI MVAr output	Outage	Contingency	Maximum Angle Swing
230kV+SVC	P2013_1-5A-SVC	LS Power	New Freedom	1.032	645	5038	2a	**54**
	P2013_1-2B-SVC	Transource	New Freedom	1.040	645	5038	2a	**47**
	P2013_1-2A-SVC	Transource	New Freedom	1.042	645	5038	2a	**48**
	P2013_1-1B-SVC	DVP	New Freedom	1.037	645	5038	2a	**46**
TCSC+SVC	P2013_1-1A	DVP	New Freedom	1.029	645	5038	2a	**88**

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Artificial Island Analytical Evaluation
Load Flow Analysis Update

- Load Flow Analysis
  - 230 kV Transmission Solutions
    - No thermal or voltage violations identified for summer peak case
  - New 500 kV transmission from the Artificial Island to Red Lion 500 kV
    - No thermal or voltage violations identified for summer peak case

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Artificial Island Analytical Evaluation
Short Circuit Analysis Update

- Short Circuit Analysis
  - 230 kV Transmission Solutions
    - Several 50 kA circuit breakers overdutied at Red Lion 230 kV
  - New 500 kV transmission from the Artificial Island to Red Lion 500 kV
    - No new overdutied breakers identified

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Cost Factors

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Constructability Review – PJM Cost Estimates

- PJM performed a per-unit cost estimate analysis
- Major components account for 70% - 90% of estimated material and construction costs
  - Submarine cable at $5.3 million per mile
  - 500kV aerial at $3.6 million per mile
  - Aerial Delaware river crossing at $100 million
  - 500/230kV auto transformer at $7.8 to $10.5 million per phase

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Constructability Review – PJM Cost Estimates

- Costs independently estimated in collaboration with PJM outside consultants
  - Engineering at 2.5%
  - Project management at 5%
  - Contingency range from 15% to 40%

- Estimate Sources
  - RTEP project cost estimates and actuals
  - Inputs from multiple outside consultants
  - Industry sources

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PJM Cost Estimates

Class	Proposals	PJM Estimate	
Southern Crossing Lines (Submarine)	LS Power 5A - Submarine Option	$ 248	$ 302
	Transource 2B - North Cedar Creek	$ 257	$ 313
	Transource 2A - Cedar Creek Expansion	$ 366	$ 446
Southern Crossing Lines (Overhead)	LS Power 5A - Overhead	$ 211	$ 257
	Dominion 1B - 500kV Overhead	$ 233	$ 283
Red Lion to Salem Lines	PHI/Exelon 4A - Red Lion to Salem	$ 216	$ 263
	LS Power 5B - Red Lion to Salem	$ 221	$ 269
	Transource 2C - Red Lion to Salem	$ 232	$ 282
Red Lion to Hope Creek Lines	Dominion 1C - Red Lion to Hope Creek	$ 242	$ 294
	PSE&G 7K- Red Lion to Hope Creek	$ 249	$ 304
	Dominion – Red Lion to Hope Creek (No New Bus Tie)	$ 211	$ 257
	PSE&G – Red Lion to Hope Creek (No New Bus Tie)	$ 211	$ 257

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Revision History

Revision History

- Original Version Distributed to PJM TEAC
  - V1 - 5/16/2014
  - V2 – 5/20/2014
    - Updated slides 15, 20, 161 and 170 to remove errors
    - Added a clarifying note to slides 187 and 188
    - Updated slide 45 with corrected failure mode

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Transmission Expansion Advisory Committee

December 11, 2013

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intervening pages intentionally omitted

Artificial Island Update

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Artificial Island Proposals

Project ID	TO	Cost ($)	Major Components	Supporting info
P2013_1-1A	Virginia Electric and Power Com	$ 133	500 MVAR SVC near New Freedom	Two (2) Thyristor Controlled Series Compensation (TCSC) Devices near New Freedom
P2013_1-1B	Virginia Electric and Power Com	$ 126	New 500 kV from Salem - a new station in Delaware	New 500/230 kV station in Delaware that taps existing Cedar Creek - Red Lion 230kV and Catanza - Red Lion 230kV
P2013_1-1C	Virginia Electric and Power Com	$ 202	New 500 kV from Hope Creek - a new Station in Delaware	Install a new 500kV line from Hope Creek - Red Lion; New Salem - Hope Creek 500 kV line
P2013_1-2A	Transource	$213 - $269	Salem - Cedar Creek 230 kV	Two (2) 500/230 Transformers near Salem; Loop in Red Lion - Cartanza 230 to Cedar Creek
P2013_1-2B	Transource	$165 - $208	Salem - North Cedar Creek (new) 230 kV	Two (2) 500/230 transformers near Salem and loop in Red Lion - Cartanza 230 and Red Lion - Cedar Creek 230 kV
P2013_1-2C	Transource	$123 - $156	Salem - Red Lion 500 kV	
P2013_1-2D	Transource	$788 - $994	New Freedom - Lumberton - North Smithburg (New) 500 kV line	New Salem - Hope Creek 500 kV line and new 500/230 station east of Lumberton
P2013_1-3A	First Energy	$410.7 (Only FirstEnergy portion)	New Freedom-Smithburg 500 kV line with a loop into Larrabee	Hope Creek - Red Lion 500 kV line
P2013_1-4A	PHI Exelon	$ 475	Peach Bottom - Keeney - Red Lion - Salem 500 kV	Remove Keeney - Red Lion 230 kV; Reconfigure 230 around Hay Road; Reconductor Harmony-Chapel St 138 kV
P2013_1-5A	LS Power	$116.3M - $148.3M	Salem - Silver Run (new) 230 kV; Salem 500/230 kV Transformer	New 230 kV station that taps existing Cedar Creek - Red Lion 230kV and Catanza - Red Lion 230kV
P2013_1-5B	LS Power	$ 170	Salem - Red Lion 500 kV	
P2013_1-6A	Atlantic Wind	$ 1,012	320 kV HVDC Salem/Hope Creek - Cardiff	SVC at Salem/Hope Creek; New HVDC Stations at Cardiff and Salem
P2013_1-7A	PSE&G	$ 1,371	Salem-Hope Creek to Peach Bottom 500 kV	Existing ROW
P2013_1-7B	PSE&G	$ 1,372	Salem-Hope Creek to Peach Bottom 500 kV	Same as 7A with Loop into Keeney
P2013_1-7C	PSE&G	$ 1,372	Salem-Hope Creek to Peach Bottom 500 kV	Same at 7A with Loop into Red Lion
P2013_1-7D	PSE&G	$ 831	Salem-Hope Creek to Peach Bottom 500 kV	Same as 7A with New ROW
P2013_1-7E	PSE&G	$ 692	New Freedom - Deans 500 & Salem - Hope Creek 500 kV lines	
P2013_1-7F	PSE&G	$ 879	New Freedom - Smithburg and Salem-Hope Creek 500 kV lines	Existing ROW
P2013_1-7G	PSE&G	$ 1,034	New Freedom - Smithburg and Salem-Hope Creek 500 kV lines	Same as 7F with a Loop into a new Larrabee 500 kV station
P2013_1-7H	PSE&G	$ 1,177	New Freedom - Whitpain and Salem - Hope Creek 500 kV lines	Northern Route
P2013_1-7I	PSE&G	$ 1,353	New Freedom - Whitpain and Salem - Hope Creek 500 kV lines	Same as 7H with the Southern Route
P2013_1-7J	PSE&G	$ 915	New Freedom - New Station on Branchburg-Elroy 500 kV line ("5017 Junction") and Salem - Hope Creek 500 kV line	Existing ROW
P2013_1-7K	PSE&G	$ 1,066	New Freedom - Deans & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7E with Hope Creek - Red Lion
P2013_1-7L	PSE&G	$ 1,250	New Freedom - Smithburg & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7F with Hope Creek - Red Lion
P2013_1-7M	PSE&G	$ 1,548	New Freedom - Whitpain (North) & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7H with Hope Creek - Red Lion
P2013_1-7N	PSE&G	$ 1,289	New Freedom - a new Station on the Branchburg-Elroy 500 kV line ("5017 Junction") & Salem-Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	

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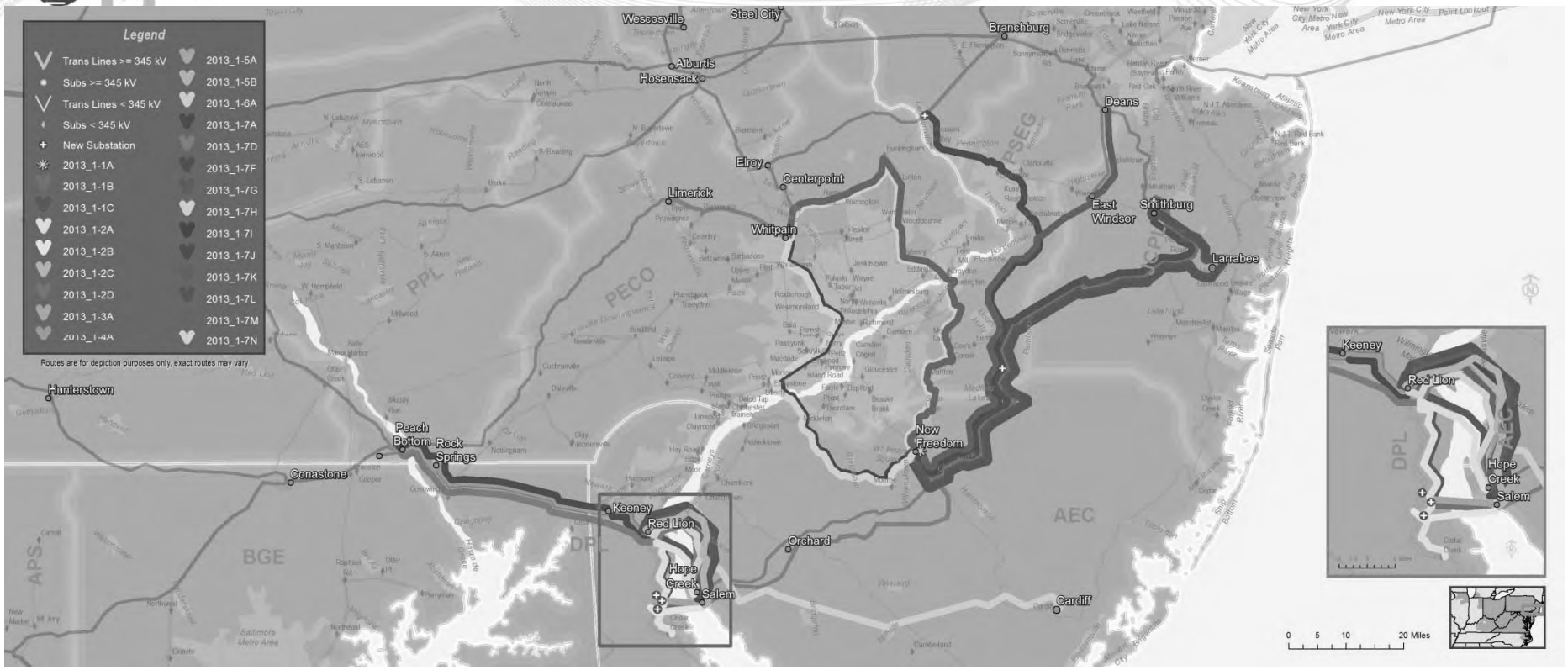
Artificial Island Proposals



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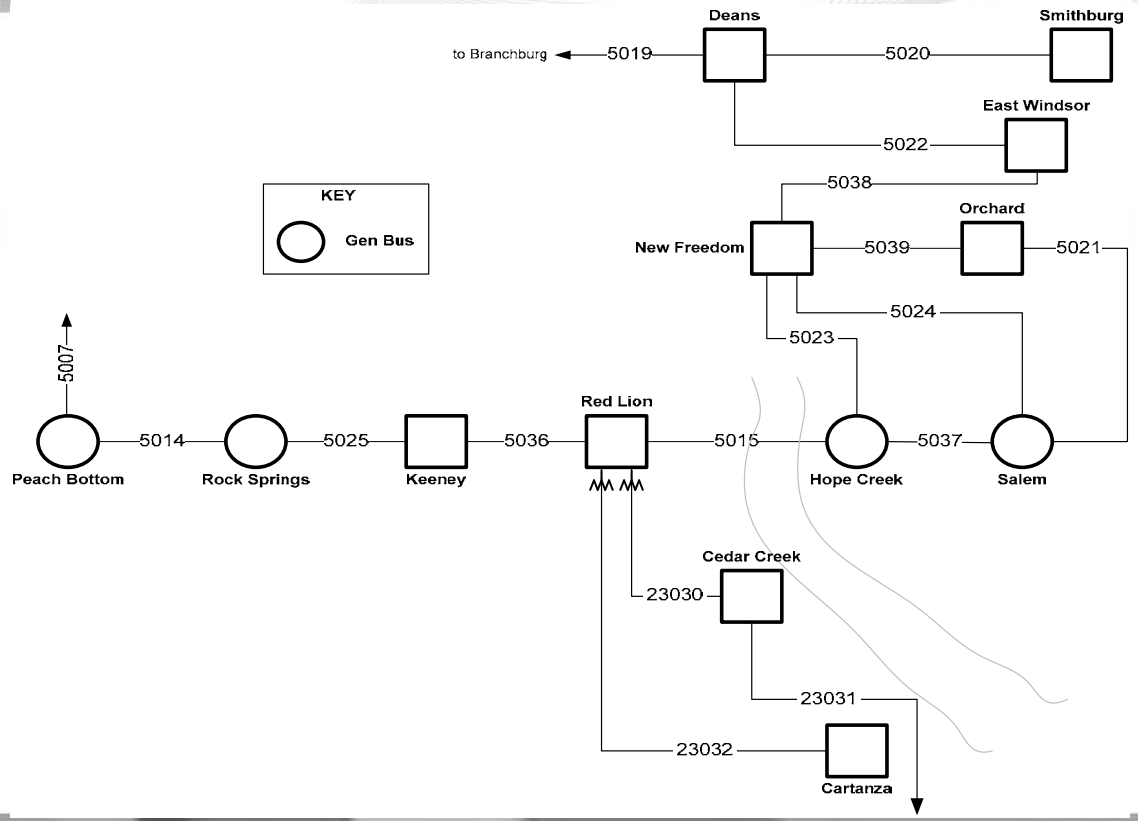
Artificial Island Area Network



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Artificial Island Analytical Evaluation Recap

- Recap of Previous November 2013 TEAC Update
  - 230 kV Transmission Solutions
    - Assuming the same AI Voltage, observe the AI MVAr output and maximum angle swing
      - Less AI MVAr output means more MVAr margin.
      - Less angle swing correlates to a larger stability margin
    - Given the same AI MVAr output compare the maximum angle swing
      - Less angle swing correlates to a larger stability margin
  - SVC Locations
    - Evaluate the effectiveness of the SVC locations by observing AI MVAr output and maximum angle swing
      - Less angle swing correlates to a larger stability margin

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Artificial Island Analytical Evaluation Update

- Current Analytical Update
  - Load Flow Analysis Update
  - Short Circuit Analysis Update

  - HVDC from the AI to Cardiff
    - Completed preliminary stability performance analysis
  - Thyristor Controlled Series Compensation – "TCSC"
    - Completed preliminary stability performance analysis
  - New 500 kV transmission from the Artificial Island to Red Lion 500 kV
    - Completed preliminary stability performance analysis

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HVDC + SVC Alternative

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"HVDC" Solution - P2013_1-6A

- P2013_1-6A
  - HVDC from the AI to Cardiff
  - SVC near the AI
  - Cost estimated by project sponsor at $1,012 M
- Project characteristics
  - HVDC + SVC
- Performance
  - Only passes criteria testing with significant real power flowing on the proposed HVDC from the AI to Cardiff
  - This solution fails the stability test without significant MW flow on the proposed HVDC facility from the AI to Cardiff
- Next Steps
  - Further analysis deferred based on cost and initial performance evaluation of alternative proposals

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TCSC + SVC Alternative

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TCSC+SVC vs. 230kV+SVC

Compare TCSC + SVC (assumes +750 MVAR) alternative to 230 kV + SVC alternatives

Project	Project ID	TO	SVC location	AI 500kV bus voltage	AI MVAr output	Outage	Contingency	Maximum Angle Swing
230kV+SVC	P2013_1-5A-SVC	LS Power	New Freedom	1.032	645	5038	2a	**54**
	P2013_1-2B-SVC	Transource	New Freedom	1.040	645	5038	2a	**47**
	P2013_1-2A-SVC	Transource	New Freedom	1.042	645	5038	2a	**48**
	P2013_1-1B-SVC	DVP	New Freedom	1.037	645	5038	2a	**46**
TCSC+SVC	P2013_1-1A	DVP	New Freedom	1.029	645	5038	2a	**88**

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TCSC + SVC Alternative

- P2013_1-1A
  - SVC @ New Freedom + two Thyristor Controlled Series Compensation (TCSC) devices near New Freedom
  - Estimated by project sponsor at $133 M
- Project characteristics
  - No new physical outlet from the Artificial Island
  - Relies on redundant breaker configurations at four 500 kV locations
    - Seven redundant breakers and associated station equipment required
- Performance
  - Did not pass testing criteria with the proposed +500 MVAR SVC near New Freedom 500 kV
  - Passed testing criteria with a larger +750 MVAR SVC near New Freedom 500 kV
- Next Steps
  - Further analysis deferred based initial performance evaluation of alternative proposals

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Artificial Island Analytical Evaluation
Load Flow Analysis Update

- Load Flow Analysis
  - 230 kV Transmission Solutions
    - No thermal or voltage violations identified for summer peak case
  - New 500 kV transmission from the Artificial Island to Red Lion 500 kV
    - No thermal or voltage violations identified for summer peak case

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Artificial Island Analytical Evaluation
Short Circuit Analysis Update

- Short Circuit Analysis
  - 230 kV Transmission Solutions
    - Several 50 kA circuit breakers overdutied at Red Lion 230 kV
  - New 500 kV transmission from the Artificial Island to Red Lion 500 kV
    - No new overdutied breakers identified

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Artificial Island to Red Lion 500 kV Solution Evaluation without SVC

Comparison Method:
Assume 1.055 p.u. at the AI (unstable below 1.055), solve the power flow for the corresponding Salem and Hope Creek MVAr output. Simulate the combination of the most critical fault and outage. Do not assume the addition of an SVC.

Result:
Measure the maximum machine angle swing.
All AI-Red Lion 500kV options are stable under the assumption of 1.055 pu at AI 500kV bus.
All 500 kV transmission from the Artificial Island to Red Lion 500 kV pass the stability test under the 1.055 pu assumption.

Project ID	Project Sponsor	AI 500kV bus voltage	AI MVAr output	Critical Outage	Critical Contingency	Maximum Angle Swing (deg.)
P2013_1-5B	LS Power	**1.055 pu**	913	5015	14b2	**109 (stable)**
P2013_1-2C	Transource	**1.055 pu**	927	5015(1)	14b2(3)	**109 (stable)**
P2013_1-1C	DVP	**1.055 pu**	914	50151(2)	2b2(4)	**110 (stable)**
P2013_1-4A	PHI/Exelon	**1.055 pu**	935	5015	14b2	**109 (stable)**
Various	PSE&G	**1.055 pu**	In-progress, expected to be similar to above			

(1) 5015: Hope Creek – Red Lion 500kV line; (2) 50151: the new Hope Creek – Red Lion 500kV second line
(3) 14b2: single-line-to-ground (SLG) fault on the new Salem-Red Lion 500kV line at Salem w/ delayed clearing due to stuck breaker
(4) 2b2: SLG fault on 5015 w/ delayed clearing due to stuck breaker resulting the loss of 5015 and 50371(Salem-Hope Creek second proposed tie)

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Artificial Island to Red Lion 500 kV Solution Evaluation without SVC

Comparison Method:
For each proposal, assume a fixed MVAr output at the Artificial Island, solve the power flow for the corresponding Artificial Island bus voltages. Simulate the combination of the most critical fault and outage. Do not assume the addition of an SVC.

Result:
Measure the maximum machine angle swing.
All AI-Red Lion 500kV proposals show similar performance given the same AI MVAr output.
All 500 kV transmission from the Artificial Island to Red Lion 500 kV pass the stability criteria.

Project ID	Project Sponsor	AI 500kV bus voltage	AI MVAr output	Critical Outage	Critical Contingency	Maximum Angle Swing (deg)
P2013_1-5B	LS Power	1.063	1044	5015	14b2	**93**
P2013_1-2C	Transource	1.062	1044	5015	14b2	**94**
P2013_1-1C	DVP	1.063	1044	50151	2b2	**92**
P2013_1-4A	PHI/Exelon	1.061	1044	5015	14b2	**95**
Various	PSE&G	In-progress, expected to be similar to above				

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Compare the maximum angle swing of the 230 kV and AI to Red Lion 500 kV proposals (without SVC)

AI to Red Lion 500kV proposals

Project ID	Project Sponsor	AI 500kV bus voltage	Maximum Angle Swing (deg)
P2013_1-5B	LS Power	1.063	**93**
P2013_1-2C	Transource	1.062	**94**
P2013_1-1C	DVP	1.063	**92**
P2013_1-4A	PHI/Exelon	1.061	**95**
Various	PSE&G	In-progress, expected to be similar to above	

230kV proposals

Project ID	Project Sponsor	AI 500kV bus voltage	Maximum Angle Swing (deg)
P2013_1-5A	LS Power	1.065	**102**
P2013_1-2B	Transource	1.071	**95**
P2013_1-1B	DVP	1.074	**97**
P2013_1-2A	Transource	1.074	**95**

Note: AI MVAr output is fixed to 1044MVAr and the result is for critical contingency under critical outage condition.

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500kV + SVC proposal comparison with SVC

Comparison Method:
For each proposal, assume the addition of an SVC at each of three locations. Simulate the combination of the most critical fault and outage.
Result:
Measure the maximum machine angle swing.
All AI-Red Lion 500kV + SVC options show similar performance.
The AI-Red Lion 500kV + SVC options show better performance than 230k+SVC options.
The Artificial Island SVC location has the best stability performance.

Project ID	Project Sponsor	SVC option	AI 500kV bus voltage	AI MVAr output	Critical Outage	Critical Contingency	Maximum Angle Swing
P2013_1-5B-SVC	LS Power	Artificial Island	1.040	667	5015	14b2	77
		Orchard	1.040	667	5015	14b2	98
		New Freedom	1.040	667	5015	14b2	102
P2013_1-2C-SVC	Transource	Artificial Island	1.041	670	5015	14b2	77
		Orchard	1.041	670	5015	14b2	98
		New Freedom	1.041	670	5015	14b2	101
P2013_1-1C-SVC	DVP	Artificial Island	1.041	675	50151	2b2	76
		Orchard	1.041	675	50151	2b2	96
		New Freedom	1.041	675	50151	2b2	99
P2013_1-4A-SVC	PHI/Exelon	Artificial Island	1.041	669	5015	14b2	78
		Orchard	1.041	669	5015	14b2	99
		New Freedom	1.041	669	5015	14b2	102
Various	PSE&G	In-progress, expected to be similar to above					

Note: The study results are obtained under the assumption of unity power factor at the high side of GSU.

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(500kV to Red Lion + SVC) vs. (230kV + SVC)

Comparison Method:
For each proposal, assume the addition of an SVC at each of three locations. Simulate the combination of the most critical fault and outage.
Result:
Observe the maximum machine angle swing.
The AI-Red Lion 500kV+SVC options show marginally better performance than the 230k+SVC options.
All evaluated proposals with SVC noted below pass the stability criteria with greater margin than without SVCs.

500kV+SVC options

Project ID	TO	SVC option	AI 500kV bus voltage	Maximum Angle Swing
P2013_1-5B-SVC	LS Power	Artificial Island	1.040	77
		Orchard	1.040	98
		New Freedom	1.040	102
P2013_1-2C-SVC	Transource	Artificial Island	1.041	77
		Orchard	1.041	98
		New Freedom	1.041	101
P2013_1-1C-SVC	DVP	Artificial Island	1.041	76
		Orchard	1.041	96
		New Freedom	1.041	99
P2013_1-4A-SVC	PHI/Exelon	Artificial Island	1.041	78
		Orchard	1.041	99
		New Freedom	1.041	102
Various	PSE&G	In-progress, expected to be similar to above		

230kV+SVC options

Project ID	TO	SVC option	AI 500kV bus voltage	Maximum Angle Swing
P2013_1-5A-SVC	LS Power	Artificial Island	1.042	80
		Orchard	1.041	108
		New Freedom	1.041	112
P2013_1-2B-SVC	Transource	Artificial Island	1.042	81
		Orchard	1.042	105
		New Freedom	1.042	109
P2013_1-2A-SVC	Transource	Artificial Island	1.043	82
		Orchard	1.042	107
		New Freedom	1.042	112
P2013_1-1B-SVC	DVP	Artificial Island	1.042	85
		Orchard	1.041	106
		New Freedom	1.041	110

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Artificial Island Analytical Observations

- Similar to the November TEAC review of the 230 kV proposals, the AI - Red Lion 500kV proposals without SVC pass the stability test under the assumption of 1.055pu at AI 500kV bus.

- The addition of an SVC improves the performance of all of the 230 kV and AI – Red Lion 500 kV proposals

- The 230 kV and AI - Red Lion 500kV proposals with SVC pass the stability test under the unity power factor assumption at the AI.

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Artificial Island Analytical Summary

- 230 kV Transmission Alternatives
  - Initial stability analysis complete

- Transmission Alternatives from the Artificial Island to Red Lion 500 kV (AI to Red Lion 500 kV portions only)
  - Initial stability analysis complete

- Remaining 500 kV proposals, TCSC and HVDC
  - Further analysis deferred based on cost and initial performance evaluation of alternative proposals

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Constructability Analysis Update

- Scope of Constructability Studies
  - 230 kV proposals
  - 500 kV proposals (AI to Red Lion 500 kV portions only)
  - SVC locations
- Draft constructability and cost reports anticipated by end of December 2013

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Conceptual Artificial Island Schedule

- September 12th TEAC
  - Update analytical progress
- October 10th TEAC
  - Update analytical progress
  - Update feasibility study progress
- November 7th TEAC
  - Update analytical progress
  - Update feasibility study progress
- December 11th TEAC
  - Update analytical progress
  - Update feasibility study progress
- February – March 2014
  - Recommend solution to TEAC
- 2014
  - Recommend solution to PJM Board

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Artificial Island

- Next Steps
  - Finalize analytical studies
  - Review draft constructability studies
  - Finalize individual project sponsor evaluations

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Questions?

Email: RTEP@pjm.com

SI-SSA-0010-0330

Revision History

- 12/10/2013 v1
  - Original version distributed to PJM TEAC

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Attachment 9

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P.O. Box 236, Hancocks Bridge, New Jersey 08038-0236

PSEG Nuclear LLC

December 8, 2014

PJM Interconnection, L.L.C.
Attention: Steven Herling
955 Jefferson Avenue
Norristown, PA 19403

Re: PSEG Nuclear Comments for December 9th TEAC
Discussion Regarding Artificial Island Open Window

Dear Mr. Herling:

PJM Interconnection, L.L.C. (PJM) has invited all PJM stakeholders to submit comments regarding the Artificial Island open window process in connection with the scheduled TEAC special meeting scheduled for December 9th. As the party that may be most directly impacted by the ultimate decision in this open window process, PSEG Nuclear LLC (PSEG Nuclear) now submits the following Comments regarding Dominion's Project 1A, which uses both TCSC and SVC technology (hereinafter referred to as the Dominion TCSC Proposal).

I. EXECUTIVE SUMMARY

PJM previously determined the Dominion TCS Proposal to be technically deficient, yet it is once again being considered by PJM among the various finalist proposals. This proposal includes an application that combines thyristor controlled series compensation (TCSC) technology with Static VAR Compensators as a means to ensure transient angular stability for AI. This proposal attempts to address stability via active, substation-based components in lieu of constructing an additional conventional transmission line.

PSEG Nuclear believes the approach set forth in the Dominion TCSC Proposal poses considerable risk to the regional 500kV system and to the nuclear units themselves at Artificial Island by relying on a technology that has never been used or tested at this scale in the United States. The Dominion TSCS Proposal can pose the risk for sub-synchronous resonance, which could have serious consequences for the nuclear units. In addition, and most importantly, based on the potential consequences of failure of this new technology, the Dominion TCSC Proposal poses an unevaluated risk to overall nuclear safety.

PSEG Nuclear relies on the following key considerations in reaching this conclusion:

- Dominion's TCSC project is inconsistent with AI RFP requirements and presents substantial challenges in ensuring compliance with the NRC licensing basis for the plant relative to offsite power sources;

- The use of the second largest nuclear site in the U.S. as a test bed for a first of its kind transmission design is problematic and presents potentially dire consequences; and

- The Dominion TCSC Proposal introduces complex circuit elements with subsequent new active failure modes that increase the potential for sub-synchronous resonance (SSR) phenomena that can damage generation equipment.

- Finally, should PJM ultimately decide to select this proposal, it would need to ensure adequate indemnification protection for PSEG Nuclear associated with SSR-related damage and/or lost generation. This is an issue that has not yet even been discussed.

These considerations, which are detailed in the comments below, must be factored into PJM's overall assessment of the competing AI transmission proposals to arrive at a technically and economically defensible path forward. PSEG Nuclear submits that careful consideration of these points counsel against selection of the Dominion TCSC Proposal.

II. COMMENTS

A. Dominion's TCSC Presents Substantial Challenges in Ensuring Compliance With the NRC Licensing Basis for the Plants Relative to Offsite Power Sources.

The goal of the transmission enhancement being pursued by PJM in the current open window process is to simplify the complexity and operational challenges presented by operations under the current Artificial Island Operating Guide (AIOG). Yet, as explained below, the TCSC project proposed by Dominion not only undermines the Artificial Island RFP objective of AIOG simplification/elimination, it raises significant issues for compliance with AI's nuclear licensing requirements relative to offsite source reliability.

Current operation of the Salem and Hope Creek nuclear generating stations at Artificial Island must accommodate the challenging transient stability margins inherent in the grid configuration in the vicinity of the AI facility. This is accomplished through strict adherence to the AIOG, which governs aspects of plant operation that have a direct impact on maintaining angular stability under any NERC mandated contingency (e.g., minimum plant MVAR output, power system stabilizer availability, trip-a-unit logic). The worst case line contingency for the site is a stuck breaker fault on the 5015 line between Hope Creek and Red Lion.

Compliance with the AIOG inherently ensures compliance with key nuclear licensing requirements with respect to offsite transmission sources, as follows:

- First, the Salem and Hope Creek nuclear units' operation must comply with 10 CFR 50 Appendix-A General Design Criterion (GDC) 17 which requires that a plant's offsite sources:

> ..be designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions.... provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit or the loss of power from the transmission network.

- Second, NRC NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, provides the primary guidance to NRC reviewers responsible for ensuring that a licensee complies with NRC regulations. Chapter 8 of NUREG-0800 provides review guidance regarding the design, analysis and testing of the offsite electrical system such that it meets the requirements of GDC 17. NUREG-0800 Chapter 8 states:

> The results of the grid stability analysis must show that loss of the largest single supply to the grid does not result in the complete loss of preferred power. The analysis should consider the loss, through a single event, of the largest capacity being supplied to the grid, removal of the largest load from the grid, or *loss of the most critical transmission line*. This could be the total output of the station, the largest station on the grid, or possibly several large stations. (Emphasis added).

- Third, of particular relevance to the consideration of projects to address the AI FRP requirements, NRC NUREG-0800 further states:

> The (NRC) reviewer should verify that adequate procedures, administrative controls, and protocols are in place to ensure that *no modifications to the offsite power system circuits credited for satisfying GDC 17 are implemented by offsite transmission system operating authorities, responsible for maintenance, modification, and operation of the offsite transmission grid, without the performance of a proper safety evaluation.* The safety evaluation of transmission system modifications is required to ensure that the transmission grid configuration, stability, and capability remain within the assumptions of the plant safety analyses. (Emphasis added).

If the Dominion TCSC Proposal is selected by PJM, stability of the system upon a fault on the critical 5015 line will no longer be ensured by the predominantly passive physics of protection provided by the AIOG, but will be predicated on the instantaneous operation of a first-of-a-kind scale of TCSC installation in coordination with an associated static VAR compensator (SVC) installation. As such, the selection of the Dominion TCSC Project could pose challenges relative to the existing licensing basis of the nuclear plants with regard to offsite power source.

B. Use of the Second Largest Nuclear Site in the U.S. as a Test Bed for First of its Kind Transmission Design Is Unacceptable and Presents Potentially Dire Consequences.

If selected by PJM, the Dominion TCSC Proposal would essentially use the second largest nuclear installation in the country as a test bed for a first of a kind application of advanced transmission components that have limited operating experience and track record in the world. Nowhere on the PJM system or, for that matter in the United States, has an integrated TCSC-SVC solution been developed to the scale proposed or used to control transient stability to the extent required for Artificial Island. Moreover, PJM is considering the approach of scaling this first of a kind technology up to compensation levels never used before, and to integrate its response with active SVCs to address stability constraints in a region of the system that has substantial challenges relative to maintaining and ensuring transient stability.

There is a significant lack of any real-world operational experience with the performance and reliability of the TCSC technology in question, especially with respect to the scale of its use in this proposal. This lack of operational experience, combined with the critical response time necessary for this solution to meet its performance objective, makes it imperative that PJM accurately model not only the "data sheet" performance of the system but also perform "real-world" sensitivity analyses to model non-ideal performance of the TCSC-SVC system (e.g., response delays, adverse timing interactions between TCSC and SVC components, non-optimum transient compensation levels, effects of inadvertent actuation, sensitivity to changing system conditions)).

Further, any theoretical benefits of such first of a kind technology use must be weighed against the consequences of the new technology not just failing, but failing at the second largest nuclear installation in the United States. In the event that this first of a kind technology application fails to operate, or does not function as modeled under a challenging contingency such as a fault on 5015, the likely consequences to the Salem and Hope Creek nuclear units would be greater than currently analyzed per GDC 17. Currently, operation under the AIOG ensures stability of offsite sources following any anticipated grid contingency. Under the TCSC proposed design, failure of these active devices in responding to a limiting grid contingency could cause one or more of the AI nuclear units to lose synchronism with the system, which could in turn result in the following cascading events:

- The immediate loss of offsite power to all three units resulting in the automatic shutdown of the units and post-transient reactor cool down operations using emergency diesel generators.
- The tripping of 3800 MW at Artificial Island may lead to a partial or system-wide black-out (PJM spinning reserve is only 1200 MW). This in turn can pose similar loss of grid challenges to regional nuclear plants.

- The physical impact/damage to the nuclear turbine generator(s) from falling out of synchronism would likely require a significant and indeterminate period to correct.

Based on the potential cascading events described above, reliance on this first of a kind technology will introduce a consequence of failure beyond that currently analyzed for the nuclear units at Artificial Island.

C. Dominion TCSC Proposal May Potentially Trigger Additional NRC Review And Impose Additional Design and Licensing Costs.

In evaluating any changes to nuclear plant equipment, processes or procedures, PSEG Nuclear must evaluate the change per 10 CFR 50.59, *Changes, tests and experiments*, to determine if the change is outside the bounds of the licensing basis of the plant and requires NRC approval prior to implementing the change. This is generally referred to as "a 50.59 review." Given that the AIOG is considered a critical design document for the site, a 50.59 review is required to implement any change to the document. The 10 CFR 50.59 review assesses a proposed change against prescribed questions relative to its impact on the safety-bases upon which the NRC has licensed the plant. Of these questions, the two that are directly challenged by the design being considered by PJM are:

> *Does the change create a possibility for a malfunction of a Structure, System or Component (SSC) important to safety with a different result than any previously evaluated in the final safety analysis report (as updated)?*[1]
>
> *Does the change result in more than a minimal increase in the consequences of a malfunction of an SSC important to safety previously evaluated in the final safety analysis report (as updated)?* [2]

Regarding the first question above, given that the scope and magnitude of the TCSC-SVC solution being considered by PJM has never before been developed anywhere in the United States, modeling assumptions for this project are incapable of being validated through real-world operating experience. Therefore, the failure modes and associated consequences of the proposed solution cannot be considered fully vetted. In light of this, PSEG Nuclear would need specific technical insights into the design and modeling of the solution, well beyond what has been publicly provided by Dominion, in order to properly address this question.

Similarly, relative to the second 50.59 review question, consequences of failure of the TCSC/SVC solution, as described in the previous section, pose a significant challenge in addressing this question, especially in light of the fact that loss of offsite power is considered one

[1] Code of Federal Regulations, Title 10 Part 50.59 – Changes, Tests and Experiments
[2] 10CFR50.59

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of the largest contributors to core damage frequency in terms of Probabilistic Risk Assessment to a nuclear plant.[3]

Based on these two questions, formal PSEG Nuclear and possible NRC review and acceptance of the subject design will be necessary before any substantial changes to the AIOG and its associated operational guidelines can be made. This review will need to be conducted to the extent necessary to satisfy any NRC inquires relative to the station's assessment of the design against the above 50.59 questions. Based on the recent publication of NUREG CR 7175, *Susceptibility of Nuclear Stations to External Faults*, the NRC has a heightened interest in vulnerabilities of nuclear plants to offsite grid disturbances. Based on this heightened level of licensee oversight in grid issues, NRC's assessment of licensee's changes relative to offsite source reliability will be also be heightened. This may extend to the point where the NRC assesses the adequacy of the TCSC design as an independent validation of the review performed by PSEG Nuclear. Considering the scope and complexity of this solution, and that the issue is a matter of first impression, such effort will likely result in additional review and processing fees being imposed on PSEG Nuclear as the licensing entity that must respond to any NRC questions and directions related to this change.

Given the above, PSEG Nuclear submits that any and all review costs, including any NRC fees, associated with this effort should be borne by Dominion. Accordingly, PJM should take such costs and schedule impacts into consideration in identifying overall project costs associated with the Dominion TCSC Proposal.

Until a safety determination can be made by PSEG Nuclear that is deemed acceptable for the regulator, Salem and Hope Creek operations would still need to comply with the AIOG as currently configured despite the status of TCSC-SVC system installation. Potential operation of the nuclear units at AI per the requirements of the current AIOG alongside operation of the subject TCSC-SVC installation would likely be incompatible to system operations and would negate the ultimate goal of the Artificial Island open window process.

D. The Dominion TCSC Proposal Introduces The Risk of Sub-Synchronous Resonance Phenomena That Can Damage Generation Equipment.

Introduction of series compensation for the first time into a congested region of the system like EMAAC poses significant concern regarding sub-synchronous resonance (SSR). The potential for SSR can result from series compensated networks and, if unmitigated, can result in opposing torques to prime movers resulting in prompt and extensive turbine-generator rotor shaft cracking. Generators most at risk to SSR are those that are electrically closer to the series capacitor and those that are long shaft / multi-mass turbine generators. The characteristics

[3] Nuclear Regulatory Commission - NUREG/CR-6890 Vol. 1 – Reevaluation of Station Blackout Risk at Nuclear Power Plants – Analysis of Offsite Power Events 1986-2004 – Published 2005

of the proposed project and its proximity to large nuclear generating units directly support the potential of developing SSR in the region of Artificial Island. Another phenomenon, Sub-Synchronous Oscillation (SSO), can occur when fast acting controllers of active power system components (e.g. TCSC or SVC controllers) have an unintended resonant point close to the system electrical resonance. SSO can result in rapidly growing currents or voltages on the system potentially challenging the design limits of transmission components.

In order to assess whether regional generators are susceptible to SSR, complex analyses must be performed based on system data, as well as extensive dynamic inertial machine data from potentially affected turbine generator systems. These data are often times not readily available, subject to change, or are of unknown accuracy and validity. It is not clear how PJM can conduct a complex assessment of SSR on regional generators, given that the critical input data to such analyses have questionable fidelity to the actual machines.

The subject SSR analysis is not a one-time effort, but must be routinely performed as the regional system changes due to upgrades, changes in regional generating units and planned and emergent outages. Planned and unanticipated system changes may have profound impacts on the tuning of the SVCs and thyristor control algorithms associated with the series capacitors. PJM must be able to accurately model all planned and forced outages and configuration changes in the region and promptly factor these changes into the configuration and tuning of TCSC-SVC controls to assure proper stability protection and prevent potentially catastrophic SSR-induced turbine shaft cracking in regional generators. PJM currently does not have these SSR concerns in this portion of their system and likely has little, if any, in-house expertise on the phenomenon or the analytical studies necessary to ensure that these issues are avoided. It is not clear how PJM can perform these complex studies on demand to meet unexpected system conditions and maintain this proposed solution in an "operable" state.

E. Should PJM Decide to Select the Dominion Proposal, PJM Must Ensure Adequate Indemnification Protection for PSEG Nuclear Associated with SSR Related Damage and/or Loss of Generation.

As mentioned above, PJM has limited, if any, experience in the application of series compensation and the associated SSR analyses that accompany this technology. Given that SSR can quickly damage generation resources and lead to cascading outages, the presence of SSR characteristics must be independently monitored in real time. In addition, depending on the results of SSR analyses and/or mandates by Nuclear Electric Insurance Limited (NEIL), some means of SSR trip protection of potentially vulnerable units may be necessary. It is not apparent to PSEG Nuclear who will be responsible for the installation and maintenance of any forced tripping protection (e.g., torsional relays, SSR current relays) on the units at AI, if they are deemed to be required. Any increased risk fees that may be mandated by NEIL due to the potential for SSR and its impact on main turbine shafts should be borne by Dominion. Also, if

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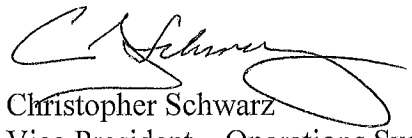
forced tripping is required, PJM needs to address the issue of providing indemnification to PSEG for any lost generation in response to spurious or legitimate SSR-based tripping of one or more PSEG Nuclear units must be addressed.

Finally, and most importantly regarding implementation of this design, it will need to be explicitly clear to PSEG Nuclear that, assuming PJM selects the Dominion 1a proposal as its preferred solution, PJM and/or Dominion will 1) take full responsibility for addressing any discovered turbine generator shaft cracking at the AI units in response to independent indications of SSR and 2) provide indemnification for all repair and lost generation associated with repair/replacement of damaged turbine generator shafts/components.

III. CONCLUSION

The risks associated with a first of a kind design such as that proposed by Dominion are not conducive to nuclear safety and overall reliability of the transmission system. Rather, when one objectively weighs the risks associated with the subject proposal and the consequences resulting from potential adverse impacts on nuclear safety and grid reliability, as described above, the Dominion TCSC Proposal should not be the recommended solution. The potential consequences arising from a failure of the proposed design to provide both stability and SSR protection when called upon are simply unacceptable from a nuclear safety perspective.

Very truly yours,



Christopher Schwarz
Vice President – Operations Support
PSEG Nuclear

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Attachment 10

Artificial Island Proposal Window

PJM TEAC

Artificial Island Recommendation

6/16/2014

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Artificial Island Timeline

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Past Timeline

- 9/13/2012 – PJM discusses the trending Artificial Island operational issues with PJM Stakeholders
- March 2013 - TEAC Previewed conceptual timeline and next steps for an Artificial Island Proposal Window
- 4/29/2013 – Artificial Island Proposal Window Opened
- 6/28/2013 – Artificial Island Proposal Window Closed
- July 2013 through April 2014 – PJM discusses the details of project performance, cost and constructability

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Artificial Island Timeline

- Monday, May 19th TEAC
  - 3 hour stakeholder technical meeting
  - In-person at PJM CTC
- Monday, June 2nd – Due date for stakeholder comment/feedback (14 day comment period)
- June 5th TEAC
- Monday, June 16th – PJM review of stakeholder comment/feedback and final decision meeting
  - Special TEAC Webex / Teleconference
- Comment Period to the PJM Board (36 days for comment period)
- July 10th TEAC
- Tuesday, July 22nd – PJM Board meeting
  - Artificial Island solution recommendation to the PJM Board

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Project ID	TO	Cost ($)	Major Components	Supporting info
P2013_1-1A	Virginia Electric and Power Com	$ 133	500 MVAR SVC near New Freedom	Two (2) Thyristor Controlled Series Compensation (TCSC) Devices near New Freedom
P2013_1-1B	Virginia Electric and Power Com	$ 126	New 500 kV from Salem - a new station in Delaware	New 500/230 kV station in Delaware that taps existing Cedar Creek - Red Lion 230kV and Catanza - Red Lion 230kV
P2013_1-1C	Virginia Electric and Power Com	$ 202	New 500 kV from Hope Creek - a new Station in Delaware	Install a new 500kV line from Hope Creek - Red Lion; New Salem - Hope Creek 500 kV line
P2013_1-2A	Transource	$213 - $269	Salem - Cedar Creek 230 kV	Two (2) 500/230 Transformers near Salem; Loop in Red Lion - Cartanza 230 to Cedar Creek
P2013_1-2B	Transource	$165 - $208	Salem - North Cedar Creek (new) 230 kV	Two (2) 500/230 transformers near Salem and loop in Red Lion - Cartanza 230 and Red Lion - Cedar Creek 230 kV
P2013_1-2C	Transource	$123 - $156	Salem - Red Lion 500 kV	
P2013_1-2D	Transource	$788 - $994	New Freedom - Lumberton - North Smithburg (New) 500 kV line	New Salem - Hope Creek 500 kV line and new 500/230 station east of Lumberton
P2013_1-3A	First Energy	$410.7 (Only FirstEnergy portion)	New Freedom-Smithburg 500 kV line with a loop into Larrabee	Hope Creek - Red Lion 500 kV line
P2013_1-4A	PHI Exelon	$ 475	Peach Bottom - Keeney - Red Lion - Salem 500 kV	Remove Keeney - Red Lion 230 kV; Reconfigure 230 around Hay Road; Reconductor Harmony-Chapel St 138 kV
P2013_1-5A	LS Power	$116.3M - $148.3M	Salem - Silver Run (new) 230 kV; Salem 500/230 kV Transformer	New 230 kV station that taps existing Cedar Creek - Red Lion 230kV and Catanza - Red Lion 230kV
P2013_1-5B	LS Power	$ 170	Salem - Red Lion 500 kV	
P2013_1-6A	Atlantic Wind	$ 1,012	320 kV HVDC Salem/Hope Creek - Cardiff	SVC at Salem/Hope Creek; New HVDC Stations at Cardiff and Salem
P2013_1-7A	PSE&G	$ 1,371	Salem-Hope Creek to Peach Bottom 500 kV	Existing ROW
P2013_1-7B	PSE&G	$ 1,372	Salem-Hope Creek to Peach Bottom 500 kV	Same as 7A with Loop into Keeney
P2013_1-7C	PSE&G	$ 1,372	Salem-Hope Creek to Peach Bottom 500 kV	Same at 7A with Loop into Red Lion
P2013_1-7D	PSE&G	$ 831	Salem-Hope Creek to Peach Bottom 500 kV	Same as 7A with New ROW
P2013_1-7E	PSE&G	$ 692	New Freedom - Deans 500 & Salem - Hope Creek 500 kV lines	
P2013_1-7F	PSE&G	$ 879	New Freedom - Smithburg and Salem-Hope Creek 500 kV lines	Existing ROW
P2013_1-7G	PSE&G	$ 1,034	New Freedom - Smithburg and Salem-Hope Creek 500 kV lines	Same as 7F with a Loop into a new Larrabee 500 kV station
P2013_1-7H	PSE&G	$ 1,177	New Freedom - Whitpain and Salem - Hope Creek 500 kV lines	Northern Route
P2013_1-7I	PSE&G	$ 1,353	New Freedom - Whitpain and Salem - Hope Creek 500 kV lines	Same as 7H with the Southern Route
P2013_1-7J	PSE&G	$ 915	New Freedom - New Station on Branchburg-Elroy 500 kV line ("5017 Junction") and Salem - Hope Creek 500 kV line	Existing ROW
P2013_1-7K	PSE&G	$ 1,066	New Freedom - Deans & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7E with Hope Creek - Red Lion
P2013_1-7L	PSE&G	$ 1,250	New Freedom - Smithburg & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7F with Hope Creek - Red Lion
P2013_1-7M	PSE&G	$ 1,548	New Freedom - Whitpain (North) & Salem - Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	Same as 7H with Hope Creek - Red Lion
P2013_1-7N	PSE&G	$ 1,289	New Freedom - a new Station on the Branchburg-Elroy 500 kV line ("5017 Junction") & Salem-Hope Creek - Red Lion 500 kV lines w/ Hope Creek - Red Lion (new);	

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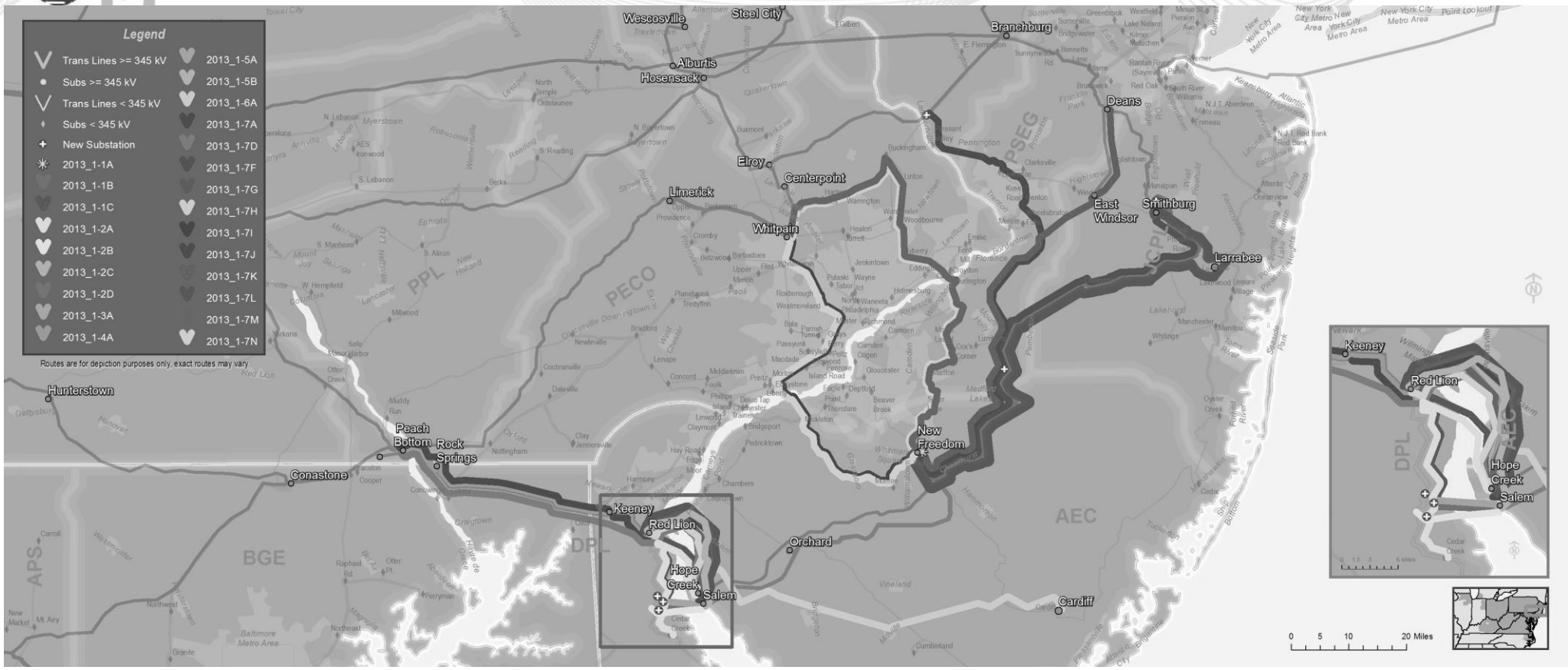
Artificial Island Proposals



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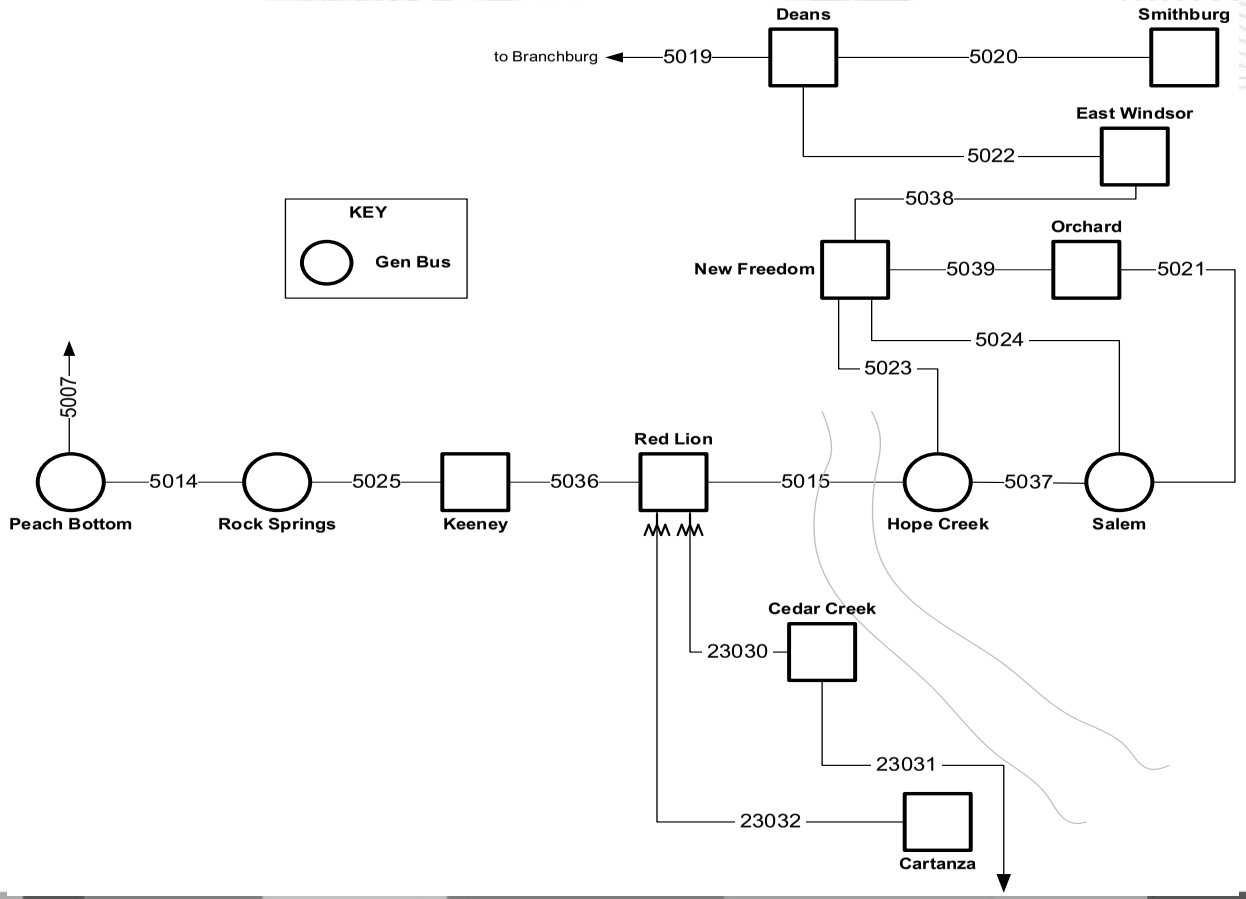
Artificial Island Area Network



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Artificial Island Feedback Received from 5/19/2014 Technical Review

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Feedback from 5/19/2014 AI Technical Review

Comments submitted by:

- Delaware PSC
- Dominion Virginia Power
- LS Power
- New Jersey BPU
- Atlantic Wind Connection
- PHI Exelon
- PSE&G
- PSE&G Nuclear
- State of Delaware Public Advocate
- Transource

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Topics Raised by Commenters

- Alternative proposed which included a neutral reactor and a 500kV CB
- Benefits of TCSC to resolve operational performance issues
- Right of way acquisition: Impact of LDV ownership, private land vs non-private and new versus expansion
- PJM cost estimates: Incorporation of EoC estimates and missing cost components
- Constructability concerns: Submarine cable installation, salt spray, modifications to existing transmission facilities

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Topics Raised by Commenters

- Environmental impact and permitting concerns: Supawna Meadows NWR, environmental management areas, Reedy Island dike, Sunken Ship Cove (NRHP), essential fish habitats and wetlands impacts
- Concerns with Delaware river crossing permitting
- Concerns with NRC review of FACTS devices impacting cost and schedule
- Concerns with cost allocation for the 230 kV solutions
- Non-incumbent ability to build transmission facilities in New Jersey and Delaware

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Exelon / PHI Feedback

- PHI/Exelon: Eliminate the need (and cost) for an SVC by:
  - Alternative # 1 - Install a 2% reactor in the neutral of the 500kV (wye grounded) side of the two Salem generator-step-up transformers (GSU) or Install a 1% neutral reactor to the 500kV side of the two Salem and the Hope Creek GSUs
  - Alternative # 2 - Employ a back-to-back circuit breaker scheme to interconnect the PHI/Exelon proposed 500kV line to the Salem Substation.
- PJM determined that the suggested modifications would only address phase to ground faults and there are three phase faults that would still be unstable and not improved by the back-to-back breakers or neutral reactors
- Reactors also have additional negative impacts that would need be considered

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Transource Feedback

- Feedback at the 5/19/2014 AI Technical Review regarding the potential Hope Creek – Red Lion proposal
  - Transource was concerned that the potential Hope Creek – Red Lion transmission solution would not solve all stability requirements
  - Resolution: PJM worked with Transource to update their technical assumptions and this concern was found to not be an issue

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Artificial Island Recommendation

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Evaluation Considerations

- Performed extensive technical analysis
  - Stability, thermal, voltage, short circuit, market efficiency
  - Studied all solutions as is and with modifications

    Initial analysis showed only two of the highest cost solutions worked as submitted
- Engaged outside engineers to perform constructability review
  - *focus on physical, cost, schedule, RoW, siting, permitting*
- Met with all proposers for clarification as needed
- Met with AI nuclear plant representatives
- PJM Operations review
- PJM independent cost evaluation
- Met with equipment manufacturers

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Evaluation Considerations

- Primary Considerations
  - Technical Analysis
    - Thermal
    - Stability
    - Short-circuit
    - Voltage
    - NERC Cat-D Contingencies
- Secondary Considerations
  - Schedule
    - Permitting
    - Construction
    - Long lead time equipment
  - Project Complexity
    - Line crossings
    - Outage requirements
    - Modifications to other transmission facilities
    - Modification to Artificial Island substations
    - Modifications to Red Lion substation
  - Cost Factors
    - Cost effectiveness
    - Market efficiency
    - PJM estimated costs
  - Right of Way and Land Acquisition
    - No eminent domain in Delaware
    - New right of way required
    - Substation land required
  - Siting and Permitting
    - Wetlands impact
    - Public opposition risk
    - Delaware river crossing
    - Land permitting
    - Historic and scenic highway
  - Operational Impact
    - Artificial island facility requirements
    - Ongoing maintenance
    - Blackstart
    - Route diversity
    - Performance

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Determination of Proposal Short List

- Overall, there were 26 proposals
  - 2 projects passed the initial analytical screen without modification
  - Through evaluation of the various proposals, PJM staff found that many of the proposals could be made more effective and efficient with some modification and the addition of other components
  - Screened proposals (with the PJM modifications) based on performance and cost

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Determination of Proposal Short List

- PJM focused on a short list of evaluations that included several projects in each of these four categories:
  - Southern Crossing – Submarine
  - Southern Crossing – Overhead
  - Salem to Red Lion 500 kV
  - Hope Creek to Red Lion 500 kV

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AI Final Project Recommendation Approach

- Primary Considerations
  - Technical Analysis
  - Cost Factors
  - Project Schedule

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Technical Analysis

- All projects on the short list, with PJM modifications included, satisfied the required criteria including:
  - Stability: Angle swing (including with AI generation at unity power factor)
  - Load flow, short circuit, voltage, NERC cat-D contingencies
- Additional analysis
  - Market efficiency
  - Additional reliability benefits

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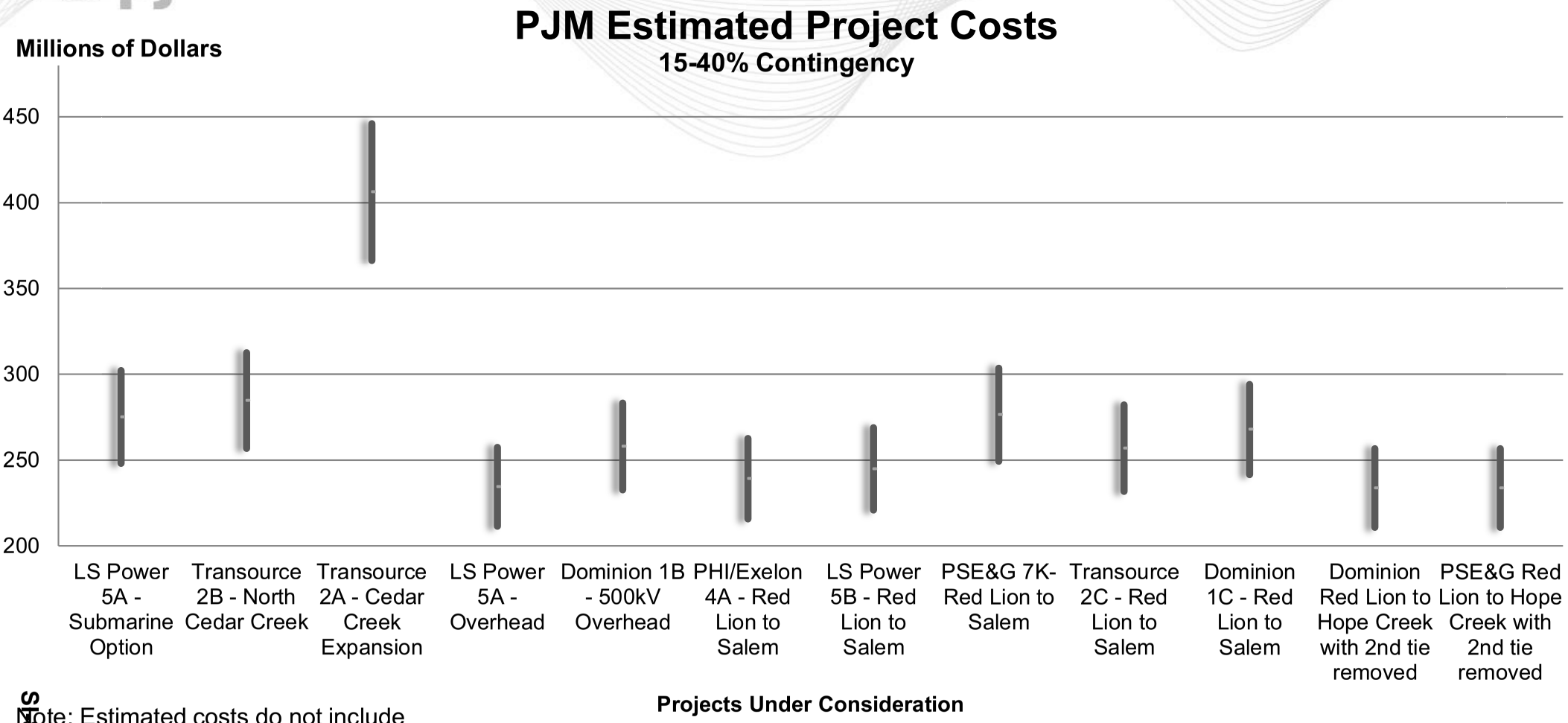
PJM Cost Estimates



Note: Estimated costs do not include the SVC cost estimate

Project Schedule

- Permitting
  - Delaware River Crossing
    - Represents the greatest component of schedule risk for all projects
  - Land Permitting
    - All projects will face challenges
      - Red Lion to Artificial Island
        - » Supawna Meadows National Wildlife Refuge
        - » State wildlife management areas
      - Southern crossing lines
        - » State wildlife management areas
    - Public opposition can be expected with all of the alternatives

- Siting and permitting for a new river crossing will be a major component in the project schedule for all projects under consideration

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Differentiating Factors

- Evaluation of risks to cost and schedule
  - Project complexity
    - Modifications to Artificial Island
    - Line Crossings
    - Outage Requirements

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Project Complexity

- Modification of Artificial Island substations
  - Salem
    - Constrained with limited space for expansion. Proposed alternatives out of Salem would need to ensure continued maintenance access to station aux transformers
    - All protection and control equipment located inside the secure area of the generating station. There is limited spare conduit from the substation into the station for control wiring.
  - Hope Creek
    - Available land for expansion to the north
    - Protection and control equipment located in a separate control building in the substation.

- A new line from Hope Creek without impacts to Salem is considered more constructible

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Project Complexity

- Line Crossings
  - All 500kV projects interconnecting at Salem substation included a line crossing
  - Line crossings create operational complexity and the potential for a multiple facility trip event
    - Referenced in NRC Regulations, General Design Criteria-17

- Solutions with no line crossings are preferable

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Project Complexity

- Outage Requirements
  - All projects require outages to support construction
  - Artificial Island to Red Lion solutions would require outages to the 5015 line
    - 5015 line outages are challenging to schedule
  - All projects would require coordination of 500kV and 230kV facility outages
  - PJM operational analysis to manage impact to system configuration to support any outage required to support construction
    - Reactive devices
    - AI SPS
    - Coordination with planned generation and transmission outages

- A solution that minimizes outage requirements during construction is preferred

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Differentiating Factors

	Project Class	Southern Crossing 230kV Lines (Submarine)			Southern Crossing Lines (Overhead)		Red Lion to Salem 500kV Lines			Red Lion to Hope Creek 500kV Lines			
Criteria	Proposal	LS Power 5A - Submarine Option	Transource 2B - North Cedar Creek	Transource 2A - Cedar Creek Expansion	LS Power 5A - 230kV Overhead	Dominion 1B - 500kV Overhead	PHI/Exelon 4A - Red Lion to Salem	LS Power 5B - Red Lion to Salem	Transource 2C - Red Lion to Salem	Dominion 1C - Red Lion to Hope Creek	PSE&G 7K- Red Lion to Hope Creek	Dominion Red Lion to Hope Creek w/ 2nd tie removed	PSE&G Red Lion to Hope Creek w/ 2nd tie removed
	Sub-Criteria												
Risks to Cost and Schedule													
Project Complexity	Line Crossings												
	Outage Requirements												
	Modification of AI Subs												

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Additional Factors in Project Selection

- Artificial Island to Red Lion 500kV solutions are more robust and provide greater power transmission capacity as compared to the 230kV southern crossing solutions
  - Under normal system conditions, southern crossing solutions would provide little system support
  - Artificial Island to Red Lion 500kV solutions improve voltage drop for loss of 500kV facilities

- An Artificial Island to Red Lion 500 kV line is a more robust solution than a southern crossing line

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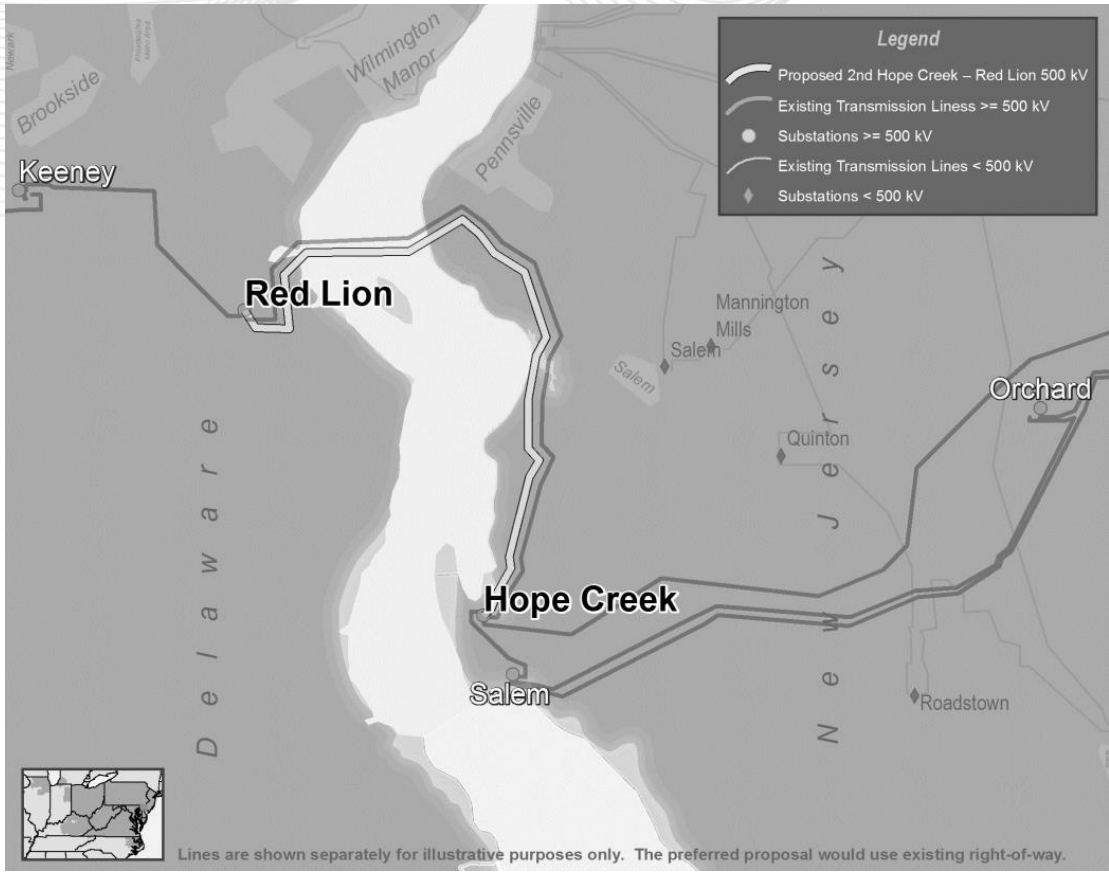
Criteria	Project Class	Southern Crossing 230kV Lines (Submarine)			Southern Crossing Lines (Overhead)		Red Lion to Salem 500kV Lines			Red Lion to Hope Creek 500kV Lines			
	Proposal	LS Power 5A - Submarine Option	Transource 2B - North Cedar Creek	Transource 2A - Cedar Creek Expansion	LS Power 5A - 230kV Overhead	Dominion 1B - 500kV Overhead	PHI/Exelon 4A - Red Lion to Salem	LS Power 5B - Red Lion to Salem	Transource 2C - Red Lion to Salem	Dominion 1C - Red Lion to Hope Creek	PSE&G 7K-Red Lion to Hope Creek	Dominion Red Lion to Hope Creek w/ 2nd tie removed	PSE&G Red Lion to Hope Creek w/ 2nd tie removed
Technical Analysis	Stability												
	Thermal												
	Market Efficiency Results	Approximate 0.15 Benefit to Cost Ratio			Approximate 0.15 Benefit to Cost Ratio		Approximate 0.2 Benefit to Cost Ratio			Approximate 0.2 Benefit to Cost Ratio			
	Short Circuit												
	NERC Cat-D Contingencies												
Cost Factors	PJM Estimated Project Cost	$248-$302	$257-$313	$366-$446	$211-$257	$233-$283	$216-$263	$221-$269	$232-$282	$242-$294	$249-$304	$211-$257	$211-$257
	Project Costs as Proposed	$148	$165-$208	$213-269	$116	$133	$181	$171	$123-156	$199	$297		
	Market Efficiency	Approximately $92 over 15 years			Approximately $92 over 15 years		Approximately $57 over 15 years			Approximately $57 over 15 years			
	Outage Cost												
Project Schedule	Permitting												
	Construction												
	Long Lead Time Materials												
Risks to Cost and Schedule													
Project Complexity	Line Crossings												
	Outage Requirements												
	Modification to other Facilities												
	Modification of AI Subs												
	Modification of Red Lion Sub												
RoW and Land Acquisition	No Eminent Domain in Delaware												
	New Right of Way Required												
	Substation Land Required												
Siting and Permitting	Wetlands Impact												
	Land Permitting												
	Public Opposition Risk												
	Historic and Scenic Highway												
	Delaware River Crossing												
Operational Impact	Artificial Island Facility Requirements												
	Blackstart												
	Route Diversity												
	Ongoing Maintenance												

SI-SSA-0010-0370

Project Recommendation

- In consideration of all factors PJM staff will recommend for inclusion in the RTEP:
  - A new 500kV circuit from Hope Creek to Red Lion



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Project Designation Differentiating Factor

- PSE&G and Dominion proposed solutions that included a new 500kV line from Red Lion to Hope Creek. FirstEnergy proposed a Red Lion to Hope Creek facility but declined construction designation.

- Right of Way Acquisition
  - The LDV agreement provides for usage of existing right of way along the recommended project path
    - PSE&G is a party to the LDV agreement
    - 8.5 miles of the right of way in New Jersey would need be expanded
  - Dominion will need to acquire right of way for the entire route of the line

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Project Designation

- Assign designation of the Hope Creek – Red Lion 500 kV transmission line to PSE&G

- Assign the necessary connection facilities to accommodate the new transmission facility:
  - Red Lion 500kV station upgrade to PHI
  - Hope Creek 500kV station upgrade to PSE&G

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SVC Considerations

- An SVC is a required component to achieve the necessary project performance
  - Locations at Artificial Island, Orchard and New Freedom were studied and all achieved the required performance

- New Freedom and Orchard locations have the lowest estimated cost and would not require construction at Artificial Island

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SVC Differentiating Factors

- PSE&G New Freedom switching station has available property to accommodate the SVC

- New Freedom has stronger system ties to both the PJM 500kV and 230kV systems as compared to the Orchard location

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SVC Recommendation

- Construct an SVC at New Freedom 500 kV substation
  - Facilities design will determine the technical parameters

- Designate SVC upgrade at New Freedom to PSE&G

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Artificial Island Recommendation

- At the Tuesday, July 22nd PJM Board meeting, PJM staff will recommend for inclusion in the RTEP:
  - Hope Creek to Red Lion 500 kV transmission line designated to PSE&G
    - Associated substation work at Hope Creek designated to PSE&G
    - Associated substation work at Red Lion designated to PHI
  - SVC at New Freedom 500 kV designated to PSE&G

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Next Steps

- Detailed facility design
- Finalize review and recommendations on the protection issues raised around current directional carrier blocking scheme (DCB)

Note: Please supply any written comments to the PJM Board through RTEP@PJM.com

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remaining pages intentionally omitted

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Attachment 11

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July 14, 2014

Howard Schneider
Chair, PJM Board
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Norristown, PA 19403-2497

Terry Boston
President and CEO
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Norristown, PA 19403-2497

Re: PJM Process for Evaluating Competitive Artificial Island Proposals

Dear Mr. Schneider and Mr. Boston:

PHI and Exelon appreciate the relentless effort by PJM Transmission Planning Staff in bringing closure to the competitive Artificial Island (AI) proposal process. Although the PJM decision is not what we would prefer, PHI and Exelon, nevertheless, will not challenge or raise issues regarding the decision. But, as we have expressed earlier, PHI and Exelon remain concerned about the AI solicitation, evaluation and selection processes. Applying our learnings from the AI process, PHI and Exelon would like to work with PJM to improve the process for future proposals.

PHI and Exelon process concerns start with the problem statement and the specific project requirements outlined by PJM. The need for clarity and specificity is evident in that none of the 26 proposals hit the PJM target and met the need. Additionally, PJM did not follow the process that was laid out in their October 25, 2012 and July 22, 2013 Order No 1000 FERC Compliance filings for facilitating a competitive transmission expansion solicitation, but resorted to different processes. These alternate processes are not transparent to participants and could be problematic in the future if they are not corrected.

To comply with the FERC Order No. 1000 requirement to eliminate the Federal Right of First Refusal (ROFR), and to establish a competitive solicitation process for transmission projects, PJM made substantial changes to Schedule 6 of the Operating Agreement. Specifically, PJM adopted a sponsorship model in which qualified entities would submit project proposals during an open window. PJM would then evaluate and validate these proposals, compare their expected performance, and determine the best proposal amongst those submitted. If none of the proposed solutions resolve the violation, depending on the time constraints, PJM could either repost the violation and open another solicitation window, or develop an optimal solution and designate the incumbent transmission owner(s) to build the PJM solution. PJM did not follow this process.

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Following the filed process would likely have resulted in a significant reduction of more than a year's worth of hard work performed by, and expenses incurred by, all participants. Instead, PJM Transmission Planning chose to modify all project submittals and, at the end of the day, selected the project closest to the one created by PJM.

With respect to the selection process, PJM used the cost estimates submitted by the proposers to screen all 26 proposals and short listed the less expensive proposals. While we understand the need by PJM Staff to narrow the proposals, if PJM was going to follow such a process, PJM should have made that clear before developers submitted their proposals, not after. Furthermore, the detailed cost estimates that PHI and Exelon, as well as others, provided were essentially cast aside and replaced by an independent contractor estimates when compared with other proposals. While we understand that there were no developer cost estimates for all the modified proposals, and PJM needs some 'sanity check' on cost estimates, following a defined process and clarifying PJM's expectations at the outset would have saved time and money by all parties involved.

PJM tried very hard to distinguish all short listed proposals. The effort is commendable as it is particularly difficult to distinguish amongst these plans that were essentially all developed by PJM. Going forward, PHI and Exelon suggest that decision metrics be developed and provided to all Stakeholders prior to the submittal of proposals so that developers know in advance how PJM will evaluate various projects. While we understand that PJM needs some flexibility to apply and weigh metrics and some metrics contain subjective components, their early visibility provides Stakeholders the necessary guidance and clarity for developing the right proposal that would meet PJM's needs. As a result, significant effort and expenses could be saved.

Finally, PHI and Exelon thank the PJM Board for their consideration and are ready and willing to work with PJM Transmission Planning to improve the competitive proposal process.

Sincerely,

David Velazquez
Executive Vice president
Power Delivery

Denis P. O'Brien
Senior Executive Vice President, Exelon and
President and Chief Executive Officer
Exelon Utilities

cc: Mike Kormos Steve Herling Dave Anders

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Attachment 12

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NORTHEAST TRANSMISSION DEVELOPMENT

400 Chesterfield Center, Suite 110
St. Louis, MO 63017

Via Email (rtep@pjm.com)

July 8, 2014

The PJM Board of Managers
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

RE: PJM Artificial Island Project Selection

Dear PJM Board of Managers:

We write regarding the PJM Interconnection, L.L.C. ("PJM") Staff's request that you approve the Hope Creek – Red Lion transmission solution ("Staff Solution") to address identified system stability needs related to Artificial Island. We commend the Board of Managers and the PJM Staff for initiating a competitive process with the policy goal of finding the more efficient or cost effective project. This process has resulted in the identification of several alternatives that could address the stated system needs. While we know the PJM Staff and its consultants have worked tirelessly over the past year to evaluate these alternatives, the resulting Staff recommendation falls short from a transparency perspective and fails the above-stated policy goal. We strongly believe that the Staff Solution, if implemented, will materially disadvantage the PJM system and electric consumers in PJM when compared to the Southern Crossing solution proposed by Northeast Transmission Development,[1] a member of the LS Power Group of companies (the "LS Power Solution").

It appears that the Staff's recommendation was founded upon the conclusion that the Staff Solution and the LS Power Solution are equivalent to each other from a cost standpoint. This conclusion was simply incorrect and inconsistent with the information presented by the independent consultants engaged by Staff.[2] While PSE&G estimated the cost of its project to be $297 million and we estimated the upper end of the LS Power Solution to be $148.6 million, the Staff attributed construction costs in the range of $211 - $257 million for either project. We appreciate that predicting the costs of constructing a project of this type is a difficult task, and that it is not unusual for actual costs to exceed the estimate. However, even taking into account the uncertainties inherent in any cost estimation process, there are real and

[1] LS Power Proposal "5A" consisting of a new connection between Salem and Silver Run (new) with an overhead or submarine crossing of the Delaware River.

[2] GAI Consultants, Inc. estimates the cost/mile for overhead 500 kV to be $5 million/mile versus Staff's stated assumption of $3.6 million/mile. GAI Consultants included an adder of $1 million/mile due to the specialized construction practices required given the extensive wetlands and limited access for the Staff Solution, which Staff did not appear to consider. UC Synergetic, LLC identifies $56 million in compensatory mitigation required for a comparable crossing of federal lands as is required for the Staff Solution, which Staff did not appear to consider.

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material differences between the reasonably expected costs of constructing the Staff Solution as compared to the reasonably expected costs associated with the LS Power Solution, and these differences were not in our view properly accounted for in the selection process.

In order to remove any cost uncertainty from the selection process, and to guarantee that the ratepayers receive the benefit of the real and material cost advantages offered by the LS Power Solution, we will agree to cap the construction cost of the LS Power Solution (overhead or submarine) at $171 million. This approach, which could be implemented by way of a covenant in the Designated Entity Agreement for this project, will guarantee $40 to $90 million of savings relative to the Staff's cost estimate for the Staff Solution and almost $130 million relative to the significantly higher cost estimate provided by PSE&G, the entity to which PJM proposes to assign the Staff Solution.[3] Please note that the $171 million figure mentioned above is a cap on the amount of construction costs we would be permitted to claim. If the actual construction costs come in at or below our upper-end estimate of $148.6 million, which we continue to believe is reasonable, the savings to the ratepayers will be significantly greater.

Moreover, the Staff's recommendation appears to reflect Staff's difficulty in consistently applying non-cost evaluation criteria in accordance with the PJM Operating Agreement.[4] As identified in Exhibit A, the LS Power Solution is either superior or equal to the Staff Solution for each of the criteria listed in the PJM Operating Agreement. Although we understand that achieving a high degree of certainty while evaluating proposed alternatives is a challenging undertaking, it appears that Staff may have made certain arbitrary judgments regarding critical aspects of the LS Power Solution (as compared to the Staff Solution) that are not supported by the PJM Operating Agreement criteria. For instance, the Staff did not appear to appropriately consider key factors that favor the LS Power Solution such as schedule, right-of-way, route diversity, black start, market efficiency, feasibility, and system outage requirements.[5] We urge the Board of Managers to reconsider how these criteria were applied, in order to ensure compliance with the PJM Operating Agreement.

In summary, relative to the Staff Solution, the LS Power Solution will:[6]

- Be $40 to $130 million lower in cost based on a firm construction cost cap (and offer even greater savings if, as expected, construction costs come in below the agreed cap);

[3] It is important that the Board look independently at Staff's cost estimate assumptions. In 2012, in selecting among competing projects, PJM estimated the cost of the Byron – Wayne transmission project to be $109.6 million relative to Commonwealth Edison's original estimate of $275 million and subsequently revised estimate of $140 million. After approval from PJM, Commonwealth Edison filed for incentive rates at FERC estimating the cost to be $277 million. See *FERC ER14-1556*.

[4] The PJM Operating Agreement identifies four criteria that PJM should consider in determining the more efficient or cost effective solution. See *PJM Operating Agreement, Schedule 6, Section 1.5.8(e)*

[5] PJM previously identified route diversity and right-of-way requirements as key differentiating factors for project selection among alternatives in Illinois in 2012. See *TEAC Recommendations to the PJM Board, PJM Staff Whitepaper, October 16, 2012*.

[6] See *Northeast Transmission Development Comments in response to the PJM RTEP – 2013 Artificial Island Proposal Window dated June 2, 2014*.

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- Provide $35 million more in market efficiency benefits;
- Be able to be placed in service one to two years earlier;
- Require no new private rights-of-way;
- Utilize a new route (for which all private rights-of-way have been secured), thereby avoiding placement of the critical outage and contingency in the same corridor;
- Provide black start benefits;
- Avoid outages of the 5015 (Hope Creek – Red Lion) 500 kV transmission line; and
- Not face the potentially insurmountable risks associated with significant wetland impacts and the crossing of the Supawna Meadows National Wildlife Refuge.

Based on the foregoing, we believe that the ratepayers in the PJM system will receive materially greater economic benefits and assume less execution risk if the PJM Board selects the LS Power Solution as the most efficient and cost effective solution to the identified need, and designates it as the Designated Entity to construct and own the project. As noted above, we are offering to guarantee these benefits by agreeing to cap the construction cost of the LS Power Solution. In any case, we stand ready to advance this project with the utmost priority immediately upon assignment from the PJM Board.

Respectfully,

NORTHEAST TRANSMISSION DEVELOPMENT, LLC

Paul Thessen
President

cc: Terry Boston
Michael Kormos
Steve Herling
Paul McGlynn
Mark Sims
Pauline Foley

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Exhibit A

PJM OPERATING AGREEMENT CRITERIA

LS Power Solution vs. Staff Solution

In accordance with the PJM Operating Agreement,[1] PJM shall consider the following criteria in determining the more efficient or cost effective solution.

1. *The extent to which a [project] would address and solve the posted violation, system condition, or economic constraint.*

   PJM has identified that both projects address and solve the system condition identified through the Artificial Island Proposal Window.

2. *The extent to which the relative benefits of the project meets a Benefit/Cost Ratio Threshold of at least 1.25:1 as calculated pursuant to Section 1.5.7(d) of this Schedule 6.*

   Although neither project meets the 1.25:1 ratio, the LS Power Solution has been identified to have $35 million more in market efficiency benefits than the Staff Solution. In addition to higher benefits, the LS Power Solution will be lower cost and, based on LS Power's cost guarantee, will be supported by a firm construction cost commitment. As a result, the Benefit/Cost Ratio for the LS Power Solution is more than double the Benefit/Cost Ratio for the Staff Solution.

3. *The extent to which the [project] would have secondary benefits, such as addressing additional or other system reliability, operational performance, economic efficiency issues or federal Public Policy Requirements or state Public Policy Requirements identified by the states in the PJM Region.*

   The LS Power Solution has numerous secondary benefits identified by PJM including providing black start benefits, route diversity, and higher economic efficiency benefits.

   The Staff Solution, in contrast, has several detriments as it will create more NERC Category-D contingencies, locate the critical contingency and outage for the Artificial Island stability issue within the same corridor, and require an extensive outage of the 5015 (Hope Creek – Red Lion) 500 kV transmission line.

   Staff has characterized the 500 kV transmission line as "more robust" and providing greater power transmission capacity. The characterization of "more robust" is unrelated to the issue being resolved – PJM has found that all of the solutions are comparable in resolving the stability concern. While a 500 kV transmission line will be rated at a higher capacity, the market efficiency analysis proves the LS Power Solution to be of a greater market benefit.

4. *Other factors such as cost-effectiveness, the ability to timely complete the project, and project development feasibility.*

[1] See *PJM Operating Agreement, Schedule 6, Section 1.5.8(e).*

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Other factors also clearly favor the LS Power Solution.

The LS Power Solution will be $40 to $130+ million lower cost and be able to be placed in service one to two years in advance of the Staff Solution.

All of the private right-of-way has been secured for the LS Power Solution as compared to over 8 miles of new right-of-way that would need to be acquired for the Staff Solution.

Both solutions require a crossing of the Delaware River. The LS Power Solution has mitigated the risk associated with permits and approvals given that both an overhead and submarine installation could be considered. Development of the Staff Solution may not be feasible given the potentially insurmountable risks associated with tens to hundreds of acres of wetland impacts and the crossing of the Supawna Meadows National Wildlife Refuge.[2]

Staff has identified space may be somewhat more limited or constrained at Salem as compared to Hope Creek; however, there are no physical limitations preventing expansion of either substation. Furthermore, the LS Power Solution could originate at Hope Creek to the extent it was beneficial.

[2] PJM has identified a technically viable, cost-comparable alternative (LS Power Solution) that addresses the Artificial Island electrical reliability issues without crossing the Supawna Meadows National Wildlife Refuge or impacting tens to hundreds of acres of wetlands. The existence of a practicable alternative that avoids these impacts will make it difficult, if not impossible, to obtain the necessary freshwater wetlands permit in New Jersey and right-of-way grant from the U.S. Fish and Wildlife Service that would be required for the Staff Solution.

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Attachment 13

2750 Monroe Blvd
Audubon, PA 19403-2497

Steven R. Herling
Vice President – Planning

July 23, 2014

Dear TEAC Members:

The PJM Board of Managers has evaluated more than 25 proposals to resolve grid stability problems in the area known as Artificial Island, including a proposal recommended by PJM staff. The Board has received a wide range of comments from interested stakeholders including issues related to electrical performance, environmental impact and cost allocation. In addition, LS Power has modified its proposal to place a fixed cap on the costs associated with the project.

The Board appreciates the analyses and comments submitted by various stakeholders through an entirely new competitive process guided by FERC Order 1000. To ensure a thorough and fair review, given the complexities of the issues, the Board has determined that it will take the matter under advisement and defer a selection at this time. To further inform the Board, PJM staff will be undertaking the following supplemental steps:

1. PJM will review, in an open stakeholder session with the Transmission Expansion Advisory Committee, our response to the specific issues raised in the letters submitted to us. We will review how issues raised in letters submitted to the Board were initially addressed and will note any issues that require further analysis. Finally we will present the rationale behind the Board's decision to defer a selection at this time;

2. As noted, LS Power has submitted a fixed cost cap on its proposal as part of its letter of July 8, 2014. While we will be working on changes in our process to ensure that any future proposals are presented to PJM in a more timely fashion, the Board feels it appropriate to allow the four "finalist" bidders to have the opportunity to supplement their proposals in light of LS Power's proposal. (Those bidders are Public Service Electric and Gas, Transource Energy, LS Power and Dominion.) The project costs included in any such supplemental proposals to PJM will be factors considered in the final selection for an Artificial Island solution. However, the Board has reiterated that cost is only one of several considerations that will drive a final decision.

3. PJM will be reaching out to the Nuclear Regulatory Commission to discuss technical issues associated with certain proposals impacting nuclear switchyards.

4. In order to ensure fairness and transparency, and to enable necessary discussions with any of the qualifying entities wishing to supplement their proposal, PJM is exploring ways to enhance our process. Additional information will be provided once we examine any submittals we receive.

The Board appreciates stakeholders' patience during this process. Order 1000, which guided our competitive bidding initiative on this project, has created entirely new processes which are especially challenging when evaluating transmission solutions as complex as those required for the Artificial Island stability issues. For these reasons, the Board is outlining these additional steps to ensure that the most technically effective and cost-efficient proposal to solve the Artificial Island stability issues is selected.

Steve Herling

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Attachment 14

2750 Monroe Boulevard
Audubon, PA 19403

Virginia Electric and Power Company
Ronnie Bailey
701 East Cary Street
Richmond, VA 23219

Transource Energy, LLC
Takis Laios
1 Riverside Plaza,
Columbus Ohio, 43215

LS Power Development, LLC
Sharon Segner
400 Chesterfield Center, Suite 110
St. Louis, MO 63017

Public Service Electric and Gas Company
Kim C. Hanemann
4000 Hadley Road
South Plainfield NJ 07080

August 12, 2014

RE: Artificial Island Supplemental Proposal Request

Project P2013_1-1A - Two (2) Thyristor Controlled Series Compensation (TCSC) Devices near New Freedom[1] (Dominion)

Proposal P2013_1-1C - Install a new 500kV line from Hope Creek - Red Lion without Salem Hope Creek 2nd Tie (Dominion)

Proposal P2013_1-2B - Two (2) 500/230 transformers near Salem and loop in Red Lion - Cartanza 230 and Red Lion - Cedar Creek 230 kV (Transource)

Proposal P2013_1-5A - New 230 kV station that taps existing Cedar Creek - Red Lion 230kV and Cartanza - Red Lion 230kV, submarine and overhead (LS Power)

Proposal P2013_1-7K New 500kV Hope Creek - Red Lion Line, without Salem-Hope Creek 2nd Tie (PSE&G)

Dear Proposer,

At the July Board meeting, the PJM Board deferred selection for the Artificial Island project solution in order to obtain additional information. PJM staff will be gathering additional information from those entities that have proposed projects that have passed the various levels of analysis undertaken by staff as laid out at the May 19 TEAC meeting. As described in the July 23rd letter to the TEAC, finalist bidders will have the opportunity to supplement their proposals.

[1] Based on Dominion's July 16th letter, PJM has determined that it would be appropriate to seek additional information as outlined above regarding the Dominion 1A project.

PJM is inviting you as a "finalist" bidder (Proposer) to submit final terms of project costs. We reiterate that cost is only one of several considerations that will be a factor in the final selection for the AI Project Proposal Window. This request is not open for Proposers to make changes to the project scope. The scope of a submission must be limited to factors that specifically address project cost. If a Proposer wishes to supplement its proposal in terms of cost, the Proposer must include sufficient detail for PJM to evaluate the details of its cost proposal, including the specific details surrounding any cost cap that a proposer wishes to submit. Submission of a cost cap is not required but if a Proposer wishes to submit a cost cap, the Proposer must be explicit in identifying the scope of the work that is included and excluded from the project cost or cost cap. Any contractual terms and conditions that would apply to the proposed project cost or cost cap must also be specified in the submission.

Each project's scope of work under consideration is that which was studied by PJM with respect to performance criteria including PJM modifications as noted on the attached diagrams and as discussed at the May 19 TEAC meeting. Any supplemental proposal must be consistent with the attached diagrams. Proposers must affirm the project schedule based on scope with PJM modifications and projected in-service date.

Further, it has been brought to PJM's attention that the State of Delaware public utility regulations may restrict the ability of a developer to site and construct new transmission in Delaware if the Proposer does not currently have a service territory as established by the state commission in the area of their project. Therefore, PJM requests that all Proposers who have submitted projects that require construction within the state of Delaware, provide a detailed response, including legal references, as well as confirmation from the Delaware Public Service Commission or the Office of the Delaware Attorney General regarding Proposer's legal ability to site and construct transmission in the State of Delaware consistent with its project proposal.

If you wish to supplement your proposal, the submission must be sent to PJM at RTEP@pjm.com no later than close of business on September 12, 2014 for consideration.

We appreciate your continued cooperation as we move forward on the Artificial Island competitive solicitation process.

Very truly yours,

Steven Herling
Vice President – Planning

Attachment

CC:
Terry Boston
Mike Kormos
Paul McGlynn
Mark Sims
Suzanne Glatz
Pauline Foley

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Attachment 15

2750 Monroe Boulevard
Audubon, PA 19403-2497

Pauline Foley
Assistant General Counsel
610.666.8248 | Fax – 610.666.8211
pauline.foley@pjm.com

August 29, 2014

VIA FEDERAL EXPRESS

The Honorable Curtis L. Wagner, Jr.
Chief Administrative Law Judge
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Status Report – Artificial Island Solicitation
Appointment of Facilitator
Docket No. MD14-1

Dear Chief Judge Wagner:

Pursuant to Rule 604(d) of the Commission's Rules of Practice and Procedure,[1] this submittal will provide an outline of the requested scope of a dispute resolution proceeding, for which PJM Interconnection, L.L.C. ("PJM") seeks ALJ-ADR assistance from your office.[2]

Following PJM's request to Your Honor to engage the Commission's non-evaluative Alternative Dispute Resolution ("ADR") process and your appointment of Administrative Law Judge Steven L. Sterner, PJM has spoken with Judge Sterner regarding PJM's request.[3] During that discussion, PJM explained its desire to have an Administrative Law Judge ("ALJ") present in a non-decisional role to ensure the fairness and due process surrounding PJM's discussions with the four final bidders of the Artificial Island Proposal Window regarding the supplemental material submitted by each bidder with the final terms of their project costs. This correspondence provides a summary of the matter and outlines PJM's expectations with regard to Judge Sterner's role as a neutral, non-decisional observer.

I. Background

As part of PJM's compliance with Order No. 1000, PJM proposed to implement a proposal window process to permit both incumbent transmission owners and non-incumbent developers the opportunity to submit project proposals through a proposal window. If the project is included in the regional transmission expansion plan ("RTEP') and the "proposer" meets the qualification

[1] 18 C.F.R. § 604(d) (2013).

[2] This communication is submitted under Rule 604(d). *See* 18 CFR § 385.604(d) (2013).

[3] Judge Sterner shall serve as a "neutral" consistent with Rule 604(c).

criteria, the proposer may be designated construction, ownership and financial responsibility for its proposed project.

In April 2013, PJM opened a 60-day proposal window[4] to solicit projects from stakeholders to address operational performance issues around Artificial Island.[5] PJM received 26 proposals from seven different entities. The proposals ranged in cost from just over $100 million to over $1,500 million. The proposals included flexible alternating current transmission system ("FACTS") devices, high-voltage direct current ("HVDC") lines, new overhead and underground/underwater 230 kV lines and new overhead 500 kV lines. For over a year, PJM staff completed extensive technical evaluations of each proposal. Based on the results of the analytical screening and the estimated cost of each proposal, PJM began to focus on a subset of proposals. The subset of proposals included both southern Delaware River crossings (overhead and submarine) that terminated at the existing 230 kV system in Delaware and new 500 kV lines from either Hope Creek or Salem substations to the Red Lion 500 kV substation in Delaware. On May 19, 2014, PJM presented to the stakeholders in the context of the Transmission Expansion Advisory Committee ("TEAC"), a detailed summary of PJM's evaluation of the submitted proposals. At the June 2, 2014 TEAC, PJM presented the project proposal (a new 500 kV line from the Hope Creek substation to Red Lion substation) and the name of the designated entity (Public Service Electric and Gas Company) it planned to recommend to the PJM Board of Managers ("PJM Board") at the July Board meeting.

At the July Board meeting, PJM briefed the PJM Board on PJM's evaluation of the Artificial Island proposals. In addition, the PJM Board reviewed ten (10) letters submitted from proposers, state commissions and stakeholders commenting on PJM's proposed recommendation. Included in those letters was a late-filed submission by Northeast Transmission Development, LLC ("LS Power") proposing to cap construction costs associated with its project. Based on its review, the PJM Board determined to take the matter under advisement and deferred selection of the Artificial Island project solution pending PJM staff gathering additional information from the following four final bidders: Virginia Electric and Power Company, Transource Energy, LLC, LS Power and Public Service Electric and Gas Company.

II. The ADR Process:

By letter dated August 12, 2014, each bidder was notified of their status and invited to supplement their submissions with the final terms of their project costs only. PJM will evaluate the details of each bidder's cost proposal, including the specific details surrounding any cost cap that a bidder may wish to submit. In anticipation of the variability of the responses PJM expects to receive and the complexity of evaluating cost submittals (particularly the terms of any

[4] The proposal window process was proposed and accepted by the Commission as part of PJM's compliance with Order No. 1000, effective January 1, 2014. *See PJM Interconnection, L.L.C., et al.*, 147 FERC ¶ 61,128 (May 15, 2014); *PJM Interconnection, L.L.C., et al.*, 146 FERC ¶ 61,030 (Jan. 16, 2014); *PJM Interconnection, L.L.C., et al.*, 142 FERC ¶ 61,214 (Mar. 22, 2013).

[5] Artificial Island is the area in Southern New Jersey where the Salem and Hope Creek nuclear generation is located. Historically, the area has been constrained. Stability of the generation has been ensured through the use of operating procedures.

proposed cost caps), PJM has requested to engage an ALJ through the Commission's Dispute Resolution Services to serve in a non-decisional role to ensure due process and fairness as PJM undertakes the final discussions with the finalists on their proposals prior to final submission of PJM staff's recommendation to the PJM Board. To that end, Judge Sterner has invited PJM to outline the process requested, including the PJM's expectations regarding Judge Sterner's role in that process. PJM appreciates the Judge's thoughtful suggestion and has prepared, in consultation with Judge Sterner, the following scope for Your Honor's consideration:

- PJM anticipates Judge Sterner's role as a neutral, non-decisional observer of the *process* PJM utilizes in discussing with the four final bidders the supplemental proposals submitted on September 12, 2014. Judge Sterner's presence either through direct attendance at meetings (either at FERC or an offsite location) or reviewing of agendas and proposed questions, if personal attendance at a particular meeting is not possible, would ensure that PJM's line of inquiry is consistent with each of the bidders and that no bidder is given an undue advantage in their presentation to PJM.
- Judge Sterner will not serve in a decision-making role nor is this process intended to be conducted as a settlement conference or a matter for traditional dispute resolution. Judge Sterner will be observing and commenting on PJM's process but not attempting to bring parties together to seek common ground or otherwise drive toward any particular substantive outcome.
- Judge Sterner will observe and comment upon, as described below, the fairness of the process undertaken by PJM through these final negotiations but not attempt to influence PJM staff's substantive recommendation or the final PJM Board decision in any way. To that end, PJM will seek Judge Sterner's timely feedback throughout the process, as appropriate, regarding PJM's comparable treatment and dissemination of information to all bidders. Given this role, Judge Sterner's comments on the process will be directed solely to PJM as PJM crafts or undertakes these meetings and will not be simultaneously reported to the developers in attendance or those not in attendance.
- PJM will not be required to follow the Judge's recommendations.
- Judge Sterner will provide a report to PJM and will publish the final report on eLibrary under Docket No. MD14-1 upon completion of the process or earlier, as mutually agreed upon by Judge Sterner and PJM. The Judge's report will help inform the PJM Board on the fairness of the process and serve as a valuable tool for guiding such future negotiations undertaken in implementing Order No. 1000's call for competitive solicitation processes. PJM's goal is to submit its recommendation to the PJM Board for consideration at the Board's December 2014 meeting.
- It is understood that Judge Sterner accepts the process to date and will oversee only these final information sessions. His presence may not be used by any participant as a judgment on any of the steps undertaken by PJM as part of this competitive solicitation prior to his formal involvement in this matter in overseeing the meetings referenced above.
- Because the discussions will involve a review of proprietary cost information, it is understood that the discussions of each party's September 12 submittal will be treated as

confidential. Accordingly, all communications and information provided under this process shall be treated in accordance with Rule 606 of the Commission's Rules of Practice and Procedure.[6]

- The involvement of Judge Sterner and the Commission's ADR process in this matter does not provide any party with rights of discovery or rights to be in attendance at meetings where confidential information of other parties is being discussed.
- All finalists will be asked to sign a letter agreeing to engage in fact finding sessions in the presence of Judge Sterner and OALJDR staff regarding the supplemental information provided by them in response to PJM's August 12, 2014 letter. Should any party refuse to sign a letter, PJM will decide the merits of that party's submittal based solely on the submitted documentation without any additional communications.
- PJM will prepare a meeting schedule that will attempt as much as possible to accommodate Judge Sterner's availability either in person or by telephone.
- Pursuant to 18 CFR §385.604(f), Judge Sterner will provide Your Honor with periodic Status Reports, as needed. The reports shall advise Your Honor of the progress and developments in this matter. In order to maintain the confidentiality of the matters herein, the reports will not be filed in FERC's eLibrary. Upon conclusion of the process, Judge Sterner shall issue a notice ending this alternative dispute resolution proceeding.

In addition to the above, PJM anticipates the following guidelines governing the conduct of any discussions undertaken with the four finalists:

- Each finalist will be asked to attend non-public fact finding sessions to answer questions by PJM staff or its consultant(s), (if a consultant is retained by PJM) in the presence of Judge Sterner and his staff. PJM shall determine whether to meet with finalists, individually or collectively, in the presence of Judge Sterner to maintain the confidentiality of proprietary information.
- The purpose of the fact finding sessions will be to ask questions regarding the terms of each bidder's project costs, including specific details about their cost cap, if applicable.
- At PJM's discretion, such fact-finding sessions may be conducted either as face-to-face meetings or teleconference calls.
- Nothing in these procedures prevents PJM from gaining additional information from other entities who have not submitted proposals, such as state commissions and the Nuclear Regulatory Commission. To the extent any additional non-confidential information impacts the PJM staff's recommendation, the results of those discussions will be reported by PJM to all stakeholders through PJM's report to the TEAC.
- The procedures outlined above governing meetings relative to the developer's September 12 submittals (and their underlying submittal) do not prohibit incidental procedural and administrative communications with individual bidders throughout this process.

[6] 18 C.F.R. § 385.606 (2013).

- PJM requests that this matter be lodged as a non-public docket.
- Following completion of this process, PJM Staff will prepare a final report for presentation to the TEAC and the PJM Board with a final recommendation.

We look forward to working with Judge Sterner and your OALJDR staff in this unique structure. We appreciate your consideration. To the extent any additional authorizations are needed for us to engage Judge Sterner in this helpful role as we implement the first-in-the-nation competitive solicitation process, pursuant to the Commission's Order No. 1000, we would seek your assistance in obtaining same.

Should you wish to discuss this further or need additional information, please contact Craig Glazer at 202-423-4743 or by e-mail at craig.glazer@pjm.com or PJM Counsel, Pauline Foley, at 610-666-8248 and pauline.foley@pjm.com.

Thank you.

Sincerely,

Pauline Foley
Assistant General Counsel

cc: Hon. Steven L. Sterner (*via* email @ steven.sterner@ferc.gov)
Mr. Thomas Kirby (*via* email @ thomas.kirby@ferc.gov)
Mr. Cyrus Zarraby (*via* email @ cyrus.zarraby@ferc.gov)

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Attachment 16

Transmission Expansion Advisory Committee

Artificial Island

December 9, 2014

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SI-SSA-0010-0402

Meeting Agenda and Format

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Meeting Format and Agenda

- Evaluation update - PJM
- Project Presentations – Finalist Proposers
- Break
- General Artificial Island Q&A session

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Artificial Island Analysis Summary
Recent Activities

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Summary of Actions Taken by PJM

- Requested and received supplemental cost proposals from finalist proposing entities
- Conducted meetings with finalist proposing entities and FERC Administrative Law Judge
- Performed additional performance analysis of the TCSC project
- Gathered input from permitting and regulatory entities
- Met with FACTS based device industry representatives
- Performed additional constructability reports

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FERC Administrative Law Judge Letter

- Conducted meetings to ensure PJM has a clear understanding of the terms and conditions of the responses to PJM's offer
- Provided an overview of the process followed at the meetings
- Affirmed that meeting formats and durations were the same for all four Proposing Entities
- Concluded that all Proposing Entities were treated equally under the process
- http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20141203-3013

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Performance Analysis Summary

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FACTS Device Industry Representative Meetings

- PJM met independently with FACTS based device industry representatives
  - Expand PJM's understanding of the technology and implementation
    - Typical applications
    - Operation
    - Modeling
    - Failure modes
    - Construction timeframes
  - Summary:

    (1) TCSC components are employed in the industry with high reliability;

    (2) TCSC application is a variant of existing FACTS installations using similar components (see 1 above)

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TCSC Performance Analysis

- PJM Simulations
  - Validated the performance of the TCSC under several failure and outage mode scenarios
    - Critical pre-contingency outage conditions
    - Critical faults
    - Assumed combinations of failure modes and outage conditions
    - Performance

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TCSC Outage and Failure Mode Evaluation

	TCSC on 5023	TCSC on 5024	SVC at New Freedom	Stability	line outage in pre-contingency	Note
Assume TCSC Outage - simulate as open circuit	outage	outage	in	unstable	Two line outages	N-2-1 Beyond criteria
	outage	in	in	stable	One line outage	N-1-1
	in	outage	in	stable		N-1-1
Assume TCSC Failure - simulate as 0% compensation	failure	failure	in	unstable		N-1-3 Beyond criteria
				unstable		N-1-3 Beyond criteria
	failure	in	in	stable		N-1-2 Beyond criteria
				stable		N-1-2 Beyond criteria
	in	failure	in	stable		N-1-2 Beyond criteria
				stable		N-1-2 Beyond criteria
	failure	failure	in	stable	no line outage	N-3 Beyond criteria
	failure	in	in	stable	no line outage	N-2 for two un-related elements - Beyond criteria
	in	failure	in	stable	no line outage	N-2 for two un-related elements - Beyond criteria
Assume SVC outage	in	in	outage	stable	no line outage	N-1-1
	in	in	outage	unstable	One line outage	N-2-1 Beyond the criteria
	in	in	outage	unstable		N-2-1 Beyond the criteria

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TCSC Performance Analysis

– Dominion 1A TCSC project proposal includes double breaker installations at four existing substations

- During study, it was determined that one proposed breaker at Hope Creek could be removed from the project scope with no impact to performance

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TCSC Analysis – SSR Study

- Engaged consultant to perform a Sub-Synchronous Resonance (SSR) study
  - Expected to be complete and posted at the end of December

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Constructability Analysis Summary

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Constructability Reports - Permit Comparison

- Report was commissioned that compares the permitting challenges between the Red Lion to Artificial Island project against those of the southern Delaware crossing projects.
  - Permitting issues identified are consistent with prior constructability reviews and stakeholder comments
  - National Environmental Policy Act (NEPA) review potential risk
  - Risk factors are such that neither has clear advantage in terms of siting and permitting hurdles to overcome
  - Final report has been posted on pjm.com

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Constructability Reports – Dominion 1A

- Report was commissioned to review the Dominion 1A FACTS based device project
  - Identified permitting challenges for the proposed project locations
    - Three of the four sites will face significant permitting challenges
  - Proposed project cost was evaluated
    - Concluded that the contingency applied could be greater due to some risk factors
  - Final report will be posted on pjm.com

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Permitting and Regulatory Agency Discussions

- NJ DEP
  - Permitting issues identified are consistent with prior constructability reviews and stakeholder comments

- NRC
  - No concerns raised about the use of FACTS-devices in the vicinity of Artificial Island
  - Nuclear licensee (PSEG Nuclear) will need to perform a 10CFR50.59 Safety Evaluation. If the evaluation concludes that there is a nuclear safety impact and a Technical Specification change is required, then NRC approval is required.

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Permitting and Regulatory Agency Discussions

- US Army Corps of Engineers
  - Discussed the NEPA process and Army Corps of Engineers' role
  - Southern Delaware crossing
    - Depth of 70 feet below mean low water required for a submarine cable within the shipping channel (based on 45ft depth in shipping channel and 25 ft. burial depth for cable)
  - Red Lion to Hope Creek line
    - Navigational concerns associated with tower foundations would need to be addressed
  - Identified that both routes face significant routing and permitting hurdles

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Non-Incumbent Developers in Delaware

- Questions were raised about the ability of non-incumbent developers to build and operate transmission infrastructure in Delaware

- Delaware issued an order affirming a non-incumbent's ability to construct, own and operate, subject to having to apply for a CPCN for specific project.

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Cost Estimate Summary

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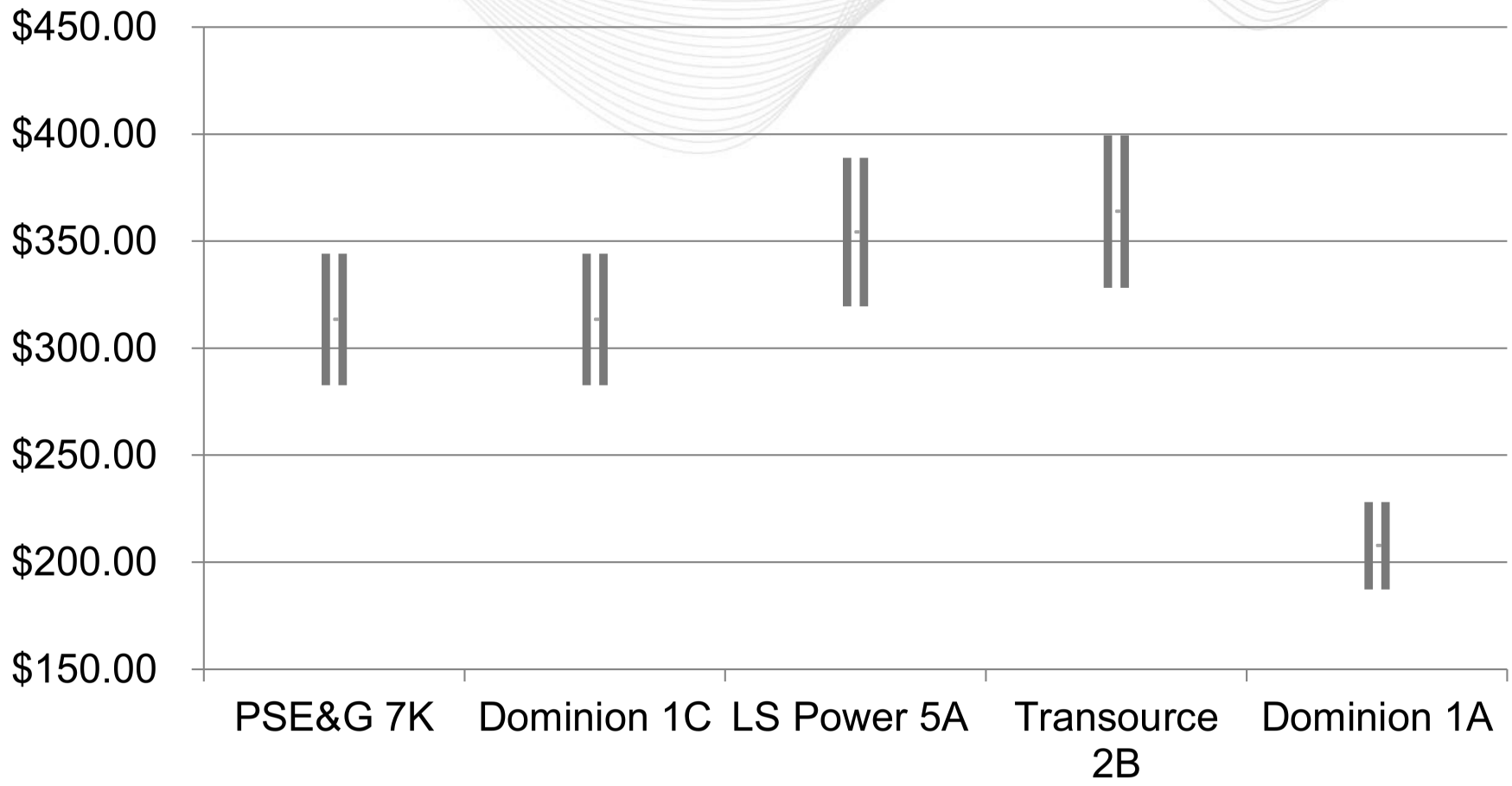
PJM Cost Estimates



- Estimates are in millions of dollars

Cost Estimates Incorporating Cost Containment/Cap

- Total cost estimates that combine Proposing Entity cost containment numbers with PJM cost estimates
  - Costs estimates provided by Proposing Entities for project components within their cost containment mechanisms utilized
  - PJM cost estimates used for project components outside of proposed cost containment mechanisms

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Cost Estimates Incorporating Cost Containment/Cap

LS Power 5A	
Cost Containment	$146
Salem Expansion	$61.3 - $74.7
SVC Cost Estimate	$71 - $86
Project Total	$278 - $307

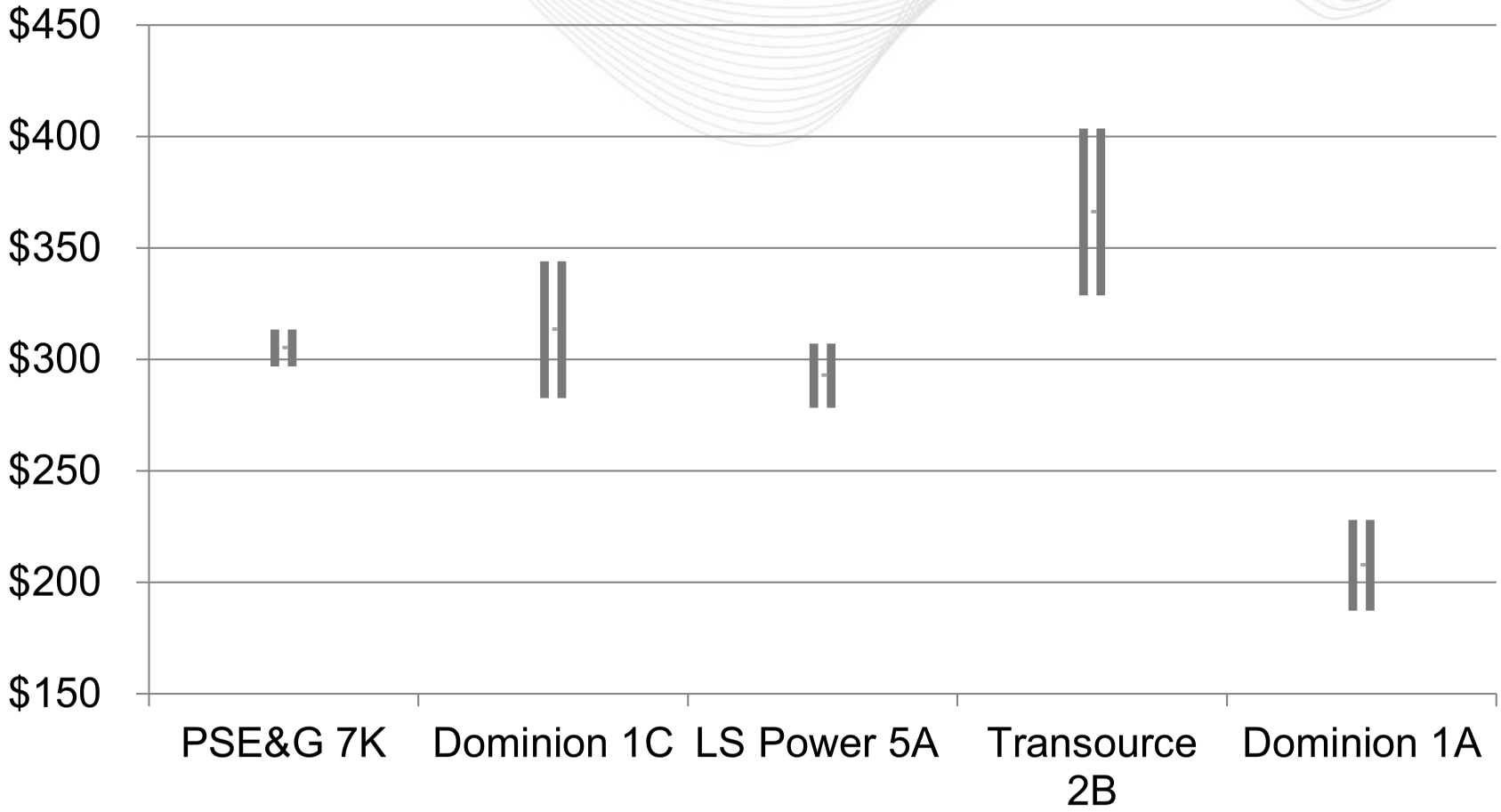
Transource 2B	
Cost Containment	$203 - $255
New Salem Substation	$41
Salem Expansion	$14.3 - $17.4
SVC Cost Estimate	$71 - $86
Project Total	$329 - $404

Dominion 1A	
Cost Containment	$0
Project Cost Estimate	$187 - $228

PSE&G 7K	
Cost Containment	$221
Red Lion Expansion	$4.9 - $6.0
SVC Cost Estimate	$71 - $86
Project Total	$297 - $313

Dominion 1C	
Cost Containment	$0
Project Cost Estimate	$211.7 - $257.7
SVC Cost Estimate	$71 - $86
Project Total	$283 - $344

Cost Estimates Incorporating Cost Containment/Cap



- Estimates are in millions of dollars

Questions?

Email: RTEP@pjm.com

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Appendix

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Supplemental Information Summary

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Supplemental Information Request Timeline

- 08/12 – Letter sent to Proposing Entity ‘finalists’ to provide opportunity to supplement their proposals
- 09/12 – Supplemental information submitted to PJM by all ‘finalists’
- 09/18 – Redacted versions of the supplemental information is posted to PJM.com
- Oct 22 through Nov 3 – Meetings with FERC Administrative Law Judge and finalists to review and confirm information

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LS Power Cost Containment Mechanism

- Costs included under the containment mechanism
  - Permits and government approvals
  - Land acquisition
  - Environmental assessment and mitigation
  - Engineering
  - Equipment, supplies and other material procurement
  - All development and construction activities

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LS Power Cost Containment Mechanism

- $146 Million

- Physical scope of work included under proposed mechanism
  - Aerial or submarine line
  - New substation located near the existing 230kV right-of-way in Delaware

- Physical scope of work not included under proposed mechanism
  - Salem substation modifications
    - New bay position
    - New 500/230kV transformer
  - 230kV turning poles cutting the two Delaware transmission lines

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LS Power Cost Containment Mechanism

- Costs not included under the containment mechanism
  - Financing costs
  - AFUDC
  - Additions and modifications to the project scope due to
    - "any material change in the enforcement, interpretation of application of any statue, rule, regulation, order or other applicable law existing.."
    - "any Breach or Default by PJM of its obligations under the DEA or any request by PJM to delay or suspend any activities associated with the Project".
    - "any breach, default, interference or failure to cooperate by any Transmission Owner in connection with the Interconnection Coordination Agreement or interconnection agreement"

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Transource Cost Containment Mechanism

- Proposed tiered cost containment mechanism
  - Up to $243 Million: entitled to recover all FERC approved ROE plus incentives
  - Portion from $243 to $299.8 million: forego 50% of any FERC approved ROE incentives
  - Above $299.8 million: forego 100% of any FERC approved ROE incentives

- Physical scope of work included under proposed mechanism
  - 230kV submarine cable from Salem substation to new substation in Delaware
  - New substation located near the existing 230kV right-of-way in Delaware
  - New 500/230kV substation adjacent to Salem substation

- Physical scope of work not included under proposed mechanism
  - Modifications in and near Salem substation
    - New bay position at Salem
  - 230kV turning poles cutting the two Delaware transmission lines

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Transource Cost Containment Mechanism

- Transource provided a contingency amount of $52.3 million which is included in the second tier of their cost containment mechanism
  - Some specific contingency items identified (redacted)
  - General 10% project contingency

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PSE&G Cost Containment Mechanism

- $221 Million

- Physical scope of work included under proposed mechanism
  - Aerial 500kV line from Hope Creek to Red Lion substations
  - Upgrade work at Hope Creek to create the new line bay

- Physical scope of work not included under proposed mechanism
  - Upgrade work at Red Lion to create the new line bay

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PSE&G Cost Containment Mechanism

- Costs included under the containment mechanism
  - All project costs with exceptions as noted below
  - Clarity is needed on what is meant by “all project costs”

- Costs not included under the containment mechanism
  - Costs associated with PJM modifications or additions to the scope of work
  - Costs incurred from the following events deemed outside of the control of PSE&G:
    - Changes in applicable laws and regulations
    - Obtaining governmental approvals and permits
    - Obtaining necessary property rights to construct the Project
    - Environmental permitting, remediation and mitigation
    - Orders of courts or action or in action by governmental agencies

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Dominion Supplemental Information

- Dominion did not provide a cost containment mechanism, but rather provided reasons for confidence in their ability to meet cost estimates and elaborated on project management approach and past experience with transmission projects
  - Red Lion to Hope Creek: agreed with PJM's cost estimate of $242 to $292 million
  - FACTS based solution: provided a revised cost estimate of $174.1 million
    - $86.4 million based upon vendor not-to-exceed budget prices

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Attachment 17

Transmission Expansion Advisory Committee

October 9, 2014

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Artificial Island Update

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Artificial Island Update

- Permitting constructability comparison
  - Compare the permitting challenges of the Southern Delaware Crossing alternatives to the AI – Red Lion 500 kV alternatives
  - Nearing completion
- Discussion with the Nuclear Regulatory Commission (NRC)

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Artificial Island Update

- Supplemental Responses
  - Supplemental responses received
  - Redacted versions posted to PJM.com
  - PJM is coordinating three party meetings between PJM, the proposing entity and a FERC Administrative Law Judge (ALJ)
    - The letter from PJM to the FERC ALJ is posted to PJM.com
  - http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows/closed-artificial-island-proposals.aspx

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Artificial Island Update - TCSC

- PJM Simulation
  - Validated the performance of the TCSC under several failure and outage mode scenarios
    - Critical pre-contingency outage conditions
    - Critical faults
    - Assumed combinations of failure modes and outage conditions

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TCSC Outage and Failure Mode Evaluation

	TCSC on 5023	TCSC on 5024	SVC at New Freedom	Stability	line outage in pre-contingency	Note
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				stable		N-1-2 Beyond criteria
	in	failure	in	stable		N-1-2 Beyond criteria
				stable		N-1-2 Beyond criteria
	failure	failure	in	stable	no line outage	N-3 Beyond criteria
	failure	in	in	stable	no line outage	N-2 for two un-related elements - Beyond criteria
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Assume SVC outage	in	in	outage	stable	no line outage	N-1-1
	in	in	outage	unstable	One line outage	N-2-1 Beyond the criteria
	in	in	outage	unstable		N-2-1 Beyond the criteria

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Artificial Island Update - TCSC

- Discussion of TCSC technology and applications with vendors
- Constructability Report is in-progress
- Evaluation of Sub Synchronous Resonance (SSR)

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remaining pages intentionally omitted

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Attachment 18

Transmission Expansion Advisory Committee

November 11, 2014

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Artificial Island Update

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Artificial Island Update

- Recent meetings the Artificial Island finalists and a FERC Administrative Law Judge (ALJ) are complete
- Engaged consultants to perform a Subsynchronous Resonance (SSR) study and constructability study
- Staff continues to evaluate the proposals

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Artificial Island Next Steps

- December 4th, 2014 TEAC
  - Review updated Artificial Island evaluation
- January 8th, 2015 TEAC
  - Recommend Artificial Island solution to the PJM TEAC
- February 2015 PJM Board
  - Recommend Artificial Island solution to the PJM Board

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RTEP Next Steps

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RTEP Next Steps

- Recommend Artificial Island solution
- Present 2015 RTEP Assumptions
- Discuss 2015 RTEP Scenario Studies
- Evaluate and recommend solutions for RTEP Proposal Window #2

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Questions?

Email: RTEP@pjm.com

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- Revision History
  - Version 1: Original version posted to the PJM TEAC on 11/10/2014
  - Version 2: Corrected Date on Slide 1, Corrected typo on slide 12 to show “November 2014” on 11/13/2014

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Attachment 19

Transmission Expansion Advisory Committee

January 7, 2015

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Artificial Island Update

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Artificial Island Update

- Sub Synchronous Resonance (SSR) study status
- Evaluation of the sensitivity of AI area assumptions
  - Fiber Optic Ground (FOG) wire installation for shorter clearing times
  - Artificial Island generation GSU tap adjustment for higher AI generation terminal voltages

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Artificial Island Update

- Next Steps
  - Finalize the AI relay clearing time improvement study (Fiber Optic Ground wire study)
  - Receive and finalize consultant Sub Synchronous Resonance (SSR) study
  - Engagement of third party to review the issues tracking and studies for the Dominion 1A – TCSC proposal
  - Cancel previously scheduled 01.21.2015 TEAC meeting to review Artificial Island, this meeting will be re-scheduled at a later date

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RTEP Next Steps

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RTEP Next Steps

- Finalize and benchmark Summer 2020 RTEP model
- 2014 RTEP Window #2 - Continue Pratts area evaluation
- RTEP Long Term RTEP window remains open through February 2015
- Recommend all final recommendations reviewed at today's TEAC to the PJM Board in February 2015 for approval and inclusion in the RTEP

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Questions?

Email: RTEP@pjm.com

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- Revision History
  - 1/6/2015 - Original version posted to the PJM TEAC
  - 1/16/2015 – remove the P2014_2-2W (original slide #35), and it should be an alternative to P2014-2-2V (original Slide #54)

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Calpine Corporation, Dynegy Inc., Eastern Generation, LLC, Homer City Generation, L.P., NRG Power Marketing LLC, GenOn Energy Management, LLC, Carroll County Energy LLC, C.P. Crane LLC, Essential Power, LLC, Essential Power OPP, LLC, Essential Power Rock Springs, LLC, Lakewood Cogeneration, L.P., GDF SUEZ Energy Marketing NA, Inc., Oregon Clean Energy, LLC and Panda Power Generation Infrastructure Fund, LLC, Complainants, v. PJM Interconnection, L.L.C., Respondent.	)	Docket No. EL16-49-000

MOTION TO INTERVENE AND COMMENTS IN PARTIAL SUPPORT OF THE PSEG COMPANIES

Pursuant to Rules 212 and 214 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission" or "FERC"), 18 C.F.R. §§ 385.212, 385.214, the PSEG Companies[1] (PSEG Power LLC ("PSEG Power");[2] Public

[1] The PSEG Companies are each wholly owned, direct and indirect subsidiaries of Public Service Enterprise Group Incorporated ("PSEG"). The principal and executive offices of PSEG are located at 80 Park Plaza, Newark, New Jersey 07102. PSEG is a public utility holding company engaged in, among other things, the generation of electric energy, and the transmission, distribution and sale of electricity and natural gas through its subsidiaries.

[2] PSEG Power is a wholesale energy supply company that integrates its generation asset operations with its wholesale energy, fuel supply, energy trading and marketing, and risk management functions through three principal subsidiaries: (i) PSEG Nuclear LLC ("PSEG Nuclear"), which owns and operates nuclear generating stations; (ii) PSEG Fossil LLC ("PSEG Fossil"), which develops, owns, and operates domestic fossil-fuel fired and other non-nuclear generating stations; and (iii) PSEG ER&T, which is described below.

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Service Electric and Gas Company ("PSE&G");[3] and PSEG Energy Resources & Trade LLC ("PSEG ER&T")[4]) submit this motion to intervene and comments in partial support of the above captioned complaint[5] against PJM Interconnection, L.L.C ("PJM") alleging that PJM's Open Access Transmission Tariff ("Tariff") is unjust and unreasonable because it does not include provisions to prevent the artificial suppression of prices by existing uneconomic generation resources not needed for reliability that are the beneficiaries of out-of-market revenues. As shown below, the PSEG Companies respectfully submit that the Complainants have effectively demonstrated that the current PJM Tariff is not just and reasonable because it fails to mitigate capacity market offers for units owned by subsidiaries of FirstEnergy Corporation ("FE") and American Electric Power Company, Inc. ("AEP") that will receive subsidies under Power Purchase Agreements ("PPA"), funded through non-bypassable distribution surcharges, recently approved by the Ohio Public Utility Commission ("PUCO"). The PSEG Companies submit, however, that more simplified mitigation procedures can be applied than those proposed by Complainants. Specifically, the Commission need not address the complex issues associated with changing the scope of the existing "minimum offer price rule" ("MOPR") at this time; instead, the Commission can directly mitigate the offers submitted by the FE/AEP units. In addition, mitigation can be accomplished through

[3] PSE&G is a public utility company organized under the laws of the State of New Jersey. PSE&G is presently engaged in, among other things, the transmission and distribution of electricity and the distribution of natural gas in New Jersey. PSE&G owns transmission facilities in PJM Interconnection, L.L.C. ("PJM").

[4] PSEG ER&T, an indirect subsidiary of PSEG, sells power and energy and certain ancillary services at market-based rates. PSEG ER&T markets the capacity and production of PSEG Nuclear's and PSEG Fossil's generating stations, manages the commodity price risks and market risks related to generation, and provides gas supply services. PSEG ER&T is engaged in extensive asset-based energy trading operations throughout the Northeast.

[5] "Complaint Requesting Fast Track Processing," *Calpine Corporation, et al. v. PJM Interconnection, L.L.C.*, Docket No. EL16-49-000 (March 21, 2016) ("Complaint").

simpler and less time-consuming measures than those proposed by Complainants. In support thereof, the PSEG Companies respectfully show as follows:

I. INTRODUCTION

The PUCO recently approved two PPAs covering generating facilities with an aggregated capability of 5,927 MWs owned by subsidiaries of FE and AEP.[6] Other FE/AEP companies with franchised service territories in Ohio with the responsibility to provide "provider of last resort" service to Ohio consumers will be the purchasers under the PPAs. The PPAs provide that the FE/AEP generating companies will be paid (or will be required to pay) the difference between the cost of operating the covered generating facilities and the revenues received by those facilities from the PJM-administered markets for energy, capacity and ancillary services. The PUCO has determined that over the eight year term of the arrangements that payments received are expected to exceed the amounts paid out thus resulting in net benefit to consumers. However, the PUCO acknowledged that for the early years of the PPAs the cost of operating the plants is expected to exceed the PJM market revenues that the plant will earn. When market revenues are insufficient to cover to the cost of operating the plants, shortfall amounts will be collected through non-bypassable charges imposed on AEP/FE distribution customers.

The instant Complaint concerns how the units receiving subsidies under the PPAs should participate in the upcoming Base Residual Auction ("BRA") for capacity that will

[6] *In the Matter of the Application of Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan*, Case No. 14-1297-EL-SSO (March 31, 2016) ("FE Order*"); In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter Into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider*, Case No. 14-1693-EL-RDR (March 31, 2016) ("AEP Order").

be conducted under the auspices of PJM's Reliability Pricing Model ("RPM"). As shown in the Complaint, the PPA units will be incentivized to bid zero or, at least, at low prices in order to assure that they clear in the auction. First, the units lack any incentives *not* to clear regardless of their actual cost of operation. In contrast to units that are dependent on market revenues to recover their costs and thus can be expected not to bid below their avoidable costs, these units will be fully compensated regardless of the PJM clearing price. Second, the PPAs require that units be bid in a manner that is "not unreasonable."[7] Thus, under the "contract for differences" construct entailed by the PPAs, FE/AEP could be deemed to have acted "unreasonably" if they bid in such a manner that they fail to avail themselves of available market revenues by not clearing. This holds true regardless of the amount of those revenues so that the units have strong incentive to bid as price-takers. Both PJM and the Independent Market Monitor ("IMM") share these concerns.

Further, although FE/AEP may contend that they will have incentives to bid the affected units competitively due to potential market impacts on their other units that do not have PPAs, such a contention would be unavailing or, if accepted, would obviate any possible objection to being mitigated. As shown *supra*, the PPA units have strong incentives to bid in a manner such they will be assured of clearing. If they do clear the auction, they can expect to recover the full cost of operating the affected plants. Before accepting the contention that the impact on the non-PPA units would supply adequate incentives to bid the units in a competitive manner and thus neutralize the strong countervailing incentives to submit bids assured of clearing, the companies would need to demonstrate that the impact on their non-PPA units would clearly exceed the value of the recovering the above-market portion of the PPA payments. Even if this were possible to

[7] FE Order, at 20; AEP Order, at 89.

demonstrate (which is by no means clear), it could not possibly be accomplished before the upcoming BRA thus leaving the auction outcome at risk unless mitigation measures are adopted. Further, if FE and AEP make the assertion that they actually have incentives to bid in a competitive manner and, that assertion is accepted at face value, the companies should not be concerned about reasonable mitigation measures since that would be how they would bid anyway.

As the Complaint further demonstrates, allowing the units to bid in this manner would impact efficient price formation in the PJM capacity market. Based on PJM's own calculations from the last BRA, approximately $990 million in market revenues that would otherwise be associated with a competitive clearing could be eliminated.[8] The basic tenet that underlies the RPM market design is that, over the long run, competitive bids will result in *average* prices commensurate with the cost of new entry for the reference unit. Thus, if developers perceive that bids by subsidized units below competitive levels will be allowed, thus tending to lower average prices, they may be unwilling to commit the necessary capital to build new plants. Further, if regulators in states other than Ohio perceive a need to "protect" capacity resources located within their borders, the breakdown in PJM's capacity markets could increase the number of subsidized units that bid as other states perceive similar actions. As the IMM states, the price suppressive impacts associated with the FE/AEP PPAs will "make it difficult or impossible for generating units without subsidies to compete in the market."[9]

[8] *See* Complaint, Attachment A, Cavicchi Affidavit, P 8 ("Cavicchi Affidavit").
[9] Complaint, at 31 (quoting Bowring AEP Supplemental Testimony at 5; Bowring FE Testimony at 5).

The MOPR was established as part of the RPM construct to prevent "uneconomic entry" by new resources.[10] As the Complaint demonstrates, however, "because PJM's auction clearing mechanism does not distinguish between offers from new and existing resources, and simply clears such offers on a least cost basis, there is not practical difference between the price suppression that will result from below-cost offers for new resources and that which will result from below-cost offers for existing resources."[11] Thus the failure of the MOPR to address the FE/AEP PPAs renders the current PJM mitigation scheme unjust and unreasonable. As relief, the Complaint calls for MOPR modifications that would be sufficiently broad to encompass the PPA units to be placed into effect for the upcoming BRA. The Complaint also proposes methodologies for calculating acceptable floor prices that take account of risks and opportunities associated with the Capacity Performance construct as well as take account of the levels of avoidable costs for the units. The Complaint acknowledges, however, that "permanent" changes to the MOPR should not be put into effect until a PJM stakeholder process has occurred.[12]

The PSEG Companies support the conclusion that the PJM Tariff, and in particular, the MOPR, is not just and reasonable under the Federal Power Act ("FPA") because it fails to mitigate the capacity market offers of the PPA units notwithstanding that FE/AEP have strong incentives to submit offers for the affected units below competitive levels. The PSEG Companies are concerned, however, that there is insufficient time to properly vet the changes proposed by the Complainants to the MOPR before the upcoming 2019-2020 BRA. While the PPAs do pose an "imminent threat" to

[10] *See* Complaint, at 13 (quoting April 2011 Order, 117 FERC ¶ 61,022, P 124).
[11] Complaint, at 24.
[12] *Id.*, at 37.

the upcoming BRA as the Complainants maintain, a simpler and more appropriate solution would be to only mitigate bids from the units covered by the PPAs without attempting to make changes to the language of the MOPR before a broad stakeholder review takes place. The PSEG Companies believe that changes to the MOPR should only be made following the conclusion of a stakeholder process at PJM, or at the minimum, following a more robust review process at the Commission. Neither of these options can be feasibly attempted during the limited time available before the next BRA. In addition, the mitigation methodologies proposed by the Complainants are complex, especially in light of the challenging time constraints. The PSEG Companies submit that, by limiting mitigation just to the units covered by the AEP/FE PPAs, much simpler mitigation methodologies could be employed that would satisfy the basic needs of the upcoming BRA and thus support a competitive outcome.

II. COMMENTS

A. The Complaint Clearly Demonstrates that the Current PJM Tariff is Not Just and Reasonable Because it Fails to Mitigate the PPA Units

As shown in the Complaint and discussed *supra*, the need for the MOPR is predicated upon concerns associated with artificial price suppression due to "uneconomic entry." As also shown *supra*, the detrimental, non-competitive impacts associated with the FE/AEP PPAs are indistinguishable from the harms that the MOPR was designed to forestall. The PPA units will lack incentives to bid competitively and in fact they have exactly contrary incentives to bid in such a manner that they are assured of clearing the auction.[13] As also demonstrated *supra*, the expected impacts on the capacity markets

[13] The PSEG Companies do note that when the complaint was filed, it appeared that the units would also be insulated from penalties associated with PJM's Capacity Performance mechanism. In the final orders, it does appear that the PUCO did shift that risk to the units but also allowed the units to receive the benefit of

appear to be extremely significant – in the range of 990 million dollars in recoveries below the competitive levels for the upcoming BRA.[14] The long-term impacts, moreover, could be even more consequential if investors lose confidence in the PJM capacity markets. Given all these presentations, it must inexorably follow that the current PJM mitigation scheme as applied to the RPM construct is not just and reasonable.

B. The Commission Should Direct PJM to Mitigate the Capacity Offers Submitted by the PPA Units

It is black letter law that, under Section 206 of the FPA, the Commission is obligated to take corrective action when it determines that a rate is not just and reasonable. As stated in a recent Commission case, in instances in which an existing rate has been shown to be unjust and unreasonable, "the Commission would then have determined a just and reasonable replacement rate, whether by accepting [the complainant's] proposal, if supported by record evidence, or implementing its own solution."[15] The PSEG Companies respectfully submit that this is the situation faced by the Commission here. The Commission must therefore devise a remedy to prevent offers submitted by the PPA units from disrupting the upcoming BRA and to prevent the subsidy paradigm created by the PUCO from undermining the entire PJM capacity market construct.

The Complaint calls for the Commission to direct PJM to modify the existing MOPR by adding language that would bring the PPAs within the scope of the

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any bonus payments. In general, however, the incentives to bid the units to clear the BRA remain intact for the reasons discussed in the text *supra*. Further, because the subsidies will enable the units to undertake capital upgrades to improve performance, the penalty risk associated with the Capacity Performance will be moderated.

[14] Complaint, at 27-28, 41.

[15] *New England Power Generators Ass'n v. ISO New England Inc.*, 153 FERC ¶ 61,222, P 35 (2015).

provision.[16] This response, however, is overly complex given the limited time available to address the problem prior to the upcoming BRA. A simpler approach that would be fully consistent with FERC's statutory authority is for the Commission to adopt a remedy of directly mitigating the PPA units at issue. While the Commission certainly may not act in an unduly discriminatory manner, FPA Section 206 does not require the Commission to act generically if it determines that the rates of specific companies may not be just and reasonable. The Commission, therefore, is not foreclosed from applying mitigation to particular identified units. In fact, there is ample precedent in support of unit-specific mitigation measures as applied to energy and capacity market bids.

Specifically, in *Southern California Edison Co on behalf of Mountainview Power Co., LLC*, 106 FERC ¶ 61,183, *on reh'g*, 109 FERC ¶ 61,086 (2004), the Commission required a specific generating unit that "could change market outcomes by bidding . . . below its costs" and that could benefit as a "net buyer in that market"[17] by depressing clearing prices, to submit energy offers at its marginal costs.[18] In *New York Independent System Operator, Inc.*, 131 FERC ¶ 61,169 (2010), the Commission approved mitigation procedures in NYISO for three specific generators that engaged in abusive market practices. Also, in *Consolidated Edison Company of New York, Inc. (ConEd)*, 96 FERC ¶ 61,095, 61,384 (2001), the Commission approved ConEd's filing, made pursuant to FPA Sections 205 and 206, seeking to expand mitigation of units located in New York City on a temporary basis where the Commission "agreed with ConEd's assertion that the in-City sellers may have market power when there are transmission and reliability

[16] Complaint, at 34-38.
[17] *Id.*, P 63.
[18] *Id.*, P 43.

constraints and supply outside of the constrained area cannot compete for the last increment of demand."[19]

There is no evidence of any "similarly situated" generating units that are recovering out-of-market payments through non-bypassable distribution surcharges other than the PPA units. Accordingly, the Commission is empowered to apply particular mitigation measures only to these units based on the finding that, if not mitigated, clearing prices in the upcoming BRA would be uncompetitive and, therefore, unjust and unreasonable. The generic MOPR language need not be changed at this time and, as a matter of policy, it would be more appropriate for a permanent MOPR change to occur only after the completion of a fulsome stakeholder process at PJM.

C. The Mitigation Methodologies Proposed by the Complainants Are Unnecessarily Complicated

The Complaint proposes two alternative methodologies for mitigation. For units with low levels of avoidable costs, the Complaint alleges that the offer floor should be "based on Net-CONE, which represents the opportunity costs of taking on a [capacity market supply obligation."[20] However, for units with higher levels of avoidable costs, "the level of net going forward costs is a key factor in the calculation [of] *sic* a competitive offer."[21] Moreover, "[i]n each of the two cases of competitive auction offer development described [in the Complaint], key inputs into the calculation are subject to uncertainty."[22] In sum, the methodologies suggested in the Complaint could be difficult and time consuming to administer.

[19] *Consolidated Edison Company of New York, Inc. (ConEd)*, 96 FERC ¶ 61,095, 61,384 (2001).
[20] Cavicchi Affidavit, P 59.
[21] *Id.*, P 60.
[22] *Id.*, P 61.

The PSEG Companies believe that the suggested approaches may work, but offer that the PPA units could be effectively mitigated through simpler methodologies. One approach would be to adopt a set of price floors for the PPA units based upon the previous year's bids which, in fact, occurred only last August. Thus, the mitigated offer amounts could be determined by taking the bids submitted by the units in the previous year (prior to the PPA approvals) and adjusting the previous year's bids for changes in energy market revenues. This could be done through a mechanical process. For example, assume that Unit A with 100 MWs of installed capacity bid at $150 MW-Day in the last BRA. The energy market component of the $150 MW-day bid could be calculated based on energy market revenues received by Unit A in the three years immediately prior to the last BRA at, say, $25 MW-day. The same energy market calculation could then be performed based on the three years prior to the upcoming BRA resulting in, say, $20 MW-Day in energy market revenues. Because the energy revenues decreased by $5 MW-day in this example, the previous year's capacity market bid of $150 MW-day would need to be increased by $5 MW-day, resulting in a mitigated bid floor of $155 MW-day.

Another approach would be to base the bids for the PPA units upon their submittal of projected costs to the PUCO in support of their filing for the PPAs. The detailed data contained in the FE/AEP submittals was confidential and not reviewed by the PSEG Companies. It appears, however, that FE and AEP did conduct projections of the units' operating costs and that they provided this data to PUCO staff. If the IMM were provided this information, it should be possible either to determine a necessary level of capacity market revenues directly from the submittals or, if only total costs are known,

to determine the necessary level of capacity market revenues by backing out an historical average of energy market revenues.

In conclusion, the PSEG Companies support Complainants' assertion that the current PJM Tariff is not just and reasonable in regards to its MOPR provision because it fails to deal with the threats posed by subsidized existing resources. We contend that the Commission should take immediate action to directly address the PPA units and thereby ensure just and reasonable rates in the upcoming BRA. We believe that defining the application of an appropriate MOPR should be achieved through a more robust process of review such as a PJM stakeholder review process or, at a minimum, a technical conference at the Commission. We therefore respectfully request that the Commission direct PJM to initiate a stakeholder process to address these rules with a compliance filing required by the end of 2016 or convene a technical conference. Finally, we recognize the difficulty of implementing the appropriate mitigation levels on these arrangements, and alternatively offer two approaches that utilize previously provided data (from the companies, themselves) as potential approaches to establishing an appropriate bid price for units participating in the markets under the aforementioned PPAs.

III. COMMUNICATIONS

The PSEG Companies request that all pleadings, correspondence and other communications concerning this docket be directed to the following persons:

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IV. MOTION TO INTERVENE

PSE&G, as an owner of transmission assets in PJM, PSEG Power as an owner and operator of generation assets in PJM, and PSEG ER&T, as a market participant, each has a substantial interest in this proceeding. No other party can adequately represent these interests. Good cause thus exists for this motion, and the PSEG Companies respectfully request that the Commission grant their motion to intervene.

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V. CONCLUSION

WHEREFORE, the PSEG Companies respectfully request that the Commission grant the relief requested hereinabove.

Respectfully submitted,

Public Service Electric and Gas Company
PSEG Power LLC
PSEG Energy Resources & Trade LLC

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Dated: April 11, 2016
Newark, New Jersey

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Newark, New Jersey, this 11th day of April, 2016.

James E. Wrynn

James E. Wrynn
Paralegal

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.	)))	Docket No. AD17-11-000

Pre-Technical Conference Comments of Lathrop Craig on Behalf of The PSEG Companies

I. Executive Summary

The PSEG Companies[1] appreciate the opportunity to express our views regarding the pressing need for the wholesale markets in the Northeast to evolve in ways that will incorporate legitimate state public policy objectives. The industry is faced with a significant challenge – the need to bridge the disconnect between market structures designed to provide electricity at the lowest cost – with the actions by states to foster particular state policy goals. Legitimate state public policy objectives such as environmental attributes and system resiliency are not being valued by the markets at this time.

A clear example of this disconnect is the efforts of certain states to fill in the gaps in the wholesale market design by taking steps to preserve the nuclear assets that support the achievement of state policies. Nuclear plants are being financially challenged by current and expected market conditions. Unless the wholesale markets evolve to ascribe value to environmental attributes and system resiliency, nuclear plants will retire prematurely. While the PSEG Companies support the Commission's willingness to discuss approaches for internalizing state public policy goals into market design, it must be acknowledged that the states are in the forefront of addressing the issues facing nuclear generation. Accordingly, until this evolution in wholesale markets occurs, the Commission should not interfere with the operation of state programs to support nuclear power.

II. The Wholesale Energy Markets are Generally Working As Intended But Need to Evolve To Internalize State Public Policy Initiatives

The competitive markets in the Northeast have delivered benefits to customers and society as a whole in the close to two decades that they have been in existence. The choice by

[1] The PSEG Companies are PSEG Power LLC, PSEG Energy Resources & Trade LLC and Public Service Electric and Gas Company.

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some states to move from a vertically-integrated, cost-of-service business model to competitive markets for the electric generation sector was the key energy policy issue towards the end of the last century. In many ways, the markets have achieved their original objectives. Competition has flourished with overall lower costs to consumers, numerous new generation owners, new generating units, and new technologies entering all of the markets, some successfully, and some not. And when there have been failures by new entrants, the costs have been born by investors rather than customers, exactly as intended.

The RTO/ISO markets in the Northeast are designed to create market signals to incent both new build (market entry), and retirement (market exit) through energy and capacity prices. The PSEG Companies provide instructive examples of response to those signals. Specifically, we are currently investing $2B in construction of three new state-of-the-art combined cycle units in the PJM and New England markets. These units will take advantage of historically low natural gas prices to provide economic energy and a combination of flexible operating characteristics and back up fuel sources, providing enhanced reliability to meet the new Capacity Performance capacity ("CP") market and Pay for Performance constructs. We are also in the process of retiring 1,200 MW of 1960's vintage sub-critical coal plants in New Jersey because they have become uneconomic and too inflexible to reliably meet market needs under CP.

Notwithstanding the success of the current market design in facilitating efficient entry and exit of resources, it is also subject to its inherent limitations. The current design of the energy market only incorporates the direct costs of generating unit operations such as fuel, labor and maintenance costs. "External" costs such as environmental impacts associated with operating units that emit carbon or impacts associated with the loss of fuel diversity exposing consumers to greater losses due to low probability, high impact events, are not addressed.[2] The omission of market structures to internalize these types of externalities is the largest driver of state public policy initiatives that seek to change the energy supply mix away from what the existing competitive markets are delivering in the way of entry and exit on their own.

PJM's wholesale markets are at a crossroads. The initial impetus for the creation of the markets was largely motivated by the desires of states to lower costs and to reduce risks to consumers – an effort that has been successful. Time has revealed, however, that the scope of this mission was too narrow. The PSEG Companies believe that, for markets to survive, they must be re-designed in ways that take into account other policy goals. The need for a broader scope is most dramatically presented with respect to the current risk to the PJM nuclear fleet.

[2] Note: Some "external" costs have been successfully internalized in energy markets over the past decades through cap and trade programs under the CSAPR, Acid Rain Program and RGGI, though these markets are for the most part all long allowances and send weak price signals.

III. Nuclear Generation Is Being Exposed to the Risk of Premature Retirement Due to The Lack of Market Structures That Properly Value Its Attributes

Nuclear units, in particular, are adversely impacted by the failure of market structures to value externalities with significant societal benefits. One valuable externality associated with nuclear generation in the PJM footprint relates to the environment. Numerous states in the Northeast (and elsewhere) have taken or are contemplating measures to ensure that a portion of their state's energy supply comes from "clean" resources. This has resulted in significant support payments to solar, wind, energy efficiency and certain demand response resources. States such as New York and Illinois have recognized that nuclear generation has an indispensable role in meeting these same environmental goals and have recently taken steps to ensure that nuclear generators stay in the market, to generate clean energy.

A second valuable externality associated with nuclear generation in the PJM footprint concerns fuel diversity. The PJM market currently enjoys a diverse, fuel-secure, dispatchable, non-intermittent and well-engineered fleet of generating units. These resources were inherited in large part from the previous vertically integrated system. Nuclear generation is a vital component of this beneficial resource mix. Since the initial formation of the RTO/ISO markets, the primary shift in generation in the Northeast markets has been from coal and oil to natural gas and renewables. Recently, nuclear has also become challenged and is increasingly at risk of exiting as well. While initially these shifts have increased resource diversity, the current trend is moving toward a generation mix dominated almost entirely by gas and renewables. This trend is troubling because it leaves PJM in a situation in which it would be relying disproportionally upon a single fuel source that is susceptible to single contingency failure. In response, some state policy makers have entertained supporting coal and nuclear units out of concern for what they perceive as a need to retain a resilient and fuel-diverse generation portfolio.

IV. State Public Policy Goals Could Be Integrated Into Market Design Structures

Both of these concerns – environmental impacts and system resiliency – are valid and worthy policy goals. As the Supreme Court indicated in the *Hughes* case, it is appropriate for states to take actions that support the public good by promoting clean technologies in a manner that does not displace the wholesale market price. The pursuit of policies in support of grid resiliency associated with fuel and technology diversity would also be appropriate. As noted in the recently drafted PJM whitepaper, "PJM must take account of the possibility of larger-scale disruptions of the natural gas supply system."[3] Because of the efficiencies that can be realized

[3] "PJM's Evolving Resource Mice and System Diversity" PJM Interconnection, dated March 30, 2017 at 35, available at: http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

through competition, our preferred approach to addressing state public policy goals is through a market-based solution and we are eager to participate in discussions to that end. There is an array of possible choices for how markets could be re-designed to achieve these public policy goals.

First, the value of clean, non-emitting energy can be reflected in energy market pricing by establishing and reflecting the cost of those attributes on resources that emit. If the value is set correctly, it will incent new entry and the retention of non-emitting or low emitting resources in an economically efficient manner. It is also possible to implement "border adjustments" to limit the impact of these policies to states or regions that have those goals and insulate states or regions that do not. Second, the value of fuel or generating technology diversity can be reflected in capacity markets through additional constraints, conceptually similar to the base capacity constraint that PJM used in the CP auctions leading up to the 2020/2021 auction. The costs of these constraints can be allocated to customers in states that agree to them, protecting customers in states that do not share those views or goals.

V. Until the Policy Goals Are Integrated Into Market Structures States Should be Allowed to Take Steps to Recognize These Attributes Without Interference

We recognize the challenges with getting stakeholders to agree on a solution that could be applied regionally and we recognize that this process will take time. In the interim, the Commission must not stand in the way of the ability of the states to take measures that preserve the nuclear fleet. If immediate steps are not taken, these resources may be forced to retire.

It is appropriate for resources which receive state support for valid public policy goals to participate in the capacity auctions without mitigation. They bid at their avoided costs, net of the support payments. The impact of this design would be to lower prices and incent market exit for some number of resources that otherwise would have been economic to stay in the market (but for the support payments received by the selected resources). Because the payment scheme is intended to support the achievement of policy goals not internalized in the markets, this should be viewed as a reasonable and necessary consequence.

PJM is currently exploring with its stakeholders potential structures to appropriately value all resources while the market design still does not internalize the achievement of state public policy goals. PJM's first priority should be to develop market design changes that will fully incorporate valid policy goals (such as environmental and fuel diversity/resiliency) into the energy and capacity markets. However, if as an interim measure PJM does seek to change market rules solely to address units that are receiving state support it is critical that these rules do not thwart the achievement of valid while at the same time ensuring competitive market outcomes.

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VI. Energy Price Formation Reforms Are Also Critical in Establishing the Right Price Signals

The competitive energy markets are currently being shaped by three primary driving forces: (1) the economics of plentiful and low-cost natural gas; (2) state public policy initiatives to shift generation supply to cleaner sources; and (3) the reality of essentially flat demand. The first two have led to a large influx of new supply, while the third suggests that none is really "needed."

This rapid and large decline in overall wholesale energy prices has exposed many inefficiencies in energy price formation. We support the Commission's leadership in recognizing these problems and in continuing to direct key reforms that will ensure the wholesale energy prices more accurately reflect the cost and value of serving load at all times. Getting energy prices right is key to ensuring that the correct price signals are sent to incent efficient investment and market exit decisions. We encourage FERC to press the RTOs/ISOs to implement reforms without delay. While this is not a complete solution to the achievement of the issues facing nuclear generation, improvements in price formation would help.

VII. Where Do We Go From Here?

The PSEG Companies believe that it is incumbent on the Commission to lead the way in seeking the most cost effective means to integrate state public policy goals into the wholesale market design. It is entirely possible, and desirable, to capture the externalities that state policy makers value in the market construct. This can be achieved by reflecting the costs of negative attributes like emissions in unit dispatch (potentially complimented with border adjustments) and allowing policy makers to establish diversity or resiliency goals that can then be implemented through centralized capacity market procurements. However, we caution the Commission to be wary of any potential solution that result in an over procurement of resources.

We understand that it will take a significant amount of time to develop and implement a market-based mechanism that internalizes legitimate state public policy objectives. While this process is underway, we believe that FERC should not interfere with the rights of the states to pursue valid policy objectives such as encouraging clean energy production and the resiliency of the electric grid.

Finally, we appreciate the Commission's efforts in pushing the RTOs/ISOs to implement a number of important energy price formation reforms and respectfully request that FERC continue to encourage the RTOs/ISOs to implement them without delay. We further request that the Commission remain engaged and monitor and evaluate the RTOs/ISOs progress to ensure that the value of these reforms are actually reflected in market pricing.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket No. ER18-1314-000 ER18-1314-001

PROTEST AND MOTION TO REJECT OF THE PSEG COMPANIES

Pursuant to Rules 211 and 212 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or the "Commission"),[1] PSEG Companies[2] submit this protest and motion to reject PJM Interconnection L.L.C.'s ("PJM") proposed revisions to the Reliability Pricing Model ("RPM") rules in the above-referenced proceeding.[3] The PSEG Companies believe that the PJM Capacity Filing should be rejected because it is fundamentally flawed. Specifically, the PJM Capacity Filing is procedurally defective because it fails to satisfy the requirements of Section 205 of the Federal Power Act ("FPA")[4] and impermissibly blurs the distinction between Sections 205 and 206 of the FPA in contravention of a recent decision by the Court of Appeals for the District of Columbia ("D.C. Circuit").[5] Therefore, the PSEG Companies recommend that the current just and reasonable RPM construct continue in its current

[1] 18 C.F.R. §§ 385.211 and 385.212.

[2] The PSEG Companies include: Public Service Electric and Gas Company, PSEG Power LLC and PSEG Energy Resources & Trade LLC.

[3] PJM Interconnection, L.L.C., Docket Nos. ER18-1314-000, *et al.,* Capacity Repricing or in the Alternative MOPR-Ex Proposal: PJM Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market ("PJM Capacity Filing").

[4] 16 U.S.C. § 824d.

[5] *NRG Power Marketing, LLC v. FERC*, 862 F.3d 108, 117 (2017) ("*NRG"*).

form.

However, if the Commission does not reject the PJM Capacity Filing on procedural grounds and decides to consider the merits of the two proposals, the PSEG Companies contend that the Commission can only accept the first alternative – the Capacity Repricing Proposal. The second alternative – MOPR-Ex – with its varied application criteria is facially discriminatory and therefore cannot be deemed just and reasonable. In contrast, the Capacity Repricing Proposal represents the only permissible alternative market design that attempts to: (1) accommodate state public policy goals; (2) achieve competitive market outcomes; and (3) acknowledge the existence of units that are part of the established market in a manner that the Commission could deem just and reasonable.

Finally, if the Commission determines that neither approach is just and reasonable under Section 205 and decides to institute a Section 206 proceeding, the PSEG Companies respectfully request that the Commission direct PJM to work with stakeholders to implement an approach that achieves public policy goals within the wholesale markets.

I. INTRODUCTION

PJM explains that, "[a]s the Commission, States, PJM, stakeholders, and other capacity market administrators have grappled with this issue over the past two years, two alternative paths have emerged for protecting wholesale capacity markets from the price suppressive effects of growing state subsidy programs: accommodate or mitigate."[6] PJM's inability to address the intersection between the achievement of state public policy goals and the wholesale market has

[6] PJM Capacity Filing, at 42. It is noted that the Commission identified other potential approaches during the technical conference covering the integration of public policy initiatives into the wholesale markets. *See State Policies and Wholesale Markets Operated by ISO New England, Inc., New York Independent System Operator Inc., and PJM Interconnection, L.L.C.*, Docket No. AD17-11-000, Notice Inviting Post-technical Conference Comments (issued May 23, 2017).

led to the instant filing. Rather than deciding for itself how this issue should be addressed, PJM requests that the Commission make a policy determination, namely, "[s]hould the state-subsidized resources be given a real opportunity to be committed as capacity in the wholesale market notwithstanding its subsidized offer."[7] To effectuate its request to obtain a policy directive from the Commission, PJM asks the Commission to consider and ultimately choose one of two mutually exclusive paths to modify the RPM rules.

One proposed path contemplates a two-settlement auction mechanism ("Capacity Repricing") and is PJM's preferred approach.[8] Under this approach, PJM would clear the capacity auction in two stages. In the first stage, PJM will use the bids from all resources (including units receiving state support payments) and clear the resources that are required to meet the reliability requirement. The resources that clear in this stage will be given a capacity obligation. In the second stage, PJM will substitute reference prices for all resources receiving state support payments (driving some out of the clearing price range) and determine the competitive clearing price. All resources that received a capacity obligation in the first stage would be paid the clearing price from the second stage. Some units can be expected to clear in the second (pricing) auction that did not receive a capacity obligation in the first (commitment) auction (these units are referred to as "in-between units").

According to PJM, this "path makes it more likely that the subsidized resource will clear and receive a capacity commitment," however, it "would not permit the subsidized offer to factor into formation of the clearing price and thereby suppress the clearing price."[9] PJM contends that

[7] PJM Capacity Filing, at 42.

[8] *Id.* at 46.

[9] *Id.* at 42-43.

this path results in "respecting and accommodating state policy choices while ensuring the market signals a competitive price."[10]

The alternative path contained in the PJM Capacity Filing was developed by the PJM Market Monitor and modified throughout the stakeholder process. This path seeks to extend the existing Minimum Offer Price Rule ("MOPR") to certain unit types and to certain existing units that are receiving support payments from states ("MOPR-Ex") in order to achieve public policy goals.[11] MOPR-Ex also readopts the substance of the competitive entry exemption that was in place from 2013 to 2017 and the self-supply exemption that was in place from 2013 through 2017.[12] Moreover, MOPR-Ex adopts a new categorical exemption for public power entities and employs relaxed tests for qualifying for the exemptions. MOPR-Ex further excludes (grandfathers) existing renewable resources and offers defined exclusions for future renewable resources.[13] Finally MOPR-Ex does not apply to Demand Resources.[14] PJM claims that this path "mitigates the harm state policy choices have in suppressing capacity market prices."[15] According to PJM, it accomplished this by "preventing the subsidized offer from being submitted at a price below a competitive offer price in the first place."[16]

PJM emphasizes that there is a critical difference between the two paths: the Capacity Repricing Proposal "honors the state's legitimate policy choice to promote resources with certain

[10] *Id.* at 46.

[11] *Id.* at 52.

[12] *Id.*

[13] *Id.*

[14] *Id.* at 53.

[15] *Id.* at 53.

[16] *Id.* at 54.

attributes not otherwise valued in the current wholesale market rules; MOPR-Ex does not."[17] PJM states explicitly that the Capacity Repricing Proposal is its preferred approach and requests that the Commission find that it is just and reasonable under Section 205. PJM further requests that if the Commission cannot accept the Capacity Repricing Proposal, even subject to suspension and further proceedings, that it accept the MOPR-Ex approach as just and reasonable.[18]

II. PROTEST AND MOTION TO REJECT

A. The PJM Capacity Filing Should Be Rejected as Procedurally Defective

As noted above, PJM submitted two alternative, competing and mutually exclusive proposals to modify the current RPM rules under Section 205 of the FPA. As a consequence, in order for the Commission to act on PJM's filing, it is asked to sort through PJM's alternative proposals, accept one and reject the other, and ultimately impose the solution the Commission deems to be just and reasonable. In doing so, PJM has impermissibly blurred the fundamental distinctions and burdens between Sections 205 and 206 of the FPA. Clearly sensitive to this flaw, PJM's filing preemptively attempts to justify its ability to utilize Section 205 rather than Section 206 as the procedural vehicle for asking the Commission to choose and impose a just and reasonable rate in its tariff. While this tactic is understandable given the different burdens that PJM would be required to demonstrate under each provision,[19] it has rendered the PJM Capacity Filing procedurally defective and therefore it must be rejected.

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[17] *Id.* at 54.

[18] *Id.* at 6.

[19] *See* 16 U.S.C. § 824d(e). Section 205, unlike Section 206, allows the Commission to approve rate increases without a showing that current rates are unjust and unreasonable; it need only find the *proposed* rates to be just and reasonable. *City of Winnfield v. FERC*, 744 F.2d 871 (D.C. Cir. 1984). In contrast, Section 206 requires a public

Section 205 requires that public utilities must file with the Commission "new schedules *stating plainly* the … changes to be made in the schedule … then in force … ."[20] When reviewing Section 205 filings, FERC, in turn, must ensure the rates "are just and reasonable" and do not "make or grant any undue preference or advantage … or subject any person to any undue prejudice or disadvantage."[21] Essentially, "[s]ection 205 puts FERC in a 'passive and reactive role.'"[22]

In submitting two alternative proposals, PJM has failed to meet the threshold requirement to "plainly" state the changes to be made to the rate schedule. Instead, PJM has proposed two possible and mutually exclusive approaches to reforming RPM, included a lengthy discussion of the deficiencies with each approach and asks the Commission to pick one and impose it. Section 205 simply does not contain any provisions that allow a public utility to submit two, three or more possible just and reasonable alternatives and then have the Commission select and impose one as though it were choosing one from a restaurant menu.

Even more problematic is the fact that the PJM Capacity Filing does not appear to be seeking a rate change, but is instead seeking policy direction from FERC to either accommodate or mitigate resources supported by state public policy initiatives. This is demonstrated by PJM's own words in which PJM states that the PJM Capacity Filing seeks "[t]he answer to a single question … [s]hould the state-subsidized resource be given a real opportunity to be committed as

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utility to demonstrate that the current rate is unjust, unreasonable, unduly discriminatory and preferential. Thus, in reviewing a Section 206 filing, FERC "is required to shoulder the 'dual burden' of finding the existing rate unjust and unreasonable and of 'find[ing] a just and reasonable rate' to replace it." *FirstEnergy*, 758 F.3d at 353 (citing *Md. PSC v. FERC*, 632 F.3d 1283, 1285 n. 1 (D.C. Cir. 2011)).

[20] 16 U.S.C. § 824d(d) (emphasis added).

[21] *FirstEnergy Serv. Co. v. FERC*, 758 F.3d 346, 348 (D.C. Cir. 2014) (citing 16 U.S.C. § 824d(a), (b)).

[22] *NRG* at 11 (citing *Advanced Energy Management Alliance v. FERC*, No. 16-1234 (D.C. Cir. June 20, 2017).

capacity in the wholesale market notwithstanding its subsidized offer?"[23] Clearly PJM's request removes the Commission from an essentially passive and reactive role envisioned by Section 205 into the realm of asking the Commission to take affirmative action and "fix" the tariff under Section 206.

Moreover, the PJM Capacity Filing will place the Commission in an untenable position of violating Section 205 if it accedes to PJM's request. As explained by the D.C. Circuit, "[s]ection 205 does not allow FERC to make modifications to a proposal that transform the proposal into an entirely new rate of FERC's own making."[24] The D.C. Circuit in *NRG* made clear that "FERC has some authority to propose modifications to a utility's proposal if the utility consents to the modifications;" however, "FERC may not unilaterally impose a new rate scheme under Section 205."[25] The Court further explained that, "although 'minor deviations' from a proposal are permissible, 'the imposition by the Commission of only half of a proposed rate' is not permissible."[26] Applying the principles described in *NRG*, the Commission would violate Section 205 if it accepted either of the proposed paths contained in the PJM Capacity Filing because, by definition, it would be imposing only one half of PJM's filing. In light of the substantial legal infirmities in PJM's filing, it should be rejected in its entirety.

B. If the Commission Deems It Necessary to Make Changes to the Current RPM Construct, It Must Accept the Capacity Repricing Proposal as the Only Viable Option

[23] PJM Capacity Filing, at 42.

[24] *NRG* at 3.

[25] *Id.* at 12.

[26] *NRG* at 13 (citing *Western Resources, Inc. v. FERC*, 9 F.3d 1568 (D.C. Cir. 1993).

The PSEG Companies have supported the markets, to date, because of the benefits that competition has brought in lowering prices, increasing innovation and protecting ratepayers. More efficient dispatch of the generating fleet has created billions in savings for customers. In addition, market forces have driven investment in new, more efficient generating resources and the retirement of older less efficient generating plants. In these respects, the current RPM model is functioning as intended.

However, the PSEG Companies agree with PJM that the limited focus of the current market construct is no longer sufficient. The markets must adapt quickly to accommodate state actions designed to advance widely-accepted public policy goals such as reduction of environmental emissions and resiliency. Failure to do so will lead to less efficient solutions, other unintended consequences and an overall weaker electric grid.

If the Commission determines that the PJM Capacity Filing meets the requirements of Section 205, the PSEG Companies request that the Commission accept the Capacity Repricing Proposal and reject MOPR-Ex. While we believe that the Capacity Repricing Proposal may not be an optimal solution, we do believe that an "accommodative" approach would be a better option than a "mitigate" approach. The accommodate path would satisfy the goal of not creating obstacles that would interfere with the efforts of the states to achieve their desired objectives. Moreover, the advantages of the Capacity Repricing Proposal are that: (1) it would allow resources receiving support payments to receive capacity obligations on payments at the same level as other resources thereby ensuring customers do not "overpay" for policy objectives; (2) it ensures that more resources would not be committed than needed to meet demand; and (3) it attempts to achieve a "competitive" capacity price.

We believe that it is imperative that the Commission avoid thwarting the efforts of the states to address carbon abatement and fuel diversity by supporting nuclear generation or other types of generation associated with achieving these goals. Under the Capacity Repricing Proposal, nuclear plants receiving state support payments to achieve their goals would qualify as capacity resources in the first "commitment" auction. Although nuclear units (and any other generators receiving support payments) committed in the first auction would be mitigated in the second "pricing" auction, they would still receive the competitive price realized in that auction regardless of whether they clear. Further, PJM would avoid over-procurement by not assigning a capacity commitment to resources that cleared only in the pricing auction.

PJM's alternative proposal – MOPR-Ex – is significantly flawed and should not be considered a viable option. Under the MOPR-Ex approach, PJM proposes to extend the current MOPR to cover some existing resources that may receive material state subsidies.[27] PJM states that this approach is "mitigative in nature" because it "alters sellers' subsidized offer prices before PJM runs the auction and assigns capacity commitments."[28] However, the application of MOPR-Ex is varied due to numerous exemptions. As a result, certain similarly-situated resources are treated differently even though they are providing the same service and achieving the same state public policy objectives. This flaw renders MOPR-Ex unduly discriminatory and preferential in violation of Section 205(b) of the FPA. Section 205(b) requires that a utility's rules be non-discriminatory and non-preferential as well as just and reasonable.[29] It further

[27] PJM Capacity Filing, at 96.

[28] *Id.* at 96-97.

[29] *See, e.g., Elec. Consumers Res. Council v. FERC,* 747 F.2d 1511, 1515 (D.C. Cir. 1984) (citing 16 U.S.C. § 824d(b)).

prohibits rules that give one group of market participants a preference over another group without an adequate justification.[30]

Here, PJM explains that "whereas MOPR has long applied to new resources regardless of whether any subsidy is received, MOPR-Ex would explicitly target *only* those resources receiving a Material Subsidy and that qualifies as a Capacity Resource with Actionable Subsidy."[31] At the same time, MOPR-Ex contains the self-supply exemption and the competitive entry exemption as well as two categorical exemptions: (1) the Public Entity Exemption for public power entities and electric cooperatives; and (2) the RPS Exemption for resources that receive out-of-market support as part of a state-sponsored renewable portfolio standard. Notably, PJM has flagged the fact that the RPS Exemption in particular may be unduly discriminatory.[32] It is undisputed that MOPR-Ex treats certain clean resources differently depending on whether it receives state support as part of a state-sponsored renewable portfolio standard or if the state support is considered an "Actionable Subsidy." Given that both sets of resources achieve the same public policy goals – carbon abatement – it is facially discriminatory to apply MOPR-Ex to one class while exempting the other class and therefore, MOPR-Ex should be rejected. Moreover, under *NRG*, the Commission cannot "fix" this defect, as PJM requests, by simply eliminating the RPS Exemption provision since such action could not be considered a minor modification.

MOPR-Ex is even unduly discriminatory within the exemptions themselves. MOPR-Ex exempts renewable resources constructed prior to the new MOPR construct becoming effective.

[30] *See id.*

[31] PJM Capacity Filing, at 98.

[32] *Id.* at 114.

Again, however, there is not any valid distinction between the "new" and "old" resources based on their function or their impact on market outcomes. This is a clear example of undue discrimination. Indeed, the Commission rejected a similar attempt to introduce an unduly discriminatory element into a MOPR mechanism when RPM was first adopted. In *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006), the Commission rejected a provision designed to award favorable avoidable cost treatment to coal units constructed prior to an arbitrary cutoff date of 1957.[33] Instead, the Commission required PJM to adopt a non-discriminatory eligibility mechanism related to the purpose of the disparate treatment.[34]

A final flaw with the MOPR-Ex proposal also was highlighted by PJM. The proposal will likely have the effect of mitigating existing resources from the auction clear. To clear the capacity market, another resource(s) will be committed. By ignoring existing resources in the capacity clearing process, the construct will perpetuate an oversupply in the markets – moving the distortion from the capacity market into energy market results through suppressed energy prices. It is imperative that energy markets provide the proper price signal to drive the efficient resource mix, and the MOPR-Ex proposal would increase the reliance on capacity markets, relative to energy, skewing the results in unknown ways.

Finally, while the PSEG Companies prefer the Capacity Repricing Proposal over MOPR-Ex, we do not believe that it fully addresses the failure of the current market designs to value important generator attributes, particularly, the achievement of environmental goals and ensuring energy resilience. We therefore believe that an approach that "achieves" state public policy goals, such as carbon abatement and fuel diversity, within the wholesale electricity market

[33] *PJM Interconnection, L.L.C.,* 117 FERC ¶ 61,331, P 108 (2006).

[34] *Id.*

structure is the correct approach. This could include measures such as carbon pricing in energy markets and enhanced ISO/RTO payments made directly to generating plants needed to meet fuel diversity standards adopted for the region. We respectfully request that, in the event the Commission institutes a Section 206, it directs PJM to develop an approach that achieves the widely-accepted public policy goals within the wholesale market designs.

III. CONCLUSION

WHEREFORE, the PSEG Companies respectfully request that the Commission reject the PJM Capacity Filing on the grounds that it fails to meet the requirements of Section 205. If the Commission finds that PJM has met the Section 205 requirements, we respectfully request that the Commission accept the Capacity Repricing Proposal. Finally, if the Commission institutes a Section 206, the PSEG Companies respectfully request that the Commission direct PJM to work with stakeholders to develop a solution that "achieves" widely-accepted public policy goals within the wholesale market structure.

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Respectfully submitted,

Public Service Electric and Gas Company
PSEG Power LLC
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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon the official service list in accordance with the requirement of Rule 2010 of the Commission's Rules of Practice.

Dated at Newark, New Jersey, this 7th day of May, 2018.

/s/ Cara J. Lewis

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Resilience in Regional Transmission Organizations and Independent System Operators	))))	Docket No. AD18-7-000

MOTION TO INTERVENE AND REPLY COMMENTS OF THE PSEG COMPANIES

Pursuant to Rules 212 and 214 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") Rules of Practice and Procedure[1] and the "Order Extending Time for Comments"[2] issued on March 20, 2018 in the above-captioned proceeding, the PSEG Companies[3] respectfully submit these reply comments to certain comments filed on March 8, 2018 by Regional Transmission Owners ("RTOs") and Independent System Operators ("ISOs") in response to the Commission's "Order Terminating Rulemaking Proceedings, Initiating New Proceeding, and Establishing Additional Procedures," issued in this docket on January 8, 2018.[4] The PSEG Companies reply comments are focused on PJM Interconnection, L.L.C.'s ("PJM") filing which is the region in which their transmission system and the bulk of their generating fleet is located.

I. Executive Summary

[1] 18 C.F.R. §§ 385.212 and 385.214.
[2] *See* 162 FERC ¶ 61,256 (2018) ("Extension Order").
[3] The PSEG Companies are comprised of Public Service Electric and Gas Company ("PSE&G"), PSEG Power LLC ("PSEG Power") and PSEG Energy Resources & Trade LLC ("PSEG ER&T"). PSE&G, as an owner of transmission in PJM, PSEG Power, as an owner of generation assets in PJM, and PSEG ER&T, as a participant in the PJM electricity markets and a transmission customer within the PJM footprint, have each a substantial interest in this proceeding. No other party can represent these interests. Good cause thus exists for this motion, and the PSEG Companies respectfully request that the Commission grant their motion to intervene and consider their comments.
[4] *Grid Reliability and Resiliency Pricing; Grid Resilience in Regional Transmission Organizations and Independent System Operators*, Docket Nos. RM18-1-000 and AD18-7-000, 162 FERC ¶ 61,012 (2018) ("January 8th Order").

The Commission is faced with a constellation of issues related to the resiliency of the Bulk Electric System ("BES") which require immediate attention. The world is changing rapidly and the BES is no exception. The BES is more efficient than ever but also faces more threats. Additional complexity and interdependence create new risks that are difficult to evaluate. At the same time, the risk of deliberate attacks – both physical and cyber – is higher than ever. Further, due to global warming, the frequency and intensity of extreme weather events is also growing. Cost-benefit analysis of most of these threats will be dubious at best. Moreover, because of the greater complexity of the BES and the likelihood of unpredictable feedback loops, there is the potential for system disruptions on a scale never seen before. It is therefore incumbent upon the Commission to take a leadership role in addressing these issues. The decisions the Commission makes now could have repercussions for many decades into the future.

The PSEG Companies believe that PJM has proposed an overly narrow definition of resiliency which fails to adequately capture the need to address low probability, high impact events that may affect the BES. PJM correctly recognizes that many events affecting BES resiliency "are not amendable to quantitative, probability-based analyses" and that the "impacts of high-impact, low-frequency events . . . are difficult to quantify."[5] Yet, PJM then assumes that it will be possible to determine "the cost efficiency of addressing the vulnerability or threat"[6] or the "incremental value"[7] of a particular measure directed towards achieving resiliency. As a result, PJM's definition of resiliency can be expected to exclude valid resiliency measures, particularly resiliency measures to address the most difficult to predict disruptive events such as cyber attacks. The PSEG Companies thus propose an expanded version of the Commission's

[5] Comments and Responses of PJM Interconnection, L.L.C., Docket No. AD18-7-000, at 4-5 (filed March 9, 2018) ("PJM Comments").
[6] *Id*. at 5, n. 7.
[7] *Id.* at 16.

resiliency definition that better recognizes the unpredictable frequency and impacts of the kind of events the definition should encompass.

The PSEG Companies generally agree with the PJM Comments regarding many of the categories of high-impact, low-probability events that should be considered. However, the PSEG Companies also do not believe that PJM has accorded the proper degree of urgency towards certain of the resiliency threats the PJM system faces. Notably, PJM fails to acknowledge the urgent risk it faces due to loss of fuel diversity associated with the potential for retirement of its nuclear fleet. Excessive reliance on gas-fired generation will expose PJM customers to potential disruptions in "just in time" gas supplies. Extreme weather events that stressed fuel supply availability such as the 2014 Polar Vortex and the 2017/2018 Bomb Cyclone are one category of risks. Accident-related physical disruptions such as the April 2016 Texas Eastern pipeline explosion in western Pennsylvania that significantly reduced pipeline delivery capacity into New Jersey for months are another category of risks. Yet even more sinister is the potential for events *intended* to disrupt the pipeline system such as physical or cyber-attacks by terrorists or unfriendly nation states.

In addition, PJM's Comments fail to acknowledge the full scope of the national security issues that would be attendant upon the loss of the nuclear fleet. The loss of the nuclear fleet would not only expose critical military and civil defense facilities to potential electric supply disruptions but would also expose the our country to less obvious national security risks such as the weakening of our nuclear navy as well as a degradation of the ability of the country to address nuclear proliferation issues. The Commission should make clear that national security issues should be considered as part of a resiliency analysis and should provide guidance to PJM and the other RTOs/ISOs regarding how to address them.

Notwithstanding the immediacy and the seriousness of the risks it faces due to the loss of nuclear generation within its footprint, PJM fails to perceive a need for urgent action. Rather, PJM indicates an intention to "conduct analysis of the anticipated future availability of [generation] attributes"[8] when it should be taking definitive steps right now to preserve the fuel diversity that currently exists. The PJM nuclear fleet is an irreplaceable asset. If the PJM nuclear fleet is lost, it will be gone for good. The Commission should direct PJM to act quickly to address this problem.

Energy market design is also an urgent issue that needs to be addressed to sustain the resiliency of the BES. Fuel diversity is an inherent characteristic of a well-designed energy market because particular generation technologies will be the most efficient means to meet the requirement of particular load segments. The lack of efficient energy market pricing in PJM energy markets, however, disproportionately disadvantages base load generation such as nuclear plants and thus contributes to the economic challenges that they face. PJM has proposed a number of price formation reforms: improvements in operating reserves, better shortage pricing and pricing that reflects the units being dispatched. The PSEG Companies support PJM's efforts in these areas and support PJM's request that the Commission set a deadline for the submittal of filing. Setting a prompt deadline will prevent PJM's efforts from becoming bogged down in an unnecessarily prolonged stakeholder process.

PJM has also requested and should be granted the ability to suspend market operations entirely if necessary to address the impacts of low probability, high impact events. However, PJM should have the ability to take these steps only during true emergencies in order to address imminent loss of load. In addition, affected generators should be paid their full cost of service. Finally, to the extent that the Commission decides not to act or fails to act in a timely manner to

[8] PJM Comments, at 46.

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address resiliency issues, the Commission should not interfere with legitimate efforts of States to address them.

Reforms and improvements with respect to the resiliency of the transmission system are also needed. The current PJM Regional Transmission Expansion Plan ("RTEP") does not include explicit resiliency criteria in many areas and must be modified to do so. Extreme weather events, cyber and physical attacks, electromagnetic pulse events, earthquakes and geomagnetic disturbances as well as other threats place the system at risk and need to be recognized in the planning process. Projects to replace aging infrastructure deserve special mention. Replacement of aging facilities with new or more modern equipment that has more robust characteristics makes the transmission system more resilient to high impact, low probability events as well as providing enhanced predictive failure information.

The Commission should recognize that TOs and RTOs/ISOs have separate but related responsibilities in planning for resiliency which will require a high degree of coordination. RTOs/ISOs need to be forthcoming to TOs with respect to information possessed by RTOs/ISOs regarding threats and vulnerabilities. But because many of the projects to address resiliency can be expected to be on the lower voltage components of transmission, the ascendant role of the transmission owners as asset managers of their own systems needs to be recognized. Also, particular consideration needs to be given to the role of NERC which the PSEG Companies believe should be in the form of identifying and assessing system vulnerabilities but not creating standards.

The PSEG Companies agree with PJM's concern about the increase in frequency and magnitude of extreme weather events and the potential impact on the transmission system.

Further, operating in a coastal state, PSE&G faces especially heightened risks from extreme weather.

Superstorm Sandy in 2012 devastated New Jersey prompting improvements in transmission infrastructure to enhance the resilience of the system. It has become necessary to plan for weather events of greater magnitude than have been previously experienced.

Compliance with NERC CIP-014 and CIP-003 standards pose special challenges. Meeting NERC's requirements will require the identification of highly critical substation information and other critical information whose release could have adverse impacts on national security. Therefore, steps must be taken to assure that compliance with CIP-014 and CIP-003 requirements limits the availably of information appropriately. New processes at PJM and FERC will need to be developed to limit disclosure on a "need to know" basis.

II. Comments

a. PJM Has Proposed an Overly Narrow Definition for Resiliency

The Commission proposed a definition for resiliency and requested comments regarding its proposal. PJM filed comments that suggested certain revisions to the Commission's proposed definitions that the PSEG Companies believe are sound. While the PSEG Companies support the revisions proposed by PJM, additional revisions are still required.

The PSEG Companies submit that two basic concepts are missing from the definition as proposed by the Commission and as amended by PJM. First, the definition should recognize that measures to address resiliency should be directed to those events at the "high end" of potentially disruptive events, i.e., those that could impose significant human costs or cause a high degree of property loss. This will serve as a limit on the kinds of matters that would be addressed through resiliency efforts. While resiliency of the BES is critical, not all potential resiliency threats can

be addressed: accordingly, only the most impactful should be considered. The PSEG Companies thus recommend that "highly" be added to the definition prior to "events."

Second, the PSEG Companies believe that the definition should capture the concept that resiliency could include particular measures that enhance the robustness of the BES generally but are not necessarily directed to particular identified threats and vulnerabilities. Protecting or enhancing certain system attributes, such as robustness towards a common mode failure of a class of widely used technology, could provide justification (in whole or in part) for resiliency measures without reference to a known threat or vulnerability. Recognition of this concept in the definition would also be consistent with FPA section 215 which defines "reliable operation" as including operations that address the "unanticipated failure of system elements."[9]

Combining most of PJM's suggested changes and the changes recommended by the PSEG Companies would result in the following definition for resiliency:

> The ability to withstand or reduce the magnitude and/or duration of potential highly disruptive events, whether anticipated or unanticipated. Resiliency includes the capability to identify vulnerabilities and threats that could be highly disruptive, the capability to identify practices that will increase robustness against unanticipated vulnerabilities and threats that could be highly disruptive, and the capability to prepare for, mitigate, absorb, adapt to, and/or timely recover from a highly disruptive event.

The PSEG Companies submit that this definition would be superior to the original definition or to the definition proposed by PJM in its comments.

b. <u>Generation System Resiliency</u>

i. <u>The Approaches Described by PJM For Identifying Valid Resiliency Measures Are Unclear and Appear to Rely Upon The Unrealistic Expectation that Predictive Modeling Can Be Used to Evaluate Low-Probability, High-Impact Events</u>

The PJM Comments acknowledge sound basic principles regarding the nature of the low probability, high impact events that resiliency measure should protect against but, repeatedly,

[9] FPA, Section 215, 16 U.S.C. § 824(a)(4).

appear to back away from these principles in describing how valid measures should be identified. For example, PJM states:

> The challenge [of deciding on resiliency measures] lies in the nature of high-impact, low-frequency events, because they are not amenable to quantitative, probability based analyses commonly used for risk management due to the difficulty of predicting the timing and impact of their occurrence. Probabilities of high-impact, low frequency events are generally unknown or extremely difficult to quantify, and the consequences or impacts of high-impact, low-frequency events - although assumed to be intolerably high in terms of both human and economic costs - are difficult to quantify.[10]

Elsewhere PJM makes similar comments:

> Generally, the primary challenge to assessing the impact of a high-impact, low-frequency event is that it is impossible to anticipate or account for every situation. Moreover, evaluating high-impact, low-frequency events is uniquely difficult for events for which there is very little data available due to the infrequent occurrence of events of such magnitude. As a result, it is impossible to develop precise quantitative metrics for the measurement of resilience risks.[11]

The PSEG Companies largely agree with these comments. Outside of weather events for which models and history provide *some* predictive value for high impact, low-probability events, we would be deceiving ourselves to contend that it is possible to determine the likelihood that a high impact, low probability event will occur or, even more importantly, the potential impact of such an event with any degree of certitude. This proposition should be a bedrock tenant in guiding decisions regarding resiliency.[12]

But, elsewhere in its comments, PJM seems to retreat from those principles. For example, PJM speaks of balancing "the cost to [make an improvement directed to resiliency

[10] *Id.* at 4 (footnote omitted).
[11] *Id*. at 31.
[12] It is clear as matter of law that under the FPA a cost-benefit is not needed in order for a rate to be valid. The Commission is not required to "engage in painstaking cost benefit analysis" when setting rates. *Process Gas Consumers Group v. FERC,* 866 F.2d 470, 477 (D.C. Cir. 1989). When evaluating the justness and reasonableness of a rate, the Commission must only conduct a "candid, common-sense assessment," *Process Gas,* 866 F.2d at 477, which can include the "consider[ation of] non-cost factors." *Pub. Utils. Comm'n of Cal. v. FERC,* 367 F.3d 925, 929 (D.C. Cir. 2004) (citing *Permian Basin Area Rate Cases,* 390 U.S. 747, 791 (1968)). These include the critically important benefit of reliable power. *See, e.g., NAACP v. FPC,* 425 U.S. 662, 670 (1976) (FERC must "promote the orderly production of plentiful supplies of electric energy ... at just and reasonable rates").

versus] . . . the incremental value that may be achieved in making such improvements for a contingency that will rarely, if ever, occur."[13] Also, after describing how evaluating high impact, low-probability events is "uniquely difficult" and that "it is impossible to develop precise quantitative metrics" to measure such risks, PJM's answer in response to these difficulties is to "use[] information from external events to address the probability and impact of it occurring within PJM's footprint"[14] Moreover, in what may be the most troubling refutation of its own principles, PJM apparently contemplates that a transmission owner could undertake system improvements based on "Commission . . . intelligence and metrics [resulting in] resilience vulnerability and threat analyses that can then guide and anchor subsequent RTO planning, market design, and/or operations directives" and subsequently be subject to prudence challenges for making those improvements "in a rate proceeding or otherwise as to the cost effectiveness of addressing the vulnerability or threat."

The Commission must be mindful of the nature of the threats we are facing. As a result of advances in computer technology and the internet, the BES is far more interdependent and complex than ever before. In addition, the efficiency gains that have been won, while saving money for consumers, have also wrung out much of the inherent redundancy that at one time resided in the system. In addition, even weather events have become more intense than our past experience. In this context, it is critical that the Commission understand that traditional cost benefit analyses of threats to central elements of the BES that could have widespread impacts or impacts on large population centers are not useful and cannot be relied upon in evaluating resiliency measures. To the extent that PJM's comments indicate PJM's intent to do otherwise, the Commission should made clear that such an approach would be improper.

[13] *Id.* at 16.
[14] *Id.* at 31.

ii. PJM's Comments Fail to Recognize the Urgency Associated with Maintaining the Fuel-Security and National Security Attributes of the Nuclear Generation Fleet Within Its Footprint

The PJM Comments acknowledge concerns about the interaction between the operation of the BES and the interstate pipeline system but never address the core concern of the potential premature retirement of fuel-secure resources which it is confronting right now. Thus, the PJM Comments identify the risk associated with the failure of "interdependent systems" related to BES operation, including interstate gas pipelines.[15] In this connection, PJM suggests that improvements could be made in communications between itself and certain interstate pipeline systems regarding conditions on the pipelines and requests the Commission to open a new docket to address is issue.[16] PJM also notes the risk of "specific vulnerabilities [including] common mode outages such as such as the loss of generation fed from common gas infrastructure . . . ."[17] PJM suggests here that "[m]ore work is needed in this area."[18] Finally, PJM asserts that "[g]eneration within PJM is both geographically and fuel diverse" but acknowledges that "[w]ith regard to the extent to which PJM considers whether specific challenges to resilience affect various technologies differently, PJM does not focus on particular fuel types . . . ."[19]

The PJM Comments simply ignore the elephant in the room. PJM is at risk of losing the fuel diversity of its fleet, in particular due to the potential loss of the nuclear generators within its footprint. This would expose the business and residents served by PJM to potentially devastating losses due to a common mode failure of the interstate gas pipeline system. Yet, its comments regarding gas infrastructure barely acknowledge this concern. Moreover, the PJM Comments fail to discuss entirely the particular national security contributions that the nuclear fleet makes

[15] *Id.* at 23.
[16] *Id*. at 26, 27.
[17] *Id.* at 36.
[18] *Id.*
[19] *Id*. at 67.

to the welfare of the nation. Finally, PJM does not acknowledge the resiliency to gas price fluctuations provided by the nuclear fleet within its footprint.

(iii) Fuel Diversity/Fuel Security Issues Associated with the Potential Loss of the PJM Nuclear Generating Fleet

The reality is that there have been announced retirements of 23 nuclear plants in the United States although in some cases the retirements have been averted due to state intervention.[20] A number of these plants are located in PJM including three nuclear plants – Davis-Besse and Perry in Ohio and Beaver Valley in Pennsylvania – whose deactivations were announced by FirstEnergy Solutions only last month. PSEG Power's Salem and Hope Creek plants also face the possibility of retirement. The risks faced by PJM if it becomes overly reliant on gas-fired generation, moreover, are quite clear. Indeed, they are potentially very large and, if they materialize, could place millions of customers at risk for a prolonged loss of electric power or, at least, an extended period of rolling blackouts.

A recent illustration of the importance of a fuel-diverse generation fleet that is not overly-reliant on gas-fired generation was the "Bomb Cyclone" event that occurred at the end of December 2017 into early January 2018. From December 27, 2017, through January 8, 2018, the eastern portion of the United States experienced extremely cold temperatures and high electric demand. During this time, nuclear generation performed extremely well while there were disproportionally high outage levels experienced by gas-fired generators.[21] Moreover, the

[20] *See Keeping the Lights on at America's Nuclear Plants*, Jeremy Carl and David Fedor, Hoover Institution Press, 2017, Appendix B: Recent Nuclear Plant Closures (this accounts for 20 of the plants). As noted in the accompanying text, FirstEnergy Solutions recently announced the retirement of three additional nuclear plants in Pennsylvania and Ohio.

[21] For example, PSEG Nuclear's parent company, Public Service Enterprise Group, stated in its most recent 10-K filing, "[i]f market prices continue to be depressed and legislation is not enacted that adequately compensates nuclear generating stations for their attributes, Power anticipates it will no longer be covering its costs nor be adequately compensated for its market and operational risks at the Salem and Hope Creek nuclear unit and would anticipate retiring these units early." Public Service Enterprise Group, 10-K filing, at 27. (http://www.ezodproxy.com/pseg/2018/ar/images/PSEG_10K2017.pdf).

situation could have been worse had the cold spell lasted much longer. During this period, PSEG Power ran its dual-fuel, combined cycle generating fleet almost entirely on oil. However, despite efforts to replenish the oil tank drawdowns, certain large generators within the PSEG Power fleet were within hours of running out of oil and it is unclear whether gas could have been procured for them. But what is clear is that if the nuclear fleet had not been operating, PJM likely would have experienced serious problems. Indeed, a recent report prepared by IHS Markit analyzed what would have happened if the PJM nuclear generating fleet had been replaced by gas-fired generation that operated with the same outage levels as the gas-fired generation actually experienced during that event. The study concludes that "[u]under these conditions, PJM would have had to exercise the remaining emergency operating procedures and would likely have been pushed beyond its limits and forced to shed load during the bomb cycle."[22]

Another weather event involving extreme winter conditions was the Polar Vortex in January 2014. The abnormal weather conditions during the Polar Vortex drove the power system demand for electricity to an all-time high winter peak demand in PJM and caused a higher-than-normal unavailability from natural gas-fired generating units. As the NOPR proposal put forth by DOE last year explained, "[d]urging the Polar Vortex, PJM . . . struggled to meet demand for electricity because a significant amount of generation was not available to run."[23] According to a DOE Staff Report, the loss of generation capacity could have been catastrophic, but a number of fuel-secure plants that were scheduled for retirement were called upon to meet the need for electricity.[24] The DOE Staff Report also noted that "overall nuclear

[22] "Ensuring resilient and efficient PJM electricity supply," Lawrence Makovich and Benjamin Levitt, IHS Markit, at 14 (April 2018) (attached as Appendix A).
[23] Department of Energy, Grid Resiliency Pricing Rule, Notice of Proposed Rulemaking, 82 *Fed. Reg*. 46940, 46942 (Oct. 10, 2017) ("DOE Proposal").
[24] U.S. Department of Energy, Staff Report to the Secretary on Electricity Markets and Reliability, August 2017 ("DOE Staff Report"), available at:

generators performed extremely well during the Polar Vortex, with an average capacity factor of 95 percent."[25]

The recently completed study undertaken by IHS Markit also provides additional visibility with respect to the financial impact of an event such as the Polar Vortex assuming additional reliance on gas-fired resources.[26] In its study, IHS Markit substituted gas-fired generators, assumed to be operating with the same outage rates as gas-fired generation actually operated during the Power Vortex, for five nuclear plants that have announced their retirement.[27] The result was that the "consumer outage costs" that would have been experienced within the PJM footprint reached $6.7 billion.[28]

Further, the PSEG Companies' recent experience demonstrates that gas pipeline fuel disruptions can last for extended periods. On April 29, 2016, an explosion occurred on a Texas Eastern 30 inch natural gas pipeline operated by Spectra Energy in Salem Township, Westmoreland County Pennsylvania.[29] In addition to the damaged pipeline, Texas Eastern stopped deliveries on two other pipelines in the area.[30] Because corrosion levels were at a rate of about five times the expected "normal" corrosion rate at a weld where the explosion occurred,[31] Texas Eastern evaluated all the welds on the three pipelines and excavated more than 600 sites to

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https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.

[25] DOE Proposal at 5 (citing DOE Staff Report, at 98).

[26] "Ensuring resilient and efficient PJM electricity supply," Lawrence Makovich and Benjamin Levitt, IHS Markit, April 2018.

[27] Oyster Creek, Three Mile Island, Davis-Besse, Perry and Beaver Valley.

[28] "Ensuring resilient and efficient PJM electricity supply," Lawrence Makovich and Benjamin Levitt, IHS Markit, pp. 12-13 (April 2018).

[29] *See* "Natural gas explosion rocks Westmoreland County and U.S. gas markets," Pittsburgh Post-Gazette, April 29, 206, available at: http://www.post-gazette.com/local/westmoreland/2016/04/29/Emergency-crews-respond-to-gas-well-explosion-in-Westmoreland-County-pennsylvania/stories/201604290161.

[30] *See* September 13, 2016 Salem Township, Westmoreland County, Pa Special Meeting concerning findings from the Spectra Energy pipeline explosion investigation, at 22;16, available at: https://youtu.be/mpx2NBwqDSM).

[31] *Id*. at 16:20.

observe suspect welds.[32] Of these, repairs were effectuated at about a third of approximately 400 excavations completed at the time of a town hall meeting in Salem Township on September 13, 2016.[33] In addition, at the time that meeting was held, the pipelines were still not being operated at their full capabilities – more than four months after the incident occurred.[34]

The potential impacts of these events, moreover, may be mild compared with what could occur in the event of a deliberate cyber or physical attack on the interstate pipeline system by terrorists or unfriendly nation states. A simultaneous attack on multiple pipeline systems during severe winter conditions could affect millions of people for a prolonged period. As recently stated by Commissioner Tim Echols of the Georgia Public Service Commission:

> God forbid that we have a terrorist hop the fence and use a shape charge filled with explosives to blow one or all of the national pipelines that deliver this "just-in-time" resource, [i.e. natural gas] to power plants. With more and more plants using natural gas to generate electricity, a lengthy outage would create chaos in many states.[35]

The risk to the electric grid and to the citizens of our country if we have a portfolio of generating resources that is overly reliant on a single fuel source – particularly one that is dependent on "just-in-time" fuel – is very real. PJM faces an urgent situation that must be addressed immediately.

(iv) National Security Issues Associated with the Potential Loss of the PJM Nuclear Generating Fleet

The national security attributes of nuclear generation should also be taken into account in analyzing resiliency. The PSEG Companies included an affidavit from an expert on national security issues – Mr. Jeremy Carl, a fellow at the Hoover Institute -- as part of their reply

[32] *Id.* at 27:27.
[33] *Id.* at 42:05
[34] *Id.* 22:20 – 22:27.
[35] *Public Utilities Fortnightly*, September 2017, "Why Nuclear Energy is a Matter of National Security," at 66.

comments regarding the DOE NOPR. His observations are equally relevant here. As Mr. Carl explained:

> Perhaps the biggest unmeasured value of nuclear is its contribution to our national security. It cannot be stressed enough that unlike any other form of energy, the nuclear enterprise has fundamental non-energy related security attributes that justify additional support in the market.[36]

Moreover, nuclear plants have the ability to maintain more on-site fuel than any other form of energy, which is particularly valuable in the event of a long-term emergency situation or an interruption to fuel supplies to other generators. Nuclear resources have also been designed to withstand many of the new types of threats to power plants such as cyber security attacks or terrorism.

The decline in the United States' nuclear technology capabilities due to a lack of domestic plant manufacturing also impacts the advantages and leverage we have previously enjoyed in the area of non-proliferation. Mr. Carl explained that the

> United States has lost several bids on nuclear power projects in the Middle East to Russia, in no small part because of our degraded capacity in this area. The closure of additional nuclear plants degrades our already fragile capabilities while empowering geopolitical rivals such as Russia and China.[37]

Mr. Carl noted that as the nuclear capability in the United States declines the rest of the world continues to invest in nuclear generation, particularly China, where nuclear power generation has almost tripled in the last decade.[38]

Mr. Carl also explained that even though nuclear power plants' technology is distinct in many ways from nuclear weapons, the two applications cannot be divorced from each other

[36] Reply Comments of the PSEG Companies, Attachment A, Affidavit of Jeremy C. Carl, Grid Reliability and Resilience Pricing at 8, Docket No. RM18-1-000 (submitted November 7, 2017) ("Carl Affidavit") (Attached as Attachment B).
[37] *Id.* at 12.
[38] *Id.*

when it comes to our national security interests. The reactors that power our nuclear navy – almost 100 submarines and aircraft carriers – run on technology virtually identical to that powering our civilian reactors. Therefore, "[l]using the technology and operating experience through the atrophy of our domestic nuclear-power sector would mean a profound loss of capability in our military."[39] The Commission should clarify to PJM (and other RTOs/ISOs) that considerations of this type are within the scope of their responsibilities to analyze and the Commission should provide guidance regarding how to perform this kind of evaluation.

(v) Natural Gas Price Variation Costs Associated with the Potential Loss of the PJM Nuclear Generating Fleet

Another aspect of resiliency associated with fuel diversity not recognized in the PJM Comments or the Commission in the January 8th Order concerns the resiliency that nuclear energy provides to natural gas price variation. The IHS Markit study included an analysis of the costs that would be associated with restoring a base-case level of the current monthly production cost variation experienced in PJM under a scenario in which all the existing PJM nuclear plants were retired and replaced by gas-fired generation. This analysis showed a 53% increase in production cost variability in PJM.[40] Addressing this increase through natural gas call options would result in incurring $714 M annually in order to achieve the same level of production cost variation experienced when existing nuclear generation was present.[41] It should be noted moreover that incurring these amounts would *not* reduce the physical deliverability risks of natural gas.[42]

(vi) PJM Should Have Authority to Suspend Operations, But Only for Well-defined, Specific Situations such as Anticipated Blackouts or Matters of National Security

[39] *Id.* at 15.
[40] IHS Markit Report, at. 33.
[41] *Id.*
[42] *Id.*

PJM contends that in order to address low probability, high-impact event affecting operations that it should have the ability:

> to direct resources to commence non-market operations during emergencies, extended periods of degraded operations, or unanticipated restoration scenarios, including provisions for cost-based compensation when the markets are not operational or when a wholesale supplier is directed to take certain emergency actions by PJM for which there is not an existing compensation mechanism.[43]

PJM currently lacks this right and the PSEG Companies support PJM having the ability to suspend market operations. However, it must be clear that PJM will only exercise this right during true emergencies that pose a high risk of blackouts or national security issues: scarcity conditions alone should not provide a justification. Rather, during scarcity conditions, markets should be allowed to operate and prices should be allowed to reflect the marginal cost of supplying load. Further, as PJM proposes, affected generators must be paid their full cost of service for operating during these conditions.

(vii) Improvements in Energy Market Price Formation Could Help Restore the Resiliency and Fuel Diversity Inherent in a Well-Designed Energy Market

An efficient market will tend to be inherently more resilient because it will result in a diverse mix of generation technologies. As explained in the IHS Markit Report:

> PJM consumers benefit from efficient power supply diversity because it inherently increases the ability of grid-based power supply to withstand and reduce the magnitude and/or duration of disruptive events on both power supply availability and costs. Efficient power supply diversity exists because no single fuel or technology is the lowest-cost source of supply to meet the base-load and variable segments of consumer demand. As a result, cost-effective power supply under expected operating conditions involves employing an efficient mix of fuels and technologies in the power supply portfolio. However, expected operating conditions are subject to disruptions because all fuels and technologies have performance and cost risks. Since many of the key electric generation fuel and technology risk factors are not highly correlated, the cost-effective diversity in a power supply portfolio results in "not having all the eggs

[43] PJM Comments, at 40.

> in one basket" and, thus, ***inherently*** mitigates the impact of disruptions from expected operating conditions.[44]

The inherent generation fuel diversity of the PJM system, however, is being lost.

PJM is losing the resiliency that currently resides in its system to a significant degree due to the "PJM wholesale electric energy markets distortions [that] arise from missing costs because price formation rules reprice security constrained market-clearing prices below power system marginal generating costs."[45] The effect of these "distortions disproportionately [is to] reduce cash flows for higher-utilization power supply resources."[46] Accordingly, technologies such as nuclear plants with high operating factors do not receive the proper level of energy market payments which contributes to the economic challenges they face.

The PJM comments do not explicitly recognize the disproportionate impact of its current energy market design on different resource types as explained in the HIS Markit Report but they do acknowledge that "clearing prices are artificially lower than they should be."[47] PJM thus discusses certain reforms that it contends "would go a long way to properly compensating *all* generation needed to serve the demand for electricity."[48] These reforms are in the areas of improvements to reserve markets, shortage pricing and enhancements that would allow all needed units to set price. PJM requests that the Commission set a deadline for the submittal of market reforms and that these market reforms be considered in conjunction with the instant docket concerning resiliency issues. PJM notes that "[t]hose market reforms are an important and inter-related component of ensuring grid resilience . . . ."[49]

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[44] *Id.* at 4, 5 (emphasis in original).
[45] IHS Markit Report, at 7.
[46] *Id*
[47] PJM Comments, at 75.
[48] *Id*. (emphasis in original).
[49] *Id.*

The PSEG Companies fully support PJM's price formation initiatives. If properly implemented, these reforms could provide substantial support to base load generating units such as nuclear plants. However, as PJM notes, these reforms are still under review in the PJM stakeholder process. A deadline to prevent these processes from becoming bogged-down is essential. Given the urgency of the need faced by base load resources, any further stakeholder processes should be truncated and PJM should be directed to make its submittals to the Commission in as timely a fashion as possible.

(viii) The Commission Should Not Interfere With Legitimate Efforts By States to Address Resiliency Issues

For the reasons discussed above, the Commission can and should address the resiliency issues with which it is faced as quickly as possible. Not only do these issues require immediate attention but they are best addressed on a regional or national level which the Commission has the power to accomplish. However, to the extent that the Commission declines to act or cannot act quickly enough to address problems, it is critical that the Commission not thwart the activities of States intended to address resiliency matters. Resiliency of the generation fleet is a legitimate State goal and within the jurisdiction of States to address. Unless it is demonstrated that the achievement of those goals is actually intended to interfere with the operation of markets, the Commission should not thwart State efforts.

(b) Transmissions System Resiliency[50]

(i) PJM Should Be Expressly Authorized to Include Consideration of Resilience Issues in its Existing Regional Transmission Planning Role

The current PJM Regional Transmission Expansion Plan does not include explicit resiliency criteria. It should be modified to do so. As discussed above, high impact, low

[50] PSE&G is a member of Transmission Owners Agreement-Administrative Committee ("TOA-AC") which is contemporaneously filing Reply Comments in this matter and participated in their preparation. The PSEG Companies support those comments as expanded and amended here.

probability events are a threat to the PJM system. Certain of these threats could be extremely impactful to the transmission system and put customers out of service for extended time frames. These include extreme weather events, cyber and physical attacks, electromagnetic pulse events, earthquakes and geomagnetic disturbances.

One category of resiliency improvements that deserves special mention is the replacement of aging infrastructure. Replacement of aging facilities with new or more modern equipment with more robust characteristics makes the transmission system more resilient to high impact, low probability events. However, this type of improvement also enhances system visibility and analytics that ensure insight into the condition of the assets as well as provide predictive failure information. For example, PSE&G is in the process of converting its aging 26 kV system to a more robust 69 kV system. The 26 kV system was built in the 1920s and met the needs of the time period in which it was built but is not adequately suited to address long-term grid modernization needs. For our new 69 kV facilities, we are using modernized equipment and stronger poles with a higher capacity for moving power through our system. Because this new system is more robust and has more capability, it will be more resilient to disruptions from many types of threats.

(ii) Transmission Owners and RTOs/ISOs Need to Coordinate Closely in Addressing Resiliency Issues

The Commission should recognize that TOs and RTOs/ISOs have separate but related responsibilities in planning for resiliency which will require a high degree of coordination. TOs are in a unique position to understand and evaluate their systems. In addition, they have an independent responsibility to safeguard their own assets. RTOs/ISOs thus need to interact with TOs more closely than with other stakeholders and at an early stage in the planning process.

Further, RTOs/ISOs need to be forthcoming to TOs with respect to information possessed by RTOs/ISOs regarding threats and vulnerabilities.

The determination of responsibilities for resiliency planning must also respect the unique role of the TOs as the asset managers of their system. This is particularly so because many transmission resiliency upgrades will occur on the lower voltage portions of the system. Under the PJM planning procedures, these projects will often be considered "Supplemental Projects" under the PJM OATT for which the TOs, not PJM, have the primary planning responsibility.

(iii) Transmission Owners Must Be Given The Same Level of Access to Threat Assessment and Threat Awareness Data As Provided to The RTOs/ISOs

Because of the active role played by the TOs in resiliency planning, construction and operations, it is important that they have access to the same threat assessment and threat awareness data as provided to the RTOs/ISOs. The PJM Comments stress the need for data from the Commission and other governmental agencies in order to address resiliency concerns:

> Simply put, in coordination with other federal agencies such as the United States Department of Defense ("DOD"), DOE, United States Department of Homeland Security ("DHS"), as well as NERC, the Commission needs to provide intelligence and metrics to apply to resilience vulnerability and threat analyses that can then guide and anchor subsequent RTO planning, market design, and/or operations directives.[51]

The TOs need this data for the same reasons that PJM does in dealing with governmental agencies. Because the TOs need to closely coordinate with PJM and, as well, have their own independent role to play in undertaking resiliency projects, it is essential that they also have the same data regarding threat assessment as made available to PJM. Similarly, having knowledge of threats awareness will allow TOs to take necessary steps to safeguard their assets as situations arise that pose specific risks.

[51] PJM Comments, at 5.

The role of NERC merits special mention. Because of its expertise regarding the BES, NERC is uniquely positioned to be a resource in identifying and assessing system vulnerabilities. The PSEG Companies submit that proper role for NERC is in the form of assessments and information gathering to be shared with the RTOs and TOs. We believe that NERC should not attempt to develop new standards. Achieving resiliency is very situation focused and does not lend itself well to a standard of general applicability.

(iv) Planning for Severe Weather Events Is Critical For All TOs but In Particular For Companies Such As PSE&G Located On Coastal Waters

As noted by PJM, "[f]rom a resiliency perspective, the frequency and magnitude of [severe terrestrial weather] events is decidedly on the rise and the resilience threat is the extreme storms that destroy infrastructure such that service cannot be restored."[52] But, as noted in legislation recently passed by the New Jersey legislature, because of its location in a coastal state, PSE&G faces special challenges:

> As a coastal state, New Jersey is particularly exposed to many of the effects of global climate change, such as rising sea levels and more extreme storms. Many of New Jersey's most important commercial and tourism assets are located in coastal areas, and events like Superstorm Sandy have demonstrated the imminent and tangible threats that intense storms pose to New Jersey's economy and environment.[53]

PSE&G's experience in New Jersey certainly bears these observations out. Superstorm Sandy in 2012 devastated New Jersey and presented extraordinary challenges to the transmission and distribution systems in our area, prompting us to replace, harden, smarten, and even *move* electric infrastructure to improve the resilience of the system. The lesson to be derived this experience is that we need to plan for weather events that we have not yet experienced and that the criteria adopted for addressing weather events should recognize this reality. Further, it must

[52] *Id*. at 29.
[53] Assembly Bill 3724 (legislative finding no. 11).

be recognized that transmission zones that border on the oceanic coast line may need to have special rules.

(v) Confidentiality Issues in Meeting NERC CIP Standards

TOs are registered NERC entities and, accordingly, have responsibility for complying with CIP-014 physical security protection standards relating to critical facilities. Compliance with this requirement will require the identification of highly critical substations essential to serve large load centers and/or particularly critical facilities and then efforts to reduce their criticality by creating system redundancies and back-up facilities. However, the information surrounding this analysis – even the knowledge of which substations are critical – is very sensitive and could reveal system vulnerabilities that pose national security concerns if disclosed. Compliance with CIP-003, regarding cyber security standards poses similar concerns.

In this context, steps must be taken to assure that compliance with CIP-014 and CIP-003 requirements limits the availably of information appropriately. While the PSEG Companies acknowledge that stakeholders have an interest in participating in the transmission planning process, that interest has to be balanced against the need to retain the confidentiality of sensitive information regarding national security concerns. New processes need to be developed for this purpose. Current Critical Electric Infrastructure Information ("CEII") rules lack sufficient stringency. Stakeholders should be provided with data only on a "need to know" basis and only to the extent necessary to verify that the project is being undertaken consistent with the standard.

III. CONCLUSION

WHEREFORE, the PSEG Companies respectfully request that the Commission recognize the importance of the resiliency issues with which it is faced and take decisive steps to them. At a minimum, to the extent that the Commission declines not to act or fails to act in a

timely manner to address resiliency issues, the Commission should not interfere with legitimate efforts of States to address them.

Respectfully submitted,

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ATTACHMENT A

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Ensuring resilient and efficient PJM electricity supply

The value of cost-effective nuclear resources in the PJM power supply portfolio

April 2018

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Ensuring resilient and efficient PJM electricity supply

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About the report

The *Ensuring resilient and efficient PJM electricity supply: The value of cost-effective nuclear resources in the PJM power supply portfolio* report from IHS Markit utilizes the company's extensive knowledge and proprietary models of the interaction between regional power system demand and supply to assess the impact on consumers of current PJM wholesale market distortions that increase the probability of uneconomic closure and replacement of PJM nuclear generating resources. This report is made up of two volumes. Volume 1 contains the main report, and Volume 2 contains the appendixes. This research was supported by Nuclear Matters.

The authors are exclusively responsible for all analysis and content.

Executive summary

PJM faces the potential loss of cost-effective nuclear resources that provide valuable resilience to the disruptive events that can affect normal power system operating conditions. This problem exists because ongoing wholesale market distortions are increasing the likelihood of uneconomic closures of existing PJM nuclear resources and the subsequent replacement by the fuel and technology mix in the current PJM new power supply pipeline (15% renewables and 85% natural gas–fired technologies). This analysis indicates that if nothing is done to prevent uneconomic nuclear closures and replacements, then the 65 million consumers relying on PJM grid-based power supply face

- **Less resilient PJM capacity availability.** This follows from the loss of the inherent resilience created by the weak correlation between nuclear and nonnuclear capacity availability risk factors, most recently observed during the polar vortex and bomb cyclone disruptive winter events. Since inherent resilience is costless to consumers, the associated increase in the cost to achieve PJM reliability levels to compensate for uneconomic nuclear closures means that an efficient trade-off between reliability benefits with costs results in a lower level of power system reliability.

- **Less consumer net benefits from electricity consumption.** The uneconomic retirement and replacement of PJM nuclear power plants reduces the consumer annual net benefit from PJM grid-based electricity. Since consumers value electricity more than what they pay for it, the net benefit of electricity purchases declines by $5–12 billion per year owing to higher retail prices and lower consumption levels. The loss in consumer net benefits is about 3 cents per kWh produced by existing PJM nuclear resources.

- **Less affordable electricity.** Annual PJM electricity supply costs increase the average retail price for electricity to consumers by 9–18% because nuclear resources are lower cost to continue to operate than they are to replace.

- **Less resilient PJM electric production costs.** Month-to-month variation (as measured in terms of standard deviation) in consumer monthly production costs increases by roughly 53% owing to the loss of the inherent electric production cost resiliency provided by the nuclear contribution to the current fuel

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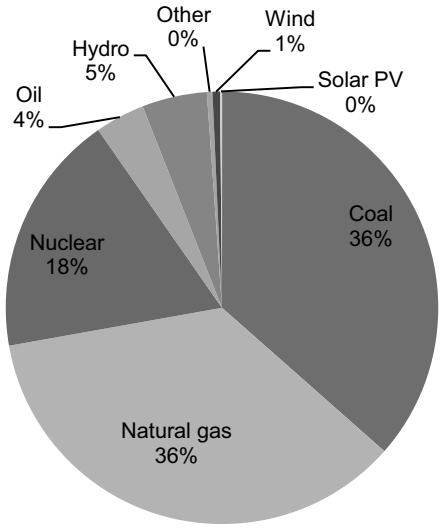
diversity in the PJM electricity supply portfolio. Since monthly production costs represent about one-third of consumer monthly power bills, the variation in monthly consumer electricity bills is about 18% greater. Replacing the production cost resilience from nuclear resources with financial hedging instruments would involve an annual cost of about $714 million.

- **Less environmentally responsible PJM power supply.** PJM nuclear resources provide 88% of the PJM non–carbon dioxide (CO_2)–emitting electric production. If these nuclear resources close prematurely, then the net effect on PJM electric greenhouse gas (GHG) emissions is an annual increase of about 100 million metric tons of CO_2. PJM nuclear closures would remove 12 times more CO_2-free power supply than currently produced by all the wind and solar resources in PJM. To put this into perspective, the potential annual increase in PJM CO_2 emissions equals the CO_2 emissions produced each year by two-thirds of the vehicles on the road in PJM. The potential annual increase in CO_2 emissions imposes an annual environmental cost of about $4.3 billion based on the $43 per metric ton midrange estimate of the social cost of incremental CO_2 emissions.

The bottom line is that efficient power supply is diverse because no single fuel or technology is the lowest-cost source of supply to meet the base-load and variable segments of consumer demand and the uneconomic loss of the nuclear contribution to the PJM power supply portfolio caused by market distortions is a lose-lose proposition. The outcome involves both higher power production costs as well as higher CO_2 emissions. Since environmental responsibility requires making efficient environmental cost and benefit trade-offs, uneconomic PJM nuclear closures and replacements are not environmentally responsible.

Figure 1

PJM installed generation capacity, December 2016: 182 GW



Note: PV = photovoltaics.
Source: IHS Markit, PJM

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Electricity consumers reveal a preference for resilience to disruptive events affecting both power supply availability and electric production costs. The 19 PJM nuclear power plants are a cost-effective source of electric energy and capacity in the current diverse PJM power supply portfolio (see Figure 1).

PJM nuclear resources supply net dependable capacity to meet power system real-time demand levels, and PJM dispatches nuclear resources to cost-effectively align energy output with the steady 24/7 base-load segment of consumer demand that accounts for 60% of annual PJM electric load. The uneconomic retirement and replacement of PJM nuclear power plants would have reduced the consumer annual net benefit from PJM grid-based electricity by about $8 billion per year over 2013–16. This translates into a consumer net benefit per kilowatt-hour of PJM nuclear generation of about 3 cents per kWh.

PJM consumers benefit from efficient power supply diversity because it inherently increases the ability of grid-based power supply to withstand and reduce the magnitude and/or duration of disruptive events on both power supply availability and costs. Efficient power supply diversity exists because no single fuel or technology is the lowest-cost source of supply to meet the base-load and variable segments of consumer demand. As a

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result, cost-effective power supply under expected operating conditions involves employing an efficient mix of fuels and technologies in the power supply portfolio. However, expected operating conditions are subject to disruptions because all fuels and technologies have performance and cost risks. Since many of the key electric generation fuel and technology risk factors are not highly correlated, the cost-effective diversity in a power supply portfolio results in "not having all the eggs in one basket" and, thus, ***inherently*** mitigates the impact of disruptions from expected operating conditions.

In particular, the nuclear power plants in the PJM power supply portfolio provide consumers with inherent resilience in both power supply availability and affordability because the PJM nuclear capacity availability and production cost risk factors are not highly correlated with the risk factors of the other resources in the PJM power supply portfolio.

The value of the inherent capacity diversity provided by nuclear resources in the PJM power supply portfolio became apparent during recent deviations from expected winter operating conditions. During the deviation from normal winter conditions known as the polar vortex in January 2014, PJM hit a record wintertime peak demand of 141.8 GW. This severe cold snap did not reduce available nuclear capacity below its expected net dependable level. However, the severe cold snap did reduce available natural gas–fired capacity by 27% from the expected net dependable level.

The polar vortex episode revealed the inherent resilience arising from the lack of correlation between natural gas–fired capacity availability risk factors and the risk factors associated with nuclear, oil-fired, and coal-fired power plants. This lack of correlation allowed these resources that did not depend on natural gas to back up and fill in for the disproportionate limitations on natural gas–fired capacity availability during the polar vortex. Looking back, if the PJM net dependable nuclear had been replaced by an equivalent amount of net dependable natural gas–fired capacity along with an expanded natural gas supply infrastructure capable of providing the same natural gas–fired capacity availability (ratio of available capacity to net dependable rating) experienced during the polar vortex, then the available capacity on 7 January 2014 would have been 9.3 GW lower. Under these conditions, PJM would have had to fully exercise the remaining emergency operating procedures that provided an estimated equivalent of 2.7–3.7 GW of firm capacity and, therefore, would likely have been pushed beyond its limits and forced to shed some load during the polar vortex.

PJM responded to the lessons of the polar vortex by changing capacity performance rules. However, these changes did not eliminate the exposure of PJM power supply to natural gas–fired generation risk factors. The continued vulnerability of PJM to the availability of natural gas–fired capacity became apparent when PJM faced another significant deviation from normal winter operating conditions during the "bomb cyclone" event during the winter of 2017/18. The bomb cyclone cold snap was not as severe as the polar vortex episode. Yet the bomb cyclone was severe enough to reduce natural gas–fired capacity and constrain natural gas supply to PJM generators. As a result, the 35% of installed PJM capacity consisting of natural gas–fired resources accounted for 59% of the PJM capacity outages that drove the 7 January 2018 PJM installed capacity forced outage rate to 12.1%.

The inherent diversity of the PJM power supply portfolio reduced the magnitude and duration of the disruptions to expected PJM operating conditions during the cold snap known as the bomb cyclone. But the implication was clear—if the PJM net dependable nuclear capacity had been replaced by an equivalent amount of net dependable natural gas–fired capacity and the gas supply infrastructure had also been proportionately expanded to provide the same natural gas–fired capacity availability factor as experienced during the bomb cyclone, then the available PJM capacity on 7 January 2018 would have been 5.2 GW lower. Under these conditions, PJM would have had to exercise all emergency operating procedures and would likely have been pushed beyond its limits and forced to shed load during the bomb cyclone.

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PJM natural gas–fired capacity availability appeared better during the bomb cyclone than during the polar vortex owing in part to the significant costs that natural gas–fired generators incurred to improve capacity availability in response to the PJM capacity performance rule changes. This cost to increase capacity resilience stands in stark contrast to the costless resilience inherently provided by the efficient fuel and technology diversity of a cost-effective PJM power supply portfolio. The cost implication is clear—if uneconomic closure and replacement of PJM nuclear resources results in the loss of inherent PJM power supply portfolio resilience, then restoring that lost resilience will impose additional costs on consumers.

The costly loss of inherent capacity availability and production cost resilience is one of the predictable negative impacts resulting from the uneconomic closure and replacement of PJM nuclear resources. This analysis quantified the potential impacts from the closure and replacement of nuclear capacity and energy in the PJM generating portfolio with an analysis of the closure and replacement of PJM nuclear resources under the operating conditions experienced from 2013 through 2016.

The findings of negative impacts from PJM nuclear power plant closure and replacement indicate that premature closure and replacement of existing PJM nuclear resources is not the result of efficient market dynamics generating cost-effective resource turnover. In an undistorted marketplace, effective cost-based competition sorts out the most efficient suppliers. Under these conditions, the exit of an unprofitable supplier benefits consumers. But to make this happen, existing suppliers would not exit the marketplace and be replaced by costlier alternatives.

The results of this study indicate that retiring existing PJM nuclear resources would trigger replacement by costlier alternatives. Such an outcome is inconsistent with an efficient market outcome and consistent with the results in a distorted marketplace that does not count all costs in the cost-based competition. Under competitive conditions with missing costs, market forces do not sort out the most efficient suppliers. Instead, market price signals support the operation of less cost-effective suppliers while more cost-effective suppliers are driven out of business.

PJM wholesale electric energy markets distortions arise from missing costs because price formation rules reprice security constrained market-clearing prices below power system marginal generating costs. In addition, current subsidies and mandates for some but not all non–CO_2-emitting competitive generators shift costs to taxpayers and alter PJM market demand and supply interactions resulting in lower market-clearing prices, at some times, enough to produce negative price levels. These energy market distortions disproportionately reduce cash flows for higher-utilization power supply resources. In addition, current uneven internalization of the full cost of CO_2 emissions among rival generators disproportionately impacts higher-utilization power resources with lower CO_2 emissions per megawatt-hour compared with the CO_2 emission intensity of the generating units whose short-run marginal cost (SRMC) bids are setting the market-clearing price.

PJM wholesale electricity capacity market distortions arise from federal and state environmental policies that subsidize and mandate capacity development and, thus, override market price–driven capacity entry, thereby delaying the point in time when electricity market demand and supply achieve long-run balance and suppressing capacity market-clearing prices.

PJM market distortions have a significant impact on competitive generator cash flows. The track record of persistent cost recovery shortfalls and bankruptcies of competitive generators, including natural gas–fired generators, indicate the magnitude of the problem. Other power systems provide examples of unresolved discord between public policies and market operations leading to market distortions that eliminated nuclear generation shares like current PJM nuclear generation shares within a dozen years. Consequently, the uneconomic closure of PJM nuclear resources is a plausible result from current market distortions. The

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recent FirstEnergy Solutions announcements to prematurely deactivate more than 4,000 MW of PJM nuclear resources are the leading edge of the potential loss of cost-effective PJM nuclear resources.

The most straightforward solution to the problem of uneconomic nuclear retirements involves reforming price formation rules to close gaps between marginal costs and market-clearing prices, along with putting an appropriate price on CO_2 emissions for all rival generators in PJM rather than subsidizing and mandating generation shares for some but not all non–CO_2-emitting generating technologies. However, since policy and market discord is entrenched, the probability is low that policy formulation will reverse course and quickly eliminate the underlying root causes of market distortions. Therefore, PJM market distortions are likely to persist. Under these conditions, other feasible policy options are under consideration to augment cash flows for cost-effective generating resources and produce outcomes closer to the results expected in an efficient market end state. These options involve providing compensation for attributes—such as cost-effective contributions to resilient capacity availability, contributions to resilient electric production costs, contributions to flexible operating capabilities, or contributions to lowering power system CO_2 emission levels.

Looking ahead, unresolved market distortions create inefficiencies that make PJM grid-based electricity supply less affordable, less reliable, less resilient, and less environmentally responsible. The implication is that the FERC Resilience Docket AD18-7-000 provides the opportunity to do something to address PJM market distortions and to avoid the consequences of uneconomic PJM nuclear power plant closures and the resulting significant declines in the consumer net benefit from PJM grid-based power supply.

Since PJM is the largest electricity market on earth and widely regarded as a model for electricity policy formulation and market design, actions to preserve the inherent resilience to electric availability and production cost levels provided by current cost-effective nuclear resources in the power supply portfolio have the potential to not only benefit electric consumers in PJM but also produce a highly influential example for other power systems to follow in addressing the consequences of market distortions arising from the lack of harmony between public policies and market operations.

Overview

This study focuses on the resilience impacts from the uneconomic closure and replacement of PJM nuclear resources for two reasons. First, current PJM market distortions disproportionately reduce cash flows for high-utilization and low–CO_2-emitting resources and make the premature loss of PJM nuclear resources a plausible scenario. Second, the inherent resilience provided from cost-effective nuclear in the PJM power supply portfolio is significant and expensive to replace.

Power system operating conditions are subject to disruptive events that can decrease the availability and increase the cost of grid-based power supply to consumers. As a result, consumers reveal preferences for cost-effective resilience in both power supply availability and electricity production costs.

Wholesale electric market operations can produce outcomes that meet consumer demands for electric supply resilience when public policies and wholesale operations are harmonized. However, resilience in power supply has become a strategic concern in the US power sector because the current lack of harmony between public policies and market operations is causing wholesale electricity market distortions and reducing power supply resilience. At the individual power plant level, market distortions are lowering cash flows and causing underinvestment in the resilience of power plant operations. At the power system level, market distortions are producing price signals that shape less efficient fuel and technology diversity in the power supply portfolio that decreases the inherent ability of an efficient power supply portfolio to withstand and reduce the magnitude and/or duration of disruptive events to expected operating conditions. The combination of plant and power

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system impacts creates an electricity system with less resilience compared with the level of resilience expected from an undistorted, efficient wholesale electricity market outcome.

The link between policy and market discord, market distortions, and resilience losses is not appreciated by some industry observers who believe that wholesale electricity markets are currently working well with subsidies that favor some rival generators and not others, with policies that count some costs but not others in the marginal cost–based competition to generate electric energy, and with rules that generate persistent gaps between power system marginal generating costs and market-clearing energy prices.

The blind spot to market distortions supports assessments that insufficient nuclear power plant cash flows are the result of existing nuclear plants being uncompetitive with natural gas–fired competitors that gained a competitive advantage from downward pressure on natural gas prices due to development of shale natural gas resources. Such assessments reflect the perception that nuclear closures are simply the result of the "creative destruction" in an efficient marketplace.[1] From this perspective, there is no distinction between economic and uneconomic nuclear power plant retirements. Further, the blind spot to market distortions fails to reconcile with the financial track record of the competitive natural gas–fired generators across the past 15 years, where the rule rather than the exception was inferior risk-adjusted returns to broader capital market benchmarks, significant asset write-downs, and periodic bankruptcy reorganization. The implication is that these natural gas–fired competitive power generators are not "winning" in the marketplace but instead are also being impacted by market distortions suppressing cash flows below levels expected in an undistorted market outcome.

Resilience in power supply is a strategic concern for the PJM wholesale electricity market because PJM operates the world's largest competitive wholesale electricity market and coordinates the power system security-constrained movement of wholesale electricity in all or part of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia) and the District of Columbia. PJM centrally dispatches generation through a bid-based competitive process that determines power system security-constrained locational market prices in day-ahead and real-time electric energy markets as well as determines prices in capacity and ancillary service markets.

This study analyzes the resilience impacts from the perspective of the 65 million consumers who rely on PJM for affordable, reliable, resilient, and environmentally responsible grid-based power supply. From this perspective, the power system objective is to cost-effectively meet the multiple dimensions of consumer demand by efficiently integrating a reliable and resilient mix of fuels and technologies to supply consumers with the electricity that they want, whenever they want it, at prices that reflect all the costs of the grid-based security-constrained economic dispatch of the power supply portfolio.

Consumers reveal preferences for resilient electric supply availability

Electric system operating conditions are uncertain because the availability of all generating fuels and technologies are vulnerable to disruptions from mechanical or software failures, accidents, political interventions, overloading network pathways, regulatory changes, extreme weather events, and physical or cyber attacks.

1. Joseph Schumpeter, *Capitalism, Socialism and Democracy,* Harper, New York, 1975 (original publication 1942), p. 83.

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Resilience in grid-based power supply provides the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such events.[2]

Consumers benefit from resilient electric supply availability that reduces the magnitude and duration of electric service outages. Estimates of total annual power outage costs for US consumers exceed hundreds of billions of dollars per year.[3] Of course, consumer outage impacts vary depending on the size, timing, and duration of an outage, but available estimates of actual annual outage costs and durations indicate that electric service disruptions in the United States result in about $75 billion per hour of electric service interruption costs.[4] This cost translates into a $170/kWh incremental outage cost.

Estimates of the value of lost load are more than 100 times greater than the price consumers pay for electricity. These value of lost load estimates align with the high valuations consumers reveal when they choose to purchase backup generation resources to provide uninterrupted power supply to critical electrical applications. US grid-based power supply is typically available 99.97% of the time, and the typical backup generation cost per kilowatt-hour to provide electric service during the 2.33 hours per year of expected grid-based supply disruptions is roughly 100 times the US average price of 12.6 cents per kWh that households pay for grid-based power supply.

Consumer choices to invest in backup generation reveal high valuations for avoiding incremental grid-based outages. Many commercial and industrial customers—especially customers with critical electric applications in hospitals and data centers—choose to install backup generation. On the residential side, more than 1 million US residential consumers have chosen to invest in emergency backup generation systems. Within PJM, a surge of residential consumer investments in backup generation followed the Hurricane Sandy outages in 2012, even though the PJM electricity supply is available over 99% of the time.[5]

Consumers chose to back up supply for some, but not all, electric loads. These choices reveal that consumers weigh the costs and benefits of improving electric reliability across all electric end uses and determine that making a power system 100% reliable for all applications is not cost effective. These consumer choices reveal that consumers recognize reducing the probability of grid-based electric supply outages to zero will cost far more than the high, but not unlimited, value that they place on unserved electric load. Therefore, from a consumer perspective, cost-effective grid-based power supply meets their preferences for resilience in power supply availability by achieving a level of reliability that balances the marginal costs and benefits of reliability investments.

Current value of lost load estimates put the benefit of avoiding an additional hour of electricity outages in PJM at about $12.5 billion. PJM is responsible for maintaining mandatory reliability standards in grid operations and network planning established by the North American Electric Reliability Corporation and approved by the Federal Energy Regulatory Commission (FERC). To meet reliability obligations, PJM establishes a forward demand curve for capacity designed to produce capacity price signals that pace investment in power supply to achieve a target loss of load probability for the power system.

2. National Infrastructure Advisory Council, *Critical Infrastructure Resilience Final Report and Recommendations,* 8 September 2009, https://www.dhs.gov/sites/default/files/publications/niac-critical-infrastructure-resilience-final-report-09-08-09-508.pdf, retrieved 21 February 2018.

3. Kristina Hamachi LaCommare and Joseph H. Eto, "Cost of Power Interruptions to Electricity Consumers in the United States," *Energy: The International Journal* 31 (7 April 2005); and Primen, "The Cost of Power Disturbances to Industrial and Digital Economy Companies," TR-1006274 (available through EPRI), 29 June 2001.

4. Michael J. Sullivan, Josh A. Schellenberg, and Marshall Blundell, "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States," Ernest Orlando Lawrence Berkeley National Laboratory, January 2015, https://emp.lbl.gov/publications/updated-value-service-reliability, retrieved 29 August 2017.

5. Ken Belson, "Power Grids Iffy, Populous Areas Go for Generators," *New York Times,* 24 April 2013, http://www.nytimes.com/2013/04/25/business/energy-environment/generators-become-must-have-appliances-in-storm-battered-areas.html, retrieved 21 February 2018.

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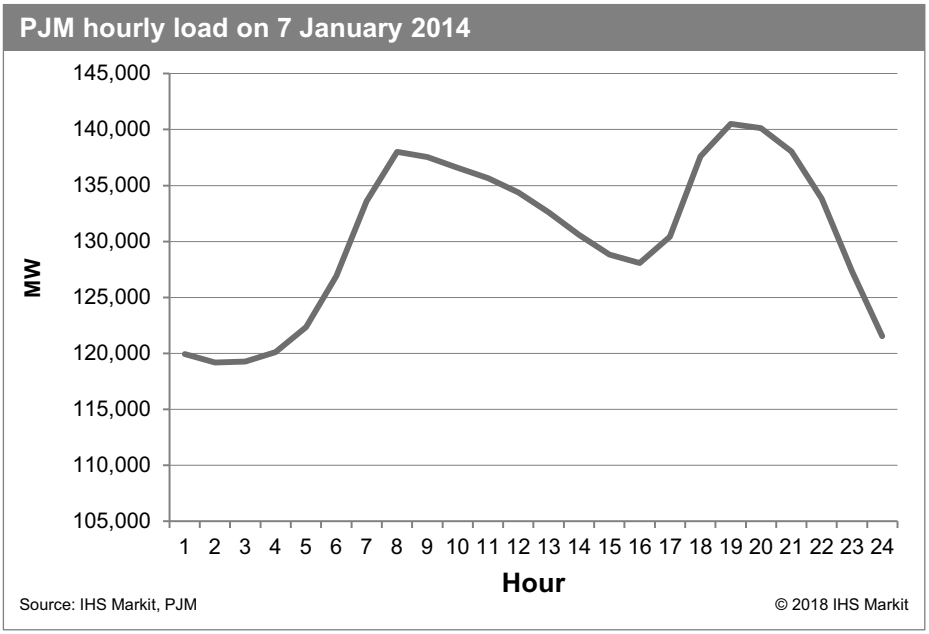
PJM consumers benefit from efficient power supply diversity because it inherently increases the ability of grid-based power supply to withstand and reduce the magnitude and/or duration of disruptive events on power supply availability. Efficient power supply diversity exists because no single fuel or technology is the lowest-cost source of supply to meet the base-load and variable segments of consumer demand. As a result, cost-effective power supply under expected operating conditions involves employing an efficient mix of fuels and technologies in the power supply portfolio. However, expected operating conditions are subject to disruptions because all fuels and technologies have performance risks. Since many of the key electric generation technology risk factors are not highly correlated, the cost-effective diversity in a power supply portfolio results in "not having all the eggs in one basket" and, thus, ***inherently*** mitigates the impact of disruptions from expected operating conditions.

The uneconomic closure of PJM nuclear capacity results in the loss of inherent resilience in PJM capacity availability. Since cost-effective nuclear generation in the PJM supply portfolio provides consumers with inherent resilience in capacity availability, this resilience comes at zero cost to consumers. Consequently, achieving the same level of power system reliability following uneconomic PJM nuclear closure and replacement requires incurring additional costs. As a result, if PJM meets consumer preferences to balance the costs and benefits of reliability investments, then the result of uneconomic nuclear closures and replacements will be a lower cost-effective level of power system reliability and higher expected outage costs for consumers.

Recent disruptive events to expected winter operating conditions in PJM illustrate the benefits of the resilience provided by the diverse technology and fuels in the electric supply portfolio, and the responses to these winter episodes indicate the cost associated with increasing the resilience of electric capacity availability.

The polar vortex was a recent disruptive event involving a significant deviation from normal winter conditions during January 2014. Figure 2 shows the aggregate consumer hourly load on 7 January 2014, when the polar vortex caused PJM to hit a record wintertime peak demand of 141.8 GW.

Figure 2



On the supply side, polar vortex conditions in the PJM power system caused significantly higher-than-expected unavailability from natural gas–fired generating units linked, in many cases, to abnormally high natural gas pipeline supply constraints. Although the polar vortex did not reduce electric supply just from natural gas–fired resources, the natural gas–fired resources were nevertheless the hardest-hit supply resource. Table 1 reports the actual PJM installed capacity in January 2014 and the associated net dependable ratings by technology and fuel type.[6] Net dependable capacity measures the

6. Monitoring Analytics, LLC, *State of the Market Report for PJM (2014)*, 12 March 2015, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume2.pdf, retrieved 27 February 2018.

Table 1

PJM polar vortex capacity

Generator fuel type	Installed capacity (MW)	Available firm capacity factor	Net dependable capacity (MW)	Total actual outages on 7 January 2014 (MW)	Actual firm capacity on 7 January 2014 (MW)	Ratio of actual firm to net dependable capacity (MW)
Coal	75,545	77.2%	58,320	13,700	61,845	1.06
Gas	53,395	87.9%	46,956	19,000	34,395	0.73
Nuclear	33,077	92.3%	30,530	1,400	31,677	1.04
Hydro	8,107	88.0%	7,134	N/A	N/A	N/A
Oil	11,314	92.3%	10,443	N/A	N/A	N/A
Wind1	872	100%	872	N/A	N/A	N/A
Solar1	84	100%	84	N/A	N/A	N/A
Other	701	100%	701	N/A	N/A	N/A
Not classified				8,512	12,567	
Total	183,095		155,041	42,612	140,483	0.91

1. PJM calculates solar and wind installed capacity by reducing nameplate capacity by 62% and 87%, respectively.

Source: IHS Markit, PJM

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expected capacity available from a resource under expected peak demand power system conditions. In PJM, the net dependable capacity of renewable solar and wind resources is typically 13% and 38%, respectively, of the capacity rating associated with operation under favorable conditions. Natural gas–fired generating units have a net dependable rating of 85–90% of the nameplate capacity, and existing PJM nuclear capacity has a net dependable rating of 92% of nameplate capacity. The table also shows the actual outage rates experienced during the polar vortex on 7 January 2014 and the associated actual firm capacity available by technology and fuel type.[7] Resilient capacity availability is a concern because disruptions to expected conditions during peak demand conditions can cause correlated outages for power plants relying on the same fuels or technologies and thus cause the actual overall capability of a class of generating resources to fall short of the expected aggregate net dependable capacity.

The polar vortex experience revealed that a severe cold snap disproportionately constrained the actual available capacity relative to the net dependable capacity of natural gas–fired generating resources. The polar vortex experience also revealed that the lack of correlation between the risk factors associated with natural gas–fired generating resources and the risk factors associated with other resources allowed nuclear, oil-fired, and coal-fired power plants to offset some of the disproportionate limitations on natural gas–fired resources.

A retrospective analysis of the polar vortex provides important resilience lessons because, as a July 2017 National Academies of Sciences, Engineering, and Medicine report notes, a process of continual learning from past events is essential for enhancing the resilience of the grid.[8]

PJM was in a fortunate position that a surplus of installed capacity was present in 2014 when the reported systemwide reserve margin was 22.5% rather than the long-run reserve margin target of about 16%. Analysis of PJM operating under polar vortex conditions shows that as capacity reserves decline, PJM approaches the point at which further reductions in available supply would likely produce increasingly large outage costs. Table 2 shows that as additional net dependable nuclear capacity is removed from the PJM supply portfolio and replaced by equal amounts of net dependable natural gas–fired capacity, the expected consumer outage costs

7. In the May 2014 report *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events,* PJM quantified power supply reserves available to its system during the peak period on 7 January 2014, including 500 MW of 10-minute synchronized reserves, 1,167 MW of 10-minute nonsynchronized reserves, and 1.1–2.0 GW of temporary voltage reduction. Although other actions may have been available, such as purchasing additional emergency energy or recalling shared reserve obligations from neighbors, this analysis does not include the potential for PJM to purchase additional energy or recall additional obligations that PJM provided to neighbors.

8. National Academies of Science, Engineering, and Medicine, *Enhancing the Resilience of the Nation's Electricity System,* National Academies Press, Washington, DC, 2017, p. 3, https://doi.org/10.17226/24836, retrieved 13 December 2017.

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under polar vortex conditions rose at an increasing rate from $153 million to $6.7 billion.

Table 2

2014 polar vortex scenario analysis to determine the resiliency value of the existing diverse power supply portfolio

	31 December 2016 capacity	31 December 2016 capacity less Oyster Creek and Three Mile Island (1.47 GW)	31 December 2016 capacity less Oyster Creek, Three Mile Island, Davis-Besse, Perry, and Beaver Valley (5.5 GW)
Hours of outage	3	5	11
Average shortfall (MW)	301	1,386	3,586
Total shortfall (MWh)	903	6,930	39,443
Cost per unserved MWh (dollars)	170,000	170,000	170,000
Total cost of shortfall (million dollars)	**153**	**1,178**	**6,705**

Source: IHS Markit

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The polar vortex episode indicates that if the PJM nuclear net dependable capacity had been replaced by an equal amount of net dependable natural gas–fired generating capacity and the gas supply infrastructure had also expanded in proportion to provide the same forced outage rate of natural gas–fired generation during the polar vortex, then the firm capacity available on 7 January 2014 would have been 9.3 GW lower. The results indicate that replacing PJM nuclear capacity with natural gas–fired capacity reduces the risk diversification in the PJM power supply portfolio. Since nuclear net dependable capacity risk factors are not highly correlated with natural gas–fired net dependable risk factors, the expected overall available capacity is higher with a combination of nuclear and natural gas–fired capacity compared with the same amount of capacity consisting entirely of natural gas–fired resources. Therefore, the increase in correlation to risk factors within a generation portfolio results in an increase in the overall power system loss of load probability. Under the conditions of closure and replacement of PJM nuclear net dependable capacity with an equivalent amount of net dependable natural gas–fired capacity, PJM would likely have been pushed beyond the power system supply limits and thus forced to shed load during the polar vortex operations even if PJM employed the remaining emergency operating procedures that provided an estimated equivalent of 2.7–3.7 GW of firm capacity.

The polar vortex experience led PJM to examine the poor generator capacity availability. The examination exposed the lack of clarity in the PJM capacity market regarding the definition of the capacity commodity. PJM responded by developing capacity performance rules for its capacity marketplace designed to provide larger capacity payments for the most available resources, including performance bonus payments for overperforming participants as well as higher penalties for nonperformers. FERC approved PJM's rule changes in June 2015.

Since the polar vortex, 8,922 MW of coal-fired capacity and the 608 MW Oyster Creek, 837 MW Three Mile Island, 908 MW Davis-Besse, 1,268 MW Perry, and 1,872 MW Beaver Valley nuclear plants announced plans for closure. In addition, PJM added 11,715 MW of natural gas–fired generating capacity by the end of 2016. As a result, the exposure of PJM electric supply to the risks in the natural gas supply chain increased because the PJM electric supply portfolio became more natural gas dependent.

Implementing the PJM capacity performance rules showed that increasing PJM power supply resilience from natural gas–fired resources came at a cost. PJM surveyed 100 units (62 GW of the 93 GW) of the generators that committed to the capacity performance auction for the 2016/17 delivery year to understand the costs being incurred to comply with the new capacity performance requirements.[9] Table 3 summarizes the types

9. "Capacity Driven Performance Investments," PJM, October 2016, http://www.pjm.com/-/media/committees-groups/committees/mc/20161024-webinar/20161024-item-03-resource-investments-in-response-to-capacity-performance-requirements.ashx, retrieved 27 March 2018.

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Table 3

Capacity performance investments in PJM

Investments	Description	MW	Percentage of total surveyed	Low (million dollars)	High (million dollars)	Average (million dollars)
Increased staffing per station	Staff generators 24 hours per day, 7 days per week to ensure unit readiness and decrease notification time	424	1%	$1	$1	
Generator infrastructure	Long-term maintenance upgrades (winterization and major unit overhauls)	17,991	29%	$2	$100	
Firm fuel supply	Gas generators procuring firm transportation services; upgrades to dual-fuel capability; installation of on-site oil storage tanks	10,110	16%	$30	$100	
Multiple unit investments	Two or more of the above	3,554	6%	N/A	N/A	
Environmental investments	Emission control upgrades to optimize megawatt-hour output while staying within emissions limits	2,150	3%	N/A	N/A	$32

Source: IHS Markit

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of investments the PJM generators reported along with the range of costs for each type of investment and the associated capacity involved in each response.

PJM capacity performance rule changes and the increased reliance on natural gas–fired resources altered the exposure of PJM power supply to natural gas–fired generation risk factors. The current vulnerability of PJM to the availability of natural gas–fired capacity became apparent when PJM faced another significant deviation from normal winter operating conditions during the bomb cyclone event during the winter 2017/18. The bomb cyclone cold snap was not as severe as the polar vortex episode, yet natural gas–fired capacity availability was again disproportionately reduced. The bomb cyclone conditions drove the 7 January 2018 PJM installed capacity forced outage rate to 12.1%, and the 35% of installed PJM capacity that consists of natural gas–fired resources accounted for 59% of the PJM capacity outages.

The bomb cyclone episode indicates that if the PJM net dependable nuclear capacity had been replaced by an equivalent amount of net dependable natural gas–fired capacity and the gas supply infrastructure had also been proportionately expanded to provide the same natural gas–fired capacity availability factor as experienced during the bomb cyclone, then the available capacity on 7 January 2018 would have been 5.2 GW lower. Under these conditions, PJM would have had to exercise the remaining emergency operating procedures and would likely have been pushed beyond its limits and forced to shed load during the bomb cyclone.

The 2014 polar vortex and the 2017/18 bomb cyclone events show that replacing the net dependable PJM nuclear capacity with an equivalent amount of net dependable natural gas–fired capacity results in a higher loss of load probability and a lower level of reliability. The costs incurred to increase resiliency in response to the PJM capacity performance rules indicate that if unresolved PJM market distortions lead to uneconomic nuclear power plant closures, then replacing the lost resiliency provided by these resources in the generation portfolio will involve significant costs. Since cost-effective nuclear resources in the PJM supply portfolio provide inherent capacity resilience, replacing this source of zero-cost capacity resilience results in higher power bills for consumers.

Since the uneconomic closure of PJM nuclear capacity increases the cost of achieving the equivalent level of capacity resilience, adjustments to the PJM capacity demand curve are likely to replace only some of the lost resilience because a rebalancing of the costs and benefits of capacity resilience results in a lower level of cost-effective resilience.

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The bottom line is that uneconomic PJM nuclear retirements will result in higher costs of capacity resilience, lower levels of cost-effective reliability, and higher expected annual consumer outage costs.

Consumers reveal preferences for affordable electric supply with production cost resilience

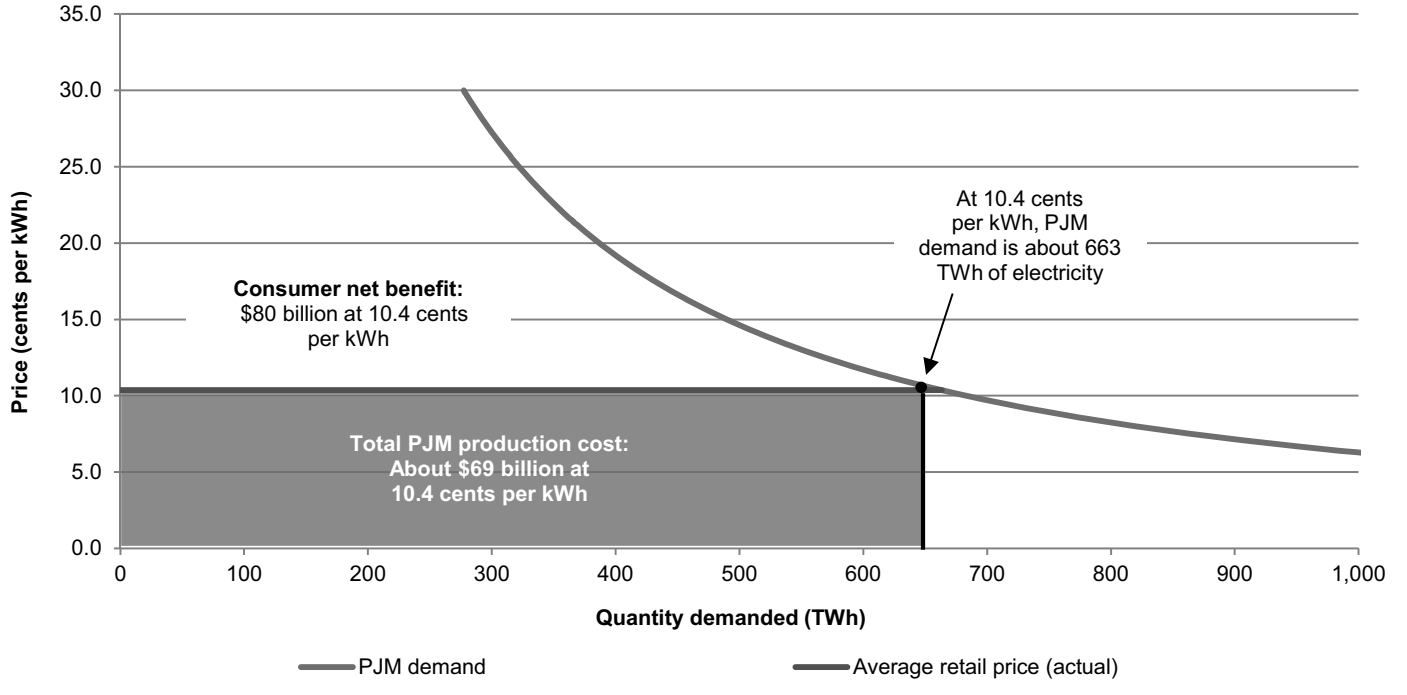
Consumers reveal a preference for affordable electric service. In 2016, electricity consumers within PJM purchased 663 billion kWh of grid-based power and paid an average retail price of 10.4 cents per kWh. These consumers had a choice to purchase electricity from the grid or to generate their own electricity off the grid. Self-generation is typically far more expensive than grid-based electricity supply because regional power grids can integrate a cost-effective mix of fuels and technologies that exploit available economies of scale that are well beyond the scale of self-generation. Therefore, the choices of most households and businesses to purchase grid-based electricity reveals a preference not to pay more than is necessary for electricity service.

Consumers also reveal that they value grid-based electricity more than what they pay for it. Consumers reveal the value that they place on different amounts of grid-based electricity purchases through the choices that they make when the price of electricity changes. For example, when the electricity price goes up, consumers choose to forgo buying some, but not all, of the electricity that they purchased at the lower price. This change in consumption indicates that the value of the forgone electricity consumption was not worth the higher price and, conversely, that the value of the new level of electric consumption is greater than or equal to the new higher price.

Analyses of consumer behavior allows for the estimation of the relationship between the amount of electricity consumers purchase at different price levels—a relationship illustrated by the 2016 aggregate PJM grid-based electricity demand curve shown in Figure 3. Appendix A explains the statistical analyses of the long-standing differences in electricity retail price and consumption levels across states and consumer segments.

Figure 3

PJM grid-based electricity demand (long run), 2016



Source: IHS Markit

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The area under the PJM demand curve from the origin to the actual consumption level in 2016 provides an estimate of the total value consumers in PJM put on electricity consumption. In 2016, a conservative estimate of the total value consumers in PJM put on electricity consumption was $149 billion. The estimate is conservative because it measures only the area under the PJM demand curve below the 30 cents per kWh level. The 30 cents per kWh price is the highest observed retail price in the United States, and limiting the price range in this assessment aligns with the statistically reliable demand curve estimated across the range of observed retail price levels in the United States.

Figure 3 also shows the observed 2016 average retail price (10.4 cents per kWh) and the corresponding observed level of aggregate consumer electricity consumption on the demand curve (663 billion kWh). The shaded area of the rectangle defined by the average retail price times the level of electricity consumption shown in Figure 3 indicates the $69 billion direct cost of grid-based electricity to PJM consumers in 2016.

Electricity consumption produces a net benefit for consumers equal to the value they place on their electricity consumption minus the direct cost of the electricity. Economic textbooks describe this value of consumption over what consumers pay as the "consumer surplus."

Table 4 shows that the 2016 PJM consumer net benefit from grid-based electricity consumption was about $80 billion along with estimates of the consumer net benefit from consumption of PJM grid-based power supply in 2013 through 2015. The implication is clear—consumers in PJM valued the electricity that they consumed over the recent past more than twice the amount that they paid for it.

Table 4

PJM consumer net benefits, 2013–16
(billion dollars, nominal)

Year	Revealed consumer electricity valuation	Consumer direct retail electricity supply cost	Consumer net benefit	Ratio of electricity value versus cost
2016	$149	$69	$80	2.2
2015	$148	$69	$78	2.1
2014	$148	$68	$80	2.2
2013	$145	$66	$80	2.2

Source: IHS Markit, Energy Information Administration (EIA) © 2018 IHS Markit

With this consumer benefits to cost ratio, it is not surprising that consumers complain when electric service restoration from an outage is slower than expected, even though a continuing outage lowers the consumer's power bill.

Analysis of consumer net benefits from grid-based electricity consumption indicates that maximizing consumer net benefits requires efficient electricity production. Since consumers demand different amounts of grid-based electricity at different points in time, an efficient electric supply portfolio involves a diverse mix of fuels and technologies that reflect a cost-effective alignment of available alternative electric generating resource performance characteristics to the pattern of aggregate consumer demand through time.

Nuclear resources are part of the cost-effective PJM fuel and technology power supply mix because nuclear output cost-effectively aligns with the steady 24/7 base-load segment of consumer demand that accounts for 60% of annual PJM electric load. As a result, replacing existing PJM nuclear resources with costlier power supply alternatives is uneconomic. The implication is that if uneconomic nuclear power plant closures and replacements make PJM grid-based electricity more expensive than it needs to be, then consumers lose quantifiable net benefits from electricity consumption.

Consumer net benefits from electricity consumption are uncertain because electricity production costs are uncertain. Power supply cost risk factors include the uncertainty in relative fuel prices for power generation

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caused by multiyear fuel price cycles, strong seasonal price movements, and periodic episodes of extreme price spikes reflecting the impact of disruptions in normal operating conditions in the fuel supply chain.

The shale natural gas revolution continues to benefit the US economy and to make natural gas–fired generating resources a major component of cost-effective power supply portfolios. Natural gas–fired resources are part of the cost-effective PJM power supply mix, particularly as a flexible resource to meet the variable segment of PJM aggregate consumer demand. This role for natural gas–fired resources results in the delivered cost of natural gas disproportionately affecting the cost of PJM electricity to consumers. Rival natural gas–fired generators' SRMC supply bids set the market-clearing wholesale electric energy price in response to changing demand levels in the PJM marketplace most of the time. As a result, the natural gas–fired share of marginal generation is greater than the natural gas–fired share of overall generation. Thus, the marginal costs of natural gas–fired resources exert a disproportionate influence on overall PJM wholesale price setting.

PJM natural gas–fired generators face long-run natural gas price cycles. The expected operating lifetime of a natural gas–fired power plant spans several decades. This links the input fuel price and fuel availability at these power plants to the long-run dynamics of the natural gas business landscape. A brief review of the dramatic changes in the natural gas industry landscape across the past several decades illustrates how several factors—disharmony between market forces and regulatory processes, consumer and producer recognition and adjustment lags, and changes in technology—combine to create dynamic natural gas price cycles in the long run.

- In the 1970s, the oil embargoes generated historically high oil prices and competitive forces drove the substitution of natural gas for oil in many energy end-use applications in the US economy, including in the generation fuel input mix for electric generation. However, at that time, disharmony between the regulatory process and competitive forces created disconnects between demand and supply trends and caused a failure to provide a sufficient price signal to incentivize development of the needed additional natural gas supply. The resulting shortages not only produced historically high price levels but also forced natural gas curtailments to consumers and ultimately generated legislated restrictions for the use of natural gas. These conditions led to contractual commitments between consumers and producers focused on security of supply, which later proved expensive as the natural gas industry moved into an era of deregulation and lower prices.

- In the 1980s, the tension between regulatory processes and market forces drove the deregulation of the natural gas industry, which resulted in a greater reliance on competitive markets to determine investment, resource development, and price levels.

- In the second half of the 1980s and in the 1990s, the transition to rely more on market forces and less on regulatory processes proved disruptive to the existing contractual commitments made during the prior era's regulatory regime. Market forces, combined with actions to unwind regulatory arrangements, produced an era of supply increases outpacing demand increases. These conditions produced historically low natural gas prices. Eventually, this "gas bubble" discouraged drilling for additional natural gas supply development while, at the same time, encouraging the growth of a natural gas–fired power plant development pipeline.

- In the early 2000s, the failure to recognize and adjust to the increasing gap between rising natural gas demand and the gradual depletion of conventional natural gas resources led to a multiyear upswing in natural gas prices and triggered investments to enable imports of LNG to satisfy expected increases in demand at these higher price levels. However, the upswing in natural gas prices drove the development of hydraulic fracturing techniques along horizontal drilling capabilities that unleashed shale and tight sands natural gas production, which led to aggregate supply outpacing demand by 2007 and subsequently causing a dramatic price decline from 2008 to 2009.

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- In the 2010s, the evolving state of technology and associated declining marginal cost of shale gas resource production drove the need to reconfigure the natural gas supply chain to accommodate the changing flow patterns arising from the shift in the geographic center of gravity of natural gas production toward Appalachia and the concentration of demand growth in the south and southwest—a shift that is currently proving to be a challenge to the timely delivery of incremental supply to meet the needs of areas with growing demand. Low-probability but high-impact events such as the polar vortex in 2014 and the bomb cyclone in 2017/18 are exposing the current vulnerabilities in the shifting natural gas supply chain.

The current natural gas business landscape remains dynamic. Although innovations in the extraction of shale natural gas continue to significantly expand the economically recoverable natural gas resource base, the typical shale gas well has a more rapid production decline rate through time compared with a conventional natural gas well. As a result, shale gas production must be continually replenished by additional in-fill drilling or new exploratory drilling and field development. However, the natural gas supply chain—including wellhead and transportation capacity—is capital intensive, and investment requires a sufficient price signal to incentivize the development of new supply. Multiyear lags exist between the recognition of the price signal, the capital investment decision, the eventual production increase, and the expansion of pipelines and storage facilities. These natural gas industry recognition and adjustment lags cause the high degree of variation in the US natural gas–directed rig count (see Figure 4).

Figure 4

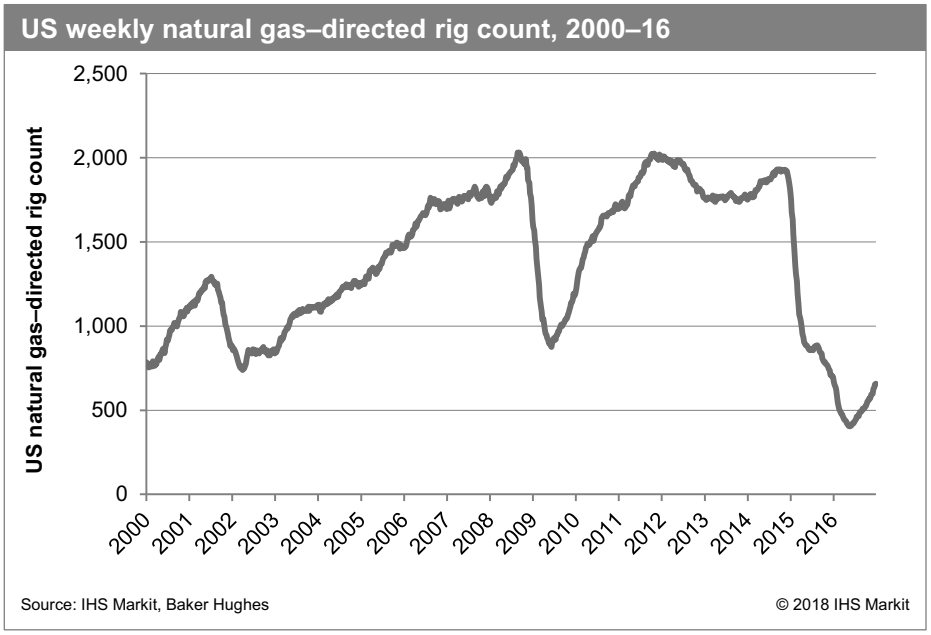

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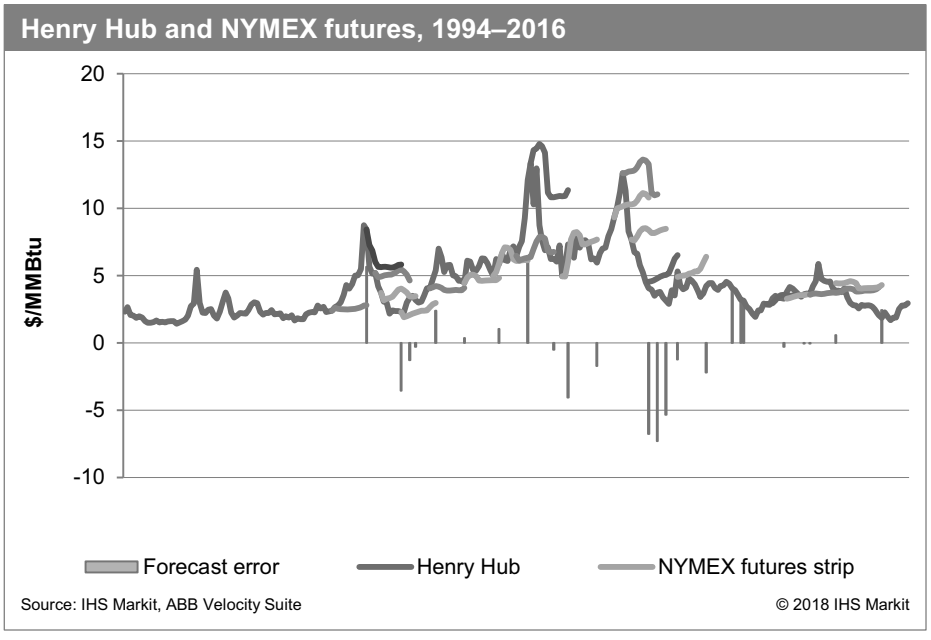
Figure 5



The swings in drilling activity are a driver of the long-run natural gas price cycles shown in Figure 5. Anticipating the timing of these multiyear price cycles has proven difficult as the Henry Hub futures price strips that are regarded as the marketplace consensus forecast of prices have proven to be a poor and biased indicator of the future Henry Hub spot price.

The drivers of multiyear natural gas price cycles are not going away, and neither is the difficulty in anticipating the timing of

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these price cycles. Prudent risk management involves recognizing the risk profile associated with multiyear delivered natural gas price cycles with hard-to-predict timing across the operating lifetime of a natural gas generating plant.

Natural gas deliverability constraints also involve multiyear cycles. Competitive natural gas–fired generators require pipeline capacity to move natural gas from the well to the burner tip. However, since a natural gas–fired generator's future fuel requirements are uncertain, competitive generators are unlikely to contract for long-term pipeline capacity that fully covers fuel delivery requirements. In addition, competitive natural gas–fired generator cash flow shortfalls due to market distortions reduce the financial capacity of these generators to pay for the desired partial contracting of the firm fuel supply. Consequently, the construction of power plants without firm transportation capacity sets up the possibility that natural gas fuel deliverability may not keep pace as power generation requirements change through time.

Significant natural gas pipeline investment is currently needed because the shale gas revolution shifted the location of natural gas supply and altered natural gas flow patterns away from the flow patterns dictated by delivering peak winter natural gas demand for home heating demand that shaped much of the existing gas pipeline infrastructure topography. The rise of the Marcellus Shale, in which there was no production as recently as 2008, currently accounts for 40% of US production and significantly altered the center of gravity of production in North America, with the associated attendant stress on the pipeline grid.

Physical pipeline flow constraints exist and increase the probability that all the natural gas needed for power generation will not always be available. Construction of pipeline infrastructure is triggering increasing political opposition, particularly in the eastern United States, and this political opposition to new pipelines limits the possibility of eliminating natural gas deliverability constraints.

Hydraulic fracturing has become controversial, and since it is the primary technological innovation that drove the growth of US shale gas production, natural gas supply hinges on the future of hydraulic fracturing. A permanent ban on hydraulic fracturing exists in some states, and if the political forces behind these bans can produce temporary or wider constraints or bans on hydraulic fracturing in the future, the impacts will quickly diminish production owing to the high initial decline rates that characterize shale production.

The current PJM natural gas supply chain operates at a relatively high utilization factor, with wellhead productive capacity routinely operating at a utilization rate of about 98%. At such a high utilization rate, shifts away from expected normal levels of demand, either up or down, typically results in large short-term price movements to bring demand back into balance with supply. Natural gas–fired power generators face the risk of seasonal or shorter-duration natural gas price run-ups as well as brief episodes of days or weeks when natural gas prices spike at multiples of the normal price level.

Natural gas storage infrastructure provides some short-run capacity to manage unanticipated ups or downs in natural gas demand. However, natural gas storage involves a seasonal injection and withdrawal pattern that manages the inverse strong seasonality in aggregate consumer natural gas demand. As a result, using the flexibility of natural gas storage to manage short-run shocks to demand and supply alters the expected seasonal injection or withdrawal pattern. For example, US lower-48 storage inventories were nearly 1 Tcf below the five-year average inventory at the end of March 2014 following the polar vortex. As a result, the accumulation of short-run storage adjustments across a season can produce inventory surplus or deficit conditions that cause a ripple effect on natural gas prices until inventory levels return to normal, an adjustment process that can take a year or more.

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The bottom line is that as PJM becomes more dependent on natural gas–fired generation, a risk exists in the short run that the expansion of natural gas supply—production, storage, and delivery—will not expand in sync with overall demand changes and short-run price variability will likely wax and wane in the years ahead.

The current risks in the power generation natural gas fuel supply chain led the US Department of Energy (DOE) to conclude, "Capacity challenges on existing pipelines combined with the difficulty in some areas of siting and constructing new natural gas pipelines, along with competing uses for natural gas such as for home heating, have created supply constraints in the past. Supply constraints can create increased price risk and, in extreme cases, could impact reliability."[10]

Fuel price and deliverability risks are not unique to natural gas. However, the current size of the PJM natural gas–fired generation share, and the dominance of natural gas–fired capacity in the PJM new electricity supply pipeline, focuses attention on increasing exposure to natural gas risk factors. Assessments of overall fuel supply risk factors indicate that price movements and deliverability constraints are not highly correlated across all fuels used to generate electricity.

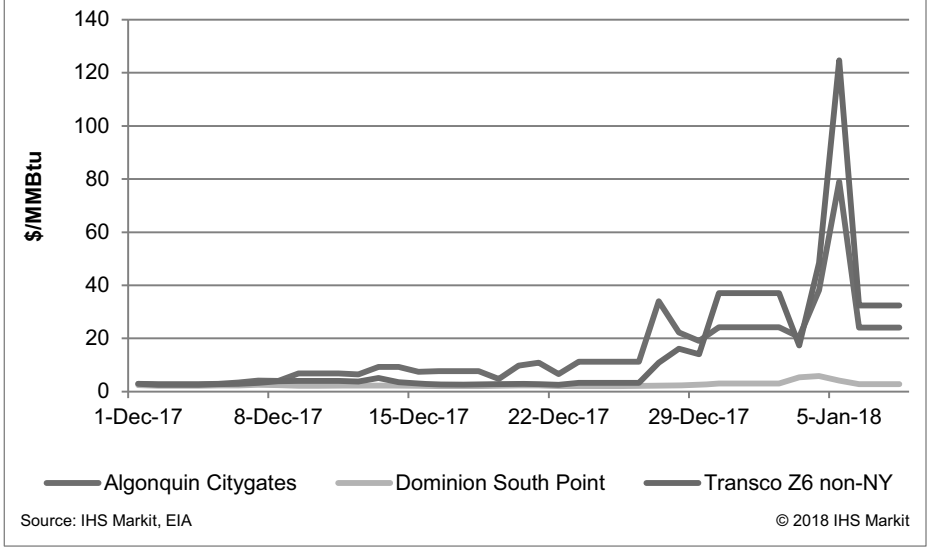
Efficient diversity in a power supply portfolio provides more stable and more predictable consumer monthly power bills because a diverse power supply portfolio mutes the impact of any single fuel price change on overall power system production costs. In addition, the cost-effective diversity of an efficient power supply portfolio also provides the capability to lower overall production costs by enabling the substitution away from more expensive generation and toward less expensive generating resources as relative generating costs change in the dispatch of supply to demand in real time. Consequently, efficient diversity in a power supply portfolio provides an inherent ability of grid-based power supply to withstand and reduce the magnitude and/or duration of disruptive events on grid-based power supply costs. As the National Academies of Sciences, Engineering, and Medicine notes, "Resilience is broader than reliability."[11] From this broader perspective, resilient grid-based power supply provides the capacity to reduce the magnitude of variations in the expected costs of electricity production.

Recent events illustrate how the uncertainty of fuel costs and the periodic changes in fuel deliverability constraints create hard-to-anticipate, real-time power production cost variability. During the 28 December 2017 to 7 January 2018 winter cold snap designated the "bomb cyclone" event, weather conditions caused a hard-to-predict and significant deviation from expected natural gas prices and delivery conditions.

The bomb cyclone event caused a spike in the delivered fuel costs of rival natural gas–fired PJM generators. Figure 6 shows that on

Figure 6

Average daily delivered price of natural gas to PJM power sector: 2017/18 winter



Source: IHS Markit, EIA

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10. Staff Report to the Secretary on Electricity Markets and Reliability, August 2017, US DOE.

11. National Academies of Sciences, Engineering, and Medicine, *Enhancing the Resilience of the Nation's Electricity System, National Academies Press,* Washington, DC, 2017, p. 1, https://doi.org/10.17226/24836, retrieved 13 December 2017.

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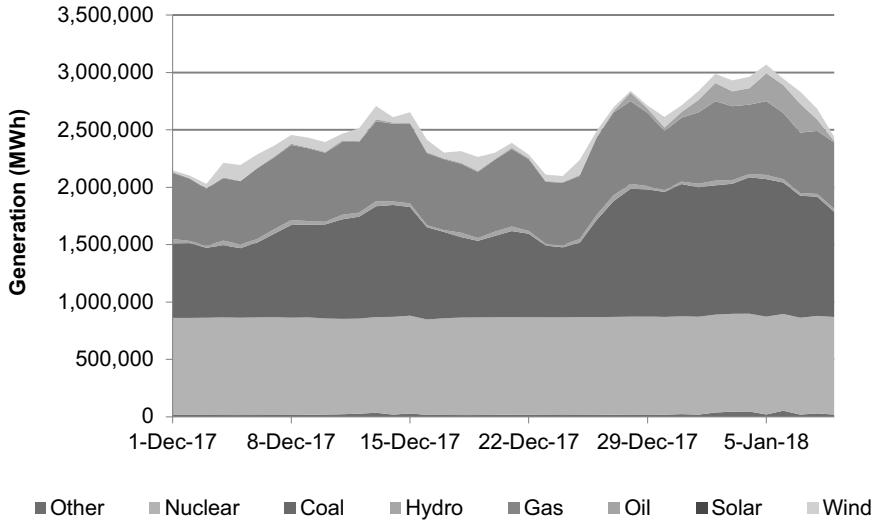
5 January 2018, the Transco Zone 6 non-NY spot price reached $124.7/MMBtu, representing a 40-fold increase from the average daily price in 2017 and a 35-fold increase from the average daily price in January 2017.

Natural gas–fired generation accounts for a minority of PJM generation output, but since natural gas–fired SRMCs disproportionately influence PJM market-clearing energy price levels, the delivered cost of natural gas price spikes caused the market-clearing hourly wholesale price of electricity in PJM to increase 20-fold, from an average of $29.4/MWh in 2017 to a peak of $586.40/MWh on 7 January 2018.

Figure 7

PJM generation by fuel type during 2017/18 bomb cyclone



Source: IHS Markit, PJM

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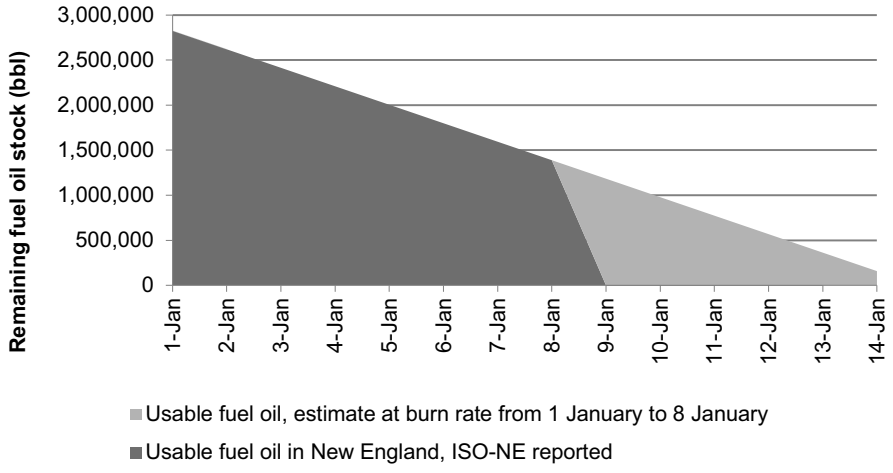
As Figure 7 shows, as the bomb cyclone unfolded, the natural gas–fired share of PJM electricity declined while generation shares increased from nuclear and other fossil resources, especially oil-fired capacity. This resilience in power supply and production costs was a direct result of the lack of correlation of risk factors among the diverse fuel and technologies employed in the current PJM generating portfolio.

During the bomb cyclone, oil-fired generation shares increased significantly, particularly in New England and other natural gas–constrained regions. The share of generation from oil-fired units exceeded 30% for six consecutive days in ISO New England (ISO-NE). This increase in generation shares from oil-fired units accelerated the depletion of on-site inventories of fuel oil. Over the course of one week, the total usable fuel oil for power generation in New England was depleted by about 50%. As shown in Figure 8, if burn rates had continued at a similar pace, without resupply, the region would have nearly fully depleted available fuel oil inventories in one week.[12]

Figure 8

Depletion of fuel oil stock at New England power plants, 1–8 January 2018 (actual); 9–14 January 2018 (estimate)



Note: Inputs account for no replenishment of fuel oil stock.
Source: IHS Markit, ISO-NE

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12. ISO-NE, *Cold Weather Operations: December 24, 2017–January 8, 2018*, 16 January 2018, https://www.iso-ne.com/static-assets/documents/2018/01/20180112_cold_weather_ops_npc.pdf, retrieved 2 March 2018.

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In scenarios where nuclear capacity was unavailable, the region would have been even more fuel constrained. For example, if New England's nuclear power generating capacity had been retired and replaced by a combination of natural gas– and/or oil-fired generation, the region would have burned even more oil during the storm and left inventories completely or close to fully depleted.

Consumers reveal a preference for stable and predictable electricity costs. The deployment of advanced metering, communication, and control technologies across the past decade enabled a wide range of consumers the option to choose retail electricity prices that reflected real-time wholesale electricity marginal costs. These "time-of-use" retail pricing schemes involved less stable and less predictable electricity costs than traditional average cost–based retail pricing schemes. A minority of electric consumers, consisting primarily of large commercial and industrial users with flexibility regarding when they consume electricity, revealed a preference for real-time pricing schemes. By contrast, when most consumers were given the choice, they revealed a preference for the retail electricity prices with less variability and more predictability than the "time-of-use" prices.[13] The choices suggest that most electricity consumers are residential and small commercial consumers who typically do not have the flexibility to benefit from shifting electricity use through time in response to real-time price changes and, therefore, find little upside to choosing more variable real-time electricity pricing options. The bottom line is that most consumers reveal a preference for resilience in power supply costs.

Cost-effective nuclear generation shares in an efficient, diverse PJM power supply portfolio provide inherent electric production cost resilience. Since the production cost risks of nuclear plants are not highly correlated to risks associated with nonnuclear fuels and generating technologies, the nuclear generation in the PJM power supply portfolio makes power production costs more stable and less variable compared with the production costs of the current PJM replacement power resource mix. Since cost-effective nuclear generation in the PJM supply portfolio provides consumers with inherent electric production cost resilience, this resilience comes at zero cost to consumers.

The bottom line is that if the uneconomic PJM nuclear capacity closure and replacement results in less production cost resilience, then consumers face more varied and less predictable monthly electricity bills unless other mechanisms, such as financial hedging instruments, are employed to restore the production cost resilience lost due to premature nuclear power plant closures. Since these other production cost risk mitigation options are more expensive, a balancing of the costs and benefits of production cost risk management results in higher costs and a lower expected level of production cost resilience.

Public policies harmonized with wholesale market operations can meet consumer preferences for cost-effective resilience in electric availability and production costs

Alignment of government policies with a well-structured electricity market design is necessary for efficient market outcomes. Addressing resilience challenges does not involve choosing between markets and regulation to organize and coordinate electric system operations. Instead, the resilience issue shows that efficient electricity market outcomes are not possible without enabling government involvement and policy and market harmonization. The importance of public policy and market harmonization is often underappreciated because many fundamental government market interventions for efficient market operations are taken for granted. For example, court systems enable electricity market interactions by providing the mechanisms to make electricity market transactions enforceable, and government regulations setting the financial disclosure requirements and accounting standards for companies enable efficient market allocation of capital to electric

13. See the IHS Markit Multiclient Study *The "Smart Grid Narrative" and the "Smarter Grid": Revolution versus Evolution—Which Way Forward?*

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Regulatory market interventions*

The market model benchmark:

The main body of microeconomic theory can be interpreted as describing how, under proper conditions, an unregulated economy will produce optimum economic results.

The economic rationale for regulation:

That for one or another of many possible reasons, competition simply does not work well.

The principle of regulation:

The single most widely accepted rule for the governance of the regulated industries is regulate them in such a way as to produce the same results as would be produced by effective competition, if it were feasible.

*Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions,* vol. 1, MIT Press, Cambridge, Massachusetts, 1998 (original publication 1970), pp. 11 and 17.

infrastructure investments. The bottom line is that federal oversight and ongoing adjustments of regional reliability standards and wholesale electricity market rules and institutions are necessary to enable efficient electricity market operations.

Alfred Kahn wrote the textbook on government regulation and established the principle that government involvement in the marketplace needs to enable effective competition (see the box "Regulatory market interventions").

From this perspective, effective wholesale electricity market competition involves a coordinated mix of competitive forces and regulatory processes that produce the timely price signals to govern the engineering and economic trade-offs that shape a diverse mix of fuels and technologies that cost-effectively align with the recurring annual hourly pattern of aggregate consumer demand, and allow for the efficient utilization of available resources, subject to the security of supply constraints in an AC power system. These conditions produce a well-functioning electricity market capable of reliably balancing power system demand and supply—in both the short and long run—to provide the electric services that consumers want, whenever they want them, at a price that internalizes all costs. Appendix B outlines the characteristics of an efficient wholesale electric market outcome.

Consumer demands for affordable electricity require achieving the lowest overall cost of the security-constrained economic dispatch of electric supply by harmonizing public policies and market operations to meet consumer demands. Enabling public policies can produce effective competition only by insuring that similarly situated rival generators are treated equally and that all costs are counted in the marginal cost–based competition.

Consumer demands for reliable electricity require harmonizing public policies and market operations to ensure effective competition yields a capacity price that complements the market-clearing electric energy price to provide a timely investment signal that maintains a capacity reserve that delivers a loss of load probability that balances the costs and benefits of incremental losses of load.

Consumer demands for resilient production costs require harmonizing public policies and market operations to ensure effective competition generates capacity and energy prices that drive each supply resource to balance the costs and benefits of investments providing cost and operating resilience to the specific fuel and

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technology risk factors. Since the risk factors associated with each fuel and technology pairing have weakly correlated risk factors, harmonized public policies and market operations also shape an efficient mix of fuels and technologies whose cost-effective diversity provides inherent resilience in overall power production costs to mitigate the potential impact of significant deviations from normal operating conditions.

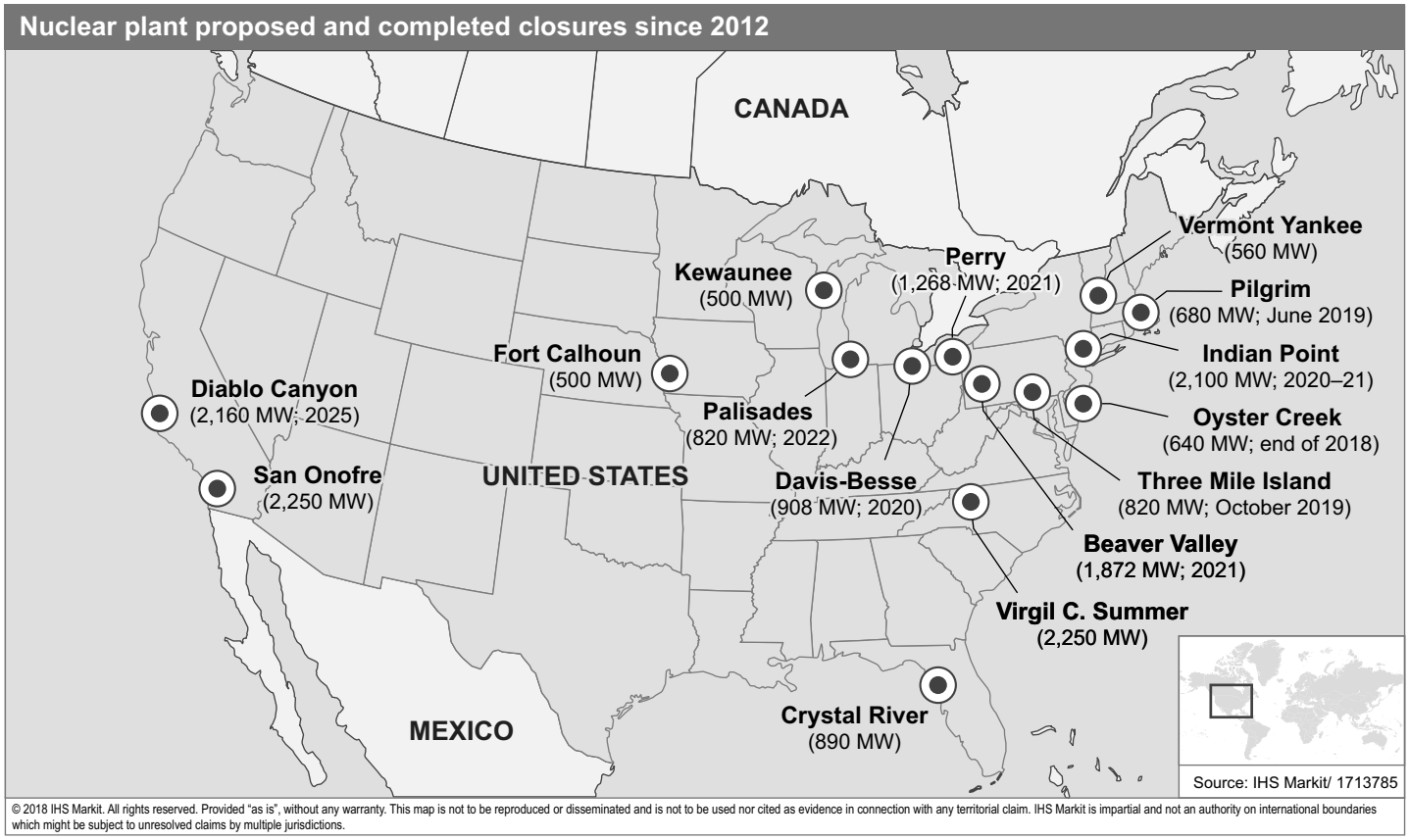
Environmental responsibility requires harmonization of public policies and market operations to enable efficient trade-offs of environmental costs and benefits. Such trade-offs ensure that investments to reduce CO_2 emissions deliver the greatest bang for the buck.

The bottom line is that an efficient market outcome provides a benchmark to access market outcomes distorted by the unequal treatment of similarly situated rival generators. Appendix C describes the predictable market distortions that arise under these conditions.

A loss of resilience due to uneconomic PJM nuclear closures is a plausible scenario

Costly premature PJM nuclear power plant closures present a plausible scenario. Such a scenario is already unfolding in other US power systems where the discord between public policy initiatives and wholesale market operations has already contributed to the premature closure of six nuclear plants in the past eight years and announced plans for eight more in the next eight years (see Figure 9). The recent FirstEnergy Solutions announcement of the premature deactivation of more than 4,000 MW of PJM nuclear resources is the leading edge of the potential rapid loss of PJM nuclear resources. The potential consequences of rapid, premature PJM nuclear closures on power system reliability, resilience, costs, and CO_2 emissions are apparent from experiences in other power systems.

Figure 9



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The consequences of unresolved discord between public policies and California Independent System Operator (CAISO) market operations is a harbinger for other power systems, including PJM. Market distortions contributed to the decisions within a span of three years to close and replace all four nuclear units and drive the in-state generation share of nuclear resources from 18% to zero within a dozen years. The lack of harmony has already caused the in-state nuclear generation share to decline from 18% to 10% in the five years from 2012 to 2016, and announced premature nuclear closures will eliminate nuclear generation in California by 2025. The consequences of the closure and replacement of nuclear capacity and energy in California already include

- **Costly capacity and energy replacement.** The replacement of nuclear capacity and generation outputs with more expensive wind, solar, and natural gas–fired resources caused California power price increases to outpace US average retail electricity price changes and pushed the California average retail electricity price in 2016 to a 50% premium to the US average.

- **CO_2 emission boomerang.** The replacement of California nuclear generation with renewable resources integrated by natural gas–fired resources to back up and fill in for the intermittent output patterns shifted most of the in-state generation to fossil fueled resources. The associated rebound in CO_2 emissions resulted in California electric generation CO_2 emission levels remaining the same in 2016 as the levels observed 15 years ago when California legislation mandated the first renewable power generation shares. As a result, California did not make an environmentally responsible trade-off of higher costs in exchange for lower CO_2 emissions.

- **Ad hoc market interventions to address unresolved market distortions.** The interventions arose to create compensation for selected generation attributes. In 2013, CAISO recognized that the suppression of CAISO wholesale market-clearing prices caused a cash flow shortfall for the continued operation of generation resources required for reliable electric supply. As a result, CAISO implemented market interventions in 2014 to augment energy market cash flows for flexible generation resources needed to back up and fill in for mandated intermittent resources by implementing ramping products to provide out-of-market payments for these selected attributes.

- **Reduction in power supply resilience.** This reduction is due to the increased exposure to natural gas supply risk factors associated with the greater reliance on natural gas in the generation portfolio. The Aliso Canyon natural gas storage outage discovered in 2015 constrained fuel deliveries and forced the in-state generation share for natural gas to decline from 61% to 50% from 2014 to 2016.

- **Inefficient market operations.** The inefficiencies involve larger cost burdens associated with managing overgeneration market conditions reflecting the mismatch between intermittent generation and aggregate consumer demands. The inefficiency results in higher costs from increasing renewable power curtailments and growing Energy Imbalance Market sales at prices well below what California consumers had to pay for the renewables.

- **Lower consumer net benefits.** Higher electricity prices and the associated consumer demand reductions lowered the annual California consumer net benefit from electricity consumption.

The bottom line is that decisions to prematurely close nuclear power plants and reduce the PJM nuclear generation share of firm capacity from 20% to zero within a dozen years is a plausible scenario because PJM could follow the example of California. In California, persistent, unresolved discord between public policies and market operations is eroding the consumer net benefits from electricity consumption, as well as the resiliency and environmental responsibility of power supply coming from nuclear resources.

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The analytical framework to assess the potential impact of uneconomic nuclear closures in the PJM power supply portfolio

Assessing the current value of nuclear generation in the PJM power supply portfolio involves the comparison of the performance of the PJM power supply portfolio with and without nuclear resources.

This assessment of the value of current nuclear resources evaluates alternative PJM power supply portfolio performance using a backcasting analysis across the most recent four years (2013 to 2016) to analyze the impacts of uneconomic PJM nuclear power plant closures. A backcasting approach uses the range and severity of deviations from expected normal operating conditions in the recent past to provide a realistic "wind tunnel" to test how the loss of PJM nuclear capacity affects overall power system production costs, as well as assess how nuclear power in the supply portfolio affects the resilience of PJM outcomes to a realistic profile of instability and deviations from normal operating conditions.

A forecasting approach can also incorporate a realistic risk profile through sensitivity analyses of forecast simulations. However, forward-looking sensitivity analyses need to foresee the risk profile of the power system operating environment. As the National Academies of Sciences, Engineering, and Medicine study notes, resiliency involves assessing how robust power systems operations are to disruptions, including those that may not be foreseen.[14]

Besides the possibility of unforeseen risks, behavioral economists observe that most people view themselves, the world, and the future in a considerably more positive light than is objectively justified or than reality can sustain.[15] Therefore, employing a forecasting approach creates the risk of bias toward underestimating the risk profile of future electric system operating conditions. To see this, imagine a PJM forecast sensitivity analysis developed four years ago that included the 2014 polar vortex episode, no PJM load growth, Hurricane Sandy (second-most destructive storm in US history), the demise of the Clean Power Plan, and daily delivered natural gas prices ranging from $0.5/MMBtu to $121.2/MMBtu. Building a consensus that this scenario represented a realistic risk profile would have been difficult because of the perception that these events occurring over a four-year interval was unrealistic. Yet experience shows that this is exactly what happened as the years unfolded.

Experience shows that deviations from expected normal electric system operating conditions are inevitable. The implication is evident in a recent PJM market assessment concluding that, "Relying too heavily on any one fuel type may create a fuel security or resilience issue …. But, a moderate level of diversity helps to ensure the system's ability to withstand unforeseen system shocks—either operational disturbances caused by contingencies beyond those studied and planned for today or both man-made and natural disasters".[16]

Looking ahead for several decades, the low-probability but high-impact events that caused past deviations from normal operating conditions will no doubt differ from the risk factors that trigger future deviations from expected operating conditions. The probability of another polar vortex episode like 2014 or the bomb cyclone event in 2017/18 may be 1 in 10 years or less. Such a low probability of recurrence can lead to complacency regarding power supply resilience. Similarly, the probability of another hurricane like Sandy in 2012 hitting New Jersey may also be 1 in 10 years or less. Likewise, the probability of another pipeline disruption such as the 2016 Texas Eastern pipeline disruption in Pennsylvania may also be 1 in 10 years. Other potential low-

14. National Academies of Sciences, Engineering, and Medicine, *Enhancing the Resilience of the Nation's Electricity System,* National Academies Press, Washington, DC, 2017, p. 1, https://doi.org/10.17226/24836, retrieved 13 December 2017.

15. Max Bazerman and Michael Watkins, *Predictable Surprises: The Disasters You Should Have Seen Coming, and How to Prevent Them,* Harvard Business School Publishing Corporation, Boston, Massachusetts, 2004.

16. PJM, PJM's *Evolving Resource Mix and System Reliability,* March 2017, http://www.pjm.com/-/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx, retrieved 21 February 2018.

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probability but high-impact deviations from normal operating conditions include a natural gas storage failure like what recently happened at the Aliso Canyon natural gas storage facility in 2014, as well as wildfires, heat waves, droughts, and physical or cyber attacks.

Political risks also define a dimension of the electric operating risk profile. For example, the growing anti–fossil fuel movement is delaying the development of the natural gas supply infrastructure to keep pace with the increased supply requirements of the electricity sector. Such political risks can shift the power production operating environment suddenly.

The consequences of these risk factors can increase when two or more high-impact events occur simultaneously. For example, the risk of a severe seismic event associated with hydraulic fracturing wastewater injections somewhere in United States could interact with the risk of a political overaction. Such an interaction could produce a ban on hydraulic fracturing for natural gas production everywhere, including the Marcellus natural gas fields that supply a significant portion of natural gas for electric generation in PJM. Even if such a ban were temporary, the price and deliverability of natural gas in PJM would likely be dramatically affected for months.

Although the probability of any one of the risk factors happening in any given year is low, the probability of some type of high-impact event that challenges electric system resilience is much higher because the probability of at least one of these events happening is the sum of the probabilities of each of these independent risk factors.

The bottom line is that prudent planning ought to account for a better-than-even chance that a major disruptive event affecting the availability of one type of electric generating resource in the PJM supply portfolio will occur within the next decade.

The backcasting approach helps to address the problem of risk blind spots and risk underestimation by providing a realistic set of significant deviations from expected conditions.

Assessing the potential impacts of uneconomic nuclear closures in the PJM power supply portfolio

Quantifying the impact of uneconomic retirement and replacement of PJM nuclear power plants involves four steps:

- Estimating PJM nuclear resource going-forward costs
- Estimating the cost of generating technologies in the current PJM new supply pipeline capable of providing equivalent capacity and energy outputs as provided by PJM nuclear resources
- Identifying the market inefficiency—retiring power plants that are lower cost to continue to operate than to replace
- Quantifying market inefficiency by estimating counterfactual outcomes from 2013 to 2016 for the PJM nuclear retirement and replacement scenario

PJM nuclear going-forward costs

PJM nuclear power plants account for 34% of the US installed nuclear fleet. Table 5 shows US nuclear power plant going-forward cost assessments from the Nuclear Energy Institute (NEI) differentiated by single-plant

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and multiplant sites.[17] The nuclear going-forward cost represents the average going-forward cost for existing nuclear power plants. The going-forward costs for a particular existing nuclear power plant will differ from the average owing to a variety of factors including different operating and market risk factors.

Table 5

Levelized going-forward costs of existing US power supply portfolio resources, 2016
($/MWh)

Plant type	Levelized cost
Single-unit nuclear plant	41.4
Multiunit nuclear plant	31.6
Average nuclear plant	33.9

Source: IHS Markit, NEI

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PJM new supply pipeline technology cost and performance profiles

The current PJM new capacity supply pipeline is composed of 85% natural gas–fired generating technologies and 15% renewable resources. Consequently, the replacement of the capacity and energy of uneconomic PJM nuclear power plant closures would likely involve a similar mix of technologies.

The cost and performance characteristics of the mix of grid-connected electric generating technologies in the PJM new supply pipeline reflect the EIA cost and performance profiles reported in the Annual Energy Outlook 2016, shown in Table 6 with adjustments to heat rates based on observed heat rates of new generating resources operating in PJM. The size of each generating technology option reflects expected current minimum efficient scale.

The operating lifetime technology parameter is the basis for the calculation of straight line depreciation to account for the consumption of capital in the production process over the life of the asset. The MACRS is the recovery period for accelerated depreciation used when calculating taxes.

Overnight costs are the total of all cost components for the project based on prices in a single year. The wind overnight costs include a transmission investment adder to reflect the incremental grid investment associated with the project interconnection to the network.[18] Renewable transmission cost adders are higher than thermal power plant transmission cost adders for two reasons. First, wind and solar resources are typically farther away from consumer loads than thermal generation technologies and therefore require longer radial spur transmission connection to the grid. Second, renewable resources are smaller and more geographically dispersed and, thus, require more granular linkages to more sites. For example, in Texas, the expansion of wind energy required about $6 billion of transmission investment to link the Competitive Renewable Energy Zones to load centers. The transmission cost adder in the Electric Reliability Council of Texas was $600/kW of

Table 6

Electric generating technology cost and performance characteristics in PJM

Technology	Size (MW)	Lifetime/ MACRS (years)	Overnight costs (2017$/kW)	Lead time (years/ CFUDC)	Contingency factor	Variable nonfuel O&M (2017$/MWh)	Fixed O&M (2017$/kW-year)	Heat rate (Btu/kWh)
Wind	100	20/7	$1,548	1/1.07	1.07	$0.0	47.5	
Solar PV, with tracking	150	20/5	$2,004	1/1.07	1.05	$0.0	22.0	
Natural gas–fired combined cycle	429	30/20	$1,026	3/1.15	1.08	$4.0	10.1	7,010

Note: MACRS = modified accelerated cost recovery system; CFUDC = cost of funds used during construction; O&M = operations and maintenance.

Source: IHS Markit, EIA

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17. NEI, *Nuclear Energy 2016: Status and Outlook, Annual Briefing for the Financial Community,* 11 February 2016.

18. Estimates of typical incremental transmission investments are based on Andrew D. Mills, Ryan H. Wiser, and Kevin Porter, *The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies,* Lawrence Berkeley National Laboratory, 2009, https://emp.lbl.gov/publications/cost-transmission-wind-energy-review, retrieved 27 March 2018; and National Academies of Sciences, Engineering, and Medicine, *The Power of Change: Innovation for Development and Deployment of Increasingly Clean Electric Power Technologies,* The National Academies Press, Washington, DC, 2016.

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installed wind capacity. An estimate of the incremental transmission investment needed to upgrade the current system capabilities as well as build new transmission to implement the estimated 15,200 MW of new renewable resources required to meet California's 50% renewables goal is $5.8 billion—implying a $382/kW incremental transmission cost adder.[19]

The lead time is the number of years required for project construction. The CFUDC factor reflects the capitalization of the cost of debt and equity funds tied up during construction.

The contingency factor reflects the specific provisions for unforeseen elements of costs within a defined project scope as defined by the American Association of Cost Engineers based on previous experience indicating that unforeseeable cost elements are likely to add to the total costs.

Variable O&M costs exclude fuel costs. Fixed O&M costs are annual costs that are expensed rather than capitalized and more a function of time than of plant annual utilization rates.

The heat rate (British thermal units of fuel input per kilowatt-hour of generation output) measures the efficiency of transforming fuel into electricity. This cost analysis employs a higher heat rate than reported in the EIA Annual Energy Outlook 2016. The EIA heat rate reflects thermal efficiency levels of equipment manufacturer performance specifications that typically express heat rates based on fuel inputs that count only the British thermal units that were converted into electric energy. In the thermal electric generation process, some of the British thermal unit content of the fuel input vaporizes the moisture present in the combustion process, and, as a result, this heat content is not converted into electricity. By contrast, a fuel input that accounts for all British thermal units involved in the electric generation process has a heating value that is higher by about 11%.

This analysis uses a heat rate reflecting all British thermal units consumed in the generation process. Since the prices of fuel inputs for power generation reflect the cost of the total British thermal unit content of the fuel expressed in a dollars per million British thermal units basis, the higher heat rate provides the appropriate transformation of fuel input cost to cents per kilowatt-hour fuel generating cost. The difference between higher and lower heating values explains the 11% difference between the actual average heat rates of new natural gas–fired combined-cycle generating technologies shown in Table 7 and the heat rate specification appearing in cost and performance characteristics of new central station natural gas–fired generating technology specifications of the EIA Annual Energy Outlook 2016.

The variation of heat rates around the capacity-weighted average shown in Table 7 reflect differences in operating conditions affecting the new natural gas–fired combined-cycle power plant heat rates that include altitude, humidity, and ambient air temperature. As a result, the actual operating experience of a new natural gas–fired generator is not as favorable as the equipment manufacturer's generating technology specifications that typically reflect more stable and favorable operating conditions of sea level altitude, 59 degrees Fahrenheit ambient air temperature, and 60% relative humidity.

EIA reports the average realized natural gas–fired power plant heat rate in 2016 was 7,878 Btu/kWh. This indicates that new natural gas–fired combined-cycle power plants operating under actual conditions have a thermal efficiency that is about 11% lower than the average thermal efficiency of installed natural gas–fired generation.

19. Renewable Energy Transmission Initiative 2.0—Transmission Technical Input Group, *Transmission Capability and Requirements Report*, 24 October 2016, http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN214168_20161025T091645_Transmission_Capability_and_Requirements_Report.pdf, retrieved 27 March 2018; and Edison Electric Institute, *Transmission Projects at a Glance*, December 2016, p. vii, http://www.eei.org/issuesandpolicy/transmission/Pages/transmissionprojectsat.aspx, retrieved 27 March 2018.

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Table 7

New central station natural gas–fired generating technology cost and performance characteristics

Plant name	Plant type	State	Online (year)	Nameplate (MW)	Generation (MWh)	Capacity factor	Fuel consumption (MMBtu)	Heat rate (Btu/kWh)
Cherokee	Combined cycle	Colorado	2015	626	2,719,773	49%	19,724,297	7,252
Cane Run	Combined cycle	Kentucky	2015	807	4,882,086	69%	32,874,527	6,734
Nelson Energy Center	Combined cycle	Illinois	2015	571	1,053,862	19%	7,761,892	7,365
Garrison Energy Center	Combined cycle	Delaware	2015	361	1,540,533	49%	10,762,503	6,986
Woodbridge Energy Center	Combined cycle	New Jersey	2015	720	4,751,779	68%	32,571,277	6,855
Panda Temple Power Station	Combined cycle	Texas	2015	1,468	4,336,063	31%	31,325,080	7,224
Newark Energy Center	Combined cycle	New Jersey	2015	685	4,330,434	67%	29,489,358	6,810
Port Everglades	Combined cycle	Florida	2016	1,260	5,997,574	67%	41,166,027	6,864
Brunswick County Power Station	Combined cycle	Virginia	2016	1,371	5,895,472	61%	43,269,513	7,339
Panda Patriot Generation Plant	Combined cycle	Pennsylvania	2016	765	2,942,537	77%	19,841,480	6,743
Panda Liberty Generation Plant	Combined cycle	Pennsylvania	2016	756	2,444,556	64%	16,349,118	6,688
Carty Generating Station	Combined cycle	Oregon	2016	413	1,362,782	62%	9,566,449	7,020
Capacity-weighted average						**57%**		**7,010**

Source: IHS Markit, EIA

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Common cost parameters for power plant development are shown in Table 8.

The fuel input costs for replacement natural gas–fired generating technologies reflect the recent PJM average delivered cost of natural gas for the electric power industry (see Table 9).

Table 8

Common cost parameters for power plant development

Input	Value
Cost of equity	10.5%
Cost of debt	6.3%
Inflation rate	2.0%
Share of debt	60%
Federal tax rate	21.0%
State tax rate	7.0%

Source: IHS Markit

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Table 9

PJM average delivered cost of natural gas for the electric power industry

Year	Trillion Btu	$/MMBtu
2013	1,071	4.2
2014	1,128	5.0
2015	1,457	2.7
2016	1,682	2.2
Weighted average, 2013–16		**3.3**

Source: IHS Markit, EIA

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Identifying market inefficiency

Capacity and energy price signals from an unfettered, efficient market would not cause generating resources to close if their cost of continued operation was lower than the cost of their replacement. Cost-effective power plant retirements occur in a well-functioning marketplace because market-clearing prices reflect the long-run marginal costs (LRMCs) of new power resources and thus provide a signal regarding the cost-effective timing for replacing existing generation. As a result, in an efficient market outcome, an existing resource is economic to operate until the existing resource going-forward costs are not covered by market cash flows reflecting the cost of replacement supply.

PJM nuclear generating plants' going-forward costs are significantly below replacement costs. Figure 10 shows the differences between average going-forward costs for PJM nuclear resources to supply the stable 24/7 base-

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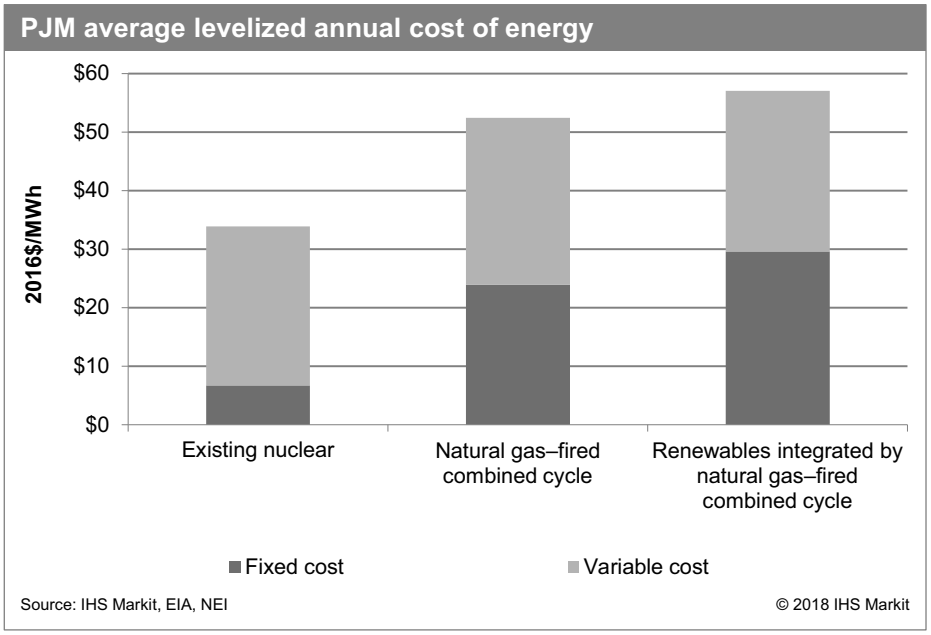
load segment of PJM consumer demand and the cost of replacement capacity and energy from natural gas–fired combined cycles integrated with a mix of intermittent wind and solar resources in the proportions found in the current PJM new power supply development pipeline.

Analyses show that the going-forward costs of nuclear plants increase by less than 1% per year over the observed age distribution of existing plants.[20] Therefore, the existing gaps between the going-forward costs of existing nuclear resources and replacement costs appear persistent.

Figure 10



The bottom line is that premature PJM nuclear power plant retirements are uneconomic because continued operation is less costly than closure and replacement. As a result, an efficient PJM wholesale market outcome would not likely involve premature nuclear power plant closures. The result is not unique to PJM. Analyses of the US electrical interconnection absent the distortions of wind and solar subsidies and mandates, and incorporating an appropriate CO_2 emission charge, indicate that the premature retirement of nuclear power plants—with typical going-forward costs—would be highly unlikely on economic grounds.[21]

Counterfactual outcomes in 2013–16 for the PJM nuclear retirement and replacement scenario

Backcasting PJM demand and supply interactions at a monthly frequency for 2013–16 with the removal of the Oyster Creek nuclear power plant provides a backcasting base case for the PJM nuclear closure and replacement scenario. The base case removes Oyster Creek because its closure is not in doubt. The PJM nuclear power plant closure and replacement scenario involves the closure and replacement of all remaining 18 PJM nuclear units. Table 10 shows differences between the PJM backcasting base case and the PJM nuclear closure and replacement scenario.

The PJM nuclear closure and replacement scenario results in higher power production costs and thus higher retail power price levels compared with the PJM base case. The retail price increases are greatest in 2013–14, when the delivered price of natural gas to electric generators averaged $4.6/MMBtu, compared with 2015–16, when the delivered price of natural gas averaged $2.4/MMBtu.

20. Thomas F. Stacy and George S. Taylor, *The Levelized Cost of Electricity from Existing Generating Resources,* Institute for Energy Research, June 2015, http://instituteforenergyresearch.org/wp-content/uploads/2015/06/ier_lcoe_2015.pdf, retrieved 27 March 2018.

21. Lawrence Makovich, *Tilting at Windmills: Making a case for reframing electric sector climate policies,* Mossavar-Rahmani Center for Business and Government Associate Working Paper No. 78, June 2017, https://www.hks.harvard.edu/centers/mrcbg/publications/awp/awp78, retrieved 27 March 2018.

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Table 10

PJM nuclear scenario, 2013–16
(billion dollars, 2016)

Calculations	2016	2015	2014	2013	2013–16
Increase in variable costs	3.0	3.9	9.0	7.0	5.7
Increase in fixed going-forward costs	3.2	3.7	3.8	3.8	3.6
Total production cost increase	6.2	7.7	12.7	10.8	9.3
PJM base retail sales (TWh)	664	664	663	660	
PJM base average real retail price (cents per kWh)	10.4	10.6	10.5	10.4	
Total base retail revenues	68.8	70.2	69.9	68.5	
Increase in average real retail electricity price (percent)	9%	11%	18%	16%	13%
Increase in monthly production cost standard deviation (percent)					53%

Source: IHS Markit, EIA

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Consumer cost impacts from uneconomic PJM nuclear retirements

Higher production costs and higher retail power prices have a negative impact on electricity consumers who rely on PJM grid-based electricity supply.

A useful metric to assess consumer impacts from the electricity price increases expected from uneconomic PJM nuclear power plant closures is the change in consumer net benefits from electricity consumption. This metric provides a better indication of consumer impacts from higher retail prices than assessments based on the change in the consumer monthly power bill. For example, if the price of electricity increased by 50% and consumers responded by reducing their consumption by 50%, then their monthly power bill remains unchanged. However, although the power bill did not change, the consumer is worse off. Employing an assessment of the change in net benefit from electricity consumption can measure economic impact on the consumer while accounting for price-induced consumer reductions in consumption.

Figure 11 show the changes in retail electricity prices estimated by the difference between the base and alternative cases of the PJM nuclear closure and replacement scenario in 2016. The figure also shows the expected PJM consumer reduction in demand due to the higher prices and the associated change in the net benefit from electricity consumption.

Table 11 shows the estimates of the loss in PJM consumer net benefits of electricity consumption in the PJM nuclear closure and replacement scenario for the power system from the baskcasting analyses with power system conditions reflecting actual conditions in 2013–16.

The bottom line is that the uneconomic retirement and replacement of PJM nuclear power plants reduces the consumer annual net benefit from PJM grid-based electricity by about $8 billion per year over 2013–16. This translates into a consumer net benefit per kilowatt-hour of PJM nuclear generation of about 3 cents per kWh.

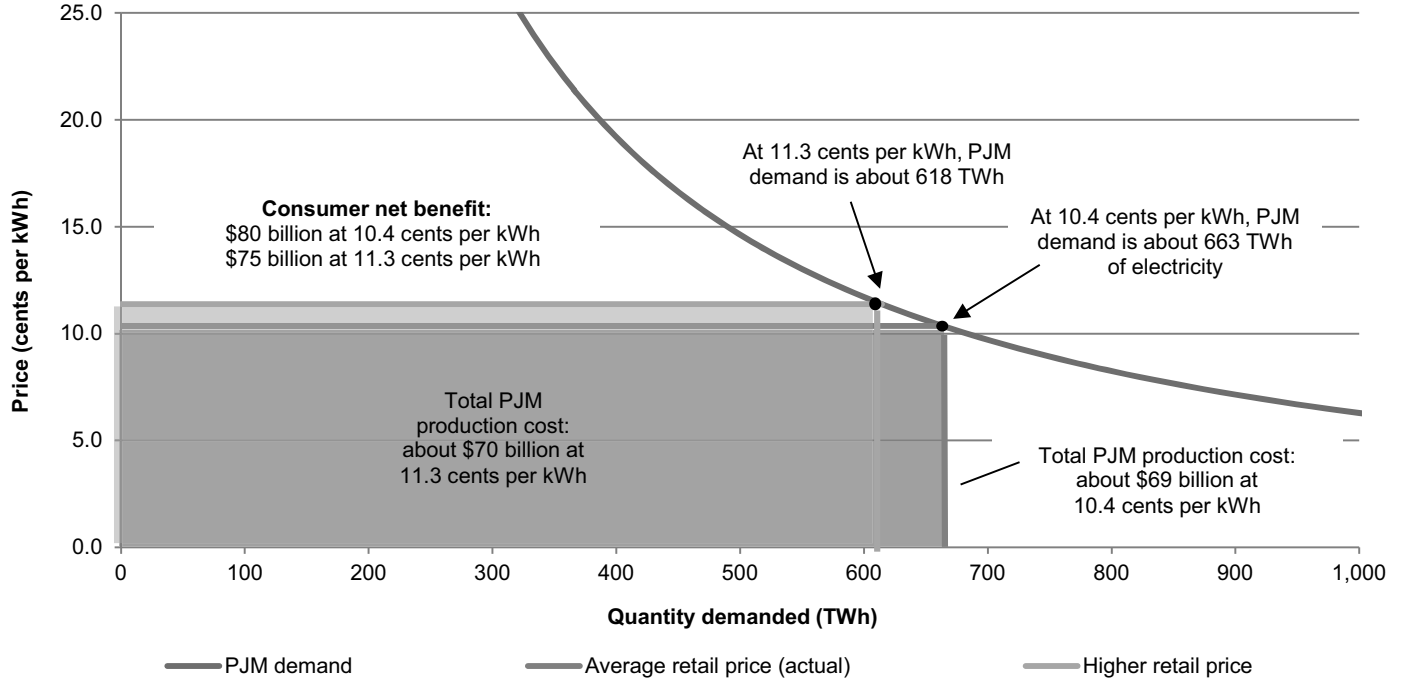
Production cost resilience impacts from uneconomic PJM nuclear retirements

The PJM nuclear closure and replacement scenario results in an increased reliance on natural gas–fired generation resources and the associated increased exposure to natural gas price variation. Backcasting the PJM nuclear closure and replacement scenario across 2013–16 results in a more than doubling of the monthly variation in PJM overall production costs (as measured by the standard deviation of PJM production costs).

PJM market distortions that cause uneconomic base-load power plant retirements accelerate the move toward a natural gas–fired generation share beyond the cost-effective share expected in an unfettered, efficient market outcome. Therefore, natural gas–fired generation risks—short-run price variability, long-run

Figure 11

PJM grid-based electricity demand (long run): 2016, impact of an approximate 9% price increase



Source: IHS Markit

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multiyear price cycles, physical limits to deliverability, and political uncertainties—become an increasing long-run concern in PJM.

Table 11

PJM consumer net benefits—Actual versus higher prices, 2013–16
(billion dollars, 2016)

Year	Total retail electricity supply cost			Total consumer net benefit		
	Base case	Nuclear scenario	Difference	Base case	Nuclear scenario	Difference
2016	68.7	69.8	1.1	80.5	74.6	-5.9
2015	69.3	70.6	1.3	78.3	73.1	-5.2
2014	68.3	70.3	2.0	80.0	68.4	-11.6
2013	65.7	67.4	1.7	79.6	70.3	-9.4

Source: IHS Markit, EIA

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The cost of replacing PJM nuclear production cost resilience

The diversity provided by cost-effective nuclear energy reduces the exposure of electric production costs to natural gas price variation. An estimate of the value of this production cost risk management provided by current PJM nuclear resources is available from another backcasting assessment in which the PJM nuclear closure and replacement scenario is altered to allow for the purchase of financial instruments—natural gas futures and options—to restore the base-case level of monthly production cost variation.

Hedging natural gas prices provides an alternative approach to limiting the impact of natural gas price variation on overall PJM electric production cost variation. A simple hedging strategy could employ natural gas call options. Purchasing a natural gas call option provides the holder with the right, but not the obligation, to purchase a specified amount of natural gas at a specified price and at a specified future point in time. Appendix D provides an example of applying this approach to create a rolling month-ahead call option on the delivered price of natural gas in PJM across 2013–16, employing a strike price set to limit the price paid for natural gas to the current delivered price of natural gas. The option cost assessment employs a variant of the Black-Scholes

option pricing formula to estimate the cost of reducing the variability of the delivered price of natural gas in PJM with this hedging strategy.

In the nuclear closure and replacement scenario, hedging PJM natural gas prices across 2013–16 with natural gas call options involves an average annual cost of $14 million to reduce the monthly variability of PJM cost of production by 1%. Because the production cost variability in PJM is 53% higher in the nuclear closure and replacement scenario, the annual cost to use natural gas call options to achieve the same level of production cost variability found in the PJM base case is $714 million. Note that this cost reduces the price risk of natural gas inputs for electric generation in PJM but does not reduce the physical deliverability risks of natural gas.

The bottom line is that the uneconomic retirement and replacement of PJM nuclear power plants increases the variation of PJM production costs, and restoring this cost resilience for consumers requires employing natural gas hedging mechanisms with an annual cost of $714 million. This translates into a consumer production cost resilience benefit per kilowatt-hour of PJM nuclear generation of about 0.3 cents per kWh.

PJM environmental impacts from uneconomic nuclear closures and replacement

The uneconomic closure of nuclear power plants in PJM due to market distortions would likely produce a power sector CO_2 emission increase. Uneconomic closures of power plants serving the base-load segment of aggregate consumer demand can increase CO_2 emissions when the replacement power resources are intermittent renewables integrated by natural gas–fired power plants. Table 12 shows the CO_2 intensity of the PJM replacement energy in the PJM nuclear closure and replacement scenario.

Table 12

Electric generation CO_2 emission intensity

	Capacity (MW)	Capacity factor	Generation (MWh)	Emissions factor (lbs/MWh)	Emissions (metric tons)
Typical nuclear power plant	1,600	93.0%	13,034,880	0	0
Total	**1,600**	**93%**	**13,034,880**	**0**	**0**
Wind—15%	797	28%	1,955,232	0	0
Natural gas combined cycle—85%	2,040	62%	11,079,648	1,003	5,040,727
Total	**2,837**	**52%**	**13,034,880**	**853**	**5,040,727**

Source: IHS Markit

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Closure and replacement of the non–CO_2-emitting PJM nuclear resources would remove 12 times the current output of PJM wind and solar resources.[22] To put this into perspective, there is approximately one vehicle for every two people in the United States, and therefore the 65 million people who rely on PJM grid-based power supply drive about 32.5 million vehicles.[23] The typical US vehicle emits 4.6 metric tons of CO_2 per year.[24] Therefore, the annual CO_2 emission increase expected from the uneconomic closure and replacement of PJM nuclear resources would equal the annual CO_2 emissions from two-thirds of the vehicles on the road in PJM.

Uneconomic closures of PJM nuclear power plants would likely create a CO_2 emission boomerang like the one observed in the New England power system. A lack of harmonization between electric sector policy implementation and ISO-NE market operations involves renewable mandates suppressing cash flows and causing the uneconomic closure of nuclear capacity. The closure of the Vermont Yankee Nuclear Power Corp.

22. Monitoring Analytics, LLC, *State of the Market Report for PJM (2017)*, 8 March 2018, p. 111 http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017-som-pjm-volume2.pdf, retrieved 10 April 2018.

23. "US States By Vehicles Per Capita," World Atlas, https://www.worldatlas.com/articles/us-states-by-vehicles-per-capita.html, retrieved 11 April 2018.

24. US Environmental Protection Agency, Office of Transportation and Air Quality, EPA-420-F-18-008, March 2018, https://www.epa.gov/sites/production/files/2018-04/documents/420f18008.pdf, retrieved 11 April 2018.

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nuclear power plant occurred at the end of 2014 even though the going-forward costs of operation were less than the cost of replacement based on the cost profiles of the electric supply pipeline of mandated subsidized renewable generation and natural gas–fired combined-cycle plants making up the replacement power sources. This premature nuclear power plant closure caused ISO-NE electricity market CO_2 emissions to increase by 7% from 2014 to 2015. In another few years, the premature closure of the Pilgrim Nuclear Power Station will have a similar upward impact on the regional electricity sector CO_2 emission level.

A PJM CO_2 boomerang is not environmentally responsible because it does not involve an efficient trade-off of higher costs in exchange for lower CO_2 emission levels. By contrast, an efficient CO_2 abatement initiative would achieve any CO_2 emission target by exploiting the lowest-cost options. Since the cost of continued PJM nuclear operation is lower than the cost of closure and replacement, continued nuclear operation provides a zero-cost option to reduce CO_2 emissions compared with offsetting the emissions associated with largely natural gas–fired replacement generation. Making such an offset by ratcheting up renewable mandates would be inefficient because the implicit cost of CO_2 reduction in PJM associated with policy-driven renewable resource development is about $220 per metric ton of CO_2 abatement.

Electric consumers reveal a preference for environmentally responsible power supply. Green power programs respond to this preference by offering more expensive renewable power options to satisfy the revealed preferences of consumers to do something about climate by limiting the CO_2 emissions associated with electricity production.

In 2016, consumers voluntarily chose to purchase 95 TWh of green power, representing 1.7% of total US retail electric energy sales. The highest customer participation rate in a utility voluntary green power program in 2016 was 17% in Portland General Electric's "Green Source" program, where consumers paid a 6.8% retail price premium.[25]

Since electricity consumers choose to purchase some, but not all, of their electricity at a green premium price, they reveal an underlying consumer preference to balance the costs and benefits of renewable power. At first blush, US consumers do not appear to be willing to pay much of a premium for renewable power, nor do they appear to be willing to purchase a large percentage of their supply from the higher-cost renewable resources.

Consumer choices for renewable power are likely suppressed by existing public policies that do not rely on voluntary individual consumer choice and instead mandate renewable generation shares and stimulate renewable development by socializing green power costs through subsidies and rate structures. Opinions vary regarding whether the politically determined level of renewable resources approximates the level expected from the aggregation of individual voluntary choices in an unfettered, efficient marketplace. However, politically determined renewable generation share mandates are like voluntary consumer choices because both typically limit renewable generation shares below 100% of supply. The implication is that politically determined collective decisions regarding renewable generation reveal an underlying trade-off between the political costs and benefits of increasing renewable generation shares.

The bottom line is that both individual consumer or collective political decisions regarding renewable generation shares reveal an underlying preference to balance the costs and benefits of increasing renewable generation in the power supply portfolio. Since environmental responsibility involves balancing environmental costs and benefits, the implication is that if premature PJM nuclear closures increase electricity costs while also increasing CO_2 emissions associated with PJM electricity production, then no trade-off is being made between environmental costs and benefits and, therefore, the outcome is less environmentally responsible.

25. Eric O'Shaughnessy, Jenny Heeter, Jeff Cook, and Christina Volpi, *Status and Trends in the U.S. Voluntary Green Power Market (2016 Data),* National Renewable Energy Laboratory, https://www.nrel.gov/docs/fy18osti/70174.pdf, retrieved 20 February 2018.

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An assessment of the higher costs associated with developing mandated wind and solar development rather than the least-cost natural gas–fired combined-cycle alternative provides the basis to calculate the implicit cost of CO_2 reduction from policies that mandate wind and solar development rather than allow the market-driven development of natural gas–fired resources.

The cost of replacing PJM nuclear generation with natural gas–fired resources alone is about $52/MWh. Replacement with 15% of the generation coming from unsubsidized wind along with 85% of the generation coming from natural gas–fired generation has a higher combined cost of about $56/MWh. The natural gas–fired generation produces 1,003 pounds of CO_2 per MWh while the wind and natural gas–fired integrated alternative is 15% lower. Therefore, if the purpose of a wind generation share mandate is to lower CO_2 emissions from the market outcome, then the difference in cost divided by the difference in CO_2 emissions yields an implicit cost of CO_2 abatement of about $59 per metric ton.

The cost of offsetting the CO_2 impact of PJM nuclear closure and replacement involves the option of purchasing CO_2 emission allowances. Within 2013–16, the market-clearing price of CO_2 emission allowances in the Regional Greenhouse Gas Initiative (RGGI), which sets a price for CO_2 emissions in some PJM states, ranged from $3.5 to $8.5 per metric ton. These prices are below the midrange estimates of the social cost of carbon if about $43 per metric ton.[26]

PJM CO_2 emission abatement through emission allowance payments provides more than five times the CO_2 emission abatement per dollar compared with mandates of renewable resources. Since continued nuclear operation is an even less costly CO_2 emission abatement compared with RGGI allowance purchases, the environmental bang for the buck is even greater from continued nuclear operation. Employing the midpoint estimate ($43 per metric ton) as an estimate of an appropriate CO_2 emission cost indicates that PJM nuclear generation provides an annual $2 billion worth of PJM CO_2 emission abatement.

The bottom line is that uneconomic PJM nuclear retirements and replacements caused by market distortions are a lose/lose proposition because the outcome involves both higher power production costs as well as higher CO_2 emissions. Since environmental responsibility requires making efficient environmental cost and benefit trade-offs, uneconomic PJM nuclear closures and replacements are not environmentally responsible.

Conclusions

The primary finding of this analysis is that the 65 million consumers who rely on PJM grid-based power supply are better off if something is done to prevent the uneconomic closures of PJM nuclear resources because the PJM power supply portfolio is more efficient, more resilient, and environmentally responsible with the continued contribution of cost-effective nuclear resources.

The impact of uneconomic PJM nuclear closures and replacement on consumer electricity bills is significant, ranging from 9% to 18% depending on the price of natural gas for the replacement generation. This conclusion is at odds with the assertion that consumers are insensitive to electricity costs. Therefore, the approach employed in this study to translate consumer behaviors and choices into preferences for resilient availability and resilient cost levels for affordable and environmentally responsible grid-based electricity provided a framework grounded in consumer behavior data. The approach defined metrics to evaluate the impact of uneconomic nuclear power plant closures and replacements in the PJM power system. Further, the fully documented statistical analyses of consumer demand used to quantify the consumer net benefits

26. Michael Greenstone, Elizabeth Kopits, and Ann Wolverton, "Developing a Social Cost of Carbon for US Regulatory Analysis: A Methodology and Interpretation," *Review of Environmental Economics and Policy* 7, no. 1 (1 January 2013), https://doi.org/10.1093/reep/res015, retrieved 27 March 2018.

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from electricity consumption provides a transparent metric to quantify the impact of losing cost-effective power supply.

Resilience in power supply is a controversial issue, and the results of this study may be different from other studies. The conclusion is that transparency in approach and the reliance on a minimum of assumptions will assist in comparing this study to others. Therefore, this analysis specifies assumptions and quantifies efficiency and resilience impacts with a backcasting approach across 2013–16 to incorporate a realistic set of PJM operating conditions and disruptive events. Comparing actual PJM outcomes with the outcomes from the backcasting analysis of the closure and replacement of PJM nuclear resources scenario provided a transparent analysis that can be replicated in a straightforward way because the analysis minimizes the influence of assumptions by holding all other analytical conditions equal to the actual recent historical conditions.

Quantifying the value of cost-effective nuclear generating resources in the efficient diversity of a PJM power supply portfolio does not infer a preference for one fuel or technology over another. Instead, the assessment focuses on efficient diversity in a power supply portfolio and confirms that consumers benefit from a cost-effective mix of fuels and technologies in their grid-based power supply.

The quantifiable benefits of continued PJM nuclear resource operations despite insufficient market cash flows leads to the conclusion that current market viability does not provide a test of economic cost effectiveness. Instead, the analysis indicates PJM market outcomes involve distortions.

The linkage between market distortions and current discord between public policies and market operations is a fuel and technology neutral assessment. Pointing out that mandates and subsidies of renewable resources distort market operations does not mean that intermittent wind and solar resources are not part of the cost-effective mix of fuels and technologies. Instead, the analysis indicates that the market distortions arise from command and control policy approaches to support renewable development rather than encouraging efficient market-based renewable development by putting an appropriate price on CO_2 emissions for all rival generators in the marketplace.

Noting that counting all costs, including CO_2 emissions costs, is a requirement for an efficient market outcome does not mean that addressing the resilience challenge in the US power system requires eliminating all subsidies and mandates and imposing a uniform CO_2 emission charge. Assuming that eliminating the cause of a problem is the only available solution does not recognize the political infeasibility of rapidly undoing entrenched public policies. Instead, the analysis supports consideration of other options to offset the predictable consequences of current market distortions.

The conclusion that market interventions can offset the impacts of market distortions is consistent with actions being taken in some states. Current feasible policy options to augment cash flows for cost-effective generating resources and to produce outcomes closer to an efficient market end state involve providing compensation for attributes—such as cost-effective contributions to capacity resilience, contributions to production cost resilience, contributions of flexible operating capabilities, or contributions to lower power system CO_2 emission levels. For example, California has implemented ramping products to compensate for flexible generation attributes, while Illinois, New York, and Connecticut have implemented zero-emission credits. However, an apparent challenge to implementing offsetting market interventions is emerging from market stakeholder conflicts. Since wholesale electricity market distortions affect rival producers in different ways, competition spills over from the marketplace to the policy arena where rival electricity producers reveal the preference to support interventions that offset the negative impacts of market distortions to their own fuel source or technology while opposing interventions that offset negative impacts on their competitors.

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Suppressing capacity and energy prices below the price levels expected in an undistorted and efficient marketplace is not a sustainable long-run outcome. Consequently, generating plant retirement and investment decisions will respond to distorted wholesale energy and capacity price signals. As market distortions cause uneconomic power plant retirements, market forces will move capacity and energy prices levels to reflect the marginal costs of the less efficient fuel and technology mix in the supply portfolio. Preventing uneconomic nuclear closures and replacements will result in lower long-run electricity costs. These actions to offset the impacts of current market distortions do not increase distortions because nuclear resources are cost-effective resources in an undistorted market outcome.

PJM faces the challenge to take actions to address the predictable consequences arising from the unresolved lack of harmony between public policies and market operations. Such actions are imperative to meet the consumer preferences for affordable, reliable, resilient, and environmentally responsible electricity services. Since PJM is the largest electricity market on earth and widely regarded as a model for electricity policy formulation and market design, actions to offset the consequences of market distortions have the potential to not only benefit electric consumers in PJM but also produce a highly influential example for other power systems to follow in addressing similar challenges.

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ATTACHMENT B

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)	Docket No. RM18-1-000

AFFIDAVIT OF
JEREMY C. CARL

My name is Jeremy C. Carl and I am a research fellow at the Hoover Institution ("Hoover") at Stanford University.

In my role at Hoover, I am the Executive Director of the Shultz-Stephenson Task Force on Energy Policy at Stanford University, and Co-Executive Director of the Hacking for Defense Program's new energy initiative at Stanford. As such, I have direct experience with both energy policy and how it relates to our security and the environment. I have a B.A. from Yale University, a Master in Public Administration from the Kennedy School of Government at Harvard University, focusing on energy policy, and did further graduate work in energy policy at Stanford University.

I have written extensively about grid reliability and resiliency, and have published a number of papers advocating for reform of state and national electricity policy.

I provide this affidavit in support of the PSEG Companies' reply comments in this proceeding on the Secretary of the Department of Energy's Notice of Proposed Rulemaking ("NOPR") for final action by the Federal Energy Regulatory Commission ("FERC" or "Commission").

The purpose of this affidavit is to address issues raised in this proceeding concerning resiliency and the need for federal policymakers to take affirmative action on

this NOPR. Specifically, I will describe how nuclear units affect grid reliability and resilience, U.S. security and economic growth, and non-proliferation interests.

I. THE CURRENT ENVIRONMENT FOR NUCLEAR

There are currently four primary factors driving the decline of the existing nuclear fleet, which I have at times referred to as the "four horsemen of the apocalypse." These four factors facing America's nuclear power sector in the current regulatory environment are:

1. Naturally and artificially depressed wholesale electricity prices in deregulated states.
2. A failure in our markets to recognize and value the unique attributes nuclear resources provide.
3. A trend of higher nuclear generation costs in older, smaller nuclear power plants and in nuclear plants requiring major refurbishment or upgrades. This trend is exacerbated by a period of general operational and regulatory cost increases that have affected all plants.
4. Increasingly effective antinuclear advocacy efforts by both those who dislike nuclear power and those who see nuclear power as competition for their own favored forms of power generation.

It is important to note that the current pressure on our nuclear fleet is largely a result of being squeezed like a vice on one side by fossil fuel plants whose emissions are not factored into their pricing, and subsidized renewables, which reflect the subsidies in their market offers. This has led to negative prices in a significant number of hours (and very low prices in others), distorting the economics for baseload resources such as nuclear units.

II. THE VALUE OF NUCLEAR IN TODAY'S GRID AND WHY THE CURRENT MARKET UNDERVALUES IT

In the remainder of this affidavit, I will explain the critical aspects of maintaining nuclear power as a vital part of our electric grid. The security and resilience aspects include:

1) The new evolving threats facing the system today, particularly terrorism and cyber-security.
2) The ways in which current nuclear unit retirements (America has lost 5 nuclear plants since 2013 and have just 61 plants remaining representing 99 reactors) are negatively impacting overall system resilience and increasing our risk exposure to extreme events.

A. RECENT NUCLEAR POWER PLANT CLOSURES[1]

- Crystal River 3 (Florida), decommissioning began in 2013 *Reactor had been licensed to 2016.*
- Fort Calhoun (Nebraska), 2016 - *Reactor had been licensed to 2033.*
- Kewaunee (Wisconsin), 2013 - *Reactor had been licensed to 2033.*
- San Onofre 2 & 3 (California), 2013 - *Reactors had been licensed to 2022.*
- Vermont Yankee (Vermont), 2014 - *Reactor had been licensed to 2032.*

B. RECENT POWER UPRATES CANCELED[2]

- Cooper (Nebraska), anticipated uprate investment called off in 2013
- LaSalle Generating Stations 1 & 2 (Illinois), 2013
- Limerick 1 & 2 (Pennsylvania), 2013
- Prairie Island 1 (Minnesota), 2012

C. CURRENTLY-OPERATING PLANTS ANNOUNCED FOR CLOSURE[3]

- Diablo Canyon 1 (California), 2024: Proposed by utility owner through decision not to pursue license extension. Licensed to 2024.

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[1] Source: Jeremy Carl and David Fedor, Keeping the Lights on at America's Nuclear Power Plants, Hoover Institution Press (2017).

[2] *Id.*

[3] *Id.*

- Diablo Canyon 2 (California), 2025: Proposed by utility owner through decision not to pursue license extension. Licensed to 2025.
- Indian Point 2 (New York), 2020: Anticipated closure as a result of negotiated state settlement, not averted by state subsidy to other plants. Licensed to 2013 (operating under temporary license).
- Indian Point 3 (New York), 2021: Anticipated closure as a result of negotiated state settlement, not averted by state subsidy to other plants. Licensed to 2015 (operating under temporary license).
- Oyster Creek 1 (New Jersey), 2019: Anticipated closure as a result of negotiated state settlement. Licensed to 2029.
- Palisades (Michigan), 2018: Proposed by utility owner. Licensed to 2031.
- Pilgrim Nuclear Power Station (Massachusetts), 2019 Proposed by utility owner. Licensed to 2032.

D. **CURRENTLY-OPERATING PLANTS CLOSURES AVERTED BY STATES**[4]

- Clinton Power Station (Illinois), decommissioning announced for 2017: Originally proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. The reactor is licensed to 2026.
- James A Fitzpatrick (New York), 2017: Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2034.
- Nine Mile Point Nuclear Station 1 (New York), 2017: Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2029.
- Nine Mile Point Nuclear Station 2 (New York), 2017: Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2046.
- Quad Cities Generating Station 1 (Illinois), 2018: Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2032.
- Quad Cities Generating Station 2 (Illinois), 2018: Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2032.
- R. E. Ginna Nuclear Power Plant (New York), 2017: Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2029.

3) The reliability, on site fuel-storage and the fact that nuclear facilities are already significantly hardened against both physical and cyber threats.

4) The critical role the U.S. leadership and nuclear fleet plays in non-proliferation.

[4] *Id.*

5) The importance of civilian nuclear for America's military leadership.

Economic factors will also be discussed, including:

1) The importance of nuclear power in workforce development.
2) The importance of the civilian nuclear supply chain for both civilian and military matters.
3) The importance of maintaining strong diverse electric generation assets with different sources of power. America needs an actual portfolio strategy for its electricity system, not simply a myopic focus on short-term cost-minimization.

III. THE CRITICAL ROLE OF NUCLEAR POWER TODAY

Nuclear energy provides critical capabilities associated with a resilient and secure electric grid. First, it provides the necessary baseload power that is reliable and available when needed.

As we continue to add more and more renewables and other intermittent sources of energy to the grid, the importance of having a supply that is always on is more important than ever.[5] These intermittent forms of power generation make up increasingly large parts of the grid and cannot always be relied upon to reliably meet system demand. The aggressive deployment of these intermittent resources leads to increased costs for the electricity system as a whole, both in terms of requiring greater transmission capacity to transmit from the generation asset to the load source and more complicated computerization and forecasting to keep up with non-dispatchable assets. In addition, as more of these intermittent sources come on to the grid, it will require the deployment of

[5] Jeffery St. John, *The California Duck Curve Is Real, and Bigger Than Expected*, Greentech Media, November 3, 2016, available at: https://www.greentechmedia.com/articles/read/the-california-duck-curve-is-real-and-bigger-than-expected#gs.VpC0WFE.

more expensive long-term storage solutions, such as batteries. As a result of all of these factors, California, which has arguably been the most aggressive state on renewable energy, has electricity costs that are more than 60% higher than the national average despite record low natural gas prices. (Natural gas makes up almost half of California's power generation.).[6]

In contrast, nuclear power has been a model of predictability. The capacity factor of nuclear power plants in 2016 was a record 92.5%,[7] light years above other low-emission alternatives such as Hydro (38.0%), Solar PV (27%) and wind (34.7%) or even fossil generation such as combined cycle gas (56%) and coal (52.7%) [8] Nuclear Power is indeed "used and useful" in America's electricity generation mix.

IV. NUCLEAR PORTFOLIO ECONOMICS

The recent nuclear unit retirements are negatively impacting overall system resilience and increasing our exposure (unnecessarily) to extreme events.[9] When the California San Onofre plant shutdown, the resulting need to contract with other generation resources led to a $350 million increase in direct customer costs as well as an increase in emissions and a need to build out extensive infrastructure at a multi-billion-

[6] United States Energy Information Agency, Electric Power Monthly with data from August 2017, available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_.

[7] United States Energy Information Agency, *Capacity Factors for Utility Scale Generators Not Primarily Using Fossil Fuels*, January 2013-August 2017, Electric Power Monthly, August 2017, available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b.

[8] United States Energy Information Agency, *Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels*, January 2013-August 2017, Electric Power Monthly, available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a.

[9] A report by the APS Panel on Public Affairs*, Integrating Renewable Electricity on the Grid,* American Physical Society, available at: https://www.aps.org/policy/reports/popa-reports/upload/integratingelec.pdf.

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dollar cost to maintain reliability.[10] In the wake of the shutdown of San Onofre, the California Independent System Operator, Inc. ("California ISO") acknowledged that "reliability has become a more pronounced concern."[11]

With low natural gas prices, the U.S. generation mix is migrating toward gas resources as the primary source of generation capability, and we cannot lose sight of the fact that there can be disruptions that could halt the natural gas revolution in its tracks. The growth in gas production is almost entirely dependent on hydraulic fracturing ("fracking"); yet fracking is under unprecedented attack in numerous states. If these attacks[12] succeed or an issue such as unexpected environmental impacts arises with the technology, we could see tremendous price spikes (akin to what we observed in 2007 thru 2009) and decreases in gas production. Declining yields could also unexpectedly thwart the fracking revolution, stressing the importance of not making all of our energy bets on one source.[13] Even if those price spikes are mitigated in short order, the damage to consumers will have been done.

In less than a decade, the Northeast markets have seen coal production decline from over 30% of our output to 11%. Nuclear, has seen small declines with the retirement of Vermont Yankee, but those declines could increase dramatically if more at risk units are lost. Natural gas has filled the gap, increasing from 23% of the generation

[10] Lucas Davis and Catherine Hausman, *Market Impacts of a Nuclear Power Plant Closure*, American Journal of Applied Economics, April 2016, available at: https://ei.haas.berkeley.edu/research/papers/WP248.pdf; Ivan Penn, *Edison will spend $12 Billion on Electric System over Next Three Years*, Los Angeles Times, November 4 2015, available at: http://beta.latimes.com/business/la-fi-edison-electric-system-20151103-story.html.

[11] California ISO, *Grid Resiliency*, available at: http://publications.caiso.com/StateOfTheGrid2014/GridResiliency.htm.

[12] Current concerns raised by fracking opponents focus on surrounding seismicity or groundwater pollution.

[13] Mason Inman, *Natural Gas: The Fracking Fallacy*, Nature, December 3, 2014, available at: https://www.nature.com/news/natural-gas-the-fracking-fallacy-1.16430.

mix to 43%. As these trends continue, overall diversity declines, and as PJM has noted in its own reports this leads to potential resiliency risks.[14]

Many argue this is so-called free-market principles at work. As an aggressive free-market proponent who has been aligned with some of the strongest pro-market forces and Congressmen in American politics, this argument garners natural sympathy. But, and this is a critical point all-too-little understood by the public, the U.S. electricity system is not a free market – it has never been a free market, and frankly it has no reasonably foreseeable prospects of becoming a free market.

It is, for better or for worse, a highly regulated market that has been manipulated for many years in ways that have been profoundly damaging to nuclear energy's competitiveness. Yet despite these challenges, nuclear still provides one-fifth of all electricity in the U.S. and creates far more emission-free energy than any other technology, including the solar and wind that capture environmentalist plaudits and journalists headlines.

V. NUCLEAR ENERGY AND NATIONAL SECURITY

Perhaps the biggest unmeasured value of nuclear power is its contribution to our national security. It cannot be stressed enough that unlike any other form of energy, the nuclear enterprise has fundamental non-energy related security attributes that justify additional support in the market. Furthermore this national security assessment is not a partisan issue. As a report by the Energy Futures Initiative (a non-partisan energy think tank founded by former Secretary of Energy Ernest Moniz), notes: "The national security

[14] PJM Interconnection, L.L.C., *PJM's Evolving Resource Mix and System Reliability*, March 30, 2017, available at: http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

imperatives of nuclear energy, however, are not addressed in state rate-making. This is understandable: national security policy is inherently Federal in nature. As such, the fundamental role of a robust nuclear energy sector in meeting national security imperatives must, in reality, be addressed by the Federal government."[15] Given FERC's rulemaking power, it is ideally situated to do just that.

Nuclear plants are able to keep more fuel on site than any other form of energy, due to nuclear fuel's high energy density.[16] Nuclear energy generation is incredibly space efficient with a fuel pellet the size of a pencil eraser providing as much electricity as 17,000 cubic feet of natural gas, 1,780 pounds of coal or 149 gallons of oil.[17] This could be particularly useful in the event of an interruption to fuel supplies to other generators. In a long-term emergency situation, transporting the necessary amount of nuclear fuel to power a reactor for years could be achieved with relative ease, even in a situation where roads and other transportation networks might be badly degraded. Overall fuel also averages just 31% of total plant costs for operation as opposed to 80-90% of coal and natural gas, making nuclear power much less prone to vacillations in fuel prices.

There are several new threats that potentially menace our power plants and the grid today – from terrorism to cyber threats. In San Jose, CA in 2013 a single non-hardened substation sustained millions of dollars of damage from a sniper attack in 2013

[15] The U.S. Nuclear Energy Enterprise: A Key National Security Enabler, A Special Report by the en4ergy Futures Initiative, at p. 6, available at: https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5992f7e0bf629ad8f9d575ec/1502803938248/EFI+Nuclear+Report+FINAL+08.2017.pdf

[16] Nuclear Energy Institute, *Reliable & Affordable Electricity Supply*, November 2017, available at: https://www.nei.org/Why-Nuclear-Energy/Reliable-Affordable-Energy/Electricity-Supply.

[17] *Id.*

when multiple gunmen opened fire on the transformers using high-powered rifles. As was noted by the ranking member of the House Energy and Commerce Subcommittee at the time who called the attack "... an unprecedented and sophisticated attack ... Communications were disrupted. The attack inflicted substantial damage. It took weeks to replace the damaged parts. Under slightly different conditions, there could have been serious power outages or worse."[18] Nuclear power plants, with their already high-levels of surveillance and security, are much less vulnerable to these types of attacks.

Nuclear has an advantage in this world because nuclear power plants are already hardened against risks and have been designed with safety and security (physical and cyber) in mind from the ground up.

One need only scan the government documents to find a wealth of information on steps nuclear plants have taken to reduce the risk from electromagnetic pulse ("EMP") attacks or the numerous recent publications and books specifically devoted to emergency planning for nuclear power plants and/or hardening their components for cyber or EMP attacks.[19] U.S. nuclear units are similarly resistant to extreme climatic events. When Hurricane Andrew had a direct hit of Florida's Turkey Point Nuclear Plant as a category 5 hurricane with wind gusts up to 175 MPH in 1992, there was no damage to the plant's critical systems.[20] Other forms of electricity generation are simply not hardened and

[18] Shane Harris, *U.S. Misses 'Military Style' Raid on California Power Complex Spooks U.S.*, Foreign Policy, November 27, 2013, available at: https://web.archive.org/web/20140705042615/http://complex.foreignpolicy.com/posts/2013/12/24/power-station-military-assault.

[19] *See e.g.,* Michael Franusich, *Security Hardened Cyber Components for Nuclear Power Plants: Phase I SBIR Final Technical Report*, March 18, 2016, available at: https://www.osti.gov/scitech/servlets/purl/1242462.

[20] Megan Guess, *As Irma approaches nuclear plants in Florida, lessons from Andrew Resonate*, Ars Technica, September 9, 2017, available at: https://arstechnica.com/science/2017/09/as-irma-approaches-nuclear-plants-in-florida-lessons-from-andrew-resonate/.

secured to nearly the same degree. With increasing concerns arising every day about foreign powers hacking into the U.S. electric grid, the hardened security around America's nuclear power plants is critical. In the U.S. nuclear industry, safety and security are a core part of the design and building process in a far more direct and substantive way than they are for any other type of resource.

VI. THE COUNTRY'S NUCLEAR TECHNOLOGY CAPABILITY IMPACTS NON-PROLFERATION EFFORTS

One of the primary areas in which America gains major strategic advantages from the civilian nuclear enterprise—advantages that are not currently accounted for in market prices - occurs in the area of non-proliferation. The U.S. has long been a leader in enforcing non-proliferation norms, as first enunciated by President Dwight Eisenhower in his Atoms for Peace initiative. We have used our leadership in nuclear technology non-proliferation to sign so-called "123" agreements with countries wishing to use civilian nuclear technology which had very strong proliferation safeguards.

These initiatives can have great value to the countries that sign them. For example, when India signed its 123 agreement with President George W. Bush in 2008, it represented the most serious lobbying the Indian government had done on any issue in the US and was described as the cornerstone of the new relationship between the U.S. and India. India was willing to expend these efforts and commit to a much stricter regime under IAEA supervision, in no small part because India's government highly valued the U.S. nuclear technologies we could bring to the table. Without a serious ongoing effort in civilian nuclear technology, these anti-proliferation efforts on the military side would not have been possible. The deal was described by the Council on Foreign Relations as a "watershed in U.S.-India relations and introduces a new aspect

to international nonproliferation efforts."[21] A similar gold-standard 123 Agreement was signed with the United Arab Emirates in December of 2009. Again, U.S. technological leadership in the nuclear arena was used to leverage a strong nonproliferation agreement in a sensitive part of the word.[22]

As our nuclear technology capability has weakened due to a lack of domestic plant manufacture (we have not completed a greenfield nuclear power plant in three decades) so has our leverage in this area, with challenges coming from countries that may have very different views on non-proliferation than we do. Recently the United States has lost several bids on nuclear power projects in the Middle East to Russia, in no small part because of our degraded capacity in this area. The closure of additional nuclear plants degrades our already fragile capabilities while empowering geopolitical rivals such as Russia and China.

Whether or not the U.S. is in the nuclear game, the rest of the world continues to play it, particularly in China where nuclear power generation has almost tripled in the last decade. There are over 400 GW of installed nuclear capacity in more than 31 countries, with more being added every year. There were 58 reactors in 15 countries with a capacity of almost 57 GW under construction as of 2016.[23]

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[21] Jayshree Bajora and Esther Pan, *The U.S.-India Nuclear Deal*, Council on Foreign Relations, November 5, 2010, available at: https://www.cfr.org/backgrounder/us-india-nuclear-deal.

[22] Christopher Blanchard and Paul Kerr, The United Arab Emirates Nuclear Program and Proposed Nuclear Collaboration, Congressional Research Service, December 20, 2010, available at: https://fas.org/sgp/crs/nuke/R40344.pdf.

[23] Myclie Schneider *et. al*., The World Nuclear Industry Status Report 2016, available at: https://www.worldnuclearreport.org/The-World-Nuclear-Industry-Status-Report-2016-HTML.html.

VII. PRESERVING NUCLEAR IS AN IMPORTANT TO THE COUNTRY'S NATIONAL SECURITY INTERESTS

In addition to our work in non-proliferation, the civilian nuclear enterprise dramatically strengthens our military capability as well, another nuclear attribute that is not priced into the market. This is most visibly seen in our Nuclear Navy, which is indubitably the world's most capable. America has almost 100 nuclear-powered vessels, consisting of aircraft carriers and submarines. We have accumulated almost 6200 reactor years of service without a single nuclear accident.[24]

For decades, the United States has gained a strategic advantage from its use of nuclear-powered ships that can deploy longer and more effectively than conventionally powered craft. The importance of fuel choice on capability has a rich history, most notably when Winston Churchill turned the British Navy from coal to oil for many of the same reasons the United States would move its key assets to nuclear. If America does not maintain a nuclear power capability domestically it is difficult to imagine that we will be able to maintain a nuclear navy at the same level of capability we have had historically. This would be a substantial degradation of our ability to project U.S. power.

One example of this degraded capability has been seen in our procurement processes for highly-enriched uranium to fuel both domestic and military reactors. Historically, the entire supply chain for highly enriched uranium has been legally mandated to be of U.S. origin. However, due to the decline of our nuclear capability, the

[24] "Nuclear Powered-Ships," *World Nuclear Association*, Updated October 2017, available at: http://www.world-nuclear.org/information-library/non-power-nuclear-applications/transport/nuclear-powered-ships.aspx.

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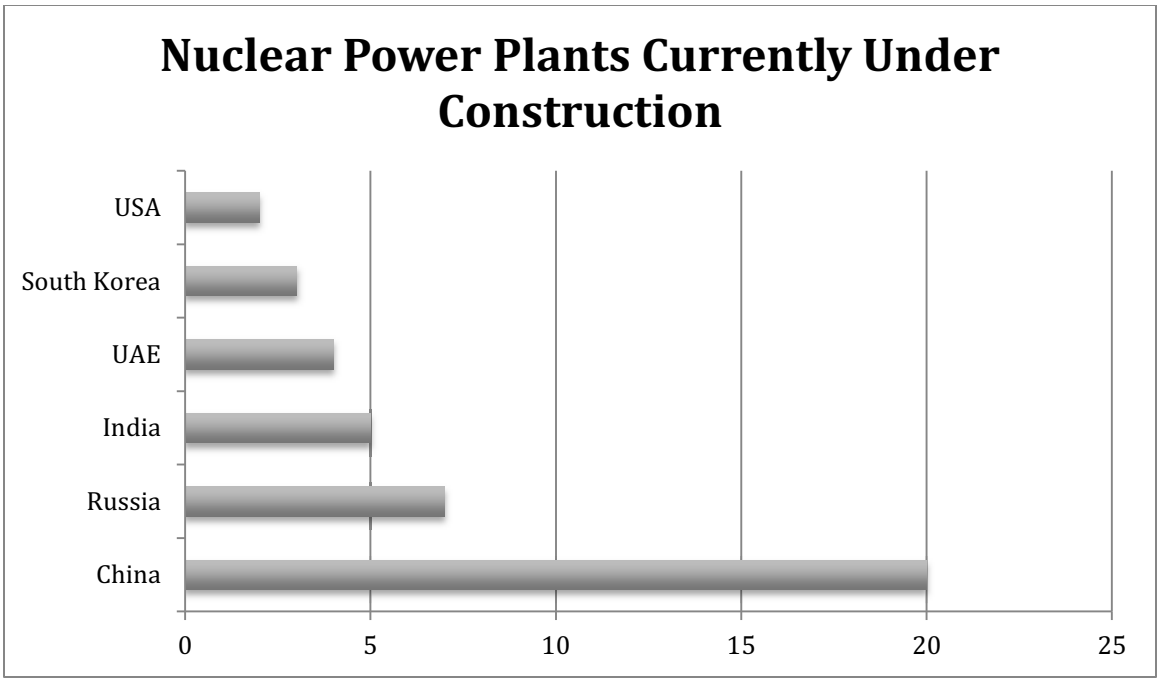
country no longer maintains all aspects of this process domestically, and other nations have gained production advantages over us."[25]

Our nuclear weapons stockpile, and its critical nature for deterring threats such as we are seeing in North Korea, is also hostage to the degradation of America's civilian nuclear capability. The stockpile requires a constant source of Tritium that must also be from U.S. origin reactors using domestically produced LEU reactor fuel. Our lack of an enrichment facility using solely U.S. origin technology represents a substantial impediment to our security in this area. As a result we find ourselves relying on Europe for the supply of this fuel at a time in which Europe's commitment to the nuclear enterprise has become questionable.

Our nuclear technology capability has profound impacts on America's national security. The failure of a new nuclear build in South Carolina and cost overrun issues in Georgia are further indications that the U.S. has lost control of its own nuclear destiny. Without a course correction we will see the future of nuclear power determined by China and Russia, who continue to move aggressively in this arena. China will complete five new nuclear power plants in this year alone.[26]

[25] Energy Futures Initiative, Inc., *The U.S. Nuclear Enterprise: A Key National Security Enabler*, August 2017, available at: https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5992f7e0bf629ad8f9d575ec/1502803938248/EFI+Nuclear+Report+FINAL+08.2017.pdf.

[26] Source: *World Nuclear Association*



The dangers of this situation should be obvious: While nuclear power plants are in many ways a quite distinct technology from nuclear weapons, the capabilities used in domestic enrichment for civilian nuclear power plants can also be used to create nuclear weapons. This fact has been at the core of much of our conflict with Iran and North Korea over their "civilian" nuclear programs. The U.S. has traditionally used its leadership in the supply of nuclear technologies to make it very difficult for nuclear-power-plant operators to proliferate the technology. Are the Chinese and Russians likely to share our interests in this? We need only look to Pyongyang and Pakistan to find out.

In addition to the critical role of nuclear energy in U.S. national security, the reactors that power our nuclear navy – almost 100 submarines and aircraft carriers – run on technology that is virtually identical to the technology powering our civilian reactors. In fact, domestic nuclear power originally grew from these naval programs. Losing the technology and operating experience through the atrophy of our domestic nuclear-power sector would mean a profound loss of capability in our military.

Although these aspects of nuclear retention are tangential to the energy markets, the importance of these resources both to the resilience of the electric system and our overall national interest must be considered in any decision. Putting these units at risk because of short-run market signals and the failure of our markets to adequately value all of the units' attributes is a deficiency that requires immediate attention and action.

VIII. SUPPLY CHAIN AND WORKFORCE DEVELOPMENT

More than 700 companies in 44 states contribute to the U.S. nuclear supply chain and this supply chain is increasingly missing links because of the lack of support for a robust domestic nuclear industry. While nuclear weapons and nuclear power are two quite distinct technologies, there are many suppliers who create specialized solutions for both markets. Without the support of the civilian nuclear fleet our weapons supply chain may also suffer badly, with consequent damage to our nuclear deterrent.

As a result of the uncertainties about our nuclear future, America's number of nuclear engineers being trained sank to less than 25% of what it was at its peak. Although rebounding impressively during the short lived nuclear renaissance created by the Energy Policy Act of 2005, the numbers remain well below peak levels reached in the 1970s.[27]

The closure of a nuclear power plant can often have a dramatic effect on local workforces. When Vermont Yankee closed more than 500 people lost their well-paying jobs that were 2.5 times the average for a worker in the region. The total economic impact within seven years of the plants closing was projected to be 1,100 jobs lost with

[27] Oak Ridge Institute for Science and Education, 2016 Nuclear Engineering Enrollments and Degrees Survey, 2016, available at: https://orise.orau.gov/stem/workforce-studies/nuclear-engineering-enrollments.html.

almost a half billion in economic activity. Nuclear plants also tend to be in more rural areas and the loss of economic activity in these areas from a shutdown is therefore more profound.

There is also the additional important issue of outlet jobs for the U.S. Navy's nuclear technicians. Without a civilian nuclear workforce for these trained nuclear engineers to "graduate" into upon leaving naval service, the U.S. Navy's ability to attract top candidates to work in the nuclear navy may badly lag.

IX. CONCLUSION

The Nuclear enterprise is a vital part of America's electricity infrastructure, that, unique among major forms of generation, provide substantial national security, resilience and reliability and environmental attributes, all of which are either poorly valued by the marketplace or not valued at all. In many cases, local power companies and public utility commissions are poorly positioned to be able to properly value these attributes, which bring benefits far beyond those that accrue to local ratepayers. Furthermore, nuclear energy's lack of price correlation with other forms of electricity generation and its lack of dependence on spot fuel prices make it an ideal component of a broad electricity-generation portfolio.

Given the varied attributes that nuclear energy brings, FERC is absolutely justified in pursuing policies to ensure that the nuclear fleet and our broader civilian nuclear enterprise, will not be irreparably damaged by a myopic focus on short-term cost-minimization.

Jeremy C. Carl

Jeremy C. Carl

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon the official service list in accordance with the requirement of Rule 2010 of the Commission's Rules of Practice.

Dated at Newark, New Jersey, this 9th day of May, 2018.

/s/ Cara J. Lewis

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. ER18-1314-000**
	)	**ER18-1314-001**
	)	
	)	

MOTION FOR LEAVE TO ANSWER AND ANSWER OF EXELON CORP. AND THE PSEG COMPANIES

Pursuant to Rules 212 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"),[1] Exelon Corp. ("Exelon") and the PSEG Companies[2] move for leave to answer, and submit their answer, to the comments and protests filed in the above-captioned dockets.

MOTION FOR LEAVE TO ANSWER

Exelon and the PSEG Companies respectfully request that the Commission permit this Answer, and the attached Declaration of Michael M. Schnitzer ("Schnitzer Decl."), to protests and comments filed in the above-captioned dockets on May 7, 2018. The protests and comments include new evidence, including many new expert affidavits. Moreover, the protests and comments stake out novel positions—not just advocating for and against Capacity Repricing and MOPR-Ex, but suggesting modified versions of both, as well as entirely new approaches. Several protests and comments also respond to PJM's Section 205 filing by urging the Commission to act under Section 206. The Commission has allowed answers to protests where the answer provides

[1] 18 C.F.R. §§ 385.212, 385.213 (2017).
[2] The PSEG Companies include: Public Service Electric and Gas Company, PSEG Power LLC and PSEG Energy Resources & Trade LLC.

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information that assists the Commission in its decision.[3] Exelon and the PSEG Companies respectfully suggest that this Answer will do so. In particular, the Schnitzer Declaration provides important new evidence concerning the Capacity Repricing proposal, in response to comments submitted by other parties.

ANSWER

The commenters clamoring for an expanded MOPR seek to exploit the Commission's commitment to markets and competition for ends that are profoundly anti-market and anti-competitive. While they purport to be purifying the Commission's markets from state intrusions, in reality they are seeking to entrench an unfair advantage they have enjoyed for decades: continuing to exploit the market's failure to value certain environmental attributes, and thereby imposing harm on society without paying for the costs. It is not a "level playing field" to treat resources that pollute as though they did not. When a coal or gas plant can underbid a wind farm, or a nuclear generator, by polluting the air we breathe, this is not a triumph of markets' power to drive efficient results. It is a market failure. When state policies attempt to internalize the pollution externality—through subsidies, taxes, or otherwise—they make markets more competitive and market outcomes more efficient.[4] This is, literally, textbook economics.[5] That is why there is broad agreement—even among advocates of MOPR-Ex—that markets should and must evolve, one way or another, to take into account environmental externalities like carbon.[6]

[3] *See, e.g.*, *Southwest Power Pool, Inc.*, 113 FERC ¶ 61,014, at P 7 (2005); *Southwest Power Pool Inc.*, 112 FERC ¶ 61,319, at P 56 (2005); *see also PJM Interconnection, L.L.C.*, 116 FERC ¶ 61,140, at P 18 (2006); *PJM Transmission Owners*, 115 FERC ¶ 61,345, at PP 10, 12 (2006).
[4] Decl. of Robert D. Willig ¶¶ 32-37 ("Willig Decl."), attached to Protest of Exelon Corp. ("Exelon Protest").
[5] *See id.* ¶¶ 30 n.28, 31 n.29, 34 n.32 (citing P.A. Samuelson & W.D. Nordhaus, *Economics* at 346-355 (1995); R.S. Pindyck & D.L. Rubinfeld, *Microeconomics*, 639-657 (2d ed. 1992); A.C. Pigou, *The Economics of Welfare* (4th ed. 1932); W.J. Baumol & W.E. Oates, The theory of environmental policy, Ch. 3 (2d ed. 1995)).
[6] Exelon Protest at 44 & n.152; *see* PJM Filing at 54-55; *infra* at 20-21.

The Commission, of course, has decided so far that its market mechanism should be fuel-neutral. But the Commission can afford to ignore the different environmental profiles of different generation types only because *states'* policies are *not* fuel neutral. Resources thus bring with them to the Commission's fuel-neutral markets a cost structure that reflects whatever fuel-related benefits or penalties states have chosen to impose in light of state environmental priorities. The Commission's market mechanism selects the least-cost set of resources against the backdrop of those state policies. As Exelon's Protest showed, the Commission thus far has always crafted market rules to respect and accommodate state programs addressing environmental externalities.[7] Doing so adheres to the principle that the Commission must, whenever possible, "fulfill [its] jurisdictional responsibilities while also respecting the states' traditional role,"[8] consistent with the Federal Power Act's purpose to "complement," not "usurp[] … State regulatory authority."[9] For two decades, this is how the Commission's markets have operated. Thus, there is no truth to the allegation that this proceeding is a referendum on the Commission's commitment to markets.[10]

Advocates of MOPR-Ex ask the Commission to sweep away this market-based model of cooperative federalism in favor of one that countermands state environmental policies, so that the Commission's market yields the outcome that would result if the state policies did not exist. The Commission should not be fooled by these parties' rhetoric: while they cloak themselves in the language of market integrity and fairness, what these generators really want is to protect the market advantage they gain by polluting without paying. They urge PJM market rules that would neuter state policies compensating for the real benefits of cleaner fuels, and thus would strangle

[7] Exelon Protest at 18-22.
[8] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1117 (2006).
[9] *Conn. Light & Power Co. v. Fed. Power Comm'n*, 324 U.S. 515, 526 (1945).
[10] *See, e.g.*, Comments of the Independent Market Monitor for PJM at 6 ("IMM Comments"); Protest of the PJM Power Providers Group at 23 ("P3 Protest"); Protest and Comments of Electric Power Supply Association at 30-32 ("EPSA Protest").

competition from cleaner generators that, when pollution costs are taken into account, would outcompete the polluters.

As Exelon and the PSEG Companies showed in their Protests, such action is not only inconsistent with sound economics and principles of cooperative federalism, but also is unjustified in light of current PJM market conditions. The Commission's markets are achieving what the Supreme Court has identified as "the principal purpose of" the Federal Power Act: "the orderly development of plentiful supplies of electricity … at reasonable prices."[11] Supply is plentiful, prices are low, and new entry remains significant. The commenters declaring that the markets are on the verge of collapse never address this reality, nor offer any evidence at all to support their panicked assertions that PJM is in the midst of a crisis.

For these reasons, the Commission should reject both PJM proposals. But if the Commission nevertheless determines to take some action to bring capacity prices closer to the levels that would exist without state environmental policies, the Commission should approve Capacity Repricing. Advocates of MOPR-Ex, of course, prefer MOPR-Ex, because it shields them from competition and furthers their goal of ridding the capacity markets of their non-emitting competitors. But if the Commission is compelled to act and finds Capacity Repricing, "PJM's preferred approach,"[12] to be just and reasonable (or that it can be rendered just and reasonable with an appropriate conditional acceptance), the Commission must approve it without reaching MOPR-Ex. Capacity Repricing satisfies the Commission's standard for market design—that it be "workably competitive."[13] And even if the comparison to MOPR-Ex were relevant, from a policy standpoint, Capacity Repricing is clearly superior to MOPR-Ex.

[11] *NAACP v. Fed. Power Comm'n*, 425 U.S. 662, 669-70 (1976).
[12] PJM Filing at 53.
[13] *See, e.g.*, *PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053, at P 84 (2005).

Under MOPR-Ex: (1) The wrong resources clear (because clean resources should have the chance to out-compete polluters, after environmental harm is accounted for); (2) Too many resources clear (given the likelihood that the clean resources excluded by MOPR-Ex will continue to supply capacity without compensation from the market); and (3) Energy market price signals are corrupted (suppressed by forced overprocurement). The MOPR's proponents claim this harm is good because it "disincentiv[izes]" states.[14] But the Commission has no business trying to deter states from protecting citizens' health and welfare, and it is doubtful that the Commission could do so in any event.

Capacity Repricing avoids all these problems. The correct resources clear, after accounting for environmental harm; the right quantity of resources clears; and energy market prices are not distorted. Advocates of MOPR-Ex nevertheless argue that Capacity Repricing must be rejected because it yields a price-quantity pairing that is not on the demand curve, and because it may create opportunities for strategic bidding. But these critiques, even if true, are not fatal to Capacity Repricing, and they certainly are no reason to select MOPR-Ex in its stead. As to the price-quantity issue, this theoretical criticism has only modest practical effects. And MOPR-Ex *also* yields a price-quantity pairing that is not on the demand curve, once one accounts for the reality that states will continue support environmentally friendly resources that will effectively provide capacity to the system. Likewise, as to alleged incentives for strategic bidding, any effects "are likely to be modest and would reduce the cost of repricing to customers."[15] To the extent there is any effect, strategic bidding will tend to result in a clearing price that is still significantly higher than the status quo, but lower than the MOPR-Ex clearing price would be. In effect, Capacity Repricing strikes a middle ground. If the Commission remains concerned about bidding incentives, they can be

[14] IMM Comments at 14-15; EPSA Protest at 28-29.
[15] Schnitzer Decl. ¶ 15.

fixed. One example of a potential fix would be including an "opportunity cost" payment in the Capacity Repricing model. Such payments, by making resources indifferent between clearing and not, could virtually eliminate these bidding incentives. In a variety of contexts, the Commission has approved similar payments to align incentives with efficient behavior.

Thus, while there are good reasons to reject any mitigation of environmental payments, including Capacity Repricing, the broad criticisms of Capacity Repricing are overblown. Capacity Repricing is flawed because clean resources should be allowed to account for environmental attribute revenues and other state compensation in making capacity bids. These revenues reflect payments for separate services, and thus those resources, to cover their going forward costs, do not need to receive those amounts from the capacity market. But if the Commission disagrees, Capacity Repricing is the only proposed workable—and "workably competitive"—alternative.

I. The Comments Confirm That PJM's "Two Alternative[]" Approach Violates Section 205.

The comments underscore why Section 205 prohibits alternative filings like PJM's. Arrayed before the Commission are dozens of comments advocating for or against an unbounded universe of potential tariffs: Capacity Repricing,[16] MOPR-Ex,[17] and assorted permutations of MOPR-Ex without certain exemptions (with various commentators seeking to sever versions of the RPS Exemption, Self-Supply Exemption, Public Entity Exemption, Competitive Entry Exemption, and the carve out for federal subsidies, among others).[18] By placing this free-for-all

[16] A number of commentators show that no change is warranted, but that Capacity Repricing is vastly superior to MOPR-Ex. *See* Comments of American Electric Power Service Corp. at 1 ("American Electric Comments"); Protest of Dominion Energy Services, Inc. at 9-11 ("Dominion Comments"); Exelon Protest at 8; Comments of Nuclear Energy Institute at 1 ("NEI Comments"); Protest and Motion to Reject of the PSEG Companies at 2 ("PSEG Protest").

[17] Comments of American Petroleum Institute, J-Power USA Development Co., Ltd., and Panda Power Generation Infrastructure Fund, LLC at 7-8 ("API Comments"); EPSA Protest at 2; IMM Comments at 3.

[18] *See, e.g.*, Comments of LS Power Associates, L.P. at 18 ("LS Power Comments"); Comments of Natural Gas Supply Association at 8 ("NGSA Comments"); Protest of the NRG Companies at 25 ("NRG Protest"); P3 Protest at 20; Comments and Protest of Rockland Capital, LLC at 5 ("Rockland Comments"); Comments of Vistra Energy Corp. and Dynegy Marketing & Trade, LLC at 13 ("Vistra Comments").

before the Commission, instead of proposing a single tariff "stating plainly the change or changes to be made,"[19] PJM's filing is inconsistent with the "passive and reactive role" that Section 205 requires the Commission to play.[20] If PJM wishes to give the Commission broad discretion to set policy, it must attempt to carry Section 206's heavy burden, or else seek a declaratory judgment. Because Section 205 does not sanction PJM's approach, the Commission must reject its filing.

II. The Comments Confirm That The Commission Should Not Hesitate To Reject Both Of PJM's Proposals And Preserve The Status Quo.

Stakeholders of every stripe have identified significant problems with both of PJM's proposals. Yet proponents of mitigation urge the Commission to press ahead anyway based on claims that the sky is falling—that state programs are "wreak[ing] havoc with PJM's markets,"[21] which are supposedly facing a "serious threat"[22] and "will collapse."[23] These are serious charges that, if true, would yield evidence for all to see. But what the comments of mitigation proponents reveal, more than anything, is that no *evidence* backs up this rhetoric. And the *actual* evidence confirms that the crisis is manufactured. As shown by Exelon, the PSEG Companies, and others, reserve margins are historically high (23.3% for the 2020-21 BRA) at prices that are historically low ($86/MW-day)—yet still, new entry continues at a significant pace (including almost 40 GW of recently entered or potential near-term entrants across PJM).[24] These high reserve margins, moreover, have been sustained despite years of claims that the capacity markets face "imminent

[19] 16 U.S.C. § 824d(d).
[20] *NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 115 (D.C. Cir. 2017).
[21] NRG Protest at 2.
[22] EPSA Protest at 34.
[23] P3 Protest at 8.
[24] Exelon Protest at 33; *see* Protest of Clean Energy Advocates at 35-42 ("Clean Energy Advocates Protest"); Protest of Clean Energy Industry Associations at 10-14 ("Clean Energy Industry Protest"); Protest of Joint Consumer Advocates at 10-14 ("Joint Consumer Protest"); Protest and Comments of the Maryland Public Service Commission at 5 ("Maryland PSC Protest"); Protest of the Office of the People's Counsel for the District of Columbia, Maryland Office of People's Counsel, and New Jersey Division of the Rate Counsel at 2-3 ("DC/MD/NJ Ratepayers Protest"); Comments of the Organization of PJM States at 5-7 ("PJM States Comments"); PSEG Protest at 11.

and substantial," and even "existential," "threat[s]."[25] The efficacy of PJM's capacity markets, and investors' faith in them, speaks for itself.

While PJM does not need to point to a crisis to justify tariff revisions under Section 205, the absence of any on-the-ground problem means that the Commission should not hesitate to reject both of PJM's proposals. Instead, until PJM formulates a new tariff that is genuinely just and reasonable, the Commission should leave PJM's capacity market rules where they are—with the MOPR limited, as it has been, to counteracting buyer-side market power by new resources.[26] That cautious approach avoids all the problems that come from expanding mitigation. And it respects stakeholders' wishes: Of the comments filed that take a position on the merits, a substantial majority urge the Commission to reject both proposals.[27] That preference has been consistent since November 2017, when 64% of stakeholders stated that they preferred the status quo.[28]

III. Although The Capacity Repricing Proposal Is Unwarranted And Flawed, Claims That The Proposal Is Unworkable Are Incorrect.

Exelon and the PSEG Companies agree with the commenters who criticize Capacity Repricing as unwarranted and unnecessary because it needlessly raises prices for customers at a

[25] Complaint Requesting Fast Track Processing at 5, *Calpine Corp. v. PJM Interconnection, L.L.C.*, Docket No. EL16-49-000 (Mar. 21, 2016); Motion to Amend, and Amendment to, Complaint and Request for Expedited Action on Amended Complaint at 2, 3, *Calpine Corp. v. PJM Interconnection, L.L.C.*, Docket No. EL16-49-000 (Jan. 9, 2017); *see* Exelon Protest at 33.

[26] Exelon Protest at 38-40.

[27] Comments of Advanced Energy Buyers Group at 1-2; American Electric Comments at 1; Comments of American Municipal Power, Inc. at 20; Protest of American Public Power Association at 1; Clean Energy Advocates Protest at 1; Clean Energy Industry Protest at 1-2; Dominion Comments at 5; Comments and Limited Protest of Duquesne Light Company at 3 ("Duquesne Comments"); Protest and Comments of FirstEnergy Service Company & East Kentucky Power Coop., Inc. at 2-3 ("FirstEnergy Comments"); Comment of Harvard Electricity Law Initiative at 1-3 ("Harvard Electricity Law Comments"); Motion to Dismiss and Protest of Illinois Commerce Commission at 4-5; Comments of Institute for Policy Integrity at 1-2; Joint Consumer Protest at 1; Maryland PSC Protest at 2; NEI Comments at 1; Protest of the New Jersey Board of Public Utilities at 1; NRG Comments at 1; PJM States Protest Comments and Protest of Public Utilities Commission of Ohio at 2; Comments and Protest of Old Dominion Electric Cooperative at 1; P3 Protest at 3; Comments of the Pennsylvania Public Utility Commission at 16; PJM States Comments at 1-2; PSEG Protest at 1-2; Protest of Solar RTO Coalition at 1 ("Solar RTO Protest"); Protest of Southern Maryland Electric Cooperative, Inc. at 3; Comments of Talen PJM Companies at 2.

[28] PJM, CCPPSTF Vote Results at 5 (Nov. 21, 2017), http://www.pjm.com/-/media/committees-groups/task-forces/ccppstf/20171121/20171121-ccppstf-vote-results.ashx; *see* Exelon Protest at 43.

time of oversupply with no corresponding benefit, and because it incorrectly mitigates payments recognizing the environmental value of clean generation. But to the extent the Commission disagrees and deems some departure from the status quo necessary, it is not "free to accept the better of the two approaches filed under Section 205," as the IMM incorrectly asserts.[29] PJM has identified Capacity Repricing as its "prefer[red]" approach, and thus the Commission must "assess first whether it can accept Option A, even if subject to suspension and further proceedings."[30] If the Commission determines Capacity Repricing is just and reasonable (or, with an appropriate conditional acceptance, can be *made* just and reasonable), it cannot reach MOPR-Ex. And while Capacity Repricing is unnecessary, the broader attacks on it are meritless. Capacity Repricing's auction mechanism can meet the Commission's "workably competitive" standard,[31] and can accommodate state programs while insulating capacity prices from those programs' effects.

A. The Criticisms Of Capacity Repricing's Auction Design Are Overstated And Can Be Remedied.

Several commentators note strategic bidding incentives that exist under Capacity Repricing's two-stage design—three such incentives, in particular. First, if a portfolio owner has high-cost resources that cannot hope to receive a capacity commitment at Stage 1, it might inflate the bids for those resources in the hope of contributing to higher Stage 2 clearing prices for other resources (what the Wilson Affidavit calls "clear-out-the-top").[32] Second, some "in between" resources—which might be economic at the Stage 2 clearing price, but cannot clear at Stage 1—may drop out.[33] Third, if resources would be economic at the anticipated Stage 2 clearing prices, they may have incentives to make offers below their forward costs in order to increase their

[29] IMM Comments at 3.
[30] PJM Filing at 46.
[31] *See, e.g.*, *PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053, at P 84 (2005).
[32] DC/MD/NJ Ratepayers Protest at 10; *see* EPSA Protest at 10.
[33] EPSA Protest at 11 n.46 and Affidavit of David W. DeRamus and Collin Cain ¶¶ 49-53.

chances of receiving a capacity commitment at Stage 1 (what the Wilson Affidavit calls "race-to-the-bottom").[34] The first two incentives tend to increase prices; the third, to decrease prices.

Even if these incentives exist, they are not *per se* fatal. Indeed, as the Schnitzer Declaration explains, "[w]hile commenters' witnesses point out these strategic bidding behaviors, they do not provide any well-supported analysis of their combined net impact."[35] And careful analysis shows that the concerns about Capacity Repricing are overblown. Any incentives to "clear-out-the-top" reflect issues that are already addressed by existing market rules, such as seller offer caps and the risk of Commission enforcement penalties for manipulative bidding.[36] Likewise, the effect of "in between" resources dropping out of the market will be limited given PJM's deep well of potential new entrants.[37] Finally, as between the three incentives, the effect termed "race-to-the-bottom" likely will affect a broader range of resources, and this price-reducing effect will likely swamp the other two price-increasing effects.[38] This effect, however, is also self-limiting: If a resource were the *only* one pursuing this strategy, perhaps it might steeply reduce its bid, predicting that Stage 2 would increase the clearing price.[39] But bidders take into account others' expected behavior.[40] And here, a resource will know that other bidders are also likely to reduce their bids—and thus if the resource reduces its bid too steeply, it risks losing money even at the higher Stage 2 price.[41] This will limit incentives to reduce bids.

The upshot of these incentives will be to mitigate the price increases that would otherwise result from Capacity Repricing. For example, one witness estimates that Capacity Repricing (and

[34] DC/MD/NJ Ratepayers Protest at 9.
[35] Schnitzer Decl. ¶ 51.
[36] *Id.* ¶ 54.
[37] *Id.* ¶ 57.
[38] *Id.* ¶ 58.
[39] *Id.* ¶¶ 59, 61.
[40] *Id.* ¶ 59.
[41] *Id.*

MOPR-Ex) would increase capacity prices by about 50% absent strategic bidding.[42] The bidding incentives, on plausible assumptions, lower this amount slightly to 39%.[43] Exelon and the PSEG Companies have shown that Capacity Repricing and MOPR-Ex both "will raise capacity market prices and costs for consumers"; the bidding incentives produced by Capacity Repricing thus somewhat limit that effect, yielding prices that are "elevated relative to the status quo, but below MOPR-Ex."[44] That is a reason to prefer it to MOPR-Ex.[45] Whatever the theoretical criticisms of Capacity Repricing's design, it cashes out as a compromise. It respects state policies by allowing state-supported clean generation to clear while still raising prices to offset this support—albeit not as much as certain fossil-fuel generators hope to achieve via MOPR-Ex.[46]

If the Commission remains concerned about Capacity Repricing's effects on bidding incentives, there are potential solutions. For example, the Schnitzer Declaration explains that resources whose offers are above the Stage 1 clearing price but below the Stage 2 clearing price could receive a "lost opportunity cost" payment equal to the difference between their offers and the Stage 2 clearing price.[47] The lower the offer, the higher the payment.

A "lost opportunity cost" payment largely could eliminate all three incentives detailed above: It could eliminate "clear-out-the-top" (artificially inflated offers would be costly, as they would reduce lost opportunity cost payments); the drop out of "in between" resources (who would receive an incentive, via the lost opportunity cost payment, to submit a bid); and the "race to the

[42] *Id.* ¶ 61.
[43] *Id.*
[44] *Id.* ¶¶ 18, 61.
[45] *Id.* ¶ 64.
[46] EPSA also contends that the effect termed "race-to-the-bottom" will cause the auction to procure too much capacity—because when the demand curve slopes down, lower offer prices will yield a larger quantity. EPSA Protest at 11. Because the demand curve is so steep, however, any such effect will be very small—on the order of 0.1% of the market, or 167 MW. Schnitzer Decl. ¶ 63.
[47] Schnitzer Decl. ¶ 67.

bottom" (as failing to clear at Stage 1 would no longer harm resources that can beat the Stage 2 price).[48] This modification could also address the concern that Stage 2 clearing prices will be set by resources with no capacity commitment at stake: A lost opportunity cost payment means that *all* resources that can beat the Stage 2 price have something at stake.[49] The size of these payments would likely be small—0.75% of total capacity payments.[50]

Nor would such payments amount to money for nothing: preparing bids is costly,[51] and PJM would be compensating generators for their expense in preparing cost-based bids that help the PJM market operate efficiently. Opportunity cost payments are already used by PJM to align bidder incentives with efficient behavior—for example, to address out-of-market dispatch for reliability reasons in energy markets, and in operating reserves markets.[52]

If the Commission concludes that a modification to Capacity Repricing is warranted, Exelon and the PSEG Companies respectfully suggest that the appropriate next step would be to reject the current filing as unjust and unreasonable, but indicate that the Commission would accept a Section 205 filing including such a modification.

B. The Broader Attacks On Capacity Repricing Are Meritless.

The broader attacks on Capacity Repricing—many pressed by fossil-fuel generators hoping to drive the Commission toward an unwarranted expansion of the MOPR—are baseless.

Clearance by state-supported resources. One supposed flaw is that clean generators receiving payments for their environmental value clear at the expense of other generators.[53] But this is Capacity Repricing's key *virtue*. As Dr. Willig's Declaration explains, this is the efficient

[48] *Id.* ¶¶ 68-72.
[49] *Id.* ¶ 68.
[50] *Id.* ¶ 73.
[51] *See* Affidavit of David W. DeRamus & Collin Cain, ¶ 50, attached to EPSA Protest.
[52] Schnitzer Decl. ¶ 74.
[53] *See, e.g.*, EPSA Protest at 9; P3 Protest at 12-13.

result when environmental externalities are taken into account,[54] and by permitting this result, Capacity Repricing avoids the costly overprocurement and distorting energy market effects that plague MOPR-Ex (as discussed further below). In this respect, Capacity Repricing follows the CASPR Order's lead—which also permitted, through a different mechanism, state-supported clean resources to replace existing polluting resources.

Effects on other states. Next, the proponents of a broader MOPR claim Capacity Repricing "would create a significant externality" by allowing "states … to shift th[e] costs of th[eir] polices … onto other" states.[55] Not so. State policies themselves do not impose any costs on other states—for example, the funds for Illinois' ZEC Program come entirely from Illinois customers—and the whole *point* of Capacity Repricing is to set prices where they would have been without state payments that qualify as Actionable Subsidies. That does not export any costs onto other states, or alter prices received by other generators. To the contrary, states *benefit* other states when they support clean generation, because the benefits of pollution abatement are experienced by citizens of all states, not only the state paying for the pollution abatement.

EPSA also repackages similar arguments as constitutional objections, claiming that Capacity Repricing unconstitutionally "[a]llow[s] [s]tates [t]o [r]egulate [b]eyond [t]heir [b]orders" by permitting "the actions of one state to affect[] … other states."[56] The Commerce Clause prohibits states from enacting extraterritorial legislation that "directly regulates transactions which take place across state lines."[57] Never could the Commission's *federal* approval of market rules violate that restriction on state authority. And regardless, EPSA does not

[54] Willig Decl. ¶ 52; *see* Institute for Policy Integrity, *Capacity Markets and Externalities: Avoiding Unnecessary and Problematic Reforms* at 10-12 (April 2018), http://policyintegrity.org/files/publications/Capacity_Markets_and_Externalities_Report.pdf.
[55] EPSA Protest at 29.
[56] *Id.* at 21 (internal quotation marks omitted).
[57] *Edgar v. MITE Corp.*, 457 U.S. 624, 641 (1982).

point to any "direct[] regulat[ion]" of interstate commerce;[58] at most, it alleges that one state's actions may have effects elsewhere.[59] But mere extraterritorial effects do not violate the Commerce Clause: "it is inevitable that a state's law … will have extraterritorial effects," and the "Supreme Court has never suggested that the … Commerce Clause" precludes such effects.[60] Indeed, EPSA's argument proves vastly too much. Whenever states have subsidized fossil-fuel plants, they have required citizens "in other states to shoulder much of the burden"—in less efficient wholesale electricity markets, and in more polluted air.[61] On EPSA's theory, all such subsidies would be unconstitutional. The Commerce Clause has never stretched so far.

Violation of constitutional limits on ratemaking. EPSA's other constitutional objection fares no better. EPSA argues that, as to resources that offer below the Stage 2 clearing price but do not receive a capacity commitment at Stage 1, Capacity Repricing violates the Constitution (and FPA) because it does not provide these resources the "*opportunity* to recover [their] costs,"[62] invoking *FPC v. Hope Natural Gas Co.*[63] and *Bridgeport Energy, LLC*.[64] That standard, however, does not apply here. When a utility is compelled to provide service to the public, as with a traditionally regulated utility, this standard forbids "confiscatory" rates for compelled service.[65] Likewise, when a generator is compelled to remain operational for reliability, the same standard governs.[66] In PJM, however, generators are not compelled to provide capacity. To be sure, generators that have sold capacity generally have a must offer obligation into the Reliability

[58] *Id.*
[59] EPSA Protest at 21-22.
[60] *Instructional Sys., Inc. v. Computer Curriculum Corp.*, 35 F.3d 813, 825 (3d Cir. 1994); *see SPGGC, LLC v. Blumenthal*, 505 F.3d 183, 194 (2d Cir. 2007).
[61] EPSA Protest at 22-23 (quotation marks omitted).
[62] *Id.* at 21 (quoting *Bridgeport Energy, LLC*, 113 FERC ¶ 61,311, at P 29 (2005)); *see* LS Power Comments at 8-9 (same argument).
[63] 320 U.S. 591, 603 (1944)
[64] *Bridgeport Energy, LLC*, 113 FERC ¶ 61,311, at P 29 (2005).
[65] *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 310 (1989) (citing *Hope Natural Gas*, 320 U.S. at 502).
[66] *Bridgeport Energy, LLC*, 113 FERC ¶ 61,311, at P 29 (2005).

Pricing Model. But if these resources choose to retire, they can do so upon 90 days' notice (and, presumably, upon covering any outstanding capacity obligations)—regardless of reliability implications.[67] In such circumstances, the Commission has held that "there can be no question of confiscation of a resource's property."[68]

Seller-side market power. The American Petroleum Institute ("API") claims, uniquely, that state support generally, and Capacity Repricing in particular, "facilitate the exercise of *supplier*"—not buyer—"market power"[69] via three anticompetitive tactics: (1) "predatory pricing"; (2) "entry deterrence"; and (3) "economic withholding" of a portion of an owner's portfolio.[70] As best Exelon and the PSEG Companies can discern, API's argument appears to be that these tactics require that the owner have the financial wherewithal to withstand temporary losses or losses in part of its portfolio, and that subsidies and Capacity Repricing "facilitate" these tactics by giving generators more money overall. But that money could just as well come from *anywhere*—utility operations, capital markets, or tax reductions. API's argument has nothing to do with Capacity Repricing.

Price/quantity pair not on the demand curve. EPSA criticizes Capacity Repricing because it yields a result that does not fall on "RPM's sloped demand curve": Because Stage 1 determines the quantity procured, and Stage 2 determines the price, Capacity Repricing yields a "price/quantity relationship" that does not appear on the demand curve.[71] But that theoretical flaw

[67] PJM Open Access Transmission Tariff, § 113.
[68] *Id.*; *see also N.Y. Indep. Sys. Operator, Inc.*, 124 FERC ¶ 61301, at P 58 (2008) (similar). To the extent EPSA's argument is that Capacity Repricing is unreasonable under the FPA because it does not "represent[] an appropriate balancing of consumer and investor interests," EPSA Protest at 19, Exelon and the PSEG Companies agree—but EPSA gets the imbalance backwards. For consumers, Capacity Repricing strikes the wrong balance because it raises prices with no sound justification. But for investors, it is not unfair that some polluting resources fail to clear due to states' efforts to address environmental externalities—which remains true even if these resources could have beaten the Stage 2 clearing price.
[69] Affidavit of Paul M. Sotkiewicz ¶ 6, attached to Comments of API.
[70] *Id.*
[71] EPSA Protest at 14; *see* Affidavit of David W. DeRamus and Collin Cain ¶ 38.

is no reason to reject Capacity Repricing absent some evidence that it is *actually* unworkable. And certainly, it is no reason to select MOPR-Ex over Capacity Repricing: As the Schnitzer Declaration explains, "the same is true of MOPR-Ex," which *also* yields a "price and quantity pair [that] does not fall on the demand curve," once one accounts for the resources that will continue to receive state support and effectively provide capacity to the system, even though they are not selected in the capacity auction.[72] "Indeed, because MOPR-Ex results in *significant over-procurement*, the effective price-quantity pair that results is even further away from the demand curve than Capacity Repricing."[73]

IV. The Proposals To Expand The MOPR Are Fundamentally Flawed.

Even if the Commission determined that a change must be made and that it could not approve Capacity Repricing (or a variant), it could not approve MOPR-Ex or any of the expansions of the MOPR proposed here. Both in theory and in execution, they are fundamentally flawed.

A. The Proposals To Expand The MOPR Are Flawed In Theory.

The commentators pushing for an expanded MOPR depict competitive markets as, by definition, insulated from the effects of state policies—which, when those policies involve payments for environmental benefits, they derisively call "subsidies."[74] Thus, they proclaim that "*all* subsidies" "are bad," "evil[]," and a "problem[]."[75] But the Commission will not find a citation to any economic authority that supports that broad proposition. That is because this proposition is false—for reasons Exelon has explained. Markets are not efficient when fossil-fuel generators inflict pollution on society without paying.[76] And state policies that attempt to

[72] Schnitzer Decl. ¶ 22.
[73] *Id.* ¶ 15 (emphasis added).
[74] *See, e.g.*, API Comments at 5; EPSA Protest at 12; NGSA Comments at 1-2; P3 Protest at 3.
[75] P3 Protest at 11 & Aff. of Roy J. Shanker, attached thereto, at PP 10, 34.
[76] Willig Decl. ¶¶ 13(c)-(d), 31.

internalize this externality, whether by taxing or penalizing pollution, or by supporting clean generation that abates pollution, make markets more efficient and competitive.[77] This is Economics 101.[78]

In reality, the MOPR's proponents do not really believe that *all* state interventions must be mitigated; instead, their pious rhetoric is only meant to encourage the Commission to adopt changes that harm cleaner competitors, while leaving untouched the massive subsidies they have long reaped. Thus, P3 proposes a supposedly "Clean MOPR" that removes MOPR-Ex's enumerated exemptions and also the carve-out from the definition of "Actionable Subsidy" for "federal production and investment tax credits."[79] But tellingly, P3 does not seek to remove the exclusion for various siting- or development-based subsidies—subsidies that happen to go to gas-fired generators. Likewise, there is not a peep about the untold billions in subsidies that coal-fired generators have and continued to receive, including both direct subsidies—$4.7 billion, just on the federal side, every year[80]—and indirect support, such as Pennsylvania's sales-tax exclusion for coal.[81] And all of this is in addition to the *implicit* subsidy that fossil-fuel generators receive from the ability to pollute without paying, which Exelon showed comes to $12.1 to $17.7 billion annually.[82] There is no justification for targeting government policies for mitigation *only* when they promote clean generation and make the Commission's markets more efficient.

[77] *Id.* ¶¶ 32-37.
[78] *See id.* ¶¶ 30 n.28, 31 n.29, 34 n.32 (citing P.A. Samuelson & W.D. Nordhaus, *Economics* at 346-355 (1995); R.S. Pindyck & D.L. Rubinfeld, *Microeconomics*, 639-657 (2d ed. 1992); A.C. Pigou, *The Economics of Welfare* (4th ed. 1932); W.J. Baumol & W.E. Oates, The theory of environmental policy, Ch. 3 (2d ed. 1995)).
[79] P3 Protest at 20 & n.50.
[80] Exelon Protest at 30; *see* Clean Energy Advocates Protest at 41 ($7.5 billion in federal subsidies to coal in 1989 alone).
[81] Clean Energy Advocates Protest at 90.
[82] Exelon Protest at 12.

The MOPR's proponents have no adequate answer for how their approach undermines not just sound economics, but federalism principles the Commission has long respected. As explained by Exelon and others, states have long exercised their FPA-protected authority as regulators of "facilities used for the generation of electric energy,"[83] and the Commission has reaffirmed that it must, whenever possible, "fulfill [its] jurisdictional responsibilities while also respecting the states' traditional role."[84] That means that when states regulate generators to protect the air citizens breathe, the Commission should not attempt to thwart or disincentivize those policies, no matter how much rhetorical noise the policies' opponents employ.

The MOPR's proponents insist that an expanded MOPR does not seek to thwart state environmental policies. But in more candid moments, they admit the opposite—that an expanded MOPR aims to create "a disincentive" for state policymaking favoring clean generation.[85] That is consistent with PJM's statement that applying the MOPR to federal payments to wind and solar resources would, in effect, "countermand … acts of Congress."[86] But under the FPA, the Commission has no authority to establish market rules that seek to deter states from legislating to protect their citizens' health and welfare, or to countermand state actions that do so.[87]

Again and again, the MOPR's proponents labor to narrowly limit the state authority over generation that the Commission must respect. First, they put states to an all-or-nothing choice—claiming that states forfeited any ability to influence the generation mix when they joined "an organized capacity market," and that states wishing to make any "policy decision[s]" concerning generation must "pursue Fixed Resource Requirement ('FRR') treatment."[88] But as many

[83] 16 U.S.C. § 824(b)(1).
[84] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1117.
[85] EPSA Protest at 27-28 (quotation marks omitted); IMM Comments at 14.
[86] PJM Filing at 71.
[87] Exelon Protest at 18-19.
[88] P3 Protest at 21.

commentators note, that claim mocks history: In myriad states, restructuring went hand-in-hand with RPS programs.[89] That is why the D.C. Circuit has held that restructured states "retain the right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities."[90] Likewise, states' ability to fulfill their obligations under *other* cooperative-federalism statutes, like the Clean Air Act, often *depends* on influencing the generation mix that serves them.[91] Indeed, the Commission's organized markets have earned sustainable support precisely *because* the Commission has not required, as a condition of entry, that states give up their authority to influence the generation mix. To the contrary, in myriad ways, the Commission has actively "accommodate[d]" such policies.[92]

Second, the MOPR's proponents insist that states must make the perfect the enemy of the good. The IMM, for example, avers that states can address the harm caused by carbon dioxide only if they can agree on "a carbon price."[93] But unlike the IMM, states cannot wait for "[t]he theoretical ideal market approach."[94] They want to protect citizens *today*. Thus, acting under their police powers, states can—and often must—"take reform 'one step at a time, addressing [themselves] to the phase of the problem which seems most acute."[95] States, like the Commission, are permitted to adopt market-based approaches, entirely non-market mechanisms, or something

[89] Clean Energy Advocates Protest at 47-52; Harvard Electricity Law Comments at 2-3; MD PSC Protest at 9.
[90] *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009).
[91] Exelon Protest at 19.
[92] *ISO New England Inc.*, 162 FERC ¶ 61,205, at P 101 (2018) ("CASPR Order"); *see, e.g.*, *California Indep. Sys. Operator Corp.*, 145 FERC ¶ 61,254, at P 34 (2013) (approving reduction in CAISO's bid floor in the energy market to negative $150/MWh to accommodate renewable resources); *Reform of Generator Interconnection Procedures & Agreements*, 163 FERC ¶ 61,043 (2018) (requiring changes to large generator interconnection agreements and processes to streamline the process for new resources, which are predominantly wind and solar); *Integration of Variable Energy Res.*, 139 FERC ¶ 61,246, at P 92 (2012) (adjusting rules for transmission scheduling periods to avoid imposing penalties on variable resources supported by states).
[93] IMM Comments at 10.
[94] PJM Filing at 54.
[95] *McDonald v. Bd. of Election Comm'rs of Chicago*, 394 U.S. 802, 809 (1969) (quoting *Williamson v. Lee Optical of Oklahoma, Inc.*, 348 U.S. 483, 489 (1955)).

in-between. As Dr. Willig explains, well-designed environmental initiatives like Illinois' ZEC Program, which tie compensation to the value of the externality being abated and procure resources based on their environmental contribution, result in more efficient markets. There is no justification for thwarting those efforts simply because a carbon price would be superior.

Third, the MOPR's proponents imply that the Commission need not respect state policy choices because states may have different views about what externalities are most important to address—noting that FirstEnergy has identified, as "externalities," "fuel diversity" and "fuel security," and that resources possessing these attributes may be different from the clean generators targeted by MOPR-Ex.[96] But this concern is purely hypothetical. The *real* programs that states have enacted, and that MOPR-Ex targets, address environmental externalities like air pollution. Such environmental externalities are the easiest and clearest case. They are "the classic example found in almost every economics textbook."[97] So while the IMM disingenuously says that action may be warranted "[*i*]*f* society determines that carbon is a pollutant with a negative value"[98]—implying that carbon *might not* be a harmful pollutant—nobody *really* doubts that air pollution is a harmful externality, and that addressing it makes markets more efficient. At the May 2017 technical conference, even representatives of Calpine and NRG agreed that "carbon [is] an externality" that should be "price[d]."[99] Indeed, the federal government has *already found* that carbon is a harmful pollutant (in, for example, the EPA's "endangerment finding," which was affirmed on judicial review)[100]—and in any event, states need not wait for the federal government

[96] EPSA Protest at 30 (quotation marks omitted).
[97] Willig Decl. ¶ 30 n.28.
[98] IMM Comments at 10 (emphasis added).
[99] Transcript of Technical Conference at 331, *State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.*, Docket No. AD17-11-000 (May 2, 2017) (comments of Thad Hill); *see id.* at 320 (comments of Abe Silverman) ("[U]ltimately you know we do want to get to the point where the wholesale markets facilitate the state desires to meet the environmental externalities").
[100] *See, e.g.*, *Coal. for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 121 (D.C. Cir. 2012), *aff'd in part, rev'd in part on other grounds sub nom. Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427 (2014).

to address threats to citizens' health and welfare. Whatever the scope of the externalities that states can permissibly address, environmental externalities are in the heartland of what states have historically addressed, and should be encouraged to address.

B. The Proposals To Expand The MOPR Are Flawed In Execution.

Apart from its conceptual flaws, MOPR-Ex is indefensible purely as a matter of auction design. The same is true of the broader variants, like "MOPR Clean." All should be rejected.

Proponents suggest that an expanded MOPR *must be* just and reasonable because PJM has a MOPR rule, which "already reflects stakeholder compromises."[101] Not so. The present MOPR is narrow in its purpose (combatting buyer-side market power), in the fuel sources it covers (gas only), and in the vintage it targets (only new generators).[102] The broader MOPRs proposed in this proceeding would twist this rule for a sweeping new purpose, and to a new universe of resources—counteracting the effects of disfavored state policies on wholesale markets, for both new and existing resources of any fuel type. PJM's MOPR was not designed for this new role, and has never been applied in this far-reaching manner. Stakeholders' agreement to, or the Commission's approval of, the narrow existing MOPR provides no support for the sea change sought here.[103]

Moreover, the comments confirm that the expanded MOPR's Swiss-cheese exceptions are incurably arbitrary. Stakeholders from all walks—generators, environmental groups, customer advocates—agree that the RPS Exemption is discriminatory: It exempts favored RPS programs for renewables, while mitigating environmental programs based on disfavored technologies (like nuclear or offshore wind), disfavored procurement processes, and even RPS programs with

[101] IMM Comments at 10; *see* API Protest at 10.
[102] Exelon Protest at 38-40.
[103] *Id.*

technology-specific tiers.[104] It does so even though the favored and disfavored programs pursue the same purposes and have the same effects on capacity markets, and even though disfavored programs like Illinois' ZEC Program may be more economically efficient than the exempted programs, by capping payments at the value of the environmental externality being abated.[105]

Likewise, myriad commentators explain why the Self-Supply and Public Entity exemptions are indefensible under MOPR-Ex's proposed new purpose of counteracting effects of state policies on wholesale markets. Because of the implicit subsidy provided by captive ratepayers, the vertically integrated utilities that qualify for these exemptions can build or maintain generation that "may be uneconomic" and that "would not have been built" or maintained, "but for being backed by ratepayer funds."[106] The state policies favoring the vertically integrated business model may be *older* than the pro-environmental policies that have spread over the last two decades. But that does not justify differential treatment.

Contra the suggestion of some fossil-fuel generators, these problems cannot be solved by blue-penciling MOPR-Ex's enumerated exemptions. One reason—again, acknowledged by several commentators—is that *NRG Power Marketing, LLC v. FERC*[107] precludes doing so.[108] But the more important reason is that once the Commission starts down the path of applying the MOPR to some disfavored policies—even state environmental policies that promote market efficiency—there is no non-arbitrary stopping point. The comments illustrate the point. Many commenters, as noted above, explain that MOPR's enumerated RPS Exemption, Self-Supply Exemption, and Public Entity Exemption are discriminatory. But even if the Commission severed these

[104] Clean Energy Advocates Protest at 102; Duquesne Comments at 4-5; Joint Consumer Advocates Comments at 22-23; LS Power Comments at 18; NEI Comments at 9-12; NGSA Comments at 8; NRG Protest at 25; P3 Protest at 20; PSEG Protest at 9-10; Rockland Comments at 5; Solar RTO Protest at 20-22; Vistra Comments at 13.
[105] Willig Decl. ¶¶ 51, 59.
[106] NRG Protest at 19; *see* Clean Energy Advocates Protest at 82-85; P3 Protest at 18.
[107] 862 F.3d 108 (D.C. Cir. 2017).
[108] Clean Energy Advocates Protest at 65; Joint Consumer Advocates Protest at 8-9; PSEG Protest at 10.

exemptions, that would still leave the sundry additional subsidies that PJM excludes from the definition of "Actionable Subsidy"—subsidies that "promote … general industrial development in an area," subsidies that "incent … siting facilities in [a particular] locality," and federal tax credits.[109] As many commentators show, those subsidies also affect wholesale capacity markets by supporting resources that might not otherwise be economic, and they may be less efficient than well-designed state environmental programs.[110] There is no justification for applying the MOPR to state environmental policies, but not to these distorting subsidies. P3 trumpets its support for a "Clean MOPR."[111] But as explained above, P3 only proposes eliminating the exclusion for federal subsidies to renewables, not the state and local subsidies that generally benefit gas and coal generators. Even if those exclusions were eliminated, that would still leave the various upstream subsidies fossil-fuel generators receive—for example, Pennsylvania's sales tax exemption for coal.[112] The solution to this problem is not to embark along the path proposed by MOPR-Ex.

If, however, PJM's market rules exempt *some* state policies from an expanded MOPR, then the market rules must, at the least, exempt Illinois' ZEC Program. As Exelon has established, that program is more efficient than state RPS programs—not to mention state policies favoring vertically integrated utilities—because it links the externality payment to a conservative estimate of the participating plants' environmental value.[113] Failing to exempt the ZEC Program thus would be arbitrary. The ratepayer advocates for the District of Columbia, Maryland, and New Jersey defend an RPS-specific exemption on the theory that RPS programs are "long-standing" and

[109] *See* proposed PJM Tariff § 1, Definitions L-M-N (Option B).
[110] Exelon Protest at 24-25; *see* Clean Energy Advocates Protest at 8, 54-55; Duquesne Comments at 5; FirstEnergy Protest at 19-20; NEI Protest at 10-11; PSEG Protest at 10; Solar RTO Protest at 19, 25-26.
[111] P3 Protest at 20.
[112] Clean Energy Advocate Protest at 90.
[113] Exelon Protest at 24-25.

widespread across PJM.[114] Exelon and the PSEG Companies agree that RPS programs should not be subject to the MOPR, but once the Commission begins applying the MOPR to environmental programs, neither the vintage nor the political popularity of RPS programs is a reasoned ground for exempting them.[115]

The proponents of an expanded MOPR also have no adequate answer for the gross overprocurement of capacity that it will yield. They predict—without evidence—that an expanded MOPR will deter states from supporting clean resources. There is no reason to think that is so, and every reason to think the opposite. Despite ISO-New England's limited MOPR exemption for 200 MW of renewables, for example, states issued the Multi-State Clean Energy request for proposals, which aims to procure 460 MW of new renewable resources, and Massachusetts enacted the 2016 Massachusetts Energy Diversity Act, which requires clean energy procurements in the range of 2,800 MW.[116] And in PJM, if the unsupported predictions of the MOPR's proponents prove wrong, the result will be a massive overprocurement of capacity estimated to cost customers $14-24.6 billion annually.[117] The Commission should not adopt a policy premised on speculation that states will abandon *en masse* policies in which they have invested for a decade and to which they have shown increasing commitment in recent years. In the CASPR Order, the Commission found that clean energy "will be developed by the operation of state environmental and clean

[114] DC/MD/NJ Ratepayers Protest at 22.

[115] The ratepayer advocates also aver that RPS programs are different because they are "designed to bring new resources … online," rather than to "prevent[] the retirement of … older facilities." DC/MD/NJ Ratepayers Protest at 22. This is backwards: PJM's MOPR has only ever applied to *new* resources, precisely because those resources are better vehicles for buyer-side market power. *See* Exelon Protest at 39-40. The ratepayer advocates assert that the "long lead time for new entry" provides time for the market to "anticipate[] and absorb[]" these resources. DC/MD/NJ Ratepayers Protest at 22. But to the extent this argument is meant to distinguish RPS programs from the ZEC Program, it does not. Nuclear generators have been in operation for decades, and have been part of the markets from their origin. Market prices have always accounted for their operation.

[116] CASPR Order, at P 4.

[117] Clean Energy Advocates Protest at 105 & Grogging Aff. at PP 3-4, 15; *see* Exelon Protest at 46-48.

energy mandates, whether that capacity clears the [market] or not."[118] There is no reason to think that PJM states will act any differently.[119]

MOPR proponents say that if states do not acquiesce to the "disincentive" provided by an expanded MOPR, the overprocurement is states' fault.[120] But this ignores the FPA's jurisdictional lines. States regulate generation, while capacity requirements—how much must be procured, and what resources count toward satisfying the administratively determined obligations—rest with the Commission.[121] So if capacity is procured inefficiently—or if more capacity is procured than is needed to ensure resource adequacy, because the Commission is ignoring capacity provided by state-supported resources—that error is squarely within the Commission's domain. Moreover, proponents of the MOPR-Ex badly disrespect state authority in claiming that states can avoid overprocurement by relinquishing the ability to legislate to protect their citizens' health and welfare. Never has the Commission sought to deter states from implementing legitimate environmental policies in their domain by punishing their citizens—and those elsewhere in PJM, too—with unnecessary capacity costs. Instead, the Commission has made sure to accommodate those policies.[122]

MOPR's proponents also have no answer to the price suppression in energy markets this overprocurement will yield. PJM identified this problem in its filing.[123] Yet the MOPR's proponents barely attempt to respond. The Commission cannot approve an expanded MOPR when the problems it creates may be larger than the problems it purports to solve.[124]

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[118] CASPR Order, at P 45.
[119] *See* Willig Decl. ¶ 73.
[120] EPSA Protest at 26, 28-29.
[121] *See Conn. Dep't of Pub. Util. Control*, 569 F.3d at 481.
[122] *Supra* at 19.
[123] PJM Filing at 57.
[124] Exelon Protest at 46-48; *see* Willig Decl. ¶ 74.

Finally, the MOPR's proponents cannot account for the CASPR Order, which made clear that the Commission's policy is to accommodate rather than countermand state initiatives. This policy is not new: more than a decade ago, the Commission likewise emphasized that it must, whenever possible, "fulfill [its] jurisdictional responsibilities while also respecting the states' traditional role."[125] MOPR proponents make much of the CASPR Order's statement that the Commission would use "the MOPR as our standard solution" "[a]bsent a showing that a different method would" be effective.[126] But that statement referred to ISO-New England's narrower MOPR applying to only new resources, and even then, only two Commissioners endorsed it. The CASPR Order's actual *holding* was that ISO-New England's proposed reforms were just and reasonable precisely because the Commission concluded that they would succeed in ISO-England's goal of reasonably "accommodat[ing] state sponsored resources … over time."[127] Moreover, Exelon and the PSEG Companies respectfully suggest that it would be unwise for the Commission to establish a rule that it will apply the MOPR unless a different "market design proposal[]" is "developed by [an RTO] and [its] stakeholders,"[128] and is "the result of extensive compromise."[129] Under that rule, stakeholders that will financially benefit from an expanded MOPR—like EPSA's fossil-fuel generators—will never compromise, knowing that a default Commission action will award them what they cannot achieve through negotiation.

[125] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1117 (2006).
[126] CASPR Order, at P 22.
[127] *Id.*, at P 102.
[128] EPSA Protest at 24 (quoting CASPR Order, at P 62,098 (LaFleur, Comm'r, concurring in part)).
[129] *Id.* (quoting CASPR Order, at 62,099 (Powelson, Comm'r, dissenting)).

C. If The Commission Finds That It Cannot Approve Either Of PJM's Proposals, It Should Not Proceed Under Section 206.

A few stakeholders urge that, if the Commission rejects both Capacity Repricing and MOPR-Ex, it should proceed under Section 206 and craft new rules itself.[130] Exelon respectfully suggests that this would be a mistake. It would require the Commission to carry the dual burdens of showing that "existing rates are 'entirely outside the zone of reasonableness,'" and that the solution crafted by the Commission is just and reasonable.[131] In turn, that would require the Commission to show, based on substantial evidence, that it is necessary for just and reasonable rates to raise prices at a time of vast oversupply, and to apply PJM's MOPR for the first time to existing resources receiving payments for their clean-energy benefits under state environmental programs. The Commission would also have to craft new rules that avoid all of the fatal flaws that parties have correctly identified in PJM's proposals, and amass a majority of Commissioners to support them. The Commission should not embark on this venture. No imminent—or even foreseeable—threat to reliability or investment has been shown, and the Commission should instead simply reject PJM's filing.

[130] *See, e.g.*, *id.* at 2; NRG Protest at 1.
[131] *NRG*, 862 F.3d at 114 n.2; *see Mkt.-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utilities*, 123 FERC ¶ 61,055, at P 24 (2008).

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CONCLUSION

The Commission should reject PJM's filing as not just or reasonable.

Dated: May 22, 2018

Respectfully submitted,

/s/ Matthew E. Price

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 22nd day of May, 2018.

/s/ *Marianne Alvarez*

_____

Marianne Alvarez
Exelon Corporation

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. ER18-1314-000**
	)	**ER18-1314-001**

DECLARATION OF MICHAEL M. SCHNITZER

May 22, 2018

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I. QUALIFICATIONS, ASSIGNMENT AND SUMMARY OF CONCLUSIONS

A. QUALIFICATIONS

1. My name is Michael M. Schnitzer. I am a director of The NorthBridge Group, Inc ("NorthBridge"). NorthBridge is a consulting firm that provides economic and strategic advice to the electric and natural gas industries. My business address is 30 Monument Square, Concord MA 01742.

2. In 1992, I co-founded NorthBridge. Before that, I was a Managing Director of Putnam, Hayes & Bartlett, which I joined in 1979. I have experience working with private sector clients in the electric utility, natural gas, and private power industries, as well as with public and nonprofit agencies. My electric industry work has focused on regulatory policy, finance, and market structure issues. I received an A.B. in chemistry, with honors, from Harvard University, and an M.S. in management from the Sloan School, Massachusetts Institute of Technology.

3. I have testified before the Commission on many matters and have participated in Commission technical conferences and workshops on capacity market and energy market design issues. I have also testified before the public utility commissions of Arkansas, California, Delaware, Illinois, Indiana, Louisiana, Maine, Maryland, Massachusetts, Mississippi, New Hampshire, New Mexico, New Orleans, New York, Ohio, Pennsylvania, Rhode Island, Texas, Vermont, and Wisconsin.

B. BACKGROUND AND PURPOSE OF TESTIMONY

4. On April 9, 2018, PJM Interconnection, LLC ("PJM") filed at the Federal Energy Regulatory Commission ("FERC" or "Commission") two proposals to modify its capacity market design.[1] In its filing, PJM requested that the Commission approve its preferred capacity market repricing proposal (referred to as "Capacity Repricing" or "Option A"), or if the Commission cannot approve PJM's preferred proposal, that it approve in the alternative PJM's MOPR-Ex proposal (referred to as "Option B").

[1] PJM Interconnection, L.L.C., Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, FERC Docket No. ER18-1314-000, April; 9, 2018 ("PJM Filing").

5. Both proposals seek to prevent capacity prices from declining, all other things equal, due to the alleged impact of state actions to support various types of generation not already covered by PJM's existing Minimum Offer Price Rule ("MOPR"), with particular focus on the increase in state sponsored zero-emission capacity resources. Under the Capacity Repricing proposal, state sponsored resources are allowed to clear in PJM's capacity auctions, while under the MOPR-Ex proposal (Option B), some state sponsored resources are allowed to clear in capacity auctions while others are not.[2]

6. Reply comments were filed by a wide range of industry stakeholders, including Exelon Corporation with an attached declaration by Robert E. Willig, on May 7th, 2018.[3]

7. I have been asked by Exelon Corporation to respond to certain issues raised by two commenters, The Electric Power Supply Association[4] and the Office of the People's Counsel for the District of Columbia, Maryland Office of People's Counsel, and New Jersey Division of the Rate Counsel[5] (collectively, "Commenters"), and their respective expert witnesses, David W. DeRamus and Collin Cain,[6] and James F. Wilson[7] (collectively, "Commenters' Witnesses"). Commenters, relying on the analysis of their respective expert witnesses, describe several issues with both of PJM's proposals, and several issues which particularly affect PJM's Capacity Repricing proposal. These issues include increased consumer costs, the fact that PJM's proposals do not produce results which fall on the capacity demand curve, and strategic bidding incentives created by Capacity Repricing. Commenters argue that these issues collectively are cause for the Commission to choose the MOPR-Ex proposal over the Capacity Repricing proposal.

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[2] PJM Filing at 6.

[3] Protest of Exelon Corporation, Docket Nos. ER18-1314-000 and ER18-1314-001 (filed May 7th, 2018) ("Exelon Protest") and Declaration of Robert E. Willig, Docket Nos. ER18-1314-000 and ER18-1314-001 (filed May 7th, 2018) ("Willig Declaration").

[4] Protest and Comments of the Electric Power Supply Association, Docket No. ER18-1314-000 (filed May 7th, 2018) ("EPSA Comments")

[5] Protest of the Office of the People's Counsel for the District of Columbia, Maryland Office of People's Counsel, and New Jersey Division of the Rate Counsel, Docket Nos. ER18-1314-000 and ER18-1314-001 (filed May 7th, 2018) ("DC-MD-NJ Consumer Coalition Comments")

[6] Affidavit of David W. Deramus, Ph.d. and Collin Cain, M.SC. on Behalf of the Electric Power Supply Association, Docket No. ER18-1314-000 (filed May 7th, 2018) ("DeRamus/Cain Affidavit")

[7] Affidavit of James F. Wilson in Support of the Protests of DC-MD-NJ Consumer Coalition, Joint Consumer Advocates, and Clean Energy Advocates, Docket No. ER18-1314-000 (filed May 7th, 2018) ("Wilson Affidavit")

8. The purpose of my testimony is to evaluate the issues raised by commenters' witnesses and place these issues in the broader context of the capacity market design choice before the Commission in these proceeding, namely whether the Commission should decline to adopt either Capacity Repricing or MOPR-Ex and preserve the status quo or, in the alternative, to choose one of the two alternatives.

C. SUMMARY OF CONCLUSIONS

9. My conclusions are as follows:

10. Commenters' witnesses raise several valid issues with respect to the two mitigation alternatives presented by PJM, Capacity Repricing and MOPR-Ex. Specifically, they show that neither alternative produces a solution that falls on the capacity demand curve and that both raise costs for consumers relative to the status quo. The issues they raise highlight the need for the Commission to confront two central economic questions. First, do the out-of-market payments at issue in this proceeding internalize externalities and contribute to retention and entry of the least-cost set of resources once social costs as well as production costs are accounted for, or are they subsidies that support uneconomic retention and entry? And second, even if the state actions driving these payments do represent inefficient subsidies, would MOPR-Ex deter this conduct or not?

11. Because the out of market payments at issue, in the main, do internalize externalities and promote economic retention and entry, the issues raised by Commenters' witnesses highlight the inefficiency of adopting either of the mitigation options proposed, and the Commission should instead choose the status quo approach. The status quo approach results in the most efficient price and resource selection, does not unnecessarily raise costs for consumers, and does not increase incentives to engage in strategic bidding. For the Zero Emission Credit ("ZEC") programs in particular, commenters provide no evidence that these payments are not an efficient mechanism for internalizing carbon emission externalities. Nor do they – or could they, given the current PJM energy market design – suggest a feasible alternative mechanism for internalizing these externalities. Under these circumstances, the Capacity Repricing alternative would be a distant "second choice" to the status quo from an efficiency standpoint, but, somewhat ironically, the strategic bidding issues identified by commenters' witnesses make Capacity Repricing less

inefficient in this case because their net effect is to push the market clearing price down closer to the price under the most efficient status quo approach.

12. If the Commission is not persuaded that the status quo is adequate, then as between the two alternatives before it, the Capacity Repricing proposal is a much better choice than MOPR-Ex. The advocates of MOPR-Ex implicitly assume that states will abandon their support of environmentally-friendly resources in response. The witnesses do not provide any theoretical or empirical support for this assumption. Yet if states do continue to make out-of-market payments to support environmentally-friendly resources, notwithstanding MOPR-Ex, then MOPR-Ex will result in the over-procurement of capacity, saddling customers with significant unnecessary costs.

13. If, on the other hand, mitigation does deter some states from enacting legitimate environmental programs, then MOPR-Ex will select the wrong set of resources to provide capacity. Resources that are more efficient once externalities are taken into account will be led to retire or will not enter. That outcome likewise leads to an inefficient mix of resources that makes society worse off than the status quo. Notably, MOPR-Ex includes a number of proposed exemptions, but these exemptions are not based on whether the out-of-market state payments promote or impair the efficient selection of resources. The ZEC program provides an illustrative example: the ZEC payments that MOPR-Ex targets are demonstrably the most economic form of carbon abatement available to the states and are the only form of support that the states can effectively utilize given PJM's energy market design. It would be unjust and unreasonable for the Commission to eliminate the only effective unilateral option that states have to support the economic retention of zero carbon resources.

14. Capacity Repricing, by contrast, avoids both of these problems. Capacity Repricing avoids over-procurement by allowing state-supported resources to clear. And Capacity Repricing selects a more efficient set of resources, by allowing the resource mix to be influenced by state programs accounting for environmental externalities.

15. Commenters argue that MOPR-Ex is preferable to Capacity Repricing, focusing on several points they allege make Capacity Repricing unworkable. First, they contend that Capacity Repricing leads to a price-quantity pair that is not on the demand curve. But the same is true of MOPR-Ex. Indeed, because MOPR-Ex results in significant over-procurement, the effective price-quantity pair that results is even farther away from the demand curve than Capacity

Repricing. Second, commenters identify potential strategic bidding issues associated with Capacity Repricing. These issues are real but are not disqualifying. The effects of such strategic bidding are likely to be modest and would reduce the cost of repricing to customers—even as Capacity Repricing significantly increases capacity prices relative to the status quo. To the extent these effects are nevertheless of concern to the Commission, the incentive to bid strategically can be largely remedied by a lost opportunity cost payment directed towards the small slice of resources that set the second stage price of Capacity Repricing without being cleared in the initial stage. Thus, strategic bidding concerns are not a valid basis to reject the PJM Capacity Repricing proposal.

16. In sum, the best course is for the Commission to maintain the status quo. If the Commission does believe some action is required, the Capacity Repricing alternative is workable and certainly preferable to MOPR-Ex.

II. COMMENTERS' WITNESSES RAISE VALID ISSUES WITH BOTH MOPR-EX AND CAPACITY REPRICING, WHICH REINFORCES THE CONCLUSION THAT CONTINUATION OF THE STATUS QUO IS THE PREFERRED APPROACH

17. Both Wilson and DeRamus & Cain correctly point out several issues with both MOPR-Ex and Capacity Repricing. These issues highlight the inefficiency of either proposal relative to the status quo.

A. BOTH CAPACITY REPRICING AND MOPR-EX RAISE COSTS

18. First, at the simplest level, commenters' witnesses show that both solutions proposed by PJM will raise capacity market prices and costs for consumers. Wilson provides an example, calibrated to the current PJM capacity demand curve and recent real-world supply curves, that shows that, relative to the status quo, Capacity Repricing with an assumed 9,000 MW of resources targeted for re-pricing (that is, with "actionable subsidies" per the terminology used by PJM) causes both the market clearing price and the capacity payments by consumers to rise by about 50%.[8] DeRamus & Cain provide a more stylized example that is directionally similar.[9]

[8] Wilson Affidavit at ¶ 48-49.

[9] DeRamus/Cain Affidavit at ¶ 29-30.

19. Specifically, Wilson's example begins with a status quo where 161,474 MW of UCAP is procured at a price of $102.8/MW-day, resulting in total customer costs of $6.1 billion. Under Capacity Repricing, the price rises to $154.53/MW-day while the quantity procured remains the same as under the status quo, increasing customer costs to $9.1 billion.

20. Wilson's example does not directly address MOPR-Ex, but if MOPR-Ex is analyzed using the same assumptions, it produces a very similar result. Under MOPR-Ex, the capacity clearing price would also rise to $154.53/MW-day but the quantity procured through the capacity market would fall to 159,800 MW. This results in capacity payments of $9.0 billion, a similar increase, 48%, as Capacity Repricing relative to the status quo. Unlike Capacity Repricing, MOPR-Ex does not clear or compensate the 9,000 MW of resources with actionable subsidies. If we assume that states continue to compensate these resources at the original status quo price to induce them to remain in the market, consumers in those states pay an additional $340 million for the capacity these resources provide outside the RPM mechanism. This additional cost raises the total cost of MOPR-Ex in Wilson's example to $9.4 billion, a 56% increase from the status quo.

B. Neither Capacity Repricing nor MOPR-Ex produce a price and quantity result which falls on demand curve

21. Commenters' witnesses correctly criticize Capacity Repricing for producing an ultimate price and cleared quantity outcome that is not located on the RPM demand curve.[10] Returning to Wilson's example, the clearing price of $154.53/MW-day corresponds to a cleared quantity of 159,800 MW on the RPM demand curve. But because Capacity Repricing clears resources using a lower supply curve in its first stage, the cleared quantity is 161,474 MW. The resulting price and quantity combination is off the demand curve. Because of this, Capacity Repricing is not consistent with the underlying reliability versus cost tradeoff embedded in the demand curve and it is costlier for customers because the elevated stage two price is paid to the resources cleared in stage one.

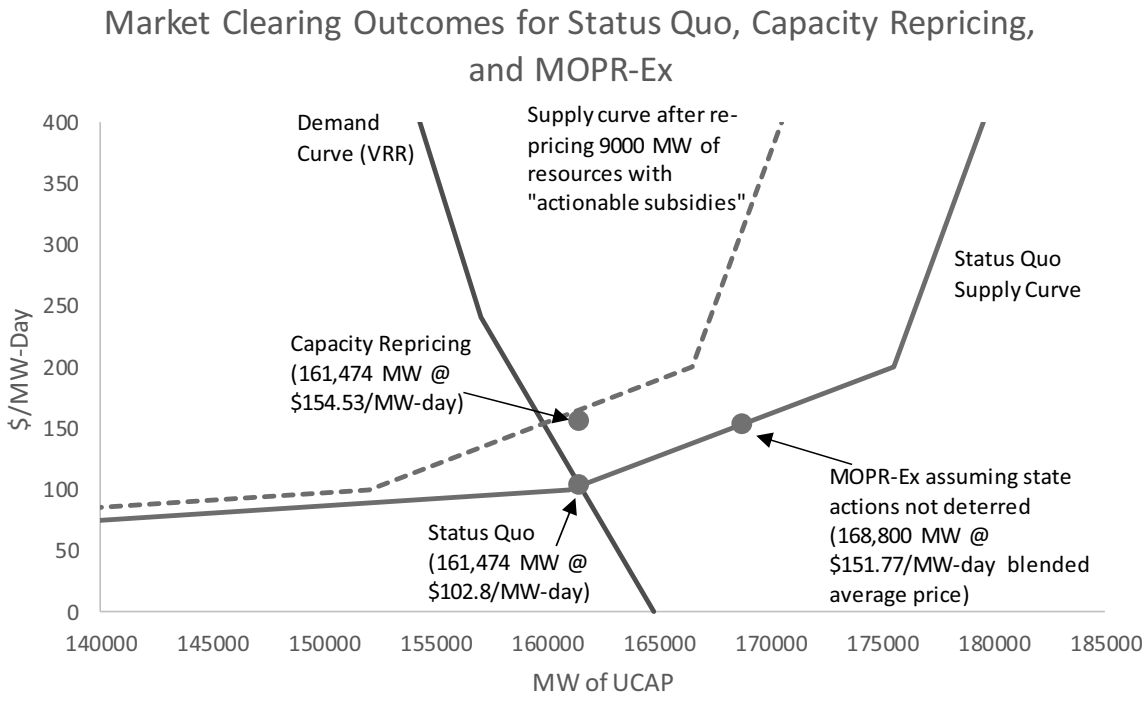
22. DeRamus & Cain claim that PJM's MOPR-Ex proposal, in contrast to Capacity Repricing, does produce a result that falls on the RPM demand curve.[11] That claim is only correct

[10] DeRamus/Cain Affidavit at ¶ 37 and Wilson Affidavit at ¶ 48-51.

[11] DeRamus/Cain Affidavit at ¶ 72.

if one assumes that states will be deterred from supporting environmentally friendly resources—and there is no evidence to support that assumption. It is true that the price and quantity capacity pair procured solely through the RPM under MOPR-Ex does fall on the demand curve. However, if MOPR-Ex does not deter states from continuing to provide compensation sufficient to retain these resources, then these resources would still effectively be committing their capacity to the market, and the total amount "procured" would not be on the demand curve. Further, it is likely that state compensation provided to these resources would need to be raised to offset the loss of capacity revenues, effectively forcing consumers in these states to pay more to retain environmental resources while simultaneously procuring more capacity than needed via RPM. Returning to Wilson's example, if all 9,000 MW of resources with actionable subsidies remain in the market and are paid the original status quo clearing price of $102.8/MW-day via increased state out-of-market payments (the actual amount of increased payments is uncertain, but an increase equal to the status quo price offsets the loss of capacity revenues under MOPR-Ex, making it a reasonable illustrative value for this example), the total capacity procured is 168,800 MW (159,800 MW directly through the market and 9,000 MW via state action) and the blended average price paid is $151.77/MW-day. This price and quantity pair also does not fall on the demand curve. The only instance where MOPR-Ex would result in a price and quantity pair that falls on the demand curve is an instance where all 9,000 MW of targeted resources were deterred from either entering or remaining in the market. Figure 1 below shows where the various options (status quo, MOPR-Ex, and Capacity Repricing) fall relative to the demand curve.

Figure 1



23. Of the three alternatives, the only approach that will always fall on the demand curve is the status quo.

C. THE STATUS QUO IS THE MOST EFFICIENT APPROACH

24. Most types of state out-of-market payments under consideration in this proceeding are intended to explicitly or implicitly account for positive environmental attributes that are not priced by RTO markets. These state actions contribute to economic retention and entry and increase overall market efficiency.

25. The subsidies that appear to primarily concern some commenters are ZECs and similar subsidies that are paid to the Quad Cities nuclear plant in Illinois and may be paid to certain nuclear plants under recently-passed legislation in New Jersey. As is discussed at length in the declaration of Robert E. Willig filed in this proceeding,[12] these subsidies, and similar subsidies for other types of zero-emission generation, are designed to correct, for the resources in question, the fact that carbon pollution externalities are not priced in PJM's markets, and thus the zero-emission attribute

[12] Willig Declaration ¶ 25-54.

of these resources is not appropriately compensated. By appropriately accounting for the positive externality they produce by displacing the pollution caused by carbon-emitting resources, ZECs and similar subsidies make the market more efficient, rather than less.

26. Thus, consideration of ZEC (or similar) revenue is appropriately part of the formation of a competitive capacity bid for these resources. That is, when developing competitive capacity bids, it is appropriate that these resources consider ZEC revenue as a deduction from production costs, similar to energy or ancillary services, which serves to reduce their capacity bid relative to where it would have been absent the ZEC. The resulting capacity bid is not artificially suppressed by the subsidy, but rather is the proper price for the resource considering the state-provided compensation for its environmental attributes.[13] ZECs in particular are designed to promote economic entry and retention because the environmental attribute payment is based on, and cannot exceed, the social cost of avoided carbon emissions, and the resource will only clear the capacity market and be economically retained if its total cost of retention, including the benefit of the positive externality it produces, is lower than the cost of alternatives.[14]

27. The status quo allows those resources to appropriately reflect the impact of the subsidies in their capacity market bids and does not re-price or adjust those bids to a higher level that purports to eliminate the impact of the subsidies, as is contemplated by Capacity Repricing and MOPR-Ex.[15] The status quo selects the most efficient mix of resources at the most efficient price. Compared to either Capacity Repricing or MOPR-Ex, the status quo does not result in unnecessarily high customer costs, it produces a result that falls on the demand curve, and it does not create any incremental strategic bidding incentives.

28. For the ZEC programs in particular, commenters provide no evidence that the state payments are not an efficient mechanism for carbon reduction. Nor do they suggest a feasible alternative under the current PJM energy market design. Several commenters (notably the PJM IMM)[16] suggest a market-wide carbon price as an efficient alternative. That alternative is not

[13] Willig Declaration at ¶ 39-44.

[14] Willig Declaration at ¶ 51-54.

[15] Willig Declaration at ¶ 13(i).

[16] Comments of the Independent Market Monitor for PJM, Docket Nos. ER18-1314-000 and ER18-1314-001 (filed May 7th, 2018), at 10-11.

available to individual states, and it is disingenuous to suggest it is a viable near-term option. If an individual state attempted to impose a carbon tax on generation within its borders, as Dr. Willig demonstrates under the present market design, a carbon price high enough to value carbon at the social cost set by the states and drive the desired emission outcome would suffer considerably from leakage issues that would render it unworkable.[17] Thus, under the present market design, ZEC programs remain the only feasible approach to efficiently accomplishing state environmental goals. The status quo approach correctly recognizes the positive externalities targeted by these programs in both the prices and resource selection that result in the capacity market.

III. IF MODIFICATION TO THE CURRENT MOPR IS PURSUED, CAPACITY REPRICING IS A BETTER CHOICE THAN MOPR-EX

29. If the Commission is not persuaded that the status quo is adequate, two central economic questions can help guide the choice between the primary proposal presented by PJM, Capacity Repricing, and its alternative, MOPR-Ex. The first question is whether the out-of-market payments at issue in this proceeding internalize externalities and contribute to the retention and entry of the least-cost set of resources, once social costs as well as production costs are accounted for. As discussed previously, most state actions under consideration in this proceeding do contribute to economic retention and entry. The second question is whether states will be deterred by a mitigation mechanism, like MOPR-Ex, that would prevent state-supported resources from clearing. Absent any reason to think that states uniformly would be deterred, MOPR-Ex risks substantial over-procurement of capacity, and thus significant unnecessary costs imposed on customers. On the other hand, if MOPR-Ex does actually deter certain state actions related to legitimate environmental programs, then it would prevent economic resources from clearing the capacity market, which will result in a less efficient mix of capacity resources.

30. Capacity Repricing avoids both problems that plague MOPR-Ex. Capacity Repricing does not depend upon how states react, and by allowing state-supported resources to clear, avoids any over-procurement. And by allowing state-supported resources to clear, Capacity Repricing also allows legitimate state environmental programs to influence the resource mix, which promotes efficiency once environmental externalities are taken into account.

[17] Willig Affidavit at ¶ 35.

A. MOPR-EX RESULTS IN OVER-PROCUREMENT IF STATES ARE NOT DETERRED

31. If states are not deterred in pursuing programs seeking to preserve certain types of generation, MOPR-Ex results in over-procurement. MOPR-Ex operates by adjusting the bids of targeted resources to a higher level that seeks to "undo" the effect of payments resulting from state actions. MOPR-Ex then clears the market in a single step incorporating these higher, modified bids. As a result, the resources targeted by MOPR-Ex will not likely clear the capacity market and will instead be replaced by other resources that would not have cleared had the targeted resources bids not been adjusted upwards. However, the targeted resources will nonetheless remain in the market if state action is not deterred. And the additional resources procured in their place under MOPR-Ex will also remain in the market.

32. As discussed in the example summarized in Figure 1, this over-procurement effect will effectively cause the market to retain a much larger portfolio of capacity resources than is needed and would be procured under either the status quo or Capacity Repricing. As Figure 1 shows, with 9,000 MW of resources targeted by Capacity Repricing, MOPR-Ex results in the effective procurement of 7,326 MW (68,800 MW vs. 61,474 MW) more resources than either the status quo or Capacity Repricing.

B. IF STATES ARE DETERRED, MOPR-EX CHOOSES THE WRONG RESOURCES

33. To the extent that MOPR-Ex does deter states from making out-of-market payments even when those payments internalize externalities, MOPR-Ex will select the wrong set of resources to provide capacity and will result in the inefficient exit of economic resources. Under this scenario, states either cease state actions when the resources in question are targeted by MOPR-Ex, or never engage in state programs they would otherwise have engaged in due to the threat of MOPR-Ex.

34. As discussed previously, in the case of state actions which compensate resources for positive externalities, the most efficient treatment is to allow those resources to reflect those payments in their capacity bids, which will generally lead to a reduction in their bid price. If the resource clears the capacity market when bidding in this fashion, its retention is economic and least cost and appropriately takes into account the value of the positive externality that it produces.

Thus, retention or entry of the resource is socially-efficient and the state action adds to the social surplus enjoyed by all market participants.

35. MOPR-Ex explicitly targets resources receiving such payments and makes it much less likely that they will clear the market and receive a capacity obligation. To the extent that these resources leave the market due to this treatment, either because the state action is discontinued, never occurs, or is not sufficient to cover the lost capacity revenue, the market as a whole is deprived of the social surplus added by the presence of these resources in the market. In place of these resources, higher cost resources (after taking account of externalities) will be cleared in their place and will displace them in the capacity portfolio. This outcome results in an inefficient mix of resources that makes society worse off than the status quo.

36. Notably, MOPR-Ex includes a number of proposed exemptions, but these exemptions do not reflect whether the out-of-market state payments promote or impair the efficient selection of resources. This is discussed at length in the Willig Declaration, and the ZEC program provides an illustrative example: the ZEC payments that MOPR-Ex targets are demonstrably the most economic form of carbon abatement available to the states and are the only form of support that the states can effectively utilize given PJM's energy market design. It would be unjust and unreasonable for the Commission to eliminate the only unilateral option that states have to support the economic retention of zero carbon resources.

37. MOPR-Ex thus implicitly assumes that all state programs other than the enumerated exceptions are inefficient. It also implicitly assumes that MOPR-Ex mitigation will deter states from pursuing these programs. Both of these implicit assumptions are incorrect. With respect to the first assumption, the state ZEC programs at which MOPR-Ex is aimed are a prime example of efficient state programs that promote economic entry and retention. MOPR-Ex proponents offer no evidence to support their conclusion that these programs are inefficient. And their arguments that states have better alternatives ring hollow in the face of PJM energy market design. With respect to the second assumption, there is no evidence that MOPR mitigation will deter state environmental action. One has only to consider the progression of state renewable energy programs and targets to reach this conclusion, including in states/regions where MOPR provisions currently apply or might be implemented. A recent example of this is the New England states, where ISO-New England put in place a modest exemption (200 MW per year) to its MOPR for

capacity entering to support state renewable portfolio standards, and several states issued the Multi-State Clean Energy request for proposals, which aims to procure 460 MW of new renewable resources, while Massachusetts enacted the 2016 Massachusetts Energy Diversity Act, which requires clean energy procurements in the range of 2,800 MW.[18] Another example is those states in PJM that are contemplating programs such as offshore wind that are not exempted under the MOPR-Ex proposal.

38. Thus, MOPR-Ex presents considerable risk on two fronts. If there is a significant likelihood that states will not be deterred in pursuing programs to support generation (and there is), it risks over procurement and additional costs to consumers. And if there is a significant likelihood that the state programs MOPR-Ex would mitigate enhance efficiency (and there is), there is risk that cost-effective, efficiency-enhancing resources will be excluded from the market.

C. CAPACITY REPRICING AVOIDS OVER-PROCUREMENT AND CHOOSES THE MOST EFFICIENT PORTFOLIO OF RESOURCES

39. Capacity Repricing, by contrast, avoids these risks. The most basic difference between Capacity Repricing (or the status quo) and MOPR-Ex is that resources receiving out-of-market payments are cleared based on their un-modified bids and are thus likely to receive a capacity obligation (and payment) under Capacity Repricing (or the status quo) whereas they are unlikely to be cleared and be paid for capacity under MOPR-Ex. In the event that states are not deterred by either option in continuing to pursue state actions to support generation, Capacity Repricing avoids the over-procurement problem suffered under MOPR-Ex because it recognizes the reality that these resources will remain in the market and provides them with a capacity obligation to the extent their un-modified bid is economic. Capacity Repricing thus avoids the inefficient excess procurement of capacity and results in a more efficient and cost-effective outcome for consumers, regardless of one's view on whether externality payments under state programs improve efficiency.

40. Capacity Repricing also chooses the most efficient portfolio of resources because resources are cleared based on their original, un-modified bid. As discussed previously, when these un-modified bids appropriately reflect the value of payments intended to internalize

[18] *See* ISO-NE Transmittal at 3-4, Docket No. ER18-619-000 (January 8, 2018).

externalities, these bids reflect the true total social cost of these resources. Because Capacity Repricing selects resources based on these costs, rather than modified bids that omit the social cost or value of externalities, it selects the most efficient, least-cost portfolio of resources.

IV. ISSUES RAISED BY COMMENTERS' WITNESSES WITH RESPECT TO CAPACITY REPRICING ARE NOT DISQUALIFYING AND DO NOT RENDER IT UNWORKABLE

41. Commenters argue that MOPR-Ex is preferable to Capacity Repricing, focusing on several points they allege make capacity repricing unworkable. First, they contend that Capacity Repricing leads to a price-quantity paid that is not on the demand curve. Second, they identify potential strategic bidding issues associated with Capacity Repricing that they contend are "fatal flaws." Both arguments are incorrect. I address each in turn below.

A. MOPR-EX DOES NOT PRODUCE A RESULT ON DEMAND CURVE EITHER, AND PRODUCING A RESULT NOT FALLING ON THE DEMAND CURVE DOES NOT RENDER CAPACITY REPRICING UNWORKABLE

42. As discussed previously, it is true that Capacity Repricing produces a result that does not fall on the demand curve. Indeed, this is one reason to prefer the status quo to either alternative offered by PJM. However, MOPR-Ex does not produce a result that falls on the demand curve either. As shown on Figure 1, unless states are deterred from pursuing the programs targeted by MOPR-Ex in all cases, MOPR-Ex will result in the procurement of significant excess capacity. The cost of this capacity will be paid for by consumers in the states in question. When this excess procurement is included, the effective price-quantity paid that results is even farther away from the demand curve than Capacity Repricing.

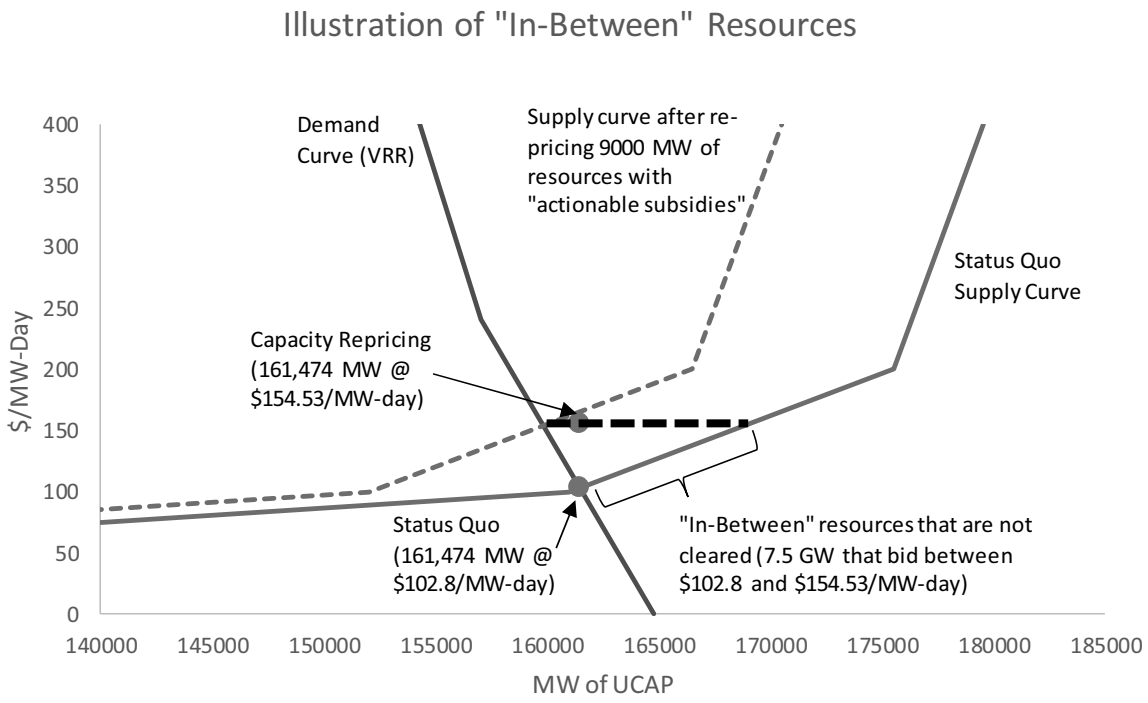
43. Second, even though the price-quantity pair resulting from Capacity Repricing does not fall on the demand curve, that does not render Capacity Repricing unworkable or impossible to execute. That is, the market clearing mechanisms identified by PJM are functional and should clear and produce stable and workable results.

B. STRATEGIC BIDDING BEHAVIORS WILL REDUCE MARKET CLEARING PRICES UNDER CAPACITY REPRICING

44. Commenters' witnesses also identify two issues associated with the two-stage market clearing mechanics of Capacity Repricing. Both issues stem from the fact that Capacity Repricing

does not jointly set the price and quantity of cleared resources. Rather, because resources with "actionable subsidies" are bid as-is in stage one but are re-priced at a higher price in stage two, the stage two price will be set by a class of resources whose bids fall at or below the stage two clearing price but who are not cleared in stage one and do not receive a capacity obligation. These resources are termed the "in-between" resources by Wilson. Figure 2 below shows the mechanics of this in graphical form:

Figure 2



45. The problems that commenters' witnesses identify with bidding under Capacity Repricing stem from the fact that the in-between resources are relied upon to set the stage two price but do not receive a capacity obligation or payment. First, commenters' witnesses claim that the resulting stage two price is arbitrary and not the result of a workably competitive process because it may be set by a resource offer that has nothing at stake in setting its offer price.[19] Second, they claim that the separation of price and quantity creates incentives for market participants to engage in a variety of strategic bidding behaviors that may cause bids to deviate either above or below their true costs, which may inappropriately increase or decrease the stage

[19] Wilson Affidavit at ¶ 75 and DeRamus/Cain Affidavit at ¶ 35-39.

two clearing price and will generally result in increased capacity price volatility. The first of these two problems is actually more of a theoretical complaint about this type of re-pricing mechanism. But the question before the Commission is not one of theory but rather of whether the specific PJM proposal is workable and will produce reasonable results. And the answer to that question turns on the specific complaints related to strategic bidding behaviors and their market implications, which I address below.

46. Commenters' witnesses collectively identify three specific strategic bidding behaviors that result from the two-stage clearing mechanics of Capacity Repricing that they collectively contend makes Capacity Repricing "unworkable." These are a "race to the bottom" or bid suppression effect, identified by both Wilson and DeRamus & Cain,[20] an enhanced incentive to engage in above-cost bidding for certain resources, termed the "clear out the top" behavior,[21] identified by Wilson, and a tendency for resources that repeatedly fall within the "in between" resource zone to cease participation in the market over the longer term, identified by DeRamus & Cain.[22]

47. The "race to the bottom" behavior arises from the fact that to receive a capacity obligation and be paid the higher stage two price, resources must clear at or below the lower stage one price. If they do not clear in stage one, even if they offer at or below the stage two price, they will not receive a capacity obligation and will realize no capacity revenue, becoming an "in-between" resource. As a result, resources generally have an incentive to reduce their bids below their cost of providing capacity to increase the likelihood of clearing in stage one. Because the stage two price will be higher than the stage one price and be set by resources higher up the supply curve that did not clear in stage one, this is a rational strategy for most resources that suspect they may be marginal or near-marginal in stage one. Its overall effect is to reduce capacity offer prices.

48. The "clear out the top" behavior identified by Wilson (but not DeRamus & Cain) describes an increased incentive for certain resources that are part of a larger portfolio to offer at a higher level than otherwise to the extent they believe they are unlikely to clear in stage one but may be marginal or near marginal in stage two. This stems from the fact that the opportunity cost

[20] Wilson Affidavit at ¶ 54-57 and DeRamus/Cain Affidavit at ¶ 40-49.

[21] Wilson Affidavit at ¶ 58.

[22] DeRamus/Cain Affidavit at ¶ 49-53.

of bidding at a higher level and not clearing is largely eliminated for those resources because as likely "in-between" resources they will not clear anyway. Because this opportunity cost is reduced or eliminated, the value to the overall portfolio of engaging in this strategy is incrementally increased, which may cause certain resources to bid higher than otherwise.

49. Finally, DeRamus & Cain suggest that over the longer-term resources that repeatedly fall in the "in-between" resource group, and particularly new entrant resources falling in this zone, will eventually cease participation in the market despite being ostensibly competitive at the stage two price because of the ongoing cost of preparing and standing behind their capacity offers. This effect will tend to steepen the supply curve in the in-between resource zone to the extent that these participants are not replaced with other new entrants at a similar offer level.

50. Of the three strategic bidding effects, one ("race to the bottom") will tend to reduce offer prices and lower the supply curve, while two ("clear out the top" and long-term exit of in-between resources) will tend to increase offer prices and/or raise the supply curve. The overall impact on market clearing prices and amount of cleared capacity under Capacity Repricing is thus ambiguous at first glance and depends on the relative strength and prevalence of the three effects.

51. While commenters' witnesses point out these strategic bidding behaviors, they do not provide any well-supported analysis of their combined net impact. Wilson provides an example, based on an approximation of the 2020/21 RPM RTO supply and demand curves, that purports to show that the "clear out the top" effect will tend to predominate, at least for purposes of determining the market clearing price, and will result in higher than otherwise prices, while the "race to the bottom" effect will drive a slightly higher cleared quantity in stage one.[23] This example, however, is completely driven by an arbitrary and unsupported assumption about which resources will choose a particular bidding strategy and the degree to which a given bidding strategy will cause them to change their offer prices. As I discuss below, a careful examination of each strategy indicates that the assumptions underlying this analysis are not representative of the likely outcome. DeRamus & Cain, on the other hand present an example that suggests that the effect is to decrease the stage two clearing price, while increasing the quantity cleared in stage one.[24]

[23] Wilson Affidavit at ¶ 60-62.

[24] DeRamus/Cain Affidavit at ¶ 45-46.

52. An analysis of the each of the strategic bidding behaviors identified by commenters' witnesses indicates that the impact of the "race to the bottom" behavior is likely to dominate the effect of the other two behaviors, leading to a net incremental reduction in offer prices and a decrease in the stage two clearing price.

53. The principal reason for this is that the "clear out the top" behavior is likely to be quite rare because it would only apply to certain resources that are part of unusually-constituted portfolios. This is because Capacity Repricing does not actually create a new incentive to engage in "clear out the top" bidding, but instead may slightly reduce the opportunity cost of engaging in this bidding strategy where there is already an incentive present. Thus, the incremental increase in the frequency of "clear out the top" bidding due specifically to Capacity Repricing is likely to be minimal. As a result, the "clear out the top" behavior will have little impact on the capacity supply curve.

54. Furthermore, it is important to note that the "clear out the top" bidding behavior, whether in the status quo or incrementally under Capacity Repricing, is bounded by existing market power mitigation rules. Existing generation resources under either the status quo, Capacity Repricing, or MOPR-Ex remain subject to the must-offer requirement, the safe harbor offer cap of Net CONE times the balancing ratio ("B"), and the requirement to justify offers above the safe harbor cap with a unit specific Avoidable Cost Rate showing. Thus, to the extent that any resource engages in the behaviors described previously, and to the extent that its offer is above "cost," it still must remain at or below Net CONE times B, which the PJM IMM and the Commission have stated is representative of the opportunity cost that resources face when choosing whether to take on a Capacity Performance obligation. The "clear out the top" behavior then is limited at most to replacing an offer for which the resource owner judges the private costs of providing capacity to be some lesser value than Net CONE times B with a different offer at some higher level that is nonetheless equal to or less than Net CONE times B. That is, the resource owner is replacing one competitive offer with a different, higher, but still competitive offer. Any argument that the prices resulting from such behaviors are somehow not competitive or otherwise inappropriate is an argument that the existing market power mitigation rules are somehow inadequate, rather than an argument against a particular market design; such an argument seems beyond the scope of this proceeding.

55. In addition, the resources that may have incentives to engage in "clear out the top" behavior will also have incentives to engage in the "race to the bottom" behavior as well. Wilson contends that resources can easily predict where they will fall within the relative range of "in-between" resources and can thus precisely determine what strategy is appropriate for them. In the real world, where bidders have highly imperfect information, this is unlikely to be the case. Resources' ability to predict where they will fall on the supply curve when formulating their offers is highly limited and imprecise.

56. Finally, as both Wilson and numerous other commenters amply document, recent experience with the PJM capacity market indicates that there is a very large pool of potential new entrants, particularly new build natural gas combined cycles, that are willing to enter the market at relatively low prices.[25] The ability of any market participant to influence prices through a particular bidding strategy will be sharply constrained by the competitive discipline provided by these potential new entrants. Any strategic bidding behavior that tends to raise prices, such as the "clear out the top" behavior, will likely be met by a new entrant response which will tend to offset its impact.

57. Like the "clear out at top" behavior, the potential impact of "in-between" resources dropping out of the market over the longer-term, identified by DeRamus & Cain, is likely to be offset by this deep pool of new entrant capacity. Evidence from recent auctions suggests that new entrants tend to bid as price takers, rather than as marginal resources, and will thus be likely to respond to any price increase caused by "in-between" resource exit simply by increasing the amount of new entrant capacity offered.

58. Unlike the other two behaviors, the "race to the bottom" behavior identified by both Wilson and DeRamus & Cain is broadly applicable to all resources and does not depend on a set of particular circumstances such as being part of a specifically-constituted portfolio. Indeed, as discussed above, even when resources potentially face countervailing incentives to engage in other behaviors such as "clear out the top," the "race to the bottom" incentive will still be present and in many cases will tend to dominate the other incentive. For this reason, of the three behaviors

[25] Wilson Affidavit at ¶ 19-22 and Exelon Protest at 32-37.

identified, "race to the bottom" is likely to be far more prevalent and will tend to dominate the other two effects.

59. While it is likely to dominate, the "race to the bottom" behavior is likely to be self-limiting to the extent that it is not likely to drive the stage two price below the stage one price. This is because rational bidders will build into their decision on how to offer their resource the expectation that most other bidders will also be engaging in the "race to the bottom" behavior. If only one bidder is reducing its bid below cost to clear in stage one, its expectation of the stage two price will remain relatively high, and thus an aggressively below-cost bid is very likely to clear stage one and will be rewarded with a relatively high stage two price. If, however, all other bidders are engaging in the same behavior, the risk of not clearing stage one is increased, and the stage two price is likely to be much lower, increasing the risk that if the resource does clear, it may not be paid a price that covers its costs. Thus, under the expectation that all resources are engaging in "race to the bottom," resources are likely to be less aggressive in reducing their bids below cost to clear in stage one.

60. To provide a sense of the likely overall aggregate magnitude of the bidding behaviors, given the likely dominance of the "race to the bottom" behavior over the others, I have modified the example provided by Wilson to show the outcome that results when resources only engage in the "race to the bottom" behavior.[26] Following Wilson's assumptions, I have assumed that 50% of resources with offers more than $80/MW-day and less than $170/MW-day reduce their offers by 20% relative to the status quo. Unlike Wilson, however, I do not assume that any offer modification due to "clear out the top" occurs. I otherwise adopt Wilson's underlying assumptions with regards to supply curve shape and other parameters. This modified example is shown in graphical form in Figure 3 and Figure 4 below:

[26] Wilson Affidavit at ¶ 60-62.

Figure 3

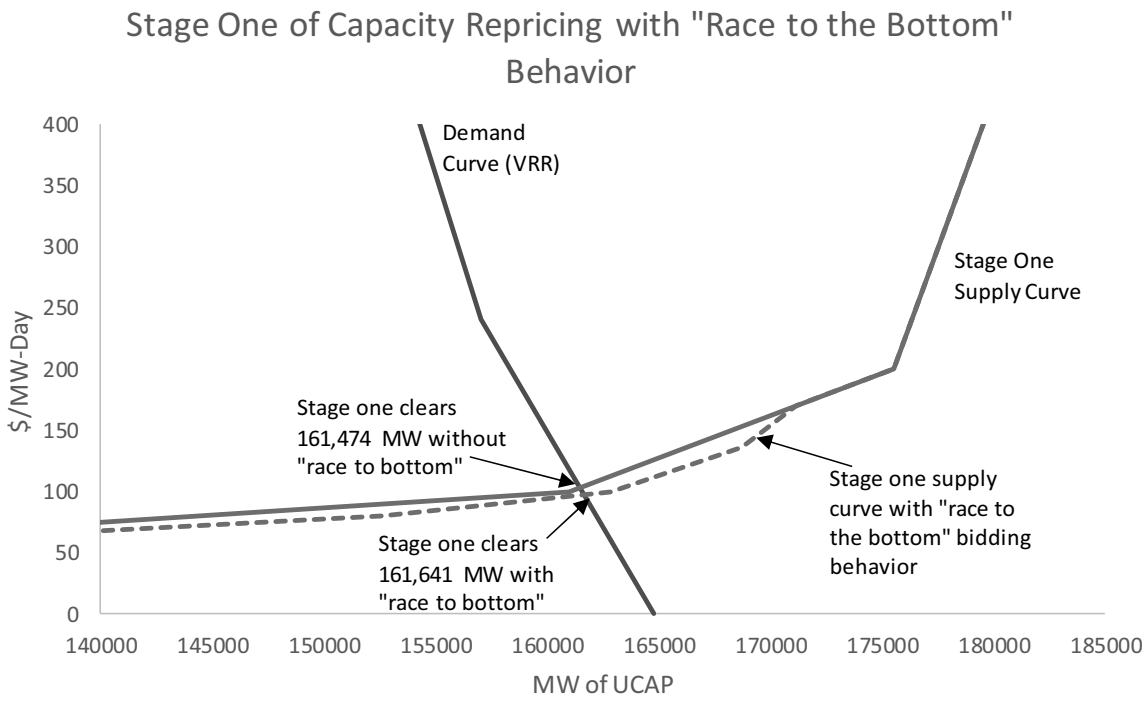
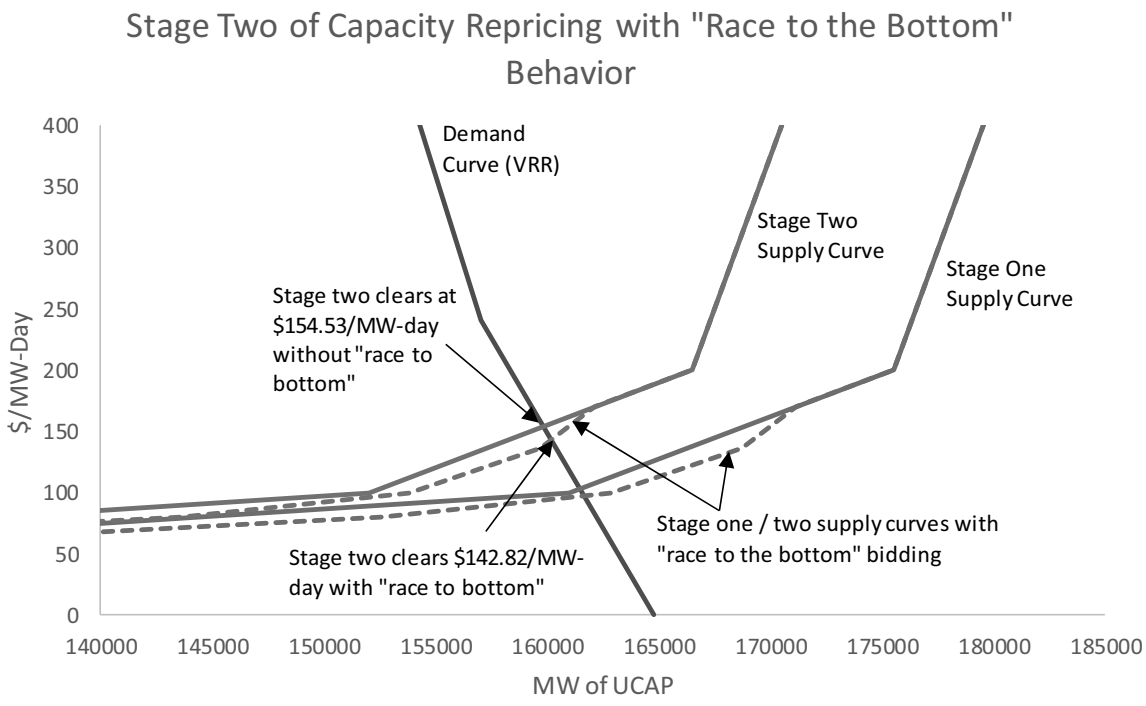


Figure 4



61. Without any strategic bidding behaviors, Capacity Repricing causes the capacity clearing price to increase from $102.8/MW-day in the status quo case to $154.53/MW-day in the Capacity Repricing case, with total unforced capacity cleared of 161,474 MW in both cases. Load payments thus rise from $6.06 billion in the status quo to $9.1 billion under Capacity Repricing, or a 50% increase. If we assume that the "race to the bottom" behavior dominates as per the assumptions discussed above, the total UCAP procured under Capacity Repricing rises slightly, by 167 MW to 161,641 MW, but the clearing price is $142.82/MW-day, or about 7.5% lower than it would have been without strategic bidding behaviors. Customer load payments with strategic bidding behaviors are $8.425 billion, or about a 39% increase relative to the status quo, rather than 50%. As discussed earlier, MOPR-Ex results in a customer cost increase of about 50% versus the status quo, so the effect of strategic bidding on Capacity Repricing in this example results in customer costs that are still considerably elevated relative to the status quo, but below MOPR-Ex.

62. The overall effect, then, of strategic bidding would be to drive the stage two clearing price under Capacity Repricing closer to the status quo price that would prevail absent Capacity Repricing. Generally, the resulting price should fall somewhere between the price absent strategic bidding (which is also the price that would result from MOPR-Ex) but above the status quo price that would result from no mitigation. Exactly where on this continuum the price would fall in this range is difficult to predict with precision, but the predominance of the "race to the bottom" behavior should ensure that it falls below the MOPR-Ex price while bidder rational expectations should ensure that it falls above the status quo price.

63. Strategic bidding would result in a total quantity procured slightly in excess of what it would be in the most efficient status quo case. Given the steepness of the demand, the incremental capacity procured because of this is minimal. In the example above, strategic bidding causes 167 MW of additional capacity to clear, or a 0.1% increase versus the status quo.

64. To the extent that the resources subject to mitigation are receiving payments addressing environmental externalities, the status quo price is more efficient than the Capacity Repricing price without these strategic bidding behaviors (which is also the same as the MOPR-Ex price). Thus, ironically, the effect of strategic bidding behaviors in the aggregate is to make Capacity Repricing less inefficient, not more inefficient, because collectively they drive a lower market clearing price that is closer to the efficient status quo price. As a result, the strategic bidding

behaviors incrementally increase the efficiency of Capacity Repricing and lower its cost to consumers. But whatever one's view of the state programs at issue, these behaviors are likely to have only modest effects that will yield a price somewhere between the status quo price and the MOPR-Ex price.

C. STRATEGIC BIDDING BEHAVIORS CAN BE REMEDIED WITH A LOST OPPORTUNITY COST PAYMENT TO "IN-BETWEEN" RESOURCES

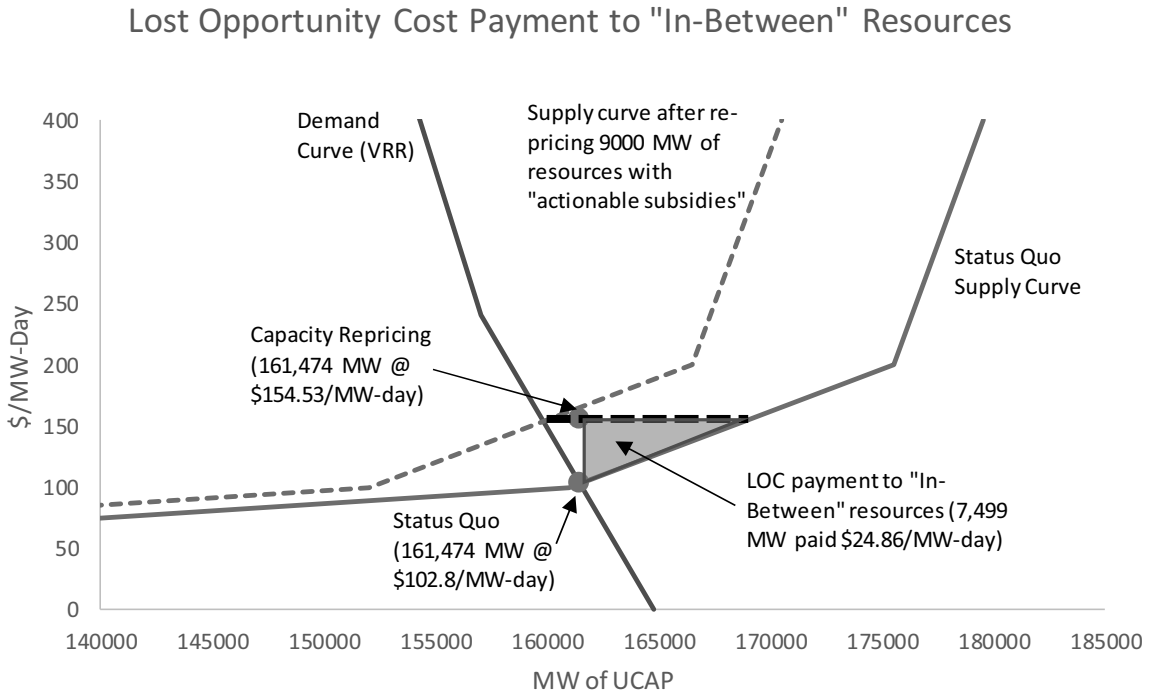
65. If the Commission does decide to proceed with Capacity Repricing but also determines that the strategic bidding behaviors identified by commenters' witnesses are undesirable, the behaviors could be largely eliminated by implementing a simple market design fix analogous to other market design fixes that the Commission has approved to address similar strategic bidding issues in RTO energy, ancillary service, and capacity markets. That is, rather than representing an insoluble "fatal flaw," these strategic bidding behaviors can easily be addressed within the broader market design. The market design fix in this case would be to implement a lost opportunity cost ("LOC") payment for "in-between" resources.

66. As discussed above, the root cause of all the potential strategic bidding behaviors identified by commenters' witnesses is the fact that "in-between" resources do not clear and thus do not bear any direct financial consequences for their bid. A LOC payment adds financial consequences for "in-between" resources in a manner that simulates the consequences that would occur if they did clear in stage two of Capacity Repricing, and in so doing largely eliminates the incremental incentives to engage in strategic bidding behaviors.

67. A LOC payment would be implemented by paying resources that do not clear in stage one the difference between the stage two clearing price and their individual bid price, if greater than zero. Despite receiving this payment, they would still not clear in stage one and would not receive a capacity obligation. The LOC payment would thus not carry an obligation that the resource receiving it remain in the market (for an existing resource) or subsequently enter the market (for a new resource); an existing resource could subsequently retire following the auction and still receive the payment. The LOC payment replicates the margin that the "in-between" resources would have earned by providing capacity if they were cleared and received a capacity obligation. That is, the stage two price represents the capacity revenue they would have received, while their offer price represents their private cost of providing capacity. The LOC payment pays

them as if they had cleared the market but recognizes that because they do not receive a capacity obligation they are able to avoid the cost of providing capacity, and thus deducts their offer price from the capacity clearing price. Figure 5 below shows how a LOC payment for "in-between" resources would work in graphic form:

Figure 5



68. The LOC payment restores financial consequences to the bidding decisions made by in-between resources. Because lack of financial consequences for their bidding decision is the root cause of the strategic bidding behaviors incentivized by Capacity Repricing, a LOC payment reduces the incentive to engage in these behaviors.

69. First, the incentive to engage in "race to the bottom" below-cost bidding is reduced because the LOC payment makes resources indifferent between clearing or not clearing in stage one. Working off the "race to the bottom" example provided by Wilson,[27] assume that a resource with costs of $115/MW-day is determining its offer price under the knowledge that an offer of $100/MW-day or less is needed to clear stage one, but the stage two price is likely to clear at around $150/MW-day. Without a LOC payment, this resource has an incentive to reduce its offer

[27] Wilson Affidavit at ¶ 55.

below its costs, to $100/MW-day or less, to avoid becoming an "in-between" resource. If it bids below costs and clears stage one, it earns a margin on its capacity sale of $35/MW-day, the difference between the stage two price of $150/MW-day and its costs of $115/MW-day. But if it bids its costs, it will not clear and will receive nothing. With a LOC payment, however, if it bids its costs of $115/MW-day, it receives a payment of $35/MW-day – the difference between the stage two price and its offer price. Thus, the resource owner's incentive to reduce its offer price to a level needed to clear stage one is eliminated – the resource's margin is equalized between the two outcomes.

70. It is true that a LOC payment likely does not fully eliminate the incentive to bid below cost in all situations. Resources that expect to fall within the "in-between" zone would have a modest incentive to reduce their offer prices slightly below cost in order to maximize the size of the LOC payment while still remaining a "in-between" resource. This incentive is much weaker, however, because it only produces gains if the resource still does not clear stage one despite reducing its offer below cost, and higher cost resources that engage in this strategy would run the risk of clearing in stage one and taking on a capacity obligation at a loss.

71. Second, the "clear out the top" behavior would be eliminated, to the extent it exists, because the LOC payment restores the opportunity cost of bidding a high cost "in-between" resource at above its costs. As discussed previously, this behavior arises because such resources are unlikely to clear in stage one and thus do not forgo any capacity margin by bidding above cost. With a LOC payment, however, bidding in this fashion would cause the resource to either forgo the payment (because it bids above the stage two price) or reduce its magnitude. Thus, the payoff to a "clear out the top" strategy of bidding such a resource above its costs is re-set back to the same level that exists under the status quo.

72. Finally, resources that consistently fall in the "in-between" region, particularly new entrant offers, will not face an incentive to stop bidding over time due to failure to cover their offer costs. LOC payments should provide sufficient compensation for such resources to continue preparing offers and participating in the market.

73. The cost of LOC payments is likely to be quite small relative to overall capacity cost. Returning to the example originally provided by Wilson, with an assumed 9,000 MW of re-priced resources, Capacity Repricing results in a clearing quantity of 161,474 MW and a clearing price

of $154.53/MW-day for stage two and $102.8/MW-day for stage one. Under these assumptions, and with the capacity supply curve assumed by Wilson, there are 7,499 MW of resources that do not clear stage one but bid below $154.53/MW-day (*i.e.*, "in-between" resources). These resources have an average bid price of $128.66/MW-day. A LOC payment system would pay this 7.5 GW of resources an average payment of $24.86/MW-day (the stage two price less their average bid). The total cost of these payments would be about $68 million, or about 0.75% of the total capacity payments under the example.

74. While LOC payments have not to date been utilized in capacity markets, they are widely used (and FERC-approved) in RTO energy and ancillary services markets to align bidder incentives and increase market efficiency. Examples include LOC payments to generators in the energy market to keep them whole when responding to out-of-market dispatch signals for reliability reasons, and co-optimization of energy and operating reserves markets, where lost opportunity cost forms the basis for the reserve price.

75. By comparison, there is no relatively simple adjustment, like a lost opportunity cost payment, that would fix the flaws in the MOPR-Ex proposal. MOPR-Ex by its nature pushes targeted resources out of the capacity market. As discussed previously, the flaws in MOPR-Ex arise from this fundamental feature of MOPR-Ex – either the resources remain and excess capacity is effectively procured, or economic resources may exit the market. There is no way to avoid these problems without changing this fundamental aspect of MOPR-Ex.

76. This completes my declaration.

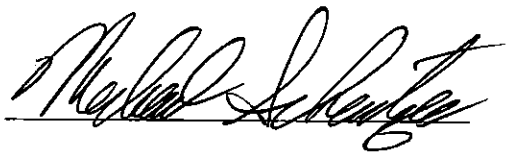
20180522-5305 FERC PDF (Unofficial) 5/22/2018 3:34:39 PM

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. ER18-1314-000**
	)	**ER18-1314-001**
	)	
	)	

DECLARATION OF MICHAEL M. SCHNITZER

I, Michael M. Schnitzer, declare under penalty of perjury that the foregoing is true and correct.



Executed: May 22, 2018

Concord, Massachusetts

Michael M. Schnitzer

20180522-5305 FERC PDF (Unofficial) 5/22/2018 3:34:39 PM

Document Content(s)

Answer5-22-2018.PDF.....1-29

Schnitzer Reply Declaration Final.PDF.....30-58

20150610-5280 FERC PDF (Unofficial) 6/10/2015 3:34:23 PM

Hesser G. McBride, Jr.
Associate General Regulatory Counsel

Law Department
PSEG Services Corporation
80 Park Plaza, T5G, Newark, NJ 07102
tel: 973.430.5333 fax:973.430.5983
Hesser.McBride@PSEG.com

PSEG Services Corporation

VIA ETARIFF FILING

June 10, 2015

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: PSEG Energy Resources & Trade, LLC
Revised Rate Schedule FERC No. 3
Docket No. ER15-1882-000
Errata to Pending Filing

Dear Secretary Bose:

On June 5, 2015, PSEG Energy Resources & Trade LLC ("PSEG ER&T") filed with the Federal Energy Regulatory Commission (Commission") in the above docket a revised Rate Schedule FERC No. 3 ("Rate Schedule"), which sets forth the cost-based revenue requirements for the provision of Reactive Supply and Voltage Control from Generation Sources Service ("Reactive Power") owned by PSEG Fossil LLC ("PSEG Fossil") and PSEG Nuclear LLC ("PSEG Nuclear"). This filing ("Reactive Power Filing") is currently pending before the Commission. PSEG ER&T submits this errata filing to correct an error in the proposed effective date and to include certain referenced workpapers.

Specifically, PSEG ER&T requested a proposed effective date of June 5, 2015. The requested proposed effective date appears on pages 2, 7, 8 and 9 of the Reactive Power Filing. The proposed effective date should be June 6, 2015 consistent with the one-day suspension effective date requested in the filing. Also, this errata amends the Reactive Power Filing to include the attached workpapers referenced in the testimony submitted with the filing. Further, an unmarked copy of the proposed tariff submitted with the Reactive Power Filing is attached and all relevant tariff records are being resubmitted with the corrected proposed effective date in the metadata.

PSEG ER&T respectfully requests that the Commission accept this within errata.

20150610-5280 FERC PDF (Unofficial) 6/10/2015 3:34:23 PM

Respectfully submitted,

PSEG Energy Resources & Trade LLC

By: *Hesser G. McBride, Jr.*

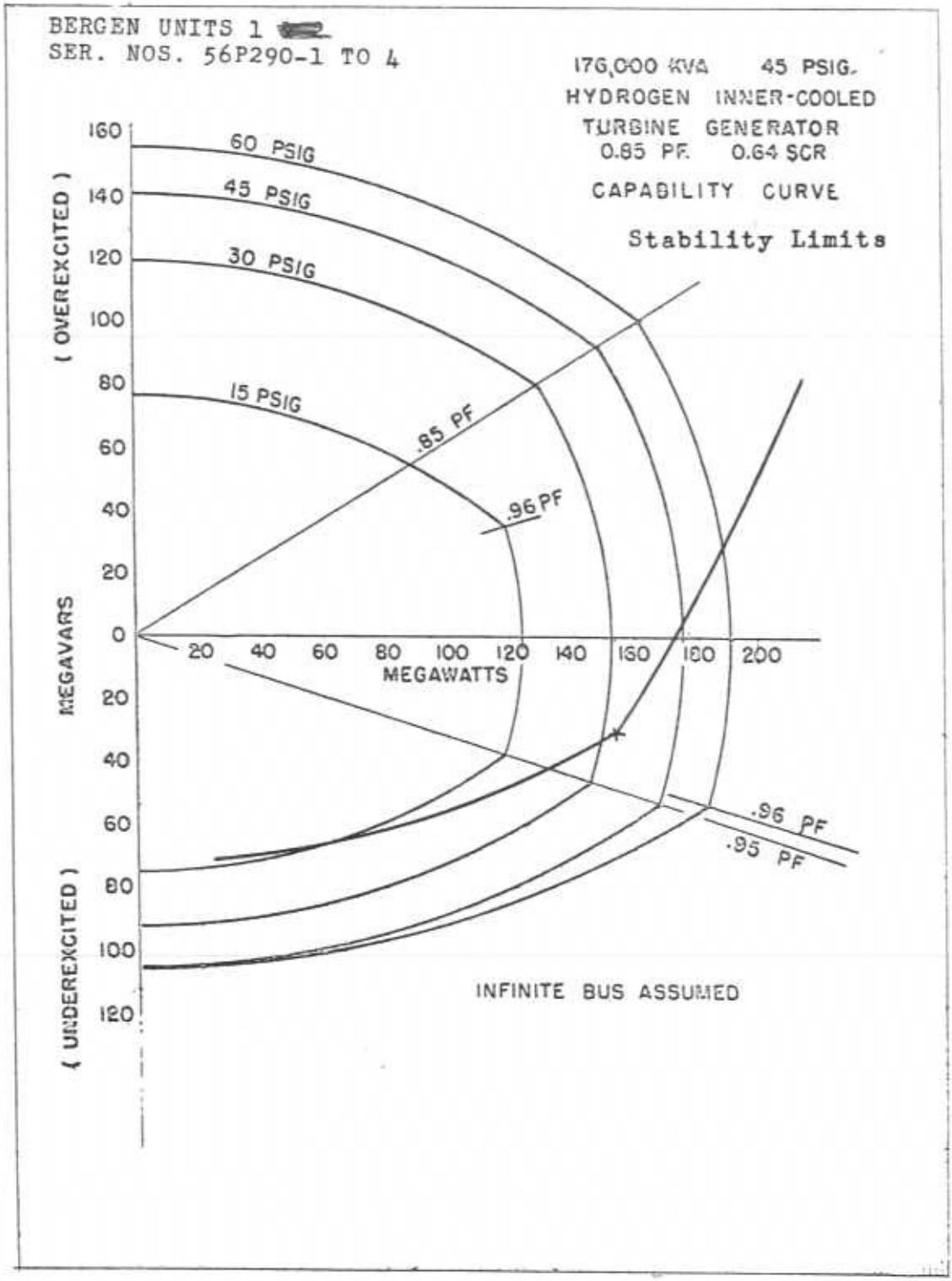
Hesser G. McBride, Jr.
Associate General Regulatory Counsel
PSEG Services Corporation
80 Park Plaza, T5
Newark, NJ 07102
(973) 430-5333
Hesser.McBride@PSEG.com

20150610-5280 FERC PDF (Unofficial) 6/10/2015 3:34:23 PM

Generation Data

20150610-5280 FERC PDF (Unofficial) 6/10/2015 3:34:23 PM

BERGEN 1 STEAM



Curve 443083A Capability Curve FIG. 20

20150610-5280 FERC PDF (Unofficial) 6/10/2015 3:34:23 PM

SIEMENS

BERGEN 1 CTG

Technical Data
Reactive Capability Curve P3/4

Generator Type: TLRI 93/33–38

Rated Apparent Power	S_N = 125.0 MVA	Rated Frequency	f_N = 60 Hz
Rated Active Power	P_N = 112.5 MW	Power Factor	P.F. = 0.9
Rated Armature Voltage	V_N = 13.8 kV	Speed	n_N = 60 s^{-1}
Rated Armature Current	I_N = 5.23 kA	Cold Air Temperature	t_K = 104°F (40°C)

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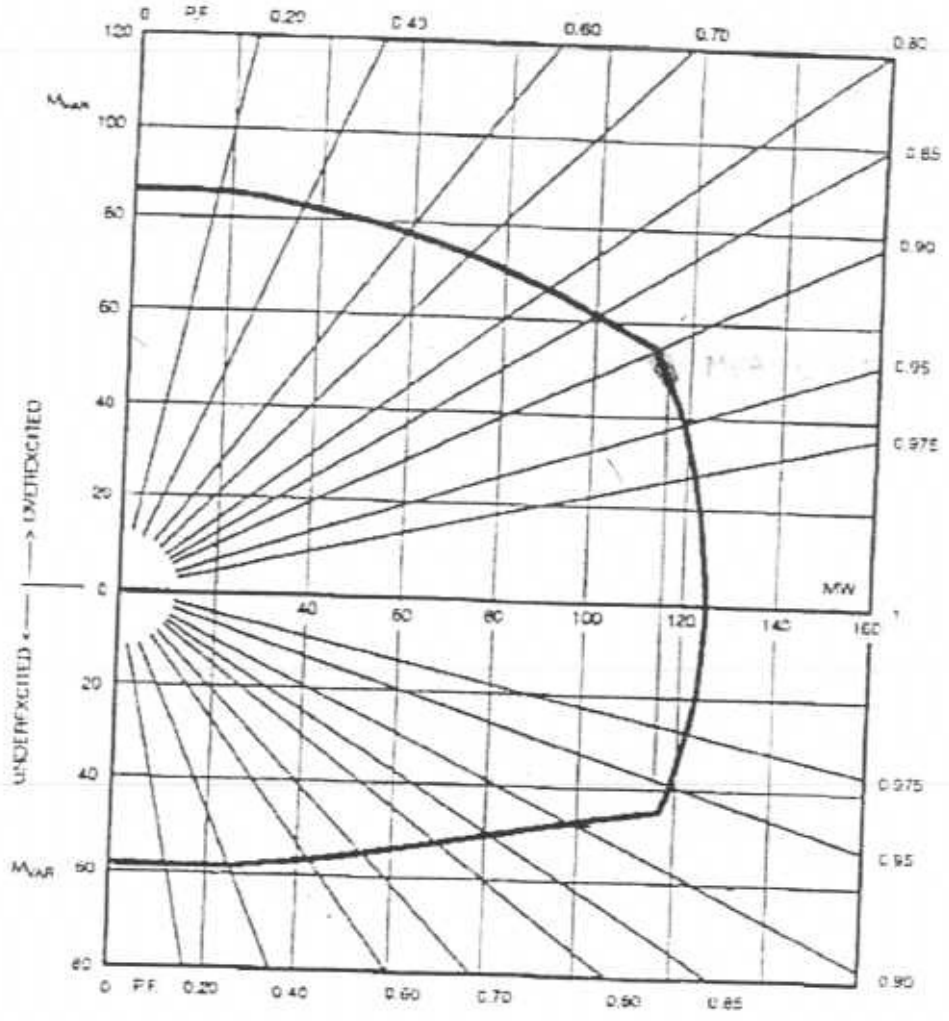

Figure 1. Reactive Capability Curve.

BERGEN 1 GG

SIEMENS

Technical Data
Reactive Capability Curve

b

Generator Type: TLRI 93 / 33-36

Rated Apparent Power	S_N	=	125.00 MVA	Rated Frequency	f_N	=	60 Hz
Rated Active Power	P_N	=	112.50 MW	Power Factor	P.F.	=	0.90
Rated Armature Voltage	V_N	=	13.80 kV	Speed	n_N	=	60 s^{-1}
Rated Armature Current	I_N	=	5.23 kV	Cold Air Temperature	t_K	=	104°F (40°C)

Per Unit Values:
Rated Armature Current = 5.230 kA (1P.U.)
Rated Field Current = 0.781 kA (1P.U.)

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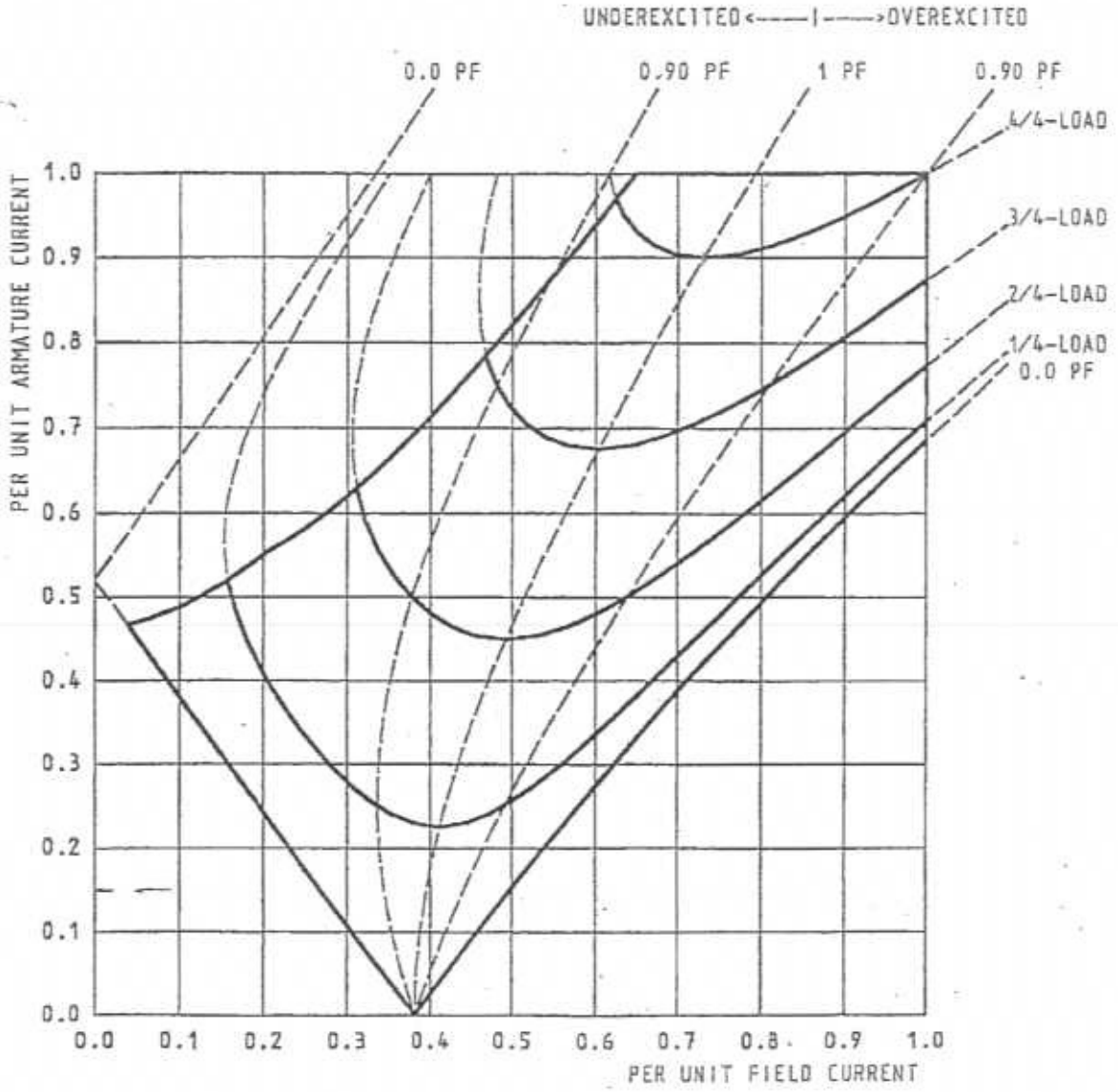


PRINTED IN U.S.A.

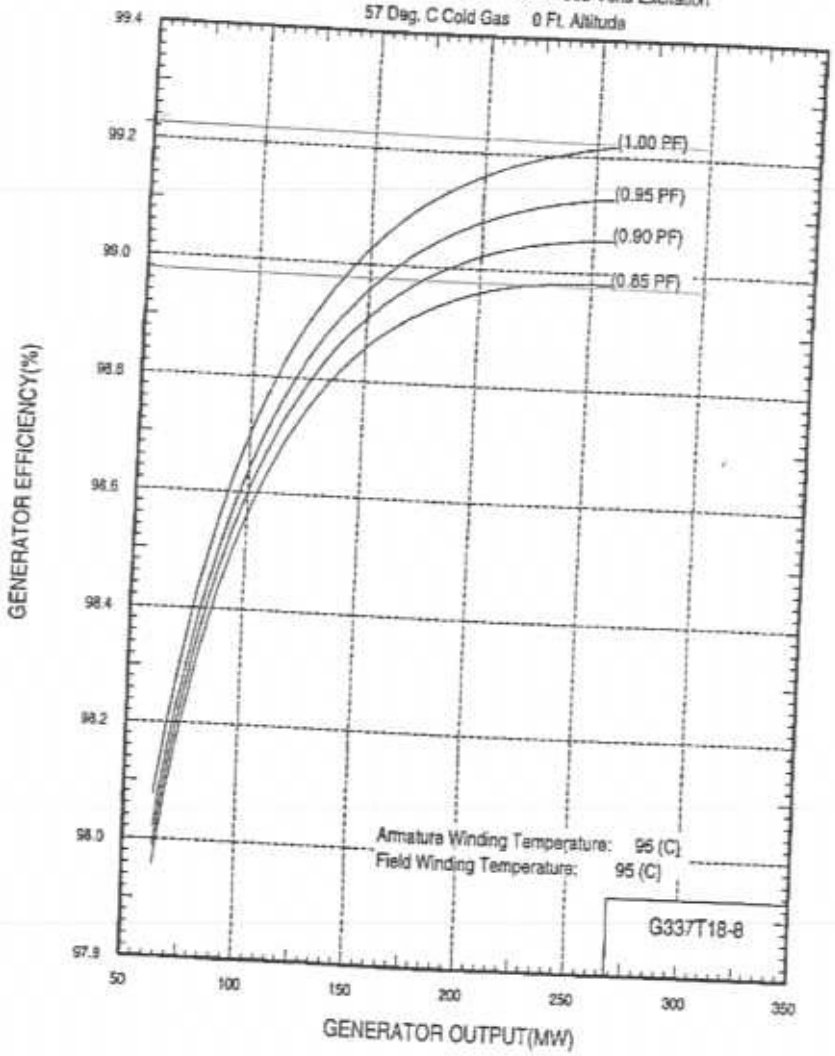
BERGEN 2 STEAM T G

SIZE	DWG NO	SH	REV
A	364A2265	12	-

Bergen 2 STG

GENERATOR EFFICIENCY CURVE

2 Pole 3600 RPM 304000 kVA 18000 Volts 0.850 PF
0.560 SCR 45.00 PSIG H2 Pressure 565 Volts Excitation
57 Deg. C Cold Gas 0 Ft. Altitude



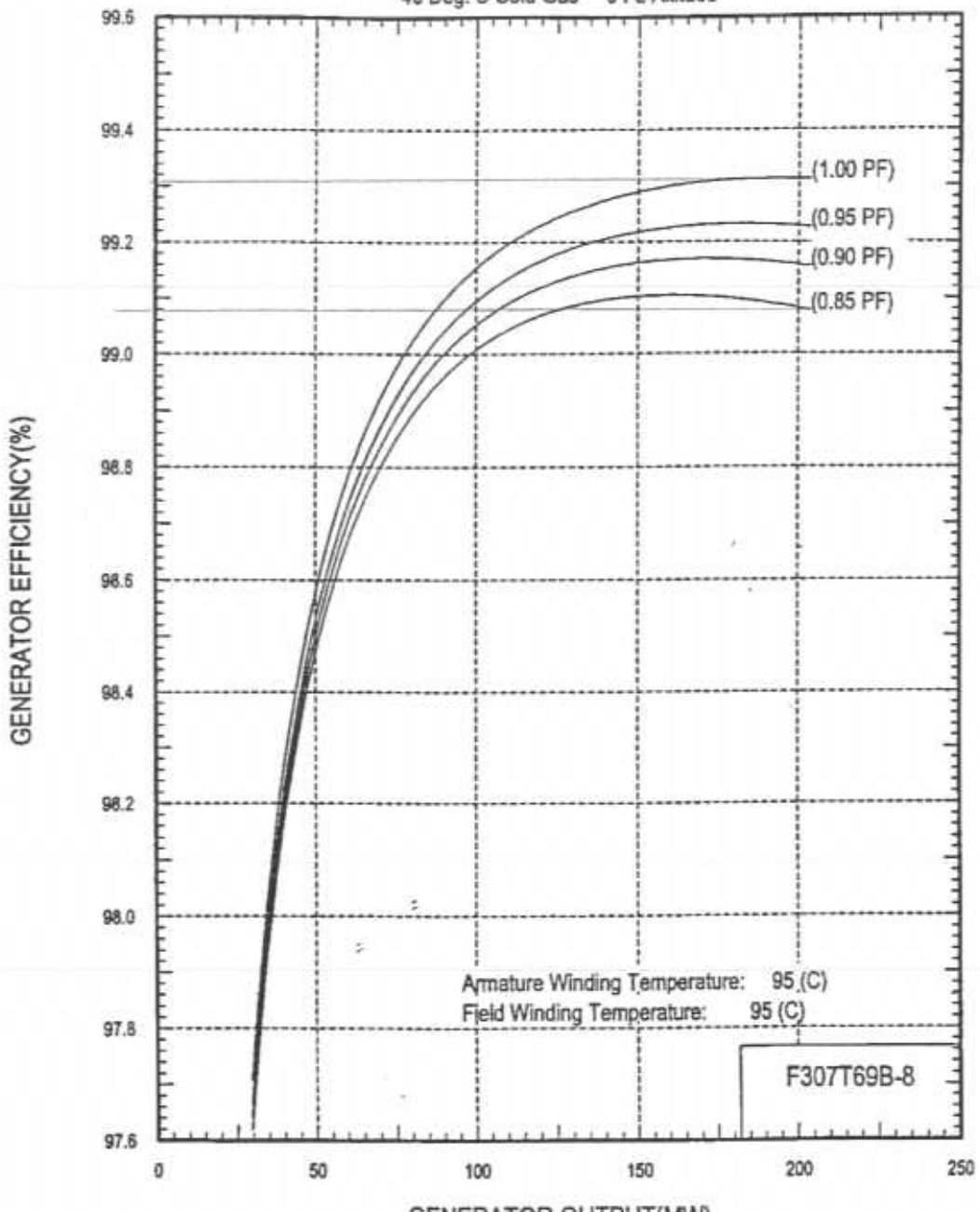
GE Power Generation	GENERAL ELECTRIC COMPANY SCHENECTADY, NY	SIZE A	CAGE CODE
DRAWN			DWG NO 364A2265
ISSUED		SCALE	SHEET 12

SIZE BERGEN 2 CTG SH 13 REV A

Bergen 2 CTG

GENERATOR EFFICIENCY CURVE

2 Pole 3600 RPM 216000 kVA 18000 Volts 0.850 PF
0.530 SCR 30.00 PSIG H2 Pressure 305 Volts Excitation
40 Deg. C Cold Gas 0 Ft. Altitude



GENERAL ELECTRIC COMPANY SCHENECTADY, NY GE Power Generation	SIZE A	CAGE CODE	DWG NO 364A2288
DRAWN ISSUED	SCALE		SHEET 13

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BURE 12
KEARNY 12
KEARNY 13
KEARNY 14

BRUSH ELECTRICAL MACHINES LTD

ELECTRICAL DATA SHEET - CONTINUATION

BDAX 7-290RT , 60.500 MW, 0.850 pf, 13.80 kV, 60 Hz

9. INHERENT VOLTAGE REGULATION

9.1	F.L to N.L rated pf, constant excitation	35 %
9.2	F.L to N.L unity pf, constant excitation	27 %
9.3	F.L to N.L steady state under full AVR control	± 0.5 %

10. EFFICIENCY AND LOSSES

These losses below are calculated values. The total loss and the resulting efficiencies are subject to a tolerance in accordance with IEC 34-1.

MW output	60.500	60.500
Power factor	0.850	Unity
Friction & windage loss(kW)	305	305
Stator core iron loss(kW)	155	155
Stator copper loss at 95°C(kW)	127	91
Stray load loss at 95°C(kW)	233	168
Rotor copper loss at 95°C(kW)	162	81
Exciter loss(kW)	12	6
Total loss(kW)	995	808

Efficiencies:

% load	100	75	50	25
0.850 power factor	98.38 %	98.31 %	97.99 %	96.67 %
Unity power factor	98.68 %	98.56 %	98.17 %	96.79 %

11. CAPACITANCE AND SURGE IMPEDANCE

11.1	Capacitance per phase of stator winding to earth	0.18 Microfarad
11.2	Surge impedance per phase	94 Ohms

The electrical details provided are calculated values. Unless otherwise stated, all values are subject to tolerances as given in the relevant national standards.
The rotor inertia value may vary slightly with generator/turbine interface. In the event of conflict, the figure quoted on the rotor geometry drawing takes precedence.

Doc: 130628/16/612S/120R
Ref: Standard
Date: 2-Nov-2000
Page: 5 of 7

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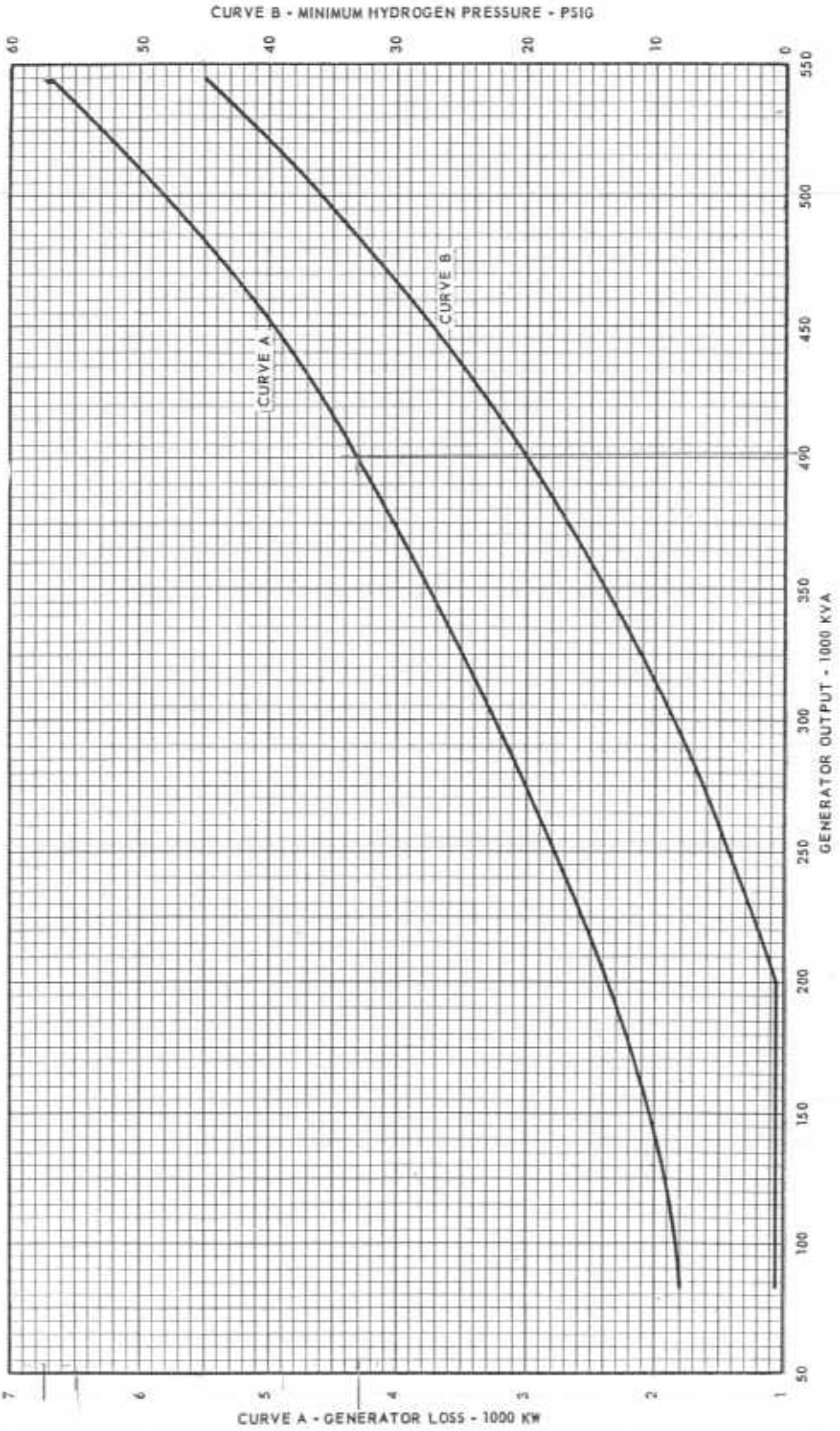
CONEMAUGH STATION

UNITS 1 & 2

3600 RPM GENERATOR LOSSES



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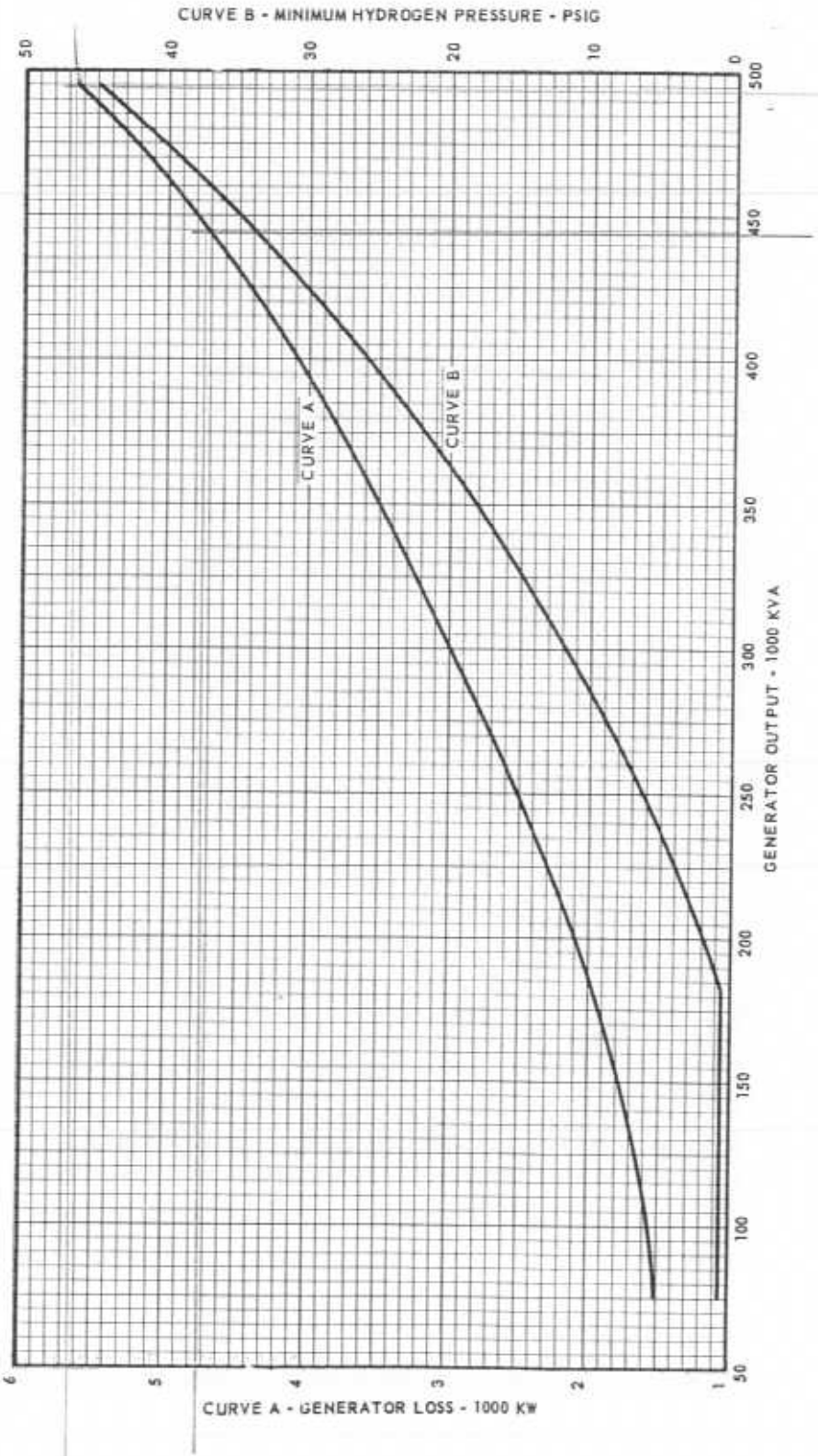
CONEMAUGH STATION
UNITS 1 & 2
1800 RPM GENERATOR LOSSES



GILBERT ASSOCIATES, INC.

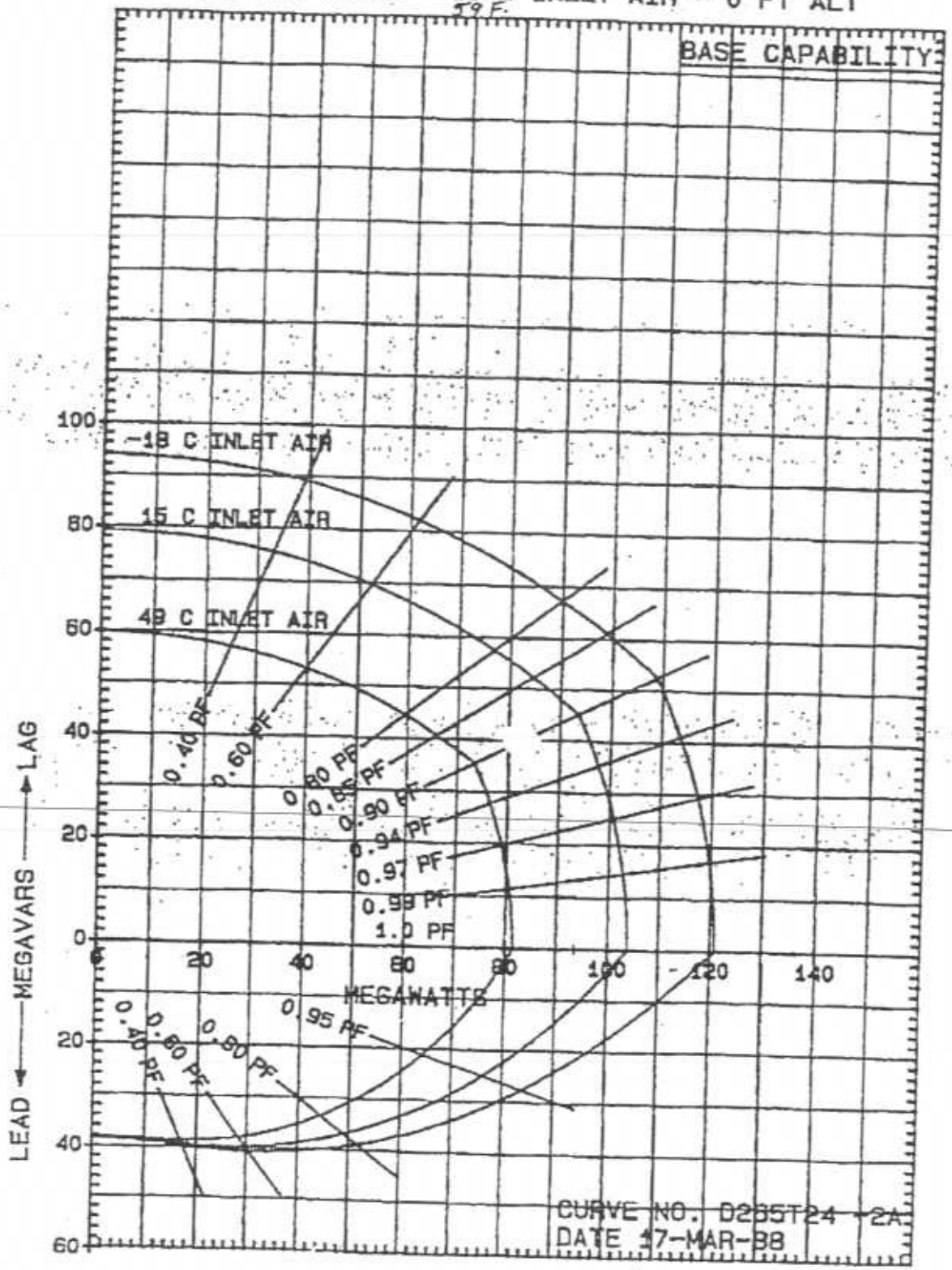
4160-700-021

ESSEX #9

ESSEX STA. UNIT NO. 9

ESTIMATED REACTIVE CAPABILITY CURVES

104000 KVA - 3600 RPM - 13800 VOLTS - 0.90 PF
375 FLD VOLTS - 15 C INLET AIR - 0 FT ALT



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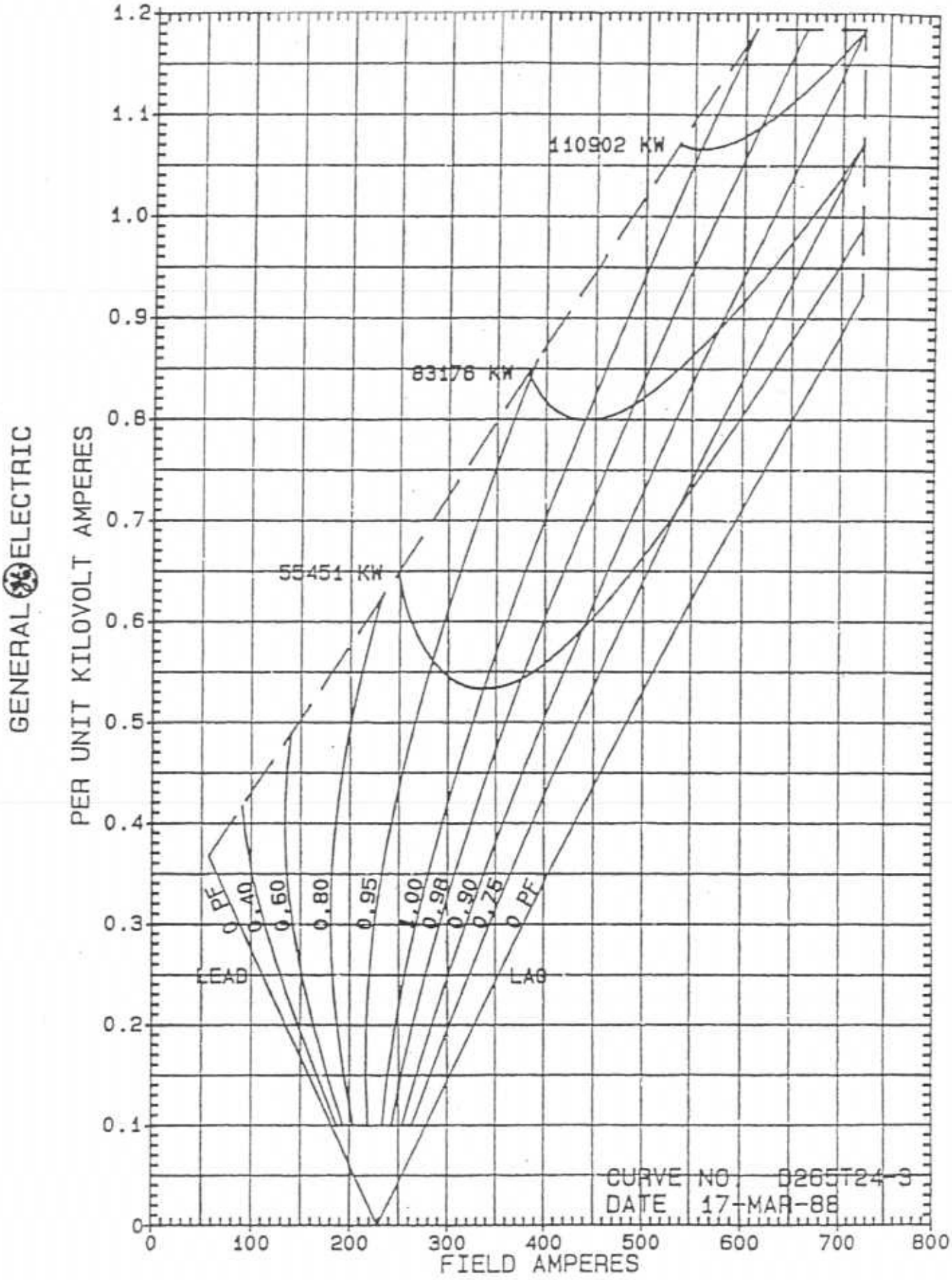
ESSEX #4

ESTIMATED EXCITATION V CURVES

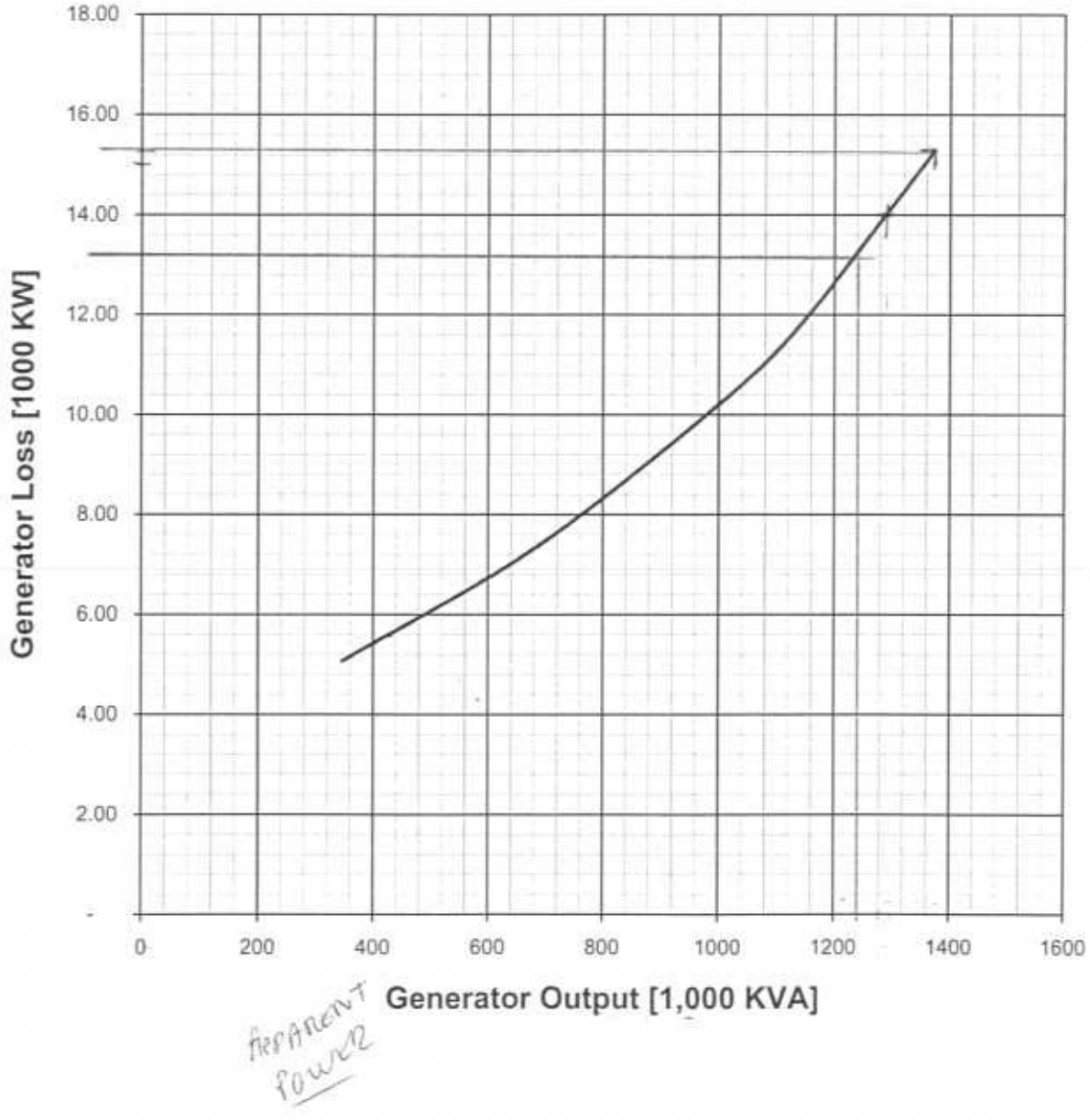
104000 KVA - 3600 RPM - 13800 VOLTS - 0.90 PF
375 FLD VOLTS - 15 C INLET AIR - 0 FT ALT



Generator Losses

13731000 KVA at 75 PSIG H2 Pressure
Conductor Cooled 1800 RPM

NOTES
1. Generator losses assume rated hydrogen pressure at all loads.
2. Generator loss at reduced hydrogen pressure
   (P) = Loss at rated hydrogen pressure - 11.5*(Prated - P)
3. Use generator reactive capability curve to determine generator capability at reduced hydrogen pressure.
4. Turbine generator mechanical losses of 5,167 are not included in the generator loss curve.



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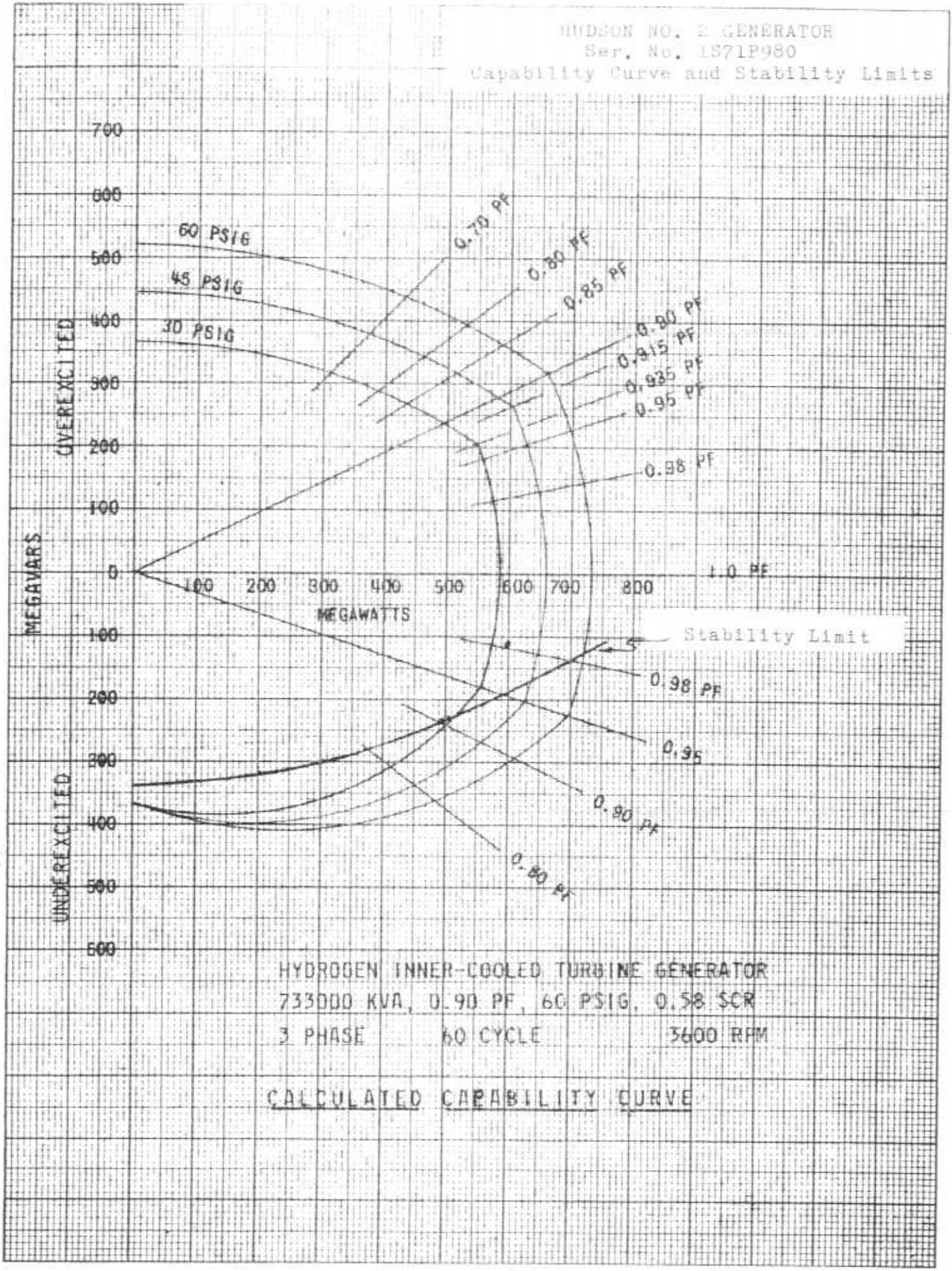
HUDSON #2

HUDSON NO. 2 GENERATOR
Ser. No. 1S71P980
Capability Curve and Stability Limits



HYDROGEN INNER-COOLED TURBINE GENERATOR
733000 KVA, 0.90 PF, 60 PSIG, 0.58 SCR
3 PHASE 60 CYCLE 3600 RPM

CALCULATED CAPABILITY CURVE

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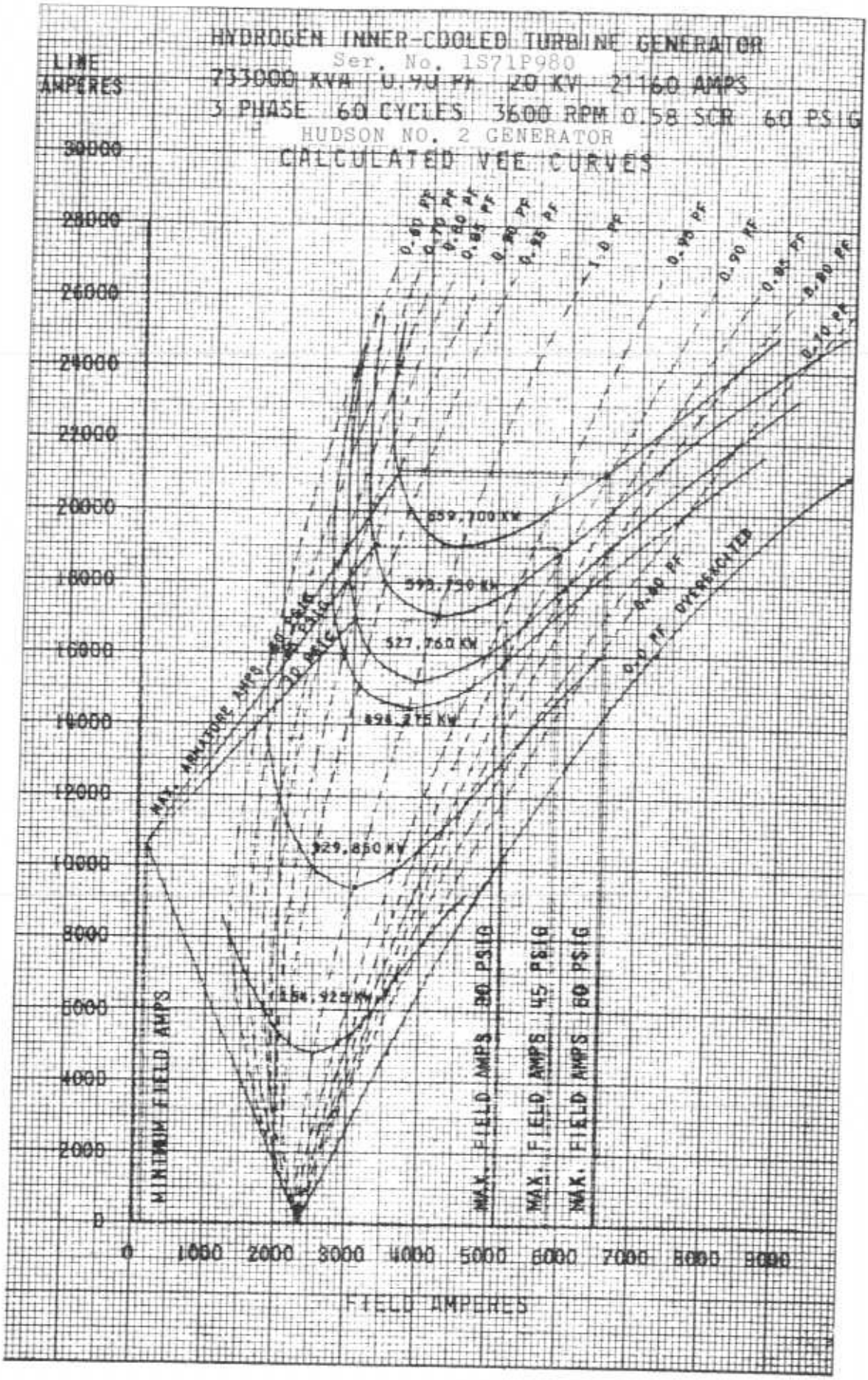
HUDSON #2



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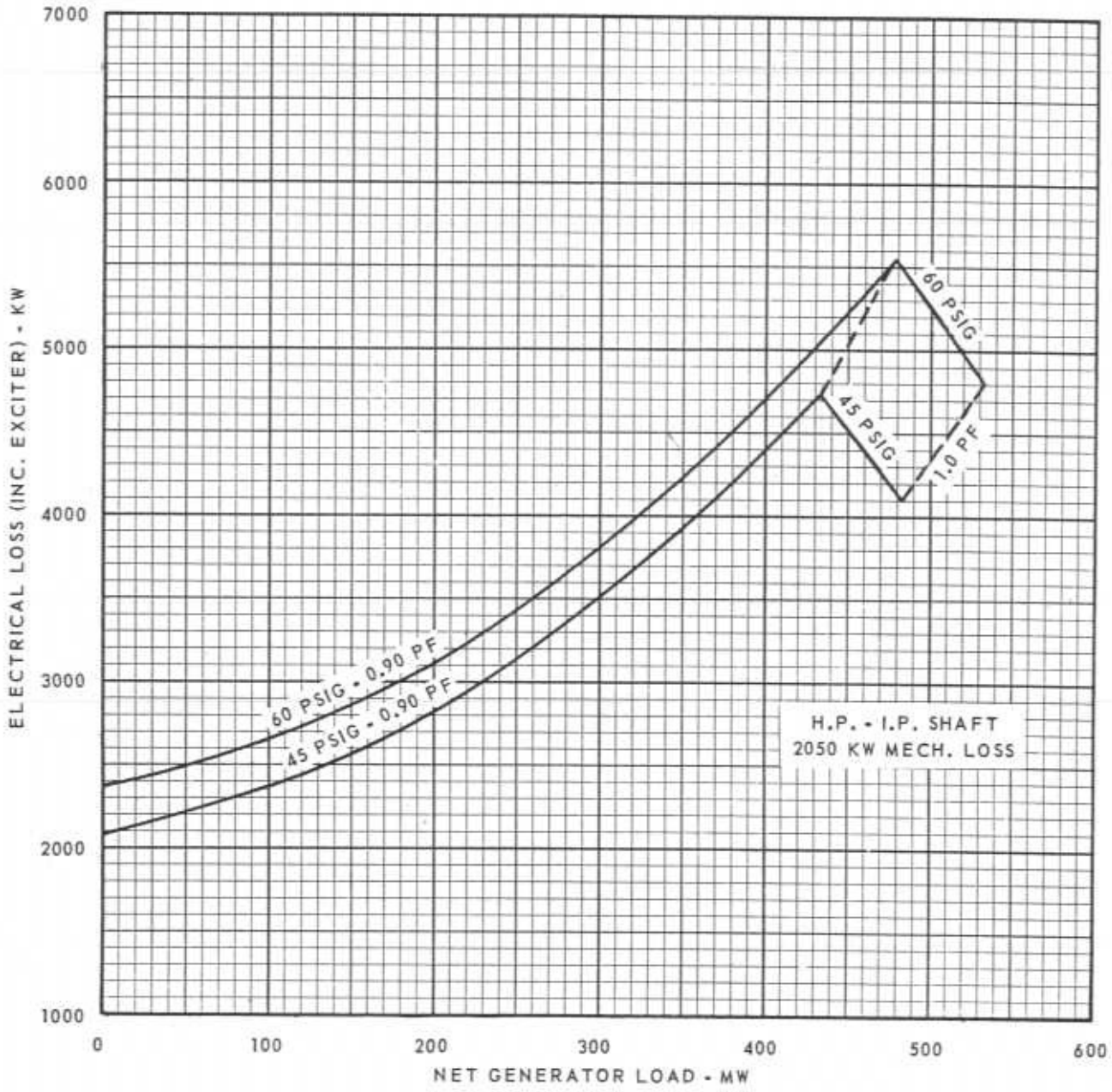
KEYSTONE 1&2
"A" GENERATOR

KEYSTONE STATION

3600 RPM GENERATOR ELECTRICAL LOSS CURVE



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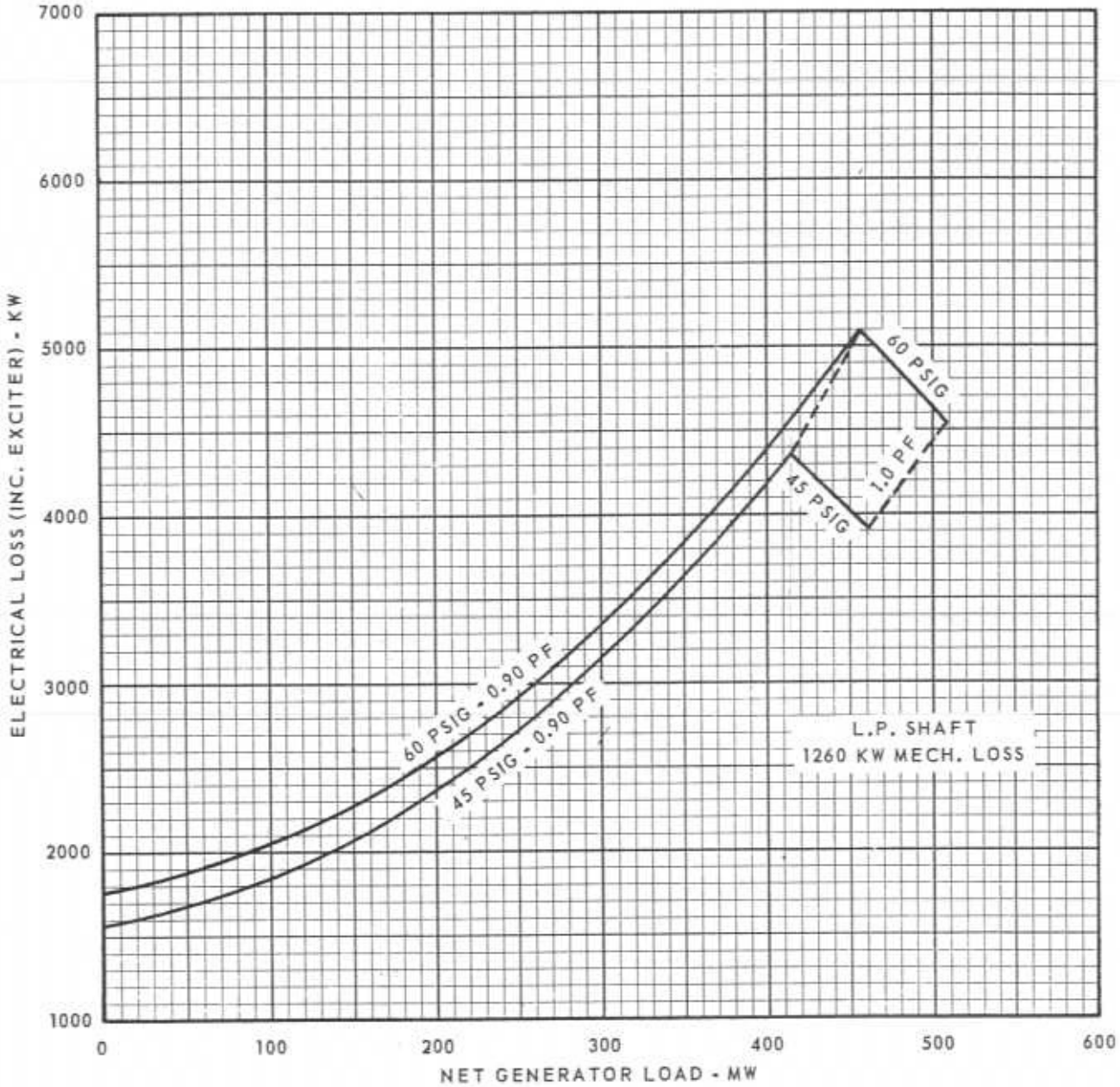
KEYSTONE 1+2
"B" GENERATOR

KEYSTONE STATION

1800 RPM GENERATOR ELECTRICAL LOSS CURVE



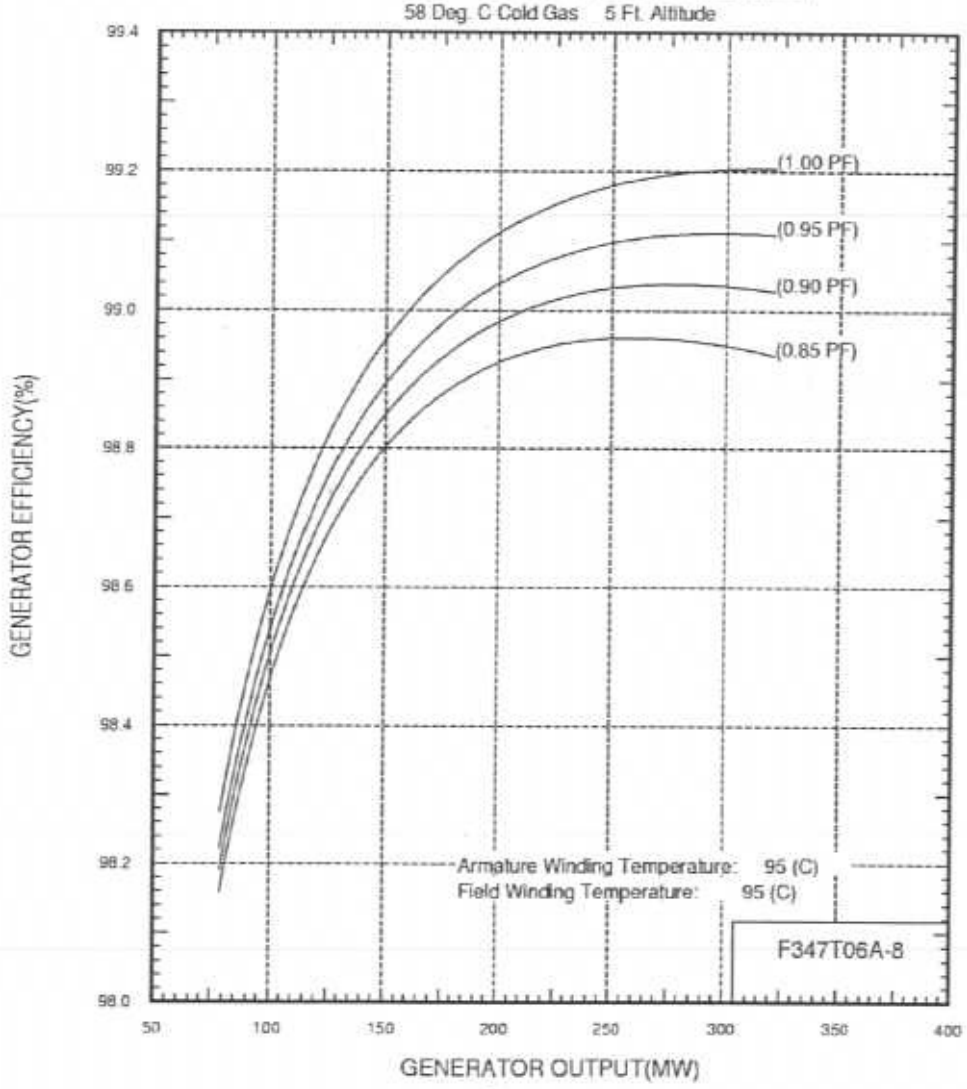
LINDEN 1&2 STEAM T/G

SIZE	DWG NO	SH	REV
A	373A4884	14	

linden 1&2 STG

GENERATOR EFFICIENCY CURVE

2 Pole 3600 RPM 370600 kVA 18000 Volts 0.850 PF
0.460 SCR 60.00 PSIG H2 Pressure 660 Volts Excitation
58 Deg. C Cold Gas 5 Ft. Altitude



GENERAL ELECTRIC COMPANY GE POWER GENERATION SCHENECTADY, NY	SIZE A	CAGE CODE	DWG NO 373A4884
DRAWN QUINTON PIERSON			
ISSUED QUINTON PIERSON	SCALE		SHEET 14

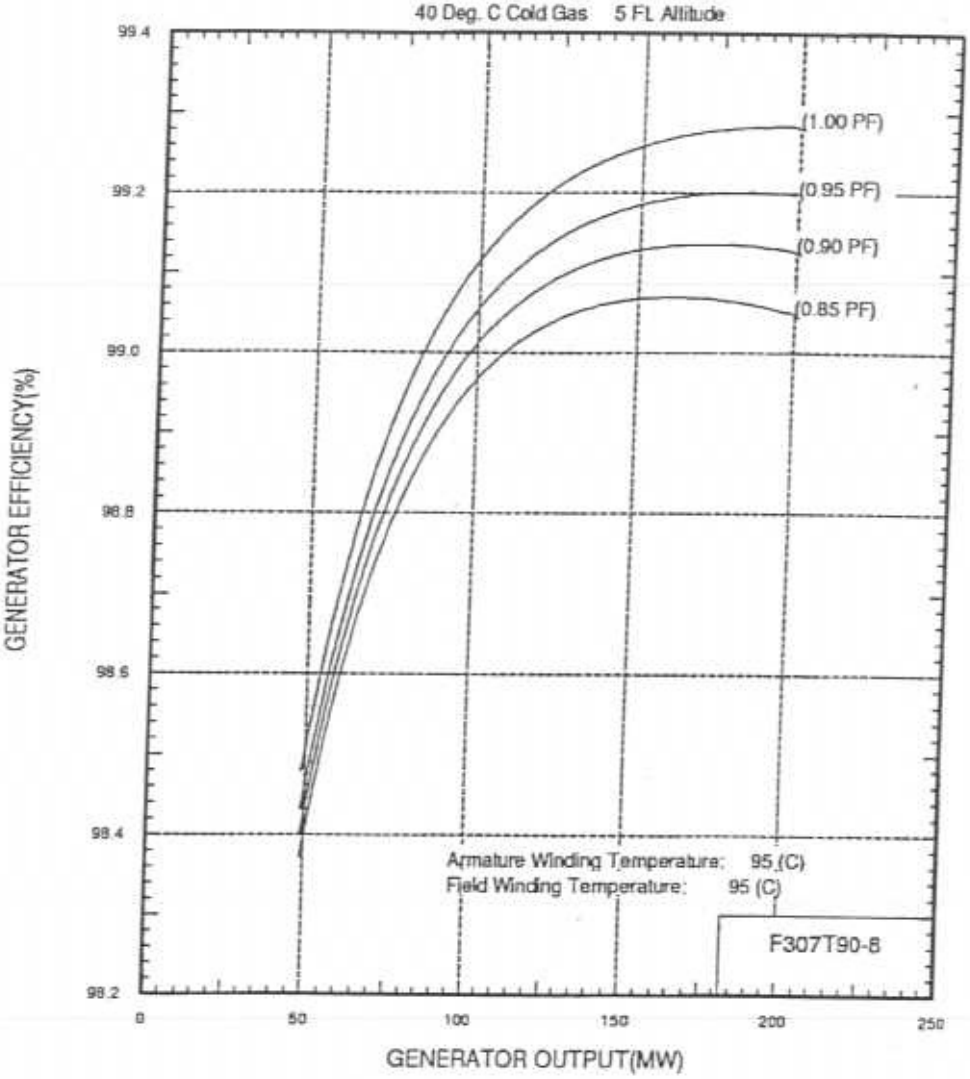
LINDEN 1 & 2 CTG

SIZE	DWG NO	SH	REV
A	373A4886	14	

LINDEN 1 & 2 CTGs

GENERATOR EFFICIENCY CURVE

2 Pole 3600 RPM 213400 kVA 18000 Volts 0.850 PF
0.540 SCR 30.00 PSIG H2 Pressure 340 Volts Excitation
40 Deg. C Cold Gas 5 FL Altitude



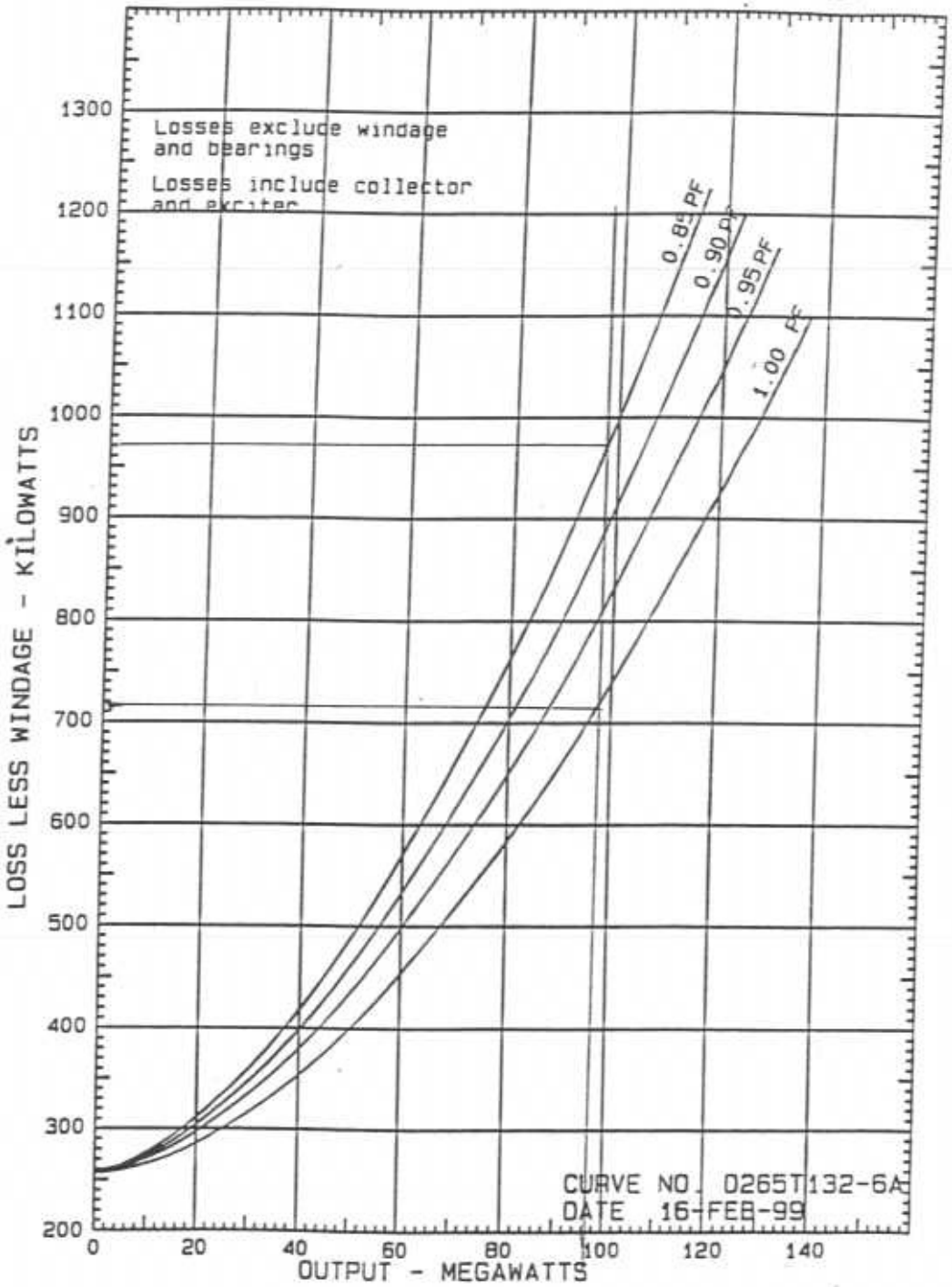
GENERAL ELECTRIC COMPANY GE POWER GENERATION SCHENECTADY, NY	SIZE A	CAGE CODE	DWG NO 373A4886
DRAWN QUINTON PIERSON			
ISSUED QUINTON PIERSON	SCALE		SHEET 14

SIZE	DWG NO	SH	REV
A	363A2972	11	-

LINDEN 546

ESTIMATED LOSS CURVE

113100 KVA - 3600 RPM - 13800 VOLTS - 0.85 PF
300 FLD VOLTS - 15 C INLET AIR - 0 FT ALT



GE Power Generation	GENERAL ELECTRIC COMPANY SCHENECTADY, NY	SIZE A	CAGE CODE	DWG NO 363A2972
DRAWN Tom Smith				
ISSUED	SCALE			SHEET 11

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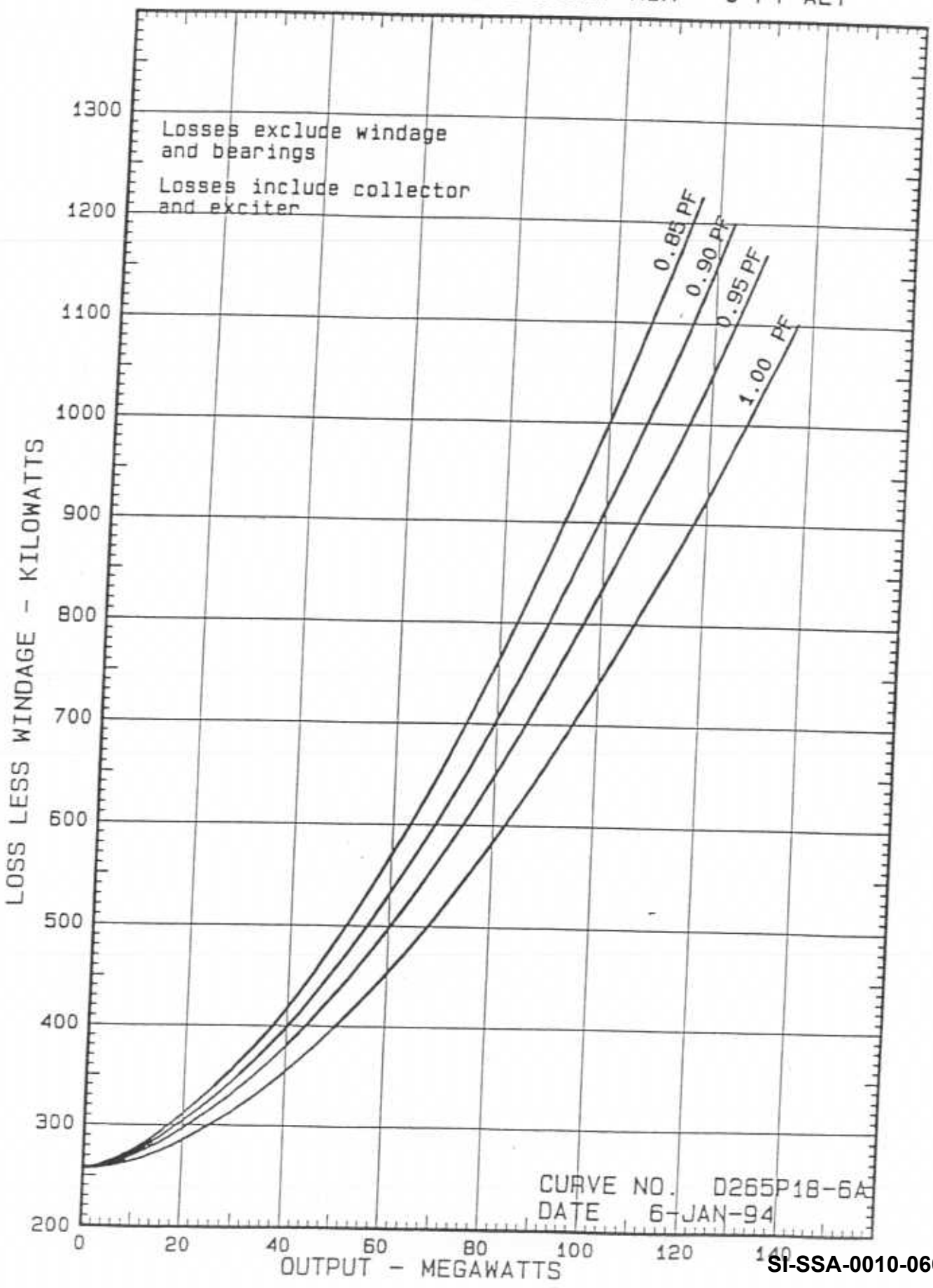
ESTIMATED LOSS CURVE

113100 KVA - 3600 RPM - 13800 VOLTS - 0.85 PF
300 FLD VOLTS - 15 C INLET AIR - 0 FT ALT



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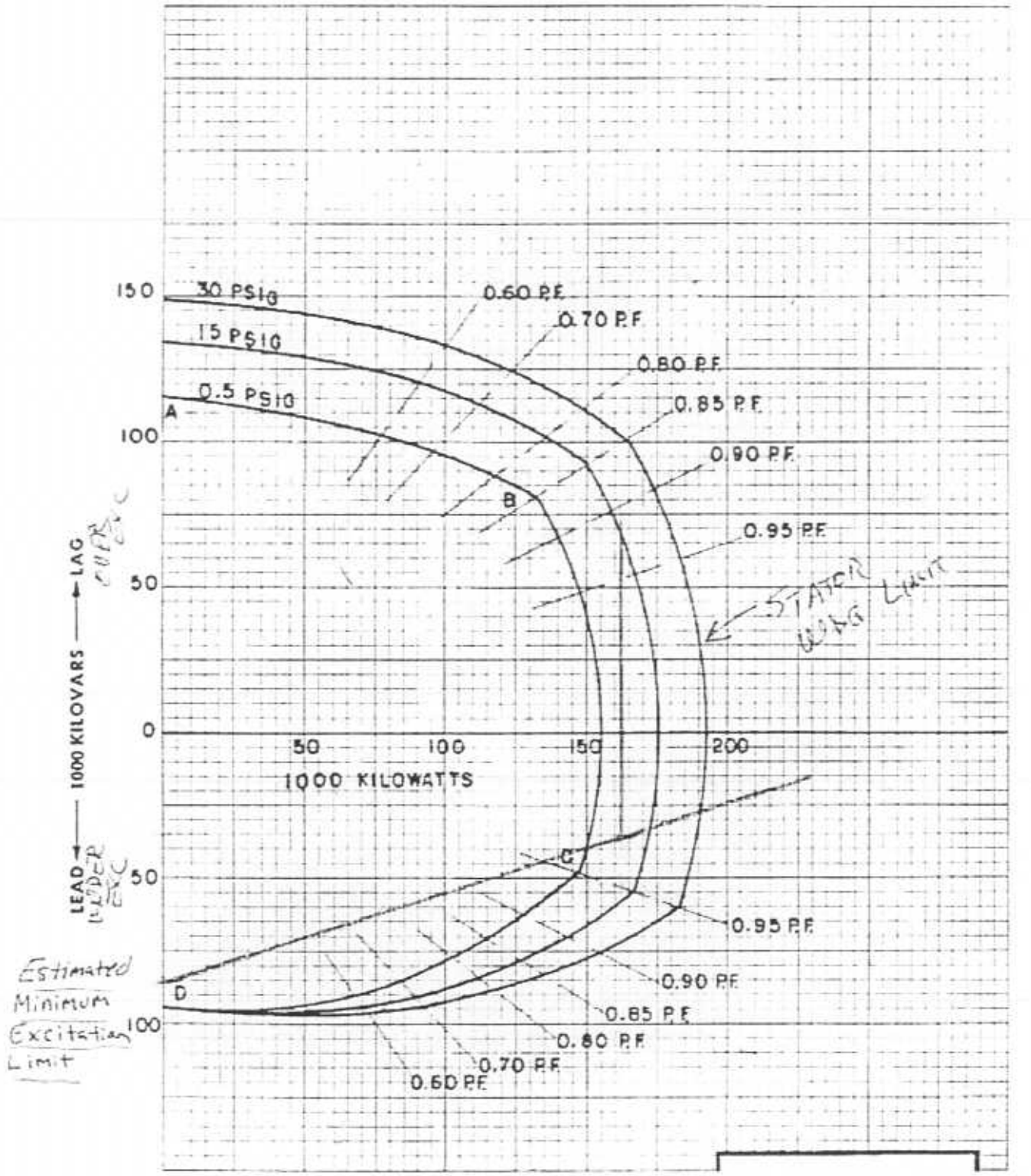
Mercer 1 & 2

ATB 2 POLE, 192,000 KVA, 3600 RPM, 18,000 VOLTS
0.85 PF, 0.64 SCR, 30 PSIG HYDROGEN PRESSURE, 375 VOLTS EXCITATION



CURVE AB LIMITED BY FIELD HEATING
CURVE BC LIMITED BY ARMATURE HEATING
CURVE CD LIMITED BY ARMATURE CORE END HEATING

Estimated capability curves
Dwg 166[illegible]

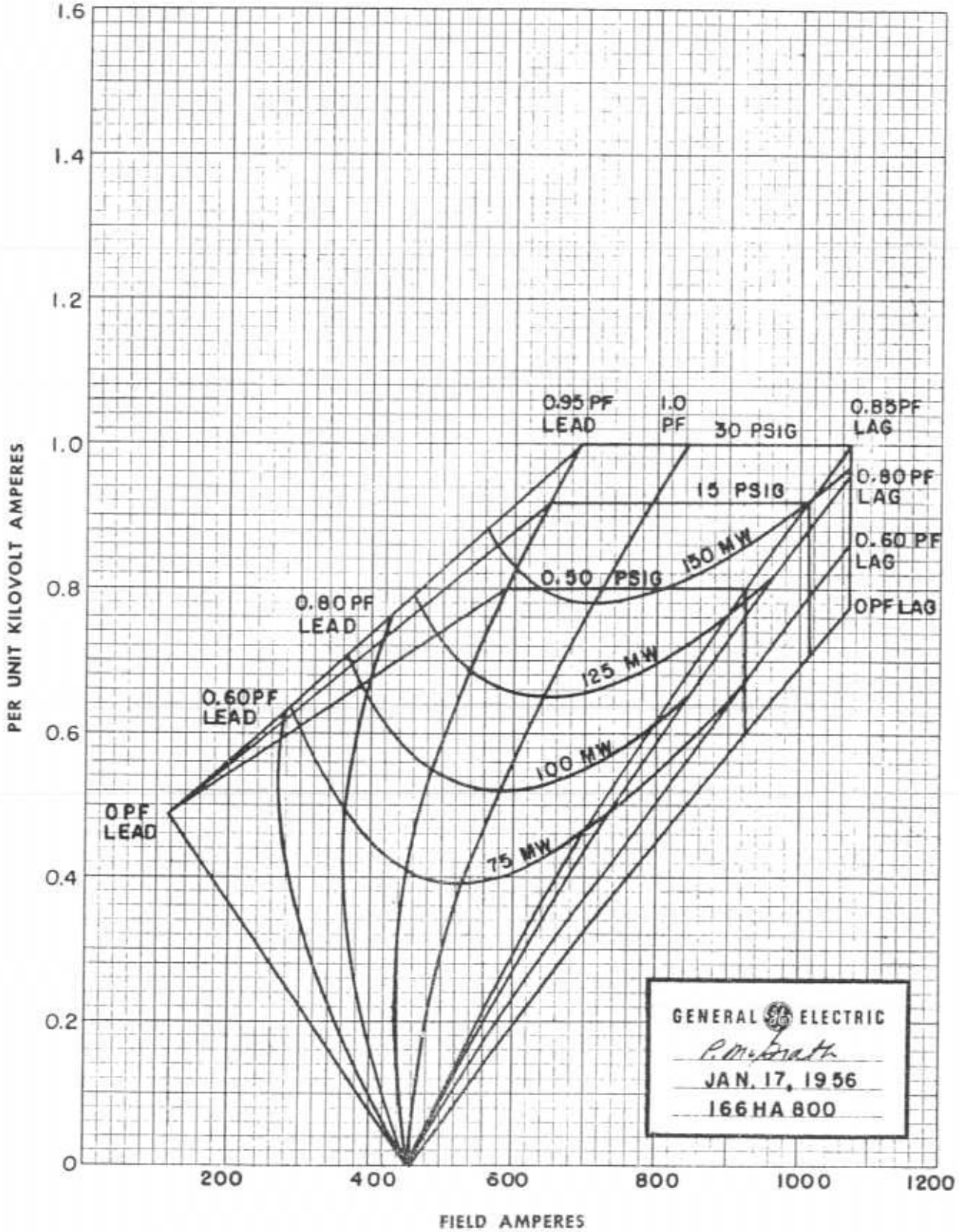
20150610-5280 FERC PDF (Unofficial) 6/10/2015 3:34:23 PM
MERCER 1&2

ESTIMATED "V" CURVES

FOR STEAM TURBINE-GENERATOR UNIT

ATB 2 POLE, 192,000 KVA, 3600 RPM, 18,000 VOLTS

0.85 PF, 0.64 SCR, 30 PSIG HYDROGEN PRESSURE, 375 VOLTS EXCITATION

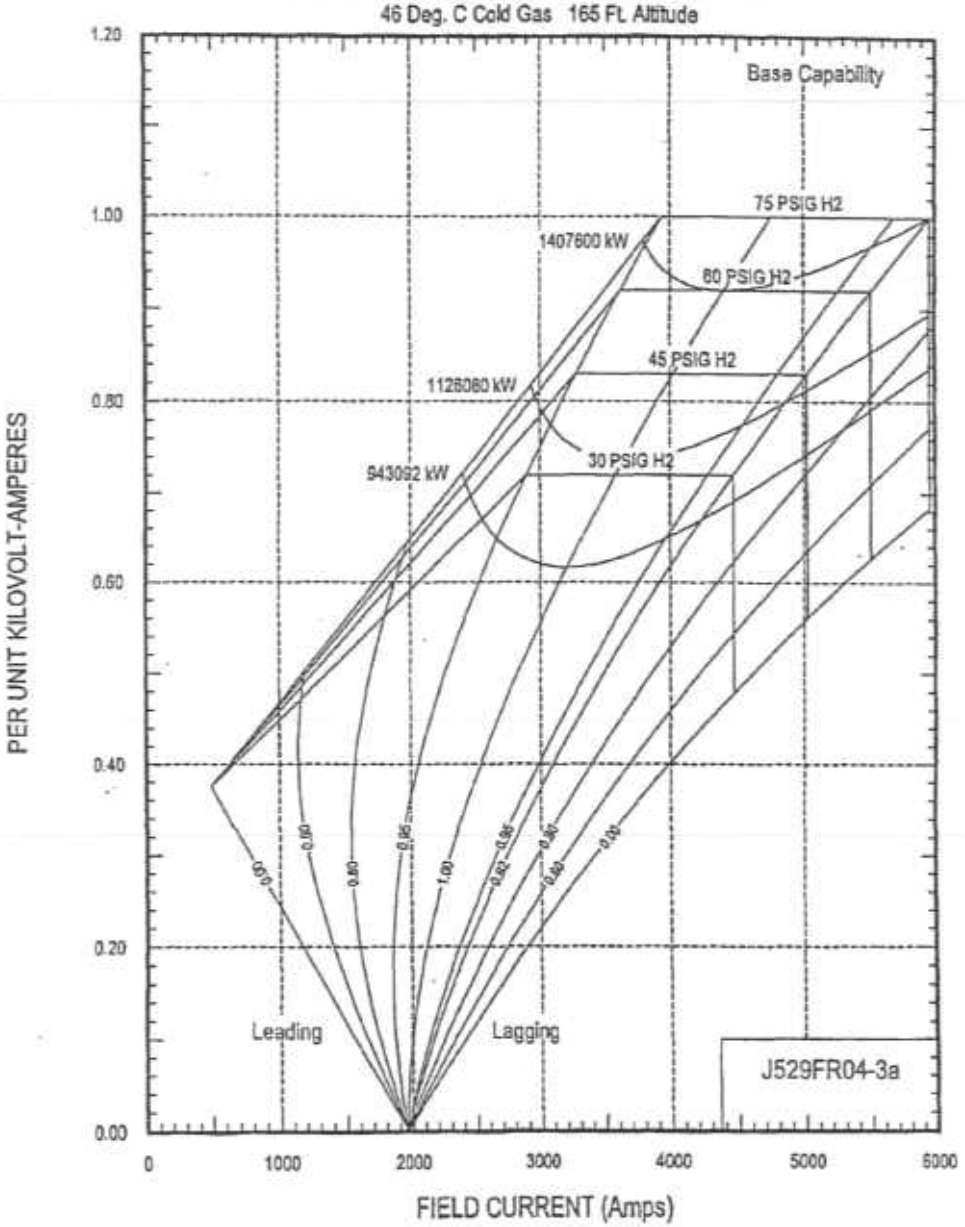


Estimated "V" curves
Dwg. 166HA800 (Rev. 0)

PB ECR 12-00197, Rev. 0
ECR Attachment 9
Page 3 of 5

ESTIMATED VEE CURVES

4 Pole 1800 RPM 1530000 kVA 22000 Volts 0.920 PF
0.510 SCR 75.00 PSIG H2 Pressure 605 Volts Excitation
46 Deg. C Cold Gas 165 Ft. Altitude



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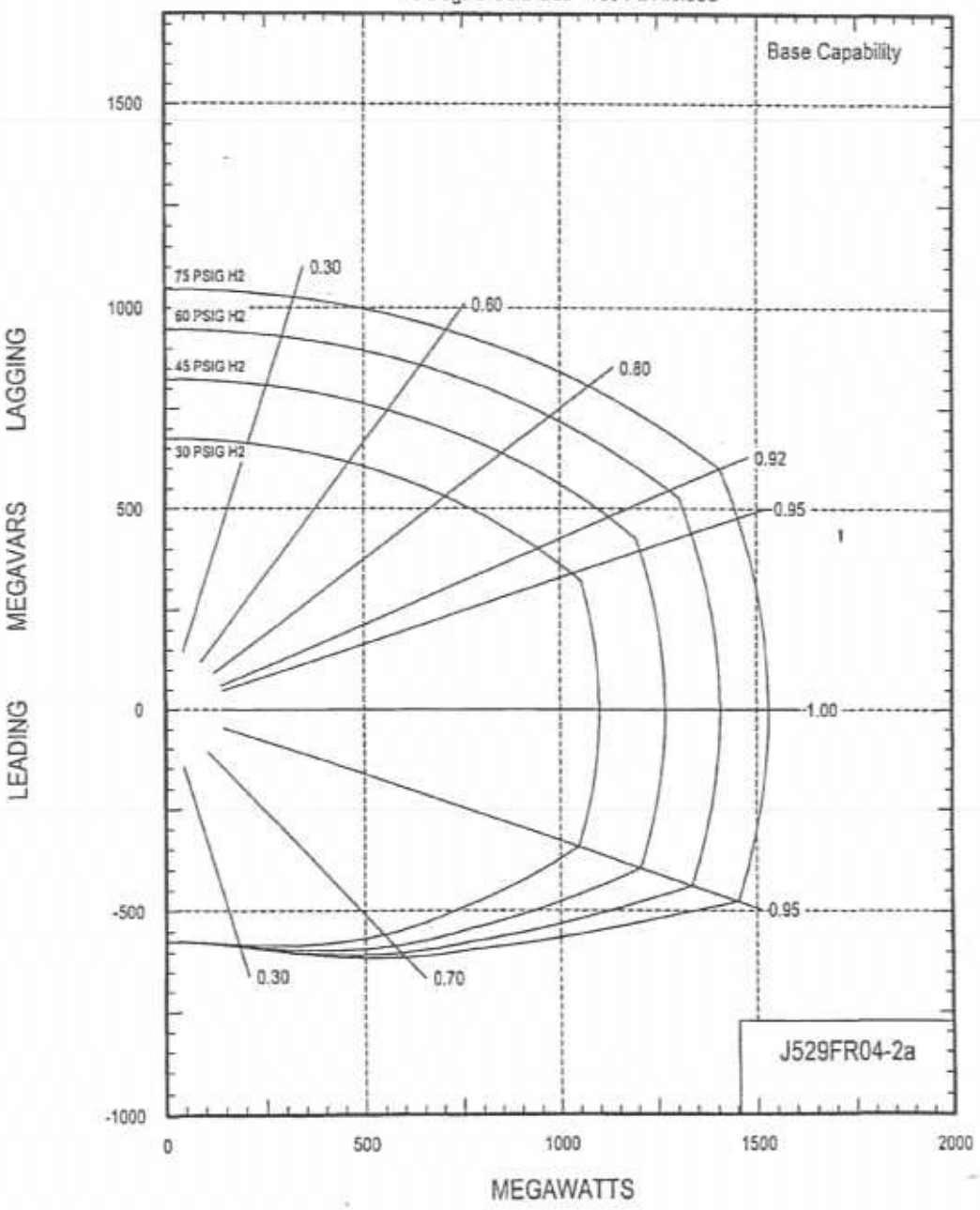
SDOC: M-2-856		SHT: 0009		REV: 1
DATE	DESCRIPTION	EVAL	IR	APP'D
	Issue this document per ECR 12-00197, Rev. 0.			

PEACH BOTTOM #2 PB UNIT 2

PB ECR 12-00197, Rev. 0
ECR Attachment 9
Page 1 of 5

ESTIMATED REACTIVE CAPABILITY CURVES

4 Pole 1800 RPM 1530000 kVA 22000 Volts 0.920 PF
0.510 SCR 75.00 PSIG H2 Pressure 605 Volts Excitation
46 Deg. C Cold Gas 165 Ft. Altitude



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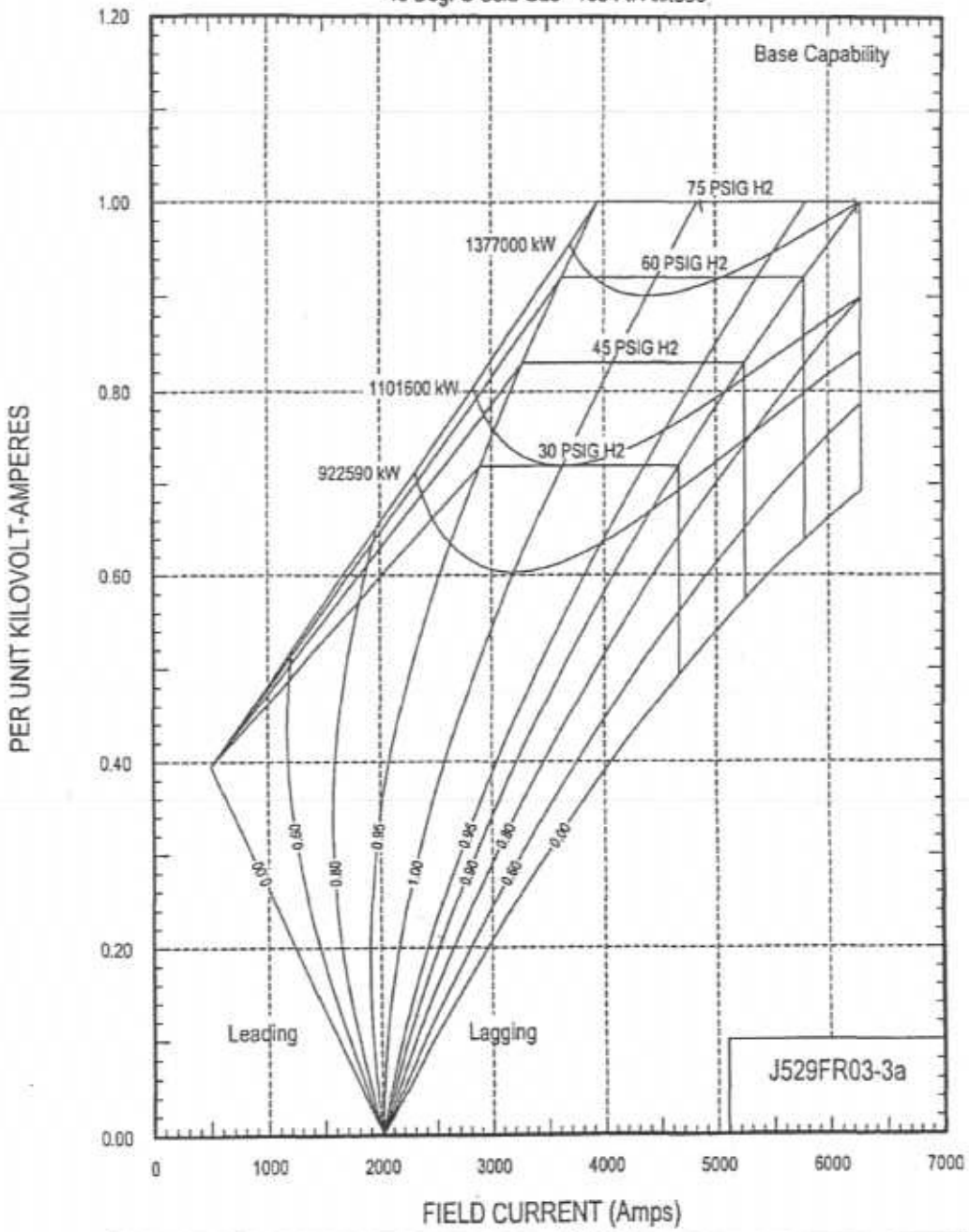
	Issue this document per ECR 12-00197, Rev. 0.			

PEACH BOTTOM #3

ECR 11-00380, Rev. 0
ECR Attachment 9
Page 3

ESTIMATED VEE CURVES

4 Pole 1800 RPM 1530000 kVA 22000 Volts 0.900 PF
0.540 SCR 75.00 PSIG H2 Pressure 705 Volts Excitation
46 Deg. C Cold Gas 165 Ft. Altitude



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SDOC: M-2-856		SHT: 0003		REV: 1
DATE	DESCRIPTION	EVAL	IR	APP'D
	Issue this document per ECR 11-00380, Rev. 0.			

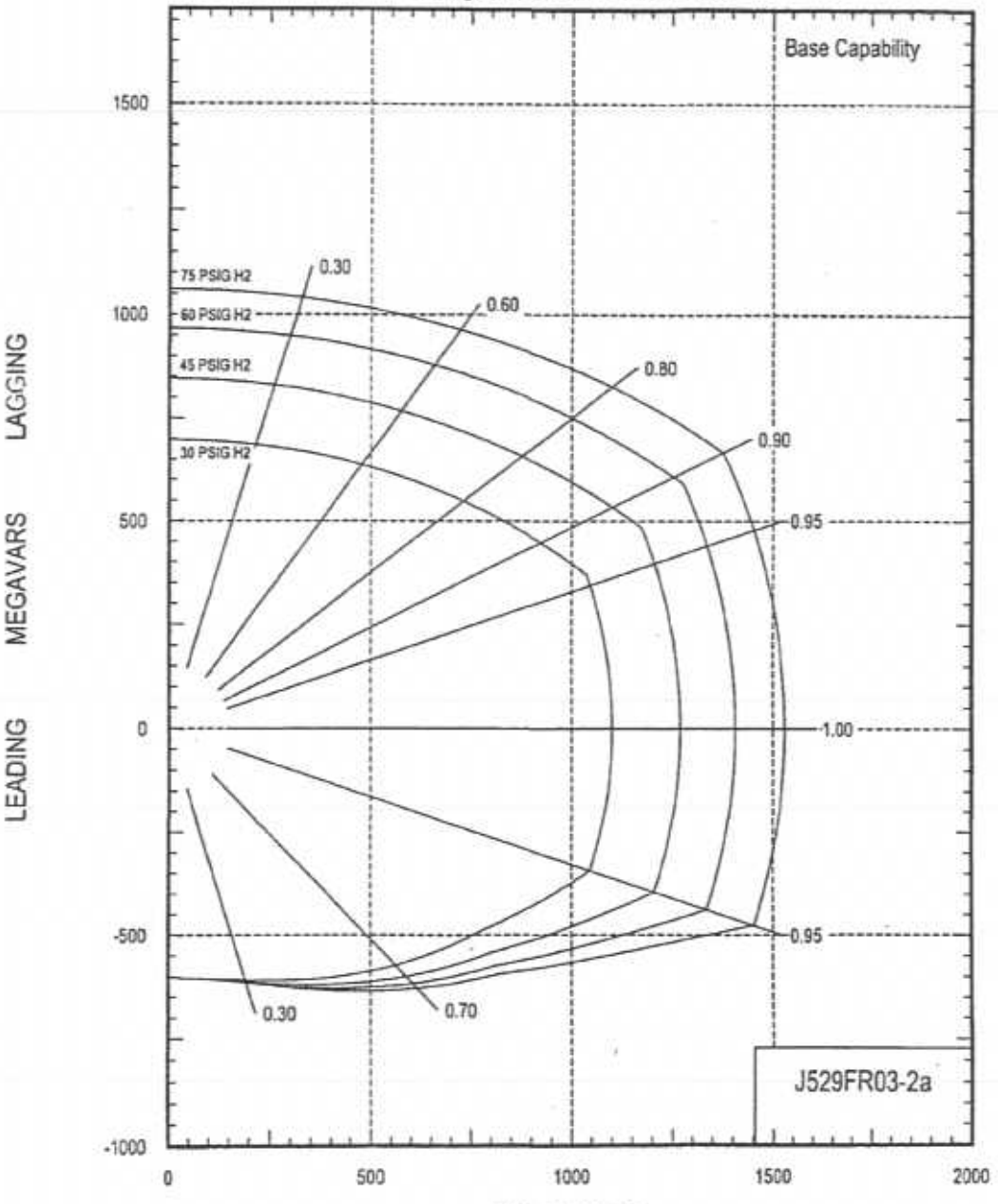
20150610-5280 FERC PDF (Unofficial) 6/10/2015 3:34:23 PM

PEACH BOTTOM 2&3

ECR 11-00380, Rev. 0
ECR Attachment 9
Page 1 of 5

ESTIMATED REACTIVE CAPABILITY CURVES

4 Pole 1800 RPM 1530000 kVA 22000 Volts 0.900 PF
0.540 SCR 75.00 PSIG H2 Pressure 705 Volts Excitation
46 Deg. C Cold Gas 165 Ft. Altitude



STATION: PBAPS		UNIT: 3		
SDOC: M-2-856		SHT: 0001		REV: 1
DATE	DESCRIPTION	EVAL	IR	APP'D
	Issue this document per ECR 11-00380, Rev. 0.			

SALEM 1+2

Salem 1 Generator Losses Curve y = 1.59875874E-15x3 + 3.43636364E-09x2 + 1.63708042E-03x + 3.96615152E+03

0.9 PF

kW	kVA	Loss @ 75 psig		
200,000	222,222	4517		200
300,000	333,333	4953		300
400,000	444,444	5513		400
500,000	555,556	6210		500
600,000	666,667	7059		600
700,000	777,778	8070		700
800,000	888,889	9259		800
900,000	1,000,000	10638		900
1,000,000	1,111,111	12221		1000
1,100,000	1,222,222	14019		1100
1,170,000	1,300,000	15414		1170

400 kw every 15 psi
950 kW Mechanical Loss

0.934 PF

kW	kVA	Loss @ 75 psig		
200,000	214,133	4450	4418	200
300,000	321,199	4750	4808	300
400,000	428,266	5300	5300	400
500,000	535,332	5950	5907	500
600,000	642,398	6600	6641	600
700,000	749,465	7550	7514	700
800,000	856,531	8550	8537	800
900,000	963,597	9700	9724	900
1,000,000	1,070,664	11100	11086	1000
1,100,000	1,177,730	12600	12634	1100
1,170,000	1,252,677		13836	1170
1,200,000	1,284,797	14400	14382	1200
1,214,200	1,300,000	14650	14647	1214.2

0.95 PF

kW	kVA	Loss @ 75 psig		
200,000	210,526	4430	4405	200
300,000	315,789	4730	4766	300
400,000	421,053	5200	5228	400
500,000	526,316	5850	5802	500
600,000	631,579	6500	6496	600
700,000	736,842	7300	7321	700
800,000	842,105	8300	8287	800
900,000	947,368	9400	9404	900
1,000,000	1,052,632	10700	10682	1000
1,100,000	1,157,895	12100	12131	1100
1,170,000	1,231,579		13253	1170
1,200,000	1,263,158	13750	13762	1200
1,214,200	1,278,105		14009	1214.2
1,235,000	1,300,000	14400	14377	1235

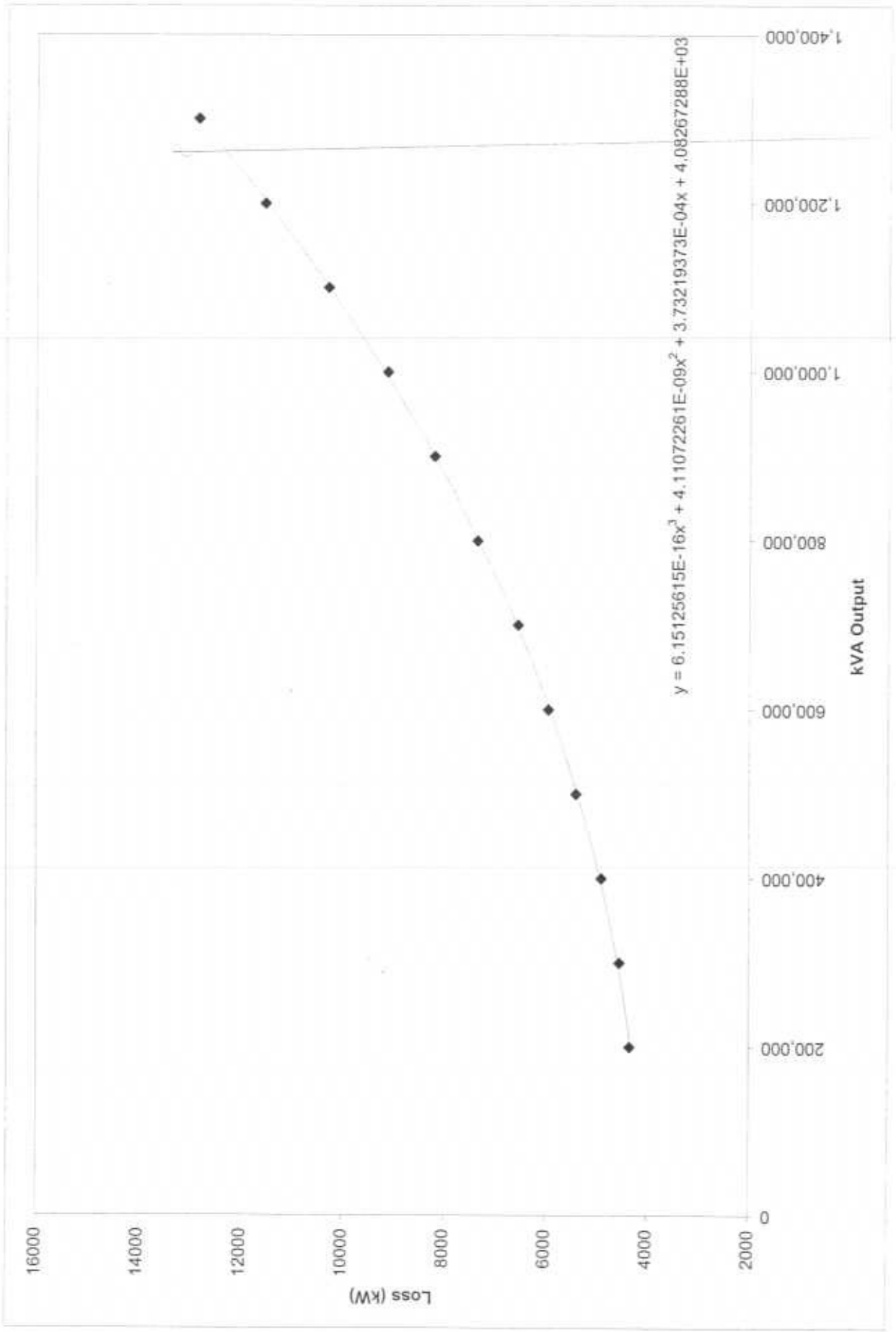
1.00 PF

kW	kVA	Loss @ 75 psig		
200,000	200,000	4350	4327	200
300,000	300,000	4550	4581	300
400,000	400,000	4900	4929	400
500,000	500,000	5400	5374	500
600,000	600,000	5950	5919	600

SALEM NJ

700,000	700,000	6550	6569	700
800,000	800,000	7350	7327	800
900,000	900,000	8200	8197	900
1,000,000	1,000,000	9120	9182	1000
1,100,000	1,100,000	10300	10286	1100
1,170,000	1,170,000		11132	1170
1,200,000	1,200,000	11550	11513	1200
1,214,200	1,214,200		11697	1214.2
1,235,000	1,235,000		11972	1235
1,300,000	1,300,000	12850	12866	1300

SALEM 1+2


y = 6.15125615E-16x^3 + 4.11072261E-09x^2 + 3.73219373E-04x + 4.08267288E+03
kVA Output
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
Loss (kW)
16000
14000
12000
10000
8000
6000
4000
2000

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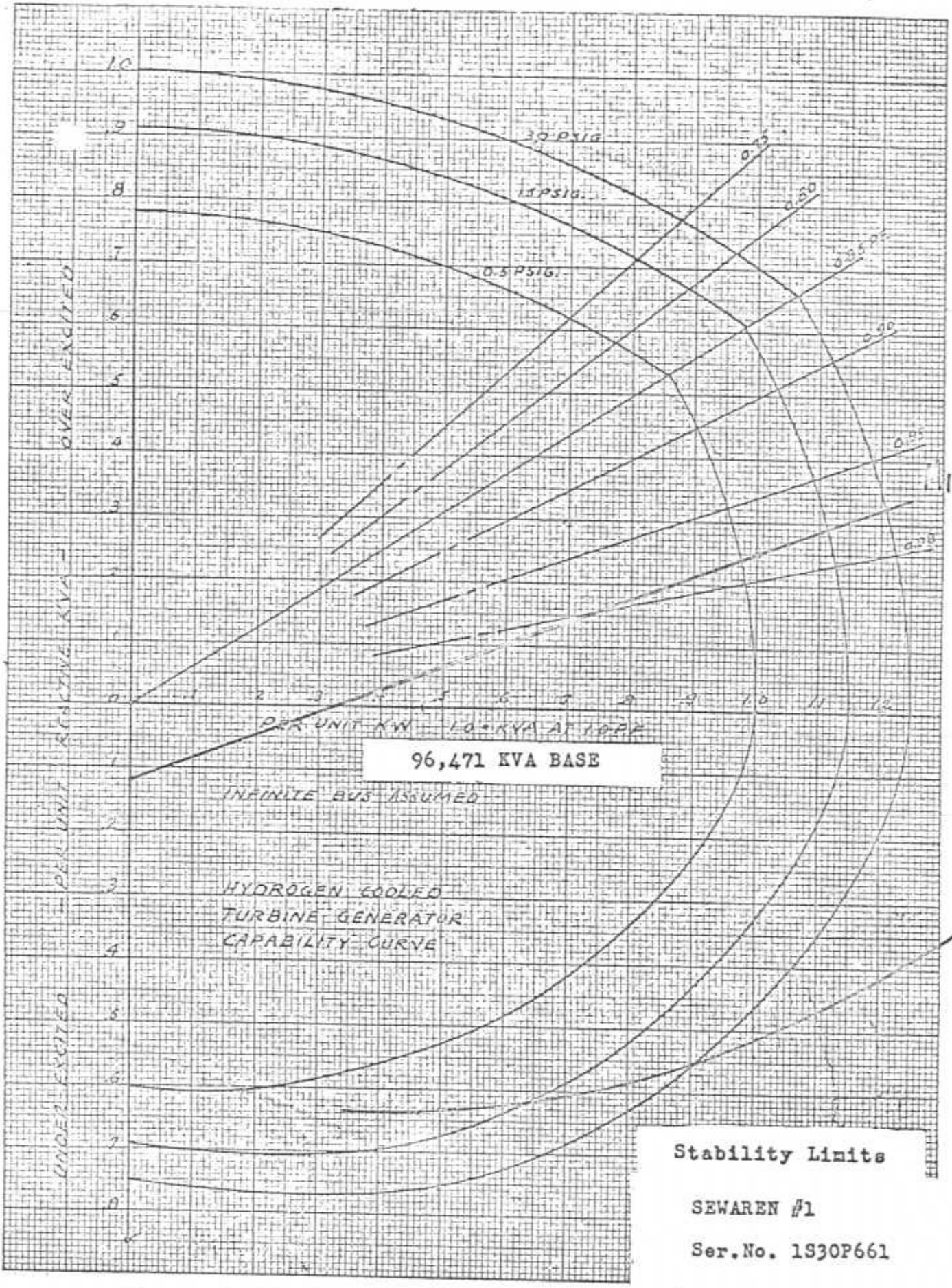
SEWAREN #1

WESTINGHOUSE ELECTRIC CORPORATION

CURVE NO. 366162



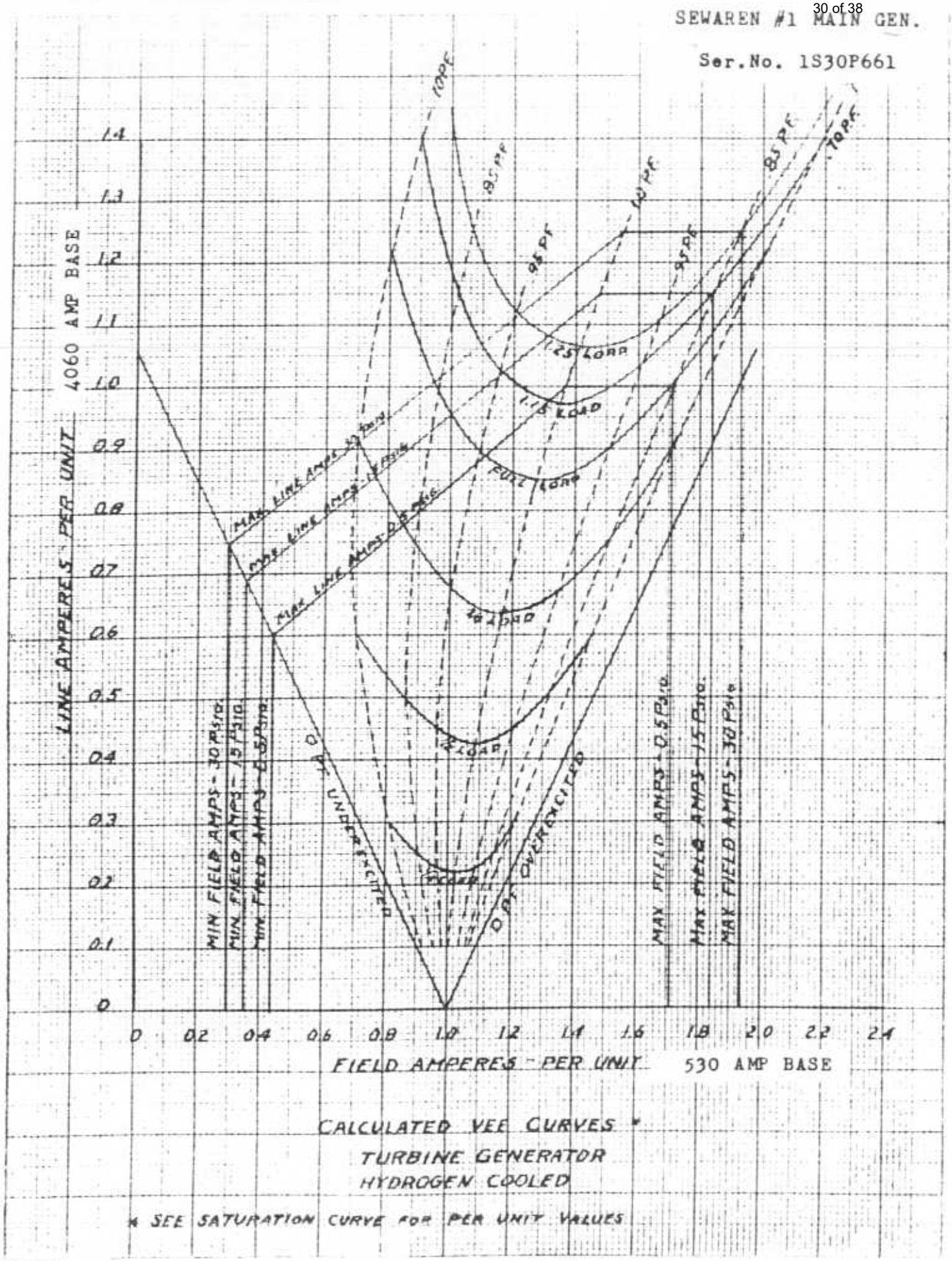
SIGNATURE C.C. STERRETT / T.J.H. DATE 8-16-51

CURVE NO. 366162

40794-21

SEWAREN #1 MAIN GEN.

Ser.No. 1S30P661



CALCULATED VEE CURVES *

TURBINE GENERATOR

HYDROGEN COOLED

* SEE SATURATION CURVE FOR PER UNIT VALUES

SIGNATURE F.J. Murphy DATE 3-18-54 CURVE NO. 40794-21

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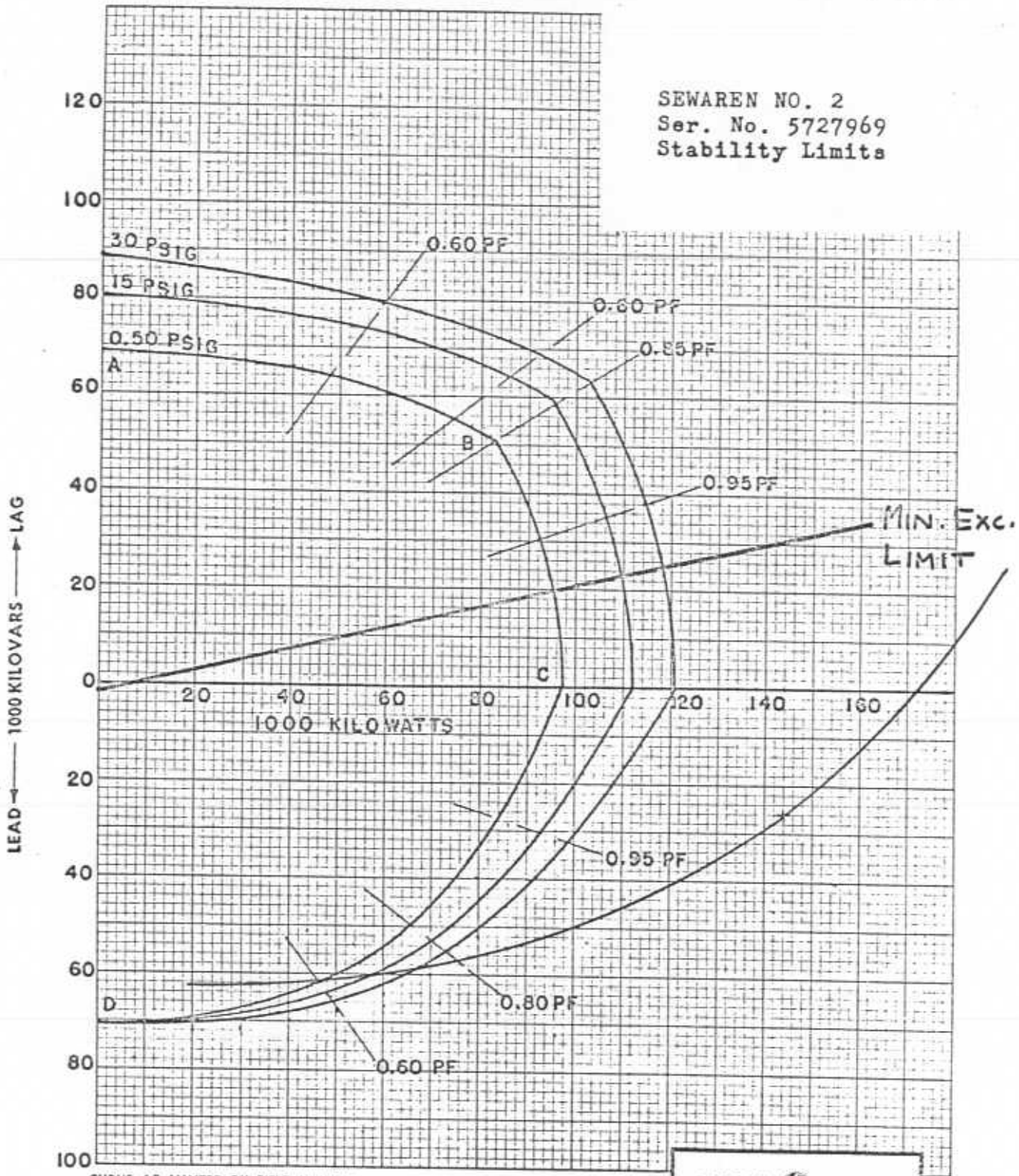
ESTIMATED REACTIVE CAPABILITY CURVES

FOR STEAM TURBINE-GENERATOR UNIT

ATB 2 POLE, 111,765 KVA, 3600 RPM, 13,800 VOLTS
0.85 PF, 0.85 SCR, 15 PSIG HYDROGEN PRESSURE, 250 VOLTS EXCITATION



CURVE AB LIMITED BY FIELD HEATING
CURVE BC LIMITED BY ARMATURE HEATING
CURVE CD LIMITED BY ARMATURE CORE END HEATING

GENERAL ELECTRIC
R. M. Soper
DEC. 6, 1956
225 HA 555
REV. 1

P.L. 10/20

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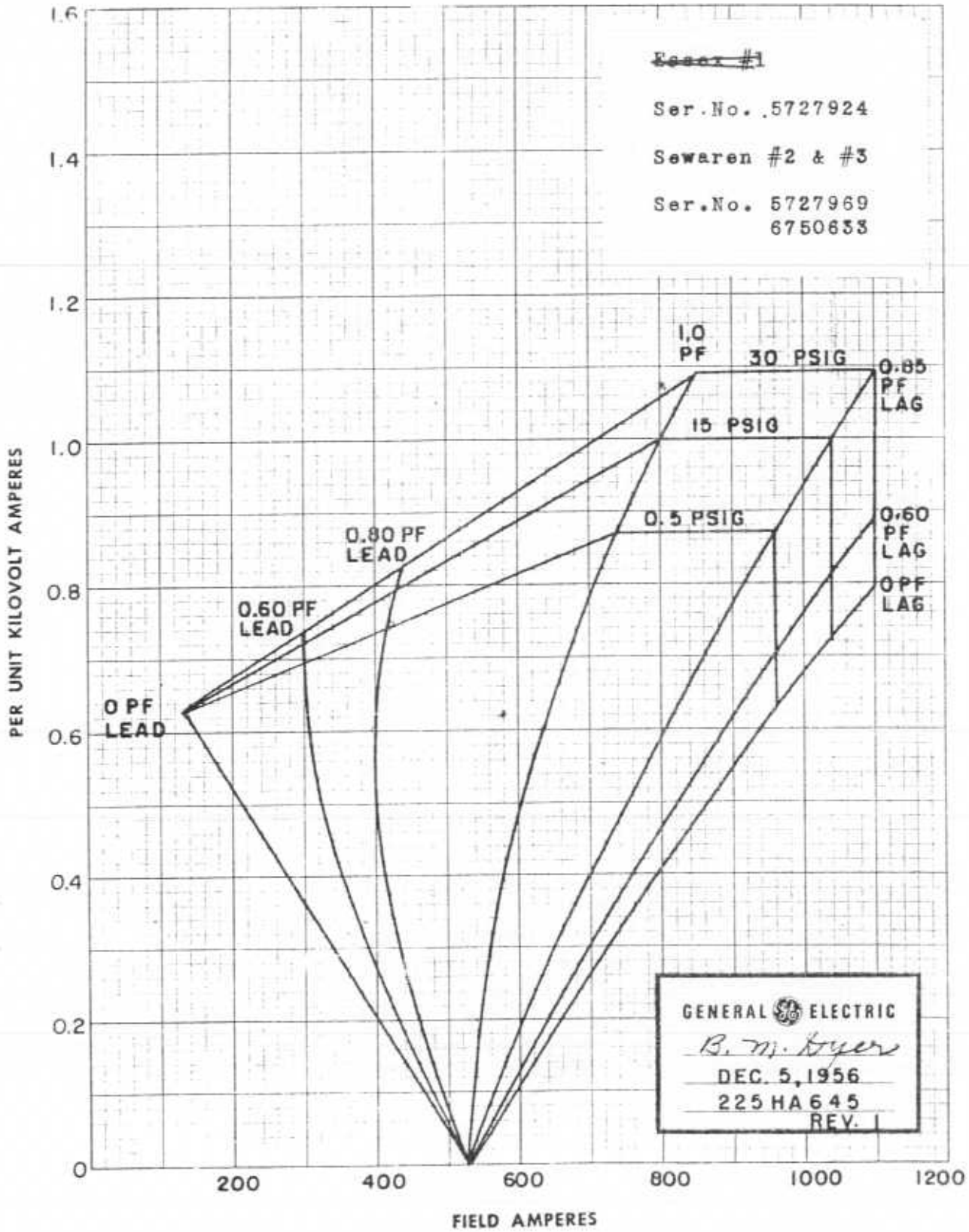
ESTIMATED "V" CURVES

FOR STEAM TURBINE-GENERATOR UNIT

ATB 2 POLE, 111,765 KVA, 3600 RPM, 13,800 VOLTS

0.85 PF, 0.85 SCR, 15 PSIG HYDROGEN PRESSURE, 250 VOLTS EXCITATION

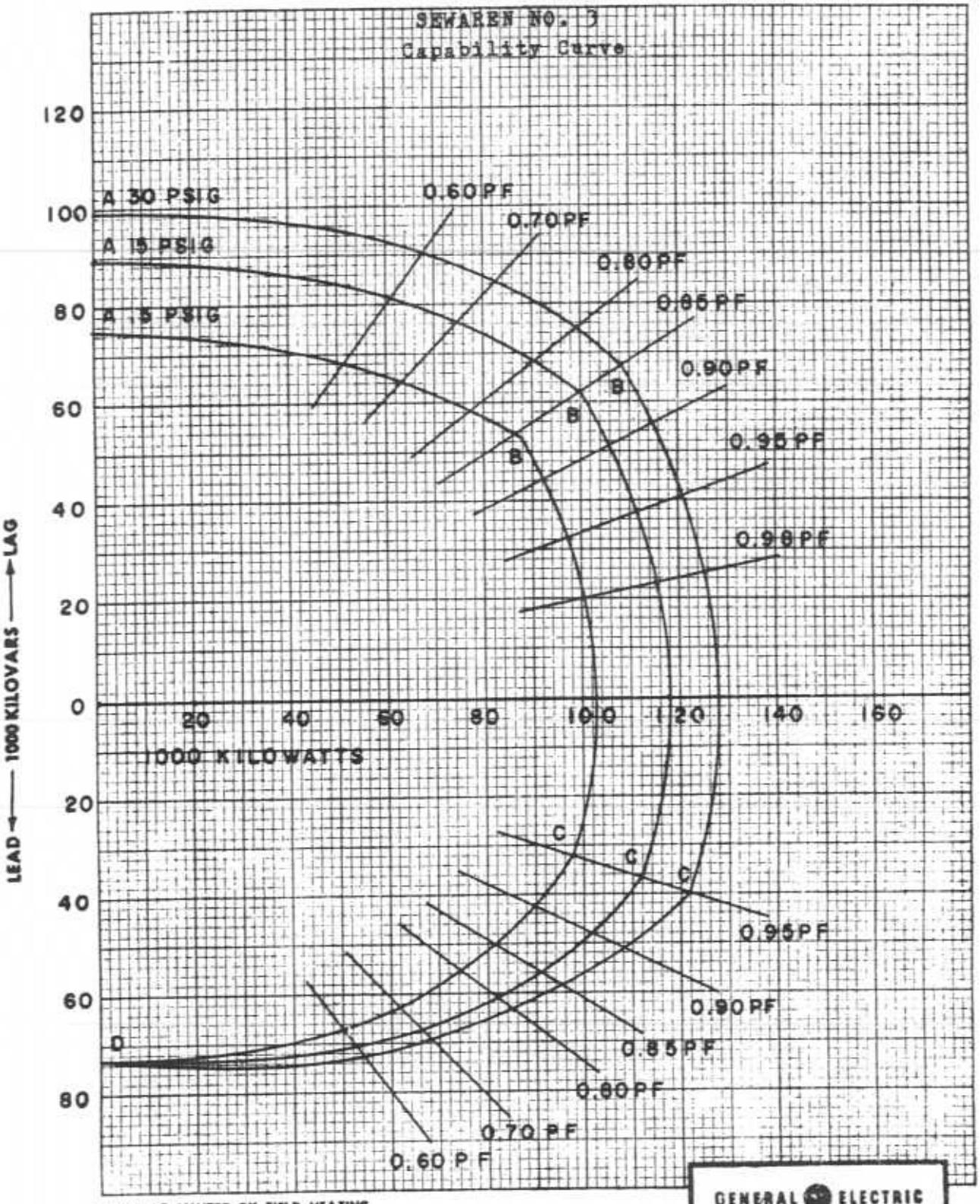


SEWAREN #3

REACTIVE CAPABILITY CURVES

FOR STEAM TURBINE-GENERATOR UNIT

ATB 2 POLE, 117,760 KVA, 3600 RPM, 13,800 VOLTS
0.85 P.F, 0.80SCR, 15 PSIG HYDROGEN PRESSURE, 250 VOLTS EXCITATION



CURVE AB LIMITED BY FIELD HEATING
CURVE BC LIMITED BY ARMATURE HEATING
CURVE CD LIMITED BY ARMATURE CORE END HEATING

GENERAL ELECTRIC
Kay Murdock
JAN. 5, 1968
345HA997

7/68

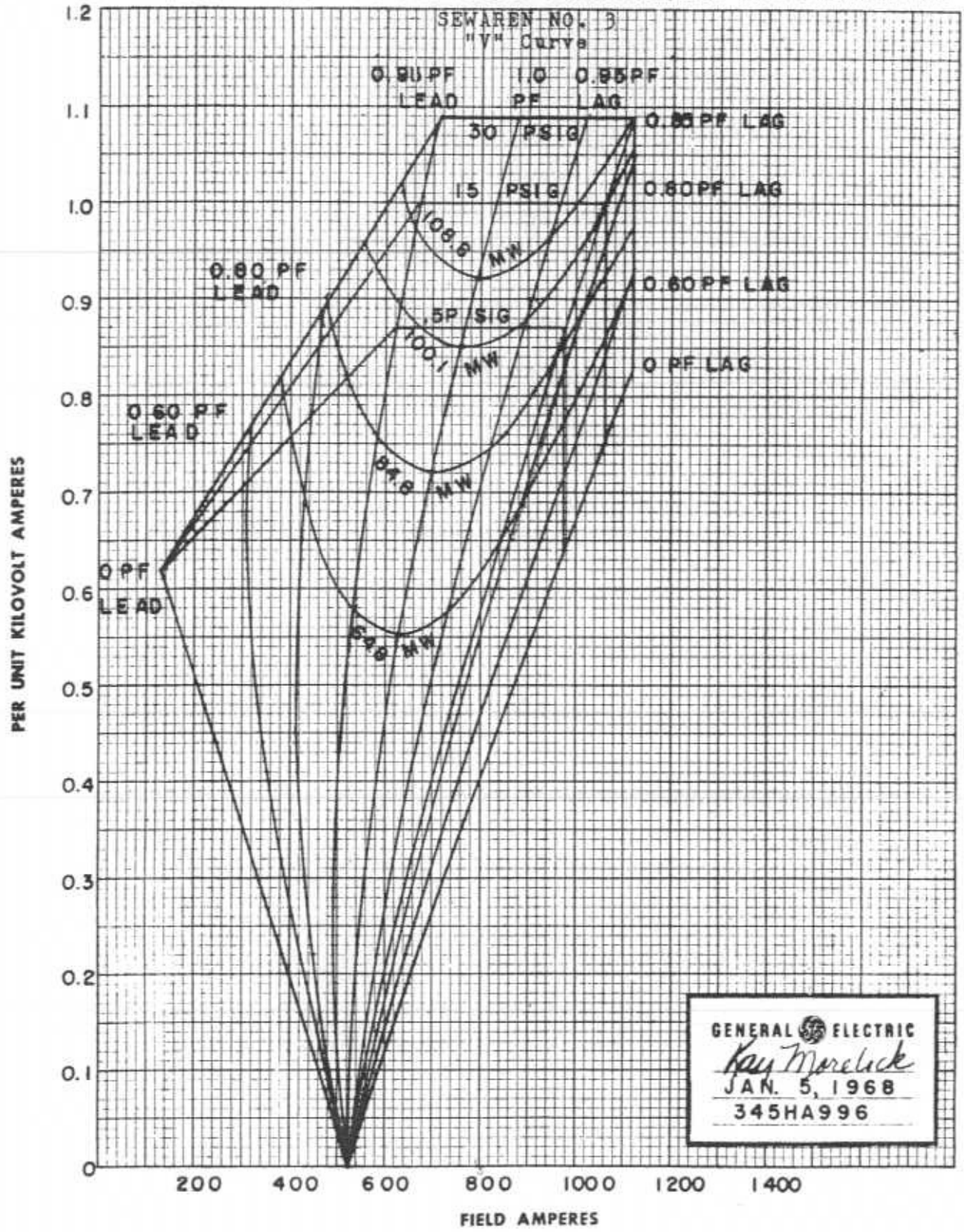
SEWAREN #3

ESTIMATED "V" CURVES

FOR STEAM TURBINE-GENERATOR UNIT

ATB 2 POLE, 117,760 KVA, 3600 RPM, 13,800 VOLTS

0.85 P.F., 0.80 SCR, 15 PSIG HYDROGEN PRESSURE, 250 VOLTS EXCITATION



7/68

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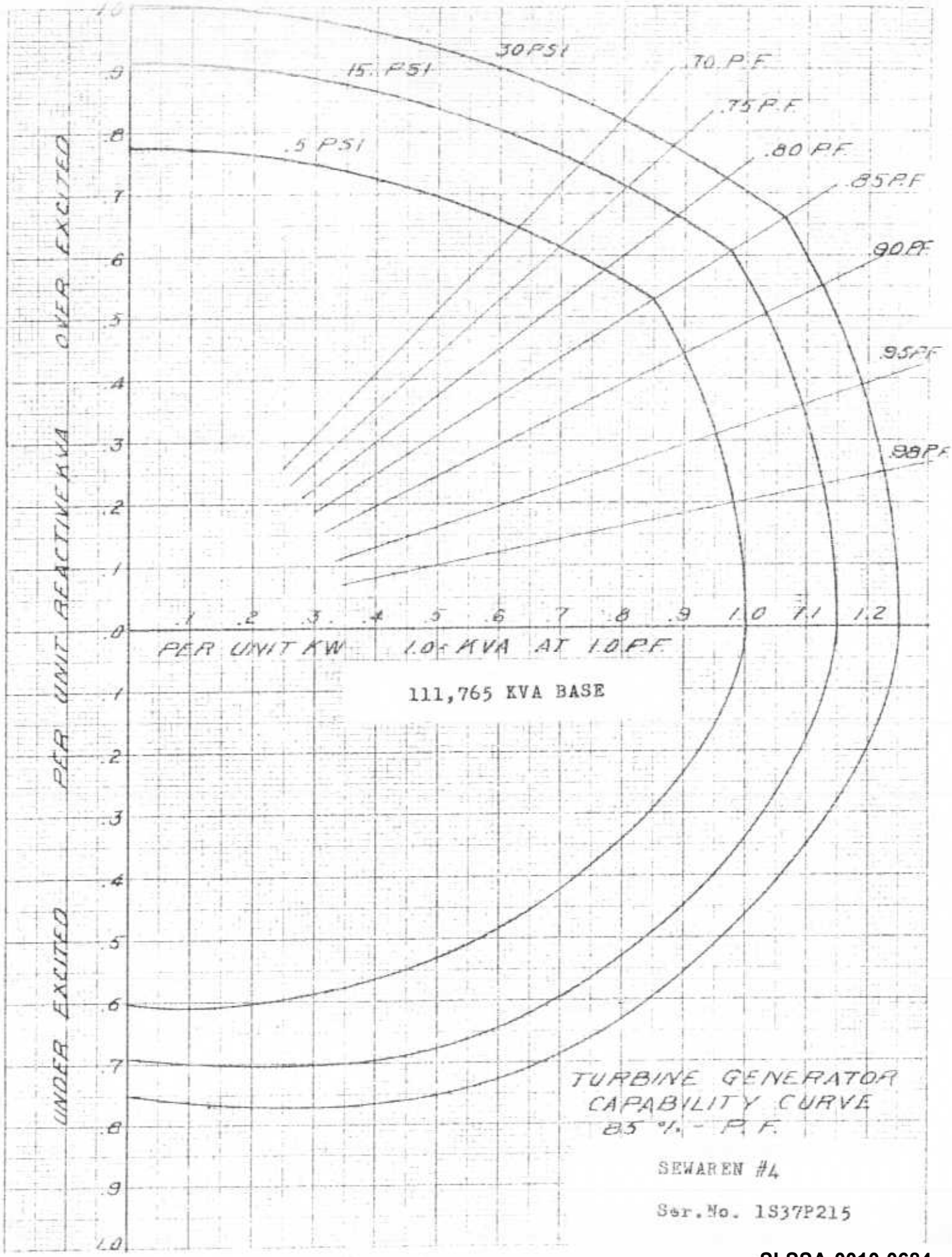
CURVE NO. 400926



SIGNATURE A Mulock / TH Mulock DATE 3/9/53 CURVE NO. 400926

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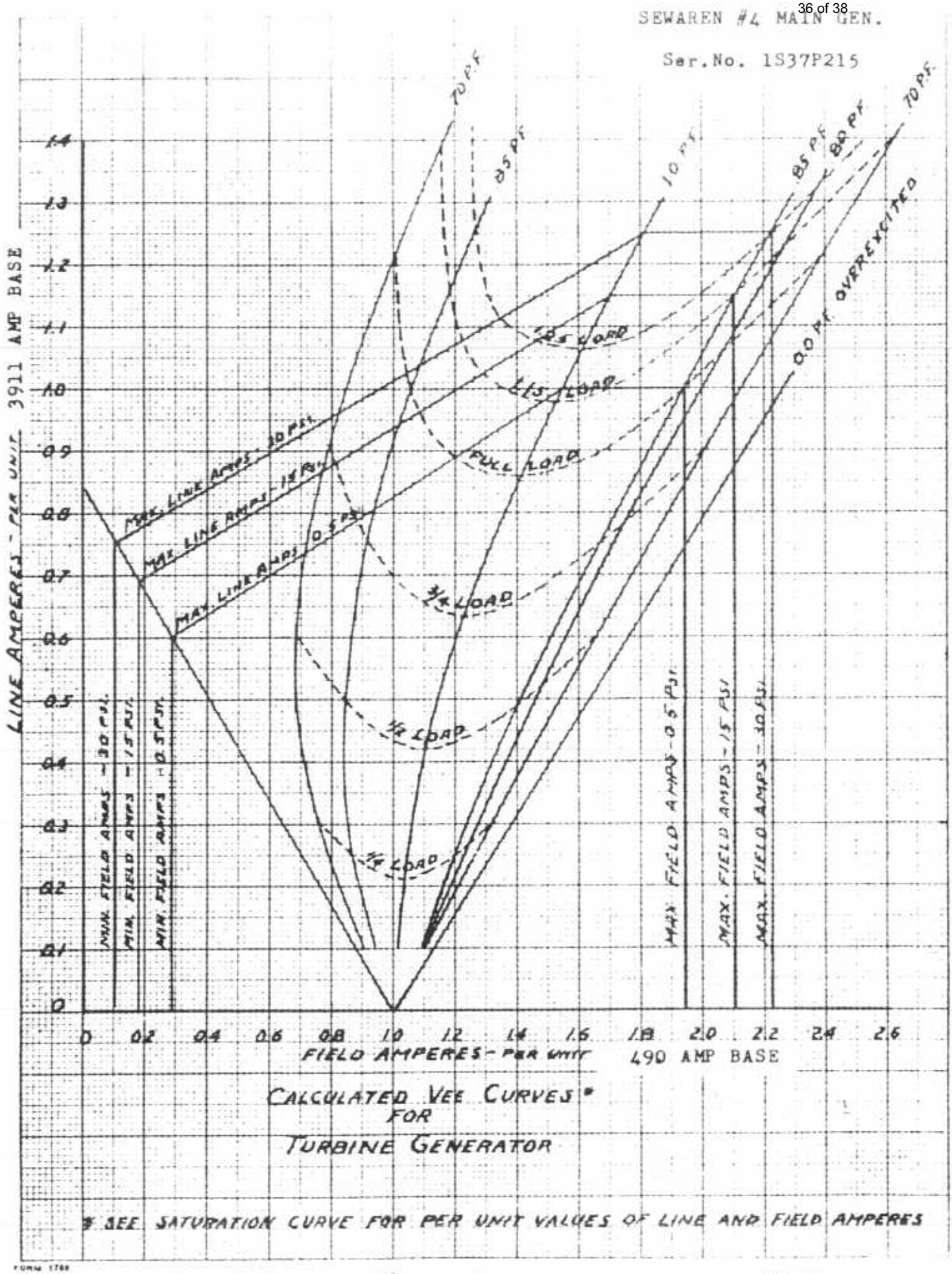
40/572

SEWAREN #4 MAIN GEN.

Ser.No. 1S37P215

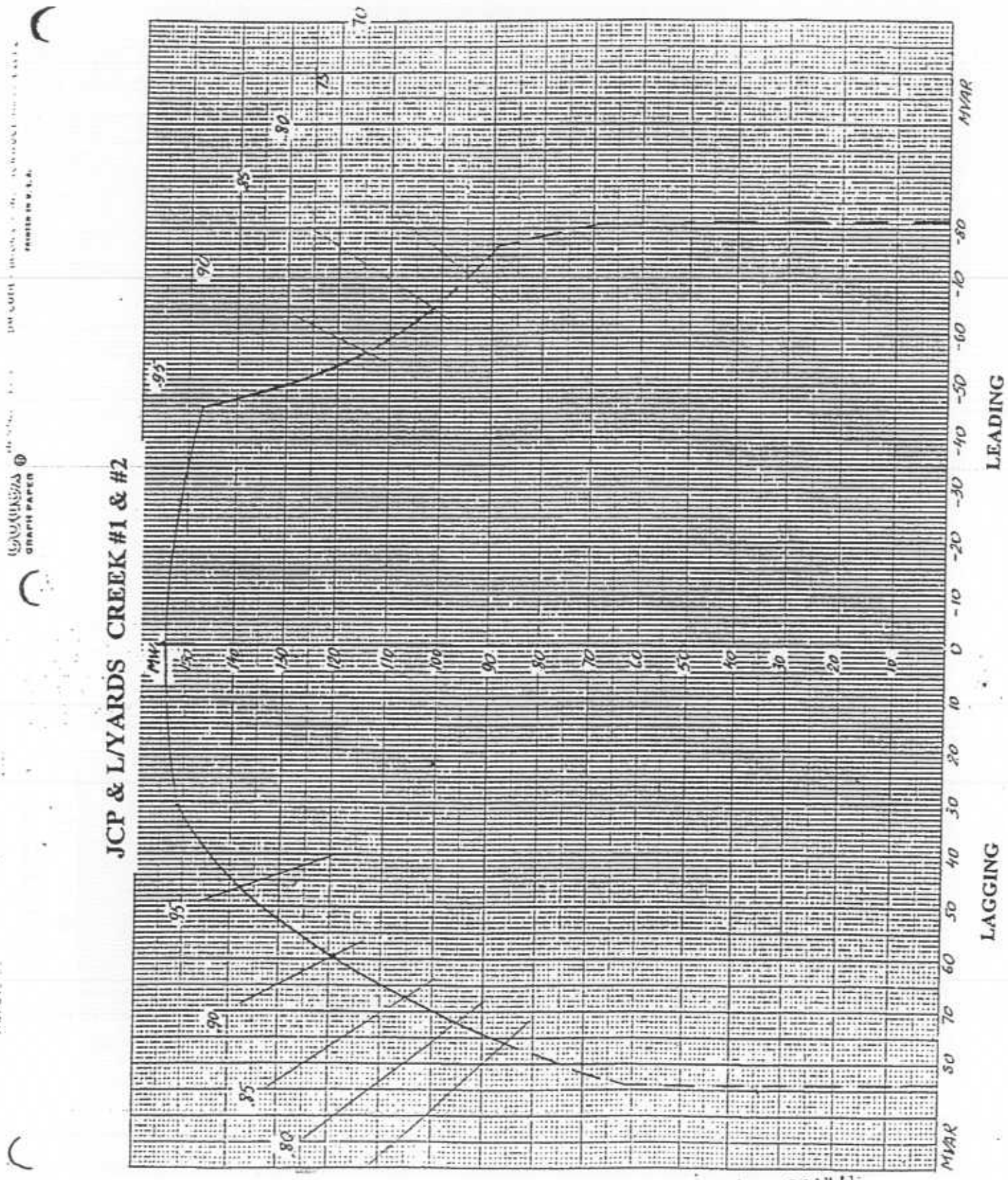


CALCULATED VEE CURVES *
FOR
TURBINE GENERATOR

* SEE SATURATION CURVE FOR PER UNIT VALUES OF LINE AND FIELD AMPERES

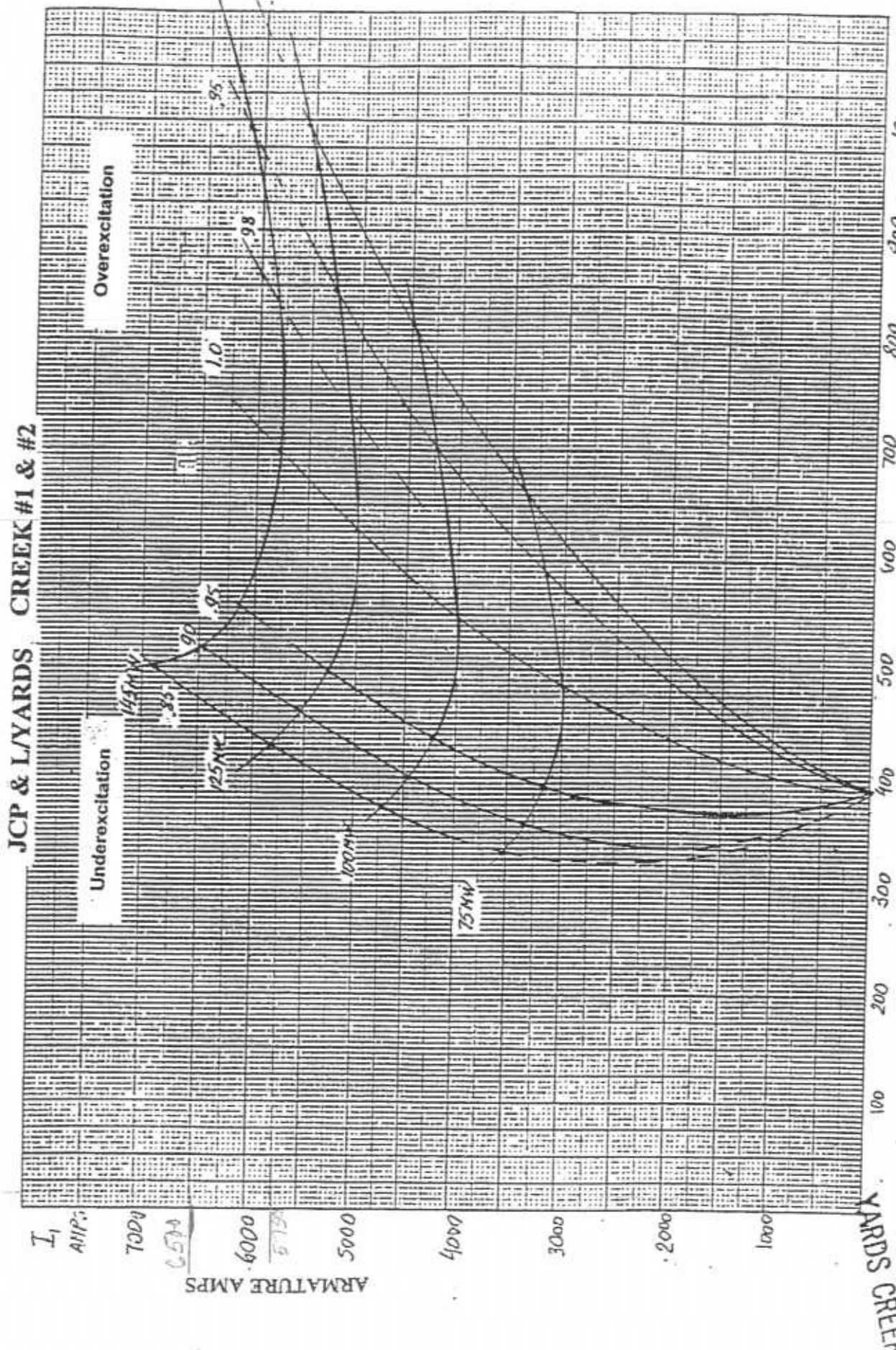
FORM 1788

SIGNATURE A. MULACH DATE 9-8-53 DRAWING NO. 407572


JCP & L/YARDS CREEK #1 & #2
LEADING
LAGGING
MVAR
MW
YARDS CREEK
MAY 8 1996

20150610-5280 FERC PDF (Unofficial) 6/10/2015 3:34:23 PM

YARDS CREEK 1,2&3



20150610-5280 FERC PDF (Unofficial) 6/10/2015 3:34:23 PM

Reactive Supply and Voltage Control from Generation Sources Service

PSEG Energy Resources & Trade LLC ("PSEG ER&T") provides Reactive Supply and Voltage from Generation Sources Service ("Reactive Supply Service") from various generating facilities to the PJM Interconnection, LLC ("PJM") system. This Rate Schedule which consists of seventeen separate tariff rate sections for each of PSEG ER&T's generating facilities sets forth PSEG ER&T's revenue requirements for the provision of Reactive Supply Service to PJM, as contemplated by Schedule 2 of the PJM open access transmission tariff.

PSEG ER&T's total monthly revenue requirement consists of the sum of the charges for the following: (1) the Fixed Capability Revenue Requirement; and (2) the Heating Losses Component for each of its generating facilities. The Fixed Capability Revenue Requirement; the Heating Losses Component, and the Total Revenue Requirement for each generating facility is set forth in the Rate Schedule sections below. This Rate Schedule and its separate sections shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

Nothing contained herein shall be construed as affecting in any way the right of PSEG ER&T to unilaterally make application to the Federal Energy Regulatory Commission for a change in rates under section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder. If PSEG ER&T seeks to change one of the revenue requirements stated herein, it will abide by relevant FERC procedures for changes in rates and notify PJM in accordance with any notice requirement in the PJM Tariff.

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BERGEN 1 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,925,105.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $28,652.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,925,105 + $28,652 = $2,953,757.

Total Monthly Revenue Requirement is $2,953,757 / 12 = $246,146.

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BERGEN 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,330,193.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $31,021.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,330,193 + $31,021= $ 2,361,214.

Total Monthly Revenue Requirement is $2,361,214 / 12 = $ 196,768.

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LINDEN 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $8,589,078.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $68,593.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $8,589,078 + $68,593 = $8,657,672.

Total Monthly Revenue Requirement is $8,657,672 / 12 = $721,473.

HUDSON 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,386,352.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $7,266.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,386,352 + $7,266 = $1,393,617.

Total Monthly Revenue Requirement is $1,393,617 / 12 = $116,135.

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MERCER 1 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $318,855.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $2,290.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $318,855 + $2,290 = $321,145.

Total Monthly Revenue Requirement is $321,145 / 12 = $26,762.

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MERCER 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $969,405.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $3,168.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $969,405 + $3,168 = $972,573.

Total Monthly Revenue Requirement is 972,573 / 12 = $81,048.

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CONEMAUGH 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $482,544.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $14,470.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $482,544 + $14,470 = $497,014.

Total Monthly Revenue Requirement is $497,014 / 12 = $41,418.

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KEYSTONE 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $559,507.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $12,524.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $559,507 + $12,524 = $572,031.

Total Monthly Revenue Requirement is $572,031 / 12 = $47,669.

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SALEM 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,200,674.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $46,757.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,200,674 + $46,757 = $2,247,431.

Total Monthly Revenue Requirement is $2,247,431 / 12 = $187,286.

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HOPE CREEK 1 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $4,602,764.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $39,360.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $4,602,764. + $39,360 = $4,642,124.

Total Monthly Revenue Requirement is $4,642,124 / 12 = $386,844.

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PEACH BOTTOM 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $ 6,139,449.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $65,956.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $6,139,449 + $65,956 = $6,205,405.

Total Monthly Revenue Requirement is $6,205,405 / 12 = $517,117.

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SEWAREN 1 - 4 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,377,492.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $1,431.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,377,492. + $1,431 = $1,378,923.

Total Monthly Revenue Requirement is $1,378,923 / 12 = $114,910.

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BURLINGTON 12 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $ 1,041,234.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $1,271.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,041,234. + $1,271 = $1,042,505

Total Monthly Revenue Requirement is $1,042,505 / 12 = $86,875.

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ESSEX 9 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,051,348.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $208.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,051,348 + $208 = $1,051,556.

Total Monthly Revenue Requirement is $1,051,556 / 12 = $87,630.

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KEARNY 12, 13, 14 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,940,897.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $4,692.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,940,897 + $4,692 = $2,945,589.

Total Monthly Revenue Requirement is $2,945,589 / 12 = $245,466.

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LINDEN 5, 6, 7, 8 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,121,530.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $879.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,121,530 + $879 = $1,122,410.

Total Monthly Revenue Requirement is $1,122,410 / 12 = $93,534.

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YARDS CREEK GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $302,956.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $3,103.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $302,956 + $3,103 = $306,059.

Total Monthly Revenue Requirement is $306,059 / 12 = $25,505.

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FERC rendition of the electronically filed tariff records in Docket No. ER15-01882-001
Filing Data:
CID: C001195
Filing Title: Amendement to Revised Reactive Tariff
Company Filing Identifier: 115
Type of Filing Code: 130
Associated Filing Identifier: 114
Tariff Title: Rate Schedule FERC No. 3 Reactive Supply And Voltage Control From Generation Sources Service
Tariff ID: 10
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Rate Schedule No. 3, Sheet 02, 3.0.0, A
Record Narative Name: Sheet 02
Tariff Record ID: 1250
Tariff Record Collation Value: 4000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

Reactive Supply and Voltage Control from Generation Sources Service

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Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Bergen 1, Sheet 3, 2.0.0, A
Record Narative Name: Sheet 3
Tariff Record ID: 2250
Tariff Record Collation Value: 5000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

BERGEN 1 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,925,105.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $28,652.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,925,105 + $28,652 = $2,953,757.

Total Monthly Revenue Requirement is $2,953,757 / 12 = $246,146.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Bergen 2, Sheet 4, 2.0.0, A
Record Narative Name: Sheet 4
Tariff Record ID: 3250
Tariff Record Collation Value: 6000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

BERGEN 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,330,193.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $31,021.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,330,193 + $31,021= $ 2,361,214.

Total Monthly Revenue Requirement is $2,361,214 / 12 = $ 196,768.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Linden 1 & 2, Sheet 5, 2.0.0, A
Record Narative Name: Sheet 5
Tariff Record ID: 4250
Tariff Record Collation Value: 7000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

LINDEN 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $8,589,078.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $68,593.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $8,589,078 + $68,593 = $8,657,672.

Total Monthly Revenue Requirement is $8,657,672 / 12 = $721,473.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Hudson 2, Sheet 6, 2.0.0, A
Record Narative Name: Sheet 6
Tariff Record ID: 5250
Tariff Record Collation Value: 8000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

HUDSON 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,386,352.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $7,266.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,386,352 + $7,266 = $1,393,617.

Total Monthly Revenue Requirement is $1,393,617 / 12 = $116,135.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Mercer 1, Sheet 7, 2.0.0, A
Record Narative Name: Sheet 7
Tariff Record ID: 6250
Tariff Record Collation Value: 9000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

MERCER 1 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $318,855.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $2,290.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $318,855 + $2,290 = $321,145.

Total Monthly Revenue Requirement is $321,145 / 12 = $26,762.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Mercer 2, Sheet 8, 2.0.0, A
Record Narative Name: Sheet 8
Tariff Record ID: 7250
Tariff Record Collation Value: 10000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

MERCER 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $969,405.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $3,168.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $969,405 + $3,168 = $972,573.

Total Monthly Revenue Requirement is 972,573 / 12 = $81,048.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Conemaugh 1 & 2, Sheet 9, 2.0.0, A
Record Narative Name: Sheet 9
Tariff Record ID: 8250
Tariff Record Collation Value: 11000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

CONEMAUGH 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $482,544.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $14,470.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $482,544 + $14,470 = $497,014.

Total Monthly Revenue Requirement is $497,014 / 12 = $41,418.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Keystone 1 & 2, Sheet 10, 2.0.0, A
Record Narative Name: Sheet 10
Tariff Record ID: 9250
Tariff Record Collation Value: 12000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

KEYSTONE 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $559,507.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $12,524.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $559,507 + $12,524 = $572,031.

Total Monthly Revenue Requirement is $572,031 / 12 = $47,669.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Salem 1 & 2, Sheet 11, 2.0.0, A
Record Narative Name: Sheet 11
Tariff Record ID: 10250
Tariff Record Collation Value: 13000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

SALEM 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,200,674.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $46,757.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,200,674 + $46,757 = $2,247,431.

Total Monthly Revenue Requirement is $2,247,431 / 12 = $187,286.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Hope Creek 1, Sheet 12, 2.0.0, A
Record Narative Name: Sheet 12
Tariff Record ID: 11250
Tariff Record Collation Value: 14000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

HOPE CREEK 1 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $4,602,764.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $39,360.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $4,602,764. + $39,360 = $4,642,124.

Total Monthly Revenue Requirement is $4,642,124 / 12 = $386,844.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Peach Bottom 1 & 2, Sheet 13, 2.0.0, A
Record Narative Name: Sheet 13
Tariff Record ID: 12250
Tariff Record Collation Value: 15000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

PEACH BOTTOM 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $ 6,139,449.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $65,956.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $6,139,449 + $65,956 = $6,205,405.

Total Monthly Revenue Requirement is $6,205,405 / 12 = $517,117.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Sewaren 1 - 4, Sheet 14, 2.0.0, A
Record Narative Name: Sheet 14
Tariff Record ID: 13250
Tariff Record Collation Value: 16000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

SEWAREN 1 - 4 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,377,492.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $1,431.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,377,492. + $1,431 = $1,378,923.

Total Monthly Revenue Requirement is $1,378,923 / 12 = $114,910.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Burlington 12, Sheet 15, 2.0.0, A
Record Narative Name: Sheet 15
Tariff Record ID: 14250
Tariff Record Collation Value: 17000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

BURLINGTON 12 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $ 1,041,234.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $1,271.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,041,234. + $1,271 = $1,042,505

Total Monthly Revenue Requirement is $1,042,505 / 12 = $86,875.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Essex 9, Sheet 16, 2.0.0, A
Record Narative Name: Sheet 16
Tariff Record ID: 15250
Tariff Record Collation Value: 18000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

ESSEX 9 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,051,348.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $208.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,051,348 + $208 = $1,051,556.

Total Monthly Revenue Requirement is $1,051,556 / 12 = $87,630.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Kearny 12, 13, 14, Sheet 17, 2.0.0, A
Record Narative Name: Sheet 17
Tariff Record ID: 16250
Tariff Record Collation Value: 19000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

KEARNY 12, 13, 14 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,940,897.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $4,692.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,940,897 + $4,692 = $2,945,589.

Total Monthly Revenue Requirement is $2,945,589 / 12 = $245,466.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Linden 5, 6, 7, 8, Sheet 18, 2.0.0, A
Record Narative Name: Sheet 18
Tariff Record ID: 17250
Tariff Record Collation Value: 20000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

LINDEN 5, 6, 7, 8 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,121,530.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $879.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,121,530 + $879 = $1,122,410.

Total Monthly Revenue Requirement is $1,122,410 / 12 = $93,534.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Yards Creek, Sheet 19, 2.0.0, A
Record Narative Name: Sheet 19
Tariff Record ID: 18250
Tariff Record Collation Value: 21000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-06
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 114

YARDS CREEK GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $302,956.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $3,103.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $302,956 + $3,103 = $306,059.

Total Monthly Revenue Requirement is $306,059 / 12 = $25,505.

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PSEG Services Corporation

VIA ETARIFF FILING

June 5, 2015

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: PSEG Energy Resources & Trade, LLC
Docket No. ER15-___-000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Part 35 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, PSEG Energy Resources & Trade LLC ("PSEG ER&T" or "Applicant"), hereby submits for filing a revised Rate Schedule FERC No. 3 ("Rate Schedule"), which sets forth the cost-based revenue requirements for the provision of Reactive Supply and Voltage Control from Generation Sources Service ("Reactive Power") owned by PSEG Fossil LLC ("PSEG Fossil") and PSEG Nuclear LLC ("PSEG Nuclear"). This filing covers all of the generating facilities currently owned by subsidiaries of PSEG Power LLC ("PSEG Power") within the PJM Interconnection, L.L.C. ("PJM") region ("the Facilities").[1] While the filing includes all of generation facilities within the PJM region owned by subsidiaries of PSEG Power, this filing sets forth a separate and distinct revenue requirement reflected in a separate tariff record for each "generating facility."[2]

PSEG ER&T provides Reactive Power Service pursuant to Schedule 2 of PJM's Open Access Transmission Tariff ("Tariff") and a Commission-approved revenue requirement rate schedule for the provision of Reactive Power Service. As explained herein, PSEG ER&T is updating its revenue requirement for Reactive Power to reflect generating facility unit retirements and to reflect significant capital expenditures relating to the provision of Reactive

[1] PSEG ER&T, PSEG Nuclear and PSEG Fossil are each direct subsidiaries of PSEG Power. PSEG ER&T is responsible for the administration within PJM of the assets covered by this filing and is currently recognized by PJM as the entity responsible for providing Reactive Power provided by the assets and is paid by PJM for providing such service. PSEG ER&T accordingly is the proper entity to provide this service.

[2] The term "generating facility" refers to a specific location where a generation unit or generation units are located. In some instances, one generating unit is located at a generating facility and in others more than one generating unit is located at a generating facility.

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Power that have occurred since the establishment of the current revenue requirement in May 2008.

In addition to updating PSEG ER&T's Reactive Power revenue requirement to reflect significant additions to generating facilities, this filing is being made, in part, to address certain concerns of the Commission's expressed in its November 20, 2014, Order to Show Cause directed to PJM.[3] In the Order to Show Cause, the Commission directed PJM to revise its Tariff to provide that a generation owner should no longer receive reactive power payments after it has retired a generating unit or if a generating unit is transferred out of a fleet. While PJM's responsive Tariff amendment, which remains pending, properly leaves it to the discretion of the filing utility to determine whether it will make a Section 205 filing to alter its revenue requirement in the event of a retirement, PSEG ER&T has concluded that disaggregation of the revenue requirement will allow it to better comply with the Commission's policy that there should be greater transparency as to the possible rate impacts of a retirement where a single company sells Reactive Power from multiple units that constitute a generating fleet.

Under the current rate structure, PSEG ER&T operates under a "fleet rate" schedule that sets forth an aggregate revenue requirement for all of the generating facilities from which it sells Reactive Power. As discussed hereafter, by way of this filing, PSEG ER&T seeks to change its rate schedule structure by establishing a separate revenue requirement and tariff record for each generating facility. This revised rate schedule structure will enable PSEG ER&T to more efficiently withdraw a revenue requirement for a generating unit should the unit be retired. Similarly, if PSEG ER&T procures new generation or modifies an existing generator, adding to or changing the relevant revenue requirement will be simplified.

PSEG ER&T respectfully requests waiver of the Commission's 60-day prior notice requirement to allow the attached revised rate schedule to become effective June 5, 2015.

I. COMMUNICATIONS

All communications and service related to this application should be directed to the following individuals:

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[3] *PJM Interconnection, LLC,* Order to Show Cause, 106 FERC ¶ 61,132, EL15-15–000, (Nov. 20 2014), ("Order to Show Cause").

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II. DOCUMENTS SUBMITTED

This filing consists of the following:

1. This Letter of Transmittal;

2. "Attachment A" consisting of PSEG ER&T's proposed amended Reactive Power Rate Schedule FERC No. 3 (including a red-lined version of the changes to the existing tariff record and a clean version of the changed and new tariff records);

3. Exhibit No. PSEG – 1: Pre-filed Direct Testimony of Stephen M. Merchant;

4. Exhibit No. PSEG – 2: List of Proceedings in which Stephen M. Merchant has filed testimony;

5. Exhibit No. PSEG – 3: Development of Reactive Power Revenue Requirements:

   (a) Revenue Requirements' Schedules

      i. Schedule No. 1 - Revenue Requirement Summary;

      ii. Schedule No. 2 - Capital Structure, Rate of Return and Income Tax Rates; and

      iii. Schedule No. 3 - Revenue Requirement for Individual Units/Facilities.

   (b) Supporting Work-papers

III. BACKGROUND AND DESCRIPTION OF REQUIREMENT FOR SERVICE

PJM administers the PJM control area and provides transmission service to customers pursuant to the Schedule 2 of its Tariff.[4] PSEG ER&T provides Reactive Power pursuant to Schedule 2 of PJM's Tariff and a Commission-approved rate schedule. The Tariff provides that each month PJM will pay "each Generation Owner an amount equal to the Generation Owner's monthly revenue requirement as accepted or approved by the Commission." (*See* PJM Tariff, OATT VI, Schedule 2).

[4] *See PJM Interconnection, L.L.C.,* 106 FERC ¶ 61,253 at P 6 (2004) (accepting for filing tariff revisions to permit the integration of ComEd's Transmissions system into PJM).

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Within the PJM region, PSEG Fossil and PSEG Nuclear own and operate twenty-two (22) generating units and own undivided interests in nine (9) generating units which in some cases they operate and which in other cases are operated by others. These consist of base-load, intermediate and peaking facilities and have a total operating capacity of about 9,869 MWs. PSEG Fossil and PSEG Nuclear acquired a large portion of their assets from Public Service Electric and Gas Company ("PSE&G") as part of the restructuring of New Jersey electric utilities as required by the New Jersey Board of Public Utilities pursuant to the New Jersey Energy Discount and Energy Competition Act. The transfer of these facilities occurred in August 2000 following the receipt of all necessary regulatory approvals. Substantial write-downs of many of the transferred assets were taken on the books of PSE&G prior to the transfer. In particular, most of the book value of interests in nuclear units at Salem, Hope Creek and Peach Bottom were written down.

PSEG ER&T's current Reactive Power rate was accepted by the Commission's Letter Order dated November 13, 2008 in Docket No. ER08-951-002.[5] The Letter Order was issued in response to PSEG ER&T's May 13, 2008 filing ("May 2008 Filing"). On July 7, 2008, PSEG ER&T supplemented its May 2008 Filing in response to Commission Staff's inquiries regarding certain cost allocation percentages. Thereafter, on September 12, 2008, PSEG ER&T further supplemented its May 2008 filing. The revenue requirement established for the PSE&G ER&T fleet based on the May 2008 Filing, as supplemented, is $26,626,787.

The 2008 revenue requirement was established based upon the Commission approved methodology set forth in *American Elec. Power Serv. Corp.,* 88 FERC ¶ 61,141 (1999), *order on reh'g,* 92 FERC ¶ 61,001 (2000) (the "*AEP methodology*"). The within filing is likewise based upon the *AEP methodology* and is consistent with the methodology used in the May 2008 Filing.

Since the establishment of the current Reactive Power revenue requirement, PSEG Fossil and PSEG Nuclear have constructed new generating units and have made significant capital expenditures to the existing generating fleet within PJM including, in particular, significant investments in rebuilding or replacing facilities associated with providing reactive power such as turbo-generators, generators, accessories and generator step-up transformers. The new generating units constructed since the establishment of the current revenue requirement are Kearny #13 and #14 owned by PSEG Fossil. Since 2008, the most significant investments, major upgrades, and replacement of equipment related to reactive power have taken place at: Linden Units #1 and #2 (approximately $1B), Hudson #2 (approximately $100M), and three nuclear facilities, Hope Creek, Peach Bottom and Salem (approximately $1B). PSEG Fossil has retired certain generating units that that were in service in 2008 and, as a result those units are not included in this filing.

PSEG Fossil's and PSEG Nuclear's investment in generating units capable of providing Reactive Power has increased since 2008 from $4,341.7M to $7,318.1M. This amount, which is an increase in investment of approximately 69%, includes the removal of the costs associated with the retired units. As a result, the currently authorized Reactive Power annual revenue requirement of $26,626,787 significantly understates PSE&G ER&T's actual annual revenue

[5] *PSEG Energy Resources and Trade, LLC*, Docket Nos. ER08-951-000, ER08-951-001, ER08-951-002, Letter Order, November 13, 2008.

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requirement for all of its generation facilities based upon updated levels of investment and operating costs.

Original investment cost and other financial and operating data were taken from the books and records of PSEG Fossil and PSEG Nuclear, as those companies do not submit a FERC Form No. 1. Information from manufacturers was used in some cases to allocate original investment or as a source for generator efficiency data.[6]

This filing is supported by the attached testimony of Stephen M. Merchant ("Merchant Testimony").

IV. DESCRIPTION OF REVENUE REQUIREMENT FOR REACTIVE POWER

The proposed rate schedules sets forth rates that represents PSEG ER&T's revenue requirement for Reactive Power on a "generating facility" specific basis for seventeen (17) generating facilities.[7] The revenue requirement for each generating facility is the sum of two components: (1) fixed costs attributable to reactive power production capability ("Fixed Capability Component") and (2) increased generator and step-up transformer heating losses that result from the production of reactive power ("Heating Losses Component").

As required by the Commission in *FPL Energy Marcus Hook, L.P.,* 110 FERC ¶ 61,087, P 16 (2005) (*"Marcus Hook I"*), the proposed revenue requirement is developed consistent with the *AEP methodology*.

The total annual revenue requirement that PSEG ER&T is seeking to recover for all of its generating facilities included in this filing is $38,671,025. This aggregate annual revenue requirement is based upon actual investment and operating costs for the 2014 test year excluding the investments and expenses of retired units. The individual components of the proposed rate schedule are briefly discussed here and are supported by the Merchant Testimony.

A. Fixed Capability Component

The Fixed Capability Component of the Reactive Power revenue requirement represents the portion of the plant investment in the Facilities that can be attributed to the production of Reactive Power. Mr. Merchant analyzes the costs associated with the reactive portion of PSEG Fossil's and PSEG Nuclear's investment in the generator/exciter system and the generator step-

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[6] In one case – the Yards Creek pumped storage facility – actual cost data from the manufacturer was not available because the GE company division that constructed the unit was sold to a consortium of European companies. In lieu of a manufacturer's letter of actual cost data, a proxy allocator equal to 15% (the same value as used in *AEP*) was used. The use of this allocator for Yards Creek is a conservative estimate that is supported by information supplied by a consulting firm (Axford Consulting) who conferred with personnel in the gas and steam turbine divisions of GE and with Hitachi America LDT, a company currently in the business of building generators/motors for pumped hydo storage. Axford Consulting concluded that an allocation between 25% and 45% would be reasonable.

[7] See Merchant Testimony, Exhibit No. PSEG – 3, Schedule 1. For the purposes of this filing, although "Bergen 1" and "Bergen 2" are at the same location, they are not being treated as a single "generating facility." Rather, each is designated as separate generating facility. Similarly, "Linden 1 & 2" and "Linden 3-4" are each designated as a separate "generating facility."

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up transformer, accessory electric equipment, and the balance of plant costs. His analysis determines the original investment cost of the (i) generator/exciter, (ii) step-up transformer, and (iii) the accessory electric equipment to determine the reactive portion of this investment.

As explained by Mr. Merchant, for some facilities, the original investment cost of the generator/exciter is specified on PSEG Power's books. In other cases, the generator/exciter investment is calculated as a share of the per books original investment cost associated with turbo-generator investment, based on data provided by the turbo-generator manufacturer.[8]

Consistent with the May 2008 Filing, for each named facility or group of units, Mr. Merchant allocates dual use plant related to the function of reactive power production. The reactive allocator is unity less the square of the facility's power factor. The balance of plant is also allocated to the provision of reactive power pursuant to the *AEP methodology*. To determine the annual revenue requirement, a fixed charge rate ("FCR") specific to each generating facility has been developed to apply to the Reactive Power production cost. The FCR includes the following components: Fixed O&M, Real Estate Tax and Property Insurance, Sinking Fund Depreciation, Levelized Tax Factor, Prepayments, Cash Working Capital ("CWC"), Return, and Accumulated Deferred Income Taxes ("ADIT").

B. Heating Losses Component

The production of Reactive Power produces higher currents and, as a result, losses occur from resistive heating associated with armature winding and field winding of the generators. Additionally, losses occur as a result of increased eddy currents in the generator and associated step-up transformer. These losses can be calculated as the real power consumed to produce Reactive Power, and therefore, constitute a cost that is directly attributable to the production of Reactive Power. Such costs associated with losses also occur in the generator step-up transformer units. Efficiency data used for the heating losses calculations was obtained from the best available sources. These sources include printed curves and specification sheets, calculations from data components on printed curves, specification sheets and instruction manuals. When possible, original plant specification data was used. For some units, however, this data was not originally included in the generator data sets. In these cases, efficiency data was obtained from the manufacturers for comparable units.

Mr. Merchant explains in his testimony how heating losses are calculated and why it is proper to include the cost of such losses in the revenue requirement for the Facilities.[9] In this filing, heating losses comprise only small portion of the total Reactive Power total annual revenue requirement for all of the generating facilities – $331,641 out of $38.67 million.

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[8] As noted *supra*, – because manufacturer data is not available for Yards Creek pumped storage facility, an allocation factor was recommended by a consulting firm (Axford Consulting).

[9] See *Dynegy Midwest Generation, Inc*., 121 FERC ¶ 61,025 (2007) (Opinion Number 498), order on reh'g, 125 FERC ¶ 61,280 (2008) ("Dynegy"), (The Commission has found that heating loss costs are recoverable).

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V. DESCRIPTION OF AMENDED RATE SCHEUDLE STRUCTURE

Under PSEG ER&T's current Rate Schedule FERC No. 3, the annual revenue requirement for Reactive Power is stated as a monthly and annual number that is based upon the sum of the revenue requirement for each of the generating facilities included in PSEG ER&T's generating fleet. By way of this filing, PSEG ER&T seeks to amend Rate Schedule No. 3 so that each "generating facility" has its own, separate FERC-accepted annual and monthly revenue requirement reflected in its own tariff record. More specifically, PSEG ER&T is requesting that the Commission accept the revenue requirement for each generating facility as set forth on Exhibit PSEG-3, Schedule 1, resulting in a separate rate for each generating facility included in Rate Schedule FERC No. 3 as amended. (Attachment A identifies proposed revisions to Rate Schedule FERC No. 3 and includes the addition of generating facility-specific tariff records.)

VI. OTHER FILING REQUIREMENTS

- 18 C.F.R. § 35.13(b)(1) – A list of documents submitted with this filing is included at Section II.
- 18 C.F.R. § 35.13(b)(2) – The date on which PSEG ER&T proposes to make the rate change effective is June 5, 2015.
- 18 C.F.R. § 35.13(b)(3) – A copy of this filing has been sent to PJM and the New Jersey Board of Public Utilities.
- 18 C.F.R. § 35.13(b)(4) – A description of the rate change is explained herein at Section IV.
- 18 C.F.R. § 35.13(b)(5) – A statement of the reasons for the rate change is explained herein at Section III.
- 18 C.F.R. § 35.13(b)(6) – PSEG ER&T hereby represents that no additional agreement, by contract or otherwise, is required for the filing of this rate.
- 18 C.F.R. § 35.13(b)(7) – PSEG ER&T hereby represents that there are no expenses or costs included in this filing that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.
- 18 C.F.R. § 35.13(c)(3) – No specifically assignable facilities have been or will be installed in connection with the proposed rate schedule.

The instant filing contains an explanation as to the method used in arriving at the cost of service for the rate proposed herein for Reactive Power. PSEG ER&T respectfully requests waiver of the requirements of Section 35.13 of the Commission's regulations to the extent necessary to permit acceptance of the Reactive Power proposed Rate Schedules.

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VII. EFFECTIVE DATE AND REQUEST FOR WAIVERS

PSEG ER&T respectfully requests waiver of the Commission's notice requirements so that its revised Rate Schedule FERC No. 3 may become effective on June 5, 2015. As discussed above, since the last time a reactive power revenue requirement for PSEG ER&T was obtained seven years ago, significant capital expenditures to units in the existing fleet have been made, new generating units have been constructed and operational expenses have increased. These additional costs associated with the provision of reactive power services more than offset the decrease in costs stemming from retirements that occurred during the same time period. The costs of these additional investments and new facilities are not reflected in the currently effective revenue requirement and, as a result, PSEG ER&T is significantly under-recovering its costs of supplying reactive power to PJM.

The Commission has regularly granted waiver establishing effective dates less than sixty (60) days after filing for Reactive Power rate schedules. *See, e.g., Tenaska Virginia Partners, L.P.,* 107 FERC ¶ 61,207 (2004) (requested suspension rejected, not set for hearing, and effective date of less than sixty (60) days after date of filing granted); *FPL Energy Marcus Hook. L.P.,* 110 FERC ¶ 61,087 (2005) (granting effective date of less than sixty (60) days after date of filing); *Cottonwood Energy Company LP,* 110 FERC ¶ 61,303 (2005) (effective date of filing eight (8) days after filing made); *Union Power Partners, L.P.,* 112 FERC ¶ 61,065 (2005) (effective date of filing one day after filing made). For the reasons set forth above, PSEG ER&T respectfully submits that good cause for waiver of the 60 day notice period exists in this case.

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VIII. CONCLUSION

WHEREFORE, for the foregoing reasons, PSEG ER&T respectfully requests that the Commission accept the proposed Rate Schedules to become effective on June 5, 2015 and grant the waivers requested herein.

Respectfully submitted,

PSEG Energy Resources & Trade LLC

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PSEG Energy Resources & Trade, LLC) **Docket No. ER15-____-000**

PREFILED DIRECT TESTIMONY OF STEPHEN M. MERCHANT

ON BEHALF OF PSEG ENERGY RESOURCES & TRADE, LLC

Introduction and Qualifications

Q. Please state your name, business address and occupation.

A. My name is Stephen M. Merchant. My business address is 1155 15th Street, NW, Suite 400, Washington, D.C. 20005. I am employed by the energy consulting firm of Brown, Williams, Moorhead & Quinn, Inc. My position is Vice President.

Q. Please describe your education and professional experience.

A. Over the last 41 years I have served an officer or associate of several public utility and energy consulting firms. In that capacity I have provided professional services to numerous clients, including gas and electric distribution, transmission and production companies. I have testified as an expert witness in many proceedings, on such matters as transmission cost of service, rates and terms and conditions of service; ancillary services pricing; rate of return, and the existence of competitive alternatives. I have performed load studies and forecasts and have prepared

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economic analyses of electric and gas supply options. I have prepared and testified in support of market power studies filed for market-based rates.

I have a Bachelor's degree in Economics from the University of Delaware and a Master's Degree in Economics from the University of Maryland.

Q. Please identify the cases for which you have offered testimony in hearings before regulatory agencies.

A. I have testified and/or prepared written testimony in many rate proceedings, including before the Federal Energy Regulatory Commission ("FERC" or "Commission"), state regulatory commissions, and federal and state courts. The cases are listed in Exhibit No. PSEG – 2.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of PSEG Energy Resources & Trade, LLC ("PSEG ER&T" or "Company"), a direct subsidiary of PSEG Power, LLC ("PSEG Power").

Q. Please list the Exhibits you are sponsoring.

A. I am sponsoring the following exhibits:

1) Exhibit No. PSEG – 1: Prefiled Direct Testimony of Stephen M. Merchant

2) Exhibit No. PSEG – 2: List of Proceedings in which Stephen M. Merchant has filed testimony

3) Exhibit No. PSEG – 3: Development of Reactive Revenue Requirement by Generating Facility – 2015

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Q. In addition to Exhibit No. PSEG – 3, which shows the details of the revenue requirement calculations for each generating facility, have you included workpapers supporting these calculations?

A. Yes. Workpapers are included showing the development of the capital structure and debt cost rate; the calculations of heating losses for each facility; test year investment and expense data; test year real estate taxes; insurance expense and common expenses and their allocation; prepayments and two workpapers showing physical characteristics of units/facilities. In addition, the filing includes thirty-eight (38) pages of generator specific data in *pdf* format, including generator reactive capability curves.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. PSEG Power, through its subsidiaries PSEG Fossil LLC and PSEG Nuclear LLC, is owner or part-owner of numerous generating facilities in or near the control area of Public Service Electric & Gas Company ("PSE&G"). The various PSEG Power generating facilities that are the subject of this filing ("PSEG Power fleet") are located within the geographic area of the PJM Interconnection, LLC ("PJM"). PJM is the control area operator, and each of the generating units in the PSEG Power fleet is eligible to recover its costs of providing Reactive Power (also, "VArs") to PJM. In order to recover its costs it is necessary to establish a FERC-approved

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monthly Reactive Power revenue requirement which PJM includes in Schedule 2 of its OATT. PJM assesses transmission customers and distributes the revenues it collects to generators with FERC-approved revenue requirements.

My testimony explains and supports the calculations and methodology that PSEG ER&T has employed to derive the reactive revenue requirement for each generating facility or grouping of units in the PSEG Power fleet.

Q. Does PSEG ER&T currently have a FERC-approved revenue requirement for Reactive Power included in PJM's Schedule 2?

A. Yes. In Docket No. ER08-951-000, et al., FERC accepted by letter order PSEG ER&T's proposed total annual Reactive Power revenue requirement for the PSEG Power Fleet of $26,626,787 (hereafter "2008 Filing").

Q. To prepare the currently proposed Reactive Revenue requirement, has PSEG ER&T utilized the same methodology as in the last filing?

A. Yes. In its November 13, 2008 letter order accepting PSEG ER&T's 2008 Filing, FERC found: "Consistent with the Commission's prior directives, you have utilized the methodology set forth in *American Electric Power Services Corp.*, 88 FERC ¶ 61,141 (1999) (AEP methodology), for determining the plant cost to be reflected in a revenue requirement for Reactive Power."

Like the 2008 Filing, this filing utilizes the FERC approved AEP

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methodology. In order to maintain consistency with the 2008 Filing accepted by FERC, PSEG ER&T has updated the same exhibits used to support the revenue requirement employed in the 2008 Filing: (a) bringing investment and operating costs to current levels; (b) removing generating units that have been retired, and (c) adding units placed in service since 2008. PSEG ER&T's proposed annual Reactive Power revenue requirement for all of the generating units in this filing is $38,671,025.

The total new revenue requirement reflects $16.0 million in revenues to support generation investment since the 2008 Filing, less $4.0 million in revenue requirement associated with the generation facilities that have been retired since the 2008 Filing.

Q. What is the primary reason for the increase in the revenue requirement?

A. While some plants included in the 2008 Filing analysis (using the 2007 test year) have since been retired, PSEG Power has made significant new investments in generation both by upgrading existing plants and adding new units. Since the last filing, PSEG Power's total investment in generating units capable of providing Reactive Power has grown from $4,341.7 million to $7,318.1 million, an increase of almost 69%. Clearly, this change in investment is the main driver of the proposed increase in the revenue requirement.

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Q. Of the generating units in the current analysis, which have had significant new investment by PSEG?

A. Two new units were installed at Kearny (#13 & #14) for $280 million. In addition, nearly one billion dollars of investment was made at Linden #1 & #2, and another $103 million at Hudson 2. Finally, upgrades and replacements of generating equipment since 2008 at three nuclear facilities (Hope Creek, Peach Bottom and Salem) have totaled slightly more than one billion dollars.

Q. Please state the major components of your testimony.

A. The major components of this testimony are:

1. Identification of all equipment employed in Reactive Power production and its installed cost. This equipment consists of generators and exciters, generator step-up transformers ("GSUs"), accessory electrical equipment and the balance of plant.
2. Explanations of the calculations of the allocation factors to be applied to the generators/exciters, GSUs, accessory electrical equipment, balance of plant and the application of these factors to derive total Reactive Power investment.
3. Support for the development and application of the fixed charge rate ("FCR") used to determine the fixed component of the Reactive Power revenue requirement for each generating facility.

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4. Explanation of the development of the heating loss component of the Reactive Power revenue requirement.

Q. Please explain the Commission's methodology for calculating the cost of Reactive Power.

A. In Order No. 888, the Commission found that Reactive Power from generators is an Ancillary Service of which the costs should be separately assessed to transmission customers. In *American Electric Power Service Corp.*, 80 FERC ¶ 63,006 (1997), *aff'd in part and rev'd in part*, 88 FERC ¶ 61,141 (1999) ("AEP") and *Dynegy Midwest Generation, Inc.*, 121 FERC ¶ 61,025 (2007) (Opinion No. 498) ("*Dynegy*"), *order on r'hg*, 125 FERC ¶ 61,280 (2009), the Commission discussed the methodology for determining the cost of Reactive Power. As I noted above, the Reactive Power revenue requirement proposed by PSEG Power was developed consistent with the methods described in *AEP* and *Dynegy*.

The *AEP* methodology identifies the Reactive Power fixed cost component with respect to four groups of investments, as noted above: (1) generator/exciter, (2) GSU transformers, (3) accessory electrical equipment, and (4) balance of plant investment. The methodology then develops an allocation factor to separate the foregoing investment into Real and Reactive components. Consistent with *Dynegy*, the Reactive Power revenue requirement also includes the cost of incremental heating losses which are incurred in the production of Reactive Power.

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Q. What is the test period?

A. The test period is calendar year 2014, the most recent calendar year data is available.

Q. Please explain how PSEG determined the plant investment associated with the generator and exciter, GSUs, accessory electrical equipment and balance of plant.

A. To determine plant investment associated with the generator and exciter, PSEG Power used one of two methods: (a) direct examination of generator/exciter costs from company's books and records, or (b) allocation of a portion of turbogenerator costs to generator/exciter, where the allocator is based on information directly from the manufacturer (e.g., a letter). For each generating unit or facility in the analysis, Exhibit No. PSEG – 3 Schedule 1 shows the source of the generator/exciter investment.

Exhibit No. PSEG – 3 Schedule 1 also shows the allocation of accessories to dual use. PSEG has sufficient data to provide an accessories allocation for only two facilities, so the accessories allocations for the other facilities are zero. With respect to GSUs, booked data provides the investment amounts, for the 12 out of 17 facilities for which such data exists. The allocator for the share of remaining plant allocable to dual use is based upon an allocation factor derived from an

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analysis conducted by PSEG Power utilizing the following formula:

$$\frac{\text{Exciter MW}}{\text{Generator MW}} * \frac{\text{Maximum MVAR}}{\text{Nameplate MVAR.}}$$

The factor is 0.14%, which in my experience is conservative.

Q. Please explain how the Reactive Power portion of each of the four components is determined.

A. First, a "Reactive Allocator" is calculated that is specific to each generating station or group of generating units. The Reactive Allocator is the value unity less pf^2, where pf is the weighted power factor of all generating units in the facility. This value is shown on line 14 of the revenue requirement calculation for each unit or group of units. See, for example, the specification of the Reactive Allocator for Bergen 1, Exhibit No. PSEG - 3, Schedule 3, page 1 of 34. The workpaper for Bergen 1 shows the development of the weighted power factor.

The dual use investment for the generator/exciter is developed at lines 5, 6 and 7 of Exhibit No. PSEG - 3, either by direct assignment of the cost or by multiplying the turbogenerator costs by the percent of generator/exciter costs specified by the manufacturer.[1] The dual use investment for accessories is

[1] In one case - the Yards Creek pumped storage facility – actual cost data from the manufacturer was not available because the GE company division that constructed the unit was sold to a consortium of European companies. In lieu of a manufacturer's letter of actual cost data, a proxy allocator equal to 15% (the same value as used in *AEP*) was used. The use of this allocator for Yards Creek is a conservative estimate that is supported by information supplied by a consulting firm (Axford Consulting) who conferred with personnel in the gas and steam turbine divisions of GE and with Hitachi America LDT, a company currently in the business of building generators/motors for pumped hydo storage. Axford Consulting concluded that an allocation between 25% and 45% would be reasonable.

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developed at lines 8, 9 and 10 by multiplying accessories investment by the percent developed by analysis. The dual use investment for GSUs is specified at line 12 as a per books amount.

The sum of these three dual-use investments is shown at line 13 and is multiplied by the Reactive Allocator at line 14 to derive the total of dual-use investment allocated to Reactive Power.

Finally, the balance of plant allocable to Reactive Power (line 16) is total plant investment (line 1) less the total allocated to Reactive Power (line 15). This balance is multiplied by the balance of plant allocator shown on line 17 to derive line 18. Total plant allocated to Reactive Power production (line 19) is the sum of lines 15 and 18.

Q. Once you have determined the Reactive Power portion of total plant investment, how do you calculate the revenue requirement for the fixed capability component?

A. Consistent with the *AEP* methodology, the method employed is a levelized gross plant method. For each named generating facility or unit, a fixed charge rate ("FCR") applicable to each facility is calculated. The FCR includes the following components: Fixed O&M, Real Estate Tax and Property Insurance, Sinking Fund Depreciation, Levelized Tax Factor, Return, Prepayments, Cash Working Capital ("CWC"), and Accumulated Deferred Income Taxes ("ADIT").

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See, for example, the specification of the components of the FCR for Bergen 1, Exhibit No. PSEG - 3, Schedule 3, page 1, lines 24 through 32.

Q. Please describe how the depreciation, income tax, and rate of return components of the FCR are calculated.

A. The depreciation component is calculated using the Commission's standard sinking fund method as employed in *AEP.* The component equals Return / (1+Return^n - 1), where "n" is the depreciable life of the plant. This calculation is shown on line 22 of the above-cited schedule for Bergen 1 (and on each of the other schedules showing the FCR calculations by plant).

The income taxes component ("LTF" = levelized tax factor) is calculated based on the composite income tax rate ("CIT" from Schedule 2, "Capital Structure and Taxes") as follows: (CIT / (1- CIT) x (Return + SFD – SLD) x (1 – LTD / Return), where SFD is the sinking fund depreciation rate, SLD is the straight line depreciation rate and LTD is the weighted interest rate component of the capital structure.

The after-tax rate of return of 8.86% is calculated on Schedule 2, page 1**.** The rate of return calculation is consistent with the weighted average cost of capital methodology used in the 2008 Filing and includes the same rate of return on equity ("ROE"). The capital structure and its associated debt cost are based upon PSEG Power's actual capital structure and debt costs as set forth in the 2014 SEC Form

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10-K filed by PSEG Power, LLC. Consistent with the 2008 Filing, and to be conservative, the current filing includes the same ROE as that in the 2008 Filing which is at the low end of the range of ROEs of transmission owners in PJM.

Q. Please explain why a heating losses component is included in the proposed rates.

A. The production of Reactive Power results in the increase of current in addition to the current flowing as a result of the production of Real Power. Due to the electrical resistance inside of the generator and GSU windings, this incremental current causes Real Power to be consumed or lost in the form of heat. This loss of Real Power is a cost of providing Reactive Power that is properly recovered through the Reactive Power rate. The Commission has accepted the inclusion of a rate component to recover the cost of heating losses in numerous proceedings. See, for example, *Dynegy,* cited earlier.

Q. Do you have schedules showing the detailed calculations of generator and transformer heating losses for each of the generating facilities?

A. Yes. Exhibit No. PSEG – 3 includes workpapers that calculate the incremental heating loses for each generating facility.

Q. When the losses for each generating facility have been calculated, how are

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they valued?

A. They are appropriately valued at the average annual locational marginal price ("LMP") of energy associated with the location of each generating facility. These values are shown on the "Plant LMP" workpaper included with Exhibit No. PSEG –3.

Q. Have you calculated the specific revenue requirement for each generation facility? And, if so, how do those calculations affect your filing?

A. Yes. The calculation of the total annual Reactive Power revenue requirement for all of the generation facilities is based on the sum of the separate revenue requirements for each facility. Thus, Exhibit No. PSEG - 3, Schedule 1, sets forth the specific revenue requirement (i.e., rate) for each generation facility. (See Exhibit No. PSEG - 3, Schedule 1, Column (A) for "generating facilities" – which may consist of one or more generation units). In this filing, PSEG Power is requesting that the Commission accept the revenue requirement for each generating facility resulting in a separate rate for each generating facility. In my opinion, each of these individual generation reactive power revenue requirements is properly calculated on a consistent basis, utilizing facility-specific data where necessary.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

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Exhibit No. PSEG - 2

STEPHEN M. MERCHANT – SUMMARY OF TESTIMONY EXPERIENCE

JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
FERC	ER78-409, 410	Philadelphia Electric Company	Borough of Lansdale, Pennsylvania.	September 1979	Competition between Electric Utilities; Price Squeeze (settled before hearing)
U.S. District Court, CT	Civil Action No. 15609	City of Groton, et al., vs. CL&P, et al.	City of Groton, Connecticut	February 1980	Competition between Electric Utilities; Market Power Study (cross-examined)
U.S. District Court, PA	Civil Action No. 78-2533	Borough of Lansdale vs. Philadelphia Electric Company	Borough of Lansdale, Pennsylvania	June 1980	Competition between Electric Utilities; Market Power Study (cross-examined)
FERC	RM81-38	Construction Work in Progress for Public Utilities	American Public Power Association	December 1981	FERC Rulemaking on Inclusion of CWIP in Rate Base
AR PSC	81-144-U	Arkansas Power & Light Company	Arkansas Public Service Commission Staff	January 1982	Cost of Service and Rate Design Issues; Time of Day Rates (cross-examined)
FERC	RM80-38	Generic Rate of Return for Electric Utilities	Arkansas Municipal Power Association	January 1983	FERC Rulemaking on Rate of Return
ICC	82-0892	Iowa-Illinois Gas & Electric Company	U.S. Department of the Army and Other Federal Agencies	June 1983	Rate Stabilization/Cost Deferral Plan; Rate of Return (cross-examined)
DC PSC	FC 813	Potomac Electric Power Company	District of Columbia Public Service Commission Staff	October 1983	Company's Proposed Attrition Adjustment (cross-examined)
NM State Corp Commission	1032	Mountain States Telephone & Telegraph Company	New Mexico State Corporation Commission Staff	November 1983	Local Exchange Cost of Service; Toll Rates (cross-examined)
NM State Corp Commission	1052	Mountain States Telephone & Telegraph Company	New Mexico State Corporation Commission Staff	December 1983	Access Charges for Toll Service Providers (cross-examined)

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JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
NJ Board of Public Utilities	841-55	Jersey Central Power & Light Company	Office of the Public Advocate; New Jersey Attorney General	June 1984	Rate of Return on Equity and Overall Rate of Return (cross-examined)
PA PUC	R-842583	Duquesne Light Company	Office of the Public Advocate; Pennsylvania Attorney General	August 1984	Rate of Return on Equity and Overall Rate of Return (cross examined)
NM State Corp Commission	1081	Mountain States Telephone & Telegraph Company	New Mexico State Corporation Commission Staff	October 1984	Access Charges for Toll Service Providers (cross examined)
FERC	RP84-76-000	Alabama-Tennessee Natural Gas Company	Tennessee Valley Municipal Gas Association	December 1984	Rate of Return; Hypothetical Capital Structure (cross examined)
NM State Corp. Commission	1114	Mountain States Telephone & Telegraph Company	New Mexico State Corporation Commission Staff	March 1985	Depreciation Rates for Telephone Plant in Service (cross examined)
NM State Corp. Commission	1114	Mountain States Telephone & Telegraph Company	New Mexico State Corporation Commission Staff	June 1985	Revision of Procedures for Independent Company Settlements (cross examined)
FERC	ER85-424-000	Southwestern Electric Power Company	City of Hope, Arkansas	September 1985	Revenue Requirement for Wholesale Electric Rates; ROE (settled)
FERC	RP85-149-000	East Tennessee Natural Gas Company	East Tennessee Municipal Gas Users Group	September 1985	Rate of Return on Equity and ROR; Capital Structure (settled)
NM State Corp Commission	1136	Mountain States Telephone & Telegraph Company	New Mexico State Corporation Commission Staff	March 1986	Competition in Certain Central Office Services (cross examined)
NM State Corp Commission	1128, 1129	Mountain States Telephone & Telegraph Company	New Mexico State Corporation Commission Staff	June 1986	Competition in Intrastate Toll Services (cross examined)

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JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
NM State Corp Commission	1138	AT&T Communications of the Mountain States, Inc.	New Mexico State Corporation Commission Staff	August 1986	Competition for Intrastate Toll Services (cross examined)
NM State Corp Commission	1142	Mountain States Telephone & Telegraph Company	New Mexico State Corporation Commission Staff	October 1986	Access Charges for Toll Service Providers (cross examined)
NM State Corp Commission	86-151-TC	General Telephone Company of the Southwest	New Mexico State Corporation Commission Staff	January 1987	Revenue Requirement for Local Exchange Service (cross examined)
NM State Corp Commission	86-154-TC	Dell Telephone Cooperative Corporation	New Mexico State Corporation Commission Staff	February 1987	Revenue Requirement for Local Exchange Service (cross examined)
FERC	82-705-002, et al.	Arkansas Power & Light Company	Arkansas Municipal Power Association	August 1987	Wholesale Power Contract Terms and Rate Design Issues (settled)
FERC	ER87-612	Niagara Mohawk Power Corporation	Municipal Electric Utilities Association of New York State	February 1988	Electric Transmission Rates; Rate of Return on Equity (settled)
DC PSC	FC 870	Washington Gas & Light Company	District of Columbia Public Service Commission Staff	March 1988	Efficacy of WGL's Marketing Program; Attrition Allowance (cross examined)
NM State Corp Commission	88-25-TC	Roosevelt County Rural Telephone Company	New Mexico State Corporation Commission Staff	June 1988	Revenue Requirement for Local Exch. Service; ROR (cross examined)
NM State Corp Commission	88-92-TC	Baca Valley Telephone Company, Inc.	New Mexico State Corporation Commission Staff	October 1988	Revenue Requirement for Local Exch. Service; ROR (cross examined)
NM State Corp Commission	87-148-TC	Western New Mexico Telephone Company	New Mexico State Corporation Commission Staff	October 1988	Revenue Requirement for Local Exch. Service; ROR (cross examined)

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JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
NM State Corp Commission	88-202-TC	Mountain States Telephone & Telegraph Company	New Mexico State Corporation Commission Staff	October 1988	Revenue Requirement for Local Exch. Service; ROR (cross examined)
NM State Corp Commission	88-144-TC	Dell Telephone Company	New Mexico State Corporation Commission Staff	November 1988	Revenue Requirement for Local Exch. Service; ROR (cross examined)
NM State Corp Commission	87-54-TC	GTE Southwest, Inc.	New Mexico State Corporation Commission Staff	April 1989	Revenue Requirement for Local Exch. Service; Performance Based Regulation Plan (cross examined)
FERC	CP88-434-000	El Paso Natural Gas Company	City of Wilcox, Arizona	June 1989	Natural Gas Transmission Rate Issues (settled)
U.S. Court of Appeals for the DC Circuit	89-1439	Vermont Department of Public Service vs. FERC	Municipal Electric Utilities Association of New York State	August 1989	Allocation of Niagara/St. Lawrence Hydroelectric Preference Power (affidavit)
FERC	RP88-44-000	El Paso Natural Gas Company	City of Wilcox, Arizona	September 1989	Gas Transmission Rate Design Issues (settled)
FERC	RP88-262-000	Panhandle Eastern Pipe Line Company	Citizens Gas & Coke Utility; Indianapolis, Indiana	November 1989	Rate Design Issues (settled)
DC PSC	FC 889	Potomac Electric Power Company	District of Columbia Public Service Commission Staff	January 1990	Rate of Return Methodology (cross examined)
DC PSC	FC 890	Washington Gas Light Company	District of Columbia Public Service Commission Staff	February 1990	Rate of Return Methodology (stipulated)
FERC	CP89-470-000	Tennessee Gas Pipeline Company	Ad Hoc Customer Group	June 1990	Design of Gas Inventory Charge (settled)

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JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
NM State Corp Commission	90-36-TC	GTE Southwest, Inc.	New Mexico State Corporation Commission Staff	July 1990	Revenue Requirement for Local Exchange Service (cross examined)
CO PUC	90A-147E	Public Service Company of Colorado, Inc.	Office of Consumer Counsel; Attorney General	August 1990	Recovery of Demand Side Management Incentive Program Costs (cross examined)
NM State Corp Commission	90-86-TC	ConTel of the West, Inc.	New Mexico State Corporation Commission Staff	August 1990	Revenue Requirement for Local Exchange Service; Performance-Based Regulation Plan (cross examined)
FERC	CP89-1119-000	Texas Gas Transmission Company	Memphis Light, Gas & Water Division, City of Memphis, TN	September 1990	Rolled-in vs. Incremental Rates re: Pipeline Expansion (settled)
FERC	ER89-678-000, EL90-16-000	System Energy Resources Inc.	Cities of Conway, Osceola and West Memphis, Arkansas	November 1990	Rate of Return on Equity in SERI's Formula Rate (settled)
Johnson County Circuit Court, AR	CIV 90-104	City of Clarksville, AR vs. Lamar Water Users	City of Clarksville, Arkansas	October 1991	Litigation support re: City's Water Rates (cross examined)
FERC	RP90-104	Texas Gas Transmission Company	Memphis Light, Gas & Water Division, City of Memphis, TN	November 1991	Natural Gas Transmission Rate Design Issues (settled)
NM State Corp. Commission	92-79-TC	U S West, Inc.	New Mexico State Corporation Commission Staff	October 1992	E911 Tariff (cross examined)
IN Utility Regulatory Commission	CGA41	Citizens Gas & Coke Utility, Indianapolis, Indiana	Citizens Gas & Coke Utility	May 1994	Recovery of FERC-mandated Gas Supply Restructuring Costs in Retail Rates (cross examined)

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JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
FERC	EL94-71-000, ER94-1128	North Little Rock Cogeneration vs. Entergy Services	City of North Little Rock Electric Department	June 1994	Statement of City's Position in Complaint by a Cogenerator at FERC (affidavit)
NM State Corp. Commission	94-291-TC	GTE Southwest, Inc.	New Mexico State Corporation Commission Staff	January 1995	Revenue Requirement for Local Exchange Service (cross examined)
AR PSC	95-396-U	Entergy Power, Inc.	Arkansas Municipal Power Association	August 1995	Wholesale Market Power Issues (affidavit)
AR PSC	97-451-U	Generic Proceeding on Retail Competition	Arkansas Municipal Power Association	May 1998	Issues of Concern to Municipal Systems in re: Retail Competition in Arkansas (cross examined)
Regulatory Commission of Alaska	U-96-36	Anchorage Municipal Light & Power Dept. re: Purchase of Beluga River Gas Field	Anchorage Municipal Light & Power Department, City of Anchorage, Alaska	June 1998 & November 2001	Rate Stabilization Plan Proposed by Petitioner (cross examined at hearing in November 2001)
West Virginia State Court	95-C-214M	Mid-Atlantic Energy Co. v. Babcock Wilcox, et al.	Babcock Wilcox Corporation	September 1998	Litigation Support in Civil Action by a Failed Co-Generating Company (deposed before case settled)
U.S. District Court for the Eastern District of Arkansas	J-C-98-475	Craighead Electric Cooperative Corporation vs. City Water & Light Plant, Jonesboro, AR	City Water & Light Plant, Jonesboro, Arkansas	November 2000	Litigation Support for Defendant re: Plaintiff's Economic Damages Study (cross examined)
Regulatory Commission of Alaska	U-99-2	Goat Lake Hydro, Inc. Alaska Power Company	Alaska Power & Telephone Company	December 2000	Rate Stabilization Plan Proposed by Petitioner

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JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
FERC	ER06-1445-000	UGI Utilities, Inc.	UGI Utilities, Inc.	October 2007	Transmission Formula Rate
Circuit Court of Johnson County, AR	CV-2010-274	Independence County, AR Vs City of Clarksville, AR	City of Clarksville, AR	November 2010	Hydroelectric Rate-making Methodology (Formula Rate)
Montana Public Service Commission	Docket D2008.8.95	NorthWestern Energy	NorthWestern Energy	November 2011	Cost Allocation and Rate Design; Ancillary Services Generating Facility
FERC	ER10-1138-000	NorthWestern Energy	NorthWestern Energy	June 2012	Cost Allocation and Rate Design; Ancillary Services Generating Facility
FERC	ER13-247-000	Sierra Pacific Power Company	NV Energy, Inc.	March 2013	Transmission Cost of Service: Ancillaries Revenue Requirement, OATT Schedules 3,5,6
FERC	ER13-255-000	Nevada Power Company	NV Energy, Inc.	March 2013	Transmission Cost of Service: Ancillaries Revenue Requirement, OATT Schedules 3,5,6

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PSEG POWER, LLC
REACTIVE REVENUE REQUIREMENT ANALYSIS

Exhibit No. PSEG-3
Schedule 1

SUMMARY -- ANNUAL REACTIVE REVENUE REQUIREMENT BY FACILITY/UNIT
2014 TEST PERIOD

	Facility/Unit	% Owned	Primary Fuel	KW Capability	Fixed Capability Component	Heating Losses Component	Total Annual Reactive Revenue Requirement	Generator/ Exciter share of Turbogenerator	Basis	Allocation of Accessories to Dual Use	Basis	Share of Remaining Plant Allocable	Basis
	(A)	(B)	(C)	(D)	(E)	(F)	(G) = (E) + (F)						
1	Bergen 1	100.00	Gas	638,000	$ 2,925,105	$ 28,652	$ 2,953,757	25.00%	Mfg. letter	0.00%	Per Books	0.14%	PSEG Analysis
2	Bergen 2	100.00	Gas	560,000	2,330,193	31,021	$ 2,361,214	14.47%	Mfg. letter	13.98%	(analysis)	0.14%	PSEG Analysis
3	Linden 1 & 2	100.00	Gas	1,300,000	8,589,078	68,593	$ 8,657,672	14.46%	Mfg. letter	19.03%	(analysis)	0.14%	PSEG Analysis
4	Hudson 2	100.00	Coal	620,000	1,386,352	7,266	$ 1,393,617	DA	Per Books	0.00%	Per Books	0.14%	PSEG Analysis
5	Mercer 1	100.00	Coal	316,000	318,855	2,290	$ 321,145	DA	Per Books	0.00%	Per Books	0.14%	PSEG Analysis
6	Mercer 2	100.00	Coal	316,000	969,405	3,168	$ 972,573	DA	Per Books	0.00%	Per Books	0.14%	PSEG Analysis
7	Conemaugh 1 & 2	22.51	Coal	382,670	482,544	14,470	$ 497,014	22.00%	Mfg. letter	0.00%	Per Books	0.14%	PSEG Analysis
8	Keystone 1 & 2	22.84	Coal	388,280	559,507	12,524	$ 572,031	22.00%	Mfg. letter	0.00%	Per Books	0.14%	PSEG Analysis
9	Salem 1 & 2	57.41	Nuclear	1,336,505	2,200,674	46,757	$ 2,247,431	DA	Per Books	0.00%	Per Books	0.14%	PSEG Analysis
10	Hope Creek 1	100.00	Nuclear	1,172,000	4,602,764	39,360	$ 4,642,124	25.00%	Mfg. letter	0.00%	Per Books	0.14%	PSEG Analysis
11	Peach Bottom 2 & 3	50.00	Nuclear	1,121,500	6,139,449	65,956	$ 6,205,405	25.00%	Mfg. letter	0.00%	Per Books	0.14%	PSEG Analysis
12	Sewaren 1 - 4	100.00	Gas	453,000	1,377,492	1,431	$ 1,378,923	DA	Per Books	0.00%	Per Books	0.14%	PSEG Analysis
13	Burlington 12	100.00	Gas	171,000	1,041,234	1,271	$ 1,042,505	12.00%	Mfg. letter	0.00%	Per Books	0.14%	PSEG Analysis
14	Essex 9	100.00	Gas	83,000	1,051,348	208	$ 1,051,556	DA	Per Books	0.00%	Per Books	0.14%	PSEG Analysis
15	Kearny 12,13,14	100.00	Gas	453,000	2,940,897	4,692	$ 2,945,589	12.00%	Mfg. letter	0.00%	Per Books	0.14%	PSEG Analysis
16	Linden 5,6,7,8	100.00	Gas	348,000	1,121,530	879	$ 1,122,410	19.00%	Mfg. letter	0.00%	Per Books	0.14%	PSEG Analysis
17	Yards Creek	50.00	Pumped Stor.	210,000	302,956	3,103	$ 306,059	15.00%	Consultant**	0.00%	Per Books	0.14%	PSEG Analysis
18	Total			9,868,955	$ 38,339,383	$ 331,641	$ 38,671,025						
19	Monthly				$ 3,194,949	$ 49,093	$ 3,222,585						

Sources: Column (E) -- Schedule 3, pages 1 - 34.
Column (F) -- Workpaper -- Incremental Heating Losses; Column (D)
** Letter from Axford Consulting in lieu of manufacturer letter because GE's pump storage division was sold off, indicated an allocation of between 25% and 45%, conservatively assuming 15%
NOTE: DA denotes the use of a direct assignment for the generator/exciter investment which eliminates the need for a percent allocation

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PSEG POWER, LLC
REACTIVE REVENUE REQUIREMENT ANALYSIS

Capital Structure, Rate of Return and Income Tax Rates

	Ratio	Cost	WtdCost
Long-term Debt	31.48%	5.29%	1.67%
Common Equity	68.52%	10.50%	7.19%
			8.86%
Tax on Equity			4.97%
Pre-tax Cost of Capital			13.83%

Source: W/P - Development of Capital Structure and Debt Cost Rate

Income Tax Rates & Factors		
State	9.00%	
Federal	35.00%	
CIT	40.85%	(composite inc. tax)
GTF	59.15%	(gross-up tax factor)

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BERGEN-1 (COMBUSTION TURBINE; 4 SIEMENS V84.2; WESTINGHOUSE MODIFIED 1958 ORIGINAL ST)

2014 TEST PERIOD

1	Gross Book Investment (incl. allocated common)	$	450,748,478	
2	O&M	$	17,795,500	
3	Depreciation (incl. common depreciation)	$	12,223,940	
4	Real Estate Taxes & Property Insurance	$	817,639	
5	Turbogenerator Investment	$	318,699,249	(Acct 344)
6	Generator/Exciter share of Turbogenerator		25.00%	(per letter from Siemens)
7	Generator/Exciter Investment	$	79,674,812	(line 5 * line 6)
8	Accesssories Investment	$	71,862,703	(Acct 345)
9	Allocation of Accessories to Dual Use		0.00%	(none)
10	Accessories Allocated	$	-	(line 8 * line 9)
11	Step-up share of total investment		N/A	
12	Step-up Investment	$	1,546,379	(per books)
13	Total Dual-Use Investment	$	81,221,191	(line 7 + line 10 + line 12)
14	Reactive Allocator [@ weighted pf of all unit(s)]		21.38%	= 1 - pf^2, where pf = power factor = 0.8867
15	Dual-Use Investment Allocated to Reactive	$	17,362,094	(line 13 * line 14)
16	Balance of Plant Allocable	$	433,386,384	(line 1 - line 15)
17	Share of Remaining Plant Allocable		0.14%	Per PSEG Analysis
18	Balance of Plant Allocated	$	606,741	(line 16 * line 17)
19	Total Allocated Reactive Investment	$	17,968,835	(line 15 + line 18)

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	2.71%	(line 3 / line 1)
21	n = life of plant	36.9	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	0.40%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	3.67%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components			
24	Production Cost		3.95%	(line 2 / line 1)
25	RE Tax & Property Ins. Component		0.18%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate		0.40%	(line 22)
27	Levelized Tax Factor		3.67%	(line 23)
28	Return		8.86%	(Schedule 2)
29	Prepayments * Pre-tax ROR / Plant =		0.00%	(WP-Prepayments & Schedule 2)/line 1
30	CWC=1/8 O&M*Pre-tax ROR / Plant =		0.07%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment		-0.86%	- (line 44 (k) / 36 (c)) Page 2
32		FCR Total	16.28%	(sum 24 through 31)
33	Annual Reactive Revenue Requirement	$	2,925,105	(line 19 * line 32)
34	kW capacity		638,000	Rated Capacity
35	Annual Vars Rate ($/mW)	$	4,585	(line 33 / line 34 * 1000)

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BERGEN-1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		450,748,478	Line 1					NPV of Col (j)>	41,742,340	
37	Asset Service Life		36.8742	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost R		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
		Line 36 / 37		(b) * (c)	((d) - (b)) * Line 38	Accum. (e)	= (f) * (Line 40)	= (f) * (Line 41)	= (g) * (Line 39)	(g) + (h) + (i)	PMT of NPV col. (j)
43											
44	1	12,223,940	3.750%	16,903,068	1,911,424	1,911,424	31,829	137,513	21,981	191,323	3,867,173
45	2	12,223,940	7.219%	32,539,533	8,298,919	10,210,343	170,021	734,558	117,419	1,021,998	3,867,173
46	3	12,223,940	6.677%	30,096,476	7,300,931	17,511,274	291,595	1,259,805	201,380	1,752,780	3,867,173
47	4	12,223,940	6.177%	27,842,734	6,380,277	23,891,551	397,838	1,718,818	274,754	2,391,410	3,867,173
48	5	12,223,940	5.713%	25,751,261	5,525,910	29,417,461	489,854	2,116,366	338,302	2,944,522	3,867,173
49	6	12,223,940	5.285%	23,822,057	4,737,831	34,155,292	568,748	2,457,217	392,787	3,418,752	3,867,173
50	7	12,223,940	4.888%	22,032,586	4,006,832	38,162,123	635,469	2,745,479	438,866	3,819,813	3,867,173
51	8	12,223,940	4.522%	20,382,846	3,332,913	41,495,036	690,968	2,985,257	477,194	4,153,419	3,867,173
52	9	12,223,940	4.462%	20,112,397	3,222,435	44,717,471	744,627	3,217,087	514,252	4,475,967	3,867,173
53	10	12,223,940	4.461%	20,107,890	3,220,593	47,938,064	798,256	3,448,784	551,289	4,798,330	3,867,173
54	11	12,223,940	4.462%	20,112,397	3,222,435	51,160,499	851,916	3,680,614	588,347	5,120,877	3,867,173
55	12	12,223,940	4.461%	20,107,890	3,220,593	54,381,092	905,544	3,912,312	625,384	5,443,241	3,867,173
56	13	12,223,940	4.462%	20,112,397	3,222,435	57,603,527	959,204	4,144,142	662,443	5,765,788	3,867,173
57	14	12,223,940	4.461%	20,107,890	3,220,593	60,824,120	1,012,833	4,375,839	699,479	6,088,151	3,867,173
58	15	12,223,940	4.462%	20,112,397	3,222,435	64,046,555	1,066,492	4,607,669	736,538	6,410,699	3,867,173
59	16	12,223,940	4.461%	20,107,890	3,220,593	67,267,148	1,120,121	4,839,367	773,575	6,733,062	3,867,173
60	17	12,223,940	4.462%	20,112,397	3,222,435	70,489,582	1,173,780	5,071,197	810,633	7,055,610	3,867,173
61	18	12,223,940	4.461%	20,107,890	3,220,593	73,710,176	1,227,409	5,302,895	847,670	7,377,973	3,867,173
62	19	12,223,940	4.462%	20,112,397	3,222,435	76,932,610	1,281,068	5,534,725	884,728	7,700,521	3,867,173
63	20	12,223,940	4.461%	20,107,890	3,220,593	80,153,204	1,334,697	5,766,422	921,765	8,022,884	3,867,173
64	21	12,223,940	2.231%	10,056,199	-885,523	79,267,681	1,319,952	5,702,715	911,581	7,934,248	3,867,173
65	22	12,223,940	0.000%	0	-4,993,480	74,274,201	1,236,801	5,343,472	854,156	7,434,429	3,867,173
66	23	12,223,940	0.000%	0	-4,993,480	69,280,722	1,153,650	4,984,229	796,731	6,934,610	3,867,173
67	24	12,223,940	0.000%	0	-4,993,480	64,287,242	1,070,500	4,624,985	739,305	6,434,790	3,867,173
68	25	12,223,940	0.000%	0	-4,993,480	59,293,762	987,349	4,265,742	681,880	5,934,971	3,867,173
69	26	12,223,940	0.000%	0	-4,993,480	54,300,283	904,199	3,906,498	624,455	5,435,152	3,867,173
70	27	12,223,940	0.000%	0	-4,993,480	49,306,803	821,048	3,547,255	567,030	4,935,333	3,867,173
71	28	12,223,940	0.000%	0	-4,993,480	44,313,324	737,898	3,188,011	509,605	4,435,514	3,867,173
72	29	12,223,940	0.000%	0	-4,993,480	39,319,844	654,747	2,828,768	452,180	3,935,695	3,867,173
73	30	12,223,940	0.000%	0	-4,993,480	34,326,364	571,597	2,469,525	394,754	3,435,876	3,867,173
74	31	12,223,940	0.000%	0	-4,993,480	29,332,885	488,446	2,110,281	337,329	2,936,056	3,867,173
75	32	12,223,940	0.000%	0	-4,993,480	24,339,405	405,295	1,751,038	279,904	2,436,237	3,867,173
76	33	12,223,940	0.000%	0	-4,993,480	19,345,925	322,145	1,391,794	222,479	1,936,418	3,867,173
77	34	12,223,940	0.000%	0	-4,993,480	14,352,446	238,994	1,032,551	165,054	1,436,599	3,867,173
78	35	12,223,940	0.000%	0	-4,993,480	9,358,966	155,844	673,307	107,628	936,780	3,867,173
79	36	12,223,940	0.000%	0	-4,993,480	4,365,487	72,693	314,064	50,203	436,961	3,867,173
80	37	12,223,940	0.000%	0	-4,993,480	-627,993	-10,457	-45,179	-7,222	-62,859	3,867,173
81	38		0.000%	0	0						
82											
83		452,285,793	100.00%	450,748,478	-627,993						

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BERGEN-2 COMBINED CYCLE
2014 TEST PERIOD

1	Gross Book Investment (incl. allocated common)	$	367,228,644	
2	O&M	$	17,795,500	
3	Depreciation (incl. common depreciation)	$	9,363,273	
4	Real Estate Taxes & Property Insurance	$	666,138	
5	Turbogenerator Investment	$	267,702,291	(Acct 344)
6	Generator/Exciter share of Turbogenerator		14.47%	(Manufacturer letter)
7	Generator/Exciter Investment	$	38,724,612	(line 5 * line 6)
8	Accesssories Investment	$	41,024,167	(Acct 345-adjusted per detailed analysis)
9	Allocation of Accessories to Dual Use		13.98%	(Internal analysis)
10	Accessories Allocated	$	5,735,179	(line 8 * line 9)
11	Step-up share of total investment		N/A	
12	Step-up Investment	$	2,855,268	(per books)
13	Total Dual-Use Investment	$	47,315,058	(line 7 + line 10 + line 12)
14	Reactive Allocator [@ weighted pf of all unit(s)]		27.75%	= 1 - pf^2, where pf = power factor = 0.85
15	Dual-Use Investment Allocated to Reactive	$	13,129,929	(line 13 * line 14)
16	Balance of Plant Allocable	$	354,098,715	(line 1 - line 15)
17	Share of Remaining Plant Allocable		0.14%	Per PSEG Analysis
18	Balance of Plant Allocated	$	495,738	(line 16 * line 17)
19	Total Allocated Reactive Investment	$	13,625,667	(line 15 + line 18)

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	2.55%	(line 3 / line 1)
21	n = life of plant	39.2	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	0.33%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	3.72%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components		
24	Production Cost	4.85%	(line 2 / line 1)
25	RE Tax & Property Ins. Component	0.18%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate	0.33%	(line 22)
27	Levelized Tax Factor	3.72%	(line 23)
28	Return	8.86%	(Cap. Struct & Taxes Sch)
29	Prepayments * Pre-tax ROR / Plant =	0.00%	(WP-Prepayments & Schedule 2)/line 1
30	CWC=1/8 O&M*Pre-tax ROR / Plant =	0.08%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment	-0.92%	- (line 44 (k) / 36 (c)) Page 2
32	FCR Total	17.10%	(sum 24 through 31)

33	Annual Reactive Revenue Requirement	$	2,330,193	(line 19 * line 32)
34	kW capacity		560,000	Rated Capacity
35	Annual Vars Rate ($/mW)	$	4,161	(line 33 / line 34 * 1000)

From GE Letter - April 17, 2008 to PSEG Power, LLC

			Unit Price	Gen. %
36	Frame 7FA	$	32,625,300	14.0%
37	Frame 7FA	$	32,625,300	14.0%
38	D11 STG	$	19,797,000	16.0%
39	Total	$	85,047,600	14.5% <weighted average

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BERGEN 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		367,228,644	Line 1					NPV of Col (j)>	36,818,447	
37	Asset Service Life		39.2201	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return on Eq		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost Rate		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
		Line 36 / 37		(b) * (c)	((d) - (b)) * Line 38	Accum. (e)	= (f) * (Line 40)	= (f) * (Line 41)	= (g) * (Line 39)	(g) + (h) + (i)	PMT of NPV col. (j)
43											
44	1	9,363,273	3.750%	13,771,074	1,800,587	1,800,587	29,983	129,539	20,707	180,229	3,383,083
45	2	9,363,273	7.219%	26,510,236	7,004,534	8,805,121	146,621	633,462	101,259	881,343	3,383,083
46	3	9,363,273	6.677%	24,519,857	6,191,464	14,996,585	249,720	1,078,892	172,461	1,501,074	3,383,083
47	4	9,363,273	6.177%	22,683,713	5,441,400	20,437,985	340,330	1,470,360	235,038	2,045,727	3,383,083
48	5	9,363,273	5.713%	20,979,772	4,745,340	25,183,324	419,348	1,811,751	289,609	2,520,709	3,383,083
49	6	9,363,273	5.285%	19,408,034	4,103,285	29,286,609	487,675	2,106,952	336,797	2,931,424	3,383,083
50	7	9,363,273	4.888%	17,950,136	3,507,733	32,794,342	546,086	2,359,307	377,136	3,282,529	3,383,083
51	8	9,363,273	4.522%	16,606,079	2,958,686	35,753,029	595,353	2,572,162	411,161	3,578,677	3,383,083
52	9	9,363,273	4.462%	16,385,742	2,868,678	38,621,707	643,122	2,778,542	444,151	3,865,815	3,383,083
53	10	9,363,273	4.461%	16,382,070	2,867,178	41,488,885	690,866	2,984,814	477,124	4,152,804	3,383,083
54	11	9,363,273	4.462%	16,385,742	2,868,678	44,357,564	738,634	3,191,194	510,114	4,439,942	3,383,083
55	12	9,363,273	4.461%	16,382,070	2,867,178	47,224,742	786,378	3,397,466	543,086	4,726,930	3,383,083
56	13	9,363,273	4.462%	16,385,742	2,868,678	50,093,421	834,147	3,603,846	576,076	5,014,069	3,383,083
57	14	9,363,273	4.461%	16,382,070	2,867,178	52,960,599	881,891	3,810,118	609,049	5,301,057	3,383,083
58	15	9,363,273	4.462%	16,385,742	2,868,678	55,829,277	929,659	4,016,498	642,039	5,588,196	3,383,083
59	16	9,363,273	4.461%	16,382,070	2,867,178	58,696,456	977,403	4,222,770	675,011	5,875,184	3,383,083
60	17	9,363,273	4.462%	16,385,742	2,868,678	61,565,134	1,025,172	4,429,150	708,001	6,162,323	3,383,083
61	18	9,363,273	4.461%	16,382,070	2,867,178	64,432,312	1,072,916	4,635,422	740,974	6,449,311	3,383,083
62	19	9,363,273	4.462%	16,385,742	2,868,678	67,300,991	1,120,684	4,841,802	773,964	6,736,450	3,383,083
63	20	9,363,273	4.461%	16,382,070	2,867,178	70,168,169	1,168,428	5,048,074	806,936	7,023,438	3,383,083
64	21	9,363,273	2.231%	8,192,871	-478,109	69,690,060	1,160,467	5,013,677	801,438	6,975,582	3,383,083
65	22	9,363,273	0.000%	0	-3,824,897	65,865,163	1,096,775	4,738,505	757,452	6,592,731	3,383,083
66	23	9,363,273	0.000%	0	-3,824,897	62,040,265	1,033,084	4,463,332	713,465	6,209,881	3,383,083
67	24	9,363,273	0.000%	0	-3,824,897	58,215,368	969,392	4,188,159	669,479	5,827,030	3,383,083
68	25	9,363,273	0.000%	0	-3,824,897	54,390,471	905,701	3,912,987	625,492	5,444,179	3,383,083
69	26	9,363,273	0.000%	0	-3,824,897	50,565,574	842,009	3,637,814	581,506	5,061,329	3,383,083
70	27	9,363,273	0.000%	0	-3,824,897	46,740,677	778,318	3,362,641	537,519	4,678,478	3,383,083
71	28	9,363,273	0.000%	0	-3,824,897	42,915,779	714,626	3,087,469	493,533	4,295,628	3,383,083
72	29	9,363,273	0.000%	0	-3,824,897	39,090,882	650,935	2,812,296	449,546	3,912,777	3,383,083
73	30	9,363,273	0.000%	0	-3,824,897	35,265,985	587,243	2,537,123	405,560	3,529,926	3,383,083
74	31	9,363,273	0.000%	0	-3,824,897	31,441,088	523,551	2,261,951	361,574	3,147,076	3,383,083
75	32	9,363,273	0.000%	0	-3,824,897	27,616,191	459,860	1,986,778	317,587	2,764,225	3,383,083
76	33	9,363,273	0.000%	0	-3,824,897	23,791,293	396,168	1,711,605	273,601	2,381,374	3,383,083
77	34	9,363,273	0.000%	0	-3,824,897	19,966,396	332,477	1,436,433	229,614	1,998,524	3,383,083
78	35	9,363,273	0.000%	0	-3,824,897	16,141,499	268,785	1,161,260	185,628	1,615,673	3,383,083
79	36	9,363,273	0.000%	0	-3,824,897	12,316,602	205,094	886,087	141,641	1,232,822	3,383,083
80	37	9,363,273	0.000%	0	-3,824,897	8,491,705	141,402	610,914	97,655	849,972	3,383,083
81	38	9,363,273	0.000%	0	-3,824,897	4,666,807	77,711	335,742	53,668	467,121	3,383,083
82	39	9,363,273	0.000%	0	-3,824,897	841,910	14,019	60,569	9,682	84,270	3,383,083
83		365,167,664	100.00%	367,228,644	4,666,807						

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LINDEN 1 & 2 (IDENTICAL, EACH CONSISTING OF TWO GE 7FA CTs AND ONE GE D11 STEAM TURBINE

2014 TEST PERIOD

1	Gross Book Investment (incl. allocated common)	$ 1,100,431,647		
2	O&M	$ 98,678,000		
3	Depreciation (incl. common depreciation)	$ 27,640,742		
4	Real Estate Taxes & Property Insurance	$ 2,465,929		
5	Turbogenerator Investment	$ 852,549,147	(Acct 344)	
6	Generator/Exciter share of Turbogenerator	14.46%	(Manufacturer letter)	
7	Generator/Exciter Investment	$ 123,260,590	(line 5 * line 6)	
8	Accesssories Investment	$ 49,369,888	(Acct 345-adjusted per detailed analysis)	
9	Allocation of Accessories to Dual Use	19.03%	(Internal analysis)	
10	Accessories Allocated	$ 9,395,090	(line 8 * line 9)	
11	Step-up share of total investment	N/A		
12	Step-up Investment	$ 7,184,622	(per books)	
13	Total Dual-Use Investment	$ 139,840,301	(line 7 + line 10 + line 12)	
14	Reactive Allocator [@ weighted pf of all unit(s)]	27.75%	= 1 - pf^2, where pf = power factor = 0.85	
15	Dual-Use Investment Allocated to Reactive	$ 38,805,684	(line 13 * line 14)	
16	Balance of Plant Allocable	1,061,625,963	(line 1 - line 15)	
17	Share of Remaining Plant Allocable	0.14%	Per PSEG Analysis	
18	Balance of Plant Allocated	$ 1,486,276	(line 16 * line 17)	
19	Total Allocated Reactive Investment	$ 40,291,960	(line 15 + line 18)	

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	2.51%	(line 3 / line 1)
21	n = life of plant	39.8	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	0.31%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	3.74%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components			
24	Production Cost		8.97%	(line 2 / line 1)
25	RE Tax & Property Ins. Component		0.22%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate		0.31%	(line 22)
27	Levelized Tax Factor		3.74%	(line 23)
28	Return		8.86%	(Cap. Struct & Taxes Sch)
29	Prepayments * Pre-tax ROR / Plant =		0.00%	(WP-Prepayments & Schedule 2)/line 1
30	CWC=1/8 O&M*Pre-tax ROR / Plant =		0.15%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment		-0.94%	- (line 44 (k) / 36 (c)) Page 2
32		FCR Total	21.32%	(sum 24 through 31)
33	Annual Reactive Revenue Requirement	$ 8,589,078		(line 19 * line 32)
34	kW capacity	1,300,000		Rated Capacity
35	Annual Vars Rate ($/mW)	$ 6,607		(line 33 / line 34 * 1000)

	From GE Letter - April 17, 2008 to PSEG Power, LLC		Unit Price	Gen. %	
36		Frame 7FA	$ 36,577,000	14.0%	
37		Frame 7FA	$ 36,577,000	14.0%	
38		Frame 7FA	$ 36,577,000	14.0%	
39		Frame 7FA	$ 36,577,000	14.0%	
40		D11 STG	$ 21,721,000	16.0%	
41		D11 STG	$ 21,721,000	16.0%	
42		Total	$ 189,750,000	14.5%	<weighted average

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Linden 1 & 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		1,100,431,647	Line 1					NPV of Col (j)>	112,310,348	
37	Asset Service Life		39.8119	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return on Eq		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost Rate		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
					((d) - (b)) *		= (f) * (Line	= (f) * (Line	= (g) * (Line		PMT of NPV
		Line 36 / 37		(b) * (c)	Line 38	Accum. (e)	40)	41)	39)	(g) + (h) + (i)	col. (j)
43											
44	1	27,640,742	3.750%	41,266,187	5,565,994	5,565,994	92,684	400,432	64,009	557,125	10,300,947
45	2	27,640,742	7.219%	79,440,161	21,160,062	26,726,056	445,038	1,922,739	307,351	2,675,128	10,300,947
46	3	27,640,742	6.677%	73,475,821	18,723,630	45,449,686	756,820	3,269,764	522,673	4,549,257	10,300,947
47	4	27,640,742	6.177%	67,973,663	16,475,998	61,925,684	1,031,176	4,455,089	712,147	6,198,412	10,300,947
48	5	27,640,742	5.713%	62,867,660	14,390,196	76,315,880	1,270,799	5,490,355	877,635	7,638,789	10,300,947
49	6	27,640,742	5.285%	58,157,813	12,466,223	88,782,103	1,478,384	6,387,207	1,020,997	8,886,588	10,300,947
50	7	27,640,742	4.888%	53,789,099	10,681,604	99,463,707	1,656,252	7,155,668	1,143,836	9,955,756	10,300,947
51	8	27,640,742	4.522%	49,761,519	9,036,337	108,500,044	1,806,724	7,805,765	1,247,754	10,860,243	10,300,947
52	9	27,640,742	4.462%	49,101,260	8,766,622	117,266,666	1,952,704	8,436,457	1,348,571	11,737,732	10,300,947
53	10	27,640,742	4.461%	49,090,256	8,762,126	126,028,792	2,098,609	9,066,827	1,449,335	12,614,771	10,300,947
54	11	27,640,742	4.462%	49,101,260	8,766,622	134,795,413	2,244,590	9,697,519	1,550,152	13,492,261	10,300,947
55	12	27,640,742	4.461%	49,090,256	8,762,126	143,557,540	2,390,495	10,327,889	1,650,917	14,369,300	10,300,947
56	13	27,640,742	4.462%	49,101,260	8,766,622	152,324,161	2,536,475	10,958,581	1,751,733	15,246,790	10,300,947
57	14	27,640,742	4.461%	49,090,256	8,762,126	161,086,287	2,682,381	11,588,951	1,852,498	16,123,829	10,300,947
58	15	27,640,742	4.462%	49,101,260	8,766,622	169,852,909	2,828,361	12,219,643	1,953,314	17,001,318	10,300,947
59	16	27,640,742	4.461%	49,090,256	8,762,126	178,615,035	2,974,266	12,850,013	2,054,079	17,878,358	10,300,947
60	17	27,640,742	4.462%	49,101,260	8,766,622	187,381,657	3,120,246	13,480,705	2,154,895	18,755,847	10,300,947
61	18	27,640,742	4.461%	49,090,256	8,762,126	196,143,783	3,266,152	14,111,075	2,255,660	19,632,887	10,300,947
62	19	27,640,742	4.462%	49,101,260	8,766,622	204,910,405	3,412,132	14,741,767	2,356,477	20,510,376	10,300,947
63	20	27,640,742	4.461%	49,090,256	8,762,126	213,672,531	3,558,037	15,372,137	2,457,241	21,387,416	10,300,947
64	21	27,640,742	2.231%	24,550,630	-1,262,311	212,410,220	3,537,018	15,281,323	2,442,725	21,261,065	10,300,947
65	22	27,640,742	0.000%	0	-11,291,243	201,118,977	3,348,998	14,469,003	2,312,875	20,130,876	10,300,947
66	23	27,640,742	0.000%	0	-11,291,243	189,827,733	3,160,978	13,656,682	2,183,025	19,000,686	10,300,947
67	24	27,640,742	0.000%	0	-11,291,243	178,536,490	2,972,958	12,844,362	2,053,176	17,870,496	10,300,947
68	25	27,640,742	0.000%	0	-11,291,243	167,245,247	2,784,938	12,032,042	1,923,326	16,740,306	10,300,947
69	26	27,640,742	0.000%	0	-11,291,243	155,954,004	2,596,919	11,219,721	1,793,476	15,610,116	10,300,947
70	27	27,640,742	0.000%	0	-11,291,243	144,662,760	2,408,899	10,407,401	1,663,627	14,479,927	10,300,947
71	28	27,640,742	0.000%	0	-11,291,243	133,371,517	2,220,879	9,595,081	1,533,777	13,349,737	10,300,947
72	29	27,640,742	0.000%	0	-11,291,243	122,080,274	2,032,859	8,782,760	1,403,927	12,219,547	10,300,947
73	30	27,640,742	0.000%	0	-11,291,243	110,789,031	1,844,839	7,970,440	1,274,078	11,089,357	10,300,947
74	31	27,640,742	0.000%	0	-11,291,243	99,497,788	1,656,820	7,158,120	1,144,228	9,959,168	10,300,947
75	32	27,640,742	0.000%	0	-11,291,243	88,206,544	1,468,800	6,345,800	1,014,378	8,828,978	10,300,947
76	33	27,640,742	0.000%	0	-11,291,243	76,915,301	1,280,780	5,533,479	884,529	7,698,788	10,300,947
77	34	27,640,742	0.000%	0	-11,291,243	65,624,058	1,092,760	4,721,159	754,679	6,568,598	10,300,947
78	35	27,640,742	0.000%	0	-11,291,243	54,332,815	904,740	3,908,839	624,829	5,438,408	10,300,947
79	36	27,640,742	0.000%	0	-11,291,243	43,041,571	716,721	3,096,518	494,980	4,308,219	10,300,947
80	37	27,640,742	0.000%	0	-11,291,243	31,750,328	528,701	2,284,198	365,130	3,178,029	10,300,947
81	38	27,640,742	0.000%	0	-11,291,243	20,459,085	340,681	1,471,878	235,280	2,047,839	10,300,947
82	39	27,640,742	0.000%	0	-11,291,243	9,167,842	152,661	659,557	105,430	917,649	10,300,947
83	40		0.000%	0	0	9,167,842	152,661	659,557	105,430	917,649	10,300,947
84		1,077,988,950	100.00%	1,100,431,647	20,459,085						

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HUDSON 2 (COAL/GAS STEAM)

2014 TEST PERIOD

1	Gross Book Investment (incl. allocated common)	$	1,231,789,410	
2	O&M	$	50,040,000	
3	Depreciation (incl. common depreciation)	$	35,780,996	
4	Real Estate Taxes & Property Insurance	$	2,461,214	
5	Turbogenerator Investment		N/A	(Acct 314)
6	Generator/Exciter share of Turbogenerator		DA	
7	Generator/Exciter Investment	$	33,866,637	(Per Book)
8	Accesssories Investment	$	17,913,039	(Acct 315)
9	Allocation of Accessories to Dual Use		0.00%	(none)
10	Accessories Allocated	$	-	(line 8 * line 9)
11	Step-up share of total investment		N/A	
12	Step-up Investment	$	1,240,805	(per books)
13	Total Dual-Use Investment	$	35,107,442	(line 7 + line 10 + line 12)
14	Reactive Allocator [@ weighted pf of all unit(s)]		19.00%	= 1 - pf^2, where pf = power factor = 0.9
15	Dual-Use Investment Allocated to Reactive	$	6,670,414	(line 13 * line 14)
16	Balance of Plant Allocable	$	1,225,118,996	(line 1 - line 15)
17	Share of Remaining Plant Allocable		0.14%	Per PSEG Analysis
18	Balance of Plant Allocated	$	1,715,167	(line 16 * line 17)
19	Total Allocated Reactive Investment	$	8,385,581	(line 15 + line 18)

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	2.90%	(line 3 / line 1)
21	n = life of plant	34.4	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	0.50%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	3.62%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components			
24	Production Cost		4.06%	(line 2 / line 1)
25	RE Tax & Property Ins. Component		0.20%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate		0.50%	(line 22)
27	Levelized Tax Factor		3.62%	(line 23)
28	Return		8.86%	(Cap. Struct & Taxes Sch)
29	Prepayments * Pre-tax ROR / Plant =		0.00%	(None)
30	CWC=1/8 O&M*Pre-tax ROR / Plant =		0.07%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment		-0.79%	- (line 44 (k) / 36 (c)) Page 2
32	FCR Total		16.53%	(sum 24 through 31)
33	Annual Reactive Revenue Requirement	$	1,386,352	(line 19 * line 32)
34	kW capacity		620,000	Rated Capacity
35	Annual Vars Rate ($/mW)	$	2,236	(line 33 / line 34 * 1000)

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Hudson 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		1,231,789,410	Line 1					NPV of Col (j)>	103,282,206	
37	Asset Service Life		34.4258	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return on Eq		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost Rate		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
					((d) - (b)) *		= (f) * (Line	= (f) * (Line	= (g) * (Line		PMT of NPV
		Line 36 / 37		(b) * (c)	Line 38	Accum. (e)	40)	41)	39)	(g) + (h) + (i)	col. (j)
43											
44	1	35,780,996	3.750%	46,192,103	4,252,937	4,252,937	70,819	305,967	48,909	425,695	9,670,583
45	2	35,780,996	7.219%	88,922,878	21,708,459	25,961,396	432,305	1,867,728	298,557	2,598,589	9,670,583
46	3	35,780,996	6.677%	82,246,579	18,981,191	44,942,586	748,376	3,233,282	516,841	4,498,500	9,670,583
47	4	35,780,996	6.177%	76,087,632	16,465,261	61,407,847	1,022,553	4,417,834	706,192	6,146,579	9,670,583
48	5	35,780,996	5.713%	70,372,129	14,130,478	75,538,325	1,257,851	5,434,416	868,693	7,560,960	9,670,583
49	6	35,780,996	5.285%	65,100,070	11,976,842	87,515,167	1,457,287	6,296,060	1,006,427	8,759,775	9,670,583
50	7	35,780,996	4.888%	60,209,866	9,979,194	97,494,361	1,623,459	7,013,988	1,121,188	9,758,636	9,670,583
51	8	35,780,996	4.522%	55,701,517	8,137,533	105,631,893	1,758,964	7,599,423	1,214,770	10,573,157	9,670,583
52	9	35,780,996	4.462%	54,962,443	7,835,621	113,467,515	1,889,441	8,163,137	1,304,880	11,357,458	9,670,583
53	10	35,780,996	4.461%	54,950,126	7,830,589	121,298,104	2,019,835	8,726,489	1,394,932	12,141,256	9,670,583
54	11	35,780,996	4.462%	54,962,443	7,835,621	129,133,726	2,150,312	9,290,203	1,485,042	12,925,558	9,670,583
55	12	35,780,996	4.461%	54,950,126	7,830,589	136,964,315	2,280,706	9,853,556	1,575,094	13,709,356	9,670,583
56	13	35,780,996	4.462%	54,962,443	7,835,621	144,799,936	2,411,183	10,417,270	1,665,204	14,493,657	9,670,583
57	14	35,780,996	4.461%	54,950,126	7,830,589	152,630,526	2,541,577	10,980,622	1,755,256	15,277,455	9,670,583
58	15	35,780,996	4.462%	54,962,443	7,835,621	160,466,147	2,672,054	11,544,336	1,845,366	16,061,757	9,670,583
59	16	35,780,996	4.461%	54,950,126	7,830,589	168,296,737	2,802,448	12,107,688	1,935,418	16,845,554	9,670,583
60	17	35,780,996	4.462%	54,962,443	7,835,621	176,132,358	2,932,925	12,671,403	2,025,528	17,629,856	9,670,583
61	18	35,780,996	4.461%	54,950,126	7,830,589	183,962,947	3,063,319	13,234,755	2,115,580	18,413,654	9,670,583
62	19	35,780,996	4.462%	54,962,443	7,835,621	191,798,569	3,193,796	13,798,469	2,205,690	19,197,955	9,670,583
63	20	35,780,996	4.461%	54,950,126	7,830,589	199,629,158	3,324,190	14,361,821	2,295,742	19,981,753	9,670,583
64	21	35,780,996	2.231%	27,481,222	-3,390,458	196,238,700	3,267,732	14,117,903	2,256,752	19,642,387	9,670,583
65	22	35,780,996	0.000%	0	-14,616,537	181,622,164	3,024,340	13,066,353	2,088,661	18,179,355	9,670,583
66	23	35,780,996	0.000%	0	-14,616,537	167,005,627	2,780,948	12,014,803	1,920,570	16,716,322	9,670,583
67	24	35,780,996	0.000%	0	-14,616,537	152,389,090	2,537,556	10,963,253	1,752,480	15,253,289	9,670,583
68	25	35,780,996	0.000%	0	-14,616,537	137,772,553	2,294,164	9,911,702	1,584,389	13,790,256	9,670,583
69	26	35,780,996	0.000%	0	-14,616,537	123,156,016	2,050,772	8,860,152	1,416,298	12,327,223	9,670,583
70	27	35,780,996	0.000%	0	-14,616,537	108,539,479	1,807,380	7,808,602	1,248,208	10,864,190	9,670,583
71	28	35,780,996	0.000%	0	-14,616,537	93,922,942	1,563,988	6,757,052	1,080,117	9,401,157	9,670,583
72	29	35,780,996	0.000%	0	-14,616,537	79,306,406	1,320,596	5,705,501	912,026	7,938,124	9,670,583
73	30	35,780,996	0.000%	0	-14,616,537	64,689,869	1,077,204	4,653,951	743,936	6,475,091	9,670,583
74	31	35,780,996	0.000%	0	-14,616,537	50,073,332	833,812	3,602,401	575,845	5,012,058	9,670,583
75	32	35,780,996	0.000%	0	-14,616,537	35,456,795	590,420	2,550,851	407,754	3,549,025	9,670,583
76	33	35,780,996	0.000%	0	-14,616,537	20,840,258	347,028	1,499,300	239,664	2,085,992	9,670,583
77	34	35,780,996	0.000%	0	-14,616,537	6,223,721	103,636	447,750	71,573	622,959	9,670,583
78	35		0.000%	0	0	6,223,721	103,636	447,750	71,573	622,959	9,670,583
79	36		0.000%	0	0						
80	37		0.000%	0	0						
81	38		0.000%	0	0						
82											
83		1,216,553,862	100.00%	1,231,789,410	6,223,721						

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MERCER 1 (COAL/GAS STEAM)
2014 TEST PERIOD

1	Gross Book Investment (incl. allocated common)	$	475,300,515	
2	O&M	$	18,035,500	
3	Depreciation (incl. common depreciation)	$	12,416,697	
4	Real Estate Taxes & Property Insurance	$	1,100,342	
5	Turbogenerator Investment		N/A	
6	Generator/Exciter share of Turbogenerator		DA	
7	Generator/Exciter Investment	$	4,738,463	(per books)
8	Accesssories Investment	$	1,404,622	(Acct 315)
9	Allocation of Accessories to Dual Use		0.00%	(none)
10	Accessories Allocated	$	-	(line 8 * line 9)
11	Step-up share of total investment		0.00%	(none)
12	Step-up Investment	$	-	(line 1 * line 11)
13	Total Dual-Use Investment	$	4,738,463	(line 7 + line 10 + line 12)
14	Reactive Allocator [@ weighted pf of all unit(s)]		27.75%	= 1 - pf^2, where pf = power factor = 0.85
15	Dual-Use Investment Allocated to Reactive	$	1,314,923	(line 13 * line 14)
16	Balance of Plant Allocable	$	473,985,592	(line 1 - line 15)
17	Share of Remaining Plant Allocable		0.14%	Per PSEG Analysis
18	Balance of Plant Allocated	$	663,580	(line 16 * line 17)
19	Total Allocated Reactive Investment	$	1,978,503	(line 15 + line 18)

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	2.61%	(line 3 / line 1)
21	n = life of plant	38.3	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	0.36%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	3.70%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components		
24	Production Cost	3.79%	(line 2 / line 1)
25	RE Tax & Property Ins. Component	0.23%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate	0.36%	(line 22)
27	Levelized Tax Factor	3.70%	(line 23)
28	Return	8.86%	(Cap. Struct & Taxes Sch)
29	Prepayments * Pre-tax ROR / Plant =	0.00%	(None)
30	CWC=1/8 O&M*Pre-tax ROR / Plant =	0.07%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment	-0.90%	- (line 44 (k) / 36 (c)) Page 2
32	FCR Total	16.12%	(sum 24 through 31)

33	Annual Reactive Revenue Requirement	$	318,855	(line 19 * line 32)
34	kW capacity		316,000	Rated Capacity
35	Annual Vars Rate ($/mW)	$	1,009	(line 33 / line 34 * 1000)

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Mercer 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		475,300,515	Line 1					NPV of Col (j)>	46,239,050	
37	Asset Service Life		38.2791	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return on Eq		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost Rate		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
					((d) - (b)) *		= (f) * (Line	= (f) * (Line	= (g) * (Line		PMT of NPV
		Line 36 / 37		(b) * (c)	Line 38	Accum. (e)	40)	41)	39)	(g) + (h) + (i)	col. (j)
43											
44	1	12,416,697	3.750%	17,823,769	2,208,789	2,208,789	36,780	158,906	25,401	221,087	4,261,865
45	2	12,416,697	7.219%	34,311,944	8,944,208	11,152,997	185,718	802,375	128,260	1,116,352	4,261,865
46	3	12,416,697	6.677%	31,735,815	7,891,860	19,044,857	317,132	1,370,135	219,017	1,906,283	4,261,865
47	4	12,416,697	6.177%	29,359,313	6,921,059	25,965,916	432,380	1,868,053	298,609	2,599,042	4,261,865
48	5	12,416,697	5.713%	27,153,918	6,020,155	31,986,071	532,626	2,301,158	367,841	3,201,625	4,261,865
49	6	12,416,697	5.285%	25,119,632	5,189,149	37,175,220	619,035	2,674,478	427,516	3,721,030	4,261,865
50	7	12,416,697	4.888%	23,232,689	4,418,333	41,593,553	692,609	2,992,344	478,327	4,163,280	4,261,865
51	8	12,416,697	4.522%	21,493,089	3,707,706	45,301,259	754,349	3,259,086	520,966	4,534,401	4,261,865
52	9	12,416,697	4.462%	21,207,909	3,591,210	48,892,469	814,149	3,517,447	562,265	4,893,860	4,261,865
53	10	12,416,697	4.461%	21,203,156	3,589,268	52,481,737	873,917	3,775,668	603,542	5,253,126	4,261,865
54	11	12,416,697	4.462%	21,207,909	3,591,210	56,072,947	933,717	4,034,028	644,841	5,612,586	4,261,865
55	12	12,416,697	4.461%	21,203,156	3,589,268	59,662,216	993,485	4,292,249	686,118	5,971,851	4,261,865
56	13	12,416,697	4.462%	21,207,909	3,591,210	63,253,426	1,053,285	4,550,610	727,417	6,331,311	4,261,865
57	14	12,416,697	4.461%	21,203,156	3,589,268	66,842,694	1,113,053	4,808,831	768,693	6,690,577	4,261,865
58	15	12,416,697	4.462%	21,207,909	3,591,210	70,433,905	1,172,853	5,067,191	809,992	7,050,037	4,261,865
59	16	12,416,697	4.461%	21,203,156	3,589,268	74,023,173	1,232,621	5,325,412	851,269	7,409,302	4,261,865
60	17	12,416,697	4.462%	21,207,909	3,591,210	77,614,383	1,292,421	5,583,773	892,568	7,768,762	4,261,865
61	18	12,416,697	4.461%	21,203,156	3,589,268	81,203,652	1,352,189	5,841,994	933,845	8,128,028	4,261,865
62	19	12,416,697	4.462%	21,207,909	3,591,210	84,794,862	1,411,989	6,100,355	975,144	8,487,488	4,261,865
63	20	12,416,697	4.461%	21,203,156	3,589,268	88,384,130	1,471,757	6,358,576	1,016,421	8,846,753	4,261,865
64	21	12,416,697	2.231%	10,603,954	-740,505	87,643,625	1,459,426	6,305,302	1,007,905	8,772,633	4,261,865
65	22	12,416,697	0.000%	0	-5,072,221	82,571,404	1,374,965	5,940,393	949,574	8,264,932	4,261,865
66	23	12,416,697	0.000%	0	-5,072,221	77,499,183	1,290,503	5,575,485	891,243	7,757,231	4,261,865
67	24	12,416,697	0.000%	0	-5,072,221	72,426,963	1,206,041	5,210,577	832,913	7,249,531	4,261,865
68	25	12,416,697	0.000%	0	-5,072,221	67,354,742	1,121,579	4,845,669	774,582	6,741,830	4,261,865
69	26	12,416,697	0.000%	0	-5,072,221	62,282,521	1,037,118	4,480,760	716,251	6,234,129	4,261,865
70	27	12,416,697	0.000%	0	-5,072,221	57,210,300	952,656	4,115,852	657,920	5,726,428	4,261,865
71	28	12,416,697	0.000%	0	-5,072,221	52,138,080	868,194	3,750,944	599,590	5,218,728	4,261,865
72	29	12,416,697	0.000%	0	-5,072,221	47,065,859	783,732	3,386,036	541,259	4,711,027	4,261,865
73	30	12,416,697	0.000%	0	-5,072,221	41,993,638	699,271	3,021,127	482,928	4,203,326	4,261,865
74	31	12,416,697	0.000%	0	-5,072,221	36,921,417	614,809	2,656,219	424,598	3,695,626	4,261,865
75	32	12,416,697	0.000%	0	-5,072,221	31,849,197	530,347	2,291,311	366,267	3,187,925	4,261,865
76	33	12,416,697	0.000%	0	-5,072,221	26,776,976	445,885	1,926,403	307,936	2,680,224	4,261,865
77	34	12,416,697	0.000%	0	-5,072,221	21,704,755	361,424	1,561,494	249,605	2,172,524	4,261,865
78	35	12,416,697	0.000%	0	-5,072,221	16,632,534	276,962	1,196,586	191,275	1,664,823	4,261,865
79	36	12,416,697	0.000%	0	-5,072,221	11,560,314	192,500	831,678	132,944	1,157,122	4,261,865
80	37	12,416,697	0.000%	0	-5,072,221	6,488,093	108,039	466,770	74,613	649,422	4,261,865
81	38	12,416,697	0.000%	0	-5,072,221	1,415,872	23,577	101,861	16,283	141,721	4,261,865
82											
83		471,834,488	100.00%	475,300,515	1,415,872						

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MERCER 2 (COAL/GAS STEAM)
2014 TEST PERIOD

1	Gross Book Investment (incl. allocated common)	$	501,726,349	
2	O&M	$	18,035,500	
3	Depreciation (incl. common depreciation)	$	13,382,566	
4	Real Estate Taxes & Property Insurance	$	1,161,519	
5	Turbogenerator Investment		N/A	
6	Generator/Exciter share of Turbogenerator		DA	
7	Generator/Exciter Investment	$	19,406,719	(per books)
8	Accesssories Investment	$	6,629,087	(Acct 315)
9	Allocation of Accessories to Dual Use		0.00%	(none)
10	Accessories Allocated	$	-	(line 8 * line 9)
11	Step-up share of total investment		0.00%	(none)
12	Step-up Investment	$	-	(line 1 * line 11)
13	Total Dual-Use Investment	$	19,406,719	(line 7 + line 10 + line 12)
14	Reactive Allocator [@ weighted pf of all unit(s)]		27.75%	= 1 - pf^2, where pf = power factor = 0.85
15	Dual-Use Investment Allocated to Reactive	$	5,385,365	(line 13 * line 14)
16	Balance of Plant Allocable	$	496,340,985	(line 1 - line 15)
17	Share of Remaining Plant Allocable		0.14%	Per PSEG Analysis
18	Balance of Plant Allocated	$	694,877	(line 16 * line 17)
19	Total Allocated Reactive Investment	$	6,080,242	(line 15 + line 18)

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	2.67%	(line 3 / line 1)
21	n = life of plant	37.5	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	0.38%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	3.69%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components		
24	Production Cost	3.59%	(line 2 / line 1)
25	RE Tax & Property Ins. Component	0.23%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate	0.38%	(line 22)
27	Levelized Tax Factor	3.69%	(line 23)
28	Return	8.86%	(Cap. Struct & Taxes Sch)
29	Prepayments * Pre-tax ROR / Plant =	0.00%	(None)
30	CWC=1/8 O&M*Pre-tax ROR / Plant =	0.06%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment	-0.88%	- (line 44 (k) / 36 (c)) Page 2
32	FCR Total	15.94%	(sum 24 through 31)

33	Annual Reactive Revenue Requirement	$	969,405	(line 19 * line 32)
34	kW capacity		316,000	Rated Capacity
35	Annual Vars Rate ($/mW)	$	3,068	(line 33 / line 34 * 1000)

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Mercer 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		501,726,349	Line 1					NPV of Col (j)>	47,512,480	
37	Asset Service Life		37.4910	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return on Eq		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost Rate		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
		Line 36 / 37		(b) * (c)	((d) - (b)) * Line 38	Accum. (e)	= (f) * (Line 40)	= (f) * (Line 41)	= (g) * (Line 39)	(g) + (h) + (i)	PMT of NPV col. (j)
43											
44	1	13,382,566	3.750%	18,814,738	2,219,042	2,219,042	36,951	159,643	25,519	222,114	4,391,502
45	2	13,382,566	7.219%	36,219,625	9,328,939	11,547,981	192,295	830,791	132,802	1,155,888	4,391,502
46	3	13,382,566	6.677%	33,500,268	8,218,081	19,766,062	329,141	1,422,020	227,310	1,978,471	4,391,502
47	4	13,382,566	6.177%	30,991,637	7,193,305	26,959,368	448,923	1,939,524	310,034	2,698,481	4,391,502
48	5	13,382,566	5.713%	28,663,626	6,242,313	33,201,681	552,869	2,388,612	381,820	3,323,301	4,391,502
49	6	13,382,566	5.285%	26,516,238	5,365,105	38,566,786	642,207	2,774,591	443,519	3,860,318	4,391,502
50	7	13,382,566	4.888%	24,524,384	4,551,433	43,118,218	717,997	3,102,033	495,861	4,315,891	4,391,502
51	8	13,382,566	4.522%	22,688,066	3,801,297	46,919,515	781,296	3,375,507	539,576	4,696,379	4,391,502
52	9	13,382,566	4.462%	22,387,030	3,678,323	50,597,838	842,546	3,640,135	581,877	5,064,558	4,391,502
53	10	13,382,566	4.461%	22,382,012	3,676,274	54,274,112	903,763	3,904,615	624,154	5,432,533	4,391,502
54	11	13,382,566	4.462%	22,387,030	3,678,323	57,952,436	965,014	4,169,243	666,455	5,800,712	4,391,502
55	12	13,382,566	4.461%	22,382,012	3,676,274	61,628,709	1,026,230	4,433,724	708,732	6,168,686	4,391,502
56	13	13,382,566	4.462%	22,387,030	3,678,323	65,307,033	1,087,481	4,698,351	751,033	6,536,866	4,391,502
57	14	13,382,566	4.461%	22,382,012	3,676,274	68,983,307	1,148,698	4,962,832	793,310	6,904,840	4,391,502
58	15	13,382,566	4.462%	22,387,030	3,678,323	72,661,630	1,209,949	5,227,460	835,611	7,273,019	4,391,502
59	16	13,382,566	4.461%	22,382,012	3,676,274	76,337,904	1,271,165	5,491,940	877,889	7,640,994	4,391,502
60	17	13,382,566	4.462%	22,387,030	3,678,323	80,016,227	1,332,416	5,756,568	920,189	8,009,173	4,391,502
61	18	13,382,566	4.461%	22,382,012	3,676,274	83,692,501	1,393,633	6,021,048	962,467	8,377,147	4,391,502
62	19	13,382,566	4.462%	22,387,030	3,678,323	87,370,825	1,454,884	6,285,676	1,004,767	8,745,327	4,391,502
63	20	13,382,566	4.461%	22,382,012	3,676,274	91,047,099	1,516,100	6,550,156	1,047,045	9,113,301	4,391,502
64	21	13,382,566	2.231%	11,193,515	-894,227	90,152,871	1,501,210	6,485,823	1,036,761	9,023,794	4,391,502
65	22	13,382,566	0.000%	0	-5,466,778	84,686,093	1,410,178	6,092,530	973,893	8,476,600	4,391,502
66	23	13,382,566	0.000%	0	-5,466,778	79,219,315	1,319,146	5,699,236	911,025	7,929,407	4,391,502
67	24	13,382,566	0.000%	0	-5,466,778	73,752,537	1,228,114	5,305,942	848,157	7,382,213	4,391,502
68	25	13,382,566	0.000%	0	-5,466,778	68,285,758	1,137,082	4,912,648	785,289	6,835,019	4,391,502
69	26	13,382,566	0.000%	0	-5,466,778	62,818,980	1,046,051	4,519,355	722,420	6,287,826	4,391,502
70	27	13,382,566	0.000%	0	-5,466,778	57,352,202	955,019	4,126,061	659,552	5,740,632	4,391,502
71	28	13,382,566	0.000%	0	-5,466,778	51,885,424	863,987	3,732,767	596,684	5,193,438	4,391,502
72	29	13,382,566	0.000%	0	-5,466,778	46,418,646	772,955	3,339,474	533,816	4,646,245	4,391,502
73	30	13,382,566	0.000%	0	-5,466,778	40,951,867	681,923	2,946,180	470,948	4,099,051	4,391,502
74	31	13,382,566	0.000%	0	-5,466,778	35,485,089	590,891	2,552,886	408,080	3,551,857	4,391,502
75	32	13,382,566	0.000%	0	-5,466,778	30,018,311	499,860	2,159,592	345,212	3,004,664	4,391,502
76	33	13,382,566	0.000%	0	-5,466,778	24,551,533	408,828	1,766,299	282,343	2,457,470	4,391,502
77	34	13,382,566	0.000%	0	-5,466,778	19,084,754	317,796	1,373,005	219,475	1,910,276	4,391,502
78	35	13,382,566	0.000%	0	-5,466,778	13,617,976	226,764	979,711	156,607	1,363,083	4,391,502
79	36	13,382,566	0.000%	0	-5,466,778	8,151,198	135,732	586,418	93,739	815,889	4,391,502
80	37	13,382,566	0.000%	0	-5,466,778	2,684,420	44,700	193,124	30,871	268,695	4,391,502
81	38		0.000%	0	0						
82											
83		495,154,942	100.00%	501,726,349	2,684,420						

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CONEMAUGH 1 & 2 (PA COAL STEAM)
2014 TEST PERIOD

1	Gross Book Investment	$	283,640,259	
2	O&M	$	25,562,000	
3	Depreciation	$	6,811,371	
4	Real Estate Taxes & Property Insurance	$	748,279	
5	Turbogenerator Investment	$	32,977,099	(Acct 314)
6	Generator/Exciter share of Turbogenerator		22.00%	(Manufacturer letter)
7	Generator/Exciter Investment	$	7,254,962	(line 5 * line 6)
8	Accesssories Investment	$	8,161,421	(Acct 315)
9	Allocation of Accessories to Dual Use		0.00%	(none)
10	Accessories Allocated	$	-	(line 8 * line 9)
11	Step-up share of total investment		DA	
12	Step-up Investment	$	2,564,919	(per books)
13	Total Dual-Use Investment	$	9,819,880	(line 7 + line 10 + line 12)
14	Reactive Allocator [@ weighted pf of all unit(s)]		19.00%	= 1 - pf^2, where pf = power factor = 0.9
15	Dual-Use Investment Allocated to Reactive	$	1,865,777	(line 13 * line 14)
16	Balance of Plant Allocable	$	281,774,482	(line 1 - line 15)
17	Share of Remaining Plant Allocable		0.14%	Per PSEG Analysis
18	Balance of Plant Allocated	$	394,484	(line 16 * line 17)
19	Total Allocated Reactive Investment	$	2,260,262	(line 15 + line 18)

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	2.40%	(line 3 / line 1)
21	n = life of plant	41.6	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	0.27%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	3.77%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components		
24	Production Cost	9.01%	(line 2 / line 1)
25	RE Tax & Property Ins. Component	0.26%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate	0.27%	(line 22)
27	Levelized Tax Factor	3.77%	(line 23)
28	Return	8.86%	(Cap. Struct & Taxes Sch)
29	Prepayments * Pre-tax ROR / Plant =	0.00%	(None)
30	CWC=1/8 O&M*Pre-tax ROR / Plant =	0.16%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment	-0.98%	- (line 44 (k) / 36 (c)) Page 2
32	FCR Total	21.35%	(sum 24 through 31)

33	Annual Reactive Revenue Requirement	$	482,544	(line 19 * line 32)
34	kW capacity		382,670	Rated Capacity
35	Annual Vars Rate ($/mW)	$	1,261	(line 33 / line 34 * 1000)

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Conemaugh

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		283,640,259	Line 1					NPV of Col (j)>	30,435,434	
37	Asset Service Life		41.6422	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return on Eq		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost Rate		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
					((d) - (b)) *		= (f) * (Line	= (f) * (Line	= (g) * (Line		PMT of NPV
		Line 36 / 37		(b) * (c)	Line 38	Accum. (e)	40)	41)	39)	(g) + (h) + (i)	col. (j)
43											
44	1	6,811,371	3.750%	10,636,510	1,562,569	1,562,569	26,020	112,415	17,970	156,404	2,777,401
45	2	6,811,371	7.219%	20,475,990	5,581,997	7,144,566	118,970	513,998	82,163	715,131	2,777,401
46	3	6,811,371	6.677%	18,938,660	4,953,998	12,098,564	201,463	870,401	139,134	1,210,998	2,777,401
47	4	6,811,371	6.177%	17,520,459	4,374,662	16,473,226	274,309	1,185,125	189,443	1,648,877	2,777,401
48	5	6,811,371	5.713%	16,204,368	3,837,039	20,310,265	338,203	1,461,171	233,569	2,032,943	2,777,401
49	6	6,811,371	5.285%	14,990,388	3,341,128	23,651,393	393,839	1,701,540	271,992	2,367,371	2,777,401
50	7	6,811,371	4.888%	13,864,336	2,881,136	26,532,529	441,815	1,908,817	305,125	2,655,757	2,777,401
51	8	6,811,371	4.522%	12,826,213	2,457,063	28,989,592	482,730	2,085,584	333,381	2,901,695	2,777,401
52	9	6,811,371	4.462%	12,656,028	2,387,542	31,377,135	522,487	2,257,350	360,838	3,140,674	2,777,401
53	10	6,811,371	4.461%	12,653,192	2,386,384	33,763,518	562,224	2,429,032	388,282	3,379,538	2,777,401
54	11	6,811,371	4.462%	12,656,028	2,387,542	36,151,061	601,981	2,600,798	415,738	3,618,517	2,777,401
55	12	6,811,371	4.461%	12,653,192	2,386,384	38,537,445	641,719	2,772,480	443,182	3,857,381	2,777,401
56	13	6,811,371	4.462%	12,656,028	2,387,542	40,924,987	681,476	2,944,246	470,639	4,096,360	2,777,401
57	14	6,811,371	4.461%	12,653,192	2,386,384	43,311,371	721,213	3,115,928	498,082	4,335,224	2,777,401
58	15	6,811,371	4.462%	12,656,028	2,387,542	45,698,913	760,970	3,287,694	525,539	4,574,204	2,777,401
59	16	6,811,371	4.461%	12,653,192	2,386,384	48,085,297	800,708	3,459,377	552,983	4,813,067	2,777,401
60	17	6,811,371	4.462%	12,656,028	2,387,542	50,472,840	840,465	3,631,142	580,439	5,052,047	2,777,401
61	18	6,811,371	4.461%	12,653,192	2,386,384	52,859,224	880,203	3,802,825	607,883	5,290,910	2,777,401
62	19	6,811,371	4.462%	12,656,028	2,387,542	55,246,766	919,959	3,974,591	635,340	5,529,890	2,777,401
63	20	6,811,371	4.461%	12,653,192	2,386,384	57,633,150	959,697	4,146,273	662,783	5,768,753	2,777,401
64	21	6,811,371	2.231%	6,328,014	-197,451	57,435,698	956,409	4,132,068	660,512	5,748,990	2,777,401
65	22	6,811,371	0.000%	0	-2,782,445	54,653,253	910,076	3,931,892	628,514	5,470,483	2,777,401
66	23	6,811,371	0.000%	0	-2,782,445	51,870,808	863,744	3,731,716	596,516	5,191,975	2,777,401
67	24	6,811,371	0.000%	0	-2,782,445	49,088,363	817,411	3,531,540	564,518	4,913,468	2,777,401
68	25	6,811,371	0.000%	0	-2,782,445	46,305,918	771,078	3,331,364	532,520	4,634,961	2,777,401
69	26	6,811,371	0.000%	0	-2,782,445	43,523,473	724,745	3,131,188	500,521	4,356,454	2,777,401
70	27	6,811,371	0.000%	0	-2,782,445	40,741,028	678,412	2,931,012	468,523	4,077,947	2,777,401
71	28	6,811,371	0.000%	0	-2,782,445	37,958,583	632,080	2,730,835	436,525	3,799,440	2,777,401
72	29	6,811,371	0.000%	0	-2,782,445	35,176,138	585,747	2,530,659	404,527	3,520,933	2,777,401
73	30	6,811,371	0.000%	0	-2,782,445	32,393,693	539,414	2,330,483	372,529	3,242,426	2,777,401
74	31	6,811,371	0.000%	0	-2,782,445	29,611,247	493,081	2,130,307	340,530	2,963,919	2,777,401
75	32	6,811,371	0.000%	0	-2,782,445	26,828,802	446,749	1,930,131	308,532	2,685,412	2,777,401
76	33	6,811,371	0.000%	0	-2,782,445	24,046,357	400,416	1,729,955	276,534	2,406,905	2,777,401
77	34	6,811,371	0.000%	0	-2,782,445	21,263,912	354,083	1,529,779	244,536	2,128,398	2,777,401
78	35	6,811,371	0.000%	0	-2,782,445	18,481,467	307,750	1,329,603	212,538	1,849,891	2,777,401
79	36	6,811,371	0.000%	0	-2,782,445	15,699,022	261,417	1,129,427	180,539	1,571,384	2,777,401
80	37	6,811,371	0.000%	0	-2,782,445	12,916,577	215,085	929,251	148,541	1,292,877	2,777,401
81	38	6,811,371	0.000%	0	-2,782,445	10,134,132	168,752	729,075	116,543	1,014,369	2,777,401
82	39	6,811,371	0.000%	0	-2,782,445	7,351,687	122,419	528,899	84,545	735,862	2,777,401
83	40	6,811,371	0.000%	0	-2,782,445	4,569,241	76,086	328,723	52,546	457,355	2,777,401
84	41	6,811,371	0.000%	0	-2,782,445	1,786,796	29,753	128,547	20,548	178,848	2,777,401
85	42	6,811,371	0.000%	0	-2,782,445	-995,649	-16,579	-71,629	-11,450	-99,659	2,777,401
		286,077,588	100.00%	283,640,259	10,134,132						

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KEYSTONE 1 & 2 (PA COAL STEAM)
2014 TEST PERIOD

1	Gross Book Investment	$	393,001,398	
2	O&M	$	22,967,000	
3	Depreciation	$	11,952,962	
4	Real Estate Taxes & Property Insurance	$	748,279	
5	Turbogenerator Investment	$	34,995,860	(Acct 314)
6	Generator/Exciter share of Turbogenerator		22.00%	(Manufacturer letter-identical unit from different manufacturer)
7	Generator/Exciter Investment	$	7,699,089	(line 5 * line 6)
8	Accesssories Investment	$	4,347,123	(Acct 315)
9	Allocation of Accessories to Dual Use		0.00%	(none)
10	Accessories Allocated	$	-	(line 8 * line 9)
11	Step-up share of total investment		DA	
12	Step-up Investment	$	5,403,570	(per Books)
13	Total Dual-Use Investment	$	13,102,659	(line 7 + line 10 + line 12)
14	Reactive Allocator [@ weighted pf of all unit(s)]		19.00%	= 1 - pf^2, where pf = power factor = 0.9
15	Dual-Use Investment Allocated to Reactive	$	2,489,505	(line 13 * line 14)
16	Balance of Plant Allocable	$	390,511,892	(line 1 - line 15)
17	Share of Remaining Plant Allocable		0.14%	Per PSEG Analysis
18	Balance of Plant Allocated	$	546,717	(line 16 * line 17)
19	Total Allocated Reactive Investment	$	3,036,222	(line 15 + line 18)

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	3.04%	(line 3 / line 1)
21	n = life of plant	32.9	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	0.58%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	3.59%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components		
24	Production Cost	5.84%	(line 2 / line 1)
25	RE Tax & Property Ins. Component	0.19%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate	0.58%	(line 22)
27	Levelized Tax Factor	3.59%	(line 23)
28	Return	8.86%	(Cap. Struct & Taxes Sch)
29	Prepayments * Pre-tax ROR / Plant =	0.00%	(None)
30	CWC=1/8 O&M*Pre-tax ROR / Plant =	0.10%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment	-0.73%	- (line 44 (k) / 36 (c)) Page 2
32	FCR Total	18.43%	(sum 24 through 31)

33	Annual Reactive Revenue Requirement	$	559,507	(line 19 * line 32)
34	kW capacity		388,280	Rated Capacity
35	Annual Vars Rate ($/mW)	$	1,441	(line 33 / line 34 * 1000)

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Keystone

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		393,001,398	Line 1					NPV of Col (j)>	30,555,232	
37	Asset Service Life		32.8790	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return on Eq		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost Rate		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
					((d) - (b)) *		= (f) * (Line	= (f) * (Line	= (g) * (Line		PMT of NPV
		Line 36 / 37		(b) * (c)	Line 38	Accum. (e)	40)	41)	39)	(g) + (h) + (i)	col. (j)
43											
44	1	11,952,962	3.750%	14,737,552	1,137,505	1,137,505	18,942	81,835	13,081	113,858	2,883,979
45	2	11,952,962	7.219%	28,370,771	6,706,675	7,844,180	130,620	564,330	90,208	785,158	2,883,979
46	3	11,952,962	6.677%	26,240,703	5,836,543	13,680,723	227,809	984,225	157,329	1,369,363	2,883,979
47	4	11,952,962	6.177%	24,275,696	5,033,837	18,714,560	311,632	1,346,372	215,218	1,873,222	2,883,979
48	5	11,952,962	5.713%	22,452,170	4,288,927	23,003,487	383,050	1,654,928	264,541	2,302,519	2,883,979
49	6	11,952,962	5.285%	20,770,124	3,601,811	26,605,298	443,027	1,914,052	305,962	2,663,040	2,883,979
50	7	11,952,962	4.888%	19,209,908	2,964,463	29,569,760	492,390	2,127,323	340,053	2,959,766	2,883,979
51	8	11,952,962	4.522%	17,771,523	2,376,882	31,946,643	531,970	2,298,321	367,387	3,197,679	2,883,979
52	9	11,952,962	4.462%	17,535,722	2,280,558	34,227,200	569,945	2,462,390	393,614	3,425,950	2,883,979
53	10	11,952,962	4.461%	17,531,792	2,278,952	36,506,153	607,894	2,626,344	419,822	3,654,060	2,883,979
54	11	11,952,962	4.462%	17,535,722	2,280,558	38,786,711	645,869	2,790,413	446,049	3,882,331	2,883,979
55	12	11,952,962	4.461%	17,531,792	2,278,952	41,065,663	683,818	2,954,367	472,257	4,110,441	2,883,979
56	13	11,952,962	4.462%	17,535,722	2,280,558	43,346,221	721,794	3,118,436	498,483	4,338,712	2,883,979
57	14	11,952,962	4.461%	17,531,792	2,278,952	45,625,173	759,742	3,282,389	524,691	4,566,823	2,883,979
58	15	11,952,962	4.462%	17,535,722	2,280,558	47,905,731	797,718	3,446,458	550,918	4,795,094	2,883,979
59	16	11,952,962	4.461%	17,531,792	2,278,952	50,184,683	835,667	3,610,412	577,126	5,023,204	2,883,979
60	17	11,952,962	4.462%	17,535,722	2,280,558	52,465,241	873,642	3,774,481	603,352	5,251,475	2,883,979
61	18	11,952,962	4.461%	17,531,792	2,278,952	54,744,194	911,591	3,938,434	629,560	5,479,585	2,883,979
62	19	11,952,962	4.462%	17,535,722	2,280,558	57,024,751	949,566	4,102,503	655,787	5,707,856	2,883,979
63	20	11,952,962	4.461%	17,531,792	2,278,952	59,303,704	987,515	4,266,457	681,995	5,935,966	2,883,979
64	21	11,952,962	2.231%	8,767,861	-1,301,114	58,002,590	965,849	4,172,852	667,032	5,805,732	2,883,979
65	22	11,952,962	0.000%	0	-4,882,785	53,119,805	884,542	3,821,572	610,880	5,316,993	2,883,979
66	23	11,952,962	0.000%	0	-4,882,785	48,237,021	803,234	3,470,292	554,727	4,828,254	2,883,979
67	24	11,952,962	0.000%	0	-4,882,785	43,354,236	721,927	3,119,012	498,575	4,339,515	2,883,979
68	25	11,952,962	0.000%	0	-4,882,785	38,471,451	640,620	2,767,732	442,423	3,850,775	2,883,979
69	26	11,952,962	0.000%	0	-4,882,785	33,588,666	559,313	2,416,453	386,271	3,362,036	2,883,979
70	27	11,952,962	0.000%	0	-4,882,785	28,705,881	478,005	2,065,173	330,119	2,873,297	2,883,979
71	28	11,952,962	0.000%	0	-4,882,785	23,823,097	396,698	1,713,893	273,966	2,384,558	2,883,979
72	29	11,952,962	0.000%	0	-4,882,785	18,940,312	315,391	1,362,613	217,814	1,895,818	2,883,979
73	30	11,952,962	0.000%	0	-4,882,785	14,057,527	234,083	1,011,334	161,662	1,407,079	2,883,979
74	31	11,952,962	0.000%	0	-4,882,785	9,174,742	152,776	660,054	105,510	918,340	2,883,979
75	32	11,952,962	0.000%	0	-4,882,785	4,291,957	71,469	308,774	49,358	429,601	2,883,979
76	33	11,952,962	0.000%	0	-4,882,785	-590,827	-9,838	-42,506	-6,795	-59,138	2,883,979
77	34		0.000%	0	0	-590,827	-9,838	-42,506	-6,795	-59,138	2,883,979
78	35		0.000%	0	0	-590,827	-9,838	-42,506	-6,795	-59,138	2,883,979
79	36		0.000%	0	0	-590,827	-9,838	-42,506	-6,795	-59,138	2,883,979
80	37		0.000%	0	0	-590,827	-9,838	-42,506	-6,795	-59,138	2,883,979
81	38		0.000%	0	0						
82											
83		394,447,731	100.00%	393,001,398	-590,827						

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SALEM NUCLEAR UNITS 1 & 2
2014 TEST PERIOD

1	Gross Book Investment (incl. allocated common)	$	722,542,909	
2	O&M	$	244,759,952	
3	Depreciation (incl. common depreciation)	$	26,598,638	
4	Real Estate Taxes & Property Insurance	$	3,086,649	
5	Turbogenerator Investment		N/A	
6	Generator/Exciter share of Turbogenerator		DA	
7	Generator/Exciter Investment	$	15,165,340	(per books)
8	Accesssories Investment	$	9,330,643	(Acct 324)
9	Allocation of Accessories to Dual Use		0.00%	(none)
10	Accessories Allocated	$	-	(line 8 * line 9)
11	Step-up share of total investment		N/A	
12	Step-up Investment	$	3,815,073	(per Book)
13	Total Dual-Use Investment	$	18,980,413	(line 7 + line 10 + line 12)
14	Reactive Allocator [@ weighted pf of all unit(s)]		19.00%	= 1 - pf^2, where pf = power factor = 0.9
15	Dual-Use Investment Allocated to Reactive	$	3,606,278	(line 13 * line 14)
16	Balance of Plant Allocable	$	718,936,630	(line 1 - line 15)
17	Share of Remaining Plant Allocable		0.14%	Per PSEG Analysis
18	Balance of Plant Allocated	$	1,006,511	(line 16 * line 17)
19	Total Allocated Reactive Investment	$	4,612,790	(line 15 + line 18)

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	3.68%	(line 3 / line 1)
21	n = life of plant	27.2	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	0.98%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	3.45%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components		
24	Production Cost	33.87%	(line 2 / line 1)
25	RE Tax & Property Ins. Component	0.43%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate	0.98%	(line 22)
27	Levelized Tax Factor	3.45%	(line 23)
28	Return	8.86%	(Cap. Struct & Taxes Sch)
29	Prepayments * Pre-tax ROR / Plant =	0.03%	(WP-Prepayments & Schedule 2)/line 1
30	CWC=1/8 O&M*Pre-tax ROR / Plant =	0.59%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment	-0.50%	- (line 44 (k) / 36 (c)) Page 2
32	FCR Total	47.71%	(sum 24 through 31)

33	Annual Reactive Revenue Requirement	$	2,200,674	(line 19 * line 32)
34	kW capacity		1,336,505	Rated Capacity
35	Annual Vars Rate ($/mW)	$	1,647	(line 33 / line 34 * 1000)

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Salem

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		722,542,909	Line 1					NPV of Col (j)>	36,786,925	
37	Asset Service Life		27.1647	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return on Eq		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost Rate		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
					((d) - (b)) *		= (f) * (Line	= (f) * (Line	= (g) * (Line		PMT of NPV
		Line 36 / 37		(b) * (c)	Line 38	Accum. (e)	40)	41)	39)	(g) + (h) + (i)	col. (j)
43											
44	1	26,598,638	3.750%	27,095,359	202,911	202,911	3,379	14,598	2,333	20,310	3,619,892
45	2	26,598,638	7.219%	52,160,373	10,441,969	10,644,879	177,257	765,819	122,416	1,065,492	3,619,892
46	3	26,598,638	6.677%	48,244,190	8,842,208	19,487,087	324,496	1,401,950	224,102	1,950,548	3,619,892
47	4	26,598,638	6.177%	44,631,475	7,366,414	26,853,502	447,160	1,931,908	308,816	2,687,884	3,619,892
48	5	26,598,638	5.713%	41,278,876	5,996,877	32,850,379	547,019	2,363,339	377,780	3,288,138	3,619,892
49	6	26,598,638	5.285%	38,186,393	4,733,598	37,583,977	625,842	2,703,885	432,217	3,761,944	3,619,892
50	7	26,598,638	4.888%	35,317,897	3,561,818	41,145,795	685,153	2,960,131	473,178	4,118,462	3,619,892
51	8	26,598,638	4.522%	32,673,390	2,481,536	43,627,331	726,475	3,138,659	501,716	4,366,850	3,619,892
52	9	26,598,638	4.462%	32,239,865	2,304,441	45,931,772	764,848	3,304,447	528,217	4,597,511	3,619,892
53	10	26,598,638	4.461%	32,232,639	2,301,490	48,233,262	803,172	3,470,022	554,684	4,827,878	3,619,892
54	11	26,598,638	4.462%	32,239,865	2,304,441	50,537,703	841,545	3,635,809	581,185	5,058,539	3,619,892
55	12	26,598,638	4.461%	32,232,639	2,301,490	52,839,193	879,869	3,801,384	607,653	5,288,905	3,619,892
56	13	26,598,638	4.462%	32,239,865	2,304,441	55,143,634	918,242	3,967,171	634,154	5,519,567	3,619,892
57	14	26,598,638	4.461%	32,232,639	2,301,490	57,445,123	956,566	4,132,746	660,621	5,749,933	3,619,892
58	15	26,598,638	4.462%	32,239,865	2,304,441	59,749,564	994,939	4,298,533	687,122	5,980,595	3,619,892
59	16	26,598,638	4.461%	32,232,639	2,301,490	62,051,054	1,033,263	4,464,108	713,589	6,210,961	3,619,892
60	17	26,598,638	4.462%	32,239,865	2,304,441	64,355,495	1,071,636	4,629,895	740,090	6,441,622	3,619,892
61	18	26,598,638	4.461%	32,232,639	2,301,490	66,656,985	1,109,960	4,795,470	766,558	6,671,988	3,619,892
62	19	26,598,638	4.462%	32,239,865	2,304,441	68,961,426	1,148,334	4,961,258	793,059	6,902,650	3,619,892
63	20	26,598,638	4.461%	32,232,639	2,301,490	71,262,916	1,186,658	5,126,833	819,526	7,133,016	3,619,892
64	21	26,598,638	2.231%	16,119,932	-4,280,551	66,982,364	1,115,379	4,818,879	770,299	6,704,557	3,619,892
65	22	26,598,638	0.000%	0	-10,865,544	56,116,821	934,447	4,037,185	645,345	5,616,977	3,619,892
66	23	26,598,638	0.000%	0	-10,865,544	45,251,277	753,516	3,255,490	520,391	4,529,398	3,619,892
67	24	26,598,638	0.000%	0	-10,865,544	34,385,734	572,585	2,473,796	395,437	3,441,818	3,619,892
68	25	26,598,638	0.000%	0	-10,865,544	23,520,190	391,654	1,692,101	270,483	2,354,238	3,619,892
69	26	26,598,638	0.000%	0	-10,865,544	12,654,647	210,723	910,407	145,529	1,266,659	3,619,892
70	27	26,598,638	0.000%	0	-10,865,544	1,789,103	29,792	128,713	20,575	179,079	3,619,892
71	28	26,598,638	0.000%	0	-10,865,544	-9,076,440	-151,139	-652,982	-104,379	-908,500	3,619,892
72	29		0.000%	0	0	-9,076,440	-151,139	-652,982	-104,379	-908,500	3,619,892
73	30		0.000%	0	0	-9,076,440	-151,139	-652,982	-104,379	-908,500	3,619,892
74	31		0.000%	0	0	-9,076,440	-151,139	-652,982	-104,379	-908,500	3,619,892
75	32		0.000%	0	0	-9,076,440	-151,139	-652,982	-104,379	-908,500	3,619,892
76	33		0.000%	0	0	-9,076,440	-151,139	-652,982	-104,379	-908,500	3,619,892
77	34		0.000%	0	0	-9,076,440	-151,139	-652,982	-104,379	-908,500	3,619,892
78	35		0.000%	0	0	-9,076,440	-151,139	-652,982	-104,379	-908,500	3,619,892
79	36		0.000%	0	0	-9,076,440	-151,139	-652,982	-104,379	-908,500	3,619,892
80	37		0.000%	0	0	-9,076,440	-151,139	-652,982	-104,379	-908,500	3,619,892
81	38		0.000%	0	0						
82											
83		744,761,857	100.00%	722,542,909	-9,076,440						

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HOPE CREEK NUCLEAR UNIT 1
2014 TEST PERIOD

1	Gross Book Investment (incl. allocated common)	$ 552,158,116		
2	O&M	$ 203,373,186		
3	Depreciation (incl. common depreciation)	$ 18,344,886		
4	Real Estate Taxes & Property Insurance	$ 2,424,998		
5	Turbogenerator Investment	$ 240,389,030	(Acct 323)	
6	Generator/Exciter share of Turbogenerator	25.00%	(Manufacturer letter)	
7	Generator/Exciter Investment	$ 60,097,258	(line 5 * line 6)	
8	Accesssories Investment	$ 33,374,026	(Acct 324)	
9	Allocation of Accessories to Dual Use	0.00%	(none)	
10	Accessories Allocated	$ -	(line 8 * line 9)	
11	Step-up share of total investment	N/A		
12	Step-up Investment	$ 11,744,003	(per books)	
13	Total Dual-Use Investment	$ 71,841,261	(line 7 + line 10 + line 12)	
14	Reactive Allocator [@ weighted pf of all unit(s)]	11.64%	= 1 - pf^2, where pf = power factor = 0.94	
15	Dual-Use Investment Allocated to Reactive	$ 8,362,323	(line 13 * line 14)	
16	Balance of Plant Allocable	$ 543,795,793	(line 1 - line 15)	
17	Share of Remaining Plant Allocable	0.14%	Per PSEG Analysis	
18	Balance of Plant Allocated	$ 761,314	(line 16 * line 17)	
19	Total Allocated Reactive Investment	$ 9,123,637	(line 15 + line 18)	

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	3.32%	(line 3 / line 1)
21	n = life of plant	30.1	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	0.75%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	3.52%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components			
24	Production Cost		36.83%	(line 2 / line 1)
25	RE Tax & Property Ins. Component		0.44%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate		0.75%	(line 22)
27	Levelized Tax Factor		3.52%	(line 23)
28	Return		8.86%	(Cap. Struct & Taxes Sch)
29	Prepayments * Pre-tax ROR / Plant =		0.04%	(WP-Prepayments & Schedule 2)/line 1
30	CWC=1/8 O&M*Pre-tax ROR / Plant =		0.64%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment		-0.63%	- (line 44 (k) / 36 (c)) Page 2
32		FCR Total	50.45%	(sum 24 through 31)
33	Annual Reactive Revenue Requirement	$ 4,602,764		(line 19 * line 32)
34	kW capacity	1,172,000		Rated Capacity
35	Annual Vars Rate ($/mW)	$ 3,927		(line 33 / line 34 * 1000)

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Hope Creek

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		552,158,116	Line 1					NPV of Col (j)>	36,422,359	
37	Asset Service Life		30.0987	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return on Eq		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost Rate		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
					((d) - (b)) *		= (f) * (Line	= (f) * (Line	= (g) * (Line		PMT of NPV
		Line 36 / 37		(b) * (c)	Line 38	Accum. (e)	40)	41)	39)	(g) + (h) + (i)	col. (j)
43											
44	1	18,344,886	3.750%	20,705,929	964,486	964,486	16,060	69,388	11,092	96,540	3,498,631
45	2	18,344,886	7.219%	39,860,294	8,789,044	9,753,531	162,414	701,693	112,166	976,273	3,498,631
46	3	18,344,886	6.677%	36,867,597	7,566,528	17,320,059	288,411	1,246,048	199,181	1,733,640	3,498,631
47	4	18,344,886	6.177%	34,106,807	6,438,745	23,758,803	395,627	1,709,268	273,227	2,378,122	3,498,631
48	5	18,344,886	5.713%	31,544,793	5,392,162	29,150,966	485,417	2,097,193	335,237	2,917,847	3,498,631
49	6	18,344,886	5.285%	29,181,556	4,426,780	33,577,746	559,131	2,415,667	386,145	3,360,943	3,498,631
50	7	18,344,886	4.888%	26,989,489	3,531,320	37,109,066	617,934	2,669,719	426,756	3,714,408	3,498,631
51	8	18,344,886	4.522%	24,968,590	2,705,783	39,814,849	662,990	2,864,380	457,872	3,985,242	3,498,631
52	9	18,344,886	4.462%	24,637,295	2,570,449	42,385,299	705,793	3,049,304	487,432	4,242,529	3,498,631
53	10	18,344,886	4.461%	24,631,774	2,568,194	44,953,492	748,558	3,234,067	516,967	4,499,591	3,498,631
54	11	18,344,886	4.462%	24,637,295	2,570,449	47,523,942	791,360	3,418,991	546,527	4,756,879	3,498,631
55	12	18,344,886	4.461%	24,631,774	2,568,194	50,092,136	834,125	3,603,754	576,061	5,013,940	3,498,631
56	13	18,344,886	4.462%	24,637,295	2,570,449	52,662,585	876,928	3,788,678	605,622	5,271,228	3,498,631
57	14	18,344,886	4.461%	24,631,774	2,568,194	55,230,779	919,693	3,973,440	635,156	5,528,290	3,498,631
58	15	18,344,886	4.462%	24,637,295	2,570,449	57,801,228	962,496	4,158,365	664,716	5,785,577	3,498,631
59	16	18,344,886	4.461%	24,631,774	2,568,194	60,369,422	1,005,261	4,343,127	694,250	6,042,639	3,498,631
60	17	18,344,886	4.462%	24,637,295	2,570,449	62,939,871	1,048,064	4,528,052	723,811	6,299,926	3,498,631
61	18	18,344,886	4.461%	24,631,774	2,568,194	65,508,065	1,090,829	4,712,814	753,345	6,556,988	3,498,631
62	19	18,344,886	4.462%	24,637,295	2,570,449	68,078,514	1,133,631	4,897,739	782,905	6,814,275	3,498,631
63	20	18,344,886	4.461%	24,631,774	2,568,194	70,646,708	1,176,397	5,082,501	812,440	7,071,337	3,498,631
64	21	18,344,886	2.231%	12,318,648	-2,461,718	68,184,989	1,135,404	4,905,399	784,130	6,824,933	3,498,631
65	22	18,344,886	0.000%	0	-7,493,886	60,691,104	1,010,618	4,366,270	697,950	6,074,837	3,498,631
66	23	18,344,886	0.000%	0	-7,493,886	53,197,218	885,831	3,827,141	611,770	5,324,742	3,498,631
67	24	18,344,886	0.000%	0	-7,493,886	45,703,332	761,044	3,288,012	525,590	4,574,646	3,498,631
68	25	18,344,886	0.000%	0	-7,493,886	38,209,446	636,257	2,748,883	439,410	3,824,550	3,498,631
69	26	18,344,886	0.000%	0	-7,493,886	30,715,561	511,470	2,209,754	353,230	3,074,454	3,498,631
70	27	18,344,886	0.000%	0	-7,493,886	23,221,675	386,683	1,670,625	267,050	2,324,359	3,498,631
71	28	18,344,886	0.000%	0	-7,493,886	15,727,789	261,896	1,131,497	180,870	1,574,263	3,498,631
72	29	18,344,886	0.000%	0	-7,493,886	8,233,903	137,110	592,368	94,690	824,167	3,498,631
73	30	18,344,886	0.000%	0	-7,493,886	740,018	12,323	53,239	8,510	74,072	3,498,631
74	31		0.000%	0	0	740,018	12,323	53,239	8,510	74,072	3,498,631
75	32		0.000%	0	0	740,018	12,323	53,239	8,510	74,072	3,498,631
76	33		0.000%	0	0	740,018	12,323	53,239	8,510	74,072	3,498,631
77	34		0.000%	0	0	740,018	12,323	53,239	8,510	74,072	3,498,631
78	35		0.000%	0	0	740,018	12,323	53,239	8,510	74,072	3,498,631
79	36		0.000%	0	0	740,018	12,323	53,239	8,510	74,072	3,498,631
80	37	0	0.000%	0	0	740,018	12,323	53,239	8,510	74,072	3,498,631
81	38		0.000%	0	0						
82											
83		550,346,567	100.00%	552,158,116	740,018						

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PEACH BOTTOM NUCLEAR UNITS 2 & 3
2014 TEST PERIOD

1	Gross Book Investment	$ 482,635,340		
2	O&M	$ 163,299,257		
3	Depreciation	$ 21,048,495		
4	Real Estate Taxes & Property Insurance	$ 1,833,828		
5	Turbogenerator Investment	$ 227,064,927		(Acct 323)
6	Generator/Exciter share of Turbogenerator	25.00%		(Manufacturer letter-identical unit from same manufacturer)
7	Generator/Exciter Investment	$ 56,766,232		(line 5 * line 6)
8	Accesssories Investment	$ 42,744,812		(Acct 324)
9	Allocation of Accessories to Dual Use	0.00%		(analysis pending)
10	Accessories Allocated	$ -		(line 8 * line 9)
11	Step-up share of total investment	N/A		
12	Step-up Investment	$ 21,869,897		(per Books)
13	Total Dual-Use Investment	$ 78,636,128		(line 7 + line 10 + line 12)
14	Reactive Allocator [@ weighted pf of all unit(s)]	15.36%		= 1 - pf^2, where pf = power factor = 0.92
15	Dual-Use Investment Allocated to Reactive	$ 12,078,509		(line 13 * line 14)
16	Balance of Plant Allocable	$ 470,556,831		(line 1 - line 15)
17	Share of Remaining Plant Allocable	0.14%		Per PSEG Analysis
18	Balance of Plant Allocated	$ 658,780		(line 16 * line 17)
19	Total Allocated Reactive Investment	$ 12,737,289		(line 15 + line 18)

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	4.36%	(line 3 / line 1)
21	n = life of plant	22.9	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	1.48%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	3.35%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components			
24	Production Cost		33.83%	(line 2 / line 1)
25	RE Tax & Property Ins. Component		0.38%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate		1.48%	(line 22)
27	Levelized Tax Factor		3.35%	(line 23)
28	Return		8.86%	(Cap. Struct & Taxes Sch)
29	Prepayments * Pre-tax ROR / Plant =		0.00%	(none)
30	CWC=1/8 O&M*Pre-tax ROR / Plant =		0.58%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment		-0.28%	- (line 44 (k) / 36 (c)) Page 2
32		FCR Total	48.20%	(sum 24 through 31)
33	Annual Reactive Revenue Requirement	$ 6,139,449		(line 19 * line 32)
34	kW capacity	1,121,500		Rated Capacity
35	Annual Vars Rate ($/mW)	$ 5,474		(line 33 / line 34 * 1000)

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Peach Bottom

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		482,635,340	Line 1					NPV of Col (j)>	13,283,978	
37	Asset Service Life		22.9297	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return on Eq		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost Rate		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
					((d) - (b)) *		= (f) * (Line	= (f) * (Line	= (g) * (Line		PMT of NPV
		Line 36 / 37		(b) * (c)	Line 38	Accum. (e)	40)	41)	39)	(g) + (h) + (i)	col. (j)
43											
44	1	21,048,495	3.750%	18,098,825	-1,204,940	-1,204,940	-20,064	-86,686	-13,857	-120,608	1,372,912
45	2	21,048,495	7.219%	34,841,445	5,634,420	4,429,480	73,759	318,668	50,939	443,366	1,372,912
46	3	21,048,495	6.677%	32,225,562	4,565,832	8,995,312	149,788	647,145	103,446	900,380	1,372,912
47	4	21,048,495	6.177%	29,812,385	3,580,049	12,575,360	209,403	904,703	144,617	1,258,723	1,372,912
48	5	21,048,495	5.713%	27,572,957	2,665,243	15,240,603	253,784	1,096,447	175,267	1,525,498	1,372,912
49	6	21,048,495	5.285%	25,507,278	1,821,413	17,062,016	284,114	1,227,484	196,214	1,707,812	1,372,912
50	7	21,048,495	4.888%	23,591,215	1,038,701	18,100,717	301,410	1,302,211	208,159	1,811,780	1,372,912
51	8	21,048,495	4.522%	21,824,770	317,108	18,417,825	306,690	1,325,024	211,806	1,843,520	1,372,912
52	9	21,048,495	4.462%	21,535,189	198,814	18,616,640	310,001	1,339,328	214,092	1,863,421	1,372,912
53	10	21,048,495	4.461%	21,530,363	196,843	18,813,482	313,279	1,353,489	216,356	1,883,124	1,372,912
54	11	21,048,495	4.462%	21,535,189	198,814	19,012,297	316,589	1,367,792	218,642	1,903,024	1,372,912
55	12	21,048,495	4.461%	21,530,363	196,843	19,209,140	319,867	1,381,954	220,906	1,922,727	1,372,912
56	13	21,048,495	4.462%	21,535,189	198,814	19,407,954	323,178	1,396,257	223,192	1,942,627	1,372,912
57	14	21,048,495	4.461%	21,530,363	196,843	19,604,797	326,456	1,410,418	225,456	1,962,330	1,372,912
58	15	21,048,495	4.462%	21,535,189	198,814	19,803,611	329,766	1,424,721	227,742	1,982,230	1,372,912
59	16	21,048,495	4.461%	21,530,363	196,843	20,000,454	333,044	1,438,883	230,006	2,001,933	1,372,912
60	17	21,048,495	4.462%	21,535,189	198,814	20,199,268	336,355	1,453,186	232,292	2,021,833	1,372,912
61	18	21,048,495	4.461%	21,530,363	196,843	20,396,111	339,632	1,467,347	234,556	2,041,536	1,372,912
62	19	21,048,495	4.462%	21,535,189	198,814	20,594,925	342,943	1,481,650	236,842	2,061,436	1,372,912
63	20	21,048,495	4.461%	21,530,363	196,843	20,791,768	346,221	1,495,812	239,106	2,081,139	1,372,912
64	21	21,048,495	2.231%	10,767,594	-4,199,748	16,592,020	276,287	1,193,671	190,809	1,660,768	1,372,912
65	22	21,048,495	0.000%	0	-8,598,310	7,993,710	133,110	575,087	91,928	800,125	1,372,912
66	23	21,048,495	0.000%	0	-8,598,310	-604,600	-10,068	-43,496	-6,953	-60,517	1,372,912
67	24		0.000%	0	0	-604,600	-10,068	-43,496	-6,953	-60,517	1,372,912
68	25		0.000%	0	0	-604,600	-10,068	-43,496	-6,953	-60,517	1,372,912
69	26		0.000%	0	0	-604,600	-10,068	-43,496	-6,953	-60,517	1,372,912
70	27		0.000%	0	0	-604,600	-10,068	-43,496	-6,953	-60,517	1,372,912
71	28		0.000%	0	0	-604,600	-10,068	-43,496	-6,953	-60,517	1,372,912
72	29		0.000%	0	0	-604,600	-10,068	-43,496	-6,953	-60,517	1,372,912
73	30		0.000%	0	0	-604,600	-10,068	-43,496	-6,953	-60,517	1,372,912
74	31		0.000%	0	0	-604,600	-10,068	-43,496	-6,953	-60,517	1,372,912
75	32		0.000%	0	0	-604,600	-10,068	-43,496	-6,953	-60,517	1,372,912
76	33		0.000%	0	0	-604,600	-10,068	-43,496	-6,953	-60,517	1,372,912
77	34		0.000%	0	0	-604,600	-10,068	-43,496	-6,953	-60,517	1,372,912
78	35		0.000%	0	0	-604,600	-10,068	-43,496	-6,953	-60,517	1,372,912
79	36		0.000%	0	0	-604,600	-10,068	-43,496	-6,953	-60,517	1,372,912
80	37		0.000%	0	0	-604,600	-10,068	-43,496	-6,953	-60,517	1,372,912
81	38		0.000%	0	0						
82											
83		484,115,390	100.00%	482,635,340	-604,600						

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SEWAREN GAS/OIL UNITS 1,2,3,4
2014 TEST PERIOD

1	Gross Book Investment (incl. allocated common)	$	80,993,926	
2	O&M	$	14,393,000	
3	Depreciation (incl. common depreciation)	$	3,587,060	
4	Real Estate Taxes & Property Insurance	$	1,843,521	
5	Turbogenerator Investment		N/A	
6	Generator/Exciter share of Turbogenerator		DA	
7	Generator/Exciter Investment	$	14,312,397	(per books)
8	Accesssories Investment	$	2,774,029	(Acct 315)
9	Allocation of Accessories to Dual Use		0.00%	(none)
10	Accessories Allocated	$	-	(line 8 * line 9)
11	Step-up share of total investment		0.00%	(none)
12	Step-up Investment	$	-	(line 1 * line 11)
13	Total Dual-Use Investment	$	14,312,397	(line 7 + line 10 + line 12)
14	Reactive Allocator [@ weighted pf of all unit(s)]		27.75%	= 1 - pf^2, where pf = power factor = 0.85
15	Dual-Use Investment Allocated to Reactive	$	3,971,690	(line 13 * line 14)
16	Balance of Plant Allocable	$	77,022,236	(line 1 - line 15)
17	Share of Remaining Plant Allocable		0.14%	Per PSEG Analysis
18	Balance of Plant Allocated	$	107,831	(line 16 * line 17)
19	Total Allocated Reactive Investment	$	4,079,521	(line 15 + line 18)

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	4.43%	(line 3 / line 1)
21	n = life of plant	22.6	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	1.53%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	3.34%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components		
24	Production Cost	17.77%	(line 2 / line 1)
25	RE Tax & Property Ins. Component	2.28%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate	1.53%	(line 22)
27	Levelized Tax Factor	3.34%	(line 23)
28	Return	8.86%	(Cap. Struct & Taxes Sch)
29	Prepayments * Pre-tax ROR / Plant =	0.00%	(none)
30	CWC=1/8 O&M*Pre-tax ROR / Plant =	0.31%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment	-0.32%	- (line 44 (k) / 36 (c)) Page 2
32	FCR Total	33.77%	(sum 24 through 31)
33	Annual Reactive Revenue Requirement	$ 1,377,492	(line 19 * line 32)
34	kW capacity	453,000	Rated Capacity
35	Annual Vars Rate ($/mW)	$ 3,041	(line 33 / line 34 * 1000)

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SEWAREN

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		80,993,926	Line 1					NPV of Col (j)>	2,468,903	
37	Asset Service Life		22.5795	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return on Eq		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost Rate		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
		Line 36 / 37		(b) * (c)	((d) - (b)) * Line 38	Accum. (e)	= (f) * (Line 40)	= (f) * (Line 41)	= (g) * (Line 39)	(g) + (h) + (i)	PMT of NPV col. (j)
43											
44	1	3,587,060	3.750%	3,037,272	-224,588	-224,588	-3,740	-16,157	-2,583	-22,480	256,452
45	2	3,587,060	7.219%	5,846,952	923,166	698,577	11,633	50,257	8,034	69,924	256,452
46	3	3,587,060	6.677%	5,407,964	743,839	1,442,416	24,019	103,771	16,588	144,378	256,452
47	4	3,587,060	6.177%	5,002,995	578,409	2,020,826	33,650	145,383	23,240	202,273	256,452
48	5	3,587,060	5.713%	4,627,183	424,890	2,445,716	40,726	175,951	28,126	244,802	256,452
49	6	3,587,060	5.285%	4,280,529	283,282	2,728,998	45,443	196,331	31,384	273,157	256,452
50	7	3,587,060	4.888%	3,958,983	151,930	2,880,928	47,973	207,261	33,131	288,365	256,452
51	8	3,587,060	4.522%	3,662,545	30,836	2,911,764	48,486	209,480	33,485	291,451	256,452
52	9	3,587,060	4.462%	3,613,949	10,984	2,922,748	48,669	210,270	33,612	292,551	256,452
53	10	3,587,060	4.461%	3,613,139	10,653	2,933,401	48,846	211,036	33,734	293,617	256,452
54	11	3,587,060	4.462%	3,613,949	10,984	2,944,385	49,029	211,826	33,861	294,716	256,452
55	12	3,587,060	4.461%	3,613,139	10,653	2,955,038	49,207	212,593	33,983	295,783	256,452
56	13	3,587,060	4.462%	3,613,949	10,984	2,966,022	49,390	213,383	34,109	296,882	256,452
57	14	3,587,060	4.461%	3,613,139	10,653	2,976,675	49,567	214,149	34,232	297,948	256,452
58	15	3,587,060	4.462%	3,613,949	10,984	2,987,659	49,750	214,940	34,358	299,048	256,452
59	16	3,587,060	4.461%	3,613,139	10,653	2,998,312	49,927	215,706	34,481	300,114	256,452
60	17		4.462%	3,613,949	1,476,298	4,474,611	74,510	321,915	51,458	447,883	256,452
61	18		4.461%	3,613,139	1,475,967	5,950,578	99,088	428,099	68,432	595,619	256,452
62	19		4.462%	3,613,949	1,476,298	7,426,876	123,671	534,308	85,409	743,388	256,452
63	20		4.461%	3,613,139	1,475,967	8,902,843	148,249	640,493	102,383	891,124	256,452
64	21		2.231%	1,806,974	738,149	9,640,992	160,540	693,597	110,872	965,009	256,452
65	22		0.000%	0	0						
66	23		0.000%	0	0						
67	24		0.000%	0	0						
68	25		0.000%	0	0						
69	26		0.000%	0	0						
70	27		0.000%	0	0						
71	28		0.000%	0	0						
72	29		0.000%	0	0						
73	30		0.000%	0	0						
74	31		0.000%	0	0						
75	32		0.000%	0	0						
76	33		0.000%	0	0						
77	34		0.000%	0	0						
78	35		0.000%	0	0						
79	36		0.000%	0	0						
80	37		0.000%	0	0						
81	38		0.000%	0	0						
82											
83		57,392,965	100.00%	80,993,926	9,640,992						

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BURLINGTON 12 SIMPLE CYCLE (4 GE LM6000 Turbines; 4 Brush Generators)
2014 TEST PERIOD

1	Gross Book Investment (incl. allocated common)	$	124,414,462	
2	O&M	$	6,530,265	
3	Depreciation (incl. common depreciation)	$	4,418,886	
4	Real Estate Taxes & Property Insurance	$	213,093	
5	Turbogenerator Investment	$	100,608,589	(Acct 344)
6	Generator/Exciter share of Turbogenerator		12.00%	Per April 15 letter from GE to PSEG Power, LLC
7	Generator/Exciter Investment	$	12,073,031	(line 5 * line 6)
8	Accesssories Investment	$	1,480,754	(Acct 345)
9	Allocation of Accessories to Dual Use		0.00%	(none)
10	Accessories Allocated	$	-	(line 8 * line 9)
11	Step-up share of total investment		N/A	
12	Step-up Investment	$	8,244,167	(per Book)
13	Total Dual-Use Investment	$	20,317,197	(line 7 + line 10 + line 12)
14	Reactive Allocator [@ weighted pf of all unit(s)]		27.75%	= 1 - pf^2, where pf = power factor = 0.85
15	Dual-Use Investment Allocated to Reactive	$	5,638,022	(line 13 * line 14)
16	Balance of Plant Allocable	$	118,776,440	(line 1 - line 15)
17	Share of Remaining Plant Allocable		0.14%	Per PSEG Analysis
18	Balance of Plant Allocated	$	166,287	(line 16 * line 17)
19	Total Allocated Reactive Investment	$	5,804,309	(line 15 + line 18)

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	3.55%	(line 3 / line 1)
21	n = life of plant	28.2	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	0.91%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	3.32%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components			
24	Production Cost		5.25%	(line 2 / line 1)
25	RE Tax & Property Ins. Component		0.17%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate		0.91%	(line 22)
27	Levelized Tax Factor		3.32%	(line 23)
28	Return		8.75%	(Cap. Struct & Taxes Sch)
29	Prepayments * Pre-tax ROR / Plant =		0.00%	(none)
30	CWC=1/8 O&M*Pre-tax ROR / Plant =		0.09%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment		-0.55%	- (line 44 (k) / 36 (c)) Page 2
32		FCR Total	17.94%	(sum 24 through 31)
33	Annual Reactive Revenue Requirement	$	1,041,234	(line 19 * line 32)
34	kW capacity		171,000	Rated Capacity
35	Annual Vars Rate ($/mW)	$	6,089	(line 33 / line 34 * 1000)

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BURLINGTON

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		124,414,462	Line 1					NPV of Col (j)>	7,057,492	
37	Asset Service Life		28.1552	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return on Eq		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost Rate		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
		Line 36 / 37		(b) * (c)	((d) - (b)) * Line 38	Accum. (e)	= (f) * (Line 40)	= (f) * (Line 41)	= (g) * (Line 39)	(g) + (h) + (i)	PMT of NPV col. (j)
43											
44	1	4,418,886	3.750%	4,665,542	100,759	100,759	1,678	7,249	1,159	10,085	688,324
45	2	4,418,886	7.219%	8,981,480	1,863,820	1,964,579	32,714	141,337	22,593	196,643	688,324
46	3	4,418,886	6.677%	8,307,154	1,588,357	3,552,937	59,163	255,607	40,859	355,629	688,324
47	4	4,418,886	6.177%	7,685,081	1,334,241	4,887,177	81,380	351,596	56,203	489,179	688,324
48	5	4,418,886	5.713%	7,107,798	1,098,421	5,985,598	99,671	430,619	68,835	599,125	688,324
49	6	4,418,886	5.285%	6,575,304	880,897	6,866,495	114,340	493,993	78,965	687,297	688,324
50	7	4,418,886	4.888%	6,081,379	679,128	7,545,624	125,648	542,851	86,775	755,274	688,324
51	8	4,418,886	4.522%	5,626,022	493,115	8,038,739	133,860	578,327	92,446	804,632	688,324
52	9	4,418,886	4.462%	5,551,373	462,621	8,501,360	141,563	611,609	97,766	850,938	688,324
53	10	4,418,886	4.461%	5,550,129	462,113	8,963,473	149,258	644,855	103,080	897,193	688,324
54	11	4,418,886	4.462%	5,551,373	462,621	9,426,094	156,962	678,137	108,400	943,499	688,324
55	12	4,418,886	4.461%	5,550,129	462,113	9,888,207	164,657	711,382	113,715	989,754	688,324
56	13	4,418,886	4.462%	5,551,373	462,621	10,350,828	172,360	744,665	119,035	1,036,060	688,324
57	14	4,418,886	4.461%	5,550,129	462,113	10,812,941	180,055	777,910	124,349	1,082,314	688,324
58	15	4,418,886	4.462%	5,551,373	462,621	11,275,563	187,759	811,192	129,669	1,128,620	688,324
59	16	4,418,886	4.461%	5,550,129	462,113	11,737,676	195,454	844,438	134,984	1,174,875	688,324
60	17	4,418,886	4.462%	5,551,373	462,621	12,200,297	203,157	877,720	140,304	1,221,181	688,324
61	18	4,418,886	4.461%	5,550,129	462,113	12,662,410	210,852	910,965	145,618	1,267,436	688,324
62	19	4,418,886	4.462%	5,551,373	462,621	13,125,031	218,556	944,248	150,938	1,313,742	688,324
63	20	4,418,886	4.461%	5,550,129	462,113	13,587,144	226,251	977,493	156,253	1,359,996	688,324
64	21	4,418,886	2.231%	2,775,687	-671,247	12,915,897	215,073	929,202	148,533	1,292,808	688,324
65	22	4,418,886	0.000%	0	-1,805,115	11,110,782	185,015	799,337	127,774	1,112,127	688,324
66	23	4,418,886	0.000%	0	-1,805,115	9,305,668	154,956	669,473	107,015	931,445	688,324
67	24	4,418,886	0.000%	0	-1,805,115	7,500,553	124,898	539,609	86,257	750,763	688,324
68	25	4,418,886	0.000%	0	-1,805,115	5,695,438	94,839	409,744	65,498	570,081	688,324
69	26	4,418,886	0.000%	0	-1,805,115	3,890,323	64,781	279,880	44,739	389,399	688,324
70	27	4,418,886	0.000%	0	-1,805,115	2,085,208	34,723	150,015	23,980	208,718	688,324
71	28	4,418,886	0.000%	0	-1,805,115	280,094	4,664	20,151	3,221	28,036	688,324
72	29										
73	30										
74	31										
75	32										
76	33										
77	34										
78	35										
79	36										
80	37										
81	38		0.000%	0	0						
82											
83		123,728,798	100.00%	124,414,462	280,094						

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ESSEX 9 SIMPLE CYCLE
2014 TEST PERIOD

1	Gross Book Investment (incl. allocated common)	$	35,105,233	
2	O&M	$	980,128	
3	Depreciation (incl. common depreciation)	$	997,115	
4	Real Estate Taxes & Property Insurance	$	928,474	
5	Turbogenerator Investment		N/A	(Acct 344)
6	Generator/Exciter share of Turbogenerator		DA	
7	Generator/Exciter Investment	$	31,067,586	Per Books
8	Accesssories Investment	$	500,601	(Acct 345)
9	Allocation of Accessories to Dual Use		0.00%	(none)
10	Accessories Allocated	$	-	(line 8 * line 9)
11	Step-up share of total investment		N/A	
12	Step-up Investment	$	78,248	(per books)
13	Total Dual-Use Investment	$	31,145,834	(line 7 + line 10 + line 12)
14	Reactive Allocator [@ weighted pf of all unit(s)]		19.00%	= 1 - pf^2, where pf = power factor = 0.9
15	Dual-Use Investment Allocated to Reactive	$	5,917,709	(line 13 * line 14)
16	Balance of Plant Allocable	$	29,187,524	(line 1 - line 15)
17	Share of Remaining Plant Allocable		0.14%	Per PSEG Analysis
18	Balance of Plant Allocated	$	40,863	(line 16 * line 17)
19	Total Allocated Reactive Investment	$	5,958,571	(line 15 + line 18)

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	2.84%	(line 3 / line 1)
21	n = life of plant	35.2	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	0.47%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	3.64%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components		
24	Production Cost	2.79%	(line 2 / line 1)
25	RE Tax & Property Ins. Component	2.64%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate	0.47%	(line 22)
27	Levelized Tax Factor	3.64%	(line 23)
28	Return	8.86%	(Cap. Struct & Taxes Sch)
29	Prepayments * Pre-tax ROR / Plant =	0.00%	(none)
30	CWC=1/8 O&M*Pre-tax ROR / Plant =	0.05%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment	-0.81%	- (line 44 (k) / 36 (c)) Page 2
32	FCR Total	17.64%	(sum 24 through 31)

33	Annual Reactive Revenue Requirement	$	1,051,348	(line 19 * line 32)
34	kW capacity		83,000	Rated Capacity
35	Annual Vars Rate ($/mW)	$	12,667	(line 33 / line 34 * 1000)

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Essex

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		35,105,233	Line 1					NPV of Col (j)>	3,044,323	
37	Asset Service Life		35.2068	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return on Eq		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost Rate		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
					((d) - (b)) *		= (f) * (Line	= (f) * (Line	= (g) * (Line		PMT of NPV
		Line 36 / 37		(b) * (c)	Line 38	Accum. (e)	40)	41)	39)	(g) + (h) + (i)	col. (j)
43											
44	1	997,115	3.750%	1,316,446	130,447	130,447	2,172	9,385	1,500	13,057	**284,012**
45	2	997,115	7.219%	2,534,247	627,918	758,365	12,628	54,559	8,721	75,908	284,012
46	3	997,115	6.677%	2,343,976	550,193	1,308,558	21,790	94,141	15,048	130,979	284,012
47	4	997,115	6.177%	2,168,450	478,490	1,787,048	29,758	128,565	20,551	178,873	284,012
48	5	997,115	5.713%	2,005,562	411,951	2,198,999	36,617	158,201	25,289	220,107	284,012
49	6	997,115	5.285%	1,855,312	350,573	2,549,572	42,455	183,423	29,320	255,198	284,012
50	7	997,115	4.888%	1,715,944	293,642	2,843,214	47,345	204,548	32,697	284,590	284,012
51	8	997,115	4.522%	1,587,459	241,155	3,084,369	51,360	221,897	35,470	308,728	284,012
52	9	997,115	4.462%	1,566,395	232,551	3,316,920	55,233	238,628	38,145	332,005	284,012
53	10	997,115	4.461%	1,566,044	232,408	3,549,327	59,103	255,348	40,817	355,268	284,012
54	11	997,115	4.462%	1,566,395	232,551	3,781,879	62,975	272,078	43,492	378,545	284,012
55	12	997,115	4.461%	1,566,044	232,408	4,014,286	66,845	288,798	46,164	401,807	284,012
56	13	997,115	4.462%	1,566,395	232,551	4,246,837	70,718	305,528	48,839	425,084	284,012
57	14	997,115	4.461%	1,566,044	232,408	4,479,245	74,588	322,248	51,511	448,347	284,012
58	15	997,115	4.462%	1,566,395	232,551	4,711,796	78,460	338,978	54,186	471,624	284,012
59	16	997,115	4.461%	1,566,044	232,408	4,944,203	82,330	355,698	56,859	494,887	284,012
60	17	997,115	4.462%	1,566,395	232,551	5,176,754	86,202	372,429	59,533	518,164	284,012
61	18	997,115	4.461%	1,566,044	232,408	5,409,162	90,072	389,149	62,206	541,427	284,012
62	19	997,115	4.462%	1,566,395	232,551	5,641,713	93,945	405,879	64,880	564,704	284,012
63	20	997,115	4.461%	1,566,044	232,408	5,874,121	97,815	422,599	67,553	587,966	284,012
64	21	997,115	2.231%	783,198	-87,385	5,786,736	96,360	416,312	66,548	579,220	284,012
65	22	997,115	0.000%	0	-407,322	5,379,414	89,577	387,009	61,863	538,449	284,012
66	23	997,115	0.000%	0	-407,322	4,972,092	82,794	357,705	57,179	497,678	284,012
67	24	997,115	0.000%	0	-407,322	4,564,771	76,012	328,401	52,495	456,908	284,012
68	25	997,115	0.000%	0	-407,322	4,157,449	69,229	299,097	47,811	416,137	284,012
69	26	997,115	0.000%	0	-407,322	3,750,128	62,446	269,794	43,127	375,367	284,012
70	27	997,115	0.000%	0	-407,322	3,342,806	55,664	240,490	38,442	334,596	284,012
71	28	997,115	0.000%	0	-407,322	2,935,485	48,881	211,186	33,758	293,825	284,012
72	29	997,115	0.000%	0	-407,322	2,528,163	42,099	181,882	29,074	253,055	284,012
73	30	997,115	0.000%	0	-407,322	2,120,842	35,316	152,579	24,390	212,284	284,012
74	31	997,115	0.000%	0	-407,322	1,713,520	28,533	123,275	19,706	171,514	284,012
75	32	997,115	0.000%	0	-407,322	1,306,199	21,751	93,971	15,021	130,743	284,012
76	33	997,115	0.000%	0	-407,322	898,877	14,968	64,667	10,337	89,973	284,012
77	34	997,115	0.000%	0	-407,322	491,556	8,185	35,364	5,653	49,202	284,012
78	35	997,115	0.000%	0	-407,322	84,234	1,403	6,060	969	8,431	284,012
79	36										
80	37										
81	38										
82											
83		34,899,029	100.00%	35,105,233	84,234						

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KEARNY 12, 13, 14 (GE LM 6000 units)
2014 TEST PERIOD

1	Gross Book Investment (incl. allocated common)	$ 388,232,256		
2	O&M	$ 37,005,178		
3	Depreciation (incl. common depreciation)	$ 12,769,626		
4	Real Estate Taxes & Property Insurance	$ 2,359,168		
5	Turbogenerator Investment	$ 371,968,128		(Acct 344)
6	Generator/Exciter share of Turbogenerator		12.00%	Per April 15 letter from GE to PSEG Power, LLC
7	Generator/Exciter Investment	$ 44,636,175		(line 5 * line 6)
8	Accesssories Investment	$ -		(Acct 345)
9	Allocation of Accessories to Dual Use		0.00%	(none)
10	Accessories Allocated	$ -		(line 8 * line 9)
11	Step-up share of total investment		0.00%	(none)
12	Step-up Investment	$ -		(line 1 * line 11)
13	Total Dual-Use Investment	$ 44,636,175		(line 7 + line 10 + line 12)
14	Reactive Allocator [@ weighted pf of all unit(s)]		27.75%	= 1 - pf^2, where pf = power factor = 0.85
15	Dual-Use Investment Allocated to Reactive	$ 12,386,539		(line 13 * line 14)
16	Balance of Plant Allocable	$ 375,845,717		(line 1 - line 15)
17	Share of Remaining Plant Allocable		0.14%	Per PSEG Analysis
18	Balance of Plant Allocated	$ 526,184		(line 16 * line 17)
19	Total Allocated Reactive Investment	$ 12,912,723		(line 15 + line 18)

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	3.29%	(line 3 / line 1)
21	n = life of plant	30.4	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	0.73%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	3.53%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components			
24	Production Cost		9.53%	(line 2 / line 1)
25	RE Tax & Property Ins. Component		0.61%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate		0.73%	(line 22)
27	Levelized Tax Factor		3.53%	(line 23)
28	Return		8.86%	(Cap. Struct & Taxes Sch)
29	Prepayments * Pre-tax ROR / Plant =		0.00%	(none)
30	CWC=1/8 O&M*Pre-tax ROR / Plant =		0.16%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment		-0.64%	- (line 44 (k) / 36 (c)) Page 2
32	FCR Total		22.78%	(sum 24 through 31)
33	Annual Reactive Revenue Requirement	$ 2,940,897		(line 19 * line 32)
34	kW capacity	178,000		Rated Capacity
35	Annual Vars Rate ($/mW)	$ 16,522		(line 33 / line 34 * 1000)

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Kearny

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		388,232,256	Line 1					NPV of Col (j)>	26,122,848	
37	Asset Service Life		30.4028	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return on Eq		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost Rate		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
					((d) - (b)) *		= (f) * (Line	= (f) * (Line	= (g) * (Line		PMT of NPV
		Line 36 / 37		(b) * (c)	Line 38	Accum. (e)	40)	41)	39)	(g) + (h) + (i)	col. (j)
43											
44	1	12,769,626	3.750%	14,558,710	730,841	730,841	12,170	52,579	8,405	73,153	2,503,914
45	2	12,769,626	7.219%	28,026,487	6,232,428	6,963,268	115,951	500,955	80,078	696,984	2,503,914
46	3	12,769,626	6.677%	25,922,268	5,372,854	12,336,122	205,419	887,492	141,866	1,234,776	2,503,914
47	4	12,769,626	6.177%	23,981,106	4,579,890	16,916,012	281,682	1,216,980	194,535	1,693,197	2,503,914
48	5	12,769,626	5.713%	22,179,709	3,844,019	20,760,031	345,692	1,493,529	238,741	2,077,962	2,503,914
49	6	12,769,626	5.285%	20,518,075	3,165,241	23,925,273	398,399	1,721,244	275,141	2,394,785	2,503,914
50	7	12,769,626	4.888%	18,976,793	2,535,628	26,460,900	440,622	1,903,663	304,301	2,648,587	2,503,914
51	8	12,769,626	4.522%	17,555,863	1,955,178	28,416,078	473,180	2,044,324	326,786	2,844,289	2,503,914
52	9	12,769,626	4.462%	17,322,923	1,860,022	30,276,100	504,152	2,178,138	348,176	3,030,467	2,503,914
53	10	12,769,626	4.461%	17,319,041	1,858,436	32,134,536	535,099	2,311,839	369,548	3,216,486	2,503,914
54	11	12,769,626	4.462%	17,322,923	1,860,022	33,994,558	566,071	2,445,654	390,939	3,402,664	2,503,914
55	12	12,769,626	4.461%	17,319,041	1,858,436	35,852,994	597,018	2,579,354	412,311	3,588,683	2,503,914
56	13	12,769,626	4.462%	17,322,923	1,860,022	37,713,016	627,991	2,713,169	433,701	3,774,860	2,503,914
57	14	12,769,626	4.461%	17,319,041	1,858,436	39,571,452	658,937	2,846,869	455,073	3,960,879	2,503,914
58	15	12,769,626	4.462%	17,322,923	1,860,022	41,431,474	689,910	2,980,684	476,463	4,147,057	2,503,914
59	16	12,769,626	4.461%	17,319,041	1,858,436	43,289,910	720,856	3,114,384	497,835	4,333,076	2,503,914
60	17	12,769,626	4.462%	17,322,923	1,860,022	45,149,932	751,829	3,248,199	519,226	4,519,254	2,503,914
61	18	12,769,626	4.461%	17,319,041	1,858,436	47,008,368	782,775	3,381,900	540,598	4,705,273	2,503,914
62	19	12,769,626	4.462%	17,322,923	1,860,022	48,868,390	813,748	3,515,714	561,988	4,891,450	2,503,914
63	20	12,769,626	4.461%	17,319,041	1,858,436	50,726,826	844,694	3,649,415	583,360	5,077,469	2,503,914
64	21	12,769,626	2.231%	8,661,462	-1,678,185	49,048,641	816,749	3,528,682	564,061	4,909,492	2,503,914
65	22	12,769,626	0.000%	0	-5,216,392	43,832,249	729,887	3,153,402	504,072	4,387,361	2,503,914
66	23	12,769,626	0.000%	0	-5,216,392	38,615,857	643,024	2,778,121	444,084	3,865,230	2,503,914
67	24	12,769,626	0.000%	0	-5,216,392	33,399,464	556,162	2,402,841	384,095	3,343,098	2,503,914
68	25	12,769,626	0.000%	0	-5,216,392	28,183,072	469,300	2,027,561	324,106	2,820,967	2,503,914
69	26	12,769,626	0.000%	0	-5,216,392	22,966,680	382,437	1,652,280	264,118	2,298,835	2,503,914
70	27	12,769,626	0.000%	0	-5,216,392	17,750,288	295,575	1,277,000	204,129	1,776,704	2,503,914
71	28	12,769,626	0.000%	0	-5,216,392	12,533,896	208,712	901,720	144,140	1,254,572	2,503,914
72	29	12,769,626	0.000%	0	-5,216,392	7,317,504	121,850	526,440	84,152	732,441	2,503,914
73	30	12,769,626	0.000%	0	-5,216,392	2,101,111	34,987	151,159	24,163	210,309	2,503,914
74	31										
75	32										
76	33										
77	34										
78	35										
79	36										
80	37										
81	38										
82											
83		383,088,776	100.00%	388,232,256	2,101,111						

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LINDEN 5,6,7,8 SIMPLE CYCLE (4 GE 7EAs)
2014 TEST PERIOD

1	Gross Book Investment (incl. allocated common)	$	119,451,357	
2	O&M	$	5,593,556	
3	Depreciation (incl. common depreciation)	$	3,839,361	
4	Real Estate Taxes & Property Insurance		257,563	
5	Turbogenerator Investment	$	112,416,036	(Acct 344)
6	Generator/Exciter share of Turbogenerator		19.00%	Per April 17 letter from GE to PSEG Power, LLC
7	Generator/Exciter Investment	$	21,359,047	(line 5 * line 6)
8	Accesssories Investment	$	1,593,061	(Acct 345)
9	Allocation of Accessories to Dual Use		0.00%	(none)
10	Accessories Allocated	$	-	(line 8 * line 9)
11	Step-up share of total investment		N/A	
12	Step-up Investment	$	1,304,780	(per books)
13	Total Dual-Use Investment	$	22,663,827	(line 7 + line 10 + line 12)
14	Reactive Allocator [@ weighted pf of all unit(s)]		27.75%	= 1 - pf^2, where pf = power factor = 0.85
15	Dual-Use Investment Allocated to Reactive	$	6,289,212	(line 13 * line 14)
16	Balance of Plant Allocable	$	113,162,145	(line 1 - line 15)
17	Share of Remaining Plant Allocable		0.14%	Per PSEG Analysis
18	Balance of Plant Allocated	$	158,427	(line 16 * line 17)
19	Total Allocated Reactive Investment	$	6,447,639	(line 15 + line 18)

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	3.21%	(line 3 / line 1)
21	n = life of plant	31.1	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	0.68%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	3.55%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components		
24	Production Cost	4.68%	(line 2 / line 1)
25	RE Tax & Property Ins. Component	0.22%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate	0.68%	(line 22)
27	Levelized Tax Factor	3.55%	(line 23)
28	Return	8.86%	(Cap. Struct & Taxes Sch)
29	Prepayments * Pre-tax ROR / Plant =	0.00%	(none)
30	CWC=1/8 O&M*Pre-tax ROR / Plant =	0.08%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment	-0.67%	- (line 44 (k) / 36 (c)) Page 2
32	FCR Total	17.39%	(sum 24 through 31)

33	Annual Reactive Revenue Requirement	$	1,121,530	(line 19 * line 32)
34	kW capacity		348,000	Rated Capacity
35	Annual Vars Rate ($/mW)	$	3,223	(line 33 / line 34 * 1000)

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LINDEN 5,6,7,8

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		119,451,357	Line 1					NPV of Col (j)>	8,409,861	
37	Asset Service Life		31.1123	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return on Eq		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost Rate		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
					((d) - (b)) *		= (f) * (Line	= (f) * (Line	= (g) * (Line		PMT of NPV
		Line 36 / 37		(b) * (c)	Line 38	Accum. (e)	40)	41)	39)	(g) + (h) + (i)	col. (j)
43											
44	1	3,839,361	3.750%	4,479,426	261,466	261,466	4,354	18,811	3,007	26,171	802,257
45	2	3,839,361	7.219%	8,623,193	1,954,196	2,215,662	36,895	159,400	25,480	221,775	802,257
46	3	3,839,361	6.677%	7,975,767	1,689,722	3,905,384	65,032	280,963	44,912	390,907	802,257
47	4	3,839,361	6.177%	7,378,510	1,445,742	5,351,126	89,106	384,973	61,538	535,618	802,257
48	5	3,839,361	5.713%	6,824,256	1,219,330	6,570,456	109,410	472,695	75,560	657,666	802,257
49	6	3,839,361	5.285%	6,313,004	1,010,483	7,580,939	126,236	545,392	87,181	758,809	802,257
50	7	3,839,361	4.888%	5,838,782	816,764	8,397,703	139,837	604,152	96,574	840,563	802,257
51	8	3,839,361	4.522%	5,401,590	638,171	9,035,873	150,464	650,063	103,913	904,440	802,257
52	9	3,839,361	4.462%	5,329,920	608,893	9,644,766	160,603	693,869	110,915	965,387	802,257
53	10	3,839,361	4.461%	5,328,725	608,405	10,253,172	170,734	737,639	117,912	1,026,285	802,257
54	11	3,839,361	4.462%	5,329,920	608,893	10,862,065	180,873	781,444	124,914	1,087,231	802,257
55	12	3,839,361	4.461%	5,328,725	608,405	11,470,470	191,004	825,214	131,911	1,148,129	802,257
56	13	3,839,361	4.462%	5,329,920	608,893	12,079,363	201,143	869,020	138,913	1,209,076	802,257
57	14	3,839,361	4.461%	5,328,725	608,405	12,687,768	211,274	912,790	145,910	1,269,974	802,257
58	15	3,839,361	4.462%	5,329,920	608,893	13,296,661	221,414	956,595	152,912	1,330,921	802,257
59	16	3,839,361	4.461%	5,328,725	608,405	13,905,067	231,545	1,000,365	159,909	1,391,819	802,257
60	17	3,839,361	4.462%	5,329,920	608,893	14,513,960	241,684	1,044,171	166,911	1,452,766	802,257
61	18	3,839,361	4.461%	5,328,725	608,405	15,122,365	251,815	1,087,941	173,908	1,513,663	802,257
62	19	3,839,361	4.462%	5,329,920	608,893	15,731,258	261,954	1,131,746	180,910	1,574,610	802,257
63	20	3,839,361	4.461%	5,328,725	608,405	16,339,663	272,085	1,175,516	187,907	1,635,508	802,257
64	21	3,839,361	2.231%	2,664,960	-479,743	15,859,920	264,097	1,141,002	182,390	1,587,489	802,257
65	22	3,839,361	0.000%	0	-1,568,379	14,291,541	237,980	1,028,169	164,353	1,430,503	802,257
66	23	3,839,361	0.000%	0	-1,568,379	12,723,162	211,864	915,336	146,317	1,273,517	802,257
67	24	3,839,361	0.000%	0	-1,568,379	11,154,783	185,747	802,503	128,280	1,116,531	802,257
68	25	3,839,361	0.000%	0	-1,568,379	9,586,404	159,631	689,670	110,244	959,545	802,257
69	26	3,839,361	0.000%	0	-1,568,379	8,018,025	133,515	576,837	92,208	802,559	802,257
70	27	3,839,361	0.000%	0	-1,568,379	6,449,646	107,398	464,004	74,171	645,573	802,257
71	28	3,839,361	0.000%	0	-1,568,379	4,881,267	81,282	351,171	56,135	488,587	802,257
72	29	3,839,361	0.000%	0	-1,568,379	3,312,888	55,166	238,337	38,098	331,601	802,257
73	30	3,839,361	0.000%	0	-1,568,379	1,744,509	29,049	125,504	20,062	174,616	802,257
74	31	3,839,361	0.000%	0	-1,568,379	176,130	2,933	12,671	2,026	17,630	802,257
75	32										
76	33										
77	34										
78	35										
79	36										
80	37										
81	38										
82											
83		119,020,193	100.00%	119,451,357	176,130						

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YARDS CREEK PUMPED STORAGE
2014 TEST PERIOD

1	Gross Book Investment	$	39,628,559	
2	O&M	$	3,079,000	
3	Depreciation	$	462,450	
4	Real Estate Taxes & Property Insurance	$	226,265	
5	Turbogenerator Investment	$	14,077,646	(Acct 333)
6	Generator/Exciter share of Turbogenerator		15.00%	Estimated
7	Generator/Exciter Investment	$	2,111,647	(line 5 * line 6)
8	Accesssories Investment	$	1,502,011	(Acct 315)
9	Allocation of Accessories to Dual Use		0.00%	(analysis pending)
10	Accessories Allocated	$	-	(line 8 * line 9)
11	Step-up share of total investment		N/A	
12	Step-up Investment	$	4,968,482	(per books)
13	Total Dual-Use Investment	$	7,080,129	(line 7 + line 10 + line 12)
14	Reactive Allocator [@ weighted pf of all unit(s)]		19.00%	= 1 - pf^2, where pf = power factor = 0.9
15	Dual-Use Investment Allocated to Reactive	$	1,345,225	(line 13 * line 14)
16	Balance of Plant Allocable	$	38,283,334	(line 1 - line 15)
17	Share of Remaining Plant Allocable		0.14%	Per PSEG Analysis
18	Balance of Plant Allocated	$	53,597	(line 16 * line 17)
19	Total Allocated Reactive Investment	$	1,398,821	(line 15 + line 18)

Depreciation Rates & Levelized Tax Factor

20	Calculated SL Depr. Rate (SLD)	1.17%	(line 3 / line 1)
21	n = life of plant	85.7	(1 / (line 3 / line 1)
22	Sinking Fund Depr. Rate (SFD)	0.01%	= ROR/ ((1+ ROR)^n - 1)
23	Levelized Tax Factor	4.32%	= CIT / GTF * (ROR + SFD - SLD) * (1 - weighted LTD / ROR)

	FCR Components		
24	Production Cost	7.77%	(line 2 / line 1)
25	RE Tax & Property Ins. Component	0.57%	(line 4 / line 1)
26	Sinking Fund Depreciation Rate	0.01%	(line 22)
27	Levelized Tax Factor	4.32%	(line 23)
28	Return	8.86%	(Cap. Struct & Taxes Sch)
29	Prepayments * Pre-tax ROR / Plant =	0.00%	(none)
30	CWC=1/8 O&M*Pre-tax ROR / Plant =	0.13%	(line 2/8 & Schedule 2)/line 1
31	ADIT Adjustment	0.00%	- (line 44 (k) / 36 (c)) Page 2
32	FCR Total	21.66%	(sum 24 through 31)

33	Annual Reactive Revenue Requirement	$	302,956	(line 19 * line 32)
34	kW capacity		210,000	Rated Capacity
35	Annual Vars Rate ($/mW)	$	1,443	(line 33 / line 34 * 1000)

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YARDS CREEK

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	ADIT CALCULATION										
36	Investment		39,628,559	Line 1					NPV of Col (j)>	0	
37	Asset Service Life		0.0000	Line 21							
38	Composite Tax Rate		40.85%	Cap. Structure & Taxes Schedule							
39	Gross Up Tax Factor		69.06%	Line 38 / (1-38)							
40	Weighted Rate of Return on Eq		7.19%	Cap. Structure & Taxes Schedule							
41	Weighted Interest Cost Rate		1.67%	"						Rev	
42	ROR		8.86%	Line 40 + 41							

	Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Req Impact	Levelized
					((d) - (b)) *		= (f) * (Line	= (f) * (Line	= (g) * (Line		PMT of NPV
		Line 36 / 37		(b) * (c)	Line 38	Accum. (e)	40)	41)	39)	(g) + (h) + (i)	col. (j)
43											
44	1	0	3.750%	0	0	0	0	0	0	0	#NUM!
45	2	0	7.219%	0	0	0	0	0	0	0	#NUM!
46	3	0	6.677%	0	0	0	0	0	0	0	#NUM!
47	4	0	6.177%	0	0	0	0	0	0	0	#NUM!
48	5	0	5.713%	0	0	0	0	0	0	0	#NUM!
49	6	0	5.285%	0	0	0	0	0	0	0	#NUM!
50	7	0	4.888%	0	0	0	0	0	0	0	#NUM!
51	8	0	4.522%	0	0	0	0	0	0	0	#NUM!
52	9	0	4.462%	0	0	0	0	0	0	0	#NUM!
53	10	0	4.461%	0	0	0	0	0	0	0	#NUM!
54	11	0	4.462%	0	0	0	0	0	0	0	#NUM!
55	12	0	4.461%	0	0	0	0	0	0	0	#NUM!
56	13	0	4.462%	0	0	0	0	0	0	0	#NUM!
57	14	0	4.461%	0	0	0	0	0	0	0	#NUM!
58	15	0	4.462%	0	0	0	0	0	0	0	#NUM!
59	16	0	4.461%	0	0	0	0	0	0	0	#NUM!
60	17	0	4.462%	0	0	0	0	0	0	0	#NUM!
61	18	0	4.461%	0	0	0	0	0	0	0	#NUM!
62	19	0	4.462%	0	0	0	0	0	0	0	#NUM!
63	20	0	4.461%	0	0	0	0	0	0	0	#NUM!
64	21	0	2.231%	0	0	0	0	0	0	0	#NUM!
65	22	0	0.000%	0	0	0	0	0	0	0	#NUM!
66	23	0	0.000%	0	0	0	0	0	0	0	#NUM!
67	24	0	0.000%	0	0	0	0	0	0	0	#NUM!
68	25	0	0.000%	0	0	0	0	0	0	0	#NUM!
69	26	0	0.000%	0	0	0	0	0	0	0	#NUM!
70	27	0	0.000%	0	0	0	0	0	0	0	#NUM!
71	28	0	0.000%	0	0	0	0	0	0	0	#NUM!
72	29	0	0.000%	0	0	0	0	0	0	0	#NUM!
73	30	0	0.000%	0	0	0	0	0	0	0	#NUM!
74	31	0	0.000%	0	0	0	0	0	0	0	#NUM!
75	32	0	0.000%	0	0	0	0	0	0	0	#NUM!
76	33	0	0.000%	0	0	0	0	0	0	0	#NUM!
77	34	0	0.000%	0	0	0	0	0	0	0	#NUM!
78	35	0	0.000%	0	0	0	0	0	0	0	#NUM!
79	36	0	0.000%	0	0	0	0	0	0	0	#NUM!
80	37	0	0.000%	0	0	0	0	0	0	0	#NUM!
81	38		0.000%	0	0						
82											
83		0	100.00%	0	0						

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DEVELOPMENT OF CAPITAL STRUCTURE & DEBT COST RATE

	FERC Account No. (Balances are EOY)	
1. Embedded Cost of Long-term Debt:		
(a) Numerator:		
+Interest on Long-term Debt*	427	130,672,204
+Amort. of Debt Disc. And Expenses	428	3,832,858
+Amort. of Loss on Reacquired Debt	428	0
-Amort. of Premium on Debt-Credit	429	0
-Amort. of Gain on Reacquired Debt	429	0
+Interest on Debt to Assoc. Companies*	430	
-Interest on Securitization Bonds*	N/A	0
Total:		**134,505,062**
(b) Denominator:		
+Bonds	221	2,553,926,000
- Reacquired Bonds	222	0
+Advances from Associated Companies*	223	0
+Other Long-term Debt	224	0
+Unamortized Premium on Long-term Debt	225	0
- Unamortized Disc. On Long-Term Debt	226	10,860,905
+Unamort. Gain on Reacquired Debt	257	0
-Unamort. Loss on Reacquired Debt	189	0
-Long-term Debt - Securitization Bonds*	N/A	0
Total:		**2,543,065,095**
Cost of Long-term Debt = (a)/(b)		**5.29%**
3. **Capital Structure:**		
i. **Long-term Debt**:		
+Bonds	221	2,553,926,000
- Reacquired Bonds	222	0
+Advances from Associated Companies*	223	0
+Other Long-term Debt	224	0
-Long-term Debt - Securitization Bonds*	N/A	0
Total Long-Term Debt:		**2,553,926,000**
ii. **Total Preferred Stock**	204	0
iii.**Common Equity**:		
+Common Stock Issued	201	0
+Capital Stock Subscribed	202, 205	0
+Stock Liablility for Conversion	203, 206	0
+Premium on Capital Stock	207	0
+Other Paid-in Capital	208-211	1,228,033,241
+Installments Received on Capital Stock	212	
-Discount on Capital Stock	213	
-Capital Stock Expense	214	
+Retained Earnings	215, 215.1, 216	4,557,569,100
-Reacquired Capital Stock	217	0
+Noncorporate Proprietorship (Non-Major only)	218	0
+Accumulated Other Comprehensive Income	219	(227,533,954)
Total Common Equity:		**5,558,068,387**
Total Capitalization:		8,111,994,387

Rate of Return Computation	Amount ($)	Ratio	Cost	Wtd Cost
Long-term Debt	2,553,926,000	31.48%	5.29%	1.67%
Preferred Stock	0	0.00%	0.00%	0.00%
Common Equity	5,558,068,387	68.52%	10.50%	7.19%
Total	8,111,994,387	100.00%		8.86%

* Total interest on Long term debt (line 6 above) is gross (not net of interest capitalized during construction).

** Bonds (line 28 above) is not net of discount or premium.

Source: 2014 Form 10-K -- PSEG Power, LLC

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SUMMARY -- HEATING LOSSES BY FACILITY/UNIT
2014 TEST YEAR

	Facility/Unit (A)	% Owned (B)	Heating Losses at 100% Ownership (C)	Heating losses for PS share D= (B) * (C)	Heating Losses Component (1) (D) * .03
1	Bergen 1	100	$ 955,064	$ 955,064	$ 28,652
2	Bergen 2	100	1,034,035	$ 1,034,035	$ 31,021
3	Linden 1 & 2	100	2,286,448	$ 2,286,448	$ 68,593
4	Hudson 2	100	242,186	$ 242,186	$ 7,266
5	Mercer 1	100	76,330	$ 76,330	$ 2,290
6	Mercer 2	100	105,600	$ 105,600	$ 3,168
7	Conemaugh 1 & 2	22.51	2,142,807	$ 482,346	$ 14,470
8	Keystone 1 & 2	22.84	1,827,842	$ 417,479	$ 12,524
9	Salem 1 & 2	57.41	2,714,800	$ 1,558,566	$ 46,757
10	Hope Creek 1	100	1,311,984	$ 1,311,984	$ 39,360
11	Peach Bottom 2 & 3	50	4,397,065	$ 2,198,532	$ 65,956
12	Sewaren 1 - 4	100	47,694	$ 47,694	$ 1,431
13	Burlington 12	100	42,355	$ 42,355	$ 1,271
14	Essex 9	100	6,930	$ 6,930	$ 208
15	Kearny 12,13,14	100	156,412	$ 156,412	$ 4,692
16	Linden 5,6,7,8	100	29,315	$ 29,315	$ 879
17	Yards Creek	50	206,875	$ 103,437	$ 3,103
	Total		$ 17,583,741	$ 11,054,714	$ 331,641

Notes: (1) 3% of calculated maximum is based on an analysis of actual unit performance in 2014

Incremental Heating Loss of Generator

	Unit 1101	Unit 1102	Unit 1103	Unit 1104	Unit 1105	Unit 2101	Unit 2102	Unit 2103
kVA	125,000	125,000	125,000	125,000	191,304	215,000	215,000	304,000
kW	112,500	112,500	112,500	112,500	162,608	183,600	183,600	258,400
pf	0.90	0.90	0.90	0.90	0.85	0.85	0.85	0.85
Generator Output Voltage (kV)	13.80	13.80	13.80	13.80	18.00	18.00	18.00	18.00
Incremental Heating Loss = kW (pf=1.0) - kW (pf= X)	247.5	247.5	247.5	247.5	455.30352	402.05	402.05	775.2
where:								
Generator Efficiency @ Full Load with pf=1.0	99.02%	99.02%	99.02%	99.02%	99.20%	99.26%	99.26%	99.22%
Generator Efficiency @ Full Load with pf= X	98.80%	98.80%	98.80%	98.80%	98.92%	99.04%	99.04%	98.92%
Total Losses @ Full Load with pf=1.0 (kW)	1,102.50	1,102.50	1,102.50	1,102.50	1,300.87	1,352.35	1,352.35	2,015.52
Total Losses @ Full Load with pf= X (kW)	1,350.00	1,350.00	1,350.00	1,350.00	1,756.17	1,754.40	1,754.40	2,790.72
Ia pf=X = X kVA/(Sqrt 3 * X kV)	5,230	5,230	5,230	5,230	6,136	6,896	6,896	9,751
Ia pf=1.0 = X kVA/(Sqrt 3 * X kV)	4,707	4,707	4,707	4,707	5,216	5,862	5,862	8,288

Incremental Heating through the Step-Up Transformer	**Transf 1112**	**Transf 1113**	**Transf 1115**	**Transf 2111**	**Transf 2112**	**Transf 2113**	
Step-Up Transformer:							
KVA	240,000	240,000	325,000	264,000	264,000	264,000	
Kvolts In	13.8	13.8	18.0	18.0	18.0	18.0	
Kvolts Out	138.0	138.0	138.0	141.0	141.0	141.0	
Incremental Heating Loss = [in kW]	125.95	125.95	254.76	207.00	207.42	204.36	
where:							
I = Transformer kVA Base/(Sqrt 3* Transformer KV Base)	1,004	1,004	1,360	1,081	1,081	1,081	
Reported Load Loss H to X [in W]	12,218	12,218	22,539	18,330	18,367	9,051	
Reported Load Loss H to Y [in W]	12,218	12,218	22,539	0	0	0	
Transformer Resistance H to X (Rtr) = watt loss/(3*I^2)	0.004039686	0.00403969	0.004063774	0.005228554	0.005239153	0.002581794	
Transformer Resistance H to Y (Rtr) = watt loss/(3*I^2)	0.004039686	0.00403969	0.004063774	0	0	0	
Incremental Transformer Loss by 1st Connected Unit [in W]	62,974.27	62,974.27	127,378.37	207,002.92	207,422.55	204,355.69	
Incremental Transformer Loss by 2nd Connected Unit [in W]	62,974.27	62,974.27	127,378.37	0.00	0.00	0.00	
Incremental Transformer Loss Total = Sum of Connected Units [in W]	125,948.53	125,948.53	254,756.73	207,002.92	207,422.55	204,355.69	

Total Generator Incremental Heating Losses	0.49	0.49	0.46	0.40	0.40	0.78	MW
Total Step-Up Transformer Incremental Heating Losses	0.13	0.13	0.25	0.21	0.21	0.20	MW
Total incremental Heating Losses	0.62	0.62	0.71	0.61	0.61	0.98	MW
Hours of Operation	8,264	8,264	8,264	7,945	7,945	7,945	Hrs
Total MWH Losses	5,131	5,131	5,868	4,839	4,842	7,783	MWH
Unit Operating Rate	$59.21	$59.21	$59.21	$59.21	$59.21	$59.21	$/MWH
Total Annual Heating Loss	$303,821	$303,821	$347,422	$286,516	$286,713	$460,806	
Unit Heating Loss			$955,064			$1,034,035	

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Burlington

Incremental Heating Loss of Generator

	Unit 121	Unit 122	Unit 123	Unit 124
kVA	71,176	71,176	71,176	71,176
kW	60,500	60,500	60,500	60,500
pf	0.85	0.85	0.85	0.85
Generator Output Voltage (kV)	13.80	13.80	13.80	13.80
Incremental Heating Loss = kW (pf=1.0) - kW (pf= X)	181.50	181.50	181.50	181.50
where:				
Generator Efficiency @ Full Load with pf=1.0	98.68%	98.68%	98.68%	98.68%
Generator Efficiency @ Full Load with pf= X	98.38%	98.38%	98.38%	98.38%
Total Losses @ Full Load with pf=1.0 (kW)	798.59	798.59	798.59	798.59
Total Losses @ Full Load with pf= X (kW)	980.09	980.09	980.09	980.09
Ia pf=X = X kVA/(Sqrt 3 * X kV)	2,978	2,978	2,978	2,978
Ia pf=1.0 = X kVA/(Sqrt 3 * X kV)	2,531	2,531	2,531	2,531

Incremental Heating through the Step-Up Transformer

Step-Up Transformer:	Transf 121	Transf 122	Transf 123	Transf 124
KVA	75,000	75,000	75,000	75,000
Kvolts In	13.8	13.8	13.8	13.8
Kvolts Out	138.0	138.0	138.0	138.0
Incremental Heating Loss = [in kW]	117.48	117.48	117.48	117.48
where:				
I = Transformer kVA Base/(Sqrt 3* Transformer KV Base)	314	314	314	314
Reported Load Loss H to X [in W]	4,701	4,701	4,701	4,701
Reported Load Loss H to Y [in W]	0	0	0	0
Transformer Resistance H to X (Rtr) = watt loss/(3*I^2)	0.0159145	0.0159145	0.0159145	0.0159145
Transformer Resistance H to Y (Rtr) = watt loss/(3*I^2)	0	0	0	0
Incremental Transformer Loss by 1st Connected Unit [in W]	117,480.28	117,480.28	117,480.28	117,480.28
Incremental Transformer Loss by 2nd Connected Unit [in W]	0.00	0.00	0.00	0.00
Incremental Transformer Loss Total = Sum of Connected Units [in W]	117,480.28	117,480.28	117,480.28	117,480.28

Total Generator Incremental Heating Losses	0.18	0.18	0.18	0.18	MW
Total Step-Up Transformer Incremental Heating Losses	0.12	0.12	0.12	0.12	MW
Total incremental Heating Losses	0.30	0.30	0.30	0.30	MW
Hours of Operation	620.90	620.90	620.90	620.90	Hrs
Total MWH Losses	186	186	186	186	MWH
Unit Operating Rate	$57.04	$57.04	$57.04	$57.04	$/MWH
Total Annual Heating Loss	$10,589	$10,589	$10,589	$10,589	
Unit Heating Loss				$42,355	

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Conemaugh

Incremental Heating Loss of Generator

	Unit 1a	Unit 1b	Unit 2a	Unit 2b
kVA	545,000	495,000	545,000	495,000
kW	491,000	445,000	491,000	445,000
pf	0.90	0.90	0.90	0.90
Generator Output Voltage (kV)	22.00	22.00	22.00	22.00
Incremental Heating Loss = kW (pf=1.0) - kW (pf= X)	2,425.00	900.00	2,425.00	900.00
where:				
Generator Efficiency @ Full Load with pf=1.0	NA	NA	NA	NA
Generator Efficiency @ Full Load with pf= X	NA	NA	NA	NA
Total Losses @ Full Load with pf=1.0 (kW)	4,300.00	4,720.00	4,300.00	4,720.00
Total Losses @ Full Load with pf= X (kW)	6,725.00	5,620.00	6,725.00	5,620.00
Ia pf=X = X kVA/(Sqrt 3 * X kV)	14,303	12,990	14,303	12,990
Ia pf=1.0 = X kVA/(Sqrt 3 * X kV)	12,872	11,691	12,872	11,691

Incremental Heating through the Step-Up Transformer

Step-Up Transformer:				
KVA	930,000		930,000	
Kvolts In	22.0		22.0	
Kvolts Out	525.0		525.0	
Incremental Heating Loss = [in kW]	132.78		132.78	
where:				
I = Transformer kVA Base/(Sqrt 3* Transformer KV Base)	1,023		1,023	
Reported Load Loss H to X [in W]	3,573		3,573	
Reported Load Loss H to Y [in W]	0		0	
Transformer Resistance H to X (Rtr) = watt loss/(3*I^2)	0.0011387		0.00113873	
Transformer Resistance H to Y (Rtr) = watt loss/(3*I^2)	0		0	
Incremental Transformer Loss by 1st Connected Unit [in W]	132,776.17		132,776.17	
Incremental Transformer Loss by 2nd Connected Unit [in W]	0.00		0.00	
Incremental Transformer Loss Total = Sum of Connected Units [in W]	132,776.17		132,776.17	

Total Generator Incremental Heating Losses	3.33		3.33		MW
Total Step-Up Transformer Incremental Heating Losses	0.13		0.13		MW
Total incremental Heating Losses	3.46		3.46		MW
Hours of Operation	6,644.61		7,981.46		Hrs
Total MWH Losses	22,976		27,598		MWH
Unit Operating Rate	$42.37		$42.37		$/MWH
Total Annual Heating Loss	$973,475		$1,169,332		
Unit Heating Loss		$973,475		$1,169,332	

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Essex

Incremental Heating Loss of Generator

	Unit 9
kVA	104,000
kW	93,600
pf	0.90
Generator Output Voltage (kV)	13.80
Incremental Heating Loss = kW (pf=1.0) - kW (pf= X)	561.60
where:	
Generator Efficiency @ Full Load with pf=1.0	98.70%
Generator Efficiency @ Full Load with pf= X	98.10%
Total Losses @ Full Load with pf=1.0 (kW)	1,216.80
Total Losses @ Full Load with pf= X (kW)	1,778.40
Ia pf=X = X kVA/(Sqrt 3 * X kV)	4,351
Ia pf=1.0 = X kVA/(Sqrt 3 * X kV)	3,916

Incremental Heating through the Step-Up Transformer

Step-Up Transformer:	Transf 9
KVA	110,000
Kvolts In	13.2
Kvolts Out	230.0
Incremental Heating Loss = [in kW]	43.44
where:	
I = Transformer kVA Base/(Sqrt 3* Transformer KV Base)	276
Reported Load Loss H to X [in W]	921
Reported Load Loss H to Y [in W]	0
Transformer Resistance H to X (Rtr) = watt loss/(3*I^2)	0.0040254
Transformer Resistance H to Y (Rtr) = watt loss/(3*I^2)	0
Incremental Transformer Loss by 1st Connected Unit [in W]	43,438.13
Incremental Transformer Loss by 2nd Connected Unit [in W]	0.00
Incremental Transformer Loss Total = Sum of Connected Units [in W]	43,438.13

Total Generator Incremental Heating Losses	0.56	MW
Total Step-Up Transformer Incremental Heating Losses	0.04	MW
Total incremental Heating Losses	0.61	MW
Hours of Operation	200.81	Hrs
Total MWH Losses	121	MWH
Unit Operating Rate	$57.04	$/MWH
Total Annual Heating Loss	$6,930	
Unit Heating Loss	$6,930	

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Hope Creek

Incremental Heating Loss of Generator

	Unit 1
kVA	1,373,000
kW	1,222,000
pf	0.94
Generator Output Voltage (kV)	25.00
Incremental Heating Loss = kW (pf=1.0) - kW (pf= X)	2,150.00
where:	
Generator Efficiency @ Full Load with pf=1.0	NA
Generator Efficiency @ Full Load with pf= X	NA
Total Losses @ Full Load with pf=1.0 (kW)	13,200
Total Losses @ Full Load with pf= X (kW)	15,350
Ia pf=X = X kVA/(Sqrt 3 * X kV)	31,708
Ia pf=1.0 = X kVA/(Sqrt 3 * X kV)	29,806

Incremental Heating through the Step-Up Transformer

Step-Up Transformer:	
KVA	466,700
Kvolts In	25.0
Kvolts Out	550.0
Incremental Heating Loss = [in kW]	771.69
where:	
I = Transformer kVA Base/(Sqrt 3* Transformer KV Base)	490
Reported Load Loss H to X [in W]	1,583
Reported Load Loss H to Y [in W]	0
Transformer Resistance H to X (Rtr) = watt loss/(3*I^2)	0.002198
Transformer Resistance H to Y (Rtr) = watt loss/(3*I^2)	0
Incremental Transformer Loss by 1st Connected Unit [in W]	771,687.96
Incremental Transformer Loss by 2nd Connected Unit [in W]	0.00
Incremental Transformer Loss Total = Sum of Connected Units [in W]	771,687.96

Total Generator Incremental Heating Losses	2.15	MW
Total Step-Up Transformer Incremental Heating Losses	0.77	MW
Total incremental Heating Losses	2.92	MW
Hours of Operation	8,635.58	Hrs
Total MWH Losses	25,230	MWH
Unit Operating Rate	$52.00	$/MWH
Total Annual Heating Loss	$1,311,984	
Unit Heating Loss	$1,311,984	

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Hudson

Incremental Heating Loss of Generator

	Unit 2	
kVA	733,000	
kW	659,700	
pf	0.90	
Generator Output Voltage (kV)	20.00	
Incremental Heating Loss = kW (pf=1.0) - kW (pf= X)	857.61	
where:		
Generator Efficiency @ Full Load with pf=1.0	98.61%	
Generator Efficiency @ Full Load with pf= X	98.48%	
Total Losses @ Full Load with pf=1.0 (kW)	9,169.83	
Total Losses @ Full Load with pf= X (kW)	10,027.44	
Ia pf=X = X kVA/(Sqrt 3 * X kV)	21,160	
Ia pf=1.0 = X kVA/(Sqrt 3 * X kV)	19,044	
Incremental Heating through the Step-Up Transformer	**Transf 2**	
Step-Up Transformer:	700,000	
KVA	19.3	
Kvolts In	230.0	
Kvolts Out	326.67	
Incremental Heating Loss = [in kW]		
where:		
I = Transformer kVA Base/(Sqrt 3* Transformer KV Base)	1,757	
Reported Load Loss H to X [in W]	11,856	
Reported Load Loss H to Y [in W]	0	
Transformer Resistance H to X (Rtr) = watt loss/$(3*I^2)$	0.00128	
Transformer Resistance H to Y (Rtr) = watt loss/$(3*I^2)$	0	
Incremental Transformer Loss by 1st Connected Unit [in W]	326,671.71	
Incremental Transformer Loss by 2nd Connected Unit [in W]	0.00	
Incremental Transformer Loss Total = Sum of Connected Units [in W]	326,671.71	
Total Generator Incremental Heating Losses	0.86	MW
Total Step-Up Transformer Incremental Heating Losses	0.33	MW
Total incremental Heating Losses	1.18	MW
Hours of Operation	3,295.21	Hrs
Total MWH Losses	3,902	MWH
Unit Operating Rate	$62.06	$/MWH
Total Annual Heating Loss	$242,186	
Unit Heating Loss	$242,186	

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Kearny

Incremental Heating Loss of Generator

	Unit 121	Unit 122	Unit 123	Unit 124	Unit 131	Unit 132	Unit 133	Unit 134	Unit 141	Unit 142
kVA	71,176	71,176	71,176	71,176	71,176	71,176	71,176	71,176	71,176	71,176
kW	60,500	60,500	60,500	60,500	60,500	60,500	60,500	60,500	60,500	60,500
pf	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Generator Output Voltage (kV)	13.80	13.80	13.80	13.80	13.80	13.80	13.80	13.80	13.80	13.80
Incremental Heating Loss = kW (pf=1.0) - kW (pf= X)	181.50	181.50	181.50	181.50	181.50	181.50	181.50	181.50	181.50	181.50
where:										
Generator Efficiency @ Full Load with pf=1.0	98.68%	98.68%	98.68%	98.68%	98.68%	98.68%	98.68%	98.68%	98.68%	98.68%
Generator Efficiency @ Full Load with pf= X	98.38%	98.38%	98.38%	98.38%	98.38%	98.38%	98.38%	98.38%	98.38%	98.38%
Total Losses @ Full Load with pf=1.0 (kW)	798.59	798.59	798.59	798.59	798.59	798.59	798.59	798.59	798.59	798.59
Total Losses @ Full Load with pf= X (kW)	980.09	980.09	980.09	980.09	980.09	980.09	980.09	980.09	980.09	980.09
Ia pf=X = X kVA/(Sqrt 3 * X kV)	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978	2,978
Ia pf=1.0 = X kVA/(Sqrt 3 * X kV)	2,531	2,531	2,531	2,531	2,531	2,531	2,531	2,531	2,531	2,531

Incremental Heating through the Step-Up Transforme

Step-Up Transformer:	Transf 12	Transf 13	Transf 14	
KVA	250,000	250,000	125,000	
Kvolts In	13.8	13.8	13.8	
Kvolts Out	230.0	138.0	138.0	
Incremental Heating Loss = [in kW]	72.05	74.92	38.33	
where:				
I = Transformer kVA Base/(Sqrt 3* Transformer KV Base)	628	1,046	523	
Reported Load Loss H to X [in W]	5,821	16,478	4,260	
Reported Load Loss H to Y [in W]	5,711	16,829	0	
Transformer Resistance H to X (Rtr) = watt loss/(3*I^2)	0.004927	0.005021	0.005192	
Transformer Resistance H to Y (Rtr) = watt loss/(3*I^2)	0.0048337	0.005128	0	
Incremental Transformer Loss by 1st Connected Unit [in W]	36,370.94	37,064.85	38,327.16	
Incremental Transformer Loss by 2nd Connected Unit [in W]	35,682.20	37,854.72	0.00	
Incremental Transformer Loss Total = Sum of Connected Units [in W]	72,053.14	74,919.56	38,327.16	
Total Generator Incremental Heating Losses	0.73	0.73	0.36	MW
Total Step-Up Transformer Incremental Heating Losses	0.07	0.07	0.04	MW
Total incremental Heating Losses	0.80	0.80	0.40	MW
Hours of Operation	1,245.03	1,434.06	1,495.02	Hrs
Total MWH Losses	994	1,149	600	MWH
Unit Operating Rate	$57.04	$57.04	$57.04	$/MWH
Total Annual Heating Loss	$56,675	$65,514	$34,223	
Unit Heating Loss	$56,675	$65,514	$34,223	

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Keystone

Incremental Heating Loss of Generator

	Unit 1a	Unit 1b	Unit 2a	Unit 2b	
kVA	530,000	510,000	530,000	510,000	
kW	477,000	459,000	477,000	459,000	
pf	0.90	0.90	0.90	0.90	
Generator Output Voltage (kV)	20.00	20.00	20.00	20.00	
Incremental Heating Loss = kW (pf=1.0) - kW (pf= X)	1,383.30	1,331.10	1,383.30	1,331.10	
where:					
Generator Efficiency @ Full Load with pf=1.0	99.12%	99.12%	99.12%	99.12%	
Generator Efficiency @ Full Load with pf= X	98.83%	98.83%	98.83%	98.83%	
Total Losses @ Full Load with pf=1.0 (kW)	4,197.60	4,039.20	4,197.60	4,039.20	
Total Losses @ Full Load with pf= X (kW)	5,580.90	5,370.30	5,580.90	5,370.30	
Ia pf=X = X kVA/(Sqrt 3 * X kV)	15,300	14,722	15,300	14,722	
Ia pf=1.0 = X kVA/(Sqrt 3 * X kV)	13,770	13,250	13,770	13,250	

Incremental Heating through the Step-Up Transformer

Step-Up Transformer:				
KVA	930,000		930,000	
Kvolts In	20.0		20.0	
Kvolts Out	525.0		525.0	
Incremental Heating Loss = [in kW]	125.57		125.57	
where:				
I = Transformer kVA Base/(Sqrt 3* Transformer KV Base)	1,023		1,023	
Reported Load Loss H to X [in W]	2,953		2,953	
Reported Load Loss H to Y [in W]	0		0	
Transformer Resistance H to X (Rtr) = watt loss/(3*I^2)	0.0009411		0.0009411	
Transformer Resistance H to Y (Rtr) = watt loss/(3*I^2)	0		0	
Incremental Transformer Loss by 1st Connected Unit [in W]	125,568.62		125,568.62	
Incremental Transformer Loss by 2nd Connected Unit [in W]	0.00		0.00	
Incremental Transformer Loss Total = Sum of Connected Units [in W]	125,568.62		125,568.62	

Total Generator Incremental Heating Losses	2.71	2.71	MW
Total Step-Up Transformer Incremental Heating Losses	0.13	0.13	MW
Total incremental Heating Losses	2.84	2.84	MW
Hours of Operation	6,896.20	8,205.01	Hrs
Total MWH Losses	19,585	23,302	MWH
Unit Operating Rate	$42.62	$42.62	$/MWH
Total Annual Heating Loss	$834,712	$993,130	
Unit Heating Loss	$834,712	$993,130	

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Linden

Incremental Heating Loss of Generator

	Unit 1101	Unit 1102	Unit 1103		Unit 2101	Unit 2102	Unit 2203	Unit 5	Unit 6	Unit 7	Unit 8	
kVA	213,400	213,400	370,600		213,400	213,400	370,600	113,100	113,100	113,100	113,100	
kW	183,600	183,600	258,400		183,600	183,600	258,400	96,135	96,135	96,135	96,135	
pf	0.85	0.85	0.85		0.85	0.85	0.85	0.85	0.85	0.85	0.85	
Generator Output Voltage (kV)	18.00	18.00	18.00		18.00	18.00	18.00	13.80	13.80	13.80	13.80	
Incremental Heating Loss = kW (pf=1.0) - kW (pf= X)	399.06	399.06	1,008.03		399.06	399.06	1,008.03	255.00	255.00	255.00	255.00	
where:												
Generator Efficiency @ Full Load with pf=1.0	99.26%	99.26%	99.20%		99.26%	99.26%	99.20%	NA	NA	NA	NA	
Generator Efficiency @ Full Load with pf= X	99.04%	99.04%	98.88%		99.04%	99.04%	98.88%	NA	NA	NA	NA	
Total Losses @ Full Load with pf=1.0 (kW)	1,342.29	1,342.29	2,520.08		1,342.29	1,342.29	2,520.08	715.00	715.00	715.00	715.00	
Total Losses @ Full Load with pf= X (kW)	1,741.34	1,741.34	3,528.11		1,741.34	1,741.34	3,528.11	970.00	970.00	970.00	970.00	
Ia pf=X = X kVA/(Sqrt 3 * X kV)	6,845	6,845	11,887		6,845	6,845	11,887	4,732	4,732	4,732	4,732	
Ia pf=1.0 = X kVA/(Sqrt 3 * X kV)	5,818	5,818	10,104		5,818	5,818	10,104	4,022	4,022	4,022	4,022	

Incremental Heating through the Step-Up Transformer

Step-Up Transformer:								Transf 5	Transf 6	Transf 7	Transf 8	
KVA	220,000	220,000	220,000	220,000	220,000	220,000	375,000	200,000	200,000	240,000	240,000	
Kvolts In	18.0	18.0	18.0	18.0	18.0	18.0	18.0	13.8	13.8	13.8	13.8	
Kvolts Out	141.0	235.7	141.0	141.0	235.7	235.7	235.7	230.0	230.0	141.5	141.5	
Incremental Heating Loss = [in kW]	162.81	173.34	524.36	524.36	170.82	170.45	346.39	209.63	209.63	182.30	182.30	
where:												
I = Transformer kVA Base/(Sqrt 3* Transformer KV Base)	901	539	901	901	539	539	919	502	502	979	979	
Reported Load Loss H to X [in W]	10,162	3,872	10,852	10,852	3,816	3,807	7,454	4,250	4,250	14,021	14,021	
Reported Load Loss H to Y [in W]	0	0	0	0	0	0	0	4,254	4,254	14,115	14,115	
Transformer Resistance H to X (Rtr) = watt loss/(3*I^2)	0.004174215	0.004444215	0.004457603	0.004457603	0.00437969	0.004370021	0.00294464	0.0056202	0.0056202	0.0048738	0.0048738	
Transformer Resistance H to Y (Rtr) = watt loss/(3*I^2)	0	0	0	0	0	0	0	0.0056263	0.0056263	0.0049065	0.0049065	
Incremental Transformer Loss by 1st Connected Unit [in W]	162,810.20	173,341.22	524,360.81	524,360.81	170,824.51	170,447.37	346,386.55	104,756.70	104,756.70	90,844.31	90,844.31	
Incremental Transformer Loss by 2nd Connected Unit [in W]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	104,870.40	104,870.40	91,453.82	91,453.82	
Incremental Transformer Loss Total = Sum of Connected Units [in W]	162,810.20	173,341.22	524,360.81	524,360.81	170,824.51	170,447.37	346,386.55	209,627.09	209,627.09	182,298.12	182,298.12	
Total Generator Incremental Heating Losses	0.40	0.40	1.01	NA	0.40	0.40	1.01	0.26	0.26	0.26	0.26	MW
Total Step-Up Transformer Incremental Heating Losses	0.16	0.17	0.52	0.52	0.17	0.17	0.35	0.21	0.21	0.18	0.18	MW
Total incremental Heating Losses	0.56	0.57	1.53	0.52	0.57	0.57	1.35	0.46	0.46	0.44	0.44	MW
Hours of Operation	7,523.42	7,523.42	7,523.42	7,523.42	6,447.01	6,447.01	6,447.01	210.08	314.30	222.36	395.74	Hrs
Total MWH Losses	4,227	4,306	11,529	3,945	3,674	3,672	8,732	98	146	97	173	MWH
Unit Operating Rate	$57.04	$57.04	$57.04	$57.04	$57.04	$57.04	$57.04	$57.04	$57.04	$57.04	$57.04	$/MWH
Total Annual Heating Loss	$241,117.80	$245,637	$657,605	$225,022	$209,567	$209,428	$498,070	$5,568	$8,330	$5,546	$9,871	
Unit Heating Loss				$1,369,382			$917,066	$5,568	$8,330	$5,546	$9,871	

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Mercer

Incremental Heating Loss of Generator

	Unit 1	Unit 2
kVA	384,000	384,000
kW	326,400	326,400
pf	0.85	0.85
Generator Output Voltage (kV)	18.00	18.00
Incremental Heating Loss = kW (pf=1.0) - kW (pf= X)	652.80	652.80
where:		
Generator Efficiency @ Full Load with pf=1.0	99.00%	99.00%
Generator Efficiency @ Full Load with pf= X	98.80%	98.80%
Total Losses @ Full Load with pf=1.0 (kW)	3,264.00	3,264.00
Total Losses @ Full Load with pf= X (kW)	3,916.80	3,916.80
Ia pf=X = X kVA/(Sqrt 3 * X kV)	12,317	12,317
Ia pf=1.0 = X kVA/(Sqrt 3 * X kV)	10,469	10,469

Incremental Heating through the Step-Up Transformer

Step-Up Transformer:	Transf 1	Transf 2
KVA	340,000	340,000
Kvolts In	17.5	17.5
Kvolts Out	230.0	230.0
Incremental Heating Loss = [in kW]	383.13	383.13
where:		
I = Transformer kVA Base/(Sqrt 3* Transformer KV Base)	853	853
Reported Load Loss H to X [in W]	6,629	6,629
Reported Load Loss H to Y [in W]	0	0
Transformer Resistance H to X (Rtr) = watt loss/(3*I^2)	0.003033616	0.003033616
Transformer Resistance H to Y (Rtr) = watt loss/(3*I^2)	0	0
Incremental Transformer Loss by 1st Connected Unit [in W]	383,125.42	383,125.42
Incremental Transformer Loss by 2nd Connected Unit [in W]	0.00	0.00
Incremental Transformer Loss Total = Sum of Connected Units [in W]	383,125.42	383,125.42

Total Generator Incremental Heating Losses	0.65	0.65	MW
Total Step-Up Transformer Incremental Heating Losses	0.38	0.38	MW
Total incremental Heating Losses	1.04	1.04	MW
Hours of Operation	1,397.10	1,932.84	Hrs
Total MWH Losses	1,447	2,002	MWH
Unit Operating Rate	$52.74	$52.74	$/MWH
Total Annual Heating Loss	$76,330	$105,600	
Unit Heating Loss	$76,330	$105,600	

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Peach Bottom

Incremental Heating Loss of Generator

	Unit 2	Unit 3	
kVA	1,530,000	1,530,000	
kW	1,332,000	1,334,000	
pf	0.92	0.90	
Generator Output Voltage (kV)	22.00	22.00	
Incremental Heating Loss = kW (pf=1.0) - kW (pf= X)	3,631.61	3,552.66	
where:			
Generator Efficiency @ Full Load with pf=1.0	98.99%	98.99%	
Generator Efficiency @ Full Load with pf= X	98.73%	98.73%	
Total Losses @ Full Load with pf=1.0 (kW)	14,188.61	13,880.16	
Total Losses @ Full Load with pf= X (kW)	17,820.22	17,432.82	
Ia pf=X = X kVA/(Sqrt 3 * X kV)	40,152	40,152	
Ia pf=1.0 = X kVA/(Sqrt 3 * X kV)	36,940	36,137	

Incremental Heating through the Step-Up Transformer

Step-Up Transformer:			
KVA	510,000	510,000	
Kvolts In	22.0	22.0	
Kvolts Out	500.0	500.0	
Incremental Heating Loss = [in kW]	1,422.17	1,759.20	
where:			
I = Transformer kVA Base/(Sqrt 3* Transformer KV Base)	589	589	
Reported Load Loss H to X [in W]	1,992	1,992	
Reported Load Loss H to Y [in W]	0	0	
Transformer Resistance H to X (Rtr) = watt loss/(3*I^2)	0.001914362	0.001914362	
Transformer Resistance H to Y (Rtr) = watt loss/(3*I^2)	0	0	
Incremental Transformer Loss by 1st Connected Unit [in W]	1,422,173.86	1,759,199.43	
Incremental Transformer Loss by 2nd Connected Unit [in W]	0.00	0.00	
Incremental Transformer Loss Total = Sum of Connected Units [in W]	1,422,173.86	1,759,199.43	

Total Generator Incremental Heating Losses	3.63	3.55	MW
Total Step-Up Transformer Incremental Heating Losses	1.42	1.76	MW
Total incremental Heating Losses	5.05	5.31	MW
Hours of Operation	7,689.02	8,758.00	Hrs
Total MWH Losses	38,859	46,521	MWH
Unit Operating Rate	$51.50	$51.50	$/MWH
Total Annual Heating Loss	$2,001,219	$2,395,845	
Unit Heating Loss	$2,001,219	$2,395,845	

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Salem

Incremental Heating Loss of Generator

	Unit 1	Unit 2
kVA	1,300,000	1,300,000
kW	1,170,000	1,170,000
pf	0.90	0.90
Generator Output Voltage (kV)	25.00	25.00
Incremental Heating Loss = kW (pf=1.0) - kW (pf= X)	2,564.00	2,564.00
where:		
Generator Efficiency @ Full Load with pf=1.0	NA	NA
Generator Efficiency @ Full Load with pf= X	NA	NA
Total Losses @ Full Load with pf=1.0 (kW)	12,850.00	12,850.00
Total Losses @ Full Load with pf= X (kW)	15,414.00	15,414.00
Ia pf=X = X kVA/(Sqrt 3 * X kV)	30,022	30,022
Ia pf=1.0 = X kVA/(Sqrt 3 * X kV)	27,020	27,020

Incremental Heating through the Step-Up Transformer

Step-Up Transformer:		
KVA	416,667	440,000
Kvolts In	24.0	24.0
Kvolts Out	500.0	500.0
Incremental Heating Loss = [in kW]	1,129.26	1,129.26
where:		
I = Transformer kVA Base/(Sqrt 3* Transformer KV Base)	481	508
Reported Load Loss H to X [in W]	1,526	1,702
Reported Load Loss H to Y [in W]	0	0
Transformer Resistance H to X (Rtr) = watt loss/(3*I^2)	0.002198028	0.002198028
Transformer Resistance H to Y (Rtr) = watt loss/(3*I^2)	0	0
Incremental Transformer Loss by 1st Connected Unit [in W]	1,129,258.77	1,129,258.77
Incremental Transformer Loss by 2nd Connected Unit [in W]	0.00	0.00
Incremental Transformer Loss Total = Sum of Connected Units [in W]	1,129,258.77	1,129,258.77

Total Generator Incremental Heating Losses	2.56	2.56	MW
Total Step-Up Transformer Incremental Heating Losses	1.13	1.13	MW
Total incremental Heating Losses	3.69	3.69	MW
Hours of Operation	7,656.55	6,487.55	Hrs
Total MWH Losses	28,278	23,960	MWH
Unit Operating Rate	$51.97	$51.97	$/MWH
Total Annual Heating Loss	$1,469,588	$1,245,212	
Unit Heating Loss	$1,469,588	$1,245,212	

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Sewaren

Incremental Heating Loss of Generator

	Unit 1		Unit 2	Unit 3	Unit 4	
kVA	121,470		121,500	128,000	140,000	
kW	103,250		103,275	108,800	119,000	
pf	0.85		0.85	0.85	0.85	
Generator Output Voltage (kV)	13.80		13.80	13.80	16.50	
Incremental Heating Loss = kW (pf=1.0) - kW (pf= X)	227.15		206.55	217.60	261.80	
where:						
Generator Efficiency @ Full Load with pf=1.0	99.02%		99.00%	99.00%	99.02%	
Generator Efficiency @ Full Load with pf= X	98.80%		98.80%	98.80%	98.80%	
Total Losses @ Full Load with pf=1.0 (kW)	1,011.85		1,032.75	1,088.00	1,166.20	
Total Losses @ Full Load with pf= X (kW)	1,238.99		1,239.30	1,305.60	1,428.00	
Ia pf=X = X kVA/(Sqrt 3 * X kV)	5,082	5,082	5,083	5,355	4,899	
Ia pf=1.0 = X kVA/(Sqrt 3 * X kV)	4,320	4,320	4,321	4,552	4,164	

Incremental Heating through the Step-Up Transformer

Step-Up Transformer:	Transf 1a	Transf 1b	Transf 2	Transf 3	Transf 4	
KVA	51,000	51,000	85,000	85,000	110,000	
Kvolts In	13.2	13.2	13.4	13.4	13.4	
Kvolts Out	27.8	27.8	138.0	138.0	138.0	
Incremental Heating Loss = [in kW]	429.64	429.64	226.59	251.49	1,053.61	
where:						
I = Transformer kVA Base/(Sqrt 3* Transformer KV Base)	1,059	1,059	356	356	460	
Reported Load Loss H to X [in W]	67,253	67,253	3,996	3,996	4,472	
Reported Load Loss H to Y [in W]	0	0	0	0	29,036	
Transformer Resistance H to X (Rtr) = watt loss/(3*I^2)	0.019983003	0.019983003	0.010533984	0.01053398	0.00703872	
Transformer Resistance H to Y (Rtr) = watt loss/(3*I^2)	0	0	0	0	0.0457	
Incremental Transformer Loss by 1st Connected Unit [in W]	429,638.94	429,638.94	226,594.84	251,488.07	140,619.28	
Incremental Transformer Loss by 2nd Connected Unit [in W]	0.00	0.00	0.00	0.00	912,992.84	
Incremental Transformer Loss Total = Sum of Connected Units [in W]	429,638.94	429,638.94	226,594.84	251,488.07	1,053,612.11	

Total Generator Incremental Heating Losses	0.23	0.21	0.22	0.26	MW
Total Step-Up Transformer Incremental Heating Losses	0.86	0.23	0.25	1.05	MW
Total incremental Heating Losses	1.09	0.43	0.47	1.32	MW
Hours of Operation	341.60	471.33	133.60	145.15	Hrs
Total MWH Losses	371	204	63	191	MWH
Unit Operating Rate	$57.54	$57.54	$57.54	$57.54	$/MWH
Total Annual Heating Loss	$21,354	$11,747	$3,606	$10,986	
Unit Heating Loss	$21,354	$11,747	$3,606	$10,986	

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Yards Creek

Incremental Heating Loss of Generator

	Unit 1	Unit 2	Unit 3
kVA	154,000	154,000	154,000
kW	141,000	141,000	141,000
pf	0.90	0.90	0.90
Generator Output Voltage (kV)	14.40	14.40	14.40
Incremental Heating Loss = kW (pf=1.0) - kW (pf= X)	69.30	69.30	69.30
where:			
Generator Efficiency @ Full Load with pf=1.0	98.10%	98.10%	98.10%
Generator Efficiency @ Full Load with pf=0.9	98.05%	98.05%	98.05%
Total Losses @ Full Load with pf=1.0 (kW)	2,633.40	2,633.40	2,633.40
Total Losses @ Full Load with pf=.9 (kW)	2,702.70	2,702.70	2,702.70
Ia pf=X = X kVA/(Sqrt 3 * X kV)	6,174	6,174	6,174
Ia pf=1.0 = X kVA/(Sqrt 3 * X kV)	5,557	5,557	5,557

Incremental Heating through the Step-Up Transformer

Step-Up Transformer:	Transf 1	Transf 2	Transf 3
KVA	160,000	160,000	160,000
Kvolts In	14.4	14.4	14.4
Kvolts Out	230.0	230.0	230.0
Incremental Heating Loss = [in kW]	378.11	367.25	375.94
where:			
I = Transformer kVA Base/(Sqrt 3* Transformer KV Base)	402	402	402
Reported Load Loss H to X [in W]	8,420	8,178	8,372
Reported Load Loss H to Y [in W]	0	0	0
Transformer Resistance H to X (Rtr) = watt loss/(3*I^2)	0.0174	0.0169	0.0173
Transformer Resistance H to Y (Rtr) = watt loss/(3*I^2)	0	0	0
Incremental Transformer Loss by 1st Connected Unit [in W]	378,111.00	367,245.74	375,937.94
Incremental Transformer Loss by 2nd Connected Unit [in W]	0.00	0.00	0.00
Incremental Transformer Loss Total = Sum of Connected Units [in W]	378,111.00	367,245.74	375,937.94

Total Generator Incremental Heating Losses	0.07	0.07	0.07	MW
Total Step-Up Transformer Incremental Heating Losses	0.38	0.37	0.38	MW
Total incremental Heating Losses	0.45	0.44	0.45	MW
Hours of Operation	2923.91	2692.59	2567.64	Hrs
Total MWH Losses	1,308	1,175	1,143	MWH
Unit Operating Rate	$57.04	$57.04	$57.04	$/MWH
Total Annual Heating Loss	$74,619	$67,047	$65,209	
Unit Heating Loss	$74,619	$67,047	$65,209	

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2014 Plant LMP Data

PSEG Power PJM Units 2014

Unit	LMP
	$/MW
Hope Creek 1	52.00
Peach Bottom 2	51.50
Peach Bottom 3	51.50
Salem 1	51.97
Salem 2	51.97
Conemaugh 1	42.37
Conemaugh 2	42.37
Hudson 2	62.06
Keystone 1	42.62
Keystone 2	42.62
Mercer 1	52.74
Mercer 2	52.74
Sewaren 1	57.54
Sewaren 2	57.54
Sewaren 3	57.54
Sewaren 4	57.54
Bergen 1	59.21
Bergen 2	59.21
Linden CC 1	57.04
Linden CC 2	57.04
Burlington 12	57.04
Essex 9	57.04
Kearny 12	57.04
Kearny 13	57.04
Kearny 14	57.04
Linden 5	57.04
Linden 6	57.04
Linden 7	57.04
Linden 8	57.04
Yards Creek 1	57.04
Yards Creek 2	57.04
Yards Creek 3	57.04

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PSEG POWER, LLC
REACTIVE REVENUE REQUIREMENT ANALYSIS

Workpaper for
Exhibit No. PSEG-3
Schedule 3

2014 Base Year Accounting and O&M Data (all costs in PSEG share)

Unit	Total Cost (as of 12/31/14) (Gross Investment)	Turbine Generator Cost	Generator Cost	Accessory Electrical Cost	2014 Depreciation and Amortization Expense	Fossil and Nuclear Operations and Maintenance
NUCLEAR						
Hope Creek 1 and Common	489,246,051	240,389,030		33,374,026	14,297,557	203,373,186
Peach Bottom 2 &3 and Common	482,635,340	227,064,927		42,744,812	21,048,495	163,299,257
Salem 1 &2 and Common	609,097,955	64,342,161	15,165,340	9,330,643	19,300,371	244,759,952
EST Enhancement						
CNO - Nuclear & Misc Com	204,567,400				13,160,458	
COAL						
Conemaugh	283,640,259	32,977,099		8,161,421	6,811,371	25,562,000
Hudson 2	1,177,392,930		33,866,637	17,913,039	33,987,395	50,040,000
Hudson Common	54,396,480				1,793,601	
Keystone	393,001,398	34,995,860		4,347,123	11,952,962	22,967,000
Mercer 1	462,287,168		4,738,464	1,404,622	12,072,220	18,035,500
Mercer 2	487,989,484		19,409,585	6,629,087	13,018,937	18,035,500
Mercer Common	27,090,692	5,433,287		0	717,119	
OIL/GAS STEAM						
Sewaren 1	17,749,095		14,312,397	2,774,029	682,487	14,393,000
Sewaren 2	21,006,067				696,547	
Sewaren 3	16,194,694				841,791	
Sewaren 4	12,507,824				826,786	
Sewaren Common	15,558,487				620,041	
COMBINED CYCLE						
Bergen 1	449,528,720	318,699,249		71,862,703	12,122,914	17,795,500
Bergen 2	366,234,897	267,702,291		41,024,167	9,280,966	17,795,500
Bergen Common	2,213,506				183,334	
Linden CC 1	550,182,688	426,274,573		24,684,944	13,818,337	49,339,000
Linden CC 2	550,182,688	426,274,573		24,684,944	13,818,337	49,339,000
Linden Common	73,193				4,493	
SIMPLE CYCLE						
Burlington 12	110,555,134	100,608,589		1,480,754	3,968,089	6,530,265
Burlington Common	10,967,741				412,420	
Essex 9	33,778,955		31,067,586	500,601	968,739	980,128
Essex Common	0				0	
Kearny 12, 13, 14	372,303,022	371,968,128		0	12,370,900	37,005,178
Kearny Common	1,312,923				86,079	
Linden 5,6,7,8*	114,931,817	112,416,036		1,593,061	3,742,388	5,593,556
Peaking Common	30,988,960				663,010	
Yards Creek	39,628,559	14,077,646		1,502,011	462,450	3,079,000
RETIRING UNITS: total cost of units not longer in service after May 1, 2014 included to apportion 2014 Real Estate tax and Insurance costs						
Hudson 1	0	NA	NA	NA	NA	NA
Bergen 3*	4,200,511	NA	NA	NA	NA	NA
Burlington 8	3,678,486	NA	NA	NA	NA	NA
Burlington 9	7,565,470	NA	NA	NA	NA	NA
Burlington 11	5,587,925	NA	NA	NA	NA	NA
Edison 1	21,495,658	NA	NA	NA	NA	NA
Edison 2	22,236,140	NA	NA	NA	NA	NA
Edison 3	15,878,428	NA	NA	NA	NA	NA
Edison Common	0	NA	NA	NA	NA	NA
Essex 10	21,753,535	NA	NA	NA	NA	NA
Essex 11	17,006,046	NA	NA	NA	NA	NA
Essex 12	16,237,093	NA	NA	NA	NA	NA
Kearny 9	0	NA	NA	NA	NA	NA
Kearny 10	450,000	NA	NA	NA	NA	NA
Kearny 11	0	NA	NA	NA	NA	NA
Mercer 3*	12,095,233	NA	NA	NA	NA	NA
National Park 1	3,626,700	NA	NA	NA	NA	NA
Sewaren 6*	10,077,804	NA	NA	NA	NA	NA
Salem 3* (now in total-included in S1&2)	0	NA	NA	NA	NA	NA
Fossil Misc / President	1,077,967					
Sys Maint Division	2,936,769					
SUM:	7,553,147,890	2,643,223,450	118,560,009	294,011,987	223,730,593	947,922,522

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ALLOCATION OF COMMON PLANT, RE TAXES AND PROPERTY INSURANCE TO UNITS

2014

	Facility/Unit	RE Taxes	Insurance	Total	Common Plant	Common Depre-ciation	Investment excluding Common	Peaking Common Allocated	Peaking Common Depre-ciation	Peaking Investment
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
								30,988,960	663,010	
1	**Bergen Total**	**1,064,065**	**419,712**	**1,483,777**	**2,213,506**	**183,334**				
2	**Bergen 1**			817,639	1,219,758	101,027	449,528,720			
3	**Bergen 2**			666,138	993,748	82,307	366,234,897			
4	**Bergen 3**			7,601	11,339	939	4,200,511	164,053	3,510	4,200,511
5	**Linden**	**1,830,546**	**892,946**	**2,723,492**	**73,193**	**4,493**				
6	**Linden 1**			1,232,964	33,136	2,034	550,182,688			
7	**Linden 2**			1,232,964	33,136	2,034	550,182,688			
8	**Linden 5,6,7,8**			257,563	6,922	425	114,931,817	4,512,618	96,548	114,931,817
9	**Hudson**	**1,295,222**	**1,165,992**	**2,461,214**	**54,396,480**	**1,793,601**				
10	**Hudson 1**			-	-	-	-			
11	**Hudson 2**			2,461,214	54,396,480	1,793,601	1,177,392,930			
12	**Mercer**	**1,079,610**	**1,211,040**	**2,290,650**	**27,090,692**	**717,119**				
13	**Mercer 1**			1,100,342	13,013,347	344,477	462,287,168			
14	**Mercer 2**			1,161,519	13,736,865	363,629	487,989,484			
15	**Mercer 3**			28,789	340,480	9,013	12,095,233	474,900	10,161	12,095,233
16	**Sewaren**	**1,786,113**	**332,820**	**2,118,933**	**15,558,487**	**620,041**				
17	**Units 1,2,3,4**			1,843,521	13,536,247	539,450	67,457,679			
18	**Unit 6**			275,412	2,022,240	80,591	10,077,804	395,689	8,466	10,077,804
19	**Peaking/Burlingtc**	**1,244,634**	**368,098**	**1,612,732**	**10,967,741**	**412,420**				
20	**Burlington 8,9,11**			213,093	1,449,188	54,494	16,831,881	660,878	14,140	16,831,881
21	**Burlington 12**			1,399,639	9,518,553	357,926	110,555,134	4,340,774	92,871	110,555,134
22	**Edison**	**111,347**	**277,349**	**388,696**	**0**	**NA**		2,340,502	50,075	59,610,226
23	**Essex**	**560,726**	**367,748**	**928,474**	**0**	**0**				
	Essex 10,11,12			575,191	-	-	54,996,674	2,159,358	46,200	54,996,674
	Essex 9			353,283	-	-	33,778,955	1,326,278	28,376	33,778,955
24	**Kearny**	**1,942,307**	**419,712**	**2,362,019**	**1,312,923**	**86,079**				
25	**Units 9,10,11**			2,852	1,585	104	450,000	17,669	378	450,000
26	**Unit 12, 13, 14**			2,359,168	1,311,338	85,975	372,303,022	14,617,896	312,751	372,303,022
27	**Yards Creek**	**99,622**	**126,643**	**226,265**						
28	**Keystone /Conn.**	**1,078,168**	**418,389**	**1,496,557**						
29	**Salem 3**				**Note: this is now included in Salem Nuclear**			-	-	0
30	**National Park 1**	**21,311**		**21,311**				142,397	3,047	3,626,700
31					**----------Nuclear Facilities----------**					
32	MISC Nuclear Common and & CNO Common split --- >				**204,567,400**	**13,160,458**				
33	**Salem**	**963,594**	**2,123,055**	**3,086,649**	113,444,954	7,298,267	609,097,955			
34	**Hope Creek**	**598,147**	**1,826,851**	**2,424,998**	62,912,065	4,047,329	489,246,051			
35	**Peach Bottom**		**1,833,828**	**1,833,828**						

Notes: (1) Common plant and depreciation at facilities is allocated among units by relative investment: for example, Bergen common shown at line 1, column (E) is allocated by Bergen 1, 2, & 3 based on investment (excluding common) shown at lines 2, 3, 4, col (F).

(2) Common plant and depreciation relating to peaking facilities at various locations is allocated to them by relative intestment. Total peaking common is shown at the top of column (G) and allocated to peaking facilities by the investment in column (H).

(3) Salem & Hope Creek RE Taxes each include an allocated portion of Francis Corp and Training Center RE taxes.

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PSEG POWER, LLC
REACTIVE REVENUE REQUIREMENT ANALYSIS

PREPAYMENTS ALLOCATED TO UNITS ON GROSS INVESTMENT

Account	***Description***	***Amount***	
	GE Services for Bergen	0	(note 3)
	Bergen 1	0	(note 3)
	Bergen 2	0	(note 3)
	GE Services for Linden	0	(note 3)
	Total Linden 1 & 2	0	(note 3)
	Electric-Prepayments	2,149,786	(Note 1)
	Prepaid Insurance	1,067,694	(Note 2)
	Total Allocable to Salem/HC	3,217,480	
	Hope Creek	1,784,287	
	Salem	1,433,193	

Note 1 These are Emergency Response Fees paid to NJ and Delaware.
Note 2 NEIL Insurance
Note 3 GE prepayments service contracts ended in 2012

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2014 Base Year Plant Specifications Data

PSEG Power PJM Units 2014

Unit	Total Rating (MW) (100% Share)		% Ownership	Generator			Exciter			Connection	GSU Transformer		Ramp Rate	LMP	Period Net Gen (MWH)
	Winter	Summer		KVA	KW	pf	KW	V-DC	Motor HP		(KVA)	KVolts In/Out	MW/min	$/MWH	
NUCLEAR															
Hope Creek 1	1172	1172	100.00%	1,373,000	1,222,000	0.94	2987	530	NA	Δ - y	466,700	24/550	0.2	52.00	10,373,818
Peach Bottom 2	1120	1120	50.00%	1,530,000	1,332,000	0.92	2764	500	NA	Δ - y	510,000	22/500	10.0	51.50	4,325,631
Peach Bottom 3	1123	1123	50.00%	1,530,000	1,334,000	0.90	2764	500	NA	Δ - y	510,000	22/500	10.0	51.50	5,059,953
Salem 1	1170	1170	57.41%	1,300,000	1,170,000	0.90	6000	570	NA	Δ - y	416,667	24/500	0.8	51.97	5,080,157
Salem 2	1158	1158	57.41%	1,300,000	1,170,000	0.90	2987	530	NA	Δ - y	440,000	24/500	0.8	51.97	4,267,567
COAL															
Conemaugh 1	850	850	22.51%	1,040,000	936,000	0.90	1930/780	525	NA	Δ - y	930,000	22-525	6.0	42.37	1,131,634
Conemaugh 2	850	850	22.51%	1,040,000	936,000	0.90	1930/780	525	NA	Δ - y	930,000	22-525	6.0	42.37	1,344,527
Hudson 2	620	620	100.00%	733,000	659,700	0.90	3200	440	NA	Δ - y	700,000	19.3-230	3.0	62.06	1,060,445
Keystone 1	850	850	22.84%	1,040,000	936,000	0.90	1700/1285	500	NA	Δ - y	930,000	20-525	6.0	42.62	1,177,410
Keystone 2	850	850	22.84%	1,040,000	936,000	0.90	1700/1285	500	NA	Δ - y	930,000	20-525	6.0	42.62	1,453,819
Mercer 1	316	316	100.00%	384,000	326,400	0.85	500	375	1450	Δ - y	340,000	17.5-230	1.5	52.74	148,241
Mercer 2	316	316	100.00%	384,000	326,400	0.85	500	375	1450	Δ - y	340,000	17.5-230	1.5	52.74	322,654
				Weighted Pf =		0.89									
OIL/GAS STEAM															
Sewaren 1	104	104	100.0%	121,470	103,250	0.85	300	250	530	Δ - y	102,000	13.4-138	0.5	57.54	10,044
Sewaren 2	118	118	100.0%	121,500	100,000	0.85	300	250	500	Δ - y	85,000	13.4-138	0.5	57.54	13,925
Sewaren 3	107	107	100.0%	128,000	108,800	0.85	300	250	500	Δ - y	85,000	13.4-138	0.5	57.54	3,190
Sewaren 4	124	124	100.0%	140,000	119,000	0.85	300	250	530	Δ - y	110,000	13.4-138	1.0	57.54	6,434
				Weighted Pf =		0.85									
COMBINED CYCLE															
Bergen 1	638	638	100.0%	691,304									2.0	59.21	3,421,842
Bergen 1101			100.0%	125,000	112,500	0.90	284	364	NA	Δ - y	240,000	13-138			
Bergen 1102			100.0%	125,000	112,500	0.90	284	364	NA	Δ - y		13-138			
Bergen 1103			100.0%	125,000	112,500	0.90	284	364	NA	Δ - y	240,000	13-138			
Bergen 1104			100.0%	125,000	112,500	0.90	284	364	NA	Δ - y		13-138			
Bergen 1105			100.0%	191,304	162,608	0.85	950	375	1450	Δ - y	325,000	18-138			
				Weighted Pf =		88.67%									
Bergen 2	560	560	100.0%	734,000									3.0	59.21	2,896,525
Bergen 2101			100.0%	215,000	183,600	0.85	610	305	NA	Δ - y	220,000	18-230			
Bergen 2102			100.0%	215,000	183,600	0.85	610	305	NA	Δ - y	220,000	18-230			
Bergen 2103			100.0%	304,000	258,400	0.85	1245	565	NA	Δ - y	333,330	18-230			
Linden CC 1	650	650	100.0%	797,400									1.5	57.04	3,068,039
Linden 1101			100.0%	213,400	183,600	0.85	610	340	NA	Δ - y	132000/176000/220000	18-141			
Linden 1102			100.0%	213,400	183,600	0.85	610	340	NA	Δ - y	132000/176000/220000	18-235.7			
Linden 1001			100.0%	370,600	258,400	0.85	1245	660	NA	Δ - y	132000/176000/220000	18-141			
Linden CC 2	650	650	100.0%	797,400									1.5	57.04	2,603,580
Linden 2101			100.0%	213,400	183,600	0.85	610	340	NA	Δ - y	132000/176000/220000	18-235.7			
Linden 2102			100.0%	213,400	183,600	0.85	610	340	NA	Δ - y	132000/176000/220000	18-235.7			
Linden 2001			100.0%	370,600	258,400	0.85	1245	660	NA	Δ - y	225000/300000/375000	18-235.7			
SIMPLE CYCLE															
Burlington 12	171	171	100.0%	284,704	242,000	0.85	175	185	NA	Δ - y	75,000	13.8-138	NA	57.04	102,616
Essex 9	83	83	100.0%	104,000	93,600	0.90	275	200	NA	Δ - y	110,000	13.2-230	NA	57.04	15,402
Kearny 12	178	178	100.0%	284,704	242,000	0.85	175	185	NA	Δ - y	250,000	13.8-230	NA	57.04	211,454
Kearny 13	183	183	100.0%	284,704	242,000	0.85	175	185	NA	Δ - y	250,000	13.8-230	NA	57.04	236,475
Kearny 14	92	92	100.0%	142,352	121,000	0.85	175	185	NA	Δ - y	125,000	13.8-230	NA	57.04	133,571
Linden 5	90	90	100.0%	113,100	96,135	0.85	275	300	NA	Δ - y	200,000	13.8-230	NA	57.04	16,128
Linden 6	90	90	100.0%	113,100	96,135	0.85	275	300	NA	Δ - y	200,000	13.8-230	NA	57.04	25,286
Linden 7	84	84	100.0%	113,100	96,135	0.85	275	300	NA	Δ - y	240,000	13.8-141	NA	57.04	16,658
Linden 8	84	84	100.0%	113,100	96,135	0.85	275	300	NA	Δ - y	240,000	13.8-141	NA	57.04	29,824
OTHER															
Yards Creek 1	140	140	50.0%	154,000	141,000	0.90	340	375	NA	Δ - y	160,000	14.4-230	NA	57.04	99457*
Yards Creek 2	140	140	50.0%	154,000	141,000	0.90	340	375	NA	Δ - y	160,000	14.4-230	NA	57.04	98299*
Yards Creek 3	140	140	50.0%	154,000	141,000	0.90	340	375	NA	Δ - y	160,000	14.4-230	NA	57.04	92938*

*Yards Creek total generation

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PSEG POWER LLC TURBINE - GENERATOR STATISTICS

Generating Station	# of Generators	Manufacturer (1)	Turbine Type	Service Date	Fuel Type	
					Primary	Alternate
Bergen 1	5	SIE/W/W	4 VA4 x 1ST	06/01/95	Gas	Oil
Bergen 2	3	GE	2 FA x 1ST	06/01/02	Gas	Oil
Burlington 12	4	GE/BE	LM6000	06/01/00	Gas	Oil
Conemaugh 1	1	GE		05/21/70	Coal	
Conemaugh 2	1	GE		05/27/71	Coal	
Essex 9	1	GE	EA Fr7	07/01/90	Gas	Oil
Hope Creek 1	2	GE		12/20/86	Nuclear	
Hudson 2	1	FW/W/W		12/18/68	Coal	Gas
Kearny 12	4	GE/BE	LM6000	08/01/01	Gas	Oil
Kearny 13	4	GE/BE	LM6000	06/01/12	Gas	
Kearny 14	2	GE/BE	LM6000	06/01/12	Gas	
Keystone 1	1	WE		08/24/67	Coal	
Keystone 2	1	WE		07/23/68	Coal	
Linden CC 1	3	GE	2 FA x 1ST	04/01/06	Gas	Oil
Linden CC 2	3	GE	2 FA x 1ST	04/01/06	Gas	Oil
Linden 5	1	GE	EA Fr7	06/01/00	Gas	Oil
Linden 6	1	GE	EA Fr7	06/01/00	Gas	Oil
Linden 7	1	GE	EA Fr7	06/01/95	Gas	Oil
Linden 8	1	GE	EA Fr7	06/01/95	Gas	Oil
Mercer 1	2	FW/GE/GE		12/19/60	Coal	Gas
Mercer 2	2	FW/GE/GE		06/04/61	Coal	Gas
Peach Bottom 2	1	GE	N	07/05/74	Nuclear	
Peach Bottom 3	1	GE	N	12/23/74	Nuclear	
Salem 1	2	W		06/30/77	Nuclear	
Salem 2	2	W		10/13/81	Nuclear	
Sewaren 1	1	CE/W/W		12/01/48	Gas	Oil
Sewaren 2	1	CE/GE/GE		11/30/48	Gas	Oil
Sewaren 3	1	CE/GE/GE		10/16/49	Gas	Oil
Sewaren 4	1	CE/W/W		07/30/51	Gas	Oil
Yards Creek 1	1	GE	N	11/26/65	Pumped Storage	
Yards Creek 2	1	GE	N	12/22/65	Pumped Storage	
Yards Creek 3	1	GE	N	09/03/65	Pumped Storage	
PSEG PJM Power Total						

(1) Manufacturer: (Jet or Boiler / Stm Turbine / Generator); if only one mfg listed then covers all components

BE = Brush Electrical Machines **W= Westinghouse** **SIE = Siemans**

EM = Electric Machinery Mfg Company **BW = Babcock & Wilcox**

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PSEG Energy Resources & Trade, LLC Docket No. ER15-____-000

I, Stephen M. Merchant, being duly sworn, depose and state that the contents of the foregoing testimony, including exhibits, on behalf of PSEG Energy Resources & Trade, LLC, are true, correct, accurate and complete to the best of my knowledge, information and belief.

Stephen M. Merchant

SUBSCRIBED AND SWORN to
Before me this 26 day of May, 2015.

Notary Public

My commission expires: 9/09/2016

PAMELA A. KRONQUIST Notary Public My Commission Expires 9/09/2016 ANNE ARUNDEL COUNTY, MD

Reactive Supply and ~~voltage~~Voltage Control from Generation Sources Service

PSEG Energy Resources & Trade LLC ("PSEG ER&T") provides Reactive Supply and Voltage from Generation Sources Service ("Reactive Supply Service") from various generating facilities to the PJM Interconnection, ~~LLC~~L.L.C. ("PJM") system. This Rate Schedule which consists of seventeen separate tariff rate sections for each of PSEG ER&T's generating facilities sets forth PSEG ER&T's revenue requirements for the provision of Reactive Supply Service to PJM, as contemplated by Schedule 2 of the PJM open access transmission tariff.

PSEG ER&T's total monthly revenue requirement consists of the sum of the charges for the following: (1) the Fixed Capability Revenue Requirement; and (2) the Heating Losses Component~~. Total charges~~ for ~~any 12-month period will not be less than~~each of its generating facilities. The Fixed Capability Revenue Requirements; the ~~sum of~~ Heating Losses Component, and the ~~annual charges specified~~Total Revenue Requirement for each generating facility is set forth in the Rate Schedule sections below. This Rate Schedule shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

Nothing contained herein shall be construed as affecting in any way the right of PSEG ER&T to unilaterally make application to the Federal Energy Regulatory Commission for a change in rates under section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder. If PSEG ER&T seeks to change one of the revenue requirements stated herein, it will abide by relevant FERC procedures for changes in rates and notify PJM in accordance with any notice requirement in the PJM Tariff.

~~**MONTHLY REVENUE REQUIREMENT:**~~

~~**1. FIXED CAPABILITY COMPONENT**~~

~~The annual revenue requirement for the Fixed Capability Component is $25,750,450.~~

~~The monthly charge to PJM is $25,750,450 / 12 = $2,145,871~~

~~**2. HEATING LOSSES COMPONENT**~~

~~The annual revenue requirement for the Heating Losses Component is $876,337.~~

~~The monthly charge to PJM is $$876,337 / 12 = $73,028.~~

~~**3. TOTAL REVENUE REQUIREMENT**~~

~~Total Annual Revenue Requirement is $25,750,450 + $876,337 = $26,626,787~~

~~Total Monthly Revenue Requirement is $26,626,787 / 12 = $2,218,899.~~

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Reactive Supply and Voltage Control from Generation Sources Service

PSEG Energy Resources & Trade LLC ("PSEG ER&T") provides Reactive Supply and Voltage from Generation Sources Service ("Reactive Supply Service") from various generating facilities to the PJM Interconnection, LLC ("PJM") system. This Rate Schedule which consists of seventeen separate tariff rate sections for each of PSEG ER&T's generating facilities sets forth PSEG ER&T's revenue requirements for the provision of Reactive Supply Service to PJM, as contemplated by Schedule 2 of the PJM open access transmission tariff.

PSEG ER&T's total monthly revenue requirement consists of the sum of the charges for the following: (1) the Fixed Capability Revenue Requirement; and (2) the Heating Losses Component for each of its generating facilities. The Fixed Capability Revenue Requirement; the Heating Losses Component, and the Total Revenue Requirement for each generating facility is set forth in the Rate Schedule sections below. This Rate Schedule and its separate sections shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

Nothing contained herein shall be construed as affecting in any way the right of PSEG ER&T to unilaterally make application to the Federal Energy Regulatory Commission for a change in rates under section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder. If PSEG ER&T seeks to change one of the revenue requirements stated herein, it will abide by relevant FERC procedures for changes in rates and notify PJM in accordance with any notice requirement in the PJM Tariff.

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BERGEN 1 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,925,105.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $28,652.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,925,105 + $28,652 = $2,953,757.

Total Monthly Revenue Requirement is $2,953,757 / 12 = $246,146.

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BERGEN 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,330,193.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $31,021.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,330,193 + $31,021= $ 2,361,214.

Total Monthly Revenue Requirement is $2,361,214 / 12 = $ 196,768.

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LINDEN 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $8,589,078.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $68,593.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $8,589,078 + $68,593 = $8,657,672.

Total Monthly Revenue Requirement is $8,657,672 / 12 = $721,473.

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HUDSON 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,386,352.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $7,266.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,386,352 + $7,266 = $1,393,617.

Total Monthly Revenue Requirement is $1,393,617 / 12 = $116,135.

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MERCER 1 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $318,855.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $2,290.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $318,855 + $2,290 = $321,145.

Total Monthly Revenue Requirement is $321,145 / 12 = $26,762.

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MERCER 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $969,405.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $3,168.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $969,405 + $3,168 = $972,573.

Total Monthly Revenue Requirement is 972,573 / 12 = $81,048.

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CONEMAUGH 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $482,544.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $14,470.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $482,544 + $14,470 = $497,014.

Total Monthly Revenue Requirement is $497,014 / 12 = $41,418.

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KEYSTONE 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $559,507.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $12,524.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $559,507 + $12,524 = $572,031.

Total Monthly Revenue Requirement is $572,031 / 12 = $47,669.

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SALEM 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,200,674.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $46,757.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,200,674 + $46,757 = $2,247,431.

Total Monthly Revenue Requirement is $2,247,431 / 12 = $187,286.

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HOPE CREEK 1 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $4,602,764.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $39,360.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $4,602,764. + $39,360 = $4,642,124.

Total Monthly Revenue Requirement is $4,642,124 / 12 = $386,844.

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PEACH BOTTOM 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $ 6,139,449.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $65,956.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $6,139,449 + $65,956 = $6,205,405.

Total Monthly Revenue Requirement is $6,205,405 / 12 = $517,117.

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SEWAREN 1 - 4 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,377,492.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $1,431.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,377,492. + $1,431 = $1,378,923.

Total Monthly Revenue Requirement is $1,378,923 / 12 = $114,910.

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BURLINGTON 12 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $ 1,041,234.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $1,271.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,041,234. + $1,271 = $1,042,505

Total Monthly Revenue Requirement is $1,042,505 / 12 = $86,875.

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ESSEX 9 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,051,348.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $208.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,051,348 + $208 = $1,051,556.

Total Monthly Revenue Requirement is $1,051,556 / 12 = $87,630.

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KEARNY 12, 13, 14 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,940,897.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $4,692.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,940,897 + $4,692 = $2,945,589.

Total Monthly Revenue Requirement is $2,945,589 / 12 = $245,466.

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LINDEN 5, 6, 7, 8 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,121,530.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $879.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,121,530 + $879 = $1,122,410.

Total Monthly Revenue Requirement is $1,122,410 / 12 = $93,534.

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YARDS CREEK GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $302,956.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $3,103.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $302,956 + $3,103 = $306,059.

Total Monthly Revenue Requirement is $306,059 / 12 = $25,505.

20150605-5178 FERC PDF (Unofficial) 6/5/2015 4:24:09 PM

FERC rendition of the electronically filed tariff records in Docket No. ER15-01882-000
Filing Data:
CID: C001195
Filing Title: Revised Reactive Tariff
Company Filing Identifier: 114
Type of Filing Code: 340
Associated Filing Identifier:
Tariff Title: Rate Schedule FERC No. 3 Reactive Supply And Voltage Control From Generation Sources Service
Tariff ID: 10
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Rate Schedule No. 3, Sheet 02, 2.0.0, A
Record Narative Name: Sheet 02
Tariff Record ID: 1250
Tariff Record Collation Value: 4000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier: 46

Reactive Supply and Voltage Control from Generation Sources Service

PSEG Energy Resources & Trade LLC ("PSEG ER&T") provides Reactive Supply and Voltage from Generation Sources Service ("Reactive Supply Service") from various generating facilities to the PJM Interconnection, LLC ("PJM") system. This Rate Schedule which consists of seventeen separate tariff rate sections for each of PSEG ER&T's generating facilities sets forth PSEG ER&T's revenue requirements for the provision of Reactive Supply Service to PJM, as contemplated by Schedule 2 of the PJM open access transmission tariff.

PSEG ER&T's total monthly revenue requirement consists of the sum of the charges for the following: (1) the Fixed Capability Revenue Requirement; and (2) the Heating Losses Component for each of its generating facilities. The Fixed Capability Revenue Requirement; the Heating Losses Component, and the Total Revenue Requirement for each generating facility is set forth in the Rate Schedule sections below. This Rate Schedule and its separate sections shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

Nothing contained herein shall be construed as affecting in any way the right of PSEG ER&T to unilaterally make application to the Federal Energy Regulatory Commission for a change in rates under section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder. If PSEG ER&T seeks to change one of the revenue requirements stated herein, it will abide by relevant FERC procedures for changes in rates and notify PJM in accordance with any notice requirement in the PJM Tariff.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Bergen 1, Sheet 3, 1.0.0, A
Record Narative Name: Sheet 3
Tariff Record ID: 2250
Tariff Record Collation Value: 5000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

BERGEN 1 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,925,105.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $28,652.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,925,105 + $28,652 = $2,953,757.

Total Monthly Revenue Requirement is $2,953,757 / 12 = $246,146.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Bergen 2, Sheet 4, 1.0.0, A
Record Narative Name: Sheet 4
Tariff Record ID: 3250
Tariff Record Collation Value: 6000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

BERGEN 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,330,193.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $31,021.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,330,193 + $31,021= $ 2,361,214.

Total Monthly Revenue Requirement is $2,361,214 / 12 = $ 196,768.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Linden 1 & 2, Sheet 5, 1.0.0, A
Record Narative Name: Sheet 5
Tariff Record ID: 4250
Tariff Record Collation Value: 7000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

LINDEN 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $8,589,078.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $68,593.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $8,589,078 + $68,593 = $8,657,672.

Total Monthly Revenue Requirement is $8,657,672 / 12 = $721,473.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Hudson 2, Sheet 6, 1.0.0, A
Record Narative Name: Sheet 6
Tariff Record ID: 5250
Tariff Record Collation Value: 8000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

HUDSON 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,386,352.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $7,266.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,386,352 + $7,266 = $1,393,617.

Total Monthly Revenue Requirement is $1,393,617 / 12 = $116,135.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Mercer 1, Sheet 7, 1.0.0, A
Record Narative Name: Sheet 7
Tariff Record ID: 6250
Tariff Record Collation Value: 9000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

MERCER 1 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $318,855.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $2,290.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $318,855 + $2,290 = $321,145.

Total Monthly Revenue Requirement is $321,145 / 12 = $26,762.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Mercer 2, Sheet 8, 1.0.0, A
Record Narative Name: Sheet 8
Tariff Record ID: 7250
Tariff Record Collation Value: 10000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

MERCER 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $969,405.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $3,168.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $969,405 + $3,168 = $972,573.

Total Monthly Revenue Requirement is 972,573 / 12 = $81,048.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Conemaugh 1 & 2, Sheet 9, 1.0.0, A
Record Narative Name: Sheet 9
Tariff Record ID: 8250
Tariff Record Collation Value: 11000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

CONEMAUGH 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $482,544.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $14,470.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $482,544 + $14,470 = $497,014.

Total Monthly Revenue Requirement is $497,014 / 12 = $41,418.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Keystone 1 & 2, Sheet 10, 1.0.0, A
Record Narative Name: Sheet 10
Tariff Record ID: 9250
Tariff Record Collation Value: 12000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

KEYSTONE 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $559,507.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $12,524.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $559,507 + $12,524 = $572,031.

Total Monthly Revenue Requirement is $572,031 / 12 = $47,669.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Salem 1 & 2, Sheet 11, 1.0.0, A
Record Narative Name: Sheet 11
Tariff Record ID: 10250
Tariff Record Collation Value: 13000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

SALEM 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,200,674.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $46,757.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,200,674 + $46,757 = $2,247,431.

Total Monthly Revenue Requirement is $2,247,431 / 12 = $187,286.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Hope Creek 1, Sheet 12, 1.0.0, A
Record Narative Name: Sheet 12
Tariff Record ID: 11250
Tariff Record Collation Value: 14000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

HOPE CREEK 1 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $4,602,764.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $39,360.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $4,602,764. + $39,360 = $4,642,124.

Total Monthly Revenue Requirement is $4,642,124 / 12 = $386,844.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Peach Bottom 1 & 2, Sheet 13, 1.0.0, A
Record Narative Name: Sheet 13
Tariff Record ID: 12250
Tariff Record Collation Value: 15000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

PEACH BOTTOM 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $ 6,139,449.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $65,956.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $6,139,449 + $65,956 = $6,205,405.

Total Monthly Revenue Requirement is $6,205,405 / 12 = $517,117.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Sewaren 1 - 4, Sheet 14, 1.0.0, A
Record Narative Name: Sheet 14
Tariff Record ID: 13250
Tariff Record Collation Value: 16000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

SEWAREN 1 - 4 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,377,492.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $1,431.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,377,492. + $1,431 = $1,378,923.

Total Monthly Revenue Requirement is $1,378,923 / 12 = $114,910.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Burlington 12, Sheet 15, 1.0.0, A
Record Narative Name: Sheet 15
Tariff Record ID: 14250
Tariff Record Collation Value: 17000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

BURLINGTON 12 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $ 1,041,234.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $1,271.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,041,234. + $1,271 = $1,042,505

Total Monthly Revenue Requirement is $1,042,505 / 12 = $86,875.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Essex 9, Sheet 16, 1.0.0, A
Record Narative Name: Sheet 16
Tariff Record ID: 15250
Tariff Record Collation Value: 18000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

ESSEX 9 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,051,348.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $208.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,051,348 + $208 = $1,051,556.

Total Monthly Revenue Requirement is $1,051,556 / 12 = $87,630.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Kearny 12, 13, 14, Sheet 17, 1.0.0, A
Record Narative Name: Sheet 17
Tariff Record ID: 16250
Tariff Record Collation Value: 19000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

KEARNY 12, 13, 14 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,940,897.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $4,692.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,940,897 + $4,692 = $2,945,589.

Total Monthly Revenue Requirement is $2,945,589 / 12 = $245,466.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Linden 5, 6, 7, 8, Sheet 18, 1.0.0, A
Record Narative Name: Sheet 18
Tariff Record ID: 17250
Tariff Record Collation Value: 20000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

LINDEN 5, 6, 7, 8 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,121,530.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $879.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,121,530 + $879 = $1,122,410.

Total Monthly Revenue Requirement is $1,122,410 / 12 = $93,534.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Yards Creek, Sheet 19, 1.0.0, A
Record Narative Name: Sheet 19
Tariff Record ID: 18250
Tariff Record Collation Value: 21000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-05
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

YARDS CREEK GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $302,956.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $3,103.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $302,956 + $3,103 = $306,059.

Total Monthly Revenue Requirement is $306,059 / 12 = $25,505.

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Document Content(s)

Reactive Power filing letter.PDF.....1-9

PSEG 1-3.PDF.....10-88

Redlined Tariff.PDF.....89-89

Clean Tariff.PDF.....90-107

FERC GENERATED TARIFF FILING.RTF.....108-117

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

CPV Power Holdings, L.P., Calpine Corporation and Eastern Generation, LLC,	)	
Complainants,	)	**Docket No. EL18-169-000**
v.	)	
PJM Interconnection, L.L.C.,	)	
Respondent.	)	

PROTEST OF EXELON CORPORATION AND THE PSEG COMPANIES

Pursuant to Rules 212 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("the Commission"), Exelon Corporation ("Exelon")[1] and the PSEG Companies ("PSEG")[2] protest the Complaint filed on May 31, 2018 by CPV Power Holdings, L.P., Calpine Corp. ("Calpine"), and Eastern Generation, LLC ("Complainants") in the above-captioned proceeding. Complainants ask the Commission to find that PJM's Minimum Offer Pricing Rule ("MOPR") is "unjust and unreasonable" under Section 206, and ask the Commission to impose as a remedy what they dub, ironically, a "Clean MOPR." The "Clean MOPR" is purpose-built to harm clean, non-emitting generators and to benefit emitting fossil-fuel generators while continuing to make arbitrary and discriminatory distinctions in its application. The Commission should reject the Complaint.

[1] Exelon timely filed a document-less intervention on June 4, 2018.
[2] The PSEG Companies include: Public Service Electric and Gas Company, PSEG Power LLC and PSEG Energy Resources & Trade LLC.

INTRODUCTION

For two years, Complainants have prophesied an imminent crisis in wholesale capacity markets due to state environmental programs. But they have never provided *evidence* of a crisis. The capacity markets have continued to fulfill the Federal Power Act's mandate of "encourag[ing] the orderly development of plentiful supplies of electricity … at reasonable prices."[3] Energy prices are at historic lows, and capacity prices are well below the estimated cost of new entry. That basic pattern continued in the most recent auction, where reserve margins barely dipped even as prices rose. With each passing year, Complainants' unsupported claims of a reliability catastrophe are thus farther from reality. No reliability problem exists in PJM—and even if it did, the Commission could not accept the Complainants' version of the MOPR.

First, Complainants purport to purify the Commission's markets of state intrusions, but in reality they are seeking to preserve a supply portfolio that ignores the harm that pollution imposes on society. That is not a triumph of efficient markets; it is a market failure. State policies addressing the costs that pollution imposes on society make markets more competitive and market outcomes more efficient.[4] This is, literally, textbook economics.[5] That is why there is broad agreement, even among Complainants, that markets should and must evolve, one way or another, to take into account environmental externalities like carbon. The Commission should seek to accommodate, not frustrate, state policies aimed at reducing pollution.

Second, Complainants dramatically depart from the principles the Commission has always followed and the cooperative federalism scheme the Federal Power Act ("FPA") enacts. The

[3] *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,157, at 30 n.39 (2016) (quoting *Pub. Utils. Comm'n of Cal. v. FERC*, 367 F.3d 925, 929 (D.C. Cir. 2004)).
[4] Decl. of Robert D. Willig ¶¶ 13(a)-(b), 27-49, attached hereto ("Willig Decl.").
[5] *See id.* ¶¶ 32 & n.28-29, 33-49 (citing P.A. Samuelson & W.D. Nordhaus, *Economics* at 346-355 (1995); R.S. Pindyck & D.L. Rubinfeld, *Microeconomics*, 639-657 (2d ed. 1992); A.C. Pigou, *The Economics of Welfare* (4th ed. 1932); W.J. Baumol & W.E. Oates, The theory of environmental policy, Ch. 3 (2d ed. 1995)).

Commission has decided so far that its market mechanisms should be fuel-neutral, but it has always accepted that state policies are *not* fuel neutral. Resources confront a cost structure that reflects whatever fuel-related benefits or penalties states have chosen to impose in light of state environmental priorities. The Commission's market mechanism selects the least-cost set of resources against the backdrop of those policies. And thus far, the Commission has always crafted market rules to respect and accommodate state programs addressing environmental externalities. Doing so adheres to the principle that the Commission must "fulfill [its] jurisdictional responsibilities while also respecting the states' traditional role,"[6] consistent with the Federal Power Act's purpose to "complement[]," not "usurp[] … State regulatory authority."[7] For two decades, that is how the Commission's markets have operated, and they should continue to do so.

Third, Complainants depart from settled precedent concerning PJM's MOPR. The Commission has always limited the MOPR to addressing buyer-side market power, and to new gas-fired resources—precisely because those resources are the most effective tools for buyer-side market power. Yet Complainants do not claim that their proposed expansion of the MOPR is necessary to address buyer-side market power, and they have not remotely justified their request to transform PJM's MOPR to reach existing resources and to become a roving tool to offset the effects of disfavored state policies on PJM's auction.

Fourth, while Complainants cloak themselves in the garb of free marketeers, they ask the Commission to massively expand government control over capacity market bidding. At a time of oversupply, the "Clean" MOPR will artificially raise clearing prices to Net CONE times B by mitigating more than 20% of the market. Over time, mitigating vertically integrated utilities and state programs may drive many into Fixed Resource Requirement plans, making PJM's market

[6] *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1117 (2006).
[7] *Conn. Light & Power Co. v. FPC*, 324 U.S. 515, 526 (1945) (quotation marks omitted).

less liquid and more fragmented. The only way to avoid that outcome is the unlikely possibility that enough mitigated resources seek and obtain unit-specific exemptions so that they set the clearing price. The end result, again, will be to drive PJM's capacity market toward an almost entirely administrative design.

Fifth, the "Clean" MOPR would massively over-procure capacity to customers' detriment. It would require PJM to ignore capacity provided by resources whose mitigated capacity offer is too high to clear, and instead procure redundant capacity. Moreover, by unnecessarily procuring capacity, the "Clean" MOPR uneconomically suppresses energy prices. PJM has admitted that such suppression will result from an expanded MOPR. Complainants do not even acknowledge this problem, much less address it.

Sixth, the "Clean" MOPR is also discriminatory. It exempts certain favored subsidies granted by state and local governments, as well as every existing federal subsidy (though not new federal subsidies), despite Complainants' admission that it should not matter whether "a federal, rather than a state" subsidy is at issue.[8] And all of this is in addition to continuing to exempt the *implicit* subsidy that fossil-fuel generators receive from the ability to pollute without paying.

Instead of pursuing Complainants' "Clean" MOPR, the Commission should move forward in two steps. *First*, if the Commission nonetheless perceives a reliability problem requiring an immediate fix—which, as Exelon and PSEG explain, does not exist—the Commission should and must pursue an option that is vastly superior: It can approve PJM's Capacity Repricing proposal. Indeed, because PJM has proposed Capacity Repricing under Section 205, the Commission *cannot* even consider the "Clean" MOPR without first rejecting Capacity Repricing. While Exelon and PSEG believe Capacity Repricing is unnecessary and would raise prices without justification,

[8] Compl. at 19.

Capacity Repricing responds to the same basic problem that Complainants allege—that "subsidized resources" are affecting "clearing prices"[9]—but imposes vastly less damage than the "Clean" MOPR. Because Capacity Repricing (like CASPR) allows resources supported by state environmental programs to obtain capacity commitments, it selects the most efficient set of resources and respects the cooperative-federalism principles on which the FPA is based. And because Capacity Repricing acknowledges capacity that will be developed under state environmental programs, it avoids over-procurement. In all respects, it is a more appropriate policy than Complainants' proposal.

Second, whether or not the Commission orders an immediate tariff change, Exelon and PSEG respectfully suggest that the Commission should direct PJM to stop treating the symptoms and work with even greater urgency on a cure for the disease. Because PJM's markets do not presently account for the environmental harms of fossil fuels, states have stepped into the gap, as they are authorized to do under the FPA. Thus the Commission's current dilemma: State environmental programs make the markets more efficient, but such state-level actions will always spur claims that they are distortionary. The answer, as many parties (including Complainants) urged at the 2017 technical conference, is that the Commission's markets should be designed to *achieve* states' legitimate goals—so that the markets themselves incorporate these goals. This could be accomplished, for example, with a price on carbon. Crafting this solution will require work, and it could take many forms. That is all the more reason for the Commission to direct PJM to commence work now on a regional carbon pricing solution and formulate a proposed tariff within a year.

[9] Compl. at 10.

PROTEST

I. Complainants Have Not Demonstrated A "Serious And Imminent Threat" Justifying Action Under Section 206.

Complainants seek radical change based on two assertions—first, that payments under state environmental programs (which they call "subsidies") in "any . . . contexts are bad," "distort prices, and interfere with the efficient entry and exit of generation," and second, that these payments have created an "imminent threat" to PJM's capacity market.[10] Both assertions are false. Because Complainants fail to show the existing market rules are not just and reasonable, the Commission should reject the Complaint.

A. Payments For Environmental Benefits Make Capacity Markets More Efficient.

These fossil-fuel generators aim at state environmental programs paying for the environmental benefits of clean generation—renewable portfolio standards and zero emissions programs that provide payments to "nuclear," "wind," and "solar … resources."[11] Such payments, Complainants say, "distort prices," and failing to mitigate them would render PJM's market rules no longer just and reasonable under Section 206.[12]

This assertion is wrong.[13] Complainants ignore the economics of externalities, and how they are addressed by the state programs that Complainants target.[14] When fossil-fuel generators owned by Complainants produce electricity, they create pollutants—notably, carbon dioxide.[15]

[10] *Id.* at 2, 13 (quotation marks omitted).
[11] *Id.* at 11.
[12] *Id.* at 13 (quotation marks omitted).
[13] Exelon and PSEG have made this point clear in prior filings, including in Docket No. EL16-49-000 and Docket No. ER18-1314-000. Protest of Exelon Corp. at 12-18, *PJM Interconnection, L.L.C.*, Docket Nos. ER18-1314-000, -001 (May 7, 2018) ("Exelon Protest"); Answer of Exelon Corp. & PSEG Companies at 16-21, *PJM Interconnection, L.L.C.*, Docket Nos. ER18-1314-000, -001 (May 22, 2018) ("Exelon & PSEG Answer"); Protest of Exelon Corp. at 19-25, *Calpine Corp. v. PJM Interconnection*, EL16-49-000 (Jan. 30, 2017).
[14] *See generally* Willig Decl. ¶¶ 32-49.
[15] *Id.* ¶¶ 13(a), 27; *see, e.g.*, *Coal. for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 121 (D.C. Cir. 2012), *aff'd in part, rev'd in part on other grounds sub nom. Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427 (2014).

These pollutants harm human health and the environment, but their costs generally fall on society, not generators that produce them—hence, they are "negative externalities."[16] Conversely, clean generators produce electricity without this harmful pollution but do not receive compensation for this benefit from the Commission-regulated markets. Instead, the benefit is externalized—a positive externality.[17] Externalities distort incentives, and so result in inefficiencies. When the fossil-fuel generator decides how much to produce, it considers only its private costs, not the full costs to society.[18] When the clean generator weighs the same decision, the same mismatch occurs in the opposite direction. The fossil-fuel generator will produce too much, and the clean generator, too little. As Dr. Willig explains, when incentives are misaligned, the outcome will not be efficient.[19] The fossil-fuel generator may continue operating when it should retire, and the clean generator may retire when it should continue operating—or the clean generator may never be constructed at all.

The ability of fossil-fuel generators to produce electricity without paying for the social harm caused by pollution amounts to a subsidy—and can be a massively distorting one. Society is bearing part of the cost of that generation, rather than the plant owners. For carbon dioxide alone, estimates put this subsidy's value for fossil-fuel generators across PJM at $12.1 billion to $17.7 billion dollars *annually*.[20] That means that when fossil-fuel generators offer into wholesale markets, their offers are artificially low: they do not reflect the true costs of producing electricity

[16] Willig Decl. ¶¶ 27, 32.
[17] *Id.*
[18] *Id.* ¶¶ 33-36.
[19] *Id.* ¶ 33; *see* Institute for Policy Integrity, *Capacity Markets and Externalities: Avoiding Unnecessary and Problematic Reforms*, at 7 (Apr. 2018), http://policyintegrity.org/files/publications/Capacity_Markets_and_Externalities_Report.pdf.
[20] These figures reflect 291.9 million tons of CO_2 emitted in PJM in 2017 and 426.6 million tons emitted in 2016, at a cost of $41.40 per ton. *See* Monitoring Analytics, LLC, *2017 State of the Market Report for PJM, Volume 2: Detailed Analysis*, at 361 (Mar. 2018).

using fossil fuels. As a result, these generators may clear at the expense of cleaner generators that would outcompete the polluters if environmental harm were taken into account.

This misalignment, however, is fixable through regulatory or market mechanisms.[21] Indeed, so compelling is the economic logic of addressing environmental externalities that even *Calpine* had to admit that "carbon [is] an externality" that should be "price[d]."[22] Likewise, at the Commission's 2017 technical conference, a broad cross-section of stakeholders agreed with that basic view.[23] Exelon and PSEG respectfully suggest that the Commission would be on firm ground in taking Calpine at its word and proceeding under Section 206 to require PJM to impose a carbon price, as explained below.[24] Thus far, though, the Commission has not attempted to address these issues itself and has relied on the fact that *states* are addressing these externalities, in the programs that Complainants target, based on states' FPA-protected authority over "facilities used for the generation of electric energy."[25] The Commission has thus "fulfill[ed its] statutory mandate under the FPA to ensure that … rates … are just, reasonable and not unduly discriminatory or preferential" by "respect[ing] the traditional role of states."[26] RPS standards are examples of such programs, and so too are the ZEC programs Complainants target. As

[21] Willig Decl. ¶¶ 34-49.
[22] Transcript of Technical Conference at 331, *State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.*, Docket No. AD17-11-000 (May 2, 2017) (comments of Thad Hill).
[23] *See, e.g.*, Post-Technical Conference Comments of Calpine Corp. at 4, *State Policies and Wholesale Markets*, Docket No. AD17-11-000 (June 22, 2017); Post-Technical Conference Comments of Dynegy Inc. at 4, *State Policies and Wholesale Markets*, Docket No. AD17-11-000 (June 22, 2017); Post-Technical Conference Comments of Electric Power Supply Association at 9, *State Policies and Wholesale Markets*, Docket No. AD17-11-000 (June 22, 2017); Post-Technical Conference Comments of NRG Energy, Inc. at 4, *State Policies and Wholesale Markets*, Docket No. AD17-11-000 (June 22, 2017); *see generally* Post-Technical Conference Reply Comments of Exelon Corp. at 4 & n.9, *State Policies and Wholesale Markets*, Docket No. AD17-11-000 (July 13, 2017) (citing additional comments in support); *see also* PJM, Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, at 54, *PJM Interconnection, L.L.C.*, Docket Nos. ER18-1314-000, -001 (Apr. 9, 2018) ("PJM Filing"); Answer of PJM Interconnection, L.L.C. at 20, *PJM Interconnection, L.L.C.*, Docket Nos. ER18-1314-000, -001 (May 25, 2018).
[24] PJM Filing at 54.
[25] 16 U.S.C. § 824(b)(1).
[26] *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1112.

explained in detail in the Willig Declaration, ZEC programs are especially efficient because compensation under them cannot exceed the social cost of carbon—a conservative estimate of the plants' environmental benefits—and thus the plants will remain operational only if doing so is socially efficient.[27]

The "first principles of capacity markets" set forth in the CASPR Order support allowing the actions that states have taken on environmental externalities to affect capacity markets.[28] When private and social costs are better aligned, "competition" is more "robust," and the markets' "price signals" more accurately "guide the orderly entry and exit of capacity resources" to select the "set of resources" that is truly "least cost."[29] By contrast, if the Commission designed rules to countermand state environmental initiatives without setting a carbon price of its own, the Commission would recreate the same type of "regulatory void" the Commission was created to address[30] and doom the Commission's markets to inefficiency. Wholesale rates designed to *prevent* consideration of environmental externalities could never be just and reasonable. Complainants get matters backwards when they suggest that environmental programs make the Commission's markets *un*just and *un*reasonable.

The Commission, of course, has not given *all* state policies a free pass: When state policies reflect exercises of buyer-side market power and "artificially depress[] capacity prices" by supporting new entry that is truly "uneconomic," the Commission has acted.[31] But when policies address environmental externalities, the Commission has explained that these "policy objectives" are "legitimate,"[32] and it has always made sure that those policies would be accommodated. Never

[27] Willig Decl. ¶¶ 55-58.
[28] *ISO New England Inc.*, 162 FERC ¶ 61,205, at P 21 (2018) ("CASPR Order").
[29] *Id.*; *see* Willig Decl. ¶ 34-49, 79.
[30] *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 767 (2016).
[31] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 141 (2011).
[32] *ISO New England Inc.*, 158 FERC ¶ 61,138, at P 68 (2017).

has it sought to *thwart* their effects. Hence, the Commission has long recognized that state command-and-control "environmental regulation … driv[es] significant changes in the mix of resources" by increasing costs of fossil-fuel generators, and "resulting in the early retirement of some coal-fired generation."[33] The Commission has not attempted to *counteract* those pro-efficiency results by rejiggering auction rules to offset the costs of regulation even though such costs impact wholesale market prices.[34] Likewise, when states have exercised their authority to incentivize clean generators, the Commission has affirmed that states may "encourage renewable or other types of resources" even when doing so "allow[s] states to affect the [wholesale] price" or makes clean generation "more competitive in a cost comparison with fossil-fueled generation."[35] States are "free" to incentivize clean generation, the Commission has explained, "even if the price signals in the regional wholesale capacity market indicate that [those] resources are [not] needed."[36]

Especially off base is Complainants' claim that when one state acts alone, it is "exporting the impact of its subsidy onto other states."[37] When one state funds resources that address environmental externalities, what it exports are environmental benefits—cleaner air that other states enjoy, even when they do not pay. The harmful "exporting" occurs when fossil-fuel generators foist their harm onto the public in other states, who then must pay the costs that result.[38]

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[33] *Transmission Planning & Cost Allocation*, 139 FERC ¶ 61,132, at P 5 (2012).

[34] Consider, for example, the cost of scrubber equipment that a fossil-fuel generator installs to satisfy state emissions requirements. Those requirements are imposed for same reason that states implement REC or ZEC programs—to promote cleaner air. The scrubber costs would increase capacity market offers and so impact the clearing price. Under Complainants' theory, such costs should somehow be expunged from the market. No one believes such mitigation would be warranted. Yet Complainants' theory demands it.

[35] *S. Cal. Edison Co.*, 71 FERC ¶ 61,269, at 62,080 (1995).

[36] Amicus Br. of United States at 33, *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288 (2016) (No. 14-614), 2016 WL 344494.

[38] *See generally, e.g.*, *Maryland v. Pruitt*, No. 1:15-cv-02873 (D. Md. filed Sept. 27, 2017) (suit by Maryland against EPA to address pollution from upwind states that causes harm in Maryland).

Indeed, the Commission has *ensured* that state environmental programs can affect wholesale markets, even in restructured states. For example, the Commission approved the proposal of the California Independent System Operator Corporation ("CAISO") to lower its "bid floor" in energy markets "from negative $30/MWh to negative $150/MWh."[39] It permitted "variable energy resources" to bid at such extremely low prices because they "generally receive, in addition to market revenues, production tax credits, renewable energy credits, and contractual energy payments."[40] As a result, such variable resources are allowed to submit large negative energy offers, and presumably reduce energy market revenues for other participants—because the Commission understood that the negative $150/MWh offer reflects the "opportunity cost" of not receiving significant revenues tied to clean energy production.[41] In New England, the Commission approved the deduction of revenues from REC payments in the calculation of the offer review trigger price applicable to new renewable resources,[42] and exempted 200 MW of new renewable generation from ISO-NE's MOPR[43]—until expansion of renewables mandates made clear that *yet more* accommodation of renewable resources was necessary, which the CASPR Order supplied.

The Commission's acceptance of state environmental programs as complementary to its markets is consistent with a more general principle: When generators receive compensation for services not captured by the Commission's markets, they properly take account of that compensation in their bids. That is why the Commission has held that resources operating pursuant to reliability services support agreements ("RSSAs") should be permitted to clear in the capacity market: Because the units "are needed for reliability and would clear a capacity market that also

[39] *Cal. Indep. Sys. Operator Corp.*, 145 FERC ¶ 61,254, at P 34 (2013).
[40] *Id.* at P 5.
[41] *Id.* at P 34.
[42] *ISO New England Inc.*, 146 FERC ¶ 61,084, at P 32 (2014) (rejecting argument that REC revenues are out-of-market revenues, and approving reduction of ORTP for new renewable resources to account for REC revenues).
[43] *ISO New England Inc.*, 158 FERC ¶ 61,138, at P 4.

reflected local reliability needs, RSSA revenues received by these resources reflect the value of the services provided by these resources to customers."[44] Similarly, revenues from state environmental programs represent the "value of the [environmental] services provided by these resources."[45] The Commission should follow its precedent and reject the proposition that just and reasonable rates require insulating market prices from the effects of state environmental programs.

The recent CASPR Order underscores that the Commission does not share Complainants' view of "just and reasonable" market rules. In CASPR, the Commission acted in the spirit of cooperative federalism and in recognition of states' legitimate role by ensuring that state-supported resources could clear and receive a capacity commitment. ISO-NE explained that "New England states recently have significantly increased both their targets and their efforts to promote the development of renewable resources," and the Commission observed that ISO-NE's existing exemption from its MOPR for renewable resources "would not be able to accommodate" the new clean energy initiatives.[46] So ISO-NE created CASPR "to better accommodate [these] actions."[47] And the Commission approved CASPR as just and reasonable because it succeeded by "accommodat[ing] the entry of new Sponsored Policy Resources into the FCM over time" and so providing a "'better way to integrate these state policies into the competitive wholesale markets.'"[48] Indeed, the CASPR Order blessed *exactly* what Complainants contend is unjust and unreasonable—CASPR "result[s] in [capacity market] participation by resources that would not

[44] *Indep. Power Producers of N.Y., Inc. v. N.Y. Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,214, at P 66 (2015), *reh'g pending*.
[45] *Id.*
[46] CASPR Order at PP 24, 26, 101 n.185.
[47] *Id.* at P 1.
[48] *Id.* at P 6 (quoting ISO-NE Transmittal at 4).

be in the market but for the subsidies."[49] Accepting Complainants' theory would thus require the Commission to abandon the approach it just approved in CASPR.[50]

B. There Is No Imminent Reliability Threat Warranting Action.

The Complaint's unsupported claims of an "imminent" reliability threat are not the first time the Commission has heard that the sky is falling. The Commission has heard such claims since Illinois and New York passed ZEC programs in 2016. The Commission was told that Illinois' legislation posed an "existential threat,"[51] and was "poised to drop onto the RPM market like an anvil onto a woeful coyote beginning with the Base Residual Auction for … 2020/2021."[52] It heard the same thing about New York's ZEC Program and the markets of the New York Independent System Operator, Inc. ("NYISO").[53] But *years* of evidence has proven these claims to be false.[54] As the empirical outcomes demonstrate, PJM's markets have been—and continue to

[49] Compl. at 12.

[50] There is nothing to Complainants' assertion that they are "deprived of their … constitutional rights to an '*opportunity* to recover [their] costs.'" Compl. at 11 (quoting *Bridgeport Energy, LLC*, 113 FERC ¶ 61,311, at P 29 (2005) (alteration in original); and citing *FPC v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944)). Exelon and PSEG have already explained why in Docket No. ER18-1314-000. *See* Exelon & PSEG Answer at 14-15. The standard of *Hope Natural Gas* and *Bridgeport Energy* simply does not apply here. When a utility is compelled to provide service to the public, as with a traditionally regulated utility, this standard forbids "confiscatory" rates for compelled service. *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 310 (1989) (citing *Hope Nat. Gas*, 320 U.S. at 602). Likewise, when a generator is compelled to remain operational for reliability, the same standard governs. *Bridgeport Energy, LLC*, 113 FERC ¶ 61,311, at P 29 (2005). In PJM, however, generators are not compelled to provide capacity. To be sure, existing generation capacity resources generally have a must offer obligation into the Reliability Pricing Model. But if these resources choose to retire, they can do so upon 90 days' notice (and, presumably, upon covering any outstanding capacity obligations)—regardless of reliability implications. PJM Open Access Transmission Tariff, § 113. In such circumstances, the Commission has held that "there can be no question of confiscation of a resource's property." *ISO New England, Inc.*, 135 FERC 61,029, at P 255 (2011).

[51] Motion to Amend, and Amendment to, Complaint and Request for Expedited Action on Amended Complaint at 2, 3, *Calpine Corp. v. PJM Interconnection, L.L.C.*, Docket No. EL16-49-000 (Jan. 9, 2017) ("Calpine Mot. to Amend"); Motion to Lodge and Request for Expedited Action on Amended Complaint at 2-3, *Calpine Corp. v. PJM Interconnection, L.L.C.*, Docket No. EL16-49-000 (Aug. 30, 2017).

[52] Calpine Mot. to Amend at 2-3.

[53] Request for Expedited Action at 13-14, *Independent Power Producers of New York, Inc. v. New York Independent System Operator, Inc.*, Docket No. EL13-62-002 (Jan. 9, 2017).

[54] Exelon Protest at 32-37.

be—robust, despite myriad forms of government intervention, and there is no evidence of market jeopardy going forward, either.[55]

The recent results of the 2021/2022 BRA confirm that PJM has "plentiful supplies."[56] The most recent auction cleared 163.6 GW of unforced capacity and a reserve margin of 21.5% (including commitments under Fixed Resource Requirement plans), or 5.7% higher than the target margin of 15.8%.[57] That pattern is stable: The last seven auctions have cleared reserve margins above 19%.[58]

The markets have achieved these reserve margins at prices that refute any suggestion of a crisis. The 2020/2021 BRA achieved historically high reserve margins (23.3%) at historically low prices ($76.53 per MW-day for rest-of-RTO).[59] In 2021/2022, rest-of-RTO prices rose to $140.00 per MW-day even as reserve margins remained high.[60] There is no reason to artificially raise prices yet higher at a time of continuing oversupply. To the extent these auction results disclose a problem, it is the need to more comprehensively address environmental externalities: Even as 10,643 MW of nuclear generation failed to clear, much of which might have been economic if its environmental benefits were taken into account, the auction "cleared 500 MW more coal

[55] Complainants thus have failed to demonstrate a problem with *reliability*: They have not shown any risk that, today or in the foreseeable future, PJM will lack adequate resources to serve load under the full range of normal operating conditions. But as Exelon has noted elsewhere, the *resilience* of the power grid is a different issue. In other words, while PJM has enough megawatts, it lacks the right kind and mixture of resources to be able to effectively serve load under all circumstances, particularly when extreme weather events are coupled with unexpected outage events. *See* Comments of Exelon Corp. at 13, Docket No. AD18-7-000 (May 9, 2018); Reply Comments of Exelon Corporation at 2, Docket No. AD18-7-000 (June 8, 2018). While the Commission should reject the Complaint, it should take appropriate action in other dockets to ensure that it understands the resilience risks in PJM and to remedy any risks that it finds.

[56] *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,157, at 30 n.39 (quoting *Pub. Utilities Comm'n of Cal.*, 367 F.3d at 929).

[57] PJM, 2021/2022 RPM Base Residual Auction Results at 3, http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx ("2021/2022 BRA Results").

[58] *Id.* at 6.

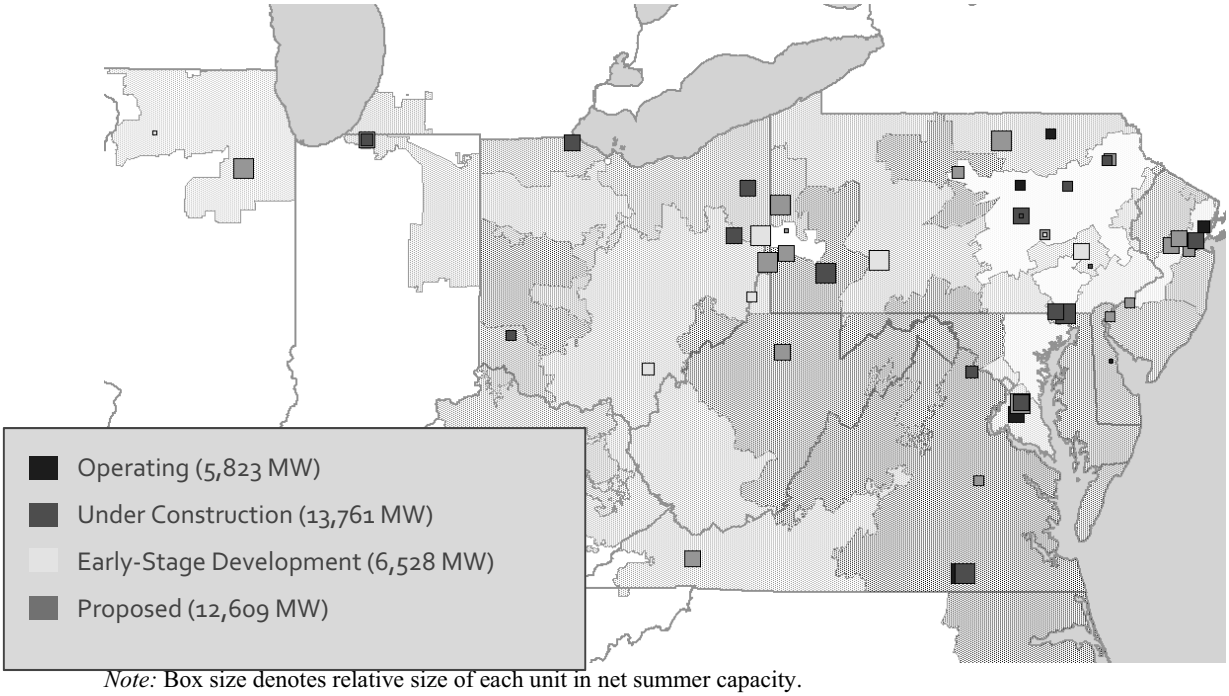
[59] *Id.*

[60] *Id.*

generation than last year's auction."[61] Given the harm that coal generation produces, that result would be inconceivable in an efficient market that valued environmental effects.

New entry also remains robust. Nearly 1,400 MW of new capacity, including uprates, cleared in the most recent auction.[62] While that is a slight decline from prior auctions, when 2-5 GW had cleared,[63] that tick downwards is exactly what one would expect given the historically high reserve margin. Indeed, looking forward, there are almost 40 GW of recently entered or potential near-term entrant gas combined-cycle plants spread across PJM—25% of the market:

Figure 1: The 40 GW Of Recently Entered Or Potential Near-Term Entrant Gas Combined-Cycle Plants In PJM



Note: Box size denotes relative size of each unit in net summer capacity.

Complainants suggest that recent state environmental initiatives have worked a sea change—implying that even if PJM's market is healthy today, state environmental programs will

[61] PJM Inside Lines, *Capacity auction attracts diverse, competitive resources* (May 23, 2018), http://insidelines.pjm.com/capacity-auction-attracts-diverse-competitive-resources/.
[62] 2021/2022 BRA Results at 7.
[63] Exelon Protest at 35.

lead investors to distrust market price signals and refuse to invest. This is a fiction. Sophisticated investors have always considered, as one of many regulatory risks they face, changes to environmental regulations.[64] If governments move to tighten (or loosen) emissions standards, for example, that can alter—dramatically—the returns that investors expected when they invested. The risk of such changes is business-as-usual. Likewise, it is nothing new that resources are receiving state-mandated payments for their environmental benefits (or other reasons).[65] For two decades, states have been implementing REC programs, as well as many other programs that impact wholesale market profits, including demand response and energy efficiency programs that reduce demand, net metering programs, and subsidies for storage. Investors have always understood that states might increase this commitment, and there is no reason to believe that this risk has changed PJM's market dynamics.

That is particularly true because PJM's markets are *designed* to maintain equilibrium, and safeguard resource adequacy, across a broad range of conditions. For example, if state programs reduce capacity prices, but tightening supply indicates that new entry is needed, prices will rise, and the downward sloping demand curve will ensure that the capacity price adjusts to reflect the costs of the generators that are necessary for resource adequacy.[66] In these circumstances, without any concrete evidence of a threat to reliability or investor confidence resulting from state environmental programs, there is no basis for Commission action under Section 206.

[64] *Compare, e.g.*, Calpine Corp., Form 10-K for Fiscal Year Ended December 31, 2007, at 6 (identifying "environmental regulations" as one of "[f]our key market 'drivers' [that] significantly affect our financial performance"), *with* Calpine Corp., Form 10-K for Fiscal Year Ended December 31, 2017, at 20-21 (identifying as a "risk" to "[m]arket prices" "federal and state power, market and environmental regulation and legislation, including mandating an RPS or creating financial incentives, each resulting in new renewable energy generation capacity creating oversupply" and "changes in prices related to RECs and other environmental allowance products").

[65] Exelon Protest at 31.

[66] *Capacity Markets and Externalities* at 18; *see* Willig Decl. ¶ 49.

II. Complainants' "Clean" MOPR Is Not Just Or Reasonable.

Even if the Commission perceived a problem, it cannot accept the "Clean" MOPR because it is not just and reasonable.

A. The "Clean" MOPR's Massive Expansion Of Mitigation Rules Is Inconsistent With Commission Precedent.

The "Clean" MOPR is not just and reasonable because it would result in an unprecedented expansion of buyer-side capacity market mitigation, in two respects—an expansion that would contradict the Commission's precedent concerning PJM's MOPR and that Complainants have not even attempted to justify.

First, Complainants ask the Commission to expand buyer-side capacity market mitigation beyond its original purpose: avoiding buyer-side market power. Combatting buyer-side market power is undoubtedly a legitimate concern under the FPA. Rates are "unjust and unreasonable … in violation of section 205(a) of the FPA" when they are "due to the exercise of market power."[67] The Commission narrowly crafted PJM's MOPR to address the concern that "net buyers might have an incentive to depress market clearing prices by offering … at less than a competitive level," and it found that the MOPR was "a reasonable method of assuring that net buyers do not exercise monopsony power."[68] The Commission has continued to describe the "very purpose"[69] and the "underlying objective[]" of "PJM's MOPR" as "to prevent the exercise of buyer-side market power."[70] Likewise, when the Commission has weighed modifications to PJM's MOPR, it has assessed whether those modifications are necessary to address buyer-side market power.[71]

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[67] *Portland Gen. Exch., Inc.*, 51 FERC ¶ 61,108, 61,243-44 (1990).
[68] *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at PP 103, 104 (2006).
[69] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 104.
[70] *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 20 (2013) (describing "PJM's MOPR [as] a mechanism that seeks to prevent the exercise of buyer-side market power").
[71] *See, e.g.*, *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 70 (2011) (revised threshold "reasonabl[y] … protect[s] against unreasonable exercises of market power"); *id.* at P 88 (amending rule that was "ineffective at

Under this precedent, Complainants' requested relief fails at the threshold. Complainants do not allege that buyers are exercising market power, or that a change is necessary to prevent the exercise of buyer-side market power. Instead, Complainants seek to transform mitigation rules into a roving tool to address any "effects" on "the wholesale capacity market" from external influences.[72] But such external influences are omnipresent and inescapable, as PJM has acknowledged,[73] and the project of "draw[ing] … lines between actionable and un-actionable" influences[74] is fraught. That is clear from the fact that Complainants' supposedly "Clean" MOPR leaves many material subsidies unmitigated.

Second, buyer-side mitigation has always, and for good reason, been limited to new resources,[75] including in CASPR.[76] If the intent is to exercise buyer-side market power by lowering prices, the best way to do it is with new resources that can be built quickly and have high capacity factors—new gas-fired plants. That is why the Commission found that PJM had properly limited its MOPR to new "gas-fired resources" as "those resources most likely to raise price suppression concerns," which the Commission determined "appropriately balanc[ed] the need for mitigation of buyer-side market power against the risk of over-mitigation."[77]

protecting against buyer market power"); *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 25 (self-supply exemption approved because it "will operate to identify those self-supply entities lacking the incentive to exercise buyer-side market power"); *id.* at P 109 (declining to "categorially exempt self-supply" because a "blanket exemption" would allow an "unacceptable opportunity to exercise buyer market power"); *id.* at P 56 (approving competitive entry exemption because qualifying entities "do[] not raise buyer-side market power concerns"); *id.* at P 166 (limiting MOPR to gas-fired generation as the "most likely" to "be used to exercise market power").

[72] Compl. at 17.

[73] PJM Filing at 15-16, 34-35.

[74] *Id.* at 15.

[75] *PJM Interconnection, L.L.C.*, 153 FERC ¶ 61,066, at P 3 (2015) ("PJM's MOPR is designed to protect against buyer-side market power by setting a price floor, i.e., a minimum bid, and by requiring that all *new*, non-exempted resources bid at that floor" (emphasis added)); *see also, e.g.*, *id.* at P 44 (approving self-supply exemption because it adequately addresses "the price effects attributable to uneconomic *new* self-supply" (emphasis added)).

[76] CASPR Order at P 8.

[77] *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 26.

By contrast, as explained in the Willig Declaration, the Clean MOPR extends the MOPR to existing units with no indicia to measure whether such an extension is guarding against the exercise of buyer-side market power, and no analysis by Complainants of whether such an extension could result in the exclusion of capacity that is efficient in the relevant time frame.[78] Indeed, existing resources are *not* a promising tool for exercising buyer-side market power, and MOPR's remedy does not fit. Existing resources already are participating in the market, and their capacity has contributed to prices the Commission has found just and reasonable. When PJM proposed extending the mitigation period to three years, the Commission rejected that request because, "given the market's demonstration of its need for the resource," there was "no reasonable basis for continuing to apply the MOPR."[79] Likewise, the mitigation remedy—resetting bids to Net CONE times the Balancing Ratio ("B")—does not fit existing resources. Their costs are largely sunk. Thus, as the Commission explained, this remedy "could lead to over-mitigation by requiring a commercially operational resource to bid at an offer floor … substantially above its going-forward costs."[80] Complainants' requested relief flouts the longstanding and well-grounded limitation of buyer-side mitigation to new entrants.

B. The "Clean" MOPR Would Result In An Inefficient Selection Of Resources.

There can be no dispute that market outcomes *should* account for environmental externalities.[81] The "Clean" MOPR, however, mitigates the programs that address these externalities and so willfully selects the wrong resources.[82] Instead of clearing clean resources that are economic after accounting for environmental externalities, the market clears marginal

[78] Willig Decl. ¶¶ 13(f)(iii), 16, 25-26.
[79] *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 211 (2013).
[80] *Id.* at P 212; *see* Willig Decl. ¶ 13(f)(iii).
[81] *Supra* at 8.
[82] Willig Decl. ¶ 79.

fossil-fuel-fired resources that, when pollution costs are accounted for, are not economic.[83] As explained above, just and reasonable market rules cannot thwart states' pro-efficiency attempts to recognize the reality that fossil-fuel generators pollute the air and that clean generators do not. Rather, mitigation rules must exempt such programs.

C. The "Clean" MOPR Disrespects Settled Federalism Principles.

The "Clean" MOPR also violates the prime directive of the FPA's scheme of cooperative federalism—that the Commission must, when possible, "fulfill [its] jurisdictional responsibilities while also respecting the states' traditional role."[84] The "Clean" MOPR attempts to thwart a broad swath of state programs by effectively forbidding resources participating in those programs from clearing in the wholesale markets. That includes not just the environmental programs targeted by PJM's April 9 filing, but also vertically integrated utilities that previously qualified for the self-supply exemption based on their "long-standing capacity procurement business models."[85] Yet Complainants offer no genuine evidence that taking a wrecking ball to state policies is necessary for the Commission to "fulfill [its] jurisdictional responsibilities."[86] And in fact, it is clear that even if the Commission believes there is a problem, the Commission has options for addressing any problem in the spirit of cooperative federalism—such as Capacity Repricing. With this more accommodating model available, it is not just and reasonable to adopt an approach that goes out of its way to frustrate state policy choices.

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[83] *Id.*

[84] *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1117; *see Conn. Light & Power*, 324 U.S. at 526 (Commission authority is "so drawn as to be a complement to and in no sense a usurpation of State regulatory authority," and Commission is obligated "to receive and consider the views of State[s]" (quoting legislative history of FPA)); *Panhandle E. Pipe Line Co. v. Pub. Serv. Comm'n of Ind.*, 332 U.S. 507, 517 (1947) (Commission authority has "no purpose or effect to cut down state power"; rather, its "primary purpose [i]s to aid in making state regulation effective, by adding the weight of federal regulation to supplement and reinforce it").

[85] PJM Filing at 75.

[86] *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1117.

Complainants make much of the CASPR Order's statement that the Commission would use "the MOPR as our standard solution" "[a]bsent a showing that a different method would" be effective.[87] But that statement referred to ISO-New England's narrower MOPR applying to only new resources, and even then, only two Commissioners endorsed it. The CASPR Order's actual *holding* was that ISO-New England's proposed reforms were just and reasonable precisely because the Commission concluded that they would succeed in ISO-New England's goal of reasonably "accommodat[ing] state sponsored resources … over time."[88] The Commission should not accept Complainants' invitation to embrace a default rule that is so inconsistent with the FPA's scheme of cooperative federalism.

D. The "Clean" MOPR Would Either Massively Increase Prices, Or Drive Much Of PJM Into FRR Plans, Or Lead To Ad Hoc Administrative Price-Setting.

The "Clean" MOPR will mitigate a massive quantity of resources, vastly more than Capacity Repricing or MOPR-Ex: at least 38 gigawatts, including renewable generators participating in RPS programs, nuclear generators participating in ZEC programs, and any generator owned by a vertically integrated utility that recovers costs through regulated rates.[89] By mitigating more than 20% of the market, the "Clean" MOPR will have one of three ill effects—perhaps all three.

First, as written, the "Clean" MOPR is designed so that the capacity market will clear at Net CONE times B. That is because the "Clean" MOPR incorporates MOPR-Ex's rules, while removing certain exemptions,[90] and mitigates offers with so-called "Actionable Subsidies" to Net CONE times B.[91] If nearly 20% of the market finds their bids reset to Net CONE times B, the

[87] CASPR Order at P 22.
[88] *Id.* at P 102.
[89] Schnitzer Decl. ¶¶ 10, 15, 20.
[90] Compl. at 18.
[91] PJM Filing at 104.

result is that the market will likely clear at Net Cone times B.[92] By contrast, the most recent capacity auction yielded "clearing prices that are between approximately 44% to 82% of Net CONE."[93] The result would be costs for customers that are $4.4 billion higher than today based purely on the increase in market prices—even leaving aside the additional costs from over-procurement and selection of an inefficient portfolio of resources, discussed elsewhere.[94] That price increase is wholly unjustified, particularly given the market's continuing oversupply. And as explained in the accompanying Schnitzer Declaration, this $4.4 billion increase is a likely result under current market conditions.[95]

Second, over the medium term, the "Clean" MOPR may drive states with substantial portfolios of affected resources to direct their utilities to elect the Fixed Resource Requirement ("FRR"), withdraw from the capacity market, and procure clean resources bilaterally.[96] The shift to FRR status is straightforward for vertically integrated utilities (and so will be virtually certain to occur across a broad swathe of PJM). It also may well happen in regions with retail competition but substantial portfolios of affected renewable and nuclear resources (where FRR could pose complexities for retail competition). Regardless, driving so much supply out of the market will only make the capacity market less liquid and more balkanized.[97]

Third, the only way to avoid these outcomes is if a large proportion of the mitigated 38 GW seeks and obtains unit-specific exemptions by showing that their avoidable cost rate and specific opportunity cost are less than Net CONE times B.[98] But that is unlikely, as explained in

[92] Schnitzer Decl. ¶¶ 22-24.
[93] PJM, 2021/2022 RPM Base Residual Auction Results at 1, http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx.
[94] Schnitzer Decl. ¶¶ 12, 28.
[95] *Id.* ¶ 24.
[96] *Id.* ¶ 30-34.
[97] *Id.* ¶ 33.
[98] PJM Filing at 51.

the Schnitzer Declaration: Because the FRR option is all-or-nothing, entities with *some* units that will not clear at the prices that result from the unit-specific exemption process are more likely to withdraw *all* their resources from the market and elect FRR status.[99] And if reliance on the unit-specific exemption *were* widespread, that would again be a dramatic—and detrimental—shift in the RPM's underlying structure. While the current RPM has administrative elements, its core price formation mechanism sets the clearing price based on competitive offers determined by market participants.[100] The Clean MOPR would drive the market towards a nearly wholly administrative design where offer prices of the resources in the zone of marginality are determined by PJM (with input from the Independent Market Monitor).[101] In turn, both the market clearing price and which resources receive capacity obligations would be largely determined by administrative decisions.[102] The Commission should not approve market rules with that foreseeable effect.

E. The "Clean" MOPR Would Over-Procure Capacity And Distort Energy Prices.

The "Clean" MOPR also is not a just and reasonable solution because, unlike CASPR or Capacity Repricing, it will over-procure capacity and so impose billions in associated costs on customers. That is because mitigating clean generation policies differs fundamentally from mitigating exercises of buyer-side market power. If a buyer's goal is to suppress capacity prices by introducing new capacity, then applying the MOPR means the capacity will not get built. Building that capacity cannot further the buyer's price-suppressive goals.

Clean energy is different. As the Commission has recognized, state-supported clean energy "will be developed by the operation of state environmental and clean energy mandates, whether

[99] Schnitzer Decl. ¶ 32.
[100] *Id.* ¶ 25.
[101] *Id.* ¶ 26.
[102] *Id.*

that capacity clears the [market] or not."[103] Even if the capacity does not clear, it still provides environmental benefits as it produces energy. States thus continue to procure clean resources even when it will be mitigated in the capacity market. The experience in New England proves this. Despite ISO-New England's limited MOPR exemption for 200 MW of renewables, states still issued the Multi-State Clean Energy request for proposals, which aims to procure 460 MW of new renewable resources, and Massachusetts enacted the 2016 Massachusetts Energy Diversity Act, which requires clean energy procurements in the range of 2,800 MW.[104] There is no reason to think that PJM states will act any differently.[105]

Applying the MOPR will therefore "send an incorrect signal to construct new capacity that is not needed."[106] State-supported clean generation will go forward, yet the wholesale markets—ignoring that capacity—will signal that further capacity is needed. The Commission has always avoided creating this type of false price signal, either by exempting clean generation policies from mitigation,[107] or by ensuring that any mitigation provides a pathway to accommodate clean generation policies and avoid over-procurement, as in CASPR.[108] The "Clean" MOPR abandons both solutions and overprocures billions of dollars of excess capacity.[109]

Complainants do not dispute that this massive overprocurement will occur; their only response is that there is "nothing wrong" with it, and that the overprocurement is states' fault.[110]

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[103] CASPR Order at P 45.
[104] *Id.* at P 4.
[105] Willig Decl. ¶ 81.
[106] *ISO New England Inc.*, 158 FERC ¶ 61,138, at P 9 (2017).
[107] *Id.* at P 48 (exemption "for state-subsidized resources … so that customers may avoid having to pay for duplicative capacity").
[108] Notably, Capacity Repricing also avoids these problems. PJM Filing at 56 ("Capacity Repricing avoids … duplication, because it allows state-selected resources to commit as capacity….").
[109] Estimates indicated that PJM's MOPR-Ex would result in an overprocurement estimated to cost customers $14-24.6 billion over 10 years, Protest of Clean Energy Advocates at 105 & Grogging Aff., attached thereto, at ¶¶ 3-4, 15, *PJM Interconnection, L.L.C.*, Docket No.18-1314 (May 7, 2018) ("Clean Energy Advocates Protest"); *see* Exelon Protest at 46-48, and the Clean MOPR's costs would only be higher.
[110] Compl. at 21-22.

Not so. First, Complainants ignore the FPA's jurisdictional lines. States regulate generation, while capacity requirements in the organized markets are the Commission's responsibility.[111] So if capacity is procured inefficiently because the Commission has chosen to ignore capacity provided by state-supported resources, that flaw is with the rules governing the Commission's markets.

Second, there *is* something "wrong" with overprocuring capacity.[112] Generation resources will be built when they are not needed, customers will pay too much with no justification, and society will be worse off for no reason. Experience demonstrates that states will continue to support clean generation even if those resources are mitigated in the capacity market, and the Commission cannot ignore that reality.

That is particularly true given the certainty that this excess capacity will yield a second problem: As PJM admitted in connection with MOPR-Ex, expanding the MOPR is likely to "enabl[e] price suppression in the wholesale energy and ancillary service markets."[113] Because PJM's system will include both the clean generation that the capacity markets ignore, and the replacement generation that the capacity markets acquire needlessly, there will be "greater supply in the energy market than economic conditions … justify," which will, in turn, "suppress prices."[114] Those problems will be even greater with the "Clean" MOPR.[115] Even if the Commission believes there is a problem with capacity markets warranting action, it cannot accomplish its goals by distorting the energy markets.

[111] *See Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009).
[112] Compl. at 21.
[113] PJM Filing at 57.
[114] *Id.*; *see* Willig Decl. ¶ 82.
[115] Schnitzer Decl. ¶ 15.

F. The "Clean" MOPR Is Discriminatory.

Complainants claim that their "Clean" MOPR, by removing MOPR-Ex's categorical exemptions, places "all units … on an equal footing" by applying "a MOPR … to all subsidized resources."[116] This claim is false. The "Clean" MOPR is just more artful in its discrimination.

First, the "Clean" MOPR discriminates by smuggling in exclusions from the definition of "Material Subsidy" that chiefly exempt subsidies that fossil-fuel generators receive. That definition excludes:

- "incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area";
- "[P]ayments, concessions, rebates, subsidies or incentives designed to incent, or participation in a program, contract or other arrangements from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality."[117]

As Exelon explained in Docket No. ER18-1314-000, some marginal gas-fired generators would not exist without subsidies from various economic development programs.[118] Likewise, the pervasive practice of states and localities of offering subsidies "designed to incent … siting facilities in" particular locations assuredly results in development of some resources that, otherwise, would not exist *at all*. The same is true of indirect support that states provide to fossil-fuel generators, such as Pennsylvania's sales-tax exclusion for coal.[119] Indeed, some of these programs are enacted or expanded to spur development of *particular* plants. In Pennsylvania, for example, a coal-to-gas plant conversion was the "anchor tenant" for a new "Keystone Opportunity

[116] Compl. at 2, 20.
[117] PJM Filing at 70; *see* Compl. at 18 (stating that the Clean MOPR relies on PJM's definition of "Material Subsidy").
[118] A recent example is the $500 million St. Joseph Energy Center, which was built after the county granted a $60 million tax abatement that would be exempt under the "Clean" MOPR. *See* Ted Booker, South Bend Tribune, *Power plant in New Carlisle area aims for March opening* (Feb. 1, 2018), https://www.southbendtribune.com/news/local/power-plant-in-new-carlisle-area-aims-for-march-opening/article_bb595c6c-9aab-537d-bde0-4f38a7dd6885.html.
[119] Clean Energy Advocates Protest at 90.

Expansion Zone"—which enabled this plant to be built by eliminating state and local taxes through 2023.[120] Indisputably, those subsidies affect who participates in PJM's auctions and the prices that result. Yet because these subsidies support Complainants, the "Clean" MOPR ignores them.

Second, the "Clean" MOPR is discriminatory because it would mitigate only those federal "subsidies or other support granted after the date of this Complaint."[121] But if the Commission decides to get into the business of ridding the capacity markets of external influences, it should not matter whether "a federal, rather than a state" subsidy is at issue.[122] Nor does it matter whether the subsidies are enacted before or after May 31, 2018. The reason for Complainants' selectivity, perhaps, is that existing federal tax incentives subsidize fossil-fuel generators to the tune of $4.7 billion a year.[123] Complainants' supposedly "Clean" MOPR also exempts the federal government's Production Tax Credit for wind and Investment Tax Credit for solar. But just like state RPS programs, these federal programs provide significant payments and have significant effects.[124] Exempting federal, but not state, programs is thus discriminatory.

Indeed, Complainants' exemption of existing federal subsidies is internally inconsistent. The Complaint endorses the Protest of the PJM Power Providers Group ("P3") in Docket No. ER18-1314-000, identifying itself as a "vehicle" that is "[c]onsistent with P3's request" in that docket for the Commission to "require PJM to adopt [the] 'Clean MOPR'" proposed by P3 and its expert, Dr. Shanker—the same expert Complainants use here.[125] In that docket, P3 "propose[d] to remove PJM's proposed exclusion … dealing with federal … tax credits" *entirely*, and Dr. Shanker

[120] *Sunbury Generation Lands First Tenant for Old Trail Industrial Park KOEZ*, Oil & Gas 360 (Oct. 28, 2015), https://www.oilandgas360.com/sunbury-generation-lands-first-tenant-for-old-trail-industrial-park-koez-with-announcement-of-financing-of-panda-hummel-station-power-plant/.
[121] Compl. at 19.
[122] *Id.*
[123] *Capacity Markets and Externalities* at 17.
[124] Exelon Protest at 30.
[125] Compl. at 9.

opined that this step "is reasonable."[126] Yet now, Complainants propose to remove the exemption only for new federal subsidies, and Dr. Shanker—flip flopping—studiously "express[es] no opinion" on the issue.[127] This patent inconsistency merely attempts to paper over the discrimination inherent in the Clean MOPR proposal.

Third, the "Clean" MOPR continues to ignore the *implicit* subsidy that fossil-fuel generators receive from the ability to pollute without paying, which—as noted above—comes to $12.1 to $17.7 billion annually.

While the "Clean" MOPR's exceptions are indefensibly arbitrary, a broader point is at stake. Once the Commission starts down the path of expanding the MOPR beyond addressing buyer-side market power and applying it to some disfavored policies—even state environmental policies that promote market efficiency—there is *no* non-arbitrary stopping point. Energy policies are pervasive and all of them, as PJM puts it, "affect behavior of many market participants"[128] and in turn affect the clearing prices in the wholesale markets. PJM's Answer illustrates the point: It prefers to retain the Self-Supply and Public Entity Exemptions because it favors the state policies underlying these exemptions[129] (even though these policies affect wholesale prices).[130] As to federal subsidies, it asks the Commission to undertake a task that is hopelessly indeterminate: to "examine … federal programs as well as any potential actions taken by federal officials with particular attention on expressions of congressional intent and the relationship of that statutory

[126] Protest of the PJM Power Providers Group at 19-20 n.50 & Shanker Aff. attached thereto at 4 n.3, *PJM Interconnection, L.L.C.*, Docket No. Er18-1314-000, -001 (May 7, 2018).
[127] Shanker Aff. at 4 n.1, attached to Complaint.
[128] PJM Filing at 34.
[129] Answer of PJM at 6. Because PJM filed its Answer on June 19, 2018, Exelon and PSEG have had only an incomplete opportunity to review and analyze it. Exelon and PSEG reserve the right to seek leave to respond further to PJM's Answer after analyzing it more fully.
[130] Exelon Protest at 27-28; Exelon Answer at 22.

authorization with the statutory requirement of just and reasonable rates under the FPA."[131] The way to avoid an endless quest to draw such untenable distinctions among different state and federal policies is to decline Complainants' invitation to try to create a wholesale capacity market that is "hermetically sealed from" outside forces.[132]

III. The Commission Should Direct PJM To Intensify Work On Solutions That Allow States To Achieve Their Legitimate Goals Through The Wholesale Markets, While Approving Capacity Repricing If It Deems Immediate Action Necessary.

For all of these reasons, the Clean MOPR takes PJM's markets in the wrong direction. Instead, the Commission should move forward in two steps. If the Commission determines that immediate action is needed, it should approve Capacity Repricing. And regardless, it should direct PJM to work with greater urgency on solutions that allow states to achieve their legitimate goals through the wholesale markets—for example, via a carbon price.

A. If The Commission Believes Immediate Action Is Needed, It Must Approve Capacity Repricing.

Complainants premise their request for Section 206 relief on the assertion that the Capacity Repricing approach that PJM has proposed under Section 205 is "unjust and unreasonable."[133] But if the Commission disagrees and determines Capacity Repricing is just and reasonable (or, with an appropriate conditional acceptance, can be *made* just and reasonable), there are no grounds for reaching Complainants' "Clean" MOPR over what PJM has identified as its "preferred approach."[134] In Docket No. ER18-1314-000, Exelon and PSEG have shown—through their Answer and the accompanying Declaration of Michael M. Schnitzer—that while Capacity Repricing unnecessarily raises prices, the broader attacks on Capacity Repricing by Complainants

[131] Answer of PJM at 8.
[132] *Elec. Power Supply Ass'n*, 136 S. Ct. at 776.
[133] Compl. at 2.
[134] PJM Filing at 6; *see Wis. Pub. Power, Inc. v. FERC*, 493 F.3d 239, 254 (D.C. Cir. 2007) ("FPA section 205 … requires FERC to approve [rates] as long as the new rates are 'just and reasonable.'").

and others are meritless. Exelon and PSEG will not repeat those points here; instead, they attach these filings from Docket No. ER18-1314-000.

B. Regardless, The Commission Should Order PJM To Develop Solutions That Achieve States' Legitimate Goals Through The Wholesale Markets.

Whether or not the Commission orders an immediate tariff change, Exelon and PSEG respectfully suggest that the Commission should direct PJM to stop treating the symptoms and work with even greater urgency on a cure for the disease. The root cause is that PJM's markets do not presently account for the environmental effects of generating electricity via fossil fuels, as any rational and efficient market should.[135] By failing to address this negative externality, the wholesale markets subsidize fossil-fuel generators to the tune of $12.1 billion to $17.7 billion every year,[136] which exceeds—by orders of magnitude—the state payments that spurred the Complaint. States often determine that they must step into this gap, as the Federal Power Act authorizes them to do. That is why, as PJM's Answer puts it, "state-mandated RPS/REC programs [are] growing and will continue to increase."[137] But when individual states must address national problems, their efforts are necessarily uneven. As the Willig Declaration explains, problems like leakage largely preclude states from taxing carbon.[138] And while attribute payments avoid some of these problems,[139] state-level actions will always spur claims that they are distorting the wholesale markets. That leads, inevitably, to the Commission's current dilemma: State programs make the Commission's markets more efficient, yet because they affect market outcomes, they are said to be distortionary.

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[135] Willig Decl. ¶¶ 32-33.
[136] *Supra* at 7.
[137] Answer of PJM at 7.
[138] Willig Decl. ¶ 37.
[139] *Id.*

The solution to this problem is clear. A broad range of stakeholders—including Calpine, the Independent Market Monitor, and PJM—have agreed that a carbon price is the "theoretical ideal market approach."[140] Likewise, at the 2017 technical conference, a broad range of stakeholder endorsed "Path 4"—that the Commission's markets should be designed to *achieve* states' legitimate goals, so that the markets themselves incorporate these goals.[141] Yet PJM has spent the last year on Band-Aids. The only way to permanently and sustainably address the present concerns with PJM's market rules is to modify those rules to price carbon. This approach could be accomplished, for example, by implementing an adder to the offers of fossil-fuel generators in the energy markets that accounts for the costs of the carbon emissions they produce.

Inevitably, some fossil-fuel generators—having embraced a carbon price as the ideal economic solution—will claim that the Commission lacks legal authority to implement it. Not so. The FPA gives the Commission authority to take account of environmental factors when regulating wholesale markets, and to approve, as just and reasonable, an ISO/RTO tariff that does so. Section 201(a) affirms that "the business of transmitting and selling electric energy for ultimate distribution

[140] PJM Filing at 54; *see* Comments of the Independent Market Monitor for PJM at 10, *PJM Interconnection, L.L.C.*, Docket No. ER-18-1314-000, -001; *supra* at 8.

[141] Comments of American Municipal Power, Inc. at 9-10; Comments of American Wind Energy Association at 5-7; Comments of Brookfield Renewable, Conservation Law Foundation, and NextEra Energy Resources, LLC at 1-2; Comments of Calpine Corp. at 3; Comments of Canadian Electricity Association at 4; Comments of Clean Energy Industries at 5-6; Comments of Connecticut at 12-13; Comments of Dominion Energy Services, Inc. at 7; Comments of Dynegy Inc. at 4; Comments of Electric Power Supply Association at 8-9; Comments of Independent Market Monitor for PJM at 10; Comments of Invenergy Wind Development LLC, Invenergy Thermal Development LLC, Invenergy Storage Development LLC, and Invenergy Solar Development LLC at 5; Comments of Independent Power Producers of New York, Inc. at 2; Comments of Massachusetts Department of Public Utilities at 6; Comments of New England States Committee on Electricity at 10; Comments of New York Power Authority at 6-7; Comments of Nuclear Energy Institute at 2; Comments of Noble Environmental Power, LLC at 3; Comments of Natural Resources Defense Council and Sustainable FERC Project at 1; Comments of NRG Energy, Inc. at 4, 13; Comments of PJM Interconnection, L.L.C. at 4-5, 10; Comments of Andrew G. Place, Vice Chairman, Pennsylvania Public Utility Commission at 2-3; Comments of PSEG Companies at 10-11; Comments of Perry D. Robinson at 2-3; Comments of Shell Energy North America (US), L.P. at 14; Comments of Solar Energy Industries Association at 1-2; Comments of Vitol Inc. at 2. All of the foregoing comments were filed on June 22, 2017 in *State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.*, Docket No. AD17-11-000.

to the public is affected with a public interest."[142] The FPA's main purpose is "to encourage the orderly development of plentiful supplies of electricity … at reasonable prices."[143] The Commission could reasonably conclude that prices are not just and reasonable when they do not account for tens of billions of dollars of harm that polluting fossil-fuel generators inflict. The Commission has wide discretion to consider non-cost factors—such as environmental harm—when assessing the justness and reasonableness of rates.[144] Indeed, the Supreme Court has expressly recognized that the FPA's "subsidiary purposes" include "conservation [and] environmental … questions."[145] Likewise, in Section 202(a), Congress authorized the Commission to establish ISOs/RTOs "[f]or the purpose of assuring an abundant supply of electric energy ... with the greatest possible economy *and with regard to the proper utilization and conservation of natural resources*."[146] These authorities provide the Commission ample power to implement a carbon price.[147]

Exelon and PSEG recognize that crafting market rules that integrate a carbon price will require work. But that is all the more reason that the Commission should direct PJM to commence work now and to formulate a proposed tariff within a year.

CONCLUSION

Exelon and PSEG respectfully request that the Commission deny the Complaint and reject Complainants' request to impose their "Clean" MOPR.

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[142] 16 U.S.C. § 824(a).
[143] *NAACP v. FPC*, 425 U.S. 662, 670 & n.6 (1976).
[144] *Pub. Utils. Comm'n of Cal. v. FERC*, 367 F.3d 925, 929 (D.C. Cir. 2004) (Commission "may consider non-cost factors as well as cost factors in setting rates").
[145] *NAACP*, 425 U.S. at 670 & n.6.
[146] 16 U.S.C. § 824a(a) (emphasis added).
[147] *See generally, e.g.*, Jim Rossi, *Carbon Taxation by Regulation*, 102 Minn. L. Rev. 277, 330-31 & n.254 (2018); Joel B. Eisen, *FERC's Expansive Authority to Transform the Electric Grid*, 49 U.C. Davis L. Rev. 1783, 1834-43 (2016).

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Dated: June 20, 2018

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 20th day of June, 2018.

/s/ *Marianne Alvarez*

_____

Marianne Alvarez
Exelon Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. ER18-1314-000**
	)	**ER18-1314-001**
	)	
	)	

MOTION FOR LEAVE TO ANSWER AND ANSWER OF EXELON CORP. AND THE PSEG COMPANIES

Pursuant to Rules 212 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"),[1] Exelon Corp. ("Exelon") and the PSEG Companies[2] move for leave to answer, and submit their answer, to the comments and protests filed in the above-captioned dockets.

MOTION FOR LEAVE TO ANSWER

Exelon and the PSEG Companies respectfully request that the Commission permit this Answer, and the attached Declaration of Michael M. Schnitzer ("Schnitzer Decl."), to protests and comments filed in the above-captioned dockets on May 7, 2018. The protests and comments include new evidence, including many new expert affidavits. Moreover, the protests and comments stake out novel positions—not just advocating for and against Capacity Repricing and MOPR-Ex, but suggesting modified versions of both, as well as entirely new approaches. Several protests and comments also respond to PJM's Section 205 filing by urging the Commission to act under Section 206. The Commission has allowed answers to protests where the answer provides

[1] 18 C.F.R. §§ 385.212, 385.213 (2017).
[2] The PSEG Companies include: Public Service Electric and Gas Company, PSEG Power LLC and PSEG Energy Resources & Trade LLC.

information that assists the Commission in its decision.[3] Exelon and the PSEG Companies respectfully suggest that this Answer will do so. In particular, the Schnitzer Declaration provides important new evidence concerning the Capacity Repricing proposal, in response to comments submitted by other parties.

ANSWER

The commenters clamoring for an expanded MOPR seek to exploit the Commission's commitment to markets and competition for ends that are profoundly anti-market and anti-competitive. While they purport to be purifying the Commission's markets from state intrusions, in reality they are seeking to entrench an unfair advantage they have enjoyed for decades: continuing to exploit the market's failure to value certain environmental attributes, and thereby imposing harm on society without paying for the costs. It is not a "level playing field" to treat resources that pollute as though they did not. When a coal or gas plant can underbid a wind farm, or a nuclear generator, by polluting the air we breathe, this is not a triumph of markets' power to drive efficient results. It is a market failure. When state policies attempt to internalize the pollution externality—through subsidies, taxes, or otherwise—they make markets more competitive and market outcomes more efficient.[4] This is, literally, textbook economics.[5] That is why there is broad agreement—even among advocates of MOPR-Ex—that markets should and must evolve, one way or another, to take into account environmental externalities like carbon.[6]

[3] *See, e.g.*, *Southwest Power Pool, Inc.*, 113 FERC ¶ 61,014, at P 7 (2005); *Southwest Power Pool Inc.*, 112 FERC ¶ 61,319, at P 56 (2005); *see also PJM Interconnection, L.L.C.*, 116 FERC ¶ 61,140, at P 18 (2006); *PJM Transmission Owners*, 115 FERC ¶ 61,345, at PP 10, 12 (2006).
[4] Decl. of Robert D. Willig ¶¶ 32-37 ("Willig Decl."), attached to Protest of Exelon Corp. ("Exelon Protest").
[5] *See id.* ¶¶ 30 n.28, 31 n.29, 34 n.32 (citing P.A. Samuelson & W.D. Nordhaus, *Economics* at 346-355 (1995); R.S. Pindyck & D.L. Rubinfeld, *Microeconomics*, 639-657 (2d ed. 1992); A.C. Pigou, *The Economics of Welfare* (4th ed. 1932); W.J. Baumol & W.E. Oates, The theory of environmental policy, Ch. 3 (2d ed. 1995)).
[6] Exelon Protest at 44 & n.152; *see* PJM Filing at 54-55; *infra* at 20-21.

The Commission, of course, has decided so far that its market mechanism should be fuel-neutral. But the Commission can afford to ignore the different environmental profiles of different generation types only because *states'* policies are *not* fuel neutral. Resources thus bring with them to the Commission's fuel-neutral markets a cost structure that reflects whatever fuel-related benefits or penalties states have chosen to impose in light of state environmental priorities. The Commission's market mechanism selects the least-cost set of resources against the backdrop of those state policies. As Exelon's Protest showed, the Commission thus far has always crafted market rules to respect and accommodate state programs addressing environmental externalities.[7] Doing so adheres to the principle that the Commission must, whenever possible, "fulfill [its] jurisdictional responsibilities while also respecting the states' traditional role,"[8] consistent with the Federal Power Act's purpose to "complement," not "usurp[] … State regulatory authority."[9] For two decades, this is how the Commission's markets have operated. Thus, there is no truth to the allegation that this proceeding is a referendum on the Commission's commitment to markets.[10]

Advocates of MOPR-Ex ask the Commission to sweep away this market-based model of cooperative federalism in favor of one that countermands state environmental policies, so that the Commission's market yields the outcome that would result if the state policies did not exist. The Commission should not be fooled by these parties' rhetoric: while they cloak themselves in the language of market integrity and fairness, what these generators really want is to protect the market advantage they gain by polluting without paying. They urge PJM market rules that would neuter state policies compensating for the real benefits of cleaner fuels, and thus would strangle

[7] Exelon Protest at 18-22.
[8] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1117 (2006).
[9] *Conn. Light & Power Co. v. Fed. Power Comm'n*, 324 U.S. 515, 526 (1945).
[10] *See, e.g.*, Comments of the Independent Market Monitor for PJM at 6 ("IMM Comments"); Protest of the PJM Power Providers Group at 23 ("P3 Protest"); Protest and Comments of Electric Power Supply Association at 30-32 ("EPSA Protest").

competition from cleaner generators that, when pollution costs are taken into account, would outcompete the polluters.

As Exelon and the PSEG Companies showed in their Protests, such action is not only inconsistent with sound economics and principles of cooperative federalism, but also is unjustified in light of current PJM market conditions. The Commission's markets are achieving what the Supreme Court has identified as "the principal purpose of" the Federal Power Act: "the orderly development of plentiful supplies of electricity … at reasonable prices."[11] Supply is plentiful, prices are low, and new entry remains significant. The commenters declaring that the markets are on the verge of collapse never address this reality, nor offer any evidence at all to support their panicked assertions that PJM is in the midst of a crisis.

For these reasons, the Commission should reject both PJM proposals. But if the Commission nevertheless determines to take some action to bring capacity prices closer to the levels that would exist without state environmental policies, the Commission should approve Capacity Repricing. Advocates of MOPR-Ex, of course, prefer MOPR-Ex, because it shields them from competition and furthers their goal of ridding the capacity markets of their non-emitting competitors. But if the Commission is compelled to act and finds Capacity Repricing, "PJM's preferred approach,"[12] to be just and reasonable (or that it can be rendered just and reasonable with an appropriate conditional acceptance), the Commission must approve it without reaching MOPR-Ex. Capacity Repricing satisfies the Commission's standard for market design—that it be "workably competitive."[13] And even if the comparison to MOPR-Ex were relevant, from a policy standpoint, Capacity Repricing is clearly superior to MOPR-Ex.

[11] *NAACP v. Fed. Power Comm'n*, 425 U.S. 662, 669-70 (1976).
[12] PJM Filing at 53.
[13] *See, e.g.*, *PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053, at P 84 (2005).

Under MOPR-Ex: (1) The wrong resources clear (because clean resources should have the chance to out-compete polluters, after environmental harm is accounted for); (2) Too many resources clear (given the likelihood that the clean resources excluded by MOPR-Ex will continue to supply capacity without compensation from the market); and (3) Energy market price signals are corrupted (suppressed by forced overprocurement). The MOPR's proponents claim this harm is good because it "disincentiv[izes]" states.[14] But the Commission has no business trying to deter states from protecting citizens' health and welfare, and it is doubtful that the Commission could do so in any event.

Capacity Repricing avoids all these problems. The correct resources clear, after accounting for environmental harm; the right quantity of resources clears; and energy market prices are not distorted. Advocates of MOPR-Ex nevertheless argue that Capacity Repricing must be rejected because it yields a price-quantity pairing that is not on the demand curve, and because it may create opportunities for strategic bidding. But these critiques, even if true, are not fatal to Capacity Repricing, and they certainly are no reason to select MOPR-Ex in its stead. As to the price-quantity issue, this theoretical criticism has only modest practical effects. And MOPR-Ex *also* yields a price-quantity pairing that is not on the demand curve, once one accounts for the reality that states will continue support environmentally friendly resources that will effectively provide capacity to the system. Likewise, as to alleged incentives for strategic bidding, any effects "are likely to be modest and would reduce the cost of repricing to customers."[15] To the extent there is any effect, strategic bidding will tend to result in a clearing price that is still significantly higher than the status quo, but lower than the MOPR-Ex clearing price would be. In effect, Capacity Repricing strikes a middle ground. If the Commission remains concerned about bidding incentives, they can be

[14] IMM Comments at 14-15; EPSA Protest at 28-29.
[15] Schnitzer Decl. ¶ 15.

fixed. One example of a potential fix would be including an "opportunity cost" payment in the Capacity Repricing model. Such payments, by making resources indifferent between clearing and not, could virtually eliminate these bidding incentives. In a variety of contexts, the Commission has approved similar payments to align incentives with efficient behavior.

Thus, while there are good reasons to reject any mitigation of environmental payments, including Capacity Repricing, the broad criticisms of Capacity Repricing are overblown. Capacity Repricing is flawed because clean resources should be allowed to account for environmental attribute revenues and other state compensation in making capacity bids. These revenues reflect payments for separate services, and thus those resources, to cover their going forward costs, do not need to receive those amounts from the capacity market. But if the Commission disagrees, Capacity Repricing is the only proposed workable—and "workably competitive"—alternative.

I. The Comments Confirm That PJM's "Two Alternative[]" Approach Violates Section 205.

The comments underscore why Section 205 prohibits alternative filings like PJM's. Arrayed before the Commission are dozens of comments advocating for or against an unbounded universe of potential tariffs: Capacity Repricing,[16] MOPR-Ex,[17] and assorted permutations of MOPR-Ex without certain exemptions (with various commentators seeking to sever versions of the RPS Exemption, Self-Supply Exemption, Public Entity Exemption, Competitive Entry Exemption, and the carve out for federal subsidies, among others).[18] By placing this free-for-all

[16] A number of commentators show that no change is warranted, but that Capacity Repricing is vastly superior to MOPR-Ex. *See* Comments of American Electric Power Service Corp. at 1 ("American Electric Comments"); Protest of Dominion Energy Services, Inc. at 9-11 ("Dominion Comments"); Exelon Protest at 8; Comments of Nuclear Energy Institute at 1 ("NEI Comments"); Protest and Motion to Reject of the PSEG Companies at 2 ("PSEG Protest").

[17] Comments of American Petroleum Institute, J-Power USA Development Co., Ltd., and Panda Power Generation Infrastructure Fund, LLC at 7-8 ("API Comments"); EPSA Protest at 2; IMM Comments at 3.

[18] *See, e.g.*, Comments of LS Power Associates, L.P. at 18 ("LS Power Comments"); Comments of Natural Gas Supply Association at 8 ("NGSA Comments"); Protest of the NRG Companies at 25 ("NRG Protest"); P3 Protest at 20; Comments and Protest of Rockland Capital, LLC at 5 ("Rockland Comments"); Comments of Vistra Energy Corp. and Dynegy Marketing & Trade, LLC at 13 ("Vistra Comments").

before the Commission, instead of proposing a single tariff "stating plainly the change or changes to be made,"[19] PJM's filing is inconsistent with the "passive and reactive role" that Section 205 requires the Commission to play.[20] If PJM wishes to give the Commission broad discretion to set policy, it must attempt to carry Section 206's heavy burden, or else seek a declaratory judgment. Because Section 205 does not sanction PJM's approach, the Commission must reject its filing.

II. The Comments Confirm That The Commission Should Not Hesitate To Reject Both Of PJM's Proposals And Preserve The Status Quo.

Stakeholders of every stripe have identified significant problems with both of PJM's proposals. Yet proponents of mitigation urge the Commission to press ahead anyway based on claims that the sky is falling—that state programs are "wreak[ing] havoc with PJM's markets,"[21] which are supposedly facing a "serious threat"[22] and "will collapse."[23] These are serious charges that, if true, would yield evidence for all to see. But what the comments of mitigation proponents reveal, more than anything, is that no *evidence* backs up this rhetoric. And the *actual* evidence confirms that the crisis is manufactured. As shown by Exelon, the PSEG Companies, and others, reserve margins are historically high (23.3% for the 2020-21 BRA) at prices that are historically low ($86/MW-day)—yet still, new entry continues at a significant pace (including almost 40 GW of recently entered or potential near-term entrants across PJM).[24] These high reserve margins, moreover, have been sustained despite years of claims that the capacity markets face "imminent

[19] 16 U.S.C. § 824d(d).
[20] *NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 115 (D.C. Cir. 2017).
[21] NRG Protest at 2.
[22] EPSA Protest at 34.
[23] P3 Protest at 8.
[24] Exelon Protest at 33; *see* Protest of Clean Energy Advocates at 35-42 ("Clean Energy Advocates Protest"); Protest of Clean Energy Industry Associations at 10-14 ("Clean Energy Industry Protest"); Protest of Joint Consumer Advocates at 10-14 ("Joint Consumer Protest"); Protest and Comments of the Maryland Public Service Commission at 5 ("Maryland PSC Protest"); Protest of the Office of the People's Counsel for the District of Columbia, Maryland Office of People's Counsel, and New Jersey Division of the Rate Counsel at 2-3 ("DC/MD/NJ Ratepayers Protest"); Comments of the Organization of PJM States at 5-7 ("PJM States Comments"); PSEG Protest at 11.

and substantial," and even "existential," "threat[s]."[25] The efficacy of PJM's capacity markets, and investors' faith in them, speaks for itself.

While PJM does not need to point to a crisis to justify tariff revisions under Section 205, the absence of any on-the-ground problem means that the Commission should not hesitate to reject both of PJM's proposals. Instead, until PJM formulates a new tariff that is genuinely just and reasonable, the Commission should leave PJM's capacity market rules where they are—with the MOPR limited, as it has been, to counteracting buyer-side market power by new resources.[26] That cautious approach avoids all the problems that come from expanding mitigation. And it respects stakeholders' wishes: Of the comments filed that take a position on the merits, a substantial majority urge the Commission to reject both proposals.[27] That preference has been consistent since November 2017, when 64% of stakeholders stated that they preferred the status quo.[28]

III. Although The Capacity Repricing Proposal Is Unwarranted And Flawed, Claims That The Proposal Is Unworkable Are Incorrect.

Exelon and the PSEG Companies agree with the commenters who criticize Capacity Repricing as unwarranted and unnecessary because it needlessly raises prices for customers at a

[25] Complaint Requesting Fast Track Processing at 5, *Calpine Corp. v. PJM Interconnection, L.L.C.*, Docket No. EL16-49-000 (Mar. 21, 2016); Motion to Amend, and Amendment to, Complaint and Request for Expedited Action on Amended Complaint at 2, 3, *Calpine Corp. v. PJM Interconnection, L.L.C.*, Docket No. EL16-49-000 (Jan. 9, 2017); *see* Exelon Protest at 33.

[26] Exelon Protest at 38-40.

[27] Comments of Advanced Energy Buyers Group at 1-2; American Electric Comments at 1; Comments of American Municipal Power, Inc. at 20; Protest of American Public Power Association at 1; Clean Energy Advocates Protest at 1; Clean Energy Industry Protest at 1-2; Dominion Comments at 5; Comments and Limited Protest of Duquesne Light Company at 3 ("Duquesne Comments"); Protest and Comments of FirstEnergy Service Company & East Kentucky Power Coop., Inc. at 2-3 ("FirstEnergy Comments"); Comment of Harvard Electricity Law Initiative at 1-3 ("Harvard Electricity Law Comments"); Motion to Dismiss and Protest of Illinois Commerce Commission at 4-5; Comments of Institute for Policy Integrity at 1-2; Joint Consumer Protest at 1; Maryland PSC Protest at 2; NEI Comments at 1; Protest of the New Jersey Board of Public Utilities at 1; NRG Comments at 1; PJM States Protest Comments and Protest of Public Utilities Commission of Ohio at 2; Comments and Protest of Old Dominion Electric Cooperative at 1; P3 Protest at 3; Comments of the Pennsylvania Public Utility Commission at 16; PJM States Comments at 1-2; PSEG Protest at 1-2; Protest of Solar RTO Coalition at 1 ("Solar RTO Protest"); Protest of Southern Maryland Electric Cooperative, Inc. at 3; Comments of Talen PJM Companies at 2.

[28] PJM, CCPPSTF Vote Results at 5 (Nov. 21, 2017), http://www.pjm.com/-/media/committees-groups/task-forces/ccppstf/20171121/20171121-ccppstf-vote-results.ashx; *see* Exelon Protest at 43.

time of oversupply with no corresponding benefit, and because it incorrectly mitigates payments recognizing the environmental value of clean generation. But to the extent the Commission disagrees and deems some departure from the status quo necessary, it is not "free to accept the better of the two approaches filed under Section 205," as the IMM incorrectly asserts.[29] PJM has identified Capacity Repricing as its "prefer[red]" approach, and thus the Commission must "assess first whether it can accept Option A, even if subject to suspension and further proceedings."[30] If the Commission determines Capacity Repricing is just and reasonable (or, with an appropriate conditional acceptance, can be *made* just and reasonable), it cannot reach MOPR-Ex. And while Capacity Repricing is unnecessary, the broader attacks on it are meritless. Capacity Repricing's auction mechanism can meet the Commission's "workably competitive" standard,[31] and can accommodate state programs while insulating capacity prices from those programs' effects.

A. The Criticisms Of Capacity Repricing's Auction Design Are Overstated And Can Be Remedied.

Several commentators note strategic bidding incentives that exist under Capacity Repricing's two-stage design—three such incentives, in particular. First, if a portfolio owner has high-cost resources that cannot hope to receive a capacity commitment at Stage 1, it might inflate the bids for those resources in the hope of contributing to higher Stage 2 clearing prices for other resources (what the Wilson Affidavit calls "clear-out-the-top").[32] Second, some "in between" resources—which might be economic at the Stage 2 clearing price, but cannot clear at Stage 1—may drop out.[33] Third, if resources would be economic at the anticipated Stage 2 clearing prices, they may have incentives to make offers below their forward costs in order to increase their

[29] IMM Comments at 3.
[30] PJM Filing at 46.
[31] *See, e.g.*, *PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053, at P 84 (2005).
[32] DC/MD/NJ Ratepayers Protest at 10; *see* EPSA Protest at 10.
[33] EPSA Protest at 11 n.46 and Affidavit of David W. DeRamus and Collin Cain ¶¶ 49-53.

chances of receiving a capacity commitment at Stage 1 (what the Wilson Affidavit calls "race-to-the-bottom").[34] The first two incentives tend to increase prices; the third, to decrease prices.

Even if these incentives exist, they are not *per se* fatal. Indeed, as the Schnitzer Declaration explains, "[w]hile commenters' witnesses point out these strategic bidding behaviors, they do not provide any well-supported analysis of their combined net impact."[35] And careful analysis shows that the concerns about Capacity Repricing are overblown. Any incentives to "clear-out-the-top" reflect issues that are already addressed by existing market rules, such as seller offer caps and the risk of Commission enforcement penalties for manipulative bidding.[36] Likewise, the effect of "in between" resources dropping out of the market will be limited given PJM's deep well of potential new entrants.[37] Finally, as between the three incentives, the effect termed "race-to-the-bottom" likely will affect a broader range of resources, and this price-reducing effect will likely swamp the other two price-increasing effects.[38] This effect, however, is also self-limiting: If a resource were the *only* one pursuing this strategy, perhaps it might steeply reduce its bid, predicting that Stage 2 would increase the clearing price.[39] But bidders take into account others' expected behavior.[40] And here, a resource will know that other bidders are also likely to reduce their bids—and thus if the resource reduces its bid too steeply, it risks losing money even at the higher Stage 2 price.[41] This will limit incentives to reduce bids.

The upshot of these incentives will be to mitigate the price increases that would otherwise result from Capacity Repricing. For example, one witness estimates that Capacity Repricing (and

[34] DC/MD/NJ Ratepayers Protest at 9.
[35] Schnitzer Decl. ¶ 51.
[36] *Id.* ¶ 54.
[37] *Id.* ¶ 57.
[38] *Id.* ¶ 58.
[39] *Id.* ¶¶ 59, 61.
[40] *Id.* ¶ 59.
[41] *Id.*

MOPR-Ex) would increase capacity prices by about 50% absent strategic bidding.[42] The bidding incentives, on plausible assumptions, lower this amount slightly to 39%.[43] Exelon and the PSEG Companies have shown that Capacity Repricing and MOPR-Ex both "will raise capacity market prices and costs for consumers"; the bidding incentives produced by Capacity Repricing thus somewhat limit that effect, yielding prices that are "elevated relative to the status quo, but below MOPR-Ex."[44] That is a reason to prefer it to MOPR-Ex.[45] Whatever the theoretical criticisms of Capacity Repricing's design, it cashes out as a compromise. It respects state policies by allowing state-supported clean generation to clear while still raising prices to offset this support—albeit not as much as certain fossil-fuel generators hope to achieve via MOPR-Ex.[46]

If the Commission remains concerned about Capacity Repricing's effects on bidding incentives, there are potential solutions. For example, the Schnitzer Declaration explains that resources whose offers are above the Stage 1 clearing price but below the Stage 2 clearing price could receive a "lost opportunity cost" payment equal to the difference between their offers and the Stage 2 clearing price.[47] The lower the offer, the higher the payment.

A "lost opportunity cost" payment largely could eliminate all three incentives detailed above: It could eliminate "clear-out-the-top" (artificially inflated offers would be costly, as they would reduce lost opportunity cost payments); the drop out of "in between" resources (who would receive an incentive, via the lost opportunity cost payment, to submit a bid); and the "race to the

[42] *Id.* ¶ 61.
[43] *Id.*
[44] *Id.* ¶¶ 18, 61.
[45] *Id.* ¶ 64.
[46] EPSA also contends that the effect termed "race-to-the-bottom" will cause the auction to procure too much capacity—because when the demand curve slopes down, lower offer prices will yield a larger quantity. EPSA Protest at 11. Because the demand curve is so steep, however, any such effect will be very small—on the order of 0.1% of the market, or 167 MW. Schnitzer Decl. ¶ 63.
[47] Schnitzer Decl. ¶ 67.

bottom" (as failing to clear at Stage 1 would no longer harm resources that can beat the Stage 2 price).[48] This modification could also address the concern that Stage 2 clearing prices will be set by resources with no capacity commitment at stake: A lost opportunity cost payment means that *all* resources that can beat the Stage 2 price have something at stake.[49] The size of these payments would likely be small—0.75% of total capacity payments.[50]

Nor would such payments amount to money for nothing: preparing bids is costly,[51] and PJM would be compensating generators for their expense in preparing cost-based bids that help the PJM market operate efficiently. Opportunity cost payments are already used by PJM to align bidder incentives with efficient behavior—for example, to address out-of-market dispatch for reliability reasons in energy markets, and in operating reserves markets.[52]

If the Commission concludes that a modification to Capacity Repricing is warranted, Exelon and the PSEG Companies respectfully suggest that the appropriate next step would be to reject the current filing as unjust and unreasonable, but indicate that the Commission would accept a Section 205 filing including such a modification.

B. The Broader Attacks On Capacity Repricing Are Meritless.

The broader attacks on Capacity Repricing—many pressed by fossil-fuel generators hoping to drive the Commission toward an unwarranted expansion of the MOPR—are baseless.

Clearance by state-supported resources. One supposed flaw is that clean generators receiving payments for their environmental value clear at the expense of other generators.[53] But this is Capacity Repricing's key *virtue*. As Dr. Willig's Declaration explains, this is the efficient

[48] *Id.* ¶¶ 68-72.
[49] *Id.* ¶ 68.
[50] *Id.* ¶ 73.
[51] *See* Affidavit of David W. DeRamus & Collin Cain, ¶ 50, attached to EPSA Protest.
[52] Schnitzer Decl. ¶ 74.
[53] *See, e.g.*, EPSA Protest at 9; P3 Protest at 12-13.

result when environmental externalities are taken into account,[54] and by permitting this result, Capacity Repricing avoids the costly overprocurement and distorting energy market effects that plague MOPR-Ex (as discussed further below). In this respect, Capacity Repricing follows the CASPR Order's lead—which also permitted, through a different mechanism, state-supported clean resources to replace existing polluting resources.

Effects on other states. Next, the proponents of a broader MOPR claim Capacity Repricing "would create a significant externality" by allowing "states … to shift th[e] costs of th[eir] polices … onto other" states.[55] Not so. State policies themselves do not impose any costs on other states—for example, the funds for Illinois' ZEC Program come entirely from Illinois customers—and the whole *point* of Capacity Repricing is to set prices where they would have been without state payments that qualify as Actionable Subsidies. That does not export any costs onto other states, or alter prices received by other generators. To the contrary, states *benefit* other states when they support clean generation, because the benefits of pollution abatement are experienced by citizens of all states, not only the state paying for the pollution abatement.

EPSA also repackages similar arguments as constitutional objections, claiming that Capacity Repricing unconstitutionally "[a]llow[s] [s]tates [t]o [r]egulate [b]eyond [t]heir [b]orders" by permitting "the actions of one state to affect[] … other states."[56] The Commerce Clause prohibits states from enacting extraterritorial legislation that "directly regulates transactions which take place across state lines."[57] Never could the Commission's *federal* approval of market rules violate that restriction on state authority. And regardless, EPSA does not

[54] Willig Decl. ¶ 52; *see* Institute for Policy Integrity, *Capacity Markets and Externalities: Avoiding Unnecessary and Problematic Reforms* at 10-12 (April 2018), http://policyintegrity.org/files/publications/Capacity_Markets_and_Externalities_Report.pdf.
[55] EPSA Protest at 29.
[56] *Id.* at 21 (internal quotation marks omitted).
[57] *Edgar v. MITE Corp.*, 457 U.S. 624, 641 (1982).

point to any "direct[] regulat[ion]" of interstate commerce;[58] at most, it alleges that one state's actions may have effects elsewhere.[59] But mere extraterritorial effects do not violate the Commerce Clause: "it is inevitable that a state's law … will have extraterritorial effects," and the "Supreme Court has never suggested that the … Commerce Clause" precludes such effects.[60] Indeed, EPSA's argument proves vastly too much. Whenever states have subsidized fossil-fuel plants, they have required citizens "in other states to shoulder much of the burden"—in less efficient wholesale electricity markets, and in more polluted air.[61] On EPSA's theory, all such subsidies would be unconstitutional. The Commerce Clause has never stretched so far.

Violation of constitutional limits on ratemaking. EPSA's other constitutional objection fares no better. EPSA argues that, as to resources that offer below the Stage 2 clearing price but do not receive a capacity commitment at Stage 1, Capacity Repricing violates the Constitution (and FPA) because it does not provide these resources the "*opportunity* to recover [their] costs,"[62] invoking *FPC v. Hope Natural Gas Co.*[63] and *Bridgeport Energy, LLC*.[64] That standard, however, does not apply here. When a utility is compelled to provide service to the public, as with a traditionally regulated utility, this standard forbids "confiscatory" rates for compelled service.[65] Likewise, when a generator is compelled to remain operational for reliability, the same standard governs.[66] In PJM, however, generators are not compelled to provide capacity. To be sure, generators that have sold capacity generally have a must offer obligation into the Reliability

[58] *Id.*
[59] EPSA Protest at 21-22.
[60] *Instructional Sys., Inc. v. Computer Curriculum Corp.*, 35 F.3d 813, 825 (3d Cir. 1994); *see SPGGC, LLC v. Blumenthal*, 505 F.3d 183, 194 (2d Cir. 2007).
[61] EPSA Protest at 22-23 (quotation marks omitted).
[62] *Id.* at 21 (quoting *Bridgeport Energy, LLC*, 113 FERC ¶ 61,311, at P 29 (2005)); *see* LS Power Comments at 8-9 (same argument).
[63] 320 U.S. 591, 603 (1944)
[64] *Bridgeport Energy, LLC*, 113 FERC ¶ 61,311, at P 29 (2005).
[65] *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 310 (1989) (citing *Hope Natural Gas*, 320 U.S. at 502).
[66] *Bridgeport Energy, LLC*, 113 FERC ¶ 61,311, at P 29 (2005).

Pricing Model. But if these resources choose to retire, they can do so upon 90 days' notice (and, presumably, upon covering any outstanding capacity obligations)—regardless of reliability implications.[67] In such circumstances, the Commission has held that "there can be no question of confiscation of a resource's property."[68]

Seller-side market power. The American Petroleum Institute ("API") claims, uniquely, that state support generally, and Capacity Repricing in particular, "facilitate the exercise of *supplier*"—not buyer—"market power"[69] via three anticompetitive tactics: (1) "predatory pricing"; (2) "entry deterrence"; and (3) "economic withholding" of a portion of an owner's portfolio.[70] As best Exelon and the PSEG Companies can discern, API's argument appears to be that these tactics require that the owner have the financial wherewithal to withstand temporary losses or losses in part of its portfolio, and that subsidies and Capacity Repricing "facilitate" these tactics by giving generators more money overall. But that money could just as well come from *anywhere*—utility operations, capital markets, or tax reductions. API's argument has nothing to do with Capacity Repricing.

Price/quantity pair not on the demand curve. EPSA criticizes Capacity Repricing because it yields a result that does not fall on "RPM's sloped demand curve": Because Stage 1 determines the quantity procured, and Stage 2 determines the price, Capacity Repricing yields a "price/quantity relationship" that does not appear on the demand curve.[71] But that theoretical flaw

[67] PJM Open Access Transmission Tariff, § 113.
[68] *Id.*; *see also N.Y. Indep. Sys. Operator, Inc.*, 124 FERC ¶ 61301, at P 58 (2008) (similar). To the extent EPSA's argument is that Capacity Repricing is unreasonable under the FPA because it does not "represent[] an appropriate balancing of consumer and investor interests," EPSA Protest at 19, Exelon and the PSEG Companies agree—but EPSA gets the imbalance backwards. For consumers, Capacity Repricing strikes the wrong balance because it raises prices with no sound justification. But for investors, it is not unfair that some polluting resources fail to clear due to states' efforts to address environmental externalities—which remains true even if these resources could have beaten the Stage 2 clearing price.
[69] Affidavit of Paul M. Sotkiewicz ¶ 6, attached to Comments of API.
[70] *Id.*
[71] EPSA Protest at 14; *see* Affidavit of David W. DeRamus and Collin Cain ¶ 38.

is no reason to reject Capacity Repricing absent some evidence that it is *actually* unworkable. And certainly, it is no reason to select MOPR-Ex over Capacity Repricing: As the Schnitzer Declaration explains, "the same is true of MOPR-Ex," which *also* yields a "price and quantity pair [that] does not fall on the demand curve," once one accounts for the resources that will continue to receive state support and effectively provide capacity to the system, even though they are not selected in the capacity auction.[72] "Indeed, because MOPR-Ex results in *significant over-procurement*, the effective price-quantity pair that results is even further away from the demand curve than Capacity Repricing."[73]

IV. The Proposals To Expand The MOPR Are Fundamentally Flawed.

Even if the Commission determined that a change must be made and that it could not approve Capacity Repricing (or a variant), it could not approve MOPR-Ex or any of the expansions of the MOPR proposed here. Both in theory and in execution, they are fundamentally flawed.

A. The Proposals To Expand The MOPR Are Flawed In Theory.

The commentators pushing for an expanded MOPR depict competitive markets as, by definition, insulated from the effects of state policies—which, when those policies involve payments for environmental benefits, they derisively call "subsidies."[74] Thus, they proclaim that "*all* subsidies" "are bad," "evil[]," and a "problem[]."[75] But the Commission will not find a citation to any economic authority that supports that broad proposition. That is because this proposition is false—for reasons Exelon has explained. Markets are not efficient when fossil-fuel generators inflict pollution on society without paying.[76] And state policies that attempt to

[72] Schnitzer Decl. ¶ 22.
[73] *Id.* ¶ 15 (emphasis added).
[74] *See, e.g.*, API Comments at 5; EPSA Protest at 12; NGSA Comments at 1-2; P3 Protest at 3.
[75] P3 Protest at 11 & Aff. of Roy J. Shanker, attached thereto, at PP 10, 34.
[76] Willig Decl. ¶¶ 13(c)-(d), 31.

internalize this externality, whether by taxing or penalizing pollution, or by supporting clean generation that abates pollution, make markets more efficient and competitive.[77] This is Economics 101.[78]

In reality, the MOPR's proponents do not really believe that *all* state interventions must be mitigated; instead, their pious rhetoric is only meant to encourage the Commission to adopt changes that harm cleaner competitors, while leaving untouched the massive subsidies they have long reaped. Thus, P3 proposes a supposedly "Clean MOPR" that removes MOPR-Ex's enumerated exemptions and also the carve-out from the definition of "Actionable Subsidy" for "federal production and investment tax credits."[79] But tellingly, P3 does not seek to remove the exclusion for various siting- or development-based subsidies—subsidies that happen to go to gas-fired generators. Likewise, there is not a peep about the untold billions in subsidies that coal-fired generators have and continued to receive, including both direct subsidies—$4.7 billion, just on the federal side, every year[80]—and indirect support, such as Pennsylvania's sales-tax exclusion for coal.[81] And all of this is in addition to the *implicit* subsidy that fossil-fuel generators receive from the ability to pollute without paying, which Exelon showed comes to $12.1 to $17.7 billion annually.[82] There is no justification for targeting government policies for mitigation *only* when they promote clean generation and make the Commission's markets more efficient.

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[77] *Id.* ¶¶ 32-37.
[78] *See id.* ¶¶ 30 n.28, 31 n.29, 34 n.32 (citing P.A. Samuelson & W.D. Nordhaus, *Economics* at 346-355 (1995); R.S. Pindyck & D.L. Rubinfeld, *Microeconomics*, 639-657 (2d ed. 1992); A.C. Pigou, *The Economics of Welfare* (4th ed. 1932); W.J. Baumol & W.E. Oates, The theory of environmental policy, Ch. 3 (2d ed. 1995)).
[79] P3 Protest at 20 & n.50.
[80] Exelon Protest at 30; *see* Clean Energy Advocates Protest at 41 ($7.5 billion in federal subsidies to coal in 1989 alone).
[81] Clean Energy Advocates Protest at 90.
[82] Exelon Protest at 12.

The MOPR's proponents have no adequate answer for how their approach undermines not just sound economics, but federalism principles the Commission has long respected. As explained by Exelon and others, states have long exercised their FPA-protected authority as regulators of "facilities used for the generation of electric energy,"[83] and the Commission has reaffirmed that it must, whenever possible, "fulfill [its] jurisdictional responsibilities while also respecting the states' traditional role."[84] That means that when states regulate generators to protect the air citizens breathe, the Commission should not attempt to thwart or disincentivize those policies, no matter how much rhetorical noise the policies' opponents employ.

The MOPR's proponents insist that an expanded MOPR does not seek to thwart state environmental policies. But in more candid moments, they admit the opposite—that an expanded MOPR aims to create "a disincentive" for state policymaking favoring clean generation.[85] That is consistent with PJM's statement that applying the MOPR to federal payments to wind and solar resources would, in effect, "countermand … acts of Congress."[86] But under the FPA, the Commission has no authority to establish market rules that seek to deter states from legislating to protect their citizens' health and welfare, or to countermand state actions that do so.[87]

Again and again, the MOPR's proponents labor to narrowly limit the state authority over generation that the Commission must respect. First, they put states to an all-or-nothing choice—claiming that states forfeited any ability to influence the generation mix when they joined "an organized capacity market," and that states wishing to make any "policy decision[s]" concerning generation must "pursue Fixed Resource Requirement ('FRR') treatment."[88] But as many

[83] 16 U.S.C. § 824(b)(1).
[84] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1117.
[85] EPSA Protest at 27-28 (quotation marks omitted); IMM Comments at 14.
[86] PJM Filing at 71.
[87] Exelon Protest at 18-19.
[88] P3 Protest at 21.

commentators note, that claim mocks history: In myriad states, restructuring went hand-in-hand with RPS programs.[89] That is why the D.C. Circuit has held that restructured states "retain the right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities."[90] Likewise, states' ability to fulfill their obligations under *other* cooperative-federalism statutes, like the Clean Air Act, often *depends* on influencing the generation mix that serves them.[91] Indeed, the Commission's organized markets have earned sustainable support precisely *because* the Commission has not required, as a condition of entry, that states give up their authority to influence the generation mix. To the contrary, in myriad ways, the Commission has actively "accommodate[d]" such policies.[92]

Second, the MOPR's proponents insist that states must make the perfect the enemy of the good. The IMM, for example, avers that states can address the harm caused by carbon dioxide only if they can agree on "a carbon price."[93] But unlike the IMM, states cannot wait for "[t]he theoretical ideal market approach."[94] They want to protect citizens *today*. Thus, acting under their police powers, states can—and often must—"take reform 'one step at a time, addressing [themselves] to the phase of the problem which seems most acute."[95] States, like the Commission, are permitted to adopt market-based approaches, entirely non-market mechanisms, or something

[89] Clean Energy Advocates Protest at 47-52; Harvard Electricity Law Comments at 2-3; MD PSC Protest at 9.
[90] *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009).
[91] Exelon Protest at 19.
[92] *ISO New England Inc.*, 162 FERC ¶ 61,205, at P 101 (2018) ("CASPR Order"); *see, e.g.*, *California Indep. Sys. Operator Corp.*, 145 FERC ¶ 61,254, at P 34 (2013) (approving reduction in CAISO's bid floor in the energy market to negative $150/MWh to accommodate renewable resources); *Reform of Generator Interconnection Procedures & Agreements*, 163 FERC ¶ 61,043 (2018) (requiring changes to large generator interconnection agreements and processes to streamline the process for new resources, which are predominantly wind and solar); *Integration of Variable Energy Res.*, 139 FERC ¶ 61,246, at P 92 (2012) (adjusting rules for transmission scheduling periods to avoid imposing penalties on variable resources supported by states).
[93] IMM Comments at 10.
[94] PJM Filing at 54.
[95] *McDonald v. Bd. of Election Comm'rs of Chicago*, 394 U.S. 802, 809 (1969) (quoting *Williamson v. Lee Optical of Oklahoma, Inc.*, 348 U.S. 483, 489 (1955)).

in-between. As Dr. Willig explains, well-designed environmental initiatives like Illinois' ZEC Program, which tie compensation to the value of the externality being abated and procure resources based on their environmental contribution, result in more efficient markets. There is no justification for thwarting those efforts simply because a carbon price would be superior.

Third, the MOPR's proponents imply that the Commission need not respect state policy choices because states may have different views about what externalities are most important to address—noting that FirstEnergy has identified, as "externalities," "fuel diversity" and "fuel security," and that resources possessing these attributes may be different from the clean generators targeted by MOPR-Ex.[96] But this concern is purely hypothetical. The *real* programs that states have enacted, and that MOPR-Ex targets, address environmental externalities like air pollution. Such environmental externalities are the easiest and clearest case. They are "the classic example found in almost every economics textbook."[97] So while the IMM disingenuously says that action may be warranted "[*i*]*f* society determines that carbon is a pollutant with a negative value"[98]—implying that carbon *might not* be a harmful pollutant—nobody *really* doubts that air pollution is a harmful externality, and that addressing it makes markets more efficient. At the May 2017 technical conference, even representatives of Calpine and NRG agreed that "carbon [is] an externality" that should be "price[d]."[99] Indeed, the federal government has *already found* that carbon is a harmful pollutant (in, for example, the EPA's "endangerment finding," which was affirmed on judicial review)[100]—and in any event, states need not wait for the federal government

[96] EPSA Protest at 30 (quotation marks omitted).
[97] Willig Decl. ¶ 30 n.28.
[98] IMM Comments at 10 (emphasis added).
[99] Transcript of Technical Conference at 331, *State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.*, Docket No. AD17-11-000 (May 2, 2017) (comments of Thad Hill); *see id.* at 320 (comments of Abe Silverman) ("[U]ltimately you know we do want to get to the point where the wholesale markets facilitate the state desires to meet the environmental externalities").
[100] *See, e.g.*, *Coal. for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 121 (D.C. Cir. 2012), *aff'd in part, rev'd in part on other grounds sub nom. Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427 (2014).

to address threats to citizens' health and welfare. Whatever the scope of the externalities that states can permissibly address, environmental externalities are in the heartland of what states have historically addressed, and should be encouraged to address.

B. The Proposals To Expand The MOPR Are Flawed In Execution.

Apart from its conceptual flaws, MOPR-Ex is indefensible purely as a matter of auction design. The same is true of the broader variants, like "MOPR Clean." All should be rejected.

Proponents suggest that an expanded MOPR *must be* just and reasonable because PJM has a MOPR rule, which "already reflects stakeholder compromises."[101] Not so. The present MOPR is narrow in its purpose (combatting buyer-side market power), in the fuel sources it covers (gas only), and in the vintage it targets (only new generators).[102] The broader MOPRs proposed in this proceeding would twist this rule for a sweeping new purpose, and to a new universe of resources—counteracting the effects of disfavored state policies on wholesale markets, for both new and existing resources of any fuel type. PJM's MOPR was not designed for this new role, and has never been applied in this far-reaching manner. Stakeholders' agreement to, or the Commission's approval of, the narrow existing MOPR provides no support for the sea change sought here.[103]

Moreover, the comments confirm that the expanded MOPR's Swiss-cheese exceptions are incurably arbitrary. Stakeholders from all walks—generators, environmental groups, customer advocates—agree that the RPS Exemption is discriminatory: It exempts favored RPS programs for renewables, while mitigating environmental programs based on disfavored technologies (like nuclear or offshore wind), disfavored procurement processes, and even RPS programs with

[101] IMM Comments at 10; *see* API Protest at 10.
[102] Exelon Protest at 38-40.
[103] *Id.*

technology-specific tiers.[104] It does so even though the favored and disfavored programs pursue the same purposes and have the same effects on capacity markets, and even though disfavored programs like Illinois' ZEC Program may be more economically efficient than the exempted programs, by capping payments at the value of the environmental externality being abated.[105]

Likewise, myriad commentators explain why the Self-Supply and Public Entity exemptions are indefensible under MOPR-Ex's proposed new purpose of counteracting effects of state policies on wholesale markets. Because of the implicit subsidy provided by captive ratepayers, the vertically integrated utilities that qualify for these exemptions can build or maintain generation that "may be uneconomic" and that "would not have been built" or maintained, "but for being backed by ratepayer funds."[106] The state policies favoring the vertically integrated business model may be *older* than the pro-environmental policies that have spread over the last two decades. But that does not justify differential treatment.

Contra the suggestion of some fossil-fuel generators, these problems cannot be solved by blue-penciling MOPR-Ex's enumerated exemptions. One reason—again, acknowledged by several commentators—is that *NRG Power Marketing, LLC v. FERC*[107] precludes doing so.[108] But the more important reason is that once the Commission starts down the path of applying the MOPR to some disfavored policies—even state environmental policies that promote market efficiency—there is no non-arbitrary stopping point. The comments illustrate the point. Many commenters, as noted above, explain that MOPR's enumerated RPS Exemption, Self-Supply Exemption, and Public Entity Exemption are discriminatory. But even if the Commission severed these

[104] Clean Energy Advocates Protest at 102; Duquesne Comments at 4-5; Joint Consumer Advocates Comments at 22-23; LS Power Comments at 18; NEI Comments at 9-12; NGSA Comments at 8; NRG Protest at 25; P3 Protest at 20; PSEG Protest at 9-10; Rockland Comments at 5; Solar RTO Protest at 20-22; Vistra Comments at 13.
[105] Willig Decl. ¶¶ 51, 59.
[106] NRG Protest at 19; *see* Clean Energy Advocates Protest at 82-85; P3 Protest at 18.
[107] 862 F.3d 108 (D.C. Cir. 2017).
[108] Clean Energy Advocates Protest at 65; Joint Consumer Advocates Protest at 8-9; PSEG Protest at 10.

exemptions, that would still leave the sundry additional subsidies that PJM excludes from the definition of "Actionable Subsidy"—subsidies that "promote … general industrial development in an area," subsidies that "incent … siting facilities in [a particular] locality," and federal tax credits.[109] As many commentators show, those subsidies also affect wholesale capacity markets by supporting resources that might not otherwise be economic, and they may be less efficient than well-designed state environmental programs.[110] There is no justification for applying the MOPR to state environmental policies, but not to these distorting subsidies. P3 trumpets its support for a "Clean MOPR."[111] But as explained above, P3 only proposes eliminating the exclusion for federal subsidies to renewables, not the state and local subsidies that generally benefit gas and coal generators. Even if those exclusions were eliminated, that would still leave the various upstream subsidies fossil-fuel generators receive—for example, Pennsylvania's sales tax exemption for coal.[112] The solution to this problem is not to embark along the path proposed by MOPR-Ex.

If, however, PJM's market rules exempt *some* state policies from an expanded MOPR, then the market rules must, at the least, exempt Illinois' ZEC Program. As Exelon has established, that program is more efficient than state RPS programs—not to mention state policies favoring vertically integrated utilities—because it links the externality payment to a conservative estimate of the participating plants' environmental value.[113] Failing to exempt the ZEC Program thus would be arbitrary. The ratepayer advocates for the District of Columbia, Maryland, and New Jersey defend an RPS-specific exemption on the theory that RPS programs are "long-standing" and

[109] *See* proposed PJM Tariff § 1, Definitions L-M-N (Option B).
[110] Exelon Protest at 24-25; *see* Clean Energy Advocates Protest at 8, 54-55; Duquesne Comments at 5; FirstEnergy Protest at 19-20; NEI Protest at 10-11; PSEG Protest at 10; Solar RTO Protest at 19, 25-26.
[111] P3 Protest at 20.
[112] Clean Energy Advocate Protest at 90.
[113] Exelon Protest at 24-25.

widespread across PJM.[114] Exelon and the PSEG Companies agree that RPS programs should not be subject to the MOPR, but once the Commission begins applying the MOPR to environmental programs, neither the vintage nor the political popularity of RPS programs is a reasoned ground for exempting them.[115]

The proponents of an expanded MOPR also have no adequate answer for the gross overprocurement of capacity that it will yield. They predict—without evidence—that an expanded MOPR will deter states from supporting clean resources. There is no reason to think that is so, and every reason to think the opposite. Despite ISO-New England's limited MOPR exemption for 200 MW of renewables, for example, states issued the Multi-State Clean Energy request for proposals, which aims to procure 460 MW of new renewable resources, and Massachusetts enacted the 2016 Massachusetts Energy Diversity Act, which requires clean energy procurements in the range of 2,800 MW.[116] And in PJM, if the unsupported predictions of the MOPR's proponents prove wrong, the result will be a massive overprocurement of capacity estimated to cost customers $14-24.6 billion annually.[117] The Commission should not adopt a policy premised on speculation that states will abandon *en masse* policies in which they have invested for a decade and to which they have shown increasing commitment in recent years. In the CASPR Order, the Commission found that clean energy "will be developed by the operation of state environmental and clean

[114] DC/MD/NJ Ratepayers Protest at 22.

[115] The ratepayer advocates also aver that RPS programs are different because they are "designed to bring new resources … online," rather than to "prevent[] the retirement of … older facilities." DC/MD/NJ Ratepayers Protest at 22. This is backwards: PJM's MOPR has only ever applied to *new* resources, precisely because those resources are better vehicles for buyer-side market power. *See* Exelon Protest at 39-40. The ratepayer advocates assert that the "long lead time for new entry" provides time for the market to "anticipate[] and absorb[]" these resources. DC/MD/NJ Ratepayers Protest at 22. But to the extent this argument is meant to distinguish RPS programs from the ZEC Program, it does not. Nuclear generators have been in operation for decades, and have been part of the markets from their origin. Market prices have always accounted for their operation.

[116] CASPR Order, at P 4.

[117] Clean Energy Advocates Protest at 105 & Grogging Aff. at PP 3-4, 15; *see* Exelon Protest at 46-48.

energy mandates, whether that capacity clears the [market] or not."[118] There is no reason to think that PJM states will act any differently.[119]

MOPR proponents say that if states do not acquiesce to the "disincentive" provided by an expanded MOPR, the overprocurement is states' fault.[120] But this ignores the FPA's jurisdictional lines. States regulate generation, while capacity requirements—how much must be procured, and what resources count toward satisfying the administratively determined obligations—rest with the Commission.[121] So if capacity is procured inefficiently—or if more capacity is procured than is needed to ensure resource adequacy, because the Commission is ignoring capacity provided by state-supported resources—that error is squarely within the Commission's domain. Moreover, proponents of the MOPR-Ex badly disrespect state authority in claiming that states can avoid overprocurement by relinquishing the ability to legislate to protect their citizens' health and welfare. Never has the Commission sought to deter states from implementing legitimate environmental policies in their domain by punishing their citizens—and those elsewhere in PJM, too—with unnecessary capacity costs. Instead, the Commission has made sure to accommodate those policies.[122]

MOPR's proponents also have no answer to the price suppression in energy markets this overprocurement will yield. PJM identified this problem in its filing.[123] Yet the MOPR's proponents barely attempt to respond. The Commission cannot approve an expanded MOPR when the problems it creates may be larger than the problems it purports to solve.[124]

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[118] CASPR Order, at P 45.
[119] *See* Willig Decl. ¶ 73.
[120] EPSA Protest at 26, 28-29.
[121] *See Conn. Dep't of Pub. Util. Control*, 569 F.3d at 481.
[122] *Supra* at 19.
[123] PJM Filing at 57.
[124] Exelon Protest at 46-48; *see* Willig Decl. ¶ 74.

Finally, the MOPR's proponents cannot account for the CASPR Order, which made clear that the Commission's policy is to accommodate rather than countermand state initiatives. This policy is not new: more than a decade ago, the Commission likewise emphasized that it must, whenever possible, "fulfill [its] jurisdictional responsibilities while also respecting the states' traditional role."[125] MOPR proponents make much of the CASPR Order's statement that the Commission would use "the MOPR as our standard solution" "[a]bsent a showing that a different method would" be effective.[126] But that statement referred to ISO-New England's narrower MOPR applying to only new resources, and even then, only two Commissioners endorsed it. The CASPR Order's actual *holding* was that ISO-New England's proposed reforms were just and reasonable precisely because the Commission concluded that they would succeed in ISO-England's goal of reasonably "accommodat[ing] state sponsored resources … over time."[127] Moreover, Exelon and the PSEG Companies respectfully suggest that it would be unwise for the Commission to establish a rule that it will apply the MOPR unless a different "market design proposal[]" is "developed by [an RTO] and [its] stakeholders,"[128] and is "the result of extensive compromise."[129] Under that rule, stakeholders that will financially benefit from an expanded MOPR—like EPSA's fossil-fuel generators—will never compromise, knowing that a default Commission action will award them what they cannot achieve through negotiation.

[125] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1117 (2006).
[126] CASPR Order, at P 22.
[127] *Id.*, at P 102.
[128] EPSA Protest at 24 (quoting CASPR Order, at P 62,098 (LaFleur, Comm'r, concurring in part)).
[129] *Id.* (quoting CASPR Order, at 62,099 (Powelson, Comm'r, dissenting)).

C. If The Commission Finds That It Cannot Approve Either Of PJM's Proposals, It Should Not Proceed Under Section 206.

A few stakeholders urge that, if the Commission rejects both Capacity Repricing and MOPR-Ex, it should proceed under Section 206 and craft new rules itself.[130] Exelon respectfully suggests that this would be a mistake. It would require the Commission to carry the dual burdens of showing that "existing rates are 'entirely outside the zone of reasonableness,'" and that the solution crafted by the Commission is just and reasonable.[131] In turn, that would require the Commission to show, based on substantial evidence, that it is necessary for just and reasonable rates to raise prices at a time of vast oversupply, and to apply PJM's MOPR for the first time to existing resources receiving payments for their clean-energy benefits under state environmental programs. The Commission would also have to craft new rules that avoid all of the fatal flaws that parties have correctly identified in PJM's proposals, and amass a majority of Commissioners to support them. The Commission should not embark on this venture. No imminent—or even foreseeable—threat to reliability or investment has been shown, and the Commission should instead simply reject PJM's filing.

[130] *See, e.g.*, *id.* at 2; NRG Protest at 1.
[131] *NRG*, 862 F.3d at 114 n.2; *see Mkt.-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utilities*, 123 FERC ¶ 61,055, at P 24 (2008).

CONCLUSION

The Commission should reject PJM's filing as not just or reasonable.

Dated: May 22, 2018

Respectfully submitted,

/s/ Matthew E. Price

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 22nd day of May, 2018.

/s/ *Marianne Alvarez*

Marianne Alvarez
Exelon Corporation

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

CPV Power Holdings, L.P., Calpine Corporation and Eastern Generation, LLC,	)	
Complainants,	)	**Docket No. EL18-169-000**
v.	)	
PJM Interconnection, L.L.C.,	)	
Respondent.	)	

DECLARATION OF MICHAEL M. SCHNITZER

June 20, 2018

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I. QUALIFICATIONS, ASSIGNMENT AND SUMMARY OF CONCLUSIONS

A. QUALIFICATIONS

1. My name is Michael M. Schnitzer. I am a director of The NorthBridge Group, Inc ("NorthBridge"). NorthBridge is a consulting firm that provides economic and strategic advice to the electric and natural gas industries. My business address is 30 Monument Square, Concord MA 01742.

2. In 1992, I co-founded NorthBridge. Before that, I was a Managing Director of Putnam, Hayes & Bartlett, which I joined in 1979. I have experience working with private sector clients in the electric utility, natural gas, and private power industries, as well as with public and nonprofit agencies. My electric industry work has focused on regulatory policy, finance, and market structure issues. I received an A.B. in chemistry, with honors, from Harvard University, and an M.S. in management from the Sloan School, Massachusetts Institute of Technology.

3. I have testified before the Commission on many matters and have participated in Commission technical conferences and workshops on capacity market and energy market design issues. I have also testified before the public utility commissions of Arkansas, California, Delaware, Illinois, Indiana, Louisiana, Maine, Maryland, Massachusetts, Mississippi, New Hampshire, New Mexico, New Orleans, New York, Ohio, Pennsylvania, Rhode Island, Texas, Vermont, and Wisconsin.

B. BACKGROUND AND PURPOSE OF TESTIMONY

4. On April 9, 2018, PJM Interconnection, LLC ("PJM") filed at the Federal Energy Regulatory Commission ("FERC" or "Commission") two proposals to modify its capacity market design.[1] In its filing, PJM requested that the Commission approve its preferred capacity market repricing proposal (referred to as "Capacity Repricing" or "Option A"), or if the Commission cannot approve PJM's preferred proposal, that it approve in the alternative PJM's MOPR-Ex proposal (referred to as "Option B").

[1] PJM Interconnection, L.L.C., Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, FERC Docket No. ER18-1314-000, April; 9, 2018 ("PJM Filing").

5. On May 22, 2018, I filed a declaration ("Prior Declaration")[2] on behalf of Exelon Corporation that concluded that the Commission should reject both of PJM's proposals in favor of the status quo, but that if it were to accept one of the proposals, it should accept the Capacity Repricing proposal over MOPR-Ex. My Prior Declaration is attached as Exhibit A.

6. On May 31, 2018, CPV Power Holdings, L.P., Calpine Corporation, and Eastern Generation, LLC (collectively "Complainants") filed a complaint under Section 206 of the Federal Power Act[3] requesting that the Commission reject both options presented in the PJM Filing and instead adopt a third option that they call the "Clean MOPR." The Clean MOPR is a modified version of PJM's "MOPR-Ex" proposal that would remove a number of exemptions offered to certain classes of resources under that proposal. Complainants supported this request with an attached affidavit from Dr. Roy J. Shanker.

7. I have been asked by Exelon Corporation to assess the impact of the Clean MOPR proposal on PJM markets relative to maintaining the status quo. Specifically, I assess the impact of the Clean MOPR on capacity price formation, both with respect to the likely level of prices, and the mechanics of how prices and capacity obligation awards are determined. Based on this analysis, I evaluate the longer term impact of the Clean MOPR proposal on overall market efficiency and its effects on market participants.

C. SUMMARY OF CONCLUSIONS

8. My conclusions are as follows:

9. Because the Clean MOPR proposal shares the same underlying structure as the MOPR-Ex proposal, it shares all the flaws associated with MOPR-Ex that I discussed in my Prior Declaration. The fundamental reason for this is that the design of both proposals re-prices the offers of affected resources to a higher level and does not award them a capacity obligation if they do not clear the market, thus greatly increasing the likelihood that they will not clear and receive a capacity obligation. As I discuss in my Prior Declaration, if the MOPR deters states from

[2] Declaration of Michael M. Schnitzer on Behalf of Exelon Corporation, Attached to Motion for Leave to Answer and Answer of Exelon Corp. and the PSEG Companies, Docket Nos. ER18-1314-000 and ER18-1314-001.

[3] CPV Power Holdings, L.P., Calpine Corporation and Eastern Generation, LLC, Complainants v. PJM Interconnection, LLC, Respondent, Complaint Seeking Fast Track Processing, Docket No. EL18-169-000, May 31, 2018 ("Complaint").

supporting economically efficient zero-emission resources such as the nuclear resources receiving state support, those resources will likely be permanently lost, leading to a reduction in total social surplus and an overall less efficient portfolio of capacity resources. To the extent that the MOPR does not deter states from continuing to support affected resources (as recent experience in New England suggests), those state-supported resources will continue to exist and provide capacity to the grid, but customers will be required to purchase additional, unneeded capacity from the resources that displace the state-supported capacity within the MOPR-Ex/Clean MOPR design. I conclude in my Prior Declaration that these flaws should lead the Commission to reject MOPR-Ex in favor of the status quo, or at a minimum to prefer PJM's Capacity Repricing proposal over MOPR-Ex. Because of the common underlying design between MOPR-Ex and the Clean MOPR proposal, these conclusions apply to the Clean MOPR as well.

10. The Clean MOPR would immediately cause the capacity offers for a very large group of existing capacity resources to be re-set upwards to the Minimum Offer Price Rule Floor ("MOPR Floor") price. Potentially as much as 38 gigawatts ("GW") of existing capacity resources, or roughly 23% of all capacity cleared in the May 2018 RPM Base Residual Auction, could be subjected to this offer modification. PJM's Capacity Repricing proposal, in comparison, would affect about 7 GW of existing capacity resources.

11. Because the Clean MOPR affects such a large portion of the capacity supply curve, a substantial portion of the affected resources would be needed to meet demand and would thus clear the market and likely set the clearing price, despite having their offers re-set to the MOPR Floor price. Thus, the determination of the capacity clearing price and of which resources actually receive a capacity award would largely rest on administrative decisions such as PJM's calculation of the MOPR Floor price for affected units, rather than on competitive offers determined by the resource owners themselves. By substituting administrative decisions for competitive offers in the price formation process, the Clean MOPR would drive inefficient entry and exit decisions, particularly for polluting units with unpriced negative externalities, and would send inefficient price signals to consumers.

12. If implemented without any resource owners electing the Fixed Resource Requirement ("FRR") option or receiving unit-specific exemptions, the Clean MOPR will result in significant and immediate capacity cost increases for consumers. If it had been applied to the May 2018

capacity auction for the 2021/22 delivery year, the Clean MOPR would have resulted in a market-wide capacity clearing price of approximately $234 per MW-day, or an increase of $78 per MW-day over the status quo clearing prices on a weighted-average basis. This increase in prices would increase consumer costs by $4.4 billion annually.

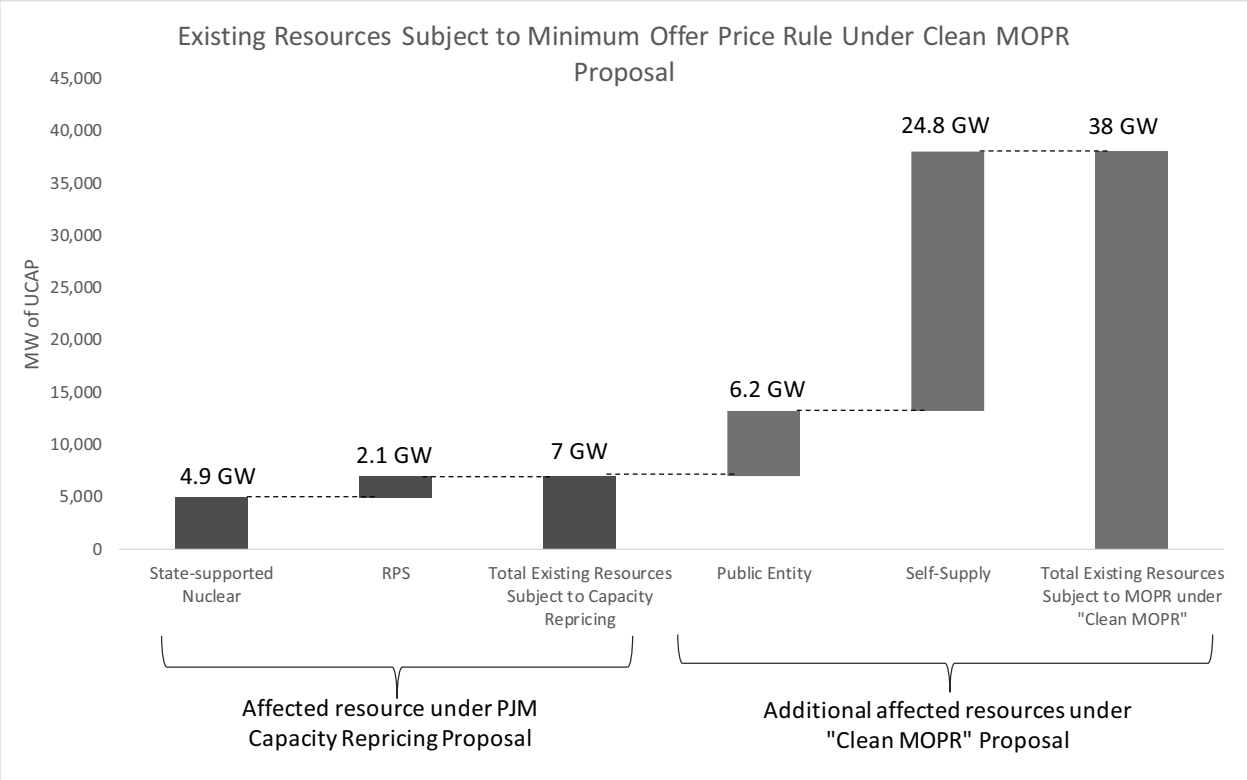
13. Over time, however, the Clean MOPR will likely create such an untenable situation for consumers in states with substantial amounts of affected capacity that load-serving entities ("LSEs") in those states will decide to elect the FRR option and cause the affected resources plus other resources selected for FRR to exit the capacity market, along with a matching amount of load. This is particularly true for vertically integrated entities where the resource owner and LSE are one and the same, but even in other cases, states with substantial amounts of state-supported nuclear and renewables will face a strong incentive to direct their resident LSEs to elect the FRR option. Under this outcome, the amount of capacity subject to MOPR treatment will likely be minimal, resulting in market clearing prices similar to the status quo. But in arriving at this result, the market will shrink substantially, making it less liquid and more fragmented.

II. THE CLEAN MOPR WILL AFFECT A VERY LARGE BLOCK OF RESOURCES

14. While complainants do not provide a detailed description of their proposal, or proposed tariff language, as I understand it, the Clean MOPR would adopt the structure of PJM's MOPR-Ex proposal with several modifications. First, the Clean MOPR would eliminate several of the exemptions provided in the MOPR-Ex proposal that shield from MOPR treatment certain resources that would otherwise be affected. Specifically, the Clean MOPR would remove the Renewable Portfolio Standard Exemption ("RPS Exemption"), the Public Entity Exemption, and the Self-Supply Exemption. The Unit-Specific Exemption and Competitive Entry Exemption would remain in place, although, as Dr. Shanker discusses, the Competitive Entry Exemption is made largely redundant by the requirement that resources must receive "actionable subsidies" to be subject to MOPR treatment. Second, the Clean MOPR proposal would expand the definition of "Actionable Subsidies" to include "material federal subsidies or other support granted after the date of this Complaint." The Capacity Repricing proposal, by comparison, does not include the RPS Exemption, but exempts municipal/cooperative entities and vertically-integrated regulated utilities in a similar fashion to MOPR-Ex.

15. The overall impact of the removal of exemptions on the total amount of capacity subject to MOPR treatment is very significant. As I discuss in detail below, under Capacity Repricing, about 7 GW of existing resources are likely subject to repricing. This includes 4.9 GW of existing nuclear capacity and 2.1 GW of existing renewable capacity that would likely not be subject to any exemption (other than the possibly the unit-specific exemption) under Capacity Repricing or the Clean MOPR. Removing the Public Entity and Self-Supply exemptions under the Clean MOPR adds 6.2 GW and 24.8 GW of capacity subject to MOPR treatment, respectively, for a total of 38 GW of affected capacity. Figure 1 below summarizes the impact of removing the exemptions:

Figure 1



Sources: PJM Interconnection, LLC, Commitments by Fuel Type & Delivery Year 2007/08 – 2021/22 and Resource Model for 2021/22 RPM auction.

16. Nuclear resources receiving state support from Illinois and New Jersey are likely to be deemed to be receiving "actionable subsidies" as defined under the both the Capacity Repricing

and Clean MOPR proposals, and they do not qualify for any of the blanket exemptions offered under either proposal. Resources falling in this category include 1,400 MW of the Quad Cities plant in Illinois and roughly 3,500 MW of nuclear capacity that may be supported by recently-enacted legislation in New Jersey, or about 4.9 GW total.[4]

17. The RPS Exemption, which applies to MOPR-Ex but not Capacity Repricing or the Clean MOPR, excuses from MOPR treatment certain resources that currently receive out-of-market payments for supplying renewable attributes for the purpose of enabling compliance with state renewable energy portfolio standards, either via tradeable renewable energy certificates, long-term contracts, or some other mechanism.[5] Approximately 2.1 GW of unforced capacity of wind, solar, and wood biomass resources cleared the 2021/22 Base Residual Auction.[6] Under both Capacity Repricing and the Clean MOPR, these resources would be subject to MOPR treatment.

18. The Public Entity Exemption excuses from MOPR treatment those resources that are owned or controlled by publicly-owned electricity providers such as municipal utilities and rural electric cooperatives, provided they conform to long/short limitations on the size of their generation portfolio relative to their load. Collectively, these entities own about 6.2 GW of capacity that participates in the RPM, with most of the capacity owned by two entities: East Kentucky Power Cooperative and Old Dominion Electric Cooperative. Removal of the Public Entity Exemption would subject these resources to MOPR treatment under the Clean MOPR.

19. The Self-Supply Exemption excuses from MOPR treatment those resources that are owned by suppliers with long-standing business models as either a vertically-integrated regulated utility, or a single customer power provider, provided again that they conform to long/short position limitations. Collectively, entities that qualify for the Self-Supply Exemption control

[4] The New Jersey legislation contemplates state support of nuclear, but no such state support has yet been awarded to specific plants.

[5] Under the Clean MOPR, while existing federal tax subsidies such as the Production Tax Credit and Investment Tax Credit are not actionable subsidies, out-of-market payments for renewable attributes would constitute an actionable subsidy and subject a resource to mitigation. Many, although not necessarily all, of the resources receiving RPS-related payments also receive, or have received, such federal tax subsidies. Likewise, most, if not all, resources receiving these federal tax subsidies also receive RPS-related payments.

[6] PJM Interconnection, LLC, Commitments by Fuel Type & Delivery Year 2007/08 – 2021/22. Spreadsheet available at http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-commitment-by-fuel-type-by-dy.ashx?la=en. Note that these totals do not include any RPS-qualified hydro, liquid biomass, or landfill gas, all of which can potentially qualify as RPS resources under certain state programs (typically subject to specific conditions) and as such likely slightly underestimate the total amount of existing RPS resources in PJM.

approximately 24.8 GW of unforced capacity that participates in the RPM. About 80% of this capacity (about 20.4 GW) is owned by the Virginia Electric Power Co., with the remainder owned by the Monogahela Power Co. Removal of the Self-Supply Exemption would subject all this capacity to MOPR treatment under the Clean MOPR. Another 13 GW of capacity is controlled by entities currently electing the FRR option (primarily vertically-integrated subsidiaries of American Electric Power Co. Duke Energy operating in Indiana, Kentucky, West Virginia, and Michigan) and thus does not currently participate in the capacity market but would likely qualify for the Self-Supply Exemption when and if this capacity was to return to the market.

20. Collectively, Clean MOPR would result in a total of 38 GW of existing capacity being subject to MOPR treatment. This represents roughly 23% of the total capacity cleared (and 20% of capacity offered) in the May 2018 Base Residual Auction. By comparison, existing resources affected by the Capacity Repricing proposal would be limited to state-supported nuclear and renewables, or about 7 GW total.

III. THE CLEAN MOPR WOULD FUNDAMENTALLY CHANGE PRICE FORMATION IN THE CAPACITY MARKET AND WOULD RAISE COSTS FOR CONSUMERS

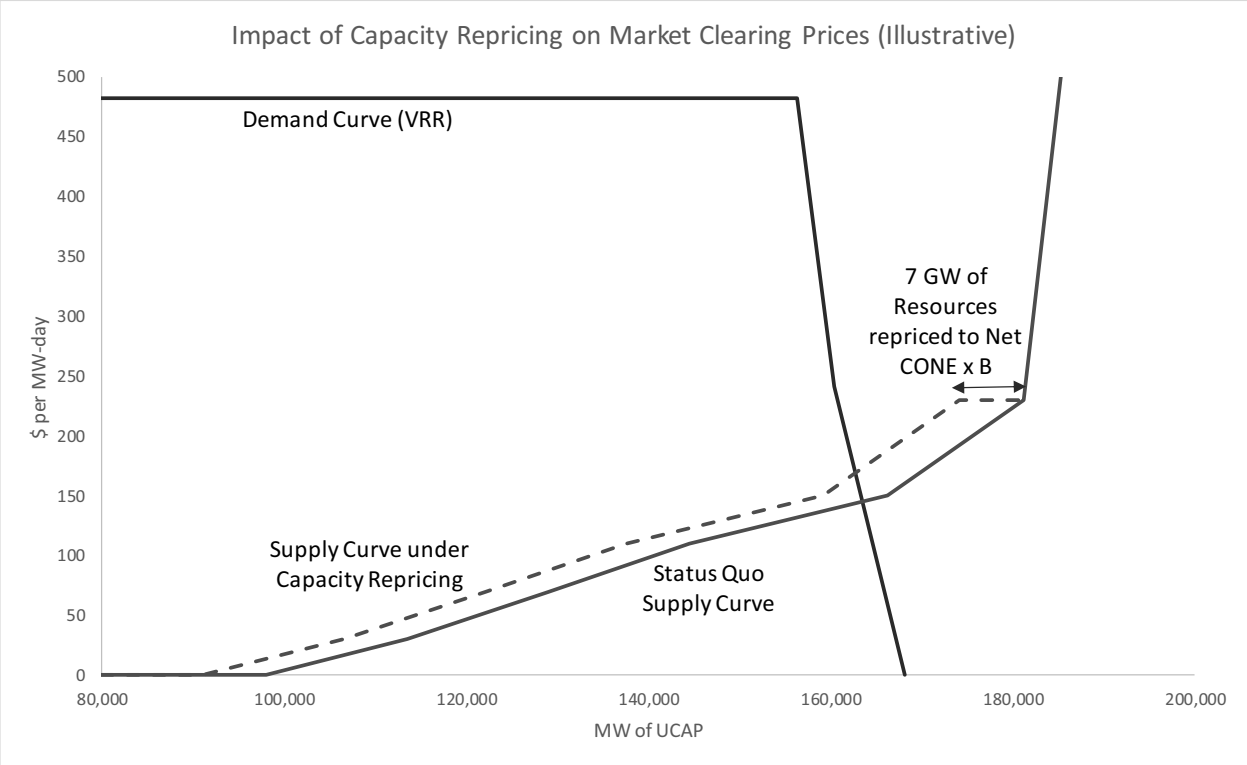
21. Under the Clean MOPR proposal, resources that are found to have "actionable subsidies," which include both explicit payments such as zero-emission credits ("ZECs") and regulated cost recovery treatment, would have their capacity offers adjusted upwards to a MOPR floor price to the extent their unadjusted offers fall below that level. The MOPR floor price would be set at the higher of the Net Cost of New Entry times the Balancing Ratio ("Net CONE times B") and the unit-specific Net Avoidable Cost Rate ("Net ACR"). Net CONE times B varies by zone but, with the exception of two small zones, ranged from $211 to $254 per MW-day for the May 2018 RPM auction, well above recent market clearing prices for most local delivery areas.[7]

22. Compared to PJM's Capacity Repricing proposal, the Clean MOPR proposal would result in a very different qualitative economic outcomes if the full 38 GW of affected capacity were subject to MOPR mitigation. Under Capacity Repricing, the amount of affected existing capacity is relatively small compared to the overall supply curve. As discussed previously, the existing capacity likely subject to Capacity Repricing is about 7 GW, or about 4% of the total

[7] The BG&E and PENELEC zones had Net CONE times B values of $181/MW-day and $158/MW-day, respectively.

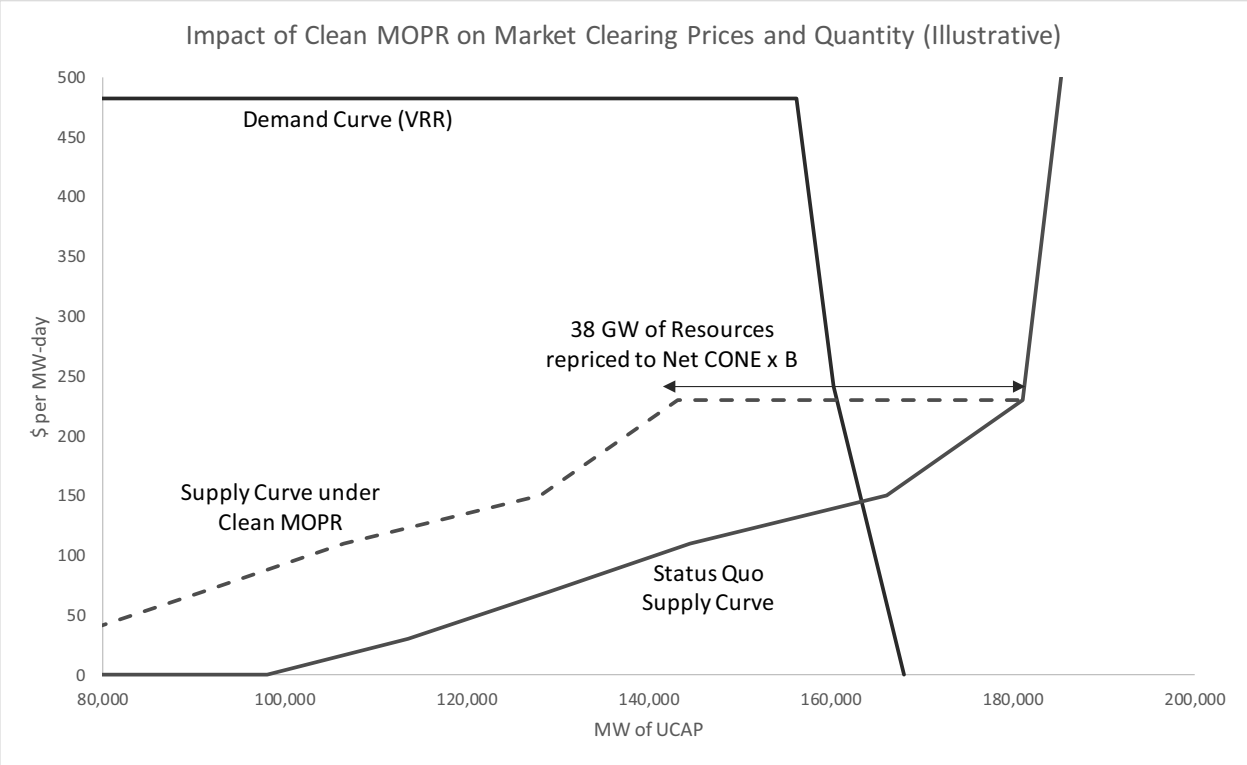
capacity offered in the May 2018 BRA. Because of this, in the price-setting run of Capacity Repricing, adjusting the offers of the affected resources to the higher "Actionable Subsidy Reference Price" (similar to the MOPR Floor price) would likely cause those resources to simply not set the price and rather be replaced by offers from non-affected resources further up the supply curve for the purposes of price-setting. Figure 2 shows this result in an illustrative fashion:

Figure 2



23. If Clean MOPR were implemented without a large amount of resources receiving a unit-specific exemption and/or electing the FRR option, the amount of affected capacity is so large – roughly 20% of the supply curve – that it is unlikely that there would be enough otherwise-uncleared excess capacity offered below the MOPR floor price to fully replace it. Therefore, the block of affected capacity subject to MOPR treatment would likely set the clearing price at the MOPR floor price. In addition, a portion of the capacity subject to MOPR treatment would likely clear the market despite having their offers increased to the MOPR floor price. Figure 3 shows this result:

Figure 3



24. Under the current supply and demand fundamentals in PJM, this outcome is very likely if the Clean MOPR is implemented without large amounts of resources existing via the FRR option or receiving unit-specific exemptions. In the May 2018 Base Residual Auction, about 21.7 GW of capacity offers did not clear the market. If we assume that (1) all of the uncleared capacity offered below Net CONE times B (a very conservative assumption) and (2) all 38.5 GW of potentially affected capacity under the Clean MOPR were re-priced to Net CONE times B, the following would happen as a result of application of the Clean MOPR: (1) the clearing price would rise to Net CONE times B, (2) the total amount of cleared capacity would decline by 2.5 GW due to the downward-sloping demand curve, (3) all 21.7 GW of the capacity that did not clear without the Clean MOPR would instead clear, and (4) 14.3 GW of the total 38 GW of capacity re-priced to the MOPR Floor price would clear. Historically between 1 and 3 GW of uncleared capacity in the RPM has bid above Net CONE times B,[8] which suggests that it is more likely that between 15 and 17 GW of affected resources would clear.

[8] The Brattle Group, *Fourth Review of PJM's Variable Resource Requirement Curve*, April 19, 2018, Figure 13. This estimate is based on a manual inspection of the graphic and is not precise.

25. The Clean MOPR thus would result in a dramatic shift in the underlying structure of the RPM. While the current RPM has administrative elements (such as the demand curve), its core price formation mechanism nonetheless relies on the clearing price being set by competitive offers determined by market participants. The Clean MOPR would upend this and drive the market towards a nearly wholly administrative design where the offer prices of the resources in the zone of marginality are determined by PJM and the Independent Market Monitor ("IMM"), rather than by competitive offers. The result of this is that both the market clearing price and which resources are awarded capacity obligations would be largely determined by administrative decisions made by PJM and the IMM with respect to the MOPR Floor prices imposed on different resources and the extent to which resources are granted unit-specific exemptions, rather than on competition.

26. By replacing the competitive price formation process with a largely administrative process, the Clean MOPR will greatly reduce the benefits of competition in the capacity market, to the point where one can legitimately question whether what remains can even be called a "market." As discussed previously, the Clean MOPR design creates a block of administratively-priced resources in the "zone of marginality" that will likely lead to prices clearing at a predictable administratively-determined level defined by the MOPR Floor price. Because of this, less efficient resources that would likely be in the "zone of marginality" under the status quo, including many resources with significant negative pollution externalities, would become infra-marginal resources under the Clean MOPR and would face minimal risk of not clearing, and thus will have reduced incentives to lower their costs and otherwise become more competitive. On the demand side, consumers will be presented with a capacity price signal indicating near-scarcity, despite such scarcity not existing in reality, leading to inefficient consumption decisions over time.

27. If we assume that the Clean MOPR is implemented without a large amount of affected capacity receiving the unit specific exemption and/or electing the FRR option, it would result in a market clearing price at the MOPR Floor price, which would subject consumers to a substantial increase in capacity costs relative to the status quo. To illustrate the magnitude of the potential cost increase, I have analyzed how the results of the May 2018 Base Residual Auction would have changed if the Clean MOPR were applied to its full extent and caused the market clearing price to rise to the MOPR Floor price.

28. Specifically, I have assumed that application of the Clean MOPR would cause the market clearing price to rise to the value of Net CONE times B for the Dominion zone, or $234 per MW-day. I chose the Dominion Zone because it comprises the largest block of resources in the group of resources affected by the Clean MOPR (roughly 20 GW out of 38.5 GW) and because it has a relatively low value for Net CONE times B compared to most other zones that also harbor potentially affected resources. If the market clearing price in the May 2018 RPM auction cleared at $234 per MW-day across the entire RTO, the weighted average clearing price paid to capacity resources would rise by $78 per MW-day, from $156 to $234 per MW-day, as shown in Table 1 below:

Table 1

LDA	UCAP Cleared MW	Clearing Price $/MW-day	Clearing Price w/ Clean MOPR $/MW-day	Price Increase $/MW-day
BG&E	1,938	200.30	234.13	33.8
PSEG	5,368	204.29	234.13	29.8
ComEd	22,358	195.55	234.13	38.6
ATSI	8007.3	171.33	234.13	62.8
Rest of EMAAC	23,921	165.73	234.13	68.4
Rest of RTO	102,036	140.00	234.13	94.1
Total	163,627	155.71	234.13	78.4

From a consumer perspective, application of the Clean MOPR would greatly increase the net load price to consumers, while slightly decreasing the capacity obligation due to the downward sloping demand curve. The net impact to consumers would be a cost increase of $4.4 billion per year, as show in Table 2 below:

Table 2

Zone	Status Quo UCAP Obligation	Status Quo Net Load Price	Status Quo Capacity Cost	UCAP Obligation Under Clean MOPR	Clean MOPR Net Load Price	Clean MOPR Capacity Cost	Cost Increase
	MW	$/MW-day	$MM	MW	$/MW-day	$MM	$MM
AE	2,687	$163.08	$160	2,646	$234.13	$226	$66
AEP	12,708	$140.53	$652	12,514	$234.13	$1,069	$418
APS	10,318	$140.53	$529	10,161	$234.13	$868	$339
ATSI	14,465	$157.99	$834	14,245	$234.13	$1,217	$383
BGE	7,435	$161.62	$439	7,322	$234.13	$626	$187
COMED	24,983	$192.69	$1,757	24,603	$234.13	$2,103	$345
DAYTON	3,786	$140.53	$194	3,729	$234.13	$319	$124
DEOK	5,190	$140.53	$266	5,111	$234.13	$437	$171
DLCO	3,195	$140.53	$164	3,146	$234.13	$269	$105
DOM	22,505	$140.53	$1,154	22,163	$234.13	$1,894	$740
DPL	4,373	$163.08	$260	4,306	$234.13	$368	$108
EKPC	2,535	$140.53	$130	2,496	$234.13	$213	$83
JCPL	6,539	$163.08	$389	6,439	$234.13	$550	$161
METED	3,338	$140.53	$171	3,287	$234.13	$281	$110
PECO	9,723	$163.08	$579	9,575	$234.13	$818	$240
PENLC	3,206	$140.53	$164	3,158	$234.13	$270	$105
PEPCO	7,116	$140.53	$365	7,008	$234.13	$599	$234
PL	8,184	$140.53	$420	8,059	$234.13	$689	$269
PS	10,901	$184.03	$732	10,735	$234.13	$917	$185
RECO	441	$163.08	$26	435	$234.13	$37	$11
Total	163,627	$157.17	$9,387	161,137	$234.13	$13,771	$4,384

This consumer cost increase does not account for the fact that some of the capacity procured in the Base Residual Auction may be duplicative and unnecessary for customers of entities with substantial amounts of affected capacity. For example, customers of regulated utilities whose capacity does not clear due to the Clean MOPR would likely continue to bear the cost of those resources embedded within their bundled regulated rates, in addition to incurring the incremental costs shown above.

29. Compared to the Clean MOPR, Capacity Repricing is likely to result in a lesser price impact simply because it affects a much smaller block of existing resources. As I discuss below, if affected resources under the Clean MOPR elect the FRR option in large numbers, this may eventually not be true, but without this forced market exit (which results in efficiency losses), the price impact of Capacity Repricing is likely to be substantially less.

IV. CLEAN MOPR COULD DRIVE ENTITIES WITH LARGE AMOUNTS OF AFFECTED RESOURCES TO SEEK THE FRR OPTION, RESULTING IN A SIMILAR PRICE OUTCOME TO THE STATUS QUO BUT WITH REDUCED EFFICIENCY AND MARKET DEPTH

30. The Clean MOPR puts resource owners and states that own or depend on significant amounts of affected capacity in an untenable position if they continue to participate in the capacity market and thus could drive those entities to cease participation in the market by electing the FRR

option. This is most obviously true for vertically-integrated entities that would have been covered under the Self-Supply and Public Entity exemptions and that have long-standing business models and rate designs centered around maintaining a portfolio of regulated generation resources paid for by a native customer base. The Clean MOPR would greatly undermine that business model by pushing a portion of those resources out of the capacity market and forcing the purchase of additional unneeded capacity in its place. If they wish to remain in the capacity market, the regulated entity, and its regulators, would be forced to choose between either requiring their customers to bear this unnecessary cost, or retiring core capacity resources whose costs are already embedded in regulated rates. Faced with these unattractive options, such entities are likely to instead decide to remove themselves from the market by electing the FRR option. As vertically-integrated entities that typically are both wires companies and franchised LSEs, electing the FRR option is administratively straightforward for these entities.

31. While electing the FRR option is less straightforward for states and entities that are no longer vertically-integrated, such states would still have an incentive to direct their resident entities to seek to elect the FRR option under the Clean MOPR (and MOPR-Ex) if they have large amounts of affected capacity. States that are providing support for nuclear facilities and renewables would be faced with the unappealing option of either discontinuing these programs and abandoning their environmental goals or having their ratepayers purchase capacity that is not needed. Such states would have a strong reason to avoid both of these bad outcomes by directing their resident LSEs to elect the FRR option and exit the market, despite the complexities it might pose for retail competition.

32. Resource owners would also have the option of seeking a unit-specific exemption as an alternative means of excusing affected capacity from MOPR treatment under both MOPR-Ex and the Clean MOPR. While it is certainly possible that some resource owners may seek to do this, the unit-specific exemption is likely to be either unattractive or non-viable for most owners of existing affected capacity, for several reasons. First, for vertically-integrated utilities or public entities with mixed portfolios, FRR requires that they include all their load in the FRR plan, not just a portion. Hence, they are unlikely to use the unit-specific exemption for any individual resources in their portfolios because all the resources will be needed to satisfy the needs of the FRR plan and will thus be withdrawn from the market. This removes the unit-specific exemption as an option for 31 out of the 38 GW of affected resources under the Clean MOPR. For the

remaining resources, state-supported nuclear is unlikely to qualify because without recognition of environmental externalities the resources in question have indicated that they are likely to retire. This leaves existing renewables as the only plausible candidates for the unit-specific exemption under Clean MOPR. However, to the extent such resources are supported by states that also support nuclear, the "all or nothing" feature of the FRR option discussed above may once again dominate and eliminate the unit-specific exemption as a viable option for even these resources.

33. Over time, then, a likely result of Clean MOPR is that the affected resources plus other resources needed to meet LSE reliability requirements are removed from the capacity market through exercise of the FRR to the point where the amount of affected resources remaining in the market is minimal. On its face, this would lead to a similar market price outcome as the status quo for the unaffected resources that remain in the centralized market. However, the market would shrink considerably in arriving at this outcome because a substantial portion of capacity would simply remove itself from the capacity market (well in excess of 40 GW, because LSEs must procure resources to meet their entire load requirement under current FRR rules). Thus, the centralized market would shrink substantially, administrative costs would increase due to numerous procurements, and the market would become less liquid and more fragmented.

34. Ultimately, then, this potential outcome simply reinforces the conclusions I put forth in my prior declaration: the status quo is the preferred option. The Clean MOPR would either result in a significant, inefficient, and unnecessary cost increase for consumers or would simply, through the exercise of the FRR option, revert to a similar market price outcome as the status quo but with reduced market depth and efficiency.

35. This completes my declaration.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

CPV Power Holdings, L.P., Calpine Corporation and Eastern Generation, LLC,	)	
Complainants,	)	**Docket No. EL18-169-000**
v.	)	
PJM Interconnection, L.L.C.	)	
Respondent.	)	

DECLARATION OF MICHAEL M. SCHNITZER

I, Michael M. Schnitzer, declare under penalty of perjury that the foregoing is true and correct.

Executed: June 20, 2018

Concord, Massachusetts

Michael M. Schnitzer

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Exhibit A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. ER18-1314-000**
	)	**ER18-1314-001**

DECLARATION OF MICHAEL M. SCHNITZER

May 22, 2018

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I. QUALIFICATIONS, ASSIGNMENT AND SUMMARY OF CONCLUSIONS

A. QUALIFICATIONS

1. My name is Michael M. Schnitzer. I am a director of The NorthBridge Group, Inc ("NorthBridge"). NorthBridge is a consulting firm that provides economic and strategic advice to the electric and natural gas industries. My business address is 30 Monument Square, Concord MA 01742.

2. In 1992, I co-founded NorthBridge. Before that, I was a Managing Director of Putnam, Hayes & Bartlett, which I joined in 1979. I have experience working with private sector clients in the electric utility, natural gas, and private power industries, as well as with public and nonprofit agencies. My electric industry work has focused on regulatory policy, finance, and market structure issues. I received an A.B. in chemistry, with honors, from Harvard University, and an M.S. in management from the Sloan School, Massachusetts Institute of Technology.

3. I have testified before the Commission on many matters and have participated in Commission technical conferences and workshops on capacity market and energy market design issues. I have also testified before the public utility commissions of Arkansas, California, Delaware, Illinois, Indiana, Louisiana, Maine, Maryland, Massachusetts, Mississippi, New Hampshire, New Mexico, New Orleans, New York, Ohio, Pennsylvania, Rhode Island, Texas, Vermont, and Wisconsin.

B. BACKGROUND AND PURPOSE OF TESTIMONY

4. On April 9, 2018, PJM Interconnection, LLC ("PJM") filed at the Federal Energy Regulatory Commission ("FERC" or "Commission") two proposals to modify its capacity market design.[1] In its filing, PJM requested that the Commission approve its preferred capacity market repricing proposal (referred to as "Capacity Repricing" or "Option A"), or if the Commission cannot approve PJM's preferred proposal, that it approve in the alternative PJM's MOPR-Ex proposal (referred to as "Option B").

[1] PJM Interconnection, L.L.C., Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, FERC Docket No. ER18-1314-000, April; 9, 2018 ("PJM Filing").

5. Both proposals seek to prevent capacity prices from declining, all other things equal, due to the alleged impact of state actions to support various types of generation not already covered by PJM's existing Minimum Offer Price Rule ("MOPR"), with particular focus on the increase in state sponsored zero-emission capacity resources. Under the Capacity Repricing proposal, state sponsored resources are allowed to clear in PJM's capacity auctions, while under the MOPR-Ex proposal (Option B), some state sponsored resources are allowed to clear in capacity auctions while others are not.[2]

6. Reply comments were filed by a wide range of industry stakeholders, including Exelon Corporation with an attached declaration by Robert E. Willig, on May 7th, 2018.[3]

7. I have been asked by Exelon Corporation to respond to certain issues raised by two commenters, The Electric Power Supply Association[4] and the Office of the People's Counsel for the District of Columbia, Maryland Office of People's Counsel, and New Jersey Division of the Rate Counsel[5] (collectively, "Commenters"), and their respective expert witnesses, David W. DeRamus and Collin Cain,[6] and James F. Wilson[7] (collectively, "Commenters' Witnesses"). Commenters, relying on the analysis of their respective expert witnesses, describe several issues with both of PJM's proposals, and several issues which particularly affect PJM's Capacity Repricing proposal. These issues include increased consumer costs, the fact that PJM's proposals do not produce results which fall on the capacity demand curve, and strategic bidding incentives created by Capacity Repricing. Commenters argue that these issues collectively are cause for the Commission to choose the MOPR-Ex proposal over the Capacity Repricing proposal.

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[2] PJM Filing at 6.

[3] Protest of Exelon Corporation, Docket Nos. ER18-1314-000 and ER18-1314-001 (filed May 7th, 2018) ("Exelon Protest") and Declaration of Robert E. Willig, Docket Nos. ER18-1314-000 and ER18-1314-001 (filed May 7th, 2018) ("Willig Declaration").

[4] Protest and Comments of the Electric Power Supply Association, Docket No. ER18-1314-000 (filed May 7th, 2018) ("EPSA Comments")

[5] Protest of the Office of the People's Counsel for the District of Columbia, Maryland Office of People's Counsel, and New Jersey Division of the Rate Counsel, Docket Nos. ER18-1314-000 and ER18-1314-001 (filed May 7th, 2018) ("DC-MD-NJ Consumer Coalition Comments")

[6] Affidavit of David W. Deramus, Ph.d. and Collin Cain, M.SC. on Behalf of the Electric Power Supply Association, Docket No. ER18-1314-000 (filed May 7th, 2018) ("DeRamus/Cain Affidavit")

[7] Affidavit of James F. Wilson in Support of the Protests of DC-MD-NJ Consumer Coalition, Joint Consumer Advocates, and Clean Energy Advocates, Docket No. ER18-1314-000 (filed May 7th, 2018) ("Wilson Affidavit")

8. The purpose of my testimony is to evaluate the issues raised by commenters' witnesses and place these issues in the broader context of the capacity market design choice before the Commission in these proceeding, namely whether the Commission should decline to adopt either Capacity Repricing or MOPR-Ex and preserve the status quo or, in the alternative, to choose one of the two alternatives.

C. SUMMARY OF CONCLUSIONS

9. My conclusions are as follows:

10. Commenters' witnesses raise several valid issues with respect to the two mitigation alternatives presented by PJM, Capacity Repricing and MOPR-Ex. Specifically, they show that neither alternative produces a solution that falls on the capacity demand curve and that both raise costs for consumers relative to the status quo. The issues they raise highlight the need for the Commission to confront two central economic questions. First, do the out-of-market payments at issue in this proceeding internalize externalities and contribute to retention and entry of the least-cost set of resources once social costs as well as production costs are accounted for, or are they subsidies that support uneconomic retention and entry? And second, even if the state actions driving these payments do represent inefficient subsidies, would MOPR-Ex deter this conduct or not?

11. Because the out of market payments at issue, in the main, do internalize externalities and promote economic retention and entry, the issues raised by Commenters' witnesses highlight the inefficiency of adopting either of the mitigation options proposed, and the Commission should instead choose the status quo approach. The status quo approach results in the most efficient price and resource selection, does not unnecessarily raise costs for consumers, and does not increase incentives to engage in strategic bidding. For the Zero Emission Credit ("ZEC") programs in particular, commenters provide no evidence that these payments are not an efficient mechanism for internalizing carbon emission externalities. Nor do they – or could they, given the current PJM energy market design – suggest a feasible alternative mechanism for internalizing these externalities. Under these circumstances, the Capacity Repricing alternative would be a distant "second choice" to the status quo from an efficiency standpoint, but, somewhat ironically, the strategic bidding issues identified by commenters' witnesses make Capacity Repricing less

inefficient in this case because their net effect is to push the market clearing price down closer to the price under the most efficient status quo approach.

12. If the Commission is not persuaded that the status quo is adequate, then as between the two alternatives before it, the Capacity Repricing proposal is a much better choice than MOPR-Ex. The advocates of MOPR-Ex implicitly assume that states will abandon their support of environmentally-friendly resources in response. The witnesses do not provide any theoretical or empirical support for this assumption. Yet if states do continue to make out-of-market payments to support environmentally-friendly resources, notwithstanding MOPR-Ex, then MOPR-Ex will result in the over-procurement of capacity, saddling customers with significant unnecessary costs.

13. If, on the other hand, mitigation does deter some states from enacting legitimate environmental programs, then MOPR-Ex will select the wrong set of resources to provide capacity. Resources that are more efficient once externalities are taken into account will be led to retire or will not enter. That outcome likewise leads to an inefficient mix of resources that makes society worse off than the status quo. Notably, MOPR-Ex includes a number of proposed exemptions, but these exemptions are not based on whether the out-of-market state payments promote or impair the efficient selection of resources. The ZEC program provides an illustrative example: the ZEC payments that MOPR-Ex targets are demonstrably the most economic form of carbon abatement available to the states and are the only form of support that the states can effectively utilize given PJM's energy market design. It would be unjust and unreasonable for the Commission to eliminate the only effective unilateral option that states have to support the economic retention of zero carbon resources.

14. Capacity Repricing, by contrast, avoids both of these problems. Capacity Repricing avoids over-procurement by allowing state-supported resources to clear. And Capacity Repricing selects a more efficient set of resources, by allowing the resource mix to be influenced by state programs accounting for environmental externalities.

15. Commenters argue that MOPR-Ex is preferable to Capacity Repricing, focusing on several points they allege make Capacity Repricing unworkable. First, they contend that Capacity Repricing leads to a price-quantity pair that is not on the demand curve. But the same is true of MOPR-Ex. Indeed, because MOPR-Ex results in significant over-procurement, the effective price-quantity pair that results is even farther away from the demand curve than Capacity

Repricing. Second, commenters identify potential strategic bidding issues associated with Capacity Repricing. These issues are real but are not disqualifying. The effects of such strategic bidding are likely to be modest and would reduce the cost of repricing to customers—even as Capacity Repricing significantly increases capacity prices relative to the status quo. To the extent these effects are nevertheless of concern to the Commission, the incentive to bid strategically can be largely remedied by a lost opportunity cost payment directed towards the small slice of resources that set the second stage price of Capacity Repricing without being cleared in the initial stage. Thus, strategic bidding concerns are not a valid basis to reject the PJM Capacity Repricing proposal.

16. In sum, the best course is for the Commission to maintain the status quo. If the Commission does believe some action is required, the Capacity Repricing alternative is workable and certainly preferable to MOPR-Ex.

II. COMMENTERS' WITNESSES RAISE VALID ISSUES WITH BOTH MOPR-EX AND CAPACITY REPRICING, WHICH REINFORCES THE CONCLUSION THAT CONTINUATION OF THE STATUS QUO IS THE PREFERRED APPROACH

17. Both Wilson and DeRamus & Cain correctly point out several issues with both MOPR-Ex and Capacity Repricing. These issues highlight the inefficiency of either proposal relative to the status quo.

A. BOTH CAPACITY REPRICING AND MOPR-EX RAISE COSTS

18. First, at the simplest level, commenters' witnesses show that both solutions proposed by PJM will raise capacity market prices and costs for consumers. Wilson provides an example, calibrated to the current PJM capacity demand curve and recent real-world supply curves, that shows that, relative to the status quo, Capacity Repricing with an assumed 9,000 MW of resources targeted for re-pricing (that is, with "actionable subsidies" per the terminology used by PJM) causes both the market clearing price and the capacity payments by consumers to rise by about 50%.[8] DeRamus & Cain provide a more stylized example that is directionally similar.[9]

[8] Wilson Affidavit at ¶ 48-49.

[9] DeRamus/Cain Affidavit at ¶ 29-30.

19. Specifically, Wilson's example begins with a status quo where 161,474 MW of UCAP is procured at a price of $102.8/MW-day, resulting in total customer costs of $6.1 billion. Under Capacity Repricing, the price rises to $154.53/MW-day while the quantity procured remains the same as under the status quo, increasing customer costs to $9.1 billion.

20. Wilson's example does not directly address MOPR-Ex, but if MOPR-Ex is analyzed using the same assumptions, it produces a very similar result. Under MOPR-Ex, the capacity clearing price would also rise to $154.53/MW-day but the quantity procured through the capacity market would fall to 159,800 MW. This results in capacity payments of $9.0 billion, a similar increase, 48%, as Capacity Repricing relative to the status quo. Unlike Capacity Repricing, MOPR-Ex does not clear or compensate the 9,000 MW of resources with actionable subsidies. If we assume that states continue to compensate these resources at the original status quo price to induce them to remain in the market, consumers in those states pay an additional $340 million for the capacity these resources provide outside the RPM mechanism. This additional cost raises the total cost of MOPR-Ex in Wilson's example to $9.4 billion, a 56% increase from the status quo.

B. Neither Capacity Repricing nor MOPR-Ex produce a price and quantity result which falls on demand curve

21. Commenters' witnesses correctly criticize Capacity Repricing for producing an ultimate price and cleared quantity outcome that is not located on the RPM demand curve.[10] Returning to Wilson's example, the clearing price of $154.53/MW-day corresponds to a cleared quantity of 159,800 MW on the RPM demand curve. But because Capacity Repricing clears resources using a lower supply curve in its first stage, the cleared quantity is 161,474 MW. The resulting price and quantity combination is off the demand curve. Because of this, Capacity Repricing is not consistent with the underlying reliability versus cost tradeoff embedded in the demand curve and it is costlier for customers because the elevated stage two price is paid to the resources cleared in stage one.

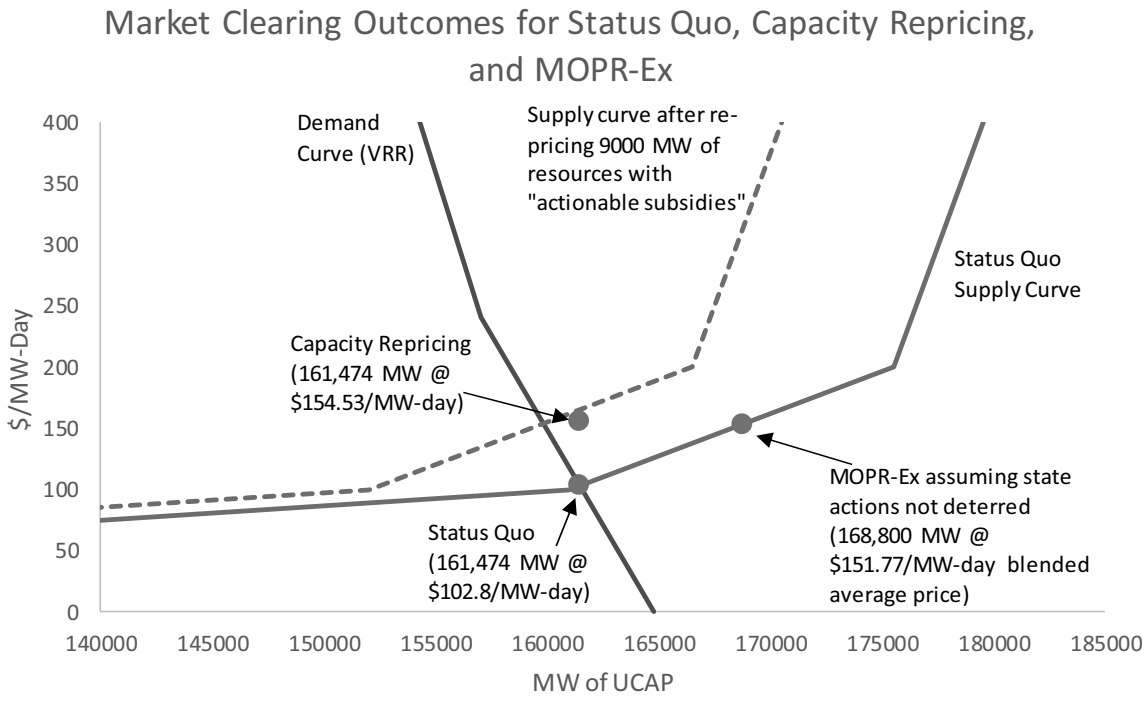
22. DeRamus & Cain claim that PJM's MOPR-Ex proposal, in contrast to Capacity Repricing, does produce a result that falls on the RPM demand curve.[11] That claim is only correct

[10] DeRamus/Cain Affidavit at ¶ 37 and Wilson Affidavit at ¶ 48-51.

[11] DeRamus/Cain Affidavit at ¶ 72.

if one assumes that states will be deterred from supporting environmentally friendly resources—and there is no evidence to support that assumption. It is true that the price and quantity capacity pair procured solely through the RPM under MOPR-Ex does fall on the demand curve. However, if MOPR-Ex does not deter states from continuing to provide compensation sufficient to retain these resources, then these resources would still effectively be committing their capacity to the market, and the total amount "procured" would not be on the demand curve. Further, it is likely that state compensation provided to these resources would need to be raised to offset the loss of capacity revenues, effectively forcing consumers in these states to pay more to retain environmental resources while simultaneously procuring more capacity than needed via RPM. Returning to Wilson's example, if all 9,000 MW of resources with actionable subsidies remain in the market and are paid the original status quo clearing price of $102.8/MW-day via increased state out-of-market payments (the actual amount of increased payments is uncertain, but an increase equal to the status quo price offsets the loss of capacity revenues under MOPR-Ex, making it a reasonable illustrative value for this example), the total capacity procured is 168,800 MW (159,800 MW directly through the market and 9,000 MW via state action) and the blended average price paid is $151.77/MW-day. This price and quantity pair also does not fall on the demand curve. The only instance where MOPR-Ex would result in a price and quantity pair that falls on the demand curve is an instance where all 9,000 MW of targeted resources were deterred from either entering or remaining in the market. Figure 1 below shows where the various options (status quo, MOPR-Ex, and Capacity Repricing) fall relative to the demand curve.

Figure 1



23. Of the three alternatives, the only approach that will always fall on the demand curve is the status quo.

C. THE STATUS QUO IS THE MOST EFFICIENT APPROACH

24. Most types of state out-of-market payments under consideration in this proceeding are intended to explicitly or implicitly account for positive environmental attributes that are not priced by RTO markets. These state actions contribute to economic retention and entry and increase overall market efficiency.

25. The subsidies that appear to primarily concern some commenters are ZECs and similar subsidies that are paid to the Quad Cities nuclear plant in Illinois and may be paid to certain nuclear plants under recently-passed legislation in New Jersey. As is discussed at length in the declaration of Robert E. Willig filed in this proceeding,[12] these subsidies, and similar subsidies for other types of zero-emission generation, are designed to correct, for the resources in question, the fact that carbon pollution externalities are not priced in PJM's markets, and thus the zero-emission attribute

[12] Willig Declaration ¶ 25-54.

of these resources is not appropriately compensated. By appropriately accounting for the positive externality they produce by displacing the pollution caused by carbon-emitting resources, ZECs and similar subsidies make the market more efficient, rather than less.

26. Thus, consideration of ZEC (or similar) revenue is appropriately part of the formation of a competitive capacity bid for these resources. That is, when developing competitive capacity bids, it is appropriate that these resources consider ZEC revenue as a deduction from production costs, similar to energy or ancillary services, which serves to reduce their capacity bid relative to where it would have been absent the ZEC. The resulting capacity bid is not artificially suppressed by the subsidy, but rather is the proper price for the resource considering the state-provided compensation for its environmental attributes.[13] ZECs in particular are designed to promote economic entry and retention because the environmental attribute payment is based on, and cannot exceed, the social cost of avoided carbon emissions, and the resource will only clear the capacity market and be economically retained if its total cost of retention, including the benefit of the positive externality it produces, is lower than the cost of alternatives.[14]

27. The status quo allows those resources to appropriately reflect the impact of the subsidies in their capacity market bids and does not re-price or adjust those bids to a higher level that purports to eliminate the impact of the subsidies, as is contemplated by Capacity Repricing and MOPR-Ex.[15] The status quo selects the most efficient mix of resources at the most efficient price. Compared to either Capacity Repricing or MOPR-Ex, the status quo does not result in unnecessarily high customer costs, it produces a result that falls on the demand curve, and it does not create any incremental strategic bidding incentives.

28. For the ZEC programs in particular, commenters provide no evidence that the state payments are not an efficient mechanism for carbon reduction. Nor do they suggest a feasible alternative under the current PJM energy market design. Several commenters (notably the PJM IMM)[16] suggest a market-wide carbon price as an efficient alternative. That alternative is not

[13] Willig Declaration at ¶ 39-44.

[14] Willig Declaration at ¶ 51-54.

[15] Willig Declaration at ¶ 13(i).

[16] Comments of the Independent Market Monitor for PJM, Docket Nos. ER18-1314-000 and ER18-1314-001 (filed May 7th, 2018), at 10-11.

available to individual states, and it is disingenuous to suggest it is a viable near-term option. If an individual state attempted to impose a carbon tax on generation within its borders, as Dr. Willig demonstrates under the present market design, a carbon price high enough to value carbon at the social cost set by the states and drive the desired emission outcome would suffer considerably from leakage issues that would render it unworkable.[17] Thus, under the present market design, ZEC programs remain the only feasible approach to efficiently accomplishing state environmental goals. The status quo approach correctly recognizes the positive externalities targeted by these programs in both the prices and resource selection that result in the capacity market.

III. IF MODIFICATION TO THE CURRENT MOPR IS PURSUED, CAPACITY REPRICING IS A BETTER CHOICE THAN MOPR-EX

29. If the Commission is not persuaded that the status quo is adequate, two central economic questions can help guide the choice between the primary proposal presented by PJM, Capacity Repricing, and its alternative, MOPR-Ex. The first question is whether the out-of-market payments at issue in this proceeding internalize externalities and contribute to the retention and entry of the least-cost set of resources, once social costs as well as production costs are accounted for. As discussed previously, most state actions under consideration in this proceeding do contribute to economic retention and entry. The second question is whether states will be deterred by a mitigation mechanism, like MOPR-Ex, that would prevent state-supported resources from clearing. Absent any reason to think that states uniformly would be deterred, MOPR-Ex risks substantial over-procurement of capacity, and thus significant unnecessary costs imposed on customers. On the other hand, if MOPR-Ex does actually deter certain state actions related to legitimate environmental programs, then it would prevent economic resources from clearing the capacity market, which will result in a less efficient mix of capacity resources.

30. Capacity Repricing avoids both problems that plague MOPR-Ex. Capacity Repricing does not depend upon how states react, and by allowing state-supported resources to clear, avoids any over-procurement. And by allowing state-supported resources to clear, Capacity Repricing also allows legitimate state environmental programs to influence the resource mix, which promotes efficiency once environmental externalities are taken into account.

[17] Willig Affidavit at ¶ 35.

A. MOPR-EX RESULTS IN OVER-PROCUREMENT IF STATES ARE NOT DETERRED

31. If states are not deterred in pursuing programs seeking to preserve certain types of generation, MOPR-Ex results in over-procurement. MOPR-Ex operates by adjusting the bids of targeted resources to a higher level that seeks to "undo" the effect of payments resulting from state actions. MOPR-Ex then clears the market in a single step incorporating these higher, modified bids. As a result, the resources targeted by MOPR-Ex will not likely clear the capacity market and will instead be replaced by other resources that would not have cleared had the targeted resources bids not been adjusted upwards. However, the targeted resources will nonetheless remain in the market if state action is not deterred. And the additional resources procured in their place under MOPR-Ex will also remain in the market.

32. As discussed in the example summarized in Figure 1, this over-procurement effect will effectively cause the market to retain a much larger portfolio of capacity resources than is needed and would be procured under either the status quo or Capacity Repricing. As Figure 1 shows, with 9,000 MW of resources targeted by Capacity Repricing, MOPR-Ex results in the effective procurement of 7,326 MW (68,800 MW vs. 61,474 MW) more resources than either the status quo or Capacity Repricing.

B. IF STATES ARE DETERRED, MOPR-EX CHOOSES THE WRONG RESOURCES

33. To the extent that MOPR-Ex does deter states from making out-of-market payments even when those payments internalize externalities, MOPR-Ex will select the wrong set of resources to provide capacity and will result in the inefficient exit of economic resources. Under this scenario, states either cease state actions when the resources in question are targeted by MOPR-Ex, or never engage in state programs they would otherwise have engaged in due to the threat of MOPR-Ex.

34. As discussed previously, in the case of state actions which compensate resources for positive externalities, the most efficient treatment is to allow those resources to reflect those payments in their capacity bids, which will generally lead to a reduction in their bid price. If the resource clears the capacity market when bidding in this fashion, its retention is economic and least cost and appropriately takes into account the value of the positive externality that it produces.

Thus, retention or entry of the resource is socially-efficient and the state action adds to the social surplus enjoyed by all market participants.

35. MOPR-Ex explicitly targets resources receiving such payments and makes it much less likely that they will clear the market and receive a capacity obligation. To the extent that these resources leave the market due to this treatment, either because the state action is discontinued, never occurs, or is not sufficient to cover the lost capacity revenue, the market as a whole is deprived of the social surplus added by the presence of these resources in the market. In place of these resources, higher cost resources (after taking account of externalities) will be cleared in their place and will displace them in the capacity portfolio. This outcome results in an inefficient mix of resources that makes society worse off than the status quo.

36. Notably, MOPR-Ex includes a number of proposed exemptions, but these exemptions do not reflect whether the out-of-market state payments promote or impair the efficient selection of resources. This is discussed at length in the Willig Declaration, and the ZEC program provides an illustrative example: the ZEC payments that MOPR-Ex targets are demonstrably the most economic form of carbon abatement available to the states and are the only form of support that the states can effectively utilize given PJM's energy market design. It would be unjust and unreasonable for the Commission to eliminate the only unilateral option that states have to support the economic retention of zero carbon resources.

37. MOPR-Ex thus implicitly assumes that all state programs other than the enumerated exceptions are inefficient. It also implicitly assumes that MOPR-Ex mitigation will deter states from pursuing these programs. Both of these implicit assumptions are incorrect. With respect to the first assumption, the state ZEC programs at which MOPR-Ex is aimed are a prime example of efficient state programs that promote economic entry and retention. MOPR-Ex proponents offer no evidence to support their conclusion that these programs are inefficient. And their arguments that states have better alternatives ring hollow in the face of PJM energy market design. With respect to the second assumption, there is no evidence that MOPR mitigation will deter state environmental action. One has only to consider the progression of state renewable energy programs and targets to reach this conclusion, including in states/regions where MOPR provisions currently apply or might be implemented. A recent example of this is the New England states, where ISO-New England put in place a modest exemption (200 MW per year) to its MOPR for

capacity entering to support state renewable portfolio standards, and several states issued the Multi-State Clean Energy request for proposals, which aims to procure 460 MW of new renewable resources, while Massachusetts enacted the 2016 Massachusetts Energy Diversity Act, which requires clean energy procurements in the range of 2,800 MW.[18] Another example is those states in PJM that are contemplating programs such as offshore wind that are not exempted under the MOPR-Ex proposal.

38. Thus, MOPR-Ex presents considerable risk on two fronts. If there is a significant likelihood that states will not be deterred in pursuing programs to support generation (and there is), it risks over procurement and additional costs to consumers. And if there is a significant likelihood that the state programs MOPR-Ex would mitigate enhance efficiency (and there is), there is risk that cost-effective, efficiency-enhancing resources will be excluded from the market.

C. CAPACITY REPRICING AVOIDS OVER-PROCUREMENT AND CHOOSES THE MOST EFFICIENT PORTFOLIO OF RESOURCES

39. Capacity Repricing, by contrast, avoids these risks. The most basic difference between Capacity Repricing (or the status quo) and MOPR-Ex is that resources receiving out-of-market payments are cleared based on their un-modified bids and are thus likely to receive a capacity obligation (and payment) under Capacity Repricing (or the status quo) whereas they are unlikely to be cleared and be paid for capacity under MOPR-Ex. In the event that states are not deterred by either option in continuing to pursue state actions to support generation, Capacity Repricing avoids the over-procurement problem suffered under MOPR-Ex because it recognizes the reality that these resources will remain in the market and provides them with a capacity obligation to the extent their un-modified bid is economic. Capacity Repricing thus avoids the inefficient excess procurement of capacity and results in a more efficient and cost-effective outcome for consumers, regardless of one's view on whether externality payments under state programs improve efficiency.

40. Capacity Repricing also chooses the most efficient portfolio of resources because resources are cleared based on their original, un-modified bid. As discussed previously, when these un-modified bids appropriately reflect the value of payments intended to internalize

[18] *See* ISO-NE Transmittal at 3-4, Docket No. ER18-619-000 (January 8, 2018).

externalities, these bids reflect the true total social cost of these resources. Because Capacity Repricing selects resources based on these costs, rather than modified bids that omit the social cost or value of externalities, it selects the most efficient, least-cost portfolio of resources.

IV. ISSUES RAISED BY COMMENTERS' WITNESSES WITH RESPECT TO CAPACITY REPRICING ARE NOT DISQUALIFYING AND DO NOT RENDER IT UNWORKABLE

41. Commenters argue that MOPR-Ex is preferable to Capacity Repricing, focusing on several points they allege make capacity repricing unworkable. First, they contend that Capacity Repricing leads to a price-quantity paid that is not on the demand curve. Second, they identify potential strategic bidding issues associated with Capacity Repricing that they contend are "fatal flaws." Both arguments are incorrect. I address each in turn below.

A. MOPR-EX DOES NOT PRODUCE A RESULT ON DEMAND CURVE EITHER, AND PRODUCING A RESULT NOT FALLING ON THE DEMAND CURVE DOES NOT RENDER CAPACITY REPRICING UNWORKABLE

42. As discussed previously, it is true that Capacity Repricing produces a result that does not fall on the demand curve. Indeed, this is one reason to prefer the status quo to either alternative offered by PJM. However, MOPR-Ex does not produce a result that falls on the demand curve either. As shown on Figure 1, unless states are deterred from pursuing the programs targeted by MOPR-Ex in all cases, MOPR-Ex will result in the procurement of significant excess capacity. The cost of this capacity will be paid for by consumers in the states in question. When this excess procurement is included, the effective price-quantity paid that results is even farther away from the demand curve than Capacity Repricing.

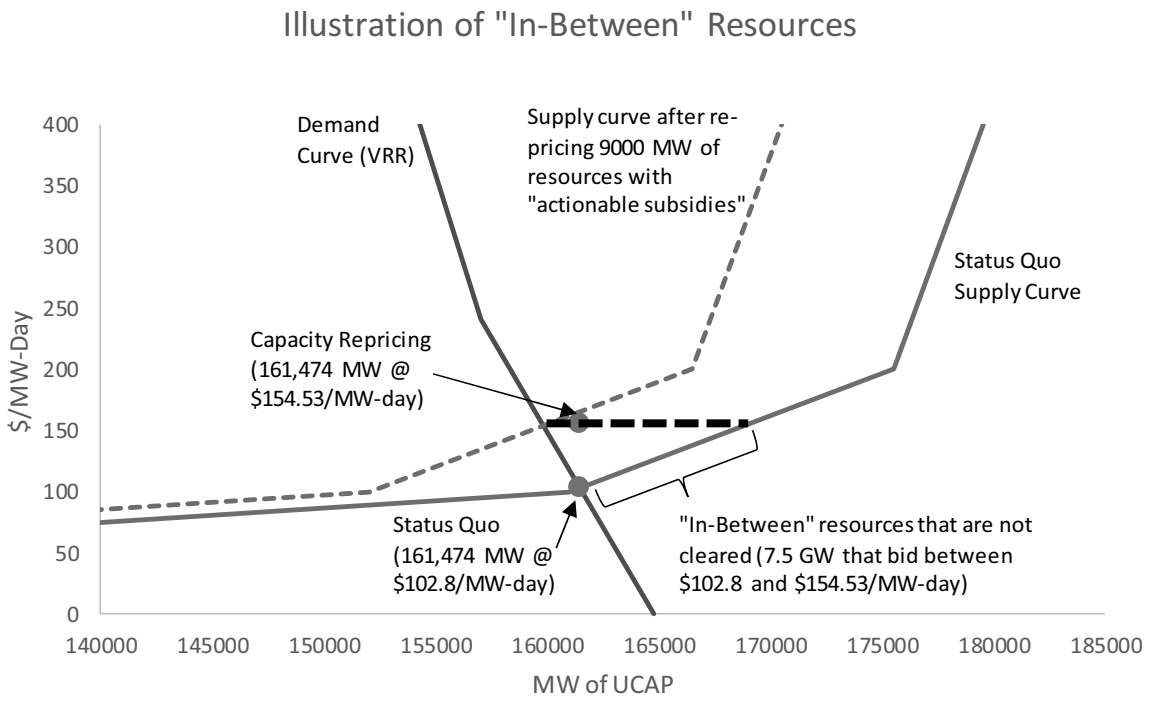
43. Second, even though the price-quantity pair resulting from Capacity Repricing does not fall on the demand curve, that does not render Capacity Repricing unworkable or impossible to execute. That is, the market clearing mechanisms identified by PJM are functional and should clear and produce stable and workable results.

B. STRATEGIC BIDDING BEHAVIORS WILL REDUCE MARKET CLEARING PRICES UNDER CAPACITY REPRICING

44. Commenters' witnesses also identify two issues associated with the two-stage market clearing mechanics of Capacity Repricing. Both issues stem from the fact that Capacity Repricing

does not jointly set the price and quantity of cleared resources. Rather, because resources with "actionable subsidies" are bid as-is in stage one but are re-priced at a higher price in stage two, the stage two price will be set by a class of resources whose bids fall at or below the stage two clearing price but who are not cleared in stage one and do not receive a capacity obligation. These resources are termed the "in-between" resources by Wilson. Figure 2 below shows the mechanics of this in graphical form:

Figure 2



45. The problems that commenters' witnesses identify with bidding under Capacity Repricing stem from the fact that the in-between resources are relied upon to set the stage two price but do not receive a capacity obligation or payment. First, commenters' witnesses claim that the resulting stage two price is arbitrary and not the result of a workably competitive process because it may be set by a resource offer that has nothing at stake in setting its offer price.[19] Second, they claim that the separation of price and quantity creates incentives for market participants to engage in a variety of strategic bidding behaviors that may cause bids to deviate either above or below their true costs, which may inappropriately increase or decrease the stage

[19] Wilson Affidavit at ¶ 75 and DeRamus/Cain Affidavit at ¶ 35-39.

two clearing price and will generally result in increased capacity price volatility. The first of these two problems is actually more of a theoretical complaint about this type of re-pricing mechanism. But the question before the Commission is not one of theory but rather of whether the specific PJM proposal is workable and will produce reasonable results. And the answer to that question turns on the specific complaints related to strategic bidding behaviors and their market implications, which I address below.

46. Commenters' witnesses collectively identify three specific strategic bidding behaviors that result from the two-stage clearing mechanics of Capacity Repricing that they collectively contend makes Capacity Repricing "unworkable." These are a "race to the bottom" or bid suppression effect, identified by both Wilson and DeRamus & Cain,[20] an enhanced incentive to engage in above-cost bidding for certain resources, termed the "clear out the top" behavior,[21] identified by Wilson, and a tendency for resources that repeatedly fall within the "in between" resource zone to cease participation in the market over the longer term, identified by DeRamus & Cain.[22]

47. The "race to the bottom" behavior arises from the fact that to receive a capacity obligation and be paid the higher stage two price, resources must clear at or below the lower stage one price. If they do not clear in stage one, even if they offer at or below the stage two price, they will not receive a capacity obligation and will realize no capacity revenue, becoming an "in-between" resource. As a result, resources generally have an incentive to reduce their bids below their cost of providing capacity to increase the likelihood of clearing in stage one. Because the stage two price will be higher than the stage one price and be set by resources higher up the supply curve that did not clear in stage one, this is a rational strategy for most resources that suspect they may be marginal or near-marginal in stage one. Its overall effect is to reduce capacity offer prices.

48. The "clear out the top" behavior identified by Wilson (but not DeRamus & Cain) describes an increased incentive for certain resources that are part of a larger portfolio to offer at a higher level than otherwise to the extent they believe they are unlikely to clear in stage one but may be marginal or near marginal in stage two. This stems from the fact that the opportunity cost

[20] Wilson Affidavit at ¶ 54-57 and DeRamus/Cain Affidavit at ¶ 40-49.

[21] Wilson Affidavit at ¶ 58.

[22] DeRamus/Cain Affidavit at ¶ 49-53.

of bidding at a higher level and not clearing is largely eliminated for those resources because as likely "in-between" resources they will not clear anyway. Because this opportunity cost is reduced or eliminated, the value to the overall portfolio of engaging in this strategy is incrementally increased, which may cause certain resources to bid higher than otherwise.

49. Finally, DeRamus & Cain suggest that over the longer-term resources that repeatedly fall in the "in-between" resource group, and particularly new entrant resources falling in this zone, will eventually cease participation in the market despite being ostensibly competitive at the stage two price because of the ongoing cost of preparing and standing behind their capacity offers. This effect will tend to steepen the supply curve in the in-between resource zone to the extent that these participants are not replaced with other new entrants at a similar offer level.

50. Of the three strategic bidding effects, one ("race to the bottom") will tend to reduce offer prices and lower the supply curve, while two ("clear out the top" and long-term exit of in-between resources) will tend to increase offer prices and/or raise the supply curve. The overall impact on market clearing prices and amount of cleared capacity under Capacity Repricing is thus ambiguous at first glance and depends on the relative strength and prevalence of the three effects.

51. While commenters' witnesses point out these strategic bidding behaviors, they do not provide any well-supported analysis of their combined net impact. Wilson provides an example, based on an approximation of the 2020/21 RPM RTO supply and demand curves, that purports to show that the "clear out the top" effect will tend to predominate, at least for purposes of determining the market clearing price, and will result in higher than otherwise prices, while the "race to the bottom" effect will drive a slightly higher cleared quantity in stage one.[23] This example, however, is completely driven by an arbitrary and unsupported assumption about which resources will choose a particular bidding strategy and the degree to which a given bidding strategy will cause them to change their offer prices. As I discuss below, a careful examination of each strategy indicates that the assumptions underlying this analysis are not representative of the likely outcome. DeRamus & Cain, on the other hand present an example that suggests that the effect is to decrease the stage two clearing price, while increasing the quantity cleared in stage one.[24]

[23] Wilson Affidavit at ¶ 60-62.

[24] DeRamus/Cain Affidavit at ¶ 45-46.

52. An analysis of the each of the strategic bidding behaviors identified by commenters' witnesses indicates that the impact of the "race to the bottom" behavior is likely to dominate the effect of the other two behaviors, leading to a net incremental reduction in offer prices and a decrease in the stage two clearing price.

53. The principal reason for this is that the "clear out the top" behavior is likely to be quite rare because it would only apply to certain resources that are part of unusually-constituted portfolios. This is because Capacity Repricing does not actually create a new incentive to engage in "clear out the top" bidding, but instead may slightly reduce the opportunity cost of engaging in this bidding strategy where there is already an incentive present. Thus, the incremental increase in the frequency of "clear out the top" bidding due specifically to Capacity Repricing is likely to be minimal. As a result, the "clear out the top" behavior will have little impact on the capacity supply curve.

54. Furthermore, it is important to note that the "clear out the top" bidding behavior, whether in the status quo or incrementally under Capacity Repricing, is bounded by existing market power mitigation rules. Existing generation resources under either the status quo, Capacity Repricing, or MOPR-Ex remain subject to the must-offer requirement, the safe harbor offer cap of Net CONE times the balancing ratio ("B"), and the requirement to justify offers above the safe harbor cap with a unit specific Avoidable Cost Rate showing. Thus, to the extent that any resource engages in the behaviors described previously, and to the extent that its offer is above "cost," it still must remain at or below Net CONE times B, which the PJM IMM and the Commission have stated is representative of the opportunity cost that resources face when choosing whether to take on a Capacity Performance obligation. The "clear out the top" behavior then is limited at most to replacing an offer for which the resource owner judges the private costs of providing capacity to be some lesser value than Net CONE times B with a different offer at some higher level that is nonetheless equal to or less than Net CONE times B. That is, the resource owner is replacing one competitive offer with a different, higher, but still competitive offer. Any argument that the prices resulting from such behaviors are somehow not competitive or otherwise inappropriate is an argument that the existing market power mitigation rules are somehow inadequate, rather than an argument against a particular market design; such an argument seems beyond the scope of this proceeding.

55. In addition, the resources that may have incentives to engage in "clear out the top" behavior will also have incentives to engage in the "race to the bottom" behavior as well. Wilson contends that resources can easily predict where they will fall within the relative range of "in-between" resources and can thus precisely determine what strategy is appropriate for them. In the real world, where bidders have highly imperfect information, this is unlikely to be the case. Resources' ability to predict where they will fall on the supply curve when formulating their offers is highly limited and imprecise.

56. Finally, as both Wilson and numerous other commenters amply document, recent experience with the PJM capacity market indicates that there is a very large pool of potential new entrants, particularly new build natural gas combined cycles, that are willing to enter the market at relatively low prices.[25] The ability of any market participant to influence prices through a particular bidding strategy will be sharply constrained by the competitive discipline provided by these potential new entrants. Any strategic bidding behavior that tends to raise prices, such as the "clear out the top" behavior, will likely be met by a new entrant response which will tend to offset its impact.

57. Like the "clear out at top" behavior, the potential impact of "in-between" resources dropping out of the market over the longer-term, identified by DeRamus & Cain, is likely to be offset by this deep pool of new entrant capacity. Evidence from recent auctions suggests that new entrants tend to bid as price takers, rather than as marginal resources, and will thus be likely to respond to any price increase caused by "in-between" resource exit simply by increasing the amount of new entrant capacity offered.

58. Unlike the other two behaviors, the "race to the bottom" behavior identified by both Wilson and DeRamus & Cain is broadly applicable to all resources and does not depend on a set of particular circumstances such as being part of a specifically-constituted portfolio. Indeed, as discussed above, even when resources potentially face countervailing incentives to engage in other behaviors such as "clear out the top," the "race to the bottom" incentive will still be present and in many cases will tend to dominate the other incentive. For this reason, of the three behaviors

[25] Wilson Affidavit at ¶ 19-22 and Exelon Protest at 32-37.

identified, "race to the bottom" is likely to be far more prevalent and will tend to dominate the other two effects.

59. While it is likely to dominate, the "race to the bottom" behavior is likely to be self-limiting to the extent that it is not likely to drive the stage two price below the stage one price. This is because rational bidders will build into their decision on how to offer their resource the expectation that most other bidders will also be engaging in the "race to the bottom" behavior. If only one bidder is reducing its bid below cost to clear in stage one, its expectation of the stage two price will remain relatively high, and thus an aggressively below-cost bid is very likely to clear stage one and will be rewarded with a relatively high stage two price. If, however, all other bidders are engaging in the same behavior, the risk of not clearing stage one is increased, and the stage two price is likely to be much lower, increasing the risk that if the resource does clear, it may not be paid a price that covers its costs. Thus, under the expectation that all resources are engaging in "race to the bottom," resources are likely to be less aggressive in reducing their bids below cost to clear in stage one.

60. To provide a sense of the likely overall aggregate magnitude of the bidding behaviors, given the likely dominance of the "race to the bottom" behavior over the others, I have modified the example provided by Wilson to show the outcome that results when resources only engage in the "race to the bottom" behavior.[26] Following Wilson's assumptions, I have assumed that 50% of resources with offers more than $80/MW-day and less than $170/MW-day reduce their offers by 20% relative to the status quo. Unlike Wilson, however, I do not assume that any offer modification due to "clear out the top" occurs. I otherwise adopt Wilson's underlying assumptions with regards to supply curve shape and other parameters. This modified example is shown in graphical form in Figure 3 and Figure 4 below:

[26] Wilson Affidavit at ¶ 60-62.

Figure 3

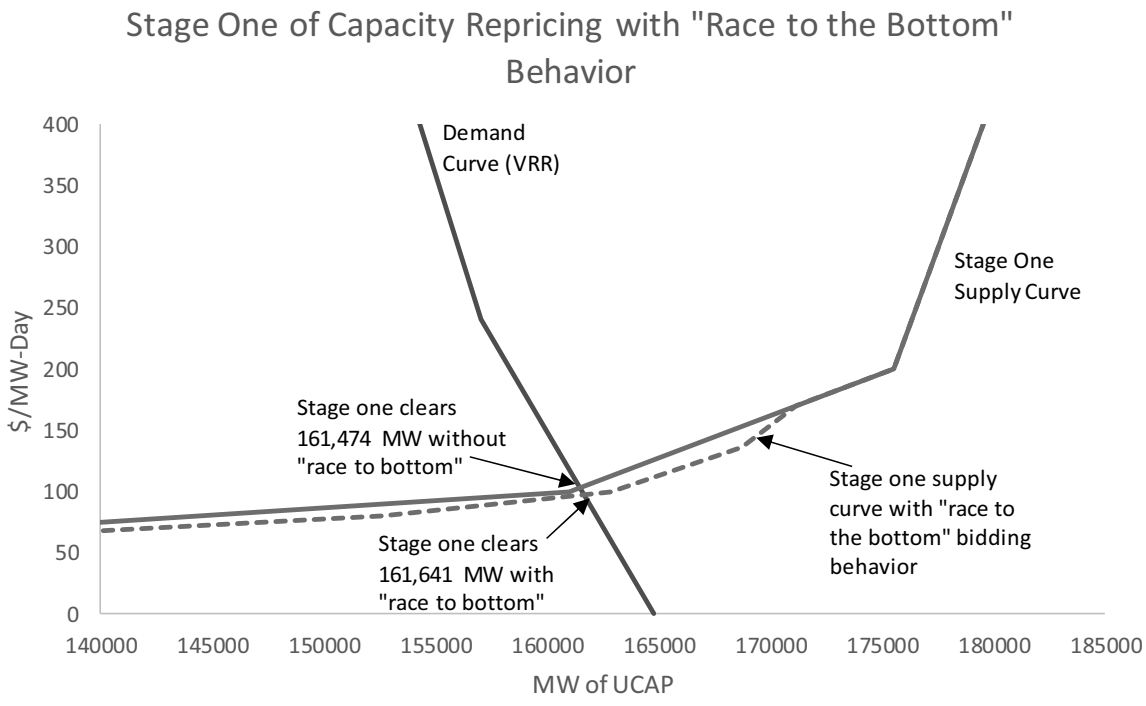
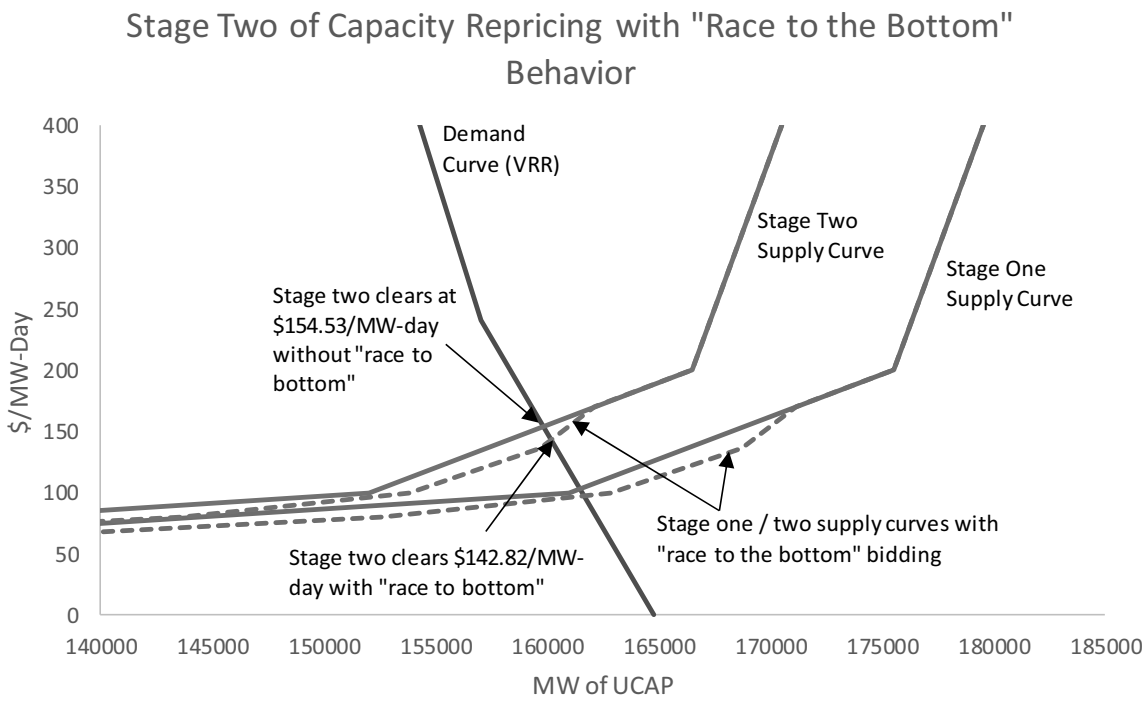


Figure 4



61. Without any strategic bidding behaviors, Capacity Repricing causes the capacity clearing price to increase from $102.8/MW-day in the status quo case to $154.53/MW-day in the Capacity Repricing case, with total unforced capacity cleared of 161,474 MW in both cases. Load payments thus rise from $6.06 billion in the status quo to $9.1 billion under Capacity Repricing, or a 50% increase. If we assume that the "race to the bottom" behavior dominates as per the assumptions discussed above, the total UCAP procured under Capacity Repricing rises slightly, by 167 MW to 161,641 MW, but the clearing price is $142.82/MW-day, or about 7.5% lower than it would have been without strategic bidding behaviors. Customer load payments with strategic bidding behaviors are $8.425 billion, or about a 39% increase relative to the status quo, rather than 50%. As discussed earlier, MOPR-Ex results in a customer cost increase of about 50% versus the status quo, so the effect of strategic bidding on Capacity Repricing in this example results in customer costs that are still considerably elevated relative to the status quo, but below MOPR-Ex.

62. The overall effect, then, of strategic bidding would be to drive the stage two clearing price under Capacity Repricing closer to the status quo price that would prevail absent Capacity Repricing. Generally, the resulting price should fall somewhere between the price absent strategic bidding (which is also the price that would result from MOPR-Ex) but above the status quo price that would result from no mitigation. Exactly where on this continuum the price would fall in this range is difficult to predict with precision, but the predominance of the "race to the bottom" behavior should ensure that it falls below the MOPR-Ex price while bidder rational expectations should ensure that it falls above the status quo price.

63. Strategic bidding would result in a total quantity procured slightly in excess of what it would be in the most efficient status quo case. Given the steepness of the demand, the incremental capacity procured because of this is minimal. In the example above, strategic bidding causes 167 MW of additional capacity to clear, or a 0.1% increase versus the status quo.

64. To the extent that the resources subject to mitigation are receiving payments addressing environmental externalities, the status quo price is more efficient than the Capacity Repricing price without these strategic bidding behaviors (which is also the same as the MOPR-Ex price). Thus, ironically, the effect of strategic bidding behaviors in the aggregate is to make Capacity Repricing less inefficient, not more inefficient, because collectively they drive a lower market clearing price that is closer to the efficient status quo price. As a result, the strategic bidding

behaviors incrementally increase the efficiency of Capacity Repricing and lower its cost to consumers. But whatever one's view of the state programs at issue, these behaviors are likely to have only modest effects that will yield a price somewhere between the status quo price and the MOPR-Ex price.

C. STRATEGIC BIDDING BEHAVIORS CAN BE REMEDIED WITH A LOST OPPORTUNITY COST PAYMENT TO "IN-BETWEEN" RESOURCES

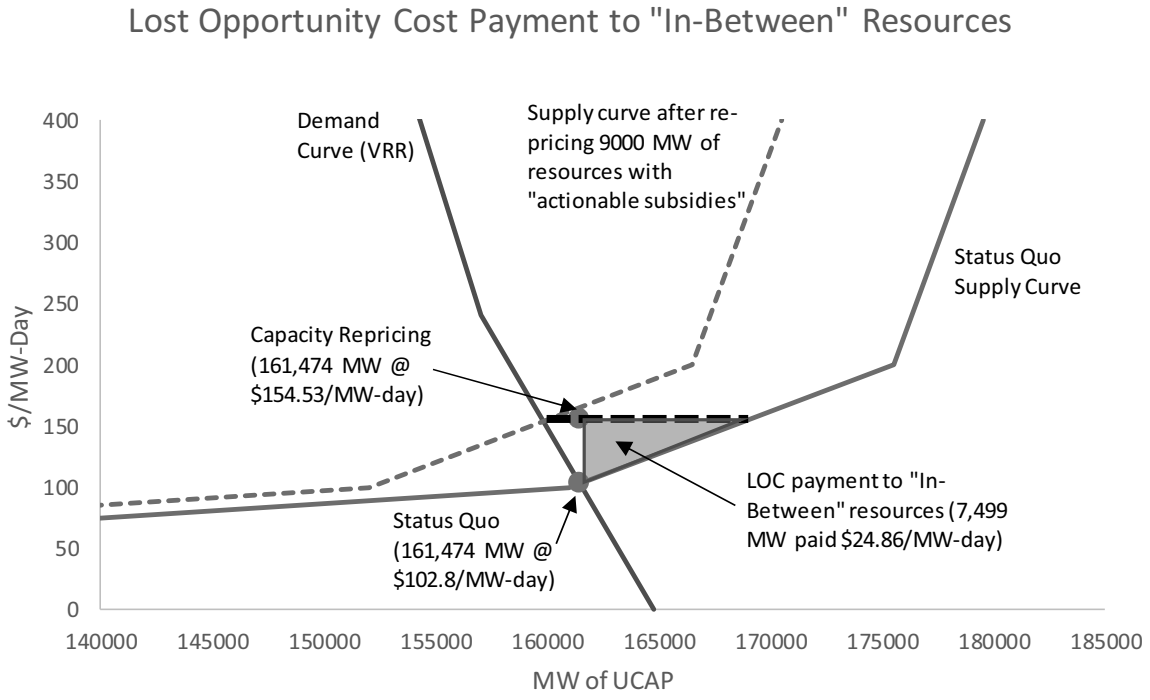
65. If the Commission does decide to proceed with Capacity Repricing but also determines that the strategic bidding behaviors identified by commenters' witnesses are undesirable, the behaviors could be largely eliminated by implementing a simple market design fix analogous to other market design fixes that the Commission has approved to address similar strategic bidding issues in RTO energy, ancillary service, and capacity markets. That is, rather than representing an insoluble "fatal flaw," these strategic bidding behaviors can easily be addressed within the broader market design. The market design fix in this case would be to implement a lost opportunity cost ("LOC") payment for "in-between" resources.

66. As discussed above, the root cause of all the potential strategic bidding behaviors identified by commenters' witnesses is the fact that "in-between" resources do not clear and thus do not bear any direct financial consequences for their bid. A LOC payment adds financial consequences for "in-between" resources in a manner that simulates the consequences that would occur if they did clear in stage two of Capacity Repricing, and in so doing largely eliminates the incremental incentives to engage in strategic bidding behaviors.

67. A LOC payment would be implemented by paying resources that do not clear in stage one the difference between the stage two clearing price and their individual bid price, if greater than zero. Despite receiving this payment, they would still not clear in stage one and would not receive a capacity obligation. The LOC payment would thus not carry an obligation that the resource receiving it remain in the market (for an existing resource) or subsequently enter the market (for a new resource); an existing resource could subsequently retire following the auction and still receive the payment. The LOC payment replicates the margin that the "in-between" resources would have earned by providing capacity if they were cleared and received a capacity obligation. That is, the stage two price represents the capacity revenue they would have received, while their offer price represents their private cost of providing capacity. The LOC payment pays

them as if they had cleared the market but recognizes that because they do not receive a capacity obligation they are able to avoid the cost of providing capacity, and thus deducts their offer price from the capacity clearing price. Figure 5 below shows how a LOC payment for "in-between" resources would work in graphic form:

Figure 5



68. The LOC payment restores financial consequences to the bidding decisions made by in-between resources. Because lack of financial consequences for their bidding decision is the root cause of the strategic bidding behaviors incentivized by Capacity Repricing, a LOC payment reduces the incentive to engage in these behaviors.

69. First, the incentive to engage in "race to the bottom" below-cost bidding is reduced because the LOC payment makes resources indifferent between clearing or not clearing in stage one. Working off the "race to the bottom" example provided by Wilson,[27] assume that a resource with costs of $115/MW-day is determining its offer price under the knowledge that an offer of $100/MW-day or less is needed to clear stage one, but the stage two price is likely to clear at around $150/MW-day. Without a LOC payment, this resource has an incentive to reduce its offer

[27] Wilson Affidavit at ¶ 55.

below its costs, to $100/MW-day or less, to avoid becoming an "in-between" resource. If it bids below costs and clears stage one, it earns a margin on its capacity sale of $35/MW-day, the difference between the stage two price of $150/MW-day and its costs of $115/MW-day. But if it bids its costs, it will not clear and will receive nothing. With a LOC payment, however, if it bids its costs of $115/MW-day, it receives a payment of $35/MW-day – the difference between the stage two price and its offer price. Thus, the resource owner's incentive to reduce its offer price to a level needed to clear stage one is eliminated – the resource's margin is equalized between the two outcomes.

70. It is true that a LOC payment likely does not fully eliminate the incentive to bid below cost in all situations. Resources that expect to fall within the "in-between" zone would have a modest incentive to reduce their offer prices slightly below cost in order to maximize the size of the LOC payment while still remaining a "in-between" resource. This incentive is much weaker, however, because it only produces gains if the resource still does not clear stage one despite reducing its offer below cost, and higher cost resources that engage in this strategy would run the risk of clearing in stage one and taking on a capacity obligation at a loss.

71. Second, the "clear out the top" behavior would be eliminated, to the extent it exists, because the LOC payment restores the opportunity cost of bidding a high cost "in-between" resource at above its costs. As discussed previously, this behavior arises because such resources are unlikely to clear in stage one and thus do not forgo any capacity margin by bidding above cost. With a LOC payment, however, bidding in this fashion would cause the resource to either forgo the payment (because it bids above the stage two price) or reduce its magnitude. Thus, the payoff to a "clear out the top" strategy of bidding such a resource above its costs is re-set back to the same level that exists under the status quo.

72. Finally, resources that consistently fall in the "in-between" region, particularly new entrant offers, will not face an incentive to stop bidding over time due to failure to cover their offer costs. LOC payments should provide sufficient compensation for such resources to continue preparing offers and participating in the market.

73. The cost of LOC payments is likely to be quite small relative to overall capacity cost. Returning to the example originally provided by Wilson, with an assumed 9,000 MW of re-priced resources, Capacity Repricing results in a clearing quantity of 161,474 MW and a clearing price

of $154.53/MW-day for stage two and $102.8/MW-day for stage one. Under these assumptions, and with the capacity supply curve assumed by Wilson, there are 7,499 MW of resources that do not clear stage one but bid below $154.53/MW-day (*i.e.*, "in-between" resources). These resources have an average bid price of $128.66/MW-day. A LOC payment system would pay this 7.5 GW of resources an average payment of $24.86/MW-day (the stage two price less their average bid). The total cost of these payments would be about $68 million, or about 0.75% of the total capacity payments under the example.

74. While LOC payments have not to date been utilized in capacity markets, they are widely used (and FERC-approved) in RTO energy and ancillary services markets to align bidder incentives and increase market efficiency. Examples include LOC payments to generators in the energy market to keep them whole when responding to out-of-market dispatch signals for reliability reasons, and co-optimization of energy and operating reserves markets, where lost opportunity cost forms the basis for the reserve price.

75. By comparison, there is no relatively simple adjustment, like a lost opportunity cost payment, that would fix the flaws in the MOPR-Ex proposal. MOPR-Ex by its nature pushes targeted resources out of the capacity market. As discussed previously, the flaws in MOPR-Ex arise from this fundamental feature of MOPR-Ex – either the resources remain and excess capacity is effectively procured, or economic resources may exit the market. There is no way to avoid these problems without changing this fundamental aspect of MOPR-Ex.

76. This completes my declaration.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. ER18-1314-000**
	)	**ER18-1314-001**
	)	
	)	

DECLARATION OF MICHAEL M. SCHNITZER

I, Michael M. Schnitzer, declare under penalty of perjury that the foregoing is true and correct.

Executed: May 22, 2018

Concord, Massachusetts

Michael M. Schnitzer

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

CPV Power Holdings, L.P., Calpine Corporation and Eastern Generation, LLC,	)	
Complainants,	)	**Docket No. EL18-169-000**
v.	)	
PJM Interconnection, L.L.C.,	)	
Respondent.	)	

DECLARATION OF ROBERT D. WILLIG

June 20, 2018

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I. QUALIFICATIONS, ASSIGNMENT AND SUMMARY OF CONCLUSIONS

A. QUALIFICATIONS

1. My name is Robert D. Willig. I am Professor of Economics and Public Affairs Emeritus at the Woodrow Wilson School of Public and International Affairs and the Economics Department of Princeton University. There I served for many years as the Field Coordinator for Economics at the Woodrow Wilson School and as the Faculty Chair of the Masters Program in Public Affairs. Before joining the senior faculty of Princeton University in 1978, I was Supervisor in the Economics Research Department of Bell Laboratories. My teaching and research have specialized in the fields of industrial organization, government-business relations, and social-welfare theory.

2. I served as Deputy Assistant Attorney General for Economics in the Antitrust Division of the U.S. Department of Justice from 1989 to 1991. I also served on the Defense Science Board task force on the antitrust aspects of defense industry consolidation and on the Governor of New Jersey's task force on the market pricing of electricity.

3. I am the author of *Welfare Analysis of Policies Affecting Prices and Products, Contestable Markets and the Theory of Industry Structure* (with William Baumol and John Panzar), and numerous articles in the professional literature of economics and law. I am a co-editor of *The Handbook of Industrial Organization*, and have served on the editorial boards of the *American Economic Review*, the *Journal of Industrial Economics* and the MIT Press Series on regulation. I am also an elected Fellow of the Econometric Society.

4. I have performed applied research and have developed expertise on market structure, competitive conduct, contractual relations, optimal pricing, micro-economic reforms, and the architecture and practice of infrastructure regulation. I have been a consultant to firms in many sectors of the economy, including telecommunications, transportation, energy, health care, pharmaceuticals, aeronautics, automobiles, information technology, chemicals, consumer products, and financial markets.

5. I have researched, taught, consulted, and testified on antitrust issues including horizontal mergers, vertical mergers, allegedly monopolizing conduct and allegedly collusive conduct in a host of industries. I have researched, taught, consulted, and testified on regulatory issues including

pricing, access, vertical and horizontal firm structure and the roles of governments and markets in the energy, telecommunications, and transportation industries.

6. I have worked as a consultant with the Federal Trade Commission, the Organization for Economic Cooperation and Development, the Inter-American Development Bank, the World Bank, and various private clients. I serve as a senior consultant to Compass Lexecon, an economic consulting firm that I helped to found. A list of my articles, books, and other professional publications and activities is presented in my curriculum vitae (Attachment A).

B. BACKGROUND AND PURPOSE OF TESTIMONY

7. On May 31, CPV Power Holdings, L.P., Calpine Corporation, and Eastern Generation, LLC ("Complainants") filed a complaint ("Complaint") alleging that the existing Minimum Offer Price Rule ("MOPR") of PJM Interconnection, LLC ("PJM") is unjust and unreasonable because the existing MOPR fails to mitigate resources receiving payments under certain state programs, and in particular, state environmental programs. Complainants further allege that both of the modifications to PJM's market design that PJM proposed in its April 9, 2018 filing[1] at the Federal Energy Regulatory Commission ("FERC" or "Commission"), called Capacity Repricing and MOPR-Ex, are also unjust and unreasonable.

8. Complainants ask the Commission to impose on PJM instead what they call a "Clean MOPR," which Complainants describe as "MOPR-Ex with the Unit-Specific Exception but without the Self-Supply, Competitive, Public Entity and RPS Exemptions."[2] The Clean MOPR, however, would continue to exempt from mitigation resources receiving payments under certain state and federal programs. Thus, Complainants' Clean MOPR proposal is designed to discriminate against resources receiving certain types of state support.

9. In particular, Complainants' Clean MOPR proposal would transform PJM's existing MOPR by applying it to certain existing capacity resources receiving a so-called "Material

[1] PJM Interconnection, LLC, Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, FERC Docket No. ER18-1314-000, April; 9, 2018 ("PJM Filing").

[2] Complaint at 18.

Subsidy."[3] By broadening the application of the MOPR to certain existing state-supported capacity resources (e.g., nuclear), Complainants propose to impose offer price floors that would likely prevent these resources from clearing in the capacity auctions. However, Complainants' Clean MOPR proposal would exclude from its definition of "Material Subsidy" state and local subsidies designed to promote "general industrial development in an area," or to incentivize "siting facilities in [one] county or locality rather than another county or locality."[4] The Clean MOPR would also exclude "federal subsidies or other support granted [before] the date of th[e] Complaint."[5] Capacity resources receiving such subsidies would be allowed to offer into PJM's capacity auctions at a price of zero.

10. The Clean MOPR would interact destructively with the Illinois Zero Emissions Standard (hereinafter "Zero Emissions Standard", "ZES" or "ZES Program"). On December 7, 2016 the Illinois legislature passed comprehensive energy legislation[6] intended to ensure that Illinois remains on track to meet its environmental goals by continued and increased reliance on zero-emission electric generation resources.[7] Among the legislative goals encompassed in the ZES is "[p]reserving existing zero emission energy generation and promoting new zero emission energy generation," which "is vital to placing the State on a glide path to achieving its environmental goals and ensuring that air quality in Illinois continues to improve."[8] The program's means of accomplishing this goal is to compensate nuclear generators that might otherwise retire for the environmental attributes of their continuing production.

11. To compensate certain Illinois nuclear generation units for the social benefits of their zero-carbon dioxide emissions generation—which would be lost if these units retired—the ZES calls for the creation of Zero Emission Credits ("ZECs"). The value of a ZEC is based on the U.S. government's estimated social cost of carbon emissions in force at the time of the program's enactment, which is not currently reflected in wholesale-power market prices. Under the ZES, the

[3] *Id.*

[4] Complaint at 18; *see* PJM Filing at 70.

[5] Complaint at 19.

[6] Illinois SB 2814 (available at http://www.ilga.gov/legislation/99/SB/PDF/09900SB2814enr.pdf) ("SB 2814").

[7] SB 2814 at Section 1.

[8] *Id.*

Illinois Power Agency ("IPA") developed a zero-emission standard procurement plan and procured contracts for ZECs from facilities capable of generating zero-emission credits cost-effectively in an amount equal to 16% of the electricity delivered by Illinois electric utilities with more than 100,000 customers in calendar year 2014.[9] Exelon's Quad Cities and Clinton nuclear plants were selected to provide ZECs based on a public interest standard that includes, among other things, minimizing carbon dioxide, sulfur dioxide, nitrogen oxide, and particulate emissions that adversely impact Illinois citizens.[10]

12. I have been asked by counsel for Exelon to provide an economic analysis of Complainants' claim that PJM's existing MOPR is not just and reasonable because it fails to mitigate resources receiving payments under state programs promoting environmentally friendly resources, as well as to provide an economic analysis of Complainants' proposed Clean MOPR.

C. SUMMARY OF FINDINGS AND CONCLUSIONS

13. I have reached the following findings and conclusions:

(a) In the analysis supporting its conclusion that reforms to market rules are needed, Complainants ignore a basic principle of economics: Actions taken by producers that impose social costs that are not accounted for in the producer's private costs result in negative externalities that harm the public interest. For example, when a coal power plant generates electricity, the plant owner incurs the private cost of operating the plant. The social costs of operating the plant, however, include not only the owner's private costs, but also the cost of pollution that the plant's operation imposes on the public. Economics teaches that when private costs diverge from social costs, the result will be an inefficient allocation of resources. For example, when a coal plant owner can operate the plant without bearing the costs of pollution, the plant owner will operate the plant more than would be efficient. Taxes and subsidies can be designed to internalize the costs to society from negative environmental externalities. For example, the government can impose a tax on the coal plant owner equal to the cost of the negative externality

[9] SB 2814 at (d-5) Zero emission standard (1).

[10] Illinois Commerce Commission, Public Notice of Successful Bidders and Average Prices, Illinois Power Agency, January 2018 Procurement of Zero Emission Credits from Facilities Fueled by Nuclear Power, January 25, 2018.

(environmental costs) that results from the plant's operation, which would predictably lead to a reduction in the plant's operations consonant with the internalization of the environmental costs borne by society. Or, the government can provide financial support to a clean source of power that rewards its positive externalities, including its displacement of coal or other fossil fuel plant emissions that reduces environmental costs borne by society.

(b) Complainants' Complaint makes the fundamental error of focusing on private production costs rather than social costs as the measure of efficiency that should be applied when evaluating its capacity market design. The proposal asserts that state public policies that seek to retain or induce the entry of environmentally friendly sources of generation by providing them with out-of-market payments "negatively impact RPM price signals and cause the retention of inefficient resources."[11] That is incorrect. The design objective of PJM's markets is to select the most efficient mixture of capacity resources to serve load. When environmental externalities are not accounted for in a marketplace, the result is an inefficient allocation of resources. To be sure, PJM's wholesale power markets are not themselves designed to require plant owners to internalize the costs of environmental externalities. But that is because FERC can rely on the states to regulate the environmental aspects of power generation. States can provide extra revenue to environmentally friendly producers (subsidize), or take revenue away from environmentally harmful producers (tax); and PJM's markets can then seek to select the least-cost set of resources against the backdrop of these state policies. The result is the most efficient set of resources to serve load, accounting for the impact of various state policies that reflect environmental externalities. Such state programs thus complement PJM's market design objective; they do not impede it. To the contrary, PJM's market design objective would be defeated by capacity market rules that would effectively prevent all environmentally friendly units receiving state support from clearing in the capacity market. The market would then select a group of resources that, from the standpoint of social welfare, is inefficient; and, moreover,

[11] Complaint at 12.

it would also select a quantity of capacity that is inefficient, by ignoring the capacity provided by the state-supported resources.

(c) The Illinois ZES Program provides an example of a state program that implements the principles of economics just discussed. It addresses the social benefits associated with eliminating a negative externality by facilitating a positive externality. The ZES Program provides compensation to nuclear power generation plants that is based on, and cannot exceed, the cost of carbon dioxide emissions that society avoids so long as these plants continue operating, but that would result from the production of electricity from the generation resources that would replace the nuclear plants. Thus, the program is designed to ensure that the estimated quantified benefit to society from the avoided carbon dioxide emissions is always greater than the amount paid to nuclear power plants to avoid those emissions. The economic rationale for the ZES is well grounded in the field of welfare economics. Compensating nuclear generation for its zero-emission attributes, thereby preventing its retirement, is a move toward greater economic efficiency as compared to allowing those plants to retire and be replaced by fossil fuel plants that impose environmental costs on the public. By offering appropriate environmental attribute payments tied to the value of the environmental externality, the ZES complements the workings of competitive wholesale electricity markets and ensures that there will be incentives to preserve existing nuclear generation if and only if it is socially efficient to do so, taking both externalities and private production costs into account. If the sum of market revenues and the value of the abated externality exceeds the costs of production, then production is socially worthwhile. A properly designed capacity market should seek to accommodate this state program, which complements and advances the goal of selecting the most efficient set of generation resources to serve load.

(d) From the standpoint of economics, the ZES Program compares favorably with other types of support programs, where compensation is not tied to the value of the environmental externality abated. For example, while renewable portfolio standard ("RPS") programs likewise provide financial support to environmentally friendly generation that would not otherwise be able to enter the market, compensation

under such programs is not often tied to the value of the environmental harm being abated. Such state compensation can result in the retention of units without regard to whether their retention is efficient or inefficient. The same is true of federal tax credits, such as the Production Tax Credit for wind and the Investment Tax Credit for solar.

(e) The zero emission certificate program recently passed by New Jersey ("New Jersey ZEC Program") also implements the principles of economics just discussed. The New Jersey ZEC Program's payments are based on a retail charge of $.004/kWh, and the program "is structured such that its costs are guaranteed to be … less than the social cost of carbon emissions avoided by the continued operation of [the] selected nuclear power plants."[12] The New Jersey ZEC Program improves efficiency compared with the status quo because it compensates the selected nuclear plants for their environmental benefits, and it does so in an amount that is guaranteed not to exceed the plants' environmental benefits.

(f) Complainants' Clean MOPR is unjustified from an economic point of view. It is based on the mistaken premise that it would defeat PJM's market design objective if capacity prices reflected state payments compensating environmentally friendly generation for abating externalities, and the Clean MOPR would unjustifiably frustrate these state programs.

i. First, by applying a MOPR to certain state-supported resources, the Clean MOPR would effectively prevent them from clearing in the capacity market. As a result, the capacity market would select an inefficient mixture of resources: it would select resources based primarily on the private cost of production, without fully accounting for the reduced social costs that result from state-supported environmentally desirable production. That mixture of resources would be less efficient than the mixture that would be selected when accounting for the positive environmental externalities associated with environmentally friendly resources. To put it another way, the absence of the

[12] Senate Bill No. 2313, § 1(b)(8).

internalization of the social cost of carbon emissions in market prices creates the appearance that certain clean resources—for example, financially challenged nuclear units—are not efficiently competitive. In fact, when externalities are taken into account, these units are economically efficient and their continued presence in the market should be viewed as pro-competitive.

ii. Second, the Clean MOPR would result in the over-procurement of capacity, imposing unnecessary costs on customers. The Clean MOPR ignores the availability of capacity from many state-supported resources, even though those resources may continue operating and supplying capacity to the grid notwithstanding the application of the MOPR to these resources. Instead, the Clean MOPR procures additional capacity from resources not requiring state support. That results in over-procurement of capacity and unnecessary costs for consumers.

iii. Third, the Clean MOPR proposes to extend the MOPR to existing capacity resources. PJM's MOPR has not previously been applied to existing resources as much of the cost of providing capacity is sunk once a resource is operating. The Clean MOPR extends the application of the MOPR to existing units with no indicia to measure whether such an extension is guarding against the exercise of buyer-side market power, and no analysis by Complainants of whether such an extension could result in the exclusion of capacity that is efficient in the relevant time frame.

(g) The Clean MOPR also draws arbitrary and discriminatory distinctions among different types of state support. These distinctions are not grounded in economics.

i. First, the Clean MOPR exempts only certain state support for clean generation, with no sound basis in economics for the distinctions it draws. It exempts certain state and local subsidies aimed to promote industrial development in an area or the siting of a project in a particular location. It also exempts existing federal subsidies. But the Clean MOPR does not consider the relevant question concerning the design of the program: whether the program is economically efficient and welfare enhancing. Complainants provide no

evidence that the programs exempted from mitigation under the Clean MOPR are likely to be economically efficient or welfare enhancing. Indeed, the Clean MOPR does not even consistently apply Complainants' apparent rationale for expanding the MOPR—that bids should not account for out-of-market support under state or federal programs, and that bids reflecting such support should be mitigated if they materially affect market outcomes. This rationale is not based on sound economics, as I have explained, but Complainants provide no evidence that the programs they exempt do not have the features that they elsewhere deem to warrant mitigation. Complainants' attempt to redefine the use of the MOPR away from preventing the exercise of buyer-side market power leaves them with no principled basis upon which to exempt some state and federal programs while not exempting others.

ii. There is no clearer example of the failings of the Clean MOPR proposal than its discrimination against existing generation units providing ZECs under the ZES Program and the New Jersey ZEC Program (together, the "ZES Programs"). Not only do ZECs raise no warranted concerns about their impact on the public interest, but ZECs will contribute to efficient and desirable outcomes in the capacity auctions. Moreover, the ZES Programs compare favorably from an efficiency perspective with the subsidies exempted from operation of the Clean MOPR, which Complainants have not shown promote economic efficiency. It is economically efficient and appropriate to not interfere with a narrowly-focused subsidy that will have a direct impact and achieve the desired result of reducing harmful environmental externalities in a cost-effective manner. The Clean MOPR arbitrarily discriminates against generation resources receiving ZECs.

(h) If PJM's MOPR remains confined to preventing the exercise of buyer-side market power, as I believe it should be, the ZES Programs should not be mitigated. There are a number of reasons why the ZES Programs are not exercises of buyer-side market power and the recipients of ZEC payments should not be subject to buyer-side market power mitigation.

i. First, the ZES Programs are clearly not an exercise of buyer-side market power because the estimated benefits of the programs exceed the costs without any consideration of the impact the programs may otherwise have on market prices. The cost of a ZEC and the financial benefit to its recipient cannot exceed the value of the externality being addressed—the social cost of the abated carbon dioxide emissions. This ensures that the receipt of the ZECs does not result in participating nuclear plants making economically inefficient decisions about whether or not to continue operating by overcompensating them for their environmental benefits. Again, if the sum of market revenues and the value of the abated externality exceeds the costs of production, then production is socially worthwhile. Improving the alignment of private and social incentives to produce power from the participating nuclear units is the core economically beneficial characteristic of the ZES Programs. In an exercise of buyer-side market power, by contrast, there is no alignment of social value and private incentives; instead, the exercise of market power is based on the buyer's private incentive to transfer value from other producers to itself by suppressing market prices, even if the added supply that suppresses prices is socially inefficient.

ii. Second, the ZES Programs do not insulate the participating nuclear generation unit owners from market risk or guarantee financially viable operations. Under the ZES Programs, the generating units could fail to produce and/or be retired in the event of significant unforeseen costs and/or operational problems. If the externality benefits of production, as reflected by the ZECs, are insufficient to close the gap between the expected private costs of production and the expected revenues derived from the market sales of production, then production from the participating units will not be compensatory. A program designed to exercise buyer-side market power, by contrast, would provide sufficient compensation to guarantee future plant operation even if the plant's operation were economically inefficient.

iii. Third, the ZES Programs do not require a unit to bid into the wholesale energy or capacity market, or clear in the wholesale capacity market. The ZES

Programs provide narrowly defined compensation associated with plant production, not sale of energy or capacity. By contrast, efforts to exercise buyer-side market power ordinarily, so as to warrant mitigation, would require bidding and clearing as a condition for compensation, in order to ensure that compensation is paid only if prices are suppressed through direct market participation. As such, the ZES Programs complement FERC's competitive market policies and do not interfere with FERC's market pricing mechanisms.

iv. A program intended to exercise market power would be structured differently without incentives so closely linked to emissions-reducing production. Compensation intended to support generation for the suppression of market prices would not be limited, as is compensation under the ZES Programs, to the social benefits of the averted carbon emissions. Instead, the exercise of buyer-side market power would motivate compensation up to the size of the buyers' financial gains from the lowered prices.

14. ZEC recipients should be allowed to bid into the organized electricity markets without the constraints of repricing or mitigation. The ZECs should be permitted to offset production costs in the determination of their recipients' market bids because the ZECs compensate real social benefits of the units' production that avert the social costs of negative environmental externalities. The resulting prices are not artificially suppressed; they are the proper prices in light of state-provided compensation for plants' environmental attributes.

15. The use of a MOPR should be confined to preventing the exercise of buyer-side market power. There is no sound economic basis for Complainants' proposed use of a MOPR as a general tool to regulate capacity resource developers' and existing capacity owners' arrangements and conduct. There is no demonstrated rationale for how a MOPR can be effective in a generalized fashion, no articulated discipline or public interest guidelines over PJM decisions about what arrangements should be regulated through the application of the MOPR, and no demonstration that application of a MOPR would be an effective and efficient corrective form of regulation generally over capacity developers' and existing capacity owners' arrangements and conduct where these are deemed to be unconducive to the public interest. In contrast, there are well known indicators of circumstances where bidding behavior may reflect the exercise of buyer-side market power, and

plain logic for why a MOPR could be an appropriate and effective tool to apply in those specific circumstances.

16. The Clean MOPR proposal exemplifies the above reasons why a MOPR should not be approved as a general tool for PJM to employ to regulate capacity developers' and existing capacity owners' arrangements and conduct. The proposal does not attempt to articulate any reasoned principle to identify what arrangements, beyond exercises of buyer-side market power, should be regulated by PJM through the application of the MOPR. For example, the proposal's exemptions from application of the MOPR are not supported by evidence that these domains are relatively likely to be free of the concerns that Complainants have expressed about capacity developers' and existing capacity owners' arrangements and conduct. Instead, the proposal's exemptions are discriminatory, and they are expressed without any justification that would show that they would promote the public interest or that they would provide needed guidance to developers and current owners of capacity resources about what types of arrangements and conduct might be subject to the MOPR in the future. Moreover, Complainants have not demonstrated that the MOPR, if applied for a broader purpose than addressing buyer-side market power, would effectively protect the public interest with respect to the broader concerns Complainants have raised.

II. PJM'S MINIMUM OFFER PRICE RULE

17. From its inception, the focus of PJM's MOPR has been preventing capacity buyers from exercising buyer-side market power by introducing uneconomic new supply resources into PJM's capacity auctions. As the MOPR has evolved, the Commission has declined to expand it beyond buyer-side market power, has not approved its application to existing capacity resources, and has created exemptions from the MOPR for circumstances that do not present a substantial risk of being an exercise of buyer-side market power. The Commission has previously authorized these exemptions even though the exemptions had the potential to lower capacity prices. The economic justification for these exemptions is thus linked to the economic justification for the MOPR itself.

18. A brief review of the evolution of PJM's MOPR, and the justifications for exemptions to it, is helpful. PJM's initial MOPR rules were refined not long after being approved by the Commission in response to the recognition that some elements of the original MOPR design undermined the MOPR's effectiveness for preventing the exercise of buyer-side market power or

were based on tariff language that was unclear. In particular, two previously defined tests, or screens, that limited the application of the MOPR and reduced its effectiveness were eliminated.[13] First, the net-short test provided an exemption from the MOPR for entities that were both buyers and sellers of capacity and whose capacity purchases in an auction were small relative to their load obligation (i.e., they were not materially "short" the capacity needed to meet their load obligation). However, the original structure of the MOPR did not prevent an entity that exceeded the net-short threshold from arranging for a new capacity addition that would not be associated with its portfolio to push down capacity prices and reduce capacity costs for the entity's net-short position. Second, a price impact screen allowed capacity offers that failed a buyer-side market power conduct test (i.e., offers below the MOPR floor) to be accepted based on a price impact test. That screen was found to be too lenient in that it allowed price depression that was substantial enough to represent an exercise of buyer-side market power. Thus, the screens were found to be ineffective and to possibly allow for an exercise of buyer-side market power.

19. In addition, disagreement over whether PJM's tariff provided a MOPR exemption for state-supported resources was reviewed by the Commission, and the Commission approved PJM's proposal to make clear that there is not an exemption from the application of the MOPR for state-supported resources that could represent exercises of buyer-side market power.[14] However, following approval of these changes, the Commission recognized that the MOPR floor could be inappropriately applied to a resource offer that was justifiably lower than the MOPR floor and approved a unit-specific exemption (or exception) process to provide resource sellers an opportunity to explain the basis for an offer below the MOPR floor.[15] Moreover, the Commission at the time reasoned that wind and solar generation resources were not resource additions associated with the exercise of buyer-side market power and allowed these resources to make offers in PJM's capacity auctions at a price of zero, effectively exempting these resources from the MOPR.[16]

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[13] *See PJM Interconnection, LLC*, 135 FERC ¶ 61,022 (2011) at PP 86 and 101 and 137 FERC ¶ 61,145 (2011) at PPs 43 and 52. The Commission approved PJM's proposals to eliminate a "net-short" test and an "impact screen" that were found to reduce the effectiveness of the MOPR.

[14] 135 FERC ¶ 61,022 (2011) at P 139 and 137 FERC ¶ 61,145 (2011) at P 87.

[15] 137 FERC ¶ 61,145 (2011) at P 242.

[16] 135 FERC ¶ 61,022 (2011) at P 152 and 137 FERC ¶ 61,145 (2011) at P 109.

20. In late 2012, following PJM's first experience administering the MOPR unit-specific exemption process, PJM sought Commission approval to create two categorical MOPR exemptions: the competitive entry and self-supply exemptions. Under the competitive entry exemption, a resource would become exempt from the MOPR if it could demonstrate that it was not receiving revenues from a state utility ratepayer-backed non-bypassable charge. Under the self-supply exemption, an entity (public power, municipal or vertically integrated utility) whose business model was based on the principle of maintaining sufficient capacity to meet its expected peak demand was allowed to obtain an exemption from the MOPR for a new resource addition so long as the entity passed certain screening criteria. These screening criteria were designed to establish that the entity was not seeking to exercise buyer-side market power and was maintaining a capacity supply/demand balance consistent with its business model. These two exemptions were approved by the Commission in early 2013, and were used by PJM for several auctions, but were recently rescinded following an appellate court ruling.[17]

21. The competitive entry and self-supply exemptions are currently not in effect, but the economic basis for each of these exemptions is important. Each of these exemptions is grounded in the principle that the MOPR's purpose is to prevent the exercise of buyer-side market power. First, the competitive entry exemption was developed to recognize that there may be new generation capacity resource developers that are bringing supply to PJM's market with no indicia implying that an entity with an incentive to exercise buyer-side market power is subsidizing the developer.[18] In particular, to be eligible for the exemption the capacity resource seller had to demonstrate the following: 1) that no costs associated with the resource's development would be recovered directly or indirectly through a non-bypassable charge paid by retail consumers; 2) no costs are recovered through contracts with a term of a year or longer resulting from non-competitive and discriminatory state-supported or state-sponsored procurement processes; and, 3) the capacity resource seller did not have any formal or informal arrangements to receive material payments, concessions, rebates, or subsidies from a governmental entity.[19] The objective of the

[17] *See PJM Interconnection, LLC*, 161 FERC ¶ 61,252 (2017). In response to a U.S. Court of Appeals order, the Commission ordered PJM to eliminate changes to its MOPR approved in 2013 and revert the MOPR to its 2011 structure.

[18] *PJM Interconnection, LLC*, 161 FERC ¶ 61,090 (2013) at PP 27-31 and 53.

[19] *Id.* However, resource sellers were allowed to receive certain incentives to develop in specific areas (e.g., industrial

competitive entry exemption was to allow resource developers responding to market prices to be exempted from the application of the MOPR when there was clearly no exercise of buyer-side market power associated with the resource's development. These resource developers are independently financing their investments and just seek to maximize the revenues available from PJM's markets. In light of the MOPR's role as a tool to address exercises of buyer-side market power, the Commission's choice to create a competitive entry exemption was based on sound economic reasoning.

22. Sound economic principles also supported a self-supply exemption from the MOPR's focus on preventing the exercise of buyer-side market power. The objective of the self-supply exemption was to provide an entity that generally seeks to maintain a balanced capacity portfolio the opportunity to build new capacity resource(s) to meet expected future demand and not have the new resource(s) be subject to the MOPR.[20] This exemption allowed a self-supply entity the flexibility to participate in the capacity market without facing the risk that a new capacity resource would not clear in the market place, causing the entity to pay for capacity twice. Moreover, by identifying net-short and net-long thresholds that self-supply entities were required to meet in order to be eligible, the self-supply exemption carefully took into account whether the entities would be likely to be seeking to exercise buyer-side market power.

23. Because of the concern that an entity seeking to self-supply capacity may have a strong incentive to bring uneconomic new supply to market in order to lower its capacity acquisition costs, the self-supply exemption was reviewed extensively by PJM stakeholders and the Commission. As part of this review, the Commission posed several questions to PJM to understand the basis for the self-supply exemption and the net-short and net-long thresholds that were established to guide determination of eligibility for the exemption.[21] In response, PJM submitted to the Commission an extensive analysis of PJM's proposed self-supply exemption.[22]

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parks) or within certain counties or localities, and federal production tax credits and investment incentives were excluded.

[20] *Id.* at PP 63-66.

[21] The self-supply exemption parameters are composed of measures of entities' capacity supply/demand balance, which provide a range within which an entity is not too "short" or too "long" capacity. If an entity met these guidelines, it was eligible for an exemption.

[22] *See PJM Interconnection, LLC*, Docket No. ER13-535-00, March 4, 2013 Response of PJM to the Commission's

PJM's analysis of the self-supply exemption focused on the ability of an entity that would be eligible for the self-supply exemption to successfully exercise buyer-side market power if it were assumed to support uneconomic entry in order to reduce its total costs of capacity. PJM's analysis showed that its proposed eligibility criteria protected against the potential exercise of buyer-side market power, and the Commission noted PJM's net-short and net-long thresholds when it initially approved the self-supply exemption.[23]

24. In both instances where the Commission recently approved PJM's requested exemptions to its MOPR, the analysis supporting the exemptions was focused on ensuring that the exemption did not allow an entity to exercise buyer-side market power by allowing uneconomic new capacity resources to escape application of the MOPR. The Commission was able to analyze these proposed exemptions in an economically rigorous and coherent manner because there are well known indicators of circumstances where bidding behavior may reflect the exercise of buyer market power, and plain logic for why a MOPR could be an appropriate and effective tool to apply in such circumstances.

25. In sharp contrast, the Complainants provide no rigorous and coherent economic analysis to support the broader application of the MOPR proposed in the Clean MOPR. The Clean MOPR would significantly expand the application of MOPR beyond the prevention of the exercise of buyer-side market power. The Clean MOPR would apply the MOPR to certain state programs just because offers of participating generators may depart from the offers they would make absent the state programs. But many programs are expected to have this effect, including state and federal programs exempted by the Clean MOPR.[24] The proposed Clean MOPR uses the MOPR to regulate only some of these programs. Complainants have not attempted to provide any reasoned principle to identify what programs, beyond exercises of buyer-side market power, should be regulated by PJM through the application of the MOPR. Nor have Complainants attempted to show that the MOPR, when applied for a broader purpose than remedying buyer-side market power, will be an effective remedy for that broader purpose; that it will not result in over-

February 5, 2013 Information Request.

[23] 143 FERC ¶ 61,090 (2013) at PP 107-109.

[24] *See infra* PP 83-86.

mitigation; and that it will improve social welfare compared with an approach that limits the MOPR to its existing scope.

26. Application of buyer-side market power mitigation in the absence of anticompetitive concerns would thus be a serious policy mistake. In such instances, the MOPR could hamper low bids that are competitive and reflect truly low costs, where costs include offsets or subsidies based on positive environmental externalities that are not otherwise reflected in market operations. Programs that provide compensation for those positive externalities improve social welfare, as I explain elsewhere in this declaration. And while PJM and the Commission could, in theory, undertake a case-by-case inquiry into which state policy initiatives improve efficiency, there are substantial reasons to hesitate before adopting this approach. The administrative costs are likely to be substantial, errors are likely, and the PJM and the Commission will be placed in the position of sitting in judgment on state policies. I therefore urge that the MOPR remain limited to addressing buyer-side market power.

III. THE ECONOMICS OF ENVIRONMENTAL EXTERNALITIES.

27. In justifying the expansion of the MOPR beyond buyer-side market power, Complainants imply that state support programs are a concern because they can cause bids to depart from what they would be in the absence of the state support program. This view, however, ignores the economics of environmental externalities. The generation of electricity causes environmental externalities to different degrees depending on the generation technology and the fuel type. In particular, all electric generation resource technologies that consume fossil fuels in the production of electricity emit pollutants into the environment. The degree to which an electric generation production process emits pollutants depends on the type of fossil fuel consumed (i.e., coal, oil, gas, etc.), the efficiency of the fuel to electricity conversion technology employed by the electric generation unit, and the presence and usage of pollution control equipment. Electric generation resource pollutants impact air, water, and land. As a result, electric generation units have been the subject of extensive federal and state environmental regulation for decades. While fossil fuel generation creates pollution, zero-emission generation resources that displace these polluting generators yield positive externalities by reducing the pollution that would have otherwise occurred.

28. Various federal and state programs directly regulate the impact of electric generation units on air quality. One of the most well-known examples of air pollution regulation is a "cap and trade" air emission control policy. The U.S. Environmental Protection Agency has relied on a federal cap and trade policy to control emissions of sulfur dioxide and nitrogen oxides from electric power generation units for decades. More recently, California and the Northeastern and Eastern Mid-Atlantic States have relied on the same type of regulatory policy for control of carbon dioxide emissions.[25]

29. In the U.S., there is not a uniform federal regulatory policy that controls the costs imposed on society by emissions of carbon dioxide through cap and trade programs. Instead, there are numerous federal and state programs that promote investment in resources with zero carbon dioxide emissions, either with forms of subsidy or with regulatory requirements.[26] Such programs include renewable-resource production and investment tax credits, and a variety of renewable portfolio-standard programs, by just over half the states, that require investment in zero-emission resources.[27]

30. Programs to limit the negative externalities from carbon dioxide emissions are needed to complement otherwise socially inefficient electricity market mechanisms. PJM's capacity and energy wholesale markets are not currently designed to induce suppliers to account for the social externality costs of carbon emissions that result from generation in their decisions. Instead, the Commission has left environmental regulation to other federal agencies and state governments, and these other federal and state programs influence the decisions of participants in the Commission's markets so as to promote environmental goals.[28] As a result, even as PJM's wholesale markets are designed to stimulate and harness competition to yield an efficient allocation of resources, market outcomes would predictably be socially inefficient in the absence of complementary environmental programs adopted by other regulators. PJM's markets would result in the emission of too much carbon dioxide, creating corresponding social externality costs.

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[25] *See* California Air Resources Board, Cap-and-Trade Program, https://www.arb.ca.gov/cc/capandtrade/capandtrade.htm, and Regional Greenhouse Gas Initiative ("RGGI"), RGGI, an Initiative of the Northeast and Mid-Atlantic States of the U.S., https://www.rggi.org/rggi-inc/contact.

[26] *See generally*, NC Clean Energy Technology Center, Database of State Incentives for Renewables & Efficiency, available at: http://www.dsireusa.org/.

[27] *Id.*

[28] Thus, for example, Maryland and Delaware have chosen to participate in RGGI.

Complementary programs, whether implemented at the state or federal level, can align suppliers' market-based decision making with social efficiency by taking environmental externalities into account, without undermining the design and effectiveness of our competitive wholesale markets. Such programs can result in better outcomes for society, without conflicting with the policy goals or operations of competitive wholesale markets.

31. In the following sections I define and provide examples of externalities. I then explain how economists analyze the impact of externalities and identify policies, including taxes and subsidies, that can be adopted to complement markets and correct for the impact of externalities.

A. THE CONCEPT OF EXTERNALITIES.

32. Basic economics defines an externality as the effect of an individual's action on a bystander that is not taken into account by the individual undertaking the action.[29] Common examples of negative externalities are air and water pollution that reduce other individuals' welfare, but the associated costs to others are not accounted for by the individual polluter when deciding whether and how much to pollute.[30] Obversely, positive externalities arise when an individual's activity improves the welfare of others, but the individual does not account for these benefits when deciding whether and how much to engage in the beneficial activity.

33. Stated more formally, externalities exist when the private benefits or costs of actions are not equal to the social benefits or costs. The first formal analysis of the impact of externalities was provided by Arthur C. Pigou, who demonstrated that when marginal social costs or benefits diverge from private marginal costs or benefits, the market outcome is unlikely to be efficient.[31] Pigou showed that a tax or subsidy could be used to internalize the negative or positive externality so that it would be taken into account by market participants and correct for the market inefficiency that would otherwise result.

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[29] *See, e.g.*, Samuelson, P. A. and Nordhaus, W. D., *Economics*, at 751, McGraw-Hill, Inc., 1995.

[30] Environmental externalities are the classic example found in almost every economics textbook. *See, e.g.*, Samuelson, P. A. and Nordhaus, W. D., *Economics*, at 346-355, McGraw-Hill, Inc., 1995 and Pindyck, R. S. and Rubinfeld, D. L., *Microeconomics*, Second Edition, at 639-657, Macmillan Publishing Company, 1992.

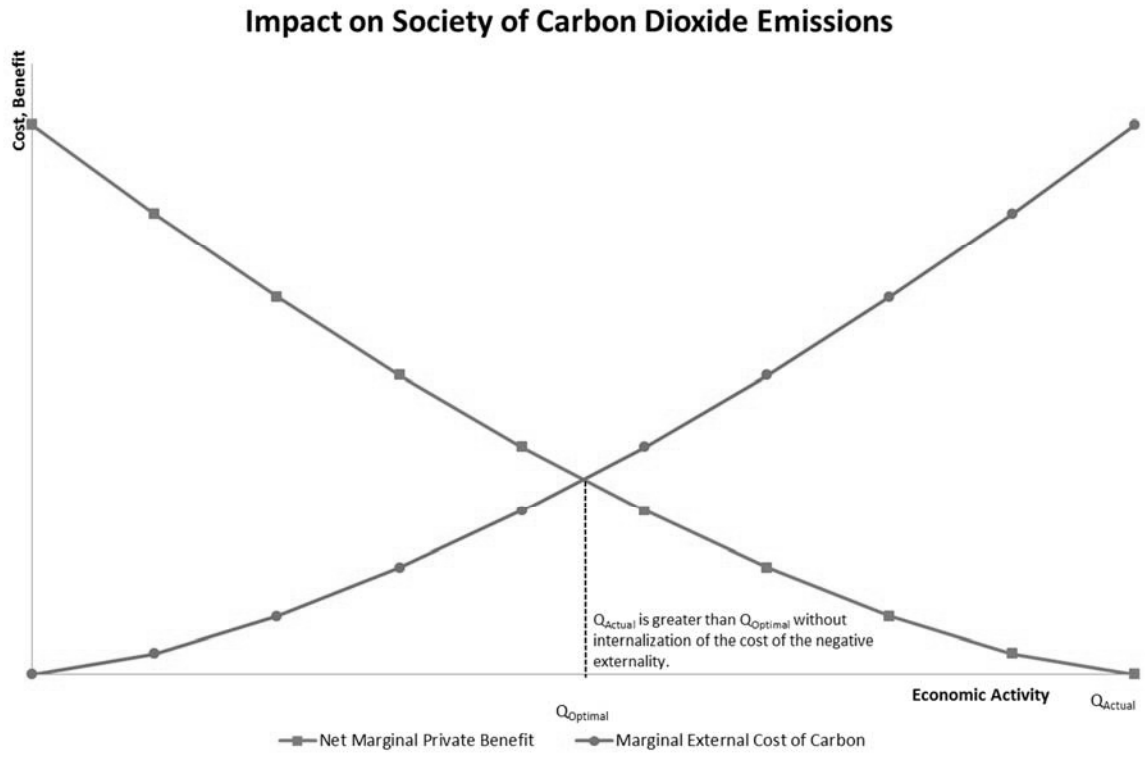
[31] Pigou, A. C. *The Economics of Welfare*, 4th edition, Macmillan and Co., 1932, available at: http://www.econlib.org/library/NPDBooks/Pigou/pgEW.html.

B. CORRECTING FOR THE IMPACT OF EXTERNALITIES.

34. Basic economics teaches that externalities can be corrected either through taxing behavior that results in harmful (negative) externalities, or subsidizing behavior that results in beneficial (positive) externalities, including behavior that prevents negative externalities. When seeking to correct for a negative externality, such as carbon dioxide emissions, an abstract theoretical approach is to measure the marginal external cost associated with the externality and compare it to the marginal private benefits net of marginal private costs (i.e., net marginal private benefits) in order to assess the cost of the externality that is not being captured by private individuals in their decision making. This idea is illustrated conceptually in Figure 1. Marginal external cost rises as economic activity increases, while net marginal private benefits decline. Increases in marginal external cost represent the impact of the damage from the amount of atmospheric carbon dioxide on society, expressed monetarily. Decreases in the net marginal private benefit represent the decline in private profitability as production levels increase and produce higher levels of atmospheric carbon dioxide.[32]

[32] This example assumes markets are competitive, however the conceptual application can apply more generally.

Figure 1



35. As Figure 1 shows, economic activity (production) is assumed to be at an equilibrium without any policy intervention to reflect the externalities where net marginal private benefits equal zero (i.e., marginal cost equals marginal revenue). Here, without market participants internalizing the marginal external cost associated with their activities, the level of actual production (shown as Q_{Actual}) is greater than its optimal level ($Q_{Optimal}$), represented as the intersection of the curves showing marginal external cost associated with the externality and net marginal private benefits. Although the exhibit depicts a stylized framework, there is an ever-increasing body of empirical analysis that estimates a range of values for the social external cost of carbon dioxide emissions over an assumed future trajectory of economic activity.[33] By having

[33] *See, e.g.*, Technical Support Document (2016): Technical Update of Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, August 2016, available at: https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf. Note that the values for the social cost of carbon reported in this technical support document are reported after adjusting for expected inflation in the following document: Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Order

a measure of the social external cost of carbon emissions, it is possible to approximate the marginal external cost of activities that emit carbon dioxide and, through a tax or subsidy, internalize the cost of the negative externality or its abatement.

36. A classical theoretical approach for internalizing the cost of a negative environmental externality, such as carbon dioxide emissions associated with fossil fuel combustion, is the imposition of a Pigouvian tax.[34] The objective of a Pigouvian tax is to internalize the marginal external cost associated with the externality that is otherwise not accounted for in producers' marginal costs. As such, producers experience higher costs due to the tax, charge higher prices, experience less demand, move away from technologies that create relatively more of the harmful externality, and reduce production to reflect the social cost of the externality.

37. A general tax on carbon emissions has not been the policy action of choice in the U.S. for addressing the social cost of carbon, for many complex and practical reasons.[35] For example, if Illinois had sought to impose a tax on electric generation resources that emit carbon dioxide, it would have encountered difficulties designing the tax so as to ensure carbon dioxide reduction. Most prominent among these difficulties would be two types of leakage: 1) Instances where high-emitting in-state resources impacted by the tax shift their facilities out-of-state, and 2) Instances where high-emitting out-of-state resources not impacted by the tax in adjacent geographic regions substitute for taxed in-state generation resources. Experiences to date in California and RGGI make clear the complexity that would be faced by a small geographic region considering the use of a cap and trade policy (which is effectively a tax) to reduce carbon dioxide.[36] The use of a

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Adopting a Clean Energy Standard, Case Nos. 15-E-0302, et al. (Aug. 1, 2016), Appendix E at 11, ("2016 SCC Estimate"), available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b44C5D5B8-14C3-4F32-8399-F5487D6D8FE8%7d.

[34] Baumol, W. J. and Oates, W. E., *The theory of environmental policy*, Second Edition, Chapter 3, Cambridge University Press, 1995.

[35] Although the carbon dioxide cap and trade programs in certain parts of the U.S. do seek to internalize the externality, the resulting cost per ton of carbon emissions under these programs has been lower than the estimated social cost of carbon.

[36] *See, e.g.*, Bushnell, J., Peterman, C., and Wolfram, C., Local Solutions to Global Problems: Climate Change Policies and Regulatory Jurisdiction, *Review of Environmental Economics and Policy*, volume 2, issue 2, summer 2008 at 175-176. Note also when California implemented its carbon emissions cap and trade policy, it struggled with complex issues associated with trying to accommodate what would be considered acceptable resource shuffling. *See* State of California Air Resources Board, California Cap-and-Trade Program, Resolution 12-51, October 18, 2012, Appendix A. Similarly, emissions leakage continues to be an important issue for the RGGI program, with ongoing studies analyzing the impact. *See* Ramseur, J. L., The Regional Greenhouse Gas Initiative: Lessons Learned and Issues for

targeted subsidy—such as the payment of environmental attribute credits—simplifies and ensures that the costs incurred will directly reduce carbon dioxide emissions.

38. In the U.S. there has been a mixture of federal tax incentives and state RPS programs that provide subsidies to zero-emission resources. States generally rely on RPS programs to account, in part, for environmental externalities arising from emissions of carbon dioxide. California is a leading example where a cap and trade program and RPS work in combination to reduce emissions of carbon dioxide and provide a less carbon-intensive footprint for the future. In particular, California has determined that "[m]eeting the state's climate change goals by reducing emissions of greenhouse gases associated with electrical generation" is itself justification for the implementation of an RPS.[37] Moreover, several other states have evaluated the impact of RPS programs on emissions of carbon dioxide and sought to estimate the costs avoided by reduced emissions.[38]

39. Estimates of the social cost of carbon emissions are a theoretically sound basis for incorporating the external cost of carbon emissions into zero-emission resource subsidization policies.[39] Given that the policy purpose of compensating zero-emission attributes is to avoid the harm that would be caused by otherwise higher emissions of carbon dioxide from more carbon-intensive resources, it is appropriate to base the level of the subsidy on the avoided social cost of carbon dioxide emissions (assuming that the subsidy is paid in accordance with output).

C. THE MARKET IMPACT OF CORRECTING FOR EXTERNALITIES.

40. Correcting for externalities—whether via appropriate taxes or subsidies—is likely to affect prices and the mix of resources in the market. However, economic theory teaches that such taxes and subsidies are complementary to the ordinary workings of competitive markets, and help to

Congress, Congressional Research Service, 7-5700, April 27, 2016 at 16.

[37] Cal. Pub. Util. Code § 399.11(b).

[38] *See, e.g.*, Heeter, J., Barbose, G., Bird, L., Weaver, S., Flores-Espino, F., Kuskova-Burns, K. and Wiser, R., 2014, A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards, *National Renewable Energy Laboratory. NREL/TP-6A20-61042(May 2014)* at 52-56, available at: http://www.res4med.org/uploads/studies/1402067633NREL.pdf.

[39] Comprehensive analyses that estimate the social cost of carbon have been completed under the auspices of the U.S. government. *See* Technical Support Document (2016): Technical Update of Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, August 2016. These estimates are based on the results of a number of detailed modeling analyses that evaluate the future costs of carbon emissions on society.

guide private economic supply and demand decisions towards socially efficient outcomes that reflect both the underlying positive and negative externalities, along with the privately experienced costs of production and benefits of consuming the production's outputs. The impacts of Pigouvian taxes or subsidies on the outcomes of competitive markets improve social welfare by internalizing to the private decision-makers the costs of negative externalities through the tax, and the benefits of positive externalities through the subsidy, thus ensuring that the private decision-makers take the externalities into account and adjust accordingly.

41. It is possible to design a subsidy to encourage production from resources whose generation does not impose negative externalities, where, but for the subsidy, generation would result in negative externalities. For example, consider a program that offers subsidies to production that prevents harmful environmental externalities, where the per-unit subsidy is equated to the social external cost of the negative externality that the unit of production prevents. Such a program does not necessarily guarantee the production. But it does efficiently complement market incentives, so that production will be motivated to occur if the market price of production output plus the unit subsidy exceeds the private cost of production. This motivation is socially efficient since the production is socially worthwhile if its value to its purchaser, which is reflected by the price of its output, plus its value from reducing negative externalities, which is reflected by the unit subsidy, together exceed the cost of production. Without the subsidy program, such socially efficient production would be lost if the output price alone failed to cover the cost of production.

42. Complainants characterize the subsidization of zero-emission resources that improve social welfare as "negatively impact[ing] … RPM price signals and caus[ing] the retention of inefficient resources."[40] Complainants, however, make a fundamental error: they assume that PJM's current market design results in an efficient capacity resource mixture in the absence of any state policies aimed at preventing pollution. But PJM's market design does not incorporate the impact of important environmental externalities. Thus, without environmental regulation, PJM's capacity markets will not result in the efficient capacity resource mixture. Rather, the efficiency

[40] Complaint at 12.

of the capacity resource mixture is increased when a well-structured subsidy is put in place to counteract the environmental impact of negative externalities.

43. Complainants cite a "simple example" provided in PJM's April 9, 2018 filing that purports to "illustrate" how state subsidies decrease capacity markets' economic efficiency.[41] But a corrected version of PJM's simplified analysis shows how its results are misleading and inaccurate.

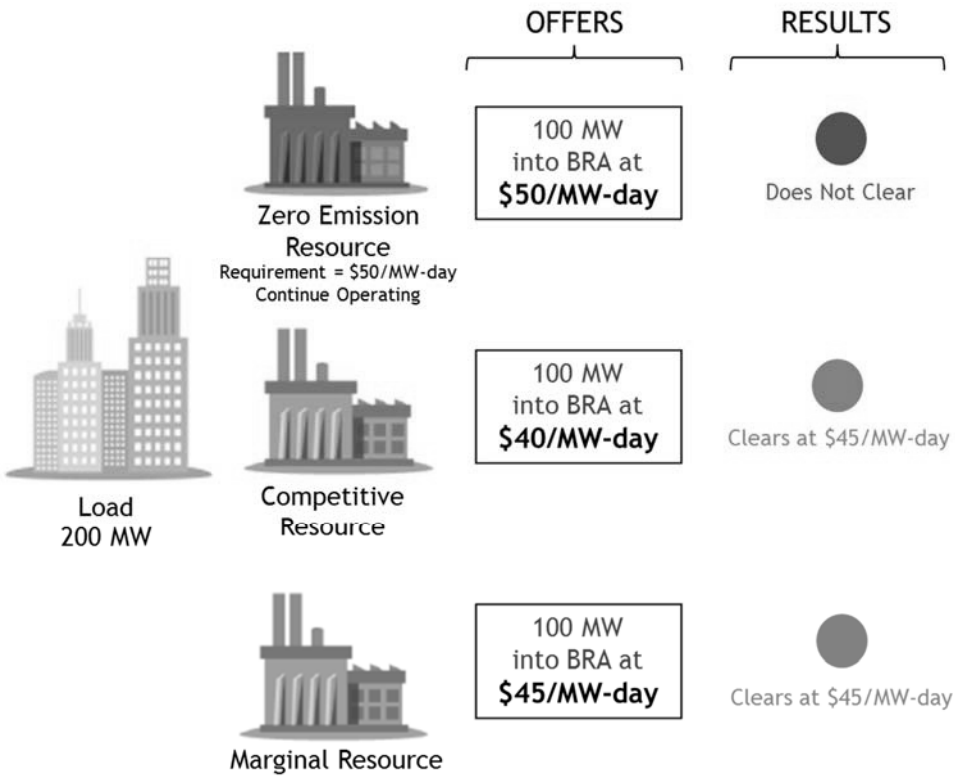
44. Consider Figure 2, which is an illustration similar to that provided by PJM in its April 9 filing. First, Figure 2 slightly changes PJM's illustration to eliminate the misperception that a new generation resource would be likely to place an offer at the margin and would be likely to be displaced by zero-emission subsidization programs. As PJM has noted in numerous results reports for its capacity market auctions, new generation capacity that participates in its capacity auctions solicit competitive entry exemptions and practically all new entry that offers into the capacity auctions clears in the capacity auctions (implying these resources bid to clear).[42] As Mr. Keech notes in his affidavit attached to the PJM Filing, "if a seller anticipates that it will recover its resource costs fully in PJM's energy and ancillary service markets, then it can safely offer into the capacity market at zero price."[43] Figure 2 instead replaces the new entrant with a "marginal resource." The marginal resource represents a conventional generation resource that earns minimal margins from the energy and ancillary services markets, and relies on the capacity market for a significant amount of its net market revenue.

[41] *See* Complaint at 5 & n. 20, 7 & n.28, 16 & n.74.

[42] *See, e.g.*, PJM 2017/2018, 2018/2019, 2019/2020 and 2020/2021 RPM Base Residual Auction Results, at Table 2A, available at: http://www.pjm.com/markets-and-operations/rpm.aspx, under Delivery Years, Base Residual Auction.

[43] Keech Affidavit, Attachment E to the PJM Filing, at P 14.

Figure 2: Without State Intervention

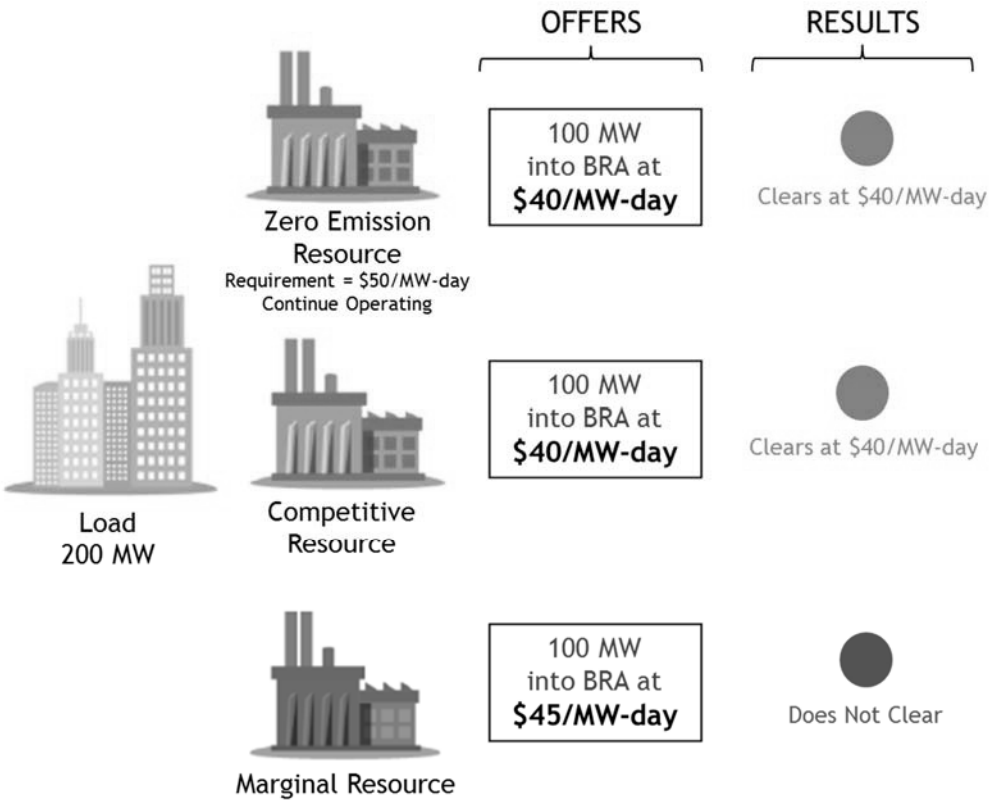


45. Figure 2 parallels PJM's illustration. PJM assumes that the outcome of its capacity market absent state subsidization would be the retirement of a zero-emission resource ("financially challenged resource" in PJM's terminology).[44] As Figure 2 shows, assuming the zero-emission resource does not clear, another conventional resource clears in its place and is the marginal resource. In this example, the marginal resource, however, will be among the highest cost and least efficient capacity resources. Thus, PJM's hypothetical assumes that the efficient market outcome is one where the zero-emission resource with no value attributed to its environmental attributes should not clear in the auction and retire, to be replaced by a conventional resource able to externalize the costs of its pollution on society. This outcome is clearly inefficient as PJM's marketplace does not account for the value of reducing harmful environmental impacts.

[44] PJM's illustration treats a financially challenged resource as generic. However, given PJM's numerous references to the Illinois ZES Program, I have assumed that this illustration is targeting subsidization of zero-emission resources.

46. Figure 3 below illustrates the impact of a subsidy that supports the continued operation of the zero-emission resource.[45] As Figure 3 shows, providing a $10/MW-day subsidy to the zero-emission resource, reflecting the environmental value of its continued operation, allows the zero-emission resource to reduce its bid in the capacity auction from $50/MW-day to $40/MW-day. It now clears the auction, along with the competitive resource, and the market clearing price is $40/MW-day instead of $45/MW-day. The marginal resource does not clear. The state subsidy results in a more efficient mixture of resources clearing in the capacity auction after accounting for the positive externality of the zero-emission resource. The state program complements, rather than defeats, the capacity market's design objective.

Figure 3: With State Intervention (Subsidy)



[45] This example is structured similarly to PJM's and assumes a $10/MW-day subsidy is paid to the zero-emission resource, and that other resource offers do not change as a result of the subsidization.

47. Complainants nevertheless assert that state subsidization "negatively impact[s] … RPM price signals and cause[s] the retention of inefficient resources."[46] This conclusion, however, is based on two faulty premises. First, Complainants argue that the impact of particular state subsidized resources on capacity market prices results in a reduction in prices that is harmful to other market sellers. But all subsidies (and taxes) impact market prices. The fact that there is an impact on prices does not mean that the impact is economically harmful, or disruptive to PJM's competitive market design. As Figure 3 illustrates, PJM's markets are designed to effectively respond to the changes in the underlying costs of resources, regardless of whether resources are subsidized or taxed by state and federal policies. The key economic principle at work is to ensure that resources are allocated efficiently, and that the capacity resource mixture resulting from PJM's marketplace accounts for all costs, including the social cost of environmental externalities.

48. Second, Complainants' assertion that subsidization may discourage new entry, and threaten resiliency, is purely speculative and wholly ignores the underlying design principles of PJM's capacity market.[47] PJM's subsidization illustration was designed in a way that suggests that new conventional generation resources would be discouraged from offering in capacity market auctions if PJM's market design is not changed to respond to increased state reliance on subsidization to support environmentally friendly resources. But this claim ignores the key design principles underlying its capacity market auction: PJM's capacity market sets an explicit reliability requirement and establishes a capacity market demand curve that tracks the administrative estimate of the cost of new entry. It is the existence of this durable market mechanism that provides resource developers the market expectations to support long-term investment decisions.

49. As the Commission has recognized consistently, capacity market designs that incorporate sloped demand curves with price schedules based on the estimated net cost of net entry are a critical capacity market design feature.[48] These capacity market designs consider the total estimated costs of a proxy new entrant (net of expected energy and ancillary services markets margins) and base the capacity price schedule on these estimated costs. To the extent that the continued operation and ongoing development of state-supported resources reduces expected

[46] Complaint at 12.

[47] *Id.* at 13, 16-17.

[48] *See, e.g.*, *PJM Interconnection, LLC.*, 119 FERC ¶ 61,318 (2007) at PP 26 and 99.

energy market revenues relative to these resources not operating, the impact is offset in part by an increase in the capacity market demand curve pricing schedule. Developers of new capacity resources can be expected to understand this key market design feature and incorporate into their projections of future revenues the collective impact of state subsidization programs, including recognizing how capacity revenues will change over time.[49] To the extent that PJM's marketplace requires new capacity resources, the capacity market design ensures capacity price signals that will bring forth new investment when needed.

IV. THE ILLINOIS ZES PROGRAM IS A WELL-STRUCTURED STATE PROGRAM THAT COMPLEMENTS PJM MARKETS AND RESULTS IN MORE EFFICIENT MARKET OUTCOMES, AS IS THE NEW JERSEY ZEC PROGRAM.

50. In the following sections, I examine the structure and implementation of the Illinois ZES Program, explain why it improves market efficiency and is a cost-effective policy for valuing the environmental attributes of zero-emission nuclear generation, and explain why it does not represent an attempt to exercise buyer-side market power. I then evaluate the New Jersey ZEC Program and conclude that my analysis of the Illinois ZES Program applies equally to the New Jersey program.

A. STRUCTURE OF THE ILLINOIS ZERO EMISSIONS STANDARD.

51. The ZES Program is an effort to correct for the harmful environmental negative externalities of fossil fuel generation by providing environmental attribute payments to zero-emission generation that might otherwise retire. As the ZES Program states, "a zero emission standard, [] will increase the State's reliance on zero emission energy through the procurement of zero emission credits from zero emission facilities, in order to achieve the State's environmental objectives and reduce the adverse impact of emitted air pollutants on the health and welfare of the State's citizens."[50]

52. The implementation of the ZES Program requires that the IPA procure on an annual basis for 10 years a quantity of ZECs defined as 16% of the actual amount of electricity delivered by Illinois electric utilities with more than 100,000 customers during calendar year 2014 (20.119

[49] *See* Keech Affidavit at P 14, which discusses capacity seller offer development.

[50] SB 2814 at Section 1.

million MWh).[51] The IPA was charged with developing a procurement plan to select nuclear facilities that will be awarded contracts to supply ZECs up to the 16% volumetric total defined above, and completed the procurement plan on January 25, 2018.[52] Under the procurement process, the selection of winning ZEC suppliers was based on public interest criteria that include: 1) "minimizing carbon dioxide emissions that result from electricity consumed in Illinois," 2) minimizing sulfur dioxide, nitrogen oxide, and particulate matter emissions that adversely affect the citizens of the State," and 3) "the incremental environmental benefits resulting from the procurement, such as any existing environmental benefits that are preserved by the procurements … and would cease to exist if the procurements were not held, including the preservation of zero emission facilities."[53] Exelon's Quad Cities and Clinton plants were selected to receive ZEC contracts.[54]

53. The program is designed to ensure that compensation for the environmental attributes of nuclear facilities that are awarded ZEC contracts does not exceed the estimated cost to society associated with the displaced carbon emissions.[55] In particular, under the ZES Program, the value of the ZEC payments is based upon the social cost of carbon ($/ton of emissions) as reported by the United States Interagency Working Group ("USIWG") in effect at the time of the promulgation of the law. The social cost of carbon is converted from $/ton to $/MWh based upon the emission rates of newer gas-fired generation facilities serving the PJM region.[56] Thus, the social cost of

[51] SB 2814 at (d-5); Zero emission standard and Illinois Commerce Commission, Public Notice of Successful Bidders and Average Prices, Illinois Power Agency, January 2018 Procurement of Zero Emission Credits from Facilities Fueled by Nuclear Power, January 25, 2018. The volume of ZECs also includes those associated with 16% of a small amount of energy being procured by the IPA on behalf of MidAmerican Energy Company customers in Illinois.

[52] Id. The IPA's ZEC Procurement was approved by the Illinois Commerce Commission ("ICC") on September 11, 2017. *See* 2017 WL 4074307 (Ill.C.C.), 339 P.U.R.4th 293.

[53] SB 2814 at (d-5) Zero emission standard (1) (C).

[54] Illinois Commerce Commission, Public Notice of Successful Bidders and Average Prices, Illinois Power Agency, January 2018 Procurement of Zero Emission Credits from Facilities Fueled by Nuclear Power, January 25, 2018.

[55] The value of a ZEC under SB 2814 is initially set at $16.50/MWh until June 1, 2023 (increasing thereafter $1/MWh each year for the final four years of a ZEC contract term).

[56] The initial ZEC value corresponds to a carbon dioxide emission rate of 800 lbs/MWh (.40 tons CO_2/MWh * $41.40/ton CO_2 (from 2016 SCC Estimate for the year 2017) ~ $16.50/MWh). The ZEC value is based on the emission rate of a new gas-fired combined cycle. For example, a new-gas fired combined cycle plant with a heat rate (a measure of efficiency) of 7 MMBTU/MWH would emit 819 lbs CO2/MWH (7 MMBTU/MWH* 117 lbs CO2/MMBTU gas). For carbon dioxide content emissions from natural gas combustion, see U.S. Energy Information Administration, "How much carbon dioxide is produced per kilowatthour when generating electricity with fossil fuels?", available at: https://www.eia.gov/tools/faqs/faq.cfm?id=74&t=11. For heat rate of new gas-fired combined cycle plant, see "Cost

carbon used in the legislation reflects the value associated with the carbon emissions that the nuclear plants avoid by continuing to operate, assuming they would be replaced by state-of-the-art gas-fired generation facilities.

54. The environmental value provided by the nuclear plants' continued operation is in reality significantly higher than the maximum ZEC value. This is so for two reasons. First, if nuclear plants retire, their output is unlikely to be replaced entirely by new gas-fired generation plants. Instead, their output is more likely to be replaced by some new gas-fired generation plants as well as less efficient, higher emitting generation units, including some coal plants. Indeed, the mixture of existing electric generation units in the PJM and MISO geographic region includes numerous coal and less-efficient gas-fired generation units (among nuclear, hydro-electric, oil and other renewable resources as well). As a result, the average carbon dioxide emissions rate associated with the generation fleet in PJM and MISO is higher than the emission rate of a newer gas-fired generation facility.[57] Moreover, the resources that are most likely to replace retiring nuclear generators hour-to-hour (i.e., at the margin) are those that are likely to be even higher emitting, especially so in the PJM region.[58] Second, the social cost of carbon does not account for the value of avoiding the emission of other harmful locally emitted pollutants, such as particulate matter and mercury. Thus, the actual cost to society of nuclear unit retirements in PJM or MISO is significantly higher than the social cost of carbon used in the legislation.

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of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM With June 1, 2018 Online Date," The Brattle Group, May 15, 2014, at 16, available at: http://www.brattle.com/system/publications/pdfs/000/005/010/original/Cost_of_New_Entry_Estimates_for_Combustion_Turbine_and_Combined_Cycle_Plants_in_PJM.pdf.

[57] The initial ZEC value corresponding to a carbon dioxide emission rate of 800 lbs/MWh is approximately 20% lower than the 2015 PJM-wide average carbon dioxide emission rate of 1,014 lbs/MWh. *See* PJM 2012-2015 CO2, SO2 and NOX Emission Rates, March 18, 2016, at 4, available at: http://www.pjm.com/~/media/library/reports-notices/special-reports/20160318-2015-emissions-report.ashx. The MISO region also relies on coal-fired resources to meet a significant amount if its electricity demand. *See* Potomac Economics, MISO 2015 State of the Market Report, Appendix: Prices and Load, at Table A1, June 2016.

[58] PJM reports that its average marginal carbon dioxide emission rate (~1,600 lbs/MWh, 2015) is higher than the average carbon dioxide emission rate such that the value of a ZEC is set at a level considerably less than the expected avoided social cost of carbon in the PJM region throughout the term of the ZEC contracts. *See also* Potomac Economics, MISO 2015 State of the Market Report, Appendix: Prices and Load, at Figure A5, June 2016 (showing that MISO coal generators are part of the resource mixture relied upon to meet hourly demand).

B. THE EFFICIENCY OF THE ILLINOIS ZERO EMISSIONS STANDARD.

55. Even if the Commission considered expanding the MOPR to any state program that might distort wholesale market outcomes, the MOPR properly should not apply to the ZES Program. The ZES Program does not distort wholesale market outcomes but only improves their efficiency. By providing zero-emission generators with compensation for the external benefits they provide, the ZES Program reduces the amount of carbon emissions and improves the social desirability of the market outcome.[59] This is especially the case, where, as with the ZES Program, the design of the procurement process specifically targets the preservation of zero-emission resources that might otherwise exit the marketplace. These nuclear resources' current production significantly reduces negative environmental externalities associated with the generation of electricity, to the extent that this production replaces output by carbon-emitting generators. Since the level of the proposed environmental attribute payments corresponds closely to the social value of reduced carbon dioxide emissions, the total direct costs of those payments are aligned with the benefits realized by society.[60]

56. Moreover, it is not a socially inefficient outcome if compensating nuclear units for their environmental attributes results in lower production from, or retirement of, polluting resources. Aligning private incentives with social welfare, whether through a tax or subsidy, will shift the market's generation resource mix as resources that impose environmental costs on society through their carbon emissions will face reduced production levels and reduced net revenues.

57. Compensating nuclear generators for their zero-emission attributes is a move toward greater efficiency relative to compensating only renewable resources going forward. This is because preserving existing nuclear generation may very well be more socially cost effective than

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[59] *See, e.g.*, Case, K. E., Fair R. C., and Oster, S. M., *Principles of Microeconomics*, Ninth Edition, Prentice Hall, 2009 at 327 (noting that "[a]ctivities that provide such external social benefits may be subsidized at the margin to give decision makers an incentive to consider them").

[60] The value of a ZEC adopted by the ZES of $16.50/MWh until June 1, 2023 (increasing thereafter $1/MWh each year for the final four years of a ZEC contract term) corresponds to a carbon dioxide emission rate of 800 lbs/MWh (.40 tons CO_2/MWh * $41.40/ton CO_2 (from 2016 SCC Estimate for the year 2017) ~ $16.50/MWh). This value is approximately 20% lower than the 2015 PJM-wide average carbon dioxide emission rate of 1,014 lbs/MWh. *See* PJM 2012-2015 CO2, SO2 and NOX Emission Rates, March 18, 2016, at 4, available at: http://www.pjm.com/~/media/library/reports-notices/special-reports/20160318-2015-emissions-report.ashx. Moreover, because PJM's average marginal carbon dioxide emission rate (~1,600 lbs/MWh, 2015) is higher than the average carbon dioxide emission rate, the value of a ZEC is set at a level considerably less than the expected avoided social cost of carbon throughout the term of the ZEC contracts.

allowing its retirement, in view of its positive externalities, and it may be a more efficient method of abating carbon emissions than subsidizing new renewable construction. By offering appropriate subsidies, the ZES complements and supports the workings of competitive wholesale markets so that there will be incentives to preserve existing nuclear generation only if doing so is socially efficient, taking externalities and private production costs into account.

58. Finally, and critically, the ZES Program is entirely consistent with the Commission's policy of reliance on competitive markets. The ZES Program complements the FERC-approved markets by providing compensation for environmental attributes that does not exceed the value of environmental externalities that FERC has left other regulators to address. This Program works in tandem with FERC-approved market mechanisms to produce outcomes that are more socially efficient. If the facilities receiving ZECs are cheaper than fossil-fueled competitors once the value of the environmental externality is taken into account, then the facilities receiving ZEC revenues should run. The ZES represents a narrow, targeted approach to contribute to the objective of complementing FERC's wholesale power markets.

C. ELIGIBILITY CRITERIA FOR THE ZES THAT MAY LIMIT IT TO NUCLEAR UNITS AT RISK OF RETIREMENT ENSURES PROGRAM COST EFFECTIVENESS.

59. The ZES establishes eligibility criteria for facilities seeking to participate in the ZEC procurement process. Among these criteria is the requirement that a candidate zero-emission facility submit to the IPA annual cost projections over the next 6 delivery years.[61] The ZES Program also requires that the IPA take into account in its ZEC procurement process "any existing environmental benefits that are preserved by the procurements […] and would cease to exist if the procurements were not held, including the preservation of zero emission facilities."[62] Thus, the ZEC procurement process includes evaluating and considering the expected operating and ongoing maintenance costs of facilities that participate in the ZES. Targeting the payment for ZECs to facilities that may otherwise be financially challenged and face retirement is a cost-effective policy decision that is in the public interest of the State of Illinois.

[61] SB 2814 at (d-5) Zero emission standard (1)(A).

[62] SB 2814 at (d-5) Zero emission standard (1)(C).

60. The purpose of a subsidy is to incentivize behavior that would not otherwise take place. Here, the goal of the ZES Program, together with other statutory changes directed at the Illinois renewable portfolio standard, is to place a value on zero-emission generation in order to incentivize that generation. The ZES Program provides for a payment for those nuclear generation facilities that can provide ZECs now at the least cost, for a given quantity, recognizing that a failure to provide the subsidy will result in a loss of zero-emission generation that cannot be timely replaced. Moreover, under the cost-effectiveness standard of the ZES Program, the cost of ZECs must compare favorably relative to the costs of additional increments of renewable resources.[63] Finally, as explained above, the cost of the ZECs is limited by the estimated marginal social cost of carbon emissions not otherwise reflected in wholesale power prices already, ensuring that Illinois consumers enjoy positive net benefits from the avoided carbon emissions resulting from the ZES Program. The ZES Program's eligibility criteria and procurement process appropriately focus on minimizing ZEC expenditures and the value of implementing the program beginning in 2017 to reduce the likelihood of nuclear facility closures.

61. Financially viable nuclear plants do not need attribute payments to continue generating, however. Private incentives are already sufficiently aligned with social welfare for these plants that environmental attribute payments are not necessary to ensure that society continues to receive the benefits. Thus, at this time it is in the public interest to target the ZEC payments to the plants that may be otherwise at risk of retirement. The ZES Program appropriately focuses on facilities that may face shut-down that would detrimentally impact Illinois consumers by the loss of their zero-emission attributes.

62. While a single uniform tax on carbon emissions, or a single uniform subsidy for production that displaces carbon emissions, would accomplish the needed internalization of externalities and correction of incentives, and would make advance information unnecessary on whether entities would or would not otherwise behave as they would with the tax or subsidy, such a program is not in the offing, perhaps due to its complexities, distributional impacts, and necessary implementation costs. The theoretical benefits of such a program should not be viewed, in its absence, as a valid argument against more practical programs like ZECs, inasmuch as the latter contribute to environmental benefits without causing inefficient interference with well-functioning

[63] SB 2814 at (d-5) Zero emission standard (1)(C-5).

wholesale markets for electric capacity and energy. The ZES's targeted subsidy design ensures that costs borne by consumers result in a direct reduction of a harmful environmental externality.

63. The ZES Program's reliance on an explicit linkage to the avoided social cost of carbon for setting the price of ZECs compares favorably to other state RPS programs. Few state RPS programs are guided by analysis of the social costs and benefits.[64] Instead, state policymakers tend to focus on the costs of the RPS programs to consumers, and the regional economic benefits that are expected to result from state RPS programs. However, in some instances the costs associated with RPS programs can be considerably greater than estimates of the negative externalities they avoid. For example, under New Jersey's clean energy program, prices for solar renewable energy credits ("SRECs") are reported to consistently exceed $220/MWh in recent years.[65] Resources participating in state RPS programs, of course, have also historically benefited from federal production and investment tax credits that reduce the costs borne by state consumers, but that bear no direct relationship to the avoided costs of emissions. The ZES Program's linkage to an objective estimate of the negative externalities it reduces compares favorably with state RPS programs.

D. THE ZES IS NOT AN EXERCISE OF BUYER-SIDE MARKET POWER.

64. Compensating zero-emission resources for their environmental attributes using a payment structure like the ZES Program does not give rise to the buyer-side market power concerns that justify the application of a MOPR as structured under PJM's current tariff. The ZES is a legitimate environmental program aimed at addressing the externalities of carbon-based power generation, and not an exercise of market power. The ZES clearly explains that "to achieve its environmental goals, Illinois must expand its commitment to zero emission energy generation and value the environmental attributes of zero emission generation that currently falls outside the scope of the existing renewable portfolio standard, including, but not limited to, nuclear power."[66] The

[64] *See* Cavicchi, J., Rethinking Government Subsidies for Renewable Electricity Generation Resources," *The Electricity Journal* 30 (2017) at 2-3.

[65] New Jersey's Clean Energy Program, Solar Activity Reports, SREC Pricing, available at: http://njcleanenergy.com/renewable-energy/project-activity-reports/srec-pricing/srec-pricing. Note that the recent U.S. government's estimated social cost of carbon is approximately $16.50/MWh based on a gas-fired combined cycle's carbon dioxide emission (see notes 57 and 61.).

[66] SB 2814 at Section 1.

Act explains further that the creation of ZECs allows Illinois to "achieve the State's environmental objectives and reduce the adverse impact of emitted air pollutants on the health and welfare of the State's citizens."[67] None of these aims is price suppression.

65. There are a number of objective characteristics of the ZES Program that bear out Illinois' stated purpose and distinguish the program from an exercise of buyer-side market power. First, the cost of a ZEC and its financial benefit to its recipient are based on the social cost of the abated carbon dioxide emissions—which is the value of the externality being addressed—and cannot rise above that amount. The cost of a ZEC may decline over time as power market conditions change (see above), and PJM's generation mix becomes cleaner, but it will not increase based on the financial obligations of the generating units. This ensures that nuclear generators will participate in the program and continue producing electricity only if they believe it will be sufficiently compensatory, and it aligns with economic efficiency, taking into account the social cost of the abated carbon emissions. In contrast, buyer-side market power increases the private incentives to build electricity plants beyond the plants' social value by the suppression of market prices caused by the plants' construction.

66. Second, ZEC payments to the nuclear units do not guarantee that the facilities will remain in operation over the 10-year term of the contracts. If the units receiving ZECs do not remain financially viable due to operational or other issues resulting in unexpected capital investment needs, even after their carbon abatement value is accounted for, market forces will impel the units to retire, which would be the socially efficient outcome under those circumstances. Thus, the ZEC payments do not shelter the units from market forces as would a program that sought to guarantee that they would remain operational in order to suppress prices.

67. Third, the ZES Program does not insulate eligible units from market risk. The generating unit owners still bear the risk of increasing costs and the risk that market prices will fall below levels that prevailed at the time the ZES Program was approved. The program is designed to align the incentives for the decision to continue operation with social efficiency, inclusive of the impact on emissions.

[67] *Id.*

68. Fourth, the ZES does not require any bid into the wholesale energy or capacity market, nor that the unit clear the wholesale capacity market.[68] Thus, if the units fail to clear the capacity market, ZEC payments will still be made, in accordance with actual production, and it is that actual production that has the positive environmental impact of displacing substitute production that creates socially costly emissions. If the ZES Program sought to exercise buyer-side market power, it would clearly condition payment on generation unit participation in the capacity market in order most directly to forestall increases in capacity prices.

69. Finally, there is no exercise of buyer-side market power as the benefits of the ZES Program exceed the costs regardless of any ancillary impact on market prices. The ZES Program's requirement that the procurement of ZECs meets a cost-effectiveness standard ensures that the benefits from the avoided costs of carbon emissions exceed the financial costs of the program.[69] The costs of the ZECs to consumers cannot exceed $16.50/MWh.[70] This ceiling is an under-estimate of the avoided costs of carbon emissions that would result from production that would replace potentially retired nuclear production. It is set conservatively at a level that is approximately 20% lower than that applicable to PJM's recently reported 2015 average system wide emission rate.[71] The value of the ZES to consumers is the benefit it provides through the preservation of zero-emission resources, and the resulting avoidance of carbon-emissions. By

[68] PJM, however, is likely to require participating nuclear units to make energy and capacity bids in its wholesale markets.

[69] SB 2814 at (d-5) Zero emission standard (C).

[70] Note that this initial value is adjusted upward by $1/MWh each year for the last four years of the ZEC contract term. This adjustment does not alter the conclusion that the benefits will exceed the costs throughout the ZEC contract term. In particular, the estimated social cost of carbon increases each year from 2017-2027 resulting in just over a 50% total increase. The increase in the ZEC cap of $4/MWh over the last four years of the contract term is just under 25%, which less than half the increase in the social cost of carbon. Thus, the ZEC cap will be at a level that does not grow as fast as the social cost of carbon. Moreover, because the ZEC cap is based upon a high-efficiency, low-emission modern gas-fired combined cycle generator, PJM's system wide average and marginal emission rates are substantially above the ZEC cap, ensuring that the cost of the ZECs to consumers will be less than the avoided social cost of carbon dioxide emissions (see notes 31 and 58).

[71] As explained above, because the ZEC cap is based on the marginal emission rate of a new gas-fired combined cycle, the PJM system would have to be composed entirely of new gas-fired combined cycles for the ZEC cap to correspond to actual system-wide emissions rates. PJM's currently reported marginal emission rates are considerably higher, as coal fired resources continue to be a large portion of the generation fleet. *See* PJM 2012-2015 CO2, SO2 and NOX Emission Rates, March 18, 2016, at 4, available at: http://www.pjm.com/~/media/library/reports-notices/special-reports/20160318-2015-emissions-report.ashx.

contrast, in a typical exercise of buyer-side market power it is rewarding for an owner to pay for an uneconomic resource only because of the price-suppression benefits that result.

70. In contrast, the previously proposed Maryland and New Jersey new generation-unit subsidization programs resulted in state regulatory agencies directly interfering with prices set in FERC-regulated capacity market auctions. These programs were not attempting to address an environmental externality. However, as I have explained before, a program that subsidizes a generation technology based on its environmental attributes is "just another element of compensation for the benefits that the state feels that generator is bringing to the population through the environmental impact. So it doesn't displace, it influences, but it doesn't displace the market mechanism."[72]

71. In summary, the features of the ZES Program indicate that it is not designed to have any particular impact on market prices and that any potential impacts on prices are incidental to the attainment of the environmental goal of the program. As explained above, a program intended to exercise market power would be structured differently, without its incentives so closely linked to emissions-reducing production. A program focused on exercising market power would place its emphasis on providing long-term plant financial guarantees and would condition payment on bidding and clearing in wholesale power markets.

E. THE NEW JERSEY ZEC PROGRAM ALSO IMPROVES CAPACITY MARKET EFFICIENCY.

72. My conclusion that the Illinois ZES Program improves market efficiency also holds as to the New Jersey ZEC Program. As the legislation states, the New Jersey legislature determined that a program that "recognizes and compensates nuclear energy generators in a manner similar to other non-emitting energy generation resources" would "further the State's interest in environmental protection" and avoid the "substantial increase in emissions of several serious pollutants, and associated adverse public health and environmental impacts" that would result from

[72] Testimony of Robert D. Willig, In the United States District Court for the District of Maryland Northern Division, Case No. MJG-12-1286, March 8th, 2013 at 81.

the "abrupt retirement of … nuclear power plants … that provide electricity to customers in New Jersey."[73]

73. The New Jersey ZEC Program provides for the New Jersey Board of Public Utilities ("Board") to award ZECs to selected nuclear power plants in an amount up to "40 percent of the total number of megawatt-hours of electricity distributed by electric public utilities in the State."[74] The Board selects power plants based on how well the nuclear power plants satisfy the criteria set forth in the statute.[75] Those criteria include, *inter alia*, whether the plant "makes a significant and material contribution to the air quality in the State by minimizing emissions that result from electricity consumed in New Jersey"; whether "if the nuclear power plant were to be retired, that that retirement would significantly and negatively impact New Jersey's ability to comply with State air emissions reduction requirements"; whether the plant's "air quality, and other environmental attributes are at risk of loss because the nuclear power plant is projected to not fully cover its costs and risks, or alternatively is projected to not cover its costs including its risk-adjusted cost of capital"; and that "the nuclear power plant will cease operations within three years unless the nuclear power plant experiences a material financial change."[76] The Board has not yet implemented the statute.

74. The New Jersey ZEC Program is "structured such that its costs are guaranteed to be significantly less than the social cost of carbon emissions avoided by the continued operation of selected nuclear power plants," based on the "social cost of carbon, as calculated by the U.S. Interagency Working Group on the Social Cost of Carbon in its August 2016 Technical Update."[77] In particular, the New Jersey ZEC Program effectively sets the ZEC price at $0.004 per kilowatt hour, which the legislation states "reflects the emissions avoidance benefits associated with the continued operation of selected nuclear power plants."[78] The state of New Jersey Office of Legislative Services reports that the estimated cost of a ZEC is $10/MWh, which is significantly

[73] N.J. Senate Bill No. 2313 § 1(b)(1), (5).

[74] *Id.* § 3(g).

[75] *Id.* § 3(f).

[76] *Id.* § 3(e)(2)-(3).

[77] *Id.* § 2(b)(8).

[78] *Id.* § 3(j)(1).

less than a conservative estimate of the avoided social cost of carbon for PJM of $16.50/MWh.[79] The legislation further states that "to ensure that the ZEC program remains affordable to New Jersey retail distribution customers," the payments may be reduced in later years if the Board "determines that a reduced charge will nonetheless be sufficient to achieve the State's air quality and other environmental objectives by preventing the retirement of the nuclear power plants that meet the eligibility criteria established" under the statute.[80]

75. The New Jersey ZEC Program improves efficiency for the same fundamental reason as the Illinois ZES Program. By providing zero-emission generators with compensation for the environmental benefits they provide by avoiding carbon emissions, the New Jersey ZEC Program improves social welfare. As with the Illinois ZES Program, the New Jersey ZEC Program complements the FERC-approved markets by providing compensation for environmental attributes that does not exceed the value of environmental externalities that FERC has left other regulators to address.

76. As with the Illinois ZES Program, the provisions in the New Jersey ZEC Program that take into account a plant's financial viability are in the public interest. As explained above, financially viable nuclear plants do not need attribute payments to continue generating because private incentives are already sufficiently aligned with social welfare for these plants that environmental attribute payments are not necessary to ensure that society continues to receive the benefits. Thus, it is a cost-effective policy to target the ZEC payments to the plants that may be otherwise at risk of retirement. Likewise, for similar reasons, it is cost-effective and in the public interest for the New Jersey ZEC Program to allow the Board to reduce the effective ZEC price if it reduces retail customers' costs while not threatening the continued delivery of the nuclear plants' environmental benefits.

77. Finally, the reasons that the Illinois ZES Program is not an exercise of buyer-side market power also apply to the New Jersey ZEC Program: First, the Program caps payments at less than the social cost of the abated carbon dioxide emissions. Second, the Program does not guarantee that the facilities will remain in operation; rather, the facilities may retire if their costs

[79] See Legislative Fiscal Estimate, Senate No. 2313, State of New Jersey, 218th Legislature, April 5, 2018 and notes 57 and 61.

[80] *Id.* § 3(j)(3)(a).

are unexpectedly high, or if the facilities' carbon abatement value does not justify their retention. Third, the Program does not insulate units from market risk; rather, the generating unit owners still bear the risk of increasing costs and the risk that market prices will fall below levels that prevailed at the time the Program was approved. Fourth, the Program does not require any bid into the wholesale energy or capacity market, nor that the unit clear the wholesale capacity market. Fifth, there is no exercise of buyer-side market power as the benefits of the Program exceed the costs regardless of any ancillary impact on market prices. That is because, as I explain above, the New Jersey ZEC Program ensures that the program's benefits—from the avoided costs of carbon emissions—exceed the program's financial costs by setting a ZEC rate that is considerably lower than a conservative estimate of the avoided cost of carbon. In contrast, in a typical exercise of buyer-side market power, it is rewarding for an owner to pay for an uneconomic resource only because of the price-suppression benefits that result.

V. THE CLEAN MOPR PROPOSAL IS NOT GROUNDED IN SOUND ECONOMIC REASONING

78. The Clean MOPR is unjustified when considered in a sound economic framework because it would in effect prevent efficient state-supported resources from clearing the capacity auction. As a result, the resources selected by the auction would not be the most efficient set of resources. Additionally, the Clean MOPR would result in the over-procurement of capacity resources, as customers would be providing funds both to the state-supported resources and to redundant capacity procured through the auction.

A. THE CLEAN MOPR LEADS TO AN INEFFICIENT SELECTION OF CAPACITY RESOURCES

79. Complainants' Clean MOPR, by applying a MOPR to certain state-supported resources, would prevent them from clearing in the capacity market auctions (absent receipt of a unit specific exception). As a result, the resource set that clears in the capacity market auctions would exclude resources that are economically efficient after accounting for externalities, and it would constitute an inefficient mixture of resources. In particular, applying the MOPR to these state-supported resources restricts their offers to their private costs of providing capacity, which excludes the significant positive social benefits from the reduction in social costs that result from these resources' production. When the social cost of carbon emissions is not internalized in capacity market offers, it appears that financially challenged nuclear units are not efficiently

competitive. In fact, these units are economically efficient, and their continued presence in the market should be viewed as pro-competitive.

B. The Clean MOPR Will Perpetuate Excess Capacity Supply

80. The Clean MOPR's likely effect is to increase capacity prices closer to the level that would result from the absence of state-supported capacity, and potentially to penalize states that wish to promote welfare-enhancing environmental policies by preventing resources receiving efficiently designed subsidies from reflecting those subsidies as credits in the calculation of their MOPR offer floor prices. If these subsidized resources do not clear in the capacity auctions as a result of the Clean MOPR mitigation, states may be faced with the choice of tolerating inefficient and costly excess capacity supply, or else abandoning their subsidization program, which could result in an inefficient capacity resource mixture.

81. When states have enacted policies offering financial support to environmentally beneficial capacity resources, they are unlikely to cease these policies even if the resources are ineligible for an exemption from the MOPR and even if the resources do not receive capacity market revenues.[81] As Dr. Giacomoni of PJM notes in the affidavit provided with PJM's April 9, 2018 filing and attached to the Complaint, state policies favoring environmentally beneficial resources are driven by legislation that calls for financial support for the development of specific resource types, and steady year-to-year growth in zero-emission resource capacity.[82] States thus can be expected to continue to support environmentally beneficial generation. But because this capacity may not clear the capacity market, the market may select additional duplicative resources. Inasmuch as PJM's capacity mixture includes environmentally friendly capacity that does not clear in capacity auctions due to the Clean MOPR, consumers will incur excess costs above the efficient level.[83]

82. Excess capacity supply can also be expected to put downward pressure on electric energy prices, all other things being equal. Some capacity resources that clear in the auctions as a result of the application of the Clean MOPR to environmentally friendly resources may exceed the

[81] Many renewable resources provide relatively little dependable capacity due to their intermittency.

[82] Giacomoni Affidavit, Attachment F to the PJM Filing, at 2-10.

[83] The impact on efficiency of the RPS policies will be dependent upon whether they are designed to increase social welfare.

amount otherwise necessary to meet PJM's reliability requirements. Inasmuch as these resources have low enough short-run marginal costs to operate frequently during a year, they will push other more expensive resources up the supply curve, resulting in lower electric energy prices and lower market revenues for other capacity suppliers.

C. The Clean MOPR's Exemptions Are Not Based on Sound Economic Analysis

83. While the Clean MOPR proposal eliminates the enumerated categorical exemptions under MOPR-Ex, in effect it exempts certain categories of state and federal programs by excluding them from the definition of "Material Subsidy." In particular, the Clean MOPR excludes certain state and local subsidies designed to promote "general industrial development in an area," or to incentivize "siting facilities in [one] county or locality rather than another county or locality."[84] The Clean MOPR also excludes "federal subsidies or other support granted [before] the date of th[e] Complaint."[85]

84. An appropriate economic evaluation of the proposed Clean MOPR's exemptions would determine if they maintain or improve capacity market efficiency. Complainants, however, do not provide a principled economic analysis that attempts to demonstrate that the proposed exemptions promote more efficient capacity market outcomes. To the contrary, the proposed exemptions draw discriminatory lines that are not supported by sound economic reasoning.

85. The Commission has previously determined that state and local subsidies that "a project might receive from a town or county to locate in that vicinity" or whose stated purpose is to provide "incentives for general industrial development," would not trigger application of the MOPR.[86] The Commission did so, however, because it determined that the "MOPR's purpose is to protect the market from the exercise of buyer-side market power," and in this context, the Commission agreed with PJM that these types of subsidies "do not raise price suppression concerns" associated with buyer-side market power.[87] But here, the stated purpose of Complainants' Clean MOPR is

[84] Complaint at 18; *see* PJM Filing at 70.

[85] Complaint at 19.

[86] *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 66 n.47 (2013).

[87] *Id.* at P 56, 66 n.47.

to offset the effects of any "below-cost offers for resources receiving out-of-market subsidies," not only to avoid exercises of buyer-side market power.[88] Thus, the Clean MOPR would substantially expand the application of the current MOPR, and exemptions that at one time were acceptable in the context of guarding against buyer-side market power must be re-evaluated.

86. By proposing to exempt resources that receive certain subsidies (defined as material), while not exempting resources that receive other types of subsidies, Complainants may be implying that certain subsidies are perceived as less likely to suppress capacity prices. However, any capacity resource that receives certain federal, state, and local subsidies may be caused to make lower-cost offers that may affect auction results. Complainants present no evidence that the federal, state, and local subsidies exempted from mitigation under the Clean MOPR will not result in the submission of lower-cost offers, or that these lower-cost offers will not affect auction results. Any type of financial subsidy might affect PJM's energy and capacity market auction results, and the Clean MOPR's proposed differential treatment of capacity resources based on the source of the subsidy can result in discrimination.

87. Moreover, expanding the use of the MOPR in the absence of any sound economic analysis and reasoning upon which to base a determination of its applicability will discriminate against and mitigate capacity resources whose operation improves social welfare (e.g., nuclear units receiving ZECs). The Clean MOPR proposal will result in the mitigation of capacity resources with no consideration of whether those resources' current or future operation enhances economic efficiency. Any expansion of the use of the MOPR should exempt capacity resources whose subsidization enhances social welfare by reflecting environmental benefits not captured in PJM's electricity markets, and any such expansion should not exempt subsidies when there is no reason to believe that those subsidies improve overall social welfare.

88. While an exemption from the MOPR is justified and necessary if a subsidy program to reduce pollution improves economic efficiency, Complainants provide no evidence that the programs proposed to be exempted from the Clean MOPR are likely to improve economic efficiency. In particular, programs whose stated purpose is to promote general industrial

[88] Complaint at 1. While Complainants use the term "below-cost" to imply that actual resource costs upon which offers are based should be higher, I assume that the impact of an appropriate subsidy would be to lower a resource's actual costs resulting in a lower cost offer.

development in a particular area, or to locate facilities in one locality rather than another, cannot validly be presumed to improve overall welfare. There is no reason to believe that such programs generally improve overall welfare, and to the extent a particular program ends up improving overall welfare, it is likely to do so only for reasons well beyond the conditions that the Clean MOPR stipulates for the exemption. In contrast, the environmental benefits of programs to support renewable or zero emissions nuclear generation, where the subsidy costs are less than the harms of the avoided pollution, contribute to social welfare directly and by design. Thus, if the MOPR were to be expanded as proposed, it would create incentives to provide inefficient financial support to resources based upon criteria unrelated to improving market efficiency and exclude, with discriminatory impact, programs that improve market efficiency.

89. The Clean MOPR's exemption for existing federal subsidies is discriminatory for an additional reason. While an exemption for existing subsidies might arguably be justified as respecting the expectations of resource owners that have incurred sunk costs, the Clean MOPR does not provide a similar exemption for existing non-federal subsidies. Complainants do not attempt to justify why those expectations should be respected only where the subsidy is from the federal government, rather than a state.

90. This completes my declaration.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

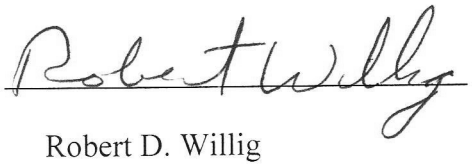
CPV Power Holdings, L.P., Calpine Corporation and Eastern Generation, LLC,	)	
Complainants,	)	**Docket No. EL18-169-000**
v.	)	
PJM Interconnection, L.L.C.	)	
Respondent.	)	

DECLARATION OF ROBERT D. WILLIG

I, Robert D. Willig, declare under penalty of perjury that the foregoing is true and correct.

Executed: June 20, 2018

New York City, New York



Robert D. Willig

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.	)))))	Docket No. AD17-11-000

POST-TECHNICAL CONFERENCE COMMENTS OF THE PSEG COMPANIES

Pursuant to Rule 212 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission" or "FERC"), 18 C.F.R. § 385.212 and the Commission's May 23, 2017 "Notice Inviting Post-Technical Conference Comments" the PSEG Companies[1] hereby submit the following comments.

I. EXECUTVE SUMMARY

The PSEG Companies have a broad perspective on the evolution of the competitive markets administered by Regional Transmission Organizations ("RTO") and Independent System Operators ("ISO") in the northeast and how those markets have been impacted by the policy goals of the states in those regions. We have operated in these markets since their inception in the 1990's and were among the original handful of vertically integrated utility companies in PJM Interconnection, L.L.C.'s ("PJM") market to champion the restructuring of the generation side of the industry toward competition. The PSEG Companies have steadfastly supported the markets to date because of the benefits that competition has brought in lowering prices, increasing innovation and protecting ratepayers. More efficient dispatch of the generating fleet has created billions in saving for consumers. In addition, markets forces have driven

[1] The "PSEG Companies" consist of PSEG Power LLC ("PSEG Power"), PSEG Energy Resources & Trade LLC and Public Service Electric and Gas Company.

SI-SSA-0010-0994

investment in new more efficient generating resources and the retirement of older less efficient generating plants. The PSEG Companies have been on both sides of this equation: we have built and are now building new generation in PJM, ISO New England Inc. ("ISO-NE") and the New York Independent System Operator, Inc. ("NYISO") markets and have retired units in all three ISOs as well.

The singular focus of the markets in driving efficiency gains is consistent with their original purposes. But this limited scope is no longer sufficient as we grapple with the need to achieve other policy goals associated with the electric grid while maintaining the beneficial aspects of competition. The markets must adapt quickly to accommodate state actions designed to advance widely-accepted public policy goals such as reduction of environmental emissions and resiliency. Failure to do so will lead to less efficient solutions, other unintended consequences and an overall weaker electric grid. The longer term objective is to modify market structures to achieve these goals and other widely supported policy directives in the most efficient manner possible. But the PSEG Companies are concerned that these needed design changes cannot be accomplished quickly enough to avoid the permanent loss of critical infrastructure, including nuclear resources. Therefore, for the immediate future, it is essential that FERC not interfere with state actions designed to retain this critical infrastructure. Empowering states to pursue goals related to environmental improvements and resiliency presents an immediate solution that sustains the existing benefits markets have achieved, while also allowing for the development over time of appropriate market solutions.

The technical conference clearly revealed the urgency with which FERC must act to find a means to bridge the gap between the increasing number of state actions to preserve or develop specific resources within their jurisdictions and the current market structures which are not

valuing the desirable attributes of those resources. The need to preserve the currently existing nuclear fleet is an important objective and the efforts to achieve this objective must be launched immediately. State action is the only viable approach that can be implemented in the short-term. Most fundamentally, the Commission should not thwart state efforts to advance goals associated with carbon abatement and resiliency.

In addition, FERC has initiated several reforms that attempt to improve overall price formation. The current delays in implementing these reforms fall most heavily on nuclear base load generators that derive most of their revenues from energy markets. The Commission has made substantial strides in addressing these shortcomings but current actions should be accelerated and additional improvements should be pursued. Energy market pricing reforms to better reflect the cost of operating the marginal units – such as the reforms recently proposed by PJM – will not provide a complete solution to the immediate problems facing the Commission, but they can be a significant part of the solution.

The PSEG Companies' comments attempt to offer a roadmap to the Commission for approaching this issue in stages so that urgent issues can be addressed in the near-term through an approach that facilitates state action along with improvements in energy market pricing. The Commission should direct the RTOs/ISOs to lay the groundwork for developing solutions that achieve widely recognized state public policy goals through market designs. The initial steps, which should begin immediately, should be a requirement that the ISOs/RTOs consider the value of achieving these policy goals, and on-going efforts to improve energy market price formation reforms should be accelerated. While we do not believe that these initiatives will provide a complete solution, they could make a significant contribution.

II. COMMENTS

a. The Wholesale Markets Were Not Designed to Recognize and Procure Desirable Attributes that Advance the Public Policy Goals of States

The organized markets for energy, capacity and ancillary services were developed to improve efficiency in the production costs of electricity while maintaining the reliability of the system. This effort has been extremely successful. For example, based on an examination of hourly supply and demand patterns on the U.S. electrical grid, research for the National Bureau of Economic Research, recently estimated that competitive electric supply reduced aggregate electricity generation costs by $3 billion a year.[2] Competitive markets, moreover, serve to insulate consumers from the risks associated with generator obsolescence and changing market conditions affecting generator profitability. Most of the generation located in PJM and the other eastern organized markets is owned by independent generators. If those generators are retired or fail to operate profitably, any unrecovered costs are borne by investors, not ratepayers. The elimination of this "stranded cost" risk to consumers provides tremendous value.

It has become clear, however, that existing market designs are not doing enough. Desirable attributes of generators such as favorable environmental characteristics and fuel diversity are not being valued in the market. Unless steps are taken immediately, generators with these desirable characteristics will be permanently lost. The risk of losing nuclear generation is a point of particular concern. Consumers suffer because the cost of achieving state environmental goals will be increased exponentially if nuclear zero-carbon resources are not part of the resource mix. Also, if the fuel diversity of the system degrades through the loss of nuclear plants,

[2] *See* "Imperfect Markets versus Imperfect Regulation in U.S. Electricity Generation." Steve Cicala, (NBER Working Paper No. 23053),Summary available in April 2017 NBER Digest ("He finds that markets encouraged both increased trade across areas, and reduced usage of higher cost units. The 20 percent improvement in each of these metrics reduced production costs by about $3 billion per year."), available at: http://www.nber.org/digest/apr17/w23053.shtml.

consumers will be exposed to a greater risk of low probability, high impact events resulting in fuel delivery disruptions.

b. The Commission Should Address the Emergent Issues It Faces Related to the Preservation of Particular Technologies Needed to Address Carbon Abatement and Fuel Diversity Goals; The Commission Need Not Address Every Potential Issue Related to State Public Policy Initiatives At this Time

FERC should take immediate steps to address the emergent issues it faces with existing market designs failing to value important generator attributes, namely, the achievement of environmental goals and ensuring energy resiliency. "An agency enjoys broad discretion in determining how best to handle related yet discrete, issues in terms of procedures, and priorities." *Mobil Oil Exploration & Producing Southeast Inc. v. United Dist. Co.*, 498 U.S. 211, 230 (1991) (citations omitted). The Commission should not feel compelled at this time to develop an all-encompassing intellectual framework to justify steps for determining which public policy goals are appropriate to pursue. "[A]n agency need not solve every problem before it in the same proceeding. This applies even where the initial solution to one problem has adverse consequences for another area that the agency was addressing." *Id.* at 231 (citations omitted). The Commission should direct its efforts towards what needs to be done now; other matters should be addressed in time.

Two areas now before the Commission – environmental goals and fuel diversity – have clearly emerged as providing a legitimate basis for the Commission to take steps to foster their achievement. For example, in PJM and the other eastern markets, the vast majority of states have adopted renewable standards. The fact that not every state has adopted standards and that standards vary among states should not deter the Commission from acknowledging the need to address this goal in a broad sense. Indeed, the Commission has already done so. In *ISO New England et. al.*, 147 FERC ¶ 61,173, P 1 (2014), the Commission approved an exemption to the

buyer-side mitigation rules to "permit[] market participants to satisfy their renewable portfolio standards without imposing additional costs on consumers." As the Commission further explained in that order, it was acting "to complement[] state programs promoting renewable resources." *Id.*, P 82. The Commission thus can (and should) determine on this basis that market designs should be adopted that include measures to achieve – or at least not thwart the achievement by states – of environmental enhancements. Although accommodating, this policy fails to ensure a competitive price is achieved. An improved structure would utilize these resources to satisfy the capacity obligation and adopt a price based on an appropriate reference level. The appropriate reference level should reflect the actual cost of that resource adjusted for the economic value ascribed to the attributes that it provides to achieve certain policy objectives.

Similarly, the value of fuel diversity and resiliency is being recognized at the state level as important attributes of the electric grid. For example, Commissioner Richard Mroz, speaking as President of the New Jersey Board of Public Utilities, framed this issue as "whether we can maintain orderly markets to ensure the [existing] diverse portfolio of energy markets across the PJM [and] whether we are valuing them appropriately."[3] With respect to nuclear units, specifically, he noted that "they are valuable, they continue to help to provide for the long-term a diverse energy mix."[4] Further, in terms of which resource attributes not currently being valued, should be valued, he stated that "First is fuel diversity."[5] Or, as stated by Robert Klee, Commissioner of Connecticut's Department of Energy and Environmental Protection, "I am actually a fan of the role that states can play in bringing diversity of resources and reliability of

[3] State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C., Technical Conference Transcript, May 1, 2017, p. 210 (Docket No. AD17-11-000) ("Technical Conference Transcript").

[4] *Id.,* p. 209.

[5] *Id.*, p. 231.

resource into play when the market isn't delivering them.[6] Susan Tierney, senior advisor at the Analysis Group, summarized the role of states at the technical conference with respect to resiliency issues stating: "So states, indeed are working a lot on resiliency issues, because of this problem of assuring that people don't die and are not harmed during [certain events]. So I do think that there is going to be increasing attention [on resiliency] because [of] cyber – because of extreme weather events."[7]

FERC is uniquely positioned to take a leadership role in these areas. Because it oversees organized markets that serve some of the most populous areas of the country, it has the ability to foster the achievement of these goals in a way that can benefit millions of people. Conversely, if FERC fails to take hold of the reins, the adverse consequences to the country could be dire. If nuclear units retire prematurely, the cost of meeting environmental goals that affect the health and welfare of citizens and the financial viability of businesses would be increased substantially imposing unnecessary economic hardships. A potentially even more devastating consequence would be the failure to achieve the desired environmental enhancements at all with the resultant adverse impacts on the health of individuals.

Failure to preserve the fuel diversity which currently is inherent in the generation mix of many markets – PJM in particular – could also have very deleterious impacts on consumers. Fuel diversity enhances the robustness of the electric grid against potential loss-of-load events – even "Black Swan" events that cannot be foreseen by limiting the impact of common mode failures. These types of events, while rare, can be extremely costly when they do occur. For example, the loss of electric power associated with Superstorm Sandy had a devastating impact

[6] *Id.*, p. 28.

[7] Technical Conference Transcript, May 2, 2017, pp. 517-518.

on the region resulting in a tremendous loss of productivity and wages as well as the spoilage of millions of dollars in perishable goods. Further, retaining fuel diversity within the generation portfolio also provides protections against price volatility. If a system has several types of generators, it will be less susceptible to price spikes associated with any single type of fuel.[8]

c. For the Present, the Commission Should Avoid Taking Steps to Interfere with State Initiatives Related to the Achievement of Environmental Goals and Fuel Diversity or Seek to Accommodate Those Goals; The Adoption of Procedures to Achieve Such Goals should be a Future Effort

Notwithstanding the vital importance of the matters at issue, it is apparent that the Commission on its own cannot act in a sufficiently timely manner to prevent irreversible harm from befalling energy and capacity markets associated with potential generator retirements. Nuclear plants throughout the eastern markets are facing severe financial challenges. Nuclear units throughout the country have retired or have announced retirements. State legislatures in Illinois and New York have adopted measures to assure the continued operation of at risk nuclear plants in recognition of their desirable attributes not currently valued in the markets. Measures to preserve nuclear generation in New Jersey, Pennsylvania, Ohio and Connecticut are under discussion. The PSEG Companies, moreover, are experiencing the challenges facing nuclear generation first hand. A subsidiary of PSEG Power, PSEG Nuclear LLC ("PSEG Nuclear"), is the operator of two nuclear plants, the co-owned Salem plant and the wholly owned Hope Creek plant located in southern New Jersey. As PSEG Nuclear has stated publicly, it will not keep the

[8] *See* "The Value of US Power Supply Diversity" Makovitch, Marks and Martin, July 2014, "Employing the diverse mix of fuels and technologies available today produces lower and less volatile power prices compared to a less diverse case with no meaningful contributions from coal and nuclear power and a smaller contribution from hydroelectric power," available at: http://www.energyxxi.org/sites/default/files/USPowerSupplyDiversityStudy.pdf.

units in-service if the plants are not economically viable – an event that it has indicated could occur within the next three years.[9]

FERC's immediate imperative, accordingly, should be to avoid thwarting the efforts of the states to address carbon abatement and fuel diversity by supporting nuclear generation or other types of generation associated with achieving these goals. In the parlance of the technical conference, FERC should either "affirmatively decide" not to mitigate resources receiving support payments ("path 1") or take steps to "accommodate" these state goals ("path 2"). Adopting path 1 would allow nuclear units receiving support payments to participate in energy and capacity markets as they do now. This approach would satisfy the basic goal of not creating obstacles that would interfere with the efforts of the states to achieve these important objectives.

An "accommodative" approach, however, would be a better option provided that it is designed correctly. The PSEG Companies believe that, in this context, a mechanism to accommodate state actions designed to preserve nuclear generation in order to achieve state environmental or resiliency goals should have three elements:

(1) allow the resources receiving support payments to receive capacity obligations on payments at the same level as other resources ensuring customers do not "overpay" for policy objectives;

(2) do not commit more resources than those needed to meet demand; and

(3) the establishment of a "competitive" price for capacity.

Each of these elements is critical. First, if resources receiving state support payments do not also receive capacity market payments, the burdens placed on the state to achieve their goals may be

[9] "N.J. Nuclear Plants Could Go Dark Without Subsidies, PSEG Warns," available at: http://www.nj.com/news/index.ssf/2017/03/nuclear_plants_could_do_dark_without_subsidies_pse.html.

magnified significantly. Second, unless the mechanism includes a means to assure that resources will not be over-procured, prices in both capacity and energy markets will be depressed below competitive levels thus exacerbating the problem that the market design reform is intended to correct. Third, it is important that committed resources lacking the attributes that make them eligible for support payments receive competitive payments in order to adequately support their operation and send proper pricing signals for entry and exit from the market.

An "accommodative" approach that would appear to have these characteristics, for example, would be a bifurcated capacity market design – along the lines of one of PJM's proposals – that would provide capacity commitments and payments to resources that receive support payments. Under this proposal, nuclear plants receiving state support payments to achieve their goals would qualify as capacity resources in the first "commitment" auction. Although nuclear units (and any other generators receiving support payments) committed in the first auction would be mitigated in the second "pricing" auction, they would still receive the competitive price realized in that auction regardless of whether they clear. Further, PJM would avoid over-procurement by not assigning a capacity commitment to resources that cleared only in the pricing auction. We believe this type of mechanism could be workable. Fundamentally, FERC should not take actions that would make it more difficult for the states to achieve policy goals designed to promote environmental improvements and resiliency.

Over the longer-term, the Commission should seek to implement an "achieves" approach to fostering carbon abatement and fuel diversity though the market design. This would provide a more efficient way of addressing these issues but will likely require years of work to implement. This could include measures such as carbon pricing in energy markets and enhanced ISO/RTO payments made directly to generating plants needed to meet fuel diversity standards adopted for

the region. While this is a longer term goal, the Commission should begin building the foundation for this work immediately. Specifically, ISOs/RTOs should be directed to study the impacts of these types of reforms and to begin discussions in their stakeholder processes for their implementation over the next few years. Periodic reports to FERC regarding the progress being achieved should also be required.

Further, the Commission clearly has the jurisdiction to accomplish this. State public policy goals are a reality. FERC need not (and should not) ignore the existence of state programs and the adverse impacts on electricity markets that their piecemeal implementation would have. Rather, the Federal Power Act ("FPA") clearly arms FERC with the necessary authority to implement tariff reforms that can incorporate public policy goals into the markets when to do so improves overall efficiency.

Under the FPA, the Commission is held to a standard of setting rates that are "just and reasonable" and has authority over practices that "affect" wholesale rates. As shown in the recent decision in *EPSA v. FERC*, the Commission does *not* impermissibly intrude on state jurisdiction when it regulates activities initiated by the states which are reasonably designed "to enhance the wholesale, not the retail, electric market."[10] Here, failing to incorporate widely supported public policy goals into markets over which FERC has jurisdiction, will lead to market outcomes that are inconsistent with core goals of the FPA such as "encourag[ing] the orderly development of plentiful supplies of electricity . . . at reasonable prices"[11] and in "maintaining competition to the maximum extent possible consistent with public interest."[12] FERC should

[10] *EPSA v. FERC*, 136 S. Ct. 760, 779 (2016).

[11] *Nat'l Ass'n for Advancement of Colored People v. Acusport Corp.*, 425 U.S. 458, 671 (1980).

[12] *Otter Tail Power Co. v. U.S.*, 410 U.S. 366, 374 (1973).

thus be vested to have the authority to place tariffs into effect designed to effectuate public policy goals when doing so "break[s] down regulatory and economic barriers that hinder a free market in wholesale electricity."[13]

d. Efforts to Get the Prices Right in the Energy Markets Should Continue on a Parallel Track to the Efforts to Preserve the Existing Nuclear Fleet

The PSEG Companies applaud the leadership role that the Commission and its staff have taken over the last several years to push the RTOs and ISOs to address the inefficiencies in the wholesale energy markets that have been exposed by declining wholesale energy prices. In response to the Commission's initiative, we analyzed the different market designs of the three eastern RTOs in which we operate and were able to identify "best practices" that we believe should be implemented across the three regions. Notably, in March of 2015, the PSEG Companies submitted comments to the Commission describing some of the "best practices" that we observed from NYISO that could be implemented in the other RTOs.[14] The Commission subsequently implemented a number of key reforms that have ensured that wholesale energy prices more accurately reflect the cost and value of servicing load during all periods. These reforms relate to offer caps, shortage pricing, hourly re-offers and five-minute settlement intervals. While we appreciate the Commission's efforts to direct these reforms, we believe that the Commission should continue to engage with stakeholders to determine additional areas where improvements can be made and push the RTOs to make those enhancements to their respective market designs.

[13] *EPSA v. FERC*, 136 S. Ct., at 768 (*quoting Morgan Stanley Capital Grp*, 554 U.S. 527, 538 (2008).

[14] *See* "Post Technical Conference Comments of the PSEG Companies," *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD14-14-000 (March 6, 2015).

For example, recently, the Commission issued a notice of proposed rulemaking ("NOPR") concerning the transparency practices of certain RTOs and ISOs related to uplift payments, operator-initiated commitments and transmission constraint penalty factors. While we support this NOPR, we believe that it is important for the Commission to continuing stressing efforts to enhance the transparency surrounding RTO/ISO dispatch and commitment decisions. In particular, all ISOs should ensure that published market information is clearly defined and is consistent with the information used in dispatch, scheduling and price calculation. The correct amount of transparency allows generators to compete more efficiently because they are able to better understand what products and characteristics of resources the system operators value most. Transparency is critical because it highlights the elements of the RTO/ISO dispatch and commitment procedures that are not effective and could be improved. Additional transparency enables market participants to understand why certain dispatch and commitment decisions are made and thereby appreciate the problems that are being addressed rather than guessing what the operator is attempting to accomplish.

The Commission has also recently issued a NOPR proposing that RTOs/ISOs modify their rules governing fast-start resources (*i.e.*, resources that can start up in 10 minutes or less, have a minimum run time of one hour or less and have submitted an economic energy offer to a market). Fast-start resources typically are committed in real-time, very close to the interval when needed and can respond quickly to unforeseen system needs. However, without fast-start pricing, some fast-start resources are ineligible to set prices due to inflexible operating limits. As a result, prices may not reflect the marginal cost of serving load. While we support the reforms described in the NOPR, we believe that it targets only a limited set of resources.

PJM appears to share our view and recently issued a whitepaper proposing to expand the class of resources that are eligible to set prices. In the whitepaper PJM states that "the range of resources eligible to set price should be expanded to include all units whose output is needed to serve load or control transmission constraints in a given interval."[15] To address this issue, PJM is proposing to allow inflexible units to set LMP, thereby "transparently indicating the cost of the most expensive unit necessary to economically serve the load."[16] PJM is proposing to accompany the pricing eligibility reform with implementation of a load-following product, "which would compensate flexible resources forced to ramp up or down uneconomically to meet demand when a larger, inflexible resource must operate at a minimum output level."[17] While the details surrounding PJM's proposal still need to be worked out, we believe that the proposal shows promise and its goals – to value flexibility and increase the universe of resource classes that are eligible to set price – are steps in the right direction. However, while we do not believe that either the Commission or the RTOs/ISOs should let up on their efforts to improve energy price formation, we caution that these reforms are not the complete solution to the challenges facing nuclear units. Consequently, the efforts to improve energy price formation should be done in parallel with efforts to enhance marginal pricing and develop ways to incorporate public policy attributes into the market. While these efforts are developed, it is essential that the Commission's efforts do not interfere with important state transitional actions.

[15] "Energy Price Formation and Valuing Flexibility," PJM Interconnection, L.L.C. at 2 (issued June 15, 2017).

[16] *Id.*, at 3.

[17] *Id.*

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III. CONCLUSION

The Commission is at a crossroads. It must act quickly and decisively to address a problem that, if not handled correctly, could have adverse impacts on millions of consumers for years to come. The PSEG Companies respectfully request that the Commission consider their comments as providing a practical means to address the most pressing matters first and then to implement a long-range solution after the crisis has passed.

Respectfully submitted,

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Dated: June 22, 2017
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PSEG Fossil

Reactive Power Capability

June 30, 2016

Jason Sine

PSEG Fossil LLC

SI-SSA-0010-1010

Reactive Power Capability

2.1 What costs do synchronous generators incur to install and maintain Reactive Supply capability?

A. Installation costs: In order to supply reactive capability, a generator must be designed/sized larger than the desired megawatt output during installation. This includes the:

- Excitation system
- Transformers
- Generator bus
- Generator breakers
- Cooling systems, must be sized larger in order to provide the increased current requirements of supplying reactive power and cooling requirements to dissipate the heat produced in the generator, bus, and transformers when providing the reactive power.

Example:

- If reactive power is NOT to be supplied (PF=1.0), a 100 MW generator can be sized at 100MVA
- If reactive power is to be supplied (ex. PF=0.9, 100 MWs, 50 MVARs), the 100MW generator would need to be sized to 111.1 MVA.
- All electrical equipment from the generator to the point of interconnection must be sized to handle the increased current in supplying the reactive power.

2.1 What costs do synchronous generators incur to install and maintain Reactive Supply capability? (continued)

B. Maintenance costs:

- To supply reactive capability, maintenance costs are the same as if not supplying reactive power as long as the equipment is sized and rated to adequately handle the reactive power.
- As equipment ages, degraded conditions can possibly occur within a generator that supplying reactive power can accelerate and cause damage to specific components within the generator. For example leading reactive power can accelerate any existing core iron insulation issues, and may result in a de-rate if the degraded condition is not repaired.

Reactive Power Capability

2.2 Is the equipment required for synchronous generators to maintain Reactive Supply capability the same as that required to produce and deliver real power, or must additional costs be incurred to provide Reactive Supply capability?

- The equipment is the same, but it is required to be a larger size if it is intended to provide reactive capability

Reactive Power Capability

2.3 Would synchronous generators be designed or operated differently were it not for the Reactive Supply capability requirements of their respective Interconnection Agreements or Reactive Supply reliability requirements?

- Design:
  - Without reactive supply capability requirements, the size/rating of the equipment (generator, bus, transformers, cooling equipment) could be reduced and a generator operated as close to unity power factor as possible.

- Operation:
  - Without reactive supply capability requirements, the unit would be operated at unity power factor

2.4 What costs do synchronous generators incur in real-time to provide Reactive Supply service?

- Aux power for Cooling:
  - Additional auxiliary power will be consumed to run the larger cooling systems required for cooling the generator, bus, and transformers.

- Aux power for Excitation:
  - **Lagging**: To provide lagging reactive power, the generator requires an increase in field current, resulting in an increase in auxiliary power used by the excitation system.
  - **Leading**: Conversely, to provide leading reactive power , the generator requires a reduction in field current, resulting in a decrease in auxiliary power used by the excitation system.
  - Increases heat losses.

Reactive Power Capability

2.5 How are the costs required for synchronous generators to maintain Reactive Supply capability and to provide Reactive Supply service recovered?

- Most of PSEG Power's generating units are located in PJM and thus are paid under the *AEP* methodology.

- The *AEP* methodology calculates a cost-of-service rate for generating units providing reactive power services based on three components of production plant directly related to the production of VARs: (i) the generator and exciter; (ii) accessory electric equipment that supports operation of the generator and exciter; and (iii) remaining total production investment required to provide real power and operate the exciter. Recovery of the costs of incremental heating losses which are incurred in the production of reactive power are also allowed.

Reactive Power Capability

2.5 How are the costs required for synchronous generators to maintain Reactive Supply capability and to provide Reactive Supply service recovered? (continued)

- The *AEP* methodology correctly recognizes that generating units required to be capable of providing reactive power incur capital and maintenance costs that they would not incur otherwise but may not adequately compensate units for these costs in some cases.

- The allowance for incremental heating losses under the *AEP* methodology may not adequately compensate for the additional auxiliary power consumed to run the larger cooling systems needed for cooling the appropriately-sized generator, bus, and transformers required to provide reactive power services.

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Calpine Corporation, Dynegy Inc., Eastern Generation, LLC, Homer City Generation, L.P., NRG Power Marketing LLC, GenOn Energy Management, LLC, Carroll County Energy LLC, C.P. Crane LLC, Essential Power, LLC, Essential Power OPP, LLC, Essential Power Rock Springs, LLC, Lakewood Cogeneration, L.P., GDF SUEZ Energy Marketing NA, Inc., Oregon Clean Energy, LLC and Panda Power Generation Infrastructure Fund, LLC	Docket Nos. EL16-49-000
v.	
PJM Interconnection, L.L.C.	ER18-1314-000
PJM Interconnection, L.L.C.	ER18-1314-001
PJM Interconnection, L.L.C.	EL18-178-000 (Consolidated)

REQUEST FOR REHEARING OF THE PSEG COMPANIES

Pursuant to Section 313(a) of the Federal Power Act ("FPA")[1] and Rules 212 and 713 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC") or the "Commission"),[2] Public Service Electric and Gas Company, PSEG Power LLC and PSEG Energy Resources & Trade LLC (collectively, the "PSEG Companies") hereby seek rehearing of FERC's June 29, 2018 Order ("Order")[3] in these proceedings.

[1] 16 U.S.C. § 825(a) (2012).

[2] 18 C.F.R. §§ 385.212; 385.713 (2017).

[3] Order, 163 FERC ¶ 61,236.

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Fundamentally, the Order errs by purporting to address a problem that has not been shown to exist. The Commission found PJM's current Open Access Transmission Tariff ("Tariff") to be unjust and unreasonable because it allegedly fails to mitigate the price-suppressive impacts of out-of-market payments to generators and further found that action must be taken to revise PJM's Tariff, based upon this determination.[4] The Commission initiated a Federal Power Act ("FPA") section 206 proceeding in Docket No. EL18-178-000 and set the proceedings for a paper hearing.

The stated bases for the Order's FPA Section 206 conclusions do not, however, withstand even rudimentary analysis. As pointedly demonstrated in Commissioner Glick's dissent, the PJM capacity market is adequately – indeed much more than adequately – performing its intended functions by any reasonable measurement. For example, the record reflects that PJM's current reserve margin is nearly double what the North American Electric Reliability Corporation ("NERC") has determined is necessary, meaning that the region currently has tens of thousands of additional MW of generating capacity beyond what it requires.[5] Moreover, there are nearly 40 GW of natural gas-fired generation under development within PJM's footprint—equivalent to 25 percent of the installed capacity in the region—with over half of those MW in a relatively advanced state of development.[6] A wealth of other evidence attesting to the health of the PJM capacity procurement mechanism can also be found in the record. The concerns that the

[4] *Id.*

[5] *See,* Exelon January 30, 2017 Protest ('Exelon Protest") at 14-15 (Docket No. EL16-49) ("The market is producing resource adequacy—achieving a reserve margin of 22 percent, exceeding its target of 16.5 percent."); Maryland Commission Protest at 5 ("Regarding investment in generation, PJM's Base Residual Auction (BRA) provides ample capacity and has consistently exceeded its target reserve margins."); Consumer Coalition Protest at 12 ("PJM has the most drastic capacity *oversupply* of any RTO in North America.").

[6] Clean Energy Advocates Protest at 36-37 (Docket No. EL16-49)(citing data compiled by S&P Global Market intelligence); Exelon Protest at 35-36.

Order purports to identify with respect to prices being suppressed below competitive levels are not only theoretical but are actually completely at odds with the facts on the ground. The Commission simply lacks the necessary support to meet its statutory burden and make a finding that the current PJM capacity market structure is not just and reasonable.

The Order is also flawed as a matter of law. It defies the carefully balanced statutory structure of the FPA by imposing its own narrow vision of which social policies should be pursued ignoring the statutorily acknowledged role of state policy makers. The states are vested with the exclusive jurisdiction over "facilities used for the generation of electric energy." As the case law makes clear – including recent Supreme Court decisions – the Commission and the states should cooperate to the extent possible in performing the roles assigned to them under the FPA. The Order contends that capacity prices are being suppressed by state actions to value generation attributes; attributes the Commission has already acknowledged are legitimate for states to pursue. The economic evidence that was presented in this proceeding [7] clearly demonstrates that these actions are not suppressive; in fact, they achieve the most efficient overall outcome. Taking account of the states' policy goals thus would actually do a better job of selecting the most economical generating units than does the current market mechanism.

The direction the Commission should take in addressing the matter before it is to incorporate widely supported public policy goals, such as carbon abatement and resiliency, into its market designs. The structure of the FPA contemplates coordination between state and federal regulatory bodies. Except to the extent that measures are "targeted" or "aimed" towards intentionally interfering with the statutorily assigned role of the other, the states and the

[7] Exelon June 20, 2018 Protest (Docket No. EL18-169-000), Declaration of Robert D. Willig.

Commission should work together to achieve their respective goals. And given that there is no indication that the goals of states to achieve clean air goals and fuel security are attempts to interfere with efficient market outcomes, the Commission's approach is simply indefensible

Pursuant to Rule 713 of the FERC's Rules of Practice and Procedure, 18 C.F.R. § 385.713,[8] the PSEG Companies hereby seek rehearing of the Order in this proceeding and request that the Commission maintain the status quo and reverse its decision to initiate an FPA 206 proceeding to seek modification of the PJM Tariff. In support of this rehearing request, the PSEG Companies respectfully shows as follows:

I. STATEMENT OF ISSUES AND SPECIFICATION OF ERRORS

Pursuant to Rule 713(c)(2) of the Commission's Rules of Practice and Procedure,[9] the PSEG Companies request rehearing of the following issues:

1. The Order errs by failing to meet the statutory burden of FPA Section 206 demonstrating that PJM's current Tariff is unjust and unreasonable where:

(i) There is no substantial evidence in the record to support a finding that there is a resource adequacy problem in PJM or that the capacity market is otherwise unjust and unreasonable or unduly discriminatory or preferential;

(ii) The Order never justifies theoretical concerns regarding price suppression; and

(iii) The Order never adequately addresses the claims of intervenors demonstrating that the capacity market is achieving its intended goals related to meeting reliability standards.

2. The Order errs because it interferes with the exclusive jurisdiction of the states under the FPA over generating facilities.

[8] 18 C.F.R. § 385.713 (2010).

[9] *Id.* at (c)(2).

3. The Order errs by failing to comply with the statutory framework of the FPA requiring that the Commission coordinate with state agencies regarding the achievement of state public policy goals within their authority provided that the states' actions are not attempts to target or aimed at thwarting legitimate federal goals in circumstances in which:

(i) States have identified clean air and fuel security initiatives that could be incorporated into market designs; and

(ii) The inclusion of widely-supported state goals for improving air quality and fuel security would actually improve market efficiency by pricing additional societal costs into market outcomes.

4. The Order violates the FPA and the Administrative Procedure Act, ignores record evidence and legitimate objections raised by parties, and fails to make a decision based on substantial evidence.[10]

II. BACKGROUND

On April 9, 2018, PJM filed, pursuant to section 205 of the FPA, to modify its capacity market design ("PJM Filing").[11] The PJM Filing consisted of two alternate proposals designed to address the price suppressing effects of state out-of-market support for certain resources.[12] PJM's first approach was comprised of a two-stage annual auction, with capacity commitments first determined in stage one of the auction and the clearing price set separately in stage two ("Capacity Repricing"). PJM's second, alternative approach, revised PJM's MOPR to mitigate capacity offers from both new and existing resources, subject to certain proposed exemptions ("MOPR-Ex"). In its filing, PJM requested that the Commission approve its preferred "Capacity Repricing", or in the alternative PJM's MOPR-Ex proposal.

[10] FPA section 205, 16 U.S.C. § 824d; FPA section 313, 16 U.S.C. § 824l(b); *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 43 (1983); *See PPL Wallingford Energy LLC v FERC*, 419 F.3d 1194, 1198 (D.C. Cir. 2005) (quoting *Canadian Association of Petroleum Producers v. FERC*, 254 F.3d 289, 299 (D.C. Cir. 2001) ("[U]nless the [agency] answers objections that on their face seem legitimate, its decision can hardly be classified as reasoned.").

[11] PJM Filing.

[12] *Id*. at 17.

Previously, the Complaints in Calpine, *et. al*. ("Calpine Complaint")[13] had argued that PJM's MOPR should be expanded to "prevent the artificial suppression of prices in the Reliability Pricing Model ('RPM") market by below-cost offers for existing resources whose continued operation is being subsidized by State approved out-of- market payments."[14] Complainants argued that the MOPR should cover not only new resources receiving out-of-market subsidies, but existing resources as well, subject to several limitations. [15]

On June 29, 2018 FERC issued the instant Order. FERC found that it has become necessary to address the price suppressive impact of resources receiving out-of-market support. Part of FERC's rational is that PJM's existing MOPR does not, because it applies only to new, natural gas-fired resources. As such, based on the combined records of the Calpine Complaint proceeding and the PJM Filing, FERC determined that PJM's Tariff is unjust and unreasonable and granted the Calpine Complaint, in part, and *sua sponte* initiated a paper section 206 proceeding.

III. REQUEST FOR REHEARING

A. THE COMMISSION FAILED TO MEET ITS BURDEN TO SHOW THAT PJM'S TARIFF IS UNJUST AND UNREASONABLE

The Administrative Procedure Act directs a reviewing court to "hold unlawful and set aside agency action, findings, and conclusions found to be – (a) arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law; ... [or] (e) unsupported by substantial evidence ...."[16] "[T]o survive this review, FERC must "examine the relevant data and articulate

[13] Calpine Complaint, *et al*., Docket No. EL16-49-000 (March 21, 2016).

[14] *Id.* at 2.

[15] *Id*.

[16] 5 U.S.C. §706(2).

a satisfactory explanation for its action including a rational connection between the facts found and the choice made."[17] An agency acts arbitrarily when it "entirely fail[s] to consider an important aspect of the problem, [or offers] an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise."[18] "Among other things, [a]n agency's failure to respond meaningfully to objections raised by a party renders its decision arbitrary and capricious."[19] Thus, FERC "must respond to objections and address contrary evidence in more than a cursory fashion."[20]

Therefore, under the Administrative Procedure Act,[21] the Commission is required to render all of its decisions in accordance with reasoned decision-making and articulate a satisfactory explanation for its decision, including a "rational connection between the facts found and the choice made."[22] The Commission must also ensure that the record it has developed is both complete and articulate and that it has satisfied its affirmative duty to inquire into and consider all relevant facts presented by the parties.[23] Further, the courts have found an agency's

[17] *PSEG Energy Res. & Trade LLC v. FERC*, 665 F.3d 203, 208 (D.C. Cir. 2011) (quoting *PPL Wallingford Energy LLC v. FERC*, 419 f.3d 1194, 1198 (D.C. Cir. 2005) (quoting *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983)).

[18] *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43.

[19] *PSEG Energy*, 665 F.3d at 208 (alterations omitted) (citations omitted).

[20] *Transmission Agency of N. Cal. v. FERC*, 628 F.3d 538, 543-44 (D.C. Cir. 2010).

[21] 5 U.S.C. § 551, et seq.

[22] *Motor Vehicles Mfrs. Ass'n v. State Farm Mutual Auto Ins. Co.*, 463 U.S. 29, 43, 48, 48, 57 (1983), *citing Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 371 U.S. 168 (1962) ("[A]n agency must cogently explain why it has exercised its discretion in a given manner.").

[23] *See Confederate Tribes and Bands of Yakima Indian Nation v. FERC*, 746 F.2d 466, 472 (9th Cir. 1984), (*quoting Scenic Hudson Pres. Conference v. FPC*, 354 F.2d 608, 620 (2nd Cir. 1965)).

ruling to be "arbitrary and capricious" if the agency "ignores important arguments or evidence."[24]

Here, FERC's Order fails to satisfy the requirements of the Administrative Procedure Act in multiple ways. First, FERC fails to identify substantial evidence justifying its determination that PJM's Tariff is unjust and unreasonable. Second, the suppositions and assumptions relied upon by FERC lacked meaningful probative value and were wholly unsupported by record evidence. Third, in many instances, FERC ignored or evaded various objections and arguments entirely.

Commissioner LaFleur aptly notes that the instant proceeding is too important to proceed on the basis of theory and conjecture:

> Here, the FERC, "through a 90 day paper hearing, is proposing the most sweeping changes to the PJM capacity construct since the market's inception more than a decade ago. If ultimately adopted, this proposal would fundamentally rebalance the resource adequacy responsibilities of the states, the Commission, and PJM….the end result is a proceeding to "overhaul the PJM capacity market based on **a thinly sketched concept**, a troubling act of regulatory hubris that could ultimately hasten, rather than halt, the re-regulation of the PJM market."[25] (emphasis added)

The Commission claims that PJM's capacity construct has become "untenably threatened" by out-of-market payments resulting from state initiatives."[26] This thinly sketched concept is fundamentally flawed and unsupported by any record evidence. Instead, the Commission, in a conclusory fashion, espouses this theory, seemingly as evidence.

In fact, the capacity markets have continued to fulfill the FPA's mandate of "encourage[ing] the orderly development of plentiful supplies of electricity … at reasonable

[24] *Natural Res. Def. Council v. U.S. EPA*, 822 F.2d 104, 111 (D.C. Cir. 1987); *Consumers Union of the United States v. Consumer Prod. Safety Council*, 491 F.2d 810, 812 (2nd Cir. 1974).

[25] Order, 163 FERC ¶ 61,236, (LaFleur, dissenting, p. 3).

[26] *E.g.*, Exelon January 30, 2017 Protest at 14-15 (Docket No. EL16-49).

prices."[27] Energy prices are at historic lows, and capacity prices are well below the cost of new entry. That basic pattern continued in the most recent auction, where reserve margins barely dipped even as prices rose.[28] The record is bereft of any evidence that there is a resource adequacy problem in PJM.

The Commission has blatantly ignored important arguments and evidence, thereby rendering its ruling arbitrary and capricious. The evidence in the record actually reflects that PJM's capacity market has a capacity surplus that is in excess of the level required to reliably meet the region's electricity demands.[29]

For example, the record reflects that PJM's current reserve margin is nearly double what NERC has determined is necessary, meaning that the region currently has tens of thousands of additional MW of generating capacity beyond what it requires.[30] Moreover, there are nearly 40 GW of natural gas-fired generation under development within PJM's footprint—equivalent to 25 percent of the installed capacity in the region—with over half of those MW in a relatively advanced state of development.[31] Both examples offer clear, record evidence of the fact that the PJM region continues to attract new "competitive" generation resources.

Again, the Commission engages in speculation and conjecture to justify its determination that, at some point in the future, the capacity market may no longer secure sufficient resources at

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[27] *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,157, at 30 n.39 (2016) (quoting *Pub. Utilities Comm'n of Cal. v. FERC*, 367 F.3d 925, 929 (D.C. Cir. 2004)).

[28] *E.g.*, Exelon January 30, 2017 Protest at 14-15 (Docket No. EL16-49).

[29] Order, 163 FERC ¶ 61,236, (Glick, dissenting, p. 2).

[30] *E.g.*, Exelon January 30, 2017 Protest at 14-15 (Docket No. EL16-49) ("The market is producing resource adequacy—achieving a reserve margin of 22 percent, exceeding its target of 16.5 percent."); Maryland Commission Protest at 5 ("Regarding investment in generation, PJM's Base Residual Auction (BRA) provides ample capacity and has consistently exceeded its target reserve margins."); Consumer Coalition Protest at 12 ("PJM has the most drastic capacity *oversupply* of any RTO in North America.").

[31] Clean Energy Advocates Protest at 36-37 (citing data compiled by S&P Global Market intelligence); Exelon Protest at 35-36.

just and reasonable rates.[32] The Commission opines that "action must be taken" because PJM's Tariff is unable "to adequately address *the evolving circumstances* presented by resources that receive out-of-market support."[33] However, the evidence in the record does not support this theory. In fact, it is again exactly to the contrary. The most recent auction continued to incentivize new entry, even though PJM's reserve margin far exceeds what is needed for reliability. The 2021/2022 Reliability Pricing Model ("RPM") Base Residual Auction ("BRA") cleared 163,627.3 MW of unforced capacity in the RTO representing a 22.0% reserve margin. The reserve margin for the entire RTO is 21.5 percent, considerably higher than the target reserve margin of 15.8 percent, when the Fixed Resource Requirement ("FRR") load and resources are considered. This reported reserve margin of 21.5 percent does not even reflect the additional 22,877.5 MW of uncleared capacity.[34]

The Commission hypothesizes that PJM's Tariff is unjust and unreasonable because it does not mitigate state policies, thereby creating uncertainty for "competitive" resources that do not know whether they will be competing against other resources that receive a subsidy considered by the Commission to be problematic.[35]

> Commissioner Glick, in his dissent, correctly and soundly debunks this theory:
>
> > Uncertainty in many forms—commodity price uncertainty, demand uncertainty, and, yes, policy uncertainty—pervades the electricity industry and the Commission leaves it to private companies to manage that uncertainty. Nothing in today's order explains why the uncertainty created by certain state policies is any different or why that difference is sufficient to render PJM's Tariff unjust and

[32] Order, 163 FERC ¶ 61,236 at P 19.

[33] *Id.* at P 32.

[34] PJM Answer at 10.

[35] *Id.* at P 150. It is unclear why the Commission limits this uncertainty to "competitive" resources. Every resources faces uncertainty that policy developments relatively favorable to its competitors will make its position less advantageous.

> unreasonable. And it is ironic to bemoan policy uncertainty when Commission's and PJM's constant tinkering with the capacity market is one of, if not the, single biggest sources of uncertainty facing capacity market participants.[36]

As there is no substantial evidence in the record to support a finding that PJM's Tariff is unjust and unreasonable and, in fact, there is evidence directly to the contrary that was disregarded by the Commission, rehearing on the Order must be granted.

B. THE ORDER ENCROACHES ON THE STATES EXCLUSIVE JURISCTION, GRANTED PURSUANT TO THE FPA

The FPA is often described as drawing a "bright line" between state and federal jurisdiction over the electricity sector. This division of authority gives the federal government jurisdiction over the interstate aspects of the electricity industry, while leaving the states to regulate its intrastate aspects.[37] As such, the FPA is clear that the states, not the Commission, are the entities responsible for shaping the generation mix. Although the FPA provides the Commission with jurisdiction over wholesale sales of electricity as well as rates and practices affecting those wholesale sales, Congress expressly precluded the Commission from regulating "facilities used for the generation of electric energy," instead vesting the states with exclusive jurisdiction over those facilities.[38] Alongside those grants of power, however, the Act also limits FERC's regulatory reach, and thereby maintains a zone of exclusive state jurisdiction. Congressional intent is clearly articulated in § 201's text: FERC's reach "extend[s] only to those

[36] *ISO New England Inc.*, 162 FERC ¶ 61,205 at 5 n.13 (Glick, Comm'r, dissenting in part and concurring in part) ("[C]hange has been the only consistent feature of capacity markets in recent years.").

[37] 16 U.S.C. § 824.

[38] 16 U.S.C. § 824(b)(1) (2012); *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288, 1292 (2016) (describing the jurisdictional divide set forth in the FPA); *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 767 (2016) (*EPSA*) (explaining that "the [FPA] also limits FERC's regulatory reach, and thereby maintains a zone of exclusive state jurisdiction").

matters which are not subject to regulation by the States."[39] States retain exclusive authority to regulate "facilities used for the generation of electric energy."[40]

As maintained by Commissioner Glick in his dissent, the FPA is clear that a state's development of generation support is clearly within states' authority, and the Order impermissibly intrudes upon the states' exclusive jurisdiction:

> The state programs of which the commission disapproves are precisely the sort of actions that Congress reserved to the states when it enacted the FPA. The Commission's role is not — and should not be — to exercise its authority over wholesale rates in a manner that aims to mitigate, frustrate, or otherwise limit the states' exercise of their exclusive authority over electric generation facilities. As contemplated, the commission's proposal would effectively force state-sponsored resources out of the capacity market, depriving them of a payment for capacity that they will actually provide and leaving it to the states to pick up that tab,"[41]

The FERC Order thus oversteps the Commission's statutory authority and, accordingly, must be reversed on rehearing.

C. THE ORDER ERRED BY FAILING TO CREATE MARKET MECHANISMS DESIGNED TO VALUE PARTICULAR GENERATOR ATTRIBUTES IDENTFIED BY STATES AS NEEDED TO ACHIEVE LEGITIMATE PUBLIC POLICY GOALS

In the past, the Commission has always crafted market rules to defer to and accommodate state programs addressing environmental externalities. Doing so adheres to the principle that the Commission must "fulfill [its] jurisdictional responsibilities while also respecting the states' traditional role,"[42] consistent with the Federal Power Act's purpose to

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[39] *Id*. at (a).

[40] 16 U.S.C. § 824(b)(1) (2012); *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288, 1292 (2016) (describing the jurisdictional divide set forth in the FPA); *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 767 (2016) (*EPSA*) (explaining that "the [FPA] also limits FERC's regulatory reach, and thereby maintains a zone of exclusive state jurisdiction").

[41] Order, 163 FERC ¶ 61,236.

[42] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1117 (2006).

"complement," not "usurp[] … State regulatory authority."[43] As a number of recent court decisions make clear, state and federal regulatory authorities should seek to coordinate their roles when possible, not attempt to neutralize each other. The FPA's jurisdictional overlap is intentional. It reflects the "congressionally designed interplay between state and federal regulation,"[44] which is limited by the principle that neither the states nor the Commission may impose measures that "target[]" or "aim[] at" the other's areas of exclusive responsibility.[45]

Yet, the Order departs dramatically from this paradigm. Until now, the Commission has decided that its market mechanisms should be fuel-neutral, but it has always accepted that state policies are *not* fuel neutral. Resources confront a cost structure that reflects whatever fuel-related benefits or penalties states have chosen to impose in light of state environmental priorities. The Commission's market mechanism selects the least-cost set of resources against the backdrop of those policies. And thus far, the Commission has always crafted market rules to respect and accommodate state programs addressing environmental externalities.[46] The Commission's role is not—and should not be—to exercise its authority over wholesale rates in a manner that aims to mitigate, frustrate, or otherwise limit the states' exercise of their exclusive

[43] *Conn. Light & Power Co. v. Fed. Power Comm'n*, 324 U.S. 515, 526 (1945).

[44] *Hughes*, 136 S. Ct. at 1300 (Sotomayor, J., concurring) (quoting *Nw. Cent. Pipeline Corp. v. State Corp. Comm'n of Kan.*, 489 U.S. 493, 518 (1989)); *id.* ("recogniz[ing] the importance of protecting the States' ability to contribute, within their regulatory domain, to the Federal Power Act's goal of ensuring a sustainable supply of efficient and price-effective energy").

[45] *EPSA*, 136 S. Ct. at 776 (emphasizing the importance of "'the *target* at which [a] law *aims*'") (citing *Oneok*, 135 S. Ct. at 1600); *Oneok*, 135 S. Ct. at 1600 (recognizing "the distinction between 'measures *aimed directly at* interstate purchasers and wholesales for resale, and those aimed at' subjects left to the States to regulate") (quoting *N. Nat. Gas Co. v. State Corp. Comm'n of Kan.*, 372 U.S. 84, 94 (1963)); *see also Coal. for Competitive Elec. v. Zibelman*, 272 F. Supp. 3d 554, 576 (S.D.N.Y. 2017) ("[W]hen the State is legitimately regulating a matter of state concern, 'FERC's exercise of its authority must accommodate' that state regulation '[u]nless clear damage to federal goals would result.'") (quoting *Nw. Cent. Pipeline Corp.*, 489 U.S. at 522)).

[46] *E.g.*, Exelon January 30, 2017 Protest at 14-15 (Docket No. EL16-49).

authority over electric generation facilities.[47] Rather than interfering with state policies that address externalities associated with electric generation, such as greenhouse gas emissions that contribute to the existential threat of climate change, the Commission should be striving to accommodate and give effect to those state initiatives.[48]

Nor can the Commission claim that the achievement of state policies designed to value clean air or fuel diversity attributes of generation would be inconsistent with the fundamental goals of markets. The loss of these desirable generator attributes would impose real costs on the citizens of the states that seek to promote them. The fact that the electricity markets designed by the Commission to date do not include these costs does not give provide license for the Commission to ignore them when they have been identified by states. Nevertheless, the Commission now claims that the "integrity and effectiveness" of PJM's capacity market "have become untenably threatened by out-of-market payments provided or required by certain states for the purpose of supporting the entry or continued operation of preferred generation resources."[49] This amounts to the Commission imposing its narrow vision of markets on the states and thus infringing on the states' role. Indeed, given the vast number of subsidies and discriminatory policies that the approach outlined in the June 29th Order ignores entirely, the order's targeting of certain state policies goals is an arbitrary and capricious exercise to inhibit state efforts to price the externalities of electricity generation, while permitting other federal, state, and local policies that interfere with the functioning of the markets. This approach is tantamount to arbitrarily picking winners and losers among various externalities (or "subsidies")

[47] Order, 163 FERC ¶ 61,236, (Glick, dissenting, p. 1).

[48] Order, 163 FERC ¶ 61,236, (Glick, dissenting, p. 2).

[49] Order, 163 FERC ¶ 61,236, at P 1.

purportedly impacting the capacity markets. The Commission fails to explain why it deems some "threats" as warranting redress, while others do not. As stated in Commission Glick's dissent:

> Rather than interfering with state policies that address externalities associated with electric generation, such as greenhouse gas emissions that contribute to the existential threat of climate change, the Commission should be striving to accommodate and give effect to those state initiatives….the Commission fundamentally misunderstands that the state policies that it targets compensate resources for their environmental attributes, not their capacity. As contemplated, the Commission's proposal would effectively force state-sponsored resources out of the capacity market, depriving them of a payment for capacity that they will actually provide and leaving it to the states to pick up that tab. [50]

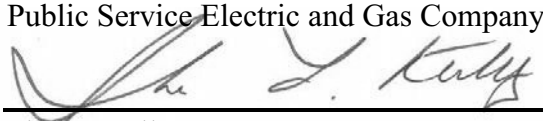
As such, the Commission's Order erred because it failed to respect the statutory interference with the scheme of the FPA by refusing to give effect to state policy choices that do not conflict with basic market design principles.

CONCLUSION

The PSEG Companies respectfully requests that the Commission grant this request for rehearing and the relief requested herein.

Respectfully submitted,

Public Service Electric and Gas Company



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Dated: 7/30/2018

[50] Order, 163 FERC ¶ 61,236, (Glick, dissenting, p. 2).

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon the official service list in accordance with the requirement of Rule 2010 of the Commission's Rules of Practice.

Dated at Newark, New Jersey, July 30, 2018.

Very truly yours,

Robert Gardinor

Robert Gardinor
Paralegal

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. EL18-178-000**
PJM Interconnection, L.L.C.	)	**ER18-1314-000** **ER18-1314-001**
Calpine Corporation, et al.,	)	**EL16-49-000**
Complainants,	)	**(Consolidated)**
v.	)	
PJM Interconnection, L.L.C.,	)	
Respondent.	)	

COMMENTS OF THE PSEG COMPANIES

Pursuant to Rules 212 and 214 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") Rules of Practice and Procedure,[1] Public Service Electric and Gas Company, PSEG Power LLC and PSEG Energy Resources & Trade LLC (collectively, the "PSEG Companies") file these comments in response to the proposed changes to PJM Interconnection, L.L.C.'s ("PJM") Open Access Transmission Tariff ("Tariff") described in the June 29, 2018 Order Rejecting Proposed Tariff Revisions, Granting In Part and Denying In Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act ("Order").[2]

[1] 18 C.F.R. §§ 385.212, 385.214 (2018).
[2] *PJM Interconnection, L.L.C.,* 163 FERC ¶ 61,236 (2018).

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The PSEG Companies do not agree that PJM's current capacity construct is unjust and unreasonable and thereby requires modification.[3] There is a wealth of support in various dockets before the Commission attesting to the health of the PJM capacity market. The PSEG Companies' believe that the direction the Commission should take in addressing any concerns with the PJM markets sending the correct investment and retirement decisions is to incorporate widely supported public policy goals such as carbon abatement and resiliency into those markets.

However, we acknowledge that FERC has determined that action is needed in order to preserve the "integrity and effectiveness of the capacity market administered by PJM Interconnection, L.L.C." because of the challenges posed by states' legitimate efforts to advance certain public policy initiatives by providing support payments to resources with desirable attributes.[4] To address its concern over the impact of "increasing out-of-market support" and perceived shortcomings with PJM's current Minimum Offer Price Rule ("MOPR") provisions, the Commission has proposed to modify PJM's tariff to: (1) expand the MOPR to cover new and existing resources that receive out-of-market payments with few or no exceptions; and (2) allow resources receiving out-of-market support to choose to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time ("FRR-Alternative").[5] The Commission contends that this approach, specifically the FRR-Alternative, is intended to accommodate resources that receive out-of-market support by allowing them to "remain on the system, despite their inability to compete in the capacity market based on their

[3] *See* The PSEG Companies Request for Rehearing, Docket No. EL18-178-000, *et al*., (submitted July 30, 2018) ("PSEG Rehearing Request") (discussing the PSEG Companies' position on why the current tariff was improperly found to be unjust and unreasonable).
[4] Order, PP 1-2.
[5] *Id*. at P 8.

costs, by permitting them to exit the capacity market with a commensurate about of load and operating reserves."[6]

The PSEG Companies support FERC's proposed approach because, if implemented correctly, it represents a fair mitigation mechanism applicable to all resources coupled with a process that accommodates and appropriately recognizes states' rights to direct the types of generation investments that advance their public policy goals. While an FRR-Alternative type mechanism could accomplish the Commission's goal of accommodating state public policy resources, it must be designed in a manner that is fair to both generators and consumers. To achieve this objective, certain key principles must be contained in the mechanism ultimately adopted by the Commission.

First, any mitigation scheme must be universally applied to resources that receive any type of support payment, consistent with the Commission's proposal that the MOPR be designed with few or no exceptions.

Second, it is critical to the proper functioning of the markets that the structure adopted by FERC account for existing generation and avoid sending erroneous price signals that incent new build when it is not truly needed.

Third, the loads and resources that are carved out of the market should have the same obligations as their equivalents participating in the markets. Specifically, generation and load pairings should include sufficient reserve procurements to match the market-based outcome. FRR-Alternative resources should also be subject to the Capacity Performance resource requirements.

[6] *Id.* at P 160.

Fourth, given the complexity of the proposed changes and need to fill in additional details around FERC's proposal, a transitional mechanism should be adopted for the first auction to allow states and market participants to implement the new design in a workable manner.

Finally, we are signatories to the shared principles submitted by the Joint Brief of Consumer Advocates, NGOs, and Industry Stakeholders. While these principles provide guidance to the Commission, the details of the PJM tariff provisions ultimately approved by FERC are important and must be carefully crafted in a manner that achieves reasonable market outcomes. The PSEG Companies therefore offer in these comments a number of design principles that are critical to achieving a well-functioning, effective capacity market.

I. COMMENTS

A. FERC's Proposal Is Only Workable If Both Aspects are Approved – A Clean MOPR and the FRR-Alternative

The PSEG Companies support FERC's proposed modifications to the existing PJM capacity market with two key structural features aimed at both protecting the competitive market and accommodating states' rights to pursue legitimate public policies for their generation supply mix. It is particularly critical that both of these features be incorporated in any approved change to PJM's Tariff in order to ensure that the new market structure avoids the very problems that led to the current complaint, namely inefficient market signals and uncertainty regarding how state sponsored generation resources should be allowed to participate in the PJM markets.

The first of these two symbiotic structures is the expanded MOPR that "would apply to new and existing resources that receive out-of-market payments, regardless of resource type, but would include few to no exemptions."[7] The PSEG Companies agree that the expanded MOPR, which would provide protection to the competitive market, must be applied broadly to all

[7] Order, P 8.

resources that receive out-of-market payments with essentially no exemptions. This is the only way to avoid the pitfalls of undue discrimination and preferential treatment that led to the determination that the current market structure is unjust and unreasonable. With very few exceptions, mostly related to materiality or administrative convenience, there is no just and reasonable explanation that supports allowing exemptions for out-of-market supported resources given the flexibility provided by the second element of the proposed modifications to the market structure – the FRR-Alternative. If a resource is receiving material out-of-market support, it should be mitigated. Any other result allows exactly the sort of market distortion that was the subject of the original complaint, regardless of the type of resource or who is providing the out-of-market support or the form of the out-of-market support.

The resource specific FRR structure ensures states that want to pursue legitimate public policy goals related to selecting or encouraging specific generation mixes to supply their customers' load, have the ability to do so. This is a critical component of a workable, just and reasonable market design. States, which have clearly and unambiguously retained regulatory authority over "facilities used for the generation of electric energy,"[8] must not be frustrated in exercising that authority by market structures that effectively ignore the fact that policy supported generation resources will be available to supply both energy and reliability (capacity) services. Appropriate, just and reasonable market structures will achieve the combined, complementary, and coequal goals of recognizing the reality that these policy resources will be providing these physical services, while separating them from having material impact on the market price setting process. Application of a MOPR without the complementary option for state supported resources to enter a resource specific FRR, would result in distorted prices in

[8] *See* Federal Power Act, section 201(b)(1).

both the energy and capacity markets, and force customers to over procure and likely unjustly over pay for overall electric supply services.

Specifically, if public policy resources are subject to a MOPR, and thereby ignored in the capacity market, capacity prices will clear at a higher level than they otherwise would if the reliability contribution of these resources were recognized (as the resource specific FRR structure does by associating appropriate load with those generators). Conversely, if the policy resources do in fact enter or remain in the markets in fulfillment of the states' goals, then they will in fact supply energy along with all resources not subject to the MOPR that clear in the capacity market, resulting in an oversupply situation and depressed energy prices. The resulting undervaluing of the energy market and overvaluing of the capacity market has the consequence of shifting reliance of all resources to capacity revenues and discourages, or at least undervalues efficiency in the energy market. This is exactly the opposite of what should be the intent of an efficient market design where value is placed on the delivered product (energy), and the "missing money" that is supplied by the capacity market is minimized. FERC's proposed dual market structures of a clean MOPR coupled with the resource specific FRR, elegantly avoids this inefficient outcome, recognizes the contributions of policy supported resources, and isolates prices setting in the remaining competitive market to competitive merchant participants.

Although the purest and theoretically best application of the MOPR would be to mitigate any out of market support, in practice it may be preferable to have some limited exceptions to this rule. PJM has proposed, and the PSEG Companies support, a materiality threshold that would avoid unnecessarily complicating both PJM's role in implementing, and bidders' roles in participating in the capacity market. The PJM proposed threshold of 1% of actual or anticipated market revenues is an appropriately strict standard.

The current PJM tariff also provides for a unit size based exemption threshold for application of the MOPR of 20 MWs. While the PSEG Companies can support a very small unit-size (MW) exemption for the same reasons that a subsidy-size materiality threshold may make sense, we do not agree with the existing MW 20 level. Many state policy supported resources are small in nature and can be easily added (or uprated) in small increments that would conveniently avoid tripping the proposed 20 MW level in any given year or at any single site, while over time adding considerable total capacity. To avoid or at least minimize the market impact of large overall increases through the use of smaller resources, any approved unit size based exemption from the MOPR should be set at a level that minimizes this risk such as not greater than 1 MW.

Other than those materiality driven exceptions, there should be no other exemptions from application of the MOPR. Other proposed exemptions such as self-supply and federal program subsidies which are not available to all resource types cannot be supported by any principled rationale for an exemption and would only serve to perpetuate discriminatory and preferential flaws in the market design which will likely lead to future successful challenges. It is not enough to continue these exemptions, along with the distortive impacts they have on the capacity market, simply because they previously existed in a market design that the Commission has now found to be unjust and unreasonable. The purer, more defensible structure of a clean MOPR and a flexible resource specific FRR, along with the existing FRR rules in the PJM Tariff, provides a workable accommodation of legitimate state policy goals, including any desire of states to avail themselves of the financial benefits associated with technology specific federal subsidy programs, as well as any load serving entities' desire to self-supply.

1. FRR-Alternative resources must be matched with the appropriate amount of load consistent with the reliability requirement

FERC's order clearly provides that when subsidized resources are paired with load and removed from the market, the subsidizing entity should have to procure its load and its associated reserve requirement. This is the appropriate solution because it ensures that the subsidizing entity meets its full obligation with its selected resource, and avoids utilizing the market to its advantage at the expense of others in procuring sufficient reliability. This approach achieves FERC's desire to provide transparency to the impacted load as to the full cost associated with the resource procurement.

2. The Reserve requirement must be defined appropriately to avoid free riders

It is important that the construct ultimately adopted by the Commission define the reserve requirement in a manner that will enable appropriate price signals to be achieved and will avoid price shifting between resources participating in the market and those resources that select the FRR-Alternative. To accomplish this objective, the reserve requirement for the load associated with the FRR-Alternative should be set at the reserve margin determined by the auction. If the value is fixed at a targeted reserve margin and the market clears at a higher reserve margin – as it almost always does – the subsidized resource and associated load would benefit as free riders from the additional reliability procured through the market without having to contribute toward that benefit.

For example, in the most recent PJM Base Residual Auction ("BRA"), the auction cleared at a reserve margin of approximately 22% while the targeted reserve margin was approximately 16%. If the FRR-Alternative resource and the associated load only had to satisfy the targeted reserve requirement, their economic contribution to the system reliability would only be at the 116% level. However, by being part of the larger PJM market, these resources and their

associated load would receive the reliability benefits associated with a 122% reserve requirement. Effectively FRR-Alternative resource and associated load would gain additional reliability from the remainder of the market while not having to pay for that benefit thereby advantaging them at the expense of the market.

As discussed above, it is important that FERC adopt a construct where the reserve requirement for the load associated with an FRR resource be set at the auction established reserve margin to prevent cost shifting from market participants to carved out resources. While the cost shifting issue exists in the current PJM construct, it has not been a significant problem because FRR participation has been limited to a small part of the PJM market. The Commission's recommendation for a MOPR with few to no exemptions has the potential to change that dynamic significantly. It is therefore important that the PJM tariff provisions adopted as part of this FERC Order address this issue, not just for FRR resources, but also for the FRR construct as well. Entities that are currently participating in the FRR construct – as of the 2021/2022 BRA – are subject to mandatory stay-in and stay-out provisions and therefore have made their decisions based on the construct that exists today where resources are procured at the targeted reserve margin. Changing the rules midstream for those entities would be arbitrary and disruptive to their business model. We therefore recommend that entities that participated as FRR resources in the 2021/2022 BRA be grandfathered into the existing rules. Finally, we believe that it is critically important that PJM be directed to modify its Tariff to ensure that resources that elect the FRR-Alternative for the 2022/2023 BRA and beyond be required to achieve a reserve margin consistent with levels established through the market.

B. <u>The Administration of the New Construct Must be Conducted By PJM, Including the FRR-Alternative Mechanism</u>

In order for the FRR-Alternative to be accomplished efficiently, the mechanism adopted

by FERC must require that PJM administer and clear the auction appropriately. Carving out certain resources and load can create significant administrative difficulties, including clearing the appropriate reserve margins (as discussed above) and honoring locational constraints in the PJM system. Although the FRR-Alternative resources are being removed from the market in the proposed approach, the physical existence of these resources and load does not change. Accordingly, the most efficient approach to achieving a just and reasonable outcome for all resources is to allow PJM to manage the auction clear with the participation of all resources and load and then adjust the outcomes by removing the FRR-Alternative resources and associated load. PJM is well positioned to manage all appropriate market outcomes and to settle all obligations as they move to delivery. For these reasons, it is our recommendation that PJM continue to manage and serve as the administrator of all aspects of the capacity market, including the coordination of FRR resources with their associated load.

1. <u>The clearing mechanism should include elements that will minimize the need for complicated location determinants</u>

The PSEG Companies recommend that the tariff provisions ultimately adopted by the Commission contain a clearing mechanism that is administered by PJM and includes the following elements:

1. All load within PJM must be included and represented on the demand curve;

2. All resources participating in the market must be represented at their offer price;

3. All resources receiving out-of-market payments that are not matched with an associated load must be represented at their MOPR price;

4. All FRR-Alternative resources with a matched load must be represented at their chosen offer price;

5. PJM must administer the auction with all resources included; the FRR-Alternative resources and their associated load (with the associated reserve margin established by the auction clear) should be included in the auction and then removed from the clearing results;

6. The revenue that would have been received by the FRR-Alternative resources should be credited against the costs of the associated loads to ensure both come out of the market with the correct impacts and a net zero effect on the market;

7. All other resources and load should settle consistent with the existing PJM rules; and

8. The FRR-Alternative resources and their associated load should balance their accounts with PJM (providing their own unique negotiated settlement terms to PJM) and be settled through PJM billing.

This approach minimizes the need for complicated locational determinants because all locational constraints will be appropriately recognized and compensated and all reliability requirements will be satisfied. The potential for cost shifting between the FRR-Alternative resources and the remaining market participants is minimized and the appropriate reserves would be procured by all entities. Administering settlement through PJM also facilitates the correct allocation of all cost responsibilities and is supportive of states' efforts to align parts of their load with their desired resources.

Alternative approaches that will likely be proposed by other commenters may raise issues concerning, among other things: (1) locational differences; (2) allocation of transfer capability between Locational Deliverability Areas ("LDAs"); (3) altering auction parameters; (4) determining appropriate reserve levels; and (5) appropriate cost allocations. The Commission's Order clearly outlines an approach that it will deem acceptable. The PSEG Companies submit

that an auction mechanism that is administered by PJM and includes the elements described above will be the most effective means to achieving the Commission's goals in this proceeding.

Finally, states may elect different ways of supporting public policy resources. Given these potential differences, different entities may be responsible for the support payments versus the direct capacity payments through the FRR-Alternative construct in lieu of capacity payments through the RPM clearing mechanism. Therefore, states need the flexibility to direct the credit back to load that comes from removing the policy resource from the auction clearing results. As a default, the PSEG Companies recommend crediting the "associated load" – the load that was identified by the state as sponsoring the public policy resource. States should also have the flexibility to direct this credit differently, provided however, that such credit allocation is consistent with promoting a competitively neutral wholesale power market.

C. The PJM Tariff Adopted By FERC Should Contain Certain Specific Design Principles

1. Reference Prices Applied to Resources Subject to the MOPR Should Be Based on Technology Type Without an Option for Unit-Specific Determinations

The MOPR must include methodologies for determining reference prices for units that are deemed to be receiving "actionable subsidies." For new units, the references prices should be based on the gross Cost of New Entry ("CONE") applicable to the class of generation technology to which the units belong. For existing units, the reference prices should be based on the Avoidable Cost Rate ("ACR") for the unit technology class – the costs that could be avoided if the unit retired or was mothballed. Unit technology classes recognized for MOPR reference prices should have a reasonable degree of granularity to reflect material cost differences. However, it would not be necessary to have separate reference prices to reflect every difference in unit characteristics.

Generally, the CONE for new units should be calculated in the same manner as the CONE is determined for the combustion turbine and combined cycle plants under the current MOPR procedures. This is an analysis that builds up the costs of constructing and operating these plants – including costs for equipment, labor, maintenance, operating and financing, levelized over an assumed useful life. PJM and the Independent Market Monitor for PJM ("IMM"), moreover, have experience in calculating ACRs for many unit types including nuclear and coal units. These same techniques could be used for other technology types recognizing that existing renewable resources generally will have very low ACRs reflecting the lack of significant going-forward costs.

The gross CONE and ACR values need to be adjusted to reflect offsets for energy, capacity and ancillary services. While this calculation should reflect the location of the resource, it should be based on historical data.[9] Attempting to apply forecasts would add much greater complexity and would be fraught with controversy.

The MOPR will also need rules to distinguish between new and existing units. The current PJM rule that "new" units clearing an auction with a mitigated reference price offer become "existing" resources should be retained. However, in order to accommodate state public policies, there also needs to be a rule that allows new subsidized units to eventually qualify for ACRs even if they do not clear an auction. There does not appear to be an obvious bright-line test for when to allow this to occur. Consideration could be given to creating a maximum period for application of the new unit reference prices. Five years may be a reasonable duration for this purpose, showing a significant level of commitment by the State or other governmental agency towards achieving the policy underlying the support payments.

[9] In the current PJM tariff, this calculation is done based on the three year historical average of energy and ancillary service revenues at the unit's specific location.

Finally, the existing unit-specific exemption under the MOPR should not be retained. The Commission previously favored the unit-specific resource exemption because of concerns that prices to consumers would be increased unnecessarily if units with particularly low costs were not allowed to bid consistently with their true economics. However, this concern is diminished under the FRR-Alternative because many units that receive support payments will be removed from the auction entirely along with a commensurate level of load. Further, the unit-specific exemption has produced controversial outcomes in the past and has required the expenditure of significant resources by PJM and the IMM. These administrative difficulties and implementation burdens would be magnified exponentially when the MOPR is expanded to apply to many more units. Accordingly, on balance, the unit-specific MOPR exemption should be removed.

2. Application of the MOPR Entry and Exit Provisions

The FRR-Alternative should include a mechanism to allow units removed from RPM auctions because of their out-of-market payments to participate in future RPM auctions when they no longer receive those support payments. To accommodate this, it remains critical to minimize potential negative market outcomes. First, it would be disruptive of market outcomes if resources were allowed to toggle back and forth between being FRR-Alternative resources and RPM auction participants. Second, resources should not automatically be permitted to perform significant capital improvements while receiving support payments and then re-enter the RPM market with the advantages gained through making those improvements.

Balancing these considerations, while it seems clear that FRR-Alternative units should not be categorically prevented from re-entering RPM markets when support payments expire or the units cease to qualify, it is also evident that there needs to be some restrictions to prevent market manipulation or disruptions. A practical approach would have these resources offer and

clear in the market using the applicable MOPR price. This would prevent toggling and would ameliorate the impact of units that return to the market after making substantial capital improvements. It would also be appropriate to consider whether these units should cease to be subject to the MOPR provisions after a specified period of time.

3. The Approved Tariff Provisions Should Include a Transition Mechanism for the Implementation of the FRR-Alternative Mechanism for the Upcoming Base Residual Auction Schedule for August 2019

The proposed changes to the MOPR and proposed introduction of the FRR-Alternative would be very significant changes to the existing RPM design. Implementing these changes in time for the upcoming BRA now scheduled for August 2019 will be challenging for PJM and the IMM. But states face even greater challenges in implementing the FRR-Alternative. They must determine whether they have existing statutory authority to utilize the FRR-Alternative and, if they determine that they do have such authority, will need to modify whatever supply procurements mechanisms are used in the state to allow FRR-Alternative resources to be included in the capacity portfolio serving the state. For states that lack existing statutory authority, it would be necessary to introduce and obtain passage of changes to currently effective state laws. In either event, for states to complete all of the necessary tasks to implement the FRR-Alternative in time for the August 2019 BRA filing requirement deadlines will be difficult if not impossible.

Recognizing these challenges and the desire of the Commission to accommodate the states' implementation of their policies, the Commission should direct PJM to create a transitional mechanism for the August 2019 BRA that will have relaxed standards for the FRR-Alternative. First, PJM has proposed that states wishing to use the FRR-Alternative should be required to give three months advanced notice. This appears to be unnecessarily long. Two

months should be sufficient. Second, and most importantly, PJM should be directed to relax the documentation requirements places on the state to utilize the FRR-Alternative. The PSEG Companies support strong documentation and commitment requirements for the PJM auctions in general, but recommend for the August 2019 BRA, that the appropriate state commission or other state agency with oversight of the procurement of supply within the state have the ability to use the FRR-Alternative for an identified capacity resource based on an order or declaration that it will engage in reasonable good faith efforts to implement the FRR-Alternative. A demonstration of this along with a definitive timeline outlining the mechanism to achieve this objective should be supplied prior to one week before the commencement of the BRA in August of 2019. Failure to meet this standard will result in resources with actionable subsidies entering the market at MOPR mitigated levels.

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II. CONCLUSION

The PSEG Companies respectfully requests that, if the Commission continues to deem it necessary to modify PJM's RPM, it adopt the expanded MOPR and the FRR-Alternative as a package as well as the design elements and principles described above.

Respectfully submitted,

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Dated: October 2, 2018

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon the official service list in accordance with the requirement of Rule 2010 of the Commission's Rules of Practice.

Dated at Newark, New Jersey, October 2, 2018.

Very truly yours,

Robert Gardinor

Robert Gardinor
Paralegal

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)	Docket No. RM18-1-000

ANSWER OF THE PSEG COMPANIES IN OPPOSITION TO MOTION TO EXTEND TIME FOR COMMENTS

Pursuant to 211 and 213 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") Rules of Practice and Procedure,[1] the PSEG Companies[2] respectfully submit this answer opposing the joint motion of Advanced Energy Economy, American Biogas Council on Renewable Energy, American Petroleum Institute, American Public Power Association, American Wind Energy Association, Business Council for Sustainable Energy, Electric Power Supply Association, Electricity Consumers Resource Council, Energy Storage Association, Interstate Natural Gas Association of America, National Rural Electric Cooperative Association, Natural Gas Supply Association and Solar Energy Industries Association (collectively, "Movants") for an extension of the comment period for the initial comments and reply comments.[3] The PSEG Companies respectfully request that the Commission deny the Motion.

The Secretary of the Department of Energy's Notice of Proposed Rulemaking ("NOPR") states that the premature retirements of fuel-secure resources impose serious risks to the electric grid and the Commission must take immediate action.[4] The NOPR further explains that "the

[1] 18 C.F.R. §§ 385.211 and 385.213.

[2] The PSEG Companies are Public Service Electric and Gas Company, PSEG Power LLC and PSEG Energy Resources & Trade LLC.

[3] Joint Motion for Extension of Time and Request for Expedited Treatment of the Energy Industry Associations, Docket No. RM18-1-000 (filed October 3, 2017) (the "Motion").

[4] Secretary of Energy's Direction that the Federal Energy Regulatory Commission Issue Grid Resiliency Rules Pursuant to the Secretary's Authority Under Section 403 of the Department of Energy Organization Act, (Sept. 28, 2017) at 1-2, 6, 11 ("NOPR").

Commission has developed an extensive record on price formation in the Commission-approved ISOs and RTOs."[5] Notably, over the last several years, the Commission has held workshops, technical conferences and invited comments on a number of important issues, including, but not limited to, various price formation reforms,[6] the intersection of state policies and the wholesale markets,[7] and the functioning of the wholesale capacity markets.[8] Through these proceedings, market participants have had the opportunity to provide the Commission with a full record regarding the market design flaws that need to be addressed and to propose solutions to address those flaws. The Commission can draw upon its existing record as well as the comments submitted in this proceeding to craft its final rule. Importantly, the NOPR requires the Commission to take final action within 60 days of the publication of the NOPR in the *Federal Register*. The Commission should not delay the opportunity for the industry to comment on the proposal contained in the NOPR or shorten the timeframe in which it has to evaluate those comments. Accordingly, the PSEG Companies respectfully request that the Commission deny the Motion.

[5] *Id.* at 8-10.

[6] Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators, Docket No. AD14-14-000.

[7] State Policies and Wholesale Markets Operated by ISO New England, Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C., Docket No. AD17-11-000.

[8] Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, Docket No. AD13-7-000.

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WHEREFORE, the PSEG Companies respectfully request that the Commission deny the Motion.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)	Docket No. RM18-1-000

COMMENTS OF THE PSEG COMPANIES

Pursuant to Section 212 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") Rules of Practice and Procedure,[1] the PSEG Companies[2] submit these comments in response to the Secretary of the United States Department of Energy's ("Secretary") proposed rule for final action by the Commission ("DOE Proposal")[3] and the questions posed by the Commission on October 4, 2017.[4]

I. Executive Summary

The PSEG Companies support immediate implementation of the DOE Proposal as an interim measure to prevent the premature retirement of fuel-secure baseload units that are undervalued as a result of distortions in organized electricity markets. The DOE Proposal calls for the full recovery of the costs for certain eligible units physically located within the Commission-approved organized markets. Under the DOE Proposal, units would be eligible for cost recovery if they are able to provide essential energy and ancillary reliability services and have a 90-day

[1] 18 C.F.R. § 385.212 (2017).

[2] The PSEG Companies are comprised of Public Service Electric and Gas Company ("PSE&G"), PSEG Power LLC ("PSEG Power") and PSEG Energy Resources & Trade LLC ("PSEG ER&T").

[3] Department of Energy, *Grid Resiliency Pricing Rule,* Notice of Proposed Rulemaking, 82 *Fed. Reg*. 46940 (October 10, 2017).

[4] Grid Reliability and Resilience Pricing, Docket No. RM18-1-000 (issued October 4, 2017).

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fuel supply on site.[5] The resource must also be compliant with environmental regulations and must not be subject to cost-of-service rate regulation by any State or local authority.[6] Finally, the rule requires the regional transmission providers ("RTO") or independent system operators ("ISO") to establish just and reasonable rate tariffs for the recovery of costs and a fair rate of return.[7]

The PSEG Companies support the Secretary's efforts to immediately address the erosion of resiliency of our electric grid due to the risk of premature retirements of baseload generation. Failing to act immediately would cause irreparable harm to these generation units and risk disastrous consequences for consumers. The Commission and its jurisdictional RTOs/ISOs also must develop permanent solutions that improve price formation in the markets and eliminate distortions that harm baseload units.

Current market designs fail to value generator attributes that contribute to the strength and reliability of the grid. The current market does not ensure that the grid can withstand disruptions as a result of overreliance on gas-fired generators whose fuel requirements are met from remote, just-in-time supply sources. Not only is there the potential for serious adverse economic consequences but the loss of a diverse fleet of baseload resources would also pose national security concerns and threaten the welfare of American citizens. As recently stated by Commissioner Tim Echols of the Georgia Public Service Commission:

> God forbid that we have a terrorist hop the fence and use a shape charge filled with explosives to blow one or all of the national pipelines that deliver this "just-in-time" resource, [i.e. natural gas] to power plants. With more and more plants

[5] DOE Proposal at 7, 11, 18.

[6] *Id.* at 7, 11-12.

[7] *Id.* at 7, 12.

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> using natural gas to generate electricity, a lengthy outage would create chaos in many states.[8]

The risk to the electric grid and to the citizens of our country if we have a portfolio of generating resources that is overly reliant on a single fuel source – particularly one that is dependent on "just-in-time" fuel – is very real. Putting our heads in the sand will not make the risk go away. Moreover, the premature retirement of nuclear units threatens critical national security interests associated with our military capabilities and with the avoidance of nuclear weapons proliferation.

Adopting the DOE Proposal as an interim measure would preserve these critical assets under cost-of-service rates and assure that the baseload resources that would be most critical to withstanding a protracted disruption of gas supplies are not prematurely retired. It is imperative that the Commission take steps now to staunch the flow of retirements of fuel-secure baseload units while effective market-based solutions to value the attributes these resources provide both to the grid and to society as a whole are developed. Implementing the DOE Proposal as an interim step would stabilize the earnings for qualified nuclear and coal units until a comprehensive, long-term market-based solution or set of solutions can be integrated into the RTO/ISO market designs.

This interim step, moreover, would safeguard the long-term efficiency of competitive markets which are currently undermined by distortions. Current market designs distort efficient market outcomes due to the disharmony between public policies and market operations. These designs fail to recognize the resiliency attri30butes of units with significant levels of on-site fuel and do not adequately value the critical reliability services being provided.

[8] Commissioner Tim Echols, *Why Nuclear Energy is a Matter of National Security*, Public Utilities Fortnightly, September 2017, at 66.

Preserving the viability of these units – particularly the nuclear units – through a short-term regime of cost-of-service payments accomplishes what the competitive markets would accomplish if they operated efficiently and properly valued all of these units' attributes. Implementing the DOE Proposal to preserve eligible units is thus a necessary interim step towards achieving an efficient market-based solution. Moreover, as discussed in detail below, we have included for the Commission's consideration, potential conceptual approaches for long-term solutions that would value resiliency and fuel security though market mechanisms.

Adopting the DOE Proposal as an interim measure should not delay the work that the Commission is undertaking to address price formation reforms that would avoid some of the continued distortions of competitive market results that disadvantage baseload resources. Thus far, the Commission has implemented a number of reforms including new rules on shortage pricing, offer caps and hourly re-offers. There is more work that needs to be done in this area. Notably, the fast-start pricing rules[9] and reforms in uplift allocation and market transparency are near-term items that the Commission could act on immediately. Also, the PJM energy price formation proposal[10] should be evaluated as part of the comprehensive solution to the challenges facing baseload units.[11] The Commission should also consider requiring the RTOs/ISOs under its jurisdiction to demonstrate that the reforms already implemented are achieving their intended

[9] Fast Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, Notice of Proposed Rulemaking, 157 FERC ¶ 61,213 (December 15, 2016).

[10] PJM Interconnection, L.L.C., Energy Price Formation and Valuing Flexibility (dated June 15, 2017), available at: http://www.pjm.com/~/media/library/reports-notices/special-reports/20170615-energy-market-price-formation.ashx.

[11] U.S. Department of Energy, Staff Report to the Secretary on Electricity Markets and Reliability, August 2017 ("DOE Staff Report"), available at: https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf. The DOE Staff Report recommended that FERC expedite its efforts to improve energy price formation and observed that after several years of fact finding and technical conference, the record now supports energy price formation reforms such as those proposed by PJM. DOE Staff Report at 126.

objectives, especially regarding the shortage pricing reforms. We therefore respectfully request that the Commission promptly finalize the fast-start pricing reforms and direct PJM through the Commission's Federal Power Act ("FPA") Section 206 authority to submit its energy price formation proposal so that it can be fully evaluated by the Commission.

II. Comments

A. The Commission Must Take Immediate Action to Prevent the Premature Retirement of Baseload Resources

The DOE Proposal states that "[i]t is time for the Commission to issue rules to protect the American people from energy outages expected to result from the loss of … fuel-secure generation capacity."[12] The PSEG Companies agree that immediate action is needed to preserve fuel-secure baseload resources given the important resiliency and security contributions they provide to the electric grid. Nuclear plants are being financially challenged by current and expected market conditions. To a degree, the RTO/ISO wholesale markets are achieving their original objectives – creating market signals that incent both new build and retirements through energy and capacity market prices. Time has revealed, however, that the scope of the original intent is too narrow. The energy markets are currently designed to incorporate only the direct costs of generating unit operations such as fuel, labor and maintenance costs. "External" costs such as those associated with the loss of fuel diversity and fuel security that expose consumers to potential catastrophic losses due to low probability, high impact events are completely ignored.

As discussed in the attached affidavit of Dr. Lawrence J. Makovich, a fuel diverse and resilient mix of generation technologies is an innate quality of an efficient electric market

[12] DOE Proposal at 3.

construct.[13] The current decline in fuel diversity thus exposes an *inefficiency* in existing markets. As Dr. Makovich explains:

> Efficient market price signals shape a diverse power supply portfolio with inherent resilient supply attributes. These resilience attributes exist because a cost effective supply portfolio involves a diverse mix of fuels and technologies with fuel and technology specific risk factors that are weakly correlated. Quite simply, there are significant benefits to an efficient electricity market outcome that generates a power supply portfolio that does not put all of the nation's power supply eggs in one basket.[14]

However, "[p]ublic policies that mandate and subsidize intermittent renewable technologies . . . result in inefficient market outcomes … ."[15] The lack of harmony between these public policies and the wholesale market construct "disproportionally reduce the market cash flow of non-peaking power plants,"[16] which in turn, is "causing premature baseload power plant retirements."[17] There have been announced retirements of 20 nuclear plants in the United States although in some cases the retirements have been averted due to state intervention.[18] PSEG's Chief Executive Officer Ralph Izzo succinctly explained the challenges that nuclear owners face in stating that: "… the need to be good stewards of your capital, and as much as we think these

[13] *See* Attachment A, "Affidavit of Dr. Lawrence J. Makovich," Docket No. RM18-1-000 (October 23, 2017) ("Makovich Affidavit").

[14] Makovich Affidavit at 3-4.

[15] *Id.* at 4.

[16] *Id.*

[17] *Id.* at 6.

[18] Jeremy Carl and David Fedor, Keeping the Lights on at America's Nuclear Plants, Hoover Institution Press (2017), at 107-108, attached Attachment B: Recent Nuclear Plant Closures. The PSEG Companies wish to underscore that, to the extent the States continue to perceive a need to take action in order preserve critical generation attributes, the Commission should not interfere with those efforts. These matters are clearly within the purview of the States particularly given the lack of a comprehensive effort by the Commission to address this area. *See e.g.,* Pre-Technical Conference Comments of Lathrop Craig on Behalf of The PSEG Companies, State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C., Docket No. AD17-11-000 at 4 (filed April 26, 2017).

[nuclear] assets are critically important to the nation and to our company, if they are not economically wise to continue to operate, we won't operate them."[19]

PJM, in particular, historically has enjoyed a diverse and resilient portfolio of generating resources consisting primarily of coal, gas and nuclear generation. However, in recent years, both coal and nuclear plants have retired or have announced plans for retirement. This trend is moving the PJM resource mix towards a greater reliance on natural gas-fired generating resources[20] and exposing the power supply portfolio to a greater risk of single mode failure. The Commission should act immediately to address the current gap between public policies and market operations in PJM and develop a mechanism that ascribes value to resiliency attributes.

1. Resiliency is a Critical Component to a Cost Effective Electric Supply Portfolio

A truly resilient system is one that anticipates, prepares for and recovers quickly from high impact, low frequency events.[21] The RTOs/ISOs and the North American Electric Reliability Corporation ("NERC") have focused primarily on traditional measurements for system reliability that focus on protecting the system from short-term disruptions.[22] However,

[19] PSEG Financial Conference held March 6, 2017, materials available at: http://investor.pseg.com/event/conference/pseg-financial-conference.

[20] *See* PJM's Evolving Resource Mix and System Reliability (dated March 30, 2017), available at: http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

[21] Achieving resiliency has become an industry-wide concept that applies not only to generation resources, but also transmission system planning given the integrated nature of the electric grid. Notably, PJM is currently engaged in an effort with its stakeholders to develop criteria for resiliency in system planning. These efforts are equally as important as achieving resiliency of the generation fleet and should be vigorously pursued. *See* Resiliency in System Planning, PJM Planning Committee (dated August 10, 2017), available at: http://www.pjm.com/-/media/committees-groups/committees/pc/20170810/20170810-item-07-grid-resilience-in-system-planning.ashx.

[22] NERC recently raised concerns about how the changing resource mix, including the premature retirement of baseload generation, is altering the operating characteristics of the bulk power system. NERC noted that "[c]oal fired and nuclear generation have the added benefits of high availability rates, low forced outages, and secured on-site fuel. Many months of on-site fuel allow these units to operate in a manner independent of supply chain disruptions." Letter from Gerry Cauley, President and CEO of NERC to Secretary of Energy Rick Perry dated May

recent events have revealed that reforms are needed to create a robust system that anticipates and protects the grid from extended disruptions that could occur from natural or man-made events. At a minimum, reforms are needed to establish measures that ensure that the power supply portfolio is sufficiently diverse and therefore capable of continuing to provide consumers with electric services that cover basic needs when operating conditions deviate from normal, especially in an unexpected way for an extended period.

The 2014 Polar Vortex provides a clear example of the need for reforms that ensure that the electric grid is resilient, fuel diverse and fuel secure. The abnormal weather conditions during the Polar Vortex drove the power system demand for electricity to an all-time high winter peak demand in PJM and caused a higher-than-normal unavailability from natural gas-fired generating units. As the DOE Proposal explains, "[d]uring the Polar Vortex, PJM Interconnection ("PJM") struggled to meet demand for electricity because a significant amount of generation was not available to run. According to the DOE Staff Report, the loss of generation capacity could have been catastrophic, but a number of fuel-secure plants that were scheduled for retirement were called upon to meet the need for electricity."[23] The DOE Staff Report also noted that "overall nuclear generators performed extremely well during the Polar Vortex, with an average capacity factor of 95 percent."[24] Accordingly, diversity in the PJM generation portfolio during the Polar Vortex enabled nuclear units and oil and coal-fired units to continue supplying power to the system when the natural gas-fired units were experiencing fuel delivery constraints. Despite the demonstration of the value of diversity, the PJM portfolio has

9, 2017, Synopsis of NERC Reliability Assessments, The Changing Resource Mix and the Impacts of Conventional Generation Retirements at 2, available at: https://www.eenews.net/assets/2017/10/03/document_ew_01.pdf.

[23] DOE Staff Report.

[24] DOE Proposal at 5 (citing DOE Staff Report at 98).

become less diverse since the Polar Vortex. Dr. Makovich analyzed the outcome of the Polar Vortex under today's less resilient PJM power supply portfolio, including reductions for the Oyster Creek and Three Mile Island nuclear plants which are expected to retire in the near future. Under this analysis, there would have been a 1.4 GW average loss of load for 5 hours during extreme winter conditions.[25] He calculated the cost of such an outage to be around $1.2 billion.[26] Dr. Makovich also conducted an analysis of the potential Polar Vortex event assuming that plants now being evaluated for premature closure — Perry and Davis Besse — were no longer available. Under this analysis, the expected outcome is a 2.4 GW average loss of load for 9 hours with an associated outage cost of around $3.7 billion.[27]

The Polar Vortex, moreover, is only one type of event that could place the electric grid at risk. Other examples of *knowable* low probability, high impact events that have been recently experienced include Super-storm Sandy that hit New Jersey in 2012, a gas supply disruption like the Texas Eastern pipeline explosion that occurred in western Pennsylvania in 2016 and the gas storage field issues associated with the Aliso Canyon natural gas facilities in California in 2015. Other *knowable* conditions with which we have familiarity would be natural events such as wildfires, heat waves and droughts. But there are still other events, that while *knowable* in theory, we have had very little real experience with such as physical and cyber-attacks on the electric system by terrorists. Finally, there are completely unpredictable political events, such as the possibility of a ban on fracking or totally unknown risks that cannot even be fathomed at this time. Some of these events could be much more impactful than the Polar Vortex, and there is

[25] Makovich Affidavit at 11.

[26] *Id.*

[27] *Id.*

always the risk of two negative events that occur simultaneously, *e.g.*, a pipeline failure at the same time as an extreme cold weather event.[28]

To "put all of the nation's power supply eggs in one basket" would be a sadly misguided policy. The costs and adverse impacts on human beings associated with a single event that triggered a common mode failure of a particular technology on which we have placed disproportionate reliance, could wipe out decades of claimed savings associated with "market efficiencies." A long-term practical view that takes into account both cost and non-cost factors is the only prudent policy choice.

While the Polar Vortex revealed a number of market flaws and the potential impacts of those flaws, it incented the RTOs, particularly PJM and ISO New England Inc. ("ISO-NE"), to propose reforms that were specifically focused. The new reforms did not consider whether it was appropriate to provide value to resiliency attributes that would be needed to meet extended disruptions of gas pipeline services. The new capacity market designs implemented by PJM and ISO-NE addressed specific concerns around unit availability and the non-firm nature of most gas pipeline services used by generators. These reforms placed the risk of performance on market participants in the face of a very specific type of event; the reforms, however, do not ensure that the electric power system is configured in a way that would be able to sustain, adapt and recover from physical disruptions such as of gas supply force majeure events which even excuse performance of firm delivery obligations.

[28] *See generally*, Makovich Affidavit at 12-13.

2. Maintaining Diversity and Fuel Security in the Generation Portfolio and, In Particular, Maintaining Nuclear Generation is Necessary as a National Security Objective

Maintaining fuel diversity and fuel security is also a matter of national security for the United States. This is particularly true with respect to nuclear generation. As stated recently by Admiral James O. Ellis Jr., (USN) (ret.) and George P. Shultz in the foreword to *Keeping the Lights on at America's Nuclear Power Plants:*[29]

> Someone concerned with security can appreciate that the fuel of nuclear power plants can be provided entirely from friendly suppliers, with low-price volatility, and long-term supplies stored on-site and not subject to weather disruptions. * * * More broadly, a well-functioning domestic civil nuclear "ecosystem" is intertwined with our space and military nuclear capabilities, such as the reactors that power our aircraft carriers and submarines.[30]

All of these aspects of nuclear generation's contributions need to be recognized, but the existing RTO/ISO power markets do not do so.

As further explained by Jeremy Carl, one of the authors of *Keeping the Lights on at America's Nuclear Power Plants*:

> America's maintaining its nuclear technological capability has profound impacts on America's national security. * * * Without a course correction [to support nuclear generation] we will see the future of nuclear energy determined by China and Russia, who continue to move aggressively in this area. China will complete five new nuclear power plants this year alone.[31]

"[T]he atrophy of our domestic nuclear-power sector would mean a profound loss of capability in our military."[32] In addition, "[t]he U.S. has traditionally used its leadership

[29] Jeremy Carl and David Fedor, Keeping the Lights on at America's Nuclear Plants, Hoover Institution Press (2017).

[30] *Id.* at vii.

[31] Jeremy Carl, *Keeping the Lights on at America's Nuclear Plants,* National Review (2017), available at: http://www.nationalreview.com/article/450114/how-save-americas-nuclear-industry.

[32] *Id.*

in the supply of nuclear technologies to make it very difficult for nuclear-power-plant operators to proliferate the technology."[33] It is appropriate for the Commission to be cognizant and to take steps to preserve all of the important, unique contributions made by nuclear generation as part of a diverse portfolio of generation assets in our country. As Mr. Carl states, "[nuclear generators] have substantial strategic dimensions, more than any other form of energy."[34]

B. The Commission Should Adopt the DOE Proposal As an Interim Measure

The Commission should take the opportunity presented by the DOE Proposal to correct the market distortions disfavoring fuel-secure baseload generators caused by the disharmony between public policy goals and market operations as well as the failure of the markets to explicitly value resiliency attributes such as fuel diversity and fuel security. As a first step, the Commission should halt the immediate threat of losing vital fuel-secure baseload resources and allow eligible resources to be compensated through cost-of-service payments, including a reasonable return on investment, in order to preserve the fuel diversity, resilient and fuel secure generation portfolios that currently exist in each of the RTOs/ISOs. This mechanism should be implemented as an interim measure to prevent the further loss of units until an effective market-based solution is developed and implemented by the RTOs/ISOs. Although a superior, market-based mechanism could be developed for the future, as shown by Dr. Makovich, "[o]n an interim basis, the Proposed Rule provides an immediate step to avoid the further erosion of existing diversity of the nation's generation portfolio."[35]

[33] *Id.*

[34] *Id.*

[35] Makovich Affidavit at 17.

Claims will undoubtedly be made that this step is not justified because the threats have not been adequately quantified, resiliency has not been adequately defined, the exact amount of cost-effective resiliency needed has not been established and the like. The Commission can and should resist these attempts to delay or avoid decisive action to protect the electric grid. Because the individual threats faced are low probability events, they are not conducive to being analyzed in this fashion. What is known is that the risks are real and that, if they do occur, they could be catastrophic. Moreover, as Dr. Makovich demonstrates, the probability of some event that will stress particular generator technology types, in the aggregate, is much higher.[36] There is an urgent issue facing the country and "analysis paralysis" is not a solution.

Declining to act on the basis that exact determinations of costs and benefits associated enhancing grid reliability cannot be calculated precisely would be neither necessary nor appropriate. The Commission is not required to "engage in painstaking cost benefit analysis" when setting rates, *Process Gas Consumers Group v. FERC,* 866 F.2d 470, 477 (D.C. Cir. 1989). When evaluating the justness and reasonableness of a rate, the Commission must only conduct a "candid, common-sense assessment," *Process Gas,* 866 F.2d at 477, which can include the "consider[ation of] non-cost factors." *Pub. Utils. Comm'n of Cal. v. FERC,* 367 F.3d 925, 929 (D.C. Cir. 2004) (citing *Permian Basin Area Rate Cases,* 390 U.S. 747, 791 (1968)). These include the critically important benefit of reliable power. *See, e.g., NAACP v. FPC,* 425 U.S. 662, 670 (1976) (FERC must "promote the orderly production of plentiful supplies of electric energy ... at just and reasonable rates"). The Commission has a more than sufficient basis to adopt the DOE Proposal in order to protect consumers and our national security.

Indeed, Courts have affirmed, again and again, that system reliability is a significant

[36] Makovich Affidavit at 11-13.

benefit to customers. *See Elec. Consumers Resource Council v. FERC,* 407 F.3d 1232, 1240 (2005) (affirming Commission's policy judgment in balancing short-term cost increases with the long-term reliability benefits of reducing price volatility and encouraging entry of new capacity resources); *see also Cent. Hudson Gas & Electric Corp. v. FERC,* 783 F.3d 92, 110-11 (2015) (affirming both the Commission's focus on reliability and its predictive judgments about long-term benefits in adopting new capacity zone); *Ill. Commerce Comm'n v. FERC,* 721 F.3d 764, 775 (7th Cir. 2013) (recognizing that system reliability is a benefit to market participants and consumers); *Blumenthal v. FERC,* 552 F.3d 875, 879 (2009) (describing system reliability as "a primary goal").

The Court of Appeals for the District of Columbia Circuit reaffirmed this point recently in *Advanced Energy Management Alliance v. FERC*, 860 F.3d 656 (D.C. Cir. 2017) in upholding the PJM "capacity performance" program. The Court stated:

> [T]he Commission decided that, on balance, increased system reliability justified even a net increase in costs. *See Consol. Edison Co. of N.Y., Inc. v. FERC*, 510 F.3d 333, 342 (D.C. Cir. 2007). Increased costs can be "just and reasonable" if the costs are warranted. 16 U.S.C. § 824d(e). The Commission explained the important non-cost reasons for approving PJM's proposal. It does not have to find net savings. *Process Gas Consumers Grp. v. FERC*, 866 F.2d 470, 476-77 (D.C. Cir. 1989). We defer to the Commission's weighing of the various considerations and ultimate "policy judgment." *Md. Pub. Serv. Comm'n v. FERC*, 632 F.3d 1283, 1286 (D.C. Cir. 2011).

Similarly, the DOE Proposal for cost-of-service support to fuel-secure baseload generators with important resiliency characteristics that address highly disruptive loss of load events provides "increased system reliability" and is justified based on "important non-cost reasons."

In any event, the Commission need not be concerned with causing a rise in costs to consumers by taking steps to preserve nuclear generation. To the contrary, preserving nuclear generation, particularly in PJM, will save consumers millions of dollars. As Dr. Makovich

explains, "the current diversified U.S. electric supply portfolio lowers the cost of electricity production by about $114 billion per year and lowers the average retail price of electricity by 27% compared with a less efficient diversity case."[37] Further, [p]reventing the erosion in reliability associated with a less resilient electric supply portfolio mitigates an additional cost of $75 billion per hour associated with more frequent power supply outages… ."[38] Dr. Makovich also compared the broader economic impacts of the less efficient diversity case with the IHS Markit baseline simulations of the U.S. economy and found that within three years of the retail price increase: (1) the 27% retail power price increase associated with the less efficient diversity case causes a decline of real US GDP of 0.8% equal to $158 billion; (2) there will be a reduction in 1 million jobs; and (3) a reduction in real disposable income per household by about $845 (2016 dollars) annually, which is equal to 0.76% of the 2016 average household disposable income.[39]

There is Commission precedent for a limited out-of-market solution such as the suggested approach. Specifically, beginning in 2013, ISO-NE proposed tariff reforms that would provide out-of-market payments to certain resources in order to maintain reliability during the winter months ("Winter Reliability Program"). ISO-NE stated in its filing that the Winter Reliability Program was a "time-limited, discrete, out-of-market solution" while a number of longer-term solutions were being developed to address the problems that necessitated the Winter Reliability Program. The Commission explained that "given the importance of ensuring reliability in New England" in the face of the particular challenges facing ISO-NE, such as increased reliance on

[37] Makovich Affidavit at 15-16.

[38] *Id.* at 16.

[39] *Id.*

natural gas-fired generation resources, the Commission would accept the Program for the limited period requested.[40] Moreover, in response to discrimination claims concerning the programs' limited participation, the Commission stated that "limiting participation to certain resource types is not unduly discriminatory but is a reasonable response to the challenge of balancing the competing goals of procuring incremental energy in time for this winter while attempting to reduce any resulting market distortions to the extent possible."[41]

The Commission's approval of the Winter Reliability Program provides a paradigm for the approached proposed here. Specifically, the premature retirement of nuclear units presents fuel diversity and security issues issue that must be immediately addressed by a time limited, discrete solution. As with the Winter Reliability Program, this interim solution would be implemented to address urgent circumstances and would provide the RTOs/ISOs with the breathing space needed to adequately study and evaluate a long-term market-based solution without further jeopardizing the overall strength of the electric system. If this step is bypassed, the lengthy stakeholder process to develop new rules may result in many of these resources being retired before a solution is developed.

C. The Criteria Contained in the DOE Proposal Are Appropriate

The DOE Proposal allows the full recovery of costs for certain eligible units physically-located within the Commission-approved organized markets.[42] According to the DOE Proposal, "eligible units must be able to provide essential energy and ancillary reliability services and have

[40] *ISO New England Inc.*, 144 FERC ¶ 61,204 at P 42 (2013).

[41] *Id.* at P 50.

[42] DOE Proposal at 11.

a 90-day fuel supply on site in the event of supply disruptions caused by emergencies, extreme weather or natural or man-made disasters."[43]

i. The Ninety-Day Fuel Requirement

The 90-day on-site fuel requirement is a reasonable criterion for an interim program as a benchmark of fuel security for the electricity grid, particularly as applied to the Mid-Atlantic and Northeast regions of the country. In these areas, the summer and winter periods when the peak demand typically occur are generally about three months in duration. A generation unit that has at least three months of fuel on-site thus can be assured of having sufficient fuel to be available to meet peak system demands even if it the unit cannot replenish its fuel supply at all during this period.

Further, recent experience demonstrates that gas pipeline fuel disruptions can last 90 days or longer. On April 29, 2016, an explosion occurred on a Texas Eastern 30 inch natural gas pipeline operated by Spectra Energy in Salem Township, Westmoreland County Pennsylvania.[44] In addition to the damaged pipeline, Texas Eastern stopped deliveries on two other pipelines in the area.[45] Because corrosion levels were at a rate of about five times the expected "normal" corrosion rate at a weld where the explosion occurred,[46] Texas Eastern evaluated all the welds on the three pipelines and excavated more than 600 sites to observe suspect welds.[47] Of these,

[43] *Id.*

[44] *See* Anya Litvak, *Natural gas explosion rocks Westmoreland County and U.S. gas markets*, Pittsburgh Post-Gazette, May 1, 2016, available at: http://www.post-gazette.com/local/westmoreland/2016/04/29/Emergency-crews-respond-to-gas-well-explosion-in-Westmoreland-County-pennsylvania/stories/201604290161.

[45] *See* September 13, 2016 Salem Township, Westmoreland County, Pa Special Meeting concerning findings from the Spectra Energy pipeline explosion investigation, at 22;16, available at: https://youtu.be/mpx2NBwqDSM).

[46] *Id.* at 16:20.

[47] *Id.* at 27:27.

repairs were effectuated at about a third of approximately 400 excavations completed at the time of a town hall meeting in Salem Township on September 13, 2016.[48] In addition, at the time that meeting was held, the pipelines were still not being operated at their full capabilities – more than four months after the incident occurred.[49]

PSE&G also recently experienced the protracted repair of a segment of pipeline it owns buried about 15 feet below the bed of the Hudson River. The "B" and "C" lines are 345 kV electric cables encased in oil-filled pipelines extending from Jersey City, New Jersey to New York City. In October 2016, a sheen of dielectric oil in the vicinity of the pipelines was detected near the New Jersey shore line.[50] While measures to contain the leaking oil were undertaken immediately, efforts to locate and repair the leak were delayed by the existence of debris from a collapsed pier wall on top of the right of way as well unsafe conditions created by instability in the existing pier structures.[51] These conditions had to be corrected before repair efforts could even commence.[52] Final repairs required excavation of the riverbed and a pain-staking inspection of the pipelines by divers. Repairs to the damaged "B" line – after the leak was located – were not completed until September 2017 – more than 11 months after the leak was first detected.

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[48] *Id.* at 42:05.

[49] *Id.* 22:20 – 22:27.

[50] *See* Form 10-Q PUBLIC SERVICE ELECTRIC & GAS CO, Filed: July 28, 2017 (period: June 30, 2017) at 36, available at: http://app.quotemedia.com/data/downloadFiling?ref=11718174&type=DOC&symbol=PEG&companyName=Public+Service+Enterprise+Group+Incorporated&formType=10-Q&formDescription=Quarterly+report+with+a+continuing+view+of+a+company%27s+financial+position&dateFiled=2017-07-280.

[51] *Id.*

[52] *Id.*

Ninety days of on-site fuel is thus reasonable because the approximate length of the Summer and Winter periods when the electric system is most likely to be under stress is ninety days. Further, assuring that resources with ninety days of fuel supply are preserved, thereby reducing the risk of electric curtailments caused by gas pipeline disruptions during peaks, enables pipeline repairs that take longer than ninety days to be done during non-peak periods when system demand is expected to be lower. Effectively, pipeline repairs could take up to nine months without necessarily causing system disruptions, *e.g*. September to May (two shoulder demand periods and one winter peak period). Periods longer or shorter than ninety days could possibly also be justified as reasonable; the Commission need not find that ninety days of on-site fuel is the *only* reasonable standard. Ninety days of on-site fuel supply is *a* reasonable fuel-security standard and ninety "does not have to be better than other estimates." *Advanced Energy Management Alliance v. FERC*, 860 F.3d 656, n. 8 (D.C. Cir. 2017).[53]

ii. <u>Capability To Supply Essential Energy and Ancillary Reliability Services</u>

The proposed tariff language provides that an eligible plant must be "able to provide essential energy and ancillary reliability services, including but not limited to voltage support,

[53] *See e.g, Elec. Power Supply Ass'n*, 136 S. Ct. 760 at 782 (2016) (Court "is not to ask whether a regulatory decision is the best one possible or even whether it is better than the alternatives," but rather must affirm the agency's finding so long as it examined the relevant data and articulated a rational connection between the facts found and the choice made."; *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74 at 109 (3d Cir. 2014)("[T]he fact that there may be a better, or more accurate, calculation does not render PJM's proposal unjust or unreasonable, or FERC's approval of it arbitrary and capricious."); *Serono Labs, Inc. v. Shalala,* 158 F.3d 1313, 1321 (D.C. Cir. 1998) ("[C]ourts are bound to uphold an agency interpretation as long as it is reasonable – regardless of whether there may be other reasonable, or even more reasonable, views"); *Fla. Gas Transmission Co. v. FERC*, 604 F.3d 636, 645 (D.C. Cir. 2010) ("[W]e do not ask whether record evidence could support the petitioner's view of the issue, but whether it supports the Commission's ultimate decision."); *see also Permian Basin Area Rate Cases*, 390 U.S. 747, 767 (1968) ("[T]his Court has often acknowledged that the Commission is not required by the Constitution or the Natural Gas Act to adopt as just and reasonable any particular rate level; rather, courts are without authority to set aside any rate selected by the Commission which is within a 'zone of reasonableness.'") (quoting *FPC v. Nat. Gas Pipeline Co*., 315 U.S. 575, 585 (1942)). *Duke Energy Trading & Mktg., L.L.C. v. FERC*, 315 F.3d 377, 382 (D.C. Cir. 2003).

frequency services, operating reserves, and reactive power."[54] Nuclear generators are capable of providing all of these services and under normal operations they provide voltage support and reactive power services. The PSEG Companies' experience as the operator of the Salem and Hope Creek nuclear plants, moreover, is that nuclear generators are among the largest providers of voltage support and reactive power services on the PJM system.

We understand that some parties are contending that the DOE Proposal expressly requires that eligible resources supply *all* of these services *all* of the time and that nuclear generation should somehow be *per se* disqualified. This is clearly contrary to the DOE Proposal's goals and common sense not to mention the fact that nuclear generation is expressly identified as one of the technology types the DOE Proposal is designed to address. Accordingly, to the extent deemed necessary to address such claims, the Commission should clarify that resources which routinely provide any of these ancillary services meet the eligibility requirements.

iii. Specific Components of the Cost-of-Service Recovery Mechanism

The PSEG Companies recommend the following specific components for inclusion in the cost-of-service mechanism:

- The level of the cost-of-service payments should be determined in a manner consistent with typical practices of regulated entities subject to FERC jurisdiction and should include a reasonable return on investment; also, cost-of-service recoveries should be net of market revenues so that units do not over-recover their costs.
- Units receiving cost-of-service payments should be required to bid into the energy markets at their short-run marginal costs and consistent with the unit parameters for the

[54] DOE Proposal at 18.

particular technology type; These requirements would preserve efficiency in the energy markets.

- In capacity markets, units receiving cost-of-service payments should be price-takers. Because the units would be expected to clear as capacity resources in an efficient market, participating in capacity markets replicates an efficient market outcome and assures that customers do not pay twice for the same capacity.
- RTOs/ISOs should adopt tariffs that authorize cost-of-service payments to preserve resiliency from the entire RTO/ISO in which the unit is located on a *pro rata* basis since the unit would help support the entire region in the event of a gas supply disruption.
- Units receiving cost-of-service payments should still be subject to performance penalties and should not be allowed to consider assessed performance penalties in determining net cost-of-service payments. This will create proper incentives for performance.
- Units eligible for cost-of-service payments should have the option to voluntarily seek cost-of-service rates from the Commission though a cost-of-service filing within 60 days of the effective date of a final order; because this will be an interim program to be effective until a market-based program can be developed, units should be required to demonstrate compliance with the eligibility criteria at the time of filing.
- The decision to participate in the program should be a one-time election that would terminate once the Commission has implemented the market reforms necessary to properly value generation attributes.

Certain of these recommendations are similar to the treatment accorded by the Commission to units receiving "reliability-must-run" payments in the past.

D. Adoption of an Interim Cost of Service Payment Mechanism for Eligible Plants Would Not Adversely Impact Competitive Market Outcomes

Adoption of a cost-of-service payment mechanism as an interim measure would not interfere with competitive market outcomes. The PSEG Companies anticipate that many commentators will contend that adoption of a cost-of-service payment mechanism will undermine competitive markets and will likely maintain that units receiving support payments result in "uneconomic retention" of those units. Such claims however do not hold up under analysis.

For "uneconomic retention" to be present it would need to be demonstrated that, in a competitive market, the affected units receiving the cost-of-service payments would otherwise retire. However, such is not the situation here, particularly as concerns the nuclear generators subject to the risk of retirement. As Dr. Makovich demonstrates in his affidavit, the current markets are distorted due to the disharmony between policy goals and the market construct.[55] He shows that the adverse impacts of the market dysfunctions fall most heavily on baseload generators.[56] Stated otherwise, in an efficient market, baseload generation would be more highly valued. In addition, the most prominent public policy goals creating market dysfunctions center around efforts to reduce carbon and other emissions into the atmosphere. In a properly designed market that valued carbon and other emissions abatement, nuclear baseload generation would receive higher revenues due to its low emissions footprint. Claims regarding "uneconomic retention," particularly as regards nuclear generation, thus ring hollow.

Commission precedent, moreover, supports this analysis. In *Independent Power*

[55] Makovich Affidavit at 2, 3, 5.

[56] *Id.* at 5.

Producers of New York, Inc. v. New York Independent System Operator, Inc., 150 FERC ¶ 61,214 (2015) ("*IPPNY")*, the complaint maintained that "reliability-must-run" support payments made to certain generators needed for local reliability requirements constituted "uneconomic retention" of those units that injured the competitive market.[57] The Commission rejected this claim:

> We agree with Dr. Patton that "the units are economic from the perspective of satisfying the NYISO's reliability requirements .... If the reliability needs satisfied by these units were reflected in the capacity market, the units would both clear." As Dr. Patton notes, these units would also contribute to addressing the NYCA capacity requirement in meeting the local reliability need. Thus, we agree with Dr. Patton that "it is efficient for these units to clear in the NYISO capacity market, [and] [a]ny provisions imposed that would cause them not to clear would be unreasonable."[58]

The situation here is directly analogous to that addressed in *IPPNY*. The units that would receive the cost-of-service payments under the DOE Proposal – in particular the nuclear units – would be "economic" if the market design were efficient. Similarly, if the market design included a component that valued resiliency, the units would also be expected to be "economic."

Finally, it should be noted, that about 30% of the units in PJM are currently under cost-of-service regulation[59] and that the PJM Independent Market Monitor deems both the energy and capacity markets to be competitive. It would thus be disingenuous to suggest that competition in the PJM market is incompatible with cost-of-service treatment for generators. If it were, the fact that almost 30% of the suppliers operate under a cost-of-service regime could not be reconciled with competitive operations. There is no apparent reason why competition would be extinguished if some set of additional resources also received cost-of-service support.

[57] *Id.* at P 3.

[58] *Id.* at P 66 (footnotes omitted).

[59] Source: SNL Energy Commodity Database.

III. Energy Price Formation Reforms Are Critical in Establishing the Right Price Signals

The rapid and large decline in overall wholesale energy prices has exposed a number of energy price formation inefficiencies. Getting energy prices right is critical to ensuring that the correct price signals are sent to incent efficient investment and market exit. The energy markets provide the primary economic signal to all commercial entities in the market and therefore, it is extremely important for energy prices to reflect the marginal cost of providing power to the grid. Real-time market prices influence the forward markets, which are essential to efficiently managing the cost and risk of providing physical service. Poor real-time prices distort the forward markets and interfere with the reliability objectives they are designed to achieve.

The Commission has been engaged on issues concerning energy and ancillary services price formation in the markets operated by the RTO/ISO since 2014 when Commission Staff convened a series of technical conferences. These technical conferences provided a forum for the Commission and the industry to discuss the elements of each RTO/ISO that appear to be working best. As a result of the information received, the Commission directed the RTOs/ISOs to implement a number of important tariff reforms concerning settlement intervals and shortage pricing in markets operated by RTOs/ISOs[60] and offer caps in markets operated by RTOs/ISOs.[61] However, there remain pending two proposed reforms, which should be finalized without delay: uplift cost allocation and transparency in markets operated by RTOs/ISOs[62] and fast start pricing

[60] *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Order No. 825, 155 FERC ¶ 61,276 (June 16, 2016).

[61] *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Order No. 831, 157 FERC ¶ 61,115 (November 17, 2016).

[62] *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Notice of Proposed Rulemaking, 158 FERC ¶ 61,047 (January 19, 2017).

in markets operated by RTOs/ISOs.[63] Additionally, the Commission should also consider requiring the RTOs/ISOs under its jurisdiction to demonstrate that the reforms already implemented are achieving their intended objectives, especially regarding the shortage pricing reforms where current system limitations appear to be limiting the ability to price transient shortages in a manner consistent with Order No. 825.[64] Additionally, the Commission is taking steps to evaluate primary frequency response service and should continue to develop proposals that facilitate economic evaluation of all essential reliability services.

Finally, we note that PJM has drafted a proposal that would allow marginal units to set price at any point in their operating range.[65] We believe this is an important reform that not only establishes the correct energy price, but also can eliminate one source of distortion presented by negative bidding resources. Therefore, we respectfully request that the Commission direct that PJM submit proposed tariff revisions concerning their proposal to expand the eligibility for all units required to supply energy on the system to set price so that it can be fully evaluated by the Commission. This logical extension of the concepts raised in the proposed fast-start pricing reforms will prevent the pernicious energy market price suppressive effect of running generators to supply load or other critical reliability services when LMP's are persistently below the generator's bid costs.

[63] *Fast Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Notice of Proposed Rulemaking, 157 FERC ¶ 61,213 (December 15, 2016).

[64] *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 155 FERC ¶ 61,276 (June 16, 2016).

[65] PJM Interconnection, L.L.C., Energy Price Formation and Valuing Flexibility, *supra* note 10.

IV. Potential Long-term Solutions for the Commission's Consideration

As discussed above, we believe that the DOE Proposal providing cost-of-service payments to qualified resources should be implemented immediately as an interim solution while a long-term market-based solution is developed. We have described below several potential market-based approaches for consideration. Naturally, all of these approaches would need to be further evaluated and developed before any could be deployed. In addition, it may be possible that while a single approach may not be sufficient in its own right, a set of solutions could be used.

(a) **Carbon Pricing**: An important long-term solution that the Commission should consider as a means to achieving some of the goals of the DOE Proposal would be to impose a carbon price on emitting resources dispatched through the RTOs/ISOs.[66] Both PJM and the New York Independent System Operator, Inc. ("NYISO") are in the process of considering mechanisms to integrate the price of carbon into their wholesale markets. On August 23, 2017, PJM issued a concept paper in which it offers to facilitate a coordinated carbon policy through the PJM market. The proposal provides states with the flexibility to opt in or opt out of the program.[67] NYISO, in coordination with the New York Public Service Commission, has also issued a report which proposes and examines the cost impacts of incorporating carbon pricing into NYISO's wholesale energy markets.[68] The Commission should consider directing all RTOs/ISOs to integrate carbon pricing in their regions.

[66] *See* Makovich Affidavit at 17.

[67] Advancing Zero Emissions Objectives through PJM's Energy Markets: A Review of Carbon-Pricing Frameworks (August 23, 2017), available at: http://pjm.com/~/media/library/reports-notices/special-reports/20170502-advancing-zero-emission-objectives-through-pjms-energy-markets.ashx.

[68] "Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals," Prepared by The Brattle Group (August 10, 2017), available at:

(b) **Fuel Security Value Curve**: Consideration could be given to including in capacity market payments an adder for the resiliency attributes that baseload resources provide to the grid, including fuel diversity and fuel security. This payment mechanism could be integrated into the existing PJM capacity market construct. To employ this mechanism, it would be necessary to establish a minimum standard for operating the grid during an extended period of a fuel supply disruption. A "fuel security value curve" could then be developed to determine an appropriate resiliency adder at various offer levels of eligible resources.

(c) **Progressive Clearing of Resources Base on On-site Fuel Characteristics**: Another potential capacity market mechanism would be to clear capacity auctions in a progressive manner that enforces a prescribed share of resources with certain characteristics. For example, there could three tranches procured in the capacity auction: Tranche 1 (say 50%) could consist of resources with the least robust fuel security characteristics; Tranche 2 (say 30%) could consist of resources that have an intermediate level of fuel security; and Tranch 3 (say 20%) could consist of resources with significant on-site fuel supply.

(d) **Clearing of Resources Based on Technology Type**: Another capacity market approach could be to establish separate capacity auction tranches for different resource technology types. The tranches could specify required quantities for each tranche as a percentage of the total capacity commitment but not specify which resource type corresponds with each tranche. Each technology type would receive a separate capacity payment based on clearing the bids within the segment. Capacity prices paid would vary within the technology segment which would provide incentives for appropriate entry and exit within the asset class.

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http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Studies/Market_Studies/Pricing_Carbon_into_NYISOs_Wholesale_Energy_Market.pdf.

(e) **More Robust Scarcity Pricing**: A possible energy market approach that could address this issue to some extent would be to increase the impact of scarcity pricing in the energy markets. In general, under this approach, steep operating reserve demand curves with maximum values tied to the value of lost load would be used to set locational marginal prices in day-ahead and real-time markets. This would not dictate a specific resource mix, but because improved scarcity pricing would result in greater volatility in energy prices, market participants would have stronger incentives to invest in resiliency enhancements.

(f) **Setting Resiliency Payments Based on Expected Outcomes If Market Inefficiencies Are Removed**: Dr. Makovich proposed an alternative to encourage an economic level and pace of retirements.[69] He suggests that the expected efficient market outcome could be used to determine the eligibility for grid reliability and resilience payment that offsets the consequences of current market distortions.[70]

IV. Conclusions and Recommendations

The Commission stands at an important crossroads. It is faced with an urgent problem that, if not handled, could have tremendous harmful impacts on the lives of millions of Americans and even on the national security of our country. At the same time, determining the best long-term solutions to the problem will require additional study and a massive collaborative effort among many stakeholders. The Commission will undoubtedly be told that it should not act now because the exact scope of the problem is not defined and the costs of implementing the cost-of-service mechanism proposed in the DOE Proposal cannot be precisely determined. But this would be the wrong lens to use for analysis. The potential for there to be severe adverse

[69] Makovich Affidavit at 17.

[70] *Id.*

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consequences if the country irretrievably loses a substantial portion of its fuel-secure baseload fleet is too grave to delay action. As an interim measure, the DOE Proposal should be implemented to assure that Americans are not exposed to the potentially catastrophic risks that would be attendant to a "wait and see" response.

Moreover, it is clearly within the scope of the Commission's authority under the FPA to address this issue based on the record before it as supplemented in these comments and as the PSEG Companies anticipate will be developed through other submittals. The record supports the existence of a major concern associated with the operation of electric markets that the Commission has the power to rectify. The Commission does not require a cost/benefit analysis to address this problem. The potential impacts on reliability and national security provide ample justification. Finally, it bears noting that, at least regarding the nuclear plants, their preservation actually will save billions of dollars for consumers and would provide billions of dollars' worth of additional benefits to society as a whole.

Nor should the Commission be swayed by the inevitable assertions that approving the DOE Proposal, even for an interim period, will destroy competitive markets. As explained above, if the markets were operating efficiently, or if resiliency was expressly valued as an attribute, the units expected to receive the cost-of-service support payments – and, in particular the nuclear units – would be expected to have a reasonable financial basis for continued operation. The cost-of-service support payments thus actually will serve to help realize outcomes consistent with the expected end result of true competition.

Finally, the Commission should take the opportunity before it to direct the RTOs/ISOs to expeditiously address the remaining price formation initiatives that are pending before it and under consideration in each region's stakeholder processes. Further, in the case of PJM, the

Commission should direct PJM under the FPA Section 206 authority to file the proposed enhancements to its energy market pricing mechanism to enable all generators, whose output is required to supply the grid power balance to be eligible to set locational marginal prices. These improvements would not fully address the issue but a better foundation for energy market price formation will be of assistance in addressing the problem of revenue adequacy for fuel-secure baseload units.

The PSEG Companies therefore recommend that the Commission take the following steps:

(i) The Commission should adopt the DOE Proposal to become effective immediately for an interim period ending when a long-term solution that adequately values generator fleet resiliency is developed. This should include the proposed eligibility requirements of having a 90-day supply of on-site fuel and of providing essential energy and ancillary services; provided however, the final rule should clarify that a unit that supplies substantial quantities of one or more essential energy and ancillary reliability services;

(ii) The Commission should direct all affected ISOs/RTOs to file tariff modifications providing for the recovery on a pro-rata basis from all ISO/RTO customers of cost-of-service payments authorized by the Commission for generating units located within the ISO/RTO region;

(iii) The Commission should direct all companies that qualify under the final rule for cost-of-service support, within 60 days following the effective date of the rule, to file (on an optional, voluntary basis) an application justifying rates for cost-of-service payments and demonstrating compliance with the eligibility requirements as of the date of such application;

(iv) The Commission should direct all affected RTOs/ISOs to commence, on an expedited schedule, stakeholder meetings for the purpose of developing a long-term market-based methodology for valuing resiliency in the generator fleet; the RTOs/ISOs should endeavor to complete the stakeholder processes within one year and to file periodic reports with the Commission regarding their progress;

(v) The Commission should expedite the implementation of all the energy market price formation issues pending before it and before the RTOs/ISOs; and

(vi) The Commission should direct PJM, under the Commission's authority derived from FPA Section 206, to file its proposal for allowing units, whose output is required to supply to grid power balance, to be eligible to set locational marginal prices.

Respectfully submitted,

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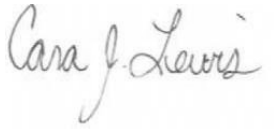
Dated: October 23, 2017
Newark, New Jersey

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Newark, New Jersey, this 23rd day of October, 2017.



Cara J. Lewis

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)	Docket No. RM18-1-000

AFFIDAVIT OF
DR. LAWRENCE J. MAKOVICH

My name is Lawrence Makovich. I am Vice President and Senior Advisor for Global Power for IHS Markit; a company that provides data, analyses, and strategic insights to businesses around the world focusing on energy, automotive, chemical and defense industries. I am an energy economist specializing in the analysis of the electric power industry. My current research focuses on electric power market structures, demand and supply fundamentals, wholesale and retail power markets, emerging technologies, least cost CO_2 emission abatement pathways, and asset valuations and strategies. I hold a Ph.D. in Public Policy from the University of Massachusetts/Boston, an MA in Social Science from the University of Chicago, and a BA in economics from Boston College. My work address is IHS Markit, 55 Cambridge Parkway, Cambridge, MA 02142, USA.

A linkage exists between electric supply portfolio fuel and technology diversity and power supply resilience. I have studied the value of U.S. power supply diversity and produced reports on the subject in 2014 and 2017. I also produced a report this year based on my research as a Senior Fellow at the Mossavar-Rahmani Center for Business and Government in the John F. Kennedy School of Government at Harvard University that analyzed the impacts on fuel and technology mix of U.S. generation portfolio from public policies that do not distort the economic trade-offs that determine efficient power supply portfolios.

I provide this Affidavit in support of the comments of the PSEG Companies on the Secretary of the Department of Energy's Notice of Proposed Rulemaking ("NOPR") issued in the captioned proceeding by the Federal Energy Regulatory Commission ("Commission") on September 28, 2017. I previously provided pre-conference comments to the Commission as well as testimony on May 2, 2017, in its proceeding on State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C., in Docket No. AD17-11-000.

The purpose of this Affidavit is to respond to some of the questions and issues raised in the October 4, 2017 request from the Federal Energy Regulatory Commission Director of the Office of Energy Policy and Innovation regarding the proposed rule on grid reliability and resilience pricing. In particular, I will address the need for reform due to the lack of harmony between public policies and efficient wholesale electric market operations, and also address the importance of supply diversity and how the premature retirement of baseload plants raises consumer electricity prices. I will discuss what I refer to as the imposed "missing money" problem in RTO/ISO markets caused by the mandates of subsidized intermittent generation resources beyond their cost effective levels. These policies are the root cause of the decline in resilience because these policies suppress wholesale energy market prices, reduce non-peaking generation resource market cash flows, and increase the probability of premature baseload power plant closures that result in a less efficient diversity in the electric supply portfolio compared to the outcome expected in an efficient wholesale electricity marketplace.

1. Need for Reform

The current lack of harmony between public policies and efficient market operations create the need for electricity market policy reform.

An efficient electricity market outcome requires the harmonization of public policies and market operations. Harmonizing public policies with market operations requires internalizing all relevant costs, including an appropriate CO_2 emission charge because an efficient market outcome does not involve externality costs. Further, an efficient electricity market outcome also requires public policies with fuel and technology neutral impacts on market operations. Under these conditions, the harmonization of public policies and market operations allows effective competitive forces to produce the right wholesale price signals. The right price signals determine the economic trade-offs that shape an efficient electric supply portfolio comprised of a diverse fuel and technology mix capable of providing consumers with the reliable electric services that they want, when they want them, at the lowest cost, subject to the security of supply and network constraints in the AC power system that defines the bounds of the marketplace.

Consumers reveal a preference for reliable, affordable power supply and predictable power bills. Reliable electric service and predictable power bills involve resilient power supply. Resilience is a measure of the ability of a power supply portfolio to avoid, react and recover from the impacts of deviations in electric operating conditions from expected normal operating conditions. Efficient market price signals shape a diverse power supply portfolio with inherent resilient supply attributes. These resilience attributes exist because a cost effective supply portfolio involves a diverse mix of fuels and technologies with fuel and technology specific risk factors that are weakly correlated. Quite simply, there are significant benefits to an efficient

electricity market outcome that generates a power supply portfolio that does not put all of the nation's power supply eggs in one basket.

Market distortions prevent the wholesale electricity market from generating the right price signals. As a result, the distorted market price signals do not shape a cost effective supply portfolio. In particular, public policies that mandate and subsidize intermittent renewable technologies are neither fuel nor technology neutral policy approaches, and therefore result in inefficient market outcomes whenever mandates of subsidized intermittent renewables result in a greater wind and solar generation shares than are cost effective. In organized electricity markets, this inefficient market outcome suppresses wholesale electric energy prices. This is an "imposed" missing money problem for competitive generators.

Capacity markets and operating reserve demand curves are designed to close the gap between energy market cash flows and the revenue streams necessary to cover the costs of peaking technologies. As a result, these mechanisms provide a backstop for peaking technology investments when energy market distortions suppress energy market cash flows. But no such cash flow backstop exists for non-peaking power plants. These power supply resources rely on the capacity market cash flows to cover part of their upfront costs, and rely on energy market cash flows to cover the additional upfront costs associated with other attributes including investments in a lower CO_2 emissions profile, operating resilience, and the greater efficiency in transforming primary energy into electricity compared to a peaking technology. As a result, current market distortions disproportionately reduce the market cash flows of non-peaking power plants and lead to underinvestment in their production attributes. This market distortion creates the need to provide support for the flexible generation that cost effectively aligns with the variable segment of power system net-load, as well as creates the need to support the baseload

power plants that cost effectively align with the majority of electric generation associated with the steady base load segment of aggregate consumer demand. For example, the cash flow suppression in the California ISO marketplace drove the implementation of FERC approved tariffs for flexible ramping products to provide payments supporting the generating technologies providing the necessary dispatchable, net load following generation in the power supply portfolio. These flexible resources are predominately natural gas-fired generating technologies and this market reform indicates that cash flow shortfalls for non-peaking power resources are not simply the result of low natural gas prices. Instead, the problem arises from disharmony between public policies and wholesale market operations distorting market prices, as described in the U.S. Department of Energy Staff Report to the Secretary on Electricity markets and Reliability.[1]

Market distortions that suppress prices for non-peaking generating resources from the levels expected in an efficient market outcome result in greater retirements of existing non-peaking power plants than expected in an efficient market outcome. Getting wholesale price signals right translates into getting the size and pace of existing power plant retirements right. This efficient retirement outcome arises when an electricity market is in long run demand and supply balance and existing generators are confronted by market prices that support the cash flows of the most cost effective replacement power supply resources. Under these conditions, a power plant retires when it is lower cost to replace its energy, capacity and ancillary service outputs as well as replace its resilience and environmental attributes, than the cost to keep it operating.

[1] U.S. Department of Energy, Staff Report to the Secretary on Electricity Markets and Reliability, August 2017, at p.110-112, available at: https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.

Current policy initiatives that ratchet up subsidized renewable generation shares are increasing market distortions and causing premature baseload power plant retirements. This trend is eroding the inherent resilience characteristics of a cost effective electric supply portfolio by moving U.S. electric supply portfolios away from the diverse fuel and technology mix expected from an efficient market outcome. Therefore, the efficient market outcome provides the benchmark to evaluate market interventions designed to offset the consequences of persistent market distortions created by discordant public policies and wholesale market operations.

Analyses of efficient U.S. power system demand and supply responses to a range of possible appropriate CO_2 emission charges in the absence of discordant public policies provide estimates of the expected outcomes from an efficient wholesale electricity marketplace.[2] The research indicates that, based on the typical going-forward costs of existing nuclear power plants, these non-CO_2 emitting electric supply resources would not be expected to prematurely retire in an efficient wholesale marketplace that does not suffer from an imposed missing money problem, and that does internalize an appropriate CO_2 emission charge. Therefore, an economic argument exists to support public policies that provide support to these nuclear resources through compensation for the resilience attributes that these resources provide to the power supply portfolio and move the current distorted market outcome toward the results expected in an effective competitive marketplace. Such policies improve economic efficiency in the electricity sector.

Analysis of U.S. efficient power system demand and supply responses to a range of possible appropriate CO_2 emission charges in the absence of discord between public policies and

[2] Lawrence Makovich, *Tilting at Windmills: Making a case for reframing electric sector climate policies,* Mossavar-Rahmani Center for Business and Government Associate Working Paper No. 78, June 2017, available at: https://www.hks.harvard.edu/centers/mrcbg/publications/awp/awp78.

market operations indicates that fossil fueled generation resource generation shares decline but are not eliminated from a cost effective electricity supply portfolio. Therefore, the problem of premature retirements of fossil-fired electric generation resource retirements is also a policy concern, as illustrated by the California flexible ramping products interventions.

As long as the lack of harmonization exists between public policies and wholesale market operations, there is an economic argument to support market interventions to offset distortions and move electricity market outcomes back toward the expected outcome of the efficient competitive market benchmark.

The October 4, 2017 request from the Federal Energy Regulatory Commission Director of the Office of Energy Policy and Innovation regarding the proposed rule on grid reliability and resilience pricing asked for descriptions of alternative approaches to the proposed rule. The 90 day fuel storage rule for cost recovery eligibility can stem the immediate problem of premature baseload retirements. However, an alternative could be developed for the longer term to encourage an economic level and pace of retirements. In particular, the expected efficient market outcome could be used to determine the eligibility for grid reliability and resilience payment that offsets the consequences of current market distortions. This benchmark provides relatively simple rules—eligibility for cost recovery support exists when a generating resource market cash flow is not sufficient to cover the costs of continued power plant operation when these costs are lower than the unsubsidized cost of the new resources that are being added to the power system to provide the equivalent energy, capacity, ancillary services outputs and resilience attributes of the existing resource. The size of the resilience payment simply reflects this cost recovery shortfall between the cost of continued operation and market cash flows.

2. Polar Vortex and Other Recent Disruptions

The proposed rule references the events of the 2014 Polar Vortex as an example of the need for reforms. I agree that the Polar Vortex provides lessons regarding the value of resilience in a power supply portfolio.

A retrospective analysis of the Polar Vortex conditions in PJM illustrates the benefits of the resilience provided by the diverse technology and fuels in the electric supply portfolio at that time. Figure 1 shows the aggregate consumer hourly load, net of demand resources, on January 7, 2014 when the Polar Vortex caused a significant deviation from expected normal operating conditions for the PJM power system and caused PJM to hit a record wintertime peak demand of 141.8 GW.

Figure 1

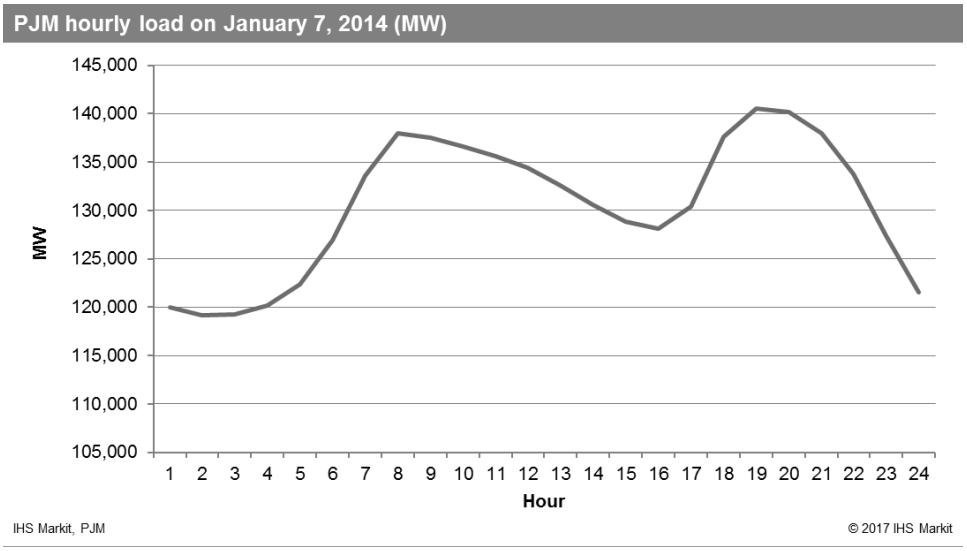

Table 1 reflects the actual PJM installed capacity in January 2014 derated by technology and fuel type based on the actual outage rates experienced during the Polar Vortex on January 7, 2014.[3] During the Polar Vortex, 90 percent of the available installed capacity came from

[3] In the May 2014 report, "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events," PJM quantified power supply reserves available to its system during the peak period on January 7,

conventional nuclear, coal and natural gas-fired resources. PJM was in a fortunate position that a surplus of installed capacity was present in 2014 when the reported system-wide reserve margin was above 20 percent rather than the installed reserve margin being at the target level of around 16 percent.[4] Otherwise, PJM would have confronted the polar vortex with over 7,000 MW less of installed capacity.

Table 1

PJM Net dependable capacity on January 7, 2014

Generator Fuel Type	Installed Capacity, January 1, 2014		Forced Outages		Other Non-Forced Outages	Net Dependable Capacity
	MW	% Total Installed Capacity	*MW*	% Installed Capacity	MW	*MW*
Coal	75,545	*41%*	13,700	18%		61,845
Gas	53,395	*29%*	19,000	36%		34,395
Nuclear	33,077	*18%*	1,400	4%		31,677
Hydro	8,107	*4%*				8,107
Oil	11,314	*6%*				11,314
Renewables	956	*1%*				956
Other	701	*0%*				701
Not Classified			6,100	N/A	2,412	(8,512)
Total	**183,095**		**40,200**		**2,412**	**140,483**

The Polar Vortex caused significantly higher than normal unavailability from natural gas-fired generating units linked, in many cases, to abnormal natural gas pipeline supply constraints. While the severe weather conditions also affected the availability of the other electric supply resources, the natural gas-fired resources were by far the hardest hit. Yet despite these conditions, the diversity in the PJM power generation portfolio allowed nuclear, oil and coal-

2014, including: 500 MW of 10-minute synchronized reserves, 1,167 MW of 10-minute non synchronized reserves and 1.1 – 2.0 GW of temporary voltage reduction. While other actions may have been available such as purchasing additional emergency energy or recalling shared reserve obligations from neighbors, this analysis does not include the potential for PJM to purchase additional energy or recall additional obligations that PJM provided to neighbors.

[4] PJM Interconnection, L.L.C., "Summer 2014 PJM Reliability Assessment" (dated June 2014) available at: http://www.puc.pa.gov/Electric/pdf/Reliability/Summer_Reliability_2014-PJM.pdf.

fired power plants to back-up and fill-in for the disproportionate limitations on natural gas-fired resources and thus, avoid costly outages.

Sensitivity analysis of PJM outcomes during the Polar Vortex to changes in the supply portfolio indicate the resilience provided by the fuel and technology mix in place in 2014. To see this, a second scenario involves holding all PJM Polar Vortex conditions constant except that the December 31, 2016 power supply portfolio shown in Table 2 shows the substitution of the 2016 supply portfolio for the actual supply portfolio on January 7, 2014.

Table 2

PJM capacity analysis for January 7, 2014: December 31, 2016 capacity mix

Generator Fuel Type	Installed capacity as of 12/31/2016		Forced Outages		Other Non-Forced Outages	Net Dependable Capacity
	MW	*%*	*MW*	*% Installed Capacity*	*MW*	*MW*
Coal	66,622	*37%*	12,082	18%		
Gas	65,110	*36%*	23,169	36%		
Nuclear	33,043	*18%*	1,399	4%		
Hydro	8,850	*5%*				
Oil	6,772	*4%*				
Renewable	1,281	*1%*			A	
Other	769	*0%*				
Not Classified			6,100		2,412	
Total	**182,449**		**42,749**		**2,412**	**137,288**

Back casting the outcome during the Polar Vortex with the 2016 rather than 2014 PJM power supply portfolio in place indicates that the probability of some loss of load during the Polar Vortex would have been higher with the current supply portfolio. In this case, PJM would have had to rely on the estimated remaining emergency operating procedures that provided an equivalent of 2.7 to 3.6 GW of firm capacity.[5] If emergency operating procedures were at the low end of this range, then as Table 3 shows, the expected outcome in the alternative scenario is

[5] PJM, "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events," May 8, 2014, pp.4-5, http://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

a 301 MW average loss of load for 3 hours. The associated cost of this outage is around $153 million.

Table 3

Polar Vortex scenario analysis to determine the resiliency value of the existing diverse supply portfolio

	December 31, 2016 capacity	December 31, 2016 capacity less Oyster Creek and Three Mile Island (1.47 GW)	December 31, 2016 capacity less Oyster Creek, Three Mile Island, Davis-Besse and Perry (3.65 GW)
Hours of outage	3	5	9
Average shortfall (MW)	301	1,386	2,407
Total shortfall (MWh)	903	6,930	21,663
Cost per unserved MWh	170,000	170,000	170,000
Total cost of shortfall	**$153,473,809**	**$1,178,157,861**	**$3,682,704,776**

Since the Oyster Creek nuclear power plant has already announced its planned closure and Exelon has announced that it has taken the first steps to close Three Mile Island, another sensitivity analysis involves back casting the outcome of the Polar Vortex with the 2016 PJM power supply portfolio in place except for the presence of the Oyster Creek and Three Mile Island capacity. Again, holding all else constant in this analysis results in an expected outcome that involves a 1.4 GW average loss of load for 5 hours. The associated cost of this outage is around $1.2 billion. Similarly, if the alternative scenario also includes the loss of nuclear power plants being evaluated for premature closure or sale—Perry and Davis Besse—then the expected outcome is a 2.4 GW average loss of load for 9 hours with an associated outage cost of around $3.7 billion.

One of the lessons from the Polar Vortex back casting analysis is that when low probability but high impact events brought PJM reliability conditions close to the edge of losing load, small changes in available supply were capable of producing large and increasing outage costs. These lessons triggered PJM market rule revisions regarding capacity performance. As the PJM response to the Polar Vortex demonstrates, anticipation and preparation are keys to power supply resiliency, proving the old adage that an ounce of prevention is worth a pound of cure.

The proposed rule also references the impacts of other extreme weather events. This is an important concern because preventing future outages requires resilience to a much broader set of risks than simply those posed by another Polar Vortex episode. The probability of another Polar Vortex episode like 2014 may be one in ten years or less. Such a low probability of recurrence or the existence of some changes specific to cold weather operating challenges that were put into place can lead to complacency or a false sense of security. However, the probability of another hurricane like Sandy in 2012 hitting New Jersey may also be one in ten years or less. Likewise, the probability of another pipeline disruption such as the 2016 Texas Eastern pipeline disruption in Pennsylvania may also be one in ten years. Other low probability but high impact possible deviations from normal operating conditions include a natural gas storage failure similar to what recently happened at the Aliso Canyon natural gas storage facility, as well as wildfires, heat waves, droughts and physical or cyber-attacks. In addition, political risks exist. For example, the growing anti-fossil fuel movement that is delaying the development of the natural gas supply infrastructure to keep pace with the increased requirements of the electricity sector. Such political risks can shift the power production operating environment suddenly. For example, a severe seismic event associated with hydraulic fracturing wastewater injections somewhere in the U.S. could lead to a wide-spread ban on hydraulic fracturing for natural gas production everywhere. Even if such a ban were temporary, the price and deliverability of natural gas would likely be dramatically affected. Although the probability of any one of these events happening in any given year is low, the probability of some type of high impact event that challenges electric system resilience is much higher because the probability of at least one of these events happening is the sum of the probabilities of these independent risk factors. Further, the consequences of these risk factors can increase when two or more high

impact events occur simultaneously. The bottom line is that prudent planning ought to account for a better-than-even chance that a major disruptive event affecting the availability of one type of electric generating resource in the supply portfolio of a US power system will occur within the next decade.

When power system operating conditions deviate from expected normal operating conditions, the price signals expected in an efficient market outcome ought to incentivize cost effective resilience investments by competitive generators. Consequently, market distortions and cash flow suppression result in underinvestment in power supply resilience. But the risk profile of U.S. power systems may expand beyond the operating environment of the power system and include threats such as terrorist attacks. Analyses of power system resilience to this expanded multi-dimensioned risk profile could lead to the conclusion that market interventions to restore the inherent supply resilience of the diverse electric supply portfolio expected from an efficient market outcome may not be enough to manage the all of the risk exposures of the future.

3. The value of the current diverse U.S. power supply portfolio

The proposed rule references Congressional concern regarding the potential further loss of valuable baseload generation. I agree that the potential exists for further loss of valuable baseload generation. Current U.S. consumers benefit from a reliable, resilient, and cost-effective electric supply portfolio that employs a diverse set of technologies and fuel sources. If supply diversity is reduced by distorted market prices discouraging the continued operation of cost effective existing baseload generating facilities and encouraging the additions of a more expensive combination of natural gas-fired units and renewable resources, then consumers will see electric prices that are both higher and more volatile. For example, public policies are supporting the addition of wind and solar resources with unsubsidized costs of around 85 to 201

$(2015)/MWh that are integrated by flexible natural gas-fired technologies with unsubsidized costs over 64 $(2015)/MWh while suppressed market cash flows are leading to the closure of nuclear power plants with going-forward costs of less than 45 $(2015)/MWh.[6] Consumers incur higher electricity costs because, although mandates and subsidies suppress wholesale prices, these subsidies do not reduce power supply costs. Instead, mandates add out-of-market costs and subsidies shift costs among consumers or from power bills to tax expenditures. This trend toward premature baseload retirements and expanding intermittent renewables and natural gas-fired generation beyond what is cost effective is discussed and analyzed at length in the IHS Markit report I directed entitled *Ensuring Resilient and Efficient Electricity Generation* dated September 2017.[7]

In 2014, I directed research and analysis of the value of fuel and technology diversity in the current U.S. power supply portfolio.[8] The analysis showed that the current diversified portfolio of U.S. power supply lowers the cost of generating electricity by more than $93 billion per year compared to a less diverse portfolio with no meaningful contributions from coal-fired or nuclear power plants, a smaller contribution from hydro-electric resources (4% of generation), and significant increases in wind and solar (22% of generation) and natural gas-fired power plants accounting for the remaining power production (74% of generation). The less diverse power supply case produced monthly power bills that were 25% higher, and twice as variable, as the current power bills reflecting the costs of the current diverse power supply portfolio.

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[6] The National Academies of Sciences, Engineering and Medicine, *The Power of Change: Innovation for Development and Deployment of Increasingly Clean Electric Power Technologies*. Washington, DC: The National Academies Press. Doi 10.17226/21712 and Nuclear Energy Institute, *Nuclear Energy 2016: Status and Outlook,* February 11, 2016.

[7] Lawrence Makovich and James Richards, *Ensuring Resilient and Efficient Electricity Generation: The value of the current diverse US power supply portfolio*, IHS Markit Report, September 18, 2017, available at: http://ihsmark.it/FezQ30feH62 (copy attached).

[8] IHS Energy, The Value of US Power Supply Diversity, July 2014.

In light of the accumulating premature baseload power plant retirements and public policy initiatives to ratchet up the generation share mandates for subsidized renewable resources, I directed the September 2017 IHS Markit study to take a fresh look at what is at stake for U.S. consumers if the U.S. supply portfolio continues to move toward a less efficient and less resilient electric supply portfolio end state. The research compared the recent U.S. electricity portfolio outcomes from 2014 to 2016 with analyses of the expected outcome from a less efficient diversity portfolio case that involved little or no coal, oil or nuclear generating resources, less hydroelectric resources, and involved a tripling of the current wind and solar generation shares with the remaining majority of electric output relying on natural gas-fired resources.

The less efficient diversity case may initially appear as an extreme change from current conditions. Yet, such a dramatic transition can unfold within a couple of decades. California is an example of a transition that began in 2002 with its first renewable mandate. Since then, California has little or no coal or oil in its generation mix, reduced nuclear generation (scheduled to be eliminated by 2025), and diminished hydroelectric resources, while intermittent wind and solar generation shares increased from 2 to 15 percent and natural gas-fired generation increased from 50 to 60 percent of in-state electric production. Along the way, the average retail price of electricity in California increased from a level 30 percent above the U.S. average price in 2002 to a level 50 percent above the U.S. average in 2015 while the CO_2 emissions from in-state generation did not decline even though in-state generation was a smaller share of overall power supply.

The comparison of these alternative cases indicates the consequences of the U.S. electricity sector following a similar path as California including:

- The current diversified U.S. electric supply portfolio **lowers the cost of electricity production by about $114 billion per year and lowers the average retail price of electricity by 27%** compared with the less efficient diversity case.

- Avoiding the consumer adjustment to the higher retail prices in the less efficient diversity case preserves current levels of electric consumption and **avoids an annual $98 billion loss in consumer net benefits** from electricity consumption.

- The resilience of the current diversified U.S. electricity portfolio to the delivered price risk profile of the fuel inputs to electric generation **reduces the variability of monthly consumer electricity bills by about 22%** compared with the less efficient diversity case.

- Preventing the erosion in reliability associated with a less resilient electric supply portfolio **mitigates an additional cost of $75 billion per hour** associated with more frequent power supply outages that add to the current US average expected outage rate of 2.33 hours per year.

Comparing the broader economic impacts of the less efficient diversity case with the IHS Markit baseline simulations of the U.S. economy indicates the following U.S. macroeconomic impacts within three years of the retail price increase:

- The 27% retail power price increase associated with the less efficient diversity case causes a **decline of real US GDP of 0.8%, equal to $158 billion** (2016 chain-weighted dollars).

- Labor market impacts of the less efficient diversity case involve a reduction of **1 million jobs**.

- A less efficient diversity case **reduces real disposable income per household by about $845 (2016 dollars) annually**, equal to 0.76% of the 2016 average household disposable income.

4. Other

The October 4, 2017 request from the Federal Energy Regulatory Commission Director of the Office of Energy Policy and Innovation regarding the proposed rule on grid reliability and resilience pricing asked for descriptions of alternative approaches to the proposed rule. An economic argument exists to support offsetting market interventions for non-peaking generating resources through flexibility and resilience payments as long as market distortions continue.

Such interventions can be temporary if an alternative approach involved the determination that further significant state subsidies or mandates of renewable generation shares are unreasonable intrusions into the interstate commerce conducted in wholesale electric market operations and discriminatory to similarly situated non-zero emitting generating resources. Such a ruling would indicate that regional approaches to putting an appropriate charge on CO_2 emissions are the necessary policy formulations to harmonize public policies and wholesale market operations.

5. Conclusion

The Proposed Rule is an attempt to address the decline in power supply resilience caused by the increasing distortions in wholesale electricity markets that are eroding the inherent resilience of the fuel and technology mix expected in a power supply portfolio shaped by efficient market price signals. I agree that something should be done to move electricity market outcomes closer to the expected outcome in an efficient marketplace. On an interim basis, the Proposed Rule provides an immediate step to avoid the further erosion of existing diversity of the nation's generation portfolio. Over the longer term, I suggest a modified approach that would employ the conditions of an efficient market outcome to determine the eligibility and level of support for baseload generation at risk for premature uneconomic retirements.

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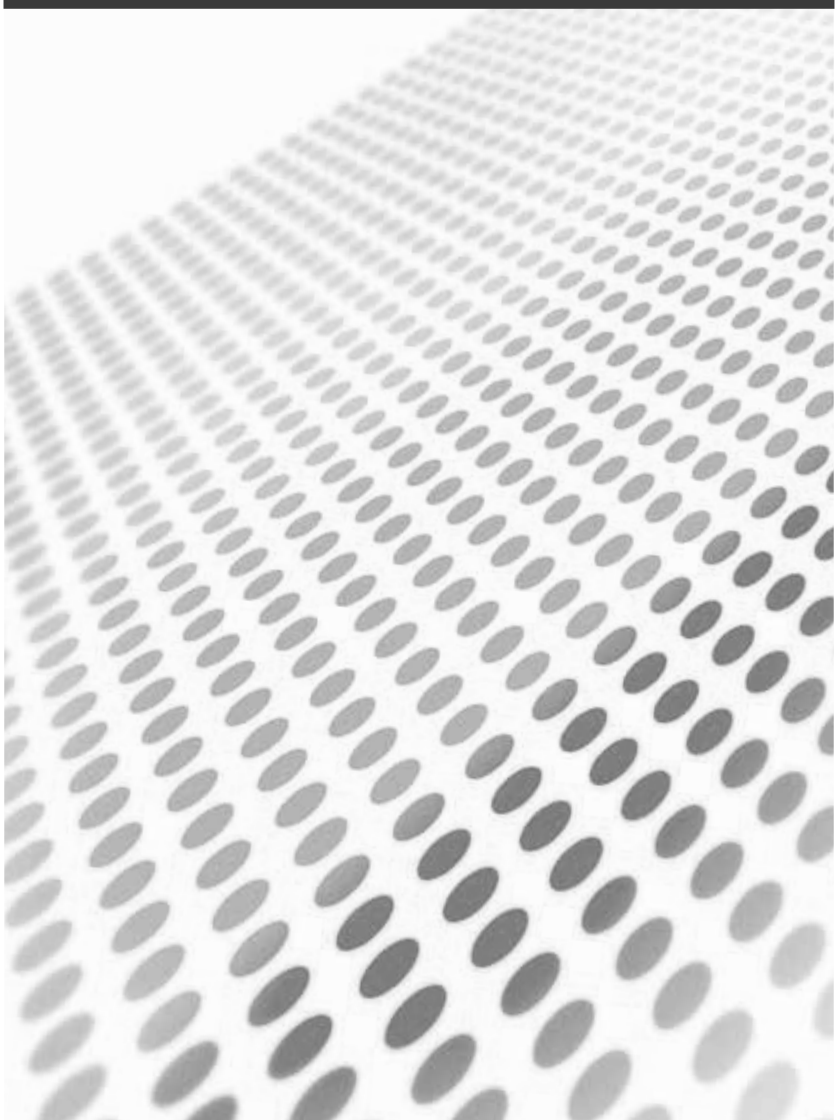
IHS **Energy**

The Value of US Power Supply Diversity

July 2014 **ihs.com**



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The Value of US Power Supply Diversity

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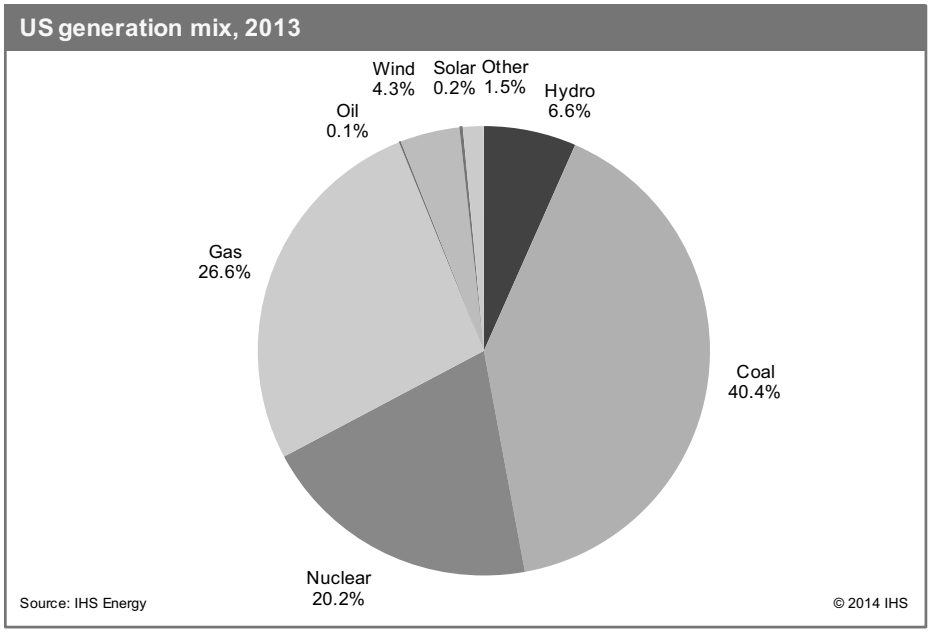
Executive summary

Engineering and economic analyses consistently show that an integration of different fuels and technologies produces the least-cost power production mix. Power production costs change because the input fuel costs—including for natural gas, oil, coal, and uranium—change over time. The inherent uncertainty around the future prices of these fuels translates into uncertainty regarding the cost to produce electricity, known as production cost risk. A diversified portfolio is the most cost-effective tool available to manage the inherent production cost risk involved in transforming primary energy fuels into electricity. In addition, a diverse power generation technology mix is essential to cost-effectively integrate intermittent renewable power resources into the power supply mix.

The current diversified portfolio of US power supply lowers the cost of generating electricity by more than $93 billion per year, and halves the potential variability of monthly power bills compared to a less diverse supply. Employing the diverse mix of fuels and technologies available today produces lower and less volatile power prices compared to a less diverse case with no meaningful contributions from coal and nuclear power and a smaller contribution from hydroelectric power (see Figure ES-1). In this less diverse scenario, called the *reduced diversity case,* wind and solar power make up one-third of installed capacity (up from about 7% in the base case) and 22.5% of generation; hydroelectric power capacity decreases from about 6.6% to 5.3% and represents 3.8% of generation; and natural gas–fired power plants account for the remaining 61.7% of installed capacity and 73.7% of generation.

FIGURE ES-1



Power supply in the reduced diversity case increases average wholesale power prices by about 75% and retail power prices by 25%. Energy production costs are a larger percentage of industrial power prices, and many industrial consumers buy power in the wholesale power market. Thus a loss of power supply diversity will disproportionally affect the industrial sector. These higher electricity prices impact the broader US economy by forcing economic

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adjustments in production and consumption. If the US power sector moved from its current diverse generation mix to the less diverse generating mix, power price impacts would reduce US GDP by nearly $200 billion, lead to roughly one million fewer jobs, and reduce the typical household's annual disposable income by around $2,100. These negative economic impacts are similar to an economic downturn. Additional potential negative impacts arise from reducing power supply diversity by accelerating the retirement of existing power plants before it is economic to do so. For example, a transition to the reduced diversity case within one decade would divert around $730 billion of capital from more productive applications in the economy. The size of the economic impact from accelerating power plant turnover and reducing supply diversity depends on the deviation from the pace of change dictated by the underlying economics.

Maintaining and preserving a diverse US power supply mix is important to consumers for two reasons:

- Consumers reveal a strong preference for not paying more than they have to for reliable electricity.
- Consumers reveal preferences for some degree of predictability and stability in their monthly power bills.

The economic benefits of diverse power supply illustrate that the conventional wisdom of not putting all your eggs in one basket applies to power production in much the same way as it does to investing. This is the *portfolio effect*. In addition, diversity enables the flexibility to respond to dynamic fuel prices by substituting lower-cost resources for more expensive resources in the short run by adjusting the utilization of different types of generating capacity. This ability to move eggs from one basket to another to generate fuel cost savings is the *substitution effect*. Looking ahead, the portfolio and substitution effects remain critically important to managing fuel price risks because of the relative fuel price dynamics between coal and natural gas.

The shale gas revolution and restrictions on coal are driving an increased reliance on natural gas for power generation and provide strong economic benefits. However, this past winter demonstrated the danger of relying too heavily on any one fuel and that all fuels are subject to seasonal price fluctuations, price spikes, and deliverability and infrastructure constraints. The natural gas price spikes and deliverability challenges during the past winter were a jolt for a number of power systems that rely significantly on natural gas in the generation supply. These recent events demonstrated that natural gas deliverability remains a risk and natural gas prices continue to be hard to predict, prone to multiyear cycles, strongly seasonal, and capable of significant spikes. The root causes of these price dynamics are not going away anytime soon. The best available tool for managing uncertainty associated with any single fuel or technology is to maintain a diverse power supply portfolio.

Maintaining power supply diversity is widely supported—the idea of an all-of-the-above approach to the energy future is supported on both sides of the aisle in Congress and at both ends of Pennsylvania Avenue. Four decades of experience demonstrate the conclusion that government should not pick fuel or technology winners, but rather should create a level playing field to encourage the economic decisions that move the power sector toward the most cost-effective generation mix.

Maintaining a diverse power supply currently is threatened by three emerging trends:

- **Awareness.** The value of fuel diversity is often taken for granted because United States consumers inherited a diverse generation mix based on decisions from decades ago.

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- **Energy policy misalignment.** Legislation and regulatory actions increasingly dictate or prohibit fuel and technology choices. The resulting power supply is increasingly at odds with the underlying engineering/economic principles of a cost-effective power supply mix.

- **Power market governance gridlock.** Market flaws produce wholesale power prices that are chronically too low to produce adequate cash flows to support and maintain investments in a cost-effective power generation mix. This "missing money" problem is not being addressed in a timely and effective way through the stakeholder governance processes found in most power markets. As a result, the loss of power supply diversity is accelerating because too many power plants are retiring before it is economic to do so. Consequently, they will be replaced with more costly sources of supply.

US power consumers are fortunate to have inherited a diverse power supply based on fuel and technology decisions made over past decades. Unfortunately, the current benefits of US power supply diversity are often taken for granted. This undervaluation of power supply diversity means there is no counterweight to current pressures moving the United States toward a future generation mix without any meaningful contribution from nuclear, coal, or oil and a diminished contribution from hydroelectric generation.[1]

The United States needs to consider the consequences of a reduced diversity case involving no meaningful contribution from nuclear, coal-fired, or oil-fueled power plants, and significantly less hydroelectric power. A reduced diversity case presents a plausible future scenario in which the power supply mix has intermittent renewable power generation capacity of 5.5% solar, 27.5% wind, and 5.3% hydro and the remaining 61.7% of capacity is natural gas–fired power plants. Comparing the performance of current US power systems to this possible reduced diversity case provides insights into the current nature and value of diversity in the US generation mix.

IHS Energy assessed the current value of fuel diversity by using data on the US power sector for the three most recent years with sufficient available data: 2010 through 2012. IHS Energy employed its proprietary Power System Razor (Razor) Model to create a base case by closely approximating the actual interactions between power demand and supply in US power systems. Following this base case, the Razor Model was employed to simulate the reduced diversity case over the same time period. The differences between the base case and the reduced diversity case provide an estimate of the impact of the current US power supply fuel and technology diversity on the level and variance of power prices in the United States. These power sector outcomes were fed through to the IHS US macroeconomic model to quantify the broader economic impacts of the resulting higher and more varied power prices along with the shifts in capital deployment associated with premature retirements that accelerate the move to the reduced diversity case.

The difference between the base case and the reduced diversity case is a conservative estimate of the value of fuel diversity. The portfolio and substitution values would be greater over a longer analysis time frame because uncertainty and variation in costs typically increase over a longer time horizon. In addition, the estimate is conservative because it excludes indirect feedback effects from a higher risk premium in the reduced diversity power supplier cost of capital. This feedback is not present because the analysis alters only the generation capacity mix and holds all else constant. This indirect cost feedback would increase capital costs in this capital-intensive industry and magnify the economic impact of current trends to replace power plants before it is economic to do so by moving shifting capital away from applications with better risk-adjusted returns.

The United States is at a critical juncture because in the next decade the need for power supply to meet increased customer demands, replace retiring power plants, and satisfy policy targets will require fuel and

1. Oil-fired power plants account for about 4% of US capacity and 0.2% of US generation but can play a critical role in providing additional electricity when the system is under stress.

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technology decisions for at least 150 gigawatts (GW)—about 15% of the installed generating capacity in the United States. However, current trends in energy policy could push that power plant turnover percentage to as much as one-third of installed capacity by 2030. The implication is clear: power supply decisions made in the next 10–15 years will significantly shape the US generation mix for decades to come.

The results of this study indicate seven key factors that will shape US power supply diversity in the years to come:

- **Energy policy development.** US policy heavily influences the US power supply mix. Implementing an all-of-the-above energy policy requires properly internalizing the value of fuel diversity.

- **Market structure.** Market flaws distort wholesale power prices downward and result in uneconomic retirement and replacement of existing cost-effective generation resources. This issue and any market structure changes to address it will significantly shape future power plant development.

- **Energy policy discourse.** Preserving the value of fuel diversity depends on public awareness and understanding. The extent and nature of public education regarding the value of power supply diversity may strongly influence public opinion.

- **Planning alignment.** Alignment of fuel and technology choices for power generation with engineering and economic principles is critical to efficient and reliable supply. There is no single fuel or technology of choice for power generation, and all forms of power production have economic, environmental, and reliability impacts.

- **Risk assessment.** To incorporate system considerations into plant-level decisions, prudent fuel price uncertainties must be used with probabilistic approaches to decision making.

- **Flexibility.** Flexibility and exemptions in rule making and implementation allow for the balancing of costs and benefits in power supply systems and may help preserve highly valuable diversity in systemwide decisions as well as on a small but impactful individual plant scale.

- **Scope.** Including fuel price risk and additional storage and transportation infrastructure costs is crucial when evaluating reduced diversity scenarios in comparison to the cost of maintaining and expanding fuel diversity.

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The Value of US Power Supply Diversity

Overview

The power business is customer driven: consumers do not want to pay more than necessary for reliable power supply, and they want some stability and predictability in their monthly power bills. Giving consumers what they want requires employing a diverse mix of fuels and technologies in power production. Employing the diverse mix of fuels and technologies available today produces lower and less volatile power prices compared to a less diverse case with no meaningful contributions from coal and nuclear power and a smaller contribution from hydroelectric power. In this less diverse scenario, called the *reduced diversity case,* wind and solar power make up one-third of installed capacity (up from about 7% in the base case) and 22.5% of generation; hydroelectric power capacity decreases from about 6.6% to 5.3% and represents 3.8% of generation; and natural gas–fired power plants account for the remaining 61.7% of installed capacity and 73.7% of generation.

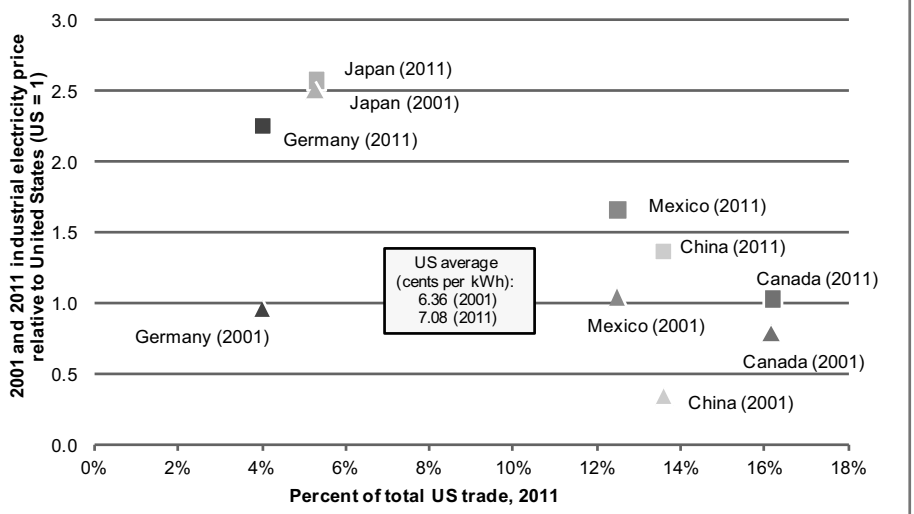
The current diverse US power supply reduces US consumer power bills by over $93 billion per year compared to a reduced diversity case. In addition, the current diversified power generation mix mitigates exposure to the price fluctuations of any single fuel and, by doing so, cuts the potential variability of monthly power bills roughly in half.

Power prices influence overall economic performance. For example, since the recovery of the US economy began in the middle of 2009, manufacturing jobs in the 15 states with the lowest power prices increased by 3.3%, while in the 15 states with the highest power prices these jobs declined by 3.2%. This job impact affected the overall economic recovery. The average annual economic growth in the 15 states with the lowest industrial power prices was 0.6 percentage points higher than in the 15 states with the highest power prices.

Higher and more varied power prices can also impact international trade. In the past decade, the competitive position for US manufacturers improved thanks to lower relative energy costs, including the improving US relative price of electric power (see Figure 1). Although power prices are only one of a number of factors that influence competitive positions in the global economy, there are clear examples, such as Germany, where moving away from a cost-effective power generating mix is resulting in significant economic costs and a looming loss of competitiveness. German power prices increased rapidly over the past decade because Germany closed nuclear power plants before it was economic to do so and added too many wind and solar power resources too quickly into the generation mix. IHS estimates that Germany's net export losses

FIGURE 1

Relative industrial electricity prices for top five US trading partners



Note: Total trade = exports plus imports.
Source: IHS Energy, US Census Bureau, OECD/IEA

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directly attributed to the electricity price differential totaled €52 billion for the six-year period from 2008 to 2013.[2]

A less diverse US power supply would make power prices higher and more varied and force a costly adjustment process for US consumers and businesses. The price increase associated with the reduced diversity case produces a serious setback to US economic activity. The value of goods and services would drop by nearly $200 billion, approximately one million fewer jobs would be supported by the US economy, and the typical household's annual disposable income would go down by over $2,100. These economic impacts take a few years to work through the economy as consumers and producers adjust to higher power prices. The eventual economic impacts are greater if current trends force the closure and replacement of power plants before it is economic to do so. Regardless of the replacement technology, it is uneconomic to close a power plant when the costs of continued operation are less than the cost of a required replacement. Premature power plant turnover imposes an additional cost burden by shifting capital away from more productive applications. A closure and replacement of all nuclear and coal-fired generating capacity in the next 10 years would involve roughly $730 billion of investment. An opportunity cost exists in deploying capital to replace productive capital rather than expanding the productive capital base.

The United States currently faces a key challenge in that many stakeholders take the current benefits of power supply diversity for granted because they inherited diversity based on fuel and technology decisions made decades ago. There is no real opposition to the idea of an all-of-the-above energy policy in power supply. Yet, a combination of factors—tightening environmental regulations, depressed wholesale power prices, and unpopular opinions of coal, oil, nuclear, and hydroelectric power plants—are currently moving the United States down a path toward a significant reduction in power supply diversity. A lack of understanding of power supply diversity means momentum will continue to move the United States toward a future generation mix without any meaningful contribution from nuclear, coal, or oil, and a diminishing contribution from hydroelectric generation.

The United States is at a critical juncture because power plant fuel and technology decisions being made today will affect the US power supply mix for decades to come. These decisions need to be grounded in engineering, economic, and risk management principles that underpin a cost-effective electric power sector. Comparing the performance of the current generation mix to results of the reduced diversity case provides key insights into the current nature and value of diversity. An assessment and quantification of the value of power supply diversity will help achieve a more cost-effective evolution of US power supply in the years ahead.

Generation diversity: A cornerstone of cost-effective power supply

If power consumers are to receive the reliable and cost-effective power supply they want, then cost-effective power production requires an alignment of power supply to power demand. Engineering, economic, and risk management assessments consistently show that an integration of fuels and technologies produces the least-cost power production mix. A cost-effective mix involves integrating nondispatchable power supply with dispatchable base-load, cycling, and peaking technologies. This cost-effective generating mix sets the metrics for cost-effective demand-side management too. Integrating cost-effective power demand management capabilities with supply options requires balancing the costs of reducing or shifting power demand with the incremental cost of increasing power supply. Appendix A reviews the principles of engineering, economics, and risk management that lead to the conclusion that cost-effective power supply requires fuel and technological diversity.

2. See the IHS study *A More Competitive Energiewende: Securing Germany's Global Competitiveness in a New Energy World,* March 2014.

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The underlying principles of cost-effective power supply produce five key insights:

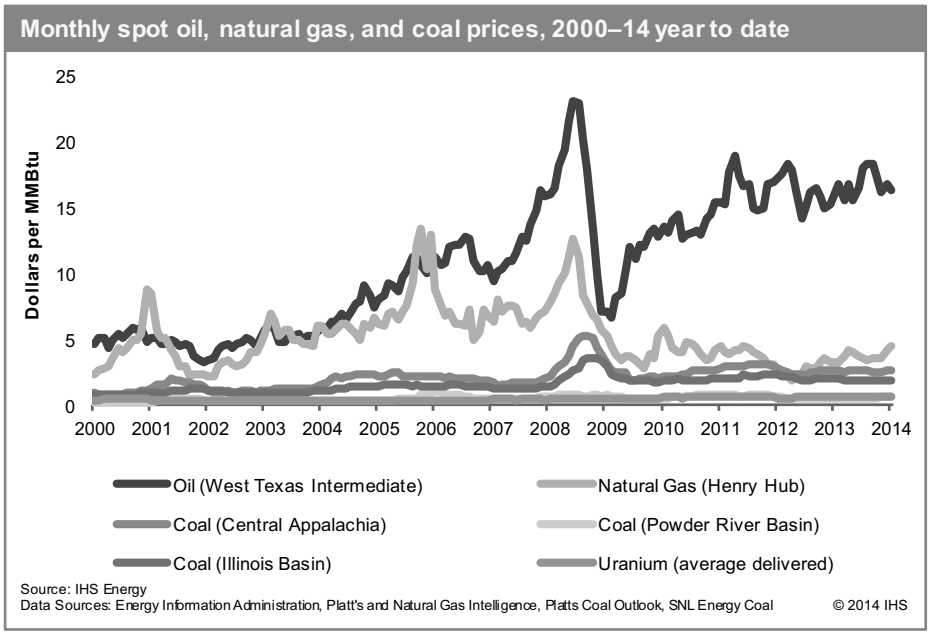
- There is no single fuel or technology of choice for power generation. Reliably and efficiently supplying consumers with the amounts of electricity they want when they want it requires a diverse generation mix.
- A cost-effective generation mix involves diversity but does not involve maximizing diversity by equalizing generation shares from all available supply options.
- A cost-effective mix of fuel and technologies for any power system is sensitive to the uncertainties surrounding the level and pattern of consumer power demands as well as the cost and performance of alternative power generating technologies and, in particular, the delivered fuel prices.
- A cost-effective generating mix will differ from one power system to the next because of differences in aggregate consumer demand patterns as well as in the cost and performance of available generating options.
- The best type of capacity to add to any generation portfolio depends on what types of capacity are already in the mix.

Power production cost fluctuations reflect inherent fuel price uncertainties

Power consumers reveal preferences for some degree of predictability and stability in their monthly power bills. These consumer preferences present a challenge on the power supply side because the costs of transforming primary energy—including natural gas, oil, coal, and uranium—into electric power is inherently risky. Experience shows that the prices of these fuel inputs to the power sector are difficult to anticipate because these prices move in multiyear cycles and fluctuate seasonally (see Figure 2). In addition, this past winter showed that dramatic price spikes occur when natural gas delivery systems are pushed to capacity (see Figure 3).

The recent volatility in the delivered price of natural gas to the US Northeast power systems demonstrates the value of fuel diversity. During this past winter, colder-than-normal weather created greater consumer demand for natural gas and electricity to heat homes and businesses. The combined impact on natural gas demand strained the capability of pipeline systems to deliver natural gas in the desired quantity and pressure. Natural gas prices soared, reflecting the market forces allocating available gas to the highest valued end uses. At some points in time, price allocation was

FIGURE 2

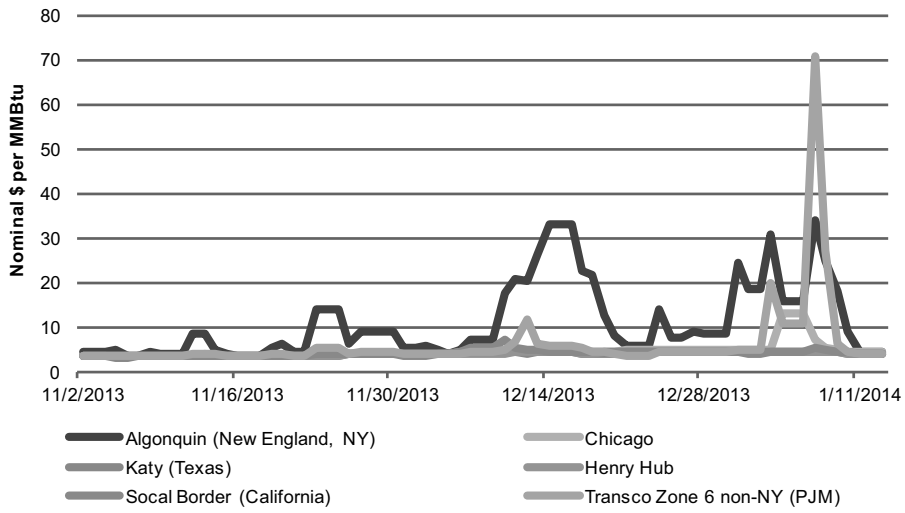


not enough and additional natural gas was not available at any price, even to power plants holding firm supply contracts.

As high as the natural gas price spikes reached, and as severe as the natural gas deliverability constraints were, things could have been worse. Although oil-fired power provided only 0.35% of generation in the Northeast in 2012, this slice of power supply diversity provided an important natural gas supply system relief valve. The oil-fired power plants and the dual-fueled oil- and natural gas–fired power plants were able to use liquid fuels to generate 12% of the New England power supply during the seven days starting 22 January 2014 (see Figure 4). This oil-fired generation offset the equivalent of 327,000 megawatt-hours (MWh) of natural gas–fired generation and thus relieved the natural gas delivery system of about 140 million cubic feet per day of natural gas deliveries. This fuel diversity provided the equivalent to a 6% expansion of the daily delivery capability of the existing natural gas pipeline system.

FIGURE 3

Delivered daily gas prices, November 2013–January 2014



Source: IHS Energy, Ventyx Velocity Suite

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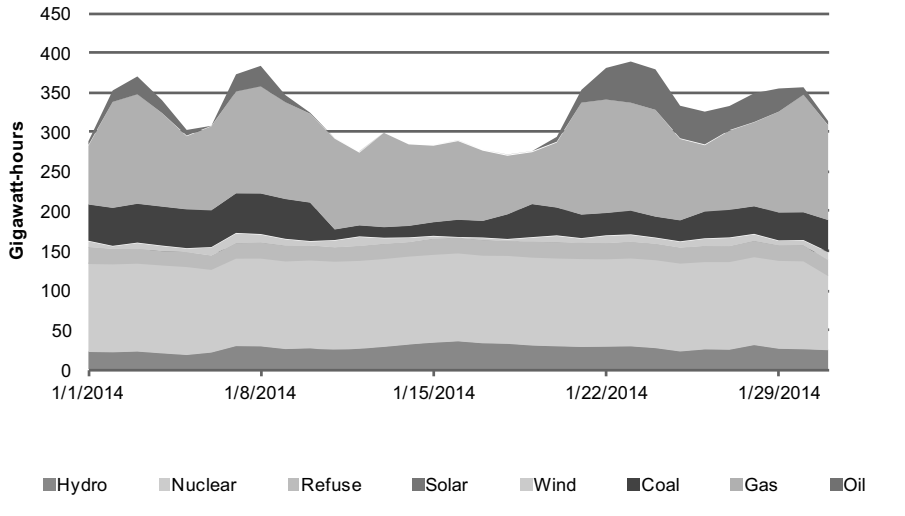
FIGURE 4

ISO New England generation, January 2014



Source: IHS Energy

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The lesson from this past winter was that a small amount of oil-fired generation in the supply mix proved to be highly valuable to the Northeast energy sector despite its production costs and emission rates. Many of these oil-fired power plants are old and relatively inefficient at converting liquid fuel to power. However, this relative inefficiency does not impose a great penalty because these power plants need to run very infrequently to provide a safety valve to natural gas deliverability. Similarly, these units have emissions rates well above those achievable with the best available technology, but the absolute amount of emissions and environmental impacts are small because their utilization rates are so low. Although the going forward costs and the environmental impacts are relatively small, the continued operation of these oil-fired power plants is at risk from tightening environmental regulations.

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Oil-fired power plants were not the only alternative to natural gas–fired generation this past winter. Coal played a major role. As the *New York Times* reported on 10 March 2014, 89% of American Electric Power Company, Inc.'s 5,573 megawatts (MW) of coal-fired power plants slated for retirement in 2015 owing to tightening environmental regulations were needed to keep the lights on during the cold snap this past winter in PJM.[3]

The critical role fuel diversity played during the recent polar vortex affected power systems that serve over 40 million US electric consumers and almost one-third of power supply. This widespread exposure to natural gas price and deliverability risks is becoming increasingly important because the share of natural gas in the US power mix continues to expand. The natural gas–fired share of power generation increased from 16% to 27% between 2000 and 2013. Twelve years ago, natural gas–fired generating capacity surpassed coal-fired capacity to represent the largest fuel share in the US installed generating mix. Currently, natural gas–fired power plants account for 40% of the US installed capacity mix.

The increasing dependence on natural gas for power generation is not an accident. The innovation of shale gas that began over a decade ago made this fuel more abundant and lowered both its actual and expected price. But the development of shale gas did not change the factors that make natural gas prices cyclical, volatile, and hard to forecast accurately.

Factors driving natural gas price dynamics include

- Recognition and adjustment lags to market conditions
- Over- and under-reactions to market developments
- Linkages to global markets through possible future liquefied natural gas (LNG) trade
- Misalignments and lags between natural gas demand trends, supply expansions, and pipeline investments
- "Black swan" events—infrequent but high-impact events such as the polar vortex

Natural gas price movements in the shale gas era illustrate the impact of recognition and adjustment lags to changing market conditions. Looking back, natural gas industry observers were slow to recognize the full commercialization potential and magnitude of the impact that shale gas would have on US natural gas supply. Although well stimulation technologies date back to the 1940s, today's shale gas technologies essentially began with the innovative efforts of George Mitchell in the Barnett resource base near Fort Worth, Texas, during the 1980s and 1990s. Mitchell Energy continued to experiment and innovate until eventually proving the economic viability of shale gas development. As a result, shale gas production expanded (see Figure 5).

Although shale gas had moved from its innovation phase to its commercialization phase, many in the oil and gas industry did not fully recognize what was happening even as US shale gas output doubled from 2002 to 2007 to reach 8% of US natural gas production. The belief that the United States was running out of natural gas persisted, and this recognition lag supported the continued investment of billions of dollars to expand LNG import facilities (see Figure 6).

3. *New York Times.* "Coal to the Rescue, But Maybe Not Next Winter." Wald, Matthew L. 10 March 2014: http://www.nytimes.com/2014/03/11/business/energy-environment/coal-to-the-rescue-this-time.html?_r=0, retrieved 12 May 2014.

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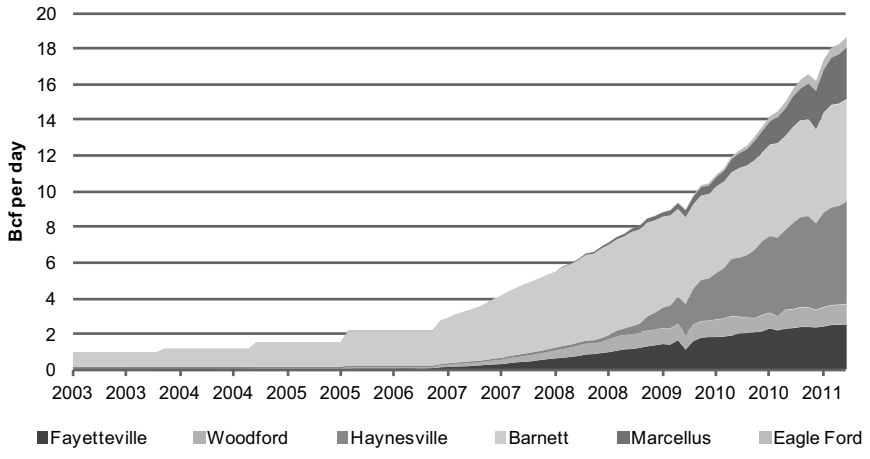
Eventually, evidence of a shale gas revolution became undeniable. However, recognition and adaptation lags continued. Productivity trends in natural gas–directed drilling rigs indicate that only about 400 gas-directed rigs are needed to keep natural gas demand and supply in balance over the long run. Yet operators in the natural gas industry did not fully anticipate this technological trend. Bullish price projections caused the US natural gas–directed rig count to rise from 690 to 1,600 rigs

FIGURE 5

Growth in major US shale plays



Note: Bcf = billion cubic feet.
Source: IHS Energy, Lippmann Consulting

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FIGURE 6

LNG facilities in North America—Existing and proposed (October 2006)

40609-1Source: IHS Energy

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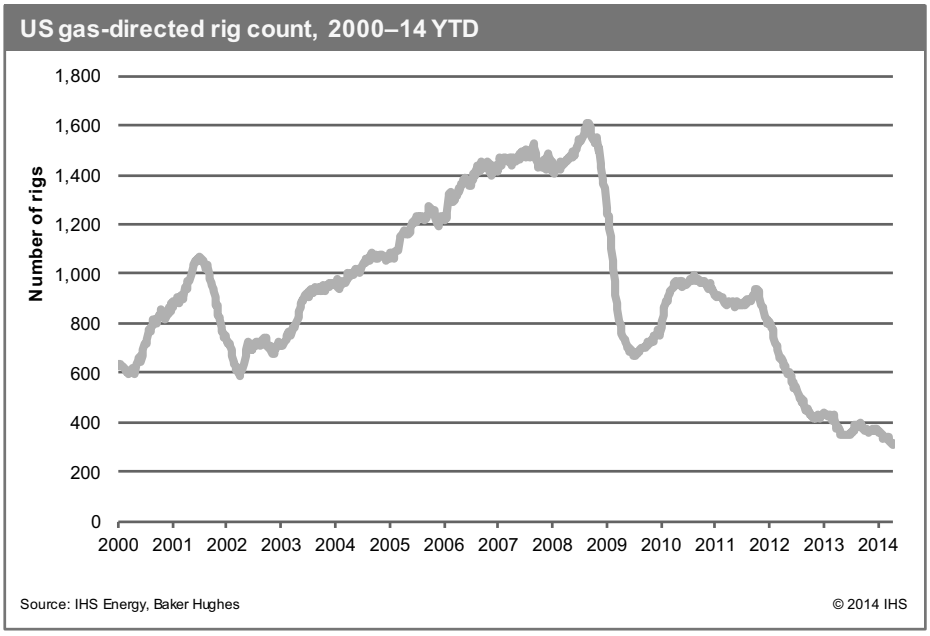
between 2002 and 2008. This level of drilling activity created a supply surplus that caused a precipitous decline of up to 85% in the Henry Hub natural gas price from 2008 to 2012. From the 2008 high count, the number of US natural gas–directed rigs dropped over fivefold to 310 by April 2014 (see Figure 7).

FIGURE 7



Natural gas investment activity also lagged market developments. During this time, the linkage between North American natural gas markets and global markets reversed from an investment hypothesis supporting an expansion of LNG *import* facilities, as shown in Figure 6, to an investment hypothesis involving the expansion of LNG *export* facilities (see Figure 8). At the same time, investment in natural gas pipelines and storage did not keep pace with the shifts in domestic demand, supply, and trade. This asymmetry created vulnerability to low frequency but high impact events, such as colder-than-normal winters that expose gas deliverability constraints and launch record-setting delivered price spikes, as happened in the Northeast in the winters of 2012/13 and 2013/14.

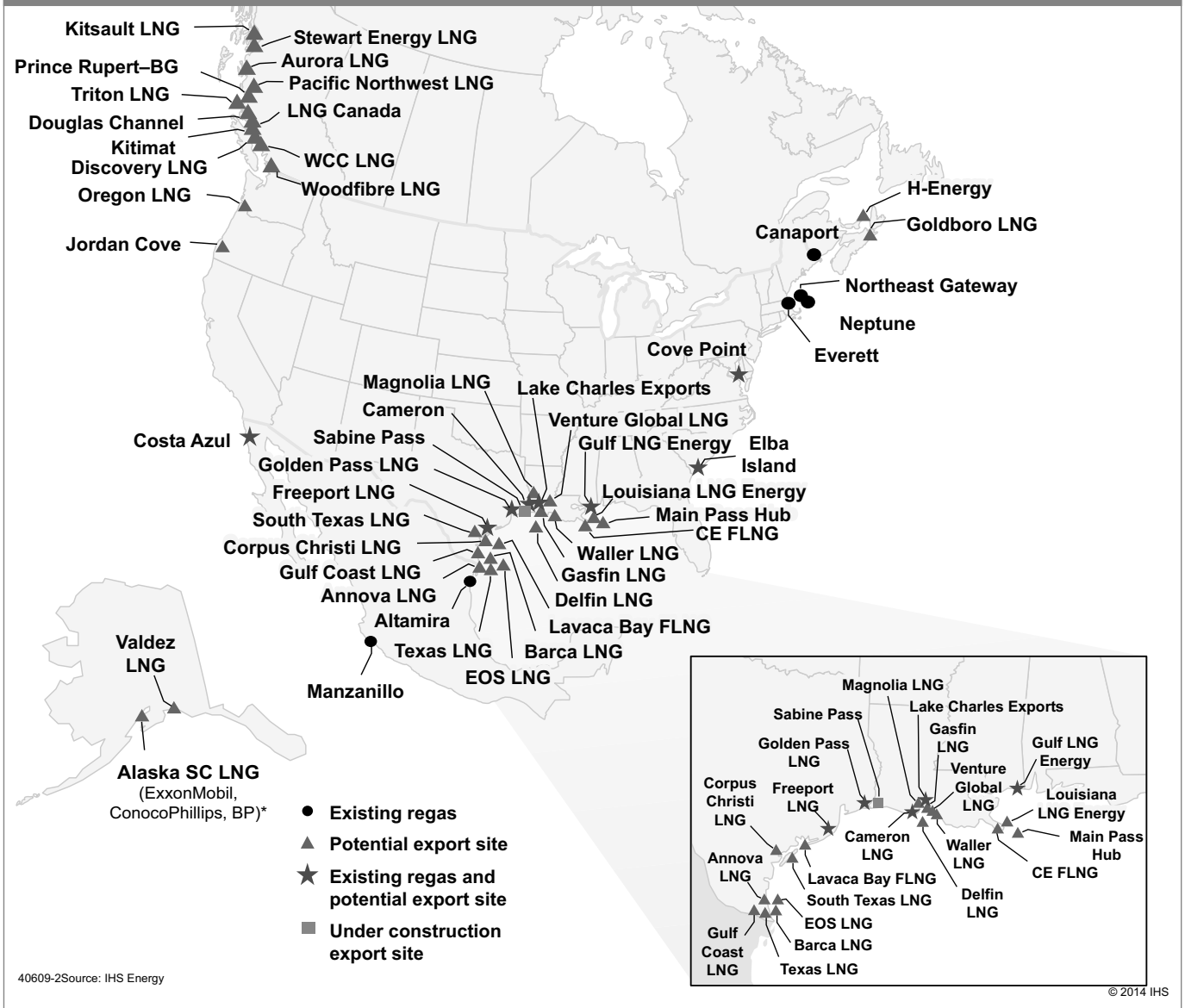
The Northeast delivered natural gas price spikes translated directly into dramatic power production cost run-ups. During the winter of 2013/14, natural gas prices delivered to the New York and PJM power system border hit $140 per MMBtu (at Transco Zone 6, 21 January 2014) and pushed natural gas–fired power production costs up 25-fold from typical levels and well beyond the $1,000 per MWh hourly wholesale power price cap in New York and PJM. This forced the New York Independent System Operator (NYISO) to allow exemptions to market price caps. The Federal Energy Regulatory Commission granted an emergency request to lift wholesale power price caps in PJM and New York. Lifting these price caps kept the lights on but also produced price shocks to 30% of the US power sector receiving monthly power bills in these power systems. The impact moved the 12-month electricity price index (a component of the consumer price index) in the Northeast up 12.7%—the largest 12-month jump in eight years.

The New York Mercantile Exchange (NYMEX) futures contract price strip illustrates how difficult it is to anticipate natural gas price movements. Figure 9 shows the price dynamics over the shale gas era and periodic examples of the NYMEX futures price expectations. The NYMEX future price error pattern indicates a bias toward expecting future natural gas prices to look like those of the recent past. Although these futures prices are often used as an indicator of future natural gas price movements, they have nonetheless proven to be a poor predictor.

The complex drivers of natural gas price dynamics continue to apply in the shale gas era. Prudent planning requires recognition that natural gas price movements remain hard to forecast, affected by multiyear

FIGURE 8

US lower-48 regasification facilities and filed liquefaction projects



40609-2Source: IHS Energy

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investment cycles that lag market developments, subject to seasonality, and capable of severe short-run price volatility.

Natural gas price cycles during the shale gas era and the recent extreme volatility in natural gas prices are clear evidence that the benefits of increased natural gas use for power generation need to be balanced against the costs of natural gas's less predictable and more variable production costs and fuel availability.

The natural gas–fired generation share is second only to the coal-fired generation share. One of the primary reasons that fuel diversity is so valuable is because natural gas prices and coal prices do not move together.

Significant variation exists in the price of natural gas relative to the price of coal delivered to US power generators (see Figure 10). The dynamics of the relative price of natural gas to coal are important because

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relative prices routinely change which power plants provide the most cost-effective source of additional power supply at any point in time.

The relative prices of natural gas to coal prior to the shale gas revolution did not trigger as much cost savings from fuel substitution as the current relative prices do. From 2003 to 2007 the price of natural gas was four times higher than the price of coal on a Btu basis. Under these relative price conditions, small changes in fuel prices did not alter the position of coal-fired generation as the lower-cost resource for power generation. The shale gas revolution brought gas prices to a more competitive level and changed the traditional relative relationship between gas and coal generation. As Table 1 shows, the 2013 dispatch cost to produce electricity at the typical US natural gas–fired power plant was equivalent to the dispatch cost at the typical US coal-fired power plant with a delivered natural gas price of $3.35 per MMBtu, about 1.39 times the delivered price of coal. Current price changes move the relative price of natural gas to coal around this average equivalency level and create more generation substitution than has historically occurred.

FIGURE 9

Henry Hub and NYMEX futures, 1994–2013

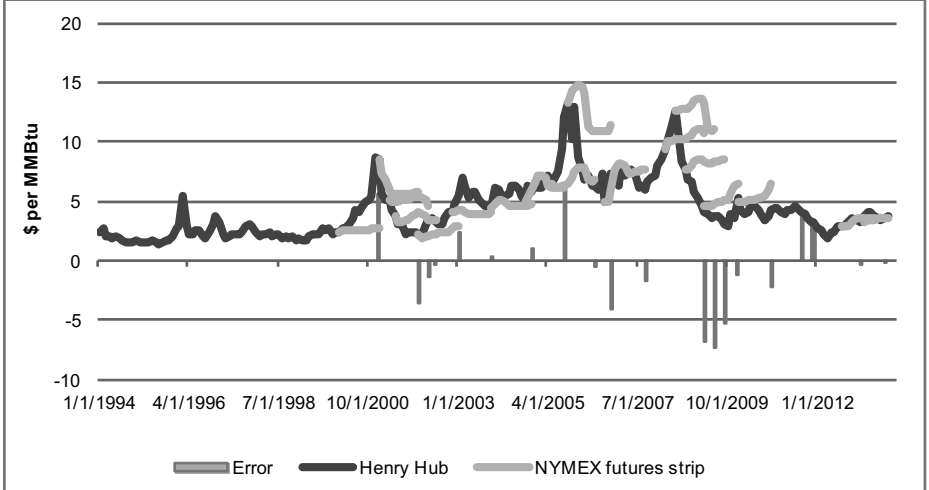

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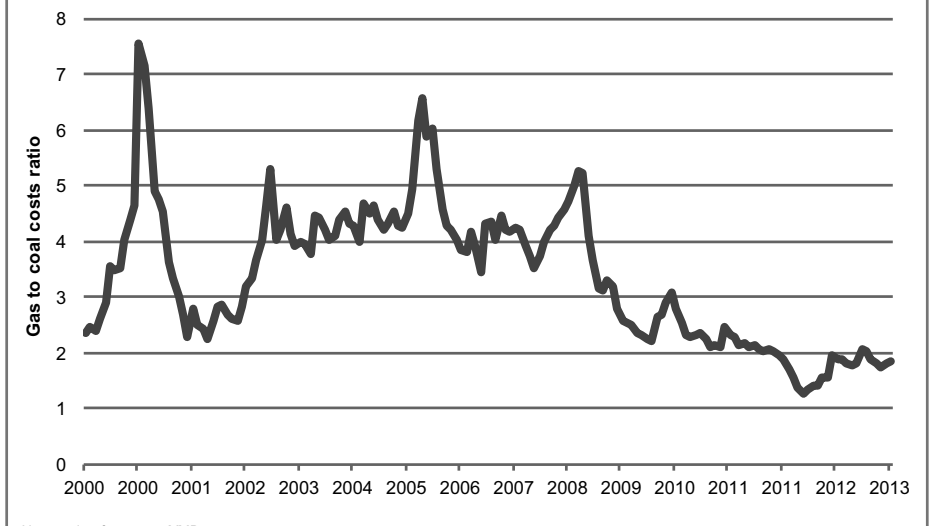
FIGURE 10

Ratio of delivered gas to delivered coal costs, 2000–13



Note: ratio of costs per MMBtu.
Source: IHS Energy, Ventyx Velocity Suite

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The average equivalency level triggers cost savings from substitution within the generation mix. Current relative prices frequently move above and below this critical relative price level. Consequently, slight movements in either coal or natural gas prices can have a big impact on which generation resource provides the most cost-effective source of generation at any given point in time.

Coal price dynamics differ from natural gas price movements. The drivers of coal price dynamics include rail and waterborne price shifts, changes in coal inventory levels, and mine closures and openings. In addition, international coal trade significantly influences some coal prices. For example, when gas prices

began to fall in 2008–12, the natural gas displacement of coal in power generation caused Appalachian coal prices also to drop. However, the coal price drop was slower and less severe than the concurrent natural gas price drop because of the offsetting increase in demand for coal exports, particularly for metallurgical coal. Linkages to global coal market prices were significant even though only about one-quarter of Appalachian coal production was involved in international trade. The implication is that as global trade expands, the influence of international trade on domestic fuel prices may strengthen.

TABLE 1

Typical generating units

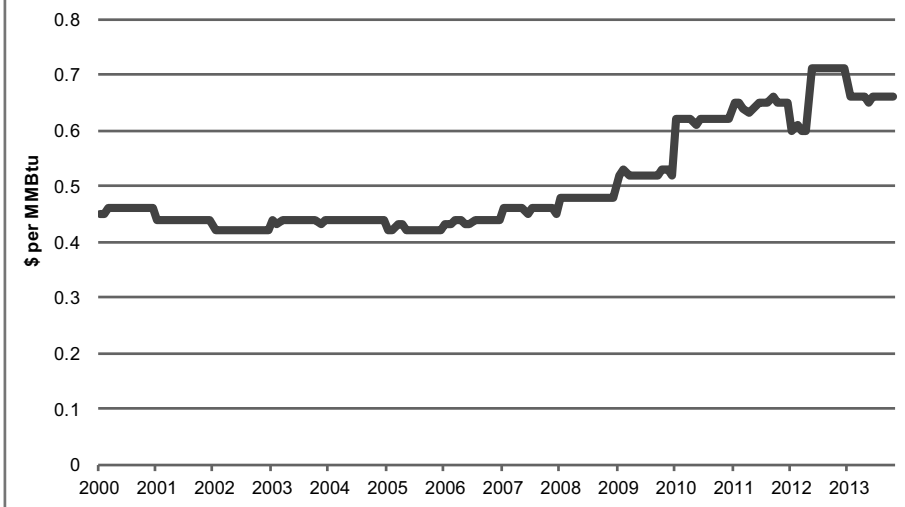
	Typical coal unit	Typical CCGT unit
Size, MW	218	348
Heat rate, Btu/kWh	10,552	7,599
Fuel cost, $/MMBtu	$2.41	$4.46
Fuel cost, $/MWh	$25.43	$33.89
Variable O&M, $/MWh	$4.70	$3.50
Lbs SO_2/MWh (with wet FGD)	1.16	0
SO_2 allowance price, $/ton	70	70
Lbs NO_x/MWh	0.74	0.15
NO_x allowance price, $/ton	252	252
SO_2,NO_x emissions cost, $/MWh	0.13	0.02
Short-run marginal cost, $/MWh	$30.26	$37.41
Breakeven fuel price, $/MMBtu	$2.41	$3.35

Note: kWh = kilowatt-hour(s); O&M = operation and maintenance (costs); SO_2 = sulfur dioxide; NO_x = nitrogen oxides; CCGT = combined-cycle gas turbine.

Source: IHS Energy

FIGURE 11

Nuclear fuel prices, 2000–13



Source: IHS Energy, Ventyx Velocity Suite

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Nuclear fuel prices are also dynamic, and are different from fossil fuel prices in two ways (see Figure 11). Nuclear fuel cost is a relatively smaller portion of a nuclear plant's overall cost per kilowatt-hour. Also nuclear fuel prices have a different set of drivers. The primary drivers of nuclear fuel price movements include uranium prices, enrichment costs, and geopolitical changes in nuclear trade. These drivers produce price dynamics dissimilar to those of either natural gas or coal. As a result, nuclear fuel price movements are not strongly correlated to fossil fuel price movements.

Diversity: The portfolio effect

A diverse fuel and technology portfolio is a cornerstone for an effective power production risk management strategy. If prices for alternative fuels moved together, there would be little value in diversity. But relative power production costs from alternative fuels or technologies are unrelated and inherently unstable. As a result, the portfolio effect in power generation exists because fuel prices do not move together, and thus changes in one fuel price can offset changes in another. The portfolio effect of power generation fuel diversity is significant because the movements of fuel prices are so out of sync with one another.

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The "correlation coefficient" is a statistical measure of the degree to which fuel price changes are related to each other. A correlation coefficient close to zero indicates no similarity in price movements. Correlation coefficients above 0.5 are considered strong correlations, and values above 0.9 are considered very strong correlations. Power production input fuel price changes (natural gas, coal, and nuclear) are not highly correlated and consequently create the basis for a portfolio approach to fuel price risk management (see Table 2).

TABLE 2

Delivered monthly fuel price correlations, 2000–13

Coal/natural gas	0.01
Natural gas/nuclear	(0.35)
Coal/nuclear	0.85

Source: IHS Energy

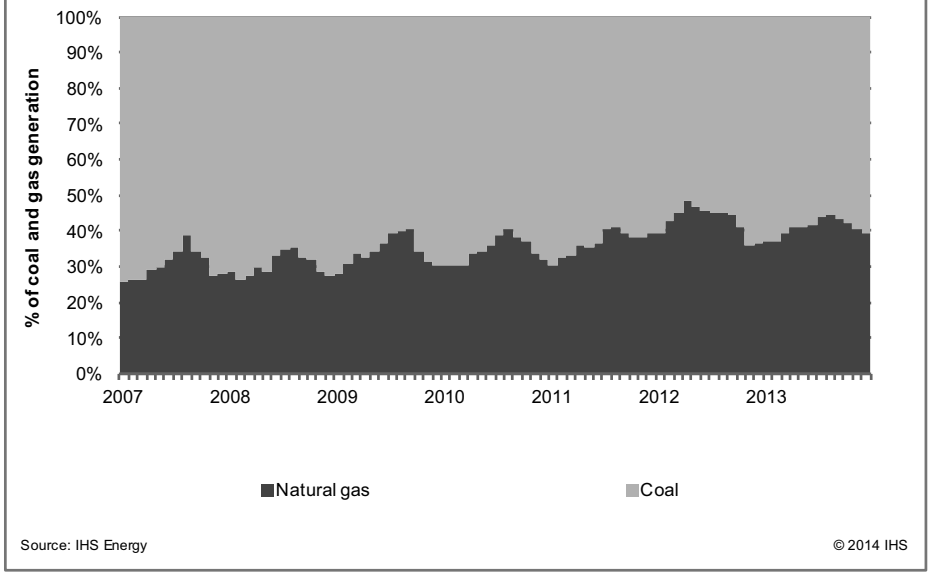
Diversity: The substitution effect

A varied portfolio mitigates power production cost risk because fuel diversity provides the flexibility to substitute one source of power for another in response to relative fuel price changes. Therefore, being able to substitute between alternative generation resources reduces the overall variation in production costs.

Substitution benefits have proven to be substantial. In the past five years, monthly generation shares for natural gas–fired generation were as high as 33% and as low as 19%. Similarly, monthly generation shares for coal-fired generation were as high as 50% and as low as 34%. The swings were driven primarily by a cost-effective alignment of fuels and technologies to consumer demand patterns and alterations of capacity utilization rates in response to changing relative fuel costs. Generation shares shifted toward natural gas–fired generation when relative prices favored natural gas and shifted toward coal-fired generation when relative prices favored coal. Figure 12 shows the recent flexibility in the utilization share tradeoffs between only coal-fired and natural gas–fired generation in the United States.

FIGURE 12

Coal and natural gas generation, 2007–13



Source: IHS Energy

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Diversity benefits differ by technology

All types of generating fuels and technologies can provide the first dimension of risk management—the *portfolio effect*. However, only some types of fuels and technologies can provide the second dimension of risk management—the *substitution effect*. Power plants need to be dispatchable to provide the substitution

effect in a diverse portfolio. As a result, the benefits of expanding installed capacity diversity by adding nondispatchable resources such as wind and solar generating technologies are less than the equivalent expansion of power capacity diversity with dispatchable power plants such as biomass, conventional fossil-fueled power plants, reservoir hydro, and nuclear power plants. Therefore, not all diversity in the capacity mix provides equal benefits.

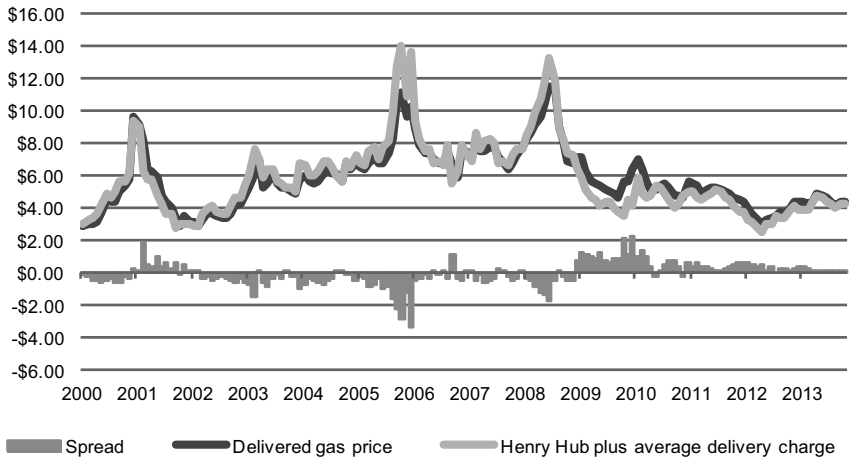
Diversity is the best available power cost risk management tool

A diverse portfolio is the best available tool for power generation cost risk management. Other risk management tools such as fuel contracts and financial derivatives complement fuel and technological diversity in power generation but fall far short of providing a cost-effective substitute for power supply diversity.

Contracts are tools available to manage power production cost risk. These tools include short-run contracts, including NYMEX futures contracts, as well as long-term contracts spanning a decade or more. Power generators have traditionally covered some portion of fuel needs with contracts to reduce the variance of delivered fuel costs. To do this, generators balance the benefits of using contracts or financial derivatives against the costs. With such assessment, only a small percentage of natural gas purchases are under long-term contracts or hedged in the futures markets. Consequently, the natural gas futures market is only liquid (has many buyers and sellers) for a few years out.

FIGURE 13

Power generation delivered gas price versus Henry Hub (plus delivery), 2000–13



Source: IHS Energy, Ventyx Velocity Suite

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The degree of risk management provided by contracts is observed in the difference between the reported delivered price of natural gas to power generators and the spot market price plus a typical delivery change. Contract prices along with spot purchases combine to determine the reported delivered price of natural gas to power generators. Delivered prices are typically about 12% higher than the Henry Hub spot price owing to transport, storage, and distribution costs, so this percentage may be used to approximate a delivery charge. Figure 13 compares the Henry Hub spot price plus this typical delivery charge to the reported delivered price of natural gas to power producers.

A comparison of the realized delivered price to the spot price plus a delivery charge shows the impact of contracting on the delivered price pattern. Natural gas contracts provided some protection from spot price highs and thus reduced some variation of natural gas prices compared to the spot market price plus transportation. Over the past 10 years, contracting reduced the monthly variation (the standard deviation) in the delivered price of natural gas to the power sector by 24% compared to the variation in the spot price

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plus delivery charges at the Henry Hub. Although fuel contracts are part of a cost-effective risk management strategy, the cost/benefit trade-offs of using contracts limit the application of these tools in a cost-effective risk management strategy.

Using a contract to lock into volumes at fixed or indexed prices involves risks and costs. Contracting for fuel creates volume risk. A buyer of a contract is taking on an obligation to purchase a given amount of fuel, at a given price, and at a future point in time. From a power generator's perspective, the variations in aggregate power consumer demand and relative prices to alternative generating sources make predicting the amount of fuel needed at any future point in time difficult. This difficulty increases the further out in time the contracted fuel delivery date. If a buyer ends up with too much or too little fuel at a future point in time, then the buyer must sell or buy at the spot market price at that time.

Contracting for fuel creates price risk. A buyer of a fuel contract locks into a price at a future point in time. When the contract delivery date arrives, the spot market price for the fuel likely differs from the contract price. If the contract price ends up higher than the spot market price, then the contract provided price certainty but also created a fuel cost that turned out to be more expensive than the alternative of spot market purchases. Conversely, if the spot market price turns out to be above the contract price, then the buyer has realized a fuel cost savings.

Past price relationships also illustrate the potential for gains and losses from contracting for natural gas in an uncertain price environment. When the spot market price at Henry Hub increased faster than expected, volumes contracted at the previously lower expected price produced a gain. For example, in June 2008 the delivered cost of natural gas was below that of the spot market. Conversely, when natural gas prices fell faster than anticipated, volumes contracted at the previously higher expected price produced a loss. For example in June 2012, the delivered cost of natural gas was above that of the spot market purchases.

The combination of volume and price risk in fuel contracting makes buying fuel under contract a speculative activity, capable of generating gains and losses depending on how closely contract prices align with spot market prices. Therefore, cost-effective risk management requires power generators to balance the benefits of gains from contracting for fuel volumes and prices against the risk of losses.

Managing fuel price risk through contracts does not always involve the physical delivery of the fuel. In particular, a futures contract is typically settled before physical delivery takes place, and thus is referred to as a financial rather than a physical hedge to fuel price uncertainty. For example, NYMEX provides a standard contract for buyers and sellers to transact for set amounts of natural gas capable of being delivered at one of many liquid trading hubs at a certain price and a certain date in the future. Since the value of a futures contract depends on the expected future price in the spot market, these futures contracts are derivatives of the physical natural gas spot market.

The potential losses facing a fuel buyer that employs financial derivatives create a risk management cost. Sellers require that buyers set aside funds as collateral to insure that potential losses can be covered. Market regulators want these guarantees in place as well in order to manage the stability of the marketplace. Recently, as part of reforms aimed at improving the stability of the financial derivatives markets, the Dodd-Frank Act increased these collateral requirements and thus the cost of employing financial derivatives.

Outside of financial derivatives, fuel deliverability is an important consideration in evaluating power cost risk management. Currently, natural gas pipeline expansion requires long-term contracts to finance projects. Looking ahead, the fastest growing segment of US natural gas demand is the power sector and, as described earlier, this sector infrequently enters into long-term natural gas supply contracts that would finance new pipelines. Consequently, pipeline expansions are not likely to stay in sync with power generation natural gas demand trends.

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The prospect of continued periodic misalignments between natural gas deliverability and natural gas demand makes price spikes a likely feature of the future power business landscape. The nominal volume of long-term fuel contracts and the costs and benefits of entering into such contracts limit the cost-effective substitution of contracts for portfolio diversity. Therefore, maintaining or expanding fuel diversity remains a competitive alternative to natural gas infrastructure expansion.

Striking a balance between the costs and benefits of fuel contracting makes this risk management tool an important complement to a diverse generation portfolio but does not indicate that it could provide a cost-effective substitute for power supply diversity.

A starting point taken for granted

US power consumers benefit from the diverse power supply mix shown in Figure 14. Simply inheriting this diverse generation mix based on fuel and technology decisions made decades ago makes it easy for current power stakeholders to take the benefits for granted. This underappreciation of power supply diversity creates an energy policy challenge because if the value of fuel and technology diversity continues to be taken for granted, then the current political and regulatory process is not likely to properly take it into account when crafting legislation or setting regulations.

FIGURE 14

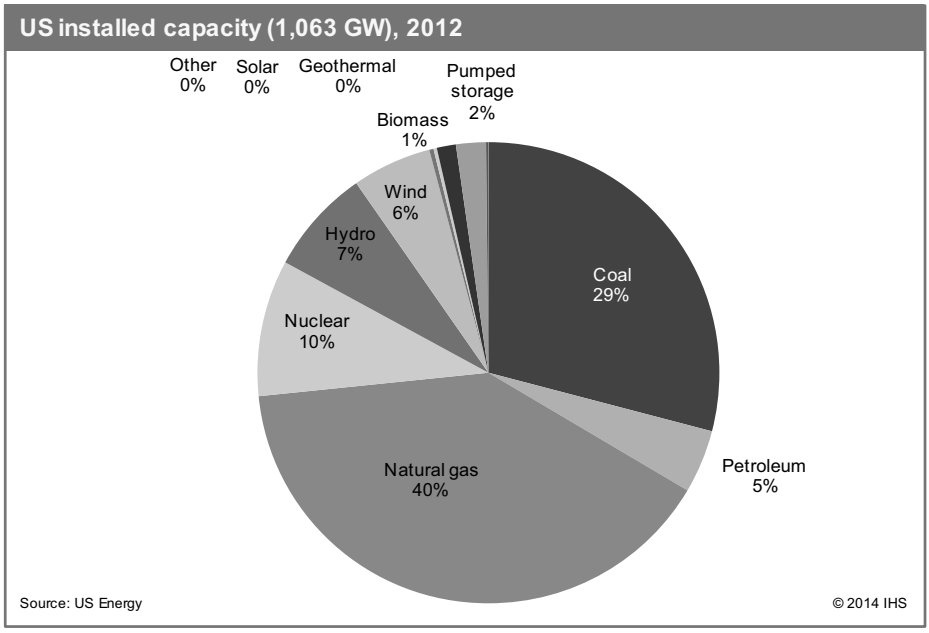

TABLE 3

The impact of fuel diversity: Power production fuel costs
(Actual versus all gas generation mix, 2000–13 YTD, cents per kWh)

	Henry Hub	All power sector fuel costs
Average	5.09	2.29
Maximum	11.02	4.20
Minimum	2.46	1.21
Standard deviation	1.63	0.55

Note: Converted the Henry Hub dollar per MMBtu price to cents per kWh using the average reported heat rate for all operating natural gas plants in the respective month.
Data source: Ventyx Velocity Suite.

Source: IHS Energy

As a result, the United States may move down a path toward a less diverse power supply without consumers realizing the value of power supply diversity until it is gone. For example, if the US power sector had been all natural gas–fired during the shale gas era to date, the average fuel cost for power would have been over twice as high, and month-to-month power bill variation (standard deviation) would have been three times greater (see Table 3). This estimate itself is conservative because the additional demand from power generation would have likely put significant upward pressure on gas prices.

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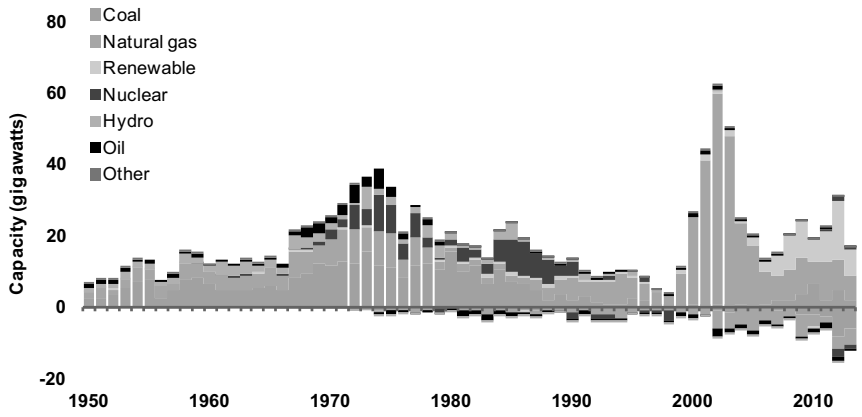
Trends in the US generation mix

The current diverse fuel and technology mix in US power supply did not come about by accident. The US generation mix evolved over many decades and reflects the fuel and technology decisions made long ago for power plants that typically operate for 30 to 50 years or more. Consequently, once a fuel and technology choice is made, the power system must live with the consequences—whatever they are—for decades.

US power supply does not evolve smoothly. The generation mix changes owing to the pace of power plant retirements, the error in forecasting power demand, price trends and other developments in the energy markets, and the impacts of public policy initiatives. All three of these factors unfold unevenly over time. The current diverse generation mix evolved from multiyear cycles of capacity additions that were typically dominated by a particular fuel and technology (see Figure 15). The swings in fuel and technology choice do not indicate a lack of appreciation for diverse power supply. Instead, they show that given the size of the existing supply base, it takes a number of years of homogenous supply additions to move the overall supply mix a small proportion. Therefore, altering the overall mix slightly required a number of years of adjustment.

FIGURE 15

US generating capacity additions and retirements, 1950–2013



Source: IHS Energy, Ventyx Velocity Suite

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The uneven historical pattern of capacity additions is important because the future pattern of retirements will tend to reflect the previous pattern of additions as similarly aged assets reach the end of their useful lives. For example, current retirements are disproportionately reducing the coal and nuclear shares in the capacity mix, reflecting the composition of power plants added in the 1960s through 1980s. Current power plant retirements are about 12,000 MW per year and are moving the annual pace of retirements in the next decade to 1.5 times the rate of the past decade.

Power plant retirements typically need to be replaced because electricity consumption continues to increase. Although power demand increases are slowing compared to historical trends and compared to the growth rate of GDP, the annual rate of change nevertheless remains positive. US power demand is expected to increase between 1.0% and 2.5% each year in the decade ahead, averaging 1.5%.

The expected pace of US power demand growth reflects a number of trends. First, US electric efficiency has been improving for over two decades. Most appliances and machinery have useful lives of many years. As technology improves, these end uses get more efficient. Therefore, overall efficiency typically increases as appliances and machinery wear out and are replaced. On the other hand, the number of electric end uses keeps expanding and the end-use penetration rates keep increasing owing to advances in digital and communication technologies that both increase capability and lower costs. These trends in existing technology turnover

and new technology adoption produce a steady rate of change in electric end-use efficiency (see Figure 16).

Underlying trends in power demand are often masked by the influences of variations in the weather and the business cycle. For example, US electric output in first quarter 2014 was over 4% greater than in the same period one year ago owing in part to the influence of the polar vortex. Therefore, trend rates need to compare power consumption increases either between points in time with similar weather conditions or on a weather-normalized basis. Similarly, power demand trends can be misleading if compared without taking the business cycle into account. Figure 17 shows the trend rate of growth in power use from the previous business cycle peak to peak and tough to trough. Overall, power consumption increased by between 0.5 and 0.6 of the rate of increase in GDP. Looking ahead, GDP is expected to increase on average 2.5% annually through 2025 and thus is likely to produce a trend rate of electric consumption of around 1.5% annually. This US power demand growth rate creates a need for about 9 GW of new power supply per year, for a total of 1,140 GW by 2025.

FIGURE 16

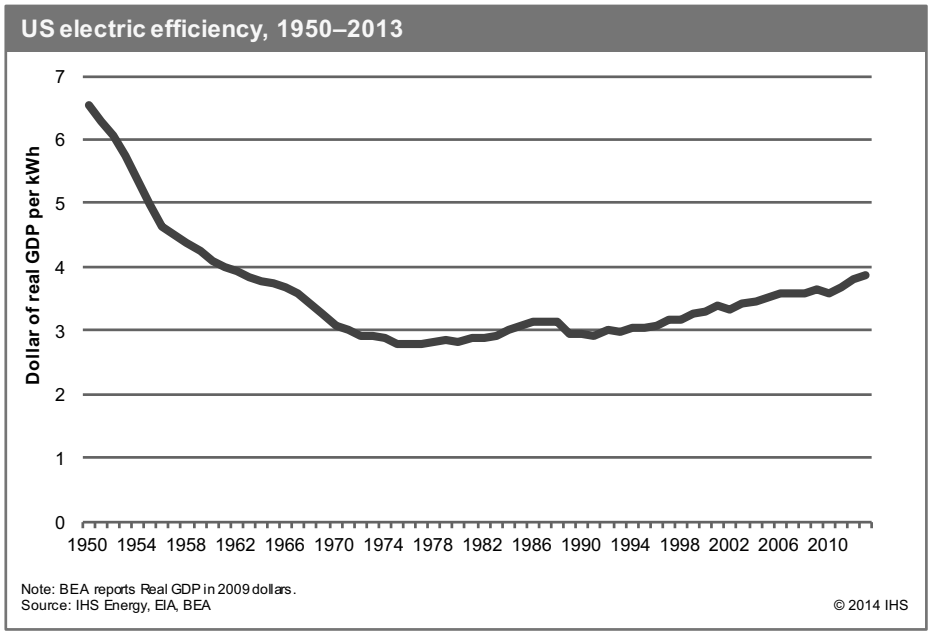
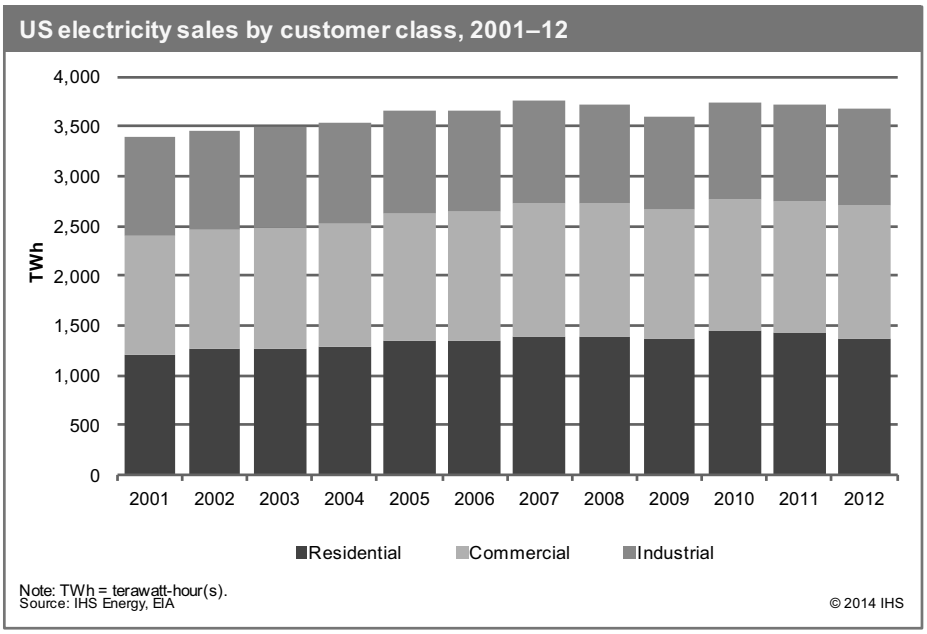


FIGURE 17



Annual power supply additions do not typically unfold simultaneously with demand increases. Historically, changes in power supply are much more pronounced than the changes in power demand. This uneven pace of change in the capacity mix reflects planning uncertainty regarding future power demand and a slow adjustment process for power supply development to forecast errors.

Future electric demand is uncertain. Figure 18 shows a sequence of power industry forecasts of future demand compared to the actual demand. The pattern of forecast errors indicates that electric demand forecasts are slow to adjust to actual conditions: overforecasts tend to be followed by overforecasts, and

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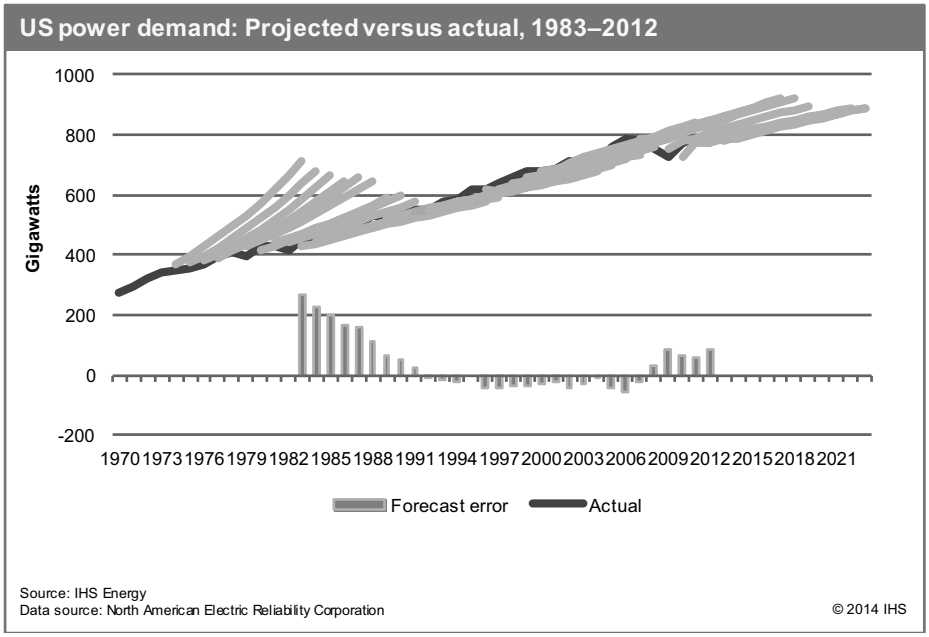
underforecasts tend to be followed by underforecasts.

FIGURE 18



Forecasting uncertainty presents a challenge because fuel and technology decisions must be made years in advance of consumer demand to accommodate the time requirements for siting, permitting, and constructing new sources of power supply. As a result, the regional power systems are subject to momentum in power plant addition activity that results in capacity surpluses and shortages. Adjustment to forecast overestimates is slow because when a surplus becomes evident, the capital intensity of power plants creates an accumulating sunk-cost balance in the construction phase of power supply development. In this case, there is an economic incentive to finish constructing a power plant because the costs to finish are the relevant costs to balance against the benefits of completion. Conversely, if a shortage becomes evident, new peaking power plants take about a year to put into place under the best of circumstances. Consequently, the forecast error and this lagged adjustment process can produce a significant over/underinstallment of new capacity development versus need. These imbalances can require a decade or more to work off in the case of a capacity overbuild and at least a few years to shore up power supply in the case of a capacity shortage.

The pace and makeup of power plant additions are influenced by energy policies. The current installed capacity mix reflects impacts from the implementation of a number of past policy initiatives. Most importantly, 35 years ago energy security was a primary concern, and the energy policy response included the Fuel Use Act (1978) and the Public Utilities Regulatory Policy Act (1978). These policies limited the use of natural gas for power generation and encouraged utility construction of coal and nuclear generating resources as well as nonutility development of cogeneration. Public policy championed coal on energy security grounds—as a safe, reliable, domestic resource.

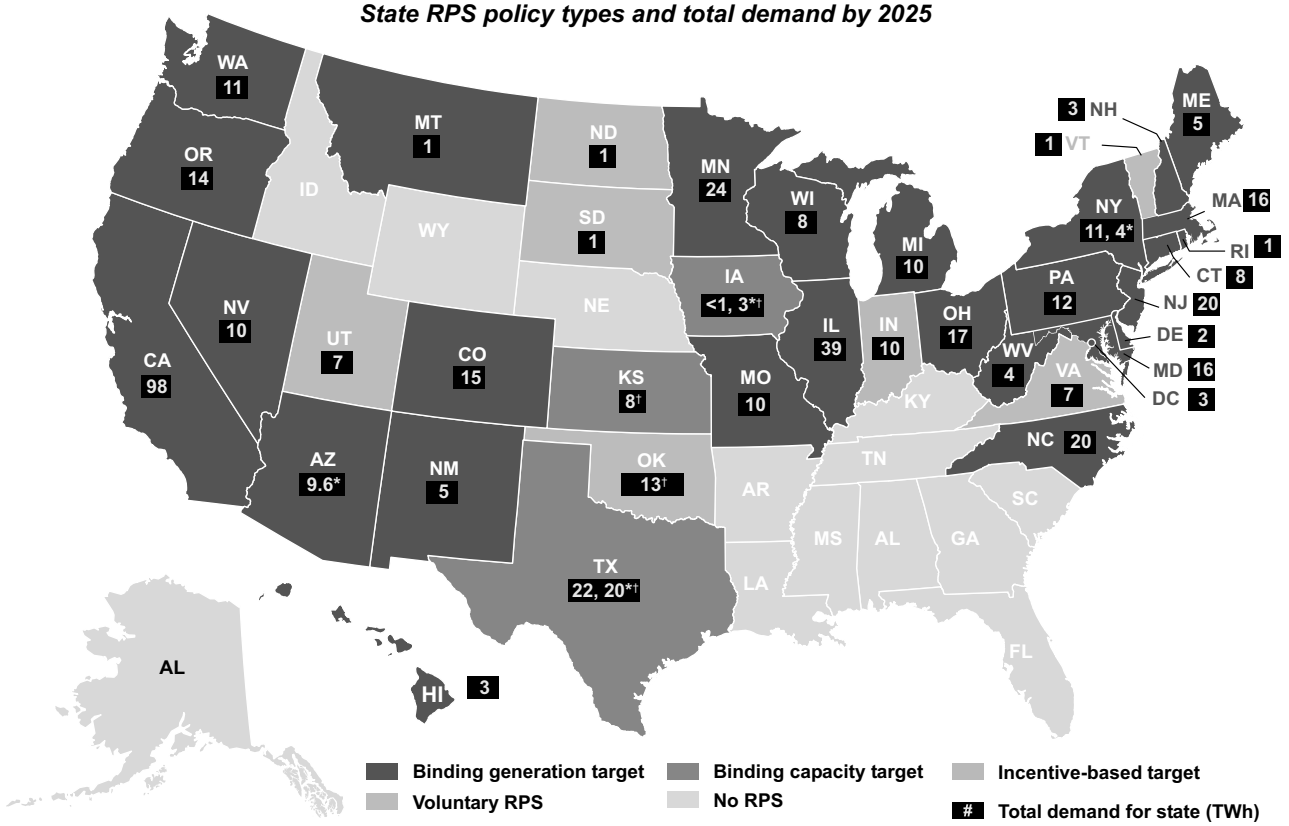
The influence of energy policy on power plant fuel and technology choice is dynamic. For example, as natural gas demand and supply conditions changed following the passage of the Fuel Use Act, the limits on natural gas use for power generation were eventually lifted in 1987. Whereas the Fuel Use Act banned a fuel and technology, other policy initiatives mandate power generation technologies. Energy policies designed to address the climate change challenge created renewable power portfolio requirements in 30 states (see Figure 19).

As states work to implement renewable generation portfolio standards, the complexity of power system operations becomes evident and triggers the need for renewable integration studies. These studies generally find that the costs to integrate intermittent power generation resources increase as the generation share of these resources increases. Some integration studies go so far as to identify the saturation point for wind resources based on their operational characteristics. A wind integration study commissioned by the

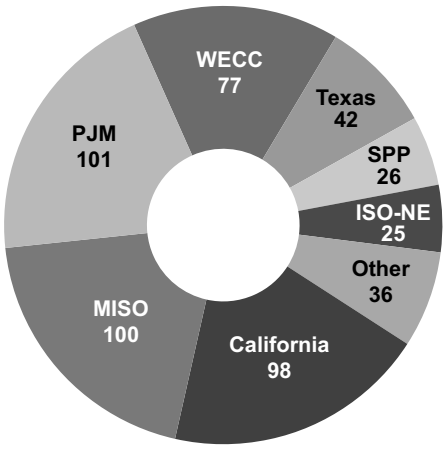
FIGURE 19

The outlook for US State RPS demand to 2025—Total demand: State policy and targets

State RPS policy types and total demand by 2025



Total RPS demand by region (TWh)



30 US states plus the District of Columbia have enacted binding renewable energy targets, and seven others have adopted incentive-based or voluntary targets. These 37 states account for 74% of US retail power sales.

40609-3
Note: *States include both mandatory and voluntary targets; first number reflects mandatory target, second number reflects additional voluntary targets (of state, municipalities, or other political divisions/utilities).
†Capacity targets have been converted to generation for comparison using estimated regional capacity factors. All quantities reflect primary renewables; see page 2 for additional notes
Source: IHS Emerging Energy Research

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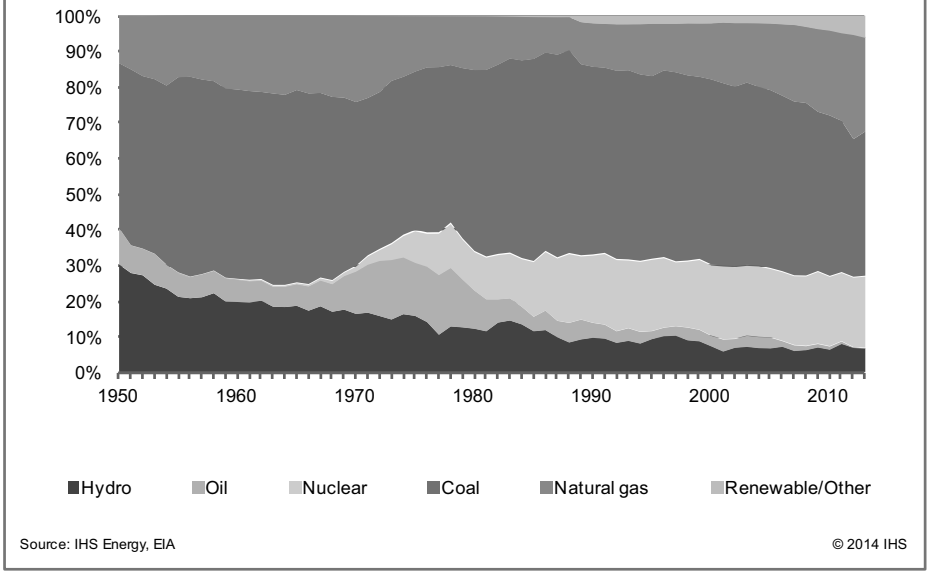
power system operator in New England estimated the saturation point for wind in the power system (24% generation share) as well as the additional resources that would be needed to integrate more wind resources.[4] Similarly, a wind integration study by the power system operator in California found that problems were ahead for the California power system because the number of hours when too much wind generation was being put on the grid was increasing. The study noted higher costs were ahead as well because additional resources would be needed to integrate expected additional wind resources planned to meet the renewable portfolio requirements in place.[5] Many of the impacts on the US generation mix from renewable power portfolio requirements are yet to come as higher generation or capacity share mandates become binding in many states in the next few years.

The United States is at a critical juncture because current trends in power plant retirements, demand and supply balances, and public policies are combining to accelerate change in the US generation mix, as shown in Figure 20. In 2013, increases in demand, power plant retirements, and renewable mandates resulted in around 15,800 MW of capacity additions. In the decade ahead, these increasing needs will require power supply decisions amounting to 15% of the installed generating capacity in the United States. In addition, public policies are expected to increase the share of wind and solar generation, and forthcoming regulations from the Environmental Protection Agency (EPA) regarding conventional power plant emissions as well as greenhouse gases (GHG) could significantly increase power plant retirements and accelerate changes further. Altogether, changes in US generating capacity in the next two decades could account for more than one-third of installed capacity.

FIGURE 10

US power generation: shares by fuel, 1950–2013



Source: IHS Energy, EIA

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Threat to power generation diversity: Complacency

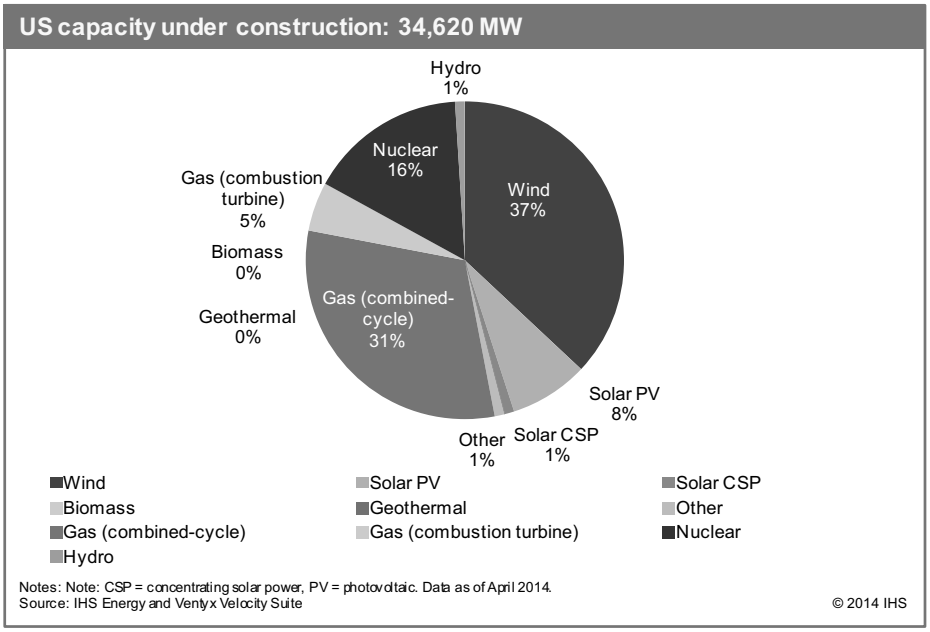
Threats to maintaining diversity in power production do not come from opposition to the idea itself, but rather from the complacency associated with simply taking diversity for granted. The familiar adage of not putting all your eggs in one basket is certainly aligned with the idea of an all-of-the-above energy policy. Four decades of experience demonstrates the conclusion that the government should not be picking fuel or technology winners, but rather should be setting up a level playing field to encourage competitive forces to move the power sector toward the most cost-effective generation mix. Nevertheless, in a striking contrast,

4. *New England Wind Integration Study* produced for ISO New England by GE Energy Applications and Systems Engineering, EnerNex Corporation, and AWS Truepower, 5 December 2010. Accessed 16 April 2014 (http://www.uwig.org/newis_es.pdf).

5. "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS." California ISO, 31 August 2010, downloaded from www.caiso.com/2804/2804d036401f0.pdf.

the value of fuel diversity to the end use consumer is not internalized in current power plant decision making. A 2013 review of over eighty integrated resource plans (IRPs) found that many reference fuel diversity but only a few of them refer to it as a risk, and none of them quantify the value of fuel diversity to incorporate it into the decision process.[6] Additionally, environmental policy initiatives do not seem to accommodate diversity issues. Therefore, one power plant decision after another is revealing a de facto energy policy to move away from oil, coal, and nuclear generation and reduce hydroelectric capability, and instead build relatively low utilization wind and solar resources backed up by natural gas–fired generating units (see Figure 21).

FIGURE 21



Threat to power generation diversity: The "missing money"

Fuel diversity is threatened as well by the inability of power markets to evolve market rules and institutions to address the "missing money" problem in competitive power generator cash flows. The missing money problem in power markets is the latest manifestation of a long-standing problem in a number of industries, including railroads, airlines, and power, where competitive markets fail to balance demand and supply at market-clearing prices high enough to support the full cost of supply.

Power markets have a missing money problem because they do not have all of the necessary conditions to produce a textbook competitive marketplace. The textbook marketplace has suppliers who maximize their profits by expanding output up to the point where their short-run marginal cost (SRMC) of production equals the market-clearing price. This means that an aggregation of rival suppliers' SRMC curves produces the market supply curve. If this market supply curve intersects the market demand curve at a price too low to support the full cost of new supply (long-run marginal cost [LRMC]), then suppliers will not expand productive capacity. Instead, they will meet increases in demand by adding more variable inputs to the production process with a fixed amount of capacity. However, doing so increases SRMC, and eventually the market-clearing price rises to the point where it covers the cost of expanding productive capacity. This produces the textbook market equilibrium where demand and supply are in balance at the unique point where market-clearing prices are equal to both SRMC and LRMC.

Several characteristics of the technologies that make up a cost-effective power supply create a persistent gap between SRMCs and LRMCs as production varies. As a result, market-clearing wholesale power prices are below the level needed to support the full cost of power supply when demand and supply are in balance with the desired level of reliability.[7] Consequently, the stable textbook market equilibrium does not exist in an electric power marketplace.

6. See the IHS Energy Insight *Reading the Tea Leaves: Trends in the power industry's future plans.*

7. See the IHS Energy Private Report *Power Supply Cost Recovery: Bridging the missing money gap.*

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A simple example of a competitive power market made up entirely of rival wind generators illustrates the missing money problem. The cost profile of wind turbine technologies comprises nearly exclusively upfront capital costs (LRMCs). SRMCs for wind technologies equal zero because the variable input to the power production process is wind, and this input is free. In a competitive market, if wind conditions allow for power production, then rival wind generators will be willing to take any price above zero to provide some contribution to recovering the upfront capital costs. If there is adequate supply to balance demand in a competitive marketplace, then rival wind suppliers will drive the market-clearing price to zero. This is not just a theoretical example. When power system conditions create wind-on-wind competition, then zero or negative market-clearing prices (reflecting the cost of losing the production tax credit) are typically observed. Wind generating technologies are a simple and extreme example of a power generating technology with a persistent gap between SRMCs and LRMCs. But this problem exists to some degree with other power generation technologies.

This technology-based market flaw means that periodic shortage-induced price spikes are the only way for market-clearing prices to close the gap between the SRMC and LRMC. This market outcome does not work because of the inherent contradiction—periodic shortages are needed to keep demand and supply in balance.

The missing money problem threatens cost-effective power supply because when market-clearing power prices are chronically too low to support new power plants, then lower expected cash flows at existing plants cause retirements before it is economic to do so, given replacement costs. It is cost effective to retire and replace a power plant only when its cost of continued operation becomes greater than the cost of replacement. Therefore, a market-clearing power price that reflects the full cost of new power supply is the appropriate economic signal for efficient power plant closure and replacement. Consequently, when this price signal is too low, power plant turnover accelerates and moves power supply toward the reduced diversity case.

"Missing money" and premature closing of nuclear power plants

The Kewaunee nuclear plant in Wisconsin is an example of a power plant retirement due to the missing money problem. Wholesale day-ahead power prices average about $30 per MWh in the Midwest power marketplace. This market does not have a supply surplus, and recently the Midwest Independent System Operator (MISO), the institution that manages the wholesale market, announced that it expects to be 7,500 MW short of generating capacity in 2016.[8] The current market-clearing power price must almost double to send an efficient price signal that supports development of a natural gas–fired combined-cycle power plant.

The Kewaunee power plant needs much less than the cost of a new plant, about $54 per MWh, to cover the costs of continued operation. Kewaunee's installed capacity was 574 MW, and the plant demonstrated effective performance since it began operation in 1974. The plant received Nuclear Regulatory Commission approval for life extension through 2033. Nevertheless, the persistent gap between market prices and new supply costs led Dominion Energy, the power plant's owner, to the October 2012 decision to close the plant because of "low gas prices and large volumes of wind without a capacity market."

Kewaunee is not an isolated case. Other nuclear power plants such as Vermont Yankee provide similar examples. Additionally, a significant number of coal-fired power plants are retiring well before it is economic to do so. For example, First Energy retired its Hatfield's Ferry plant in Ohio on 9 October 2013. This is a large (1,700 MW) power plant with a $33 per MWh variable cost of power production.[9] The going-forward

8. Whieldon, Esther. "MISO-OMS survey of LSEs, generators finds resource shortfall remains likely in 2016." SNL Energy, 6 December 2013. Accessed on 14 May 2014 http://www.snl.com/InteractiveX/ArticleAbstract.aspx?id=26168778. Note: LSE = load-serving entity.

9. Source: SNL Financial data for 2012 operations, accessed 5 May 2014. Available at http://www.snl.com/InteractiveX/PlantProductionCostDetail.aspx?ID=3604.

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costs involved some additional environmental retrofits, but the plant had already invested $650 million to retrofit a scrubber just four years prior to the announced retirement.

Reducing diversity and increasing risk

Proposed EPA regulations on new power plants accommodate the carbon footprint of new natural gas–fired power plants but do not accommodate the carbon footprint of any new state-of-the-art conventional coal-fired power plants that do not have carbon capture and storage (CSS). Since the cost and performance of CSS technologies remain uneconomic, the United States is now on a path to eliminating coal-fired generation in US power supply expansion. This move toward a greatly reduced role for coal in power generation may accelerate because the EPA is now developing GHG emission standards for existing power plants that could tighten emissions enough to dramatically increase coal-fired power plant retirements.

The impact of a particular fuel or technology on fuel diversity depends on overall power system conditions. As a general rule, the benefits of fuel diversity from any source typically increase as its share in the portfolio decreases. Oil-fired generation illustrated this principle when it proved indispensable in New England in keeping electricity flowing this past winter. Despite only accounting for 0.2% of US generation, it provided a critical safety valve for natural gas deliverability during the polar vortex. Yet, these oil-fired power plants are not likely to survive the tightening environmental regulations across the next decade. The implication is clear: there is a much higher cost from losing this final 0.2% of oil in the generation mix compared to the cost of losing a small percentage of oil-fired generation back in 1978, when oil accounted for 17% of the US generation mix. Losing this final 0.2% of the generation mix will be relatively expensive because the alternative to meet infrequent surges in natural gas demand involves expanding natural gas storage and pipeline capacity in a region where geological constraints make it increasingly difficult to do so.

Public opinion is a powerful factor influencing the power generation mix. The loss of coal- or oil-fired power plants in the generation mix is often ignored or dismissed because of public opinion. Coal- or oil-fired power plants are generally viewed less favorably than wind and solar resources. In particular, labeling some sources of power as “clean energy” necessarily defines other power generating sources as “dirty energy.” This distinction makes many conventional power supply sources increasingly unpopular in the political process. Yet, all sources of power supply employed to meet customer needs have an environmental impact. For example, wind and solar resources require lots of land and must be integrated with conventional grid-based power supply to provide consumers with electricity when the wind is not blowing or the sun is not shining. Therefore, integrating these “clean energy” resources into a power system to meet consumer needs produces an environmental footprint, including a GHG emission rate. The arbitrary distinctions involved in “clean energy” are evident when comparing the emissions profiles of integrated wind and solar power production to that of nuclear power production. A simplistic and misleading distinction between power supply resources is a contributing factor to the loss of fuel diversity.

Edison International provides an example of the impact of public opinion. Antinuclear political pressures in California contributed to the decision in 2013 to prematurely close its San Onofre nuclear power plant. This closure created a need for replacement power supply that is more expensive, more risky, and more carbon intensive.

The going-forward costs of continued operation of the San Onofre nuclear plant were less than the cost of replacement power. Therefore, the closure and replacement of the San Onofre power plant made California power supply more expensive in a state that already has among the highest power costs in the nation. A study released in May 2014 by the Energy Institute at Haas at the University of California Berkeley estimated that closing the San Onofre nuclear power station increased the cost of electricity by $350 million during the

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first twelve months.[10] This was a large change in power production costs, equivalent to a 13% increase in the total generation costs for the state.

Closing San Onofre makes California power costs more risky. California imports about 30% of its electricity supply. Prior to the closure, nuclear generation provided 18.3% of California generation in 2011, and the San Onofre nuclear units accounted for nearly half of that installed nuclear capacity. The Haas study found that imports increase with system demand but not much, likely owing to transmission constraints, grid limitations, and correlated demand across states. The results imply that the loss of the San Onofre power plant was primarily made up through the use of more expensive generation, as much as 75% of which was out-of-merit generation running to supply energy as well as voltage support. The report's analysis found that up to 25% of the lost San Onofre generation could have come from increased imports of power. The substitute power increases California consumers' exposure to the risks of fossil fuel price movements as well as the risks of low hydroelectric generation due to Western Interconnection drought cycles.

Closing San Onofre makes California power production more carbon intensive. Nuclear power production does not produce carbon dioxide (CO_2) emissions. These nuclear units were a major reason that the CO_2 intensity of California power production was around 0.5 pounds (lb) per kilowatt-hour (kWh). Replacement power coming from in-state natural gas–fired power plants has associated emissions of about 0.9 lb per kWh. Replacement power coming from the rest of the Western Interconnection has associated emissions of 1.5 lb per kWh. Even additional wind and solar power sources in California with natural gas–fired power plants filling in and backing them up have a 0.7 lb per kWh emissions profile. The Haas study found that closing San Onofre caused carbon emissions to increase by an amount worth almost $320 million, in addition to the $350 million in increased electricity prices in the first year. In the big picture, California CO_2 emissions have not declined in the past decade, and the closure of the San Onofre nuclear units will negate the carbon abatement impacts of 20% of the state's current installed wind and solar power supply.

The path toward a less diverse power supply

The relative unpopularity of coal, oil, nuclear, and hydroelectric power plants (compared to renewables), combined with the missing money problem, tightening environmental regulations, and a lack of public awareness of the value of fuel diversity create the potential for the United States to move down a path toward a significant reduction in power supply diversity. Within a couple of decades, the US generation mix could have the following capacity characteristics:

- No meaningful nuclear power supply share
- No meaningful coal-fired power supply share
- No meaningful oil-fired power supply share
- Hydroelectric capacity in the United States reduced by 20%, from 6.6% to 5.3% of installed capacity
- Renewables power supply shares at operational limits in power supply mix: 5.5% solar, 27.5% wind
- Natural gas–fired generation becoming the default option for the remaining US power supply of about 61.7%

10. http://ei.haas.berkeley.edu/pdf/working_papers/WP248.pdf, accessed 30 May 2014.

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Comparing the performance of current diverse power supply to this reduced diversity case provides a basis for quantifying the current value of fuel and technology diversity in US power supply.

Quantifying the value of current power supply diversity

A number of metrics exist to compare and contrast the performance of power systems under different scenarios. Three power system performance metrics are relevant in judging the performance of alternative generation portfolios:

- SRMC of electric production (the basis for wholesale power prices)
- Average variable cost of electric production
- Production cost variability

IHS Energy chose a geographic scope for the diversity analyses at the interconnection level of US power systems. The United States has three power interconnections: Electric Reliability Council of Texas (ERCOT), Eastern, and Western. These interconnections define the bounds of the power supply network systems that coordinate the synchronous generation and delivery of alternating current electrical energy to match the profile of aggregate consumer demands in real time.

Analysis at the interconnection level is the minimum level of disaggregation needed to analyze the portfolio and substitution effects of a diverse fuel and technology generation mix. In particular, the substitution effect involves the ability to shift generation from one source of power supply to another. The degree of supply integration within an interconnection makes this possible, whereas the power transfer capability between interconnections does not. The degree of power demand and supply integration within these interconnections creates the incentive and capability to substitute lower-cost generation for higher-cost generation at any point in time. These competitive forces cause the incremental power generation cost-based wholesale power prices at various locations within each interconnection to move together. An average correlation coefficient of monthly average wholesale prices at major trading hubs within each interconnection is roughly 0.8, indicating a high degree of supply linkage within each interconnection.

IHS Energy assessed the current value of fuel diversity by using the most recently available data on the US power sector. Sufficient data were available for 2010 to 2012, given the varied reporting lags of US power system data.

IHS employed its Razor Model to simulate the interactions of demand and supply within each of these US power interconnections from 2010 to 2012. The 2010 to 2012 backcasting analysis created a base case of the current interactions between power demand and supply in US power systems. Appendix B describes the IHS Razor Model and reports the accuracy of this power system simulation tool to replicate the actual performance of these power systems. The high degree of predictive power produced by this model in the backcasting exercise establishes the credibility of using this analytical framework to quantify the impacts of more or less fuel and technology diversity. The macroeconomic impact analysis used the most recently available IHS simulation of the US economy (December 2013) as a base case.

Once this base case was in place, the Razor Model was employed to simulate an alternative case involving a less diverse generation mix. The current generation mix in each of the three interconnections—Eastern, Western, and ERCOT—were altered as follows to produce the reduced diversity case generation:

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- The nuclear generating share went to zero.
- The coal-fired electric generating share went to zero.
- The hydroelectric generation share dropped to 3.8%.
- Intermittent wind and solar generation increased its combined base case generation share of about 2% to shares approximating the operational limits—24% in the East, 45% in the West, and 23% in ERCOT—resulting in an overall wind generation share of 21.0% and a solar generation share of 1.5%.
- Natural gas–fired generation provided the remaining generation share in each power system, ranging from about 55% in the West to over 75% in the East and ERCOT, for an overall share of nearly 74%.

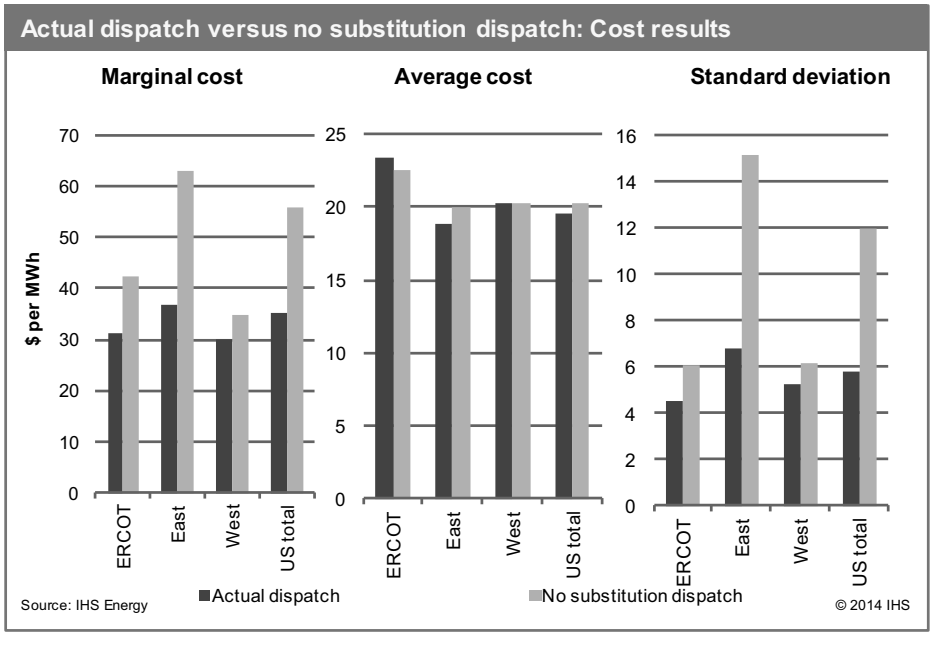
Differences between the performance metrics of the current diverse generating portfolio simulation and the reduced diversity case simulation provide an estimate for the current value of fuel diversity. The differences in the level and variance of power prices were fed through to the IHS US macroeconomic model to quantify the broader economic impacts of the higher and more varied power prices and shifts in capital deployment associated with the reduced diversity case.

Quantification of the impact of fuel diversity within the US power sector involved a two-step process. The first step quantifies the current value of the substitution effect enabled by a diverse power generating portfolio. The second step quantified the additional value created by the portfolio effect.

The value of the substitution effect

The first step alters the base case by holding relative fuel prices at the average level across 2010 to 2012. Doing this removes the opportunity to substitute back and forth between generation resources based on changes to the marginal cost of generation. This case maintains a portfolio effect but eliminates the substitution effect in power generation. The difference between this constant relative fuel price case and the base case provides an estimate of the current value of the substitution effect provided by the current diverse power generation fuel mix. The results show significantly higher fuel costs from a generation mix deprived of substitution based on fuel price changes. The substitution effects in the current diverse US power generating portfolio reduced the fuel cost for US power production by over $2.8 billion per year. In just the three years of the base case, US power consumers realized nearly $8.5 billion in fuel savings from the substitution effect. Figure 22 shows the results of this first step in the analysis for each interconnection and the United States as a whole.

FIGURE 22

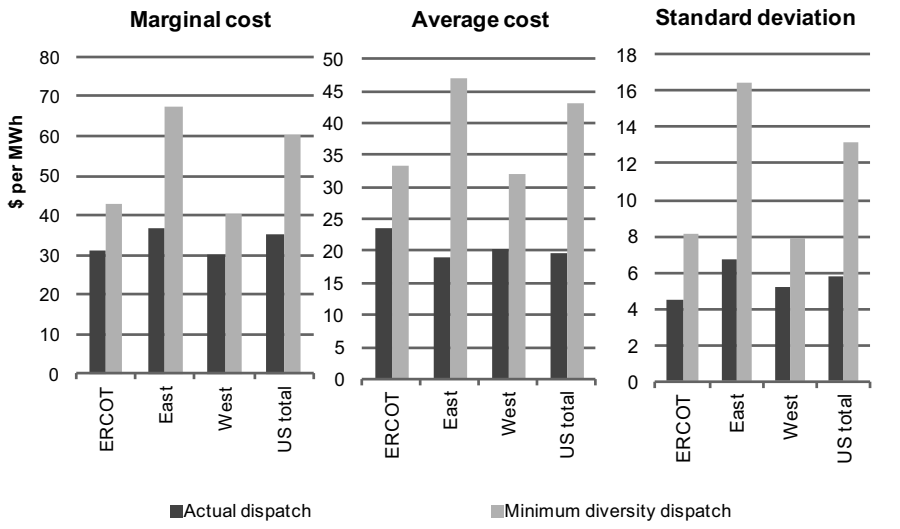


The value of the portfolio effect

The second step quantifies the portfolio value of the current generation mix. To measure this, the base case is altered by replacing the actual current generation mix with the less diverse generation mix. All else is held constant in this reduced diversity case, including the actual monthly fuel prices. Therefore, this reduced diversity simulation reduces the portfolio effect of diverse generation and allows any economic generation substitution to take place utilizing this less diverse capacity mix.

FIGURE 13

Actual dispatch versus minimum diversity dispatch: Cost results



Source: IHS Energy

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Figure 23 shows the performance metrics for each interconnection and the United States as a whole in the less diverse portfolio case compared to the base case.

The portfolio effect reduces not only costs, but also the variation in costs. This translates into a reduction in the typical monthly variation in consumers' power bills of between 25% and 30%.

The differences in average power production costs between the reduced diversity case and the current supply case indicate that fuel and technology diversity in the base case US generation mix provides power consumers with benefits of $93 billion per year. This difference between the reduced diversity case and the base case includes both the substitution and portfolio effects. Using the results of step one allows separation of these two effects, as shown in Table 4.

Figures 24 and 25 show the progression from the base case to the reduced diversity case. The results indicate that the Eastern power interconnection has the most to lose from a less diverse power supply because it faces more significant increases in cost, price, and variability in moving from the base case to the reduced diversity case. The Eastern interconnection ends up with greater variation in part because its delivered fuel costs are more varied than in Texas or the West. In addition, the natural endowments of hydroelectric power in the Western interconnection generation mix continue to mitigate some of the fuel price risk even at a reduced generation share.

In the past three years, generation supply diversity reduced US power supply costs by $93 billion per year, with the majority of the benefit coming from the portfolio effect. These estimates are conservative because they were made only across the recent past, 2010 to 2012. An evaluation over a longer period of history would show increased benefits from managing greater levels of fuel price risk.

The estimates of the current value of power supply diversity are conservative as well because they do not include the feedback effects of higher power cost variation on the cost of capital for power suppliers, as outlined in Appendix A. The analyses indicate that a power supplier with the production cost variation equal to the current US average would have a cost of capital 310 basis points lower than a power supplier

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TABLE 4

Diversity cases cost results

		Substitution effect	Portfolio effect	Total
ERCOT	Output (2011, TWh)	334	334	334
	Marginal cost increase ($/MWh)	$11.10	$0.35	$11.45
	Average cost increase ($/MWh)	($0.91)	$10.62	$9.71
	Marginal cost increase split	97%	3%	100%
	Average cost increase split	-9%	109%	100%
	Marginal cost increase percentage	35.40%	1.10%	36.50%
	Average cost increase percentage	-3.90%	45.20%	41.40%
	Marginal cost increase (total)	$3,708,970,847	$116,702,120	$3,825,672,967
	Average cost increase (total)	($302,604,000)	$3,547,080,000	$3,244,476,000
Eastern interconnection	Output (2011, TWh)	2,916	2,916	2,916
	Marginal cost increase ($/MWh)	$26.01	$4.73	$30.74
	Average cost increase ($/MWh)	$1.10	$26.92	$28.02
	Marginal cost increase split	85%	15%	100%
	Average cost increase split	4%	96%	100%
	Marginal cost increase percentage	70.70%	12.80%	83.50%
	Average cost increase percentage	5.80%	142.70%	148.50%
	Marginal cost increase (total)	$75,840,639,098	$13,791,489,884	$89,632,128,981
	Average cost increase (total)	$3,207,600,000	$78,498,720,000	$81,706,320,000
Western interconnection	Output (2011, TWh)	728	728	728
	Marginal cost increase ($/MWh)	$4.94	$5.27	$10.21
	Average cost increase ($/MWh)	($0.10)	$11.67	$11.57
	Marginal cost increase split	48%	52%	100%
	Average cost increase split	-1%	101%	100%
	Marginal cost increase percentage	16.50%	17.60%	34.10%
	Average cost increase percentage	-0.50%	57.50%	57.00%
	Marginal cost increase (total)	$3,593,597,137	$3,837,638,788	$7,431,235,926
	Average cost increase (total)	($72,800,000)	$8,495,760,000	$8,422,960,000
US total	Output (2011, TWh)	3,978	3,978	3,978
	Marginal cost increase ($/MWh)	$20.90	$4.46	$25.36
	Average cost increase ($/MWh)	$0.71	$22.76	$23.47
	Marginal cost increase split	82%	18%	100%
	Average cost increase split	3%	97%	100%
	Marginal cost increase percentage	59.50%	12.70%	72.20%
	Average cost increase percentage	3.60%	116.70%	120.30%
	Marginal cost increase (total)	$83,143,207,082	$17,745,830,792	$100,889,037,874
	Average cost increase (total)	$2,832,196,000	$90,541,560,000	$93,373,756,000

Source: IHS Energy

with the production cost variation associated with the generation mix of the reduced diversity case. Since 14% of total power costs are returned to capital, this difference accounts for 1–3% of the overall cost of electricity. This cost-of-capital effect can have a magnified impact on overall costs if more capital has to be deployed with an acceleration of power plant closures and replacements from the pace that reflects underlying economics.

The cost of accelerating change in the generation mix

Current trends in public policies and flawed power market outcomes can trigger power plant retirements before the end of a power plant's economic life. When this happens, the closure creates cost impacts beyond the level and volatility of power production costs because it requires shifting capital away from a productive alternative use and toward a replacement power plant investment.

All existing power plants are economic to close and replace at some point in the future. The economic life of a power plant ends when the expected costs of continued operation exceed the cost of replacement. When

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this happens, the most cost-effective replacement power resource depends on the current capacity mix and what type of addition creates the greatest overall benefit—including the impact on the total cost of power and the management of power production cost risk.

Figure 26 shows the current distribution of the net present value (NPV) of the going-forward costs for the existing US coal-fired generation fleet on a cents per MWh basis in relation to the levelized NPV of replacement power on a per MWh basis.

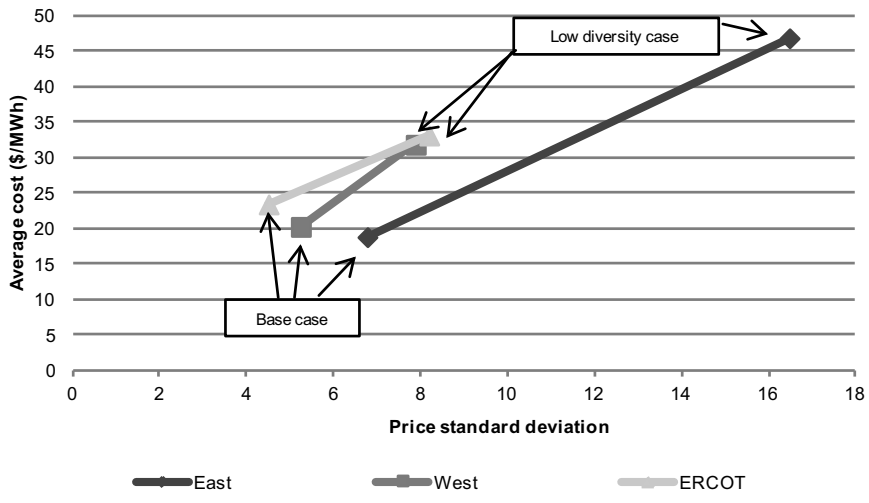
As the distribution of coal-fired power plant going-forward costs indicates, there is a significant difference between the going-forward costs and the replacement costs for the majority of plants. As a result, a substantial cost exists to accelerate the turnover of coal-fired power plants in the capacity mix. For example, closing coal-fired power plants and replacing them as quickly as possible with natural gas–fired power plants would impose a turnover cost of around $500 billion.

Figure 27 shows the going-forward costs of the existing US nuclear power plant fleet. As with the coal units, there is currently a high cost associated with premature closure. As a point of comparison, closing all existing nuclear power plants and replacing them as quickly as possible with natural gas–fired power plants would impose a turnover cost of around $230 billion. Unlike the coal fleet, where a nominal amount of older capacity has a going-forward cost that exceeds the expected levelized cost of replacement, none of the US nuclear capacity is currently more expensive than the lowest of projected replacement costs.

Closing a power plant and replacing it before its time means incurring additional capital costs. The average depreciation rate of capital in the United States is 8.3%. This implies that the average economic life of a

FIGURE 14

Average cost: Base case versus low diversity case



Source: IHS Energy

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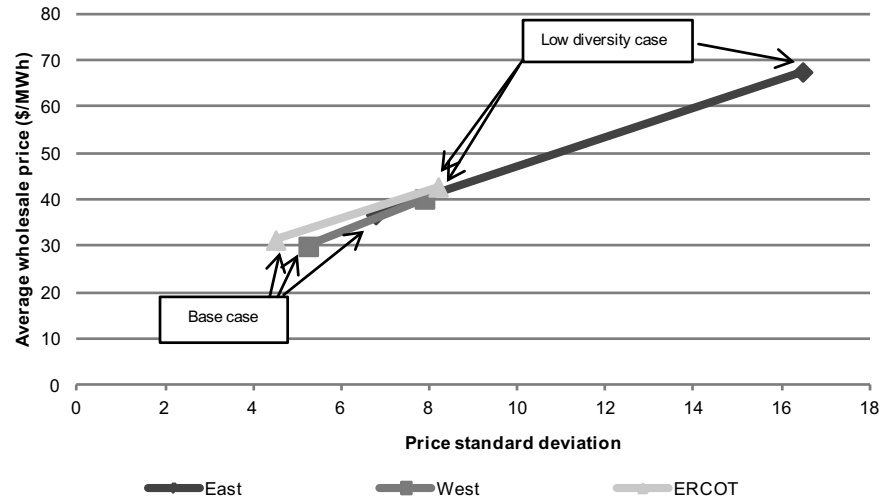
FIGURE 15

Average wholesale price: Base case versus low diversity case



Source: IHS Energy

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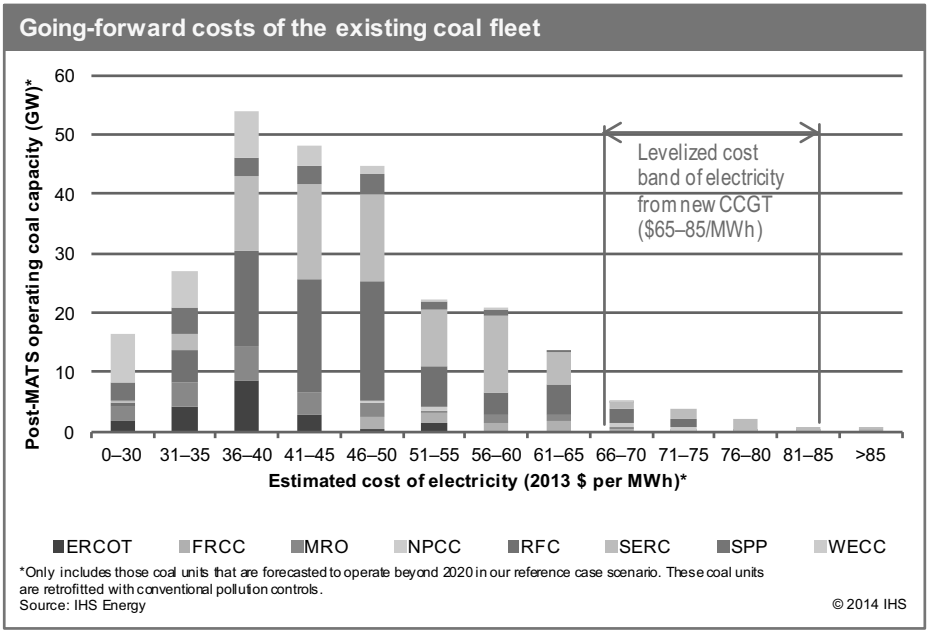
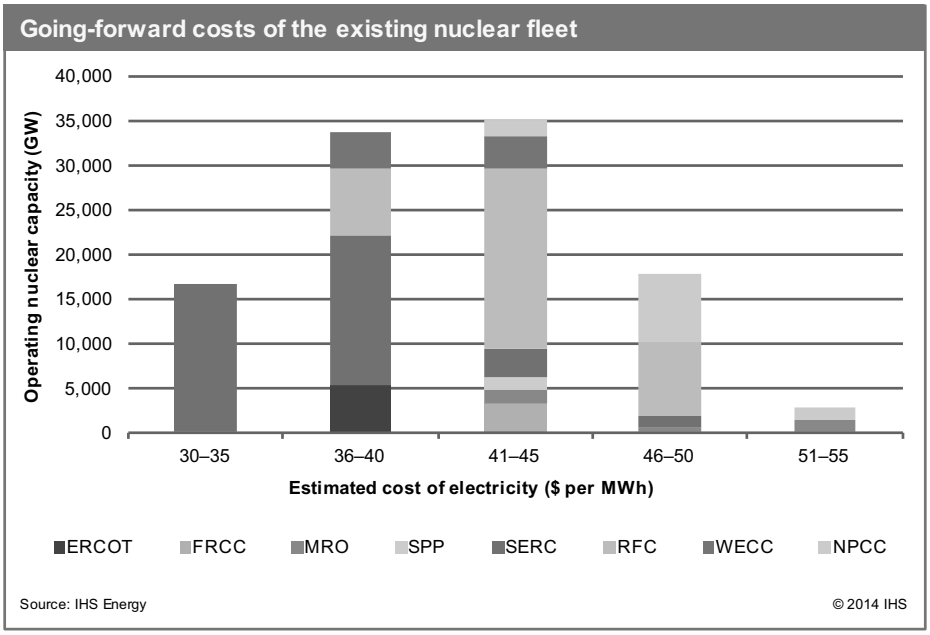
capital investment in the United States economy is 12 years. Altering the amount of capital deployed in the US economy by $1 in Year 1 results in an equivalent impact on GDP as deploying a steady stream of about $0.15 of capital for each of the 12 years of economic life. This annual levelized cost approximates the value of the marginal product of capital. Therefore, each dollar of capital deployed to replace a power plant that retires prematurely imposes an opportunity cost equal to the value of the marginal productivity of capital in each year.

FIGURE 16



Economywide impacts

FIGURE 17



In addition to the $93 billion in lost savings from the portfolio and substitution effects, depending upon the pace of premature closures, there is a cost to the economy of diverting capital from other productive uses. The power price increases associated with the reduced diversity case would profoundly affect the US economy. The reduced diversity case shows a 75% increase in average wholesale power prices compared to the base case. IHS Economics conducted simulations using its US Macroeconomic Model to assess the potential impact of the change in the level and variance of power prices between the base case and the reduced diversity case. The latest IHS base line macroeconomic outlook in December 2013 provides a basis for evaluating the impacts of an electricity price shock due to a reduced diversity case for power supply. Subjecting the current US economy to such a power price increase would trigger economic disruptions, some lasting over a multiyear time frame. As a result, it would take several years for most of these disruptions to dissipate. To capture most of these effects, power price changes were evaluated over the period spanning the past two and the next three years to approximate effects of a power price change to the current state of the economy. Wholesale power price increases were modeled by increasing the

Producer Price Index for electricity by 75% in the macroeconometric model; consumers were affected by the resulting higher prices for retail electricity and other goods and services.

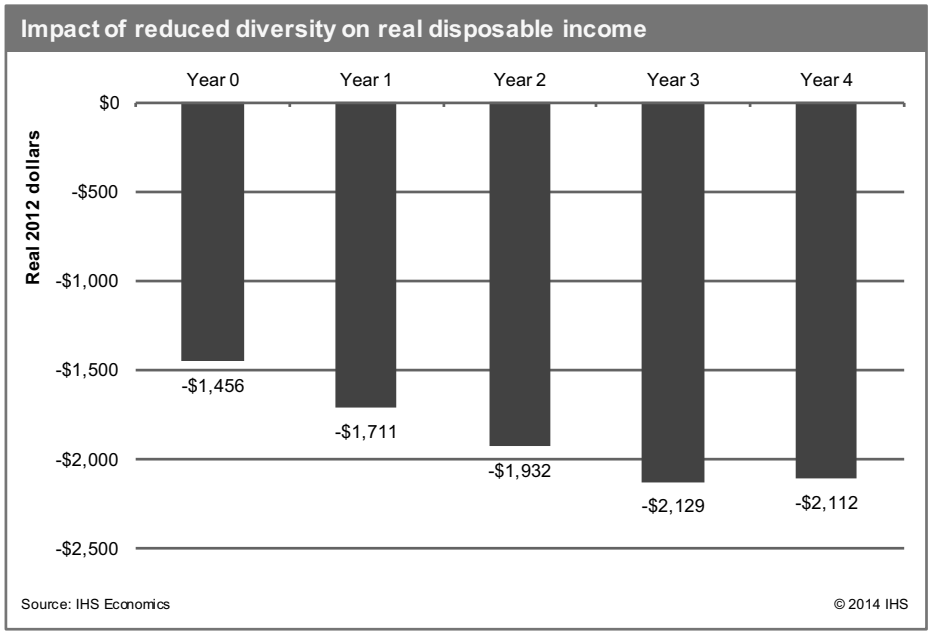
Economic impacts of the power supply reduced diversity case are quantified as deviations from the IHS macroeconomic baseline simulations of the US economy. The major impacts within the three years after the power price change would include

- A drop in real disposable income per household of about $2,100
- A reduction of 1,100,000 jobs
- A decline in real GDP of 1.2%

Consumers will bear the brunt of the impact of higher power prices. The higher price of electricity would trigger a reduction in power use in the longer run (10 or more years out) of around 10%. Yet even with such dramatic reductions in consumption, the typical power bill in the United States would increase from around $65 to $72 per month.

Not only will consumers face higher electric bills, but some portion of increases in manufacturers' costs ultimately will be passed on to consumers through higher prices for goods and services. Faced with lower purchasing power, consumers will scale back on discretionary purchases because expected real disposable income per household is lower by over $2,100 three years after the electric price increase (see Figure 28). Unlike other economic indicators (such as real GDP) that converge toward equilibrium after a few years, real disposable income per household does not recover, even if the simulations are extended out 25 years. This indicates that the price increases will have a longer-term negative effect on disposable income and power consumption levels.

FIGURE 18



Businesses will face the dual challenge of higher operational costs coupled with decreased demand for their products and services. Industrial production will decline, on average, by about 1% through Year 4. This will lead to fewer jobs (i.e., a combination of current jobs that are eliminated and future jobs that are never created) within a couple of years relative to the IHS baseline forecast, as shown in Figure 29, with the largest impact appearing in Year 2, with 1,100,000 fewer jobs than the IHS baseline level.

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Impact on GDP

The US economy is a complex adaptive system that seeks to absorb shocks (e.g., increases in prices) and converge toward a long-term state of equilibrium. Although the simulations conducted for this study do not project that the US economy will fall into a recession because of power price increases, it is informative to gauge the underperformance of the US economy under the reduced diversity case. In essence, the higher power prices resulting from the reduced diversity conditions cause negative economic impacts equivalent to a mild recession relative to the forgone potential GDP of the baseline. The economic impacts of the reduced diversity case set back GDP by $198 billion, or 1.2% in Year 1 (see Figure 30). This deviation from the baseline GDP is a drop that is equivalent to about half of the average decline in GDP in US recessions since the Great Depression. However, the impacts on key components of GDP such as personal consumption and business investment will differ.

FIGURE 19

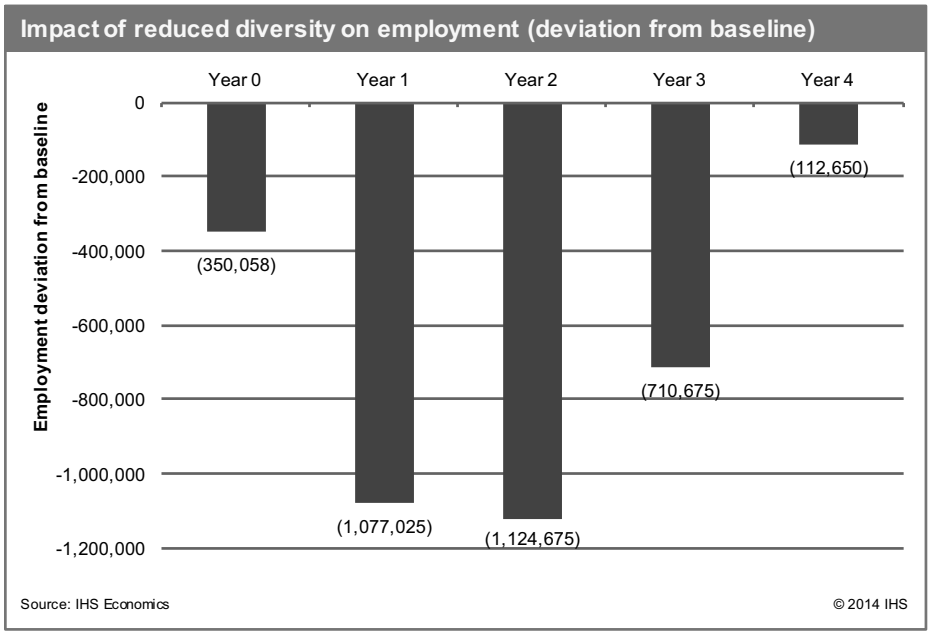
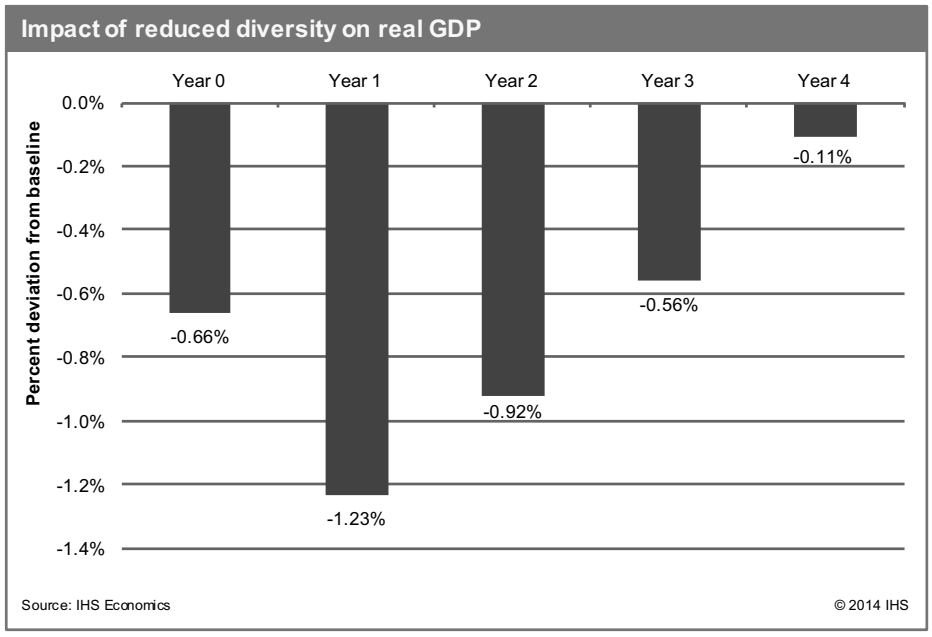


FIGURE 10



Consumption

Analyzing personal consumption provides insights on the changes to consumer purchasing behavior under the scenario conditions. Consumption, which accounts for approximately two-thirds of US GDP, remains lower over the period with each of its three subcomponents—durable goods, nondurable goods, and services—displaying a different response to the reduced power supply scenario conditions. In contrast with overall GDP, consumer spending shows little recovery by Year 4, as shown in Figure 31. This is due to continued higher prices for goods and services and decreased household disposable income. About 57% of the decline will occur in purchases of services, where household operations including spending on electricity will have a significant impact.

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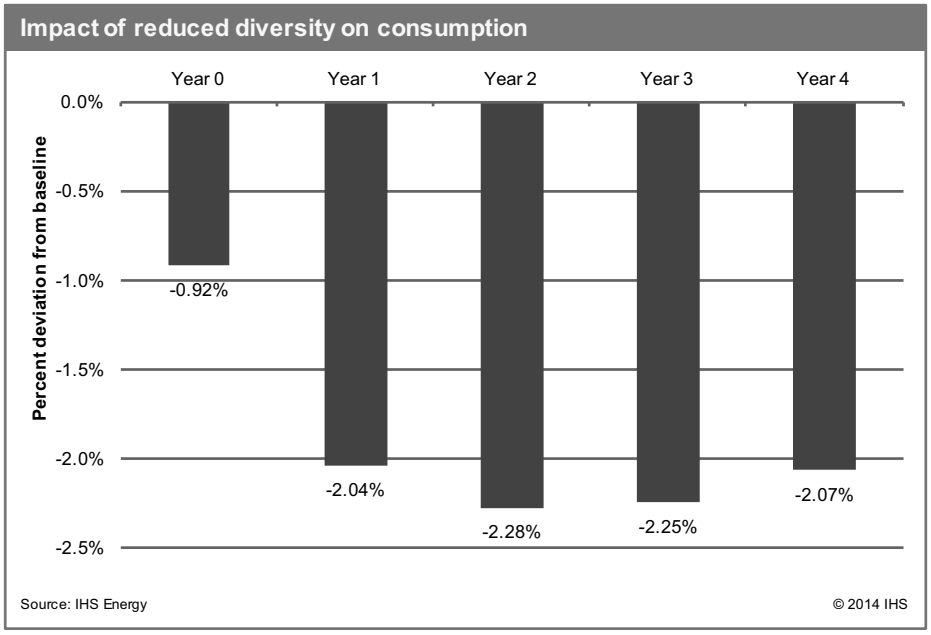
In the early years, lower spending on durable goods (appliances, furniture, consumer electronics, etc.) will account for about 33% of the decline, before moderating to 25% in the longer term. This indicates that consumers, faced with less disposable income, will simply delay purchases in the early years. The US macro simulations also predict moderate delays in housing starts and light vehicle sales, ostensibly due to consumers trying to minimize their spending.

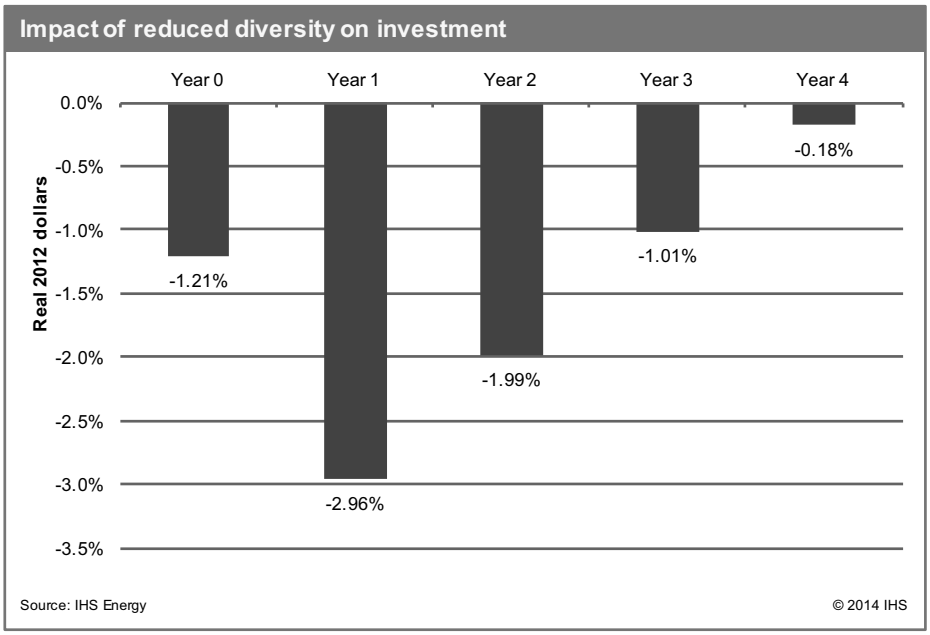
FIGURE 21



Investment

Following an initial setback relative to the baseline, investment will recover by the end of the forecast horizon. Nonresidential investment will initially be characterized by delays in equipment and software purchases, which will moderate a few years after the electric price shock. Spending on residential structures will remain negative relative to the baseline over the four years, as shown in Figure 32. The net effect in overall investment is a recovery as the economy rebounds back to a long-run equilibrium.

FIGURE 12



In the longer term, if current trends cause the reduced diversity case to materialize within the next decade, then the premature closure and replacement of existing power plants would shift billions of dollars of capital from alternative deployments in the US economy.

Conclusions

Consumers want a cost-effective generation mix. Obtaining one on the regulated and public power side of the industry involves employing an integrated resource planning process that properly incorporates

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cost-effective risk management. Obtaining such a mix on the competitive side of the power business involves employing time-differentiated market-clearing prices for energy and capacity commodities that can provide efficient economic signals. The linkage between risk and cost of capital can internalize cost-effective risk management into competitive power business strategies. Regardless of industry structure, a diverse generation mix is the desired outcome of cost-effective power system planning and operation.

The results of this study indicate seven key factors that will shape US power supply diversity in the years to come:

- **Energy policy development.** US policy heavily influences the US power supply mix. Implementing an all-of-the-above energy policy requires properly internalizing the value of fuel diversity.

- **Market structure.** Market flaws distort wholesale power prices downward and result in uneconomic retirement and replacement of existing cost-effective generation resources. This issue and any market structure changes to address it will significantly shape future power plant development.

- **Energy policy discourse.** Preserving the value of fuel diversity depends on public awareness and understanding. The extent and nature of public education regarding the value of power supply diversity may strongly influence public opinion.

- **Planning alignment.** Alignment of fuel and technology choices for power generation with engineering and economic principles is critical to efficient and reliable supply. There is no single fuel or technology of choice for power generation, and all forms of power production have economic, environmental, and reliability impacts.

- **Risk assessment.** To incorporate system considerations into plant-level decisions, prudent fuel price uncertainties must be used with probabilistic approaches to decision making.

- **Flexibility.** Flexibility and exemptions in rule making and implementation allow for the balancing of costs and benefits in power supply systems and may help preserve highly valuable diversity in systemwide decisions as well as on a small but impactful individual plant scale.

- **Scope.** Including fuel price risk and additional storage and transportation infrastructure costs is crucial when evaluating reduced diversity scenarios in comparison to the cost of maintaining and expanding fuel diversity.

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Appendix A: Cost-effective electric generating mix

The objective of power supply is to provide reliable, efficient, and environmentally responsible electric production to meet the aggregate power needs of consumers at various points in time. Consumers determine how much electricity they want at any point in time, and since the power grid physically connects consumers, it aggregates individual consumer demands into a power system demand pattern that varies considerably from hour to hour. For example, Figure A-1 shows the hourly aggregate demand for electricity in ERCOT.

In order to reliably meet aggregate power demands, enough generating capacity needs to be installed and available to meet demand at any point in time. The overall need for installed capacity is determined by the peak demand and a desired reserve margin. A 15% reserve margin is a typical planning target to insure reliable power supply.

The chronological hourly power demands plus the required reserve margin allow the construction of a unitized load duration curve (see Figure A-2). The unitized load duration curve orders hourly electric demands from highest to lowest and unitizes the hourly loads by expressing the values on the y-axis as a percentage of the maximum (peak) demand plus the desired reserve margin. The x-axis shows the percentage of the year that load is at or above the declining levels of aggregate demand.

This unitized load duration curve has a load factor—the ratio of average load to peak load—of 0.60. Although load duration curve shapes vary from one power system to another, this load factor and unitized load duration curve shape is a reasonable approximation of a typical pattern of electric

FIGURE A-1

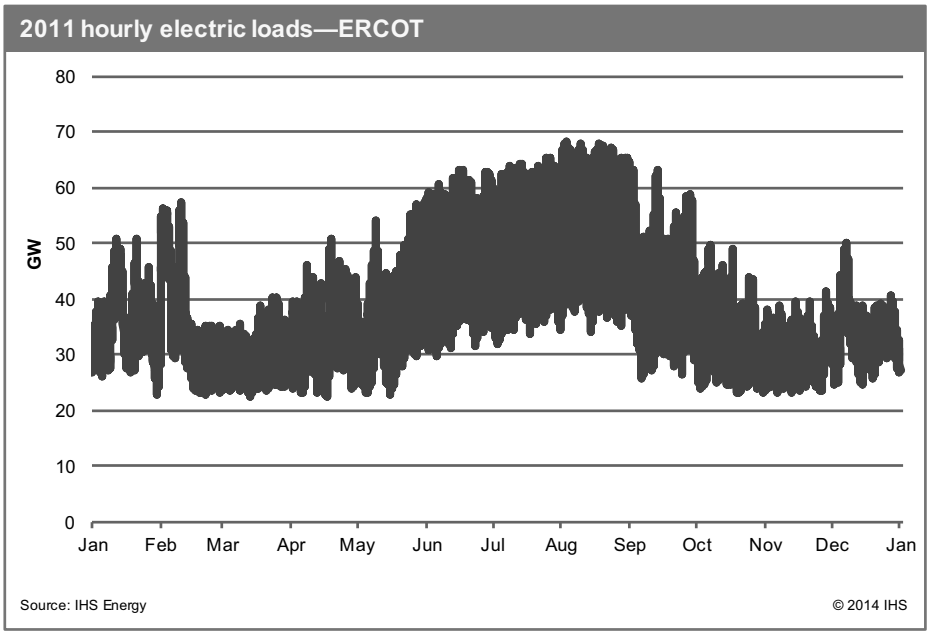
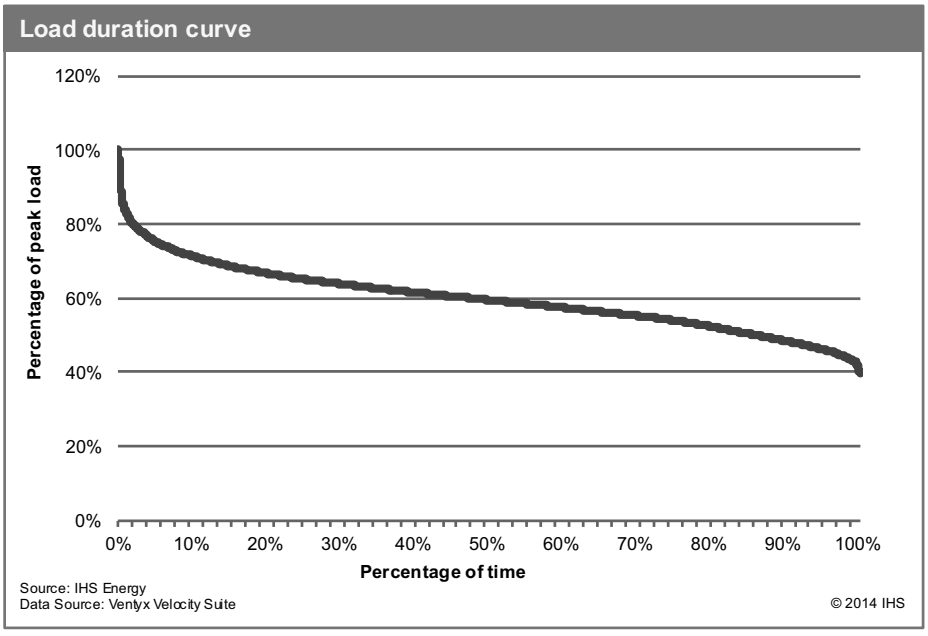


FIGURE A-2



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demand in a US power system. The objective of any power system would be to match its demand pattern with cost-effective power supply.

There are a number of alternative technologies available to produce electricity. These power supply alternatives have different operating characteristics. Most importantly, some power generating technologies can produce electricity on demand that aligns with the pattern of consumer demand through time, while others cannot. For example, solar PV panels can only provide electric output during hours of sunlight and thus cannot meet aggregate demand during the night. In contrast, thermal generation such as coal and natural gas can ramp up and down or turn on and off to match output with customer demand. Technologies such as coal and natural gas are considered dispatchable, while technologies such as solar and wind are considered nondispatchable. A number of combinations of technologies can together provide electric output that matches the pattern of consumer needs.

The lowest-cost generating technologies that can meet the highest increases in demand are peaking technologies such as combustion turbines (CTs). CTs are the most economical technology to meet loads that occur for only a small amount of time. These technologies can start-up quickly and change output flexibly to meet the relatively infrequent hours of highest power demand. They are economic even though they are not the best available technology for efficiently transforming fuel into electricity. CTs have relatively low upfront capital costs and thus present a trade-off with more efficient but higher capital cost generating technology alternatives. Since these resources are expected to be used so infrequently, the additional cost of more efficient power generation is not justified by fuel savings, given their expected low utilization rates.

Cycling technologies are most economical to follow changes in power demand across most hours. Consequently, utilization rates can be high enough to generate enough fuel savings to cover the additional capital cost of these technologies over a peaking technology. These intermediate technologies provide flexible operation along with efficient conversion of fuel into power. A natural gas–fired combined-cycle gas turbine (CCGT) is one technology that is suitable and frequently used for this role.

Base-load technologies are the lowest-cost power supply sources to meet power demand across most hours. These technologies are cost-effective because they allow the trading of some flexibility in varying output for the lower operating costs associated with high utilization rates. These technologies include nuclear power plants, coal-fired power plants, and reservoir hydroelectric power supply resources.

Nondispatchable power resources include technologies such as run-of-the-river hydroelectric, wind, and solar power supplies. These technologies produce power when external conditions allow—river flows, wind speeds, and solar insolation levels. Variations in electric output from these resources reflect changes in these external conditions rather than changes initiated by the generator or system operator to follow shifts in power consumer needs. Some of these resources can be economic in a generation mix if the value of the fuel they displace and their net dependable capacity are enough to cover their total cost. However, since nondispatchable production profiles do not align with changes in consumer demands, there are limits to how much of these resources can be cost-effectively incorporated into a power supply mix.

Alternative power generating technologies also have different operating costs. Typical cost profiles for alternative power technologies are shown in Table A-1. Both nuclear and supercritical pulverized coal (SCPC) technologies are based on steam turbines, whereby superheated steam spins a turbine; in coal's case, supercritical refers to the high-pressure phase of steam where heat transfer and therefore the turbine itself is most efficient. Natural gas CTs are akin to jet engines, where the burning fuel's exhaust spins the turbine. A CCGT combines both of these technologies, first spinning a CT with exhaust and then using that exhaust to create steam which spins a second turbine.

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TABLE A-1

Typical cost profiles for alternative power technologies

	CCGT	SCPC	Nuclear	CT
Capital cost (US$ per kW)	1,350	3,480	7,130	790
Variable O&M cost (US$ per MWh)	3.5	4.7	1.6	4.8
First year fixed O&M cost (US$ per kW-yr)	13	39	107	9
Property tax and insurance (US$ per kW-yr)	13	36	78	8
Fuel price (US$ per MMBtu)	4.55	2.6	0.7	4.55
Heat rate (Btu per kWh)	6,750	8,300	9,800	10,000
CO_2 emission rate (lbs per kWh)	0.8	1.73	0	1.18

Total capital cost figures include owner's costs: development/permitting, land acquisition, construction general and administrative, financing, interest during construction, etc.

Source: IHS Energy

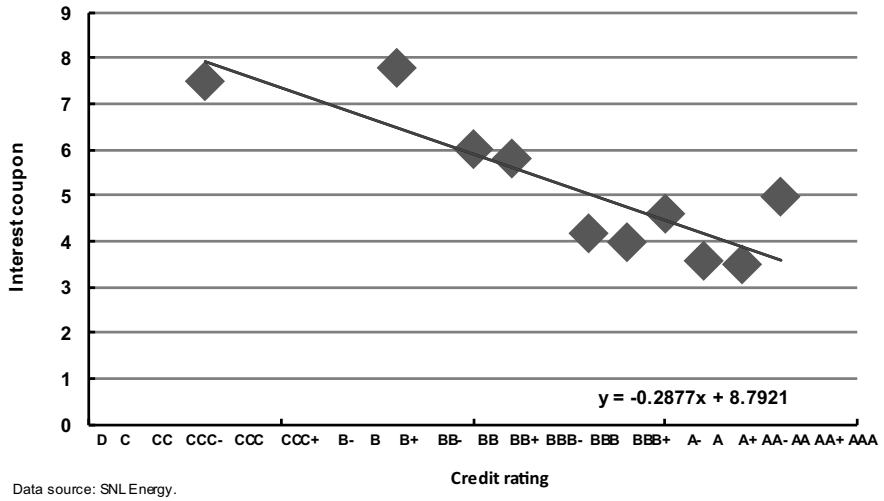
Power production technologies tend to be capital intensive; the cost of capital is an important determinant of overall costs. The cost of capital is made up of two components: a risk-free rate of return and a risk premium. Short-term US government bond interest rates are considered an approximation of the risk-free cost of capital. Currently, short-term US government bond interest rates are running at 0.1%. In order to attract capital to more risky investments, the return to capital needs to be greater. For example, the average cost of new debt to the US investor-owned power industry is around 4.5%.[11] This indicates an average risk premium of 4.4%.

Power generating technologies have different risk profiles. For example, the fluctuations in natural gas prices and demand levels create uncertainty in plant utilization and the level of operating costs and revenues. This makes future net income uncertain. Greater variation in net income makes the risk of covering debt obligations greater. In addition, more uncertain operating cost profiles add costs by imposing higher working capital requirements.

Risk profiles are important because they affect the cost of capital for power generation projects. If a project is seen as more risky, investors demand a higher return for their investment in the project, which can have a significant impact on the overall project cost.

FIGURE A-3

2010 shareholder-owned utilities senior debt offerings average interest coupon versus credit rating



Data source: SNL Energy.

Source: IHS Energy

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Credit agencies provide risk assessments and credit ratings to reflect these differences. Credit ratings reflect the perceived risk of earning a return on, and a return of, capital deployments. As Figure A-3 shows, the higher credit ratings associated with less risky investments have a lower risk premium, and conversely lower credit ratings associated with more risky investments have a higher risk premium.

Lower credit ratings result from higher variations in net

11. Data collected by Stern School of Business, NYU, January 2014. Cost of Capital. Accessed at http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/wacc.htm.

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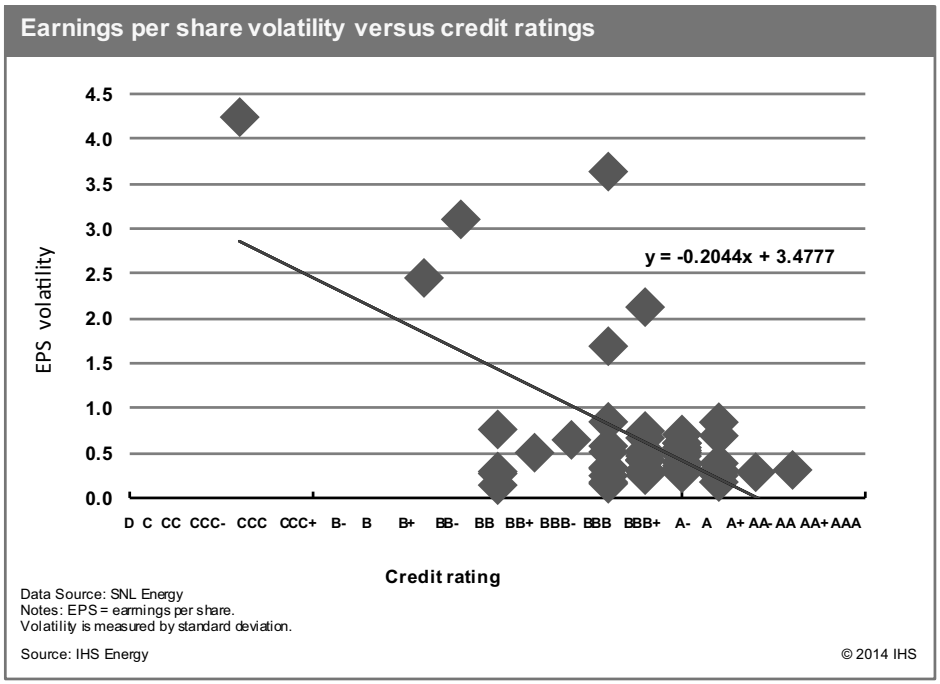
income, as shown in Figure A-4.

FIGURE A-4



Sometimes the cost of capital is directly related to the power plant when project financing is used. In other cases, power companies raise capital at the corporate level with a capital cost that reflects the overall company risk profile rather than just the power plant risk profile. Utilities typically have diverse power supply portfolios, whereas merchant generators tend to be much less diverse—typically almost entirely natural gas-fired. As a result of the different supply mixes and associated risk profiles, utilities and merchant generators have different costs of capital. This difference in the cost of capital provides an approximation of the difference in risk premium.

Overall, the cost of capital for merchant generators is higher than that for utilities broadly. While the power industry has an average cost of debt of roughly 4.5%, merchant generators with significant natural gas holdings tend to have a cost of debt of around 8%. As many of these firms have gone through bankruptcies in the past, this number may be lower than the cost of debt these firms had prior to restructuring.[12] The implied risk premium of a merchant generator to a utility is 3.5%, which is similar to the cost of capital analysis results discussed in the body of the report, where the reduced diversity case generator was calculated to have a cost of capital 310 basis points (3.1%) higher than that of the current US power sector as a whole.

Merchant generators with majority natural gas holdings have higher costs of capital because of the increased earnings volatility and risk of an all natural gas portfolio. In contrast, a generator with a more diverse portfolio needing to secure financing for the same type of plant would have costs of capital more in line with the industry as a whole. This can have a significant impact on the overall cost of the plant. This is not due specifically to the properties of natural gas as a fuel, but rather to the diversity of generating resources available. If a merchant generator were to have an exclusively coal-fired generating fleet or an exclusively nuclear generating fleet, its cost of capital would also increase owing to the higher uncertainty in generation cash flows.

The expected annual power supply costs can be calculated over the expected life of a power plant once the cost of capital is set and combined with the cost and operating profile data. These power costs are uneven through time for a given utilization rate. Therefore, an uneven cost stream can be expressed as a levelized cost by finding a constant cost in each year that has the same present value as the uneven cost stream. The discount rate used to determine this present value is based on the typical cost of capital for the power

12. Based on analysis of the "Competitive" business strategy group, defined by IHS as businesses with generation portfolios that are over 70% nonutility, based on asset value and revenue. Cost of debt based on coupon rates of outstanding debt as of May 2014.

industry as a whole. Dividing the levelized cost by the output of the power plant at a given utilization rate produces a levelized cost of energy (LCOE) for a given technology at a given utilization rate (see Figure A-5).

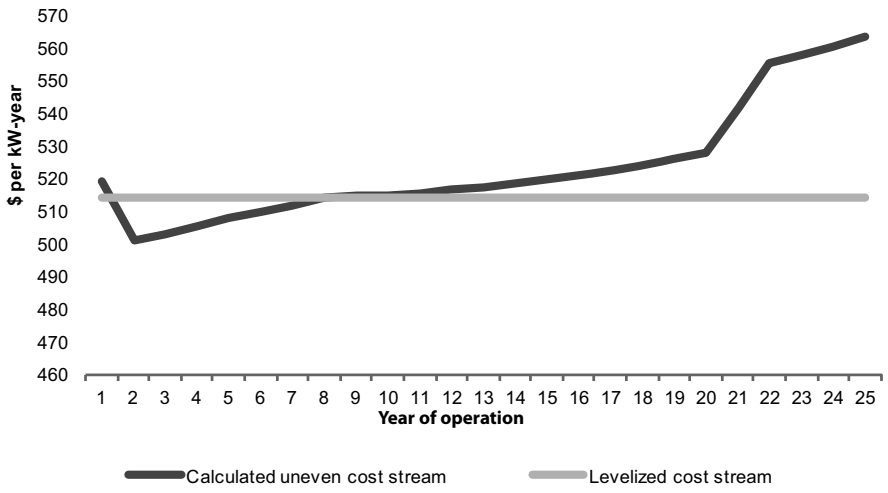
A levelized cost stream makes it possible to compare production costs at different expected utilization rates. A lower utilization rate forces spreading fixed costs over fewer units of output and thus produces higher levelized costs (see Figure A-6).

Figure A-7 adds the LCOE of a CT. Since the LCOE of the CT is lower than that of the CCGT at high utilization rates, adding CTs shows the point at which the savings for a CCGT's greater efficiency in fuel use are enough to offset the lower fixed costs of a CT.

There is a utilization rate at which a CCGT is cheaper to run than a CT. Below a utilization rate of roughly 35%, a CT is more economical. At higher utilization rates, the CCGT is more economical. When referring back to the load duration curve, it can be calculated that a generation mix that is 37% CT and 63% CCGT would produce a least-cost outcome. This can be demonstrated by comparing the LCOE graph with the load duration curve: the intersection point of CT and CCGT LCOEs occurs at the same time percentage on the LCOE graph at which 63% load occurs on the load duration curve (see Figure A-8).

FIGURE A-5

Cost stream comparisons—CCGT, 85% utilization rate



Source: IHS Energy

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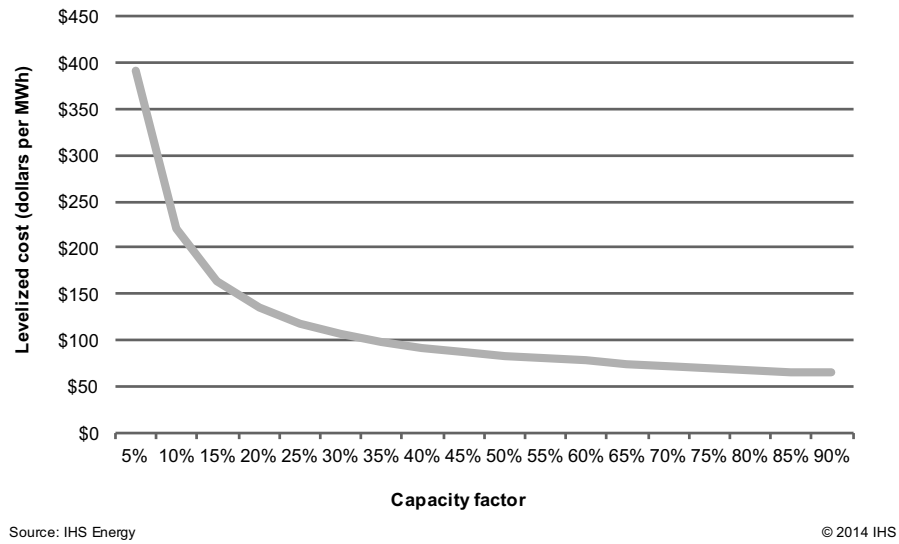
FIGURE A-6

LCOE of CCGT generation



Source: IHS Energy

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The levelized cost of production for each technology can be determined by finding the average load (and corresponding utilization rate) for the segment of the load duration curve (LDC) that corresponds to each technology (in this example, the two segments that are created by splitting the curve at the 35% mark). Loads that occur less than 35% of the time will be considered peak loads, so the average cost of meeting

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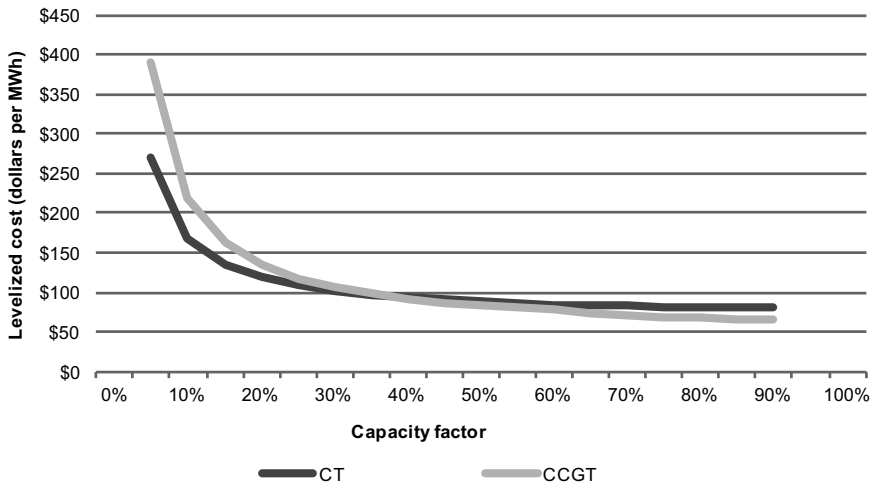
a peak load will be equivalent to the cost of a CT operating at a 17.5% utilization rate, the average of the peak loads. Cycling loads will be defined as loads occurring between 35% to 80% of the time, with base loads occurring more than 80% of the time. As the CCGT is covering both cycling and base loads in this example, the average cost of meeting theses loads with a CCGT will be equivalent to the levelized cost of a CCGT at a 57.5% utilization rate. A weighted average of the costs of each technology is then equivalent to an average cost of production for the power system. For this generation mix, the levelized cost of production is equal to 9.6 cents per kWh.

FIGURE A-7

LCOE of CCGT and CT generation



Source: IHS Energy

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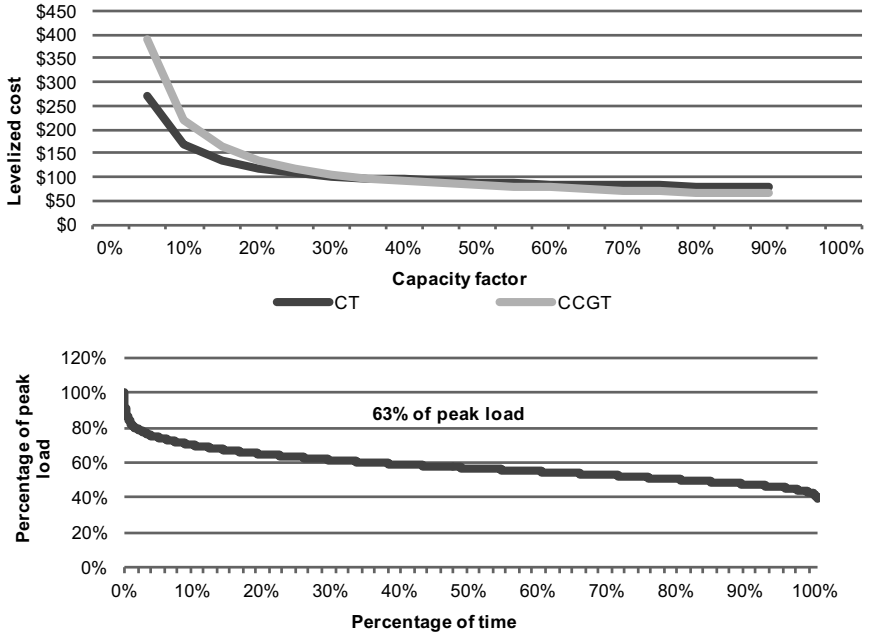
FIGURE A-8

Determination of generation mix based on load duration curve



Source: IHS Energy
Data Source: Ventyx Velocity Suite, National Renewable Energy Laboratory

Source:

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The generating options also can be expanded to include fuels besides natural gas. Stand-alone coal and stand-alone nuclear are not lower cost than stand-alone gas, as shown in Figure A-9, and all have a high-risk premium associated with the lack of diversity. However, when combined as part of a generation mix, the cost of capital will be lower owing to the more diverse (and therefore less risky) expected cash flow.

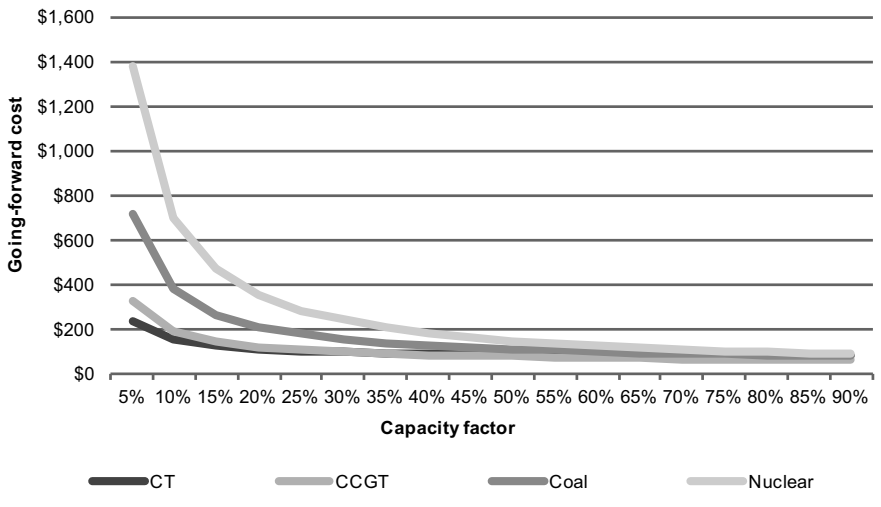
Based on the LDC, in this example base-load generation was modeled at 52.5% of capacity and was composed of equal parts gas, coal, and nuclear capacity. This combination of fuels and technology produces a diverse portfolio that can reduce risk and measurably lower the risk premium in the cost of capital. The point at which a CCGT becomes cheaper than a CT changes slightly from the previous example owing to the change in cost of capital, but the result is similar, with a 30% utilization rate the critical point and 36% CT capacity the most economical. Cycling loads with utilization

rates between 30% and 80% can be covered by CCGTs, equaling 11.5% of capacity. The levelized cost of production for this more diverse portfolio is equal to 9.3 cents per kWh. Even though coal and nuclear have higher levelized costs than gas, all else being equal, the reduced cost of capital is more than enough to offset the increased costs of generation. The implication is that a least-cost mix to meet a pattern of demand is a diverse mix of fuels and technologies.

If the power system has a renewables mandate, this can be incorporated as well. Solar PV has a levelized cost of 14.2 cents per kWh, given a 4.5% cost of capital. If solar made up 10% of generating capacity, the load duration curve for the remaining dispatchable resources would change, as shown in Figure A-10. Using hourly solar irradiation data from a favorable location to determine solar output, the peak load of the power system does not change, as there is less than full solar insulation in the hour when demand peaks.[13] The load factor for this new curve is 0.58, a small decrease from the original curve. A lower load factor typically means that larger loads occur less often, so more peaking capacity is necessary.

FIGURE A-9

Levelized cost curves of generating resources



Source: IHS Energy

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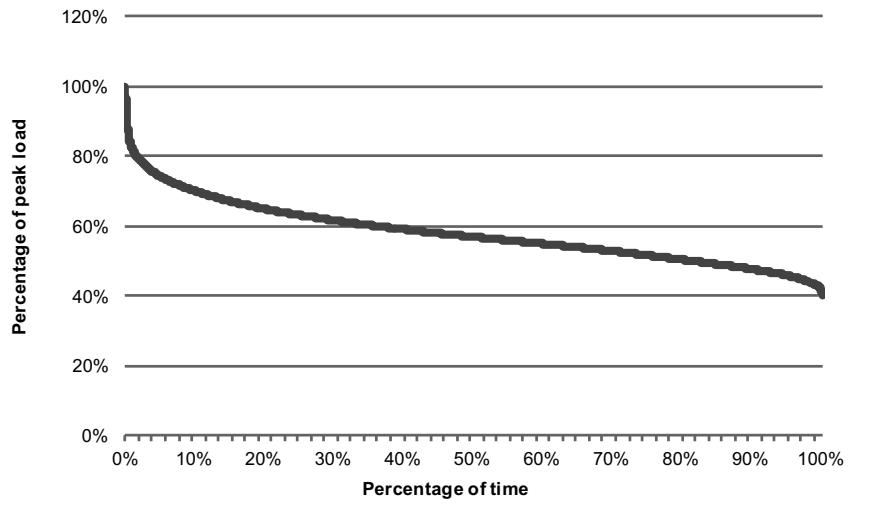
FIGURE A-10

Load duration curve, after solar additions



Source: IHS Energy
Data Source: Ventyx Velocity Suite, National Renewable Energy Laboratory

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The needed dispatchable resources can be recalculated using the new curve, integrating the solar generation. The new curve increases the amount of peaking resources needed, but otherwise changes only very slightly. After solar is added, the total cost is 10.8 cents per kWh. Since the output pattern of solar doesn't match the demand pattern for the power system, adding solar does not significantly decrease the amount of capacity needed.

13. Solar data from National Renewable Energy Laboratory, Austin, TX, site. Data from 1991–2005 update, used for example purposes. http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/tmy3/by_state_and_city.html accessed 13 May 2014.

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Conclusion

- There is no single fuel or technology of choice for power generation. Reliably and efficiently supplying consumers with the amounts of electricity that they want, when they want it, requires a diverse generation mix.

- A cost-effective generation mix involves diversity but does not involve maximizing diversity by equalizing generation shares from all available supply options.

- The cost-effective mix of fuel and technologies for any power system is sensitive to the uncertainties surrounding the level and pattern of consumer power demands as well as expectations regarding the cost and performance of alternative power generating technologies and, in particular, the expectations for delivered fuel prices.

- The cost-effective generating mix will differ from one power system to the next because of differences in aggregate consumer demand patterns as well as the cost and performance of available generating options.

- The best type of capacity to add to any generation portfolio depends on what types of capacity are already in the mix.

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Appendix B: IHS Power System Razor Model overview

Design

The IHS Power System Razor (Razor) Model was developed to simulate the balancing of power system demand and supply. The model design provides flexibility to define analyses' frequency and resolution in line with available data and the analytical requirements of the research investigation.

For this assessment of the value of fuel diversity, the following analytical choices were selected:

- **Analysis time frame**—Backcasting 2010 to 2012
- **Analysis frequency**—Weekly balancing of demand and supply
- **Geographic scope**—US continental power interconnections—Western, Eastern, and ERCOT
- **Demand input data**—Estimates of weekly interconnection aggregate consumer energy demand plus losses
- **Fuel and technology types**—Five separate dispatchable supply alternatives: nuclear, coal steam, natural gas CCGT, gas CT, and oil CT
- **Supply input data by type**—Monthly installed capacity, monthly delivered fuel prices, monthly variable operations and maintenance (O&M), heat rate as a function of utilization
- **Load modifiers**—Wind, solar, hydroelectric, net interchange, peaking generation levels, and weekly patterns

Demand

The Razor Model enables the input of historical demand for backcasting analyses as well as the projection of demand for forward-looking scenarios. In both cases, the Razor Model evaluates demand in a region as a single aggregate power system load.

For backcasting analyses, the model relies upon estimates of actual demand by interconnection. For forward-looking simulations, Razor incorporates a US state-level cross-sectional, regression-based demand model for each of the three customer classes—residential, commercial, and industrial. Power system composite state indexes drive base year demand levels by customer class into the future.

Load modifiers

Utilization of some power supply resources is independent of SRMC–based dispatch dynamics. Some power supply is determined by out-of-merit-order utilization, normal production patterns, or external conditions—such as solar insolation levels, water flows, and wind patterns. These power supply resources are treated as load modifiers.

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Net load

Net load is the difference between power system aggregate electric output needs and the aggregate supply from load modifiers. It is the amount of generation that must be supplied by dispatchable power supply resources.

Calibration of the inputs determining net load is possible using data reporting the aggregate output of dispatchable power sources.

Fuel- and technology-specific supply curves

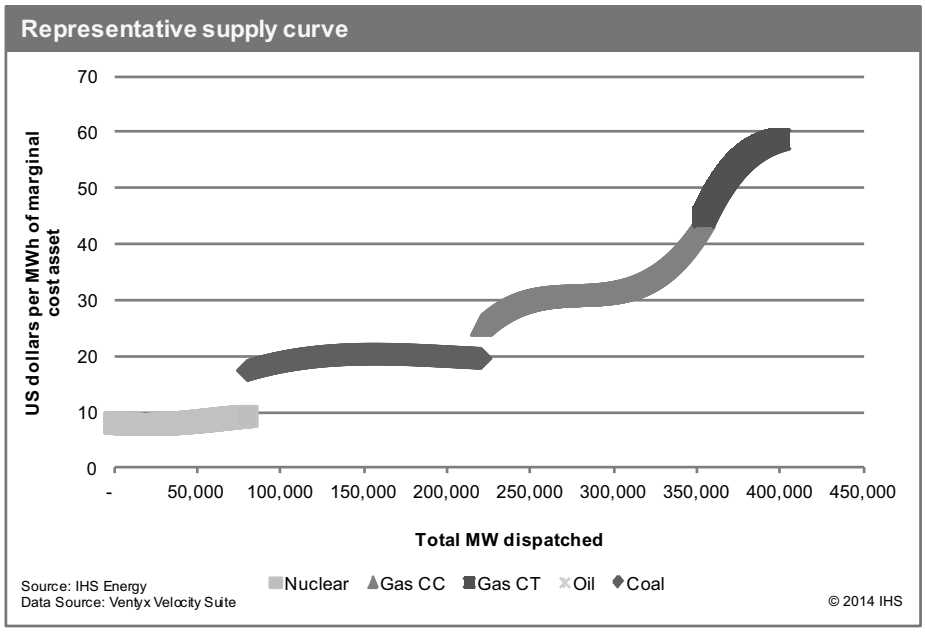
Supply curves are constructed for each fuel and technology type. The supply curve for each dispatchable power supply type reflects the SRMCs of the capacity across the possible range of utilization rates. Applying availability factors to installed capacity produces estimates of net dependable (firm, derated) capacity by fuel and technology type.

Each cost curve incorporates heat rate as a function of utilization rate.[14] *Heat rate* describes the efficiency of a thermal power plant in its conversion of fuel into electricity. Heat rate is measured by the amount of heat (in Btu) required each hour to produce 1 kWh of electricity, or most frequently shown as MMBtu per MWh. The higher the heat rate, the more fuel required to produce a given unit of electricity. This level of efficiency is determined primarily by the fuel type and plant design. Outliers are pruned from data to give a sample of heat rates most representative of the range of operational plants by fuel and technology type.[15]

Dispatch fuel costs are the product of the heat rate and the delivered fuel cost. Total dispatch costs involve adding variable operations and maintenance (VOM, or O&M) costs to the dispatch fuel costs. These O&M costs include environmental allowance costs.

The power system aggregate supply curve is the horizontal summation of the supply curves for all fuel and technology types. Figure B-1 illustrates the construction of the aggregate power system supply curve. The supply curve shows the SRMC at each megawatt dispatch level and the associated marginal resource.

FIGURE B-1



Balancing power system aggregate demand and supply

The Razor Model balances aggregate power system demand and supply by intersecting the demand and supply curves. At the intersection point, power supply equals demand; supply by type involves equilibrating the dispatch costs of available alternative sources of supply.

14. Power plant data sourced from Ventyx Velocity Suite.

15. Outliers are defined as plants with an average heat rate higher than the maximum observed fully loaded heat rate.

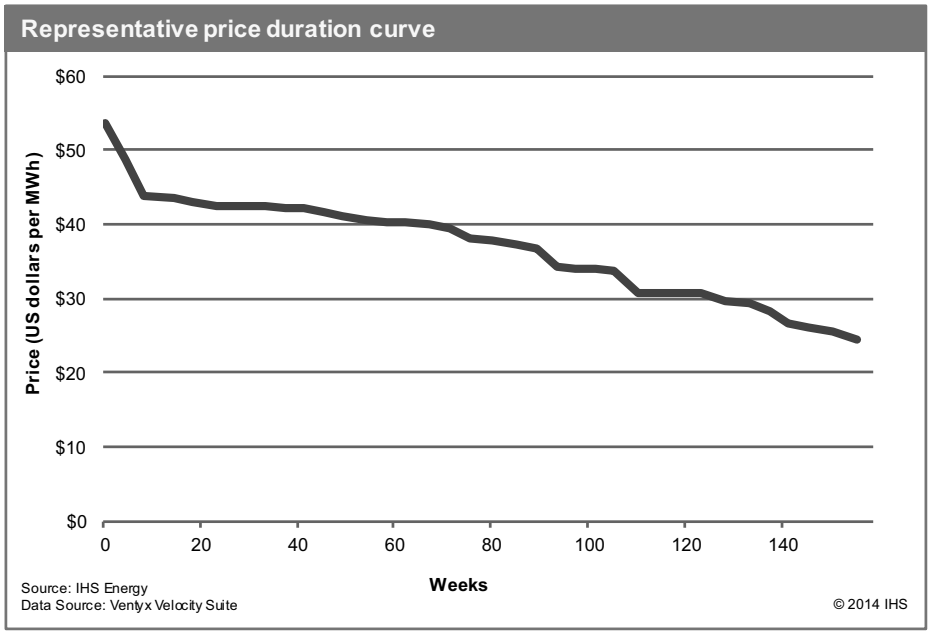
This power system–wide marginal cost of production is the basis for the wholesale power price level that clears an energy market.

The Razor Model results in the following outputs:

- **Power system SRMC/wholesale price**
- **Generation by fuel and technology type**
- **Average variable cost of production.** The average variable cost is calculated at each dispatch increment by taking the total cost at that generation level divided by the total megawatt dispatch.
- **Price duration curve.** The price duration curve illustrated in Figure B-2 provides an example of wholesale power price distribution across the weeks from 2010 through 2012.

Calibration

FIGURE B-2



The predictive power of the Razor Model for portfolio and substitution analysis is revealed by comparing the estimated values of the backcasting simulations to the actual outcomes in 2010–12.

The Razor Model backcasting results provide a comparison of the estimated and actual wholesale power prices. The average difference in the marginal cost varied between (3.8%) and +2.3% by interconnection region. A comparison of the average rather than marginal cost of power production also indicated a close correspondence. The average difference between the estimate and the actual average cost of power production varied between (4.7%) and (0.1%) by interconnection region. Table B-1 shows the assessment of the predictive power of the Razor Model for these two metrics across all three interconnections in the 2010 to 2012 weekly backcasting exercise.

TABLE B-1

IHS power system Razor Model analysis

	East	West	ERCOT
Average wholesale power price difference	2.3	0.3	-3.8
Average production cost difference	-0.2	-4.7	-0.1

Note: Differences reflect deviation averaged over backcasting period. Production cost difference reflects average of five power sources: Coal, gas combined-cycle, gas combustion turbine, nuclear, and oil.

Source: IHS Energy

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Attachment B

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Recent Nuclear Plant Closures

Closure

Crystal River 3 (Florida), decommissioning began in 2013
Reactor had been licensed to 2016.
Fort Calhoun (Nebraska), 2016
Reactor had been licensed to 2033.
Kewaunee (Wisconsin), 2013
Reactor had been licensed to 2033.
San Onofre 2 (California), 2013
Reactor had been licensed to 2022.
San Onofre 3 (California), 2013
Reactor had been licensed to 2022.
Vermont Yankee (Vermont), 2014
Reactor had been licensed to 2032.

Power Uprate Cancelled

Cooper (Nebraska), anticipated uprate investment called off in 2013
LaSalle Generating Station 1 (Illinois), 2013
LaSalle Generating Station 2 (Illinois), 2013
Limerick 1 (Pennsylvania), 2013
Limerick 2 (Pennsylvania), 2013
Prairie Island 1 (Minnesota), 2012

Announced for Closure

Clinton Power Station (Illinois), decommissioning announced for 2017
Originally proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. The reactor is licensed to 2026.
Diablo Canyon 1 (California), 2024
Proposed by utility owner through decision not to pursue license extension. Licensed to 2024.
Diablo Canyon 2 (California), 2025
Proposed by utility owner through decision not to pursue license extension. Licensed to 2025.
Indian Point 2 (New York), 2020
Anticipated closure as a result of negotiated state settlement, not averted by state subsidy to other plants. Licensed to 2013 (operating under temporary license).
Indian Point 3 (New York), 2021
Anticipated closure as a result of negotiated state settlement, not averted by state subsidy to other plants. Licensed to 2015 (operating under

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temporary license).

James A Fitzpatrick (New York), 2017

Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2034.

Nine Mile Point Nuclear Station 1 (New York), 2017

Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2029.

Nine Mile Point Nuclear Station 2 (New York), 2017

Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2046.

Oyster Creek 1 (New Jersey), 2019

Anticipated closure as a result of negotiated state settlement. Licensed to 2029.

Palisades (Michigan), 2018

Proposed by utility owner. Licensed to 2031.

Pilgrim Nuclear Power Station (Massachusetts), 2019

Proposed by utility owner. Licensed to 2032.

Quad Cities Generating Station 1 (Illinois), 2018

Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2032.

Quad Cities Generating Station 2 (Illinois), 2018

Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2032.

R. E. Ginna Nuclear Power Plant (New York), 2017

Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2029.

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Document Content(s)

Final PSEG Companies Comments RM18-1-000.PDF.....1-106

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PSEG
Services Corporation

October 24, 2017

VIA EFILING

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Grid Reliability and Resilience Pricing
Docket No. RM18-1-000

Dear Ms. Bose:

On October 23, 2017, The PSEG Companies[1] electronically filed comments in the above referenced proceeding.[2] The Verification to the Affidavit of Dr. Lawrence J. Makovich was inadvertently not included with the filing. Therefore, we respectfully request that the attached Verification be accepted as part of the record in this proceeding.

Please contact the undersigned with any questions.

Very truly yours,

Kenneth R. Carretta

Kenneth R. Carretta

[1] The PSEG Companies are Public Service Electric and Gas Company, PSEG Power LLC and PSEG Energy Resources & Trade LLC.

[2] "Comments of the PSEG Companies," Grid Reliability and Resilience Pricing, Docket No. RM18-1-000 (October 23, 2017) (Accession Number 20171023-5555).

VERIFICATION

Suffolk County)
) ss:
Massachusetts)

I, the undersigned, being duly sworn, depose and say that the foregoing is the "Affidavit of Dr. Lawrence J. Makovich" and that such Affidavit to the best of my knowledge, information and belief, is true, correct, and accurate, and I hereby adopt this Affidavit as if given by me in formal hearing, under oath. MASS D.L. S18830738

Lawrence J. Makovich

Subscribed and sworn to before me this 20th day of October, 2017.

Notary Public

ROBERT W. SWEENEY
NOTARY PUBLIC
COMMONWEALTH OF MASSACHUSETTS
MY COMMISSION EXPIRES 02/02/2018

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Newark, New Jersey, this 24th day of October, 2017.

James E. Wrynn

James E. Wrynn
Paralegal

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Document Content(s)

2017-10-24_Grid Reliability Cover Letter.PDF.....1-3

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. EL18-178-000**
PJM Interconnection, L.L.C.	)	**ER18-1314-000** **ER18-1314-001**
Calpine Corporation, et al.,	)	**EL16-49-000**
Complainants,	)	**(Consolidated)**
v.	)	
PJM Interconnection, L.L.C.,	)	
Respondent.	)	

REPLY COMMENTS OF THE PSEG COMPANIES

Pursuant to Rule 213 of the Federal Energy Regulatory Commission's ("Commission") Rules of Practice and Procedure,[1] the PSEG Companies submit this reply to comments submitted concerning the proposed changes to PJM Interconnection, L.L.C.'s ("PJM") Open Access Transmission Tariff ("Tariff") described in the June 29, 2018 Order Rejecting Proposed Tariff Revisions, Granting In Part and Denying In Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act ("Order").[2]

This proceeding was established to consider the Commission's proposal to modify the PJM Tariff to: (1) expand the MOPR to cover new and existing resources that receive out-of-market payments with few or no exceptions; and (2) allow resources receiving out-of-market

[1] 18 C.F.R. §§ 385.212, 385.214 (2018).

[2] *PJM Interconnection, L.L.C.,* 163 FERC ¶ 61,236 (2018).

support to choose to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time ("FRR-Alternative").

The PSEG Companies continue to maintain that PJM's current capacity construct is just and reasonable and therefore does not require modification.[3] As described below, the PSEG Companies respectfully request that if the Commission determines changes are required, it approve the expanded Minimum Offer Price Rule ("Expanded MOPR") with little or no exceptions, along with either an approach aligned with PJM's Resource Carve-Out Option ("RCO"),[4] proposal or consider an alternate version of PJM's Proposed Extended RCO alternative as discussed below. The PSEG Companies stress that it is critical that the features we recommend below are incorporated in any approved changes to PJM's Tariff. In its initial comments, the PSEG Companies proposed an FRR-Alternative mechanism that is generally aligned with PJM's RCO option.[5] As such, the PSEG Companies support most aspects of PJM's RCO option, but propose modifications to ensure just and reasonable capacity market outcomes. It is particularly important that the RCO mechanism is structured to recognize all capacity that exists in the market and does not create an unnecessary oversupply situation that will lead to perpetually suppressed energy market prices and inefficient market signals to suppliers.

The PSEG Companies initial comments generally supported the Commission's proposal given our foundational belief that PJM should continue to manage a market construct that both

[3] *See* The PSEG Companies Request for Rehearing, Docket No. EL18-178-000, *et al*., (submitted July 30, 2018) ("PSEG Rehearing Request") (discussing the PSEG Companies' position on why the current tariff was improperly found to be unjust and unreasonable).

[4] Initial Submission of PJM Interconnection, L.L.C., Docket No. EL16-49-000, *et al*. (filed October 2, 2018) ("PJM Comments").

[5] *See* Comments of the PSEG Companies, Docket No. EL16-49-000, *et al*. (filed October 2, 2018) ("PSEG Comments").

accommodates legitimate state public policy initiatives[6] and honors the physical nature of the locational capacity market.[7] In its comments, PJM provides a mostly workable approach. However, there are a number of elements in PJM's proposal that should either be modified or rejected. These elements include the numerous exemptions to the MOPR and the capacity repricing mechanism ("Extended RCO"). Moreover, while the PSEG Companies disagree with the PJM's Extended RCO re-pricing proposal, if the Commission deems it just and reasonable, we offer an alternative that retains many of its elements, but request that the Commission adopt it with design elements identified below in order to ensure that the auction produces just and reasonable outcomes.

Therefore, we respectfully request that the Commission issue an order that supports the PSEG Companies' FRR-Alternative approach or a modified version of the PJM RCO approach should it still determine that changes are necessary to the MOPR construct. These are the alternatives that provide appropriate pricing for both load and resources, are fair across all Regional Transmission Organization ("RTO") participants and achieve the accommodative approach described in the Commission's Order.

I. COMMENTS

(a) The Commission Should Support PJM's RCO Option With Modifications Consistent With The PSEG Companies' Proposal

The PSEG Companies generally support PJM's proposed RCO clearing mechanism, but request that the Commission reject certain aspects of PJM's proposal to better align it with the PSEG Companies' suggestions. Specifically, the Commission was clear and many respondents

[6] For example, New Jersey's Zero Emissions Certificate ("ZEC") and other renewable energy programs designed to achieve the State's environmental goals.

[7] PSEG Comments at pp. 4-7.

have stated their strong support for a MOPR with few or no exceptions.[8] The PJM proposal falls well short of that bar, and with its broad exceptions, could easily be seen as unduly discriminatory by targeting specific asset classes or certain state activities, while accommodating those same actions in other places. The PSEG Companies do not support such an approach as proposed and have therefore provided suggestions to improve the PJM Extended RCO proposal if the Commission should determine a repricing mechanism is acceptable. The PSEG Companies believes PJM has provided a workable roadmap for the Commission to follow. We further emphasize that the PJM proposal does not have to be implemented in its entirety. The proposal includes several elements that should be approved by the Commission while other elements should be rejected.

PJM's RCO proposal – submitted in response to the Commission's guidance – remains riddled with exemptions that have little to no basis in either economics or policy and would likely have a material impact on market outcomes. The PSEG Companies reiterate our position that only materiality thresholds are appropriate as exceptions to applying the MOPR.[9] Several self-supply entities have submitted comments highlighting differences in their business models to rationalize exemptions from the Expanded MOPR. None of these commenters, however, provide a legitimate basis for differentiating between these business models and the goals of states that have chosen to select and compensate specific generation resources to achieve policy objectives. The Expanded MOPR construct should apply to all generation receiving material

[8] Initial Brief of Eastern Generation, LLC, Docket No. EL16-49-000, *et al.,* at pp. 10-12 (filed Oct. 1, 2018); Initial Brief of Exelon Corporation, Docket No. EL16-49-000, *et al.,* (filed Oct. 2, 2018); Initial Brief of the PJM Power Providers Group, Docket No. EL16-49-000, *et al*., at p. 10 (filed October 2, 2018); Initial Brief of The Electric Power Supply Association, Docket No. EL16-49-000, *et al*., at pp. 6-8 (filed Oct. 2, 2018).

[9] *See* Comments of the PSEG Companies, Docket No. EL16-49-000, *et al*., at p. 6 (filed October 2, 2018) (agreeing with PJM's proposed 1% of revenue value threshold, and suggested a 1 MW size threshold).

out-of-market support and the RCO option should serve as the accommodation mechanism for all entities looking to self-select generation resources.

Several commenters highlighted the locational difficulties that would be created if both resources and load were removed from the clearing algorithm. Specifically, Mr. Keech in his testimony outlined several of the problems that would be encountered.[10] The clearing algorithm proposed by PJM directly addresses those concerns and most importantly, aligns with the PSEG Companies' recommendation that there be a requirement that carved-out resources achieve the same reliability standard (i.e., reserve margin) as the market.[11]

A careful review of PJM's RCO approach reveals that there are aspects of the PJM design that may be superior to the PSEG Companies' suggested approach. Specifically, PJM's proposals for bidding and settlement offer a simpler solution than those proposed by the PSEG Companies and may better facilitate implementation of the RCO mechanism. PJM would require that the RCO resources offer into the market at zero. In contrast, the PSEG Companies suggested that the RCO resources establish their own economic offer. The PSEG Companies offered this suggestion believing that a resource may wish to get out of an obligation to either avoid capacity performance risk or pursue retirement. After further consideration of the PJM proposal, these options exist and the risks can be effectively managed within the normal process. Therefore, the PSEG Companies support the PJM recommendation that resources that elect the RCO option offer into the market at zero.

(b) <u>The RCO Option Must Provide States With Sufficient Flexibility to Pursue Their Policy Goals</u>

[10] *See* PJM Comments, Attached Affidavit of Adam J. Keech on Behalf of PJM Interconnection, L.L.C.

[11] PSEG Comments at pp. 8-9.

A second aspect of PJM's proposal that warrants consideration is PJM's suggested approach to settling loads associated with a state supported RCO election. The PSEG Companies argued that states could designate specific customers or categories of customers such as default service load that would be matched with the RCO resources. PJM takes a different approach. Under PJM's approach a capacity resource that elects the RCO option will be matched with a portion of the total state load.[12] PJM explains that:

> "[T]he financial settlement (which begins in the Delivery Year, three years after the auction has cleared) can assess charges and remit revenues according to the auction clearing rules (a pro-rata credit across all load in the state) *or impose the rate on load in different manner as may be proposed by the state*. The actual mechanics of this settlement can be facilitated by PJM Settlement as a billing agent, should the state so wish."[13]

The PSEG Companies support this statement. It is critical that states be allowed to determine how capacity allocations to load should occur. This allows states with different wholesale / retail models to determine the mechanism that will best support its constituency. This choice is also aligned with the PSEG Companies initial comments and further emphasizes a key point made in those comments: that what PJM refers to as the Resource Carve-Out offset, should be allocated to the affected load. In PJM's proposal, where the full state has its capacity obligation reduced by the RCO resource election, allocating the credit back on a load — ratio share to all LSEs is appropriate. However, if a state elects to have the RCO resource election impact only a subset of its loads (such as default service or specific rate-classes), the credit should only be allocated back to those impacted loads.

[12] PJM Comments at p. 61.

[13] *Id.*, at p. 59 (emphasis added).

But the pro forma tariff provisions that allow for deviations from the default pro-rata allocation of credits to load for Resource Carve-Out offset resources requires that the Commission accept or approve deviations from the default allocation mechanism under Federal Power Act ("FPA") Sections 205 or 206. The PSEG Companies do not perceive the need for FPA approval simply in order to identify which customers that the state wishes to receive the credits. The tariff should be modified to allow a state agency to identify to PJM which load serving entities serving load within that state should receive the Resource Carve-Out offset. This is consistent with the practice under the currently-effective FRR mechanism that allows states to determine how the *entirety* of a state's capacity obligation is met.

The situation faced by New Jersey in implementing the recently enacted Zero Emission Certificate ("ZEC") Act designed to preserve environmental and fuel diversity/resiliency attributes of nuclear generation serving the state illustrates this point. New Jersey is a retail open-access state but a sizable share of New Jersey's load is still served by "provider of last resort" service known as "Basic Generation Service" ("BGS"). The state's electric distribution companies are responsible for obtaining electricity supplies needed for BGS load which are procured thought a yearly state-wide auction. The successful auction winners each become Load Serving Entities ("LSEs") for an undivided portion of the BGS load. Although no decisions have been reached nor has a formal process been convened by the New Jersey Board of Public Utilities, the potential for using BGS to facilitate implementation the RCO mechanism is currently being discussed. If BGS were to be used for this purpose, PJM's proposed default would be problematic because it would allocate credits to all the LSEs not just the LSEs serving BGS load.

For example, New Jersey's total capacity procurement obligation is about 17,600 MWs of which somewhat more than half consists of BGS load – approximately 10,600 MWs. If the BPU awards ZECs to nuclear generators with 3,000 MWs of capacity which units then seek to become RCO resources, the BGS suppliers would need to be credited with the entire Resource Carve-Out offset of 3,000 MWs. If the 3,000 MW credit were allocated to all LSEs serving the state, *i.e.*, both BGS and Third Party Suppliers ("TPS"), almost half of the 3,000 MW Resource Carve-Out offset would be conferred on the TPS companies that are not responsible for paying for the resources. Moreover, there is no reason why it should be necessary to seek Commission approval under circumstances, such as these, in which the allocation of the Resource Carve-Out offset associated with the RCO resources conforms to a state's normal procurement practices.

(c) <u>If the Commission Decides Not To Accept PJM's Extended RCO, It Should Adopt the PSEG Companies' Repricing Alternative Instead</u>

The PSEG Companies do not support the Extended RCO proposal offered by PJM for several reasons. First, it presumes that state actions to address their resource mix result in market outcomes that are not just and reasonable. In the carve-out proposal, these actions are effectively removed from the market and priced separately through a bilateral action – an approach that achieves reasonable outcomes as the remaining resources and balance of the load clear. Second, PJM takes the step of removing the RCO resources from the second clearing mechanism without removing the corresponding load. Putting the market "out of balance" in this regard is guaranteed to lead to higher prices. PJM also offers no reason why these resources should be removed from the market as opposed to being represented at a competitive price. The methodology then goes on to establish a "competitive" price, and offers to pay resources that have no obligation to the market an "uplift" payment simply because they would have been

economic. This assumption is without foundation and lacks any economic basis. For all of these reasons, the construct proposed would not result in appropriate market outcomes and would increase consumer charges with no benefits.

Recognizing these drawbacks, the PSEG Companies understand that the idea of creating a competitive generation proxy price may receive some consideration. We therefore offer several modifications to the PJM Extended RCO approach that address several of the deficiencies in the PJM design.

i. Modifications To The PJM Extended RCO Proposal are Necessary

The most simplistic approach to repricing is closer to what PJM provided originally. All units would participate in round one of the auction, the commitment phase, with all resources providing their competitive offer.

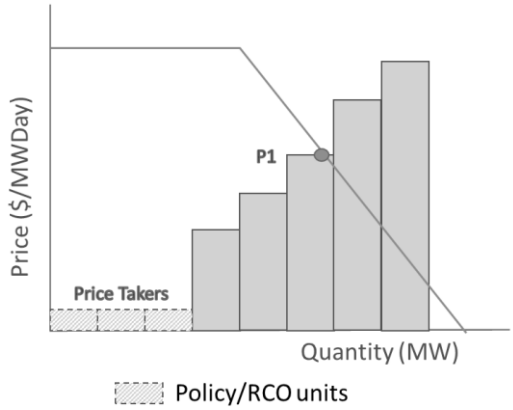

Figure 1. Commitment round, and how the market would work under current rules – Policy resources are entered as price takers.

To achieve a just and reasonable price in the second round, all resources must be included in the pricing round, where all load is being represented. The RCO resources can be offered at their MOPR price level, which will have already been found to reflect a "competitive" rate.

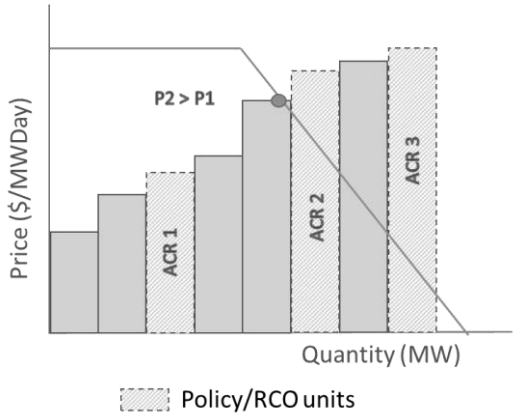

Figure 2. A better alternative for repricing. Policy resources are entered at their ACR's, which limits the price increase in the pricing round.

Excluding these resources would result in unnecessary and excessive costs to ratepayers[14] while sending false price signals to the remainder of the market.

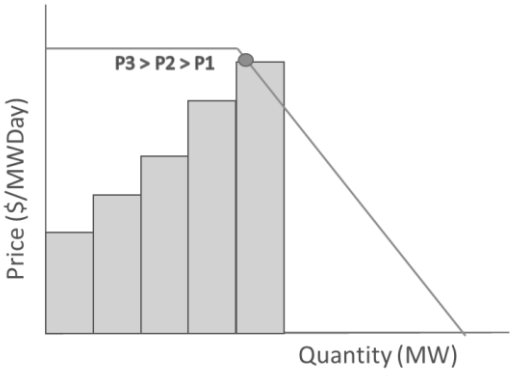

Figure 3. PJM's proposal for the pricing round. Policy resources are removed entirely. All load remains. Result is prices rise to a high level, possibly all the way to the market cap depending on the number of policy resources electing RCO and shape of the supply curve.

Once the price is determined, it will only be paid to the merchant generators. Therefore, generators receiving a material subsidy would not be eligible for a market payment unless their mitigated offers cleared in the pricing round.

[14] Should the Commission adopt a strong MOPR with few or no exceptions, the amount of resources that would be removed from the market rather than re-priced would be significant and would cause certain PJM zones to clear at the top (horizontal portion) of the demand curve.

The other adjustment that must be addressed is the unnecessary payment proposed to resources that did not receive an obligation in the commitment round, but had offers at or below the clearing price in the pricing run. These resources have no performance obligations or commitments to the market and should therefore not receive any payment. This payment only represents another layer of costs that are being unnecessarily placed on consumers.

ii. The PSEG Companies Offer Additional Changes To The PJM Extended RCO Proposal

Building off of the last proposal we would offer another alternative that adjusts settlement and payments for the resources that did not have a commitment but were economic in the pricing run.

The PSEG Companies note that recognizing appropriate obligations through the capacity markets is required to maintain the balance and integrity of the energy markets, and that the Commission should take all steps necessary to ensure energy price signals are appropriate. The market design ultimately adopted by the Commission should minimize the uneconomic retention and speculative rent seeking behavior that would most certainly accompany a mechanism which pays resources that do not receive a commitment in round one, but are inframarginal in round two ("Inframarginal Resources"). To achieve this, we believe the Commission should make any payments, such as those proposed by PJM, optional to the Inframarginal Resources. Should the Inframarginal Resources elect to receive the payment, they would also be obligated to submit a binding retirement notification and forfeit their Capacity Interconnection Rights. This payment will be a "severance payment" for resources that the auction determines are not needed to meet reliability requirements, but completely at the resources' discretion. This is consistent with the

successful, voluntary nature of the PJM markets and works to maintain appropriate resource balances going forward.

In settlement, ratepayers should not have to pay more than the total dollars determined by multiplying the clearing price times the quantity based on the point at which the supply curve intersects the Variable Resource Requirement ("VRR") curve in the pricing round along with any make whole payments as is required in the current construct. This estimates the amount that ratepayers would pay in a market with no subsidies. This pool of dollars would be used to compensate resources clearing the market in round one and, if the Commission determines it is appropriate that the units electing binding retirement.

The PSEG Companies believe that paying all merchant resources receiving a capacity obligation in the first round plus Inframarginal Resources electing the severance payment option from the "pool of dollars," which would necessitate a final settled clearing price between the round 1 and round 2 clearing prices is appropriate for two reasons. First, all remaining resources will benefit from retiring excess supply in both the energy and capacity markets. Second, state supported resources have always been a factor in capacity markets. Capacity markets, since their inception, have always included subsidized resources and prices have settled accordingly. Merchant generators have never had an expectation that they would be participating in a "pure" market devoid of any subsidized resources. PJM's Extended RCO proposal would create a windfall for merchant resources because it would completely remove supported resources from the market. The PSEG Companies' repricing alternative seeks a middle ground, where much of the price suppression is removed and load pays no more than they would in a market without subsidies.

iii. The Commission Should Adopt the PSEG Companies Proposed FRR-Alternative Mechanics

The Commission should adopt the following design elements. All load in PJM should continue to be represented in the VRR curve. Moreover, all resources should continue to be represented in the supply curve as follows: (a) merchant resources should be represented at their chosen price either at or below their applicable offer cap; (b) resources receiving support payment, but that are not electing the RCO option should be represented at their mitigated or MOPR offer level; and (c) resources receiving support payments and electing the RCO option should be offered in the supply curve as price takers. Resources should have the option to elect the "severance payment" option at this point and allowed to indicate whether they would agree to a binding retirement in exchange for a payment in the event they do not clear first round but eventually become Inframarginal Resources.

(1) PJM administers the first round of the auction to establish which resources will receive a capacity commitment.

(2) Resources receiving support payments are removed from the supply curve and reentered at their MOPR price.

(3) PJM administers the pricing round of the auction. The point at which the supply curve intersects the VRR curve is used to create a funding pool by multiplying the price times the quantity at the point of intersection. This applies to the RTO and any Locational Deliverability Areas ("LDA") that separate from the RTO. Additionally, Inframarginal Resources that elected the binding retirement option and did not receive a commitment are identified as "Severance Payment Eligible" ("SPE").

(4) An iterative settlement process is then initiated where:

a. The initial revenue requirement is determined by multiplying the round two clearing price by the round one capacity obligations ("Obligation Requirement") and adding the total SPE revenue requirement, which is determined by subtracting the round two clearing price for each SPE by each SPE's bid price multiplied by its unforced capacity ("SPE Requirement").

b. If the Obligation Requirement plus SPE Requirement exceeds the funding pool – which we believe it will initially due to the slope of the VRR curve – the capacity price is lowered by $0.01 to determine the Adjusted Capacity Payment Price ("ACPP").

c. If an Inframarginal Resource's offer price drops below the ACPP, it is no longer considered inframarginal and is removed from the settlement round and not eligible for a severance payment.

d. The first three steps are repeated, substituting the ACPP for the round two price in the first step until the revenue requirement no longer exceeds the funding pool.

(d) <u>The Commission Should Reject Requests to Implement a CASPR-like Mechanism</u>

The Commission should reject requests by commenters to implement a mechanism similar to ISO New England Inc.'s ("ISO-NE") Competitive Auctions with Sponsored Resources ("CASPR")[15] mechanism. Initially, the CASPR structure was designed to fit the unique circumstances of ISO-NE and does not translate well to the PJM structure. Specifically, it was

[15] Comments of Vistra Energy Corp. and Dynegy Marketing and Trade, LLC, Docket Nos. EL16-49-000, *et al*., at pp. 3, 6-7 (filed October 2, 2018); Initial Arguments of Starwood Energy Group Global, L.L.C., Docket Nos. EL16-49-000, *et al*., at pp. 12-15 (filed October 2, 2018).

designed to accommodate the efficient entry of new resources that do not have existing capacity supply obligations. While the issues underlying the need for the CASPR design are present in PJM, the primary concern in PJM is the retention of existing resources to meet legitimate state public policy objectives.

Unlike the ISO-NE situation, the existing PJM units have already satisfied all necessary requirements to be capacity resources and therefore do not need to buy their way into the markets to become existing resources. Forcing these resources into a substitution auction, where they may or may not get an obligation, is an inefficient methodology to try to establish a competitive price and is likely to thwart state efforts rather than accommodate them.

Moreover, the price established in the first round of the CASPR design is similar to the price that would be established under a repricing mechanism that values subsidized resources at their mitigated levels during the auction step that determines the clearing price. Under this approach, existing resources would have to pay a second time to obtain the status that they already hold, with this "one-time tax" ultimately born by consumers. Unlike PJM's proposal, this approach would not provide the states with the option to satisfy load obligations with the resources that they selected to achieve their desired public policy objectives, so it serves only as a penalty. Given the voluntary nature of the proposed substitution auctions, there is no guarantee that there will be enough resources available and willing to retire to satisfy the objectives of a state. Under these conditions, states may end up supporting the resource mix they choose as well as being forced to procure other resources through the primary auction above and beyond their load and reserve requirements. This approach has the potential to significantly overburden customers in states that pursue or already have secured resources consistent with their jurisdictional rights.

(e) The Commission Should Reject Caps and Other Limitations that Would Thwart the Accommodative Approach Described in the Commission's Order

The Commission's Order recognized the rights of states to support a particular resource mix in order to achieve public policy objectives. Some states have legitimately pursued renewable portfolio standards to attract a specific resource profile while other states have enacted legislation that provides for ZECs in order to achieve environmental objectives. The Commission's Order clearly recognizes and attempts to accommodate these programs by offering a carve-out mechanism to mitigate the impacts of these activities on the markets.

A number of commenters raised concerns that there will be a "rush to the door" by states as they try to protect their favored resources. We believe that states are cognizant of the many benefits they have received from the markets through the years. The creation of an accommodative approach that allows those states to satisfy their objectives will not lead to states undoing markets, rather it can serve as a bridge to a broader objective of reflecting the attributes states are pursuing in those markets. To address these unfounded concerns, LS Power proposed caps and limitations on the amount of state supported resources that should be eligible for a carve-out.[16] The adoption of such provisions would be both arbitrary and unnecessary. LS Power's analysis for determining "a reasonable cap" highlights how arbitrary it would be to determine the appropriate limitation on the number of resources that can be carved-out.[17] Further, even if a state has chosen to provide bilateral payments to resources that offset 100% of their load, no legal basis has been identified to deny them that right.

[16] Initial Brief of LS Power Associates, L.P., Docket Nos. EL16-49-000, *et al*., at pp. 14-19 (filed October 2, 2018).

[17] *Id*., at pp. 16-17.

(f) PJM Should Clarify that Units Receiving Actionable Subsidies Subsequent To The "Self-Certification" Date 150 Days Prior to a Base Residual Auction Are Not Subject to the MOPR

PJM's pro forma tariff specifies that units receiving an Actionable Subsidy must "certify [to PJM] whether or not such Capacity Resource is a Capacity Resource with Actionable Subsidy" 150 days prior to the commencement of a Base Residual Auction ("BRA").[18] The Tariff further states that a resource will retain its status as a Capacity Resource with Actionable Subsidy "unless and until the Capacity Market Seller provides notification of a change in such status or the Office of the Interconnection removes such status . . . ."[19] An additional tariff provision in the same tariff section that addresses the retention of status by a Capacity Resource with Actionable Subsidy provides that "[a]ll Capacity Market Sellers shall have an ongoing obligation to provide notification of any change in status."[20]

Analyzed in context, the PSEG Companies understand the referenced tariff provision requiring Capacity Market Sellers "to provide notification of any change in status" as applicable to situations in which a Capacity Resource with Actionable Subsidy loses its subsidy during the 150 day period prior to a BRA. But they do not read the provision as being applicable to situations in which Capacity Resource that did not have an Actionable Subsidy obtains one during the 150 day period after supplying it self-certification. Stated otherwise, as the PSEG Companies understand the intent of the tariff provision, a Capacity Resource that lacks an Actionable Subsidy at 150 days prior to a BRA but obtains an Actionable Subsidy during the

[18] *See* pro forma Tariff, Attachment DD, section 5.14(h)(iii)(A).

[19] *See* pro forma Tariff, Attachment DD, section 5.14(h)(iii)(B).

[20] *Id.*

ensuing 150 day period retains its status as a Capacity Resource *without* an Actionable Subsidy for the relevant BRA. The Commission should direct PJM to clarify this understanding.

A contrary reading would place Capacity Resources that have not qualified for subsidies by 150 days prior to a BRA, but receive them later in an untenable position. In addition, it would interfere with the ability of the RCO construct to adequately accommodate state policies. If a Capacity Resource that obtained an Actionable Subsidy in close proximity to the BRA, *i.e.*, within the 150 day period, becomes subject to the MOPR as a result, it would lack adequate time as an RCO resource to make necessary arrangements for alternate capacity payment mechanisms. The ability of the state to further the public policy goals associated with the subsidy would thus be thwarted if the affected unit were forced to bid at the MOPR reference price and was unable to clear the market. A "bright-line" standard for units to determine if they will be subject to the MOPR – such as PJM apparently intends – needs to be incorporated into the tariff in order for the Expanded MOPR/RCO construct to be workable. The 150 day cut-off for units to self-certify their status creates a reasonable and defensible standard.[21]

[21] *See Emily's List v. FEC,* 581 F.3d 1, 22 n. 20 (D.C.Cir.2009) ("Agencies generally do not violate the [Administrative Procedures Act's] deferential arbitrary-and-capricious standard when they employ bright-lines rules for reasons of administrative convenience, so long as those rules fall within a zone of reasonableness and are reasonably explained.").

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II. CONCLUSION

If the Commission continues to deem it necessary to adopt the proposal contained in its June 29th Order, the PSEG Companies request that the Commission adopt the Expanded MOPR and PJM's RCO option with the recommended modifications. The PSEG Companies also request that the Commission acknowledge that a transition year may be necessary to accommodate states as the Commission pursues solutions that will facilitate full and appropriate participation in the upcoming RPM auction.

Respectfully submitted,

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Dated: November 6, 2018

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon the official service list in accordance with the requirement of Rule 2010 of the Commission's Rules of Practice.

Dated at Newark, New Jersey, November 6, 2018.

Very truly yours,

Robert Gardinor

Robert Gardinor
Paralegal

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)	Docket No. RM18-1-000

REPLY COMMENTS OF THE PSEG COMPANIES

The PSEG Companies[1] submit these reply comments concerning the Secretary of the United States Department of Energy's ("Secretary") proposed rule ("DOE Proposal")[2] for final action by the Federal Energy Regulatory Commission ("Commission") and in response to the Commission's October 2, 2017 notice inviting comments.[3] As previously explained,[4] the PSEG Companies support the immediate implementation of the DOE Proposal as an interim measure to prevent the premature retirement of fuel-secure baseload units until a permanent market-based solution is developed through the RTO/ISO stakeholder processes.

The PSEG Companies' reply comments include a proposal for a streamlined interim mechanism that could be implemented by the Commission without an onerous administrative burden. The streamlined cost-of-service approach described below and in the attached affidavit of Alan R. Lovinger is intended to counter claims that it would be too onerous for the Commission to direct and thereafter implement a cost-of-service

[1] The PSEG Companies are comprised of Public Service Electric and Gas Company ("PSE&G"), PSEG Power LLC ("PSEG Power") and PSEG Energy Resources & Trade LLC ("PSEG ER&T").

[2] *Grid Resiliency Pricing Rule*, Notice of Proposed Rulemaking, *82 Fed. Reg. 46,940* (October 10, 2017) ("DOE Proposal").

[3] *Grid Reliability and Resilience Pricing,* Notice Inviting Comments, Docket No. RM18-1-000 (October 2, 2017).

[4] *See generally*, Comments of the PSEG Companies, Grid Reliability and Resilience Pricing, Docket No. RM18-1-000 (submitted October 23, 2017) ("PSEG Initial Comments").

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approach. In his testimony, Mr. Lovinger describes a simplified methodology that could be used to set just and reasonable cost-of-service rates through formula rates for eligible baseload generating units.[5] Given the urgent need to preserve fuel-secure baseload resources, we respectfully request that the Commission direct the RTOs/ISOs to modify their tariffs to include an interim mechanism such as the one Mr. Lovinger describes.

In sum, these reply comments show that:

(1) The Commission could implement a streamlined interim cost-of-service mechanism that would result in just and reasonable rates such as the one described by Mr. Lovinger without creating an onerous administrative burden;

(2) Implementing the DOE Proposal as an interim solution will not compromise competitive markets and will provide a lifeline that will prevent economic fuel-secure baseload resources from prematurely retiring while a market-based solution could be developed;

(3) An interim cost-of-service mechanism would be upheld by the courts since it would not be unduly discriminatory, it is in the public interest and certain resources would suffer irreparable harm without it;

(4) Maintaining fuel diversity and fuel security in the generation portfolio through the preservation of nuclear generation is necessary given the national security issues at stake;

(5) Certain RTO/ISO initiatives such as capacity performance and pay-for-performance do not address grid resiliency; and

[5] Reply Comments of the PSEG Companies, Attachment B, Affidavit of Alan R. Lovinger, Grid Reliability and Resilience Pricing, Docket No. RM18-1-000 (submitted November 7, 2017) ("Lovinger Affidavit").

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(6) There is widespread support for Commission action on the outstanding price formation reforms – namely, fast-start pricing[6] and uplift allocation and market transparency[7] reforms – and PJM's proposed energy price formation reform.[8]

I. REPLY COMMENTS

A. The Commission Must Assume a Leadership Role and Promptly Address the Risk of Imminent Retirements of Fuel-Secure Baseload Resources

The PSEG Companies showed in their Initial Comments that there was a compelling need for immediate Commission action to address the risk of imminent retirements of fuel-secure resources. Some commentators have contended, however, that there is not a need for immediate action.[9] Most of these commenters make claims along the lines that system reliability is being adequately met by existing resources and that, to the extent that retirements are occurring, new gas and renewable resources are replacing them. Notably, the RTOs/ISOs believe that there is not currently a problem and that they can judge how to address any future action held under their own time tables. But taking

[6] *Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Notice of Proposed Rulemaking, 157 FERC ¶ 61,213 (December 15, 2016).

[7] *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Notice of Proposed Rulemaking, 158 FERC ¶ 61,047 (January 19, 2017).

[8] PJM Interconnection, L.L.C., Energy Price Formation and Valuing Flexibility (dated June 15, 2017), available at: http://www.pjm.com/~/media/library/reports-notices/special-reports/20170615-energy-market-price-formation.ashx.

[9] Comments of the ISO/RTO Council, Grid Reliability and Resilience Pricing, Docket No. RM18-1-000 at 14 (submitted October 23, 2017); Comments of ISO New England Inc., Grid Reliability and Resilience Pricing, Docket No. RM18-1-000 at 5-8 (submitted October 23, 2017); ExxonMobil Power & Gas Services Inc., Grid Reliability and Resilience Pricing, Docket No. RM18-1-000 at 1-2 (submitted October 23, 2017) (ExxonMobil Comments"); Comments of the Independent Market Monitor for PJM, Grid Reliability and Resilience Pricing, Docket No. RM18-1-000 at 2 (submitted October 23, 2017) ("IMM Comments"); Comments of the Electricity Consumers Resource Council, *et al.,* Grid Reliability and Resiliency Pricing, Docket No. RM18-1-000 at 7-11 (submitted October 23, 2017) ("ELCON Comments"); Comments of LS Power Development, LLC on Notice of Proposed Rulemaking, Grid Reliability and Resiliency Pricing, Docket No. RM18-1-000 at 5-7 (submitted October 23, 2017).

such a wait and see approach would be perilous. The Commission needs to take a leadership role and take decisive action now.

For example, PJM points to a study it released earlier in which it "assessed future likely and plausible generation mix portfolios on their ability to provide certain essential reliability services . . . ."[10] Those "likely and plausible generation mix portfolios" include portfolios in which nuclear generation was as low as 4.5% and coal generation was as low as 8.6%. A finding of the report, moreover, is that PJM could reliably operate its system with as much as 86% natural gas fired generation.[11] While PJM also claims that on-going stakeholder processes are reviewing broader concepts of resiliency, the main focus of these activities is on real-time "operating procedures" such as conservative operations during periods of pipeline contingencies. In sum, it is clear that PJM does not at present perceive a need to preserve the existing fuel diversity of its fleet to meet typical reliability criteria, the processes in which it is currently engaged to address resiliency issues are at best in a fledging state and when (and if) it does address the make-up of the resource mix, a significant portion of the fuel diversity on the PJM system will have already been lost.[12] Like many respondents, these conclusions cloud the issue at hand by mixing traditional RTO reliability concepts with the idea of resiliency. The existing system could likely be planned to achieve the modeled reliability on a single fuel, but

[10] Initial Comments of PJM Interconnection, L.L.C. On the United States Department of Energy Proposed Rule, Grid Reliability and Resilience Pricing, Docket No. RM18-1-000 at 15 (submitted October 23, 2017) ("PJM Comments").

[11] *See* PJM Comments (citing PJM's Evolving Resource Mix and System Reliability (dated March 30, 2017)), available at: http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx).

[12] PJM has presented its "resilience roadmap" to stakeholders, which provides a proposed timeline that indicates that PJM does not intend to take any action to address resilience concerns in the near-term, available at: http://www.pjm.com/~/media/committees-groups/committees/oc/20170606/20170606-item-18-resilience-roadmap.ashx.

nobody would contend that is a resilient system. Our markets are fortunate to have a broad, diverse set of assets today, but as was pointed out, this status is changing quickly and the Commission needs to take the leadership role now.

The Independent Market Monitor for PJM ("IMM") also contends that imminent action by the Commission is not needed.[13] The IMM references its 2017 Quarterly State of the Market Report for PJM ("State of the Market Report") to support the claim that three quarters of nuclear plants are recovering their "going forward" costs.[14] The State of the Market Report identifies operating costs for nuclear plants of $25.83 per MWh for single unit sites and $18.73 per MWh for multi-unit sites and uses these figures as "avoidable costs."[15] Using this data, the IMM draws the conclusion that only about one-quarter of the nuclear units in PJM failed to recover their "avoidable costs" in the past year. In fact, however, these "avoidable cost" values are not realistic estimates of the true costs of operating a nuclear plant. The figures identified by the IMM for avoidable costs come from the Nuclear Energy Institute's ("NEI") 2017 Whitepaper.[16] The following table from the NEI Whitepaper compares the costs between single units and multi-units.

[13] IMM Comments at 2.

[14] Monitoring Analytics, LLC, 2017 Quarterly State of the Market Report for PJM, May 11, 2017, available at: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017q1-som-pjm.pdf.

[15] IMM Comments at 18 (footnote omitted).

[16] Nuclear Energy Institute, Nuclear Costs in Context, August 2017 ("NEI Whitepaper"), available at: https://www.nei.org/CorporateSite/media/filefolder/Policy/Papers/Nuclear-Costs-in-Context.pdf?ext=.pdf. In fact, although the IMM Comments cite to this report as the source for the operating costs data in its comments, as shown in the chart reproduced below, the NEI operating cost value for single site nuclear plants is actually $25.95 /MWh and not $25.83 /MWh.

2016 Cost Summary ($/MWh)

Category	Number of Plants / Sites	Fuel	Capital	Operating	Total Operating (Fuel + Operating)	Total Generating (Fuel + Capital + Operating)
All U.S.	60*	6.76	6.74	20.43	27.19	33.93
Plant Size						
Single-Unit	25	6.77	8.67	25.95	32.72	41.39
Multi-Unit	35	6.75	6.15	18.73	25.48	31.63
Operator						
Single	12	7.18	8.19	21.20	28.38	36.57
Fleet	48	6.63	6.32	20.21	26.84	33.16

**Costs exclude shutdown plants.*
Source: Electric Utility Cost Group (EUCG)

The IMM values thus include only the "operating" costs in its avoidable cost recovery calculations and exclude fuel and capital costs. When those costs are included, the actual cost of running a nuclear plant is approximately 65% - 75% higher. It is not optional (avoidable) to choose not to continue refueling if a plant is to be kept in operation. Likewise, it is not optional to choose not to invest in ongoing capital for a nuclear plant most of which is driven by regulatory, security and safety requirements. These costs must be included when considering whether a nuclear plant is financially viable. It would be both unrealistic and financially irresponsible for an entity not to consider these costs. The IMM's analysis, accordingly, should be rejected. In fact, as shown by the PSEG Companies in another proceeding in which the IMM provided a similar analysis, when adjustments are made to determine a more realistic "avoidable

cost" based on NEI data, *at least three quarters of nuclear plants in PJM did not cover 100 percent of their going forward costs*.[17]

Comments like the ISO/RTO's and the IMM's should not deter the Commission from taking steps to address the urgent issues presented. In particular, the Commission must not shy away from its statutory duties to protect national interests. While the RTOs/ISOs certainly have a role to play, and regional differences should be considered, it is important that the Commission exercise its independent judgment and act before there is additional erosion of fuel diversity in the country's fuel supply portfolio.

B. There Is An Immediate and Urgent Need For the Commission to Take Action

Many commenters who claimed that the DOE Proposal has not been shown to be justified appear to have failed to understand the problem identified. The main issue identified in the DOE Proposal was the risk to the electric grid posed by the loss of generating plants with sufficient quantities of on-site fuel so as to be resilient to disruptions of fuel deliveries – particularly deliveries effectuated by natural gas pipelines. As stated in the DOE Proposal, the purpose of preserving resources with 90-days of on-site fuel is to retain the capacity to "withstand major fuel supply disruptions."[18] Quoting the North American Electric Reliability Corporation ("NERC"), the DOE Proposal states that "[m]any months of on-site fuel allow these units to be operated in a manner

[17] Reply Comments of the PSEG Companies, State Policies and Wholesale Markets Operated by ISO New England, Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C., Docket No. AD17-11-000 (submitted July 14, 2017), available at: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14588093.

[18] DOE Proposal at 1.

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independent of the supply chain disruptions."[19] The Commission should not get distracted from these clearly defined concerns.

First, contentions that the Commission cannot act without the ability to precisely measure the risk addressed or the benefit gained[20] ignore the inherent nature of high impact, low probability events. As the PSEG Companies showed in their initial comments, the risk of an event such as a major prolonged disruption of gas supply obtained from the interstate pipeline system is not amenable to a cost-benefit analysis.[21] A prolonged widespread pipeline disruption is statistically unlikely but, if such an event did occur, clearly would have devastating impacts unless alternate fuel-secure baseload sources were available. In the end, the value of having a fuel diverse generating fleet with meaningful quantities of fuel-secure resources is very real and of critical importance but cannot be precisely determined. Telling the Commission that it cannot act or should not act until a probability-weighted cost-benefit analysis is complete is tantamount to telling the Commission not to act at all.

Second, the fact that preserving fuel-secure generation resources would not address every potential resiliency issue presented is irrelevant. It is correct that nuclear

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[19] *Id.* at 5 (quoting NERC Letter to Secretary of Energy Rick Perry, May 9, 2017, Attachment "Synopsis of NERC Reliability Assessments" at 2).

[20] *See, e.g.*, PJM Comments at 20 ("[T]he next steps for PJM and its stakeholders include defining metrics for resilience . . . ."); Joint Industry Comments Opposing The DOE Proposal, Docket No. RM18-1-000 at 20 (filed October 23, 2017), Attachment A, "Evaluation of the DOE's Proposed Grid Resiliency Pricing Rule," dated October 23, 2017, prepared by The Brattle Group at 10-11, 48-52 ("Brattle Group Evaluation") ("[T]he benefits of resiliency and on-site fuel assurance have not been sufficiently defined or quantified . . . .) (Brattle Group proposes "metric and methods [for analyzing grid resilience that] would . . . permit the examination of economic tradeoffs of such adjustments in a cost-benefit study" and endorses a seven-step "Resilience Analysis Process."); Comments of The American Public Power Association on Proposed Rule, Docket No. RM18-1-000 at 2 (filed October 23, 2017) (stating that "the NOPR does not clearly define what it means by resilience in this context or explain how resilience should be measured.")

[21] PSEG Initial Comments at 13, 29.

and coal generations have certain vulnerabilities and that most loss-of-load events relate to the distribution system.[22] However, that is the point of fuel diversity: avoiding exposure to *single* mode failure risk in recognition of the fact that all technologies have some vulnerabilities. Moreover, the fact there may be other issues to address in order to promote resiliency besides preserving fuel-secure resources does not preclude the Commission from addressing the immediate problem before it.[23]

Ultimately, objections of this ilk are merely distractions from the issue identified in the DOE Proposal: It is clear that our electric grid would be more robust to potentially devastating disruptions of the gas supply system if we preserve a reasonable level of fuel-secure resources as part of the generation fleet and the Commission does not need precise "metrics" to determine that is true. Given the undeniable erosion that has occurred in the fuel-secure baseload resources to date and which threatens to continue absent positive action to prevent it, the Commission has compelling grounds upon which to take immediate action in order to address this looming risk.

[22] *See e.g.,* PJM Comments at 11 (quoting DOE Staff Report noting that, during the Polar Vortex, "[m]any coal plants could not operate due to conveyor belts and coal piles freezing."); APPA Comments, at 10 ("[C]oal and nuclear plants can face challenges of their own during extreme weather events."); Comments By Amory B. Lovins, Cofounder And Chief Scientist, Rocky Mountain Institute, Docket No. RM18-1-000 at 7 (filed October 23, 2017 ("[T]he NOPR says and does nothing about the brittle grid connecting power plants to customers . . .")); Brattle Group Evaluation at 16 ("Brattle Group analyses have found that 99% of customers' loss of power in typical utility service territories is due to distribution system disruptions.").

[23] *See Mobil Oil Exploration & Producing Southeast Inc. v. United Dist. Co.*, 498 U.S. 211, 231 (1991) ("[A]n agency need not solve every problem before it in the same proceeding").

C. Competitive Markets Will Not Be Compromised by an Interim Cost-of-Service Payment Mechanism

1. The DOE NOPR Will Correct Market Distortions

A number of parties contend that the DOE Proposal would have substantial negative impacts on competitive markets.[24] These arguments fail to recognize that in order for the competitive markets to continue producing efficient outcomes, they must evolve to align with public policy objectives. To this point, the PSEG Companies agree that, to date, the competitive markets have produced "tangible benefits for American consumers and the American economy."[25] However, time has revealed that the competitive markets are not operating in an efficient manner, resulting in the loss of fuel diversity and fuel security. As a consequence, consumers are now exposed to a greater risk of catastrophic losses due to low probability, high impact events. As Dr. Makovich explained, the lack of harmony between market operations and public policies such as those mandating renewable technologies are creating market distortions that are preventing the wholesale electricity market from generating the right price signals.[26] Dr. Makovich states that:

> As a result, the distorted market price signals do not shape a cost effective supply portfolio. In particular, public policies that mandate and subsidize intermittent renewable technologies are neither fuel nor technology neutral policy approaches and therefore result in inefficient market outcomes whenever mandates of subsidized intermittent renewables result in a greater wind and solar generation shares than are cost effective. In organized

[24] ExxonMobil Comments at 1-2; Initial Comments of the Electric Power Supply Association, Grid Reliability and Resilience Pricing, Docket No. RM18-1-000 at 51-53 (submitted October 23, 2017) ("EPSA Comments"); PJM Power Providers Group, Grid Reliability and Resilience Pricing, Docket No. RM18-1-000 at 4-6 (submitted October 23, 2017) ("P3 Comments").

[25] EPSA Comments at 19.

[26] Makovich Affidavit at 4.

> electricity markets, this inefficient market outcome suppresses wholesale electric energy prices. This is an "imposed" missing money problem for competitive generators."[27]

The market distortions described by Dr. Makovich are heavily impacting baseload generators and causing their premature retirement. This is resulting in a trend where the resiliency in the U.S. supply portfolio is eroding to the point that immediate action must be taken to stop additional premature retirements of fuel-secure baseload resources. Currently, these resources are relying on revenue streams from markets that many commenters agree are flawed and must be fixed.[28] Thus, the best solution to resolve the issues that are causing the current market distortions would be to develop a market-based solution that would value "external" costs such as those associated with the loss of fuel diversity and fuel security that the current market construct completely ignores.

Under a market-design that takes account of "external costs," fuel-secure baseload generation would be highly valued. More specifically, in a properly designed market that values resiliency, fuel diversity, fuel security and carbon abatement, nuclear baseload generation would receive higher revenues. Therefore, nuclear resources, if valued properly, would be economic. According to Dr. Makovich "an economic argument exists to support public policies that provide support to these nuclear resources through compensation for resilience attributes that these resources provide to the power supply portfolio and move the current distorted market outcome toward the results in an effective competitive marketplace."[29] Accordingly, economic fuel-secure baseload resources such as nuclear should not be forced to succumb to early retirements simply

[27] *Id.*

[28] EPSA Comments at 2; ELCON Comments at 6, 11.

[29] Makovich Affidavit at 6.

because the current competitive markets are distorted and the process to determine a market-based solution to fix these distortions may require a significant amount of time.

Therefore, it is appropriate to provide a lifeline to fuel-secure baseload resources through the interim cost-of-service mechanism proposed in this filing. This will prevent the retirement of valuable resources until they can be properly valued through a market-based solution.

2. Competition In Energy Markets Can Be Preserved by Requiring Units That Receive Cost-of-Service Payments to Bid at The Level of Their Marginal Costs and Consistently with Their Approved Operational Parameters

Some commenters contend that making cost-of-service payments to plants that qualify under the DOE Proposal will result in those plants engaging in behavior in the energy market that will have deleterious impacts on efficient price formation. They contend, in particular, that units receiving cost-of-service payments will increase their run-times beyond what would occur in a competitive market and thus cause price suppression. While the extent of the issue presented is not clear, the PSEG Companies submit that any such concerns can be addressed by specifying bidding procedures for the day-ahead and real-time energy markets. Specifically, units receiving cost-of-service payments should be required to submit energy market bids at their marginal costs and consistently with unit operating parameters approved by the ISO/RTO or market monitor in the region.

It is extremely well-settled that marginal cost bids in the energy market are consistent with bidding behavior expected in a competitive market. As stated by the Commission for PJM:

> Under PJM's LMP pricing system, all generators that lack market power have an incentive to submit bids at their marginal costs, because any price above marginal cost will generate sufficient revenue to cover the unit's operating costs and contribute to the recovery of the unit's fixed costs. This is the same incentive that exists in a competitive market, where competitors are expected to produce at the point where prices exceed their short-run marginal costs.[30]

In PJM, FERC also followed this practice in connection with Reliability Must Run ("RMR") agreements. Thus, in *PSEG Energy Resources & Trading, LLC,* the Commission noted that "the [RMR] tariff [ultimately approved] provides that PSEG will not delist the units as capacity resources and that each unit will be bid into the day-ahead and the real time PJM Energy Exchange Markets at rates equal to their cost-based bids as determined by PJM."[31]

In *NYISO,* the Commission affirmed that "in a competitive market, a generator lacking market power would be expected to submit bids . . . at a level that . . . would be expected to cover the generator's marginal costs."[32] The Commission also found its expectation of marginal cost bidding in the energy market was "consistent with precedent" and independent of concerns about how fixed costs would be recovered.[33]

In CAISO, the Commission explained that "marginal cost pricing generally reflects the prices that would be bid into an auction by generators in a competitive

[30] *PJM Interconnection, LLC*, 110 FERC ¶ 61,053 P 25 (2005).

[31] *PSEG Energy Resources & Trading, LLC, et al.,* 111 FERC ¶ 61,121 P 11 (2005).

[32] *N.Y. Indep. Sys. Operator, Inc.*, 131 FERC ¶ 61,169 P 73 (2010), *reh'g denied*, 139 FERC ¶ 61,001 (2012).

[33] *N.Y. Indep. Sys. Operator, Inc.,* 139 FERC ¶ 61,001 PP 42-44 (finding that concerns about fixed cost recovery should be addressed by means other than "bids [that] significantly exceed a bid expected in a competitive market [] that is, at marginal cost.").

market."[34] The Commission has affirmed this concept again and again in CAISO, most recently in January 2017.[35] Similarly, in ISO-NE, the Commission approved a mitigation plan because it was a "reasonable means of obtaining a rough estimate of competitive bids (which would ordinarily reflect the bidder's marginal cost)."[36] Further, in connection with an RMR filing, the Commission stated that "[u]nder RMR agreements, generators submit stipulated marginal operating cost bids and receive a cost-based revenue guarantee that is offset by energy market revenues earned."[37]

Requiring units receiving cost-of-service payments to bid at their marginal costs is thus an appropriate measure to assure that energy markets remain competitive. In addition, in some regions, such as PJM, marginal-cost bids already are routinely calculated by all market participants and submitted to the RTO as reference prices. However, even when that is not the case, they are reasonably calculable under a methodology such as the one used by PJM and the bids could be verified by RTO/ISO staff if deemed necessary.

In addition, units receiving cost-of-service payments should be required to submit energy market bids consistent with their approved operating parameters such as start-up times, ramp rates and minimum run times. This requirement will also help assure efficient price formation outcomes.[38]

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[34] *San Diego Gas & Elec. Co. v. Sellers*, 95 FERC ¶ 61,115 at 61,363 (2001).

[35] *See San Diego Gas & Elec. Co. v. Sellers*, 158 FERC ¶ 61,076 P 44 (2017) (affirming "that the marginal cost-based proxy methodology" is "a credible proxy of prices in a normal competitive environment").

[36] *New England Power Pool*, 85 FERC ¶ 61,379 at 62,482 (1998).

[37] *Bridgeport Energy, LLC*, 113 FERC ¶ 61,311 P 27 (2005).

[38] *See PJM Interconnection, L.L.C.*, 151 FER 61,208 P 433 (2015) (Commission finding that units should "reflect their current, actual operating capabilities" in bids to produce efficient prices).

D. An Interim Cost-of-Service Measure Is Not Discriminatory and is Consistent with the Public Interest

A number of parties contend that the DOE Proposal should be rejected on the grounds that it provides "discriminatory compensation in favor of a preferred set of generation resources," specifically, for certain coal and nuclear resources located within RTOs and ISOs with energy and capacity markets.[39] However, "discrimination" is not prohibited by the Federal Power Act; only when discrimination is "undue" does it run afoul of the statute. These critics fail to acknowledge that the DOE Proposal is intended to address the risk to the electric grid and to the citizens of our country as the generation supplier portfolio becomes overly reliant on a single fuel source. The DOE Proposal, therefore, correctly focuses on the resources that are being most heavily impacted by the deficiencies in the current competitive market design even though they supply valuable resiliency attributes. Discrimination among resource types is fully justified given the problem being addressed in this matter. Unless the Commission takes immediate steps through an interim measure to prevent fuel-secure baseload resources from prematurely retiring, those resources and the public they serve will suffer irreparable harm.

As discussed in the PSEG Initial Comments, there is Commission-precedent supporting a temporary program (i.e., the Winter Reliability Program) that allowed only a limited set of resources to participate on the grounds that the program was needed to address urgent circumstances until a long-term solution could be developed.[40] Moreover, the discretion of agencies to establish appropriate relief through interim rules while they

[39] Joint Industry Comments Opposing the DOE Proposal, Grid Reliability and Resilience Pricing, Docket No. RM18-1-000 at 1, 5 (submitted October 23, 2017) ("Joint Industry Comments"); ExxonMobil Comments at 1-2; P3 Comments at 7-9.

[40] PSEG Initial Comments at 15-16.

are engaged with stakeholders in a rulemaking has been upheld by the courts, particularly where there has been a demonstration of irreparable harm.[41] In *Mid-Tex Elec. Co-op., Inc. v. FERC*, 822 F.2d 1123 (D.C. Cir. 1987), the U.S. Court of Appeals for the D.C. Circuit ("D.C. Circuit") upheld the Commission's authority to put in place an interim rule without notice or comment procedures while the Commission evaluated a permanent solution, noting that it was "necessary or proper to provide a regulation prior to completing its full consideration."[42] The D.C. Circuit found that the "irremedial financial consequences" supported allowing the interim rule to remain.[43] *Id.* This is precisely the remedy we believe is appropriate here

In a separate case, *Arizona Elec. Power Co-op., Inc. v. FERC*, 631 F.2d 802 (D.C. Cir. 1980, the D.C. Circuit explained that in fashioning a remedy, the Commission has an obligation to consider the general public interest. The *Arizona Elec. Power* case concerned temporary measures that the Commission approved in order to address gas shortages in the winter months and ensure that customers in California received adequate supplies of gas. The D. C. Circuit applied a highly deferential standard in evaluating whether the Commission's actions were appropriate and explained that "it is not the role of the courts to second guess the Commission's judgment because we think we could

[41] *Rural Cellular Ass'n v. FCC*, 588 F.3d 1095, 1105 (D.C. Cir. 2009) (In upholding the temporary regulation, the Court emphasized the "irreparable harm to the [universal service fund] and the telecommunications markets generally that might result from waiting until comprehensive reform, which is often complex and difficult to achieve, was adopted. Courts, including this one, have deferred to the Commission's decisions to enact interim rules based on its predictive judgment that such rules were necessary to preserve universal service").

[42] *Id.* at 1131-32. After the D.C. Circuit vacated portions of a Commission rule and remanded an issue concerning a utility's ability to include a portion of its construction work-in-progress ("CWIP") costs in rate base, the Commission promulgated an interim rule that did "not change the substance of the general provision of the [vacated] CWIP rule." *Id.* at 1124.

[43] *Id.*

devise a better solution than that which the agency has adopted so long as the agency's determination has a rational basis."[44]

Under the theories applied in these cases, it is clear that an interim cost-of-service solution as suggested by the PSEG Companies would be upheld by the courts as an appropriate remedy to address the urgent issues facing at risk fuel-secure baseload resources. First, preserving fuel-secure baseload resources is in the public interest. Specifically, maintaining fuel diversity and fuel security in the nation's electric grid is a matter of national security. As Mr. Carl explains in his attached affidavit, nuclear power plants are well-equipped to withstand new threats to our power plants.[45] Nuclear plants are already hardened against risks and have been designed to ensure safety and security. In addition, the erosion of resiliency in the electric grid increases the likelihood that consumers would be exposed to high impact, low frequency events.[46] As Dr. Makovich's Affidavit demonstrates, the loss of nuclear units would significantly increase costs to consumers.[47] Second, without an interim measure, there is a strong likelihood that fuel-secure baseload resources would prematurely retire and, in many cases, be unable to reopen. In these circumstances, both fuel-secure baseload resources and consumers would sustain irreparable harm. Finally, as the courts have made clear, the Commission

[44] *Arizona Elec. Power Co-op., Inc. v. FERC*, 631 F.2d 802, 808 (D.C. Cir. 1980).

[45] Reply Comments of the PSEG Companies, Attachment A, Affidavit of Jeremy C. Carl, Grid Reliability and Resilience Pricing at 9-11, Docket No. RM18-1-000 (submitted November 7, 2017) ("Carl Affidavit").

[46] Dr. Makovich analyzed the outcome if the 2014 Polar Vortex took place under today's PJM electric supply portfolio. He calculated the cost of such an outage to be around $1.2 billion. *See* PSEG Initial Comments at 8-9 (citing Makovich Affidavit at 11). Dr. Makovich further determined that if the 2014 Polar Vortex took place and plants in PJM now being evaluated for premature closure – Perry and Davis Besse – were no longer available, the expected cost of the Polar Vortex-induced outage would be around $3.7 billion. *Id.*

[47] Makovich Affidavit at 16-17.

has broad remedial powers to fashion appropriate remedies, particularly where there is an urgent need to protect consumers.[48]

E. Maintaining Diversity and Fuel Security in the Generation Portfolio Through the Preservation of Nuclear Generation is Needed for National Security

The DOE Proposal emphasizes the important role that grid resiliency plays in our national security and the welfare of American citizens. It specifically states that: "[o]ur economy, government and national defense all depend on electricity. Therefore, ensuring a reliable and resilient electric supply and corresponding supply chain are vital to national security."[49] However, as Dr. Makovich explains, the distortions in the current markets designs are heavily impacting fuel-secure baseload resources and leading to their premature retirement. As discussed in his attached affidavit, Mr. Carl also believes that today's "highly regulated market" has been manipulated in ways that "have been profoundly damaging to nuclear's competitiveness."[50] Mr. Carl further explains that:

> Perhaps the biggest unmeasured value of nuclear is its contribution to our national security. It cannot be stressed enough that unlike any other form of energy, the nuclear enterprise has fundamental non-energy related security attributes that justify additional support in the market.[51]

Moreover, nuclear plants have the ability to maintain more on-site fuel than any other form of energy, which is particularly valuable in the event of a long-term emergency situation or an interruption to fuel supplies to other generators. Nuclear resources have

[48] *See Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 159 (D.C.Cir.1967).

[49] DOE Proposal at 2.

[50] Carl Affidavit at 8.

[51] *Id.*

also been designed to withstand many of the new types of threats to power plants such as cyber security attacks or terrorism.

The decline in the United States' nuclear technology capabilities due to a lack of domestic plant manufacturing also impacts the advantages and leverage we have previously enjoyed in the area of non-proliferation. Mr. Carl explains that the:

> United States has lost several bids on nuclear power projects in the Middle East to Russia, in no small part because of our degraded capacity in this area. The closure of additional nuclear plants degrades our already fragile capabilities while empowering geopolitical rivals such as Russia and China.[52]

Mr. Carl notes that as the nuclear capability in the United States declines the rest of the world continues to invest in nuclear generation, particularly China, where nuclear power generation has almost tripled in the last decade.[53]

Mr. Carl explains that even though nuclear power plants' technology is distinct in many ways from nuclear weapons, you cannot divorce the two when it comes to our national security interests. The reactors that power our nuclear navy – almost 100 submarines and aircraft carriers – run on technology virtually identical to that powering our civilian reactors. Therefore, "[l]osing the technology and operating experience through the atrophy of our domestic nuclear-power sector would mean a profound loss of capability in our military."[54] Given the important role nuclear generation plays in our national security and the resiliency of the electric system, Mr. Carl believes that "[p]utting these units at risk because of short-run market signals and the failure of [the RTO/ISO] markets to adequately value all of the units' attributes is a deficiency that

[52] *Id.* at 12.

[53] *Id.*

[54] *Id.* at 15.

requires immediate attention and action."[55] Finally, Mr. Carl notes that the DOE Proposal provides an opportunity for the federal government to address and preserve the fundamental role that a robust nuclear energy sector has in meeting national security imperatives.[56]

F. Initiatives Such as Capacity Performance and Pay-For-Performance Do Not Sufficiently Address Resiliency Issues

Some commenters contend that the actions identified in the DOE NOPR are not needed because RTOs/ISOs already have mechanisms in place to address resiliency concerns. They point to the "Capacity Performance" mechanism in PJM and the "Pay-For-Performance" mechanism in ISO-NE as examples. These comments, however, miss the mark: the issues identified in the DOE Proposal are different than the intended scope of the existing RTO/ISO programs.

The concern targeted by the DOE Proposal was never intended to be addressed and is not addressed by programs such as PJM's "Capacity Performance" initiative or ISO-NE's "Pay-for-Performance" initiative. These programs have had an impact on incentivizing actions to make generators more resilient to short-term emergencies, including upgrades to gas-fired generators to withstand short-term disruptions in gas deliveries. In particular, they have driven improvements that increase system resilience to certain extreme weather events. But they do not address the risk of extended emergencies affecting fuel deliveries identified in the DOE Proposal, particularly of gas pipeline deliveries. As noted by the Commission in approving the PJM Capacity Performance mechanism, PJM characterized its initiative as an alternative to

[55] *Id.*

[56] *Id.* at 9.

"establishing prescriptive eligibility requirements such as delineating acceptable fuel transportation arrangements, storage requirements for dual fuel capable units, or weatherization requirements."[57] Enhancements of this type, however, will not address the problem that the DOE Proposal is seeking to remedy.

The reference to "acceptable fuel transportation arrangements" is primarily directed to the firmness of gas delivery supplies.[58] The existence of firm pipeline delivery arrangements will not assure gas deliveries, however, when the pipeline is physically impaired from operating. As shown in our initial comments, pipeline repairs and testing can take months to complete.[59] Moreover, some of the most notable contingencies that the DOE Proposal is designed to address – such as a pipeline explosion or terrorist attack – would likely excuse performance under the *force majeure* provision of firm service tariffs maintained by the pipelines. Similarly, events that could disrupt the availability of gas supplies – such as regulatory action restricting fracking – would be expected to excuse performance under gas supply arrangements pursuant to the *force majeure* or "change of law" provisions of those agreements. Incentives designed to cause gas-fired generators to enter into more firm supply arrangements therefore do not obviate the need for the NOPR Proposal.

Similarly, the incentives supplied by Capacity Performance intended to promote investments in "dual-fuel capable units" will only address short-term emergencies. As

[57] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 P 51 (2015).

[58] *See PJM Interconnection, L.L.C., et al*, 151 FERC ¶ 61,208 P 46 (2015) (Commission noting that "current tariff does not allow sellers to include in their sell offers costs attributable to means of securing reliable fuel, such as natural gas firm transportation arrangements . . . . PJM asserts that the deficiencies in its existing rules, in this regard, will only be exacerbated if they remain in effect as additional natural gas-fired resources come on line.").

[59] PSEG Initial Comments at 9-10, 17-18.

explicitly required in the original Capacity Performance mechanism initially proposed by PJM "[a] generator must have on-site fuel (or dual-fuel backup capability) for at least 16 hours of continuous operation per day for three consecutive days at an output equal to its quantity of committed Installed Capacity."[60] While an on-site three day fuel source would be adequate to address some types of emergencies, it would not be sufficient to ensure operations over an extended gas supply disruption of the type that the DOE Proposal is designed to address. Finally, improvements in "weatherization" of individual generating plants clearly could not address many types of long-term fuel disruptions and, in particular, could not address the vulnerabilities of the interstate pipeline system or gas production areas.

Capacity Performance and Pay-For-Performance also fall short of addressing the concern identified in the DOE NOPR because they do not address the national security aspects of resiliency. As discussed elsewhere in the PSEG Companies' comments, a diverse portfolio of generating resources including, in particular, nuclear generation makes a significant contribution to our national security. The incentives created by the Capacity Performance and Pay-for-Performance programs do not, however, foster investments to achieve that goal. The DOE Proposal, in contrast, provides an opportunity to recognize the value of this aspect of a fuel diverse generating portfolio.

G. Streamlined Cost-of-Service Mechanism

Certain commentators have claimed that the adoption of a cost-of-service rate mechanism such as set forth in the DOE Proposal would impose an onerous

[60] PJM Staff Proposal, PJM Capacity Performance Proposal, August 20, 2014, available at: http://www.pjm.com/~/media/committees-groups/committees/elc/20140822/20140822-pjm-capacity-performance-proposal.ashx.

administrative burden on the Commission.[61] The PSEG Companies submit that these allegations are greatly overstated. They appear to assume that virtually every coal and nuclear plant in the regions covered by the organized markets would be eligible for cost-of-service payments, which is not realistic.[62] Moreover, the Commission could adopt streamlined procedures for setting cost-of-service rates that would greatly reduce the administrative burden and yet still yield rates consistent with the FPA's just and reasonable standard. The adoption of a streamlined approach would be particularly appropriate under the PSEG Companies' proposal for interim cost-of-service rates until a market-based approach for valuing resiliency can be developed.

The PSEG Companies have retained a consultant – Mr. Alan R. Lovinger – with extensive experience in cost-of-service rate proceedings before the Commission to develop a streamlined procedure that could be used to set rates for nuclear and coal units that are eligible for payments under the DOE Proposal. Mr. Lovinger's affidavit is included as an exhibit to our comments. As explained by Mr. Lovinger, the "mechanism described will maintain FERC's cost-based and original cost principles" but will "resolve up-front those rate issues that require . . . time consuming efforts to resolve and often cause protracted litigation."[63] Mr. Lovinger proposes that applicants would submit standardized data in a "template format includ[ing]: the cost of return on equity and debt as well as the makeup of an appropriate capitalization structure, depreciation and amortization expense, allocation of overhead, and the eligible plant investment included

[61] Brattle Group Evaluation at 25 (stating that "we anticipate that more than 300 generating units would likely be eligible and [setting rates] would require extensive FERC Staff review ….").

[62] *See, e.g.*, Comments of American Electric Power Company, Inc., Docket No. RM18-1-00 at 6 (submitted October 23, 2017) ("Many coal units do not store 90 days of coal, or even have the capability to store that much coal due to space constraints and safety concerns.").

[63] Lovinger Affidavit at 2.

in rate base."[64] The streamlined methodologies recommended by Mr. Lovinger "have been widely used in various electric and gas transmission rate proceedings before the Commission, thereby establishing precedents in such venues."[65] He further notes that his "proposals . . . should streamline both the applicants' rate filings and the resolution of those filings at FERC."[66] He also suggests that "the template currently used by the Commission to set formula rates for transmission providers may be a useful foundation, both in structure and instructions, for creating a NOPR template."[67]

Mr. Lovinger's proposal recognizes the reality that most, if not all, of the plants that would be eligible for cost-of-service payments under the DOE Proposal were at some point in time transferred from traditional utilities to merchant generating companies. In most cases, the original costs of constructing the plants 30 or 40 years ago are fully depreciated or have been written down. He thus recommends two elements for the cost-of-service determination to adequately capture costs and operational risks: (1) a typical (but streamlined) cost-of-service determination based on the current costs of operating the plant, plus the recovery of the cost of capital, including a return of equity, determined from a rate base consisting of plant additions made after the plant was transferred from a traditional utility;[68] and (2) a management fee based on a fraction of the original cost in order to reflect the operational risks associated with owning and managing the transferred facilities plus account for any rate base that may not have been fully recovered

[64] *Id.* at 2-3.

[65] *Id.* at 3.

[66] *Id.*

[67] *Id.*

[68] *Id.* at 3-4.

subsequent to the asset transfer.[69] Mr. Lovinger identifies specific approaches consistent with Commission precedent that could be applied in a mechanical manner for determining capital structure, return on equity, accumulated depreciation, accumulated deferred income taxes, allocations of operating and maintenance costs, depreciation expenses and other elements used in a cost of service calculation.

Because the template approach would provide a means for applicants to mechanically populate a pre-approved formula for determining a units' cost of service, the resultant rate would automatically satisfy the just and reasonable standard upon the Commission's determination that the template was complete. The template filing thus would be for information purposes only but could be challenged by intervenors under FPA Section 206. This approach would be fully consistent with Commission precedent.

For example, in *Public Utilities Comm'n of State of California v. FERC*, 254 F.3d 250 (D.C. Cir. 2001) the Court upheld a formula rate for RMR payments under the CAISO tariff. The Court rejected claims that RMR contracts whose costs would be passed through to non-jurisdictional entities had to be filed under FPA Section 205. As explained there, "[w]hen the Commission accepts a formula rate as a filed rate, it grants waiver of the filing and notice requirements of [§ 205] [, and] [t]he utility's rates, then, can change repeatedly, without notice to the Commission, *provided* those changes are

[69] *Id.* at 4-6; *See, e.g., High Island Offshore Sys., L.L.C.*, 110 FERC ¶ 61,043 PP 107, 115 (2005) (Commission approving management fee for fully depreciated assets equal to the overall rate of return of 9.60 percent multiplied by 10 percent of the modified average rate base which the Commission determined was adequate "to compensate HIOS' owners for the risks of continuing to operate the pipeline."), *remanded on other grounds, Petal Gas Storage, L.L.C. v. FERC*, 496 F.3d 695 (D.C. Cir. 2007); *Tarpon Transmission Co.*, 57 FERC ¶ 61,371 at 62,239-41 (1991) (Commission approving management fee for fully depreciated assets by applying the pretax cost of capital to 10 percent of the pipeline's historical average rate base "to compensate Tarpon's owners for the risks of continuing to operate the pipeline and to provide an incentive for efficient operations."). A fee of this type would appropriately reflect operational risks associated with elements of gross plant whose costs are not reflected in the current rate base.

consistent with the formula."[70] Indeed, as observed by the Court "[i]t can hardly be doubted at this late date [in 2001] that the Commission need not confine rates to specific, absolute numbers but may approve a tariff containing a rate 'formula' or a rate 'rule'...."[71] Finally, the Court noted that "[i]n approving formula rates, the Commission has relied on § 206 as a mechanism to ensure that the rates are just and reasonable, and its reliance on § 206 has survived judicial scrutiny."[72]

As the Commission itself has explained "with formula rates, the specific formula itself is the rate, not the particular components of the formula."[73] Further, *Transwestern Pipeline Co. v. FERC*, 897 F.2d 570 (D.C. Cir. 1990), confirms that the Commission's express adoption of a formula, indicating when it will take effect, provides sufficient notice of the rate to ratepayers, notwithstanding the lack of numerical specificity until the components of the formula are added.[74] Because the elements of the cost-of-service rate as proposed by Mr. Lovinger could be calculated in a mechanical fashion, the formula rate approach would be appropriate here until a market-based mechanism for valuing resiliency is developed.

H. There Is Widespread Support for the Commission to Continue Its Energy Price Formation Efforts

The PSEG Companies are encouraged that there appears to be widespread support among the commenters in this proceeding for the Commission to continue pushing

[70] 254 F.3d at 254 (internal punctuation and citations omitted).

[71] *Id.* (citations omitted).

[72] *Id.* at 257 (internal punctuation and citations omitted).

[73] *Ocean State Power II*, 69 FERC ¶ 61,146 at 61,544 (1994)

[74] *Transwestern*, 897 F.2d at 578 (discussing *Electrical District No. 1 v. FERC*, 774 F.2d 490 (D.C. Cir. 1985))

forward with efforts to improve energy price formation.[75] The PSEG Companies, therefore, reiterate their request here for the Commission to finalize the pending price formation reforms (*i.e.,* uplift cost allocation and transparency and fast-start pricing reforms)[76] and to issue a directive to PJM for the submittal of its proposal to allow marginal units to set price at any point in their operating range so that it can be evaluated. Our position is supported by PJM's Comments. Specifically, PJM states that there are particular price formation reforms that are eligible for "prompt remedy" in the PJM region.[77] PJM further explains that it "has not yet adopted the level of reforms as other regions with respect to fast-start pricing. Other regions have already experienced the benefit of more flexible pricing methods whereas PJM has yet to make similar enhancements."[78] Therefore, because "PJM does not have many units that meet the FERC definition of 'fast-start' the universe of resources that can qualify as "fast-start" should be broadened in PJM to account for the composition of PJM's fleet."[79] Dr. Hogan also supports PJM's enhanced price formation proposal "to reform the existing pricing model in order to ensure that the incremental cost of serving load is reflected in LMP to the fullest extent possible, uplift is reduced and incentives are maintained."[80] According to Dr. Hogan, "PJM's proposal to implement integer relaxation is a beneficial and

[75] ELCON Comments at 6, 11; Comments of Edison Electric Institute, Grid Reliability and Resiliency Pricing, Docket No. RM18-1-000 at 4-5(submitted October 23, 2017); Comments of the PJM Power Providers Group, Grid Reliability and Resiliency Pricing, Docket No. RM18-1-000 at 9-14 (submitted October 23, 2017); Comments of Exelon Corporation, Grid Reliability and Resiliency Pricing, Docket No. RM18-1-000 at 6, 9-22 (submitted October 23, 2017).

[76] *See supra* at n.6&7.

[77] PJM Comments at 39.

[78] *Id.* at 40.

[79] *Id.* at 40-41.

[80] PJM Comments, Appendix B, Letter to Stu Bresler from William Hogan, at 1.

essential first step toward solving the bigger issue of a more comprehensive enhancement of energy and reserve price formation."[81]

Given that the PJM Comments have explained in detail the issues that need to be addressed – "circumstances where prices could fail to reflect all elements relevant to sending the right market signals"[82] – and Dr. Hogan has explained that PJM's proposal is an appropriate step to addressing needed price formation reforms in the PJM market, the Commission should direct PJM to submit its energy price reform proposal without delay so that it can be fully evaluated by the Commission.

Further, both PJM and the IMM raised several other critical areas of reform that were aligned with the PSEG Initial Comments. Specifically, refinements to the scarcity pricing mechanism and enhanced reserve modeling are critical components to the efficient functioning of the markets. Therefore, we believe that the Commission should direct reforms in these areas.[83]

II. CONCLUSION

The PSEG Companies believe that the DOE Proposal has brought to the forefront important concerns regarding the resilience of the Nation's electric grid that require immediate action. We are encouraged by the industry's engagement in this proceeding and believe that a permanent market-based solution could be developed through each region's stakeholder processes. However, the Commission is very aware of the timing issues associated with gaining consensus and implementing a complex set of solutions, even ones that appear to have the broad support. Therefore, we reiterate that the prudent

[81] *Id.* at 3.

[82] PJM Comments at 45.

[83] PSEG Initial Comment at 28.

and proper course of action is to implement the DOE Proposal immediately as an interim solution before further damage is done to the resilience of the electric grid. This should be accompanied by an order directing the RTOs/ISOs to investigate issues unique to their regions, develop viable market-based solutions and submit those solutions to the Commission by a specific date for full evaluation.

Respectfully submitted,

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Dated: November 7, 2017
Newark, New Jersey

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ATTACHMENT A

AFFIDAVIT OF JEREMY C. CARL

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)	Docket No. RM18-1-000

AFFIDAVIT OF
JEREMY C. CARL

My name is Jeremy C. Carl and I am a research fellow at the Hoover Institution ("Hoover") at Stanford University.

In my role at Hoover, I am the Executive Director of the Shultz-Stephenson Task Force on Energy Policy at Stanford University, and Co-Executive Director of the Hacking for Defense Program's new energy initiative at Stanford. As such, I have direct experience with both energy policy and how it relates to our security and the environment. I have a B.A. from Yale University, a Master in Public Administration from the Kennedy School of Government at Harvard University, focusing on energy policy, and did further graduate work in energy policy at Stanford University.

I have written extensively about grid reliability and resiliency, and have published a number of papers advocating for reform of state and national electricity policy.

I provide this affidavit in support of the PSEG Companies' reply comments in this proceeding on the Secretary of the Department of Energy's Notice of Proposed Rulemaking ("NOPR") for final action by the Federal Energy Regulatory Commission ("FERC" or "Commission").

The purpose of this affidavit is to address issues raised in this proceeding concerning resiliency and the need for federal policymakers to take affirmative action on

this NOPR. Specifically, I will describe how nuclear units affect grid reliability and resilience, U.S. security and economic growth, and non-proliferation interests.

I. THE CURRENT ENVIRONMENT FOR NUCLEAR

There are currently four primary factors driving the decline of the existing nuclear fleet, which I have at times referred to as the "four horsemen of the apocalypse." These four factors facing America's nuclear power sector in the current regulatory environment are:

1. Naturally and artificially depressed wholesale electricity prices in deregulated states.
2. A failure in our markets to recognize and value the unique attributes nuclear resources provide.
3. A trend of higher nuclear generation costs in older, smaller nuclear power plants and in nuclear plants requiring major refurbishment or upgrades. This trend is exacerbated by a period of general operational and regulatory cost increases that have affected all plants.
4. Increasingly effective antinuclear advocacy efforts by both those who dislike nuclear power and those who see nuclear power as competition for their own favored forms of power generation.

It is important to note that the current pressure on our nuclear fleet is largely a result of being squeezed like a vice on one side by fossil fuel plants whose emissions are not factored into their pricing, and subsidized renewables, which reflect the subsidies in their market offers. This has led to negative prices in a significant number of hours (and very low prices in others), distorting the economics for baseload resources such as nuclear units.

II. THE VALUE OF NUCLEAR IN TODAY'S GRID AND WHY THE CURRENT MARKET UNDERVALUES IT

In the remainder of this affidavit, I will explain the critical aspects of maintaining nuclear power as a vital part of our electric grid. The security and resilience aspects include:

1) The new evolving threats facing the system today, particularly terrorism and cyber-security.
2) The ways in which current nuclear unit retirements (America has lost 5 nuclear plants since 2013 and have just 61 plants remaining representing 99 reactors) are negatively impacting overall system resilience and increasing our risk exposure to extreme events.

A. RECENT NUCLEAR POWER PLANT CLOSURES[1]

- Crystal River 3 (Florida), decommissioning began in 2013 *Reactor had been licensed to 2016.*
- Fort Calhoun (Nebraska), 2016 - *Reactor had been licensed to 2033.*
- Kewaunee (Wisconsin), 2013 - *Reactor had been licensed to 2033.*
- San Onofre 2 & 3 (California), 2013 - *Reactors had been licensed to 2022.*
- Vermont Yankee (Vermont), 2014 - *Reactor had been licensed to 2032.*

B. RECENT POWER UPRATES CANCELED[2]

- Cooper (Nebraska), anticipated uprate investment called off in 2013
- LaSalle Generating Stations 1 & 2 (Illinois), 2013
- Limerick 1 & 2 (Pennsylvania), 2013
- Prairie Island 1 (Minnesota), 2012

C. CURRENTLY-OPERATING PLANTS ANNOUNCED FOR CLOSURE[3]

- Diablo Canyon 1 (California), 2024: Proposed by utility owner through decision not to pursue license extension. Licensed to 2024.

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[1] Source: Jeremy Carl and David Fedor, Keeping the Lights on at America's Nuclear Power Plants, Hoover Institution Press (2017).

[2] *Id.*

[3] *Id.*

- Diablo Canyon 2 (California), 2025: Proposed by utility owner through decision not to pursue license extension. Licensed to 2025.
- Indian Point 2 (New York), 2020: Anticipated closure as a result of negotiated state settlement, not averted by state subsidy to other plants. Licensed to 2013 (operating under temporary license).
- Indian Point 3 (New York), 2021: Anticipated closure as a result of negotiated state settlement, not averted by state subsidy to other plants. Licensed to 2015 (operating under temporary license).
- Oyster Creek 1 (New Jersey), 2019: Anticipated closure as a result of negotiated state settlement. Licensed to 2029.
- Palisades (Michigan), 2018: Proposed by utility owner. Licensed to 2031.
- Pilgrim Nuclear Power Station (Massachusetts), 2019 Proposed by utility owner. Licensed to 2032.

D. **CURRENTLY-OPERATING PLANTS CLOSURES AVERTED BY STATES**[4]

- Clinton Power Station (Illinois), decommissioning announced for 2017: Originally proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. The reactor is licensed to 2026.
- James A Fitzpatrick (New York), 2017: Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2034.
- Nine Mile Point Nuclear Station 1 (New York), 2017: Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2029.
- Nine Mile Point Nuclear Station 2 (New York), 2017: Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2046.
- Quad Cities Generating Station 1 (Illinois), 2018: Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2032.
- Quad Cities Generating Station 2 (Illinois), 2018: Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2032.
- R. E. Ginna Nuclear Power Plant (New York), 2017: Proposed by utility owner, but near-term closure risk averted through adoption of a state subsidy program. Licensed to 2029.

3) The reliability, on site fuel-storage and the fact that nuclear facilities are already significantly hardened against both physical and cyber threats.

4) The critical role the U.S. leadership and nuclear fleet plays in non-proliferation.

[4] *Id.*

5) The importance of civilian nuclear for America's military leadership.

Economic factors will also be discussed, including:

1) The importance of nuclear power in workforce development.
2) The importance of the civilian nuclear supply chain for both civilian and military matters.
3) The importance of maintaining strong diverse electric generation assets with different sources of power. America needs an actual portfolio strategy for its electricity system, not simply a myopic focus on short-term cost-minimization.

III. THE CRITICAL ROLE OF NUCLEAR POWER TODAY

Nuclear energy provides critical capabilities associated with a resilient and secure electric grid. First, it provides the necessary baseload power that is reliable and available when needed.

As we continue to add more and more renewables and other intermittent sources of energy to the grid, the importance of having a supply that is always on is more important than ever.[5] These intermittent forms of power generation make up increasingly large parts of the grid and cannot always be relied upon to reliably meet system demand. The aggressive deployment of these intermittent resources leads to increased costs for the electricity system as a whole, both in terms of requiring greater transmission capacity to transmit from the generation asset to the load source and more complicated computerization and forecasting to keep up with non-dispatchable assets. In addition, as more of these intermittent sources come on to the grid, it will require the deployment of

[5] Jeffery St. John, *The California Duck Curve Is Real, and Bigger Than Expected*, Greentech Media, November 3, 2016, available at: https://www.greentechmedia.com/articles/read/the-california-duck-curve-is-real-and-bigger-than-expected#gs.VpC0WFE.

more expensive long-term storage solutions, such as batteries. As a result of all of these factors, California, which has arguably been the most aggressive state on renewable energy, has electricity costs that are more than 60% higher than the national average despite record low natural gas prices. (Natural gas makes up almost half of California's power generation.).[6]

In contrast, nuclear power has been a model of predictability. The capacity factor of nuclear power plants in 2016 was a record 92.5%,[7] light years above other low-emission alternatives such as Hydro (38.0%), Solar PV (27%) and wind (34.7%) or even fossil generation such as combined cycle gas (56%) and coal (52.7%) [8] Nuclear Power is indeed "used and useful" in America's electricity generation mix.

IV. NUCLEAR PORTFOLIO ECONOMICS

The recent nuclear unit retirements are negatively impacting overall system resilience and increasing our exposure (unnecessarily) to extreme events.[9] When the California San Onofre plant shutdown, the resulting need to contract with other generation resources led to a $350 million increase in direct customer costs as well as an increase in emissions and a need to build out extensive infrastructure at a multi-billion-

[6] United States Energy Information Agency, Electric Power Monthly with data from August 2017, available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_.

[7] United States Energy Information Agency, *Capacity Factors for Utility Scale Generators Not Primarily Using Fossil Fuels*, January 2013-August 2017, Electric Power Monthly, August 2017, available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b.

[8] United States Energy Information Agency, *Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels*, January 2013-August 2017, Electric Power Monthly, available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a.

[9] A report by the APS Panel on Public Affairs*, Integrating Renewable Electricity on the Grid,* American Physical Society, available at: https://www.aps.org/policy/reports/popa-reports/upload/integratingelec.pdf.

dollar cost to maintain reliability.[10] In the wake of the shutdown of San Onofre, the California Independent System Operator, Inc. ("California ISO") acknowledged that "reliability has become a more pronounced concern."[11]

With low natural gas prices, the U.S. generation mix is migrating toward gas resources as the primary source of generation capability, and we cannot lose sight of the fact that there can be disruptions that could halt the natural gas revolution in its tracks. The growth in gas production is almost entirely dependent on hydraulic fracturing ("fracking"); yet fracking is under unprecedented attack in numerous states. If these attacks[12] succeed or an issue such as unexpected environmental impacts arises with the technology, we could see tremendous price spikes (akin to what we observed in 2007 thru 2009) and decreases in gas production. Declining yields could also unexpectedly thwart the fracking revolution, stressing the importance of not making all of our energy bets on one source.[13] Even if those price spikes are mitigated in short order, the damage to consumers will have been done.

In less than a decade, the Northeast markets have seen coal production decline from over 30% of our output to 11%. Nuclear, has seen small declines with the retirement of Vermont Yankee, but those declines could increase dramatically if more at risk units are lost. Natural gas has filled the gap, increasing from 23% of the generation

[10] Lucas Davis and Catherine Hausman, *Market Impacts of a Nuclear Power Plant Closure*, American Journal of Applied Economics, April 2016, available at: https://ei.haas.berkeley.edu/research/papers/WP248.pdf; Ivan Penn, *Edison will spend $12 Billion on Electric System over Next Three Years*, Los Angeles Times, November 4 2015, available at: http://beta.latimes.com/business/la-fi-edison-electric-system-20151103-story.html.

[11] California ISO, *Grid Resiliency*, available at: http://publications.caiso.com/StateOfTheGrid2014/GridResiliency.htm.

[12] Current concerns raised by fracking opponents focus on surrounding seismicity or groundwater pollution.

[13] Mason Inman, *Natural Gas: The Fracking Fallacy*, Nature, December 3, 2014, available at: https://www.nature.com/news/natural-gas-the-fracking-fallacy-1.16430.

mix to 43%. As these trends continue, overall diversity declines, and as PJM has noted in its own reports this leads to potential resiliency risks.[14]

Many argue this is so-called free-market principles at work. As an aggressive free-market proponent who has been aligned with some of the strongest pro-market forces and Congressmen in American politics, this argument garners natural sympathy. But, and this is a critical point all-too-little understood by the public, the U.S. electricity system is not a free market – it has never been a free market, and frankly it has no reasonably foreseeable prospects of becoming a free market.

It is, for better or for worse, a highly regulated market that has been manipulated for many years in ways that have been profoundly damaging to nuclear energy's competitiveness. Yet despite these challenges, nuclear still provides one-fifth of all electricity in the U.S. and creates far more emission-free energy than any other technology, including the solar and wind that capture environmentalist plaudits and journalists headlines.

V. NUCLEAR ENERGY AND NATIONAL SECURITY

Perhaps the biggest unmeasured value of nuclear power is its contribution to our national security. It cannot be stressed enough that unlike any other form of energy, the nuclear enterprise has fundamental non-energy related security attributes that justify additional support in the market. Furthermore this national security assessment is not a partisan issue. As a report by the Energy Futures Initiative (a non-partisan energy think tank founded by former Secretary of Energy Ernest Moniz), notes: "The national security

[14] PJM Interconnection, L.L.C., *PJM's Evolving Resource Mix and System Reliability*, March 30, 2017, available at: http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

imperatives of nuclear energy, however, are not addressed in state rate-making. This is understandable: national security policy is inherently Federal in nature. As such, the fundamental role of a robust nuclear energy sector in meeting national security imperatives must, in reality, be addressed by the Federal government."[15] Given FERC's rulemaking power, it is ideally situated to do just that.

Nuclear plants are able to keep more fuel on site than any other form of energy, due to nuclear fuel's high energy density.[16] Nuclear energy generation is incredibly space efficient with a fuel pellet the size of a pencil eraser providing as much electricity as 17,000 cubic feet of natural gas, 1,780 pounds of coal or 149 gallons of oil.[17] This could be particularly useful in the event of an interruption to fuel supplies to other generators. In a long-term emergency situation, transporting the necessary amount of nuclear fuel to power a reactor for years could be achieved with relative ease, even in a situation where roads and other transportation networks might be badly degraded. Overall fuel also averages just 31% of total plant costs for operation as opposed to 80-90% of coal and natural gas, making nuclear power much less prone to vacillations in fuel prices.

There are several new threats that potentially menace our power plants and the grid today – from terrorism to cyber threats. In San Jose, CA in 2013 a single non-hardened substation sustained millions of dollars of damage from a sniper attack in 2013

[15] The U.S. Nuclear Energy Enterprise: A Key National Security Enabler, A Special Report by the en4ergy Futures Initiative, at p. 6, available at: https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5992f7e0bf629ad8f9d575ec/1502803938248/EFI+Nuclear+Report+FINAL+08.2017.pdf

[16] Nuclear Energy Institute, *Reliable & Affordable Electricity Supply*, November 2017, available at: https://www.nei.org/Why-Nuclear-Energy/Reliable-Affordable-Energy/Electricity-Supply.

[17] *Id.*

when multiple gunmen opened fire on the transformers using high-powered rifles. As was noted by the ranking member of the House Energy and Commerce Subcommittee at the time who called the attack "... an unprecedented and sophisticated attack ... Communications were disrupted. The attack inflicted substantial damage. It took weeks to replace the damaged parts. Under slightly different conditions, there could have been serious power outages or worse."[18] Nuclear power plants, with their already high-levels of surveillance and security, are much less vulnerable to these types of attacks.

Nuclear has an advantage in this world because nuclear power plants are already hardened against risks and have been designed with safety and security (physical and cyber) in mind from the ground up.

One need only scan the government documents to find a wealth of information on steps nuclear plants have taken to reduce the risk from electromagnetic pulse ("EMP") attacks or the numerous recent publications and books specifically devoted to emergency planning for nuclear power plants and/or hardening their components for cyber or EMP attacks.[19] U.S. nuclear units are similarly resistant to extreme climatic events. When Hurricane Andrew had a direct hit of Florida's Turkey Point Nuclear Plant as a category 5 hurricane with wind gusts up to 175 MPH in 1992, there was no damage to the plant's critical systems.[20] Other forms of electricity generation are simply not hardened and

[18] Shane Harris, *U.S. Misses 'Military Style' Raid on California Power Complex Spooks U.S.*, Foreign Policy, November 27, 2013, available at: https://web.archive.org/web/20140705042615/http://complex.foreignpolicy.com/posts/2013/12/24/power-station-military-assault.

[19] *See e.g.,* Michael Franusich, *Security Hardened Cyber Components for Nuclear Power Plants: Phase I SBIR Final Technical Report*, March 18, 2016, available at: https://www.osti.gov/scitech/servlets/purl/1242462.

[20] Megan Guess, *As Irma approaches nuclear plants in Florida, lessons from Andrew Resonate*, Ars Technica, September 9, 2017, available at: https://arstechnica.com/science/2017/09/as-irma-approaches-nuclear-plants-in-florida-lessons-from-andrew-resonate/.

secured to nearly the same degree. With increasing concerns arising every day about foreign powers hacking into the U.S. electric grid, the hardened security around America's nuclear power plants is critical. In the U.S. nuclear industry, safety and security are a core part of the design and building process in a far more direct and substantive way than they are for any other type of resource.

VI. THE COUNTRY'S NUCLEAR TECHNOLOGY CAPABILITY IMPACTS NON-PROLFERATION EFFORTS

One of the primary areas in which America gains major strategic advantages from the civilian nuclear enterprise—advantages that are not currently accounted for in market prices - occurs in the area of non-proliferation. The U.S. has long been a leader in enforcing non-proliferation norms, as first enunciated by President Dwight Eisenhower in his Atoms for Peace initiative. We have used our leadership in nuclear technology non-proliferation to sign so-called "123" agreements with countries wishing to use civilian nuclear technology which had very strong proliferation safeguards.

These initiatives can have great value to the countries that sign them. For example, when India signed its 123 agreement with President George W. Bush in 2008, it represented the most serious lobbying the Indian government had done on any issue in the US and was described as the cornerstone of the new relationship between the U.S. and India. India was willing to expend these efforts and commit to a much stricter regime under IAEA supervision, in no small part because India's government highly valued the U.S. nuclear technologies we could bring to the table. Without a serious ongoing effort in civilian nuclear technology, these anti-proliferation efforts on the military side would not have been possible. The deal was described by the Council on Foreign Relations as a "watershed in U.S.-India relations and introduces a new aspect

to international nonproliferation efforts."[21] A similar gold-standard 123 Agreement was signed with the United Arab Emirates in December of 2009. Again, U.S. technological leadership in the nuclear arena was used to leverage a strong nonproliferation agreement in a sensitive part of the word.[22]

As our nuclear technology capability has weakened due to a lack of domestic plant manufacture (we have not completed a greenfield nuclear power plant in three decades) so has our leverage in this area, with challenges coming from countries that may have very different views on non-proliferation than we do. Recently the United States has lost several bids on nuclear power projects in the Middle East to Russia, in no small part because of our degraded capacity in this area. The closure of additional nuclear plants degrades our already fragile capabilities while empowering geopolitical rivals such as Russia and China.

Whether or not the U.S. is in the nuclear game, the rest of the world continues to play it, particularly in China where nuclear power generation has almost tripled in the last decade. There are over 400 GW of installed nuclear capacity in more than 31 countries, with more being added every year. There were 58 reactors in 15 countries with a capacity of almost 57 GW under construction as of 2016.[23]

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[21] Jayshree Bajora and Esther Pan, *The U.S.-India Nuclear Deal*, Council on Foreign Relations, November 5, 2010, available at: https://www.cfr.org/backgrounder/us-india-nuclear-deal.

[22] Christopher Blanchard and Paul Kerr, The United Arab Emirates Nuclear Program and Proposed Nuclear Collaboration, Congressional Research Service, December 20, 2010, available at: https://fas.org/sgp/crs/nuke/R40344.pdf.

[23] Myclie Schneider *et. al*., The World Nuclear Industry Status Report 2016, available at: https://www.worldnuclearreport.org/The-World-Nuclear-Industry-Status-Report-2016-HTML.html.

VII. PRESERVING NUCLEAR IS AN IMPORTANT TO THE COUNTRY'S NATIONAL SECURITY INTERESTS

In addition to our work in non-proliferation, the civilian nuclear enterprise dramatically strengthens our military capability as well, another nuclear attribute that is not priced into the market. This is most visibly seen in our Nuclear Navy, which is indubitably the world's most capable. America has almost 100 nuclear-powered vessels, consisting of aircraft carriers and submarines. We have accumulated almost 6200 reactor years of service without a single nuclear accident.[24]

For decades, the United States has gained a strategic advantage from its use of nuclear-powered ships that can deploy longer and more effectively than conventionally powered craft. The importance of fuel choice on capability has a rich history, most notably when Winston Churchill turned the British Navy from coal to oil for many of the same reasons the United States would move its key assets to nuclear. If America does not maintain a nuclear power capability domestically it is difficult to imagine that we will be able to maintain a nuclear navy at the same level of capability we have had historically. This would be a substantial degradation of our ability to project U.S. power.

One example of this degraded capability has been seen in our procurement processes for highly-enriched uranium to fuel both domestic and military reactors. Historically, the entire supply chain for highly enriched uranium has been legally mandated to be of U.S. origin. However, due to the decline of our nuclear capability, the

[24] "Nuclear Powered-Ships," *World Nuclear Association*, Updated October 2017, available at: http://www.world-nuclear.org/information-library/non-power-nuclear-applications/transport/nuclear-powered-ships.aspx.

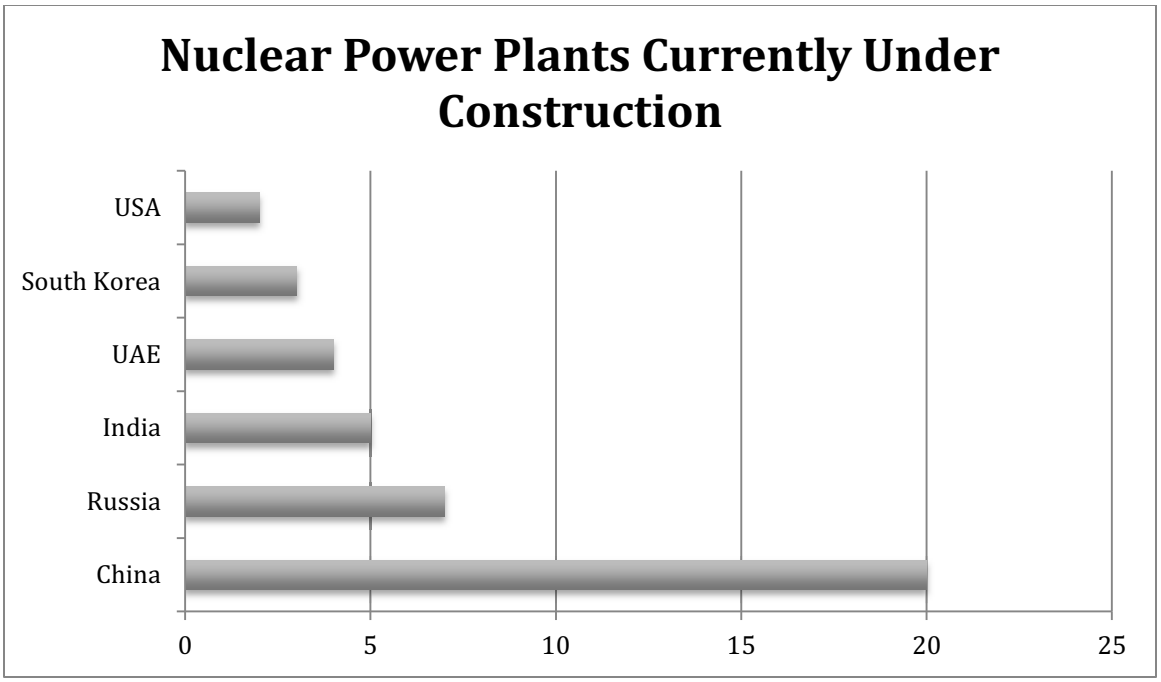
country no longer maintains all aspects of this process domestically, and other nations have gained production advantages over us."[25]

Our nuclear weapons stockpile, and its critical nature for deterring threats such as we are seeing in North Korea, is also hostage to the degradation of America's civilian nuclear capability. The stockpile requires a constant source of Tritium that must also be from U.S. origin reactors using domestically produced LEU reactor fuel. Our lack of an enrichment facility using solely U.S. origin technology represents a substantial impediment to our security in this area. As a result we find ourselves relying on Europe for the supply of this fuel at a time in which Europe's commitment to the nuclear enterprise has become questionable.

Our nuclear technology capability has profound impacts on America's national security. The failure of a new nuclear build in South Carolina and cost overrun issues in Georgia are further indications that the U.S. has lost control of its own nuclear destiny. Without a course correction we will see the future of nuclear power determined by China and Russia, who continue to move aggressively in this arena. China will complete five new nuclear power plants in this year alone.[26]

[25] Energy Futures Initiative, Inc., *The U.S. Nuclear Enterprise: A Key National Security Enabler*, August 2017, available at: https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5992f7e0bf629ad8f9d575ec/1502803938248/EFI+Nuclear+Report+FINAL+08.2017.pdf.

[26] Source: *World Nuclear Association*



The dangers of this situation should be obvious: While nuclear power plants are in many ways a quite distinct technology from nuclear weapons, the capabilities used in domestic enrichment for civilian nuclear power plants can also be used to create nuclear weapons. This fact has been at the core of much of our conflict with Iran and North Korea over their "civilian" nuclear programs. The U.S. has traditionally used its leadership in the supply of nuclear technologies to make it very difficult for nuclear-power-plant operators to proliferate the technology. Are the Chinese and Russians likely to share our interests in this? We need only look to Pyongyang and Pakistan to find out.

In addition to the critical role of nuclear energy in U.S. national security, the reactors that power our nuclear navy – almost 100 submarines and aircraft carriers – run on technology that is virtually identical to the technology powering our civilian reactors. In fact, domestic nuclear power originally grew from these naval programs. Losing the technology and operating experience through the atrophy of our domestic nuclear-power sector would mean a profound loss of capability in our military.

Although these aspects of nuclear retention are tangential to the energy markets, the importance of these resources both to the resilience of the electric system and our overall national interest must be considered in any decision. Putting these units at risk because of short-run market signals and the failure of our markets to adequately value all of the units' attributes is a deficiency that requires immediate attention and action.

VIII. SUPPLY CHAIN AND WORKFORCE DEVELOPMENT

More than 700 companies in 44 states contribute to the U.S. nuclear supply chain and this supply chain is increasingly missing links because of the lack of support for a robust domestic nuclear industry. While nuclear weapons and nuclear power are two quite distinct technologies, there are many suppliers who create specialized solutions for both markets. Without the support of the civilian nuclear fleet our weapons supply chain may also suffer badly, with consequent damage to our nuclear deterrent.

As a result of the uncertainties about our nuclear future, America's number of nuclear engineers being trained sank to less than 25% of what it was at its peak. Although rebounding impressively during the short lived nuclear renaissance created by the Energy Policy Act of 2005, the numbers remain well below peak levels reached in the 1970s.[27]

The closure of a nuclear power plant can often have a dramatic effect on local workforces. When Vermont Yankee closed more than 500 people lost their well-paying jobs that were 2.5 times the average for a worker in the region. The total economic impact within seven years of the plants closing was projected to be 1,100 jobs lost with

[27] Oak Ridge Institute for Science and Education, 2016 Nuclear Engineering Enrollments and Degrees Survey, 2016, available at: https://orise.orau.gov/stem/workforce-studies/nuclear-engineering-enrollments.html.

almost a half billion in economic activity. Nuclear plants also tend to be in more rural areas and the loss of economic activity in these areas from a shutdown is therefore more profound.

There is also the additional important issue of outlet jobs for the U.S. Navy's nuclear technicians. Without a civilian nuclear workforce for these trained nuclear engineers to "graduate" into upon leaving naval service, the U.S. Navy's ability to attract top candidates to work in the nuclear navy may badly lag.

IX. CONCLUSION

The Nuclear enterprise is a vital part of America's electricity infrastructure, that, unique among major forms of generation, provide substantial national security, resilience and reliability and environmental attributes, all of which are either poorly valued by the marketplace or not valued at all. In many cases, local power companies and public utility commissions are poorly positioned to be able to properly value these attributes, which bring benefits far beyond those that accrue to local ratepayers. Furthermore, nuclear energy's lack of price correlation with other forms of electricity generation and its lack of dependence on spot fuel prices make it an ideal component of a broad electricity-generation portfolio.

Given the varied attributes that nuclear energy brings, FERC is absolutely justified in pursuing policies to ensure that the nuclear fleet and our broader civilian nuclear enterprise, will not be irreparably damaged by a myopic focus on short-term cost-minimization.

Jeremy C. Carl

Jeremy C. Carl

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ATTACHMENT B

AFFIDAVIT OF ALAN R. LOVINGER

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)	Docket No. RM18-1-000

AFFIDAVIT OF
ALAN R. LOVINGER

My name is Alan R. Lovinger. I am a Vice President of Brown, Williams, Moorhead & Quinn, Inc. ("BWMQ"). My business address is 1155 Fifteenth Street, N.W., Suite 1004, Washington, D.C. 20005. I have been employed by the firm since March 1, 1998. BWMQ is a leading energy-consulting firm that has been providing advice and assistance to clients for over thirty years. BWMQ provides comprehensive energy related services on business and regulatory matters to over one hundred clients, including independent power producers, natural gas and oil pipelines, electric transmission providers, local distribution companies, energy producers, energy trade associations, pipeline shippers, and federal and state agencies. I graduated from Bryant University in 1965 with a B.S. Degree in Business Management. In 1965, I enrolled in an MBA program at Texas Tech University majoring in Accounting. Prior to joining BWMQ, I was employed by the Federal Energy Regulatory Commission ("FERC" or "Commission") as a Senior Accountant. I was employed by FERC for twenty-five years, from 1966 to the end of 1969, and from 1976 to 1998. My work at FERC was primarily related to cost-of-service issues with an emphasis on income tax matters, gas storage accounting, allocation of shared services, and rate base matters. I provided accounting and tax advice on the rate treatment of storage gas in rate proceedings and participated in

proceedings involving the determination of purchased gas costs in purchased gas adjustment matters. I also represented the Commission in dealings with the Internal Revenue Service on income tax issues that arose in various rate proceedings and assisted the Commission on rulemakings on various cost-of-service matters such as tax normalization, cash working capital, and Post-Retirement Benefits Other than Pensions. Between 1970 and 1976, I was employed by the Internal Revenue Service as an Internal Revenue Agent.

During my employment at FERC and BWMQ, I performed hundreds of cost-of-service studies and provided expert testimony using FERC precedent to support these studies. As an employee of BWMQ, I perform cost-of-service studies for coal generating plants in Reliability-Must-Run ("RMR") rate proceedings where the operator was unable to perform the required reliability required by the grid under market rates. I also perform cost-of-service studies for coal generators supporting compensation for generating reactive power for the grid.

I have been requested by the PSEG Companies to develop a simplified methodology that could be used to set just and reasonable ("J&R") cost-of-service rates for a defined class of eligible resources in connection with the DOE NOPR. The process outlined below sets forth a template approach that could be used to set a J&R cost-of-service in a streamlined manner that could be used to meet the requirements of DOE's NOPR.

The mechanism described will maintain FERC's cost-based and original cost principles to achieve this goal. The primary objective is to resolve up-front those rate issues that are present in rates filings that require applicants, FERC staff and intervenors

time-consuming efforts to resolve and often cause protracted litigation. The issues that can be resolved easily in a template format include: the cost-of-return on equity and debt as well as the makeup of an appropriate capitalization, depreciation and amortization expense, allocation of overhead, and the eligible plant investment included in rate base. The mechanisms proposed here to resolve these issues have been widely used in various electric and gas transmission rate proceedings before the Commission, thereby establishing precedents in such venues. The proposals listed below should streamline both the applicants' rate filings and the resolution of those filings at FERC. It is important to note that cost-of-service recoveries should be net of market revenues so that units do not over-recover their costs. If the Commission finds that the use of a template is appropriate for filing the cost-of-service payment, then the template currently used by the Commission to set formula rates for transmission providers may be a useful foundation, both in structure and instructions, for creating a NOPR template. The descriptions of those issues to be streamlined in a template structure are as follows:

1. **Rate Base** – Rate base will be computed using the Commission's original cost principles. For applicants that are the original owners of the generation facility, the composition of their rate base will be computed using traditional FERC precedent. For the unit owners that are not the original owners and such change in ownership resulted in the facilities to be operated under a market-based authority, the applicant's rate base can be composed of all documented capitalized plant additions made after the change in the original ownership that ended FERC cost-of-service regulation. The coal-fired and nuclear power generators that are likely to file for a cost-of-service payment are those originally placed into service

under the ownership of traditional FERC-regulated utilities. These utilities were required to file an annual Form No. 1 at FERC. The last FERC Form No. 1 filed can form the base to which subsequent additions and retirements can be added. Many of these generating facilities have changed hands at purchase prices that are different from original cost. Use of a purchase price in determining rate base should be allowed only to the extent it is equal to or lesser than original cost. For those allowable plant additions, the applicant will be required to compute appropriate accumulated depreciation and accumulated deferred income taxes ("ADIT") through the starting date authorizing a cost-of-service payment. Unless the applicant has recorded the appropriate ADIT on its books, ADIT should be computed using all applicable federal income elections including bonus depreciation and book recorded depreciation rates. Applicant should also be allowed to include working capital, cash working capital[1] and prepaid expenses using FERC rate case precedent including, but not limited to, the use of a thirteen-month average. Applicant should also be permitted to include general and intangible plant, net of accumulated depreciation and amortization computed through the date prior to the authorization of a cost-of-service payment. General and intangible plant would include only those assets that are both physically located at the plant and whose cost is recorded on the books of the generating plant.

2. **Management Fee** – Because a majority of the coal- and nuclear-fired generators likely to apply for cost-of-service were placed into service in and around the

[1] FERC's precedent in electric rate cases is to permit one-eighth of annual accrued operating and administrative costs to be included in rate base.

1960s and 1970s, many could be fully depreciated, taking into effect FERC's authorized depreciation rates and the significant length of time these facilities have been in service. Since there remains significant operating risk borne by the owners and operators of these fully-depreciated facilities (under FERC precedent), the cost-of-service payment would provide an alternate method of compensating the owners for incurring this significant risk. The Commission has previously addressed the issue of a fully depreciated gas pipeline system and acknowledged that such utilities are entitled to compensation for undertaking the risk of continued operation of the utility service. To provide the necessary incentive for undertaking the risk of ownership and operation of these units, the Commission found that the owners are entitled to a management fee. The mechanism for such a management fee is based on FERC precedent which can be found in FERC gas pipeline decisions.[2] The formula can be simply stated as an average of the pipeline's rate base over its depreciable life multiplied by a factor of ten percent. The product of this computation is then multiplied by the allowed pretax return[3] determined in the rate proceeding to arrive at the allowable management fee. The formula presented in the cited cases is based on

[2] *See, e.g., High Island Offshore Sys., L.L.C.*, 110 FERC ¶ 61,043 PP 107, 115 (2005) (Commission approving management fee for fully depreciated assets equal to the overall rate of return of 9.60 percent multiplied by 10 percent of the modified average rate base which the Commission determined was adequate "to compensate HIOS' owners for the risks of continuing to operate the pipeline."), *remanded on other grounds, Petal Gas Storage, L.L.C. v. FERC*, 496 F.3d 695 (D.C. Cir. 2007); *Tarpon Transmission Co.*, 57 FERC ¶ 61,371 at 62,239-41 (1991) (Commission approving management fee for fully depreciated assets by applying the pretax cost of capital to 10 percent of the pipeline's historical average rate base "to compensate Tarpon's owners for the risks of continuing to operate the pipeline and to provide an incentive for efficient operations.").

[3] A pretax return is the amount earned by a generating unit before income taxes and debt interest payments. A generating unit's after-tax return on equity is grossed up to reflect its income taxes. The formula to calculate a pretax rate of return can be presented as: *pretax rate of return = (debt percentage * debt rate) + (equity percentage * equity rate) * (1 + Composite Tax Rate / (1 – Composite Tax Rate)).*

multiplying the original cost of the plant by five percent (a ten percent rate multiplied by an average of the depreciated plant converts to a five percent rate of the total plant) and multiplying the allowed plant number by a pretax return to arrive at the allowed management fee.[4] Page 402 of the original utility unit owners' Form No. 1 during their ownership contains the original cost plant data. From this Form No. 1 data, the current unit owners can calculate an appropriate management fee simply by multiplying the original cost of the generating units by five percent and multiplying the allowable original plant investment by the pretax return. Ascertaining the allowable pretax components will be discussed below. The management fee accordingly once computed should be directly included as a cost element in the cost-of-service payment. This management fee structure would provide some means of compensation for the operating risk associated with the asset.

3. **Return and Capitalization** – For reactive rate case filings made at FERC, the Commission permits the use of a proxy to establish a reasonable return on equity, cost of debt and capital structure. The proxy used is that of a transmission owner that is interconnected to the generating unit. The Commission found that it is reasonable to use the cost of capital and the capitalization of the transmission owner with which each facility is interconnected as a proxy. Such capital cost was fully investigated either in a transmission rate proceeding or in an annual formula rate filing and was either accepted by the Commission and the parties to the proceeding in settlement or through litigation. For those unit owners that are

[4] This abbreviated computation is appropriate because the necessary information to calculate an average rate base is not available. The use of rate base, instead of the plant investment, in the orders makes the computation more complex than it needs to be.

not connected to a transmission owner that files annual formula rates, the capital structure and debt and equity returns can be used from the transmission owner's last approved FERC rate case.

4. **Fuel and Variable Costs** – As in the Commission's RMR rate proceedings, units receiving cost-of-service payments should be required to bid into the energy markets for the recovery of fuel and applicable variable costs. Assuming that the energy bidding procedures should be largely unchanged, the cost-of-service payment will only consist of operating costs other than fuel and fuel-related variable costs such as water, ammonia or other consumables. The instructions in the template should make it clear that any variable costs recoverable in the energy bidding process should be excluded from the proposed cost-of-service payment to eliminate the possibility of a double recovery of such costs.

5. **Operating Cost Recovery** – Applicants should be entitled to recover all direct and indirect operating costs not already recoverable in their energy bid price. For such recovery of operating costs, the Applicant must provide in its rate filing complete income and balance sheet statements supporting the twelve-month period ("test period") used in the template cost-of-service. These statements can be either an "audited" financial statement or a financial statement review.[5] The Income Statement should provide the necessary detail itemizing the various direct

[5] An audit is an objective examination and evaluation of the financial statements of an organization to make sure that the records are a fair and accurate representation of the transactions they claim to represent. It includes an evaluation of the internal controls of the organization, detail tests of the accounting records through examination of source documents and verifying that the information in the report footnotes is accurate. A financial statement review is a service under which the accountant obtains limited assurance that there are no material modifications that need to be made to an entity's financial statements for them to be in conformity with the applicable financial reporting framework. This work would include inquiries of management, analytical procedures, comparisons to industry benchmarks and review of documentation only to the extent considered necessary.

cost categories that accrued during the test period. No test period adjustments should be permitted. Due to the operating capabilities of turbine generators, periodic costly overhauls (outages) are required and nuclear generators take periodic fuel outages. To normalize the cost effect of these major cost incurrences, Applicants would be required to include a level of overhaul costs in the cost-of-service representing a twelve-month average cost. Thus, if an Applicant incurs in the test period an overhaul cost that is incurred every twenty-four months only one-half of the expenditure ("normalized costs") would be permitted in the test period. Nuclear fuel outages would be treated in a similar manner. Likewise, if the Applicant has zero overhaul cost in the test period, the Applicant will be entitled to a normalized cost adjustment. Administrative and General ("A&G") expense incurred on the generating unit's behalf that can be directly assigned will be permitted in the cost-of-service payment. For A&G costs that cannot be directly assigned, such costs can be allocated to the generating unit if it can be determined that such cost is incurred on behalf of the generator unit, providing such allocations are performed using the Commission's preferred labor allocator. A labor ratio is the product of all the operating labor cost of the consolidated group as the denominator and the Applicant's labor costs as the numerator. Thus, all non-assignable overhead either at a parent or division, or similar cost centers, can be assigned to the Applicant based on the computed labor allocator. Although the attached financial statements will not be in accordance with FERC's Uniform System of Accounts ("USofA"), the cost

categories should be generally consistent with the cost categories prescribed by FERC's USofA.

6. **Depreciation Expense** – Depreciation expense recoverable in the cost-of-service payment should only include plant investment that satisfies the Commission's original cost principles and such plant items that are included in the computation of rate base. Depreciation expense should be computed based on the applicable depreciation rates for the subject plant additions. The sum of the calculated depreciation expense for the eligible plant additions will be included in the computation of the cost-of-service payment. Applicant should also be permitted to recover depreciation and amortization of general and intangible plant directly associated with the generating unit.

7. **Taxes Other Than Income Taxes** – State and local taxes that are attributable directly to the generator should be allowed in the cost-of-service payment, assuming they are included in the attached financial statements and are consistent with Generally Accepted Accounting Principles. Employment taxes that are not included in labor loading costs should likewise be allowed.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)	Docket No. RM18-1-000

VERIFICATION

)

)

I, the undersigned, being duly sworn, depose and say that the foregoing is the "Affidavit of Alan R. Lovinger," and that such Affidavit to the best of my knowledge, information and belief, is true, correct and accurate, and I hereby adopt this Affidavit as if given by me in formal hearing, under oath.

Alan R. Lovinger

Subscribed and sworn to before me this 7th day of November, 2017

Notary Public

STEPHANIE J. WILKERSON
NOTARY PUBLIC DISTRICT OF COLUMBIA
My Commission Expires June 30, 2019

STEPHANIE J. WILKERSON NOTARY PUBLIC MY COMMISSION EXPIRES 6/30/2019 DISTRICT OF COLUMBIA

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon the official service list in accordance with the requirement of Rule 2010 of the Commission's Rules of Practice.

Dated at Newark, New Jersey, this 7th day of November, 2017.

James E. Wrynn

James E. Wrynn
Paralegal

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Document Content(s)

PSEG Reply Comments RM18-1-000.PDF.....1-59

Exelon

March 28, 2014

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Docket Nos. RM05-15-000; RM94-14

Enclosed please find our annual Federal Energy Regulatory Commission (FERC) financial report as produced by our trustee, The Northern Trust Company. The Exelon Generation Company, LLC units are reported as follows:

those formerly owned by Commonwealth Edison Company (Braidwood 1 & 2, Byron 1 & 2, Dresden 1, 2 & 3, LaSalle 1& 2, and Quad Cities 1 & 2) – the reports are consolidated for the Tax Qualified and Non-Tax Qualified Trusts;

those formerly owned by PECO Energy Company (Limerick 1 & 2, Salem 1 & 2, and Peach Bottom 1, 2 & 3) - the reports are consolidated for the Tax Qualified and Non-Tax Qualified Trusts; and

those formerly owned by AmerGen Energy Company, LLC the reports are provided separately for each of the three units (TMI, Oyster Creek and Clinton) and the reports are consolidated for Tax Qualified and Non-Tax Qualified Trusts.

In 2013, there were no decommissioning expenses paid out of any Exelon units and only the legacy PECO units received rate payer contributions.

Please note that the Northern Trust reports reflect a zero opening balance for the legacy PECO and AmerGen units due to the trustee transition on January 1st, 2013 from BNY Mellon to Northern Trust. To address this issue, the ending balances from 2012 reports produced by the prior trustee, BNY Mellon, are included in our filing for these units.

There has not been an opinion expressed on any of the attached reports by an independent public accountant, therefore none is enclosed.

If you have any questions, please contact me at (312) 394-3956.

Sincerely,

Brian E. Andersen

Brian E. Andersen
Senior Portfolio Manager

Clinton

SI-SSA-0010-1253

Change in Book and Market Value

	Cost	Market value	For more information
Opening balance	0.00	0.00	
Miscellaneous Cash Receipts	22,091,063.97	22,091,063.97	See funding & disbursement summary
Interportfolio Transfers In	106,841,264.69	106,841,264.69	See funding & disbursement summary
Security Receipts	316,240,936.46	414,074,130.86	See funding & disbursement summary
Total receipts	445,173,265.12	543,006,459.52	See funding & disbursement summary
Miscellaneous Cash Disbursements	- 1,287,310.09	- 1,287,310.09	See funding & disbursement summary
Interportfolio Transfers Out	- 106,841,264.69	- 106,841,264.69	See funding & disbursement summary
Security Deliveries	- 1,133,620.08	- 1,161,998.24	See funding & disbursement summary
Total disbursements	- 109,262,194.86	- 109,290,573.02	See funding & disbursement summary
Income received	12,697,219.61	12,697,219.61	See income & expense summary, cash activity detail
Expenses paid Fund Expenses & Taxes	- 4,448,032.60	- 4,448,032.60	See income & expense summary
Unrealized gain/loss change	0.00	136,174,540.39	See asset summary
Unrealized gain/loss on security movements	0.00	- 97,804,816.24	See funding & disbursement summary
Realized gain/loss	9,901,014.45	9,901,014.45	See realized gain/loss summary
Accrued income change	2,035,006.72	2,035,006.72	See income & expense summary
Total amortization expense	- 428,589.80	- 428,589.80	See fixed income amortization
Total OID/MKT accretion income	22,349.95	22,349.95	See fixed income amortization
Closing balance	355,690,038.59	491,864,578.98	Ending Assets

No Rate Payer Contributions

No Decommissioning Expenses

SI-SSA-0010-1254

Change in Cash Value

	Market value	Cost	For more information
Opening balance	0.00	0.00	
Miscellaneous cash receipts	22,091,063.97	22,091,063.97	See funding & disbursement summary
Interportfolio transfers in	106,841,264.69	106,841,264.69	See funding & disbursement summary
Total receipts	128,932,328.66	128,932,328.66	See funding & disbursement summary
Miscellaneous cash disbursements	- 1,287,310.09	- 1,287,310.09	See funding & disbursement summary
Interportfolio transfers out	- 106,841,264.69	- 106,841,264.69	See funding & disbursement summary
Total disbursements	- 108,128,574.78	- 108,128,574.78	See funding & disbursement summary
Income received	12,679,003.71	12,679,003.71	See income & expense summary, cash activity detail
Expenses paid	- 4,448,032.60	- 4,448,032.60	See income & expense summary
Capital changes	6,517,210.88	6,517,210.88	See capital change detail
Foreign currency bought	10,624,556.35	10,624,556.35	See foreign exchange summary
Foreign currency sold	- 10,624,556.35	- 10,624,556.35	See foreign exchange summary
Realized gain/loss	5,702.79	5,702.79	See realized gain/loss summary
Unrealized gain/loss	- 704.59	0.00	See asset summary
Securities bought	- 94,918,649.91	- 94,918,649.91	See investment transaction summary
Securities sold	86,188,705.50	86,188,705.50	See investment transaction summary
Principal paydowns	1,524,743.14	1,524,743.14	See investment transaction summary
Intra portfolio transfer	0.00	0.00	
Closing balance	28,351,732.80	28,352,437.39	

SI-SSA-0010-1255

◆ Asset Summary - Taxable

Cost Method: HIGH COST

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Unrealized gain/loss Translation	Unrealized gain/loss Total	Market value incl. accruals	%
Adjustments To Cash								
Pending foreign exchange sales								
Pending foreign exchange sales - all currencies	0.00	- 33,486.64	- 33,486.71	0.00	0.07	0.07	- 33,486.64	- .007%
Total pending foreign exchange sales	**0.00**	**- 33,486.64**	**- 33,486.71**	**0.00**	**0.07**	**0.07**	**- 33,486.64**	**- .007%**
Pending trade purchases								
Pending trade purchases - all currencies	0.00	- 29,088,248.98	- 29,088,248.98	0.00	0.00	0.00	- 29,088,248.98	- 5.914%
Total pending trade purchases Ending Liability	**0.00**	**- 29,088,248.98**	**- 29,088,248.98**	**0.00**	**0.00**	**0.00**	**- 29,088,248.98**	**- 5.914%**
Pending trade sales								
Pending trade sales - all currencies	0.00	3,425,242.23	3,425,242.23	0.00	0.00	0.00	3,425,242.23	.696%
Total pending trade sales	**0.00**	**3,425,242.23**	**3,425,242.23**	**0.00**	**0.00**	**0.00**	**3,425,242.23**	**.696%**
Total adjustments to cash	**0.00**	**- 25,663,006.54**	**- 25,663,006.75**	**0.00**	**0.21**	**0.21**	**- 25,663,006.54**	**- 5.217%**
Total unrealized gain for lotted securities						**142,682,796.09**		
Total unrealized loss for lotted securities						**- 6,507,551.32**		
Total unrealized gain for non-lotted securities						**405.36**		
Total unrealized loss for non-lotted securities						**- 1,109.74**		
Grand Total by Lots		**489,829,572.26**	**353,655,031.87**	**136,379,389.31**	**- 204,848.92**	**136,174,540.39**	**489,829,572.26**	
Grand Total	**2,035,006.72**	**489,829,572.26**	**353,655,031.87**	**136,379,389.39**	**- 204,849.00**	**136,174,540.39**	**491,864,578.98**	**100.000%**

** - Lot Level Information Not Verified

SI-SSA-0010-1256

ASSETS			
INVESTMENTS:			
INVESTMENTS AT IDENTIFIED COST	$ 161,565,508.87		
UNREALIZED APPRECIATION-INVEST	13,100,353.50		
		$	174,665,862.37
RECEIVABLES:			
INTEREST	1,278,058.53		
			1,278,058.53
CASH			5,010.78-
TOTAL ASSETS			175,938,910.12
LIABILITIES			
PAYABLES			
PAYABLE FOR UNITS REDEEMED	625,632.00-		
			625,632.00-
TOTAL LIABILITIES			625,632.00-
NET ASSETS		$	176,564,542.12

SI-SSA-0010-1257

ASSETS			
INVESTMENTS:			
INVESTMENTS AT IDENTIFIED COST	$ 173,835,012.27		
UNREALIZED APPRECIATION-INVEST	84,738,667.16		
		$	258,573,679.43
RECEIVABLES:			
INTEREST	461,563.04		
DIVIDENDS	166,094.86		
			627,657.90
TOTAL ASSETS			259,201,337.33
LIABILITIES			
TOTAL LIABILITIES			0.00
NET ASSETS		$	259,201,337.33

Legacy PECO

SI-SSA-0010-1259

◆ Change in Book and Market Value

	Cost	Market value	For more information
Opening balance	0.00	0.00	
Miscellaneous Cash Receipts	66,673,492.56	66,673,492.56	See funding & disbursement summary
Sponsor Contributions Rate Payer Contributions	23,454,732.96	23,454,732.96	See funding & disbursement summary
Interportfolio Transfers In	194,900,187.19	194,900,187.19	See funding & disbursement summary
Security Receipts	1,186,837,045.14	1,382,212,750.14	See funding & disbursement summary
Total receipts	1,471,865,457.85	1,667,241,162.85	See funding & disbursement summary
Miscellaneous Cash Disbursements	- 9,547,487.40	- 9,547,487.40	See funding & disbursement summary
Interportfolio Transfers Out	- 194,900,187.19	- 194,900,187.19	See funding & disbursement summary
Security Deliveries	- 696,530.58	- 726,826.89	See funding & disbursement summary
Total disbursements	- 205,144,205.17	- 205,174,501.48	See funding & disbursement summary
Income received	39,919,254.77	39,919,254.77	See income & expense summary, cash activity detail
Expenses paid	- 15,340,467.92	- 15,340,467.92	See income & expense summary
Unrealized gain/loss change	0.00	330,580,511.91	See asset summary
Unrealized gain/loss on security movements	0.00	- 195,345,408.69	See funding & disbursement summary
Realized gain/loss	15,976,623.22	15,976,623.22	See realized gain/loss summary
Accrued income change	6,281,222.33	6,281,222.33	See income & expense summary
Total amortization expense	- 2,986,497.02	- 2,986,497.02	See fixed income amortization
Total OID/MKT accretion income	86,629.66	86,629.66	See fixed income amortization
Closing balance	1,310,658,017.72	1,641,238,529.63	

No Decommissioning Expences

SI-SSA-0010-1260

◆ Change in Cash Value

	Market value	Cost	For more information
Opening balance	0.00	0.00	
Miscellaneous cash receipts	66,673,492.56	66,673,492.56	See funding & disbursement summary
Sponsor contributions	23,454,732.96	23,454,732.96	See funding & disbursement summary
Interportfolio transfers in	194,900,187.19	194,900,187.19	See funding & disbursement summary
Total receipts	285,028,412.71	285,028,412.71	See funding & disbursement summary
Miscellaneous cash disbursements	- 9,547,487.40	- 9,547,487.40	See funding & disbursement summary
Interportfolio transfers out	- 194,900,187.19	- 194,900,187.19	See funding & disbursement summary
Total disbursements	- 204,447,674.59	- 204,447,674.59	See funding & disbursement summary
Income received	39,900,918.40	39,900,918.40	See income & expense summary, cash activity detail
Expenses paid	- 15,340,467.92	- 15,340,467.92	See income & expense summary
Capital changes	19,361,758.60	19,361,758.60	See capital change detail
Foreign currency bought	836,000.00	836,000.00	See foreign exchange summary
Foreign currency sold	- 836,000.00	- 836,000.00	See foreign exchange summary
Realized gain/loss	- 5,745.70	- 5,745.70	See realized gain/loss summary
Unrealized gain/loss	- 64.14	0.00	See asset summary
Securities bought	- 717,722,781.30	- 717,722,781.30	See investment transaction summary
Securities sold	675,187,402.67	675,187,402.67	See investment transaction summary
Principal paydowns	100,602.80	100,602.80	See investment transaction summary
Intra portfolio transfer	0.00	0.00	
Closing balance	82,062,361.53	82,062,425.67	

SI-SSA-0010-1261

Asset Summary - Taxable

Cost Method: HIGH COST

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Unrealized gain/loss Translation	Unrealized gain/loss Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Funds - short term investment								
Funds - Short Term Investment - all currencies	661.70	71,963,258.18	71,963,258.18	0.00	0.00	0.00	71,963,919.88	4.385%
Total funds - short term investment	**661.70**	**71,963,258.18**	**71,963,258.18**	**0.00**	**0.00**	**0.00**	**71,963,919.88**	**4.385%**
Total cash and cash equivalents	**719.77**	**82,062,361.53**	**82,062,425.67**	**0.00**	**- 64.14**	**- 64.14**	**82,063,081.30**	**5.000%**
Adjustments To Cash								
Pending trade purchases								
Pending trade purchases - all currencies	0.00	- 16,524,546.41	- 16,524,546.41	0.00	0.00	0.00	- 16,524,546.41	- 1.007%
Total pending trade purchases	**0.00**	**- 16,524,546.41**	**- 16,524,546.41**	**0.00**	**0.00**	**0.00**	**- 16,524,546.41**	**- 1.007%**
Pending trade sales								
Pending trade sales - all currencies	0.00	9,983,767.73	9,983,767.73	0.00	0.00	0.00	9,983,767.73	.608%
Total pending trade sales	**0.00**	**9,983,767.73**	**9,983,767.73**	**0.00**	**0.00**	**0.00**	**9,983,767.73**	**.608%**
Total adjustments to cash	**0.00**	**- 6,540,778.68**	**- 6,540,778.68**	**0.00**	**0.00**	**0.00**	**- 6,540,778.68**	**- .399%**
Total unrealized gain for lotted securities						**346,279,492.77**		
Total unrealized loss for lotted securities						**- 15,699,495.74**		
Total unrealized gain for non-lotted securities						**497.20**		
Total unrealized loss for non-lotted securities						**- 561.34**		
Grand Total by Lots		**1,634,955,872.64**	**1,304,375,939.75**	**330,730,052.68**	**- 150,119.79**	**330,579,932.89**	**1,634,955,872.64**	
Grand Total	**6,281,222.33**	**1,634,957,307.30**	**1,304,376,795.39**	**330,730,738.11**	**- 150,226.20**	**330,580,511.91**	**1,641,238,529.63**	**100.000%**

** - Lot Level Information Not Verified

EIN G714447
EXELON NQ (FORMER PECO UNITS)
OVERALL EXELON NQ

ASSETS		
INVESTMENTS:		
INVESTMENTS AT IDENTIFIED COST	$ 90,000,553.57	
UNREALIZED APPRECIATION-INVEST	6,769,044.83	
		$ 96,769,598.40
RECEIVABLES:		
INTEREST	1,059,003.04	
		1,059,003.04
TOTAL ASSETS		97,828,601.44
LIABILITIES		
TOTAL LIABILITIES		0.00
NET ASSETS		$ 97,828,601.44

SI-SSA-0010-1262

FOREIGN CURRENCY FLUCTUATIONS		
FOREIGN TAXES PAYABLE - DIVIDEND	$ 9.56	
		$ 9.56
TOTAL LIABILITIES		2,260,572.96
NET ASSETS		$ 1,345,950,744.86

SI-SSA-0010-1263

TMI

SI-SSA-0010-1265

Change in Book and Market Value

	Cost	Market value	For more information
Opening balance	0.00	0.00	
Miscellaneous Cash Receipts	25,102,719.59	25,102,719.59	See funding & disbursement summary
Interportfolio Transfers In	96,722,110.93	96,722,110.93	See funding & disbursement summary
Security Receipts	448,181,853.76	509,170,211.49	See funding & disbursement summary
Total receipts	570,006,684.28	630,995,042.01	See funding & disbursement summary
Miscellaneous Cash Disbursements	- 3,562,737.87	- 3,562,737.87	See funding & disbursement summary
Interportfolio Transfers Out	- 96,722,110.93	- 96,722,110.93	See funding & disbursement summary
Security Deliveries	- 1,665,765.54	- 1,703,547.73	See funding & disbursement summary
Total disbursements	- 101,950,614.34	- 101,988,396.53	See funding & disbursement summary
Income received	14,132,179.45	14,132,179.45	See income & expense summary, cash activity detail
Expenses paid	- 6,481,452.55	- 6,481,452.55	See income & expense summary
Unrealized gain/loss change	0.00	104,536,320.54	See asset summary
Unrealized gain/loss on security movements	0.00	- 60,950,575.54	See funding & disbursement summary
Realized gain/loss	9,130,261.88	9,130,261.88	See realized gain/loss summary
Accrued income change	1,931,353.27	1,931,353.27	See income & expense summary
Total amortization expense	- 263,798.08	- 263,798.08	See fixed income amortization
Total OID/MKT accretion income	22,350.30	22,350.30	See fixed income amortization
Closing balance	486,526,964.21	591,063,284.75	

SI-SSA-0010-1266

Change in Cash Value

	Market value	Cost	For more information
Opening balance	0.00	0.00	
Miscellaneous cash receipts	25,102,719.59	25,102,719.59	See funding & disbursement summary
Interportfolio transfers in	96,722,110.93	96,722,110.93	See funding & disbursement summary
Total receipts	121,824,830.52	121,824,830.52	See funding & disbursement summary
Miscellaneous cash disbursements	- 3,562,737.87	- 3,562,737.87	See funding & disbursement summary
Interportfolio transfers out	- 96,722,110.93	- 96,722,110.93	See funding & disbursement summary
Total disbursements	- 100,284,848.80	- 100,284,848.80	See funding & disbursement summary
Income received	14,118,286.83	14,118,286.83	See income & expense summary, cash activity detail
Expenses paid	- 6,481,452.55	- 6,481,452.55	See income & expense summary
Capital changes	7,704,188.32	7,704,188.32	See capital change detail
Foreign currency bought	12,856,933.75	12,856,933.75	See foreign exchange summary
Foreign currency sold	- 12,856,933.75	- 12,856,933.75	See foreign exchange summary
Realized gain/loss	7,644.37	7,644.37	See realized gain/loss summary
Unrealized gain/loss	- 811.03	0.00	See asset summary
Securities bought	- 265,181,329.29	- 265,181,329.29	See investment transaction summary
Securities sold	268,986,686.40	268,986,686.40	See investment transaction summary
Intra portfolio transfer	0.00	0.00	
Closing balance	40,693,194.77	40,694,005.80	

SI-SSA-0010-1267

Asset Summary - Taxable

Cost Method: HIGH COST

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Unrealized gain/loss Translation	Unrealized gain/loss Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Cash								
Cash - all currencies	- 6.51	52,254.35	53,065.38	0.00	- 811.03	- 811.03	52,247.84	.009%
Total cash	**- 6.51**	**52,254.35**	**53,065.38**	**0.00**	**- 811.03**	**- 811.03**	**52,247.84**	**.009%**
Invested cash								
Invested cash - all currencies	21.03	3,015,240.80	3,015,240.80	0.00	0.00	0.00	3,015,261.83	.510%
Total invested cash	**21.03**	**3,015,240.80**	**3,015,240.80**	**0.00**	**0.00**	**0.00**	**3,015,261.83**	**.510%**
Funds - short term investment								
Funds - Short Term Investment - all currencies	336.11	37,625,699.62	37,625,699.62	0.00	0.00	0.00	37,626,035.73	6.366%
Total funds - short term investment	**336.11**	**37,625,699.62**	**37,625,699.62**	**0.00**	**0.00**	**0.00**	**37,626,035.73**	**6.366%**
Total cash and cash equivalents	**350.63**	**40,693,194.77**	**40,694,005.80**	**0.00**	**- 811.03**	**- 811.03**	**40,693,545.40**	**6.885%**
Adjustments To Cash								
Pending foreign exchange purchases								
Pending foreign exchange purchases - all currencies	0.00	70.71	70.71	0.00	0.00	0.00	70.71	.000%
Total pending foreign exchange purchases	**0.00**	**70.71**	**70.71**	**0.00**	**0.00**	**0.00**	**70.71**	**.000%**
Pending foreign exchange sales								
Pending foreign exchange sales - all currencies	0.00	- 70.63	- 70.71	0.00	0.08	0.08	- 70.63	.000%
Total pending foreign exchange sales	**0.00**	**- 70.63**	**- 70.71**	**0.00**	**0.08**	**0.08**	**- 70.63**	**.000%**
Pending trade purchases								
Pending trade purchases - all currencies	0.00	- 6,904,847.35	- 6,904,847.35	0.00	0.00	0.00	- 6,904,847.35	- 1.168%
Total pending trade purchases	**0.00**	**- 6,904,847.35**	**- 6,904,847.35**	**0.00**	**0.00**	**0.00**	**- 6,904,847.35**	**- 1.168%**

** - Lot Level Information Not Verified

SI-SSA-0010-1268

ASSETS			
INVESTMENTS:			
INVESTMENTS AT IDENTIFIED COST	$ 449,176,728.84		
UNREALIZED APPRECIATION-INVEST	53,668,540.74		
		$	502,845,269.58
RECEIVABLES:			
SECURITIES SOLD	1,249,690.20		
INTEREST	1,948,908.85		
			3,198,599.05
CASH			6,377.33-
TOTAL ASSETS			506,037,491.30
LIABILITIES			
PAYABLES			
SECURITIES PURCHASED	1,648,136.85		
PAYABLE FOR UNITS REDEEMED	796,259.00-		
			851,877.85
TOTAL LIABILITIES			851,877.85
NET ASSETS		$	505,185,613.45

SI-SSA-0010-1269

ASSETS			
INVESTMENTS:			
INVESTMENTS AT IDENTIFIED COST	$ 18,318,474.19		
UNREALIZED APPRECIATION-INVEST	7,321,595.57		
		$	25,640,069.76
RECEIVABLES:			
INTEREST	26.35		
			26.35
TOTAL ASSETS			25,640,096.11
LIABILITIES			
TOTAL LIABILITIES			0.00
NET ASSETS		$	25,640,096.11

Oyster Creek

SI-SSA-0010-1271

Change in Book and Market Value

	Cost	Market value	For more information
Opening balance	0.00	0.00	
Miscellaneous Cash Receipts	15,966,173.22	15,966,173.22	See funding & disbursement summary
Interportfolio Transfers In	164,633,093.02	164,633,093.02	See funding & disbursement summary
Security Receipts	657,644,912.14	803,566,627.46	See funding & disbursement summary
Total receipts	838,244,178.38	984,165,893.70	See funding & disbursement summary
Miscellaneous Cash Disbursements	- 5,760,971.08	- 5,760,971.08	See funding & disbursement summary
Interportfolio Transfers Out	- 164,633,093.02	- 164,633,093.02	See funding & disbursement summary
Security Deliveries	- 2,849,116.46	- 2,926,001.95	See funding & disbursement summary
Total disbursements	- 173,243,180.56	- 173,320,066.05	See funding & disbursement summary
Income received	22,300,725.91	22,300,725.91	See income & expense summary, cash activity detail
Expenses paid	- 5,994,658.32	- 5,994,658.32	See income & expense summary
Unrealized gain/loss change	0.00	203,919,341.64	See asset summary
Unrealized gain/loss on security movements	0.00	- 145,844,829.83	See funding & disbursement summary
Realized gain/loss	- 2,894,305.66	- 2,894,305.66	See realized gain/loss summary
Accrued income change	3,399,195.14	3,399,195.14	See income & expense summary
Total amortization expense	- 1,103,695.91	- 1,103,695.91	See fixed income amortization
Total OID/MKT accretion income	2,016,528.25	2,016,528.25	See fixed income amortization
Closing balance	682,724,787.23	886,644,128.87	

SI-SSA-0010-1272

Change in Cash Value

	Market value	Cost	For more information
Opening balance	0.00	0.00	
Miscellaneous cash receipts	15,966,173.22	15,966,173.22	See funding & disbursement summary
Interportfolio transfers in	164,633,093.02	164,633,093.02	See funding & disbursement summary
Total receipts	180,599,266.24	180,599,266.24	See funding & disbursement summary
Miscellaneous cash disbursements	- 5,760,971.08	- 5,760,971.08	See funding & disbursement summary
Interportfolio transfers out	- 164,633,093.02	- 164,633,093.02	See funding & disbursement summary
Total disbursements	- 170,394,064.10	- 170,394,064.10	See funding & disbursement summary
Income received	22,267,416.35	22,267,416.35	See income & expense summary, cash activity detail
Expenses paid	- 5,994,658.32	- 5,994,658.32	See income & expense summary
Capital changes	12,702,254.96	12,702,254.96	See capital change detail
Foreign currency bought	19,300,749.18	19,300,749.18	See foreign exchange summary
Foreign currency sold	- 19,300,749.18	- 19,300,749.18	See foreign exchange summary
Realized gain/loss	11,175.40	11,175.40	See realized gain/loss summary
Unrealized gain/loss	- 1,183.30	0.00	See asset summary
Securities bought	- 442,417,865.18	- 442,417,865.18	See investment transaction summary
Securities sold	452,716,135.33	452,716,135.33	See investment transaction summary
Intra portfolio transfer	0.00	0.00	
Closing balance	49,488,477.38	49,489,660.68	

SI-SSA-0010-1273

Asset Summary - Taxable

Cost Method: HIGH COST

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Unrealized gain/loss Translation	Unrealized gain/loss Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Cash								
Cash - all currencies	- 0.43	148,847.37	150,030.67	0.00	- 1,183.30	- 1,183.30	148,846.94	.017%
Total cash	**- 0.43**	**148,847.37**	**150,030.67**	**0.00**	**- 1,183.30**	**- 1,183.30**	**148,846.94**	**.017%**
Invested cash								
Invested cash - all currencies	22.82	3,203,644.56	3,203,644.56	0.00	0.00	0.00	3,203,667.38	.361%
Total invested cash	**22.82**	**3,203,644.56**	**3,203,644.56**	**0.00**	**0.00**	**0.00**	**3,203,667.38**	**.361%**
Funds - short term investment								
Funds - Short Term Investment - all currencies	422.14	46,135,985.45	46,135,985.45	0.00	0.00	0.00	46,136,407.59	5.203%
Total funds - short term investment	**422.14**	**46,135,985.45**	**46,135,985.45**	**0.00**	**0.00**	**0.00**	**46,136,407.59**	**5.203%**
Total cash and cash equivalents	**444.53**	**49,488,477.38**	**49,489,660.68**	**0.00**	**- 1,183.30**	**- 1,183.30**	**49,488,921.91**	**5.582%**
Adjustments To Cash								
Pending foreign exchange purchases								
Pending foreign exchange purchases - all currencies	0.00	106.07	106.07	0.00	0.00	0.00	106.07	.000%
Total pending foreign exchange purchases	**0.00**	**106.07**	**106.07**	**0.00**	**0.00**	**0.00**	**106.07**	**.000%**
Pending foreign exchange sales								
Pending foreign exchange sales - all currencies	0.00	- 105.94	- 106.07	0.00	0.13	0.13	- 105.94	.000%
Total pending foreign exchange sales	**0.00**	**- 105.94**	**- 106.07**	**0.00**	**0.13**	**0.13**	**- 105.94**	**.000%**
Pending trade purchases								
Pending trade purchases - all currencies	0.00	- 10,493,416.33	- 10,493,416.33	0.00	0.00	0.00	- 10,493,416.33	- 1.184%
Total pending trade purchases	**0.00**	**- 10,493,416.33**	**- 10,493,416.33**	**0.00**	**0.00**	**0.00**	**- 10,493,416.33**	**- 1.184%**

** - Lot Level Information Not Verified

MERGEN OC QUALIFIED MGR
MERGEN OC QUALIFIED MGR

SI-SSA-0010-1274

ASSETS			
INVESTMENTS:			
INVESTMENTS AT IDENTIFIED COST	$ 603,536,166.26		
UNREALIZED APPRECIATION-INVEST	81,149,023.19		
		$	684,685,189.45
RECEIVABLES:			
SECURITIES SOLD	2,205,170.43		
INTEREST	3,608,889.57		
			5,814,060.00
TOTAL ASSETS			690,499,249.45
LIABILITIES			
PAYABLES			
SECURITIES PURCHASED	2,395,418.86		
			2,395,418.86
TOTAL LIABILITIES			2,395,418.86
NET ASSETS		$	688,103,830.59

OM G716289
MERGEN OC NQ MGR
MERGEN OC NQ MGR

ASSETS		
INVESTMENTS:		
INVESTMENTS AT IDENTIFIED COST	$ 60,579,855.52	
UNREALIZED APPRECIATION-INVEST	64,760,343.69	
		$ 125,340,199.21
RECEIVABLES:		
INTEREST	621,478.64	
		621,478.64
TOTAL ASSETS		125,961,677.85
LIABILITIES		
TOTAL LIABILITIES		0.00
NET ASSETS		$ 125,961,677.85

SI-SSA-0010-1275

Legacy ComEd

SI-SSA-0010-1277

Change in Book and Market Value

	Cost	Market value	For more information
Opening balance	3,022,664,954.22	4,023,396,057.49	
Miscellaneous Cash Receipts	10,117.61	10,117.61	See funding & disbursement summary
Sponsor Contributions	325,618.82	325,618.82	See funding & disbursement summary
Interportfolio Transfers In	576,345,804.53	576,345,804.53	See funding & disbursement summary
Security Receipts	980,035.52	977,585.83	See funding & disbursement summary
Total receipts	577,661,576.48	577,659,126.79	See funding & disbursement summary
Interportfolio Transfers Out	- 576,345,804.53	- 576,345,804.53	See funding & disbursement summary
Security Deliveries	- 980,035.52	- 985,783.03	See funding & disbursement summary
Total disbursements	- 577,325,840.05	- 577,331,587.56	See funding & disbursement summary
Income received	122,692,802.88	122,692,802.88	See income & expense summary, cash activity detail
Expenses paid	- 62,134,332.41	- 62,134,332.41	See income & expense summary
Unrealized gain/loss change	0.00	267,101,108.08	See asset summary
Unrealized gain/loss on security movements	0.00	8,197.20	See funding & disbursement summary
Realized gain/loss	113,867,342.97	113,867,342.97	See realized gain/loss summary
Accrued income change	428,130.73	428,130.73	See income & expense summary
Total amortization expense	- 6,355,733.98	- 6,355,733.98	See fixed income amortization
Total OID/MKT accretion income	469,879.43	469,879.43	See fixed income amortization
Return of capital	- 13,218.66	- 13,218.66	See capital change detail
Wash Sale Cost Adjustments	2.26	2.26	See investment transaction detail
Wash Sale Adjustment Reclassification	- 2.26	- 2.26	See investment transaction detail
Closing balance	3,191,955,561.61	4,459,787,772.96	

SI-SSA-0010-1278

Change in Cash Value

	Market value	Cost	For more information
Opening balance	132,979,803.82	132,979,752.80	
Miscellaneous cash receipts	10,117.61	10,117.61	See funding & disbursement summary
Sponsor contributions	325,618.82	325,618.82	See funding & disbursement summary
Interportfolio transfers in	576,345,804.53	576,345,804.53	See funding & disbursement summary
Total receipts	576,681,540.96	576,681,540.96	See funding & disbursement summary
Interportfolio transfers out	- 576,345,804.53	- 576,345,804.53	See funding & disbursement summary
Total disbursements	- 576,345,804.53	- 576,345,804.53	See funding & disbursement summary
Income received	122,651,290.91	122,651,290.91	See income & expense summary, cash activity detail
Expenses paid	- 62,134,332.41	- 62,134,332.41	See income & expense summary
Capital changes	56,866,152.07	56,866,152.07	See capital change detail
Foreign currency bought	1,595,340,315.70	1,595,340,315.70	See foreign exchange summary
Foreign currency sold	- 1,595,340,315.70	- 1,595,340,315.70	See foreign exchange summary
Realized gain/loss	- 985,042.48	- 985,042.48	See realized gain/loss summary
Mark-to-markets	- 15,583.02	- 15,583.02	See realized gain/loss summary
Unrealized gain/loss	- 17,252.83	0.00	See asset summary
Securities bought	- 1,657,409,736.09	- 1,657,409,736.09	See investment transaction summary
Securities sold	1,601,732,353.84	1,601,732,353.84	See investment transaction summary
Principal paydowns	21,392,869.91	21,392,869.91	See investment transaction summary
Intra portfolio transfer	0.00	0.00	
Closing balance	215,396,260.15	215,413,461.96	

SI-SSA-0010-1279

Asset Summary - Taxable

Cost Method: HIGH COST

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Unrealized gain/loss Translation	Unrealized gain/loss Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Funds - short term investment								
Funds - Short Term Investment - all currencies	1,956.21	212,469,246.49	212,469,246.49	0.00	0.00	0.00	212,471,202.70	4.764%
Total funds - short term investment	**1,956.21**	**212,469,246.49**	**212,469,246.49**	**0.00**	**0.00**	**0.00**	**212,471,202.70**	**4.764%**
Currency								
Currency - all currencies	0.00	336.63	336.63	0.00	0.00	0.00	336.63	.000%
Total currency	**0.00**	**336.63**	**336.63**	**0.00**	**0.00**	**0.00**	**336.63**	**.000%**
Total cash and cash equivalents	**12,662.73**	**410,498,547.65**	**410,778,258.03**	**- 262,508.57**	**- 17,201.81**	**- 279,710.38**	**410,511,210.38**	**9.205%**
Adjustments To Cash								
Pending foreign exchange purchases								
Pending foreign exchange purchases - all currencies	0.00	136,025,052.80	135,960,941.12	0.00	64,111.68	64,111.68	136,025,052.80	3.050%
Total pending foreign exchange purchases	**0.00**	**136,025,052.80**	**135,960,941.12**	**0.00**	**64,111.68**	**64,111.68**	**136,025,052.80**	**3.050%**
Pending foreign exchange sales								
Pending foreign exchange sales - all currencies	0.00	- 136,166,664.39	- 135,960,941.12	0.00	- 205,723.27	- 205,723.27	- 136,166,664.39	- 3.053%
Total pending foreign exchange sales	**0.00**	**- 136,166,664.39**	**- 135,960,941.12**	**0.00**	**- 205,723.27**	**- 205,723.27**	**- 136,166,664.39**	**- 3.053%**
Pending trade purchases								
Pending trade purchases - all currencies	0.00	- 18,620,372.98	- 18,620,372.98	0.00	0.00	0.00	- 18,620,372.98	- .418%
Total pending trade purchases	**0.00**	**- 18,620,372.98**	**- 18,620,372.98**	**0.00**	**0.00**	**0.00**	**- 18,620,372.98**	**- .418%**
Pending trade sales								
Pending trade sales - all currencies	0.00	14,007,405.67	14,007,404.26	0.00	1.41	1.41	14,007,405.67	.314%
Total pending trade sales	**0.00**	**14,007,405.67**	**14,007,404.26**	**0.00**	**1.41**	**1.41**	**14,007,405.67**	**.314%**

** - Lot Level Information Not Verified

contract_u	seller_com	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_t	actual_terr
C1	PSEG Nucle	PSEG Energ	Y	Supplemen	415	19991001	20050101		

extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units	rate
Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate	

rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date	end_date
		FERC Acces	Flat Rate			PJM	PJM CONTROL AREA		

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201309

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Supplemen	415	NUCLEAR	2.01E+11	2.01E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Supplemen	415	NUCLEAR	2.01E+11	2.01E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Supplemen	415	NUCLEAR	2.01E+11	2.01E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2638999
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2588275
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2271275

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
25.81945	Flat Rate			0	68137496
27.45143	Flat Rate			0	71051836
36.6003	Flat Rate			0	83129338

contract_u	seller_com	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_t	actual_terr
C1	PSEG Nucle	PSEG Energ	Y	Supplemen	415	19991001	20050101		

extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units	rate
Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate	

rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date	end_date
		FERC Acces	Flat Rate			PJM	PJM CONTROL AREA		

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201312

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Supplemen	415	NUCLEAR	2.01E+11	2.01E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Supplemen	415	NUCLEAR	2.01E+11	2.01E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Supplemen	415	NUCLEAR	2.01E+11	2.01E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	1799585
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2385315
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2527227

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
56.51291	Flat Rate			0	1.02E+08
31.80231	Flat Rate			0	75858512
27.14576	Flat Rate			0	68603481

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Supplemen	415	NUCLEAR	2.01E+11	2.01E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Supplemen	415	NUCLEAR	2.01E+11	2.01E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Supplemen	415	NUCLEAR	2.01E+11	2.01E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2801978
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2453394
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2794028

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
26.86053	Flat Rate			0	75262617
25.5544	Flat Rate			0	62694995
25.83718	Flat Rate			0	72189794

contract_u	seller_com	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_t	actual_terr
C1	PSEG Nucle	PSEG Energ	Y	Supplemen	415	19991001	20050101		

extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units	rate
Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate	

rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date	end_date
		FERC Acces	Flat Rate			PJM	PJM CONTROL AREA		

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201403
973-430-68	rahul.shett	N	201403

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Supplemen	415	NUCLEAR	2.01E+11	2.01E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Supplemen	415	NUCLEAR	2.01E+11	2.01E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Supplemen	415	NUCLEAR	2.01E+11	2.01E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2235431
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2145361
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2156899

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
37.66062	Flat Rate			0	84187689
34.03166	Flat Rate			0	73010184
30.63719	Flat Rate			0	66081335

contract_u	seller_com	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_t	actual_terr
C1	PSEG Nucle	PSEG Energ	Y	Supplemen	415	19991001	20050101		

extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units	rate
Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate	

rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date	end_date
		FERC Acces	Flat Rate			PJM	PJM CONTROL AREA		

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201406
973-430-68	rahul.shett	N	201406

filer_uniqu Seller_Com Index_Price Transactions_Reported

filer_uniqu Seller_Com Index_Price Transactions_Reported

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201409
973-430-68	rahul.shett	N	201409

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Supplemen	415	NUCLEAR	2.01E+11	2.01E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Supplemen	415	NUCLEAR	2.01E+11	2.01E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Supplemen	415	NUCLEAR	2.01E+11	2.01E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2448211
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2707475
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2409015

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
27.01072	Flat Rate			0	66127949
23.61943	Flat Rate			0	63949018
28.80368	Flat Rate			0	69388497

contract_u	seller_com	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_t	actual_terr
C1	PSEG Nucle	PSEG Energ	Y	Supplemen	415	19991001	20050101		

extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units	rate
Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate	

rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date	end_date
		FERC Acces	Flat Rate			PJM	PJM CONTROL AREA		

contract_u	seller_com	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_t	actual_terr
C1	PSEG Nucle	PSEG Energ	Y	Market-Bas	415	19991001	20050101		

extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units	rate
Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate	

rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date	end_date
		FERC Acces	Flat Rate			PJM	PJM CONTROL AREA		

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201412
973-430-68	rahul.shett	N	201412

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.01E+11	2.01E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.01E+11	2.01E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.01E+11	2.01E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2341947
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	1886422
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2727389

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
37.25791	Flat Rate			0	87256046
38.4739	Flat Rate			0	72578016
25.85631	Flat Rate			0	70520216

contract_u	seller_com	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_t	actual_terr
C1	PSEG Nucle	PSEG Energ	Y	Market-Bas	415	19991001	20050101		

extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units	rate
Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate	

rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date	end_date
		FERC Acces	Flat Rate			PJM	PJM CONTROL AREA		

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-6[illegible]	rahul.shett	N	201503
973-430-6[illegible]	rahul.shett	N	201503

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2795114
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2478133
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2558343

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
26.75008	Flat Rate			0	74769525
27.05773	Flat Rate			0	67052668
30.24931	Flat Rate			0	77388107

contract_u	seller_com	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_t	actual_terr
C1	PSEG Nucle	PSEG Energ	Y	Market-Bas	415	19991001	20050101		

extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units	rate
Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate	

rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date	end_date
		FERC Acces	Flat Rate			PJM	PJM CONTROL AREA		

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201506
973-430-68	rahul.shett	N	201506

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2089967
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2373806
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2665333

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
49.52396	Flat Rate			0	1.04E+08
32.98137	Flat Rate			0	78291394
26.84603	Flat Rate			0	71553609

contract_u	seller_com	seller_histo	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_te
C1	PSEG Nuclear LLC	PSEG Energ	Y		Market-Bas	415	19991001	20050101	

actual_terr	extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units
	Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate

rate	rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date
			FERC Acces	Flat Rate			PJM	PJM CONTROL AREA	

end_date

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201509
973-430-68	rahul.shett	N	201509

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2734018
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2639647
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2413318

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
26.04435	Flat Rate			0	71205697
26.94898	Flat Rate			0	71135793
36.16045	Flat Rate			0	87266668

contract_u	seller_com	seller_histc	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_te
C1	PSEG Nuclear LLC	PSEG Energ	Y		Market-Bas	415	19991001	20050101	

actual_terr	extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units
	Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate

rate	rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date
			FERC Acces	Flat Rate			PJM	PJM CONTROL AREA	

end_date

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201512
973-430-68	rahul.shett	N	201512

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2285300
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2193288
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2786845

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
38.3707	Flat Rate			0	87688576
35.6919	Flat Rate			0	78282616
29.37705	Flat Rate			0	81869299

contract_u	seller_com	seller_histo	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_te
C1	PSEG Nuclear LLC	PSEG Energ	Y		Market-Bas	415	19991001	20050101	

actual_terr	extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units
	Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate

rate	rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date
			FERC Acces	Flat Rate			PJM	PJM CONTROL AREA	

end_date

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201603
973-430-68	rahul.shett	N	201603

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2910456
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2624699
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2883922

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
26.63967	Flat Rate			0	77533585
25.9449	Flat Rate			0	68097544
25.97691	Flat Rate			0	74915374

contract_u	seller_com	seller_histc	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_te
C1	PSEG Nuclear LLC	PSEG Energ	Y		Market-Bas	415	19991001	20050101	

actual_terr	extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units
	Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate

rate	rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date
			FERC Acces	Flat Rate			PJM	PJM CONTROL AREA	

end_date

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201606
973-430-68	rahul.shett	N	201606

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2518403
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2351539
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2112858

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
31.87259	Flat Rate			0	80268048
32.98247	Flat Rate			0	77559577
29.24279	Flat Rate			0	61785849

contract_u	seller_com	seller_histo	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_te
C1	PSEG Nuclear LLC	PSEG Energ	Y		Market-Bas	415	19991001	20050101	

actual_terr	extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units
	Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate

rate	rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date
			FERC Acces	Flat Rate			PJM	PJM CONTROL AREA	

end_date

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201609
973-430-68	rahul.shett	N	201609

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	1818342
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2582318
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2462488

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
34.86395	Flat Rate			0	63394592
27.42174	Flat Rate			0	70811650
30.05766	Flat Rate			0	74016605

contract_u	seller_com	seller_histo	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_te
C1	PSEG Nuclear LLC	PSEG Energ	Y		Market-Bas	415	19991001	20050101	

actual_terr	extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units
	Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate

rate	rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date
			FERC Acces	Flat Rate			PJM	PJM CONTROL AREA	

end_date

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201612
973-430-68	rahul.shett	N	201612

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2157274
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2215155
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2915058

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
50.00883	Flat Rate			0	1.08E+08
38.8004	Flat Rate			0	85948890
26.76372	Flat Rate			0	78017792

contract_u	seller_com	seller_histo	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_te
C1	PSEG Nuclear LLC	PSEG Energ	Y		Market-Bas	415	19991001	20050101	

actual_terr	extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units
	Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate

rate	rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date
			FERC Acces	Flat Rate			PJM	PJM CONTROL AREA	

end_date

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201703
973-430-68	rahul.shett	N	201703

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contrc	UP	LT	M	FP	Tolling Ene	2897772
Formula	ED	PJM	PJM Contrc	UP	LT	M	FP	Tolling Ene	2584081
Formula	ED	PJM	PJM Contrc	UP	LT	M	FP	Tolling Ene	2873917

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
24.57755	Flat Rate			0	71220159
24.52722	Flat Rate			0	63380320
24.24772	Flat Rate			0	69685935

contract_u	seller_com	seller_histo	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_te
C1	PSEG Nuclear LLC	PSEG Energ	Y		Market-Bas	415	19991001	20050101	

actual_terr	extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units
	Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate

rate	rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date
			FERC Acces	Flat Rate			PJM	PJM CONTROL AREA	

end_date

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201706
973-430-68	rahul.shett	N	201706

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2531356
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2307874
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2726485

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
30.1342	Flat Rate			0	76280393
32.60508	Flat Rate			0	75248403
27.39174	Flat Rate			0	74683161

contract_u	seller_com	seller_histo	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_te
C1	PSEG Nuclear LLC	PSEG Energ	Y		Market-Bas	415	19991001	20050101	

actual_terr	extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units
	Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate

rate	rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date
			FERC Acces	Flat Rate			PJM	PJM CONTROL AREA	

end_date

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201709
973-430-68	rahul.shett	N	201709

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_nam	term_nam	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contrc	UP	LT	M	FP	Tolling Ene	2792264
Formula	ED	PJM	PJM Contrc	UP	LT	M	FP	Tolling Ene	2787771
Formula	ED	PJM	PJM Contrc	UP	LT	M	FP	Tolling Ene	2628843

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
23.91049	Flat Rate	0	0	0	66764403
24.40866	Flat Rate	0	0	0	68045765
25.75675	Flat Rate	0	0	0	67710465

contract_u	seller_com	seller_histo	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_te
C1	PSEG Nuclear LLC	PSEG Energ	Y		Market-Bas	415	19991001	20050101	

actual_terr	extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units
	Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate

rate	rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date
			FERC Acces	Flat Rate			PJM	PJM CONTROL AREA	

end_date

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201712
973-430-68	rahul.shett	N	201712

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2304819
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2476374
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2894142

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
42.56008	Flat Rate	0	0	0	98093297
32.34267	Flat Rate	0	0	0	80092557
25.27904	Flat Rate	0	0	0	73161129

contract_u	seller_com	seller_histc	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_te
C1	PSEG Nuclear LLC	PSEG Energ	Y		Market-Bas	415	19991001	20050101	

actual_terr	extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units
	Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate

rate	rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date
			FERC Acces	Flat Rate			PJM	PJM CONTROL AREA	

end_date

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201803
973-430-68	rahul.shett	N	201803

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_nam	term_nam	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contrc	UP	LT	M	FP	Tolling Ene	2905775
Formula	ED	PJM	PJM Contrc	UP	LT	M	FP	Tolling Ene	2614072
Formula	ED	PJM	PJM Contrc	UP	LT	M	FP	Tolling Ene	2867834

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
24.23211	Flat Rate	0	0	0	70413070
23.57174	Flat Rate	0	0	0	61618226
25.50119	Flat Rate	0	0	0	73133183

contract_u	seller_com	seller_histo	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_te
C1	PSEG Nuclear LLC	PSEG Energ	Y		Market-Bas	415	19991001	20050101	

actual_terr	extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units
	Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate

rate	rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date
			FERC Acces	Flat Rate			PJM	PJM CONTROL AREA	

end_date

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201806
973-430-68	rahul.shett	N	201806

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2225795
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2447863
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2692583

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
37.51764	Flat Rate	0	0	0	83506565
33.10355	Flat Rate	0	0	0	81032949
25.25395	Flat Rate	0	0	0	67998367

contract_u	seller_com	seller_histo	customer_	contract_a	ferc_tariff_	contract_s	contract_e	commence	contract_te
C1	PSEG Nuclear LLC	PSEG Energ	Y		Market-Bas	415	19991001	20050101	

actual_terr	extension_	class_name	term_name	increment_	increment_	product_ty	product_na	quantity	units
	Evergreen	UP	LT	M	FP	CB	Tolling Energy		Flat Rate

rate	rate_minim	rate_maxir	rate_descri	rate_units	point_of_r	point_of_r	point_of_d	point_of_d	begin_date
			FERC Acces	Flat Rate			PJM	PJM CONTROL AREA	

end_date

filer_uniqu	company_r	company_i	contact_na	contact_tit	contact_ad	contact_cit	contact_st	contact_zi	contact_co
FS1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US
FA1	PSEG Nucle	C001197	Rahul Shet	Business A	80 Park Pla	Newark	NJ	7102	US

contact_ph	contact_en	transaction	filing_quarter
973-430-68	rahul.shett	N	201809
973-430-68	rahul.shett	N	201809

filer_uniqu Seller_Com Index_Price Transactions_Reported

transaction	seller_com	customer_	ferc_tariff_	contract_s	transaction	transaction	transaction	trade_date	exchange_
T1	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T2	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	
T3	PSEG Nucle	PSEG Energ	Market-Bas	415	NUCLEAR	2.02E+11	2.02E+11	20050101	

type_of_ra	time_zone	point_of_d	point_of_d	class_name	term_name	increment_	increment_	product_na	transaction
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2769326
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2792024
Formula	ED	PJM	PJM Contro	UP	LT	M	FP	Tolling Ene	2429168

price	rate_units	standardize	standardize	total_trans	total_transaction_charge
23.52817	Flat Rate	0	0	0	65157186
25.11652	Flat Rate	0	0	0	70125938
29.25806	Flat Rate	0	0	0	71072720

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June 10, 2014

VIA ELECTRONIC FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: **AV Solar Ranch 1, LLC, Docket No. ER12-2178-___**
Baltimore Gas and Electric Company, Docket No. ER10-2172-___
Beebe Renewable Energy, LLC, Docket No. ER12-2311-___
Calvert Cliffs Nuclear Power Plant, LLC, Docket No. ER10-2179-___
Cassia Gulch Wind Park, LLC, Docket No. ER11-2016-___
CER Generation II, LLC, Docket No. ER10-2183-___
CER Generation, LLC, Docket No. ER10-2184-___
Commonwealth Edison Company, Docket No. ER10-1048-___
Constellation Energy Commodities Group Maine, LLC, Docket No. ER10-2192-__
Constellation Mystic Power, LLC, Docket No. ER11-2056-___
Constellation NewEnergy, Inc., Docket No. ER10-2178-___
Constellation Power Source Generation, LLC, Docket No. ER14-1524-___
Cow Branch Wind Power, LLC, Docket No. ER11-2014-___
CR Clearing, LLC, Docket No. ER11-2013-___
Criterion Power Partners, LLC, Docket No. ER10-3308-___
Exelon Framingham, LLC, Docket No. ER10-1020-___
Exelon Generation Company, LLC, Docket No. ER13-1536-___
Exelon New Boston, LLC, Docket No. ER10-1078-___
Exelon West Medway, LLC, Docket No. ER10-1080-___
Exelon Wind 4, LLC, Docket No. ER11-2010-___
Exelon Wyman, LLC, Docket No. ER10-1081-___
Handsome Lake Energy, LLC, Docket No. ER10-2180-___
Harvest II Windfarm, LLC, Docket No. ER12-2201-___
Harvest Windfarm, LLC, Docket No. ER11-2011-___
High Mesa Energy, LLC, Docket No. ER12-2528-___
Michigan Wind 1, LLC, Docket No. ER11-2009-___
Michigan Wind 2, LLC, Docket No. ER11-3989-___
Nine Mile Point Nuclear Station, LLC, Docket No. ER10-2181-___
PECO Energy Company, Docket No. ER14-767-___
R.E. Ginna Nuclear Power Plant, LLC, Docket No. ER10-2182-___
Safe Harbor Water Power Corporation, Docket No. ER11-2383-___

Shooting Star Wind Project, LLC, Docket No. ER12-1829-___
Tuana Springs Energy, LLC, Docket No. ER11-2007-___
Wildcat Wind, LLC, Docket No. ER12-1223-___
Wind Capital Holdings, LLC, Docket No. ER11-2005-___

Notice of Change in Status of the Exelon MBR Entities

Dear Secretary Bose:

Pursuant to the requirements of section 35.42 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[1] the above-captioned affiliates of Exelon Corporation ("Exelon") with market-based rate authority (the "Exelon MBR Entities") submit this notice of change in status to inform the Commission of certain new affiliations with entities that own or will own generation facilities.[2]

On May 13, 2014, Constellation Solar Georgia, LLC ("Constellation Solar Georgia"), an indirect wholly owned subsidiary of Exelon, began the operation of a 0.8 MW (net) solar-powered generation facility located in Sparta, Georgia. The facility is a qualifying facility ("QF") under the Public Utility Regulatory Policies Act of 1978[3] and is interconnected to Georgia Power Company's ("Georgia Power") transmission system within the Southern Company Services, Inc. ("SOCO") balancing authority area ("BAA"). Constellation Solar Georgia sells the output of its facility to Georgia Power Company under a power purchase agreement.

In addition, on June 6, 2014 two indirect wholly owned subsidiaries of Exelon, Beebe 1B Renewable Energy, LLC ("Beebe 1B") and Fourmile Wind Energy, LLC ("Fourmile") filed with the Commission applications for market-based rate authority in Docket Nos. ER14-2144-000 and ER14-2145-000, respectively. Beebe 1B is developing and will own and operate an approximately 50.4 MW (nameplate) wind-powered electric generation facility located in Gratiot County, Michigan and interconnected to the transmission system owned by Michigan Electric Transmission Company, LLC and operated by the Midcontinent Independent System Operator, Inc. ("MISO"). Beebe 1B is an exempt wholesale generator ("EWG") under the Public Utility Holding Company Act of 2005[4] and will sell the output of its facility under separate long-term contracts to the Lansing Board of Water and Light and the Michigan Public Power Agency. Fourmile is developing and will own and operate an approximately 40 MW (nameplate) wind-powered electric generation facility located in

[1] 18 C.F.R. § 35.42 (2013).

[2] The Exelon MBR Entities have attached an updated asset appendix in the format set forth in Appendix B to 18 C.F.R. Part 35, Subpart H that reflects the new affiliations.

[3] *See* the notice of self-certification of QF status filed on May 2, 2014 by Fresh Air Energy VI, LLC in Docket No. QF14-505-000 and the notice of self-recertification of QF status filed on May 13, 2014 by Constellation Solar Georgia. Effective May 7, 2014, Fresh Air Energy VI, LLC changed its name to Constellation Solar Georgia.

[4] *See* the notice of self-certification of EWG status filed on June 3, 2014 by Beebe 1B in Docket No. EG14-60-000.

Garrett County, Maryland and interconnected to the transmission system owned by The Potomac Edison Company and operated by the PJM Interconnection, L.L.C. ("PJM"). Fourmile will file a Form 556 to certify its facility as a QF prior to its commercial operation date and will sell the output of its facility into PJM's market. Both Beebe 1B and Fourmile expect to begin sales of test power from their respective facilities on September 1, 2014 and to begin commercial operations in the fall of 2014.

The affiliations reported herein do not raise any horizontal or vertical market power concerns. Constellation Solar Georgia owns only a *de minimis* (0.8 MW) amount of generation and therefore has no material impact on the ability of any of the Exelon MBR Entities to exercise horizontal market power in the SOCO BAA. In addition, Beebe 1B's and Fourmile's applications for market-based rate authority demonstrate that they pass the pivotal supplier and market share screens for MISO and PJM, respectively. Therefore, the affiliations reported herein do not raise any horizontal market power concerns. With respect to vertical market power, neither Constellation Solar Georgia nor Beebe 1B or Fourmile owns or controls any transmission facilities, except for limited interconnection facilities required to connect individual generating facilities to the transmission grid, or any inputs to electric power production, as defined in section 35.36 of the Commission's regulations.[5] Therefore the affiliations reported herein do not raise any vertical market power concerns.

For the reasons set forth above, the Exelon MBR Entities' affiliations with Constellation Solar Georgia, Beebe 1B, and Fourmile do not materially change the facts and circumstances that the Commission relied upon in granting the Exelon MBR Entities market-based rate authority. Nor do the new affiliations raise any horizontal or vertical market power concerns with respect to the Exelon MBR Entities. Therefore, the Exelon MBR Entities respectfully request that the Commission accept for filing this notice of change in status and find that no further inquiry is necessary.

Respectfully submitted,

/s/ Vincenzo Franco

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Enclosures

[5] 18 C.F.R. § 35.36(a)(4) defines "[i]nputs to electric power production" as "intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; physical coal supply sources and ownership of or control over who may access transportation of coal supplies."

Electric Generating Facilitates Affiliates and Assets

Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
AgriWind LLC	N/A[3]	AgriWind	AgriWind LLC	AgriWind LLC	N/A	Midcontinent Independent System Operator, Inc. ("MISO")	Central	2007	2.1[4]
AgriWind Project L.L.C.	N/A[3]	AgriWind Project	AgriWind Project L.L.C.	AgriWind Project L.L.C.	N/A	MISO	Central	2007	6.3[4]
B & K Energy Systems, LLC	N/A[3]	B & K Energy Systems	B & K Energy Systems, LLC	B & K Energy Systems, LLC	N/A	MISO	Central	2003	1.9[4]
BC Energy LLC	N/A[3]	BC Energy	BC Energy LLC	BC Energy LLC	N/A	MISO	Central	2007	4.2[4]
Beebe 1B Renewable Energy, LLC	(pending)	Beebe 1B Renewable Energy	Beebe 1B Renewable Energy, LLC	Beebe 1B Renewable Energy, LLC	N/A	MISO	Central	Expected 2014	50.4[4]
Beebe Renewable Energy, LLC	ER12-2311	Beebe Renewable Energy	Beebe Renewable Energy, LLC	Beebe Renewable Energy, LLC	N/A	MISO	Central	2012	81.6[4]
Blue Breezes, L.L.C.	N/A [3]	Blue Breezes	Blue Breezes, L.L.C.	Blue Breezes, L.L.C.	N/A	MISO	Central	2006	1.25[4]
Blue Breezes II, L.L.C.	N/A[3]	Blue Breezes II	Blue Breezes II, L.L.C.	Blue Breezes II, L.L.C.	N/A	MISO	Central	2006	1.25[4]
Breezy Bucks-I LLC	N/A[3]	Breezy Bucks-I	Breezy Bucks-I LLC	Breezy Bucks-I LLC	N/A	MISO	Central	2006	1.25[4]
Breezy Bucks-II LLC	N/A[3]	Breezy Bucks-II	Breezy Bucks-II LLC	Breezy Bucks-II LLC	N/A	MISO	Central	2006	1.25[4]
Christoffer Wind Energy I LLC	N/A[3]	Christoffer Wind Energy I	Christoffer Wind Energy I LLC	Christoffer Wind Energy I LLC	N/A	MISO	Central	2008	2.1[4]
Christoffer Wind Energy II LLC	N/A[3]	Christoffer Wind Energy II	Christoffer Wind Energy H LLC	Christoffer Wind Energy II LLC	N/A	MISO	Central	2008	2.1[4]
Christoffer Wind	N/A[3]	Christoffer Wind	Christoffer Wind	Christoffer Wind	N/A	MISO	Central	2008	2.1[4]

Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
Energy III LLC		Energy III	Energy III LLC	Energy HI LLC					
Christoffer Wind Energy IV LLC	N/A[3]	Christoffer Wind Energy IV	Christoffer Wind Energy IV LLC	Christoffer Wind Energy IV LLC	N/A	MISO	Central	2008	2.1[4]
CP Windfarm, LLC	N/A[3]	CP Windfarm	CP Windfarm, LLC	CP Windfarm, LLC	N/A	MISO	Central	2008	4.2[4]
DL Windy Acres, LLC	N/A[3]	DL Windy Acres	DL Windy Acres, LLC	DL Windy Acres, LLC	N/A	MISO	Central	2003	1.9[4]
Exelon Generation Company, LLC ("ExGen")	ER00-3251	Clinton	ExGen	ExGen	N/A	MISO	Central	1987	1,065
ExGen	ER00-3251	Tenaska Frontier Generation Station	Tenaska Frontier Partners Ltd	ExGen	N/A	MISO	Central	2001	860[7]
G-Flow Wind, LLC	N/A [3]	G-Flow Wind	G-Flow Wind, LLC	G-Flow Wind, LLC	N/A	MISO	Central	2006	1.25[4]
Green Acres Breeze, LLC	N/A[3]	Green Acres Breeze	Green Acres Breeze, LLC	Green Acres Breeze, LLC	N/A	MISO	Central	2006	1.25[4]
Harvest Windfarm, LLC	ER07-1246	Harvest Windfarm	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	2007	52.8[4]
Harvest II Windfarm, LLC	ER12-2201	Harvest II Windfarm	Harvest II	Harvest II	N/A	MISO	Central	2012	59.4[4]
K & D Energy LLC	N/A [3]	K & D Energy	K & D Energy LLC	K & D Energy LLC	N/A	MISO	Central	2007	4[4]
KC Energy LLC	N/A [3]	KC Energy	KC Energy LLC	KC Energy LLC	N/A	MISO	Central	2007	4[4]
KSS Turbines LLC	N/A [3]	KSS Turbines	KSS Turbines LLC	KSS Turbines LLC	N/A	MISO	Central	2007	4[4]
Michigan Wind 1, LLC	ER05-1511	Michigan Wind 1	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	2008	69[4]
Michigan Wind 2, LLC	ER11-3989	Michigan Wind 2	Michigan Wind 2, LLC	Michigan Wind 2, LLC	N/A	MISO	Central	2011	90[4]

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
Minnesota Breeze, LLC	N/A[3]	Minnesota Breeze	Minnesota Breeze, LLC	Minnesota Breeze, LLC	N/A	MISO	Central	2006	1.25[4]
Prairie Wind Power LLC	N/A[3]	Prairie Wind Power	Prairie Wind Power LLC	Prairie Wind Power LLC	N/A	MISO	Central	2007	4[4]
Roadrunner-I LLC	N/A[3]	Roadrunner-I	Roadrunner-I LLC	Roadrunner-I LLC	N/A	MISO	Central	2006	1.25[4]
S & P Windfarm, LLC	N/A[3]	S & P Windfarm	S & P Windfarm, LLC	S & P Windfarm, LLC	N/A	MISO	Central	2003	1.9[4]
Salty Dog-I LLC	N/A[3]	Salty Dog-I	Salty Dog-I LLC	Salty Dog-I LLC	N/A	MISO	Central	2006	1.25[4]
Salty Dog-II LLC	N/A[3]	Salty Dog-II	Salty Dog-II LLC	Salty Dog-II LLC	N/A	MISO	Central	2006	1.25[4]
Shane's Wind Machine LLC	N/A[3]	Shane's Wind Machine	Shane's Wind Machine LLC	Shane's Wind Machine LLC	N/A	MISO	Central	2006	2[4]
Sunset Breeze, LLC	N/A[3]	Sunset Breeze	Sunset Breeze, LLC	Sunset Breeze, LLC	N/A	MISO	Central	2006	1.25[4]
Wally's Wind Farm LLC	N/A[3]	Wally's Wind Farm	Wally's Wind Farm LLC	Wally's Wind Farm LLC	N/A	MISO	Central	2006	1.25[4]
Windy Dog-I LLC	N/A[3]	Windy Dog-I	Windy Dog-I LLC	Windy Dog-I LLC	N/A	MISO	Central	2006	1.25[4]
Wolf Wind Enterprises, LLC	N/A[3]	Wolf Wind Enterprises	Wolf Wind Enterprises, LLC	Wolf Wind Enterprises, LLC	N/A	MISO	Central	2006	1.25[4]
Marshall Wind 2, LLC	N/A[3]	Marshall Wind 2	Marshall Wind 2, LLC	Marshall Wind 2, LLC	N/A	Western Area Power Administration - Upper Great Plains East ("WAUE")	Central	2007	4.2[4]
Marshall Wind 3, LLC	N/A[3]	Marshall Wind 3	Marshall Wind 3, LLC	Marshall Wind 3, LLC	N/A	WAUE	Central	2007	4.2[4]
Marshall Wind 4,	N/A[3]	Marshall Wind 4	Marshall Wind	Marshall Wind	N/A	WAUE	Central	2007	4.2[4]

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
LLC			4, LLC	4, LLC					
Marshall Wind 5, LLC	N/A[3]	Marshall Wind 5	Marshall Wind 5, LLC	Marshall Wind 5, LLC	N/A	WAUE	Central	2007	2.1[4]
Marshall Wind 6, LLC	N/A[3]	Marshall Wind 6	Marshall Wind 6, LLC	Marshall Wind 6 LLC	N/A	WAUE	Central	2007	2.1[4]
Marshall Wind 1, LLC	N/A[3]	Marshall Wind 1	Marshall Wind 1, LLC	Marshall Wind 1, LLC	N/A	WAUE	Central	2007	2.1[4]
ExGen	ER97-2261	Kleen	Kleen Energy Systems, LLC	ExGen	2011	ISO New England Inc. ("ISO-NE")	Northeast	2011	620
Constellation Mystic Power, LLC ("Constellation Mystic")	ER10-2281	Mystic - 7	Constellation Mystic	Constellation Mystic	2011	ISO-NE	Northeast	1975	575.48
Constellation Mystic	ER10-2281	Mystic - 8	Constellation Mystic	Constellation Mystic	2011	ISO-NE	Northeast	2003	704
Constellation Mystic	ER10-2281	Mystic – 9	Constellation Mystic	Constellation Mystic	2011	ISO-NE	Northeast	2003	703
Constellation Mystic	ER10-2281	Mystic - Jet	Constellation Mystic	Constellation Mystic	2011	ISO-NE	Northeast	1969	9.07
Constellation Mystic	ER10-2281	Fore River	Constellation Mystic	Constellation Mystic	2011	ISO-NE	Northeast	2003	688
Constellation Solar Connecticut, LLC	N/A[8]	Parker Hannifin Corp at New Britain	Constellation Solar Connecticut, LLC	Constellation Solar Connecticut, LLC	N/A	ISO-NE	Northeast	2008	0.18
Constellation Solar Connecticut, LLC	N/A[8]	East Lyme Bd of Ed at East Lyme HS	Constellation Solar Connecticut, LLC	Constellation Solar Connecticut, LLC	N/A	ISO-NE	Northeast	2009	0.41
Constellation Solar Massachusetts, LLC ("CSMA")	N/A[8]	Kollmorgen Corp at Kollmorgen Electro-Optical HQ Bldg	CSMA	CSMA	N/A	ISO-NE	Northeast	2011	0.17

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
CSMA	N/A[8]	Majilite Corp	CSMA	CSMA	N/A	ISO-NE	Northeast	2009	0.35
CSMA	N/A[8]	NPP Development, LLC at Patriot Place	CSMA	CSMA	N/A	ISO-NE	Northeast	2010	0.45
CSMA	N/A[8]	Town of Norfolk	CSMA	CSMA	N/A	ISO-NE	Northeast	2012	1.35
CSMA	N/A[8]	Town of Swampscott	CSMA	CSMA	N/A	ISO-NE	Northeast	2012	0.32
Constellation Solar Net Metering, LLC	N/A[8]	Town of Uxbridge	Constellation Solar Net Metering, LLC	Constellation Solar Net Metering, LLC	N/A	ISO-NE	Northeast	2012	1.93
Exelon Framingham LLC	ER01-513	Framingham Jet 1-3	Exelon Framingham, LLC	Exelon Framingham, LLC	N/A	ISO-NE	Northeast	1969	33.08
ExGen	N/A	Granite Ridge	Granite Ridge Energy, LLC	ExGen	Jan. 1, 2014	ISO-NE	Northeast	N/A	661
Exelon New Boston, LLC ("Exelon New Boston")	ER01-513	New Boston GT (L Street)	Exelon New Boston	Exelon New Boston	N/A	ISO-NE	Northeast	1966	16.03
Exelon West Medway LLC ("Exelon West Medway")	ER01-513	West Medway Jet 2	Exelon West Medway	Exelon West Medway	N/A	ISO-NE	Northeast	1971	39.85
Exelon West Medway	ER01-513	West Medway Jet 3	Exelon West Medway	Exelon West Medway	N/A	ISO-NE	Northeast	1970	35.44
Exelon West Medway	ER01-513	West Medway Jet 1	Exelon West Medway	Exelon West Medway	N/A	ISO-NE	Northeast	1970	42.00
Exelon Wyman, LLC	ER01-513	Wyman 4	Exelon Wyman, LLC (5.89%)	FPL Wyman Energy, LLC	N/A	ISO-NE	Northeast	1978	610[7]
Holyoke Solar LLC	N/A [3]	City of Holyoke G & E Dept at Mueller	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	2012	2.95
Holyoke Solar LLC	N/A [3]	City of Holyoke G & E Dept at	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	2011	0.87

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
		Meadow							
Residential Solar II, LLC ("RS II")	N/A[8]	Residential Solar	RS II	RS II	N/A	ISO-NE	Northeast	N/A	2.68
Nine Mile Point Nuclear Station, LLC ("Nine Mile Point")	ER01-1654	Nine Mile Point - 1	Nine Mile Point	Nine Mile Point	2010	New York Independent System Operator, Inc. ("NYISO")	Northeast	1969	626.9[7]
Nine Mile Point	ER01-1654	Nine Mile Point - 2	Nine Mile Point (82%)	Nine Mile Point	2010	NYISO	Northeast	1988	1, 287.2[7]
R.E. Ginna Nuclear Power Plant, LLC ("Ginna")	ER04-485	Ginna	Ginna	Ginna	2010	NYISO	Northeast	1970	581.5[7]
RS II	N/A[8]	Residential Solar	RS II	RS II	N/A	NYISO	Northeast	N/A	1.08
Constellation Solar New York, LLC ("CSNY")	N/A[8]	Owens Corning at Bethlehem, NY	CSNY	CSNY	N/A	NYISO	Northeast	2013	2.21
Calvert Cliffs Nuclear Power Plant, LLC ("Calvert Cliffs")	ER00-2917	Calvert Cliffs - 2	Calvert Cliffs	Calvert Cliffs	2010	PJM Interconnection, L.L.C. ("PJM")	Northeast	1977	862[7]
Calvert Cliffs	ER00-2917	Calvert Cliffs - 1	Calvert Cliffs	Calvert Cliffs	2010	PJM	Northeast	1975	873[7]
Constellation Solar Ohio, LLC	N/A[8]	University of Toledo (Solar) Scott Park Campus of Energy & Innovation	Constellation Solar Ohio, LLC	Constellation Solar Ohio, LLC	N/A	PJM	Northeast	2010	0.88
Constellation Solar Ohio, LLC	N/A[8]	University of Toledo (Wind) Scott Park Campus of Energy & Innovation	Constellation Solar Ohio, LLC	Constellation Solar Ohio, LLC	N/A	PJM	Northeast	2010	0.07
ExGen	ER97-2261	York Delta	Calpine Mid Merit LLC	ExGen	2011	PJM	Northeast	2011	565
ExGen	ER97-2261	Cordova Purchase - 1	Cordova Energy, LLC	ExGen	2005	PJM	Northeast	N/A	475

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
ExGen	ER97-2261	Elwood Purchase – 1	Elwood Energy, LLC	ExGen	2006	PJM	Northeast	N/A	600
Constellation Solar DC, LLC	N/A[8]	DC Dept. of General Services at Washington, DC	Constellation Solar DC, LLC	Constellation NewEnergy, Inc.	N/A	PJM	Northeast	2013	0.38
Constellation Solar Federal LLC	N/A[3]	Constellation New Energy, Inc. at US Dept. of State	Constellation Solar Federal LLC	Constellation Solar Federal LLC	N/A	PJM	Northeast	2011	4.23
Constellation Solar Horizons, LLC	N/A[3]	MD Generating Clean Horizons MSM I	Constellation Solar Horizons, LLC	Constellation Solar Horizons, LLC	N/A	PJM	Northeast	2012	13.61
Constellation Solar New Jersey LLC ("CSNJ")	N/A[3]	The City of Vineland at North Vineland	CSNJ	CSNJ	NA	PJM	Northeast	2011	2.54
CSNJ	N/A[3]	The City of Vineland at West Vineland	CSNJ	CSNJ	N/A	PJM	Northeast	2011	4.06
CSNJ	N/A[8]	Benjamin Moore & Co at Flanders NJ	CSNJ	CSNJ	N/A	PJM	Northeast	2011	1.50
CSNJ	N/A[8]	Jet Aviation Teterboro, LP at Teterboro Airport	CSNJ	CSNJ	N/A	PJM	Northeast	2008	0.15
Constellation Solar New Jersey II, LLC ("CSNJ II")	N/A[8]	Johnson Matthey, Inc at West Deptford	CSNJ II	CSNJ II	N/A	PJM	Northeast	2011	4.41
Constellation Solar New Jersey II	N/A[8]	Toys-R-Us Delaware, Inc at Mt Olive	CSNJ II	CSNJ II	N/A	PJM	Northeast	2011	4.57
Constellation Solar New Jersey III, LLC ("CSNJ III")	N/A[8]	Middle Township Elem School 1	CSNJ III	CSNJ III	N/A	PJM	Northeast	2011	0.17
CSNJ III	N/A[8]	Middle Township Elem School 2	CSNJ III	CSNJ III	N/A	PJM	Northeast	2011	0.39

SI-SSA-0010-1491

Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
CSNJ III	N/A[8]	Middle Township High School	CSNJ III	CSNJ III	N/A	PJM	Northeast	2011	0.69
Constellation Power, Inc. ("CPI")	N/A[5]	Colver	Inter-Power/Ahlcon Partners (Colver)	Inter-Power/Ahlcon Partners (Colver)	N/A	PJM	Northeast	1995	104[7]
CPS Gen	ER00-1598	Gould Street - 3	CPS Gen	CPS Gen	N/A	PJM	Northeast	2008	97
CPS Gen	ER00-1598	Notch Cliff 1-8	CPS Gen	CPS Gen	N/A	PJM	Northeast	1969	118
CPS Gen	ER00-1598	Perryman - 1	CPS Gen	CPS Gen	N/A	PJM	Northeast	1972	52
CPS Gen	ER00-1598	Perryman - 51	CPS Gen	CPS Gen	N/A	PJM	Northeast	1995	147
CPS Gen	ER00-1598	Perryman 2-4	CPS Gen	CPS Gen	N/A	PJM	Northeast	1972	154
CPS Gen	ER00-1598	Philadelphia Road 1-2	CPS Gen	CPS Gen	N/A	PJM	Northeast	1970	31
CPS Gen	ER00-1598	Philadelphia Road 3-4	CPS Gen	CPS Gen	N/A	PJM	Northeast	1970	30
CPS Gen	ER00-1598	Riverside - 4	CPS Gen	CPS Gen	N/A	PJM	Northeast	1951	74
CPS Gen	ER00-1598	Riverside 7-8	CPS Gen	CPS Gen	N/A	PJM	Northeast	1970	39
CPS Gen	ER00-1598	Westport - 5	CPS Gen	CPS Gen	N/A	PJM	Northeast	1969	115
Exelon Solar Chicago LLC	N/A[3]	Chicago City Solar	Exelon Solar Chicago LLC	Exelon Solar Chicago LLC	N/A	PJM	Northeast	2010	8.25
Constellation Solar Maryland, LLC ("CSMD")	N/A[8]	AA County, MD at Shared Svcs Complex	CSMD	CSMD	N/A	PJM	Northeast	2011	0.63
CSMD	N/A[8]	Coppin State Univ at Coppin State Univ - PEC	CSMD	CSMD	N/A	PJM	Northeast	2011	0.42
CSMD	N/A[8]	CPSG Fort Smallwood Road Complex	CSMD	CSMD	N/A	PJM	Northeast	2011	0.78
CSMD	N/A[8]	GM Allison Plant-I	CSMD	CSMD	N/A	PJM	Northeast	2011	1.04
CSMD	N/A[8]	Maryland Science Center	CSMD	CSMD	N/A	PJM	Northeast	2011	0.09

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
CSMD	N/A[8]	McCormick & Co, Inc at Belcamp	CSMD	CSMD	N/A	PJM	Northeast	2011	1.56
CSMD	N/A[8]	McCormick & Co, Inc at Hunt Valley	CSMD	CSMD	N/A	PJM	Northeast	2009	0.78
CSMD	N/A[8]	McCormick & Co, Inc Corporate HQ	CSMD	CSMD	N/A	PJM	Northeast	2011	0.08
CSMD	N/A[8]	MD Env Service at MES Headquarters	CSMD	CSMD	N/A	PJM	Northeast	2008	0.25
CSMD	N/A[8]	Mount St. Mary's University at Emmitsburg	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	2012	1.42
CSMD	N/A[3]	General Motors, LLC at Allison Transmission Plant	Constellation Solar Maryland, LLC	Constellation NewEnergy, Inc.	N/A	PJM	Northeast	2012	1.04
CSMD	N/A[3]	McCormick & Company, Inc. at Sparks	Constellation Solar Maryland, LLC	Constellation NewEnergy, Inc.	N/A	PJM	Northeast	2012	0.08
Constellation Solar Maryland II, LLC	N/A[8]	UMMS (U of MD Medical System)	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	2013	3.09
Constellation Solar Maryland II, LLC	N/A[8]	UMMS - CRE	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	2013	0.35
Criterion Power Partners, LLC	ER10-1443	Criterion 1-28	Criterion Power Partners, LLC	Criterion Power Partners, LLC	2010	PJM	Northeast	2010	70
ExGen	ER00-3251	Braidwood 1	ExGen	ExGen	N/A	PJM	Northeast	1988	1,178
ExGen	ER00-3251	Braidwood 2	ExGen	ExGen	N/A	PJM	Northeast	1988	1,152
ExGen	ER00-3251	Byron 1	ExGen	ExGen	N/A	PJM	Northeast	1985	1,164

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
ExGen	ER00-3251	Byron 2	ExGen	ExGen	N/A	PJM	Northeast	1987	1,136
ExGen	ER00-3251	Chester 7	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Chester 8	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Chester 9	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Conemaugh 1	ExGen (31.22%)	ExGen	N/A	PJM	Northeast	1970	850[7]
ExGen	ER00-3251	Conemaugh 2	ExGen (31.22%)	ExGen	N/A	PJM	Northeast	1970	850[7]
ExGen	ER00-3251	Conemaugh A-D	ExGen (31.22%)	ExGen	N/A	PJM	Northeast	1970	10.8[7]
ExGen	ER00-3251	Conowingo 1	ExGen	ExGen	N/A	PJM	Northeast	1928	48
ExGen	ER00-3251	Conowingo 2	ExGen	ExGen	N/A	PJM	Northeast	1928	36
ExGen	ER00-3251	Conowingo 3	ExGen	ExGen	N/A	PJM	Northeast	1928	48
ExGen	ER00-3251	Conowingo 4	ExGen	ExGen	N/A	PJM	Northeast	1928	48
ExGen	ER00-3251	Conowingo 5	ExGen	ExGen	N/A	PJM	Northeast	1928	36
ExGen	ER00-3251	Conowingo 6	ExGen	ExGen	N/A	PJM	Northeast	1928	48
ExGen	ER00-3251	Conowingo 7	ExGen	ExGen	N/A	PJM	Northeast	1928	48
ExGen	ER00-3251	Conowingo 8	ExGen	ExGen	N/A	PJM	Northeast	1964	65
ExGen	ER00-3251	Conowingo 9	ExGen	ExGen	N/A	PJM	Northeast	1964	65
ExGen	ER00-3251	Conowingo 10	ExGen	ExGen	N/A	PJM	Northeast	1964	65
ExGen	ER00-3251	Conowingo 11	ExGen	ExGen	N/A	PJM	Northeast	1964	65
ExGen	ER00-3251	Croydon 11	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 12	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 21	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 22	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 31	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 32	ExGen	ExGen	N/A	PJM	Northeast	1974	48
ExGen	ER00-3251	Croydon 41	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 42	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Delaware 9	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Delaware 10	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Delaware 11	ExGen	ExGen	N/A	PJM	Northeast	1969	13

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
ExGen	ER00-3251	Delaware 12	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Dresden 2	ExGen	ExGen	N/A	PJM	Northeast	1970	883.5
ExGen	ER00-3251	Dresden 3	ExGen	ExGen	N/A	PJM	Northeast	1971	903
ExGen	ER00-3251	Eddystone 3	ExGen	ExGen	N/A	PJM	Northeast	1974	380
ExGen	ER00-3251	Eddystone 4	ExGen	ExGen	N/A	PJM	Northeast	1976	380
ExGen	ER00-3251	Eddystone 10	ExGen	ExGen	N/A	PJM	Northeast	1967	13
ExGen	ER00-3251	Eddystone 20	ExGen	ExGen	N/A	PJM	Northeast	1967	13
ExGen	ER00-3251	Eddystone 30	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Eddystone 40	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Fairless Hills A	ExGen	ExGen	N/A	PJM	Northeast	1996	30
ExGen	ER00-3251	Fairless Hills B	ExGen	ExGen	N/A	PJM	Northeast	1996	30
ExGen	ER00-3251	Falls 1	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Falls 2	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Falls 3	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Keystone 1	ExGen (41.98%)	ExGen	N/A	PJM	Northeast	1967	850[7]
ExGen	ER00-3251	Keystone 2	ExGen (41.98%)	ExGen	N/A	PJM	Northeast	1968	850
ExGen	ER00-3251	Keystone 3-6	ExGen (41.98%)	ExGen	N/A	PJM	Northeast	1968	10.8[7]
ExGen	ER00-3251	LaSalle 1	ExGen	ExGen	N/A	PJM	Northeast	1984	1,137
ExGen	ER00-3251	LaSalle 2	ExGen	ExGen	N/A	PJM	Northeast	1984	1,140
ExGen	ER00-3251	Limerick 1	ExGen	ExGen	N/A	PJM	Northeast	1986	1,146
ExGen	ER00-3251	Limerick 2	ExGen	ExGen	N/A	PJM	Northeast	1990	1,150
ExGen	ER00-3251	Moser 1	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Moser 2	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Moser 3	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Muddy Run 1	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Muddy Run 2	ExGen	ExGen	N/A	PJM	Northeast	1967	133
ExGen	ER00-3251	Muddy Run 3	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Muddy Run 4	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Muddy Run 5	ExGen	ExGen	N/A	PJM	Northeast	1967	134

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
ExGen	ER00-3251	Muddy Run 6	ExGen	ExGen	N/A	PJM	Northeast	1967	133
ExGen	ER00-3251	Muddy Run 7	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Muddy Run 8	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Oyster Creek	ExGen	ExGen	N/A	PJM	Northeast	1969	614.5
ExGen	ER00-3251	Peach Bottom 2	ExGen (50%)	ExGen	N/A	PJM	Northeast	1974	1,125.4[7]
ExGen	ER00-3251	Peach Bottom 3	ExGen (50%)	ExGen	N/A	PJM	Northeast	1974	1,125.4[7]
ExGen	ER00-3251	Pennsbury 1	ExGen	ExGen	N/A	PJM	Northeast	1996	2.67
ExGen	ER00-3251	Pennsbury 2	ExGen	ExGen	N/A	PJM	Northeast	1996	2.67
ExGen	ER00-3251	Quad Cities 1	ExGen (75%)	ExGen	N/A	PJM	Northeast	1972	908[7]
ExGen	ER00-3251	Quad Cities 2	ExGen (75%)	ExGen	N/A	PJM	Northeast	1972	911[7]
ExGen	ER00-3251	Richmond 91	ExGen	ExGen	N/A	PJM	Northeast	1973	49
ExGen	ER00-3251	Richmond 92	ExGen	ExGen	N/A	PJM	Northeast	1973	49
ExGen	ER00-3251	Salem 1	ExGen (42.59%)	PSEG	N/A	PJM	Northeast	1977	1,174[7]
ExGen	ER00-3251	Salem 2	ExGen (42.59%)	PSEG	N/A	PJM	Northeast	1981	1,158[7]
ExGen	ER00-3251	Salem 3	ExGen (42.59%)	PSEG	N/A	PJM	Northeast	1971	37.57[7]
ExGen	ER00-3251	Schuylkill 10	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Schuylkill 11	ExGen	ExGen	N/A	PJM	Northeast	1971	17
ExGen	ER00-3251	Southeast Chicago Energy Project 5	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 6	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 7	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 8	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 9	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 10	ExGen	ExGen	N/A	PJM	Northeast	2002	37

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
ExGen	ER00-3251	Southeast Chicago Energy Project 11	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 12	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southwark 3	ExGen	ExGen	N/A	PJM	Northeast	1967	13
ExGen	ER00-3251	Southwark 4	ExGen	ExGen	N/A	PJM	Northeast	1967	13
ExGen	ER00-3251	Southwark 5	ExGen	ExGen	N/A	PJM	Northeast	1967	13
ExGen	ER00-3251	Southwark 6	ExGen	ExGen	N/A	PJM	Northeast	1968	13
ExGen	ER00-3251	TMI # 1	ExGen	ExGen	N/A	PJM	Northeast	1974	805
Fourmile Wind Energy, LLC	(pending)	Fourmile Wind Energy	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	Expected 2014	40[4]
Handsome Lake Energy, LLC ("Handsome Lake")	ER01-556	Handsome Lake 3-5	Handsome Lake	Handsome Lake	N/A	PJM	Northeast	2001	160.5
Handsome Lake	ER01-556	Handsome Lake 1-2	Handsome Lake	Handsome Lake	N/A	PJM	Northeast	2001	107
RS II	N/A[8]	Residential Solar	RS II	RS II	N/A	PJM	Northeast	N/A	3.56
Safe Harbor Water Power Corporation ("Safe Harbor")	ER08-537	Safe Harbor - 10	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1985	38.5
Safe Harbor	ER08-537	Safe Harbor - 11	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1986	38[7]
Safe Harbor	ER08-537	Safe Harbor - 12	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1985	38.5[7]
Safe Harbor	ER08-537	Safe Harbor - 2	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1934	32[7]
Safe Harbor	ER08-537	Safe Harbor - 7	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1933	32.5[7]
Safe Harbor	ER08-537	Safe Harbor - 8	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1985	37.5[7]
Safe Harbor	ER08-537	Safe Harbor - 9	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1986	38.5[7]
Safe Harbor	ER08-537	Safe Harbor 3-4	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1931	64.5[7]
Safe Harbor	ER08-537	Safe Harbor 5-6	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1932	64.5[7]
Safe Harbor	ER08-537	Safe Harbor - 1	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1940	32[7]
Denver Airport Solar, LCC	N/A[8]	City & County of Denver at Denver International Airport	Denver Airport Solar, LCC	Denver Airport Solar, LCC	N/A	Public Service Co. of Colorado (Xcel Energy)	Northwest	2011	3.77

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
Bennett Creek, LLC	N/A[5]	Mountain Home	Bennett Creek, LLC	Bennett Creek, LLC	N/A	Idaho Power	Northwest	2008	21[4]
Cassia Gulch Wind Park LLC	ER10-75	Cassia Gulch	Cassia Gulch Wind Park LLC	Cassia Gulch Wind Park LLC	N/A	Idaho Power	Northwest	2009	18.9[4]
Cassia Wind Farm LLC	N/A[3]	Cassia Wind	Cassia Wind Farm LLC	Cassia Wind Farm LLC	N/A	Idaho Power	Northwest	2009	10.5[4]
High Mesa Energy, LLC	ER12-2528	High Mesa	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	Idaho Power	Northwest	2012	40[4]
Hot Springs Windfarm, LLC	N/A[5]	Mountain Home	Hot Springs Windfarm, LLC	Hot Springs Windfarm, LLC	N/A	Idaho Power	Northwest	2008	21[4]
Tuana Springs Energy, LLC	ER10-87	Tuana Springs	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	Idaho Power	Northwest	2010	16.8[4]
CER Generation II, LLC	ER08-860	West Valley 1-5	CER Generation-II, LLC	CER Generation-II, LLC	2008	PacifiCorp East	Northwest	2002	200
Big Top, LLC	N/A[3]	Big Top	Big Top, LLC	Big Top, LLC	N/A	PacifiCorp West	Northwest	2009	1.65[4]
Butter Creek Power, LLC	N/A[3]	Butter Creek Power	Butter Creek Power, LLC	Butter Creek Power, LLC	N/A	PacifiCorp West	Northwest	2009	4.95[4]
Sunnyside Cogeneration Assoc.	N/A[5]	Sunnyside Cogen	Sunnyside Cogeneration Assoc.	Sunnyside Cogeneration Assoc.	N/A	PacifiCorp West	Northwest	1993	51
Four Corners Windfarm, LLC	N/A[3]	Four Corners Windfarm	Four Corners Windfarm, LLC	Four Corners Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	10[4]
Four Mile Canyon Windfarm, LLC	N/A [3]	Four Mile Canyon Windfarm	Four Mile Canyon Windfarm, LLC	Four Mile Canyon Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	10[4]
Oregon Trail Windfarm, LLC	N/A[3]	Oregon Trail Windfarm	Oregon Trail Windfarm, LLC	Oregon Trail Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	9.9[4]
Pacific Canyon Windfarm, LLC	N/A [3]	Pacific Canyon Windfarm	Pacific Canyon Windfarm, LLC	Pacific Canyon Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	8.25[4]

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
Sand Ranch Windfarm, LLC	N/A[3]	Sand Ranch Windfarm	Sand Ranch Windfarm, LLC	Sand Ranch Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	9.9[4]
Threemile Canyon Wind I, LLC	N/A[3]	Threemile Canyon	Threemile Canyon Wind I, LLC	Threemile Canyon Wind I, LLC	N/A	PacifiCorp West	Northwest	2009	9.9[4]
Wagon Trail, LLC	N/A[3]	Wagon Trail	Wagon Trail, LLC	Wagon Trail, LLC	N/A	PacifiCorp West	Northwest	2009	3.3[4]
Ward Butte Windfarm, LLC	N/A[3]	Ward Butte Windfarm	Ward Butte Windfarm, LLC	Ward Butte Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	6.6[4]
Outback Solar, LLC	N/A[3]	Outback Solar	Outback Solar, LLC	Outback Solar, LLC	N/A	Bonneville Power Administration	Northwest	2012	4.8
Cow Branch Wind Power, L.L.C.	ER07-1223	Cow Branch	Cow Branch Wind Power, L.L.C.	Cow Branch Wind Power, L.L.C.	N/A	Associated Electric Cooperative, Inc. ("AECI")	Southeast	2008	50.4[4]
CR Clearing, LLC	ER07-1222	Conception	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	2008	50.4[4]
Loess Hills Wind Farm, LLC	N/A[3]	Loess Hills	Loess Hills Wind Farm, LLC	Loess Hills Wind Farm, LLC	N/A	AECI	Southeast	2007	5[4]
Wind Capital Holdings, LLC	ER07-1208	Bluegrass Ridge	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	2007	56.7[4]
Constellation Solar Georgia, LLC	N/A[3]	Georgia Power at Sparta	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	Southern Company Services, Inc. ("SOCO")	Southeast	N/A	0.84
ExGen	ER97-2261	Sowega 1	Georgia Energy Cooperative ("GEC")	ExGen	2011	SOCO	Southeast	2000	48
ExGen	ER97-2261	Sowega 2	GEC	ExGen	2011	SOCO	Southeast	2000	48
ExGen	ER97-2261	Effingham - 1	Effingham County Power,	Effingham County Power,	2007	SOCO	Southeast	2003	502

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
			LLC	LLC					
ExGen	ER97-2261	Washington 1 & 4	Washington County Power, LLC	Washington County Power, LLC	2007	SOCO	Southeast	N/A	307
ExGen	ER97-2261	Franklin - 1	Southern Power Company	Southern Power Company	2007	SOCO	Southeast	N/A	621
CER Generation, LLC	ER10-662	Hillabee	CER Generation, LLC	CER Generation, LLC	2008	SOCO	Southeast	2010	684
ExGen	ER00-325 I	Heard	Tenaska Georgia Partners LP	ExGen	N/A	SOCO	Southeast	2001	945[7]
AV Solar Ranch 1, LLC ("AV Solar")	ER12-2178	Antelope Valley	AV Solar	AV Solar	N/A	California Independent System Operator Corporation ("CAISO")	Southwest	2012	230
Luz Solar Partners IV	N/A[5]	SEGS IV	Luz Solar Partners IV	Luz Solar Partners IV	N/A	CAISO	Southwest	1986	33
Luz Solar Partners V	N/A[5]	SEGS V	Luz Solar Partners V	Luz Solar Partners V	N/A	CAISO	Southwest	1987	24
Luz Solar Partners VI	N/A[5]	SEGS VI	Luz Solar Partners VI	Luz Solar Partners VI	N/A	CAISO	Southwest	1988	34
Constellation Solar California, LLC	N/A[8]	GSA, PBS, Pacific Service Center at Sacramento, Ca.	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	2008	0.44
Constellation Solar California, LLC	N/A[8]	Kawneer Co., Inc. (Alcoa)	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	2007	0.50
Constellation Solar California, LLC	N/A[8]	General Motors Corp. at Fontana, Ca.	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	2007	0.80
Constellation Solar California, LLC	N/A[8]	Univ. of San Francisco at Univ. of	Constellation Solar California,	Constellation Solar California,	N/A	CAISO	Southwest	2008	0.42

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
		San Francisco	LLC	LLC					
Sacramento PV Energy, LLC ("Sacramento PV Energy")	N/A[3]	Sacramento Municipal Utility District at Fleshman	Sacramento PV Energy	Sacramento PV Energy	N/A	CAISO	Southwest	2011	3.08
Sacramento PV Energy	N/A[3]	Sacramento Municipal Utility District at Grundman	Sacramento PV Energy	Sacramento PV Energy	N/A	CAISO	Southwest	2011	18.5
Sacramento PV Energy	N/A[3]	Sacramento Municipal Utility District at Lawrence	Sacramento PV Energy	Sacramento PV Energy	N/A	CAISO	Southwest	2011	1.03
Sacramento PV Energy	N/A[3]	Sacramento Municipal Utility District at VanConnet	Sacramento PV Energy	Sacramento PV Energy	N/A	CAISO	Southwest	2011	3.08
California PV Energy, LLC ("CAPV")	N/A[8]	California PV Energy	CAPV	CAPV	N/A	CAISO	Southwest	N/A	3.3
CAPV	N/A[8]	California PV Energy at Castaic ES	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.12
CAPV	N/A[8]	California PV Energy at Castaic MS	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.28
CAPV	N/A[8]	California PV Energy at Live Oak ES	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.11
CAPV	N/A[8]	California PV Energy at Northlake Hills ES	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.13
CAPV	N/A[8]	Oltmans SCE at Jurupa	CAPV	CAPV	N/A	CAISO	Southwest	2013	1.6
CAPV	N/A[8]	SCE Oltmans at Champagne	CAPV	CAPV	N/A	CAISO	Southwest	2013	1.03
Constellation Solar Arizona, LLC ("CSAZ")	N/A[8]	Buckeye Union High School District 201	CSAZ	CSAZ	N/A	AZPS	Southwest	2011	3.62

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
CSAZ	N/A[8]	Casa Grande at Casa Verde High School	CSAZ	CSAZ	N/A	AZPS	Southwest	2012	0.35
CSAZ	N/A[8]	Casa Grande at Union High School	CSAZ	CSAZ	N/A	AZPS	Southwest	2012	1.79
CSAZ	N/A[8]	Casa Grande at Vista Grande High School	CSAZ	CSAZ	N/A	AZPS	Southwest	2012	1.54
CSAZ	N/A[8]	Isaac School District at Butler	CSAZ	CSAZ	N/A	AZPS	Southwest	2014	0.21
CSAZ	N/A[8]	Miami Phase II at Lee Kornegay HS	CSAZ	CSAZ	N/A	AZPS	Southwest	2014	0.12
CSAZ	N/A[8]	Miami School District	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.36
CSAZ	N/A[8]	Miami School District at Charles Bejarano	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.09
CSAZ	N/A[8]	Peoria School District Phase II at Parkridge Elementary	CSAZ	CSAZ	N/A	AZPS	Southwest	2014	0.44
CSAZ	N/A[8]	Somerton School District at Orange Grove	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.18
CSAZ	N/A[8]	Somerton School District at Tierra del Sol	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.23
CSAZ	N/A[8]	Somerton School District at Valle del Encanto	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.17
CSAZ	N/A[8]	Somerton School District at Desert Sonora	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.29
CSAZ	N/A[8]	Somerton School District at Somerton Middle School	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.47
CSAZ	N/A[8]	Tucson Unified School District at	CSAZ	CSAZ	N/A	AZPS	Southwest	2014	0.25

SI-SSA-0010-1502

Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
		Collier ES							
CSAZ	N/A[8]	Vail School District at Andrada Polytechnic High School	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.33
CSAZ	N/A[8]	Vail School District at Mesquite Elementary School	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.23
CSAZ	N/A[8]	Vail School District at Old Vail Middle School	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.25
CSAZ	N/A[8]	Dysart School District	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	8.8
CSAZ	N/A[8]	Marana School District	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	3.18
CSAZ	N/A[8]	Peoria School District	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	5.05
CSAZ	N/A[8]	Crane School District at Mesquite	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.17
CSAZ	N/A[8]	Crane School District at Gary A. Knox	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.19
CSAZ	N/A[8]	Crane School District at Centennial	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.38
CSAZ	N/A[8]	Crane School District at Valley Horizon	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.27
CSAZ	N/A[8]	Crane School District at Crane	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.38
CSAZ	N/A[8]	Crane School District at Pueblo	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.21
CSAZ	N/A[8]	Crane School District at Salida del Sol	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.26
CSAZ	N/A[8]	Crane School District at Suverkrup	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.27
ExGen	ER00-3251	Green Country 1-3	Green Country	ExGen	N/A	Southwest Power	SPP	2002	785[6]

SI-SSA-0010-1503

Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
			OP Services LLC			Pool ("SPP")			
Exelon Wind 1, LLC	N/A[3]	Exelon Wind 1	Exelon Wind 1, LLC	Exelon Wind 1, LLC	N/A	SPP	SPP	2005	10[4]
Exelon Wind 10, LLC	N/A[3]	Exelon Wind 10	Exelon Wind 10, LLC	Exelon Wind 10, LLC	N/A	SPP	SPP	2008	10[4]
Exelon Wind 11, LLC	N/A[3]	Exelon Wind 11	Exelon Wind 11, LLC	Exelon Wind 11, LLC	N/A	SPP	SPP	2008	10[4]
Exelon Wind 2, LLC	N/A[3]	Exelon Wind 2	Exelon Wind 2, LLC	Exelon Wind 2, LLC	N/A	SPP	SPP	2005	10[4]
Exelon Wind 3, LLC	N/A[3]	Exelon Wind 3	Exelon Wind 3, LLC	Exelon Wind 3, LLC	N/A	SPP	SPP	2005	10[4]
Exelon Wind 4, LLC	ER07-1202	Exelon Wind 4	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	2007	79.8[4]
Exelon Wind 5, LLC	N/A[3]	Exelon Wind 5	Exelon Wind 5, LLC	Exelon Wind 5, LLC	N/A	SPP	SPP	2006	10[4]
Exelon Wind 6, LLC	N/A[3]	Exelon Wind 6	Exelon Wind 6, LLC	Exelon Wind 6, LLC	N/A	SPP	SPP	2006	10[4]
Exelon Wind 7, LLC	N/A[3]	Exelon Wind 7	Exelon Wind 7, LLC	Exelon Wind 7, LLC	N/A	SPP	SPP	2008	10[4]
Exelon Wind 8, LLC	N/A[3]	Exelon Wind 8	Exelon Wind 8, LLC	Exelon Wind 8, LLC	N/A	SPP	SPP	2008	10[4]
Exelon Wind 9, LLC	N/A[3]	Exelon Wind 9	Exelon Wind 9, LLC	Exelon Wind 9, LLC	N/A	SPP	SPP	2008	10[4]
High Plains Wind Power, LLC	N/A [3]	High Plains	High Plains Wind Power, LLC	High Plains Wind Power, LLC	N/A	SPP	SPP	2008	10[4]
Wildcat Wind, LLC	ER12-1223	Wildcat Wind	Wildcat Wind, LLC	Wildcat Wind, LLC	N/A	SPP	SPP	2012	27.3[4]

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
Greensburg Wind Farm, LLC	N/A[3]	Greensburg	Greensburg Wind Farm, LLC	Greensburg Wind Farm, LLC	N/A	SPP	SPP	2010	12.5[4]
Shooting Star Wind Project, LLC	ER12-1829	Shooting Star	Shooting Star Wind Project, LLC	Shooting Star Wind Project, LLC	N/A	SPP	SPP	2012	104
Baltimore Gas and Electric Company ("BGE")	ER99-2948	N/A	N/A	N/A	NA	N/A	N/A	N/A	NA
Commonwealth Edison Company ("ComEd")	ER98-1734	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Constellation Energy Commodities Group Maine, LLC	ER02-699	N/A	N/A	N/A	NA	N/A	N/A	N/A	NA
Constellation NewEnergy, Inc.	ER96-1387	N/A	N/A	N/A	NA	N/A	N/A	N/A	NA
PECO Energy Company ("PECO")	ER01-1147	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1 Unless otherwise indicated, generation capacity ratings (megawatts) are based on the summer seasonal ratings.

2 Facilities solely in the region administered by the Electric Reliability Council of Texas ("ERCOT") are not included herein.

3 MBR authority was not obtained for this entity, because it is a qualifying facility with a capacity of less than 20 MW *(see* 18 C.F.R. § 292.601(c)(1)).

4 The capacity rating for this entity is based on its nameplate capacity.

5 MBR authority was not obtained for this entity, because it is a qualifying facility that sells power pursuant to a PURPA contract or pursuant to a contract executed on or before March 17, 2006 *(see* 18 C.F.R. § 292.601(c)(1)).

6 ExGen has a tolling agreement for 795 MW from Green Country.

7 This generation rating reflects the full plant rating, not just Exelon's ownership share.

8 This row pertains to one or more behind-the-meter facilities that sell entirely at retail and therefore do not participate in the wholesale market.

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Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas Storage

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
Constellation Mystic Power, LLC	Limited & discrete interconnection facilities[1]	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon Framingham, LLC	Limited & discrete interconnection facilities[1]	Exelon Framingham, LLC	Exelon Framingham, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon New Boston, LLC	Limited & discrete interconnection facilities[1]	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon West Medway, LLC	Limited & discrete interconnection facilities[1]	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon Wyman, LLC	Limited & discrete interconnection facilities[1]	Exelon Wyman, LLC	Exelon Wyman, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Holyoke Solar LLC	Limited & discrete interconnection facilities[1]	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Nine Mile Point Nuclear Station, LLC	Limited & discrete interconnection facilities[1]	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	N/A (OATT Waiver)
R.E. Ginna Nuclear Power Plant, LLC	Limited & discrete interconnection facilities[1]	R.E. Ginna Nuclear Power Plant, LLC	R.E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	N/A (OATT Waiver)
BGE	Combined 115kV Lines	BGE	PJM	1998	PJM	Northeast	695.85 combined miles
BGE	Combined 138kV Lines	BGE	PJM	1998	PJM	Northeast	54.44 combined miles

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
BGE	Combined 230kV Lines	BGE	PJM	1998	PJM	Northeast	320.97 combined miles
BGE	Combined 500kV Lines	BGE	PJM	1998	PJM	Northeast	217.42 combined miles
BGE	Intrastate Gas Transmission	BGE	BGE	N/A	PJM	Northeast	approx. 165 combined miles
Calvert Cliffs Nuclear Power Plant, LLC	Limited & discrete interconnection facilities[1]	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
ComEd	Electric Transmission Combined 765 kV Lines	ComEd	ComEd/PJM	N/A	PJM	Northeast	89.59 combined miles
ComEd	Electric Transmission Combined 345 kV Lines	ComEd	ComEd/PJM	N/A	PJM	Northeast	2,634.29 combined miles
ComEd	Electric Transmission Combined 138 kV Lines	ComEd	ComEd/PJM	N/A	PJM	Northeast	2,877.02 combined miles
Criterion Power Partners, LLC	Limited & discrete interconnection facilities[1]	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Exelon Solar Chicago LLC	Limited & discrete interconnection facilities[1]	Exelon Solar Chicago LLC	Exelon Solar Chicago LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Fourmile Wind Energy, LLC	Limited & discrete interconnection facilities[1]	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Handsome Lake	Limited & discrete	Handsome	Handsome	N/A	PJM	Northeast	N/A (OATT Waiver)

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
Energy, LLC	interconnection facilities[1]	Lake Energy, LLC	Lake Energy, LLC				
PECO	Electric Transmission 500 kV Lines	PECO	PECO/PJM	N/A	PJM	Northeast	316.23 combined miles
PECO	Electric Transmission Combined 200/220 kV Lines	PECO	PECO/PJM	N/A	PJM	Northeast	503.05 combined miles
PECO	Electric Transmission Combined 132 kV Lines	PECO	PECO/PJM	N/A	PJM	Northeast	127.70 combined miles
PECO	Electric Transmission Combined 66 kV Lines	PECO	PECO/PJM	N/A	PJM	Northeast	169.54 combined miles
PECO	Electric Transmission Combined 13.2 kV Lines	PECO	PECO/PJM	N/A	PJM	Northeast	0.47 combined miles
PECO	Intrastate Gas Transmission	PECO	PECO	N/A	PJM	Northeast	31 combined miles
PECO	Intrastate Gas Storage (LNG)	PECO	PECO	N/A	PJM	Northeast	1,200 mmcf
Cassia Gulch Wind Park, LLC	Limited & discrete interconnection facilities[1]	Cassia Gulch Wind Park, LLC	Cassia Gulch Wind Park, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
High Mesa Energy, LLC	Limited & discrete interconnection facilities[1]	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
Tuana Springs Energy, LLC	Limited & discrete interconnection	Tuana Springs	Tuana Springs	N/A	Idaho Power	Northwest	N/A (OATT Waiver)

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
	facilities[1]	Energy, LLC	Energy, LLC				
CER Generation II, LLC	Limited & discrete interconnection facilities[1]	CER Generation II, LLC	CER Generation II, LLC	N/A	PacifiCorp East	Northwest	N/A (OATT Waiver)
Beebe 1B Renewable Energy, LLC and Beebe Renewable Energy, LLC ("Beebe")[2]	Limited & discrete interconnection facilities[1]	Beebe	Beebe	N/A	MISO	Central	N/A (OATT Waiver)
Harvest Windfarm, LLC	Limited & discrete interconnection facilities[1]	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	N/A (OATT Waiver)
Michigan Wind 1, LLC	Limited & discrete interconnection facilities[1]	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	N/A (OATT Waiver)
CER Generation, LLC	Limited & discrete interconnection facilities[1]	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	N/A (OATT Waiver)
Constellation Power Source Generation, LLC	Limited & discrete interconnection facilities[1]	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	Various	Various	N/A (OATT Waiver)
Constellation Power, Inc.	Limited & discrete interconnection facilities[1]	Constellation Power, Inc.	Constellation Power, Inc.	N/A	Various	Various	N/A (OATT Waiver)
ExGen	Limited & discrete interconnection facilities[1]	ExGen	ExGen	N/A	Various	Various	N/A (OATT Waiver)
Cow Branch Wind Power, L.L.C.	Limited & discrete interconnection facilities[1]	Cow Branch Wind Power, LLC	Cow Branch Wind Power, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
CR Clearing, LLC	Limited & discrete interconnection	CR Clearing,	CR Clearing,	N/A	AECI	Southeast	N/A (OATT Waiver)

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
	facilities[1]	LLC	LLC				
Wind Capital Holdings, LLC	Limited & discrete interconnection facilities[1]	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
Exelon Wind 4, LLC	Limited & discrete interconnection facilities[1]	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	N/A (OATT Waiver)

[1] These facilities are included because waiver of Order Nos. 888, 889, 890, their implementing regulations, and the requirements of Part 358 of FERC's regulations has been sought with respect to them.

[2] Beebe 1B Renewable Energy, LLC and Beebe Renewable Energy, LLC share certain interconnection facilities.

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CERTIFICATE OF SERVICE

I hereby certify that this day I have caused to be served the foregoing document upon each person designated on the official service lists compiled by the Secretary in these dockets.

Dated at Baltimore, MD this 10th day of June, 2014.

/s/ Vincenzo Franco
Vincenzo Franco
Assistant General Counsel – Wholesale
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Document Content(s)

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November 24, 2014

BY E-FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: AV Solar Ranch 1, LLC, Docket No. ER12-2178-___
Baltimore Gas and Electric Company, Docket No. ER10-2172-
Beebe 1B Renewable Energy, LLC, Docket No. ER14-2144-___
Beebe Renewable Energy, LLC, Docket No. ER12-2311-___
Calvert Cliffs Nuclear Power Plant, LLC, Docket No. ER10-2179-___
Cassia Gulch Wind Park, LLC, Docket No. ER11-2016-___
CER Generation, LLC, Docket No. ER10-2184-___
CER Generation II, LLC, Docket No. ER10-2183-___
Commonwealth Edison Company, Docket No. ER10-1048-___
Constellation Energy Commodities Group Maine, LLC, Docket No. ER10-2192-___
Constellation Mystic Power, LLC, Docket No. ER11-2056-___
Constellation NewEnergy, Inc., Docket No. ER10-2178-___
Constellation Power Source Generation, LLC, Docket No. ER14-1524-___
Cow Branch Wind Power, LLC, Docket No. ER11-2014-___
CR Clearing, LLC, Docket No. ER11-2013-___
Criterion Power Partners, LLC, Docket No. ER10-3308-___
Exelon Framingham, LLC, Docket No. ER10-1020-___
Exelon Generation Company, LLC, Docket No. ER13-1536-___
Exelon New Boston, LLC, Docket No. ER10-1078-___
Exelon West Medway, LLC, Docket No. ER10-1080-___
Exelon Wind 4, LLC, Docket No. ER11-2010-___
Exelon Wyman, LLC, Docket No. ER10-1081-___
Fourmile Wind Energy, LLC, Docket No. ER14-2145-___
Handsome Lake Energy, LLC, Docket No. ER10-2180-___
Harvest Windfarm, LLC, Docket No. ER11-2011-___
Harvest II Windfarm, LLC, Docket No. ER12-2201-___
High Mesa Energy, LLC, Docket No. ER12-2528-___
Integrys Energy Services, Inc., Docket No. ER10-3025-___

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Integrys Energy Services of New York, Inc. Docket No. ER10-3027-___
Michigan Wind 1, LLC, Docket No. ER11-2009-___
Michigan Wind 2, LLC, Docket No. ER11-3989-___
Nine Mile Point Nuclear Station, LLC, Docket No. ER10-2181-___
PECO Energy Company, Docket No. ER14-767-___
R.E. Ginna Nuclear Power Plant, LLC, Docket No. ER10-2182-___
Shooting Star Wind Project, LLC, Docket No. ER12-1829-___
Tuana Springs Energy, LLC, Docket No. ER11-2007-___
Wildcat Wind, LLC, Docket No. ER12-1223-___
Wind Capital Holdings, LLC, Docket No. ER11-2005-___

Notice of Change in Status of the Integrys Entities and the Exelon Entities

Dear Secretary Bose:

Pursuant to Section 35.42(a)(2) of the Federal Energy Regulatory Commission's ("Commission" or "FERC") regulations,[1] Integrys Energy Services, Inc. ("Integrys Energy Services") and Integrys Energy Services of New York, Inc. ("Integrys Energy Services NY" and, collectively with Integrys Energy Services, "Integrys Entities") and the remaining above-captioned affiliates of Exelon Corporation ("Exelon") with market-based rate authority ("Exelon Entities" and, with Integrys Entities, "Sellers") respectfully submit this notice of change in status to inform the Commission of certain new affiliations. As explained below, the affiliations reported herein do not constitute a material departure from the characteristics the Commission relied upon in granting Sellers market-based rate authority. Therefore, Sellers respectfully request that the Commission accept for filing this Notice of Change in Status.

I. COMMUNICATIONS

Communications concerning this notice should be directed to the following persons:

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[1] 18 C.F.R. §35.42(a)(2) (2014).

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*The persons denoted with an asterisk are designated for service pursuant to 18 C.F.R. § 385.2010.

II. NON-MATERIAL CHANGE IN STATUS

Effective November 1, 2014, Exelon Generation Company, LLC ("Exelon Generation") indirectly acquired all of the issued and outstanding voting stock of Integrys Energy Services and its wholly owned subsidiary Integrys Energy Services NY ("Transaction").[2] As a result of the Transaction, the Integrys Entities became indirect wholly owned subsidiaries of Exelon Generation.

The Integrys Entities are retail power marketers that do not own or control any electric generation facilities, electric transmission facilities, distribution facilities, or inputs to electric power production, as defined in Section 35.36 of the Commission's regulations.[3] The Integrys Entities also do not hold a franchise or service territory for the transmission, distribution, or sale of electric power in the United States. The Commission has authorized both Integrys Energy Services[4] and Integrys Energy Services NY[5] to sell power at market-based rates.

In addition, Sellers inform the Commission of their affiliation with Mohave Sunrise Solar I, LLC ("Mohave Sunrise") and 2014 ESA Project Company, LLC ("2014 ESA"). Mohave Sunrise is an indirect, wholly owned subsidiary of Exelon Generation that is developing a 4.6 MW (net) solar-powered generation facility located in Fort Mohave, Arizona. The facility is expected to be installed and begin operations in April 2015. The facility will be a qualifying

[2] The Commission authorized the Transaction under FPA Section 203 on September 16, 2014. *Integrys Energy Group, Inc., et al.*, 148 FERC ¶ 62,206 (2014). Exelon Generation notified the Commission on November 6, 2014 that the Transaction was consummated effective November 1, 2014. *See* Notice of Consummation of Exelon Generation Co., LLC, FERC Docket No. EC14-124-000 (Nov. 6, 2014).

[3] 18 C.F.R. § 35.36(a)(4) defines "[i]nputs to electric power production" as "intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; physical coal supply sources and ownership of or control over who may access transportation of coal supplies."

[4] *Wisconsin Public Service Corp., et al.*, 75 FERC ¶ 61,057 (1996). *See also, Integrys Energy Group, Inc.* Docket No. ER07-650-000, unpublished letter order (May 10, 2007) (accepting the notice of succession of WPS Energy Services, Inc. changing its name to Integrys Energy Services, Inc.).

[5] *Advantage Energy, Inc.*, Docket No. ER97-2758-000, unpublished letter order (July 14, 1997). *See also, Integrys Energy Group, Inc.* Docket No. ER07-651-000, unpublished letter order (May 10, 2007) (accepting the notice of succession of Advantage Energy, Inc. changing its name to Integrys Energy Services of New York, Inc.).

facility ("QF") under the Public Utility Regulatory Policies Act of 1978[6] and will be interconnected to Mohave Electric Cooperative's ("MEC") transmission system within the Western Area Power Administration - Lower Colorado Region ("WALC") balancing authority area. Mohave Sunrise will sell the output of its facility to MEC under a long-term power purchase agreement.

2014 ESA is a Delaware limited liability company indirectly owned by Bloom Energy Corporation ("Bloom Energy") and Exelon Generation. 2014 ESA is developing fuel cell generation projects in California, Connecticut, New Jersey, and New York to provide energy services to third-party commercial and industrial customers. 2014 ESA will only own fuel cells located behind-the-meter, is not a public utility under the Federal Power Act, and does not engage in wholesale sales of electricity. The electricity generated by the fuel cells will be sold only to retail users or pursuant to state-approved net metering programs. 2014 ESA's first fuel cell project commenced operations on October 24, 2014. Since then, three additional fuel cell projects have commenced operations for a total of approximately 1.4 MW, all located in California.

The Exelon Entities' affiliation with the Integrys Entities does not materially affect the facts upon which the Commission relied in granting the Exelon Entities and the Integrys Entities market-based rate authority. The affiliation does not raise any horizontal market power concerns for the Exelon Entities because the Integrys Entities do not own or control any generation facilities and therefore the affiliation does not change the Exelon Entities' affiliated uncommitted capacity under the pivotal supplier and market share screens in any market. Likewise, the affiliation does not raise any horizontal market power concerns for the Integrys Entities because the Commission previously granted market-based rate authority to the Exelon Entities, having found that the Exelon Entities lack horizontal market power. Affiliation with the Integrys Entities would not change the results of the pivotal supplier and market share screens in any market since the Integrys Entities do not own or control any generation facilities. The affiliation also does not raise any vertical market power concerns, because the Integrys Entities do not own or control any transmission facilities or any inputs to electric power production as defined in Section 35.36 of the Commission's regulations and cannot raise barriers to entry.[7]

The affiliation with Mohave Sunrise and 2014 ESA similarly does not raise any horizontal market power concerns. Mohave Sunrise will own only a *de minimis* amount of generation (4.6 MW) that will be under long-term contract to MEC, an unaffiliated third party. 2014 ESA will only own behind-the-meter generation that is not used for wholesale sales. Therefore, the affiliation with Mohave Sunrise and 2014 ESA has no material impact on the ability of any of the Sellers to exercise horizontal market power in any relevant market. With respect to vertical market power, neither Mohave Sunrise nor 2014 ESA owns or controls any transmission facilities, except for limited interconnection facilities required to connect individual generating facilities to the transmission grid, or any inputs to electric power production, as

[6] A notice of self-certification of QF status is being filed concurrently.

[7] To the extent necessary, the Sellers confirm that they have not erected barriers to entry into the relevant markets and will not erect barriers to entry into the relevant markets.

defined in Section 35.36 of the Commission's regulations and cannot raise barriers to entry. Therefore the affiliation with Mohave Sunrise and 2014 ESA does not raise any vertical market power concerns.

Therefore, Sellers continue to satisfy the requirements for market-based rate authority.

III. CONCLUSION

Sellers request that the Commission accept this notice of change in status for filing. Attached hereto are the required tables listing (1) all affiliates that have market-based rate authority and identifying all generation assets the corporate family owns or controls by balancing authority area and geographic region, and (2) all electric transmission and regulated natural gas intrastate pipelines and/or gas storage facilities the corporate family owns or controls.[8]

Respectfully submitted,

/s/ Jane E. Rueger

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[8] 18 C.F.R. § 35.42(c).

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ASSET APPENDICES
OF
EXELON CORPORATION
AND AFFILIATES

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Electric Generating Facilitates Affiliates and Assets

Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
AgriWind LLC	N/A[3]	AgriWind	AgriWind LLC	AgriWind LLC	N/A	Midcontinent Independent System Operator, Inc. ("MISO")	Central	2007	2.1[4]
AgriWind Project L.L.C.	N/A[3]	AgriWind Project	AgriWind Project L.L.C.	AgriWind Project L.L.C.	N/A	MISO	Central	2007	6.3[4]
Beebe 1B Renewable Energy, LLC	ER14-2144	Beebe 1B Renewable Energy	Beebe 1B Renewable Energy, LLC	Beebe 1B Renewable Energy, LLC	N/A	MISO	Central	Expected 2014	50.4[4]
Beebe Renewable Energy, LLC	ER12-2311	Beebe Renewable Energy	Beebe Renewable Energy, LLC	Beebe Renewable Energy, LLC	N/A	MISO	Central	2012	81.6[4]
Blue Breezes, L.L.C.	N/A[3]	Blue Breezes	Blue Breezes, L.L.C.	Blue Breezes, L.L.C.	N/A	MISO	Central	2006	1.25[4]
Blue Breezes II, L.L.C.	N/A[3]	Blue Breezes II	Blue Breezes II, L.L.C.	Blue Breezes II, L.L.C.	N/A	MISO	Central	2006	1.25[4]
Breezy Bucks-I LLC	N/A[3]	Breezy Bucks-I	Breezy Bucks-I LLC	Breezy Bucks-I LLC	N/A	MISO	Central	2006	1.25[4]
Breezy Bucks-II LLC	N/A[3]	Breezy Bucks-II	Breezy Bucks-II LLC	Breezy Bucks-II LLC	N/A	MISO	Central	2006	1.25[4]
Christoffer Wind Energy I LLC	N/A[3]	Christoffer Wind Energy I	Christoffer Wind Energy I LLC	Christoffer Wind Energy I LLC	N/A	MISO	Central	2008	2.1[4]
Christoffer Wind Energy II LLC	N/A[3]	Christoffer Wind Energy II	Christoffer Wind EnergyII LLC	Christoffer Wind Energy II LLC	N/A	MISO	Central	2008	2.1[4]
Christoffer Wind Energy III LLC	N/A[3]	Christoffer Wind Energy III	Christoffer Wind Energy III LLC	Christoffer Wind Energy HI LLC	N/A	MISO	Central	2008	2.1[4]
Christoffer Wind Energy IV LLC	N/A[3]	Christoffer Wind Energy IV	Christoffer Wind Energy IV LLC	Christoffer Wind Energy IV LLC	N/A	MISO	Central	2008	2.1[4]

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
CP Windfarm, LLC	N/A[3]	CP Windfarm	CP Windfarm, LLC	CP Windfarm, LLC	N/A	MISO	Central	2008	4.2[4]
Exelon Generation Company, LLC ("ExGen")	ER00-3251	Clinton	ExGen	ExGen	N/A	MISO	Central	1987	1,065
ExGen	ER00-3251	Tenaska Frontier Generation Station	Tenaska Frontier Partners Ltd	ExGen	2000	MISO	Central	2000	860[7]
G-Flow Wind, LLC	N/A[3]	G-Flow Wind	G-Flow Wind, LLC	G-Flow Wind, LLC	N/A	MISO	Central	2006	1.25[4]
Green Acres Breeze, LLC	N/A[3]	Green Acres Breeze	Green Acres Breeze, LLC	Green Acres Breeze, LLC	N/A	MISO	Central	2006	1.25[4]
Harvest Windfarm, LLC	ER07-1246	Harvest Windfarm	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	2007	52.8[4]
Harvest II Windfarm, LLC	ER12-2201	Harvest II Windfarm	Harvest II	Harvest II	N/A	MISO	Central	2012	59.4[4]
K & D Energy LLC	N/A[3]	K & D Energy	K & D Energy LLC	K & D Energy LLC	N/A	MISO	Central	2007	4[4]
KC Energy LLC	N/A[3]	KC Energy	KC Energy LLC	KC Energy LLC	N/A	MISO	Central	2007	4[4]
KSS Turbines LLC	N/A[3]	KSS Turbines	KSS Turbines LLC	KSS Turbines LLC	N/A	MISO	Central	2007	4[4]
Michigan Wind 1, LLC	ER05-1511	Michigan Wind 1	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	2008	69[4]
Michigan Wind 2, LLC	ER11-3989	Michigan Wind 2	Michigan Wind 2, LLC	Michigan Wind 2, LLC	N/A	MISO	Central	2011	90[4]
Minnesota Breeze, LLC	N/A[3]	Minnesota Breeze	Minnesota Breeze, LLC	Minnesota Breeze, LLC	N/A	MISO	Central	2006	1.25[4]
Prairie Wind Power LLC	N/A[3]	Prairie Wind Power	Prairie Wind Power LLC	Prairie Wind Power LLC	N/A	MISO	Central	2007	4[4]
Roadrunner-I LLC	N/A[3]	Roadrunner-I	Roadrunner-I	Roadrunner-I	N/A	MISO	Central	2006	1.25[4]

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
			LLC	LLC					
Salty Dog-I LLC	N/A[3]	Salty Dog-I	Salty Dog-I LLC	Salty Dog-I LLC	N/A	MISO	Central	2006	1.25[4]
Salty Dog-II LLC	N/A[3]	Salty Dog-II	Salty Dog-II LLC	Salty Dog-II LLC	N/A	MISO	Central	2006	1.25[4]
Shane's Wind Machine LLC	N/A[3]	Shane's Wind Machine	Shane's Wind Machine LLC	Shane's Wind Machine LLC	N/A	MISO	Central	2006	2[4]
Sunset Breeze, LLC	N/A[3]	Sunset Breeze	Sunset Breeze, LLC	Sunset Breeze, LLC	N/A	MISO	Central	2006	1.25[4]
Wally's Wind Farm LLC	N/A[3]	Wally's Wind Farm	Wally's Wind Farm LLC	Wally's Wind Farm LLC	N/A	MISO	Central	2006	1.25[4]
Windy Dog-I LLC	N/A[3]	Windy Dog-I	Windy Dog-I LLC	Windy Dog-I LLC	N/A	MISO	Central	2006	1.25[4]
Wolf Wind Enterprises, LLC	N/A[3]	Wolf Wind Enterprises	Wolf Wind Enterprises, LLC	Wolf Wind Enterprises, LLC	N/A	MISO	Central	2006	1.25[4]
Marshall Wind 2, LLC	N/A[3]	Marshall Wind 2	Marshall Wind 2, LLC	Marshall Wind 2, LLC	N/A	MISO	Central	2007	4.2[4]
Marshall Wind 3, LLC	N/A[3]	Marshall Wind 3	Marshall Wind 3, LLC	Marshall Wind 3, LLC	N/A	MISO	Central	2007	4.2[4]
Marshall Wind 4, LLC	N/A[3]	Marshall Wind 4	Marshall Wind 4, LLC	Marshall Wind 4, LLC	N/A	MISO	Central	2007	4.2[4]
Marshall Wind 5, LLC	N/A[3]	Marshall Wind 5	Marshall Wind 5, LLC	Marshall Wind 5, LLC	N/A	MISO	Central	2007	2.1[4]
Marshall Wind 6, LLC	N/A[3]	Marshall Wind 6	Marshall Wind 6, LLC	Marshall Wind 6 LLC	N/A	MISO	Central	2007	2.1[4]
Marshall Wind 1, LLC	N/A[3]	Marshall Wind 1	Marshall Wind 1, LLC	Marshall Wind 1, LLC	N/A	MISO	Central	2007	2.1[4]
ExGen	ER00-3251	Kleen	Kleen Energy Systems, LLC	ExGen	2011	ISO New England Inc. ("ISO-NE")	Northeast	2011	620
Constellation Mystic Power, LLC	ER10-2281	Mystic - 7	Constellation Mystic	Constellation Mystic	2011	ISO-NE	Northeast	1975	575.48

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
("Constellation Mystic")									
Constellation Mystic	ER10-2281	Mystic - 8	Constellation Mystic	Constellation Mystic	2011	ISO-NE	Northeast	2003	704
Constellation Mystic	ER10-2281	Mystic – 9	Constellation Mystic	Constellation Mystic	2011	ISO-NE	Northeast	2003	703
Constellation Mystic	ER10-2281	Mystic - Jet	Constellation Mystic	Constellation Mystic	2011	ISO-NE	Northeast	1969	9.07
Constellation Solar Connecticut, LLC	N/A[8]	Parker Hannifin Corp at New Britain	Constellation Solar Connecticut, LLC	Constellation Solar Connecticut, LLC	N/A	ISO-NE	Northeast	2008	0.18
Constellation Solar Connecticut, LLC	N/A[8]	East Lyme Bd of Ed at East Lyme HS	Constellation Solar Connecticut, LLC	Constellation Solar Connecticut, LLC	N/A	ISO-NE	Northeast	2009	0.41
Constellation Solar Massachusetts, LLC ("CSMA")	N/A[8]	Kollmorgen Corp at Kollmorgen Electro-Optical HQ Bldg	CSMA	CSMA	N/A	ISO-NE	Northeast	2011	0.17
CSMA	N/A[8]	Majilite Corp	CSMA	CSMA	N/A	ISO-NE	Northeast	2009	0.35
CSMA	N/A[8]	NPP Development, LLC at Patriot Place	CSMA	CSMA	N/A	ISO-NE	Northeast	2010	0.45
CSMA	N/A[8]	Town of Norfolk	CSMA	CSMA	N/A	ISO-NE	Northeast	2012	1.35
CSMA	N/A[8]	Town of Swampscott	CSMA	CSMA	N/A	ISO-NE	Northeast	2012	0.32
Constellation Solar Net Metering, LLC	N/A[8]	Town of Uxbridge	Constellation Solar Net Metering, LLC	Constellation Solar Net Metering, LLC	N/A	ISO-NE	Northeast	2012	1.93
Exelon Framingham LLC	ER01-513	Framingham Jet 1-3	Exelon Framingham, LLC	Exelon Framingham, LLC	N/A	ISO-NE	Northeast	1969	33.08

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
ExGen	ER00-3251	Granite Ridge	Granite Ridge Energy, LLC	ExGen	Jan. 1, 2014	ISO-NE	Northeast	N/A	661
Exelon New Boston, LLC ("Exelon New Boston")	ER01-513	New Boston GT (L Street)	Exelon New Boston	Exelon New Boston	N/A	ISO-NE	Northeast	1966	16.03
Exelon West Medway LLC ("Exelon West Medway")	ER01-513	West Medway Jet 2	Exelon West Medway	Exelon West Medway	N/A	ISO-NE	Northeast	1971	39.85
Exelon West Medway	ER01-513	West Medway Jet 3	Exelon West Medway	Exelon West Medway	N/A	ISO-NE	Northeast	1970	35.44
Exelon West Medway	ER01-513	West Medway Jet 1	Exelon West Medway	Exelon West Medway	N/A	ISO-NE	Northeast	1970	42.00
Exelon Wyman, LLC	ER01-513	Wyman 4	Exelon Wyman, LLC (5.89%)	FPL Wyman Energy, LLC	N/A	ISO-NE	Northeast	1978	610[7]
Holyoke Solar LLC	N/A [3]	City of Holyoke G & E Dept at Mueller	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	2012	2.95
Holyoke Solar LLC	N/A [3]	City of Holyoke G & E Dept at Meadow	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	2011	0.87
Residential Solar II, LLC ("RS II")	N/A[8]	Residential Solar	RS II	RS II	N/A	ISO-NE	Northeast	N/A	2.68
Nine Mile Point Nuclear Station, LLC ("Nine Mile Point")	ER01-1654	Nine Mile Point - 1	Nine Mile Point	Nine Mile Point	2010	New York Independent System Operator, Inc. ("NYISO")	Northeast	1969	626.9[7]
Nine Mile Point	ER01-1654	Nine Mile Point - 2	Nine Mile Point (82%)	Nine Mile Point	2010	NYISO	Northeast	1988	1, 287.2[7]
R.E. Ginna Nuclear Power Plant, LLC ("Ginna")	ER04-485	Ginna	Ginna	Ginna	2010	NYISO	Northeast	1970	581.5[7]

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
RS II	N/A[8]	Residential Solar	RS II	RS II	N/A	NYISO	Northeast	N/A	1.08
Constellation Solar New York, LLC ("CSNY")	N/A[8]	Owens Corning at Bethlehem, NY	CSNY	CSNY	N/A	NYISO	Northeast	2013	2.21
Calvert Cliffs Nuclear Power Plant, LLC ("Calvert Cliffs")	ER00-2917	Calvert Cliffs - 2	Calvert Cliffs	Calvert Cliffs	N/A	PJM Interconnection, L.L.C. ("PJM")	Northeast	1977	862[7]
Calvert Cliffs	ER00-2917	Calvert Cliffs - 1	Calvert Cliffs	Calvert Cliffs	N/A	PJM	Northeast	1975	873[7]
Constellation Solar Ohio, LLC	N/A[8]	University of Toledo (Solar) Scott Park Campus of Energy & Innovation	Constellation Solar Ohio, LLC	Constellation Solar Ohio, LLC	N/A	PJM	Northeast	2010	0.88
Constellation Solar Ohio, LLC	N/A[8]	University of Toledo (Wind) Scott Park Campus of Energy & Innovation	Constellation Solar Ohio, LLC	Constellation Solar Ohio, LLC	N/A	PJM	Northeast	2010	0.07
ExGen	ER00-3251	York Delta	Calpine Mid Merit LLC	ExGen	2011	PJM	Northeast	2011	565
ExGen	ER00-3251	Cordova Purchase - 1	Cordova Energy, LLC	ExGen	2005	PJM	Northeast	N/A	475
ExGen	ER00-3251	Elwood Purchase – 1	Elwood Energy, LLC	ExGen	2006	PJM	Northeast	N/A	600
Constellation Solar DC, LLC	N/A[8]	DC Dept. of General Services at Washington, DC	Constellation Solar DC, LLC	Constellation NewEnergy, Inc.	N/A	PJM	Northeast	2013	0.38
Constellation Solar Federal LLC	N/A[3]	Constellation New Energy, Inc. at US Dept. of State	Constellation Solar Federal LLC	Constellation Solar Federal LLC	N/A	PJM	Northeast	2011	4.23
Constellation Solar Horizons, LLC	N/A[3]	MD Generating Clean Horizons MSM I	Constellation Solar Horizons, LLC	Constellation Solar Horizons, LLC	N/A	PJM	Northeast	2012	13.61

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
Constellation Solar New Jersey LLC ("CSNJ")	N/A[3]	The City of Vineland at North Vineland	CSNJ	CSNJ	NA	PJM	Northeast	2011	2.54
CSNJ	N/A[3]	The City of Vineland at West Vineland	CSNJ	CSNJ	N/A	PJM	Northeast	2011	4.06
CSNJ	N/A[8]	Benjamin Moore & Co at Flanders NJ	CSNJ	CSNJ	N/A	PJM	Northeast	2011	1.50
CSNJ	N/A[8]	Jet Aviation Teterboro, LP at Teterboro Airport	CSNJ	CSNJ	N/A	PJM	Northeast	2008	0.15
Constellation Solar New Jersey II, LLC ("CSNJ II")	N/A[8]	Johnson Matthey, Inc at West Deptford	CSNJ II	CSNJ II	N/A	PJM	Northeast	2011	4.41
Constellation Solar New Jersey II	N/A[8]	Toys-R-Us Delaware, Inc at Mt Olive	CSNJ II	CSNJ II	N/A	PJM	Northeast	2011	4.57
Constellation Solar New Jersey III, LLC ("CSNJ III")	N/A[8]	Middle Township Elem School 1	CSNJ III	CSNJ III	N/A	PJM	Northeast	2011	0.17
CSNJ III	N/A[8]	Middle Township Elem School 2	CSNJ III	CSNJ III	N/A	PJM	Northeast	2011	0.39
CSNJ III	N/A[8]	Middle Township High School	CSNJ III	CSNJ III	N/A	PJM	Northeast	2011	0.69
Constellation Power, Inc. ("CPI")	N/A[5]	Colver	Inter-Power/Ahlcon Partners (Colver)	Inter-Power/Ahlcon Partners (Colver)	N/A	PJM	Northeast	1995	104[7]
Constellation Power Source Generation, LLC ("CPS Gen")	ER14-1169	Gould Street - 3	CPS Gen	CPS Gen	N/A	PJM	Northeast	2008	97
CPS Gen	ER14-1169	Notch Cliff 1-8	CPS Gen	CPS Gen	N/A	PJM	Northeast	1969	118
CPS Gen	ER14-1169	Perryman - 1	CPS Gen	CPS Gen	N/A	PJM	Northeast	1972	52

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
CPS Gen	ER14-1169	Perryman - 51	CPS Gen	CPS Gen	N/A	PJM	Northeast	1995	147
CPS Gen	ER14-1169	Perryman 2-4	CPS Gen	CPS Gen	N/A	PJM	Northeast	1972	154
CPS Gen	ER14-1169	Philadelphia Road 1-2	CPS Gen	CPS Gen	N/A	PJM	Northeast	1970	31
CPS Gen	ER14-1169	Philadelphia Road 3-4	CPS Gen	CPS Gen	N/A	PJM	Northeast	1970	30
CPS Gen	ER14-1169	Riverside - 4	CPS Gen	CPS Gen	N/A	PJM	Northeast	1951	74
CPS Gen	ER14-1169	Riverside 7-8	CPS Gen	CPS Gen	N/A	PJM	Northeast	1970	39
CPS Gen	ER14-1169	Westport - 5	CPS Gen	CPS Gen	N/A	PJM	Northeast	1969	115
Exelon Solar Chicago LLC	N/A[3]	Chicago City Solar	Exelon Solar Chicago LLC	Exelon Solar Chicago LLC	N/A	PJM	Northeast	2010	8.25
Constellation Solar Maryland, LLC ("CSMD")	N/A[8]	AA County, MD at Shared Svcs Complex	CSMD	CSMD	N/A	PJM	Northeast	2011	0.63
CSMD	N/A[8]	Coppin State Univ at Coppin State Univ - PEC	CSMD	CSMD	N/A	PJM	Northeast	2011	0.42
CSMD	N/A[8]	CPSG Fort Smallwood Road Complex	CSMD	CSMD	N/A	PJM	Northeast	2011	0.78
CSMD	N/A[8]	GM Allison Plant-I	CSMD	CSMD	N/A	PJM	Northeast	2011	1.04
CSMD	N/A[8]	Maryland Science Center	CSMD	CSMD	N/A	PJM	Northeast	2011	0.09
CSMD	N/A[8]	McCormick & Co, Inc at Belcamp	CSMD	CSMD	N/A	PJM	Northeast	2011	1.56
CSMD	N/A[8]	McCormick & Co, Inc at Hunt Valley	CSMD	CSMD	N/A	PJM	Northeast	2009	0.78
CSMD	N/A[8]	McCormick & Co, Inc Corporate HQ	CSMD	CSMD	N/A	PJM	Northeast	2011	0.08
CSMD	N/A[8]	MD Env Service at MES Headquarters	CSMD	CSMD	N/A	PJM	Northeast	2008	0.25

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
CSMD	N/A[8]	Mount St. Mary's University at Emmitsburg	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	2012	1.42
CSMD	N/A[3]	General Motors, LLC at Allison Transmission Plant	Constellation Solar Maryland, LLC	Constellation NewEnergy, Inc.	N/A	PJM	Northeast	2012	1.04
CSMD	N/A[3]	McCormick & Company, Inc. at Sparks	Constellation Solar Maryland, LLC	Constellation NewEnergy, Inc.	N/A	PJM	Northeast	2012	0.08
Constellation Solar Maryland II, LLC	N/A[8]	UMMS (U of MD Medical System)	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	2013	3.09
Constellation Solar Maryland II, LLC	N/A[8]	UMMS - CRE	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	2013	0.35
Criterion Power Partners, LLC	ER10-1443	Criterion 1-28	Criterion Power Partners, LLC	Criterion Power Partners, LLC	2010	PJM	Northeast	2010	70
ExGen	ER00-3251	Braidwood 1	ExGen	ExGen	N/A	PJM	Northeast	1988	1,178
ExGen	ER00-3251	Braidwood 2	ExGen	ExGen	N/A	PJM	Northeast	1988	1,152
ExGen	ER00-3251	Byron 1	ExGen	ExGen	N/A	PJM	Northeast	1985	1,164
ExGen	ER00-3251	Byron 2	ExGen	ExGen	N/A	PJM	Northeast	1987	1,136
ExGen	ER00-3251	Chester 7	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Chester 8	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Chester 9	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Conemaugh 1	ExGen (31.22%)	ExGen	N/A	PJM	Northeast	1970	850[7]
ExGen	ER00-3251	Conemaugh 2	ExGen (31.22%)	ExGen	N/A	PJM	Northeast	1970	850[7]
ExGen	ER00-3251	Conemaugh A-D	ExGen	ExGen	N/A	PJM	Northeast	1970	10.8[7]

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
			(31.22%)						
ExGen	ER00-3251	Conowingo 1	ExGen	ExGen	N/A	PJM	Northeast	1928	48
ExGen	ER00-3251	Conowingo 2	ExGen	ExGen	N/A	PJM	Northeast	1928	36
ExGen	ER00-3251	Conowingo 3	ExGen	ExGen	N/A	PJM	Northeast	1928	48
ExGen	ER00-3251	Conowingo 4	ExGen	ExGen	N/A	PJM	Northeast	1928	48
ExGen	ER00-3251	Conowingo 5	ExGen	ExGen	N/A	PJM	Northeast	1928	36
ExGen	ER00-3251	Conowingo 6	ExGen	ExGen	N/A	PJM	Northeast	1928	48
ExGen	ER00-3251	Conowingo 7	ExGen	ExGen	N/A	PJM	Northeast	1928	48
ExGen	ER00-3251	Conowingo 8	ExGen	ExGen	N/A	PJM	Northeast	1964	65
ExGen	ER00-3251	Conowingo 9	ExGen	ExGen	N/A	PJM	Northeast	1964	65
ExGen	ER00-3251	Conowingo 10	ExGen	ExGen	N/A	PJM	Northeast	1964	65
ExGen	ER00-3251	Conowingo 11	ExGen	ExGen	N/A	PJM	Northeast	1964	65
ExGen	ER00-3251	Croydon 11	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 12	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 21	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 22	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 31	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 32	ExGen	ExGen	N/A	PJM	Northeast	1974	48
ExGen	ER00-3251	Croydon 41	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 42	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Delaware 9	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Delaware 10	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Delaware 11	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Delaware 12	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Dresden 2	ExGen	ExGen	N/A	PJM	Northeast	1970	883.5
ExGen	ER00-3251	Dresden 3	ExGen	ExGen	N/A	PJM	Northeast	1971	903
ExGen	ER00-3251	Eddystone 3	ExGen	ExGen	N/A	PJM	Northeast	1974	380
ExGen	ER00-3251	Eddystone 4	ExGen	ExGen	N/A	PJM	Northeast	1976	380
ExGen	ER00-3251	Eddystone 10	ExGen	ExGen	N/A	PJM	Northeast	1967	13
ExGen	ER00-3251	Eddystone 20	ExGen	ExGen	N/A	PJM	Northeast	1967	13
ExGen	ER00-3251	Eddystone 30	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Eddystone 40	ExGen	ExGen	N/A	PJM	Northeast	1970	17

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
ExGen	ER00-3251	Fairless Hills A	ExGen	ExGen	N/A	PJM	Northeast	1996	30
ExGen	ER00-3251	Fairless Hills B	ExGen	ExGen	N/A	PJM	Northeast	1996	30
ExGen	ER00-3251	Falls 1	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Falls 2	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Falls 3	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Keystone 1	ExGen (41.98%)	ExGen	N/A	PJM	Northeast	1967	850[7]
ExGen	ER00-3251	Keystone 2	ExGen (41.98%)	ExGen	N/A	PJM	Northeast	1968	850
ExGen	ER00-3251	Keystone 3-6	ExGen (41.98%)	ExGen	N/A	PJM	Northeast	1968	10.8[7]
ExGen	ER00-3251	LaSalle 1	ExGen	ExGen	N/A	PJM	Northeast	1984	1,137
ExGen	ER00-3251	LaSalle 2	ExGen	ExGen	N/A	PJM	Northeast	1984	1,140
ExGen	ER00-3251	Limerick 1	ExGen	ExGen	N/A	PJM	Northeast	1986	1,146
ExGen	ER00-3251	Limerick 2	ExGen	ExGen	N/A	PJM	Northeast	1990	1,150
ExGen	ER00-3251	Moser 1	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Moser 2	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Moser 3	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Muddy Run 1	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Muddy Run 2	ExGen	ExGen	N/A	PJM	Northeast	1967	133
ExGen	ER00-3251	Muddy Run 3	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Muddy Run 4	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Muddy Run 5	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Muddy Run 6	ExGen	ExGen	N/A	PJM	Northeast	1967	133
ExGen	ER00-3251	Muddy Run 7	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Muddy Run 8	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Oyster Creek	ExGen	ExGen	N/A	PJM	Northeast	1969	614.5
ExGen	ER00-3251	Peach Bottom 2	ExGen (50%)	ExGen	N/A	PJM	Northeast	1974	1,125.4[7]
ExGen	ER00-3251	Peach Bottom 3	ExGen (50%)	ExGen	N/A	PJM	Northeast	1974	1,125.4[7]
ExGen	ER00-3251	Pennsbury 1	ExGen	ExGen	N/A	PJM	Northeast	1996	2.67
ExGen	ER00-3251	Pennsbury 2	ExGen	ExGen	N/A	PJM	Northeast	1996	2.67
ExGen	ER00-3251	Quad Cities 1	ExGen (75%)	ExGen	N/A	PJM	Northeast	1972	908[7]

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
ExGen	ER00-3251	Quad Cities 2	ExGen (75%)	ExGen	N/A	PJM	Northeast	1972	911[7]
ExGen	ER00-3251	Richmond 91	ExGen	ExGen	N/A	PJM	Northeast	1973	49
ExGen	ER00-3251	Richmond 92	ExGen	ExGen	N/A	PJM	Northeast	1973	49
ExGen	ER00-3251	Salem 1	ExGen (42.59%)	PSEG	N/A	PJM	Northeast	1977	1,174[7]
ExGen	ER00-3251	Salem 2	ExGen (42.59%)	PSEG	N/A	PJM	Northeast	1981	1,158[7]
ExGen	ER00-3251	Salem 3	ExGen (42.59%)	PSEG	N/A	PJM	Northeast	1971	37.57[7]
ExGen	ER00-3251	Schuylkill 10	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Schuylkill 11	ExGen	ExGen	N/A	PJM	Northeast	1971	17
ExGen	ER00-3251	Southeast Chicago Energy Project 5	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 6	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 7	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 8	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 9	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 10	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 11	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 12	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southwark 3	ExGen	ExGen	N/A	PJM	Northeast	1967	13
ExGen	ER00-3251	Southwark 4	ExGen	ExGen	N/A	PJM	Northeast	1967	13
ExGen	ER00-3251	Southwark 5	ExGen	ExGen	N/A	PJM	Northeast	1967	13
ExGen	ER00-3251	Southwark 6	ExGen	ExGen	N/A	PJM	Northeast	1968	13
ExGen	ER00-3251	TMI # 1	ExGen	ExGen	N/A	PJM	Northeast	1974	805

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
Fourmile Wind Energy, LLC	ER14-2145	Fourmile Wind Energy	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	Expected 2014	40[4]
Handsome Lake Energy, LLC ("Handsome Lake")	ER01-556	Handsome Lake 3-5	Handsome Lake	Handsome Lake	N/A	PJM	Northeast	2001	160.5
Handsome Lake	ER01-556	Handsome Lake 1-2	Handsome Lake	Handsome Lake	N/A	PJM	Northeast	2001	107
RS II	N/A[8]	Residential Solar	RS II	RS II	N/A	PJM	Northeast	N/A	3.56
Denver Airport Solar, LCC	N/A[8]	City & County of Denver at Denver International Airport	Denver Airport Solar, LCC	Denver Airport Solar, LCC	N/A	Public Service Co. of Colorado (Xcel Energy)	Northwest	2011	3.77
Bennett Creek Windfarm, LLC	N/A[5]	Mountain Home	Bennett Creek Windfarm, LLC	Bennett Creek Windfarm, LLC	N/A	Idaho Power	Northwest	2008	21[4]
Cassia Gulch Wind Park LLC	ER10-75	Cassia Gulch	Cassia Gulch Wind Park LLC	Cassia Gulch Wind Park LLC	N/A	Idaho Power	Northwest	2009	18.9[4]
Cassia Wind Farm LLC	N/A[3]	Cassia Wind	Cassia Wind Farm LLC	Cassia Wind Farm LLC	N/A	Idaho Power	Northwest	2009	10.5[4]
High Mesa Energy, LLC	ER12-2528	High Mesa	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	Idaho Power	Northwest	2012	40[4]
Hot Springs Windfarm, LLC	N/A[5]	Mountain Home	Hot Springs Windfarm, LLC	Hot Springs Windfarm, LLC	N/A	Idaho Power	Northwest	2008	21[4]
Tuana Springs Energy, LLC	ER10-87	Tuana Springs	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	Idaho Power	Northwest	2010	16.8[4]
CER Generation II, LLC	ER08-860	West Valley 1-5	CER Generation-II, LLC	CER Generation-II, LLC	2008	PacifiCorp East	Northwest	2002	200
Big Top, LLC	N/A[3]	Big Top	Big Top, LLC	Big Top, LLC	N/A	PacifiCorp West	Northwest	2009	1.65[4]
Butter Creek Power, LLC	N/A[3]	Butter Creek Power	Butter Creek Power, LLC	Butter Creek Power, LLC	N/A	PacifiCorp West	Northwest	2009	4.95[4]
Sunnyside Cogeneration Assoc.	N/A[5]	Sunnyside Cogen	Sunnyside Cogeneration	Sunnyside Cogeneration	N/A	PacifiCorp West	Northwest	1993	51

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
			Assoc.	Assoc.					
Four Corners Windfarm, LLC	N/A[3]	Four Corners Windfarm	Four Corners Windfarm, LLC	Four Corners Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	10[4]
Four Mile Canyon Windfarm, LLC	N/A[3]	Four Mile Canyon Windfarm	Four Mile Canyon Windfarm, LLC	Four Mile Canyon Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	10[4]
Oregon Trail Windfarm, LLC	N/A[3]	Oregon Trail Windfarm	Oregon Trail Windfarm, LLC	Oregon Trail Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	9.9[4]
Pacific Canyon Windfarm, LLC	N/A[3]	Pacific Canyon Windfarm	Pacific Canyon Windfarm, LLC	Pacific Canyon Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	8.25[4]
Sand Ranch Windfarm, LLC	N/A[3]	Sand Ranch Windfarm	Sand Ranch Windfarm, LLC	Sand Ranch Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	9.9[4]
Threemile Canyon Wind I, LLC	N/A[3]	Threemile Canyon	Threemile Canyon Wind I, LLC	Threemile Canyon Wind I, LLC	N/A	PacifiCorp West	Northwest	2009	9.9[4]
Wagon Trail, LLC	N/A[3]	Wagon Trail	Wagon Trail, LLC	Wagon Trail, LLC	N/A	PacifiCorp West	Northwest	2009	3.3[4]
Ward Butte Windfarm, LLC	N/A[3]	Ward Butte Windfarm	Ward Butte Windfarm, LLC	Ward Butte Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	6.6[4]
Outback Solar, LLC	N/A[3]	Outback Solar	Outback Solar, LLC	Outback Solar, LLC	N/A	Bonneville Power Administration	Northwest	2012	4.8
Cow Branch Wind Power, L.L.C.	ER07-1223	Cow Branch	Cow Branch Wind Power, L.L.C.	Cow Branch Wind Power, L.L.C.	N/A	Associated Electric Cooperative, Inc. ("AECI")	Southeast	2008	50.4[4]
CR Clearing, LLC	ER07-1222	Conception	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	2008	50.4[4]
Loess Hills Wind Farm, LLC	N/A[3]	Loess Hills	Loess Hills Wind Farm, LLC	Loess Hills Wind Farm, LLC	N/A	AECI	Southeast	2007	5[4]

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
Wind Capital Holdings, LLC	ER07-1208	Bluegrass Ridge	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	2007	56.7[4]
Constellation Solar Georgia, LLC	N/A[3]	Georgia Power at Sparta	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	Southern Company Services, Inc. ("SOCO")	Southeast	N/A	0.84
ExGen	ER00-3251	Sowega 1	Georgia Energy Cooperative ("GEC")	ExGen	2011	SOCO	Southeast	2000	48
ExGen	ER00-3251	Sowega 2	GEC	ExGen	2011	SOCO	Southeast	2000	48
ExGen	ER00-3251	Effingham - 1	Effingham County Power, LLC	Effingham County Power, LLC	2007	SOCO	Southeast	2003	502
ExGen	ER00-3251	Washington 1 & 4	Washington County Power, LLC	Washington County Power, LLC	2007	SOCO	Southeast	N/A	307
ExGen	ER00-3251	Franklin - 3	Southern Power Company	Southern Power Company	2007	SOCO	Southeast	N/A	621
CER Generation, LLC	ER10-662	Hillabee	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	2010	684
ExGen	ER00-3251	Heard	Tenaska Georgia Partners LP	ExGen	2001	SOCO	Southeast	2001	945[7]
AV Solar Ranch 1, LLC ("AV Solar")	ER12-2178	Antelope Valley	AV Solar	AV Solar	N/A	California Independent System Operator Corporation ("CAISO")	Southwest	2012	230
Luz Solar Partners IV	N/A[5]	SEGS IV	Luz Solar Partners IV	Luz Solar Partners IV	N/A	CAISO	Southwest	1986	33
Luz Solar Partners V	N/A[5]	SEGS V	Luz Solar Partners V	Luz Solar Partners V	N/A	CAISO	Southwest	1987	24
Luz Solar Partners VI	N/A[5]	SEGS VI	Luz Solar	Luz Solar	N/A	CAISO	Southwest	1988	34

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
			Partners VI	Partners VI					
Constellation Solar California, LLC	N/A[8]	GSA, PBS, Pacific Service Center at Sacramento, Ca.	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	2008	0.44
Constellation Solar California, LLC	N/A[8]	Kawneer Co., Inc. (Alcoa)	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	2007	0.50
Constellation Solar California, LLC	N/A[8]	General Motors Corp. at Fontana, Ca.	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	2007	0.80
Constellation Solar California, LLC	N/A[8]	Univ. of San Francisco at Univ. of San Francisco	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	2008	0.42
Sacramento PV Energy, LLC ("Sacramento PV Energy")	N/A[3]	Sacramento Municipal Utility District at Fleshman	Sacramento PV Energy	Sacramento PV Energy	N/A	CAISO	Southwest	2011	3.08
Sacramento PV Energy	N/A[3]	Sacramento Municipal Utility District at Grundman	Sacramento PV Energy	Sacramento PV Energy	N/A	CAISO	Southwest	2011	18.5
Sacramento PV Energy	N/A[3]	Sacramento Municipal Utility District at Lawrence	Sacramento PV Energy	Sacramento PV Energy	N/A	CAISO	Southwest	2011	1.03
Sacramento PV Energy	N/A[3]	Sacramento Municipal Utility District at VanConnet	Sacramento PV Energy	Sacramento PV Energy	N/A	CAISO	Southwest	2011	3.08
California PV Energy, LLC ("CAPV")	N/A[8]	California PV Energy	CAPV	CAPV	N/A	CAISO	Southwest	N/A	3.3
CAPV	N/A[8]	California PV Energy at Castaic ES	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.12
CAPV	N/A[8]	California PV Energy	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.28

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
		at Castaic MS							
CAPV	N/A[8]	California PV Energy at Live Oak ES	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.11
CAPV	N/A[8]	California PV Energy at Northlake Hills ES	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.13
CAPV	N/A[8]	Oltmans SCE at Jurupa	CAPV	CAPV	N/A	CAISO	Southwest	2013	1.6
CAPV	N/A[8]	SCE Oltmans at Champagne	CAPV	CAPV	N/A	CAISO	Southwest	2013	1.03
CAPV	N/A[8]	Ironhouse Sanitary District	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.85
CAPV	N/A[8]	Keppel Alpine North ES	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.12
CAPV	N/A[8]	Keppel Antelope ES	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.05
CAPV	N/A[8]	Keppel Alpine South ES	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.09
CAPV	N/A[8]	Keppel Lake Los Angeles	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.13
CAPV	N/A[8]	Keppel Gibson ES	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.15
CAPV	N/A[8]	Keppel Pearblossom ES	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.13
CAPV	N/A[8]	Keppel Academy	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.11
CAPV	N/A[8]	Palmdale Marie Park E1	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.07
CAPV	N/A[8]	Palmdale Marie Park E2	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.06
CAPV	N/A[8]	Palmdale Marie Park E3	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.04
CAPV	N/A[8]	Palmdale Development Services Bldg.	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.11
CAPV	N/A[8]	Palmdale Cultural	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.06

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
		Center							
CAPV	N/A[8]	Palmdale Library	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.07
CAPV	N/A[8]	Palmdale Water Park	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.28
CAPV	N/A[8]	Palmdale Recreation Center	CAPV	CAPV	N/A	CAISO	Southwest	2014	0.05
Constellation Solar Arizona, LLC ("CSAZ")	N/A[8]	Buckeye Union High School District 201	CSAZ	CSAZ	N/A	AZPS	Southwest	2011	3.62
CSAZ	N/A[8]	Casa Grande at Casa Verde High School	CSAZ	CSAZ	N/A	AZPS	Southwest	2012	0.35
CSAZ	N/A[8]	Casa Grande at Union High School	CSAZ	CSAZ	N/A	AZPS	Southwest	2012	1.79
CSAZ	N/A[8]	Casa Grande at Vista Grande High School	CSAZ	CSAZ	N/A	AZPS	Southwest	2012	1.54
CSAZ	N/A[8]	Isaac School District at Butler	CSAZ	CSAZ	N/A	AZPS	Southwest	2014	0.21
CSAZ	N/A[8]	Miami Phase II at Lee Kornegay HS	CSAZ	CSAZ	N/A	AZPS	Southwest	2014	0.12
CSAZ	N/A[8]	Miami School District	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.36
CSAZ	N/A[8]	Miami School District at Charles Bejarano	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.09
CSAZ	N/A[8]	Peoria School District Phase II at Parkridge Elementary	CSAZ	CSAZ	N/A	AZPS	Southwest	2014	0.44
CSAZ	N/A[8]	Somerton School District at Orange Grove	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.18
CSAZ	N/A[8]	Somerton School District at Tierra del Sol	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.23
CSAZ	N/A[8]	Somerton School District at Valle del	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.17

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
		Encanto							
CSAZ	N/A[8]	Somerton School District at Desert Sonora	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.29
CSAZ	N/A[8]	Somerton School District at Somerton Middle School	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.47
CSAZ	N/A[8]	Tucson Unified School District at Collier ES	CSAZ	CSAZ	N/A	AZPS	Southwest	2014	0.25
CSAZ	N/A[8]	Vail School District at Andrada Polytechnic High School	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.33
CSAZ	N/A[8]	Vail School District at Mesquite Elementary School	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.23
CSAZ	N/A[8]	Vail School District at Old Vail Middle School	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.25
CSAZ	N/A[8]	Dysart School District	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	8.8
CSAZ	N/A[8]	Marana School District	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	3.18
CSAZ	N/A[8]	Peoria School District	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	5.05
CSAZ	N/A[8]	Crane School District at Mesquite	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.17
CSAZ	N/A[8]	Crane School District at Gary A. Knox	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.19
CSAZ	N/A[8]	Crane School District at Centennial	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.38
CSAZ	N/A[8]	Crane School District at Valley Horizon	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.27

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
CSAZ	N/A[8]	Crane School District at Crane	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.38
CSAZ	N/A[8]	Crane School District at Pueblo	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.21
CSAZ	N/A[8]	Crane School District at Salida del Sol	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.26
CSAZ	N/A[8]	Crane School District at Suverkrup	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.27
CSAZ	N/A[8]	Willow Canyon HS at Dysart	CSAZ	CSAZ	N/A	AZPS	Southwest	2014	.5
CSAZ	N/A[8]	Western Peaks ES at Dysart	CSAZ	CSAZ	N/A	AZPS	Southwest	2014	.5
Mohave Sunrise Solar I, LLC	N/A[3]	Mohave Electric at Fort Mohave	Mohave Sunrise Solar I, LLC	Mohave Sunrise Solar I, LLC	N/A	WALC	Southwest	2015	4.6
ExGen	ER00-3251	Green Country 1-3	Green Country OP Services LLC	ExGen	2002	Southwest Power Pool ("SPP")	SPP	2002	785[6]
Exelon Wind 1, LLC	N/A[3]	Exelon Wind 1	Exelon Wind 1, LLC	Exelon Wind 1, LLC	N/A	SPP	SPP	2005	10[4]
Exelon Wind 10, LLC	N/A[3]	Exelon Wind 10	Exelon Wind 10, LLC	Exelon Wind 10, LLC	N/A	SPP	SPP	2008	10[4]
Exelon Wind 11, LLC	N/A[3]	Exelon Wind 11	Exelon Wind 11, LLC	Exelon Wind 11, LLC	N/A	SPP	SPP	2008	10[4]
Exelon Wind 2, LLC	N/A[3]	Exelon Wind 2	Exelon Wind 2, LLC	Exelon Wind 2, LLC	N/A	SPP	SPP	2005	10[4]
Exelon Wind 3, LLC	N/A[3]	Exelon Wind 3	Exelon Wind 3, LLC	Exelon Wind 3, LLC	N/A	SPP	SPP	2005	10[4]
Exelon Wind 4, LLC	ER07-1202	Exelon Wind 4	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	2007	79.8[4]
Exelon Wind 5, LLC	N/A[3]	Exelon Wind 5	Exelon Wind 5, LLC	Exelon Wind 5, LLC	N/A	SPP	SPP	2006	10[4]

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
Exelon Wind 6, LLC	N/A[3]	Exelon Wind 6	Exelon Wind 6, LLC	Exelon Wind 6, LLC	N/A	SPP	SPP	2006	10[4]
Exelon Wind 7, LLC	N/A[3]	Exelon Wind 7	Exelon Wind 7, LLC	Exelon Wind 7, LLC	N/A	SPP	SPP	2008	10[4]
Exelon Wind 8, LLC	N/A[3]	Exelon Wind 8	Exelon Wind 8, LLC	Exelon Wind 8, LLC	N/A	SPP	SPP	2008	10[4]
Exelon Wind 9, LLC	N/A[3]	Exelon Wind 9	Exelon Wind 9, LLC	Exelon Wind 9, LLC	N/A	SPP	SPP	2008	10[4]
High Plains Wind Power, LLC	N/A[3]	High Plains	High Plains Wind Power, LLC	High Plains Wind Power, LLC	N/A	SPP	SPP	2008	10[4]
Wildcat Wind, LLC	ER12-1223	Wildcat Wind	Wildcat Wind, LLC	Wildcat Wind, LLC	N/A	SPP	SPP	2012	27.3[4]
Greensburg Wind Farm, LLC	N/A[3]	Greensburg	Greensburg Wind Farm, LLC	Greensburg Wind Farm, LLC	N/A	SPP	SPP	2010	12.5[4]
Shooting Star Wind Project, LLC	ER12-1829	Shooting Star	Shooting Star Wind Project, LLC	Shooting Star Wind Project, LLC	N/A	SPP	SPP	2012	104
Baltimore Gas and Electric Company ("BGE")	ER99-2948	N/A	N/A	N/A	NA	N/A	N/A	N/A	NA
Commonwealth Edison Company ("ComEd")	ER98-1734	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Constellation Energy Commodities Group Maine, LLC	ER02-699	N/A	N/A	N/A	NA	N/A	N/A	N/A	NA
Constellation NewEnergy, Inc.	ER96-1387	N/A	N/A	N/A	NA	N/A	N/A	N/A	NA
Integrys Energy	ER07-650	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
Services, Inc.									
Integrys Energy Services of New York, Inc.,	ER07-651	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
PECO Energy Company ("PECO")	ER01-1147	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

1 Unless otherwise indicated, generation capacity ratings (megawatts) are based on the summer seasonal ratings.

2 Facilities solely in the region administered by the Electric Reliability Council of Texas ("ERCOT") are not included herein.

3 MBR authority was not obtained for this entity, because it is a qualifying facility with a capacity of less than 20 MW *(see* 18 C.F.R. § 292.601(c)(1)).

4 The capacity rating for this entity is based on its nameplate capacity.

5 MBR authority was not obtained for this entity, because it is a qualifying facility that sells power pursuant to a PURPA contract or pursuant to a contract executed on or before March 17, 2006 *(see* 18 C.F.R. § 292.601(c)(1)).

6 ExGen has a tolling agreement for 795 MW from Green Country.

7 This generation rating reflects the full plant rating, not just Exelon's ownership share.

8 This row pertains to one or more behind-the-meter facilities that sell entirely at retail and therefore do not participate in the wholesale market.

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Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas Storage

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
Constellation Mystic Power, LLC	Limited & discrete interconnection facilities[1]	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon Framingham, LLC	Limited & discrete interconnection facilities[1]	Exelon Framingham, LLC	Exelon Framingham, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon New Boston, LLC	Limited & discrete interconnection facilities[1]	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon West Medway, LLC	Limited & discrete interconnection facilities[1]	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon Wyman, LLC	Limited & discrete interconnection facilities[1]	Exelon Wyman, LLC	Exelon Wyman, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Holyoke Solar LLC	Limited & discrete interconnection facilities[1]	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Nine Mile Point Nuclear Station, LLC	Limited & discrete interconnection facilities[1]	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	N/A (OATT Waiver)
R.E. Ginna Nuclear Power	Limited & discrete	R.E. Ginna Nuclear	R.E. Ginna Nuclear	N/A	NYISO	Northeast	N/A (OATT Waiver)

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
Plant, LLC	interconnection facilities[1]	Power Plant, LLC	Power Plant, LLC				
BGE	Combined 115kV Lines	BGE	PJM	1998	PJM	Northeast	695.85 combined miles
BGE	Combined 138kV Lines	BGE	PJM	1998	PJM	Northeast	54.44 combined miles
BGE	Combined 230kV Lines	BGE	PJM	1998	PJM	Northeast	320.97 combined miles
BGE	Combined 500kV Lines	BGE	PJM	1998	PJM	Northeast	217.42 combined miles
BGE	Intrastate Gas Transmission	BGE	BGE	N/A	PJM	Northeast	approx. 165 combined miles
Calvert Cliffs Nuclear Power Plant, LLC	Limited & discrete interconnection facilities[1]	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
ComEd	Electric Transmission Combined 765 kV Lines	ComEd	ComEd/PJM	N/A	PJM	Northeast	89.59 combined miles
ComEd	Electric Transmission Combined 345 kV Lines	ComEd	ComEd/PJM	N/A	PJM	Northeast	2,634.29 combined miles
ComEd	Electric Transmission Combined 138 kV Lines	ComEd	ComEd/PJM	N/A	PJM	Northeast	2,877.02 combined miles
Criterion Power Partners, LLC	Limited & discrete interconnection facilities[1]	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Exelon Solar Chicago LLC	Limited & discrete	Exelon Solar	Exelon Solar	N/A	PJM	Northeast	N/A (OATT Waiver)

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
	interconnection facilities[1]	Chicago LLC	Chicago LLC				
Fourmile Wind Energy, LLC	Limited & discrete interconnection facilities[1]	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Handsome Lake Energy, LLC	Limited & discrete interconnection facilities[1]	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
PECO	Electric Transmission 500 kV Lines	PECO	PECO/PJM	N/A	PJM	Northeast	316.23 combined miles
PECO	Electric Transmission Combined 200/220 kV Lines	PECO	PECO/PJM	N/A	PJM	Northeast	503.05 combined miles
PECO	Electric Transmission Combined 132 kV Lines	PECO	PECO/PJM	N/A	PJM	Northeast	127.70 combined miles
PECO	Electric Transmission Combined 66 kV Lines	PECO	PECO/PJM	N/A	PJM	Northeast	169.54 combined miles
PECO	Electric Transmission Combined 13.2 kV Lines	PECO	PECO/PJM	N/A	PJM	Northeast	0.47 combined miles
PECO	Intrastate Gas Transmission	PECO	PECO	N/A	PJM	Northeast	31 combined miles
PECO	Intrastate Gas Storage (LNG)	PECO	PECO	N/A	PJM	Northeast	1,200 mmcf
Cassia Gulch Wind Park, LLC	Limited & discrete	Cassia Gulch Wind	Cassia Gulch Wind	N/A	Idaho Power	Northwest	N/A (OATT Waiver)

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
	interconnection facilities[1]	Park, LLC	Park, LLC				
High Mesa Energy, LLC	Limited & discrete interconnection facilities[1]	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
Tuana Springs Energy, LLC	Limited & discrete interconnection facilities[1]	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
CER Generation II, LLC	Limited & discrete interconnection facilities[1]	CER Generation II, LLC	CER Generation II, LLC	N/A	PacifiCorp East	Northwest	N/A (OATT Waiver)
Beebe 1B Renewable Energy, LLC and Beebe Renewable Energy, LLC ("Beebe")[2]	Limited & discrete interconnection facilities[1]	Beebe	Beebe	N/A	MISO	Central	N/A (OATT Waiver)
Harvest Windfarm, LLC	Limited & discrete interconnection facilities[1]	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	N/A (OATT Waiver)
Michigan Wind 1, LLC	Limited & discrete interconnection facilities[1]	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	N/A (OATT Waiver)
CER Generation, LLC	Limited & discrete interconnection facilities[1]	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	N/A (OATT Waiver)
Constellation Power Source Generation, LLC	Limited & discrete interconnection	Constellation Power Source	Constellation Power Source	N/A	Various	Various	N/A (OATT Waiver)

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
	facilities[1]	Generation, LLC	Generation, LLC				
Constellation Power, Inc.	Limited & discrete interconnection facilities[1]	Constellation Power, Inc.	Constellation Power, Inc.	N/A	Various	Various	N/A (OATT Waiver)
ExGen	Limited & discrete interconnection facilities[1]	ExGen	ExGen	N/A	Various	Various	N/A (OATT Waiver)
Cow Branch Wind Power, L.L.C.	Limited & discrete interconnection facilities[1]	Cow Branch Wind Power, LLC	Cow Branch Wind Power, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
CR Clearing, LLC	Limited & discrete interconnection facilities[1]	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
Wind Capital Holdings, LLC	Limited & discrete interconnection facilities[1]	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
Exelon Wind 4, LLC	Limited & discrete interconnection facilities[1]	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	N/A (OATT Waiver)

[1] These facilities are included because waiver of Order Nos. 888, 889, 890, their implementing regulations, and the requirements of Part 358 of FERC's regulations has been sought with respect to them.

[2] Beebe 1B Renewable Energy, LLC and Beebe Renewable Energy, LLC share certain interconnection facilities.

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ASSET APPENDICES
OF EDF, INC.

ONLY affiliated with the following Sellers:
Calvert Cliffs Nuclear Power Plant, LLC,
Nine Mile Point Nuclear Station, LLC,
and R.E. Ginna Nuclear Power Plant, LLC

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EDF Affiliates with Market-Based Rate Authority and Generation Assets[1]

Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Location		In-service Date	Nameplate and/or Seasonal Rating
						Balancing Authority Area	Geographic Region (per Appendix D)		
EDF Trading North America, LLC	ER03-774	N/A	EDF Trading Holdings LLC	EDF Trading Holdings LLC	10/31/2008	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)
EDF Industrial Power Services (CA), LLC	ER12-1825	N/A	EDF Trading North America, LLC	EDF Trading North America, LLC	N/A	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)
EDF Industrial Power Services (IL), LLC	ER10-1424	N/A	EDF Trading North America LLC	EDF Trading North America LLC	N/A	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)
EDF Industrial Power Services (NY), LLC	ER10-1425	N/A	EDF Trading North America LLC	EDF Trading North America LLC	N/A	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)
EDF Industrial Power Services (OH), LLC	ER13-1680	N/A	EDF Trading North America LLC	EDF Trading North America LLC	N/A	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)

[1] Excludes assets outside the continental U.S and within ERCOT.

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Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Location		In-service Date	Nameplate and/or Seasonal Rating
						Balancing Authority Area	Geographic Region (per Appendix D)		
EDF Energy Services, LLC	ER14-2672	N/A	EDF Trading North America LLC	EDF Trading North America LLC	N/A	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)
Champion Energy Marketing LLC	ER08-836	N/A	Champion Energy Holdings, LLC & EDF Trading North America, LLC	Champion Energy Holdings, LLC	N/A	N/A	N/A	N/A	N/A
Champion Energy Services, LLC	ER10-3049	N/A	Champion Energy Marketing LLC	Champion Energy Marketing LLC	N/A	N/A	N/A	N/A	N/A
Champion Energy, LLC	ER10-3051	N/A	Champion Energy Marketing LLC	Champion Energy Marketing LLC	N/A	N/A	N/A	N/A	N/A
AP Holdings, LLC	ER10-1806	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
AP Gas & Electric (PA), LLC	ER11-1939	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Location		In-service Date	Nameplate and/or Seasonal Rating
						Balancing Authority Area	Geographic Region (per Appendix D)		
AP Gas & Electric (TX), LLC	ER11-2754	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
AP Gas & Electric (MD), LLC	ER12-999	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
AP Gas & Electric (NJ), LLC	ER12-1002	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
AP Gas & Electric (IL), LLC	ER12-1005	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
AP Gas & Electric (OH), LLC	ER12-1006	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
AP Gas & Electric (NY), LLC	ER12-1007	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Anahau Energy, LLC	ER13-415	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Location		In-service Date	Nameplate and/or Seasonal Rating
						Balancing Authority Area	Geographic Region (per Appendix D)		
Allendale Biomass, LLC	N/A	N/A	Allendale Biomass	Allendale Biomass	N/A	Santee Cooper	Southeast	10/1/13	19.3
Alta Mesa Phase III Partners	N/A	N/A	Alta Mesa	Alta Mesa	N/A	CAISO	Southwest	2/1995	9.5
Bellevue Solar, LLC	ER11-4380-000	N/A	Bellevue Solar	Bellevue Solar	N/A	PGE	Northwest	10/26/2011	1.66
Buffalo Ridge Wind Farm, LLC	N/A	N/A	Buffalo Ridge Wind Farm, LLC	Buffalo Ridge Wind Farm, LLC	N/A	MISO	Central	12/18/2003	1.5
Catalina Solar Lessee, LLC	ER13-1562-000	N/A	Catalina Solar, LLC	N/A	N/A	CAISO	Southwest	2013	110
Champepadan Wind Power Partners, LLC	N/A	N/A	Champepadan	Champepadan	N/A	MISO	Central	12/19/2001	1.98
Chanarambie Power Partners, LLC	ER03-1340-000	N/A	Chanarambie	Chanarambie	N/A	MISO	Central	12/15/2003	85.5
Chestnut Flats Lessee, LLC	ER13-1641-000	N/A	Chestnut Flats Wind, LLC	N/A	9/30/13	PJM	Northeast	12/29/11	38
DifWind Farms LTD VI	N/A	N/A	DifWind VI	DifWind VI	N/A	CAISO	Southwest	12/31/1984	26.8

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Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Location		In-service Date	Nameplate and/or Seasonal Rating
						Balancing Authority Area	Geographic Region (per Appendix D)		
DifWind Farms LTD VII	N/A	N/A	DifWind VII	DifWind VII	N/A	CAISO	Southwest	1/1/1985	23
DifWind Farms LTD VIII	N/A	N/A	DifWind VIII	DifWind VIII	N/A	CAISO	Southwest	12/31/1986	15
DifWind Farms LTD IX	N/A	N/A	DifWind IX	DifWind IX	N/A	CAISO	Southwest	1/1/1985	15
Dorchester Biomass, LLC	N/A	N/A	Dorchester Biomass	Dorchester Biomass	N/A	Santee Cooper	Southeast	10/1/13	19.3
EDF Renewable Wind Farm IV	N/A	N/A	EDF Renewable Wind Farm IV	EDF Renewable Wind Farm IV	N/A	CAISO	Southwest	12/31/1988	18.7
EDF Renewable Wind Farm V, Inc.	N/A	N/A	EDF Renewable Wind Farm V	EDF Renewable Wind Farm V	N/A	CAISO	Southwest	1989	16.2
Fenton Power Partners I, LLC	ER07-357-000	N/A	Fenton Power Partners	Fenton Power Partners	N/A	MISO	Central	11/13/2007	205.5
Hoosier Wind Project, LLC	ER09-1181-000	N/A	Hoosier Wind Project	Hoosier Wind Project	N/A	MISO	Central	11/2009	106
Moulton Heights Wind Power Project, LLC	N/A	N/A	Moulton Heights	Moulton Heights	N/A	MISO	Central	12/18/2003	1.5
Moulton Wind Power Partners, LLC	N/A	N/A	Moulton Wind	Moulton Wind	N/A	MISO	Central	12/19/2001	1.98

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Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Location		In-service Date	Nameplate and/or Seasonal Rating
						Balancing Authority Area	Geographic Region (per Appendix D)		
Muncie Power Partners, LLC	N/A	N/A	Muncie Power	Muncie Power	N/A	MISO	Central	12/18/2003	1.5
North Ridge Wind Farm, LLC	N/A	N/A	North Ridge	North Ridge	N/A	MISO	Central	12/18/2003	1.5
Oasis Power Partners, LLC	ER05-41-000	N/A	Oasis Power	Oasis Power	N/A	CAISO	Southwest	12/24/2004	60
Pacific Wind Lessee, LLC	ER12-1931-000	N/A	Pacific Wind, LLC	Pacific Wind Lessee, LLC	N/A	CAISO	Southwest	8/16/2012	140
Patterson Pass Wind Farm LLC	N/A	N/A	Patterson Pass	Patterson Pass	N/A	CAISO	Southwest	3/1995	21.7
Sacramento Soleil, LLC	N/A	N/A	Sacramento Soleil	Sacramento Soleil	N/A	CAISO	Southwest	7/14/2008	1
Shiloh Wind Project 2, LLC	ER08-1237-000	N/A	Shiloh 2	Shiloh 2	N/A	CAISO	Southwest	1/30/2009	150
Shiloh III Lessee, LLC	ER12-610-009	N/A	Shiloh III Wind Project, LLC	Shiloh III Lessee	2/16/12	CAISO	Southwest	12/22/11	100
Shiloh IV Lessee, LLC	ER13-338-000	N/A	Shiloh IV Wind Project	Shiloh IV Lessee	12/27/12	CAISO	Southwest	12/21/2012	102.5
Spearville 3, LLC	ER12-2037-000	N/A	Spearville 3, LLC	Spearville 3, LLC	N/A	KCPL	SPP	10/1/2012	100.8

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Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Location		In-service Date	Nameplate and/or Seasonal Rating
						Balancing Authority Area	Geographic Region (per Appendix D)		
Spinning Spur Wind, LLC	ER12-2314	N/A	Spinning Spur Wind, LLC	Spinning Spur Wind, LLC	N/A	SPS	SPP	12/20/2012	161
Vandy South Project, LLC	N/A	N/A	Vandy South	Vandy South	N/A	MISO	Central	12/18/2003	1.5
Viking Wind Farm, LLC	N/A	N/A	Viking	Viking	N/A	MISO	Central	12/18/2003	1.5
Vindy Power Partners, LLC	N/A	N/A	Vindy South	Vindy South	N/A	MISO	Central	12/18/2003	1.5
Wapsipinicon Wind Project, LLC	ER08-1288-000	N/A	Wapsipinicon	Wapsipinicon	N/A	MISO	Central	2/20/2009	100.5
Wilson-West Wind Farm, LLC	N/A	N/A	Wilson-West	Wilson-West	N/A	MISO	Central	12/18/2003	1.5
Yamhill Solar, LLC	ER11-4381-000	N/A	Yamhill Solar	Yamhill Solar	N/A	PGE	Northwest	10/26/2011	1.19
Calvert Cliffs Nuclear Power Plant LLC	ER00-2917-000	Calvert Cliffs Nuclear Power Plant (Unit 1)	Calvert Cliffs Nuclear Power Plant LLC	Calvert Cliffs Nuclear Power Plant LLC	11/6/2009	PJM Interconnection	Northeast	1975	873
Calvert Cliffs Nuclear Power Plant LLC	ER00-2917-000	Calvert Cliffs Nuclear Power Plant (Unit 2)	Calvert Cliffs Nuclear Power Plant LLC	Calvert Cliffs Nuclear Power Plant LLC	11/6/2009	PJM Interconnection	Northeast	1977	862
R.E. Ginna Unit 1 Nuclear Power Plant, LLC	ER04-485-000	Ginna	R.E. Ginna Unit 1 Nuclear Power Plant, LLC	R.E. Ginna Unit 1 Nuclear Power Plant, LLC	11/6/2009	NYISO	Northeast	1970	582

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Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Location		In-service Date	Nameplate and/or Seasonal Rating
						Balancing Authority Area	Geographic Region (per Appendix D)		
Nine Mile Point Nuclear Station, LLC	ER01-1654-000	Nine Mile Point (Unit 1)	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	11/6/2009	NYISO	Northeast	1969	627
Nine Mile Point Nuclear Station, LLC	ER01-1654-000	Nine Mile Point (Unit 2)	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	11/6/2009	NYISO	Northeast	1988	1287.2
Tanner Street Generation, LLC	ER11-3642-000	Tanner Street Facility	Tanner Street Generation, LLC	Tanner Street Generation, LLC	7/1/2011	ISO-NE	Northeast	7/2008	80 MW (net winter)

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EDF Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas Storage Facilities

Filing Entity and its Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per Appendix D)	
Oasis Power Partners, LLC	Sagebrush Line – used to connect wind power generation in Tehachapi Region to So. Cal. Edison substation	Sagebrush Partners	Sagebrush Partners	N/A	CAISO	Southwest	46-mile, 230kV
Pacific Wind Lessee, LLC and Catalina Solar	Antelope Valley Line (230 kV gen tie line)	Catalina Solar, LLC and affiliates	Catalina Solar and affiliates	N/A	CAISO	Southwest	10.55-mile for one 230 kV line and approximately 14-mile for the other 230 kV line

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service lists compiled by the Secretary in these proceedings.

Dated at Washington, DC this 24th day of November, 2014.

/s/ Corey Neal

Corey Neal
White & Case LLP
701 Thirteenth Street, NW
Washington, DC 20005
Telephone: (202) 637-6195

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Document Content(s)

CIS of Integrys and Exelon Entities.PDF.....1-44

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January 12, 2015

BY E-FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: AV Solar Ranch 1, LLC, Docket No. ER12-2178-___
Baltimore Gas and Electric Company, Docket No. ER10-2172-
Beebe 1B Renewable Energy, LLC, Docket No. ER14-2144-___
Beebe Renewable Energy, LLC, Docket No. ER12-2311-___
Calvert Cliffs Nuclear Power Plant, LLC, Docket No. ER10-2179-___
Cassia Gulch Wind Park, LLC, Docket No. ER11-2016-___
CER Generation, LLC, Docket No. ER10-2184-___
CER Generation II, LLC, Docket No. ER10-2183-___
Commonwealth Edison Company, Docket No. ER10-1048-___
Constellation Energy Commodities Group Maine, LLC, Docket No. ER10-2192-___
Constellation Mystic Power, LLC, Docket No. ER11-2056-___
Constellation NewEnergy, Inc., Docket No. ER10-2178-___
Constellation Power Source Generation, LLC, Docket No. ER14-1524-___
Cow Branch Wind Power, LLC, Docket No. ER11-2014-___
CR Clearing, LLC, Docket No. ER11-2013-___
Criterion Power Partners, LLC, Docket No. ER10-3308-___
Exelon Framingham, LLC, Docket No. ER10-1020-___
Exelon Generation Company, LLC, Docket No. ER13-1536-___
Exelon New Boston, LLC, Docket No. ER10-1078-___
Exelon West Medway, LLC, Docket No. ER10-1080-___
Exelon Wind 4, LLC, Docket No. ER11-2010-___
Exelon Wyman, LLC, Docket No. ER10-1081-___
Fourmile Wind Energy, LLC, Docket No. ER14-2145-___
Handsome Lake Energy, LLC, Docket No. ER10-2180-___
Harvest Windfarm, LLC, Docket No. ER11-2011-___
Harvest II Windfarm, LLC, Docket No. ER12-2201-___
High Mesa Energy, LLC, Docket No. ER12-2528-___
Integrys Energy Services, Inc., Docket No. ER10-3025-___

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Integrys Energy Services of New York, Inc. Docket No. ER10-3027-___
Michigan Wind 1, LLC, Docket No. ER11-2009-___
Michigan Wind 2, LLC, Docket No. ER11-3989-___
Nine Mile Point Nuclear Station, LLC, Docket No. ER10-2181-___
PECO Energy Company, Docket No. ER14-767-___
R.E. Ginna Nuclear Power Plant, LLC, Docket No. ER10-2182-___
Shooting Star Wind Project, LLC, Docket No. ER12-1829-___
Tuana Springs Energy, LLC, Docket No. ER11-2007-___
Wildcat Wind, LLC, Docket No. ER12-1223-___
Wind Capital Holdings, LLC, Docket No. ER11-2005-___

Re: Revised Asset Appendices for Notice of Non-Material Change in Status

Per Staff's request, enclosed please find revised asset appendices for the above-captioned entities' November 24, 2014 Notice of Non-Material Change in Status (Change in Status Notice). The asset appendices attached to the November 24 Filing inadvertently ommitted 2014 ESA Project Company, LLC, one of the new affiliations that was the subject of the non-material change in status. The above-captioned entities respectfully renew their request that the Commission accept the Change in Status Notice.

Respectfully submitted,

/s/ Jane E. Rueger

Jane E. Rueger
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Counsel for the Sellers

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service lists compiled by the Secretary in these proceedings.

Dated at Washington, DC this 12th day of January, 2015.

/s/ Corey Neal

Corey Neal
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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Commonwealth Edison Company	ER98-1734	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Constellation Energy Commodities Group Maine, LLC	ER02-699	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Constellation NewEnergy, Inc.	ER96-1387	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Integrys Energy Services of New York, Inc.,	ER07-651	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Integrys Energy Services, Inc.	ER07-650	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
PECO Energy Company	ER01-1147	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
AgriWind LLC	N/A QF07-214	Agriwind LLC WF	AgriWind LLC	AgriWind LLC	N/A	MISO	Central	Jul-2007	2.10
AgriWind Project L.L.C.	N/A QF07-215	Agriwind Project LLC WF	AgriWind Project L.L.C.	AgriWind Project L.L.C.	N/A	MISO	Central	Jul-2007	6.30
BC Energy LLC	N/A QF07-219	BC Energy LLC WF	BC Energy LLC	BC Energy LLC	N/A	MISO	Central	May-2008	4.20
Beebe 1B Renewable Energy, LLC	ER14-2144	Beebe 1b WF	Beebe 1B Renewable Energy, LLC	Beebe 1B Renewable Energy, LLC	N/A	MISO	Central	Dec-2014	50.40
Beebe Renewable Energy, LLC	ER12-2311	Beebe 1a WF	Beebe Renewable Energy, LLC	Beebe Renewable Energy, LLC	N/A	MISO	Central	Jan-2013	81.60
Blue Breezes II, L.L.C.	N/A QF07-243	Blue Breezes II LLC WF	Blue Breezes II, L.L.C.	Blue Breezes II, L.L.C.	N/A	MISO	Central	May-2006	1.25
Blue Breezes, L.L.C.	N/A QF07-242	Blue Breezes I LLC WF	Blue Breezes, L.L.C.	Blue Breezes, L.L.C.	N/A	MISO	Central	May-2006	1.25
Breezy Bucks I LLC	N/A QF07-234	Breezy Bucks I LLC WF	Breezy Bucks I LLC	Breezy Bucks I LLC	N/A	MISO	Central	May-2006	1.25
Breezy Bucks II LLC	N/A QF07-235	Breezy Bucks II LLC WF	Breezy Bucks II LLC	Breezy Bucks II LLC	N/A	MISO	Central	May-2006	1.25
Christoffer Wind Energy I LLC	N/A QF07-250	Christoffer Wind I WF	Christoffer Wind Energy I LLC	Christoffer Wind Energy I LLC	N/A	MISO	Central	Jun-2008	2.10
Christoffer Wind Energy II LLC	N/A QF07-252	Christoffer Wind II WF	Christoffer Wind Energy II LLC	Christoffer Wind Energy II LLC	N/A	MISO	Central	Jun-2008	2.10
Christoffer Wind Energy III LLC	N/A QF07-251	Christoffer Wind III WF	Christoffer Wind Energy III LLC	Christoffer Wind Energy III LLC	N/A	MISO	Central	Jun-2008	2.10
Christoffer Wind Energy IV LLC	N/A QF07-249	Christoffer Wind IV WF	Christoffer Wind Energy IV LLC	Christoffer Wind Energy IV LLC	N/A	MISO	Central	Jun-2008	2.10
CP Windfarm, LLC	N/A QF07-178	CP Wind Farms LLC WF	CP Windfarm, LLC	CP Windfarm, LLC	N/A	MISO	Central	Oct-2007	4.20
Exelon Generation Company, LLC	ER00-3251	Clinton	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	MISO	Central	Nov-1987	1065.00
G-Flow Wind, LLC	N/A QF07-223	G-Flow Wind LLC WF	G-Flow Wind, LLC	G-Flow Wind, LLC	N/A	MISO	Central	Mar-2006	1.25
Green Acres Breeze, LLC	N/A QF07-227	Green Acres Breeze LLC WF	Green Acres Breeze, LLC	Green Acres Breeze, LLC	N/A	MISO	Central	Mar-2006	1.25

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Harvest II Windfarm, LLC	ER12-2201 QF12-522	Harvest 2 WF	Harvest II Windfarm, LLC	Harvest II Windfarm, LLC	N/A	MISO	Central	Nov-2012	59.40
Harvest Windfarm, LLC	ER07-1246 QF07-29	Harvest 1 WF	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	Feb-2008	52.80
K&D Energy LLC	N/A QF07-218	K&D Energy LLC WF	K&D Energy LLC	K&D Energy LLC	N/A	MISO	Central	May-2008	4.00
KC Energy LLC	N/A QF07-217	KC Energy LLC WF	KC Energy LLC	KC Energy LLC	N/A	MISO	Central	May-2008	4.00
KSS Turbines LLC	N/A QF07-220	KSS Turbines LLC WF	KSS Turbines LLC	KSS Turbines LLC	N/A	MISO	Central	May-2008	4.00
Marshall Wind 1, LLC	N/A QF08-59	Marshall Wind 1 WF	Marshall Wind 1, LLC	Marshall Wind 1, LLC	N/A	MISO	Central	May-2008	2.10
Marshall Wind 2, LLC	N/A QF08-58	Marshall Wind 2 WF	Marshall Wind 2, LLC	Marshall Wind 2, LLC	N/A	MISO	Central	May-2008	4.20
Marshall Wind 3, LLC	N/A QF08-55	Marshall Wind 3 WF	Marshall Wind 3, LLC	Marshall Wind 3, LLC	N/A	MISO	Central	May-2008	4.20
Marshall Wind 4, LLC	N/A QF08-56	Marshall Wind 4 WF	Marshall Wind 4, LLC	Marshall Wind 4, LLC	N/A	MISO	Central	May-2008	4.20
Marshall Wind 5, LLC	N/A QF08-57	Marshall Wind 5 WF	Marshall Wind 5, LLC	Marshall Wind 5, LLC	N/A	MISO	Central	May-2008	2.10
Marshall Wind 6, LLC	N/A QF08-60	Marshall Wind 6 WF	Marshall Wind 6, LLC	Marshall Wind 6, LLC	N/A	MISO	Central	May-2008	2.10
Michigan Wind 1, LLC	ER05-1511 QF05-228	Michigan Wind 1 WF	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	Dec-2008	69.00
Michigan Wind 2, LLC	ER11-3989	Michigan Wind 2 WF	Michigan Wind 2, LLC	Michigan Wind 2, LLC	N/A	MISO	Central	Jan-2012	90.00
Minnesota Breeze, LLC	N/A QF07-224	Minnesota Breeze LLC WF	Minnesota Breeze, LLC	Minnesota Breeze, LLC	N/A	MISO	Central	Mar-2006	1.25
Prairie Wind Power LLC	N/A QF07-216	Prairie Wind Power LLC WF	Prairie Wind Power LLC	Prairie Wind Power LLC	N/A	MISO	Central	May-2008	4.00
Roadrunner I LLC	N/A QF07-236	Roadrunner I LLC WF	Roadrunner I LLC	Roadrunner I LLC	N/A	MISO	Central	May-2006	1.25
Salty Dog I LLC	N/A QF07-237	Salty Dog I LLC WF	Salty Dog I LLC	Salty Dog I LLC	N/A	MISO	Central	May-2006	1.25
Salty Dog II LLC	N/A QF07-238	Salty Dog II LLC WF	Salty Dog II LLC	Salty Dog II LLC	N/A	MISO	Central	May-2006	1.25
Shane's Wind Machine LLC	N/A QF07-247	Shanes Wind Machine LLC WF	Shane's Wind Machine LLC	Shane's Wind Machine LLC	N/A	MISO	Central	Jul-2006	2.00
Sunset Breeze, LLC	N/A QF07-226	Sunset Breeze LLC WF	Sunset Breeze, LLC	Sunset Breeze, LLC	N/A	MISO	Central	Mar-2006	1.25
Wally's Wind Farm LLC	N/A QF07-239	Wally's Wind Farm	Wally's Wind Farm LLC	Wally's Wind Farm LLC	N/A	MISO	Central	May-2006	1.25
Windy Dog I LLC	N/A QF07-240	Windy Dog I LLC WF	Windy Dog I LLC	Windy Dog I LLC	N/A	MISO	Central	May-2006	1.25
Wolf Wind Enterprises, LLC	N/A QF07-225	Wolf Wind Enterprises LLC WF	Wolf Wind Enterprises, LLC	Wolf Wind Enterprises, LLC	N/A	MISO	Central	Mar-2006	1.25
Exelon Generation Company, LLC	ER00-3251	Frontier GT1	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	Sep-2000	MISO & ERCOT	Central	Sep-2000	160.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Frontier GT2	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	Sep-2000	MISO & ERCOT	Central	Sep-2000	160.00
Exelon Generation Company, LLC	ER00-3251	Frontier GT3	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	Sep-2000	MISO & ERCOT	Central	Sep-2000	160.00
Exelon Generation Company, LLC	ER00-3251	Frontier ST	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	Sep-2000	MISO & ERCOT	Central	Sep-2000	390.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 7	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	Jun-1975	575.48
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	Apr-2003	225.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	Apr-2003	227.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	Apr-2003	252.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	Jun-2003	231.09
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	Jun-2003	230.80
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	Jun-2003	252.00
Constellation Mystic Power, LLC	ER10-2281	Mystic Jet	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	Jun-1969	9.07
Constellation Solar Connecticut, LLC	N/A QF10-654	East Lyme Bd of Ed at East Lyme HS	Constellation Solar Connecticut LLC	Constellation Solar Connecticut LLC	N/A	ISO-NE	Northeast	Mar-2009	0.41
Constellation Solar Connecticut, LLC	N/A QF10-663	Parker Hannifin Corp at New Britain	Constellation Solar Connecticut LLC	Constellation Solar Connecticut LLC	N/A	ISO-NE	Northeast	Dec-2008	0.18
Constellation Solar Massachusetts, LLC	N/A QF11-411	Kollmorgen Corp at Kollmorgen Electro-Optical HQ Bldg	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Jul-2011	0.17
Constellation Solar Massachusetts, LLC	N/A QF15-188	Macy's at Marlborough	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Dec-2014	0.41
Constellation Solar Massachusetts, LLC	N/A QF15-187	Macy's at Natick	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Dec-2014	0.56
Constellation Solar Massachusetts, LLC	N/A QF15-186	Macy's at Saugus	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Dec-2014	0.30
Constellation Solar Massachusetts, LLC	N/A QF15-190	Macy's at Burlington	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Dec-2014	0.25
Constellation Solar Massachusetts, LLC	N/A QF15-189	Macy's at Dartmouth	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Dec-2014	0.35
Constellation Solar Massachusetts, LLC	N/A QF09-89	Majilite Corp	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Feb-2009	0.35
Constellation Solar Massachusetts, LLC	N/A QF10-655	NPP Development, LLC at Patriot Place	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Jul-2010	0.45
Constellation Solar Massachusetts, LLC	N/A QF12-292	Town of Norfolk	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Jun-2012	1.35
Constellation Solar Massachusetts, LLC	N/A QF12-212	Town of Swampscott	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Feb-2012	0.32
Constellation Solar Net Metering, LLC	N/A QF12-293	Town of Uxbridge	Constellation Solar Net Metering, LLC	Constellation Solar Net Metering, LLC	N/A	ISO-NE	Northeast	Jun-2012	1.93

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Framingham LLC	ER01-513	Framingham Jet 1	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	Mar-1970	10.15
Exelon Framingham LLC	ER01-513	Framingham Jet 2	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	Sep-1969	11.69
Exelon Framingham LLC	ER01-513	Framingham Jet 3	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	Sep-1969	11.25
Exelon Generation Company, LLC	ER00-3251	Granite Ridge	Granite Ridge Energy, LLC	Exelon Generation Company, LLC	Jan-2014	ISO-NE	Northeast	Dec-2002	661.32
Exelon Generation Company, LLC	ER00-3251	Kleen GT1	Kleen Energy Systems, LLC	Exelon Generation Company, LLC	Jul-2011	ISO-NE	Northeast	Jul-2011	186.00
Exelon Generation Company, LLC	ER00-3251	Kleen GT2	Kleen Energy Systems, LLC	Exelon Generation Company, LLC	Jul-2011	ISO-NE	Northeast	Jul-2011	188.00
Exelon Generation Company, LLC	ER00-3251	Kleen STG1	Kleen Energy Systems, LLC	Exelon Generation Company, LLC	Jul-2011	ISO-NE	Northeast	Jul-2011	246.00
Exelon New Boston, LLC	ER01-513	New Boston Jet	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	Sep-1966	16.03
Exelon West Medway, LLC	ER01-513	West Medway Jet 1	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	Jul-1970	42.00
Exelon West Medway, LLC	ER01-513	West Medway Jet 2	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	Mar-1971	39.85
Exelon West Medway, LLC	ER01-513	West Medway Jet 3	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	Jul-1970	35.44
Exelon Wyman, LLC	ER01-513	Wyman 4	Exelon Wyman, LLC (5.9%)	FPL Wyman Energy, LLC	N/A	ISO-NE	Northeast	Jan-1978	610.00
Holyoke Solar LLC	N/A QF12-294	City of Holyoke G & E Dept at Meadow	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	Dec-2011	0.87
Holyoke Solar LLC	N/A QF12-267	City of Holyoke G & E Dept at Mueller	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	Mar-2012	2.95
Constellation Solar New York, LLC	N/A QF13-550	Owens Corning	Constellation Solar New York, LLC	Constellation Solar New York, LLC	N/A	NYISO	Northeast	Oct-2013	2.28
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 1	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	Dec-1969	626.90
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 2	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	Aug-1988	1287.20
R. E. Ginna Nuclear Power Plant, LLC	ER04-485	Ginna	R. E. Ginna Nuclear Power Plant, LLC	R. E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	Jul-1970	581.70
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 1	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	May-1975	873.00
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 2	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	Apr-1977	841.80
Constellation Power Source Generation, LLC	ER14-1169	Gould Street 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Dec-1952	97.00
Constellation Power Source Generation, LLC	ER14-1169	Notch Cliff 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1969	14.00
Constellation Power Source Generation, LLC	ER14-1169	Notch Cliff 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1969	14.00
Constellation Power Source Generation, LLC	ER14-1169	Notch Cliff 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1969	14.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Constellation Power Source Generation, LLC	ER14-1169	Notch Cliff 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1969	14.00
Constellation Power Source Generation, LLC	ER14-1169	Notch Cliff 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1969	15.00
Constellation Power Source Generation, LLC	ER14-1169	Notch Cliff 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1969	16.00
Constellation Power Source Generation, LLC	ER14-1169	Notch Cliff 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1969	15.00
Constellation Power Source Generation, LLC	ER14-1169	Notch Cliff 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1969	16.00
Constellation Power Source Generation, LLC	ER14-1169	Perryman 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jan-1972	52.00
Constellation Power Source Generation, LLC	ER14-1169	Perryman 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Apr-1972	51.00
Constellation Power Source Generation, LLC	ER14-1169	Perryman 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Apr-1972	51.00
Constellation Power Source Generation, LLC	ER14-1169	Perryman 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Apr-1972	52.00
Constellation Power Source Generation, LLC	ER14-1169	Perryman 51	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1995	147.60
Constellation Power Source Generation, LLC	ER14-1169	Philadelphia Road 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Aug-1970	15.30
Constellation Power Source Generation, LLC	ER14-1169	Philadelphia Road 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Aug-1970	16.00
Constellation Power Source Generation, LLC	ER14-1169	Philadelphia Road 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Sep-1970	14.80
Constellation Power Source Generation, LLC	ER14-1169	Philadelphia Road 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Sep-1970	14.80
Constellation Power Source Generation, LLC	ER14-1169	Riverside 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Sep-1951	74.00
Constellation Power Source Generation, LLC	ER14-1169	Riverside 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Sep-1970	19.00
Constellation Power Source Generation, LLC	ER14-1169	Riverside 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Sep-1970	20.00
Constellation Power Source Generation, LLC	ER14-1169	Westport 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Feb-1969	115.80
Constellation Solar DC, LLC	N/A QF13-575	Dunbar	Constellation Solar DC, LLC	Constellation Solar DC, LLC	N/A	PJM	Northeast	Dec-2013	0.38
Constellation Solar Federal LLC	N/A QF12-78	US Department of State (Reeves)	Constellation Solar Federal LLC	Constellation Solar Federal LLC	N/A	PJM	Northeast	Dec-2011	4.23
Constellation Solar Horizons, LLC	N/A QF10-586	MD Generating Clean Horizons MSM I	Constellation Solar Horizons, LLC	Constellation Solar Horizons, LLC	N/A	PJM	Northeast	Jul-2012	13.61
Constellation Solar Maryland II, LLC	N/A QF13-135	UMMS - CRE	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	Feb-2013	0.35
Constellation Solar Maryland II, LLC	N/A QF13-136	UMMS (U of MD Medical System)	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	Feb-2013	3.09
Constellation Solar Maryland, LLC	N/A QF11-271	AA County, MD at Shared Svcs Complex	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	Mar-2011	0.63

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Constellation Solar Maryland, LLC	N/A QF11-333	Coppin State Univ at Coppin State Univ - PEC	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	Sep-2011	0.42
Constellation Solar Maryland, LLC	N/A QF11-410	CPSG Fort Smallwood Road Complex	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	Oct-2011	0.78
Constellation Solar Maryland, LLC	N/A QF11-335	GM Allison Plant-I	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	May-2011	1.04
Constellation Solar Maryland, LLC	N/A QF11-407	Maryland Science Center	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	May-2011	0.09
Constellation Solar Maryland, LLC	N/A QF11-268	McCormick & Co, Inc at Belcamp	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	Jan-2011	1.56
Constellation Solar Maryland, LLC	N/A QF10-662	McCormick & Co, Inc at Hunt Valley	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	Jan-2009	0.78
Constellation Solar Maryland, LLC	N/A QF11-334	McCormick & Co, Inc at Sparks	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	Jun-2011	0.08
Constellation Solar Maryland, LLC	N/A QF10-661	MD Env Service at MES Headquarters	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	Dec-2008	0.25
Constellation Solar Maryland, LLC	N/A QF12-507	Mount St. Mary's University at Emmitsburg	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	Jul-2012	1.42
Constellation Solar New Jersey II, LLC	N/A QF11-267	Johnson Matthey, Inc at West Deptford	Constellation Solar New Jersey II, LLC	Constellation Solar New Jersey II, LLC	N/A	PJM	Northeast	Apr-2011	4.41
Constellation Solar New Jersey II, LLC	N/A QF11-461	Toys-R-Us Delaware, Inc at Mt Olive	Constellation Solar New Jersey II, LLC	Constellation Solar New Jersey II, LLC	N/A	PJM	Northeast	Dec-2011	4.55
Constellation Solar New Jersey III, LLC	N/A QF12-81	Middle Township Elem School 1	Constellation Solar New Jersey III, LLC	Constellation Solar New Jersey III, LLC	N/A	PJM	Northeast	Dec-2011	0.17
Constellation Solar New Jersey III, LLC	N/A QF12-79	Middle Township Elem School 2	Constellation Solar New Jersey III, LLC	Constellation Solar New Jersey III, LLC	N/A	PJM	Northeast	Dec-2011	0.39
Constellation Solar New Jersey III, LLC	N/A QF12-80	Middle Township High School	Constellation Solar New Jersey III, LLC	Constellation Solar New Jersey III, LLC	N/A	PJM	Northeast	Dec-2011	0.69
Constellation Solar New Jersey LLC	N/A QF11-270	Benjamin Moore & Co at Flanders NJ	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	Jan-2011	1.50
Constellation Solar New Jersey LLC	N/A QF11-464	City of Vineland at North Vineland	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	Oct-2011	2.54
Constellation Solar New Jersey LLC	N/A QF11-463	City of Vineland at West Vineland	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	Oct-2011	4.06
Constellation Solar New Jersey LLC	N/A QF10-666	Jet Aviation Teterboro, LP at Teterboro Airport	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	Mar-2008	0.15
Constellation Solar Ohio, LLC	N/A QF10-664	University of Toledo (Solar) Scott Park Campus of Energy & Innovation	Constellation Solar Ohio, LLC	Constellation Solar Ohio, LLC	N/A	PJM	Northeast	Mar-2010	0.88
Constellation Solar Ohio, LLC	N/A QF10-659	University of Toledo (Wind) Scott Park Campus of Energy & Innovation	Constellation Solar Ohio, LLC	Constellation Solar Ohio, LLC	N/A	PJM	Northeast	Mar-2010	0.07
Criterion Power Partners, LLC	ER10-1443	Criterion WF	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	Feb-2011	70.00
Exelon Generation Company, LLC	ER00-3251	Braidwood 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jul-1988	1178.00
Exelon Generation Company, LLC	ER00-3251	Braidwood 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Oct-1988	1152.00

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						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Byron 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Sep-1985	1164.00
Exelon Generation Company, LLC	ER00-3251	Byron 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Aug-1987	1136.00
Exelon Generation Company, LLC	ER00-3251	Chester 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Feb-1969	13.00
Exelon Generation Company, LLC	ER00-3251	Chester 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1969	13.00
Exelon Generation Company, LLC	ER00-3251	Chester 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Mar-1969	13.00
Exelon Generation Company, LLC	ER00-3251	Conemaugh 1	ExGen (31.28%)	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1970	850.00
Exelon Generation Company, LLC	ER00-3251	Conemaugh 2	ExGen (31.28%)	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1971	850.00
Exelon Generation Company, LLC	ER00-3251	Conemaugh DG	ExGen (31.28%)	Exelon Generation Company, LLC	N/A	PJM	Northeast	Feb-1970	10.80
Exelon Generation Company, LLC	ER00-3251	Conowingo 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Mar-1928	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1964	65.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1964	65.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Mar-1928	36.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Mar-1928	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Apr-1928	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1928	36.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jul-1928	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1928	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Mar-1964	65.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Mar-1964	65.00
Exelon Generation Company, LLC	ER00-3251	Cordova GT1	Cordova Energy Company, LLC	Exelon Generation Company, LLC	Dec-2005	PJM	Northeast	Jun-2001	165.00
Exelon Generation Company, LLC	ER00-3251	Cordova GT2	Cordova Energy Company, LLC	Exelon Generation Company, LLC	Dec-2005	PJM	Northeast	Jun-2001	165.00
Exelon Generation Company, LLC	ER00-3251	Cordova STG1	Cordova Energy Company, LLC	Exelon Generation Company, LLC	Dec-2005	PJM	Northeast	Jun-2001	191.20
Exelon Generation Company, LLC	ER00-3251	Croydon 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1974	49.00

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						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Croydon 21	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 22	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 31	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Aug-1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 32	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Aug-1974	48.00
Exelon Generation Company, LLC	ER00-3251	Croydon 41	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jul-1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 42	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jul-1974	49.00
Exelon Generation Company, LLC	ER00-3251	Delaware 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1969	13.00
Exelon Generation Company, LLC	ER00-3251	Delaware 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Apr-1969	13.00
Exelon Generation Company, LLC	ER00-3251	Delaware 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1969	13.00
Exelon Generation Company, LLC	ER00-3251	Delaware 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jul-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Dresden 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Aug-1970	883.50
Exelon Generation Company, LLC	ER00-3251	Dresden 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Oct-1971	895.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1967	13.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 20	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Oct-1967	13.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Sep-1974	380.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 30	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Mar-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1976	380.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 40	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 5	Elwood Energy, LLC	Exelon Generation Company, LLC	Jun-2006	PJM	Northeast	Jul-2001	150.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 6	Elwood Energy, LLC	Exelon Generation Company, LLC	Jun-2006	PJM	Northeast	Jul-2001	150.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 7	Elwood Energy, LLC	Exelon Generation Company, LLC	Jun-2006	PJM	Northeast	Jul-2001	150.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 8	Elwood Energy, LLC	Exelon Generation Company, LLC	Jun-2006	PJM	Northeast	Jul-2001	150.00
Exelon Generation Company, LLC	ER00-3251	Fairless Hills A	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Dec-1996	30.00
Exelon Generation Company, LLC	ER00-3251	Fairless Hills B	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Dec-1996	30.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Falls 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Falls 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Falls 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Keystone 1	ExGen (41.98%)	Exelon Generation Company, LLC	N/A	PJM	Northeast	Aug-1967	850.00
Exelon Generation Company, LLC	ER00-3251	Keystone 2	ExGen (41.98%)	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jul-1968	850.00
Exelon Generation Company, LLC	ER00-3251	Keystone DG	ExGen (41.98%)	Exelon Generation Company, LLC	N/A	PJM	Northeast	Nov-1968	10.80
Exelon Generation Company, LLC	ER00-3251	LaSalle 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jan-1984	1135.40
Exelon Generation Company, LLC	ER00-3251	LaSalle 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Oct-1984	1136.20
Exelon Generation Company, LLC	ER00-3251	Limerick 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Feb-1986	1119.70
Exelon Generation Company, LLC	ER00-3251	Limerick 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jan-1990	1122.10
Exelon Generation Company, LLC	ER00-3251	Moser 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Moser 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Moser 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Apr-1967	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Apr-1967	133.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1967	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1967	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Oct-1967	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Oct-1967	133.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Feb-1968	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Feb-1968	134.00
Exelon Generation Company, LLC	ER00-3251	Oyster Creek 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Dec-1969	609.90
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 2	ExGen (PSEG 50%)	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jul-1974	1119.70
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 3	ExGen (PSEG 50%)	Exelon Generation Company, LLC	N/A	PJM	Northeast	Dec-1974	1125.40

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Pennsbury 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Sep-1996	2.67
Exelon Generation Company, LLC	ER00-3251	Pennsbury 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Sep-1996	2.67
Exelon Generation Company, LLC	ER00-3251	Quad Cities 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Dec-1972	908.00
Exelon Generation Company, LLC	ER00-3251	Quad Cities 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Dec-1972	911.00
Exelon Generation Company, LLC	ER00-3251	Richmond 91	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1973	49.00
Exelon Generation Company, LLC	ER00-3251	Richmond 92	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1973	49.00
Exelon Generation Company, LLC	ER00-3251	Salem 1	PSEG (ExGen 42.59%)	PSEG	N/A	PJM	Northeast	Jun-1977	1173.99
Exelon Generation Company, LLC	ER00-3251	Salem 2	PSEG (ExGen 42.59%)	PSEG	N/A	PJM	Northeast	Oct-1981	1158.02
Exelon Generation Company, LLC	ER00-3251	Salem 3	PSEG (ExGen 42.59%)	PSEG	N/A	PJM	Northeast	Jun-1971	37.57
Exelon Generation Company, LLC	ER00-3251	Schuylkill 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1969	13.00
Exelon Generation Company, LLC	ER00-3251	Schuylkill 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1971	17.00
Exelon Generation Company, LLC	ER00-3251	Southeast Chicago Energy Project 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southeast Chicago Energy Project 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southeast Chicago Energy Project 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southeast Chicago Energy Project 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southeast Chicago Energy Project 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southeast Chicago Energy Project 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southeast Chicago Energy Project 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southeast Chicago Energy Project 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southwark 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1967	13.00
Exelon Generation Company, LLC	ER00-3251	Southwark 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Oct-1967	13.00
Exelon Generation Company, LLC	ER00-3251	Southwark 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jul-1967	13.00
Exelon Generation Company, LLC	ER00-3251	Southwark 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Nov-1968	13.00
Exelon Generation Company, LLC	ER00-3251	TMI 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Sep-1974	802.80

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	York Delta GT1	Calpine Mid Merit LLC	Exelon Generation Company, LLC	Jun-2011	PJM	Northeast	Mar-2011	118.00
Exelon Generation Company, LLC	ER00-3251	York Delta GT2	Calpine Mid Merit LLC	Exelon Generation Company, LLC	Jun-2011	PJM	Northeast	Mar-2011	127.00
Exelon Generation Company, LLC	ER00-3251	York Delta GT3	Calpine Mid Merit LLC	Exelon Generation Company, LLC	Jun-2011	PJM	Northeast	Mar-2011	127.00
Exelon Generation Company, LLC	ER00-3251	York Delta STG1	Calpine Mid Merit LLC	Exelon Generation Company, LLC	Jun-2011	PJM	Northeast	Mar-2011	193.00
Exelon Solar Chicago LLC	N/A QF10-174	Chicago City Solar	Exelon Solar Chicago LLC	Exelon Solar Chicago LLC	N/A	PJM	Northeast	Mar-2010	8.00
Fourmile Wind Energy, LLC	ER14-2145 QF14-721	Fourmile Ridge	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	Jan-2015	40.00
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 1	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	Jul-2001	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 2	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	Jul-2001	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 3	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	Jul-2001	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 4	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	Jul-2001	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 5	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	Jul-2001	53.50
Bennett Creek Windfarm, LLC	N/A QF07-36	Bennett Creek WF	Bennett Creek, LLC	Bennett Creek, LLC	N/A	IPCO	Northwest	Aug-2008	21.00
Cassia Gulch Wind Park LLC	ER10-75 QF05-180	Cassia Gulch WF	Cassia Gulch Wind Park LLC	Cassia Gulch Wind Park LLC	N/A	IPCO	Northwest	Mar-2009	18.90
Cassia Wind Farm, LLC	N/A QF05-170	Cassia Wind WF	Cassia Wind Farm, LLC	Cassia Wind Farm, LLC	N/A	IPCO	Northwest	Mar-2009	10.50
High Mesa Energy, LLC	ER12-2528 QF13-77	High Mesa WF	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	IPCO	Northwest	Aug-2012	40.00
Hot Springs Windfarm, LLC	N/A QF07-37	Hot Springs WF	Hot Springs Windfarm, LLC	Hot Springs Windfarm, LLC	N/A	IPCO	Northwest	Aug-2008	21.00
Tuana Springs Energy, LLC	ER10-87 QF08-742	Tuana Springs WF	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	IPCO	Northwest	Jul-2010	16.80
Sunnyside Cogeneration Assoc.	N/A QF86-556	Sunnyside Cogen	Sunnyside Cogeneration Assoc.	Sunnyside Cogeneration Assoc.	N/A	PACE	Northwest	Feb-1993	51.00
Big Top, LLC	N/A QF08-539	Big Top WF	Big Top, LLC	Big Top, LLC	N/A	PACW	Northwest	Jun-2009	1.65
Butter Creek Power, LLC	N/A QF08-536	Butter Creek WF	Butter Creek Power, LLC	Butter Creek Power, LLC	N/A	PACW	Northwest	Jun-2009	4.95
Four Corners Windfarm, LLC	N/A QF08-372	Four Corner WF	Four Corners Windfarm, LLC	Four Corners Windfarm, LLC	N/A	PACW	Northwest	Sep-2009	10.00
Four Mile Canyon Windfarm, LLC	N/A QF08-370	Four Mile Canyon WF	Four Mile Canyon Windfarm, LLC	Four Mile Canyon Windfarm, LLC	N/A	PACW	Northwest	Sep-2009	10.00
Oregon Trail Windfarm, LLC	N/A QF08-371	Oregon Trail WF	Oregon Trail Windfarm, LLC	Oregon Trail Windfarm, LLC	N/A	PACW	Northwest	Jun-2009	9.90
Pacific Canyon Windfarm, LLC	N/A QF08-373	Pacific Canyon WF	Pacific Canyon Windfarm, LLC	Pacific Canyon Windfarm, LLC	N/A	PACW	Northwest	Jun-2009	8.25

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Sand Ranch Windfarm, LLC	N/A QF08-368	Sand Ranch WF	Sand Ranch Windfarm, LLC	Sand Ranch Windfarm, LLC	N/A	PACW	Northwest	Jun-2009	9.90
Three Mile Canyon Wind I, LLC	N/A QF09-142	Three Mile Canyon WF	Three Mile Canyon Wind I, LLC	Three Mile Canyon Wind I, LLC	N/A	PACW	Northwest	Sep-2009	9.90
Wagon Trail, LLC	N/A QF08-537	Wagon Trail WF	Wagon Trail, LLC	Wagon Trail, LLC	N/A	PACW	Northwest	Jun-2009	3.30
Ward Butte Windfarm, LLC	N/A QF08-369	Ward Butte WF	Ward Butte Windfarm, LLC	Ward Butte Windfarm, LLC	N/A	PACW	Northwest	Jun-2009	6.60
Outback Solar, LLC	N/A QF13-34	Outback Solar	Outback Solar, LLC	Outback Solar, LLC	N/A	BPA	Northwest	Oct-2012	4.82
Denver Airport Solar, LLC	N/A QF11-336	City & County of Denver at Denver International Airport	Denver Airport Solar, LLC	Denver Airport Solar, LLC	N/A	PSCO	Northwest	Jun-2011	3.77
Cow Branch Wind Power, L.L.C.	ER07-1223 QF07-253	Cow Branch WF	Cow Branch Wind Power, L.L.C.	Cow Branch Wind Power, L.L.C.	N/A	AECI	Southeast	Mar-2008	50.40
CR Clearing, LLC	ER07-1222 QF07-248	CR Clearing LLC WF	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	May-2008	50.40
Loess Hills Wind Farm, LLC	N/A QF07-241	Loess Hills WF	Loess Hills Wind Farm, LLC	Loess Hills Wind Farm, LLC	N/A	AECI	Southeast	Apr-2008	5.00
Wind Capital Holdings, LLC	ER07-1208 QF07-222	Wind Capital Holdings LLC WF	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	May-2007	56.70
CER Generation, LLC	ER10-662	Hillabee GT1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	Jun-2010	207.00
CER Generation, LLC	ER10-662	Hillabee GT2	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	Jun-2010	207.00
CER Generation, LLC	ER10-662	Hillabee STG1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	Jun-2010	281.00
Constellation Solar Georgia, LLC	N/A QF15-203	Eastanollee	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	Dec-2014	0.84
Constellation Solar Georgia, LLC	N/A QF15-202	Cave Spring	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	Dec-2014	0.85
Constellation Solar Georgia, LLC	N/A QF15-204	Gibson	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	Dec-2014	0.62
Constellation Solar Georgia, LLC	N/A QF14-505	Sparta	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	May-2014	0.85
Constellation Solar Georgia, LLC	N/A QF15-205	Summerville	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	Dec-2014	0.38
Constellation Solar Georgia, LLC	N/A QF15-206	Wadley	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	Dec-2014	1.11
Constellation Solar Georgia, LLC	N/A QF15-207	Wrens	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	Dec-2014	0.34
Exelon Generation Company, LLC	ER00-3251	Effingham 1	Effingham County Power, LLC	Effingham County Power, LLC / Exelon Generation Company, LLC	Jun-2007	SOCO	Southeast	Aug-2003	502.00
Exelon Generation Company, LLC	ER00-3251	Franklin 1	Southern Power Company	Southern Power Company / Exelon Generation Company, LLC	Jun-2007	SOCO	Southeast	Jun-2003	621.00
Exelon Generation Company, LLC	ER00-3251	Heard 1	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	Jun-2001	SOCO	Southeast	Jun-2001	157.50

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Heard 2	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	Jun-2001	SOCO	Southeast	Jun-2001	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 3	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	Jun-2001	SOCO	Southeast	Jun-2001	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 4	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	Jun-2001	SOCO	Southeast	May-2002	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 5	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	Jun-2001	SOCO	Southeast	May-2002	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 6	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	Jun-2001	SOCO	Southeast	May-2002	157.50
Exelon Generation Company, LLC	ER00-3251	Sowega 1	Georgia Energy Cooperative	Exelon Generation Company, LLC	Jan-2011	SOCO	Southeast	Jun-1999	48.00
Exelon Generation Company, LLC	ER00-3251	Sowega 2	Georgia Energy Cooperative	Exelon Generation Company, LLC	Jan-2011	SOCO	Southeast	Jun-1999	48.00
Exelon Generation Company, LLC	ER00-3251	Washington 1	Washington County Power, LLC	Washington County Power, LLC / Exelon Generation Company, LLC	Jun-2007	SOCO	Southeast	Jun-2003	153.50
Exelon Generation Company, LLC	ER00-3251	Washington 4	Washington County Power, LLC	Washington County Power, LLC / Exelon Generation Company, LLC	Jun-2007	SOCO	Southeast	Jun-2003	153.50
Constellation Solar Arizona, LLC	N/A QF12-211	Buckeye Union HS at Estrella & Youngkers	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2011	3.62
Constellation Solar Arizona, LLC	N/A QF13-76	Casa Grande - Casa Verde HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2012	0.35
Constellation Solar Arizona, LLC	N/A QF13-75	Casa Grande - Union HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2012	1.79
Constellation Solar Arizona, LLC	N/A QF13-74	Casa Grande - Vista Grande HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2012	1.54
Constellation Solar Arizona, LLC	N/A QF13-599	Charles Bejarando	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Sep-2013	0.09
Constellation Solar Arizona, LLC	N/A QF14-498	Collier ES	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Jun-2014	0.25
Constellation Solar Arizona, LLC	N/A QF13-511	Crane School District at Centennial	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Aug-2013	0.38
Constellation Solar Arizona, LLC	N/A QF13-516	Crane School District at Crane Middle School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Aug-2013	0.38
Constellation Solar Arizona, LLC	N/A QF13-378	Crane School District at GAK	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Mar-2013	0.19
Constellation Solar Arizona, LLC	N/A QF13-377	Crane School District at Mesquite	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Mar-2013	0.17
Constellation Solar Arizona, LLC	N/A QF13-515	Crane School District at Valley Horizon	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Jul-2013	0.28
Constellation Solar Arizona, LLC	N/A QF13-537	Dysart I School District	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Jun-2013	8.81
Constellation Solar Arizona, LLC	N/A QF14-496	Isaac School District at Butler	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Jul-2014	0.21
Constellation Solar Arizona, LLC	N/A QF14-497	Lee Kornegay HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Jul-2014	0.12
Constellation Solar Arizona, LLC	N/A QF13-538	Marana School District	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Jul-2013	1.54

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Constellation Solar Arizona, LLC	N/A QF13-598	Miami High School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Sep-2013	0.36
Constellation Solar Arizona, LLC	N/A QF14-499	Parkridge ES	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Jul-2014	0.44
Constellation Solar Arizona, LLC	N/A QF13-536	Peoria Unified School District	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Nov-2013	2.55
Constellation Solar Arizona, LLC	N/A QF14-27	Pueblo Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2013	0.21
Constellation Solar Arizona, LLC	N/A QF14-29	Salida del Sol Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2013	0.26
Constellation Solar Arizona, LLC	N/A QF13-514	Somerton School District at Desert Sonora	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Mar-2013	0.29
Constellation Solar Arizona, LLC	N/A QF13-137	Somerton School District at Orange Grove	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2012	0.18
Constellation Solar Arizona, LLC	N/A QF13-513	Somerton School District at Somerton Middle School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Mar-2013	0.47
Constellation Solar Arizona, LLC	N/A QF13-138	Somerton School District at Tierra del Sol	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2012	0.22
Constellation Solar Arizona, LLC	N/A QF13-139	Somerton School District at Valle del Encanto	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2012	0.17
Constellation Solar Arizona, LLC	N/A QF14-26	Suverkrup Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2013	0.27
Constellation Solar Arizona, LLC	N/A QF13-376	Vail Unified School District at Andrada	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Apr-2013	0.33
Constellation Solar Arizona, LLC	N/A QF13-378	Vail Unified School District at Mesquite Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Apr-2013	0.23
Constellation Solar Arizona, LLC	N/A QF13-380	Vail Unified School District at OVMS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Apr-2013	0.25
Constellation Solar Arizona, LLC	N/A QF15-163	Western Peaks ES	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Oct-2014	0.47
Constellation Solar Arizona, LLC	N/A QF15-162	Willow Canyon HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Oct-2014	0.47
Mohave Sunrise Solar I LLC	N/A QF15-161	Mohave Electric at Fort Mohave	Mohave Sunrise Solar I LLC	Mohave Sunrise Solar I LLC	N/A	APS	Southwest	2nd Qtr 2015	4.56
Sacramento PV Energy, LLC	N/A QF11-329	Sacremento Municipal Utility District at Fleshman	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	Nov-2011	3.08
Sacramento PV Energy, LLC	N/A QF11-330	Sacremento Municipal Utility District at Grundman	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	Dec-2011	18.50
Sacramento PV Energy, LLC	N/A QF11-331	Sacremento Municipal Utility District at Lawrence	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	Dec-2011	1.03
Sacramento PV Energy, LLC	N/A QF11-332	Sacremento Municipal Utility District at VanConnet	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	Dec-2011	3.08
2014 ESA Project Company, LLC	N/A	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	N/A	CAISO	Southwest	Jul-2014	1.40
AV Solar Ranch 1, LLC	ER12-2178	Antelope Valley	AV Solar Ranch 1, LLC	AV Solar Ranch 1, LLC	N/A	CAISO	Southwest	Dec-2012	230.00
California PV Energy, LLC	N/A QF15-76	Alto Loma HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jan-2015	0.56

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
California PV Energy, LLC	N/A QF14-214	Castaic Elementary School	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Apr-2014	0.12
California PV Energy, LLC	N/A QF14-212	Castaic Middle School	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Apr-2014	0.28
California PV Energy, LLC	N/A QF15-78	Chaffey HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Feb-2015	0.54
California PV Energy, LLC	N/A QF15-79	Colony HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Feb-2015	0.76
California PV Energy, LLC	N/A QF15-80	Etiwanda HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jan-2015	0.72
California PV Energy, LLC	N/A QF14-28	Ironhouse Sanitary District	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	1.01
California PV Energy, LLC	N/A QF14-335	Keppel Academy	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.11
California PV Energy, LLC	N/A QF14-329	Keppel Alpine North ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.12
California PV Energy, LLC	N/A QF14-331	Keppel Alpine South ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.09
California PV Energy, LLC	N/A QF14-330	Keppel Antelope ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.05
California PV Energy, LLC	N/A QF14-333	Keppel Gibson ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.15
California PV Energy, LLC	N/A QF14-332	Keppel Lake Los Angleles	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.13
California PV Energy, LLC	N/A QF14-334	Keppel Pearblossom ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.13
California PV Energy, LLC	N/A QF14-213	Live Oak Elementary School,	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Apr-2014	0.12
California PV Energy, LLC	N/A QF15-81	Los Osos HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Feb-2015	0.76
California PV Energy, LLC	N/A QF15-82	Montclair HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Feb-2015	0.76
California PV Energy, LLC	N/A QF14-211	Northlake Hills Elementary School	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Apr-2014	0.13
California PV Energy, LLC	N/A QF13-602	Oltmans SCE at Champagne	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Dec-2013	1.03
California PV Energy, LLC	N/A QF13-601	Oltmans SCE at Jurupa	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Dec-2013	1.58
California PV Energy, LLC	N/A QF15-83	Ontario HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jan-2015	0.33
California PV Energy, LLC	N/A QF14-325	Palmdale Cultural Center	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.06
California PV Energy, LLC	N/A QF14-324	Palmdale Development Services Bldg	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.12
California PV Energy, LLC	N/A QF14-326	Palmdale Library	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.07
California PV Energy, LLC	N/A QF14-321	Palmdale Marie Park E1	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.07

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
California PV Energy, LLC	N/A QF14-322	Palmdale Marie Park E2	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.06
California PV Energy, LLC	N/A QF14-323	Palmdale Marie Park E3	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.05
California PV Energy, LLC	N/A QF14-328	Palmdale Recreation Center	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.05
California PV Energy, LLC	N/A QF14-327	Palmdale Water Park	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.28
California PV Energy, LLC	N/A QF15-84	Rancho Cucamonga	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jan-2015	0.42
Constellation Solar California, LLC	N/A QF10-656	General Motors Corp. at Fontana, Ca.	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	Dec-2007	0.80
Constellation Solar California, LLC	N/A QF10-657	GSA, PBS, Pacific Service Center at Sacramento, Ca.	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	Mar-2008	0.44
Constellation Solar California, LLC	N/A QF10-658	Kawneer Co., Inc. (Alcoa)	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	Oct-2007	0.50
Constellation Solar California, LLC	N/A QF10-665	Univ of San Francisco at Univ of San Francisco	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	Apr-2008	0.42
Luz Solar Partners IV	N/A QF86-736	SEGS IV	Luz Solar Partners IV	Luz Solar Partners IV	N/A	CAISO	Southwest	Dec-1986	33.00
Luz Solar Partners V	N/A QF87-402	SEGS V	Luz Solar Partners V	Luz Solar Partners V	N/A	CAISO	Southwest	Oct-1987	24.00
Luz Solar Partners VI	N/A QF88-33	SEGS VI	Luz Solar Partners VI	Luz Solar Partners VI	N/A	CAISO	Southwest	Dec-1988	34.00
Exelon Generation Company, LLC	ER00-3251	Green Country 1	Green Country OP Services LLC	Exelon Generation Company, LLC	Feb-2002	SPP	SPP	Feb-2002	262.00
Exelon Generation Company, LLC	ER00-3251	Green Country 2	Green Country OP Services LLC	Exelon Generation Company, LLC	Feb-2002	SPP	SPP	Feb-2002	262.00
Exelon Generation Company, LLC	ER00-3251	Green Country 3	Green Country OP Services LLC	Exelon Generation Company, LLC	Feb-2002	SPP	SPP	Feb-2002	261.00
Exelon Wind 1, LLC	N/A QF05-114	Exelon Wind 1 WF	Exelon Wind 1, LLC	Exelon Wind 1, LLC	N/A	SPP	SPP	Dec-2005	10.00
Exelon Wind 10, LLC	N/A QF07-55	Exelon Wind 10 WF	Exelon Wind 10, LLC	Exelon Wind 10, LLC	N/A	SPP	SPP	Jul-2008	10.00
Exelon Wind 11, LLC	N/A QF07-56	Exelon Wind 11 WF	Exelon Wind 11, LLC	Exelon Wind 11, LLC	N/A	SPP	SPP	Jul-2008	10.00
Exelon Wind 2, LLC	N/A QF05-116	Exelon Wind 2 WF	Exelon Wind 2, LLC	Exelon Wind 2, LLC	N/A	SPP	SPP	Dec-2005	10.00
Exelon Wind 3, LLC	N/A QF05-115	Exelon Wind 3 WF	Exelon Wind 3, LLC	Exelon Wind 3, LLC	N/A	SPP	SPP	Dec-2005	10.00
Exelon Wind 4, LLC	ER07-1202 QF03-13	Exelon Wind 4 WF	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	Dec-2006	79.80
Exelon Wind 5, LLC	N/A QF06-289	Exelon Wind 5 WF	Exelon Wind 5, LLC	Exelon Wind 5, LLC	N/A	SPP	SPP	Oct-2005	10.00
Exelon Wind 6, LLC	N/A QF06-290	Exelon Wind 6 WF	Exelon Wind 6, LLC	Exelon Wind 6, LLC	N/A	SPP	SPP	Nov-2006	10.00
Exelon Wind 7, LLC	N/A QF07-46	Exelon Wind 7 WF	Exelon Wind 7, LLC	Exelon Wind 7, LLC	N/A	SPP	SPP	Jul-2008	10.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Wind 8, LLC	N/A QF07-53	Exelon Wind 8 WF	Exelon Wind 8, LLC	Exelon Wind 8, LLC	N/A	SPP	SPP	Jul-2008	10.00
Exelon Wind 9, LLC	N/A QF07-54	Exelon Wind 9 WF	Exelon Wind 9, LLC	Exelon Wind 9, LLC	N/A	SPP	SPP	Jul-2008	10.00
Greensburg Wind Farm, LLC	N/A QF10-291	Greensburg WF	Greensburg Wind Farm, LLC	Greensburg Wind Farm, LLC	N/A	SPP	SPP	Mar-2010	12.50
High Plains Wind Power, LLC	N/A QF07-257	High Plains WF	High Plains Wind Power, LLC	High Plains Wind Power, LLC	N/A	SPP	SPP	Mar-2008	10.00
Shooting Star Wind Project, LLC	ER12-1829	Shooting Star WF	Shooting Star Wind Project, LLC	Shooting Star Wind Project, LLC	N/A	SPP	SPP	Sep-2012	104.00
Wildcat Wind, LLC	ER12-1223 QF12-412	Wildcat WF	Wildcat Wind, LLC	Wildcat Wind, LLC	N/A	SPP	SPP	Jul-2012	27.30

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Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas Storage

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
Constellation Mystic Power, LLC	Limited & discrete interconnection facilities[1]	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon Framingham, LLC	Limited & discrete interconnection facilities[1]	Exelon Framingham, LLC	Exelon Framingham, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon New Boston, LLC	Limited & discrete interconnection facilities[1]	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon West Medway, LLC	Limited & discrete interconnection facilities[1]	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon Wyman, LLC	Limited & discrete interconnection facilities[1]	Exelon Wyman, LLC	Exelon Wyman, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Holyoke Solar LLC	Limited & discrete interconnection facilities[1]	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Nine Mile Point Nuclear Station, LLC	Limited & discrete interconnection facilities[1]	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	N/A (OATT Waiver)

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
R.E. Ginna Nuclear Power Plant, LLC	Limited & discrete interconnection facilities[1]	R.E. Ginna Nuclear Power Plant, LLC	R.E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	N/A (OATT Waiver)
Baltimore Gas and Electric Company	Combined 115kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	695.85 combined miles
Baltimore Gas and Electric Company	Combined 138kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	54.44 combined miles
Baltimore Gas and Electric Company	Combined 230kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	320.97 combined miles
Baltimore Gas and Electric Company	Combined 500kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	217.42 combined miles
Baltimore Gas and Electric Company	Intrastate Gas Transmission	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	approx. 165 combined miles
Calvert Cliffs Nuclear Power Plant, LLC	Limited & discrete interconnection facilities[1]	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Commonwealth Edison Company	Electric Transmission Combined 765 kV Lines	Commonwealth Edison Company	PJM	N/A	PJM	Northeast	89.59 combined miles
Commonwealth Edison Company	Electric Transmission Combined 345 kV Lines	Commonwealth Edison Company	PJM	N/A	PJM	Northeast	2,634.29 combined miles

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
Commonwealth Edison Company	Electric Transmission Combined 138 kV Lines	Commonwealth Edison Company	PJM	N/A	PJM	Northeast	2,877.02 combined miles
Criterion Power Partners, LLC	Limited & discrete interconnection facilities[1]	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Exelon Solar Chicago LLC	Limited & discrete interconnection facilities[1]	Exelon Solar Chicago LLC	Exelon Solar Chicago LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Fourmile Wind Energy, LLC	Limited & discrete interconnection facilities[1]	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Handsome Lake Energy, LLC	Limited & discrete interconnection facilities[1]	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
PECO Energy Company	Electric Transmission 500 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	316.23 combined miles
PECO Energy Company	Electric Transmission Combined 200/220 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	503.05 combined miles
PECO Energy Company	Electric Transmission Combined 132 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	127.70 combined miles
PECO Energy Company	Electric Transmission Combined 66 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	169.54 combined miles

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
PECO Energy Company	Electric Transmission Combined 13.2 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	0.47 combined miles
PECO Energy Company	Intrastate Gas Transmission	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	31 combined miles
PECO Energy Company	Intrastate Gas Storage (LNG)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	1,200 mmcf
Cassia Gulch Wind Park, LLC	Limited & discrete interconnection facilities[1]	Cassia Gulch Wind Park, LLC	Cassia Gulch Wind Park, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
High Mesa Energy, LLC	Limited & discrete interconnection facilities[1]	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
Tuana Springs Energy, LLC	Limited & discrete interconnection facilities[1]	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
Beebe 1B Renewable Energy, LLC and Beebe Renewable Energy, LLC ("Beebe")[2]	Limited & discrete interconnection facilities[1]	Beebe	Beebe	N/A	MISO	Central	N/A (OATT Waiver)
Harvest Windfarm, LLC	Limited & discrete interconnection facilities[1]	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	N/A (OATT Waiver)
Michigan Wind 1, LLC	Limited & discrete interconnection facilities[1]	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	N/A (OATT Waiver)

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
CER Generation, LLC	Limited & discrete interconnection facilities[1]	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	N/A (OATT Waiver)
Constellation Power Source Generation, LLC	Limited & discrete interconnection facilities[1]	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Exelon Generation Company, LLC	Limited & discrete interconnection facilities[1]	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	Various	Various	N/A (OATT Waiver)
Cow Branch Wind Power, L.L.C.	Limited & discrete interconnection facilities[1]	Cow Branch Wind Power, LLC	Cow Branch Wind Power, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
CR Clearing, LLC	Limited & discrete interconnection facilities[1]	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
Wind Capital Holdings, LLC	Limited & discrete interconnection facilities[1]	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
AV Solar Ranch 1, LLC	Limited & discrete interconnection facilities[1]	AV Solar Ranch 1, LLC	AV Solar Ranch 1, LLC	N/A	CAISO	Southwest	N/A (OATT Waiver)
Exelon Wind 4, LLC	Limited & discrete interconnection facilities[1]	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	N/A (OATT Waiver)

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[1] These facilities are included because waiver of Order Nos. 888, 889, 890, their implementing regulations, and the requirements of Part 358 of FERC's regulations has been sought with respect to them.

[2] Beebe 1B Renewable Energy, LLC and Beebe Renewable Energy, LLC share certain interconnection facilities.

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Document Content(s)

Exelon Integrys CIS Supplemental Filing 1.12.15.PDF.....1-26

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February 2, 2015

VIA ELECTRONIC FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: **AV Solar Ranch 1, LLC, Docket No. ER12-2178-___**
Baltimore Gas and Electric Company, Docket No. ER10-2172-___
Beebe 1B Renewable Energy, LLC, Docket No. ER14-2144-___
Beebe Renewable Energy, LLC, Docket No. ER12-2311-___
Calvert Cliffs Nuclear Power Plant, LLC, Docket No. ER10-2179-___
Cassia Gulch Wind Park, LLC, Docket No. ER11-2016-___
CER Generation, LLC, Docket No. ER10-2184-___
Commonwealth Edison Company, Docket No. ER10-1048-___
Constellation Energy Commodities Group Maine, LLC, Docket No. ER10-2192-__
Constellation Mystic Power, LLC, Docket No. ER11-2056-___
Constellation NewEnergy, Inc., Docket No. ER10-2178-___
Constellation Power Source Generation, LLC, Docket No. ER14-1524-___
Cow Branch Wind Power, LLC, Docket No. ER11-2014-___
CR Clearing, LLC, Docket No. ER11-2013-___
Criterion Power Partners, LLC, Docket No. ER10-3308-___
Exelon Framingham, LLC, Docket No. ER10-1020-___
Exelon Generation Company, LLC, Docket No. ER13-1536-___
Exelon New Boston, LLC, Docket No. ER10-1078-___
Exelon West Medway, LLC, Docket No. ER10-1080-___
Exelon Wind 4, LLC, Docket No. ER11-2010-___
Exelon Wyman, LLC, Docket No. ER10-1081-___
Fourmile Wind Energy, LLC, Docket No. ER14-2145-___
Handsome Lake Energy, LLC, Docket No. ER10-2180-___
Harvest II Windfarm, LLC, Docket No. ER12-2201-___
Harvest Windfarm, LLC, Docket No. ER11-2011-___
High Mesa Energy, LLC, Docket No. ER12-2528-___
Integrys Energy Services, Inc., Docket No. ER10-3025-___
Integrys Energy Services of New York, Inc. Docket No. ER10-3027-___
Michigan Wind 1, LLC, Docket No. ER11-2009-___
Michigan Wind 2, LLC, Docket No. ER11-3989-___
Nine Mile Point Nuclear Station, LLC, Docket No. ER10-2181-___

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PECO Energy Company, Docket No. ER14-767-___
R.E. Ginna Nuclear Power Plant, LLC, Docket No. ER10-2182-___
Shooting Star Wind Project, LLC, Docket No. ER12-1829-___
Tuana Springs Energy, LLC, Docket No. ER11-2007-___
Wildcat Wind, LLC, Docket No. ER12-1223-___
Wind Capital Holdings, LLC, Docket No. ER11-2005-___

Notice of Change in Status of the Exelon MBR Entities

Dear Secretary Bose:

Pursuant to the requirements of section 35.42 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[1] the above-captioned affiliates of Exelon Corporation ("Exelon") with market-based rate authority (the "Exelon MBR Entities") submit this notice of change in status to inform the Commission that on December 30, 2014, Exelon Generation Company, LLC ("Exelon Generation") entered into a long-term tolling agreement ("Tolling Agreement") with Mobile Energy LLC ("Mobile"). Mobile owns and operates the Hog Bayou Energy Center, a 230 MW (summer) natural gas-fired, combined cycle electric generation facility located in Mobile County, Alabama and interconnected to Alabama Power Company's transmission system within the Southern Company Services, Inc. ("SOCO") balancing authority area ("BAA"). The Commission authorized Mobile to sell energy, capacity, and ancillary services at market-based rates.[2] Pursuant to the Tolling Agreement, Exelon Generation purchases all of the output of the Hog Bayou Energy Center. Power deliveries under the Tolling Agreement commenced on January 1, 2015.

On December 23, 2014, Exelon Generation and its affiliates that are Category 2 Sellers in the Southeast region filed an Updated Market Analysis for the Southeast Region ("SE Triennial") in Docket Nos. ER12-2178-022, *et al.* The SE Triennial demonstrated that Exelon Generation and its affiliates pass the pivotal supplier and market share screens for the SOCO and Associated Electric Cooperative, Inc. BAAs, the two relevant markets for Exelon Generation in the Southeast region, and lack vertical market power.

The Tolling Agreement does not affect the SE Triennial's conclusion that Exelon Generation and its affiliates lack market power in the SOCO BAA. With respect to horizontal market power, the Exelon MBR Sellers have revised the pivotal supplier and market share screens submitted with the SE Triennial to reflect the purchase of the Hog Bayou Energy Center. The revised screens show that in the SOCO BAA the Exelon MBR Sellers continue to pass the pivotal screen and their market share ranges from 10.6% to 15.1%. A copy of the revised screens is provided as Attachment A hereto.[3] With respect to

[1] 18 C.F.R. § 35.42 (2014).

[2] Mobile Energy, LLC, Letter Order, Docket Nos. ER01-480-000, *et al.* (Jan. 10, 2001) (granting market-based rate authority).

[3] Attachments B and C hereto provide updated asset appendices in the format set forth in Appendix B to 18 C.F.R. Part 35, Subpart H.

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vertical market power, the Tolling Agreement did not result in the acquisition of ownership or control of, or affiliation with, any electric transmission facilities or inputs to electric power production, as defined in section 35.36 of the Commission's regulations.[4] Therefore, the Exelon MBR Sellers continue to lack vertical market power in the SOCO BAA.

For the reasons set forth above, the Tolling Agreement between Exelon Generation and Mobile did not materially change the facts and circumstances that the Commission relied upon in granting the Exelon MBR Entities market-based rate authority. Therefore, the Exelon MBR Entities respectfully request that the Commission accept for filing this notice of change in status and find that no further inquiry is necessary.

Respectfully submitted,

Vincenzo Franco
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Enclosures

[4] 18 C.F.R. § 35.36(a)(4) defines "[i]nputs to electric power production" as "intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; physical coal supply sources and ownership of or control over who may access transportation of coal supplies."

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CERTIFICATE OF SERVICE

I hereby certify that this day I have caused to be served the foregoing document upon each person designated on the official service lists compiled by the Secretary in these dockets.

Dated at Baltimore, MD this 2nd day of February, 2015.

/s/ Vincenzo Franco
Vincenzo Franco
Assistant General Counsel – Wholesale
Trading Compliance
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ATTACHMENT A

MARKET POWER SCREENS

Exhibit JRS-2

Exelon Affiliated Generation in the Southeast Region and Relevant First-Tier Markets

BAA	Plant Name	Total Capacity (MW) Summer	Total Capacity (MW) Winter	Ownership Share	Net Capacity (MW) Summer	Net Capacity (MW) Winter
SOCO						
SOCO	Hillabee	695.4	797.6	100%	695.4	797.6
SOCO	Constellation Solar Georgia (2014)	5.0	5.0	100%	5.0	5.0
Long-Term Purchases						
SOCO	Hog Bayou	230.0	245.0	0%	230.0	245.0
SOCO	Heard County (Tenaska Georgia)	933.0	1,071.0	0%	933.0	1,071.0
SOCO	Franklin 3	625.6	642.9	0%	625.6	642.9
SOCO	Washington 1 and 4	303.0	344.0	0%	303.0	344.0
SOCO	Effingham-1	509.0	527.0	0%	509.0	527.0
SOCO	Sowega 1 and 2	97.0	97.0	0%	97.0	97.0
Subtotal, SOCO					3,398.0	3,729.5
AECI						
AECI	Cow Branch	50.4	50.4	100%	50.4	50.4
AECI	Conception	50.4	50.4	100%	50.4	50.4
AECI	Loess Hills	5.0	5.0	100%	5.0	5.0
AECI	Bluegrass Ridge (Wind Capital Holdings)	56.7	56.7	100%	56.7	56.7
Subtotal, AECI					162.5	162.5
First-Tier Markets to SOCO and AECI						
MISO	AgriWind	8.4	8.4	100%	8.4	8.4
MISO	Beebe Renewable Energy	81.6	81.6	100%	81.6	81.6
MISO	Beebe 1B Renewable Energy, LLC (2014)	50.0	50.0	100%	50.0	50.0
MISO	Blue Breezes	1.3	1.3	100%	1.3	1.3
MISO	Blue Breezes II	1.3	1.3	100%	1.3	1.3
MISO	Breezy Bucks-I	1.3	1.3	100%	1.3	1.3
MISO	Breezy Bucks-II	1.3	1.3	100%	1.3	1.3
MISO	Christoffer Wind Energy I	2.1	2.1	100%	2.1	2.1
MISO	Christoffer Wind Energy II	2.1	2.1	100%	2.1	2.1
MISO	Christoffer Wind Energy III	2.1	2.1	100%	2.1	2.1
MISO	Christoffer Wind Energy IV	2.1	2.1	100%	2.1	2.1
MISO	CP Windfarm	4.2	4.2	100%	4.2	4.2
MISO	Clinton	1,065.0	1,078.0	100%	1,065.0	1,078.0
MISO	G-Flow Wind	1.3	1.3	100%	1.3	1.3
MISO	Green Acres Breeze	1.3	1.3	100%	1.3	1.3
MISO	Harvest Windfarm	52.8	52.8	100%	52.8	52.8

Exhibit JRS-2

BAA	Plant Name	Total Capacity (MW) Summer	Total Capacity (MW) Winter	Ownership Share	Net Capacity (MW) Summer	Net Capacity (MW) Winter
MISO	Harvest II Windfarm	59.4	59.4	100%	59.4	59.4
MISO	K & D Energy	4.0	4.0	100%	4.0	4.0
MISO	KC Energy	4.0	4.0	100%	4.0	4.0
MISO	KSS Turbines	4.0	4.0	100%	4.0	4.0
MISO	Marshall Wind	18.9	18.9	100%	18.9	18.9
MISO	Michigan Wind 1	69.0	69.0	100%	69.0	69.0
MISO	Michigan Wind 2	90.0	90.0	100%	90.0	90.0
MISO	Minnesota Breeze	1.3	1.3	100%	1.3	1.3
MISO	Prairie Wind Power	4.0	4.0	100%	4.0	4.0
MISO	Roadrunner-I	1.3	1.3	100%	1.3	1.3
MISO	S & P Windfarm	2.0	2.0	100%	2.0	2.0
MISO	Salty Dog-I	1.3	1.3	100%	1.3	1.3
MISO	Salty Dog-II	1.3	1.3	100%	1.3	1.3
MISO	Shane's Wind Machine	1.3	1.3	100%	1.3	1.3
MISO	Sunset Breeze	1.3	1.3	100%	1.3	1.3
MISO	Wally's Wind Farm	1.3	1.3	100%	1.3	1.3
MISO	Windy Dog-I	1.3	1.3	100%	1.3	1.3
MISO	Wolf Wind Enterprises	1.3	1.3	100%	1.3	1.3
Long-Term Purchases						
MISO	Tenaska Frontier	860.0	926.0	0%	860.0	926.0
Subtotal, First-Tier (MISO)		2,405.2	2,484.2		2,405.2	2,484.2
First-Tier Markets to AECI						
SPP	Exelon Wind 1	10.0	10.0	100%	10.0	10.0
SPP	Exelon Wind 2	10.0	10.0	100%	10.0	10.0
SPP	Exelon Wind 3	10.0	10.0	100%	10.0	10.0
SPP	Exelon Wind 4	79.8	79.8	100%	79.8	79.8
SPP	Exelon Wind 5	10.0	10.0	100%	10.0	10.0
SPP	Exelon Wind 6	10.0	10.0	100%	10.0	10.0
SPP	Exelon Wind 7	10.0	10.0	100%	10.0	10.0
SPP	Exelon Wind 8	10.0	10.0	100%	10.0	10.0
SPP	Exelon Wind 9	10.0	10.0	100%	10.0	10.0
SPP	Exelon Wind 10	10.0	10.0	100%	10.0	10.0
SPP	Exelon Wind 11	10.0	10.0	100%	10.0	10.0
SPP	High Plains	10.0	10.0	100%	10.0	10.0
SPP	Wildcat Wind	27.3	27.3	100%	27.3	27.3
SPP	Greensburg	12.5	12.5	100%	12.5	12.5
SPP	Shooting Star	104.0	104.0	100%	104.0	104.0
Long-Term Purchases						

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BAA	Plant Name	Total Capacity (MW) Summer	Total Capacity (MW) Winter	Ownership Share	Net Capacity (MW) Summer	Net Capacity (MW) Winter
SPP	Green Country [1/]	783.0	819.0	0%	261.0	273.0
Subtotal, First-Tier (SPP)		1,116.6	1,152.6		594.6	606.6

[1/] Exelon has a long-term tolling agreement with respect to Green Country, but has sold two-thirds of the output under a long-term contract with Public Service Co of Oklahoma.

Note: Generation ratings generally are based on EIA-860.
http://www.eia.gov/cneaf/electricity/page/eia860.html

Part I -- Pivotal Supplier Analysis

Row	Generation	SOCO MW	Reference (December '11 - November '12)
	Seller and Affiliate Capacity		
A	Installed Capacity	700	Exhibit JRS-2
B	Long-Term Firm Purchases	2,698	Exhibit JRS-2
C	Long-Term Firm Sales	-	
D	Imported Power	312	Wkp - Import Allocation
	Non-Affiliate Capacity		
E	Installed Capacity	58,294	Duke MBR Sellers, Exhibit JRS-8, Rows A+E, less Rows A and B above
F	Long-Term Firm Purchases	2,456	Duke MBR Sellers, Exhibit JRS-8, Row F
G	Long-Term Firm Sales	-	
H	Imported Power	5,497	Duke MBR Sellers, Exhibit JRS-8, Rows D+H, less Row D above
I	Balancing Authority Area Reserve Requirement	(951)	Duke MBR Sellers, Exhibit JRS-8, Row I
J	Amount of Line I Attributable to Seller, if any	-	
K	Total Uncommitted Capacity	26,851	SUM (A,B,C,D,E,F,G,H,I,M)
	Load		
L	Balancing Authority Area Annual Peak Load	53,123	Duke MBR Sellers, Exhibit JRS-8, Row L
M	Average Daily Peak Native Load in Peak Month	(42,156)	Duke MBR Sellers, Exhibit JRS-8, Row M
N	Amount of Line M Attributable to Seller, if any	-	
O	Wholesale Load	10,967	(L+M)
P	Net Uncommitted Supply	15,884	(K-O)
Q	Seller's Uncommitted Capacity	3,710	SUM (A,B,C,D,J,N)
R	Result of Pivotal Supplier Screen	**PASS**	(Pass if (Q < P); (Fail if Q > P)

Duke MBR Sellers, Docket No. ER10-1325, triennial market-based rate filing for the Southeast Region, filed June 30, 2014, Exhibit JRS-8.

Part II -- Market Share Analysis

Row		SOCO Winter (MW)	SOCO Spring (MW)	SOCO Summer (MW)	SOCO Fall (MW)	Reference December '11 - November '12
	Seller and Affiliate Capacity					
A	Installed Capacity	803	803	700	803	Exhibit JRS-2
B	Long-Term Firm Purchases	2,927	2,927	2,698	2,927	Exhibit JRS-2
C	Long-Term Firm Sales	-	-	-	-	
D	Seasonal Average Planned Outages	-	-	-	-	
E	Imported Power	327	394	321	289	Wkp - Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	(32,643)	(33,381)	(44,156)	(32,786)	Duke MBR Sellers, Exhibit JRS-9, Row F
G	Amount of Line F Attributable to Seller, if any	-	-	-	-	
H	Amount of Line F Attributable to Others, if any	(32,643)	(33,381)	(44,156)	(32,786)	
I	Balancing Authority Area Reserve Requirement, if any	(938)	(942)	(951)	(944)	Duke MBR Sellers, Exhibit JRS-9, Row I
J	Amount of Line I Attributable to Seller, if any	-	-	-	-	
K	Amount of Line I Attributable to Others, if any	(938)	(942)	(951)	(944)	
	Non-Affiliate Capacity					
L	Installed Capacity	59,814	60,616	58,294	61,468	Duke MBR Sellers, Exhibit JRS-9, Rows A+L, less Rows A and B above
M	Long-Term Firm Purchases	2,664	2,068	2,456	2,022	Duke MBR Sellers, Exhibit JRS-9, Row M
N	Long-Term Firm Sales	-	-	-	-	
O	Local Seasonal Average Planned Outages	(3,352)	(3,362)	(197)	(2,031)	Duke MBR Sellers, Exhibit JRS-9, Row O
P	Uncommitted Capacity Imports	7,372	8,441	5,489	6,208	Duke MBR Sellers, Exhibit JRS-9, Rows E+P, less Row E above
	Supply Calculation					
Q	Total Competing Supply	32,917	33,440	20,935	33,937	SUM (L,M,N,O,P,H,K)
R	Seller's Uncommitted Capacity	4,056	4,123	3,719	4,019	SUM (A,B,C,D,E,G,J)
S	Total Seasonal Uncommitted Capacity	36,973	37,563	24,653	37,956	SUM (Q,R)
T	**Seller's Market Share**	11.0%	11.0%	15.1%	10.6%	(R/S)
	Results	**PASS**	**PASS**	**PASS**	**PASS**	Pass if T <20%; Fail if T > 20%

Duke MBR Sellers, Docket No. ER10-1325, triennial market-based rate filing for the Southeast Region, filed June 30, 2014, Exhibit JRS-9.

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	PST	Winter	Spring	Summer	Fall
Allocation of Imports into SOCO					
Seller's Uncommitted Capacity in MISO	2,405	2,484	2,484	2,405	2,484
Seller's Uncommitted Capacity in SC	0	0	0	0	0
Seller's Uncommitted Capacity in SCEG	0	0	0	0	0
Seller's Uncommitted Capacity in SMEE	0	0	0	0	0
Seller's Uncommitted Capacity in DUKE	0	0	0	0	0
Seller's Uncommitted Capacity in TVA	0	0	0	0	0
Seller's Uncommitted Capacity	**2,405**	**2,484**	**2,484**	**2,405**	**2,484**
Total Uncommitted Capacity in MISO (EES only)	22,338	27,875	24,625	22,442	26,563
Total Uncommitted Capacity in SC	2,187	2,583	2,644	1,561	2,642
Total Uncommitted Capacity in SCEG	1,772	2,642	2,635	1,986	2,233
Total Uncommitted Capacity in SMEE	250	456	487	277	589
Total Uncommitted Capacity in DUK	4,779	9,316	9,153	5,950	7,818
Total Uncommitted Capacity in TVA	13,455	15,667	16,176	11,380	15,949
Total Uncommitted Capacity	**44,782**	**58,538**	**55,720**	**43,596**	**55,794**
Seller's Share of Uncommitted Capacity into SOCO	5.4%	4.2%	4.5%	5.5%	4.5%
Imports into SOCO	5,810	7,698	8,835	5,810	6,497
Seller's Share of Imports into SOCO	312	327	394	321	289

	PST	Winter	Spring	Summer	Fall	
Allocation of Imports into AECI						
Seller's Uncommitted Capacity in MISO	2,405	2,484	2,484	2,405	2,484	
Seller's Uncommitted Capacity in SPP	595	607	607	595	607	
Seller's Uncommitted Capacity in TVA	0	0	0	0	0	
Seller's Uncommitted Capacity	**3,000**	**3,091**	**3,091**	**3,000**	**3,091**	
Total Uncommitted Capacity in MISO (EES Only)	22,338	27,875	24,625	22,442	26,563	
Total Uncommitted Capacity in SPP	28,367	36,878	35,338	27,567	40,441	SPP 2013 Filings
Total Uncommitted Capacity in TVA	13,455	15,667	16,176	11,380	15,949	
Total Uncommitted Capacity	**64,160**	**80,420**	**76,139**	**61,388**	**82,953**	
Seller's Share of Uncommitted Capacity into AECI	4.7%	3.8%	4.1%	4.9%	3.7%	2009 SILs
Imports into AECI	2,673	3,520	2,873	2,673	0	
Seller's Share of Imports into AECI	125	135	117	131	0	

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ATTACHMENT B

ASSET APPENDICES OF EXELON CORPORATION AND AFFILIATES

Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Commonwealth Edison Company	ER98-1734	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Constellation Energy Commodities Group Maine, LLC	ER02-699	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Constellation NewEnergy, Inc.	ER96-1387	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
ExGen Texas Power, LLC	N/A	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Integrys Energy Services of New York, Inc.,	ER07-651	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Integrys Energy Services, Inc.	ER07-650	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
PECO Energy Company	ER01-1147	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
AgriWind LLC	N/A QF07-214	Agriwind LLC WF	AgriWind LLC	AgriWind LLC	N/A	MISO	Central	Jul-2007	2.10
AgriWind Project L.L.C.	N/A QF07-215	Agriwind Project LLC WF	AgriWind Project L.L.C.	AgriWind Project L.L.C.	N/A	MISO	Central	Jul-2007	6.30
BC Energy LLC	N/A QF07-219	BC Energy LLC WF	BC Energy LLC	BC Energy LLC	N/A	MISO	Central	May-2008	4.20
Beebe 1B Renewable Energy, LLC	ER14-2144	Beebe 1b WF	Beebe 1B Renewable Energy, LLC	Beebe 1B Renewable Energy, LLC	N/A	MISO	Central	Dec-2014	50.40
Beebe Renewable Energy, LLC	ER12-2311	Beebe 1a WF	Beebe Renewable Energy, LLC	Beebe Renewable Energy, LLC	N/A	MISO	Central	Jan-2013	81.60
Blue Breezes II, L.L.C.	N/A QF07-243	Blue Breezes II LLC WF	Blue Breezes II, L.L.C.	Blue Breezes II, L.L.C.	N/A	MISO	Central	May-2006	1.25
Blue Breezes, L.L.C.	N/A QF07-242	Blue Breezes I LLC WF	Blue Breezes, L.L.C.	Blue Breezes, L.L.C.	N/A	MISO	Central	May-2006	1.25
Breezy Bucks I LLC	N/A QF07-234	Breezy Bucks I LLC WF	Breezy Bucks I LLC	Breezy Bucks I LLC	N/A	MISO	Central	May-2006	1.25
Breezy Bucks II LLC	N/A QF07-235	Breezy Bucks II LLC WF	Breezy Bucks II LLC	Breezy Bucks II LLC	N/A	MISO	Central	May-2006	1.25
Christoffer Wind Energy I LLC	N/A QF07-250	Christoffer Wind I WF	Christoffer Wind Energy I LLC	Christoffer Wind Energy I LLC	N/A	MISO	Central	Jun-2008	2.10
Christoffer Wind Energy II LLC	N/A QF07-252	Christoffer Wind II WF	Christoffer Wind Energy II LLC	Christoffer Wind Energy II LLC	N/A	MISO	Central	Jun-2008	2.10
Christoffer Wind Energy III LLC	N/A QF07-251	Christoffer Wind III WF	Christoffer Wind Energy III LLC	Christoffer Wind Energy III LLC	N/A	MISO	Central	Jun-2008	2.10
Christoffer Wind Energy IV LLC	N/A QF07-249	Christoffer Wind IV WF	Christoffer Wind Energy IV LLC	Christoffer Wind Energy IV LLC	N/A	MISO	Central	Jun-2008	2.10
CP Windfarm, LLC	N/A QF07-178	CP Wind Farms LLC WF	CP Windfarm, LLC	CP Windfarm, LLC	N/A	MISO	Central	Oct-2007	4.20
Exelon Generation Company, LLC	ER00-3251	Clinton	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	MISO	Central	Nov-1987	1065.00
G-Flow Wind, LLC	N/A QF07-223	G-Flow Wind LLC WF	G-Flow Wind, LLC	G-Flow Wind, LLC	N/A	MISO	Central	Mar-2006	1.25
Green Acres Breeze, LLC	N/A QF07-227	Green Acres Breeze LLC WF	Green Acres Breeze, LLC	Green Acres Breeze, LLC	N/A	MISO	Central	Mar-2006	1.25
Harvest II Windfarm, LLC	ER12-2201 QF12-522	Harvest 2 WF	Harvest II Windfarm, LLC	Harvest II Windfarm, LLC	N/A	MISO	Central	Nov-2012	59.40
Harvest Windfarm, LLC	ER07-1246 QF07-29	Harvest 1 WF	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	Feb-2008	52.80
K&D Energy LLC	N/A QF07-218	K&D Energy LLC WF	K&D Energy LLC	K&D Energy LLC	N/A	MISO	Central	May-2008	4.00
KC Energy LLC	N/A QF07-217	KC Energy LLC WF	KC Energy LLC	KC Energy LLC	N/A	MISO	Central	May-2008	4.00
KSS Turbines LLC	N/A QF07-220	KSS Turbines LLC WF	KSS Turbines LLC	KSS Turbines LLC	N/A	MISO	Central	May-2008	4.00
Marshall Wind 1, LLC	N/A QF08-59	Marshall Wind 1 WF	Marshall Wind 1, LLC	Marshall Wind 1, LLC	N/A	MISO	Central	May-2008	2.10

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Marshall Wind 2, LLC	N/A QF08-58	Marshall Wind 2 WF	Marshall Wind 2, LLC	Marshall Wind 2, LLC	N/A	MISO	Central	May-2008	4.20
Marshall Wind 3, LLC	N/A QF08-55	Marshall Wind 3 WF	Marshall Wind 3, LLC	Marshall Wind 3, LLC	N/A	MISO	Central	May-2008	4.20
Marshall Wind 4, LLC	N/A QF08-56	Marshall Wind 4 WF	Marshall Wind 4, LLC	Marshall Wind 4, LLC	N/A	MISO	Central	May-2008	4.20
Marshall Wind 5, LLC	N/A QF08-57	Marshall Wind 5 WF	Marshall Wind 5, LLC	Marshall Wind 5, LLC	N/A	MISO	Central	May-2008	2.10
Marshall Wind 6, LLC	N/A QF08-60	Marshall Wind 6 WF	Marshall Wind 6, LLC	Marshall Wind 6, LLC	N/A	MISO	Central	May-2008	2.10
Michigan Wind 1, LLC	ER05-1511 QF05-228	Michigan Wind 1 WF	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	Dec-2008	69.00
Michigan Wind 2, LLC	ER11-3989	Michigan Wind 2 WF	Michigan Wind 2, LLC	Michigan Wind 2, LLC	N/A	MISO	Central	Jan-2012	90.00
Minnesota Breeze, LLC	N/A QF07-224	Minnesota Breeze LLC WF	Minnesota Breeze, LLC	Minnesota Breeze, LLC	N/A	MISO	Central	Mar-2006	1.25
Prairie Wind Power LLC	N/A QF07-216	Prairie Wind Power LLC WF	Prairie Wind Power LLC	Prairie Wind Power LLC	N/A	MISO	Central	May-2008	4.00
Roadrunner I LLC	N/A QF07-236	Roadrunner I LLC WF	Roadrunner I LLC	Roadrunner I LLC	N/A	MISO	Central	May-2006	1.25
Salty Dog I LLC	N/A QF07-237	Salty Dog I LLC WF	Salty Dog I LLC	Salty Dog I LLC	N/A	MISO	Central	May-2006	1.25
Salty Dog II LLC	N/A QF07-238	Salty Dog II LLC WF	Salty Dog II LLC	Salty Dog II LLC	N/A	MISO	Central	May-2006	1.25
Shane's Wind Machine LLC	N/A QF07-247	Shanes Wind Machine LLC WF	Shane's Wind Machine LLC	Shane's Wind Machine LLC	N/A	MISO	Central	Jul-2006	2.00
Sunset Breeze, LLC	N/A QF07-226	Sunset Breeze LLC WF	Sunset Breeze, LLC	Sunset Breeze, LLC	N/A	MISO	Central	Mar-2006	1.25
Wally's Wind Farm LLC	N/A QF07-239	Wally's Wind Farm	Wally's Wind Farm LLC	Wally's Wind Farm LLC	N/A	MISO	Central	May-2006	1.25
Windy Dog I LLC	N/A QF07-240	Windy Dog I LLC WF	Windy Dog I LLC	Windy Dog I LLC	N/A	MISO	Central	May-2006	1.25
Wolf Wind Enterprises, LLC	N/A QF07-225	Wolf Wind Enterprises LLC WF	Wolf Wind Enterprises, LLC	Wolf Wind Enterprises, LLC	N/A	MISO	Central	Mar-2006	1.25
Exelon Generation Company, LLC	ER00-3251	Frontier GT1	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	9/20/2000	MISO & ERCOT	Central	Sep-2000	160.00
Exelon Generation Company, LLC	ER00-3251	Frontier GT2	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	9/20/2000	MISO & ERCOT	Central	Sep-2000	160.00
Exelon Generation Company, LLC	ER00-3251	Frontier GT3	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	9/20/2000	MISO & ERCOT	Central	Sep-2000	160.00
Exelon Generation Company, LLC	ER00-3251	Frontier ST	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	9/20/2000	MISO & ERCOT	Central	Sep-2000	390.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 7	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	Jun-1975	575.48
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	Apr-2003	225.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	Apr-2003	227.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	Apr-2003	252.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	Jun-2003	231.09
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	Jun-2003	230.80
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	Jun-2003	252.00
Constellation Mystic Power, LLC	ER10-2281	Mystic Jet	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	Jun-1969	9.07
Constellation Solar Connecticut, LLC	N/A QF10-654	East Lyme Bd of Ed at East Lyme HS	Constellation Solar Connecticut LLC	Constellation Solar Connecticut LLC	N/A	ISO-NE	Northeast	Mar-2009	0.41
Constellation Solar Connecticut, LLC	N/A QF10-663	Parker Hannifin Corp at New Britain	Constellation Solar Connecticut LLC	Constellation Solar Connecticut LLC	N/A	ISO-NE	Northeast	Dec-2008	0.18

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Constellation Solar Massachusetts, LLC	N/A QF11-411	Kollmorgen Electro-Optical HQ Bldg	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Jul-2011	0.17
Constellation Solar Massachusetts, LLC	N/A QF15-188	Macy's at Marlborough	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Dec-2014	0.41
Constellation Solar Massachusetts, LLC	N/A QF15-187	Macy's at Natick	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Dec-2014	0.56
Constellation Solar Massachusetts, LLC	N/A QF15-186	Macy's at Saugus	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Dec-2014	0.30
Constellation Solar Massachusetts, LLC	N/A QF15-190	Macy's at Burlington	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Dec-2014	0.25
Constellation Solar Massachusetts, LLC	N/A QF15-189	Macy's at Dartmouth	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Dec-2014	0.35
Constellation Solar Massachusetts, LLC	N/A QF09-89	Majilite Corp	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Feb-2009	0.35
Constellation Solar Massachusetts, LLC	N/A QF10-655	NPP Development, LLC at Patriot Place	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Jul-2010	0.45
Constellation Solar Massachusetts, LLC	N/A QF12-292	Town of Norfolk	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Jun-2012	1.35
Constellation Solar Massachusetts, LLC	N/A QF12-212	Town of Swampscott	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	Feb-2012	0.32
Constellation Solar Net Metering, LLC	N/A QF12-293	Town of Uxbridge	Constellation Solar Net Metering, LLC	Constellation Solar Net Metering, LLC	N/A	ISO-NE	Northeast	Jun-2012	1.93
Exelon Framingham LLC	ER01-513	Framingham Jet 1	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	Mar-1970	10.15
Exelon Framingham LLC	ER01-513	Framingham Jet 2	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	Sep-1969	11.69
Exelon Framingham LLC	ER01-513	Framingham Jet 3	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	Sep-1969	11.25
Exelon Generation Company, LLC	ER00-3251	Granite Ridge	Granite Ridge Energy, LLC	Exelon Generation Company, LLC	1/1/2014	ISO-NE	Northeast	Dec-2002	661.32
Exelon Generation Company, LLC	ER00-3251	Kleen GT1	Kleen Energy Systems, LLC	Exelon Generation Company, LLC	7/23/2011	ISO-NE	Northeast	Jul-2011	186.00
Exelon Generation Company, LLC	ER00-3251	Kleen GT2	Kleen Energy Systems, LLC	Exelon Generation Company, LLC	7/23/2011	ISO-NE	Northeast	Jul-2011	188.00
Exelon Generation Company, LLC	ER00-3251	Kleen STG1	Kleen Energy Systems, LLC	Exelon Generation Company, LLC	7/23/2011	ISO-NE	Northeast	Jul-2011	246.00
Exelon New Boston, LLC	ER01-513	New Boston Jet	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	Sep-1966	16.03
Exelon West Medway, LLC	ER01-513	West Medway Jet 1	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	Jul-1970	42.00
Exelon West Medway, LLC	ER01-513	West Medway Jet 2	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	Mar-1971	39.85
Exelon West Medway, LLC	ER01-513	West Medway Jet 3	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	Jul-1970	35.44
Exelon Wyman, LLC	ER01-513	Wyman 4	Exelon Wyman, LLC (5.9%)	FPL Wyman Energy, LLC	N/A	ISO-NE	Northeast	Jan-1978	610.00
Holyoke Solar LLC	N/A QF12-294	City of Holyoke G & E Dept at Meadow	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	Dec-2011	0.87
Holyoke Solar LLC	N/A QF12-267	City of Holyoke G & E Dept at Mueller	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	Mar-2012	2.95
2014 ESA Project Company, LLC	N/A	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	N/A	NYISO	Northeast	Jan-2015	0.20
Constellation Solar New York, LLC	N/A QF13-550	Owens Corning	Constellation Solar New York, LLC	Constellation Solar New York, LLC	N/A	NYISO	Northeast	Oct-2013	2.28
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 1	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	Dec-1969	626.90
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 2	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	Aug-1988	1287.20
R. E. Ginna Nuclear Power Plant, LLC	ER04-485	Ginna	R. E. Ginna Nuclear Power Plant, LLC	R. E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	Jul-1970	581.70
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 1	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	May-1975	873.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 2	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	Apr-1977	841.80
Constellation Power Source Generation, LLC	ER14-1169	Gould Street 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Dec-1952	97.00
Constellation Power Source Generation, LLC	ER14-1169	Notch Cliff 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1969	14.00
Constellation Power Source Generation, LLC	ER14-1169	Notch Cliff 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1969	14.00
Constellation Power Source Generation, LLC	ER14-1169	Notch Cliff 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1969	14.00
Constellation Power Source Generation, LLC	ER14-1169	Notch Cliff 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1969	14.00
Constellation Power Source Generation, LLC	ER14-1169	Notch Cliff 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1969	15.00
Constellation Power Source Generation, LLC	ER14-1169	Notch Cliff 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1969	16.00
Constellation Power Source Generation, LLC	ER14-1169	Notch Cliff 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1969	15.00
Constellation Power Source Generation, LLC	ER14-1169	Notch Cliff 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1969	16.00
Constellation Power Source Generation, LLC	ER14-1169	Perryman 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jan-1972	52.00
Constellation Power Source Generation, LLC	ER14-1169	Perryman 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Apr-1972	51.00
Constellation Power Source Generation, LLC	ER14-1169	Perryman 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Apr-1972	51.00
Constellation Power Source Generation, LLC	ER14-1169	Perryman 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Apr-1972	52.00
Constellation Power Source Generation, LLC	ER14-1169	Perryman 51	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Jun-1995	147.60
Constellation Power Source Generation, LLC	ER14-1169	Philadelphia Road 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Aug-1970	15.30
Constellation Power Source Generation, LLC	ER14-1169	Philadelphia Road 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Aug-1970	16.00
Constellation Power Source Generation, LLC	ER14-1169	Philadelphia Road 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Sep-1970	14.80
Constellation Power Source Generation, LLC	ER14-1169	Philadelphia Road 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Sep-1970	14.80
Constellation Power Source Generation, LLC	ER14-1169	Riverside 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Sep-1951	74.00
Constellation Power Source Generation, LLC	ER14-1169	Riverside 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Sep-1970	19.00
Constellation Power Source Generation, LLC	ER14-1169	Riverside 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Sep-1970	20.00
Constellation Power Source Generation, LLC	ER14-1169	Westport 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	Feb-1969	115.80
Constellation Solar DC, LLC	N/A QF13-575	Dunbar	Constellation Solar DC, LLC	Constellation Solar DC, LLC	N/A	PJM	Northeast	Dec-2013	0.32
Constellation Solar Federal LLC	N/A QF12-78	US Department of State (Reeves)	Constellation Solar Federal LLC	Constellation Solar Federal LLC	N/A	PJM	Northeast	Dec-2011	4.23
Constellation Solar Horizons, LLC	N/A QF10-586	University System of Maryland & Department of General Services	Constellation Solar Horizons, LLC	Constellation Solar Horizons, LLC	N/A	PJM	Northeast	Jul-2012	13.61
Constellation Solar Maryland II, LLC	N/A QF13-135	UMMS - CRE	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	Feb-2013	0.35
Constellation Solar Maryland II, LLC	N/A QF13-136	UMMS (U of MD Medical System)	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	Feb-2013	3.09
Constellation Solar Maryland, LLC	N/A QF11-271	AA County, MD at Shared Svcs Complex	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	Mar-2011	0.63
Constellation Solar Maryland, LLC	N/A QF11-333	Coppin State Univ at Coppin State Univ - PEC	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	Sep-2011	0.42
Constellation Solar Maryland, LLC	N/A QF11-410	CPSG Fort Smallwood Road Complex	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	Oct-2011	0.78

Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Constellation Solar Maryland, LLC	N/A QF11-335	GM Allison Plant-I	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	May-2011	1.04
Constellation Solar Maryland, LLC	N/A QF11-407	Maryland Science Center	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	May-2011	0.09
Constellation Solar Maryland, LLC	N/A QF11-268	McCormick & Co, Inc at Belcamp	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	Jan-2011	1.56
Constellation Solar Maryland, LLC	N/A QF10-662	McCormick & Co, Inc at Hunt Valley	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	Jan-2009	0.78
Constellation Solar Maryland, LLC	N/A QF11-334	McCormick & Co, Inc at Sparks	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	Jun-2011	0.08
Constellation Solar Maryland, LLC	N/A QF10-661	MD Env Service at MES Headquarters	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	Dec-2008	0.25
Constellation Solar Maryland, LLC	N/A QF12-507	University System of Maryland II	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	Jul-2012	1.42
Constellation Solar New Jersey II, LLC	N/A QF11-267	Johnson Matthey, Inc at West Deptford	Constellation Solar New Jersey II, LLC	Constellation Solar New Jersey II, LLC	N/A	PJM	Northeast	Apr-2011	4.41
Constellation Solar New Jersey II, LLC	N/A QF11-461	Toys-R-Us Delaware, Inc at Mt Olive	Constellation Solar New Jersey II, LLC	Constellation Solar New Jersey II, LLC	N/A	PJM	Northeast	Dec-2011	4.55
Constellation Solar New Jersey III, LLC	N/A QF12-81	Middle Township Elem School 1	Constellation Solar New Jersey III, LLC	Constellation Solar New Jersey III, LLC	N/A	PJM	Northeast	Dec-2011	0.17
Constellation Solar New Jersey III, LLC	N/A QF12-79	Middle Township Elem School 2	Constellation Solar New Jersey III, LLC	Constellation Solar New Jersey III, LLC	N/A	PJM	Northeast	Dec-2011	0.39
Constellation Solar New Jersey III, LLC	N/A QF12-80	Middle Township High School	Constellation Solar New Jersey III, LLC	Constellation Solar New Jersey III, LLC	N/A	PJM	Northeast	Dec-2011	0.69
Constellation Solar New Jersey LLC	N/A QF11-270	Benjamin Moore & Co at Flanders NJ	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	Jan-2011	1.50
Constellation Solar New Jersey LLC	N/A QF10-666	Jet Aviation Teterboro, LP at Teterboro Airport	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	Mar-2008	0.15
Constellation Solar New Jersey LLC	N/A QF11-464	North Vineland	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	Oct-2011	2.54
Constellation Solar New Jersey LLC	N/A QF11-463	West Vineland	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	Oct-2011	4.06
Constellation Solar Ohio, LLC	N/A QF10-664	Univ of Toledo (Solar) Scott Park Campus of Energy & Innovation	Constellation Solar Ohio, LLC	Constellation Solar Ohio, LLC	N/A	PJM	Northeast	Mar-2010	0.88
Constellation Solar Ohio, LLC	N/A QF10-659	Univ of Toledo (Wind) Scott Park Campus of Energy & Innovation	Constellation Solar Ohio, LLC	Constellation Solar Ohio, LLC	N/A	PJM	Northeast	Mar-2010	0.07
Criterion Power Partners, LLC	ER10-1443	Criterion WF	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	Feb-2011	70.00
Exelon Generation Company, LLC	ER00-3251	Braidwood 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jul-1988	1178.00
Exelon Generation Company, LLC	ER00-3251	Braidwood 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Oct-1988	1152.00
Exelon Generation Company, LLC	ER00-3251	Byron 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Sep-1985	1164.00
Exelon Generation Company, LLC	ER00-3251	Byron 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Aug-1987	1136.00
Exelon Generation Company, LLC	ER00-3251	Chester 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Feb-1969	13.00
Exelon Generation Company, LLC	ER00-3251	Chester 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1969	13.00
Exelon Generation Company, LLC	ER00-3251	Chester 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Mar-1969	13.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Mar-1928	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1964	65.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1964	65.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Mar-1928	36.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Mar-1928	48.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Conowingo 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Apr-1928	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1928	36.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jul-1928	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1928	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Mar-1964	65.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Mar-1964	65.00
Exelon Generation Company, LLC	ER00-3251	Cordova GT1	Cordova Energy Company, LLC	Exelon Generation Company, LLC	###### #####	PJM	Northeast	Jun-2001	165.00
Exelon Generation Company, LLC	ER00-3251	Cordova GT2	Cordova Energy Company, LLC	Exelon Generation Company, LLC	###### #####	PJM	Northeast	Jun-2001	165.00
Exelon Generation Company, LLC	ER00-3251	Cordova STG1	Cordova Energy Company, LLC	Exelon Generation Company, LLC	###### #####	PJM	Northeast	Jun-2001	191.20
Exelon Generation Company, LLC	ER00-3251	Croydon 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 21	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 22	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 31	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Aug-1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 32	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Aug-1974	48.00
Exelon Generation Company, LLC	ER00-3251	Croydon 41	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jul-1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 42	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jul-1974	49.00
Exelon Generation Company, LLC	ER00-3251	Delaware 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1969	13.00
Exelon Generation Company, LLC	ER00-3251	Delaware 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Apr-1969	13.00
Exelon Generation Company, LLC	ER00-3251	Delaware 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1969	13.00
Exelon Generation Company, LLC	ER00-3251	Delaware 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jul-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Dresden 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Aug-1970	883.50
Exelon Generation Company, LLC	ER00-3251	Dresden 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Oct-1971	895.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1967	13.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 20	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Oct-1967	13.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Sep-1974	380.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 30	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Mar-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1976	380.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 40	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 5	Elwood Energy, LLC	Exelon Generation Company, LLC	6/15/2006	PJM	Northeast	Jul-2001	150.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 6	Elwood Energy, LLC	Exelon Generation Company, LLC	6/15/2006	PJM	Northeast	Jul-2001	150.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 7	Elwood Energy, LLC	Exelon Generation Company, LLC	6/15/2006	PJM	Northeast	Jul-2001	150.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 8	Elwood Energy, LLC	Exelon Generation Company, LLC	6/15/2006	PJM	Northeast	Jul-2001	150.00
Exelon Generation Company, LLC	ER00-3251	Fairless Hills A	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Dec-1996	30.00
Exelon Generation Company, LLC	ER00-3251	Fairless Hills B	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Dec-1996	30.00
Exelon Generation Company, LLC	ER00-3251	Falls 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Falls 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Falls 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1970	17.00
Exelon Generation Company, LLC	ER00-3251	LaSalle 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jan-1984	1135.40
Exelon Generation Company, LLC	ER00-3251	LaSalle 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Oct-1984	1136.20
Exelon Generation Company, LLC	ER00-3251	Limerick 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Feb-1986	1119.70
Exelon Generation Company, LLC	ER00-3251	Limerick 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jan-1990	1122.10
Exelon Generation Company, LLC	ER00-3251	Moser 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Moser 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Moser 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1970	17.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Apr-1967	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Apr-1967	133.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1967	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1967	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Oct-1967	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Oct-1967	133.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Feb-1968	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Feb-1968	134.00
Exelon Generation Company, LLC	ER00-3251	Oyster Creek 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Dec-1969	609.90
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 2	ExGen (PSEG 50%)	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jul-1974	1119.70
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 3	ExGen (PSEG 50%)	Exelon Generation Company, LLC	N/A	PJM	Northeast	Dec-1974	1125.40
Exelon Generation Company, LLC	ER00-3251	Pennsbury 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Sep-1996	2.67
Exelon Generation Company, LLC	ER00-3251	Pennsbury 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Sep-1996	2.67
Exelon Generation Company, LLC	ER00-3251	Quad Cities 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Dec-1972	908.00
Exelon Generation Company, LLC	ER00-3251	Quad Cities 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Dec-1972	911.00
Exelon Generation Company, LLC	ER00-3251	Richmond 91	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1973	49.00
Exelon Generation Company, LLC	ER00-3251	Richmond 92	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1973	49.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Salem 1	PSEG (ExGen 42.59%)	PSEG	N/A	PJM	Northeast	Jun-1977	1173.99
Exelon Generation Company, LLC	ER00-3251	Salem 2	PSEG (ExGen 42.59%)	PSEG	N/A	PJM	Northeast	Oct-1981	1158.02
Exelon Generation Company, LLC	ER00-3251	Salem 3	PSEG (ExGen 42.59%)	PSEG	N/A	PJM	Northeast	Jun-1971	37.57
Exelon Generation Company, LLC	ER00-3251	Schuylkill 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-1969	13.00
Exelon Generation Company, LLC	ER00-3251	Schuylkill 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1971	17.00
Exelon Generation Company, LLC	ER00-3251	Southeast Chicago Energy Project 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southeast Chicago Energy Project 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southeast Chicago Energy Project 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southeast Chicago Energy Project 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southeast Chicago Energy Project 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southeast Chicago Energy Project 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southeast Chicago Energy Project 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southeast Chicago Energy Project 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	May-2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southwark 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jun-1967	13.00
Exelon Generation Company, LLC	ER00-3251	Southwark 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Oct-1967	13.00
Exelon Generation Company, LLC	ER00-3251	Southwark 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Jul-1967	13.00
Exelon Generation Company, LLC	ER00-3251	Southwark 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Nov-1968	13.00
Exelon Generation Company, LLC	ER00-3251	TMI 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	Sep-1974	802.80
Exelon Generation Company, LLC	ER00-3251	York Delta GT1	Calpine Mid Merit LLC	Exelon Generation Company, LLC	6/1/2011	PJM	Northeast	Mar-2011	118.00
Exelon Generation Company, LLC	ER00-3251	York Delta GT2	Calpine Mid Merit LLC	Exelon Generation Company, LLC	6/1/2011	PJM	Northeast	Mar-2011	127.00
Exelon Generation Company, LLC	ER00-3251	York Delta GT3	Calpine Mid Merit LLC	Exelon Generation Company, LLC	6/1/2011	PJM	Northeast	Mar-2011	127.00
Exelon Generation Company, LLC	ER00-3251	York Delta STG1	Calpine Mid Merit LLC	Exelon Generation Company, LLC	6/1/2011	PJM	Northeast	Mar-2011	193.00
Exelon Solar Chicago LLC	N/A QF10-174	Chicago City Solar SF	Exelon Solar Chicago LLC	Exelon Solar Chicago LLC	N/A	PJM	Northeast	Mar-2010	8.00
Fourmile Wind Energy, LLC	ER14-2145 QF14-721	Fourmile Ridge	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	Jan-2015	40.00
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 1	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	Jul-2001	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 2	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	Jul-2001	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 3	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	Jul-2001	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 4	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	Jul-2001	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 5	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	Jul-2001	53.50
Bennett Creek Windfarm, LLC	N/A QF07-36	Bennett Creek WF	Bennett Creek, LLC	Bennett Creek, LLC	N/A	IPCO	Northwest	Aug-2008	21.00
Cassia Gulch Wind Park LLC	ER10-75 QF05-180	Cassia Gulch WF	Cassia Gulch Wind Park LLC	Cassia Gulch Wind Park LLC	N/A	IPCO	Northwest	Mar-2009	18.90

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Cassia Wind Farm, LLC	N/A QF05-170	Cassia Wind WF	Cassia Wind Farm, LLC	Cassia Wind Farm, LLC	N/A	IPCO	Northwest	Mar-2009	10.50
High Mesa Energy, LLC	ER12-2528 QF13-77	High Mesa WF	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	IPCO	Northwest	Aug-2012	40.00
Hot Springs Windfarm, LLC	N/A QF07-37	Hot Springs WF	Hot Springs Windfarm, LLC	Hot Springs Windfarm, LLC	N/A	IPCO	Northwest	Aug-2008	21.00
Tuana Springs Energy, LLC	ER10-87 QF08-742	Tuana Springs WF	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	IPCO	Northwest	Jul-2010	16.80
Sunnyside Cogeneration Assoc.	N/A QF86-556	Sunnyside Cogen	Sunnyside Cogeneration Assoc.	Sunnyside Cogeneration Assoc.	N/A	PACE	Northwest	Feb-1993	51.00
Big Top, LLC	N/A QF08-539	Big Top WF	Big Top, LLC	Big Top, LLC	N/A	PACW	Northwest	Jun-2009	1.65
Butter Creek Power, LLC	N/A QF08-536	Butter Creek WF	Butter Creek Power, LLC	Butter Creek Power, LLC	N/A	PACW	Northwest	Jun-2009	4.95
Four Corners Windfarm, LLC	N/A QF08-372	Four Corner WF	Four Corners Windfarm, LLC	Four Corners Windfarm, LLC	N/A	PACW	Northwest	Sep-2009	10.00
Four Mile Canyon Windfarm, LLC	N/A QF08-370	Four Mile Canyon WF	Four Mile Canyon Windfarm, LLC	Four Mile Canyon Windfarm, LLC	N/A	PACW	Northwest	Sep-2009	10.00
Oregon Trail Windfarm, LLC	N/A QF08-371	Oregon Trail WF	Oregon Trail Windfarm, LLC	Oregon Trail Windfarm, LLC	N/A	PACW	Northwest	Jun-2009	9.90
Pacific Canyon Windfarm, LLC	N/A QF08-373	Pacific Canyon WF	Pacific Canyon Windfarm, LLC	Pacific Canyon Windfarm, LLC	N/A	PACW	Northwest	Jun-2009	8.25
Sand Ranch Windfarm, LLC	N/A QF08-368	Sand Ranch WF	Sand Ranch Windfarm, LLC	Sand Ranch Windfarm, LLC	N/A	PACW	Northwest	Jun-2009	9.90
Three Mile Canyon Wind I, LLC	N/A QF09-142	Three Mile Canyon WF	Three Mile Canyon Wind I, LLC	Three Mile Canyon Wind I, LLC	N/A	PACW	Northwest	Sep-2009	9.90
Wagon Trail, LLC	N/A QF08-537	Wagon Trail WF	Wagon Trail, LLC	Wagon Trail, LLC	N/A	PACW	Northwest	Jun-2009	3.30
Ward Butte Windfarm, LLC	N/A QF08-369	Ward Butte WF	Ward Butte Windfarm, LLC	Ward Butte Windfarm, LLC	N/A	PACW	Northwest	Jun-2009	6.60
Outback Solar, LLC	N/A QF13-34	Outback Solar	Outback Solar, LLC	Outback Solar, LLC	N/A	BPA	Northwest	Oct-2012	4.82
Denver Airport Solar, LLC	N/A QF11-336	City & County of Denver at Denver International Airport	Denver Airport Solar, LLC	Denver Airport Solar, LLC	N/A	PSCO	Northwest	Jun-2011	3.77
Cow Branch Wind Power, L.L.C.	ER07-1223 QF07-253	Cow Branch WF	Cow Branch Wind Power, L.L.C.	Cow Branch Wind Power, L.L.C.	N/A	AECI	Southeast	Mar-2008	50.40
CR Clearing, LLC	ER07-1222 QF07-248	CR Clearing LLC WF	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	May-2008	50.40
Loess Hills Wind Farm, LLC	N/A QF07-241	Loess Hills WF	Loess Hills Wind Farm, LLC	Loess Hills Wind Farm, LLC	N/A	AECI	Southeast	Apr-2008	5.00
Wind Capital Holdings, LLC	ER07-1208 QF07-222	Wind Capital Holdings LLC WF	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	May-2007	56.70
CER Generation, LLC	ER10-662	Hillabee GT1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	Jun-2010	207.00
CER Generation, LLC	ER10-662	Hillabee GT2	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	Jun-2010	207.00
CER Generation, LLC	ER10-662	Hillabee STG1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	Jun-2010	281.00
Constellation Solar Georgia, LLC	N/A QF15-203	Eastanollee	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	Dec-2014	0.84
Constellation Solar Georgia, LLC	N/A QF15-202	Cave Spring	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	Dec-2014	0.85
Constellation Solar Georgia, LLC	N/A QF15-204	Gibson	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	Dec-2014	0.62
Constellation Solar Georgia, LLC	N/A QF14-505	Sparta	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	May-2014	0.85
Constellation Solar Georgia, LLC	N/A QF15-205	Summerville	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	Dec-2014	0.38
Constellation Solar Georgia, LLC	N/A QF15-206	Wadley	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	Dec-2014	1.11
Constellation Solar Georgia, LLC	N/A QF15-207	Wrens	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	Dec-2014	0.34

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Effingham GT1	Effingham County Power, LLC	Effingham County Power, LLC / Exelon Generation Company, LLC	6/1/2007	SOCO	Southeast	Aug-2003	163.00
Exelon Generation Company, LLC	ER00-3251	Franklin GT1	Southern Power Company	Southern Power Company / Exelon Generation Company, LLC	6/1/2007	SOCO	Southeast	Jun-2003	183.00
Exelon Generation Company, LLC	ER00-3251	Heard 1	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/2001	SOCO	Southeast	Jun-2001	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 2	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/2001	SOCO	Southeast	Jun-2001	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 3	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/2001	SOCO	Southeast	Jun-2001	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 4	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/2001	SOCO	Southeast	May-2002	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 5	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/2001	SOCO	Southeast	May-2002	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 6	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/2001	SOCO	Southeast	May-2002	157.50
Exelon Generation Company, LLC	ER00-3251	Hog Bayou	Mobile Energy LLC	Exelon Generation Company, LLC	1/1/2015	SOCO	Southeast	Jul-2001	230.00
Exelon Generation Company, LLC	ER00-3251	Sowega 1	Georgia Energy Cooperative	Exelon Generation Company, LLC	1/1/2011	SOCO	Southeast	Jun-1999	48.00
Exelon Generation Company, LLC	ER00-3251	Sowega 2	Georgia Energy Cooperative	Exelon Generation Company, LLC	1/1/2011	SOCO	Southeast	Jun-1999	48.00
Exelon Generation Company, LLC	ER00-3251	Washington 1	Washington County Power, LLC	Washington County Power, LLC / Exelon Generation Company, LLC	6/1/2007	SOCO	Southeast	Jun-2003	153.50
Exelon Generation Company, LLC	ER00-3251	Washington 4	Washington County Power, LLC	Washington County Power, LLC / Exelon Generation Company, LLC	6/1/2007	SOCO	Southeast	Jun-2003	153.50
Constellation Solar Arizona, LLC	N/A QF12-211	Buckeye Union HS at Estrella & Youngkers	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2011	3.62
Constellation Solar Arizona, LLC	N/A QF13-76	Casa Grande - Casa Verde HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2012	0.35
Constellation Solar Arizona, LLC	N/A QF13-75	Casa Grande - Union HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2012	1.79
Constellation Solar Arizona, LLC	N/A QF13-74	Casa Grande - Vista Grande HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2012	1.54
Constellation Solar Arizona, LLC	N/A QF13-599	Charles Bejarando	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Sep-2013	0.09
Constellation Solar Arizona, LLC	N/A QF14-498	Collier ES	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Jun-2014	0.25
Constellation Solar Arizona, LLC	N/A QF13-511	Crane School District at Centennial	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Aug-2013	0.38
Constellation Solar Arizona, LLC	N/A QF13-516	Crane School District at Crane Middle School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Aug-2013	0.38
Constellation Solar Arizona, LLC	N/A QF13-378	Crane School District at GAK	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Mar-2013	0.19
Constellation Solar Arizona, LLC	N/A QF13-377	Crane School District at Mesquite	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Mar-2013	0.17
Constellation Solar Arizona, LLC	N/A QF13-515	Crane School District at Valley Horizon	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Jul-2013	0.28
Constellation Solar Arizona, LLC	N/A QF13-537	Dysart I School District	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Jun-2013	8.81
Constellation Solar Arizona, LLC	N/A QF14-496	Isaac School District at Butler	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Jul-2014	0.21
Constellation Solar Arizona, LLC	N/A QF14-497	Lee Kornegay HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Jul-2014	0.11
Constellation Solar Arizona, LLC	N/A QF13-538	Marana School District	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Jul-2013	1.59
Constellation Solar Arizona, LLC	N/A QF13-598	Miami High School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Sep-2013	0.36
Constellation Solar Arizona, LLC	N/A QF14-499	Parkridge ES	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Jul-2014	0.42
Constellation Solar Arizona, LLC	N/A QF13-536	Peoria Unified School District	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Nov-2013	2.53

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Constellation Solar Arizona, LLC	N/A QF14-27	Pueblo Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2013	0.24
Constellation Solar Arizona, LLC	N/A QF14-29	Salida del Sol Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2013	0.30
Constellation Solar Arizona, LLC	N/A QF13-514	Somerton School District at Desert Sonora	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Mar-2013	0.29
Constellation Solar Arizona, LLC	N/A QF13-137	Somerton School District at Orange Grove	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2012	0.18
Constellation Solar Arizona, LLC	N/A QF13-513	Somerton School District at Somerton Middle School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Mar-2013	0.47
Constellation Solar Arizona, LLC	N/A QF13-138	Somerton School District at Tierra del Sol	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2012	0.22
Constellation Solar Arizona, LLC	N/A QF13-139	Somerton School District at Valle del Encanto	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2012	0.17
Constellation Solar Arizona, LLC	N/A QF14-26	Suverkrup Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Dec-2013	0.27
Constellation Solar Arizona, LLC	N/A QF13-376	Vail Unified School District at Andrada	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Apr-2013	0.33
Constellation Solar Arizona, LLC	N/A QF13-378	Vail Unified School District at Mesquite Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Apr-2013	0.23
Constellation Solar Arizona, LLC	N/A QF13-380	Vail Unified School District at OVMS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Apr-2013	0.25
Constellation Solar Arizona, LLC	N/A QF15-163	Western Peaks ES	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Oct-2014	0.47
Constellation Solar Arizona, LLC	N/A QF15-162	Willow Canyon HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	Oct-2014	0.44
Mohave Sunrise Solar I LLC	N/A QF15-161	Mohave Electric at Fort Mohave	Mohave Sunrise Solar I LLC	Mohave Sunrise Solar I LLC	N/A	APS	Southwest	2nd Qtr 2015	4.56
Sacramento PV Energy, LLC	N/A QF11-329	SMUD at Fleshman	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	Nov-2011	3.08
Sacramento PV Energy, LLC	N/A QF11-330	SMUD at Grundman	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	Dec-2011	18.50
Sacramento PV Energy, LLC	N/A QF11-331	SMUD at Lawrence	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	Dec-2011	1.03
Sacramento PV Energy, LLC	N/A QF11-332	SMUD at VanConnet	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	Dec-2011	3.08
2014 ESA Project Company, LLC	N/A	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	N/A	CAISO	Southwest	Oct-2014	2.60
AV Solar Ranch 1, LLC	ER12-2178	Antelope Valley SF	AV Solar Ranch 1, LLC	AV Solar Ranch 1, LLC	N/A	CAISO	Southwest	Dec-2012	241.50
California PV Energy, LLC	N/A QF15-76	Alto Loma HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Dec-2014	0.56
California PV Energy, LLC	N/A QF14-214	Castaic Elementary School	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Apr-2014	0.12
California PV Energy, LLC	N/A QF14-212	Castaic Middle School	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Apr-2014	0.28
California PV Energy, LLC	N/A QF15-78	Chaffey HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Feb-2015	0.54
California PV Energy, LLC	N/A QF15-79	Colony HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Feb-2015	0.76
California PV Energy, LLC	N/A QF15-80	Etiwanda HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Dec-2014	0.72
California PV Energy, LLC	N/A QF14-28	Ironhouse Sanitary District	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.85
California PV Energy, LLC	N/A QF14-335	Keppel Academy	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.11
California PV Energy, LLC	N/A QF14-329	Keppel Alpine North ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.12
California PV Energy, LLC	N/A QF14-331	Keppel Alpine South ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.05
California PV Energy, LLC	N/A QF14-330	Keppel Antelope ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.09

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
California PV Energy, LLC	N/A QF14-333	Keppel Gibson ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.15
California PV Energy, LLC	N/A QF14-332	Keppel Lake Los Angeles	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.13
California PV Energy, LLC	N/A QF14-334	Keppel Pearblossom ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.13
California PV Energy, LLC	N/A QF14-213	Live Oak Elementary School,	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Apr-2014	0.12
California PV Energy, LLC	N/A QF15-81	Los Osos HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Feb-2015	0.76
California PV Energy, LLC	N/A QF14-321	Marie Kerr Park E1	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.07
California PV Energy, LLC	N/A QF14-322	Marie Kerr Park E2	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.06
California PV Energy, LLC	N/A QF14-323	Marie Kerr Park E3	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.05
California PV Energy, LLC	N/A QF15-82	Montclair HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Feb-2015	0.76
California PV Energy, LLC	N/A QF14-211	Northlake Hills Elementary School	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Apr-2014	0.13
California PV Energy, LLC	N/A QF13-602	Oltmans SCE at Champagne	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Dec-2013	1.15
California PV Energy, LLC	N/A QF13-601	Oltmans SCE at Jurupa	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Dec-2013	1.71
California PV Energy, LLC	N/A QF15-83	Ontario HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Dec-2014	0.33
California PV Energy, LLC	N/A QF14-325	Palmdale Cultural Center	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.06
California PV Energy, LLC	N/A QF14-324	Palmdale Development Services Bldg	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.12
California PV Energy, LLC	N/A QF14-326	Palmdale Library	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.07
California PV Energy, LLC	N/A QF14-328	Palmdale Recreation Center	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.05
California PV Energy, LLC	N/A QF14-327	Palmdale Water Park	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Jul-2014	0.28
California PV Energy, LLC	N/A QF15-84	Rancho Cucamonga HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	Dec-2014	0.42
Constellation Solar California, LLC	N/A QF10-656	General Motors Corp. at Fontana, Ca.	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	Dec-2007	0.80
Constellation Solar California, LLC	N/A QF10-657	GSA, PBS, Pacific Service Center at Sacramento, Ca.	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	Mar-2008	0.44
Constellation Solar California, LLC	N/A QF10-658	Kawneer Co., Inc. (Alcoa)	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	Oct-2007	0.50
Constellation Solar California, LLC	N/A QF10-665	Univ of San Francisco	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	Apr-2008	0.42
Luz Solar Partners IV	N/A QF86-736	SEGS IV SF	Luz Solar Partners IV	Luz Solar Partners IV	N/A	CAISO	Southwest	Dec-1986	33.00
Luz Solar Partners V	N/A QF87-402	SEGS V SF	Luz Solar Partners V	Luz Solar Partners V	N/A	CAISO	Southwest	Oct-1987	24.00
Luz Solar Partners VI	N/A QF88-33	SEGS VI SF	Luz Solar Partners VI	Luz Solar Partners VI	N/A	CAISO	Southwest	Dec-1988	34.00
Exelon Generation Company, LLC	ER00-3251	Green Country 1	Green Country OP Services LLC	Exelon Generation Company, LLC	2/11/2002	SPP	SPP	Feb-2002	262.00
Exelon Generation Company, LLC	ER00-3251	Green Country 2	Green Country OP Services LLC	Exelon Generation Company, LLC	2/11/2002	SPP	SPP	Feb-2002	262.00
Exelon Generation Company, LLC	ER00-3251	Green Country 3	Green Country OP Services LLC	Exelon Generation Company, LLC	2/11/2002	SPP	SPP	Feb-2002	261.00
Exelon Wind 1, LLC	N/A QF05-114	Exelon Wind 1 WF	Exelon Wind 1, LLC	Exelon Wind 1, LLC	N/A	SPP	SPP	Dec-2005	10.00
Exelon Wind 10, LLC	N/A QF07-55	Exelon Wind 10 WF	Exelon Wind 10, LLC	Exelon Wind 10, LLC	N/A	SPP	SPP	Jul-2008	10.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Wind 11, LLC	N/A QF07-56	Exelon Wind 11 WF	Exelon Wind 11, LLC	Exelon Wind 11, LLC	N/A	SPP	SPP	Jul-2008	10.00
Exelon Wind 2, LLC	N/A QF05-116	Exelon Wind 2 WF	Exelon Wind 2, LLC	Exelon Wind 2, LLC	N/A	SPP	SPP	Dec-2005	10.00
Exelon Wind 3, LLC	N/A QF05-115	Exelon Wind 3 WF	Exelon Wind 3, LLC	Exelon Wind 3, LLC	N/A	SPP	SPP	Dec-2005	10.00
Exelon Wind 4, LLC	ER07-1202 QF03-13	Exelon Wind 4 WF	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	Dec-2006	79.80
Exelon Wind 5, LLC	N/A QF06-289	Exelon Wind 5 WF	Exelon Wind 5, LLC	Exelon Wind 5, LLC	N/A	SPP	SPP	Oct-2005	10.00
Exelon Wind 6, LLC	N/A QF06-290	Exelon Wind 6 WF	Exelon Wind 6, LLC	Exelon Wind 6, LLC	N/A	SPP	SPP	Nov-2006	10.00
Exelon Wind 7, LLC	N/A QF07-46	Exelon Wind 7 WF	Exelon Wind 7, LLC	Exelon Wind 7, LLC	N/A	SPP	SPP	Jul-2008	10.00
Exelon Wind 8, LLC	N/A QF07-53	Exelon Wind 8 WF	Exelon Wind 8, LLC	Exelon Wind 8, LLC	N/A	SPP	SPP	Jul-2008	10.00
Exelon Wind 9, LLC	N/A QF07-54	Exelon Wind 9 WF	Exelon Wind 9, LLC	Exelon Wind 9, LLC	N/A	SPP	SPP	Jul-2008	10.00
Greensburg Wind Farm, LLC	N/A QF10-291	Greensburg WF	Greensburg Wind Farm, LLC	Greensburg Wind Farm, LLC	N/A	SPP	SPP	Mar-2010	12.50
High Plains Wind Power, LLC	N/A QF07-257	High Plains WF	High Plains Wind Power, LLC	High Plains Wind Power, LLC	N/A	SPP	SPP	Mar-2008	10.00
Shooting Star Wind Project, LLC	ER12-1829	Shooting Star WF	Shooting Star Wind Project, LLC	Shooting Star Wind Project, LLC	N/A	SPP	SPP	Sep-2012	104.00
Wildcat Wind, LLC	ER12-1223 QF12-412	Wildcat WF	Wildcat Wind, LLC	Wildcat Wind, LLC	N/A	SPP	SPP	Jul-2012	27.30

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Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas Storage

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
Constellation Mystic Power, LLC	Limited & discrete interconnection facilities[1]	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon Framingham, LLC	Limited & discrete interconnection facilities[1]	Exelon Framingham, LLC	Exelon Framingham, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon New Boston, LLC	Limited & discrete interconnection facilities[1]	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon West Medway, LLC	Limited & discrete interconnection facilities[1]	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon Wyman, LLC	Limited & discrete interconnection facilities[1]	Exelon Wyman, LLC	Exelon Wyman, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Holyoke Solar LLC	Limited & discrete interconnection facilities[1]	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Nine Mile Point Nuclear Station, LLC	Limited & discrete interconnection facilities[1]	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	N/A (OATT Waiver)

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
R.E. Ginna Nuclear Power Plant, LLC	Limited & discrete interconnection facilities[1]	R.E. Ginna Nuclear Power Plant, LLC	R.E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	N/A (OATT Waiver)
Baltimore Gas and Electric Company	Combined 115kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	695.85 combined miles
Baltimore Gas and Electric Company	Combined 138kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	54.44 combined miles
Baltimore Gas and Electric Company	Combined 230kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	320.97 combined miles
Baltimore Gas and Electric Company	Combined 500kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	217.42 combined miles
Baltimore Gas and Electric Company	Intrastate Gas Transmission	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	approx. 165 combined miles
Calvert Cliffs Nuclear Power Plant, LLC	Limited & discrete interconnection facilities[1]	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Commonwealth Edison Company	Electric Transmission Combined 765 kV Lines	Commonwealth Edison Company	PJM	N/A	PJM	Northeast	89.59 combined miles
Commonwealth Edison Company	Electric Transmission Combined 345 kV Lines	Commonwealth Edison Company	PJM	N/A	PJM	Northeast	2,634.29 combined miles

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
Commonwealth Edison Company	Electric Transmission Combined 138 kV Lines	Commonwealth Edison Company	PJM	N/A	PJM	Northeast	2,877.02 combined miles
Criterion Power Partners, LLC	Limited & discrete interconnection facilities[1]	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Exelon Solar Chicago LLC	Limited & discrete interconnection facilities[1]	Exelon Solar Chicago LLC	Exelon Solar Chicago LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Fourmile Wind Energy, LLC	Limited & discrete interconnection facilities[1]	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Handsome Lake Energy, LLC	Limited & discrete interconnection facilities[1]	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
PECO Energy Company	Electric Transmission 500 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	316.23 combined miles
PECO Energy Company	Electric Transmission Combined 200/220 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	503.05 combined miles
PECO Energy Company	Electric Transmission Combined 132 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	127.70 combined miles
PECO Energy Company	Electric Transmission Combined 66 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	169.54 combined miles

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
PECO Energy Company	Electric Transmission Combined 13.2 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	0.47 combined miles
PECO Energy Company	Intrastate Gas Transmission	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	31 combined miles
PECO Energy Company	Intrastate Gas Storage (LNG)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	1,200 mmcf
Cassia Gulch Wind Park, LLC	Limited & discrete interconnection facilities[1]	Cassia Gulch Wind Park, LLC	Cassia Gulch Wind Park, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
High Mesa Energy, LLC	Limited & discrete interconnection facilities[1]	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
Tuana Springs Energy, LLC	Limited & discrete interconnection facilities[1]	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
Beebe 1B Renewable Energy, LLC and Beebe Renewable Energy, LLC ("Beebe")[2]	Limited & discrete interconnection facilities[1]	Beebe	Beebe	N/A	MISO	Central	N/A (OATT Waiver)
Harvest Windfarm, LLC	Limited & discrete interconnection facilities[1]	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	N/A (OATT Waiver)
Michigan Wind 1, LLC	Limited & discrete interconnection facilities[1]	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	N/A (OATT Waiver)

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
CER Generation, LLC	Limited & discrete interconnection facilities[1]	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	N/A (OATT Waiver)
Constellation Power Source Generation, LLC	Limited & discrete interconnection facilities[1]	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Exelon Generation Company, LLC	Limited & discrete interconnection facilities[1]	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	Various	Various	N/A (OATT Waiver)
Cow Branch Wind Power, L.L.C.	Limited & discrete interconnection facilities[1]	Cow Branch Wind Power, LLC	Cow Branch Wind Power, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
CR Clearing, LLC	Limited & discrete interconnection facilities[1]	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
Wind Capital Holdings, LLC	Limited & discrete interconnection facilities[1]	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
AV Solar Ranch 1, LLC	Limited & discrete interconnection facilities[1]	AV Solar Ranch 1, LLC	AV Solar Ranch 1, LLC	N/A	CAISO	Southwest	N/A (OATT Waiver)
Exelon Wind 4, LLC	Limited & discrete interconnection facilities[1]	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	N/A (OATT Waiver)

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[1] These facilities are included because waiver of Order Nos. 888, 889, 890, their implementing regulations, and the requirements of Part 358 of FERC's regulations has been sought with respect to them.

[2] Beebe 1B Renewable Energy, LLC and Beebe Renewable Energy, LLC share certain interconnection facilities.

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ATTACHMENT C

ASSET APPENDICES OF EDF, INC.

ONLY affiliated with the following Exelon MBR Entities:
Calvert Cliffs Nuclear Power Plant, LLC,
Nine Mile Point Nuclear Station, LLC, and
R.E> Ginna Nuclear Power Plant, LLC

Affiliates with Market-Based Rate Authority and Generation Assets[1]

Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Location		In-service Date	Nameplate and/or Seasonal Rating
						Balancing Authority Area	Geographic Region (per Appendix D)		
EDF Trading North America, LLC	ER03-774	N/A	EDF Trading Holdings LLC	EDF Trading Holdings LLC	10/31/2008	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)
EDF Industrial Power Services (CA), LLC	ER12-1825	N/A	EDF Trading North America, LLC	EDF Trading North America, LLC	N/A	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)
EDF Industrial Power Services (IL), LLC	ER10-1424	N/A	EDF Trading North America LLC	EDF Trading North America LLC	N/A	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)
EDF Industrial Power Services (NY), LLC	ER10-1425	N/A	EDF Trading North America LLC	EDF Trading North America LLC	N/A	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)
EDF Industrial Power Services (OH), LLC	ER13-1680	N/A	EDF Trading North America LLC	EDF Trading North America LLC	N/A	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)
EDF Energy Services, LLC	ER14-2672	N/A	EDF Trading North America LLC	EDF Trading North America LLC	N/A	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)	N/A (power marketer)

[1] Excludes assets outside the continental U.S and within ERCOT.

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Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Location		In-service Date	Nameplate and/or Seasonal Rating
						Balancing Authority Area	Geographic Region (per Appendix D)		
Champion Energy Marketing LLC	ER08-836	N/A	Champion Energy Holdings, LLC & EDF Trading North America, LLC	Champion Energy Holdings, LLC	N/A	N/A	N/A	N/A	N/A
Champion Energy Services, LLC	ER10-3049	N/A	Champion Energy Marketing LLC	Champion Energy Marketing LLC	N/A	N/A	N/A	N/A	N/A
Champion Energy, LLC	ER10-3051	N/A	Champion Energy Marketing LLC	Champion Energy Marketing LLC	N/A	N/A	N/A	N/A	N/A
Anahau Energy, LLC	ER13-415	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Allendale Biomass, LLC	N/A	N/A	Allendale Biomass	Allendale Biomass	N/A	Santee Cooper	Southeast	10/1/13	19.3
Alta Mesa Phase III Partners	N/A	N/A	Alta Mesa	Alta Mesa	N/A	CAISO	Southwest	2/1995	9.5
Bellevue Solar, LLC	ER11-4380-000	N/A	Bellevue Solar	Bellevue Solar	N/A	PGE	Northwest	10/26/2011	1.66

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Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Location		In-service Date	Nameplate and/or Seasonal Rating
						Balancing Authority Area	Geographic Region (per Appendix D)		
Buffalo Ridge Wind Farm, LLC	N/A	N/A	Buffalo Ridge Wind Farm, LLC	Buffalo Ridge Wind Farm, LLC	N/A	MISO	Central	12/18/2003	1.5
Catalina Solar Lessee, LLC	ER13-1562-000	N/A	Catalina Solar, LLC	N/A	N/A	CAISO	Southwest	2013	110
Champepadan Wind Power Partners, LLC	N/A	N/A	Champepadan	Champepadan	N/A	MISO	Central	12/19/2001	1.98
Chanarambie Power Partners, LLC	ER03-1340-000	N/A	Chanarambie	Chanarambie	N/A	MISO	Central	12/15/2003	85.5
Chestnut Flats Lessee, LLC	ER13-1641-000	N/A	Chestnut Flats Wind, LLC	N/A	9/30/13	PJM	Northeast	12/29/11	38
DifWind Farms LTD VI	N/A	N/A	DifWind VI	DifWind VI	N/A	CAISO	Southwest	12/31/1984	26.8
DifWind Farms LTD VII	N/A	N/A	DifWind VII	DifWind VII	N/A	CAISO	Southwest	1/1/1985	23
DifWind Farms LTD VIII	N/A	N/A	DifWind VIII	DifWind VIII	N/A	CAISO	Southwest	12/31/1986	15
DifWind Farms LTD IX	N/A	N/A	DifWind IX	DifWind IX	N/A	CAISO	Southwest	1/1/1985	15
Dorchester Biomass, LLC	N/A	N/A	Dorchester Biomass	Dorchester Biomass	N/A	Santee Cooper	Southeast	10/1/13	19.3

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Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Location		In-service Date	Nameplate and/or Seasonal Rating
						Balancing Authority Area	Geographic Region (per Appendix D)		
EDF Renewable Wind Farm IV	N/A	N/A	EDF Renewable Wind Farm IV	EDF Renewable Wind Farm IV	N/A	CAISO	Southwest	12/31/1988	18.7
EDF Renewable Wind Farm V, Inc.	N/A	N/A	EDF Renewable Wind Farm V	EDF Renewable Wind Farm V	N/A	CAISO	Southwest	1989	16.2
Fenton Power Partners I, LLC	ER07-357-000	N/A	Fenton Power Partners	Fenton Power Partners	N/A	MISO	Central	11/13/2007	205.5
Hoosier Wind Project, LLC	ER09-1181-000	N/A	Hoosier Wind Project	Hoosier Wind Project	N/A	MISO	Central	11/2009	106
Moulton Heights Wind Power Project, LLC	N/A	N/A	Moulton Heights	Moulton Heights	N/A	MISO	Central	12/18/2003	1.5
Moulton Wind Power Partners, LLC	N/A	N/A	Moulton Wind	Moulton Wind	N/A	MISO	Central	12/19/2001	1.98
Muncie Power Partners, LLC	N/A	N/A	Muncie Power	Muncie Power	N/A	MISO	Central	12/18/2003	1.5
North Ridge Wind Farm, LLC	N/A	N/A	North Ridge	North Ridge	N/A	MISO	Central	12/18/2003	1.5
Oasis Power Partners, LLC	ER05-41-000	N/A	Oasis Power	Oasis Power	N/A	CAISO	Southwest	12/24/2004	60
Pacific Wind Lessee, LLC	ER12-1931-000	N/A	Pacific Wind, LLC	Pacific Wind Lessee, LLC	N/A	CAISO	Southwest	8/16/2012	140

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Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Location		In-service Date	Nameplate and/or Seasonal Rating
						Balancing Authority Area	Geographic Region (per Appendix D)		
Patterson Pass Wind Farm LLC	N/A	N/A	Patterson Pass	Patterson Pass	N/A	CAISO	Southwest	3/1995	21.7
Sacramento Soleil, LLC	N/A	N/A	Sacramento Soleil	Sacramento Soleil	N/A	CAISO	Southwest	7/14/2008	1
Shiloh Wind Project 2, LLC	ER08-1237-000	N/A	Shiloh 2	Shiloh 2	N/A	CAISO	Southwest	1/30/2009	150
Shiloh III Lessee, LLC	ER12-610-009	N/A	Shiloh III Wind Project, LLC	Shiloh III Lessee	2/16/12	CAISO	Southwest	12/22/11	100
Shiloh IV Lessee, LLC	ER13-338-000	N/A	Shiloh IV Wind Project	Shiloh IV Lessee	12/27/12	CAISO	Southwest	12/21/2012	102.5
Spearville 3, LLC	ER12-2037-000	N/A	Spearville 3, LLC	Spearville 3, LLC	N/A	KCPL	SPP	10/1/2012	100.8
Spinning Spur Wind, LLC	ER12-2314	N/A	Spinning Spur Wind, LLC	Spinning Spur Wind, LLC	N/A	SPS	SPP	12/20/2012	161
Vandy South Project, LLC	N/A	N/A	Vandy South	Vandy South	N/A	MISO	Central	12/18/2003	1.5
Viking Wind Farm, LLC	N/A	N/A	Viking	Viking	N/A	MISO	Central	12/18/2003	1.5
Vindy Power Partners, LLC	N/A	N/A	Vindy South	Vindy South	N/A	MISO	Central	12/18/2003	1.5

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Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Location		In-service Date	Nameplate and/or Seasonal Rating
						Balancing Authority Area	Geographic Region (per Appendix D)		
Wapsipinicon Wind Project, LLC	ER08-1288-000	N/A	Wapsipinicon	Wapsipinicon	N/A	MISO	Central	2/20/2009	100.5
Wilson-West Wind Farm, LLC	N/A	N/A	Wilson-West	Wilson-West	N/A	MISO	Central	12/18/2003	1.5
Yamhill Solar, LLC	ER11-4381-000	N/A	Yamhill Solar	Yamhill Solar	N/A	PGE	Northwest	10/26/2011	1.19
Calvert Cliffs Nuclear Power Plant LLC	ER00-2917-000	Calvert Cliffs Nuclear Power Plant (Unit 1)	Calvert Cliffs Nuclear Power Plant LLC	Calvert Cliffs Nuclear Power Plant LLC	11/6/2009	PJM Interconnection	Northeast	1975	873
Calvert Cliffs Nuclear Power Plant LLC	ER00-2917-000	Calvert Cliffs Nuclear Power Plant (Unit 2)	Calvert Cliffs Nuclear Power Plant LLC	Calvert Cliffs Nuclear Power Plant LLC	11/6/2009	PJM Interconnection	Northeast	1977	862
R.E. Ginna Unit 1 Nuclear Power Plant, LLC	ER04-485-000	Ginna	R.E. Ginna Unit 1 Nuclear Power Plant, LLC	R.E. Ginna Unit 1 Nuclear Power Plant, LLC	11/6/2009	NYISO	Northeast	1970	582
Nine Mile Point Nuclear Station, LLC	ER01-1654-000	Nine Mile Point (Unit 1)	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	11/6/2009	NYISO	Northeast	1969	627
Nine Mile Point Nuclear Station, LLC	ER01-1654-000	Nine Mile Point (Unit 2)	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	11/6/2009	NYISO	Northeast	1988	1287.2
Tanner Street Generation, LLC	ER11-3642-000	Tanner Street Facility	Tanner Street Generation, LLC	Tanner Street Generation, LLC	7/1/2011	ISO-NE	Northeast	7/2008	80 MW (net winter)

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Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas Storage Facilities

Filing Entity and its Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per Appendix D)	
Oasis Power Partners, LLC	Sagebrush Line – used to connect wind power generation in Tehachapi Region to So. Cal. Edison substation	Sagebrush Partners	Sagebrush Partners	N/A	CAISO	Southwest	46-mile, 230kV
Pacific Wind Lessee, LLC and Catalina Solar	Antelope Valley Line (230 kV gen tie line)	Catalina Solar, LLC and affiliates	Catalina Solar and affiliates	N/A	CAISO	Southwest	10.55-mile for one 230 kV line and approximately 14-mile for the other 230 kV line

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April 30, 2015

VIA E-TARIFF FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: AV Solar Ranch 1, LLC, Docket No. ER12-2178-___
Baltimore Gas and Electric Company, Docket No. ER10-2172-___
Beebe 1B Renewable Energy, LLC, Docket No. ER14-2144-___
Beebe Renewable Energy, LLC, Docket No. ER12-2311-___
Calvert Cliffs Nuclear Power Plant, LLC, Docket No. ER10-2179-___
Cassia Gulch Wind Park, LLC, Docket No. ER11-2016-___
CER Generation, LLC, Docket No. ER10-2184-___
Commonwealth Edison Company, Docket No. ER10-1048-___
Constellation Energy Commodities Group Maine, LLC, Docket No. ER10-2192-__
Constellation Energy Services, Inc., Docket No. ER15-1537-___
Constellation Energy Services of New York, Inc., Docket No. ER15-1539-___
Constellation Mystic Power, LLC, Docket No. ER11-2056-___
Constellation NewEnergy, Inc., Docket No. ER10-2178-___
Constellation Power Source Generation, LLC, Docket No. ER14-1524-___
Cow Branch Wind Power, LLC, Docket No. ER11-2014-___
CR Clearing, LLC, Docket No. ER11-2013-___
Criterion Power Partners, LLC, Docket No. ER10-3308-___
Exelon Framingham, LLC, Docket No. ER10-1020-___
Exelon Generation Company, LLC, Docket No. ER13-1536-___
Exelon New Boston, LLC, Docket No. ER10-1078-___
Exelon West Medway, LLC, Docket No. ER10-1080-___
Exelon Wind 4, LLC, Docket No. ER11-2010-___
Exelon Wyman, LLC, Docket No. ER10-1081-___
Fourmile Wind Energy, LLC, Docket No. ER14-2145-___
Handsome Lake Energy, LLC, Docket No. ER10-2180-___
Harvest II Windfarm, LLC, Docket No. ER12-2201-___
Harvest Windfarm, LLC, Docket No. ER11-2011-___

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High Mesa Energy, LLC, Docket No. ER12-2528-___
Michigan Wind 1, LLC, Docket No. ER11-2009-___
Michigan Wind 2, LLC, Docket No. ER11-3989-___
Nine Mile Point Nuclear Station, LLC, Docket No. ER10-2181-___
PECO Energy Company, Docket No. ER14-767-___
R.E. Ginna Nuclear Power Plant, LLC, Docket No. ER10-2182-___
Shooting Star Wind Project, LLC, Docket No. ER12-1829-___
Tuana Springs Energy, LLC, Docket No. ER11-2007-___
Wildcat Wind, LLC, Docket No. ER12-1223-___
Wind Capital Holdings, LLC, Docket No. ER11-2005-___

Notice of Change in Status and Tariff Revisions of the Exelon MBR Entities

Dear Secretary Bose:

Pursuant to the requirements of section 35.42 of the regulations of the Federal Energy Regulatory Commission (FERC or Commission),[1] the above-captioned affiliates of Exelon Corporation (Exelon) with market-based rate authority (the Exelon MBR Entities) submit this notice of change in status to inform the Commission that as of April 1, 2015, the Exelon MBR Entities could be deemed to have acquired control over additional generation in the Northwest region as a result of a transaction described below. In addition, certain of the Exelon MBR Entities specified below submit revisions to their market-based rate tariffs (Tariffs) to update their seller category designation and make additional ministerial changes, and respectfully request an effective date of April 1, 2015 for such revisions.

I. DESCRIPTION OF CHANGE IN STATUS

Exelon Generation Company, LLC (Exelon Generation) is a direct, wholly-owned subsidiary of Exelon that has Commission-granted market-based rate authority.[2] Exelon Generation entered into an agreement (Transaction) with J.P. Morgan Ventures Energy Corporation (JPMVEC) that will result in Exelon Generation being assigned JPMVEC's rights and obligations under certain contracts for the purchase and sale of the output of the Stateline Wind Energy Project (Stateline Project). The Stateline Project is a wind-powered electric generation facility with approximately 300 MW aggregate nameplate capacity located in the states of Oregon and Washington within the PacifiCorp-West (PACW) balancing authority area (BAA). The Stateline Project is owned and operated by FPL Energy Vansycle, LLC (Vansycle), which sells the output of the facility at market-based rates.[3]

1 18 C.F.R. § 35.42 (2014).

2 *Exelon Generating Co.*, 93 FERC ¶ 61,140 (2000), *reh'g denied*, 95 FERC ¶ 61,309 (2001).

3 *See FPL Energy Vansycle, LLC*, Docket No. ER01-838-000 (letter order issued Feb. 15, 2001) (granting market-based rate authority).

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Prior to the Transaction, JPMVEC purchased from Vansycle the entire output of the Stateline Project and resold a combined total of 290 MW to Bonneville Power Administration (BPA), Eugene Water & Electric Board, and Seattle City Light (collectively, Buyers) pursuant to long-term agreements. As a result of the Transaction, Exelon Generation will purchase from Vansycle the entire output of the Stateline Project and resell a combined total of 290 MW to the Buyers. Accordingly, only about 10 MW of uncommitted generation capacity will be added to the total uncommitted generation capacity owned or controlled by Exelon Generation and its affiliates in the PACW BAA[4] as a result of the Transaction.

Exelon Generation has not yet received consents to assign all of the contracts affected by the Transaction, but under the terms of the Transaction Exelon Generation began receiving the economic benefits and being exposed to the economic risks associated with the purchase and sale of the output of the Stateline Project as of April 1, 2015, and could be deemed to "control" the output of the Stateline Project as of that date. Therefore, for purposes of this notice of change in status, Exelon Generation is conservatively treating the Transaction as closed as of April 1, 2015.

II. ANALYSIS OF CHANGE IN STATUS

The change in status described in this notice does not change the conclusion that the Exelon MBR Entities continue to satisfy the Commission's test for determining whether to grant a public utility market-based rate authority. As demonstrated in Attachment A, the Exelon MBR Entities pass both the pivotal supplier screen (PSS) and market share screen (MSS) taking into account the small net increase in uncommitted generation capacity. The Exelon MBR Entities pass the PSS in the PACW BAA because the Exelon MBR Entities' net uncommitted capacity (126 MW) is significantly less than the market net uncommitted supply (1,647 MW).[5] The Exelon MBR Entities also pass the MSS in the PACW BAA because the Exelon MBR Entities' market share ranges from 4.7% (Summer) to 6.0% (Winter), well below the 20% threshold. Because the Exelon MBR Entities pass both the PSS and MSS, the Exelon MBR Entities continue to satisfy the Commission's test for determining whether to grant a public utility market-based rate authority.

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4 The Stateline Project is electrically interconnected with the BPA BAA in addition to the PACW BAA. However, the full capacity of the BPA interconnection (90 MW) is used for the long-term sales to BPA from the Stateline Project. In addition, except for the 4.8 MW owned by Outback Solar, LLC—which are fully committed—none of the Exelon MBR Entities or any of their affiliates owns or controls any generation in the BPA BAA. Moreover, the Simultaneous Transmission Import Limit (SIL) values for imports into the BPA BAA are zero. *See Puget Sound Energy, Inc.*, 147 FERC ¶ 61,021 (2014). In any event, as shown in the attached market power screens analyzing the PACW BAA market, all other generation located within markets first-tier to the BPA BAA that is owned or controlled by the Exelon MBR Entities or their affiliates is fully committed, other than the uncommitted 10 MW from the Stateline Project, a *de minimis* amount. Therefore, the Exelon MBR Entities have not produced separate screens analyzing the BPA BAA market.

5 In the PACW BAA, the Exelon MBR Entities used to be affiliated with CER Generation II, LLC (CER II), which owned and operated an approximately 189 MW generation facility located in West Valley City, Utah. All of the interests in CER II were sold to an unaffiliated third party in a transaction authorized by the Commission in Docket No. EC15-2-000 and consummated on December 3, 2014.

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Because the Transaction involves only the purchase and sale of power and does not involve any transmission or distribution facilities or inputs to electric power production as defined in 18 C.F.R. §35.36, there have been no changes with respect to the Exelon MBR Entities' lack of transmission market power or their lack of ability to erect barriers to entry that would affect the Commission's prior finding that the Exelon MBR Entities lack vertical market power. To the extent necessary, the Exelon MBR Entities confirm that they have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market. Therefore, the Exelon MBR Entities continue to qualify for market-based rate authority.

As required by 18 C.F.R. § 35.42, attached hereto is an updated asset appendix listing (1) all affiliates that have market-based rate authority and identifying all generation assets owned or controlled by Exelon or its affiliates by BAA and geographic region, and (2) all electric transmission and natural gas intrastate pipelines and/or gas storage facilities owned or controlled by Exelon or its affiliates (Attachment B).[6]

III. TARIFF REVISIONS, EFFECTIVE DATE AND WAIVER

Exelon Generation, Constellation Energy Commodities Group Maine, LLC, Constellation NewEnergy, Inc., Constellation Energy Services, Inc.,[7] Constellation Energy Services of New York, Inc.,[8] Cassia Gulch Wind Park, LLC (Cassia Gulch), High Mesa Energy, LLC (High Mesa), and Tuana Springs Energy, LLC (Tuana Springs) (collectively, the Exelon NW Sellers)[9] have revised their Tariffs in several ministerial respects and have included herewith "redlined" versions of the Tariffs in Attachment C. The Exelon NW Sellers have submitted "clean" Tariffs in RTF format with metadata attached through the Commission's eTariff system. The Tariff revisions include:

- Updated ancillary services language to match the FERC-approved, standard ancillary services language;
- Updated language regarding compliance with Commission regulations to match the FERC-approved, standard compliance language;
- Elimination of Order No. 614 formatting and removal of the legal name of the market-based rate seller, which is now reflected in the CID; and

6 18 C.F.R. § 35.42(c) (2014).

7 Constellation Energy Services, Inc. was formerly known as Integrys Energy Services, Inc. A notice of succession reflecting the change in name was filed in Docket No. ER15-1537-000.

8 Constellation Energy Services of New York, Inc. was formerly known as Integrys Energy Services of New York, Inc. A notice of succession reflecting the change in name was filed in Docket No. ER15-1539-000.

9 The Exelon NW Sellers are the subset of Exelon MBR Entities that are either power marketers or own or control generation within the Northwest region.

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- Revised seller category classifications. Currently, the effective Tariffs reflect category 1 seller status in the Northwest region. However, as of the April 1, 2015, Exelon Generation could be deemed to "control" the output of the Stateline Project pursuant to the Transaction, which results in Exelon Generation and its affiliates owning and/or controlling more than 500 MW of generation in the Northwest region. Therefore, the Exelon NW Sellers are updating their Tariffs to reflect that they are category 2 sellers in the Northwest region.

  In addition, Cassia Gulch, High Mesa, and Tuana Springs have revised their seller category classifications to reflect that they are category 1 sellers in the Central, Northeast, Southeast, Southwest, and Southwest Power Pool (SPP) regions.[10] Currently, their Tariffs reflect category 2 status in the Central, Northeast, Southeast, and SPP regions due to their affiliation with entities that own or control, collectively, over 500 MW of generation in those regions. However, Cassia Gulch, High Mesa, and Tuana Springs do not themselves own or control any generation in any region outside of the Northwest region. Likewise, Cassia Gulch, High Mesa, and Tuana Springs do not own, operate, or control transmission facilities other than limited equipment necessary to interconnect their individual generating facilities to the transmission grid. Further, Cassia Gulch, High Mesa, and Tuana Springs are not affiliated with any entity that owns, operates or controls transmission facilities or is a franchised public utility in the same region as their generation assets. Finally, Cassia Gulch, High Mesa, and Tuana Springs do not raise other vertical market power issues. For these reasons, Cassia Gulch, High Mesa, and Tuana Springs respectfully request a determination that they meet the criteria for classification as a category 1 seller in the Central, Northeast, Southeast, Southwest, and SPP regions.

The Exelon MBR Entities respectfully ask that the Commission accept this notice and the updated Tariffs for filing, effective April 1, 2015. To the extent necessary, the Exelon NW Sellers request waiver of the 60-day prior notice requirement pursuant to Section 35.11 of the Commission's regulations[11] in order to permit the revised Tariffs to become effective April 1, 2015. Good cause for such waiver exists because the Commission generally finds a waiver of notice requirements "appropriate when an uncontested filing has no rate impact."[12] The Exelon NW Sellers' tariff revisions specified in this filing have no impact on rates since no substantive changes have been made to the Tariffs. The Commission routinely grants waiver of its notice requirements in similar circumstances.[13]

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[10] Cassia Gulch, High Mesa, and Tuana Springs are already classified as category 1 sellers in the Southwest region.

[11] 18 C.F.R. § 35.11 (2014).

[12] *Cent. Hudson Gas & Elec. Corp.*, 61 FERC ¶ 61,089, at 61,354 (1992).

[13] *See, e.g.*, *New Brunswick Energy Mktg. Corp.*, Docket No. ER14-225-000 (issued Dec. 18, 2013) (delegated letter order accepting a Notice of Succession and corresponding revised tariff reflecting the successor's name filed Oct. 30, 2013 and granting the requested effective date of Oct. 1, 2013, the effective

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IV. COMMUNICATIONS

Communications concerning this notice should be directed to the following persons:

Vincenzo Franco*
Assistant General Counsel – Wholesale
Trading Compliance
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*The persons denoted with an asterisk are designated for service pursuant to 18 C.F.R. § 385.2010.

V. DOCUMENTS SUBMITTED WITH FILING

The Exelon MBR Entities submit the following documents:

1. This transmittal letter;
2. Attachment A: Pivotal supplier and market share screens;
3. Attachment B: Asset appendices of Exelon Corporation and affiliates; and
4. Attachment C: Redlined tariffs.

VI. CONCLUSION

For the reasons set forth above, the change in status described herein does not materially change the facts and circumstances that the Commission relied upon in granting the Exelon MBR Entities market-based rate authority. Therefore, the Exelon MBR Entities respectfully request that the Commission accept for filing this notice of change in status. Further, the Exelon NW Sellers also request that the Commission accept the included Tariff revisions, waive any

date of the name change); *Pastoria Energy Facility, L.L.C.*, Docket No. ER12- 2645-000 (unpublished delegated letter order issued Oct. 16, 2012).

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applicable prior notice requirements, and grant an effective date of April 1, 2015.

Thank you for your attention to this matter.

Respectfully submitted,

/s/ Jane E. Rueger
Jane E. Rueger
Harold W. Bulger, III

Counsel to
Exelon MBR Entities

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in these proceedings.

Dated at Washington, D.C., this 30th day of April, 2015.

/s/ Corey Neal

Corey Neal
White & Case LLP
701 Thirteenth Street, NW
Washington, D.C. 20005
Tel.: (202) 637-6195

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Attachment A:

Pivotal Supplier and Market Share Screens

Generation Affiliated with Exelon

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Balancing Authority Area/ RTO	Plant Name	Total Capacity (MW)		Ownership Share	Net Interest Owned/Purchased (MW)		Long Term (Sales) (MW)	
		Summer	Winter		Summer	Winter	Summer	Winter
PACW	**Vansycle (Stateline)**	**299.7**	**299.7**	**0%**	**299.7**	**299.7**	**(289.7)**	**(289.7)**
PACW	Big Top Windfarm	1.7	1.7	100%	1.7	1.7	(1.7)	(1.7)
PACW	Butter Creek Windfarm	5.0	5.0	100%	5.0	5.0	(5.0)	(5.0)
PACW	Four Corner Windfarm	10.0	10.0	100%	10.0	10.0	(10.0)	(10.0)
PACW	Four Mile Canyon Windfarm	10.0	10.0	100%	10.0	10.0	(10.0)	(10.0)
PACW	Oregon Trail Windfarm	9.9	9.9	100%	9.9	9.9	(9.9)	(9.9)
PACW	Pacific Canyon Windfarm	8.3	8.3	100%	8.3	8.3	(8.3)	(8.3)
PACW	Sand Ranch Windfarm	9.9	9.9	100%	9.9	9.9	(9.9)	(9.9)
PACW	Threemile Canyon Windfarm	9.9	9.9	100%	9.9	9.9	(9.9)	(9.9)
PACW	Wagon Trail Windfarm	3.3	3.3	100%	3.3	3.3	(3.3)	(3.3)
PACW	Ward Butte Windfarm	6.6	6.6	100%	6.6	6.6	(6.6)	(6.6)
Total, PACW		374.3	374.3		374.3	374.3	(364.3)	(364.3)
First-Tier Markets								
PACE	Sunnyside	51.0	51.0	50%	51.0	51.0	(51.0)	(51.0)
BPA	Outback Solar	4.4	4.4	100%	4.4	4.4	(4.4)	(4.4)
CAISO	2014 ESA Project Company, LLC	7.4	7.4	100%	7.4	7.4	(7.4)	(7.4)
CAISO	Antelope Valley SF (AV Solar 1)	241.5	241.5	100%	241.5	241.5	(241.5)	(241.5)
CAISO	Alto Loma HS	0.56	0.56	100%	0.56	0.56	-	-
CAISO	Castaic Elementary School	0.12	0.12	100%	0.12	0.12	-	-
CAISO	Castaic Middle School	0.28	0.28	100%	0.28	0.28	-	-
CAISO	Chaffey HS	0.54	0.54	100%	0.54	0.54	-	-
CAISO	Colony HS	0.76	0.76	100%	0.76	0.76	-	-
CAISO	Etiwanda HS	0.72	0.72	100%	0.72	0.72	-	-
CAISO	Ironhouse Sanitary District	0.85	0.85	100%	0.85	0.85	-	-
CAISO	Keppel Academy	0.11	0.11	100%	0.11	0.11	-	-
CAISO	Keppel Alpine North ES	0.12	0.12	100%	0.12	0.12	-	-
CAISO	Keppel Alpine South ES	0.05	0.05	100%	0.05	0.05	-	-
CAISO	Keppel Antelope ES	0.09	0.09	100%	0.09	0.09	-	-
CAISO	Keppel Gibson ES	0.15	0.15	100%	0.15	0.15	-	-
CAISO	Keppel Lake Los Angleles	0.13	0.13	100%	0.13	0.13	-	-
CAISO	Keppel Pearblossom ES	0.13	0.13	100%	0.13	0.13	-	-
CAISO	Live Oak Elementary School	0.12	0.12	100%	0.12	0.12	-	-
CAISO	Los Osos HS	0.76	0.76	100%	0.76	0.76	-	-
CAISO	Marie Kerr Park E1	0.07	0.07	100%	0.07	0.07	-	-
CAISO	Marie Kerr Park E2	0.06	0.06	100%	0.06	0.06	-	-
CAISO	Marie Kerr Park E3	0.05	0.05	100%	0.05	0.05	-	-
CAISO	Montclair HS	0.76	0.76	100%	0.76	0.76	-	-
CAISO	Northlake Hills Elementary School	0.13	0.13	100%	0.13	0.13	-	-
CAISO	Oltmans SCE at Champagne SF	1.15	1.15	100%	1.15	1.15	-	-
CAISO	Oltmans SCE at Jurupa SF	1.71	1.71	100%	1.71	1.71	-	-
CAISO	Ontario HS	0.33	0.33	100%	0.33	0.33	-	-
CAISO	Palmdale Cultural Center	0.06	0.06	100%	0.06	0.06	-	-

Balancing Authority Area/ RTO	Plant Name	Total Capacity (MW)		Ownership Share	Net Interest Owned/Purchased (MW)		Long Term (Sales) (MW)	
		Summer	Winter		Summer	Winter	Summer	Winter
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CAISO	Palmdale Development Services Bldg	0.12	0.12	100%	0.12	0.12	-	-
CAISO	Palmdale Library	0.07	0.07	100%	0.07	0.07	-	-
CAISO	Palmdale Recreation Center	0.05	0.05	100%	0.05	0.05	-	-
CAISO	Palmdale Water Park	0.28	0.28	100%	0.28	0.28	-	-
CAISO	Rancho Cucamonga HS	0.42	0.42	100%	0.42	0.42	-	-
CAISO	General Motors Corp. at Fontana, Ca.	0.80	0.80	100%	0.80	0.80	-	-
CAISO	GSA, PBS, Pacific Service Center at Sacramento, Ca.	0.44	0.44	100%	0.44	0.44	-	-
CAISO	Kawneer Co., Inc. (Alcoa)	0.50	0.50	100%	0.50	0.50	-	-
CAISO	Univ of San Francisco	0.42	0.42	100%	0.42	0.42	-	-
CAISO	SEGS IV SF	36.0	34.0	100%	36.0	34.0	-	-
CAISO	SEGS V SF	36.0	34.0	100%	36.0	34.0	-	-
CAISO	SEGS VI SF	36.0	35.0	100%	36.0	35.0	-	-
IPCO	Cassia Gulch Windfarm	18.9	18.9	100%	18.9	18.9	(18.9)	(18.9)
IPCO	Cassia Wind Windfarm	10.5	10.5	100%	10.5	10.5	(10.5)	(10.5)
IPCO	High Mesa Windfarm	40.0	40.0	100%	40.0	40.0	(40.0)	(40.0)
IPCO	Bennett Creek Windfarm	21.0	21.0	100%	21.0	21.0	(21.0)	(21.0)
IPCO	Hot Springs Windfarm	21.0	21.0	100%	21.0	21.0	(21.0)	(21.0)
IPCO	Tuana Springs Windfarm	16.8	16.8	100%	16.8	16.8	(16.8)	(16.8)
Total, First-Tier		553.4	548.4		553.4	548.4	(432.5)	(432.5)

Ratings based on EIA-860 or Asset Appendix.

Part I -- Pivotal Supplier Analysis

Row	Generation	PACW MW	PACW Reference
			December 12 - November 13
	Seller and Affiliate Capacity		
A	Installed Capacity	374	Generation
B	Long-Term Firm Purchases	-	
C	Long-Term Firm Sales	(364)	Generation
D	Imported Power	116	Affiliated uncommitted capacity in first-tier markets
	Non-Affiliate Capacity		
E	Installed Capacity	3,862	WKp-Energy Velocity PACW Gen, less Row A above
F	Long-Term Firm Purchases	364	Offset, Row C
G	Long-Term Firm Sales	-	
H	Imported Power	1,294	147 FERC ¶ 61,021 (2014), less Row D above
I	Balancing Authority Area Reserve Requirement	(215)	7% of peak load, based on WECC requirement
J	Amount of Line I Attributable to Seller, if any	-	
K	Total Uncommitted Capacity	2,357	SUM A,B,C,D,E,F,G,H,I,M
	Load		
L	Balancing Authority Area Annual Peak Load	3,784	Estimated from PACW FERC Form 714 and PacifiCorp triennial
M	Average Daily Peak Native Load in Peak Month	(3,074)	Estimated from PACW FERC Form 714 and PacifiCorp triennial
N	Amount of Line M Attributable to Seller, if any	-	
O	Wholesale Load (SUM L,M)	710	
P	Net Uncommitted Supply (K-O)	1,647	
Q	Seller's Uncommitted Capacity	126	SUM A,B,C,D,J,N
Result of Pivotal Supplier Screen		**PASS**	Pass if Line Q < Line P Fail if Line Q > Line P

Part II -- Market Share Analysis

Row		PACW Winter (MW)	PACW Spring (MW)	PACW Summer (MW)	PACW Fall (MW)	Reference December 12 - November 13
	Seller and Affiliate Capacity					
A	Installed Capacity	374	374	374	374	Generation
B	Long-Term Firm Purchases	-	-	-	-	
C	Long-Term Firm Sales	(364)	(364)	(364)	(364)	Generation
D	Seasonal Average Planned Outages	-	-	-	-	
E	Imported Power	116	116	121	116	Affiliated uncommitted capacity in first-tier markets
	Capacity Deductions					
F	Average Peak Native Load in the Season	(3,084)	(2,621)	(2,647)	(2,681)	Estimated from PACW FERC Form 714 and PacifiCorp triennial
G	Amount of Line F Attributable to Seller, if any	-	-	-	-	
H	Amount of Line F Attributable to Others, if any	(3,084)	(2,621)	(2,647)	(2,681)	
I	Balancing Authority Area Reserve Requirement, if any	(216)	(184)	(185)	(188)	7% of peak load, based on WECC requirement
J	Amount of Line I Attributable to Seller, if any	-	-	-	-	
K	Amount of Line I Attributable to Others, if any	(216)	(184)	(185)	(188)	
	Non-Affiliate Capacity					
L	Installed Capacity	3,862	3,862	3,837	3,862	WKp-Energy Velocity PACW Gen, less Row A above
M	Long-Term Firm Purchases	364	364	364	364	Offset, Row C
N	Long-Term Firm Sales	-	-	-	-	
O	Local Seasonal Average Planned Outages	(28)	(263)	(25)	(203)	FERC Form 714
P	Uncommitted Capacity Imports	1,062	1,119	1,289	1,097	147 FERC ¶ 61,021 (2014), less Row E above
	Supply Calculation					
Q	Total Competing Supply	1,961	2,278	2,633	2,252	SUM L,M,N,O,P,H,K
R	Seller's Uncommitted Capacity	126	126	131	126	SUM A,B,C,D,E,G,J
S	Total Seasonal Uncommitted Capacity	2,087	2,404	2,764	2,377	SUM Q,R
T	**Seller's Market Share (R/S)**	6.0%	5.2%	4.7%	5.3%	
	Results	**PASS**	**PASS**	**PASS**	**PASS**	Pass if < 20% Fail if > 20%

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WORKPAPERS

EIA 860

2013 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Prime Mover	Unit Code	Ownership	Nameplate Capacity (MW)	Summer Capacity (MW)	Winter Capacity (MW)	Status	Synchronized to Transmission Grid	Operating Month	Operating Year
6607	FPL Energy Vansycle LLC	55560	FPL Energy Vansycle LLC (WA)	WA	Walla Walla	V-47	WT		S	176.9	176.9	176.9	OP		12	2001
6607	FPL Energy Vansycle LLC	55989	FPL Energy Vansycle LLC (OR)	OR	Umatilla	V-47	WT		S	122.8	122.8	122.8	OP		12	2001
21734	Sunnyside Cogeneration Assoc	50951	Sunnyside Cogen Associates	UT	Carbon	GEN1	ST		J	58.1	51.0	51.0	OP		2	1993
58083	Outback Solar, LLC	58131	Outback Solar At Christmas Valley	OR	Lake	PV1	PV		S	4.4	4.4	4.4	OP		10	2012
55711	Inc - SEGS	10440	SEGS IV	CA	San Bernardino	GEN1	ST		J	34.2	36.0	34.0	OP		12	1986
55711	Inc - SEGS	10441	SEGS V	CA	San Bernardino	GEN1	ST		J	34.2	36.0	34.0	OP		10	1987
55711	Inc - SEGS	10442	SEGS VI	CA	San Bernardino	GEN1	ST		J	35.0	36.0	35.0	OP		12	1988
56157	Cassia Gulch	56935	Cassia Gulch Wind Park LLC	ID	Twin Falls	1	WT		S	18.9	18.9	18.9	OP		3	2009
56158	Cassia Wind	56934	Cassia Wind Farm LLC	ID	Twin Falls	1	WT		S	10.5	10.5	10.5	OP		3	2009
56159	Threemile Canyon Wind I	56933	Threemile Canyon Wind I LLC	OR	Morrow	1	WT		S	9.9	9.9	9.9	OP		7	2009
57396	High Mesa Energy LLC	58019	High Mesa Energy LLC	ID	Twin Falls	1	WT		S	40.0	40.0	40.0	OP		12	2012
56475	Tuana Springs Energy LLC	57136	Tuana Springs	ID	Gooding	1	WT		S	16.8	16.8	16.8	OP		5	2010
56802	Echo 1	56971	Oregon Trail Windfarm LLC	OR	Umatilla	1	WT		S	9.9	9.9	9.9	OP		6	2009
56802	Echo 1	56972	Pacific Canyon Windfarm LLC	OR	Morrow	1	WT		S	8.3	8.3	8.3	OP		6	2009
56802	Echo 1	56973	Sand Ranch Windfarm LLC	OR	Morrow	1	WT		S	9.9	9.9	9.9	OP		6	2009
56802	Echo 1	56975	Ward Butte Windfarm LLC	OR	Umatilla	1	WT		S	6.6	6.6	6.6	OP		6	2009
56803	Echo 2	56969	Four Corners Windfarm LLC	OR	Umatilla	1	WT		S	10.0	10.0	10.0	OP		6	2009
56803	Echo 2	56970	Four Mile Canyon Windfarm LLC	OR	Morrow	1	WT		S	10.0	10.0	10.0	OP		6	2009
56804	Echo 3	56967	Butter Creek Power LLC	OR	Umatilla	1	WT		S	5.0	5.0	5.0	OP		6	2009
56804	Echo 3	56968	Big Top LLC	OR	Morrow	1	WT		S	1.7	1.7	1.7	OP		6	2009
56804	Echo 3	56974	Wagon Trail LLC	OR	Morrow	1	WT		S	3.3	3.3	3.3	OP		6	2009
11556	Malacha Hydro Ltd Partnership	10458	Muck Valley Hydroelectric	CA	LASSEN	GEN1	HY		S	29.9	29.9	29.9	OP		12	1988
56615	First Solar Energy LLC	57378	AV Solar Ranch One	CA	Los Angeles	AVSR	PV		W	253.0	230.0	230.0	2014	N	CHP	2
55890	Bennett Creek Windfarm LLC	56637	Bennett Creek Windfarm LLC	ID	Elmore	1	WT		S	21.0	21.0	21.0	OP		7	2008
55891	Hot Springs	56636	Hot Springs Windfarm LLC	ID	Elmore	1	WT		S	21.0	21.0	21.0	OP		5	2008

WKp-Energy Velocity PACW Gen

Unit Balancing Authority Area Abbrev	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Plant State	Unit	Unit ID	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PACE	Idaho Falls ID (City of)	Idaho Falls ID (City of	Idaho Falls ID (City of)	Upper Power Plant	Idaho	1	660194	100	1	1	1	HY	WAT	Retired	1/3/30	12/31/79
PACE	Idaho Falls ID (City of)	Idaho Falls ID (City of	Idaho Falls ID (City of)	Upper Power Plant	Idaho	2	660195	100	1	1	1	HY	WAT	Retired	1/3/36	12/31/79
PACW	Avista Corp	Avista Corp	Avista Corp	Lewiston (ID)	Idaho	1	632149	100	5	5	5	HY	WAT	Retired	1/1/27	1/1/73
PACW	Avista Corp	Avista Corp	Avista Corp	Lewiston (ID)	Idaho	2	632150	100	5	5	5	HY	WAT	Retired	1/1/27	1/1/73
PACW	Baker OR (City of)	Baker OR (City of)	Baker OR (City of)	Baker (OR)	Oregon	1	630536	100	0.2	0.2	0.2	HY	WAT	Operating	1/1/70	
PACW	Big Top LLC	Exelon Corp	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT1 27	1137851	3.7	1.648	1.648	1.648	WT	WND	Operating	6/27/09	
PACW	Biomass One LP	Brookfield Asset Man	Biomass One LP	Biomass One LP	Oregon	BBC	393928	100	10	8.5	8.5	ST	WDS	Operating	12/1/85	
PACW	Biomass One LP	Brookfield Asset Man	Biomass One LP	Biomass One LP	Oregon	GE	393929	100	15	14	14	ST	WDS	Operating	12/1/85	
PACW	Birch Power Co	Birch Power Co	Birch Power Co	Birch Creek	Idaho	GEN1	393932	100	2.6	2.6	2.6	HY	WAT	Operating	4/1/86	
PACW	Bridger Valley Electric Association Inc	Bridger Valley Electric	Bridger Valley Electric Assoc	Lyman	Wyoming	1	659621	100	1	1	1	ST	N/A	Retired	1/3/40	1/31/74
PACW	Bridger Valley Electric Association Inc	Bridger Valley Electric	Bridger Valley Electric Assoc	Lyman	Wyoming	2	659622	100	1	1	1	ST	N/A	Retired	1/3/40	1/31/74
PACW	Bridger Valley Electric Association Inc	Bridger Valley Electric	Bridger Valley Electric Assoc	Lyman	Wyoming	3	659623	100	1	1	1	ST	N/A	Retired	1/3/41	1/31/74
PACW	Bridger Valley Electric Association Inc	Bridger Valley Electric	Bridger Valley Electric Assoc	Lyman	Wyoming	4	659624	100	1	1	1	ST	N/A	Retired	1/3/41	1/31/74
PACW	Bridger Valley Electric Association Inc	Bridger Valley Electric	Bridger Valley Electric Assoc	Lyman	Wyoming	5	659625	100	1	1	1	ST	N/A	Retired	1/3/47	1/31/74
PACW	Bridger Valley Electric Association Inc	Bridger Valley Electric	Bridger Valley Electric Assoc	Lyman	Wyoming	6	659626	100	1	1	1	ST	N/A	Retired	1/3/47	1/31/74
PACW	Bridger Valley Electric Association Inc	Bridger Valley Electric	Bridger Valley Electric Assoc	Lyman	Wyoming	7	659627	100	1	1	1	ST	N/A	Retired	1/3/52	1/31/74
PACW	Bridger Valley Electric Association Inc	Bridger Valley Electric	Bridger Valley Electric Assoc	Lyman	Wyoming	8	659628	100	1	1	1	ST	N/A	Retired	1/3/52	1/31/74
PACW	BT Capital	Deutsche Bank AG	Slate Creek Hydro Associate	Slate Creek	California	GEN1	403197	5	0.21	0.2	0.193	HY	WAT	Operating	5/1/90	
PACW	Butter Creek Power LLC	Exelon Corp	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT1 27	1137851	11.1	4.945	4.945	4.945	WT	WND	Operating	6/27/09	
PACW	C Drop Hydro LLC	Warm Springs Hydro	C Drop Hydro LLC	C Drop Hydroelectric	Oregon	HY1	1553538	100	1.1	1.093	1.093	HY	WAT	Operating	5/4/12	
PACW	CDM Hydroelectric Co	CDM	CDM Hydroelectric Co	Felt Hydro	Idaho	GEN1	396178	100	2.7	2.3	2.3	HY	WAT	Operating	12/1/85	
PACW	CDM Hydroelectric Co	CDM	CDM Hydroelectric Co	Felt Hydro	Idaho	GEN2	396179	100	2.7	2.3	2.3	HY	WAT	Operating	12/1/85	
PACW	CDM Hydroelectric Co	CDM	CDM Hydroelectric Co	Felt Hydro	Idaho	GEN3	396180	100	1.1	0.8	0.8	HY	WAT	Standby	4/1/86	
PACW	CDM Hydroelectric Co	CDM	CDM Hydroelectric Co	Felt Hydro	Idaho	GEN4	396181	100	0.9	0.5	0.5	HY	WAT	Standby	4/1/86	
PACW	Central Oregon Irrigation District	Central Oregon Irrigat	Central Oregon Irrigation Dis	Juniper Ridge Project	Oregon	HY1	1168532	100	5	3	1.1	HY	WAT	Operating	9/21/10	
PACW	Central Oregon Irrigation District	Central Oregon Irrigat	Central Oregon Irrigation Dis	Siphon	Oregon	GEN1	403211	100	2.7	2.65	2.65	HY	WAT	Operating	8/1/89	
PACW	Central Oregon Irrigation District	Central Oregon Irrigat	Central Oregon Irrigation Dis	Siphon	Oregon	GEN2	403212	100	2.7	2.65	2.65	HY	WAT	Operating	8/1/89	
PACW	Co Generating II	Pacific Northwest Ger	Co Generating II	Co Generating II LLC	Oregon	GEN1	394956	100	7.5	7.8	7.3	ST	WDS	Operating	10/1/87	
PACW	David & Patty Jacobs	David & Patty Jacobs	David & Patty Jacobs	Jacobs Hydro	Oregon	HY	1131050	100	0.075	0.075	0.075	HY	WAT	Operating	9/1/09	
PACW	Deschutes Valley Water District	Deschular Valley Wat	Deschutes Valley Water Dist	Opal Springs Hydro	Oregon	1	399971	100	4.3	3.3	5	HY	WAT	Operating	1/1/85	
PACW	Douglas County	Douglas County	Douglas County	Galesville	Oregon	GV1	396472	100	0.8	0.8	1	HY	WAT	Operating	2/1/87	
PACW	Douglas County	Douglas County	Douglas County	Galesville	Oregon	GV2	396473	100	0.8	0.8	1	HY	WAT	Operating	2/1/87	
PACW	Douglas County Forest Products	Douglas County Fores	Douglas County Forest Prod	Douglas County Forest Pr	Oregon	ST	879463	100	3.2	3.2	3.2	ST	WDS	Operating	8/29/06	
PACW	Douglas County Forest Products	Douglas County Fores	Douglas County Forest Prod	Douglas County Forest Pr	Oregon	ST2	915637	100	3.2	3.2	3.2	ST	WDS	Operating	12/31/06	

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WKp-Energy Velocity PACW Gen

Unit Balancing Authority Area Abbrev	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Plant State	Unit	Unit ID	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PACW	Emerald Peoples Utility District	Emerald Peoples Utili	Emerald Peoples Utility Distr	Short Mountain	Oregon	1	403254	100	0.8	0.8	0.8	IC	LFG	Operating	2/1/92	
PACW	Emerald Peoples Utility District	Emerald Peoples Utili	Emerald Peoples Utility Distr	Short Mountain	Oregon	2	403255	100	0.8	0.8	0.8	IC	LFG	Operating	2/1/92	
PACW	Emerald Peoples Utility District	Emerald Peoples Utili	Emerald Peoples Utility Distr	Short Mountain	Oregon	3	403256	100	0.8	0.8	0.8	IC	LFG	Operating	11/1/93	
PACW	Emerald Peoples Utility District	Emerald Peoples Utili	Emerald Peoples Utility Distr	Short Mountain	Oregon	4	403257	100	0.8	0.8	0.8	IC	LFG	Operating	11/1/93	
PACW	Eugene Water & Electric Board	Eugene Water & Elect	Eugene Water & Electric Boa	Willamette	Oregon	1	607381	100	6	6	6	ST	PC	Retired	1/3/31	7/31/81
PACW	Eugene Water & Electric Board	Eugene Water & Elect	Eugene Water & Electric Boa	Willamette	Oregon	2	607382	100	7.5	6	6	ST	WDS	Retired	1/1/41	7/31/81
PACW	Eugene Water & Electric Board	Eugene Water & Elect	Eugene Water & Electric Boa	Willamette	Oregon	3	607383	100	11.5	7	7	ST	WDS	Retired	1/3/50	6/30/98
PACW	Eurus Combine Hills I LLC	Tokyo Electric Power	Eurus Energy America Corp	Combine Hills	Oregon	WT1 41	589463	100	41	41	41	WT	WND	Operating	12/15/03	
PACW	Eurus Combine Hills II LLC	Tokyo Electric Power	Eurus Energy America Corp	Combine Hills	Oregon	WT42 104	589423	100	63	63	63	WT	WND	Operating	1/1/10	
PACW	Evergreen Biopower LLC	Evergreen Biopower	Evergreen Biopower LLC	Freres Lumber	Oregon	ST1	1157038	100	21	10	10	ST	WDS	Operating	9/30/07	
PACW	Facebook	Facebook	Facebook	Facebook Data Center (Pr	Oregon	IC 1 28	1996252	100	84	84	84	IC	DSL	Standby	4/1/11	
PACW	Fall River Rural Electric Coop Inc	Fall River Rural Electri	Fall River Rural Electric Coop	Felt	Idaho	1	445401	100	0.3	0.3	0.3	HY	WAT	Retired	1/3/12	9/30/68
PACW	Fall River Rural Electric Coop Inc	Fall River Rural Electri	Fall River Rural Electric Coop	Felt	Idaho	2	445402	100	0.2	0.2	0.2	HY	WAT	Retired	1/3/38	9/30/68
PACW	Fall River Rural Electric Coop Inc	Fall River Rural Electri	Fall River Rural Electric Coop	Felt	Idaho	3	445403	100	0.3	0.3	0.3	HY	WAT	Retired	1/3/37	9/30/68
PACW	Fall River Rural Electric Coop Inc	Fall River Rural Electri	Fall River Rural Electric Coop	Felt	Idaho	4	396176	100	0.6	0.6	0.6	HY	WAT	Operating	1/3/46	
PACW	Fall River Rural Electric Coop Inc	Fall River Rural Electri	Fall River Rural Electric Coop	Felt	Idaho	5	396177	100	0.7	0.7	0.6	HY	WAT	Operating	1/3/47	
PACW	Fall River Rural Electric Coop Inc	Fall River Rural Electri	Fall River Rural Electric Coop	Felt	Idaho	HC1	592993	100	2.75	2.75	2.75	HY	WAT	Operating	1/1/80	
PACW	Fall River Rural Electric Coop Inc	Fall River Rural Electri	Fall River Rural Electric Coop	Felt	Idaho	HC2	592994	100	2.75	2.75	2.75	HY	WAT	Operating	1/1/80	
PACW	Farmers Irrigation District	Farmers Irrigation Dis	Farmers Irrigation District	Copper Dam	Oregon	GEN1	395133	100	2	1	2	HY	WAT	Operating	1/1/86	
PACW	Farmers Irrigation District	Farmers Irrigation Dis	Farmers Irrigation District	Copper Dam	Oregon	GEN2	395134	100	1	0.5	1	HY	WAT	Operating	1/1/86	
PACW	Farmers Irrigation District	Farmers Irrigation Dis	Farmers Irrigation District	Peters Drive	Oregon	GEN3	400419	100	1.8	0.3	1.17	HY	WAT	Operating	11/1/87	
PACW	FMC Corp	FMC Corp	FMC Corp	Green River (WY)	Wyoming	CG	649555	100	3.5	3.5	3.5	ST	SUB	Operating	6/1/53	
PACW	FMC Corp	FMC Corp	FMC Corp	Green River (WY)	Wyoming	ST2	1836392	100	3.5	3.5	3.5	ST	SUB	Operating	6/1/53	
PACW	FMC Corp	FMC Corp	FMC Corp	Green River (WY)	Wyoming	ST3	1836393	100	4	3.5	3.5	ST	SUB	Operating	6/1/64	
PACW	FMC Corp	FMC Corp	FMC Corp	Green River (WY)	Wyoming	ST4	1836395	100	10	10	10	ST	SUB	Operating	6/1/72	
PACW	FMC Corp	FMC Corp	FMC Corp	Green River (WY)	Wyoming	ST5	1836394	100	10	10	10	ST	SUB	Operating	6/1/75	
PACW	FMC Corp	FMC Corp	FMC Corp	Green River (WY)	Wyoming	ST6	1836396	100	10	10	10	ST	SUB	Operating	6/1/75	
PACW	Four Corners Windfarm LLC	Exelon Corp	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT28 38	1156451	50	10	10	10	WT	WND	Operating	9/30/09	
PACW	Four Mile Canyon Windfarm LLC	Exelon Corp	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT28 38	1156451	50	10	10	10	WT	WND	Operating	9/30/09	
PACW	FPL Energy Stateline II Inc	NextEra Energy Inc	FPL Energy Vansycle LLC	Stateline Wind (OR)	Oregon	WT182 22	589544	100	99	99	99	WT	WND	Operating	12/31/09	
PACW	FPL Energy Vansycle LLC	NextEra Energy Inc	FPL Energy Vansycle LLC	Stateline Wind (OR)	Oregon	WT1 126	396080	100	83.2	83.2	83.2	WT	WND	Operating	12/20/01	
PACW	FPL Energy Vansycle LLC	NextEra Energy Inc	FPL Energy Vansycle LLC	Stateline Wind (OR)	Oregon	WT127 18	651715	100	36.3	36.3	36.3	WT	WND	Operating	12/1/02	
PACW	Hermiston Generating Co LP	Sumitomo Corp	PacifiCorp	Hermiston Generating Pla	Oregon	CC1	584417	50	155.3	116	121.5	CC	NG	Operating	7/1/96	
PACW	Hermiston Generating Co LP	Sumitomo Corp	PacifiCorp	Hermiston Generating Pla	Oregon	CC2	650010	50	155.3	116	121.5	CC	NG	Operating	7/1/96	

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WKp-Energy Velocity PACW Gen

Unit Balancing Authority Area Abbrev	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Plant State	Unit	Unit ID	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PACW	Howard & Verna Cornwell	Howard & Verna Corr	Howard & Verna Cornwell	Cornwell Microhydro	California	HY	1127326	100	0.012	0.012	0.012	HY	WAT	Operating	5/7/80	
PACW	Idaho Falls ID (City of)	Idaho Falls ID (City of	Idaho Falls ID (City of)	Upper Power Plant	Idaho	4	402165	100	8	8	8	HY	WAT	Operating	9/1/82	
PACW	Idaho Power Co	IDACORP Inc	PacifiCorp	Jim Bridger	Wyoming	1	387706	33.33	192.614	176.982	176.982	ST	SUB	Operating	11/1/74	
PACW	Idaho Power Co	IDACORP Inc	PacifiCorp	Jim Bridger	Wyoming	2	389615	33.33	192.614	175.649	175.649	ST	SUB	Operating	12/1/75	
PACW	Idaho Power Co	IDACORP Inc	PacifiCorp	Jim Bridger	Wyoming	3	389616	33.33	192.614	174.316	174.316	ST	SUB	Operating	9/1/76	
PACW	Idaho Power Co	IDACORP Inc	PacifiCorp	Jim Bridger	Wyoming	4	389617	33.33	194.647	176.649	176.649	ST	SUB	Operating	11/1/79	
PACW	International Paper Co	International Paper C	International Paper Co	Springfield Oregon	Oregon	TG1	402957	100	7.5	7.5	7.5	ST	BLQ	Standby	1/1/49	
PACW	International Paper Co	International Paper C	International Paper Co	Springfield Oregon	Oregon	TG2	402958	100	5	5	5	ST	BLQ	Standby	1/1/49	
PACW	International Paper Co	International Paper C	International Paper Co	Springfield Oregon	Oregon	TG3	402959	100	12.5	12.5	12.5	ST	BLQ	Operating	1/1/53	
PACW	International Paper Co	International Paper C	International Paper Co	Springfield Oregon	Oregon	TG4	402960	100	40	33	33	ST	BLQ	Operating	10/1/76	
PACW	Leaning Juniper Wind Power II LLC	Iberdrola SA	enXco Service Corp	Leaning Juniper 1	Oregon	WT112 18	1161585	100	111	111	111	WT	WND	Operating	3/15/11	
PACW	Leaning Juniper Wind Power II LLC	Iberdrola SA	enXco Service Corp	Leaning Juniper 1	Oregon	WT68 111	1161583	100	90.3	90.3	90.3	WT	WND	Operating	3/1/11	
PACW	Lower Valley Energy Inc	Lower Valley Energy I	Lower Valley Energy Inc	Strawberry Creek	Wyoming	1	387439	100	0.5	0.5	0.5	HY	WAT	Operating	1/3/51	
PACW	Lower Valley Energy Inc	Lower Valley Energy I	Lower Valley Energy Inc	Strawberry Creek	Wyoming	2	402766	100	0.5	0.5	0.5	HY	WAT	Operating	1/3/51	
PACW	Lower Valley Energy Inc	Lower Valley Energy I	Lower Valley Energy Inc	Strawberry Creek	Wyoming	3	402767	100	0.5	0.5	0.5	HY	WAT	Operating	1/3/51	
PACW	Marsh Valley Development Inc	Marsh Valley Develop	Marsh Valley Development I	Marsh Valley Developmer	Idaho	1	387289	100	1.6	1.52	1.47	HY	WAT	Operating	4/1/93	
PACW	Mound Solar Owner VI LLC	SolarCity Corp	Oregon University System	Oregon Inst of Tech	Oregon	PV1	1575211	100	2.5	2	2	PV	SUN	Operating	4/23/14	
PACW	Ocean Power Technologies	Ocean Power Techno	Ocean Power Technologies	Reedsport OPT Wave Parl	Oregon	HT1	1519390	100	0.15	0.15	0.15	HK	WAT	Operating	9/13/11	
PACW	Oregon Environmental Industries	Oregon Environmenta	SCS Energy LLC	Dry Creek Landfill	Oregon	IC1	870272	100	1.6	1.5	1.5	IC	LFG	Operating	7/6/07	
PACW	Oregon Environmental Industries	Oregon Environmenta	SCS Energy LLC	Dry Creek Landfill	Oregon	IC2	870274	100	1.6	1.6	1.6	IC	LFG	Operating	7/6/07	
PACW	Oregon Environmental Industries	Oregon Environmenta	SCS Energy LLC	Dry Creek Landfill	Oregon	IC3	879270	100	1.3	1.3	1.3	IC	LFG	Operating	9/29/07	
PACW	Oregon Trail Windfarm LLC	Exelon Corp	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT1 27	1137851	22.2	9.89	9.89	9.89	WT	WND	Operating	6/27/09	
PACW	Oregon University System	Oregon University Sys	Oregon University System	Oregon Inst of Tech	Oregon	GE1	2024389	100	0.28	0.28	0.28	GE	GEO	Operating	4/20/10	
PACW	Oregon University System	Oregon University Sys	Oregon University System	Oregon Inst of Tech	Oregon	GE2	2024391	100	0.75	0.75	0.75	GE	GEO	Operating	4/24/14	
PACW	Oregon University System	Oregon University Sys	Oregon University System	Oregon Inst of Tech	Oregon	GE3	2024392	100	0.75	0.75	0.75	GE	GEO	Operating	4/24/14	
PACW	Pacific Canyon Windfarm LLC	Exelon Corp	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT1 27	1137851	18.5	8.242	8.242	8.242	WT	WND	Operating	6/27/09	
PACW	PacifiCorp	Berkshire Hathaway I	enXco Service Corp	Leaning Juniper 1	Oregon	WT1 67	735621	100	100.5	100.5	100.5	WT	WND	Operating	10/1/06	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Bend	Oregon	1	387793	100	0.2	0.2	0.2	HY	WAT	Operating	1/3/13	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Bend	Oregon	2	393786	100	0.3	0.3	0.3	HY	WAT	Operating	1/3/16	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Bend	Oregon	3	393787	100	0.6	0.5	0.5	HY	WAT	Operating	1/3/17	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Big Fork	Montana	1	393899	100	1.7	1.9	1.9	HY	WAT	Operating	1/3/24	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Big Fork	Montana	2	393900	100	1.7	1.9	1.9	HY	WAT	Operating	1/3/29	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Big Fork	Montana	3	393901	100	0.7	0.8	0.8	HY	WAT	Operating	1/3/10	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Black Cap Solar	Oregon	PV1	1678446	100	2	2	2	PV	SUN	Operating	11/9/12	

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Unit Balancing Authority Area Abbrev	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Plant State	Unit	Unit ID	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Clearwater 1	Oregon	1	394925	100	15	18	18	HY	WAT	Operating	6/1/53	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Clearwater 2	Oregon	1	387800	100	26	31	31	HY	WAT	Operating	11/1/53	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Cline Falls	Oregon	1	394944	100	1	1.1	1.1	HY	WAT	Operating	5/1/43	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Condit	Washingto	1	395079	100	7	7.7	7.7	HY	WAT	Retired	4/1/13	10/25/11
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Condit	Washingto	2	395080	100	6.7	7.4	7.4	HY	WAT	Retired	4/1/13	10/25/11
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Copco 1	California	1	395126	100	10	13.2	13.2	HY	WAT	Operating	1/1/18	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Copco 1	California	2	395127	100	10	13.2	13.2	HY	WAT	Operating	11/1/22	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Copco 2	California	1	395128	100	13.5	17.8	17.8	HY	WAT	Operating	7/1/25	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Copco 2	California	2	395129	100	13.5	17.8	17.8	HY	WAT	Operating	8/1/25	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Eagle Point (OR)	Oregon	1	395711	100	2.8	2.8	2.8	HY	WAT	Operating	11/1/57	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	East Side	Oregon	1	387683	100	3.2	3	3	HY	WAT	Operating	8/1/24	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Fall Creek	California	1	396124	100	0.5	0.4	0.4	HY	WAT	Operating	9/1/03	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Fall Creek	California	2	396125	100	0.4	0.4	0.4	HY	WAT	Operating	8/1/07	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Fall Creek	California	3	396126	100	1.2	1.1	1.1	HY	WAT	Operating	1/1/10	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Fish Creek	Oregon	1	387799	100	11	10.4	10.4	HY	WAT	Operating	6/1/52	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Gold Ray	Oregon	1	614297	100	1	0	0	HY	WAT	Retired	1/3/05	1/31/72
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Gold Ray	Oregon	2	614298	100	1	0	0	HY	WAT	Retired	1/3/05	1/31/72
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Hermiston Generating Pla	Oregon	CC1	584417	50	155.3	116	121.5	CC	NG	Operating	7/1/96	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Hermiston Generating Pla	Oregon	CC2	650010	50	155.3	116	121.5	CC	NG	Operating	7/1/96	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Iron Gate	California	1	397608	100	18	18.8	18.8	HY	WAT	Operating	2/1/62	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Jim Bridger	Wyoming	1	387706	66.67	385.286	354.018	354.018	ST	SUB	Operating	11/1/74	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Jim Bridger	Wyoming	2	389615	66.67	385.286	351.351	351.351	ST	SUB	Operating	12/1/75	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Jim Bridger	Wyoming	3	389616	66.67	385.286	348.684	348.684	ST	SUB	Operating	9/1/76	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Jim Bridger	Wyoming	4	389617	66.67	389.353	353.351	353.351	ST	SUB	Operating	11/1/79	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	John C Boyle	Oregon	1	397731	100	50.3	50.4	50.4	HY	WAT	Operating	10/1/58	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	John C Boyle	Oregon	2	397732	100	48.4	47.6	47.6	HY	WAT	Operating	10/1/58	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Lemolo 1	Oregon	1	398280	100	32.8	32	32	HY	WAT	Operating	7/1/55	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Lemolo 2	Oregon	1	398281	100	33	38	38	HY	WAT	Operating	11/1/56	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Marengo Wind	Washingto	WT1	78	875838	100	140.4	140.4	140.4	WT	WND	Operating	8/20/07
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Marengo Wind	Washingto	WT2	117	910724	100	70.2	70.2	70.2	WT	WND	Operating	9/30/08
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Merwin	Washingto	1	398965	100	45	50	50	HY	WAT	Operating	1/1/32	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Merwin	Washingto	2	398966	100	45	50	50	HY	WAT	Operating	12/1/49	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Merwin	Washingto	3	398967	100	45	50	50	HY	WAT	Operating	9/1/58	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Merwin	Washingto	H	879131	100	1	1	1	HY	WAT	Operating	7/1/31	

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Unit Balancing Authority Area Abbrev	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Plant State	Unit	Unit ID	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Naches	Washingto	2	399403	100	3	2.6	2.6	HY	WAT	Retired	1/3/09	10/31/03
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Naches	Washingto	4	399404	100	3.3	4	4	HY	WAT	Retired	1/3/13	10/31/03
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Naches Drop	Washingto	1	399405	100	1.4	1	1	HY	WAT	Retired	3/1/15	10/31/03
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	North Bend	Oregon	1	659780	100	5	5	5	HY	WAT	Retired	1/3/24	5/31/90
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	North Bend	Oregon	2	659781	100	10	10	10	HY	WAT	Retired	1/3/30	5/31/90
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	North Bend	Oregon	A	659782	100	1	1	1	HY	WAT	Retired	1/3/24	5/31/90
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Powerdale	Oregon	1	387708	100	6	6.5	6.5	HY	WAT	Retired	5/1/23	10/31/10
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Prospect 1	Oregon	1	400894	100	3.8	4.6	4.6	HY	WAT	Operating	1/1/12	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Prospect 2	Oregon	1	387798	100	16	18	18	HY	WAT	Operating	1/1/28	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Prospect 2	Oregon	2	400895	100	16	18	18	HY	WAT	Operating	2/1/28	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Prospect 3	Oregon	1	400896	100	7.2	7.7	7.7	HY	WAT	Operating	4/1/32	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Prospect 4	Oregon	1	387797	100	1	0.9	0.9	HY	WAT	Operating	11/1/44	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Slide Creek	Oregon	1	403191	100	18	18	18	HY	WAT	Operating	7/1/51	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Soda Springs	Oregon	1	403119	100	11	11.6	11.6	HY	WAT	Operating	3/1/52	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Swift 1	Washingto	HY11	402684	100	80	87.9	87.9	HY	WAT	Operating	12/1/58	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Swift 1	Washingto	HY12	402685	100	80	87.9	87.9	HY	WAT	Operating	12/1/58	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Swift 1	Washingto	HY13	402686	100	80	87.9	87.9	HY	WAT	Operating	12/1/58	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Toketee	Oregon	1	387796	100	14.2	15	15	HY	WAT	Operating	2/1/50	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Toketee	Oregon	2	402454	100	14.2	15	15	HY	WAT	Operating	12/1/49	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Toketee	Oregon	3	402455	100	14.2	15	15	HY	WAT	Operating	3/1/50	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Trona	Wyoming	1	660215	100	16	16	16	ST	NG	Retired	1/3/68	12/31/80
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Wallowa Falls	Oregon	1	401918	100	1.1	1.1	1.1	HY	WAT	Operating	1/3/21	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	West Side	Oregon	1	444700	100	0.6	0.6	1	HY	WAT	Operating	10/1/08	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Whisky Run	Oregon	1	660112	100	0.3	0.3	0.3	WT	WND	Retired	12/1/81	9/30/87
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Yale	Washingto	1	401370	100	67	81.8	81.8	HY	WAT	Operating	9/1/53	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Yale	Washingto	2	401371	100	67	81.8	81.8	HY	WAT	Operating	11/1/53	
PACW	Portland General Electric Co	Portland General Elec	Portland General Electric Co	Pelton Re Reg	Oregon	1	400375	100	18.9	20.8	20.8	HY	WAT	Operating	6/1/82	
PACW	Portland General Electric Co	Portland General Elec	Puget Sound Energy Inc	Lower Snake River Wind E	Washingto	WT150	265 1163491	100	267	267	267	WT	WND	Operating	12/15/14	
PACW	Publishers Paper Co	Blue Heron Paper	Publishers Paper Co	Oregon City	Oregon	1	630495	100	1.75	1.75	1.75	HY	WAT	Operating	1/1/70	
PACW	Publishers Paper Co	Blue Heron Paper	Publishers Paper Co	Oregon City	Oregon	2	630496	100	1.75	1.75	1.75	HY	WAT	Operating	1/1/70	
PACW	PUD No 1 of Cowlitz County	PUD No 1 of Cowlitz (	PacifiCorp	Swift 2	Washingto	21	402682	100	36	34	34	HY	WAT	Restarted	1/1/59	
PACW	PUD No 1 of Cowlitz County	PUD No 1 of Cowlitz (	PacifiCorp	Swift 2	Washingto	22	402683	100	36	31	31	HY	WAT	Restarted	12/1/58	
PACW	Puget Sound Energy Inc	Puget Energy Inc	Puget Sound Energy Inc	Lower Snake River Wind E	Washingto	WT1	94 1163490	100	216.2	216.2	216.2	WT	WND	Operating	12/1/11	
PACW	Puget Sound Energy Inc	Puget Energy Inc	Puget Sound Energy Inc	Lower Snake River Wind E	Washingto	WT95	149 1649820	100	126.5	126.5	126.5	WT	WND	Operating	2/29/12	

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Unit Balancing Authority Area Abbrev	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Plant State	Unit	Unit ID	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PACW	R & R Lumber	Rough & Ready Lumb	R & R Lumber	D R Johnson Lumber	Oregon	ST1	395322	100	1.5	1.4	1.41	ST	WDS	Restarted	2/1/90	
PACW	Robert Fackrell	Robert Fackrell	Robert Fackrell	Mink Creek Hydro	Idaho	GEN1	399095	100	3.1	2	2	HY	WAT	Operating	12/1/86	
PACW	Rock Creek Ranch	Rock Creek Ranch	Rock Creek Ranch	Denny Creek	Oregon	1	746060	100	0.05	0.05	0.05	HY	WAT	Operating	10/1/83	
PACW	Roseburg Forest Products Co	Roseburg Forest Prod	Roseburg Forest Products Co	Dillard Complex	Oregon	GEN1	395543	100	5	5	5	ST	WDS	Operating	1/1/55	
PACW	Roseburg Forest Products Co	Roseburg Forest Prod	Roseburg Forest Products Co	Dillard Complex	Oregon	GEN2	395544	100	5	5	5	ST	WDS	Operating	1/1/55	
PACW	Roseburg Forest Products Co	Roseburg Forest Prod	Roseburg Forest Products Co	Dillard Complex	Oregon	GEN3	395545	100	7	7	7	ST	WDS	Operating	1/1/55	
PACW	Roseburg Forest Products Co	Roseburg Forest Prod	Roseburg Forest Products Co	Dillard Complex	Oregon	GEN4	395546	100	11.5	11.5	11.5	ST	WDS	Operating	1/1/55	
PACW	Roseburg Forest Products Co	Roseburg Forest Prod	Roseburg Forest Products Co	Dillard Complex	Oregon	GEN5	395547	100	11.5	11.5	11.5	ST	WDS	Operating	1/1/55	
PACW	Roseburg Forest Products Co	Roseburg Forest Prod	Roseburg Forest Products Co	Roseburg Forest Products	California	ST	870931	100	15	13.4	13.4	ST	WDS	Operating	8/25/11	
PACW	Roseburg LFG Energy LLC	Cascade Energy Partn	Energyneering Solutions Inc	Roseburg LFG Energy	Oregon	GEN1	1623951	100	1.6	1.6	1.6	IC	LFG	Operating	12/1/11	
PACW	Sand Ranch Windfarm LLC	Exelon Corp	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT1 27	1137851	22.2	9.89	9.89	9.89	WT	WND	Operating	6/27/09	
PACW	Slate Creek Hydro Associates LP	Enel SpA	Slate Creek Hydro Associate	Slate Creek	California	GEN1	403197	95	3.99	3.791	3.667	HY	WAT	Operating	5/1/90	
PACW	St Anthony Hydro LLC	St Anthony Hydro LLC	St Anthony Hydro LLC	St Anthony	Idaho	1	593056	100	0.5	0.4	0.4	HY	WAT	Operating	1/1/15	
PACW	Synergics Inc	Synergics Inc	Synergics Inc	Box Canyon (CA)	California	GEN1	394145	100	2.5	2.5	2.5	HY	WAT	Operating	6/1/86	
PACW	Synergics Inc	Synergics Inc	Synergics Inc	Box Canyon (CA)	California	GEN2	394146	100	2.5	2.5	2.5	HY	WAT	Operating	6/1/86	
PACW	Threemile Canyon Farm	Threemile Canyon Fai	Finley Bioenergy LLC	Threemile Canyon Farms	Oregon	IC1	1182369	100	1.6	1.6	1.6	IC	OBG	Operating	9/1/12	
PACW	Threemile Canyon Wind I LLC	Exelon Corp	Threemile Canyon Wind I LL	Threemile Canyon Wind	Oregon	WT1 6	875484	100	9.9	9.9	9.9	WT	WND	Operating	9/30/09	
PACW	Tieton Hydropower LLC	Burbank (City of)	Energy Northwest	Tieton Hydro	Washingto	HY1	882396	100	6.9	6.9	6.9	HY	WAT	Operating	7/1/06	
PACW	Tieton Hydropower LLC	Burbank (City of)	Energy Northwest	Tieton Hydro	Washingto	HY2	882397	100	6.9	6.9	6.9	HY	WAT	Operating	7/1/06	
PACW	TMF Biomass LLC	Threemile Canyon Fai	Finley Bioenergy LLC	Threemile Canyon Farms	Oregon	IC2	1580632	100	1.6	1.6	1.6	IC	OBG	Operating	9/1/12	
PACW	TMF Biomass LLC	Threemile Canyon Fai	Finley Bioenergy LLC	Threemile Canyon Farms	Oregon	IC3	1580633	100	1.6	1.6	1.6	IC	OBG	Operating	9/1/12	
PACW	U S Bureau of Reclamation	U S Bureau of Reclam	U S Bureau of Reclamation	Green Springs	Oregon	1	396905	100	17.2	17.2	17.2	HY	WAT	Operating	5/1/60	
PACW	University of Oregon	University of Oregon	University of Oregon	Univ of Oregon Central	Oregon	1	386524	100	1.5	1.4	1.5	ST	NG	Retired	1/1/50	5/31/09
PACW	University of Oregon	University of Oregon	University of Oregon	Univ of Oregon Central	Oregon	2	386547	100	1.5	1.4	1.41	ST	NG	Retired	1/1/50	10/31/04
PACW	University of Oregon	University of Oregon	University of Oregon	Univ of Oregon Central	Oregon	3	386567	100	2.5	2.5	2.5	ST	NG	Retired	1/1/60	10/31/09
PACW	University of Oregon	University of Oregon	University of Oregon	Univ of Oregon Central	Oregon	CC1	1954070	100	11	9	10.5	CC	NG	Operating	12/1/12	
PACW	Wagon Trail LLC	Wagon Trail LLC	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT1 27	1137851	7.5	3.341	3.341	3.341	WT	WND	Operating	6/27/09	
PACW	Ward Butte Windfarm LLC	Exelon Corp	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT1 27	1137851	14.8	6.593	6.593	6.593	WT	WND	Operating	6/27/09	
PACW	Warm Springs Power Enterprises	Columbia River Inter	Warm Springs Power Enterp	Warm Springs Biomass (C	Oregon	GEN1	401873	100	3	2.63	2.5	ST	WDS	Standby	1/1/77	
PACW	Warm Springs Power Enterprises	Columbia River Inter	Warm Springs Power Enterp	Warm Springs Biomass (C	Oregon	GEN2	401874	100	3	2.63	2.5	ST	WDS	Operating	1/1/77	
PACW	Warm Springs Power Enterprises	Columbia River Inter	Warm Springs Power Enterp	Warm Springs Biomass (C	Oregon	GEN3	401875	100	3	2.63	2.5	ST	WDS	Operating	1/1/77	
PACW	Warm Springs Power Enterprises	Columbia River Inter	Warm Springs Power Enterp	Warm Springs Hydro (OR)	Oregon	1	386492	100	19.6	18.5	18.5	HY	WAT	Operating	6/1/82	
PACW	Western Wind Energy Corp	Brookfield Asset Man	Biomass One LP	Biomass One LP	Oregon	GE2	1479534	100	15	14	14	ST	WDS	Operating	1/1/09	
PACW	Yakima Tieton Irrigation District	Yakima Tieton Irrigati	Yakima Tieton Irrigation Dist	Cowiche	Washingto	983	395211	100	1.7	1.62	1.56	HY	WAT	Operating	3/1/87	

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WKp-Energy Velocity PACW Gen

Unit Balancing Authority Area Abbrev	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Plant State	Unit	Unit ID	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PACW	Yakima Tieton Irrigation District	Yakima Tieton Irrigati	Yakima Tieton Irrigation Dist	Orchard Avenue 1	Washingto	201	399977	100	0.8	0.76	0.74	HY	WAT	Operating	3/1/87	
PACW	Yakima Tieton Irrigation District	Yakima Tieton Irrigati	Yakima Tieton Irrigation Dist	Orchard Avenue 1	Washingto	301	399978	100	0.8	0.76	0.74	HY	WAT	Operating	3/1/87	

Operating		5,485	5,510
Subtract with on-line dates post-study period		(271)	(271)
Restarted		66	66
Retired	All retired before start of study period	107	107
Standby		100	100
Generation owned by Others			
Avista Corp		10	10
Douglas County		2	2
Eugene Water & Electric Board		19	19
Idaho Power Co		704	704
Portland General Electric Co		288	288
Puget Sound Energy Inc		343	343
Retired		(29)	(29)
Subtract new builds		(267)	(267)
Operating-New Builds+Restarted		5,280	5,306
Subtract Gen Owned by Others (less retired)		1,069	1,069
Total Gen		4,212	4,237

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Planned Outages, FERC Form 714

		PACW
2012	Dec	7
2013	Jan	18
2013	Feb	59
2013	Mar	45
2013	Apr	366
2013	May	378
2013	Jun	2
2013	Jul	2
2013	Aug	72
2013	Sep	80
2013	Oct	529
2013	Nov	0

	Winter	Spring	Summer	Fall
PACW	28	263	25	203

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229	2012	12	0	1200	4408	7	766	0	5181	0	0	5181
229	2013	12	0	100	5791	18	704	0	6513	0	0	6513
229	2013	12	0	200	5791	59	2	0	5852	0	0	5852
229	2013	12	0	300	5791	45	37	0	5873	0	0	5873
229	2013	12	0	400	5791	366	421	0	6578	0	0	6578
229	2013	12	0	500	5791	378	74	0	6243	0	0	6243
229	2013	12	0	600	5791	2	121	0	5914	0	0	5914
229	2013	12	0	700	5791	2	95	0	5888	0	0	5888
229	2013	12	0	800	5791	72	90	0	5953	0	0	5953
229	2013	12	0	900	5791	80	484	0	6355	0	0	6355
229	2013	12	0	1000	5791	529	122	0	6442	0	0	6442
229	2013	12	0	1100	5791	0	624	0	6415	0	0	6415

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Wkp-PACE+PACW load

	PacifiCorp	PACW Estimated	MEHC Filing Attach 7 PACW	FF714, Pt II, Sch 3 2013 PACW
Peak	10,507	3,784	3844	3784 Peak, Jan 2013
Avg Mo	9,263	3,074	3123	
Winter	7,985	3,084	3133	
Spring	6,980	2,621	2663	
Summer	8,769	2,647	2689	
Fall	7,309	2,681	2724	

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
12/1/12	PACE+W	5,798	5,668	5,607	5,616	5,696	5,927	6,146	6,434	6,699	6,779	6,772	6,711	6,651	6,609	6,599	6,755	7,162	7,274	7,148	7,037	6,900	6,633	6,276	5,931
12/2/12	PACE+W	5,675	5,531	5,496	5,482	5,561	5,738	5,965	6,249	6,447	6,555	6,564	6,566	6,546	6,559	6,637	6,872	7,268	7,471	7,403	7,286	7,123	6,731	6,247	5,938
12/3/12	PACE+W	5,780	5,661	5,669	5,754	6,067	6,646	7,281	7,516	7,473	7,434	7,450	7,302	7,235	7,182	7,090	7,231	7,727	7,947	7,840	7,755	7,510	7,025	6,530	6,165
12/4/12	PACE+W	5,963	5,816	5,730	5,814	6,054	6,634	7,206	7,359	7,290	7,261	7,212	7,183	7,160	7,153	7,176	7,351	7,728	7,804	7,690	7,618	7,354	6,901	6,376	6,026
12/5/12	PACE+W	5,789	5,662	5,622	5,623	5,874	6,446	7,005	7,274	7,225	7,274	7,189	7,092	7,071	6,998	7,065	7,205	7,610	7,805	7,682	7,636	7,387	6,985	6,467	6,120
12/6/12	PACE+W	5,927	5,841	5,818	5,872	6,107	6,726	7,336	7,529	7,384	7,328	7,285	7,181	7,145	7,087	7,080	7,150	7,581	7,856	7,812	7,741	7,495	7,096	6,639	6,238
12/7/12	PACE+W	6,001	5,898	5,877	5,926	6,206	6,748	7,336	7,549	7,555	7,481	7,416	7,320	7,164	7,176	7,137	7,242	7,644	7,774	7,622	7,556	7,364	7,043	6,633	6,268
12/8/12	PACE+W	6,007	5,888	5,858	5,868	5,973	6,241	6,505	6,829	7,111	7,219	7,148	7,124	7,039	6,957	6,958	7,141	7,613	7,720	7,611	7,511	7,394	6,959	6,650	6,309
12/9/12	PACE+W	6,064	5,936	5,868	5,925	6,015	6,231	6,479	6,772	6,951	7,017	6,986	6,933	6,839	6,834	6,837	7,010	7,554	7,843	7,725	7,704	7,495	7,107	6,610	6,245
12/10/12	PACE+W	6,088	5,984	5,989	6,070	6,365	6,982	7,595	7,852	7,826	7,834	7,780	7,658	7,590	7,445	7,368	7,461	7,913	8,076	7,986	7,874	7,736	7,243	6,720	6,346
12/11/12	PACE+W	6,155	6,051	6,025	6,101	6,375	6,945	7,510	7,727	7,614	7,673	7,597	7,477	7,452	7,375	7,425	7,536	7,986	8,189	8,118	7,987	7,759	7,253	6,734	6,356
12/12/12	PACE+W	6,132	6,000	5,979	6,059	6,326	6,871	7,502	7,658	7,631	7,631	7,536	7,408	7,336	7,298	7,295	7,405	7,905	8,104	8,027	7,946	7,666	7,173	6,768	6,373
12/13/12	PACE+W	6,150	6,058	6,053	6,130	6,392	6,977	7,632	7,932	7,864	7,844	7,710	7,557	7,496	7,435	7,391	7,512	7,950	8,181	8,088	8,013	7,796	7,282	6,796	6,401
12/14/12	PACE+W	6,189	6,070	6,036	6,104	6,382	6,941	7,550	7,818	7,774	7,745	7,650	7,513	7,422	7,416	7,399	7,519	7,870	7,962	7,895	7,810	7,665	7,377	6,961	6,562
12/15/12	PACE+W	6,308	6,183	6,171	6,206	6,298	6,559	6,864	7,167	7,424	7,544	7,498	7,483	7,403	7,333	7,301	7,378	7,801	7,937	7,783	7,605	7,387	7,130	6,769	6,395
12/16/12	PACE+W	6,214	6,033	6,026	6,032	6,143	6,362	6,601	6,884	7,081	7,260	7,227	7,213	7,167	7,130	7,101	7,283	7,747	7,983	7,871	7,746	7,462	7,036	6,510	6,209
12/17/12	PACE+W	5,999	5,895	5,897	5,982	6,271	6,865	7,502	7,787	7,792	7,731	7,700	7,665	7,649	7,554	7,545	7,733	8,178	8,410	8,345	8,294	8,025	7,567	7,043	6,659
12/18/12	PACE+W	6,435	6,340	6,302	6,392	6,704	7,277	7,947	8,176	8,064	8,032	8,028	7,970	7,897	7,785	7,790	7,896	8,350	8,584	8,534	8,455	8,234	7,766	7,228	6,817
12/19/12	PACE+W	6,602	6,491	6,501	6,601	6,824	7,400	8,000	8,235	8,206	8,196	8,065	7,883	7,781	7,784	7,737	7,821	8,268	8,523	8,409	8,310	8,084	7,686	7,134	6,733
12/20/12	PACE+W	6,493	6,398	6,367	6,428	6,658	7,220	7,798	8,020	8,044	8,017	7,956	7,895	7,840	7,718	7,700	7,751	8,193	8,403	8,310	8,229	8,052	7,636	7,093	6,661
12/21/12	PACE+W	6,429	6,331	6,298	6,359	6,608	7,065	7,569	7,814	7,861	7,871	7,743	7,630	7,528	7,446	7,387	7,480	7,907	8,083	7,960	7,838	7,656	7,338	6,926	6,545
12/22/12	PACE+W	6,285	6,135	6,100	6,123	6,213	6,439	6,677	6,951	7,203	7,265	7,208	7,119	6,979	6,886	6,820	6,987	7,455	7,679	7,672	7,589	7,426	7,142	6,701	6,398
12/23/12	PACE+W	6,181	6,039	6,034	6,031	6,149	6,342	6,659	6,923	7,108	7,201	7,123	7,099	7,069	6,989	6,965	7,124	7,530	7,694	7,646	7,539	7,441	7,149	6,698	6,361
12/24/12	PACE+W	6,093	6,024	5,985	6,043	6,128	6,431	6,797	7,118	7,330	7,406	7,353	7,269	7,135	7,041	6,998	7,105	7,427	7,538	7,326	7,275	7,138	6,970	6,669	6,361
12/25/12	PACE+W	6,110	5,932	5,791	5,950	6,072	6,285	6,594	6,830	7,000	7,023	6,971	6,881	6,789	6,644	6,618	6,671	7,048	7,246	7,238	7,207	7,126	6,847	6,447	6,139
12/26/12	PACE+W	5,960	5,884	5,916	6,007	6,218	6,652	7,106	7,420	7,648	7,776	7,786	7,761	7,677	7,625	7,615	7,713	8,075	8,280	8,213	8,129	7,849	7,437	6,981	6,580
12/27/12	PACE+W	6,331	6,246	6,195	6,283	6,500	6,897	7,332	7,565	7,609	7,638	7,707	7,650	7,501	7,448	7,413	7,474	7,884	8,133	8,071	8,023	7,789	7,398	6,940	6,550
12/28/12	PACE+W	6,372	6,279	6,259	6,348	6,548	6,991	7,465	7,739	7,875	8,005	8,000	7,848	7,771	7,659	7,591	7,754	8,069	8,267	8,171	8,083	7,857	7,526	7,094	6,728

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Wkp-PACE+PACW load

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
12/29/12	PACE+W	6,480	6,293	6,298	6,401	6,477	6,715	6,982	7,255	7,499	7,561	7,560	7,442	7,312	7,179	7,084	7,226	7,690	7,960	7,907	7,785	7,623	7,336	6,874	6,558
12/30/12	PACE+W	6,298	6,184	6,176	6,219	6,304	6,533	6,820	7,073	7,233	7,269	7,186	7,110	6,973	6,920	6,875	7,011	7,525	7,901	7,883	7,765	7,584	7,329	6,892	6,616
12/31/12	PACE+W	6,484	6,414	6,433	6,504	6,655	7,033	7,430	7,613	7,821	7,883	7,855	7,743	7,613	7,526	7,436	7,536	7,914	8,088	7,890	7,727	7,491	7,243	6,976	6,721
1/1/13	PACE+W	6,516	6,335	6,286	6,272	6,382	6,516	6,741	6,902	7,084	7,192	7,209	7,140	7,042	6,913	6,854	6,992	7,520	7,930	7,951	7,871	7,665	7,324	6,883	6,583
1/2/13	PACE+W	6,425	6,386	6,426	6,553	6,882	7,439	8,040	8,295	8,383	8,303	8,173	8,038	7,950	7,877	7,784	7,827	8,265	8,636	8,607	8,476	8,255	7,808	7,317	7,032
1/3/13	PACE+W	6,872	6,798	6,779	6,744	7,094	7,622	8,217	8,499	8,515	8,469	8,309	8,123	7,993	7,850	7,824	7,878	8,296	8,588	8,548	8,404	8,168	7,764	7,265	6,926
1/4/13	PACE+W	6,703	6,604	6,599	6,707	6,976	7,450	8,022	8,282	8,342	8,255	8,074	7,836	7,728	7,647	7,559	7,585	7,961	8,265	8,206	8,019	7,848	7,564	7,187	6,931
1/5/13	PACE+W	6,728	6,624	6,570	6,547	6,705	6,981	7,258	7,506	7,718	7,800	7,723	7,618	7,533	7,397	7,347	7,423	7,854	8,103	7,988	7,852	7,655	7,315	7,009	6,661
1/6/13	PACE+W	6,464	6,355	6,314	6,294	6,414	6,577	6,808	7,074	7,248	7,301	7,259	7,209	7,140	7,078	7,044	7,153	7,609	7,917	7,857	7,704	7,495	7,131	6,772	6,492
1/7/13	PACE+W	6,354	6,280	6,286	6,374	6,685	7,250	7,887	8,089	8,013	7,910	7,733	7,675	7,615	7,563	7,503	7,613	7,966	8,194	8,124	7,907	7,647	7,262	6,788	6,440
1/8/13	PACE+W	6,265	6,147	6,129	6,205	6,434	6,925	7,573	7,776	7,705	7,678	7,660	7,565	7,469	7,399	7,301	7,409	7,785	8,065	7,994	7,876	7,579	7,088	6,556	6,274
1/9/13	PACE+W	6,119	6,005	6,014	6,062	6,341	6,822	7,482	7,729	7,569	7,427	7,480	7,383	7,380	7,347	7,266	7,355	7,728	8,077	8,052	7,927	7,684	7,249	6,793	6,472
1/10/13	PACE+W	6,242	6,199	6,179	6,254	6,493	7,048	7,746	7,997	7,926	7,875	7,843	7,701	7,651	7,610	7,645	7,736	8,115	8,367	8,254	8,127	7,855	7,457	6,934	6,551
1/11/13	PACE+W	6,393	6,321	6,309	6,398	6,651	7,211	7,903	8,177	8,175	8,172	8,100	7,991	7,885	7,776	7,683	7,687	8,004	8,300	8,235	8,125	7,928	7,609	7,238	6,900
1/12/13	PACE+W	6,726	6,577	6,552	6,687	6,812	7,038	7,357	7,663	7,890	7,990	7,894	7,734	7,522	7,473	7,332	7,388	7,786	8,188	8,199	8,114	7,954	7,577	7,201	6,898
1/13/13	PACE+W	6,718	6,667	6,646	6,734	6,812	7,035	7,303	7,571	7,758	7,812	7,708	7,641	7,495	7,367	7,386	7,505	7,914	8,337	8,344	8,276	8,065	7,670	7,291	7,020
1/14/13	PACE+W	6,861	6,825	6,871	6,984	7,257	7,828	8,483	8,792	8,777	8,701	8,523	8,339	8,170	7,995	7,985	7,953	8,325	8,825	8,779	8,692	8,416	7,951	7,454	7,125
1/15/13	PACE+W	6,992	6,902	6,918	7,000	7,303	7,869	8,583	8,819	8,758	8,586	8,438	8,265	8,146	8,006	7,908	7,934	8,239	8,667	8,680	8,551	8,293	7,824	7,335	7,051
1/16/13	PACE+W	6,860	6,762	6,804	6,882	7,114	7,669	8,298	8,547	8,484	8,416	8,286	8,175	8,056	8,002	7,917	7,948	8,282	8,669	8,647	8,517	8,258	7,783	7,265	6,986
1/17/13	PACE+W	6,806	6,758	6,778	6,819	7,093	7,726	8,370	8,619	8,555	8,410	8,259	8,148	8,015	7,910	7,819	7,850	8,169	8,551	8,578	8,459	8,253	7,767	7,290	7,012
1/18/13	PACE+W	6,835	6,799	6,823	6,942	7,098	7,709	8,391	8,664	8,647	8,510	8,346	8,147	7,970	7,818	7,657	7,670	7,959	8,296	8,270	8,172	7,973	7,671	7,293	6,977
1/19/13	PACE+W	6,802	6,717	6,721	6,759	6,880	7,155	7,528	7,841	8,086	8,100	7,977	7,783	7,551	7,388	7,264	7,297	7,608	7,994	7,972	7,933	7,787	7,536	7,202	6,905
1/20/13	PACE+W	6,735	6,655	6,658	6,711	6,812	7,030	7,301	7,621	7,768	7,758	7,597	7,469	7,288	7,172	7,100	7,187	7,538	7,915	7,953	7,932	7,760	7,452	7,069	6,808
1/21/13	PACE+W	6,704	6,679	6,693	6,801	7,095	7,575	8,033	8,339	8,432	8,476	8,332	8,154	8,031	7,859	7,850	7,863	8,152	8,570	8,560	8,486	8,237	7,805	7,334	7,000
1/22/13	PACE+W	6,892	6,818	6,835	6,933	7,235	7,775	8,471	8,732	8,611	8,497	8,280	8,093	8,035	7,907	7,810	7,847	8,143	8,498	8,487	8,375	8,135	7,676	7,255	6,934
1/23/13	PACE+W	6,732	6,655	6,663	6,727	6,985	7,486	8,129	8,368	8,317	8,195	8,096	7,973	7,989	7,944	7,893	7,990	8,232	8,498	8,465	8,327	8,068	7,604	7,095	6,755
1/24/13	PACE+W	6,561	6,447	6,447	6,526	6,804	7,370	7,973	8,194	8,108	8,013	7,988	7,932	7,805	7,769	7,667	7,750	8,001	8,229	8,160	8,026	7,803	7,394	6,942	6,568
1/25/13	PACE+W	6,365	6,243	6,220	6,275	6,523	6,954	7,556	7,838	7,862	7,876	7,825	7,713	7,631	7,558	7,466	7,423	7,586	7,888	7,827	7,662	7,461	7,168	6,789	6,428
1/26/13	PACE+W	6,248	6,112	6,080	6,087	6,213	6,427	6,708	6,994	7,227	7,352	7,365	7,287	7,185	7,067	6,949	7,007	7,197	7,544	7,549	7,410	7,246	6,963	6,603	6,302
1/27/13	PACE+W	6,101	5,976	5,987	6,010	6,123	6,337	6,606	6,885	7,080	7,166	7,133	7,131	7,049	7,089	7,030	7,192	7,530	7,837	7,794	7,677	7,324	7,116	6,690	6,429
1/28/13	PACE+W	6,270	6,161	6,096	6,207	6,485	7,049	7,682	7,966	8,021	8,049	7,918	7,805	7,757	7,674	7,649	7,669	7,917	8,165	8,201	8,103	7,806	7,346	6,909	6,610
1/29/13	PACE+W	6,404	6,356	6,320	6,373	6,652	7,215	7,868	8,039	7,944	7,906	7,866	7,788	7,699	7,590	7,490	7,498	7,728	8,145	8,066	7,987	7,736	7,219	6,691	6,446
1/30/13	PACE+W	6,269	6,145	6,131	6,206	6,489	7,059	7,708	7,899	7,861	7,775	7,695	7,566	7,542	7,433	7,337	7,358	7,600	7,945	7,892	7,824	7,567	7,112	6,646	6,304
1/31/13	PACE+W	6,106	6,004	6,019	6,096	6,412	6,972	7,582	7,828	7,773	7,705	7,595	7,429	7,309	7,245	7,175	7,135	7,313	7,672	7,720	7,581	7,415	7,052	6,627	6,283
2/1/13	PACE+W	6,119	6,057	6,030	6,114	6,323	6,827	7,406	7,653	7,635	7,491	7,429	7,222	7,121	7,027	6,885	6,802	6,938	7,344	7,418	7,363	7,204	7,002	6,702	6,405
2/2/13	PACE+W	6,248	6,161	6,138	6,176	6,315	6,568	6,877	7,127	7,312	7,340	7,229	7,053	6,885	6,750	6,639	6,635	6,885	7,299	7,400	7,304	7,195	6,937	6,600	6,287
2/3/13	PACE+W	6,140	6,033	6,029	6,020	6,139	6,325	6,605	6,871	7,087	7,182	7,108	7,058	6,899	6,861	6,785	6,738	6,835	7,130	7,212	7,144	7,212	6,895	6,486	6,206
2/4/13	PACE+W	6,099	6,036	6,047	6,169	6,441	7,021	7,654	7,865	7,939	7,859	7,638	7,505	7,447	7,312	7,215	7,210	7,424	7,906	7,985	7,875	7,607	7,186	6,716	6,392
2/5/13	PACE+W	6,217	6,111	6,122	6,179	6,479	6,974	7,609	7,822	7,694	7,625	7,518	7,387	7,293	7,156	7,116	7,168	7,361	7,711	7,773	7,681	7,419	7,024	6,641	6,356

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Wkp-PACE+PACW load

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2/6/13	PACE+W	6,172	6,079	6,081	6,160	6,429	7,008	7,646	7,839	7,715	7,632	7,477	7,350	7,205	7,107	7,088	7,151	7,351	7,740	7,755	7,670	7,436	6,996	6,673	6,389
2/7/13	PACE+W	6,228	6,158	6,142	6,244	6,505	7,091	7,728	7,933	7,852	7,733	7,593	7,404	7,276	7,245	7,134	7,182	7,383	7,810	7,881	7,775	7,628	7,267	6,835	6,525
2/8/13	PACE+W	6,363	6,308	6,283	6,350	6,596	7,163	7,745	7,994	7,873	7,825	7,658	7,484	7,420	7,349	7,283	7,235	7,315	7,664	7,718	7,649	7,473	7,100	6,694	6,523
2/9/13	PACE+W	6,345	6,267	6,206	6,275	6,390	6,651	6,905	7,196	7,407	7,463	7,398	7,236	7,064	6,924	6,873	6,907	7,107	7,437	7,487	7,389	7,231	6,960	6,623	6,363
2/10/13	PACE+W	6,156	6,112	6,077	6,100	6,233	6,419	6,700	6,899	7,077	7,120	6,979	6,912	6,790	6,686	6,633	6,740	6,975	7,386	7,505	7,480	7,253	6,949	6,590	6,316
2/11/13	PACE+W	6,157	6,134	6,156	6,318	6,625	7,235	7,872	8,052	7,968	7,888	7,749	7,583	7,539	7,451	7,368	7,359	7,488	7,886	8,009	7,941	7,672	7,265	6,857	6,411
2/12/13	PACE+W	6,295	6,343	6,345	6,371	6,670	7,205	7,791	7,999	7,967	7,839	7,764	7,538	7,394	7,358	7,268	7,309	7,462	7,779	7,923	7,813	7,605	7,149	6,750	6,446
2/13/13	PACE+W	6,244	6,175	6,140	6,212	6,439	6,957	7,526	7,683	7,482	7,547	7,410	7,324	7,250	7,156	7,129	7,056	7,250	7,576	7,691	7,553	7,375	6,989	6,500	6,284
2/14/13	PACE+W	6,086	6,013	6,029	6,109	6,388	6,950	7,532	7,752	7,676	7,513	7,386	7,181	7,028	6,935	6,839	6,832	6,893	7,233	7,429	7,331	7,183	6,849	6,489	6,214
2/15/13	PACE+W	6,067	6,065	6,041	6,147	6,372	6,899	7,491	7,734	7,668	7,559	7,394	7,241	7,125	6,984	6,870	6,789	6,843	7,172	7,350	7,234	7,092	6,792	6,470	6,230
2/16/13	PACE+W	6,094	6,002	5,978	6,039	6,159	6,400	6,691	6,742	7,106	7,083	7,011	6,853	6,670	6,504	6,429	6,436	6,578	6,984	7,150	7,096	6,951	6,732	6,439	6,142
2/17/13	PACE+W	5,977	5,880	5,876	5,908	6,012	6,274	6,502	6,787	6,938	6,908	6,772	6,679	6,541	6,487	6,438	6,458	6,599	7,055	7,279	7,197	7,073	6,792	6,451	6,263
2/18/13	PACE+W	6,125	6,083	6,120	6,226	6,471	6,899	7,272	7,607	7,762	7,786	7,708	7,576	7,439	7,306	7,222	7,232	7,374	7,782	7,904	7,777	7,583	7,125	6,699	6,423
2/19/13	PACE+W	6,263	6,160	6,182	6,273	6,547	7,150	7,697	7,931	7,900	7,774	7,650	7,492	7,322	7,241	7,188	7,171	7,304	7,699	7,844	7,789	7,569	7,101	6,682	6,384
2/20/13	PACE+W	6,220	6,121	6,105	6,226	6,521	7,075	7,704	7,898	7,800	7,664	7,479	7,320	7,218	7,114	7,074	7,168	7,343	7,720	7,825	7,741	7,516	7,108	6,696	6,404
2/21/13	PACE+W	6,186	6,138	6,151	6,168	6,395	6,908	7,502	7,724	7,657	7,573	7,425	7,360	7,332	7,287	7,266	7,266	7,408	7,684	7,814	7,700	7,484	7,034	6,627	6,310
2/22/13	PACE+W	6,122	6,036	6,028	6,139	6,370	6,913	7,414	7,661	7,487	7,449	7,480	7,382	7,255	7,180	7,145	7,174	7,227	7,486	7,561	7,475	7,299	7,000	6,668	6,335
2/23/13	PACE+W	6,161	6,061	6,055	6,070	6,165	6,412	6,654	6,899	7,138	7,254	7,225	7,119	7,021	6,865	6,832	6,830	6,983	7,256	7,432	7,378	7,216	6,917	6,483	6,271
2/24/13	PACE+W	6,125	6,081	6,067	6,107	6,180	6,400	6,598	6,905	7,003	7,079	6,911	6,807	6,667	6,539	6,434	6,432	6,578	6,933	7,227	7,254	7,070	6,757	6,369	6,113
2/25/13	PACE+W	5,992	5,972	5,974	6,091	6,357	6,901	7,424	7,723	7,600	7,531	7,435	7,405	7,345	7,268	7,180	7,145	7,277	7,662	7,903	7,845	7,612	7,193	6,729	6,476
2/26/13	PACE+W	6,272	6,241	6,220	6,318	6,636	7,214	7,815	7,992	7,908	7,709	7,523	7,387	7,287	7,224	7,159	7,147	7,220	7,603	7,838	7,814	7,585	7,181	6,753	6,467
2/27/13	PACE+W	6,314	6,269	6,316	6,385	6,639	7,241	7,760	7,932	7,808	7,697	7,533	7,313	7,173	7,139	7,089	7,027	7,105	7,454	7,662	7,577	7,352	6,915	6,504	6,237
2/28/13	PACE+W	6,084	6,031	5,996	6,074	6,322	6,838	7,308	7,549	7,497	7,503	7,454	7,315	7,187	7,141	7,089	7,097	7,165	7,433	7,599	7,523	7,255	6,876	6,448	6,145
3/1/13	PACE+W	5,961	5,844	5,805	5,854	6,059	6,509	7,008	7,207	7,139	7,102	7,018	6,884	6,811	6,698	6,603	6,563	6,553	6,769	7,008	6,923	6,805	6,522	6,215	5,933
3/2/13	PACE+W	5,735	5,668	5,656	5,690	5,791	5,981	6,232	6,473	6,682	6,752	6,719	6,584	6,432	6,371	6,312	6,300	6,412	6,706	6,835	6,798	6,619	6,351	6,029	5,782
3/3/13	PACE+W	5,607	5,560	5,525	5,538	5,660	5,860	6,140	6,447	6,627	6,690	6,630	6,566	6,490	6,381	6,343	6,393	6,573	6,855	7,127	7,151	6,982	6,537	6,269	6,014
3/4/13	PACE+W	5,920	5,846	5,897	6,015	6,286	6,940	7,565	7,780	7,701	7,602	7,419	7,205	7,136	7,014	6,927	6,861	6,900	7,194	7,535	7,547	7,279	6,903	6,546	6,256
3/5/13	PACE+W	6,085	6,049	6,021	6,164	6,420	6,971	7,498	7,724	7,622	7,606	7,525	7,428	7,355	7,254	7,217	7,173	7,234	7,543	7,733	7,669	7,403	6,969	6,547	6,247
3/6/13	PACE+W	6,056	5,974	5,942	6,041	6,289	6,817	7,328	7,492	7,448	7,438	7,377	7,333	7,289	7,200	7,137	7,095	7,217	7,442	7,595	7,562	7,323	6,922	6,538	6,173
3/7/13	PACE+W	5,944	5,850	5,825	5,943	6,235	6,865	7,411	7,609	7,494	7,350	7,179	7,020	6,917	6,843	6,734	6,743	6,808	7,075	7,326	7,311	7,119	6,759	6,368	6,086
3/8/13	PACE+W	5,908	5,870	5,880	5,966	6,231	6,764	7,321	7,544	7,379	7,292	7,152	6,978	6,863	6,748	6,641	6,582	6,606	6,827	7,051	7,042	6,893	6,575	6,307	6,000
3/9/13	PACE+W	5,880	5,810	5,805	5,842	5,941	6,297	6,583	6,841	6,841	6,668	6,600	6,546	6,397	6,270	6,151	6,136	6,193	6,432	6,748	6,729	6,632	6,376	6,083	5,828
3/10/13	PACE+W	5,704	5,656	5,695	5,713	5,853	6,097	6,333	6,519	6,563	6,509	6,400	6,269	6,114	6,069	6,043	6,107	6,177	6,394	6,725	6,707	6,403	6,003	5,704	5,523
3/11/13	PACE+W	5,459	5,443	5,535	5,790	6,339	7,016	7,326	7,318	7,311	7,161	7,031	6,916	6,797	6,679	6,618	6,567	6,620	6,771	7,015	6,898	6,548	6,109	5,760	5,555
3/12/13	PACE+W	5,440	5,405	5,465	5,687	6,230	6,887	7,134	7,126	7,089	6,983	6,879	6,772	6,713	6,661	6,590	6,523	6,542	6,699	6,940	6,856	6,495	6,063	5,718	5,525
3/13/13	PACE+W	5,421	5,402	5,474	5,703	6,213	6,780	7,052	6,995	6,917	6,886	6,794	6,769	6,734	6,624	6,487	6,514	6,518	6,674	6,880	6,771	6,360	5,948	5,619	5,412
3/14/13	PACE+W	5,322	5,294	5,328	5,562	6,073	6,676	6,908	6,899	6,861	6,863	6,800	6,714	6,657	6,575	6,533	6,462	6,483	6,610	6,806	6,711	6,362	5,924	5,600	5,389
3/15/13	PACE+W	5,295	5,232	5,326	5,503	6,001	6,574	6,823	6,808	6,845	6,766	6,666	6,605	6,528	6,395	6,381	6,277	6,247	6,321	6,511	6,411	6,125	5,818	5,516	5,298
3/16/13	PACE+W	5,175	5,144	5,148	5,263	5,444	5,712	5,994	6,205	6,293	6,302	6,200	6,139	6,066	6,009	5,984	6,007	6,063	6,138	6,427	6,398	6,166	5,886	5,610	5,434

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Wkp-PACE+PACW load

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
3/17/13	PACE+W	5,335	5,333	5,354	5,462	5,646	5,836	6,153	6,421	6,500	6,482	6,491	6,373	6,294	6,230	6,262	6,243	6,289	6,412	6,816	6,822	6,493	6,106	5,803	5,644
3/18/13	PACE+W	5,566	5,592	5,729	6,017	6,597	7,298	7,624	7,567	7,433	7,252	7,073	7,003	6,920	6,771	6,691	6,593	6,601	6,737	7,061	6,969	6,615	6,191	5,846	5,670
3/19/13	PACE+W	5,559	5,569	5,637	5,908	6,488	7,179	7,436	7,353	7,275	7,175	7,050	6,943	6,844	6,852	6,786	6,777	6,764	6,819	7,010	6,919	6,534	6,152	5,869	5,646
3/20/13	PACE+W	5,560	5,509	5,573	5,771	6,316	6,965	7,196	7,256	7,254	7,177	7,095	7,043	6,997	6,939	6,860	6,810	6,776	6,859	7,097	7,075	6,683	6,246	5,954	5,757
3/21/13	PACE+W	5,674	5,664	5,736	5,980	6,556	7,222	7,535	7,453	7,417	7,338	7,250	7,210	7,085	6,968	6,874	6,826	6,833	6,983	7,247	7,259	6,845	6,447	6,148	5,949
3/22/13	PACE+W	5,884	5,841	5,903	6,133	6,710	7,354	7,639	7,642	7,523	7,404	7,260	7,126	7,018	6,895	6,798	6,706	6,731	6,836	7,101	7,058	6,865	6,517	6,238	6,035
3/23/13	PACE+W	6,001	5,944	5,988	6,112	6,363	6,648	6,947	7,091	7,043	6,962	6,798	6,631	6,486	6,345	6,283	6,270	6,316	6,449	6,750	6,806	6,544	6,295	6,010	5,844
3/24/13	PACE+W	5,741	5,776	5,822	5,931	6,087	6,350	6,622	6,774	6,809	6,718	6,588	6,470	6,362	6,279	6,253	6,250	6,251	6,370	6,696	6,741	6,443	6,090	5,825	5,689
3/25/13	PACE+W	5,639	5,661	5,769	6,068	6,620	7,210	7,430	7,524	7,448	7,315	7,142	7,045	6,876	6,790	6,698	6,569	6,619	6,731	6,987	6,913	6,541	6,165	5,851	5,669
3/26/13	PACE+W	5,581	5,537	5,620	5,842	6,354	6,884	7,147	7,211	7,216	7,183	7,032	6,897	6,806	6,770	6,685	6,602	6,633	6,674	6,917	6,857	6,493	6,082	5,773	5,590
3/27/13	PACE+W	5,492	5,463	5,517	5,759	6,260	6,800	6,997	7,027	7,005	6,939	6,815	6,760	6,690	6,637	6,555	6,489	6,428	6,499	6,763	6,689	6,379	5,987	5,643	5,470
3/28/13	PACE+W	5,377	5,338	5,396	5,599	6,032	6,555	6,760	6,823	6,875	6,846	6,745	6,637	6,651	6,566	6,507	6,423	6,357	6,405	6,644	6,662	6,234	5,876	5,584	5,390
3/29/13	PACE+W	5,299	5,242	5,270	5,458	5,844	6,292	6,580	6,668	6,673	6,650	6,545	6,485	6,427	6,407	6,349	6,271	6,207	6,192	6,384	6,373	6,151	5,819	5,504	5,279
3/30/13	PACE+W	5,189	5,087	5,148	5,243	5,478	5,637	5,941	6,182	6,116	6,134	6,113	6,014	5,956	5,908	5,906	5,903	5,903	5,977	6,254	6,250	6,058	5,688	5,367	5,140
3/31/13	PACE+W	5,042	4,999	4,998	5,069	5,271	5,455	5,670	5,863	5,951	5,912	5,922	5,864	5,814	5,766	5,732	5,735	5,710	5,812	6,110	6,186	5,878	5,550	5,255	5,092
4/1/13	PACE+W	5,009	5,025	5,116	5,306	5,730	6,257	6,570	6,654	6,721	6,752	6,703	6,687	6,670	6,557	6,535	6,486	6,485	6,561	6,702	6,658	6,281	5,881	5,506	5,343
4/2/13	PACE+W	5,227	5,157	5,240	5,432	5,919	6,426	6,689	6,705	6,732	6,658	6,629	6,571	6,509	6,503	6,387	6,349	6,333	6,356	6,597	6,637	6,213	5,813	5,510	5,329
4/3/13	PACE+W	5,239	5,158	5,238	5,468	5,930	6,416	6,669	6,701	6,719	6,677	6,620	6,574	6,516	6,481	6,448	6,416	6,404	6,437	6,668	6,645	6,280	5,835	5,533	5,318
4/4/13	PACE+W	5,192	5,179	5,238	5,389	5,860	6,346	6,574	6,676	6,743	6,828	6,743	6,745	6,731	6,676	6,633	6,523	6,438	6,499	6,731	6,666	6,289	5,925	5,631	5,424
4/5/13	PACE+W	5,270	5,222	5,242	5,446	5,883	6,383	6,604	6,774	6,820	6,781	6,709	6,669	6,544	6,540	6,480	6,470	6,443	6,394	6,580	6,516	6,260	5,951	5,658	5,422
4/6/13	PACE+W	5,312	5,249	5,220	5,283	5,453	5,640	5,896	6,186	6,250	6,278	6,259	6,187	6,118	6,028	6,035	6,072	6,094	6,172	6,391	6,373	6,182	5,832	5,518	5,374
4/7/13	PACE+W	5,240	5,212	5,171	5,227	5,393	5,545	5,737	6,045	6,207	6,231	6,267	6,222	6,123	6,132	6,148	6,224	6,294	6,385	6,615	6,610	6,277	5,870	5,576	5,392
4/8/13	PACE+W	5,344	5,331	5,409	5,674	6,270	6,941	7,250	7,161	7,269	7,258	7,171	7,088	7,049	6,976	6,922	6,844	6,933	7,007	7,150	7,088	6,757	6,249	5,907	5,781
4/9/13	PACE+W	5,721	5,699	5,761	5,998	6,596	7,169	7,338	7,291	7,216	7,102	7,026	6,986	6,853	6,783	6,734	6,664	6,639	6,647	6,929	6,965	6,596	6,136	5,799	5,587
4/10/13	PACE+W	5,534	5,529	5,594	5,820	6,376	6,884	6,994	6,971	6,967	6,813	6,863	6,824	6,774	6,699	6,628	6,547	6,504	6,509	6,763	6,830	6,498	6,055	5,722	5,524
4/11/13	PACE+W	5,470	5,481	5,552	5,827	6,361	6,967	7,116	7,088	7,031	6,835	6,735	6,739	6,679	6,586	6,506	6,494	6,371	6,377	6,617	6,702	6,404	5,964	5,627	5,395
4/12/13	PACE+W	5,298	5,313	5,419	5,651	6,180	6,714	6,962	6,907	6,832	6,684	6,569	6,488	6,424	6,344	6,304	6,239	6,215	6,226	6,432	6,431	6,186	5,806	5,507	5,276
4/13/13	PACE+W	5,180	5,152	5,161	5,255	5,491	5,755	6,047	6,333	6,460	6,468	6,358	6,237	6,117	6,033	6,059	6,073	6,079	6,146	6,244	6,322	6,179	5,858	5,541	5,361
4/14/13	PACE+W	5,300	5,286	5,281	5,376	5,510	5,726	6,033	6,144	6,237	6,231	6,183	6,084	6,011	5,941	5,960	5,998	6,052	6,207	6,470	6,515	6,264	5,821	5,528	5,371
4/15/13	PACE+W	5,352	5,378	5,496	5,741	6,308	6,882	7,196	7,181	7,115	7,040	6,967	6,905	6,813	6,734	6,659	6,597	6,578	6,595	6,823	6,835	6,513	6,054	5,702	5,560
4/16/13	PACE+W	5,497	5,490	5,602	5,847	6,436	6,999	7,207	7,129	7,121	6,964	6,873	6,807	6,795	6,672	6,630	6,538	6,458	6,552	6,820	6,899	6,528	6,155	5,851	5,684
4/17/13	PACE+W	5,609	5,611	5,717	5,957	6,522	7,042	7,247	7,078	6,979	6,867	6,718	6,652	6,615	6,549	6,516	6,455	6,472	6,493	6,736	6,779	6,456	6,027	5,732	5,545
4/18/13	PACE+W	5,471	5,486	5,513	5,806	6,365	6,874	7,011	6,967	6,891	6,762	6,697	6,609	6,619	6,532	6,412	6,366	6,327	6,376	6,589	6,662	6,316	5,919	5,588	5,372
4/19/13	PACE+W	5,289	5,246	5,324	5,566	6,040	6,559	6,863	6,901	6,917	6,847	6,792	6,741	6,650	6,570	6,470	6,361	6,314	6,289	6,448	6,492	6,215	5,836	5,547	5,293
4/20/13	PACE+W	5,247	5,175	5,201	5,295	5,483	5,732	6,002	6,223	6,233	6,163	6,148	6,043	5,917	5,840	5,793	5,803	5,844	5,864	6,016	6,150	5,909	5,601	5,361	5,208
4/21/13	PACE+W	5,139	5,087	5,097	5,181	5,322	5,483	5,723	5,878	5,931	5,804	5,910	5,812	5,792	5,758	5,784	5,836	5,875	5,940	6,182	6,249	6,006	5,617	5,331	5,152
4/22/13	PACE+W	5,072	5,093	5,186	5,436	5,990	6,537	6,820	6,734	6,740	6,710	6,694	6,642	6,598	6,522	6,463	6,412	6,383	6,345	6,571	6,672	6,339	5,887	5,607	5,450
4/23/13	PACE+W	5,392	5,375	5,454	5,713	6,231	6,719	6,935	6,883	6,803	6,709	6,654	6,573	6,543	6,502	6,447	6,409	6,349	6,376	6,570	6,558	6,304	5,841	5,567	5,398
4/24/13	PACE+W	5,308	5,302	5,379	5,635	6,211	6,658	6,879	6,807	6,762	6,678	6,621	6,636	6,618	6,597	6,509	6,484	6,400	6,346	6,505	6,583	6,257	5,815	5,473	5,258

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Wkp-PACE+PACW load

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
4/25/13	PACE+W	5,187	5,109	5,198	5,438	5,957	6,378	6,622	6,649	6,666	6,655	6,624	6,616	6,594	6,585	6,541	6,471	6,368	6,314	6,456	6,525	6,229	5,792	5,459	5,232
4/26/13	PACE+W	5,103	5,071	5,128	5,350	5,729	6,232	6,514	6,583	6,599	6,620	6,631	6,610	6,611	6,599	6,532	6,493	6,411	6,308	6,392	6,403	6,192	5,838	5,476	5,248
4/27/13	PACE+W	5,125	5,027	5,035	5,121	5,238	5,374	5,658	5,998	6,125	6,131	6,125	6,102	6,036	6,093	6,110	6,178	6,166	6,086	6,225	6,297	6,071	5,741	5,443	5,254
4/28/13	PACE+W	5,083	5,007	4,961	5,003	5,065	5,238	5,567	5,812	5,968	6,001	6,079	6,003	6,053	6,097	6,103	6,168	6,198	6,220	6,349	6,463	6,171	5,689	5,387	5,235
4/29/13	PACE+W	5,152	5,116	5,158	5,346	5,766	6,277	6,602	6,744	6,828	6,892	6,905	6,898	6,864	6,873	6,856	6,840	6,779	6,671	6,818	6,897	6,589	6,077	5,759	5,531
4/30/13	PACE+W	5,425	5,330	5,403	5,615	6,117	6,624	6,925	6,970	6,964	6,933	6,891	6,838	6,825	6,774	6,702	6,642	6,568	6,556	6,710	6,850	6,516	6,112	5,781	5,619
5/1/13	PACE+W	5,509	5,499	5,585	5,861	6,394	6,878	7,121	7,077	7,056	6,993	6,898	6,822	6,792	6,721	6,670	6,615	6,550	6,505	6,616	6,709	6,454	6,051	5,721	5,510
5/2/13	PACE+W	5,425	5,374	5,423	5,691	6,173	6,623	6,837	6,843	6,859	6,834	6,788	6,729	6,764	6,710	6,709	6,671	6,577	6,530	6,690	6,790	6,418	6,003	5,670	5,467
5/3/13	PACE+W	5,355	5,303	5,357	5,540	5,929	6,367	6,652	6,747	6,766	6,825	6,806	6,813	6,818	6,761	6,688	6,662	6,548	6,417	6,475	6,587	6,383	6,022	5,644	5,401
5/4/13	PACE+W	5,255	5,161	5,144	5,227	5,337	5,516	5,828	6,057	6,154	6,274	6,325	6,308	6,260	6,222	6,259	6,251	6,273	6,214	6,334	6,380	6,216	5,825	5,498	5,237
5/5/13	PACE+W	5,121	5,084	5,058	5,090	5,121	5,217	5,524	5,801	6,014	6,081	6,195	6,179	6,231	6,248	6,329	6,405	6,409	6,378	6,430	6,555	6,260	5,868	5,505	5,308
5/6/13	PACE+W	5,180	5,111	5,153	5,370	5,769	6,229	6,651	6,799	6,898	6,866	7,029	7,040	7,088	7,074	7,003	6,918	6,891	6,869	6,928	6,955	6,583	6,107	5,720	5,493
5/7/13	PACE+W	5,316	5,220	5,226	5,403	5,797	6,274	6,576	6,592	6,803	6,866	6,853	6,947	6,997	7,038	7,056	7,024	7,010	6,899	6,926	6,923	6,626	6,105	5,729	5,463
5/8/13	PACE+W	5,334	5,219	5,206	5,340	5,778	6,270	6,598	6,704	6,789	6,878	6,917	6,952	6,969	6,985	6,978	6,972	6,882	6,838	6,853	6,937	6,656	6,154	5,746	5,491
5/9/13	PACE+W	5,340	5,249	5,287	5,527	5,899	6,377	6,732	6,863	6,922	7,001	7,082	7,116	7,195	7,180	7,190	7,182	7,121	6,981	6,999	7,074	6,741	6,226	5,804	5,524
5/10/13	PACE+W	5,377	5,307	5,311	5,496	5,787	6,282	6,672	6,846	7,004	7,125	7,107	7,121	7,269	7,390	7,420	7,362	7,274	7,114	7,018	7,117	6,873	6,386	5,924	5,637
5/11/13	PACE+W	5,449	5,351	5,273	5,311	5,394	5,555	5,892	6,222	6,446	6,601	6,683	6,778	6,826	6,938	7,024	7,036	7,022	6,919	6,879	6,929	6,692	6,247	5,847	5,559
5/12/13	PACE+W	5,251	5,252	5,184	5,218	5,169	5,300	5,637	5,972	6,214	6,313	6,477	6,567	6,628	6,730	6,832	6,915	6,906	6,808	6,757	6,865	6,640	6,143	5,736	5,440
5/13/13	PACE+W	5,330	5,255	5,290	5,448	5,831	6,312	6,701	6,980	7,293	7,510	7,649	7,766	7,843	7,840	7,813	7,855	7,773	7,683	7,547	7,529	7,121	6,504	6,034	5,753
5/14/13	PACE+W	5,598	5,494	5,485	5,667	6,041	6,514	6,929	7,150	7,320	7,495	7,607	7,723	7,877	7,986	8,106	8,085	8,002	7,855	7,689	7,693	7,276	6,635	6,157	5,862
5/15/13	PACE+W	5,701	5,614	5,599	5,750	6,111	6,642	7,112	7,262	7,410	7,576	7,686	7,724	7,845	7,879	7,824	7,680	7,526	7,342	7,286	7,342	7,015	6,465	6,039	5,766
5/16/13	PACE+W	5,632	5,574	5,585	5,736	6,110	6,677	7,078	7,296	7,419	7,564	7,531	7,512	7,540	7,642	7,533	7,397	7,227	7,115	7,138	7,204	6,871	6,332	5,934	5,683
5/17/13	PACE+W	5,545	5,492	5,504	5,651	6,015	6,473	6,823	6,931	7,039	7,053	7,043	6,994	6,964	6,886	6,807	6,709	6,623	6,521	6,559	6,526	6,407	6,036	5,680	5,456
5/18/13	PACE+W	5,309	5,240	5,208	5,307	5,405	5,590	5,921	6,190	6,376	6,441	6,388	6,276	6,274	6,167	6,158	6,173	6,131	6,104	6,123	6,263	6,112	5,818	5,463	5,248
5/19/13	PACE+W	5,132	5,045	5,025	5,078	5,109	5,195	5,529	5,758	5,915	5,891	6,052	5,994	6,017	6,015	6,074	6,112	6,131	6,091	6,264	6,333	6,109	5,748	5,436	5,236
5/20/13	PACE+W	5,159	5,116	5,205	5,396	5,830	6,407	6,728	6,839	6,948	6,939	6,942	6,965	6,969	6,972	6,962	6,912	6,833	6,807	6,793	6,898	6,610	6,108	5,710	5,388
5/21/13	PACE+W	5,262	5,165	5,193	5,395	5,769	6,249	6,520	6,742	6,891	6,949	6,944	6,971	6,961	6,895	6,812	6,900	6,898	6,802	6,784	6,962	6,679	6,131	5,680	5,517
5/22/13	PACE+W	5,400	5,335	5,369	5,577	5,949	6,541	6,895	7,061	7,175	7,235	7,279	7,215	7,255	7,284	7,243	7,225	7,127	6,902	6,909	6,989	6,759	6,213	5,799	5,654
5/23/13	PACE+W	5,540	5,508	5,490	5,702	6,114	6,656	6,861	6,954	6,960	7,047	7,014	6,979	7,059	7,011	6,984	6,940	6,883	6,723	6,774	6,907	6,656	6,162	5,821	5,555
5/24/13	PACE+W	5,304	5,377	5,406	5,585	5,913	6,342	6,710	6,818	6,800	6,911	6,848	6,796	6,830	6,827	6,796	6,716	6,657	6,535	6,348	6,592	6,471	6,097	5,782	5,494
5/25/13	PACE+W	5,394	5,321	5,317	5,346	5,440	5,607	5,929	6,195	6,365	6,414	6,411	6,356	6,406	6,421	6,500	6,553	6,576	6,476	6,444	6,512	6,350	5,986	5,688	5,366
5/26/13	PACE+W	5,240	5,160	5,169	5,145	5,114	5,261	5,468	5,788	5,999	6,086	6,162	6,198	6,229	6,295	6,381	6,412	6,381	6,269	6,265	6,324	6,165	5,855	5,514	5,265
5/27/13	PACE+W	5,147	5,060	5,067	5,104	5,092	5,277	5,680	6,027	6,194	6,356	6,450	6,390	6,429	6,510	6,553	6,588	6,582	6,485	6,539	6,667	6,404	5,936	5,594	5,359
5/28/13	PACE+W	5,223	5,153	5,229	5,405	5,821	6,353	6,719	6,859	6,925	6,976	7,040	6,984	6,915	6,772	6,753	6,694	6,664	6,582	6,665	6,711	6,485	6,030	5,676	5,464
5/29/13	PACE+W	5,331	5,276	5,295	5,435	5,747	6,241	6,583	6,695	6,751	6,796	6,746	6,609	6,695	6,708	6,670	6,639	6,578	6,525	6,542	6,641	6,485	6,041	5,711	5,502
5/30/13	PACE+W	5,383	5,374	5,378	5,580	5,969	6,410	6,720	6,867	6,946	6,917	6,918	6,878	6,921	6,930	6,839	6,818	6,791	6,700	6,687	6,815	6,604	6,147	5,779	5,563
5/31/13	PACE+W	5,456	5,388	5,406	5,561	5,911	6,385	6,793	6,885	6,919	6,958	6,956	6,933	6,918	6,877	6,841	6,814	6,690	6,648	6,580	6,683	6,610	6,241	5,861	5,566
6/1/13	PACE+W	5,436	5,353	5,349	5,385	5,412	5,600	5,930	6,175	6,320	6,436	6,462	6,501	6,521	6,561	6,656	6,737	6,740	6,705	6,645	6,637	6,531	6,109	5,740	5,486
6/2/13	PACE+W	5,318	5,061	5,164	5,183	5,142	5,299	5,581	5,879	6,165	6,343	6,451	6,584	6,699	6,841	7,057	7,160	7,257	7,202	7,109	7,053	6,863	6,381	5,900	5,577

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Wkp-PACE+PACW load

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
6/3/13	PACE+W	5,449	5,380	5,396	5,571	5,882	6,413	6,848	7,032	7,239	7,366	7,357	7,498	7,558	7,629	7,707	7,708	7,708	7,585	7,412	7,400	7,120	6,564	6,143	5,816
6/4/13	PACE+W	5,643	5,518	5,594	5,722	5,997	6,495	6,864	7,018	7,201	7,278	7,372	7,377	7,558	7,740	7,865	7,898	7,879	7,766	7,584	7,545	7,305	6,769	6,306	5,936
6/5/13	PACE+W	5,738	5,634	5,623	5,746	6,010	6,469	6,963	7,167	7,367	7,535	7,628	7,782	7,866	8,055	8,169	8,223	8,203	8,075	7,834	7,764	7,426	6,888	6,377	5,980
6/6/13	PACE+W	5,762	5,627	5,634	5,786	6,078	6,569	7,015	7,341	7,559	7,727	7,888	8,074	8,281	8,452	8,553	8,556	8,479	8,200	7,980	7,947	7,653	7,023	6,469	6,097
6/7/13	PACE+W	5,875	5,724	5,701	5,809	6,052	6,517	7,025	7,337	7,555	7,853	8,031	8,181	8,407	8,520	8,593	8,534	8,438	8,225	7,932	7,689	7,389	6,983	6,483	6,112
6/8/13	PACE+W	5,895	5,750	5,675	5,669	5,627	5,880	6,313	6,765	7,134	7,361	7,429	7,561	7,683	7,820	7,906	8,000	7,955	7,835	7,617	7,436	7,248	6,739	6,265	5,887
6/9/13	PACE+W	5,637	5,538	5,464	5,450	5,374	5,561	5,954	6,324	6,696	6,924	7,233	7,368	7,672	7,868	8,098	8,273	8,328	8,192	7,935	7,809	7,459	6,952	6,480	6,118
6/10/13	PACE+W	5,949	5,812	5,850	5,987	6,275	6,830	7,405	7,789	8,153	8,442	8,562	8,677	8,715	8,718	8,745	8,824	8,746	8,488	8,096	7,932	7,587	6,956	6,448	6,151
6/11/13	PACE+W	5,946	5,867	5,845	5,970	6,256	6,761	7,234	7,520	7,799	7,965	8,033	8,185	8,299	8,378	8,488	8,470	8,367	8,122	7,899	7,835	7,553	6,969	6,485	6,164
6/12/13	PACE+W	5,943	5,820	5,835	5,935	6,213	6,705	7,139	7,396	7,607	7,678	7,793	8,005	8,210	8,299	8,354	8,284	8,150	7,939	7,763	7,758	7,542	6,997	6,539	6,232
6/13/13	PACE+W	6,028	5,908	5,868	5,994	6,319	6,738	7,220	7,516	7,795	7,973	8,102	8,180	8,257	8,294	8,254	8,110	7,979	7,797	7,498	7,397	7,177	6,721	6,283	5,929
6/14/13	PACE+W	5,770	5,664	5,637	5,773	6,025	6,440	6,789	7,037	7,191	7,302	7,354	7,380	7,423	7,473	7,510	7,501	7,341	7,125	7,009	7,054	6,912	6,536	6,184	5,880
6/15/13	PACE+W	5,719	5,615	5,578	5,579	5,539	5,739	6,077	6,355	6,589	6,708	6,797	6,974	7,081	7,273	7,384	7,508	7,436	7,363	7,230	7,220	7,058	6,651	6,184	5,841
6/16/13	PACE+W	5,663	5,576	5,515	5,486	5,451	5,583	5,939	6,309	6,619	6,829	7,023	7,192	7,381	7,563	7,733	7,861	7,867	7,793	7,566	7,444	7,225	6,660	6,172	5,880
6/17/13	PACE+W	5,718	5,634	5,613	5,793	6,016	6,444	7,009	7,317	7,732	7,981	8,135	8,324	8,538	8,727	8,840	8,852	8,802	8,564	8,251	8,055	7,734	7,125	6,621	6,224
6/18/13	PACE+W	5,935	5,849	5,841	5,973	6,243	6,639	7,100	7,444	7,743	7,907	8,057	8,153	8,387	8,378	8,373	8,396	8,325	8,294	8,118	7,964	7,628	7,129	6,646	6,290
6/19/13	PACE+W	6,142	5,993	5,958	6,114	6,360	6,743	7,233	7,553	7,761	7,843	7,897	7,999	8,081	8,091	8,034	7,880	7,693	7,455	7,239	7,246	7,146	6,648	6,243	5,967
6/20/13	PACE+W	5,790	5,746	5,749	5,895	6,144	6,538	6,855	7,015	7,241	7,392	7,423	7,441	7,533	7,534	7,568	7,523	7,515	7,430	7,308	7,317	7,141	6,720	6,246	5,986
6/21/13	PACE+W	5,807	5,721	5,752	5,832	6,049	6,414	6,813	7,049	7,238	7,362	7,421	7,391	7,547	7,619	7,586	7,562	7,510	7,349	7,128	7,135	6,978	6,671	6,258	5,979
6/22/13	PACE+W	5,751	5,648	5,626	5,660	5,657	5,811	6,131	6,465	6,656	6,827	6,940	7,011	7,030	7,106	7,185	7,327	7,347	7,293	7,120	7,067	6,911	6,492	6,090	5,817
6/23/13	PACE+W	5,683	5,539	5,487	5,476	5,444	5,549	5,832	6,178	6,402	6,526	6,736	6,859	6,961	7,105	7,217	7,268	7,311	7,201	7,031	7,138	6,973	6,456	6,070	5,789
6/24/13	PACE+W	5,675	5,603	5,613	5,794	6,054	6,507	7,035	7,374	7,691	7,872	7,978	8,040	8,151	8,091	7,946	7,750	7,531	7,384	7,306	7,296	7,134	6,705	6,257	5,942
6/25/13	PACE+W	5,778	5,677	5,715	5,860	6,101	6,515	6,852	7,187	7,436	7,698	7,874	7,914	8,083	8,175	8,231	8,229	8,213	8,047	7,810	7,676	7,516	6,971	6,457	6,126
6/26/13	PACE+W	5,959	5,842	5,804	5,951	6,253	6,724	7,220	7,592	7,905	8,042	8,347	8,470	8,626	8,740	8,819	8,821	8,749	8,615	8,404	8,255	7,954	7,328	6,796	6,397
6/27/13	PACE+W	6,112	5,877	5,837	5,985	6,266	6,799	7,365	7,810	8,233	8,578	8,842	9,115	9,363	9,475	9,632	9,632	9,595	9,453	9,216	9,002	8,600	7,939	7,271	6,795
6/28/13	PACE+W	6,500	6,285	6,260	6,310	6,501	6,977	7,596	8,108	8,510	8,904	9,202	9,432	9,678	9,696	9,833	9,797	9,681	9,415	9,188	8,964	8,629	8,070	7,485	7,012
6/29/13	PACE+W	6,689	6,465	6,296	6,279	6,262	6,503	7,006	7,563	8,024	8,419	8,768	9,044	9,289	9,365	9,521	9,543	9,527	9,286	9,009	8,781	8,428	7,830	7,333	6,943
6/30/13	PACE+W	6,635	6,486	6,340	6,280	6,209	6,418	6,920	7,458	7,881	8,359	8,692	8,994	9,218	9,422	9,602	9,695	9,677	9,465	9,277	9,061	8,724	8,103	7,460	7,011
7/1/13	PACE+W	6,710	6,524	6,456	6,542	6,783	7,305	7,949	8,516	8,987	9,432	9,744	10,085	10,291	10,299	10,507	10,410	10,363	10,247	9,960	9,694	9,237	8,497	7,815	7,290
7/2/13	PACE+W	6,981	6,751	6,657	6,715	6,893	7,455	7,986	8,618	9,101	9,524	9,829	10,124	10,370	10,397	10,410	10,415	10,341	10,141	9,837	9,618	9,124	8,389	7,741	7,241
7/3/13	PACE+W	6,943	6,725	6,628	6,679	6,886	7,318	7,969	8,514	8,950	9,350	9,648	9,868	10,044	9,980	9,939	9,851	9,680	9,460	9,154	8,901	8,495	7,901	7,327	6,903
7/4/13	PACE+W	6,637	6,360	6,181	6,160	6,096	6,233	6,553	6,998	7,393	7,744	8,043	8,234	8,427	8,531	8,640	8,643	8,497	8,303	7,915	7,609	7,308	7,011	6,616	6,290
7/5/13	PACE+W	5,935	5,803	5,678	5,684	5,807	6,176	6,696	7,181	7,623	7,942	8,103	8,354	8,569	8,708	8,798	8,729	8,424	8,051	7,827	7,702	7,420	7,000	6,550	6,205
7/6/13	PACE+W	5,982	5,814	5,812	5,821	5,814	5,952	6,353	6,801	7,120	7,248	7,450	7,663	7,862	8,129	8,234	8,178	7,997	7,696	7,579	7,460	7,282	6,868	6,425	6,114
7/7/13	PACE+W	5,910	5,786	5,662	5,584	5,621	5,746	6,194	6,593	6,909	7,302	7,661	7,887	8,060	8,086	8,249	8,269	8,274	8,108	7,896	7,786	7,528	7,022	6,531	6,136
7/8/13	PACE+W	5,950	5,878	5,896	5,996	6,230	6,758	7,281	7,697	8,156	8,460	8,784	9,133	9,365	9,334	9,406	9,502	9,464	9,301	9,003	8,747	8,204	7,514	7,064	6,641
7/9/13	PACE+W	6,407	6,273	6,244	6,339	6,587	6,951	7,535	7,928	8,340	8,760	8,988	9,327	9,576	9,653	9,688	9,725	9,643	9,689	9,423	9,018	8,693	7,912	7,256	6,794
7/10/13	PACE+W	6,490	6,306	6,226	6,242	6,391	6,830	7,288	7,786	8,187	8,512	8,883	9,265	9,577	9,636	9,756	9,789	9,732	9,589	9,280	9,040	8,596	7,855	7,219	6,768
7/11/13	PACE+W	6,511	6,352	6,262	6,368	6,628	6,993	7,485	7,883	8,152	8,314	8,456	8,687	8,908	9,103	9,014	8,764	8,499	8,221	8,029	7,996	7,738	7,237	6,725	6,389

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Wkp-PACE+PACW load

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
7/12/13	PACE+W	6,206	6,077	6,032	6,163	6,408	6,720	7,183	7,492	7,664	7,835	8,002	8,185	8,354	8,503	8,648	8,658	8,605	8,385	8,091	8,009	7,813	7,351	6,855	6,476
7/13/13	PACE+W	6,270	6,131	6,049	6,086	6,083	6,216	6,625	7,048	7,378	7,678	7,876	7,976	8,088	8,191	8,394	8,383	8,176	7,982	7,783	7,730	7,521	7,081	6,607	6,293
7/14/13	PACE+W	6,073	5,923	5,827	5,809	5,643	5,905	6,328	6,773	7,224	7,512	7,885	8,089	8,340	8,595	8,789	8,898	8,937	8,868	8,645	8,442	8,110	7,466	6,896	6,492
7/15/13	PACE+W	6,233	6,093	6,060	6,182	6,380	6,839	7,475	7,913	8,447	8,760	9,030	9,405	9,679	9,857	10,069	10,038	9,942	9,673	9,362	9,199	8,657	7,952	7,329	6,915
7/16/13	PACE+W	6,638	6,474	6,419	6,529	6,755	7,173	7,637	8,010	8,337	8,480	8,795	9,092	9,303	9,433	9,544	9,336	9,071	8,722	8,454	8,215	7,810	7,170	6,608	6,261
7/17/13	PACE+W	5,993	5,947	5,907	6,061	6,325	6,809	7,346	7,783	8,161	8,506	8,770	9,030	9,142	9,259	9,349	9,340	9,296	9,053	8,763	8,619	8,147	7,496	6,936	6,490
7/18/13	PACE+W	6,243	6,084	5,991	6,165	6,426	6,850	7,330	7,843	8,256	8,582	8,908	9,216	9,417	9,550	9,620	9,655	9,551	9,451	9,179	8,940	8,503	7,791	7,152	6,702
7/19/13	PACE+W	6,449	6,211	6,149	6,218	6,419	6,840	7,333	7,804	8,237	8,609	8,891	9,175	9,399	9,541	9,511	9,653	9,606	9,380	8,987	8,702	8,245	7,680	7,083	6,624
7/20/13	PACE+W	6,333	6,116	6,007	5,961	5,980	6,072	6,557	7,072	7,533	7,946	8,306	8,628	8,846	9,052	9,226	9,309	9,277	9,041	8,753	8,481	8,064	7,466	6,862	6,382
7/21/13	PACE+W	6,086	5,881	5,767	5,735	5,723	5,859	6,274	6,785	7,223	7,613	8,036	8,315	8,615	8,844	9,052	9,184	9,180	9,065	8,773	8,520	8,074	7,392	6,824	6,429
7/22/13	PACE+W	6,212	6,022	6,000	6,129	6,339	6,804	7,321	7,912	8,359	8,707	9,027	9,358	9,649	9,821	9,863	9,902	9,950	9,711	9,328	9,051	8,611	7,873	7,178	6,699
7/23/13	PACE+W	6,381	6,194	6,126	6,214	6,477	6,912	7,396	7,834	8,219	8,638	8,963	9,264	9,463	9,713	9,856	9,800	9,642	9,384	9,029	8,900	8,404	7,818	7,161	6,652
7/24/13	PACE+W	6,434	6,252	6,164	6,231	6,312	6,685	7,124	7,509	7,900	8,253	8,529	8,847	9,123	9,341	9,525	9,498	9,404	9,192	8,890	8,678	8,280	7,682	7,073	6,647
7/25/13	PACE+W	6,355	6,225	6,142	6,234	6,388	6,842	7,397	7,875	8,331	8,732	9,063	9,351	9,583	9,667	9,718	9,829	9,708	9,566	9,263	9,009	8,547	7,772	7,139	6,698
7/26/13	PACE+W	6,419	6,244	6,167	6,259	6,430	6,774	7,297	7,858	8,266	8,608	8,974	9,268	9,533	9,638	9,740	9,697	9,490	9,220	8,887	8,666	8,274	7,684	7,072	6,633
7/27/13	PACE+W	6,337	6,238	6,131	6,131	6,184	6,271	6,600	7,007	7,265	7,499	7,621	7,689	7,753	7,837	7,861	7,891	7,736	7,625	7,563	7,478	7,251	6,773	6,279	5,974
7/28/13	PACE+W	5,740	5,616	5,572	5,582	5,574	5,660	6,033	6,428	6,801	7,077	7,366	7,559	7,644	7,747	7,886	7,940	7,948	7,778	7,542	7,456	7,137	6,673	6,197	5,876
7/29/13	PACE+W	5,749	5,630	5,650	5,792	6,113	6,522	6,878	7,243	7,576	7,768	7,941	8,053	8,191	8,360	8,459	8,498	8,477	8,265	8,035	7,947	7,578	6,972	6,488	6,127
7/30/13	PACE+W	5,943	5,736	5,664	5,816	6,124	6,488	6,945	7,345	7,702	8,003	8,244	8,518	8,670	8,835	9,001	9,028	8,959	8,789	8,488	8,390	7,951	7,313	6,780	6,393
7/31/13	PACE+W	6,176	6,044	6,021	6,125	6,380	6,697	7,053	7,537	7,962	8,237	8,519	8,735	8,911	9,074	9,078	9,108	9,038	8,820	8,516	8,357	7,961	7,348	6,821	6,454
8/1/13	PACE+W	6,219	6,046	6,025	6,124	6,395	6,771	7,237	7,692	8,126	8,379	8,565	8,768	8,896	8,966	8,960	8,862	8,683	8,506	8,308	8,236	7,906	7,282	6,732	6,336
8/2/13	PACE+W	6,065	5,868	5,842	5,935	6,104	6,432	6,884	7,312	7,623	7,855	8,006	8,194	8,368	8,485	8,595	8,617	8,522	8,251	7,916	7,825	7,459	6,992	6,533	6,126
8/3/13	PACE+W	5,946	5,828	5,794	5,802	5,848	5,946	6,349	6,795	7,186	7,483	7,695	7,874	8,117	8,267	8,464	8,560	8,560	8,399	8,063	7,905	7,539	7,010	6,516	6,166
8/4/13	PACE+W	5,976	5,859	5,776	5,736	5,757	5,813	6,194	6,637	7,097	7,374	7,680	7,936	8,201	8,465	8,644	8,768	8,822	8,645	8,446	8,315	7,876	7,267	6,796	6,427
8/5/13	PACE+W	6,194	6,014	5,979	6,105	6,373	6,770	7,336	7,857	8,273	8,597	8,913	9,014	9,034	9,241	9,468	9,501	9,361	9,073	8,832	8,676	8,217	7,450	6,901	6,526
8/6/13	PACE+W	6,237	6,061	6,006	6,155	6,422	6,800	7,250	7,605	8,059	8,449	8,783	9,009	9,295	9,447	9,502	9,440	9,358	9,183	8,869	8,709	8,203	7,553	6,974	6,543
8/7/13	PACE+W	6,283	6,100	6,051	6,157	6,355	6,704	7,174	7,591	7,883	8,230	8,405	8,712	8,981	9,116	9,036	8,903	8,639	8,396	8,258	8,117	7,708	7,212	6,695	6,322
8/8/13	PACE+W	6,124	5,967	5,925	6,074	6,359	6,730	7,145	7,493	7,787	8,089	8,327	8,636	8,890	8,801	8,705	8,696	8,535	8,310	8,132	8,096	7,729	7,130	6,629	6,280
8/9/13	PACE+W	6,071	5,963	5,915	6,046	6,282	6,569	6,932	7,375	7,736	8,020	8,246	8,466	8,592	8,618	8,584	8,436	8,173	7,999	7,785	7,715	7,441	6,892	6,470	6,209
8/10/13	PACE+W	5,948	5,869	5,790	5,813	5,883	5,937	6,262	6,703	7,045	7,337	7,649	7,831	8,044	8,156	8,253	8,268	8,156	7,905	7,652	7,606	7,311	6,824	6,383	6,082
8/11/13	PACE+W	5,852	5,743	5,628	5,646	5,663	5,723	6,108	6,523	6,890	7,209	7,431	7,689	7,895	8,065	8,186	8,307	8,239	8,047	7,807	7,630	7,349	6,842	6,424	6,068
8/12/13	PACE+W	5,884	5,784	5,779	5,911	6,202	6,550	7,015	7,352	7,794	8,116	8,373	8,548	8,764	8,899	9,000	8,906	8,758	8,440	8,258	8,174	7,752	7,096	6,579	6,240
8/13/13	PACE+W	6,029	5,868	5,844	5,958	6,265	6,540	6,897	7,307	7,718	8,056	8,286	8,580	8,814	8,991	9,090	9,182	9,131	8,852	8,563	8,400	7,899	7,222	6,694	6,312
8/14/13	PACE+W	6,076	5,930	5,905	5,997	6,271	6,581	6,894	7,418	7,761	8,097	8,375	8,650	8,912	9,132	9,227	9,257	9,131	8,816	8,565	8,410	7,888	7,150	6,590	6,217
8/15/13	PACE+W	6,023	5,876	5,858	5,961	6,270	6,546	6,966	7,435	7,845	8,168	8,440	8,752	9,027	9,245	9,377	9,424	9,292	8,930	8,619	8,455	7,968	7,276	6,780	6,391
8/16/13	PACE+W	6,131	6,010	5,984	6,075	6,372	6,652	7,103	7,337	7,802	8,128	8,423	8,796	9,051	9,199	9,171	9,073	9,034	8,715	8,440	8,218	7,874	7,282	6,778	6,418
8/17/13	PACE+W	6,187	6,009	5,949	5,950	6,015	6,075	6,414	6,979	7,410	7,842	8,150	8,309	8,347	8,328	8,292	8,257	8,254	8,083	7,881	7,793	7,434	6,950	6,483	6,174
8/18/13	PACE+W	5,922	5,790	5,730	5,717	5,754	5,750	6,129	6,616	6,997	7,368	7,721	8,027	8,268	8,511	8,695	8,814	8,791	8,636	8,330	8,261	7,754	7,099	6,592	6,237
8/19/13	PACE+W	5,996	5,919	5,914	6,043	6,361	6,697	7,080	7,761	8,184	8,567	8,897	9,191	9,445	9,571	9,569	9,524	9,281	8,962	8,743	8,546	8,021	7,376	6,829	6,495

Wkp-PACE+PACW load

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
8/20/13	PACE+W	6,256	6,125	6,072	6,198	6,529	6,868	7,211	7,607	7,986	8,324	8,586	8,853	8,962	8,984	9,083	9,053	8,876	8,642	8,536	8,396	7,858	7,244	6,677	6,376
8/21/13	PACE+W	6,190	6,073	6,029	6,195	6,476	6,777	7,165	7,467	7,948	8,258	8,495	8,753	9,018	9,187	9,285	9,202	9,112	8,972	8,725	8,468	7,948	7,312	6,791	6,460
8/22/13	PACE+W	6,206	6,052	6,025	6,184	6,600	6,872	7,226	7,448	7,862	8,228	8,480	8,777	8,994	9,051	9,076	8,960	8,687	8,422	8,344	8,122	7,576	7,068	6,636	6,318
8/23/13	PACE+W	6,095	5,971	5,953	6,103	6,438	6,823	7,150	7,455	7,755	7,902	7,927	7,892	7,858	7,896	7,861	7,841	7,685	7,473	7,417	7,410	7,133	6,792	6,367	6,064
8/24/13	PACE+W	5,839	5,745	5,702	5,709	5,788	5,869	6,145	6,548	6,837	7,102	7,364	7,573	7,684	7,696	7,607	7,487	7,334	7,137	7,135	7,048	6,816	6,421	6,006	5,755
8/25/13	PACE+W	5,561	5,494	5,458	5,453	5,578	5,584	5,837	6,221	6,597	6,868	7,102	7,244	7,358	7,451	7,509	7,483	7,407	7,294	7,369	7,359	6,941	6,467	6,100	5,849
8/26/13	PACE+W	5,698	5,614	5,649	5,831	6,316	6,717	6,958	7,244	7,492	7,619	7,694	7,798	7,905	7,936	7,914	7,814	7,760	7,664	7,712	7,656	7,182	6,679	6,239	5,957
8/27/13	PACE+W	5,737	5,739	5,742	5,963	6,379	6,763	7,024	7,254	7,535	7,774	7,848	7,853	7,962	7,977	8,102	8,039	8,141	8,067	7,967	7,773	7,250	6,710	6,287	6,016
8/28/13	PACE+W	5,859	5,758	5,725	5,856	6,208	6,603	6,939	7,290	7,633	7,910	8,147	8,443	8,672	8,781	8,880	8,924	8,841	8,572	8,439	8,295	7,725	7,076	6,559	6,232
8/29/13	PACE+W	6,034	5,932	5,950	6,119	6,526	6,907	7,251	7,601	7,954	8,230	8,524	8,834	9,013	9,114	9,240	9,268	9,103	8,834	8,659	8,433	7,867	7,209	6,643	6,311
8/30/13	PACE+W	6,103	5,988	5,935	6,057	6,419	6,761	7,199	7,581	7,935	8,273	8,578	8,839	9,017	9,125	9,225	9,090	8,976	8,708	8,403	8,102	7,678	7,126	6,645	6,296
8/31/13	PACE+W	6,063	5,903	5,821	5,852	5,872	5,919	6,307	6,787	7,194	7,492	7,806	8,004	8,134	8,170	8,249	8,312	8,225	8,057	7,932	7,801	7,353	6,861	6,391	6,084
9/1/13	PACE+W	5,868	5,715	5,661	5,638	5,683	5,683	5,954	6,293	6,603	6,776	6,949	7,128	7,416	7,608	7,811	7,871	7,742	7,651	7,647	7,540	7,143	6,678	6,274	6,025
9/2/13	PACE+W	5,839	5,730	5,672	5,723	5,860	5,889	6,117	6,521	6,951	7,292	7,481	7,626	7,790	7,950	8,176	8,260	8,246	8,082	8,001	7,812	7,210	6,629	6,223	5,940
9/3/13	PACE+W	5,768	5,713	5,660	5,824	6,228	6,679	7,067	7,428	7,755	8,019	8,265	8,506	8,632	8,576	8,572	8,524	8,407	8,164	8,110	7,983	7,405	6,834	6,369	6,049
9/4/13	PACE+W	5,890	5,762	5,751	5,911	6,322	6,707	7,036	7,323	7,658	7,887	8,097	8,299	8,592	8,780	8,789	8,683	8,489	8,259	8,155	8,035	7,496	6,932	6,451	6,121
9/5/13	PACE+W	5,955	5,822	5,796	5,979	6,440	6,841	7,142	7,288	7,589	7,847	8,149	8,413	8,674	8,822	8,816	8,747	8,477	8,266	8,229	7,998	7,434	6,883	6,406	6,094
9/6/13	PACE+W	5,914	5,771	5,748	5,905	6,365	6,838	7,236	7,494	7,770	8,055	8,213	8,384	8,438	8,497	8,553	8,412	8,003	7,740	7,643	7,470	7,065	6,644	6,218	5,911
9/7/13	PACE+W	5,739	5,614	5,573	5,575	5,618	5,656	6,093	6,553	6,931	7,140	7,313	7,462	7,535	7,541	7,452	7,320	7,138	6,948	6,943	6,873	6,598	6,126	5,737	5,506
9/8/13	PACE+W	5,336	5,245	5,197	5,270	5,329	5,522	5,719	6,015	6,255	6,342	6,489	6,604	6,778	6,918	7,078	7,185	7,228	7,112	7,164	7,085	6,632	6,113	5,694	5,432
9/9/13	PACE+W	5,325	5,265	5,263	5,417	5,885	6,385	6,606	6,867	7,096	7,357	7,549	7,799	7,917	8,016	8,177	8,087	8,032	7,875	7,813	7,576	7,013	6,396	5,930	5,603
9/10/13	PACE+W	5,445	5,362	5,369	5,551	5,987	6,466	6,686	6,830	7,027	7,188	7,289	7,463	7,715	7,898	7,964	7,973	7,890	7,776	7,806	7,667	7,091	6,506	6,058	5,740
9/11/13	PACE+W	5,552	5,455	5,399	5,582	6,062	6,614	6,855	7,038	7,262	7,488	7,667	7,859	7,968	8,161	8,281	8,191	8,065	7,896	7,904	7,680	7,064	6,465	6,044	5,747
9/12/13	PACE+W	5,548	5,446	5,425	5,574	6,046	6,504	6,719	6,915	7,123	7,221	7,269	7,281	7,507	7,737	7,888	7,911	7,813	7,671	7,656	7,474	6,957	6,375	5,969	5,676
9/13/13	PACE+W	5,535	5,417	5,421	5,552	5,948	6,354	6,596	6,817	6,981	7,156	7,308	7,353	7,353	7,389	7,425	7,447	7,355	7,213	7,097	6,945	6,563	6,113	5,770	5,485
9/14/13	PACE+W	5,337	5,248	5,207	5,250	5,365	5,462	5,656	5,985	6,261	6,442	6,548	6,580	6,656	6,765	6,869	6,961	6,931	6,845	6,867	6,741	6,408	5,977	5,629	5,369
9/15/13	PACE+W	5,188	5,103	5,052	5,079	5,134	5,219	5,451	5,800	6,016	6,224	6,480	6,647	6,829	6,982	7,095	7,173	7,126	6,958	6,951	6,704	6,347	5,833	5,445	5,241
9/16/13	PACE+W	5,092	5,088	5,148	5,327	5,812	6,315	6,629	6,820	7,010	7,180	7,227	7,397	7,612	7,751	7,844	7,829	7,713	7,545	7,508	7,306	6,774	6,228	5,824	5,596
9/17/13	PACE+W	5,426	5,359	5,366	5,545	6,013	6,472	6,740	6,953	7,144	7,273	7,307	7,342	7,554	7,613	7,623	7,545	7,433	7,312	7,348	7,142	6,638	6,101	5,689	5,459
9/18/13	PACE+W	5,278	5,175	5,190	5,349	5,796	6,225	6,493	6,636	6,749	6,850	6,918	6,979	6,982	7,030	7,004	6,901	6,805	6,737	6,863	6,746	6,291	5,791	5,480	5,332
9/19/13	PACE+W	5,169	5,143	5,189	5,377	5,805	6,312	6,537	6,516	6,542	6,593	6,685	6,764	6,819	6,847	6,915	6,877	6,859	6,830	6,939	6,793	6,348	5,815	5,556	5,311
9/20/13	PACE+W	5,183	5,134	5,153	5,321	5,755	6,165	6,328	6,534	6,622	6,698	6,726	6,712	6,885	6,953	6,956	6,935	6,837	6,734	6,768	6,565	6,255	5,887	5,534	5,360
9/21/13	PACE+W	5,220	5,131	5,104	5,178	5,277	5,441	5,731	6,010	6,301	6,444	6,548	6,588	6,659	6,744	6,814	6,851	6,720	6,644	6,781	6,587	6,321	5,953	5,606	5,349
9/22/13	PACE+W	5,225	5,112	5,068	5,069	5,156	5,274	5,499	5,829	6,101	6,144	6,183	6,208	6,278	6,342	6,402	6,392	6,385	6,397	6,542	6,401	6,063	5,629	5,351	5,219
9/23/13	PACE+W	5,118	5,135	5,138	5,317	5,814	6,324	6,525	6,734	6,866	6,955	6,974	6,971	6,986	6,955	6,955	6,927	6,848	6,904	7,022	6,820	6,380	5,930	5,601	5,420
9/24/13	PACE+W	5,230	5,186	5,249	5,422	5,889	6,412	6,663	6,783	6,846	6,891	6,881	6,887	6,948	6,908	6,893	6,889	6,872	6,978	7,084	6,876	6,475	5,997	5,670	5,458
9/25/13	PACE+W	5,336	5,222	5,272	5,461	5,948	6,478	6,690	6,799	6,877	6,823	6,812	6,712	6,720	6,651	6,641	6,604	6,617	6,724	6,890	6,704	6,319	5,901	5,519	5,365
9/26/13	PACE+W	5,267	5,209	5,263	5,472	5,967	6,544	6,740	6,809	6,822	6,748	6,717	6,671	6,618	6,592	6,547	6,445	6,559	6,705	6,783	6,712	6,391	5,976	5,579	5,408
9/27/13	PACE+W	5,304	5,318	5,371	5,553	6,022	6,559	6,762	6,818	6,821	6,806	6,690	6,609	6,580	6,507	6,427	6,381	6,359	6,529	6,595	6,388	6,140	5,865	5,634	5,427

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Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
9/28/13	PACE+W	5,332	5,248	5,269	5,333	5,434	5,656	5,887	6,131	6,271	6,299	6,238	6,184	6,111	6,092	6,070	6,105	6,153	6,268	6,344	6,224	6,024	5,701	5,407	5,216
9/29/13	PACE+W	5,112	5,063	5,053	5,069	5,210	5,306	5,619	5,840	6,075	6,127	6,204	6,170	6,190	6,232	6,251	6,247	6,336	6,530	6,596	6,435	6,070	5,707	5,477	5,308
9/30/13	PACE+W	5,246	5,238	5,267	5,458	5,975	6,500	6,658	6,790	6,925	6,953	6,969	6,970	6,960	6,949	6,792	6,848	6,823	6,948	7,063	6,851	6,409	5,978	5,664	5,445
10/1/13	PACE+W	5,368	5,312	5,339	5,543	6,008	6,548	6,776	6,796	6,796	6,791	6,824	6,882	6,880	6,884	6,863	6,841	6,778	6,933	7,095	6,863	6,521	6,069	5,771	5,563
10/2/13	PACE+W	5,462	5,424	5,479	5,686	6,138	6,692	6,850	6,897	6,939	6,913	6,848	6,831	6,788	6,711	6,679	6,687	6,679	6,992	7,081	6,871	6,493	6,091	5,785	5,593
10/3/13	PACE+W	5,494	5,421	5,469	5,694	6,174	6,773	7,007	7,029	7,027	6,969	6,903	6,860	6,824	6,726	6,660	6,649	6,710	6,896	7,080	6,900	6,544	6,136	5,837	5,683
10/4/13	PACE+W	5,569	5,557	5,612	5,836	6,333	6,882	7,084	7,108	7,093	6,994	6,900	6,821	6,622	6,678	6,585	6,501	6,527	6,737	6,800	6,701	6,459	6,116	5,821	5,630
10/5/13	PACE+W	5,550	5,524	5,542	5,630	5,856	6,102	6,403	6,606	6,657	6,515	6,467	6,319	6,183	6,133	6,171	6,242	6,250	6,383	6,497	6,398	6,161	5,829	5,567	5,372
10/6/13	PACE+W	5,293	5,270	5,306	5,359	5,514	5,711	5,962	6,235	6,267	6,275	6,277	6,212	6,138	6,152	6,175	6,177	6,265	6,462	6,631	6,426	6,106	5,730	5,452	5,301
10/7/13	PACE+W	5,244	5,260	5,312	5,561	6,105	6,641	6,821	6,902	6,948	6,926	6,921	6,901	6,870	6,855	6,784	6,694	6,716	6,971	7,025	6,807	6,408	5,997	5,695	5,514
10/8/13	PACE+W	5,391	5,370	5,421	5,650	6,157	6,723	6,937	6,999	7,022	7,053	6,993	6,993	6,931	6,874	6,833	6,796	6,797	7,104	7,149	6,951	6,547	6,167	5,828	5,596
10/9/13	PACE+W	5,462	5,475	5,523	5,700	6,208	6,783	7,079	7,083	7,020	6,941	6,891	6,906	6,873	6,794	6,782	6,787	6,851	6,972	7,070	6,902	6,503	6,042	5,722	5,530
10/10/13	PACE+W	5,452	5,457	5,494	5,704	6,178	6,820	6,992	7,061	7,055	6,997	6,865	6,813	6,756	6,735	6,689	6,686	6,788	6,977	7,012	6,823	6,485	6,095	5,784	5,597
10/11/13	PACE+W	5,488	5,482	5,520	5,723	6,202	6,719	6,976	7,010	6,962	6,869	6,794	6,693	6,637	6,567	6,469	6,386	6,333	6,660	6,686	6,500	6,291	5,979	5,652	5,494
10/12/13	PACE+W	5,401	5,362	5,341	5,370	5,605	5,874	6,146	6,381	6,453	6,417	6,355	6,303	6,242	6,219	6,188	6,217	6,324	6,549	6,569	6,431	6,186	5,891	5,609	5,437
10/13/13	PACE+W	5,370	5,280	5,286	5,328	5,499	5,699	5,959	6,193	6,332	6,297	6,251	6,189	6,149	6,120	6,167	6,222	6,343	6,561	6,690	6,517	6,220	5,840	5,592	5,440
10/14/13	PACE+W	5,413	5,378	5,489	5,770	6,255	6,862	7,095	7,135	7,101	7,033	6,959	6,849	6,818	6,730	6,670	6,715	6,828	7,092	7,160	6,938	6,514	6,129	5,890	5,666
10/15/13	PACE+W	5,570	5,529	5,587	5,863	6,421	7,046	7,235	7,185	7,055	6,975	6,894	6,825	6,784	6,689	6,631	6,611	6,728	6,997	7,049	6,890	6,490	6,099	5,824	5,679
10/16/13	PACE+W	5,591	5,594	5,639	5,867	6,433	7,056	7,298	7,215	7,206	7,076	6,958	6,881	6,822	6,716	6,626	6,615	6,700	6,926	7,008	6,834	6,490	6,096	5,787	5,617
10/17/13	PACE+W	5,530	5,513	5,594	5,810	6,313	6,900	7,088	7,117	6,989	6,917	6,824	6,761	6,693	6,638	6,587	6,553	6,611	6,918	6,976	6,742	6,422	6,046	5,772	5,594
10/18/13	PACE+W	5,541	5,536	5,626	5,832	6,268	6,760	7,066	7,104	7,096	6,992	6,873	6,743	6,572	6,564	6,564	6,525	6,548	6,790	6,801	6,624	6,306	6,054	5,762	5,540
10/19/13	PACE+W	5,515	5,520	5,553	5,648	5,898	6,100	6,364	6,519	6,573	6,562	6,445	6,309	6,175	6,140	6,088	6,108	6,220	6,428	6,446	6,273	6,033	5,744	5,541	5,343
10/20/13	PACE+W	5,287	5,265	5,270	5,359	5,501	5,707	5,975	6,169	6,253	6,132	6,036	6,034	6,030	5,992	6,063	6,132	6,279	6,514	6,559	6,345	6,086	5,701	5,481	5,341
10/21/13	PACE+W	5,291	5,331	5,428	5,683	6,243	6,849	7,118	7,110	7,095	7,056	6,975	6,889	6,819	6,775	6,722	6,693	6,776	7,035	7,031	6,734	6,375	5,976	5,716	5,525
10/22/13	PACE+W	5,443	5,444	5,516	5,741	6,264	6,837	7,094	7,044	6,988	6,915	6,828	6,773	6,793	6,760	6,717	6,657	6,734	7,007	6,999	6,760	6,346	5,994	5,682	5,489
10/23/13	PACE+W	5,418	5,398	5,472	5,697	6,241	6,800	6,963	6,961	6,839	6,763	6,734	6,721	6,693	6,647	6,600	6,601	6,755	7,000	6,965	6,801	6,447	5,994	5,744	5,574
10/24/13	PACE+W	5,487	5,507	5,551	5,779	6,335	6,969	7,206	7,145	7,049	6,942	6,916	6,835	6,826	6,771	6,712	6,684	6,756	7,025	6,980	6,783	6,405	6,008	5,745	5,528
10/25/13	PACE+W	5,469	5,472	5,512	5,728	6,202	6,817	7,058	7,005	6,855	6,862	6,847	6,847	6,742	6,720	6,628	6,566	6,638	6,831	6,744	6,611	6,257	6,037	5,761	5,553
10/26/13	PACE+W	5,472	5,399	5,430	5,507	5,711	6,012	6,268	6,487	6,569	6,548	6,489	6,368	6,221	6,222	6,216	6,224	6,381	6,594	6,548	6,434	6,228	5,933	5,661	5,463
10/27/13	PACE+W	5,350	5,310	5,321	5,365	5,520	5,763	6,028	6,188	6,261	6,323	6,398	6,338	6,319	6,280	6,292	6,352	6,582	6,773	6,783	6,616	6,289	5,903	5,650	5,476
10/28/13	PACE+W	5,416	5,373	5,466	5,708	6,213	6,860	7,107	7,096	7,184	7,136	7,069	7,011	6,980	6,943	6,954	7,017	7,187	7,342	7,297	7,078	6,652	6,261	5,931	5,781
10/29/13	PACE+W	5,662	5,662	5,730	5,995	6,593	7,201	7,412	7,374	7,310	7,116	6,975	6,872	6,788	6,730	6,689	6,700	6,937	7,218	7,209	7,033	6,635	6,143	5,932	5,752
10/30/13	PACE+W	5,692	5,663	5,740	6,000	6,579	7,264	7,512	7,410	7,328	7,199	7,046	6,903	6,825	6,770	6,753	6,779	6,956	7,208	7,151	6,958	6,639	6,217	5,929	5,720
10/31/13	PACE+W	5,605	5,593	5,639	5,886	6,420	7,016	7,131	7,214	7,142	7,091	7,004	6,938	6,832	6,719	6,579	6,679	6,755	6,809	6,735	6,631	6,373	6,080	5,827	5,647
11/1/13	PACE+W	5,570	5,513	5,576	5,769	6,155	6,749	7,029	7,087	7,073	6,997	6,890	6,826	6,704	6,581	6,485	6,468	6,580	6,843	6,753	6,596	6,320	6,013	5,686	5,515
11/2/13	PACE+W	5,409	5,353	5,361	5,408	5,641	5,879	6,140	6,339	6,442	6,390	6,367	6,233	6,177	6,170	6,193	6,232	6,441	6,662	6,613	6,453	6,242	5,932	5,658	5,468
11/3/13	PACE+W	5,369	5,308	5,285	5,333	5,501	5,725	6,039	6,377	6,581	6,586	6,438	6,410	6,341	6,373	6,395	6,490	6,844	7,106	7,050	6,951	6,720	6,317	5,977	5,783
11/4/13	PACE+W	5,658	5,621	5,614	5,743	6,023	6,639	7,217	7,482	7,361	7,350	7,279	7,181	7,100	7,034	6,981	7,073	7,367	7,568	7,626	7,464	7,175	6,696	6,279	6,031
11/5/13	PACE+W	5,847	5,766	5,741	5,834	6,098	6,678	7,212	7,395	7,307	7,263	7,204	7,097	7,068	6,993	6,957	7,004	7,361	7,627	7,583	7,454	7,152	6,747	6,363	6,077

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Wkp-PACE+PACW load

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
11/6/13	PACE+W	5,935	5,832	5,780	5,834	6,086	6,658	7,172	7,352	7,325	7,261	7,238	7,083	7,031	6,960	6,933	6,937	7,222	7,362	7,339	7,194	6,942	6,522	6,118	5,846
11/7/13	PACE+W	5,666	5,615	5,557	5,607	5,864	6,386	6,920	7,072	7,069	7,074	6,999	6,977	6,943	6,918	6,904	6,974	7,257	7,472	7,391	7,211	6,987	6,599	6,211	5,864
11/8/13	PACE+W	5,729	5,631	5,585	5,640	5,885	6,399	6,930	7,164	7,167	7,160	7,085	6,951	6,874	6,806	6,755	6,709	6,958	7,165	7,080	6,891	6,680	6,445	6,119	5,874
11/9/13	PACE+W	5,694	5,606	5,581	5,579	5,689	5,943	6,179	6,447	6,620	6,630	6,582	6,471	6,408	6,339	6,279	6,316	6,647	6,864	6,792	6,702	6,515	6,270	5,962	5,703
11/10/13	PACE+W	5,554	5,474	5,453	5,504	5,554	5,750	5,927	6,170	6,345	6,383	6,329	6,326	6,229	6,155	6,101	6,175	6,523	6,813	6,776	6,683	6,496	6,225	5,938	5,709
11/11/13	PACE+W	5,593	5,540	5,472	5,532	5,824	6,331	6,787	6,967	7,087	7,181	7,112	6,974	7,002	6,910	6,878	6,876	7,129	7,427	7,322	7,124	6,903	6,507	6,115	5,819
11/12/13	PACE+W	5,649	5,554	5,527	5,592	5,842	6,329	6,857	7,037	6,950	6,958	6,934	6,869	6,820	6,813	6,743	6,741	7,081	7,312	7,229	7,106	6,864	6,460	6,079	5,766
11/13/13	PACE+W	5,627	5,522	5,508	5,549	5,803	6,332	6,897	7,079	7,053	7,048	6,951	6,886	6,824	6,783	6,746	6,771	7,068	7,302	7,238	7,119	6,885	6,496	6,093	5,817
11/14/13	PACE+W	5,674	5,619	5,618	5,656	5,923	6,504	7,050	7,234	7,079	7,037	7,011	7,033	6,980	6,927	6,897	6,933	7,248	7,478	7,405	7,252	7,033	6,642	6,236	5,955
11/15/13	PACE+W	5,809	5,745	5,746	5,821	6,067	6,567	7,112	7,378	7,369	7,355	7,270	7,129	7,103	7,049	7,000	7,047	7,365	7,506	7,360	7,221	6,993	6,701	6,415	6,138
11/16/13	PACE+W	5,912	5,816	5,788	5,768	5,882	6,086	6,356	6,664	6,932	7,010	7,011	6,920	6,866	6,727	6,746	6,807	7,123	7,282	7,205	7,015	6,872	6,599	6,290	6,004
11/17/13	PACE+W	5,803	5,703	5,660	5,689	5,763	5,918	6,093	6,330	6,569	6,636	6,570	6,457	6,425	6,353	6,361	6,472	6,889	7,148	7,104	6,999	6,692	6,468	6,105	5,851
11/18/13	PACE+W	5,729	5,663	5,664	5,799	6,104	6,643	7,182	7,439	7,396	7,376	7,266	7,230	7,221	7,154	7,121	7,141	7,442	7,617	7,486	7,332	7,053	6,637	6,238	5,940
11/19/13	PACE+W	5,760	5,690	5,605	5,685	5,940	6,419	7,010	7,234	7,207	7,184	7,145	7,187	7,183	7,101	7,095	7,204	7,517	7,645	7,593	7,435	7,199	6,765	6,363	6,070
11/20/13	PACE+W	5,888	5,793	5,795	5,847	6,110	6,709	7,267	7,484	7,494	7,446	7,404	7,315	7,254	7,227	7,244	7,362	7,680	7,891	7,855	7,775	7,525	7,184	6,756	6,426
11/21/13	PACE+W	6,274	6,196	6,225	6,301	6,621	7,245	7,909	8,080	7,952	7,888	7,780	7,587	7,489	7,425	7,409	7,529	7,925	8,190	8,136	8,048	7,861	7,436	6,976	6,705
11/22/13	PACE+W	6,570	6,525	6,530	6,652	6,919	7,484	8,090	8,213	8,163	8,005	7,799	7,629	7,476	7,385	7,292	7,330	7,691	7,942	7,892	7,814	7,637	7,336	6,964	6,669
11/23/13	PACE+W	6,506	6,413	6,390	6,427	6,580	6,836	7,162	7,386	7,546	7,516	7,361	7,153	6,921	6,799	6,760	6,870	7,315	7,545	7,493	7,389	7,201	6,988	6,651	6,392
11/24/13	PACE+W	6,210	6,164	6,155	6,216	6,355	6,540	6,828	7,083	7,223	7,190	7,052	6,940	6,785	6,632	6,610	6,735	7,169	7,497	7,493	7,449	7,261	6,957	6,609	6,376
11/25/13	PACE+W	6,239	6,187	6,230	6,380	6,664	7,236	7,806	8,098	7,986	7,839	7,673	7,451	7,239	7,189	7,166	7,245	7,680	7,986	7,937	7,830	7,610	7,162	6,815	6,526
11/26/13	PACE+W	6,363	6,308	6,317	6,422	6,704	7,273	7,864	8,047	7,954	7,825	7,661	7,531	7,401	7,232	7,197	7,281	7,684	7,907	7,868	7,767	7,579	7,181	6,785	6,454
11/27/13	PACE+W	6,200	6,192	6,194	6,313	6,543	7,020	7,488	7,813	7,840	7,826	7,730	7,590	7,425	7,287	7,174	7,199	7,511	7,726	7,677	7,590	7,414	7,115	6,683	6,233
11/28/13	PACE+W	6,052	5,945	5,933	5,979	6,077	6,282	6,591	6,890	7,091	7,167	7,144	6,938	6,659	6,380	6,167	6,083	6,338	6,462	6,466	6,536	6,506	6,408	6,169	5,968
11/29/13	PACE+W	5,879	5,839	5,833	5,937	6,101	6,382	6,711	6,922	7,067	7,073	7,001	6,847	6,741	6,608	6,567	6,637	7,053	7,233	7,220	7,111	7,025	6,764	6,413	6,118
11/30/13	PACE+W	5,918	5,840	5,781	5,863	5,939	6,168	6,412	6,641	6,854	6,978	6,858	6,780	6,634	6,496	6,464	6,558	6,977	7,206	7,168	7,024	6,968	6,667	6,355	6,057

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June 28, 2013

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE, Room 1A
Washington, DC 20426

RE: *PacifiCorp*
Docket No. ER10-3246-___
Triennial Market Power Update

Dear Secretary Bose:

Pursuant to Section 35.37(a)(1) of the Commission's regulations,[1] and Order No. 697, *et seq.*,[2] PacifiCorp respectfully submits this Triennial Market Power Update ("Triennial Update") in the above-referenced proceeding. Concurrent with this filing, PacifiCorp is submitting under separate cover through the Commission's eTariff system certain changes to its market-based rate tariff in Docket No. ER13-1823-000.

1. Description of PacifiCorp and Public Utility Affiliates

PacifiCorp is a vertically-integrated public utility primarily engaged in the business of providing retail electric service to approximately 1.8 million residential, commercial, industrial, and other customers in portions of the following states: Utah, Oregon, Wyoming, Washington, Idaho, and California. In addition, PacifiCorp provides electric transmission service in nine Western states and owns, controls, or has interests in: (i) approximately 9,191 pole miles of transmission lines and (ii) certain thermal, hydroelectric, and wind-powered generating plants with a combined rated capacity of approximately 11,004 MW.[3]

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[1] 18 C.F.R. § 35.37(a)(1) (2013).

[2] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, 119 FERC ¶ 61,295, *clarified*, 121 FERC ¶ 61,260 (2007), *on reh'g*, Order No. 697-A, 123 FERC ¶ 61,055 (2008), *on reh'g*, Order No. 697-B, 125 FERC ¶ 61,326 (2008), *on reh'g*, Order No. 697-C, 127 FERC ¶ 61,284 (2009); *on reh'g*, Order No. 697-D, 130 FERC ¶ 61,206 (2010); *clarified*, 131 FERC ¶ 61,021 (2010).

[3] This figure, which reflects nameplate ratings for solar and wind facilities, and summer seasonal ratings for all other facilities, includes approximately 495 MW of capacity leased or purchased through long-term contract, and

Part I - Pivotal Supplier Analysis
Base Case
PACW Balancing Authority Area
Applicant: PacifiCorp

Row		MW	Reference
	Generation		
	Seller and Affiliate Capacity		
A	Installed Capacity	2,889	Workpaper - Generation
B	Long-Term Firm Purchases	243	Workpaper - Generation
C	Long-Term Firm Sales	0	Workpaper - Generation
D	Imported Power	118	Workpaper - Imported Power
	Non-Affiliate Capacity		
E	Installed Capacity	237	Workpaper - Generation
F	Long-Term Firm Purchases	0	Workpaper - Generation
G	Long-Term Firm Sales	-6	Workpaper - Generation
H	Imported Power	1,601	Workpaper - Imported Power
I	Balancing Authority Area Reserve Requirement	-377	Workpaper - Reserves
J	Amount of Line I Attributable to Seller, if any	-359	Workpaper - Reserves
K	Total Uncommitted Supply (SUM A,B,C,D,E,F,G,H,I,M)	1,581	
	Load		
L	Balancing Authority Area Annual Peak Load	3,844	Workpaper - Load
M	Average Daily Peak Native Load in Peak Month	-3,123	Workpaper - Load
N	Amount of Line M Attributable to Seller, if any	-2,974	Workpaper - Load
O	Wholesale Load (SUM L,M)	721	
P	Net Uncommitted Supply (K-O)	860	
Q	Seller's Uncommitted Capacity (SUM A,B,C,D,J,N)	-84	

Result of Pivotal Supplier Screen (Pass if Line Q < Line P) **PASS**
(Fail if Line Q > 0 and Line Q > Line P)[1]

Note:
[1] Formulation in Appendix A of Order No. 697 adjusted to ensure that an applicant with zero or negative uncommitted capacity does not fail the pivotal supplier analysis.

Part II - Market Share Analysis
Base Case
PACW Balancing Authority Area
Applicant: PacifiCorp

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity					
A	Installed Capacity	2,801	2,868	2,610	2,601	Workpaper - Generation
B	Long-Term Firm Purchases	243	243	232	243	Workpaper - Generation
C	Long-Term Firm Sales	0	0	0	0	Workpaper - Generation
D	Seasonal Average Planned Outages	0	-203	-166	0	Workpaper - Planned Outages
E	Imported Power	135	225	0	122	Workpaper - Imported Power
	Capacity Deductions					
F	Average Peak Native Load in the Season	-3,133	-2,663	-2,689	-2,724	Workpaper - Load
G	Amount of Line F Attributable to Seller, if any	-2,990	-2,539	-2,562	-2,591	Workpaper - Load
H	Amount of Line F Attributable to Others, if any	-143	-125	-128	-133	Workpaper - Load
I	Balancing Authority Area Reserve Requirement	-371	-362	-361	-366	Workpaper - Reserves
J	Amount of Line I Attributable to Seller, if any	-354	-345	-344	-348	Workpaper - Reserves
K	Amount of Line I Attributable to Others, if any	-17	-17	-17	-18	Workpaper - Reserves
	Non-Affiliate Capacity					
L	Installed Capacity	216	246	228	192	Workpaper - Generation
M	Long-Term Firm Purchases	0	0	0	0	Workpaper - Generation
N	Long-Term Firm Sales	-5	-6	-6	-4	Workpaper - Generation
O	Local Seasonal Average Planned Outages	0	-16	-13	0	Workpaper - Planned Outages
P	Uncommitted Capacity Imports	1,583	1,010	1,410	1,091	Workpaper - Imported Power
	Supply Calculation					
Q	Total Competing Supply (SUM L,M,N,O,P,H,K)	1,635	1,093	1,475	1,127	
R	Seller's Uncommitted Capacity (Greater of 0 and SUM A,B,C,D,E,G,J)[1]	0	248	0	27	
S	Total Seasonal Uncommitted Capacity (SUM Q,R)	1,635	1,341	1,475	1,154	
T	**Seller's Market Share** (R/S)[1]					
	Results (Pass if < 20%)	0.0%	18.5%	0.0%	2.4%	
	(Fail if >= 20%)	**PASS**	**PASS**	**PASS**	**PASS**	

Note:
[1] Formulation in Appendix A of Order No. 697 adjusted to require value to be nonnegative.

Federal Energy Regulatory Commission
FERC Form No. 714

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2012

Utility Code: 14355
Utility Name: PacifiCorp - West

Part II - Schedule 3. Balancing Authority Area Net Energy for Load and Peak Demand Sources by Month

Enter the monthly "Net Energy for Load" which is the amount of energy that the balancing authority area requires internally including balancing authority area losses. The total in column (d) should equal the difference in the totals for columns (e) minus (f) on Schedule 5. The value in column (f) for the month of the annual peak demand should equal the total in column (e) in Schedule 1. Any differences must be explained in a footnote. Refer to the Form 714 instructions for specific guidelines.

Line No (a)	Month (b)	Balancing Authority Area Net Generation (MWh) (c)	Net Actual Interchange (MWh) (d)	Net Energy for Load (MWh) (c + d) (e)	Balancing Authority Area Area Load Sources at Time of Balancing Authority Area Area Monthly Peak Demand, Based on Net Energy For Load (NEL)					Monthly Minimum Demand (MW) (k)
					Output of Generating Plants (MW) (f)	Unit or Firm Purchases (MW) (g)	Unit or Firm Sales (MW) (h)	Net Non-Firm & Inadvertent (MW) (i)	Monthly Peak Demand (MW) (f+g-h+i) (j)	
1	January	1,982,034	38,686	2,020,720	2,479	4,654	3,406	-19	3,708	1,871
2	February	1,863,414	-63,777	1,799,637	2,697	4,168	3,351	-36	3,478	1,879
3	March	1,855,177	-42,936	1,812,241	2,785	3,688	3,019	28	3,482	1,712
4	April	1,191,616	335,923	1,527,539	2,214	3,090	2,300	17	3,021	1,378
5	May	1,279,836	300,810	1,580,646	2,082	4,725	4,075	-16	2,716	1,478
6	June	1,397,721	158,765	1,556,486	1,712	4,282	3,172	8	2,830	1,496
7	July	1,425,458	352,213	1,777,671	2,235	5,635	4,524	5	3,351	1,601
8	August	1,487,511	366,777	1,854,288	2,260	5,302	4,050	6	3,518	1,626
9	September	1,567,774	56,140	1,623,914	2,362	4,590	3,974	42	3,020	1,589
10	October	1,675,820	-7,354	1,668,466	2,299	4,201	3,453	-54	2,993	1,588
11	November	1,804,369	-71,838	1,732,531	2,578	3,963	3,335	-78	3,128	1,609
12	December	1,945,472	42,070	1,987,542	2,829	4,210	3,583	-20	3,436	1,807
13	Total	19,476,202	1,465,479	20,941,681						

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Attachment B:
Asset Appendices of Exelon Corporation and Affiliates

Electric Generating Facilities and Assets

Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Commonwealth Edison Company	ER98-1734	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Constellation Energy Commodities Group Maine, LLC	ER02-699	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Constellation Energy Services of New York, Inc.	ER07-651	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Constellation Energy Services, Inc.	ER07-650	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Constellation NewEnergy, Inc.	ER96-1387	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
PECO Energy Company	ER01-1147	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
AgriWind LLC	N/A QF07-214	Agriwind LLC WF	AgriWind LLC	AgriWind LLC	N/A	MISO	Central	7/1/07	2.10
AgriWind Project L.L.C.	N/A QF07-215	Agriwind Project LLC WF	AgriWind Project L.L.C.	AgriWind Project L.L.C.	N/A	MISO	Central	7/1/07	6.30
BC Energy LLC	N/A QF07-219	BC Energy LLC WF	BC Energy LLC	BC Energy LLC	N/A	MISO	Central	5/28/08	4.20
Beebe 1B Renewable Energy, LLC	ER14-2144	Beebe 1b WF	Beebe 1B Renewable Energy, LLC	Beebe 1B Renewable Energy, LLC	N/A	MISO	Central	12/12/14	50.40
Beebe Renewable Energy, LLC	ER12-2311	Beebe 1a WF	Beebe Renewable Energy, LLC	Beebe Renewable Energy, LLC	N/A	MISO	Central	1/17/13	81.60
Blue Breezes II, L.L.C.	N/A QF07-243	Blue Breezes II LLC WF	Blue Breezes II, L.L.C.	Blue Breezes II, L.L.C.	N/A	MISO	Central	5/1/06	1.25
Blue Breezes, L.L.C.	N/A QF07-242	Blue Breezes I LLC WF	Blue Breezes, L.L.C.	Blue Breezes, L.L.C.	N/A	MISO	Central	5/1/06	1.25
Breezy Bucks I LLC	N/A QF07-234	Breezy Bucks I LLC WF	Breezy Bucks I LLC	Breezy Bucks I LLC	N/A	MISO	Central	5/31/06	1.25
Breezy Bucks II LLC	N/A QF07-235	Breezy Bucks II LLC WF	Breezy Bucks II LLC	Breezy Bucks II LLC	N/A	MISO	Central	5/31/06	1.25
Christoffer Wind Energy I LLC	N/A QF07-250	Christoffer Wind I WF	Christoffer Wind Energy I LLC	Christoffer Wind Energy I LLC	N/A	MISO	Central	6/13/08	2.10
Christoffer Wind Energy II LLC	N/A QF07-252	Christoffer Wind II WF	Christoffer Wind Energy II LLC	Christoffer Wind Energy II LLC	N/A	MISO	Central	6/13/08	2.10
Christoffer Wind Energy III LLC	N/A QF07-251	Christoffer Wind III WF	Christoffer Wind Energy III LLC	Christoffer Wind Energy III LLC	N/A	MISO	Central	6/13/08	2.10
Christoffer Wind Energy IV LLC	N/A QF07-249	Christoffer Wind IV WF	Christoffer Wind Energy IV LLC	Christoffer Wind Energy IV LLC	N/A	MISO	Central	6/13/08	2.10
CP Windfarm, LLC	N/A QF07-178	CP Wind Farms LLC WF	CP Windfarm, LLC	CP Windfarm, LLC	N/A	MISO	Central	10/9/07	4.20
Exelon Generation Company, LLC	ER00-3251	Clinton	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	MISO	Central	11/1/87	1065.00
G-Flow Wind, LLC	N/A QF07-223	G-Flow Wind LLC WF	G-Flow Wind, LLC	G-Flow Wind, LLC	N/A	MISO	Central	3/6/06	1.25
Green Acres Breeze, LLC	N/A QF07-227	Green Acres Breeze LLC WF	Green Acres Breeze, LLC	Green Acres Breeze, LLC	N/A	MISO	Central	3/6/06	1.25
Harvest II Windfarm, LLC	ER12-2201 QF12-522	Harvest 2 WF	Harvest II Windfarm, LLC	Harvest II Windfarm, LLC	N/A	MISO	Central	11/28/12	59.40
Harvest Windfarm, LLC	ER07-1246 QF07-29	Harvest 1 WF	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	2/28/08	52.80

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
K&D Energy LLC	N/A QF07-218	K&D Energy LLC WF	K&D Energy LLC	K&D Energy LLC	N/A	MISO	Central	5/28/08	4.00
KC Energy LLC	N/A QF07-217	KC Energy LLC WF	KC Energy LLC	KC Energy LLC	N/A	MISO	Central	5/28/08	4.00
KSS Turbines LLC	N/A QF07-220	KSS Turbines LLC WF	KSS Turbines LLC	KSS Turbines LLC	N/A	MISO	Central	5/28/08	4.00
Marshall Wind 1, LLC	N/A QF08-59	Marshall Wind 1 WF	Marshall Wind 1, LLC	Marshall Wind 1, LLC	N/A	MISO	Central	5/30/08	2.10
Marshall Wind 2, LLC	N/A QF08-58	Marshall Wind 2 WF	Marshall Wind 2, LLC	Marshall Wind 2, LLC	N/A	MISO	Central	5/30/08	4.20
Marshall Wind 3, LLC	N/A QF08-55	Marshall Wind 3 WF	Marshall Wind 3, LLC	Marshall Wind 3, LLC	N/A	MISO	Central	5/30/08	4.20
Marshall Wind 4, LLC	N/A QF08-56	Marshall Wind 4 WF	Marshall Wind 4, LLC	Marshall Wind 4, LLC	N/A	MISO	Central	5/30/08	4.20
Marshall Wind 5, LLC	N/A QF08-57	Marshall Wind 5 WF	Marshall Wind 5, LLC	Marshall Wind 5, LLC	N/A	MISO	Central	5/30/08	2.10
Marshall Wind 6, LLC	N/A QF08-60	Marshall Wind 6 WF	Marshall Wind 6, LLC	Marshall Wind 6, LLC	N/A	MISO	Central	5/30/08	2.10
Michigan Wind 1, LLC	ER05-1511 QF05-228	Michigan Wind 1 WF	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	12/16/08	69.00
Michigan Wind 2, LLC	ER11-3989	Michigan Wind 2 WF	Michigan Wind 2, LLC	Michigan Wind 2, LLC	N/A	MISO	Central	1/5/12	90.00
Minnesota Breeze, LLC	N/A QF07-224	Minnesota Breeze LLC WF	Minnesota Breeze, LLC	Minnesota Breeze, LLC	N/A	MISO	Central	3/6/06	1.25
Prairie Wind Power LLC	N/A QF07-216	Prairie Wind Power LLC WF	Prairie Wind Power LLC	Prairie Wind Power LLC	N/A	MISO	Central	5/28/08	4.00
Roadrunner I LLC	N/A QF07-236	Roadrunner I LLC WF	Roadrunner I LLC	Roadrunner I LLC	N/A	MISO	Central	5/31/06	1.25
Salty Dog I LLC	N/A QF07-237	Salty Dog I LLC WF	Salty Dog I LLC	Salty Dog I LLC	N/A	MISO	Central	5/31/06	1.25
Salty Dog II LLC	N/A QF07-238	Salty Dog II LLC WF	Salty Dog II LLC	Salty Dog II LLC	N/A	MISO	Central	5/31/06	1.25
Shane's Wind Machine LLC	N/A QF07-247	Shanes Wind Machine LLC WF	Shane's Wind Machine LLC	Shane's Wind Machine LLC	N/A	MISO	Central	7/1/06	2.00
Sunset Breeze, LLC	N/A QF07-226	Sunset Breeze LLC WF	Sunset Breeze, LLC	Sunset Breeze, LLC	N/A	MISO	Central	3/6/06	1.25
Wally's Wind Farm LLC	N/A QF07-239	Wally's Wind Farm WF	Wally's Wind Farm LLC	Wally's Wind Farm LLC	N/A	MISO	Central	5/31/06	1.25
Windy Dog I LLC	N/A QF07-240	Windy Dog I LLC WF	Windy Dog I LLC	Windy Dog I LLC	N/A	MISO	Central	5/31/06	1.25
Wolf Wind Enterprises, LLC	N/A QF07-225	Wolf Wind Enterprises LLC WF	Wolf Wind Enterprises, LLC	Wolf Wind Enterprises, LLC	N/A	MISO	Central	3/6/06	1.25
Exelon Generation Company, LLC	ER00-3251	Frontier GT1	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	9/20/00	MISO & ERCOT	Central	9/20/00	160.00
Exelon Generation Company, LLC	ER00-3251	Frontier GT2	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	9/20/00	MISO & ERCOT	Central	9/20/00	160.00
Exelon Generation Company, LLC	ER00-3251	Frontier GT3	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	9/20/00	MISO & ERCOT	Central	9/20/00	160.00
Exelon Generation Company, LLC	ER00-3251	Frontier ST	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	9/20/00	MISO & ERCOT	Central	9/20/00	390.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 7	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/75	575.48
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/03	225.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/03	227.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/03	252.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/03	231.09
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/03	230.80
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/03	252.00
Constellation Mystic Power, LLC	ER10-2281	Mystic Jet	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/69	9.07
Constellation Solar Connecticut, LLC	N/A QF10-654	East Lyme Bd of Ed at East Lyme HS	Constellation Solar Connecticut LLC	Constellation Solar Connecticut LLC	N/A	ISO-NE	Northeast	3/2/09	0.41
Constellation Solar Connecticut, LLC	N/A QF10-663	Parker Hannifin Corp at New Britain	Constellation Solar Connecticut LLC	Constellation Solar Connecticut LLC	N/A	ISO-NE	Northeast	12/30/08	0.18
Constellation Solar Massachusetts, LLC	N/A QF11-411	Kollmorgen Electro-Optical HQ Bldg	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	7/19/11	0.17
Constellation Solar Massachusetts, LLC	N/A QF15-188	Macy's at Marlborough	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	12/31/14	0.41
Constellation Solar Massachusetts, LLC	N/A QF15-187	Macy's at Natick	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	12/6/14	0.56
Constellation Solar Massachusetts, LLC	N/A QF15-186	Macy's at Saugus	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	12/31/14	0.30
Constellation Solar Massachusetts, LLC	N/A QF15-190	Macy's at Burlington	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	12/4/14	0.25
Constellation Solar Massachusetts, LLC	N/A QF15-189	Macy's at Dartmouth	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	12/31/14	0.35
Constellation Solar Massachusetts, LLC	N/A QF09-89	Majilite Corp	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	2/16/09	0.35
Constellation Solar Massachusetts, LLC	N/A QF10-655	NPP Development, LLC at Patriot Place	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	7/14/10	0.45
Constellation Solar Massachusetts, LLC	N/A QF12-212	Swampscott High School	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	2/7/12	0.32
Constellation Solar Massachusetts, LLC	N/A QF12-292	Town of Norfolk SF	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	6/25/12	1.35
Constellation Solar Net Metering, LLC	N/A QF12-293	Town of Uxbridge SF	Constellation Solar Net Metering, LLC	Constellation Solar Net Metering, LLC	N/A	ISO-NE	Northeast	6/1/12	1.93
Exelon Framingham LLC	ER01-513	Framingham Jet 1	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	3/1/70	10.15
Exelon Framingham LLC	ER01-513	Framingham Jet 2	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/69	11.69
Exelon Framingham LLC	ER01-513	Framingham Jet 3	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/69	11.25
Exelon Generation Company, LLC	ER00-3251	Granite Ridge GT1	Granite Ridge Energy, LLC	Exelon Generation Company, LLC	1/1/14	ISO-NE	Northeast	12/13/02	220.00
Exelon Generation Company, LLC	ER00-3251	Granite Ridge GT2	Granite Ridge Energy, LLC	Exelon Generation Company, LLC	1/1/14	ISO-NE	Northeast	12/13/02	220.00
Exelon Generation Company, LLC	ER00-3251	Granite Ridge STG1	Granite Ridge Energy, LLC	Exelon Generation Company, LLC	1/1/14	ISO-NE	Northeast	12/13/02	221.32
Exelon Generation Company, LLC	ER00-3251	Kleen GT1	Kleen Energy Systems, LLC	Exelon Generation Company, LLC	7/23/11	ISO-NE	Northeast	7/8/11	186.00
Exelon Generation Company, LLC	ER00-3251	Kleen GT2	Kleen Energy Systems, LLC	Exelon Generation Company, LLC	7/23/11	ISO-NE	Northeast	7/8/11	188.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Kleen STG1	Kleen Energy Systems, LLC	Exelon Generation Company, LLC	7/23/11	ISO-NE	Northeast	7/8/11	246.00
Exelon New Boston, LLC	ER01-513	New Boston Jet	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	9/1/66	16.03
Exelon West Medway, LLC	ER01-513	West Medway Jet 1	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/70	42.00
Exelon West Medway, LLC	ER01-513	West Medway Jet 2	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	3/1/71	39.85
Exelon West Medway, LLC	ER01-513	West Medway Jet 3	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/70	35.44
Exelon Wyman, LLC	ER01-513	Wyman 4	Exelon Wyman, LLC (5.9%)	FPL Wyman Energy, LLC	N/A	ISO-NE	Northeast	1/1/78	610.00
Holyoke Solar LLC	N/A QF12-294	City of Holyoke G & E Dept at Meadow SF	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	12/27/11	0.87
Holyoke Solar LLC	N/A QF12-267	City of Holyoke G & E Dept at Mueller SF	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	3/12/12	2.95
2014 ESA Project Company, LLC	ER15-1496 (pending)	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	N/A	NYISO	Northeast	12/31/14	0.20
Constellation Solar New York, LLC	N/A QF13-550	Owens Corning	Constellation Solar New York, LLC	Constellation Solar New York, LLC	N/A	NYISO	Northeast	10/9/13	2.28
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 1	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	12/1/69	626.90
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 2	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	8/1/88	1287.20
R. E. Ginna Nuclear Power Plant, LLC	ER04-485	Ginna	R. E. Ginna Nuclear Power Plant, LLC	R. E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	7/1/70	581.70
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 1	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	5/1/75	873.00
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 2	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	4/1/77	841.80
Constellation Power Source Generation, LLC	ER00-1598	Gould Street 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	12/1/52	97.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/69	14.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/69	14.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/69	14.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/69	14.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/69	15.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/69	16.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/69	15.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/69	16.00
Constellation Power Source Generation, LLC	ER00-1598	Perryman 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	1/1/72	52.00
Constellation Power Source Generation, LLC	ER00-1598	Perryman 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	4/1/72	51.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Constellation Power Source Generation, LLC	ER00-1598	Perryman 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	4/1/72	51.00
Constellation Power Source Generation, LLC	ER00-1598	Perryman 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	4/1/72	52.00
Constellation Power Source Generation, LLC	ER00-1598	Perryman 51	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/95	147.60
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	8/1/70	15.30
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	8/1/70	16.00
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	9/1/70	14.80
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	9/1/70	14.80
Constellation Power Source Generation, LLC	ER00-1598	Riverside 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	9/1/51	74.00
Constellation Power Source Generation, LLC	ER00-1598	Riverside 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	9/1/70	19.00
Constellation Power Source Generation, LLC	ER00-1598	Riverside 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	9/1/70	20.00
Constellation Power Source Generation, LLC	ER00-1598	Westport 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	2/1/69	115.80
Constellation Solar DC, LLC	N/A QF13-575	Dunbar	Constellation Solar DC, LLC	Constellation Solar DC, LLC	N/A	PJM	Northeast	12/27/13	0.32
Constellation Solar Federal LLC	N/A QF12-78	Reeves SF	Constellation Solar Federal LLC	Constellation Solar Federal LLC	N/A	PJM	Northeast	12/20/11	4.23
Constellation Solar Horizons, LLC	N/A QF10-586	University System of Maryland & Department of General Services SF	Constellation Solar Horizons, LLC	Constellation Solar Horizons, LLC	N/A	PJM	Northeast	7/1/12	13.61
Constellation Solar Maryland II, LLC	N/A QF15-660	CNE at Cambridge	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	4/30/15	3.67
Constellation Solar Maryland II, LLC	N/A QF13-135	UMMS - CRE	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	2/21/13	0.35
Constellation Solar Maryland II, LLC	N/A QF13-136	UMMS (U of MD Medical System) SF	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	2/21/13	3.09
Constellation Solar Maryland, LLC	N/A QF11-271	AA County, MD at Shared Svcs Complex	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	3/4/11	0.63
Constellation Solar Maryland, LLC	N/A QF11-333	Coppin State Univ at Coppin State Univ - PEC	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	9/14/11	0.42
Constellation Solar Maryland, LLC	N/A QF11-410	CPSG Fort Smallwood Road Complex	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	10/3/11	0.78
Constellation Solar Maryland, LLC	N/A QF11-335	GM Allison Plant-I	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	5/18/11	1.04
Constellation Solar Maryland, LLC	N/A QF11-407	Maryland Science Center	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	5/24/11	0.09
Constellation Solar Maryland, LLC	N/A QF11-268	McCormick & Co, Inc at Belcamp	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	1/1/11	1.56
Constellation Solar Maryland, LLC	N/A QF10-662	McCormick & Co, Inc at Hunt Valley	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	1/26/09	0.78
Constellation Solar Maryland, LLC	N/A QF11-334	McCormick & Co, Inc at Sparks	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	6/24/11	0.08
Constellation Solar Maryland, LLC	N/A QF10-661	MD Env Service at MES Headquarters	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	12/29/08	0.25
Constellation Solar Maryland, LLC	N/A QF12-507	University System of Maryland II	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	7/1/12	1.42

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Constellation Solar New Jersey II, LLC	N/A QF11-267	Johnson Matthey, Inc at West Deptford	Constellation Solar New Jersey II, LLC	Constellation Solar New Jersey II, LLC	N/A	PJM	Northeast	4/25/11	4.41
Constellation Solar New Jersey II, LLC	N/A QF11-461	Toys-R-Us Delaware, Inc at Mt Olive	Constellation Solar New Jersey II, LLC	Constellation Solar New Jersey II, LLC	N/A	PJM	Northeast	12/22/11	4.55
Constellation Solar New Jersey III, LLC	N/A QF12-81	Middle Township Elem School 1	Constellation Solar New Jersey III, LLC	Constellation Solar New Jersey III, LLC	N/A	PJM	Northeast	12/7/11	0.17
Constellation Solar New Jersey III, LLC	N/A QF12-79	Middle Township Elem School 2	Constellation Solar New Jersey III, LLC	Constellation Solar New Jersey III, LLC	N/A	PJM	Northeast	12/5/11	0.39
Constellation Solar New Jersey III, LLC	N/A QF12-80	Middle Township High School	Constellation Solar New Jersey III, LLC	Constellation Solar New Jersey III, LLC	N/A	PJM	Northeast	12/14/11	0.69
Constellation Solar New Jersey LLC	N/A QF11-270	Benjamin Moore & Co at Flanders NJ	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	1/3/11	1.50
Constellation Solar New Jersey LLC	N/A QF10-666	Jet Aviation Teterboro, LP at Teterboro Airport	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	3/1/08	0.15
Constellation Solar New Jersey LLC	N/A QF11-464	North Vineland SF	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	10/18/11	2.54
Constellation Solar New Jersey LLC	N/A QF11-463	West Vineland SF	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	10/19/11	4.06
Constellation Solar Ohio, LLC	N/A QF10-664	Univ of Toledo (Solar) Scott Park Campus of Energy & Innovation	Constellation Solar Ohio, LLC	Constellation Solar Ohio, LLC	N/A	PJM	Northeast	3/31/10	0.88
Constellation Solar Ohio, LLC	N/A QF10-659	Univ of Toledo (Wind) Scott Park Campus of Energy & Innovation	Constellation Solar Ohio, LLC	Constellation Solar Ohio, LLC	N/A	PJM	Northeast	3/31/10	0.07
Criterion Power Partners, LLC	ER10-1443	Criterion WF	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	2/4/11	70.00
Exelon Generation Company, LLC	ER00-3251	Braidwood 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/1/88	1178.00
Exelon Generation Company, LLC	ER00-3251	Braidwood 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/88	1152.00
Exelon Generation Company, LLC	ER00-3251	Byron 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/1/85	1164.00
Exelon Generation Company, LLC	ER00-3251	Byron 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/87	1136.00
Exelon Generation Company, LLC	ER00-3251	Chester 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	2/7/69	13.00
Exelon Generation Company, LLC	ER00-3251	Chester 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/20/69	13.00
Exelon Generation Company, LLC	ER00-3251	Chester 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/6/69	13.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/1/28	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/25/64	65.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/4/64	65.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/1/28	36.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/6/28	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	4/5/28	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/1/28	36.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/1/28	48.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Conowingo 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/1/28	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/10/64	65.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/25/64	65.00
Exelon Generation Company, LLC	ER00-3251	Cordova GT1	Cordova Energy Company, LLC	Exelon Generation Company, LLC	12/30/05	PJM	Northeast	6/12/01	165.00
Exelon Generation Company, LLC	ER00-3251	Cordova GT2	Cordova Energy Company, LLC	Exelon Generation Company, LLC	12/30/05	PJM	Northeast	6/12/01	165.00
Exelon Generation Company, LLC	ER00-3251	Cordova STG1	Cordova Energy Company, LLC	Exelon Generation Company, LLC	12/30/05	PJM	Northeast	6/12/01	191.20
Exelon Generation Company, LLC	ER00-3251	Croydon 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/18/74	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/18/74	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 21	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/18/74	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 22	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/18/74	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 31	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/6/74	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 32	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/8/74	48.00
Exelon Generation Company, LLC	ER00-3251	Croydon 41	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/24/74	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 42	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/24/74	49.00
Exelon Generation Company, LLC	ER00-3251	Delaware 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/7/69	13.00
Exelon Generation Company, LLC	ER00-3251	Delaware 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	4/19/69	13.00
Exelon Generation Company, LLC	ER00-3251	Delaware 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/12/69	13.00
Exelon Generation Company, LLC	ER00-3251	Delaware 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/24/70	17.00
Exelon Generation Company, LLC	ER00-3251	Dresden 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/70	883.50
Exelon Generation Company, LLC	ER00-3251	Dresden 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/71	895.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/20/67	13.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 20	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/11/67	13.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/24/74	380.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 30	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/7/70	17.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/29/76	380.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 40	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/21/70	17.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 5	Elwood Energy, LLC	Exelon Generation Company, LLC	6/15/06	PJM	Northeast	7/18/01	150.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 6	Elwood Energy, LLC	Exelon Generation Company, LLC	6/15/06	PJM	Northeast	7/18/01	150.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 7	Elwood Energy, LLC	Exelon Generation Company, LLC	6/15/06	PJM	Northeast	7/18/01	150.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 8	Elwood Energy, LLC	Exelon Generation Company, LLC	6/15/06	PJM	Northeast	7/18/01	150.00
Exelon Generation Company, LLC	ER00-3251	Fairless Hills A	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/96	30.00
Exelon Generation Company, LLC	ER00-3251	Fairless Hills B	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/96	30.00
Exelon Generation Company, LLC	ER00-3251	Falls 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/22/70	17.00
Exelon Generation Company, LLC	ER00-3251	Falls 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/10/70	17.00
Exelon Generation Company, LLC	ER00-3251	Falls 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/28/70	17.00
Exelon Generation Company, LLC	ER00-3251	LaSalle 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	1/1/84	1135.40
Exelon Generation Company, LLC	ER00-3251	LaSalle 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/84	1136.20
Exelon Generation Company, LLC	ER00-3251	Limerick 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	2/1/86	1119.70
Exelon Generation Company, LLC	ER00-3251	Limerick 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	1/1/90	1122.10
Exelon Generation Company, LLC	ER00-3251	Moser 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/9/70	17.00
Exelon Generation Company, LLC	ER00-3251	Moser 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/29/70	17.00
Exelon Generation Company, LLC	ER00-3251	Moser 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/11/70	17.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	4/10/67	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	4/10/67	133.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/1/67	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/1/67	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/11/67	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/11/67	133.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	2/10/68	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	2/10/68	134.00
Exelon Generation Company, LLC	ER00-3251	Oyster Creek 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/69	609.90
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 2	ExGen (PSEG 50%)	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/5/74	1254.00
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 3	ExGen (PSEG 50%)	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/23/74	1125.40
Exelon Generation Company, LLC	ER00-3251	Pennsbury 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/1/96	2.67

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Pennsbury 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/1/96	2.67
Exelon Generation Company, LLC	ER00-3251	Quad Cities 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/72	908.00
Exelon Generation Company, LLC	ER00-3251	Quad Cities 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/72	911.00
Exelon Generation Company, LLC	ER00-3251	Richmond 91	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/7/73	49.00
Exelon Generation Company, LLC	ER00-3251	Richmond 92	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/7/73	49.00
Exelon Generation Company, LLC	ER00-3251	Salem 1	PSEG (ExGen 42.59%)	PSEG	N/A	PJM	Northeast	6/30/77	1173.99
Exelon Generation Company, LLC	ER00-3251	Salem 2	PSEG (ExGen 42.59%)	PSEG	N/A	PJM	Northeast	10/13/81	1158.02
Exelon Generation Company, LLC	ER00-3251	Salem 3	PSEG (ExGen 42.59%)	PSEG	N/A	PJM	Northeast	6/17/71	37.57
Exelon Generation Company, LLC	ER00-3251	Schuylkill 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/30/69	13.00
Exelon Generation Company, LLC	ER00-3251	Schuylkill 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/11/71	17.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/02	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/02	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/02	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/02	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/02	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/02	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/02	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/02	37.00
Exelon Generation Company, LLC	ER00-3251	Southwark 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/14/67	13.00
Exelon Generation Company, LLC	ER00-3251	Southwark 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/9/67	13.00
Exelon Generation Company, LLC	ER00-3251	Southwark 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/26/67	13.00
Exelon Generation Company, LLC	ER00-3251	Southwark 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	11/7/68	13.00
Exelon Generation Company, LLC	ER00-3251	TMI 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/2/74	802.80
Exelon Generation Company, LLC	ER00-3251	York Delta GT1	Calpine Mid Merit LLC	Exelon Generation Company, LLC	6/1/11	PJM	Northeast	3/3/11	118.00
Exelon Generation Company, LLC	ER00-3251	York Delta GT2	Calpine Mid Merit LLC	Exelon Generation Company, LLC	6/1/11	PJM	Northeast	3/3/11	127.00
Exelon Generation Company, LLC	ER00-3251	York Delta GT3	Calpine Mid Merit LLC	Exelon Generation Company, LLC	6/1/11	PJM	Northeast	3/3/11	127.00
Exelon Generation Company, LLC	ER00-3251	York Delta STG1	Calpine Mid Merit LLC	Exelon Generation Company, LLC	6/1/11	PJM	Northeast	3/3/11	193.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Solar Chicago LLC	N/A QF10-174	Chicago City Solar SF	Exelon Solar Chicago LLC	Exelon Solar Chicago LLC	N/A	PJM	Northeast	3/23/10	8.00
Fourmile Wind Energy, LLC	ER14-2145 QF14-721	Fourmile Ridge WF	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	1/15/15	40.00
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 1	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/01	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 2	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/01	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 3	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/01	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 4	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/01	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 5	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/01	53.50
Bennett Creek Windfarm, LLC	N/A QF07-36	Bennett Creek WF	Bennett Creek, LLC	Bennett Creek, LLC	N/A	IPCO	Northwest	8/31/08	21.00
Cassia Gulch Wind Park LLC	ER10-75 QF05-180	Cassia Gulch WF	Cassia Gulch Wind Park LLC	Cassia Gulch Wind Park LLC	N/A	IPCO	Northwest	3/31/09	18.90
Cassia Wind Farm, LLC	N/A QF05-170	Cassia Wind WF	Cassia Wind Farm, LLC	Cassia Wind Farm, LLC	N/A	IPCO	Northwest	3/31/09	10.50
High Mesa Energy, LLC	ER12-2528 QF13-77	High Mesa WF	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	IPCO	Northwest	8/28/12	40.00
Hot Springs Windfarm, LLC	N/A QF07-37	Hot Springs WF	Hot Springs Windfarm, LLC	Hot Springs Windfarm, LLC	N/A	IPCO	Northwest	8/31/08	21.00
Tuana Springs Energy, LLC	ER10-87 QF08-742	Tuana Springs WF	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	IPCO	Northwest	7/27/10	16.80
Sunnyside Cogeneration Assoc.	N/A QF86-556	Sunnyside Cogen	Sunnyside Cogeneration Assoc.	Sunnyside Cogeneration Assoc.	N/A	PACE	Northwest	2/1/93	51.00
Big Top, LLC	N/A QF08-539	Big Top WF	Big Top, LLC	Big Top, LLC	N/A	PACW	Northwest	6/27/09	1.65
Butter Creek Power, LLC	N/A QF08-536	Butter Creek WF	Butter Creek Power, LLC	Butter Creek Power, LLC	N/A	PACW	Northwest	6/27/09	4.95
Four Corners Windfarm, LLC	N/A QF08-372	Four Corner WF	Four Corners Windfarm, LLC	Four Corners Windfarm, LLC	N/A	PACW	Northwest	9/30/09	10.00
Four Mile Canyon Windfarm, LLC	N/A QF08-370	Four Mile Canyon WF	Four Mile Canyon Windfarm, LLC	Four Mile Canyon Windfarm, LLC	N/A	PACW	Northwest	9/30/09	10.00
Oregon Trail Windfarm, LLC	N/A QF08-371	Oregon Trail WF	Oregon Trail Windfarm, LLC	Oregon Trail Windfarm, LLC	N/A	PACW	Northwest	6/27/09	9.90
Pacific Canyon Windfarm, LLC	N/A QF08-373	Pacific Canyon WF	Pacific Canyon Windfarm, LLC	Pacific Canyon Windfarm, LLC	N/A	PACW	Northwest	6/27/09	8.25
Sand Ranch Windfarm, LLC	N/A QF08-368	Sand Ranch WF	Sand Ranch Windfarm, LLC	Sand Ranch Windfarm, LLC	N/A	PACW	Northwest	6/27/09	9.90
Three Mile Canyon Wind I, LLC	N/A QF09-142	Three Mile Canyon WF	Three Mile Canyon Wind I, LLC	Three Mile Canyon Wind I, LLC	N/A	PACW	Northwest	9/30/09	9.90
Wagon Trail, LLC	N/A QF08-537	Wagon Trail WF	Wagon Trail, LLC	Wagon Trail, LLC	N/A	PACW	Northwest	6/27/09	3.30
Ward Butte Windfarm, LLC	N/A QF08-369	Ward Butte WF	Ward Butte Windfarm, LLC	Ward Butte Windfarm, LLC	N/A	PACW	Northwest	6/27/09	6.60
Outback Solar, LLC	N/A QF13-34	Outback Solar SF	Outback Solar, LLC	Outback Solar, LLC	N/A	BPA	Northwest	10/30/12	4.82
FPL Energy Vansycle, L.L.C.	ER01-838	Stateline WF	FPL Energy Vansycle, L.L.C.	FPL Energy Vansycle, L.L.C.	4/1/15	PACW	Northwest	12/1/01	300.00
Denver Airport Solar, LLC	N/A QF11-336	City & County of Denver at Denver International Airport	Denver Airport Solar, LLC	Denver Airport Solar, LLC	N/A	PSCO	Northwest	6/7/11	3.77

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Cow Branch Wind Power, L.L.C.	ER07-1223 QF07-253	Cow Branch WF	Cow Branch Wind Power, L.L.C.	Cow Branch Wind Power, L.L.C.	N/A	AECI	Southeast	3/3/08	50.40
CR Clearing, LLC	ER07-1222 QF07-248	CR Clearing LLC WF	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	5/1/08	50.40
Loess Hills Wind Farm, LLC	N/A QF07-241	Loess Hills WF	Loess Hills Wind Farm, LLC	Loess Hills Wind Farm, LLC	N/A	AECI	Southeast	4/19/08	5.00
Wind Capital Holdings, LLC	ER07-1208 QF07-222	Wind Capital Holdings LLC WF	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	5/14/07	56.70
CER Generation, LLC	ER10-662	Hillabee GT1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/10	207.00
CER Generation, LLC	ER10-662	Hillabee GT2	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/10	207.00
CER Generation, LLC	ER10-662	Hillabee STG1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/10	281.00
Constellation Solar Georgia, LLC	N/A QF15-202	Cave Spring	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/14	0.85
Constellation Solar Georgia, LLC	N/A QF15-659	Dublin	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	5/30/15	0.85
Constellation Solar Georgia, LLC	N/A QF15-203	Eastanollee	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/14	0.84
Constellation Solar Georgia, LLC	N/A QF15-204	Gibson	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/14	0.62
Constellation Solar Georgia, LLC	N/A QF14-505	Sparta SF	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	5/7/14	0.85
Constellation Solar Georgia, LLC	N/A QF15-205	Summerville	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/14	0.38
Constellation Solar Georgia, LLC	N/A QF15-658	Toccoa	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	4/22/15	0.68
Constellation Solar Georgia, LLC	N/A QF15-206	Wadley	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/14	1.11
Constellation Solar Georgia, LLC	N/A QF15-207	Wrens	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/14	0.34
Exelon Generation Company, LLC	ER00-3251	Effingham GT1	Effingham County Power, LLC	Effingham County Power, LLC / Exelon Generation Company, LLC	6/1/07	SOCO	Southeast	8/27/03	163.00
Exelon Generation Company, LLC	ER00-3251	Effingham GT2	Effingham County Power, LLC	Effingham County Power, LLC / Exelon Generation Company, LLC	6/1/07	SOCO	Southeast	8/27/03	163.00
Exelon Generation Company, LLC	ER00-3251	Effingham STG1	Effingham County Power, LLC	Effingham County Power, LLC / Exelon Generation Company, LLC	6/1/07	SOCO	Southeast	8/27/03	176.00
Exelon Generation Company, LLC	ER00-3251	Franklin GT1	Southern Power Company	Southern Power Company / Exelon Generation Company, LLC	6/1/07	SOCO	Southeast	6/6/03	183.00
Exelon Generation Company, LLC	ER00-3251	Franklin GT2	Southern Power Company	Southern Power Company / Exelon Generation Company, LLC	6/1/07	SOCO	Southeast	6/6/03	183.00
Exelon Generation Company, LLC	ER00-3251	Franklin STG1	Southern Power Company	Southern Power Company / Exelon Generation Company, LLC	6/1/07	SOCO	Southeast	6/6/03	255.00
Exelon Generation Company, LLC	ER00-3251	Heard 1	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/01	SOCO	Southeast	6/29/01	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 2	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/01	SOCO	Southeast	6/29/01	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 3	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/01	SOCO	Southeast	6/29/01	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 4	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/01	SOCO	Southeast	5/31/02	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 5	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/01	SOCO	Southeast	5/31/02	157.50

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Heard 6	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/01	SOCO	Southeast	5/31/02	157.50
Exelon Generation Company, LLC	ER00-3251	Hog Bayou	Mobile Energy LLC	Exelon Generation Company, LLC	1/1/15	SOCO	Southeast	7/11/01	230.00
Exelon Generation Company, LLC	ER00-3251	Sowega 1	Georgia Energy Cooperative	Exelon Generation Company, LLC	1/1/11	SOCO	Southeast	6/1/99	48.00
Exelon Generation Company, LLC	ER00-3251	Sowega 2	Georgia Energy Cooperative	Exelon Generation Company, LLC	1/1/11	SOCO	Southeast	6/1/99	48.00
Exelon Generation Company, LLC	ER00-3251	Washington 1	Washington County Power, LLC	Washington County Power, LLC / Exelon Generation Company, LLC	6/1/07	SOCO	Southeast	6/1/03	153.50
Exelon Generation Company, LLC	ER00-3251	Washington 4	Washington County Power, LLC	Washington County Power, LLC / Exelon Generation Company, LLC	6/1/07	SOCO	Southeast	6/1/03	153.50
Constellation Solar Arizona, LLC	N/A QF12-211	Buckeye Union HS at Estrella & Youngkers	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/7/11	3.62
Constellation Solar Arizona, LLC	N/A QF13-76	Casa Grande - Casa Verde HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/19/12	0.35
Constellation Solar Arizona, LLC	N/A QF13-75	Casa Grande - Union HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/19/12	1.79
Constellation Solar Arizona, LLC	N/A QF13-74	Casa Grande - Vista Grande HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/19/12	1.54
Constellation Solar Arizona, LLC	N/A QF13-599	Charles Bejarando	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	9/20/13	0.09
Constellation Solar Arizona, LLC	N/A QF14-498	Collier ES	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	6/30/14	0.25
Constellation Solar Arizona, LLC	N/A QF13-511	Crane School District at Centennial	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	8/1/13	0.38
Constellation Solar Arizona, LLC	N/A QF13-516	Crane School District at Crane Middle School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	8/28/13	0.38
Constellation Solar Arizona, LLC	N/A QF13-378	Crane School District at GAK	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	3/28/13	0.19
Constellation Solar Arizona, LLC	N/A QF13-377	Crane School District at Mesquite	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	3/28/13	0.17
Constellation Solar Arizona, LLC	N/A QF13-515	Crane School District at Valley Horizon	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	7/11/13	0.28
Constellation Solar Arizona, LLC	N/A QF13-537	Dysart I School District	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	6/19/13	8.81
Constellation Solar Arizona, LLC	N/A QF14-496	Isaac School District at Butler	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	7/8/14	0.21
Constellation Solar Arizona, LLC	N/A QF14-497	Lee Kornegay HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	7/9/14	0.11
Constellation Solar Arizona, LLC	N/A QF13-538	Marana School District	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	7/26/13	1.59
Constellation Solar Arizona, LLC	N/A QF13-598	Miami High School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	9/30/13	0.36
Constellation Solar Arizona, LLC	N/A QF14-499	Parkridge ES	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	7/3/14	0.42
Constellation Solar Arizona, LLC	N/A QF13-536	Peoria Unified School District	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	11/4/13	2.53
Constellation Solar Arizona, LLC	N/A QF14-27	Pueblo Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/15/13	0.24
Constellation Solar Arizona, LLC	N/A QF14-29	Salida del Sol Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/15/13	0.30
Constellation Solar Arizona, LLC	N/A QF13-514	Somerton School District at Desert Sonora	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	3/27/13	0.29

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Constellation Solar Arizona, LLC	N/A QF13-137	Somerton School District at Orange Grove	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/21/12	0.18
Constellation Solar Arizona, LLC	N/A QF13-513	Somerton School District at Somerton Middle School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	3/27/13	0.47
Constellation Solar Arizona, LLC	N/A QF13-138	Somerton School District at Tierra del Sol	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/21/12	0.22
Constellation Solar Arizona, LLC	N/A QF13-139	Somerton School District at Valle del Encanto	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/21/12	0.17
Constellation Solar Arizona, LLC	N/A QF14-26	Suverkrup Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/15/13	0.27
Constellation Solar Arizona, LLC	N/A QF13-376	Vail Unified School District at Andrada	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	4/5/13	0.33
Constellation Solar Arizona, LLC	N/A QF13-378	Vail Unified School District at Mesquite Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	4/5/13	0.23
Constellation Solar Arizona, LLC	N/A QF13-380	Vail Unified School District at OVMS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	4/19/13	0.25
Constellation Solar Arizona, LLC	N/A QF15-163	Western Peaks ES	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	10/16/14	0.47
Constellation Solar Arizona, LLC	N/A QF15-162	Willow Canyon HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	10/15/14	0.44
Mohave Sunrise Solar I LLC	N/A QF15-161	Mohave Electric at Fort Mohave	Mohave Sunrise Solar I LLC	Mohave Sunrise Solar I LLC	N/A	APS	Southwest	2nd Qtr 2015	4.56
Sacramento PV Energy, LLC	N/A QF11-329	SMUD at Fleshman SF	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	11/19/11	3.08
Sacramento PV Energy, LLC	N/A QF11-330	SMUD at Grundman SF	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	12/28/11	18.50
Sacramento PV Energy, LLC	N/A QF11-331	SMUD at Lawrence SF	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	12/30/11	1.03
Sacramento PV Energy, LLC	N/A QF11-332	SMUD at Van Conett SF	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	12/20/11	3.08
2014 ESA Project Company, LLC	ER15-1496 (pending)	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	N/A	CAISO	Southwest	12/31/14	7.40
AV Solar Ranch 1, LLC	ER12-2178	Antelope Valley SF	AV Solar Ranch 1, LLC	AV Solar Ranch 1, LLC	N/A	CAISO	Southwest	12/28/12	241.50
California PV Energy, LLC	N/A QF14-322	Palmdale Marie Kerr Park E2	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/14	0.06
California PV Energy, LLC	N/A QF15-76	Alto Loma HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/23/14	0.56
California PV Energy, LLC	N/A QF14-214	Castaic Elementary School	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	4/8/14	0.12
California PV Energy, LLC	N/A QF14-212	Castaic Middle School	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	4/9/14	0.28
California PV Energy, LLC	N/A QF15-78	Chaffey HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	1/30/15	0.54
California PV Energy, LLC	N/A QF15-79	Colony HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	1/27/15	0.76
California PV Energy, LLC	N/A QF15-80	Etiwanda HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/31/14	0.72
California PV Energy, LLC	N/A QF14-28	Ironhouse Sanitary District	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/24/14	0.85
California PV Energy, LLC	N/A QF14-335	Keppel Academy	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/14	0.11

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
California PV Energy, LLC	N/A QF14-329	Keppel Alpine North ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/14	0.12
California PV Energy, LLC	N/A QF14-331	Keppel Alpine South ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/14	0.05
California PV Energy, LLC	N/A QF14-330	Keppel Antelope ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/14	0.09
California PV Energy, LLC	N/A QF14-333	Keppel Gibson ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/14	0.15
California PV Energy, LLC	N/A QF14-332	Keppel Lake Los Angleles	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/14	0.13
California PV Energy, LLC	N/A QF14-334	Keppel Pearblossom ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/14	0.13
California PV Energy, LLC	N/A QF14-213	Live Oak Elementary School,	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	4/9/14	0.12
California PV Energy, LLC	N/A QF15-81	Los Osos HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	1/27/15	0.76
California PV Energy, LLC	N/A QF15-82	Montclair HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	1/30/15	0.76
California PV Energy, LLC	N/A QF14-211	Northlake Hills Elementary School	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	4/8/14	0.13
California PV Energy, LLC	N/A QF13-602	Oltmans SCE at Champagne SF	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/20/13	1.15
California PV Energy, LLC	N/A QF13-601	Oltmans SCE at Jurupa SF	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/20/13	1.71
California PV Energy, LLC	N/A QF15-83	Ontario HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/31/14	0.33
California PV Energy, LLC	N/A QF14-325	Palmdale Cultural Center	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/14	0.06
California PV Energy, LLC	N/A QF14-324	Palmdale Development Services Bldg	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/14	0.12
California PV Energy, LLC	N/A QF14-326	Palmdale Library	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/14	0.07
California PV Energy, LLC	N/A QF14-321	Palmdale Marie Kerr Park E1	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/14	0.07
California PV Energy, LLC	N/A QF14-323	Palmdale Marie Kerr Park E3	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/14	0.05
California PV Energy, LLC	N/A QF14-328	Palmdale Recreation Center	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/14	0.05
California PV Energy, LLC	N/A QF14-327	Palmdale Water Park	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/14	0.28
California PV Energy, LLC	N/A QF15-84	Rancho Cucamonga HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/29/14	0.42
Constellation Solar California, LLC	N/A QF10-656	General Motors Corp. at Fontana, Ca.	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	12/1/07	0.80
Constellation Solar California, LLC	N/A QF10-657	GSA, PBS, Pacific Service Center at Sacramento, Ca.	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	3/1/08	0.44
Constellation Solar California, LLC	N/A QF10-658	Kawneer Co., Inc. (Alcoa)	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	10/1/07	0.50
Constellation Solar California, LLC	N/A QF10-665	Univ of San Francisco	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	4/1/08	0.42
Luz Solar Partners IV	N/A QF86-736	SEGS IV SF	Luz Solar Partners IV	Luz Solar Partners IV	N/A	CAISO	Southwest	12/1/86	36.00
Luz Solar Partners V	N/A QF87-402	SEGS V SF	Luz Solar Partners V	Luz Solar Partners V	N/A	CAISO	Southwest	10/1/87	36.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Luz Solar Partners VI	N/A QF88-33	SEGS VI SF	Luz Solar Partners VI	Luz Solar Partners VI	N/A	CAISO	Southwest	12/1/88	36.00
Exelon Generation Company, LLC	ER00-3251	Green Country 1	Green Country OP Services LLC	Exelon Generation Company, LLC	2/11/02	SPP	SPP	2/11/02	262.00
Exelon Generation Company, LLC	ER00-3251	Green Country 2	Green Country OP Services LLC	Exelon Generation Company, LLC	2/11/02	SPP	SPP	2/11/02	262.00
Exelon Generation Company, LLC	ER00-3251	Green Country 3	Green Country OP Services LLC	Exelon Generation Company, LLC	2/11/02	SPP	SPP	2/11/02	261.00
Exelon Wind 1, LLC	N/A QF05-114	Exelon Wind 1 WF	Exelon Wind 1, LLC	Exelon Wind 1, LLC	N/A	SPP	SPP	12/31/05	10.00
Exelon Wind 10, LLC	N/A QF07-55	Exelon Wind 10 WF	Exelon Wind 10, LLC	Exelon Wind 10, LLC	N/A	SPP	SPP	7/1/08	10.00
Exelon Wind 11, LLC	N/A QF07-56	Exelon Wind 11 WF	Exelon Wind 11, LLC	Exelon Wind 11, LLC	N/A	SPP	SPP	7/1/08	10.00
Exelon Wind 2, LLC	N/A QF05-116	Exelon Wind 2 WF	Exelon Wind 2, LLC	Exelon Wind 2, LLC	N/A	SPP	SPP	12/31/05	10.00
Exelon Wind 3, LLC	N/A QF05-115	Exelon Wind 3 WF	Exelon Wind 3, LLC	Exelon Wind 3, LLC	N/A	SPP	SPP	12/31/05	10.00
Exelon Wind 4, LLC	ER07-1202 QF03-13	Exelon Wind 4 WF	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	12/15/06	79.80
Exelon Wind 5, LLC	N/A QF06-289	Exelon Wind 5 WF	Exelon Wind 5, LLC	Exelon Wind 5, LLC	N/A	SPP	SPP	10/4/05	10.00
Exelon Wind 6, LLC	N/A QF06-290	Exelon Wind 6 WF	Exelon Wind 6, LLC	Exelon Wind 6, LLC	N/A	SPP	SPP	11/1/06	10.00
Exelon Wind 7, LLC	N/A QF07-46	Exelon Wind 7 WF	Exelon Wind 7, LLC	Exelon Wind 7, LLC	N/A	SPP	SPP	7/1/08	10.00
Exelon Wind 8, LLC	N/A QF07-53	Exelon Wind 8 WF	Exelon Wind 8, LLC	Exelon Wind 8, LLC	N/A	SPP	SPP	7/1/08	10.00
Exelon Wind 9, LLC	N/A QF07-54	Exelon Wind 9 WF	Exelon Wind 9, LLC	Exelon Wind 9, LLC	N/A	SPP	SPP	7/1/08	10.00
Greensburg Wind Farm, LLC	N/A QF10-291	Greensburg WF	Greensburg Wind Farm, LLC	Greensburg Wind Farm, LLC	N/A	SPP	SPP	3/5/10	12.50
High Plains Wind Power, LLC	N/A QF07-257	High Plains WF	High Plains Wind Power, LLC	High Plains Wind Power, LLC	N/A	SPP	SPP	3/31/08	10.00
Shooting Star Wind Project, LLC	ER12-1829	Shooting Star WF	Shooting Star Wind Project, LLC	Shooting Star Wind Project, LLC	N/A	SPP	SPP	9/29/12	104.00
Wildcat Wind, LLC	ER12-1223 QF12-412	Wildcat WF	Wildcat Wind, LLC	Wildcat Wind, LLC	N/A	SPP	SPP	7/1/12	27.30

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Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas Storage

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
Constellation Mystic Power, LLC	Limited & discrete interconnection facilities[1]	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon Framingham, LLC	Limited & discrete interconnection facilities[1]	Exelon Framingham, LLC	Exelon Framingham, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon New Boston, LLC	Limited & discrete interconnection facilities[1]	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon West Medway, LLC	Limited & discrete interconnection facilities[1]	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon Wyman, LLC	Limited & discrete interconnection facilities[1]	Exelon Wyman, LLC	Exelon Wyman, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Holyoke Solar LLC	Limited & discrete interconnection facilities[1]	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Nine Mile Point Nuclear Station, LLC	Limited & discrete interconnection facilities[1]	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	N/A (OATT Waiver)

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
R.E. Ginna Nuclear Power Plant, LLC	Limited & discrete interconnection facilities[1]	R.E. Ginna Nuclear Power Plant, LLC	R.E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	N/A (OATT Waiver)
Baltimore Gas and Electric Company	Combined 115kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	695.85 combined miles
Baltimore Gas and Electric Company	Combined 138kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	54.44 combined miles
Baltimore Gas and Electric Company	Combined 230kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	320.97 combined miles
Baltimore Gas and Electric Company	Combined 500kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	217.42 combined miles
Baltimore Gas and Electric Company	Intrastate Gas Transmission	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	approx. 165 combined miles
Calvert Cliffs Nuclear Power Plant, LLC	Limited & discrete interconnection facilities[1]	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Commonwealth Edison Company	Electric Transmission Combined 765 kV Lines	Commonwealth Edison Company	PJM	N/A	PJM	Northeast	89.59 combined miles
Commonwealth Edison Company	Electric Transmission Combined 345 kV Lines	Commonwealth Edison Company	PJM	N/A	PJM	Northeast	2,634.29 combined miles

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
Commonwealth Edison Company	Electric Transmission Combined 138 kV Lines	Commonwealth Edison Company	PJM	N/A	PJM	Northeast	2,877.02 combined miles
Criterion Power Partners, LLC	Limited & discrete interconnection facilities[1]	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Exelon Solar Chicago LLC	Limited & discrete interconnection facilities[1]	Exelon Solar Chicago LLC	Exelon Solar Chicago LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Fourmile Wind Energy, LLC	Limited & discrete interconnection facilities[1]	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Handsome Lake Energy, LLC	Limited & discrete interconnection facilities[1]	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
PECO Energy Company	Electric Transmission 500 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	316.23 combined miles
PECO Energy Company	Electric Transmission Combined 200/220 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	503.05 combined miles
PECO Energy Company	Electric Transmission Combined 132 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	127.70 combined miles
PECO Energy Company	Electric Transmission Combined 66 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	169.54 combined miles

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
PECO Energy Company	Electric Transmission Combined 13.2 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	0.47 combined miles
PECO Energy Company	Intrastate Gas Transmission	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	31 combined miles
PECO Energy Company	Intrastate Gas Storage (LNG)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	1,200 mmcf
Cassia Gulch Wind Park, LLC	Limited & discrete interconnection facilities[1]	Cassia Gulch Wind Park, LLC	Cassia Gulch Wind Park, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
High Mesa Energy, LLC	Limited & discrete interconnection facilities[1]	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
Tuana Springs Energy, LLC	Limited & discrete interconnection facilities[1]	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
Beebe 1B Renewable Energy, LLC and Beebe Renewable Energy, LLC ("Beebe")[2]	Limited & discrete interconnection facilities[1]	Beebe	Beebe	N/A	MISO	Central	N/A (OATT Waiver)
Harvest Windfarm, LLC	Limited & discrete interconnection facilities[1]	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	N/A (OATT Waiver)
Michigan Wind 1, LLC	Limited & discrete interconnection facilities[1]	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	N/A (OATT Waiver)

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
CER Generation, LLC	Limited & discrete interconnection facilities[1]	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	N/A (OATT Waiver)
Constellation Power Source Generation, LLC	Limited & discrete interconnection facilities[1]	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Exelon Generation Company, LLC	Limited & discrete interconnection facilities[1]	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	Various	Various	N/A (OATT Waiver)
Cow Branch Wind Power, L.L.C.	Limited & discrete interconnection facilities[1]	Cow Branch Wind Power, LLC	Cow Branch Wind Power, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
CR Clearing, LLC	Limited & discrete interconnection facilities[1]	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
Wind Capital Holdings, LLC	Limited & discrete interconnection facilities[1]	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
AV Solar Ranch 1, LLC	Limited & discrete interconnection facilities[1]	AV Solar Ranch 1, LLC	AV Solar Ranch 1, LLC	N/A	CAISO	Southwest	N/A (OATT Waiver)
Exelon Wind 4, LLC	Limited & discrete interconnection facilities[1]	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	N/A (OATT Waiver)

SI-SSA-0010-1682

[1] These facilities are included because waiver of Order Nos. 888, 889, 890, their implementing regulations, and the requirements of Part 358 of FERC's regulations has been sought with respect to them.

[2] Beebe 1B Renewable Energy, LLC and Beebe Renewable Energy, LLC share certain interconnection facilities.

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Attachment C:

Redlined Tariffs

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CASSIA GULCH WIND PARK, LLC
FERC ELECTRIC TARIFF

1. Availability: Cassia Gulch Wind Park, LLC ("Cassia Gulch" or "Seller") makes electric energy, capacity, and ancillary services available under this Tariff to any purchaser for resale, except as prohibited below.

   Ancillary Services - Third Party Provider

   Third-party ancillary services: Seller offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

2. Applicability: This schedule is applicable to all wholesale sales of energy, capacity, and ancillary services by Seller not otherwise subject to a particular rate schedule of Seller.

3. Rates: All sales shall be made at rates established by agreement between the purchaser and Seller.

4. Other Terms and Conditions: All other terms and conditions shall be established by agreement between the purchaser and Cassia Gulch.

5. Compliance with Commission Regulations: ~~Cassia Gulch~~Seller shall comply with the provisions of 18 C.F.R. Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning ~~Cassia Gulch~~Seller's market-based rate authority, including orders in which the Commission authorizes ~~Cassia Gulch~~Seller to engage in affiliate sales under this tariff or otherwise restricts or limits ~~Cassia Gulch~~Seller's market-based rate authority. Failure to comply with the applicable provisions of 18 C.F.R. Part 35, Subpart H, and with any orders of the Commission concerning ~~Cassia Gulch~~Seller's market-based rate authority, will constitute a violation of this tariff.

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6. Limitations and Exemptions Regarding Market-Based Rate Authority: The Commission granted Cassia Gulch in Docket No. ER10-75-000 the following waivers and exemptions in connection with its market-based rate authority: (i) waiver of Subparts B and C of Part 35 regarding the filing of rate schedules, except Sections 35.12(a), 35.13(b), 35.15 and 35.16; (ii) waiver of the accounting and related reporting requirements under Part 41, Part 101 and Part 141, except sections 141.14 and 141.15, of the Commission's regulations; and (iii) blanket approval under Section 204 of the Federal Power Act, 16 U.S.C. § 824c, and Part 34 of the Commission's regulations for all future issuances of securities and debt and assumptions and liabilities.

   The Commission has granted waiver of its code of conduct and affiliate sales restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC ¶ 61,140 at 61,425 (2000), *on reh'g*, 95 FERC ¶ 61,309 (2001); *AmerGen VT, LLC*, 90 FERC ¶ 61,307 at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co.*, 91 FERC ¶ 61,270 (2000).

7. Seller Category: Cassia Gulch is a Category 1 Seller in the Central, Northeast, Southeast, Southwest, and Southwest Power Pool ~~Northwest and Southwest~~ regions, and a Category 2 Seller in the Northwest region ~~Northeast, Southeast, Central, and Southwest Power Pool regions~~, as defined in 18 C.F.R. § 35.36(a).

8. Effective Date: This Tariff shall be effective on and after the date on which the Commission permits it to become effective.

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CONSTELLATION ENERGY COMMODITIES GROUP MAINE, LLC
FERC ELECTRIC TARIFF

1. **Availability.** Constellation Energy Commodities Group Maine, LLC ("CCG Maine" or "Seller") will make available under this Tariff for sales to any purchaser for resale, including bilateral sales, into wholesale markets administered by an ISO or RTO that has market monitoring and mitigation measures approved by the Commission: (i) electric capacity; (ii) electric energy; and (iii) the following Ancillary Services:

    a. ~~NYISO~~New York: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc~~NYISO~~.

    b. New England~~ISO NE~~: Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO New England, Inc~~ISO NE~~.

    c. PJM: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, LLC ("PJM") and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

    d. California~~CAISO~~: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation ("CAISO") and to others that are self-supplying ancillary services to the CAISO.

    e. Southwest Power Pool: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Southwest Power Pool, Inc. (SPP) and to others that are self- supplying ancillary services to SPP.

2. **Applicability.** This Tariff is applicable to all wholesale sales of each of the services listed in Paragraph 1 of this Tariff to the extent such sales are not otherwise subject to a particular Tariff of CCG Maine.

3. **Rates.** All sales shall be made at the rates established between the purchaser and CCG Maine.

4. **Compliance with Commission Regulations.** Seller shall comply with the provisions of 18 CFR Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 CFR Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

5. **Limitations and Exemptions Regarding Market-Based Rate Authority.**

   - The Commission has granted waiver of its code of conduct and affiliate sales restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC ¶ 61,140 at 61,425 (2000), *on reh'g*, 95 FERC ¶ 61,309 (2001); *AmerGen VT, LLC*, 90 FERC ¶ 61,307 at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co*., 91 FERC ¶ 61,270 (2000).

   - Seller has requested and been granted (1) waiver of Subparts B and C of Part 35 of the Commission's regulations, except as to sections 35.12(a), 35.13(b), 35.15 and 35.16; (2) waiver of Parts 41, 101 and 141 of the Commission's accounting and reporting regulations, with the exception of 18 C.F.R. §§ 141.14, 141.15 (1999); and (3) blanket authorization for all future issuances of securities or assumptions of liabilities pursuant to Part 34 of the Commission's regulations. *See Constellation Power Source Maine, LLC*, Docket No. ER02-699-000 (unpublished delegated letter order issued Feb. 26, 2002).

6. **Other Terms and Conditions.** All other terms and conditions of sale shall be established between the purchaser and CCG Maine.

7. **Effective Date.** This Tariff shall become effective upon the date specified by the Commission.

8. **Seller Category.** Seller is a Category 1 Seller in the ~~Northwest and~~ Southwest region~~s~~, and a Category 2 Seller in the Northeast, Northwest, Southeast, Central, and Southwest Power Pool regions, as ~~those categories are~~ defined in 18 C.F.R. § 35.36(a).

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WHOLESALE MARKET-BASED RATE TARIFF

OF

CONSTELLATION ENERGY SERVICES, INC.

PROVIDING FOR

SALES OF CAPACITY, ENERGY AND/OR ANCILLARY SERVICES

**MARKET-BASED RATE TARIFF
OF
CONSTELLATION ENERGY SERVICES, INC.
PROVIDING FOR
SALES OF CAPACITY, ENERGY AND/OR ANCILLARY SERVICES**

I. DEFINITIONS

The following words and terms used herein shall be understood to have the following meanings:

1. Buyer: A purchaser of electric capacity, energy and/or ancillary services under this Tariff.

2. Commission: "Commission" means the Federal Energy Regulatory Commission or such successor Federal regulatory agency as may have jurisdiction over this Tariff.

3. Parties: "Parties" mean Seller and Buyer that have entered into a Transaction pursuant to this Tariff.

4. Seller: Constellation Energy Services, Inc.

5. Tariff: "Tariff" means this market-based rate tariff, as amended from time to time.

6. Transaction: "Transaction" means a particular transaction agreed to by the Parties under this Tariff.

II. SALES OF ELECTRIC CAPACITY, ENERGY AND/OR ANCILLARY SERVICES

1. Electric Capacity and Energy: Seller may sell electric capacity and/or energy to Buyer under this Tariff from time to time at rates, terms and conditions established by the agreement of the Parties. All such Transactions shall be voluntary.

2. Ancillary Services: Seller may sell the following ancillary services to Buyer under this Tariff from time to time at rates, terms and conditions established by the agreement of the Parties. All such Transactions shall be voluntary.

a. New England: Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO New England, Inc.

b. PJM: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, L.L.C. ("PJM") and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

c. New York: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc.

d. California: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation ("CAISO") and to others that are self-supplying ancillary services to the CAISO.

e. MISO: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Midcontinent Independent System Operator, Inc. (MISO) and to others that are self-supplying ancillary services to MISO.

f. Southwest Power Pool: Seller offers regulation service and operating

reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Southwest Power Pool, Inc. (SPP) and to others that are self-supplying ancillary services to SPP.

g. Ancillary Services – Third-Party Provider
Third-party ancillary services: Seller offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, i.e., where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

III. RATES

All sales shall be made at rates established by agreement between Seller and Buyer.

IV. OTHER TERMS AND CONDITIONS

All other terms and conditions shall be established by agreement between Seller and Buyer.

V. EFFECTIVE DATE

This Tariff is effective on the date specified by the Commission.

VI. REVISIONS TO THE TARIFF

Seller may file revisions to this Tariff by notifying Buyer in writing and by unilaterally making the appropriate filing with the Commission pursuant to the provisions

of Section 205 of the Federal Power Act; provided, however, that such revision shall not affect the rates, terms and conditions of Transactions entered into prior to the date of such revision, unless otherwise agreed by the Parties.

VII. COMPLIANCE WITH THE COMMISSION REGULATIONS

Seller shall comply with the provisions of 18 CFR Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 CFR Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

VIII. LIMITATIONS AND EXEMPTIONS REGARDING MARKET-BASED RATE AUTHORITY

The Commission has granted waiver of its code of conduct and affiliate sales restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC 61,140 at 61,425 (2000), *on reh'g*, 95 FERC 61,309 (2001); *AmerGen VT, LLC*, 90 FERC 61,307 at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co.*, 91 FERC 61,270 (2000). The Commission also granted Seller the following waivers and blanket authorization: (a) waiver of Subparts B and C of Part 35 of the Commission's regulations requiring the filing of cost-of-service information, except for sections 35.12(a), 35.13(b), 35.15 and 35.16; (b) waiver of the accounting and other requirements Parts 41, 101 and 141, except sections 141.14 and 141.15, of the Commission's regulations; and (c) blanket approval as to Section 204 of the Federal Power Act and Part 34 of the Commission's regulations for all future issuances of securities and assumption of liabilities. *Wisconsin Public Service Corp., et al.*, 75 FERC 61,057 (1996) (Docket No. ER96-1088-000).

IX. SELLER CATEGORY

Seller is a Category 1 seller in the Southwest region, and a Category 2 seller in the Central, Northeast, Northwest, Southeast, and Southwest Power Pool rRegions ~~and a Category 1 seller in the Northwest and Southwest Regions,~~ , as defined in 18 C.F.R. § 35.36(a).

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WHOLESALE MARKET-BASED RATE TARIFF

OF

CONSTELLATION ENERGY SERVICES OF NEW YORK, INC.

PROVIDING FOR

SALES OF CAPACITY AND ENERGY
MARKET-BASED RATE TARIFF OF
CONSTELLATION ENERGY SERVICES OF NEW YORK, INC.
PROVIDING FOR
SALES OF CAPACITY AND ENERGY

I. DEFINITIONS

The following words and terms used herein shall be understood to have the following meanings:

1. Buyer: A purchaser of electric capacity, energy and/or ancillary services under this Tariff.

2. Commission: "Commission" means the Federal Energy Regulatory Commission or such successor Federal regulatory agency as may have jurisdiction over this Tariff.

3. Parties: "Parties" mean Seller and Buyer that have entered into a Transaction pursuant to this Tariff.

4. Seller: Constellation Energy Services of New York, Inc.

5. Tariff: "Tariff" means this market-based rate tariff, as amended from time to time.

6. Transaction: "Transaction" means a particular transaction agreed to by the Parties under this Tariff.

II. SALES OF ELECTRIC CAPACITY, ENERGY AND/OR ANCILLARY SERVICES

1. Electric Capacity and Energy: Seller may sell electric capacity and/or energy to Buyer under this Tariff from time to time at rates, terms and conditions established by the agreement of the Parties. All such Transactions shall be voluntary.

2. Ancillary Services: Seller may sell the following ancillary services to Buyer under this Tariff from time to time at rates, terms and conditions established by the agreement of the Parties. All such Transactions shall be voluntary.

a. New England: Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO New England, Inc.

b. PJM: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, L.L.C. ("PJM") and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

c. New York: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc.

d. California: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation ("CAISO") and to others that are self-supplying ancillary services to the CAISO.

e. MISO: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Midcontinent Independent System Operator, Inc. (MISO) and to others that are self-supplying ancillary services to MISO.

f. Southwest Power Pool: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute

supplemental reserve) for sale to the Southwest Power Pool, Inc. (SPP) and to others that are self-supplying ancillary services to SPP.

g. Ancillary Services – Third-Party Provider

Third-party ancillary services: Seller offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, i.e., where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

III. RATES

All sales shall be made at rates established by agreement between Seller and Buyer.

IV. OTHER TERMS AND CONDITIONS

All other terms and conditions shall be established by agreement between Seller and Buyer.

V. EFFECTIVE DATE

This Tariff is effective on the date specified by the Commission.

VI. REVISIONS TO THE TARIFF

Seller may file revisions to this Tariff by notifying Buyer in writing and by

unilaterally making the appropriate filing with the Commission pursuant to the provisions of Section 205 of the Federal Power Act; provided, however, that such revision shall not affect the rates, terms and conditions of Transactions entered into prior to the date of such revision, unless otherwise agreed by the Parties.

VII. COMPLIANCE WITH THE COMMISSION REGULATIONS

Seller shall comply with the provisions of 18 CFR Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 CFR Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

VIII. LIMITATIONS AND EXEMPTIONS REGARDING MARKET-BASED RATE AUTHORITY

The Commission has granted waiver of its code of conduct and affiliate sales restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC 61,140 at 61,425 (2000), *on reh'g*, 95 FERC 61,309 (2001); *AmerGen VT, LLC*, 90 FERC 61,307 at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co.*, 91 FERC 61,270 (2000). The Commission also granted Seller the following waivers and blanket authorization: (a) waiver of Subparts B and C of Part 35 of the Commission's regulations requiring the filing of cost-of-service information, except for sections 35.12(a), 35.13(b), 35.15 and 35.16; (b) waiver of the accounting and other requirements Parts 41, 101 and 141, except sections 141.14 and 141.15, of the Commission's regulations; and (c) blanket approval as to Section 204 of the Federal Power Act and Part 34 of the Commission's regulations for all future issuances of securities and assumption of liabilities. *See Advantage Energy, Inc.*, Docket No. ER97-2758-000 (July 14, 1997) (unpublished letter order).

IX. SELLER CATEGORY

Seller is a Category 1 seller in the Southwest region, and a Category 2 seller in the Central, Northeast, Northwest, Southeast, and Southwest Power Pool rRegions ~~and a Category 1 seller in the Northwest and Southwest Regions,~~ as defined in 18 C.F.R. § 35.36(a).

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CONSTELLATION NEWENERGY, INC.

FERC ELECTRIC TARIFF NO. 1

1. Availability: Constellation NewEnergy, Inc. ("Constellation NewEnergy" or "Seller") makes electric energy and capacity available under this tariff to any purchaser for resale. Constellation NewEnergy also separately makes available for wholesale sales to purchasers with whom Constellation NewEnergy has contracted the following ancillary services:

(A) ~~Within the market administered by PJM Interconnection, L.L.C. ("PJM")~~: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, LLC ("PJM") and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

(B) ~~Within the markets administered by the Independent System Operator of~ New England ("ISO-NE"): Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO New England, Inc~~ISO-NE~~.

(C) ~~Within the markets administered by the~ New York ~~Independent System Operator ("NYISO")~~: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc~~NYISO~~.

(D) ~~Within the markets administered by the~ California ~~Independent System Operator ("CAISO")~~: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation ("CAISO") and to others that are self-supplying ancillary services to the CAISO.

(E) ~~Within the markets administered by the Midcontinent Independent System Operator ("MISO")~~: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Midcontinent Independent System Operator, Inc. (MISO) and to

others that are self-supplying ancillary services to MISO.

(F) ~~*Within the markets administered by the*~~ *Southwest Power Pool*: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Southwest Power Pool, Inc. (SPP) and to others that are self- supplying ancillary services to SPP.

(G) Ancillary Services – Third Party Provider

Third-party ancillary services: Seller offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, i.e., where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

2. Applicability: This tariff is applicable to wholesale sales of each of the services listed in Paragraph 1 by Constellation NewEnergy not otherwise subject to a particular tariff of Constellation NewEnergy.

3. Rates: All sales shall be made at rates established by agreement between the purchaser and Constellation NewEnergy.

4. Other Terms and Conditions: All other terms and conditions shall be established by agreement between the purchaser and Constellation NewEnergy.

5. Compliance with Commission Regulations: Seller shall comply with the provisions of 18 CFR Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 CFR Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

6. Limitations and Exemptions Regarding Market-Based Rate Authority:

   - The Commission has granted waiver of its code of conduct and affiliate sales restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC ¶ 61,140 at 61,425 (2000), *on reh'g*, 95 FERC ¶ 61,309 (2001); *AmerGen VT, LLC*, 90 FERC ¶ 61,307 at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co.*, 91 FERC ¶ 61,270 (2000).

   - Seller has requested and been granted (1) waiver of Subparts B and C of Part 35 of the Commission's regulations, except as to sections 35.12(a), 35.13(b), 35.15 and 35.16; (2) waiver of Parts 41,101 and 141, except sections 141.14 and 141.15, of the Commission's accounting and reporting regulations; and (3) blanket authorization for all future issuances of securities or assumptions of liabilities pursuant to Part 34 of the Commission's regulations. *See NEV, L.L.C.*, 81 FERC ¶ 61,186 (1997).

7. Effective Date: This tariff shall be effective on the date specified by the Federal Energy Regulatory Commission.

8. Seller Category: Seller is a Category 1 Seller in the ~~Northwest and~~ Southwest region~~s~~, and a Category 2 Seller in the Northeast, Northwest, Southeast, Central, and Southwest Power Pool regions, as ~~those categories are~~ defined in 18 C.F.R. § 35.36(a).

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Exelon Generation Company, LLC

Market-Based Rate Tariff

1. Availability and Character of Service

Exelon Generation Company, LLC ("Exelon Generation" or "Seller") may sell electric capacity and/or energy under this tariff in amounts, at levels of firmness or priorities of service, for periods of service, and under such other terms and conditions, all as established by agreement between Exelon Generation and the Customer under a transaction agreement hereunder.

2. Ancillary Services

PJM: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, L.L.C. ("PJM") and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

New York: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc.

New England: Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO New England, Inc.

California: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation ("CAISO") and to others that are self-supplying ancillary services to the CAISO.

MISO: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Midcontinent Independent System Operator, Inc. (MISO) and to others that are self-supplying ancillary services to MISO.

Southwest Power Pool: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Southwest Power Pool, Inc. (SPP) and to others that are self- supplying ancillary services to SPP.

3. Ancillary Services - Third Party Provider

Third-party ancillary services: Seller offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, i.e., where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

4. Rates

All rates for sales under this rate schedule shall be established by agreement between Exelon Generation and Customer.

5. General Terms and Conditions:

A. Acceptance of service hereunder by a Customer shall bind Customer to the provisions of this tariff and to the terms of a transaction agreement between or among the parties.

B. The rights of Exelon Generation and a customer to seek changes to the rates or other terms and conditions of service initially agreed upon between them shall be governed by parties' transaction agreement.

C. Compliance with Commission Regulations: Seller shall comply with the provisions of 18 C.F.R. Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 C.F.R. Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

D. Limitations and Exemptions Regarding Market-Based Rate Authority: The Commission has granted waiver of its code of conduct and affiliate sales

restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC ¶ 61,140 at 61,425 (2000), *on reh'g*, 95 FERC ¶ 61,309 (2001); *AmerGen VT, LLC*, 90 FERC ¶ 61,307 at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co.*, 91 FERC ¶ 61,270 (2000). The Commission also granted Seller the following waivers and blanket authorization: (a) waiver of Subparts B and C of Part 35 of the Commission's regulations requiring the filing of cost-of-service information, except for sections 35.12(a), 35.13(b), 35.15 and 35.16; (b) waiver of the accounting and other requirements Parts 41, 101 and 141, except sections 141.14 and 141.15, of the Commission's regulations; and (c) blanket approval as to Section 204 of the Federal Power Act and Part 34 of the Commission's regulations for all future issuances of securities and assumption of liabilities. *See Exelon Generation Co., LLC*, 93 FERC ¶ 61,140, at 61,427 (2000); *Exelon Generation Co., LLC*, Docket No. ER01-2794-000 (Oct. 3, 2001) (unreported) (accepting Tariff No. 2 under Exelon Generation's market based rate authority).

E. Seller Category: Seller is a Category 1 Seller in the Southwest region, and a Category 2 Seller in the Central, Northeast, Northwest, Southeast, and Southwest Power Pool regions~~, and a Category 1 Seller in the Southwest and Northwest regions~~, as defined in 18 C.F.R. § 35.36(a).

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FERC Electric Tariff, Volume No. 1

Market Based Rate Tariff

I. Availability

Seller makes electric energy, capacity, and ancillary services available under this tariff to any purchaser with whom Seller has contracted, except as prohibited below.

II. Rates

All sales shall be made at rates established by agreement between the purchaser and Seller.

III. Other Terms and Conditions

All other terms and conditions of sale shall be established by agreement between the purchaser and Seller.

IV. Seller Category

Seller is a Category 1 Seller in the ~~Northwest and~~ Central, Northeast, Southeast, Southwest, and Southwest Power Pool ~~Southwest~~ ~~,~~ regions and a Category 2 Seller in the Northwest region ~~all other regions~~, as ~~those Categories are~~ defined in 18 C.F.R. § 35.36(a).

V. Compliance with Commission Regulations

Seller shall comply with the provisions of 18 C.F.R. Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 C.F.R. Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

VI. Limitations and Exemptions Regarding Market-Based Rate Authority

In *High Mesa Energy, LLC*, ER12-2528-000 (2012):

- The Commission has granted waiver of its code of conduct and affiliate sales restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC ¶ 61,140, at 61,425 (2000), *on reh'g*, 95 FERC ¶ 61,309 (2001); *AmerGen VT, LLC*, 90 FERC ¶ 61,307, at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co.*, 91 FERC ¶ 61,270 (2000).

- Seller has received (1) waiver of Subparts B and C of Part 35, except for sections 35.12(a), 35.13(b), 35.15 and 35.16; (2) waiver of Parts 41, 101 and 141 except sections 141.14 and 141.15; and (3) blanket authorization for all future issuances of securities or assumptions of liabilities pursuant to Part 34 of the Commission's regulations.

VII. Ancillary Services

(A) ~~Within the market administered by PJM Interconnection, LLC ("PJM")~~: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, L.L.C. ("PJM")~~,~~ and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

(B) ~~Within the markets administered by the Independent System Operator of~ New England ("ISO NE")~~: Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO -New England, Inc.

(C) ~~Within the markets administered by the~ New York Independent System Operator ("NYISO")~~: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc.

(D) ~~Within the markets administered by the~ California Independent System Operator ("CAISO")~~: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation ("CAISO") and to others that are self-supplying ancillary services to the CAISO.

(E) ~~Within the markets administered by the Midcontinent System Operator ("MISO")~~: Seller offers regulation service and operating reserve service (including 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Midcontinent Independent System Operator, Inc. (MISO) and to others that are self-supplying ancillary services to MISO.

(F) Ancillary Services – Third Party Provider

Third-party ancillary services: Seller offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, i.e., where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales

to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

VIII. Effective Date

This Rate Schedule shall be effective as of the date specified by the Federal Energy Regulatory Commission.

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TUANA SPRINGS ENERGY, LLC
FERC ELECTRIC TARIFF

1. Availability: Tuana Springs Energy, LLC ("Tuana Springs" or "Seller") makes electric energy, capacity, and ancillary services available under this Tariff to any purchaser for resale, except as prohibited below.

   Ancillary Services - Third Party Provider

   Third-party ancillary services: Seller offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

2. Applicability: This schedule is applicable to all wholesale sales of energy, capacity, and ancillary services by Seller not otherwise subject to a particular rate schedule of Seller.

3. Rates: All sales shall be made at rates established by agreement between the purchaser and Tuana Springs.

4. Other Terms and Conditions: All other terms and conditions shall be established by agreement between the purchaser and Tuana Springs.

5. Compliance with Commission Regulations: ~~Tuana Springs~~Seller shall comply with the provisions of 18 C.F.R. Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning ~~Tuana Spring~~Seller~~s~~'s market-based rate authority, including orders in which the Commission authorizes ~~Tuana Springs~~Seller to engage in affiliate sales under this tariff or otherwise restricts or limits ~~Tuana Springs~~Seller's market-based rate authority. Failure to comply with the applicable provisions of 18 C.F.R. Part 35, Subpart H, and with any orders of the Commission concerning ~~Tuana Springs~~Seller's~~'~~ market-based rate authority, will constitute a violation of this tariff.

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6. Limitations and Exemptions Regarding Market-Based Rate Authority: The Commission granted Tuana Springs in Docket No. ER10-87-000 the following waivers and exemptions in connection with its market-based rate authority: (i) waiver of Subparts B and C of Part 35 regarding the filing of rate schedules, except Sections 35.12(a), 35.13(b), 35.15 and 35.16; (ii) waiver of the accounting and related reporting requirements under Part 41, Part 101 and Part 141, except sections 141.14 and 141.15, of the Commission's regulations; and (iii) blanket approval under Section 204 of the Federal Power Act, 16 U.S.C. § 824c, and Part 34 of the Commission's regulations for all future issuances of securities and debt and assumptions and liabilities.

   The Commission has granted waiver of its code of conduct and affiliate sales restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC ¶ 61,140 at 61,425 (2000), *on reh'g*, 95 FERC ¶ 61,309 (2001); *AmerGen VT, LLC*, 90 FERC ¶ 61,307 at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co.*, 91 FERC ¶ 61,270 (2000).

7. Seller Category: Tuana Springs is a Category 1 Seller in the Central, Northeast, Southeast, Southwest, and Southwest Power Pool ~~Northwest and Southwest~~ regions, and a Category 2 Seller in the Northwest~~Northeast, Southeast, Central, and Southwest Power Pool regions~~ region, as defined in 18 C.F.R. § 35.36(a).

8. Effective Date: This Tariff shall be effective on and after the date on which the Commission permits it to become effective.

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FERC rendition of the electronically filed tariff records in Docket No. ER15-01625-000
Filing Data:
CID: C000202
Filing Title: Notice of Change in Status
Company Filing Identifier: 43015
Type of Filing Code: 80
Associated Filing Identifier:
Tariff Title:
Tariff ID: 122
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
FERC Electric, Market Based Rate Tariff, 4.0.0, A
Record Narative Name:
Tariff Record ID: 3
Tariff Record Collation Value: 800000 Tariff Record Parent Identifier: 0
Proposed Date: 2015-04-01
Priority Order: 100
Record Change Type: Change
Record Content Type: 1
Associated Filing Identifier:

Market-Based Rate Tariff

1. Availability and Character of Service

Seller may sell electric capacity and/or energy under this tariff in amounts, at levels of firmness or priorities of service, for periods of service, and under such other terms and conditions, all as established by agreement between Seller and the Customer under a transaction agreement hereunder.

2. Ancillary Services

PJM: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, L.L.C. ("PJM") and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

New York: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc.

New England: Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO New England, Inc.

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California: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation ("CAISO") and to others that are self-supplying ancillary services to the CAISO.

MISO: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Midcontinent Independent System Operator, Inc. (MISO) and to others that are self-supplying ancillary services to MISO.

Southwest Power Pool: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Southwest Power Pool, Inc. (SPP) and to others that are self- supplying ancillary services to SPP.

3. Ancillary Services - Third Party Provider

Third-party ancillary services: Seller offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, i.e., where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

4. Rates

All rates for sales under this rate schedule shall be established by agreement between Exelon Generation and Customer.

5. General Terms and Conditions:

A. Acceptance of service hereunder by a Customer shall bind Customer to the provisions of this tariff and to the terms of a transaction agreement between or among the parties.

B. The rights of Seller and a customer to seek changes to the rates or other terms and conditions of service initially agreed upon between them shall be governed by parties' transaction agreement.

C. Compliance with Commission Regulations: Seller shall comply with the provisions of 18 C.F.R. Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 C.F.R. Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

D. Limitations and Exemptions Regarding Market-Based Rate Authority: The Commission has granted waiver of its code of conduct and affiliate sales

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restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC 61,140 at 61,425 (2000), *on reh'g*, 95 FERC 61,309 (2001); *AmerGen VT, LLC*, 90 FERC 61,307 at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co*., 91 FERC 61,270 (2000). The Commission also granted Seller the following waivers and blanket authorization: (a) waiver of Subparts B and C of Part 35 of the Commission's regulations requiring the filing of cost-of-service information, except for sections 35.12(a), 35.13(b), 35.15 and 35.16; (b) waiver of the accounting and other requirements Parts 41, 101 and 141, except sections 141.14 and 141.15, of the Commission's regulations; and (c) blanket approval as to Section 204 of the Federal Power Act and Part 34 of the Commission's regulations for all future issuances of securities and assumption of liabilities. *See Exelon Generation Co., LLC*, 93 FERC 61,140, at 61,427 (2000); *Exelon Generation Co., LLC*, Docket No. ER01-2794-000 (Oct. 3, 2001) (unreported).

E. Seller Category: Seller is a Category 1 Seller in the Southwest region, and a Category 2 Seller in the Central, Northeast, Northwest, Southeast, and Southwest Power Pool regions, as defined in 18 C.F.R. § 35.36(a).

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April 30, 2015

VIA E-TARIFF FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: AV Solar Ranch 1, LLC, Docket No. ER12-2178-___
Baltimore Gas and Electric Company, Docket No. ER10-2172-___
Beebe 1B Renewable Energy, LLC, Docket No. ER14-2144-___
Beebe Renewable Energy, LLC, Docket No. ER12-2311-___
Calvert Cliffs Nuclear Power Plant, LLC, Docket No. ER10-2179-___
Cassia Gulch Wind Park, LLC, Docket No. ER11-2016-___
CER Generation, LLC, Docket No. ER10-2184-___
Commonwealth Edison Company, Docket No. ER10-1048-___
Constellation Energy Commodities Group Maine, LLC, Docket No. ER10-2192-__
Constellation Energy Services, Inc., Docket No. ER15-1537-___
Constellation Energy Services of New York, Inc., Docket No. ER15-1539-___
Constellation Mystic Power, LLC, Docket No. ER11-2056-___
Constellation NewEnergy, Inc., Docket No. ER10-2178-___
Constellation Power Source Generation, LLC, Docket No. ER14-1524-___
Cow Branch Wind Power, LLC, Docket No. ER11-2014-___
CR Clearing, LLC, Docket No. ER11-2013-___
Criterion Power Partners, LLC, Docket No. ER10-3308-___
Exelon Framingham, LLC, Docket No. ER10-1020-___
Exelon Generation Company, LLC, Docket No. ER13-1536-___
Exelon New Boston, LLC, Docket No. ER10-1078-___
Exelon West Medway, LLC, Docket No. ER10-1080-___
Exelon Wind 4, LLC, Docket No. ER11-2010-___
Exelon Wyman, LLC, Docket No. ER10-1081-___
Fourmile Wind Energy, LLC, Docket No. ER14-2145-___
Handsome Lake Energy, LLC, Docket No. ER10-2180-___
Harvest II Windfarm, LLC, Docket No. ER12-2201-___
Harvest Windfarm, LLC, Docket No. ER11-2011-___

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High Mesa Energy, LLC, Docket No. ER12-2528-___
Michigan Wind 1, LLC, Docket No. ER11-2009-___
Michigan Wind 2, LLC, Docket No. ER11-3989-___
Nine Mile Point Nuclear Station, LLC, Docket No. ER10-2181-___
PECO Energy Company, Docket No. ER14-767-___
R.E. Ginna Nuclear Power Plant, LLC, Docket No. ER10-2182-___
Shooting Star Wind Project, LLC, Docket No. ER12-1829-___
Tuana Springs Energy, LLC, Docket No. ER11-2007-___
Wildcat Wind, LLC, Docket No. ER12-1223-___
Wind Capital Holdings, LLC, Docket No. ER11-2005-___

Notice of Change in Status and Tariff Revisions of the Exelon MBR Entities

Dear Secretary Bose:

Pursuant to the requirements of section 35.42 of the regulations of the Federal Energy Regulatory Commission (FERC or Commission),[1] the above-captioned affiliates of Exelon Corporation (Exelon) with market-based rate authority (the Exelon MBR Entities) submit this notice of change in status to inform the Commission that as of April 1, 2015, the Exelon MBR Entities could be deemed to have acquired control over additional generation in the Northwest region as a result of a transaction described below. In addition, certain of the Exelon MBR Entities specified below submit revisions to their market-based rate tariffs (Tariffs) to update their seller category designation and make additional ministerial changes, and respectfully request an effective date of April 1, 2015 for such revisions.

I. DESCRIPTION OF CHANGE IN STATUS

Exelon Generation Company, LLC (Exelon Generation) is a direct, wholly-owned subsidiary of Exelon that has Commission-granted market-based rate authority.[2] Exelon Generation entered into an agreement (Transaction) with J.P. Morgan Ventures Energy Corporation (JPMVEC) that will result in Exelon Generation being assigned JPMVEC's rights and obligations under certain contracts for the purchase and sale of the output of the Stateline Wind Energy Project (Stateline Project). The Stateline Project is a wind-powered electric generation facility with approximately 300 MW aggregate nameplate capacity located in the states of Oregon and Washington within the PacifiCorp-West (PACW) balancing authority area (BAA). The Stateline Project is owned and operated by FPL Energy Vansycle, LLC (Vansycle), which sells the output of the facility at market-based rates.[3]

1 18 C.F.R. § 35.42 (2014).

2 *Exelon Generating Co.*, 93 FERC ¶ 61,140 (2000), *reh'g denied*, 95 FERC ¶ 61,309 (2001).

3 *See FPL Energy Vansycle, LLC*, Docket No. ER01-838-000 (letter order issued Feb. 15, 2001) (granting market-based rate authority).

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Prior to the Transaction, JPMVEC purchased from Vansycle the entire output of the Stateline Project and resold a combined total of 290 MW to Bonneville Power Administration (BPA), Eugene Water & Electric Board, and Seattle City Light (collectively, Buyers) pursuant to long-term agreements. As a result of the Transaction, Exelon Generation will purchase from Vansycle the entire output of the Stateline Project and resell a combined total of 290 MW to the Buyers. Accordingly, only about 10 MW of uncommitted generation capacity will be added to the total uncommitted generation capacity owned or controlled by Exelon Generation and its affiliates in the PACW BAA[4] as a result of the Transaction.

Exelon Generation has not yet received consents to assign all of the contracts affected by the Transaction, but under the terms of the Transaction Exelon Generation began receiving the economic benefits and being exposed to the economic risks associated with the purchase and sale of the output of the Stateline Project as of April 1, 2015, and could be deemed to "control" the output of the Stateline Project as of that date. Therefore, for purposes of this notice of change in status, Exelon Generation is conservatively treating the Transaction as closed as of April 1, 2015.

II. ANALYSIS OF CHANGE IN STATUS

The change in status described in this notice does not change the conclusion that the Exelon MBR Entities continue to satisfy the Commission's test for determining whether to grant a public utility market-based rate authority. As demonstrated in Attachment A, the Exelon MBR Entities pass both the pivotal supplier screen (PSS) and market share screen (MSS) taking into account the small net increase in uncommitted generation capacity. The Exelon MBR Entities pass the PSS in the PACW BAA because the Exelon MBR Entities' net uncommitted capacity (126 MW) is significantly less than the market net uncommitted supply (1,647 MW).[5] The Exelon MBR Entities also pass the MSS in the PACW BAA because the Exelon MBR Entities' market share ranges from 4.7% (Summer) to 6.0% (Winter), well below the 20% threshold. Because the Exelon MBR Entities pass both the PSS and MSS, the Exelon MBR Entities continue to satisfy the Commission's test for determining whether to grant a public utility market-based rate authority.

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[4] The Stateline Project is electrically interconnected with the BPA BAA in addition to the PACW BAA. However, the full capacity of the BPA interconnection (90 MW) is used for the long-term sales to BPA from the Stateline Project. In addition, except for the 4.8 MW owned by Outback Solar, LLC—which are fully committed—none of the Exelon MBR Entities or any of their affiliates owns or controls any generation in the BPA BAA. Moreover, the Simultaneous Transmission Import Limit (SIL) values for imports into the BPA BAA are zero. *See Puget Sound Energy, Inc.*, 147 FERC ¶ 61,021 (2014). In any event, as shown in the attached market power screens analyzing the PACW BAA market, all other generation located within markets first-tier to the BPA BAA that is owned or controlled by the Exelon MBR Entities or their affiliates is fully committed, other than the uncommitted 10 MW from the Stateline Project, a *de minimis* amount. Therefore, the Exelon MBR Entities have not produced separate screens analyzing the BPA BAA market.

[5] In the PACW BAA, the Exelon MBR Entities used to be affiliated with CER Generation II, LLC (CER II), which owned and operated an approximately 189 MW generation facility located in West Valley City, Utah. All of the interests in CER II were sold to an unaffiliated third party in a transaction authorized by the Commission in Docket No. EC15-2-000 and consummated on December 3, 2014.

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Because the Transaction involves only the purchase and sale of power and does not involve any transmission or distribution facilities or inputs to electric power production as defined in 18 C.F.R. §35.36, there have been no changes with respect to the Exelon MBR Entities' lack of transmission market power or their lack of ability to erect barriers to entry that would affect the Commission's prior finding that the Exelon MBR Entities lack vertical market power. To the extent necessary, the Exelon MBR Entities confirm that they have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market. Therefore, the Exelon MBR Entities continue to qualify for market-based rate authority.

As required by 18 C.F.R. § 35.42, attached hereto is an updated asset appendix listing (1) all affiliates that have market-based rate authority and identifying all generation assets owned or controlled by Exelon or its affiliates by BAA and geographic region, and (2) all electric transmission and natural gas intrastate pipelines and/or gas storage facilities owned or controlled by Exelon or its affiliates (Attachment B).[6]

III. TARIFF REVISIONS, EFFECTIVE DATE AND WAIVER

Exelon Generation, Constellation Energy Commodities Group Maine, LLC, Constellation NewEnergy, Inc., Constellation Energy Services, Inc.,[7] Constellation Energy Services of New York, Inc.,[8] Cassia Gulch Wind Park, LLC (Cassia Gulch), High Mesa Energy, LLC (High Mesa), and Tuana Springs Energy, LLC (Tuana Springs) (collectively, the Exelon NW Sellers)[9] have revised their Tariffs in several ministerial respects and have included herewith "redlined" versions of the Tariffs in Attachment C. The Exelon NW Sellers have submitted "clean" Tariffs in RTF format with metadata attached through the Commission's eTariff system. The Tariff revisions include:

- Updated ancillary services language to match the FERC-approved, standard ancillary services language;
- Updated language regarding compliance with Commission regulations to match the FERC-approved, standard compliance language;
- Elimination of Order No. 614 formatting and removal of the legal name of the market-based rate seller, which is now reflected in the CID; and

6 18 C.F.R. § 35.42(c) (2014).

7 Constellation Energy Services, Inc. was formerly known as Integrys Energy Services, Inc. A notice of succession reflecting the change in name was filed in Docket No. ER15-1537-000.

8 Constellation Energy Services of New York, Inc. was formerly known as Integrys Energy Services of New York, Inc. A notice of succession reflecting the change in name was filed in Docket No. ER15-1539-000.

9 The Exelon NW Sellers are the subset of Exelon MBR Entities that are either power marketers or own or control generation within the Northwest region.

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- Revised seller category classifications. Currently, the effective Tariffs reflect category 1 seller status in the Northwest region. However, as of the April 1, 2015, Exelon Generation could be deemed to "control" the output of the Stateline Project pursuant to the Transaction, which results in Exelon Generation and its affiliates owning and/or controlling more than 500 MW of generation in the Northwest region. Therefore, the Exelon NW Sellers are updating their Tariffs to reflect that they are category 2 sellers in the Northwest region.

  In addition, Cassia Gulch, High Mesa, and Tuana Springs have revised their seller category classifications to reflect that they are category 1 sellers in the Central, Northeast, Southeast, Southwest, and Southwest Power Pool (SPP) regions.[10] Currently, their Tariffs reflect category 2 status in the Central, Northeast, Southeast, and SPP regions due to their affiliation with entities that own or control, collectively, over 500 MW of generation in those regions. However, Cassia Gulch, High Mesa, and Tuana Springs do not themselves own or control any generation in any region outside of the Northwest region. Likewise, Cassia Gulch, High Mesa, and Tuana Springs do not own, operate, or control transmission facilities other than limited equipment necessary to interconnect their individual generating facilities to the transmission grid. Further, Cassia Gulch, High Mesa, and Tuana Springs are not affiliated with any entity that owns, operates or controls transmission facilities or is a franchised public utility in the same region as their generation assets. Finally, Cassia Gulch, High Mesa, and Tuana Springs do not raise other vertical market power issues. For these reasons, Cassia Gulch, High Mesa, and Tuana Springs respectfully request a determination that they meet the criteria for classification as a category 1 seller in the Central, Northeast, Southeast, Southwest, and SPP regions.

The Exelon MBR Entities respectfully ask that the Commission accept this notice and the updated Tariffs for filing, effective April 1, 2015. To the extent necessary, the Exelon NW Sellers request waiver of the 60-day prior notice requirement pursuant to Section 35.11 of the Commission's regulations[11] in order to permit the revised Tariffs to become effective April 1, 2015. Good cause for such waiver exists because the Commission generally finds a waiver of notice requirements "appropriate when an uncontested filing has no rate impact."[12] The Exelon NW Sellers' tariff revisions specified in this filing have no impact on rates since no substantive changes have been made to the Tariffs. The Commission routinely grants waiver of its notice requirements in similar circumstances.[13]

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[10] Cassia Gulch, High Mesa, and Tuana Springs are already classified as category 1 sellers in the Southwest region.

[11] 18 C.F.R. § 35.11 (2014).

[12] *Cent. Hudson Gas & Elec. Corp.*, 61 FERC ¶ 61,089, at 61,354 (1992).

[13] *See, e.g.*, *New Brunswick Energy Mktg. Corp.*, Docket No. ER14-225-000 (issued Dec. 18, 2013) (delegated letter order accepting a Notice of Succession and corresponding revised tariff reflecting the successor's name filed Oct. 30, 2013 and granting the requested effective date of Oct. 1, 2013, the effective

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IV. COMMUNICATIONS

Communications concerning this notice should be directed to the following persons:

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*The persons denoted with an asterisk are designated for service pursuant to 18 C.F.R. § 385.2010.

V. DOCUMENTS SUBMITTED WITH FILING

The Exelon MBR Entities submit the following documents:

1. This transmittal letter;
2. Attachment A: Pivotal supplier and market share screens;
3. Attachment B: Asset appendices of Exelon Corporation and affiliates; and
4. Attachment C: Redlined tariffs.

VI. CONCLUSION

For the reasons set forth above, the change in status described herein does not materially change the facts and circumstances that the Commission relied upon in granting the Exelon MBR Entities market-based rate authority. Therefore, the Exelon MBR Entities respectfully request that the Commission accept for filing this notice of change in status. Further, the Exelon NW Sellers also request that the Commission accept the included Tariff revisions, waive any

date of the name change); *Pastoria Energy Facility, L.L.C.*, Docket No. ER12- 2645-000 (unpublished delegated letter order issued Oct. 16, 2012).

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applicable prior notice requirements, and grant an effective date of April 1, 2015.

Thank you for your attention to this matter.

Respectfully submitted,

/s/ Jane E. Rueger
Jane E. Rueger
Harold W. Bulger, III

Counsel to
Exelon MBR Entities

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in these proceedings.

Dated at Washington, D.C., this 30th day of April, 2015.

/s/ Corey Neal

Corey Neal
White & Case LLP
701 Thirteenth Street, NW
Washington, D.C. 20005
Tel.: (202) 637-6195

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Attachment A:

Pivotal Supplier and Market Share Screens

Generation Affiliated with Exelon

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Balancing Authority Area/ RTO	Plant Name	Total Capacity (MW) Summer	Total Capacity (MW) Winter	Ownership Share	Net Interest Owned/Purchased (MW) Summer	Net Interest Owned/Purchased (MW) Winter	Long Term (Sales) (MW) Summer	Long Term (Sales) (MW) Winter
PACW	**Vansycle (Stateline)**	**299.7**	**299.7**	**0%**	**299.7**	**299.7**	**(289.7)**	**(289.7)**
PACW	Big Top Windfarm	1.7	1.7	100%	1.7	1.7	(1.7)	(1.7)
PACW	Butter Creek Windfarm	5.0	5.0	100%	5.0	5.0	(5.0)	(5.0)
PACW	Four Corner Windfarm	10.0	10.0	100%	10.0	10.0	(10.0)	(10.0)
PACW	Four Mile Canyon Windfarm	10.0	10.0	100%	10.0	10.0	(10.0)	(10.0)
PACW	Oregon Trail Windfarm	9.9	9.9	100%	9.9	9.9	(9.9)	(9.9)
PACW	Pacific Canyon Windfarm	8.3	8.3	100%	8.3	8.3	(8.3)	(8.3)
PACW	Sand Ranch Windfarm	9.9	9.9	100%	9.9	9.9	(9.9)	(9.9)
PACW	Threemile Canyon Windfarm	9.9	9.9	100%	9.9	9.9	(9.9)	(9.9)
PACW	Wagon Trail Windfarm	3.3	3.3	100%	3.3	3.3	(3.3)	(3.3)
PACW	Ward Butte Windfarm	6.6	6.6	100%	6.6	6.6	(6.6)	(6.6)
Total, PACW		374.3	374.3		374.3	374.3	(364.3)	(364.3)
First-Tier Markets								
PACE	Sunnyside	51.0	51.0	50%	51.0	51.0	(51.0)	(51.0)
BPA	Outback Solar	4.4	4.4	100%	4.4	4.4	(4.4)	(4.4)
CAISO	2014 ESA Project Company, LLC	7.4	7.4	100%	7.4	7.4	(7.4)	(7.4)
CAISO	Antelope Valley SF (AV Solar 1)	241.5	241.5	100%	241.5	241.5	(241.5)	(241.5)
CAISO	Alto Loma HS	0.56	0.56	100%	0.56	0.56	-	-
CAISO	Castaic Elementary School	0.12	0.12	100%	0.12	0.12	-	-
CAISO	Castaic Middle School	0.28	0.28	100%	0.28	0.28	-	-
CAISO	Chaffey HS	0.54	0.54	100%	0.54	0.54	-	-
CAISO	Colony HS	0.76	0.76	100%	0.76	0.76	-	-
CAISO	Etiwanda HS	0.72	0.72	100%	0.72	0.72	-	-
CAISO	Ironhouse Sanitary District	0.85	0.85	100%	0.85	0.85	-	-
CAISO	Keppel Academy	0.11	0.11	100%	0.11	0.11	-	-
CAISO	Keppel Alpine North ES	0.12	0.12	100%	0.12	0.12	-	-
CAISO	Keppel Alpine South ES	0.05	0.05	100%	0.05	0.05	-	-
CAISO	Keppel Antelope ES	0.09	0.09	100%	0.09	0.09	-	-
CAISO	Keppel Gibson ES	0.15	0.15	100%	0.15	0.15	-	-
CAISO	Keppel Lake Los Angleles	0.13	0.13	100%	0.13	0.13	-	-
CAISO	Keppel Pearblossom ES	0.13	0.13	100%	0.13	0.13	-	-
CAISO	Live Oak Elementary School	0.12	0.12	100%	0.12	0.12	-	-
CAISO	Los Osos HS	0.76	0.76	100%	0.76	0.76	-	-
CAISO	Marie Kerr Park E1	0.07	0.07	100%	0.07	0.07	-	-
CAISO	Marie Kerr Park E2	0.06	0.06	100%	0.06	0.06	-	-
CAISO	Marie Kerr Park E3	0.05	0.05	100%	0.05	0.05	-	-
CAISO	Montclair HS	0.76	0.76	100%	0.76	0.76	-	-
CAISO	Northlake Hills Elementary School	0.13	0.13	100%	0.13	0.13	-	-
CAISO	Oltmans SCE at Champagne SF	1.15	1.15	100%	1.15	1.15	-	-
CAISO	Oltmans SCE at Jurupa SF	1.71	1.71	100%	1.71	1.71	-	-
CAISO	Ontario HS	0.33	0.33	100%	0.33	0.33	-	-
CAISO	Palmdale Cultural Center	0.06	0.06	100%	0.06	0.06	-	-

Balancing Authority Area/ RTO	Plant Name	Total Capacity (MW)		Ownership Share	Net Interest Owned/Purchased (MW)		Long Term (Sales) (MW)	
		Summer	Winter		Summer	Winter	Summer	Winter
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CAISO	Palmdale Development Services Bldg	0.12	0.12	100%	0.12	0.12	-	-
CAISO	Palmdale Library	0.07	0.07	100%	0.07	0.07	-	-
CAISO	Palmdale Recreation Center	0.05	0.05	100%	0.05	0.05	-	-
CAISO	Palmdale Water Park	0.28	0.28	100%	0.28	0.28	-	-
CAISO	Rancho Cucamonga HS	0.42	0.42	100%	0.42	0.42	-	-
CAISO	General Motors Corp. at Fontana, Ca.	0.80	0.80	100%	0.80	0.80	-	-
CAISO	GSA, PBS, Pacific Service Center at Sacramento, Ca.	0.44	0.44	100%	0.44	0.44	-	-
CAISO	Kawneer Co., Inc. (Alcoa)	0.50	0.50	100%	0.50	0.50	-	-
CAISO	Univ of San Francisco	0.42	0.42	100%	0.42	0.42	-	-
CAISO	SEGS IV SF	36.0	34.0	100%	36.0	34.0	-	-
CAISO	SEGS V SF	36.0	34.0	100%	36.0	34.0	-	-
CAISO	SEGS VI SF	36.0	35.0	100%	36.0	35.0	-	-
IPCO	Cassia Gulch Windfarm	18.9	18.9	100%	18.9	18.9	(18.9)	(18.9)
IPCO	Cassia Wind Windfarm	10.5	10.5	100%	10.5	10.5	(10.5)	(10.5)
IPCO	High Mesa Windfarm	40.0	40.0	100%	40.0	40.0	(40.0)	(40.0)
IPCO	Bennett Creek Windfarm	21.0	21.0	100%	21.0	21.0	(21.0)	(21.0)
IPCO	Hot Springs Windfarm	21.0	21.0	100%	21.0	21.0	(21.0)	(21.0)
IPCO	Tuana Springs Windfarm	16.8	16.8	100%	16.8	16.8	(16.8)	(16.8)
Total, First-Tier		553.4	548.4		553.4	548.4	(432.5)	(432.5)

Ratings based on EIA-860 or Asset Appendix.

Part I -- Pivotal Supplier Analysis

Row	Generation	PACW MW	PACW Reference
			December 12 - November 13
	Seller and Affiliate Capacity		
A	Installed Capacity	374	Generation
B	Long-Term Firm Purchases	-	
C	Long-Term Firm Sales	(364)	Generation
D	Imported Power	116	Affiliated uncommitted capacity in first-tier markets
	Non-Affiliate Capacity		
E	Installed Capacity	3,862	WKp-Energy Velocity PACW Gen, less Row A above
F	Long-Term Firm Purchases	364	Offset, Row C
G	Long-Term Firm Sales	-	
H	Imported Power	1,294	147 FERC ¶ 61,021 (2014), less Row D above
I	Balancing Authority Area Reserve Requirement	(215)	7% of peak load, based on WECC requirement
J	Amount of Line I Attributable to Seller, if any	-	
K	Total Uncommitted Capacity	2,357	SUM A,B,C,D,E,F,G,H,I,M
	Load		
L	Balancing Authority Area Annual Peak Load	3,784	Estimated from PACW FERC Form 714 and PacifiCorp triennial
M	Average Daily Peak Native Load in Peak Month	(3,074)	Estimated from PACW FERC Form 714 and PacifiCorp triennial
N	Amount of Line M Attributable to Seller, if any	-	
O	Wholesale Load (SUM L,M)	710	
P	Net Uncommitted Supply (K-O)	1,647	
Q	Seller's Uncommitted Capacity	126	SUM A,B,C,D,J,N
Result of Pivotal Supplier Screen		**PASS**	Pass if Line Q < Line P Fail if Line Q > Line P

Part II -- Market Share Analysis

Row		PACW Winter (MW)	PACW Spring (MW)	PACW Summer (MW)	PACW Fall (MW)	Reference December 12 - November 13
	Seller and Affiliate Capacity					
A	Installed Capacity	374	374	374	374	Generation
B	Long-Term Firm Purchases	-	-	-	-	
C	Long-Term Firm Sales	(364)	(364)	(364)	(364)	Generation
D	Seasonal Average Planned Outages	-	-	-	-	
E	Imported Power	116	116	121	116	Affiliated uncommitted capacity in first-tier markets
	Capacity Deductions					
F	Average Peak Native Load in the Season	(3,084)	(2,621)	(2,647)	(2,681)	Estimated from PACW FERC Form 714 and PacifiCorp triennial
G	Amount of Line F Attributable to Seller, if any	-	-	-	-	
H	Amount of Line F Attributable to Others, if any	(3,084)	(2,621)	(2,647)	(2,681)	
I	Balancing Authority Area Reserve Requirement, if any	(216)	(184)	(185)	(188)	7% of peak load, based on WECC requirement
J	Amount of Line I Attributable to Seller, if any	-	-	-	-	
K	Amount of Line I Attributable to Others, if any	(216)	(184)	(185)	(188)	
	Non-Affiliate Capacity					
L	Installed Capacity	3,862	3,862	3,837	3,862	WKp-Energy Velocity PACW Gen, less Row A above
M	Long-Term Firm Purchases	364	364	364	364	Offset, Row C
N	Long-Term Firm Sales	-	-	-	-	
O	Local Seasonal Average Planned Outages	(28)	(263)	(25)	(203)	FERC Form 714
P	Uncommitted Capacity Imports	1,062	1,119	1,289	1,097	147 FERC ¶ 61,021 (2014), less Row E above
	Supply Calculation					
Q	Total Competing Supply	1,961	2,278	2,633	2,252	SUM L,M,N,O,P,H,K
R	Seller's Uncommitted Capacity	126	126	131	126	SUM A,B,C,D,E,G,J
S	Total Seasonal Uncommitted Capacity	2,087	2,404	2,764	2,377	SUM Q,R
T	**Seller's Market Share (R/S)**	6.0%	5.2%	4.7%	5.3%	
	Results	**PASS**	**PASS**	**PASS**	**PASS**	Pass if < 20% Fail if > 20%

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WORKPAPERS

EIA 860

2013 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Prime Mover	Unit Code	Ownership	Nameplate Capacity (MW)	Summer Capacity (MW)	Winter Capacity (MW)	Status	Synchronized to Transmission Grid	Operating Month	Operating Year
6607	FPL Energy Vansycle LLC	55560	FPL Energy Vansycle LLC (WA)	WA	Walla Walla	V-47	WT		S	176.9	176.9	176.9	OP		12	2001
6607	FPL Energy Vansycle LLC	55989	FPL Energy Vansycle LLC (OR)	OR	Umatilla	V-47	WT		S	122.8	122.8	122.8	OP		12	2001
21734	Sunnyside Cogeneration Assoc	50951	Sunnyside Cogen Associates	UT	Carbon	GEN1	ST		J	58.1	51.0	51.0	OP		2	1993
58083	Outback Solar, LLC	58131	Outback Solar At Christmas Valley	OR	Lake	PV1	PV		S	4.4	4.4	4.4	OP		10	2012
55711	Inc - SEGS	10440	SEGS IV	CA	San Bernardino	GEN1	ST		J	34.2	36.0	34.0	OP		12	1986
55711	Inc - SEGS	10441	SEGS V	CA	San Bernardino	GEN1	ST		J	34.2	36.0	34.0	OP		10	1987
55711	Inc - SEGS	10442	SEGS VI	CA	San Bernardino	GEN1	ST		J	35.0	36.0	35.0	OP		12	1988
56157	Cassia Gulch	56935	Cassia Gulch Wind Park LLC	ID	Twin Falls	1	WT		S	18.9	18.9	18.9	OP		3	2009
56158	Cassia Wind	56934	Cassia Wind Farm LLC	ID	Twin Falls	1	WT		S	10.5	10.5	10.5	OP		3	2009
56159	Threemile Canyon Wind I	56933	Threemile Canyon Wind I LLC	OR	Morrow	1	WT		S	9.9	9.9	9.9	OP		7	2009
57396	High Mesa Energy LLC	58019	High Mesa Energy LLC	ID	Twin Falls	1	WT		S	40.0	40.0	40.0	OP		12	2012
56475	Tuana Springs Energy LLC	57136	Tuana Springs	ID	Gooding	1	WT		S	16.8	16.8	16.8	OP		5	2010
56802	Echo 1	56971	Oregon Trail Windfarm LLC	OR	Umatilla	1	WT		S	9.9	9.9	9.9	OP		6	2009
56802	Echo 1	56972	Pacific Canyon Windfarm LLC	OR	Morrow	1	WT		S	8.3	8.3	8.3	OP		6	2009
56802	Echo 1	56973	Sand Ranch Windfarm LLC	OR	Morrow	1	WT		S	9.9	9.9	9.9	OP		6	2009
56802	Echo 1	56975	Ward Butte Windfarm LLC	OR	Umatilla	1	WT		S	6.6	6.6	6.6	OP		6	2009
56803	Echo 2	56969	Four Corners Windfarm LLC	OR	Umatilla	1	WT		S	10.0	10.0	10.0	OP		6	2009
56803	Echo 2	56970	Four Mile Canyon Windfarm LLC	OR	Morrow	1	WT		S	10.0	10.0	10.0	OP		6	2009
56804	Echo 3	56967	Butter Creek Power LLC	OR	Umatilla	1	WT		S	5.0	5.0	5.0	OP		6	2009
56804	Echo 3	56968	Big Top LLC	OR	Morrow	1	WT		S	1.7	1.7	1.7	OP		6	2009
56804	Echo 3	56974	Wagon Trail LLC	OR	Morrow	1	WT		S	3.3	3.3	3.3	OP		6	2009
11556	Malacha Hydro Ltd Partnership	10458	Muck Valley Hydroelectric	CA	LASSEN	GEN1	HY		S	29.9	29.9	29.9	OP		12	1988
56615	First Solar Energy LLC	57378	AV Solar Ranch One	CA	Los Angeles	AVSR	PV		W	253.0	230.0	230.0	2014	N	CHP	2
55890	Bennett Creek Windfarm LLC	56637	Bennett Creek Windfarm LLC	ID	Elmore	1	WT		S	21.0	21.0	21.0	OP		7	2008
55891	Hot Springs	56636	Hot Springs Windfarm LLC	ID	Elmore	1	WT		S	21.0	21.0	21.0	OP		5	2008

WKp-Energy Velocity PACW Gen

Unit Balancing Authority Area Abbrev	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Plant State	Unit	Unit ID	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PACE	Idaho Falls ID (City of)	Idaho Falls ID (City of	Idaho Falls ID (City of)	Upper Power Plant	Idaho	1	660194	100	1	1	1	HY	WAT	Retired	1/3/30	12/31/79
PACE	Idaho Falls ID (City of)	Idaho Falls ID (City of	Idaho Falls ID (City of)	Upper Power Plant	Idaho	2	660195	100	1	1	1	HY	WAT	Retired	1/3/36	12/31/79
PACW	Avista Corp	Avista Corp	Avista Corp	Lewiston (ID)	Idaho	1	632149	100	5	5	5	HY	WAT	Retired	1/1/27	1/1/73
PACW	Avista Corp	Avista Corp	Avista Corp	Lewiston (ID)	Idaho	2	632150	100	5	5	5	HY	WAT	Retired	1/1/27	1/1/73
PACW	Baker OR (City of)	Baker OR (City of)	Baker OR (City of)	Baker (OR)	Oregon	1	630536	100	0.2	0.2	0.2	HY	WAT	Operating	1/1/70	
PACW	Big Top LLC	Exelon Corp	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT1 27	1137851	3.7	1.648	1.648	1.648	WT	WND	Operating	6/27/09	
PACW	Biomass One LP	Brookfield Asset Man	Biomass One LP	Biomass One LP	Oregon	BBC	393928	100	10	8.5	8.5	ST	WDS	Operating	12/1/85	
PACW	Biomass One LP	Brookfield Asset Man	Biomass One LP	Biomass One LP	Oregon	GE	393929	100	15	14	14	ST	WDS	Operating	12/1/85	
PACW	Birch Power Co	Birch Power Co	Birch Power Co	Birch Creek	Idaho	GEN1	393932	100	2.6	2.6	2.6	HY	WAT	Operating	4/1/86	
PACW	Bridger Valley Electric Association Inc	Bridger Valley Electric	Bridger Valley Electric Assoc	Lyman	Wyoming	1	659621	100	1	1	1	ST	N/A	Retired	1/3/40	1/31/74
PACW	Bridger Valley Electric Association Inc	Bridger Valley Electric	Bridger Valley Electric Assoc	Lyman	Wyoming	2	659622	100	1	1	1	ST	N/A	Retired	1/3/40	1/31/74
PACW	Bridger Valley Electric Association Inc	Bridger Valley Electric	Bridger Valley Electric Assoc	Lyman	Wyoming	3	659623	100	1	1	1	ST	N/A	Retired	1/3/41	1/31/74
PACW	Bridger Valley Electric Association Inc	Bridger Valley Electric	Bridger Valley Electric Assoc	Lyman	Wyoming	4	659624	100	1	1	1	ST	N/A	Retired	1/3/41	1/31/74
PACW	Bridger Valley Electric Association Inc	Bridger Valley Electric	Bridger Valley Electric Assoc	Lyman	Wyoming	5	659625	100	1	1	1	ST	N/A	Retired	1/3/47	1/31/74
PACW	Bridger Valley Electric Association Inc	Bridger Valley Electric	Bridger Valley Electric Assoc	Lyman	Wyoming	6	659626	100	1	1	1	ST	N/A	Retired	1/3/47	1/31/74
PACW	Bridger Valley Electric Association Inc	Bridger Valley Electric	Bridger Valley Electric Assoc	Lyman	Wyoming	7	659627	100	1	1	1	ST	N/A	Retired	1/3/52	1/31/74
PACW	Bridger Valley Electric Association Inc	Bridger Valley Electric	Bridger Valley Electric Assoc	Lyman	Wyoming	8	659628	100	1	1	1	ST	N/A	Retired	1/3/52	1/31/74
PACW	BT Capital	Deutsche Bank AG	Slate Creek Hydro Associate	Slate Creek	California	GEN1	403197	5	0.21	0.2	0.193	HY	WAT	Operating	5/1/90	
PACW	Butter Creek Power LLC	Exelon Corp	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT1 27	1137851	11.1	4.945	4.945	4.945	WT	WND	Operating	6/27/09	
PACW	C Drop Hydro LLC	Warm Springs Hydro	C Drop Hydro LLC	C Drop Hydroelectric	Oregon	HY1	1553538	100	1.1	1.093	1.093	HY	WAT	Operating	5/4/12	
PACW	CDM Hydroelectric Co	CDM	CDM Hydroelectric Co	Felt Hydro	Idaho	GEN1	396178	100	2.7	2.3	2.3	HY	WAT	Operating	12/1/85	
PACW	CDM Hydroelectric Co	CDM	CDM Hydroelectric Co	Felt Hydro	Idaho	GEN2	396179	100	2.7	2.3	2.3	HY	WAT	Operating	12/1/85	
PACW	CDM Hydroelectric Co	CDM	CDM Hydroelectric Co	Felt Hydro	Idaho	GEN3	396180	100	1.1	0.8	0.8	HY	WAT	Standby	4/1/86	
PACW	CDM Hydroelectric Co	CDM	CDM Hydroelectric Co	Felt Hydro	Idaho	GEN4	396181	100	0.9	0.5	0.5	HY	WAT	Standby	4/1/86	
PACW	Central Oregon Irrigation District	Central Oregon Irrigat	Central Oregon Irrigation Dis	Juniper Ridge Project	Oregon	HY1	1168532	100	5	3	1.1	HY	WAT	Operating	9/21/10	
PACW	Central Oregon Irrigation District	Central Oregon Irrigat	Central Oregon Irrigation Dis	Siphon	Oregon	GEN1	403211	100	2.7	2.65	2.65	HY	WAT	Operating	8/1/89	
PACW	Central Oregon Irrigation District	Central Oregon Irrigat	Central Oregon Irrigation Dis	Siphon	Oregon	GEN2	403212	100	2.7	2.65	2.65	HY	WAT	Operating	8/1/89	
PACW	Co Generating II	Pacific Northwest Ger	Co Generating II	Co Generating II LLC	Oregon	GEN1	394956	100	7.5	7.8	7.3	ST	WDS	Operating	10/1/87	
PACW	David & Patty Jacobs	David & Patty Jacobs	David & Patty Jacobs	Jacobs Hydro	Oregon	HY	1131050	100	0.075	0.075	0.075	HY	WAT	Operating	9/1/09	
PACW	Deschutes Valley Water District	Deschular Valley Wat	Deschutes Valley Water Dist	Opal Springs Hydro	Oregon	1	399971	100	4.3	3.3	5	HY	WAT	Operating	1/1/85	
PACW	Douglas County	Douglas County	Douglas County	Galesville	Oregon	GV1	396472	100	0.8	0.8	1	HY	WAT	Operating	2/1/87	
PACW	Douglas County	Douglas County	Douglas County	Galesville	Oregon	GV2	396473	100	0.8	0.8	1	HY	WAT	Operating	2/1/87	
PACW	Douglas County Forest Products	Douglas County Fores	Douglas County Forest Prod	Douglas County Forest Pr	Oregon	ST	879463	100	3.2	3.2	3.2	ST	WDS	Operating	8/29/06	
PACW	Douglas County Forest Products	Douglas County Fores	Douglas County Forest Prod	Douglas County Forest Pr	Oregon	ST2	915637	100	3.2	3.2	3.2	ST	WDS	Operating	12/31/06	

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Unit Balancing Authority Area Abbrev	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Plant State	Unit	Unit ID	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PACW	Emerald Peoples Utility District	Emerald Peoples Utili	Emerald Peoples Utility Distr	Short Mountain	Oregon	1	403254	100	0.8	0.8	0.8	IC	LFG	Operating	2/1/92	
PACW	Emerald Peoples Utility District	Emerald Peoples Utili	Emerald Peoples Utility Distr	Short Mountain	Oregon	2	403255	100	0.8	0.8	0.8	IC	LFG	Operating	2/1/92	
PACW	Emerald Peoples Utility District	Emerald Peoples Utili	Emerald Peoples Utility Distr	Short Mountain	Oregon	3	403256	100	0.8	0.8	0.8	IC	LFG	Operating	11/1/93	
PACW	Emerald Peoples Utility District	Emerald Peoples Utili	Emerald Peoples Utility Distr	Short Mountain	Oregon	4	403257	100	0.8	0.8	0.8	IC	LFG	Operating	11/1/93	
PACW	Eugene Water & Electric Board	Eugene Water & Elect	Eugene Water & Electric Boa	Willamette	Oregon	1	607381	100	6	6	6	ST	PC	Retired	1/3/31	7/31/81
PACW	Eugene Water & Electric Board	Eugene Water & Elect	Eugene Water & Electric Boa	Willamette	Oregon	2	607382	100	7.5	6	6	ST	WDS	Retired	1/1/41	7/31/81
PACW	Eugene Water & Electric Board	Eugene Water & Elect	Eugene Water & Electric Boa	Willamette	Oregon	3	607383	100	11.5	7	7	ST	WDS	Retired	1/3/50	6/30/98
PACW	Eurus Combine Hills I LLC	Tokyo Electric Power	Eurus Energy America Corp	Combine Hills	Oregon	WT1 41	589463	100	41	41	41	WT	WND	Operating	12/15/03	
PACW	Eurus Combine Hills II LLC	Tokyo Electric Power	Eurus Energy America Corp	Combine Hills	Oregon	WT42 104	589423	100	63	63	63	WT	WND	Operating	1/1/10	
PACW	Evergreen Biopower LLC	Evergreen Biopower	Evergreen Biopower LLC	Freres Lumber	Oregon	ST1	1157038	100	21	10	10	ST	WDS	Operating	9/30/07	
PACW	Facebook	Facebook	Facebook	Facebook Data Center (Pr	Oregon	IC 1 28	1996252	100	84	84	84	IC	DSL	Standby	4/1/11	
PACW	Fall River Rural Electric Coop Inc	Fall River Rural Electri	Fall River Rural Electric Coop	Felt	Idaho	1	445401	100	0.3	0.3	0.3	HY	WAT	Retired	1/3/12	9/30/68
PACW	Fall River Rural Electric Coop Inc	Fall River Rural Electri	Fall River Rural Electric Coop	Felt	Idaho	2	445402	100	0.2	0.2	0.2	HY	WAT	Retired	1/3/38	9/30/68
PACW	Fall River Rural Electric Coop Inc	Fall River Rural Electri	Fall River Rural Electric Coop	Felt	Idaho	3	445403	100	0.3	0.3	0.3	HY	WAT	Retired	1/3/37	9/30/68
PACW	Fall River Rural Electric Coop Inc	Fall River Rural Electri	Fall River Rural Electric Coop	Felt	Idaho	4	396176	100	0.6	0.6	0.6	HY	WAT	Operating	1/3/46	
PACW	Fall River Rural Electric Coop Inc	Fall River Rural Electri	Fall River Rural Electric Coop	Felt	Idaho	5	396177	100	0.7	0.7	0.6	HY	WAT	Operating	1/3/47	
PACW	Fall River Rural Electric Coop Inc	Fall River Rural Electri	Fall River Rural Electric Coop	Felt	Idaho	HC1	592993	100	2.75	2.75	2.75	HY	WAT	Operating	1/1/80	
PACW	Fall River Rural Electric Coop Inc	Fall River Rural Electri	Fall River Rural Electric Coop	Felt	Idaho	HC2	592994	100	2.75	2.75	2.75	HY	WAT	Operating	1/1/80	
PACW	Farmers Irrigation District	Farmers Irrigation Dis	Farmers Irrigation District	Copper Dam	Oregon	GEN1	395133	100	2	1	2	HY	WAT	Operating	1/1/86	
PACW	Farmers Irrigation District	Farmers Irrigation Dis	Farmers Irrigation District	Copper Dam	Oregon	GEN2	395134	100	1	0.5	1	HY	WAT	Operating	1/1/86	
PACW	Farmers Irrigation District	Farmers Irrigation Dis	Farmers Irrigation District	Peters Drive	Oregon	GEN3	400419	100	1.8	0.3	1.17	HY	WAT	Operating	11/1/87	
PACW	FMC Corp	FMC Corp	FMC Corp	Green River (WY)	Wyoming	CG	649555	100	3.5	3.5	3.5	ST	SUB	Operating	6/1/53	
PACW	FMC Corp	FMC Corp	FMC Corp	Green River (WY)	Wyoming	ST2	1836392	100	3.5	3.5	3.5	ST	SUB	Operating	6/1/53	
PACW	FMC Corp	FMC Corp	FMC Corp	Green River (WY)	Wyoming	ST3	1836393	100	4	3.5	3.5	ST	SUB	Operating	6/1/64	
PACW	FMC Corp	FMC Corp	FMC Corp	Green River (WY)	Wyoming	ST4	1836395	100	10	10	10	ST	SUB	Operating	6/1/72	
PACW	FMC Corp	FMC Corp	FMC Corp	Green River (WY)	Wyoming	ST5	1836394	100	10	10	10	ST	SUB	Operating	6/1/75	
PACW	FMC Corp	FMC Corp	FMC Corp	Green River (WY)	Wyoming	ST6	1836396	100	10	10	10	ST	SUB	Operating	6/1/75	
PACW	Four Corners Windfarm LLC	Exelon Corp	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT28 38	1156451	50	10	10	10	WT	WND	Operating	9/30/09	
PACW	Four Mile Canyon Windfarm LLC	Exelon Corp	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT28 38	1156451	50	10	10	10	WT	WND	Operating	9/30/09	
PACW	FPL Energy Stateline II Inc	NextEra Energy Inc	FPL Energy Vansycle LLC	Stateline Wind (OR)	Oregon	WT182 22	589544	100	99	99	99	WT	WND	Operating	12/31/09	
PACW	FPL Energy Vansycle LLC	NextEra Energy Inc	FPL Energy Vansycle LLC	Stateline Wind (OR)	Oregon	WT1 126	396080	100	83.2	83.2	83.2	WT	WND	Operating	12/20/01	
PACW	FPL Energy Vansycle LLC	NextEra Energy Inc	FPL Energy Vansycle LLC	Stateline Wind (OR)	Oregon	WT127 18	651715	100	36.3	36.3	36.3	WT	WND	Operating	12/1/02	
PACW	Hermiston Generating Co LP	Sumitomo Corp	PacifiCorp	Hermiston Generating Pla	Oregon	CC1	584417	50	155.3	116	121.5	CC	NG	Operating	7/1/96	
PACW	Hermiston Generating Co LP	Sumitomo Corp	PacifiCorp	Hermiston Generating Pla	Oregon	CC2	650010	50	155.3	116	121.5	CC	NG	Operating	7/1/96	

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Unit Balancing Authority Area Abbrev	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Plant State	Unit	Unit ID	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PACW	Howard & Verna Cornwell	Howard & Verna Corr	Howard & Verna Cornwell	Cornwell Microhydro	California	HY	1127326	100	0.012	0.012	0.012	HY	WAT	Operating	5/7/80	
PACW	Idaho Falls ID (City of)	Idaho Falls ID (City of	Idaho Falls ID (City of)	Upper Power Plant	Idaho	4	402165	100	8	8	8	HY	WAT	Operating	9/1/82	
PACW	Idaho Power Co	IDACORP Inc	PacifiCorp	Jim Bridger	Wyoming	1	387706	33.33	192.614	176.982	176.982	ST	SUB	Operating	11/1/74	
PACW	Idaho Power Co	IDACORP Inc	PacifiCorp	Jim Bridger	Wyoming	2	389615	33.33	192.614	175.649	175.649	ST	SUB	Operating	12/1/75	
PACW	Idaho Power Co	IDACORP Inc	PacifiCorp	Jim Bridger	Wyoming	3	389616	33.33	192.614	174.316	174.316	ST	SUB	Operating	9/1/76	
PACW	Idaho Power Co	IDACORP Inc	PacifiCorp	Jim Bridger	Wyoming	4	389617	33.33	194.647	176.649	176.649	ST	SUB	Operating	11/1/79	
PACW	International Paper Co	International Paper C	International Paper Co	Springfield Oregon	Oregon	TG1	402957	100	7.5	7.5	7.5	ST	BLQ	Standby	1/1/49	
PACW	International Paper Co	International Paper C	International Paper Co	Springfield Oregon	Oregon	TG2	402958	100	5	5	5	ST	BLQ	Standby	1/1/49	
PACW	International Paper Co	International Paper C	International Paper Co	Springfield Oregon	Oregon	TG3	402959	100	12.5	12.5	12.5	ST	BLQ	Operating	1/1/53	
PACW	International Paper Co	International Paper C	International Paper Co	Springfield Oregon	Oregon	TG4	402960	100	40	33	33	ST	BLQ	Operating	10/1/76	
PACW	Leaning Juniper Wind Power II LLC	Iberdrola SA	enXco Service Corp	Leaning Juniper 1	Oregon	WT112 18	1161585	100	111	111	111	WT	WND	Operating	3/15/11	
PACW	Leaning Juniper Wind Power II LLC	Iberdrola SA	enXco Service Corp	Leaning Juniper 1	Oregon	WT68 111	1161583	100	90.3	90.3	90.3	WT	WND	Operating	3/1/11	
PACW	Lower Valley Energy Inc	Lower Valley Energy I	Lower Valley Energy Inc	Strawberry Creek	Wyoming	1	387439	100	0.5	0.5	0.5	HY	WAT	Operating	1/3/51	
PACW	Lower Valley Energy Inc	Lower Valley Energy I	Lower Valley Energy Inc	Strawberry Creek	Wyoming	2	402766	100	0.5	0.5	0.5	HY	WAT	Operating	1/3/51	
PACW	Lower Valley Energy Inc	Lower Valley Energy I	Lower Valley Energy Inc	Strawberry Creek	Wyoming	3	402767	100	0.5	0.5	0.5	HY	WAT	Operating	1/3/51	
PACW	Marsh Valley Development Inc	Marsh Valley Develop	Marsh Valley Development I	Marsh Valley Developmer	Idaho	1	387289	100	1.6	1.52	1.47	HY	WAT	Operating	4/1/93	
PACW	Mound Solar Owner VI LLC	SolarCity Corp	Oregon University System	Oregon Inst of Tech	Oregon	PV1	1575211	100	2.5	2	2	PV	SUN	Operating	4/23/14	
PACW	Ocean Power Technologies	Ocean Power Techno	Ocean Power Technologies	Reedsport OPT Wave Parl	Oregon	HT1	1519390	100	0.15	0.15	0.15	HK	WAT	Operating	9/13/11	
PACW	Oregon Environmental Industries	Oregon Environmenta	SCS Energy LLC	Dry Creek Landfill	Oregon	IC1	870272	100	1.6	1.5	1.5	IC	LFG	Operating	7/6/07	
PACW	Oregon Environmental Industries	Oregon Environmenta	SCS Energy LLC	Dry Creek Landfill	Oregon	IC2	870274	100	1.6	1.6	1.6	IC	LFG	Operating	7/6/07	
PACW	Oregon Environmental Industries	Oregon Environmenta	SCS Energy LLC	Dry Creek Landfill	Oregon	IC3	879270	100	1.3	1.3	1.3	IC	LFG	Operating	9/29/07	
PACW	Oregon Trail Windfarm LLC	Exelon Corp	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT1 27	1137851	22.2	9.89	9.89	9.89	WT	WND	Operating	6/27/09	
PACW	Oregon University System	Oregon University Sys	Oregon University System	Oregon Inst of Tech	Oregon	GE1	2024389	100	0.28	0.28	0.28	GE	GEO	Operating	4/20/10	
PACW	Oregon University System	Oregon University Sys	Oregon University System	Oregon Inst of Tech	Oregon	GE2	2024391	100	0.75	0.75	0.75	GE	GEO	Operating	4/24/14	
PACW	Oregon University System	Oregon University Sys	Oregon University System	Oregon Inst of Tech	Oregon	GE3	2024392	100	0.75	0.75	0.75	GE	GEO	Operating	4/24/14	
PACW	Pacific Canyon Windfarm LLC	Exelon Corp	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT1 27	1137851	18.5	8.242	8.242	8.242	WT	WND	Operating	6/27/09	
PACW	PacifiCorp	Berkshire Hathaway I	enXco Service Corp	Leaning Juniper 1	Oregon	WT1 67	735621	100	100.5	100.5	100.5	WT	WND	Operating	10/1/06	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Bend	Oregon	1	387793	100	0.2	0.2	0.2	HY	WAT	Operating	1/3/13	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Bend	Oregon	2	393786	100	0.3	0.3	0.3	HY	WAT	Operating	1/3/16	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Bend	Oregon	3	393787	100	0.6	0.5	0.5	HY	WAT	Operating	1/3/17	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Big Fork	Montana	1	393899	100	1.7	1.9	1.9	HY	WAT	Operating	1/3/24	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Big Fork	Montana	2	393900	100	1.7	1.9	1.9	HY	WAT	Operating	1/3/29	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Big Fork	Montana	3	393901	100	0.7	0.8	0.8	HY	WAT	Operating	1/3/10	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Black Cap Solar	Oregon	PV1	1678446	100	2	2	2	PV	SUN	Operating	11/9/12	

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Unit Balancing Authority Area Abbrev	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Plant State	Unit	Unit ID	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Clearwater 1	Oregon	1	394925	100	15	18	18	HY	WAT	Operating	6/1/53	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Clearwater 2	Oregon	1	387800	100	26	31	31	HY	WAT	Operating	11/1/53	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Cline Falls	Oregon	1	394944	100	1	1.1	1.1	HY	WAT	Operating	5/1/43	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Condit	Washingto	1	395079	100	7	7.7	7.7	HY	WAT	Retired	4/1/13	10/25/11
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Condit	Washingto	2	395080	100	6.7	7.4	7.4	HY	WAT	Retired	4/1/13	10/25/11
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Copco 1	California	1	395126	100	10	13.2	13.2	HY	WAT	Operating	1/1/18	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Copco 1	California	2	395127	100	10	13.2	13.2	HY	WAT	Operating	11/1/22	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Copco 2	California	1	395128	100	13.5	17.8	17.8	HY	WAT	Operating	7/1/25	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Copco 2	California	2	395129	100	13.5	17.8	17.8	HY	WAT	Operating	8/1/25	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Eagle Point (OR)	Oregon	1	395711	100	2.8	2.8	2.8	HY	WAT	Operating	11/1/57	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	East Side	Oregon	1	387683	100	3.2	3	3	HY	WAT	Operating	8/1/24	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Fall Creek	California	1	396124	100	0.5	0.4	0.4	HY	WAT	Operating	9/1/03	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Fall Creek	California	2	396125	100	0.4	0.4	0.4	HY	WAT	Operating	8/1/07	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Fall Creek	California	3	396126	100	1.2	1.1	1.1	HY	WAT	Operating	1/1/10	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Fish Creek	Oregon	1	387799	100	11	10.4	10.4	HY	WAT	Operating	6/1/52	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Gold Ray	Oregon	1	614297	100	1	0	0	HY	WAT	Retired	1/3/05	1/31/72
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Gold Ray	Oregon	2	614298	100	1	0	0	HY	WAT	Retired	1/3/05	1/31/72
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Hermiston Generating Pla	Oregon	CC1	584417	50	155.3	116	121.5	CC	NG	Operating	7/1/96	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Hermiston Generating Pla	Oregon	CC2	650010	50	155.3	116	121.5	CC	NG	Operating	7/1/96	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Iron Gate	California	1	397608	100	18	18.8	18.8	HY	WAT	Operating	2/1/62	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Jim Bridger	Wyoming	1	387706	66.67	385.286	354.018	354.018	ST	SUB	Operating	11/1/74	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Jim Bridger	Wyoming	2	389615	66.67	385.286	351.351	351.351	ST	SUB	Operating	12/1/75	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Jim Bridger	Wyoming	3	389616	66.67	385.286	348.684	348.684	ST	SUB	Operating	9/1/76	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Jim Bridger	Wyoming	4	389617	66.67	389.353	353.351	353.351	ST	SUB	Operating	11/1/79	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	John C Boyle	Oregon	1	397731	100	50.3	50.4	50.4	HY	WAT	Operating	10/1/58	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	John C Boyle	Oregon	2	397732	100	48.4	47.6	47.6	HY	WAT	Operating	10/1/58	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Lemolo 1	Oregon	1	398280	100	32.8	32	32	HY	WAT	Operating	7/1/55	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Lemolo 2	Oregon	1	398281	100	33	38	38	HY	WAT	Operating	11/1/56	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Marengo Wind	Washingto	WT1	78	875838	100	140.4	140.4	140.4	WT	WND	Operating	8/20/07
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Marengo Wind	Washingto	WT2	117	910724	100	70.2	70.2	70.2	WT	WND	Operating	9/30/08
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Merwin	Washingto	1	398965	100	45	50	50	HY	WAT	Operating	1/1/32	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Merwin	Washingto	2	398966	100	45	50	50	HY	WAT	Operating	12/1/49	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Merwin	Washingto	3	398967	100	45	50	50	HY	WAT	Operating	9/1/58	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Merwin	Washingto	H	879131	100	1	1	1	HY	WAT	Operating	7/1/31	

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WKp-Energy Velocity PACW Gen

Unit Balancing Authority Area Abbrev	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Plant State	Unit	Unit ID	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Naches	Washingto	2	399403	100	3	2.6	2.6	HY	WAT	Retired	1/3/09	10/31/03
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Naches	Washingto	4	399404	100	3.3	4	4	HY	WAT	Retired	1/3/13	10/31/03
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Naches Drop	Washingto	1	399405	100	1.4	1	1	HY	WAT	Retired	3/1/15	10/31/03
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	North Bend	Oregon	1	659780	100	5	5	5	HY	WAT	Retired	1/3/24	5/31/90
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	North Bend	Oregon	2	659781	100	10	10	10	HY	WAT	Retired	1/3/30	5/31/90
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	North Bend	Oregon	A	659782	100	1	1	1	HY	WAT	Retired	1/3/24	5/31/90
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Powerdale	Oregon	1	387708	100	6	6.5	6.5	HY	WAT	Retired	5/1/23	10/31/10
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Prospect 1	Oregon	1	400894	100	3.8	4.6	4.6	HY	WAT	Operating	1/1/12	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Prospect 2	Oregon	1	387798	100	16	18	18	HY	WAT	Operating	1/1/28	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Prospect 2	Oregon	2	400895	100	16	18	18	HY	WAT	Operating	2/1/28	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Prospect 3	Oregon	1	400896	100	7.2	7.7	7.7	HY	WAT	Operating	4/1/32	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Prospect 4	Oregon	1	387797	100	1	0.9	0.9	HY	WAT	Operating	11/1/44	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Slide Creek	Oregon	1	403191	100	18	18	18	HY	WAT	Operating	7/1/51	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Soda Springs	Oregon	1	403119	100	11	11.6	11.6	HY	WAT	Operating	3/1/52	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Swift 1	Washingto	HY11	402684	100	80	87.9	87.9	HY	WAT	Operating	12/1/58	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Swift 1	Washingto	HY12	402685	100	80	87.9	87.9	HY	WAT	Operating	12/1/58	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Swift 1	Washingto	HY13	402686	100	80	87.9	87.9	HY	WAT	Operating	12/1/58	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Toketee	Oregon	1	387796	100	14.2	15	15	HY	WAT	Operating	2/1/50	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Toketee	Oregon	2	402454	100	14.2	15	15	HY	WAT	Operating	12/1/49	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Toketee	Oregon	3	402455	100	14.2	15	15	HY	WAT	Operating	3/1/50	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Trona	Wyoming	1	660215	100	16	16	16	ST	NG	Retired	1/3/68	12/31/80
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Wallowa Falls	Oregon	1	401918	100	1.1	1.1	1.1	HY	WAT	Operating	1/3/21	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	West Side	Oregon	1	444700	100	0.6	0.6	1	HY	WAT	Operating	10/1/08	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Whisky Run	Oregon	1	660112	100	0.3	0.3	0.3	WT	WND	Retired	12/1/81	9/30/87
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Yale	Washingto	1	401370	100	67	81.8	81.8	HY	WAT	Operating	9/1/53	
PACW	PacifiCorp	Berkshire Hathaway I	PacifiCorp	Yale	Washingto	2	401371	100	67	81.8	81.8	HY	WAT	Operating	11/1/53	
PACW	Portland General Electric Co	Portland General Elec	Portland General Electric Co	Pelton Re Reg	Oregon	1	400375	100	18.9	20.8	20.8	HY	WAT	Operating	6/1/82	
PACW	Portland General Electric Co	Portland General Elec	Puget Sound Energy Inc	Lower Snake River Wind E	Washingto	WT150	265 1163491	100	267	267	267	WT	WND	Operating	12/15/14	
PACW	Publishers Paper Co	Blue Heron Paper	Publishers Paper Co	Oregon City	Oregon	1	630495	100	1.75	1.75	1.75	HY	WAT	Operating	1/1/70	
PACW	Publishers Paper Co	Blue Heron Paper	Publishers Paper Co	Oregon City	Oregon	2	630496	100	1.75	1.75	1.75	HY	WAT	Operating	1/1/70	
PACW	PUD No 1 of Cowlitz County	PUD No 1 of Cowlitz (	PacifiCorp	Swift 2	Washingto	21	402682	100	36	34	34	HY	WAT	Restarted	1/1/59	
PACW	PUD No 1 of Cowlitz County	PUD No 1 of Cowlitz (	PacifiCorp	Swift 2	Washingto	22	402683	100	36	31	31	HY	WAT	Restarted	12/1/58	
PACW	Puget Sound Energy Inc	Puget Energy Inc	Puget Sound Energy Inc	Lower Snake River Wind E	Washingto	WT1	94 1163490	100	216.2	216.2	216.2	WT	WND	Operating	12/1/11	
PACW	Puget Sound Energy Inc	Puget Energy Inc	Puget Sound Energy Inc	Lower Snake River Wind E	Washingto	WT95	149 1649820	100	126.5	126.5	126.5	WT	WND	Operating	2/29/12	

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WKp-Energy Velocity PACW Gen

Unit Balancing Authority Area Abbrev	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Plant State	Unit	Unit ID	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PACW	R & R Lumber	Rough & Ready Lumb	R & R Lumber	D R Johnson Lumber	Oregon	ST1	395322	100	1.5	1.4	1.41	ST	WDS	Restarted	2/1/90	
PACW	Robert Fackrell	Robert Fackrell	Robert Fackrell	Mink Creek Hydro	Idaho	GEN1	399095	100	3.1	2	2	HY	WAT	Operating	12/1/86	
PACW	Rock Creek Ranch	Rock Creek Ranch	Rock Creek Ranch	Denny Creek	Oregon	1	746060	100	0.05	0.05	0.05	HY	WAT	Operating	10/1/83	
PACW	Roseburg Forest Products Co	Roseburg Forest Prod	Roseburg Forest Products Co	Dillard Complex	Oregon	GEN1	395543	100	5	5	5	ST	WDS	Operating	1/1/55	
PACW	Roseburg Forest Products Co	Roseburg Forest Prod	Roseburg Forest Products Co	Dillard Complex	Oregon	GEN2	395544	100	5	5	5	ST	WDS	Operating	1/1/55	
PACW	Roseburg Forest Products Co	Roseburg Forest Prod	Roseburg Forest Products Co	Dillard Complex	Oregon	GEN3	395545	100	7	7	7	ST	WDS	Operating	1/1/55	
PACW	Roseburg Forest Products Co	Roseburg Forest Prod	Roseburg Forest Products Co	Dillard Complex	Oregon	GEN4	395546	100	11.5	11.5	11.5	ST	WDS	Operating	1/1/55	
PACW	Roseburg Forest Products Co	Roseburg Forest Prod	Roseburg Forest Products Co	Dillard Complex	Oregon	GEN5	395547	100	11.5	11.5	11.5	ST	WDS	Operating	1/1/55	
PACW	Roseburg Forest Products Co	Roseburg Forest Prod	Roseburg Forest Products Co	Roseburg Forest Products	California	ST	870931	100	15	13.4	13.4	ST	WDS	Operating	8/25/11	
PACW	Roseburg LFG Energy LLC	Cascade Energy Partn	Energyneering Solutions Inc	Roseburg LFG Energy	Oregon	GEN1	1623951	100	1.6	1.6	1.6	IC	LFG	Operating	12/1/11	
PACW	Sand Ranch Windfarm LLC	Exelon Corp	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT1 27	1137851	22.2	9.89	9.89	9.89	WT	WND	Operating	6/27/09	
PACW	Slate Creek Hydro Associates LP	Enel SpA	Slate Creek Hydro Associate	Slate Creek	California	GEN1	403197	95	3.99	3.791	3.667	HY	WAT	Operating	5/1/90	
PACW	St Anthony Hydro LLC	St Anthony Hydro LLC	St Anthony Hydro LLC	St Anthony	Idaho	1	593056	100	0.5	0.4	0.4	HY	WAT	Operating	1/1/15	
PACW	Synergics Inc	Synergics Inc	Synergics Inc	Box Canyon (CA)	California	GEN1	394145	100	2.5	2.5	2.5	HY	WAT	Operating	6/1/86	
PACW	Synergics Inc	Synergics Inc	Synergics Inc	Box Canyon (CA)	California	GEN2	394146	100	2.5	2.5	2.5	HY	WAT	Operating	6/1/86	
PACW	Threemile Canyon Farm	Threemile Canyon Fai	Finley Bioenergy LLC	Threemile Canyon Farms	Oregon	IC1	1182369	100	1.6	1.6	1.6	IC	OBG	Operating	9/1/12	
PACW	Threemile Canyon Wind I LLC	Exelon Corp	Threemile Canyon Wind I LL	Threemile Canyon Wind	Oregon	WT1 6	875484	100	9.9	9.9	9.9	WT	WND	Operating	9/30/09	
PACW	Tieton Hydropower LLC	Burbank (City of)	Energy Northwest	Tieton Hydro	Washingto	HY1	882396	100	6.9	6.9	6.9	HY	WAT	Operating	7/1/06	
PACW	Tieton Hydropower LLC	Burbank (City of)	Energy Northwest	Tieton Hydro	Washingto	HY2	882397	100	6.9	6.9	6.9	HY	WAT	Operating	7/1/06	
PACW	TMF Biomass LLC	Threemile Canyon Fai	Finley Bioenergy LLC	Threemile Canyon Farms	Oregon	IC2	1580632	100	1.6	1.6	1.6	IC	OBG	Operating	9/1/12	
PACW	TMF Biomass LLC	Threemile Canyon Fai	Finley Bioenergy LLC	Threemile Canyon Farms	Oregon	IC3	1580633	100	1.6	1.6	1.6	IC	OBG	Operating	9/1/12	
PACW	U S Bureau of Reclamation	U S Bureau of Reclam	U S Bureau of Reclamation	Green Springs	Oregon	1	396905	100	17.2	17.2	17.2	HY	WAT	Operating	5/1/60	
PACW	University of Oregon	University of Oregon	University of Oregon	Univ of Oregon Central	Oregon	1	386524	100	1.5	1.4	1.5	ST	NG	Retired	1/1/50	5/31/09
PACW	University of Oregon	University of Oregon	University of Oregon	Univ of Oregon Central	Oregon	2	386547	100	1.5	1.4	1.41	ST	NG	Retired	1/1/50	10/31/04
PACW	University of Oregon	University of Oregon	University of Oregon	Univ of Oregon Central	Oregon	3	386567	100	2.5	2.5	2.5	ST	NG	Retired	1/1/60	10/31/09
PACW	University of Oregon	University of Oregon	University of Oregon	Univ of Oregon Central	Oregon	CC1	1954070	100	11	9	10.5	CC	NG	Operating	12/1/12	
PACW	Wagon Trail LLC	Wagon Trail LLC	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT1 27	1137851	7.5	3.341	3.341	3.341	WT	WND	Operating	6/27/09	
PACW	Ward Butte Windfarm LLC	Exelon Corp	Oregon Windfarms LLC	Echo Windfarm (OR)	Oregon	WT1 27	1137851	14.8	6.593	6.593	6.593	WT	WND	Operating	6/27/09	
PACW	Warm Springs Power Enterprises	Columbia River Inter	Warm Springs Power Enterp	Warm Springs Biomass (C	Oregon	GEN1	401873	100	3	2.63	2.5	ST	WDS	Standby	1/1/77	
PACW	Warm Springs Power Enterprises	Columbia River Inter	Warm Springs Power Enterp	Warm Springs Biomass (C	Oregon	GEN2	401874	100	3	2.63	2.5	ST	WDS	Operating	1/1/77	
PACW	Warm Springs Power Enterprises	Columbia River Inter	Warm Springs Power Enterp	Warm Springs Biomass (C	Oregon	GEN3	401875	100	3	2.63	2.5	ST	WDS	Operating	1/1/77	
PACW	Warm Springs Power Enterprises	Columbia River Inter	Warm Springs Power Enterp	Warm Springs Hydro (OR)	Oregon	1	386492	100	19.6	18.5	18.5	HY	WAT	Operating	6/1/82	
PACW	Western Wind Energy Corp	Brookfield Asset Man	Biomass One LP	Biomass One LP	Oregon	GE2	1479534	100	15	14	14	ST	WDS	Operating	1/1/09	
PACW	Yakima Tieton Irrigation District	Yakima Tieton Irrigati	Yakima Tieton Irrigation Dist	Cowiche	Washingto	983	395211	100	1.7	1.62	1.56	HY	WAT	Operating	3/1/87	

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WKp-Energy Velocity PACW Gen

Unit Balancing Authority Area Abbrev	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Plant State	Unit	Unit ID	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PACW	Yakima Tieton Irrigation District	Yakima Tieton Irrigati	Yakima Tieton Irrigation Dist	Orchard Avenue 1	Washingto	201	399977	100	0.8	0.76	0.74	HY	WAT	Operating	3/1/87	
PACW	Yakima Tieton Irrigation District	Yakima Tieton Irrigati	Yakima Tieton Irrigation Dist	Orchard Avenue 1	Washingto	301	399978	100	0.8	0.76	0.74	HY	WAT	Operating	3/1/87	

Operating		5,485	5,510
Subtract with on-line dates post-study period		(271)	(271)
Restarted		66	66
Retired	All retired before start of study period	107	107
Standby		100	100
Generation owned by Others			
Avista Corp		10	10
Douglas County		2	2
Eugene Water & Electric Board		19	19
Idaho Power Co		704	704
Portland General Electric Co		288	288
Puget Sound Energy Inc		343	343
Retired		(29)	(29)
Subtract new builds		(267)	(267)
Operating-New Builds+Restarted		5,280	5,306
Subtract Gen Owned by Others (less retired)		1,069	1,069
Total Gen		4,212	4,237

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Planned Outages, FERC Form 714

		PACW
2012	Dec	7
2013	Jan	18
2013	Feb	59
2013	Mar	45
2013	Apr	366
2013	May	378
2013	Jun	2
2013	Jul	2
2013	Aug	72
2013	Sep	80
2013	Oct	529
2013	Nov	0

	Winter	Spring	Summer	Fall
PACW	28	263	25	203

responden	report_yr	report_prd	spplmnt_n	row_num	avail_cap	plan_outag	unplan_ou	other_outa	tot_net	ex_avail_c	ex_not_av	tot_capabi
229	2012	12	0	1200	4408	7	766	0	5181	0	0	5181
229	2013	12	0	100	5791	18	704	0	6513	0	0	6513
229	2013	12	0	200	5791	59	2	0	5852	0	0	5852
229	2013	12	0	300	5791	45	37	0	5873	0	0	5873
229	2013	12	0	400	5791	366	421	0	6578	0	0	6578
229	2013	12	0	500	5791	378	74	0	6243	0	0	6243
229	2013	12	0	600	5791	2	121	0	5914	0	0	5914
229	2013	12	0	700	5791	2	95	0	5888	0	0	5888
229	2013	12	0	800	5791	72	90	0	5953	0	0	5953
229	2013	12	0	900	5791	80	484	0	6355	0	0	6355
229	2013	12	0	1000	5791	529	122	0	6442	0	0	6442
229	2013	12	0	1100	5791	0	624	0	6415	0	0	6415

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Wkp-PACE+PACW load

	PacifiCorp	PACW Estimated	MEHC Filing Attach 7 PACW	FF714, Pt II, Sch 3 2013 PACW
Peak	10,507	3,784	3844	3784 Peak, Jan 2013
Avg Mo	9,263	3,074	3123	
Winter	7,985	3,084	3133	
Spring	6,980	2,621	2663	
Summer	8,769	2,647	2689	
Fall	7,309	2,681	2724	

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
12/1/12	PACE+W	5,798	5,668	5,607	5,616	5,696	5,927	6,146	6,434	6,699	6,779	6,772	6,711	6,651	6,609	6,599	6,755	7,162	7,274	7,148	7,037	6,900	6,633	6,276	5,931
12/2/12	PACE+W	5,675	5,531	5,496	5,482	5,561	5,738	5,965	6,249	6,447	6,555	6,564	6,566	6,546	6,559	6,637	6,872	7,268	7,471	7,403	7,286	7,123	6,731	6,247	5,938
12/3/12	PACE+W	5,780	5,661	5,669	5,754	6,067	6,646	7,281	7,516	7,473	7,434	7,450	7,302	7,235	7,182	7,090	7,231	7,727	7,947	7,840	7,755	7,510	7,025	6,530	6,165
12/4/12	PACE+W	5,963	5,816	5,730	5,814	6,054	6,634	7,206	7,359	7,290	7,261	7,212	7,183	7,160	7,153	7,176	7,351	7,728	7,804	7,690	7,618	7,354	6,901	6,376	6,026
12/5/12	PACE+W	5,789	5,662	5,622	5,623	5,874	6,446	7,005	7,274	7,225	7,274	7,189	7,092	7,071	6,998	7,065	7,205	7,610	7,805	7,682	7,636	7,387	6,985	6,467	6,120
12/6/12	PACE+W	5,927	5,841	5,818	5,872	6,107	6,726	7,336	7,529	7,384	7,328	7,285	7,181	7,145	7,087	7,080	7,150	7,581	7,856	7,812	7,741	7,495	7,096	6,639	6,238
12/7/12	PACE+W	6,001	5,898	5,877	5,926	6,206	6,748	7,336	7,549	7,555	7,481	7,416	7,320	7,164	7,176	7,137	7,242	7,644	7,774	7,622	7,556	7,364	7,043	6,633	6,268
12/8/12	PACE+W	6,007	5,888	5,858	5,868	5,973	6,241	6,505	6,829	7,111	7,219	7,148	7,124	7,039	6,957	6,958	7,141	7,613	7,720	7,611	7,511	7,394	6,959	6,650	6,309
12/9/12	PACE+W	6,064	5,936	5,868	5,925	6,015	6,231	6,479	6,772	6,951	7,017	6,986	6,933	6,839	6,834	6,837	7,010	7,554	7,843	7,725	7,704	7,495	7,107	6,610	6,245
12/10/12	PACE+W	6,088	5,984	5,989	6,070	6,365	6,982	7,595	7,852	7,826	7,834	7,780	7,658	7,590	7,445	7,368	7,461	7,913	8,076	7,986	7,874	7,736	7,243	6,720	6,346
12/11/12	PACE+W	6,155	6,051	6,025	6,101	6,375	6,945	7,510	7,727	7,614	7,673	7,597	7,477	7,452	7,375	7,425	7,536	7,986	8,189	8,118	7,987	7,759	7,253	6,734	6,356
12/12/12	PACE+W	6,132	6,000	5,979	6,059	6,326	6,871	7,502	7,658	7,631	7,631	7,536	7,408	7,336	7,298	7,295	7,405	7,905	8,104	8,027	7,946	7,666	7,173	6,768	6,373
12/13/12	PACE+W	6,150	6,058	6,053	6,130	6,392	6,977	7,632	7,932	7,864	7,844	7,710	7,557	7,496	7,435	7,391	7,512	7,950	8,181	8,088	8,013	7,796	7,282	6,796	6,401
12/14/12	PACE+W	6,189	6,070	6,036	6,104	6,382	6,941	7,550	7,818	7,774	7,745	7,650	7,513	7,422	7,416	7,399	7,519	7,870	7,962	7,895	7,810	7,665	7,377	6,961	6,562
12/15/12	PACE+W	6,308	6,183	6,171	6,206	6,298	6,559	6,864	7,167	7,424	7,544	7,498	7,483	7,403	7,333	7,301	7,378	7,801	7,937	7,783	7,605	7,387	7,130	6,769	6,395
12/16/12	PACE+W	6,214	6,033	6,026	6,032	6,143	6,362	6,601	6,884	7,081	7,260	7,227	7,213	7,167	7,130	7,101	7,283	7,747	7,983	7,871	7,746	7,462	7,036	6,510	6,209
12/17/12	PACE+W	5,999	5,895	5,897	5,982	6,271	6,865	7,502	7,787	7,792	7,731	7,700	7,665	7,649	7,554	7,545	7,733	8,178	8,410	8,345	8,294	8,025	7,567	7,043	6,659
12/18/12	PACE+W	6,435	6,340	6,302	6,392	6,704	7,277	7,947	8,176	8,064	8,032	8,028	7,970	7,897	7,785	7,790	7,896	8,350	8,584	8,534	8,455	8,234	7,766	7,228	6,817
12/19/12	PACE+W	6,602	6,491	6,501	6,601	6,824	7,400	8,000	8,235	8,206	8,196	8,065	7,883	7,781	7,784	7,737	7,821	8,268	8,523	8,409	8,310	8,084	7,686	7,134	6,733
12/20/12	PACE+W	6,493	6,398	6,367	6,428	6,658	7,220	7,798	8,020	8,044	8,017	7,956	7,895	7,840	7,718	7,700	7,751	8,193	8,403	8,310	8,229	8,052	7,636	7,093	6,661
12/21/12	PACE+W	6,429	6,331	6,298	6,359	6,608	7,065	7,569	7,814	7,861	7,871	7,743	7,630	7,528	7,446	7,387	7,480	7,907	8,083	7,960	7,838	7,656	7,338	6,926	6,545
12/22/12	PACE+W	6,285	6,135	6,100	6,123	6,213	6,439	6,677	6,951	7,203	7,265	7,208	7,119	6,979	6,886	6,820	6,987	7,455	7,679	7,672	7,589	7,426	7,142	6,701	6,398
12/23/12	PACE+W	6,181	6,039	6,034	6,031	6,149	6,342	6,659	6,923	7,108	7,201	7,123	7,099	7,069	6,989	6,965	7,124	7,530	7,694	7,646	7,539	7,441	7,149	6,698	6,361
12/24/12	PACE+W	6,093	6,024	5,985	6,043	6,128	6,431	6,797	7,118	7,330	7,406	7,353	7,269	7,135	7,041	6,998	7,105	7,427	7,538	7,326	7,275	7,138	6,970	6,669	6,361
12/25/12	PACE+W	6,110	5,932	5,791	5,950	6,072	6,285	6,594	6,830	7,000	7,023	6,971	6,881	6,789	6,644	6,618	6,671	7,048	7,246	7,238	7,207	7,126	6,847	6,447	6,139
12/26/12	PACE+W	5,960	5,884	5,916	6,007	6,218	6,652	7,106	7,420	7,648	7,776	7,786	7,761	7,677	7,625	7,615	7,713	8,075	8,280	8,213	8,129	7,849	7,437	6,981	6,580
12/27/12	PACE+W	6,331	6,246	6,195	6,283	6,500	6,897	7,332	7,565	7,609	7,638	7,707	7,650	7,501	7,448	7,413	7,474	7,884	8,133	8,071	8,023	7,789	7,398	6,940	6,550
12/28/12	PACE+W	6,372	6,279	6,259	6,348	6,548	6,991	7,465	7,739	7,875	8,005	8,000	7,848	7,771	7,659	7,591	7,754	8,069	8,267	8,171	8,083	7,857	7,526	7,094	6,728

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Wkp-PACE+PACW load

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
12/29/12	PACE+W	6,480	6,293	6,298	6,401	6,477	6,715	6,982	7,255	7,499	7,561	7,560	7,442	7,312	7,179	7,084	7,226	7,690	7,960	7,907	7,785	7,623	7,336	6,874	6,558
12/30/12	PACE+W	6,298	6,184	6,176	6,219	6,304	6,533	6,820	7,073	7,233	7,269	7,186	7,110	6,973	6,920	6,875	7,011	7,525	7,901	7,883	7,765	7,584	7,329	6,892	6,616
12/31/12	PACE+W	6,484	6,414	6,433	6,504	6,655	7,033	7,430	7,613	7,821	7,883	7,855	7,743	7,613	7,526	7,436	7,536	7,914	8,088	7,890	7,727	7,491	7,243	6,976	6,721
1/1/13	PACE+W	6,516	6,335	6,286	6,272	6,382	6,516	6,741	6,902	7,084	7,192	7,209	7,140	7,042	6,913	6,854	6,992	7,520	7,930	7,951	7,871	7,665	7,324	6,883	6,583
1/2/13	PACE+W	6,425	6,386	6,426	6,553	6,882	7,439	8,040	8,295	8,383	8,303	8,173	8,038	7,950	7,877	7,784	7,827	8,265	8,636	8,607	8,476	8,255	7,808	7,317	7,032
1/3/13	PACE+W	6,872	6,798	6,779	6,744	7,094	7,622	8,217	8,499	8,515	8,469	8,309	8,123	7,993	7,850	7,824	7,878	8,296	8,588	8,548	8,404	8,168	7,764	7,265	6,926
1/4/13	PACE+W	6,703	6,604	6,599	6,707	6,976	7,450	8,022	8,282	8,342	8,255	8,074	7,836	7,728	7,647	7,559	7,585	7,961	8,265	8,206	8,019	7,848	7,564	7,187	6,931
1/5/13	PACE+W	6,728	6,624	6,570	6,547	6,705	6,981	7,258	7,506	7,718	7,800	7,723	7,618	7,533	7,397	7,347	7,423	7,854	8,103	7,988	7,852	7,655	7,315	7,009	6,661
1/6/13	PACE+W	6,464	6,355	6,314	6,294	6,414	6,577	6,808	7,074	7,248	7,301	7,259	7,209	7,140	7,078	7,044	7,153	7,609	7,917	7,857	7,704	7,495	7,131	6,772	6,492
1/7/13	PACE+W	6,354	6,280	6,286	6,374	6,685	7,250	7,887	8,089	8,013	7,910	7,733	7,675	7,615	7,563	7,503	7,613	7,966	8,194	8,124	7,907	7,647	7,262	6,788	6,440
1/8/13	PACE+W	6,265	6,147	6,129	6,205	6,434	6,925	7,573	7,776	7,705	7,678	7,660	7,565	7,469	7,399	7,301	7,409	7,785	8,065	7,994	7,876	7,579	7,088	6,556	6,274
1/9/13	PACE+W	6,119	6,005	6,014	6,062	6,341	6,822	7,482	7,729	7,569	7,427	7,480	7,383	7,380	7,347	7,266	7,355	7,728	8,077	8,052	7,927	7,684	7,249	6,793	6,472
1/10/13	PACE+W	6,242	6,199	6,179	6,254	6,493	7,048	7,746	7,997	7,926	7,875	7,843	7,701	7,651	7,610	7,645	7,736	8,115	8,367	8,254	8,127	7,855	7,457	6,934	6,551
1/11/13	PACE+W	6,393	6,321	6,309	6,398	6,651	7,211	7,903	8,177	8,175	8,172	8,100	7,991	7,885	7,776	7,683	7,687	8,004	8,300	8,235	8,125	7,928	7,609	7,238	6,900
1/12/13	PACE+W	6,726	6,577	6,552	6,687	6,812	7,038	7,357	7,663	7,890	7,990	7,894	7,734	7,522	7,473	7,332	7,388	7,786	8,188	8,199	8,114	7,954	7,577	7,201	6,898
1/13/13	PACE+W	6,718	6,667	6,646	6,734	6,812	7,035	7,303	7,571	7,758	7,812	7,708	7,641	7,495	7,367	7,386	7,505	7,914	8,337	8,344	8,276	8,065	7,670	7,291	7,020
1/14/13	PACE+W	6,861	6,825	6,871	6,984	7,257	7,828	8,483	8,792	8,777	8,701	8,523	8,339	8,170	7,995	7,985	7,953	8,325	8,825	8,779	8,692	8,416	7,951	7,454	7,125
1/15/13	PACE+W	6,992	6,902	6,918	7,000	7,303	7,869	8,583	8,819	8,758	8,586	8,438	8,265	8,146	8,006	7,908	7,934	8,239	8,667	8,680	8,551	8,293	7,824	7,335	7,051
1/16/13	PACE+W	6,860	6,762	6,804	6,882	7,114	7,669	8,298	8,547	8,484	8,416	8,286	8,175	8,056	8,002	7,917	7,948	8,282	8,669	8,647	8,517	8,258	7,783	7,265	6,986
1/17/13	PACE+W	6,806	6,758	6,778	6,819	7,093	7,726	8,370	8,619	8,555	8,410	8,259	8,148	8,015	7,910	7,819	7,850	8,169	8,551	8,578	8,459	8,253	7,767	7,290	7,012
1/18/13	PACE+W	6,835	6,799	6,823	6,942	7,098	7,709	8,391	8,664	8,647	8,510	8,346	8,147	7,970	7,818	7,657	7,670	7,959	8,296	8,270	8,172	7,973	7,671	7,293	6,977
1/19/13	PACE+W	6,802	6,717	6,721	6,759	6,880	7,155	7,528	7,841	8,086	8,100	7,977	7,783	7,551	7,388	7,264	7,297	7,608	7,994	7,972	7,933	7,787	7,536	7,202	6,905
1/20/13	PACE+W	6,735	6,655	6,658	6,711	6,812	7,030	7,301	7,621	7,768	7,758	7,597	7,469	7,288	7,172	7,100	7,187	7,538	7,915	7,953	7,932	7,760	7,452	7,069	6,808
1/21/13	PACE+W	6,704	6,679	6,693	6,801	7,095	7,575	8,033	8,339	8,432	8,476	8,332	8,154	8,031	7,859	7,850	7,863	8,152	8,570	8,560	8,486	8,237	7,805	7,334	7,000
1/22/13	PACE+W	6,892	6,818	6,835	6,933	7,235	7,775	8,471	8,732	8,611	8,497	8,280	8,093	8,035	7,907	7,810	7,847	8,143	8,498	8,487	8,375	8,135	7,676	7,255	6,934
1/23/13	PACE+W	6,732	6,655	6,663	6,727	6,985	7,486	8,129	8,368	8,317	8,195	8,096	7,973	7,989	7,944	7,893	7,990	8,232	8,498	8,465	8,327	8,068	7,604	7,095	6,755
1/24/13	PACE+W	6,561	6,447	6,447	6,526	6,804	7,370	7,973	8,194	8,108	8,013	7,988	7,932	7,805	7,769	7,667	7,750	8,001	8,229	8,160	8,026	7,803	7,394	6,942	6,568
1/25/13	PACE+W	6,365	6,243	6,220	6,275	6,523	6,954	7,556	7,838	7,862	7,876	7,825	7,713	7,631	7,558	7,466	7,423	7,586	7,888	7,827	7,662	7,461	7,168	6,789	6,428
1/26/13	PACE+W	6,248	6,112	6,080	6,087	6,213	6,427	6,708	6,994	7,227	7,352	7,365	7,287	7,185	7,067	6,949	7,007	7,197	7,544	7,549	7,410	7,246	6,963	6,603	6,302
1/27/13	PACE+W	6,101	5,976	5,987	6,010	6,123	6,337	6,606	6,885	7,080	7,166	7,133	7,131	7,049	7,089	7,030	7,192	7,530	7,837	7,794	7,677	7,324	7,116	6,690	6,429
1/28/13	PACE+W	6,270	6,161	6,096	6,207	6,485	7,049	7,682	7,966	8,021	8,049	7,918	7,805	7,757	7,674	7,649	7,669	7,917	8,165	8,201	8,103	7,806	7,346	6,909	6,610
1/29/13	PACE+W	6,404	6,356	6,320	6,373	6,652	7,215	7,868	8,039	7,944	7,906	7,866	7,788	7,699	7,590	7,490	7,498	7,728	8,145	8,066	7,987	7,736	7,219	6,691	6,446
1/30/13	PACE+W	6,269	6,145	6,131	6,206	6,489	7,059	7,708	7,899	7,861	7,775	7,695	7,566	7,542	7,433	7,337	7,358	7,600	7,945	7,892	7,824	7,567	7,112	6,646	6,304
1/31/13	PACE+W	6,106	6,004	6,019	6,096	6,412	6,972	7,582	7,828	7,773	7,705	7,595	7,429	7,309	7,245	7,175	7,135	7,313	7,672	7,720	7,581	7,415	7,052	6,627	6,283
2/1/13	PACE+W	6,119	6,057	6,030	6,114	6,323	6,827	7,406	7,653	7,635	7,491	7,429	7,222	7,121	7,027	6,885	6,802	6,938	7,344	7,418	7,363	7,204	7,002	6,702	6,405
2/2/13	PACE+W	6,248	6,161	6,138	6,176	6,315	6,568	6,877	7,127	7,312	7,340	7,229	7,053	6,885	6,750	6,639	6,635	6,885	7,299	7,400	7,304	7,195	6,937	6,600	6,287
2/3/13	PACE+W	6,140	6,033	6,029	6,020	6,139	6,325	6,605	6,871	7,087	7,182	7,108	7,058	6,899	6,861	6,785	6,738	6,835	7,130	7,212	7,144	7,212	6,895	6,486	6,206
2/4/13	PACE+W	6,099	6,036	6,047	6,169	6,441	7,021	7,654	7,865	7,939	7,859	7,638	7,505	7,447	7,312	7,215	7,210	7,424	7,906	7,985	7,875	7,607	7,186	6,716	6,392
2/5/13	PACE+W	6,217	6,111	6,122	6,179	6,479	6,974	7,609	7,822	7,694	7,625	7,518	7,387	7,293	7,156	7,116	7,168	7,361	7,711	7,773	7,681	7,419	7,024	6,641	6,356

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Wkp-PACE+PACW load

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2/6/13	PACE+W	6,172	6,079	6,081	6,160	6,429	7,008	7,646	7,839	7,715	7,632	7,477	7,350	7,205	7,107	7,088	7,151	7,351	7,740	7,755	7,670	7,436	6,996	6,673	6,389
2/7/13	PACE+W	6,228	6,158	6,142	6,244	6,505	7,091	7,728	7,933	7,852	7,733	7,593	7,404	7,276	7,245	7,134	7,182	7,383	7,810	7,881	7,775	7,628	7,267	6,835	6,525
2/8/13	PACE+W	6,363	6,308	6,283	6,350	6,596	7,163	7,745	7,994	7,873	7,825	7,658	7,484	7,420	7,349	7,283	7,235	7,315	7,664	7,718	7,649	7,473	7,100	6,694	6,523
2/9/13	PACE+W	6,345	6,267	6,206	6,275	6,390	6,651	6,905	7,196	7,407	7,463	7,398	7,236	7,064	6,924	6,873	6,907	7,107	7,437	7,487	7,389	7,231	6,960	6,623	6,363
2/10/13	PACE+W	6,156	6,112	6,077	6,100	6,233	6,419	6,700	6,899	7,077	7,120	6,979	6,912	6,790	6,686	6,633	6,740	6,975	7,386	7,505	7,480	7,253	6,949	6,590	6,316
2/11/13	PACE+W	6,157	6,134	6,156	6,318	6,625	7,235	7,872	8,052	7,968	7,888	7,749	7,583	7,539	7,451	7,368	7,359	7,488	7,886	8,009	7,941	7,672	7,265	6,857	6,411
2/12/13	PACE+W	6,295	6,343	6,345	6,371	6,670	7,205	7,791	7,999	7,967	7,839	7,764	7,538	7,394	7,358	7,268	7,309	7,462	7,779	7,923	7,813	7,605	7,149	6,750	6,446
2/13/13	PACE+W	6,244	6,175	6,140	6,212	6,439	6,957	7,526	7,683	7,482	7,547	7,410	7,324	7,250	7,156	7,129	7,056	7,250	7,576	7,691	7,553	7,375	6,989	6,500	6,284
2/14/13	PACE+W	6,086	6,013	6,029	6,109	6,388	6,950	7,532	7,752	7,676	7,513	7,386	7,181	7,028	6,935	6,839	6,832	6,893	7,233	7,429	7,331	7,183	6,849	6,489	6,214
2/15/13	PACE+W	6,067	6,065	6,041	6,147	6,372	6,899	7,491	7,734	7,668	7,559	7,394	7,241	7,125	6,984	6,870	6,789	6,843	7,172	7,350	7,234	7,092	6,792	6,470	6,230
2/16/13	PACE+W	6,094	6,002	5,978	6,039	6,159	6,400	6,691	6,742	7,106	7,083	7,011	6,853	6,670	6,504	6,429	6,436	6,578	6,984	7,150	7,096	6,951	6,732	6,439	6,142
2/17/13	PACE+W	5,977	5,880	5,876	5,908	6,012	6,274	6,502	6,787	6,938	6,908	6,772	6,679	6,541	6,487	6,438	6,458	6,599	7,055	7,279	7,197	7,073	6,792	6,451	6,263
2/18/13	PACE+W	6,125	6,083	6,120	6,226	6,471	6,899	7,272	7,607	7,762	7,786	7,708	7,576	7,439	7,306	7,222	7,232	7,374	7,782	7,904	7,777	7,583	7,125	6,699	6,423
2/19/13	PACE+W	6,263	6,160	6,182	6,273	6,547	7,150	7,697	7,931	7,900	7,774	7,650	7,492	7,322	7,241	7,188	7,171	7,304	7,699	7,844	7,789	7,569	7,101	6,682	6,384
2/20/13	PACE+W	6,220	6,121	6,105	6,226	6,521	7,075	7,704	7,898	7,800	7,664	7,479	7,320	7,218	7,114	7,074	7,168	7,343	7,720	7,825	7,741	7,516	7,108	6,696	6,404
2/21/13	PACE+W	6,186	6,138	6,151	6,168	6,395	6,908	7,502	7,724	7,657	7,573	7,425	7,360	7,332	7,287	7,266	7,266	7,408	7,684	7,814	7,700	7,484	7,034	6,627	6,310
2/22/13	PACE+W	6,122	6,036	6,028	6,139	6,370	6,913	7,414	7,661	7,487	7,449	7,480	7,382	7,255	7,180	7,145	7,174	7,227	7,486	7,561	7,475	7,299	7,000	6,668	6,335
2/23/13	PACE+W	6,161	6,061	6,055	6,070	6,165	6,412	6,654	6,899	7,138	7,254	7,225	7,119	7,021	6,865	6,832	6,830	6,983	7,256	7,432	7,378	7,216	6,917	6,483	6,271
2/24/13	PACE+W	6,125	6,081	6,067	6,107	6,180	6,400	6,598	6,905	7,003	7,079	6,911	6,807	6,667	6,539	6,434	6,432	6,578	6,933	7,227	7,254	7,070	6,757	6,369	6,113
2/25/13	PACE+W	5,992	5,972	5,974	6,091	6,357	6,901	7,424	7,723	7,600	7,531	7,435	7,405	7,345	7,268	7,180	7,145	7,277	7,662	7,903	7,845	7,612	7,193	6,729	6,476
2/26/13	PACE+W	6,272	6,241	6,220	6,318	6,636	7,214	7,815	7,992	7,908	7,709	7,523	7,387	7,287	7,224	7,159	7,147	7,220	7,603	7,838	7,814	7,585	7,181	6,753	6,467
2/27/13	PACE+W	6,314	6,269	6,316	6,385	6,639	7,241	7,760	7,932	7,808	7,697	7,533	7,313	7,173	7,139	7,089	7,027	7,105	7,454	7,662	7,577	7,352	6,915	6,504	6,237
2/28/13	PACE+W	6,084	6,031	5,996	6,074	6,322	6,838	7,308	7,549	7,497	7,503	7,454	7,315	7,187	7,141	7,089	7,097	7,165	7,433	7,599	7,523	7,255	6,876	6,448	6,145
3/1/13	PACE+W	5,961	5,844	5,805	5,854	6,059	6,509	7,008	7,207	7,139	7,102	7,018	6,884	6,811	6,698	6,603	6,563	6,553	6,769	7,008	6,923	6,805	6,522	6,215	5,933
3/2/13	PACE+W	5,735	5,668	5,656	5,690	5,791	5,981	6,232	6,473	6,682	6,752	6,719	6,584	6,432	6,371	6,312	6,300	6,412	6,706	6,835	6,798	6,619	6,351	6,029	5,782
3/3/13	PACE+W	5,607	5,560	5,525	5,538	5,660	5,860	6,140	6,447	6,627	6,690	6,630	6,566	6,490	6,381	6,343	6,393	6,573	6,855	7,127	7,151	6,982	6,537	6,269	6,014
3/4/13	PACE+W	5,920	5,846	5,897	6,015	6,286	6,940	7,565	7,780	7,701	7,602	7,419	7,205	7,136	7,014	6,927	6,861	6,900	7,194	7,535	7,547	7,279	6,903	6,546	6,256
3/5/13	PACE+W	6,085	6,049	6,021	6,164	6,420	6,971	7,498	7,724	7,622	7,606	7,525	7,428	7,355	7,254	7,217	7,173	7,234	7,543	7,733	7,669	7,403	6,969	6,547	6,247
3/6/13	PACE+W	6,056	5,974	5,942	6,041	6,289	6,817	7,328	7,492	7,448	7,438	7,377	7,333	7,289	7,200	7,137	7,095	7,217	7,442	7,595	7,562	7,323	6,922	6,538	6,173
3/7/13	PACE+W	5,944	5,850	5,825	5,943	6,235	6,865	7,411	7,609	7,494	7,350	7,179	7,020	6,917	6,843	6,734	6,743	6,808	7,075	7,326	7,311	7,119	6,759	6,368	6,086
3/8/13	PACE+W	5,908	5,870	5,880	5,966	6,231	6,764	7,321	7,544	7,379	7,292	7,152	6,978	6,863	6,748	6,641	6,582	6,606	6,827	7,051	7,042	6,893	6,575	6,307	6,000
3/9/13	PACE+W	5,880	5,810	5,805	5,842	5,941	6,297	6,583	6,841	6,841	6,668	6,600	6,546	6,397	6,270	6,151	6,136	6,193	6,432	6,748	6,729	6,632	6,376	6,083	5,828
3/10/13	PACE+W	5,704	5,656	5,695	5,713	5,853	6,097	6,333	6,519	6,563	6,509	6,400	6,269	6,114	6,069	6,043	6,107	6,177	6,394	6,725	6,707	6,403	6,003	5,704	5,523
3/11/13	PACE+W	5,459	5,443	5,535	5,790	6,339	7,016	7,326	7,318	7,311	7,161	7,031	6,916	6,797	6,679	6,618	6,567	6,620	6,771	7,015	6,898	6,548	6,109	5,760	5,555
3/12/13	PACE+W	5,440	5,405	5,465	5,687	6,230	6,887	7,134	7,126	7,089	6,983	6,879	6,772	6,713	6,661	6,590	6,523	6,542	6,699	6,940	6,856	6,495	6,063	5,718	5,525
3/13/13	PACE+W	5,421	5,402	5,474	5,703	6,213	6,780	7,052	6,995	6,917	6,886	6,794	6,769	6,734	6,624	6,487	6,514	6,518	6,674	6,880	6,771	6,360	5,948	5,619	5,412
3/14/13	PACE+W	5,322	5,294	5,328	5,562	6,073	6,676	6,908	6,899	6,861	6,863	6,800	6,714	6,657	6,575	6,533	6,462	6,483	6,610	6,806	6,711	6,362	5,924	5,600	5,389
3/15/13	PACE+W	5,295	5,232	5,326	5,503	6,001	6,574	6,823	6,808	6,845	6,766	6,666	6,605	6,528	6,395	6,381	6,277	6,247	6,321	6,511	6,411	6,125	5,818	5,516	5,298
3/16/13	PACE+W	5,175	5,144	5,148	5,263	5,444	5,712	5,994	6,205	6,293	6,302	6,200	6,139	6,066	6,009	5,984	6,007	6,063	6,138	6,427	6,398	6,166	5,886	5,610	5,434

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Wkp-PACE+PACW load

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
3/17/13	PACE+W	5,335	5,333	5,354	5,462	5,646	5,836	6,153	6,421	6,500	6,482	6,491	6,373	6,294	6,230	6,262	6,243	6,289	6,412	6,816	6,822	6,493	6,106	5,803	5,644
3/18/13	PACE+W	5,566	5,592	5,729	6,017	6,597	7,298	7,624	7,567	7,433	7,252	7,073	7,003	6,920	6,771	6,691	6,593	6,601	6,737	7,061	6,969	6,615	6,191	5,846	5,670
3/19/13	PACE+W	5,559	5,569	5,637	5,908	6,488	7,179	7,436	7,353	7,275	7,175	7,050	6,943	6,844	6,852	6,786	6,777	6,764	6,819	7,010	6,919	6,534	6,152	5,869	5,646
3/20/13	PACE+W	5,560	5,509	5,573	5,771	6,316	6,965	7,196	7,256	7,254	7,177	7,095	7,043	6,997	6,939	6,860	6,810	6,776	6,859	7,097	7,075	6,683	6,246	5,954	5,757
3/21/13	PACE+W	5,674	5,664	5,736	5,980	6,556	7,222	7,535	7,453	7,417	7,338	7,250	7,210	7,085	6,968	6,874	6,826	6,833	6,983	7,247	7,259	6,845	6,447	6,148	5,949
3/22/13	PACE+W	5,884	5,841	5,903	6,133	6,710	7,354	7,639	7,642	7,523	7,404	7,260	7,126	7,018	6,895	6,798	6,706	6,731	6,836	7,101	7,058	6,865	6,517	6,238	6,035
3/23/13	PACE+W	6,001	5,944	5,988	6,112	6,363	6,648	6,947	7,091	7,043	6,962	6,798	6,631	6,486	6,345	6,283	6,270	6,316	6,449	6,750	6,806	6,544	6,295	6,010	5,844
3/24/13	PACE+W	5,741	5,776	5,822	5,931	6,087	6,350	6,622	6,774	6,809	6,718	6,588	6,470	6,362	6,279	6,253	6,250	6,251	6,370	6,696	6,741	6,443	6,090	5,825	5,689
3/25/13	PACE+W	5,639	5,661	5,769	6,068	6,620	7,210	7,430	7,524	7,448	7,315	7,142	7,045	6,876	6,790	6,698	6,569	6,619	6,731	6,987	6,913	6,541	6,165	5,851	5,669
3/26/13	PACE+W	5,581	5,537	5,620	5,842	6,354	6,884	7,147	7,211	7,216	7,183	7,032	6,897	6,806	6,770	6,685	6,602	6,633	6,674	6,917	6,857	6,493	6,082	5,773	5,590
3/27/13	PACE+W	5,492	5,463	5,517	5,759	6,260	6,800	6,997	7,027	7,005	6,939	6,815	6,760	6,690	6,637	6,555	6,489	6,428	6,499	6,763	6,689	6,379	5,987	5,643	5,470
3/28/13	PACE+W	5,377	5,338	5,396	5,599	6,032	6,555	6,760	6,823	6,875	6,846	6,745	6,637	6,651	6,566	6,507	6,423	6,357	6,405	6,644	6,662	6,234	5,876	5,584	5,390
3/29/13	PACE+W	5,299	5,242	5,270	5,458	5,844	6,292	6,580	6,668	6,673	6,650	6,545	6,485	6,427	6,407	6,349	6,271	6,207	6,192	6,384	6,373	6,151	5,819	5,504	5,279
3/30/13	PACE+W	5,189	5,087	5,148	5,243	5,478	5,637	5,941	6,182	6,116	6,134	6,113	6,014	5,956	5,908	5,906	5,903	5,903	5,977	6,254	6,250	6,058	5,688	5,367	5,140
3/31/13	PACE+W	5,042	4,999	4,998	5,069	5,271	5,455	5,670	5,863	5,951	5,912	5,922	5,864	5,814	5,766	5,732	5,735	5,710	5,812	6,110	6,186	5,878	5,550	5,255	5,092
4/1/13	PACE+W	5,009	5,025	5,116	5,306	5,730	6,257	6,570	6,654	6,721	6,752	6,703	6,687	6,670	6,557	6,535	6,486	6,485	6,561	6,702	6,658	6,281	5,881	5,506	5,343
4/2/13	PACE+W	5,227	5,157	5,240	5,432	5,919	6,426	6,689	6,705	6,732	6,658	6,629	6,571	6,509	6,503	6,387	6,349	6,333	6,356	6,597	6,637	6,213	5,813	5,510	5,329
4/3/13	PACE+W	5,239	5,158	5,238	5,468	5,930	6,416	6,669	6,701	6,719	6,677	6,620	6,574	6,516	6,481	6,448	6,416	6,404	6,437	6,668	6,645	6,280	5,835	5,533	5,318
4/4/13	PACE+W	5,192	5,179	5,238	5,389	5,860	6,346	6,574	6,676	6,743	6,828	6,743	6,745	6,731	6,676	6,633	6,523	6,438	6,499	6,731	6,666	6,289	5,925	5,631	5,424
4/5/13	PACE+W	5,270	5,222	5,242	5,446	5,883	6,383	6,604	6,774	6,820	6,781	6,709	6,669	6,544	6,540	6,480	6,470	6,443	6,394	6,580	6,516	6,260	5,951	5,658	5,422
4/6/13	PACE+W	5,312	5,249	5,220	5,283	5,453	5,640	5,896	6,186	6,250	6,278	6,259	6,187	6,118	6,028	6,035	6,072	6,094	6,172	6,391	6,373	6,182	5,832	5,518	5,374
4/7/13	PACE+W	5,240	5,212	5,171	5,227	5,393	5,545	5,737	6,045	6,207	6,231	6,267	6,222	6,123	6,132	6,148	6,224	6,294	6,385	6,615	6,610	6,277	5,870	5,576	5,392
4/8/13	PACE+W	5,344	5,331	5,409	5,674	6,270	6,941	7,250	7,161	7,269	7,258	7,171	7,088	7,049	6,976	6,922	6,844	6,933	7,007	7,150	7,088	6,757	6,249	5,907	5,781
4/9/13	PACE+W	5,721	5,699	5,761	5,998	6,596	7,169	7,338	7,291	7,216	7,102	7,026	6,986	6,853	6,783	6,734	6,664	6,639	6,647	6,929	6,965	6,596	6,136	5,799	5,587
4/10/13	PACE+W	5,534	5,529	5,594	5,820	6,376	6,884	6,994	6,971	6,967	6,813	6,863	6,824	6,774	6,699	6,628	6,547	6,504	6,509	6,763	6,830	6,498	6,055	5,722	5,524
4/11/13	PACE+W	5,470	5,481	5,552	5,827	6,361	6,967	7,116	7,088	7,031	6,835	6,735	6,739	6,679	6,586	6,506	6,494	6,371	6,377	6,617	6,702	6,404	5,964	5,627	5,395
4/12/13	PACE+W	5,298	5,313	5,419	5,651	6,180	6,714	6,962	6,907	6,832	6,684	6,569	6,488	6,424	6,344	6,304	6,239	6,215	6,226	6,432	6,431	6,186	5,806	5,507	5,276
4/13/13	PACE+W	5,180	5,152	5,161	5,255	5,491	5,755	6,047	6,333	6,460	6,468	6,358	6,237	6,117	6,033	6,059	6,073	6,079	6,146	6,244	6,322	6,179	5,858	5,541	5,361
4/14/13	PACE+W	5,300	5,286	5,281	5,376	5,510	5,726	6,033	6,144	6,237	6,231	6,183	6,084	6,011	5,941	5,960	5,998	6,052	6,207	6,470	6,515	6,264	5,821	5,528	5,371
4/15/13	PACE+W	5,352	5,378	5,496	5,741	6,308	6,882	7,196	7,181	7,115	7,040	6,967	6,905	6,813	6,734	6,659	6,597	6,578	6,595	6,823	6,835	6,513	6,054	5,702	5,560
4/16/13	PACE+W	5,497	5,490	5,602	5,847	6,436	6,999	7,207	7,129	7,121	6,964	6,873	6,807	6,795	6,672	6,630	6,538	6,458	6,552	6,820	6,899	6,528	6,155	5,851	5,684
4/17/13	PACE+W	5,609	5,611	5,717	5,957	6,522	7,042	7,247	7,078	6,979	6,867	6,718	6,652	6,615	6,549	6,516	6,455	6,472	6,493	6,736	6,779	6,456	6,027	5,732	5,545
4/18/13	PACE+W	5,471	5,486	5,513	5,806	6,365	6,874	7,011	6,967	6,891	6,762	6,697	6,609	6,619	6,532	6,412	6,366	6,327	6,376	6,589	6,662	6,316	5,919	5,588	5,372
4/19/13	PACE+W	5,289	5,246	5,324	5,566	6,040	6,559	6,863	6,901	6,917	6,847	6,792	6,741	6,650	6,570	6,470	6,361	6,314	6,289	6,448	6,492	6,215	5,836	5,547	5,293
4/20/13	PACE+W	5,247	5,175	5,201	5,295	5,483	5,732	6,002	6,223	6,233	6,163	6,148	6,043	5,917	5,840	5,793	5,803	5,844	5,864	6,016	6,150	5,909	5,601	5,361	5,208
4/21/13	PACE+W	5,139	5,087	5,097	5,181	5,322	5,483	5,723	5,878	5,931	5,804	5,910	5,812	5,792	5,758	5,784	5,836	5,875	5,940	6,182	6,249	6,006	5,617	5,331	5,152
4/22/13	PACE+W	5,072	5,093	5,186	5,436	5,990	6,537	6,820	6,734	6,740	6,710	6,694	6,642	6,598	6,522	6,463	6,412	6,383	6,345	6,571	6,672	6,339	5,887	5,607	5,450
4/23/13	PACE+W	5,392	5,375	5,454	5,713	6,231	6,719	6,935	6,883	6,803	6,709	6,654	6,573	6,543	6,502	6,447	6,409	6,349	6,376	6,570	6,558	6,304	5,841	5,567	5,398
4/24/13	PACE+W	5,308	5,302	5,379	5,635	6,211	6,658	6,879	6,807	6,762	6,678	6,621	6,636	6,618	6,597	6,509	6,484	6,400	6,346	6,505	6,583	6,257	5,815	5,473	5,258

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Wkp-PACE+PACW load

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
4/25/13	PACE+W	5,187	5,109	5,198	5,438	5,957	6,378	6,622	6,649	6,666	6,655	6,624	6,616	6,594	6,585	6,541	6,471	6,368	6,314	6,456	6,525	6,229	5,792	5,459	5,232
4/26/13	PACE+W	5,103	5,071	5,128	5,350	5,729	6,232	6,514	6,583	6,599	6,620	6,631	6,610	6,611	6,599	6,532	6,493	6,411	6,308	6,392	6,403	6,192	5,838	5,476	5,248
4/27/13	PACE+W	5,125	5,027	5,035	5,121	5,238	5,374	5,658	5,998	6,125	6,131	6,125	6,102	6,036	6,093	6,110	6,178	6,166	6,086	6,225	6,297	6,071	5,741	5,443	5,254
4/28/13	PACE+W	5,083	5,007	4,961	5,003	5,065	5,238	5,567	5,812	5,968	6,001	6,079	6,003	6,053	6,097	6,103	6,168	6,198	6,220	6,349	6,463	6,171	5,689	5,387	5,235
4/29/13	PACE+W	5,152	5,116	5,158	5,346	5,766	6,277	6,602	6,744	6,828	6,892	6,905	6,898	6,864	6,873	6,856	6,840	6,779	6,671	6,818	6,897	6,589	6,077	5,759	5,531
4/30/13	PACE+W	5,425	5,330	5,403	5,615	6,117	6,624	6,925	6,970	6,964	6,933	6,891	6,838	6,825	6,774	6,702	6,642	6,568	6,556	6,710	6,850	6,516	6,112	5,781	5,619
5/1/13	PACE+W	5,509	5,499	5,585	5,861	6,394	6,878	7,121	7,077	7,056	6,993	6,898	6,822	6,792	6,721	6,670	6,615	6,550	6,505	6,616	6,709	6,454	6,051	5,721	5,510
5/2/13	PACE+W	5,425	5,374	5,423	5,691	6,173	6,623	6,837	6,843	6,859	6,834	6,788	6,729	6,764	6,710	6,709	6,671	6,577	6,530	6,690	6,790	6,418	6,003	5,670	5,467
5/3/13	PACE+W	5,355	5,303	5,357	5,540	5,929	6,367	6,652	6,747	6,766	6,825	6,806	6,813	6,818	6,761	6,688	6,662	6,548	6,417	6,475	6,587	6,383	6,022	5,644	5,401
5/4/13	PACE+W	5,255	5,161	5,144	5,227	5,337	5,516	5,828	6,057	6,154	6,274	6,325	6,308	6,260	6,222	6,259	6,251	6,273	6,214	6,334	6,380	6,216	5,825	5,498	5,237
5/5/13	PACE+W	5,121	5,084	5,058	5,090	5,121	5,217	5,524	5,801	6,014	6,081	6,195	6,179	6,231	6,248	6,329	6,405	6,409	6,378	6,430	6,555	6,260	5,868	5,505	5,308
5/6/13	PACE+W	5,180	5,111	5,153	5,370	5,769	6,229	6,651	6,799	6,898	6,866	7,029	7,040	7,088	7,074	7,003	6,918	6,891	6,869	6,928	6,955	6,583	6,107	5,720	5,493
5/7/13	PACE+W	5,316	5,220	5,226	5,403	5,797	6,274	6,576	6,592	6,803	6,866	6,853	6,947	6,997	7,038	7,056	7,024	7,010	6,899	6,926	6,923	6,626	6,105	5,729	5,463
5/8/13	PACE+W	5,334	5,219	5,206	5,340	5,778	6,270	6,598	6,704	6,789	6,878	6,917	6,952	6,969	6,985	6,978	6,972	6,882	6,838	6,853	6,937	6,656	6,154	5,746	5,491
5/9/13	PACE+W	5,340	5,249	5,287	5,527	5,899	6,377	6,732	6,863	6,922	7,001	7,082	7,116	7,195	7,180	7,190	7,182	7,121	6,981	6,999	7,074	6,741	6,226	5,804	5,524
5/10/13	PACE+W	5,377	5,307	5,311	5,496	5,787	6,282	6,672	6,846	7,004	7,125	7,107	7,121	7,269	7,390	7,420	7,362	7,274	7,114	7,018	7,117	6,873	6,386	5,924	5,637
5/11/13	PACE+W	5,449	5,351	5,273	5,311	5,394	5,555	5,892	6,222	6,446	6,601	6,683	6,778	6,826	6,938	7,024	7,036	7,022	6,919	6,879	6,929	6,692	6,247	5,847	5,559
5/12/13	PACE+W	5,251	5,252	5,184	5,218	5,169	5,300	5,637	5,972	6,214	6,313	6,477	6,567	6,628	6,730	6,832	6,915	6,906	6,808	6,757	6,865	6,640	6,143	5,736	5,440
5/13/13	PACE+W	5,330	5,255	5,290	5,448	5,831	6,312	6,701	6,980	7,293	7,510	7,649	7,766	7,843	7,840	7,813	7,855	7,773	7,683	7,547	7,529	7,121	6,504	6,034	5,753
5/14/13	PACE+W	5,598	5,494	5,485	5,667	6,041	6,514	6,929	7,150	7,320	7,495	7,607	7,723	7,877	7,986	8,106	8,085	8,002	7,855	7,689	7,693	7,276	6,635	6,157	5,862
5/15/13	PACE+W	5,701	5,614	5,599	5,750	6,111	6,642	7,112	7,262	7,410	7,576	7,686	7,724	7,845	7,879	7,824	7,680	7,526	7,342	7,286	7,342	7,015	6,465	6,039	5,766
5/16/13	PACE+W	5,632	5,574	5,585	5,736	6,110	6,677	7,078	7,296	7,419	7,564	7,531	7,512	7,540	7,642	7,533	7,397	7,227	7,115	7,138	7,204	6,871	6,332	5,934	5,683
5/17/13	PACE+W	5,545	5,492	5,504	5,651	6,015	6,473	6,823	6,931	7,039	7,053	7,043	6,994	6,964	6,886	6,807	6,709	6,623	6,521	6,559	6,526	6,407	6,036	5,680	5,456
5/18/13	PACE+W	5,309	5,240	5,208	5,307	5,405	5,590	5,921	6,190	6,376	6,441	6,388	6,276	6,274	6,167	6,158	6,173	6,131	6,104	6,123	6,263	6,112	5,818	5,463	5,248
5/19/13	PACE+W	5,132	5,045	5,025	5,078	5,109	5,195	5,529	5,758	5,915	5,891	6,052	5,994	6,017	6,015	6,074	6,112	6,131	6,091	6,264	6,333	6,109	5,748	5,436	5,236
5/20/13	PACE+W	5,159	5,116	5,205	5,396	5,830	6,407	6,728	6,839	6,948	6,939	6,942	6,965	6,969	6,972	6,962	6,912	6,833	6,807	6,793	6,898	6,610	6,108	5,710	5,388
5/21/13	PACE+W	5,262	5,165	5,193	5,395	5,769	6,249	6,520	6,742	6,891	6,949	6,944	6,971	6,961	6,895	6,812	6,900	6,898	6,802	6,784	6,962	6,679	6,131	5,680	5,517
5/22/13	PACE+W	5,400	5,335	5,369	5,577	5,949	6,541	6,895	7,061	7,175	7,235	7,279	7,215	7,255	7,284	7,243	7,225	7,127	6,902	6,909	6,989	6,759	6,213	5,799	5,654
5/23/13	PACE+W	5,540	5,508	5,490	5,702	6,114	6,656	6,861	6,954	6,960	7,047	7,014	6,979	7,059	7,011	6,984	6,940	6,883	6,723	6,774	6,907	6,656	6,162	5,821	5,555
5/24/13	PACE+W	5,304	5,377	5,406	5,585	5,913	6,342	6,710	6,818	6,800	6,911	6,848	6,796	6,830	6,827	6,796	6,716	6,657	6,535	6,348	6,592	6,471	6,097	5,782	5,494
5/25/13	PACE+W	5,394	5,321	5,317	5,346	5,440	5,607	5,929	6,195	6,365	6,414	6,411	6,356	6,406	6,421	6,500	6,553	6,576	6,476	6,444	6,512	6,350	5,986	5,688	5,366
5/26/13	PACE+W	5,240	5,160	5,169	5,145	5,114	5,261	5,468	5,788	5,999	6,086	6,162	6,198	6,229	6,295	6,381	6,412	6,381	6,269	6,265	6,324	6,165	5,855	5,514	5,265
5/27/13	PACE+W	5,147	5,060	5,067	5,104	5,092	5,277	5,680	6,027	6,194	6,356	6,450	6,390	6,429	6,510	6,553	6,588	6,582	6,485	6,539	6,667	6,404	5,936	5,594	5,359
5/28/13	PACE+W	5,223	5,153	5,229	5,405	5,821	6,353	6,719	6,859	6,925	6,976	7,040	6,984	6,915	6,772	6,753	6,694	6,664	6,582	6,665	6,711	6,485	6,030	5,676	5,464
5/29/13	PACE+W	5,331	5,276	5,295	5,435	5,747	6,241	6,583	6,695	6,751	6,796	6,746	6,609	6,695	6,708	6,670	6,639	6,578	6,525	6,542	6,641	6,485	6,041	5,711	5,502
5/30/13	PACE+W	5,383	5,374	5,378	5,580	5,969	6,410	6,720	6,867	6,946	6,917	6,918	6,878	6,921	6,930	6,839	6,818	6,791	6,700	6,687	6,815	6,604	6,147	5,779	5,563
5/31/13	PACE+W	5,456	5,388	5,406	5,561	5,911	6,385	6,793	6,885	6,919	6,958	6,956	6,933	6,918	6,877	6,841	6,814	6,690	6,648	6,580	6,683	6,610	6,241	5,861	5,566
6/1/13	PACE+W	5,436	5,353	5,349	5,385	5,412	5,600	5,930	6,175	6,320	6,436	6,462	6,501	6,521	6,561	6,656	6,737	6,740	6,705	6,645	6,637	6,531	6,109	5,740	5,486
6/2/13	PACE+W	5,318	5,061	5,164	5,183	5,142	5,299	5,581	5,879	6,165	6,343	6,451	6,584	6,699	6,841	7,057	7,160	7,257	7,202	7,109	7,053	6,863	6,381	5,900	5,577

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Wkp-PACE+PACW load

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
6/3/13	PACE+W	5,449	5,380	5,396	5,571	5,882	6,413	6,848	7,032	7,239	7,366	7,357	7,498	7,558	7,629	7,707	7,708	7,708	7,585	7,412	7,400	7,120	6,564	6,143	5,816
6/4/13	PACE+W	5,643	5,518	5,594	5,722	5,997	6,495	6,864	7,018	7,201	7,278	7,372	7,377	7,558	7,740	7,865	7,898	7,879	7,766	7,584	7,545	7,305	6,769	6,306	5,936
6/5/13	PACE+W	5,738	5,634	5,623	5,746	6,010	6,469	6,963	7,167	7,367	7,535	7,628	7,782	7,866	8,055	8,169	8,223	8,203	8,075	7,834	7,764	7,426	6,888	6,377	5,980
6/6/13	PACE+W	5,762	5,627	5,634	5,786	6,078	6,569	7,015	7,341	7,559	7,727	7,888	8,074	8,281	8,452	8,553	8,556	8,479	8,200	7,980	7,947	7,653	7,023	6,469	6,097
6/7/13	PACE+W	5,875	5,724	5,701	5,809	6,052	6,517	7,025	7,337	7,555	7,853	8,031	8,181	8,407	8,520	8,593	8,534	8,438	8,225	7,932	7,689	7,389	6,983	6,483	6,112
6/8/13	PACE+W	5,895	5,750	5,675	5,669	5,627	5,880	6,313	6,765	7,134	7,361	7,429	7,561	7,683	7,820	7,906	8,000	7,955	7,835	7,617	7,436	7,248	6,739	6,265	5,887
6/9/13	PACE+W	5,637	5,538	5,464	5,450	5,374	5,561	5,954	6,324	6,696	6,924	7,233	7,368	7,672	7,868	8,098	8,273	8,328	8,192	7,935	7,809	7,459	6,952	6,480	6,118
6/10/13	PACE+W	5,949	5,812	5,850	5,987	6,275	6,830	7,405	7,789	8,153	8,442	8,562	8,677	8,715	8,718	8,745	8,824	8,746	8,488	8,096	7,932	7,587	6,956	6,448	6,151
6/11/13	PACE+W	5,946	5,867	5,845	5,970	6,256	6,761	7,234	7,520	7,799	7,965	8,033	8,185	8,299	8,378	8,488	8,470	8,367	8,122	7,899	7,835	7,553	6,969	6,485	6,164
6/12/13	PACE+W	5,943	5,820	5,835	5,935	6,213	6,705	7,139	7,396	7,607	7,678	7,793	8,005	8,210	8,299	8,354	8,284	8,150	7,939	7,763	7,758	7,542	6,997	6,539	6,232
6/13/13	PACE+W	6,028	5,908	5,868	5,994	6,319	6,738	7,220	7,516	7,795	7,973	8,102	8,180	8,257	8,294	8,254	8,110	7,979	7,797	7,498	7,397	7,177	6,721	6,283	5,929
6/14/13	PACE+W	5,770	5,664	5,637	5,773	6,025	6,440	6,789	7,037	7,191	7,302	7,354	7,380	7,423	7,473	7,510	7,501	7,341	7,125	7,009	7,054	6,912	6,536	6,184	5,880
6/15/13	PACE+W	5,719	5,615	5,578	5,579	5,539	5,739	6,077	6,355	6,589	6,708	6,797	6,974	7,081	7,273	7,384	7,508	7,436	7,363	7,230	7,220	7,058	6,651	6,184	5,841
6/16/13	PACE+W	5,663	5,576	5,515	5,486	5,451	5,583	5,939	6,309	6,619	6,829	7,023	7,192	7,381	7,563	7,733	7,861	7,867	7,793	7,566	7,444	7,225	6,660	6,172	5,880
6/17/13	PACE+W	5,718	5,634	5,613	5,793	6,016	6,444	7,009	7,317	7,732	7,981	8,135	8,324	8,538	8,727	8,840	8,852	8,802	8,564	8,251	8,055	7,734	7,125	6,621	6,224
6/18/13	PACE+W	5,935	5,849	5,841	5,973	6,243	6,639	7,100	7,444	7,743	7,907	8,057	8,153	8,387	8,378	8,373	8,396	8,325	8,294	8,118	7,964	7,628	7,129	6,646	6,290
6/19/13	PACE+W	6,142	5,993	5,958	6,114	6,360	6,743	7,233	7,553	7,761	7,843	7,897	7,999	8,081	8,091	8,034	7,880	7,693	7,455	7,239	7,246	7,146	6,648	6,243	5,967
6/20/13	PACE+W	5,790	5,746	5,749	5,895	6,144	6,538	6,855	7,015	7,241	7,392	7,423	7,441	7,533	7,534	7,568	7,523	7,515	7,430	7,308	7,317	7,141	6,720	6,246	5,986
6/21/13	PACE+W	5,807	5,721	5,752	5,832	6,049	6,414	6,813	7,049	7,238	7,362	7,421	7,391	7,547	7,619	7,586	7,562	7,510	7,349	7,128	7,135	6,978	6,671	6,258	5,979
6/22/13	PACE+W	5,751	5,648	5,626	5,660	5,657	5,811	6,131	6,465	6,656	6,827	6,940	7,011	7,030	7,106	7,185	7,327	7,347	7,293	7,120	7,067	6,911	6,492	6,090	5,817
6/23/13	PACE+W	5,683	5,539	5,487	5,476	5,444	5,549	5,832	6,178	6,402	6,526	6,736	6,859	6,961	7,105	7,217	7,268	7,311	7,201	7,031	7,138	6,973	6,456	6,070	5,789
6/24/13	PACE+W	5,675	5,603	5,613	5,794	6,054	6,507	7,035	7,374	7,691	7,872	7,978	8,040	8,151	8,091	7,946	7,750	7,531	7,384	7,306	7,296	7,134	6,705	6,257	5,942
6/25/13	PACE+W	5,778	5,677	5,715	5,860	6,101	6,515	6,852	7,187	7,436	7,698	7,874	7,914	8,083	8,175	8,231	8,229	8,213	8,047	7,810	7,676	7,516	6,971	6,457	6,126
6/26/13	PACE+W	5,959	5,842	5,804	5,951	6,253	6,724	7,220	7,592	7,905	8,042	8,347	8,470	8,626	8,740	8,819	8,821	8,749	8,615	8,404	8,255	7,954	7,328	6,796	6,397
6/27/13	PACE+W	6,112	5,877	5,837	5,985	6,266	6,799	7,365	7,810	8,233	8,578	8,842	9,115	9,363	9,475	9,632	9,632	9,595	9,453	9,216	9,002	8,600	7,939	7,271	6,795
6/28/13	PACE+W	6,500	6,285	6,260	6,310	6,501	6,977	7,596	8,108	8,510	8,904	9,202	9,432	9,678	9,696	9,833	9,797	9,681	9,415	9,188	8,964	8,629	8,070	7,485	7,012
6/29/13	PACE+W	6,689	6,465	6,296	6,279	6,262	6,503	7,006	7,563	8,024	8,419	8,768	9,044	9,289	9,365	9,521	9,543	9,527	9,286	9,009	8,781	8,428	7,830	7,333	6,943
6/30/13	PACE+W	6,635	6,486	6,340	6,280	6,209	6,418	6,920	7,458	7,881	8,359	8,692	8,994	9,218	9,422	9,602	9,695	9,677	9,465	9,277	9,061	8,724	8,103	7,460	7,011
7/1/13	PACE+W	6,710	6,524	6,456	6,542	6,783	7,305	7,949	8,516	8,987	9,432	9,744	10,085	10,291	10,299	10,507	10,410	10,363	10,247	9,960	9,694	9,237	8,497	7,815	7,290
7/2/13	PACE+W	6,981	6,751	6,657	6,715	6,893	7,455	7,986	8,618	9,101	9,524	9,829	10,124	10,370	10,397	10,410	10,415	10,341	10,141	9,837	9,618	9,124	8,389	7,741	7,241
7/3/13	PACE+W	6,943	6,725	6,628	6,679	6,886	7,318	7,969	8,514	8,950	9,350	9,648	9,868	10,044	9,980	9,939	9,851	9,680	9,460	9,154	8,901	8,495	7,901	7,327	6,903
7/4/13	PACE+W	6,637	6,360	6,181	6,160	6,096	6,233	6,553	6,998	7,393	7,744	8,043	8,234	8,427	8,531	8,640	8,643	8,497	8,303	7,915	7,609	7,308	7,011	6,616	6,290
7/5/13	PACE+W	5,935	5,803	5,678	5,684	5,807	6,176	6,696	7,181	7,623	7,942	8,103	8,354	8,569	8,708	8,798	8,729	8,424	8,051	7,827	7,702	7,420	7,000	6,550	6,205
7/6/13	PACE+W	5,982	5,814	5,812	5,821	5,814	5,952	6,353	6,801	7,120	7,248	7,450	7,663	7,862	8,129	8,234	8,178	7,997	7,696	7,579	7,460	7,282	6,868	6,425	6,114
7/7/13	PACE+W	5,910	5,786	5,662	5,584	5,621	5,746	6,194	6,593	6,909	7,302	7,661	7,887	8,060	8,086	8,249	8,269	8,274	8,108	7,896	7,786	7,528	7,022	6,531	6,136
7/8/13	PACE+W	5,950	5,878	5,896	5,996	6,230	6,758	7,281	7,697	8,156	8,460	8,784	9,133	9,365	9,334	9,406	9,502	9,464	9,301	9,003	8,747	8,204	7,514	7,064	6,641
7/9/13	PACE+W	6,407	6,273	6,244	6,339	6,587	6,951	7,535	7,928	8,340	8,760	8,988	9,327	9,576	9,653	9,688	9,725	9,643	9,689	9,423	9,018	8,693	7,912	7,256	6,794
7/10/13	PACE+W	6,490	6,306	6,226	6,242	6,391	6,830	7,288	7,786	8,187	8,512	8,883	9,265	9,577	9,636	9,756	9,789	9,732	9,589	9,280	9,040	8,596	7,855	7,219	6,768
7/11/13	PACE+W	6,511	6,352	6,262	6,368	6,628	6,993	7,485	7,883	8,152	8,314	8,456	8,687	8,908	9,103	9,014	8,764	8,499	8,221	8,029	7,996	7,738	7,237	6,725	6,389

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Wkp-PACE+PACW load

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
7/12/13	PACE+W	6,206	6,077	6,032	6,163	6,408	6,720	7,183	7,492	7,664	7,835	8,002	8,185	8,354	8,503	8,648	8,658	8,605	8,385	8,091	8,009	7,813	7,351	6,855	6,476
7/13/13	PACE+W	6,270	6,131	6,049	6,086	6,083	6,216	6,625	7,048	7,378	7,678	7,876	7,976	8,088	8,191	8,394	8,383	8,176	7,982	7,783	7,730	7,521	7,081	6,607	6,293
7/14/13	PACE+W	6,073	5,923	5,827	5,809	5,643	5,905	6,328	6,773	7,224	7,512	7,885	8,089	8,340	8,595	8,789	8,898	8,937	8,868	8,645	8,442	8,110	7,466	6,896	6,492
7/15/13	PACE+W	6,233	6,093	6,060	6,182	6,380	6,839	7,475	7,913	8,447	8,760	9,030	9,405	9,679	9,857	10,069	10,038	9,942	9,673	9,362	9,199	8,657	7,952	7,329	6,915
7/16/13	PACE+W	6,638	6,474	6,419	6,529	6,755	7,173	7,637	8,010	8,337	8,480	8,795	9,092	9,303	9,433	9,544	9,336	9,071	8,722	8,454	8,215	7,810	7,170	6,608	6,261
7/17/13	PACE+W	5,993	5,947	5,907	6,061	6,325	6,809	7,346	7,783	8,161	8,506	8,770	9,030	9,142	9,259	9,349	9,340	9,296	9,053	8,763	8,619	8,147	7,496	6,936	6,490
7/18/13	PACE+W	6,243	6,084	5,991	6,165	6,426	6,850	7,330	7,843	8,256	8,582	8,908	9,216	9,417	9,550	9,620	9,655	9,551	9,451	9,179	8,940	8,503	7,791	7,152	6,702
7/19/13	PACE+W	6,449	6,211	6,149	6,218	6,419	6,840	7,333	7,804	8,237	8,609	8,891	9,175	9,399	9,541	9,511	9,653	9,606	9,380	8,987	8,702	8,245	7,680	7,083	6,624
7/20/13	PACE+W	6,333	6,116	6,007	5,961	5,980	6,072	6,557	7,072	7,533	7,946	8,306	8,628	8,846	9,052	9,226	9,309	9,277	9,041	8,753	8,481	8,064	7,466	6,862	6,382
7/21/13	PACE+W	6,086	5,881	5,767	5,735	5,723	5,859	6,274	6,785	7,223	7,613	8,036	8,315	8,615	8,844	9,052	9,184	9,180	9,065	8,773	8,520	8,074	7,392	6,824	6,429
7/22/13	PACE+W	6,212	6,022	6,000	6,129	6,339	6,804	7,321	7,912	8,359	8,707	9,027	9,358	9,649	9,821	9,863	9,902	9,950	9,711	9,328	9,051	8,611	7,873	7,178	6,699
7/23/13	PACE+W	6,381	6,194	6,126	6,214	6,477	6,912	7,396	7,834	8,219	8,638	8,963	9,264	9,463	9,713	9,856	9,800	9,642	9,384	9,029	8,900	8,404	7,818	7,161	6,652
7/24/13	PACE+W	6,434	6,252	6,164	6,231	6,312	6,685	7,124	7,509	7,900	8,253	8,529	8,847	9,123	9,341	9,525	9,498	9,404	9,192	8,890	8,678	8,280	7,682	7,073	6,647
7/25/13	PACE+W	6,355	6,225	6,142	6,234	6,388	6,842	7,397	7,875	8,331	8,732	9,063	9,351	9,583	9,667	9,718	9,829	9,708	9,566	9,263	9,009	8,547	7,772	7,139	6,698
7/26/13	PACE+W	6,419	6,244	6,167	6,259	6,430	6,774	7,297	7,858	8,266	8,608	8,974	9,268	9,533	9,638	9,740	9,697	9,490	9,220	8,887	8,666	8,274	7,684	7,072	6,633
7/27/13	PACE+W	6,337	6,238	6,131	6,131	6,184	6,271	6,600	7,007	7,265	7,499	7,621	7,689	7,753	7,837	7,861	7,891	7,736	7,625	7,563	7,478	7,251	6,773	6,279	5,974
7/28/13	PACE+W	5,740	5,616	5,572	5,582	5,574	5,660	6,033	6,428	6,801	7,077	7,366	7,559	7,644	7,747	7,886	7,940	7,948	7,778	7,542	7,456	7,137	6,673	6,197	5,876
7/29/13	PACE+W	5,749	5,630	5,650	5,792	6,113	6,522	6,878	7,243	7,576	7,768	7,941	8,053	8,191	8,360	8,459	8,498	8,477	8,265	8,035	7,947	7,578	6,972	6,488	6,127
7/30/13	PACE+W	5,943	5,736	5,664	5,816	6,124	6,488	6,945	7,345	7,702	8,003	8,244	8,518	8,670	8,835	9,001	9,028	8,959	8,789	8,488	8,390	7,951	7,313	6,780	6,393
7/31/13	PACE+W	6,176	6,044	6,021	6,125	6,380	6,697	7,053	7,537	7,962	8,237	8,519	8,735	8,911	9,074	9,078	9,108	9,038	8,820	8,516	8,357	7,961	7,348	6,821	6,454
8/1/13	PACE+W	6,219	6,046	6,025	6,124	6,395	6,771	7,237	7,692	8,126	8,379	8,565	8,768	8,896	8,966	8,960	8,862	8,683	8,506	8,308	8,236	7,906	7,282	6,732	6,336
8/2/13	PACE+W	6,065	5,868	5,842	5,935	6,104	6,432	6,884	7,312	7,623	7,855	8,006	8,194	8,368	8,485	8,595	8,617	8,522	8,251	7,916	7,825	7,459	6,992	6,533	6,126
8/3/13	PACE+W	5,946	5,828	5,794	5,802	5,848	5,946	6,349	6,795	7,186	7,483	7,695	7,874	8,117	8,267	8,464	8,560	8,560	8,399	8,063	7,905	7,539	7,010	6,516	6,166
8/4/13	PACE+W	5,976	5,859	5,776	5,736	5,757	5,813	6,194	6,637	7,097	7,374	7,680	7,936	8,201	8,465	8,644	8,768	8,822	8,645	8,446	8,315	7,876	7,267	6,796	6,427
8/5/13	PACE+W	6,194	6,014	5,979	6,105	6,373	6,770	7,336	7,857	8,273	8,597	8,913	9,014	9,034	9,241	9,468	9,501	9,361	9,073	8,832	8,676	8,217	7,450	6,901	6,526
8/6/13	PACE+W	6,237	6,061	6,006	6,155	6,422	6,800	7,250	7,605	8,059	8,449	8,783	9,009	9,295	9,447	9,502	9,440	9,358	9,183	8,869	8,709	8,203	7,553	6,974	6,543
8/7/13	PACE+W	6,283	6,100	6,051	6,157	6,355	6,704	7,174	7,591	7,883	8,230	8,405	8,712	8,981	9,116	9,036	8,903	8,639	8,396	8,258	8,117	7,708	7,212	6,695	6,322
8/8/13	PACE+W	6,124	5,967	5,925	6,074	6,359	6,730	7,145	7,493	7,787	8,089	8,327	8,636	8,890	8,801	8,705	8,696	8,535	8,310	8,132	8,096	7,729	7,130	6,629	6,280
8/9/13	PACE+W	6,071	5,963	5,915	6,046	6,282	6,569	6,932	7,375	7,736	8,020	8,246	8,466	8,592	8,618	8,584	8,436	8,173	7,999	7,785	7,715	7,441	6,892	6,470	6,209
8/10/13	PACE+W	5,948	5,869	5,790	5,813	5,883	5,937	6,262	6,703	7,045	7,337	7,649	7,831	8,044	8,156	8,253	8,268	8,156	7,905	7,652	7,606	7,311	6,824	6,383	6,082
8/11/13	PACE+W	5,852	5,743	5,628	5,646	5,663	5,723	6,108	6,523	6,890	7,209	7,431	7,689	7,895	8,065	8,186	8,307	8,239	8,047	7,807	7,630	7,349	6,842	6,424	6,068
8/12/13	PACE+W	5,884	5,784	5,779	5,911	6,202	6,550	7,015	7,352	7,794	8,116	8,373	8,548	8,764	8,899	9,000	8,906	8,758	8,440	8,258	8,174	7,752	7,096	6,579	6,240
8/13/13	PACE+W	6,029	5,868	5,844	5,958	6,265	6,540	6,897	7,307	7,718	8,056	8,286	8,580	8,814	8,991	9,090	9,182	9,131	8,852	8,563	8,400	7,899	7,222	6,694	6,312
8/14/13	PACE+W	6,076	5,930	5,905	5,997	6,271	6,581	6,894	7,418	7,761	8,097	8,375	8,650	8,912	9,132	9,227	9,257	9,131	8,816	8,565	8,410	7,888	7,150	6,590	6,217
8/15/13	PACE+W	6,023	5,876	5,858	5,961	6,270	6,546	6,966	7,435	7,845	8,168	8,440	8,752	9,027	9,245	9,377	9,424	9,292	8,930	8,619	8,455	7,968	7,276	6,780	6,391
8/16/13	PACE+W	6,131	6,010	5,984	6,075	6,372	6,652	7,103	7,337	7,802	8,128	8,423	8,796	9,051	9,199	9,171	9,073	9,034	8,715	8,440	8,218	7,874	7,282	6,778	6,418
8/17/13	PACE+W	6,187	6,009	5,949	5,950	6,015	6,075	6,414	6,979	7,410	7,842	8,150	8,309	8,347	8,328	8,292	8,257	8,254	8,083	7,881	7,793	7,434	6,950	6,483	6,174
8/18/13	PACE+W	5,922	5,790	5,730	5,717	5,754	5,750	6,129	6,616	6,997	7,368	7,721	8,027	8,268	8,511	8,695	8,814	8,791	8,636	8,330	8,261	7,754	7,099	6,592	6,237
8/19/13	PACE+W	5,996	5,919	5,914	6,043	6,361	6,697	7,080	7,761	8,184	8,567	8,897	9,191	9,445	9,571	9,569	9,524	9,281	8,962	8,743	8,546	8,021	7,376	6,829	6,495

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Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
8/20/13	PACE+W	6,256	6,125	6,072	6,198	6,529	6,868	7,211	7,607	7,986	8,324	8,586	8,853	8,962	8,984	9,083	9,053	8,876	8,642	8,536	8,396	7,858	7,244	6,677	6,376
8/21/13	PACE+W	6,190	6,073	6,029	6,195	6,476	6,777	7,165	7,467	7,948	8,258	8,495	8,753	9,018	9,187	9,285	9,202	9,112	8,972	8,725	8,468	7,948	7,312	6,791	6,460
8/22/13	PACE+W	6,206	6,052	6,025	6,184	6,600	6,872	7,226	7,448	7,862	8,228	8,480	8,777	8,994	9,051	9,076	8,960	8,687	8,422	8,344	8,122	7,576	7,068	6,636	6,318
8/23/13	PACE+W	6,095	5,971	5,953	6,103	6,438	6,823	7,150	7,455	7,755	7,902	7,927	7,892	7,858	7,896	7,861	7,841	7,685	7,473	7,417	7,410	7,133	6,792	6,367	6,064
8/24/13	PACE+W	5,839	5,745	5,702	5,709	5,788	5,869	6,145	6,548	6,837	7,102	7,364	7,573	7,684	7,696	7,607	7,487	7,334	7,137	7,135	7,048	6,816	6,421	6,006	5,755
8/25/13	PACE+W	5,561	5,494	5,458	5,453	5,578	5,584	5,837	6,221	6,597	6,868	7,102	7,244	7,358	7,451	7,509	7,483	7,407	7,294	7,369	7,359	6,941	6,467	6,100	5,849
8/26/13	PACE+W	5,698	5,614	5,649	5,831	6,316	6,717	6,958	7,244	7,492	7,619	7,694	7,798	7,905	7,936	7,914	7,814	7,760	7,664	7,712	7,656	7,182	6,679	6,239	5,957
8/27/13	PACE+W	5,737	5,739	5,742	5,963	6,379	6,763	7,024	7,254	7,535	7,774	7,848	7,853	7,962	7,977	8,102	8,039	8,141	8,067	7,967	7,773	7,250	6,710	6,287	6,016
8/28/13	PACE+W	5,859	5,758	5,725	5,856	6,208	6,603	6,939	7,290	7,633	7,910	8,147	8,443	8,672	8,781	8,880	8,924	8,841	8,572	8,439	8,295	7,725	7,076	6,559	6,232
8/29/13	PACE+W	6,034	5,932	5,950	6,119	6,526	6,907	7,251	7,601	7,954	8,230	8,524	8,834	9,013	9,114	9,240	9,268	9,103	8,834	8,659	8,433	7,867	7,209	6,643	6,311
8/30/13	PACE+W	6,103	5,988	5,935	6,057	6,419	6,761	7,199	7,581	7,935	8,273	8,578	8,839	9,017	9,125	9,225	9,090	8,976	8,708	8,403	8,102	7,678	7,126	6,645	6,296
8/31/13	PACE+W	6,063	5,903	5,821	5,852	5,872	5,919	6,307	6,787	7,194	7,492	7,806	8,004	8,134	8,170	8,249	8,312	8,225	8,057	7,932	7,801	7,353	6,861	6,391	6,084
9/1/13	PACE+W	5,868	5,715	5,661	5,638	5,683	5,683	5,954	6,293	6,603	6,776	6,949	7,128	7,416	7,608	7,811	7,871	7,742	7,651	7,647	7,540	7,143	6,678	6,274	6,025
9/2/13	PACE+W	5,839	5,730	5,672	5,723	5,860	5,889	6,117	6,521	6,951	7,292	7,481	7,626	7,790	7,950	8,176	8,260	8,246	8,082	8,001	7,812	7,210	6,629	6,223	5,940
9/3/13	PACE+W	5,768	5,713	5,660	5,824	6,228	6,679	7,067	7,428	7,755	8,019	8,265	8,506	8,632	8,576	8,572	8,524	8,407	8,164	8,110	7,983	7,405	6,834	6,369	6,049
9/4/13	PACE+W	5,890	5,762	5,751	5,911	6,322	6,707	7,036	7,323	7,658	7,887	8,097	8,299	8,592	8,780	8,789	8,683	8,489	8,259	8,155	8,035	7,496	6,932	6,451	6,121
9/5/13	PACE+W	5,955	5,822	5,796	5,979	6,440	6,841	7,142	7,288	7,589	7,847	8,149	8,413	8,674	8,822	8,816	8,747	8,477	8,266	8,229	7,998	7,434	6,883	6,406	6,094
9/6/13	PACE+W	5,914	5,771	5,748	5,905	6,365	6,838	7,236	7,494	7,770	8,055	8,213	8,384	8,438	8,497	8,553	8,412	8,003	7,740	7,643	7,470	7,065	6,644	6,218	5,911
9/7/13	PACE+W	5,739	5,614	5,573	5,575	5,618	5,656	6,093	6,553	6,931	7,140	7,313	7,462	7,535	7,541	7,452	7,320	7,138	6,948	6,943	6,873	6,598	6,126	5,737	5,506
9/8/13	PACE+W	5,336	5,245	5,197	5,270	5,329	5,522	5,719	6,015	6,255	6,342	6,489	6,604	6,778	6,918	7,078	7,185	7,228	7,112	7,164	7,085	6,632	6,113	5,694	5,432
9/9/13	PACE+W	5,325	5,265	5,263	5,417	5,885	6,385	6,606	6,867	7,096	7,357	7,549	7,799	7,917	8,016	8,177	8,087	8,032	7,875	7,813	7,576	7,013	6,396	5,930	5,603
9/10/13	PACE+W	5,445	5,362	5,369	5,551	5,987	6,466	6,686	6,830	7,027	7,188	7,289	7,463	7,715	7,898	7,964	7,973	7,890	7,776	7,806	7,667	7,091	6,506	6,058	5,740
9/11/13	PACE+W	5,552	5,455	5,399	5,582	6,062	6,614	6,855	7,038	7,262	7,488	7,667	7,859	7,968	8,161	8,281	8,191	8,065	7,896	7,904	7,680	7,064	6,465	6,044	5,747
9/12/13	PACE+W	5,548	5,446	5,425	5,574	6,046	6,504	6,719	6,915	7,123	7,221	7,269	7,281	7,507	7,737	7,888	7,911	7,813	7,671	7,656	7,474	6,957	6,375	5,969	5,676
9/13/13	PACE+W	5,535	5,417	5,421	5,552	5,948	6,354	6,596	6,817	6,981	7,156	7,308	7,353	7,353	7,389	7,425	7,447	7,355	7,213	7,097	6,945	6,563	6,113	5,770	5,485
9/14/13	PACE+W	5,337	5,248	5,207	5,250	5,365	5,462	5,656	5,985	6,261	6,442	6,548	6,580	6,656	6,765	6,869	6,961	6,931	6,845	6,867	6,741	6,408	5,977	5,629	5,369
9/15/13	PACE+W	5,188	5,103	5,052	5,079	5,134	5,219	5,451	5,800	6,016	6,224	6,480	6,647	6,829	6,982	7,095	7,173	7,126	6,958	6,951	6,704	6,347	5,833	5,445	5,241
9/16/13	PACE+W	5,092	5,088	5,148	5,327	5,812	6,315	6,629	6,820	7,010	7,180	7,227	7,397	7,612	7,751	7,844	7,829	7,713	7,545	7,508	7,306	6,774	6,228	5,824	5,596
9/17/13	PACE+W	5,426	5,359	5,366	5,545	6,013	6,472	6,740	6,953	7,144	7,273	7,307	7,342	7,554	7,613	7,623	7,545	7,433	7,312	7,348	7,142	6,638	6,101	5,689	5,459
9/18/13	PACE+W	5,278	5,175	5,190	5,349	5,796	6,225	6,493	6,636	6,749	6,850	6,918	6,979	6,982	7,030	7,004	6,901	6,805	6,737	6,863	6,746	6,291	5,791	5,480	5,332
9/19/13	PACE+W	5,169	5,143	5,189	5,377	5,805	6,312	6,537	6,516	6,542	6,593	6,685	6,764	6,819	6,847	6,915	6,877	6,859	6,830	6,939	6,793	6,348	5,815	5,556	5,311
9/20/13	PACE+W	5,183	5,134	5,153	5,321	5,755	6,165	6,328	6,534	6,622	6,698	6,726	6,712	6,885	6,953	6,956	6,935	6,837	6,734	6,768	6,565	6,255	5,887	5,534	5,360
9/21/13	PACE+W	5,220	5,131	5,104	5,178	5,277	5,441	5,731	6,010	6,301	6,444	6,548	6,588	6,659	6,744	6,814	6,851	6,720	6,644	6,781	6,587	6,321	5,953	5,606	5,349
9/22/13	PACE+W	5,225	5,112	5,068	5,069	5,156	5,274	5,499	5,829	6,101	6,144	6,183	6,208	6,278	6,342	6,402	6,392	6,385	6,397	6,542	6,401	6,063	5,629	5,351	5,219
9/23/13	PACE+W	5,118	5,135	5,138	5,317	5,814	6,324	6,525	6,734	6,866	6,955	6,974	6,971	6,986	6,955	6,955	6,927	6,848	6,904	7,022	6,820	6,380	5,930	5,601	5,420
9/24/13	PACE+W	5,230	5,186	5,249	5,422	5,889	6,412	6,663	6,783	6,846	6,891	6,881	6,887	6,948	6,908	6,893	6,889	6,872	6,978	7,084	6,876	6,475	5,997	5,670	5,458
9/25/13	PACE+W	5,336	5,222	5,272	5,461	5,948	6,478	6,690	6,799	6,877	6,823	6,812	6,712	6,720	6,651	6,641	6,604	6,617	6,724	6,890	6,704	6,319	5,901	5,519	5,365
9/26/13	PACE+W	5,267	5,209	5,263	5,472	5,967	6,544	6,740	6,809	6,822	6,748	6,717	6,671	6,618	6,592	6,547	6,445	6,559	6,705	6,783	6,712	6,391	5,976	5,579	5,408
9/27/13	PACE+W	5,304	5,318	5,371	5,553	6,022	6,559	6,762	6,818	6,821	6,806	6,690	6,609	6,580	6,507	6,427	6,381	6,359	6,529	6,595	6,388	6,140	5,865	5,634	5,427

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Wkp-PACE+PACW load

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
9/28/13	PACE+W	5,332	5,248	5,269	5,333	5,434	5,656	5,887	6,131	6,271	6,299	6,238	6,184	6,111	6,092	6,070	6,105	6,153	6,268	6,344	6,224	6,024	5,701	5,407	5,216
9/29/13	PACE+W	5,112	5,063	5,053	5,069	5,210	5,306	5,619	5,840	6,075	6,127	6,204	6,170	6,190	6,232	6,251	6,247	6,336	6,530	6,596	6,435	6,070	5,707	5,477	5,308
9/30/13	PACE+W	5,246	5,238	5,267	5,458	5,975	6,500	6,658	6,790	6,925	6,953	6,969	6,970	6,960	6,949	6,792	6,848	6,823	6,948	7,063	6,851	6,409	5,978	5,664	5,445
10/1/13	PACE+W	5,368	5,312	5,339	5,543	6,008	6,548	6,776	6,796	6,796	6,791	6,824	6,882	6,880	6,884	6,863	6,841	6,778	6,933	7,095	6,863	6,521	6,069	5,771	5,563
10/2/13	PACE+W	5,462	5,424	5,479	5,686	6,138	6,692	6,850	6,897	6,939	6,913	6,848	6,831	6,788	6,711	6,679	6,687	6,679	6,992	7,081	6,871	6,493	6,091	5,785	5,593
10/3/13	PACE+W	5,494	5,421	5,469	5,694	6,174	6,773	7,007	7,029	7,027	6,969	6,903	6,860	6,824	6,726	6,660	6,649	6,710	6,896	7,080	6,900	6,544	6,136	5,837	5,683
10/4/13	PACE+W	5,569	5,557	5,612	5,836	6,333	6,882	7,084	7,108	7,093	6,994	6,900	6,821	6,622	6,678	6,585	6,501	6,527	6,737	6,800	6,701	6,459	6,116	5,821	5,630
10/5/13	PACE+W	5,550	5,524	5,542	5,630	5,856	6,102	6,403	6,606	6,657	6,515	6,467	6,319	6,183	6,133	6,171	6,242	6,250	6,383	6,497	6,398	6,161	5,829	5,567	5,372
10/6/13	PACE+W	5,293	5,270	5,306	5,359	5,514	5,711	5,962	6,235	6,267	6,275	6,277	6,212	6,138	6,152	6,175	6,177	6,265	6,462	6,631	6,426	6,106	5,730	5,452	5,301
10/7/13	PACE+W	5,244	5,260	5,312	5,561	6,105	6,641	6,821	6,902	6,948	6,926	6,921	6,901	6,870	6,855	6,784	6,694	6,716	6,971	7,025	6,807	6,408	5,997	5,695	5,514
10/8/13	PACE+W	5,391	5,370	5,421	5,650	6,157	6,723	6,937	6,999	7,022	7,053	6,993	6,993	6,931	6,874	6,833	6,796	6,797	7,104	7,149	6,951	6,547	6,167	5,828	5,596
10/9/13	PACE+W	5,462	5,475	5,523	5,700	6,208	6,783	7,079	7,083	7,020	6,941	6,891	6,906	6,873	6,794	6,782	6,787	6,851	6,972	7,070	6,902	6,503	6,042	5,722	5,530
10/10/13	PACE+W	5,452	5,457	5,494	5,704	6,178	6,820	6,992	7,061	7,055	6,997	6,865	6,813	6,756	6,735	6,689	6,686	6,788	6,977	7,012	6,823	6,485	6,095	5,784	5,597
10/11/13	PACE+W	5,488	5,482	5,520	5,723	6,202	6,719	6,976	7,010	6,962	6,869	6,794	6,693	6,637	6,567	6,469	6,386	6,333	6,660	6,686	6,500	6,291	5,979	5,652	5,494
10/12/13	PACE+W	5,401	5,362	5,341	5,370	5,605	5,874	6,146	6,381	6,453	6,417	6,355	6,303	6,242	6,219	6,188	6,217	6,324	6,549	6,569	6,431	6,186	5,891	5,609	5,437
10/13/13	PACE+W	5,370	5,280	5,286	5,328	5,499	5,699	5,959	6,193	6,332	6,297	6,251	6,189	6,149	6,120	6,167	6,222	6,343	6,561	6,690	6,517	6,220	5,840	5,592	5,440
10/14/13	PACE+W	5,413	5,378	5,489	5,770	6,255	6,862	7,095	7,135	7,101	7,033	6,959	6,849	6,818	6,730	6,670	6,715	6,828	7,092	7,160	6,938	6,514	6,129	5,890	5,666
10/15/13	PACE+W	5,570	5,529	5,587	5,863	6,421	7,046	7,235	7,185	7,055	6,975	6,894	6,825	6,784	6,689	6,631	6,611	6,728	6,997	7,049	6,890	6,490	6,099	5,824	5,679
10/16/13	PACE+W	5,591	5,594	5,639	5,867	6,433	7,056	7,298	7,215	7,206	7,076	6,958	6,881	6,822	6,716	6,626	6,615	6,700	6,926	7,008	6,834	6,490	6,096	5,787	5,617
10/17/13	PACE+W	5,530	5,513	5,594	5,810	6,313	6,900	7,088	7,117	6,989	6,917	6,824	6,761	6,693	6,638	6,587	6,553	6,611	6,918	6,976	6,742	6,422	6,046	5,772	5,594
10/18/13	PACE+W	5,541	5,536	5,626	5,832	6,268	6,760	7,066	7,104	7,096	6,992	6,873	6,743	6,572	6,564	6,564	6,525	6,548	6,790	6,801	6,624	6,306	6,054	5,762	5,540
10/19/13	PACE+W	5,515	5,520	5,553	5,648	5,898	6,100	6,364	6,519	6,573	6,562	6,445	6,309	6,175	6,140	6,088	6,108	6,220	6,428	6,446	6,273	6,033	5,744	5,541	5,343
10/20/13	PACE+W	5,287	5,265	5,270	5,359	5,501	5,707	5,975	6,169	6,253	6,132	6,036	6,034	6,030	5,992	6,063	6,132	6,279	6,514	6,559	6,345	6,086	5,701	5,481	5,341
10/21/13	PACE+W	5,291	5,331	5,428	5,683	6,243	6,849	7,118	7,110	7,095	7,056	6,975	6,889	6,819	6,775	6,722	6,693	6,776	7,035	7,031	6,734	6,375	5,976	5,716	5,525
10/22/13	PACE+W	5,443	5,444	5,516	5,741	6,264	6,837	7,094	7,044	6,988	6,915	6,828	6,773	6,793	6,760	6,717	6,657	6,734	7,007	6,999	6,760	6,346	5,994	5,682	5,489
10/23/13	PACE+W	5,418	5,398	5,472	5,697	6,241	6,800	6,963	6,961	6,839	6,763	6,734	6,721	6,693	6,647	6,600	6,601	6,755	7,000	6,965	6,801	6,447	5,994	5,744	5,574
10/24/13	PACE+W	5,487	5,507	5,551	5,779	6,335	6,969	7,206	7,145	7,049	6,942	6,916	6,835	6,826	6,771	6,712	6,684	6,756	7,025	6,980	6,783	6,405	6,008	5,745	5,528
10/25/13	PACE+W	5,469	5,472	5,512	5,728	6,202	6,817	7,058	7,005	6,855	6,862	6,847	6,847	6,742	6,720	6,628	6,566	6,638	6,831	6,744	6,611	6,257	6,037	5,761	5,553
10/26/13	PACE+W	5,472	5,399	5,430	5,507	5,711	6,012	6,268	6,487	6,569	6,548	6,489	6,368	6,221	6,222	6,216	6,224	6,381	6,594	6,548	6,434	6,228	5,933	5,661	5,463
10/27/13	PACE+W	5,350	5,310	5,321	5,365	5,520	5,763	6,028	6,188	6,261	6,323	6,398	6,338	6,319	6,280	6,292	6,352	6,582	6,773	6,783	6,616	6,289	5,903	5,650	5,476
10/28/13	PACE+W	5,416	5,373	5,466	5,708	6,213	6,860	7,107	7,096	7,184	7,136	7,069	7,011	6,980	6,943	6,954	7,017	7,187	7,342	7,297	7,078	6,652	6,261	5,931	5,781
10/29/13	PACE+W	5,662	5,662	5,730	5,995	6,593	7,201	7,412	7,374	7,310	7,116	6,975	6,872	6,788	6,730	6,689	6,700	6,937	7,218	7,209	7,033	6,635	6,143	5,932	5,752
10/30/13	PACE+W	5,692	5,663	5,740	6,000	6,579	7,264	7,512	7,410	7,328	7,199	7,046	6,903	6,825	6,770	6,753	6,779	6,956	7,208	7,151	6,958	6,639	6,217	5,929	5,720
10/31/13	PACE+W	5,605	5,593	5,639	5,886	6,420	7,016	7,131	7,214	7,142	7,091	7,004	6,938	6,832	6,719	6,579	6,679	6,755	6,809	6,735	6,631	6,373	6,080	5,827	5,647
11/1/13	PACE+W	5,570	5,513	5,576	5,769	6,155	6,749	7,029	7,087	7,073	6,997	6,890	6,826	6,704	6,581	6,485	6,468	6,580	6,843	6,753	6,596	6,320	6,013	5,686	5,515
11/2/13	PACE+W	5,409	5,353	5,361	5,408	5,641	5,879	6,140	6,339	6,442	6,390	6,367	6,233	6,177	6,170	6,193	6,232	6,441	6,662	6,613	6,453	6,242	5,932	5,658	5,468
11/3/13	PACE+W	5,369	5,308	5,285	5,333	5,501	5,725	6,039	6,377	6,581	6,586	6,438	6,410	6,341	6,373	6,395	6,490	6,844	7,106	7,050	6,951	6,720	6,317	5,977	5,783
11/4/13	PACE+W	5,658	5,621	5,614	5,743	6,023	6,639	7,217	7,482	7,361	7,350	7,279	7,181	7,100	7,034	6,981	7,073	7,367	7,568	7,626	7,464	7,175	6,696	6,279	6,031
11/5/13	PACE+W	5,847	5,766	5,741	5,834	6,098	6,678	7,212	7,395	7,307	7,263	7,204	7,097	7,068	6,993	6,957	7,004	7,361	7,627	7,583	7,454	7,152	6,747	6,363	6,077

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Wkp-PACE+PACW load

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
11/6/13	PACE+W	5,935	5,832	5,780	5,834	6,086	6,658	7,172	7,352	7,325	7,261	7,238	7,083	7,031	6,960	6,933	6,937	7,222	7,362	7,339	7,194	6,942	6,522	6,118	5,846
11/7/13	PACE+W	5,666	5,615	5,557	5,607	5,864	6,386	6,920	7,072	7,069	7,074	6,999	6,977	6,943	6,918	6,904	6,974	7,257	7,472	7,391	7,211	6,987	6,599	6,211	5,864
11/8/13	PACE+W	5,729	5,631	5,585	5,640	5,885	6,399	6,930	7,164	7,167	7,160	7,085	6,951	6,874	6,806	6,755	6,709	6,958	7,165	7,080	6,891	6,680	6,445	6,119	5,874
11/9/13	PACE+W	5,694	5,606	5,581	5,579	5,689	5,943	6,179	6,447	6,620	6,630	6,582	6,471	6,408	6,339	6,279	6,316	6,647	6,864	6,792	6,702	6,515	6,270	5,962	5,703
11/10/13	PACE+W	5,554	5,474	5,453	5,504	5,554	5,750	5,927	6,170	6,345	6,383	6,329	6,326	6,229	6,155	6,101	6,175	6,523	6,813	6,776	6,683	6,496	6,225	5,938	5,709
11/11/13	PACE+W	5,593	5,540	5,472	5,532	5,824	6,331	6,787	6,967	7,087	7,181	7,112	6,974	7,002	6,910	6,878	6,876	7,129	7,427	7,322	7,124	6,903	6,507	6,115	5,819
11/12/13	PACE+W	5,649	5,554	5,527	5,592	5,842	6,329	6,857	7,037	6,950	6,958	6,934	6,869	6,820	6,813	6,743	6,741	7,081	7,312	7,229	7,106	6,864	6,460	6,079	5,766
11/13/13	PACE+W	5,627	5,522	5,508	5,549	5,803	6,332	6,897	7,079	7,053	7,048	6,951	6,886	6,824	6,783	6,746	6,771	7,068	7,302	7,238	7,119	6,885	6,496	6,093	5,817
11/14/13	PACE+W	5,674	5,619	5,618	5,656	5,923	6,504	7,050	7,234	7,079	7,037	7,011	7,033	6,980	6,927	6,897	6,933	7,248	7,478	7,405	7,252	7,033	6,642	6,236	5,955
11/15/13	PACE+W	5,809	5,745	5,746	5,821	6,067	6,567	7,112	7,378	7,369	7,355	7,270	7,129	7,103	7,049	7,000	7,047	7,365	7,506	7,360	7,221	6,993	6,701	6,415	6,138
11/16/13	PACE+W	5,912	5,816	5,788	5,768	5,882	6,086	6,356	6,664	6,932	7,010	7,011	6,920	6,866	6,727	6,746	6,807	7,123	7,282	7,205	7,015	6,872	6,599	6,290	6,004
11/17/13	PACE+W	5,803	5,703	5,660	5,689	5,763	5,918	6,093	6,330	6,569	6,636	6,570	6,457	6,425	6,353	6,361	6,472	6,889	7,148	7,104	6,999	6,692	6,468	6,105	5,851
11/18/13	PACE+W	5,729	5,663	5,664	5,799	6,104	6,643	7,182	7,439	7,396	7,376	7,266	7,230	7,221	7,154	7,121	7,141	7,442	7,617	7,486	7,332	7,053	6,637	6,238	5,940
11/19/13	PACE+W	5,760	5,690	5,605	5,685	5,940	6,419	7,010	7,234	7,207	7,184	7,145	7,187	7,183	7,101	7,095	7,204	7,517	7,645	7,593	7,435	7,199	6,765	6,363	6,070
11/20/13	PACE+W	5,888	5,793	5,795	5,847	6,110	6,709	7,267	7,484	7,494	7,446	7,404	7,315	7,254	7,227	7,244	7,362	7,680	7,891	7,855	7,775	7,525	7,184	6,756	6,426
11/21/13	PACE+W	6,274	6,196	6,225	6,301	6,621	7,245	7,909	8,080	7,952	7,888	7,780	7,587	7,489	7,425	7,409	7,529	7,925	8,190	8,136	8,048	7,861	7,436	6,976	6,705
11/22/13	PACE+W	6,570	6,525	6,530	6,652	6,919	7,484	8,090	8,213	8,163	8,005	7,799	7,629	7,476	7,385	7,292	7,330	7,691	7,942	7,892	7,814	7,637	7,336	6,964	6,669
11/23/13	PACE+W	6,506	6,413	6,390	6,427	6,580	6,836	7,162	7,386	7,546	7,516	7,361	7,153	6,921	6,799	6,760	6,870	7,315	7,545	7,493	7,389	7,201	6,988	6,651	6,392
11/24/13	PACE+W	6,210	6,164	6,155	6,216	6,355	6,540	6,828	7,083	7,223	7,190	7,052	6,940	6,785	6,632	6,610	6,735	7,169	7,497	7,493	7,449	7,261	6,957	6,609	6,376
11/25/13	PACE+W	6,239	6,187	6,230	6,380	6,664	7,236	7,806	8,098	7,986	7,839	7,673	7,451	7,239	7,189	7,166	7,245	7,680	7,986	7,937	7,830	7,610	7,162	6,815	6,526
11/26/13	PACE+W	6,363	6,308	6,317	6,422	6,704	7,273	7,864	8,047	7,954	7,825	7,661	7,531	7,401	7,232	7,197	7,281	7,684	7,907	7,868	7,767	7,579	7,181	6,785	6,454
11/27/13	PACE+W	6,200	6,192	6,194	6,313	6,543	7,020	7,488	7,813	7,840	7,826	7,730	7,590	7,425	7,287	7,174	7,199	7,511	7,726	7,677	7,590	7,414	7,115	6,683	6,233
11/28/13	PACE+W	6,052	5,945	5,933	5,979	6,077	6,282	6,591	6,890	7,091	7,167	7,144	6,938	6,659	6,380	6,167	6,083	6,338	6,462	6,466	6,536	6,506	6,408	6,169	5,968
11/29/13	PACE+W	5,879	5,839	5,833	5,937	6,101	6,382	6,711	6,922	7,067	7,073	7,001	6,847	6,741	6,608	6,567	6,637	7,053	7,233	7,220	7,111	7,025	6,764	6,413	6,118
11/30/13	PACE+W	5,918	5,840	5,781	5,863	5,939	6,168	6,412	6,641	6,854	6,978	6,858	6,780	6,634	6,496	6,464	6,558	6,977	7,206	7,168	7,024	6,968	6,667	6,355	6,057

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June 28, 2013

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE, Room 1A
Washington, DC 20426

RE: *PacifiCorp*
Docket No. ER10-3246-___
Triennial Market Power Update

Dear Secretary Bose:

Pursuant to Section 35.37(a)(1) of the Commission's regulations,[1] and Order No. 697, *et seq.*,[2] PacifiCorp respectfully submits this Triennial Market Power Update ("Triennial Update") in the above-referenced proceeding. Concurrent with this filing, PacifiCorp is submitting under separate cover through the Commission's eTariff system certain changes to its market-based rate tariff in Docket No. ER13-1823-000.

1. Description of PacifiCorp and Public Utility Affiliates

PacifiCorp is a vertically-integrated public utility primarily engaged in the business of providing retail electric service to approximately 1.8 million residential, commercial, industrial, and other customers in portions of the following states: Utah, Oregon, Wyoming, Washington, Idaho, and California. In addition, PacifiCorp provides electric transmission service in nine Western states and owns, controls, or has interests in: (i) approximately 9,191 pole miles of transmission lines and (ii) certain thermal, hydroelectric, and wind-powered generating plants with a combined rated capacity of approximately 11,004 MW.[3]

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[1] 18 C.F.R. § 35.37(a)(1) (2013).

[2] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, 119 FERC ¶ 61,295, *clarified*, 121 FERC ¶ 61,260 (2007), *on reh'g*, Order No. 697-A, 123 FERC ¶ 61,055 (2008), *on reh'g*, Order No. 697-B, 125 FERC ¶ 61,326 (2008), *on reh'g*, Order No. 697-C, 127 FERC ¶ 61,284 (2009); *on reh'g*, Order No. 697-D, 130 FERC ¶ 61,206 (2010); *clarified*, 131 FERC ¶ 61,021 (2010).

[3] This figure, which reflects nameplate ratings for solar and wind facilities, and summer seasonal ratings for all other facilities, includes approximately 495 MW of capacity leased or purchased through long-term contract, and

Part I - Pivotal Supplier Analysis
Base Case
PACW Balancing Authority Area
Applicant: PacifiCorp

Row		MW	Reference
	Generation		
	Seller and Affiliate Capacity		
A	Installed Capacity	2,889	Workpaper - Generation
B	Long-Term Firm Purchases	243	Workpaper - Generation
C	Long-Term Firm Sales	0	Workpaper - Generation
D	Imported Power	118	Workpaper - Imported Power
	Non-Affiliate Capacity		
E	Installed Capacity	237	Workpaper - Generation
F	Long-Term Firm Purchases	0	Workpaper - Generation
G	Long-Term Firm Sales	-6	Workpaper - Generation
H	Imported Power	1,601	Workpaper - Imported Power
I	Balancing Authority Area Reserve Requirement	-377	Workpaper - Reserves
J	Amount of Line I Attributable to Seller, if any	-359	Workpaper - Reserves
K	Total Uncommitted Supply (SUM A,B,C,D,E,F,G,H,I,M)	1,581	
	Load		
L	Balancing Authority Area Annual Peak Load	3,844	Workpaper - Load
M	Average Daily Peak Native Load in Peak Month	-3,123	Workpaper - Load
N	Amount of Line M Attributable to Seller, if any	-2,974	Workpaper - Load
O	Wholesale Load (SUM L,M)	721	
P	Net Uncommitted Supply (K-O)	860	
Q	Seller's Uncommitted Capacity (SUM A,B,C,D,J,N)	-84	

Result of Pivotal Supplier Screen (Pass if Line Q < Line P) **PASS**
(Fail if Line Q > 0 and Line Q > Line P)[1]

Note:
[1] Formulation in Appendix A of Order No. 697 adjusted to ensure that an applicant with zero or negative uncommitted capacity does not fail the pivotal supplier analysis.

Part II - Market Share Analysis
Base Case
PACW Balancing Authority Area
Applicant: PacifiCorp

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity					
A	Installed Capacity	2,801	2,868	2,610	2,601	Workpaper - Generation
B	Long-Term Firm Purchases	243	243	232	243	Workpaper - Generation
C	Long-Term Firm Sales	0	0	0	0	Workpaper - Generation
D	Seasonal Average Planned Outages	0	-203	-166	0	Workpaper - Planned Outages
E	Imported Power	135	225	0	122	Workpaper - Imported Power
	Capacity Deductions					
F	Average Peak Native Load in the Season	-3,133	-2,663	-2,689	-2,724	Workpaper - Load
G	Amount of Line F Attributable to Seller, if any	-2,990	-2,539	-2,562	-2,591	Workpaper - Load
H	Amount of Line F Attributable to Others, if any	-143	-125	-128	-133	Workpaper - Load
I	Balancing Authority Area Reserve Requirement	-371	-362	-361	-366	Workpaper - Reserves
J	Amount of Line I Attributable to Seller, if any	-354	-345	-344	-348	Workpaper - Reserves
K	Amount of Line I Attributable to Others, if any	-17	-17	-17	-18	Workpaper - Reserves
	Non-Affiliate Capacity					
L	Installed Capacity	216	246	228	192	Workpaper - Generation
M	Long-Term Firm Purchases	0	0	0	0	Workpaper - Generation
N	Long-Term Firm Sales	-5	-6	-6	-4	Workpaper - Generation
O	Local Seasonal Average Planned Outages	0	-16	-13	0	Workpaper - Planned Outages
P	Uncommitted Capacity Imports	1,583	1,010	1,410	1,091	Workpaper - Imported Power
	Supply Calculation					
Q	Total Competing Supply (SUM L,M,N,O,P,H,K)	1,635	1,093	1,475	1,127	
R	Seller's Uncommitted Capacity (Greater of 0 and SUM A,B,C,D,E,G,J)[1]	0	248	0	27	
S	Total Seasonal Uncommitted Capacity (SUM Q,R)	1,635	1,341	1,475	1,154	
T	**Seller's Market Share** (R/S)[1]					
	Results (Pass if < 20%)	0.0%	18.5%	0.0%	2.4%	
	(Fail if >= 20%)	**PASS**	**PASS**	**PASS**	**PASS**	

Note:
[1] Formulation in Appendix A of Order No. 697 adjusted to require value to be nonnegative.

Federal Energy Regulatory Commission
FERC Form No. 714

Annual Electric Balancing Authority Area and Planning Area Report

For the Year Ending December 31, 2012

Utility Code: 14355
Utility Name: PacifiCorp - West

Part II - Schedule 3. Balancing Authority Area Net Energy for Load and Peak Demand Sources by Month

Enter the monthly "Net Energy for Load" which is the amount of energy that the balancing authority area requires internally including balancing authority area losses. The total in column (d) should equal the difference in the totals for columns (e) minus (f) on Schedule 5. The value in column (f) for the month of the annual peak demand should equal the total in column (e) in Schedule 1. Any differences must be explained in a footnote. Refer to the Form 714 instructions for specific guidelines.

Line No (a)	Month (b)	Balancing Authority Area Net Generation (MWh) (c)	Net Actual Interchange (MWh) (d)	Net Energy for Load (MWh) (c + d) (e)	Balancing Authority Area Area Load Sources at Time of Balancing Authority Area Area Monthly Peak Demand, Based on Net Energy For Load (NEL)					Monthly Minimum Demand (MW) (k)
					Output of Generating Plants (MW) (f)	Unit or Firm Purchases (MW) (g)	Unit or Firm Sales (MW) (h)	Net Non-Firm & Inadvertent (MW) (i)	Monthly Peak Demand (MW) (f+g-h+i) (j)	
1	January	1,982,034	38,686	2,020,720	2,479	4,654	3,406	-19	3,708	1,871
2	February	1,863,414	-63,777	1,799,637	2,697	4,168	3,351	-36	3,478	1,879
3	March	1,855,177	-42,936	1,812,241	2,785	3,688	3,019	28	3,482	1,712
4	April	1,191,616	335,923	1,527,539	2,214	3,090	2,300	17	3,021	1,378
5	May	1,279,836	300,810	1,580,646	2,082	4,725	4,075	-16	2,716	1,478
6	June	1,397,721	158,765	1,556,486	1,712	4,282	3,172	8	2,830	1,496
7	July	1,425,458	352,213	1,777,671	2,235	5,635	4,524	5	3,351	1,601
8	August	1,487,511	366,777	1,854,288	2,260	5,302	4,050	6	3,518	1,626
9	September	1,567,774	56,140	1,623,914	2,362	4,590	3,974	42	3,020	1,589
10	October	1,675,820	-7,354	1,668,466	2,299	4,201	3,453	-54	2,993	1,588
11	November	1,804,369	-71,838	1,732,531	2,578	3,963	3,335	-78	3,128	1,609
12	December	1,945,472	42,070	1,987,542	2,829	4,210	3,583	-20	3,436	1,807
13	Total	19,476,202	1,465,479	20,941,681						

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Attachment B:
Asset Appendices of Exelon Corporation and Affiliates

Electric Generating Facilities and Assets

Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Commonwealth Edison Company	ER98-1734	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Constellation Energy Commodities Group Maine, LLC	ER02-699	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Constellation Energy Services of New York, Inc.	ER07-651	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Constellation Energy Services, Inc.	ER07-650	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
Constellation NewEnergy, Inc.	ER96-1387	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
PECO Energy Company	ER01-1147	N/A	N/A	N/A	N/A	N/A	(N/A)	N/A	N/A
AgriWind LLC	N/A QF07-214	Agriwind LLC WF	AgriWind LLC	AgriWind LLC	N/A	MISO	Central	7/1/07	2.10
AgriWind Project L.L.C.	N/A QF07-215	Agriwind Project LLC WF	AgriWind Project L.L.C.	AgriWind Project L.L.C.	N/A	MISO	Central	7/1/07	6.30
BC Energy LLC	N/A QF07-219	BC Energy LLC WF	BC Energy LLC	BC Energy LLC	N/A	MISO	Central	5/28/08	4.20
Beebe 1B Renewable Energy, LLC	ER14-2144	Beebe 1b WF	Beebe 1B Renewable Energy, LLC	Beebe 1B Renewable Energy, LLC	N/A	MISO	Central	12/12/14	50.40
Beebe Renewable Energy, LLC	ER12-2311	Beebe 1a WF	Beebe Renewable Energy, LLC	Beebe Renewable Energy, LLC	N/A	MISO	Central	1/17/13	81.60
Blue Breezes II, L.L.C.	N/A QF07-243	Blue Breezes II LLC WF	Blue Breezes II, L.L.C.	Blue Breezes II, L.L.C.	N/A	MISO	Central	5/1/06	1.25
Blue Breezes, L.L.C.	N/A QF07-242	Blue Breezes I LLC WF	Blue Breezes, L.L.C.	Blue Breezes, L.L.C.	N/A	MISO	Central	5/1/06	1.25
Breezy Bucks I LLC	N/A QF07-234	Breezy Bucks I LLC WF	Breezy Bucks I LLC	Breezy Bucks I LLC	N/A	MISO	Central	5/31/06	1.25
Breezy Bucks II LLC	N/A QF07-235	Breezy Bucks II LLC WF	Breezy Bucks II LLC	Breezy Bucks II LLC	N/A	MISO	Central	5/31/06	1.25
Christoffer Wind Energy I LLC	N/A QF07-250	Christoffer Wind I WF	Christoffer Wind Energy I LLC	Christoffer Wind Energy I LLC	N/A	MISO	Central	6/13/08	2.10
Christoffer Wind Energy II LLC	N/A QF07-252	Christoffer Wind II WF	Christoffer Wind Energy II LLC	Christoffer Wind Energy II LLC	N/A	MISO	Central	6/13/08	2.10
Christoffer Wind Energy III LLC	N/A QF07-251	Christoffer Wind III WF	Christoffer Wind Energy III LLC	Christoffer Wind Energy III LLC	N/A	MISO	Central	6/13/08	2.10
Christoffer Wind Energy IV LLC	N/A QF07-249	Christoffer Wind IV WF	Christoffer Wind Energy IV LLC	Christoffer Wind Energy IV LLC	N/A	MISO	Central	6/13/08	2.10
CP Windfarm, LLC	N/A QF07-178	CP Wind Farms LLC WF	CP Windfarm, LLC	CP Windfarm, LLC	N/A	MISO	Central	10/9/07	4.20
Exelon Generation Company, LLC	ER00-3251	Clinton	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	MISO	Central	11/1/87	1065.00
G-Flow Wind, LLC	N/A QF07-223	G-Flow Wind LLC WF	G-Flow Wind, LLC	G-Flow Wind, LLC	N/A	MISO	Central	3/6/06	1.25
Green Acres Breeze, LLC	N/A QF07-227	Green Acres Breeze LLC WF	Green Acres Breeze, LLC	Green Acres Breeze, LLC	N/A	MISO	Central	3/6/06	1.25
Harvest II Windfarm, LLC	ER12-2201 QF12-522	Harvest 2 WF	Harvest II Windfarm, LLC	Harvest II Windfarm, LLC	N/A	MISO	Central	11/28/12	59.40
Harvest Windfarm, LLC	ER07-1246 QF07-29	Harvest 1 WF	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	2/28/08	52.80

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
K&D Energy LLC	N/A QF07-218	K&D Energy LLC WF	K&D Energy LLC	K&D Energy LLC	N/A	MISO	Central	5/28/08	4.00
KC Energy LLC	N/A QF07-217	KC Energy LLC WF	KC Energy LLC	KC Energy LLC	N/A	MISO	Central	5/28/08	4.00
KSS Turbines LLC	N/A QF07-220	KSS Turbines LLC WF	KSS Turbines LLC	KSS Turbines LLC	N/A	MISO	Central	5/28/08	4.00
Marshall Wind 1, LLC	N/A QF08-59	Marshall Wind 1 WF	Marshall Wind 1, LLC	Marshall Wind 1, LLC	N/A	MISO	Central	5/30/08	2.10
Marshall Wind 2, LLC	N/A QF08-58	Marshall Wind 2 WF	Marshall Wind 2, LLC	Marshall Wind 2, LLC	N/A	MISO	Central	5/30/08	4.20
Marshall Wind 3, LLC	N/A QF08-55	Marshall Wind 3 WF	Marshall Wind 3, LLC	Marshall Wind 3, LLC	N/A	MISO	Central	5/30/08	4.20
Marshall Wind 4, LLC	N/A QF08-56	Marshall Wind 4 WF	Marshall Wind 4, LLC	Marshall Wind 4, LLC	N/A	MISO	Central	5/30/08	4.20
Marshall Wind 5, LLC	N/A QF08-57	Marshall Wind 5 WF	Marshall Wind 5, LLC	Marshall Wind 5, LLC	N/A	MISO	Central	5/30/08	2.10
Marshall Wind 6, LLC	N/A QF08-60	Marshall Wind 6 WF	Marshall Wind 6, LLC	Marshall Wind 6, LLC	N/A	MISO	Central	5/30/08	2.10
Michigan Wind 1, LLC	ER05-1511 QF05-228	Michigan Wind 1 WF	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	12/16/08	69.00
Michigan Wind 2, LLC	ER11-3989	Michigan Wind 2 WF	Michigan Wind 2, LLC	Michigan Wind 2, LLC	N/A	MISO	Central	1/5/12	90.00
Minnesota Breeze, LLC	N/A QF07-224	Minnesota Breeze LLC WF	Minnesota Breeze, LLC	Minnesota Breeze, LLC	N/A	MISO	Central	3/6/06	1.25
Prairie Wind Power LLC	N/A QF07-216	Prairie Wind Power LLC WF	Prairie Wind Power LLC	Prairie Wind Power LLC	N/A	MISO	Central	5/28/08	4.00
Roadrunner I LLC	N/A QF07-236	Roadrunner I LLC WF	Roadrunner I LLC	Roadrunner I LLC	N/A	MISO	Central	5/31/06	1.25
Salty Dog I LLC	N/A QF07-237	Salty Dog I LLC WF	Salty Dog I LLC	Salty Dog I LLC	N/A	MISO	Central	5/31/06	1.25
Salty Dog II LLC	N/A QF07-238	Salty Dog II LLC WF	Salty Dog II LLC	Salty Dog II LLC	N/A	MISO	Central	5/31/06	1.25
Shane's Wind Machine LLC	N/A QF07-247	Shanes Wind Machine LLC WF	Shane's Wind Machine LLC	Shane's Wind Machine LLC	N/A	MISO	Central	7/1/06	2.00
Sunset Breeze, LLC	N/A QF07-226	Sunset Breeze LLC WF	Sunset Breeze, LLC	Sunset Breeze, LLC	N/A	MISO	Central	3/6/06	1.25
Wally's Wind Farm LLC	N/A QF07-239	Wally's Wind Farm WF	Wally's Wind Farm LLC	Wally's Wind Farm LLC	N/A	MISO	Central	5/31/06	1.25
Windy Dog I LLC	N/A QF07-240	Windy Dog I LLC WF	Windy Dog I LLC	Windy Dog I LLC	N/A	MISO	Central	5/31/06	1.25
Wolf Wind Enterprises, LLC	N/A QF07-225	Wolf Wind Enterprises LLC WF	Wolf Wind Enterprises, LLC	Wolf Wind Enterprises, LLC	N/A	MISO	Central	3/6/06	1.25
Exelon Generation Company, LLC	ER00-3251	Frontier GT1	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	9/20/00	MISO & ERCOT	Central	9/20/00	160.00
Exelon Generation Company, LLC	ER00-3251	Frontier GT2	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	9/20/00	MISO & ERCOT	Central	9/20/00	160.00
Exelon Generation Company, LLC	ER00-3251	Frontier GT3	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	9/20/00	MISO & ERCOT	Central	9/20/00	160.00
Exelon Generation Company, LLC	ER00-3251	Frontier ST	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	9/20/00	MISO & ERCOT	Central	9/20/00	390.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 7	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/75	575.48
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/03	225.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/03	227.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/03	252.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/03	231.09
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/03	230.80
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/03	252.00
Constellation Mystic Power, LLC	ER10-2281	Mystic Jet	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/69	9.07
Constellation Solar Connecticut, LLC	N/A QF10-654	East Lyme Bd of Ed at East Lyme HS	Constellation Solar Connecticut LLC	Constellation Solar Connecticut LLC	N/A	ISO-NE	Northeast	3/2/09	0.41
Constellation Solar Connecticut, LLC	N/A QF10-663	Parker Hannifin Corp at New Britain	Constellation Solar Connecticut LLC	Constellation Solar Connecticut LLC	N/A	ISO-NE	Northeast	12/30/08	0.18
Constellation Solar Massachusetts, LLC	N/A QF11-411	Kollmorgen Electro-Optical HQ Bldg	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	7/19/11	0.17
Constellation Solar Massachusetts, LLC	N/A QF15-188	Macy's at Marlborough	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	12/31/14	0.41
Constellation Solar Massachusetts, LLC	N/A QF15-187	Macy's at Natick	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	12/6/14	0.56
Constellation Solar Massachusetts, LLC	N/A QF15-186	Macy's at Saugus	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	12/31/14	0.30
Constellation Solar Massachusetts, LLC	N/A QF15-190	Macy's at Burlington	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	12/4/14	0.25
Constellation Solar Massachusetts, LLC	N/A QF15-189	Macy's at Dartmouth	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	12/31/14	0.35
Constellation Solar Massachusetts, LLC	N/A QF09-89	Majilite Corp	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	2/16/09	0.35
Constellation Solar Massachusetts, LLC	N/A QF10-655	NPP Development, LLC at Patriot Place	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	7/14/10	0.45
Constellation Solar Massachusetts, LLC	N/A QF12-212	Swampscott High School	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	2/7/12	0.32
Constellation Solar Massachusetts, LLC	N/A QF12-292	Town of Norfolk SF	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	6/25/12	1.35
Constellation Solar Net Metering, LLC	N/A QF12-293	Town of Uxbridge SF	Constellation Solar Net Metering, LLC	Constellation Solar Net Metering, LLC	N/A	ISO-NE	Northeast	6/1/12	1.93
Exelon Framingham LLC	ER01-513	Framingham Jet 1	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	3/1/70	10.15
Exelon Framingham LLC	ER01-513	Framingham Jet 2	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/69	11.69
Exelon Framingham LLC	ER01-513	Framingham Jet 3	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/69	11.25
Exelon Generation Company, LLC	ER00-3251	Granite Ridge GT1	Granite Ridge Energy, LLC	Exelon Generation Company, LLC	1/1/14	ISO-NE	Northeast	12/13/02	220.00
Exelon Generation Company, LLC	ER00-3251	Granite Ridge GT2	Granite Ridge Energy, LLC	Exelon Generation Company, LLC	1/1/14	ISO-NE	Northeast	12/13/02	220.00
Exelon Generation Company, LLC	ER00-3251	Granite Ridge STG1	Granite Ridge Energy, LLC	Exelon Generation Company, LLC	1/1/14	ISO-NE	Northeast	12/13/02	221.32
Exelon Generation Company, LLC	ER00-3251	Kleen GT1	Kleen Energy Systems, LLC	Exelon Generation Company, LLC	7/23/11	ISO-NE	Northeast	7/8/11	186.00
Exelon Generation Company, LLC	ER00-3251	Kleen GT2	Kleen Energy Systems, LLC	Exelon Generation Company, LLC	7/23/11	ISO-NE	Northeast	7/8/11	188.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Kleen STG1	Kleen Energy Systems, LLC	Exelon Generation Company, LLC	7/23/11	ISO-NE	Northeast	7/8/11	246.00
Exelon New Boston, LLC	ER01-513	New Boston Jet	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	9/1/66	16.03
Exelon West Medway, LLC	ER01-513	West Medway Jet 1	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/70	42.00
Exelon West Medway, LLC	ER01-513	West Medway Jet 2	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	3/1/71	39.85
Exelon West Medway, LLC	ER01-513	West Medway Jet 3	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/70	35.44
Exelon Wyman, LLC	ER01-513	Wyman 4	Exelon Wyman, LLC (5.9%)	FPL Wyman Energy, LLC	N/A	ISO-NE	Northeast	1/1/78	610.00
Holyoke Solar LLC	N/A QF12-294	City of Holyoke G & E Dept at Meadow SF	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	12/27/11	0.87
Holyoke Solar LLC	N/A QF12-267	City of Holyoke G & E Dept at Mueller SF	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	3/12/12	2.95
2014 ESA Project Company, LLC	ER15-1496 (pending)	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	N/A	NYISO	Northeast	12/31/14	0.20
Constellation Solar New York, LLC	N/A QF13-550	Owens Corning	Constellation Solar New York, LLC	Constellation Solar New York, LLC	N/A	NYISO	Northeast	10/9/13	2.28
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 1	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	12/1/69	626.90
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 2	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	8/1/88	1287.20
R. E. Ginna Nuclear Power Plant, LLC	ER04-485	Ginna	R. E. Ginna Nuclear Power Plant, LLC	R. E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	7/1/70	581.70
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 1	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	5/1/75	873.00
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 2	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	4/1/77	841.80
Constellation Power Source Generation, LLC	ER00-1598	Gould Street 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	12/1/52	97.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/69	14.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/69	14.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/69	14.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/69	14.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/69	15.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/69	16.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/69	15.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/69	16.00
Constellation Power Source Generation, LLC	ER00-1598	Perryman 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	1/1/72	52.00
Constellation Power Source Generation, LLC	ER00-1598	Perryman 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	4/1/72	51.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Constellation Power Source Generation, LLC	ER00-1598	Perryman 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	4/1/72	51.00
Constellation Power Source Generation, LLC	ER00-1598	Perryman 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	4/1/72	52.00
Constellation Power Source Generation, LLC	ER00-1598	Perryman 51	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/95	147.60
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	8/1/70	15.30
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	8/1/70	16.00
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	9/1/70	14.80
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	9/1/70	14.80
Constellation Power Source Generation, LLC	ER00-1598	Riverside 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	9/1/51	74.00
Constellation Power Source Generation, LLC	ER00-1598	Riverside 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	9/1/70	19.00
Constellation Power Source Generation, LLC	ER00-1598	Riverside 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	9/1/70	20.00
Constellation Power Source Generation, LLC	ER00-1598	Westport 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	2/1/69	115.80
Constellation Solar DC, LLC	N/A QF13-575	Dunbar	Constellation Solar DC, LLC	Constellation Solar DC, LLC	N/A	PJM	Northeast	12/27/13	0.32
Constellation Solar Federal LLC	N/A QF12-78	Reeves SF	Constellation Solar Federal LLC	Constellation Solar Federal LLC	N/A	PJM	Northeast	12/20/11	4.23
Constellation Solar Horizons, LLC	N/A QF10-586	University System of Maryland & Department of General Services SF	Constellation Solar Horizons, LLC	Constellation Solar Horizons, LLC	N/A	PJM	Northeast	7/1/12	13.61
Constellation Solar Maryland II, LLC	N/A QF15-660	CNE at Cambridge	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	4/30/15	3.67
Constellation Solar Maryland II, LLC	N/A QF13-135	UMMS - CRE	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	2/21/13	0.35
Constellation Solar Maryland II, LLC	N/A QF13-136	UMMS (U of MD Medical System) SF	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	2/21/13	3.09
Constellation Solar Maryland, LLC	N/A QF11-271	AA County, MD at Shared Svcs Complex	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	3/4/11	0.63
Constellation Solar Maryland, LLC	N/A QF11-333	Coppin State Univ at Coppin State Univ - PEC	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	9/14/11	0.42
Constellation Solar Maryland, LLC	N/A QF11-410	CPSG Fort Smallwood Road Complex	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	10/3/11	0.78
Constellation Solar Maryland, LLC	N/A QF11-335	GM Allison Plant-I	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	5/18/11	1.04
Constellation Solar Maryland, LLC	N/A QF11-407	Maryland Science Center	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	5/24/11	0.09
Constellation Solar Maryland, LLC	N/A QF11-268	McCormick & Co, Inc at Belcamp	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	1/1/11	1.56
Constellation Solar Maryland, LLC	N/A QF10-662	McCormick & Co, Inc at Hunt Valley	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	1/26/09	0.78
Constellation Solar Maryland, LLC	N/A QF11-334	McCormick & Co, Inc at Sparks	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	6/24/11	0.08
Constellation Solar Maryland, LLC	N/A QF10-661	MD Env Service at MES Headquarters	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	12/29/08	0.25
Constellation Solar Maryland, LLC	N/A QF12-507	University System of Maryland II	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	7/1/12	1.42

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Constellation Solar New Jersey II, LLC	N/A QF11-267	Johnson Matthey, Inc at West Deptford	Constellation Solar New Jersey II, LLC	Constellation Solar New Jersey II, LLC	N/A	PJM	Northeast	4/25/11	4.41
Constellation Solar New Jersey II, LLC	N/A QF11-461	Toys-R-Us Delaware, Inc at Mt Olive	Constellation Solar New Jersey II, LLC	Constellation Solar New Jersey II, LLC	N/A	PJM	Northeast	12/22/11	4.55
Constellation Solar New Jersey III, LLC	N/A QF12-81	Middle Township Elem School 1	Constellation Solar New Jersey III, LLC	Constellation Solar New Jersey III, LLC	N/A	PJM	Northeast	12/7/11	0.17
Constellation Solar New Jersey III, LLC	N/A QF12-79	Middle Township Elem School 2	Constellation Solar New Jersey III, LLC	Constellation Solar New Jersey III, LLC	N/A	PJM	Northeast	12/5/11	0.39
Constellation Solar New Jersey III, LLC	N/A QF12-80	Middle Township High School	Constellation Solar New Jersey III, LLC	Constellation Solar New Jersey III, LLC	N/A	PJM	Northeast	12/14/11	0.69
Constellation Solar New Jersey LLC	N/A QF11-270	Benjamin Moore & Co at Flanders NJ	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	1/3/11	1.50
Constellation Solar New Jersey LLC	N/A QF10-666	Jet Aviation Teterboro, LP at Teterboro Airport	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	3/1/08	0.15
Constellation Solar New Jersey LLC	N/A QF11-464	North Vineland SF	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	10/18/11	2.54
Constellation Solar New Jersey LLC	N/A QF11-463	West Vineland SF	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	10/19/11	4.06
Constellation Solar Ohio, LLC	N/A QF10-664	Univ of Toledo (Solar) Scott Park Campus of Energy & Innovation	Constellation Solar Ohio, LLC	Constellation Solar Ohio, LLC	N/A	PJM	Northeast	3/31/10	0.88
Constellation Solar Ohio, LLC	N/A QF10-659	Univ of Toledo (Wind) Scott Park Campus of Energy & Innovation	Constellation Solar Ohio, LLC	Constellation Solar Ohio, LLC	N/A	PJM	Northeast	3/31/10	0.07
Criterion Power Partners, LLC	ER10-1443	Criterion WF	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	2/4/11	70.00
Exelon Generation Company, LLC	ER00-3251	Braidwood 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/1/88	1178.00
Exelon Generation Company, LLC	ER00-3251	Braidwood 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/88	1152.00
Exelon Generation Company, LLC	ER00-3251	Byron 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/1/85	1164.00
Exelon Generation Company, LLC	ER00-3251	Byron 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/87	1136.00
Exelon Generation Company, LLC	ER00-3251	Chester 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	2/7/69	13.00
Exelon Generation Company, LLC	ER00-3251	Chester 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/20/69	13.00
Exelon Generation Company, LLC	ER00-3251	Chester 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/6/69	13.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/1/28	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/25/64	65.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/4/64	65.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/1/28	36.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/6/28	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	4/5/28	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/1/28	36.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/1/28	48.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Conowingo 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/1/28	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/10/64	65.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/25/64	65.00
Exelon Generation Company, LLC	ER00-3251	Cordova GT1	Cordova Energy Company, LLC	Exelon Generation Company, LLC	12/30/05	PJM	Northeast	6/12/01	165.00
Exelon Generation Company, LLC	ER00-3251	Cordova GT2	Cordova Energy Company, LLC	Exelon Generation Company, LLC	12/30/05	PJM	Northeast	6/12/01	165.00
Exelon Generation Company, LLC	ER00-3251	Cordova STG1	Cordova Energy Company, LLC	Exelon Generation Company, LLC	12/30/05	PJM	Northeast	6/12/01	191.20
Exelon Generation Company, LLC	ER00-3251	Croydon 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/18/74	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/18/74	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 21	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/18/74	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 22	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/18/74	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 31	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/6/74	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 32	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/8/74	48.00
Exelon Generation Company, LLC	ER00-3251	Croydon 41	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/24/74	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 42	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/24/74	49.00
Exelon Generation Company, LLC	ER00-3251	Delaware 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/7/69	13.00
Exelon Generation Company, LLC	ER00-3251	Delaware 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	4/19/69	13.00
Exelon Generation Company, LLC	ER00-3251	Delaware 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/12/69	13.00
Exelon Generation Company, LLC	ER00-3251	Delaware 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/24/70	17.00
Exelon Generation Company, LLC	ER00-3251	Dresden 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/70	883.50
Exelon Generation Company, LLC	ER00-3251	Dresden 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/71	895.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/20/67	13.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 20	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/11/67	13.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/24/74	380.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 30	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/7/70	17.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/29/76	380.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 40	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/21/70	17.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 5	Elwood Energy, LLC	Exelon Generation Company, LLC	6/15/06	PJM	Northeast	7/18/01	150.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 6	Elwood Energy, LLC	Exelon Generation Company, LLC	6/15/06	PJM	Northeast	7/18/01	150.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 7	Elwood Energy, LLC	Exelon Generation Company, LLC	6/15/06	PJM	Northeast	7/18/01	150.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 8	Elwood Energy, LLC	Exelon Generation Company, LLC	6/15/06	PJM	Northeast	7/18/01	150.00
Exelon Generation Company, LLC	ER00-3251	Fairless Hills A	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/96	30.00
Exelon Generation Company, LLC	ER00-3251	Fairless Hills B	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/96	30.00
Exelon Generation Company, LLC	ER00-3251	Falls 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/22/70	17.00
Exelon Generation Company, LLC	ER00-3251	Falls 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/10/70	17.00
Exelon Generation Company, LLC	ER00-3251	Falls 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/28/70	17.00
Exelon Generation Company, LLC	ER00-3251	LaSalle 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	1/1/84	1135.40
Exelon Generation Company, LLC	ER00-3251	LaSalle 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/84	1136.20
Exelon Generation Company, LLC	ER00-3251	Limerick 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	2/1/86	1119.70
Exelon Generation Company, LLC	ER00-3251	Limerick 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	1/1/90	1122.10
Exelon Generation Company, LLC	ER00-3251	Moser 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/9/70	17.00
Exelon Generation Company, LLC	ER00-3251	Moser 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/29/70	17.00
Exelon Generation Company, LLC	ER00-3251	Moser 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/11/70	17.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	4/10/67	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	4/10/67	133.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/1/67	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/1/67	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/11/67	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/11/67	133.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	2/10/68	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	2/10/68	134.00
Exelon Generation Company, LLC	ER00-3251	Oyster Creek 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/69	609.90
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 2	ExGen (PSEG 50%)	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/5/74	1254.00
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 3	ExGen (PSEG 50%)	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/23/74	1125.40
Exelon Generation Company, LLC	ER00-3251	Pennsbury 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/1/96	2.67

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Pennsbury 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/1/96	2.67
Exelon Generation Company, LLC	ER00-3251	Quad Cities 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/72	908.00
Exelon Generation Company, LLC	ER00-3251	Quad Cities 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/72	911.00
Exelon Generation Company, LLC	ER00-3251	Richmond 91	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/7/73	49.00
Exelon Generation Company, LLC	ER00-3251	Richmond 92	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/7/73	49.00
Exelon Generation Company, LLC	ER00-3251	Salem 1	PSEG (ExGen 42.59%)	PSEG	N/A	PJM	Northeast	6/30/77	1173.99
Exelon Generation Company, LLC	ER00-3251	Salem 2	PSEG (ExGen 42.59%)	PSEG	N/A	PJM	Northeast	10/13/81	1158.02
Exelon Generation Company, LLC	ER00-3251	Salem 3	PSEG (ExGen 42.59%)	PSEG	N/A	PJM	Northeast	6/17/71	37.57
Exelon Generation Company, LLC	ER00-3251	Schuylkill 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/30/69	13.00
Exelon Generation Company, LLC	ER00-3251	Schuylkill 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/11/71	17.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/02	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/02	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/02	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/02	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/02	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/02	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/02	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/02	37.00
Exelon Generation Company, LLC	ER00-3251	Southwark 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/14/67	13.00
Exelon Generation Company, LLC	ER00-3251	Southwark 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/9/67	13.00
Exelon Generation Company, LLC	ER00-3251	Southwark 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/26/67	13.00
Exelon Generation Company, LLC	ER00-3251	Southwark 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	11/7/68	13.00
Exelon Generation Company, LLC	ER00-3251	TMI 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/2/74	802.80
Exelon Generation Company, LLC	ER00-3251	York Delta GT1	Calpine Mid Merit LLC	Exelon Generation Company, LLC	6/1/11	PJM	Northeast	3/3/11	118.00
Exelon Generation Company, LLC	ER00-3251	York Delta GT2	Calpine Mid Merit LLC	Exelon Generation Company, LLC	6/1/11	PJM	Northeast	3/3/11	127.00
Exelon Generation Company, LLC	ER00-3251	York Delta GT3	Calpine Mid Merit LLC	Exelon Generation Company, LLC	6/1/11	PJM	Northeast	3/3/11	127.00
Exelon Generation Company, LLC	ER00-3251	York Delta STG1	Calpine Mid Merit LLC	Exelon Generation Company, LLC	6/1/11	PJM	Northeast	3/3/11	193.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Solar Chicago LLC	N/A QF10-174	Chicago City Solar SF	Exelon Solar Chicago LLC	Exelon Solar Chicago LLC	N/A	PJM	Northeast	3/23/10	8.00
Fourmile Wind Energy, LLC	ER14-2145 QF14-721	Fourmile Ridge WF	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	1/15/15	40.00
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 1	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/01	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 2	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/01	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 3	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/01	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 4	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/01	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 5	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/01	53.50
Bennett Creek Windfarm, LLC	N/A QF07-36	Bennett Creek WF	Bennett Creek, LLC	Bennett Creek, LLC	N/A	IPCO	Northwest	8/31/08	21.00
Cassia Gulch Wind Park LLC	ER10-75 QF05-180	Cassia Gulch WF	Cassia Gulch Wind Park LLC	Cassia Gulch Wind Park LLC	N/A	IPCO	Northwest	3/31/09	18.90
Cassia Wind Farm, LLC	N/A QF05-170	Cassia Wind WF	Cassia Wind Farm, LLC	Cassia Wind Farm, LLC	N/A	IPCO	Northwest	3/31/09	10.50
High Mesa Energy, LLC	ER12-2528 QF13-77	High Mesa WF	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	IPCO	Northwest	8/28/12	40.00
Hot Springs Windfarm, LLC	N/A QF07-37	Hot Springs WF	Hot Springs Windfarm, LLC	Hot Springs Windfarm, LLC	N/A	IPCO	Northwest	8/31/08	21.00
Tuana Springs Energy, LLC	ER10-87 QF08-742	Tuana Springs WF	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	IPCO	Northwest	7/27/10	16.80
Sunnyside Cogeneration Assoc.	N/A QF86-556	Sunnyside Cogen	Sunnyside Cogeneration Assoc.	Sunnyside Cogeneration Assoc.	N/A	PACE	Northwest	2/1/93	51.00
Big Top, LLC	N/A QF08-539	Big Top WF	Big Top, LLC	Big Top, LLC	N/A	PACW	Northwest	6/27/09	1.65
Butter Creek Power, LLC	N/A QF08-536	Butter Creek WF	Butter Creek Power, LLC	Butter Creek Power, LLC	N/A	PACW	Northwest	6/27/09	4.95
Four Corners Windfarm, LLC	N/A QF08-372	Four Corner WF	Four Corners Windfarm, LLC	Four Corners Windfarm, LLC	N/A	PACW	Northwest	9/30/09	10.00
Four Mile Canyon Windfarm, LLC	N/A QF08-370	Four Mile Canyon WF	Four Mile Canyon Windfarm, LLC	Four Mile Canyon Windfarm, LLC	N/A	PACW	Northwest	9/30/09	10.00
Oregon Trail Windfarm, LLC	N/A QF08-371	Oregon Trail WF	Oregon Trail Windfarm, LLC	Oregon Trail Windfarm, LLC	N/A	PACW	Northwest	6/27/09	9.90
Pacific Canyon Windfarm, LLC	N/A QF08-373	Pacific Canyon WF	Pacific Canyon Windfarm, LLC	Pacific Canyon Windfarm, LLC	N/A	PACW	Northwest	6/27/09	8.25
Sand Ranch Windfarm, LLC	N/A QF08-368	Sand Ranch WF	Sand Ranch Windfarm, LLC	Sand Ranch Windfarm, LLC	N/A	PACW	Northwest	6/27/09	9.90
Three Mile Canyon Wind I, LLC	N/A QF09-142	Three Mile Canyon WF	Three Mile Canyon Wind I, LLC	Three Mile Canyon Wind I, LLC	N/A	PACW	Northwest	9/30/09	9.90
Wagon Trail, LLC	N/A QF08-537	Wagon Trail WF	Wagon Trail, LLC	Wagon Trail, LLC	N/A	PACW	Northwest	6/27/09	3.30
Ward Butte Windfarm, LLC	N/A QF08-369	Ward Butte WF	Ward Butte Windfarm, LLC	Ward Butte Windfarm, LLC	N/A	PACW	Northwest	6/27/09	6.60
Outback Solar, LLC	N/A QF13-34	Outback Solar SF	Outback Solar, LLC	Outback Solar, LLC	N/A	BPA	Northwest	10/30/12	4.82
FPL Energy Vansycle, L.L.C.	ER01-838	Stateline WF	FPL Energy Vansycle, L.L.C.	FPL Energy Vansycle, L.L.C.	4/1/15	PACW	Northwest	12/1/01	300.00
Denver Airport Solar, LLC	N/A QF11-336	City & County of Denver at Denver International Airport	Denver Airport Solar, LLC	Denver Airport Solar, LLC	N/A	PSCO	Northwest	6/7/11	3.77

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Cow Branch Wind Power, L.L.C.	ER07-1223 QF07-253	Cow Branch WF	Cow Branch Wind Power, L.L.C.	Cow Branch Wind Power, L.L.C.	N/A	AECI	Southeast	3/3/08	50.40
CR Clearing, LLC	ER07-1222 QF07-248	CR Clearing LLC WF	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	5/1/08	50.40
Loess Hills Wind Farm, LLC	N/A QF07-241	Loess Hills WF	Loess Hills Wind Farm, LLC	Loess Hills Wind Farm, LLC	N/A	AECI	Southeast	4/19/08	5.00
Wind Capital Holdings, LLC	ER07-1208 QF07-222	Wind Capital Holdings LLC WF	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	5/14/07	56.70
CER Generation, LLC	ER10-662	Hillabee GT1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/10	207.00
CER Generation, LLC	ER10-662	Hillabee GT2	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/10	207.00
CER Generation, LLC	ER10-662	Hillabee STG1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/10	281.00
Constellation Solar Georgia, LLC	N/A QF15-202	Cave Spring	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/14	0.85
Constellation Solar Georgia, LLC	N/A QF15-659	Dublin	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	5/30/15	0.85
Constellation Solar Georgia, LLC	N/A QF15-203	Eastanollee	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/14	0.84
Constellation Solar Georgia, LLC	N/A QF15-204	Gibson	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/14	0.62
Constellation Solar Georgia, LLC	N/A QF14-505	Sparta SF	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	5/7/14	0.85
Constellation Solar Georgia, LLC	N/A QF15-205	Summerville	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/14	0.38
Constellation Solar Georgia, LLC	N/A QF15-658	Toccoa	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	4/22/15	0.68
Constellation Solar Georgia, LLC	N/A QF15-206	Wadley	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/14	1.11
Constellation Solar Georgia, LLC	N/A QF15-207	Wrens	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/14	0.34
Exelon Generation Company, LLC	ER00-3251	Effingham GT1	Effingham County Power, LLC	Effingham County Power, LLC / Exelon Generation Company, LLC	6/1/07	SOCO	Southeast	8/27/03	163.00
Exelon Generation Company, LLC	ER00-3251	Effingham GT2	Effingham County Power, LLC	Effingham County Power, LLC / Exelon Generation Company, LLC	6/1/07	SOCO	Southeast	8/27/03	163.00
Exelon Generation Company, LLC	ER00-3251	Effingham STG1	Effingham County Power, LLC	Effingham County Power, LLC / Exelon Generation Company, LLC	6/1/07	SOCO	Southeast	8/27/03	176.00
Exelon Generation Company, LLC	ER00-3251	Franklin GT1	Southern Power Company	Southern Power Company / Exelon Generation Company, LLC	6/1/07	SOCO	Southeast	6/6/03	183.00
Exelon Generation Company, LLC	ER00-3251	Franklin GT2	Southern Power Company	Southern Power Company / Exelon Generation Company, LLC	6/1/07	SOCO	Southeast	6/6/03	183.00
Exelon Generation Company, LLC	ER00-3251	Franklin STG1	Southern Power Company	Southern Power Company / Exelon Generation Company, LLC	6/1/07	SOCO	Southeast	6/6/03	255.00
Exelon Generation Company, LLC	ER00-3251	Heard 1	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/01	SOCO	Southeast	6/29/01	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 2	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/01	SOCO	Southeast	6/29/01	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 3	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/01	SOCO	Southeast	6/29/01	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 4	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/01	SOCO	Southeast	5/31/02	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 5	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/01	SOCO	Southeast	5/31/02	157.50

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Exelon Generation Company, LLC	ER00-3251	Heard 6	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/01	SOCO	Southeast	5/31/02	157.50
Exelon Generation Company, LLC	ER00-3251	Hog Bayou	Mobile Energy LLC	Exelon Generation Company, LLC	1/1/15	SOCO	Southeast	7/11/01	230.00
Exelon Generation Company, LLC	ER00-3251	Sowega 1	Georgia Energy Cooperative	Exelon Generation Company, LLC	1/1/11	SOCO	Southeast	6/1/99	48.00
Exelon Generation Company, LLC	ER00-3251	Sowega 2	Georgia Energy Cooperative	Exelon Generation Company, LLC	1/1/11	SOCO	Southeast	6/1/99	48.00
Exelon Generation Company, LLC	ER00-3251	Washington 1	Washington County Power, LLC	Washington County Power, LLC / Exelon Generation Company, LLC	6/1/07	SOCO	Southeast	6/1/03	153.50
Exelon Generation Company, LLC	ER00-3251	Washington 4	Washington County Power, LLC	Washington County Power, LLC / Exelon Generation Company, LLC	6/1/07	SOCO	Southeast	6/1/03	153.50
Constellation Solar Arizona, LLC	N/A QF12-211	Buckeye Union HS at Estrella & Youngkers	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/7/11	3.62
Constellation Solar Arizona, LLC	N/A QF13-76	Casa Grande - Casa Verde HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/19/12	0.35
Constellation Solar Arizona, LLC	N/A QF13-75	Casa Grande - Union HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/19/12	1.79
Constellation Solar Arizona, LLC	N/A QF13-74	Casa Grande - Vista Grande HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/19/12	1.54
Constellation Solar Arizona, LLC	N/A QF13-599	Charles Bejarando	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	9/20/13	0.09
Constellation Solar Arizona, LLC	N/A QF14-498	Collier ES	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	6/30/14	0.25
Constellation Solar Arizona, LLC	N/A QF13-511	Crane School District at Centennial	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	8/1/13	0.38
Constellation Solar Arizona, LLC	N/A QF13-516	Crane School District at Crane Middle School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	8/28/13	0.38
Constellation Solar Arizona, LLC	N/A QF13-378	Crane School District at GAK	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	3/28/13	0.19
Constellation Solar Arizona, LLC	N/A QF13-377	Crane School District at Mesquite	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	3/28/13	0.17
Constellation Solar Arizona, LLC	N/A QF13-515	Crane School District at Valley Horizon	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	7/11/13	0.28
Constellation Solar Arizona, LLC	N/A QF13-537	Dysart I School District	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	6/19/13	8.81
Constellation Solar Arizona, LLC	N/A QF14-496	Isaac School District at Butler	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	7/8/14	0.21
Constellation Solar Arizona, LLC	N/A QF14-497	Lee Kornegay HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	7/9/14	0.11
Constellation Solar Arizona, LLC	N/A QF13-538	Marana School District	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	7/26/13	1.59
Constellation Solar Arizona, LLC	N/A QF13-598	Miami High School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	9/30/13	0.36
Constellation Solar Arizona, LLC	N/A QF14-499	Parkridge ES	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	7/3/14	0.42
Constellation Solar Arizona, LLC	N/A QF13-536	Peoria Unified School District	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	11/4/13	2.53
Constellation Solar Arizona, LLC	N/A QF14-27	Pueblo Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/15/13	0.24
Constellation Solar Arizona, LLC	N/A QF14-29	Salida del Sol Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/15/13	0.30
Constellation Solar Arizona, LLC	N/A QF13-514	Somerton School District at Desert Sonora	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	3/27/13	0.29

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Constellation Solar Arizona, LLC	N/A QF13-137	Somerton School District at Orange Grove	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/21/12	0.18
Constellation Solar Arizona, LLC	N/A QF13-513	Somerton School District at Somerton Middle School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	3/27/13	0.47
Constellation Solar Arizona, LLC	N/A QF13-138	Somerton School District at Tierra del Sol	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/21/12	0.22
Constellation Solar Arizona, LLC	N/A QF13-139	Somerton School District at Valle del Encanto	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/21/12	0.17
Constellation Solar Arizona, LLC	N/A QF14-26	Suverkrup Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/15/13	0.27
Constellation Solar Arizona, LLC	N/A QF13-376	Vail Unified School District at Andrada	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	4/5/13	0.33
Constellation Solar Arizona, LLC	N/A QF13-378	Vail Unified School District at Mesquite Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	4/5/13	0.23
Constellation Solar Arizona, LLC	N/A QF13-380	Vail Unified School District at OVMS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	4/19/13	0.25
Constellation Solar Arizona, LLC	N/A QF15-163	Western Peaks ES	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	10/16/14	0.47
Constellation Solar Arizona, LLC	N/A QF15-162	Willow Canyon HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	10/15/14	0.44
Mohave Sunrise Solar I LLC	N/A QF15-161	Mohave Electric at Fort Mohave	Mohave Sunrise Solar I LLC	Mohave Sunrise Solar I LLC	N/A	APS	Southwest	2nd Qtr 2015	4.56
Sacramento PV Energy, LLC	N/A QF11-329	SMUD at Fleshman SF	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	11/19/11	3.08
Sacramento PV Energy, LLC	N/A QF11-330	SMUD at Grundman SF	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	12/28/11	18.50
Sacramento PV Energy, LLC	N/A QF11-331	SMUD at Lawrence SF	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	12/30/11	1.03
Sacramento PV Energy, LLC	N/A QF11-332	SMUD at Van Conett SF	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	12/20/11	3.08
2014 ESA Project Company, LLC	ER15-1496 (pending)	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	N/A	CAISO	Southwest	12/31/14	7.40
AV Solar Ranch 1, LLC	ER12-2178	Antelope Valley SF	AV Solar Ranch 1, LLC	AV Solar Ranch 1, LLC	N/A	CAISO	Southwest	12/28/12	241.50
California PV Energy, LLC	N/A QF14-322	Palmdale Marie Kerr Park E2	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/14	0.06
California PV Energy, LLC	N/A QF15-76	Alto Loma HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/23/14	0.56
California PV Energy, LLC	N/A QF14-214	Castaic Elementary School	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	4/8/14	0.12
California PV Energy, LLC	N/A QF14-212	Castaic Middle School	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	4/9/14	0.28
California PV Energy, LLC	N/A QF15-78	Chaffey HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	1/30/15	0.54
California PV Energy, LLC	N/A QF15-79	Colony HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	1/27/15	0.76
California PV Energy, LLC	N/A QF15-80	Etiwanda HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/31/14	0.72
California PV Energy, LLC	N/A QF14-28	Ironhouse Sanitary District	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/24/14	0.85
California PV Energy, LLC	N/A QF14-335	Keppel Academy	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/14	0.11

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
California PV Energy, LLC	N/A QF14-329	Keppel Alpine North ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/14	0.12
California PV Energy, LLC	N/A QF14-331	Keppel Alpine South ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/14	0.05
California PV Energy, LLC	N/A QF14-330	Keppel Antelope ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/14	0.09
California PV Energy, LLC	N/A QF14-333	Keppel Gibson ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/14	0.15
California PV Energy, LLC	N/A QF14-332	Keppel Lake Los Angleles	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/14	0.13
California PV Energy, LLC	N/A QF14-334	Keppel Pearblossom ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/14	0.13
California PV Energy, LLC	N/A QF14-213	Live Oak Elementary School,	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	4/9/14	0.12
California PV Energy, LLC	N/A QF15-81	Los Osos HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	1/27/15	0.76
California PV Energy, LLC	N/A QF15-82	Montclair HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	1/30/15	0.76
California PV Energy, LLC	N/A QF14-211	Northlake Hills Elementary School	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	4/8/14	0.13
California PV Energy, LLC	N/A QF13-602	Oltmans SCE at Champagne SF	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/20/13	1.15
California PV Energy, LLC	N/A QF13-601	Oltmans SCE at Jurupa SF	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/20/13	1.71
California PV Energy, LLC	N/A QF15-83	Ontario HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/31/14	0.33
California PV Energy, LLC	N/A QF14-325	Palmdale Cultural Center	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/14	0.06
California PV Energy, LLC	N/A QF14-324	Palmdale Development Services Bldg	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/14	0.12
California PV Energy, LLC	N/A QF14-326	Palmdale Library	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/14	0.07
California PV Energy, LLC	N/A QF14-321	Palmdale Marie Kerr Park E1	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/14	0.07
California PV Energy, LLC	N/A QF14-323	Palmdale Marie Kerr Park E3	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/14	0.05
California PV Energy, LLC	N/A QF14-328	Palmdale Recreation Center	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/14	0.05
California PV Energy, LLC	N/A QF14-327	Palmdale Water Park	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/14	0.28
California PV Energy, LLC	N/A QF15-84	Rancho Cucamonga HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/29/14	0.42
Constellation Solar California, LLC	N/A QF10-656	General Motors Corp. at Fontana, Ca.	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	12/1/07	0.80
Constellation Solar California, LLC	N/A QF10-657	GSA, PBS, Pacific Service Center at Sacramento, Ca.	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	3/1/08	0.44
Constellation Solar California, LLC	N/A QF10-658	Kawneer Co., Inc. (Alcoa)	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	10/1/07	0.50
Constellation Solar California, LLC	N/A QF10-665	Univ of San Francisco	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	4/1/08	0.42
Luz Solar Partners IV	N/A QF86-736	SEGS IV SF	Luz Solar Partners IV	Luz Solar Partners IV	N/A	CAISO	Southwest	12/1/86	36.00
Luz Solar Partners V	N/A QF87-402	SEGS V SF	Luz Solar Partners V	Luz Solar Partners V	N/A	CAISO	Southwest	10/1/87	36.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Luz Solar Partners VI	N/A QF88-33	SEGS VI SF	Luz Solar Partners VI	Luz Solar Partners VI	N/A	CAISO	Southwest	12/1/88	36.00
Exelon Generation Company, LLC	ER00-3251	Green Country 1	Green Country OP Services LLC	Exelon Generation Company, LLC	2/11/02	SPP	SPP	2/11/02	262.00
Exelon Generation Company, LLC	ER00-3251	Green Country 2	Green Country OP Services LLC	Exelon Generation Company, LLC	2/11/02	SPP	SPP	2/11/02	262.00
Exelon Generation Company, LLC	ER00-3251	Green Country 3	Green Country OP Services LLC	Exelon Generation Company, LLC	2/11/02	SPP	SPP	2/11/02	261.00
Exelon Wind 1, LLC	N/A QF05-114	Exelon Wind 1 WF	Exelon Wind 1, LLC	Exelon Wind 1, LLC	N/A	SPP	SPP	12/31/05	10.00
Exelon Wind 10, LLC	N/A QF07-55	Exelon Wind 10 WF	Exelon Wind 10, LLC	Exelon Wind 10, LLC	N/A	SPP	SPP	7/1/08	10.00
Exelon Wind 11, LLC	N/A QF07-56	Exelon Wind 11 WF	Exelon Wind 11, LLC	Exelon Wind 11, LLC	N/A	SPP	SPP	7/1/08	10.00
Exelon Wind 2, LLC	N/A QF05-116	Exelon Wind 2 WF	Exelon Wind 2, LLC	Exelon Wind 2, LLC	N/A	SPP	SPP	12/31/05	10.00
Exelon Wind 3, LLC	N/A QF05-115	Exelon Wind 3 WF	Exelon Wind 3, LLC	Exelon Wind 3, LLC	N/A	SPP	SPP	12/31/05	10.00
Exelon Wind 4, LLC	ER07-1202 QF03-13	Exelon Wind 4 WF	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	12/15/06	79.80
Exelon Wind 5, LLC	N/A QF06-289	Exelon Wind 5 WF	Exelon Wind 5, LLC	Exelon Wind 5, LLC	N/A	SPP	SPP	10/4/05	10.00
Exelon Wind 6, LLC	N/A QF06-290	Exelon Wind 6 WF	Exelon Wind 6, LLC	Exelon Wind 6, LLC	N/A	SPP	SPP	11/1/06	10.00
Exelon Wind 7, LLC	N/A QF07-46	Exelon Wind 7 WF	Exelon Wind 7, LLC	Exelon Wind 7, LLC	N/A	SPP	SPP	7/1/08	10.00
Exelon Wind 8, LLC	N/A QF07-53	Exelon Wind 8 WF	Exelon Wind 8, LLC	Exelon Wind 8, LLC	N/A	SPP	SPP	7/1/08	10.00
Exelon Wind 9, LLC	N/A QF07-54	Exelon Wind 9 WF	Exelon Wind 9, LLC	Exelon Wind 9, LLC	N/A	SPP	SPP	7/1/08	10.00
Greensburg Wind Farm, LLC	N/A QF10-291	Greensburg WF	Greensburg Wind Farm, LLC	Greensburg Wind Farm, LLC	N/A	SPP	SPP	3/5/10	12.50
High Plains Wind Power, LLC	N/A QF07-257	High Plains WF	High Plains Wind Power, LLC	High Plains Wind Power, LLC	N/A	SPP	SPP	3/31/08	10.00
Shooting Star Wind Project, LLC	ER12-1829	Shooting Star WF	Shooting Star Wind Project, LLC	Shooting Star Wind Project, LLC	N/A	SPP	SPP	9/29/12	104.00
Wildcat Wind, LLC	ER12-1223 QF12-412	Wildcat WF	Wildcat Wind, LLC	Wildcat Wind, LLC	N/A	SPP	SPP	7/1/12	27.30

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Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas Storage

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
Constellation Mystic Power, LLC	Limited & discrete interconnection facilities[1]	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon Framingham, LLC	Limited & discrete interconnection facilities[1]	Exelon Framingham, LLC	Exelon Framingham, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon New Boston, LLC	Limited & discrete interconnection facilities[1]	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon West Medway, LLC	Limited & discrete interconnection facilities[1]	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon Wyman, LLC	Limited & discrete interconnection facilities[1]	Exelon Wyman, LLC	Exelon Wyman, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Holyoke Solar LLC	Limited & discrete interconnection facilities[1]	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Nine Mile Point Nuclear Station, LLC	Limited & discrete interconnection facilities[1]	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	N/A (OATT Waiver)

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
R.E. Ginna Nuclear Power Plant, LLC	Limited & discrete interconnection facilities[1]	R.E. Ginna Nuclear Power Plant, LLC	R.E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	N/A (OATT Waiver)
Baltimore Gas and Electric Company	Combined 115kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	695.85 combined miles
Baltimore Gas and Electric Company	Combined 138kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	54.44 combined miles
Baltimore Gas and Electric Company	Combined 230kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	320.97 combined miles
Baltimore Gas and Electric Company	Combined 500kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	217.42 combined miles
Baltimore Gas and Electric Company	Intrastate Gas Transmission	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	approx. 165 combined miles
Calvert Cliffs Nuclear Power Plant, LLC	Limited & discrete interconnection facilities[1]	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Commonwealth Edison Company	Electric Transmission Combined 765 kV Lines	Commonwealth Edison Company	PJM	N/A	PJM	Northeast	89.59 combined miles
Commonwealth Edison Company	Electric Transmission Combined 345 kV Lines	Commonwealth Edison Company	PJM	N/A	PJM	Northeast	2,634.29 combined miles

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
Commonwealth Edison Company	Electric Transmission Combined 138 kV Lines	Commonwealth Edison Company	PJM	N/A	PJM	Northeast	2,877.02 combined miles
Criterion Power Partners, LLC	Limited & discrete interconnection facilities[1]	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Exelon Solar Chicago LLC	Limited & discrete interconnection facilities[1]	Exelon Solar Chicago LLC	Exelon Solar Chicago LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Fourmile Wind Energy, LLC	Limited & discrete interconnection facilities[1]	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Handsome Lake Energy, LLC	Limited & discrete interconnection facilities[1]	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
PECO Energy Company	Electric Transmission 500 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	316.23 combined miles
PECO Energy Company	Electric Transmission Combined 200/220 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	503.05 combined miles
PECO Energy Company	Electric Transmission Combined 132 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	127.70 combined miles
PECO Energy Company	Electric Transmission Combined 66 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	169.54 combined miles

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
PECO Energy Company	Electric Transmission Combined 13.2 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	0.47 combined miles
PECO Energy Company	Intrastate Gas Transmission	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	31 combined miles
PECO Energy Company	Intrastate Gas Storage (LNG)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	1,200 mmcf
Cassia Gulch Wind Park, LLC	Limited & discrete interconnection facilities[1]	Cassia Gulch Wind Park, LLC	Cassia Gulch Wind Park, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
High Mesa Energy, LLC	Limited & discrete interconnection facilities[1]	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
Tuana Springs Energy, LLC	Limited & discrete interconnection facilities[1]	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
Beebe 1B Renewable Energy, LLC and Beebe Renewable Energy, LLC ("Beebe")[2]	Limited & discrete interconnection facilities[1]	Beebe	Beebe	N/A	MISO	Central	N/A (OATT Waiver)
Harvest Windfarm, LLC	Limited & discrete interconnection facilities[1]	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	N/A (OATT Waiver)
Michigan Wind 1, LLC	Limited & discrete interconnection facilities[1]	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	N/A (OATT Waiver)

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
CER Generation, LLC	Limited & discrete interconnection facilities[1]	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	N/A (OATT Waiver)
Constellation Power Source Generation, LLC	Limited & discrete interconnection facilities[1]	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Exelon Generation Company, LLC	Limited & discrete interconnection facilities[1]	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	Various	Various	N/A (OATT Waiver)
Cow Branch Wind Power, L.L.C.	Limited & discrete interconnection facilities[1]	Cow Branch Wind Power, LLC	Cow Branch Wind Power, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
CR Clearing, LLC	Limited & discrete interconnection facilities[1]	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
Wind Capital Holdings, LLC	Limited & discrete interconnection facilities[1]	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
AV Solar Ranch 1, LLC	Limited & discrete interconnection facilities[1]	AV Solar Ranch 1, LLC	AV Solar Ranch 1, LLC	N/A	CAISO	Southwest	N/A (OATT Waiver)
Exelon Wind 4, LLC	Limited & discrete interconnection facilities[1]	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	N/A (OATT Waiver)

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[1] These facilities are included because waiver of Order Nos. 888, 889, 890, their implementing regulations, and the requirements of Part 358 of FERC's regulations has been sought with respect to them.

[2] Beebe 1B Renewable Energy, LLC and Beebe Renewable Energy, LLC share certain interconnection facilities.

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Attachment C:

Redlined Tariffs

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CASSIA GULCH WIND PARK, LLC
FERC ELECTRIC TARIFF

1. Availability: Cassia Gulch Wind Park, LLC ("Cassia Gulch" or "Seller") makes electric energy, capacity, and ancillary services available under this Tariff to any purchaser for resale, except as prohibited below.

   Ancillary Services - Third Party Provider

   Third-party ancillary services: Seller offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

2. Applicability: This schedule is applicable to all wholesale sales of energy, capacity, and ancillary services by Seller not otherwise subject to a particular rate schedule of Seller.

3. Rates: All sales shall be made at rates established by agreement between the purchaser and Seller.

4. Other Terms and Conditions: All other terms and conditions shall be established by agreement between the purchaser and Cassia Gulch.

5. Compliance with Commission Regulations: ~~Cassia Gulch~~Seller shall comply with the provisions of 18 C.F.R. Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning ~~Cassia Gulch~~Seller's market-based rate authority, including orders in which the Commission authorizes ~~Cassia Gulch~~Seller to engage in affiliate sales under this tariff or otherwise restricts or limits ~~Cassia Gulch~~Seller's market-based rate authority. Failure to comply with the applicable provisions of 18 C.F.R. Part 35, Subpart H, and with any orders of the Commission concerning ~~Cassia Gulch~~Seller's market-based rate authority, will constitute a violation of this tariff.

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6. Limitations and Exemptions Regarding Market-Based Rate Authority: The Commission granted Cassia Gulch in Docket No. ER10-75-000 the following waivers and exemptions in connection with its market-based rate authority: (i) waiver of Subparts B and C of Part 35 regarding the filing of rate schedules, except Sections 35.12(a), 35.13(b), 35.15 and 35.16; (ii) waiver of the accounting and related reporting requirements under Part 41, Part 101 and Part 141, except sections 141.14 and 141.15, of the Commission's regulations; and (iii) blanket approval under Section 204 of the Federal Power Act, 16 U.S.C. § 824c, and Part 34 of the Commission's regulations for all future issuances of securities and debt and assumptions and liabilities.

   The Commission has granted waiver of its code of conduct and affiliate sales restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC ¶ 61,140 at 61,425 (2000), *on reh'g*, 95 FERC ¶ 61,309 (2001); *AmerGen VT, LLC*, 90 FERC ¶ 61,307 at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co.*, 91 FERC ¶ 61,270 (2000).

7. Seller Category: Cassia Gulch is a Category 1 Seller in the Central, Northeast, Southeast, Southwest, and Southwest Power Pool ~~Northwest and Southwest~~ regions, and a Category 2 Seller in the Northwest region ~~Northeast, Southeast, Central, and Southwest Power Pool regions~~, as defined in 18 C.F.R. § 35.36(a).

8. Effective Date: This Tariff shall be effective on and after the date on which the Commission permits it to become effective.

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CONSTELLATION ENERGY COMMODITIES GROUP MAINE, LLC
FERC ELECTRIC TARIFF

1. Availability. Constellation Energy Commodities Group Maine, LLC ("CCG Maine" or "Seller") will make available under this Tariff for sales to any purchaser for resale, including bilateral sales, into wholesale markets administered by an ISO or RTO that has market monitoring and mitigation measures approved by the Commission: (i) electric capacity; (ii) electric energy; and (iii) the following Ancillary Services:

a. ~~NYISO~~New York: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc~~NYISO~~.

b. New England~~ISO NE~~: Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO New England, Inc~~ISO NE~~.

c. PJM: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, LLC ("PJM") and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

d. California~~CAISO~~: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation ("CAISO") and to others that are self-supplying ancillary services to the CAISO.

e. Southwest Power Pool: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Southwest Power Pool, Inc. (SPP) and to others that are self- supplying ancillary services to SPP.

2. Applicability. This Tariff is applicable to all wholesale sales of each of the services listed in Paragraph 1 of this Tariff to the extent such sales are not otherwise subject to a particular Tariff of CCG Maine.

3. **Rates.** All sales shall be made at the rates established between the purchaser and CCG Maine.

4. **Compliance with Commission Regulations.** Seller shall comply with the provisions of 18 CFR Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 CFR Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

5. **Limitations and Exemptions Regarding Market-Based Rate Authority.**

   - The Commission has granted waiver of its code of conduct and affiliate sales restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC ¶ 61,140 at 61,425 (2000), *on reh'g*, 95 FERC ¶ 61,309 (2001); *AmerGen VT, LLC*, 90 FERC ¶ 61,307 at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co*., 91 FERC ¶ 61,270 (2000).

   - Seller has requested and been granted (1) waiver of Subparts B and C of Part 35 of the Commission's regulations, except as to sections 35.12(a), 35.13(b), 35.15 and 35.16; (2) waiver of Parts 41, 101 and 141 of the Commission's accounting and reporting regulations, with the exception of 18 C.F.R. §§ 141.14, 141.15 (1999); and (3) blanket authorization for all future issuances of securities or assumptions of liabilities pursuant to Part 34 of the Commission's regulations. *See Constellation Power Source Maine, LLC*, Docket No. ER02-699-000 (unpublished delegated letter order issued Feb. 26, 2002).

6. **Other Terms and Conditions.** All other terms and conditions of sale shall be established between the purchaser and CCG Maine.

7. **Effective Date.** This Tariff shall become effective upon the date specified by the Commission.

8. **Seller Category.** Seller is a Category 1 Seller in the ~~Northwest and~~ Southwest region~~s~~, and a Category 2 Seller in the Northeast, Northwest, Southeast, Central, and Southwest Power Pool regions, as ~~those categories are~~ defined in 18 C.F.R. § 35.36(a).

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WHOLESALE MARKET-BASED RATE TARIFF

OF

CONSTELLATION ENERGY SERVICES, INC.

PROVIDING FOR

SALES OF CAPACITY, ENERGY AND/OR ANCILLARY SERVICES

**MARKET-BASED RATE TARIFF
OF
CONSTELLATION ENERGY SERVICES, INC.
PROVIDING FOR
SALES OF CAPACITY, ENERGY AND/OR ANCILLARY SERVICES**

I. DEFINITIONS

The following words and terms used herein shall be understood to have the following meanings:

1. Buyer: A purchaser of electric capacity, energy and/or ancillary services under this Tariff.

2. Commission: "Commission" means the Federal Energy Regulatory Commission or such successor Federal regulatory agency as may have jurisdiction over this Tariff.

3. Parties: "Parties" mean Seller and Buyer that have entered into a Transaction pursuant to this Tariff.

4. Seller: Constellation Energy Services, Inc.

5. Tariff: "Tariff" means this market-based rate tariff, as amended from time to time.

6. Transaction: "Transaction" means a particular transaction agreed to by the Parties under this Tariff.

II. SALES OF ELECTRIC CAPACITY, ENERGY AND/OR ANCILLARY SERVICES

1. Electric Capacity and Energy: Seller may sell electric capacity and/or energy to Buyer under this Tariff from time to time at rates, terms and conditions established by the agreement of the Parties. All such Transactions shall be voluntary.

2. Ancillary Services: Seller may sell the following ancillary services to Buyer under this Tariff from time to time at rates, terms and conditions established by the agreement of the Parties. All such Transactions shall be voluntary.

a. New England: Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO New England, Inc.

b. PJM: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, L.L.C. ("PJM") and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

c. New York: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc.

d. California: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation ("CAISO") and to others that are self-supplying ancillary services to the CAISO.

e. MISO: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Midcontinent Independent System Operator, Inc. (MISO) and to others that are self-supplying ancillary services to MISO.

f. Southwest Power Pool: Seller offers regulation service and operating

reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Southwest Power Pool, Inc. (SPP) and to others that are self-supplying ancillary services to SPP.

g. Ancillary Services – Third-Party Provider
Third-party ancillary services: Seller offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, i.e., where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

III. RATES

All sales shall be made at rates established by agreement between Seller and Buyer.

IV. OTHER TERMS AND CONDITIONS

All other terms and conditions shall be established by agreement between Seller and Buyer.

V. EFFECTIVE DATE

This Tariff is effective on the date specified by the Commission.

VI. REVISIONS TO THE TARIFF

Seller may file revisions to this Tariff by notifying Buyer in writing and by unilaterally making the appropriate filing with the Commission pursuant to the provisions

of Section 205 of the Federal Power Act; provided, however, that such revision shall not affect the rates, terms and conditions of Transactions entered into prior to the date of such revision, unless otherwise agreed by the Parties.

VII. COMPLIANCE WITH THE COMMISSION REGULATIONS

Seller shall comply with the provisions of 18 CFR Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 CFR Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

VIII. LIMITATIONS AND EXEMPTIONS REGARDING MARKET-BASED RATE AUTHORITY

The Commission has granted waiver of its code of conduct and affiliate sales restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC 61,140 at 61,425 (2000), *on reh'g*, 95 FERC 61,309 (2001); *AmerGen VT, LLC*, 90 FERC 61,307 at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co.*, 91 FERC 61,270 (2000). The Commission also granted Seller the following waivers and blanket authorization: (a) waiver of Subparts B and C of Part 35 of the Commission's regulations requiring the filing of cost-of-service information, except for sections 35.12(a), 35.13(b), 35.15 and 35.16; (b) waiver of the accounting and other requirements Parts 41, 101 and 141, except sections 141.14 and 141.15, of the Commission's regulations; and (c) blanket approval as to Section 204 of the Federal Power Act and Part 34 of the Commission's regulations for all future issuances of securities and assumption of liabilities. *Wisconsin Public Service Corp., et al.*, 75 FERC 61,057 (1996) (Docket No. ER96-1088-000).

IX. SELLER CATEGORY

Seller is a Category 1 seller in the Southwest region, and a Category 2 seller in the Central, Northeast, Northwest, Southeast, and Southwest Power Pool rRegions ~~and a Category 1 seller in the Northwest and Southwest Regions,~~ , as defined in 18 C.F.R. § 35.36(a).

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WHOLESALE MARKET-BASED RATE TARIFF

OF

CONSTELLATION ENERGY SERVICES OF NEW YORK, INC.

PROVIDING FOR

SALES OF CAPACITY AND ENERGY
MARKET-BASED RATE TARIFF OF
CONSTELLATION ENERGY SERVICES OF NEW YORK, INC.
PROVIDING FOR
SALES OF CAPACITY AND ENERGY

I. DEFINITIONS

The following words and terms used herein shall be understood to have the following meanings:

1. Buyer: A purchaser of electric capacity, energy and/or ancillary services under this Tariff.

2. Commission: "Commission" means the Federal Energy Regulatory Commission or such successor Federal regulatory agency as may have jurisdiction over this Tariff.

3. Parties: "Parties" mean Seller and Buyer that have entered into a Transaction pursuant to this Tariff.

4. Seller: Constellation Energy Services of New York, Inc.

5. Tariff: "Tariff" means this market-based rate tariff, as amended from time to time.

6. Transaction: "Transaction" means a particular transaction agreed to by the Parties under this Tariff.

II. SALES OF ELECTRIC CAPACITY, ENERGY AND/OR ANCILLARY SERVICES

1. Electric Capacity and Energy: Seller may sell electric capacity and/or energy to Buyer under this Tariff from time to time at rates, terms and conditions established by the agreement of the Parties. All such Transactions shall be voluntary.

2. Ancillary Services: Seller may sell the following ancillary services to Buyer under this Tariff from time to time at rates, terms and conditions established by the agreement of the Parties. All such Transactions shall be voluntary.

a. New England: Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO New England, Inc.

b. PJM: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, L.L.C. ("PJM") and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

c. New York: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc.

d. California: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation ("CAISO") and to others that are self-supplying ancillary services to the CAISO.

e. MISO: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Midcontinent Independent System Operator, Inc. (MISO) and to others that are self-supplying ancillary services to MISO.

f. Southwest Power Pool: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute

supplemental reserve) for sale to the Southwest Power Pool, Inc. (SPP) and to others that are self-supplying ancillary services to SPP.

g. Ancillary Services – Third-Party Provider

Third-party ancillary services: Seller offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, i.e., where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

III. RATES

All sales shall be made at rates established by agreement between Seller and Buyer.

IV. OTHER TERMS AND CONDITIONS

All other terms and conditions shall be established by agreement between Seller and Buyer.

V. EFFECTIVE DATE

This Tariff is effective on the date specified by the Commission.

VI. REVISIONS TO THE TARIFF

Seller may file revisions to this Tariff by notifying Buyer in writing and by

unilaterally making the appropriate filing with the Commission pursuant to the provisions of Section 205 of the Federal Power Act; provided, however, that such revision shall not affect the rates, terms and conditions of Transactions entered into prior to the date of such revision, unless otherwise agreed by the Parties.

VII. COMPLIANCE WITH THE COMMISSION REGULATIONS

Seller shall comply with the provisions of 18 CFR Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 CFR Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

VIII. LIMITATIONS AND EXEMPTIONS REGARDING MARKET-BASED RATE AUTHORITY

The Commission has granted waiver of its code of conduct and affiliate sales restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC 61,140 at 61,425 (2000), *on reh'g*, 95 FERC 61,309 (2001); *AmerGen VT, LLC*, 90 FERC 61,307 at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co.*, 91 FERC 61,270 (2000). The Commission also granted Seller the following waivers and blanket authorization: (a) waiver of Subparts B and C of Part 35 of the Commission's regulations requiring the filing of cost-of-service information, except for sections 35.12(a), 35.13(b), 35.15 and 35.16; (b) waiver of the accounting and other requirements Parts 41, 101 and 141, except sections 141.14 and 141.15, of the Commission's regulations; and (c) blanket approval as to Section 204 of the Federal Power Act and Part 34 of the Commission's regulations for all future issuances of securities and assumption of liabilities. *See Advantage Energy, Inc.*, Docket No. ER97-2758-000 (July 14, 1997) (unpublished letter order).

IX. SELLER CATEGORY

Seller is a Category 1 seller in the Southwest region, and a Category 2 seller in the Central, Northeast, Northwest, Southeast, and Southwest Power Pool rRegions ~~and a Category 1 seller in the Northwest and Southwest Regions,~~ as defined in 18 C.F.R. § 35.36(a).

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CONSTELLATION NEWENERGY, INC.

FERC ELECTRIC TARIFF NO. 1

1. Availability: Constellation NewEnergy, Inc. ("Constellation NewEnergy" or "Seller") makes electric energy and capacity available under this tariff to any purchaser for resale. Constellation NewEnergy also separately makes available for wholesale sales to purchasers with whom Constellation NewEnergy has contracted the following ancillary services:

(A) ~~Within the market administered by PJM Interconnection, L.L.C. ("PJM")~~: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, LLC ("PJM") and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

(B) ~~Within the markets administered by the Independent System Operator of~ New England ("ISO-NE"): Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO New England, Inc~~ISO-NE~~.

(C) ~~Within the markets administered by the~ New York ~~Independent System Operator ("NYISO")~~: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc~~NYISO~~.

(D) ~~Within the markets administered by the~ California ~~Independent System Operator ("CAISO")~~: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation ("CAISO") and to others that are self-supplying ancillary services to the CAISO.

(E) ~~Within the markets administered by the Midcontinent Independent System Operator ("MISO")~~: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Midcontinent Independent System Operator, Inc. (MISO) and to

others that are self-supplying ancillary services to MISO.

(F) ~~*Within the markets administered by the*~~ *Southwest Power Pool*: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Southwest Power Pool, Inc. (SPP) and to others that are self- supplying ancillary services to SPP.

(G) Ancillary Services – Third Party Provider

Third-party ancillary services: Seller offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, i.e., where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

2. Applicability: This tariff is applicable to wholesale sales of each of the services listed in Paragraph 1 by Constellation NewEnergy not otherwise subject to a particular tariff of Constellation NewEnergy.

3. Rates: All sales shall be made at rates established by agreement between the purchaser and Constellation NewEnergy.

4. Other Terms and Conditions: All other terms and conditions shall be established by agreement between the purchaser and Constellation NewEnergy.

5. Compliance with Commission Regulations: Seller shall comply with the provisions of 18 CFR Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 CFR Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

6. Limitations and Exemptions Regarding Market-Based Rate Authority:

   - The Commission has granted waiver of its code of conduct and affiliate sales restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC ¶ 61,140 at 61,425 (2000), *on reh'g*, 95 FERC ¶ 61,309 (2001); *AmerGen VT, LLC*, 90 FERC ¶ 61,307 at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co.*, 91 FERC ¶ 61,270 (2000).

   - Seller has requested and been granted (1) waiver of Subparts B and C of Part 35 of the Commission's regulations, except as to sections 35.12(a), 35.13(b), 35.15 and 35.16; (2) waiver of Parts 41,101 and 141, except sections 141.14 and 141.15, of the Commission's accounting and reporting regulations; and (3) blanket authorization for all future issuances of securities or assumptions of liabilities pursuant to Part 34 of the Commission's regulations. *See NEV, L.L.C.*, 81 FERC ¶ 61,186 (1997).

7. Effective Date: This tariff shall be effective on the date specified by the Federal Energy Regulatory Commission.

8. Seller Category: Seller is a Category 1 Seller in the ~~Northwest and~~ Southwest region~~s~~, and a Category 2 Seller in the Northeast, Northwest, Southeast, Central, and Southwest Power Pool regions, as ~~those categories are~~ defined in 18 C.F.R. § 35.36(a).

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Exelon Generation Company, LLC

Market-Based Rate Tariff

1. Availability and Character of Service

Exelon Generation Company, LLC ("Exelon Generation" or "Seller") may sell electric capacity and/or energy under this tariff in amounts, at levels of firmness or priorities of service, for periods of service, and under such other terms and conditions, all as established by agreement between Exelon Generation and the Customer under a transaction agreement hereunder.

2. Ancillary Services

PJM: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, L.L.C. ("PJM") and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

New York: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc.

New England: Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO New England, Inc.

California: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation ("CAISO") and to others that are self-supplying ancillary services to the CAISO.

MISO: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Midcontinent Independent System Operator, Inc. (MISO) and to others that are self-supplying ancillary services to MISO.

Southwest Power Pool: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Southwest Power Pool, Inc. (SPP) and to others that are self- supplying ancillary services to SPP.

3. Ancillary Services - Third Party Provider

Third-party ancillary services: Seller offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, i.e., where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

4. Rates

All rates for sales under this rate schedule shall be established by agreement between Exelon Generation and Customer.

5. General Terms and Conditions:

A. Acceptance of service hereunder by a Customer shall bind Customer to the provisions of this tariff and to the terms of a transaction agreement between or among the parties.

B. The rights of Exelon Generation and a customer to seek changes to the rates or other terms and conditions of service initially agreed upon between them shall be governed by parties' transaction agreement.

C. Compliance with Commission Regulations: Seller shall comply with the provisions of 18 C.F.R. Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 C.F.R. Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

D. Limitations and Exemptions Regarding Market-Based Rate Authority: The Commission has granted waiver of its code of conduct and affiliate sales

restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC ¶ 61,140 at 61,425 (2000), *on reh'g*, 95 FERC ¶ 61,309 (2001); *AmerGen VT, LLC*, 90 FERC ¶ 61,307 at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co.*, 91 FERC ¶ 61,270 (2000). The Commission also granted Seller the following waivers and blanket authorization: (a) waiver of Subparts B and C of Part 35 of the Commission's regulations requiring the filing of cost-of-service information, except for sections 35.12(a), 35.13(b), 35.15 and 35.16; (b) waiver of the accounting and other requirements Parts 41, 101 and 141, except sections 141.14 and 141.15, of the Commission's regulations; and (c) blanket approval as to Section 204 of the Federal Power Act and Part 34 of the Commission's regulations for all future issuances of securities and assumption of liabilities. *See Exelon Generation Co., LLC*, 93 FERC ¶ 61,140, at 61,427 (2000); *Exelon Generation Co., LLC*, Docket No. ER01-2794-000 (Oct. 3, 2001) (unreported) (accepting Tariff No. 2 under Exelon Generation's market based rate authority).

E. Seller Category: Seller is a Category 1 Seller in the Southwest region, and a Category 2 Seller in the Central, Northeast, Northwest, Southeast, and Southwest Power Pool regions~~, and a Category 1 Seller in the Southwest and Northwest regions~~, as defined in 18 C.F.R. § 35.36(a).

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FERC Electric Tariff, Volume No. 1

Market Based Rate Tariff

I. Availability

Seller makes electric energy, capacity, and ancillary services available under this tariff to any purchaser with whom Seller has contracted, except as prohibited below.

II. Rates

All sales shall be made at rates established by agreement between the purchaser and Seller.

III. Other Terms and Conditions

All other terms and conditions of sale shall be established by agreement between the purchaser and Seller.

IV. Seller Category

Seller is a Category 1 Seller in the ~~Northwest and~~ Central, Northeast, Southeast, Southwest, and Southwest Power Pool ~~Southwest~~ , ~~-~~regions and a Category 2 Seller in the Northwest region ~~all other regions~~, as ~~those Categories are~~ defined in 18 C.F.R. § 35.36(a).

V. Compliance with Commission Regulations

Seller shall comply with the provisions of 18 C.F.R. Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning seller's market-based rate authority, including orders in which the Commission authorizes seller to engage in affiliate sales under this tariff or otherwise restricts or limits the seller's market-based rate authority. Failure to comply with the applicable provisions of 18 C.F.R. Part 35, Subpart H, and with any orders of the Commission concerning seller's market-based rate authority, will constitute a violation of this tariff.

VI. Limitations and Exemptions Regarding Market-Based Rate Authority

In *High Mesa Energy, LLC*, ER12-2528-000 (2012):

- The Commission has granted waiver of its code of conduct and affiliate sales restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC ¶ 61,140, at 61,425 (2000), *on reh'g*, 95 FERC ¶ 61,309 (2001); *AmerGen VT, LLC*, 90 FERC ¶ 61,307, at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co.*, 91 FERC ¶ 61,270 (2000).

- Seller has received (1) waiver of Subparts B and C of Part 35, except for sections 35.12(a), 35.13(b), 35.15 and 35.16; (2) waiver of Parts 41, 101 and 141 except sections 141.14 and 141.15; and (3) blanket authorization for all future issuances of securities or assumptions of liabilities pursuant to Part 34 of the Commission's regulations.

VII. Ancillary Services

(A) ~~Within the market administered by PJM Interconnection, LLC ("PJM")~~: Seller offers regulation and frequency response service, energy imbalance service, and operating reserve service (which includes spinning, 10-minute, and 30-minute reserves) for sale into the market administered by PJM Interconnection, L.L.C. ("PJM")~~,~~ and, where the PJM Open Access Transmission Tariff permits, the self-supply of these services to purchasers for a bilateral sale that is used to satisfy the ancillary services requirements of the PJM Office of Interconnection.

(B) ~~Within the markets administered by the Independent System Operator of~ New England ("ISO NE")~~: Seller offers regulation and frequency response service (automatic generator control), operating reserve service (which includes 10-minute spinning reserve, 10-minute non-spinning reserve, and 30-minute operating reserve service) to purchasers within the markets administered by the ISO -New England, Inc.

(C) ~~Within the markets administered by the~ New York Independent System Operator ("NYISO")~~: Seller offers regulation and frequency response service, and operating reserve service (which include 10-minute non-synchronous, 30-minute operating reserves, 10-minute spinning reserves, and 10-minute non-spinning reserves) for sale to purchasers in the market administered by the New York Independent System Operator, Inc.

(D) ~~Within the markets administered by the~ California Independent System Operator ("CAISO")~~: Seller offers regulation service, spinning reserve service, and non-spinning reserve service to the California Independent System Operator Corporation ("CAISO") and to others that are self-supplying ancillary services to the CAISO.

(E) ~~Within the markets administered by the Midcontinent System Operator ("MISO")~~: Seller offers regulation service and operating reserve service (including 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Midcontinent Independent System Operator, Inc. (MISO) and to others that are self-supplying ancillary services to MISO.

(F) Ancillary Services – Third Party Provider

Third-party ancillary services: Seller offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, i.e., where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales

to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

VIII. Effective Date

This Rate Schedule shall be effective as of the date specified by the Federal Energy Regulatory Commission.

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TUANA SPRINGS ENERGY, LLC
FERC ELECTRIC TARIFF

1. Availability: Tuana Springs Energy, LLC ("Tuana Springs" or "Seller") makes electric energy, capacity, and ancillary services available under this Tariff to any purchaser for resale, except as prohibited below.

   Ancillary Services - Third Party Provider

   Third-party ancillary services: Seller offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

2. Applicability: This schedule is applicable to all wholesale sales of energy, capacity, and ancillary services by Seller not otherwise subject to a particular rate schedule of Seller.

3. Rates: All sales shall be made at rates established by agreement between the purchaser and Tuana Springs.

4. Other Terms and Conditions: All other terms and conditions shall be established by agreement between the purchaser and Tuana Springs.

5. Compliance with Commission Regulations: ~~Tuana Springs~~Seller shall comply with the provisions of 18 C.F.R. Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning ~~Tuana Spring~~Seller~~s~~'s market-based rate authority, including orders in which the Commission authorizes ~~Tuana Springs~~Seller to engage in affiliate sales under this tariff or otherwise restricts or limits ~~Tuana Springs~~Seller's market-based rate authority. Failure to comply with the applicable provisions of 18 C.F.R. Part 35, Subpart H, and with any orders of the Commission concerning ~~Tuana Springs~~Seller's~~'~~ market-based rate authority, will constitute a violation of this tariff.

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6. Limitations and Exemptions Regarding Market-Based Rate Authority: The Commission granted Tuana Springs in Docket No. ER10-87-000 the following waivers and exemptions in connection with its market-based rate authority: (i) waiver of Subparts B and C of Part 35 regarding the filing of rate schedules, except Sections 35.12(a), 35.13(b), 35.15 and 35.16; (ii) waiver of the accounting and related reporting requirements under Part 41, Part 101 and Part 141, except sections 141.14 and 141.15, of the Commission's regulations; and (iii) blanket approval under Section 204 of the Federal Power Act, 16 U.S.C. § 824c, and Part 34 of the Commission's regulations for all future issuances of securities and debt and assumptions and liabilities.

   The Commission has granted waiver of its code of conduct and affiliate sales restrictions for transactions between Seller and its franchised public utility affiliates. *See Exelon Generation Co.*, 93 FERC ¶ 61,140 at 61,425 (2000), *on reh'g*, 95 FERC ¶ 61,309 (2001); *AmerGen VT, LLC*, 90 FERC ¶ 61,307 at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co.*, 91 FERC ¶ 61,270 (2000).

7. Seller Category: Tuana Springs is a Category 1 Seller in the Central, Northeast, Southeast, Southwest, and Southwest Power Pool ~~Northwest and Southwest~~ regions, and a Category 2 Seller in the Northwest~~Northeast, Southeast, Central, and Southwest Power Pool regions~~ region, as defined in 18 C.F.R. § 35.36(a).

8. Effective Date: This Tariff shall be effective on and after the date on which the Commission permits it to become effective.

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Document Content(s)

Exelon MBR Entities State Line CIS 4.30.15.PDF.....1-83

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July 30, 2015

VIA ELECTRONIC FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: **AV Solar Ranch 1, LLC, Docket No. ER12-2178-___**
Baltimore Gas and Electric Company, Docket No. ER10-2172-___
Beebe 1B Renewable Energy, LLC, Docket No. ER14-2144-___
Beebe Renewable Energy, LLC, Docket No. ER12-2311-___
Calvert Cliffs Nuclear Power Plant, LLC, Docket No. ER10-2179-___
Cassia Gulch Wind Park, LLC, Docket No. ER11-2016-___
CER Generation, LLC, Docket No. ER10-2184-___
Commonwealth Edison Company, Docket No. ER10-1048-___
Constellation Energy Commodities Group Maine, LLC, Docket No. ER10-2192-__
Constellation Energy Services, Inc., Docket No. ER15-1537-___
Constellation Energy Services of New York, Inc., Docket No. ER15-1539-___
Constellation Mystic Power, LLC, Docket No. ER11-2056-___
Constellation NewEnergy, Inc., Docket No. ER10-2178-___
Constellation Power Source Generation, LLC, Docket No. ER14-1524-___
Cow Branch Wind Power, LLC, Docket No. ER11-2014-___
CR Clearing, LLC, Docket No. ER11-2013-___
Criterion Power Partners, LLC, Docket No. ER10-3308-___
Exelon Framingham, LLC, Docket No. ER10-1020-___
Exelon Generation Company, LLC, Docket No. ER13-1536-___
Exelon New Boston, LLC, Docket No. ER10-1078-___
Exelon West Medway, LLC, Docket No. ER10-1080-___
Exelon Wind 4, LLC, Docket No. ER11-2010-___
Exelon Wyman, LLC, Docket No. ER10-1081-___
Fourmile Wind Energy, LLC, Docket No. ER14-2145-___
Handsome Lake Energy, LLC, Docket No. ER10-2180-___
Harvest II Windfarm, LLC, Docket No. ER12-2201-___
Harvest Windfarm, LLC, Docket No. ER11-2011-___
High Mesa Energy, LLC, Docket No. ER12-2528-___
Michigan Wind 1, LLC, Docket No. ER11-2009-___
Michigan Wind 2, LLC, Docket No. ER11-3989-___
Nine Mile Point Nuclear Station, LLC, Docket No. ER10-2181-___

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PECO Energy Company, Docket No. ER14-767-___
R.E. Ginna Nuclear Power Plant, LLC, Docket No. ER10-2182-___
Shooting Star Wind Project, LLC, Docket No. ER12-1829-___
Tuana Springs Energy, LLC, Docket No. ER11-2007-___
Wildcat Wind, LLC, Docket No. ER12-1223-___
Wind Capital Holdings, LLC, Docket No. ER11-2005-___
2014 ESA Project Company, LLC, Docket No. ER15-1496-___

Notice of Change in Status of the Exelon MBR Entities

Dear Secretary Bose:

Pursuant to the requirements of section 35.42 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[1] the above-captioned affiliates of Exelon Corporation ("Exelon") with market-based rate authority (the "Exelon MBR Entities") and 2014 ESA Project Company, LLC[2] submit this notice of change in status to inform the Commission of certain new affiliations with entities that own or will own generation facilities.[3]

On June 26, 2015, 2015 ESA Project Company, LLC ("Bloom PPA V") filed in Docket No. ER15-2009-000 an application seeking acceptance of a market-based rate tariff for the sale of energy, capacity, and ancillary services. Bloom PPA V is developing and will own and operate Bloom Energy Servers, which are small distributed-energy generation facilities that convert methane into electricity using direct electrochemical reaction rather than combustion. The Bloom Energy Servers are installed behind-the-meter and are used to provide energy services to third-party industrial and commercial customers. Bloom PPA V is developing Bloom Energy Servers in California (approximately 28.6 MW), Connecticut (approximately 2 MW), New Jersey (approximately 4.75 MW), and New York (approximately 4.6 MW). All of output of these Bloom Energy Servers is (or will be upon deployment of the facilities) fully committed pursuant long-term contracts with customers that will take service under retail or applicable state net-metering programs. Exelon Generation Company, LLC ("Exelon Generation") owns certain non-managing interests in Bloom PPA V. Specifically, Bloom PPA V is wholly owned by 2015 ESA Holdco, LLC ("2015 Holdco"). 2015 ESA InvestoCo, LLC owns 100% of the non-managing Class B interests in 2015 Holdco; a wholly owned subsidiary of Bloom Energy Corporation ("Bloom") owns 100% of the Class A managing interests. 2015 ESA InvestoCo, LLC is wholly owned by Exelon Generation.

On July 28, 2015, Fair Wind Power Partners, LLC ("Fair Wind"), an indirect wholly owned subsidiary of Exelon, filed with the Commission an application for market-based rate authority in Docket No. ER15-2293-000. Fair Wind is a wholly owned subsidiary of Exelon

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[1] 18 C.F.R. § 35.42 (2015).

[2] 2014 ESA Project Company, LLC is included out of an abundance of caution as a result of Exelon Generation Company, LLC's indirect, non-managing equity interests in that entity.

[3] The Exelon MBR Entities have attached an updated asset appendix in the format set forth in Appendix B to 18 C.F.R. Part 35, Subpart H that reflects the new affiliations.

Wind, LLC ("Exelon Wind"). Exelon Wind is a wholly owned subsidiary of Exelon Generation Acquisitions, LLC, which is a wholly owned subsidiary of Exelon Generation. Fair Wind is developing and will own and operate an approximately 30 MW (nameplate) wind-powered electric generation facility located in Garrett County, Maryland and interconnected to the transmission system owned by The Potomac Edison Company and operated by the PJM Interconnection, L.L.C. ("PJM"). Fair Wind will sell all of its output into PJM's market. It is currently anticipated that Fair Wind will begin sale of test power in October 2015 and will begin commercial operations in November 2015. Fair Wind will file a notice of exempt wholesale generator EWG status under the Public Utility Holding Company Act of 2005 ("PUHCA") prior to the commencement of commercial operations.

On July 29, 2015, Constellation Solar Maryland MC, LLC ("CSMMC") began the operation of a 0.25 MW (net) solar-powered generation facility located in Millersville, Maryland. The facility is a qualifying facility ("QF") under the Public Utility Regulatory Policies Act of 1978 and is interconnected to the transmission system owned by Baltimore Gas and Electric Company and operated by PJM.[4]

The affiliations reported herein do not raise any horizontal or vertical market power concerns. Each of Bloom PPA V, Fair Wind, and CSMMC will own only *de minimis* amounts of generation in each relevant market, which will have no material impact on the ability of any of the Exelon MBR Entities to exercise horizontal market power. In addition, Bloom PPA V's and Fair Wind's respective applications for market-based rate authority demonstrate that they pass the pivotal supplier and market share screens in the relevant markets. Therefore, the affiliations reported herein do not raise any horizontal market power concerns.[5] With respect to vertical market power, none of Bloom PPA V, Fair Wind, or

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[4] *See* the notice of self-certification of QF status filed on July 29, 2015 in Docket No. QF15-938-000. CSMMC is developing and will own additional solar QFs, for which CSMMC will submit the necessary notice of self-certification.

[5] Certain of the Exelon MBR Entities recently increased their generation capacity in PJM, but those additions do not result in a net increase of 100 MW since the last time the Commission reviewed Exelon's market power analysis for the PJM market and its submarkets. Exelon Generation owns 50% of the Peach Bottom 2 nuclear generating facility. In May 2015, Peach Bottom 2 completed an approximately 100 MW uprate, which resulted in approximately 50 MW of additional generation capacity affiliated with Exelon. In addition, Constellation Power Source Generation, LLC owns the new Perryman 6 unit, an approximately 110 MW gas-fired generating unit that commenced commercial operations on June 28, 2015. On August 5, 2014, the Commission accepted the Exelon MBR Entities' updated market power analysis for the Northeast region ("Northeast Triennial"). *See AV Solar Ranch 1, LLC*, 148 ¶ 61,102 (2014); *see also Fourmile Wind Energy, LLC*, 148 FERC ¶ 61,104 (2014). Since the Commission's acceptance of the Northeast Triennial, Exelon, through its subsidiaries, completed the following transactions, resulting in the sale of Exelon's indirect interests in approximately 1,556 MW of generation capacity in PJM and its submarkets: (1) Exelon sold its indirect 66% ownership interest in Safe Harbor Water Power Corp., which owns and operates a 417.5 MW hydroelectric generation facility located within the 5004/5005 and AP South submarkets of PJM (s*ee Constellation Power Source Generation, LLC*, 148 FERC ¶ 62,043 (2014)); (2) Exelon sold its indirect 25% ownership interest in Inter-Power/AhlCon Partners, L.P., which owns and operates the approximately 110 MW Colver generating facility (*see* Notice of Self-Recertification filed on January 12, 2015 in Docket No. QF87-632-011); and (3) Exelon sold its indirect undivided ownership interests in the Conemaugh Electric Generation Station (corresponding to approximately 535 MW) and the Keystone Electric Generating Station (corresponding to approximately 718 MW) (*see Constellation Power Source Generation, LLC*, 149 FERC ¶ 62,214 (2014). The net result of these transactions is that, even after taking into account the uprate of Peach Bottom 2, the completion of Perryman 6, and the new affiliations

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CSMMC owns or controls any transmission facilities, except for limited interconnection facilities required to connect individual generating facilities to the transmission grid, or any inputs to electric power production, as defined in section 35.36 of the Commission's regulations.[6] Therefore the affiliations reported herein do not raise any vertical market power concerns.

For the reasons set forth above, the Exelon MBR Entities' affiliations with Bloom PPA V, Fair Wind, and CSMMC do not materially change the facts and circumstances that the Commission relied upon in granting the Exelon MBR Entities market-based rate authority. Nor do the new affiliations raise any horizontal or vertical market power concerns with respect to the Exelon MBR Entities. Therefore, the Exelon MBR Entities respectfully request that the Commission accept for filing this notice of change in status and find that no further inquiry is necessary.

Respectfully submitted,

/s/ Vincenzo Franco
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Assistant General Counsel – Wholesale
Trading Compliance
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Enclosures

described herein, the Exelon MBR Entities' uncommitted capacity in PJM or any of the PJM submarkets is less than was attributed to them in the Northeast Triennial.

[6] 18 C.F.R. § 35.36(a)(4) defines "[i]nputs to electric power production" as "intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; physical coal supply sources and ownership of or control over who may access transportation of coal supplies."

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CERTIFICATE OF SERVICE

I hereby certify that this day I have caused to be served the foregoing document upon each person designated on the official service lists compiled by the Secretary in these dockets.

Dated at Baltimore, MD this 30th day of July, 2015.

/s/ Vincenzo Franco
Vincenzo Franco
Assistant General Counsel – Wholesale
Trading Compliance
Exelon Corporation
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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Commonwealth Edison Company	ER98-1734	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Constellation Energy Commodities Group Maine, LLC	ER02-699	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Constellation Energy Services of New York, Inc.	ER07-651	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Constellation Energy Services, Inc.	ER07-650	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Constellation NewEnergy, Inc.	ER96-1387	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
PECO Energy Company	ER01-1147	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
AgriWind LLC	N/A QF07-214	Agriwind LLC WF	AgriWind LLC	AgriWind LLC	N/A	MISO	Central	7/1/2007	2.10
AgriWind Project L.L.C.	N/A QF07-215	Agriwind Project LLC WF	AgriWind Project L.L.C.	AgriWind Project L.L.C.	N/A	MISO	Central	7/1/2007	6.30
BC Energy LLC	N/A QF07-219	BC Energy LLC WF	BC Energy LLC	BC Energy LLC	N/A	MISO	Central	5/28/2008	4.00
Beebe 1B Renewable Energy, LLC	ER14-2144	Beebe 1b WF	Beebe 1B Renewable Energy, LLC	Beebe 1B Renewable Energy, LLC	N/A	MISO	Central	12/12/2014	50.40
Beebe Renewable Energy, LLC	ER12-2311	Beebe 1a WF	Beebe Renewable Energy, LLC	Beebe Renewable Energy, LLC	N/A	MISO	Central	1/17/2013	81.60
Blue Breezes II, L.L.C.	N/A QF07-243	Blue Breezes II LLC WF	Blue Breezes II, L.L.C.	Blue Breezes II, L.L.C.	N/A	MISO	Central	5/1/2006	1.25
Blue Breezes, L.L.C.	N/A QF07-242	Blue Breezes I LLC WF	Blue Breezes, L.L.C.	Blue Breezes, L.L.C.	N/A	MISO	Central	5/1/2006	1.25
Breezy Bucks I LLC	N/A QF07-234	Breezy Bucks I LLC WF	Breezy Bucks I LLC	Breezy Bucks I LLC	N/A	MISO	Central	5/31/2006	1.25
Breezy Bucks II LLC	N/A QF07-235	Breezy Bucks II LLC WF	Breezy Bucks II LLC	Breezy Bucks II LLC	N/A	MISO	Central	5/31/2006	1.25
Christoffer Wind Energy I LLC	N/A QF07-250	Christoffer Wind I WF	Christoffer Wind Energy I LLC	Christoffer Wind Energy I LLC	N/A	MISO	Central	6/13/2008	2.10
Christoffer Wind Energy II LLC	N/A QF07-252	Christoffer Wind II WF	Christoffer Wind Energy II LLC	Christoffer Wind Energy II LLC	N/A	MISO	Central	6/13/2008	2.10
Christoffer Wind Energy III LLC	N/A QF07-251	Christoffer Wind III WF	Christoffer Wind Energy III LLC	Christoffer Wind Energy III LLC	N/A	MISO	Central	6/13/2008	2.10
Christoffer Wind Energy IV LLC	N/A QF07-249	Christoffer Wind IV WF	Christoffer Wind Energy IV LLC	Christoffer Wind Energy IV LLC	N/A	MISO	Central	6/13/2008	2.10
CP Windfarm, LLC	N/A QF07-178	CP Wind Farms LLC WF	CP Windfarm, LLC	CP Windfarm, LLC	N/A	MISO	Central	10/9/2007	4.20
Exelon Generation Company, LLC	ER00-3251	Clinton	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	MISO	Central	11/1/1987	1065.00
G-Flow Wind, LLC	N/A QF07-223	G-Flow Wind LLC WF	G-Flow Wind, LLC	G-Flow Wind, LLC	N/A	MISO	Central	3/6/2006	1.25
Green Acres Breeze, LLC	N/A QF07-227	Green Acres Breeze LLC WF	Green Acres Breeze, LLC	Green Acres Breeze, LLC	N/A	MISO	Central	3/6/2006	1.25
Harvest II Windfarm, LLC	ER12-2201 QF12-522	Harvest 2 WF	Harvest II Windfarm, LLC	Harvest II Windfarm, LLC	N/A	MISO	Central	11/28/2012	59.40
Harvest Windfarm, LLC	ER07-1246 QF07-29	Harvest 1 WF	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	2/28/2008	52.80
K&D Energy LLC	N/A QF07-217	K&D Energy LLC WF	K&D Energy LLC	K&D Energy LLC	N/A	MISO	Central	5/28/2008	4.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
KC Energy LLC	N/A QF07-218	KC Energy LLC WF	KC Energy LLC	KC Energy LLC	N/A	MISO	Central	5/28/2008	4.00
KSS Turbines LLC	N/A QF07-220	KSS Turbines LLC WF	KSS Turbines LLC	KSS Turbines LLC	N/A	MISO	Central	5/28/2008	4.00
Marshall Wind 1, LLC	N/A QF08-59	Marshall Wind 1 WF	Marshall Wind 1, LLC	Marshall Wind 1, LLC	N/A	MISO	Central	5/30/2008	2.10
Marshall Wind 2, LLC	N/A QF08-58	Marshall Wind 2 WF	Marshall Wind 2, LLC	Marshall Wind 2, LLC	N/A	MISO	Central	5/30/2008	4.20
Marshall Wind 3, LLC	N/A QF08-55	Marshall Wind 3 WF	Marshall Wind 3, LLC	Marshall Wind 3, LLC	N/A	MISO	Central	5/30/2008	4.20
Marshall Wind 4, LLC	N/A QF08-56	Marshall Wind 4 WF	Marshall Wind 4, LLC	Marshall Wind 4, LLC	N/A	MISO	Central	5/30/2008	4.20
Marshall Wind 5, LLC	N/A QF08-57	Marshall Wind 5 WF	Marshall Wind 5, LLC	Marshall Wind 5, LLC	N/A	MISO	Central	5/30/2008	2.10
Marshall Wind 6, LLC	N/A QF08-60	Marshall Wind 6 WF	Marshall Wind 6, LLC	Marshall Wind 6, LLC	N/A	MISO	Central	5/30/2008	2.10
Michigan Wind 1, LLC	ER05-1511 QF05-228	Michigan Wind 1 WF	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	12/16/2008	69.00
Michigan Wind 2, LLC	ER11-3989	Michigan Wind 2 WF	Michigan Wind 2, LLC	Michigan Wind 2, LLC	N/A	MISO	Central	1/5/2012	90.00
Minnesota Breeze, LLC	N/A QF07-224	Minnesota Breeze LLC WF	Minnesota Breeze, LLC	Minnesota Breeze, LLC	N/A	MISO	Central	3/6/2006	1.25
Prairie Wind Power LLC	N/A QF07-216	Prairie Wind Power LLC WF	Prairie Wind Power LLC	Prairie Wind Power LLC	N/A	MISO	Central	5/28/2008	4.00
Roadrunner I LLC	N/A QF07-236	Roadrunner I LLC WF	Roadrunner I LLC	Roadrunner I LLC	N/A	MISO	Central	5/31/2006	1.25
Salty Dog I LLC	N/A QF07-237	Salty Dog I LLC WF	Salty Dog I LLC	Salty Dog I LLC	N/A	MISO	Central	5/31/2006	1.25
Salty Dog II LLC	N/A QF07-238	Salty Dog II LLC WF	Salty Dog II LLC	Salty Dog II LLC	N/A	MISO	Central	5/31/2006	1.25
Shane's Wind Machine LLC	N/A QF07-247	Shanes Wind Machine LLC WF	Shane's Wind Machine LLC	Shane's Wind Machine LLC	N/A	MISO	Central	7/1/2006	2.00
Sunset Breeze, LLC	N/A QF07-226	Sunset Breeze LLC WF	Sunset Breeze, LLC	Sunset Breeze, LLC	N/A	MISO	Central	3/6/2006	1.25
Wally's Wind Farm LLC	N/A QF07-239	Wally's Wind Farm WF	Wally's Wind Farm LLC	Wally's Wind Farm LLC	N/A	MISO	Central	5/31/2006	1.25
Windy Dog I LLC	N/A QF07-240	Windy Dog I LLC WF	Windy Dog I LLC	Windy Dog I LLC	N/A	MISO	Central	5/31/2006	1.25
Wolf Wind Enterprises, LLC	N/A QF07-225	Wolf Wind Enterprises LLC WF	Wolf Wind Enterprises, LLC	Wolf Wind Enterprises, LLC	N/A	MISO	Central	3/6/2006	1.25
Exelon Generation Company, LLC	ER00-3251	Frontier GT1	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	9/20/2000	MISO & ERCOT	Central	9/20/2000	160.00
Exelon Generation Company, LLC	ER00-3251	Frontier GT2	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	9/20/2000	MISO & ERCOT	Central	9/20/2000	160.00
Exelon Generation Company, LLC	ER00-3251	Frontier GT3	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	9/20/2000	MISO & ERCOT	Central	9/20/2000	160.00
Exelon Generation Company, LLC	ER00-3251	Frontier ST	Tenaska Frontier Partners Ltd	Exelon Generation Company, LLC	9/20/2000	MISO & ERCOT	Central	9/20/2000	390.00
2014 ESA Project Company, LLC	ER15-1496	2014 ESA Project Company, LLC - ISO-NE	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	N/A	ISO-NE	Northeast	TBD	1.00
2015 ESA Project Company, LLC	ER15-2009	2015 ESA Project Company, LLC - ISO-NE	2015 ESA Project Company, LLC	2015 ESA Project Company, LLC	N/A	ISO-NE	Northeast	TBD	2.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Constellation Mystic Power, LLC	ER10-2281	Mystic 7	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/1975	575.48
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	225.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	227.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	252.00
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	231.09
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	230.80
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	252.00
Constellation Mystic Power, LLC	ER10-2281	Mystic Jet	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/1969	9.07
Constellation Solar Connecticut, LLC	N/A QF10-654	East Lyme Bd of Ed at East Lyme HS	Constellation Solar Connecticut LLC	Constellation Solar Connecticut LLC	N/A	ISO-NE	Northeast	3/2/2009	0.41
Constellation Solar Connecticut, LLC	N/A QF10-663	Parker Hannifin Corp at New Britain	Constellation Solar Connecticut LLC	Constellation Solar Connecticut LLC	N/A	ISO-NE	Northeast	12/30/2008	0.18
Constellation Solar Massachusetts, LLC	N/A QF11-411	Kollmorgen Electro-Optical HQ Bldg	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	7/19/2011	0.17
Constellation Solar Massachusetts, LLC	N/A QF15-188	Macy's at Marlborough	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	12/31/2014	0.41
Constellation Solar Massachusetts, LLC	N/A QF15-187	Macy's at Natick	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	12/6/2014	0.56
Constellation Solar Massachusetts, LLC	N/A QF15-186	Macy's at Saugus	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	12/31/2014	0.30
Constellation Solar Massachusetts, LLC	N/A QF15-190	Macy's at Burlington	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	12/4/2014	0.25
Constellation Solar Massachusetts, LLC	N/A QF15-189	Macy's at Dartmouth	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	12/31/2014	0.35
Constellation Solar Massachusetts, LLC	N/A QF09-89	Majilite Corp	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	2/16/2009	0.35
Constellation Solar Massachusetts, LLC	N/A QF10-655	NPP Development, LLC at Patriot Place	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	7/14/2010	0.45
Constellation Solar Massachusetts, LLC	N/A QF12-212	Swampscott High School	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	2/7/2012	0.32
Constellation Solar Massachusetts, LLC	N/A QF12-292	Town of Norfolk	Constellation Solar Massachusetts, LLC	Constellation Solar Massachusetts, LLC	N/A	ISO-NE	Northeast	6/25/2012	1.35
Constellation Solar Net Metering, LLC	N/A QF12-293	Town of Uxbridge	Constellation Solar Net Metering, LLC	Constellation Solar Net Metering, LLC	N/A	ISO-NE	Northeast	6/1/2012	1.93
Exelon Framingham LLC	ER01-513	Framingham Jet 1	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	3/1/1970	10.15
Exelon Framingham LLC	ER01-513	Framingham Jet 2	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/1969	11.69
Exelon Framingham LLC	ER01-513	Framingham Jet 3	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/1969	11.25
Exelon Generation Company, LLC	ER00-3251	Granite Ridge GT1	Granite Ridge Energy, LLC	Exelon Generation Company, LLC	1/1/2014	ISO-NE	Northeast	12/13/2002	220.00
Exelon Generation Company, LLC	ER00-3251	Granite Ridge GT2	Granite Ridge Energy, LLC	Exelon Generation Company, LLC	1/1/2014	ISO-NE	Northeast	12/13/2002	220.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Exelon Generation Company, LLC	ER00-3251	Granite Ridge STG1	Granite Ridge Energy, LLC	Exelon Generation Company, LLC	1/1/2014	ISO-NE	Northeast	12/13/2002	221.32
Exelon Generation Company, LLC	ER00-3251	Kleen GT1	Kleen Energy Systems, LLC	Exelon Generation Company, LLC	7/23/2011	ISO-NE	Northeast	7/8/2011	186.00
Exelon Generation Company, LLC	ER00-3251	Kleen GT2	Kleen Energy Systems, LLC	Exelon Generation Company, LLC	7/23/2011	ISO-NE	Northeast	7/8/2011	188.00
Exelon Generation Company, LLC	ER00-3251	Kleen STG1	Kleen Energy Systems, LLC	Exelon Generation Company, LLC	7/23/2011	ISO-NE	Northeast	7/8/2011	246.00
Exelon New Boston, LLC	ER01-513	New Boston Jet	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	9/1/1966	16.03
Exelon West Medway, LLC	ER01-513	West Medway Jet 1	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/1970	42.00
Exelon West Medway, LLC	ER01-513	West Medway Jet 2	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	3/1/1971	39.85
Exelon West Medway, LLC	ER01-513	West Medway Jet 3	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/1970	35.44
Exelon Wyman, LLC	ER01-513	Wyman 4	Exelon Wyman, LLC (5.9%)	FPL Wyman Energy, LLC	N/A	ISO-NE	Northeast	1/1/1978	610.00
Holyoke Solar LLC	N/A QF12-294	City of Holyoke G & E Dept at Meadow SF	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	12/27/2011	0.87
Holyoke Solar LLC	N/A QF12-267	City of Holyoke G & E Dept at Mueller SF	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	3/12/2012	2.95
2014 ESA Project Company, LLC	ER15-1496	2014 ESA Project Company, LLC - NYISO	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	N/A	NYISO	Northeast	12/30/2014	3.60
2015 ESA Project Company, LLC	ER15-2009	2015 ESA Project Company, LLC - NYISO	2015 ESA Project Company, LLC	2015 ESA Project Company, LLC	N/A	NYISO	Northeast	TBD	4.60
Constellation Solar New York, LLC	N/A QF13-550	Owens Corning	Constellation Solar New York, LLC	Constellation Solar New York, LLC	N/A	NYISO	Northeast	10/9/2013	2.28
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 1	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	12/1/1969	626.90
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 2	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	8/1/1988	1287.20
R. E. Ginna Nuclear Power Plant, LLC	ER04-485	Ginna	R. E. Ginna Nuclear Power Plant, LLC	R. E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	7/1/1970	581.70
2014 ESA Project Company, LLC	ER15-1496	2014 ESA Project Company, LLC - PJM	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	N/A	PJM	Northeast	TBD	2.60
2015 ESA Project Company, LLC	ER15-2009	2015 ESA Project Company, LLC - PJM	2015 ESA Project Company, LLC	2015 ESA Project Company, LLC	N/A	PJM	Northeast	5/26/2015	4.75
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 1	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	5/1/1975	866.00
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 2	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	4/1/1977	841.80
Constellation Power Source Generation, LLC	ER00-1598	Gould Street 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	12/1/1952	97.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/1969	14.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/1969	14.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/1969	14.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/1969	14.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/1969	15.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/1969	16.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/1969	15.00
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/1969	16.00
Constellation Power Source Generation, LLC	ER00-1598	Perryman 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	1/1/1972	52.00
Constellation Power Source Generation, LLC	ER00-1598	Perryman 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	4/1/1972	51.00
Constellation Power Source Generation, LLC	ER00-1598	Perryman 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	4/1/1972	51.00
Constellation Power Source Generation, LLC	ER00-1598	Perryman 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	4/1/1972	52.00
Constellation Power Source Generation, LLC	ER00-1598	Perryman 51	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/1/1995	147.60
Constellation Power Source Generation, LLC	ER00-1598	Perryman 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	6/28/2015	109.80
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	8/1/1970	15.30
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	8/1/1970	16.00
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	9/1/1970	14.80
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	9/1/1970	14.80
Constellation Power Source Generation, LLC	ER00-1598	Riverside 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	9/1/1951	74.00
Constellation Power Source Generation, LLC	ER00-1598	Riverside 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	9/1/1970	19.00
Constellation Power Source Generation, LLC	ER00-1598	Riverside 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	9/1/1970	20.00
Constellation Power Source Generation, LLC	ER00-1598	Westport 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	2/1/1969	115.80
Constellation Solar DC, LLC	N/A QF13-575	Dunbar	Constellation Solar DC, LLC	Constellation Solar DC, LLC	N/A	PJM	Northeast	12/27/2013	0.32
Constellation Solar Federal LLC	N/A QF12-78	Reeves SF	Constellation Solar Federal LLC	Constellation Solar Federal LLC	N/A	PJM	Northeast	12/20/2011	4.23
Constellation Solar Horizons, LLC	N/A QF10-586	University System of Maryland & Department of General Services SF	Constellation Solar Horizons, LLC	Constellation Solar Horizons, LLC	N/A	PJM	Northeast	7/1/2012	13.61
Constellation Solar Maryland II, LLC	N/A QF15-660	CNE at Cambridge	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	4/30/2015	3.67
Constellation Solar Maryland II, LLC	N/A QF13-135	UMMS - CRE	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	2/21/2013	0.35
Constellation Solar Maryland II, LLC	N/A QF13-136	UMMS (U of MD Medical System) SF	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	2/21/2013	3.09
Constellation Solar Maryland, LLC	N/A QF11-271	AA County, MD at Shared Svcs Complex	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	3/4/2011	0.63
Constellation Solar Maryland, LLC	N/A QF11-333	Coppin State Univ at Coppin State Univ - PEC	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	9/14/2011	0.42

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Constellation Solar Maryland, LLC	N/A QF11-410	CPSG Fort Smallwood Road Complex	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	10/3/2011	0.78
Constellation Solar Maryland, LLC	N/A QF11-335	GM Allison Plant-I	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	5/18/2011	1.04
Constellation Solar Maryland, LLC	N/A QF11-407	Maryland Science Center	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	5/24/2011	0.09
Constellation Solar Maryland, LLC	N/A QF11-268	McCormick & Co, Inc at Belcamp	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	1/1/2011	1.56
Constellation Solar Maryland, LLC	N/A QF10-662	McCormick & Co, Inc at Hunt Valley	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	1/26/2009	0.78
Constellation Solar Maryland, LLC	N/A QF11-334	McCormick & Co, Inc at Sparks	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	6/24/2011	0.08
Constellation Solar Maryland, LLC	N/A QF10-661	MD Env Service at MES Headquarters	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	12/29/2008	0.25
Constellation Solar Maryland, LLC	N/A QF12-507	University System of Maryland II	Constellation Solar Maryland, LLC	Constellation Solar Maryland, LLC	N/A	PJM	Northeast	7/1/2012	1.42
Constellation Solar New Jersey II, LLC	N/A QF11-267	Johnson Matthey, Inc at West Deptford	Constellation Solar New Jersey II, LLC	Constellation Solar New Jersey II, LLC	N/A	PJM	Northeast	4/25/2011	4.41
Constellation Solar New Jersey II, LLC	N/A QF11-461	Toys-R-Us Delaware, Inc at Mt Olive	Constellation Solar New Jersey II, LLC	Constellation Solar New Jersey II, LLC	N/A	PJM	Northeast	12/22/2011	4.55
Constellation Solar New Jersey III, LLC	N/A QF12-81	Middle Township Elem School 1	Constellation Solar New Jersey III, LLC	Constellation Solar New Jersey III, LLC	N/A	PJM	Northeast	12/7/2011	0.17
Constellation Solar New Jersey III, LLC	N/A QF12-79	Middle Township Elem School 2	Constellation Solar New Jersey III, LLC	Constellation Solar New Jersey III, LLC	N/A	PJM	Northeast	12/5/2011	0.39
Constellation Solar New Jersey III, LLC	N/A QF12-80	Middle Township High School	Constellation Solar New Jersey III, LLC	Constellation Solar New Jersey III, LLC	N/A	PJM	Northeast	12/14/2011	0.69
Constellation Solar New Jersey LLC	N/A QF11-270	Benjamin Moore & Co at Flanders NJ	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	1/3/2011	1.50
Constellation Solar New Jersey LLC	N/A QF10-666	Jet Aviation Teterboro, LP at Teterboro Airport	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	3/1/2008	0.15
Constellation Solar New Jersey LLC	N/A QF11-464	North Vineland SF	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	10/18/2011	2.54
Constellation Solar New Jersey LLC	N/A QF11-463	West Vineland SF	Constellation Solar New Jersey LLC	Constellation Solar New Jersey LLC	N/A	PJM	Northeast	10/19/2011	4.06
Constellation Solar Ohio, LLC	N/A QF10-664	Univ of Toledo (Solar) Scott Park Campus of Energy & Innovation	Constellation Solar Ohio, LLC	Constellation Solar Ohio, LLC	N/A	PJM	Northeast	3/31/2010	0.88
Constellation Solar Ohio, LLC	N/A QF10-659	Univ of Toledo (Wind) Scott Park Campus of Energy & Innovation	Constellation Solar Ohio, LLC	Constellation Solar Ohio, LLC	N/A	PJM	Northeast	3/31/2010	0.07
Criterion Power Partners, LLC	ER10-1443	Criterion WF	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	2/4/2011	70.00
Exelon Generation Company, LLC	ER00-3251	Braidwood 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/1/1988	1178.00
Exelon Generation Company, LLC	ER00-3251	Braidwood 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1988	1152.00
Exelon Generation Company, LLC	ER00-3251	Byron 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/1/1985	1164.00
Exelon Generation Company, LLC	ER00-3251	Byron 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/1987	1136.00
Exelon Generation Company, LLC	ER00-3251	Chester 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	2/7/1969	13.00
Exelon Generation Company, LLC	ER00-3251	Chester 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/20/1969	13.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Exelon Generation Company, LLC	ER00-3251	Chester 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/6/1969	13.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/1/1928	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/25/1964	65.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/4/1964	65.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/1/1928	36.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/6/1928	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	4/5/1928	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/1/1928	36.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/1/1928	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/1/1928	48.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/10/1964	65.00
Exelon Generation Company, LLC	ER00-3251	Conowingo 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/25/1964	65.00
Exelon Generation Company, LLC	ER00-3251	Cordova GT1	Cordova Energy Company, LLC	Exelon Generation Company, LLC	12/30/2005	PJM	Northeast	6/12/2001	165.00
Exelon Generation Company, LLC	ER00-3251	Cordova GT2	Cordova Energy Company, LLC	Exelon Generation Company, LLC	12/30/2005	PJM	Northeast	6/12/2001	165.00
Exelon Generation Company, LLC	ER00-3251	Cordova STG1	Cordova Energy Company, LLC	Exelon Generation Company, LLC	12/30/2005	PJM	Northeast	6/12/2001	191.20
Exelon Generation Company, LLC	ER00-3251	Croydon 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/18/1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/18/1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 21	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/18/1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 22	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/18/1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 31	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/6/1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 32	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/8/1974	48.00
Exelon Generation Company, LLC	ER00-3251	Croydon 41	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/24/1974	49.00
Exelon Generation Company, LLC	ER00-3251	Croydon 42	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/24/1974	49.00
Exelon Generation Company, LLC	ER00-3251	Delaware 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/7/1969	13.00
Exelon Generation Company, LLC	ER00-3251	Delaware 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	4/19/1969	13.00
Exelon Generation Company, LLC	ER00-3251	Delaware 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/12/1969	13.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Exelon Generation Company, LLC	ER00-3251	Delaware 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/24/1970	17.00
Exelon Generation Company, LLC	ER00-3251	Dresden 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/1970	902.00
Exelon Generation Company, LLC	ER00-3251	Dresden 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1971	895.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/20/1967	13.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 20	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/11/1967	13.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/24/1974	380.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 30	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	3/7/1970	17.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/29/1976	380.00
Exelon Generation Company, LLC	ER00-3251	Eddystone 40	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/21/1970	17.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 5	Elwood Energy, LLC	Exelon Generation Company, LLC	6/15/2006	PJM	Northeast	7/18/2001	150.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 6	Elwood Energy, LLC	Exelon Generation Company, LLC	6/15/2006	PJM	Northeast	7/18/2001	150.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 7	Elwood Energy, LLC	Exelon Generation Company, LLC	6/15/2006	PJM	Northeast	7/18/2001	150.00
Exelon Generation Company, LLC	ER00-3251	Elwood CEG 8	Elwood Energy, LLC	Exelon Generation Company, LLC	6/15/2006	PJM	Northeast	7/18/2001	150.00
Exelon Generation Company, LLC	ER00-3251	Fairless Hills A	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1996	30.00
Exelon Generation Company, LLC	ER00-3251	Fairless Hills B	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1996	30.00
Exelon Generation Company, LLC	ER00-3251	Falls 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/22/1970	17.00
Exelon Generation Company, LLC	ER00-3251	Falls 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/10/1970	17.00
Exelon Generation Company, LLC	ER00-3251	Falls 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/28/1970	17.00
Exelon Generation Company, LLC	ER00-3251	LaSalle 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	1/1/1984	1135.40
Exelon Generation Company, LLC	ER00-3251	LaSalle 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1984	1136.20
Exelon Generation Company, LLC	ER00-3251	Limerick 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	2/1/1986	1119.70
Exelon Generation Company, LLC	ER00-3251	Limerick 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	1/1/1990	1122.10
Exelon Generation Company, LLC	ER00-3251	Moser 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/9/1970	17.00
Exelon Generation Company, LLC	ER00-3251	Moser 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/29/1970	17.00
Exelon Generation Company, LLC	ER00-3251	Moser 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/11/1970	17.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	4/10/1967	134.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Exelon Generation Company, LLC	ER00-3251	Muddy Run 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	4/10/1967	133.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/1/1967	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/1/1967	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/11/1967	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/11/1967	133.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	2/10/1968	134.00
Exelon Generation Company, LLC	ER00-3251	Muddy Run 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	2/10/1968	134.00
Exelon Generation Company, LLC	ER00-3251	Oyster Creek 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1969	609.90
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 2	ExGen (PSEG 50%)	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/5/1974	1223.70
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 3	ExGen (PSEG 50%)	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/23/1974	1125.40
Exelon Generation Company, LLC	ER00-3251	Pennsbury 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/1/1996	2.67
Exelon Generation Company, LLC	ER00-3251	Pennsbury 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/1/1996	2.67
Exelon Generation Company, LLC	ER00-3251	Quad Cities 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1972	908.00
Exelon Generation Company, LLC	ER00-3251	Quad Cities 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1972	911.00
Exelon Generation Company, LLC	ER00-3251	Richmond 91	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/7/1973	49.00
Exelon Generation Company, LLC	ER00-3251	Richmond 92	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/7/1973	49.00
Exelon Generation Company, LLC	ER00-3251	Salem 1	PSEG (ExGen 42.59%)	PSEG	N/A	PJM	Northeast	6/30/1977	1173.99
Exelon Generation Company, LLC	ER00-3251	Salem 2	PSEG (ExGen 42.59%)	PSEG	N/A	PJM	Northeast	10/13/1981	1158.02
Exelon Generation Company, LLC	ER00-3251	Salem 3	PSEG (ExGen 42.59%)	PSEG	N/A	PJM	Northeast	6/17/1971	37.57
Exelon Generation Company, LLC	ER00-3251	Schuylkill 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/30/1969	13.00
Exelon Generation Company, LLC	ER00-3251	Schuylkill 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/11/1971	17.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	37.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	37.00
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	37.00
Exelon Generation Company, LLC	ER00-3251	Southwark 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	6/14/1967	13.00
Exelon Generation Company, LLC	ER00-3251	Southwark 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/9/1967	13.00
Exelon Generation Company, LLC	ER00-3251	Southwark 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/26/1967	13.00
Exelon Generation Company, LLC	ER00-3251	Southwark 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	11/7/1968	13.00
Exelon Generation Company, LLC	ER00-3251	TMI 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/2/1974	802.80
Exelon Generation Company, LLC	ER00-3251	York Delta GT1	Calpine Mid Merit LLC	Exelon Generation Company, LLC	6/1/2011	PJM	Northeast	3/3/2011	118.00
Exelon Generation Company, LLC	ER00-3251	York Delta GT2	Calpine Mid Merit LLC	Exelon Generation Company, LLC	6/1/2011	PJM	Northeast	3/3/2011	127.00
Exelon Generation Company, LLC	ER00-3251	York Delta GT3	Calpine Mid Merit LLC	Exelon Generation Company, LLC	6/1/2011	PJM	Northeast	3/3/2011	127.00
Exelon Generation Company, LLC	ER00-3251	York Delta STG1	Calpine Mid Merit LLC	Exelon Generation Company, LLC	6/1/2011	PJM	Northeast	3/3/2011	193.00
Exelon Solar Chicago LLC	N/A QF10-174	Chicago City Solar SF	Exelon Solar Chicago LLC	Exelon Solar Chicago LLC	N/A	PJM	Northeast	3/23/2010	9.00
Fair Wind Power Partners, LLC	ER15-2293	Fair Wind WF	Fair Wind Power Partners, LLC	Fair Wind Power Partners, LLC	N/A	PJM	Northeast	TBD	30.00
Fourmile Wind Energy, LLC	ER14-2145 QF14-721	Fourmile Ridge WF	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	1/15/2015	40.00
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 1	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 2	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 3	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 4	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	53.50
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 5	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	53.50
Bennett Creek Windfarm, LLC	N/A QF07-36	Bennett Creek WF	Bennett Creek, LLC	Bennett Creek, LLC	N/A	IPCO	Northwest	8/31/2008	21.00
Cassia Gulch Wind Park LLC	ER10-75 QF05-180	Cassia Gulch WF	Cassia Gulch Wind Park LLC	Cassia Gulch Wind Park LLC	N/A	IPCO	Northwest	3/31/2009	18.90
Cassia Wind Farm, LLC	N/A QF05-170	Cassia Wind WF	Cassia Wind Farm, LLC	Cassia Wind Farm, LLC	N/A	IPCO	Northwest	3/31/2009	10.50
High Mesa Energy, LLC	ER12-2528 QF13-77	High Mesa WF	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	IPCO	Northwest	8/28/2012	40.00
Hot Springs Windfarm, LLC	N/A QF07-37	Hot Springs WF	Hot Springs Windfarm, LLC	Hot Springs Windfarm, LLC	N/A	IPCO	Northwest	8/31/2008	21.00
Tuana Springs Energy, LLC	ER10-87 QF08-742	Tuana Springs WF	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	IPCO	Northwest	7/27/2010	16.80

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Sunnyside Cogeneration Assoc.	N/A QF86-556	Sunnyside Cogen	Sunnyside Cogeneration Assoc.	Sunnyside Cogeneration Assoc.	N/A	PACE	Northwest	2/1/1993	51.00
Big Top, LLC	N/A QF08-539	Big Top WF	Big Top, LLC	Big Top, LLC	N/A	PACW	Northwest	6/27/2009	1.65
Butter Creek Power, LLC	N/A QF08-536	Butter Creek WF	Butter Creek Power, LLC	Butter Creek Power, LLC	N/A	PACW	Northwest	6/27/2009	4.95
Four Corners Windfarm, LLC	N/A QF08-372	Four Corner WF	Four Corners Windfarm, LLC	Four Corners Windfarm, LLC	N/A	PACW	Northwest	9/30/2009	10.00
Four Mile Canyon Windfarm, LLC	N/A QF08-370	Four Mile Canyon WF	Four Mile Canyon Windfarm, LLC	Four Mile Canyon Windfarm, LLC	N/A	PACW	Northwest	9/30/2009	10.00
Oregon Trail Windfarm, LLC	N/A QF08-371	Oregon Trail WF	Oregon Trail Windfarm, LLC	Oregon Trail Windfarm, LLC	N/A	PACW	Northwest	6/27/2009	9.90
Pacific Canyon Windfarm, LLC	N/A QF08-373	Pacific Canyon WF	Pacific Canyon Windfarm, LLC	Pacific Canyon Windfarm, LLC	N/A	PACW	Northwest	6/27/2009	8.25
Sand Ranch Windfarm, LLC	N/A QF08-368	Sand Ranch WF	Sand Ranch Windfarm, LLC	Sand Ranch Windfarm, LLC	N/A	PACW	Northwest	6/27/2009	9.90
Threemile Canyon Wind I, LLC	N/A QF09-142	Threemile Canyon WF	Three Mile Canyon Wind I, LLC	Three Mile Canyon Wind I, LLC	N/A	PACW	Northwest	9/30/2009	9.90
Wagon Trail, LLC	N/A QF08-537	Wagon Trail WF	Wagon Trail, LLC	Wagon Trail, LLC	N/A	PACW	Northwest	6/27/2009	3.30
Ward Butte Windfarm, LLC	N/A QF08-369	Ward Butte WF	Ward Butte Windfarm, LLC	Ward Butte Windfarm, LLC	N/A	PACW	Northwest	6/27/2009	6.60
Outback Solar, LLC	N/A QF13-34	Outback Solar SF	Outback Solar, LLC	Outback Solar, LLC	N/A	BPA	Northwest	10/30/2012	4.82
Exelon Generation Company, LLC	ER00-3251	Stateline WF	FPL Energy Vansycle, L.L.C.	Exelon Generation Company, LLC	4/1/2015	PACW	Northwest	12/1/2001	300.00
Denver Airport Solar, LLC	N/A QF11-336	City & County of Denver at Denver International Airport	Denver Airport Solar, LLC	Denver Airport Solar, LLC	N/A	PSCO	Northwest	6/7/2011	3.77
Cow Branch Wind Power, L.L.C.	ER07-1223 QF07-253	Cow Branch WF	Cow Branch Wind Power, L.L.C.	Cow Branch Wind Power, L.L.C.	N/A	AECI	Southeast	3/3/2008	50.40
CR Clearing, LLC	ER07-1222 QF07-248	CR Clearing LLC WF	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	5/1/2008	50.40
Loess Hills Wind Farm, LLC	N/A QF07-241	Loess Hills WF	Loess Hills Wind Farm, LLC	Loess Hills Wind Farm, LLC	N/A	AECI	Southeast	4/19/2008	5.00
Wind Capital Holdings, LLC	ER07-1208 QF07-222	Wind Capital Holdings LLC WF	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	5/14/2007	56.70
CER Generation, LLC	ER10-662	Hillabee GT1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	220.40
CER Generation, LLC	ER10-662	Hillabee GT2	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	220.40
CER Generation, LLC	ER10-662	Hillabee STG1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	281.00
Constellation Solar Georgia, LLC	N/A QF15-202	Cave Spring	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/2014	0.85
Constellation Solar Georgia, LLC	N/A QF15-659	Dublin	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	5/30/2015	0.85
Constellation Solar Georgia, LLC	N/A QF15-203	Eastanollee	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/2014	0.84
Constellation Solar Georgia, LLC	N/A QF15-204	Gibson	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/2014	0.62
Constellation Solar Georgia, LLC	N/A QF14-505	Sparta SF	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	5/7/2014	0.85

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Constellation Solar Georgia, LLC	N/A QF15-205	Summerville	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/2014	0.38
Constellation Solar Georgia, LLC	N/A QF15-658	Toccoa	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	4/22/2015	0.68
Constellation Solar Georgia, LLC	N/A QF15-206	Wadley	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/2014	1.11
Constellation Solar Georgia, LLC	N/A QF15-207	Wrens	Constellation Solar Georgia, LLC	Constellation Solar Georgia, LLC	N/A	SOCO	Southeast	12/1/2014	0.34
Exelon Generation Company, LLC	ER00-3251	Effingham GT1	Effingham County Power, LLC	Effingham County Power, LLC / Exelon Generation Company, LLC	6/1/2007	SOCO	Southeast	8/27/2003	167.00
Exelon Generation Company, LLC	ER00-3251	Effingham GT2	Effingham County Power, LLC	Effingham County Power, LLC / Exelon Generation Company, LLC	6/1/2007	SOCO	Southeast	8/27/2003	167.00
Exelon Generation Company, LLC	ER00-3251	Effingham STG1	Effingham County Power, LLC	Effingham County Power, LLC / Exelon Generation Company, LLC	6/1/2007	SOCO	Southeast	8/27/2003	175.00
Exelon Generation Company, LLC	ER00-3251	Franklin GT1	Southern Power Company	Southern Power Company / Exelon Generation Company, LLC	6/1/2007	SOCO	Southeast	6/6/2003	183.00
Exelon Generation Company, LLC	ER00-3251	Franklin GT2	Southern Power Company	Southern Power Company / Exelon Generation Company, LLC	6/1/2007	SOCO	Southeast	6/6/2003	183.00
Exelon Generation Company, LLC	ER00-3251	Franklin STG1	Southern Power Company	Southern Power Company / Exelon Generation Company, LLC	6/1/2007	SOCO	Southeast	6/6/2003	259.60
Exelon Generation Company, LLC	ER00-3251	Heard 1	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/2001	SOCO	Southeast	6/29/2001	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 2	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/2001	SOCO	Southeast	6/29/2001	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 3	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/2001	SOCO	Southeast	6/29/2001	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 4	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/2001	SOCO	Southeast	5/31/2002	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 5	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/2001	SOCO	Southeast	5/31/2002	157.50
Exelon Generation Company, LLC	ER00-3251	Heard 6	Tenaska Georgia Partners LP	Exelon Generation Company, LLC	6/1/2001	SOCO	Southeast	5/31/2002	157.50
Exelon Generation Company, LLC	ER00-3251	Hog Bayou	Mobile Energy LLC	Exelon Generation Company, LLC	1/1/2015	SOCO	Southeast	7/11/2001	230.00
Exelon Generation Company, LLC	ER00-3251	Sowega 1	Georgia Energy Cooperative	Exelon Generation Company, LLC	1/1/2011	SOCO	Southeast	6/1/1999	48.50
Exelon Generation Company, LLC	ER00-3251	Sowega 2	Georgia Energy Cooperative	Exelon Generation Company, LLC	1/1/2011	SOCO	Southeast	6/1/1999	48.50
Exelon Generation Company, LLC	ER00-3251	Washington 1	Washington County Power, LLC	Washington County Power, LLC / Exelon Generation Company, LLC	6/1/2007	SOCO	Southeast	6/1/2003	151.00
Exelon Generation Company, LLC	ER00-3251	Washington 4	Washington County Power, LLC	Washington County Power, LLC / Exelon Generation Company, LLC	6/1/2007	SOCO	Southeast	6/1/2003	152.00
Constellation Solar Arizona, LLC	N/A QF12-211	Buckeye Union HS at Estrella & Youngkers	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/7/2011	3.62
Constellation Solar Arizona, LLC	N/A QF13-76	Casa Grande - Casa Verde HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/19/2012	0.35
Constellation Solar Arizona, LLC	N/A QF13-75	Casa Grande - Union HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/19/2012	1.79
Constellation Solar Arizona, LLC	N/A QF13-74	Casa Grande - Vista Grande HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/19/2012	1.54
Constellation Solar Arizona, LLC	N/A QF13-599	Charles Bejarano	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	9/20/2013	0.09

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Constellation Solar Arizona, LLC	N/A QF14-498	Collier ES	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	6/30/2014	0.25
Constellation Solar Arizona, LLC	N/A QF13-511	Crane School District at Centennial	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	8/1/2013	0.38
Constellation Solar Arizona, LLC	N/A QF13-516	Crane School District at Crane Middle School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	8/28/2013	0.38
Constellation Solar Arizona, LLC	N/A QF13-378	Crane School District at GAK	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	3/28/2013	0.19
Constellation Solar Arizona, LLC	N/A QF13-377	Crane School District at Mesquite	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	3/28/2013	0.17
Constellation Solar Arizona, LLC	N/A QF13-515	Crane School District at Valley Horizon	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	7/11/2013	0.28
Constellation Solar Arizona, LLC	N/A QF13-537	Dysart I School District	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	6/19/2013	8.81
Constellation Solar Arizona, LLC	N/A QF14-496	Isaac School District at Butler	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	7/8/2014	0.21
Constellation Solar Arizona, LLC	N/A QF14-497	Lee Kornegay MS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	7/9/2014	0.11
Constellation Solar Arizona, LLC	N/A QF13-538	Marana School District	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	7/26/2013	1.59
Constellation Solar Arizona, LLC	N/A QF13-598	Miami High School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	9/30/2013	0.36
Constellation Solar Arizona, LLC	N/A QF14-499	Parkridge ES	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	7/3/2014	0.42
Constellation Solar Arizona, LLC	N/A QF13-536	Peoria Unified School District	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	11/4/2013	2.53
Constellation Solar Arizona, LLC	N/A QF14-27	Pueblo Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/15/2013	0.24
Constellation Solar Arizona, LLC	N/A QF14-29	Salida del Sol Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/15/2013	0.30
Constellation Solar Arizona, LLC	N/A QF13-514	Somerton School District at Desert Sonora	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	3/27/2013	0.29
Constellation Solar Arizona, LLC	N/A QF13-137	Somerton School District at Orange Grove	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/21/2012	0.18
Constellation Solar Arizona, LLC	N/A QF13-513	Somerton School District at Somerton Middle School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	3/27/2013	0.47
Constellation Solar Arizona, LLC	N/A QF13-138	Somerton School District at Tierra del Sol	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/21/2012	0.22
Constellation Solar Arizona, LLC	N/A QF13-139	Somerton School District at Valle del Encanto	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/21/2012	0.17
Constellation Solar Arizona, LLC	N/A QF14-26	Suverkrup Elementary School	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	12/15/2013	0.27
Constellation Solar Arizona, LLC	N/A QF13-380	Vail School District at Andrada HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	4/19/2013	0.33
Constellation Solar Arizona, LLC	N/A QF13-378	Vail School District at Mesquite ES	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	4/5/2013	0.23
Constellation Solar Arizona, LLC	N/A QF13-376	Vail School District at Old Vail MS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	4/5/2013	0.25
Constellation Solar Arizona, LLC	N/A QF15-163	Western Peaks ES	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	10/16/2014	0.47
Constellation Solar Arizona, LLC	N/A QF15-162	Willow Canyon HS	Constellation Solar Arizona, LLC	Constellation Solar Arizona, LLC	N/A	APS	Southwest	10/15/2014	0.44

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mohave Sunrise Solar I LLC	N/A QF15-161	Mohave Electric at Fort Mohave	Mohave Sunrise Solar I LLC	Mohave Sunrise Solar I LLC	N/A	APS	Southwest	2nd Qtr 2015	4.56
Sacramento PV Energy, LLC	N/A QF11-329	SMUD at Fleshman SF	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	11/19/2011	3.08
Sacramento PV Energy, LLC	N/A QF11-330	SMUD at Grundman SF	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	12/28/2011	18.50
Sacramento PV Energy, LLC	N/A QF11-331	SMUD at Lawrence SF	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	12/30/2011	1.03
Sacramento PV Energy, LLC	N/A QF11-332	SMUD at Van Conett SF	Sacramento PV Energy, LLC	Sacramento PV Energy, LLC	N/A	BANC	Southwest	12/20/2011	3.08
2014 ESA Project Company, LLC	ER15-1496	2014 ESA Project Company, LLC - CAISO	2014 ESA Project Company, LLC	2014 ESA Project Company, LLC	N/A	CAISO	Southwest	10/24/2014	12.60
2015 ESA Project Company, LLC	ER15-2009	2015 ESA Project Company, LLC - CAISO	2015 ESA Project Company, LLC	2015 ESA Project Company, LLC	N/A	CAISO	Southwest	TBD	28.60
AV Solar Ranch 1, LLC	ER12-2178	Antelope Valley SF	AV Solar Ranch 1, LLC	AV Solar Ranch 1, LLC	N/A	CAISO	Southwest	12/28/2012	241.50
California PV Energy, LLC	N/A QF14-322	Palmdale Marie Kerr Park E2	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/2014	0.06
California PV Energy, LLC	N/A QF15-76	Alta Loma HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/23/2014	0.56
California PV Energy, LLC	N/A QF14-214	Castaic Elementary School	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	4/8/2014	0.12
California PV Energy, LLC	N/A QF14-212	Castaic Middle School	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	4/9/2014	0.28
California PV Energy, LLC	N/A QF15-78	Chaffey HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	1/30/2015	0.54
California PV Energy, LLC	N/A QF15-79	Colony HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	1/27/2015	0.76
California PV Energy, LLC	N/A QF15-80	Etiwanda HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/31/2014	0.72
California PV Energy, LLC	N/A QF14-28	Ironhouse Sanitary District	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/24/2014	0.85
California PV Energy, LLC	N/A QF14-335	Keppel Academy	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/2014	0.11
California PV Energy, LLC	N/A QF14-329	Keppel Alpine ES North	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/2014	0.12
California PV Energy, LLC	N/A QF14-331	Keppel Alpine ES South	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/2014	0.05
California PV Energy, LLC	N/A QF14-330	Keppel Antelope ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/2014	0.09
California PV Energy, LLC	N/A QF14-333	Keppel Gibson ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/2014	0.15
California PV Energy, LLC	N/A QF14-332	Keppel Lake Los Angeles	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/2014	0.13
California PV Energy, LLC	N/A QF14-334	Keppel Pearblossom ES	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/1/2014	0.13
California PV Energy, LLC	N/A QF14-213	Live Oak Elementary School	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	4/9/2014	0.12
California PV Energy, LLC	N/A QF15-81	Los Osos HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	1/27/2015	0.76
California PV Energy, LLC	N/A QF15-82	Montclair HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	1/30/2015	0.76

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
California PV Energy, LLC	N/A QF14-211	Northlake Hills Elementary School	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	4/8/2014	0.13
California PV Energy, LLC	N/A QF13-602	Oltmans SCE at Champagne SF	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/20/2013	1.15
California PV Energy, LLC	N/A QF13-601	Oltmans SCE at Jurupa SF	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/20/2013	1.71
California PV Energy, LLC	N/A QF15-83	Ontario HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/31/2014	0.33
California PV Energy, LLC	N/A QF14-325	Palmdale Cultural Center	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/2014	0.06
California PV Energy, LLC	N/A QF14-324	Palmdale Development Services Bldg	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/2014	0.12
California PV Energy, LLC	N/A QF14-326	Palmdale Library	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/2014	0.07
California PV Energy, LLC	N/A QF14-321	Palmdale Marie Kerr Park E1	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/2014	0.07
California PV Energy, LLC	N/A QF14-323	Palmdale Marie Kerr Park E3	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/2014	0.05
California PV Energy, LLC	N/A QF14-328	Palmdale Recreation Center	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/2014	0.05
California PV Energy, LLC	N/A QF14-327	Palmdale Water Park	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	7/16/2014	0.28
California PV Energy, LLC	N/A QF15-84	Rancho Cucamonga HS	California PV Energy, LLC	California PV Energy, LLC	N/A	CAISO	Southwest	12/29/2014	0.42
Constellation Solar California, LLC	N/A QF10-656	General Motors Corp. at Fontana, Ca.	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	12/1/2007	0.80
Constellation Solar California, LLC	N/A QF10-657	GSA, PBS, Pacific Service Center at Sacramento, Ca.	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	3/1/2008	0.44
Constellation Solar California, LLC	N/A QF10-658	Kawneer Co., Inc. (Alcoa)	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	10/1/2007	0.50
Constellation Solar California, LLC	N/A QF10-665	Univ of San Francisco	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	4/1/2008	0.42
Luz Solar Partners IV	N/A QF86-736	SEGS IV SF	Luz Solar Partners IV	Luz Solar Partners IV	N/A	CAISO	Southwest	12/1/1986	36.00
Luz Solar Partners V	N/A QF87-402	SEGS V SF	Luz Solar Partners V	Luz Solar Partners V	N/A	CAISO	Southwest	10/1/1987	36.00
Luz Solar Partners VI	N/A QF88-33	SEGS VI SF	Luz Solar Partners VI	Luz Solar Partners VI	N/A	CAISO	Southwest	12/1/1988	36.00
Exelon Generation Company, LLC	ER00-3251	Green Country 1	Green Country OP Services LLC	Exelon Generation Company, LLC	2/11/2002	SPP	SPP	2/11/2002	261.00
Exelon Generation Company, LLC	ER00-3251	Green Country 2	Green Country OP Services LLC	Exelon Generation Company, LLC	2/11/2002	SPP	SPP	2/11/2002	261.00
Exelon Generation Company, LLC	ER00-3251	Green Country 3	Green Country OP Services LLC	Exelon Generation Company, LLC	2/11/2002	SPP	SPP	2/11/2002	261.00
Exelon Wind 1, LLC	N/A QF05-114	Exelon Wind 1 WF	Exelon Wind 1, LLC	Exelon Wind 1, LLC	N/A	SPP	SPP	12/31/2005	10.00
Exelon Wind 10, LLC	N/A QF07-55	Exelon Wind 10 WF	Exelon Wind 10, LLC	Exelon Wind 10, LLC	N/A	SPP	SPP	7/1/2008	10.00
Exelon Wind 11, LLC	N/A QF07-56	Exelon Wind 11 WF	Exelon Wind 11, LLC	Exelon Wind 11, LLC	N/A	SPP	SPP	7/1/2008	10.00
Exelon Wind 2, LLC	N/A QF05-116	Exelon Wind 2 WF	Exelon Wind 2, LLC	Exelon Wind 2, LLC	N/A	SPP	SPP	12/31/2005	10.00

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Filing Entity and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-Service Date	Nameplate and/or Seasonal Rating (MW)
						Balancing Authority Area	FERC Geographic Region		
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Exelon Wind 3, LLC	N/A QF05-115	Exelon Wind 3 WF	Exelon Wind 3, LLC	Exelon Wind 3, LLC	N/A	SPP	SPP	12/31/2005	10.00
Exelon Wind 4, LLC	ER07-1202 QF03-13	Exelon Wind 4 WF	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	12/15/2006	79.80
Exelon Wind 5, LLC	N/A QF06-289	Exelon Wind 5 WF	Exelon Wind 5, LLC	Exelon Wind 5, LLC	N/A	SPP	SPP	10/4/2005	10.00
Exelon Wind 6, LLC	N/A QF06-290	Exelon Wind 6 WF	Exelon Wind 6, LLC	Exelon Wind 6, LLC	N/A	SPP	SPP	11/1/2006	10.00
Exelon Wind 7, LLC	N/A QF07-46	Exelon Wind 7 WF	Exelon Wind 7, LLC	Exelon Wind 7, LLC	N/A	SPP	SPP	7/1/2008	10.00
Exelon Wind 8, LLC	N/A QF07-53	Exelon Wind 8 WF	Exelon Wind 8, LLC	Exelon Wind 8, LLC	N/A	SPP	SPP	7/1/2008	10.00
Exelon Wind 9, LLC	N/A QF07-54	Exelon Wind 9 WF	Exelon Wind 9, LLC	Exelon Wind 9, LLC	N/A	SPP	SPP	7/1/2008	10.00
Greensburg Wind Farm, LLC	N/A QF10-291	Greensburg WF	Greensburg Wind Farm, LLC	Greensburg Wind Farm, LLC	N/A	SPP	SPP	3/5/2010	12.50
High Plains Wind Power, LLC	N/A QF07-257	High Plains WF	High Plains Wind Power, LLC	High Plains Wind Power, LLC	N/A	SPP	SPP	3/31/2008	10.00
Shooting Star Wind Project, LLC	ER12-1829	Shooting Star WF	Shooting Star Wind Project, LLC	Shooting Star Wind Project, LLC	N/A	SPP	SPP	9/29/2012	104.00
Wildcat Wind, LLC	ER12-1223 QF12-412	Wildcat WF	Wildcat Wind, LLC	Wildcat Wind, LLC	N/A	SPP	SPP	7/1/2012	27.30

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Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas Storage

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
Constellation Mystic Power, LLC	Limited & discrete interconnection facilities[1]	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon Framingham, LLC	Limited & discrete interconnection facilities[1]	Exelon Framingham, LLC	Exelon Framingham, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon New Boston, LLC	Limited & discrete interconnection facilities[1]	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon West Medway, LLC	Limited & discrete interconnection facilities[1]	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Exelon Wyman, LLC	Limited & discrete interconnection facilities[1]	Exelon Wyman, LLC	Exelon Wyman, LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Holyoke Solar LLC	Limited & discrete interconnection facilities[1]	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	N/A (OATT Waiver)
Nine Mile Point Nuclear Station, LLC	Limited & discrete interconnection facilities[1]	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	N/A (OATT Waiver)

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
R.E. Ginna Nuclear Power Plant, LLC	Limited & discrete interconnection facilities[1]	R.E. Ginna Nuclear Power Plant, LLC	R.E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	N/A (OATT Waiver)
Baltimore Gas and Electric Company	Combined 115kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	695.85 combined miles
Baltimore Gas and Electric Company	Combined 138kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	54.44 combined miles
Baltimore Gas and Electric Company	Combined 230kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	320.97 combined miles
Baltimore Gas and Electric Company	Combined 500kV Lines	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	217.42 combined miles
Baltimore Gas and Electric Company	Intrastate Gas Transmission	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	approx. 165 combined miles
Calvert Cliffs Nuclear Power Plant, LLC	Limited & discrete interconnection facilities[1]	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Commonwealth Edison Company	Electric Transmission Combined 765 kV Lines	Commonwealth Edison Company	PJM	N/A	PJM	Northeast	89.59 combined miles
Commonwealth Edison Company	Electric Transmission Combined 345 kV Lines	Commonwealth Edison Company	PJM	N/A	PJM	Northeast	2,634.29 combined miles

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
Commonwealth Edison Company	Electric Transmission Combined 138 kV Lines	Commonwealth Edison Company	PJM	N/A	PJM	Northeast	2,877.02 combined miles
Criterion Power Partners, LLC	Limited & discrete interconnection facilities[1]	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Exelon Solar Chicago LLC	Limited & discrete interconnection facilities[1]	Exelon Solar Chicago LLC	Exelon Solar Chicago LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Fourmile Wind Energy, LLC	Limited & discrete interconnection facilities[1]	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Handsome Lake Energy, LLC	Limited & discrete interconnection facilities[1]	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
PECO Energy Company	Electric Transmission 500 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	316.23 combined miles
PECO Energy Company	Electric Transmission Combined 200/220 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	503.05 combined miles
PECO Energy Company	Electric Transmission Combined 132 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	127.70 combined miles
PECO Energy Company	Electric Transmission Combined 66 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	169.54 combined miles

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
PECO Energy Company	Electric Transmission Combined 13.2 kV Lines	PECO Energy Company	PJM	N/A	PJM	Northeast	0.47 combined miles
PECO Energy Company	Intrastate Gas Transmission	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	31 combined miles
PECO Energy Company	Intrastate Gas Storage (LNG)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	1,200 mmcf
Cassia Gulch Wind Park, LLC	Limited & discrete interconnection facilities[1]	Cassia Gulch Wind Park, LLC	Cassia Gulch Wind Park, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
High Mesa Energy, LLC	Limited & discrete interconnection facilities[1]	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
Tuana Springs Energy, LLC	Limited & discrete interconnection facilities[1]	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	Idaho Power	Northwest	N/A (OATT Waiver)
Beebe 1B Renewable Energy, LLC and Beebe Renewable Energy, LLC ("Beebe")[2]	Limited & discrete interconnection facilities[1]	Beebe	Beebe	N/A	MISO	Central	N/A (OATT Waiver)
Harvest Windfarm, LLC	Limited & discrete interconnection facilities[1]	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	N/A (OATT Waiver)
Michigan Wind 1, LLC	Limited & discrete interconnection facilities[1]	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	N/A (OATT Waiver)

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
CER Generation, LLC	Limited & discrete interconnection facilities[1]	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	N/A (OATT Waiver)
Constellation Power Source Generation, LLC	Limited & discrete interconnection facilities[1]	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM	Northeast	N/A (OATT Waiver)
Exelon Generation Company, LLC	Limited & discrete interconnection facilities[1]	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	Various	Various	N/A (OATT Waiver)
Cow Branch Wind Power, L.L.C.	Limited & discrete interconnection facilities[1]	Cow Branch Wind Power, LLC	Cow Branch Wind Power, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
CR Clearing, LLC	Limited & discrete interconnection facilities[1]	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
Wind Capital Holdings, LLC	Limited & discrete interconnection facilities[1]	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	N/A (OATT Waiver)
AV Solar Ranch 1, LLC	Limited & discrete interconnection facilities[1]	AV Solar Ranch 1, LLC	AV Solar Ranch 1, LLC	N/A	CAISO	Southwest	N/A (OATT Waiver)
Exelon Wind 4, LLC	Limited & discrete interconnection facilities[1]	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	N/A (OATT Waiver)

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[1] These facilities are included because waiver of Order Nos. 888, 889, 890, their implementing regulations, and the requirements of Part 358 of FERC's regulations has been sought with respect to them.

[2] Beebe 1B Renewable Energy, LLC and Beebe Renewable Energy, LLC share certain interconnection facilities.

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April 22, 2016

PUBLIC VERSION
Pursuant to the Commission's Regulations
Regarding Requests for Privileged Treatment of Documents,
18 C.F.R. § 388.112, Information Contained in Attachment A of This
Submission Constitutes Privileged, Protected, and Confidential Information
and Has Been Redacted from This Public Version

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BY ELECTRONIC FILING

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Atlantic City Electric Company, Docket No. ER10-2997-___
AV Solar Ranch 1, LLC, Docket No. ER12-2178-___
Baltimore Gas and Electric Company, Docket No. ER10-2172-___
Beebe 1B Renewable Energy, LLC, Docket No. ER14-2144-___
Beebe Renewable Energy, LLC, Docket No. ER12-2311-___
Bethlehem Renewable Energy, LLC, Docket No. ER10-3003-___
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R.E. Ginna Nuclear Power Plant, LLC, Docket No. ER10-2182-___
Shooting Star Wind Project, LLC, Docket No. ER12-1829-___
Tuana Springs Energy, LLC, Docket No. ER11-2007-___
Wildcat Wind, LLC, Docket No. ER12-1223-___
Wind Capital Holdings, LLC, Docket No. ER11-2005-___

Notice of Change in Status of the Exelon MBR Entities

Dear Secretary Bose:

Pursuant to the requirements of section 35.42 of the regulations of the Federal Energy Regulatory Commission (FERC or Commission),[1] the above-captioned affiliates of Exelon Corporation (Exelon) with market-based rate authority (collectively, the Exelon MBR Entities) respectfully submit for filing this notice of change in status (Notice) to reflect the March 23, 2016 consummation of a transaction whereby Exelon purchased the outstanding stock of Pepco Holdings, Inc. (PHI) and merged PHI into a wholly-owned subsidiary of Exelon (the Transaction).[2] As a result of the Transaction, the following entities with market-based rate authority are now affiliates of Exelon and the other above-captioned Exelon MBR Entities: Atlantic City Electric Company (ACE), Bethlehem Renewable Energy, LLC (Bethlehem Renewable), Delmarva Power & Light Company (DPL), Eastern Landfill Gas, LLC (Eastern Landfill), Fauquier Landfill Gas, LLC (Fauquier), Pepco Energy Services, Inc. (PES), Potomac Electric Power Company (Pepco) and Potomac Power Resources, LLC (PPR) (collectively, the PHI MBR Entities).[3] The new affiliation does not present any competitive concerns in the PJM Interconnection, L.L.C. (PJM) balancing authority area (BAA) and its submarkets, which are the

1 18 C.F.R. § 35.42 (2016).

2 *See Exelon Corporation and Pepco Holdings, Inc.*, 149 FERC ¶ 61,148 (2014) (approving the Transaction); *See also* Notice of Consummation, Docket No. EC14-96-000 (filed Mar. 28, 2016).

3 On April 20, 2016, Fauquier and PPR both filed notices to cancel their market-based rate tariffs, effective April 21, 2016 (one day before submission of this filing) in Docket Nos. ER16-1471-000 and ER16-1470-000, respectively. The notices are currently pending before the Commission.

relevant markets for this Notice, and does not materially alter the facts upon which the Commission relied in granting market-based rate authority to the Exelon MBR Entities. Although some market share screens exceed 20% in two submarkets of PJM, the Exelon MBR Entities continue to satisfy the Commission's requirements for market-based rates regarding horizontal market power.

I. REQUEST FOR PRIVILEGED TREATMENT

The Exelon MBR Entities request privileged treatment pursuant to Section 388.112 of the Commission's regulations for the Exelon MBR Entities' hourly load data, which is accessible via links to the work papers of Julie Solomon contained in the market screens submitted as part of Attachment A. The work papers contain information about confidential, commercially sensitive load data that could harm the Exelon MBR Entities if publicly released. Pursuant to Section 35.37(f) of the Commission's regulations, a proposed protective order is included herewith as Attachment B. Communications concerning this request for privileged treatment should be directed to Jane Rueger at 202-626-6534 or Harold Bulger at 202-637-6182.

II. DOCUMENTS SUBMITTED

The Exelon MBR Entities submit the following documents:

1. This transmittal letter;

2. Attachment A: Affidavit of Julie R. Solomon, Managing Director of Navigant Consulting, Inc. including exhibits and work papers;

3. Attachment B: Proposed protective order; and

4. Attachment C: Asset appendices of Exelon Corporation and affiliates in workable file format.

III. COMMUNICATIONS

Communications concerning this filing should be directed to the individuals listed below:

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*The persons denoted with an asterisk are designated for service pursuant to 18 C.F.R. § 385.2010.

IV. DESCRIPTION OF CHANGE IN STATUS

Exelon is a publicly traded company headquartered in Chicago, Illinois and has operations and business activities in 48 states, the District of Columbia, and Canada. Exelon Generation Company, LLC (Exelon Generation) is a direct wholly-owned subsidiary of Exelon that owns, directly or through its subsidiaries, electric generation facilities in PJM and the PJM submarkets, as well as in markets first-tier to PJM.[4] In addition, Exelon Generation has certain long-term power purchase agreements (PPAs) pursuant to which it purchase power generated from electric facilities located in PJM and its submarkets as well as in markets first-tier to PJM.[5] In PJM, Exelon also owns indirectly Commonwealth Edison Company (ComEd), PECO Energy Company (PECO), and Baltimore Gas and Electric Company (BGE). ComEd, PECO, and BGE are franchised public utilities within the meaning of 18 C.F.R. § 35.36(a)(5) and own electric distribution systems through which they deliver electricity to approximately 6.6 million customers in Illinois, Pennsylvania, and Maryland. ComEd, PECO, and BGE own transmission facilities, but have transferred operational control over such facilities to PJM, which provides transmission service pursuant to its Open Access Transmission Tariff (OATT) on file with the Commission.[6] In addition, PECO and BGE own certain intrastate natural gas transportation and distribution facilities used distribute natural gas to customers in Philadelphia and central Maryland and operate liquefied natural gas facilities and propane-air facilities associated with their respective distribution activities that do not offer services to third parties.[7] Affiliates of Exelon own or control sites for the development of new generation capacity that are in the interconnection process in PJM as well as in other markets. In Order No. 816 the Commission eliminated the requirement to file land acquisition reports and revised section 35.37 of its

[4] The electric generation facilities owned by Exelon Generation and its subsidiaries are identified in the asset appendix provided in Attachment C.

[5] The PPAs that are relevant for the market power analysis as a result of the refinements to the Commission's market-based rate program adopted in Order No. 816 are identified in the asset appendix provided in Attachment C.

[6] The electric transmission facilities owned by ComEd, PECO, and BGE are identified in the asset appendix in Attachment C.

[7] The intrastate natural gas facilities owned by PECO and BGE are identified in the asset appendix in Attachment C.

regulations to remove the requirement that sellers provide information regarding sites for generation capacity development to demonstrate lack of vertical market power.[8]

As a result of the Transaction, the PHI MBR Entities are now indirect wholly-owned subsidiaries of Exelon.[9] ACE, DPL, and Pepco are now direct wholly-owned subsidiaries of Pepco Holdings LLC, which is a direct wholly-owned subsidiary of PH Holdco LLC. PH Holdco LLC is a direct wholly-owned subsidiary of Exelon Energy Delivery Company, LLC, which is a direct wholly-owned subsidiary of Exelon. ACE, DPL, and Pepco are state-regulated franchised public utilities and together provide transmission and distribution services to retail customers in the Mid-Atlantic Region. All of ACE, DPL, and Pepco's retail customers have access to competitively priced retail power and, as a result, are not considered captive for the purposes of the Commission's market-based rate regulations.[10] ACE, DPL, and Pepco have been granted authority to sell energy, capacity, and ancillary services at market-based rates by the Commission.[11]

ACE, DPL, and Pepco do not own any electric generation facilities, except for limited behind-the-meter facilities located at substation sites.[12] ACE and DPL have long-term power purchase agreements that, as a result of the refinements to the Commission's market-based rate program adopted in Order No. 816,[13] are now included in the asset appendix and in the market power analysis. ACE has long-term power purchase agreements with Logan Generating Company, L.P., Chambers Cogeneration, Limited Partnership, and Covanta Delaware Valley, L.P., each of which owns a qualifying facility under the Public Utility Regulatory Policies Act of 1978 located in the PJM East submarket. These contracts obligate ACE to pay the generators for specified amounts of energy at a specified price, and the costs are recovered from ACE's retail customers. ACE bids the energy into the PJM market and credits retail customers for all energy revenues received by ACE from PJM. ACE does not control those generating units and cannot withhold the output of the units from the market. DPL has long-term power purchase agreements with Armenia Mountain Wind, LLC, Roth Rock Wind Farm, LLC, and Chestnut

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8 *See* Order No. 816 at P 212. The Commission however retained the right to request additional information about land acquisitions. *Id.* at P 210.

9 The Exelon MBR Entities anticipate filing proposed tariff revisions in the next week, as necessitated by consummation of the Transaction and to comply with recent Commission orders on market-based rate tariff filings.

10 *See Potomac Elec. Power Co.*, *et al.*, 93 FERC ¶ 61,240 at 61,781-82 (2000) (granting waiver of the code of conduct requirement, in part, on the basis that Pepco's customers have retail choice and are not captive); *see also Pepco Holdings, Inc*., 141 FERC ¶ 61,034 (2012) (granting waiver of affiliate restrictions, in part, on the basis that ACE, DPL, and Pepco do not have captive customers).

11 *Atlantic City Elec. Co.*, *et al.*, Docket Nos. ER10-2997-003, *et al*, (Jun. 20, 2014) (unpublished letter order) (renewing the market-based rate authority of the PHI MBR Entities).

12 Consistent with Order No. 816, these behind-the-meter facilities have not been included in the indicative screens or asset appendix herewith. *See* Order No. 816 at P 255 (2015) ("[W]e clarify that qualifying facilities that are exempt from [Federal Power Act] section 205 and facilities that are behind-the-meter facilities do not need to be reported in the asset appendix or indicative screens.").

13 *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 153 FERC ¶ 61,065 (2015) (Order No. 816).

Flats, LLC, each of which owns a wind-power electric generation facility located in PJM. Each of these agreements is fixed-price, must-run contract, and DPL has no ability to withhold this generation.

PES is now a direct wholly-owned subsidiary of Constellation NewEnergy, Inc., which is owned by Constellation Energy Resources, LLC (Constellation Energy Resources). Constellation Energy Resources is owned by Exelon Generation, which is a direct wholly-owned subsidiary of Exelon. Bethlehem Renewable and Eastern Landfill are now direct wholly-owned subsidiaries of Exelon Generation. PES, Bethlehem Renewable and Eastern Landfill each have been granted market-based rate authority by the Commission.[14]

PES is primarily engaged in providing energy services, including investment-grade energy audits and installation of energy conservation measures for federal, state and local governments, specialized construction work for electric utilities, and the delivery of thermal energy under long-term contracts. PES does not own any electrical generation facilities, except for certain limited behind-the-meter generation facilities.[15] Bethlehem Renewable owns a 4.7 MW landfill gas-fired facility located in Bethlehem, Pennsylvania and interconnected with the transmission system of PPL Electric Utilities Corporation in the 5004/5005 PJM submarket. Bethlehem Renewable is an exempt wholesale generator (EWG) within the meaning of the Public Utility Holding Company Act of 2005.[16] Eastern Landfill owns a 3 MW landfill gas-fired facility located in Baltimore County, Maryland and interconnected with the transmission system of Baltimore Gas and Electric Company in the 5004/5005 PJM submarket. Eastern Landfill is an EWG.[17]

Other than the generation facilities described above, PES and its subsidiaries do not own, operate, or have reportable long-term firm purchases from any other generating capacity in the Northeast Region or in any other region.

V. ANALYSIS OF CHANGE IN STATUS

The change in status reported herein does not raise any horizontal market power concerns. Likewise, the Exelon MBR Entities continue to satisfy the Commission's requirements with respect to transmission market power and the ability to erect barriers to entry. Therefore, the Exelon MBR Entities respectfully request that the Commission accept this notice of change in status.

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[14] *See id.*; *see also supra* n. 3 regarding the recent notices of cancellation of the market-based rate tariffs of PPR and Fauquier, which are now also indirect wholly-owned subsidiaries of Exelon but no longer own any operational generating facilities as explained in the notices of cancellation.

[15] Consistent with Order No. 816, these behind-the-meter facilities owned by PES have not been included in the indicative screens or asset appendix herewith. *See* Order No. 816 at P 255 (2015).

[16] *Bethlehem Renewable Energy, LLC*, *et al.*, Notice of Effectiveness of Exempt Wholesale Generator or Foreign Utility Company Status, Docket Nos. EG07-53-000, et al. (Sept. 12, 2007) (unpublished letter order).

[17] *Eastern Landfill Gas, LLC*, 112 FERC ¶ 62,065 (2005).

a. Horizontal Market Power Analysis

As demonstrated below and in the Affidavit of Julie Solomon attached hereto as Attachment A (Solomon Affidavit), the Exelon MBR Entities continue to satisfy the Commission's requirements for showing a lack of horizontal market power. Ms. Solomon conducted her analyses consistent with Order No. 697, Order No. 816 and related orders, performing the two indicative horizontal market power screens required by the Commission, namely the pivotal supplier screen (PSS) and the market share screen (MSS). The relevant geographic markets for purposes of this change in status notice are the PJM BAA and three submarkets within the PJM BAA, the PJM East, AP South, and 5004/5005 submarkets. Ms. Solomon's analysis is based on the study period of December 2014-November 2015, the most recent available actual historical data. Consistent with Order No. 816, Ms. Solomon attributes to the Exelon MBR Entities the generation owned by the Exelon MBR Entities and their affiliates in each of the relevant markets and submarkets, adjusted for long-term firm purchases and sales, as well as a pro rata share of imports from affiliated uncommitted capacity in relevant first-tier markets.[18] As permitted by the Commission in Order No. 816, however, Ms. Solomon has not included qualifying facilities that are exempt from Section 205 of the Federal Power Act or behind-the-meter facilities in the generation attributed to the Exelon MBR Entities.[19]

As demonstrated in the Solomon Affidavit, the Exelon MBR Entities pass the PSS in PJM and all relevant submarkets because the Exelon MBR Entities' net uncommitted capacity is less than each market's net uncommitted supply. The following table summarizes the results of the PSS.

Relevant Market	Exelon MBR Entities Uncommitted Capacity	Net Uncommitted Supply	Result
PJM	6,215 MW	45,884 MW	Pass[20]
AP South	3,635 MW	18,207 MW	Pass[21]
5004/5005	3,591 MW	11,732 MW	Pass[22]
PJM East	4,314 MW	8,403 MW	Pass[23]

The Exelon MBR Entities pass the MSS in PJM and in the AP South submarket, because their market share is below the 20% threshold in each season. The Exelon MBR Entities do not pass the MSS in one season of the 5004/5005 submarket (Spring), or in the PJM East submarket, because the Exelon MBR Entities' market share exceeds the 20% threshold in these submarkets. The following table summarizes the results of the MSS.

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[18] Attachment A, Solomon Aff. at 4-9.

[19] *See* Order No. 816 at P 255. Likewise, consistent with Order No. 816, these assets are not included in the Exelon MBR Entities' asset appendix.

[20] Attachment A, Exhibit JRS-4.

[21] *Id.* at JRS-6.

[22] *Id.* at JRS-8.

[23] *Id.* at JRS-10.

Relevant Market	Winter	Spring	Summer	Fall	Result
PJM	10.6%	10.9%	9.0%	9.7%	Pass[24]
AP South	14.3%	14.8%	11.7%	11.2%	Pass[25]
5004/5005	19.1%	21.3%	16.4%	15.8%	Fail[26]
PJM East	26.7%	30.2%	28.6%	23.0%	Fail[27]

Although the Exelon MBR Entities do not pass the MSS in the 5004/5005 and PJM East submarkets, as Ms. Solomon explains in Attachment A, PJM and each of the relevant submarkets are subject to extensive Commission-approved market monitoring and mitigation, and the Commission previously has found that such market monitoring and mitigation generally results in transparent pricing and mitigates any attempts to exercise market power.[28] For example, the Commission recently found that market-based rate sellers with MSS for PJM or its submarkets in excess of 20% continue to satisfy the Commission's requirements for market-based rates regarding horizontal market power.[29] Also, Ms. Solomon notes the Exelon MBR Entities are subject to certain additional behavioral commitments in PJM, entered into via a Settlement Agreement with the PJM Market Monitor at the time of the merger between Exelon and Constellation Energy Group, Inc. that mitigates any horizontal market power.[30] Further, Exelon's hedging strategy also reduces its ability or incentive to exercise market power; as of the end of 2015, expected generation was more than 90% hedged for 2016 and more than 60% hedged for 2017.[31] Finally, Ms. Solomon's market share analysis is extremely conservative, which means the Exelon MBR Entities' market share is overstated in PJM and the relevant submarkets.[32]

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[24] *Id.* at JRS-5.

[25] *Id.* at JRS-7.

[26] *Id.* at JRS-9.

[27] *Id.* at JRS-11.

[28] Attachment A, Solomon Aff. at 3 (citing Order No. 697 at PP 241-242). *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 241-242), *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31, 268 (2008), *clarified*, 124 FERC ¶ 61,055 (2008), *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *clarified*, 131 FERC ¶ 61,021 (2010), *aff'd sub nom. Montana Consumer Council v. FERC*, 659 F.3d 910 (9th Cir. 2011) (Order No. 697).

[29] *See NRG Power Marketing LLC*, 150 FERC ¶ 61,011 (2015) (accepting for filing notice of change in status with MSS for PJM ranging from 21.2% to 25.8%); *See also Lower Mount Bethel Energy, LLC*, ER10-1959-004, Letter Order (Dec. 21, 2015) (accepting for filing notice of change in status with MSS for the AP South submarket ranging from 25.5% to 36.8% and MSS for the 5004/5005 submarket ranging from 31.6% to 45.9%).

[30] Attachment A, Solomon Aff. at 3.

[31] *Id.*

[32] *Id.* at 8-9. Ms. Solomon explains that her Total Uncommitted Capacity determination in PJM and the relative submarkets is "extremely conservative" because her "analysis assumes that every MW of generation is

In sum, Ms. Solomon concludes that the Exelon MBR Entities do not have market power in any of the relevant markets in the Northeast Region. Therefore, the new affiliation of the Exelon MBR Entities with the PHI MBR Entities does not raise any horizontal market power concerns.

b. Vertical Market Power Analysis

The change in status does not raise any vertical market power concerns. PES, Bethlehem Renewable, and Eastern Landfill do not own, operate, or control transmission facilities other than the limited and discrete facilities necessary to connect their generating facilities to the grid. In addition, neither PES nor its subsidiaries control inputs to electric power production as defined in section 35.36 of the Commission's regulations. While ACE, DPL, and Pepco own transmission facilities, their transmission facilities are operated by PJM and service over these facilities is provided pursuant to PJM's OATT. The Commission has frequently held that membership in a Commission-approved regional transmission organization (RTO) sufficiently addresses vertical market power concerns in an RTO market such as PJM.[33] ACE, DPL, and Pepco do not own or control inputs to electric power production other than DPL's ownership of approximately 111 combined miles of intrastate natural gas transportation pipelines, 3,279 combined miles of intrastate natural gas distribution pipelines, and a 248 million cubic foot liquefied natural gas (LNG) storage facility, all located within the PJM footprint. The Commission has adopted a rebuttable presumption that sellers cannot erect barriers to entry based on ownership or control of, or affiliation with an entity that owns or controls such natural gas facilities.[34] Further, the Exelon MBR Entities and their affiliates affirmatively state that they have not erected barriers to entry into the relevant markets and will not erect barriers to entry into the relevant markets.[35] Thus, the new affiliations reported herein do not raise any vertical market power concerns.

VI. CONCLUSION

For the reasons set forth above, the Exelon MBR Entities' new affiliation reported herein does not materially change the facts and circumstances that the Commission relied upon in granting the Exelon MBR Entities market-based rate authority. Nor does the affiliation raise any horizontal or vertical market power concerns with respect to the Exelon MBR Entities. Therefore, the Exelon MBR Entities respectfully request that the Commission accept this Notice for filing. Submitted with this Notice are asset appendices in workable file format listing (1) all

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'committed' to the extent there is load, even though in reality every MW of generation is not necessarily committed by ownership or contractual commitment to serving a specific load." As Ms. Solomon notes, some parties rely on short-term purchases from PJM and the relevant submarkets to meet load obligations and thus competing uncommitted capacity is conservatively low in her analysis.

[33] *See*, *e.g.*, *Exelon Corp.*, 138 FERC ¶ 61,167 at P 113 (2012); *Duke Energy*, 136 FERC ¶ 61,245 at P 161 (2011); *FirstEnergy Corp.*, 133 FERC ¶ 61,222 at PP 56-57 (2010); *PPL Corp.*, 133 FERC ¶ 61,083 at P 18 (2010); *Exelon Corp.*, 127 FERC ¶ 61,161 at PP 90, 93 (2009).

[34] Order No. 697 at P 446.

[35] 18 CFR 35.37(e)(3) (2016).

Exelon affiliates that have market-based rate authority and identifying all generation assets the corporate family owns or from which there are long-term firm purchases by balancing authority area and geographic region,[36] and (2) all electric transmission and regulated natural gas intrastate pipelines and/or gas storage facilities the corporate family owns or controls.[37]

Respectfully submitted,

/s/ Jane E. Rueger
Jane E. Rueger
Harold W. Bulger, III

Counsel for the Exelon MBR Entities

[36] The Exelon asset appendices have been updated to comply with the new requirements of Order No. 816. Accordingly, there are additional contracts included in this generation asset appendix that were not previously included in pre-Order No. 816 versions of the Exelon generation asset appendix and some contracts that were included in pre-Order No. 816 versions of the Exelon generation asset appendix have been removed since such contracts are no longer reportable long-term purchases.

[37] 18 C.F.R. § 35.42(c) (2016).

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in these proceedings.

Dated at Washington, D.C., this 22nd day of April, 2016.

/s/ Harold W. Bulger, III

Harold W. Bulger, III
White & Case LLP
701 Thirteenth Street, NW
Washington, D.C. 20005
Tel.: (202) 637-6182

Attachment A:

Affidavit and Exhibits of Julie R. Solomon of Navigant Consulting, Inc.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Atlantic City Electric Company	**)**	**Docket No. ER10-2997-___**
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Potomac Power Resources, LLC	**)**	**Docket No. ER10-2990-__**
R.E. Ginna Nuclear Power Plant, LLC	**)**	**Docket No. ER10-2182-__**
Shooting Star Wind Project, LLC	**)**	**Docket No. ER12-1829-__**
Tuana Springs Energy, LLC	**)**	**Docket No. ER11-2007-__**
Wildcat Wind, LLC	**)**	**Docket No. ER12-1223-__**
Wind Capital Holdings, LLC	**)**	**Docket No. ER11-2005-__**

AFFIDAVIT OF
JULIE R. SOLOMON

I. INTRODUCTION

My name is Julie R. Solomon. I am a Managing Director of Navigant Consulting, Inc. My business address is 1200 19th Street, N.W., Suite 700, Washington, DC 20036. A large portion of my consulting activities involves electric utility industry restructuring and the transition from regulation to competition. I have been involved extensively in consulting on market power issues concerning mergers, other asset transactions and market-based rate applications. I have filed a number of affidavits before the Federal Energy Regulatory Commission (the "Commission") in connection with electric utility mergers, the purchase and sale of jurisdictional assets, applications for market-based rates, and triennial updates. Included among these, I have filed a number of affidavits with the Commission on behalf of relevant affiliates of Exelon Corporation ("Exelon") with market-based rate authority in connection with past triennial updates. My resume is attached as Exhibit JRS-1.

I have been asked by counsel for the above-captioned subsidiaries of Exelon with market-based rate authority (the "Exelon MBR Entities" or "Sellers") to perform an analysis of market power in compliance with the Commission's guidelines contained in Order No. 697[1] and Order No. 816[2] in connection with a notice of change in status arising from the merger of Exelon and

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[1] *Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity and Ancillary Servs. by Pub. Utils.*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g and clarification*, Order No. 697-A, FERC Stats. & Regs ¶ 31,268, *order on reh'g and clarification*, 124 FERC ¶ 61,055, *order on reh'g and clarification*, Order No. 697-B, FERC Stats. & Regs ¶ 31,285 (2008), *order on reh'g and clarification*, Order No. 697-C, FERC Stats. & Regs ¶ 31,291 (2009), *order on reh'g and clarification*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305, *order on clarification*, 131 FERC ¶ 61,021, *reh'g denied*, 134 FERC ¶ 61,046 (2010), *appeal docketed sub nom. Mont. Consumer Counsel v. FERC,* Nos. 08-71827, *et al.* (9th Cir. filed May 1, 2008) (collectively, "Order No. 697") (codified at 18 C.F.R. pt. 35).

[2] *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 816, 153 FERC ¶ 61,065 (2015).

Pepco Holdings, Inc. ("PHI").[3] Here I provide an evaluation of horizontal and vertical market power issues for PJM Interconnection, L.L.C. ("PJM") and relevant submarkets, where the Exelon MBR Entities own or control generation facilities, and are now affiliated with generation and transmission facilities that were previously owned or controlled by affiliates of PHI.

II. SUMMARY OF CONCLUSIONS

Based on the analyses discussed herein, I find that, under the Commission's guidelines, the Exelon MBR Entities satisfy the Commission's horizontal market power screens, or are subject to Commission-approved market monitoring and mitigation rules that are sufficient to address any market power concerns. The Exelon MBR Entities also do not have vertical market power in PJM.

Order No. 697 contemplates that Commission-approved market monitoring and mitigation in RTO markets or submarkets be considered as part of market power analysis.[4] Each of the relevant Northeast Region markets and submarkets is subject to extensive Commission-approved market monitoring and mitigation that generally results in transparent pricing and mitigates attempts to exercise market power.[5] Second, the Exelon MBR Entities are subject to additional behavioral commitments in PJM, entered into as part of the transaction between Exelon Corporation and Constellation Energy Group, Inc. (*see* Docket No. EC11-83-000) (the "Exelon-Constellation merger") that mitigate any horizontal market power.[6] Further, Exelon's hedging strategy limits exposure to risk but also reduces its ability or incentive to exercise market power. Exelon Generation Company, LLC ("Exelon Generation") maintains hedge percentage targets for its entire generation fleet, and as of the end of 2015 expected generation was more than 90 percent hedged for 2016 and more than 60 percent hedged for 2017.

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3 *Exelon Corporation*, 149 FERC ¶ 61,148 (2014). The merger was consummated on March 23, 2016.

4 *See* Order No. 697 at PP 241-242.

5 Order No. 697 at P 241.

6 *See* Answer of Exelon Corporation and Constellation Energy Group, Inc., Docket No. EC11-83-000 (filed Oct. 11, 2011) ("Section 203 Amendment") (describing the behavioral commitments). A copy of the Section 203 Amendment was provided in Attachment A-2 to the Exelon MBR Entities' April 11, 2012 Change in Status Filing in the captioned dockets.

The analysis I have conducted is consistent with Order No. 697, Order No. 816 and related orders. I have performed the two indicative horizontal market power screens required by the Commission, namely a pivotal supplier analysis based on the annual peak demand of the relevant market ("Pivotal Supplier Analysis") and a market share analysis ("Market Share Analysis") applied on a seasonal basis for the relevant study period of December 2014-November 2015.

I understand that an affirmative statement on behalf of the Exelon MBR Entities and their affiliates is included in their submission to the effect that they have not erected barriers to entry and will not erect barriers to entry.

III. DESCRIPTION OF EXELON MBR ENTITIES

For purposes of my analysis, Exhibit JRS-2 details the generation owned or controlled by the Exelon MBR Entities in PJM, and also reflects generation owned or controlled in relevant first-tier markets. A more detailed description of the Exelon MBR Entities is provided in the submittal letter.

IV. HORIZONTAL MARKET POWER

In Order No. 697, the Commission codified a methodology for assessing market power to be used by applicants requesting market-based rate authority under Section 205 of the Federal Power Act or making their required triennial market power update filings. The Commission applies two screens – the Pivotal Supplier Analysis and the Market Share Analysis – intended to demonstrate a lack of horizontal market power. If an entity fails to pass either of the screens, there is a presumption of horizontal market power and further analysis is required.

In Order No. 697, the Commission defines the default relevant market as the Balancing Authority Area ("BAA") in which the applicant is physically located and markets directly interconnected to the seller's balancing authority area (first-tier balancing authority area markets). Where a generator is interconnected to a non-affiliate owned transmission system, the only relevant market is the BAA in which the generator is located.[7] Sellers located in, and members of, Regional Transmission Organizations ("RTOs") may use the geographic region under the control

[7] *Order No.697* at P 232 n.217.

of the RTO as the default relevant geographic market.[8] Sellers located in and a member of an RTO/ISO are not required to analyze first-tier markets to the RTO/ISO.

Pivotal Supplier Analysis

The Pivotal Supplier Analysis seeks to determine if load can be served without an applicant's generation. Order No. 697-A specifies a number of calculations for the Pivotal Supplier Analysis.[9]

First, Total Uncommitted Supply is calculated based on installed capacity (adjusted for long-term firm purchases and sales) plus imports less the reserve requirement (*i.e.*, operating reserves) less the average daily peak native load for the peak month.

Second, Wholesale Load is calculated based on the difference between the annual peak load (needle peak) and the average daily peak native load for the peak month.

Third, Net Uncommitted Supply is calculated based on the difference between Total Uncommitted Supply and Wholesale Load. Seller's Uncommitted Capacity is based on Seller's Total Uncommitted Capacity less its average daily peak native load.

If Seller's Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Analysis is passed.

Market Share Analysis

The Market Share Analysis evaluates, for each of the four seasons, whether the seller has a dominant position in the market, with dominance defined as a market share in excess of 20 percent.

Order No. 697 specifies a number of calculations for the market share screen.[10]

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[8] *Id.* at P 235.

[9] *See* Order No. 697-A at Appendix A to Subpart H.

[10] *See id.*

First, Seller and Affiliate Capacity is calculated based on installed capacity (adjusted for long-term firm purchases and sales) plus imports less planned outages. Non-Affiliate Capacity is calculated in a similar manner.

Second, Capacity Deductions are calculated based on average peak native load in the season (averaged over all days)[11] plus operating reserves.

Third, Seller's Uncommitted Capacity is calculated by subtracting the Capacity Deductions attributed to Seller from Seller and Affiliate Capacity, and Total Competing Supply is calculated by subtracting the Capacity Deductions attributed to others from Non-Affiliate Capacity. Total Seasonal Uncommitted Capacity is the sum of Seller's Uncommitted Capacity and Total Competing Supply.

Finally, Seller's Market Share is calculated as Seller's Uncommitted Capacity as a percentage of Total Seasonal Uncommitted Capacity.

If Seller's Market Share is less than 20 percent in all seasons, the Market Share Analysis is passed.

Assumptions

Relevant Geographic Markets. My analysis is focused on PJM and submarkets (namely PJM East, 5004/5005, and AP South) as the only relevant geographic markets.

Study Period. My analysis is based on a December 2014-November 2015 study period, consistent with the instruction that "[t]ransmission-owning applicants…submitting a change in status filing, should rely on the most recent available actual historical data for each complete season of: winter (December – February), spring (March – May), summer (June – August) and fall (September – November)."[12]

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[11] Consistent with the *Clarification Order* at P 12(a), I used the following seasons for my analysis: Winter (December-February), Spring (March-May), Summer (June-August) and Fall (September-November).

[12] Clarification Order, 121 FERC ¶ 61,260 at P 12(c) (2007).

Generating Capacity. For seasonal ratings relevant to the Exelon MBR Entities' generation, I rely on summer and winter ratings reported in the Energy Information Administration's "Annual Electric Generator Report," Form EIA-860.[13] For PJM installed capacity, I relied on data reported by Energy Velocity based on seasonal EIA-860 ratings.[14] For the PJM submarkets, I relied on the same installed capacity data, identifying generating units in the submarkets consistent with the submarket definitions outlined by PJM in its 2012 Simultaneous Import Limit ("SIL") Study.[15]

Operating Reserves. I calculated operating reserves for PJM and its relevant submarkets based on *PJM Manual 13 (Emergency Operations)*.[16] Day-ahead scheduling (operating) reserves in 2015 were based on 5.93 percent of the peak load forecast for the portion of PJM within the NERC Reliability*First* Corporation region. For the Dominion zone, the operating reserve requirement is based on Dominion's share of the Virginia-Carolinas ("VACAR") reserve sharing requirement.[17] I conservatively did not assign any operating reserves to the Exelon MBR Entities.

Load Data. I used hourly load data reported on the websites for the Northeast Region RTOs.

The PJM submarkets are defined based on the following transmission zones:

Transmission Zones		PJM East	5004/5005	AP South
AE	Atlantic City Electric Company	x	x	x
DP&L	Delmarva Power & Light	x	x	x
JCP&L	Jersey Central Power & Light Company	x	x	x
PE	PECO Energy Company	x	x	x
PSE&G	Public Service Electric & Gas Company	x	x	x
RECO	Rockland Electric Company	x	x	x
ME	Metropolitan Edison Company		x	x
PPL	PPL Electric Utilities		x	x

[13] http://www.eia.gov/cneaf/electricity/page/eia860.html.

[14] http://www.eia.gov/cneaf/electricity/page/eia860.html.

[15] *See 2012 Simultaneous Import Limit Study*, PJM, Docket No. AD10-002, October 2, 2013.

[16] The current version of Manual 13 can be found at http://www.pjm.com/documents/~/media/documents/manuals/m13.ashx.

[17] *See Manual 13* and http://www.serc1.org/Documents/SERC%20Standing%20Committee%20Documents/Regional%20Criteria/SERC%20Reg%20Criteria_Contingency%20Reserve%20Policy_Rev%205%20(10-07-11).pdf

Transmission Zones		PJM East	5004/5005	AP South
BGE	Baltimore Gas & Electric		x	x
PEPCO	Potomac Electric Power Company		x	x
UGI	UGI Utilities, Inc.		x	x
VAP	Virginia Electric & Power (Dominion)			x

The Exelon MBR Entities provided me with data on the load they served in the relevant markets during the study period. This includes load directly supplied by Exelon Generation, including net physical sales to parties that primarily serve load,[18] as well as sales by Exelon Generation to retail affiliates of the Exelon MBR Entities in support of their load obligations.[19]

Other Load and Generation Commitments. I note that the Total Uncommitted Capacity determined in PJM and submarkets is extremely conservative, because no attempt has been made to match load commitments (and, correspondingly, generation commitments) attributable to individual parties, other than the Exelon MBR Entities, in these markets. Under the Market Share Analysis, for example, the amount of load attributable to "others" is simply the difference between the total average peak native load in the season and the amount attributable to the seller (in this case, the Exelon MBR Entities). The result is conservative in that it assumes all load in the market is met with specific generation committed to serving it via ownership or contractual commitment, which is not an accurate reflection of the facts in a market where some parties rely on short-term market purchases from PJM to meet load obligations. In other words, my analysis assumes that every MW of generation is "committed" to the extent there is load, even though in reality every MW of generation is not necessarily committed by ownership or contractual commitment to serving a specific load. Thus, the Total Competing (Uncommitted) Supply that is assumed to

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[18] The Commission allows market-based rate sellers to consider their sales to load-serving entities on a short-term basis when computing their uncommitted capacity ("We will allow IPPs to deduct short term native load obligations if they can show that the power sold to the utility was used to meet native load." Order No. 697 at P 155). For purposes of my screen calculations, I considered only sales by the Exelon MBR Entities to load-serving entities that are subject to contracts for the sale of physical energy while simultaneously netting out purchases from the same load-serving entities.

[19] Sellers may deduct "long-term load following contracts to the extent that the seller has included in its total capacity a corresponding generating unit or long-term firm purchase contract that will be used to meet the obligation." Order No. 697 at P 154.

compete with Exelon MBR Entities' Uncommitted Capacity in my analysis is conservatively low, which means the Exelon MBR Entities' market share is overstated.

Planned Outages. I calculated average planned outages for each of the season based on the day-ahead planned outage forecast. For the submarkets, I estimated outages based on the submarket's share of generation relative to total RTO generation. For the Exelon MBR Entities, I estimated outages based on their share of generation relative to total generation in the relevant market or submarket.

SIL. I rely on the Commission's order approving SILs in the Northeast Region,[20] which covered an earlier (December 2011-November 2012) study period.

Allocating Imports. I allocated imports to the Exelon MBR Entities in a manner consistent with the Order No. 697-A Clarification Order, which states that "market-based rate sellers, after accounting for the firm transmission rights held by the sellers and their affiliates, may allocate simultaneous transmission import capability on a *pro rata* basis (*i.e.*, based on the relative shares of the market-based rate seller's (and its affiliates') and competing suppliers' uncommitted generation capacity in first-tier markets when performing the indicative screens."[21] Based on the Exelon MBR Entities' share of uncommitted capacity in markets first-tier to the relevant markets (or submarkets) being analyzed, I allocated a pro rata share of the SIL to them. The remainder of the SIL was assumed to be Non-Affiliate Capacity.

Results of Analysis

The detailed results of the Pivotal Supplier Analysis and Market Share Analysis are contained in Exhibits JRS-3 and JRS-4, respectively, consistent with the Appendix A screen format

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20 *New Brunswick Energy Marketing Corporation*, Order On Simultaneous Transmission Import Limit Values For The Northeast Region, 147 FERC ¶ 61,190 (2014).

21 Order No. 697-A Clarification Order at Ordering Paragraph (A).

contained in Order No. 816.[22] The indicative screens also are being provided in a workable spreadsheet format, as is required under Order No. 816.[23]

As shown in Exhibit JRS-3, the Pivotal Supplier Analysis is passed in PJM (including submarkets). The Market Share Analysis is passed in PJM and the AP South submarket. However, the Exelon MBR Entities market share exceeds the 20 percent threshold for the Market Share Analysis in one season in the 5004/5005 submarket, and in the PJM East submarket. This result should not result in a determination that the Exelon MBR Entities have horizontal market power because any perceived generation market power in PJM or its submarkets is deemed to be adequately mitigated by existing Commission-approved market structure and market monitoring and mitigation. Order No. 697 contemplates that Commission-approved market monitoring and mitigation in RTO/ISO markets or submarkets be considered as part of market power analysis.[24] PJM is subject to extensive Commission-approved market monitoring and mitigation, and the Commission has previously found that the PJM market monitoring and mitigation rules are sufficient to address market power concerns in the PJM submarkets,[25] and the Commission re-affirmed this policy as recently as December 2015.[26] In addition, as I noted earlier, Exelon MBR Entities are subject to additional behavioral commitments in PJM that further mitigate any concerns regarding horizontal market power.[27]

PJM

Pivotal Supplier Analysis. The Exelon MBR Entities' Installed Capacity in PJM is 22,574 MW. They have 2,913 MW of long-term purchases and 854 MW of long-term sales. After taking into account their load commitments and imports attributed to them, Sellers' Uncommitted

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22 *Order No. 816*, 153 FERC ¶ 61,065 (2015). The screen formats are provided electronically on the FERC website. http://www.ferc.gov/industries/electric/gen-info/mbr/OrderNo816/appendix-A.xls.

23 *Id*. at P 80.

24 Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 240-42, P 290. *See also*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 111 (adopting a rebuttable presumption that existing Commission-approved RTO/ISO market monitoring and mitigation is sufficient to address any market power concerns).

25 *NRG Power Marketing LLC*, 150 FERC ¶ 61,011 (2015).

26 *See Lower Mount Bethel Energy, LLC*, ER10-1959-004, Letter Order (Dec. 21, 2015).

27 *See* note 3.

Capacity is 6,215 MW. Net Uncommitted Supply is 45,884 MW. Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Analysis is passed in PJM. *See* Exhibit JRS-4.

Market Share Analysis. The Exelon MBR Entities' Installed Capacity in PJM ranges from 22,574 MW to 23,261 MW. The Exelon MBR Entities have 2,913 MW to 3,161 MW of long-term purchases, 854 MW to 867 MW of long-term sales. After taking into account their load commitments and planned outages and imports attributed to them, Sellers' Uncommitted Capacity ranges from 6,312 MW to 9,671 MW. Total Seasonal Uncommitted Capacity ranges from 70,042 MW to 91,168 MW. Sellers' Market Share ranges from 9.0 to 10.9 percent. Because Sellers' Market Share is less than 20 percent in all seasons, the Market Share Analysis is passed in PJM. *See* Exhibit JRS-5.

Thus, on the basis of the Commission's screens, the Exelon MBR Entities do not have horizontal market power in PJM.

AP South

Pivotal Supplier Analysis. The Exelon MBR Entities' Installed Capacity in AP South is 11,818 MW. They have 1,108 MW of long-term purchases and 854 MW of long-term sales. After taking into account their load commitments and imports attributed to them, Sellers' Uncommitted Capacity is 3,635 MW. Net Uncommitted Supply is 18,207 MW. Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Analysis is passed in AP South. *See* Exhibit JRS-6.

Market Share Analysis. The Exelon MBR Entities' Installed Capacity in AP South ranges from 11,818 MW to 12,331 MW. The Exelon MBR Entities have 1,107 MW to 1,108 MW of long-term purchases, 854 MW to 867 MW of long-term sales. After taking into account their load commitments and planned outages and imports attributed to them, Sellers' Uncommitted Capacity ranges from 3,774 MW to 5,429 MW. Total Seasonal Uncommitted Capacity ranges from 32,269 MW to 39,860 MW. Sellers' Market Share ranges from 11.2 to 14.8 percent. Because Sellers' Market Share is less than 20 percent in all seasons, the Market Share Analysis is passed in AP South. *See* Exhibit JRS-7.

Thus, on the basis of the Commission's screens, the Exelon MBR Entities do not have horizontal market power in AP South.

5004/5005

Pivotal Supplier Analysis. The Exelon MBR Entities' Installed Capacity in 5004/5005 is 11,816 MW. They have 1,102 MW of long-term purchases and 854 MW of long-term sales. After taking into account their load commitments and imports attributed to them, Sellers' Uncommitted Capacity is 3,591 MW. Net Uncommitted Supply is 11,732 MW. Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Analysis is passed in 5004/5005. *See* Exhibit JRS-8.

Market Share Analysis. The Exelon MBR Entities' Installed Capacity in 5004/5005 ranges from 11,816 MW to 12,330 MW. The Exelon MBR Entities have 1,102 MW of long-term purchases, 854 MW to 867 MW of long-term sales. After taking into account their load commitments and planned outages and imports attributed to them, Sellers' Uncommitted Capacity ranges from 3,748 MW to 5,679 MW. Total Seasonal Uncommitted Capacity ranges from 22,808 MW to 29,798 MW. Seller's Market Share exceeds 20 percent in one season (Spring) and, hence, the Market Share Screen is failed. See Exhibit JRS-9.

However, as I explained earlier, the Commission previously has found that the presence of Commission-approved market monitoring and mitigation in PJM adequately mitigates any market power concerns in that market. Therefore, the Exelon MBR Entities satisfy the Commission's requirements for market-based rates regarding horizontal market power in the 5004/5005 submarket notwithstanding the violation of the market share screen.

PJM East

Pivotal Supplier Analysis. The Exelon MBR Entities' Installed Capacity in PJM East is 7,156 MW. They have 476 MW of long-term purchases. After taking into account their load commitments and imports attributed to them, Sellers' Uncommitted Capacity is 4,314 MW. Net Uncommitted Supply is 8,403 MW. Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Analysis is passed in PJM East. *See* Exhibit JRS-10.

Market Share Analysis. The Exelon MBR Entities' Installed Capacity in PJM East ranges from 7,156 MW to 7,576 MW. The Exelon MBR Entities have 476 MW of long-term purchases. After taking into account their load commitments and planned outages and imports attributed to them, Sellers' Uncommitted Capacity ranges from 4,434 MW to 5,760 MW. Total Seasonal Uncommitted Capacity ranges from 15,517 MW to 20,775 MW. Seller's Market Share exceeds 20 percent and, hence, the Market Share Screen is failed. See Exhibit JRS-11.

Again, the presence of Commission-approved market monitoring and mitigation in PJM adequately mitigates any market power concerns in that market. Therefore, the Exelon MBR Entities satisfy the Commission's requirements for market-based rates regarding horizontal market power in the PJM East submarket notwithstanding the violation of the market share screen.

V. VERTICAL MARKET POWER

Transmission

Exelon's franchised public utilities each own transmission facilities located in PJM, but those facilities are under the functional control of PJM and subject to the terms and conditions of the PJM OATT, which the Commission has deemed to mitigate a seller's transmission market power.[28]

Barriers to Entry

The Exelon MBR Entities have no ownership or control of intrastate natural gas transportation or intrastate natural gas storage, except for Baltimore Gas and Electric Company, Delmarva Power & Light Gas Company, and PECO Energy Company, which provide natural gas distribution service to their customers and own certain intrastate transportation, storage, and distribution facilities in PJM. As the Commission has determined, there is rebuttable presumption that such ownership does not allow a seller to raise entry barriers.[29]

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[28] Order No. 697 at P 21.

[29] *Id.* at P 22.

The Exelon MBR Entities or their affiliates own or control sites for the development of new generation capacity that are in the interconnection process in PJM as well as in other markets. In Order No. 816 the Commission eliminated the requirement to file land acquisition reports and revised section 35.37 of its regulations to remove the requirement that sellers provide information regarding sites for generation capacity development to demonstrate lack of vertical market power.[30] The Exelon MBR Entities do not own or control sources of coal supplies or the transportation of coal supplies. Here again, the Commission has determined that there is a rebuttable presumption that such ownership or control does not allow a seller to raise entry barriers. There are no other issues that raise any relevant competitive concerns.

I understand that an affirmative statement on behalf of the Exelon MBR Entities is included in their submission that they have not erected barriers to entry and will not erect barriers to entry.

Based on these facts, the Exelon MBR Entities have demonstrated a lack of vertical market power.

VI. CONCLUSION

On the basis of the foregoing analysis, the Exelon MBR Entities continue to satisfy the Commission's horizontal and vertical market power requirements for market-based rate authority in PJM.

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[30] *See* Order No. 816 at P 212. The Commission however retained the right to request additional information about land acquisitions. *Id.* at P 210.

NAVIGANT

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Professional History

- Managing Director, Navigant Consulting - 2010-Present
- Vice President, Charles River Associates - 2001-2010
- Senior Vice President, Putnam, Hayes and Bartlett, Inc. and PHB Hagler Bailly, Inc., Washington, DC - 1986-2000
- Economist, Economic Consulting Services, Inc., Washington, DC - 1979-1986
- Economist, U.S. Department of Labor, Washington, DC - 1976-1979

Education

- M.B.A. Finance, The Wharton School University of Pennsylvania
- B.A. Economics, Connecticut College

Testimony

- Written testimony provided in more than 150 regulatory proceedings

Julie Solomon is a Managing Director at Navigant Consulting, Inc. in the Energy Practice's Power Systems, Markets & Pricing group. She has more than 20 years of consulting experience, specializing in the areas of regulatory and utility economics, financial analysis and business valuation. Ms. Solomon has participated in analysis of proposed regulatory reforms, supply options and utility industry restructuring in the gas and electric industries. She also has advised utility clients in corporate strategy and corporate restructuring, and consulted to legal counsel on a variety of litigation and regulatory matters, including antitrust litigation and contract disputes. She has filed testimony in numerous proceedings before the Federal Energy Regulatory Commission. Much of her current practice focuses on regulatory and market power issues concerning mergers and acquisitions and compliance filings in the electricity market.

» Advised clients in the electric and gas utility industry on competition issues, including the impact of mergers on competition. Directed a large number of analytic studies relating to obtaining merger approval from regulatory authorities.

» Advised clients in the electric utility industry on restructuring strategies, including potential mergers and acquisitions, functional unbundling and cost savings.

» Consulted in the electric and gas utility industries in a variety of regulatory and competition matters, including rate proceedings, prudence reviews, proposed regulatory reforms, analysis of supply options, privatization and restructuring.

» Advised utility and non-utility clients on many aspects of the competitive independent power industry, including strategic and financial consulting assignments.

» Consulted legal counsel on a variety of litigation matters, including the development of expert testimony on liability issues and the calculation of damages in a variety of industries.

» Provided strategic and economic analyses for clients in trade regulatory proceedings such as dumping and subsidies.

» Provided financial and business valuation analyses in a number of transactions, including fair market value for taxation purposes and valuation of family-owned businesses.

Professional Experience

Electric and Gas Utilities

Mergers and Acquisitions (Market Power and Competition Issues)

» Advised clients and conducted analytic studies in connection with a large number of major electric and electric-gas mergers and asset transactions of regulated companies. Provided testimony to FERC for a number of these types of transactions.

» Advised clients and provided confidential pre-screening analyses for potential mergers and acquisitions.

» Conducted numerous analytic studies in connection with FERC market-based rate applications and compliance filings for electricity sellers. Provided testimony to FERC for a number of these types of transactions.

» Conducted numerous analytic studies in connection with FERC market-based rate applications and compliance filings for gas storage facilities. Provided testimony to FERC for a number of these types of transactions.

Utility Restructuring and Stranded Cost

» Conducted analytic studies and provided litigation support in connection with state stranded cost proceedings in Ohio (Cincinnati Gas & Electric and Dayton Power & Light); West Virginia (Monongahela Power and Potomac Edison); Maryland (Potomac Edison) and Pennsylvania (West Penn Power).

» Provided analytic support evaluating the benefits of Public Service of Colorado's proposed DC transmission line between Colorado and Kansas in support of a regulatory proceeding.

» Assisted in studies relating to privatization of the electricity industry in the United Kingdom, including development of a computer model to simulate electricity dispatch and project future prices, capacity needs and utility revenues under various scenarios. During temporary assignment to London office.

» Participated in antitrust litigation involving a utility and a cogenerator, including preparation of an expert report on liability and damage issues, preparation of expert witnesses for deposition, and assistance in preparation for depositions of opposing expert and in-house witnesses.

» Assisted in the valuation of the interests of several firms in various cogeneration projects for the purpose of combining these interests into a new entity or selling interests to third parties.

» Analyzed the financial feasibility and viability of a large number of cogeneration projects, assisted in the preparation of presentations and filings and presented testimony to the relevant public utility commission. Ms. Solomon also assisted in the development of a PC-based financial model to analyze various cogeneration projects.

» Participated in a study to analyze the financial effects of a variety of restructuring options for a utility, including transfer and/or sale of assets and subsequent sale-leasebacks, and debt restructuring alternatives. In addition, she developed a PC-based financial model with applications to utility restructuring plans.

» Provided litigation support in major utility rate proceedings, including assisting in the preparation of responses to interrogatories and data requests, preparation of company and outside expert witnesses for deposition and hearings, and assistance in the deposition and cross-examination of intervenor witnesses.

» Participated in proceedings involving regulation of an oil pipeline, which included evaluating the business risks faced by the company.

Business Valuation

» Participated in a valuation study involving the fair market value of a privately held company for purposes of an IRS proceeding.

» Participated in a valuation study in a divorce proceeding, where the assets being valued included a privately held business.

» Participated in two strategic engagements that developed business plans and identified potential acquisition candidates for the client.

» Provided advice to a client concerning the benefits and potential risks of developing a partnership with a competitor.

Testimony or Expert Report Experience (2012-Mar 2015)

- Affidavit on behalf of Grande Prairie Wind, LLC, Docket No. ER16-1258, application for market-based rates, March 22, 2016.
- Affidavit on behalf of Florida Power & Light Company, Docket No. ER16-628-001, application for market-based rates, March 21, 2016.
- Affidavit on behalf of Essential Power, LLC, Docket No. ER16-82, application for authorization of disposition of jurisdictional facilities, February 29, 2016.
- Affidavit on behalf of Duke Energy Florida, LLC, Docket No. ER16-69, application for authorization of disposition of jurisdictional facilities, February 10, 2016.
- Affidavit on behalf of Nassau Energy, LLC, Docket No. ER16-806, application for market-based rates, January 21, 2016.
- Affidavit on behalf of ECP MBR Sellers, Docket No. ER16-72, market-based rate triennial filing, December 31, 2015.
- Affidavit on behalf of SDG&E Sellers, Docket No. ER14-474, market-based rate triennial filing, December 30, 2015.
- Affidavit on behalf of New Harquahala Generating Company, Docket No. ER15-2013, market-based rate triennial filing, December 30, 2015.
- Affidavit on behalf of Exelon SPP Entities, Docket No. ER14-474, market-based rate triennial filing, December 29, 2015.
- Affidavit on behalf of Florida Power & Light Company, Docket No. ER16-628-000, application for market-based rates, December 23, 2015.
- Affidavit on behalf of ENGIE Portfolio Management, LLC et al, Docket No. ER16-581 et al., application for market-based rates, December 18, 2015.
- Affidavit on behalf of Marshall Wind Energy, LLC, Docket No. ER16-438, market-based rate triennial filing, December 18, 2015.
- Affidavit on behalf of Marshall Wind Energy, LLC, Docket No. ER16-438, application for market-based rates, December 1, 2015.
- Affidavit on behalf of Calpine Granite Holdings, LLC, Docket No. EC16-19, application for authorization of disposition of jurisdictional facilities, October 27, 2015.
- Affidavit on behalf of Berkshire Hathaway, Inc., Docket No. EC16-10, application for authorization of disposition of jurisdictional facilities, October 8, 2015.
- Affidavit on behalf of Panda Patriot, LLC, Docket No. ER15-2472, application for market-based rates, September 29, 2015.
- Affidavit on behalf of Talen Energy Corporation, Docket No. EC14-112, Motion to Amend Mitigation Plan, September 25, 2015.

- Affidavit on behalf of BHE MBR Sellers, Docket No. ER12-162, notification of change in status, September 25, 2015.
- Affidavit on behalf of Talen Energy Corporation, Docket No. EC14-112, Motion to Amend Mitigation Plan, September 8, 2015.
- Affidavit on behalf of BHE MBR Sellers, Docket No. ER13-521, response to Commission Staff Deficiency Letter and Request for Additional Information, September 24, 2015.
- Affidavit on behalf of BHE MBR Sellers, Docket No. ER13-521, supplemental filing, September 8, 2015.
- Affidavit on behalf of GDF SUEZ MBR Sellers, Docket No. ER14-1699, notice of change, August 31, 2015.
- Affidavits on behalf of PacifiCorp and NV Energy, Docket No. ER15-2283, EIM analysis, July 27, 2015.
- Affidavit on behalf of NorthWestern Corporation and Beethoven Wind, LLC, Docket No. EC15-176, application for authorization of disposition of jurisdictional facilities, July 24 2015.
- Affidavit on behalf of MidAmerican Energy Services, LLC, Docket No. ER15-2211, application for market-based rates, July 24, 2015.
- Affidavit on behalf of The Empire District Electric Company, Docket No. ER10-2738, market-based rate triennial filing, June 30, 2015.
- Affidavit on behalf of Exelon MBR Sellers, Docket No. ER10-2172 *et al*., market-based rate triennial filing, June 30, 2015.
- Affidavit on behalf of Oklahoma Gas & Electric, Docket No. ER11-2105, market-based rate triennial filing, June 30, 2015.
- Affidavit on behalf of LG&E Energy Marketing, Inc., Docket No. ER10-1714, market-based rate triennial filing, June 30, 2015.
- Affidavit on behalf of Westar Energy, Inc., Docket No. ER10-2507, market-based rate triennial filing, June 29, 2015.
- Affidavit on behalf of the Alabama Power Company, *et al*., Docket No. EL15-39, *et al*., response to show cause order, June 26, 2015.
- Affidavit on behalf of Wisconsin Electric Power Company, Docket No. ER15-2019 market-based rate triennial filing, June 26, 2015.
- Affidavit on behalf of Panda Liberty LLC, Docket No. ER15-1841, market-based rate application, June 2, 2015.
- Affidavit on behalf of CCI U.S. Asset Holdings LLC, Docket No. EC15-108, application for authorization of disposition of jurisdictional facilities, March 31, 2015.
- Affidavit on behalf of Florida Power & Light Company, Docket No. EC15-102, application for authorization of disposition of jurisdictional facilities, March 23, 2015.

- Affidavit on behalf of Osprey Energy Center, LLC, Docket No. EC15-96, application for authorization of disposition of jurisdictional facilities, March 13, 2015.
- Affidavit on behalf of the Berkshire Hathaway Energy MBR Sellers, Docket No. EL15-22, *et al*., response to show cause order, February 9, 2015.
- Affidavit on behalf of ECP MBR Sellers, Docket No. ER13-2477, notice of change in status, January 20, 2015.
- Affidavit on behalf of NorthWestern Corporation, Docket No. ER11-1859, market-based rate triennial filing, December 30, 2014.
- Affidavit on behalf of Exelon, Docket No. ER12-2178, market-based rate triennial filing, December 23, 2014.
- Affidavit on behalf of Dynegy Inc., Docket No. ER14-1569, market-based rate triennial filing, December 23, 2014.
- Affidavit on behalf of Northern Indiana Public Service, Docket No. ER10-1781, market-based rate triennial filing, December 23, 2014.
- Affidavit on behalf of AES Corp, Docket No. ER10-3415, market-based rate triennial filing, December 22, 2014.
- Affidavit on behalf of Ameren Illinois Company, Union Electric Company, and AmerenEnergy Medina Valley Cogen, L.L.C. Docket No. ER10-1119, ER10-1123, and ER10-1103 , market-based rate triennial filing, December 19, 2014.
- Affidavit on behalf of Duke Energy MBR Sellers, Docket No. ER10-1325, market-based rate triennial filing, December 19, 2014.
- Affidavit on behalf of Duke Energy Progress, Inc., Docket No. EC15-9, application for authorization of disposition of jurisdictional facilities, October 10, 2014.
- Comments of Julie R. Solomon and Matthew E. Arenchild regarding NOPR on market-based rate authority, Docket No. RM14-14, September 23, 2014.
- Affidavit on behalf of Dynegy Resource I, LLC, Docket No. EC14-141, application for authorization of disposition of jurisdictional facilities, September 11, 2014.
- Affidavit on behalf of Dynegy Inc., Docket No. EC14-140, application for authorization of disposition of jurisdictional facilities, September 11, 2014.
- Affidavit on behalf of Calpine Fore River Energy Center, LLC, Docket No. EC14-135, application for authorization of disposition of jurisdictional facilities, September 5, 2014.
- Affidavit on behalf of Seiling Wind, LLC; Seiling Wind II, LLC; Mammoth Plains Wind Project, LLC; and Palo Duro Wind Energy, LLC, Docket No. ER14-2707-10, market-based rate applications, August 26, 2014.
- Affidavit on behalf of ECP MBR Sellers, Docket No. ER10-2302, notification of change in status, August 18, 2014.

- Affidavit on behalf of Millennium Power Partners, L.P., Docket No. ER10-3286, notification of change in status, August 4, 2014.
- Affidavit on behalf of Granite Acquisition, Inc., Docket No. EC14-125, application for authorization of disposition of jurisdictional facilities, August 15, 2014.
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- Testimony (Direct and Rebuttal), on behalf of Duke Energy Florida, Inc., Docket No. 140111-EI before the Florida Public Service Commission, Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018, May 27, 2014 and August 5, 2014.
- Affidavit on behalf of LS Power Development, LLC, Docket No. ER13-2318, notification of change in status, August 4, 2014.
- Supplemental Affidavit on behalf of Powerex Corp., Docket No. ER11-2664, market-based rate triennial filing, July 25, 2014.
- Supplemental Affidavit on behalf of Berkshire Hathaway Energy, Docket No. ER13-1266, notification of change in status, August 17, 2014.
- Affidavit on behalf of RJS Power Holdings LLC and PPL Corporation, Docket No. EC14-112, application for authorization of disposition of jurisdictional facilities, July 15, 2014.
- Affidavit on behalf of South Carolina Electric & Gas Company, Docket No. ER10-2498, market-based rate triennial filing, July 14, 2014.
- Affidavit on behalf of Consumers Energy Company, Docket No. EC14-110, application for authorization of disposition of jurisdictional facilities, July 1, 2014.
- Affidavit on behalf of J.P. Morgan Sellers, Docket No. ER10-2331, market-based rate triennial filing, June 30, 2014.
- Affidavit on behalf of Duke Energy MBR Sellers, Docket No. ER10-1325, market-based rate triennial filing, June 30, 2014.
- Affidavit on behalf of PPL Southeast Companies, Docket No. ER10-1511, market-based rate triennial filing, June 30, 2014.
- Affidavit on behalf of NextEra Companies, Docket No. ER10-1852, market-based rate triennial filing, June 30, 2014.
- Affidavit on behalf of NextEra Companies, Docket No. ER10-1838, market-based rate triennial filing, June 30, 2014.
- Affidavit on behalf of Brookfield Companies, Docket No. ER11-2292, market-based rate triennial filing, June 30, 2014.
- Affidavit on behalf of Calpine Corp, Docket No. ER10-1944, market-based rate triennial filing, June 30, 2014.

- Affidavit on behalf of LS Northeast MBR Sellers, Docket No. ER13-2318, market-based rate triennial filing, June 30, 2014.
- Affidavit on behalf of GDF SUEZ Northeast MBR Sellers, Docket No. ER10-2670, market-based rate triennial filing, June 30, 2014.
- Affidavit on behalf of Safe Harbor Water Power Corp., Docket No. ER13-395, market-based rate triennial filing, June 27, 2014.
- Affidavit on behalf of ECP MBR Sellers, Docket No. ER13-2477, market-based rate triennial filing, June 23, 2014.
- Affidavit on behalf of Rockland Sellers, Docket No. ER12-1436, market-based rate triennial filing and notification of change in status, June 19, 2014.
- Affidavit on behalf of Exelon Corp and Pepco Holdings, Inc., Docket No. EC14-96, application for authorization of disposition of jurisdictional facilities, May 30, 2014.
- Affidavit on behalf of Nevada Power Co and Nevada Sun-Peak Limited Partnership, Docket No. EC14-83, application for authorization of disposition of jurisdictional facilities, May 2, 2014.
- Affidavit on behalf of Nevada Power Co and Las Vegas Cogeneration Limited Partnership, Docket No. EC14-84, application for authorization of disposition of jurisdictional facilities, May 2, 2014.
- Affidavit on behalf of NatGen Southeast Power LLC, Docket No. EC14-81, application for authorization of disposition of jurisdictional facilities, April 28, 2014.
- Surrebuttal Testimony on Behalf of Commonwealth Edison Company, Illinois Commerce Commission, Application for a Certificate of Public Convenience and Necessity, No. 13-0657, April 9, 2014.
- Affidavit on behalf of KMC Thermo, LLC, Docket No. ER14-1468, market-based rate application, March 12, 2014.
- Affidavit on behalf of Trailstone Power, LLC, Docket No. ER14-1439, market-based rate application, March 6, 2014.
- Affidavit on behalf of MACH Gen, LLC et al., Docket No. EC14-61, application for authorization of disposition of jurisdictional facilities, March 4, 2014.
- Affidavit on behalf of MidAmerican Geothermal, LLC, et al., Docket No. EC14-59, application for authorization of disposition of jurisdictional facilities, February 20, 2014.
- Affidavit on behalf of Green Mountain Power Corporation, Docket No. ER11-1933, market-based rate triennial filing, February 7, 2014.
- Affidavit on behalf of NorthWestern Corporation, et al., Docket No. EC14-41, application for authorization of disposition of jurisdictional facilities, January 10, 2014.
- Affidavit on behalf of NorthWestern Corporation, Docket No. ER11-1858, notification of change in status, January 10, 2014.

- Affidavit on behalf of MidAmerican Energy, Docket No. ER10-2475, notification of change in status, January 2, 2014.
- Affidavit on behalf of Powerex Corp., Docket No. ER11-2664, market-based rate triennial filing, December 31, 2013.
- Affidavit on behalf of TransAlta, Docket No. ER10-2847, market-based rate triennial filing, December 31, 2013.
- Affidavit on behalf of Duquesne Light Company, Docket No. ER10-1910, market-based rate triennial filing, December 31, 2013.
- Affidavit on behalf of Constellation Energy Nuclear Group, Docket No. ER10-2179, market-based rate triennial filing, December 30, 2013.
- Affidavit on behalf of Exelon, Docket No. ER12-2178, market-based rate triennial filing, December 30, 2013.
- Affidavit on behalf of Dominion, Docket No. ER13-434, market-based rate triennial filing, December 30, 2013.
- Affidavit on behalf of Brookfield Companies, Docket No. ER10-2895, market-based rate triennial filing, December 30, 2013.
- Affidavit on behalf of Oklahoma Gas & Electric, Docket No. ER14-882, notification of change in status/tariff filing, December 30, 2013.
- Affidavit on behalf of AES Corp, Docket No. ER10-3415, market-based rate triennial filing, December 26, 2013.
- Affidavit on behalf of JPMorgan, Docket No. ER10-2331, market-based rate triennial filing, December 23, 2013.
- Affidavit on behalf of Northeast Utilities, Docket No. ER10-1801, market-based rate triennial filing, December 20, 2013.
- Affidavit on behalf of Iberdrola, Docket No. ER10-2822, market-based rate triennial filing, December 20, 2013.
- Affidavit on behalf of PHI, Docket No. ER10-2997, market-based rate triennial filing, December 20, 2013.
- Affidavit on behalf of Essential Power, Docket No. ER12-952, market-based rate triennial filing, December 20, 2013.
- Affidavit on behalf of Empire District, Docket No. ER14-793, notification of change in status/tariff filing, December 20, 2013.
- Affidavit on behalf of Westar Energy, Inc., Docket No. ER14-724, notification of change in status/tariff filing, December 19, 2013.
- Affidavit on behalf of Alpha Gen Power, LLC, Docket No. ER14-630, market-based rate application, December 16, 2013.

- Affidavit on behalf of Black Bear Hydro Partners, LLC, Docket No. EC14-28, application for authorization of disposition of jurisdictional facilities, November 14, 2013.
- Affidavit on behalf of Sierra Pacific Power Company, Docket No. ER10-2474, notification of change in status, November 4, 2013.
- Affidavit on behalf of ECP, Docket No. ER11-3859, notification of change in status, September 30, 2013.
- Affidavit on behalf of Steele Flats Wind Project, LLC, Docket No. ER13-2474, market-based rate application, September 27, 2013.
- Affidavit on behalf of Tuscola Wind II, LLC, Docket No. ER13-2458, market-based rate application, September 26, 2013.
- Affidavit on behalf of Pheasant Run Wind, LLC and Pheasant Run Wind II, LLC, Docket Nos. ER13-2461-2, market-based rate applications, September 26, 2013.
- Affidavit on behalf of TPF II and USPG Holdings, LLC, Docket No. EC13-154, application for authorization of disposition of jurisdictional facilities, September 25, 2013.
- Affidavit on behalf of Seneca Generation, LLC et al., Docket Nos. ER13-2316-9, market-based rate applications, September 4, 2013.
- Affidavit on behalf of Seneca Generation, LLC et al., Docket No. EC13-143, application for authorization of disposition of jurisdictional facilities, September 4, 2013.
- Supplemental Affidavit on behalf of MidAmerican Energy (Silver Merger Sub, Inc.), Docket No. EC13-128, application for authorization of disposition of jurisdictional facilities, August 17, 2013.
- Affidavit on behalf of Desert Sunlight 250, LLC and Desert Sunlight 300, LLC, Docket Nos. ER13-1991-2, market-based rate applications, July 17, 2013.
- Affidavit on behalf of MidAmerican Energy (Silver Merger Sub, Inc.), Docket No. EC13-128, application for authorization of disposition of jurisdictional facilities, July 12, 2013.
- Affidavit on behalf of Calpine Southwest MBR Sellers, Docket No. ER10-1942, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of NextEra Companies, Docket No. ER10-1847, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of Wayzata Entities, Docket No. ER10-1777, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of AES MBR Affiliates, Docket No. ER10-3415, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of Sierra Pacific Power Company, *et al.* under ER10-2474, Docket No. ER10-24744, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of NorthWestern Corporation, Docket No. ER11-1858, market-based rate triennial filing, July 1, 2013.

- » Affidavit on behalf of SGOC Southwest MBR Sellers, Docket No. ER10-2864, market-based rate triennial filing, June 28, 2013.
- » Affidavit on behalf of GWF Energy LLC, et al. Docket No. ER10-3301, market-based rate triennial filing, June 28, 2013.
- » Affidavit on behalf of NV Energy, Inc., application for approval of internal reorganization, Docket No. EC13-113, May 31, 2013.
- » Affidavit on behalf of Midwest Generation, LLC, Docket No. EC13-103, application for authorization of disposition of jurisdictional facilities, May 6, 2013.
- » Affidavit of behalf of Nevada Power Company (with Matthew E. Arenchild), Docket No. EC13-96, application for authorization of disposition of jurisdictional facilities, April 17, 2013.
- » Affidavit of behalf of Dynegy Inc., Docket No. EC13-93, application for authorization of disposition of jurisdictional facilities, April 16, 2013.
- » Application on behalf of Florida Power & Light Company, Docket No. EC13-91, application for authorization of disposition of jurisdictional facilities, April 12, 2013.
- » Affidavit on behalf of Blythe Energy LLC, et al., Docket No. EC13-89, application for authorization of disposition of jurisdictional facilities, April 2, 2013.
- » Affidavit on behalf of New Harquahala Generating Company, LLC, Docket No. ER10-3310, market-based rate triennial filing, March 29, 2013.
- » Affidavit on behalf of Dominion Energy Brayton Point, et al., Docket No. EC13-82, application for authorization of disposition of jurisdictional facilities, March 21, 2013.
- » Affidavit on behalf of Duke Energy Carolinas, LLC et al., Docket No. ER10-2566, et al., notice of change in status, January 29, 2013.
- » Affidavit on behalf of CCI Roseton LLC, Docket No. ER13-773, market-based rate application, January 17, 2013.
- » Affidavit on behalf of CCI Roseton LLC, Docket No. EC13-63, application for authorization of disposition of jurisdictional facilities, January 16, 2013.
- » Affidavit on behalf of Calpine Oneta Power, LLC, Docket No. ER11-3777, et al., market-based rate triennial filing, December 31, 2012.
- » Affidavit on behalf of NextEra Energy Companies, Docket No. ER12-569, et al., market-based rate triennial filing, December 27, 2012.
- » Affidavit on behalf of Nevada Power Company, Docket No. ER10-2474, market-based rate triennial filing, December 26, 2012.
- » Testimony on behalf of Powerex Corp re Puget Sound Energy, Inc v. All Jurisdictional Sellers of Energy & Capacity, Docket No. EL01-10, December 17, 2012.
- » Affidavit on behalf of AES Beaver Valley, LLC, Docket No. ER13-442, market-based rate application, November 21, 2012.

- Affidavit on behalf of Broad River Energy LLC, et al., Docket No. EC13-42, application for authorization of disposition of jurisdictional facilities, November 16, 2012.
- Affidavit on behalf of Westar Energy, Inc., Docket No. ER10-2507, notice of change in status, October 29, 2012.
- Affidavit on behalf of Homer City Generation, L.P., Docket No. ER13-55, market-based rate application, October 9, 2012.
- Affidavit on behalf of Homer City Generation, L.P., et al., Docket No. EC13-9, application for authorization of disposition of jurisdictional facilities, October 9, 2012.
- Affidavit on behalf of GenOn Marsh Landing, LLC, Docket No. ER12-2545, market-based rate application, August 29, 2012.
- Affidavit on behalf of High Mesa Energy, LLC, Docket No. ER12-2528, market-based rate application, August 27, 2012.
- Affidavit on behalf of Brandon Shores LLC, et al., Docket No. EC12-137, application for authorization of disposition of jurisdictional facilities, August 23, 2012.
- Affidavit on behalf of North Sky River Energy, LLC, Docket No. ER12-2444, market-based rate application, August 14, 2012.
- Affidavit on behalf of Duke Energy Carolinas, LLC et al., Docket No. ER10-2566, et al., notice of change in status, August 1, 2012.
- Affidavit on behalf of Canandaigua Power Partners, LLC et al., Docket No. ER10-2460, notice of change in status, July 16, 2012.
- Affidavit on behalf of Limon Wind I and Limon Wind II, LLC, Docket Nos. ER12-2225 and -2226, market-based rate application, July 10, 2012.
- Affidavit on behalf of Ensign Wind, LLC, Docket No. ER12-2227, market-based rate application, July 10, 2012.
- Affidavit on behalf of NextEra Energy Companies, Docket No. ER10-1836, et al., market-based rate triennial filing, July 2, 2012.
- Affidavit on behalf of Iberdrola Renewables, LLC, et al., Docket No. ER10-2994, et al., market-based rate triennial filing, June 29, 2012.
- Affidavit on behalf of The Empire District Electric Company, Docket No. ER10-2738, market-based rate triennial filing, June 29, 2012.
- Affidavit on behalf of Wisconsin Electric Power Company, Docket No. ER10-2563, market-based rate triennial filing, June 29, 2012.
- Affidavit on behalf of Baltimore Gas and Electric Company, et al., Docket No. ER10-2172, et al., market-based rate triennial filing, June 29, 2012.
- Affidavit on behalf of Westar Energy, Inc., Docket No. ER12-2124, market-based rate triennial filing, June 28, 2012.

- Affidavit on behalf of Duke Energy Beckjord, LLC, et al., Docket No. ER12-1946 et al., market-based rate application, June 5, 2012.
- Affidavit on behalf of Minco Wind III, LLC, Docket No. ER12-1880, market-based rate application, May 31, 2012.
- Affidavit on behalf of Tuscola Bay Wind, LLC, Docket No. ER12-1660, market-based rate application, April 30, 2012.
- Affidavit on behalf of Powerex Corp., Docket No. ER11-2664, notice of change in status, April 13, 2012.
- Affidavit on behalf of Safe Harbor Water Power Corporation, Docket No. ER11-2780, notice of change in status, April 11, 2012.
- Affidavit on behalf of Hot Spring Power Company, LLC, Docket No. EC12-87, application for authorization of disposition of jurisdictional facilities, March 28, 2012.
- Affidavit on behalf of High Majestic Wind II, LLC, Docket No. ER12-1228, market-based rate application, March 8, 2012.
- Affidavit on behalf of Duke Energy Indiana, Inc. et al., Docket No. ER10-2034 et al., notice of change in status, January 31, 2012.
- Affidavit on behalf of CPV Cimarron Renewable Energy Company, LLC, Docket No. ER12-775, market-based rate application, January 6, 2012.
- Affidavit on behalf of LS Power Marketing, LLC, et al., Docket No. ER10-2739, et al., market-based rate triennial filing, January 3, 2012.
- Affidavit on behalf of Auburndale Peaker Energy Center, LLC, et al., Docket No. ER10-1945, et al., market-based rate triennial filing, January 3, 2012.

Generation Affiliated with Exelon in PJM and Relevant First-Tier Markets

BAA	Sub Market	Plant Name	Total Capacity (MW) Summer	Total Capacity (MW) Winter	Ownership Share	Net Capacity (MW) Summer	Net Capacity (MW) Winter
PJM							
PJM		Braidwood	2,330.0	2,384.0	100.0%	2,330.0	2,384.0
PJM		Byron	2,300.0	2,346.0	100.0%	2,300.0	2,346.0
PJM	5004/5005	Calvert Cliffs	1,707.8	1,734.0	50.0%	1,707.8	1,734.0
PJM	East	Chester	39.0	54.0	100.0%	39.0	54.0
PJM	East	Conowingo	572.0	572.0	100.0%	572.0	572.0
PJM		Criterion Power	70.0	70.0	100.0%	70.0	70.0
PJM	East	Croydon	392.0	512.0	100.0%	392.0	512.0
PJM	East	Delaware	56.0	74.0	100.0%	56.0	74.0
PJM		Dresden	1,778.5	1,786.5	100.0%	1,778.5	1,786.5
PJM	East	Eddystone	820.0	836.0	100.0%	820.0	836.0
PJM		Exelon Solar Chicago	9.0	9.0	100.0%	9.0	9.0
PJM	East	Fairless Hills	60.0	60.0	100.0%	60.0	60.0
PJM	East	Falls	51.0	60.0	100.0%	51.0	60.0
PJM		Fair Wind Facility	30.0	30.0	100.0%	30.0	30.0
PJM		Fourmile Wind	40.0	40.0	100.0%	40.0	40.0
PJM	5004/5005	Gould Street	97.0	97.0	100.0%	97.0	97.0
PJM		Handsome Lake	267.5	267.5	100.0%	267.5	267.5
PJM		La Salle	2,271.6	2,313.0	100.0%	2,271.6	2,313.0
PJM	East	Limerick	2,241.8	2,386.0	100.0%	2,241.8	2,386.0
PJM	East	Moser	51.0	60.0	100.0%	51.0	60.0
PJM	East	Muddy Run	1,070.0	1,070.0	100.0%	1,070.0	1,070.0
PJM	5004/5005	Notch Cliff	116.7	116.7	100.0%	116.7	116.7
PJM	East	Oyster Creek	609.9	637.0	100.0%	609.9	637.0
PJM	5004/5005	Peach Bottom	2,450.4	2,504.0	50.0%	1,225.2	1,252.0
PJM	East	Pennsbury	5.4	5.4	100.0%	5.4	5.4
PJM	5004/5005	Perryman	302.6	302.6	100.0%	302.6	302.6
PJM	5004/5005	Perryman 6	110.0	130.0	100.0%	110.0	130.0
PJM	5004/5005	Philadelphia Road	60.9	60.9	100.0%	60.9	60.9
PJM		Quad Cities	1,819.0	1,819.0	75.0%	1,364.3	1,364.3
PJM	East	Richmond	98.0	132.0	100.0%	98.0	132.0
PJM	5004/5005	Riverside	113.0	113.0	100.0%	113.0	113.0
PJM	East	Salem	2,366.6	2,366.6	42.6%	1,007.9	1,007.9
PJM	East	Schuylkill	30.0	38.0	100.0%	30.0	38.0
PJM		Southeast Chicago	296.0	320.0	100.0%	296.0	320.0
PJM	East	Southwark	52.0	72.0	100.0%	52.0	72.0
PJM	5004/5005	Three Mile Island 1	802.8	829.0	100.0%	802.8	829.0
PJM	5004/5005	Westport	115.8	115.8	100.0%	115.8	115.8
PJM	5004/5005	Bethlehem Renewable Plant	4.7	1.2	100.0%	4.7	1.2
PJM	5004/5005	Eastern LFG	3.0	1.5	100.0%	3.0	1.5
PJM	AP South	Fauquier LFG	2.0	1.0	100.0%	2.0	1.0

BAA	Sub Market	Plant Name	Total Capacity (MW) Summer	Total Capacity (MW) Winter	Ownership Share	Net Capacity (MW) Summer	Net Capacity (MW) Winter
Long-Term Purchases							
PJM		Elwood Energy, LLC				600.0	768.0
PJM	5004/5005	Calpine Mid Merit LLC				545.0	545.0
PJM		Cordova Energy Company, LLC				521.2	601.2
PJM		Backbone Mountain Windpower LLC				66.0	66.0
PJM		Bellefontaine Gas Producers, LLC				4.8	4.8
PJM		Forward Wind Power LLC				29.4	29.4
PJM		High Trail Wind Farm, LLC				198.0	198.0
PJM		Mill Run Windpower, LLC				15.0	15.0
PJM		Old Trail Wind Farm, LLC				198.0	198.0
PJM		Patton Wind Farm, LLC				30.0	30.0
PJM		Somerset Windpower, LLC				9.0	9.0
PJM		WM Renewable Energy, LLC				6.1	6.1
PJM	AP South	WM Renewable Energy, LLC				3.8	3.8
PJM	5004/5005	Green Gas Pioneer Crossing Energy, LLC				8.0	8.0
PJM	5004/5005	Green Knight Economic Development Corporation				3.3	3.3
PJM	5004/5005	Keystone Solar, L.L.C.				5.0	5.0
PJM	5004/5005	Waymart Wind Farm, L.P.				64.5	64.5
PJM	AP South	Ameresco Stafford, LLC				2.0	2.0
PJM	East	Ameresco Delaware Energy, LLC				7.0	7.0
PJM	East	MF Mesa Lane LLC				1.5	1.1
PJM	East	Chambers Cogeneration				187.6	187.6
PJM	East	Logan Generating				200.0	200.0
PJM	East	Covanta Delaware Valley				80.0	80.0
PJM		AES Armenia Mountain				50.0	50.0
PJM		Roth Rock				40.0	40.0
PJM		Chestnut Flats				38.0	38.0
Long-Term Sales							
PJM	5004/5005	CENG sale to EDF				(853.7)	(866.8)
Subtotal, PJM						24,633.9	25,555.3
First-Tier Markets							
MISO		AgriWind	8.4	8.4	100%	8.4	8.4
MISO		BC Energy	4.2	4.2	100%	4.2	4.2
MISO		Beebe Renewable Energy	81.6	81.6	100%	81.6	81.6
MISO		Beebe 1B Renewable Energy, LLC (2014)	50.0	50.0	100%	50.0	50.0
MISO		Blue Breezes	1.3	1.3	100%	1.3	1.3
MISO		Blue Breezes II	1.3	1.3	100%	1.3	1.3
MISO		Breezy Bucks-I	1.3	1.3	100%	1.3	1.3
MISO		Breezy Bucks-II	1.3	1.3	100%	1.3	1.3
MISO		Christoffer Wind Energy I	2.1	2.1	100%	2.1	2.1
MISO		Christoffer Wind Energy II	2.1	2.1	100%	2.1	2.1
MISO		Christoffer Wind Energy III	2.1	2.1	100%	2.1	2.1

BAA	Sub Market	Plant Name	Total Capacity (MW) Summer	Total Capacity (MW) Winter	Ownership Share	Net Capacity (MW) Summer	Net Capacity (MW) Winter
MISO		Christoffer Wind Energy IV	2.1	2.1	100%	2.1	2.1
MISO		CP Windfarm	4.2	4.2	100%	4.2	4.2
MISO		Clinton	1,065.0	1,078.0	100%	1,065.0	1,078.0
MISO		G-Flow Wind	1.3	1.3	100%	1.3	1.3
MISO		Green Acres Breeze	1.3	1.3	100%	1.3	1.3
MISO		Harvest Windfarm	52.8	52.8	100%	52.8	52.8
MISO		Harvest II Windfarm	59.4	59.4	100%	59.4	59.4
MISO		K & D Energy	4.0	4.0	100%	4.0	4.0
MISO		KC Energy	4.0	4.0	100%	4.0	4.0
MISO		KSS Turbines	4.0	4.0	100%	4.0	4.0
MISO		Marshall Wind	18.9	18.9	100%	18.9	18.9
MISO		Michigan Wind 1	69.0	69.0	100%	69.0	69.0
MISO		Michigan Wind 2	90.0	90.0	100%	90.0	90.0
MISO		Minnesota Breeze	1.3	1.3	100%	1.3	1.3
MISO		Prairie Wind Power	4.0	4.0	100%	4.0	4.0
MISO		Roadrunner-I	1.3	1.3	100%	1.3	1.3
MISO		S & P Windfarm	2.0	2.0	100%	2.0	2.0
MISO		Salty Dog-I	1.3	1.3	100%	1.3	1.3
MISO		Salty Dog-II	1.3	1.3	100%	1.3	1.3
MISO		Shane's Wind Machine	1.3	1.3	100%	1.3	1.3
MISO		Sunset Breeze	1.3	1.3	100%	1.3	1.3
MISO		Wally's Wind Farm	1.3	1.3	100%	1.3	1.3
MISO		Windy Dog-I	1.3	1.3	100%	1.3	1.3
MISO		Wolf Wind Enterprises	1.3	1.3	100%	1.3	1.3
Long-Term Purchases							
MISO		Tenaska Frontier				860.0	926.0
MISO		Pioneer Trail Wind Farm, LLC				110.4	110.4
Subtotal, MISO			1,549.4	1,562.4		2,519.8	2,598.8
NYISO		Nine Mile Point	1,702.8	1,702.8	50%	1,702.8	1,702.8
NYISO		Ginna	582.0	582.0	50%	582.0	582.0
NYISO		CENG sale to EDF				(851.2)	(851.2)
Long-Term Purchases							
NYISO		WM Renewable Energy, LLC				28.8	28.8
Subtotal, NYISO			5,228.0	5,254.0		1,462.4	1,462.4

Note: Generation ratings generally are based on EIA-860.
http://www.eia.gov/cneaf/electricity/page/eia860.html

Market/ Submarket	Exhibit	Pivotal Supplier Analysis	Exhibit	Market Share Analysis			
				Winter	Spring	Summer	Fall
PJM	JRS-4	Pass	JRS-5	10.6%	10.9%	9.0%	9.7%
AP South	JRS-6	Pass	JRS-7	14.3%	14.8%	11.7%	11.2%
5004/5005	JRS-8	Pass	JRS-9	19.1%	21.3%	16.4%	15.8%
East	JRS-10	Pass	JRS-11	26.7%	30.2%	28.6%	23.0%

Part I – Pivotal Supplier Analysis

Applicant-> **Exelon**
Market -> **PJM**
Data Year -> **Dec 2014-Nov 2015**

Row			Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	22,574	Exhibit JRS-2
A1	Remote Capacity (from outside the study area)	0	
B	Long-Term Firm Purchases (from inside the study area)	2,913	Exhibit JRS-2
B1	Long-Term Firm Purchases (from outside the study area)	0	
C	Long-Term Firm Sales (in and outside the study area)	854	Exhibit JRS-2
D	Uncommitted Capacity Imports	1,120	Wkp-Import Allocation
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	165,208	Wkp - Generation Summary, less Row A above
E1	Remote Capacity (from outside the study area)	0	
F	Long-Term Firm Purchases (from inside the study area)	854	Offset Row C
F1	Long-Term Firm Purchases (from outside the study area)	0	
G	Long-Term Firm Sales (in and outside the study area)	2,913	Offset Row B
H	Uncommitted Capacity Imports	7,081	Order on SIL Values for the Northeast Region, 147 FERC ¶ 61,190 (2014) less Row D above
I	Study Area Reserve Requirement	6,466	Wkp - PJM Operating Reserves
J	Amount of Line I Attributable to Seller, if any	0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	67,917	
	Load		
L	Balancing Authority Area Annual Peak Load	143,633	Wkp - PJM Load Summary
M	Average Daily Peak Native Load in Peak Month	121,600	Wkp - PJM Load Summary
N	Amount of Line M Attributable to Seller, if any	19,538	Exelon Load Data
O	Wholesale Load (L-M)	22,034	
P	Net Uncommitted Supply (K-O)	45,884	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	6,215	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->	8,201	
	% of SIL for Seller's imported capacity ->	0.14	
	% of SIL for Other's imported capacity ->	0.86	
	SIL value ->	8,201	Wkp-SILs
	Do Total Imports exceed the SIL value? ->	No	

Part II – Market Share Analysis

Applicant-> **Exelon**
Study Area -> **PJM**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled or under LT contract)					
A	Installed Capacity (inside the study area)	23,261	23,261	22,574	23,261	Exhibit JRS-2
A1	Remote Capacity (from outside the study area)	0	0	0	0	
B	Long-Term Firm Purchases (inside the study area)	3,161	3,161	2,913	3,161	Exhibit JRS-2
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
C	Long-Term Firm Sales (in and outside the study area)	867	867	854	867	Exhibit JRS-2
D	Seasonal Average Planned Outages	591	3,658	178	2,902	Pro rata share of outages
E	Uncommitted Capacity Imports	718	402	597	871	Wkp-Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	112,387	94,917	117,821	95,685	Wkp - PJM Load Summary
G	Amount of Line F Attributable to Seller, if any	16,011	14,104	18,740	15,366	Exelon Load Data
H	Amount of Line F Attributable to Non-Affiliates, if any	96,376	80,812	99,080	80,318	
I	Study Area Reserve Requirement	6,086	5,134	6,637	5,119	Wkp - PJM Operating Reserves
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	
K	Amount of Line I Attributable to Non-Affiliates, if any	6,086	5,134	6,637	5,119	
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	179,748	177,569	165,208	172,824	Wkp - Generation Summary, less Row A above
L1	Remote Capacity (from outside the study area)	0	0	0	0	
M	Long-Term Firm Purchases (inside the study area)	867	867	854	867	Offset Row C
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
N	Long-Term Firm Sales (in and outside the study area)	3,161	3,161	2,913	3,161	Offset Row B
O	Seasonal Average Planned Outages	4,568	27,923	1,306	21,557	Wkp - PJM Outages Summary, less Row D above
P	Uncommitted Capacity Imports	11,073	5,497	7,604	12,070	Order on SIL Values for the Northeast Region, 147 FERC ¶ 61,190 (2014) less Row E above
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	81,497	66,904	63,730	75,605	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	9,671	8,195	6,312	8,159	
S	Total Seasonal Uncommitted Capacity (Q+R)	91,168	75,099	70,042	83,764	
T	**Seller's Market Share** (R÷S)	10.6%	10.9%	9.0%	9.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass	
U	Total Imports, as filed by Seller (E+P)	11,791	5,899	8,201	12,941	
V	SIL value*	11,791	5,899	8,201	12,941	
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No	

Part I – Pivotal Supplier Analysis

Applicant-> **Exelon**
Market -> **AP South**
Data Year -> **Dec 2014-Nov 2015**

Row			Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	11,818	Exhibit JRS-2
A1	Remote Capacity (from outside the study area)	0	
B	Long-Term Firm Purchases (from inside the study area)	1,108	Exhibit JRS-2
B1	Long-Term Firm Purchases (from outside the study area)	0	
C	Long-Term Firm Sales (in and outside the study area)	854	Exhibit JRS-2
D	Uncommitted Capacity Imports	422	Wkp-Import Allocation
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	72,496	Wkp - Generation Summary, less Row A above
E1	Remote Capacity (from outside the study area)	0	
F	Long-Term Firm Purchases (from inside the study area)	854	Offset Row C
F1	Long-Term Firm Purchases (from outside the study area)	0	
G	Long-Term Firm Sales (in and outside the study area)	1,108	Offset Row B
H	Uncommitted Capacity Imports	7,067	Order on SIL Values for the Northeast Region, 147 FERC ¶ 61,190 (2014) less Row D above
I	Study Area Reserve Requirement	2,867	Wkp - PJM Operating Reserves
J	Amount of Line I Attributable to Seller, if any	0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	30,827	
	Load		
L	Balancing Authority Area Annual Peak Load	70,729	Wkp - PJM Load Summary
M	Average Daily Peak Native Load in Peak Month	58,108	Wkp - PJM Load Summary
N	Amount of Line M Attributable to Seller, if any	8,859	Exelon Load Data
O	Wholesale Load (L-M)	12,621	
P	Net Uncommitted Supply (K-O)	18,207	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	3,635	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->	7,489	
	% of SIL for Seller's imported capacity ->	0.06	
	% of SIL for Other's imported capacity ->	0.94	
	SIL value ->	7,489	Wkp-SILs
	Do Total Imports exceed the SIL value? ->	No	

Part II – Market Share Analysis

Applicant-> **Exelon**
Study Area -> **AP South**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled or under LT contract)					
A	Installed Capacity (inside the study area)	12,331	12,331	11,818	12,331	Exhibit JRS-2
A1	Remote Capacity (from outside the study area)	0	0	0	0	
B	Long-Term Firm Purchases (inside the study area)	1,107	1,107	1,108	1,107	Exhibit JRS-2
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
C	Long-Term Firm Sales (in and outside the study area)	867	867	854	867	Exhibit JRS-2
D	Seasonal Average Planned Outages	313	1,939	93	1,538	Pro rata share of outages
E	Uncommitted Capacity Imports	258	232	350	444	Wkp-Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	51,235	43,394	56,097	43,472	Wkp - PJM Load Summary
G	Amount of Line F Attributable to Seller, if any	7,087	5,923	8,554	6,998	Exelon Load Data
H	Amount of Line F Attributable to Non-Affiliates, if any	44,148	37,471	47,543	36,475	
I	Study Area Reserve Requirement	2,543	2,224	2,771	2,241	Wkp - PJM Operating Reserves
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	
K	Amount of Line I Attributable to Non-Affiliates, if any	2,543	2,224	2,771	2,241	
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	76,701	76,144	72,496	76,333	Wkp - Generation Summary, less Row A above
L1	Remote Capacity (from outside the study area)	0	0	0	0	
M	Long-Term Firm Purchases (inside the study area)	867	867	854	867	Offset Row C
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
N	Long-Term Firm Sales (in and outside the study area)	1,107	1,107	1,108	1,107	Offset Row B
O	Seasonal Average Planned Outages	1,949	11,974	573	9,521	Wkp - PJM Outages Summary, less Row D above
P	Uncommitted Capacity Imports	4,630	4,114	7,139	7,524	Order on SIL Values for the Northeast Region, 147 FERC ¶ 61,190 (2014) less Row E above
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	32,451	28,350	28,494	35,380	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	5,429	4,941	3,774	4,480	
S	Total Seasonal Uncommitted Capacity (Q+R)	37,880	33,291	32,269	39,860	
T	**Seller's Market Share** (R÷S)	14.3%	14.8%	11.7%	11.2%	
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass	
U	Total Imports, as filed by Seller (E+P)	4,888	4,346	7,489	7,968	
V	SIL value*	4,888	4,346	7,489	7,968	
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No	

Part I – Pivotal Supplier Analysis

Applicant-> **Exelon**
Market -> **5004-5005**
Data Year -> **Dec 2014-Nov 2015**

Row			Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	11,816	Exhibit JRS-2
A1	Remote Capacity (from outside the study area)	0	
B	Long-Term Firm Purchases (from inside the study area)	1,102	Exhibit JRS-2
B1	Long-Term Firm Purchases (from outside the study area)	0	
C	Long-Term Firm Sales (in and outside the study area)	854	Exhibit JRS-2
D	Uncommitted Capacity Imports	386	Wkp-Import Allocation
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	46,663	Wkp - Generation Summary, less Row A above
E1	Remote Capacity (from outside the study area)	0	
F	Long-Term Firm Purchases (from inside the study area)	854	Offset Row C
F1	Long-Term Firm Purchases (from outside the study area)	0	
G	Long-Term Firm Sales (in and outside the study area)	1,102	Offset Row B
H	Uncommitted Capacity Imports	7,570	Order on SIL Values for the Northeast Region, 147 FERC ¶ 61,190 (2014) less Row D above
I	Study Area Reserve Requirement	2,512	Wkp - PJM Operating Reserves
J	Amount of Line I Attributable to Seller, if any	0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	21,554	
	Load		
L	Balancing Authority Area Annual Peak Load	52,190	Wkp - PJM Load Summary
M	Average Daily Peak Native Load in Peak Month	42,368	Wkp - PJM Load Summary
N	Amount of Line M Attributable to Seller, if any	8,859	Exelon Load Data
O	Wholesale Load (L-M)	9,822	
P	Net Uncommitted Supply (K-O)	11,732	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	3,591	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->	7,956	
	% of SIL for Seller's imported capacity ->	0.05	
	% of SIL for Other's imported capacity ->	0.95	
	SIL value ->	7,956	Wkp-SILs
	Do Total Imports exceed the SIL value? ->	No	

Part II – Market Share Analysis

Applicant-> **Exelon**
Study Area -> **5004-5005**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled or under LT contract)					
A	Installed Capacity (inside the study area)	12,330	12,330	11,816	12,330	Exhibit JRS-2
A1	Remote Capacity (from outside the study area)	0	0	0	0	
B	Long-Term Firm Purchases (inside the study area)	1,102	1,102	1,102	1,102	Exhibit JRS-2
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
C	Long-Term Firm Sales (in and outside the study area)	867	867	854	867	Exhibit JRS-2
D	Seasonal Average Planned Outages	313	1,939	93	1,538	Pro rata share of outages
E	Uncommitted Capacity Imports	409	257	332	395	Wkp-Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	36,907	31,515	40,748	31,805	Wkp - PJM Load Summary
G	Amount of Line F Attributable to Seller, if any	6,982	5,856	8,554	6,998	Exelon Load Data
H	Amount of Line F Attributable to Non-Affiliates, if any	29,925	25,659	32,194	24,807	
I	Study Area Reserve Requirement	2,189	1,869	2,416	1,886	Wkp - PJM Operating Reserves
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	
K	Amount of Line I Attributable to Non-Affiliates, if any	2,189	1,869	2,416	1,886	
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	49,260	48,686	46,663	48,949	Wkp - Generation Summary, less Row A above
L1	Remote Capacity (from outside the study area)	0	0	0	0	
M	Long-Term Firm Purchases (inside the study area)	867	867	854	867	Offset Row C
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
N	Long-Term Firm Sales (in and outside the study area)	1,102	1,102	1,102	1,102	Offset Row B
O	Seasonal Average Planned Outages	1,252	7,656	369	6,106	Wkp - PJM Outages Summary, less Row D above
P	Uncommitted Capacity Imports	8,460	5,260	7,624	7,676	Order on SIL Values for the Northeast Region, 147 FERC ¶ 61,190 (2014) less Row E above
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	24,119	18,527	19,060	23,591	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	5,679	5,027	3,748	4,424	
S	Total Seasonal Uncommitted Capacity (Q+R)	29,798	23,554	22,808	28,015	
T	**Seller's Market Share** (R÷S)	19.1%	21.3%	16.4%	15.8%	
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Fail	Pass	Pass	
U	Total Imports, as filed by Seller (E+P)	8,869	5,517	7,956	8,071	
V	SIL value*	8,869	5,517	7,956	8,071	
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No	

Part I – Pivotal Supplier Analysis

Applicant-> **Exelon**
Market -> **PJM East**
Data Year -> **Dec 2014-Nov 2015**

Row			Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,156	Exhibit JRS-2
A1	Remote Capacity (from outside the study area)	0	
B	Long-Term Firm Purchases (from inside the study area)	476	Exhibit JRS-2
B1	Long-Term Firm Purchases (from outside the study area)	0	
C	Long-Term Firm Sales (in and outside the study area)	0	
D	Uncommitted Capacity Imports	230	Wkp-Import Allocation
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	25,923	Wkp - Generation Summary, less Row A above
E1	Remote Capacity (from outside the study area)	0	
F	Long-Term Firm Purchases (from inside the study area)	0	
F1	Long-Term Firm Purchases (from outside the study area)	0	
G	Long-Term Firm Sales (in and outside the study area)	476	Offset Row B
H	Uncommitted Capacity Imports	6,763	Order on SIL Values for the Northeast Region, 147 FERC ¶ 61,190 (2014) less Row D above
I	Study Area Reserve Requirement	1,429	Wkp - PJM Operating Reserves
J	Amount of Line I Attributable to Seller, if any	0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	14,551	
	Load		
L	Balancing Authority Area Annual Peak Load	30,240	Wkp - PJM Load Summary
M	Average Daily Peak Native Load in Peak Month	24,093	Wkp - PJM Load Summary
N	Amount of Line M Attributable to Seller, if any	3,549	Exelon Load Data
O	Wholesale Load (L-M)	6,148	
P	Net Uncommitted Supply (K-O)	8,403	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,314	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->	6,993	
	% of SIL for Seller's imported capacity ->	0.03	
	% of SIL for Other's imported capacity ->	0.97	
	SIL value ->	6,993	Wkp-SILs
	Do Total Imports exceed the SIL value? ->	No	

Part II – Market Share Analysis

Applicant-> **Exelon**
Study Area -> **PJM East**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled or under LT contract)					
A	Installed Capacity (inside the study area)	7,576	7,576	7,156	7,576	Exhibit JRS-2
A1	Remote Capacity (from outside the study area)	0	0	0	0	
B	Long-Term Firm Purchases (inside the study area)	476	476	476	476	Exhibit JRS-2
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	
D	Seasonal Average Planned Outages	193	1,191	57	945	Pro rata share of outages
E	Uncommitted Capacity Imports	305	202	214	348	Wkp-Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	19,368	16,803	22,934	17,407	Wkp - PJM Load Summary
G	Amount of Line F Attributable to Seller, if any	2,404	2,144	3,356	2,680	Exelon Load Data
H	Amount of Line F Attributable to Non-Affiliates, if any	16,964	14,659	19,577	14,726	
I	Study Area Reserve Requirement	1,149	996	1,360	1,032	Wkp - PJM Operating Reserves
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	
K	Amount of Line I Attributable to Non-Affiliates, if any	1,149	996	1,360	1,032	
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	28,116	27,423	25,923	27,666	Wkp - Generation Summary, less Row A above
L1	Remote Capacity (from outside the study area)	0	0	0	0	
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
N	Long-Term Firm Sales (in and outside the study area)	476	476	476	476	Offset Row B
O	Seasonal Average Planned Outages	715	4,312	205	3,451	Wkp - PJM Outages Summary, less Row D above
P	Uncommitted Capacity Imports	6,962	4,368	6,779	8,020	Order on SIL Values for the Northeast Region, 147 FERC ¶ 61,190 (2014) less Row E above
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	15,776	11,347	11,084	16,001	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	5,760	4,919	4,434	4,774	
S	Total Seasonal Uncommitted Capacity (Q+R)	21,536	16,266	15,517	20,775	
T	**Seller's Market Share** (R÷S)	26.7%	30.2%	28.6%	23.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	Fail	Fail	Fail	Fail	
U	Total Imports, as filed by Seller (E+P)	7,267	4,570	6,993	8,368	
V	SIL value*	7,267	4,570	6,993	8,368	
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No	

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Atlantic City Electric Company	)	Docket No. ER10-2997-___
AV Solar Ranch 1, LLC	)	Docket No. ER12-2178-___
Baltimore Gas and Electric Company	)	Docket No. ER10-2175-___
Beebe 1B Renewable Energy, LLC	)	Docket No. ER14-2144-___
Beebe Renewable Energy, LLC	)	Docket No. ER12-2311-___
Bethlehem Renewable Energy, LLC	)	Docket No. ER10-3003-___
Calvert Cliffs Nuclear Power Plant, LLC	)	Docket No. ER10-2179-___
Cassia Gulch Wind Park, LLC	)	Docket No. ER11-2016-___
CER Generation, LLC	)	Docket No. ER10-2184-___
Commonwealth Edison Company	)	Docket No. ER10-1048-___
Constellation Energy Commodities Group Maine, LLC	)	Docket No. ER10-2192-__
Constellation Energy Services, Inc.	)	Docket No. ER15-1537-__
Constellation Energy Services of New York, Inc.	)	Docket No. ER15-1539-__
Constellation Mystic Power, LLC	)	Docket No. ER11-2056-__
Constellation NewEnergy, Inc.	)	Docket No. ER10-2178-__
Constellation Power Source Generation, LLC	)	Docket No. ER14-1524-__
Cow Branch Wind Power, LLC	)	Docket No. ER11-2014-__
CR Clearing, LLC	)	Docket No. ER11-2013-__
Criterion Power Partners, LLC	)	Docket No. ER10-3308-__
Delmarva Power & Light Company	)	Docket No. ER10-3018-__
Eastern Landfill Gas, LLC	)	Docket No. ER10-3015-__
Exelon Framingham, LLC	)	Docket No. ER10-1020-__
Exelon Generation Company, LLC	)	Docket No. ER13-1536-__
Exelon New Boston, LLC	)	Docket No. ER10-1078-__
Exelon West Medway, LLC	)	Docket No. ER10-1080-__
Exelon Wind 4, LLC	)	Docket No. ER11-2010-__
Exelon Wyman, LLC	)	Docket No. ER10-1081-__
Fair Wind Power Partners, LLC	)	Docket No. ER15-2293-__
Fauquier Landfill Gas, LLC	)	Docket No. ER10-3016-__
FourmileWind Energy, LLC	)	Docket No. ER14-2145-__
Handsome Lake Energy, LLC	)	Docket No. ER10-2180-__
Harvest II Windfarm, LLC	)	Docket No. ER12-2201-__
Harvest Windfarm, LLC	)	Docket No. ER11-2011-__
High Mesa Energy, LLC	)	Docket No. ER12-2528-__
Michigan Wind 1, LLC	)	Docket No. ER11-2009__
Michigan Wind 2, LLC	)	Docket No. ER11-3989-__
Nine Mile Point Nuclear Station, LLC	)	Docket No. ER10-2181-__
PECO Energy Company	)	Docket No. ER14-767-__
Pepco Energy Services, Inc.	)	Docket No. ER10-2992-__
Potomac Electric Power Company	)	Docket No. ER10-3030-__
Potomac Power Resources, LLC	)	Docket No. ER10-2990-__
R.E. Ginna Nuclear Power Plant, LLC	)	Docket No. ER10-2182-__
Shooting Star Wind Project, LLC	)	Docket No. ER12-1829-__
Tuana Springs Energy, LLC	)	Docket No. ER11-2007-__
Wildcat Wind, LLC	)	Docket No. ER12-1223-__
Wind Capital Holdings, LLC	)	Docket No. ER11-2005-__

AFFIDAVIT

District of Columbia §
§
§

JULIE R. SOLOMON being duly sworn, deposes and states: that she prepared the Affidavit and Exhibits of Julie R. Solomon and that the statements contained therein and the Exhibits attached hereto are true and correct to the best of her knowledge and belief.

Julie R. Solomon

SUBSCRIBED AND SWORN TO BEFORE ME, this the 21 day of April 2016.

Notary Public, District of Columbia

Printed Name: Avis Dickens

My Commission Expires: 3/31/2019

Attachment B:
Proposed Protective Order

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Atlantic City Electric Company	**)**	**Docket No. ER10-2997-___**
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Wildcat Wind, LLC	**)**	**Docket No. ER12-1223-__**
Wind Capital Holdings, LLC	**)**	**Docket No. ER11-2005-__**

PROTECTIVE ORDER

(Issued April __, 2016)

1. This Protective Order shall govern the use of all Protected Materials produced by, or on behalf of, any Participant. Notwithstanding any order terminating this proceeding, this Protective Order shall remain in effect until specifically modified or terminated by the Presiding Administrative Law Judge ("Presiding Judge") or the Federal Energy Regulatory Commission ("Commission").

2. This Protective Order applies to the following two categories of materials: (A) A Participant may designate as protected those materials which customarily are treated by that Participant as sensitive or proprietary, which are not available to the public, and which, if disclosed freely, would subject that Participant or its customers to risk of competitive disadvantage or other business injury; and (B) A Participant shall designate as protected those materials which contain critical energy infrastructure information, as defined in 18 C.F.R. § 388.113(c)(1) ("Critical Energy Infrastructure Information").

3. Definitions -- For purposes of this Order:

(a) The term "Participant" shall mean a Participant as defined in 18 C.F.R. § 385.102(b).

(b)(1) The term "Protected Materials" means (A) materials (including depositions) provided by a Participant in response to discovery requests and/or filed with the Commission and, in each case, designated by such Participant as protected; (B) any information contained in or obtained from such designated materials; (C) any other materials which are made subject to this Protective Order by the Presiding Judge, by the Commission, by any court or other body having appropriate authority, or by agreement of the Participants; (D) notes of Protected Materials; and (E) copies of Protected Materials. The Participant producing the Protected Materials shall physically mark them on each page as "PROTECTED MATERIALS" or with words of similar import as long as the term "Protected Materials" is included in that designation to indicate that they are Protected Materials. If the Protected Materials contain Critical Energy Infrastructure Information, the Participant producing such information shall additionally mark on each page containing such information the words "Contains Critical Energy Infrastructure Information — Do Not Release." In addition if the Protected Materials contain market sensitive information, public disclosure of which the disclosing Participant believes in

good faith would competitively harm the Participant, the disclosing Participant shall additionally mark on each page containing such information the words "HIGHLY SENSITIVE PROTECTED MATERIALS." Except for the more limited list of persons who qualify as Reviewing Representatives for purposes of reviewing Highly Sensitive Protected Materials, such materials are subject to the same provisions in the Protective Order as Protected Materials.

(2) The term "Notes of Protected Materials" means memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses materials described in Paragraph 3(b)(1). Notes of Protected Materials are subject to the same restrictions provided in this order for Protected Materials except as specifically provided in this order.

(3) Protected Materials shall not include (A) any information or document contained in the files of the Commission (other than pursuant to this Protective Order), or any other federal or state agency, or any federal or state court, unless the information or document has been determined to be protected by such agency or court, or (B) information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Protective Order, or (C) any information or document labeled as "Non-Internet Public" by a Participant, in accordance with Paragraph 30 of FERC Order No. 630, FERC Stat. & Reg. & 31,140. Protected Materials do include any information or document contained in the files of the Commission that has been designated as Critical Energy Infrastructure Information.

(c) The term "Non-Disclosure Certificate" shall mean the certificate annexed hereto by which Participants who have been granted access to Protected Materials shall certify their understanding that such access to Protected Materials is provided pursuant to the terms and restrictions of this Protective Order, and that such Participants have read the Protective Order and agree to be bound by it. All Non-Disclosure Certificates shall be served on all parties on the official service list maintained by the Secretary in this proceeding.

(d) The term "Reviewing Representative" shall mean a person who has signed a Non-Disclosure Certificate (to the extent required by Section 9) and:

(i) For purposes of reviewing Protected Materials (other than Highly Sensitive Protected Materials), who is

(1) Commission Staff ("Staff");

(2) an attorney who has made an appearance in this proceeding for a Participant;

(3) attorneys, paralegals, and other employees associated for purposes of this case with an attorney described in Subparagraph (2);

(4) an expert or an employee of an expert retained by a Participant for the purpose of advising, preparing for or testifying in this proceeding;

(5) a person designated as a Reviewing Representative by order of the Presiding Judge or the Commission; or

(6) employees or other representatives of Participants appearing in this proceeding with significant responsibility for this docket.

(ii) For purposes of reviewing Highly Sensitive Protected Materials, who is:

(1) Staff;

(2) Members or staff of any state or local utilities commission which is a Participant;

(3) An outside attorney who has made an appearance in this proceeding for a Participant;

(4) Attorneys, paralegals, and other employees of the firm of the outside attorney described in Paragraph 3(d)(ii)(3) working with such outside attorney for purposes of this case;

(5) An outside expert or an employee of an outside expert retained by a Participant for the purpose of advising, preparing for or testifying in this proceeding who is working under the direction of an attorney described in Paragraph 3(d)(ii)(2) or 3(d)(ii)(3);

(6) If, after a good faith effort, parties fail to agree on designating a specifically-named inside employee(s) of a non-governmental Participant as a Reviewing Representative for the review of specific Highly Sensitive Protected Material(s), a party may request that the Presiding Judge so-designate such a specifically-named inside employee(s) who, for example, is not directly involved in, or having direct or supervisory responsibilities over, the purchase, sale, or marketing of electricity (including transmission service) at retail or wholesale, the negotiation or development of participation or cost-sharing arrangements for transmission or generation facilities, or other activities or transactions of a type with respect to which the disclosure of Highly Sensitive Protected Materials may present an unreasonable risk of harm; or

(7) A person designated as a Reviewing Representative by order of the Presiding Judge or the Commission specifically ruling on and indicating each such person by name.

4. Protected Materials shall be made available under the terms of this Protective Order only to Participants and only through their Reviewing Representatives as provided in Paragraphs 7-9.

5. Protected Materials shall remain available to Participants until the later of the date that an order terminating this proceeding becomes no longer subject to judicial review, or the date that any other Commission proceeding relating to the Protected Material is concluded and no longer subject to judicial review. If requested to do so in writing after that date, the Participants shall, within fifteen days of such request, return the Protected Materials (excluding Notes of Protected Materials) to the Participant that produced them, or shall destroy the materials, except that copies of filings, official transcripts and exhibits in this proceeding that contain Protected Materials, and Notes of Protected Material may be retained, if they are maintained in accordance with Paragraph 6, below. Within such time period each Participant, if requested to do so, shall also submit to the producing Participant an affidavit stating that, to the best of its knowledge, all Protected Materials and all Notes of Protected Materials have been returned or have been destroyed or will be maintained in accordance with Paragraph 6. To the extent Protected Materials are not returned or destroyed, they shall remain subject to the Protective Order.

6. All Protected Materials shall be maintained by the Participant in a secure place. Access to those materials shall be limited to those Reviewing Representatives specifically authorized pursuant to Paragraphs 8-9. The Secretary shall place any Protected Materials filed with the Commission in a non-public file. By placing such documents in a non-public file, the Commission is not making a determination of any claim of privilege. The Commission retains the right to make determinations regarding any claim of privilege and the discretion to release information necessary to carry out its jurisdictional responsibilities. For documents submitted to Staff, Staff shall follow the notification procedures of 18 C.F.R. § 388.112 before making public any Protected Materials.

7. Protected Materials shall be treated as confidential by each Participant and by the Reviewing Representative in accordance with the certificate executed pursuant to Paragraph 9. Protected Materials shall not be used except as necessary for the conduct of this proceeding, nor shall they be disclosed in any manner to any person except a Reviewing Representative who is engaged in the conduct of this proceeding and who needs to know the information in order to carry out that person's responsibilities in this proceeding. Reviewing Representatives may make copies of Protected Materials, but such copies become Protected Materials. Reviewing Representatives may make notes of Protected Materials, which shall be treated as Notes of Protected Materials if they disclose the contents of Protected Materials.

8. (a) If a Reviewing Representative's scope of employment includes the marketing of energy, the direct supervision of any employee or employees whose duties include the marketing of energy, the provision of consulting services to any person whose duties include the marketing of energy, or the direct supervision of any employee or employees whose duties include the marketing of energy, such Reviewing Representative may not

use information contained in any Protected Materials obtained through this proceeding to give any Participant or any competitor of any Participant a commercial advantage.

(b) In the event that a Participant wishes to designate as a Reviewing Representative a person not described in Paragraph 3 (d) above, the Participant shall seek agreement from the Participant providing the Protected Materials. If an agreement is reached that person shall be a Reviewing Representative pursuant to Paragraphs 3(d) above with respect to those materials. If no agreement is reached, the Participant shall submit the disputed designation to the Presiding Judge for resolution.

9. (a) A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Protected Materials pursuant to this Protective Order unless that Reviewing Representative has first executed a Non-Disclosure Certificate; provided, that if an attorney qualified as a Reviewing Representative has executed such a certificate, the paralegals, secretarial and clerical personnel under the attorney's instruction, supervision or control need not do so. A copy of each Non-Disclosure Certificate shall be provided to counsel for the Participant asserting confidentiality prior to disclosure of any Protected Material to that Reviewing Representative. NOTWITHSTANDING THE FOREGOING, A MEMBER OF THE COMMISSION'S ADVISORY STAFF REVIEWING PROTECTED MATERIAL OR HIGHLY SENSITIVE PROTECTED MATERIAL SUBJECT TO THIS AGREEMENT IN CONNECTION WITH ITS REVIEW OF APPLICANT'S MARKET-BASED RATE AUTHORIZATION SHALL NOT BE REQUIRED TO SIGN OR RETURN A NON-DISCLOSURE CERTIFICATE.

(b) Attorneys qualified as Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this order.

10. Any Reviewing Representative may disclose Protected Materials to any other Reviewing Representative as long as the disclosing Reviewing Representative and the receiving Reviewing Representative both have executed a Non-Disclosure Certificate. In the event that any Reviewing Representative to whom the Protected Materials are disclosed ceases to be engaged in these proceedings, or is employed or retained for a position whose occupant is not qualified to be a Reviewing Representative under Paragraph 3(d), access to Protected Materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Non-Disclosure Certificate shall continue to be bound by the provisions of this Protective Order and the certification.

11. Subject to Paragraph 18, the Presiding Administrative Law Judge shall resolve any disputes arising under this Protective Order. Prior to presenting any dispute under this Protective Order to the Presiding Administrative Law Judge, the parties to the dispute shall use their best efforts to resolve it. Any participant that contests the designation of materials as protected shall notify the party that provided the protected materials by specifying in writing the materials the designation of which is contested. This Protective Order shall automatically cease to apply to such materials five (5) business days after the

notification is made unless the designator, within said 5-day period, files a motion with the Presiding Administrative Law Judge, with supporting affidavits, demonstrating that the materials should continue to be protected. In any challenge to the designation of materials as protected, the burden of proof shall be on the participant seeking protection. If the Presiding Administrative Law Judge finds that the materials at issue are not entitled to protection, the procedures of Paragraph 18 shall apply. The procedures described above shall not apply to protected materials designated by a Participant as Critical Energy Infrastructure Information. Materials so designated shall remain protected and subject to the provisions of this Protective Order, unless a Participant requests and obtains a determination from the Commission's Critical Energy Infrastructure Information Coordinator that such materials need not remain protected.

12. All copies of all documents reflecting Protected Materials, including the portion of the hearing testimony, exhibits, transcripts, briefs and other documents which refer to Protected Materials, shall be filed and served in sealed envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Protective Order. Such documents shall be marked "PROTECTED MATERIALS" and shall be filed under seal and served under seal upon the Presiding Judge and all Reviewing Representatives who are on the service list. Such documents containing Critical Energy Infrastructure Information shall be additionally marked "Contains Critical Energy Infrastructure Information — Do Not Release." For anything filed under seal, redacted versions or, where an entire document is protected, a letter indicating such, will also be filed with the Commission and served on all parties on the service list and the Presiding Judge. Counsel for the producing Participant shall provide to all Participants who request the same, a list of Reviewing Representatives who are entitled to receive such material. Counsel shall take all reasonable precautions necessary to assure that Protected Materials are not distributed to unauthorized persons.

13. If any Participant desires to include, utilize or refer to any Protected Materials or information derived therefrom in testimony or exhibits during the hearing in these proceedings in such a manner that might require disclosure of such material to persons other than reviewing representatives, such participant shall first notify both counsel for the disclosing participant and the Presiding Judge of such desire, identifying with particularity each of the Protected Materials. Thereafter, use of such Protected Material will be governed by procedures determined by the Presiding Judge.

14. Nothing in this Protective Order shall be construed as precluding any Participant from objecting to the use of Protected Materials on any legal grounds.

15. Nothing in this Protective Order shall preclude any Participant from requesting the Presiding Judge, the Commission, or any other body having appropriate authority, to find that this Protective Order should not apply to all or any materials previously designated as Protected Materials pursuant to this Protective Order. The Presiding Judge may alter or amend this Protective Order as circumstances warrant at any time during the course of this proceeding.

16. Each party governed by this Protective Order has the right to seek changes in it as appropriate from the Presiding Judge or the Commission.

17. All Protected Materials filed with the Commission, the Presiding Judge, or any other judicial or administrative body, in support of, or as a part of, a motion, other pleading, brief, or other document, shall be filed and served in sealed envelopes or other appropriate containers bearing prominent markings indicating that the contents include Protected Materials subject to this Protective Order. Such documents containing Critical Energy Infrastructure Information shall be additionally marked "Contains Critical Energy Infrastructure Information – Do Not Release."

18. If the Presiding Judge finds at any time in the course of this proceeding that all or part of the Protected Materials need not be protected, those materials shall, nevertheless, be subject to the protection afforded by this Protective Order for three (3) business days from the date of issuance of the Presiding Judge's determination, and if the Participant seeking protection files an interlocutory appeal or requests that the issue be certified to the Commission, for an additional seven (7) business days. None of the Participants waives its rights to seek additional administrative or judicial remedies after the Presiding Judge's decision respecting Protected Materials or Reviewing Representatives, or the Commission's denial of any appeal thereof. The provisions of 18 C.F.R. §§ 388.112 and 388.113 shall apply to any requests under the Freedom of Information Act. (5 U.S.C. ¶ 552) for Protected Materials in the files of the Commission.

19. Nothing in this Protective Order shall be deemed to preclude any Participant from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced in this proceeding under this Protective Order.

20. None of the Participants waives the right to pursue any other legal or equitable remedies that may be available in the event of actual or anticipated disclosure of Protected Materials.

21. The contents of Protected Materials or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with this Protective Order and shall be used only in connection with this (these) proceeding(s). Any violation of this Protective Order and of any Non-Disclosure Certificate executed hereunder shall constitute a violation of an order of the Commission.

_____

Presiding Administrative Law Judge

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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Exelon New Boston, LLC	**)**	**Docket No. ER10-1078-__**
Exelon West Medway, LLC	**)**	**Docket No. ER10-1080-__**
Exelon Wind 4, LLC	**)**	**Docket No. ER11-2010-__**
Exelon Wyman, LLC	**)**	**Docket No. ER10-1081-__**
Fair Wind Power Partners, LLC	**)**	**Docket No. ER15-2293-__**
Fauquier Landfill Gas, LLC	**)**	**Docket No. ER10-3016-__**
FourmileWind Energy, LLC	**)**	**Docket No. ER14-2145-__**
Handsome Lake Energy, LLC	**)**	**Docket No. ER10-2180-__**
Harvest II Windfarm, LLC	**)**	**Docket No. ER12-2201-__**
Harvest Windfarm, LLC	**)**	**Docket No. ER11-2011-__**
High Mesa Energy, LLC	**)**	**Docket No. ER12-2528-__**
Michigan Wind 1, LLC	**)**	**Docket No. ER11-2009__**
Michigan Wind 2, LLC	**)**	**Docket No. ER11-3989-__**
Nine Mile Point Nuclear Station, LLC	**)**	**Docket No. ER10-2181-__**
PECO Energy Company	**)**	**Docket No. ER14-767-__**
Pepco Energy Services, Inc.	**)**	**Docket No. ER10-2992-__**
Potomac Electric Power Company	**)**	**Docket No. ER10-3030-__**

Potomac Power Resources, LLC	**)**	**Docket No. ER10-2990-__**
R.E. Ginna Nuclear Power Plant, LLC	**)**	**Docket No. ER10-2182-__**
Shooting Star Wind Project, LLC	**)**	**Docket No. ER12-1829-__**
Tuana Springs Energy, LLC	**)**	**Docket No. ER11-2007-__**
Wildcat Wind, LLC	**)**	**Docket No. ER12-1223-__**
Wind Capital Holdings, LLC	**)**	**Docket No. ER11-2005-__**

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Protected Materials is provided to me pursuant to the terms and restrictions of the Protective Order in this proceeding, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by it. I understand that the contents of the Protected Materials, any notes or other memoranda, or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with that Protective Order. I acknowledge that a violation of this certificate constitutes a violation of an order of the Federal Energy Regulatory Commission.

By: _____
Title: _____
Representing: _____
Date: _____

Attachment C:
Asset Appendices

Asset Appendix: Generation Assets - April 2016

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned by**	**Controlled by**	**Date Control Transferred**	**Location**		**In-Service Date**	**Capacity Rating: Nameplate (MW)**	**Capacity Rating: Used in Filing (MW)**	**Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative**	**End Note Number (Enter text in End Note Tab)**
						Market / Balancing Authority Area	**Geographic Region**					
Beebe 1B Renewable Energy, LLC	ER14-2144	Beebe 1b WF	Beebe 1B Renewable Energy, LLC	Beebe 1B Renewable Energy, LLC	N/A	MISO	Central	12/12/2014	50.40	50.40	S	
Beebe Renewable Energy, LLC	ER12-2311	Beebe 1a WF	Beebe Renewable Energy, LLC	Beebe Renewable Energy, LLC	N/A	MISO	Central	1/17/2013	81.60	81.60	S	
Exelon Generation Company, LLC	ER00-3251	Clinton	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	MISO	Central	11/1/1987	1138.30	1065.00	S	
Harvest II Windfarm, LLC	ER12-2201 QF12-522	Harvest 2 WF	Harvest II Windfarm, LLC	Harvest II Windfarm, LLC	N/A	MISO	Central	11/28/2012	59.40	59.40	S	
Harvest Windfarm, LLC	ER07-1246 QF07-29	Harvest 1 WF	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	2/28/2008	52.80	52.80	S	
Michigan Wind 1, LLC	ER05-1511 QF05-228	Michigan Wind 1 WF	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	12/16/2008	69.00	69.00	S	
Michigan Wind 2, LLC	ER11-3989	Michigan Wind 2 WF	Michigan Wind 2, LLC	Michigan Wind 2, LLC	N/A	MISO	Central	1/5/2012	90.00	90.00	S	
Atlantic City Electric Company	ER96-1361	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Commonwealth Edison Company	ER98-1734	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Energy Commodities Group Maine, LLC	ER02-699	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Energy Services of New York, Inc.	ER07-651	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Energy Services, Inc.	ER07-650	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation NewEnergy, Inc.	ER96-1387	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Delmarva Power & Light Company	ER96-2571	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
PECO Energy Company	ER01-1147	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Pepco Energy Services, Inc.	ER98-3096	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Potomac Electric Power Company	ER98-4138	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Mystic Power, LLC	ER10-2281	Mystic 7	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/1975	617.00	575.48	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	278.60	228.77	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	278.60	229.97	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	315.00	244.58	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	278.60	231.40	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	278.60	232.50	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	315.00	247.24	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic Jet	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/1969	14.20	8.28	S	
Exelon Framingham LLC	ER98-1943	Framingham Jet 1	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	3/1/1970	14.20	10.15	S	
Exelon Framingham LLC	ER98-1943	Framingham Jet 2	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/1969	14.20	10.05	S	
Exelon Framingham LLC	ER98-1943	Framingham Jet 3	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/1969	14.20	11.25	S	
Exelon New Boston, LLC	ER98-1943	New Boston Jet	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	9/1/1966	18.60	16.00	S	
Exelon West Medway, LLC	ER98-1943	West Medway Jet 1	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/1970	45.00	42.00	S	
Exelon West Medway, LLC	ER98-1943	West Medway Jet 2	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	3/1/1971	45.00	39.80	S	

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[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
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						Market / Balancing Authority Area	**Geographic Region**					
Exelon West Medway, LLC	ER98-1943	West Medway Jet 3	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/1970	45.00	42.00	S	
Exelon Wyman, LLC	ER98-1943	Wyman 4	Exelon Wyman, LLC (5.9%)	FPL Energy Wyman IV LLC	N/A	ISO-NE	Northeast	1/1/1978	632.40	602.00	S	1
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 1	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	12/1/1969	641.80	637.00	S	
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 2	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	8/1/1988	1428.45	1287.00	S	2
R. E. Ginna Nuclear Power Plant, LLC	ER04-485	Ginna	R. E. Ginna Nuclear Power Plant, LLC	R. E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	7/1/1970	614.00	582.00	S	
Criterion Power Partners, LLC	ER10-1443	Criterion WF	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	2/4/2011	70.00	70.00	S	
Exelon Generation Company, LLC	ER00-3251	Braidwood 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/1/1988	1224.90	1183.00	S	
Exelon Generation Company, LLC	ER00-3251	Braidwood 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1988	1224.90	1154.00	S	
Exelon Generation Company, LLC	ER00-3251	Byron 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/1/1985	1224.90	1164.00	S	
Exelon Generation Company, LLC	ER00-3251	Byron 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/1987	1224.90	1136.00	S	
Exelon Generation Company, LLC	ER00-3251	Dresden 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/1970	1009.00	902.00	S	
Exelon Generation Company, LLC	ER00-3251	Dresden 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1971	1009.00	895.00	S	
Exelon Generation Company, LLC	ER00-3251	LaSalle 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	1/1/1984	1170.00	1135.40	S	
Exelon Generation Company, LLC	ER00-3251	LaSalle 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1984	1170.00	1136.20	S	
Exelon Generation Company, LLC	ER00-3251	Quad Cities 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1972	1009.30	908.00	S	3
Exelon Generation Company, LLC	ER00-3251	Quad Cities 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1972	1009.30	911.00	S	4
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Fair Wind Power Partners, LLC	ER15-2293	Fair Wind WF	Fair Wind Power Partners, LLC	Fair Wind Power Partners, LLC	N/A	PJM	Northeast	11/24/2015	30.00	30.00	S	
Fourmile Wind Energy, LLC	ER14-2145 QF14-721	Fourmile Ridge WF	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	1/15/2015	40.00	40.00	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 1	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 2	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 3	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 4	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 5	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Bethlehem Renewable Energy, LLC	ER07-903	Bethlehem Landfill	Bethlehem Renewable Energy, LLC	Bethlehem Renewable Energy, LLC	N/A	PJM-5004/5005	Northeast	3/1/2008	5.50	4.70	S	

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Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned by**	**Controlled by**	**Date Control Transferred**	**Location**		**In-Service Date**	**Capacity Rating: Nameplate (MW)**	**Capacity Rating: Used in Filing (MW)**	**Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative**	**End Note Number (Enter text in End Note Tab)**
						Market / Balancing Authority Area	**Geographic Region**					
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 1	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM-5004/5005	Northeast	5/1/1975	918.00	866.00	S	
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 2	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM-5004/5005	Northeast	4/1/1977	910.70	841.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Gould Street 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	12/1/1952	103.50	97.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	6/1/1969	18.00	14.60	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	6/1/1969	18.00	15.60	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	6/1/1969	18.00	14.50	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	6/1/1969	18.00	16.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	1/1/1972	53.10	52.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	4/1/1972	53.10	51.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	4/1/1972	53.10	52.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 51	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	6/1/1995	192.00	147.60	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	6/28/2015	141.00	109.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	8/1/1970	20.70	15.30	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	8/1/1970	20.70	16.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	9/1/1970	20.70	14.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	9/1/1970	20.70	14.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Riverside 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	9/1/1951	72.20	74.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Riverside 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	9/1/1970	25.00	19.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Riverside 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	9/1/1970	25.00	20.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Westport 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM-5004/5005	Northeast	2/1/1969	121.50	115.80	S	
Eastern Landfill Gas, LLC	ER05-1054	Eastern Landfill	Eastern Landfill Gas, LLC	Eastern Landfill Gas, LLC	N/A	PJM-5004/5005	Northeast	10/26/2006	3.00	3.00	S	
Exelon Generation Company, LLC	ER00-3251	TMI 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-5004/5005	Northeast	9/2/1974	980.90	802.80	S	
Exelon Generation Company, LLC	ER00-3251	Chester 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/7/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Chester 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/20/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Chester 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/6/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/1/1928	45.00	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/25/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/4/1964	55.60	65.00	S	

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						Market / Balancing Authority Area	Geographic Region					
Exelon Generation Company, LLC	ER00-3251	Conowingo 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/1/1928	36.00	36.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/6/1928	48.00	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/5/1928	47.70	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1928	36.00	36.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/1/1928	47.70	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1928	48.00	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/10/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/25/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 21	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 22	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 31	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	8/6/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 32	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	8/8/1974	68.30	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 41	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 42	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/7/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/19/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/12/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/20/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 20	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/24/1974	391.00	380.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 30	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/7/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/29/1976	391.00	380.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 40	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/21/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Fairless Hills A	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1996	30.00	30.00	S	
Exelon Generation Company, LLC	ER00-3251	Fairless Hills B	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1996	30.00	30.00	S	
Exelon Generation Company, LLC	ER00-3251	Falls 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/22/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Falls 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/10/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Falls 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/28/1970	21.10	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Limerick 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/1/1986	1138.50	1119.70	S	

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[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned by	Controlled by	Date Control Transferred	Location		In-Service Date	Capacity Rating: Nameplate (MW)	Capacity Rating: Used in Filing (MW)	Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative	End Note Number (Enter text in End Note Tab)
						Market / Balancing Authority Area	Geographic Region					
Exelon Generation Company, LLC	ER00-3251	Limerick 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	1/1/1990	1138.50	1122.10	S	
Exelon Generation Company, LLC	ER00-3251	Moser 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/9/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Moser 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/29/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Moser 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/11/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/10/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/10/1967	134.00	133.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	134.00	133.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/10/1968	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/10/1968	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Oyster Creek 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1969	550.00	607.70	S	
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/5/1974	1244.80	1223.70	S	5
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/23/1974	1377.00	1226.70	S	6
Exelon Generation Company, LLC	ER00-3251	Pennsbury 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/1/1996	3.00	3.00	S	
Exelon Generation Company, LLC	ER00-3251	Pennsbury 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/1/1996	3.00	3.00	S	
Exelon Generation Company, LLC	ER00-3251	Richmond 91	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/7/1973	65.80	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Richmond 92	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/7/1973	65.80	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Salem 1	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	6/30/1977	1251.40	1173.99	S	7
Exelon Generation Company, LLC	ER00-3251	Salem 2	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	10/13/1981	1216.40	1158.02	S	8
Exelon Generation Company, LLC	ER00-3251	Salem 3	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	6/17/1971	41.80	37.57	S	9
Exelon Generation Company, LLC	ER00-3251	Schuylkill 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/30/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Schuylkill 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/11/1971	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/14/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/9/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/26/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	11/7/1968	18.60	13.00	S	
Cassia Gulch Wind Park LLC	ER10-75 QF05-180	Cassia Gulch WF	Cassia Gulch Wind Park LLC	Cassia Gulch Wind Park LLC	N/A	IPCO	Northwest	3/31/2009	18.90	18.90	S	
High Mesa Energy, LLC	ER12-2528 QF13-77	High Mesa WF	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	IPCO	Northwest	8/28/2012	39.90	39.90	S	
Tuana Springs Energy, LLC	ER10-87 QF08-742	Tuana Springs WF	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	IPCO	Northwest	7/27/2010	16.80	16.80	S	
Cow Branch Wind Power, L.L.C.	ER07-1223 QF07-253	Cow Branch WF	Cow Branch Wind Power, L.L.C.	Cow Branch Wind Power, L.L.C.	N/A	AECI	Southeast	3/3/2008	50.40	50.40	S	

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[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned by**	**Controlled by**	**Date Control Transferred**	**Location**		**In-Service Date**	**Capacity Rating: Nameplate (MW)**	**Capacity Rating: Used in Filing (MW)**	**Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative**	**End Note Number (Enter text in End Note Tab)**
						Market / Balancing Authority Area	**Geographic Region**					
CR Clearing, LLC	ER07-1222 QF07-248	Conception WF	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	5/1/2008	50.40	50.40	S	
Wind Capital Holdings, LLC	ER07-1208 QF07-222	Wind Capital Holdings LLC WF	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	5/14/2007	56.70	56.70	S	
CER Generation, LLC	ER10-662	Hillabee GT1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	258.40	246.00	S	
CER Generation, LLC	ER10-662	Hillabee GT2	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	258.40	246.00	S	
CER Generation, LLC	ER10-662	Hillabee STG1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	306.00	285.00	S	
AV Solar Ranch 1, LLC	ER12-2178	Antelope Valley SF	AV Solar Ranch 1, LLC	AV Solar Ranch 1, LLC	N/A	CAISO	Southwest	12/28/2012	253.00	241.50	S	
Exelon Wind 4, LLC	ER07-1202 QF03-13	Exelon Wind 4 WF	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	12/15/2006	79.80	79.80	S	
Shooting Star Wind Project, LLC	ER00-3251	Shooting Star WF	Shooting Star Wind Project, LLC	Shooting Star Wind Project, LLC	N/A	SPP	SPP	9/29/2012	104.00	104.00	S	
Wildcat Wind, LLC	ER12-1223 QF12-412	Wildcat WF	Wildcat Wind, LLC	Wildcat Wind, LLC	N/A	SPP	SPP	7/1/2012	27.30	27.30	S	

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Asset Appendix: Long-Term Power Purchase Agreements - April 2016

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
				Location				
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Seller Name**	**Amount of PPA (MW)**	**Market / Balancing Authority Area**	**Geographic Region**	**Start Date (mo/da/yr)**	**End Date (mo/da/yr)**	**End Note Number (Enter text in End Note Tab)**
Exelon Generation Company, LLC	ER00-3251	Pioneer Trail Wind Farm, LLC	110	MISO	Central	2/15/2012	7/1/2020	
Exelon Generation Company, LLC	ER00-3251	Tenaska Frontier Partners Ltd	160	MISO	Central	9/20/2000	8/31/2020	
Exelon Generation Company, LLC	ER00-3251	Tenaska Frontier Partners Ltd	160	MISO	Central	9/20/2000	8/31/2020	
Exelon Generation Company, LLC	ER00-3251	Tenaska Frontier Partners Ltd	160	MISO	Central	9/20/2000	8/31/2020	
Exelon Generation Company, LLC	ER00-3251	Tenaska Frontier Partners Ltd	390	MISO	Central	9/20/2000	8/31/2020	
Exelon Generation Company, LLC	ER00-3251	Ameresco Northampton, Inc	1	ISO-NE	Northeast	3/13/2008	12/31/2017	
Exelon Generation Company, LLC	ER00-3251	Kleen Energy Systems, LLC	186	ISO-NE-Conn	Northeast	7/23/2011	12/31/2017	
Exelon Generation Company, LLC	ER00-3251	Kleen Energy Systems, LLC	188	ISO-NE-Conn	Northeast	7/23/2011	12/31/2017	
Exelon Generation Company, LLC	ER00-3251	Kleen Energy Systems, LLC	246	ISO-NE-Conn	Northeast	7/23/2011	12/31/2017	
Exelon Generation Company, LLC	ER00-3251	WM Renewable Energy, LLC	6	NYISO	Northeast	1/1/2012	12/31/2016	
Exelon Generation Company, LLC	ER00-3251	WM Renewable Energy, LLC	3	NYISO	Northeast	1/1/2012	12/31/2016	
Exelon Generation Company, LLC	ER00-3251	WM Renewable Energy, LLC	6	NYISO	Northeast	1/1/2012	12/31/2016	
Exelon Generation Company, LLC	ER00-3251	WM Renewable Energy, LLC	2	NYISO	Northeast	1/1/2012	12/31/2016	
Exelon Generation Company, LLC	ER00-3251	WM Renewable Energy, LLC	6	NYISO	Northeast	1/1/2012	12/31/2016	
Exelon Generation Company, LLC	ER00-3251	WM Renewable Energy, LLC	2	NYISO	Northeast	1/1/2012	12/31/2016	
Exelon Generation Company, LLC	ER00-3251	WM Renewable Energy, LLC	3	NYISO	Northeast	2/1/2013	12/31/2016	
Delmarva Power & Light Company	ER96-2571	AES Armenia Mountain Wind LLC	50	PJM	Northeast	12/18/2009	12/31/2024	
Exelon Generation Company, LLC	ER00-3251	Backbone Mountain Windpower LLC	66	PJM	Northeast	12/20/2002	12/31/2022	
Exelon Generation Company, LLC	ER00-3251	Bellefontaine Gas Producers, LLC	5	PJM	Northeast	3/5/2009	3/31/2019	
Delmarva Power & Light Company	ER96-2571	Chestnut Flats Wind LLC	38	PJM	Northeast	12/31/2011	12/31/2031	
Exelon Generation Company, LLC	ER00-3251	Cordova Energy Company, LLC	165	PJM	Northeast	12/30/2005	12/31/2019	
Exelon Generation Company, LLC	ER00-3251	Cordova Energy Company, LLC	165	PJM	Northeast	12/30/2005	12/31/2019	
Exelon Generation Company, LLC	ER00-3251	Cordova Energy Company, LLC	191	PJM	Northeast	12/30/2005	12/31/2019	
Exelon Generation Company, LLC	ER00-3251	Elwood Energy, LLC	150	PJM	Northeast	6/15/2006	8/31/2016	
Exelon Generation Company, LLC	ER00-3251	Elwood Energy, LLC	150	PJM	Northeast	6/15/2006	8/31/2016	
Exelon Generation Company, LLC	ER00-3251	Elwood Energy, LLC	150	PJM	Northeast	6/15/2006	8/31/2017	
Exelon Generation Company, LLC	ER00-3251	Elwood Energy, LLC	150	PJM	Northeast	6/15/2006	8/31/2017	
Exelon Generation Company, LLC	ER00-3251	Forward Wind Power LLC	29	PJM	Northeast	4/11/2008	12/31/2017	
Exelon Generation Company, LLC	ER00-3251	High Trail Wind Farm, LLC	99	PJM	Northeast	1/1/2010	12/31/2017	
Exelon Generation Company, LLC	ER00-3251	Mill Run Windpower, LLC	16	PJM	Northeast	12/20/2001	12/31/2021	
Exelon Generation Company, LLC	ER00-3251	Old Trail Wind Farm, LLC	198	PJM	Northeast	9/1/2008	12/31/2022	
Exelon Generation Company, LLC	ER00-3251	Patton Wind Farm, LLC	16	PJM	Northeast	1/1/2013	12/31/2032	
Delmarva Power & Light Company	ER96-2571	Roth Rock Wind Farm LLC	40	PJM	Northeast	12/31/2010	12/31/2040	
Exelon Generation Company, LLC	ER00-3251	Somerset Windpower, LLC	9	PJM	Northeast	12/19/2001	12/31/2021	

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[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
				Location				
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Seller Name**	**Amount of PPA (MW)**	**Market / Balancing Authority Area**	**Geographic Region**	**Start Date (mo/da/yr)**	**End Date (mo/da/yr)**	**End Note Number (Enter text in End Note Tab)**
Exelon Generation Company, LLC	ER00-3251	WM Renewable Energy, LLC	4	PJM	Northeast	3/1/2012	12/31/2016	
Exelon Generation Company, LLC	ER00-3251	WM Renewable Energy, LLC	6	PJM	Northeast	6/1/2012	12/31/2016	
Exelon Generation Company, LLC	ER00-3251	Green Gas Pioneer Crossing Energy, LLC	5	PJM-5004/5005	Northeast	11/10/2008	11/9/2021	
Exelon Generation Company, LLC	ER00-3251	Green Knight Economic Development Corporation	3	PJM-5004/5005	Northeast	1/1/2012	12/31/2016	
Exelon Generation Company, LLC	ER00-3251	Keystone Solar, L.L.C.	5	PJM-5004/5005	Northeast	5/4/2011	10/1/2027	
Exelon Generation Company, LLC	ER00-3251	Waymart Wind Farm, L.P.	65	PJM-5004/5005	Northeast	10/20/2003	10/31/2023	
Exelon Generation Company, LLC	ER00-3251	Ameresco Stafford, LLC	2	PJM-AP South	Northeast	5/19/2009	5/1/2019	
Exelon Generation Company, LLC	ER00-3251	WM Renewable Energy, LLC	4	PJM-AP South	Northeast	12/1/2007	12/31/2016	
Exelon Generation Company, LLC	ER00-3251	Ameresco Delaware Energy, LLC	3	PJM-East	Northeast	2/1/2007	1/31/2017	
Exelon Generation Company, LLC	ER00-3251	Ameresco Delaware Energy, LLC	4	PJM-East	Northeast	10/24/2006	10/23/2016	
Exelon Generation Company, LLC	ER00-3251	Calpine Mid Merit LLC	118	PJM-East	Northeast	6/1/2011	5/31/2017	
Exelon Generation Company, LLC	ER00-3251	Calpine Mid Merit LLC	127	PJM-East	Northeast	6/1/2011	5/31/2017	
Exelon Generation Company, LLC	ER00-3251	Calpine Mid Merit LLC	127	PJM-East	Northeast	6/1/2011	5/31/2017	
Exelon Generation Company, LLC	ER00-3251	Calpine Mid Merit LLC	193	PJM-East	Northeast	6/1/2011	5/31/2017	
Atlantic City Electric Company	ER96-1361	Chambers Cogeneration LP	188	PJM-East	Northeast	3/1/1994	3/31/2024	
Atlantic City Electric Company	ER96-1361	Covanta Delaware Valley LP	80	PJM-East	Northeast	9/1/1991	9/30/2016	
Atlantic City Electric Company	ER96-1361	Logan Generating Co LP	200	PJM-East	Northeast	9/1/1994	9/30/2024	
Exelon Generation Company, LLC	ER00-3251	MF Mesa Lane LLC	3	PJM-East	Northeast	12/1/2008	11/30/2028	
Exelon Generation Company, LLC	ER00-3251	Constellation Solar New Jersey, LLC	2	BPA	Northwest	1/1/2016	12/31/2016	
Exelon Generation Company, LLC	ER00-3251	Sagebrush Power Partners, LLC	101	BPA	Northwest	9/1/2012	12/31/2018	
Exelon Generation Company, LLC	ER00-3251	Public Utility District No. 1 of Chelan County, Washington	47	CHPD	Northwest	2/16/2012	12/31/2017	
Exelon Generation Company, LLC	ER00-3251	Public Utility District No. 1 of Chelan County, Washington	98	CHPD	Northwest	2/16/2012	12/31/2017	
Exelon Generation Company, LLC	ER00-3251	Wind Power Partners 1993, LLC	17	CAISO	Southwest	2/15/2012	12/31/2024	
Exelon Generation Company, LLC	ER00-3251	Wind Power Partners 1993, LLC	6	CAISO	Southwest	2/15/2012	12/31/2024	
Exelon Generation Company, LLC	ER00-3251	Wind Power Partners 1993, LLC	9	CAISO	Southwest	2/15/2012	12/31/2024	
Exelon Generation Company, LLC	ER00-3251	Wind Power Partners 1993, LLC	11	CAISO	Southwest	2/15/2012	12/31/2024	
Exelon Generation Company, LLC	ER00-3251	Wind Power Partners 1993, LLC	8	CAISO	Southwest	2/15/2012	12/31/2024	
Exelon Generation Company, LLC	ER00-3251	Green Country Energy, LLC	261	SPP	SPP	2/11/2002	12/28/2021	
Exelon Generation Company, LLC	ER00-3251	Green Country Energy, LLC	261	SPP	SPP	2/11/2002	12/28/2021	
Exelon Generation Company, LLC	ER00-3251	Green Country Energy, LLC	261	SPP	SPP	2/11/2002	12/28/2021	

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Asset Appendix: Transmission Assets/Natural Gas Asset - April 2016

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
						Location			
Filing Entity and its Energy Affiliates	**Cite to order accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO**	**Asset Name and Use**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Market / Balancing Authority Area**	**Geographic Region**	**Size: (length and kV)**	**End Note Number (Enter text in End Note Tab)**
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	703.18 combined miles 115kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	54.82 combined miles 138kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	322.23 combined miles 230kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	217.94 combined miles 500kV lines	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Transportation	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	161.4 combined miles	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Storage (LNG)	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	1,056 mmcf	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Distribution	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	13,398 combined miles	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	90 combined miles 765kV lines	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	2,656 combined miles 345kV lines	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	2,904 combined miles 138kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	446 combined miles 500kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	548 combined miles 230kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	156 combined miles 138kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	200 combined miles 69kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	0.47 combined miles 13.2kV lines	
PECO Energy Company	N/A	Intrastate Gas Transportation	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	30 combined miles	
PECO Energy Company	N/A	Intrastate Gas Storage (LNG)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	1,200 mmcf	
PECO Energy Company	N/A	Intrastate Gas Stogare (LP)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	125 mmcf	
PECO Energy Company	N/A	Intrastate Gas Distribution	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	13,046 combined miles	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	281 combined miles 500kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	223 combined miles 230kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	242 combined miles 138kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	636 combined miles 69kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	297 combined miles 500kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	470 combined miles 230kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	557 combined miles 138kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	580 combined miles 69kV lines	
Delmarva Power & Light Company	N/A	Intrastate Gas Transportation	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	111 combined miles	
Delmarva Power & Light Company	N/A	Intrastate Gas Storage (LNG)	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	248 mmcf	
Delmarva Power & Light Company	N/A	Intrastate Gas Distribution	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	3,279 combined miles	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	142 combined miles 500kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	821 combined miles 230kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	89 combined miles 138kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	38 combined miles 115kV lines	

Asset Appendix: End Notes - February 2016

[A] End Note Number	[B] List (Generation, PPA or Transmission)	[C] Explanatory Note
1	Generation	Exelon owns only 5.9% of the Wiman 4 generating unit
2	Generation	Nine Mile Point Nuclear Stations, LLC owns only 82% of Unit 2
3	Generation	Exelon owns only 75% of the Quad Cities 1 generating unit
4	Generation	Exelon owns only 75% of the Quad Cities 2 generating unit
5	Generation	Exelon owns only 50% of the Peach Bottom 2 generating unit
6	Generation	Exelon owns only 50% of the Peach Bottom 3 generating unit
7	Generation	Exelon owns only 42.59% of the Salem 1 generating unit
8	Generation	Exelon owns only 42.59% of the Salem 2 generating unit
9	Generation	Exelon owns only 42.59% of the Salem 3 generating unit

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November 2, 2016

VIA ELECTRONIC FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Exelon Generation Company, LLC, Docket No. ER13-1536-__
Constellation Energy Commodities Group Maine, LLC, Docket No. ER10-2192-__
Constellation Energy Services, Inc., Docket No. ER15-1537-__
Constellation Energy Services of New York, Inc., Docket No. ER15-1539-__
Constellation NewEnergy, Inc., Docket No. ER10-2178-__
Exelon Wind 4, LLC, Docket No. ER11-2010-__
Shooting Star Wind Project, LLC, Docket No. ER12-1829-__
Wildcat Wind, LLC, Docket No. ER12-1223-__

Notice of Change in Status

Dear Secretary Bose:

Pursuant to the requirements of section 35.42(a)(2) of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[1] Exelon Generation Company, LLC ("Exelon Generation"), Constellation Energy Commodities Group Maine, LLC ("CECG Maine"), Constellation Energy Services, Inc. ("CES"), Constellation Energy Services of New York, Inc. ("CES of NY"), Constellation NewEnergy, Inc. ("CNE," and with CECG Maine, CES, and CES of NY, the "Retail Marketers"), Exelon Wind 4, LLC ("EW4"), Shooting Star Wind Project, LLC ("Shooting Star"), and Wildcat Wind, LLC ("Wildcat Wind," and with EW4 and Shooting Star, the "SPP Projects") (Exelon Generation, the Retail Marketers, and the SPP Projects, collectively, the "Sellers") submit this notice of change in status ("Notice") to inform the Commission of their new affiliation with Bluestem Wind Energy, LLC ("Bluestem"), which will own a new 198 MW generation facility located within the footprint of the Southwest Power Pool, Inc. ("SPP").[2]

[1] 18 C.F.R. § 35.42(a)(2) (2016).

[2] The Sellers have attached an updated asset appendix in the format set forth in Appendix B to 18 C.F.R. Part 35, Subpart H that reflects the new affiliation.

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Sellers are direct or indirect wholly owned subsidiaries of Exelon Corporation ("Exelon") with market-based rate authority. Bluestem is an indirect, wholly owned subsidiary of Exelon that is developing and will own and operate an approximately 198 MW (summer) wind-powered electric generation facility located in Beaver County, Oklahoma ("Facility"). The Facility will be interconnected to the transmission system owned by Oklahoma Gas and Electric Company ("OG&E") and operated by SPP. It is currently anticipated that the Facility will achieve commercial operation in December, 2016. Bluestem will not own any transmission facilities, except for the limited and discrete equipment necessary to interconnect the Facility to the grid. The Commission granted Bluestem authorization to sell energy, capacity, and ancillary services at market-based rates and accepted for filing Bluestem's market-based rate tariff effective October 3, 2016.[3] On October 17, 2016, Bluestem filed a notice of self-certification of exempt wholesale generator status in Docket No. EG17-15-000.

Sellers' affiliation with Bluestem will result in a cumulative net increase of more than 100 MW of generation capacity in SPP.[4] SPP is Sellers' relevant geographic market for purposes of this Notice. The SPP Projects own generation facilities located in SPP, Exelon Generation purchases via a long-term agreement the output of generation located in SPP and operates as a power marketer (in addition to directly owning generation in other markets), and the Retail Marketers operate as power marketers that do now own any generation facilities, except for limited behind-the-meter facilities.[5]

Bluestem's affiliation with Sellers does not raise any horizontal or vertical market power concerns. As demonstrated in Bluestem's application for market-based rate authority, Bluestem and Sellers pass the pivotal supplier and market share screens in SPP and neither Bluestem nor any of Sellers own or control any transmission facilities, except for limited and discrete interconnection facilities required to connect individual generating facilities to the transmission grid, or any inputs to electric power production, as defined in section 35.36 of the Commission's regulations.[6] To the extent necessary, Sellers confirm that they have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.

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[3] *Bluestem Wind Energy, LLC*, Letter Order, Docket No. ER16-2363-000 (Sept. 15, 2016) ("Bluestem MBR Order").

[4] *See Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 816, 153 FERC ¶ 61,065 at P 238 (2015), reh'g, Order No. 816-A, 155 FERC ¶ 61,188 (2016) ("if a seller's affiliate is granted market-based rate authority, and that results in 100 MW or more of new generation capacity in a market, then the seller will have to file a corresponding change in status.").

[5] The Commission clarified that, for purposes of compliance with the notice of change in status requirements, "for a power producer, the relevant geographic market is where the seller's generation is physically located" and for a power marketer "the relevant markets . . . include any market where the power marketer's affiliates own generation." Order No. 816-A at 36.

[6] *See* Bluestem MBR Order (finding that Bluestem satisfies the Commission's requirements for market-based rates regarding both horizontal and vertical market power).

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For the reasons set forth above, Sellers' affiliation with Bluestem does not materially change the facts and circumstances that the Commission relied upon in granting market-based rate authority to Sellers. Therefore, Sellers respectfully request that the Commission accept for filing this notice of change in status and find that no further inquiry is necessary.

Respectfully submitted,

/s/ Vincenzo Franco
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Enclosures

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CERTIFICATE OF SERVICE

I hereby certify that this day I have caused to be served the foregoing document upon each person designated on the official service lists compiled by the Secretary in these dockets.

Dated at Baltimore, MD this 2nd day of November, 2016.

/s/ Vincenzo Franco
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Asset Appendix: Generation Assets - October 2016

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned by**	**Controlled by**	**Date Control Transferred**	**Location**		**In-Service Date**	**Capacity Rating: Nameplate (MW)**	**Capacity Rating: Used in Filing (MW)**	**Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative**	**End Note Number (Enter text in End Note Tab)**
						Market / Balancing Authority Area	**Geographic Region**					
Beebe 1B Renewable Energy, LLC	ER14-2144	Beebe 1b WF	Beebe 1B Renewable Energy, LLC	Beebe 1B Renewable Energy, LLC	N/A	MISO	Central	12/12/2014	50.40	50.40	S	
Beebe Renewable Energy, LLC	ER12-2311	Beebe 1a WF	Beebe Renewable Energy, LLC	Beebe Renewable Energy, LLC	N/A	MISO	Central	1/17/2013	81.60	81.60	S	
Exelon Generation Company, LLC	ER00-3251	Clinton	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	MISO	Central	11/1/1987	1138.30	1065.00	S	
Harvest II Windfarm, LLC	ER12-2201 QF12-522	Harvest 2 WF	Harvest II Windfarm, LLC	Harvest II Windfarm, LLC	N/A	MISO	Central	11/28/2012	59.40	59.40	S	
Harvest Windfarm, LLC	ER07-1246 QF07-29	Harvest 1 WF	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	2/28/2008	52.80	52.80	S	
Michigan Wind 1, LLC	ER05-1511 QF05-228	Michigan Wind 1 WF	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	12/16/2008	69.00	69.00	S	
Michigan Wind 2, LLC	ER11-3989	Michigan Wind 2 WF	Michigan Wind 2, LLC	Michigan Wind 2, LLC	N/A	MISO	Central	1/5/2012	90.00	90.00	S	
Atlantic City Electric Company	ER96-1361	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Commonwealth Edison Company	ER98-1734	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Energy Commodities Group Maine, LLC	ER02-699	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Energy Services of New York, Inc.	ER07-651	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Energy Services, Inc.	ER07-650	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation NewEnergy, Inc.	ER96-1387	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Delmarva Power & Light Company	ER96-2571	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
PECO Energy Company	ER01-1147	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Pepco Energy Services, Inc.	ER98-3096	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Potomac Electric Power Company	ER98-4138	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Mystic Power, LLC	ER10-2281	Mystic 7	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/1975	617.00	575.48	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	278.60	228.77	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	278.60	229.97	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	315.00	244.58	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	278.60	231.40	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	278.60	232.50	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	315.00	247.24	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic Jet	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/1969	14.20	8.28	S	
Exelon Framingham LLC	ER98-1943	Framingham Jet 1	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	3/1/1970	14.20	10.15	S	
Exelon Framingham LLC	ER98-1943	Framingham Jet 2	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/1969	14.20	10.05	S	
Exelon Framingham LLC	ER98-1943	Framingham Jet 3	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/1969	14.20	11.25	S	
Exelon New Boston, LLC	ER98-1943	New Boston Jet	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	9/1/1966	18.60	16.00	S	1
Exelon West Medway, LLC	ER98-1943	West Medway Jet 1	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/1970	45.00	42.00	S	
Exelon West Medway, LLC	ER98-1943	West Medway Jet 2	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	3/1/1971	45.00	39.85	S	
Exelon West Medway, LLC	ER98-1943	West Medway Jet 3	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/1970	45.00	42.00	S	
Exelon Wyman, LLC	ER98-1943	Wyman 4	Exelon Wyman, LLC (5.9%)	FPL Energy Wyman IV LLC	N/A	ISO-NE	Northeast	1/1/1978	632.40	602.00	S	2
Exelon West Medway II, LLC	ER16-2708	West Medway 4	West Medway II, LLC	West Medway II, LLC	N/A	ISO-NE	Northeast	6/1/2018	100.00	97.40	S	
Exelon West Medway II, LLC	ER16-2708	West Medway 5	West Medway II, LLC	West Medway II, LLC	N/A	ISO-NE	Northeast	6/1/2018	100.00	97.40	S	
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 1	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	12/1/1969	641.80	626.10	S	
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 2	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	8/1/1988	1428.45	1289.60	S	3
R. E. Ginna Nuclear Power Plant, LLC	ER04-485	Ginna	R. E. Ginna Nuclear Power Plant, LLC	R. E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	7/1/1970	614.00	582.00	S	
Clinton Battery Utility, LLC	ER16-2194	Clinton Battery Project	Clinton Battery Utility, LLC	Clinton Battery Utility, LLC	N/A	PJM	Northeast	10/14/2016	10.00	10.00	N	
Criterion Power Partners, LLC	ER10-1443	Criterion WF	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	2/4/2011	70.00	70.00	S	
Exelon Generation Company, LLC	ER00-3251	Braidwood 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/1/1988	1224.90	1183.00	S	
Exelon Generation Company, LLC	ER00-3251	Braidwood 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1988	1224.90	1154.00	S	
Exelon Generation Company, LLC	ER00-3251	Byron 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/1/1985	1224.90	1164.00	S	
Exelon Generation Company, LLC	ER00-3251	Byron 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/1987	1224.90	1136.00	S	
Exelon Generation Company, LLC	ER00-3251	Dresden 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/1970	1009.00	902.00	S	
Exelon Generation Company, LLC	ER00-3251	Dresden 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1971	1009.00	895.00	S	
Exelon Generation Company, LLC	ER00-3251	LaSalle 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	1/1/1984	1170.00	1130.00	S	
Exelon Generation Company, LLC	ER00-3251	LaSalle 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1984	1170.00	1133.90	S	
Exelon Generation Company, LLC	ER00-3251	Quad Cities 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1972	1009.30	908.00	S	4
Exelon Generation Company, LLC	ER00-3251	Quad Cities 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1972	1009.30	911.00	S	5
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Fair Wind Power Partners, LLC	ER15-2293	Fair Wind WF	Fair Wind Power Partners, LLC	Fair Wind Power Partners, LLC	N/A	PJM	Northeast	11/24/2015	30.00	30.00	S	
Fourmile Wind Energy, LLC	ER14-2145 QF14-721	Fourmile Ridge WF	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	1/15/2015	40.00	40.00	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 1	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	

Asset Appendix: Generation Assets - October 2016

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned by**	**Controlled by**	**Date Control Transferred**	**Location**		**In-Service Date**	**Capacity Rating: Nameplate (MW)**	**Capacity Rating: Used in Filing (MW)**	**Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative**	**End Note Number (Enter text in End Note Tab)**
						Market / Balancing Authority Area	**Geographic Region**					
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 2	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 3	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 4	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 5	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Bethlehem Renewable Energy, LLC	ER07-903	Bethlehem Landfill	Bethlehem Renewable Energy, LLC	Bethlehem Renewable Energy, LLC	N/A	PJM 5004/5005	Northeast	3/1/2008	5.50	3.70	S	
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 1	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM 5004/5005	Northeast	5/1/1975	918.00	866.00	S	
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 2	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM 5004/5005	Northeast	4/1/1977	910.70	841.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Gould Street 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	12/1/1952	103.50	97.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.60	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	15.60	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.50	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	16.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	1/1/1972	53.10	52.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	4/1/1972	53.10	51.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	4/1/1972	53.10	52.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 51	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1995	192.00	147.60	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/28/2015	141.00	109.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	8/1/1970	20.70	15.30	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	8/1/1970	20.70	16.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	20.70	14.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	20.70	14.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Riverside 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	25.00	19.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Riverside 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	25.00	20.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Westport 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	2/1/1969	121.50	115.80	S	
Eastern Landfill Gas, LLC	ER05-1054	Eastern Landfill	Eastern Landfill Gas, LLC	Eastern Landfill Gas, LLC	N/A	PJM 5004/5005	Northeast	10/26/2006	3.00	4.00	S	
Exelon Generation Company, LLC	ER00-3251	TMI 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM 5004/5005	Northeast	9/2/1974	980.90	802.80	S	
Exelon Generation Company, LLC	ER00-3251	Chester 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/7/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Chester 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/20/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Chester 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/6/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/1/1928	45.00	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/25/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/4/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/1/1928	36.00	36.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/6/1928	48.00	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/5/1928	47.70	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1928	36.00	36.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/1/1928	47.70	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1928	48.00	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/10/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/25/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 21	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 22	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 31	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	8/6/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 32	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	8/8/1974	68.30	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 41	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 42	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/7/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/19/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/12/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/20/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 20	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/24/1974	391.00	380.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 30	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/7/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/29/1976	391.00	380.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 40	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/21/1970	21.20	17.00	S	

Asset Appendix: Generation Assets - October 2016

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned by**	**Controlled by**	**Date Control Transferred**	**Location**		**In-Service Date**	**Capacity Rating: Nameplate (MW)**	**Capacity Rating: Used in Filing (MW)**	**Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative**	**End Note Number (Enter text in End Note Tab)**
						Market / Balancing Authority Area	**Geographic Region**					
Exelon Generation Company, LLC	ER00-3251	Fairless Hills A	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1996	30.00	30.00	S	
Exelon Generation Company, LLC	ER00-3251	Fairless Hills B	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1996	30.00	30.00	S	
Exelon Generation Company, LLC	ER00-3251	Falls 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/22/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Falls 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/10/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Falls 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/28/1970	21.10	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Limerick 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/1/1986	1138.50	1119.70	S	
Exelon Generation Company, LLC	ER00-3251	Limerick 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	1/1/1990	1138.50	1122.10	S	
Exelon Generation Company, LLC	ER00-3251	Moser 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/9/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Moser 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/29/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Moser 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/11/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/10/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/10/1967	134.00	133.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	134.00	133.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/10/1968	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/10/1968	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Oyster Creek 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1969	550.00	607.70	S	
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/5/1974	1244.80	1223.70	S	6
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/23/1974	1377.00	1226.70	S	7
Exelon Generation Company, LLC	ER00-3251	Pennsbury 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/1/1996	3.00	3.00	S	
Exelon Generation Company, LLC	ER00-3251	Pennsbury 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/1/1996	3.00	3.00	S	
Exelon Generation Company, LLC	ER00-3251	Richmond 91	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/7/1973	65.80	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Richmond 92	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/7/1973	65.80	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Salem 1	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	6/30/1977	1251.40	1173.99	S	8
Exelon Generation Company, LLC	ER00-3251	Salem 2	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	10/13/1981	1216.40	1158.02	S	9
Exelon Generation Company, LLC	ER00-3251	Salem 3	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	6/17/1971	41.80	37.57	S	10
Exelon Generation Company, LLC	ER00-3251	Schuylkill 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/30/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Schuylkill 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/11/1971	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/14/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/9/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/26/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	11/7/1968	18.60	13.00	S	
Cassia Gulch Wind Park LLC	ER10-75 QF05-180	Cassia Gulch WF	Cassia Gulch Wind Park LLC	Cassia Gulch Wind Park LLC	N/A	IPCO	Northwest	3/31/2009	18.90	18.90	S	
High Mesa Energy, LLC	ER12-2528 QF13-77	High Mesa WF	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	IPCO	Northwest	8/28/2012	39.90	39.90	S	
Tuana Springs Energy, LLC	ER10-87 QF08-742	Tuana Springs WF	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	IPCO	Northwest	7/27/2010	16.80	16.80	S	
Cow Branch Wind Power, L.L.C.	ER07-1223 QF07-253	Cow Branch WF	Cow Branch Wind Power, L.L.C.	Cow Branch Wind Power, L.L.C.	N/A	AECI	Southeast	3/3/2008	50.40	50.40	S	
CR Clearing, LLC	ER07-1222 QF07-248	Conception WF	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	5/1/2008	50.40	50.40	S	
Wind Capital Holdings, LLC	ER07-1208 QF07-222	Wind Capital Holdings LLC WF	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	5/14/2007	56.70	56.70	S	
CER Generation, LLC	ER10-662	Hillabee GT1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	258.40	234.40	S	
CER Generation, LLC	ER10-662	Hillabee GT2	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	258.40	234.40	S	
CER Generation, LLC	ER10-662	Hillabee STG1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	306.00	283.90	S	
AV Solar Ranch 1, LLC	ER12-2178	Antelope Valley SF	AV Solar Ranch 1, LLC	AV Solar Ranch 1, LLC	N/A	CAISO	Southwest	12/28/2012	253.00	241.50	S	
Bluestem Wind Energy, LLC	ER16-2363	Bluestem WF	Bluestem Wind Energy, LLC	Bluestem Wind Energy, LLC	N/A	SPP	SPP	12/26/2016	198.00	198.00	N	
Exelon Wind 4, LLC	ER07-1202 QF03-13	Exelon Wind 4 WF	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	12/15/2006	79.80	79.80	S	
Shooting Star Wind Project, LLC	ER00-3251	Shooting Star WF	Shooting Star Wind Project, LLC	Shooting Star Wind Project, LLC	N/A	SPP	SPP	9/29/2012	104.00	104.00	S	
Wildcat Wind, LLC	ER12-1223 QF12-412	Wildcat WF	Wildcat Wind, LLC	Wildcat Wind, LLC	N/A	SPP	SPP	7/1/2012	27.30	27.30	S	

Asset Appendix: Transmission Assets/Natural Gas Asset - October 2016

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
						Location			
Filing Entity and its Energy Affiliates	**Cite to order accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO**	**Asset Name and Use**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Market / Balancing Authority Area**	**Geographic Region**	**Size: (length and kV)**	**End Note Number (Enter text in End Note Tab)**
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	703.18 combined miles 115kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	54.82 combined miles 138kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	322.23 combined miles 230kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	217.94 combined miles 500kV lines	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Transportation	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	161.4 combined miles	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Storage (LNG)	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	1,056 mmcf	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Distribution	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	13,398 combined miles	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	90 combined miles 765kV lines	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	2,656 combined miles 345kV lines	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	2,904 combined miles 138kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	446 combined miles 500kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	548 combined miles 230kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	156 combined miles 138kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	200 combined miles 69kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	0.47 combined miles 13.2kV lines	
PECO Energy Company	N/A	Intrastate Gas Transportation	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	30 combined miles	
PECO Energy Company	N/A	Intrastate Gas Storage (LNG)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	1,200 mmcf	
PECO Energy Company	N/A	Intrastate Gas Stogare (LP)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	125 mmcf	
PECO Energy Company	N/A	Intrastate Gas Distribution	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	13,046 combined miles	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	281 combined miles 500kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	223 combined miles 230kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	242 combined miles 138kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	636 combined miles 69kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	297 combined miles 500kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	470 combined miles 230kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	557 combined miles 138kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	580 combined miles 69kV lines	
Delmarva Power & Light Company	N/A	Intrastate Gas Transportation	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	111 combined miles	
Delmarva Power & Light Company	N/A	Intrastate Gas Storage (LNG)	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	248 mmcf	
Delmarva Power & Light Company	N/A	Intrastate Gas Distribution	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	3,279 combined miles	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	142 combined miles 500kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	821 combined miles 230kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	89 combined miles 138kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	38 combined miles 115kV lines	

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May 1, 2017

VIA ELECTRONIC FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Exelon Generation Company, LLC, Docket No. ER13-1536-____
Constellation Energy Commodities Group Maine, LLC, Docket No. ER10-2192-__
Constellation Energy Services, Inc., Docket No. ER15-1537-__
Constellation Energy Services of New York, Inc., Docket No. ER15-1539-__
Constellation NewEnergy, Inc., Docket No. ER10-2178-__
Nine Mile Point Nuclear Station, LLC, Docket No. ER10-2181-___
R.E. Ginna Nuclear Power Plant, LLC, Docket No. ER10-2182-__

Notice of Change in Status

Dear Secretary Bose:

Pursuant to the requirements of section 35.42 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[1] Exelon Generation Company, LLC ("Exelon Generation"), Constellation Energy Commodities Group Maine, LLC ("CECG Maine"), Constellation Energy Services, Inc. ("CES"), Constellation Energy Services of New York, Inc. ("CES of NY"), Constellation NewEnergy, Inc. ("CNE," and with Exelon Generation, CECG Maine, CES, and CES of NY, the "Exelon Sellers"), Nine Mile Point Nuclear Station, LLC ("Nine Mile"), and R.E. Ginna Nuclear Power Plant, LLC ("Ginna," and with Nine Mile, the "CENG Sellers") submit this notice of change in status ("Notice").

On December 7, 2016, the Commission authorized Exelon Generation to acquire the James A. FitzPatrick Nuclear Power Plant and associated interconnection equipment (the "FitzPatrick Facility") from Entergy Nuclear FitzPatrick, LLC (the "Transaction").[2] The FitzPatrick Facility is located in the balancing authority area operated by the New York Independent System Operator, Inc. ("NYISO"). This Notice is filed as a result of the consummation of the Transaction on March 31, 2017.

[1] 18 C.F.R. § 35.42 (2016).

[2] *Entergy Nuclear FitzPatrick, LLC*, 157 FERC ¶ 61,183 (2016).

I. Documents Submitted

The Exelon Sellers and the CENG Sellers submit the following documents:

1. This transmittal letter;

2. Attachment A: Pivotal supplier and market share screens for the Exelon Sellers;

3. Attachment B: Pivotal supplier and market share screens for the CENG Sellers;

4. Attachment C: Asset appendix for Exelon Corporation ("Exelon") and its affiliates in the format set forth in Appendix B to 18 C.F.R. Part 35, Subpart H; and

5. Attachment D: Asset appendix for EDF Inc. ("EDF") and its affiliates in the format set forth in Appendix B to 18 C.F.R. Part 35, Subpart H.

II. Communications

Communications regarding this Application should be addressed to the following individuals:

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Persons denoted with an asterisk (*) are those designated for service pursuant to 18 C.F.R § 385.2010.

III. Description of Exelon Sellers and CENG Sellers

The Exelon Sellers are direct or indirect wholly owned subsidiaries of Exelon. Exelon is a publicly traded holding company, headquartered in Chicago, Illinois, with operations and business activities in 48 states, the District of Columbia, Canada, and the United Kingdom.[3]

Exelon Generation is owned directly by Exelon. Exelon Generation is one of the largest competitive power generators in the United States. Exelon Generation and its subsidiaries operate one of the nation's cleanest and lowest-cost power generation fleets, with generation facilities located in a number of organized markets across the country. In addition, Constellation, an Exelon Generation business unit consisting of subsidiaries and divisions of Exelon Generation, is one of the nation's leading marketers of electricity, natural gas, and related products in wholesale and retail markets. Exelon Generation serves as a supplier of energy to, among others, utilities and municipalities to meet their native load obligations. Through various subsidiaries, Exelon Generation is also a retail competitive energy provider. The Commission granted Exelon Generation market-based rate authority.[4] Except for the FitzPatrick Facility, Exelon Generation does not directly own any generation facility in NYISO. Exelon Generation purchases under long term-contracts approximately 29 MW from generation facilities located in the NYISO BAA.

CECG Maine, CES, CES of NY, and CNE are indirect, wholly owned subsidiary of Exelon Generation that operate as power marketers and do not own or control any generation facilities, except for limited behind-the-meter facilities, or any transmission facilities in the United States. Each of CECG Maine, CES, CES of NY, and CNE has been granted market-based rate authority.[5]

The CENG Sellers are indirect, wholly owned subsidiaries of Constellation Energy Nuclear Group, LLC ("CENG"), which is a joint venture between Exelon Generation and EDF.[6]

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[3] No individual shareholder of Exelon owns a 10% or greater interest in Exelon's outstanding voting securities.

[4] *Exelon Generating Co.*, 93 FERC ¶ 61,140 (2000), *reh'g denied*, 95 FERC ¶ 61,309 (2001).

[5] *See Constellation Power Source Maine, LLC*, Letter Order, Docket No. ER02-699-000 (Feb. 26, 2002); *NEV, L.L.C.*, 81 FERC ¶ 61,186 (1997) (granting Constellation NewEnergy, Inc. market-based rate authority); *Wisconsin Public Service Corp., et al.*, 75 FERC ¶ 61,057 (1996) (granting Constellation Energy Services, Inc. market-based rate authority); *Advantage Energy, Inc.*, Letter Order, Docket No. ER97-2758-000 (July 14, 1997) (granting Constellation Energy Services of New York, Inc. market-based rate authority). In a letter order issued on June 23, 2015 in Docket Nos. ER15-1537-000, et al., the Commission accepted for filing the notice of succession reflecting the names changes from Integrys Energy Services, Inc. to Constellation Energy Services, Inc. and from Integrys Energy Services of New York, Inc. to Constellation Energy Services of New York, Inc.

[6] Specifically, the CENG Sellers are wholly owned subsidiaries of Constellation Nuclear Power Plants, LLC, which is a wholly owned subsidiary of CENG. Constellation Nuclear, LLC ("Constellation Nuclear") and its subsidiary own 50.01% of the interests in CENG. The remaining 49.99% interest in CENG is owned by EDF, which is not affiliated with Exelon Generation.

Nine Mile owns 100% of an approximately 630 MW unit and an 82% share of an approximately 1,287 MW unit of a nuclear generation facility located in the NYISO BAA. Nine Mile sells all of the energy produced by its facility to Exelon Generation and EDF Trading NA under long-term firm agreements executed in 2009 that remain in effect, as amended, through the complete and permanent cessation of power generation by the facility. Each of Exelon Generation and EDF Trading NA receives approximately 50% of the energy output of Nine Mile's facility under its respective agreement. The Commission has granted Nine Mile Point market-based rate authority.[7]

Ginna owns an approximately 582 MW nuclear generation facility located in the NYISO BAA. The Commission has granted Ginna MBR authority.[8]

IV. Notice of Change in Status

As a result of the consummation of the Transaction, on March 31, 2017 Exelon Generation became the owner of the FitzPatrick Facility, an approximately 837 MW (summer) nuclear generation facility located in Oswego County, New York.

The Transaction does not raise any horizontal market power concerns. The Transaction resulted in a *de minimis* increase in the generation affiliated with the Exelon Sellers and the CENG Sellers, because the FitzPatrick Facility represents only 2 percent of the installed capacity in NYISO.[9] To demonstrate that they continue to pass the pivotal supplier and market share screens and lack horizontal market power, the Exelon Sellers and the CENG Sellers rely on the screens recently submitted with their respective updated market power analyses for the Northeast Region, which are currently pending before the Commission.[10]

In the Exelon Triennial, Exhibits NCI-17 and NCI-18 demonstrated that the Exelon Sellers pass the pivotal supplier and the market share screens in NYISO. The Exelon Sellers submit herewith updated versions of Exhibits NCI-17 and NCI-18 that have been modified by adding in Row A the generation capacity of the FitzPatrick Facility and by subtracting it from the rows reporting non-affiliated installed capacity. After the addition of the FitzPatrick Facility, the Exelon Sellers continue to pass the pivotal supplier screen and their share of uncommitted capacity under the market share screen does not exceed 8% in any season. In

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Constellation Nuclear is owned by Exelon Generation (95%) and Constellation Holdings, LLC ("Constellation Holdings") (5%). Constellation Holdings is a wholly owned subsidiary of Exelon Generation.

[7] *Nine Mile Point Nuclear Station, LLC*, 95 FERC ¶ 61,202 (2001).

[8] *R.E. Ginna Nuclear Power Plant, LLC*, Letter Order, Docket No. ER04-485-000 (Mar. 24, 2004).

[9] NYISO's installed capacity is approximately 39,039 MW. *See* https://www.ferc.gov/market-oversight/mkt-electric/new-york/elec-ny-glance.pdf

[10] The Exelon Sellers filed their updated market power analysis on December 29, 2016 in Docket Nos. ER10-2997-005, *et al.* ("Exelon Triennial"). The CENG Sellers filed their updated market power analysis on December 29, 2016 in Docket Nos. ER10-2179-033, *et al.* ("CENG Triennial").

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the CENG Triennial, Exhibits NCI-11 and NCI-12 similarly demonstrated that the CENG Sellers pass the pivotal supplier and market share screens in NYISO. The CENG Sellers submit herewith updated versions of Exhibits NCI-11 and NCI-12 that have been modified by adding in Row A the generation capacity of the FitzPatrick Facility and by subtracting it from the rows reporting non-affiliated installed capacity. After the addition of the FitzPatrick Facility, the CENG Sellers continue to pass the pivotal supplier screen and their share of uncommitted capacity under the market share screen does not exceed 12.6% in any season. Therefore, the Transaction does not raise any horizontal market power concerns.

The Transaction also does not raise any vertical market power concerns. The Transaction did not involve any transmission facilities, other than the FitzPatrick Facility's limited and discrete interconnection facilities required to connect the FitzPatrick Facility to the transmission grid. The Transaction also did not involve any inputs to electric power production.[11]

V. Conclusion

For the reasons set forth above, the Transaction did not materially change the facts and circumstances that the Commission relied upon in granting market-based rate authority to the Exelon Sellers and the CENG Sellers and the new affiliation with the FitzPatrick Facility does not raise any horizontal or vertical market power concerns with respect to the Exelon Seller or the CENG Sellers. Therefore, the Exelon Sellers and the CENG Sellers respectfully request that the Commission accept for filing this Notice and find that no further inquiry is necessary.

Respectfully submitted,

/s/ Vincenzo Franco
Vincenzo Franco
Associate General Counsel
Exelon Corporation

[11] Section 35.36(a)(4) of the Commission's regulations, 18 C.F.R. § 35.36(a)(4), defines input to electric power production to include: intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; physical coal supply sources and ownership of or control over who may access transportation of coal supplies.

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CERTIFICATE OF SERVICE

I hereby certify that this day I have caused to be served the foregoing document upon each person designated on the official service lists compiled by the Secretary in these proceedings.

Dated at Baltimore, MD this 1st day of May, 2017.

/s/ Vincenzo Franco
Vincenzo Franco
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Exhibit NCI-3 (UPDATED)

Generation Affiliated with Exelon NE Entities in the Northeast Region and Relevant First-Tier Markets

Balancing Authority Area		Plant Name	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share	Owned and Purchased (MW) Summer	Owned and Purchased (MW) Winter
ISO-NE							
ISO-NE		Wyman (Yarmouth) 4	602.1	605.8	5.90%	35.5	35.7
ISO-NE		Framingham Jet	31.4	43.4	100.00%	31.4	43.4
ISO-NE		West Medway 1-2	81.8	125.6	100.00%	81.8	125.6
ISO-NE		West Medway 3	42.0	64.0	100.00%	42.0	64.0
ISO-NE		New Boston (L Street Jet)	16.0	21.8	100.00%	16.0	21.8
ISO-NE		Mystic 7	570.8	559.8	100.00%	570.8	559.8
ISO-NE		Mystic 8	703.4	841.5	100.00%	703.4	841.5
ISO-NE		Mystic 9	713.9	858.5	100.00%	713.9	858.5
ISO-NE		Mystic Jet	9.1	14.5	100.00%	9.1	14.5
ISO-NE	CT	Kleen Energy (purchase)				622.0	623.0
ISO-NE		Ameresco Northampton (purchase)				0.8	0.8
Subtotal, ISO-NE			**2,770.5**	**3,134.9**		**2,826.7**	**3,188.6**
Subtotal, CT						**622.0**	**623.0**
NYISO							
NYISO		Nine Mile Point [1/]	1,692.3	1,703.8	50.01%	1,692.3	1,703.8
NYISO		Ginna	582.0	583.0	50.01%	582.0	583.0
NYISO		Fitzpatrick	836.8	853.3	100.00%	836.8	853.3
NYISO		Sale of Nine Mile Point to EDF [2/]				(846.0)	(851.7)
NYISO		Purchase (WM Renewable Energy, LLC)				28.8	28.8
Subtotal, NYISO			**3,111.1**	**3,140.1**		**2,293.9**	**2,317.2**
PJM							
PJM		Braidwood	2,361.0	2,416.0	100.0%	2,361.0	2,416.0
PJM		Byron	2,318.0	2,364.0	100.0%	2,318.0	2,364.0
PJM	5004/5005	Calvert Cliffs [4/]	1,707.8	1,768.0	50.0%	1,707.8	1,768.0
PJM	East	Chester	39.0	54.0	100.0%	39.0	54.0
PJM	East	Conowingo	572.0	572.0	100.0%	572.0	572.0
PJM		Criterion Power	70.0	70.0	100.0%	70.0	70.0
PJM	East	Croydon	392.0	512.0	100.0%	392.0	512.0
PJM	East	Delaware	56.0	74.0	100.0%	56.0	74.0
PJM		Dresden	1,797.0	1,805.0	100.0%	1,797.0	1,805.0
PJM	East	Eddystone	820.0	836.0	100.0%	820.0	836.0
PJM	East	Fairless Hills	60.0	60.0	100.0%	60.0	60.0
PJM	East	Falls	51.0	60.0	100.0%	51.0	60.0
PJM		Fair Wind Facility	30.0	30.0	100.0%	30.0	30.0
PJM		Fourmile Wind	40.0	40.0	100.0%	40.0	40.0
PJM	5004/5005	Gould Street	97.0	97.0	100.0%	97.0	97.0
PJM		Handsome Lake	267.5	267.5	100.0%	267.5	267.5
PJM		La Salle	2,271.6	2,313.0	100.0%	2,271.6	2,313.0

Exhibit NCI-3 (UPDATED)

Balancing Authority Area		Plant Name	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share	Owned and Purchased (MW) Summer	Owned and Purchased (MW) Winter
PJM	East	Limerick	2,241.8	2,386.0	100.0%	2,241.8	2,386.0
PJM	East	Moser	51.0	60.0	100.0%	51.0	60.0
PJM	East	Muddy Run	1,070.0	1,070.0	100.0%	1,070.0	1,070.0
PJM	5004/5005	Notch Cliff	116.7	116.7	100.0%	116.7	116.7
PJM	East	Oyster Creek	607.7	637.0	100.0%	607.7	637.0
PJM	5004/5005	Peach Bottom (inc. upgrade)	2,450.40	2,658.0	50.0%	1,225.2	1,329.0
PJM	East	Pennsbury	5.4	5.4	100.0%	5.4	5.4
PJM	5004/5005	Perryman	302.6	302.6	100.0%	302.6	302.6
PJM	5004/5005	Perryman 6	110.0	130.0	100.0%	110.0	130.0
PJM	5004/5005	Philadelphia Road	60.9	60.9	100.0%	60.9	60.9
PJM		Quad Cities	1,819.0	1,819.0	75.0%	1,364.3	1,364.3
PJM	East	Richmond	98.0	132.0	100.0%	98.0	132.0
PJM	5004/5005	Riverside	39.0	39.0	100.0%	39.0	39.0
PJM	East	Salem	2,366.6	2,366.6	42.6%	1,007.9	1,007.9
PJM	East	Schuylkill	30.0	38.0	100.0%	30.0	38.0
PJM		Southeast Chicago	296.0	320.0	100.0%	296.0	320.0
PJM	East	Southwark	52.0	72.0	100.0%	52.0	72.0
PJM	5004/5005	Three Mile Island 1	802.8	829.0	100.0%	802.8	829.0
PJM	5004/5005	Westport	115.8	115.8	100.0%	115.8	115.8
PJM	5004/5005	Bethlehem Renewable Plant	4.7	1.2	100.0%	4.7	1.2
PJM	5004/5005	Eastern LFG	3.0	1.5	100.0%	3.0	1.5
PJM	AP South	Fauquier LFG (retired Jan 2016)	2.0	1.0	100.0%	2.0	1.0
PJM		Clinton Battery (2016)	10.0	10.0	100.0%	10.0	10.0
Subtotal, PJM						22,566.7	23,367.8
Long-Term Purchases							
PJM		Elwood Energy, LLC [3/]				600.0	768.0
PJM	5004/5005	Calpine Mid Merit LLC				545.0	545.0
PJM		Cordova Energy Company, LLC				521.2	601.2
PJM		Backbone Mountain Windpower LLC				66.0	66.0
PJM		Bellefontaine Gas Producers, LLC				4.5	4.5
PJM		Forward Wind Power LLC				29.4	29.4
PJM		High Trail Wind Farm, LLC				99.0	99.0
PJM		Mill Run Windpower, LLC				15.6	15.6
PJM		Old Trail Wind Farm, LLC				198.0	198.0
PJM		Patton Wind Farm, LLC				16.0	16.0
PJM		Somerset Windpower, LLC				9.0	9.0
PJM		WM Renewable Energy, LLC				10.1	10.1
PJM	AP South	WM Renewable Energy, LLC				3.8	3.8
PJM	5004/5005	Green Gas Pioneer Crossing Energy, LLC				5.0	5.0
PJM	5004/5005	Green Knight Economic Development Corporation				3.3	3.3
PJM	5004/5005	Keystone Solar, L.L.C.				4.9	4.9
PJM	5004/5005	Waymart Wind Farm, L.P.				64.5	64.5
PJM	AP South	Ameresco Stafford, LLC				2.0	2.0
PJM	East	Ameresco Delaware Energy, LLC				7.0	7.0

Exhibit NCI-3 (UPDATED)

Balancing Authority Area		Plant Name	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share	Owned and Purchased (MW) Summer	Owned and Purchased (MW) Winter
PJM	East	MF Mesa Lane LLC				3.0	3.0
PJM	East	Chambers Cogeneration				187.6	187.6
PJM	East	Logan Generating				200.0	200.0
PJM		AES Armenia Mountain				50.0	50.0
PJM		Roth Rock				40.0	40.0
PJM		Chestnut Flats				38.0	38.0
Subtotal, PJM						2,722.9	2,970.9
Long-Term Sales							
PJM	5004/5005	CENG sale (Calvert Cliffs) to EDF [4/]				(853.7)	(883.8)
Subtotal, PJM						24,435.9	25,454.9
Subtotal, PJM East						7,551.4	7,973.9
Subtotal, 5004/5005						11,905.9	12,503.5
Subtotal, AP South						11,913.7	12,510.3
First-Tier Markets							
MISO		Beebe Renewable Energy	81.6	81.6	100%	81.6	81.6
MISO		Beebe 1B Renewable Energy, LLC (2014)	50.4	50.4	100%	50.4	50.4
MISO		Clinton	1,065.0	1,078.0	100%	1,065.0	1,078.0
MISO		Harvest Windfarm	52.8	52.8	100%	52.8	52.8
MISO		Harvest II Windfarm	59.4	59.4	100%	59.4	59.4
MISO		Michigan Wind 1	69.0	69.0	100%	69.0	69.0
MISO		Michigan Wind 2	90.0	90.0	100%	90.0	90.0
Long-Term Purchases							
MISO		Tenaska Frontier				870.0	936.0
MISO		Pioneer Trail Wind Farm, LLC				110.4	110.4
Subtotal, MISO			1,468.2	1,481.2		2,448.6	2,527.6

Plant ratings based on 2015 EIA-860 data
https://www.eia.gov/electricity/data/eia860/

[1/] Total capacity reflects 100% of unit 1 and 82% of unit 2. The remaining 18% of unit 2 is owned by Long Island Power Authority.

[2/] A subsidiary of Electricite de France SA ("EDF"), which owns the other 49.99% of Constellation Energy Nuclear Group, Inc. ("CENG") (owner of the nuclear plants), purchases on a unit-contingent basis 49.99 percent of the nuclear plant output owned by CENG not sold to third parties. The sale represents 49.99% of CENG's share of Nine Mile Point.

[3/] The current PPA is only 300 MW PPA. Another PPA was terminated August 16, 2016.

[4/] A subsidiary of Electricite de France SA ("EDF"), which owns the other 49.99% of Constellation Energy Nuclear Group, Inc. ("CENG") (owner of the nuclear plants), purchases on a unit-contingent basis 49.99 percent of the nuclear plant output owned by CENG not sold to third parties. The sale represents 49.99% of CENG's share of Calvert Cliff.

Exhibit NCI-17 (UPDATED)

Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **NYISO**
Data Year -> **Dec 2014-Nov 2015**

Row			
	Generation		**Reference**
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	3,111	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0	
B	Long-Term Firm Purchases (from inside the study area)	29	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	
C	Long-Term Firm Sales (in and outside the study area)	846	Exhibit NCI-3
D	Uncommitted Capacity Imports	414	Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	35,554	Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)	0	
F	Long-Term Firm Purchases (from inside the study area)	846	Offset Row C
F1	Long-Term Firm Purchases (from outside the study area)	0	
G	Long-Term Firm Sales (in and outside the study area)	29	Offset Row B
H	Uncommitted Capacity Imports	7,281	Wkp - SILs, less Row D
I	Study Area Reserve Requirement	2,620	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	18,496	
	Load		
L	Balancing Authority Area Annual Peak Load	31,138	Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month	25,244	Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any	1,774	Wkp - Exelon Load Summary
O	Wholesale Load (L-M)	5,894	
P	Net Uncommitted Supply (K-O)	12,602	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	934	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->	7,695	
	% of SIL for Seller's imported capacity ->	0.05	
	% of SIL for Other's imported capacity ->	0.95	
	SIL value ->	7,695	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->	No	

Exhibit NCI-18 (UPDATED)

Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **NYISO**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled or under LT contract)				
A	Installed Capacity (inside the study area)	3,140	3,140	3,111	3,140
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	29	29	29	29
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	852	852	846	852
D	Seasonal Average Planned Outages	256	454	59	363
E	Uncommitted Capacity Imports	625	542	456	526
	Capacity Deductions				
F	Average Peak Native Load in the Season	22,045	19,393	24,144	20,374
G	Amount of Line F Attributable to Seller, if any	1,053	1,345	1,785	1,610
H	Amount of Line F Attributable to Non-Affiliates, if any	20,992	18,048	22,359	18,764
I	Study Area Reserve Requirement	2,620	2,620	2,620	2,620
J	Amount of Line I Attributable to Seller, if any	0	0	0	0
K	Amount of Line I Attributable to Non-Affiliates, if any	2,620	2,620	2,620	2,620
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	37,873	37,873	35,554	37,873
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	852	852	846	852
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	29	29	29	29
O	Seasonal Average Planned Outages	3,092	5,481	680	4,380
P	Uncommitted Capacity Imports	6,899	6,308	7,239	7,109
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	18,891	18,856	17,952	20,041
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	1,633	1,059	905	870
S	Total Seasonal Uncommitted Capacity (Q+R)	20,524	19,915	18,857	20,911
T	**Seller's Market Share** (R÷S)	8.0%	5.3%	4.8%	4.2%
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass
U	Total Imports, as filed by Seller (E+P)	7,524	6,850	7,695	7,635
V	SIL value*	7,524	6,850	7,695	7,635
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No

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Reference

Exhibit NCI-3

Exhibit NCI-3

Exhibit NCI-3
Pro Rata Share of Outages
Wkp - Import Allocation

Wkp - Summary of Inputs Data
Wkp - Exelon Load Summary

Wkp - Summary of Inputs Data

Wkp - Summary of Inputs Data, less Row A

Offset Row C

Offset Row B
Wkp - Summary of Inputs Data, less Row D
Wkp - SILs, less Row E

PJM Interconnection 2015 SIL Study

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Market/ Submarket	Exhibit	Pivotal Supplier Analysis	Exhibit	Market Share Analysis			
				Winter	Spring	Summer	Fall
PJM	NCI-5	Pass	NCI-6	10.7%	10.5%	9.1%	9.9%
PJM East	NCI-7	#REF!	NCI-8	#REF!	#REF!	#REF!	#REF!
5004/5005	NCI-9	#REF!	NCI-10	#REF!	#REF!	#REF!	#REF!
AP South	NCI-11	#REF!	NCI-12	#REF!	#REF!	#REF!	#REF!
ISO-NE	NCI-13	Pass	NCI-14	0.0%	0.0%	0.0%	0.0%
CT	NCI-15	#REF!	NCI-16	#REF!	#REF!	#REF!	#REF!
NYISO	NCI-17	Pass	NCI-18	8.0%	5.3%	4.8%	4.2%

Exhibit NCI-5

Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **PJM**
Data Year -> **Dec 2014-Nov 2015**

Row			Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	22,567	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0	
B	Long-Term Firm Purchases (from inside the study area)	2,723	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	
C	Long-Term Firm Sales (in and outside the study area)	854	Exhibit NCI-3
D	Uncommitted Capacity Imports	236	Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	160,493	Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)	0	
F	Long-Term Firm Purchases (from inside the study area)	854	Offset Row C
F1	Long-Term Firm Purchases (from outside the study area)	0	
G	Long-Term Firm Sales (in and outside the study area)	2,723	Offset Row B
H	Uncommitted Capacity Imports	7,364	Wkp - SILs, less Row D
I	Study Area Reserve Requirement	9,097	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	59,963	
	Load		
L	Balancing Authority Area Annual Peak Load	143,633	Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month	121,600	Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any	19,538	Wkp - Exelon Load Summary
O	Wholesale Load (L-M)	22,033	
P	Net Uncommitted Supply (K-O)	37,930	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,134	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->	7,600	
	% of SIL for Seller's imported capacity ->	0.03	
	% of SIL for Other's imported capacity ->	0.97	
	SIL value ->	7,600	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->	No	

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Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **PJM**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled or under LT contract)				
A	Installed Capacity (inside the study area)	23,368	23,368	22,567	23,368
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	2,971	2,971	2,723	2,971
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	884	884	854	884
D	Seasonal Average Planned Outages	979	3,106	524	2,981
E	Uncommitted Capacity Imports	372	335	236	175
	Capacity Deductions				
F	Average Peak Native Load in the Season	112,390	94,917	117,821	95,173
G	Amount of Line F Attributable to Seller, if any	16,011	14,104	18,740	15,366
H	Amount of Line F Attributable to Non-Affiliates, if any	96,379	80,813	99,081	79,807
I	Study Area Reserve Requirement	8,067	6,367	9,097	6,391
J	Amount of Line I Attributable to Seller, if any	0	0	0	0
K	Amount of Line I Attributable to Non-Affiliates, if any	8,067	6,367	9,097	6,391
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	176,232	173,322	160,493	169,417
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	884	884	854	884
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	2,971	2,971	2,723	2,971
O	Seasonal Average Planned Outages	7,380	23,036	3,730	21,608
P	Uncommitted Capacity Imports	11,625	12,388	7,364	6,892
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	73,944	73,407	54,081	66,416
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	8,837	8,580	5,407	7,283
S	Total Seasonal Uncommitted Capacity (Q+R)	82,781	81,987	59,488	73,699
T	**Seller's Market Share** (R÷S)	10.7%	10.5%	9.1%	9.9%
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass
U	Total Imports, as filed by Seller (E+P)	11,997	12,723	7,600	7,067
V	SIL value*	11,997	12,723	7,600	7,067
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No

P.

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Reference

Exhibit NCI-3

Exhibit NCI-3

Exhibit NCI-3
Pro Rata Share of Outages
Wkp - Import Allocation

Wkp - Summary of Inputs Data
Wkp - Exelon Load Summary

Wkp - Summary of Inputs Data

Wkp - Summary of Inputs Data, less Row A

Offset Row C

Offset Row B
Wkp - Summary of Inputs Data, less Row D
Wkp - SILs, less Row E

JM Interconnection 2015 SIL Study

Exhibit NCI-13

Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **ISO-NE**
Data Year -> **Dec 2014-Nov 2015**

Row				Reference
	Generation			
	Seller and Affiliate Capacity (owned or controlled)			
A	Installed Capacity (from inside the study area)	2,204		Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0		
B	Long-Term Firm Purchases (from inside the study area)	623		Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0		
C	Long-Term Firm Sales (in and outside the study area)	0		
D	Uncommitted Capacity Imports	102		Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)			
E	Installed Capacity (from inside the study area)	31,220		Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)	0		
F	Long-Term Firm Purchases (from inside the study area)	0		
F1	Long-Term Firm Purchases (from outside the study area)	0		
G	Long-Term Firm Sales (in and outside the study area)	623		Offset Row B
H	Uncommitted Capacity Imports	4,446		Wkp - SILs, less Row D
I	Study Area Reserve Requirement	1,310		Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0		
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)		17,041	
	Load			
L	Balancing Authority Area Annual Peak Load	24,437		Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month	19,621		Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any	4,000		Wkp - Exelon Load Summary
O	Wholesale Load (L-M)		4,816	
P	Net Uncommitted Supply (K-O)		12,225	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)		0	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)		**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->		4,548	
	% of SIL for Seller's imported capacity ->		0.02	
	% of SIL for Other's imported capacity ->		0.98	
	SIL value ->	4,548		PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->		No	

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Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **ISO-NE**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled or under LT contract)				
A	Installed Capacity (inside the study area)	2,565	2,565	2,204	2,565
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	624	624	623	624
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
D	Seasonal Average Planned Outages	81	233	16	213
E	Uncommitted Capacity Imports	211	94	79	52
	Capacity Deductions				
F	Average Peak Native Load in the Season	18,391	15,604	18,719	16,307
G	Amount of Line F Attributable to Seller, if any	3,627	3,224	4,080	3,720
H	Amount of Line F Attributable to Non-Affiliates, if any	14,764	12,380	14,639	12,587
I	Study Area Reserve Requirement	1,562	1,436	1,310	1,436
J	Amount of Line I Attributable to Seller, if any	0	0	0	0
K	Amount of Line I Attributable to Non-Affiliates, if any	1,562	1,436	1,310	1,436
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	33,011	33,011	31,220	33,011
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	624	624	623	624
O	Seasonal Average Planned Outages	1,046	3,001	220	2,747
P	Uncommitted Capacity Imports	4,337	4,454	4,469	4,496
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	19,353	20,025	18,897	20,114
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	0	0	0	0
S	Total Seasonal Uncommitted Capacity (Q+R)	19,353	20,025	18,897	20,114
T	**Seller's Market Share** (R÷S)	0.0%	0.0%	0.0%	0.0%
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass
U	Total Imports, as filed by Seller (E+P)	4,548	4,548	4,548	4,548
V	SIL value*	4,548	4,548	4,548	4,548
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No

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Reference

Exhibit NCI-3

Exhibit NCI-3

Pro Rata Share of Outages
Wkp - Import Allocation

Wkp - Summary of Inputs Data
Wkp - Exelon Load Summary

Wkp - Summary of Inputs Data

Wkp - Summary of Inputs Data, less Row A

Offset Row B
Wkp - Summary of Inputs Data, less Row D
Wkp - SILs, less Row E

PJM Interconnection 2015 SIL Study

2015 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Technology
58962	Fair Wind Power Partners	59147	Fair Wind Power	MD	Garrett	1	Wind
55951	Exelon Nuclear	6022	Braidwood Generation Station	IL	Will	1	Nuclear
55951	Exelon Nuclear	6022	Braidwood Generation Station	IL	Will	1	Nuclear
55951	Exelon Nuclear	6022	Braidwood Generation Station	IL	Will	2	Nuclear
55951	Exelon Nuclear	6023	Byron Generating Station	IL	Ogle	1	Nuclear
55951	Exelon Nuclear	6023	Byron Generating Station	IL	Ogle	2	Nuclear
55951	Exelon Nuclear	6011	Calvert Cliffs Nuclear Power Plant	MD	Calvert	1	Nuclear
55951	Exelon Nuclear	6011	Calvert Cliffs Nuclear Power Plant	MD	Calvert	2	Nuclear
6035	Exelon Power	3157	Chester Generating Station	PA	Chester	7	Liquids
6035	Exelon Power	3157	Chester Generating Station	PA	Chester	8	Liquids
6035	Exelon Power	3157	Chester Generating Station	PA	Chester	9	Liquids
6035	Exelon Power	1574	Conowingo	MD	Harford	1	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	10	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	11	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	2	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	3	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	4	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	5	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	6	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	7	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	8	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	9	Conventio
56661	Criterion Power Partners LLC	57300	Criterion Wind Project	MD	GARRET	1	Onshore
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	11	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	12	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	21	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	22	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	31	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	32	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	41	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	42	Petroleum
6035	Exelon Power	3160	Delaware Generating Station	PA	Philadelph	10	Petroleum
6035	Exelon Power	3160	Delaware Generating Station	PA	Philadelph	11	Petroleum
6035	Exelon Power	3160	Delaware Generating Station	PA	Philadelph	12	Petroleum
6035	Exelon Power	3160	Delaware Generating Station	PA	Philadelph	9	Petroleum
55951	Exelon Nuclear	869	Dresden Generating Station	IL	Grundy	2	Nuclear
55951	Exelon Nuclear	869	Dresden Generating Station	IL	Grundy	3	Nuclear
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	10	Petroleum
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	20	Petroleum
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	3	Petroleum
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	30	Petroleum
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	4	Petroleum
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	40	Petroleum
6035	Exelon Power	57191	Exelon Solar Chicago	IL	Cook	ECS1	PV
6035	Exelon Power	7701	Fairless Hills	PA	Bucks	A	Landfill
6035	Exelon Power	7701	Fairless Hills	PA	Bucks	B	Landfill
6035	Exelon Power	3162	Falls	PA	Bucks	1	Petroleum
6035	Exelon Power	3162	Falls	PA	Bucks	2	Petroleum
6035	Exelon Power	3162	Falls	PA	Bucks	3	Petroleum
4161	Constellation Power Source Gen	1553	Gould Street	MD	Baltimore	3	Natural
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT01	Natural
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT02	Natural
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT03	Natural
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT04	Natural
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT05	Natural
55951	Exelon Nuclear	6026	LaSalle Generating Station	IL	LaSalle	1	Nuclear
55951	Exelon Nuclear	6026	LaSalle Generating Station	IL	LaSalle	2	Nuclear
55951	Exelon Nuclear	6105	Limerick	PA	Montgom	1	Nuclear
55951	Exelon Nuclear	6105	Limerick	PA	Montgom	2	Nuclear
6035	Exelon Power	3163	Moser Generating Station	PA	Montgom	1	Petroleum
6035	Exelon Power	3163	Moser Generating Station	PA	Montgom	2	Petroleum
6035	Exelon Power	3163	Moser Generating Station	PA	Montgom	3	Petroleum
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	1	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	2	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	3	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	4	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	5	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	6	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	7	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	8	Hydroelec
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT1	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT2	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT3	Natural

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Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Technology
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT4	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT5	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT6	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT7	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT8	Natural
55951	Exelon Nuclear	2388	Oyster Creek	NJ	Ocean	1	Nuclear
14432	Panther Creek Power Operating, LLC	50776	Panther Creek Energy Facility	PA	Carbon	GEN1	Conventio
55951	Exelon Nuclear	3166	Peach Bottom	PA	York	2	Nuclear
55951	Exelon Nuclear	3166	Peach Bottom	PA	York	3	Nuclear
6035	Exelon Power	7690	Pennsbury	PA	Bucks	1	Landfill
6035	Exelon Power	7690	Pennsbury	PA	Bucks	2	Landfill
4161	Constellation Power Source Gen	1556	Perryman	MD	Harford	GT1	Petroleum
4161	Constellation Power Source Gen	1556	Perryman	MD	Harford	GT2	Petroleum
4161	Constellation Power Source Gen	1556	Perryman	MD	Harford	GT3	Petroleum
4161	Constellation Power Source Gen	1556	Perryman	MD	Harford	GT4	Petroleum
4161	Constellation Power Source Gen	1556	Perryman	MD	Harford	GT5	Natural
4161	Constellation Power Source Gen	1557	Philadelphia	MD	Baltimore	GT1	Petroleum
4161	Constellation Power Source Gen	1557	Philadelphia	MD	Baltimore	GT2	Petroleum
4161	Constellation Power Source Gen	1557	Philadelphia	MD	Baltimore	GT3	Petroleum
4161	Constellation Power Source Gen	1557	Philadelphia	MD	Baltimore	GT4	Petroleum
55951	Exelon Nuclear	880	Quad Cities Generating Station	IL	Rock	1	Nuclear
55951	Exelon Nuclear	880	Quad Cities Generating Station	IL	Rock	2	Nuclear
6035	Exelon Power	3168	Richmond Generating Station	PA	Philadelph	91	Petroleum
6035	Exelon Power	3168	Richmond Generating Station	PA	Philadelph	92	Petroleum
4161	Constellation Power Source Gen	1559	Riverside (MD)	MD	Baltimore	4	Natural
4161	Constellation Power Source Gen	1559	Riverside (MD)	MD	Baltimore	GT7	Petroleum
4161	Constellation Power Source Gen	1559	Riverside (MD)	MD	Baltimore	GT8	Petroleum
15478	PSEG Nuclear LLC	2410	PSEG Salem Generating Station	NJ	Salem	1	Nuclear
15478	PSEG Nuclear LLC	2410	PSEG Salem Generating Station	NJ	Salem	2	Nuclear
15478	PSEG Nuclear LLC	2410	PSEG Salem Generating Station	NJ	Salem	3	Petroleum
6035	Exelon Power	3169	Schuylkill Generating Station	PA	Philadelph	10	Petroleum
6035	Exelon Power	3169	Schuylkill Generating Station	PA	Philadelph	11	Petroleum
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT05	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT06	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT07	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT08	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT09	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT10	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT11	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT12	Natural
6035	Exelon Power	3170	Southwark	PA	Philadelph	3	Petroleum
6035	Exelon Power	3170	Southwark	PA	Philadelph	4	Petroleum
6035	Exelon Power	3170	Southwark	PA	Philadelph	5	Petroleum
6035	Exelon Power	3170	Southwark	PA	Philadelph	6	Petroleum
55951	Exelon Nuclear	8011	Three Mile Island	PA	Dauphin	1	Nuclear
4161	Constellation Power Source Gen	1560	Westport	MD	Baltimore	GT5	Natural
57311	Constellation Solar Federal LLC	58029	Constellation New Energy Inc	NJ	Burlington	PV1	Solar
57044	Constellation Solar New Jersey, LLC	57733	Benjamin Moore & Co. Solar	NJ	Morris	PV1	Solar
56976	Constellation Solar New Jersey II, LLC	57723	Johnson Matthey, Inc. Solar	NJ	Glouceste	PV1	Solar
56975	Constellation Solar Maryland, LLC	57646	McCormick & Co. Inc. at Belcamp	MD	Harford	PV1	Solar
57065	Constellation Solar Horizons LLC	57758	Mount Saint Mary's	MD	Frederick	PV1	Solar
56976	Constellation Solar New Jersey II, LLC	57647	Toys R Us- DE, Inc. at Mt. Olive, NJ	NJ	Morris	PV1	Solar
57044	Constellation Solar New Jersey, LLC	57745	The City of Vineland at West Vineland	NJ	Cumberla	PV1	Solar
57044	Constellation Solar New Jersey, LLC	57746	The City of Vineland at North Vineland	NJ	Cumberla	PV1	Solar
56975	Constellation Solar Maryland, LLC	59841	General Motors Corp at White Marsh	MD	Baltimore	PV1	Solar
58304	Constellation Solar Maryland II LLC	58329	UMMS at Pocomoke	MD	Somerset	PV1	Solar
56608	Calpine Mid-Merit LLC	55524	York Energy Center	PA	York	CTG1	Gas Fired
56608	Calpine Mid-Merit LLC	55524	York Energy Center	PA	York	CTG2	Gas Fired
56608	Calpine Mid-Merit LLC	55524	York Energy Center	PA	York	CTG3	Gas Fired
56608	Calpine Mid-Merit LLC	55524	York Energy Center	PA	York	STG1	Gas Fired
4210	Cordova Energy Co LLC	55188	Cordova Energy	IL	Island	PT11	Gas Fired
4210	Cordova Energy Co LLC	55188	Cordova Energy	IL	Island	PT21	Gas Fired
4210	Cordova Energy Co LLC	55188	Cordova Energy	IL	Island	PT31	Gas Fired
5259	Elwood Energy LLC	55199	Elwood Energy LLC	IL	Will	GT5	Gas Fired
5259	Elwood Energy LLC	55199	Elwood Energy LLC	IL	Will	GT6	Gas Fired
5259	Elwood Energy LLC	55199	Elwood Energy LLC	IL	Will	GT7	Gas Fired
5259	Elwood Energy LLC	55199	Elwood Energy LLC	IL	Will	GT8	Gas Fired
55951	Exelon Nuclear	6122	R E Ginna Nuclear Power Plant	NY	Wayne	1	Nuclear

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Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Technology
55951	Exelon Nuclear	2589	Nine Mile Point Nuclear Station	NY	Oswego	1	Nuclear
55951	Exelon Nuclear	2589	Nine Mile Point Nuclear Station	NY	Oswego	2	Nuclear
58784	Fourmile Wind Energy, LLC	58904	Fourmile Ridge	MD	Garrett	1	Wind

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Prime Mover	Unit Code	Ownership	Duct Burners	Can Bypass Heat Recovery Steam Generator?	RTO/ISO LMP Node Designation	RTO/ISO Location Designation for Reporting Wholesale Sales Data to FERC	Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Status	Operating Month	Operating Year
WT		S	X	X			30.0		30.0	30.0	OP	11	2015
ST		S	X	X	86031201	86031201	1,224.9	0.900	1,178.0	1,208.0	OP	7	1988
ST		S	X	X	86031201	86031201	1,224.9	0.900	1,183.0	1,208.0	OP	7	1988
ST		S	X	X	86031202	86031202	1,224.9	0.900	1,154.0	1,176.0	OP	10	1988
ST		S	X	X	86041201	86041201	1,224.9	0.900	1,164.0	1,188.0	OP	9	1985
ST		S	X	X	86041202	86041202	1,224.9	0.900	1,136.0	1,158.0	OP	8	1987
ST		J	X	X			918.0	0.900	866.0	890.0	OP	5	1975
ST		J	X	X			910.7	0.900	841.8	878.0	OP	4	1977
GT		S	X	X			18.6	0.850	13.0	18.0	OP	2	1969
GT		S	X	X			18.6	0.850	13.0	18.0	OP	5	1969
GT		S	X	X			18.6	0.850	13.0	18.0	OP	3	1969
HY		S	X	X			45.0	0.900	48.0	48.0	OP	3	1928
HY		S	X	X			55.6	0.900	65.0	65.0	OP	5	1964
HY		S	X	X			55.6	0.900	65.0	65.0	OP	5	1964
HY		S	X	X			36.0	0.900	36.0	36.0	OP	3	1928
HY		S	X	X			48.0	0.900	48.0	48.0	OP	3	1928
HY		S	X	X			47.7	0.900	48.0	48.0	OP	4	1928
HY		S	X	X			36.0	0.900	36.0	36.0	OP	6	1928
HY		S	X	X			47.7	0.900	48.0	48.0	OP	7	1928
HY		S	X	X			48.0	0.900	48.0	48.0	OP	6	1928
HY		S	X	X			55.6	0.900	65.0	65.0	OP	3	1964
HY		S	X	X			55.6	0.900	65.0	65.0	OP	3	1964
WT		S	X	X			70.0		70.0	70.0	OP	12	2010
GT		S	X	X			68.3	0.900	49.0	64.0	OP	6	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	6	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	6	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	6	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	8	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	8	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	7	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	7	1974
GT		S	X	X			18.6	0.850	13.0	18.0	OP	5	1969
GT		S	X	X			18.6	0.850	13.0	18.0	OP	4	1969
GT		S	X	X			18.6	0.850	13.0	18.0	OP	5	1969
GT		S	X	X			21.2	0.850	17.0	20.0	OP	7	1970
ST		S	X	X	86101102	86101102	1,009.3	0.945	902.0	902.0	OP	8	1970
ST		S	X	X	86101103	86101103	1,009.3	0.945	895.0	903.0	OP	10	1971
GT		S	X	X			18.6	0.850	13.0	18.0	OP	5	1967
GT		S	X	X			18.6	0.850	13.0	18.0	OP	10	1967
ST		S	X	X			391.0	0.850	380.0	380.0	OP	9	1974
GT		S	X	X			21.2	0.850	17.0	20.0	OP	3	1970
ST		S	X	X		20060104	391.0	0.850	380.0	380.0	OP	6	1976
GT		S	X	X			21.2	0.850	17.0	20.0	OP	6	1970
	S	N	N			9.0			9.0	9.0	OP	12	2009
ST		S	X	X			30.0	0.850	30.0	30.0	OP	12	1996
ST		S	X	X			30.0	0.800	30.0	30.0	OP	12	1996
GT		S	X	X			21.2	0.850	17.0	20.0	OP	5	1970
GT		S	X	X			21.2	0.850	17.0	20.0	OP	5	1970
GT		S	X	X			21.2	0.850	17.0	20.0	OP	6	1970
ST		S	X	X			103.5	0.850	97.0	97.0	OP	12	1952
GT		S	X	X	1104241	1104241	58.9	0.850	53.5	53.5	OP	8	2001
GT		S	X	X	1104241	1104241	58.9	0.850	53.5	53.5	OP	8	2001
GT		S	X	X	1104241	1104241	58.9	0.850	53.5	53.5	OP	7	2001
GT		S	X	X	1104241	1104241	58.9	0.850	53.5	53.5	OP	7	2001
GT		S	X	X	1104241	1104241	58.9	0.850	53.5	53.5	OP	7	2001
ST		S	X	X	86191101	86191101	1,170.0	0.900	1,135.4	1,152.0	OP	1	1984
ST		S	X	X	86191102	86191102	1,170.0	0.900	1,136.2	1,161.0	OP	10	1984
ST		S	X	X	20021101	20021101	1,138.5	0.900	1,119.7	1,191.0	OP	2	1986
ST		S	X	X	20021102	20021102	1,138.5	0.900	1,122.1	1,195.0	OP	1	1990
GT		S	X	X			21.2	0.850	17.0	20.0	OP	6	1970
GT		S	X	X			21.2	0.850	17.0	20.0	OP	5	1970
GT		S	X	X			21.2	0.850	17.0	20.0	OP	6	1970
PS		S	X	X			134.0	0.900	134.0	134.0	OP	4	1967
PS		S	X	X			134.0	0.900	133.0	133.0	OP	4	1967
PS		S	X	X			134.0	0.900	134.0	134.0	OP	4	1967
PS		S	X	X			134.0	0.900	134.0	134.0	OP	6	1967
PS		S	X	X			134.0	0.900	134.0	134.0	OP	10	1967
PS		S	X	X			134.0	0.900	133.0	133.0	OP	10	1967
PS		S	X	X			134.0	0.900	134.0	134.0	OP	2	1968
PS		S	X	X			134.0	0.900	134.0	134.0	OP	2	1968
GT		S	X	X			18.0	0.850	14.0	14.0	OP	6	1969
GT		S	X	X			18.0	0.850	14.0	14.0	OP	6	1969
GT		S	X	X			18.0	0.850	14.0	14.0	OP	6	1969

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Prime Mover	Unit Code	Ownership	Duct Burners	Can Bypass Heat Recovery Steam Generator?	RTO/ISO LMP Node Designation	RTO/ISO Location Designation for Reporting Wholesale Sales Data to FERC	Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Status	Operating Month	Operating Year
GT		S	X	X			18.0	0.850	14.0	14.0	OP	6	1969
GT		S	X	X			18.0	0.850	14.6	14.6	OP	6	1969
GT		S	X	X			18.0	0.850	15.6	15.6	OP	6	1969
GT		S	X	X			18.0	0.850	14.5	14.5	OP	6	1969
GT		S	X	X			18.0	0.850	16.0	16.0	OP	6	1969
ST		S	X	X	51101101	51101101	550.0	0.800	607.7	637.0	OP	12	1969
ST		S	X	X			94.0	0.850	83.0	83.0	OP	7	1992
ST		J	X	X	20141102	20141102	1,244.8	0.920	1,223.7	1,296.0	OP	7	1974
ST		J	X	X	20141103	20141103	1,377.0	0.900	1,122.7	1,284.0	OP	12	1974
GT		S	X	X			3.0	0.800	2.7	2.7	OP	9	1996
GT		S	X	X			3.0	0.800	2.7	2.7	OP	9	1996
GT		S	X	X			53.1	0.850	52.0	52.0	OP	1	1972
GT		S	X	X			53.1	0.850	51.0	51.0	OP	4	1972
GT		S	X	X			53.1	0.850	51.0	51.0	OP	4	1972
GT		S	X	X			53.1	0.850	52.0	52.0	OP	4	1972
GT		S	X	X			192.0	0.900	147.6	147.6	OP	6	1995
GT		S	X	X			20.7	0.850	15.3	15.3	OP	8	1970
GT		S	X	X			20.7	0.850	16.0	16.0	OP	8	1970
GT		S	X	X			20.7	0.850	14.8	14.8	OP	9	1970
GT		S	X	X			20.7	0.850	14.8	14.8	OP	9	1970
ST		J	X	X	86251101	86251101	1,009.3	0.945	908.0	908.0	OP	12	1972
ST		J	X	X	86251102	86251102	1,009.3	0.945	911.0	911.0	OP	12	1972
GT		S	X	X			65.8	0.900	49.0	66.0	OP	6	1973
GT		S	X	X			65.8	0.900	49.0	66.0	OP	6	1973
ST		S	X	X			72.2	0.850	74.0	74.0	OP	9	1951
GT		S	X	X			25.0	0.850	19.0	19.0	OP	9	1970
GT		S	X	X			25.0	0.850	20.0	20.0	OP	9	1970
ST		J	X	X	50489	SALEM	1,170.0	0.900	1,170.2	1,170.2	OP	6	1977
ST		J	X	X	50490	SALEM	1,170.0	0.900	1,158.0	1,158.0	OP	10	1981
GT		J	X	X	50488	SALEM	41.8	0.900	38.4	38.4	SB	6	1971
GT		S	X	X			18.6	0.850	13.0	18.0	OP	5	1969
GT		S	X	X			21.2	0.850	17.0	20.0	OP	6	1971
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			18.6	0.850	13.0	18.0	OP	6	1967
GT		S	X	X			18.6	0.850	13.0	18.0	OP	10	1967
GT		S	X	X			18.6	0.850	13.0	18.0	OP	7	1967
GT		S	X	X			18.6	0.850	13.0	18.0	OP	11	1968
ST		S	X	X	20111201	20111201	980.8	0.945	802.8	829.0	OP	8	1974
GT		S	X	X			121.5	0.900	115.8	115.8	OP	2	1969
PV		S	X	X			3.9		3.9	3.9	OP	12	2011
PV		S	X	X			1.4		1.4	1.4	OP	12	2010
PV		S	X	X			4.0		4.0	4.0	OP	3	2011
PV		S	X	X			1.4		1.4	1.4	OP	12	2010
PV		S	X	X			13.7		13.7	13.7	OP	7	2012
PV		S	X	X			4.1		4.1	4.1	OP	12	2011
PV		S	X	X			3.7		3.7	3.7	OP	10	2011
PV		S	X	X			2.3		2.3	2.3	OP	10	2011
PV		S	X	X			1.0		1.0	1.0	OP	5	2011
PV		S	X	X			2.8		2.8	2.8	OP	2	2013
CT	CCB1	S	X	N	T	T	120.0	0.850	113.0	113.0	OP	3	2011
CT	CCB1	S	X	N	T	T	120.0	0.850	122.0	122.0	OP	3	2011
CT	CCB1	S	X	N	T	T	120.0	0.850	122.0	122.0	OP	3	2011
CA	CCB1	S	N	X			200.0	0.850	188.0	188.0	OP	3	2011
CT	CC1	S	X	N	32417721	32417721	210.0	0.850	165.0	205.0	OP	6	2001
CT	CC1	S	X	N	32417723	32417723	210.0	0.850	165.0	205.0	OP	6	2001
CA	CC1	S	N	X	32417725	32417725	191.2	0.850	191.2	191.2	OP	6	2001
GT		J	X	X			192.0	0.850	150.0	192.0	OP	7	2001
GT		J	X	X			192.0	0.850	150.0	192.0	OP	7	2001
GT		J	X	X			192.0	0.850	150.0	192.0	OP	8	2001
GT		J	X	X			192.0	0.850	150.0	192.0	OP	8	2001
ST		J	X	X			614.0	0.920	582.0	583.0	OP	7	1970

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Prime Mover	Unit Code	Ownership	Duct Burners	Can Bypass Heat Recovery Steam Generator?	RTO/ISO LMP Node Designation	RTO/ISO Location Designation for Reporting Wholesale Sales Data to FERC	Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Status	Operating Month	Operating Year
ST		J	X	X			641.8	0.850	637.0	637.0	OP	12	1969
ST		J	X	X			1,259.3	0.900	1,287.0	1,301.0	OP	7	1987
WT		S	X	X			40.0		40.0	40.0	OP	12	2014

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Energy Source 1
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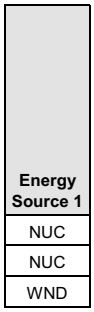

Energy Source 1
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2015 Form EIA-860 Data - Schedule 3, 'Generator Data' (Prelim)

Utility ID	Utility Name	Plant Code	Plant Name	State
6035	Exelon Power	59882	Exelon West Medway II LLC	MA
6035	Exelon Power	59882	Exelon West Medway II LLC	MA
55951	Exelon Nuclear	2589	Nine Mile Point Nuclear Station	NY
55951	Exelon Nuclear	2589	Nine Mile Point Nuclear Station	NY
55951	Exelon Nuclear	6122	R E Ginna Nuclear Power Plant	NY
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
6035	Exelon Power	1586	Exelon Framingham LLC	MA
6035	Exelon Power	1586	Exelon Framingham LLC	MA
6035	Exelon Power	1586	Exelon Framingham LLC	MA
6035	Exelon Power	1587	Exelon L Street	MA
6035	Exelon Power	1592	Exelon Medway LLC	MA
6035	Exelon Power	1592	Exelon Medway LLC	MA
6035	Exelon Power	1592	Exelon Medway LLC	MA
31719	FPL Energy Wyman LLC	1507	William F Wyman	ME
55993	Kleen Energy Systems, LLC	56798	Kleen Energy Systems Project	CT
55993	Kleen Energy Systems, LLC	56798	Kleen Energy Systems Project	CT
55993	Kleen Energy Systems, LLC	56798	Kleen Energy Systems Project	CT
5943	Entergy Nuc Fitzpatrick LLC	6110	James A Fitzpatrick	NY

County	Generator ID	Technology	Prime Mover	Unit Code	Ownership	Duct Burners	Can Bypass Heat Recovery Steam Generator?	RTO/ISO LMP Node Designation	RTO/ISO Location Designation for Reporting Wholesale Sales Data to FERC
Norfolk	4	Gas Fired	GT		S	X	X		
Norfolk	5	Gas Fired	GT		S	X	X		
Oswego	1	Nuclear	ST		J	X	X		
Oswego	2	Nuclear	ST		J	X	X		
Wayne	1	Nuclear	ST		J	X	X		
Middlesex	7	m Liquids	ST		S	X	X	MYSTIC	MYSTIC
Middlesex	GT1	m Liquids	GT		S	X	X	MYSTIC	MYSTIC
Middlesex	GT81	Gas Fired	CT	G941	S	X	Y	MYSTIC	MYSTIC
Middlesex	GT82	Gas Fired	CT	G941	S	X	Y	MYSTIC	MYSTIC
Middlesex	GT93	Gas Fired	CT	G942	S	X	Y	MYSTIC	MYSTIC
Middlesex	GT94	Gas Fired	CT	G942	S	X	Y	MYSTIC	MYSTIC
Middlesex	ST85	Gas Fired	CA	G941	S	Y	X	MYSTIC	MYSTIC
Middlesex	ST96	Gas Fired	CA	G942	S	Y	X	MYSTIC	MYSTIC
Norfolk	GT1	m Liquids	GT		S	X	X		
Norfolk	GT2	m Liquids	GT		S	X	X		
Norfolk	GT3	m Liquids	GT		S	X	X		
Suffolk	GT1	m Liquids	GT		S	X	X		
Norfolk	GT1	m Liquids	GT		S	X	X		
Norfolk	GT2	m Liquids	GT		S	X	X		
Norfolk	GT3	m Liquids	GT		S	X	X		
Cumberland	4	Petroleum Liquids	ST		J	X	X		
Middlesex	ST	Gas Fired	CA	CC01	S	Y	X	14614	14614
Middlesex	U1	Gas Fired	CT	CC01	S	X	N	14614	14614
Middlesex	U2	Gas Fired	CT	CC01	S	X	N	14614	14614
Oswego	1	Nuclear	ST		S	X	X	23598	23598

637.0
1055.34

Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Status	Effective Month	Effective Year	Current Month	Current Year	Associated with Combined Heat and Power System
100.0	0.900	97.4	103.5	L	6	2018	6	2018	N
100.0	0.900	97.4	103.5	L	6	2018	6	2018	N
641.8	0.850	637.0	637.0						
1,259.3	0.900	1,287.0	1,301.0						
614.0	0.920	582.0	583.0						
617.0	0.900	570.8	559.8	90.0	N			OP	X
14.2	0.850	9.1	14.5	5.0	N			SB	Y
278.6	0.850	224.6	268.7	140.0	N			OP	X
278.6	0.850	226.7	271.2	140.0	N			OP	X
278.6	0.850	227.9	274.1	140.0	N			OP	X
278.6	0.850	230.1	276.7	140.0	N			OP	X
315.0	0.850	252.1	301.6	75.0	N			OP	X
315.0	0.850	255.9	307.7	75.0	N			OP	X
14.2	0.850	10.2	14.2	5.0	N			OP	X
14.2	0.850	9.9	13.9	5.0	N			OP	X
14.2	0.850	11.3	15.3	5.0	N			OP	X
18.6	0.850	16.0	21.8	6.0	N			OP	X
45.0	0.850	42.0	64.0	20.0	N			OP	X
45.0	0.850	39.8	61.6	20.0	N			OP	X
45.0	0.850	42.0	64.0	20.0	N			OP	X
632.4	0.930	602.1	605.8	60.0	N			OP	X
295.0	1.000	268.0	233.0	177.0	N			OP	X
199.0	1.000	177.0	195.0	120.0	N			OP	X
199.0	1.000	177.0	195.0	120.0	N			OP	X
882.0	0.800	836.8	853.3	0.0	N			OP	X

Sector Name	Sector	Previously Canceled	Energy Source 1	Energy Source 2	Energy Source 3	Energy Source 4	Energy Source 5	Energy Source 6	Turbines, Inverters, or Hydrokinetic Buoys
CHP	2	N	NG	DFO					1
CHP	2	N	NG	DFO					1

6	1975			N	CHP	2	X	RFO	NG
6	1969			N	CHP	2	X	DFO	
4	2003			N	CHP	2	X	NG	
4	2003			N	CHP	2	X	NG	
6	2003			N	CHP	2	X	NG	
6	2003			N	CHP	2	X	NG	
4	2003			N	CHP	2	X	NG	
6	2003			N	CHP	2	X	NG	
3	1970			N	CHP	2	X	DFO	
9	1969			N	CHP	2	X	DFO	
9	1969			N	CHP	2	X	DFO	
9	1966	10	2016	N	CHP	2	X	DFO	
7	1970			N	CHP	2	X	DFO	
3	1971			N	CHP	2	X	DFO	
7	1970			N	CHP	2	X	DFO	
1	1978			N	IPP Non-CHP	2	X	RFO	
7	2011			N	CHP	2	X	NG	DFO
7	2011			N	CHP	2	X	NG	DFO
7	2011			N	CHP	2	X	NG	DFO
8	1976	1	2017	N	IPP Non-CHP	2	X	NUC	

Fluidized Bed Technology?	Pulverized Coal Technology?	Stoker Technology?	Other Combustion Technology?	Subcritical Technology?	Supercritical Technology?	Ultrasupercritical Technology?	Solid Fuel Gasification System?	Carbon Capture Technology?	Switch Between Oil and Natural Gas?
									Y
							N	N	Y

				NG		NG		N	N
				DFO		DFO		N	N
				NG		NG		N	N
				NG				N	N
				NG				N	N
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				DFO				N	N
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Cofire Fuels?
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					N	N
					N	N
					N	Y
					N	Y
					N	

2015 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Technology
57397	Beebe Renewable Energy LLC	58020	Beebe Renewable Energy LLC	MI	Gratiot	1	Wind

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Prime Mover	Unit Code	Ownership	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Status	Operating Month	Operating Year	Energy Source 1	Energy Source 2
WT		S		81.6	81.6	OP	12	2012	WND	

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SIL Values used for the Northeast Region Triennials

Study Period of December 2014 to November 2015

	Study Area	Area Abbr	Winter 2014	Spring 2015	Summer 2015	Fall 2015	SIL Values Source
1	ISO-NE	ISO-NE	4,548	4,548	4,548	4,548	*Simultaneous Import Limit for 2015*, ISO New England Inc., Docket No. AD10-2-00_, (filed Dec. 20, 2016).
2	Connecticut	CT	3,050	3,050	3,050	3,050	
3	Southwest Connecticut	SWCT	2,540	2,370	3,200	3,190	
4	New Brunswick	NBPC	1,768	1,742	1,337	1,305	FERC Accepted Notheast SILs Dec11 to Nov12
5	NYISO	NYISO	7,524	6,850	7,695	7,635	NYISO's Informational Filing Regarding the
6	New York City	NYC	6,575	6,325	6,325	6,325	Simultaneous Import Limitation Study, Docket
7	Long Island	Long Island	1,760	2,090	2,090	2,090	No. AD10-2. (Filed Dec 19, 2016)
8	PJM	PJM	11,997	12,723	7,600	7,067	PJM Interconnection, L.L.C., Docket No. AD10-2
9	PJM East	PJM East	7,502	8,830	6,537	7,859	PJM Interconnection, L.L.C., Docket No. AD10-2
10	AP South	AP South	7,897	8,856	4,455	6,068	PJM Interconnection, L.L.C., Docket No. AD10-2
11	5004/5005	5004/5005	8,104	8,293	6,319	6,103	PJM Interconnection, L.L.C., Docket No. AD10-2

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		PST Summer	Winter	Spring	Summer	Fall
	Allocation of Imports into ISO-NE					
A	Seller's Uncommitted Capacity in NYISO	520	1,008	517	449	344
B	Seller's Uncommitted Capacity in HQT	0	0	0	0	0
C	Seller's Uncommitted Capacity in NBPC	0	0	0	0	0
D	**Seller's Uncommitted Capacity (SUM A-C)**	**520**	**1,008**	**517**	**449**	**344**
E	Total Uncommitted Capacity in NYISO	10,800	12,999	13,065	11,161	13,276
F	Total Uncommitted Capacity in HQT	11,132	7,914	10,905	13,475	15,221
G	Total Uncommitted Capacity in NBPC	1,203	825	994	1,228	1,339
H	**Total Uncommitted Capacity (SUM E-G)**	**23,135**	**21,738**	**24,964**	**25,864**	**29,836**
I	**Seller's Share of Uncommitted Capacity into ISO-NE (D/H)**	2.2%	4.6%	2.1%	1.7%	1.2%
J	**Imports into ISO-NE**	4,548	4,548	4,548	4,548	4,548
L	**Seller's Share of Imports into ISO-NE**	102	211	94	79	52

		PST Summer	Winter	Spring	Summer	Fall
	Allocation of Imports into CT					
A	Seller's Uncommitted Capacity in NYISO	520	1,008	517	449	344
B	Plus Seller's Ucommitted Capacity in ISO-NE	0	0	0	0	0
C	Less Seller's Uncommitted Capacity in CT	#REF!	#REF!	#REF!	#REF!	#REF!
D	**Seller's Uncommitted Capacity (SUM A-B Less C)**	**#REF!**	**#REF!**	**#REF!**	**#REF!**	**#REF!**
E	Total Uncommitted Capacity in NYISO	10,800	12,999	13,065	11,161	13,276
F	Plus Total Uncommitted Capacity in ISO-NE	12,493	14,497	15,302	13,159	14,873
G	Less Total Uncommitted Capacity in CT	2,020	3,092	3,139	2,192	2,986
H	**Total Uncommitted Capacity (SUM E-F Less G)**	**21,272**	**24,404**	**25,228**	**22,128**	**25,163**
I	**Seller's Share of Uncommitted Capacity into CT (D/H)**	#REF!	#REF!	#REF!	#REF!	#REF!
J	**Imports into CT**	3,050	3,050	3,050	3,050	3,050
K	**Seller's Share of Imports into CT (I*J)**	#REF!	#REF!	#REF!	#REF!	#REF!

		PST Summer	Winter	Spring	Summer	Fall
	Allocation of Imports into NYISO					
A	Seller's Uncommitted Capacity in PJM	4,897	8,465	8,245	5,171	7,108
B	Seller's Uncommitted Capacity in ISO-NE	0	0	0	0	0
C	Seller's Uncommitted Capacity in HQT	0	0	0	0	0
D	Seller's Uncommitted Capacity in IESO	0	0	0	0	0
E	**Seller's Uncommitted Capacity (SUM A-F)**	**4,897**	**8,465**	**8,245**	**5,171**	**7,108**
F	Total Uncommitted Capacity in PJM	52,364	70,785	69,265	51,889	66,633
G	Total Uncommitted Capacity in ISO-NE	12,493	14,497	15,302	13,159	14,873
H	Total Uncommitted Capacity in HQT	11,132	7,914	10,905	13,475	15,221
I	Total Uncommitted Capacity in IESO	14,987	8,702	8,820	8,649	6,486

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J	**Total Uncommitted Capacity (SUM G-K)**	**90,975**	**101,897**	**104,292**	**87,172**	**103,213**
K	**Seller's Share of Uncommitted Capacity into NYISO (F/K)**	5.4%	8.3%	7.9%	5.9%	6.9%
L	**Imports into NYISO**	7,695	7,524	6,850	7,695	7,635
M	**Seller's Share of Imports into NYISO (L*M)**	414	625	542	456	526

Seller Uncommitted Capacity in all BAAs, Markets or Sub-Markets

Dec 2014-Nov 2015

	Pivotal Supplier Analysis	Market Share Analysis			
ISONE Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	2,827	3,189	3,189	2,827	3,189
Average Daily Peak Native Load in Peak Month	(4,000)				
Average Peak Native Load in the Season		(3,627)	(3,224)	(4,080)	(3,720)
Operating Reserves	0	0	0	0	0
Planned Outages		(81)	(233)	(16)	(213)
Total Uncommitted Capacity in ISONE	0	0	0	0	0

	Pivotal Supplier Analysis	Market Share Analysis			
CT Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	622	623	623	622	623
Average Daily Peak Native Load in Peak Month	#REF!				
Average Peak Native Load in the Season		#REF!	#REF!	#REF!	#REF!
Operating Reserves	0	0	0	0	0
Planned Outages		0	0	0	0
Total Uncommitted Capacity in CT	#REF!	#REF!	#REF!	#REF!	#REF!

	Pivotal Supplier Analysis	Market Share Analysis			
PJM Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	24,436	25,455	25,455	24,436	25,455
Average Daily Peak Native Load in Peak Month	(19,538)				
Average Peak Native Load in the Season		(16,011)	(14,104)	(18,740)	(15,366)
Operating Reserves	0	0	0	0	0
Planned Outages		(979)	(3,106)	(524)	(2,981)
Total Uncommitted Capacity in PJM	4,897	8,465	8,245	5,171	7,108

	Pivotal Supplier Analysis	Market Share Analysis			
AP South Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	11,914	12,510	12,510	11,914	12,510
Average Daily Peak Native Load in Peak Month	#REF!				
Average Peak Native Load in the Season		#REF!	#REF!	#REF!	#REF!

Operating Reserves	0	0	0	0	0
Planned Outages		#REF!	#REF!	#REF!	#REF!
Total Uncommitted Capacity in AP South	#REF!	#REF!	#REF!	#REF!	#REF!

	Pivotal Supplier Analysis	Market Share Analysis			
5004/5005 Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	11,906	12,504	12,504	11,906	12,504
Average Daily Peak Native Load in Peak Month	#REF!				
Average Peak Native Load in the Season		#REF!	#REF!	#REF!	#REF!
Operating Reserves	0	0	0	0	0
Planned Outages		#REF!	#REF!	#REF!	#REF!
Total Uncommitted Capacity in 5004/5005	#REF!	#REF!	#REF!	#REF!	#REF!

	Pivotal Supplier Analysis	Market Share Analysis			
PJM East Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	7,551	7,974	7,974	7,551	7,974
Average Daily Peak Native Load in Peak Month	#REF!				
Average Peak Native Load in the Season		#REF!	#REF!	#REF!	#REF!
Operating Reserves	0	0	0	0	0
Planned Outages		#REF!	#REF!	#REF!	#REF!
Total Uncommitted Capacity in PJM East	#REF!	#REF!	#REF!	#REF!	#REF!

	Pivotal Supplier Analysis	Market Share Analysis			
NYISO Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	2,294	2,317	2,317	2,294	2,317
Average Daily Peak Native Load in Peak Month	(1,774)				
Average Peak Native Load in the Season		(1,053)	(1,345)	(1,785)	(1,610)
Operating Reserves	0	0	0	0	0
Planned Outages		(256)	(454)	(59)	(363)
Total Uncommitted Capacity in NYISO	520	1,008	517	449	344

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Total Uncommitted Capacity in all BAAs, Markets or Sub-Markets

Dec 2014-Nov 2015

	Pivotal Supplier		Market Share Analysis				
NBPC Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	4,361	4,427	4,427	4,427	4,361	4,427	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(2,741)	(2,741)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(2,654)	(2,062)	(1,595)	(1,764)	Wkp - Summary of Inputs Data
Operating Reserves	(417)	(417)	(417)	(430)	(441)	(429)	Wkp - Summary of Inputs Data
Planned Outages			(531)	(942)	(1,096)	(895)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in NBPC	1,203	1,269	825	994	1,228	1,339	

	Pivotal Supplier		Market Share Analysis				
NSPI Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	2,659	2,648	2,648	2,648	2,659	2,748	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(2,041)	(2,041)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(1,759)	(1,366)	(1,057)	(1,169)	Wkp - Summary of Inputs Data
Operating Reserves	(276)	(276)	(276)	(285)	(293)	(285)	Wkp - Summary of Inputs Data
Planned Outages			(318)	(563)	(669)	(555)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in NSPI	342		295	433	641	739	

	Pivotal Supplier		Market Share Analysis				
IESO Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	36,740	36,058	36,058	36,428	36,740	36,995	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(20,089)	(20,089)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(19,875)	(16,965)	(17,949)	(17,489)	Wkp - Summary of Inputs Data
Operating Reserves	(1,664)	(1,664)	(1,392)	(1,540)	(1,664)	(1,656)	Wkp - Summary of Inputs Data
Planned Outages			(6,089)	(9,103)	(8,478)	(11,364)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in IESO	14,987	14,305	8,702	8,820	8,649	6,486	

	Pivotal Supplier		Market Share Analysis				
HQT Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	45,936	45,885	45,885	46,280	45,936	46,269	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(33,304)	(33,304)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(32,242)	(25,046)	(19,377)	(21,430)	Wkp - Summary of Inputs Data
Operating Reserves	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	Wkp - Summary of Inputs Data
Planned Outages			(4,230)	(8,830)	(11,584)	(8,117)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in HQT	11,132	11,082	7,914	10,905	13,475	15,221	

	Pivotal Supplier		Market Share Analysis				
NYISO Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	38,665	41,013	41,013	41,013	38,665	41,013	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(25,244)	(25,244)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(22,045)	(19,393)	(24,144)	(20,374)	Wkp - Summary of Inputs Data
Operating Reserves	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	Wkp - Summary of Inputs Data
Planned Outages			(3,348)	(5,935)	(739)	(4,743)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in NYISO	10,800	13,148	12,999	13,065	11,161	13,276	

	Pivotal Supplier		Market Share Analysis				
NYC Sub-Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data

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Average Daily Peak Native Load in Peak Month	#N/A	#N/A					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Operating Reserves	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Planned Outages			#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in NYC	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	

	Pivotal Supplier		Market Share Analysis				
Long Island Sub-Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	#N/A	#N/A					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Operating Reserves	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Planned Outages			#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in Long Island	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	

	Pivotal Supplier		Market Share Analysis				
ISO-NE Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	33,424	35,576	35,576	35,576	33,424	35,576	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(19,621)	(19,621)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(18,391)	(15,604)	(18,719)	(16,307)	Wkp - Summary of Inputs Data
Operating Reserves	(1,310)	(1,310)	(1,562)	(1,436)	(1,310)	(1,436)	Wkp - Summary of Inputs Data
Planned Outages			(1,127)	(3,234)	(236)	(2,960)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in ISO-NE	12,493	14,645	14,497	15,302	13,159	14,873	

	Pivotal Supplier		Market Share Analysis				
CT Sub-Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	7,789	8,213	8,213	8,213	7,789	8,213	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(5,054)	(5,054)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(4,497)	(3,789)	(4,827)	(4,005)	Wkp - Summary of Inputs Data
Operating Reserves	(714)	(714)	(363)	(539)	(714)	(539)	Wkp - Summary of Inputs Data
Planned Outages			(260)	(747)	(55)	(683)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in CT	2,020	2,444	3,092	3,139	2,192	2,986	

	Pivotal Supplier		Market Share Analysis				
SWCT Sub-Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	#N/A	#N/A					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Operating Reserves	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Planned Outages			#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in SWCT	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	

	Pivotal Supplier		Market Share Analysis				
PJM Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	183,060	199,600	199,600	196,690	183,060	192,785	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(121,600)	(121,600)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(112,390)	(94,917)	(117,821)	(95,173)	Wkp - Summary of Inputs Data
Operating Reserves	(9,097)	(9,097)	(8,067)	(6,367)	(9,097)	(6,391)	Wkp - Summary of Inputs Data
Planned Outages			(8,359)	(26,142)	(4,254)	(24,589)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in PJM	52,364	68,903	70,785	69,265	51,889	66,633	

	Pivotal Supplier		Market Share Analysis

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AP South Sub-Market	Pivotal Supplier PST Summer	Pivotal Supplier PST Winter	Market Share Analysis Winter	Spring	Summer	Fall	Reference
Installed Capacity	78,969	84,538	84,538	83,829	78,969	84,193	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(58,108)	(58,108)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(51,170)	(43,394)	(56,097)	(43,262)	Wkp - Summary of Inputs Data
Operating Reserves	(2,868)	(2,868)	(2,552)	(2,266)	(2,772)	(2,230)	Wkp - Summary of Inputs Data
Planned Outages			(3,540)	(11,141)	(1,835)	(10,738)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in AP South	17,993	23,562	27,276	27,027	18,265	27,963	

5004/5005 Sub-Market	Pivotal Supplier PST Summer	Pivotal Supplier PST Winter	Market Share Analysis Winter	Spring	Summer	Fall	Reference
Installed Capacity	55,814	59,991	59,991	59,282	55,814	59,741	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(42,368)	(42,368)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(36,840)	(31,515)	(40,748)	(31,648)	Wkp - Summary of Inputs Data
Operating Reserves	(2,512)	(2,512)	(2,185)	(1,869)	(2,416)	(1,877)	Wkp - Summary of Inputs Data
Planned Outages			(2,512)	(7,879)	(1,297)	(7,620)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in 5004/5005	10,934	15,111	18,454	18,018	11,353	18,595	

PJM East Sub-Market	Pivotal Supplier PST Summer	Pivotal Supplier PST Winter	Market Share Analysis Winter	Spring	Summer	Fall	Reference
Installed Capacity	34,630	38,116	38,116	37,407	34,630	37,735	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(24,093)	(24,093)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(19,303)	(16,803)	(22,934)	(17,326)	Wkp - Summary of Inputs Data
Operating Reserves	(1,429)	(1,429)	(1,145)	(996)	(1,360)	(1,027)	Wkp - Summary of Inputs Data
Planned Outages			(1,596)	(4,972)	(805)	(4,813)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in PJM East	9,109	12,594	16,072	14,636	9,532	14,569	

MISO Balancing Authority Area	Pivotal Supplier PST Summer	Pivotal Supplier PST Winter	Market Share Analysis Winter	Spring	Summer	Fall	Reference
Installed Capacity	168,505	175,367	175,367	175,695	168,505	175,039	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(102,563)	(102,563)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(86,929)	(76,192)	(97,947)	(80,875)	Wkp - Summary of Inputs Data
Operating Reserves	(2,438)	(2,438)	(2,440)	(2,439)	(2,438)	(2,440)	Wkp - Summary of Inputs Data
Planned Outages			(13,735)	(24,153)	(7,363)	(19,757)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in MISO	63,504	70,366	72,264	72,912	60,757	71,967	

CPLE Balancing Authority Area	Pivotal Supplier PST Summer	Pivotal Supplier PST Winter	Market Share Analysis Winter	Spring	Summer	Fall	Reference
Installed Capacity	13,525	14,696	14,696	14,696	13,525	14,720	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(10,538)	(10,538)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(9,332)	(7,425)	(10,231)	(7,487)	Wkp - Summary of Inputs Data
Operating Reserves	(244)	(244)	(244)	(233)	(221)	(230)	Wkp - Summary of Inputs Data
Planned Outages			(655)	(1,525)	(16)	(1,175)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in CPLE	2,743	3,914	4,465	5,514	3,057	5,827	

CPLW Balancing Authority Area	Pivotal Supplier PST Summer	Pivotal Supplier PST Winter	Market Share Analysis Winter	Spring	Summer	Fall	Reference
Installed Capacity	826	878	878	878	826	878	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(869)	(869)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(770)	(612)	(844)	(618)	Wkp - Summary of Inputs Data
Operating Reserves	(20)	(20)	(20)	(19)	(18)	(19)	Wkp - Summary of Inputs Data
Planned Outages			(39)	(91)	(1)	(70)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in CPLW	0	0	49	155	0	171	

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	Pivotal Supplier		Market Share Analysis				
LGEE Balancing Authority Area	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	8,838	9,033	9,033	8,793	8,838	9,108	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(5,754)	(5,754)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(5,124)	(4,348)	(5,616)	(4,421)	Wkp - Summary of Inputs Data
Operating Reserves	(222)	(222)	(222)	(223)	(231)	(242)	Wkp - Summary of Inputs Data
Planned Outages			0	(1,187)	0	(892)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in LGEE	2,862	3,057	3,687	3,034	2,991	3,553	

	Pivotal Supplier		Market Share Analysis				
DUKE Balancing Authority Area	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	24,632	25,619	25,619	25,619	24,632	25,619	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(16,433)	(16,433)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(14,053)	(11,801)	(15,919)	(11,970)	Wkp - Summary of Inputs Data
Operating Reserves	(358)	(358)	(358)	(365)	(372)	(393)	Wkp - Summary of Inputs Data
Planned Outages			(1,002)	(3,838)	(254)	(2,127)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in DUKE	7,840	8,828	10,207	9,616	8,087	11,129	

	Pivotal Supplier		Market Share Analysis				
TVA Balancing Authority Area	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	35,065	37,014	37,014	37,014	35,065	36,069	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(25,981)	(25,981)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(22,486)	(18,523)	(24,974)	(18,959)	Wkp - Summary of Inputs Data
Operating Reserves	(1,043)	(1,043)	(1,043)	(1,042)	(1,008)	(1,023)	Wkp - Summary of Inputs Data
Planned Outages			(3,257)	(6,237)	(1,810)	(6,067)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in TVA	8,040	9,990	10,228	11,213	7,272	10,021	

	Generation (MW)						
	PST	MST					
Markets or Sub-Markets	PSA	Winter	Spring	Summer	Fall	Reference	Markets or Sub-Markets
NBPC	4,427	4,427	4,427	4,361	4,427	Wkp - Canadian BAAs Generation	NBPC
NSPI	2,648	2,648	2,648	2,659	2,748	Wkp - Canadian BAAs Generation	NSPI
IESO	36,058	36,058	36,428	36,740	36,995	Wkp - Canadian BAAs Generation	IESO
HQT	45,885	45,885	46,280	45,936	46,269	Wkp - Canadian BAAs Generation	HQT
NYISO	38,665	41,013	41,013	38,665	41,013	Wkp - NYCA_2015	NYISO
ISO-NE	33,424	35,576	35,576	33,424	35,576	Wkp - ISO-NE CELT	ISO-NE
CT	7,789	8,213	8,213	7,789	8,213	Wkp - ISO-NE CELT	CT
PJM	183,060	199,600	196,690	183,060	192,785	Wkp - PJM Generation Summary	PJM
AP South	78,969	84,538	83,829	78,969	84,193	Wkp - PJM Generation Summary	AP South
5004/5005	55,814	59,991	59,282	55,814	59,741	Wkp - PJM Generation Summary	5004/5005
PJM East	34,630	38,116	37,407	34,630	37,735	Wkp - PJM Generation Summary	PJM East

1st Tiers

CPLE	13,525	14,696	14,696	13,525	14,720	Wkp - SE-MISO Gen Summary	CPLE
CPLW	826	878	878	826	878	Wkp - SE-MISO Gen Summary	CPLW
DUKE	24,632	25,619	25,619	24,632	25,619	Wkp - SE-MISO Gen Summary	DUKE
LGEE	8,838	9,033	8,793	8,838	9,108	Wkp - SE-MISO Gen Summary	LGEE
MISO	168,505	175,367	175,695	168,505	175,039	Wkp - SE-MISO Gen Summary	MISO
TVA	35,065	37,014	37,014	35,065	36,069	Wkp - SE-MISO Gen Summary	TVA

Load (MW)								
PST		MST						PST
Peak	Avg	Winter	Spring	Summer	Fall	Reference	Markets or Sub-Markets	PSA
3,206	2,741	2,654	2,062	1,595	1,764	Wkp - Canadian BAAs Loads	NBPC	417
2,604	2,041	1,759	1,366	1,057	1,169	Wkp - Canadian BAAs Loads	NSPI	276
21,814	20,089	19,875	16,965	17,949	17,489	Wkp - Canadian BAAs Loads	IESO	1,664
38,950	33,304	32,242	25,046	19,377	21,430	Wkp - Canadian BAAs Loads	HQT	1,500
31,138	25,244	22,045	19,393	24,144	20,374	Wkp - NYISO Load	NYISO	2,620
24,437	19,621	18,391	15,604	18,719	16,307	Wkp - ISO-NE Load	ISO-NE	1,310
6,419	5,054	4,497	3,789	4,827	4,005	Wkp - CT Load	CT	714
143,633	121,600	112,390	94,917	117,821	95,173	Wkp - PJM Load	PJM	9,097
70,729	58,108	51,170	43,394	56,097	43,262	Wkp - AP South Load	AP South	2,868
52,190	42,368	36,840	31,515	40,748	31,648	Wkp - 5004 5005 Load	5004/5005	2,512
30,240	24,093	19,303	16,803	22,934	17,326	Wkp - PJM East Load	PJM East	1,429
14,383	10,538	9,332	7,425	10,231	7,487	Wkp - Southeast & MISO Load	CPLE	244
1,186	869	770	612	844	618	Wkp - Southeast & MISO Load	CPLW	20
21,101	16,433	14,053	11,801	15,919	11,970	Wkp - Southeast & MISO Load	DUKE	358
7,236	5,754	5,124	4,348	5,616	4,421	Wkp - Southeast & MISO Load	LGEE	222
118,332	102,563	86,929	76,192	97,947	80,875	Wkp - Southeast & MISO Load	MISO	2,438
32,751	25,981	22,486	18,523	24,974	18,959	Wkp - Southeast & MISO Load	TVA	1,043

Reserves (MW) MST					Outages (MW) MST			
Winter	Spring	Summer	Fall	Reference	Markets or Sub-Markets	Winter	Spring	Summer
417	430	441	429	Wkp - NPCC Outages & Reserves	NBPC	531	942	1,096
276	285	293	285	Wkp - NPCC Outages & Reserves	NSPI	318	563	669
1,392	1,540	1,664	1,656	Wkp - NPCC Outages & Reserves	IESO	6,089	9,103	8,478
1,500	1,500	1,500	1,500	Wkp - NPCC Outages & Reserves	HQT	4,230	8,830	11,584
2,620	2,620	2,620	2,620	Wkp - NYISO Reserves	NYISO	3,348	5,935	739
1,562	1,436	1,310	1,436	Wkp - ISO-NE Reserves	ISO-NE	1,127	3,234	236
363	539	714	539	Wkp - ISO-NE Reserves	CT	260	747	55
8,067	6,367	9,097	6,391	Wkp - PJM Operating Reserves	PJM	8,359	26,142	4,254
2,552	2,266	2,772	2,230	Wkp - PJM Operating Reserves	AP South	3,540	11,141	1,835
2,185	1,869	2,416	1,877	Wkp - PJM Operating Reserves	5004/5005	2,512	7,879	1,297
1,145	996	1,360	1,027	Wkp - PJM Operating Reserves	PJM East	1,596	4,972	805
244	233	221	230	Wkp - SERC Operating Reserves	CPLE	655	1,525	16
20	19	18	19	Wkp - SERC Operating Reserves	CPLW	39	91	1
358	365	372	393	Wkp - SERC Operating Reserves	DUKE	1,002	3,838	254
222	223	231	242	Wkp - SERC Operating Reserves	LGEE	0	1,187	0
2,440	2,439	2,438	2,440	MISO Triennials Data (Dec12 to Nov13)	MISO	13,735	24,153	7,363
1,043	1,042	1,008	1,023	Wkp - SERC Operating Reserves	TVA	3,257	6,237	1,810

Fall	Reference
895	Wkp - NPCC Outages & Reserves
555	Wkp - NPCC Outages & Reserves
11,364	Wkp - NPCC Outages & Reserves
8,117	Wkp - NPCC Outages & Reserves
4,743	Wkp - NYISO Outages
2,960	Wkp - ISO-NE Outages
683	Wkp - ISO-NE Outages
24,589	Wkp - PJM Outages
10,738	Wkp - PJM Outages
7,620	Wkp - PJM Outages
4,813	Wkp - PJM Outages

1,175	Wkp -Southeast and MISO Outages
70	Wkp -Southeast and MISO Outages
2,127	Wkp -Southeast and MISO Outages
892	Wkp -Southeast and MISO Outages
19,757	Wkp -Southeast and MISO Outages
6,067	Wkp -Southeast and MISO Outages

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Ventyx IESO Load Summary	
Peak	22,516
Peak Month	July
January Peak	21,814
January Avg	20,089
February Peak	21,494
February Avg	20,556
PST	18,815
Winter	19,875
Spring	16,965
Summer	17,949
Fall	17,489

Modeled Loads	
IESO	
January Peak	21,814
Peak Month	Jan
IESO July Peak	22,516
IESO July Avg	18,815
Summer Peak	22,516
PST	20,089
Winter	19,875
Spring	16,965
Summer	17,949
Fall	17,489

Modeled Loads	
Maritimes	
Peak	5,314
Peak Month	Feb
Summer Peak	3,688
PST	4,782
Winter	4,413
Spring	3,428
Summer	2,652
Fall	2,933

Modeled Loads	
NBPC	
Peak	3,206
Peak Month	Jan
NBPC Feb Peak	3,196
NBPC Feb Avg	2,876
PST	2,741
Winter	2,654
Spring	2,062
Summer	1,595
Fall	1,764

Modeled Loads	
NSPI	
Peak	2,604
Peak Month	Feb
PST	2,041
Winter	1,759
Spring	1,366
Summer	1,057
Fall	1,169

Modeled Loads	
HQT BAA	
Peak	38,950
Peak Month	Jan
NBPC Jan Peak	3,206
NBPC Jan Avg	2,741
Summer Peak	20,766
PST	33,304
Winter	32,242
Spring	25,046
Summer	19,377
Fall	21,430

IESO load from ABB, The Velocity Suite
NBPC Load from New Bruswick Power archive website
Maritimes and Hydro Quebec Peak demand from NPCC seasonnal assessment.
NSPI load is assumed to be the difference between the Maritimes and NBPC Loads
https://www.npcc.org/Library/Seasonal%20Assessment/2015-16W_NPCC%20Seasonal%20Assessment%20-%20Final%20Report%20-%20Posted%20NPCC%20Web%20Site%2020151204.pdf
https://www.npcc.org/Library/Seasonal%20Assessment/NPCC_Reliability_Assessment_for_2016_Summer-Final_Report.pdf

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Ontario Balancing Authority Areas Load Data - Source: Ventyx, The Velocity Suite
Dec 2014-Nov 2015 Load

Needle Peak	**IESO**	22,516
Avg July (P Month)	**IESO**	18,815
Winter	**IESO**	19,875
Spring	**IESO**	16,965
Summer	**IESO**	17,949
Fall	**IESO**	17,489

Source: ABB, The Velocity Suite
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Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
12/1/2014	IESO																								
12/2/2014	IESO																								
12/3/2014	IESO																								
12/4/2014	IESO																								
12/5/2014	IESO																								
12/6/2014	IESO																								
12/7/2014	IESO																								
12/8/2014	IESO																								
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Table AP-6 – Québec

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat. (MW)	Req. Reserves (MW)
7-Dec-14	44,681	4,290	1,500
14-Dec-14	44,681	4,394	1,500
21-Dec-14	44,681	4,549	1,500
28-Dec-14	44,681	4,386	1,500
4-Jan-15	44,681	3,924	1,500
11-Jan-15	44,681	3,985	1,500
18-Jan-15	44,681	4,125	1,500
25-Jan-15	44,681	4,142	1,500
1-Feb-15	44,681	4,137	1,500
8-Feb-15	44,681	4,214	1,500
15-Feb-15	44,681	4,284	1,500
22-Feb-15	44,681	4,324	1,500
1-Mar-15	44,681	4,592	1,500
8-Mar-15	44,681	4,756	1,500
15-Mar-15	44,681	4,761	1,500
22-Mar-15	44,681	4,686	1,500
29-Mar-15	44,681	5,301	1,500

Season	Outages Factors (%)
Winter	10%
Winter	10%
Winter	10%
Winter	10%
Winter	9%
Winter	9%
Winter	9%
Winter	9%
Winter	9%
Winter	9%
Winter	10%
Winter	10%
Spring	10%
Spring	11%
Spring	11%
Spring	10%
Spring	12%

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat (MW)	Req. Reserves (MW)
26-Mar-15	44,813	12,693	1,500
2-Apr-15	44,813	12,162	1,500
10-Apr-15	44,813	12,393	1,500
17-Apr-15	44,813	12,637	1,500
24-Apr-15	44,813	13,052	1,500
31-May-15	44,813	11,604	1,500
7-Jun-15	44,813	12,488	1,500
14-Jun-15	44,813	11,837	1,500
21-Jun-15	44,813	10,650	1,500
28-Jun-15	44,813	11,198	1,500
5-Jul-15	44,813	12,299	1,500
12-Jul-15	44,813	11,708	1,500
19-Jul-15	44,813	11,430	1,500
26-Jul-15	44,813	10,731	1,500
2-Aug-15	44,813	10,892	1,500
9-Aug-15	44,813	11,795	1,500
16-Aug-15	44,813	11,605	1,500
23-Aug-15	44,813	11,665	1,500
30-Aug-15	44,813	12,299	1,500
6-Sep-15	44,813	12,287	1,500
13-Sep-15	44,813	11,287	1,500

Season	Outages Factors (%)
Spring	28%
Spring	27%
Spring	28%
Spring	28%
Spring	27%
Spring	26%
Summer	28%
Summer	28%
Summer	24%
Summer	25%
Summer	27%
Summer	28%
Summer	24%
Summer	26%
Summer	26%
Summer	27%
Fall	27%
Fall	25%

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat (MW)	Req. Reserves (MW)
22-Nov-15	45,380	4,487	1,500
29-Nov-15	45,380	4,406	1,500

Season	Outages Factors (%)
Fall	10%
Fall	10%

Tables AP-5 – Ontario

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat. (MW)	Req. Reserves (MW)
7-Dec-14	34,382	5,888	1,392
14-Dec-14	34,382	5,853	1,392
21-Dec-14	34,382	5,063	1,392
28-Dec-14	34,382	4,565	1,392
4-Jan-15	34,628	5,379	1,392
11-Jan-15	34,628	6,148	1,392
18-Jan-15	34,628	6,120	1,392
25-Jan-15	34,628	6,142	1,392
1-Feb-15	35,065	6,585	1,392
8-Feb-15	35,165	7,119	1,392
15-Feb-15	35,065	7,156	1,392
22-Feb-15	35,065	7,050	1,392
1-Mar-15	35,232	7,288	1,392
8-Mar-15	35,232	7,436	1,392
15-Mar-15	35,232	7,456	1,392
22-Mar-15	35,232	7,513	1,392
29-Mar-15	35,232	11,368	1,392

Season	Outages Factors (%)
Winter	17%
Winter	17%
Winter	15%
Winter	13%
Winter	16%
Winter	18%
Winter	18%
Winter	19%
Winter	20%
Winter	20%
Winter	20%
Winter	20%
Spring	21%
Spring	21%
Spring	21%
Spring	21%
Spring	32%

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat (MW)	Req. Reserves (MW)
26-Mar-15	35,126	10,754	1,664
2-Apr-15	35,251	10,036	1,664
10-Apr-15	35,251	10,707	1,664
17-Apr-15	35,251	8,738	1,664
24-Apr-15	35,251	8,660	1,664
31-May-15	35,251	9,291	1,664
7-Jun-15	35,251	9,329	1,664
14-Jun-15	35,251	9,273	1,664
21-Jun-15	35,251	8,724	1,664
28-Jun-15	35,251	8,768	1,664
5-Jul-15	35,547	7,851	1,664
12-Jul-15	35,547	7,820	1,664
19-Jul-15	35,547	7,794	1,664
26-Jul-15	35,547	7,848	1,664
2-Aug-15	35,547	8,863	1,664
9-Aug-15	35,547	8,357	1,664
16-Aug-15	35,547	7,637	1,664
23-Aug-15	35,547	8,358	1,664
30-Aug-15	35,845	9,606	1,664
6-Sep-15	35,845	13,618	1,664
13-Sep-15	35,845	13,030	1,632

Season	Outages Factors (%)
Spring	31%
Spring	31%
Spring	30%
Spring	35%
Spring	35%
Spring	36%
Summer	36%
Summer	38%
Summer	35%
Summer	35%
Summer	22%
Summer	22%
Summer	22%
Summer	22%
Summer	25%
Summer	24%
Summer	27%
Fall	38%
Fall	39%

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat (MW)	Req. Reserves (MW)
22-Nov-15	35,748	9,051	1,664
29-Nov-15	35,748	8,875	1,664

Season	Outages Factors (%)
Fall	35%
Fall	35%

Tables AP-2 – Maritimes

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat. (MW)	Req. Reserves (MW)
7-Dec-14	7,557	847	693
14-Dec-14	7,557	847	693
21-Dec-14	7,557	847	693
28-Dec-14	7,557	798	693
4-Jan-15	7,586	820	693
11-Jan-15	7,586	820	693
18-Jan-15	7,586	820	693
25-Jan-15	7,586	836	693
1-Feb-15	7,618	893	693
8-Feb-15	7,618	893	693
15-Feb-15	7,618	893	693
22-Feb-15	7,618	877	693
1-Mar-15	7,639	1,046	693
8-Mar-15	7,639	1,046	693
15-Mar-15	7,639	1,046	693
22-Mar-15	7,639	970	693
29-Mar-15	7,647	1,187	693

Season	Outages Factors (%)
Winter	11%
Winter	11%
Winter	11%
Winter	11%
Winter	11%
Winter	11%
Winter	11%
Winter	12%
Winter	12%
Winter	12%
Winter	12%
Winter	12%
Spring	14%
Spring	14%
Spring	14%
Spring	13%
Spring	18%

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat. (MW)	Req. Reserves (MW)
26-Mar-15	7,693	2,048	734
2-Apr-15	7,722	2,131	734
10-Apr-15	7,722	1,978	734
17-Apr-15	7,722	1,605	734
24-Apr-15	7,722	1,718	734
31-May-15	7,722	1,784	734
7-Jun-15	7,723	1,906	734
14-Jun-15	7,723	1,859	734
21-Jun-15	7,723	1,644	734
28-Jun-15	7,723	1,616	734
5-Jul-15	7,726	1,674	734
12-Jul-15	7,726	1,671	734
19-Jul-15	7,726	1,667	734
26-Jul-15	7,726	1,850	734
2-Aug-15	7,726	1,615	734
9-Aug-15	7,726	1,720	734
16-Aug-15	7,726	2,044	734
23-Aug-15	7,726	2,065	734
30-Aug-15	7,726	1,809	734
6-Sep-15	7,741	1,788	734
13-Sep-15	7,741	2,115	734

Season	Outages Factors (%)
Spring	27%
Spring	28%
Spring	28%
Spring	21%
Spring	22%
Spring	23%
Summer	29%
Summer	24%
Summer	21%
Summer	21%
Summer	22%
Summer	22%
Summer	22%
Summer	21%
Summer	22%
Summer	28%
Summer	27%
Summer	23%
Fall	23%
Fall	27%

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat (MW)	Req. Reserves (MW)
22-Nov-15	7,743	935	693
29-Nov-15	7,744	960	693

Season	Outages Factors (%)
Fall	12%
Fall	12%

	Québec				Ontario				Maritimes			
	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Average Outage Factors	9%	26%	26%	18%	18%	26%	24%	32%	11%	20%	23%	19%
Average Outages	4,130	8,830	11,584	8,117	6,089	9,103	8,478	11,364	849	1,505	1,765	1,450
Operating Reserves	1,500	1,500	1,500	1,500	1,392	1,540	1,664	1,656	693	715	734	714

	NBPC Generation				NSR Generation			
	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Total Generation	4,427	4,427	4,261	4,427	2,648	2,648	2,659	2,748
Share of Maritimes Outages	521	942	1,096	895	328	563	669	555
Share of Operating Reserves	417	430	441	429	276	285	293	285
Total Load	2,654	2,062	1,595	1,764	1,759	1,266	1,057	1,369

Source Links
2014: https://www.npcc.org/Library/Seasonal%20Assessment/NPCC%20Seasonal%20Assessment%20Report-Final_20141202.pdf

https://www.npcc.org/Library/Seasonal%20Assessment/20145_NPCC%20Seasonal%20Assessment%20Final%20Report.pdf

2015: https://www.npcc.org/Library/Seasonal%20Assessment/2014-2015_Winter_NPCC%20Seasonal%20Assessment%20Report-Final_20141202.pdf

https://www.npcc.org/Library/Seasonal%20Assessment/2015-16W_NPCC%20Seasonal%20Assessment%20-%20Final%20Report%20-%20Posted%20NPCC%20Web%20Site%2020151204.pdf

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Max	3,206
Max Month	1
PST	2,741
Winter	2,654
Spring	2,062
Summer	1,595
Fall	1,764

Source: New Brunswick Power Website Archive data
http://tso.nbpower.com/Public/en/system_information_archive.aspx

NB Power load assumed to be "NB_DEMAND" +/- "NMISA" +/- "PEI"

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	2,087	12/1/2014	1,586	1,500	1,485	1,469	1,462	1,472	1,528	1,734	1,949	1,936	1,869	1,848	1,825	1,781	1,771	1,782	1,807	1,966	2,087	2,067	2,040	2,005	1,936	1,817
Winter	12	2,586	12/2/2014	1,699	1,616	1,647	1,672	1,697	1,756	1,873	2,087	2,348	2,375	2,295	2,243	2,206	2,154	2,152	2,161	2,234	2,436	2,586	2,543	2,568	2,550	2,461	2,330
Winter	12	2,357	12/3/2014	2,178	2,058	2,009	2,007	1,976	1,991	2,019	2,205	2,357	2,297	2,229	2,181	2,144	2,071	2,022	1,954	1,927	2,013	2,067	2,003	1,972	1,911	1,787	1,635
Winter	12	2,296	12/4/2014	1,555	1,469	1,475	1,495	1,507	1,541	1,617	1,828	2,078	2,074	2,008	1,933	1,903	1,860	1,858	1,876	1,879	2,032	2,250	2,269	2,296	2,284	2,228	2,154
Winter	12	2,729	12/5/2014	2,052	2,001	2,008	2,028	2,037	2,100	2,210	2,451	2,729	2,723	2,642	2,552	2,491	2,400	2,352	2,302	2,318	2,436	2,565	2,546	2,530	2,483	2,429	2,366
Winter	12	2,403	12/6/2014	2,270	2,159	2,094	2,057	2,026	2,019	2,028	2,100	2,209	2,320	2,395	2,403	2,352	2,305	2,259	2,221	2,242	2,332	2,335	2,230	2,121	2,034	1,947	1,877
Winter	12	2,567	12/7/2014	1,763	1,719	1,666	1,663	1,667	1,695	1,751	1,838	1,943	2,077	2,162	2,178	2,180	2,174	2,134	2,107	2,159	2,357	2,520	2,541	2,563	2,567	2,479	2,365
Winter	12	3,009	12/8/2014	2,255	2,207	2,196	2,248	2,300	2,358	2,480	2,701	2,995	3,009	2,922	2,811	2,721	2,579	2,480	2,452	2,494	2,647	2,739	2,696	2,654	2,618	2,528	2,409
Winter	12	2,668	12/9/2014	2,260	2,175	2,123	2,131	2,173	2,186	2,272	2,412	2,642	2,668	2,608	2,531	2,417	2,389	2,367	2,364	2,377	2,481	2,530	2,462	2,430	2,348	2,228	2,052
Winter	12	2,285	#########	1,941	1,742	1,707	1,693	1,698	1,717	1,795	1,972	2,197	2,285	2,186	2,124	2,177	2,192	2,184	2,153	2,143	2,228	2,285	2,211	2,277	2,191	2,120	1,967
Winter	12	2,206	#########	1,767	1,670	1,653	1,636	1,617	1,621	1,681	1,886	2,100	2,064	2,039	2,022	2,013	1,989	1,959	1,939	1,984	2,111	2,206	2,172	2,111	2,052	1,952	1,836
Winter	12	2,199	#########	1,700	1,595	1,594	1,585	1,575	1,644	1,722	1,928	2,167	2,167	2,127	2,118	2,109	2,059	2,064	2,057	2,073	2,164	2,199	2,146	2,079	2,024	1,953	1,862
Winter	12	2,146	#########	1,746	1,704	1,652	1,638	1,649	1,659	1,710	1,823	1,935	2,036	2,049	2,037	1,965	1,963	1,915	1,912	1,979	2,112	2,135	2,146	2,133	2,124	2,064	1,969
Winter	12	2,273	#########	1,873	1,791	1,752	1,723	1,705	1,717	1,768	1,850	1,953	2,064	2,145	2,156	2,153	2,115	2,085	2,073	2,088	2,193	2,273	2,223	2,168	2,128	2,063	1,914
Winter	12	2,352	#########	1,780	1,679	1,656	1,640	1,657	1,696	1,760	1,979	2,198	2,193	2,166	2,107	2,129	2,099	2,085	2,070	2,104	2,245	2,350	2,352	2,286	2,263	2,187	2,044
Winter	12	2,395	#########	1,906	1,797	1,776	1,782	1,798	1,839	1,935	2,157	2,383	2,395	2,332	2,259	2,237	2,194	2,164	2,147	2,184	2,285	2,361	2,372	2,343	2,313	2,224	2,079
Winter	12	2,395	#########	1,929	1,837	1,802	1,795	1,793	1,820	1,908	2,144	2,391	2,395	2,303	2,254	2,228	2,172	2,132	2,139	2,176	2,265	2,355	2,352	2,328	2,324	2,223	2,055
Winter	12	2,455	#########	1,871	1,734	1,679	1,657	1,645	1,664	1,729	1,929	2,178	2,201	2,195	2,195	2,220	2,181	2,174	2,189	2,219	2,337	2,455	2,435	2,418	2,361	2,271	2,123
Winter	12	2,318	#########	1,976	1,823	1,815	1,766	1,771	1,789	1,859	2,039	2,286	2,301	2,253	2,188	2,135	2,074	2,135	2,119	2,165	2,229	2,318	2,278	2,238	2,205	2,149	2,030
Winter	12	2,396	#########	1,913	1,813	1,808	1,809	1,808	1,833	1,875	1,992	2,109	2,233	2,309	2,316	2,289	2,244	2,186	2,164	2,215	2,330	2,396	2,329	2,278	2,236	2,185	2,094
Winter	12	2,399	#########	1,999	1,933	1,891	1,864	1,869	1,874	1,908	1,972	2,092	2,227	2,313	2,331	2,315	2,297	2,259	2,230	2,244	2,322	2,399	2,370	2,342	2,288	2,236	2,124
Winter	12	2,442	#########	2,000	1,926	1,893	1,881	1,898	1,934	2,019	2,192	2,364	2,409	2,420	2,395	2,355	2,280	2,253	2,198	2,241	2,364	2,442	2,416	2,395	2,359	2,293	2,165
Winter	12	2,387	#########	2,036	1,919	1,894	1,895	1,870	1,893	1,974	2,137	2,318	2,374	2,373	2,356	2,332	2,277	2,243	2,217	2,218	2,317	2,387	2,368	2,332	2,286	2,229	2,095
Winter	12	2,239	#########	1,948	1,837	1,774	1,753	1,752	1,775	1,827	1,960	2,106	2,188	2,239	2,228	2,211	2,144	2,087	2,091	2,077	2,096	2,063	1,956	1,881	1,859	1,799	1,728
Winter	12	1,762	#########	1,641	1,588	1,543	1,491	1,476	1,472	1,489	1,542	1,586	1,651	1,706	1,747	1,762	1,741	1,712	1,678	1,655	1,658	1,694	1,671	1,682	1,677	1,657	1,598
Winter	12	1,897	#########	1,568	1,489	1,483	1,467	1,476	1,495	1,552	1,618	1,679	1,750	1,821	1,835	1,802	1,761	1,716	1,670	1,645	1,755	1,897	1,889	1,873	1,833	1,805	1,747
Winter	12	1,999	#########	1,678	1,620	1,559	1,571	1,556	1,564	1,592	1,653	1,738	1,831	1,851	1,865	1,824	1,746	1,679	1,657	1,678	1,802	1,957	1,998	1,999	1,980	1,954	1,889
Winter	12	2,093	#########	1,796	1,756	1,723	1,717	1,731	1,737	1,715	1,802	1,847	1,926	1,968	1,959	1,944	1,921	1,912	1,904	1,916	1,987	2,093	2,053	1,992	1,954	1,889	1,783
Winter	12	2,319	#########	1,696	1,639	1,619	1,612	1,644	1,677	1,752	1,880	1,992	2,051	2,035	2,002	2,009	1,990	1,969	1,928	1,986	2,154	2,292	2,319	2,317	2,284	2,230	2,158
Winter	12	2,788	#########	2,067	1,997	2,027	2,051	2,095	2,147	2,252	2,414	2,603	2,672	2,667	2,583	2,572	2,536	2,499	2,469	2,492	2,653	2,788	2,768	2,760	2,745	2,688	2,551
Winter	12	2,887	#########	2,457	2,399	2,387	2,385	2,418	2,442	2,522	2,670	2,817	2,887	2,885	2,834	2,749	2,611	2,568	2,536	2,557	2,691	2,790	2,736	2,673	2,638	2,579	2,516
Winter	1	2,521	1/1/2015	2,461	2,386	2,371	2,344	2,339	2,349	2,400	2,457	2,475	2,493	2,521	2,481	2,389	2,305	2,247	2,203	2,231	2,356	2,426	2,354	2,356	2,319	2,258	2,146
Winter	1	2,445	1/2/2015	2,033	1,952	1,908	1,889	1,912	1,952	2,058	2,187	2,306	2,308	2,333	2,347	2,282	2,220	2,177	2,139	2,164	2,286	2,445	2,429	2,405	2,386	2,355	2,276
Winter	1	2,804	1/3/2015	2,217	2,169	2,187	2,208	2,246	2,288	2,344	2,435	2,559	2,666	2,691	2,662	2,617	2,599	2,556	2,528	2,533	2,682	2,804	2,797	2,780	2,743	2,693	2,585
Winter	1	2,520	1/4/2015	2,504	2,418	2,378	2,362	2,344	2,333	2,315	2,350	2,400	2,435	2,507	2,517	2,520	2,495	2,429	2,408	2,404	2,469	2,481	2,438	2,413	2,329	2,207	2,037
Winter	1	2,634	1/5/2015	1,913	1,849	1,799	1,750	1,764	1,819	1,906	2,076	2,234	2,254	2,209	2,217	2,211	2,192	2,185	2,185	2,251	2,417	2,578	2,601	2,629	2,634	2,573	2,461
Winter	1	3,067	1/6/2015	2,375	2,319	2,338	2,378	2,415	2,465	2,586	2,819	3,064	3,067	2,955	2,871	2,822	2,747	2,681	2,640	2,728	2,921	3,025	3,010	2,994	2,953	2,863	2,715
Winter	1	3,041	1/7/2015	2,584	2,526	2,535	2,523	2,536	2,580	2,670	2,837	3,041	3,020	2,960	2,845	2,751	2,637	2,549	2,539	2,559	2,664	2,770	2,755	2,746	2,699	2,636	2,513
Winter	1	3,099	1/8/2015	2,414	2,349	2,377	2,430	2,495	2,530	2,616	2,841	3,092	3,099	2,968	2,884	2,806	2,701	2,669	2,641	2,712	2,918	3,091	3,088	3,084	3,046	2,965	2,819
Winter	1	3,023	1/9/2015	2,689	2,573	2,586	2,580	2,591	2,646	2,716	2,879	3,023	2,966	2,915	2,856	2,791	2,653	2,589	2,574	2,552	2,541	2,594	2,578	2,573	2,546	2,488	2,375
Winter	1	2,629	1/10/2015	2,284	2,216	2,219	2,256	2,277	2,319	2,365	2,444	2,549	2,629	2,626	2,540	2,452	2,355	2,279	2,247	2,308	2,434	2,603	2,614	2,611	2,576	2,512	2,412
Winter	1	2,752	1/11/2015	2,312	2,240	2,245	2,272	2,301	2,357	2,390	2,528	2,646	2,752	2,732	2,624	2,480	2,391	2,317	2,306	2,339	2,505	2,634	2,630	2,602	2,545	2,504	2,354
Winter	1	2,688	1/12/2015	2,196	2,125	2,123	2,123	2,110	2,158	2,249	2,471	2,688	2,678	2,628	2,610	2,552	2,504	2,505	2,475	2,491	2,560	2,610	2,572	2,529	2,488	2,398	2,215
Winter	1	2,873	1/13/2015	2,080	1,950	1,924	1,916	1,967	2,049	2,184	2,437	2,701	2,724	2,641	2,541	2,498	2,437	2,384	2,373	2,437	2,606	2,805	2,855	2,873	2,858	2,792	2,622
Winter	1	3,206	1/14/2015	2,575	2,503	2,504	2,508	2,548	2,622	2,732	2,953	3,206	3,191	3,074	2,916	2,788	2,640	2,568	2,522	2,527	2,663	2,801	2,812	2,808	2,758	2,669	2,539
Winter	1	2,956	1/15/2015	2,433	2,330	2,335	2,338	2,346	2,397	2,491	2,739	2,956	2,922	2,827	2,717	2,627	2,520	2,476	2,441	2,469	2,558	2,645	2,647	2,637	2,597	2,509	2,353
Winter	1	2,510	1/16/2015	2,212	2,131	2,076	2,058	2,027	2,098	2,118	2,304	2,510	2,501	2,435	2,372	2,307	2,257	2,234	2,246	2,233	2,329	2,427	2,464	2,465	2,396	2,383	2,313
Winter	1	2,812	1/17/2015	2,236	2,210	2,218	2,273	2,324	2,378	2,447	2,567	2,703	2,811	2,812	2,756	2,669	2,598	2,492	2,429	2,424	2,578	2,768	2,775	2,747	2,681	2,660	2,590
Winter	1	2,632	1/18/2015	2,513	2,505	2,483	2,497	2,507	2,482	2,501	2,548	2,623	2,632	2,610	2,577	2,519	2,442	2,362	2,240	2,236	2,309	2,372	2,318	2,247	2,170	2,065	1,952
Winter	1	2,167	1/19/2015	1,815	1,713	1,644	1,638	1,653	1,672	1,762	1,992	2,154	2,110	2,078	2,074	2,056	2,050	2,023	2,005	2,017	2,087	2,167	2,125	2,087	2,031	1,963	1,865
Winter	1	2,489	1/20/2015	1,772	1,658	1,630	1,640	1,676	1,715	1,819	2,059	2,296	2,336	2,304	2,245	2,233	2,183	2,162	2,123	2,158	2,282	2,424	2,470	2,489	2,480	2,440	2,349
Winter	1	2,852	1/21/2015	2,256	2,185	2,204	2,228	2,253	2,300	2,412	2,626	2,852	2,806	2,666	2,561	2,500	2,411	2,332	2,294	2,302	2,366	2,522	2,571	2,617	2,607	2,562	2,453
Winter	1	2,982	1/22/2015	2,356	2,280	2,279	2,300	2,332	2,394	2,507	2,745	2,982	2,965	2,876	2,776	2,679	2,568	2,519	2,483	2,498	2,575	2,626	2,622	2,622	2,533	2,455	2,309
Winter	1	2,794	1/23/2015	2,196	2,141	2,163	2,205	2,242	2,300	2,363	2,563	2,794	2,781	2,691	2,583	2,454	2,366	2,288	2,235	2,251	2,358	2,485	2,498	2,453	2,406	2,340	2,201
Winter	1	2,374	1/24/2015	2,090	2,018	2,006	2,013	2,024	2,022	2,014	2,095	2,237	2,333	2,371	2,356	2,326	2,268	2,222	2,191	2,164	2,267	2,374	2,345	2,241	2,203	2,137	2,047
Winter	1	2,545	1/25/2015	1,946	1,862	1,850	1,844	1,819	1,845	1,889	1,957	2,067	2,196	2,233	2,162	2,187	2,164	2,112	2,093	2,124	2,251	2,400	2,472	2,540	2,545	2,445	2,339
Winter	1	2,834	1/26/2015	2,242	2,182	2,187	2,211	2,196	2,274	2,391	2,633	2,834	2,824	2,700	2,595	2,510	2,424	2,321	2,295	2,342	2,470	2,650	2,693	2,681	2,670	2,627	2,529
Winter	1	2,817	1/27/2015	2,405	2,357	2,349	2,404	2,398	2,435	2,475	2,585	2,763	2,792	2,816	2,806	2,817	2,801	2,732	2,677	2,649	2,713	2,720	2,665	2,599	2,522	2,411	2,274
Winter	1	2,614	1/28/2015	2,177	2,150	2,119	2,117	2,109	2,132	2,187	2,420	2,588	2,576	2,566	2,558	2,576	2,540	2,502	2,479	2,498	2,577	2,604	2,614	2,587	2,533	2,468	2,335
Winter	1	2,908	1/29/2015	2,245	2,196	2,213	2,241	2,279	2,325	2,435	2,659	2,908	2,850	2,692	2,553	2,452	2,352	2,266	2,230	2,242	2,331	2,457	2,571	2,589	2,581	2,528	2,447
Winter	1	2,915	1/30/2015	2,353	2,280	2,288	2,331	2,361	2,418	2,506	2,719	2,915	2,887	2,809	2,743	2,669	2,590	2,519	2,481	2,486	2,552	2,575	2,572	2,524	2,470	2,401	2,294
Winter	1	2,476	1/31/2015	2,168	2,082	2,050	2,037	2,038	2,053	2,079	2,139	2,202	2,267	2,360	2,396	2,451	2,476	2,404	2,343	2,337	2,409	2,466	2,462	2,431	2,384	2,363	2,242
Winter	2	2,753	2/1/2015	2,194	2,158	2,169	2,185	2,150	2,185	2,237	2,330	2,434	2,539	2,537	2,482	2,447	2,384	2,333	2,298	2,315	2,435	2,628	2,731	2,753	2,739	2,693	2,609
Winter	2	3,169	2/2/2015	2,509	2,403	2,373	2,379	2,447	2,502	2,619	2,900	3,169	3,160	3,120	3,074	3,049	3,014	2,999	3,010	2,990	3,091	3,152	3,125	3,066	2,984	2,861	2,705
Winter	2	2,983	2/3/2015	2,555	2,434	2,438	2,456	2,493	2,529	2,581	2,692	2,846	2,983	2,867	2,798	2,752	2,622	2,547	2,501	2,509	2,645	2,795	2,838	2,837	2,802	2,741	2,631
Winter	2	3,196	2/4/2015	2,550	2,505	2,513	2,539	2,564	2,610	2,733	2,974	3,196	3,132	3,007	2,856	2,726	2,673	2,599	2,575	2,562	2,632	2,691	2,704	2,650	2,542	2,424	2,274
Winter	2	2,562	2/5/2015	2,140	2,060	2,064	2,027	1,986	1,986	2,067	2,217	2,406	2,397	2,404	2,375	2,363	2,342	2,308	2,317	2,374	2,479	2,545	2,562	2,543	2,503	2,442	2,374
Winter	2	2,966	2/6/2015	2,333	2,239	2,237	2,283	2,315	2,381	2,492	2,752	2,966	2,900	2,766	2,658	2,576	2,491	2,430	2,387	2,397	2,492	2,635	2,727	2,733	2,707	2,638	2,573
Winter	2	2,915	2/7/2015	2,494	2,369	2,419	2,438	2,457	2,514	2,564	2,686	2,838	2,915	2,850	2,738	2,622	2,550	2,482	2,462	2,469	2,551	2,682	2,734	2,707	2,667	2,603	2,537
Winter	2	2,859	2/8/2015	2,470	2,411	2,415	2,419	2,426	2,480	2,566	2,660	2,769	2,859	2,836	2,733	2,581	2,500	2,422	2,386	2,415	2,560	2,671	2,755	2,741	2,726	2,650	2,538
Winter	2	3,132	2/9/2015	2,449	2,402	2,406	2,428	2,473	2,521	2,627	2,880	3,132	3,130	3,020	2,937	2,853	2,740	2,681	2,633	2,661	2,779	2,874	2,948	2,952	2,910	2,847	2,701
Winter	2	3,090	2/10/2015	2,590	2,516	2,518	2,537	2,577	2,611	2,710	2,919	3,090	3,075	2,998	2,886	2,797	2,701	2,618	2,569	2,573	2,636	2,694	2,763	2,750	2,756	2,674	2,518
Winter	2	3,044	2/11/2015	2,378	2,355	2,350	2,358	2,391	2,447	2,590	2,791	3,044	2,993	2,844	2,717	2,595	2,495	2,397	2,361	2,422	2,547	2,679	2,799	2,812	2,781	2,692	2,551
Winter	2	2,898	2/12/2015	2,432	2,362	2,352	2,367	2,385	2,417	2,484	2,692	2,898	2,876	2,873	2,718	2,654	2,593	2,628	2,557	2,553	2,643	2,683	2,728	2,702	2,645	2,547	2,462
Winter	2	2,902	2/13/2015	2,331	2,252	2,239	2,256	2,290	2,327	2,425	2,615	2,855	2,902	2,770	2,665	2,559	2,431	2,306	2,279	2,332	2,406	2,541	2,684	2,697	2,648	2,598	2,539
Winter	2	2,952	2/14/2015	2,455	2,424	2,443	2,483	2,532	2,586	2,639	2,779	2,899	2,952	2,931	2,886	2,831	2,732	2,652	2,584	2,577	2,649	2,732	2,789	2,786	2,744	2,677	2,590
Winter	2	2,949	2/15/2015	2,521	2,453	2,420	2,418	2,388	2,390	2,416	2,464	2,565	2,630	2,709	2,771	2,804	2,815	2,816	2,776	2,818	2,895	2,948	2,949	2,917	2,854	2,766	2,647
Winter	2	2,936	2/16/2015	2,556	2,481	2,486	2,483	2,506	2,536	2,620	2,799	2,910	2,936	2,935	2,911	2,900	2,794	2,713	2,673	2,674	2,736	2,789	2,863	2,868	2,798	2,709	2,590
Winter	2	2,937	2/17/2015	2,477	2,430	2,416	2,412	2,417	2,452	2,540	2,744	2,937	2,911	2,783	2,697	2,629	2,519	2,448	2,392	2,407	2,510	2,600	2,709	2,727	2,693	2,634	2,539
Winter	2	3,010	2/18/2015	2,436	2,354	2,365	2,382	2,408	2,456	2,563	2,808	3,010	2,971	2,809	2,615	2,565	2,442	2,388	2,346	2,366	2,437	2,525	2,633	2,656	2,637	2,565	2,443
Winter	2	2,787	2/19/2015	2,345	2,284	2,271	2,277	2,295	2,317	2,400	2,614	2,787	2,759	2,696	2,618	2,550	2,533	2,481	2,462	2,489	2,548	2,518	2,554	2,580	2,518	2,424	2,258
Winter	2	2,626	2/20/2015	2,133	1,987	1,967	1,962	1,961	2,001	2,125	2,308	2,539	2,534	2,449	2,391	2,360	2,325	2,292	2,287	2,321	2,406	2,492	2,591	2,626	2,585	2,516	2,408
Winter	2	2,626	2/21/2015	2,269	2,282	2,199	2,234	2,266	2,314	2,377	2,485	2,600	2,626	2,586	2,520	2,446	2,356	2,273	2,218	2,191	2,278	2,416	2,512	2,498	2,426	2,337	2,208
Winter	2	2,397	2/22/2015	2,120	2,041	1,987	1,962	1,923	1,910	1,940	2,001	2,091	2,189	2,282	2,267	2,232	2,215	2,181	2,150	2,159	2,218	2,278	2,372	2,397	2,358	2,298	2,204
Winter	2	2,671	2/23/2015	2,120	2,067	2,067	2,089	2,096	2,147	2,234	2,467	2,652	2,605	2,504	2,404	2,336	2,288	2,232	2,197	2,214	2,327	2,466	2,612	2,671	2,646	2,641	2,566
Winter	2	3,160	2/24/2015	2,511	2,472	2,509	2,563	2,618	2,669	2,750	2,962	3,160	3,048	2,904	2,823	2,742	2,635	2,572	2,536	2,547	2,624	2,722	2,829	2,852	2,814	2,735	2,591
Winter	2	2,636	2/25/2015	2,489	2,365	2,365	2,348	2,322	2,344	2,340	2,501	2,636	2,627	2,544	2,498	2,519	2,442	2,416	2,368	2,352	2,325	2,330	2,389	2,415	2,364	2,298	2,277
Winter	2	2,711	2/26/2015	2,198	2,064	2,134	2,160	2,194	2,230	2,299	2,529	2,711	2,651	2,547	2,474	2,415	2,394	2,382	2,374	2,431	2,539	2,607	2,686	2,687	2,653	2,588	2,510
Winter	2	2,900	2/27/2015	2,342	2,251	2,243	2,246	2,267	2,329	2,438	2,700	2,900	2,803	2,674	2,590	2,486	2,377	2,308	2,265	2,281	2,348	2,417	2,563	2,592	2,552	2,466	2,447
Winter	2	2,766	2/28/2015	2,384	2,322	2,306	2,321	2,367	2,415	2,495	2,635	2,758	2,766	2,697	2,585	2,462	2,344	2,238	2,139	2,057	2,114	2,205	2,332	2,386	2,350	2,298	2,224
Spring	3	2,553	3/1/2015	2,168	2,123	2,108	2,132	2,190	2,242	2,295	2,395	2,475	2,553	2,534	2,478	2,395	2,340	2,284	2,211	2,193	2,249	2,333	2,412	2,407	2,344	2,260	2,153
Spring	3	2,454	3/2/2015	2,059	1,994	1,948	1,937	1,950	1,967	2,048	2,229	2,387	2,454	2,423	2,395	2,344	2,239	2,205	2,193	2,172	2,272	2,260	2,352	2,372	2,293	2,219	2,117
Spring	3	2,678	3/3/2015	2,120	1,999	2,048	2,094	2,137	2,227	2,334	2,536	2,678	2,609	2,507	2,451	2,394

Contains Proprietary Material
Do Not Distribute

Spring	3	2,495	3/7/2015	2,264	2,176	2,159	2,172	2,195	2,223	2,284	2,380	2,465	2,495	2,429	2,345	2,252	2,159	2,056	1,978	1,960	2,011	2,125	2,271	2,326	2,279	2,213	2,131
Spring	3	2,360	3/8/2015	2,068	2,010		1,995	2,040	2,074	2,085	2,154	2,264	2,360	2,341	2,292	2,226	2,166	2,107	2,065	2,065	2,114	2,180	2,217	2,309	2,354	2,288	2,169
Spring	3	2,701	3/9/2015	2,038	1,938	1,905	1,939	2,015	2,070	2,144	2,401	2,678	2,701	2,586	2,467	2,370	2,258	2,231	2,161	2,195	2,236	2,251	2,239	2,329	2,361	2,312	2,216
Spring	3	2,639	3/10/2015	2,106	2,021	1,993	2,004	2,013	2,062	2,159	2,362	2,634	2,639	2,487	2,335	2,256	2,129	2,042	1,965	1,929	1,971	1,978	2,027	2,111	2,152	2,103	1,954
Spring	3	2,068	3/11/2015	1,815	1,729	1,692	1,668	1,674	1,685	1,738	1,861	2,068	2,060	1,982	1,902	1,827	1,805	1,728	1,642	1,592	1,706	1,702	1,697	1,801	1,880	1,852	1,771
Spring	3	2,375	3/12/2015	1,662	1,605	1,590	1,617	1,633	1,685	1,767	1,989	2,241	2,258	2,183	2,109	2,051	2,015	2,051	2,026	2,029	2,121	2,145	2,177	2,294	2,375	2,325	2,216
Spring	3	2,760	3/13/2015	2,104	2,096	2,090	2,118	2,162	2,213	2,303	2,512	2,755	2,760	2,629	2,508	2,439	2,340	2,270	2,192	2,152	2,151	2,148	2,155	2,274	2,361	2,348	2,276
Spring	3	2,578	3/14/2015	2,168	2,122	2,129	2,155	2,180	2,235	2,300	2,420	2,532	2,578	2,523	2,439	2,343	2,250	2,145	2,072	2,025	2,045	2,081	2,108	2,178	2,192	2,151	2,076
Spring	3	2,435	3/15/2015	1,965	1,832	1,798	1,798	1,805	1,809	1,845	1,953	2,057	2,175	2,303	2,364	2,397	2,391	2,361	2,321	2,329	2,366	2,393	2,372	2,420	2,435	2,354	2,239
Spring	3	2,526	3/16/2015	2,146	2,065	2,037	2,080	2,114	2,149	2,210	2,344	2,500	2,526	2,450	2,391	2,328	2,240	2,171	2,099	2,043	2,051	2,079	2,088	2,179	2,241	2,224	2,137
Spring	3	2,739	3/17/2015	2,040	1,963	1,988	2,020	2,061	2,134	2,229	2,500	2,739	2,710	2,544	2,482	2,423	2,306	2,246	2,194	2,169	2,231	2,252	2,259	2,291	2,323	2,225	2,107
Spring	3	2,445	3/18/2015	2,050	1,920	1,912	1,916	1,942	1,979	2,055	2,234	2,420	2,445	2,426	2,395	2,360	2,284	2,227	2,182	2,203	2,240	2,264	2,294	2,377	2,416	2,320	2,215
Spring	3	2,700	3/19/2015	2,113	2,054	2,080	2,092	2,119	2,159	2,301	2,492	2,700	2,676	2,582	2,488	2,392	2,263	2,189	2,121	2,084	2,100	2,062	2,078	2,187	2,284	2,228	2,129
Spring	3	2,638	3/20/2015	2,032	2,015	1,975	1,992	2,016	2,062	2,147	2,395	2,638	2,570	2,417	2,317	2,237	2,130	2,066	1,994	1,947	1,962	1,946	1,967	2,054	2,131	2,102	2,021
Spring	3	2,246	3/21/2015	1,944	1,888	1,876	1,876	1,895	1,934	1,977	2,070	2,170	2,246	2,245	2,221	2,156	2,075	1,997	1,917	1,877	1,893	1,916	1,933	1,999	2,032	2,003	1,940
Spring	3	2,466	3/22/2015	1,851	1,809	1,786	1,775	1,768	1,774	1,776	1,801	1,870	1,947	2,027	2,068	2,087	2,054	1,993	1,994	2,035	2,128	2,185	2,242	2,361	2,466	2,440	2,336
Spring	3	2,798	3/23/2015	2,257	2,222	2,238	2,259	2,298	2,333	2,412	2,607	2,798	2,795	2,695	2,575	2,456	2,294	2,249	2,175	2,140	2,141	2,127	2,117	2,215	2,317	2,247	2,126
Spring	3	2,611	3/24/2015	2,022	1,969	1,985	2,008	2,030	2,072	2,169	2,391	2,611	2,581	2,446	2,327	2,234	2,098	2,024	1,958	1,938	1,968	1,956	1,955	2,040	2,156	2,117	2,014
Spring	3	2,531	3/25/2015	1,886	1,837	1,884	1,918	1,945	1,992	2,074	2,297	2,531	2,444	2,283	2,160	2,050	1,938	1,868	1,829	1,825	1,854	1,841	1,838	1,913	2,015	1,988	1,887
Spring	3	2,213	3/26/2015	1,820	1,762	1,631	1,620	1,630	1,674	1,772	1,973	2,213	2,201	2,101	2,047	2,013	1,947	1,910	1,867	1,868	1,903	1,920	1,889	1,931	1,970	1,974	1,882
Spring	3	2,212	3/27/2015	1,775	1,697	1,678	1,680	1,686	1,715	1,791	1,986	2,182	2,212	2,180	2,154	2,099	2,006	1,946	1,900	1,871	1,875	1,885	1,875	1,914	1,952	1,924	1,853
Spring	3	2,200	3/28/2015	1,771	1,703	1,687	1,687	1,705	1,739	1,789	1,883	1,997	2,096	2,200	2,194	2,083	2,004	1,928	1,863	1,837	1,853	1,921	1,931	1,977	2,021	1,997	1,937
Spring	3	2,120	3/29/2015	1,864	1,816	1,839	1,791	1,801	1,823	1,867	1,942	2,046	2,120	2,101	2,036	1,979	1,914	1,859	1,800	1,766	1,794	1,811	1,811	1,880	1,986	1,956	1,876
Spring	3	2,368	3/30/2015	1,778	1,703	1,694	1,733	1,769	1,830	1,937	2,164	2,368	2,351	2,256	2,166	2,130	2,063	2,015	1,975	1,965	2,021	2,009	2,019	2,070	2,105	2,006	1,879
Spring	3	2,188	3/31/2015	1,757	1,676	1,662	1,665	1,668	1,702	1,794	2,003	2,188	2,187	2,122	2,083	2,006	1,948	1,916	1,880	1,885	1,934	1,931	1,910	1,950	2,023	1,976	1,868
Spring	4	2,343	4/1/2015	1,752	1,679	1,659	1,669	1,687	1,726	1,819	2,078	2,343	2,286	2,182	2,114	2,047	1,981	1,936	1,889	1,878	1,905	1,873	1,879	1,962	2,077	2,050	1,949
Spring	4	2,433	4/2/2015	1,849	1,775	1,792	1,821	1,848	1,879	1,989	2,237	2,433	2,371	2,248	2,117	2,048	1,954	1,903	1,845	1,848	1,854	1,856	1,876	1,936	2,002	1,963	1,874
Spring	4	1,960	4/3/2015	1,761	1,684	1,646	1,593	1,611	1,623	1,667	1,756	1,841	1,929	1,960	1,957	1,949	1,898	1,828	1,776	1,717	1,706	1,658	1,627	1,652	1,740	1,740	1,693
Spring	4	2,062	4/4/2015	1,630	1,583	1,556	1,550	1,536	1,543	1,592	1,690	1,807	1,926	1,971	1,990	1,984	1,936	1,916	1,901	1,917	1,981	2,037	2,048	2,023	2,062	2,044	1,979
Spring	4	2,122	4/5/2015	1,899	1,868	1,866	1,845	1,865	1,897	1,944	2,021	2,109	2,122	2,108	2,044	2,062	2,026	1,970	1,937	1,924	1,909	1,867	1,870	1,909	2,043	2,063	1,994
Spring	4	2,523	4/6/2015	1,920	1,882	1,906	1,914	1,985	2,084	2,213	2,398	2,523	2,493	2,414	2,338	2,250	2,167	2,090	2,009	1,972	2,009	2,058	2,073	2,099	2,176	2,150	2,044
Spring	4	2,440	4/7/2015	1,946	1,861	1,845	1,843	1,844	1,902	2,005	2,231	2,440	2,428	2,329	2,228	2,132	2,009	1,963	1,932	1,922	1,951	1,939	1,915	1,948	2,042	2,028	1,949
Spring	4	2,397	4/8/2015	1,829	1,778	1,790	1,810	1,850	1,899	1,985	2,221	2,397	2,323	2,210	2,134	2,093	2,019	1,960	1,902	1,886	1,916	1,933	1,918	1,987	2,059	2,038	1,959
Spring	4	2,402	4/9/2015	1,854	1,796	1,783	1,776	1,797	1,850	1,941	2,171	2,402	2,368	2,239	2,119	2,047	1,965	1,913	1,862	1,846	1,868	1,855	1,844	1,887	2,010	1,980	1,900
Spring	4	2,308	4/10/2015	1,812	1,768	1,749	1,744	1,748	1,784	1,865	2,053	2,262	2,308	2,267	2,220	2,189	2,128	2,097	2,050	2,052	2,090	2,041	2,007	1,978	1,987	1,911	1,795
Spring	4	1,802	4/11/2015	1,678	1,579	1,540	1,505	1,510	1,506	1,539	1,618	1,710	1,762	1,794	1,790	1,778	1,759	1,680	1,643	1,627	1,673	1,706	1,691	1,731	1,802	1,776	1,698
Spring	4	1,817	4/12/2015	1,623	1,573	1,551	1,536	1,549	1,582	1,617	1,694	1,755	1,778	1,816	1,781	1,766	1,760	1,712	1,668	1,650	1,693	1,702	1,674	1,713	1,815	1,817	1,721
Spring	4	2,225	4/13/2015	1,634	1,546	1,532	1,560	1,607	1,673	1,784	2,020	2,225	2,170	2,036	1,938	1,855	1,775	1,721	1,669	1,654	1,676	1,648	1,594	1,590	1,644	1,601	1,475
Spring	4	1,865	4/14/2015	1,392	1,366	1,388	1,406	1,426	1,457	1,506	1,660	1,845	1,865	1,842	1,816	1,808	1,740	1,699	1,631	1,625	1,678	1,657	1,623	1,603	1,675	1,658	1,588
Spring	4	1,930	4/15/2015	1,489	1,422	1,438	1,445	1,460	1,481	1,542	1,741	1,930	1,825	1,749	1,769	1,756	1,709	1,710	1,678	1,691	1,729	1,746	1,742	1,773	1,883	1,886	1,771
Spring	4	2,130	4/16/2015	1,658	1,596	1,615	1,650	1,672	1,695	1,727	1,917	2,130	2,047	1,938	1,881	1,821	1,767	1,759	1,703	1,694	1,711	1,700	1,688	1,696	1,846	1,840	1,670
Spring	4	1,975	4/17/2015	1,563	1,519	1,545	1,561	1,571	1,601	1,641	1,799	1,971	1,975	1,944	1,892	1,844	1,780	1,760	1,732	1,682	1,626	1,622	1,579	1,583	1,652	1,650	1,552
Spring	4	1,777	4/18/2015	1,481	1,449	1,372	1,392	1,376	1,407	1,470	1,576	1,675	1,736	1,772	1,777	1,762	1,717	1,668	1,628	1,604	1,630	1,647	1,615	1,643	1,747	1,746	1,672
Spring	4	1,947	4/19/2015	1,608	1,569	1,567	1,574	1,591	1,618	1,635	1,694	1,772	1,907	1,947	1,928	1,879	1,816	1,748	1,680	1,632	1,662	1,668	1,660	1,667	1,760	1,767	1,692
Spring	4	2,124	4/20/2015	1,570	1,492	1,477	1,495	1,535	1,605	1,714	1,960	2,124	2,065	1,988	1,937	1,877	1,800	1,761	1,703	1,697	1,778	1,796	1,786	1,797	1,843	1,782	1,609
Spring	4	1,980	4/21/2015	1,481	1,380	1,390	1,390	1,399	1,428	1,509	1,687	1,946	1,980	1,952	1,911	1,907	1,873	1,849	1,849	1,854	1,916	1,915	1,885	1,876	1,881	1,816	1,685
Spring	4	1,904	4/22/2015	1,573	1,497	1,466	1,467	1,446	1,464	1,490	1,669	1,881	1,904	1,882	1,810	1,766	1,689	1,638	1,619	1,619	1,662	1,660	1,655	1,680	1,798	1,775	1,651
Spring	4	2,034	4/23/2015	1,546	1,490	1,479	1,490	1,505	1,540	1,613	1,816	2,027	2,034	2,022	2,003	1,970	1,921	1,908	1,902	1,901	1,944	1,945	1,911	1,891	1,921	1,849	1,750
Spring	4	2,113	4/24/2015	1,616	1,555	1,547	1,553	1,557	1,594	1,677	1,897	2,110	2,113	2,084	2,051	2,016	1,941	1,923	1,886	1,698	1,709	1,677	1,816	1,847	1,863	1,846	1,760
Spring	4	1,947	4/25/2015	1,664	1,607	1,558	1,553	1,571	1,587	1,619	1,693	1,799	1,905	1,915	1,947	1,931	1,878	1,809	1,734	1,695	1,713	1,718	1,706	1,712	1,770	1,783	1,722
Spring	4	1,828	4/26/2015	1,632	1,569	1,509	1,498	1,515	1,562	1,609	1,660	1,727	1,776	1,819	1,828	1,803	1,785	1,753	1,700	1,704	1,744	1,766	1,761	1,759	1,787	1,731	1,637
Spring	4	1,974	4/27/2015	1,526	1,458	1,445	1,456	1,460	1,467	1,544	1,750	1,974	1,974	1,909	1,854	1,801	1,782	1,763	1,706	1,720	1,824	1,924	1,852	1,890	1,974	1,923	1,786
Spring	4	2,023	4/28/2015	1,657	1,578	1,568	1,566	1,565	1,581	1,649	1,816	2,023	2,005	1,924	1,901	1,903	1,857	1,856	1,809	1,831	1,888	1,903	1,884	1,882	1,894	1,859	1,737
Spring	4	2,099	4/29/2015	1,649	1,586	1,579	1,585	1,588	1,606	1,682	1,880	2,092	2,099	2,059	2,010	1,941	1,858	1,831	1,784	1,844	1,823	1,827	1,826	1,816	1,839	1,769	1,653
Spring	4	2,036	4/30/2015	1,545	1,475	1,454	1,446	1,457	1,504	1,593	1,785	1,999	2,036	2,013	1,999	1,977	1,925	1,900	1,858	1,856	1,880	1,885	1,863	1,874	1,924	1,897	1,782
Spring	5	2,101	5/1/2015	1,675	1,607	1,595	1,592	1,602	1,629	1,713	1,888	2,077	2,101	1,980	1,951	1,906	1,849	1,812	1,736	1,697	1,681	1,654	1,625	1,645	1,743	1,787	1,714
Spring	5	1,848	5/2/2015	1,628	1,583	1,561	1,569	1,587	1,617	1,647	1,723	1,798	1,840	1,848	1,813	1,764	1,694	1,623	1,557	1,517	1,524	1,526	1,508	1,485	1,524	1,550	1,455
Spring	5	1,699	5/3/2015	1,368	1,316	1,314	1,318	1,307	1,344	1,395	1,485	1,557	1,644	1,699	1,693	1,653	1,607	1,548	1,494	1,469	1,450	1,454	1,440	1,464	1,530	1,561	1,444
Spring	5	1,844	5/4/2015	1,363	1,294	1,273	1,280	1,293	1,331	1,432	1,641	1,844	1,826	1,759	1,718	1,676	1,633	1,574	1,531	1,490	1,498	1,470	1,426	1,382	1,417	1,402	1,304
Spring	5	1,415	5/5/2015	1,215	1,164	1,178	1,160	1,156	1,167	1,195	1,206	1,282	1,279	1,406	1,407	1,361	1,307	1,279	1,260	1,257	1,295	1,298	1,283	1,295	1,360	1,415	1,310
Spring	5	1,582	5/6/2015	1,209	1,126	1,128	1,139	1,158	1,179	1,228	1,401	1,582	1,554	1,507	1,436	1,471	1,466	1,447	1,429	1,445	1,507	1,506	1,483	1,520	1,551	1,565	1,465
Spring	5	1,629	5/7/2015	1,346	1,241	1,232	1,199	1,211	1,230	1,284	1,434	1,629	1,611	1,556	1,505	1,495	1,468	1,469	1,445	1,443	1,483	1,471	1,435	1,444	1,506	1,540	1,460
Spring	5	1,812	5/8/2015	1,335	1,261	1,246	1,245	1,224	1,279	1,321	1,508	1,757	1,812	1,808	1,796	1,785	1,740	1,707	1,654	1,614	1,618	1,609	1,592	1,588	1,631	1,661	1,592
Spring	5	1,588	5/9/2015	1,489	1,404	1,381	1,370	1,365	1,370	1,396	1,400	1,466	1,556	1,588	1,568	1,541	1,477	1,411	1,356	1,342	1,369	1,378	1,392	1,374	1,389	1,384	1,308
Spring	5	1,563	5/10/2015	1,240	1,179	1,149	1,111	1,133	1,119	1,167	1,242	1,339	1,452	1,527	1,558	1,563	1,538	1,500	1,465	1,419	1,458	1,467	1,458	1,487	1,525	1,548	1,451
Spring	5	1,619	5/11/2015	1,332	1,242	1,178	1,125	1,148	1,130	1,180	1,352	1,552	1,574	1,546	1,569	1,569	1,563	1,543	1,527	1,529	1,581	1,585	1,567	1,573	1,619	1,597	1,452
Spring	5	1,653	5/12/2015	1,316	1,240	1,207	1,208	1,204	1,215	1,276	1,429	1,648	1,653	1,628	1,620	1,606	1,568	1,557	1,532	1,543	1,596	1,616	1,592	1,556	1,573	1,549	1,422
Spring	5	1,641	5/13/2015	1,316	1,240	1,224	1,206	1,218	1,228	1,258	1,389	1,603	1,598	1,630	1,630	1,641	1,601	1,564	1,524	1,558	1,577	1,554	1,518	1,492	1,550	1,609	1,505
Spring	5	1,744	5/14/2015	1,389	1,334	1,327	1,324	1,340	1,367	1,428	1,586	1,744	1,685	1,645	1,645	1,622	1,591	1,549	1,509	1,502	1,527	1,524	1,495	1,489	1,509	1,566	1,492
Spring	5	1,654	5/15/2015	1,311	1,226	1,225	1,243	1,258	1,298	1,338	1,483	1,627	1,654	1,642	1,610	1,597	1,570	1,546	1,512	1,497	1,491	1,495	1,456	1,427	1,433	1,450	1,371
Spring	5	1,494	5/16/2015	1,247	1,171	1,132	1,121	1,141	1,166	1,194	1,240	1,337	1,427	1,486	1,494	1,480	1,457	1,409	1,362	1,358	1,366	1,376	1,369	1,352	1,357	1,331	1,246
Spring	5	1,542	5/17/2015	1,146	1,099	1,067	1,064	1,045	1,046	1,053	1,087	1,189	1,324	1,430	1,505	1,532	1,542	1,523	1,487	1,494	1,515	1,539	1,521	1,523	1,525	1,517	1,445
Spring	5	1,618	5/18/2015	1,334	1,246	1,240	1,226	1,232	1,255	1,298	1,375	1,463	1,544	1,590	1,618	1,611	1,571	1,516	1,467	1,449	1,474	1,479	1,461	1,457	1,481	1,492	1,356
Spring	5	1,627	5/19/2015	1,192	1,107	1,031	1,024	1,020	1,052	1,095	1,296	1,525	1,566	1,622	1,577	1,583	1,548	1,554	1,540	1,550	1,599	1,627	1,596	1,590	1,609	1,569	1,413
Spring	5	1,546	5/20/2015	1,271	1,154	1,125	1,122	1,147	1,151	1,208	1,378	1,539	1,546	1,501	1,464	1,434	1,401	1,410	1,370	1,370	1,397	1,411	1,402	1,411	1,430	1,463	1,372
Spring	5	1,545	5/21/2015	1,290	1,237	1,219	1,209	1,225	1,234	1,266	1,397	1,545	1,526	1,480	1,454	1,441	1,387	1,401	1,417	1,427	1,473	1,473	1,436	1,415	1,425	1,457	1,370
Spring	5	1,635	5/22/2015	1,226	1,126	1,117	1,114	1,133	1,162	1,214	1,380	1,595	1,635	1,632	1,604	1,599	1,552	1,553	1,455	1,454	1,471	1,515	1,485	1,474	1,491	1,517	1,456
Spring	5	1,629	5/23/2015	1,350	1,267	1,157	1,183	1,216	1,202	1,216	1,289	1,394	1,515	1,604	1,629	1,594	1,570	1,512	1,447	1,447	1,472	1,459	1,382	1,370	1,365	1,462	1,403
Spring	5	1,514	5/24/2015	1,345	1,244	1,242	1,258	1,276	1,280	1,286	1,306	1,381	1,468	1,514	1,480	1,449	1,405	1,344	1,308	1,302	1,337	1,337	1,383	1,408	1,408	1,435	1,376
Spring	5	1,515	5/25/2015	1,237	1,157	1,150	1,142	1,133	1,144	1,200	1,352	1,503	1,515	1,506	1,501	1,470	1,452	1,438	1,419	1,398	1,419	1,439	1,452	1,419	1,403	1,410	1,305
Spring	5	1,450	5/26/2015	1,192	1,056	1,023	1,015	1,010	1,024	1,069	1,221	1,401	1,442	1,447	1,450	1,441	1,395	1,387	1,380	1,404	1,424	1,431	1,442	1,410	1,387	1,385	1,313
Spring	5	1,553	5/27/2015	1,187	1,102	1,060	1,056	1,051	1,058	1,086	1,199	1,398	1,462	1,507	1,549	1,553	1,528	1,512	1,490	1,480	1,501	1,486	1,454	1,433	1,431	1,415	1,312
Spring	5	1,561	5/28/2015	1,206	1,136	1,100	1,067	1,055	1,058	1,044	1,179	1,373	1,448	1,445	1,482	1,527	1,502	1,516	1,483	1,443	1,457	1,488	1,487	1,494	1,530	1,561	1,486
Spring	5	1,590	5/29/2015	1,350	1,218	1,189	1,176	1,177	1,179	1,206	1,350	1,531	1,572	1,589	1,581	1,563	1,548	1,571	1,579	1,579	1,590	1,559	1,541	1,502	1,485	1,480	1,371
Spring	5	1,475	5/30/2015	1,268	1,156	1,142	1,110	1,110	1,112	1,136	1,163	1,271	1,396	1,437	1,458	1,475	1,470	1,442	1,396	1,384	1,398	1,407	1,399	1,392	1,377	1,415	1,382
Spring	5	1,564	5/31/2015	1,303	1,241	1,190	1,144	1,132	1,137	1,138	1,129	1,174	1,256	1,331	1,359	1,329	1,357	1,397	1,454	1,470	1,528	1,564	1,553	1,553	1,554	1,562	1,471
Summer	6	1,715	6/1/2015	1,341	1,253	1,217	1,201	1,204	1,211	1,272	1,446	1,671	1,699	1,709	1,712	1,715	1,692	1,677	1,639	1,618	1,635	1,626	1,595	1,583	1,595	1,596	1,509
Summer	6	1,825	6/2/2015	1,400	1,321	1,284	1,279	1,273	1,290	1,353	1,517	1,717	1,754	1,753	1,758	1,729	1,728	1,725	1,706	1,734	1,800	1,817	1,825	1,815	1,814	1,777	1,637
Summer	6	1,799	6/3/2015	1,503	1,389	1,373	1,347	1,347	1,349	1,394	1,588	1,790	1,799	1,759	1,722	1,702	1,634	1,587	1,570	1,587	1,627	1,628	1,660	1,679	1,684	1,674	1,571
Summer	6	1,766	6/4/2015	1,436	1,351	1,344	1,347	1,322	1,373	1,427	1,607	1,766	1,734	1,681	1,657	1,657	1,618	1,599	1,571	1,559	1,585	1,563	1,534	1,514	1,516	1,535	1,432
Summer	6	1,634	6/5/2015	1,328	1,220	1,171	1,170	1,168	1,203	1,234	1,402	1,603	1,634	1,624	1,590	1,548	1,501	1,493	1,463	1,441	1,439	1,425	1,334	1,301	1,286	1,329	1,276
Summer	6	1,524	6/6/2015	1,217	1,182	1,118	1,075	1,081	1,094	1,087	1,157	1,278	1,406	1,495	1,515	1,524	1,523	1,474	1,420	1,398	1,412	1,415	1,396	1,370	1,378	1,399	1,379
Summer	6	1,462	6/7/2015	1,307	1,236	1,186	1,149	1,124	1,135	1,121	1,173	1,215	1,268	1,354	1,385	1,421	1,412	1,376	1,351	1,362	1,405	1,443	1,423	1,425	1,436	1,462	1,366
Summer	6	1,578	6/8/2015	1,250	1,178	1,152	1,134	1,157	1,187	1,228	1,382	1,524	1,567

Contains Proprietary Material
Do Not Distribute

Summer	6	1,524	6/20/2015	1,310	1,216	1,186	1,167	1,176	1,173	1,178	1,206	1,266	1,371	1,457	1,510	1,524	1,502	1,464	1,429	1,416	1,432	1,429	1,407	1,381	1,355	1,361	1,309
Summer	6	1,528	6/21/2015	1,207	1,122	1,084	1,067	1,071	1,084	1,088	1,121	1,203	1,316	1,423	1,483	1,511	1,516	1,504	1,491	1,480	1,528	1,522	1,503	1,492	1,520	1,503	1,384
Summer	6	1,626	6/22/2015	1,267	1,184	1,160	1,137	1,127	1,132	1,112	1,241	1,424	1,481	1,520	1,589	1,626	1,569	1,541	1,524	1,523	1,541	1,555	1,535	1,502	1,495	1,498	1,416
Summer	6	1,598	6/23/2015	1,279	1,179	1,179	1,188	1,188	1,197	1,234	1,378	1,529	1,527	1,538	1,555	1,573	1,582	1,588	1,574	1,555	1,592	1,598	1,588	1,547	1,515	1,493	1,355
Summer	6	1,514	6/24/2015	1,235	1,161	1,149	1,118	1,106	1,109	1,106	1,226	1,367	1,444	1,484	1,494	1,478	1,491	1,514	1,500	1,492	1,503	1,478	1,467	1,455	1,453	1,494	1,432
Summer	6	1,513	6/25/2015	1,283	1,192	1,199	1,151	1,102	1,118	1,129	1,273	1,419	1,480	1,474	1,513	1,503	1,503	1,482	1,472	1,456	1,497	1,512	1,493	1,447	1,472	1,474	1,423
Summer	6	1,537	6/26/2015	1,291	1,211	1,169	1,148	1,145	1,170	1,196	1,304	1,456	1,517	1,530	1,532	1,537	1,521	1,508	1,476	1,484	1,487	1,476	1,442	1,407	1,416	1,429	1,391
Summer	6	1,484	6/27/2015	1,292	1,213	1,151	1,137	1,124	1,125	1,129	1,173	1,258	1,364	1,445	1,477	1,484	1,472	1,441	1,412	1,404	1,417	1,427	1,401	1,376	1,347	1,326	1,292
Summer	6	1,450	6/28/2015	1,196	1,105	1,120	1,052	1,051	1,019	1,024	1,060	1,155	1,257	1,353	1,415	1,430	1,450	1,438	1,407	1,401	1,441	1,429	1,394	1,384	1,408	1,411	1,285
Summer	6	1,570	6/29/2015	1,191	1,122	1,081	1,045	1,044	1,007	1,019	1,155	1,267	1,439	1,490	1,540	1,557	1,546	1,558	1,537	1,535	1,570	1,547	1,510	1,481	1,452	1,439	1,365
Summer	6	1,568	6/30/2015	1,256	1,137	1,121	1,094	1,082	1,081	1,101	1,214	1,412	1,502	1,526	1,548	1,558	1,533	1,529	1,530	1,531	1,568	1,558	1,516	1,480	1,468	1,469	1,406
Summer	7	1,530	7/1/2015	1,281	1,188	1,138	1,105	1,094	1,102	1,099	1,139	1,262	1,373	1,460	1,517	1,530	1,506	1,466	1,429	1,421	1,443	1,437	1,402	1,386	1,382	1,362	1,268
Summer	7	1,526	7/2/2015	1,180	1,104	1,084	1,057	1,051	1,048	1,074	1,171	1,334	1,409	1,437	1,481	1,518	1,501	1,526	1,495	1,478	1,476	1,457	1,444	1,395	1,404	1,416	1,385
Summer	7	1,514	7/3/2015	1,261	1,154	1,085	1,062	1,042	1,058	1,063	1,153	1,303	1,434	1,463	1,503	1,491	1,506	1,514	1,513	1,474	1,471	1,458	1,429	1,396	1,409	1,399	1,349
Summer	7	1,501	7/4/2015	1,269	1,178	1,122	1,080	1,067	1,024	1,013	1,063	1,170	1,292	1,415	1,462	1,486	1,501	1,483	1,461	1,458	1,470	1,455	1,441	1,421	1,380	1,373	1,319
Summer	7	1,518	7/5/2015	1,222	1,138	1,074	1,061	1,057	1,072	1,070	1,075	1,195	1,329	1,430	1,452	1,495	1,505	1,482	1,475	1,465	1,498	1,518	1,484	1,466	1,465	1,471	1,391
Summer	7	1,656	7/6/2015	1,276	1,191	1,157	1,116	1,095	1,091	1,143	1,287	1,452	1,560	1,590	1,617	1,624	1,614	1,614	1,602	1,618	1,656	1,647	1,608	1,565	1,548	1,548	1,463
Summer	7	1,600	7/7/2015	1,301	1,207	1,153	1,118	1,093	1,109	1,133	1,229	1,326	1,398	1,441	1,494	1,525	1,556	1,600	1,584	1,569	1,565	1,544	1,476	1,414	1,395	1,373	1,303
Summer	7	1,556	7/8/2015	1,174	1,074	1,039	1,022	1,008	1,020	1,051	1,123	1,262	1,343	1,370	1,407	1,473	1,523	1,519	1,484	1,488	1,512	1,556	1,531	1,493	1,473	1,426	1,365
Summer	7	1,632	7/9/2015	1,228	1,158	1,097	1,083	1,098	1,104	1,139	1,259	1,439	1,553	1,592	1,615	1,617	1,625	1,626	1,604	1,596	1,632	1,617	1,577	1,530	1,530	1,560	1,503
Summer	7	1,684	7/10/2015	1,328	1,221	1,183	1,160	1,134	1,133	1,172	1,294	1,462	1,571	1,619	1,669	1,675	1,665	1,684	1,674	1,654	1,666	1,644	1,621	1,545	1,496	1,494	1,426
Summer	7	1,573	7/11/2015	1,326	1,269	1,212	1,191	1,171	1,173	1,179	1,209	1,316	1,428	1,521	1,562	1,573	1,563	1,542	1,536	1,525	1,542	1,545	1,527	1,501	1,464	1,443	1,381
Summer	7	1,566	7/12/2015	1,259	1,178	1,098	1,071	1,041	1,032	1,075	1,043	1,130	1,269	1,389	1,480	1,526	1,550	1,535	1,497	1,513	1,547	1,554	1,540	1,548	1,550	1,566	1,503
Summer	7	1,719	7/13/2015	1,348	1,231	1,156	1,144	1,118	1,125	1,151	1,307	1,459	1,563	1,650	1,698	1,719	1,718	1,688	1,655	1,650	1,671	1,661	1,607	1,556	1,574	1,574	1,485
Summer	7	1,641	7/14/2015	1,306	1,187	1,106	1,093	1,063	1,074	1,100	1,215	1,384	1,509	1,571	1,609	1,641	1,609	1,630	1,608	1,596	1,620	1,613	1,582	1,539	1,490	1,487	1,384
Summer	7	1,680	7/15/2015	1,223	1,123	1,094	1,101	1,099	1,091	1,143	1,261	1,442	1,540	1,609	1,628	1,680	1,655	1,644	1,636	1,612	1,613	1,594	1,589	1,570	1,524	1,489	1,445
Summer	7	1,587	7/16/2015	1,307	1,163	1,132	1,048	1,044	1,058	1,118	1,218	1,387	1,468	1,493	1,519	1,532	1,499	1,503	1,502	1,515	1,574	1,587	1,556	1,544	1,517	1,519	1,438
Summer	7	1,642	7/17/2015	1,272	1,103	1,069	1,058	1,091	1,103	1,137	1,259	1,417	1,526	1,590	1,612	1,642	1,636	1,618	1,566	1,551	1,561	1,565	1,516	1,463	1,429	1,449	1,399
Summer	7	1,494	7/18/2015	1,279	1,164	1,087	1,071	1,048	1,040	1,042	1,079	1,165	1,273	1,400	1,461	1,492	1,494	1,464	1,440	1,438	1,473	1,479	1,460	1,450	1,439	1,426	1,353
Summer	7	1,500	7/19/2015	1,229	1,142	1,093	1,091	1,088	1,076	1,082	1,085	1,154	1,230	1,156	1,156	1,156	1,356	1,500	1,442	1,417	1,442	1,463	1,445	1,437	1,448	1,445	1,371
Summer	7	1,640	7/20/2015	1,243	1,151	1,123	1,093	1,110	1,123	1,149	1,248	1,435	1,522	1,592	1,631	1,640	1,633	1,617	1,579	1,578	1,611	1,582	1,546	1,527	1,499	1,529	1,405
Summer	7	1,592	7/21/2015	1,276	1,175	1,231	1,195	1,203	1,206	1,233	1,292	1,411	1,480	1,527	1,569	1,592	1,578	1,568	1,541	1,530	1,542	1,508	1,485	1,478	1,458	1,442	1,383
Summer	7	1,604	7/22/2015	1,222	1,111	1,066	1,044	1,028	1,048	1,061	1,159	1,325	1,476	1,505	1,567	1,573	1,586	1,567	1,517	1,477	1,564	1,604	1,550	1,504	1,505	1,483	1,420
Summer	7	1,566	7/23/2015	1,301	1,199	1,151	1,154	1,124	1,126	1,172	1,277	1,423	1,495	1,530	1,557	1,552	1,537	1,520	1,492	1,538	1,566	1,549	1,523	1,500	1,477	1,510	1,424
Summer	7	1,552	7/24/2015	1,295	1,186	1,147	1,116	1,105	1,119	1,129	1,252	1,381	1,458	1,531	1,552	1,550	1,507	1,500	1,474	1,456	1,462	1,451	1,407	1,379	1,370	1,396	1,343
Summer	7	1,466	7/25/2015	1,245	1,174	1,130	1,115	1,109	1,107	1,130	1,140	1,220	1,328	1,401	1,451	1,466	1,450	1,413	1,399	1,384	1,415	1,417	1,412	1,377	1,334	1,399	1,319
Summer	7	1,415	7/26/2015	1,220	1,143	1,114	1,078	1,071	1,065	1,082	1,056	1,151	1,258	1,315	1,385	1,411	1,415	1,385	1,354	1,338	1,370	1,387	1,367	1,370	1,359	1,368	1,271
Summer	7	1,591	7/27/2015	1,120	1,041	1,016	1,006	1,006	1,036	1,078	1,174	1,330	1,413	1,482	1,509	1,497	1,496	1,524	1,550	1,533	1,586	1,591	1,535	1,492	1,501	1,511	1,408
Summer	7	1,567	7/28/2015	1,267	1,166	1,135	1,105	1,097	1,088	1,123	1,186	1,316	1,414	1,460	1,536	1,567	1,538	1,519	1,498	1,488	1,514	1,508	1,476	1,483	1,488	1,491	1,418
Summer	7	1,644	7/29/2015	1,289	1,148	1,112	1,079	1,057	1,081	1,138	1,246	1,396	1,526	1,575	1,588	1,593	1,588	1,624	1,623	1,618	1,644	1,628	1,586	1,545	1,522	1,560	1,485
Summer	7	1,644	7/30/2015	1,338	1,211	1,174	1,157	1,131	1,134	1,157	1,251	1,448	1,527	1,597	1,630	1,644	1,629	1,610	1,606	1,613	1,634	1,616	1,582	1,538	1,527	1,540	1,448
Summer	7	1,599	7/31/2015	1,286	1,173	1,093	1,075	1,054	1,055	1,087	1,183	1,337	1,409	1,470	1,540	1,549	1,557	1,585	1,572	1,582	1,599	1,588	1,562	1,491	1,461	1,434	1,358
Summer	8	1,576	8/1/2015	1,255	1,173	1,100	1,090	1,091	1,085	1,093	1,135	1,243	1,395	1,496	1,551	1,574	1,576	1,551	1,514	1,484	1,484	1,494	1,458	1,393	1,376	1,381	1,373
Summer	8	1,510	8/2/2015	1,265	1,201	1,152	1,114	1,096	1,076	1,087	1,097	1,168	1,277	1,427	1,484	1,510	1,499	1,429	1,400	1,390	1,429	1,457	1,443	1,410	1,371	1,398	1,318
Summer	8	1,563	8/3/2015	1,247	1,108	1,072	1,084	1,079	1,079	1,097	1,141	1,215	1,321	1,442	1,504	1,563	1,542	1,520	1,494	1,482	1,515	1,544	1,506	1,454	1,461	1,466	1,387
Summer	8	1,643	8/4/2015	1,268	1,153	1,116	1,087	1,072	1,066	1,089	1,198	1,375	1,459	1,518	1,566	1,626	1,615	1,606	1,617	1,605	1,643	1,622	1,549	1,508	1,469	1,481	1,323
Summer	8	1,634	8/5/2015	1,182	1,106	1,131	1,077	1,067	1,086	1,140	1,257	1,441	1,530	1,577	1,573	1,626	1,634	1,616	1,604	1,561	1,580	1,603	1,552	1,515	1,485	1,493	1,401
Summer	8	1,621	8/6/2015	1,268	1,196	1,135	1,117	1,117	1,140	1,181	1,254	1,418	1,525	1,608	1,609	1,621	1,574	1,582	1,556	1,526	1,541	1,537	1,500	1,481	1,487	1,513	1,391
Summer	8	1,609	8/7/2015	1,236	1,155	1,114	1,086	1,081	1,087	1,130	1,231	1,398	1,498	1,571	1,602	1,609	1,582	1,573	1,563	1,555	1,578	1,567	1,529	1,484	1,451	1,460	1,386
Summer	8	1,531	8/8/2015	1,287	1,201	1,149	1,119	1,158	1,158	1,155	1,154	1,230	1,353	1,445	1,503	1,531	1,509	1,486	1,470	1,439	1,460	1,461	1,437	1,414	1,411	1,405	1,349
Summer	8	1,511	8/9/2015	1,266	1,183	1,118	1,099	1,104	1,104	1,108	1,110	1,164	1,280	1,388	1,451	1,495	1,511	1,479	1,387	1,350	1,380	1,415	1,436	1,459	1,483	1,503	1,410
Summer	8	1,636	8/10/2015	1,283	1,187	1,120	1,098	1,069	1,080	1,134	1,250	1,400	1,467	1,520	1,558	1,569	1,556	1,565	1,581	1,593	1,632	1,636	1,601	1,564	1,559	1,581	1,477
Summer	8	1,622	8/11/2015	1,343	1,230	1,147	1,122	1,121	1,134	1,158	1,276	1,437	1,509	1,570	1,611	1,563	1,593	1,622	1,601	1,620	1,612	1,580	1,564	1,510	1,528	1,512	1,408
Summer	8	1,505	8/12/2015	1,243	1,166	1,157	1,138	1,143	1,125	1,134	1,221	1,347	1,408	1,453	1,477	1,472	1,445	1,461	1,428	1,440	1,490	1,505	1,470	1,470	1,484	1,478	1,363
Summer	8	1,683	8/13/2015	1,235	1,131	1,087	1,077	1,077	1,071	1,132	1,239	1,380	1,504	1,551	1,580	1,610	1,591	1,612	1,573	1,600	1,672	1,683	1,644	1,596	1,594	1,622	1,489
Summer	8	1,699	8/14/2015	1,370	1,261	1,213	1,185	1,181	1,186	1,219	1,310	1,452	1,557	1,627	1,670	1,699	1,680	1,664	1,610	1,603	1,607	1,599	1,560	1,518	1,504	1,520	1,414
Summer	8	1,602	8/15/2015	1,285	1,179	1,137	1,117	1,091	1,080	1,098	1,140	1,246	1,352	1,471	1,531	1,575	1,584	1,576	1,559	1,557	1,588	1,602	1,576	1,545	1,525	1,536	1,447
Summer	8	1,592	8/16/2015	1,345	1,260	1,200	1,157	1,129	1,119	1,143	1,163	1,221	1,351	1,462	1,539	1,585	1,592	1,566	1,535	1,513	1,553	1,578	1,574	1,548	1,561	1,571	1,419
Summer	8	1,766	8/17/2015	1,294	1,189	1,135	1,135	1,130	1,139	1,182	1,304	1,481	1,600	1,697	1,736	1,766	1,757	1,755	1,749	1,755	1,761	1,733	1,694	1,667	1,669	1,669	1,517
Summer	8	1,825	8/18/2015	1,382	1,259	1,213	1,186	1,172	1,189	1,225	1,340	1,513	1,625	1,698	1,776	1,819	1,816	1,825	1,811	1,809	1,811	1,800	1,750	1,728	1,746	1,743	1,590
Summer	8	1,803	8/19/2015	1,457	1,320	1,293	1,243	1,219	1,238	1,272	1,387	1,556	1,652	1,704	1,741	1,786	1,778	1,777	1,769	1,771	1,803	1,789	1,736	1,696	1,697	1,702	1,542
Summer	8	1,765	8/20/2015	1,385	1,269	1,246	1,217	1,197	1,214	1,240	1,355	1,536	1,632	1,684	1,735	1,765	1,734	1,738	1,738	1,739	1,756	1,709	1,668	1,640	1,627	1,620	1,490
Summer	8	1,715	8/21/2015	1,352	1,252	1,229	1,200	1,211	1,188	1,207	1,319	1,486	1,603	1,662	1,676	1,706	1,715	1,676	1,672	1,657	1,657	1,614	1,569	1,567	1,533	1,527	1,430
Summer	8	1,634	8/22/2015	1,310	1,237	1,204	1,176	1,165	1,163	1,189	1,219	1,304	1,429	1,536	1,611	1,634	1,620	1,600	1,595	1,594	1,606	1,616	1,589	1,542	1,576	1,563	1,479
Summer	8	1,618	8/23/2015	1,382	1,302	1,230	1,207	1,199	1,203	1,211	1,222	1,274	1,400	1,506	1,566	1,606	1,618	1,606	1,536	1,536	1,588	1,600	1,591	1,583	1,609	1,605	1,482
Summer	8	1,763	8/24/2015	1,359	1,234	1,201	1,183	1,177	1,188	1,236	1,347	1,522	1,621	1,687	1,738	1,754	1,730	1,729	1,721	1,728	1,763	1,745	1,700	1,640	1,666	1,611	1,468
Summer	8	1,724	8/25/2015	1,340	1,255	1,264	1,245	1,240	1,233	1,264	1,374	1,518	1,610	1,625	1,663	1,690	1,686	1,695	1,685	1,699	1,724	1,706	1,672	1,665	1,668	1,633	1,523
Summer	8	1,660	8/26/2015	1,363	1,253	1,217	1,198	1,191	1,200	1,220	1,305	1,446	1,516	1,553	1,604	1,653	1,625	1,578	1,554	1,588	1,619	1,660	1,654	1,628	1,627	1,574	1,429
Summer	8	1,644	8/27/2015	1,299	1,196	1,165	1,138	1,136	1,145	1,185	1,304	1,469	1,575	1,611	1,626	1,597	1,601	1,586	1,591	1,607	1,644	1,624	1,581	1,553	1,601	1,576	1,466
Summer	8	1,645	8/28/2015	1,358	1,269	1,226	1,202	1,181	1,157	1,218	1,340	1,465	1,529	1,578	1,629	1,645	1,628	1,616	1,600	1,605	1,614	1,603	1,579	1,542	1,565	1,548	1,465
Summer	8	1,558	8/29/2015	1,352	1,240	1,208	1,179	1,155	1,146	1,160	1,218	1,284	1,394	1,490	1,547	1,558	1,542	1,526	1,504	1,467	1,483	1,468	1,441	1,414	1,464	1,448	1,372
Summer	8	1,589	8/30/2015	1,270	1,237	1,169	1,146	1,130	1,136	1,158	1,157	1,217	1,322	1,424	1,487	1,527	1,536	1,515	1,496	1,496	1,538	1,547	1,545	1,532	1,589	1,571	1,443
Summer	8	1,596	8/31/2015	1,307	1,218	1,179	1,127	1,125	1,131	1,177	1,274	1,422	1,487	1,533	1,580	1,596	1,580	1,538	1,521	1,531	1,550	1,529	1,478	1,459	1,492	1,461	1,327
Fall	9	1,559	9/1/2015	1,210	1,142	1,143	1,100	1,060	1,061	1,087	1,198	1,351	1,435	1,465	1,495	1,466	1,450	1,456	1,438	1,437	1,505	1,517	1,499	1,494	1,559	1,515	1,397
Fall	9	1,650	9/2/2015	1,263	1,176	1,158	1,138	1,140	1,137	1,160	1,293	1,420	1,468	1,504	1,547	1,574	1,587	1,611	1,616	1,627	1,650	1,619	1,600	1,593	1,623	1,567	1,452
Fall	9	1,589	9/3/2015	1,295	1,215	1,185	1,144	1,148	1,145	1,170	1,288	1,451	1,532	1,571	1,589	1,588	1,546	1,551	1,536	1,537	1,562	1,547	1,506	1,478	1,489	1,445	1,343
Fall	9	1,571	9/4/2015	1,256	1,154	1,131	1,126	1,102	1,120	1,164	1,285	1,418	1,484	1,517	1,569	1,571	1,543	1,534	1,533	1,519	1,534	1,513	1,483	1,448	1,479	1,464	1,382
Fall	9	1,463	9/5/2015	1,287	1,240	1,183	1,161	1,142	1,129	1,120	1,162	1,247	1,308	1,388	1,463	1,463	1,439	1,406	1,389	1,376	1,401	1,403	1,383	1,360	1,354	1,303	1,226
Fall	9	1,518	9/6/2015	1,178	1,124	1,052	1,049	1,038	1,055	1,096	1,131	1,206	1,311	1,396	1,456	1,507	1,514	1,494	1,473	1,472	1,499	1,518	1,496	1,477	1,508	1,426	1,309
Fall	9	1,548	9/7/2015	1,206	1,119	1,075	1,053	1,035	1,041	1,058	1,054	1,118	1,204	1,292	1,383	1,443	1,462	1,448	1,457	1,472	1,520	1,524	1,503	1,524	1,548	1,469	1,375
Fall	9	1,606	9/8/2015	1,241	1,155	1,146	1,128	1,104	1,177	1,191	1,353	1,502	1,470	1,486	1,560	1,605	1,574	1,588	1,567	1,579	1,605	1,595	1,571	1,570	1,606	1,530	1,391
Fall	9	1,524	9/9/2015	1,285	1,214	1,192	1,162	1,144	1,149	1,199	1,353	1,494	1,501	1,521	1,524	1,491	1,451	1,451	1,450	1,477	1,501	1,470	1,448	1,487	1,509	1,435	1,325
Fall	9	1,571	9/10/2015	1,214	1,166	1,135	1,131	1,111	1,098	1,133	1,295	1,465	1,537	1,571	1,566	1,555	1,541	1,513	1,439	1,452	1,493	1,476	1,443	1,444	1,493	1,425	1,283
Fall	9	1,557	9/11/2015	1,147	1,084	1,058	1,047	1,027	1,043	1,089	1,288	1,465	1,495	1,494	1,546	1,557	1,547	1,542	1,514	1,462	1,453	1,463	1,446	1,384	1,373	1,344	1,286
Fall	9	1,394	9/12/2015	1,198	1,136	1,072	1,018	994	1,002	1,029	1,056	1,119	1,217	1,303	1,376	1,394	1,370	1,334	1,312	1,300	1,351	1,372	1,348	1,344	1,382	1,345	1,312
Fall	9	1,531	9/13/2015	1,205	1,161	1,096	1,063	1,059	1,054	1,067	1,102	1,169	1,283	1,381	1,452	1,488	1,499	1,463	1,432	1,428	1,466	1,481	1,472	1,492	1,531	1,473	1,340
Fall	9	1,566	9/14/2015	1,218	1,144	1,091	1,070	1,069	1,077	1,095	1,228	1,447	1,444	1,487	1,499	1,516	1,527	1,506	1,492	1,527	1,566	1,542	1,506	1,486	1,515	1,437	1,287
Fall	9	1,569	9/15/2015	1,164	1,107	1,058	1,064	1,067	1,076	1,120	1,286	1,482	1,500	1,489	1,447	1,455	1,450	1,475	1,463	1,473	1,541	1,528	1,502	1,522	1,569	1,512	1,356
Fall	9	1,587	9/16/2015	1,227	1,140	1,113	1,101	1,089	1,081	1,121	1,273	1,445	1,457	1,463	1,490	1,520	1,500	1,514	1,514	1,529	1,587	1,567	1,533	1,549	1,577	1,509	1,406
Fall	9	1,588	9/17/2015	1,274	1,183	1,149	1,120	1,136	1,110	1,168	1,301	1,473	1,462	1,488	1,522	1,536	1,535	1,559	1,555	1,529	1,569	1,581	1,537	1,550	1,588	1,509	1,384
Fall	9	1,654	9/18/2015	1,257	1,163	1,135	1,115	1,105	1,117	1,154	1,300	1,490	1,516	1,559	1,591	1,618	1,613	1,629	1,634	1,638	1,654	1,607	1,551	1,545	1,516	1,454	1,364
Fall	9	1,510	9/19/2015	1,264	1,137	1,119	1,083	1,068	1,029	1,034	1,073	1,181	1,309	1,413	1,467	1,497	1,510	1,495	1,436	1,406	1,422	1,426	1,388	1,404	1,383	1,320	1,253
Fall	9	1,395	9/20/2015	1,151	1,061	1,105	1,067	1,032	1,010	1,020	1,068	1,077	1,184	1,278	1,365	1,395	1,383	1,344	1,313	1,316	1,367	1,380	1,383	1,321	1,335	1,285	1,203
Fall	9	1,541	9/21/2015	1,117	1,032	1,021	1,016	1,023	1,045	1,098	1,275	1,477

Contains Proprietary Material
Do Not Distribute

Fall	10	1,555	10/3/2015	1,313	1,238	1,224	1,221	1,246	1,243	1,232	1,301	1,394	1,501	1,551	1,555	1,523	1,496	1,432	1,404	1,376	1,403	1,407	1,415	1,477	1,483	1,492	1,428
Fall	10	1,644	10/4/2015	1,361	1,313	1,309	1,333	1,316	1,341	1,367	1,431	1,518	1,611	1,644	1,631	1,607	1,566	1,501	1,466	1,453	1,481	1,515	1,527	1,616	1,627	1,563	1,456
Fall	10	1,809	10/5/2015	1,361	1,297	1,282	1,270	1,276	1,302	1,378	1,587	1,809	1,799	1,752	1,725	1,686	1,621	1,584	1,543	1,557	1,571	1,587	1,599	1,655	1,635	1,531	1,394
Fall	10	1,727	10/6/2015	1,296	1,219	1,219	1,221	1,229	1,251	1,317	1,518	1,705	1,727	1,665	1,622	1,565	1,514	1,491	1,488	1,497	1,535	1,536	1,536	1,602	1,594	1,499	1,399
Fall	10	1,627	10/7/2015	1,281	1,204	1,188	1,161	1,167	1,209	1,264	1,427	1,627	1,592	1,545	1,509	1,484	1,450	1,432	1,405	1,406	1,445	1,449	1,412	1,436	1,485	1,415	1,265
Fall	10	1,585	10/8/2015	1,153	1,003	1,004	978	989	1,018	1,098	1,245	1,447	1,493	1,489	1,472	1,504	1,458	1,458	1,450	1,446	1,483	1,488	1,517	1,580	1,585	1,512	1,411
Fall	10	1,701	10/9/2015	1,300	1,208	1,216	1,221	1,242	1,273	1,343	1,528	1,663	1,701	1,680	1,654	1,639	1,627	1,669	1,653	1,643	1,678	1,686	1,692	1,687	1,638	1,565	1,463
Fall	10	1,515	#########	1,289	1,213	1,200	1,192	1,198	1,204	1,259	1,344	1,395	1,486	1,515	1,514	1,483	1,438	1,411	1,371	1,358	1,342	1,364	1,391	1,506	1,494	1,438	1,382
Fall	10	1,704	#########	1,332	1,285	1,283	1,287	1,305	1,328	1,305	1,342	1,438	1,593	1,650	1,667	1,658	1,704	1,660	1,592	1,528	1,559	1,531	1,545	1,573	1,522	1,510	1,395
Fall	10	1,684	#########	1,325	1,250	1,199	1,176	1,190	1,211	1,244	1,344	1,427	1,535	1,622	1,673	1,684	1,647	1,608	1,564	1,548	1,539	1,506	1,508	1,595	1,571	1,464	1,299
Fall	10	1,657	#########	1,181	1,112	1,102	1,084	1,057	1,089	1,167	1,353	1,599	1,582	1,574	1,598	1,613	1,568	1,522	1,494	1,530	1,589	1,622	1,628	1,657	1,574	1,469	1,370
Fall	10	1,564	#########	1,261	1,153	1,128	1,112	1,097	1,098	1,137	1,310	1,504	1,499	1,490	1,472	1,466	1,433	1,440	1,428	1,425	1,475	1,472	1,500	1,564	1,528	1,463	1,359
Fall	10	1,742	#########	1,217	1,143	1,110	1,102	1,120	1,163	1,245	1,450	1,728	1,742	1,691	1,705	1,665	1,610	1,604	1,578	1,536	1,568	1,590	1,628	1,709	1,675	1,577	1,458
Fall	10	1,733	#########	1,349	1,278	1,249	1,253	1,272	1,354	1,384	1,550	1,733	1,720	1,675	1,654	1,613	1,559	1,537	1,527	1,562	1,612	1,605	1,619	1,641	1,601	1,549	1,485
Fall	10	1,805	#########	1,396	1,347	1,318	1,322	1,325	1,371	1,449	1,549	1,694	1,805	1,785	1,787	1,771	1,724	1,675	1,641	1,660	1,725	1,767	1,788	1,804	1,778	1,680	1,609
Fall	10	1,777	#########	1,458	1,392	1,406	1,318	1,307	1,347	1,392	1,436	1,532	1,642	1,658	1,659	1,660	1,627	1,590	1,588	1,588	1,623	1,649	1,697	1,763	1,777	1,696	1,612
Fall	10	2,017	#########	1,519	1,466	1,448	1,476	1,487	1,457	1,554	1,797	1,985	2,017	1,950	1,912	1,842	1,780	1,754	1,708	1,708	1,745	1,757	1,843	1,946	1,942	1,854	1,713
Fall	10	1,858	#########	1,584	1,496	1,446	1,425	1,413	1,420	1,493	1,665	1,858	1,837	1,783	1,737	1,720	1,644	1,600	1,560	1,555	1,514	1,524	1,621	1,687	1,684	1,616	1,509
Fall	10	1,805	#########	1,353	1,301	1,310	1,321	1,348	1,388	1,464	1,620	1,805	1,789	1,691	1,622	1,556	1,504	1,473	1,441	1,434	1,479	1,506	1,555	1,661	1,666	1,669	1,575
Fall	10	2,033	#########	1,500	1,456	1,468	1,484	1,494	1,538	1,621	1,837	2,033	2,022	2,008	1,976	1,940	1,903	1,871	1,814	1,800	1,850	1,777	1,750	1,722	1,683	1,592	1,479
Fall	10	1,749	#########	1,372	1,291	1,254	1,218	1,215	1,248	1,311	1,526	1,749	1,747	1,693	1,665	1,630	1,578	1,594	1,592	1,603	1,660	1,642	1,668	1,679	1,657	1,590	1,488
Fall	10	1,786	#########	1,395	1,356	1,335	1,312	1,312	1,339	1,384	1,450	1,580	1,751	1,786	1,751	1,729	1,661	1,612	1,563	1,539	1,571	1,606	1,657	1,713	1,675	1,622	1,534
Fall	10	1,633	#########	1,437	1,359	1,289	1,276	1,278	1,305	1,322	1,377	1,415	1,535	1,563	1,584	1,582	1,588	1,565	1,529	1,530	1,591	1,611	1,630	1,633	1,583	1,520	1,409
Fall	10	1,882	#########	1,302	1,250	1,253	1,269	1,264	1,314	1,391	1,599	1,882	1,853	1,790	1,746	1,732	1,688	1,679	1,634	1,644	1,703	1,688	1,749	1,842	1,849	1,781	1,653
Fall	10	2,126	#########	1,566	1,506	1,508	1,546	1,576	1,583	1,646	1,880	2,126	2,111	2,009	1,930	1,844	1,747	1,684	1,638	1,645	1,686	1,731	1,826	1,862	1,812	1,776	1,636
Fall	10	2,072	#########	1,499	1,443	1,451	1,447	1,449	1,475	1,536	1,801	2,062	2,072	1,989	1,873	1,797	1,732	1,689	1,646	1,655	1,737	1,792	1,851	1,867	1,818	1,750	1,627
Fall	10	1,806	#########	1,512	1,416	1,384	1,374	1,381	1,384	1,439	1,622	1,806	1,725	1,697	1,680	1,685	1,616	1,589	1,528	1,510	1,543	1,558	1,562	1,589	1,556	1,471	1,415
Fall	10	1,673	#########	1,334	1,296	1,279	1,265	1,250	1,276	1,323	1,492	1,673	1,671	1,620	1,599	1,584	1,541	1,523	1,487	1,528	1,548	1,510	1,536	1,626	1,642	1,577	1,539
Fall	10	1,789	#########	1,484	1,387	1,394	1,459	1,475	1,506	1,536	1,612	1,674	1,781	1,789	1,756	1,706	1,664	1,606	1,547	1,534	1,580	1,622	1,668	1,683	1,670	1,633	1,581
Fall	11	1,883	11/1/2015	1,530	1,435	1,412	1,423	1,443	1,479	1,517	1,582	1,704	1,806	1,858	1,836	1,822	1,803	1,790	1,755	1,789	1,841	1,883	1,821	1,714	1,630	1,512	1,428
Fall	11	1,845	11/2/2015	1,338	1,295	1,241	1,228	1,230	1,265	1,347	1,579	1,787	1,742	1,717	1,674	1,647	1,598	1,629	1,621	1,657	1,758	1,841	1,845	1,827	1,819	1,691	1,622
Fall	11	2,060	11/3/2015	1,522	1,429	1,470	1,471	1,490	1,521	1,611	1,820	1,998	1,998	1,981	1,956	1,932	1,904	1,903	1,884	1,907	2,003	2,060	2,027	1,984	1,946	1,852	1,731
Fall	11	1,867	11/4/2015	1,594	1,496	1,495	1,467	1,460	1,496	1,568	1,700	1,867	1,843	1,790	1,749	1,704	1,658	1,623	1,567	1,589	1,645	1,746	1,770	1,738	1,713	1,631	1,537
Fall	11	1,958	11/5/2015	1,453	1,349	1,363	1,380	1,374	1,402	1,478	1,680	1,883	1,886	1,871	1,835	1,860	1,813	1,800	1,777	1,803	1,888	1,948	1,958	1,939	1,890	1,796	1,660
Fall	11	1,841	11/6/2015	1,547	1,429	1,391	1,357	1,354	1,371	1,458	1,579	1,841	1,826	1,795	1,753	1,715	1,661	1,659	1,609	1,622	1,662	1,666	1,612	1,580	1,509	1,435	1,376
Fall	11	1,633	11/7/2015	1,332	1,252	1,242	1,228	1,224	1,230	1,226	1,264	1,278	1,350	1,380	1,386	1,389	1,376	1,366	1,385	1,424	1,544	1,627	1,633	1,599	1,562	1,525	1,475
Fall	11	1,825	11/8/2015	1,399	1,378	1,345	1,365	1,392	1,388	1,435	1,497	1,574	1,687	1,736	1,743	1,739	1,722	1,662	1,622	1,622	1,695	1,819	1,825	1,810	1,787	1,748	1,660
Fall	11	2,018	11/9/2015	1,573	1,542	1,502	1,493	1,502	1,523	1,598	1,820	2,018	1,996	1,918	1,788	1,757	1,697	1,609	1,562	1,561	1,661	1,805	1,817	1,792	1,752	1,677	1,556
Fall	11	1,883	#########	1,438	1,370	1,353	1,391	1,401	1,422	1,516	1,715	1,883	1,838	1,756	1,700	1,655	1,584	1,549	1,543	1,551	1,658	1,798	1,777	1,739	1,692	1,626	1,527
Fall	11	1,873	#########	1,481	1,417	1,405	1,396	1,399	1,418	1,443	1,519	1,628	1,734	1,800	1,807	1,738	1,710	1,704	1,703	1,726	1,808	1,870	1,862	1,873	1,823	1,746	1,623
Fall	11	2,029	#########	1,553	1,493	1,480	1,476	1,502	1,537	1,590	1,842	2,029	2,027	1,958	1,894	1,845	1,773	1,741	1,705	1,746	1,798	1,878	1,893	1,860	1,803	1,711	1,589
Fall	11	1,750	#########	1,480	1,395	1,328	1,337	1,363	1,353	1,407	1,550	1,750	1,739	1,707	1,712	1,675	1,609	1,599	1,562	1,595	1,666	1,735	1,722	1,695	1,661	1,616	1,538
Fall	11	1,800	#########	1,407	1,320	1,277	1,282	1,277	1,306	1,357	1,446	1,565	1,679	1,749	1,697	1,691	1,685	1,662	1,631	1,640	1,720	1,800	1,762	1,730	1,701	1,644	1,575
Fall	11	1,867	#########	1,496	1,446	1,431	1,439	1,450	1,475	1,509	1,562	1,652	1,732	1,774	1,753	1,702	1,663	1,610	1,621	1,662	1,778	1,867	1,854	1,811	1,794	1,743	1,643
Fall	11	2,038	#########	1,496	1,426	1,443	1,443	1,479	1,514	1,586	1,800	1,998	1,973	1,921	1,888	1,867	1,825	1,820	1,822	1,871	1,956	2,038	2,011	1,950	1,883	1,818	1,697
Fall	11	2,014	#########	1,579	1,482	1,504	1,493	1,491	1,521	1,585	1,822	1,999	1,978	1,876	1,829	1,803	1,765	1,744	1,731	1,762	1,890	1,993	2,014	2,008	1,970	1,863	1,730
Fall	11	2,182	#########	1,624	1,548	1,524	1,530	1,529	1,564	1,667	1,920	2,130	2,161	2,103	2,077	2,061	2,023	1,985	1,939	1,921	2,057	2,182	2,162	2,119	2,072	1,970	1,857
Fall	11	2,195	#########	1,725	1,626	1,639	1,611	1,612	1,644	1,734	1,962	2,195	2,160	2,112	2,078	2,050	1,992	1,969	1,912	1,921	2,007	2,094	2,058	2,018	1,962	1,882	1,717
Fall	11	1,877	#########	1,591	1,498	1,477	1,444	1,442	1,443	1,521	1,688	1,877	1,853	1,840	1,843	1,831	1,783	1,756	1,742	1,742	1,799	1,830	1,777	1,732	1,684	1,628	1,551
Fall	11	1,907	#########	1,475	1,424	1,387	1,370	1,367	1,334	1,367	1,447	1,604	1,737	1,778	1,756	1,721	1,724	1,691	1,673	1,700	1,805	1,907	1,881	1,850	1,802	1,740	1,652
Fall	11	1,795	#########	1,560	1,512	1,401	1,391	1,398	1,408	1,392	1,451	1,510	1,594	1,643	1,636	1,630	1,620	1,608	1,612	1,590	1,708	1,782	1,795	1,786	1,772	1,723	1,573
Fall	11	2,014	#########	1,451	1,356	1,346	1,319	1,341	1,395	1,492	1,714	1,824	1,811	1,783	1,783	1,777	1,764	1,766	1,758	1,777	1,921	1,965	2,004	2,014	1,971	1,898	1,792
Fall	11	2,326	#########	1,694	1,611	1,645	1,647	1,652	1,693	1,768	1,982	2,218	2,210	2,169	2,143	2,129	2,093	2,078	2,057	2,101	2,227	2,326	2,289	2,276	2,239	2,148	2,006
Fall	11	2,444	#########	1,885	1,809	1,797	1,817	1,831	1,875	1,994	2,217	2,444	2,383	2,255	2,153	2,076	2,004	1,987	1,963	1,977	2,144	2,285	2,288	2,277	2,247	2,182	2,047
Fall	11	2,443	#########	1,931	1,863	1,876	1,888	1,901	1,926	2,008	2,237	2,443	2,376	2,242	2,133	2,083	2,023	1,964	1,910	1,939	1,997	2,050	2,017	1,971	1,921	1,851	1,716
Fall	11	1,821	#########	1,560	1,455	1,459	1,454	1,458	1,466	1,506	1,673	1,821	1,797	1,751	1,706	1,666	1,623	1,616	1,592	1,619	1,671	1,715	1,698	1,654	1,600	1,556	1,491
Fall	11	2,063	#########	1,422	1,367	1,328	1,310	1,323	1,358	1,417	1,476	1,581	1,727	1,834	1,894	1,926	1,916	1,914	1,900	1,900	2,006	2,063	2,035	2,018	2,006	1,941	1,863
Fall	11	2,173	#########	1,776	1,683	1,674	1,649	1,651	1,675	1,713	1,792	1,895	1,992	2,012	1,993	1,982	1,974	1,929	1,890	1,933	2,055	2,173	2,156	2,147	2,102	2,001	1,904
Fall	11	2,474	#########	1,850	1,794	1,790	1,813	1,827	1,864	1,951	2,222	2,471	2,474	2,384	2,338	2,320	2,259	2,253	2,240	2,286	2,411	2,474	2,428	2,359	2,289	2,178	2,041

Contains Proprietary Material
Do Not Distribute

Max	2,974
Max Month	2
PST	2,643
Winter	2,431
Spring	1,898
Summer	1,402
Fall	1,603

Source: ABB, The Velocity Suite
CONFIDENTIAL DATA REDACTED

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	1																										

Contains Proprietary Material
Do Not Distribute

Spring	1
Spring	1
Spring	1

Contains Proprietary Material
Do Not Distribute

Summer	1
Summer	1
Summer	1

Contains Proprietary Material
Do Not Distribute

Fall	1																										

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Contains Proprietary Material
Do Not Distribute

2.1 Generator List with Existing and Expected Seasonal Claimed Capability (SCC)

- **Generator Information as of January 1, 2015**
- **Summer and Winter SCC as of January 1, 2015, and as of the 2014/15 Winter and 2015 Summer Peaks**

														As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		
ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICI-PANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	Change in Summer SCC from 8/1/14
194	FOUR HILLS LOAD REDUCER	194	FOUR HILLS LOAD REDUCER	IC	LFG		BIO/REFUSE	01-Apr-96	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	55006	0.000	0.000	0.000	0.000	0.000
253	TURNKEY LANDFILL	253	TURNKEY LANDFILL	IC	LFG		BIO/REFUSE	01-Mar-92	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH	54663	0.730	0.732	0.730	0.732	-0.003
321	MANCHESTER 10/10A CC	321	MANCHESTER 10 10A CC	CC	NG	DFO	GAS/OIL COMBINED CYCLE	15-Nov-95	Dominion Energy Marketing, Inc.	DEM	RI	07	RI	RI	3236	170.000	149.000	170.000	159.000	10.000
322	MANCHESTER 11 11A CC	322	MANCHESTER 11 11A CC	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Oct-95	Dominion Energy Marketing, Inc.	DEM	RI	07	RI	RI	3236	170.000	153.594	170.000	159.000	5.406
323	MANCHESTER 9/9A CC	323	MANCHESTER 9 9A CC	CC	NG	DFO	GAS/OIL COMBINED CYCLE	14-Nov-95	Dominion Energy Marketing, Inc.	DEM	RI	07	RI	RI	3236	169.785	148.785	169.785	159.000	10.215
324	CDECCA	324	CDECCA	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Nov-88	Pawtucket Power Holding Company LLC	PPH	CT	03	CT	CT	50498	61.334	49.522	61.334	49.522	-5.732
326	ALTRESCO	326	ALTRESCO	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Sep-90	Pawtucket Power Holding Company LLC	PPH	MA	03	WMA	WCMA	50002	178.879	144.612	178.879	144.612	-6.370
327	AMOSKEAG	327	AMOSKEAG	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-22	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	2354	17.500	16.781	17.500	16.781	0.000
328	GULF ISLAND COMPOSITE	328	GULF ISLAND COMPOSITE Incremental	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-26	Brookfield White Pine Hydro LLC	FPLEMH	ME	01	ME	ME	1480	32.970	32.970	32.970	32.970	0.000
329	ASCUTNEY GT	329	ASCUTNEY GT	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Nov-61	Green Mountain Power Corporation	GMP	VT	27	VT	VT	3708	12.581	8.503	12.581	8.503	-0.143
330	AYERS ISLAND	330	AYERS ISLAND	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-25	Public Service Company of New Hampshire	PSNH	NH	01	NH	NH	2355	9.080	8.474	9.080	8.474	0.000
331	AZISCOHOS HYDRO	331	AZISCOHOS HYDRO	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jul-88	Brookfield Energy Marketing, LP	BEMLP	ME	19	ME	ME	50999	6.800	6.800	6.800	6.800	-0.010
332	BAR HARBOR DIESELS 1-4	332	BAR HARBOR DIESELS 1-4	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-69	Energy New England LLC	ENE	ME	09	BHE	ME	1486	4.000	0.000	4.000	0.000	-3.800
335	BELLOWS FALLS	335	BELLOWS FALLS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-28	TransCanada Power Marketing, Ltd.	TCPM	VT	25	VT	NH	3745	48.540	48.540	48.540	48.540	0.000
336	BERLIN 1 GT	336	BERLIN 1 GT	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-72	Green Mountain Power Corporation	GMP	VT	23	VT	VT	3734	50.409	40.260	50.409	40.260	0.000
337	BETHLEHEM	337	BETHLEHEM	ST	WDS		BIO/REFUSE	01-Dec-86	GDF Suez Energy Marketing NA, Inc.	SUEZ	NH	07	NH	NH	50208	15.321	15.303	15.321	15.303	0.129
340	BRIDGEPORT HARBOR 3	340	BRIDGEPORT HARBOR 3	ST	SUB		COAL STEAM	01-Aug-68	PSEG Energy Resources & Trade LLC	PSEG	CT	01	SWCT	CT	568	384.984	383.426	384.984	383.426	0.000
341	BRIDGEPORT HARBOR 4	341	BRIDGEPORT HARBOR 4	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Oct-67	PSEG Energy Resources & Trade LLC	PSEG	CT	01	SWCT	CT	568	21.924	16.907	21.924	16.907	0.000
345	MEAD	345	MEAD	ST	BIT	OBS	COAL STEAM	01-Feb-90	American PowerNet Management, LP	APNM	ME	17	ME	ME	10495	0.000	0.000	0.000	0.000	-0.485
346	BOLTON FALLS	346	BOLTON FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Green Mountain Power Corporation	GMP	VT	23	VT	VT	7056	3.397	0.000	3.397	0.000	-2.149
348	BOOT MILLS	348	BOOT MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-85	NSTAR Electric Company	NSTAR	MA	17	CMA/NEMA	WCMA	10556	11.400	6.010	11.400	6.010	-6.355
349	WHEELABRATOR BRIDGEPORT, L.P.	349	WHEELABRATOR BRIDGEPORT, L.P.	ST	MSW		BIO/REFUSE	01-Apr-88	Wheelabrator Bridgeport, L.P.	WB	CT	01	SWCT	CT	50883	59.267	59.069	59.267	59.069	0.195
350	BRAYTON PT 1	350	BRAYTON PT 1	ST	BIT	NG	COAL STEAM	01-Aug-63	Brayton Point Energy, LLC	BPE	MA	05	RI	SEMA	1619	241.366	225.230	241.366	225.230	0.000
351	BRAYTON PT 2	351	BRAYTON PT 2	ST	BIT	NG	COAL STEAM	01-Jul-64	Brayton Point Energy, LLC	BPE	MA	05	RI	SEMA	1619	242.455	237.842	242.455	237.842	0.000
352	BRAYTON PT 3	352	BRAYTON PT 3	ST	BIT	NG	COAL STEAM	01-Jul-69	Brayton Point Energy, LLC	BPE	MA	05	RI	SEMA	1619	598.606	596.289	598.606	596.289	-15.195
353	BRAYTON PT 4	353	BRAYTON PT 4	ST	RFO	NG	GAS/OIL STEAM	01-Dec-74	Brayton Point Energy, LLC	BPE	MA	05	RI	SEMA	1619	445.520	434.025	445.520	434.025	0.000
354	BRAYTON DIESELS 1-4	354	Brayton Diesels 1-4 Incremental	IC	DFO		OIL INTERNAL COMBUSTION	01-Mar-67	Brayton Point Energy, LLC	BPE	MA	05	RI	SEMA	1619	0.000	0.000	0.000	0.000	0.000
355	BRANFORD 10	355	BRANFORD 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	NextEra Energy Power Marketing, LLC	NRGPM	CT	09	SWCT	CT	540	20.950	15.840	20.950	15.840	0.000
356	BRISTOL REFUSE	356	BRISTOL REFUSE	ST	MSW		BIO/REFUSE	01-May-88	Covanta Energy Marketing, LLC	CEM	CT	03	CT	CT	50648	12.440	12.941	12.440	12.941	0.571
357	BRIDGEWATER	357	BRIDGEWATER	ST	WDS		BIO/REFUSE	01-Sep-87	Bridgewater Power Company L.P.	BPCLP	NH	09	NH	NH	10290	14.395	14.170	14.395	14.170	-0.622
358	BRUNSWICK	358	BRUNSWICK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-82	Brookfield White Pine Hydro LLC	FPLEMH	ME	05	ME	ME	1483	11.107	10.585	11.107	10.585	-3.237
359	J. COCKWELL 1	359	J. COCKWELL 1	PS	WAT		HYDRO (PUMPED STORAGE)	01-Sep-74	Bear Swamp Power Company LLC	BSP	MA	03	WMA	WCMA	8005	292.275	292.275	292.275	292.275	0.000
360	J. COCKWELL 2	360	J. COCKWELL 2	PS	WAT		HYDRO (PUMPED STORAGE)	01-Oct-74	Bear Swamp Power Company LLC	BSP	MA	03	WMA	WCMA	8005	292.113	293.238	292.113	293.238	0.000
362	BULLS BRIDGE	362	BULLS BRIDGE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-03	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	05	SWCT	CT	541	5.470	5.388	5.470	5.388	2.159
363	BURLINGTON GT	363	BURLINGTON GT	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jul-71	Burlington Electric Department	BED	VT	07	VT	VT	3754	23.354	19.104	23.354	19.104	0.000
365	CANAL 1	365	CANAL 1	ST	RFO		OIL STEAM	01-Jul-68	Genon Energy Management, LLC	MET	MA	01	SEMA	SEMA	1599	562.305	565.240	562.305	565.240	565.240
366	CANAL 2	366	CANAL 2	ST	RFO	NG	GAS/OIL STEAM	01-Feb-76	Genon Energy Management, LLC	MET	MA	01	SEMA	SEMA	1599	303.000	558.750	303.000	558.750	0.000
367	CAPE GT 4	367	CAPE GT 4	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jan-70	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1484	20.011	15.487	20.011	15.487	-0.209
368	CAPE GT 5	368	CAPE GT 5	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jan-70	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1484	20.272	15.822	20.272	15.822	0.000
369	CATARACT EAST	369	CATARACT EAST	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-37	Brookfield White Pine Hydro LLC	FPLEMH	ME	31	SME	ME	1486	8.000	7.775	8.000	7.775	0.000
370	COS COB 10	370	COS COB 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	NRG Power Marketing LLC	NRGPM	CT	01	NOR	CT	542	23.000	18.932	23.000	18.932	0.000
371	COS COB 11	371	COS COB 11	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-89	NRG Power Marketing LLC	NRGPM	CT	01	NOR	CT	542	23.000	18.724	23.000	18.724	0.000
372	COS COB 12	372	COS COB 12	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-89	NRG Power Marketing LLC	NRGPM	CT	01	NOR	CT	542	23.000	19.082	23.000	19.082	0.000
375	CLEARY 9 9A CC	375	CLEARY 9 9A CC	CC	NG	DFO	GAS COMBINED CYCLE	01-Dec-75	Taunton Municipal Lighting Plant	TMLP	MA	05	SEMA	SEMA	1682	109.931	104.931	109.931	104.931	0.000
376	CLEARY 8	376	CLEARY 8	ST	RFO		OIL STEAM	01-Jan-66	Taunton Municipal Lighting Plant	TMLP	MA	05	SEMA	SEMA	1682	22.253	24.825	22.253	24.825	0.000
379	COBBLE MOUNTAIN	379	COBBLE MOUNTAIN	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-23	Hydro-Quebec Gas & Electric Department	HQE	MA	13	WMA	WCMA	1630	32.480	31.126	32.480	31.126	0.000
380	COMERFORD	380	COMERFORD	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-30	TransCanada Power Marketing, Ltd.	TCPM	NH	09	NH	NH	2349	168.111	166.135	168.111	166.135	0.000
382	MERRIMACK CT1	382	MERRIMACK CT1	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Jul-69	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2364	21.676	16.826	21.676	16.826	0.000
383	MERRIMACK CT2	383	MERRIMACK CT2	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-68	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2364	21.304	16.804	21.304	16.804	0.000
388	DARTMOUTH POWER	388	DARTMOUTH POWER	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-May-92	Consolidated Edison Energy, Inc	CEEI	MA	05	SEMA	SEMA	52026	67.656	60.457	67.656	60.457	-1.692
389	DERBY DAM	389	DERBY DAM	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Mar-89	Connecticut Light and Power Company, The	CLP	CT	01	SWCT	CT	10063	7.050	7.050	7.050	7.050	0.000
393	DEERFIELD 5	393	DEERFIELD 5	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Oct-74	TransCanada Power Marketing, Ltd.	TCPM	MA	11	WMA	WCMA	1620	13.990	13.703	13.990	13.703	0.000
395	DOREEN	395	DOREEN	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	Essential Power Massachusetts, LLC	NAEA-EM	MA	03	WMA	WCMA	1631	20.670	15.820	20.670	15.820	0.000
396	DEVON 10	396	DEVON 10	GT	JF	DFO	OIL COMBUSTION (GAS) TURBINE	01-Apr-88	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	544	18.852	14.407	18.852	14.407	0.000
397	DEVON 11	397	DEVON 11	GT	JF	NG	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	544	38.819	29.299	38.819	29.299	0.000
398	DEVON 12	398	DEVON 12	GT	JF	NG	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	544	38.437	29.227	38.437	29.227	0.000
399	DEVON 13	399	DEVON 13	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	544	38.967	29.967	38.967	29.967	0.000
400	DEVON 14	400	DEVON 14	GT	JF	NG	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	544	40.274	29.704	40.274	29.704	0.000
401	EASTMAN FALLS	401	EASTMAN FALLS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-12	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2356	6.470	5.582	6.470	5.582	0.000
405	ELLSWORTH HYDRO	405	ELLSWORTH HYDRO	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-19	Black Bear Hydro Partners, LLC	BBHP	ME	09	BHE	ME	1469	9.050	9.044	9.050	9.044	0.000
407	EASTPORT DIESELS 1-3	407	EASTPORT DIESELS 1-3	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-48	Energy New England LLC	ENE	ME	29	BHE	ME	1468	2.100	1.800	2.100	1.800	-0.200
410	ESSEX 19 HYDRO	410	ESSEX 19 HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-17	Green Mountain Power Corporation	GMP	VT	07	VT	VT	3737	4.258	2.266	4.258	2.266	-2.918
411	EXETER	411	EXETER	ST	TDF	OBS	BIO/REFUSE	01-Dec-88	ReEnergy Sterling CT Limited Partnership	REENERGY	CT	13	CT	CT	50736	0.000	0.000	0.000	0.000	-20.981
412	FALLS VILLAGE	412	FALLS VILLAGE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-14	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	05	CT	CT	560	4.349	3.939	4.349	3.939	1.561
413	FIFE BROOK	413	FIFE BROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-74	Bear Swamp Power Company LLC	BSP	MA	03	WMA	WCMA	8004	9.900	6.089	9.900	6.089	0.000
417	FRAMINGHAM JET 1	417	FRAMINGHAM JET 1	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	Exelon Generation Company, LLC	EXGC	MA	17	BOSTON	NEMA	1586	14.175	10.145	14.175	10.145	0.000
418	FRAMINGHAM JET 2	418	FRAMINGHAM JET 2	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	Exelon Generation Company, LLC	EXGC	MA	17	BOSTON	NEMA	1586	15.686	9.743	15.686	9.743	0.000
419	FRAMINGHAM JET 3	419	FRAMINGHAM JET 3	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	Exelon Generation Company, LLC	EXGC	MA	17	BOSTON	NEMA	1586	15.250	10.790	15.250	10.790	0.000
420	FRANKLIN DRIVE 10	420	FRANKLIN DRIVE 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Nov-68	NRG Power Marketing LLC	NRGPM	CT	05	CT	CT	561	20.527	15.417	20.527	15.417	0.000
421	FRONT STREET DIESELS 1-3	421	FRONT STREET DIESELS 1-3	IC	DFO		OIL INTERNAL COMBUSTION	01-Dec-80	Chicopee Municipal Lighting Plant	CMLP	MA	13	WMA	WCMA	7396	8.250	7.713	8.250	7.713	0.000
424	GREAT LAKES - MILLINOCKET	424	GREAT LAKES - MILLINOCKET	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Mar-87	Brookfield Energy Marketing, LP	BEMLP	ME	19	BHE	ME	55830	55.317	74.958	55.317	74.958	44.575
426	GORGE 1 DIESEL	426	GORGE 1 DIESEL	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jan-85	Green Mountain Power Corporation	GMP	VT	07	VT	VT	3735	11.000	0.000	11.000	0.000	-7.099
427	GORHAM	427	GORHAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-87	Public Service Company of New Hampshire	PSNH	NH	07	NH	NH	2358	1.518	1.434	1.518	1.434	0.001
432	HARRIS 1	432	HARRIS 1	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-54	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1492	16.776	16.790	16.776	16.790	0.000
433	HARRIS 2	433	HARRIS 2	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-54	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1492	34.500	34.865	34.500	34.865	0.000
434	HARRIS 3	434	HARRIS 3	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-53	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1492	33.905	34.210	33.905	34.210	0.000
435	HARRIMAN	435	HARRIMAN	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-24	TransCanada Power Marketing, Ltd.	TCPM	VT	25	WMA	WCMA	3746	38.663	40.943	38.663	40.943	0.000
436	HEMPHILL 1	436	HEMPHILL 1	ST	WDS		BIO/REFUSE	01-Dec-87	Springfield Power, LLC	SPRING	NH	19	NH	NH	10838	16.764	16.968	16.764	16.968	0.270
440	HIRAM	440	HIRAM	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-17	Brookfield White Pine Hydro LLC	FPLEMH	ME	05	SME	ME	1493	11.600	11.189	11.600	11.189	0.000
445	COVANTA WEST ENFIELD	445	COVANTA WEST ENFIELD	ST	WDS		BIO/REFUSE	01-Nov-87	Covanta Maine, LLC	CM	ME	19	BHE	ME	10766	21.446	20.461	21.446	20.461	0.000
446	COVANTA JONESBORO	446	COVANTA JONESBORO	ST	WDS		BIO/REFUSE	01-Nov-87	Covanta Maine, LLC	CM	ME	29	BHE	ME	10765	20.226	20.226	20.226	20.226	0.000
448	IPSWICH DIESELS	448	IPSWICH DIESELS	IC	DFO	NG	GAS/OIL INTERNAL COMBUSTION	01-Jan-51	Ipswich Municipal Light Department	IMLD	MA	09	BOSTON	NEMA	1670	9.495	9.729	9.495	9.729	-0.511
449	JACKMAN	449	JACKMAN	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Feb-26	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	2360	3.541	3.600	3.541	3.600	0.000
452	KENDALL JET 1	452	KENDALL JET 1	GT	DFO		OIL COMBUSTION (GAS) TURBINE	24-Sep-70	Kendall Green Energy, LLC	KENDALL	MA	17	BOSTON	NEMA	1595	23.000	18.000	23.000	18.000	0.000
457	LAWRENCE HYDRO	457	LAWRENCE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-81	CHI Power Marketing, Inc.	CHIPM	MA	09	CMA/NEMA	WCMA	50545	8.576	6.160	8.576	6.160	-3.318
460	LOCKWOOD	460	LOCKWOOD	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Brookfield Energy Marketing, LP	BEMLP	ME	11	ME	ME	10066	4.113	4.046	4.113	4.046	0.162
461	LENERGIA ENERGY CENTER	12521	Lowell Power Reactivation	CC	NG	DFO	GAS/OIL COMBINED CYCLE	11-Mar-93	EDF Trading North America, LLC	EDFT	MA	17	CMA/NEMA	WCMA	54586	78.446	74.638	78.446	74.638	0.000
462	LISBON RESOURCE RECOVERY	462	LISBON RESOURCE RECOVERY	ST	MSW		BIO/REFUSE	01-Jan-96	Connecticut Light and Power Company, The	CLP	CT	11	CT	CT	54758	13.530	13.325	13.530	13.325	-0.197
463	REENERGY LIVERMORE FALLS	463	AEI LIVERMORE	ST	WDS		BIO/REFUSE	01-Oct-92	ReEnergy Stratton LLC	REH	ME	01	ME	ME	10354	34.430	34.695	34.430	34.695	0.000
464	LOST NATION	464	LOST NATION	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	Public Service Company of New Hampshire	PSNH	NH	07	NH	NH	2362	17.992	13.926	17.992	13.926	0.000
465	DEERFIELD 2/LWR DRFIELD	465	DEERFIELD 2 LWR DRFIELD	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-12	TransCanada Power Marketing, Ltd.	TCPM	MA	11	WMA	WCMA	7, 6083, 6	19.500	19.275	19.500	19.275	0.000
466	L STREET JET	466	L STREET JET	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-66	Exelon Generation Company, LLC	EXGC	MA	25	BOSTON	NEMA	1587	21.770	16.030	21.770	16.030	0.000
467	MARBLEHEAD DIESELS	467	MARBLEHEAD DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	25-Sep-68	Marblehead Municipal Light Department	MMLD	MA	09	BOSTON	NEMA	6586	5.000	5.000	5.000	5.000	0.000
468	MARSHFIELD 6 HYDRO	468	MARSHFIELD 6 HYDRO	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-27	Green Mountain Power Corporation	GMP	VT	23	NH	VT	3739	4.380	4.412	4.380	4.412	0.000
472	M STREET JET	472	M STREET JET	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-78	Massachusetts Bay Transportation Authority	MBTA	MA	25	BOSTON	NEMA	10176	67.200	47.000	67.200	47.000	0.000
473	MCINDOES	473	MCINDOES	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-31	TransCanada Power Marketing, Ltd.	TCPM	NH	09	NH	NH	6483	10.571	10.066	10.571	10.066	0.000
474	J C MCNEIL	474	J C MCNEIL	ST	WDS	NG	BIO/REFUSE	01-Feb-84	Burlington Electric Department	BED	VT	07	VT	VT	589	54.000	52.000	54.000	52.000	0.000
475	MEDWAY DIESELS 1-4	475	MEDWAY DIESELS 1-4	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-68	Energy New England LLC	ENE	ME	19	BHE	ME	1474	6.412	4.029	6.412	4.029	-3.921
478	MIDDLETOWN 10	478	MIDDLETOWN 10	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Jan-66	NRG Power Marketing LLC	NRGPM	CT	07	CT	CT	562	20.015	15.515	20.015	15.515	0.000
480	MIDDLETOWN 2	480	MIDDLETOWN 2	ST	RFO	NG	GAS/OIL STEAM	01-Jan-58	NRG Power Marketing LLC	NRGPM	CT	07	CT	CT	562	120.000	117.000	120.000	117.000	0.000
481	MIDDLETOWN 3	481	MIDDLETOWN 3	ST	RFO	NG	GAS/OIL STEAM	01-Jan-64	NRG Power Marketing LLC	NRGPM	CT	07	CT	CT	562	244.398	233.679	244.398	233.679	0.000
482	MIDDLETOWN 4	482	MIDDLETOWN 4	ST	RFO		OIL STEAM	01-Jun-73	NRG Power Marketing LLC	NRGPM	CT	07	CT	CT	562	402.000	399.923	402.000	399.923	0.000
484	MILLSTONE POINT 2	484	MILLSTONE POINT 2	ST	NUC		NUCLEAR STEAM	01-Dec-75	Dominion Energy Marketing, Inc.	DEM	CT	11	CT	CT	566	875.912	870.855	875.912	870.855	0.000
485	MILLSTONE POINT 3	485	MILLSTONE POINT 3	ST	NUC		NUCLEAR STEAM	01-Apr-86	Dominion Energy Marketing, Inc.	DEM	CT	11	CT	CT	566	1,235.001	1,225.000	1,235.001	1,225.000	0.000
486	MILFORD POWER	486	MILFORD POWER	CC	NG		GAS COMBINED CYCLE	01-Jan-94	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	27	RI	SEMA	54805	170.730	149.000	170.730	149.000	0.000
487	MILLER HYDRO	487	MILLER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-84	Energy New England LLC	ENE	ME	01	ME	ME	50278	9.769	9.428	9.769	9.428	0.002
489	MERRIMACK 1	489	MERRIMACK 1	ST	BIT		COAL STEAM	01-Dec-60	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2364	108.000	108.000	108.000	108.000	0.000
490	MERRIMACK 2	490	MERRIMACK 2	ST	BIT		COAL STEAM	30-Apr-68	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2364	330.513	330.000	330.513	330.000	0.000
492	MONTVILLE 10 and 11	492	MONTVILLE 10 and 11	IC	KER		OIL INTERNAL COMBUSTION	01-Jan-67	NRG Power Marketing LLC	NRGPM	CT	11	CT	CT	546	5.354	5.296	5.354	5.296	0.000
493	MONTVILLE 5	493	MONTVILLE 5	ST	RFO	NG	GAS/OIL STEAM	01-Jan-54	NRG Power Marketing LLC	NRGPM	CT	11	CT	CT	546	81.590	81.000	81.590	81.000	0.000
494	MONTVILLE 6	494	MONTVILLE 6	ST	RFO		OIL STEAM	01-Jul-71	NRG Power Marketing LLC	NRGPM	CT	11	CT	CT	546	406.659

Contains Proprietary Material
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															As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		
ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC-IPANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 9, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	Change in Summer SCC from 8/1/14
561	SEARSBURG	561	SEARSBURG	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Mar-22	TransCanada Power Marketing, Ltd.	TCPM	VT	03	WMA	WCMA	6529	4.960	4.755	4.960	4.755	0.000
562	SECREC-PRESTON	562	SECREC-PRESTON	ST	MSW	DFO	BIO/REFUSE	01-Jan-92	Connecticut Light and Power Company, The	CLP	CT	11	CT	CT	10646	16.232	15.857	16.232	15.857	0.044
563	SEMASS 1	563	SEMASS 1	ST	MSW	DFO	BIO/REFUSE	01-Oct-88	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA	50290	50.314	49.185	50.314	49.185	1.171
564	SEMASS 2	564	SEMASS 2	ST	MSW	DFO	BIO/REFUSE	01-May-93	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA	50290	24.878	22.640	24.878	22.640	0.585
565	SHELDON SPRINGS	565	SHELDON SPRINGS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-88	Vermont Electric Power Company, Inc.	VELCO	VT	11	VT	VT	10494	9.370	2.286	9.370	2.286	-6.381
566	SHEPAUG	566	SHEPAUG	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-55	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	09	SWCT	CT	552	42.523	41.511	42.523	41.511	0.000
567	SHERMAN	567	SHERMAN	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Dec-26	TransCanada Power Marketing, Ltd.	TCPM	MA	11	WMA	WCMA	6012	6.220	6.154	6.220	6.154	0.000
568	SHREWSBURY DIESELS	35657	Shrewsbury Diesels	IC	DFO		OIL INTERNAL COMBUSTION	01-May-78	Shrewsbury Electric & Cable Operations	SELP	MA	27	CMA/NEMA	WCMA	6125	13.650	13.750	13.650	13.750	0.000
569	SKELTON	569	SKELTON	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-48	Brookfield White Pine Hydro LLC	FPLEMH	ME	31	SME	ME	1505	19.704	19.704	19.704	21.600	1.896
570	SMITH	570	SMITH	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-48	Public Service Company of New Hampshire	PSNH	NH	07	NH	NH	2368	13.214	8.353	13.214	8.353	-4.787
571	SO. MEADOW 11	571	SO. MEADOW 11	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-70	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	46.921	35.781	46.921	35.781	0.000
572	SO. MEADOW 12	572	SO. MEADOW 12	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-70	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	47.815	37.649	47.815	37.649	0.000
573	SO. MEADOW 13	573	SO. MEADOW 13	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-70	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	47.917	38.317	47.917	38.317	0.000
574	SO. MEADOW 14	574	SO. MEADOW 14	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-70	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	46.346	36.746	46.346	36.746	0.000
575	SO. MEADOW 5	575	SO. MEADOW 5	ST	MSW	NG	BIO/REFUSE	01-Nov-87	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	24.327	26.136	24.327	26.136	4.140
576	SO. MEADOW 6	576	SO. MEADOW 6	ST	MSW	NG	BIO/REFUSE	01-Nov-87	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	22.050	16.623	22.050	16.623	-1.836
577	STONY BROOK 2A	577	STONY BROOK 2A	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Nov-82	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	13	WMA	WCMA	6081	87.400	67.400	87.400	67.400	0.000
578	STONY BROOK 2B	578	STONY BROOK 2B	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Nov-82	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	13	WMA	WCMA	6081	85.300	65.300	85.300	65.300	0.000
579	STEVENSON	579	STEVENSON	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-19	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	01	SWCT	CT	553	28.844	28.311	28.844	28.311	0.000
580	REENERGY STRATTON	580	BORALEX STRATTON ENERGY	ST	WDS		BIO/REFUSE	01-Sep-89	ReEnergy Stratton LLC	REH	ME	07	ME	ME	50650	44.363	45.024	44.363	45.024	0.000
581	S.D. WARREN-WESTBROOK	581	S.D. WARREN-WESTBROOK	ST	WDS	RFO	BIO/REFUSE	01-Nov-97	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	50447	49.103	42.590	49.103	42.590	0.000
582	TAMWORTH	582	TAMWORTH	ST	WDS		BIO/REFUSE	01-Jan-88	GDF Suez Energy Marketing NA, Inc.	SUEZ	NH	03	NH	NH	50739	19.973	20.074	19.973	20.074	0.720
583	TORRINGTON TERMINAL 10	583	TORRINGTON TERMINAL 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Aug-67	NRG Power Marketing LLC	NRGPM	CT	05	CT	CT	565	20.748	15.638	20.748	15.638	0.000
584	TUNNEL 10	584	TUNNEL 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	11	CT	CT	557	21.691	16.257	21.691	16.257	-0.334
585	VERGENNES 5 AND 6 DIESELS	585	VERGENNES 5 and 6 DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-64	Green Mountain Power Corporation	GMP	VT	01	VT	VT	6519	4.240	3.940	4.240	3.940	0.000
586	VERNON	586	VERNON	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-09	TransCanada Power Marketing, Ltd.	TCPM	VT	25	WMA	WCMA	2352	32.000	32.000	32.000	32.000	0.000
587	WATERS RIVER JET 1	587	WATERS RIVER JET 1	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	01-Dec-71	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	09	BOSTON	NEMA	1678	21.974	15.974	21.974	15.974	0.000
588	WATERS RIVER JET 2	588	WATERS RIVER JET 2	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	01-Apr-91	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	09	BOSTON	NEMA	1678	40.000	28.500	40.000	28.500	0.000
589	WATERBURY 22	589	WATERBURY 22	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-53	Green Mountain Power Corporation	GMP	VT	23	VT	VT	6520	5.000	5.000	5.000	5.000	0.000
590	WEST ENFIELD	590	WEST ENFIELD	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-88	New Brunswick Energy Marketing Corporation	NBPGC	ME	19	BHE	ME	10255	10.646	8.818	10.646	8.818	-7.577
591	WESTON	591	WESTON	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-20	Brookfield White Pine Hydro LLC	FPLEMH	ME	17	ME	ME	1509	8.315	10.831	8.315	10.831	1.644
592	DG WHITEFIELD, LLC	592	DG WHITEFIELD, LLC	ST	WDS		BIO/REFUSE	01-Apr-88	Exelon Generation Company, LLC	EXGC	NH	07	NH	NH	10839	15.726	15.603	15.726	15.603	-0.567
593	WHITE LAKE JET	593	WHITE LAKE JET	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-68	Public Service Company of New Hampshire	PSNH	NH	03	NH	NH	2369	22.397	17.447	22.397	17.447	0.000
594	WILDER	594	WILDER	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-50	TransCanada Power Marketing, Ltd.	TCPM	VT	27	VT	NH	2353	40.698	39.083	40.698	39.083	0.000
595	WILLIAMS	595	WILLIAMS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-39	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1510	14.900	14.900	14.900	14.900	0.000
596	WINOOSKI 1	596	WINOOSKI 1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-93	Burlington Electric Department	BED	VT	07	VT	VT	54355	2.614	1.363	2.614	1.363	-1.828
597	COVANTA PROJECTS WALLINGFORD	597	WALLINGFORD REFUSE	ST	MSW	DFO	BIO/REFUSE	01-Mar-89	Covanta Projects of Wallingford, L.P.	CPW	CT	09	SWCT	CT	50664	5.275	5.027	5.275	5.027	-1.542
598	WMI MILLBURY 1	598	WMI MILLBURY 1	ST	MSW		BIO/REFUSE	01-Sep-87	New England Power Company	NEP	MA	27	CMA/NEMA	WCMA	50878	39.891	39.811	39.891	39.811	0.000
599	WEST MEDWAY JET 1	599	WEST MEDWAY JET 1	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jul-70	Exelon Generation Company, LLC	EXGC	MA	21	BOSTON	NEMA	1592	62.915	42.000	62.915	42.000	0.000
600	WEST MEDWAY JET 2	600	WEST MEDWAY JET 2	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Mar-71	Exelon Generation Company, LLC	EXGC	MA	21	BOSTON	NEMA	1592	61.598	39.848	61.598	39.848	0.000
601	WEST MEDWAY JET 3	601	WEST MEDWAY JET 3	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jul-70	Exelon Generation Company, LLC	EXGC	MA	21	RI	SEMA	1592	62.401	42.001	62.401	42.001	6.580
602	WOODLAND ROAD	602	WOODLAND ROAD	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jul-69	Essential Power Massachusetts, LLC	NAEA-EM	MA	03	WMA	WCMA	1643	20.658	15.808	20.658	15.808	0.000
603	WEST SPRINGFIELD 10	603	WEST SPRINGFIELD 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-68	Essential Power Massachusetts, LLC	NAEA-EM	MA	13	WMA	WCMA	1642	21.928	17.143	21.928	17.143	0.000
604	WEST SPRINGFIELD 3	604	WEST SPRINGFIELD 3	ST	NG	RFO	GAS/OIL STEAM	01-Jan-57	Essential Power Massachusetts, LLC	NAEA-EM	MA	13	WMA	WCMA	1642	100.087	94.276	100.087	94.276	0.000
605	WYMAN HYDRO 1	605	WYMAN HYDRO 1	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-30	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1511	27.400	27.362	27.400	27.362	0.000
606	WYMAN HYDRO 2	606	WYMAN HYDRO 2	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-31	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1511	29.900	29.866	29.900	29.866	0.000
607	WYMAN HYDRO 3	607	WYMAN HYDRO 3	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-40	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1511	25.700	25.548	25.700	25.548	0.000
608	YARMOUTH 1	608	YARMOUTH 1	ST	RFO		OIL STEAM	01-Jan-57	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1507	50.065	0.000	50.065	0.000	0.000
609	YARMOUTH 2	609	YARMOUTH 2	ST	RFO		OIL STEAM	01-Jan-58	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1507	52.823	50.045	52.823	50.045	-0.760
610	YARMOUTH 3	610	YARMOUTH 3	ST	RFO		OIL STEAM	01-Jul-65	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1507	114.720	109.040	114.720	109.040	-1.830
611	YARMOUTH 4	611	YARMOUTH 4	ST	RFO		OIL STEAM	01-Dec-78	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1507	605.875	602.050	605.875	602.050	0.000
612	ROCHESTER LANDFILL	612	ROCHESTER LANDFILL	GT	LFG		BIO/REFUSE	01-May-98	New Hampshire Electric Cooperative, Inc.	NHEC	NH	17	NH	NH	2007	2.257	2.192	2.257	2.192	0.048
613	SIMPSON G LOAD REDUCER	613	SIMPSON G LOAD REDUCER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Green Mountain Power Corporation	GMP	VT	09	NH	VT	10608	2.656	2.388	2.656	2.388	-0.620
614	ROCKY RIVER	614	ROCKY RIVER	PS	WAT		HYDRO (PUMPED STORAGE)	01-Jan-28	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	09	SWCT	CT	539	28.127	28.853	28.127	28.853	0.000
615	BAR MILLS	615	BAR MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-56	Brookfield White Pine Hydro LLC	FPLEMH	ME	31	SME	ME	1481	1.586	0.000	1.586	0.000	-2.067
616	BONNY EAGLE/W. BUXTON	616	BONNY EAGLE W. BUXTON	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-10	Brookfield White Pine Hydro LLC	FPLEMH	ME	31	SME	ME	1482, 1508	17.500	16.151	17.500	16.151	0.000
617	HARRIS 4	617	HARRIS 4	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-54	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1492	1.249	1.436	1.249	1.436	0.000
618	MESSALONSKEE COMPOSITE	618	MESSALONSKEE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-17	Messalonskee Stream Hydro, LLC	MESSA	ME	11	ME	ME	1497	4.016	3.948	4.016	3.948	-0.099
619	NORTH GORHAM	619	NORTH GORHAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-25	Brookfield White Pine Hydro LLC	FPLEMH	ME	05	SME	ME	1501	1.121	1.475	1.121	1.475	-0.283
620	SHAWMUT	620	SHAWMUT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-13	Brookfield White Pine Hydro LLC	FPLEMH	ME	11	ME	ME	1504	6.066	7.239	6.066	7.239	0.738
621	SIES CONCORD	621	SIES CONCORD	ST	MSW		BIO/REFUSE	01-May-89	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	50873	12.397	12.096	12.397	12.096	-0.020
622	GARVINS/HOOKSETT	622	GARVINS HOOKSETT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-02	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2357, 2358	5.844	3.853	5.844	3.853	-3.423
623	HADLEY FALLS 1&2	623	HADLEY FALLS 1&2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-83	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	1605	23.436	20.229	23.436	20.229	2.509
624	NEWPORT HYDRO	624	NEWPORT HYDRO	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-80	Great Bay Power Marketing, Inc	GBPM	VT	19	NH	VT	3731	1.722	1.215	1.722	1.215	-0.912
625	LOWER LAMOILLE COMPOSITE	625	LOWER LAMOILLE COMPOSITE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-48	Green Mountain Power Corporation	GMP	VT	07	VT	VT	3711	16.000	10.106	16.000	10.106	-5.694
626	MIDDLEBURY COMPOSITE	626	MIDDLEBURY COMPOSITE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-17	Green Mountain Power Corporation	GMP	VT	01	VT	VT	3716	5.724	5.678	5.724	5.678	0.079
627	N. RUTLAND COMPOSITE	627	N. RUTLAND COMPOSITE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-80	Green Mountain Power Corporation	GMP	VT	21	VT	VT	3714	4.155	4.503	4.155	4.503	0.000
628	MIDDLESEX 2	628	MIDDLESEX 2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-28	Green Mountain Power Corporation	GMP	VT	23	VT	VT	3740	1.504	0.000	1.504	0.000	-1.368
629	WEST DANVILLE 1	629	WEST DANVILLE 1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-86	Green Mountain Power Corporation	GMP	VT	05	VT	VT	3743	0.000	0.000	0.000	0.000	0.000
630	HIGHGATE FALLS	630	HIGHGATE FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	VT	11	VT	VT	6618	7.895	1.663	7.895	1.663	-2.653
631	CEC 002 PAWTUCKET U5	631	CEC 002 PAWTUCKET U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-85	The Narragansett Electric Company	NEC	RI	07	RI	SEMA	3233	0.556	0.000	0.556	0.000	-0.219
632	CENTENNIAL HYDRO	632	CENTENNIAL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-90	Sterling Municipal Electric Light Department	SMED	MA	17	CMA/NEMA	WCMA	7112	0.554	0.108	0.554	0.108	-0.181
633	METHUEN HYDRO	633	METHUEN HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Aug-88	Sterling Municipal Electric Light Department	SMED	MA	09	BOSTON	NEMA		0.118	0.000	0.118	0.000	0.000
634	MINIWAWA	634	MINIWAWA	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-92	Littleton Electric Light & Water Department	LELWD	NH	05	VT	NH		0.605	0.190	0.605	0.190	-0.007
635	RIVER MILL HYDRO	635	RIVER MILL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-89	Middleton Municipal Light Department	MMELD	NH	09	VT	NH	3049	0.000	0.000	0.000	0.000	0.000
636	GOODWIN DAM	636	GOODWIN DAM	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Feb-86	Connecticut Light and Power Company, The	CLP	CT	05	CT	CT	54302	3.000	3.000	3.000	3.000	0.000
637	WYRE WYND HYDRO	637	CEC 003 WYRE WYND U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-97	Summit Hydropower, Inc.	SUMMIT	CT	11	CT	CT		0.000	0.079	0.000	0.079	-0.853
638	COLEBROOK	638	COLEBROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-88	Connecticut Light and Power Company, The	CLP	CT	05	CT	CT	54301	0.388	0.948	0.388	0.948	0.190
639	KINNEYTOWN B	639	KINNEYTOWN B	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-86	Connecticut Light and Power Company, The	CLP	CT	09	SWCT	CT	54385	0.523	0.000	0.523	0.000	0.000
640	WILLIMANTIC 1	640	WILLIMANTIC 1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-90	Connecticut Light and Power Company, The	CLP	CT	15	CT	CT		0.343	0.000	0.343	0.000	0.000
641	WILLIMANTIC 2	641	WILLIMANTIC 2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-90	Connecticut Light and Power Company, The	CLP	CT	15	CT	CT		0.191	0.000	0.191	0.000	0.000
642	TOUTANT	642	TOUTANT	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Feb-94	Connecticut Light and Power Company, The	CLP	CT	15	CT	CT		0.396	0.251	0.396	0.251	0.000
643	PUTNAM	643	PUTNAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-87	Putnam Hydropower, Inc.	PUTNAM	CT	15	CT	CT		0.384	0.000	0.384	0.000	-0.185
644	MECHANICSVILLE	644	MECHANICSVILLE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-95	Sterling Municipal Electric Light Department	SMED	CT	15	CT	CT		0.098	0.000	0.098	0.000	-0.033
645	CEC 004 DAYVILLE POND U5	645	CEC 004 DAYVILLE POND U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-95	Connecticut Light and Power Company, The	CLP	CT	15	CT	CT		0.049	0.000	0.049	0.000	0.000
646	SANDY HOOK HYDRO	646	SANDY HOOK HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-89	Connecticut Light and Power Company, The	CLP	CT	05	SWCT	CT		0.070	0.000	0.070	0.000	0.000
647	PINCHBECK	647	PINCHBECK	ST	WDS		BIO/REFUSE	01-Jul-87	Connecticut Light and Power Company, The	CLP	CT	13	CT	CT		0.000	0.000	0.000	0.000	0.000
648	QUINEBAUG	648	QUINEBAUG	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-90	Connecticut Light and Power Company, The	CLP	CT	15	CT	CT	543	0.892	0.040	0.892	0.040	-0.290
649	BANTAM	649	BANTAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-05	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	05	CT	CT	6457	0.085	0.000	0.085	0.000	-0.068
650	BEEBE HOLBROOK	650	BEEBE HOLBROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-48	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	1602	0.000	0.000	0.000	0.000	-0.170
651	TUNNEL	651	TUNNEL	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-19	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	11	CT	CT	557	1.048	0.000	1.048	0.000	-0.746
652	PATCH	652	PATCH	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	21	VT	VT	3719	0.087	0.031	0.087	0.031	0.031
653	CARVER FALLS	653	CARVER FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	25-Sep-98	Green Mountain Power Corporation	GMP	VT	21	VT	VT	6456	0.770	0.000	0.770	0.000	-0.083
654	CAVENDISH	654	CAVENDISH	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	25-Sep-98	Green Mountain Power Corporation	GMP	VT	27	VT	VT	3710	0.457	0.337	0.457	0.337	-0.029
655	TAFTSVILLE VT	655	TAFTSVILLE VT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	27	VT	VT	3727	0.000	0.000	0.000	0.000	0.000
656	PIERCE MILLS	656	PIERCE MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	05	NH	VT	3721	0.135	0.056	0.135	0.056	0.180
657	ARNOLD FALLS	657	ARNOLD FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	25-Sep-98	Green Mountain Power Corporation	GMP	VT	05	NH	VT	3707	0.123	0.000	0.123	0.000	-0.320
658	PASSUMPSIC	658	PASSUMPSIC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	05	NH	VT	3718	0.232	0.077	0.232	0.077	-0.170
659	GAGE	659	GAGE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	05	NH	VT	3713	0.252	0.000	0.252	0.000	-0.401
660	SMITH (CVPS)	660	SMITH (CVPS)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	17	VT	VT	3709	0.460	0.264	0.460	0.264	-0.643
661	EAST BARNET	661	EAST BARNET	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	05	NH	VT	788	0.907	0.399	0.907	0.399	-0.195
662	BATH ELECTRIC HYDRO	662	BATH ELECTRIC HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-85	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.154	0.270	0.154	0.270	-0.036
663	SEARSBURG WIND	663	SEARSBURG WIND	WT	WND		WIND TURBINE	01-Jul-97	Green Mountain Power Corporation	GMP	VT	03	WMA	WCMA	7381	1.123	0.113	1.123	0.113	-0.222
664	BARTON HYDRO	664	BARTON HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-31	Vermont Public Power Supply Authority	VPPSA	VT	19	NH	VT	3753	0.384	0.073	0.384	0.073	-0.371
665	ENOSBURG HYDRO	665	ENOSBURG HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	VT	11	VT	VT	3757	0.315	0.457	0.315	0.457	-0.078
666	VAIL & GREAT FALLS	666	VAIL & GREAT FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	VT	05	NH	VT	3726	0.992	0.196	0.992	0.196	0.067
667	CENTER RUTLAND	667	CENTER RUTLAND	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Aug-01	Green Mountain Power Corporation	GMP	VT	21	VT	VT	6453	0.000	0.096	0.000	0.096	0.096
668	BARNET	668	BARNET	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-01	Green Mountain Power Corporation	GMP	VT	05	VT	VT		0.139	0.000	0.139	0.000	-0.167
669	COMTU FALLS	669	COMPTU FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-82	Green Mountain Power Corporation	GMP	VT	27	VT	VT		0.251	0.214	0.251	0.214	-0.002
670	DEW

Contains Proprietary Material
Do Not Distribute

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PAINT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC (kW)	SUMMER SCC (kW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
875	RIVER BEND	875	RIVER BEND	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-86	Massachusetts Municipal Wholesale Electric Company	MMWEC	NH	13	NH			1.218	0.705	1.218	0.705	-0.712
876	ROBERTSVILLE	876	ROBERTSVILLE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-24	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	03	CT	CT	549	0.065	0.000	0.065	0.000	0.000
877	SCOTLAND	877	SCOTLAND	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-37	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	15	CT	CT	551	1.340	0.000	1.340	0.000	0.000
878	SKINNER	878	SKINNER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-24	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	1608	0.000	0.000	0.000	0.000	-0.248
879	TAFTVILLE CT	879	TAFTVILLE CT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-06	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	11	CT	CT	554	0.993	0.000	0.993	0.000	0.000
882	FRANKLIN FALLS	882	FRANKLIN FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-78	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	10109	0.436	0.444	0.436	0.444	-0.198
883	SALMON FALLS HYDRO		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-83	CHI Power Marketing, Inc.	CHIPM	NH	17	SME	ME	50702	0.392	0.000	0.392	0.000	-0.145
884	SWANS FALLS	884	SWANS FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-98	Public Service Company of New Hampshire	PSNH	ME	17	NH	NH	1518	0.280	0.259	0.280	0.259	-0.184
886	COCHECO FALLS	886	COCHECO FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-83	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.223	0.175	0.223	0.175	0.175
887	CHINA MILLS DAM	887	CHINA MILLS DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-81	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	50103	0.344	0.000	0.344	0.000	-0.025
888	NEWFOUND HYDRO	888	NEWFOUND HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-83	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH	50324	0.687	0.237	0.687	0.237	-0.435
889	SUNAPEE HYDRO	889	SUNAPEE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-85	Public Service Company of New Hampshire	PSNH	NH	19	NH	NH		0.328	0.180	0.328	0.180	0.005
890	NASHUA HYDRO	890	NASHUA HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.492	0.287	0.492	0.287	0.287
891	HILLSBORO MILLS	891	HILLSBORO MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-88	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	10036	0.136	0.000	0.136	0.000	0.000
892	LAKEPORT DAM	892	LAKEPORT DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-83	Power Supply Services, LLC	PSS	NH	01	NH	NH		0.136	0.212	0.136	0.212	-0.240
893	WEST HOPKINTON HYDRO	893	WEST HOPKINTON HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-82	CHI Power Marketing, Inc.	CHIPM	NH	13	NH	NH	54384	0.384	0.270	0.384	0.270	-0.139
894	LISBON HYDRO	894	LISBON HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-86	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.203	0.241	0.203	0.241	-0.109
895	LOWER ROBERTSON DAM	895	LOWER ROBERTSON DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-87	Massachusetts Municipal Wholesale Electric Company	MMWEC	NH	05	VT	NH		0.538	0.374	0.538	0.374	-0.130
897	OLD NASH DAM	897	OLD NASH DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	NH	05	VT	NH		0.081	0.041	0.081	0.041	0.007
898	SUGAR RIVER HYDRO	898	SUGAR RIVER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-86	Public Service Company of New Hampshire	PSNH	NH	19	NH	NH		0.119	0.058	0.119	0.058	0.058
900	GREAT FALLS 1 LOWER	900	GREAT FALLS 1 LOWER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-84	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH	50704	0.478	0.168	0.478	0.168	0.100
901	WATERLOOM FALLS	901	WATERLOOM FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-81	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.031	0.000	0.031	0.000	0.000
902	HOSIERY MILL DAM	902	HOSIERY MILL DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-84	Swift River Trading Company LLC	SRTC	NH	11	NH	NH		0.000	0.001	0.000	0.001	0.001
903	WYANDOTTE HYDRO	903	WYANDOTTE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-83	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.034	0.000	0.034	0.000	0.000
904	LOCHMERE DAM	904	LOCHMERE DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Massachusetts Municipal Wholesale Electric Company	MMWEC	NH	01	NH	NH	54572	0.482	0.231	0.482	0.231	-0.220
905	ASHUELOT HYDRO	905	ASHUELOT HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-87	Massachusetts Municipal Wholesale Electric Company	MMWEC	NH	05	VT	NH		0.452	0.392	0.452	0.392	-0.172
906	ROLLINSFORD HYDRO	906	ROLLINSFORD HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-80	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH	54418	0.734	0.178	0.734	0.178	-0.104
908	OTIS MILL HYDRO	908	OTIS MILL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-82	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	50080	0.007	0.000	0.007	0.000	0.000
909	STEELS POND HYDRO	909	STEELS POND HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.000	0.000	0.000	0.000	0.000
910	CAMPTON DAM	910	CAMPTON DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-85	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.091	0.106	0.091	0.106	-0.007
911	KELLEYS FALLS	911	KELLEYS FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-89	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.000	0.000	0.000	0.000	-0.105
913	GOODRICH FALLS	913	GOODRICH FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-81	Public Service Company of New Hampshire	PSNH	NH	03	NH	NH		0.237	0.189	0.237	0.189	-0.099
914	CHAMBERLAIN FALLS	914	CHAMBERLAIN FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-83	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.000	0.000	0.000	0.000	0.000
915	MONADNOCK PAPER MILLS	915	MONADNOCK PAPER MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-75	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.000	0.000	0.000	0.000	0.000
919	HOPKINTON HYDRO	919	HOPKINTON HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Sterling Municipal Electric Light Department	SMED	NH	13	NH	NH		0.151	0.119	0.151	0.119	-0.004
922	NOONE FALLS	922	NOONE FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-85	Public Service Company of New Hampshire	PSNH	NH	11	VT	NH		0.067	0.000	0.067	0.000	0.000
925	OTTER LANE HYDRO	925	OTTER LANE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-84	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH		0.033	0.015	0.033	0.015	-0.004
926	PETERBOROUGH LOWER HYDRO	926	PETERBOROUGH LOWER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-89	Public Service Company of New Hampshire	PSNH	NH	11	VT	NH		0.130	0.037	0.130	0.037	0.001
928	SALMON BROOK STATION 3	928	SALMON BROOK STATION 3	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-85	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH		0.000	0.000	0.000	0.000	-0.117
931	AVERY DAM	931	AVERY DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-85	Public Service Company of New Hampshire	PSNH	NH	01	NH	NH		0.163	0.175	0.163	0.175	-0.073
932	WATSON DAM	932	WATSON DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-85	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.122	0.066	0.122	0.066	-0.004
933	WESTON DAM	933	WESTON DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-87	Public Service Company of New Hampshire	PSNH	NH	07	NH	NH	1509	0.236	0.254	0.236	0.254	-0.060
935	SUNNYBROOK HYDRO 2	935	SUNNYBROOK HYDRO 2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-82	Public Service Company of New Hampshire	PSNH	NH	07	NH	NH		0.004	0.009	0.004	0.009	-0.007
941	PETERBOROUGH UPPER HYDRO	941	PETERBOROUGH UPPER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-90	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.147	0.000	0.147	0.000	-0.051
942	DUNBARTON ROAD LANDFILL	942	DUNBARTON ROAD LANDFILL	IC	LFG		BIO/REFUSE	01-Aug-89	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	55779	0.000	0.000	0.000	0.000	0.000
943	FOUR HILLS LANDFILL	943	FOUR HILLS LANDFILL	IC	LFG		BIO/REFUSE	01-Apr-96	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.723	0.694	0.723	0.694	-0.027
947	RIVERDALE MILLS - QF	947	RIVERDALE MILLS - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-85	Massachusetts Electric Company	MEC	MA	27	RI	SEMA	50601	0.000	0.000	0.000	0.000	0.000
948	PEPPERELL HYDRO COMPANY LLC	948	PEPPERELL HYDRO COMPANY LLC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-20	Swift River Trading Company LLC	SRTC	MA	17	CMA/NEMA	WCMA	10694	0.484	0.446	0.484	0.446	-0.275
949	VALLEY HYDRO - QF	949	VALLEY HYDRO - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-84	The Narragansett Electric Company	NEC	RI	03	RI	RI		0.106	0.000	0.106	0.000	-0.004
950	LP ATHOL - QF	950	LP ATHOL - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-31	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.049	0.055	0.049	0.055	-0.058
951	BALTIC MILLS - QF	951	BALTIC MILLS - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-81	Sterling Municipal Electric Light Department	SMED	NH	09	VT	NH		0.061	0.061	0.061	0.061	-0.002
952	PONTIAC ENERGY - QF	952	PONTIAC ENERGY - QF	IC	OBG		BIO/REFUSE	01-Oct-98	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
953	ATTLEBORO LANDFILL - QF	953	ATTLEBORO LANDFILL - QF	IC	OBG		BIO/REFUSE	01-Nov-97	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.105	0.119	0.105	0.119	0.119
954	MM LOWELL LANDFILL - QF	954	MM LOWELL LANDFILL - QF	IC	LFG		BIO/REFUSE	01-Aug-97	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA	55095	0.099	0.077	0.099	0.077	-0.020
957	HG&E HYDRO/CABOT 1-4	957	HG&E HYDRO/CABOT 1-4	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	9864	0.607	0.922	0.607	0.922	-0.863
959	BARTON 1-4 DIESELS	959	BARTON 1-4 DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	01-Jul-56	Vermont Public Power Supply Authority	VPPSA	VT	19	NH	VT	3753	0.000	0.000	0.000	0.000	0.000
969	POWDER MILL HYDRO	969	POWDER MILL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-90	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
970	DUDLEY HYDRO	970	DUDLEY HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-87	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.106	0.000	0.106	0.000	-0.040
973	CONCORD STEAM		No Resource (1)	ST	WDS		BIO/REFUSE	01-Oct-86	Unitil Energy Systems, Inc.	UNITIL-ES	NH	13	NH	NH		0.208	0.000	0.208	0.000	0.000
978	NEW MILFORD	978	NEW MILFORD	IC	OBG	DFO	BIO/REFUSE	01-Aug-91	Connecticut Light and Power Company, The	CLP	CT	05	SWCT	CT	50564	1.282	1.177	1.282	1.177	-0.127
1005	EIGHTON POWER LLC	1005	EIGHTON POWER LLC	CC	NG		GAS COMBINED CYCLE	01-May-99	EquiPower Resources Management, LLC	EPRM	MA	05	SEMA	SEMA	55026	185.000	160.539	185.000	160.539	0.000
1028	BUNKER RD #12 GAS TURB	1028	BUNKER RD #12 GAS TURB	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Apr-00	New England Power Company	NEP	MA	19	SEMA	SEMA	1615	3.012	2.351	3.012	2.351	0.000
1029	BUNKER RD #13 GAS TURB	1029	BUNKER RD #13 GAS TURB	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Apr-00	New England Power Company	NEP	MA	19	SEMA	SEMA	1615	3.281	2.806	3.281	2.806	0.000
1030	OAK BLUFFS	1030	OAK BLUFFS	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-70	Genon Energy Management, LLC	MET	MA	07	SEMA	SEMA	1597	8.120	7.471	8.120	7.471	0.000
1031	WEST TISBURY	1031	WEST TISBURY	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-75	Genon Energy Management, LLC	MET	MA	07	SEMA	SEMA	6049	5.142	5.005	5.142	5.005	0.000
1032	BRIDGEPORT ENERGY 1	1032	BRIDGEPORT ENERGY 1	CC	NG		GAS COMBINED CYCLE	01-Aug-98	Emera Energy Services Subsidiary No. 5 LLC	EES5	CT	01	SWCT	CT	55042	519.937	451.264	519.937	487.000	36.736
1034	RIVERSIDE 4-7	1034	RIVERSIDE 4-7	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-21	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	1607	1.477	1.139	1.477	1.139	-0.826
1035	RIVERSIDE 8	1035	RIVERSIDE 8	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-31	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	1607	3.190	3.083	3.190	3.083	-0.211
1047	FAIRFAX	1047	FAIRFAX	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	25-Sep-98	Green Mountain Power Corporation	GMP	VT	11	VT	VT	3712	3.775	1.122	3.775	1.122	-2.629
1048	WARE HYDRO	1048	WARE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-84	Pioneer Hydro Electric Co., Inc.	PHE	MA	15	WMA	WCMA	50419	0.450	0.000	0.450	0.000	-0.273
1049	COLLINS HYDRO	1049	COLLINS HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-82	Swift River Trading Company LLC	SRTC	MA	13	WMA	WCMA	52166	0.660	0.234	0.660	0.234	-0.258
1050	CHICOPEE HYDRO	1050	CHICOPEE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-85	Chicopee Municipal Lighting Plant	CMLP	MA	13	WMA	WCMA	50832	0.989	0.411	0.989	0.411	-0.410
1054	BLACKSTONE HYDRO ASSOC	1054	BLACKSTONE HYDRO ASSOC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-89	The Narragansett Electric Company	NEC	RI	07	RI	RI	3245	0.000	0.000	0.000	0.000	0.000
1057	BLACKSTONE HYDRO LOAD REDUCER	1057	BLACKSTONE HYDRO LOAD REDUCER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-89	Blackstone Hydro, Inc.	BHI	RI	07	RI	RI	50177	0.494	0.104	0.494	0.104	-0.198
1059	BARRE LANDFILL	1059	BARRE LANDFILL	IC	LFG		BIO/REFUSE	01-Jul-96	Dominion Energy Marketing, Inc.	DEM	MA	27	WMA	WCMA	55776	0.592	0.658	0.592	0.658	0.230
1061	MASCOMA HYDRO	1061	MASCOMA HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-88	TransCanada Power Marketing, Ltd.	TCPM	NH	09	VT	NH	54471	0.558	0.000	0.558	0.000	0.380
1062	MWRA COSGROVE	1062	MWRA COSGROVE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Oct-95	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA	10825	0.148	0.834	0.148	0.834	-0.064
1086	BERKSHIRE POWER	1086	BERKSHIRE POWER	CC	NG		GAS COMBINED CYCLE	19-Jun-00	Direct Energy Business Marketing, LLC	DEBM	MA	13	WMA	WCMA	55041	246.279	229.279	246.279	229.279	0.000
1107	SOMERSET	1107	SOMERSET	ST	BLQ	WDS	BIO/REFUSE	01-Jan-76	NextEra Energy Power Marketing, LLC	FPLP	ME	11	ME	ME	50406	0.000	0.000	0.000	0.000	0.000
1109	MMWAC	1109	MMWAC	ST	MSW		BIO/REFUSE	01-Jun-92	Mid-Maine Waste Action Corporation	MMWAC	ME	01	ME	ME	50035	2.039	1.986	2.039	1.986	0.052
1113	BRASSUA HYDRO	1113	BRASSUA HYDRO	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Aug-89	Brookfield Energy Marketing, LP	BEMLP	ME	25	ME	ME	10555	1.071	2.696	1.071	2.696	0.002
1114	MADISON COMPOSITE	1114	MADISON COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-84	Competitive Energy Services, LLC	CESLLC	ME	25	ME	ME	7469	0.000	0.000	0.000	0.000	0.000
1117	GREAT WORKS COMPOSITE	1117	GREAT WORKS COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-84	Blackstone Hydro, Inc.	BHI	ME	31	SME	ME		0.111	0.009	0.111	0.009	-0.039
1119	KENNEBAGO HYDRO	1119	KENNEBAGO HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-88	Exelon Generation Company, LLC	EXGC	ME	29	ME	ME		0.252	0.285	0.252	0.285	0.081
1122	CASCADE-DIAMOND-QF	1122	CASCADE-DIAMOND-QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-19	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.216	0.038	0.216	0.038	-0.182
1165	CADYS FALLS	1165	CADYS FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	VT	15	VT	VT	3765	0.454	0.226	0.454	0.226	0.162
1166	MORRISVILLE PLANT #2	1166	MORRISVILLE PLANT #2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	VT	15	VT	VT	3764	0.579	0.135	0.579	0.135	-0.208
1167	WOLCOTT HYDRO #1	1167	WOLCOTT HYDRO #1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-37	Vermont Public Power Supply Authority	VPPSA	VT	15	VT	VT	6477	0.275	0.136	0.275	0.136	-0.266
1168	H.K. SANDERS	1168	H.K. SANDERS	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-83	Vermont Public Power Supply Authority	VPPSA	VT	15	VT	VT	678	1.715	1.800	1.715	1.800	0.000
1185	STONY BROOK GT1A	1185	STONY BROOK GT1A	CC	DFO	NG	GAS/OIL COMBINED CYCLE	01-Nov-81	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	13	WMA	WCMA	6081	119.000	103.858	119.000	103.858	-0.142
1186	STONY BROOK GT1B	1186	STONY BROOK GT1B	CC	DFO	NG	GAS/OIL COMBINED CYCLE	01-Nov-81	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	13	WMA	WCMA	6081	115.932	99.932	115.932	99.932	0.000
1187	STONY BROOK GT1C	1187	STONY BROOK GT1C	CC	DFO	NG	GAS/OIL COMBINED CYCLE	01-Nov-81	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	13	WMA	WCMA	6081	119.000	100.143	119.000	100.143	-3.857
1209	CRRA HARTFORD LANDFILL	1209	CRRA HARTFORD LANDFILL	IC	LFG		BIO/REFUSE	01-Aug-98	Connecticut Light and Power Company, The	CLP	CT	03	CT	CT	55163	1.285	1.212	1.285	1.212	-0.036
1210	MILLENNIUM	1210	MILLENNIUM	CC	NG		GAS COMBINED CYCLE	06-Apr-01	Consolidated Edison Energy, Inc	CEEI	MA	27	WMA	WCMA	55079	383.904	334.904	383.904	334.904	0.000
1221	ESSEX DIESELS	1221	ESSEX DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-47	Green Mountain Power Corporation	GMP	VT	07	VT	VT	3737	7.246	7.215	7.246	7.215	0.000
1225	TANNERY DAM	1225	TANNERY DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-00	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA	55924	0.000	0.000	0.000	0.000	0.000
1226	TIVERTON POWER	1226	TIVERTON POWER	CC	NG		GAS COMBINED CYCLE	18-Aug-00	Emera Energy Services Subsidiary No. 6 LLC	EES6	RI	05	SEMA	RI	55048	278.756	243.208	278.756	243.208	0.000
1255	RUMFORD POWER	1255	RUMFORD POWER	CC	NG		GAS COMBINED CYCLE	16-Oct-00	Emera Energy Services Subsidiary No. 7 LLC	EES7	ME	17	ME	ME	55100	269.091	244.281	269.091	244.281	0.000
1258	BHE SMALL HYDRO COMPOSITE	1258	BHE SMALL HYDRO COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-82	New Brunswick Energy Marketing Corporation	NBPGC	ME	21	BHE	ME		0.813	0.496	0.813	0.496	-0.473
1266	MARSH POWER	1266	MARSH POWER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-86	Christopher M. Anthony	CMA	ME	27	ME	ME	1469	0.000	0.000	0.000	0.000	0.000
1267	SPARHAWK	1267	SPARHAWK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-85	Union Atlantic Electricity	UNION	ME	05	SME	ME		0.013	0.000	0.013	0.000	0.003
1270	SYSKO STONY BROOK	1270	SYSKO STONY BROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Union Atlantic Electricity	UNION	ME	17	ME	ME		0.016	0.015	0.016	0.015	-0.002
1271	SYSKO WIGHT BROOK	1271	SYSKO WIGHT BROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-84	Union Atlantic Electricity	UNION	ME	17	ME	ME		0.021	0.000	0.021	0.000	0.000
1273	KENNEBEC WATER US	1273	KENNEBEC WATER US	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-95	Messalonskee Stream Hydro, LLC	MESSA	ME	11	ME	ME	54148	0.518	0.512	0.518	0.512	0.512
1286	ANP-BLACKSTONE ENERGY 1	1286	ANP-BLACKSTONE ENERGY CO. #1	CC	NG		GAS COMBINED CYCLE	07-Jun-01	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	27	RI	SEMA	55212	246.947	239.174	246.947	239.174	0.000
1287	ANP-BLACKSTONE ENERGY 2	1287	ANP-BLACKSTONE ENERGY 2	CC	NG		GAS COMBINED CYCLE	13-Jul-01	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	27	RI	SEMA	55212	249.338	234.134	249.338	234.134	0.000
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Contains Proprietary Material
Do Not Distribute

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICI-PANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 81/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
2425	SPRINGFIELD REFUSE-NEW	2425	SPRINGFIELD REFUSE-NEW	ST	MSW	DFO	BIO/REFUSE	01-Sep-88	Covanta Energy Marketing, LLC	CEM	MA	13	WMA	WCMA	50273	5.700	6.124	5.700	6.124	0.201
2426	HYDRO KENNEBEC	2426	Hydro Kennebec	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-89	Brookfield Energy Marketing, LP	BEMLP	ME	11	ME	ME	54148	9.520	11.524	9.520	11.524	3.463
2430	BELDENS-NEW	2430	BELDENS-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Green Mountain Power Corporation	GMP	VT	01	VT	VT	6451	1.616	0.906	1.616	0.906	-1.440
2431	DODGE FALLS-NEW	2431	DODGE FALLS-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-90	Vermont Electric Power Company, Inc.	VELCO	NH	09	VT	VT	10526	3.371	3.629	3.371	3.629	-0.672
2432	HUNTINGTON FALLS-NEW	2432	HUNTINGTON FALLS-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-88	Green Mountain Power Corporation	GMP	VT	01	VT	VT	50713	2.008	1.728	2.008	1.728	-1.493
2433	RYEGATE 1-NEW	2433	RYEGATE 1-NEW	ST	WDS		BIO/REFUSE	01-Nov-92	Vermont Electric Power Company, Inc.	VELCO	VT	05	NH	VT	51026	19.920	19.560	19.920	19.560	-0.700
2434	GORGE 18 HYDRO-NEW	2434	GORGE 18 HYDRO-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-28	Green Mountain Power Corporation	GMP	VT	07	VT	VT	6475	1.542	0.000	1.542	0.000	-0.670
2435	VERGENNES HYDRO-NEW	2435	VERGENNES HYDRO-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-12	Green Mountain Power Corporation	GMP	VT	01	VT	VT	6519	1.476	0.923	1.476	0.923	-0.817
2439	BROCKWAY MILLS U5	2439	BROCKWAY MILLS U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-03	Green Mountain Power Corporation	GMP	VT	25	VT	VT		0.196	0.000	0.196	0.000	-0.139
2462	PLAINVILLE GEN GF U5	2462	PLAINVILLE GEN GF U5	IC	OBG		BIO/REFUSE	24-Mar-03	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		2.287	2.106	2.287	2.106	0.001
2466	CHERRY 7	2466	CHERRY 7	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	MA	17	CMA/NEMA	WCMA	9038	2.800	2.800	2.800	2.800	0.000
2467	CHERRY 8	2467	CHERRY 8	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	MA	17	CMA/NEMA	WCMA	9038	3.400	3.400	3.400	3.400	0.000
2468	CHERRY 10	2468	CHERRY 10	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	MA	17	CMA/NEMA	WCMA	9038	2.100	2.100	2.100	2.100	0.000
2469	CHERRY 11	2469	CHERRY 11	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	MA	17	CMA/NEMA	WCMA	9038	2.100	2.100	2.100	2.100	0.000
2470	CHERRY 12	2470	CHERRY 12	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	MA	17	CMA/NEMA	WCMA	9038	4.999	4.999	4.999	4.999	0.000
10308	NECCO COGENERATION FACILITY	10308	NECCO COGENERATION FACILITY	IC	NG		GAS INTERNAL COMBUSTION	01-Oct-03	New England Confectionery Company, Inc	NECCO	MA	25	BOSTON	NEMA	55999	4.939	0.017	4.939	0.017	-4.726
10347	KENDALL STEAM 1	37040	KENDALL STEAM	CC	NG		GAS COMBINED CYCLE	01-Jan-50	Kendall Green Energy, LLC	KENDALL	MA	17	BOSTON	NEMA	1595	14.752	14.505	14.752	14.505	0.000
10348	KENDALL STEAM 2	37040	KENDALL STEAM	CC	NG		GAS COMBINED CYCLE	01-Jan-50	Kendall Green Energy, LLC	KENDALL	MA	17	BOSTON	NEMA	1595	19.669	19.340	19.669	19.340	0.000
10349	KENDALL STEAM 3	37040	KENDALL STEAM	CC	NG		GAS COMBINED CYCLE	01-Jan-50	Kendall Green Energy, LLC	KENDALL	MA	17	BOSTON	NEMA	1595	20.141	19.805	20.141	19.805	0.000
10401	CELLEY MILL U5	10401	CELLEY MILL U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.064	0.031	0.064	0.031	-0.040
10402	PETTYBORO HYDRO U5	10402	PETTYBORO HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	09-May-99	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.000	0.000	0.000	0.000	0.000
10403	EASTMAN BROOK U5	10403	EASTMAN BROOK U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-85	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.030	0.008	0.030	0.008	-0.021
10404	WHEELABRATOR CLAREMONT U5	10404	WHEELABRATOR CLAREMONT U5	ST	MSW		BIO/REFUSE	01-Mar-04	Wheelabrator North Andover Inc	WNE	NH	19	NH	NH	50872	0.000	0.000	0.000	0.000	-3.648
10406	LOWER VALLEY HYDRO U5	10406	LOWER VALLEY HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-04	Green Mountain Power Corporation	GMP	NH	19	NH	NH		0.083	0.000	0.083	0.000	-0.177
10407	WOODSVILLE HYDRO U5	10407	WOODSVILLE HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-87	Green Mountain Power Corporation	GMP	NH	19	NH	NH		0.069	0.166	0.069	0.166	-0.071
10408	LOWER VILLAGE HYDRO U5	10408	LOWER VILLAGE HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-95	Green Mountain Power Corporation	GMP	NH	19	NH	NH	50285	0.000	0.000	0.000	0.000	0.000
10409	SWEETWATER HYDRO U5	10409	SWEETWATER HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-04	Green Mountain Power Corporation	GMP	NH	19	NH	NH		0.257	0.221	0.257	0.221	0.015
10424	GREAT LAKES - BERLIN	10424	Great Lakes - Berlin Incremental	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	22-Jun-04	Brookfield Energy Marketing, LP	BEMLP	NH	07	NH	NH	54639	10.854	9.230	10.854	9.230	-0.364
10451	WESTFIELD #1 U5	10451	WESTFIELD #1 U5	IC	OBG		BIO/REFUSE	01-Mar-04	Westfield Gas and Electric Light Department	WGED	MA	13	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
10615	BLUE SPRUCE FARM U5	10615	BLUE SPRUCE FARM U5	IC	OBG		BIO/REFUSE	01-Nov-04	Green Mountain Power Corporation	GMP	VT	21	VT			0.296	0.305	0.296	0.305	0.018
10770	WEST SPRINGFIELD HYDRO U5	10770	WEST SPRINGFIELD HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	10-Jan-05	Littleton Electric Light & Water Department	LELWD	MA	13	WMA	WCMA		0.774	0.515	0.774	0.515	-0.074
10801	COVENTRY CLEAN ENERGY	10801	COVENTRY CLEAN ENERGY	IC	LFG		BIO/REFUSE	01-Feb-05	Vermont Public Power Supply Authority	VPPSA	VT	19	NH	VT		3.300	3.268	3.300	3.268	-0.152
10880	GE LYNN EXCESS REPLACEMENT	10880	GE LYNN EXCESS REPLACEMENT	GT	DFO	NG	GAS/OIL COMBUSTION (GAS) TURBINE	11-Oct-05	Constellation NewEnergy, Inc.	CNE	MA	25	BOSTON	NEMA	10029	0.000	0.000	0.000	0.000	0.000
10959	RRIG EXPANSION PHASE 2	10959	RRIG EXPANSION PHASE 2	IC	LFG		BIO/REFUSE	01-Jun-05	Rhode Island Engine Genco, LLC	RRIG	RI	07	RI	RI	50365	0.000	0.000	0.000	0.000	0.000
10998	MASSINNOVATION FITCHBURG	10998	MASSINNOVATION FITCHBURG	PV	SUN		PHOTOVOLTAIC	01-Aug-05	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
11052	GRTR NEW BEDFORD LFG UTIL PROJ	11052	GRTR NEW BEDFORD LFG UTIL PROJ	IC	LFG		BIO/REFUSE	15-Aug-05	Exelon Generation Company, LLC	EXGC	MA	05	SEMA	SEMA		2.458	2.449	2.458	2.449	0.021
11126	NORTH HARTLAND HYDRO	11126	NORTH HARTLAND HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	27-Sep-06	Green Mountain Power Corporation	GMP	VT	27	VT	VT		0.983	1.207	0.983	1.207	0.122
11408	HULL WIND TURBINE II	11408	HULL WIND TURBINE II	WT	WND		WIND TURBINE	27-Sep-05	Hull Municipal Lighting Plant	HULL	MA	23	SEMA	SEMA	56800	0.248	0.075	0.248	0.075	0.038
11424	RUMFORD FALLS	11424	RUMFORD FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	06-Jul-06	Brookfield Energy Marketing, LP	BEMLP	ME	17	ME	ME	10493	30.830	32.470	30.830	32.470	-1.690
11827	PORTSMOUTH ABBEY WIND QF		No Resource (1)	WT	WND		WIND TURBINE	25-Jul-06	The Narragansett Electric Company	NEC	RI	05	SEMA	RI		0.000	0.000	0.000	0.000	0.000
11842	WATERSIDE POWER	11842	WATERSIDE POWER	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-May-04	Waterside Power, LLC	WATERSIDE	CT	01	NOR	CT	56189	71.557	70.017	71.557	70.017	0.000
11889	BEW LOCAL 99 SOLAR QF		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-06	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
11925	BROCKTON BRIGHTFIELDS	11925	BROCKTON BRIGHTFIELDS	PV	SUN		PHOTOVOLTAIC	18-Sep-06	Exelon Generation Company, LLC	EXGC	MA	23	SEMA	SEMA		0.000	0.152	0.000	0.152	0.006
12108	FIEC DIESEL	12108	FIEC DIESEL	IC	DFO		OIL INTERNAL COMBUSTION	01-Dec-06	Vermont Public Power Supply Authority	VPPSA	ME	13	ME	ME		1.596	1.540	1.596	1.540	0.000
12163	PPL GREAT WORKS - RED SHIELD	12163	PPL GREAT WORKS - RED SHIELD	ST	WDS		BIO/REFUSE	24-Jan-07	Competitive Energy Services, LLC	CESLLC	ME	19	BHE	ME	10700	0.000	0.000	0.000	0.000	0.000
12168	HARRIS ENERGY	12168	HARRIS ENERGY	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-06	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	54981	0.000	0.000	0.000	0.000	0.000
12180	BERKSHIRE COW POWER	12180	BERKSHIRE COW POWER	IC	OBG		BIO/REFUSE	06-Dec-06	Vermont Electric Cooperative, Inc.	VEC	VT	11	VT	VT		0.262	0.207	0.262	0.207	-0.004
12274	GREEN MOUNTAIN DAIRY	12274	GREEN MOUNTAIN DAIRY	IC	OBG		BIO/REFUSE	01-Feb-07	Green Mountain Power Corporation	GMP	VT	11	VT	VT		0.220	0.218	0.220	0.218	-0.031
12323	COVENTRY CLEAN ENERGY #4	12323	COVENTRY CLEAN ENERGY #4	IC	LFG		BIO/REFUSE	20-Jan-07	Vermont Public Power Supply Authority	VPPSA	VT	19	NH	VT		2.200	2.179	2.200	2.179	-0.101
12504	Devon 15-18	12504	Devon 15-18	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	12-Jul-10	GenConn Energy LLC	GCE	CT	09	SWCT	CT	57070	49.200	46.889	49.200	46.889	0.000
12505	MIDDLETOWN 12-15	12505	MIDDLETOWN 12-15	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	24-Jun-11	GenConn Energy LLC	GCE	CT	07	CT	CT	57068	49.200	46.900	49.200	46.900	0.000
12509	UNH POWER PLANT	12509	UNH Power Plant	GT	LFG		BIO/REFUSE	20-Oct-09	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH	58180	4.378	3.008	4.378	3.008	0.000
12510	SWANTON GT-1	12510	Swanton Gas Turbine 1	GT	DFO	OBL	OIL COMBUSTION (GAS) TURBINE	12-Feb-10	Vermont Public Power Supply Authority	VPPSA	VT	11	VT	VT		23.954	19.304	23.954	19.304	0.000
12511	SWANTON GT-2	12511	Swanton Gas Turbine 2	GT	DFO	OBL	OIL COMBUSTION (GAS) TURBINE	24-May-10	Vermont Public Power Supply Authority	VPPSA	VT	11	VT	VT		23.839	19.349	23.839	19.349	0.000
12529	HOOSAC WIND		No Resource (1)	WT	WND		WIND TURBINE	27-Dec-12	Iberdrola Renewables, LLC	IR	MA	03	WMA	WCMA	57380	13.627	3.942	13.627	3.942	-1.332
12530	SHEFFIELD WIND PLANT	12530	Sheffield Wind Farm	WT	WND		WIND TURBINE	19-Oct-11	Vermont Wind LLC	VTWIND	VT	05	VT	VT	57080	9.685	3.295	9.685	3.295	0.995
12551	KIBBY WIND POWER	12551	Kibby Wind Power	WT	WND		WIND TURBINE	16-Sep-09	TransCanada Power Marketing, Ltd.	TCPM	ME	07	ME	ME	56829	35.060	18.275	35.060	18.275	0.480
12564	WATERBURY GENERATION FACILITY	12564	Waterbury Generation Facility	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	21-May-09	Waterbury Generation LLC	WATERBURY	CT	09	SWCT	CT	56629	98.128	95.821	98.128	95.821	1.088
13515	PIERCE STATION	12526	Pierce	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-07	Connecticut Municipal Electric Energy Cooperative	CMEEC	CT	09	SWCT	CT	6635	94.590	74.085	94.590	74.085	0.000
13669	EAST WINDSOR NORCAP LFG PLANT	13669	Manchester Methane LLC East Windsor Facility	IC	LFG		BIO/REFUSE	07-May-07	Manchester Methane, LLC	MMLLC	CT	03	CT	CT		0.698	0.783	0.698	0.783	0.000
13673	MATEP (DIESEL)	13673	MATEP (DIESEL)	IC	DFO		OIL INTERNAL COMBUSTION	28-Jun-07	MATEP, LLC	MATEP	MA	25	BOSTON	NEMA	10883	17.460	17.120	17.460	17.120	0.000
13675	MATEP (COMBINED CYCLE)	13675	MATEP (COMBINED CYCLE)	CC	NG	DFO	GAS/OIL COMBINED CYCLE	28-Jun-07	MATEP, LLC	MATEP	MA	25	BOSTON	NEMA	10883	48.275	42.515	48.275	42.515	0.000
13703	VERSO COGEN 1	13703	Verso VCG1	GT	NG	KER	GAS COMBUSTION (GAS) TURBINE	28-Dec-00	Verso Maine Energy LLC	VERSO	ME	07	ME	ME	55031	53.760	42.483	53.760	42.483	0.000
13704	VERSO COGEN 2	13704	Verso VCG2	GT	NG	KER	GAS COMBUSTION (GAS) TURBINE	28-Dec-00	Verso Maine Energy LLC	VERSO	ME	07	ME	ME	55031	56.333	44.314	56.333	44.314	0.000
13705	VERSO COGEN 3	13705	Verso VCG3	GT	NG	KER	GAS COMBUSTION (GAS) TURBINE	28-Dec-00	Verso Maine Energy LLC	VERSO	ME	07	ME	ME	55031	55.123	41.962	55.123	41.962	0.000
13933	UMINY PEAK WIND QF		No Resource (1)	WT	WND		WIND TURBINE	01-Jul-07	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.020	0.000	0.020	0.000	0.000
13975	CORRIVEAU HYDROELECTRIC LLC	13975	Corriveau Hydroelectric LLC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	10-Aug-07	Union Atlantic Electricity	UNION	ME	17	ME	ME		0.053	0.063	0.053	0.063	-0.040
14087	MAT3	14087	MAT3	IC	DFO		OIL INTERNAL COMBUSTION	11-Dec-07	MATEP, LLC	MATEP	MA	25	BOSTON	NEMA	10883	18.630	17.970	18.630	17.970	0.000
14098	FITCHBURG LANDFILL	35485	Fitchburg-FCA-5	IC	LFG		BIO/REFUSE	16-Aug-07	Vermont Public Power Supply Authority	VPPSA	MA	27	WMA	WCMA	56527	3.316	3.093	3.316	3.093	-1.093
14134	MONTAGNE FARM	14134	MONTAGNE FARM	IC	LFG		BIO/REFUSE	17-Sep-07	Green Mountain Power Corporation	GMP	VT	11	VT	VT		0.000	0.000	0.000	0.000	-0.080
14152	COS COB 13	12524	Cos Cob 13&14	GT	KER		OIL COMBUSTION (GAS) TURBINE	29-May-08	NRG Power Marketing LLC	NRGPM	CT	01	NOR	CT	542	22.852	19.053	22.852	19.053	0.000
14158	COS COB 14	12524	Cos Cob 13&14	GT	KER		OIL COMBUSTION (GAS) TURBINE	29-May-08	NRG Power Marketing LLC	NRGPM	CT	01	NOR	CT	542	22.602	19.209	22.602	19.209	0.000
14177	WESTBROOK ENERGY CENTER G1	1345	WESTBROOK	CC	NG		GAS COMBINED CYCLE	13-Apr-01	Calpine Energy Services, LP	CALP	ME	05	SME	ME	55294	281.835	261.204	281.835	261.204	0.268
14178	WESTBROOK ENERGY CENTER G2	1345	WESTBROOK	CC	NG		GAS COMBINED CYCLE	13-Apr-01	Calpine Energy Services, LP	CALP	ME	05	SME	ME	55294	285.063	261.204	285.063	261.204	6.824
14211	INDECK ALEXANDRIA	1631	Indeck-Energy Alexandria, LLC	ST	WDS		BIO/REFUSE	06-Nov-08	Indeck Energy-Alexandria, L.L.C.	IEA	NH	09	NH	NH		15.200	15.031	15.200	15.031	0.000
14217	NORTHFIELD MOUNTAIN 1	14217	NORTHFIELD MOUNTAIN 1	PS	WAT		HYDRO (PUMPED STORAGE)	30-Nov-72	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	547	270.000	270.000	270.000	270.000	0.000
14218	NORTHFIELD MOUNTAIN 2	14218	NORTHFIELD MOUNTAIN 2	PS	WAT		HYDRO (PUMPED STORAGE)	30-Nov-72	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	547	293.500	293.500	293.500	293.500	0.000
14219	NORTHFIELD MOUNTAIN 3	14219	NORTHFIELD MOUNTAIN 3	PS	WAT		HYDRO (PUMPED STORAGE)	30-Nov-72	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	547	292.000	292.000	292.000	292.000	0.000
14220	NORTHFIELD MOUNTAIN 4	14220	NORTHFIELD MOUNTAIN 4	PS	WAT		HYDRO (PUMPED STORAGE)	30-Nov-72	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	547	274.638	293.500	274.638	293.500	0.000
14271	AMERESCO NORTHAMPTON	14271	Ameresco Northampton	IC	LFG		BIO/REFUSE	01-Nov-07	Exelon Generation Company, LLC	EXGC	MA	15	WMA	WCMA		0.752	0.748	0.752	0.748	0.000
14595	GRANITE RELIABLE POWER, LLC	14595	Granite Reliable Power	WT	WND		WIND TURBINE	15-Feb-12	Granite Reliable Power, LLC	GRP	NH	07	NH	NH	58004	26.748	14.034	26.748	14.034	0.102
14610	PRINCETON WIND FARM PROJECT	14610	Princeton Wind Farm Project	WT	WND		WIND TURBINE	01-Sep-09	Princeton Municipal Light Department	PMLD	MA	27	WMA	WCMA	7501	0.297	0.154	0.297	0.154	0.124
14614	KLEEN ENERGY	14614	Kleen Energy	CC	NG	DFO	GAS/OIL COMBINED CYCLE	12-Jul-11	Exelon Generation Company, LLC	EXGC	CT	07	CT	CT	56798	620.000	620.000	620.000	620.000	0.000
14623	VALLEY HYDRO (STATION NO. 5)	14623	Valley Hydro (Station No. 5)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-08	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA		0.604	0.000	0.604	0.000	-0.552
14652	TEMPLETON WIND TURBINE	14652	Templeton Wind Turbine	WT	WND		WIND TURBINE	18-May-11	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	27	WMA	WCMA		0.157	0.058	0.157	0.058	-0.041
14665	RECORD HILL WIND	14665	Record Hill Wind	WT	WND		WIND TURBINE	31-Jan-12	Record Hill Wind, LLC	RHW	ME	17	ME	ME	57568	12.305	5.168	12.305	5.168	-1.780
14695	ORONO	14695	Orono Hydro Station	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	29-Dec-08	Black Bear Hydro Partners, LLC	BBHP	ME	19	BHE	ME	57184	1.681	1.790	1.681	1.790	1.790
14707	COVANTA HAVERHILL - LF GAS	12553	Covanta Haverhill Landfill Gas Engine	IC	LFG		BIO/REFUSE	05-Dec-07	Covanta Haverhill Associates	CHA	MA	09	BOSTON	NEMA	50661	1.091	1.089	1.091	1.089	-0.099
14767	PINE TREE LFGTE		No Resource (1)	IC	LFG		BIO/REFUSE	01-Jan-08	NextEra Energy Power Marketing, LLC	FPLP	ME	19	BHE	ME		0.000	0.000	0.000	0.000	0.000
14801	CABOT	766	CABOT TURNERS FALLS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-05	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	1629	61.800	61.481	61.800	61.481	0.000
14808	TURNERSFALLS	766	CABOT TURNERS FALLS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-05	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	6388	6.400	6.400	6.400	6.400	0.000
14816	NORDEN 1	16688	Nor1	IC	DFO		OIL INTERNAL COMBUSTION	26-Feb-09	Connecticut Municipal Electric Energy Cooperative	CMEEC	CT	01	NOR	CT	57689	1.958	1.789	1.958	1.789	0.000
14817	NORDEN 2	16750	Norden #2	IC	DFO		OIL INTERNAL COMBUSTION	26-Feb-09	Connecticut Municipal Electric Energy Cooperative	CMEEC	CT	01	NOR	CT	57689	1.947	1.789	1.947	1.789	-0.159
14818	NORDEN 3	16752	Norden #3	IC	DFO		OIL INTERNAL COMBUSTION	26-Feb-09	Connecticut Municipal Electric Energy Cooperative	CMEEC	CT	01	NOR	CT	57689	1.942	1.775	1.942	1.775	-0.167
14823	NORWICH WWTP		No Resource (1)	IC	DFO		OIL INTERNAL COMBUSTION	29-May-08	Connecticut Municipal Electric Energy Cooperative	CMEEC	CT	11	CT	CT	57624	2.000	2.000	2.000	2.000	0.000
14919	DBE-001		No Resource (1)	GT	WDS	DFO	BIO/REFUSE	01-Mar-08	Public Service Company of New Hampshire	PSNH	NH	05	VT	NH		0.000	0.000	0.000	0.000	0.000
14925	ICE HOUSE PARTNERS INC.		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-08	Littleton Electric Light & Water Department	LELWD	MA	17	CMA/NEMA	WCMA		0.093	0.101	0.093	0.101	0.008
14937	UNION GAS STATION	759	MESSALONSKEE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	19-Mar-08	Messalonskee Stream Hydro, LLC	MESSA	ME	11	ME	ME		1.303	1.218	1.303	1.218	-0.113
15097	KIMB ROCKY RIVER PH2	14706	Kimberly-Clark Corp Energy Independence Project	CC	NG		GAS COMBINED CYCLE	15-Jul-08	Kimberly-Clark Corporation	KCC	CT	05	SWCT	CT	58084	14.451	13.853	14.451	13.853	0.837
15115	LEMPSTER WIND	14660	Lempster Wind	WT	WND		WIND TURBINE	24-Sep-08	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	56399	8.224	2.430	8.224	2.430	-0.815
15201	FSKE HYDRO	35593	Fiske #8	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-08	Public Service Company of New Hampshire	PSNH	NH	05	VT	NH		0.000	0.000	0.000	0.000	-1.399
15462	HOLY NAME CC JR SR HGH SCHOOL		No Resource (1)	WT	WND		WIND TURBINE	01-Sep-08	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
15464	STETSON WIND FARM		No Resource (1)	WT	WND		WIND TURBINE	09-Dec-08	Stetson Holdings, LLC	STETSON	ME	29	BHE	ME	56989	15.189	6.490	15.189	6.490	-1.103
15477	NEW HAVEN HARBOR UNIT 2	15477	New Haven Harbor Units 2, 3, & 4	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	30-May-12	PSEG New Haven, LLC	PSEG-NH	CT	09	CT	CT	6156	48.600	43.200	48.600	43.200	0.000
15484	THOMAS A. WATSON UNIT #1	12500	Thomas A. Watson	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	22-Apr-09	Braintree Electric Light Department, Town of	BELD	MA	21	SEMA	SEMA	1660	57.400	52.600	57.400	52.600	0.000
15485	THOMAS A. WATSON UNIT #2	12500	Thomas A. Watson	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	14-Apr-09	Braintree Electric Light Department, Town of	BELD	MA	21	SEMA	SEMA	1660	57.400	52.600	57.400	52.600	0.000
15488	MIDDLETON BUILDING SUPPLY		No Resource (1)	ST	WDS		BIO/REFUSE	01-Oct-08	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.000	0.000	0.000	0.000	0.000
15509	PLAINFIELD RENEWABLE ENERGY	15509	Plainfield Renewable Energy	ST	WDS	OBS	BIO/REFUSE	12-Dec-13	Plainfield Renewable Energy, LLC	PRE	CT	15	CT	CT	56847	36.464	35.534	36.464	35.534	0.333
15617	MORETOWN LFGTE	35728	Moretown LG	IC	LFG		BIO/REFUSE	01-Dec-08	Green M

Contains Proprietary Material
Do Not Distribute

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PAINT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
17233	RAINBOW UNIT 1	35658	Rainbow_1	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-80	Connecticut Light and Power Company, The	CLP	CT	03	CT	CT	559	4.100	4.100	4.100	4.100	0.000
17234	RAINBOW UNIT 2	35658	Rainbow_2	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-80	Connecticut Light and Power Company, The	CLP	CT	03	CT	CT	559	4.100	4.100	4.100	4.100	0.000
17259	SEAMAN ENERGY LLC	35442	Seaman Energy	IC	LFG		BIO/REFUSE	31-Mar-10	Templeton Municipal Lighting Plant	TTMLP	MA	27	CMA/NEMA	WCMA		0.249	0.170	0.249	0.170	-0.146
35379	SPAULDING POND HYDRO	35594	Spaulding Pond Hydro	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-10	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.201	0.035	0.201	0.035	-0.028
35555	GMCW	35555	GMCW	WT	WND		WIND TURBINE	31-Dec-12	Burlington Electric Department	BED	VT	07	VT	VT	58238	3.289	0.888	3.289	0.888	0.038
35693	SPRUCE MOUNTAIN WIND	35693	Spruce Mountain Wind	WT	WND		WIND TURBINE	21-Dec-11	Spruce Mountain Wind, LLC	SPRUCE	ME	17	ME	ME	58026	6.873	2.410	6.873	2.410	0.077
35979	KINGDOM COMMUNITY WIND	35979	Kingdom Community Wind	WT	WND		WIND TURBINE	16-Nov-12	Green Mountain Power Corporation	GMP	VT	19	VT	VT	57979	21.720	8.400	21.720	8.400	-1.360
36882	NOTUS WIND I		No Resource (1)	WT	WND		WIND TURBINE	23-Jun-10	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA	57414	0.483	0.280	0.483	0.280	-0.092
37050	GROTON WIND	37050	Groton Wind Project	WT	WND		WIND TURBINE	28-Dec-12	Iberdrola Renewables, LLC	IR	NH	09	NH	NH	58141	8.244	5.019	8.244	5.019	-1.395
37073	SOUTHBRIDGE LANDFILL	38178	Southbridge Landfill Gas to Energy 17-18	IC	LFG		BIO/REFUSE	15-Feb-12	NextEra Energy Power Marketing, LLC	FPLP	MA	27	CMA/NEMA	WCMA	59011	1.506	1.402	1.506	1.402	0.095
37175	ROLLINS WIND PLANT		No Resource (1)	WT	WND		WIND TURBINE	26-Jul-11	Evergreen Wind (II), LLC	EWP3	ME	19	BHE	ME	56990	14.915	6.391	14.915	6.391	-1.383
37224	PATRIOT PL_D FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.038	0.000	0.038	0.002
37225	PATRIOT PL_E FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.000	0.000	0.000	0.000
37226	PATRIOT PL_F FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.042	0.000	0.042	0.003
37227	PATRIOT PL_H FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.023	0.000	0.023	0.003
37228	PATRIOT PL_J FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.038	0.000	0.038	0.005
37229	PATRIOT PL_K FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.033	0.000	0.033	0.001
37230	UNITED NAT. FOODS PROV. RI PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.003	0.000	0.003	0.003
37266	CARLSON ORCH HARVARD MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Nov-10	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.065	0.000	0.065	-0.023
37267	SPRUCE ENV HAVERHILL MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Nov-10	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
37366	MIDDLETOWN 13	12505	Middletown 12-15	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	23-Jun-11	GenConn Energy LLC	GCE	CT	07	CT	CT	57068	49.200	46.900	49.200	46.900	0.000
37367	MIDDLETOWN 14	12505	Middletown 12-15	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	01-Jun-11	GenConn Energy LLC	GCE	CT	07	CT	CT	57068	49.200	46.900	49.200	46.900	0.000
37368	MIDDLETOWN 15	12505	Middletown 12-15	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	01-Jun-11	GenConn Energy LLC	GCE	CT	07	CT	CT	57068	49.200	46.900	49.200	46.900	0.000
37721	ROYAL MILLS WARWICK RI HYDRO		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-10	The Narragansett Electric Company	NEC	RI	03	RI	RI		0.000	0.000	0.000	0.000	0.000
37722	SILVER LAKE SOLAR PV FACILITY	37051	Silver lake PV	PV	SUN		PHOTOVOLTAIC	06-Dec-10	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA	57676	0.000	0.696	0.000	0.696	0.014
37751	NM-UNISTRESS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37752	NM-COUNTRY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37753	NM-HANCOCK		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.017	0.000	0.017	0.010
37754	NM-QUALITY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37755	NM-WOOD		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.014	0.000	0.014	0.002
37756	NM-FOURSTAR		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.020	0.000	0.020	-0.001
37757	NM-ASTRO		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	13	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37758	NM-MARLEY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	15	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37759	NM-STONE		No Resource (1)	WT	WND		WIND TURBINE	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.022	0.000	0.022	0.000	0.000
37760	NM-RIVERVIEW		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.006	0.000	0.006	0.006
37761	NM-PETRICCA		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37823	INDIAN RIVER POWER SUPPLY LLC	37079	Indian River Power Supply LLC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-11	Swift River Trading Company LLC	SRTC	MA	13	WMA	WCMA		0.309	0.280	0.309	0.280	0.096
37955	TRANS MED TYNGSBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.028	0.000	0.028	0.003
37956	PH HENBIL BILLERICA MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.010	0.000	0.010	0.002
37957	CHELM WTR N CHELMSFORD MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.044	0.000	0.044	-0.002
37958	PETER W ELEM LOWELL MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.016	0.000	0.016	0.002
37959	CIRCLE FIN NEWBURYPORT MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Mar-11	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
37965	BIO-DETEK PAWTUCKET RI PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Mar-11	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
37966	LTI HARVARD AP HARVARD MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Mar-11	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
37967	HILLSIDE MARLBOROUGH MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.002	0.000	0.002	0.002
37969	LOW MEM AUD LOWELL MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.026	0.000	0.026	0.000
37972	DARTMOUTHBUSPARK_PV_ID1592		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Mar-11	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA	57473	0.000	0.708	0.000	0.708	0.057
37973	GENERAL MILLS METHUEN MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Mar-11	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.017	0.000	0.017	0.004
38083	ORONO B HYDRO	38083	Orono "B" Hydro	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-13	Black Bear Hydro Partners, LLC	BBHP	ME	19	BHE	ME		3.030	3.290	3.030	3.290	3.290
38084	STILLWATER B HYDRO	38084	Stillwater "B" Hydro	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	20-Sep-13	Black Bear Hydro Partners, LLC	BBHP	ME	19	BHE	ME		1.638	1.487	1.638	1.487	1.487
38172	SADDLEBACK RIDGE WIND		No Resource (1)	WT	WND		WIND TURBINE	19-Dec-14	Spruce Mountain Wind, LLC	SPRUCE	ME	07	ME	ME	58608	0.000	0.000	0.000	0.000	0.000
38287	WMA CHESTER SOLAR 1	38287	WMA Chester Solar 1	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Vermont Public Power Supply Authority	VPPSA	MA	13	WMA	WCMA		0.000	2.078	0.000	2.078	2.078
38302	TOWN_OF_CARVER_PV_1763		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-14	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
39663	BARNSTABLE_DPW_ID1545		No Resource (1)	WT	WND		WIND TURBINE	01-Aug-11	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.020	0.320	0.020	0.320	0.022
39664	DART_BLDG_SUPPLY_ID1476		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-11	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.048	0.000	0.048	0.007
39665	YARMOUTH_ DPW_ID1740		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-11	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.117	0.000	0.117	0.016
39675	TURKEY HILL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-11	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.016	0.000	0.016	0.003
39717	HI GEAR		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-11	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.103	0.000	0.103	0.003
39722	GTR_BOSTON_FOODBANKS_ID1628		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Oct-11	NSTAR Electric Company	NSTAR	MA	25	BOSTON	NEMA		0.000	0.089	0.000	0.089	0.006
39724	EASTERN_AVE_HOLDINGS_PV_ID1652		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Oct-11	NSTAR Electric Company	NSTAR	MA	25	BOSTON	NEMA		0.000	0.089	0.000	0.089	0.007
39738	MWRA_LORING_RD_ID1400		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-11	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.091	0.155	0.091	0.155	-0.021
40015	INDIAN ORCHARD SOLAR FACILITY	38081	Indian Orchard Solar PV	PV	SUN		PHOTOVOLTAIC	01-Dec-11	Western Massachusetts Electric Company	WMECO	MA	13	WMA	WCMA	57674	0.000	0.803	0.000	0.803	-0.078
40050	EXETER AGRI ENERGY		No Resource (1)	IC	OBG		BIO/REFUSE	19-Dec-11	Vermont Public Power Supply Authority	VPPSA	ME	19	BHE	ME		0.935	0.895	0.935	0.895	-0.002
40052	NEW HAVEN HARBOR UNIT 3	15477	New Haven Harbor Units 2, 3, & 4	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	30-May-12	PSEG New Haven, LLC	PSEG-NH	CT	09	CT	CT	6156	48.600	43.200	48.600	43.200	0.000
40053	NEW HAVEN HARBOR UNIT 4	15477	New Haven Harbor Units 2, 3, & 4	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	30-May-12	PSEG New Haven, LLC	PSEG-NH	CT	09	CT	CT	6156	48.600	43.200	48.600	43.200	0.000
40054	JOHNSTON LFG TURBINE PLANT	14599	Rhode Island LFG Genco, LLC - ST	CC	LFG		BIO/REFUSE	25-May-13	Rhode Island Engine Genco, LLC	RRIG	RI	07	RI	RI	59254	27.891	26.430	27.891	26.430	0.067
40066	OLDBARNET_RD_MASHPEE_PV_ID1798		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-12	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.133	0.000	0.133	0.015
40067	MARION_DR_KINGSTON_WT_ID1656		No Resource (1)	WT	WND		WIND TURBINE	16-Jan-12	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.819	0.473	0.819	0.473	-0.409
40085	QUABBIN 1_ORANGE MA PV NET		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Jan-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40086	QUABBIN 2_ORANGE MA PV NET		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Jan-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40116	DELAWARE VALLEY CORP PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	31-Jan-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
40119	WORCESTER STATE COLLEGE PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	31-Jan-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40137	BERKSHIRE EAST WIND		No Resource (1)	WT	WND		WIND TURBINE	03-Feb-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.263	0.000	0.263	-0.038
40176	NFM SOLAR POWER, LLC	38078	NFM Solar Power, LLC	PV	SUN		PHOTOVOLTAIC	18-Feb-12	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	58210	0.000	0.649	0.000	0.649	0.042
40194	MICRON		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Mar-12	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40207	KEZAR UPPER FALLS	786	KEZAR LEDGEMERE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-12	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	7668	0.280	0.118	0.280	0.118	-0.136
40208	KEZAR LOWER FALLS	786	KEZAR LEDGEMERE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-12	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	7668	0.453	0.248	0.453	0.248	-0.188
40209	LEDGEMERE	786	KEZAR LEDGEMERE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-12	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	7668	0.235	0.057	0.235	0.057	-0.095
40225	MILLIPORE PV - BILLERICA		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Mar-12	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.000	0.000	0.000	0.000
40242	TANTASQUA JR HIGH_PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Mar-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	-0.008
40243	SOLAR SHOP LLC BLDG 14_PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Mar-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.038	0.000	0.038	0.000
40244	SOLAR SHOP LLC BLDG 10_PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Mar-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.049	0.000	0.049	0.001
40246	HODGES BADGE CO_WIND		No Resource (1)	WT	WND		WIND TURBINE	30-Mar-12	The Narragansett Electric Company	NEC	RI	05	SEMA	RI		0.000	0.000	0.000	0.000	0.000
40247	QUABBIN BARRE - WIND		No Resource (1)	WT	WND		WIND TURBINE	29-Mar-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.408	0.000	0.406	-0.004
40248	JJ CARROLL WW PLANT_PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Mar-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.205	0.000	0.205	-0.009
40249	WESTBORO SUITES		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Mar-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.006	0.000	0.006	0.000
40250	SHAWS SUPER MARKET		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Mar-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40251	VETERAN HOMESTEAD PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Mar-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.003	0.000	0.003	-0.010
40259	COMMERCE_PK_RD_PV_ID1871		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Apr-12	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.131	0.000	0.131	0.018
40263	MATOUK TEXTILE WORKS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Apr-12	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
40270	TECTA AMERICA		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Apr-12	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.007	0.000	0.007	-0.017
40327	FORE RIVER 11	1691	FORE RIVER-1	CC	NG		GAS COMBINED CYCLE	04-Aug-03	Calpine Energy Services, LP	CALP	MA	21	SEMA	SEMA	55317	416.611	362.997	416.611	362.997	0.000
40328	FORE RIVER 12	1691	FORE RIVER-1	CC	NG		GAS COMBINED CYCLE	04-Aug-03	Calpine Energy Services, LP	CALP	MA	21	SEMA	SEMA	55317	421.500	362.712	421.500	362.712	0.000
40338	MAINE INDEPENDENCE STATION 1	1216	MAINE INDEPENDENCE STATION	CC	NG		GAS COMBINED CYCLE	01-May-00	Dynegy Marketing and Trade, LLC	DMT1	ME	19	BHE	ME	55068	269.138	244.138	269.138	244.138	0.000
40339	MAINE INDEPENDENCE STATION 2	1216	MAINE INDEPENDENCE STATION	CC	NG		GAS COMBINED CYCLE	01-May-00	Dynegy Marketing and Trade, LLC	DMT1	ME	19	BHE	ME	55068	269.138	244.138	269.138	244.138	0.000
40340	NEXAMP CAP-WORCESTER ACADEMY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Apr-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
40342	VERSO BUCKSPORT G5		No Resource (1)	ST	OBS	NG	BIO/REFUSE	15-Nov-12	Verso Maine Energy LLC	VERSO	ME	09	BHE	ME	50243	22.265	0.000	22.265	0.000	-22.494
40343	BULL HILL WIND		No Resource (1)	WT	WND		WIND TURBINE	27-Oct-12	Blue Sky East, LLC	BSE	ME	09	BHE	ME	57083	13.458	6.457	13.458	6.457	1.483
40365	EAST ISLAND COMMUNITY - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Apr-12	Massachusetts Electric Company	MEC	MA	09	CMA/NEMA	WCMA		0.000	0.037	0.000	0.037	0.001
40482	DURFEE UNION MILLS BLDG 9 - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-May-12	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
40483	TYNGSBOROUGH SPORTS PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-May-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
40484	BANCROFT SCHOOL PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-May-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40485	LITCHFIELD LECOMINSTER PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-May-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40520	MANCHESTER-BOSTON REGIONAL PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-May-12	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.000	0.000	0.000	0.000	-0.008
40524	MOUNT WACHUSSETT CC WIND		No Resource (1)	WT	WND		WIND TURBINE	11-May-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA	58025	0.000	0.000	0.000	0.000	0.000
40555	BLACKCOMB WORC MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-May-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.063	0.000	0.063	0.007
41782	PAWTUCKET MEMORIAL ELEM SCH		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-May-12	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
41783	PHOENIX FINANCE LLC		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-May-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.017	0.000	0.017	-0.005
41784	NANTUCKET HIGH SCHOOL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-May-12	Massachusetts Electric Company	MEC	MA	19	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
41806	NM-PROPEL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.000	0.000	0.000	-0.014
41807	NM-PITTSFIELD WWTP		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA	59060	0.000	0.550	0.000	0.550	-0.103
41808	NM-MASS DEP		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	13	WMA	WCMA		0.000	0.006	0.000	0.006	0.005
41809	NM-GREENFIELD CC		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
41810	NM-FULL BLOOM MARKET		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.033	0.000	0.033	0.033
41811	NM-BERKSHIRE CC		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
41815	TIFFANY AND CO - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Jun-12	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
41816	QUABOAG REGIONAL ELEM - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Jun-12	Massachusetts Electric Company	ME

Contains Proprietary Material
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ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC-IPANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
41881	TOWN OF SWAMPSCOTT HS - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jul-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.156	0.000	0.156	-0.069
41882	NEXAMP CAP-NASHOBA VALLEY THS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Jul-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
41921	MBI REALTY JAMES ST - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Jul-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
41922	LIGHTOLIER - WIND		No Resource (1)	WT	WND		WIND TURBINE	23-Jul-12	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.194	0.127	0.194	0.127	0.127
41923	BLACKCOMB SOLAR III-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Jul-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.379	0.000	0.379	0.002
41924	COREMARK-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Jul-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.173	0.000	0.173	0.007
42041	D.D. BEAN		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	02-Aug-12	Constellation NewEnergy, Inc.	CNE	NH	05	VT	NH		0.000	0.000	0.000	0.000	0.000
42043	SWANSEA WATER DISTRICT		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Aug-12	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.000	0.000	0.000	0.000	0.000
42045	NM-GREENFIELD MA LANDFILL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-12	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.635	0.000	0.635	-0.186
42046	ST. MARYS HIGH SCHOOL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Aug-12	Massachusetts Electric Company	MEC	MA	25	BOSTON	NEMA		0.000	0.011	0.000	0.011	0.006
42048	TANTASQUA HIGH- PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Aug-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.012	0.012
42050	PETE'S TIRE BARN		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Aug-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.065	0.000	0.065	0.018
42083	CANTON_LANDFILL_PV_ID1726		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Aug-12	NSTAR Electric Company	NSTAR	MA	21	SEMA	SEMA		0.000	2.559	0.000	2.559	0.177
42091	QUABOAG REGIONAL HS - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Aug-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.048	0.000	0.048	0.002
42092	TOWN OF SUTTON MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Aug-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42104	HYDEPARKSTORPV_ID919		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	25	BOSTON	NEMA		0.000	0.059	0.000	0.059	-0.016
42105	MILLST_NATICKPV_ID1818		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.070	0.000	0.070	-0.015
42106	SUBURBANATHLETIC2_ID1637		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.036	0.000	0.036	0.000
42107	4M_ALDRINRDPV_ID1856		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.000	0.049	0.000	0.049	0.001
42108	BROADWAY_RENEWABLE_ID1772		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.000	0.382	0.000	0.382	-0.013
42109	COCHITUATERD_FRAMPV_ID1873		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.079	0.000	0.079	0.006
42110	DOUGLAS_SCHOOLPV_ID1464		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.034	0.000	0.034	0.006
42111	HYANNIS_SELF_STOR_ID1946		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.198	0.000	0.198	0.030
42112	POND_ST_ASHLAND_ID1736		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.185	0.000	0.185	0.009
42113	COBSCOOK BAY TEP TGU 1		No Resource (1)	OT	WAT		MISC. OTHER	04-Sep-12	New Brunswick Energy Marketing Corporation	NBPGC	ME	29	BHE	ME		0.000	0.000	0.000	0.000	0.000
42114	PUMPKIN HILL	1258	BHE SMALL HYDRO COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-82	New Brunswick Energy Marketing Corporation	NBPGC	ME	19	BHE	ME	50699	0.000	0.572	0.000	0.572	-0.638
42115	GLC_ACUSHNETLLC_ID1821_1824		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.000	1.861	0.000	1.861	0.025
42116	DSD_REALTY_TRUST_ID1672		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.500	0.000	0.500	-0.003
42117	CONST_SOLAR_NORFOLK_ID1846		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	21	RI	SEMA	57942	0.000	0.649	0.000	0.649	0.003
42118	CONED_HIXVILLERD_ID1862		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	1.123	0.000	1.123	0.071
42123	KEZAR LEDGEMERE COMPOSITE	786	KEZAR LEDGEMERE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-12	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME		0.057	0.076	0.057	0.076	0.010
42135	18 PHOENIX PARK BLDG DEAST & F		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Sep-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42136	18 PHOENIX PARK BLDG DEAST & J		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Sep-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42137	18 PHOENIX PARK BLDG DWEST		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Sep-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.017	0.000	0.017	0.000
42149	FAVORITE FOODS PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-12	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.000	0.000	0.000	0.000	0.000
42155	LEICESTER HS - BWSC RENEWABLE		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Oct-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
42158	UMASS LOWELL LEITCH HALL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Oct-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42157	MILLBROOK RIVERSIDE LLC		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Oct-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42158	MOHAWK DRIVE CORPORATION		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Oct-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.036	0.000	0.036	0.004
42193	TRUE NORTH ENERGY A		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59390	0.000	0.601	0.000	0.601	0.073
42194	TRUE NORTH ENERGY B		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59390	0.000	0.458	0.000	0.458	-0.045
42195	TRUE NORTH ENERGY C		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59390	0.000	0.423	0.000	0.423	0.027
42196	TRUE NORTH ENERGY D		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59390	0.000	0.541	0.000	0.541	0.019
42197	TRUE NORTH ENERGY E		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59390	0.000	0.562	0.000	0.562	0.059
42201	MATTHEW KUSS MS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Nov-12	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
42202	DR AMP 100 AMES POND - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Nov-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.025	0.000	0.025	0.016
42203	WESTFORD SOLAR 3 - PV	38181	Westford Solar	PV	SUN		PHOTOVOLTAIC	08-Nov-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA	58534	0.000	0.463	0.000	0.463	0.007
42204	BPV LOWELL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Nov-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.033	0.000	0.033	0.003
42205	SALEM STATE UNIVERSITY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
42212	DR AMP 200 AMES POND - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Nov-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.028	0.000	0.028	-0.004
42213	CUMMINGS PROPERTY E GMR		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.040	0.000	0.040	0.040
42214	ORCHARD MADE PRODUCTS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.012	0.000	0.012	-0.007
42215	WESTBOROUGH TREATMENT PL BD		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Nov-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42344	CAMELOT_WIND_ID1240		No Resource (1)	WT	WND		WIND TURBINE	01-Dec-12	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA	58958	0.198	0.159	0.198	0.159	-0.004
42346	3 RIVERS PALMER-SPRINGFLD-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Dec-12	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
42347	CONSTELLATION SOLAR-UXBRG-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Dec-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA	57941	0.000	0.830	0.000	0.830	0.059
42349	15 UNION SOLAR LLC-LAWRENCE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Dec-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.075	0.000	0.075	0.037
42350	BARRETT-FRANKLIN-SOLAR		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Dec-12	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.257	0.000	0.257	0.019
42351	OMA GROUP-CHARLTON-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Dec-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.419	0.000	0.419	-0.016
42352	OSG SOLAR 1-ORANGE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Dec-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.439	0.000	0.439	0.006
42353	OSG SOLAR 2-ORANGE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Dec-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.439	0.000	0.439	0.003
42354	OSG SOLAR 3-ORANGE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Dec-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.217	0.000	0.217	0.001
42355	CIL CEDAR-MARLBORO-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Dec-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.047	0.000	0.047	0.047
42356	LEEWOOD SWIX-HAVERHILL-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Dec-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.125	0.000	0.125	-0.004
42357	UP BLACKSTONE WWTP-MILLBURY-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Dec-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.126	0.000	0.126	-0.003
42359	FOREKICKS-MARLBORO-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Dec-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.088	0.000	0.088	0.008
42360	35 LYMAN LLC-NORTHBORO-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Dec-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.092	0.000	0.092	0.007
42364	CAPITAL GROUP-SOUTHBORO-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Dec-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.376	0.000	0.376	-0.013
42365	LOFT 27-LOWELL-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Dec-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.107	0.000	0.107	-0.007
42366	SOLTAS SPECTOR-LAWRENCE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Dec-12	Massachusetts Electric Company	MEC	MA	09	CMA/NEMA	WCMA		0.000	0.149	0.000	0.149	0.000
42375	DEXTER 1	392	DEXTER	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-May-90	Algonquin Energy Services Inc.	AESR	CT	03	CT	CT	10567	38.363	37.839	38.363	37.839	0.205
42376	DEXTER 2	392	DEXTER	CC	NG		GAS COMBINED CYCLE	01-May-90	Algonquin Energy Services Inc.	AESR	CT	03	CT	CT	10567	4.833	4.432	4.833	4.432	0.205
42383	SALEM STATE-SALEM-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Dec-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
42384	BJS WHOLESALE CLUB LEOMINSTER		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Dec-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
42385	CORNER BROOK-MILFORD-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Dec-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.056	0.000	0.056	0.001
42394	WINDENERGYDEV-MKINGSTOWN-WIND		No Resource (1)	WT	WND		WIND TURBINE	02-Jan-13	The Narragansett Electric Company	NEC	RI	09	RI	RI		0.187	0.134	0.187	0.134	0.056
42411	EXTRA SPACE-PLAINVILLE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Jan-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.040	0.000	0.040	0.040
42412	EXTRA SPACE-SAUGUS-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.039	0.000	0.039	0.007
42413	35 LYMAN LLC - ACTIVE		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Jan-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.023	0.000	0.023	0.023
42414	NE ELECTRO-FALL RIVER-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Jan-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.016	0.000	0.016	-0.010
42424	IPSWICH WIND II		No Resource (1)	WT	WND		WIND TURBINE	09-Jan-13	Ipswich Municipal Light Department	IMLD	MA	09	BOSTON	NEMA	59023	0.313	0.152	0.313	0.152	0.007
42431	SOLECT PLUMBING-NORWELL-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Jan-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.049	0.000	0.049	-0.003
42432	VAUGHN CORP-SALISBURY-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Jan-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.031	0.000	0.031	0.003
42433	BETHANY CHURCH-MENDON-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Jan-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.029	0.000	0.029	-0.001
42438	EXTRA SPACE-NORTHBORO-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jan-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.038	0.000	0.038	0.005
42439	CITY OF BROCKTON-SWANSEA-PV1		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jan-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.520	0.000	0.520	0.034
42440	CITY OF BROCKTON-SWANSEA-PV2		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jan-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.770	0.000	0.770	0.051
42443	WAL-MART LUN (PV)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Jan-13	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
42444	MRTA (PV)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Jan-13	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.019	0.000	0.019	0.012
42448	CITY OF GLOUCESTER 1 - WIND		No Resource (1)	WT	WND		WIND TURBINE	06-Feb-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.395	0.127	0.395	0.127	0.009
42449	CITY OF GLOUCESTER 2 - WIND		No Resource (1)	WT	WND		WIND TURBINE	06-Feb-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.274	0.106	0.274	0.106	-0.053
42482	CITY_OF_WALTHAM_PV_ID1805		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.072	0.000	0.072	0.016
42483	FIRST_HIGHLAND_PV_ID2021		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	25	BOSTON	NEMA		0.000	0.346	0.000	0.346	-0.043
42484	UNITEDSALVAGE_PV_ID1966		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.213	0.000	0.213	0.082
42485	SOLCHEMY_PV_ID1969		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	07	SEMA	SEMA		0.000	0.118	0.000	0.118	0.030
42486	AIRPORT_WAY_PV_ID1875		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.633	0.000	0.633	0.096
42487	BILL_BENNETT_PV_ID1967		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	07	SEMA	SEMA		0.000	0.387	0.000	0.387	0.141
42495	VARIANSEMICON-GLOUCESTER-WT		No Resource (1)	WT	WND		WIND TURBINE	21-Feb-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
42496	HANOVER SOLAR-LEICESTER-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Feb-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.363	0.000	0.363	-0.077
42497	WESTFORD SOLAR 4- PV	38181	Westford Solar	PV	SUN		PHOTOVOLTAIC	21-Feb-13	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA	58534	0.000	0.444	0.000	0.444	-0.008
42504	BERKSHIRE SRECS-GT BARRGTN-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Feb-13	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
42505	CUMMINGS 1000-BEVERLY-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Feb-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.083	0.000	0.083	-0.002
42597	GPT JACLEN-BEVERLY-CHP		No Resource (1)	IC	NG		GAS INTERNAL COMBUSTION	26-Mar-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
42598	NEW BARRE HYDRO	852	SOUTH BARRE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	02-Apr-13	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	27	WMA	WCMA		0.047	0.000	0.047	0.000	0.000
42599	MAPREMCT-97GREEN-02035-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Apr-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.052	0.000	0.052	0.002
42600	HOSIACWALREG-ORCHARD-01225-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Apr-13	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.000	0.081	0.000	0.081	0.014
42601	CARLSTROMPM-65FISHER-0158-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Apr-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.200	0.000	0.200	0.007
42602	KEYPOLYMER-1 JACOB-01843-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Apr-13	Massachusetts Electric Company	MEC	MA	09	CMA/NEMA	WCMA		0.000	0.112	0.000	0.112	0.049
42603	BARRE1-750BARRE-01005-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Apr-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.343	0.000	0.343	0.016
42611	AUBUCHON-95AUBUCHON-01473-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Apr-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.116	0.000	0.116	0.022
42612	NPPDEVELOP-370PATRIOT-02035-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Apr-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.229	0.000	0.229	0.013
42613	AMERICOLD-0PEW-01930-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Apr-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
42631	CABRAL-247BAKER-02777-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Apr-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.231	0.000	0.231	0.029
42632	ALPHA GRAINGER-02038PV250NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Apr-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.000	0.000	0.000	0.000
42633	NORTHBORSPORTS-0153ZPV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Apr-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.061	0.000	0.061	0.033
42641	NATICKMEMORIAL SCHOOL_PV_ID1892		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Apr-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.043	0.000	0.043	0.002
42812	PEGASUS_PV_ID1809		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-May-13	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.441	0.000	0.441

Contains Proprietary Material
Do Not Distribute

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
43492	NARR BAY - 02903WT4500NM		No Resource (1)	WT	WND		WIND TURBINE	09-Jul-13	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
43509	DOUGLAS SOLAR-01516PV200NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Jul-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA	57934	0.000	1.048	0.000	1.048	0.068
43510	SANDF MGMNT-02725PV623NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Jul-13	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.000	0.239	0.000	0.239	-0.002
43512	WEST GREENWICH - 02817PV2000DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jul-13	The Narragansett Electric Company	NEC	RI	03	RI	RI		0.000	0.934	0.000	0.934	0.067
43527	STUART THOMAS - 02842PV500DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jul-13	The Narragansett Electric Company	NEC	RI	05	SEMA	RI		0.000	0.213	0.000	0.213	0.038
43528	EXTRA SPC MGMT-02035PV102NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Jul-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.026	0.000	0.026	0.000
43529	CREEDON AND CO-01604PV110NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Jul-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.012	0.000	0.012	-0.002
43531	28 HASTINGS - 01756PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Jul-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.038	0.000	0.038	0.022
43556	CALLAHAN - 02324PV110NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.010	0.000	0.010	0.004
43557	BRDGWTR RECYCLE-02324PV66NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.045	0.000	0.045	0.004
43558	COMMERCE GRN-02339PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.032	0.000	0.032	0.000
43572	JDH_SOLAR_SYSTEMS_PV_2221		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-13	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.000	0.242	0.000	0.242	0.035
43573	NEW_ENGLAND_RESINS_PV_2309		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.188	0.000	0.188	0.016
43574	TOWN_OF_FAIRHAVEN_LF_PV_1714		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.189	0.000	0.189	0.053
43575	NE_ELEMENTARY_WALTHAM_PV_1872		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.114	0.000	0.114	0.012
43576	GLC_ACUSHNET_PV_1888		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.507	0.000	0.507	0.028
43577	GLC_ACUSHNET_PV_1889		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.383	0.000	0.383	0.027
43578	GLC_ACUSHNET_PV_1890		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.508	0.000	0.508	0.038
43579	GOIS_SOLAR_ONE_PV_2040		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.386	0.000	0.386	0.011
43586	COMTRAN CABLE-02864PV400DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Aug-13	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.217	0.000	0.217	0.006
43587	TRAVIS_HOSPITALITY_PV_2239		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Aug-13	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.066	0.000	0.066	0.020
43603	WORC GEAR AND RACK-01537PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Aug-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
43604	METRO WST PROVIS-01747PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Aug-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.033	0.000	0.033	0.011
43605	PRECISE PACK-02720PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
43606	CITY NORTHAMPTON-02721PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-13	Massachusetts Electric Company	MEC	MA	15	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
43607	COX PRTSMTH-02871PV500DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-13	The Narragansett Electric Company	NEC	RI	05	RI	RI		0.000	0.235	0.000	0.235	0.235
43608	35 LYMAN LLC-01532PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Aug-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.016	0.000	0.016	0.000
43609	MA CORRECTIONAL-01440WT3300NM		No Resource (1)	WT	WND		WIND TURBINE	05-Sep-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
43623	E BRIDGEWATER-02333PV2000NM	38114	East Bridgewater Solar Energy Project	PV	SUN		PHOTOVOLTAIC	12-Sep-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	1.062	0.000	1.062	1.062
43624	TJ MAXX - 02061PV260NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Sep-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
43643	SUNGEN UXBRIDGE1-01569PV550NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Sep-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.501	0.000	0.501	0.501
43644	SUNGEN UXBRIDGE2-01569PV550NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Sep-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.494	0.000	0.494	0.494
43645	SUNGEN UXBRIDGE3-01569PV950NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Sep-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.479	0.000	0.479	0.479
43652	TWN W BRDGEWTR-02379PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Sep-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.768	0.000	0.768	0.768
43653	40 WASHINGTON LTD-01581PV750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Sep-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.165	0.000	0.165	0.165
43654	3 COUNTY FAIR ASN-01060PV250NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Sep-13	Massachusetts Electric Company	MEC	MA	15	WMA	WCMA		0.000	0.108	0.000	0.108	0.108
43655	SPRING HILL FARM-01835PV229NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Oct-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.073	0.000	0.073	0.073
43656	SVC TIRE TRUCK - 01527PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Oct-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
43657	RIPTA - 02907PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Sep-13	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
43658	TWN LANCASTER-01523PV500GF		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Oct-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.195	0.000	0.195	0.195
43659	TWN OF SCITUATE2-02066PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Oct-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA	59013	0.000	0.810	0.000	0.810	0.810
43678	DISCOVER MARBLE - 01527PV142NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Oct-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
43682	NEXTSUN ENERGY-01516PV3000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Oct-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	1.590	0.000	1.590	1.590
43683	TWN OF SCITUATE1-02066PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Oct-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA	59013	0.000	0.544	0.000	0.544	0.544
43684	KEY BOSTON-02039PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Oct-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.776	0.000	0.776	0.776
43685	CONNNCUT MARINE-02859PV120DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Oct-13	The Narragansett Electric Company	NEC	RI	05	SEMA	RI		0.000	0.049	0.000	0.049	0.049
43686	SHEA CONCRETE-01913PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Oct-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.088	0.000	0.088	0.088
43687	SUNGEN ORANGE1-01364PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Oct-13	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA	58411	0.000	0.654	0.000	0.654	0.654
43688	SUNGEN ORANGE2-01364PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Oct-13	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA	58411	0.000	0.208	0.000	0.208	0.208
43689	BOSTON NORTH TECH-01913PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Oct-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
43690	OXFORD REALTY-01604PV149NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Oct-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.030	0.000	0.030	0.030
43691	CRAFT INC-02703PV28SNM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Oct-13	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.000	0.037	0.000	0.037	0.037
43695	KOHLS-01906PV252NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Oct-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
43696	STOP AND SHOP-02155PV200NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Oct-13	Massachusetts Electric Company	MEC	MA	17	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
43698	NTHBRDGE SOLAR-01560PV1910NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Oct-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA	58385	0.000	1.125	0.000	1.125	1.125
43706	CITY OF LOWELL1-01364PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Nov-13	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.421	0.000	0.421	0.421
43707	CITY OF LOWELL2-01364PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Nov-13	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.859	0.000	0.859	0.859
43708	HANNAFORD-02061PV135NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Nov-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
43709	CITY OF LOWELL 1-01331PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Nov-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.430	0.000	0.430	0.430
43710	CITY OF LOWELL 2-01331PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Nov-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.487	0.000	0.487	0.487
43711	CITY OF LOWELL 3-01331PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Nov-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.492	0.000	0.492	0.492
43712	PHOENIX FINS-01464PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Nov-13	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
43713	CUMMINGS PROP-01915PV110NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Nov-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.040	0.000	0.040	0.040
43714	EXTRA SPC STOR-02189PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Nov-13	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.031	0.000	0.031	0.031
43715	MILFORD IND-01757PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Nov-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.038	0.000	0.038	0.038
43716	NEXAMP-02852PV2000DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Nov-13	The Narragansett Electric Company	NEC	RI	09	RI	RI		0.000	0.940	0.000	0.940	0.940
43717	ASSUMPTION-01562PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Nov-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	1.034	0.000	1.034	1.034
43729	GRAFTON WATER-01519PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Nov-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA	59394	0.000	0.715	0.000	0.715	0.715
43731	JEFFERSON-02720PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Nov-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.011	0.000	0.011	0.011
43734	TOWN EASTON-02375PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Nov-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA	59134	0.000	0.812	0.000	0.812	0.812
43735	28 HASTINGS-01756PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Nov-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.030	0.000	0.030	0.030
43736	SMITH COLLEGE-01060NG3500QF		No Resource (1)	IC	NG		GAS INTERNAL COMBUSTION	22-Nov-13	Massachusetts Electric Company	MEC	MA	15	WMA	WCMA	58166	0.134	0.000	0.134	0.000	0.000
43747	PARSONS GRP-01581PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Dec-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.027	0.000	0.027	0.027
43748	ACUMEN-01752PV65NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Dec-13	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.033	0.000	0.033	0.033
43749	WILVECO-01821PV62NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Dec-13	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.002	0.000	0.002	0.002
43750	CANTON HIGH SCHOOL 2009		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Dec-13	NSTAR Electric Company	NSTAR	MA	21	SEMA	SEMA		0.000	0.200	0.000	0.200	0.200
43751	EAGLE LEASE-01540PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Dec-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.016	0.000	0.016	0.016
43752	EXTRA SPACE-01607PV91.2NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Dec-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.029	0.000	0.029	0.029
43762	FORBES STREET 1-02914PV3000DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Dec-13	The Narragansett Electric Company	NEC	RI	07	RI	RI	58583	0.012	1.449	0.012	1.449	1.449
43766	EXTRA SPACE-02149PV237NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Dec-13	Massachusetts Electric Company	MEC	MA	17	BOSTON	NEMA		0.000	0.029	0.000	0.029	0.029
43840	SOLVENTERRA-01089PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jan-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.019	0.479	0.019	0.479	0.479
43841	FLAIR ONE-01507PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jan-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.010	0.366	0.010	0.366	0.366
43842	FORRESTALL-01507PV950NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jan-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.009	0.342	0.009	0.342	0.342
43869	FRPV WEST-02720PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Jan-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.025	0.508	0.025	0.508	0.508
43870	FRPV EAST-02720PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Jan-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.030	0.506	0.030	0.506	0.506
43871	SYNAGRO-02886CHP2000QF		No Resource (1)	ST	NG		GAS STEAM	07-Jan-14	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.094	0.000	0.094	0.000
43874	MASS MOCA1-01247PV225NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Jan-14	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
43875	CUMMINGS PROP-01915PV230NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Jan-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.073	0.000	0.073	0.073
43876	KENNEDY CARPET-02189PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Jan-14	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.025	0.000	0.025	0.025
43878	MCI WORLD COMM-01821PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Jan-14	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.000	0.000	0.000	0.000
43884	MASS MOCA3 01247PV177NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-14	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.000	0.049	0.000	0.049	0.049
43885	NM-HP HOOD AND SONS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Feb-14	Western Massachusetts Electric Company	WMECO	MA	13	WMA	WCMA		0.038	0.702	0.038	0.702	0.702
43886	NM-FRANKLIN COUNTY SHERIFF		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Feb-14	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.037	0.617	0.037	0.617	0.617
43887	NM-TOWN OF AGAWAM SOLAR		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Feb-14	Western Massachusetts Electric Company	WMECO	MA	13	WMA	WCMA		0.062	0.739	0.062	0.739	0.739
43892	SYNCARPHA SOLAR-01740PV495NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Jan-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.201	2.516	0.201	2.516	2.516
43893	HUBBARDSTON-01452PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Jan-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.087	1.015	0.087	1.015	0.485
43903	SUNGEN-02720PV2850NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.160	1.748	0.160	1.748	1.748
43904	CITY OF METHUEN-01523PV3000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.176	1.550	0.176	1.550	1.550
43907	PALMER SOLAR-01069PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Feb-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.092	0.917	0.092	0.917	0.917
43908	NEXTSUN ENERGY-02370PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Feb-14	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.076	0.844	0.076	0.844	0.844
43915	CITIZENS-02769PV200NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Feb-14	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.127	1.093	0.127	1.093	1.093
43916	TOWN OF ADAMS-01220PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Feb-14	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.055	0.434	0.055	0.434	0.434
43917	CHEER PACK-02397PV1750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-14	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.195	0.000	0.195	0.195
43918	CITY OF LOWELL-01851PV1333NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-14	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.050	0.615	0.050	0.615	0.615
43919	SOLVENTERRA 1-01535PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.034	0.515	0.034	0.515	0.515
43920	SOLVENTERRA 2-01535PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.039	0.519	0.039	0.519	0.519
43921	COXCOM-02893PV135DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Feb-14	The Narragansett Electric Company	NEC	RI	03	RI	RI		0.009	0.072	0.009	0.072	0.072
43922	SOLVENTERRA 4-01083PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.062	0.552	0.062	0.552	0.552
43923	PLYMOUTH PUBLIC SCHOOLS-#2062		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.278	2.284	0.278	2.284	2.284
43924	TOWN OF DARTMOUTH #1777		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.059	0.575	0.059	0.575	0.575
43927	SOUTHERN SKY-CARVER #1 (1997)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.067	0.509	0.067	0.509	0.509
43928	SOUTHERN SKY-CARVER #2 (1998)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.075	0.502	0.075	0.502	0.502
43929	SOUTHERN SKY-CARVER #4 (2000)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.069	0.478	0.069	0.478	0.478
43930	SOUTHERN SKY-CARVER #5 (2001)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.079	0.504	0.079	0.504	0.504
43932	SOUTHERN SKY-CARVER #3 (1999)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.071	0.464	0.071	0.464	0.464
43936	SOLVENTERRA 1-01083PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.039	0.536	0.039	0.536	0.536
43937	SOLVENTERRA 2-01083PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.060	0.537	0.060	0.537	0.537
43938	SOLVENTERRA 3-01083PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.062	0.552	0.062	0.552	0.552
43948	SUNGEN 1-01810PV950NM	

Contains Proprietary Material
Do Not Distribute

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC ($/kW)	SUMMER SCC ($/kW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
46210	NEXAMP-01475PV1900NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Apr-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.246	0.887	0.246	0.887	0.887
46211	GIGUERE-01524PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Apr-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.006	0.000	0.006	0.006
46212	BODWELL REALTY-02322PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Apr-14	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
46213	PINGREE SCHOOL-01982PV85NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Apr-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.026	0.000	0.026	0.026
46220	BERKELEY-01844PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Apr-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.263	0.921	0.263	0.921	0.921
46221	JP SULLIVAN-01432PV90NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Apr-14	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.025	0.000	0.025	0.025
46267	COTTAGE STREET SOLAR FACILITY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-May-14	Western Massachusetts Electric Company	WMECO	MA	19	WMA	WCMA	58568	0.000	1.635	0.000	1.635	1.635
46268	OLD TIME SPORTS-01952PV150NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-May-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.031	0.000	0.031	0.031
46294	LAWRENCE 1-01840PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-May-14	Massachusetts Electric Company	MEC	MA	09	CMA/NEMA	WCMA		0.000	0.032	0.000	0.032	0.032
46295	LAWRENCE 2-01840PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-May-14	Massachusetts Electric Company	MEC	MA	09	CMA/NEMA	WCMA		0.000	0.034	0.000	0.034	0.034
46479	CANTON_MIDDLE_SCHOOL_2013		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-May-14	NSTAR Electric Company	NSTAR	MA	21	SEMA	SEMA		0.000	0.138	0.000	0.138	0.138
46480	CEDAR_SOLAR1_2411		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-May-14	NSTAR Electric Company	NSTAR	MA	25	BOSTON	NEMA		0.000	0.039	0.000	0.039	0.039
46481	TOWN_OF_MARSHFIELD_1865		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-May-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA	58410	0.000	1.716	0.000	1.716	1.716
46482	NEWBEDFORD_DPI_1843_1844		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-May-14	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	1.676	0.000	1.676	1.676
46483	MILFORD INDUSTRIAL-0175PV82NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-May-14	Massachusetts Electric Company	MEC	MA	09	RI	SEMA		0.000	0.030	0.000	0.030	0.030
46484	WORCESTER SCHL-01602PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-May-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
46485	NPP DEVELOPMENT-02035PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-May-14	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.030	0.000	0.030	0.030
46486	WB HUNT-02176PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jun-14	Massachusetts Electric Company	MEC	MA	17	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
46487	CIDER HILL-01913PV78NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jun-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.030	0.000	0.030	0.030
46537	CUMMINGS-01911PV82NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jun-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.023	0.000	0.023	0.023
46538	SILVIA-02720PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Jun-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
46539	BCC SEA QALIBC-01854PV66NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Jun-14	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.026	0.000	0.026	0.026
46540	NPP DEVELOPMENT-02035PV62NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Jun-14	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.018	0.000	0.018	0.018
46541	TEKNOR APEX-02703PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Jun-14	Massachusetts Electric Company	MEC	MA	23	RI	SEMA		0.000	0.000	0.000	0.000	0.000
46564	EPG SOLAR-01009PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Jun-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.832	0.000	0.832	0.832
46565	CABOT BEVERLY-01915PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Jun-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59242	0.000	1.205	0.000	1.205	1.205
46566	PRECISE PACKAGING-02720PV250NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.082	0.000	0.082	0.082
46567	NORTH BROOKFIELD-01535PV3000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	1.402	0.000	1.402	1.402
46568	GLC-MA SOLAR-01440PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.392	0.000	0.392	0.392
46569	NUGEN NCMC (PV)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.223	0.000	0.223	0.223
46570	NUGEN LUN (PV)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.860	0.000	0.860	0.860
46607	HARVARD SOLAR-01451PV260NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Jul-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.115	0.000	0.115	0.115
46636	GOOSE RIVER HYDRO, INC.		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Aug-14	Goose River Hydro, Inc.	GOOSE	ME	27	ME	ME		0.000	0.037	0.000	0.037	0.037
46641	205 STURBRIDGE-01010PV3000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.000	0.943	0.000	0.943	0.943
46643	EPG SOLAR-01005PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.678	0.000	0.678	0.678
46644	UGT RENEW ENERGY-01540PV2750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Aug-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	1.348	0.000	1.348	1.348
46645	NEXAMP CAPITAL-01007PV1300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-14	Massachusetts Electric Company	MEC	MA	15	WMA	WCMA		0.000	0.595	0.000	0.595	0.595
46646	SOLTAS ENERGY-01010PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Aug-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.000	1.642	0.000	1.642	1.642
46647	BLUEWAVE CAPITAL-02769PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Aug-14	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.000	0.368	0.000	0.368	0.368
46653	WESTBORO SOLAR-01581PV1820NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Aug-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA	59368	0.000	0.054	0.000	0.054	0.054
46657	INDIAN HILL-01069PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Aug-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA	59362	0.000	0.477	0.000	0.477	0.477
46659	BROWN SOLAR-01069PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Aug-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA	59361	0.000	0.325	0.000	0.325	0.325
46660	STATE SOLAR-01069PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Aug-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.000	0.462	0.000	0.462	0.462
46662	DISTRIBUTOR CORP-02148PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-14	Massachusetts Electric Company	MEC	MA	17	BOSTON	NEMA		0.000	0.000	0.000	0.120	0.120
46663	CITY OF LAWRENCE-01841PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-14	Massachusetts Electric Company	MEC	MA	09	CMA/NEMA	WCMA		0.000	0.000	0.000	0.120	0.120
46664	NEXAMP CAPITAL-01543PV4099NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	2.000	2.000
46665	SX INDUSTRIES-02072PV170NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Sep-14	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.000	0.000	0.068	0.068
46666	CUMMINGS-01915PV224NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Sep-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.090	0.090
46667	E NAZARENE-02170PV85NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Sep-14	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.000	0.000	0.034	0.034
46691	CORNERSTONE-01057PV3000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Sep-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.000	0.000	0.000	1.200	1.200
46717	EAST BAY-02915PV70NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Sep-14	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.028	0.028
46718	EXTRA SPACE-02151PV144.3NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Sep-14	Massachusetts Electric Company	MEC	MA	25	BOSTON	NEMA		0.000	0.000	0.000	0.058	0.058
46719	STONEHILL COLL-02356PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Sep-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.800	0.800
46721	ALL AMERICAN-02852PV250DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Sep-14	The Narragansett Electric Company	NEC	RI	09	RI	RI		0.000	0.000	0.000	0.100	0.100
46733	BILLERICA-01821PV499NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Sep-14	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.000	0.000	2.000	2.000
46732	PIONEER SOLAR-01453PV495NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Sep-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.198	0.198
46733	TKS SOLAR-02301PV180NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Sep-14	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.000	0.000	0.072	0.072
46911	NEXTSUN ENERGY-02896PV850DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Dec-14	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.340	0.340
46913	WOONSOCKET-02895PV190DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Dec-14	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.076	0.076
46914	BILLERICA-01523PV2499NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Dec-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	1.000	1.000
46915	NEXAMP-01844PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Dec-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.800	0.800
46916	PHILLIPS-01810PV495NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Dec-14	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.198	0.198
46917	NEWPORT VINEYARDS-02882PV50DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Dec-14	The Narragansett Electric Company	NEC	RI	05	SEMA	RI		0.000	0.000	0.000	0.029	0.029
46918	TOWN OF WESTFORD-01452PV2800NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Dec-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	1.120	1.120
46924	BILLERICA-01523PV2500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Dec-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	1.000	1.000
46925	GLC-MA SOLAR-01440PV1980NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Dec-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.792	0.792
46926	STILLWATER-02917PV56DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Dec-14	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.022	0.022
46947	AMERIPRIDE-01607PV225NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.090	0.090
46948	MILFORD IND-01757PV170NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Jan-15	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.000	0.000	0.068	0.068
46949	NEW SALEM-01452PV675NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Jan-15	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.270	0.270
46952	TOWN OF WENDELL-01876PV260NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-15	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.000	0.000	0.104	0.104
46953	MACHINE INC-02072PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-15	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.000	0.000	0.030	0.030
46954	PROTECTOWIRE-02359PV70NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-15	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.000	0.000	0.028	0.028
46955	MASS FISHERIES-01581PV251NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.100	0.100
46982	GLOBAL LIQUORS-02720PV85NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Jan-15	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.034	0.034
46984	FIVEMILE RIVER1-01503PV750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.300	0.300
46985	FIVEMILE RIVER2-01503PV750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.300	0.300
46986	FIVEMILE RIVER3-01503PV750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.300	0.300
46987	FIVEMILE RIVER4-01503PV750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.300	0.300
46992	RIN LOGISTICS-02720PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Feb-15	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.600	0.600
46993	PARAGON HOLDINGS-01740PV995NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Feb-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.398	0.398
46997	BOLTONVILLE HYDRO		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-15	Green Mountain Power Corporation	GMP	VT	17	VT	VT	50539	0.000	0.000	0.000	0.527	0.527
46998	STEERE ELECTRIC-02814PV72DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Feb-15	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.029	0.029
47002	ONE KENWOOD-02038PV266NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-15	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.000	0.000	0.106	0.106
47003	S SHORE MILLWORK-02766PV648NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-15	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.000	0.000	0.000	0.259	0.259
47004	IRON MOUNTAIN-01532PV760NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.304	0.304
47007	FRANKLIN FORD-02038PV140NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-15	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.000	0.000	0.056	0.056
47008	MCGEE TOYOTA-02339PV85NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-15	Massachusetts Electric Company	MEC	MA	23	RI	SEMA		0.000	0.000	0.000	0.034	0.034
47020	NEXAMP-02898PV499DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Feb-15	The Narragansett Electric Company	NEC	RI	09	RI	RI		0.000	0.000	0.000	0.200	0.200
47032	ABINGTON TARGET-02351PV418NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Feb-15	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.000	0.000	0.167	0.167
47033	HANOVER TARGET-02339PV441NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Feb-15	Massachusetts Electric Company	MEC	MA	23	RI	SEMA		0.000	0.000	0.000	0.176	0.176
47034	MARLBORO TARGET-01752PV441NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Feb-15	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.176	0.176
47035	MILFORD TARGET-01757PV302NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Mar-15	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.000	0.000	0.121	0.121
47036	NORTHBORO WALMART-01532PV368NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Mar-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.147	0.147
47037	LYNN WALMART-01905PV232NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Mar-15	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.093	0.093
47040	BOOTHBAY ENERGY STORAGE		No Resource (1)	OT	OTR		MISC. OTHER	09-Mar-15	Convergent Energy and Power LLC	CONV	ME	15	ME	ME		0.000	0.000	0.000	0.483	0.483
47060	HANNAFORD FOOD-01535PV120NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Mar-15	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.048	0.048
47061	WHITTIER FARMS-01590PV114NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Mar-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.046	0.046
47062	EASTERN BANK-01901PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Mar-15	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.040	0.040
47063	SWISS TURN-01540PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Mar-15	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.040	0.040
47064	1ST CONGREGATION-02176PV90NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Mar-15	Massachusetts Electric Company	MEC	MA	17	BOSTON	NEMA		0.000	0.000	0.000	0.036	0.036
47065	210 UPHAM (PV)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Mar-15	Fitchburg Gas and Electric Lig	FGE	MA	27	WMA	WCMA		0.000	0.000	0.000	0.029	0.029
47066	S.D. WARREN SACCARAPPA HYDRO		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	20-Mar-15	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME		0.000	0.000	0.000	0.540	0.540
46976	BUCKSPORT G3		No Resource (1)	ST	WDS		BIO/REFUSE	16-Apr-15	. Tenaska Power Services Company	TPS	ME	09	BHE	ME	50243	0.000	0.000	0.000	73.000	73.000
	Forecasted Photovoltaic Capacity			PV	SUN		PHOTOVOLTAIC	01-Jul-15								0.000	0.000	0.000	8.248	8.248
															Total	32.647	30.494	32.647	30.749	677
															CT			5,333	5,163	(43)
															NOR			192	170	2
															SWCT			2,536	2,320	561

NOTES:

Appendix A - defines the codes used.

Generator details, including Lead Market Participant, as of January 1, 2015.

Additional information and changes to generating asset Lead Participant since January 1, 2015 may be found in the Endnotes following Section 2.1.

The Expected Summer Peak SCC is based on the April 2015 SCC Report and capacity that is expected to be added by August 1st based on the interconnection queue and information provided to ISO-NE by the lead participants. In this table, new capacity consists of one new 73 MW generator and uprates to Manchester Station, Bridgeport Energy, Granite Ridge Energy, and EP Newington Energy totaling approximately 147 MW.

New PV resources that do not yet have an SCC value due to a lack of historical generation data have an assumed SCC of 40 percent of nameplate.

Based on the PV forecast, approximately 8 MW of additional capacity is expected to go commercial by July 1, 2015. See Sec. 3.1.2, "PV in Markets" category for more details on the forecast.

When an alternate fuel is listed, the unit may not necessarily be fully operable on both fuels.

FOOTNOTES:

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Table 3-5
Local Operating Reserve Requirements
Summer 2014 and Winter 2014/2015 Forward Reserve Auctions (MW)

Location Name	Product	Summer 2013	Winter 2013/2014	Summer 2014	Winter 2014/2015
CT	TMOR[a]	747	578	900	363
NEMA/Boston	TMOR[a]	0	0	0	0
SWCT	TMOR[a]	0	155	94	87
Systemwide	TMNSR	1,349	1,532	1,573	1,562
Systemwide	TMOR[a]	723	915	891	831

(a) TMNSR also can be used to satisfy this requirement.

http://www.iso-ne.com/static-assets/documents/2015/05/2014-amr.pdf
http://www.iso-ne.com/static-assets/documents/2016/05/2015_imm_amr_final_5_25_2016.pdf
ISO-NE 2014 Annual Markets Report
ISO-NE 2015 Annual Markets Report

	Winter	Spring	Summer	Fall
ISO-NE	1562	1436	1310	1436
CT	363	538.5	714	538.5
SWCT	87	112.5	138	112.5

Spring, Fall = average of Winter, Summer

Operating Reserves: The bulk power system needs reserve capacity to be able to respond to contingencies, such as those caused by unexpected outages. Operating reserves are provided by the unloaded capacity of generating resources, either online or offline, which can deliver energy within 10 or 30 minutes. The ISO procures both system-wide reserve, and local reserve for import-constrained areas. The system reserve requirement has been relatively constant over the past three years, with a total ten-minute reserve requirement of about 1,700MW and total thirty-minute reserve requirement of about 2,500MW in 2015.

Per ISO-NE ISO New England's Internal Market Monitor 2015 Annual Markets Report Note above, the 2014-2015 reserves are assumed to be the same as the 2013-2014 Reserves.

The TMNSR and TMOR requirements are based on first- and second-contingency losses (refer to Sections 2.1.4 and 2.2.1). The methodology to calculate these requirements is described in OP 8 (Section 2.2.1) and the ISO New England Manual for Forward Reserve (Manual M-36) (December 3, 2013), http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

The Forward Reserve requirements for the New England Control Area are based on expected system operating conditions. The TMNSR purchase amount represents the expected single contingency of the HQ Phase II Interconnection, including a TMNSR bias of 63%. The TMNSR purchase amount is increased to reflect a 20% average fleet-wide historical non-performance of resources called upon after a contingency.[1] The TMOR purchase amount represents the expected single contingency of Seabrook. The Replacement Reserve will be equal to 160 MW.

Forward Reserve Requirements

Reserve Zone	Reserve Category	Local 2nd Contingency MW	External Reserve Support MW	Reserve Requirement MW
New England Control Area	TMNSR	N/A	N/A	1310
New England Control Area	TMOR	N/A	N/A	785
SWCT	TMOR	503	365	138
CT	TMOR	1213	499	714
NEMA/Boston	TMOR	880	549	331

The New England Control Area Forward Reserve Requirements are based on a 1st contingency of 1,664 MW and a 2nd contingency of 1,249 MW.

https://www.iso-ne.com/static-assets/documents/2015/03/forward_reserve_auction_assumptions_summer_2015.docx

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FERC Form 714 Outages

Month	Planned Outage and Derating (MW)
Dec-14	2,033
Jan15	160
Feb15	1,187
Mar15	2,362
Apr15	4,595
May15	2,746
Jun15	627
Jul15	80
Aug15	0
Sep15	482
Oct15	6,598
Nov15	1,801

	Planned Outage and Derating (MW)				
	Winter	Spring	Summer	Fall	Notes
ISO-NE	1,127	3,234	236	2,960	NYISO outages
CT	260	747	55	683	Estimated based on generation ratios

	Generation (MW)			
	Winter	Spring	Summer	Fall
ISO-NE	35,576	35,576	33,424	35,576
CT	8,213	8,213	7,789	8,213

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Needle Peak	24,437
Peak Month	7
PST	19,621
Winter	18,391
Spring	15,604
Summer	18,719
Fall	16,307

Source: ISO-NE

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	17,146	12/1/2014	10,753	10,347	10,184	10,211	10,595	11,749	13,695	14,747	14,901	14,876	14,968	14,940	14,880	14,917	14,890	15,129	16,299	17,146	17,055	16,653	16,038	14,961	13,562	12,334
Winter	12	18,415	12/2/2014	11,554	11,158	11,002	11,048	11,468	12,683	14,792	15,870	16,092	16,135	16,194	16,156	16,133	16,233	16,254	16,551	17,736	18,415	18,275	17,865	17,174	15,998	14,422	13,024
Winter	12	17,801	12/3/2014	12,145	11,634	11,401	11,366	11,702	12,775	14,690	15,788	16,039	16,127	16,214	16,229	16,100	16,041	15,967	16,233	17,236	17,801	17,579	17,106	16,462	15,373	13,948	12,668
Winter	12	18,125	12/4/2014	11,869	11,434	11,271	11,311	11,703	12,905	15,005	15,959	15,966	15,847	15,736	15,586	15,404	15,401	15,440	15,752	17,062	18,114	18,125	17,776	17,277	16,131	14,708	13,434
Winter	12	17,857	12/5/2014	12,626	12,189	11,996	12,034	12,438	13,615	15,658	16,657	16,667	16,481	16,328	16,084	15,910	15,930	15,962	16,215	17,364	17,857	17,501	16,969	16,410	15,595	14,406	13,143
Winter	12	16,745	12/6/2014	12,198	11,647	11,305	11,147	11,190	11,592	12,392	13,274	14,339	15,108	15,486	15,575	15,504	15,286	15,172	15,318	16,291	16,745	16,436	15,905	15,375	14,652	13,678	12,620
Winter	12	18,005	12/7/2014	11,795	11,311	11,036	10,952	11,048	11,387	12,054	12,830	13,838	14,534	14,789	14,782	14,712	14,625	14,627	15,043	16,641	17,925	18,005	17,743	17,262	16,268	15,051	13,882
Winter	12	19,843	12/8/2014	12,989	12,586	12,469	12,522	12,986	14,175	16,312	17,492	17,745	17,844	17,984	17,949	17,849	17,801	17,734	17,992	19,134	19,843	19,640	19,189	18,476	17,231	15,564	14,085
Winter	12	19,049	12/9/2014	13,146	12,609	12,312	12,237	12,546	13,615	15,416	16,646	17,066	17,309	17,500	17,597	17,536	17,566	17,493	17,643	18,501	19,049	18,712	18,081	17,196	15,912	14,309	12,952
Winter	12	18,372	12/10/2014	12,049	11,557	11,334	11,312	11,648	12,760	14,719	15,930	16,176	16,330	16,253	16,536	16,537	16,528	16,310	16,561	17,627	18,372	18,217	17,763	17,083	15,941	14,420	12,995
Winter	12	18,636	12/11/2014	12,114	11,611	11,410	11,429	11,776	12,907	14,915	16,078	16,313	16,421	16,519	16,547	16,485	16,465	16,440	16,630	17,789	18,636	18,488	18,094	17,502	16,439	14,903	13,479
Winter	12	18,208	12/12/2014	12,576	12,097	11,875	11,859	12,229	13,362	15,330	16,421	16,594	16,517	16,441	16,328	16,149	16,093	16,091	16,362	17,500	18,208	17,919	17,442	16,861	16,021	14,857	13,600
Winter	12	17,064	12/13/2014	12,601	12,035	11,759	11,680	11,802	12,271	13,105	13,975	14,895	15,361	15,436	15,299	15,026	14,729	14,620	14,901	16,197	17,064	16,849	16,403	15,944	15,280	14,328	13,214
Winter	12	17,219	12/14/2014	12,304	11,741	11,444	11,334	11,390	11,714	12,322	13,006	13,873	14,417	14,556	14,513	14,465	14,339	14,317	14,616	16,076	17,219	17,178	16,861	16,325	15,311	13,968	12,719
Winter	12	18,367	12/15/2014	11,906	11,504	11,355	11,405	11,864	13,101	15,196	16,278	16,300	16,147	16,009	15,830	15,609	15,526	15,447	15,701	17,093	18,362	18,367	17,998	17,383	16,238	14,684	13,283
Winter	12	18,485	12/16/2014	12,358	11,882	11,667	11,660	12,032	13,183	15,241	16,373	16,554	16,604	16,656	16,629	16,478	16,465	16,384	16,634	17,773	18,485	18,303	17,836	17,172	16,013	14,447	12,957
Winter	12	17,878	12/17/2014	11,949	11,436	11,177	11,157	11,486	12,598	14,570	15,783	15,971	15,978	15,976	15,891	15,703	15,653	15,561	15,779	17,025	17,878	17,735	17,340	16,773	15,725	14,231	12,792
Winter	12	18,215	12/18/2014	11,828	11,322	11,102	11,115	11,491	12,684	14,765	15,931	16,092	16,033	15,955	15,924	15,805	15,798	15,737	16,008	17,289	18,215	18,128	17,740	17,208	16,194	14,732	13,275
Winter	12	18,279	12/19/2014	12,343	11,835	11,589	11,569	11,926	13,038	15,030	16,198	16,436	16,531	16,574	16,474	16,258	16,172	16,068	16,287	17,435	18,279	18,065	17,617	17,097	16,293	15,148	13,854
Winter	12	17,569	12/20/2014	12,873	12,324	12,049	11,940	12,060	12,518	13,366	14,320	15,277	15,819	15,985	15,936	15,785	15,603	15,558	15,825	16,932	17,569	17,317	16,837	16,386	15,701	14,695	13,535
Winter	12	17,728	12/21/2014	12,599	11,983	11,676	11,553	11,604	11,922	12,537	13,345	14,371	15,130	15,504	15,650	15,678	15,579	15,534	15,665	16,930	17,728	17,616	17,262	16,711	15,763	14,411	13,109
Winter	12	18,112	12/22/2014	12,199	11,709	11,504	11,503	11,887	12,971	14,837	16,013	16,338	16,364	16,298	16,201	16,035	15,934	15,859	16,080	17,266	18,112	17,994	17,581	16,988	15,964	14,538	13,054
Winter	12	17,711	12/23/2014	12,016	11,426	11,119	11,071	11,400	12,420	14,219	15,510	15,915	16,108	16,218	16,211	16,071	16,010	15,939	16,104	17,106	17,711	17,492	17,048	16,485	15,572	14,232	12,854
Winter	12	16,368	12/24/2014	11,739	11,087	10,746	10,620	10,830	11,575	12,863	14,090	14,956	15,597	15,962	16,011	15,808	15,703	15,667	15,738	16,355	16,368	15,510	14,727	14,238	13,736	13,027	12,105
Winter	12	14,122	12/25/2014	11,160	10,508	10,090	9,896	9,919	10,227	10,811	11,641	12,613	13,374	13,657	13,648	13,374	13,103	12,832	12,755	13,465	14,122	14,047	13,912	13,754	13,324	12,520	11,584
Winter	12	16,379	12/26/2014	10,857	10,411	10,209	10,195	10,453	11,121	12,135	12,929	13,608	14,085	14,327	14,348	14,166	13,954	13,870	14,057	15,221	16,379	16,203	15,790	15,325	14,577	13,535	12,453
Winter	12	15,621	12/27/2014	11,599	11,117	10,840	10,741	10,854	11,222	11,884	12,537	13,296	13,786	13,954	13,875	13,642	13,333	13,168	13,340	14,530	15,621	15,524	15,140	14,737	14,073	13,084	12,052
Winter	12	16,107	12/28/2014	11,188	10,641	10,320	10,166	10,208	10,497	10,977	11,615	12,464	13,284	13,774	13,997	14,073	13,980	13,834	13,974	15,207	16,107	15,994	15,552	15,010	14,229	13,108	12,076
Winter	12	17,910	12/29/2014	11,316	10,879	10,753	10,821	11,226	12,173	13,628	14,689	15,295	15,522	15,550	15,565	15,479	15,418	15,396	15,605	16,763	17,910	17,796	17,338	16,776	15,830	14,543	13,328
Winter	12	18,734	12/30/2014	12,533	12,093	11,928	11,934	12,275	13,216	14,644	15,731	16,298	16,607	16,721	16,585	16,362	16,253	16,187	16,396	17,531	18,734	18,622	18,209	17,662	16,734	15,445	14,229
Winter	12	18,443	12/31/2014	13,381	12,892	12,677	12,660	12,955	13,800	15,097	16,101	16,713	16,902	16,889	16,747	16,540	16,347	16,208	16,291	17,356	18,443	18,037	17,255	16,548	15,844	15,062	14,362
Winter	1	17,326	1/1/2015	13,662	13,069	12,645	12,425	12,454	12,774	13,247	13,537	13,966	14,429	14,771	14,887	14,869	14,796	14,714	14,949	16,151	17,326	17,155	16,688	16,134	15,328	14,227	13,154
Winter	1	17,673	1/2/2015	12,361	11,854	11,618	11,615	11,881	12,616	13,763	14,673	15,267	15,608	15,761	15,808	15,699	15,541	15,407	15,522	16,575	17,673	17,421	16,934	16,394	15,599	14,537	13,486
Winter	1	17,710	1/3/2015	12,648	12,187	11,933	11,864	11,987	12,386	13,125	13,857	14,644	15,217	15,538	15,728	15,731	15,680	15,729	15,958	16,976	17,710	17,486	16,958	16,342	15,468	14,387	13,283
Winter	1	17,000	1/4/2015	12,363	11,763	11,404	11,245	11,217	11,431	11,916	12,527	13,337	14,193	14,805	15,202	15,425	15,448	15,358	15,475	16,379	17,000	16,695	16,058	15,372	14,210	12,960	11,863
Winter	1	19,224	1/5/2015	11,133	10,791	10,672	10,747	11,208	12,419	14,504	15,627	15,772	15,875	16,000	16,031	16,015	16,092	16,146	16,518	17,717	19,163	19,224	18,867	18,277	17,163	15,747	14,529
Winter	1	20,011	1/6/2015	13,743	13,368	13,240	13,287	13,664	14,793	16,749	17,910	18,047	18,216	18,382	18,401	18,273	18,167	18,017	18,100	18,994	20,011	19,956	19,554	18,877	17,745	16,270	15,010
Winter	1	20,439	1/7/2015	14,233	13,824	13,645	13,639	13,951	14,981	16,931	18,016	18,072	17,921	17,812	17,718	17,661	17,670	17,688	17,977	19,062	20,293	20,439	20,159	19,706	18,690	17,348	16,129
Winter	1	20,583	1/8/2015	15,415	15,090	14,955	15,016	15,420	16,446	18,253	19,413	19,647	19,556	19,397	19,188	18,833	18,625	18,406	18,503	19,468	20,583	20,543	20,143	19,473	18,317	16,786	15,442
Winter	1	19,111	1/9/2015	14,646	14,193	13,965	13,884	14,130	15,059	16,816	17,946	18,121	18,341	18,505	18,371	17,933	17,611	17,337	17,315	18,075	19,111	18,928	18,454	17,883	17,046	15,974	14,835
Winter	1	18,376	1/10/2015	14,041	13,582	13,357	13,329	13,486	13,961	14,795	15,640	16,418	16,866	16,959	16,804	16,510	16,330	16,223	16,435	17,363	18,376	18,367	17,899	17,615	16,966	15,998	15,000
Winter	1	18,668	1/11/2015	14,251	13,793	13,576	13,503	13,566	13,862	14,417	15,005	15,779	16,335	16,531	16,660	16,709	16,648	16,626	16,758	17,631	18,668	18,479	17,874	17,154	16,019	14,714	13,568
Winter	1	18,797	1/12/2015	12,794	12,367	12,182	12,231	12,581	13,691	15,497	16,608	16,879	17,130	17,379	17,497	17,486	17,382	17,203	17,233	18,006	18,797	18,577	17,993	17,218	16,036	14,658	13,466
Winter	1	19,614	1/13/2015	12,713	12,310	12,193	12,271	12,718	13,961	16,079	17,241	17,367	17,344	17,323	17,202	17,024	16,993	16,918	17,116	18,103	19,521	19,614	19,307	18,749	17,693	16,314	15,118
Winter	1	19,803	1/14/2015	14,387	14,054	13,938	13,980	14,346	15,423	17,404	18,536	18,656	18,717	18,783	18,699	18,513	18,364	18,171	18,212	18,930	19,803	19,682	19,213	18,524	17,344	15,887	14,612
Winter	1	19,000	1/15/2015	13,803	13,386	13,202	13,205	13,536	14,640	16,591	17,632	17,701	17,707	17,714	17,615	17,413	17,286	17,137	17,174	17,909	19,000	18,942	18,513	17,895	16,845	15,468	14,276
Winter	1	18,650	1/16/2015	13,506	13,164	12,967	12,969	13,316	14,361	16,251	17,227	17,363	17,201	16,969	16,725	16,603	16,636	16,574	16,676	17,469	18,650	18,606	18,219	17,740	16,981	15,968	14,915
Winter	1	18,122	1/17/2015	14,177	13,768	13,600	13,563	13,722	14,237	15,068	15,914	16,726	17,093	17,123	16,893	16,538	16,140	15,898	16,025	16,857	18,122	18,049	17,574	17,054	16,282	15,290	14,289
Winter	1	17,072	1/18/2015	13,515	13,023	12,703	12,554	12,565	12,806	13,277	13,843	14,658	15,353	15,769	15,977	15,990	15,921	15,863	15,904	16,479	17,072	16,675	15,929	15,308	14,502	13,585	12,511
Winter	1	18,025	1/19/2015	11,740	11,321	11,140	11,194	11,509	12,388	13,680	14,651	15,294	15,720	16,054	16,174	16,112	16,028	15,943	16,071	16,794	18,025	17,933	17,443	16,746	15,639	14,306	13,149
Winter	1	18,339	1/20/2015	12,454	12,065	11,892	11,918	12,313	13,466	15,457	16,477	16,467	16,363	16,255	16,088	15,915	15,836	15,813	15,999	16,864	18,261	18,339	17,917	17,294	16,174	14,833	13,644
Winter	1	18,521	1/21/2015	12,944	12,590	12,449	12,513	12,954	14,161	16,230	17,295	17,197	16,967	16,836	16,731	16,569	16,436	16,259	16,379	17,216	18,521	18,520	18,084	17,404	16,239	14,788	13,566
Winter	1	18,058	1/22/2015	12,781	12,371	12,195	12,216	12,601	13,722	15,730	16,787	16,887	16,757	16,582	16,380	16,173	16,070	15,902	15,973	16,664	18,011	18,058	17,687	17,100	16,058	14,695	13,550
Winter	1	17,523	1/23/2015	12,853	12,484	12,360	12,429	12,840	13,965	15,983	17,021	16,997	16,766	16,544	16,290	15,994	15,799	15,616	15,664	16,322	17,523	17,482	17,028	16,461	15,634	14,549	13,454
Winter	1	17,403	1/24/2015	12,625	12,145	11,877	11,755	11,863	12,286	13,079	13,876	14,749	15,523	16,014	16,200	16,191	16,034	15,827	15,805	16,355	17,403	17,183	16,533	15,844	14,990	13,988	13,041
Winter	1	17,425	1/25/2015	12,281	11,829	11,556	11,458	11,521	11,850	12,468	13,101	13,949	14,446	14,622	14,623	14,515	14,341	14,298	14,593	15,570	17,210	17,425	17,125	16,590	15,677	14,562	13,584
Winter	1	19,531	1/26/2015	12,944	12,629	12,541	12,642	13,128	14,408	16,588	17,722	17,899	17,932	17,953	17,896	17,826	17,815	17,737	17,766	18,395	19,531	19,425	18,697	17,769	16,628	15,416	14,359
Winter	1	18,727	1/27/2015	13,622	13,219	13,044	13,053	13,256	13,727	14,443	15,060	15,785	16,399	16,696	16,822	16,870	16,743	16,605	16,628	17,318	18,727	18,632	18,035	17,290	16,299	15,153	14,165
Winter	1	19,361	1/28/2015	13,545	13,239	13,111	13,133	13,457	14,313	15,707	16,734	17,410	17,689	17,831	17,816	17,666	17,477	17,181	17,127	17,711	19,186	19,361	18,896	18,214	17,099	15,764	14,630
Winter	1	18,661	1/29/2015	13,975	13,660	13,544	13,652	14,075	15,201	17,142	18,092	18,089	17,838	17,587	17,272	16,915	16,667	16,451	16,516	17,151	18,521	18,661	18,268	17,611	16,515	15,106	13,840
Winter	1	18,114	1/30/2015	13,077	12,658	12,464	12,435	12,747	13,738	15,519	16,610	16,915	17,105	17,190	17,100	16,917	16,834	16,669	16,626	17,054	18,040	18,114	17,711	17,248	16,531	15,538	14,570
Winter	1	18,686	1/31/2015	13,905	13,544	13,412	13,436	13,639	14,191	15,072	15,951	16,886	17,423	17,505	17,379	17,080	16,700	16,444	16,483	17,075	18,452	18,686	18,292	17,790	17,032	16,051	15,037
Winter	2	17,999	2/1/2015	14,296	13,847	13,621	13,522	13,606	13,894	14,452	15,041	15,750	16,132	16,132	16,037	15,931	15,743	15,713	15,923	16,643	17,999	17,647	16,743	16,265	15,631	15,013	14,306
Winter	2	19,916	2/2/2015	13,458	13,029	12,888	12,959	13,314	14,155	15,354	16,231	17,027	17,719	18,242	18,537	18,613	18,528	18,399	18,379	18,844	19,916	19,911	19,321	18,477	17,310	16,017	14,882
Winter	2	19,599	2/3/2015	14,276	13,964	13,889	13,992	14,372	15,392	16,969	17,957	18,367	18,360	18,282	18,191	17,869	17,638	17,371	17,293	17,754	19,174	19,599	19,320	18,725	17,690	16,286	15,088
Winter	2	18,581	2/4/2015	14,383	14,045	13,886	13,885	14,212	15,246	17,103	18,007	18,021	17,917	17,846	17,648	17,344	17,172	16,971	16,868	17,223	18,401	18,581	18,164	17,487	16,371	14,927	13,711
Winter	2	19,642	2/5/2015	12,892	12,428	12,215	12,201	12,537	13,618	15,452	16,500	16,815	17,092	17,341	17,437	17,383	17,355	17,180	17,149	17,636	19,097	19,642	19,397	18,916	17,944	16,572	15,423
Winter	2	19,112	2/6/2015	14,726	14,403	14,280	14,342	14,710	15,815	17,689	18,577	18,594	18,530	18,484	18,374	18,115	17,848	17,512	17,339	17,695	18,829	19,112	18,773	18,266	17,449	16,368	15,251
Winter	2	17,680	2/7/2015	14,412	13,923	13,637	13,498	13,528	13,897	14,640	15,476	16,271	16,632	16,825	16,721	16,552	16,440	16,320	16,315	16,664	17,643	17,680	17,174	16,607	15,811	14,832	13,861
Winter	2	18,491	2/8/2015	13,125	12,679	12,430	12,317	12,400	12,650	13,160	13,758	14,767	15,558	16,056	16,340	16,466	16,438	16,404	16,607	17,243	18,401	18,491	17,986	17,293	16,326	15,293	14,366
Winter	2	19,658	2/9/2015	13,691	13,324	13,175	13,192	13,529	14,391	15,619	16,507	17,287	17,920	18,386	18,662	18,686	18,537	18,252	18,062	18,413	19,585	19,658	19,057	18,211	17,045	15,698	14,563
Winter	2	18,822	2/10/2015	13,846	13,470	13,294	13,286	13,604	14,543	16,034	17,042	17,546	17,683	17,646	17,506	17,290	17,082	16,843	16,690	17,026	18,296	18,822	18,442	17,802	16,732	15,350	14,196
Winter	2	18,964	2/11/2015	13,476	13,121	12,959	13,046	13,510	14,623	16,527	17,449	17,607	17,560	17,443	17,285	17,083	16,922	16,713	16,721	17,205	18,463	18,964	18,662	18,122	17,116	15,757	14,573
Winter	2	18,792	2/12/2015	13,874	13,477	13,306	13,350	13,674	14,737	16,561	17,499	17,692	17,785	17,782	17,613	17,381	17,264	17,054	17,042	17,454	18,424	18,792	18,492	17,948	16,990	15,671	14,537
Winter	2	19,343	2/13/2015	13,808	13,519	13,480	13,633	14,080	15,292	17,174	18,188	18,390	18,444	18,428	18,256	17,956	17,736	17,480	17,429	17,772	18,826	19,343	19,038	18,623	17,879	16,832	15,792
Winter	2	18,532	2/14/2015	15,034	14,607	14,413	14,354	14,495	14,942	15,698	16,516	17,286	17,685	17,724	17,524	17,269	17,022	16,855	16,895	17,287	18,300	18,532	17,952	17,247	16,326	15,333	14,409
Winter	2	19,590	2/15/2015	13,712	13,338	13,157	13,096	13,169	13,434	13,929	14,514	15,496	16,330	16,886	17,163	17,204	17,074	16,887	16,950	17,471	18,929	19,590	19,179	18,609	17,806	16,889	15,993
Winter	2	20,108	2/16/2015	15,404	15,093	14,989	15,036	15,319	16,029	17,083	17,955	18,664	19,043	19,153	19,037	18,746	18,405	18,131	18,093	18,554	19,713	20,108	19,659	18,989	17,947	16,673	15,508
Winter	2	19,514	2/17/2015	14,780	14,388	14,208	14,215	14,560	15,494	17,047	18,070	18,609	18,839	18,908	18,751	18,433	18,137	17,769	17,643	17,962	19,018	19,514	19,123	18,477	17,421	16,094	14,935
Winter	2	18,763	2/18/2015	14,214	13,876	13,728	13,777	14,171	15,199	16,839	17,786	18,010	17,968	17,830	17,551	17,191	17,006	16,808	16,782	17,174	18,304	18,763	18,380	17,739	16,725	15,414	14,279
Winter	2	19,705	2/19/2015	13,549	13,150	12,999	13,046	13,397	14,407	15,982	16,951	17,283	17,333	17,367	17,451	17,356	17,290	17,192	17,293	17,763	19,007	19,705	19,475	18,954	18,008	16,737	15,669
Winter	2	19,540	2/20/2015	14,988	14,666	14,546	14,610	14,992	16,017	17,575	18,601	18,944	19,022	18,959	18,769	18,478	18,234	17,951	17,789	18,060	18,952	19,540	19,229	18,714	17,903	16,878	15,834
Winter	2	18,223	2/21/2015	15,076	14,746	14,603	14,575	14,748	15,216	15,905	16,679	17,340	17,576	17,499	17,265	17,008	16,864	16,776	16,833	17,156	18,013	18,223	17,679	16,991	16,077	14,980	13,954
Winter	2	17,270	2/22/2015	13,180	12,690	12,392	12,260	12,291	12,553	12,997	13,593	14,450	15,111	15,449	15,499	15,285	14,931	14,668	14,678	15,135	16,476	17,270	16,942	16,306	15,309	14,244	13,274
Winter	2	19,862	2/23/2015	12,653	12,315	12,175	12,224	12,650	13,803	15,699	16,819	17,273	17,466	17,502	17,501	17,305	17,190	17,059	17,185	17,714	18,940	19,862	19,670	19,172	18,190	16,893	15,773
Winter	2	19,983	2/24/2015	15,118	14,851	14,768	14,851	15,246	16,370	18,127	18,962	18,920	18,870	18,674	18,416	18,102	17,876	17,680	17,647	18,106	19,254	19,983	19,649	18,960	17,818	16,325	15,045
Winter	2	18,605	2/25/2015	14,276	13,903	13,730	13,747	14,079	15,163	16,878	17,706	17,669	17,458	17,290	17,026	16,729	16,523	16,292	16,286	16,707	17,763	18,605	18,408	17,835	16,840	15,518	14,393
Winter	2	19,206	2/26/2015	13,691	13,356	13,217	13,278	13,634	14,728	16,525	17,527	17,856	18,044	18,124	18,062	17,834	17,510	17,272	17,360	17,759	18,605	19,206	18,894	18,276	17,198	15,818	14,627
Winter	2	18,313	2/27/2015	13,939	13,626	13,520	13,584	13,975	15,073	16,812	17,653	17,697	17,554	17,382	17,144	16,808	16,587	16,335	16,262	16,587	17,461	18,313	18,029	17,623	16,900	15,897	14,889
Winter	2	17,337	2/28/2015	14,220	13,868	13,724	13,697	13,867	14,367	15,110	15,883	16,454	16,691	16,593	16,298	15,870	15,443	15,150	15,100	15,483	16,452	17,337	17,091	16,703	16,096	15,264	14,418
Spring	3	18,198	3/1/2015	13,805	13,493	13,354	13,314	13,406	13,740	14,163	14,861	15,605	16,039	16,241	16,293	16,151	16,050	16,038	16,233	16,708	17,664	18,198	17,749	17,009	15,882	14,667	13,629
Spring	3	18,586	3/2/2015	12,963	12,621	12,492	12,524	12,901	13,943	15,501	16,491	16,823	16,835	16,823	16,718	16,576	16,454	16,310	16,279	16,664	17,682	18,586	18,308	17,710	16,594	15,221	14,092

Contains Proprietary Material
Do Not Distribute

Spring	3	18,800	3/3/2015	13,422	13,097	12,982	13,053	13,521	14,694	16,484	17,227	17,140	16,987	16,878	16,714	16,543	16,545	16,515	16,629	17,111	18,201	18,800	18,451	17,783	16,568	15,109	13,866
Spring	3	17,706	3/4/2015	13,021	12,549	12,294	12,272	12,601	13,619	15,248	16,169	16,449	16,473	16,400	16,273	16,097	15,963	15,746	15,796	16,223	17,129	17,706	17,345	16,672	15,568	14,195	13,040
Spring	3	18,848	3/5/2015	12,294	11,923	11,769	11,790	12,183	13,320	15,134	16,201	16,620	16,923	17,203	17,293	17,294	17,293	17,136	17,142	17,503	18,306	18,848	18,512	17,948	16,884	15,579	14,474
Spring	3	18,082	3/6/2015	13,870	13,586	13,504	13,596	14,038	15,209	16,904	17,742	17,746	17,559	17,400	17,125	16,752	16,494	16,219	16,123	16,416	17,192	18,082	17,835	17,357	16,577	15,510	14,478
Spring	3	16,572	3/7/2015	13,703	13,283	13,103	13,076	13,268	13,758	14,408	15,177	15,752	15,971	15,884	15,597	15,176	14,762	14,553	14,611	14,983	15,761	16,572	16,265	15,783	15,030	14,107	13,218
Spring	3	16,400	3/8/2015	12,539		12,361	12,183	11,975	11,980	12,198	12,680	13,189	13,928	14,575	14,840	14,870	14,859	14,724	14,432	14,244	14,370	14,806	15,505	16,400	16,129	15,235	14,074
Spring	3	16,717	3/9/2015	12,989	12,301	11,979	11,852	11,923	12,298	13,380	15,325	16,461	16,566	16,083	16,085	15,816	15,508	15,286	14,984	14,782	14,839	15,227	15,830	16,717	16,372	15,394	14,080
Spring	3	16,610	3/10/2015	12,905	12,162	11,778	11,632	11,681	12,028	13,118	15,120	16,188	16,235	15,968	15,715	15,431	15,174	15,003	14,825	14,804	15,063	15,553	16,147	16,610	16,125	15,095	13,700
Spring	3	15,840	3/11/2015	12,498	11,711	11,331	11,105	11,087	11,395	12,406	14,302	15,381	15,334	15,094	15,021	14,884	14,684	14,516	14,267	14,149	14,231	14,577	15,026	15,840	15,583	14,634	13,362
Spring	3	16,839	3/12/2015	12,196	11,446	11,089	10,939	10,988	11,347	12,477	14,529	15,625	15,714	15,617	15,553	15,392	15,170	15,047	14,847	14,741	14,889	15,330	15,941	16,839	16,623	15,735	14,446
Spring	3	16,560	3/13/2015	13,295	12,545	12,203	12,073	12,126	12,472	13,547	15,514	16,541	16,560	16,357	16,122	15,865	15,535	15,247	14,916	14,672	14,725	14,990	15,433	16,101	15,815	15,111	14,042
Spring	3	15,563	3/14/2015	12,969	12,176	11,713	11,468	11,349	11,424	11,784	12,542	13,411	14,364	15,075	15,467	15,563	15,436	15,200	14,978	14,858	14,952	15,191	15,372	15,487	15,092	14,409	13,499
Spring	3	16,279	3/15/2015	12,524	11,761	11,318	11,026	10,899	10,924	11,164	11,706	12,355	13,309	14,049	14,382	14,568	14,597	14,388	14,240	14,334	14,745	15,258	15,699	16,279	15,912	14,977	13,816
Spring	3	16,474	3/16/2015	12,777	12,092	11,773	11,633	11,697	12,116	13,268	15,280	16,247	16,251	16,033	15,850	15,598	15,303	15,141	14,868	14,673	14,723	15,108	15,684	16,474	16,137	15,111	13,751
Spring	3	16,826	3/17/2015	12,569	11,824	11,381	11,177	11,154	11,488	12,558	14,535	15,694	16,000	16,136	16,218	16,079	15,653	15,388	15,158	14,961	15,193	15,575	15,978	16,826	16,612	15,723	14,443
Spring	3	17,853	3/18/2015	13,310	12,588	12,243	12,130	12,199	12,606	13,733	15,743	16,765	16,797	16,615	16,501	16,354	16,163	16,038	15,831	15,773	15,982	16,464	17,005	17,853	17,573	16,564	15,169
Spring	3	17,212	3/19/2015	13,970	13,229	12,886	12,746	12,770	13,161	14,291	16,265	17,198	17,079	16,836	16,692	16,463	16,146	15,904	15,570	15,398	15,511	15,872	16,356	17,212	17,005	16,092	14,793
Spring	3	16,984	3/20/2015	13,602	12,863	12,495	12,362	12,398	12,759	13,849	15,764	16,755	16,984	16,920	16,818	16,599	16,335	16,273	16,151	16,067	16,181	16,389	16,575	16,937	16,548	15,725	14,595
Spring	3	15,695	3/21/2015	13,476	12,662	12,215	11,967	11,823	11,918	12,298	13,068	13,898	14,862	15,504	15,695	15,470	14,961	14,442	14,048	13,828	13,930	14,248	14,576	15,104	14,877	14,260	13,418
Spring	3	16,441	3/22/2015	12,517	11,822	11,416	11,223	11,186	11,340	11,704	12,308	12,982	13,750	14,226	14,465	14,542	14,454	14,234	14,000	13,968	14,217	14,796	15,434	16,441	16,335	15,482	14,346
Spring	3	17,333	3/23/2015	13,326	12,669	12,406	12,343	12,431	12,907	14,122	16,126	17,115	17,076	16,890	16,765	16,549	16,284	16,020	15,696	15,468	15,573	16,008	16,494	17,333	17,118	16,087	14,727
Spring	3	16,945	3/24/2015	13,523	12,812	12,479	12,394	12,428	12,823	13,973	15,963	16,945	16,854	16,456	16,103	15,818	15,509	15,276	14,990	14,847	14,965	15,332	15,730	16,574	16,447	15,465	14,107
Spring	3	16,448	3/25/2015	12,929	12,277	11,961	11,833	11,914	12,335	13,509	15,497	16,363	16,172	15,756	15,441	15,136	14,843	14,648	14,430	14,443	14,767	15,326	15,889	16,448	16,055	15,034	13,646
Spring	3	16,030	3/26/2015	12,455	11,690	11,293	11,084	11,039	11,321	12,378	14,292	15,255	15,420	15,399	15,301	15,192	15,064	15,142	15,112	15,082	15,323	15,645	15,802	16,030	15,598	14,585	13,216
Spring	3	15,683	3/27/2015	12,036	11,288	10,847	10,648	10,643	10,951	11,990	13,947	15,113	15,440	15,621	15,683	15,556	15,322	15,228	15,006	14,879	14,970	15,071	15,112	15,447	15,223	14,485	13,430
Spring	3	15,402	3/28/2015	12,376	11,588	11,140	10,908	10,818	10,923	11,330	12,133	13,068	14,115	14,847	15,208	15,201	15,027	14,762	14,474	14,353	14,431	14,683	14,936	15,402	15,220	14,601	13,738
Spring	3	15,238	3/29/2015	12,817	12,120	11,729	11,510	11,437	11,535	11,857	12,387	13,044	13,743	14,066	14,072	13,929	13,702	13,401	13,117	12,999	13,189	13,708	14,240	15,166	15,238	14,372	13,242
Spring	3	16,512	3/30/2015	12,229	11,589	11,285	11,167	11,230	11,606	12,733	14,708	15,847	16,210	16,353	16,512	16,477	16,302	16,066	15,736	15,396	15,479	15,811	16,008	16,389	16,112	15,086	13,689
Spring	3	15,964	3/31/2015	12,473	11,712	11,317	11,152	11,162	11,545	12,673	14,551	15,447	15,390	15,228	15,089	14,857	14,563	14,458	14,331	14,358	14,620	15,075	15,379	15,964	15,759	14,762	13,374
Spring	4	15,783	4/1/2015	12,231	11,537	11,190	11,066	11,095	11,520	12,694	14,653	15,537	15,467	15,195	15,041	14,876	14,625	14,468	14,205	14,073	14,187	14,537	14,913	15,693	15,783	14,897	13,605
Spring	4	15,818	4/2/2015	12,476	11,765	11,443	11,342	11,381	11,770	12,903	14,787	15,755	15,818	15,717	15,611	15,264	14,847	14,517	14,182	13,952	13,967	14,220	14,528	15,199	15,113	14,239	12,958
Spring	4	14,652	4/3/2015	11,748	10,921	10,474	10,227	10,173	10,415	11,219	12,607	13,565	14,190	14,531	14,652	14,561	14,322	14,197	14,054	13,939	14,017	14,138	14,139	14,404	14,185	13,455	12,432
Spring	4	14,370	4/4/2015	11,397	10,609	10,155	9,888	9,761	9,851	10,217	10,911	11,773	12,811	13,356	13,581	13,608	13,413	13,137	12,887	12,773	12,900	13,224	13,538	14,202	14,370	13,843	13,032
Spring	4	14,278	4/5/2015	12,082	11,261	10,808	10,593	10,510	10,582	10,900	11,414	12,181	12,911	13,337	13,379	13,359	13,223	12,843	12,492	12,336	12,479	12,808	13,234	14,075	14,278	13,562	12,506
Spring	4	15,410	4/6/2015	11,502	10,819	10,521	10,451	10,538	10,959	12,117	14,003	15,067	15,274	15,187	15,106	14,940	14,676	14,517	14,276	14,106	14,165	14,444	14,740	15,410	15,373	14,356	13,014
Spring	4	16,021	4/7/2015	11,814	10,982	10,587	10,407	10,401	10,738	11,830	13,730	14,832	15,091	15,217	15,383	15,379	15,287	15,260	15,096	15,061	15,259	15,601	15,745	16,021	15,744	14,733	13,350
Spring	4	16,441	4/8/2015	12,128	11,363	10,983	10,825	10,841	11,197	12,326	14,156	15,164	15,250	15,134	15,108	15,103	15,077	15,204	15,182	15,257	15,542	15,959	16,159	16,441	16,095	15,138	13,743
Spring	4	16,455	4/9/2015	12,563	11,810	11,396	11,227	11,240	11,576	12,673	14,572	15,699	15,990	16,120	16,223	16,173	16,013	15,890	15,724	15,640	15,747	16,023	16,171	16,455	16,180	15,215	13,830
Spring	4	15,697	4/10/2015	12,592	11,782	11,328	11,103	11,090	11,385	12,398	14,221	15,338	15,599	15,667	15,697	15,581	15,371	15,237	15,045	14,891	14,918	14,959	14,911	15,066	14,871	14,071	12,979
Spring	4	13,799	4/11/2015	11,854	10,993	10,515	10,260	10,173	10,270	10,677	11,317	12,142	12,873	13,312	13,428	13,313	13,057	12,776	12,518	12,359	12,446	12,711	12,967	13,543	13,799	13,241	12,390
Spring	4	13,853	4/12/2015	11,439	10,761	10,361	10,175	10,111	10,203	10,509	10,913	11,545	12,141	12,486	12,558	12,499	12,335	12,092	11,908	11,899	12,143	12,572	12,886	13,573	13,853	12,952	11,813
Spring	4	14,644	4/13/2015	10,732	10,128	9,783	9,647	9,692	10,110	11,255	12,941	13,952	14,129	14,172	14,219	14,161	14,024	13,944	13,783	13,669	13,736	13,949	14,057	14,587	14,644	13,602	12,235
Spring	4	14,745	4/14/2015	11,017	10,290	9,861	9,663	9,645	9,940	10,948	12,646	13,855	14,207	14,314	14,410	14,305	14,161	14,121	13,943	13,833	13,935	14,145	14,298	14,745	14,624	13,617	12,236
Spring	4	14,493	4/15/2015	11,053	10,283	9,881	9,678	9,674	10,015	11,085	12,700	13,683	13,826	13,858	13,867	13,826	13,717	13,713	13,571	13,495	13,535	13,725	13,811	14,272	14,493	13,540	12,205
Spring	4	14,485	4/16/2015	10,989	10,229	9,834	9,650	9,699	10,079	11,184	12,823	13,806	13,908	13,917	13,918	13,835	13,687	13,624	13,442	13,368	13,417	13,620	13,767	14,291	14,485	13,555	12,242
Spring	4	14,781	4/17/2015	11,058	10,265	9,860	9,645	9,619	9,907	10,869	12,532	13,742	14,296	14,629	14,781	14,726	14,533	14,378	14,103	13,865	13,763	13,733	13,649	13,800	13,963	13,225	12,155
Spring	4	13,032	4/18/2015	11,022	10,220	9,747	9,489	9,395	9,477	9,859	10,384	11,234	11,983	12,451	12,541	12,479	12,304	12,117	11,985	11,955	12,131	12,410	12,516	12,752	13,032	12,426	11,501
Spring	4	13,353	4/19/2015	10,579	9,864	9,442	9,194	9,097	9,160	9,417	9,753	10,408	11,153	11,627	11,834	11,853	11,778	11,611	11,476	11,474	11,716	12,147	12,508	13,074	13,353	12,532	11,483
Spring	4	15,288	4/20/2015	10,490	9,858	9,520	9,378	9,394	9,733	10,698	12,116	13,360	14,101	14,589	14,917	15,076	15,124	15,128	14,985	14,897	15,024	15,272	15,276	15,288	14,909	13,846	12,542
Spring	4	14,565	4/21/2015	11,359	10,589	10,172	9,945	9,903	10,191	11,077	12,591	13,742	14,247	14,412	14,545	14,565	14,392	14,277	14,013	13,824	13,820	13,894	13,904	14,220	14,471	13,599	12,290
Spring	4	14,448	4/22/2015	11,116	10,326	9,908	9,730	9,685	10,040	11,005	12,420	13,467	13,759	13,857	13,937	13,934	13,881	13,902	13,796	13,710	13,854	14,123	14,241	14,448	14,431	13,476	12,182
Spring	4	14,939	4/23/2015	11,039	10,281	9,878	9,669	9,674	10,001	11,003	12,431	13,523	13,899	14,074	14,236	14,277	14,250	14,241	14,025	13,910	14,029	14,276	14,436	14,759	14,939	14,107	12,859
Spring	4	14,577	4/24/2015	11,709	10,981	10,560	10,373	10,369	10,665	11,607	12,987	14,052	14,430	14,502	14,529	14,429	14,253	14,118	13,927	13,752	13,769	13,926	14,058	14,381	14,577	13,898	12,883
Spring	4	13,287	4/25/2015	11,826	11,042	10,621	10,385	10,328	10,452	10,835	11,389	12,143	12,748	12,996	12,984	12,795	12,548	12,329	12,101	12,038	12,164	12,467	12,688	12,986	13,287	12,730	11,870
Spring	4	13,679	4/26/2015	10,956	10,283	9,876	9,663	9,580	9,643	9,882	10,227	10,864	11,575	12,029	12,207	12,366	12,417	12,371	12,286	12,317	12,559	12,975	13,231	13,561	13,679	12,788	11,641
Spring	4	14,635	4/27/2015	10,594	9,940	9,567	9,420	9,454	9,801	10,881	12,565	13,727	14,005	14,064	14,123	14,154	14,117	14,090	13,903	13,845	13,970	14,271	14,357	14,536	14,635	13,667	12,281
Spring	4	14,470	4/28/2015	11,079	10,317	9,897	9,715	9,711	10,029	11,068	12,738	13,801	14,022	14,057	14,037	13,797	13,683	13,723	13,566	13,463	13,552	13,725	13,782	14,072	14,470	13,555	12,176
Spring	4	14,357	4/29/2015	10,946	10,157	9,746	9,532	9,520	9,837	10,827	12,474	13,489	13,717	13,756	13,855	13,879	13,792	13,817	13,700	13,565	13,588	13,691	13,737	14,075	14,357	13,442	12,076
Spring	4	14,359	4/30/2015	10,858	10,081	9,657	9,451	9,456	9,767	10,780	12,441	13,573	13,844	13,929	13,967	13,889	13,789	13,773	13,658	13,577	13,617	13,759	13,832	14,129	14,359	13,466	12,163
Spring	5	13,960	5/1/2015	10,940	10,175	9,755	9,551	9,529	9,820	10,754	12,369	13,502	13,853	13,931	13,960	13,884	13,743	13,665	13,491	13,323	13,301	13,298	13,239	13,429	13,807	13,190	12,142
Spring	5	12,974	5/2/2015	11,057	10,249	9,785	9,561	9,484	9,592	9,942	10,566	11,469	12,139	12,369	12,375	12,277	12,130	11,959	11,794	11,759	11,891	12,118	12,217	12,478	12,974	12,443	11,517
Spring	5	13,460	5/3/2015	10,577	9,849	9,467	9,200	9,081	9,132	9,304	9,628	10,343	11,100	11,596	11,835	11,929	11,978	11,920	11,863	11,927	12,146	12,517	12,745	13,043	13,460	12,665	11,433
Spring	5	15,035	5/4/2015	10,330	9,615	9,248	9,084	9,083	9,426	10,389	12,037	13,160	13,566	13,873	14,196	14,425	14,552	14,696	14,677	14,629	14,688	14,751	14,614	14,673	15,035	14,067	12,577
Spring	5	15,037	5/5/2015	11,223	10,355	9,880	9,625	9,540	9,813	10,733	12,386	13,696	14,173	14,441	14,615	14,823	14,863	14,957	14,984	14,981	14,983	14,926	14,716	14,745	15,037	14,070	12,558
Spring	5	14,769	5/6/2015	11,216	10,346	9,869	9,595	9,506	9,732	10,638	12,239	13,446	13,862	14,150	14,352	14,423	14,400	14,463	14,416	14,404	14,480	14,536	14,407	14,391	14,769	13,845	12,382
Spring	5	15,335	5/7/2015	11,030	10,160	9,677	9,430	9,363	9,652	10,491	12,116	13,323	13,806	14,197	14,596	14,838	14,957	15,152	15,214	15,241	15,335	15,277	15,022	14,893	15,202	14,334	12,776
Spring	5	14,887	5/8/2015	11,406	10,490	9,951	9,628	9,527	9,764	10,575	12,139	13,411	13,983	14,385	14,650	14,816	14,833	14,887	14,797	14,715	14,680	14,536	14,232	14,104	14,354	13,661	12,444
Spring	5	13,831	5/9/2015	11,198	10,274	9,758	9,436	9,292	9,357	9,647	10,179	11,127	12,023	12,537	12,685	12,717	12,722	12,681	12,722	12,835	13,000	13,236	13,307	13,408	13,831	13,333	12,341
Spring	5	15,908	5/10/2015	11,239	10,422	9,883	9,567	9,427	9,443	9,557	9,900	10,796	11,868	12,699	13,222	13,559	13,787	14,007	14,246	14,523	14,909	15,256	15,348	15,439	15,908	15,220	13,838
Spring	5	16,955	5/11/2015	12,477	11,528	10,994	10,646	10,520	10,792	11,664	13,347	14,900	15,705	16,313	16,778	16,955	16,934	16,952	16,840	16,764	16,738	16,585	16,289	16,112	16,175	15,094	13,452
Spring	5	17,077	5/12/2015	11,984	11,073	10,572	10,294	10,196	10,460	11,351	12,980	14,278	14,806	15,192	15,688	16,184	16,606	16,955	17,073	17,012	17,077	16,968	16,613	16,344	16,359	15,263	13,486
Spring	5	14,543	5/13/2015	11,858	10,829	10,235	9,905	9,789	10,002	10,757	12,348	13,562	13,991	14,235	14,463	14,543	14,474	14,484	14,358	14,257	14,303	14,302	14,166	14,137	14,464	13,684	12,255
Spring	5	14,510	5/14/2015	10,965	10,127	9,672	9,449	9,433	9,719	10,546	12,179	13,282	13,632	13,860	14,058	14,157	14,127	14,209	14,187	14,195	14,309	14,362	14,245	14,177	14,510	13,781	12,347
Spring	5	14,394	5/15/2015	11,013	10,165	9,693	9,472	9,424	9,705	10,468	12,047	13,202	13,682	13,995	14,245	14,355	14,341	14,394	14,277	14,108	14,123	14,020	13,778	13,674	13,971	13,388	12,244
Spring	5	13,564	5/16/2015	11,070	10,196	9,673	9,389	9,277	9,352	9,618	10,219	11,258	12,230	12,839	13,146	13,215	13,141	13,056	12,980	12,949	13,009	13,164	13,187	13,265	13,564	13,079	12,134
Spring	5	15,349	5/17/2015	11,088	10,278	9,792	9,503	9,361	9,364	9,409	9,798	10,705	11,749	12,577	13,148	13,590	13,869	13,992	14,148	14,388	14,789	15,160	15,262	15,140	15,349	14,591	13,117
Spring	5	15,068	5/18/2015	11,704	10,783	10,263	9,961	9,857	10,103	10,950	12,545	13,770	14,214	14,470	14,678	14,832	14,859	15,006	15,032	15,022	15,066	15,068	14,869	14,757	14,965	14,097	12,632
Spring	5	15,353	5/19/2015	11,264	10,416	9,955	9,710	9,639	9,919	10,775	12,405	13,720	14,223	14,565	14,901	15,050	15,033	15,014	14,978	14,974	15,160	15,346	15,265	15,153	15,353	14,544	13,096
Spring	5	14,297	5/20/2015	11,763	10,823	10,256	9,878	9,730	9,949	10,672	12,309	13,495	13,909	14,098	14,253	14,297	14,246	14,278	14,151	14,007	14,026	14,092	13,982	13,956	14,285	13,651	12,304
Spring	5	14,381	5/21/2015	11,013	10,167	9,747	9,486	9,458	9,752	10,563	12,192	13,326	13,758	13,949	14,161	14,203	14,188	14,212	14,108	14,077	14,106	14,142	14,028	14,027	14,381	13,735	12,359
Spring	5	14,514	5/22/2015	11,069	10,202	9,736	9,489	9,445	9,688	10,494	12,029	13,278	13,787	14,116	14,348	14,472	14,507	14,514	14,368	14,233	14,177	14,128	13,903	13,667	13,824	13,351	12,227
Spring	5	12,796	5/23/2015	11,044	10,137	9,639	9,349	9,220	9,264	9,400	9,979	10,815	11,630	12,101	12,268	12,241	12,129	11,943	11,799	11,799	11,993	12,303	12,455	12,459	12,796	12,516	11,605
Spring	5	13,198	5/24/2015	10,609	9,856	9,411	9,162	9,046	9,083	9,120	9,502	10,241	11,073	11,741	12,091	12,293	12,357	12,350	12,356	12,483	12,713	12,969	12,971	12,872	13,198	12,873	11,942
Spring	5	14,992	5/25/2015	10,910	10,099	9,608	9,317	9,183	9,245	9,380	9,874	10,691	11,761	12,647	13,206	13,623	13,873	13,909	13,923	14,056	14,377	14,720	14,714	14,671	14,992	14,336	12,908
Spring	5	18,470	5/26/2015	11,607	10,745	10,271	10,013	9,967	10,219	11,030	12,769	14,295	15,089	15,794	16,453	16,830	17,088	17,544	17,913	18,229	18,470	18,462	18,130	17,785	17,785	16,890	15,097
Spring	5	19,544	5/27/2015	13,446	12,303	11,643	11,241	11,069	11,277	12,042	13,727	15,168	15,992	16,733	17,514	18,155	18,623	19,109	19,354	19,524	19,544	19,254	18,700	18,211	17,996	16,973	15,225
Spring	5	19,363	5/28/2015	13,615	12,503	11,837	11,405	11,248	11,453	12,241	14,030	15,466	16,175	16,763	17,361	17,900	18,324	18,831	19,143	19,363	19,296	18,925	18,280	17,766	17,654	16,780	14,948
Spring	5	17,854	5/29/2015	13,222	12,028	11,309	10,879	10,673	10,830	11,510	13,169	14,587	15,435	16,055	16,548	16,890	17,071	17,348	17,534	17,738	17,854	17,602	16,928	16,303	16,202	15,546	14,171
Spring	5	17,405	5/30/2015	12,756	11,677	10,986	10,547	10,331	10,334	10,443	11,058	12,103	13,300	14,296	15,076	15,726	16,177	16,484	16,790	17,076	17,324	17,405	17,084	16,494	16,383	15,883	14,655
Spring	5	15,409	5/31/2015	13,343	12,284	11,625	11,201	10,928	10,865	10,855	11,166	11,963	13,000	13,999	14,688	15,162	15,409	15,401	15,141	14,837	14,709	14,768	14,550	14,218	13,963	13,089	11,848
Summer	6	14,984	6/1/2015	10,734	10,030	9,636	9,430	9,422	9,731	10,652	12,270	13,583	14,164	14,504	14,783	14,880	14,801	14,745	14,586	14,532	14,702	14,984	14,953	14,804	14,623	13,697	12,329
Summer	6	14,864	6/2/2015	11,137	10,349	9,923	9,724	9,664	9,940	10,836	12,495	13,773	14,275	14,607	14,820	14,864	14,778	14,721	14,545	14,499	14,637	14,850	14,828	14,684	14,649	13,898	12,508
Summer	6	14,352	6/3/2015	11,246	10,409	9,968	9,755	9,708	10,017	10,798	12,451	13,570	13,890	14,029	14,242	14,302	14,246	14,247	14,157	14,128	14,186	14,261	14,169	14,062	14,352	13,876	12,476
Summer	6	14,460	6/4/2015	11,163	10,272	9,819	9,589	9,563	9,847	10,635	12,273	13,470	13,886

Contains Proprietary Material
Do Not Distribute

Summer	6	19,755	6/12/2015	14,488	13,201	12,351	11,815	11,550	11,661	12,296	13,911	15,309	16,154	16,900	17,631	18,275	18,664	19,224	19,552	19,720	19,755	19,420	18,700	17,983	17,856	17,343	16,049
Summer	6	17,740	6/13/2015	14,618	13,490	12,771	12,323	12,034	11,964	12,008	12,645	13,752	14,842	15,593	16,125	16,497	16,715	16,839	17,033	17,296	17,605	17,740	17,496	16,908	16,562	16,119	14,850
Summer	6	16,648	6/14/2015	13,451	12,304	11,564	11,071	10,766	10,646	10,530	10,946	11,812	12,928	13,962	14,696	15,210	15,570	15,754	15,933	16,182	16,447	16,648	16,502	16,052	16,045	15,440	13,979
Summer	6	15,928	6/15/2015	12,588	11,633	11,037	10,707	10,612	10,875	11,727	13,246	14,542	15,190	15,545	15,844	15,928	15,854	15,806	15,615	15,469	15,496	15,550	15,397	15,192	15,036	14,257	12,919
Summer	6	16,707	6/16/2015	11,679	10,828	10,343	10,137	10,081	10,351	11,098	12,691	14,049	14,725	15,158	15,565	15,835	16,048	16,361	16,426	16,427	16,594	16,707	16,593	16,436	16,412	15,934	14,436
Summer	6	16,423	6/17/2015	12,958	11,898	11,254	10,862	10,668	10,797	11,420	13,078	14,475	15,145	15,493	15,769	15,963	15,997	16,195	16,272	16,385	16,423	16,257	15,862	15,516	15,525	14,977	13,481
Summer	6	16,482	6/18/2015	12,054	11,053	10,471	10,159	10,043	10,249	10,924	12,465	13,776	14,498	15,004	15,426	15,743	15,913	16,156	16,335	16,447	16,482	16,374	15,998	15,684	15,689	15,184	13,819
Summer	6	18,328	6/19/2015	12,439	11,434	10,864	10,568	10,471	10,720	11,463	13,023	14,455	15,355	16,100	16,807	17,393	17,734	18,034	18,230	18,328	18,275	18,034	17,494	16,842	16,445	15,934	14,558
Summer	6	14,307	6/20/2015	13,028	11,841	11,049	10,542	10,258	10,150	10,175	10,762	11,767	12,806	13,572	14,006	14,235	14,307	14,279	14,190	14,129	14,130	14,134	13,995	13,876	13,987	13,694	12,838
Summer	6	16,718	6/21/2015	11,835	11,038	10,531	10,238	10,122	10,148	10,280	10,667	11,511	12,612	13,610	14,338	14,833	15,072	15,164	15,295	15,628	16,107	16,613	16,718	16,506	16,459	16,144	14,793
Summer	6	20,012	6/22/2015	13,354	12,302	11,657	11,239	11,122	11,342	12,066	13,665	15,269	16,405	17,259	17,959	18,511	18,863	19,275	19,518	19,779	20,012	19,999	19,687	19,092	18,653	17,893	16,044
Summer	6	20,923	6/23/2015	14,276	13,008	12,217	11,684	11,518	11,683	12,356	13,932	15,564	16,681	17,601	18,594	19,322	19,543	19,981	20,512	20,923	20,867	20,511	20,008	19,458	19,049	18,272	16,563
Summer	6	19,392	6/24/2015	14,777	13,353	12,500	11,935	11,598	11,630	12,166	13,764	15,317	16,242	16,891	17,511	17,937	18,234	18,565	18,869	19,168	19,392	19,338	18,866	18,199	17,743	17,133	15,471
Summer	6	18,472	6/25/2015	13,778	12,520	11,756	11,267	11,038	11,136	11,661	13,138	14,662	15,634	16,348	17,002	17,513	17,859	18,256	18,452	18,472	18,402	18,178	17,704	17,293	17,190	16,663	15,195
Summer	6	16,993	6/26/2015	13,692	12,599	11,919	11,505	11,321	11,447	11,995	13,259	14,521	15,268	15,763	16,126	16,363	16,516	16,766	16,878	16,921	16,993	16,865	16,427	15,831	15,467	15,050	13,849
Summer	6	14,227	6/27/2015	12,493	11,435	10,775	10,363	10,141	10,107	10,158	10,744	11,748	12,729	13,481	13,935	14,170	14,227	14,115	13,986	13,862	13,846	13,876	13,798	13,701	13,798	13,388	12,492
Summer	6	13,700	6/28/2015	11,470	10,661	10,149	9,871	9,703	9,691	9,798	10,096	10,795	11,740	12,635	13,254	13,587	13,677	13,576	13,405	13,341	13,496	13,700	13,684	13,548	13,502	13,046	11,992
Summer	6	15,859	6/29/2015	10,914	10,196	9,761	9,534	9,514	9,755	10,471	11,801	13,172	13,994	14,565	15,060	15,400	15,558	15,727	15,750	15,693	15,750	15,859	15,676	15,480	15,388	14,957	13,600
Summer	6	17,912	6/30/2015	12,221	11,244	10,667	10,341	10,204	10,390	10,993	12,365	13,870	14,854	15,608	16,300	16,840	17,207	17,645	17,842	17,897	17,912	17,771	17,369	16,881	16,705	16,181	14,775
Summer	7	18,681	7/1/2015	13,268	12,232	11,606	11,258	11,126	11,338	12,061	13,488	14,879	15,792	16,422	16,960	17,323	17,545	17,921	18,202	18,436	18,650	18,681	18,304	17,762	17,403	16,766	15,248
Summer	7	17,682	7/2/2015	13,652	12,460	11,653	11,187	10,962	11,022	11,537	12,861	14,381	15,390	16,103	16,697	17,090	17,345	17,598	17,682	17,585	17,486	17,311	16,845	16,404	16,290	15,833	14,576
Summer	7	16,376	7/3/2015	13,194	12,083	11,330	10,835	10,540	10,487	10,603	11,262	12,309	13,328	14,127	14,677	15,007	15,191	15,379	15,596	15,882	16,230	16,376	15,971	15,323	15,056	14,613	13,632
Summer	7	13,992	7/4/2015	12,529	11,472	10,772	10,342	10,123	10,065	10,057	10,403	11,198	12,143	12,974	13,519	13,817	13,992	13,876	13,631	13,444	13,409	13,510	13,455	13,245	13,173	12,952	12,441
Summer	7	16,692	7/5/2015	11,646	10,807	10,220	9,867	9,693	9,629	9,575	9,866	10,690	11,775	12,797	13,642	14,302	14,824	15,188	15,505	15,895	16,322	16,688	16,692	16,438	16,382	16,068	14,818
Summer	7	20,106	7/6/2015	13,336	12,277	11,592	11,212	11,023	11,195	11,729	13,061	14,642	15,836	16,897	17,863	18,640	19,099	19,494	19,717	19,877	20,058	20,106	19,696	19,126	18,786	18,036	16,273
Summer	7	20,988	7/7/2015	14,563	13,329	12,540	12,091	11,906	12,088	12,777	14,272	15,880	16,967	17,890	18,818	19,588	20,107	20,604	20,868	20,977	20,988	20,903	20,481	20,016	19,803	18,980	17,320
Summer	7	21,638	7/8/2015	15,656	14,457	13,659	13,155	12,898	13,049	13,683	15,233	16,899	17,992	18,721	19,515	20,261	20,808	21,319	21,603	21,638	21,621	21,397	20,866	20,114	19,668	18,748	16,888
Summer	7	17,917	7/9/2015	15,030	13,717	12,783	12,229	11,926	11,998	12,543	13,769	15,080	15,866	16,385	16,859	17,166	17,370	17,729	17,857	17,889	17,917	17,761	17,362	17,059	17,020	16,371	14,926
Summer	7	18,844	7/10/2015	13,530	12,501	11,891	11,551	11,395	11,525	12,107	13,382	14,760	15,737	16,462	17,042	17,575	17,895	18,227	18,461	18,663	18,844	18,800	18,320	17,667	17,272	16,795	15,442
Summer	7	18,602	7/11/2015	13,924	12,678	11,874	11,337	11,026	10,909	10,958	11,483	12,644	13,974	15,117	15,974	16,635	17,054	17,371	17,651	18,025	18,374	18,602	18,434	17,884	17,534	17,058	15,819
Summer	7	20,162	7/12/2015	14,414	13,232	12,428	11,881	11,509	11,331	11,181	11,518	12,494	13,780	15,092	16,279	17,331	18,109	18,650	19,080	19,532	19,915	20,162	19,983	19,574	19,469	18,942	17,334
Summer	7	21,122	7/13/2015	15,595	14,329	13,513	13,016	12,749	12,871	13,508	14,909	16,537	17,709	18,664	19,526	20,171	20,681	21,042	21,122	21,098	21,111	20,992	20,454	19,713	19,239	18,384	16,532
Summer	7	20,048	7/14/2015	14,778	13,526	12,786	12,370	12,177	12,368	13,045	14,483	16,108	17,211	18,090	18,738	19,090	19,338	19,791	20,048	20,048	19,822	19,676	19,516	19,180	19,108	18,436	16,922
Summer	7	21,117	7/15/2015	15,374	14,214	13,513	13,075	12,883	13,057	13,765	15,260	16,913	18,010	18,917	19,752	20,351	20,726	21,094	21,117	20,958	20,755	20,327	19,622	18,826	18,339	17,356	15,643
Summer	7	17,211	7/16/2015	13,947	12,712	11,936	11,410	11,147	11,212	11,729	12,888	14,251	15,015	15,504	15,905	16,171	16,328	16,593	16,752	16,921	17,154	17,211	16,884	16,366	16,170	15,647	14,253
Summer	7	17,773	7/17/2015	12,789	11,705	11,050	10,670	10,523	10,680	11,207	12,434	13,883	14,877	15,586	16,217	16,702	17,002	17,376	17,583	17,686	17,773	17,717	17,170	16,630	16,559	16,082	14,861
Summer	7	16,838	7/18/2015	13,563	12,524	11,904	11,487	11,283	11,268	11,476	11,969	12,878	13,957	14,819	15,359	15,609	15,747	15,885	15,967	16,210	16,549	16,838	16,830	16,646	16,707	16,406	15,422
Summer	7	21,368	7/19/2015	14,223	13,241	12,611	12,222	11,959	11,879	11,915	12,277	13,353	14,896	16,437	17,772	18,898	19,758	20,273	20,478	20,655	21,045	21,368	21,132	20,777	20,677	19,835	18,255
Summer	7	24,437	7/20/2015	16,655	15,498	14,738	14,201	13,972	14,153	14,894	16,293	18,284	19,917	21,243	22,383	23,213	23,689	24,143	24,291	24,357	24,437	24,365	23,813	22,971	22,463	21,343	19,206
Summer	7	22,683	7/21/2015	17,170	15,746	14,727	14,061	13,655	13,685	14,265	15,581	17,027	17,946	18,611	19,325	19,963	20,504	21,207	21,741	22,268	22,683	22,622	22,024	21,236	20,760	19,759	17,865
Summer	7	19,755	7/22/2015	15,969	14,581	13,642	12,967	12,570	12,569	13,082	14,369	15,893	16,886	17,578	18,193	18,657	19,001	19,402	19,631	19,739	19,755	19,595	19,004	18,344	18,037	17,359	15,776
Summer	7	18,942	7/23/2015	14,195	12,975	12,226	11,737	11,466	11,549	12,123	13,420	14,967	16,012	16,757	17,399	17,855	18,206	18,587	18,782	18,834	18,942	18,843	18,432	17,863	17,692	17,050	15,527
Summer	7	18,199	7/24/2015	13,987	12,778	12,010	11,541	11,305	11,413	11,923	13,111	14,634	15,743	16,509	17,155	17,631	17,903	18,127	18,199	18,195	18,152	17,923	17,376	16,759	16,584	16,045	14,764
Summer	7	15,778	7/25/2015	13,402	12,307	11,590	11,132	10,873	10,797	10,910	11,397	12,397	13,456	14,323	14,896	15,240	15,397	15,439	15,483	15,571	15,705	15,778	15,538	15,181	15,280	14,895	13,929
Summer	7	17,080	7/26/2015	12,855	11,965	11,367	10,980	10,796	10,769	10,899	11,189	11,931	12,930	13,869	14,589	15,112	15,568	15,945	16,179	16,414	16,797	17,080	17,044	16,889	16,952	16,456	15,232
Summer	7	20,877	7/27/2015	13,884	12,947	12,356	12,006	11,868	12,104	12,842	14,169	15,720	16,834	17,695	18,456	19,052	19,522	20,056	20,467	20,750	20,877	20,790	20,346	19,740	19,549	18,652	16,939
Summer	7	23,171	7/28/2015	15,298	14,062	13,313	12,856	12,652	12,776	13,473	14,828	16,469	17,725	18,901	20,088	21,071	21,895	22,597	22,989	23,162	23,171	23,032	22,430	21,683	21,364	20,333	18,359
Summer	7	24,437	7/29/2015	16,400	15,009	14,102	13,546	13,245	13,308	13,901	15,262	17,099	18,597	19,966	21,301	22,374	23,094	23,720	24,029	24,216	24,437	24,399	23,946	23,277	22,875	21,801	19,746
Summer	7	23,865	7/30/2015	17,763	16,286	15,333	14,662	14,328	14,404	15,017	16,442	18,181	19,627	20,937	22,041	22,736	23,181	23,626	23,865	23,702	23,297	22,747	21,989	21,326	20,989	20,053	18,334
Summer	7	21,880	7/31/2015	16,633	15,317	14,469	13,857	13,525	13,524	14,019	15,205	16,867	18,186	19,191	20,103	20,707	21,046	21,431	21,690	21,830	21,880	21,649	20,930	19,952	19,330	18,401	16,781
Summer	8	18,939	8/1/2015	15,085	13,769	12,895	12,302	11,982	11,910	12,037	12,529	13,713	15,148	16,445	17,340	18,038	18,588	18,837	18,939	18,932	18,826	18,781	18,530	17,971	17,756	17,123	15,816
Summer	8	19,003	8/2/2015	14,383	13,226	12,404	11,829	11,456	11,243	11,172	11,370	12,288	13,522	14,671	15,598	16,388	16,969	17,412	17,772	18,199	18,670	19,003	18,880	18,380	18,299	17,589	16,122
Summer	8	22,919	8/3/2015	14,660	13,625	12,969	12,530	12,369	12,589	13,323	14,679	16,469	17,852	18,960	19,982	20,820	21,443	22,077	22,476	22,743	22,919	22,715	21,997	21,208	20,936	19,969	18,184
Summer	8	21,920	8/4/2015	16,449	15,205	14,413	13,960	13,743	13,897	14,620	15,695	16,827	17,595	18,531	19,541	20,477	21,137	21,759	21,920	21,549	21,060	20,887	20,374	19,770	19,531	18,490	16,768
Summer	8	20,212	8/5/2015	15,053	13,786	12,953	12,413	12,125	12,184	12,756	13,874	15,374	16,506	17,395	18,103	18,701	19,263	19,774	20,099	20,170	20,212	20,006	19,357	18,604	18,435	17,508	15,795
Summer	8	18,322	8/6/2015	14,126	12,894	12,126	11,627	11,372	11,481	12,105	13,245	14,673	15,705	16,447	17,056	17,501	17,795	18,085	18,263	18,300	18,322	18,163	17,682	17,264	17,314	16,482	15,073
Summer	8	18,025	8/7/2015	13,666	12,543	11,814	11,379	11,161	11,272	11,830	12,926	14,356	15,453	16,231	16,845	17,271	17,572	17,858	17,999	18,025	18,008	17,842	17,290	16,650	16,550	15,852	14,577
Summer	8	15,982	8/8/2015	13,189	12,137	11,451	11,004	10,736	10,679	10,799	11,180	12,205	13,311	14,208	14,816	15,208	15,450	15,535	15,591	15,728	15,916	15,982	15,674	15,362	15,510	14,955	13,928
Summer	8	15,622	8/9/2015	12,761	11,814	11,206	10,775	10,542	10,457	10,517	10,703	11,469	12,519	13,388	13,989	14,376	14,662	14,786	14,854	14,987	15,311	15,622	15,597	15,364	15,527	14,877	13,654
Summer	8	18,988	8/10/2015	12,401	11,529	10,988	10,663	10,560	10,801	11,524	12,691	14,159	15,284	16,142	16,858	17,467	17,914	18,405	18,733	18,901	18,988	18,882	18,386	17,833	17,792	16,793	15,280
Summer	8	17,745	8/11/2015	13,864	12,794	12,192	11,844	11,710	11,950	12,794	14,095	15,452	16,351	16,939	17,391	17,586	17,620	17,676	17,596	17,538	17,616	17,745	17,598	17,494	17,429	16,534	15,148
Summer	8	19,898	8/12/2015	13,834	12,849	12,267	11,895	11,729	11,893	12,631	13,806	15,260	16,407	17,247	18,004	18,585	18,953	19,352	19,573	19,733	19,898	19,834	19,306	18,681	18,510	17,482	15,837
Summer	8	19,250	8/13/2015	14,208	13,065	12,307	11,830	11,601	11,698	12,366	13,450	14,884	15,944	16,730	17,423	17,952	18,293	18,708	18,951	19,111	19,250	19,154	18,647	18,026	17,907	16,950	15,375
Summer	8	20,051	8/14/2015	13,814	12,651	11,912	11,430	11,170	11,287	11,923	12,963	14,413	15,618	16,590	17,388	17,990	18,423	18,980	19,455	19,796	20,051	19,981	19,386	18,652	18,475	17,506	16,035
Summer	8	20,198	8/15/2015	14,556	13,352	12,556	12,045	11,748	11,671	11,861	12,263	13,334	14,680	15,980	17,157	18,157	18,935	19,501	19,851	20,115	20,198	20,056	19,522	18,951	18,761	17,822	16,417
Summer	8	20,923	8/16/2015	15,012	13,908	13,117	12,599	12,255	12,072	12,115	12,270	13,187	14,550	15,864	17,101	18,149	18,958	19,546	19,991	20,367	20,694	20,923	20,673	20,199	20,170	19,103	17,427
Summer	8	24,047	8/17/2015	15,815	14,648	13,885	13,397	13,164	13,279	13,995	15,191	16,835	18,357	19,745	21,068	22,105	22,849	23,502	23,790	23,934	24,047	23,991	23,470	22,857	22,553	21,117	19,100
Summer	8	24,216	8/18/2015	17,163	15,746	14,878	14,281	13,937	13,998	14,698	15,901	17,520	18,898	20,219	21,536	22,642	23,484	24,113	24,216	23,939	23,700	23,295	22,530	21,995	21,731	20,407	18,503
Summer	8	23,624	8/19/2015	16,695	15,481	14,695	14,185	13,958	14,072	14,814	16,056	17,627	18,918	20,002	21,026	21,874	22,510	23,098	23,456	23,598	23,624	23,406	22,664	21,911	21,645	20,362	18,480
Summer	8	22,513	8/20/2015	16,677	15,403	14,591	14,143	13,920	14,084	14,870	16,183	17,662	18,815	19,744	20,628	21,314	21,770	22,252	22,484	22,513	22,468	22,146	21,410	20,828	20,667	19,521	17,879
Summer	8	21,166	8/21/2015	16,296	15,116	14,373	13,931	13,743	13,969	14,794	16,058	17,432	18,414	19,046	19,496	19,811	20,217	20,671	20,940	21,061	21,166	20,935	20,253	19,738	19,494	18,439	16,989
Summer	8	17,706	8/22/2015	15,472	14,291	13,477	12,938	12,582	12,427	12,565	12,870	13,716	14,781	15,748	16,473	16,923	17,179	17,332	17,413	17,541	17,697	17,706	17,423	17,100	17,107	16,326	15,189
Summer	8	17,474	8/23/2015	13,982	13,015	12,367	11,930	11,654	11,567	11,678	11,887	12,548	13,581	14,503	15,262	15,855	16,279	16,507	16,664	16,793	17,061	17,355	17,385	17,374	17,474	16,628	15,358
Summer	8	20,880	8/24/2015	14,100	13,188	12,645	12,364	12,280	12,558	13,462	14,829	16,197	17,212	18,018	18,797	19,404	19,902	20,441	20,707	20,833	20,880	20,856	20,370	19,964	19,793	18,536	16,877
Summer	8	21,733	8/25/2015	15,268	14,110	13,392	12,917	12,721	12,944	13,778	15,155	16,572	17,584	18,447	19,317	19,997	20,542	21,045	21,454	21,660	21,733	21,562	21,003	20,633	20,311	18,965	17,201
Summer	8	20,376	8/26/2015	15,538	14,315	13,515	12,996	12,725	12,819	13,617	14,933	16,144	17,058	17,879	18,655	19,262	19,670	20,085	20,301	20,376	20,334	20,076	19,365	18,848	18,563	17,267	15,567
Summer	8	18,281	8/27/2015	13,936	12,787	12,098	11,656	11,454	11,582	12,280	13,463	14,744	15,703	16,394	17,004	17,459	17,769	18,120	18,274	18,281	18,272	18,185	17,709	17,416	17,311	16,193	14,647
Summer	8	17,691	8/28/2015	13,195	12,156	11,496	11,112	10,924	11,042	11,776	12,939	14,186	15,152	15,866	16,444	16,878	17,147	17,445	17,562	17,595	17,691	17,556	17,054	16,768	16,576	15,614	14,309
Summer	8	16,517	8/29/2015	12,985	11,945	11,288	10,840	10,576	10,530	10,738	11,088	11,962	13,134	14,120	14,773	15,200	15,491	15,704	15,905	16,140	16,410	16,517	16,250	16,139	16,078	15,298	14,227
Summer	8	18,767	8/30/2015	13,096	12,221	11,600	11,210	10,992	10,921	11,019	11,233	11,984	13,162	14,354	15,424	16,391	17,056	17,503	17,840	18,171	18,550	18,767	18,612	18,758	18,710	17,596	16,110
Summer	8	22,568	8/31/2015	14,697	13,634	12,987	12,564	12,400	12,603	13,538	14,981	16,409	17,562	18,637	19,701	20,624	21,298	21,887	22,221	22,419	22,568	22,484	21,898	21,655	21,199	19,624	17,609
Fall	9	21,458	9/1/2015	15,766	14,522	13,684	13,115	12,796	12,885	13,679	15,033	16,250	17,251	18,173	19,040	19,641	20,126	20,702	21,038	21,301	21,458	21,245	20,552	20,231	19,788	18,249	16,370
Fall	9	22,766	9/2/2015	14,655	13,526	12,776	12,326	12,111	12,281	13,186	14,690	15,919	16,851	17,851	18,915	19,911	20,727	21,533	22,072	22,520	22,766	22,595	21,906	21,567	21,011	19,392	17,398
Fall	9	22,759	9/3/2015	15,599	14,359	13,553	13,062	12,785	12,908	13,772	15,264	16,484	17,503	18,541	19,596	20,547	21,351	22,097	22,460	22,707	22,759	22,350	21,714	21,608	21,121	19,658	17,756
Fall	9	18,396	9/4/2015	16,014	14,814	14,019	13,522	13,225	13,301	13,951	15,151	16,106	16,728	17,174	17,595	17,949	18,143	18,333	18,396	18,355	18,343	18,090	17,381	17,115	16,742	15,692	14,314
Fall	9	15,974	9/5/2015	12,956	11,915	11,246	10,809	10,528	10,476	10,674	10,987	11,748	12,815	13,651	14,193	14,537	14,815	15,051	15,291	15,571	15,851	15,974	15,690	15,587	15,359	14,527	13,411
Fall	9	17,102	9/6/2015	12,262	11,364	10,797	10,441	10,233	10,186	10,301	10,480	11,163	12,243	13,166	13,947	14,648	15,228	15,721	16,136	16,584	16,978	17,102	16,719	16,556	16,251	15,359	14,237
Fall	9	20,921	9/7/2015	13,071	12,127	11,500	11,102	10,883	10,868	11,134	11,449	12,176	13,389	14,679	15,884	16,996	17,963	18,800	19,535	20,158	20,699	20,921	20,570	20,664	20,301	18,862	17,000
Fall	9	24,368	9/8/2015	15,383	14,269	13,601	13,194	12,999	13,209	14,192	15,904	17,322	18,527	19,766	21,045	22,186	23,167	23,963	24,291	24,368	24,338	24,032	23,444	23,380	22,570	20,841	18,725
Fall	9	24,275	9/9/2015	16,886	15,577	14,750	14,237	13,974	14,081	14,983	16,547	17,786	18,830	19,918	21,031	21,920	22,706	23,492	23,961	24,199	24,275	23,917	23,267	23,202	22,483	20,960	18,908
Fall	9	19,108	9/10/2015	17,067	15,790	15,021	14,508	14,240	14,291	15,170	16,775	17,806	18,335	18,768	19,048	19,108	19,067	18,947	18,593	18,313	18,198	18,131	17,970	18,003	17,369	16,174	14,838
Fall	9	16,866	9/11/2015	13,504	12,490	11,876	11,490	11,363	11,555	12,429	14,049	15,093	15,632	16,012	16,294	16,418	16,444	16,633	16,729	16,799	16,866	16,764	16,424	16,519	16,094	15,097	13,844
Fall	9	15,638	9/12/2015	12,606	11,652	11,057	10,676	10,498	10,490	10,767	11,244	12,077	13,099	13,878	14,446	14,808	15,056	15,218	15,303	15,397	15,395	15,342	15,364	15,638	15,255	14,471	13,468
Fall	9	15,810	9/13/2015	12,396	11,563	11,028	10,667	10,484	10,437	10,588	10,929	11,535	12,523

Contains Proprietary Material
Do Not Distribute

Fall	9	15,610	9/21/2015	11,104	10,329	9,905	9,681	9,666	9,936	10,890	12,480	13,425	13,852	14,177	14,466	14,653	14,719	14,900	14,913	14,906	14,984	15,068	15,216	15,610	14,930	13,764	12,343
Fall	9	15,611	9/22/2015	11,162	10,384	9,959	9,756	9,717	10,010	10,950	12,692	13,725	14,111	14,454	14,790	14,948	14,984	15,090	15,051	15,047	15,086	15,129	15,219	15,611	14,991	13,844	12,431
Fall	9	15,879	9/23/2015	11,185	10,415	9,986	9,774	9,706	9,958	10,867	12,427	13,389	13,862	14,192	14,534	14,762	14,891	15,103	15,225	15,352	15,526	15,607	15,564	15,879	15,220	14,026	12,574
Fall	9	16,032	9/24/2015	11,332	10,506	10,076	9,833	9,743	10,027	10,965	12,628	13,619	14,108	14,503	14,891	15,165	15,316	15,550	15,621	15,682	15,764	15,715	15,663	16,032	15,399	14,217	12,781
Fall	9	14,817	9/25/2015	11,493	10,658	10,175	9,884	9,797	10,014	10,907	12,496	13,458	13,953	14,264	14,541	14,668	14,653	14,726	14,701	14,613	14,608	14,545	14,595	14,817	14,237	13,369	12,251
Fall	9	13,602	9/26/2015	11,150	10,319	9,826	9,567	9,453	9,501	9,818	10,430	11,206	12,076	12,571	12,746	12,770	12,678	12,534	12,433	12,458	12,635	12,899	13,256	13,602	13,174	12,453	11,523
Fall	9	14,456	9/27/2015	10,577	9,876	9,434	9,192	9,086	9,119	9,355	9,769	10,424	11,259	11,808	12,078	12,253	12,392	12,437	12,489	12,628	13,035	13,511	13,987	14,456	13,827	12,810	11,641
Fall	9	16,780	9/28/2015	10,672	9,966	9,583	9,411	9,392	9,698	10,712	12,487	13,529	14,034	14,478	14,907	15,233	15,486	15,792	15,891	15,938	16,060	16,199	16,475	16,780	16,030	14,790	13,359
Fall	9	18,219	9/29/2015	12,089	11,227	10,738	10,486	10,423	10,725	11,795	13,727	14,882	15,495	16,035	16,558	17,012	17,359	17,670	17,758	17,759	17,791	17,860	18,151	18,219	17,473	16,266	14,757
Fall	9	18,044	9/30/2015	13,422	12,514	12,020	11,760	11,671	11,969	13,031	15,035	16,349	16,991	17,450	17,872	18,044	18,027	17,920	17,589	17,114	16,785	16,685	16,695	16,660	15,895	14,637	13,133
Fall	10	15,367	10/1/2015	11,765	10,835	10,321	10,016	9,930	10,154	11,048	12,813	13,801	14,154	14,346	14,525	14,522	14,481	14,490	14,397	14,369	14,470	14,779	15,260	15,367	14,713	13,675	12,292
Fall	10	14,927	10/2/2015	11,098	10,324	9,874	9,648	9,590	9,828	10,759	12,538	13,599	14,059	14,291	14,447	14,452	14,404	14,364	14,231	14,186	14,293	14,550	14,927	14,844	14,256	13,424	12,332
Fall	10	14,032	10/3/2015	11,226	10,430	9,977	9,695	9,566	9,657	9,995	10,716	11,611	12,569	13,229	13,509	13,519	13,409	13,178	12,990	12,938	13,068	13,418	13,962	14,032	13,583	12,903	11,983
Fall	10	14,440	10/4/2015	11,022	10,263	9,811	9,531	9,400	9,417	9,662	10,126	10,746	11,604	12,145	12,355	12,442	12,413	12,289	12,194	12,295	12,658	13,255	14,047	14,440	13,835	12,833	11,657
Fall	10	15,416	10/5/2015	10,603	9,937	9,595	9,436	9,466	9,825	10,898	12,792	13,803	14,063	14,144	14,253	14,283	14,261	14,280	14,181	14,107	14,250	14,584	15,191	15,416	14,720	13,580	12,193
Fall	10	15,427	10/6/2015	11,039	10,295	9,894	9,692	9,680	9,979	11,005	12,882	13,825	13,989	14,053	14,144	14,190	14,176	14,257	14,203	14,199	14,402	14,704	15,267	15,427	14,740	13,612	12,198
Fall	10	15,509	10/7/2015	10,974	10,200	9,818	9,624	9,590	9,879	10,866	12,744	13,766	13,969	14,091	14,221	14,308	14,297	14,389	14,417	14,456	14,635	14,868	15,343	15,509	14,825	13,693	12,280
Fall	10	15,192	10/8/2015	11,050	10,289	9,855	9,671	9,613	9,884	10,856	12,687	13,643	13,844	13,920	14,024	14,031	14,037	14,104	14,055	14,039	14,178	14,404	14,998	15,192	14,585	13,581	12,233
Fall	10	15,478	10/9/2015	11,009	10,223	9,826	9,633	9,592	9,858	10,784	12,568	13,690	14,206	14,577	14,916	15,056	15,065	15,101	15,010	14,911	15,014	15,237	15,478	15,146	14,487	13,609	12,485
Fall	10	13,613	10/10/2015	11,320	10,460	9,921	9,596	9,445	9,491	9,843	10,540	11,298	12,121	12,540	12,645	12,534	12,346	12,139	11,995	12,031	12,318	12,794	13,495	13,613	13,192	12,547	11,667
Fall	10	13,768	10/11/2015	10,752	10,052	9,645	9,403	9,311	9,351	9,610	10,100	10,696	11,494	12,013	12,192	12,190	12,118	12,031	12,005	12,160	12,553	13,015	13,678	13,768	13,280	12,393	11,452
Fall	10	15,334	10/12/2015	10,525	9,826	9,464	9,265	9,230	9,479	10,175	11,374	12,296	13,006	13,493	13,783	13,908	13,931	13,979	13,989	14,072	14,335	14,727	15,334	15,310	14,545	13,418	12,099
Fall	10	15,855	10/13/2015	10,920	10,158	9,729	9,514	9,485	9,782	10,811	12,691	13,822	14,258	14,596	14,776	14,841	14,904	15,003	14,957	14,881	14,993	15,246	15,855	15,741	14,992	13,858	12,496
Fall	10	15,285	10/14/2015	11,266	10,417	9,945	9,672	9,609	9,863	10,848	12,642	13,595	13,871	14,074	14,293	14,405	14,406	14,416	14,320	14,240	14,311	14,602	15,285	15,273	14,578	13,446	12,086
Fall	10	15,204	10/15/2015	10,909	10,151	9,740	9,513	9,510	9,803	10,852	12,766	13,764	13,924	13,912	13,898	13,850	13,761	13,787	13,731	13,748	13,992	14,380	15,152	15,204	14,605	13,586	12,247
Fall	10	14,673	10/16/2015	11,052	10,273	9,845	9,598	9,571	9,856	10,870	12,730	13,802	14,125	14,259	14,294	14,180	14,021	13,941	13,820	13,718	13,795	14,055	14,673	14,570	14,041	13,277	12,227
Fall	10	14,091	10/17/2015	11,160	10,366	9,917	9,684	9,597	9,694	10,085	10,870	11,737	12,543	12,897	12,973	12,878	12,724	12,527	12,409	12,438	12,740	13,304	14,091	14,035	13,595	12,988	12,135
Fall	10	15,285	10/18/2015	11,212	10,512	10,117	9,888	9,802	9,889	10,210	10,809	11,492	12,326	12,745	12,867	12,945	13,012	13,061	13,055	13,174	13,601	14,328	15,284	15,285	14,776	13,811	12,762
Fall	10	16,227	10/19/2015	11,775	11,025	10,616	10,486	10,523	10,940	12,114	14,174	15,287	15,404	15,260	15,129	14,906	14,635	14,446	14,247	14,198	14,524	15,242	16,227	16,168	15,486	14,375	12,946
Fall	10	15,710	10/20/2015	11,701	10,891	10,472	10,263	10,222	10,515	11,588	13,526	14,514	14,626	14,594	14,622	14,563	14,420	14,349	14,208	14,181	14,397	14,856	15,710	15,579	14,854	13,738	12,352
Fall	10	15,580	10/21/2015	11,147	10,386	9,976	9,754	9,714	10,004	11,011	12,949	14,054	14,331	14,477	14,586	14,569	14,439	14,406	14,292	14,259	14,421	14,847	15,580	15,400	14,715	13,624	12,291
Fall	10	15,656	10/22/2015	11,102	10,342	9,914	9,676	9,645	9,937	10,990	12,925	13,990	14,210	14,359	14,524	14,598	14,568	14,598	14,555	14,509	14,640	15,050	15,656	15,409	14,737	13,675	12,323
Fall	10	14,975	10/23/2015	11,081	10,289	9,795	9,536	9,460	9,763	10,768	12,659	13,740	14,002	14,089	14,112	14,058	13,939	13,865	13,737	13,625	13,810	14,263	14,975	14,778	14,335	13,601	12,589
Fall	10	14,399	10/24/2015	11,518	10,767	10,341	10,104	10,056	10,178	10,603	11,442	12,288	13,182	13,598	13,632	13,534	13,368	13,176	13,044	13,092	13,359	13,934	14,399	14,126	13,624	12,969	12,062
Fall	10	14,578	10/25/2015	11,109	10,367	9,911	9,632	9,507	9,540	9,782	10,304	11,042	11,931	12,739	13,163	13,383	13,455	13,230	13,003	12,905	13,111	13,687	14,578	14,399	13,756	12,768	11,631
Fall	10	15,792	10/26/2015	10,624	9,997	9,670	9,508	9,542	9,933	11,137	13,213	14,342	14,412	14,303	14,251	14,124	13,954	13,864	13,730	13,731	14,034	14,787	15,792	15,638	15,004	14,004	12,653
Fall	10	15,868	10/27/2015	11,496	10,786	10,427	10,280	10,308	10,663	11,822	13,883	14,921	14,956	14,722	14,446	14,330	14,108	14,002	13,862	13,878	14,180	14,916	15,868	15,663	15,021	13,978	12,622
Fall	10	16,247	10/28/2015	11,482	10,755	10,355	10,149	10,140	10,456	11,554	13,562	14,612	14,722	14,797	14,878	14,830	14,817	14,931	14,884	14,943	15,328	16,023	16,247	15,836	15,187	14,111	12,795
Fall	10	15,494	10/29/2015	11,587	10,804	10,352	10,135	10,075	10,312	11,333	13,240	14,525	14,795	14,933	15,008	14,933	14,880	14,898	14,670	14,453	14,396	14,767	15,494	15,244	14,616	13,545	12,273
Fall	10	14,820	10/30/2015	11,151	10,292	9,816	9,552	9,508	9,778	10,783	12,726	13,834	13,985	14,002	14,076	14,028	13,829	13,700	13,503	13,475	13,675	14,158	14,820	14,538	14,049	13,327	12,353
Fall	10	13,708	10/31/2015	11,287	10,569	10,140	9,920	9,838	9,987	10,445	11,267	12,133	12,912	13,234	13,199	12,993	12,784	12,610	12,484	12,515	12,841	13,372	13,708	13,370	13,051	12,540	11,755
Fall	11	14,993	11/1/2015	10,562	9,651	9,384	9,367	9,485	9,836	10,439	11,259	12,189	12,839	13,163	13,278	13,205	13,074	12,956	13,023	13,825	14,993	14,773	14,244	13,542	12,490	11,373	10,491
Fall	11	15,931	11/2/2015	9,937	9,603	9,503	9,557	9,979	11,198	13,009	13,902	14,061	14,076	14,162	14,134	14,093	14,053	14,009	14,088	14,810	15,931	15,723	15,166	14,384	13,310	12,064	11,000
Fall	11	15,937	11/3/2015	10,348	9,989	9,828	9,844	10,229	11,377	13,089	13,924	13,992	14,026	14,110	14,143	14,118	14,218	14,238	14,321	14,866	15,937	15,780	15,220	14,421	13,292	11,976	10,875
Fall	11	15,825	11/4/2015	10,215	9,859	9,677	9,702	10,061	11,186	12,948	13,843	13,926	13,927	14,009	14,038	13,997	14,059	14,054	14,165	14,731	15,825	15,693	15,178	14,432	13,311	12,035	10,929
Fall	11	16,157	11/5/2015	10,242	9,874	9,689	9,694	10,041	11,135	12,906	13,824	14,085	14,254	14,424	14,541	14,576	14,619	14,608	14,610	15,203	16,157	15,917	15,409	14,707	13,614	12,279	11,124
Fall	11	16,006	11/6/2015	10,412	9,981	9,768	9,719	10,024	11,026	12,785	13,840	14,355	14,714	14,943	14,986	14,889	15,006	14,878	14,803	15,313	16,006	15,621	15,011	14,348	13,450	12,357	11,232
Fall	11	14,357	11/7/2015	10,341	9,811	9,528	9,396	9,452	9,853	10,455	11,262	12,127	12,648	12,842	12,851	12,760	12,625	12,596	12,761	13,584	14,357	14,021	13,589	13,044	12,344	11,527	10,686
Fall	11	14,918	11/8/2015	10,024	9,619	9,376	9,318	9,415	9,723	10,214	10,899	11,615	12,036	12,185	12,275	12,336	12,300	12,351	12,609	13,645	14,918	14,783	14,372	13,766	12,796	11,728	10,837
Fall	11	16,203	11/9/2015	10,264	9,972	9,838	9,904	10,344	11,564	13,412	14,297	14,288	14,187	14,159	14,065	13,980	13,980	13,986	14,128	15,073	16,203	16,061	15,550	14,819	13,720	12,395	11,272
Fall	11	16,326	11/10/2015	10,571	10,210	10,031	10,051	10,431	11,567	13,452	14,367	14,562	14,607	14,651	14,618	14,591	14,653	14,612	14,773	15,561	16,326	16,075	15,527	14,826	13,762	12,527	11,403
Fall	11	16,431	11/11/2015	10,648	10,237	10,018	9,998	10,263	11,137	12,514	13,615	14,311	14,726	14,962	15,017	14,939	14,907	14,823	14,912	15,716	16,431	16,092	15,529	14,825	13,721	12,411	11,316
Fall	11	16,415	11/12/2015	10,601	10,210	9,985	10,006	10,332	11,424	13,291	14,303	14,686	14,897	15,049	15,166	15,130	15,122	15,053	15,161	15,848	16,415	16,150	15,620	14,928	13,832	12,485	11,347
Fall	11	15,665	11/13/2015	10,539	10,092	9,863	9,851	10,168	11,205	12,947	13,820	13,992	14,068	14,195	14,164	14,032	14,091	14,058	14,123	14,875	15,665	15,391	14,882	14,293	13,462	12,426	11,381
Fall	11	15,304	11/14/2015	10,625	10,214	9,985	9,881	10,020	10,488	11,207	12,010	12,819	13,265	13,526	13,542	13,354	13,104	13,072	13,326	14,330	15,304	15,058	14,622	14,169	13,469	12,575	11,707
Fall	11	15,262	11/15/2015	11,029	10,589	10,343	10,280	10,353	10,684	11,178	11,758	12,389	12,811	12,940	13,001	12,961	12,830	12,865	13,234	14,364	15,262	15,081	14,448	14,043	13,041	11,884	11,010
Fall	11	16,287	11/16/2015	10,266	9,930	9,813	9,884	10,343	11,519	13,427	14,369	14,444	14,330	14,254	14,231	14,137	14,150	14,114	14,275	15,224	16,287	16,161	15,716	15,009	13,880	12,603	11,464
Fall	11	16,616	11/17/2015	10,819	10,506	10,359	10,422	10,845	12,070	13,987	14,824	14,777	14,586	14,440	14,254	14,114	14,104	14,117	14,422	15,519	16,616	16,570	16,237	15,651	14,553	13,234	12,112
Fall	11	16,647	11/18/2015	11,426	11,100	10,939	10,992	11,415	12,605	14,481	15,317	15,228	15,064	14,855	14,642	14,425	14,391	14,412	14,659	15,780	16,647	16,474	16,075	15,395	14,290	12,878	11,682
Fall	11	16,355	11/19/2015	10,909	10,461	10,254	10,233	10,568	11,672	13,581	14,532	14,759	14,855	14,929	14,939	14,852	14,832	14,804	14,982	15,834	16,355	16,113	15,649	14,952	13,849	12,517	11,378
Fall	11	15,576	11/20/2015	10,617	10,198	9,971	9,912	10,194	11,192	13,011	13,961	14,161	14,207	14,195	14,107	13,936	13,899	13,861	13,982	14,765	15,576	15,279	14,813	14,283	13,504	12,530	11,542
Fall	11	15,124	11/21/2015	10,828	10,433	10,230	10,167	10,341	10,842	11,607	12,418	13,183	13,467	13,391	13,227	13,000	12,842	12,840	13,103	14,191	15,124	14,909	14,487	14,038	13,355	12,497	11,576
Fall	11	15,744	11/22/2015	10,798	10,398	10,093	10,002	10,065	10,375	10,896	11,567	12,489	13,117	13,410	13,660	13,815	13,881	13,905	14,194	15,199	15,744	15,518	15,040	14,425	13,475	12,432	11,467
Fall	11	17,439	11/23/2015	10,832	10,504	10,368	10,469	10,906	12,099	14,108	15,062	15,162	15,033	14,985	14,886	14,745	14,790	14,867	15,191	16,378	17,439	17,362	17,000	16,450	15,408	14,176	13,018
Fall	11	17,211	11/24/2015	12,217	11,728	11,541	11,561	12,008	13,168	15,058	15,941	15,918	15,679	15,504	15,283	15,077	15,016	14,995	15,235	16,289	17,211	17,147	16,861	16,275	15,284	13,986	12,792
Fall	11	16,828	11/25/2015	12,035	11,599	11,421	11,456	11,857	12,911	14,577	15,562	15,764	15,626	15,426	15,184	14,898	14,831	14,786	14,935	15,946	16,828	16,577	16,131	15,563	14,667	13,510	12,301
Fall	11	14,394	11/26/2015	11,412	10,880	10,579	10,460	10,569	10,996	11,667	12,499	13,435	14,013	14,287	14,394	13,997	13,274	12,611	12,235	12,630	12,919	12,812	12,703	12,552	12,120	11,507	10,761
Fall	11	14,683	11/27/2015	10,163	9,832	9,633	9,619	9,796	10,344	11,103	11,684	12,310	12,737	12,847	12,828	12,760	12,688	12,673	12,874	13,961	14,683	14,388	13,912	13,400	12,681	11,786	10,831
Fall	11	14,954	11/28/2015	10,070	9,614	9,331	9,236	9,327	9,685	10,333	11,114	12,150	12,939	13,435	13,654	13,706	13,630	13,497	13,681	14,534	14,954	14,692	14,306	13,880	13,254	12,390	11,486
Fall	11	16,211	11/29/2015	10,735	10,358	10,154	10,103	10,226	10,567	11,167	11,827	12,617	13,069	13,177	13,202	13,183	13,159	13,257	13,673	15,132	16,211	16,201	15,839	15,305	14,351	13,292	12,273
Fall	11	17,692	11/30/2015	11,514	11,108	10,961	11,031	11,486	12,698	14,513	15,600	15,732	15,665	15,599	15,528	15,418	15,481	15,470	15,707	16,831	17,692	17,605	17,189	16,538	15,417	13,969	12,695

Contains Proprietary Material
Do Not Distribute

Max	6,419
Max Month	7
PST	5,054
Winter	4,497
Spring	3,789
Summer	4,827
Fall	4,005

Source: ISONE 2015 SIL Filing

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	4,108	12/1/2014	2,619	2,462	2,403	2,390	2,407	2,552	2,964	3,424	3,536	3,505	3,522	3,526	3,546	3,531	3,534	3,522	3,626	3,992	4,108	4,052	3,927	3,775	3,461	3,112
Winter	12	4,392	12/2/2014	2,813	2,665	2,604	2,578	2,602	2,788	3,204	3,695	3,852	3,860	3,831	3,839	3,811	3,837	3,838	3,868	3,997	4,329	4,392	4,323	4,233	4,009	3,666	3,255
Winter	12	4,285	12/3/2014	2,959	2,808	2,723	2,676	2,700	2,850	3,202	3,669	3,809	3,857	3,885	3,872	3,845	3,839	3,812	3,842	3,970	4,231	4,285	4,196	4,085	3,885	3,576	3,183
Winter	12	4,322	12/4/2014	2,926	2,772	2,694	2,678	2,727	2,891	3,324	3,789	3,887	3,813	3,773	3,729	3,639	3,646	3,656	3,672	3,809	4,237	4,322	4,265	4,171	4,019	3,735	3,370
Winter	12	4,313	12/5/2014	3,089	2,926	2,825	2,843	2,881	3,025	3,458	3,888	4,012	3,958	3,975	3,931	3,868	3,891	3,902	3,895	4,024	4,313	4,312	4,233	4,051	3,867	3,628	3,322
Winter	12	4,023	12/6/2014	3,010	2,827	2,711	2,650	2,618	2,662	2,826	3,058	3,299	3,539	3,680	3,739	3,721	3,711	3,667	3,648	3,729	4,023	3,996	3,892	3,757	3,646	3,440	3,199
Winter	12	4,273	12/7/2014	2,934	2,753	2,638	2,594	2,599	2,649	2,763	2,937	3,150	3,382	3,459	3,479	3,467	3,435	3,418	3,455	3,613	4,166	4,273	4,260	4,181	4,032	3,745	3,431
Winter	12	4,830	12/8/2014	3,183	3,029	2,976	2,970	3,026	3,201	3,618	4,086	4,282	4,314	4,341	4,363	4,313	4,306	4,310	4,299	4,429	4,737	4,830	4,709	4,590	4,390	4,033	3,613
Winter	12	4,627	12/9/2014	3,284	3,076	2,984	2,938	2,932	3,098	3,426	3,837	4,121	4,202	4,256	4,308	4,300	4,325	4,292	4,270	4,320	4,593	4,627	4,525	4,371	4,074	3,796	3,352
Winter	12	4,514	12/10/2014	3,044	2,884	2,783	2,744	2,763	2,915	3,290	3,809	3,916	3,945	3,963	3,947	3,949	3,969	3,923	3,855	4,075	4,443	4,514	4,478	4,367	4,155	3,819	3,422
Winter	12	4,578	12/11/2014	3,118	2,957	2,852	2,826	2,871	3,011	3,425	3,855	4,017	4,043	4,043	4,053	4,027	4,007	4,012	3,987	4,089	4,469	4,578	4,490	4,382	4,203	3,873	3,478
Winter	12	4,427	12/12/2014	3,167	2,992	2,928	2,908	2,944	3,078	3,470	3,967	4,065	4,057	4,059	4,027	3,943	3,950	3,888	3,875	3,969	4,393	4,427	4,331	4,172	4,043	3,813	3,500
Winter	12	4,102	12/13/2014	3,174	2,959	2,870	2,825	2,815	2,872	3,015	3,258	3,476	3,644	3,694	3,649	3,578	3,487	3,452	3,426	3,567	4,021	4,102	4,014	3,905	3,767	3,617	3,353
Winter	12	4,170	12/14/2014	3,062	2,884	2,781	2,717	2,709	2,746	2,834	2,978	3,123	3,383	3,454	3,499	3,498	3,525	3,427	3,461	3,577	4,094	4,170	4,110	4,046	3,853	3,602	3,238
Winter	12	4,443	12/15/2014	2,929	2,794	2,720	2,704	2,742	2,943	3,341	3,833	3,950	3,931	3,856	3,798	3,734	3,721	3,675	3,654	3,781	4,307	4,443	4,385	4,292	4,122	3,803	3,416
Winter	12	4,518	12/16/2014	3,069	2,919	2,841	2,824	2,850	3,030	3,414	3,909	4,054	4,036	4,068	4,062	4,008	4,012	3,979	3,962	4,076	4,438	4,518	4,421	4,289	4,087	3,749	3,332
Winter	12	4,302	12/17/2014	2,970	2,792	2,687	2,635	2,655	2,798	3,164	3,678	3,806	3,789	3,736	3,695	3,660	3,642	3,650	3,679	3,830	4,221	4,302	4,239	4,127	3,926	3,640	3,253
Winter	12	4,439	12/18/2014	2,925	2,746	2,646	2,630	2,660	2,806	3,240	3,728	3,879	3,838	3,862	3,890	3,824	3,764	3,760	3,783	3,897	4,335	4,439	4,365	4,272	4,116	3,821	3,429
Winter	12	4,481	12/19/2014	3,059	2,867	2,796	2,746	2,778	2,929	3,319	3,795	3,979	3,966	3,999	3,940	3,851	3,851	3,808	3,861	3,981	4,369	4,481	4,362	4,225	4,080	3,870	3,565
Winter	12	4,280	12/20/2014	3,223	3,022	2,892	2,859	2,854	2,917	3,054	3,295	3,554	3,772	3,869	3,918	3,947	3,880	3,851	3,847	3,944	4,253	4,280	4,147	4,043	3,917	3,719	3,452
Winter	12	4,295	12/21/2014	3,141	2,958	2,827	2,783	2,660	2,787	2,904	3,067	3,282	3,554	3,657	3,741	3,770	3,769	3,735	3,752	3,844	4,249	4,295	4,258	4,154	3,995	3,710	3,352
Winter	12	4,411	12/22/2014	3,048	2,868	2,784	2,737	2,777	2,916	3,282	3,763	3,927	3,950	3,957	3,928	3,874	3,828	3,795	3,814	3,955	4,338	4,411	4,342	4,207	4,019	3,713	3,333
Winter	12	4,279	12/23/2014	2,998	2,783	2,669	2,634	2,654	2,777	3,140	3,588	3,800	3,839	3,890	3,879	3,871	3,836	3,847	3,817	3,873	4,224	4,279	4,186	4,072	3,919	3,655	3,300
Winter	12	4,005	12/24/2014	2,967	2,725	2,578	2,524	2,543	2,640	2,853	3,197	3,440	3,642	3,792	3,888	3,849	3,853	3,820	3,793	3,841	4,005	3,944	3,677	3,526	3,377	3,249	3,077
Winter	12	3,364	12/25/2014	2,825	2,570	2,435	2,353	2,297	2,341	2,428	2,569	2,815	3,063	3,211	3,209	3,200	3,206	3,135	3,076	3,049	3,338	3,363	3,364	3,347	3,292	3,163	2,935
Winter	12	3,919	12/26/2014	2,729	2,547	2,488	2,466	2,501	2,581	2,776	3,022	3,184	3,345	3,425	3,428	3,400	3,361	3,288	3,270	3,340	3,813	3,919	3,875	3,752	3,644	3,442	3,174
Winter	12	3,726	12/27/2014	2,938	2,767	2,655	2,602	2,608	2,667	2,769	2,932	3,104	3,281	3,356	3,357	3,279	3,219	3,118	3,087	3,188	3,635	3,726	3,680	3,574	3,447	3,301	3,062
Winter	12	3,821	12/28/2014	2,838	2,616	2,497	2,438	2,409	2,432	2,504	2,662	2,794	3,049	3,202	3,321	3,301	3,335	3,272	3,266	3,372	3,770	3,821	3,756	3,645	3,488	3,289	3,006
Winter	12	4,271	12/29/2014	2,793	2,632	2,558	2,538	2,575	2,746	3,014	3,367	3,586	3,711	3,701	3,693	3,701	3,642	3,632	3,625	3,685	4,167	4,271	4,172	4,063	3,884	3,656	3,339
Winter	12	4,547	12/30/2014	3,072	2,885	2,816	2,799	2,838	2,994	3,263	3,606	3,805	3,926	4,028	4,035	3,961	3,933	3,866	3,863	3,959	4,403	4,547	4,452	4,353	4,176	3,931	3,619
Winter	12	4,440	12/31/2014	3,308	3,145	3,067	3,021	3,020	3,146	3,381	3,704	3,893	3,965	4,008	3,988	3,907	3,885	3,837	3,812	3,927	4,364	4,440	4,301	4,104	3,910	3,716	3,551
Winter	1	4,144	1/1/2015	3,394	3,243	3,112	3,032	3,002	3,036	3,127	3,232	3,254	3,371	3,481	3,565	3,569	3,538	3,503	3,501	3,609	4,051	4,144	4,077	3,946	3,796	3,536	3,279
Winter	1	4,208	1/2/2015	3,031	2,889	2,777	2,750	2,767	2,885	3,103	3,367	3,555	3,701	3,762	3,761	3,719	3,724	3,668	3,621	3,692	4,112	4,208	4,089	3,968	3,850	3,650	3,373
Winter	1	4,303	1/3/2015	3,112	2,968	2,866	2,824	2,831	2,899	3,021	3,181	3,358	3,507	3,648	3,698	3,740	3,736	3,772	3,815	3,907	4,266	4,303	4,192	4,021	3,811	3,595	3,317
Winter	1	4,044	1/4/2015	3,018	2,860	2,744	2,678	2,650	2,687	2,746	2,894	3,036	3,289	3,459	3,598	3,685	3,713	3,679	3,660	3,709	4,018	4,044	3,939	3,794	3,543	3,271	2,948
Winter	1	4,690	1/5/2015	2,695	2,560	2,505	2,498	2,531	2,720	3,119	3,644	3,770	3,766	3,817	3,857	3,825	3,838	3,822	3,869	3,998	4,469	4,690	4,650	4,554	4,352	4,037	3,679
Winter	1	4,897	1/6/2015	3,411	3,262	3,218	3,201	3,233	3,375	3,749	4,246	4,361	4,385	4,424	4,435	4,411	4,389	4,375	4,329	4,416	4,751	4,897	4,841	4,767	4,543	4,212	3,835
Winter	1	5,123	1/7/2015	3,568	3,441	3,354	3,318	3,336	3,471	3,837	4,336	4,431	4,374	4,378	4,371	4,344	4,356	4,341	4,417	4,520	4,902	5,123	5,027	5,018	4,869	4,546	4,170
Winter	1	5,110	1/8/2015	3,930	3,831	3,735	3,730	3,782	3,940	4,280	4,735	4,900	4,855	4,765	4,741	4,642	4,564	4,491	4,479	4,555	4,940	5,110	5,039	4,937	4,738	4,402	4,006
Winter	1	4,718	1/9/2015	3,726	3,560	3,466	3,405	3,401	3,533	3,837	4,281	4,437	4,502	4,572	4,591	4,455	4,355	4,301	4,206	4,265	4,575	4,718	4,629	4,476	4,314	4,091	3,792
Winter	1	4,594	1/10/2015	3,525	3,375	3,279	3,264	3,275	3,356	3,498	3,710	3,946	4,114	4,212	4,160	4,126	4,034	3,979	3,937	4,031	4,406	4,594	4,527	4,425	4,307	4,123	3,882
Winter	1	4,549	1/11/2015	3,636	3,468	3,376	3,317	3,330	3,382	3,476	3,608	3,761	3,939	4,003	4,049	4,076	4,082	4,064	4,074	4,081	4,437	4,549	4,430	4,304	4,091	3,770	3,429
Winter	1	4,599	1/12/2015	3,183	3,017	2,970	2,920	2,962	3,110	3,448	3,850	4,009	4,128	4,239	4,299	4,310	4,308	4,261	4,207	4,253	4,542	4,599	4,502	4,333	4,083	3,756	3,412
Winter	1	4,877	1/13/2015	3,134	2,980	2,914	2,885	2,925	3,127	3,547	4,049	4,190	4,170	4,157	4,169	4,129	4,110	4,076	4,064	4,208	4,628	4,877	4,807	4,716	4,562	4,255	3,894
Winter	1	4,863	1/14/2015	3,621	3,584	3,450	3,445	3,468	3,650	4,001	4,512	4,586	4,608	4,638	4,633	4,569	4,527	4,464	4,417	4,477	4,717	4,863	4,813	4,705	4,471	4,144	3,783
Winter	1	4,697	1/15/2015	3,518	3,347	3,286	3,268	3,316	3,473	3,854	4,328	4,417	4,357	4,311	4,276	4,180	4,114	4,091	4,038	4,102	4,444	4,697	4,611	4,523	4,339	4,046	3,665
Winter	1	4,585	1/16/2015	3,406	3,285	3,187	3,153	3,188	3,326	3,691	4,142	4,260	4,199	4,155	4,068	4,007	4,005	3,990	3,994	4,027	4,361	4,585	4,535	4,419	4,273	4,078	3,804
Winter	1	4,429	1/17/2015	3,576	3,425	3,347	3,299	3,335	3,415	3,566	3,772	3,976	4,147	4,198	4,138	4,056	3,951	3,856	3,810	3,883	4,199	4,429	4,327	4,232	4,081	3,880	3,623
Winter	1	4,177	1/18/2015	3,403	3,238	3,145	3,080	3,082	3,103	3,189	3,310	3,473	3,699	3,877	4,005	4,049	4,053	3,994	3,951	3,951	4,174	4,177	4,039	3,852	3,724	3,492	3,211
Winter	1	4,445	1/19/2015	2,969	2,836	2,747	2,733	2,776	2,886	3,152	3,437	3,679	3,805	3,929	3,968	3,941	3,921	3,919	3,907	3,925	4,250	4,445	4,356	4,225	4,021	3,713	3,350
Winter	1	4,437	1/20/2015	3,093	2,951	2,784	2,846	2,874	3,034	3,442	3,923	4,009	3,964	3,930	3,900	3,843	3,854	3,858	3,871	3,873	4,206	4,437	4,386	4,257	4,061	3,760	3,452
Winter	1	4,536	1/21/2015	3,207	3,110	3,020	3,012	3,067	3,247	3,660	4,136	4,226	4,185	4,142	4,120	4,083	4,035	3,938	3,903	3,993	4,322	4,536	4,443	4,346	4,117	3,791	3,438
Winter	1	4,392	1/22/2015	3,174	3,025	2,979	2,936	2,960	3,127	3,485	3,935	4,076	4,084	4,052	3,997	3,918	3,885	3,797	3,769	3,785	4,113	4,392	4,335	4,261	4,081	3,777	3,435
Winter	1	4,261	1/23/2015	3,183	3,073	2,998	2,996	3,029	3,217	3,612	4,071	4,186	4,091	4,053	3,984	3,875	3,798	3,740	3,740	3,779	4,073	4,261	4,182	4,037	3,921	3,657	3,388
Winter	1	4,195	1/24/2015	3,109	2,953	2,846	2,838	2,841	2,902	3,023	3,199	3,349	3,565	3,750	3,867	3,919	3,891	3,822	3,777	3,831	4,079	4,195	4,043	3,899	3,731	3,545	3,279
Winter	1	4,179	1/25/2015	3,045	2,886	2,819	2,764	2,750	2,805	2,891	3,050	3,210	3,398	3,473	3,493	3,478	3,434	3,403	3,426	3,542	3,877	4,173	4,179	4,086	3,944	3,712	3,448
Winter	1	4,859	1/26/2015	3,208	3,093	2,989	2,988	3,057	3,240	3,687	4,173	4,327	4,330	4,363	4,441	4,433	4,475	4,464	4,419	4,409	4,685	4,859	4,674	4,421	4,154	3,896	3,631
Winter	1	4,639	1/27/2015	3,384	3,275	3,206	3,179	3,211	3,269	3,389	3,537	3,647	3,841	3,939	3,964	3,964	3,975	3,950	3,959	4,050	4,387	4,639	4,526	4,364	4,169	3,894	3,628
Winter	1	4,759	1/28/2015	3,415	3,322	3,273	3,237	3,279	3,440	3,745	4,103	4,351	4,441	4,438	4,452	4,366	4,268	4,187	4,117	4,142	4,410	4,759	4,704	4,588	4,390	4,081	3,752
Winter	1	4,606	1/29/2015	3,500	3,393	3,355	3,359	3,381	3,525	3,987	4,422	4,511	4,420	4,358	4,232	4,147	4,081	4,020	4,030	4,106	4,342	4,606	4,521	4,416	4,184	3,882	3,506
Winter	1	4,463	1/30/2015	3,251	3,115	3,031	2,992	3,029	3,159	3,488	3,876	4,065	4,101	4,167	4,106	4,087	4,053	4,029	3,954	3,998	4,213	4,463	4,438	4,357	4,243	4,014	3,789
Winter	1	4,573	1/31/2015	3,542	3,443	3,369	3,395	3,421	3,497	3,681	3,887	4,097	4,285	4,342	4,314	4,248	4,186	4,049	4,018	4,036	4,254	4,573	4,526	4,428	4,331	4,108	3,846
Winter	2	4,341	2/1/2015	3,623	3,470	3,381	3,360	3,346	3,396	3,473	3,600	3,768	3,944	3,960	3,913	3,868	3,788	3,771	3,748	3,827	4,070	4,341	4,125	3,926	3,808	3,648	3,509
Winter	2	4,885	2/2/2015	3,268	3,111	3,018	3,037	3,087	3,220	3,431	3,704	3,891	4,109	4,259	4,387	4,450	4,437	4,465	4,418	4,413	4,590	4,885	4,735	4,623	4,369	4,069	3,777
Winter	2	4,775	2/3/2015	3,562	3,468	3,426	3,429	3,472	3,624	3,941	4,283	4,507	4,567	4,518	4,480	4,372	4,298	4,196	4,158	4,191	4,410	4,775	4,764	4,680	4,506	4,233	3,902
Winter	2	4,536	2/4/2015	3,684	3,471	3,429	3,426	3,438	3,563	3,905	4,355	4,358	4,366	4,368	4,311	4,243	4,173	4,101	4,078	4,060	4,227	4,536	4,513	4,345	4,207	3,857	3,507
Winter	2	4,796	2/5/2015	3,219	3,126	2,968	2,847	2,881	3,091	3,408	3,816	4,086	4,148	4,238	4,256	4,245	4,208	4,137	4,079	4,111	4,374	4,791	4,796	4,705	4,546	4,245	3,920
Winter	2	4,714	2/6/2015	3,720	3,583	3,473	3,484	3,518	3,719	3,985	4,517	4,600	4,520	4,541	4,536	4,493	4,370	4,275	4,217	4,317	4,318	4,714	4,665	4,551	4,401	4,196	3,999
Winter	2	4,314	2/7/2015	3,655	3,497	3,379	3,336	3,307	3,354	3,444	3,682	3,838	4,033	4,090	4,117	4,053	4,107	4,022	3,888	3,948	4,110	4,314	4,243	4,099	3,954	3,732	3,478
Winter	2	4,373	2/8/2015	3,251	3,094	3,028	2,998	2,969	2,963	3,037	3,180	3,344	3,590	3,748	3,823	3,826	3,842	3,810	3,834	3,841	4,131	4,373	4,323	4,218	4,003	3,792	3,549
Winter	2	4,859	2/9/2015	3,339	3,210	3,169	3,156	3,192	3,358	3,589	3,887	4,108	4,198	4,408	4,614	4,562	4,562	4,510	4,423	4,442	4,565	4,859	4,729	4,627	4,382	4,116	3,671
Winter	2	4,567	2/10/2015	3,577	3,350	3,260	3,235	3,249	3,398	3,689	4,021	4,291	4,313	4,258	4,206	4,150	4,093	4,039	3,976	3,964	4,109	4,567	4,497	4,316	4,190	3,949	3,586
Winter	2	4,549	2/11/2015	3,372	3,193	3,133	3,158	3,183	3,358	3,759	4,159	4,314	4,250	4,205	4,121	4,030	3,988	3,920	3,903	3,924	4,127	4,538	4,549	4,419	4,280	3,956	3,755
Winter	2	4,522	2/12/2015	3,432	3,323	3,225	3,228	3,275	3,400	3,680	4,149	4,290	4,257	4,276	4,238	4,138	4,108	4,087	3,900	4,074	4,246	4,522	4,506	4,432	4,277	4,047	3,687
Winter	2	4,763	2/13/2015	3,504	3,412	3,381	3,386	3,468	3,651	4,044	4,421	4,517	4,571	4,575	4,572	4,555	4,447	4,337	4,265	4,277	4,411	4,763	4,746	4,636	4,534	4,327	4,070
Winter	2	4,534	2/14/2015	3,831	3,711	3,673	3,624	3,646	3,696	3,860	4,016	4,218	4,422	4,415	4,257	4,325	4,235	4,121	4,122	4,147	4,276	4,534	4,461	4,310	4,147	3,900	3,719
Winter	2	4,791	2/15/2015	3,450	3,296	3,291	3,241	3,252	3,254	3,385	3,540	3,729	3,966	4,219	4,330	4,319	4,289	4,198	4,130	4,168	4,405	4,791	4,767	4,689	4,661	4,380	4,199
Winter	2	5,029	2/16/2015	3,978	3,860	3,827	3,821	3,860	3,971	4,158	4,438	4,681	4,811	4,882	4,811	4,796	4,703	4,577	4,555	4,572	4,661	5,029	4,971	4,861	4,715	4,401	4,019
Winter	2	4,934	2/17/2015	3,704	3,612	3,565	3,516	3,549	3,701	4,016	4,403	4,580	4,744	4,769	4,675	4,568	4,496	4,355	4,257	4,271	4,521	4,915	4,934	4,792	4,651	4,259	3,935

Contains Proprietary Material
Do Not Distribute

Winter	2	4,716	2/18/2015	3,764	3,616	3,521	3,525	3,634	3,649	4,176	4,566	4,703	4,716	4,544	4,480	4,324	4,253	4,136	4,108	4,084	4,276	4,690	4,662	4,477	4,489	4,059	3,651
Winter	2	5,186	2/19/2015	3,430	3,320	3,271	3,290	3,314	3,434	3,830	4,271	4,463	4,458	4,475	4,379	4,372	4,316	4,292	4,295	4,407	4,655	5,076	5,180	5,186	4,790	4,497	4,196
Winter	2	4,990	2/20/2015	3,946	3,900	3,860	3,840	3,911	4,085	4,441	4,853	4,964	4,966	4,971	4,852	4,804	4,745	4,578	4,540	4,522	4,657	4,976	4,990	4,934	4,792	4,572	4,303
Winter	2	4,671	2/21/2015	3,977	3,805	3,778	3,738	3,748	3,813	3,969	4,099	4,325	4,435	4,476	4,358	4,302	4,313	4,196	4,189	4,240	4,398	4,671	4,569	4,397	4,227	3,947	3,607
Winter	2	4,212	2/22/2015	3,379	3,231	3,106	3,043	3,035	3,066	3,093	3,242	3,393	3,627	3,671	3,780	3,668	3,625	3,562	3,528	3,560	3,729	4,186	4,212	3,978	3,917	3,679	3,360
Winter	2	4,963	2/23/2015	3,167	3,062	2,987	2,961	3,027	3,207	3,568	4,063	4,253	4,364	4,334	4,375	4,305	4,276	4,222	4,209	4,260	4,449	4,903	4,963	4,950	4,794	4,541	4,145
Winter	2	5,107	2/24/2015	3,884	3,786	3,738	3,738	3,829	3,963	4,381	4,735	4,786	4,783	4,754	4,718	4,579	4,488	4,406	4,391	4,490	4,658	5,081	5,107	4,999	4,637	4,295	3,897
Winter	2	4,551	2/25/2015	3,708	3,506	3,483	3,428	3,474	3,642	4,002	4,407	4,521	4,399	4,314	4,295	4,137	4,109	3,928	3,956	4,022	4,158	4,505	4,551	4,496	4,336	4,042	3,618
Winter	2	4,770	2/26/2015	3,420	3,316	3,285	3,228	3,214	3,387	3,778	4,197	4,457	4,423	4,450	4,453	4,419	4,299	4,206	4,183	4,203	4,437	4,769	4,770	4,636	4,417	4,134	3,781
Winter	2	4,529	2/27/2015	3,484	3,404	3,335	3,334	3,399	3,539	3,931	4,341	4,396	4,357	4,343	4,226	4,202	4,095	4,059	4,005	3,992	4,127	4,443	4,529	4,423	4,297	4,131	3,901
Winter	2	4,326	2/28/2015	3,608	3,497	3,435	3,403	3,431	3,516	3,707	3,816	4,070	4,157	4,147	4,121	4,019	3,875	3,810	3,725	3,708	3,860	4,121	4,326	4,200	4,180	4,052	3,773
Spring	3	4,553	3/1/2015	3,600	3,440	3,401	3,340	3,350	3,401	3,399	3,574	3,744	3,909	4,019	4,077	4,071	4,047	4,021	4,060	4,122	4,254	4,553	4,550	4,352	4,156	3,845	3,525
Spring	3	4,538	3/2/2015	3,295	3,180	3,112	3,095	3,126	3,258	3,509	3,848	4,090	4,111	4,061	4,105	4,070	4,018	3,958	3,929	4,010	4,111	4,400	4,538	4,392	4,292	3,956	3,750
Spring	3	4,720	3/3/2015	3,372	3,251	3,187	3,209	3,331	3,425	3,818	4,236	4,266	4,202	4,152	4,129	4,066	4,088	4,073	4,069	4,152	4,367	4,720	4,718	4,544	4,315	3,932	3,559
Spring	3	4,310	3/4/2015	3,217	3,112	3,031	2,989	3,007	3,150	3,460	3,805	3,968	4,052	4,017	3,995	3,955	3,954	3,869	3,868	3,902	4,022	4,310	4,299	4,236	3,970	3,642	3,301
Spring	3	4,645	3/5/2015	3,041	3,002	2,851	2,831	2,896	3,098	3,408	3,687	3,990	4,100	4,238	4,330	4,322	4,350	4,324	4,267	4,287	4,431	4,632	4,645	4,570	4,367	4,003	3,777
Spring	3	4,484	3/6/2015	3,529	3,381	3,361	3,343	3,383	3,543	3,927	4,352	4,423	4,366	4,313	4,271	4,176	4,097	4,019	3,963	3,932	4,069	4,361	4,484	4,376	4,260	4,088	3,754
Spring	3	4,068	3/7/2015	3,480	3,351	3,242	3,261	3,248	3,362	3,531	3,589	3,850	3,962	3,974	3,865	3,848	3,648	3,517	3,602	3,622	3,767	3,984	4,068	3,979	3,815	3,678	3,397
Spring	3	3,918	3/8/2015	3,153	3,043	2,981	2,994	2,919	2,921	2,982	3,123	3,179	3,444	3,543	3,550	3,511	3,503	3,444	3,344	3,383	3,426	3,552	3,785	3,918	3,802	3,597	3,299
Spring	3	4,060	3/9/2015	3,010	2,946	2,906	2,879	2,919	3,076	3,388	3,899	4,060	3,976	3,879	3,794	3,751	3,665	3,590	3,517	3,481	3,547	3,624	3,807	3,969	3,841	3,572	3,254
Spring	3	4,047	3/10/2015	3,054	2,880	2,818	2,812	2,846	3,011	3,362	3,878	4,004	3,922	3,840	3,789	3,731	3,677	3,610	3,592	3,637	3,731	3,860	3,930	4,047	3,884	3,561	3,234
Spring	3	3,779	3/11/2015	2,914	2,784	2,707	2,653	2,674	2,819	3,136	3,644	3,752	3,779	3,740	3,692	3,660	3,622	3,559	3,545	3,483	3,535	3,649	3,689	3,772	3,728	3,373	3,082
Spring	3	3,992	3/12/2015	2,756	2,681	2,626	2,593	2,616	2,732	3,172	3,663	3,809	3,753	3,669	3,707	3,719	3,574	3,537	3,474	3,486	3,551	3,627	3,821	3,992	3,885	3,623	3,304
Spring	3	4,015	3/13/2015	3,073	2,926	2,889	2,848	2,919	3,025	3,401	3,816	4,015	3,952	3,892	3,811	3,749	3,669	3,573	3,530	3,460	3,534	3,613	3,709	3,856	3,746	3,541	3,274
Spring	3	3,765	3/14/2015	3,060	2,895	2,767	2,700	2,696	2,702	2,799	3,076	3,283	3,521	3,689	3,753	3,765	3,690	3,564	3,560	3,472	3,511	3,574	3,653	3,616	3,490	3,294	3,119
Spring	3	3,850	3/15/2015	2,859	2,700	2,617	2,634	2,567	2,569	2,666	2,844	2,974	3,234	3,323	3,339	3,444	3,396	3,341	3,328	3,338	3,499	3,637	3,672	3,850	3,691	3,456	3,190
Spring	3	3,896	3/16/2015	2,909	2,801	2,742	2,731	2,781	2,872	3,302	3,770	3,854	3,746	3,766	3,723	3,615	3,575	3,485	3,492	3,440	3,471	3,602	3,764	3,896	3,752	3,429	3,103
Spring	3	3,991	3/17/2015	2,842	2,663	2,616	2,604	2,611	2,737	3,147	3,617	3,778	3,800	3,787	3,857	3,716	3,573	3,603	3,500	3,523	3,564	3,683	3,756	3,991	3,849	3,620	3,317
Spring	3	4,326	3/18/2015	3,079	2,949	2,858	2,864	2,894	2,953	3,443	3,874	4,025	3,956	3,935	3,925	3,887	3,900	3,807	3,804	3,735	3,786	3,989	4,083	4,326	4,118	3,832	3,471
Spring	3	4,152	3/19/2015	3,403	3,085	3,046	3,034	3,061	3,209	3,638	4,060	4,152	4,086	4,015	3,974	3,884	3,837	3,737	3,649	3,636	3,671	3,741	3,911	4,097	3,991	3,701	3,373
Spring	3	4,199	3/20/2015	3,153	3,013	2,938	2,900	2,973	3,081	3,479	3,915	4,057	4,054	4,047	4,064	4,033	4,041	4,036	3,980	3,999	4,070	4,141	4,146	4,199	4,012	3,793	3,510
Spring	3	3,818	3/21/2015	3,196	3,091	3,000	2,944	2,877	2,937	3,114	3,284	3,520	3,735	3,818	3,805	3,678	3,504	3,410	3,305	3,254	3,303	3,340	3,481	3,587	3,487	3,291	3,183
Spring	3	3,897	3/22/2015	2,834	2,755	2,758	2,667	2,673	2,705	2,819	2,952	3,113	3,327	3,413	3,445	3,415	3,386	3,259	3,264	3,278	3,376	3,502	3,650	3,897	3,806	3,567	3,337
Spring	3	4,184	3/23/2015	3,109	2,977	2,936	2,921	3,023	3,191	3,551	4,001	4,173	4,109	4,041	4,001	3,927	3,860	3,789	3,701	3,669	3,736	3,872	3,963	4,184	4,040	3,764	3,418
Spring	3	4,095	3/24/2015	3,174	3,152	3,010	2,942	2,951	3,110	3,547	4,001	4,095	4,055	3,967	3,892	3,796	3,739	3,680	3,586	3,553	3,581	3,738	3,841	4,055	3,906	3,632	3,260
Spring	3	4,055	3/25/2015	3,060	2,952	2,877	2,898	2,936	3,103	3,430	3,842	4,055	3,933	3,759	3,728	3,643	3,508	3,565	3,492	3,551	3,750	3,895	3,938	3,990	3,813	3,513	3,139
Spring	3	3,813	3/26/2015	2,859	2,738	2,659	2,627	2,635	2,779	3,147	3,582	3,720	3,740	3,730	3,747	3,706	3,688	3,726	3,669	3,687	3,672	3,741	3,813	3,806	3,647	3,327	3,032
Spring	3	3,759	3/27/2015	2,753	2,615	2,524	2,507	2,520	2,676	3,014	3,518	3,627	3,710	3,759	3,747	3,675	3,672	3,619	3,570	3,607	3,569	3,563	3,529	3,713	3,615	3,407	3,101
Spring	3	3,778	3/28/2015	2,926	2,730	2,643	2,597	2,609	2,658	2,797	3,002	3,276	3,529	3,669	3,678	3,693	3,622	3,560	3,500	3,464	3,469	3,549	3,698	3,778	3,657	3,519	3,274
Spring	3	3,497	3/29/2015	3,048	2,929	2,867	2,777	2,776	2,862	2,935	3,066	3,291	3,430	3,462	3,408	3,360	3,260	3,212	3,119	2,984	3,033	3,095	3,240	3,497	3,438	3,210	3,070
Spring	3	3,524	3/30/2015	2,877	2,763	2,717	2,739	2,706	2,640	2,900	3,248	3,430	3,517	3,495	3,524	3,468	3,373	3,249	3,189	3,199	3,187	3,283	3,364	3,372	3,382	3,196	3,126
Spring	3	3,735	3/31/2015	2,820	2,769	2,626	2,636	2,654	2,828	3,096	3,372	3,476	3,473	3,420	3,448	3,364	3,339	3,305	3,366	3,387	3,444	3,574	3,622	3,707	3,735	3,481	3,053
Spring	4	3,387	4/1/2015	2,862	2,742	2,668	2,662	2,684	2,606	2,964	3,247	3,387	3,367	3,280	3,220	3,136	3,107	3,110	3,091	2,999	3,043	3,130	3,230	3,386	3,282	3,203	2,986
Spring	4	3,450	4/2/2015	2,776	2,772	2,756	2,695	2,725	2,908	3,139	3,297	3,450	3,336	3,236	3,211	3,113	3,142	3,037	2,976	2,904	2,966	3,043	3,149	3,198	3,101	3,023	2,709
Spring	4	2,834	4/3/2015	2,614	2,459	2,390	2,358	2,348	2,408	2,447	2,608	2,596	2,629	2,713	2,834	2,726	2,744	2,611	2,618	2,644	2,635	2,691	2,718	2,744	2,572	2,465	2,447
Spring	4	3,371	4/4/2015	2,269	2,418	2,298	2,229	2,216	2,275	2,354	2,557	2,799	3,005	3,080	3,157	3,136	3,029	2,977	2,954	2,934	3,004	3,084	3,136	3,371	3,322	3,245	2,988
Spring	4	3,347	4/5/2015	2,700	2,547	2,503	2,497	2,445	2,473	2,536	2,753	2,921	3,107	3,146	3,156	3,175	3,103	3,042	2,957	2,995	2,991	3,027	3,130	3,347	3,312	3,187	2,855
Spring	4	3,665	4/6/2015	2,629	2,529	2,491	2,499	2,511	2,679	3,099	3,461	3,665	3,644	3,609	3,557	3,491	3,439	3,379	3,309	3,291	3,287	3,386	3,442	3,654	3,559	3,235	2,909
Spring	4	3,763	4/7/2015	2,607	2,473	2,394	2,360	2,364	2,543	2,892	3,299	3,485	3,546	3,627	3,635	3,662	3,642	3,573	3,590	3,614	3,686	3,763	3,737	3,759	3,732	3,384	3,018
Spring	4	3,903	4/8/2015	2,793	2,650	2,582	2,500	2,510	2,658	3,033	3,404	3,668	3,683	3,665	3,711	3,708	3,692	3,653	3,685	3,640	3,726	3,749	3,812	3,903	3,756	3,517	3,146
Spring	4	3,862	4/9/2015	2,839	2,724	2,658	2,623	2,647	2,783	3,153	3,601	3,759	3,788	3,823	3,862	3,821	3,759	3,764	3,707	3,684	3,798	3,828	3,812	3,822	3,747	3,515	3,175
Spring	4	3,741	4/10/2015	2,846	2,676	2,629	2,593	2,604	2,726	3,035	3,472	3,616	3,680	3,703	3,741	3,694	3,660	3,616	3,550	3,431	3,522	3,572	3,532	3,510	3,535	3,230	2,961
Spring	4	3,205	4/11/2015	2,692	2,573	2,437	2,364	2,353	2,381	2,545	2,685	2,884	3,043	3,123	3,084	3,023	2,978	2,905	2,804	2,791	2,824	2,874	2,922	3,205	3,159	2,999	2,752
Spring	4	3,199	4/12/2015	2,562	2,532	2,362	2,343	2,337	2,359	2,497	2,602	2,755	2,858	2,908	2,907	2,851	2,824	2,776	2,728	2,750	2,826	2,871	2,901	3,199	3,084	2,928	2,664
Spring	4	3,587	4/13/2015	2,435	2,355	2,351	2,343	2,392	2,523	2,873	3,219	3,402	3,445	3,485	3,510	3,429	3,401	3,362	3,333	3,281	3,325	3,368	3,362	3,587	3,471	3,191	2,877
Spring	4	3,582	4/14/2015	2,637	2,442	2,370	2,312	2,325	2,443	2,761	3,105	3,343	3,408	3,435	3,582	3,476	3,413	3,400	3,414	3,375	3,385	3,417	3,434	3,564	3,429	3,218	2,829
Spring	4	3,523	4/15/2015	2,598	2,443	2,430	2,316	2,333	2,461	2,813	3,097	3,266	3,360	3,328	3,373	3,349	3,387	3,334	3,300	3,266	3,293	3,313	3,161	3,523	3,438	3,124	2,821
Spring	4	3,509	4/16/2015	2,532	2,522	2,295	2,313	2,328	2,445	2,695	3,183	3,328	3,354	3,384	3,374	3,341	3,301	3,363	3,274	3,243	3,259	3,239	3,302	3,509	3,395	3,134	2,845
Spring	4	3,599	4/17/2015	2,620	2,443	2,366	2,282	2,332	2,458	2,740	3,106	3,321	3,471	3,582	3,599	3,562	3,539	3,484	3,467	3,398	3,330	3,381	3,327	3,351	3,376	3,161	2,916
Spring	4	3,189	4/18/2015	2,578	2,446	2,300	2,294	2,287	2,317	2,461	2,588	2,812	2,985	3,099	3,074	3,056	3,016	2,960	2,971	2,955	3,022	3,048	3,000	3,189	3,164	2,965	2,676
Spring	4	3,314	4/19/2015	2,426	2,400	2,218	2,162	2,142	2,138	2,176	2,337	2,516	2,715	2,813	2,868	2,872	2,844	2,872	2,820	2,826	2,923	2,990	3,107	3,314	3,209	2,978	2,680
Spring	4	3,786	4/20/2015	2,453	2,305	2,265	2,238	2,269	2,444	2,808	3,252	3,470	3,585	3,651	3,721	3,724	3,750	3,672	3,662	3,675	3,705	3,770	3,756	3,786	3,587	3,261	2,912
Spring	4	3,546	4/21/2015	2,600	2,479	2,386	2,358	2,352	2,486	2,780	3,213	3,396	3,454	3,497	3,489	3,445	3,434	3,377	3,323	3,323	3,319	3,321	3,353	3,546	3,473	3,201	2,844
Spring	4	3,580	4/22/2015	2,519	2,385	2,318	2,299	2,303	2,461	2,779	3,227	3,387	3,388	3,398	3,423	3,387	3,376	3,381	3,366	3,369	3,449	3,472	3,528	3,580	3,477	3,161	2,888
Spring	4	3,719	4/23/2015	2,601	2,413	2,327	2,317	2,351	2,492	2,727	3,158	3,431	3,470	3,483	3,494	3,488	3,496	3,448	3,411	3,390	3,486	3,504	3,537	3,719	3,690	3,385	3,053
Spring	4	3,663	4/24/2015	2,729	2,617	2,552	2,508	2,517	2,684	3,037	3,409	3,540	3,576	3,580	3,577	3,556	3,521	3,486	3,452	3,459	3,469	3,478	3,532	3,663	3,611	3,434	3,151
Spring	4	3,239	4/25/2015	2,912	2,715	2,629	2,557	2,595	2,664	2,757	2,943	3,115	3,220	3,239	3,155	3,115	3,053	2,916	2,889	2,860	2,912	2,974	3,014	3,183	3,183	3,034	2,798
Spring	4	3,346	4/26/2015	2,598	2,468	2,385	2,364	2,337	2,412	2,445	2,592	2,767	2,941	3,021	3,013	3,016	3,017	2,977	2,972	2,945	3,041	3,162	3,221	3,346	3,294	3,026	2,748
Spring	4	3,623	4/27/2015	2,565	2,273	2,194	2,191	2,188	2,326	2,677	3,201	3,382	3,386	3,468	3,445	3,395	3,424	3,406	3,375	3,342	3,425	3,477	3,503	3,623	3,496	3,208	2,795
Spring	4	3,429	4/28/2015	2,581	2,443	2,345	2,307	2,339	2,483	2,770	3,288	3,389	3,429	3,373	3,356	3,286	3,361	3,307	3,217	3,217	3,229	3,278	3,243	3,411	3,374	3,118	2,701
Spring	4	3,369	4/29/2015	2,448	2,304	2,231	2,179	2,195	2,341	2,656	3,064	3,240	3,223	3,287	3,299	3,268	3,314	3,353	3,319	3,276	3,295	3,282	3,187	3,369	3,364	3,057	2,725
Spring	4	3,383	4/30/2015	2,421	2,280	2,186	2,169	2,189	2,348	2,578	3,058	3,241	3,249	3,284	3,279	3,290	3,277	3,308	3,240	3,211	3,239	3,229	3,255	3,383	3,346	3,066	2,696
Spring	5	3,364	5/1/2015	2,587	2,267	2,228	2,175	2,200	2,294	2,591	3,041	3,221	3,254	3,265	3,354	3,364	3,266	3,264	3,230	3,163	3,163	3,136	3,154	3,249	3,267	3,029	2,773
Spring	5	3,051	5/2/2015	2,478	2,306	2,222	2,199	2,179	2,226	2,327	2,570	2,748	2,918	2,987	2,937	2,913	2,922	2,838	2,828	2,849	2,859	2,902	2,846	3,011	3,051	2,829	2,639
Spring	5	3,176	5/3/2015	2,421	2,283	2,196	2,146	2,115	2,165	2,176	2,292	2,551	2,689	2,792	2,850	2,860	2,876	2,886	2,875	2,869	2,960	3,022	3,059	3,176	3,143	2,922	2,623
Spring	5	3,585	5/4/2015	2,289	2,243	2,146	2,112	2,129	2,237	2,491	3,051	3,184	3,264	3,359	3,456	3,523	3,558	3,580	3,585	3,539	3,520	3,526	3,472	3,559	3,544	3,214	2,866
Spring	5	3,742	5/5/2015	2,537	2,368	2,267	2,166	2,209	2,328	2,566	3,113	3,302	3,404	3,506	3,589	3,593	3,669	3,697	3,730	3,727	3,724	3,742	3,694	3,737	3,664	3,343	2,924
Spring	5	3,594	5/6/2015	2,642	2,509	2,345	2,306	2,296	2,404	2,668	3,062	3,312	3,369	3,568	3,583	3,569	3,594	3,583	3,553	3,541	3,538	3,555	3,497	3,514	3,572	3,252	2,904
Spring	5	3,810	5/7/2015	2,600	2,514	2,328	2,274	2,276	2,380	2,693	3,109	3,314	3,412	3,498	3,625	3,687	3,721	3,779	3,782	3,810	3,774	3,739	3,666	3,695	3,736	3,344	2,994
Spring	5	4,058	5/8/2015	2,678	2,486	2,418	2,303	2,335	2,420	2,675	3,141	3,327	3,520	3,627	3,757	3,824	3,954	4,016	4,043	4,050	4,058	3,983	3,793	3,764	3,757	3,465	3,087
Spring	5	3,440	5/9/2015	2,775	2,577	2,472	2,321	2,322	2,382	2,439	2,553	2,841	3,116	3,197	3,238	3,252	3,241	3,254	3,255	3,286	3,326	3,341	3,342	3,400	3,440	3,260	2,962
Spring	5	3,961	5/10/2015	2,740	2,538	2,377	2,329	2,343	2,314	2,344	2,495	2,742	3,014	3,191	3,343	3,476	3,521	3,571	3,622	3,713	3,814	3,824	3,799	3,844	3,961	3,568	3,344
Spring	5	4,685	5/11/2015	2,957	2,758	2,629	2,591	2,553	2,673	2,955	3,443	3,771	3,941	4,099	4,264	4,392	4,507	4,575	4,659	4,685	4,684	4,611	4,516	4,466	4,417	4,027	3,559
Spring	5	4,691	5/12/2015	3,158	2,960	2,839	2,756	2,746	2,870	3,176	3,621	3,917	4,064	4,245	4,479	4,626	4,691	4,602	4,577	4,517	4,557	4,484	4,380	4,319	4,220	3,768	3,152
Spring	5	3,578	5/13/2015	2,788	2,549	2,427	2,361	2,333	2,428	2,571	3,118	3,294	3,404	3,481	3,503	3,491	3,523	3,578	3,460	3,415	3,416	3,440	3,384	3,424	3,422	3,139	2,774
Spring	5	3,508	5/14/2015	2,518	2,322	2,190	2,175	2,204	2,327	2,606	3,053	3,227	3,321	3,381	3,428	3,444	3,464	3,485	3,503	3,487	3,507	3,508	3,419	3,461	3,427	3,209	2,801
Spring	5	3,502	5/15/2015	2,488	2,333	2,233	2,213	2,181	2,335	2,500	3,000	3,218	3,309	3,398	3,438	3,443	3,466	3,502	3,470	3,433	3,433	3,367	3,325	3,308	3,338	3,115	2,839
Spring	5	3,249	5/16/2015	2,529	2,347	2,242	2,177	2,164	2,192	2,255	2,429	2,702	2,994	3,123	3,165	3,193	3,213	3,157	3,108	3,137	3,167	3,184	3,164	3,214	3,249	3,086	2,833

Contains Proprietary Material
Do Not Distribute

Spring	5	4,011	5/17/2015	2,557	2,426	2,258	2,234	2,213	2,185	2,181	2,372	2,632	2,945	3,143	3,333	3,499	3,581	3,626	3,717	3,806	3,938	3,947	4,011	3,934	3,974	3,682	3,245
Spring	5	3,886	5/18/2015	2,930	2,681	2,569	2,483	2,482	2,617	2,875	3,294	3,496	3,598	3,683	3,755	3,782	3,847	3,867	3,886	3,842	3,779	3,716	3,655	3,764	3,698	3,401	3,039
Spring	5	3,896	5/19/2015	2,692	2,535	2,412	2,368	2,385	2,526	2,763	3,238	3,490	3,575	3,626	3,644	3,718	3,728	3,742	3,749	3,816	3,896	3,864	3,856	3,886	3,873	3,531	3,166
Spring	5	3,540	5/20/2015	2,866	2,499	2,465	2,398	2,412	2,504	2,725	3,170	3,387	3,492	3,498	3,540	3,395	3,426	3,502	3,463	3,452	3,463	3,464	3,414	3,467	3,519	3,249	2,904
Spring	5	3,525	5/21/2015	2,603	2,436	2,374	2,320	2,332	2,440	2,680	3,115	3,368	3,429	3,499	3,505	3,503	3,525	3,477	3,479	3,473	3,474	3,468	3,439	3,487	3,512	3,250	2,917
Spring	5	3,626	5/22/2015	2,570	2,453	2,335	2,302	2,279	2,403	2,588	3,082	3,307	3,364	3,517	3,539	3,579	3,626	3,584	3,552	3,523	3,491	3,466	3,383	3,336	3,389	3,144	2,872
Spring	5	3,128	5/23/2015	2,699	2,396	2,254	2,267	2,232	2,220	2,270	2,368	2,718	2,839	2,990	3,028	3,011	2,953	2,956	2,946	2,933	2,991	3,048	3,027	3,028	3,128	2,983	2,780
Spring	5	3,260	5/24/2015	2,496	2,370	2,288	2,192	2,181	2,192	2,185	2,293	2,546	2,805	2,878	3,010	3,045	3,069	3,045	3,030	3,104	3,140	3,121	3,058	3,081	3,260	3,100	2,801
Spring	5	3,783	5/25/2015	2,564	2,392	2,305	2,253	2,232	2,272	2,309	2,324	2,676	2,928	3,102	3,252	3,389	3,489	3,536	3,592	3,651	3,721	3,770	3,696	3,669	3,783	3,461	3,116
Spring	5	4,621	5/26/2015	2,759	2,616	2,498	2,340	2,419	2,454	2,784	3,283	3,573	3,806	3,950	4,186	4,353	4,373	4,517	4,621	4,609	4,604	4,503	4,357	4,264	4,259	3,873	3,403
Spring	5	4,673	5/27/2015	3,015	2,791	2,620	2,553	2,533	2,643	2,842	3,362	3,599	3,891	4,095	4,289	4,414	4,521	4,609	4,673	4,669	4,633	4,459	4,364	4,300	4,145	3,746	3,371
Spring	5	4,556	5/28/2015	3,027	2,761	2,624	2,537	2,548	2,678	2,845	3,393	3,666	3,769	3,938	4,051	4,102	4,207	4,498	4,554	4,556	4,511	4,475	4,321	4,247	4,188	3,845	3,344
Spring	5	4,585	5/29/2015	2,983	2,725	2,588	2,432	2,410	2,465	2,644	3,200	3,497	3,677	3,865	4,007	4,109	4,273	4,354	4,435	4,585	4,520	4,437	4,208	4,112	3,966	3,770	3,414
Spring	5	4,358	5/30/2015	2,998	2,816	2,629	2,526	2,483	2,494	2,525	2,759	3,060	3,349	3,605	3,795	3,986	4,093	4,176	4,267	4,312	4,358	4,260	4,106	3,914	3,904	3,762	3,467
Spring	5	3,941	5/31/2015	3,127	2,892	2,765	2,669	2,596	2,609	2,566	2,692	2,962	3,252	3,496	3,666	3,752	3,847	3,926	3,906	3,941	3,876	3,908	3,763	3,691	3,513	3,142	2,884
Summer	6	3,678	6/1/2015	2,616	2,465	2,289	2,331	2,333	2,444	2,709	3,129	3,351	3,506	3,572	3,615	3,644	3,663	3,615	3,567	3,571	3,652	3,678	3,577	3,602	3,531	3,214	2,822
Summer	6	3,628	6/2/2015	2,610	2,492	2,342	2,392	2,344	2,406	2,729	3,149	3,399	3,482	3,582	3,545	3,555	3,628	3,611	3,532	3,548	3,588	3,622	3,580	3,560	3,565	3,253	2,890
Summer	6	3,575	6/3/2015	2,614	2,506	2,372	2,348	2,347	2,477	2,724	3,173	3,335	3,353	3,433	3,385	3,508	3,539	3,480	3,544	3,548	3,565	3,558	3,496	3,482	3,575	3,316	2,914
Summer	6	3,625	6/4/2015	2,603	2,439	2,341	2,299	2,357	2,394	2,696	3,060	3,308	3,423	3,506	3,550	3,594	3,625	3,623	3,617	3,597	3,586	3,604	3,500	3,507	3,569	3,292	2,930
Summer	6	3,287	6/5/2015	2,692	2,459	2,349	2,374	2,317	2,364	2,697	2,814	2,903	2,948	3,045	3,114	3,180	3,234	3,276	3,287	3,236	3,238	3,225	3,053	3,059	2,985	2,911	2,671
Summer	6	3,111	6/6/2015	2,466	2,157	2,023	1,983	1,969	1,939	2,050	2,176	2,425	2,741	2,867	3,026	3,111	3,028	3,067	2,926	2,924	2,992	2,943	2,842	2,778	2,864	2,669	2,534
Summer	6	3,399	6/7/2015	2,278	2,144	2,029	1,889	1,782	1,755	1,871	1,933	1,991	2,364	2,555	2,723	2,635	2,674	2,682	2,721	2,743	2,851	2,884	3,000	3,359	3,399	3,189	2,898
Summer	6	4,011	6/8/2015	2,649	2,403	2,338	2,309	2,323	2,480	2,821	3,154	3,413	3,558	3,710	3,775	3,801	3,779	3,904	3,926	3,947	4,011	3,947	3,846	3,785	3,918	3,560	3,167
Summer	6	4,318	6/9/2015	2,870	2,651	2,566	2,492	2,520	2,632	2,944	3,362	3,658	3,809	3,961	4,020	4,067	4,147	4,160	4,211	4,305	4,318	4,303	4,207	4,147	4,093	3,772	3,353
Summer	6	4,576	6/10/2015	2,929	2,731	2,616	2,514	2,493	2,512	2,857	3,301	3,613	3,773	3,966	4,139	4,148	4,304	4,462	4,469	4,560	4,576	4,499	4,361	4,284	4,298	3,954	3,491
Summer	6	5,262	6/11/2015	3,129	2,942	2,782	2,678	2,703	2,797	3,024	3,497	3,819	3,976	4,201	4,480	4,713	4,813	5,005	5,123	5,262	5,260	5,260	5,155	5,067	5,038	4,651	4,072
Summer	6	5,301	6/12/2015	3,638	3,362	3,149	2,994	2,925	3,018	3,219	3,722	4,038	4,260	4,497	4,682	4,900	5,012	5,198	5,301	5,272	5,224	5,131	4,976	4,763	4,763	4,465	4,069
Summer	6	4,716	6/13/2015	3,656	3,386	3,221	3,097	3,070	3,032	3,029	3,326	3,711	3,880	4,141	4,272	4,340	4,413	4,516	4,552	4,630	4,716	4,622	4,519	4,311	4,282	4,049	3,683
Summer	6	4,686	6/14/2015	3,289	3,019	2,858	2,726	2,631	2,607	2,582	2,757	3,005	3,422	3,651	3,959	4,142	4,264	4,379	4,496	4,589	4,675	4,686	4,513	4,327	4,397	4,053	3,564
Summer	6	4,176	6/15/2015	3,284	2,997	2,847	2,769	2,774	2,867	3,098	3,570	3,820	3,939	4,037	4,145	4,176	4,129	4,066	4,047	3,991	3,991	3,983	3,891	3,851	3,811	3,537	3,169
Summer	6	4,385	6/16/2015	2,871	2,682	2,592	2,529	2,527	2,651	2,839	3,295	3,626	3,786	3,870	3,990	4,043	4,152	4,219	4,179	4,243	4,385	4,381	4,311	4,269	4,309	4,031	3,610
Summer	6	4,450	6/17/2015	3,194	2,975	2,824	2,703	2,660	2,739	2,982	3,395	3,766	3,966	4,093	4,182	4,250	4,338	4,391	4,444	4,450	4,368	4,228	4,063	3,969	4,022	3,690	3,307
Summer	6	4,210	6/18/2015	3,006	2,615	2,477	2,418	2,407	2,515	2,703	3,146	3,414	3,645	3,871	3,960	3,916	4,060	4,078	4,210	4,147	4,066	3,885	3,833	3,852	3,815	3,555	3,212
Summer	6	4,828	6/19/2015	2,958	2,760	2,622	2,571	2,605	2,713	2,955	3,432	3,698	3,958	4,199	4,404	4,585	4,716	4,800	4,828	4,821	4,803	4,772	4,566	4,322	4,341	4,092	3,688
Summer	6	3,627	6/20/2015	3,272	3,019	2,792	2,670	2,589	2,559	2,632	2,686	3,034	3,194	3,475	3,580	3,596	3,627	3,596	3,506	3,339	3,427	3,421	3,424	3,423	3,478	3,299	3,102
Summer	6	4,625	6/21/2015	2,856	2,687	2,661	2,521	2,502	2,517	2,547	2,656	2,921	3,236	3,433	3,635	3,800	3,944	4,083	4,221	4,365	4,537	4,625	4,466	4,318	4,330	4,133	3,715
Summer	6	5,324	6/22/2015	3,344	3,126	2,938	2,861	2,833	2,912	3,219	3,573	3,987	4,290	4,555	4,769	4,883	5,059	5,098	5,221	5,264	5,324	5,264	5,215	4,942	4,888	4,498	3,976
Summer	6	5,776	6/23/2015	3,469	3,239	3,028	2,903	2,922	2,946	3,173	3,610	4,132	4,469	4,830	5,039	5,198	5,425	5,561	5,776	5,684	5,235	5,113	4,981	4,824	4,727	4,457	3,953
Summer	6	4,996	6/24/2015	3,566	3,198	2,994	2,872	2,840	2,843	3,002	3,381	3,867	4,106	4,331	4,493	4,596	4,695	4,796	4,887	4,976	4,996	4,968	4,748	4,563	4,508	4,181	3,730
Summer	6	4,737	6/25/2015	3,283	3,076	2,818	2,696	2,669	2,683	2,895	3,336	3,678	3,884	4,105	4,336	4,463	4,568	4,690	4,737	4,733	4,674	4,602	4,414	4,369	4,325	4,064	3,692
Summer	6	4,575	6/26/2015	3,314	3,074	2,955	2,848	2,818	2,868	3,090	3,484	3,784	3,926	4,127	4,243	4,266	4,378	4,466	4,551	4,575	4,550	4,459	4,272	4,109	4,068	3,831	3,511
Summer	6	3,614	6/27/2015	3,116	2,911	2,736	2,653	2,565	2,578	2,594	2,769	3,063	3,298	3,493	3,555	3,614	3,531	3,495	3,415	3,374	3,398	3,386	3,370	3,354	3,353	3,176	2,909
Summer	6	3,375	6/28/2015	2,640	2,547	2,489	2,398	2,352	2,358	2,383	2,507	2,701	2,965	3,135	3,244	3,293	3,323	3,342	3,264	3,289	3,351	3,375	3,299	3,340	3,365	3,219	2,887
Summer	6	4,095	6/29/2015	2,676	2,542	2,433	2,425	2,397	2,509	2,740	3,076	3,445	3,648	3,756	3,903	3,986	4,032	4,080	4,075	4,067	4,095	4,095	4,057	3,926	3,947	3,687	3,322
Summer	6	4,678	6/30/2015	2,976	2,738	2,678	2,578	2,560	2,661	2,866	3,267	3,583	3,839	4,117	4,322	4,428	4,467	4,598	4,678	4,643	4,609	4,529	4,358	4,259	4,248	3,984	3,632
Summer	7	4,973	7/1/2015	3,291	3,148	2,961	2,900	2,900	3,007	3,276	3,613	3,906	4,003	4,300	4,505	4,623	4,767	4,862	4,931	4,967	4,973	4,922	4,739	4,540	4,503	4,250	3,771
Summer	7	4,596	7/2/2015	3,420	3,121	2,882	2,779	2,714	2,695	2,917	3,312	3,715	3,997	4,169	4,374	4,482	4,569	4,596	4,580	4,492	4,466	4,405	4,215	4,089	4,083	3,872	3,554
Summer	7	4,240	7/3/2015	3,182	2,956	2,751	2,620	2,577	2,573	2,617	2,809	3,071	3,391	3,585	3,686	3,838	3,923	3,974	4,144	4,172	4,240	4,202	4,010	3,823	3,818	3,584	3,379
Summer	7	3,567	7/4/2015	3,064	2,849	2,683	2,573	2,516	2,518	2,552	2,556	2,849	3,104	3,313	3,490	3,532	3,567	3,509	3,466	3,430	3,462	3,498	3,402	3,343	3,405	3,263	3,155
Summer	7	4,399	7/5/2015	2,866	2,705	2,535	2,456	2,441	2,419	2,357	2,525	2,776	3,042	3,350	3,581	3,761	3,868	3,962	4,082	4,216	4,326	4,399	4,289	4,202	4,203	3,997	3,673
Summer	7	5,099	7/6/2015	3,293	3,060	2,876	2,853	2,732	2,819	3,001	3,382	3,742	4,037	4,336	4,631	4,817	4,984	5,046	5,058	5,099	5,083	5,038	4,869	4,677	4,649	4,258	3,874
Summer	7	5,397	7/7/2015	3,493	3,270	3,087	3,021	3,005	3,112	3,363	3,725	4,163	4,381	4,635	4,823	5,028	5,144	5,185	5,349	5,397	5,339	5,263	5,142	5,005	4,909	4,529	4,071
Summer	7	5,504	7/8/2015	3,732	3,409	3,249	3,121	3,084	3,190	3,415	3,893	4,163	4,440	4,561	4,815	5,114	5,323	5,439	5,504	5,496	5,411	5,411	5,307	5,072	5,040	4,701	4,166
Summer	7	4,488	7/9/2015	3,800	3,440	3,219	3,097	3,049	3,099	3,257	3,624	3,925	4,128	4,168	4,316	4,367	4,393	4,480	4,488	4,419	4,433	4,398	4,295	4,256	4,246	3,943	3,599
Summer	7	4,952	7/10/2015	3,258	3,044	2,965	2,877	2,857	2,927	3,132	3,544	3,912	4,077	4,326	4,470	4,576	4,732	4,774	4,867	4,893	4,952	4,880	4,633	4,427	4,391	4,120	3,741
Summer	7	4,802	7/11/2015	3,334	3,075	2,954	2,787	2,698	2,698	2,655	2,905	3,220	3,574	3,950	4,171	4,311	4,527	4,553	4,657	4,714	4,757	4,802	4,610	4,395	4,361	4,103	3,764
Summer	7	5,044	7/12/2015	3,395	3,156	2,967	2,831	2,763	2,689	2,620	2,851	3,089	3,438	3,792	4,113	4,400	4,559	4,720	4,802	4,909	4,930	5,044	4,806	4,740	4,701	4,437	4,013
Summer	7	5,530	7/13/2015	3,605	3,346	3,228	3,046	3,001	3,092	3,300	3,695	4,089	4,338	4,651	4,909	5,158	5,350	5,467	5,530	5,526	5,529	5,492	5,229	4,957	4,808	4,423	3,937
Summer	7	5,175	7/14/2015	3,505	3,365	3,152	3,107	3,068	3,170	3,287	3,786	4,187	4,412	4,692	4,847	4,988	4,990	5,175	5,125	5,008	4,872	4,886	4,824	4,737	4,634	4,397	4,012
Summer	7	5,283	7/15/2015	3,649	3,429	3,289	3,190	3,168	3,233	3,532	3,975	4,303	4,508	4,769	4,940	5,157	5,283	5,269	5,200	5,098	5,094	5,037	4,794	4,605	4,433	4,128	3,688
Summer	7	4,474	7/16/2015	3,293	3,030	2,831	2,723	2,662	2,766	2,887	3,285	3,588	3,752	3,863	4,041	4,125	4,211	4,238	4,412	4,423	4,474	4,455	4,286	4,098	4,101	3,814	3,472
Summer	7	4,613	7/17/2015	3,061	2,840	2,652	2,570	2,549	2,628	2,845	3,226	3,552	3,720	3,916	4,129	4,302	4,403	4,498	4,570	4,599	4,613	4,520	4,256	4,120	4,092	3,867	3,553
Summer	7	4,615	7/18/2015	3,265	2,988	2,904	2,803	2,784	2,794	2,823	2,989	3,285	3,587	3,758	3,946	3,994	4,036	4,120	4,264	4,444	4,567	4,615	4,518	4,388	4,432	4,224	3,927
Summer	7	5,754	7/19/2015	3,625	3,390	3,243	3,124	3,065	3,038	3,003	3,167	3,595	3,955	4,385	4,775	5,101	5,341	5,422	5,560	5,610	5,754	5,683	5,517	5,383	5,412	5,086	4,605
Summer	7	6,419	7/20/2015	4,219	3,992	3,825	3,701	3,651	3,721	3,958	4,385	4,969	5,315	5,651	5,962	6,184	6,220	6,332	6,397	6,419	6,394	6,306	6,122	5,955	5,844	5,389	4,809
Summer	7	5,975	7/21/2015	4,307	3,930	3,693	3,543	3,467	3,499	3,645	4,109	4,346	4,538	4,768	4,990	5,189	5,380	5,648	5,865	5,975	5,971	5,852	5,636	5,293	5,085	4,782	4,241
Summer	7	5,042	7/22/2015	3,745	3,445	3,233	3,055	2,965	2,998	3,156	3,568	3,988	4,138	4,379	4,595	4,613	4,827	4,901	4,990	5,027	5,042	4,983	4,807	4,511	4,465	4,098	3,697
Summer	7	4,918	7/23/2015	3,271	3,021	2,892	2,710	2,694	2,787	2,958	3,316	3,676	3,978	4,178	4,382	4,462	4,597	4,707	4,782	4,886	4,918	4,857	4,707	4,476	4,458	4,082	3,685
Summer	7	4,827	7/24/2015	3,331	3,039	2,864	2,751	2,757	2,780	2,916	3,283	3,682	3,901	4,153	4,346	4,448	4,606	4,602	4,783	4,794	4,827	4,754	4,510	4,258	4,283	4,149	3,677
Summer	7	4,479	7/25/2015	3,324	3,048	2,878	2,769	2,681	2,701	2,669	2,905	3,211	3,546	3,804	4,021	4,149	4,266	4,354	4,414	4,466	4,479	4,429	4,229	4,096	4,115	3,954	3,667
Summer	7	4,563	7/26/2015	3,414	3,135	3,008	2,878	2,834	2,824	2,870	2,847	3,140	3,418	3,691	3,891	4,078	4,278	4,370	4,519	4,546	4,563	4,543	4,440	4,309	4,375	4,131	3,821
Summer	7	5,500	7/27/2015	3,479	3,318	3,155	3,059	3,039	3,172	3,342	3,732	4,005	4,300	4,444	4,609	4,775	4,914	5,071	5,319	5,439	5,500	5,498	5,257	5,074	5,035	4,620	4,187
Summer	7	4,630	7/28/2015	3,827	3,519	3,308	3,224	3,157	3,227	3,429	3,847	4,317	4,630	3,767	3,779	3,729	3,871	3,980	4,059	4,014	4,150	4,057	3,900	3,911	3,883	3,740	3,734
Summer	7	6,266	7/29/2015	3,612	3,458	3,627	3,599	3,608	3,418	3,381	3,366	3,772	4,060	4,174	4,834	5,057	5,982	6,153	6,239	6,266	6,198	6,188	5,988	5,746	5,668	5,239	4,655
Summer	7	5,829	7/30/2015	4,109	3,868	3,666	3,551	3,497	3,569	3,734	4,165	4,598	4,872	5,159	5,341	5,489	5,656	5,829	5,761	5,649	5,447	5,251	5,074	4,820	4,857	4,654	4,193
Summer	7	5,726	7/31/2015	3,703	3,568	3,388	3,244	3,172	3,181	3,363	3,747	4,139	4,564	4,728	4,974	5,168	5,409	5,543	5,640	5,690	5,726	5,584	5,334	4,995	4,802	4,385	4,075
Summer	8	4,984	8/1/2015	3,575	3,334	3,173	3,034	2,970	2,970	2,982	3,150	3,527	3,883	4,265	4,509	4,715	4,857	4,908	4,943	4,984	4,926	4,862	4,712	4,494	4,499	4,213	3,861
Summer	8	4,947	8/2/2015	3,477	3,187	3,031	2,876	2,789	2,734	2,705	2,801	3,165	3,467	3,766	4,049	4,274	4,430	4,557	4,696	4,820	4,947	4,916	4,739	4,633	4,615	4,354	3,898
Summer	8	5,844	8/3/2015	3,582	3,349	3,212	3,091	3,014	3,142	3,331	3,774	4,204	4,569	4,788	5,024	5,280	5,486	5,661	5,750	5,841	5,844	5,741	5,524	5,345	5,361	4,964	4,446
Summer	8	5,925	8/4/2015	4,013	3,729	3,550	3,451	3,410	3,472	3,669	4,007	4,281	4,545	4,873	5,217	5,429	5,642	5,776	5,860	5,925	5,898	5,791	5,590	5,297	5,183	4,712	4,211
Summer	8	5,243	8/5/2015	3,729	3,450	3,236	3,079	3,057	3,004	3,204	3,580	3,975	4,232	4,475	4,600	4,845	5,051	5,165	5,243	5,184	5,165	5,072	4,833	4,555	4,601	4,235	3,762
Summer	8	4,616	8/6/2015	3,372	3,079	2,919	2,821	2,763	2,850	2,951	3,338	3,681	3,930	4,205	4,326	4,369	4,509	4,577	4,616	4,578	4,581	4,524	4,351	4,311	4,268	3,960	3,614
Summer	8	4,748	8/7/2015	3,241	3,026	2,883	2,781	2,727	2,795	2,937	3,307	3,646	3,899	4,119	4,305	4,420	4,528	4,635	4,705	4,748	4,729	4,673	4,455	4,316	4,216	3,947	3,571
Summer	8	4,134	8/8/2015	3,186	3,036	2,848	2,728	2,679	2,664	2,672	2,826	3,084	3,405	3,658	3,815	3,952	3,995	4,044	4,064	4,112	4,134	4,071	3,949	3,917	3,948	3,701	3,422
Summer	8	4,192	8/9/2015	3,144	2,911	2,775	2,654	2,599	2,593	2,563	2,651	2,921	3,233	3,463	3,634	3,776	3,910	4,019	4,065	4,121	4,147	4,192	4,074	3,984	4,074	3,750	3,458
Summer	8	4,898	8/10/2015	3,148	2,933	2,810	2,691	2,703	2,813	3,026	3,369	3,749	3,942	4,138	4,445	4,649	4,725	4,830	4,898	4,898	4,834	4,742	4,525	4,443	4,416	4,134	3,770
Summer	8	4,518	8/11/2015	3,396	3,203	3,079	3,010	2,989	3,101	3,398	3,750	4,008	4,204	4,338	4,433	4,448	4,504	4,487	4,407	4,426	4,470	4,518	4,400	4,403	4,348	4,052	3,655
Summer	8	4,997	8/12/2015	3,355	3,159	3,050	2,898	2,868	2,931	3,150	3,474	3,837	4,077	4,323	4,530	4,633	4,782	4,891	4,958	4,997	4,994	4,960	4,735	4,587	4,523	4,203	3,726

Contains Proprietary Material
Do Not Distribute

Summer	8	4,880	8/13/2015	3,395	3,100	2,996	2,841	2,798	2,853	3,031	3,340	3,717	3,959	4,190	4,315	4,474	4,631	4,726	4,806	4,850	4,880	4,755	4,619	4,435	4,335	4,026	3,669
Summer	8	5,210	8/14/2015	3,147	3,073	2,879	2,779	2,683	2,727	2,957	3,247	3,598	3,894	4,187	4,367	4,561	4,705	4,859	5,033	5,110	5,210	5,003	4,789	4,634	4,564	4,214	3,841
Summer	8	5,319	8/15/2015	3,505	3,225	3,054	2,924	2,859	2,857	2,825	2,999	3,338	3,725	4,092	4,415	4,692	4,846	5,034	5,178	5,262	5,319	5,217	5,012	4,875	4,770	4,477	4,056
Summer	8	5,402	8/16/2015	3,715	3,447	3,260	3,137	3,058	3,025	3,030	2,997	3,376	3,703	4,121	4,501	4,789	5,007	5,162	5,236	5,325	5,390	5,402	5,217	5,112	5,055	4,726	4,245
Summer	8	6,237	8/17/2015	3,856	3,650	3,369	3,283	3,217	3,278	3,497	3,824	4,263	4,712	5,023	5,449	5,661	5,995	6,064	6,160	6,169	6,237	6,155	5,947	5,776	5,617	5,034	4,596
Summer	8	6,200	8/18/2015	4,118	3,814	3,631	3,477	3,367	3,467	3,695	4,012	4,479	4,771	5,150	5,514	5,765	6,030	6,089	6,200	6,097	6,046	5,932	5,643	5,545	5,358	4,879	4,398
Summer	8	6,027	8/19/2015	3,973	3,749	3,656	3,504	3,439	3,506	3,770	4,040	4,481	4,778	5,119	5,428	5,603	5,777	5,933	5,962	6,009	6,027	5,845	5,541	5,389	5,294	4,858	4,407
Summer	8	5,849	8/20/2015	4,002	3,748	3,567	3,473	3,441	3,512	3,791	4,089	4,525	4,896	5,125	5,383	5,396	5,684	5,823	5,849	5,788	5,763	5,570	5,368	5,363	5,115	4,726	4,313
Summer	8	4,996	8/21/2015	3,952	3,710	3,533	3,455	3,430	3,550	3,799	4,075	4,386	4,565	4,624	4,717	4,799	4,812	4,867	4,929	4,983	4,996	4,978	4,753	4,701	4,488	4,284	3,925
Summer	8	4,614	8/22/2015	3,570	3,311	3,084	2,955	2,847	2,771	2,869	2,931	3,223	3,490	3,785	3,972	4,145	4,287	4,420	4,514	4,573	4,614	4,544	4,404	4,337	4,248	3,968	3,652
Summer	8	4,658	8/23/2015	3,345	3,104	3,034	2,867	2,828	2,780	2,791	2,874	3,068	3,272	3,591	3,877	4,062	4,225	4,336	4,439	4,531	4,618	4,658	4,523	4,580	4,500	4,222	3,879
Summer	8	5,635	8/24/2015	3,507	3,328	3,182	3,136	3,113	3,187	3,483	3,850	4,206	4,508	4,718	5,000	5,186	5,391	5,520	5,594	5,635	5,626	5,564	5,288	5,241	5,014	4,557	4,154
Summer	8	5,800	8/25/2015	3,786	3,565	3,256	3,210	3,202	3,312	3,591	3,980	4,290	4,554	4,827	5,111	5,248	5,462	5,617	5,789	5,776	5,800	5,642	5,432	5,338	5,148	4,660	4,142
Summer	8	4,916	8/26/2015	3,770	3,530	3,291	3,108	2,956	2,994	3,331	3,586	3,886	4,088	4,269	4,470	4,653	4,787	4,807	4,878	4,883	4,916	4,840	4,581	4,530	4,236	3,978	3,618
Summer	8	4,482	8/27/2015	3,180	2,921	2,800	2,726	2,696	2,769	2,948	3,341	3,586	3,854	3,996	4,222	4,318	4,385	4,429	4,469	4,469	4,465	4,482	4,274	4,294	4,184	3,760	3,460
Summer	8	4,474	8/28/2015	3,136	2,844	2,702	2,637	2,612	2,679	2,942	3,274	3,549	3,806	3,946	4,110	4,202	4,269	4,339	4,474	4,429	4,459	4,363	4,145	4,141	3,978	3,713	3,405
Summer	8	4,211	8/29/2015	3,033	2,790	2,688	2,579	2,538	2,485	2,589	2,690	2,954	3,278	3,498	3,785	3,834	3,899	4,026	4,077	4,145	4,211	4,175	4,076	4,114	3,991	3,745	3,477
Summer	8	4,956	8/30/2015	3,187	3,012	2,832	2,758	2,692	2,667	2,695	2,645	2,994	3,361	3,726	4,041	4,278	4,516	4,567	4,718	4,825	4,888	4,883	4,853	4,956	4,784	4,376	3,984
Summer	8	5,874	8/31/2015	3,673	3,371	3,232	3,144	3,124	3,209	3,549	3,888	4,276	4,468	4,756	5,036	5,275	5,501	5,632	5,762	5,753	5,874	5,868	5,686	5,628	5,327	4,849	4,283
Fall	9	5,728	9/1/2015	3,855	3,655	3,407	3,268	3,209	3,280	3,586	3,832	4,203	4,470	4,736	5,055	5,191	5,286	5,552	5,666	5,622	5,728	5,616	5,393	5,340	5,058	4,528	4,020
Fall	9	5,966	9/2/2015	3,627	3,360	3,159	3,077	3,038	3,062	3,408	3,703	4,113	4,352	4,676	4,906	5,255	5,480	5,667	5,798	5,920	5,966	5,864	5,571	5,516	5,236	4,689	4,195
Fall	9	5,969	9/3/2015	3,710	3,446	3,298	3,182	3,097	3,181	3,447	3,816	4,162	4,415	4,700	5,068	5,265	5,601	5,809	5,904	5,968	5,969	5,779	5,605	5,637	5,360	4,820	4,342
Fall	9	5,232	9/4/2015	4,003	3,636	3,468	3,357	3,307	3,385	3,730	4,060	4,341	4,515	4,651	4,780	4,921	5,021	5,157	5,208	5,232	5,188	5,024	4,707	4,731	4,499	4,137	3,718
Fall	9	4,194	9/5/2015	3,358	3,093	2,929	2,808	2,696	2,656	2,732	2,781	2,974	3,357	3,494	3,698	3,755	3,894	3,957	4,032	4,148	4,194	4,111	3,978	4,000	3,824	3,528	3,313
Fall	9	4,308	9/6/2015	3,005	2,781	2,629	2,577	2,491	2,480	2,497	2,557	2,763	3,070	3,272	3,535	3,736	3,878	4,015	4,150	4,263	4,308	4,279	4,042	4,059	3,915	3,626	3,395
Fall	9	5,221	9/7/2015	3,137	2,937	2,720	2,595	2,589	2,637	2,711	2,736	2,989	3,310	3,670	3,999	4,302	4,550	4,741	4,954	5,110	5,221	5,174	4,984	5,097	4,866	4,468	4,042
Fall	9	6,332	9/8/2015	3,652	3,387	3,281	3,183	3,162	3,262	3,597	3,997	4,299	4,648	4,997	5,394	5,717	5,999	6,292	6,203	6,328	6,332	6,229	5,997	6,048	5,571	5,076	4,526
Fall	9	6,195	9/9/2015	4,120	3,789	3,603	3,483	3,414	3,511	3,799	4,144	4,478	4,719	5,064	5,399	5,587	5,840	6,040	6,156	6,195	6,174	5,973	5,695	5,730	5,440	4,973	4,475
Fall	9	4,735	9/10/2015	4,052	3,750	3,633	3,494	3,417	3,448	3,828	4,202	4,442	4,515	4,553	4,735	4,677	4,723	4,710	4,631	4,621	4,625	4,610	4,565	4,529	4,300	3,892	3,551
Fall	9	4,409	9/11/2015	3,240	2,977	2,880	2,782	2,767	2,850	3,155	3,467	3,726	3,855	3,981	4,048	4,060	4,121	4,205	4,283	4,320	4,409	4,310	4,200	4,191	4,002	3,774	3,359
Fall	9	3,916	9/12/2015	2,929	2,823	2,749	2,636	2,600	2,568	2,662	2,743	3,084	3,298	3,538	3,739	3,814	3,913	3,912	3,916	3,832	3,798	3,838	3,879	3,892	3,751	3,540	3,276
Fall	9	4,032	9/13/2015	3,116	2,815	2,690	2,604	2,548	2,570	2,591	2,686	2,898	3,189	3,369	3,549	3,668	3,779	3,852	3,908	3,973	4,002	4,008	4,032	3,934	3,780	3,399	3,065
Fall	9	3,909	9/14/2015	2,804	2,600	2,491	2,432	2,442	2,511	2,820	3,127	3,279	3,513	3,577	3,733	3,746	3,822	3,816	3,825	3,805	3,857	3,829	3,776	3,909	3,663	3,274	3,027
Fall	9	4,319	9/15/2015	2,690	2,574	2,470	2,417	2,406	2,534	2,855	3,088	3,456	3,533	3,680	3,841	3,921	4,002	4,174	4,188	4,279	4,319	4,316	4,234	4,260	3,979	3,579	3,312
Fall	9	4,696	9/16/2015	2,854	2,744	2,588	2,533	2,520	2,584	3,027	3,283	3,512	3,709	3,913	4,074	4,174	4,356	4,525	4,601	4,696	4,687	4,694	4,465	4,533	4,181	3,869	3,441
Fall	9	4,955	9/17/2015	3,067	2,919	2,800	2,657	2,601	2,732	3,019	3,362	3,630	3,796	3,996	4,259	4,401	4,604	4,731	4,880	4,955	4,942	4,874	4,656	4,645	4,375	3,956	3,505
Fall	9	4,799	9/18/2015	3,193	2,980	2,813	2,634	2,651	2,775	3,061	3,336	3,575	3,771	4,023	4,243	4,386	4,557	4,686	4,766	4,799	4,792	4,657	4,392	4,425	4,066	3,844	3,506
Fall	9	4,151	9/19/2015	3,132	2,874	2,705	2,603	2,561	2,605	2,706	2,809	3,041	3,417	3,588	3,720	3,886	4,017	4,086	4,150	4,151	4,129	4,024	4,016	4,044	3,923	3,715	3,462
Fall	9	3,756	9/20/2015	3,207	2,991	2,891	2,813	2,731	2,751	2,785	2,757	2,909	3,120	3,200	3,365	3,519	3,547	3,581	3,648	3,654	3,735	3,724	3,705	3,756	3,506	3,145	2,972
Fall	9	3,790	9/21/2015	2,515	2,452	2,411	2,313	2,320	2,470	2,768	3,132	3,318	3,417	3,520	3,579	3,620	3,689	3,719	3,787	3,726	3,772	3,725	3,790	3,779	3,562	3,217	2,851
Fall	9	3,787	9/22/2015	2,530	2,475	2,397	2,318	2,351	2,487	2,778	3,209	3,339	3,435	3,561	3,639	3,642	3,711	3,730	3,711	3,705	3,733	3,727	3,786	3,787	3,551	3,254	2,956
Fall	9	3,943	9/23/2015	2,633	2,500	2,411	2,362	2,342	2,464	2,768	3,031	3,302	3,405	3,507	3,657	3,651	3,807	3,818	3,834	3,880	3,943	3,907	3,912	3,876	3,643	3,372	2,983
Fall	9	4,058	9/24/2015	2,656	2,491	2,409	2,356	2,348	2,459	2,757	3,152	3,316	3,475	3,611	3,727	3,806	3,895	3,959	4,058	4,049	4,052	4,043	4,019	4,053	3,802	3,472	3,110
Fall	9	3,747	9/25/2015	2,771	2,583	2,493	2,435	2,412	2,498	2,830	3,152	3,359	3,494	3,575	3,653	3,651	3,733	3,747	3,708	3,714	3,712	3,626	3,703	3,656	3,463	3,264	2,959
Fall	9	3,290	9/26/2015	2,602	2,415	2,339	2,298	2,339	2,278	2,519	2,511	2,692	3,023	3,071	3,107	3,174	3,181	3,150	3,131	3,116	3,143	3,189	3,290	3,283	3,182	2,955	2,746
Fall	9	3,473	9/27/2015	2,433	2,361	2,320	2,186	2,182	2,182	2,250	2,337	2,548	2,757	2,884	2,986	3,020	3,041	3,068	3,100	3,131	3,277	3,327	3,473	3,473	3,301	3,016	2,764
Fall	9	4,178	9/28/2015	2,476	2,349	2,356	2,233	2,251	2,427	2,781	3,095	3,340	3,436	3,561	3,734	3,790	3,878	3,923	3,946	3,987	4,023	4,010	4,178	4,075	3,877	3,493	3,163
Fall	9	4,604	9/29/2015	2,852	2,661	2,571	2,532	2,510	2,643	3,051	3,473	3,775	3,865	4,036	4,189	4,304	4,445	4,518	4,535	4,542	4,539	4,505	4,604	4,481	4,239	3,911	3,539
Fall	9	4,553	9/30/2015	3,218	3,003	2,964	2,899	2,919	3,037	3,419	3,837	4,159	4,301	4,475	4,553	4,491	4,415	4,276	4,192	4,068	4,109	4,048	4,174	4,044	3,803	3,414	3,072
Fall	10	3,767	10/1/2015	2,681	2,531	2,452	2,377	2,377	2,474	2,808	3,212	3,383	3,386	3,445	3,524	3,516	3,532	3,522	3,500	3,452	3,544	3,595	3,767	3,680	3,506	3,184	2,825
Fall	10	3,638	10/2/2015	2,518	2,408	2,338	2,286	2,303	2,375	2,711	3,083	3,345	3,392	3,475	3,508	3,506	3,512	3,475	3,452	3,444	3,499	3,618	3,638	3,549	3,409	3,197	2,885
Fall	10	3,509	10/3/2015	2,605	2,470	2,376	2,328	2,357	2,424	2,527	2,667	2,960	3,172	3,349	3,402	3,396	3,384	3,328	3,283	3,263	3,267	3,389	3,509	3,414	3,291	3,084	2,844
Fall	10	3,565	10/4/2015	2,723	2,339	2,261	2,246	2,193	2,148	2,262	2,379	2,653	2,896	3,014	2,988	3,117	3,022	2,975	2,944	3,028	3,130	3,259	3,565	3,461	3,283	3,000	2,721
Fall	10	3,672	10/5/2015	2,561	2,266	2,162	2,175	2,215	2,324	2,682	3,121	3,281	3,352	3,413	3,372	3,354	3,338	3,380	3,355	3,310	3,382	3,468	3,672	3,657	3,392	3,143	2,744
Fall	10	3,689	10/6/2015	2,532	2,306	2,274	2,226	2,270	2,358	2,724	3,109	3,268	3,307	3,332	3,387	3,359	3,375	3,409	3,401	3,399	3,471	3,544	3,689	3,574	3,366	3,126	2,751
Fall	10	3,691	10/7/2015	2,402	2,312	2,239	2,192	2,197	2,296	2,671	3,149	3,225	3,307	3,326	3,372	3,380	3,421	3,474	3,452	3,460	3,514	3,520	3,691	3,574	3,374	3,056	2,683
Fall	10	3,596	10/8/2015	2,508	2,304	2,206	2,178	2,202	2,303	2,673	3,131	3,246	3,293	3,332	3,382	3,355	3,398	3,424	3,373	3,410	3,421	3,436	3,596	3,584	3,399	3,050	2,699
Fall	10	3,642	10/9/2015	2,434	2,296	2,242	2,190	2,209	2,317	2,683	3,064	3,251	3,360	3,472	3,520	3,495	3,525	3,552	3,502	3,468	3,570	3,633	3,642	3,504	3,325	3,057	2,812
Fall	10	3,186	10/10/2015	2,527	2,382	2,236	2,156	2,137	2,148	2,293	2,465	2,652	2,899	2,963	2,939	2,907	2,862	2,833	2,890	2,905	2,958	3,010	3,186	3,114	3,003	2,834	2,628
Fall	10	3,260	10/11/2015	2,420	2,293	2,238	2,133	2,073	2,155	2,226	2,342	2,522	2,757	2,840	2,876	2,858	2,849	2,804	2,837	2,890	3,037	3,084	3,260	3,207	3,055	2,835	2,602
Fall	10	3,745	10/12/2015	2,407	2,346	2,272	2,226	2,236	2,249	2,532	2,821	3,076	3,207	3,249	3,378	3,336	3,381	3,399	3,419	3,496	3,404	3,504	3,737	3,745	3,492	3,160	2,910
Fall	10	3,852	10/13/2015	2,521	2,392	2,329	2,293	2,285	2,415	2,817	3,226	3,374	3,443	3,556	3,602	3,615	3,677	3,669	3,683	3,642	3,681	3,730	3,852	3,753	3,567	3,206	2,894
Fall	10	3,670	10/14/2015	2,639	2,452	2,347	2,348	2,305	2,432	2,715	3,148	3,143	3,228	3,456	3,481	3,459	3,493	3,483	3,512	3,371	3,482	3,512	3,670	3,642	3,453	3,068	2,807
Fall	10	3,707	10/15/2015	2,541	2,376	2,263	2,284	2,357	2,403	2,819	3,273	3,363	3,390	3,406	3,420	3,383	3,406	3,371	3,353	3,381	3,430	3,507	3,707	3,628	3,499	3,161	2,827
Fall	10	3,560	10/16/2015	2,557	2,430	2,348	2,303	2,296	2,437	2,782	3,220	3,388	3,392	3,416	3,425	3,439	3,415	3,374	3,367	3,340	3,379	3,439	3,560	3,487	3,311	3,010	2,855
Fall	10	3,409	10/17/2015	2,587	2,431	2,365	2,316	2,246	2,363	2,492	2,651	2,868	3,047	3,133	3,124	3,106	3,076	3,000	2,974	3,002	3,102	3,179	3,409	3,365	3,264	3,105	2,901
Fall	10	3,765	10/18/2015	2,691	2,502	2,412	2,410	2,386	2,438	2,552	2,655	2,850	3,086	3,156	3,129	3,202	3,204	3,165	3,142	3,166	3,369	3,507	3,765	3,689	3,565	3,257	2,945
Fall	10	3,990	10/19/2015	2,767	2,642	2,593	2,531	2,609	2,807	3,174	3,691	3,845	3,814	3,779	3,746	3,642	3,612	3,542	3,513	3,530	3,628	3,750	3,990	3,934	3,750	3,350	3,020
Fall	10	3,794	10/20/2015	2,686	2,646	2,494	2,445	2,524	2,533	2,998	3,396	3,527	3,511	3,516	3,524	3,476	3,451	3,447	3,436	3,436	3,480	3,643	3,794	3,672	3,558	3,160	2,858
Fall	10	3,790	10/21/2015	2,635	2,349	2,244	2,214	2,193	2,325	2,717	3,127	3,283	3,433	3,371	3,432	3,428	3,474	3,541	3,466	3,400	3,478	3,593	3,790	3,714	3,487	3,035	2,898
Fall	10	3,776	10/22/2015	2,544	2,440	2,278	2,295	2,298	2,414	2,878	3,183	3,375	3,413	3,472	3,548	3,493	3,536	3,590	3,489	3,591	3,481	3,719	3,776	3,669	3,499	3,189	2,815
Fall	10	3,582	10/23/2015	2,565	2,409	2,253	2,261	2,244	2,430	2,720	3,213	3,326	3,403	3,415	3,385	3,352	3,361	3,295	3,299	3,272	3,321	3,476	3,582	3,572	3,396	3,210	2,970
Fall	10	3,457	10/24/2015	2,700	2,547	2,454	2,431	2,446	2,507	2,650	2,847	3,085	3,271	3,276	3,250	3,213	3,163	3,133	3,078	3,103	3,200	3,311	3,457	3,337	3,219	3,052	2,736
Fall	10	3,500	10/25/2015	2,571	2,344	2,263	2,195	2,160	2,179	2,261	2,340	2,614	2,829	3,018	3,019	3,113	3,098	2,990	2,967	3,015	3,091	3,305	3,500	3,424	3,214	2,793	2,573
Fall	10	3,808	10/26/2015	2,342	2,259	2,228	2,186	2,221	2,353	2,796	3,283	3,453	3,448	3,484	3,415	3,326	3,309	3,267	3,267	3,368	3,460	3,663	3,808	3,721	3,578	3,246	2,850
Fall	10	3,798	10/27/2015	2,587	2,410	2,459	2,389	2,397	2,554	3,013	3,455	3,484	3,546	3,497	3,434	3,376	3,338	3,294	3,296	3,328	3,429	3,656	3,798	3,713	3,515	3,096	2,792
Fall	10	3,849	10/28/2015	2,648	2,474	2,358	2,310	2,314	2,452	2,830	3,333	3,398	3,465	3,511	3,525	3,531	3,555	3,555	3,541	3,555	3,653	3,849	3,824	3,702	3,495	3,212	2,785
Fall	10	3,596	10/29/2015	2,546	2,427	2,358	2,289	2,312	2,390	2,688	3,201	3,361	3,403	3,467	3,470	3,461	3,445	3,431	3,343	3,300	3,284	3,416	3,596	3,565	3,286	3,024	2,653
Fall	10	3,464	10/30/2015	2,501	2,262	2,168	2,220	2,143	2,268	2,656	3,147	3,275	3,246	3,251	3,296	3,243	3,228	3,172	3,127	3,127	3,206	3,387	3,464	3,371	3,267	3,051	2,840
Fall	10	3,204	10/31/2015	2,544	2,383	2,308	2,300	2,282	2,339	2,481	2,703	2,920	3,083	3,137	3,096	3,052	3,011	2,931	2,905	2,953	3,049	3,204	3,160	3,095	3,028	2,906	2,677
Fall	11	3,513	11/1/2015	2,487	2,323	2,187	2,147	2,101	2,222	2,298	2,395	2,710	2,973	3,007	3,091	3,061	3,054	2,994	2,973	3,028	3,316	3,513	3,405	3,279	3,074	2,831	2,513
Fall	11	3,838	11/2/2015	2,402	2,255	2,199	2,197	2,242	2,413	2,807	3,177	3,300	3,371	3,381	3,368	3,374	3,351	3,322	3,331	3,313	3,636	3,838	3,733	3,547	3,289	3,062	2,746
Fall	11	3,805	11/3/2015	2,511	2,397	2,336	2,303	2,351	2,507	2,847	3,172	3,295	3,338	3,328	3,400	3,360	3,385	3,389	3,377	3,390	3,610	3,805	3,692	3,583	3,319	3,016	2,757
Fall	11	3,844	11/4/2015	2,461	2,332	2,262	2,241	2,314	2,407	2,800	3,176	3,306	3,291	3,325	3,360	3,348	3,378	3,386	3,363	3,355	3,557	3,844	3,701	3,554	3,357	3,030	2,747
Fall	11	3,856	11/5/2015	2,463	2,295	2,260	2,233	2,274	2,404	2,746	3,173	3,365	3,370	3,413	3,481	3,382	3,473	3,478	3,460	3,481	3,735	3,856	3,741	3,630	3,375	3,068	2,748
Fall	11	3,852	11/6/2015	2,501	2,372	2,291	2,231	2,231	2,397	2,768	3,155	3,371	3,439	3,535	3,542	3,541	3,521	3,528	3,495	3,488	3,728	3,852	3,745	3,552	3,301	3,049	2,832
Fall	11	3,474	11/7/2015	2,800	2,706	2,723	2,709	2,682	2,729	2,919	3,059	3,228	3,365	2,969	3,037	3,021	2,997	2,997	2,952	3,063	3,369	3,474	3,316	3,165	2,994	2,752	2,531
Fall	11	3,542	11/8/2015	2,313	2,251	2,152	2,081	2,069	2,130	2,263	2,300	2,517	2,657	2,784	2,696	2,858	2,892	2,784	2,876	2,903	3,385	3,542	3,453	3,319	3,216	2,919	2,633

Contains Proprietary Material
Do Not Distribute

Fall	11	3,947	11/9/2015	2,574	2,514	2,451	2,433	2,439	2,523	2,663	3,130	3,194	3,183	3,394	3,379	3,431	3,408	3,351	3,291	3,303	3,741	3,947	3,779	3,578	3,471	3,135	2,777
Fall	11	3,963	11/10/2015	2,537	2,350	2,358	2,339	2,327	2,601	2,816	3,185	3,428	3,513	3,482	3,432	3,351	3,244	3,540	3,533	3,544	3,888	3,963	3,780	3,689	3,592	3,112	2,935
Fall	11	3,936	11/11/2015	2,595	2,447	2,392	2,340	2,372	2,500	2,747	3,118	3,331	3,472	3,527	3,588	3,515	3,471	3,561	3,488	3,517	3,936	3,920	3,794	3,768	3,532	3,298	3,022
Fall	11	4,046	11/12/2015	2,666	2,609	2,430	2,470	2,379	2,578	2,893	3,317	3,536	3,636	3,681	3,665	3,689	3,709	3,688	3,653	3,770	3,887	4,046	3,914	3,772	3,518	3,206	2,979
Fall	11	3,846	11/13/2015	2,654	2,497	2,452	2,375	2,412	2,508	2,870	3,179	3,369	3,471	3,417	3,412	3,510	3,412	3,435	3,395	3,383	3,715	3,846	3,747	3,576	3,426	3,237	2,949
Fall	11	3,734	11/14/2015	2,713	2,572	2,476	2,447	2,425	2,492	2,622	2,807	3,011	3,197	3,268	3,278	3,203	3,181	3,147	3,175	3,272	3,658	3,734	3,616	3,561	3,463	3,214	2,995
Fall	11	3,742	11/15/2015	2,817	2,661	2,585	2,557	2,514	2,582	2,725	2,802	2,928	3,150	3,173	3,181	3,122	3,102	3,076	3,147	3,215	3,654	3,742	3,647	3,529	3,368	3,088	2,840
Fall	11	3,972	11/16/2015	2,609	2,444	2,410	2,412	2,451	2,631	2,999	3,398	3,510	3,482	3,487	3,505	3,490	3,483	3,464	3,381	3,434	3,880	3,972	3,869	3,715	3,526	3,224	2,893
Fall	11	4,006	11/17/2015	2,677	2,561	2,596	2,508	2,577	2,749	3,044	3,590	3,530	3,555	3,541	3,512	3,465	3,447	3,438	3,456	3,438	3,886	4,006	3,970	3,918	3,690	3,435	3,189
Fall	11	4,038	11/18/2015	2,905	2,766	2,663	2,686	2,706	2,852	3,248	3,619	3,748	3,787	3,728	3,659	3,589	3,623	3,570	3,596	3,636	3,911	4,038	3,927	3,821	3,637	3,352	2,919
Fall	11	3,936	11/19/2015	2,702	2,561	2,473	2,416	2,430	2,560	2,879	3,323	3,491	3,532	3,591	3,639	3,611	3,651	3,552	3,593	3,652	3,876	3,936	3,891	3,737	3,565	3,330	2,984
Fall	11	3,748	11/20/2015	2,675	2,517	2,448	2,368	2,322	2,525	2,853	3,091	3,394	3,369	3,397	3,427	3,368	3,331	3,364	3,346	3,376	3,664	3,748	3,689	3,567	3,440	3,217	2,938
Fall	11	3,643	11/21/2015	2,745	2,599	2,507	2,421	2,499	2,555	2,704	2,843	3,056	3,306	3,311	3,116	3,074	2,997	3,013	3,038	3,136	3,495	3,643	3,607	3,471	3,355	3,105	2,942
Fall	11	3,797	11/22/2015	2,578	2,430	2,340	2,280	2,271	2,284	2,405	2,610	2,775	3,012	3,053	3,138	3,237	3,312	3,297	3,367	3,456	3,699	3,797	3,729	3,582	3,444	3,213	2,947
Fall	11	4,237	11/23/2015	2,761	2,591	2,554	2,545	2,592	2,756	3,149	3,529	3,716	3,705	3,687	3,644	3,584	3,576	3,645	3,625	3,699	4,102	4,237	4,209	4,101	3,959	3,641	3,314
Fall	11	4,213	11/24/2015	3,032	2,894	2,848	2,810	2,827	3,035	3,386	3,838	3,947	3,925	3,861	3,759	3,657	3,657	3,641	3,656	3,784	3,975	4,213	4,160	4,104	3,966	3,648	3,358
Fall	11	4,166	11/25/2015	3,062	2,820	2,887	2,756	2,793	3,101	3,378	3,789	3,878	3,893	3,784	3,846	3,720	3,781	3,711	3,647	3,669	4,084	4,166	4,054	3,940	3,722	3,492	3,263
Fall	11	3,573	11/26/2015	3,084	2,767	2,676	2,587	2,606	2,681	2,783	2,954	3,328	3,406	3,516	3,565	3,573	3,464	3,235	3,127	3,013	3,168	3,160	3,109	3,127	3,092	2,958	2,737
Fall	11	3,551	11/27/2015	2,602	2,439	2,326	2,347	2,362	2,455	2,557	2,749	2,892	3,089	3,172	3,080	3,136	3,076	3,069	3,045	3,115	3,438	3,551	3,452	3,310	3,207	3,018	2,775
Fall	11	3,637	11/28/2015	2,535	2,323	2,302	2,247	2,261	2,259	2,396	2,564	2,780	2,996	3,102	3,252	3,338	3,244	3,280	3,221	3,351	3,567	3,637	3,511	3,433	3,316	3,180	2,934
Fall	11	3,930	11/29/2015	2,690	2,559	2,474	2,505	2,342	2,467	2,549	2,726	2,903	3,103	3,143	3,276	3,185	3,092	3,131	3,197	3,314	3,853	3,930	3,862	3,787	3,581	3,406	3,130
Fall	11	4,287	11/30/2015	2,845	2,600	2,585	2,579	2,627	2,732	3,176	3,646	3,851	3,853	3,793	3,846	3,805	3,749	3,687	3,719	3,813	4,188	4,287	4,240	4,155	3,932	3,630	3,204

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
a	b	c	d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t
1001	Albany Energy LLC	Albany LFGE	F	323615	Albany	001	36	1998-05-01	5.6	4.5	5.6	5.6		IC	MTE			24.3	
1002	Astoria Energy II, LLC	Astoria Energy 2 - CC3	J	323677	Queens	081	36	2011-07-01	330.0	288.0	269.4	312.9		CC	NG	FO2		3,082.5	**(G)**
1003	Astoria Energy II, LLC	Astoria Energy 2 - CC4	J	323678	Queens	081	36	2011-07-01	330.0	288.0	269.4	312.9		CC	NG	FO2			
1004	Astoria Energy, LLC	Astoria East Energy - CC1	J	323581	Queens	081	36	2006-04-01	320.0	278.7	276.9	311.6		CC	NG	FO2		3,496.2	**(G)**
1005	Astoria Energy, LLC	Astoria East Energy - CC2	J	323582	Queens	081	36	2006-04-01	320.0	278.7	276.9	311.6		CC	NG	FO2			
1006	Astoria Generating Company L.P.	Astoria 2 (ReAct. - 12/31/14)	J	24149	Queens	081	36	1954-03-01	180.0	177.0	167.9	166.6		ST	NG			2.4	**(D) (1)**
1007	Astoria Generating Company L.P.	Astoria 3	J	23516	Queens	081	36	1958-09-01	376.0	369.9	376.0	376.4		ST	FO6	NG		188.8	
1008	Astoria Generating Company L.P.	Astoria 5	J	23518	Queens	081	36	1962-05-01	387.0	376.3	381.0	380.6		ST	FO6	NG		993.9	
1009	Astoria Generating Company L.P.	Astoria GT 01	J	23523	Queens	081	36	1967-07-01	16.0	15.7	14.7	18.0		GT	NG			0.7	
1010	Astoria Generating Company L.P.	Gowanus 1-1	J	24077	Brooklyn	047	36	1971-06-01	20.0	19.1	18.2	24.1		GT	FO2			0.1	
1011	Astoria Generating Company L.P.	Gowanus 1-2	J	24078	Brooklyn	047	36	1971-06-01	20.0	17.1	18.5	21.3		GT	FO2			0.2	
1012	Astoria Generating Company L.P.	Gowanus 1-3	J	24079	Brooklyn	047	36	1971-06-01	20.0	17.2	16.3	21.9		GT	FO2			0.2	
1013	Astoria Generating Company L.P.	Gowanus 1-4	J	24080	Brooklyn	047	36	1971-06-01	20.0	17.1	16.0	21.3		GT	FO2			0.1	
1014	Astoria Generating Company L.P.	Gowanus 1-5	J	24084	Brooklyn	047	36	1971-06-01	20.0	16.5	16.1	22.4		GT	FO2			0.2	
1015	Astoria Generating Company L.P.	Gowanus 1-6	J	24111	Brooklyn	047	36	1971-06-01	20.0	18.0	15.6	21.8		GT	FO2			0.2	
1016	Astoria Generating Company L.P.	Gowanus 1-7	J	24112	Brooklyn	047	36	1971-06-01	20.0	17.6	16.7	22.3		GT	FO2			0.2	
1017	Astoria Generating Company L.P.	Gowanus 1-8	J	24113	Brooklyn	047	36	1971-06-01	20.0	16.1	14.6	19.9		GT	FO2			0.2	
1018	Astoria Generating Company L.P.	Gowanus 2-1	J	24114	Brooklyn	047	36	1971-06-01	20.0	17.9	17.3	21.4		GT	FO2	NG		0.7	
1019	Astoria Generating Company L.P.	Gowanus 2-2	J	24115	Brooklyn	047	36	1971-06-01	20.0	18.8	18.3	22.0		GT	FO2	NG		0.6	
1020	Astoria Generating Company L.P.	Gowanus 2-3	J	24116	Brooklyn	047	36	1971-06-01	20.0	20.6	19.1	24.2		GT	FO2	NG		0.5	
1021	Astoria Generating Company L.P.	Gowanus 2-4	J	24117	Brooklyn	047	36	1971-06-01	20.0	19.3	17.4	22.2		GT	FO2	NG		0.5	
1022	Astoria Generating Company L.P.	Gowanus 2-5	J	24118	Brooklyn	047	36	1971-06-01	20.0	18.6	17.0	21.4		GT	FO2	NG		0.6	
1023	Astoria Generating Company L.P.	Gowanus 2-6	J	24119	Brooklyn	047	36	1971-06-01	20.0	20.3	19.1	23.6		GT	FO2	NG		0.7	
1024	Astoria Generating Company L.P.	Gowanus 2-7	J	24120	Brooklyn	047	36	1971-06-01	20.0	19.6	18.5	23.0		GT	FO2	NG		0.6	
1025	Astoria Generating Company L.P.	Gowanus 2-8	J	24121	Brooklyn	047	36	1971-06-01	20.0	17.7	17.0	21.5		GT	FO2	NG		0.3	
1026	Astoria Generating Company L.P.	Gowanus 3-1	J	24122	Brooklyn	047	36	1971-07-01	20.0	17.7	16.9	22.0		GT	FO2	NG		0.4	
1027	Astoria Generating Company L.P.	Gowanus 3-2	J	24123	Brooklyn	047	36	1971-07-01	20.0	17.7	16.9	21.9		GT	FO2	NG		0.4	
1028	Astoria Generating Company L.P.	Gowanus 3-3	J	24124	Brooklyn	047	36	1971-07-01	20.0	19.8	18.0	23.9		GT	FO2	NG		0.5	
1029	Astoria Generating Company L.P.	Gowanus 3-4	J	24125	Brooklyn	047	36	1971-07-01	20.0	17.9	16.3	21.7		GT	FO2	NG		0.4	
1030	Astoria Generating Company L.P.	Gowanus 3-5	J	24126	Brooklyn	047	36	1971-07-01	20.0	19.0	17.3	24.0		GT	FO2	NG		0.5	
1031	Astoria Generating Company L.P.	Gowanus 3-6	J	24127	Brooklyn	047	36	1971-07-01	20.0	17.6	15.4	20.0		GT	FO2	NG		0.8	
1032	Astoria Generating Company L.P.	Gowanus 3-7	J	24128	Brooklyn	047	36	1971-07-01	20.0	18.1	18.0	24.2		GT	FO2	NG		0.4	
1033	Astoria Generating Company L.P.	Gowanus 3-8	J	24129	Brooklyn	047	36	1971-07-01	20.0	19.0	17.6	23.8		GT	FO2	NG		0.3	
1034	Astoria Generating Company L.P.	Gowanus 4-1	J	24130	Brooklyn	047	36	1971-07-01	20.0	16.8	18.6	23.0		GT	FO2			0.2	
1035	Astoria Generating Company L.P.	Gowanus 4-2	J	24131	Brooklyn	047	36	1971-07-01	20.0	17.3	17.4	20.9		GT	FO2			0.2	
1036	Astoria Generating Company L.P.	Gowanus 4-3	J	24132	Brooklyn	047	36	1971-07-01	20.0	17.6	17.1	22.0		GT	FO2			0.2	
1037	Astoria Generating Company L.P.	Gowanus 4-4	J	24133	Brooklyn	047	36	1971-07-01	20.0	17.1	16.5	21.5		GT	FO2			0.1	
1038	Astoria Generating Company L.P.	Gowanus 4-5	J	24134	Brooklyn	047	36	1971-07-01	20.0	17.1	16.2	21.2		GT	FO2			0.2	
1039	Astoria Generating Company L.P.	Gowanus 4-6	J	24135	Brooklyn	047	36	1971-07-01	20.0	18.6	18.0	22.9		GT	FO2			0.2	
1040	Astoria Generating Company L.P.	Gowanus 4-7	J	24136	Brooklyn	047	36	1971-07-01	20.0	16.6	16.4	21.3		GT	FO2			0.1	
1041	Astoria Generating Company L.P.	Gowanus 4-8	J	24137	Brooklyn	047	36	1971-07-01	20.0	19.0	17.0	22.1		GT	FO2			0.2	
1042	Astoria Generating Company L.P.	Narrows 1-1	J	24228	Brooklyn	047	36	1972-05-01	22.0	21.0	19.2	23.6		GT	KER	NG		2.4	
1043	Astoria Generating Company L.P.	Narrows 1-2	J	24229	Brooklyn	047	36	1972-05-01	22.0	19.5	17.2	22.2		GT	KER	NG		2.0	
1044	Astoria Generating Company L.P.	Narrows 1-3	J	24230	Brooklyn	047	36	1972-05-01	22.0	20.4	18.2	23.3		GT	KER	NG		2.1	
1045	Astoria Generating Company L.P.	Narrows 1-4	J	24231	Brooklyn	047	36	1972-05-01	22.0	20.1	19.2	24.2		GT	KER	NG		1.7	
1046	Astoria Generating Company L.P.	Narrows 1-5	J	24232	Brooklyn	047	36	1972-05-01	22.0	19.8	18.5	24.5		GT	KER	NG		1.4	
1047	Astoria Generating Company L.P.	Narrows 1-6	J	24233	Brooklyn	047	36	1972-05-01	22.0	18.9	16.1	21.7		GT	KER	NG		1.4	
1048	Astoria Generating Company L.P.	Narrows 1-7	J	24234	Brooklyn	047	36	1972-05-01	22.0	18.4	16.2	21.7		GT	KER	NG		1.8	
1049	Astoria Generating Company L.P.	Narrows 1-8	J	24235	Brooklyn	047	36	1972-05-01	22.0	19.9	17.2	22.6		GT	KER	NG		1.3	
1050	Astoria Generating Company L.P.	Narrows 2-1	J	24236	Brooklyn	047	36	1972-06-01	22.0	19.4	19.0	24.0		GT	KER	NG		2.1	
1051	Astoria Generating Company L.P.	Narrows 2-2	J	24237	Brooklyn	047	36	1972-06-01	22.0	18.7	17.2	21.0		GT	KER	NG		1.4	
1052	Astoria Generating Company L.P.	Narrows 2-3	J	24238	Brooklyn	047	36	1972-06-01	22.0	18.4	18.1	22.0		GT	KER	NG		1.4	
1053	Astoria Generating Company L.P.	Narrows 2-4	J	24239	Brooklyn	047	36	1972-06-01	22.0	18.4	18.4	21.9		GT	KER	NG		1.7	
1054	Astoria Generating Company L.P.	Narrows 2-5	J	24240	Brooklyn	047	36	1972-06-01	22.0	19.9	17.9	22.8		GT	KER	NG		1.4	
1055	Astoria Generating Company L.P.	Narrows 2-6	J	24241	Brooklyn	047	36	1972-06-01	22.0	18.1	15.8	20.7		GT	KER	NG		1.3	
1056	Astoria Generating Company L.P.	Narrows 2-7	J	24242	Brooklyn	047	36	1972-06-01	22.0	20.7	18.7	23.8		GT	KER	NG		1.4	
1057	Astoria Generating Company L.P.	Narrows 2-8	J	24243	Brooklyn	047	36	1972-06-01	22.0	17.5	16.5	20.8		GT	KER	NG		1.3	
1058	Athens Generating Company, LP	Athens 1	F	23668	Athens	039	36	2004-05-01	441.0	316.6	321.2	398.2		CC	NG	FO2		1,056.8	
1059	Athens Generating Company, LP	Athens 2	F	23670	Athens	039	36	2004-05-01	441.0	315.6	315.5	398.7		CC	NG	FO2		757.8	
1060	Athens Generating Company, LP	Athens 3	F	23677	Athens	039	36	2004-05-01	441.0	312.8	313.2	389.3		CC	NG	FO2		844.7	
1061	Bayonne Energy Center, LLC	Bayonne EC CTG1	J	323682	Bayonne NJ	017	34	2012-06-01	64.0	64.0	58.9	62.9		JE	NG	KER		152.1	
1062	Bayonne Energy Center, LLC	Bayonne EC CTG2	J	323683	Bayonne NJ	017	34	2012-06-01	64.0	64.0	59.0	62.8		JE	NG	KER		182.2	
1063	Bayonne Energy Center, LLC	Bayonne EC CTG3	J	323684	Bayonne NJ	017	34	2012-06-01	64.0	64.0	56.4	62.9		JE	NG	KER		154.7	
1064	Bayonne Energy Center, LLC	Bayonne EC CTG4	J	323685	Bayonne NJ	017	34	2012-06-01	64.0	64.0	56.3	62.8		JE	NG	KER		152.2	
1065	Bayonne Energy Center, LLC	Bayonne EC CTG5	J	323686	Bayonne NJ	017	34	2012-06-01	64.0	64.0	57.0	62.8		JE	NG	KER		149.2	
1066	Bayonne Energy Center, LLC	Bayonne EC CTG6	J	323687	Bayonne NJ	017	34	2012-06-01	64.0	64.0	55.5	62.8		JE	NG	KER		180.6	
1067	Bayonne Energy Center, LLC	Bayonne EC CTG7	J	323688	Bayonne NJ	017	34	2012-06-01	64.0	64.0	57.6	62.9		JE	NG	KER		160.1	
1068	Bayonne Energy Center, LLC	Bayonne EC CTG8	J	323689	Bayonne NJ	017	34	2012-06-01	64.0	64.0	58.9	62.7		JE	NG	KER		169.3	
1069	Binghamton BOP, LLC	Binghamton (ReAct. - 12/16/	C	23790	Binghamton	007	36	2001-03-01	47.7	43.8	45.1	46.9	Yes	CC	NG	KER		0.5	**(D) (2)**
1070	Boralex Hydro Operations Inc	Fourth Branch	F	23824	Waterford	091	36	1987-12-01	3.3	3.5	3.3	3.3		HY	WAT			16.6	
1071	Boralex Hydro Operations Inc	NYS Dam	F	23527	Waterford	091	36	1990-12-01	11.4	11.3	11.4	11.4		HY	WAT			53.1	

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1072	Boralex Hydro Operations Inc	Sissonville		E	23735	Potsdam	089	36	1990-08-01	3.1	3.0	3.1	3.1		HY	WAT			14.6	
1073	Boralex Hydro Operations Inc	Warrensburg		F	23737	Warrensburg	113	36	1988-12-01	2.9	3.0	2.9	2.9		HY	WAT			11.8	
1074	Calpine Energy Services LP	Bethpage		K	23823	Hicksville	059	36	1989-09-01	83.6	54.9	50.0	56.7		CC	NG			295.2	
1075	Calpine Energy Services LP	Bethpage GT4		K	323586	Hicksville	059	36	2002-07-01	60.0	48.2	44.3	46.6		GT	NG			123.6	
1076	Calpine Energy Services LP	KIAC_JFK_GT1		J	23816	Jamaica	081	36	1995-02-01	60.6	58.7	59.9	60.4	YES	CC	NG	FO2		734.3	(G)
1077	Calpine Energy Services LP	KIAC_JFK_GT2		J	23817	Jamaica	081	36	1995-02-01	60.6	58.3	59.7	61.2	YES	CC	NG	FO2			
1078	Canandaigua Power Partners, LLC	Canandaigua Wind Power		C	323617	Avoca	101	36	2008-12-05	125.0	125.0	125.0	125.0		WT	WND			259.5	
1079	Canastota Windpower LLC	Fenner Wind Power		C	24204	Fenner	053	36	2001-12-01	30.0	0.0	0.0	0.0		WT	WND			66.8	
1080	Carr Street Generating Station LP	Carr St.-E. Syr		C	24060	Dewitt	067	36	1993-08-01	122.6	89.0	83.2	105.1		CC	NG	FO2		97.7	
1081	Castleton Power, LLC	Castleton Energy Center		F	23900	Castleton	083	36	1992-01-01	72.0	67.0	60.0	72.0		CC	NG	FO2		229.4	
1082	Cayuga Operating Company, LLC	Cayuga 1		C	23584	Lansing	109	36	1955-09-01	155.3	154.1	153.3	153.7		ST	BIT			408.8	(S)
1083	Cayuga Operating Company, LLC	Cayuga 2		C	23585	Lansing	109	36	1958-10-01	167.2	154.7	151.0	153.6		ST	BIT			507.4	(S)
1084	Cayuga Operating Company, LLC	Cayuga IC 1		C	23629	Lansing	109	36	1967-08-01	2.8	0.0	0.0	0.0		IC	FO2				
1085	Cayuga Operating Company, LLC	Cayuga IC 2		C	23629	Lansing	109	36	1967-08-01	2.8	0.0	0.0	0.0		IC	FO2				
1086	Central Hudson Gas & Elec. Corp.	Coxsackie GT		G	23611	Coxsackie	039	36	1969-12-01	21.6	19.9	19.0	23.3		GT	KER	NG		0.3	
1087	Central Hudson Gas & Elec. Corp.	Dashville 1		G	23610	Rifton	111	36	1920-01-01	2.4	2.7	0.0	0.0		HY	WAT				
1088	Central Hudson Gas & Elec. Corp.	Dashville 2		G	23610	Rifton	111	36	1920-01-01	2.4	2.7	0.0	0.0		HY	WAT				
1089	Central Hudson Gas & Elec. Corp.	DCRRA		G	23765	Poughkeepsie	027	36	1987-09-01	9.2	8.8	7.7	7.4		ST	REF			43.2	
1090	Central Hudson Gas & Elec. Corp.	High Falls		G	23754	Marbletown	111	36	1986-12-01	3.2	3.0	0.0	0.0		HY	WAT				
1091	Central Hudson Gas & Elec. Corp.	Millpond		G	5004	Catskill	039	36	1993-12-01	0.9		0.0	0.0		HY	WAT				
1092	Central Hudson Gas & Elec. Corp.	Montgomery West		G	5005	Montgomery	071	36	1985-11-01	0.2		0.0	0.0		HY	WAT				
1093	Central Hudson Gas & Elec. Corp.	Salisbury Mills		G	5006	Salisbury Mills	071	36	1986-12-01	0.5		0.0	0.0		HY	WAT				
1094	Central Hudson Gas & Elec. Corp.	South Cairo		G	23612	Cairo	039	36	1970-06-01	21.6	17.8	18.2	23.3		GT	KER			0.1	
1095	Central Hudson Gas & Elec. Corp.	Sturgeon 1		G	23609	Rifton	111	36	1924-01-01	4.8	5.0	0.0	0.0		HY	WAT				
1096	Central Hudson Gas & Elec. Corp.	Sturgeon 2		G	23609	Rifton	111	36	1924-01-01	4.8	5.8	0.0	0.0		HY	WAT				
1097	Central Hudson Gas & Elec. Corp.	Sturgeon 3		G	23609	Rifton	111	36	1924-01-01	4.8	5.0	0.0	0.0		HY	WAT				
1098	Central Hudson Gas & Elec. Corp.	Wallkill		G	5007	Shwangunk	111	36	1986-12-01	0.5		0.0	0.0		HY	WAT				
1099	Central Hudson Gas & Elec. Corp.	Wappingers Falls		G	23765	Wappingers	027	36	1988-12-01	2.0	2.0	2.0	2.0		HY	WAT			8.8	
1100	CHI Energy Inc	Goodyear Lake		E	323669	Milford	077	36	1980-07-01	1.4	1.4	0.0	0.0		HY	WAT			4.3	
1101	Consolidated Edison Co. of NY, Inc.	59 St. GT 1		J	24138	Manhattan	061	36	1969-06-01	17.1	15.4	15.1	20.7		GT	KER	NG		0.3	
1102	Consolidated Edison Co. of NY, Inc.	74 St. GT 1		J	24260	Manhattan	061	36	1968-10-01	18.5	19.0	17.7	17.9		GT	KER			0.2	
1103	Consolidated Edison Co. of NY, Inc.	74 St. GT 2		J	24261	Manhattan	061	36	1968-10-01	18.5	20.1	17.4	20.1		GT	KER			0.5	
1104	Consolidated Edison Co. of NY, Inc.	Brooklyn Navy Yard		J	23515	Brooklyn	047	36	1996-11-01	322.0	266.9	261.5	296.1	YES	CC	NG	FO2		1,953.5	
1105	Consolidated Edison Co. of NY, Inc.	East River 1		J	323558	Manhattan	061	36	2005-04-01	185.0	150.5	144.6	180.4		CC	NG	KER		1,058.1	
1106	Consolidated Edison Co. of NY, Inc.	East River 2		J	323559	Manhattan	061	36	2005-04-05	185.0	152.4	144.8	181.8		CC	NG	KER		1,156.7	
1107	Consolidated Edison Co. of NY, Inc.	East River 6		J	23660	Manhattan	061	36	1951-11-01	156.2	134.3	138.3	137.9	YES	ST	FO6	NG		431.5	
1108	Consolidated Edison Co. of NY, Inc.	East River 7		J	23524	Manhattan	061	36	1955-06-01	200.0	184.7	183.6	185.0	YES	ST	FO6	NG		105.9	
1109	Consolidated Edison Co. of NY, Inc.	Hudson Ave 3		J	23810	Brooklyn	047	36	1970-07-01	16.3	16.0	14.8	18.7		GT	KER			0.2	
1110	Consolidated Edison Co. of NY, Inc.	Hudson Ave 4		J	23540	Brooklyn	047	36	1970-07-01	16.3	13.9	13.7	17.5		GT	KER			0.4	
1111	Consolidated Edison Co. of NY, Inc.	Hudson Ave 5		J	23657	Brooklyn	047	36	1970-07-01	16.3	15.1	15.0	18.6		GT	KER			0.5	
1112	Consolidated Edison Energy, Inc.	Broome 2 LFGE		C	323671	Binghamton	007	36	2013-01-31	1.6	1.6	1.6	1.6		IC	MTE			13.1	
1113	Consolidated Edison Energy, Inc.	Massena		D	23902	Massena	089	36	1992-07-01	102.1	82.2	80.3	90.7		CC	NG	FO2		1.7	
1114	Consolidated Edison Energy, Inc.	Rensselaer		F	23796	Rensselaer	083	36	1993-12-01	96.9	79.0	77.0	82.7		CC	NG	FO2		48.0	
1115	Consolidated Edison Energy, Inc.	Roseton 1		G	23587	Newburgh	071	36	1974-12-01	621.0	614.8	610.5	618.7		ST	FO6	NG	FO2	176.4	
1116	Consolidated Edison Energy, Inc.	Roseton 2		G	23588	Newburgh	071	36	1974-09-01	621.0	605.7	597.0	587.2		ST	FO6	NG	FO2	202.0	
1117	Consolidated Hydro New York, Inc.	Groveville Hydro		G	323602	Beacon	027	36	1983-12-01	0.9	0.9	0.0	0.0		HY	WAT			1.6	
1118	Consolidated Hydro New York, Inc.	Walden Hydro		G	24148	Walden	071	36	1983-12-01	2.4	0.0	0.0	0.0		HY	WAT			3.0	
1119	Covanta Niagara, LP	American Ref-Fuel 1		A	24010	Niagara	063	36	1993-05-01	25.0	19.6	18.4	17.5	YES	ST	REF			241.1	(G)
1120	Covanta Niagara, LP	American Ref-Fuel 2		A	24010	Niagara	063	36	1993-05-01	25.0	19.6	18.4	17.5	YES	ST	REF				
1121	Danskammer Energy, LLC	Danskammer 1	(ReAct. - 10/	G	23586	Newburgh	071	36	1951-12-01	72.0	67.0	60.7	60.7		ST	NG	FO6			(D)
1122	Danskammer Energy, LLC	Danskammer 2	(ReAct. - 10/	G	23589	Newburgh	071	36	1954-09-01	73.5	62.7	59.5	59.5		ST	NG	FO6			(D)
1123	Danskammer Energy, LLC	Danskammer 3	(ReAct. - 12/	G	23590	Newburgh	071	36	1959-10-01	147.1	137.2	137.5	137.5		ST	NG			1.2	(D) (3)
1124	Danskammer Energy, LLC	Danskammer 4	(ReAct. - 11/	G	23591	Newburgh	071	36	1967-09-01	239.4	236.2	232.0	178.7		ST	NG			3.1	(D) (4)
1125	Dynegy Danskammer, LLC	Danskammer 5		G	23592	Newburgh	071	36	1967-01-01	2.7	0.0	0.0	0.0		IC	FO2				
1126	Dynegy Danskammer, LLC	Danskammer 6		G	23592	Newburgh	071	36	1967-01-01	2.7	0.0	0.0	0.0		IC	FO2				
1127	Dynegy Marketing and Trade, LLC	Independence		C	23800	Scriba	075	36	1994-11-01	1,254.0	954.4	910.8	1,112.0		CC	NG			6,026.3	
1128	Eagle Creek Hydro Power, LLC	Mongaup 1		G	23641	Forestburg	105	36	1923-07-01	1.0	0.9	1.0	1.0		HY	WAT			10.3	(G)
1129	Eagle Creek Hydro Power, LLC	Mongaup 2		G	23641	Forestburg	105	36	1923-07-01	1.0	1.0	1.0	1.0		HY	WAT				
1130	Eagle Creek Hydro Power, LLC	Mongaup 3		G	23641	Forestburg	105	36	1923-07-01	1.0	1.0	1.0	1.0		HY	WAT				
1131	Eagle Creek Hydro Power, LLC	Mongaup 4		G	23641	Forestburg	105	36	1926-01-01	1.0	1.0	1.0	1.0		HY	WAT				
1132	Eagle Creek Hydro Power, LLC	Rio		G	23641	Glen Spey	105	36	1927-12-01	10.8	10.8	10.4	10.1		HY	WAT			23.0	
1133	Eagle Creek Hydro Power, LLC	Swinging Bridge 2		G	23641	Forestburg	105	36	1930-02-01	7.0	7.9	6.6	6.5		HY	WAT			9.1	
1134	East Coast Power, LLC	Linden Cogen		J	23786	Linden NJ	039	34	1992-05-01	1,034.9	755.3	757.8	800.0	YES	CC	NG	BUT		3,308.3	
1135	Empire Generating Co, LLC	EMPIRE_CC_1		F	323656	Rensselaer	083	36	2010-09-02	335.0	294.2	287.3	335.9		CC	NG	FO2		1,357.3	
1136	Empire Generating Co, LLC	EMPIRE_CC_2		F	323658	Rensselaer	083	36	2010-09-02	335.0	298.2	288.3	335.8		CC	NG	FO2		1,339.2	
1137	Entergy Nuclear Power Marketing LLC	Fitzpatrick 1		C	23598	Scriba	075	36	1975-07-01	882.0	858.9	836.8	842.9		NB	UR			5,828.7	
1138	Entergy Nuclear Power Marketing LLC	Indian Point 2		H	23530	Buchanan	119	36	1973-08-01	1,299.0	1,026.5	1,020.0	1,031.0		NP	UR			8,331.3	
1139	Entergy Nuclear Power Marketing LLC	Indian Point 3		H	23531	Buchanan	119	36	1976-04-01	1,012.0	1,040.4	1,034.8	1,047.0		NP	UR			8,979.0	
1140	Erie Blvd. Hydro - Beaver River	Belfort 1		E	24048	Belfort	049	36	1903-01-01	0.4	0.4	0.4	0.4		HY	WAT			1.8	
1141	Erie Blvd. Hydro - Beaver River	Belfort 2		E	24048	Belfort	049	36	1915-01-01	0.6	0.6	0.6	0.6		HY	WAT			5.1	
1142	Erie Blvd. Hydro - Beaver River	Belfort 3		E	24048	Belfort	049	36	1918-01-01	1.0	1.0	1.0	1.0		HY	WAT			5.2	
1143	Erie Blvd. Hydro - Beaver River	Eagle 1		E	24048	Watson	049	36	1914-01-01	1.3	1.2	1.3	1.3		HY	WAT			10.2	

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1144	Erie Blvd. Hydro - Beaver River	Eagle 2		E	24048	Watson	049	36	1915-01-01	1.4	1.3	1.4	1.4		HY	WAT			9.0	
1145	Erie Blvd. Hydro - Beaver River	Eagle 3		E	24048	Watson	049	36	1919-01-01	1.4	1.3	1.4	1.4		HY	WAT			7.0	
1146	Erie Blvd. Hydro - Beaver River	Eagle 4		E	24048	Watson	049	36	1925-01-01	2.1	2.0	2.1	2.1		HY	WAT			12.2	
1147	Erie Blvd. Hydro - Beaver River	Effley 1		E	24048	Belfort	049	36	1902-01-01	0.4	0.3	0.4	0.4		HY	WAT			2.6	
1148	Erie Blvd. Hydro - Beaver River	Effley 2		E	24048	Belfort	049	36	1907-01-01	0.4	0.3	0.4	0.4		HY	WAT			2.2	
1149	Erie Blvd. Hydro - Beaver River	Effley 3		E	24048	Belfort	049	36	1910-01-01	0.6	0.5	0.6	0.6		HY	WAT			4.3	
1150	Erie Blvd. Hydro - Beaver River	Effley 4		E	24048	Belfort	049	36	1923-01-01	1.6	1.5	1.6	1.6		HY	WAT			9.2	
1151	Erie Blvd. Hydro - Beaver River	Elmer 1		E	24048	Belfort	049	36	1916-01-01	0.8	0.9	0.8	0.8		HY	WAT			5.9	
1152	Erie Blvd. Hydro - Beaver River	Elmer 2		E	24048	Belfort	049	36	1916-01-01	0.8	0.9	0.8	0.8		HY	WAT			7.4	
1153	Erie Blvd. Hydro - Beaver River	High Falls 1		E	24048	Indian River	049	36	1925-01-01	1.6	1.9	1.6	1.6		HY	WAT			12.1	
1154	Erie Blvd. Hydro - Beaver River	High Falls 2		E	24048	Indian River	049	36	1925-01-01	1.6	1.9	1.6	1.6		HY	WAT			9.4	
1155	Erie Blvd. Hydro - Beaver River	High Falls 3		E	24048	Indian River	049	36	1925-01-01	1.6	1.9	1.6	1.6		HY	WAT			13.5	
1156	Erie Blvd. Hydro - Beaver River	Moshier 1		E	24048	Belfort	043	36	1929-01-01	4.0	4.0	4.0	4.0		HY	WAT			28.5	
1157	Erie Blvd. Hydro - Beaver River	Moshier 2		E	24048	Belfort	043	36	1929-01-01	4.0	4.0	4.0	4.0		HY	WAT			18.8	
1158	Erie Blvd. Hydro - Beaver River	Soft Maple 1		E	24048	Croghan	049	36	1925-01-01	7.5	8.0	7.5	7.5		HY	WAT			37.6	
1159	Erie Blvd. Hydro - Beaver River	Soft Maple 2		E	24048	Croghan	049	36	1925-01-01	7.5	8.0	7.5	7.5		HY	WAT			8.0	
1160	Erie Blvd. Hydro - Beaver River	Taylorville 1		E	24048	Belfort	049	36	1913-01-01	1.1	1.0	1.1	1.1		HY	WAT			8.4	
1161	Erie Blvd. Hydro - Beaver River	Taylorville 2		E	24048	Belfort	049	36	1913-01-01	1.1	1.0	1.1	1.1		HY	WAT			5.1	
1162	Erie Blvd. Hydro - Beaver River	Taylorville 3		E	24048	Belfort	049	36	1913-01-01	1.1	1.0	1.1	1.1		HY	WAT			6.8	
1163	Erie Blvd. Hydro - Beaver River	Taylorville 4		E	24048	Belfort	049	36	1927-01-01	1.2	1.1	1.2	1.2		HY	WAT			8.4	
1164	Erie Blvd. Hydro - Black River	Beebee Island 1		E	24047	Watertown	045	36	1963-01-01	4.0	4.4	4.0	4.0		HY	WAT			13.0	
1165	Erie Blvd. Hydro - Black River	Beebee Island 2		E	24047	Watertown	045	36	1968-01-01	4.0	4.4	4.0	4.0		HY	WAT			31.0	
1166	Erie Blvd. Hydro - Black River	Black River 1		E	24047	Black River	045	36	1920-01-01	2.0	2.3	2.0	2.0		HY	WAT			10.8	
1167	Erie Blvd. Hydro - Black River	Black River 2		E	24047	Black River	045	36	1920-01-01	2.0	2.3	2.0	2.0		HY	WAT			15.4	
1168	Erie Blvd. Hydro - Black River	Black River 3		E	24047	Black River	045	36	1920-01-01	2.0	2.3	2.0	2.0		HY	WAT			7.7	
1169	Erie Blvd. Hydro - Black River	Deferiet 1		E	24047	Deferiet	045	36	1925-01-01	3.6	3.7	3.6	3.6		HY	WAT			15.7	
1170	Erie Blvd. Hydro - Black River	Deferiet 2		E	24047	Deferiet	045	36	1925-01-01	3.6	3.7	3.6	3.6		HY	WAT			29.9	
1171	Erie Blvd. Hydro - Black River	Deferiet 3		E	24047	Deferiet	045	36	1925-01-01	3.6	3.7	3.6	3.6		HY	WAT			13.5	
1172	Erie Blvd. Hydro - Black River	Herrings 1		E	24047	Herrings	045	36	1924-01-01	1.8	1.8	1.8	1.8		HY	WAT			4.5	
1173	Erie Blvd. Hydro - Black River	Herrings 2		E	24047	Herrings	045	36	1924-01-01	1.8	1.8	1.8	1.8		HY	WAT			9.6	
1174	Erie Blvd. Hydro - Black River	Herrings 3		E	24047	Herrings	045	36	1924-01-01	1.8	1.8	1.8	1.8		HY	WAT			4.0	
1175	Erie Blvd. Hydro - Black River	Kamargo 1		E	24047	Black River	045	36	1921-01-01	1.8	1.8	1.8	1.8		HY	WAT			7.8	
1176	Erie Blvd. Hydro - Black River	Kamargo 2		E	24047	Black River	045	36	1921-01-01	1.8	1.8	1.8	1.8		HY	WAT			12.8	
1177	Erie Blvd. Hydro - Black River	Kamargo 3		E	24047	Black River	045	36	1921-01-01	1.8	1.8	1.8	1.8		HY	WAT			2.3	
1178	Erie Blvd. Hydro - Black River	Sewalls 1		E	24047	Watertown	045	36	1925-01-01	1.0	1.1	1.0	1.0		HY	WAT			6.2	
1179	Erie Blvd. Hydro - Black River	Sewalls 2		E	24047	Watertown	045	36	1925-01-01	1.0	1.1	1.0	1.0		HY	WAT			4.2	
1180	Erie Blvd. Hydro - East Canada Capita	Beardslee 1		F	24051	Little Falls	043	36	1924-01-01	10.0	9.5	10.0	10.0		HY	WAT			22.6	
1181	Erie Blvd. Hydro - East Canada Capita	Beardslee 2		F	24051	Little Falls	043	36	1924-01-01	10.0	9.5	10.0	10.0		HY	WAT			28.8	
1182	Erie Blvd. Hydro - East Canada Capita	Ephratah 1		F	24051	Caroga Lake	035	36	1920-01-01	1.4	0.7	1.4	1.4		HY	WAT			1.0	
1183	Erie Blvd. Hydro - East Canada Capita	Ephratah 2		F	24051	Caroga Lake	035	36	1911-01-01	1.2	0.6	1.2	1.2		HY	WAT			0.5	
1184	Erie Blvd. Hydro - East Canada Capita	Ephratah 3		F	24051	Caroga Lake	035	36	1911-01-01	1.3	0.0	0.0	0.0		HY	WAT			4.2	
1185	Erie Blvd. Hydro - East Canada Capita	Ephratah 4		F	24051	Caroga Lake	035	36	1911-01-01	1.3	0.7	1.3	1.3		HY	WAT			7.6	
1186	Erie Blvd. Hydro - East Canada Moha	Inghams 1		E	24050	Little Falls	043	36	1912-01-01	3.2	3.5	3.2	3.2		HY	WAT			11.9	
1187	Erie Blvd. Hydro - East Canada Moha	Inghams 2		E	24050	Little Falls	043	36	1912-01-01	3.2	3.5	3.2	3.2		HY	WAT			16.5	
1188	Erie Blvd. Hydro - Lower Hudson	Johnsonville 1		F	24059	Johnsonville	083	36	1909-01-01	1.2	1.3	1.2	1.2		HY	WAT			3.3	
1189	Erie Blvd. Hydro - Lower Hudson	Johnsonville 2		F	24059	Johnsonville	083	36	1909-01-01	1.2	1.3	1.2	1.2		HY	WAT			6.8	
1190	Erie Blvd. Hydro - Lower Hudson	Schaghticoke 1		F	24059	Schaghticoke	083	36	1908-01-01	3.3	4.1	3.3	3.3		HY	WAT			19.9	
1191	Erie Blvd. Hydro - Lower Hudson	Schaghticoke 2		F	24059	Schaghticoke	083	36	1908-01-01	3.3	4.1	3.3	3.3		HY	WAT			8.5	
1192	Erie Blvd. Hydro - Lower Hudson	Schaghticoke 3		F	24059	Schaghticoke	083	36	1908-01-01	3.3	4.1	3.3	3.3		HY	WAT			12.6	
1193	Erie Blvd. Hydro - Lower Hudson	Schaghticoke 4		F	24059	Schaghticoke	083	36	1908-01-01	3.3	4.1	3.3	3.3		HY	WAT			16.4	
1194	Erie Blvd. Hydro - Lower Hudson	School Street 1		F	24059	Cohoes	001	36	1974-01-01	7.2	6.9	7.2	7.2		HY	WAT			39.7	
1195	Erie Blvd. Hydro - Lower Hudson	School Street 2		F	24059	Cohoes	001	36	1915-01-01	7.2	6.9	7.2	7.2		HY	WAT			40.2	
1196	Erie Blvd. Hydro - Lower Hudson	School Street 3		F	24059	Cohoes	001	36	1915-01-01	7.2	6.9	7.2	7.2		HY	WAT			35.2	
1197	Erie Blvd. Hydro - Lower Hudson	School Street 4		F	24059	Cohoes	001	36	1922-01-01	7.2	6.9	7.2	7.2		HY	WAT			31.8	
1198	Erie Blvd. Hydro - Lower Hudson	School Street 5		F	24059	Cohoes	001	36	1924-01-01	10.0	9.6	10.0	10.0		HY	WAT			21.2	
1199	Erie Blvd. Hydro - Lower Hudson	Schuylerville		F	24059	Schuylerville	091	36	1919-01-01	1.2	1.5	1.2	1.2		HY	WAT			7.3	
1200	Erie Blvd. Hydro - Lower Raquette	Colton 1		E	24057	Colton	089	36	1962-01-01	10.0	10.0	10.0	10.0		HY	WAT			64.8	
1201	Erie Blvd. Hydro - Lower Raquette	Colton 2		E	24057	Colton	089	36	1918-01-01	10.0	10.0	10.0	10.0		HY	WAT			56.5	
1202	Erie Blvd. Hydro - Lower Raquette	Colton 3		E	24057	Colton	089	36	1928-01-01	10.0	10.0	10.0	10.0		HY	WAT			68.6	
1203	Erie Blvd. Hydro - Lower Raquette	East Norfolk		E	24057	East Norfolk	089	36	1928-01-01	3.0	4.0	3.0	3.0		HY	WAT			24.9	
1204	Erie Blvd. Hydro - Lower Raquette	Hannawa Falls 1		E	24057	Hannawa Falls	089	36	1914-01-01	3.6	3.7	3.6	3.6		HY	WAT			20.6	
1205	Erie Blvd. Hydro - Lower Raquette	Hannawa Falls 2		E	24057	Hannawa Falls	089	36	1920-01-01	3.6	3.7	3.6	3.6		HY	WAT			26.4	
1206	Erie Blvd. Hydro - Lower Raquette	Higley 1		E	24057	Colton	089	36	1913-01-01	1.2	1.1	1.2	1.2		HY	WAT			8.0	
1207	Erie Blvd. Hydro - Lower Raquette	Higley 2		E	24057	Colton	089	36	1913-01-01	1.2	1.1	1.2	1.2		HY	WAT			7.9	
1208	Erie Blvd. Hydro - Lower Raquette	Higley 3		E	24057	Colton	089	36	1943-01-01	2.1	2.0	2.1	2.1		HY	WAT			10.0	
1209	Erie Blvd. Hydro - Lower Raquette	Higley 4		E	24057	Colton	089	36	1943-01-01	2.1	2.0	2.1	2.1		HY	WAT			7.5	
1210	Erie Blvd. Hydro - Lower Raquette	Norfolk		E	24057	Norfolk	089	36	1928-01-01	4.5	4.8	4.5	4.5		HY	WAT			28.2	
1211	Erie Blvd. Hydro - Lower Raquette	Norwood		E	24057	Norwood	089	36	1928-01-01	2.0	2.2	2.0	2.0		HY	WAT			13.6	
1212	Erie Blvd. Hydro - Lower Raquette	Raymondville		E	24057	Raymondville	089	36	1928-01-01	2.0	2.1	2.0	2.0		HY	WAT			13.1	
1213	Erie Blvd. Hydro - Lower Raquette	Sugar Island 1		E	24057	Potsdam	089	36	1924-01-01	2.6	2.1	2.6	2.6		HY	WAT			9.9	
1214	Erie Blvd. Hydro - Lower Raquette	Sugar Island 2		E	24057	Potsdam	089	36	1924-01-01	2.4	2.0	2.4	2.4		HY	WAT			17.1	
1215	Erie Blvd. Hydro - Lower Raquette	Yaleville 1		E	24057	Norwood	089	36	1940-01-01	0.5	0.2	0.5	0.5		HY	WAT			2.3	

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EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1216	Erie Blvd. Hydro - Lower Raquette	Yaleville 2		E	24057	Norwood	089	36	1940-01-01	0.2	0.3	0.2	0.2		HY	WAT			0.8	
1217	Erie Blvd. Hydro - North Salmon	Allens Falls		D	24042	Allens Falls	089	36	1927-01-01	4.4	5.0	4.4	4.4		HY	WAT			24.8	
1218	Erie Blvd. Hydro - North Salmon	Chasm 1		D	24042	Chateaugay	033	36	1913-01-01	1.0	1.1	1.0	1.0		HY	WAT			5.2	
1219	Erie Blvd. Hydro - North Salmon	Chasm 2		D	24042	Chateaugay	033	36	1913-01-01	1.0	1.1	1.0	1.0		HY	WAT			2.8	
1220	Erie Blvd. Hydro - North Salmon	Chasm 3		D	24042	Chateaugay	033	36	1926-01-01	1.4	1.6	1.4	1.4		HY	WAT			0.0	
1221	Erie Blvd. Hydro - North Salmon	Franklin 1		D	24042	Franklin	033	36	1911-01-01	1.1	1.1	1.1	1.1		HY	WAT			5.5	
1222	Erie Blvd. Hydro - North Salmon	Franklin 2		D	24042	Franklin	033	36	1926-01-01	1.1	1.1	1.1	1.1		HY	WAT			3.6	
1223	Erie Blvd. Hydro - North Salmon	Hogansburg		D	24042	Hogansburg	033	36	1930-01-01	0.7	0.3	0.7	0.7		HY	WAT			0.7	
1224	Erie Blvd. Hydro - North Salmon	Macomb		D	24042	Malone	033	36	1940-01-01	1.0	0.9	1.0	1.0		HY	WAT			4.4	
1225	Erie Blvd. Hydro - North Salmon	Parishville		D	24042	Parishville	089	36	1925-01-01	2.4	2.3	2.4	2.4		HY	WAT			14.1	
1226	Erie Blvd. Hydro - North Salmon	Piercefield 1		D	24042	Piercefield	089	36	1957-01-01	1.5	1.6	1.5	1.5		HY	WAT			9.5	
1227	Erie Blvd. Hydro - North Salmon	Piercefield 2		D	24042	Piercefield	089	36	1924-01-01	0.6	0.6	0.6	0.6		HY	WAT			3.6	
1228	Erie Blvd. Hydro - North Salmon	Piercefield 3		D	24042	Piercefield	089	36	1924-01-01	0.6	0.6	0.6	0.6		HY	WAT			2.7	
1229	Erie Blvd. Hydro - NYS Barge	Hydraulic Race		A	23848	Lockport	063	36	1942-01-01	4.7	3.1	4.7	4.7		HY	WAT			9.3	
1230	Erie Blvd. Hydro - Oak Orchard	Glenwood 1		B	24046	Medina	073	36	1950-01-01	0.5	0.5	0.5	0.5		HY	WAT			2.7	
1231	Erie Blvd. Hydro - Oak Orchard	Glenwood 2		B	24046	Medina	073	36	1950-01-01	0.5	0.5	0.5	0.5		HY	WAT			3.6	
1232	Erie Blvd. Hydro - Oak Orchard	Glenwood 3		B	24046	Medina	073	36	1950-01-01	0.5	0.5	0.5	0.5		HY	WAT			0.0	
1233	Erie Blvd. Hydro - Oak Orchard	Oak Orchard		B	24046	Waterport	073	36	1941-01-01	0.4	0.3	0.4	0.4		HY	WAT			1.1	
1234	Erie Blvd. Hydro - Oak Orchard	Waterport 1		B	24046	Waterport	073	36	1941-01-01	2.3	1.6	2.3	2.3		HY	WAT			6.6	
1235	Erie Blvd. Hydro - Oak Orchard	Waterport 2		B	24046	Waterport	073	36	1968-01-01	2.5	1.8	2.5	2.5		HY	WAT			7.8	
1236	Erie Blvd. Hydro - Oswegatchie	Browns Falls 1		E	24044	Oswegatchie	089	36	1923-01-01	7.5	8.0	7.5	7.5		HY	WAT			37.9	
1237	Erie Blvd. Hydro - Oswegatchie	Browns Falls 2		E	24044	Oswegatchie	089	36	1923-01-01	7.5	8.0	7.5	7.5		HY	WAT			23.6	
1238	Erie Blvd. Hydro - Oswegatchie	Eel Weir 1		E	24044	Heuvelton	089	36	1928-01-01	0.5	0.3	0.5	0.5		HY	WAT			2.1	
1239	Erie Blvd. Hydro - Oswegatchie	Eel Weir 2		E	24044	Heuvelton	089	36	1938-01-01	1.1	0.8	1.1	1.1		HY	WAT			2.7	
1240	Erie Blvd. Hydro - Oswegatchie	Eel Weir 3		E	24044	Heuvelton	089	36	1938-01-01	1.1	0.8	1.1	1.1		HY	WAT			4.8	
1241	Erie Blvd. Hydro - Oswegatchie	Flat Rock 1		E	24044	Flat Rock	089	36	1924-01-01	3.0	2.6	3.0	3.0		HY	WAT			12.9	
1242	Erie Blvd. Hydro - Oswegatchie	Flat Rock 2		E	24044	Flat Rock	089	36	1924-01-01	3.0	2.6	3.0	3.0		HY	WAT			5.8	
1243	Erie Blvd. Hydro - Oswegatchie	Heuvelton 1		E	24044	Heuvelton	089	36	1924-01-01	0.5	0.4	0.5	0.5		HY	WAT			2.5	
1244	Erie Blvd. Hydro - Oswegatchie	Heuvelton 2		E	24044	Heuvelton	089	36	1924-01-01	0.5	0.4	0.5	0.5		HY	WAT			2.2	
1245	Erie Blvd. Hydro - Oswegatchie	Lower Newton Falls 1		E	24044	Newton Falls	089	36	2002-07-01	0.5	0.6	0.5	0.5		HY	WAT			2.9	
1246	Erie Blvd. Hydro - Oswegatchie	Oswegatchie 1		E	24044	Oswegatchie	089	36	1937-01-01	0.6	1.3	0.6	0.6		HY	WAT			5.3	
1247	Erie Blvd. Hydro - Oswegatchie	Oswegatchie 2		E	24044	Oswegatchie	089	36	1937-01-01	0.2	0.5	0.2	0.2		HY	WAT			2.8	
1248	Erie Blvd. Hydro - Oswegatchie	South Edwards 1		E	24044	South Edwards	089	36	1937-01-01	1.0	1.2	1.0	1.0		HY	WAT			9.3	
1249	Erie Blvd. Hydro - Oswegatchie	South Edwards 2		E	24044	South Edwards	089	36	1937-01-01	1.0	1.2	1.0	1.0		HY	WAT			5.1	
1250	Erie Blvd. Hydro - Oswegatchie	South Edwards 3		E	24044	South Edwards	089	36	1921-01-01	0.7	0.8	0.7	0.7		HY	WAT			4.5	
1251	Erie Blvd. Hydro - Oswegatchie	South Edwards 4		E	24044	South Edwards	089	36	1937-01-01	0.2	0.2	0.2	0.2		HY	WAT			0.0	
1252	Erie Blvd. Hydro - Oswegatchie	Talcville 1		E	24044	Edwards	089	36	1986-12-01	0.5	0.4	0.5	0.5		HY	WAT			3.1	
1253	Erie Blvd. Hydro - Oswegatchie	Talcville 2		E	24044	Edwards	089	36	1986-12-01	0.5	0.4	0.5	0.5		HY	WAT			0.3	
1254	Erie Blvd. Hydro - Oswegatchie	Upper Newton Falls 2		E	24044	Newton Falls	089	36	2002-07-01	0.5	0.4	0.5	0.5		HY	WAT			2.2	
1255	Erie Blvd. Hydro - Oswegatchie	Upper Newton Falls 3		E	24044	Newton Falls	089	36	2002-07-01	0.5	0.4	0.5	0.5		HY	WAT			1.4	
1256	Erie Blvd. Hydro - Oswegatchie	Upper Newton Falls 4		E	24044	Newton Falls	089	36	2002-07-01	0.5	0.4	0.5	0.5		HY	WAT			1.8	
1257	Erie Blvd. Hydro - Seneca Oswego	Baldwinsville 1		C	24041	Baldwinsville	067	36	1927-01-01	0.3	0.2	0.3	0.3		HY	WAT			1.6	
1258	Erie Blvd. Hydro - Seneca Oswego	Baldwinsville 2		C	24041	Baldwinsville	067	36	1927-01-01	0.3	0.2	0.3	0.3		HY	WAT			1.4	
1259	Erie Blvd. Hydro - Seneca Oswego	Granby 1		C	24041	Granby	075	36	1983-05-01	5.0	5.1	5.2	5.2		HY	WAT			22.0	
1260	Erie Blvd. Hydro - Seneca Oswego	Granby 2		C	24041	Granby	075	36	1983-05-01	5.0	5.1	5.2	5.2		HY	WAT			25.8	
1261	Erie Blvd. Hydro - Seneca Oswego	Minetto 2		C	24041	Minetto	075	36	1915-01-01	1.6	1.5	1.7	1.7		HY	WAT			9.3	
1262	Erie Blvd. Hydro - Seneca Oswego	Minetto 3		C	24041	Minetto	075	36	1915-01-01	1.6	1.5	1.7	1.7		HY	WAT			9.2	
1263	Erie Blvd. Hydro - Seneca Oswego	Minetto 4		C	24041	Minetto	075	36	1915-01-01	1.6	1.5	1.7	1.7		HY	WAT			7.8	
1264	Erie Blvd. Hydro - Seneca Oswego	Minetto 5		C	24041	Minetto	075	36	1975-01-01	1.6	1.5	1.7	1.7		HY	WAT			6.9	
1265	Erie Blvd. Hydro - Seneca Oswego	Minetto 6		C	24041	Minetto	075	36	1975-01-01	1.6	1.5	1.7	1.7		HY	WAT			5.5	
1266	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls E 1		C	24041	Oswego	075	36	1914-01-01	1.5	1.5	1.6	1.6		HY	WAT			10.1	
1267	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls E 2		C	24041	Oswego	075	36	1914-01-01	1.5	1.5	1.6	1.6		HY	WAT			6.9	
1268	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls E 3		C	24041	Oswego	075	36	1914-01-01	1.5	1.5	1.6	1.6		HY	WAT			6.4	
1269	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls W 4		C	24041	Oswego	075	36	1914-01-01	0.9	1.0	0.9	0.9		HY	WAT			4.6	
1270	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls W 5		C	24041	Oswego	075	36	1914-01-01	0.9	1.0	0.9	0.9		HY	WAT			5.1	
1271	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls W 6		C	24041	Oswego	075	36	2007-01-01	0.5	0.5	0.5	0.5		HY	WAT			0.1	
1272	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls W 7		C	24041	Oswego	075	36	2007-01-01	0.5	0.5	0.5	0.5		HY	WAT			0.3	
1273	Erie Blvd. Hydro - Seneca Oswego	Varick 2		C	24041	Oswego	075	36	1926-01-01	2.2	1.9	2.3	2.3		HY	WAT			9.9	
1274	Erie Blvd. Hydro - Seneca Oswego	Varick 3		C	24041	Oswego	075	36	1926-01-01	2.2	2.1	2.3	2.3		HY	WAT			5.3	
1275	Erie Blvd. Hydro - Seneca Oswego	Varick 4		C	24041	Oswego	075	36	1926-01-01	2.2	1.9	2.3	2.3		HY	WAT			6.5	
1276	Erie Blvd. Hydro - Seneca Oswego	Varick 5		C	24041	Oswego	075	36	1926-01-01	2.2	1.9	2.3	2.3		HY	WAT			7.1	
1277	Erie Blvd. Hydro - South Salmon	Bennetts Bridge 1		C	24043	Altmar	075	36	1964-01-01	6.4	7.0	6.4	6.4		HY	WAT			7.7	
1278	Erie Blvd. Hydro - South Salmon	Bennetts Bridge 2		C	24043	Altmar	075	36	1966-01-01	6.4	7.0	6.4	6.4		HY	WAT			20.2	
1279	Erie Blvd. Hydro - South Salmon	Bennetts Bridge 3		C	24043	Altmar	075	36	1970-01-01	7.0	7.7	7.0	7.0		HY	WAT			38.1	
1280	Erie Blvd. Hydro - South Salmon	Bennetts Bridge 4		C	24043	Altmar	075	36	1970-01-01	7.0	7.7	7.0	7.0		HY	WAT			38.0	
1281	Erie Blvd. Hydro - South Salmon	Lighthouse Hill 1		C	24043	Altmar	075	36	1930-01-01	3.8	4.1	3.8	3.8		HY	WAT			17.4	
1282	Erie Blvd. Hydro - South Salmon	Lighthouse Hill 2		C	24043	Altmar	075	36	1930-01-01	3.8	4.1	3.8	3.8		HY	WAT			8.0	
1283	Erie Blvd. Hydro - Upper Hudson	E J West 1		F	24058	Hadley	091	36	1930-01-01	10.0	11.9	10.0	10.0		HY	WAT			31.4	
1284	Erie Blvd. Hydro - Upper Hudson	E J West 2		F	24058	Hadley	091	36	1930-01-01	10.0	11.9	10.0	10.0		HY	WAT			35.9	
1285	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 1		F	24058	S Glens Falls	091	36	1924-01-01	1.2	0.9	1.2	1.2		HY	WAT			5.1	
1286	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 2		F	24058	S Glens Falls	091	36	1924-01-01	1.2	0.9	1.2	1.2		HY	WAT			4.3	
1287	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 3		F	24058	S Glens Falls	091	36	1924-01-01	1.2	0.9	1.2	1.2		HY	WAT			4.5	

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1288	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 4		F	24058	S Glens Falls	091	36	1924-01-01	1.2	0.9	1.2	1.2		HY	WAT			6.2	
1289	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 5		F	24058	S Glens Falls	091	36	1924-01-01	1.2	0.9	1.2	1.2		HY	WAT			6.3	
1290	Erie Blvd. Hydro - Upper Hudson	Sherman Island 1		F	24058	Queensbury	113	36	2009-03-01	8.0	0.0	0.0	0.0		HY	WAT			36.2	
1291	Erie Blvd. Hydro - Upper Hudson	Sherman Island 2		F	24058	Queensbury	113	36	1923-01-01	7.2	8.1	7.2	7.2		HY	WAT			39.0	
1292	Erie Blvd. Hydro - Upper Hudson	Sherman Island 3		F	24058	Queensbury	113	36	1923-01-01	8.7	9.7	8.7	8.7		HY	WAT			34.9	
1293	Erie Blvd. Hydro - Upper Hudson	Sherman Island 4		F	24058	Queensbury	113	36	1923-01-01	7.2	8.1	7.2	7.2		HY	WAT			34.0	
1294	Erie Blvd. Hydro - Upper Hudson	Sherman Island 5		F	24058	Queensbury	113	36	1923-01-01	7.2	8.1	7.2	7.2		HY	WAT			19.9	
1295	Erie Blvd. Hydro - Upper Hudson	Sherman Island 6		F	24058	Queensbury	113	36	2009-02-02	1.0	0.0	0.0	0.0		HY	WAT			10.1	
1296	Erie Blvd. Hydro - Upper Hudson	Spier Falls 1		F	24058	Moreau	091	36	1924-01-01	6.8	8.4	6.8	6.8		HY	WAT			56.2	
1297	Erie Blvd. Hydro - Upper Hudson	Spier Falls 2		F	24058	Moreau	091	36	1930-01-01	37.6	46.9	37.6	37.6		HY	WAT			172.6	
1298	Erie Blvd. Hydro - Upper Hudson	Stewarts Bridge		F	24058	Hadley	091	36	1952-01-01	30.0	35.8	30.0	30.0		HY	WAT			113.3	
1299	Erie Blvd. Hydro - Upper Raquette	Blake		E	24056	Stark	089	36	1957-01-01	14.4	15.6	14.4	14.4		HY	WAT			58.1	
1300	Erie Blvd. Hydro - Upper Raquette	Five Falls		E	24056	Colton	089	36	1955-01-01	22.5	24.4	22.5	22.5		HY	WAT			97.7	
1301	Erie Blvd. Hydro - Upper Raquette	Rainbow Falls		E	24056	Colton	089	36	1956-01-01	22.5	24.4	22.5	22.5		HY	WAT			99.4	
1302	Erie Blvd. Hydro - Upper Raquette	South Colton		E	24056	South Colton	089	36	1954-01-01	19.4	20.9	19.4	19.4		HY	WAT			82.3	
1303	Erie Blvd. Hydro - Upper Raquette	Stark		E	24056	Stark	089	36	1957-01-01	22.5	24.6	22.5	22.5		HY	WAT			91.6	
1304	Erie Blvd. Hydro - West Canada	Prospect		E	24049	Prospect	043	36	1959-01-01	17.3	21.7	17.3	17.3		HY	WAT			77.9	
1305	Erie Blvd. Hydro - West Canada	Trenton Falls 5		E	24049	Trenton	065	36	1919-01-01	6.8	9.6	6.8	6.8		HY	WAT			59.5	
1306	Erie Blvd. Hydro - West Canada	Trenton Falls 6		E	24049	Trenton	065	36	1919-01-01	6.4	9.1	6.4	6.4		HY	WAT			54.1	
1307	Erie Blvd. Hydro - West Canada	Trenton Falls 7		E	24049	Trenton	065	36	1922-01-01	6.4	9.1	6.4	6.4		HY	WAT			39.7	
1308	Erie Blvd. Hydropower LP	West Delaware Hydro		G	323627	Grahamsville	105	36	1988-12-01	7.5	7.5	7.5	7.5		HY	WAT			23.0	
1309	Erie Wind, LLC	Erie Wind		A	323693	Lackawanna	029	36	2012-02-01	15.0	0.0	0.0	0.0		WT	WND			39.3	
1310	Exelon Generation Company, LLC	Chaffee		A	323603	Chaffee	029	36	2007-08-09	6.4	6.4	6.4	6.4		IC	MTE			49.4	
1311	Exelon Generation Company, LLC	High Acres 1		C	23767	Fairport	117	36	1991-06-01	3.2	3.2	3.2	3.2		IC	MTE			26.6	
1312	Exelon Generation Company, LLC	High Acres 2		C	23767	Fairport	117	36	2008-02-28	6.4	6.4	6.4	6.4		IC	MTE			51.7	
1313	Exelon Generation Company, LLC	Madison County LF		E	323628	Wampsville	053	36	2010-03-01	1.6	1.6	1.6	1.6		IC	MTE			6.2	
1314	Exelon Generation Company, LLC	Mill Seat		B	323607	Riga	055	36	2007-07-20	6.4	6.4	6.4	6.4		IC	MTE			48.6	
1315	Exelon Generation Company, LLC	Monroe Livingston		B	24207	Scottsville	055	36	1988-11-01	2.4	2.4	2.4	2.4		IC	MTE			8.6	
1316	Exelon Generation Company, LLC	Oneida-Herkimer LFGE		E	323681	Boonville	065	36	2012-04-01	3.2	3.2	3.2	3.2		IC	MTE			24.7	
1317	Exelon Generation Company, LLC	Synergy Biogas		B	323694	Wyoming	121	36	2012-09-01	2.0	2.0	0.0	0.0		IC	MTE			6.2	
1318	Flat Rock Windpower II, LLC	Maple Ridge Wind 2		E	323611	Lowville	049	36	2007-12-01	90.7	90.7	90.8	90.8		WT	WND			225.8	
1319	Flat Rock Windpower, LLC	Maple Ridge Wind 1		E	323574	Lowville	049	36	2006-01-01	231.0	231.0	231.0	231.0		WT	WND			587.4	
1320	Freeport Electric	Freeport 1-2		K	1660	Freeport	059	36	1949-08-01	2.9	2.0	2.5	2.9		IC	FO2			0.0	
1321	Freeport Electric	Freeport 1-3		K	1660	Freeport	059	36	1954-08-01	3.1	2.1	2.7	3.0		IC	FO2			0.0	
1322	Freeport Electric	Freeport 1-4		K	1660	Freeport	059	36	1964-10-01	5.1	4.4	4.5	5.0		IC	FO2			0.2	
1323	Freeport Electric	Freeport 2-3		K	1660	Freeport	059	36	1973-05-01	18.1	18.1	15.8	17.9		GT	KER			0.2	
1324	Freeport Electric	Freeport CT 2		K	23818	Freeport	059	36	2004-03-01	60.5	50.3	48.5	49.9		GT	NG			52.5	
1325	GenOn Energy Management, LLC	Bowline 1		G	23526	West Haverstraw	087	36	1972-09-01	621.0	577.7	579.3	576.7		ST	NG	FO6		1,387.8	
1326	GenOn Energy Management, LLC	Bowline 2		G	23595	West Haverstraw	087	36	1974-05-01	621.0	557.4	183.0	183.0		ST	NG	FO6		99.6	
1327	Hampshire Paper Co., Inc.	Hampshire Paper		E	323593	Gouverneur	089	36	1987-03-01	3.4	3.5	3.4	3.4		HY	WAT			18.8	
1328	Hardscrabble Wind Power LLC	Hardscrabble Wind		E	323673	Fairfield	043	36	2011-02-01	74.0	74.0	74.0	74.0		WT	WND			184.3	
1329	Howard Wind LLC	Howard Wind		C	323690	Howard	101	36	2011-12-01	57.4	57.4	55.4	55.4		WT	WND			133.0	
1330	Indeck Energy Services of Silver Sprir	Indeck-Silver Springs		C	23768	Silver Springs	121	36	1991-04-01	56.6	51.5	50.3	61.3	YES	CC	NG	FO2		36.4	
1331	Indeck-Corinth LP	Indeck-Corinth		F	23802	Corinth	091	36	1995-07-01	147.0	131.2	129.5	132.2	YES	CC	NG	FO2		876.7	
1332	Indeck-Olean LP	Indeck-Olean		A	23982	Olean	009	36	1993-12-01	90.6	79.4	76.0	84.4	YES	CC	NG	FO2		330.0	
1333	Indeck-Oswego LP	Indeck-Oswego		C	23783	Oswego	075	36	1990-05-01	57.4	51.6	48.8	61.5		CC	NG	FO2		65.6	
1334	Indeck-Yerkes LP	Indeck-Yerkes		A	23781	Tonawanda	029	36	1990-02-01	59.9	49.7	47.9	56.2	YES	CC	NG	FO2		68.1	
1335	Innovative Energy Systems, Inc.	Chautauqua LFGE		A	323629	Jamestown	013	36	2010-02-12	9.6	0.0	0.0	0.0		IC	MTE			42.4	
1336	Innovative Energy Systems, Inc.	Clinton LFGE		D	323618	Morrisonville	019	36	2008-10-01	6.4	6.4	6.4	6.4		IC	MTE			39.6	
1337	Innovative Energy Systems, Inc.	Colonie LFGTE		F	323577	Colonie	001	36	2006-03-01	4.8	4.8	4.8	4.8		IC	MTE			37.0	
1338	Innovative Energy Systems, Inc.	DANC LFGE		E	323619	Watertown	045	36	2008-09-08	6.4	6.4	6.4	6.4		IC	MTE			39.4	
1339	Innovative Energy Systems, Inc.	Fulton LFGE		F	323630	Johnstown	035	36	2010-06-04	3.2	0.0	0.0	0.0		IC	MTE			12.4	
1340	Innovative Energy Systems, Inc.	Hyland LFGE		B	323620	Angelica	003	36	2008-09-08	4.8	4.8	4.8	4.8		IC	MTE			31.6	
1341	Innovative Energy Systems, Inc.	Steuben County LF		C	323667	Bath	101	36	2012-08-01	3.2	3.2	3.2	3.2		IC	MTE			22.3	
1342	International Paper Company	Ticonderoga		F	23804	Ticonderoga	031	36	1970-01-01	42.1	7.6	9.5	9.8	YES	ST	FO6			0.0	
1343	Jamestown Board of Public Utilities	Jamestown 5		A	1658	Jamestown	013	36	1951-08-01	28.7	23.0	16.2	16.6	YES	ST	BIT	NG		4.7	
1344	Jamestown Board of Public Utilities	Jamestown 6		A	1658	Jamestown	013	36	1968-08-01	25.0	22.4	14.2	14.7	YES	ST	BIT	NG		45.5	
1345	Jamestown Board of Public Utilities	Jamestown 7		A	1659	Jamestown	013	36	2002-01-01	47.3	40.0	38.6	45.6	YES	GT	NG			174.0	
1346	Lakeside New York, LLC	Beaver Falls		E	23983	Beaver Falls	049	36	1995-03-01	107.8	80.2	81.1	89.3		CC	NG	FO2		1.3	
1347	Lakeside New York, LLC	Syracuse		C	23985	Syracuse	067	36	1993-09-01	102.7	86.8	85.6	97.8		CC	NG	FO2		41.0	
1348	Long Island Power Authority	Babylon (RR)		K	323704	Babylon	103	36	1989-04-01	17.0	15.5	14.3	15.0		ST	REF			109.5	
1349	Long Island Power Authority	Barrett 03		K	23706	Island Park	059	36	1970-06-01	18.0	17.9	17.0	19.2		GT	NG	FO2		2.4	
1350	Long Island Power Authority	Barrett 04		K	23707	Island Park	059	36	1970-07-01	18.0	17.7	17.5	20.4		GT	NG	FO2		6.6	
1351	Long Island Power Authority	Barrett 05		K	23708	Island Park	059	36	1970-07-01	18.0	17.8	17.3	19.9		GT	NG	FO2		2.0	
1352	Long Island Power Authority	Barrett 06		K	23709	Island Park	059	36	1970-07-01	18.0	17.8	17.1	20.1		GT	NG	FO2		3.0	
1353	Long Island Power Authority	Barrett 08		K	23711	Island Park	059	36	1970-07-01	18.0	17.3	17.2	20.4		GT	NG	FO2		2.2	
1354	Long Island Power Authority	Barrett 09		K	23700	Island Park	059	36	1971-06-01	41.8	43.4	39.4	48.2		JE	NG	FO2		9.1	
1355	Long Island Power Authority	Barrett 10		K	23701	Island Park	059	36	1971-06-01	41.8	42.7	39.9	49.4		JE	NG	FO2		24.3	
1356	Long Island Power Authority	Barrett 11		K	23702	Island Park	059	36	1971-06-01	41.8	43.3	39.8	49.5		JE	NG	FO2		14.5	
1357	Long Island Power Authority	Barrett 12		K	23703	Island Park	059	36	1971-06-01	41.8	44.0	40.3	49.5		JE	NG	FO2		23.2	
1358	Long Island Power Authority	Barrett GT 01		K	23704	Island Park	059	36	1970-06-01	18.0	18.1	11.4	0.0		GT	NG	FO2		0.1	
1359	Long Island Power Authority	Barrett GT 02		K	23705	Island Park	059	36	1970-06-01	18.0	17.4	14.7	17.1		GT	NG	FO2		4.7	

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1360	Long Island Power Authority	Barrett ST 01		K	23545	Island Park	059	36	1956-11-01	188.0	200.2	195.2	192.5		ST	NG	FO6		623.4	
1361	Long Island Power Authority	Barrett ST 02		K	23546	Island Park	059	36	1963-10-01	188.0	197.5	196.0	194.8		ST	NG	FO6		804.8	
1362	Long Island Power Authority	Bethpage 3		K	323564	Hicksville	059	36	2005-05-01	96.0	79.9	77.1	77.3		CC	NG			140.6	
1363	Long Island Power Authority	Caithness_CC_1		K	323624	Brookhaven	103	36	2009-08-01	375.0	315.6	306.7	358.6		CC	NG	FO2		2,393.7	
1364	Long Island Power Authority	East Hampton 2		K	23722	E Hampton	103	36	1962-12-01	2.0	2.0	2.0	2.0		IC	FO2			0.4	
1365	Long Island Power Authority	East Hampton 3		K	23722	E Hampton	103	36	1962-12-01	2.0	2.0	2.0	2.0		IC	FO2			0.5	
1366	Long Island Power Authority	East Hampton 4		K	23722	E Hampton	103	36	1962-12-01	2.0	2.0	2.0	2.0		IC	FO2			0.5	
1367	Long Island Power Authority	East Hampton GT 01		K	23717	E Hampton	103	36	1970-12-01	21.3	19.2	19.0	24.4		JE	FO2			5.0	
1368	Long Island Power Authority	Far Rockaway GT1		K	24212	Far Rockaway	081	36	2002-07-01	60.5	53.5	53.9	57.1		JE	NG			225.6	
1369	Long Island Power Authority	Far Rockaway GT2		K	23815	Jamaica Bay	081	36	2003-07-02	60.5	55.4	54.3	53.8		JE	FO2			16.9	
1370	Long Island Power Authority	Freeport CT 1		K	23764	Freeport	059	36	2004-06-01	60.0	48.3	48.3	49.7		GT	NG	FO2		105.5	
1371	Long Island Power Authority	Glenwood GT 01		K	23712	Glenwood	059	36	1967-04-01	16.0	14.6	12.6	17.6		GT	FO2			0.1	
1372	Long Island Power Authority	Glenwood GT 02		K	23688	Glenwood	059	36	1972-06-01	55.0	52.7	50.0	62.0		GT	FO2			2.5	
1373	Long Island Power Authority	Glenwood GT 03		K	23689	Glenwood	059	36	1972-06-01	55.0	52.7	51.2	67.3		GT	FO2			3.1	
1374	Long Island Power Authority	Glenwood GT 04		K	24219	Glenwood	059	36	2002-06-01	53.0	40.3	39.7	46.4		GT	NG	FO2		99.6	
1375	Long Island Power Authority	Glenwood GT 05		K	24220	Glenwood	059	36	2002-06-01	53.0	40.0	38.3	47.2		GT	NG	FO2		97.2	
1376	Long Island Power Authority	Greenport GT1		K	23814	Greenport	103	36	2003-07-02	54.0	51.9	51.3	56.8		JE	FO2			13.9	
1377	Long Island Power Authority	Hempstead (RR)		K	23647	Hempstead	059	36	1989-10-01	78.6	73.7	72.1	73.4		ST	REF			574.6	
1378	Long Island Power Authority	Holtsville 01		K	23690	Holtsville	103	36	1974-07-01	56.7	55.1	53.2	62.6		JE	FO2			3.4	
1379	Long Island Power Authority	Holtsville 02		K	23691	Holtsville	103	36	1974-07-01	56.7	55.3	47.6	59.3		JE	FO2			3.2	
1380	Long Island Power Authority	Holtsville 03		K	23692	Holtsville	103	36	1974-07-01	56.7	52.1	47.4	60.1		JE	FO2			2.4	
1381	Long Island Power Authority	Holtsville 04		K	23693	Holtsville	103	36	1974-07-01	56.7	52.7	51.9	59.0		JE	FO2			2.8	
1382	Long Island Power Authority	Holtsville 05		K	23694	Holtsville	103	36	1974-07-01	56.7	53.3	53.8	66.3		JE	FO2			3.8	
1383	Long Island Power Authority	Holtsville 06		K	23695	Holtsville	103	36	1975-07-01	56.7	53.0	51.2	63.9		JE	FO2			10.6	
1384	Long Island Power Authority	Holtsville 07		K	23696	Holtsville	103	36	1975-07-01	56.7	55.1	52.2	60.1		JE	FO2			1.1	
1385	Long Island Power Authority	Holtsville 08		K	23697	Holtsville	103	36	1975-07-01	56.7	57.4	52.3	68.3		JE	FO2			2.4	
1386	Long Island Power Authority	Holtsville 09		K	23698	Holtsville	103	36	1975-07-01	56.7	57.5	53.2	66.5		JE	FO2			6.9	
1387	Long Island Power Authority	Holtsville 10		K	23699	Holtsville	103	36	1975-07-01	56.7	55.1	52.9	66.1		JE	FO2			2.1	
1388	Long Island Power Authority	Huntington (RR)		K	323705	Huntington	103	36	1991-12-01	28.0	24.7	24.2	24.3		ST	REF			190.1	
1389	Long Island Power Authority	Islip (RR)		K	323679	Ronkonkoma	103	36	1990-03-01	12.5	11.2	8.6	8.7		ST	REF			51.2	
1390	Long Island Power Authority	Long Island Solar Farm		K	323691	Upton	103	36	2011-11-01	31.5	31.5	31.5	31.5		PV	SUN			51.0	
1391	Long Island Power Authority	Northport 1		K	23551	Northport	103	36	1967-07-01	387.0	395.0	399.7	391.3		ST	NG	FO6		356.5	
1392	Long Island Power Authority	Northport 2		K	23552	Northport	103	36	1968-06-01	387.0	396.0	396.5	398.7		ST	NG	FO6		609.8	
1393	Long Island Power Authority	Northport 3		K	23553	Northport	103	36	1972-07-01	387.0	399.2	391.2	382.2		ST	NG	FO6		685.1	
1394	Long Island Power Authority	Northport 4		K	23650	Northport	103	36	1977-12-01	387.0	399.2	391.2	393.2		ST	NG	FO6		1,060.3	
1395	Long Island Power Authority	Northport GT		K	23718	Northport	103	36	1967-03-01	16.0	13.8	11.9	15.4		GT	FO2			0.1	
1396	Long Island Power Authority	Oceanside (LF)		K	5008	Oceanside	059	36	1991-02-01	2.1	1.1	0.0	0.0		IC	MTE				
1397	Long Island Power Authority	Oyster Bay (LF)		K	5009	Bethpage	059	36	1986-07-01	1.3	0.0	0.0	0.0		IC	MTE				
1398	Long Island Power Authority	Pilgrim GT1		K	24216	Brentwood	103	36	2002-08-01	50.0	45.6	45.3	46.5		GT	NG			86.9	
1399	Long Island Power Authority	Pilgrim GT2		K	24217	Brentwood	103	36	2002-08-01	50.0	46.2	45.3	46.3		GT	NG			94.3	
1400	Long Island Power Authority	Pinelawn Power 1		K	323563	Babylon	103	36	2005-06-01	82.0	78.0	76.1	77.8		CC	NG	KER		136.4	
1401	Long Island Power Authority	Port Jefferson 3		K	23555	Port Jefferson	103	36	1958-11-01	188.0	194.5	196.7	195.3		ST	FO6	NG		93.6	
1402	Long Island Power Authority	Port Jefferson 4		K	23616	Port Jefferson	103	36	1960-11-01	188.0	198.7	196.7	198.0		ST	FO6	NG		191.2	
1403	Long Island Power Authority	Port Jefferson GT 01		K	23713	Port Jefferson	103	36	1966-12-01	16.0	14.1	12.9	18.0		GT	FO2			0.1	
1404	Long Island Power Authority	Port Jefferson GT 02		K	24210	Port Jefferson	103	36	2002-07-01	53.0	42.0	41.0	45.9		GT	NG	FO2		93.3	
1405	Long Island Power Authority	Port Jefferson GT 03		K	24211	Port Jefferson	103	36	2002-07-01	53.0	41.1	40.5	46.1		GT	NG	FO2		88.2	
1406	Long Island Power Authority	S Hampton 1		K	23720	South Hampton	103	36	1963-03-01	11.5	10.3	8.3	12.0		GT	FO2			0.1	
1407	Long Island Power Authority	Shoreham 1		K	23715	Shoreham	103	36	1971-07-01	52.9	48.9	48.9	65.6		GT	FO2			0.9	
1408	Long Island Power Authority	Shoreham 2		K	23716	Shoreham	103	36	1984-04-01	18.6	18.5	15.8	20.9		JE	FO2			0.2	
1409	Long Island Power Authority	Shoreham GT3		K	24213	Shoreham	103	36	2002-08-01	50.0	45.1	45.0	45.9		GT	FO2			6.4	
1410	Long Island Power Authority	Shoreham GT4		K	24214	Shoreham	103	36	2002-08-01	50.0	41.9	44.2	45.9		GT	FO2			6.0	
1411	Long Island Power Authority	Smithtown (LF)		K	5010	Smithtown	103	36	1985-12-01	1.1	0.0	0.0	0.0		IC	MTE				
1412	Long Island Power Authority	South Oaks Hosp		K	5011	Amityville	103	36	1990-06-01	1.0	0.0	0.0	0.0		IC	NG				
1413	Long Island Power Authority	Southold 1		K	23719	Southold	103	36	1964-08-01	14.0	12.3	13.0	15.3		GT	FO2			0.2	
1414	Long Island Power Authority	Stony Brook		K	24151	Stony Brook	103	36	1995-04-01	47.0	9.6	17.2	19.0	YES	GT	NG	FO2		283.3	
1415	Long Island Power Authority	Trigen-NDEC		K	323695	Garden City	059	36	1991-03-01	55.0	51.6	43.0	56.4	YES	CC	NG	FO2		343.0	
1416	Long Island Power Authority	Wading River 1		K	23522	Shoreham	103	36	1989-08-01	79.5	81.2	78.8	98.3		GT	FO2			9.7	
1417	Long Island Power Authority	Wading River 2		K	23547	Shoreham	103	36	1989-08-01	79.5	81.3	76.6	96.2		GT	FO2			13.4	
1418	Long Island Power Authority	Wading River 3		K	23601	Shoreham	103	36	1989-08-01	79.5	81.3	73.3	95.5		GT	FO2			8.2	
1419	Long Island Power Authority	West Babylon 4		K	23714	West Babylon	103	36	1971-08-01	52.4	49.0	47.8	66.1		GT	FO2			2.4	
1420	Long Island Power Authority	Yaphank (LF)		K	5012	Yaphank	103	36	1983-09-01	1.6	1.5	0.0	0.0		IC	MTE				
1421	Madison Windpower, LLC	Madison Wind Power		E	24146	Madison	053	36	2000-09-01	11.6	11.5	11.6	11.6		WT	WND			21.0	
1422	Marble River LLC	Marble River Wind		D	323696	Ellenburg	019	36	2012-07-01	215.5	0.0	0.0	0.0		WT	WND			539.2	
1423	Marsh Hill Energy LLC	Marsh Hill Wind Farm		C	323713	Jasper	101	36	2014-12-01	16.2	0.0	0.0	0.0		WT	WND			8.8	**(N) (5)**
1424	Model City Energy LLC	Model City Energy		A	24167	Lewiston	063	36	2001-06-01	5.6	5.6	5.6	5.6		IC	MTE			39.5	
1425	Modern Innovative Energy, LLC	Modern LF		A	323580	Lewiston	063	36	2006-02-01	6.4	6.4	6.4	6.4		IC	MTE			31.5	
1426	New York Power Authority	Ashokan 1		G	23654	Ashokan	111	36	1982-11-01	2.3	1.8	2.3	2.3		HY	WAT			4.7	
1427	New York Power Authority	Ashokan 2		G	23654	Ashokan	111	36	1982-11-01	2.3	1.8	2.3	2.3		HY	WAT			3.0	
1428	New York Power Authority	Astoria CC 1		J	323568	Queens	081	36	2006-01-01	288.0	246.2	229.5	260.0		CC	NG	JF	KER	3,246.7	**(G)**
1429	New York Power Authority	Astoria CC 2		J	323569	Queens	081	36	2006-01-01	288.0	246.2	229.4	260.0		CC	NG	JF	KER		
1430	New York Power Authority	Blenheim - Gilboa 1		F	23756	Gilboa NY	095	36	1973-07-01	290.0	290.7	290.9	292.2		PS	WAT			83.1	
1431	New York Power Authority	Blenheim - Gilboa 2		F	23757	Gilboa NY	095	36	1973-07-01	290.0	291.2	291.6	292.1		PS	WAT			217.1	

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EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1432	New York Power Authority	Blenheim - Gilboa 3		F	23758	Gilboa NY	095	36	1973-07-01	290.0	291.7	292.0	291.2		PS	WAT			35.0	
1433	New York Power Authority	Blenheim - Gilboa 4		F	23759	Gilboa NY	095	36	1973-07-01	290.0	291.5	292.7	293.7		PS	WAT			30.9	
1434	New York Power Authority	Brentwood		K	24164	Brentwood	103	36	2001-08-01	50.0	47.1	45.5	46.4		GT	NG			43.2	
1435	New York Power Authority	Crescent 1		F	24018	Crescent	001	36	1991-07-01	2.8	3.2	2.8	2.8		HY	WAT			15.4	
1436	New York Power Authority	Crescent 2		F	24018	Crescent	001	36	1991-07-01	2.8	3.2	2.8	2.8		HY	WAT			15.3	
1437	New York Power Authority	Crescent 3		F	24018	Crescent	001	36	1991-07-01	3.0	3.2	3.0	3.0		HY	WAT			21.0	
1438	New York Power Authority	Crescent 4		F	24018	Crescent	001	36	1991-07-01	3.0	3.2	3.0	3.0		HY	WAT			0.0	
1439	New York Power Authority	Flynn		K	23794	Holtsville	103	36	1994-05-01	170.0	135.5	133.8	162.7		CC	NG	FO2		1,208.0	
1440	New York Power Authority	Gowanus 5		J	24156	Brooklyn	047	36	2001-08-01	50.0	45.4	40.0	40.0		GT	NG			31.3	
1441	New York Power Authority	Gowanus 6		J	24157	Brooklyn	047	36	2001-08-01	50.0	46.1	39.9	39.9		GT	NG			40.1	
1442	New York Power Authority	Grahamsville		G	23607	Grahamsville	105	36	1956-12-01	18.0	16.3	18.0	18.0		HY	WAT			98.8	
1443	New York Power Authority	Greenport IC 4		K	1652	Greenport	103	36	1957-06-06	1.2	1.7	1.0	1.0		IC	FO2			0.0	
1444	New York Power Authority	Greenport IC 5		K	1652	Greenport	103	36	1965-07-08	1.8	1.7	1.5	1.5		IC	FO2			0.0	
1445	New York Power Authority	Greenport IC 6		K	1652	Greenport	103	36	1971-09-17	3.8	2.7	2.5	2.5		IC	FO2			0.0	
1446	New York Power Authority	Harlem River 1		J	24160	Bronx	005	36	2001-08-01	50.0	46.0	39.9	39.9		GT	NG			31.0	
1447	New York Power Authority	Harlem River 2		J	24161	Bronx	005	36	2001-08-01	50.0	45.2	40.0	40.0		GT	NG			23.3	
1448	New York Power Authority	Hellgate 1		J	24158	Bronx	005	36	2001-08-01	50.0	45.0	39.9	39.9		GT	NG			24.7	
1449	New York Power Authority	Hellgate 2		J	24159	Bronx	005	36	2001-08-01	50.0	45.0	40.0	40.0		GT	NG			20.9	
1450	New York Power Authority	Jarvis 1		E	23743	Hinckley	065	36	1991-07-01	4.5	4.5	4.5	4.5		HY	WAT			26.2	
1451	New York Power Authority	Jarvis 2		E	23743	Hinckley	065	36	1991-07-01	4.5	4.5	4.5	4.5		HY	WAT			0.0	
1452	New York Power Authority	Kent		J	24152	Brooklyn	047	36	2001-08-01	50.0	46.9	46.0	46.6		GT	NG			39.8	
1453	New York Power Authority	Lewiston PS (Fleet)		A	23760	Niagara Falls	063	36	1961-01-01	240.0	240.0	240.0	240.0		PS	WAT			483.2	
1454	New York Power Authority	Moses Niagara (Fleet)		A	23760	Niagara Falls	063	36	1961-01-01	2,860.0	2,460.0	2,444.7	2,442.0		HY	WAT			13,211.9	
1455	New York Power Authority	Neversink		G	23608	Grahamsville	105	36	1953-12-01	25.0	22.0	25.0	25.0		HY	WAT			41.4	
1456	New York Power Authority	Pouch		J	24155	Staten Island	085	36	2001-08-01	50.0	47.1	46.0	46.8		GT	NG			40.7	
1457	New York Power Authority	St Lawrence - FDR (Fleet)		D	23600	Massena	089	36	1958-07-01	1,088.0	856.0	843.2	820.8		HY	WAT			7,077.5	
1458	New York Power Authority	Vernon Blvd 2		J	24162	Queens	081	36	2001-08-01	50.0	46.2	40.0	40.0		GT	NG			20.9	
1459	New York Power Authority	Vernon Blvd 3		J	24163	Queens	081	36	2001-08-01	50.0	43.8	39.9	39.9		GT	NG			28.3	
1460	New York Power Authority	Vischer Ferry 1		F	24020	Vischer Ferry	091	36	1991-07-01	2.8	3.2	2.8	2.9		HY	WAT			15.0	
1461	New York Power Authority	Vischer Ferry 2		F	24020	Vischer Ferry	091	36	1991-07-01	2.8	3.2	2.8	2.9		HY	WAT			14.4	
1462	New York Power Authority	Vischer Ferry 3		F	24020	Vischer Ferry	091	36	1991-07-01	3.0	3.2	3.0	2.9		HY	WAT			0.0	
1463	New York Power Authority	Vischer Ferry 4		F	24020	Vischer Ferry	091	36	1991-07-01	3.0	3.2	3.0	2.9		HY	WAT			21.0	
1464	New York State Elec. & Gas Corp.	AA Dairy		C	5013	Ithaca	109	36	1998-06-01	0.1		0.0	0.0		IC	MTE			0.0	
1465	New York State Elec. & Gas Corp.	Alice Falls 1		D	23915	Ausable	019	36	1991-11-01	1.5	1.6	0.0	0.0		HY	WAT			0.0	
1466	New York State Elec. & Gas Corp.	Alice Falls 2		D	23915	Ausable	019	36	1991-11-01	0.6	0.6	0.0	0.0		HY	WAT			0.0	
1467	New York State Elec. & Gas Corp.	Allegheny 8		C	23528	Kittanning PA	005	42	1990-10-01	16.0	14.7	16.0	16.0		HY	WAT			105.8	
1468	New York State Elec. & Gas Corp.	Allegheny 9		C	23528	Kittanning PA	005	42	1990-10-01	22.0	20.2	22.0	22.0		HY	WAT			129.3	
1469	New York State Elec. & Gas Corp.	Auburn - Mill St.		C	5014	Auburn	011	36	1981-10-01	0.4		0.0	0.0		HY	WAT				
1470	New York State Elec. & Gas Corp.	Auburn - No. Div.St		C	5015	Auburn	011	36	1992-12-01	0.8		0.0	0.0		HY	WAT				
1471	New York State Elec. & Gas Corp.	Auburn - State St.		C	24147	Auburn	011	36	1995-01-01	7.4	5.8	5.0	6.9		GT	NG			0.9	
1472	New York State Elec. & Gas Corp.	Broome LFGE		C	323600	Binghamton	007	36	2007-09-01	2.1	2.1	2.1	2.1		IC	MTE			16.9	
1473	New York State Elec. & Gas Corp.	Cadyville 1		D	23628	Schuyler Falls	019	36	1921-08-01	1.2	1.0	1.2	1.2		HY	WAT			5.1	
1474	New York State Elec. & Gas Corp.	Cadyville 2		D	23628	Schuyler Falls	019	36	1921-08-01	1.2	1.0	1.2	1.2		HY	WAT			5.4	
1475	New York State Elec. & Gas Corp.	Cadyville 3		D	23628	Schuyler Falls	019	36	1986-09-01	3.1	2.7	3.1	3.1		HY	WAT			13.2	
1476	New York State Elec. & Gas Corp.	Chasm Hydro		D	5016	Chateaugay	033	36	1982-03-01	1.6		0.0	0.0		HY	WAT				
1477	New York State Elec. & Gas Corp.	Croton Fall Hydro		I	5017	North Salem	119	36	1987-01-01	0.2		0.0	0.0		HY	WAT				
1478	New York State Elec. & Gas Corp.	Harris Lake		D	5018	Newcomb	031	36	1967-08-01	1.7		0.0	0.0		IC	FO2				
1479	New York State Elec. & Gas Corp.	High Falls 1		D	23628	Saranac	019	36	1948-08-01	4.0	4.3	4.0	4.0		HY	WAT			13.1	
1480	New York State Elec. & Gas Corp.	High Falls 2		D	23628	Saranac	019	36	1949-08-01	4.0	4.3	4.0	4.0		HY	WAT			21.7	
1481	New York State Elec. & Gas Corp.	High Falls 3		D	23628	Saranac	019	36	1956-08-01	7.0	8.2	7.0	7.0		HY	WAT			41.0	
1482	New York State Elec. & Gas Corp.	Kent Falls 1		D	23628	Schuyler Falls	019	36	1928-08-01	3.6	3.0	3.6	3.6		HY	WAT			17.5	
1483	New York State Elec. & Gas Corp.	Kent Falls 2		D	23628	Schuyler Falls	019	36	1928-08-01	3.6	3.0	3.6	3.6		HY	WAT			0.0	
1484	New York State Elec. & Gas Corp.	Kent Falls 3		D	23628	Schuyler Falls	019	36	1985-07-01	6.4	6.0	6.4	6.4		HY	WAT			37.5	
1485	New York State Elec. & Gas Corp.	Lower Saranac 1		D	23913	Schuyler Falls	019	36	1990-10-01	3.2	3.5	0.0	0.0		HY	WAT			0.0	
1486	New York State Elec. & Gas Corp.	Lower Saranac 2		D	23913	Schuyler Falls	019	36	1990-10-01	3.2	3.5	0.0	0.0		HY	WAT			0.0	
1487	New York State Elec. & Gas Corp.	Lower Saranac 3		D	23913	Schuyler Falls	019	36	1990-10-01	0.3	2.9	0.0	0.0		HY	WAT			0.0	
1488	New York State Elec. & Gas Corp.	Mechanicville 1		F	23645	Stillwater	091	36	1983-09-01	9.2	10.0	9.2	9.3		HY	WAT			45.7	
1489	New York State Elec. & Gas Corp.	Mechanicville 2		F	23645	Stillwater	091	36	1983-09-01	9.3	10.0	9.3	9.3		HY	WAT			40.0	
1490	New York State Elec. & Gas Corp.	Mill C 1		D	23628	Plattsburgh	019	36	1944-08-01	1.0	0.9	1.0	1.0		HY	WAT			4.9	
1491	New York State Elec. & Gas Corp.	Mill C 2		D	23628	Plattsburgh	019	36	1943-08-01	1.2	1.2	1.2	1.2		HY	WAT			4.8	
1492	New York State Elec. & Gas Corp.	Mill C 3		D	23628	Plattsburgh	019	36	1984-11-01	3.8	3.7	3.8	3.8		HY	WAT			15.8	
1493	New York State Elec. & Gas Corp.	Montville Falls		C	5019	Moravia	011	36	1992-08-01	0.2		0.0	0.0		HY	WAT				
1494	New York State Elec. & Gas Corp.	Rainbow Falls 1		D	23628	Ausable	019	36	1926-08-01	1.3	1.5	1.3	1.3		HY	WAT			0.0	
1495	New York State Elec. & Gas Corp.	Rainbow Falls 2		D	23628	Ausable	019	36	1927-08-01	1.3	1.5	1.3	1.3		HY	WAT			0.0	
1496	New York State Elec. & Gas Corp.	Waterloo 2		C	5020	Waterloo	099	36	1998-06-01	0.5		0.0	0.0		HY	WAT				
1497	New York State Elec. & Gas Corp.	Waterloo 3		C	5021	Waterloo	099	36	1998-06-01	0.5		0.0	0.0		HY	WAT				
1498	New York State Elec. & Gas Corp.	Waterloo 4		C	5022	Waterloo	099	36	1998-06-01	0.5		0.0	0.0		HY	WAT				
1499	Niagara Generation, LLC	Niagara Bio-Gen		A	23895	Niagara Falls	063	36	1991-08-01	56.0	50.5	43.2	37.2		ST	WD			89.3	
1500	Niagara Mohawk Power Corp.	Boralex - Hudson Falls		F	24011	Hudson Falls	115	36	1995-10-01	44.0	43.7	44.0	44.0		HY	WAT			228.5	
1501	Niagara Mohawk Power Corp.	Boralex - South Glens Falls		F	24028	Moreau	091	36	1994-12-01	13.8	14.8	0.0	0.0		HY	WAT			89.9	
1502	Niagara Mohawk Power Corp.	CHI-LaChute		F	1654	Ticonderoga	031	36	1987-12-01	9.0	8.9	0.0	0.0		HY	WAT			33.5	
1503	Niagara Mohawk Power Corp.	Fortis - Dolgeville		E	23807	Dolgeville	043	36	1985-07-01	5.0	6.3	0.0	0.0		HY	WAT			17.4	

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1504	Niagara Mohawk Power Corp.	Fortis Energy - Philadelphia	E	1656	Philadelphia	045	36	1986-08-01	3.6	3.2	0.0	0.0		HY	WAT			8.8	
1505	Niagara Mohawk Power Corp.	Fortis Energy - Moose River	E	24016	Moose River	049	36	1987-09-01	12.6	12.0	0.0	0.0		HY	WAT			45.9	
1506	Niagara Mohawk Power Corp.	Fortistar - N.Tonawanda	A	24026	N Tonawanda	029	36	1993-06-01	55.3	57.0	54.9	63.9		CC	NG	FO2		39.8	
1507	Niagara Mohawk Power Corp.	General Mills Inc	A	23808	Buffalo	029	36	1988-12-01	3.8	3.8	0.0	0.0		GT	NG			0.5	
1508	Niagara Mohawk Power Corp.	International Paper - Curtis	F	1655	Corinth	091	36	1986-01-01	9.8	30.8	0.0	0.0		HY	WAT			415.8	(G)
1509	Niagara Mohawk Power Corp.	International Paper - Palmer	F	1655	Corinth	091	36	1986-01-01	49.2	30.8	0.0	0.0		HY	WAT				
1510	Niagara Mohawk Power Corp.	Little Falls Hydro	E	24013	Little Falls	043	36	1987-01-01	13.0	12.6	0.0	0.0		HY	WAT			61.1	
1511	Niagara Mohawk Power Corp.	Onondaga County	C	23987	North Syracuse	067	36	1994-12-01	39.5	32.6	32.1	30.8		ST	REF			187.6	
1512	Niagara Mohawk Power Corp.	Pyrites Assoc.	E	24023	Canton	089	36	1985-12-01	8.2	7.5	0.0	0.0		HY	WAT			29.7	
1513	Niagara Mohawk Power Corp.	Adams Hydro	E	23633	Adams	045	36	1987-11-01	0.2		0.0	0.0		HY	WAT			0.0	
1514	Niagara Mohawk Power Corp.	Algon.-Burt Dam Assoc.	A	23774	Burt	063	36	1987-12-01	0.4		0.0	0.0		HY	WAT			2.2	
1515	Niagara Mohawk Power Corp.	Algon.-Christine.Falls	F	23643	Wells	041	36	1987-12-01	0.8		0.0	0.0		HY	WAT			2.5	
1516	Niagara Mohawk Power Corp.	Algon.-Cranberry. Lake	E	23633	Cranberry Lake	049	36	1987-12-01	0.5		0.0	0.0		HY	WAT			0.0	
1517	Niagara Mohawk Power Corp.	Algon.-Forrestport	E	23633	Forrestport	065	36	1987-12-01	3.4		0.0	0.0		HY	WAT			8.1	
1518	Niagara Mohawk Power Corp.	Algon.-Herkimer	E	23633	Herkimer	043	36	1987-12-01	1.6		0.0	0.0		HY	WAT			0.0	
1519	Niagara Mohawk Power Corp.	Algon.-Hollow Dam Power	E	23633	Saint Lawrence	089	36	1987-12-01	1.0		0.0	0.0		HY	WAT			3.1	
1520	Niagara Mohawk Power Corp.	Algon.-Kayuta	E	23633	Kayuta	065	36	1988-05-01	0.4		0.0	0.0		HY	WAT			0.0	
1521	Niagara Mohawk Power Corp.	Algon.-Ogdensburg	E	23633	Ogdensberg	089	36	1987-12-01	3.5		0.0	0.0		HY	WAT			10.0	
1522	Niagara Mohawk Power Corp.	Algon.-Otter Creek	E	23633	Greig	049	36	1986-11-01	0.5		0.0	0.0		HY	WAT			1.2	
1523	Niagara Mohawk Power Corp.	Allied Frozen Storage	A	23774	Cheektowaga	029	36	2008-05-01	0.1		0.0	0.0		IC	NG			0.1	
1524	Niagara Mohawk Power Corp.	Azure Mnt. Pwr Co	E	23633	St. Regis Falls	033	36	1993-08-01	0.6		0.0	0.0		HY	WAT			1.8	
1525	Niagara Mohawk Power Corp.	Beaver Falls #1	E	23633	Beaver Falls	049	36	1986-01-01	1.5		0.0	0.0		HY	WAT			10.4	
1526	Niagara Mohawk Power Corp.	Beaver Falls #2	E	23633	Beaver Falls	049	36	1986-01-01	1.0		0.0	0.0		HY	WAT			5.7	
1527	Niagara Mohawk Power Corp.	Bellows Towers	E	23633	Malone	033	36	1987-06-01	0.2		0.0	0.0		HY	WAT			0.0	
1528	Niagara Mohawk Power Corp.	Black River Hyd#1	E	23633	Port Leyden	049	36	1984-07-01	1.9		0.0	0.0		HY	WAT			4.9	
1529	Niagara Mohawk Power Corp.	Black River Hyd#2	E	23633	Port Leyden	049	36	1985-12-01	1.6		0.0	0.0		HY	WAT			2.1	
1530	Niagara Mohawk Power Corp.	Black River Hyd#3	E	23633	Port Leyden	049	36	1984-07-01	2.2		0.0	0.0		HY	WAT			14.9	
1531	Niagara Mohawk Power Corp.	Boralex - Middle Falls	F	23643	Easton	115	36	1989-12-01	2.2		0.0	0.0		HY	WAT			13.2	
1532	Niagara Mohawk Power Corp.	Burrstone Energy Center, LLC	E	23633	Utica	065	36	2009-11-01	1.1		0.0	0.0		IC	NG			2.7	
1533	Niagara Mohawk Power Corp.	Burrstone Energy Center, LLC	E	23633	Utica	065	36	2009-11-01	2.2		0.0	0.0		IC	NG			0.1	
1534	Niagara Mohawk Power Corp.	Cal Ban Power	A	23774	Allegany	003	36	1995-06-01	0.1		0.0	0.0		IC	NG			0.1	
1535	Niagara Mohawk Power Corp.	Cellu-Tissue Corp - Natural Di	E	23633	Natural Dam	089	36	1986-01-01	1.0		0.0	0.0		HY	WAT			0.0	
1536	Niagara Mohawk Power Corp.	Champlain Spinner	F	23643	Whitehall	031	36	1992-07-01	0.4		0.0	0.0		HY	WAT			1.2	
1537	Niagara Mohawk Power Corp.	CHI Dexter Hydro	E	23633	Dexter	045	36	1988-01-01	4.2		0.0	0.0		HY	WAT			11.7	
1538	Niagara Mohawk Power Corp.	CHI Diamond Is HY	E	23633	Watertown	045	36	1986-01-01	1.2		0.0	0.0		HY	WAT			6.3	
1539	Niagara Mohawk Power Corp.	CHI Fowler	E	23633	Fowler	049	36	1986-01-01	0.6		0.0	0.0		HY	WAT			1.7	
1540	Niagara Mohawk Power Corp.	CHI Hailsboro #3	E	23633	Hailsboro	089	36	1986-01-01	0.8		0.0	0.0		HY	WAT			4.3	
1541	Niagara Mohawk Power Corp.	CHI Hailsboro #4	E	23633	Hailsboro	089	36	1986-01-01	1.4		0.0	0.0		HY	WAT			11.6	
1542	Niagara Mohawk Power Corp.	CHI Hailsboro #6	E	23633	Hailsboro	089	36	1986-01-01	0.8		0.0	0.0		HY	WAT			5.2	
1543	Niagara Mohawk Power Corp.	CHI Theresa Hydro	E	23633	Theresa	089	36	1986-01-01	1.3		0.0	0.0		HY	WAT			7.5	
1544	Niagara Mohawk Power Corp.	Chittenden Falls	F	23643	Stuyvesant	021	36	1995-12-01	0.6		0.0	0.0		HY	WAT			0.6	
1545	Niagara Mohawk Power Corp.	City of Oswego (H.D.)	C	23634	Oswego	075	36	1994-02-01	11.9		0.0	0.0		HY	WAT			50.0	
1546	Niagara Mohawk Power Corp.	City of Utica - Sand Road	E	23633	Utica	065	36	1993-05-01	0.2		0.0	0.0		HY	WAT			1.6	
1547	Niagara Mohawk Power Corp.	City of Utica -Trenton Falls	E	23633	Utica	065	36	1993-02-01	0.2		0.0	0.0		HY	WAT			0.4	
1548	Niagara Mohawk Power Corp.	City of Watertown	E	23633	Watertown	045	36	1986-01-01	8.1		0.0	0.0		HY	WAT			13.6	
1549	Niagara Mohawk Power Corp.	City of Watervliet	F	23643	Guilderland	001	36	1986-01-01	1.2		0.0	0.0		HY	WAT			3.3	
1550	Niagara Mohawk Power Corp.	Cons. HY-Victory	F	23643	Victory Falls	091	36	1986-12-01	1.7		0.0	0.0		HY	WAT			5.7	
1551	Niagara Mohawk Power Corp.	Copenhagen Assoc.	E	23633	Copenhagen	049	36	1986-01-01	3.3		0.0	0.0		HY	WAT			10.4	
1552	Niagara Mohawk Power Corp.	Cottrell Paper	F	23643	Rock City Falls	091	36	1987-01-01	0.3		0.0	0.0		HY	WAT			0.1	
1553	Niagara Mohawk Power Corp.	Edison Hydro Electric	F	23643	Stottville	021	36	2009-11-01	0.4		0.0	0.0		HY	WAT			1.9	
1554	Niagara Mohawk Power Corp.	Empire HY Partner	E	23633	Port Leyden	049	36	1984-11-01	1.0		0.0	0.0		HY	WAT			5.0	
1555	Niagara Mohawk Power Corp.	Finch Paper LLC - Glens Falls	F	23643	Glens Falls	113	36	2009-11-01	11.8		0.0	0.0		HY	WAT			2.0	
1556	Niagara Mohawk Power Corp.	Finch Pruyn	F	23643	Glens Falls	113	36	1989-12-01	29.0		0.0	0.0		HY	WAT			0.0	
1557	Niagara Mohawk Power Corp.	Fort Miller Assoc	F	23643	Schuylerville	091	36	1985-10-01	5.0		0.0	0.0		HY	WAT			24.3	
1558	Niagara Mohawk Power Corp.	Fortis Energy - Diana	E	23633	Diana	049	36	1985-07-01	1.8		0.0	0.0		HY	WAT			7.1	
1559	Niagara Mohawk Power Corp.	Franklin Hydro	D	24055	Franklin Falls	033	36	1995-03-01	0.3		0.0	0.0		HY	WAT			0.0	
1560	Niagara Mohawk Power Corp.	Green Island Power Authority	F	23643	Green Island	001	36	1971-01-01	6.0		0.0	0.0		HY	WAT			35.7	
1561	Niagara Mohawk Power Corp.	Hewittville Hydro	E	23633	Potsdam	089	36	1984-07-01	3.0		0.0	0.0		HY	WAT			13.5	
1562	Niagara Mohawk Power Corp.	Hollings&Vose-Center	F	23643	Easton	115	36	1986-01-01	0.4		0.0	0.0		HY	WAT			0.2	
1563	Niagara Mohawk Power Corp.	Hollings&Vose-Lower	F	23643	Easton	115	36	1986-01-01	0.4		0.0	0.0		HY	WAT			0.0	
1564	Niagara Mohawk Power Corp.	Hollings&Vose-Upper	F	23643	Easton	115	36	1986-01-01	0.4		0.0	0.0		HY	WAT			4.6	
1565	Niagara Mohawk Power Corp.	Hoosick Falls	F	23643	Hoosick Falls	083	36	1988-08-01	0.6		0.0	0.0		HY	WAT			0.0	
1566	Niagara Mohawk Power Corp.	Hydrocarbon-Algny	A	23774	Allegany	003	36	1992-12-01	0.2		0.0	0.0		IC	NG			0.0	
1567	Niagara Mohawk Power Corp.	Indian Falls HY	E	23633	Theresa	045	36	1986-01-01	0.3		0.0	0.0		HY	WAT			0.6	
1568	Niagara Mohawk Power Corp.	Kings Falls	E	23633	Copenhagen	049	36	1988-05-01	1.6		0.0	0.0		HY	WAT			0.0	
1569	Niagara Mohawk Power Corp.	Laidlaw Energy	A	23774	Ellicottville	009	36	1991-07-01	3.4		0.0	0.0		GT	NG			0.0	
1570	Niagara Mohawk Power Corp.	Laidlaw Energy	A	23774	Ellicottville	009	36	1991-07-01	2.4		0.0	0.0		ST	NG			0.0	
1571	Niagara Mohawk Power Corp.	Laquidara-Long Falls	E	23633	Carthage	045	36	1991-06-01	3.3		0.0	0.0		HY	WAT			5.2	
1572	Niagara Mohawk Power Corp.	Lyonsdale Assoc. (Burrows)	E	23633	Lyons Falls	049	36	1984-07-01	3.0		0.0	0.0		HY	WAT			11.1	
1573	Niagara Mohawk Power Corp.	Mechanicville	F	23643	Mechanicville	091	36	2005-03-01	2.0		0.0	0.0		HY	WAT			17.2	
1574	Niagara Mohawk Power Corp.	Mountainaire Massage Spa	F	23643	Wevertown	113	36	2009-11-01	0.0		0.0	0.0		HY	WAT			0.0	
1575	Niagara Mohawk Power Corp.	Mt. Ida Assoc.	F	23643	Troy	083	36	1986-01-01	6.0		0.0	0.0		HY	WAT			9.1	

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EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1576	Niagara Mohawk Power Corp.	Newport HY Assoc		E	23633	Newport	043	36	1987-12-01	1.7		0.0	0.0		HY	WAT			7.3	
1577	Niagara Mohawk Power Corp.	Nottingham High School		C	23634	Syracuse	067	36	1988-06-01	0.2		0.0	0.0		CC	NG			0.0	
1578	Niagara Mohawk Power Corp.	Oakvale Construction		D	24055	Wilmington	031	36	2009-11-01	0.4		0.0	0.0		HY	WAT			1.6	
1579	Niagara Mohawk Power Corp.	Onondaga Energy Partners		C	23634	Onondaga	067	36	1987-12-01	1.4		0.0	0.0		IC	MTE			0.0	
1580	Niagara Mohawk Power Corp.	Oswego County		C	23634	Oswego	075	36	1986-03-01	3.6		0.0	0.0		ST	REF			5.0	
1581	Niagara Mohawk Power Corp.	Oswego HY Partners (Phoeni		C	23634	Phoenix	067	36	1990-12-01	3.4		0.0	0.0		HY	WAT			11.6	
1582	Niagara Mohawk Power Corp.	Riverrat Glass&Electric		F	23643	Wadhams	031	36	1986-01-01	0.6		0.0	0.0		HY	WAT			2.2	
1583	Niagara Mohawk Power Corp.	Sandy Hollow HY		E	23633	Sandy Hollow	045	36	1986-09-01	0.6		0.0	0.0		HY	WAT			1.5	
1584	Niagara Mohawk Power Corp.	Seneca Limited		C	23634	Syracuse	067	36	1985-12-01	0.2		0.0	0.0		HY	WAT			0.0	
1585	Niagara Mohawk Power Corp.	St. Elizabeth Medical Center		E	23633	Utica	065	36	2012-02-01	0.6		0.0	0.0		IC	NG			0.6	
1586	Niagara Mohawk Power Corp.	Stevens&Thompson Paper Cc		F	23643	Middle Falls	115	36	1987-12-01	10.5		0.0	0.0		HY	WAT			14.3	
1587	Niagara Mohawk Power Corp.	Stillwater Assoc.		E	23633	Webb	043	36	1987-01-01	1.8		0.0	0.0		HY	WAT			7.5	
1588	Niagara Mohawk Power Corp.	Stillwater HY Partners		F	23643	Stillwater	091	36	1993-04-01	3.4		0.0	0.0		HY	WAT			13.6	
1589	Niagara Mohawk Power Corp.	Stuyvesant Falls		F	23643	Stuyvesant	021	36	2013-02-01	7.0		0.0	0.0		HY	WAT			12.7	
1590	Niagara Mohawk Power Corp.	Sustainable Bioelectric LLC		A	23774	Wheeatfield	063	36	2014-03-01	0.6		0.0	0.0		IC	MTE				
1591	Niagara Mohawk Power Corp.	Synergics - Middle Greenwich		F	23643	Greenwich	115	36	1987-12-01	0.2		0.0	0.0		HY	WAT			0.0	
1592	Niagara Mohawk Power Corp.	Synergics - Union Falls		D	24055	Union Falls	019	36	1987-12-01	3.0		0.0	0.0		HY	WAT			13.4	
1593	Niagara Mohawk Power Corp.	Synergics - Upper Greenwich		F	23643	Greenwich	115	36	1987-12-01	0.4		0.0	0.0		HY	WAT			0.0	
1594	Niagara Mohawk Power Corp.	Tannery Island		E	23633	Carthage	045	36	1986-01-01	1.5		0.0	0.0		HY	WAT			9.2	
1595	Niagara Mohawk Power Corp.	Town of Wells		F	23643	Wells	041	36	1987-12-01	0.5		0.0	0.0		HY	WAT			1.6	
1596	Niagara Mohawk Power Corp.	Tri-City JATC		F	23643	Latham	001	36	2009-11-01	0.0		0.0	0.0		IC	NG			0.0	
1597	Niagara Mohawk Power Corp.	Unionville Hydro		E	23633	Potsdam	089	36	1984-07-01	3.0		0.0	0.0		HY	WAT			13.6	
1598	Niagara Mohawk Power Corp.	United States Gypsum		A	23774	Batavia	037	36	2009-11-01	5.8		0.0	0.0		CC	NG			0.9	
1599	Niagara Mohawk Power Corp.	Valatie Falls		F	23643	Valatie	021	36	1992-12-01	0.1		0.0	0.0		HY	WAT			0.5	
1600	Niagara Mohawk Power Corp.	Valley Falls Assoc.		F	23643	Valley Falls	083	36	1985-08-01	2.5		0.0	0.0		HY	WAT			8.2	
1601	Niagara Mohawk Power Corp.	Village of Gouverneur		E	23633	Gouverneur	089	36	1986-01-01	0.1		0.0	0.0		HY	WAT			0.5	
1602	Niagara Mohawk Power Corp.	Village of Potsdam		E	23633	Potsdam	089	36	1986-01-01	0.8		0.0	0.0		HY	WAT			3.1	
1603	Niagara Mohawk Power Corp.	Village of Potsdam 2		E	23633	Potsdam	089	36	2014-04-01	0.5		0.0	0.0		HY	WAT			1.2	
1604	Niagara Mohawk Power Corp.	Village of Saranac Lake		E	23633	Saranac Lake	033	36	1996-12-01	0.2		0.0	0.0		HY	WAT			0.5	
1605	Niagara Mohawk Power Corp.	Wave Hydro LLC		C	23634	Baldwinsville	067	36	2010-02-07	0.8		0.0	0.0		HY	WAT			0.0	
1606	Niagara Mohawk Power Corp.	West End Dam Assoc.		E	23633	Carthage	045	36	1986-01-01	4.4		0.0	0.0		HY	WAT			24.3	
1607	Niagara Wind Power, LLC	Steel Wind		A	323596	Lackawanna	029	36	2007-01-23	20.0	20.0	20.0	20.0		WT	WND			46.6	
1608	Nine Mile Point Nuclear Station, LLC	Nine Mile Point 1		C	23575	Scriba	075	36	1969-11-01	641.8	630.5	636.6	639.7		NB	UR			5,442.1	
1609	Nine Mile Point Nuclear Station, LLC	Nine Mile Point 2		C	23744	Scriba	075	36	1988-08-01	1,259.3	1,246.6	1,290.4	1,296.5		NB	UR			9,797.1	
1610	Noble Altona Windpark, LLC	Altona Wind Power		D	323606	Altona	019	36	2008-09-23	97.5	97.5	97.5	97.5		WT	WND			186.4	
1611	Noble Bliss Windpark, LLC	Bliss Wind Power		A	323608	Bliss	121	36	2008-03-20	100.5	100.5	100.5	100.5		WT	WND			206.6	
1612	Noble Chateaugay Windpark, LLC	Chateaugay Wind Power		D	323614	Chateaugay	033	36	2008-10-07	106.5	106.5	106.5	106.5		WT	WND			200.5	
1613	Noble Clinton Windpark 1, LLC	Clinton Wind Power		D	323605	Clinton	019	36	2008-04-09	100.5	100.5	100.5	100.5		WT	WND			186.2	
1614	Noble Ellenburg Windpark, LLC	Ellenburg Wind Power		D	323604	Ellenburg	019	36	2008-03-31	81.0	81.0	81.0	81.0		WT	WND			176.6	
1615	Noble Wethersfield Windpark, LLC	Wethersfield Wind Power		C	323626	Wethersfield	121	36	2008-12-11	126.0	126.0	126.0	126.0		WT	WND			267.8	
1616	Northbrook Lyons Falls, LLC	Lyons Falls Hydro		E	23570	Lyons Falls	049	36	1986-01-01	8.0	7.3	8.0	8.0		HY	WAT			41.1	
1617	NRG Power Marketing LLC	Arthur Kill GT 1		J	23520	Staten Island	085	36	1970-06-01	20.0	16.5	10.9	11.8		GT	NG			0.3	
1618	NRG Power Marketing LLC	Arthur Kill ST 2		J	23512	Staten Island	085	36	1959-08-01	376.2	357.7	338.3	340.9		ST	NG			788.8	
1619	NRG Power Marketing LLC	Arthur Kill ST 3		J	23513	Staten Island	085	36	1969-06-01	535.5	518.0	503.0	527.1		ST	NG			331.4	
1620	NRG Power Marketing LLC	Astoria GT 05		J	24106	Queens	081	36	1970-06-01	19.2	16.0	12.3	15.8		GT	FO2			0.1	
1621	NRG Power Marketing LLC	Astoria GT 07		J	24107	Queens	081	36	1970-06-01	19.2	15.5	11.5	14.0		GT	FO2			0.1	
1622	NRG Power Marketing LLC	Astoria GT 08		J	24108	Queens	081	36	1970-06-01	19.2	15.3	11.4	14.8		GT	FO2			0.1	
1623	NRG Power Marketing LLC	Astoria GT 10		J	24110	Queens	081	36	1971-01-01	31.8	24.9	18.4	22.6		GT	FO2			0.5	
1624	NRG Power Marketing LLC	Astoria GT 11		J	24225	Queens	081	36	1971-02-01	31.8	23.6	16.5	25.0		GT	FO2			1.0	
1625	NRG Power Marketing LLC	Astoria GT 12		J	24226	Queens	081	36	1971-05-01	31.8	22.7	17.7	22.4		GT	FO2			0.6	
1626	NRG Power Marketing LLC	Astoria GT 13		J	24227	Queens	081	36	1971-05-01	31.8	24.0	16.9	22.1		GT	FO2			0.4	
1627	NRG Power Marketing LLC	Astoria GT 2-1		J	24094	Queens	081	36	1970-06-01	46.5	41.2	35.7	43.9		JE	KER	NG		6.2	
1628	NRG Power Marketing LLC	Astoria GT 2-2		J	24095	Queens	081	36	1970-06-01	46.5	42.4	32.2	42.7		JE	KER	NG		6.8	
1629	NRG Power Marketing LLC	Astoria GT 2-3		J	24096	Queens	081	36	1970-06-01	46.5	41.2	31.8	42.2		JE	KER	NG		3.6	
1630	NRG Power Marketing LLC	Astoria GT 2-4		J	24097	Queens	081	36	1970-06-01	46.5	41.0	32.6	43.4		JE	KER	NG		3.1	
1631	NRG Power Marketing LLC	Astoria GT 3-1		J	24098	Queens	081	36	1970-06-01	46.5	41.2	31.7	41.8		JE	KER	NG		4.1	
1632	NRG Power Marketing LLC	Astoria GT 3-2		J	24099	Queens	081	36	1970-06-01	46.5	43.5	33.7	42.5		JE	KER	NG		3.1	
1633	NRG Power Marketing LLC	Astoria GT 3-3		J	24100	Queens	081	36	1970-06-01	46.5	43.0	32.2	42.3		JE	KER	NG		4.5	
1634	NRG Power Marketing LLC	Astoria GT 3-4		J	24101	Queens	081	36	1970-06-01	46.5	43.0	34.3	42.5		JE	KER	NG		3.1	
1635	NRG Power Marketing LLC	Astoria GT 4-1		J	24102	Queens	081	36	1970-07-01	46.5	42.6	34.3	42.7		JE	KER	NG		6.9	
1636	NRG Power Marketing LLC	Astoria GT 4-2		J	24103	Queens	081	36	1970-07-01	46.5	41.4	33.6	43.6		JE	KER	NG		3.8	
1637	NRG Power Marketing LLC	Astoria GT 4-3		J	24104	Queens	081	36	1970-07-01	46.5	41.1	32.8	42.8		JE	KER	NG		2.6	
1638	NRG Power Marketing LLC	Astoria GT 4-4		J	24105	Queens	081	36	1970-07-01	46.5	42.8	31.6	42.5		JE	KER	NG		3.8	
1639	NRG Power Marketing LLC	Dunkirk 2		A	23564	Dunkirk	013	36	1950-12-01	100.0	97.2	75.0	75.0		ST	BIT			368.5	(S)
1640	NRG Power Marketing LLC	Dunkirk IC 2		A	5050	Dunkirk	013	36	1990-01-01	0.5		0.0	0.0		IC	FO2				
1641	NRG Power Marketing LLC	Huntley 67		A	23561	Tonawanda	029	36	1957-12-01	218.0	196.5	187.9	187.0		ST	BIT			500.0	
1642	NRG Power Marketing LLC	Huntley 68		A	23562	Tonawanda	029	36	1958-12-01	218.0	198.0	189.5	187.2		ST	BIT			703.9	
1643	NRG Power Marketing LLC	Huntley IC 1		A	5051	Tonawanda	029	36	1967-08-01	0.7		0.0	0.0		IC	FO2				
1644	NRG Power Marketing LLC	Oswego 5		C	23606	Oswego	075	36	1976-02-01	901.8	850.3	828.5	825.5		ST	FO6			43.3	
1645	NRG Power Marketing LLC	Oswego 6		C	23613	Oswego	075	36	1980-07-01	901.8	835.2	826.5	832.0		ST	FO6	NG		40.6	
1646	NRG Power Marketing LLC	Oswego IC 1		C	5052	Oswego	075	36	1967-08-01	0.7		0.0	0.0		IC	FO2				
1647	NRG Power Marketing LLC	Oswego IC 2		C	5053	Oswego	075	36	1976-02-01	0.8		0.0	0.0		IC	FO2				

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1648	NRG Power Marketing LLC	Oswego IC	3	C	5054	Oswego	075	36	1980-07-01	0.8		0.0	0.0		IC	FO2				
1649	Orange and Rockland Utilities	Buttermilk Falls		G	5055	Highland Falls	071	36	1986-12-01	0.1		0.0	0.0		HY	WAT				
1650	Orange and Rockland Utilities	Intl. Crossroads		G	5056	Mahwah NJ	003	34	1987-12-01	3.0		0.0	0.0		IC	NG	FO2			
1651	Orange and Rockland Utilities	Landfill G.Part19		G	5057	Goshen	071	36	1988-12-01	2.5		0.0	0.0		IC	MTE				
1652	Orange and Rockland Utilities	Middletown LFG		G	5058	Goshen	071	36	1988-12-01	3.0		0.0	0.0		IC	MTE				
1653	PSEG Energy Resource & Trade, LLC	Bethlehem Energy Center		F	23843	Bethlehem	001	36	2005-07-01	893.1	756.9	762.0	870.3		CC	NG	FO2		4,526.7	
1654	R.E. Ginna Nuclear Power Plant, LLC	Ginna		B	23603	Ontario	117	36	1970-07-01	614.0	582.0	581.4	582.8		NP	UR			4,662.5	
1655	ReEnergy Holdings LLC	Black River		E	23780	Watertown	045	36	2013-05-30	55.5	55.6	50.8	52.4		ST	WD			302.6	
1656	ReEnergy Holdings LLC	Lyonsdale		E	23803	Lyonsdale	049	36	1992-08-01	21.1	20.2	20.3	20.6	YES	ST	WD			146.7	
1657	Rochester Gas and Electric Corp.	Mills Mills		B	5059	Fillmore	003	36	1906-07-01	0.2		0.0	0.0		HY	WAT				
1658	Rochester Gas and Electric Corp.	Mt Morris		B	5060	Mt Morris	051	36	1916-07-01	0.3		0.0	0.0		HY	WAT				
1659	Rochester Gas and Electric Corp.	Station 2	1	B	23604	Rochester	055	36	1913-07-01	8.5	6.5	8.5	8.5		HY	WAT			36.5	
1660	Rochester Gas and Electric Corp.	Station 26	1	B	23604	Rochester	055	36	1952-08-01	3.0	3.0	3.0	3.0		HY	WAT			0.8	
1661	Rochester Gas and Electric Corp.	Station 5	1	B	23604	Rochester	055	36	1918-07-01	14.0	11.8	14.0	14.0		HY	WAT			4.3	
1662	Rochester Gas and Electric Corp.	Station 5	2	B	23604	Rochester	055	36	1918-07-01	13.6	11.8	13.6	13.6		HY	WAT			0.0	
1663	Rochester Gas and Electric Corp.	Station 5	3	B	23604	Rochester	055	36	1918-07-01	18.0	16.5	18.0	18.0		HY	WAT			86.9	
1664	Rochester Gas and Electric Corp.	Wiscoy	1	B	5061	Fillmore	003	36	1922-07-01	0.6		0.0	0.0		HY	WAT				
1665	Rochester Gas and Electric Corp.	Wiscoy	2	B	5062	Fillmore	003	36	1922-07-01	0.5		0.0	0.0		HY	WAT				
1666	Rockville Centre, Village of	Charles P Keller	07	K	1661	Rockville Centre	059	36	1942-09-01	2.0	2.0	2.0	2.0		IC	FO2			0.0	
1667	Rockville Centre, Village of	Charles P Keller	08	K	1661	Rockville Centre	059	36	1950-09-01	2.4	2.8	2.4	2.4		IC	FO2			0.0	
1668	Rockville Centre, Village of	Charles P Keller	09	K	1661	Rockville Centre	059	36	1954-09-01	3.5	3.3	3.5	3.5		IC	FO2	NG		0.0	
1669	Rockville Centre, Village of	Charles P Keller	10	K	1661	Rockville Centre	059	36	1954-09-01	3.5	3.2	3.5	3.5		IC	FO2	NG		0.0	
1670	Rockville Centre, Village of	Charles P Keller	11	K	1661	Rockville Centre	059	36	1962-09-01	5.2	5.2	5.2	5.2		IC	FO2	NG		0.1	
1671	Rockville Centre, Village of	Charles P Keller	12	K	1661	Rockville Centre	059	36	1967-09-01	5.5	5.5	5.5	5.5		IC	FO2	NG		0.0	
1672	Rockville Centre, Village of	Charles P Keller	13	K	1661	Rockville Centre	059	36	1974-09-01	5.5	5.6	5.5	5.5		IC	FO2	NG		0.1	
1673	Rockville Centre, Village of	Charles P Keller	14	K	1661	Rockville Centre	059	36	1994-09-01	6.2	6.3	6.2	6.2		IC	FO2	NG		0.5	
1674	Selkirk Cogen Partners, L.P.	Selkirk-I		F	23801	Selkirk	001	36	1992-03-01	107.2	82.1	76.2	107.6	YES	CC	NG	FO2		287.0	
1675	Selkirk Cogen Partners, L.P.	Selkirk-II		F	23799	Selkirk	001	36	1994-09-01	338.8	291.3	270.4	334.2	YES	CC	NG	FO2		928.6	
1676	Seneca Energy II, LLC	Ontario LFGE		C	23819	Canandaigua	069	36	2003-12-01	11.2	5.6	11.2	11.2		IC	MTE			75.7	
1677	Seneca Energy II, LLC	Seneca Energy 1		C	23797	Seneca Falls	099	36	1996-03-01	8.8	8.8	8.8	8.8		IC	MTE			141.8	**(G)**
1678	Seneca Energy II, LLC	Seneca Energy 2		C	23797	Seneca Falls	099	36	1997-08-01	8.8	8.8	8.8	8.8		IC	MTE				
1679	Seneca Falls Power Corp.	Seneca Falls 1		C	23627	Seneca Falls	099	36	1998-06-01	1.8	1.6	0.0	0.0		HY	WAT			0.0	
1680	Seneca Falls Power Corp.	Seneca Falls 2		C	23627	Seneca Falls	099	36	1998-06-01	1.8	1.6	0.0	0.0		HY	WAT			0.0	
1681	Seneca Falls Power Corp.	Seneca Falls 4		C	23627	Seneca Falls	099	36	1998-06-01	2.0	1.8	0.0	0.0		HY	WAT			0.0	
1682	Seneca Power Partners, L.P.	Allegany		B	23514	Hume	003	36	1995-03-01	67.0	62.9	60.0	61.7	YES	CC	NG			96.5	
1683	Seneca Power Partners, L.P.	Batavia		B	24024	Batavia	037	36	1992-06-01	67.3	57.1	48.8	60.1		CC	NG			10.8	
1684	Seneca Power Partners, L.P.	Carthage Energy		E	23857	Carthage	045	36	1991-08-01	62.9	59.0	55.5	63.6		CC	NG	FO2		11.4	
1685	Seneca Power Partners, L.P.	Hillburn GT		G	23639	Hillburn	087	36	1971-04-01	46.5	37.9	34.8	43.3		JE	KER			0.3	
1686	Seneca Power Partners, L.P.	Shoemaker GT		G	23640	Middletown	071	36	1971-05-01	41.9	33.1	31.6	41.0		JE	KER			0.4	
1687	Seneca Power Partners, L.P.	Sterling		E	23777	Sherrill	065	36	1991-06-01	65.3	57.4	50.1	63.0		CC	NG			22.4	
1688	Sheldon Energy LLC	High Sheldon Wind Farm		C	323625	Sheldon	121	36	2009-02-01	112.5	112.5	112.5	112.5		WT	WND			270.7	
1689	Shell Energy North America (US), L.P.	Glen Park Hydro		E	23778	Glen Park	045	36	1986-01-01	32.6	40.4	32.6	32.6		HY	WAT			168.3	
1690	Shell Energy North America (US), L.P.	Lockport		A	23791	Lockport	063	36	1992-07-01	221.3	225.2	202.7	220.3		CC	NG	FO2		388.8	
1691	Shell Energy North America (US), L.P.	Munnsville Wind Power		E	323609	Bouckville	053	36	2007-08-20	34.5	34.5	34.5	34.5		WT	WND			96.0	
1692	Somerset Operating Company, LLC	Somerset		A	23543	Somerset	063	36	1984-08-01	655.1	686.5	681.5	681.2		ST	BIT			1,786.6	
1693	Stephentown Spindle LLC	Beacon LESR		F	323632	Stephentown	083	36	2010-11-29	20.0	0.0	0.0	0.0		ES	FW			0.0	
1694	Stony Creek Energy LLC	Orangeville Wind Farm		C	323706	Orangeville	121	36	2013-12-01	93.9	88.5	93.9	93.9		WT	WND			274.1	
1695	TC Ravenswood, LLC	Ravenswood 01		J	23729	Queens	081	36	1967-07-01	18.6	8.8	9.3	9.6		GT	NG			0.1	
1696	TC Ravenswood, LLC	Ravenswood 04		J	24252	Queens	081	36	1970-09-01	21.1	15.2	12.9	15.4		GT	KER	NG		0.2	
1697	TC Ravenswood, LLC	Ravenswood 05		J	24254	Queens	081	36	1970-08-01	21.1	15.7	13.6	15.6		GT	KER			0.1	
1698	TC Ravenswood, LLC	Ravenswood 06		J	24253	Queens	081	36	1970-08-01	22.0	16.7	13.4	15.8		GT	KER	NG		0.2	
1699	TC Ravenswood, LLC	Ravenswood 09		J	24257	Queens	081	36	1970-07-01	25.0	21.7	16.9	21.7		JE	KER	NG		1.6	
1700	TC Ravenswood, LLC	Ravenswood 10		J	24258	Queens	081	36	1970-08-01	25.0	21.2	18.0	22.8		JE	KER	NG		0.3	
1701	TC Ravenswood, LLC	Ravenswood 11		J	24259	Queens	081	36	1970-08-01	25.0	20.2	17.2	22.8		JE	KER	NG		1.4	
1702	TC Ravenswood, LLC	Ravenswood 2-1		J	24244	Queens	081	36	1970-12-01	42.9	40.4	32.7	37.4		JE	NG			1.6	
1703	TC Ravenswood, LLC	Ravenswood 2-2		J	24245	Queens	081	36	1970-12-01	42.9	37.6	31.4	43.0		JE	NG			1.5	
1704	TC Ravenswood, LLC	Ravenswood 2-3		J	24246	Queens	081	36	1970-12-01	42.9	39.2	0.0	0.0		JE	NG			0.0	
1705	TC Ravenswood, LLC	Ravenswood 2-4		J	24247	Queens	081	36	1970-12-01	42.9	39.8	32.0	37.5		JE	NG			1.8	
1706	TC Ravenswood, LLC	Ravenswood 3-1		J	24248	Queens	081	36	1970-08-01	42.9	40.5	30.3	40.9		JE	NG			1.4	
1707	TC Ravenswood, LLC	Ravenswood 3-2		J	24249	Queens	081	36	1970-08-01	42.9	38.1	30.6	35.8		JE	NG			1.3	
1708	TC Ravenswood, LLC	Ravenswood 3-3	(MB - 10/3	J	24250	Queens	081	36	1970-08-01	42.9	37.7	0.0	0.0		JE	NG			0.9	**(M) (6)**
1709	TC Ravenswood, LLC	Ravenswood 3-4	(ReAct. - 8	J	24251	Queens	081	36	1970-08-01	42.9	35.8	30.9	38.6		JE	NG			1.5	**(D) (7)**
1710	TC Ravenswood, LLC	Ravenswood CC	04	J	23820	Queens	081	36	2004-05-01	250.0	231.2	216.6	262.9		CC	NG	FO2		1,527.2	
1711	TC Ravenswood, LLC	Ravenswood ST	01	J	23533	Queens	081	36	1963-02-01	400.0	365.1	366.2	363.6		ST	FO6	NG		696.3	
1712	TC Ravenswood, LLC	Ravenswood ST	02	J	23534	Queens	081	36	1963-05-01	400.0	391.6	363.5	373.7		ST	FO6	NG		1,006.0	
1713	TC Ravenswood, LLC	Ravenswood ST	03	J	23535	Queens	081	36	1965-06-01	1,027.0	986.8	969.2	960.1		ST	FO6	NG		1,540.3	
1714	TransAlta Energy Marketing (U.S.) Inc	Saranac Energy		D	23793	Plattsburgh	019	36	1994-06-01	285.6	253.7	244.9	273.4		CC	NG			224.3	
1715	Triton Power Company	Chateaugay High Falls		D	323578	Chateaugay	033	36	1987-12-01	1.7	1.7	0.0	0.0		HY	WAT			4.3	
1716	Western New York Wind Corp.	Western NY Wind Power		B	24143	Wethersfield	121	36	2000-10-01	6.6	0.0	0.0	0.0		WT	WND			9.3	
1717	Wheelabrator Hudson Falls, LLC	Wheelabrator Hudson Falls		F	23798	Hudson Falls	115	36	1991-10-01	14.4	12.7	11.4	11.7		ST	REF			74.9	
1718	Wheelabrator Westchester, LP	Wheelabrator Westchester		H	23653	Peekskill	119	36	1984-04-01	59.7	53.5	52.7	53.6		ST	REF			388.7	
1719																				

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Contains Proprietary Material
Do Not Distribute

TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1720										44,866.1	40,333.7	38,664.5	41,012.8						141,186.6	
1721				J						11,398.8	10,223.4	9,597.0	10,560.6							

Contains Proprietary Material
Do Not Distribute

Max	31,138
Peak Month	7
PST	25,244
Winter	22,045
Spring	19,393
Summer	24,144
Fall	20,374

Source: NYISO

SIL Study
24,893
24,418
31,266
31,179

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	21,185	12/1/2014	14,220	13,616	13,287	13,224	13,497	14,498	16,506	17,769	18,270	18,637	18,888	18,940	18,882	18,884	18,880	19,092	20,181	21,185	21,029	20,601	20,071	19,094	17,738	16,283
Winter	12	21,996	12/2/2014	15,242	14,655	14,333	14,246	14,541	15,635	17,671	18,946	19,413	19,603	19,837	19,833	19,845	19,937	20,024	20,287	21,327	21,996	21,835	21,369	20,649	19,560	17,986	16,471
Winter	12	21,652	12/3/2014	15,318	14,675	14,270	14,138	14,334	15,250	17,166	18,527	19,044	19,407	19,666	19,733	19,721	19,811	19,863	19,865	20,847	21,652	21,389	21,004	20,464	19,490	18,020	16,551
Winter	12	21,613	12/4/2014	15,512	14,928	14,575	14,494	14,762	15,747	17,679	18,896	19,323	19,560	19,572	19,387	19,325	19,267	19,209	19,467	20,446	21,613	21,466	21,085	20,583	19,689	18,278	16,864
Winter	12	21,460	12/5/2014	15,822	15,229	14,954	14,850	15,006	16,053	17,942	19,131	19,557	19,848	19,958	19,960	19,914	19,882	19,901	20,132	20,997	21,460	21,073	20,573	19,992	19,212	18,031	16,660
Winter	12	20,018	12/6/2014	15,536	14,773	14,307	14,084	14,094	14,433	15,170	16,023	16,988	17,791	18,293	18,494	18,523	18,408	18,348	18,490	19,303	20,018	19,855	19,424	19,000	18,380	17,434	16,389
Winter	12	20,968	12/7/2014	15,426	14,738	14,348	14,178	14,207	14,511	15,102	15,697	16,556	17,170	17,486	17,593	17,648	17,629	17,665	17,984	19,296	20,864	20,968	20,770	20,358	19,525	18,319	17,050
Winter	12	23,095	12/8/2014	16,111	15,590	15,329	15,267	15,562	16,598	18,519	19,872	20,452	20,837	21,037	21,023	20,899	20,901	20,864	21,078	22,091	23,095	22,917	22,422	21,725	20,649	19,086	17,449
Winter	12	22,518	12/9/2014	16,176	15,502	15,093	14,964	15,179	16,098	18,003	19,567	20,081	20,496	20,838	20,931	20,877	20,834	20,702	20,817	21,686	22,518	22,242	21,698	20,924	19,879	18,327	16,737
Winter	12	22,828	12/10/2014	15,639	14,986	14,637	14,544	14,775	15,739	17,646	19,107	19,682	20,144	20,359	20,438	20,450	20,467	20,456	20,687	21,765	22,828	22,655	22,190	21,509	20,441	18,901	17,276
Winter	12	22,609	12/11/2014	16,148	15,501	15,141	15,061	15,281	16,239	18,052	19,426	19,965	20,268	20,413	20,417	20,335	20,318	20,306	20,495	21,515	22,609	22,385	21,936	21,334	20,326	18,859	17,292
Winter	12	22,122	12/12/2014	16,167	15,528	15,169	15,041	15,199	16,161	18,080	19,451	19,978	20,349	20,396	20,292	20,106	20,067	19,977	20,100	21,048	22,122	21,854	21,315	20,699	19,923	18,755	17,390
Winter	12	20,486	12/13/2014	16,205	15,449	14,975	14,771	14,767	15,142	15,912	16,689	17,578	18,163	18,441	18,444	18,303	18,141	18,077	18,329	19,410	20,486	20,410	20,025	19,565	18,924	17,974	16,772
Winter	12	20,471	12/14/2014	15,744	14,964	14,502	14,280	14,265	14,498	15,028	15,631	16,480	17,241	17,676	17,854	17,912	17,889	17,850	18,012	19,138	20,471	20,407	20,298	19,829	18,984	17,640	16,327
Winter	12	21,987	12/15/2014	15,278	14,688	14,407	14,317	14,574	15,580	17,568	18,949	19,367	19,631	19,725	19,662	19,475	19,451	19,374	19,543	20,656	21,987	21,889	21,453	20,848	19,872	18,377	16,778
Winter	12	21,968	12/16/2014	15,564	14,900	14,551	14,442	14,687	15,668	17,694	19,133	19,610	19,932	20,075	20,042	19,924	19,834	19,719	19,925	20,985	21,968	21,749	21,330	20,713	19,683	18,172	16,514
Winter	12	21,926	12/17/2014	15,256	14,556	14,201	14,063	14,274	15,187	17,214	18,618	19,068	19,344	19,514	19,476	19,418	19,508	19,587	19,886	20,933	21,926	21,675	21,245	20,671	19,779	18,335	16,819
Winter	12	22,187	12/18/2014	15,628	14,959	14,600	14,512	14,779	15,810	17,781	19,129	19,549	19,847	19,947	19,942	19,840	19,789	19,745	19,999	21,119	22,187	22,014	21,611	21,048	20,109	18,694	17,137
Winter	12	22,134	12/19/2014	16,050	15,391	14,980	14,867	15,132	16,103	17,932	19,353	19,927	20,272	20,419	20,363	20,111	19,962	19,843	20,038	21,027	22,134	21,852	21,436	20,852	20,105	19,004	17,659
Winter	12	21,028	12/20/2014	16,467	15,746	15,308	15,060	15,072	15,429	16,187	17,022	17,966	18,789	19,172	19,272	19,191	19,014	18,948	19,060	20,001	21,028	20,927	20,544	20,110	19,469	18,569	17,390
Winter	12	20,957	12/21/2014	16,310	15,534	15,072	14,780	14,750	14,989	15,540	16,178	17,060	17,907	18,414	18,585	18,640	18,539	18,528	18,769	19,891	20,957	20,943	20,681	20,237	19,458	18,208	16,903
Winter	12	22,074	12/22/2014	15,844	15,128	14,779	14,674	14,896	15,806	17,589	18,981	19,639	20,075	20,265	20,242	20,031	19,964	19,936	20,163	21,078	22,074	21,848	21,353	20,763	19,861	18,478	16,991
Winter	12	21,324	12/23/2014	15,742	14,944	14,520	14,362	14,519	15,356	17,007	18,464	19,175	19,660	19,905	19,917	19,756	19,700	19,595	19,658	20,477	21,324	21,144	20,666	20,071	19,265	17,973	16,495
Winter	12	19,625	12/24/2014	15,187	14,350	13,872	13,647	13,749	14,354	15,564	16,812	17,763	18,590	19,069	19,265	19,135	19,006	18,834	18,731	19,296	19,625	18,899	18,160	17,560	17,058	16,315	15,428
Winter	12	17,507	12/25/2014	14,450	13,720	13,238	12,909	12,866	13,075	13,573	14,232	14,957	15,682	16,015	16,128	16,225	16,184	16,030	16,025	16,620	17,507	17,497	17,358	17,165	16,832	16,125	15,108
Winter	12	19,843	12/26/2014	14,254	13,650	13,287	13,159	13,315	13,962	15,048	16,003	16,797	17,468	17,801	17,892	17,738	17,513	17,326	17,421	18,349	19,843	19,775	19,424	18,976	18,284	17,253	16,101
Winter	12	18,786	12/27/2014	15,021	14,315	13,858	13,648	13,662	13,932	14,598	15,162	15,844	16,467	16,851	16,935	16,801	16,533	16,354	16,399	17,316	18,745	18,786	18,488	18,076	17,447	16,542	15,453
Winter	12	19,288	12/28/2014	14,459	13,733	13,298	13,087	13,070	13,287	13,758	14,326	15,024	15,846	16,471	16,820	17,037	17,039	16,998	17,165	18,228	19,288	19,267	18,939	18,467	17,806	16,795	15,648
Winter	12	21,428	12/29/2014	14,687	14,136	13,815	13,726	13,962	14,858	16,276	17,509	18,349	18,877	19,210	19,343	19,256	19,185	19,140	19,233	20,129	21,428	21,311	20,887	20,289	19,452	18,229	16,832
Winter	12	22,203	12/30/2014	15,741	15,119	14,776	14,683	14,869	15,668	17,076	18,328	19,129	19,669	19,944	20,015	19,949	19,857	19,834	19,956	20,853	22,203	22,084	21,665	21,148	20,310	19,067	17,612
Winter	12	21,953	12/31/2014	16,482	15,744	15,338	15,167	15,314	16,021	17,320	18,408	19,146	19,649	19,904	20,023	19,888	19,775	19,682	19,719	20,473	21,953	21,656	20,900	20,098	19,310	18,552	17,809
Winter	1	20,225	1/1/2015	17,052	16,304	15,759	15,425	15,341	15,530	15,879	16,081	16,454	17,001	17,527	17,843	17,944	17,887	17,784	17,932	18,822	20,225	20,108	19,810	19,410	18,746	17,667	16,518
Winter	1	21,193	1/2/2015	15,636	15,043	14,684	14,495	14,635	15,377	16,494	17,468	18,225	18,904	19,265	19,394	19,322	19,191	19,063	19,148	19,955	21,193	21,023	20,519	19,987	19,206	18,173	17,013
Winter	1	20,642	1/3/2015	15,981	15,332	14,982	14,760	14,784	15,105	15,727	16,396	17,089	17,828	18,435	18,807	18,973	18,966	19,026	19,143	19,878	20,642	20,520	20,081	19,474	18,618	17,601	16,436
Winter	1	19,736	1/4/2015	15,452	14,695	14,170	13,853	13,736	13,924	14,332	14,846	15,516	16,317	16,980	17,419	17,607	17,673	17,692	17,816	18,690	19,736	19,680	19,278	18,711	17,779	16,642	15,526
Winter	1	23,003	1/5/2015	14,657	14,234	14,028	14,020	14,391	15,567	17,647	19,085	19,552	19,957	20,226	20,332	20,377	20,400	20,408	20,624	21,482	22,957	23,003	22,683	22,052	21,005	19,539	18,099
Winter	1	23,632	1/6/2015	17,175	16,600	16,274	16,185	16,441	17,302	19,168	20,670	21,174	21,563	21,844	21,884	21,764	21,715	21,610	21,750	22,433	23,623	23,632	23,256	22,605	21,545	19,957	18,488
Winter	1	24,648	1/7/2015	17,480	16,888	16,544	16,431	16,653	17,553	19,489	20,930	21,418	21,715	21,916	21,974	21,986	22,014	22,054	22,288	23,094	24,514	24,648	24,289	23,709	22,711	21,316	19,864
Winter	1	24,327	1/8/2015	18,913	18,314	17,947	17,835	18,114	19,022	20,738	22,137	22,510	22,895	22,974	22,816	22,572	22,408	22,223	22,292	23,036	24,327	24,322	23,954	23,321	22,234	20,662	19,176
Winter	1	23,069	1/9/2015	18,138	17,564	17,185	17,034	17,194	17,959	19,717	21,187	21,626	22,020	22,190	22,085	21,773	21,575	21,363	21,357	21,901	23,069	22,930	22,414	21,827	21,044	19,927	18,731
Winter	1	22,334	1/10/2015	17,763	17,177	16,819	16,653	16,721	17,096	17,826	18,592	19,469	20,142	20,447	20,478	20,400	20,170	20,007	20,068	20,756	22,142	22,334	21,945	21,514	20,867	19,905	18,871
Winter	1	21,443	1/11/2015	17,924	17,200	16,773	16,525	16,477	16,646	17,125	17,627	18,354	19,016	19,504	19,723	19,700	19,609	19,413	19,402	20,114	21,443	21,431	21,029	20,427	19,475	18,241	17,012
Winter	1	22,559	1/12/2015	16,094	15,607	15,309	15,204	15,466	16,408	18,217	19,685	20,291	20,784	21,107	21,270	21,227	21,159	21,048	21,095	21,704	22,559	22,396	21,874	21,168	20,133	18,796	17,448
Winter	1	23,668	1/13/2015	16,454	15,930	15,665	15,646	15,938	17,080	19,100	20,567	21,021	21,390	21,568	21,456	21,311	21,236	21,149	21,361	22,045	23,465	23,668	23,355	22,720	21,756	20,407	19,062
Winter	1	23,222	1/14/2015	18,120	17,572	17,249	17,160	17,404	18,368	20,286	21,735	22,165	22,383	22,363	22,115	21,799	21,655	21,488	21,500	22,048	23,222	23,207	22,748	22,078	21,087	19,673	18,250
Winter	1	22,679	1/15/2015	17,274	16,739	16,405	16,326	16,567	17,518	19,461	20,838	21,228	21,421	21,397	21,211	20,894	20,736	20,557	20,631	21,300	22,635	22,679	22,314	21,693	20,692	19,168	17,822
Winter	1	22,452	1/16/2015	16,850	16,282	15,933	15,814	16,004	16,879	18,776	20,120	20,542	20,780	20,831	20,758	20,621	20,449	20,425	20,566	21,128	22,309	22,452	22,023	21,523	20,788	19,706	18,524
Winter	1	21,099	1/17/2015	17,608	17,031	16,722	16,579	16,650	17,002	17,782	18,552	19,390	20,007	20,237	20,170	19,835	19,443	19,182	19,143	19,713	20,968	21,099	20,727	20,193	19,510	18,597	17,528
Winter	1	20,222	1/18/2015	16,685	16,041	15,596	15,318	15,264	15,399	15,814	16,338	17,092	17,902	18,513	18,854	18,999	19,019	18,948	19,027	19,515	20,222	20,121	19,690	19,096	18,306	17,328	16,263
Winter	1	21,623	1/19/2015	15,459	14,964	14,658	14,574	14,778	15,473	16,677	17,732	18,604	19,312	19,731	19,899	19,850	19,872	19,886	19,970	20,506	21,623	21,579	21,149	20,477	19,523	18,161	16,881
Winter	1	22,144	1/20/2015	15,940	15,425	15,130	15,052	15,345	16,419	18,424	19,709	20,192	20,437	20,411	20,335	20,183	20,217	20,172	20,247	20,944	22,140	22,144	21,771	21,172	20,282	18,920	17,526
Winter	1	22,439	1/21/2015	16,584	16,119	15,893	15,880	16,220	17,235	19,224	20,552	20,930	21,242	21,367	21,257	20,945	20,701	20,595	20,730	21,260	22,385	22,439	22,013	21,353	20,329	18,943	17,526
Winter	1	22,118	1/22/2015	16,500	15,910	15,612	15,515	15,778	16,748	18,631	20,019	20,454	20,729	20,843	20,691	20,453	20,257	20,081	20,100	20,622	21,923	22,118	21,755	21,192	20,248	18,912	17,528
Winter	1	21,425	1/23/2015	16,523	16,044	15,753	15,664	15,895	16,882	18,800	20,141	20,508	20,756	20,704	20,523	20,208	20,008	19,788	19,778	20,249	21,349	21,425	20,954	20,373	19,561	18,445	17,247
Winter	1	20,458	1/24/2015	16,307	15,650	15,318	15,163	15,212	15,515	16,196	16,942	17,808	18,603	19,122	19,365	19,308	19,068	18,919	18,969	19,455	20,428	20,458	20,060	19,498	18,761	17,830	16,787
Winter	1	20,754	1/25/2015	15,900	15,258	14,849	14,679	14,681	14,957	15,505	16,099	16,960	17,606	17,975	18,107	18,087	17,948	17,891	18,035	18,697	20,263	20,754	20,582	20,165	19,368	18,326	17,309
Winter	1	23,112	1/26/2015	16,491	16,034	15,804	15,788	16,101	17,157	19,074	20,598	21,154	21,635	21,932	22,092	22,092	22,046	21,858	21,705	22,021	23,112	23,105	22,509	21,712	20,671	19,454	18,169
Winter	1	22,964	1/27/2015	17,249	16,686	16,398	16,319	16,505	17,128	18,210	18,983	19,553	20,196	20,607	20,784	20,805	20,697	20,600	20,635	21,175	22,642	22,964	22,575	21,891	20,876	19,535	18,245
Winter	1	23,166	1/28/2015	17,391	16,951	16,719	16,677	16,962	17,922	19,752	21,041	21,561	21,881	21,979	21,781	21,487	21,289	21,039	20,993	21,394	22,749	23,166	22,815	22,225	21,204	19,779	18,429
Winter	1	22,758	1/29/2015	17,516	17,002	16,778	16,713	17,029	17,961	19,879	21,127	21,530	21,736	21,692	21,534	21,312	21,268	21,174	21,246	21,713	22,690	22,758	22,290	21,546	20,429	18,980	17,642
Winter	1	22,613	1/30/2015	16,704	16,122	15,760	15,608	15,792	16,665	18,455	19,844	20,462	20,972	21,207	21,157	21,013	20,879	20,733	20,745	21,109	22,229	22,613	22,243	21,754	21,006	19,925	18,825
Winter	1	22,020	1/31/2015	17,917	17,354	17,055	16,927	17,014	17,363	18,121	18,931	19,835	20,509	20,828	20,763	20,513	20,160	19,916	19,858	20,243	21,483	22,020	21,744	21,233	20,527	19,534	18,476
Winter	2	21,227	2/1/2015	17,551	16,910	16,464	16,233	16,190	16,423	16,849	17,356	18,148	18,688	19,033	19,190	19,206	19,199	19,234	19,448	20,067	21,154	21,227	20,641	20,143	19,547	18,787	17,731
Winter	2	23,654	2/2/2015	16,782	16,287	16,030	15,981	16,203	16,988	18,447	19,665	20,644	21,492	22,008	22,218	22,225	22,262	22,212	22,172	22,393	23,423	23,654	23,242	22,508	21,461	20,200	18,886
Winter	2	23,494	2/3/2015	17,976	17,460	17,215	17,152	17,428	18,352	20,111	21,317	21,924	22,162	22,207	22,091	21,812	21,635	21,410	21,338	21,713	22,921	23,494	23,181	22,519	21,543	20,021	18,595
Winter	2	22,432	2/4/2015	17,576	16,992	16,662	16,520	16,731	17,616	19,431	20,588	21,031	21,325	21,423	21,323	21,150	21,026	20,870	20,745	21,041	22,088	22,432	22,069	21,381	20,294	18,881	17,483
Winter	2	23,633	2/5/2015	16,508	15,903	15,615	15,525	15,792	16,776	18,741	20,153	20,747	21,260	21,495	21,523	21,381	21,294	21,167	21,180	21,650	22,952	23,633	23,459	22,887	21,905	20,549	19,201
Winter	2	22,829	2/6/2015	18,232	17,702	17,427	17,383	17,626	18,598	20,459	21,730	22,129	22,386	22,461	22,421	22,174	21,845	21,481	21,353	21,581	22,463	22,829	22,426	21,847	21,044	19,918	18,628
Winter	2	20,783	2/7/2015	17,605	16,952	16,507	16,273	16,256	16,548	17,224	17,967	18,848	19,553	19,979	20,124	19,944	19,698	19,486	19,315	19,450	20,362	20,783	20,391	19,860	19,169	18,292	17,295
Winter	2	21,114	2/8/2015	16,373	15,772	15,402	15,149	15,156	15,400	15,873	16,373	17,263	18,074	18,602	18,858	19,009	19,025	19,092	19,209	19,726	20,782	21,114	20,787	20,259	19,448	18,374	17,300
Winter	2	23,242	2/9/2015	16,513	16,065	15,804	15,741	16,068	17,006	18,665	19,971	20,767	21,422	21,887	22,041	22,074	22,051	21,885	21,855	22,165	23,050	23,242	22,831	22,050	20,961	19,480	18,081
Winter	2	22,506	2/10/2015	17,090	16,514	16,199	16,101	16,339	17,300	19,123	20,455	21,008	21,200	21,300	21,223	20,947	20,791	20,598	20,635	20,914	21,919	22,506	22,273	21,696	20,732	19,311	17,960
Winter	2	22,529	2/11/2015	16,978	16,513	16,227	16,228	16,492	17,540	19,516	20,798	21,101	21,313	21,284	21,102	20,818	20,589	20,353	20,371	20,764	21,798	22,529	22,222	21,675	20,622	19,264	17,851
Winter	2	22,826	2/12/2015	16,777	16,257	15,910	15,821	16,054	16,953	18,848	20,074	20,602	20,921	21,045	20,972	20,789	20,742	20,584	20,802	21,201	22,164	22,826	22,635	22,188	21,343	20,062	18,903
Winter	2	23,321	2/13/2015	18,061	17,584	17,367	17,387	17,716	18,673	20,514	21,761	22,306	22,680	22,816	22,560	22,209	21,969	21,732	21,586	21,829	22,693	23,321	23,029	22,513	21,744	20,550	19,326
Winter	2	21,698	2/14/2015	18,393	17,756	17,408	17,198	17,158	17,444	18,041	18,657	19,642	20,402	20,731	20,759	20,555	20,354	20,230	20,182	20,362	21,165	21,698	21,398	20,868	20,169	19,192	18,222
Winter	2	23,163	2/15/2015	17,342	16,840	16,655	16,589	16,678	16,969	17,478	18,007	19,121	20,077	20,640	20,812	20,761	20,592	20,363	20,418	20,951	22,151	23,163	22,887	22,341	21,772	20,926	19,919
Winter	2	23,754	2/16/2015	19,081	18,560	18,260	18,131	18,285	18,911	19,955	20,880	21,755	22,353	22,616	22,667	22,402	22,139	21,973	21,941	22,221	23,110	23,754	23,412	22,805	21,888	20,656	19,403
Winter	2	23,397	2/17/2015	18,429	17,857	17,569	17,506	17,785	18,603	19,976	21,174	21,979	22,479	22,688	22,566	22,286	22,014	21,720	21,557	21,785	22,549	23,397	23,091	22,505	21,600	20,319	19,090
Winter	2	22,839	2/18/2015	18,152	17,642	17,351	17,273	17,539	18,413	19,885	21,024	21,710	22,001	21,971	21,690	21,364	21,180	20,994	20,961	21,247	22,175	22,839	22,467	21,848	21,004	19,713	18,452
Winter	2	24,024	2/19/2015	17,496	16,970	16,711	16,679	16,953	17,844	19,384	20,545	21,321	21,760	21,950	22,090	22,083	22,044	21,918	21,938	22,208	23,102	24,024	23,853	23,360	22,541	21,374	20,171
Winter	2	23,746	2/20/2015	19,187	18,608	18,352	18,307	18,542	19,424	20,895	21,981	22,834	23,331	23,471	23,408	23,105	22,828	22,491	22,287	22,438	23,013	23,746	23,483	22,979	22,323	21,246	20,077
Winter	2	22,108	2/21/2015	19,020	18,448	18,050	17,824	17,805	18,126	18,773	19,416	20,252	20,756	21,008	21,025	20,966	20,819	20,802	20,762	21,016	21,679	22,108	21,766	21,142	20,212	19,191	18,142
Winter	2	20,911	2/22/2015	17,285	16,683	16,230	15,977	15,942	16,121	16,567	16,975	17,823	18,509	18,878	18,867	18,695	18,493	18,278	18,359	18,790	19,909	20,911	20,753	20,260	19,422	18,397	17,362
Winter	2	24,144	2/23/2015	16,584	16,109	15,928	15,925	16,109	17,319	19,264	20,572	21,274	21,871	22,168	22,133	22,009	21,810	21,772	21,805	22,282	23,158	24,144	24,071	23,571	22,628	21,339	19,973
Winter	2	23,955	2/24/2015	18,917	18,365	18,096	18,050	18,375	19,365	21,150	22,275	22,665	22,855	22,894	22,636	22,362	22,209	22,028	21,993	22,207	23,062	23,955	23,584	22,936	21,919	20,417	18,905
Winter	2	22,679	2/25/2015	17,939	17,341	17,027	16,915	17,196	18,136	19,894	21,003	21,344	21,484	21,436	21,221	20,951	20,765	20,597	20,600	20,942	21,642	22,679	22,565	21,949	21,062	19,638	18,323
Winter	2	23,331	2/26/2015	17,454	17,003	16,744	16,726	16,969	17,963	19,823	21,058	21,625	22,026	22,187	22,094	21,754	21,495	21,487	21,590	21,929	22,590	23,331	23,050	22,492	21,530	20,175	18,808
Winter	2	22,501	2/27/2015	17,893	17,365	17,079	17,030	17,292	18,321	20,041	21,171	21,564	21,770	21,750	21,578	21,278	21,095	20,865	20,800	21,014	21,573	22,501	22,349	21,903	21,206	20,183	19,041
Winter	2	21,244	2/28/2015	18,150	17,626	17,329	17,215	17,282	17,659	18,314	19,034	19,808	20,275	20,439	20,259	19,933	19,591	19,290	19,133	19,352	20,046	21,244	21,231	20,838	20,277	19,451	18,581
Spring	3	21,805	3/1/2015	17,761	17,217	16,876	16,682	16,663	16,865	17,216	17,662	18,492	19,000	19,388	19,613	19,743	19,826	19,891	19,967	20,339	21,061	21,805	21,547	20,885	19,879	18,698	17,514
Spring	3	22,544	3/2/2015	16,668	16,214	15,959	15,911	16,160	17,139	18,732	19,914	20,686	21,041	21,183	21,135	20,996	20,894	20,665	20,568	20,786	21,449	22,544	22,397	21,833	20,848	19,488	18,126

SI-SSA-0010

Contains Proprietary Material
Do Not Distribute

Spring	3	22,697	3/3/2015	17,203	16,720	16,485	16,451	16,744	17,829	19,550	20,570	21,035	21,285	21,366	21,328	21,248	21,267	21,254	21,293	21,494	22,106	22,697	22,494	21,857	20,737	19,243	17,791
Spring	3	21,683	3/4/2015	16,731	16,124	15,751	15,599	15,815	16,781	18,472	19,651	20,171	20,434	20,544	20,494	20,293	20,126	20,015	20,137	20,426	21,019	21,683	21,421	20,799	19,855	18,521	17,243
Spring	3	23,122	3/5/2015	16,315	15,803	15,505	15,476	15,776	16,775	18,510	19,828	20,655	21,213	21,635	21,769	21,785	21,722	21,536	21,474	21,720	22,313	23,122	22,963	22,318	21,335	20,013	18,716
Spring	3	22,378	3/6/2015	17,960	17,487	17,240	17,257	17,587	18,603	20,060	21,071	21,438	21,720	21,848	21,730	21,420	21,184	20,920	20,806	20,965	21,472	22,378	22,156	21,626	20,882	19,861	18,671
Spring	3	20,390	3/7/2015	17,693	17,156	16,758	16,614	16,654	17,028	17,596	18,317	19,130	19,543	19,647	19,529	19,325	19,106	18,980	18,913	19,123	19,576	20,390	20,266	19,817	19,076	18,118	17,127
Spring	3	19,580	3/8/2015	16,235	0	15,630	15,303	15,120	15,215	15,604	16,039	16,658	17,314	17,692	17,884	17,938	17,860	17,686	17,491	17,548	17,818	18,330	19,505	19,580	18,956	17,918	16,707
Spring	3	20,238	3/9/2015	15,830	15,364	15,113	15,046	15,268	16,133	18,029	19,485	19,833	19,882	19,816	19,657	19,390	19,133	18,874	18,670	18,722	18,956	19,244	20,238	20,091	19,306	18,017	16,664
Spring	3	20,286	3/10/2015	15,673	15,099	14,801	14,746	14,939	15,934	17,892	19,283	19,579	19,615	19,580	19,457	19,259	19,150	19,011	19,065	19,251	19,536	19,815	20,286	19,884	18,970	17,667	16,306
Spring	3	19,534	3/11/2015	15,342	14,733	14,326	14,170	14,300	15,202	17,175	18,559	18,908	19,045	19,072	18,951	18,781	18,628	18,329	18,201	18,318	18,438	18,637	19,534	19,492	18,665	17,400	16,051
Spring	3	20,127	3/12/2015	15,120	14,600	14,304	14,262	14,439	15,444	17,443	18,833	19,246	19,446	19,557	19,460	19,146	19,012	18,832	18,734	18,787	18,990	19,248	20,127	20,074	19,340	18,028	16,723
Spring	3	19,789	3/13/2015	15,800	15,241	14,959	14,924	15,172	16,087	18,045	19,367	19,700	19,789	19,685	19,434	19,068	18,854	18,528	18,363	18,423	18,515	18,770	19,455	19,273	18,612	17,557	16,418
Spring	3	18,772	3/14/2015	15,363	14,735	14,373	14,194	14,179	14,475	15,233	16,119	17,097	17,978	18,525	18,688	18,574	18,334	18,054	17,920	17,992	18,212	18,433	18,772	18,411	17,616	16,924	15,949
Spring	3	19,419	3/15/2015	15,029	14,381	13,961	13,759	13,767	14,028	14,541	15,200	16,151	17,074	17,598	17,840	17,899	17,809	17,791	17,886	18,053	18,449	18,688	19,419	19,266	18,524	17,387	16,167
Spring	3	19,909	3/16/2015	15,325	14,816	14,519	14,456	14,723	15,688	17,697	18,963	19,287	19,509	19,565	19,436	19,209	19,033	18,753	18,522	18,569	18,791	19,097	19,909	19,713	18,792	17,457	15,981
Spring	3	20,268	3/17/2015	14,887	14,262	13,905	13,796	14,046	15,023	17,030	18,510	19,063	19,431	19,584	19,542	19,408	19,263	19,013	18,901	18,985	19,087	19,266	20,169	20,268	19,531	18,221	16,873
Spring	3	20,950	3/18/2015	15,975	15,491	15,220	15,163	15,417	16,407	18,362	19,554	20,037	20,271	20,352	20,279	20,071	19,942	19,737	19,729	19,835	20,040	20,171	20,950	20,883	20,007	18,696	17,344
Spring	3	20,295	3/19/2015	16,338	15,729	15,453	15,437	15,742	16,759	18,728	19,888	20,208	20,295	20,224	20,047	19,791	19,623	19,357	19,161	19,185	19,329	19,451	20,246	20,269	19,533	18,352	17,056
Spring	3	20,490	3/20/2015	15,982	15,423	15,105	14,997	15,209	16,121	17,957	19,291	19,935	20,285	20,490	20,475	20,322	20,280	20,185	20,133	20,086	20,069	20,020	20,385	20,197	19,403	18,376	17,217
Spring	3	18,639	3/21/2015	16,176	15,512	15,090	14,894	14,884	15,171	15,919	16,722	17,701	18,381	18,616	18,577	18,421	18,173	17,896	17,737	17,691	17,712	17,840	18,493	18,639	18,153	17,372	16,408
Spring	3	19,649	3/22/2015	15,537	14,949	14,599	14,463	14,503	14,783	15,369	15,916	16,738	17,336	17,720	17,814	17,815	17,651	17,472	17,401	17,580	17,953	18,382	19,444	19,649	18,968	17,896	16,798
Spring	3	20,914	3/23/2015	16,006	15,604	15,380	15,382	15,667	16,659	18,539	19,757	20,274	20,511	20,622	20,484	20,258	20,121	19,881	19,661	19,709	19,889	20,073	20,883	20,914	20,083	18,827	17,390
Spring	3	20,382	3/24/2015	16,381	15,876	15,626	15,564	15,839	16,819	18,739	19,977	20,332	20,382	20,333	20,194	19,942	19,712	19,359	19,136	19,104	19,189	19,296	20,043	20,238	19,442	18,072	16,766
Spring	3	20,365	3/25/2015	15,846	15,348	15,091	15,048	15,310	16,284	18,217	19,441	19,755	19,746	19,654	19,473	19,207	19,146	19,204	19,453	19,803	20,113	20,189	20,365	19,994	19,095	17,733	16,341
Spring	3	19,864	3/26/2015	15,327	14,758	14,421	14,284	14,499	15,337	17,308	18,530	19,027	19,341	19,546	19,625	19,617	19,536	19,412	19,351	19,487	19,618	19,594	19,864	19,589	18,675	17,318	16,015
Spring	3	19,680	3/27/2015	15,048	14,450	14,120	13,996	14,224	15,183	17,078	18,415	19,058	19,526	19,680	19,633	19,456	19,369	19,215	19,135	19,097	19,011	18,914	19,310	19,233	18,580	17,573	16,409
Spring	3	19,173	3/28/2015	15,500	14,961	14,628	14,460	14,482	14,806	15,590	16,429	17,453	18,204	18,695	18,762	18,620	18,369	18,121	17,944	17,921	18,084	18,316	18,914	19,173	18,758	17,951	17,008
Spring	3	18,596	3/29/2015	16,152	15,583	15,234	15,082	15,082	15,309	15,795	16,255	16,906	17,339	17,568	17,599	17,477	17,239	16,982	16,817	16,852	17,070	17,352	18,187	18,596	17,996	17,043	15,967
Spring	3	20,279	3/30/2015	15,116	14,640	14,382	14,310	14,555	15,491	17,272	18,672	19,461	19,966	20,279	20,234	19,918	19,606	19,345	19,275	19,308	19,351	19,304	19,697	19,826	18,961	17,682	16,314
Spring	3	19,820	3/31/2015	15,268	14,759	14,385	14,264	14,512	15,473	17,184	18,332	18,854	19,126	19,154	19,138	19,064	19,175	19,086	19,063	19,129	19,243	19,412	19,820	19,769	18,978	17,631	16,354
Spring	4	19,178	4/1/2015	15,345	14,818	14,550	14,501	14,752	15,689	17,337	18,513	18,975	19,139	19,113	18,951	18,709	18,522	18,307	18,151	18,145	18,191	18,220	18,823	19,178	18,570	17,374	16,060
Spring	4	18,842	4/2/2015	15,132	14,534	14,275	14,192	14,419	15,367	16,993	18,058	18,633	18,842	18,815	18,606	18,334	18,125	17,895	17,696	17,749	17,860	17,954	18,486	18,449	17,674	16,493	15,255
Spring	4	17,839	4/3/2015	14,187	13,525	13,124	12,950	13,048	13,697	14,859	15,930	16,885	17,489	17,783	17,839	17,687	17,566	17,382	17,288	17,252	17,297	17,228	17,476	17,395	16,792	15,870	14,829
Spring	4	17,567	4/4/2015	13,877	13,300	12,928	12,737	12,777	13,085	13,721	14,416	15,374	16,158	16,576	16,649	16,538	16,297	16,070	15,957	15,996	16,214	16,440	17,070	17,567	17,167	16,391	15,424
Spring	4	17,062	4/5/2015	14,568	13,890	13,507	13,293	13,310	13,610	14,037	14,533	15,216	15,783	16,092	16,152	16,065	15,881	15,758	15,652	15,640	15,678	15,896	16,644	17,062	16,656	15,763	14,771
Spring	4	18,482	4/6/2015	13,995	13,533	13,295	13,219	13,481	14,401	15,916	17,111	17,832	18,226	18,294	18,201	18,010	17,896	17,703	17,574	17,579	17,772	17,868	18,388	18,482	17,604	16,429	15,123
Spring	4	19,026	4/7/2015	14,130	13,529	13,198	13,086	13,304	14,248	15,799	17,022	17,858	18,349	18,596	18,617	18,545	18,487	18,365	18,270	18,397	18,669	18,744	19,026	18,894	18,067	16,815	15,484
Spring	4	19,521	4/8/2015	14,558	13,994	13,671	13,586	13,806	14,691	16,330	17,597	18,374	18,860	19,181	19,267	19,217	19,183	19,071	19,032	19,187	19,318	19,329	19,521	19,316	18,528	17,248	15,903
Spring	4	19,406	4/9/2015	14,941	14,372	14,025	13,877	14,078	14,939	16,512	17,771	18,594	19,038	19,281	19,277	19,173	19,092	18,920	18,775	18,827	18,992	19,124	19,406	19,282	18,448	17,138	15,829
Spring	4	19,020	4/10/2015	14,853	14,260	13,889	13,728	13,926	14,756	16,307	17,465	18,192	18,675	18,978	19,020	18,820	18,706	18,509	18,359	18,292	18,284	18,090	18,123	18,265	17,623	16,514	15,378
Spring	4	17,148	4/11/2015	14,441	13,763	13,332	13,134	13,137	13,473	14,021	14,729	15,583	16,207	16,538	16,605	16,494	16,266	16,022	15,862	15,866	15,928	16,039	16,515	17,148	16,795	16,069	15,156
Spring	4	16,966	4/12/2015	14,281	13,686	13,364	13,175	13,168	13,403	13,727	14,202	14,841	15,269	15,533	15,578	15,468	15,282	15,109	15,023	15,182	15,474	15,693	16,274	16,966	16,338	15,344	14,250
Spring	4	18,208	4/13/2015	13,369	12,886	12,656	12,604	12,859	13,910	15,686	16,930	17,525	17,766	17,809	17,766	17,673	17,679	17,605	17,560	17,566	17,567	17,432	17,864	18,208	17,343	15,972	14,528
Spring	4	18,116	4/14/2015	13,445	12,862	12,524	12,384	12,563	13,494	15,323	16,646	17,406	17,691	17,902	17,861	17,737	17,734	17,650	17,573	17,639	17,715	17,716	17,965	18,116	17,254	15,945	14,541
Spring	4	17,965	4/15/2015	13,464	12,912	12,633	12,561	12,797	13,797	15,436	16,688	17,197	17,422	17,552	17,522	17,411	17,410	17,330	17,302	17,357	17,386	17,247	17,524	17,965	17,194	15,884	14,499
Spring	4	17,892	4/16/2015	13,495	12,944	12,632	12,579	12,831	13,832	15,492	16,719	17,252	17,497	17,602	17,583	17,438	17,379	17,273	17,189	17,249	17,295	17,213	17,540	17,892	17,102	15,763	14,414
Spring	4	18,136	4/17/2015	13,438	12,854	12,557	12,404	12,552	13,443	15,229	16,591	17,341	17,831	18,114	18,136	18,036	17,925	17,692	17,540	17,526	17,371	17,100	17,184	17,504	16,889	15,824	14,552
Spring	4	16,471	4/18/2015	13,547	12,876	12,476	12,273	12,273	12,550	13,007	13,852	14,805	15,400	15,758	15,861	15,889	15,760	15,619	15,533	15,582	15,680	15,681	15,861	16,471	15,993	15,080	14,091
Spring	4	16,663	4/19/2015	13,227	12,597	12,200	12,000	11,981	12,171	12,381	13,015	13,814	14,471	14,853	14,984	15,010	14,924	14,801	14,784	14,961	15,245	15,522	16,142	16,663	16,023	14,958	13,819
Spring	4	18,858	4/20/2015	12,998	12,534	12,288	12,228	12,456	13,449	15,313	16,878	17,688	18,304	18,694	18,858	18,764	18,651	18,480	18,360	18,391	18,486	18,392	18,480	18,434	17,450	16,040	14,597
Spring	4	18,010	4/21/2015	13,624	13,087	12,712	12,589	12,815	13,702	15,354	16,754	17,513	17,912	18,001	17,953	17,824	17,772	17,624	17,562	17,596	17,636	17,432	17,605	18,010	17,239	15,953	14,540
Spring	4	18,397	4/22/2015	13,568	13,009	12,678	12,581	12,816	13,770	15,379	16,652	17,285	17,641	17,862	17,895	17,896	17,947	17,887	18,021	18,254	18,353	18,270	18,234	18,397	17,572	16,245	14,855
Spring	4	18,962	4/23/2015	13,900	13,358	13,060	12,979	13,242	14,212	15,838	17,126	17,759	18,142	18,336	18,417	18,348	18,283	18,187	18,106	18,274	18,490	18,482	18,667	18,962	18,151	16,761	15,417
Spring	4	18,675	4/24/2015	14,435	13,921	13,603	13,520	13,745	14,661	16,292	17,604	18,249	18,532	18,675	18,650	18,522	18,412	18,220	18,081	18,052	18,010	17,844	17,973	18,431	17,932	16,950	15,702
Spring	4	16,668	4/25/2015	14,669	14,043	13,718	13,553	13,584	13,884	14,329	15,094	15,857	16,273	16,389	16,287	16,081	15,808	15,534	15,368	15,375	15,535	15,649	15,939	16,668	16,393	15,605	14,648
Spring	4	17,014	4/26/2015	13,783	13,224	12,906	12,725	12,743	12,928	13,185	13,836	14,558	15,072	15,340	15,477	15,516	15,464	15,403	15,384	15,616	15,930	16,155	16,475	17,014	16,431	15,386	14,261
Spring	4	18,327	4/27/2015	13,392	12,906	12,581	12,517	12,859	13,838	15,458	16,807	17,548	17,870	17,912	17,987	17,977	17,943	17,877	17,783	17,826	17,939	17,899	18,089	18,327	17,534	16,150	14,771
Spring	4	17,910	4/28/2015	13,732	13,185	12,901	12,777	13,031	13,980	15,548	16,762	17,334	17,617	17,730	17,747	17,682	17,658	17,551	17,498	17,558	17,550	17,355	17,380	17,910	17,279	15,893	14,483
Spring	4	17,948	4/29/2015	13,500	12,935	12,614	12,526	12,744	13,617	15,132	16,513	17,123	17,521	17,728	17,873	17,877	17,911	17,879	17,891	17,948	17,875	17,546	17,432	17,916	17,166	15,767	14,317
Spring	4	17,831	4/30/2015	13,373	12,801	12,448	12,318	12,596	13,455	15,014	16,400	17,071	17,420	17,690	17,756	17,668	17,718	17,660	17,615	17,601	17,496	17,267	17,301	17,831	17,166	15,855	14,432
Spring	5	17,580	5/1/2015	13,449	12,836	12,538	12,430	12,626	13,461	15,012	16,397	17,033	17,349	17,580	17,575	17,449	17,416	17,309	17,169	17,090	16,961	16,745	16,771	17,193	16,731	15,667	14,442
Spring	5	16,216	5/2/2015	13,439	12,867	12,516	12,310	12,341	12,624	13,062	13,963	14,843	15,426	15,704	15,782	15,714	15,598	15,420	15,297	15,355	15,511	15,464	15,612	16,216	15,897	15,055	14,028
Spring	5	16,847	5/3/2015	13,209	12,675	12,291	12,059	12,040	12,154	12,345	13,041	13,882	14,498	14,978	15,246	15,429	15,447	15,455	15,533	15,706	15,932	16,023	16,171	16,847	16,319	15,199	13,986
Spring	5	19,209	5/4/2015	13,106	12,593	12,313	12,236	12,411	13,219	14,804	16,298	17,224	17,819	18,355	18,690	18,931	19,081	19,060	19,132	19,209	19,139	18,759	18,671	18,952	18,181	16,704	15,173
Spring	5	19,846	5/5/2015	14,092	13,371	12,952	12,812	12,958	13,733	15,248	16,846	17,761	18,389	18,934	19,192	19,320	19,515	19,695	19,811	19,846	19,609	19,116	18,900	19,085	18,310	16,850	15,328
Spring	5	18,612	5/6/2015	14,226	13,575	13,171	12,998	13,115	13,921	15,526	17,050	17,777	18,228	18,533	18,612	18,591	18,612	18,527	18,499	18,554	18,491	18,152	17,911	18,260	17,686	16,277	14,768
Spring	5	19,603	5/7/2015	13,688	13,022	12,688	12,548	12,714	13,501	14,978	16,490	17,368	18,051	18,551	18,890	19,052	19,250	19,362	19,472	19,603	19,473	18,961	18,579	18,810	18,208	16,722	15,177
Spring	5	20,708	5/8/2015	14,018	13,347	12,944	12,757	12,899	13,637	15,172	16,699	17,809	18,601	19,272	19,765	20,038	20,333	20,516	20,674	20,708	20,522	19,918	19,373	19,359	18,753	17,470	15,990
Spring	5	18,130	5/9/2015	14,750	13,930	13,426	13,150	13,055	13,198	13,539	14,516	15,695	16,533	17,043	17,328	17,478	17,572	17,705	17,839	17,945	17,959	17,922	17,850	18,130	17,802	16,827	15,674
Spring	5	19,286	5/10/2015	14,650	13,820	13,264	12,987	12,937	12,966	13,110	13,910	15,059	16,118	17,009	17,611	18,001	18,290	18,513	18,777	18,938	18,995	18,895	18,803	19,286	18,901	17,707	16,303
Spring	5	23,036	5/11/2015	15,125	14,477	14,075	13,892	14,057	14,899	16,580	18,363	19,491	20,417	21,252	21,854	22,214	22,667	22,862	23,029	23,036	22,872	22,250	21,612	21,564	20,817	19,138	17,396
Spring	5	22,379	5/12/2015	16,095	15,245	14,730	14,501	14,639	15,412	17,084	18,841	19,927	20,657	21,460	21,953	22,239	22,374	22,379	22,239	22,219	21,972	21,289	20,693	20,741	19,942	18,156	16,232
Spring	5	18,671	5/13/2015	14,869	14,041	13,529	13,283	13,336	14,020	15,478	16,924	17,758	18,217	18,495	18,592	18,667	18,671	18,643	18,604	18,585	18,435	18,009	17,773	17,981	17,493	16,156	14,704
Spring	5	18,354	5/14/2015	13,679	13,054	12,682	12,581	12,760	13,520	15,034	16,429	17,166	17,592	17,722	17,880	17,938	18,079	18,191	18,238	18,354	18,317	17,949	17,604	17,882	17,438	16,035	14,600
Spring	5	18,448	5/15/2015	13,557	12,956	12,600	12,457	12,641	13,400	14,922	16,353	17,151	17,652	18,052	18,239	18,276	18,437	18,442	18,448	18,437	18,190	17,734	17,495	17,704	17,235	16,157	14,924
Spring	5	17,576	5/16/2015	13,929	13,264	12,864	12,651	12,592	12,758	13,177	14,119	15,245	16,087	16,682	16,917	17,100	17,140	17,107	17,155	17,311	17,364	17,313	17,308	17,576	17,312	16,391	15,339
Spring	5	20,000	5/17/2015	14,372	13,650	13,194	12,916	12,828	12,826	13,024	13,878	15,116	16,216	17,075	17,815	18,360	18,726	19,001	19,334	19,753	20,000	19,888	19,568	19,788	19,465	18,080	16,675
Spring	5	20,418	5/18/2015	15,541	14,733	14,257	14,047	14,199	15,002	16,440	17,904	18,860	19,491	19,950	20,167	20,268	20,330	20,370	20,360	20,418	20,314	19,833	19,604	19,574	18,793	17,280	15,698
Spring	5	20,718	5/19/2015	14,613	13,896	13,489	13,306	13,437	14,237	15,823	17,402	18,338	18,850	19,324	19,612	19,700	19,844	20,145	20,511	20,713	20,718	20,182	19,570	19,522	18,926	17,535	16,004
Spring	5	18,351	5/20/2015	14,701	13,855	13,314	13,055	13,160	13,820	15,310	16,825	17,683	18,105	18,280	18,351	18,247	18,196	18,091	18,031	18,023	17,950	17,630	17,483	17,797	17,445	16,153	14,733
Spring	5	18,029	5/21/2015	13,717	13,076	12,722	12,604	12,787	13,530	15,040	16,490	17,180	17,684	17,921	18,029	17,964	17,970	17,921	17,851	17,849	17,801	17,588	17,498	17,742	17,270	16,019	14,625
Spring	5	18,182	5/22/2015	13,615	13,022	12,664	12,513	12,673	13,269	14,580	16,023	16,936	17,509	17,877	18,076	18,156	18,182	18,086	17,950	17,830	17,711	17,433	17,160	17,328	17,127	16,080	14,801
Spring	5	16,151	5/23/2015	13,777	13,109	12,724	12,537	12,500	12,535	12,936	13,740	14,649	15,270	15,614	15,707	15,618	15,498	15,364	15,395	15,529	15,750	15,818	15,760	16,088	16,151	15,362	14,361
Spring	5	16,537	5/24/2015	13,528	12,894	12,519	12,332	12,265	12,224	12,426	13,092	14,013	14,800	15,409	15,780	15,988	16,073	16,117	16,190	16,345	16,430	16,341	16,180	16,534	16,537	15,782	14,790
Spring	5	19,529	5/25/2015	13,885	13,242	12,860	12,594	12,585	12,684	12,993	13,753	14,795	15,891	16,775	17,580	18,126	18,456	18,709	19,043	19,314	19,529	19,434	19,254	19,483	19,224	17,915	16,483
Spring	5	24,285	5/26/2015	15,404	14,636	14,193	13,936	14,037	14,713	16,366	18,260	19,641	20,730	21,640	22,340	22,892	23,433	23,790	24,108	24,285	24,070	23,362	22,635	22,373	21,826	20,121	18,277
Spring	5	24,190	5/27/2015	16,892	15,994	15,415	15,113	15,200	15,873	17,587	19,434	20,637	21,477	22,264	22,800	23,046	23,537	23,871	24,094	24,190	23,881	22,968	22,178	21,922	21,226	19,552	17,794
Spring	5	23,754	5/28/2015	16,455	15,649	15,163	14,912	14,979	15,706	17,280	19,023	20,003	20,726	21,209	21,940	22,440	22,988	23,350	23,606	23,754	23,462	22,700	21,997	21,705	21,187	19,467	17,597
Spring	5	23,435	5/29/2015	16,133	15,193	14,611	14,280	14,341	14,862	16,362	18,086	19,347	20,264	21,016	21,608	22,084	22,538	22,908	23,293	23,435	23,017	22,025	21,182	20,837	20,473	19,278	17,777
Spring	5	22,447	5/30/2015	16,476	15,548	14,969	14,625	14,537	14,586	15,113	16,377	17,912	19,248	20,406	21,244	21,755	22,072	22,338	22,423	22,447	22,210	21,646	20,976	20,650	20,324	19,219	17,879
Spring	5	19,841	5/31/2015	16,671	15,724	15,088	14,639	14,376	14,260	14,423	15,138	16,332	17,499	18,444	19,200	19,667	19,841	19,813	19,754	19,508	19,515	19,361	19,215	19,193	18,484	17,165	15,634
Summer	6	19,071	6/1/2015	14,495	13,863	13,486	13,320	13,459	14,195	15,746	17,305	18,070	18,602	18,984	19,071	19,014	18,898	18,732	18,602	18,553	18,582	18,297	18,073	17,979	17,305	15,968	14,586
Summer	6	18,382	6/2/2015	13,606	13,014	12,639	12,490	12,660	13,394	14,911	16,460	17,354	17,896	18,241	18,382	18,339	18,307	18,173	18,093	18,128	18,142	17,942	17,697	17,711	17,314	15,970	14,552
Summer	6	18,600	6/3/2015	13,533	12,954	12,575	12,428	12,620	13,315	14,861	16,296	17,082	17,526	17,794	17,969	18,068	18,292	18,385	18,490	18,600	18,530	18,099	17,721	17,803	17,644	16,278	14,760
Summer	6	18,696	6/4/2015	13,677	13,015	12,629	12,452	12,603	13,210	14,729	16,246	17,151	17,729

Contains Proprietary Material
Do Not Distribute

Summer	6	26,231	6/12/2015	18,513	17,465	16,776	16,284	16,156	16,622	18,113	19,864	21,172	22,220	23,165	23,925	24,387	25,028	25,645	26,231	26,179	25,676	24,883	24,147	23,769	23,265	21,851	20,201
Summer	6	22,589	6/13/2015	18,742	17,831	17,156	16,628	16,366	16,245	16,665	17,793	19,053	20,018	20,631	21,100	21,390	21,600	21,838	22,143	22,467	22,589	22,236	21,515	20,938	20,776	19,707	18,314
Summer	6	22,719	6/14/2015	17,051	16,069	15,425	15,018	14,812	14,626	14,847	15,857	17,263	18,676	19,860	20,823	21,505	21,947	22,247	22,484	22,658	22,719	22,246	21,702	21,732	21,321	19,973	18,329
Summer	6	24,111	6/15/2015	17,116	16,284	15,778	15,547	15,698	16,517	18,107	19,895	21,079	21,897	22,508	23,006	23,531	23,930	24,111	24,017	23,734	23,298	22,558	21,865	21,463	20,961	19,465	17,750
Summer	6	23,396	6/16/2015	16,450	15,626	15,111	14,907	15,061	15,871	17,442	19,254	20,426	21,126	21,702	22,127	22,420	22,691	22,733	22,987	23,396	23,394	22,958	22,554	22,153	21,707	20,048	18,174
Summer	6	22,746	6/17/2015	16,702	15,733	15,099	14,739	14,766	15,230	16,822	18,682	19,974	20,856	21,520	22,035	22,328	22,630	22,746	22,625	22,365	21,849	21,086	20,515	20,322	20,048	18,671	17,096
Summer	6	21,701	6/18/2015	15,837	15,106	14,596	14,346	14,423	15,053	16,551	18,246	19,404	20,145	20,694	21,059	21,339	21,627	21,701	21,664	21,628	21,425	20,897	20,505	20,346	20,021	18,682	17,124
Summer	6	23,993	6/19/2015	15,854	15,143	14,676	14,477	14,573	15,257	16,831	18,607	19,842	20,868	21,688	22,494	23,012	23,396	23,608	23,821	23,993	23,681	22,858	22,001	21,408	21,106	19,937	18,371
Summer	6	18,735	6/20/2015	16,913	15,837	15,114	14,637	14,419	14,270	14,588	15,484	16,641	17,576	18,292	18,604	18,735	18,696	18,633	18,562	18,586	18,685	18,672	18,592	18,711	18,636	17,891	16,901
Summer	6	23,277	6/21/2015	15,922	15,246	14,800	14,550	14,426	14,394	14,616	15,453	16,682	17,954	19,186	20,261	21,172	21,791	22,180	22,594	23,126	23,277	22,728	22,196	21,912	21,962	20,839	19,274
Summer	6	26,544	6/22/2015	17,864	16,876	16,288	15,897	15,885	16,370	17,876	19,782	21,275	22,342	23,247	23,969	24,511	25,132	25,716	26,232	26,544	26,452	25,875	25,136	24,672	24,195	22,491	20,513
Summer	6	28,100	6/23/2015	18,963	17,916	17,334	17,017	17,023	17,650	19,391	21,418	23,251	24,529	25,470	26,474	27,213	27,623	27,987	28,100	27,890	27,726	26,793	25,863	24,981	24,234	22,542	20,639
Summer	6	24,895	6/24/2015	18,896	17,672	16,658	16,033	15,886	16,238	17,684	19,466	20,762	21,729	22,508	23,106	23,521	23,973	24,332	24,684	24,832	24,895	24,254	23,382	22,547	22,157	20,634	18,734
Summer	6	24,007	6/25/2015	17,231	16,211	15,500	15,097	15,051	15,440	16,889	18,720	20,156	21,252	22,115	22,789	23,279	23,731	23,934	24,007	23,856	23,319	22,483	21,901	21,673	21,363	20,124	18,548
Summer	6	23,412	6/26/2015	17,221	16,260	15,652	15,334	15,362	15,874	17,224	18,893	20,224	21,193	21,963	22,339	22,669	22,970	23,226	23,360	23,412	23,170	22,349	21,391	20,735	20,462	19,310	17,800
Summer	6	18,483	6/27/2015	16,514	15,605	15,004	14,612	14,451	14,402	14,771	15,668	16,856	17,658	18,191	18,475	18,483	18,310	18,097	17,872	17,707	17,655	17,549	17,461	17,480	17,152	16,269	15,296
Summer	6	17,787	6/28/2015	14,461	13,844	13,437	13,204	13,127	13,145	13,284	13,850	14,822	15,795	16,534	16,975	17,118	17,105	17,119	17,180	17,349	17,569	17,613	17,583	17,787	17,762	16,852	15,760
Summer	6	20,932	6/29/2015	14,824	14,090	13,606	13,390	13,499	14,049	15,409	17,048	18,367	19,284	19,926	20,319	20,543	20,795	20,904	20,856	20,865	20,932	20,571	20,104	19,780	19,643	18,389	16,839
Summer	6	22,663	6/30/2015	15,596	14,853	14,426	14,202	14,197	14,789	16,151	17,916	19,310	20,340	21,177	21,770	22,002	22,186	22,377	22,660	22,663	22,379	21,772	21,177	20,938	20,721	19,589	18,160
Summer	7	23,804	7/1/2015	16,891	16,027	15,541	15,283	15,304	15,874	17,161	18,690	19,956	20,971	21,849	22,471	22,809	23,260	23,606	23,778	23,804	23,664	22,984	22,262	21,746	21,525	20,149	18,493
Summer	7	22,337	7/2/2015	17,090	16,052	15,356	14,936	14,884	15,314	16,591	18,271	19,470	20,364	21,181	21,714	22,057	22,313	22,337	22,136	21,972	21,717	21,071	20,473	20,195	19,896	18,717	17,352
Summer	7	20,675	7/3/2015	16,108	15,179	14,519	14,107	13,947	13,996	14,541	15,620	16,746	17,752	18,535	19,062	19,430	19,745	20,061	20,435	20,675	20,585	20,138	19,525	19,172	19,034	18,112	16,956
Summer	7	18,211	7/4/2015	15,872	15,036	14,479	14,118	13,930	13,891	14,069	14,758	15,804	16,822	17,572	17,963	18,211	18,192	18,058	17,974	18,087	18,168	17,927	17,503	17,246	17,159	16,777	16,141
Summer	7	21,343	7/5/2015	15,281	14,584	14,057	13,744	13,582	13,440	13,566	14,354	15,567	16,691	17,785	18,706	19,403	19,949	20,348	20,764	21,148	21,343	21,123	20,670	20,539	20,580	19,517	18,130
Summer	7	25,621	7/6/2015	16,923	16,095	15,537	15,261	15,325	15,803	17,065	18,915	20,549	22,019	23,238	24,085	24,614	25,089	25,381	25,580	25,621	25,415	24,683	23,922	23,446	23,139	21,698	19,969
Summer	7	28,172	7/7/2015	18,563	17,683	17,136	16,843	16,974	17,651	19,086	21,006	22,626	23,979	25,154	26,127	26,871	27,642	28,023	28,043	28,172	27,882	27,070	26,232	25,652	25,164	23,422	21,433
Summer	7	26,609	7/8/2015	19,820	18,682	17,953	17,588	17,523	18,064	19,436	21,111	22,320	23,232	24,050	24,785	25,462	26,092	26,609	26,567	26,146	25,603	24,933	24,309	24,012	23,595	22,139	20,337
Summer	7	22,900	7/9/2015	18,834	17,785	17,114	16,565	16,456	16,926	18,037	19,574	20,610	21,271	21,701	22,044	22,253	22,481	22,513	22,624	22,900	22,857	22,253	21,692	21,529	21,057	19,883	18,562
Summer	7	24,406	7/10/2015	17,437	16,648	16,174	15,896	15,858	16,283	17,452	19,155	20,465	21,391	22,189	22,674	23,087	23,491	23,829	24,157	24,406	24,314	23,604	22,764	22,069	21,683	20,442	18,890
Summer	7	23,172	7/11/2015	17,542	16,522	15,829	15,339	15,120	15,003	15,330	16,405	17,807	19,188	20,355	21,167	21,757	22,119	22,434	22,793	23,092	23,172	22,879	22,183	21,652	21,465	20,481	19,160
Summer	7	23,904	7/12/2015	17,903	16,963	16,143	15,664	15,322	15,109	15,214	16,110	17,531	19,027	20,405	21,492	22,278	22,872	23,310	23,713	23,904	23,869	23,592	23,129	22,878	22,811	21,618	20,031
Summer	7	27,754	7/13/2015	18,648	17,678	17,059	16,744	16,749	17,299	18,562	20,485	22,146	23,643	24,805	25,711	26,447	27,045	27,430	27,638	27,754	27,462	26,490	25,448	24,677	24,171	22,533	20,667
Summer	7	25,453	7/14/2015	19,115	18,074	17,407	17,038	17,023	17,647	19,033	20,947	22,425	23,562	24,223	24,749	25,029	25,107	25,085	25,120	25,380	25,453	24,857	24,310	24,079	23,792	22,418	20,657
Summer	7	23,901	7/15/2015	19,250	18,248	17,552	17,163	17,112	17,671	19,059	20,712	21,839	22,736	23,301	23,508	23,527	23,596	23,625	23,729	23,901	23,707	22,940	22,142	21,618	21,151	19,685	17,980
Summer	7	22,715	7/16/2015	16,630	15,663	15,002	14,592	14,540	15,035	16,164	17,749	18,956	19,867	20,492	20,919	21,250	21,705	22,037	22,412	22,689	22,715	22,149	21,361	20,816	20,507	19,174	17,638
Summer	7	23,069	7/17/2015	16,378	15,565	14,909	14,627	14,690	15,234	16,421	18,124	19,464	20,593	21,453	22,002	22,390	22,748	22,915	23,010	23,069	22,853	22,089	21,277	20,997	20,766	19,771	18,450
Summer	7	24,465	7/18/2015	17,358	16,506	15,986	15,683	15,602	15,754	16,144	17,101	18,411	19,591	20,587	21,495	22,173	22,605	23,108	23,766	24,361	24,465	24,179	23,633	23,364	23,158	22,109	20,827
Summer	7	27,776	7/19/2015	19,556	18,598	17,872	17,371	17,088	16,891	16,973	18,035	19,809	21,644	23,480	24,852	25,865	26,574	27,160	27,606	27,776	27,687	27,249	26,653	26,495	26,295	24,962	23,353
Summer	7	30,575	7/20/2015	21,942	20,979	20,325	19,920	19,880	20,439	21,566	23,560	25,433	26,899	28,117	29,064	29,652	30,212	30,449	30,575	30,573	30,329	29,625	28,794	28,220	27,474	25,559	23,448
Summer	7	27,893	7/21/2015	21,655	20,427	19,609	19,135	19,093	19,705	20,945	22,502	23,829	24,820	25,761	26,304	26,704	26,983	27,281	27,668	27,893	27,588	26,718	25,749	24,893	24,331	22,717	20,735
Summer	7	24,949	7/22/2015	19,104	17,869	16,958	16,499	16,382	16,762	17,858	19,575	20,913	21,899	22,666	23,237	23,643	24,129	24,480	24,793	24,949	24,823	23,991	23,010	22,454	22,034	20,643	18,910
Summer	7	24,622	7/23/2015	17,525	16,569	15,857	15,496	15,465	15,978	17,195	18,966	20,338	21,380	22,168	22,759	23,137	23,565	23,998	24,380	24,622	24,525	23,809	22,920	22,272	21,853	20,432	18,680
Summer	7	24,579	7/24/2015	17,289	16,345	15,733	15,399	15,369	15,859	16,947	18,715	20,126	21,213	22,151	22,787	23,230	23,685	24,069	24,370	24,579	24,437	23,687	22,822	22,282	21,885	20,623	19,110
Summer	7	22,978	7/25/2015	17,746	16,742	16,029	15,550	15,331	15,333	15,614	16,676	18,073	19,366	20,448	21,214	21,750	22,110	22,440	22,749	22,978	22,967	22,568	21,933	21,774	21,619	20,700	19,497
Summer	7	24,389	7/26/2015	18,314	17,368	16,694	16,244	16,001	15,951	16,007	16,711	17,934	19,368	20,708	21,810	22,705	23,434	23,936	24,206	24,360	24,389	23,862	23,424	23,420	23,103	21,752	20,232
Summer	7	28,345	7/27/2015	18,901	18,017	17,423	17,098	17,160	17,887	19,037	20,720	22,241	23,602	24,698	25,622	26,406	27,154	27,711	28,106	28,345	28,276	27,555	26,649	26,042	25,460	23,726	21,760
Summer	7	30,434	7/28/2015	20,143	19,034	18,285	17,813	17,765	18,380	19,645	21,638	23,515	25,164	26,621	27,746	28,524	29,215	29,742	30,148	30,434	30,278	29,510	28,442	27,741	27,077	25,258	23,174
Summer	7	31,138	7/29/2015	21,427	20,162	19,264	18,721	18,622	19,144	20,312	22,279	24,149	25,870	27,446	28,617	29,451	30,211	30,687	30,938	31,138	30,975	30,354	29,427	28,851	28,245	26,387	24,267
Summer	7	28,775	7/30/2015	22,465	21,222	20,389	19,934	19,906	20,510	21,763	23,507	24,969	26,030	26,908	27,686	28,307	28,722	28,775	28,435	28,035	27,532	26,886	26,131	25,682	25,224	23,679	21,879
Summer	7	27,615	7/31/2015	20,324	19,228	18,417	17,863	17,689	18,033	19,022	20,802	22,411	23,711	24,823	25,626	26,210	26,774	27,175	27,497	27,615	27,371	26,468	25,350	24,549	23,935	22,526	20,894
Summer	8	24,132	8/1/2015	19,452	18,358	17,554	17,033	16,778	16,771	16,946	18,018	19,623	21,130	22,305	22,994	23,543	23,730	23,880	24,044	24,132	24,034	23,565	22,843	22,465	22,106	20,959	19,550
Summer	8	24,325	8/2/2015	18,278	17,302	16,564	16,039	15,703	15,535	15,494	16,421	17,877	19,320	20,658	21,605	22,316	22,840	23,228	23,678	24,107	24,325	24,028	23,448	23,438	23,242	22,185	20,654
Summer	8	28,275	8/3/2015	19,395	18,419	17,758	17,432	17,440	18,039	19,231	21,058	22,714	24,032	25,138	25,968	26,658	27,369	27,851	28,119	28,275	27,957	27,046	26,177	25,789	25,188	23,519	21,703
Summer	8	27,615	8/4/2015	20,199	19,198	18,545	18,219	17,811	18,155	19,231	20,714	22,064	23,436	24,716	25,664	26,354	26,994	27,356	27,533	27,615	27,289	26,398	25,371	24,885	24,127	22,388	20,524
Summer	8	25,757	8/5/2015	19,066	17,966	17,202	16,832	16,736	17,255	18,364	19,965	21,273	22,411	23,415	24,147	24,663	25,109	25,419	25,656	25,757	25,405	24,504	23,639	23,211	22,673	21,134	19,395
Summer	8	24,049	8/6/2015	17,921	16,881	16,190	15,755	15,730	16,244	17,298	18,926	20,237	21,291	22,071	22,622	22,952	23,376	23,748	24,013	24,049	23,738	22,971	22,308	22,222	21,708	20,394	18,875
Summer	8	24,098	8/7/2015	17,592	16,677	16,056	15,636	15,611	16,151	17,135	18,750	20,155	21,306	22,178	22,793	23,160	23,519	23,734	23,957	24,098	23,931	23,152	22,244	21,809	21,207	19,937	18,465
Summer	8	20,977	8/8/2015	17,221	16,240	15,589	15,162	14,995	15,079	15,321	16,261	17,522	18,674	19,580	20,141	20,412	20,591	20,806	20,945	20,977	20,761	20,330	19,942	20,071	19,843	18,932	17,859
Summer	8	21,862	8/9/2015	16,921	16,114	15,454	15,023	14,804	14,789	14,813	15,612	16,873	17,929	18,919	19,693	20,263	20,675	21,019	21,275	21,640	21,862	21,637	21,055	21,102	20,825	19,653	18,273
Summer	8	25,010	8/10/2015	17,148	16,354	15,865	15,638	15,759	16,469	17,612	19,337	20,818	22,053	23,015	23,753	24,268	24,751	24,992	25,010	24,793	24,351	23,578	23,003	22,913	22,192	20,843	19,391
Summer	8	24,598	8/11/2015	18,180	17,332	16,821	16,582	16,710	17,473	18,858	20,263	21,337	22,141	22,734	23,085	23,339	23,695	23,927	24,301	24,598	24,494	23,972	23,335	23,100	22,453	21,034	19,433
Summer	8	24,960	8/12/2015	18,019	17,012	16,347	16,014	15,978	16,575	17,740	19,383	20,740	21,766	22,630	23,279	23,675	24,119	24,496	24,767	24,960	24,761	23,909	23,054	22,841	22,151	20,659	18,958
Summer	8	24,374	8/13/2015	17,524	16,522	15,850	15,455	15,436	16,027	17,119	18,768	20,149	21,224	22,063	22,671	23,126	23,553	23,872	24,178	24,374	24,262	23,550	22,631	22,455	21,784	20,359	18,706
Summer	8	25,722	8/14/2015	17,390	16,500	15,859	15,495	15,455	16,028	17,146	18,756	20,340	21,588	22,525	23,311	24,014	24,699	25,214	25,560	25,722	25,386	24,506	23,570	23,355	22,668	21,361	19,928
Summer	8	25,348	8/15/2015	18,584	17,565	16,873	16,390	16,152	16,186	16,380	17,416	18,943	20,483	21,908	23,026	23,865	24,472	24,864	25,216	25,348	25,157	24,573	23,791	23,689	23,127	22,013	20,633
Summer	8	25,910	8/16/2015	19,344	18,325	17,562	17,056	16,702	16,633	16,602	17,343	18,874	20,395	21,893	23,256	24,356	25,058	25,434	25,568	25,797	25,910	25,579	24,943	25,040	24,422	23,024	21,380
Summer	8	30,543	8/17/2015	20,047	19,083	18,392	18,006	18,001	18,640	19,771	21,550	23,263	24,967	26,555	27,874	28,941	29,758	30,171	30,382	30,543	30,408	29,558	28,526	28,192	27,047	25,090	23,013
Summer	8	29,569	8/18/2015	21,303	20,146	19,320	18,827	18,775	19,397	20,535	22,236	23,886	25,333	26,807	28,084	28,830	29,381	29,569	29,536	29,354	29,075	28,174	27,298	27,066	26,082	24,277	22,419
Summer	8	29,550	8/19/2015	20,864	19,829	19,112	18,763	18,747	19,433	20,758	22,443	24,142	25,572	26,831	27,784	28,467	29,038	29,371	29,550	29,417	29,038	28,259	27,482	27,382	26,473	24,816	22,911
Summer	8	28,651	8/20/2015	21,428	20,367	19,664	19,289	19,294	20,026	21,273	22,931	24,559	26,003	27,092	27,878	28,276	28,581	28,651	28,557	28,382	27,780	26,823	26,281	26,053	25,248	23,722	21,992
Summer	8	25,483	8/21/2015	20,554	19,449	18,694	18,251	18,164	18,694	19,721	20,866	21,935	22,662	23,389	23,995	24,348	24,739	25,071	25,316	25,483	25,315	24,507	23,683	23,461	22,589	21,160	19,594
Summer	8	22,004	8/22/2015	18,204	17,186	16,476	15,927	15,617	15,631	15,762	16,471	17,834	18,983	19,856	20,498	20,976	21,279	21,591	21,832	21,990	22,004	21,586	20,930	20,932	20,274	19,213	18,020
Summer	8	22,867	8/23/2015	16,962	16,168	15,594	15,254	15,117	15,187	15,240	15,944	17,070	18,284	19,368	20,268	20,996	21,610	21,955	22,239	22,613	22,867	22,644	22,290	22,605	21,972	20,782	19,465
Summer	8	26,483	8/24/2015	18,290	17,491	16,939	16,693	16,794	17,514	18,783	20,318	21,796	22,980	23,957	24,825	25,366	25,903	26,222	26,451	26,483	26,230	25,313	24,584	24,564	23,598	22,024	20,228
Summer	8	27,036	8/25/2015	18,850	17,985	17,363	17,111	17,179	17,941	19,245	20,704	22,159	23,338	24,435	25,206	25,865	26,460	26,848	27,026	27,036	26,747	25,789	25,062	24,754	23,558	21,700	19,726
Summer	8	23,823	8/26/2015	18,162	17,092	16,360	15,918	15,873	16,475	17,576	18,993	20,261	21,261	22,023	22,553	22,990	23,450	23,758	23,823	23,794	23,475	22,702	22,181	22,146	21,222	19,767	18,235
Summer	8	22,374	8/27/2015	17,003	16,169	15,592	15,295	15,309	15,938	17,050	18,453	19,780	20,732	21,426	21,890	22,103	22,160	22,299	22,374	22,368	22,291	21,647	21,136	21,159	20,288	18,880	17,449
Summer	8	22,692	8/28/2015	16,203	15,383	14,847	14,587	14,613	15,231	16,361	17,741	19,012	20,069	20,848	21,360	21,652	22,008	22,279	22,520	22,692	22,480	21,761	21,141	21,035	20,190	18,976	17,625
Summer	8	21,578	8/29/2015	16,348	15,469	14,901	14,560	14,412	14,553	14,861	15,661	17,006	18,248	19,242	19,975	20,416	20,700	20,998	21,313	21,578	21,556	21,088	20,739	20,902	20,240	19,268	18,190
Summer	8	23,452	8/30/2015	17,103	16,246	15,689	15,282	15,077	15,119	15,224	15,814	17,117	18,446	19,736	20,912	21,855	22,552	23,100	23,385	23,452	23,441	23,156	23,129	23,430	22,707	21,525	20,059
Summer	8	28,661	8/31/2015	18,811	17,918	17,400	17,097	17,167	17,995	19,299	20,823	22,397	23,702	24,878	25,842	26,597	27,384	28,060	28,433	28,661	28,426	27,582	27,035	26,879	25,681	23,847	21,904
Fall	9	28,425	9/1/2015	20,324	19,189	18,396	17,925	17,879	18,497	19,828	21,282	22,711	23,975	25,153	26,070	26,776	27,398	27,853	28,205	28,425	28,136	27,104	26,349	26,067	24,727	22,898	20,971
Fall	9	28,978	9/2/2015	19,455	18,383	17,706	17,301	17,318	18,071	19,472	20,917	22,329	23,724	25,027	26,215	27,176	27,968	28,630	28,978	28,961	28,479	27,439	26,854	26,646	25,384	23,567	21,697
Fall	9	29,420	9/3/2015	20,134	19,098	18,377	17,947	17,904	18,593	20,048	21,509	22,921	24,212	25,471	26,582	27,564	28,516	29,176	29,401	29,420	29,082	28,065	27,559	27,255	25,961	24,041	22,080
Fall	9	26,616	9/4/2015	20,508	19,398	18,662	18,151	18,106	18,742	20,024	21,379	22,867	24,133	24,999	25,517	25,772	26,085	26,373	26,590	26,616	26,276	25,217	24,445	23,969	22,818	21,337	19,693
Fall	9	22,888	9/5/2015	18,333	17,335	16,575	16,067	15,828	15,882	16,104	16,822	18,095	19,334	20,320	21,021	21,595	22,015	22,395	22,701	22,888	22,826	22,198	21,681	21,537	20,695	19,525	18,205
Fall	9	22,713	9/6/2015	17,042	16,139	15,525	15,108	14,886	14,888	14,966	15,523	16,834	18,168	19,354	20,378	21,236	21,848	22,256	22,533	22,713	22,589	21,979	21,621	21,539	20,830	19,768	18,559
Fall	9	26,257	9/7/2015	17,476	16,641	16,088	15,740	15,622	15,786	16,036	16,762	18,246	19,843	21,345	22,627	23,655	24,485	25,173	25,778	26,209	26,257	25,765	25,685	25,777	24,675	22,948	21,163
Fall	9	31,058	9/8/2015	19,807	18,847	18,170	17,814	17,819	18,603	20,283	21,801	23,459	25,039	26,526	27,987	29,214	30,173	30,734	31,010	31,058	30,744	29,753	29,370	28,902	27,396	25,141	22,926
Fall	9	29,426	9/9/2015	21,264	20,061	19,326	18,900	18,902	19,794	21,606	23,095	24,421	25,807	26,926	27,880	28,554	29,119	29,325	29,426	29,139	28,604	27,647	27,388	27,166	25,911	23,974	22,051
Fall	9	23,969	9/10/2015	20,459	19,341	18,527	18,134	18,082	18,748	20,374	21,553	22,386	23,056	23,506	23,734	23,795	23,923	23,874	23,928	23,969	23,830	23,362	23,330	23,044	21,980	20,452	18,785
Fall	9	23,351	9/11/2015	17,489	16,567	15,938	15,586	15,613	16,372	18,010	19,205	20,111	20,836	21,386	21,746	22,024	22,464	22,815	23,108	23,351	23,169	22,392	22,137	21,724	20,781	19,509	18,141
Fall	9	20,384	9/12/2015	16,927	16,013	15,417	15,075	14,944	15,131	15,575	16,353	17,666	18,860	19,608	20,024	20,237	20,314	20,265	20,115	20,019	20,114	20,191	20,384	20,115	19,505	18,551	17,433
Fall	9	19,850	9/13/2015	16,419	15,666	15,166	14,823	14,685	14,737	14,972	15,420	16,406	17,498

Contains Proprietary Material
Do Not Distribute

Fall	9	19,855	9/21/2015	14,418	13,804	13,428	13,269	13,438	14,333	16,059	17,190	17,998	18,593	19,036	19,263	19,442	19,626	19,609	19,558	19,622	19,614	19,491	19,855	19,348	18,263	16,893	15,480
Fall	9	19,802	9/22/2015	14,399	13,691	13,360	13,195	13,384	14,246	16,119	17,357	18,097	18,666	19,086	19,351	19,496	19,636	19,703	19,766	19,802	19,704	19,372	19,725	19,244	18,182	16,852	15,498
Fall	9	20,482	9/23/2015	14,540	13,852	13,446	13,280	13,426	14,199	15,633	16,752	17,627	18,285	18,799	19,115	19,419	19,809	20,045	20,249	20,482	20,362	19,899	20,111	19,610	18,489	17,015	15,641
Fall	9	21,303	9/24/2015	14,649	14,004	13,587	13,349	13,489	14,292	15,933	17,110	18,054	18,777	19,394	19,856	20,197	20,586	20,844	21,102	21,303	21,132	20,580	20,872	20,324	19,208	17,744	16,285
Fall	9	20,140	9/25/2015	15,158	14,417	13,944	13,732	13,839	14,618	16,297	17,473	18,313	18,924	19,405	19,706	19,871	20,078	20,140	20,128	20,002	19,661	19,312	19,508	18,967	18,080	16,880	15,632
Fall	9	17,717	9/26/2015	14,588	13,902	13,454	13,217	13,147	13,388	13,948	14,577	15,593	16,366	16,790	16,966	17,027	17,025	17,018	17,013	17,064	17,105	17,192	17,717	17,405	16,728	15,815	14,845
Fall	9	18,255	9/27/2015	14,021	13,396	12,970	12,758	12,703	12,851	13,164	13,475	14,421	15,184	15,711	16,053	16,271	16,442	16,602	16,773	17,058	17,391	17,643	18,255	17,927	17,043	15,973	14,959
Fall	9	21,354	9/28/2015	14,112	13,585	13,345	13,266	13,481	14,418	16,311	17,667	18,503	19,174	19,646	20,020	20,221	20,430	20,627	20,894	21,072	21,038	20,931	21,354	20,678	19,577	18,185	16,824
Fall	9	22,937	9/29/2015	15,742	15,091	14,736	14,546	14,724	15,626	17,709	19,138	20,158	20,998	21,701	22,236	22,641	22,937	22,843	22,772	22,767	22,758	22,707	22,811	22,125	21,024	19,462	17,882
Fall	9	22,116	9/30/2015	16,700	16,039	15,604	15,292	15,418	16,385	18,377	19,925	20,804	21,490	21,967	22,116	22,065	21,908	21,213	20,724	20,613	20,400	20,191	20,332	19,545	18,357	16,897	15,424
Fall	10	18,899	10/1/2015	14,355	13,711	13,238	12,969	13,088	13,917	15,715	16,925	17,529	17,927	18,177	18,218	18,167	18,151	18,091	18,069	18,132	18,296	18,576	18,899	18,371	17,346	16,042	14,761
Fall	10	18,581	10/2/2015	13,791	13,147	12,791	12,618	12,775	13,633	15,428	16,702	17,380	17,818	18,071	18,130	18,060	18,106	18,033	17,998	18,109	18,236	18,451	18,581	18,041	17,224	16,147	14,964
Fall	10	17,538	10/3/2015	13,905	13,255	12,899	12,703	12,717	13,035	13,684	14,404	15,461	16,268	16,752	16,905	16,909	16,763	16,653	16,589	16,676	16,899	17,302	17,538	17,164	16,594	15,735	14,730
Fall	10	17,444	10/4/2015	13,852	13,198	12,786	12,542	12,493	12,700	13,115	13,553	14,453	15,190	15,576	15,676	15,610	15,526	15,462	15,563	15,766	16,116	16,683	17,444	17,072	16,294	15,220	14,182
Fall	10	18,959	10/5/2015	13,350	12,849	12,591	12,529	12,754	13,684	15,528	16,810	17,392	17,733	17,907	17,966	17,947	17,971	17,904	17,854	17,932	18,090	18,419	18,959	18,431	17,404	16,040	14,702
Fall	10	19,179	10/6/2015	13,696	13,147	12,789	12,645	12,861	13,719	15,556	16,769	17,313	17,671	17,889	17,951	18,023	18,125	18,176	18,273	18,478	18,607	18,873	19,179	18,578	17,538	16,170	14,813
Fall	10	19,323	10/7/2015	13,822	13,197	12,835	12,677	12,830	13,679	15,536	16,760	17,404	17,816	18,043	18,233	18,327	18,474	18,545	18,667	18,790	18,858	19,043	19,323	18,663	17,625	16,251	14,899
Fall	10	19,113	10/8/2015	13,869	13,270	12,885	12,744	12,909	13,817	15,717	16,962	17,543	17,939	18,171	18,256	18,310	18,402	18,382	18,359	18,464	18,470	18,759	19,113	18,524	17,538	16,225	14,853
Fall	10	19,457	10/9/2015	13,866	13,308	12,972	12,854	13,030	13,894	15,725	17,134	18,008	18,603	18,989	19,211	19,256	19,326	19,386	19,364	19,407	19,439	19,457	19,206	18,527	17,667	16,562	15,273
Fall	10	17,043	10/10/2015	14,125	13,404	12,923	12,612	12,563	12,835	13,464	14,127	14,998	15,592	15,858	15,889	15,779	15,634	15,515	15,463	15,642	15,913	16,544	17,043	16,728	16,136	15,335	14,458
Fall	10	17,217	10/11/2015	13,607	12,979	12,551	12,338	12,299	12,494	12,967	13,459	14,235	14,867	15,217	15,357	15,409	15,396	15,403	15,487	15,767	16,106	16,699	17,217	16,830	16,144	15,260	14,280
Fall	10	19,162	10/12/2015	13,420	12,857	12,530	12,406	12,567	13,300	14,585	15,710	16,744	17,439	17,828	18,057	18,206	18,296	18,381	18,448	18,600	18,637	18,923	19,162	18,447	17,435	16,097	14,773
Fall	10	19,571	10/13/2015	13,715	13,102	12,784	12,658	12,838	13,784	15,716	17,105	17,754	18,281	18,698	18,921	19,022	19,054	18,877	18,922	18,936	19,027	19,422	19,571	18,830	17,792	16,393	14,968
Fall	10	18,987	10/14/2015	13,835	13,250	12,873	12,695	12,834	13,662	15,553	16,897	17,482	17,897	18,096	18,177	18,203	18,272	18,255	18,232	18,300	18,390	18,821	18,987	18,350	17,323	15,999	14,614
Fall	10	18,796	10/15/2015	13,607	13,053	12,722	12,603	12,781	13,726	15,644	16,910	17,454	17,766	17,935	17,922	17,847	17,862	17,805	17,817	17,946	18,100	18,627	18,796	18,242	17,256	15,985	14,707
Fall	10	18,206	10/16/2015	13,666	13,059	12,704	12,587	12,782	13,642	15,541	16,843	17,390	17,687	17,889	17,925	17,821	17,764	17,654	17,600	17,675	17,788	18,206	18,201	17,701	16,949	15,880	14,713
Fall	10	17,592	10/17/2015	13,783	13,199	12,835	12,634	12,641	12,975	13,689	14,432	15,361	15,987	16,266	16,281	16,192	16,026	15,902	15,895	16,088	16,468	17,300	17,592	17,212	16,655	15,863	14,895
Fall	10	18,340	10/18/2015	14,043	13,513	13,130	12,925	12,920	13,174	13,684	14,258	15,078	15,723	16,030	16,244	16,345	16,331	16,229	16,264	16,515	16,994	17,983	18,340	17,986	17,211	16,174	15,082
Fall	10	19,695	10/19/2015	14,229	13,757	13,523	13,473	13,763	14,797	16,767	18,047	18,484	18,697	18,770	18,599	18,345	18,261	18,094	18,058	18,238	18,635	19,505	19,695	19,093	18,098	16,709	15,330
Fall	10	19,191	10/20/2015	14,314	13,728	13,366	13,231	13,404	14,312	16,209	17,527	17,985	18,174	18,317	18,241	18,142	18,111	18,060	18,088	18,278	18,556	19,191	19,163	18,477	17,464	16,174	14,828
Fall	10	19,145	10/21/2015	13,733	13,192	12,831	12,721	12,916	13,757	15,662	17,068	17,520	17,882	18,123	18,274	18,323	18,383	18,336	18,338	18,384	18,535	19,145	19,112	18,482	17,477	16,181	14,882
Fall	10	19,278	10/22/2015	13,812	13,207	12,856	12,754	12,911	13,756	15,665	17,036	17,606	17,987	18,224	18,343	18,448	18,533	18,505	18,474	18,584	18,714	19,278	19,213	18,580	17,595	16,297	14,955
Fall	10	18,361	10/23/2015	13,959	13,302	12,929	12,775	12,931	13,749	15,635	16,945	17,488	17,803	17,916	17,867	17,744	17,650	17,549	17,426	17,499	17,701	18,356	18,361	17,859	17,171	16,193	15,064
Fall	10	17,579	10/24/2015	14,134	13,532	13,149	12,990	13,016	13,377	14,082	14,891	15,717	16,312	16,602	16,658	16,592	16,476	16,367	16,315	16,440	16,898	17,579	17,477	17,034	16,481	15,697	14,747
Fall	10	17,587	10/25/2015	13,914	13,328	12,902	12,623	12,538	12,720	13,172	13,781	14,635	15,500	15,999	16,265	16,311	16,208	16,043	16,010	16,168	16,530	17,454	17,587	17,136	16,345	15,326	14,237
Fall	10	19,273	10/26/2015	13,413	12,966	12,700	12,660	12,934	13,979	15,977	17,412	17,858	18,096	18,148	18,056	17,918	17,858	17,769	17,736	17,883	18,288	19,218	19,273	18,679	17,744	16,418	15,102
Fall	10	19,298	10/27/2015	14,148	13,651	13,332	13,255	13,526	14,516	16,505	17,896	18,207	18,343	18,349	18,237	18,086	17,997	17,851	17,809	17,989	18,399	19,298	19,247	18,638	17,697	16,432	15,146
Fall	10	20,088	10/28/2015	14,185	13,596	13,229	13,098	13,282	14,208	16,139	17,646	18,205	18,618	18,878	19,018	19,028	19,030	18,942	19,020	19,372	19,803	20,088	19,706	19,018	18,022	16,698	15,331
Fall	10	19,185	10/29/2015	14,315	13,687	13,306	13,145	13,255	14,093	16,039	17,475	17,973	18,327	18,528	18,668	18,535	18,492	18,316	18,189	18,270	18,592	19,185	18,979	18,394	17,509	16,231	14,907
Fall	10	18,425	10/30/2015	13,912	13,333	12,950	12,799	12,955	13,861	15,733	17,216	17,601	17,834	17,927	17,978	17,786	17,706	17,555	17,460	17,489	17,772	18,425	18,336	17,839	17,174	16,181	15,050
Fall	10	17,137	10/31/2015	14,106	13,511	13,156	12,972	13,002	13,342	14,122	14,938	15,720	16,286	16,512	16,486	16,280	16,085	15,930	15,880	16,077	16,424	17,137	17,005	16,711	16,235	15,481	14,611
Fall	11	17,969	11/1/2015	13,498	12,837	12,617	12,516	12,534	12,816	13,352	14,016	14,984	15,626	15,953	16,093	16,088	16,011	16,001	16,126	16,638	17,944	17,969	17,570	16,992	16,023	15,072	14,110
Fall	11	19,568	11/2/2015	13,421	12,891	12,623	12,591	12,901	13,972	15,888	16,957	17,503	17,835	18,038	18,084	17,981	17,933	17,877	17,902	18,420	19,568	19,491	18,975	18,224	17,211	15,904	14,653
Fall	11	19,615	11/3/2015	13,765	13,259	12,981	12,902	13,195	14,195	15,841	16,872	17,406	17,705	17,932	18,021	18,036	18,124	18,151	18,202	18,534	19,615	19,507	18,911	18,162	17,096	15,816	14,571
Fall	11	19,579	11/4/2015	13,611	13,077	12,794	12,705	12,962	13,934	15,769	16,876	17,444	17,746	18,009	18,123	18,120	18,202	18,200	18,212	18,535	19,579	19,486	18,923	18,216	17,165	15,844	14,578
Fall	11	20,065	11/5/2015	13,663	13,128	12,822	12,720	12,945	13,884	15,709	16,996	17,677	18,160	18,490	18,544	18,580	18,651	18,689	18,741	19,197	20,065	19,842	19,319	18,605	17,629	16,279	15,010
Fall	11	20,071	11/6/2015	14,006	13,403	13,084	12,965	13,167	14,122	15,949	17,368	18,277	18,819	19,087	19,254	19,258	19,209	19,091	19,043	19,337	20,071	19,662	19,026	18,303	17,472	16,394	15,191
Fall	11	17,872	11/7/2015	14,190	13,523	13,109	12,861	12,817	13,098	13,678	14,502	15,516	16,140	16,519	16,638	16,593	16,487	16,382	16,443	17,008	17,872	17,766	17,354	16,907	16,323	15,528	14,621
Fall	11	18,094	11/8/2015	13,785	13,215	12,851	12,647	12,645	12,906	13,326	13,843	14,646	15,190	15,499	15,706	15,754	15,734	15,730	15,902	16,586	17,963	18,094	17,810	17,358	16,536	15,539	14,523
Fall	11	19,805	11/9/2015	13,803	13,362	13,118	13,075	13,413	14,458	16,322	17,425	17,859	18,077	18,102	17,987	17,852	17,844	17,796	17,895	18,594	19,805	19,718	19,300	18,616	17,649	16,340	14,968
Fall	11	20,106	11/10/2015	13,937	13,433	13,100	13,023	13,278	14,232	16,097	17,337	17,983	18,431	18,661	18,750	18,674	18,637	18,583	18,777	19,394	20,106	19,772	19,222	18,464	17,486	16,254	15,030
Fall	11	19,783	11/11/2015	14,072	13,471	13,119	12,995	13,190	13,979	15,235	16,469	17,445	17,987	18,273	18,344	18,279	18,241	18,183	18,240	18,868	19,783	19,617	19,116	18,419	17,482	16,220	14,948
Fall	11	20,173	11/12/2015	13,913	13,358	13,001	12,906	13,160	14,156	15,999	17,352	17,981	18,407	18,681	18,733	18,684	18,743	18,691	18,786	19,390	20,173	19,933	19,348	18,626	17,603	16,346	15,032
Fall	11	19,553	11/13/2015	13,993	13,409	13,019	12,916	13,123	14,031	15,821	17,026	17,602	17,925	18,155	18,192	18,110	18,068	17,970	18,027	18,646	19,553	19,374	18,837	18,204	17,395	16,366	15,180
Fall	11	18,449	11/14/2015	14,265	13,695	13,321	13,139	13,182	13,567	14,224	14,930	15,819	16,474	16,795	16,849	16,779	16,671	16,618	16,700	17,340	18,449	18,373	18,000	17,552	16,862	16,033	15,100
Fall	11	18,177	11/15/2015	14,281	13,736	13,371	13,174	13,177	13,418	13,827	14,280	14,948	15,428	15,677	15,804	15,804	15,767	15,804	15,932	16,711	18,094	18,177	17,807	17,325	16,531	15,458	14,312
Fall	11	19,730	11/16/2015	13,542	13,082	12,854	12,846	13,141	14,139	16,026	17,100	17,557	17,786	17,868	17,854	17,873	17,876	17,859	17,909	18,544	19,730	19,594	19,158	18,517	17,570	16,301	14,962
Fall	11	20,221	11/17/2015	14,052	13,520	13,270	13,242	13,542	14,629	16,598	17,668	18,078	18,186	18,181	18,111	17,981	17,955	17,940	18,085	18,941	20,221	20,112	19,687	19,050	18,076	16,731	15,347
Fall	11	20,098	11/18/2015	14,397	13,852	13,538	13,433	13,681	14,638	16,561	17,721	18,148	18,291	18,283	18,235	18,143	18,187	18,184	18,376	19,244	20,098	19,844	19,317	18,635	17,632	16,310	14,938
Fall	11	20,061	11/19/2015	13,940	13,383	13,066	12,957	13,152	14,060	15,935	17,202	17,800	18,202	18,444	18,531	18,565	18,564	18,535	18,653	19,319	20,061	19,801	19,299	18,611	17,559	16,341	15,018
Fall	11	19,423	11/20/2015	14,034	13,431	13,058	12,922	13,109	13,988	15,825	16,932	17,475	17,775	17,836	17,792	17,701	17,667	17,645	17,705	18,345	19,423	19,171	18,640	18,104	17,353	16,320	15,217
Fall	11	18,314	11/21/2015	14,305	13,713	13,385	13,211	13,285	13,693	14,379	15,101	15,934	16,430	16,641	16,609	16,491	16,334	16,290	16,407	17,232	18,314	18,222	17,810	17,325	16,653	15,796	14,823
Fall	11	18,819	11/22/2015	14,010	13,443	13,041	12,813	12,814	13,029	13,517	14,040	14,876	15,550	16,010	16,303	16,475	16,576	16,659	16,931	17,847	18,819	18,769	18,467	17,974	17,172	16,063	14,983
Fall	11	20,993	11/23/2015	14,194	13,755	13,547	13,528	13,852	14,916	16,854	18,041	18,532	18,758	18,828	18,828	18,731	18,706	18,715	18,900	19,807	20,993	20,913	20,538	19,908	18,885	17,583	16,205
Fall	11	20,739	11/24/2015	15,191	14,605	14,290	14,218	14,473	15,544	17,397	18,622	19,079	19,194	19,154	19,020	18,875	18,823	18,763	18,879	19,692	20,739	20,562	20,177	19,560	18,646	17,373	16,027
Fall	11	20,080	11/25/2015	15,038	14,486	14,143	14,056	14,340	15,264	16,991	18,123	18,657	18,900	18,875	18,742	18,512	18,355	18,249	18,285	19,006	20,080	19,923	19,490	18,903	18,097	16,961	15,731
Fall	11	16,936	11/26/2015	14,679	14,019	13,586	13,370	13,444	13,796	14,372	14,922	15,694	16,373	16,776	16,936	16,811	16,399	15,919	15,576	15,814	16,274	16,119	15,924	15,721	15,452	14,865	14,103
Fall	11	18,286	11/27/2015	13,370	12,911	12,626	12,510	12,676	13,176	14,045	14,785	15,464	16,007	16,358	16,476	16,460	16,361	16,406	16,567	17,419	18,286	18,038	17,588	17,063	16,368	15,465	14,464
Fall	11	18,336	11/28/2015	13,594	13,015	12,662	12,456	12,491	12,850	13,486	14,196	15,146	15,944	16,448	16,754	16,827	16,796	16,763	16,944	17,723	18,336	18,270	17,943	17,529	16,945	16,072	15,049
Fall	11	19,199	11/29/2015	14,196	13,614	13,264	13,054	13,102	13,381	13,915	14,447	15,242	15,920	16,359	16,410	16,414	16,416	16,457	16,760	17,843	19,135	19,199	18,951	18,460	17,621	16,474	15,360
Fall	11	21,086	11/30/2015	14,541	14,076	13,837	13,764	14,099	15,186	17,182	18,457	18,824	19,078	19,162	19,028	18,859	18,759	18,666	18,832	19,869	21,086	21,009	20,549	19,871	18,822	17,369	15,916

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FERC Form 714 Outages

Month	Planned Outage and Derating (MW)
Dec-14	3,297
Jan15	3,180
Feb15	3,568
Mar15	6,026
Apr15	7,520
May15	4,259
Jun15	1,496
Jul15	440
Aug15	281
Sep15	1,327
Oct15	7,477
Nov15	5,426

	Planned Outage and Derating (MW)				
	Winter	Spring	Summer	Fall	Notes
NYISO	3,348	5,935	739	4,743	NYISO outages
NY-City	862	1,528	183	1,221	Estimated based on generation ratios
Long Island	468	829	101	663	Estimated based on generation ratios

	Generation (MW)			
	Winter	Spring	Summer	Fall
NYISO	41,013	41,013	38,665	41,013
NY-City	10,561	10,561	9,597	10,561
Long Island	5,732	5,732	5,281	5,732

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	PSA	Winter	Spring	Summer	Fall	Notes
NYISO Reserves	2,620	2,620	2,620	2,620	2,620	NYISO Locational Reserve Requirements (30-minute reserves)
NY-City	#REF!	#REF!	#REF!	#REF!	#REF!	Estimated based on load ratios
Long Island	540	540	540	540	540	Maximum LI Locational Reserve Requirements (30-minute reserves)

	Loads				
	PSA	Winter	Spring	Summer	Fall
NYISO	25,244	22,045	19,393	24,144	20,374
NY-City	#REF!	#REF!	#REF!	#REF!	#REF!
Long Island	#REF!	#REF!	#REF!	#REF!	#REF!

http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf

NYISO
Locational Reserve Requirements

The NYISO shall define requirements for Spinning Reserve, which may be met only by Suppliers that are eligible to provide Spinning Reserve; 10-Minute Reserve, which may be met by Suppliers that are eligible to provide either Spinning Reserve or 10-Minute Non-Synchronized Reserve; and 30-Minute Reserve, which may be met by Suppliers that are eligible to provide any Operating Reserve product. The NYISO shall also define locational requirements for Spinning Reserve, 10-Minute Reserve, and 30-Minute Reserve located in East of Central–East (EAST), in Southeastern New York (SENY) and on Long Island (LI) as shown in the following table:

	NYCA	EAST	SENY	LI
A=most severe NYCA Operating Capability Loss (1310 MWs)	Zone A-K	Zone F-K	Zone G-K	Zone K
10 Minute Spinning Reserve	½ A = 655 MWs (I)	¼ A = 330 MWs (IV)	0 MWs	0 MWs
10 Minute Total Reserve	A = 1310 MWs (II)	1200 MWs (V)	0 MWs	$^{1}/_{10}$ V = 120 MWs (VIII)
30 Minute Reserve	2 A = 2620 MWs (III)	1200 MWs (VI)	1300 MWs (VII)	270-540 MWs (IX)

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Do Not Distribute

Source: RTO

	PJM
Max	143,633
Peak Month	7
PST	121,600
Winter	112,390
Spring	94,917
Summer	117,821
Fall	95,173

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	102,668	12/1/2014	70,381	68,446	67,764	68,161	70,444	76,128	84,884	90,282	91,203	91,189	91,836	91,776	91,829	91,811	91,779	92,445	95,733	101,439	102,668	101,987	100,291	96,470	90,714	84,732
Winter	12	110,873	12/2/2014	80,525	78,286	77,574	77,980	80,090	85,967	95,553	101,320	102,173	102,630	103,122	103,037	102,901	102,911	102,603	103,044	106,193	110,792	110,873	109,348	106,785	101,968	95,298	88,771
Winter	12	106,204	12/3/2014	83,905	81,113	79,602	79,325	81,114	86,183	95,107	100,446	100,367	99,996	99,745	99,041	98,104	97,266	96,052	95,696	98,556	104,849	106,204	105,479	104,054	100,662	94,871	88,963
Winter	12	109,104	12/4/2014	84,723	82,551	81,758	82,124	84,287	90,141	99,955	104,875	104,152	102,630	101,256	99,544	98,606	98,133	97,941	98,533	102,027	108,501	109,104	108,029	106,297	102,316	96,191	89,658
Winter	12	104,351	12/5/2014	84,891	81,949	80,646	80,558	82,192	87,130	96,094	101,346	101,410	101,125	101,214	100,457	99,438	98,682	97,895	97,865	100,427	104,351	103,620	101,486	99,179	95,844	91,032	85,028
Winter	12	96,752	12/6/2014	80,208	76,949	75,150	74,391	74,752	76,530	80,068	83,883	87,393	90,142	91,406	91,509	90,735	89,824	88,960	88,996	91,693	96,170	96,752	95,591	94,358	92,148	88,444	84,077
Winter	12	102,331	12/7/2014	79,958	77,424	76,296	76,130	77,032	79,002	82,258	85,648	88,254	89,170	88,566	87,148	86,119	84,990	84,516	85,364	90,142	99,259	101,864	102,331	101,962	98,965	94,151	88,877
Winter	12	113,955	12/8/2014	85,216	83,506	82,915	83,514	85,975	91,863	101,605	107,058	107,620	107,275	106,802	105,963	104,859	104,117	103,414	103,912	107,321	113,305	113,955	112,514	110,388	106,093	99,412	92,296
Winter	12	110,721	12/9/2014	87,318	84,683	83,420	83,438	85,167	90,647	99,563	105,126	105,422	105,171	104,880	103,946	102,866	102,008	101,037	101,305	104,426	110,215	110,721	109,407	107,222	102,824	96,096	89,371
Winter	12	113,559	12/10/2014	84,508	81,989	80,995	81,151	83,268	88,825	98,226	103,449	103,468	102,684	102,571	102,242	101,639	101,558	101,257	101,841	105,788	112,411	113,559	112,382	110,709	106,921	100,621	93,962
Winter	12	114,045	12/11/2014	89,594	87,225	86,339	86,577	88,735	94,425	104,168	109,511	108,929	107,689	106,446	104,902	103,726	102,882	101,914	102,090	105,641	112,601	114,045	113,234	111,866	108,250	101,952	95,291
Winter	12	109,191	12/12/2014	90,392	87,870	86,702	86,834	88,742	94,114	103,252	108,674	108,384	107,292	105,509	103,484	101,379	100,147	98,801	98,632	101,774	108,575	109,191	107,840	106,268	103,585	98,951	93,203
Winter	12	100,490	12/13/2014	88,294	85,371	84,023	83,775	84,441	86,721	90,223	94,274	96,806	97,313	96,502	94,990	93,191	91,605	90,505	90,632	93,713	99,671	100,490	99,427	98,173	96,027	91,991	87,198
Winter	12	98,486	12/14/2014	82,641	80,025	78,576	77,886	78,015	79,446	82,076	85,015	87,614	88,694	88,521	87,864	87,549	86,491	85,813	86,105	89,557	96,827	98,486	98,159	97,021	93,763	88,793	83,253
Winter	12	105,072	12/15/2014	79,058	76,804	76,020	76,514	78,941	84,785	94,566	100,339	100,184	98,490	96,999	95,206	93,472	92,271	91,027	91,013	94,614	102,884	105,072	104,783	103,565	99,779	93,918	87,114
Winter	12	106,709	12/16/2014	82,294	79,686	78,574	78,654	80,467	85,925	95,301	100,953	100,495	99,400	98,884	98,145	97,445	97,116	97,150	97,648	100,871	106,394	106,709	105,346	103,550	99,760	93,347	86,305
Winter	12	109,307	12/17/2014	81,302	78,612	77,534	77,405	79,395	85,188	94,651	100,406	100,161	98,992	98,337	97,490	96,786	96,686	96,502	96,916	100,687	107,877	109,307	108,659	107,473	104,435	98,828	92,226
Winter	12	113,423	12/18/2014	87,282	85,004	84,127	84,317	86,588	92,352	102,125	107,737	107,287	106,133	105,488	104,426	102,891	102,040	101,581	101,837	105,584	112,361	113,423	112,264	110,939	107,230	100,985	94,134
Winter	12	110,832	12/19/2014	88,924	86,015	84,812	84,921	86,932	92,223	101,340	107,405	107,566	106,809	106,055	104,283	102,547	100,967	99,680	99,657	103,020	109,961	110,832	109,497	108,054	105,391	100,902	95,173
Winter	12	105,010	12/20/2014	90,098	87,297	85,773	85,397	85,878	88,332	91,906	96,297	99,456	101,486	101,848	100,663	98,742	96,702	95,461	95,362	98,267	104,403	105,010	103,880	102,853	100,690	96,674	91,778
Winter	12	104,387	12/21/2014	87,358	84,412	82,846	82,240	82,546	84,158	86,902	90,241	93,210	94,515	93,944	92,596	91,207	89,094	87,922	88,183	92,142	100,729	103,851	104,387	104,095	101,821	97,572	92,569
Winter	12	109,089	12/22/2014	88,412	85,962	85,180	85,311	87,217	91,984	99,540	105,061	106,251	106,052	105,268	104,072	102,539	101,196	100,525	100,327	103,042	108,610	109,089	107,587	105,744	101,813	95,998	89,201
Winter	12	100,145	12/23/2014	83,660	80,274	78,624	77,852	79,136	83,221	90,333	95,691	97,012	97,274	97,163	96,304	94,828	93,806	92,654	92,162	94,428	99,611	100,145	98,523	96,412	92,985	87,818	81,237
Winter	12	88,815	12/24/2014	75,581	71,879	69,800	68,921	69,578	72,287	76,856	81,383	84,298	86,842	88,399	88,352	87,085	85,851	84,852	84,140	85,605	88,815	87,014	84,326	82,595	80,993	78,334	74,445
Winter	12	83,815	12/25/2014	70,175	67,079	65,166	64,390	64,845	66,331	69,161	72,757	75,930	78,240	79,165	79,439	78,810	77,524	76,045	75,231	76,498	81,692	83,346	83,498	83,815	83,249	81,159	77,865
Winter	12	93,069	12/26/2014	74,906	73,058	72,560	73,239	75,198	78,945	84,275	88,555	89,997	89,375	87,724	85,802	83,737	81,728	80,235	79,960	82,713	90,696	93,069	92,554	91,697	89,678	86,012	81,607
Winter	12	88,934	12/27/2014	77,511	75,287	74,125	73,763	74,352	76,209	79,177	82,517	84,509	84,901	84,064	82,770	80,915	79,077	77,752	77,568	80,120	87,269	88,934	88,340	87,299	85,432	81,929	77,593
Winter	12	92,467	12/28/2014	73,533	70,859	69,288	68,585	68,753	70,038	72,252	75,165	77,542	80,060	81,199	81,692	82,016	81,653	81,340	81,673	84,799	90,242	92,467	91,819	90,693	87,979	84,307	79,709
Winter	12	106,148	12/29/2014	76,057	73,839	73,136	73,466	75,375	79,840	86,424	92,427	94,719	96,108	96,824	96,719	95,558	95,083	94,650	94,646	97,087	104,388	106,148	104,906	103,166	99,992	94,934	89,310
Winter	12	110,969	12/30/2014	85,158	82,961	81,918	81,927	83,766	88,076	94,820	100,377	102,214	103,005	102,649	101,217	99,391	98,078	97,027	96,779	99,895	107,912	110,969	110,315	109,205	106,587	102,033	96,808
Winter	12	110,712	12/31/2014	92,824	90,825	90,213	90,391	92,159	96,213	102,039	106,177	106,966	106,284	104,907	103,100	101,041	98,994	97,394	96,911	100,075	108,863	110,712	108,487	105,835	102,991	99,729	96,399
Winter	1	100,418	1/1/2015	94,002	91,930	90,377	89,636	89,869	91,496	93,609	94,661	94,393	93,595	93,037	92,148	90,712	88,937	87,566	87,639	90,579	98,472	100,418	99,622	98,106	95,346	91,232	86,865
Winter	1	102,363	1/2/2015	83,243	81,050	79,966	79,816	81,302	85,142	90,711	95,487	97,348	97,671	97,117	96,171	94,593	93,186	92,091	91,900	94,277	101,121	102,363	101,127	99,669	97,212	93,105	88,464
Winter	1	98,387	1/3/2015	84,415	81,797	80,286	79,699	79,928	81,614	84,139	87,128	89,799	92,616	94,899	95,640	95,306	94,640	93,652	93,100	94,728	98,387	97,974	95,964	93,496	90,264	86,137	81,225
Winter	1	95,931	1/4/2015	76,690	73,582	71,615	70,618	70,505	71,601	73,364	76,032	78,390	80,803	82,444	83,440	84,311	84,568	84,318	84,797	87,843	93,682	95,931	95,028	94,128	90,877	86,854	82,810
Winter	1	119,815	1/5/2015	79,944	78,810	78,898	79,993	82,975	89,652	100,128	106,670	107,140	106,612	106,112	105,633	104,812	104,105	103,709	104,398	108,250	116,660	119,815	119,285	117,705	113,945	108,021	102,163
Winter	1	122,846	1/6/2015	98,195	96,106	95,176	95,196	97,136	102,616	111,077	116,543	116,476	116,026	115,483	114,466	113,053	111,749	110,567	110,015	112,517	120,195	122,846	122,385	120,670	116,843	111,068	105,659
Winter	1	135,639	1/7/2015	101,571	99,579	98,804	99,208	101,335	106,680	114,922	120,461	121,092	120,319	119,993	119,579	119,189	119,289	119,290	120,394	124,240	131,953	135,424	135,639	134,763	131,875	126,616	121,623
Winter	1	118,502	1/8/2015	118,502	117,119	116,828	117,144	119,316	124,060	131,396	136,197	135,305	133,080	130,834	128,427	126,223	124,293	123,179	123,214	125,800	132,509	134,759	133,640	131,229	126,824	120,108	113,728
Winter	1	122,167	1/9/2015	108,949	106,487	105,074	104,539	105,718	109,710	116,898	121,704	121,409	120,176	118,113	115,500	113,330	111,596	110,255	109,958	112,332	119,266	122,167	121,493	120,294	117,981	114,018	109,342
Winter	1	119,065	1/10/2015	106,201	104,570	104,250	104,682	106,176	108,963	113,020	117,234	119,065	118,510	116,514	113,773	110,625	107,315	105,225	104,923	108,084	115,500	119,027	118,968	118,430	116,574	112,914	108,868
Winter	1	109,169	1/11/2015	105,354	103,403	102,366	102,072	102,390	103,729	106,065	108,686	109,169	107,281	104,271	101,458	99,304	97,352	96,045	96,259	99,665	106,626	108,701	107,561	105,704	101,773	96,767	91,716
Winter	1	113,974	1/12/2015	88,199	86,206	85,742	85,963	88,132	93,149	101,131	107,630	109,235	109,643	109,517	109,352	108,528	107,717	106,653	106,492	108,191	112,613	113,974	112,515	110,010	105,613	100,289	94,790
Winter	1	121,214	1/13/2015	90,741	88,452	87,906	88,563	90,994	96,952	106,849	113,166	113,271	112,227	111,242	109,939	108,667	107,583	107,177	107,634	110,467	117,588	121,214	120,989	119,514	115,895	110,058	104,471
Winter	1	121,315	1/14/2015	100,703	98,717	98,152	98,659	100,747	106,284	114,884	120,549	120,956	120,280	119,168	117,851	116,665	114,618	113,150	112,676	114,265	119,266	121,315	120,171	118,253	113,961	107,744	101,669
Winter	1	116,668	1/15/2015	97,651	95,639	94,615	94,862	96,902	102,120	111,013	116,668	115,936	113,989	111,582	109,019	106,641	104,875	103,386	103,077	105,101	111,271	114,737	114,338	113,000	109,335	103,530	97,774
Winter	1	112,992	1/16/2015	94,058	92,038	91,508	91,662	93,894	99,342	107,895	112,992	111,753	108,980	106,918	104,847	102,692	100,980	99,604	99,021	100,724	106,405	109,484	108,652	107,396	104,783	101,042	96,542
Winter	1	104,517	1/17/2015	93,001	91,161	90,606	90,858	92,071	94,552	98,520	102,531	104,517	103,877	101,601	98,712	95,244	92,333	90,257	89,754	92,132	98,326	101,907	101,398	100,108	97,703	93,907	89,613
Winter	1	98,475	1/18/2015	85,813	83,580	81,932	81,296	81,152	82,141	84,235	87,036	89,840	92,376	93,566	93,890	93,746	92,730	91,617	90,892	92,173	96,520	98,475	98,411	96,712	94,174	90,375	86,670
Winter	1	106,188	1/19/2015	83,833	82,395	81,993	82,443	84,445	88,567	95,060	100,413	102,519	102,752	101,668	100,242	98,809	97,682	96,318	95,571	96,982	102,674	106,188	105,974	104,528	101,041	95,610	90,186
Winter	1	108,376	1/20/2015	86,501	84,813	84,408	84,972	87,346	93,404	102,897	108,376	107,518	105,135	101,841	100,571	98,458	97,423	96,288	96,183	98,165	103,602	106,713	106,327	104,953	101,506	96,189	90,689
Winter	1	112,252	1/21/2015	86,648	84,800	84,236	84,413	86,723	92,555	101,982	107,373	106,948	106,060	105,549	104,970	104,012	103,682	103,256	103,142	105,036	109,832	112,252	111,085	109,397	105,245	99,349	93,904
Winter	1	110,280	1/22/2015	89,895	87,720	86,890	87,056	89,116	94,564	103,574	109,259	109,309	108,374	106,946	104,772	102,811	101,250	100,050	99,900	101,676	107,125	110,280	109,759	108,129	104,856	98,994	93,708
Winter	1	110,667	1/23/2015	89,583	87,617	87,243	87,620	89,904	95,666	105,125	110,667	109,670	107,668	105,653	103,553	101,574	100,588	99,815	99,989	101,881	106,038	107,736	106,503	104,633	101,456	96,980	91,868
Winter	1	102,257	1/24/2015	87,741	85,509	83,997	83,517	83,903	85,884	89,002	92,901	95,846	98,614	99,927	99,896	98,513	96,783	95,252	94,231	94,940	99,431	102,257	101,434	99,712	97,115	93,053	88,487
Winter	1	100,769	1/25/2015	84,828	82,421	81,080	80,707	81,178	82,746	85,195	88,046	90,652	91,867	91,642	91,172	90,172	89,171	88,074	88,446	90,950	97,053	100,769	100,557	99,311	96,304	92,046	87,909
Winter	1	118,210	1/26/2015	84,673	83,351	83,095	83,834	86,436	92,550	101,654	108,345	109,803	110,475	111,011	110,530	110,039	109,713	108,977	108,805	110,528	115,330	118,210	116,939	114,359	110,230	104,637	99,354
Winter	1	118,540	1/27/2015	95,260	93,519	92,838	93,228	95,179	100,019	107,895	113,311	114,303	114,021	112,945	111,368	109,458	107,953	106,404	106,023	108,121	114,088	118,540	118,182	116,531	112,922	107,606	102,192
Winter	1	122,273	1/28/2015	99,006	97,919	97,648	98,479	101,236	107,345	116,990	122,273	120,526	116,971	113,732	110,354	107,445	105,272	103,220	102,849	104,827	111,239	116,674	116,963	116,000	112,314	106,679	101,111
Winter	1	118,159	1/29/2015	97,643	96,032	95,629	96,209	98,637	104,453	113,600	118,159	116,433	113,967	111,964	109,936	108,212	107,436	106,541	106,497	108,211	112,391	114,590	113,517	111,117	106,596	100,378	94,385
Winter	1	115,519	1/30/2015	89,969	87,576	86,497	86,566	88,716	94,043	103,096	108,744	108,967	108,411	107,796	106,856	105,577	104,744	103,632	103,241	104,792	110,122	115,228	115,519	114,676	112,601	108,829	104,888
Winter	1	111,797	1/31/2015	101,771	100,336	99,937	100,284	101,337	104,023	107,767	111,409	111,797	111,655	111,313	110,868	109,986	109,144	108,253	107,567	109,151	107,590	107,465	106,441	104,318	100,742	96,459	92,059
Winter	2	103,665	2/1/2015	93,181	91,116	90,027	89,404	89,340	90,417	92,480	94,907	97,059	98,130	97,669	96,915	96,319	95,704	95,189	95,691	98,040	102,508	103,665	101,206	99,217	96,655	93,595	89,116
Winter	2	120,485	2/2/2015	85,143	82,973	82,025	82,271	84,148	89,472	97,673	103,631	104,978	106,049	107,013	107,109	106,628	106,180	105,715	105,671	108,056	113,967	119,733	120,485	119,029	115,425	109,737	104,236
Winter	2	121,191	2/3/2015	101,026	99,518	99,007	99,597	101,976	107,505	116,460	121,191	120,326	118,223	115,519	111,995	108,765	106,495	104,450	103,729	105,380	110,812	116,476	117,036	115,673	111,978	106,275	100,385
Winter	2	114,251	2/4/2015	96,493	94,345	93,552	93,487	95,294	100,693	109,768	114,251	112,409	109,160	106,370	103,676	101,233	99,147	97,636	96,975	98,566	103,397	108,264	108,785	107,499	103,866	98,222	92,661
Winter	2	123,695	2/5/2015	88,862	86,959	86,318	86,913	89,452	95,485	105,344	111,724	112,602	112,617	112,499	111,261	109,696	108,404	107,130	106,823	109,216	115,615	122,417	123,695	123,097	120,228	115,132	110,157
Winter	2	127,381	2/6/2015	106,845	105,644	105,473	105,954	108,312	113,982	122,847	127,381	124,753	121,387	118,524	115,612	112,284	109,722	107,726	106,542	106,712	109,887	113,924	113,325	112,048	108,929	104,658	99,494
Winter	2	102,343	2/7/2015	95,484	93,255	92,148	91,654	91,826	93,432	96,676	100,017	102,023	102,343	100,646	97,412	93,329	89,931	87,475	86,304	86,958	90,717	95,530	95,786	94,665	92,392	88,809	84,969
Winter	2	93,941	2/8/2015	81,514	79,227	78,177	77,599	77,998	79,206	81,612	84,155	86,376	87,349	86,570	85,371	84,201	82,955	82,193	82,323	84,315	88,903	93,684	93,941	92,495	89,170	85,054	80,872
Winter	2	113,055	2/9/2015	77,452	75,751	75,380	76,214	78,904	84,915	94,774	101,065	102,276	103,101	104,038	104,232	104,046	103,830	103,319	103,704	105,606	109,804	113,055	112,567	110,696	106,660	100,806	95,204
Winter	2	114,183	2/10/2015	91,452	89,783	89,329	89,846	91,880	97,629	106,710	112,407	112,838	112,615	112,005	110,371	108,451	106,628	104,777	103,675	104,217	108,378	113,706	114,183	112,810	109,500	103,557	97,862
Winter	2	114,516	2/11/2015	94,031	92,302	91,812	92,309	94,713	100,641	110,188	114,516	112,644	110,164	107,750	104,941	102,105	100,250	98,580	98,164	99,674	104,224	109,821	110,396	109,216	105,705	100,377	94,654
Winter	2	130,851	2/12/2015	96,621	94,703	93,575	94,665	96,060	101,368	111,366	116,005	116,157	114,706	112,872	111,011	109,596	108,227	107,311	106,596	106,256	108,128	112,997	119,161	120,853	120,450	118,152	113,639
Winter	2	128,761	2/13/2015	106,589	105,760	105,817	106,966	109,618	115,318	124,228	128,761	127,115	124,532	121,764	118,647	115,369	112,651	110,147	108,746	109,698	113,889	119,031	119,266	118,181	115,593	111,400	106,437
Winter	2	113,813	2/14/2015	102,598	100,403	99,014	98,250	98,345	99,728	102,497	105,212	107,801	109,548	109,747	108,714	106,818	104,868	103,273	102,426	103,781	107,432	112,534	113,813	113,421	112,731	111,055	109,263
Winter	2	127,475	2/15/2015	108,340	108,384	108,947	109,968	111,591	113,967	117,242	119,757	121,290	121,821	120,710	119,016	116,729	113,986	111,717	110,857	112,599	118,316	125,719	127,475	126,774	124,797	121,472	118,270
Winter	2	134,183	2/16/2015	115,800	114,993	114,643	115,338	116,884	121,072	126,900	130,754	132,213	132,926	132,553	130,548	128,516	127,214	126,349	125,961	127,053	130,389	134,183	133,384	130,682	126,451	120,492	115,177
Winter	2	126,240	2/17/2015	111,777	109,999	109,231	109,579	111,177	115,018	121,233	125,025	126,240	124,877	122,766	119,538	116,639	114,283	112,248	111,380	112,566	117,166	123,265	124,109	122,445	119,115	113,795	109,517
Winter	2	127,107	2/18/2015	106,542	105,692	105,838	106,867	109,221	114,528	123,117	127,107	125,447	121,808	118,853	116,241	114,330	112,921	112,054	112,594	114,785	119,605	125,758	126,798	126,071	123,374	118,885	114,776
Winter	2	140,386	2/19/2015	112,308	111,506	111,882	113,337	116,203	121,808	129,594	133,522	133,056	131,649	129,766	128,346	126,737	125,716	124,944	125,214	127,477	132,392	138,886	140,386	139,399	137,114	132,574	128,428
Winter	2	143,129	2/20/2015	125,665	124,750	124,784	125,840	127,861	132,615	139,530	143,129	141,840	138,982	136,112	132,570	128,896	125,386	122,339	121,024	121,613	125,154	130,983	131,932	130,985	128,469	124,216	119,717
Winter	2	119,441	2/21/2015	115,795	113,625	112,199	111,672	111,824	113,207	115,763	117,517	118,370	119,441	119,436	118,438	116,950	114,880	112,717	111,260	111,438	113,377	116,182	115,007	111,797	107,847	103,335	98,365
Winter	2	106,323	2/22/2015	94,329	91,919	90,713	90,234	90,356	91,571	93,725	95,416	98,060	99,924	99,269	97,105	94,934	92,933	91,393	91,304	93,015	98,054	104,324	106,323	105,586	102,715	98,799	94,819
Winter	2	127,775	2/23/2015	92,310	90,989	90,875	91,421	93,753	100,690	110,049	115,430	117,204	117,039	116,813	115,631	113,922	112,080	110,686	110,451	112,414	117,208	124,876	127,775	127,500	124,785	120,076	115,573
Winter	2	134,132	2/24/2015	113,038	112,293	112,470	113,561	116,332	122,154	130,663	134,132	131,619	127,664	123,917	120,643	117,816	115,732	114,181	113,487	115,094	118,761	123,988	125,187	123,438	119,706	114,019	108,778
Winter	2	122,289	2/25/2015	104,851	103,413	102,938	103,537	105,352	110,699	119,253	122,289	119,043	114,969	111,633	108,481	105,697	103,888	102,247	101,718	103,418	107,515	113,838	115,072	113,933	110,691	105,185	99,941
Winter	2	119,359	2/26/2015	96,185	94,426	93,983	94,535	96,754	102,025	110,488	114,913	116,127	116,135	115,534	113,417	111,170	109,437	108,388	107,999	109,108	112,816	118,000	119,359	118,457	115,205	110,028	104,998
Winter	2	121,067	2/27/2015	101,799	100,213	99,730	100,389	102,570	108,019	116,914	121,067	119,702	116,521	114,083	111,431	109,088	107,330	105,622	104,454	105,326	108,858	115,204	117,755	117,731	115,900	112,363	108,312
Winter	2	114,963	2/28/2015	105,369	104,029	103,695	104,084	105,412	108,302	112,177	114,498	114,963	113,688	110,850	107,153	103,464	99,803	97,302	95,925	96,924	100,770	107,473	109,837	109,554	107,931	104,836	101,028
Spring	3	111,112	3/1/2015	98,093	96,299	95,423	94,705	94,766	95,609	97,359	99,031	101,620	103,803	104,778	104,825	104,833	103,980	103,245	102,798	103,875	106,722	110,320	111,112	108,884	104,867	99,922	95,310
Spring	3	112,134	3/2/2015	91,845	90,213	89,883	90,319	92,327	97,672	105,816	110,085	110,809	108,462	106,375	104,019	101,841	99,943	98,251	97,187	98,253	101,857	109,138	112,134	111,207	108,148	103,227	98,064
Spring	3	114,461	3/3/2015	94,755	93,228	92,644	93,093	95,238	100,687	109,474

Contains Proprietary Material
Do Not Distribute

Spring	4	92,469	4/2/2015	74,038	72,233	71,643	72,056	74,288	79,817	88,359	92,469	91,936	90,200	89,057	87,695	86,282	85,471	84,304	83,194	82,754	82,645	82,498	84,066	86,135	83,363	78,070	71,975
Spring	4	82,162	4/3/2015	67,345	64,351	62,999	62,433	63,259	66,416	72,127	76,252	78,853	81,016	82,109	82,162	81,518	80,704	80,055	79,272	79,231	79,524	79,296	80,288	81,514	79,574	75,811	71,107
Spring	4	79,892	4/4/2015	66,975	64,476	63,114	62,441	63,048	64,829	67,923	71,194	74,994	77,620	78,339	77,701	76,274	74,511	72,934	71,893	71,859	72,333	72,972	75,596	79,892	79,527	77,064	73,348
Spring	4	76,582	4/5/2015	69,823	67,499	66,641	66,447	67,225	69,067	71,972	74,641	76,582	76,565	74,866	73,114	71,601	69,905	68,020	66,736	66,014	66,174	67,314	70,599	75,660	75,327	72,263	68,471
Spring	4	87,056	4/6/2015	65,718	64,305	64,151	64,880	67,218	72,715	81,173	85,879	87,056	86,730	86,391	85,668	84,849	84,070	83,083	82,149	81,800	82,023	82,041	84,289	87,015	84,186	78,721	72,844
Spring	4	89,290	4/7/2015	68,242	65,555	64,075	63,725	64,986	69,331	77,566	82,792	84,778	85,913	87,166	87,212	87,047	86,874	86,379	85,669	85,659	86,039	86,274	87,898	89,290	85,918	80,036	73,905
Spring	4	91,683	4/8/2015	69,529	66,992	65,670	65,303	66,603	71,332	79,596	84,771	86,795	88,033	89,048	89,164	89,000	88,686	87,903	87,214	87,418	88,003	88,667	90,339	91,683	88,704	83,058	77,153
Spring	4	92,720	4/9/2015	72,761	70,126	68,661	68,444	69,923	74,863	83,615	88,232	89,951	90,805	91,487	91,617	91,531	91,031	90,165	89,619	89,636	90,073	90,415	91,566	92,720	89,818	83,999	77,893
Spring	4	89,432	4/10/2015	73,079	70,467	69,055	68,451	69,649	74,005	82,049	86,831	88,612	89,338	89,432	88,826	87,987	87,058	85,943	84,396	83,531	82,820	81,693	81,875	84,381	82,640	78,136	73,040
Spring	4	77,383	4/11/2015	68,479	66,006	64,527	64,084	64,485	66,488	69,495	72,120	74,798	76,427	76,842	76,103	74,985	73,686	72,287	71,602	71,427	71,758	72,089	73,370	77,383	76,894	73,748	69,829
Spring	4	79,870	4/12/2015	66,217	64,326	63,425	63,383	64,006	65,979	68,500	70,441	72,389	73,011	72,580	71,981	71,350	70,547	69,930	70,015	70,647	71,953	72,998	75,470	79,870	78,068	73,336	68,309
Spring	4	88,036	4/13/2015	64,510	62,577	61,672	61,896	63,756	69,084	78,361	83,252	84,277	84,120	84,856	84,750	84,928	85,348	85,071	84,908	84,942	84,934	84,280	85,074	88,036	84,995	78,846	72,131
Spring	4	86,675	4/14/2015	67,171	64,433	62,776	62,158	63,295	67,770	76,508	81,417	83,410	84,603	85,545	85,568	85,318	84,993	84,321	83,418	83,366	83,444	83,674	84,637	86,675	84,278	78,175	72,132
Spring	4	86,396	4/15/2015	67,842	65,650	64,357	64,321	65,913	70,964	79,577	83,887	84,708	84,781	84,528	84,133	83,758	83,491	82,726	81,983	81,819	81,992	81,677	83,062	86,396	83,764	78,485	72,461
Spring	4	86,192	4/16/2015	68,344	65,813	64,633	64,630	66,067	71,146	79,491	83,804	84,385	84,302	84,577	84,103	83,796	83,567	82,978	82,465	82,293	82,318	82,040	83,433	86,192	84,003	78,153	72,090
Spring	4	85,616	4/17/2015	67,646	64,887	63,574	63,032	64,333	68,658	76,934	81,272	83,153	84,432	85,383	85,334	85,477	85,616	85,139	84,511	84,188	83,451	82,066	81,704	84,057	82,565	77,378	71,253
Spring	4	78,849	4/18/2015	66,218	62,905	61,011	59,934	60,136	61,506	63,922	66,672	70,508	73,520	75,233	75,889	75,987	75,878	75,760	75,921	76,724	77,113	76,472	76,271	78,849	77,651	73,401	68,184
Spring	4	79,522	4/19/2015	63,590	60,461	58,554	57,532	57,390	58,131	59,264	61,280	65,111	68,150	69,682	70,564	71,110	71,077	71,014	71,216	72,233	73,901	75,040	77,195	79,522	77,140	72,623	67,863
Spring	4	88,161	4/20/2015	64,223	62,118	61,169	61,076	62,619	67,388	76,234	81,458	84,122	85,521	86,895	87,414	87,495	87,494	87,333	87,009	86,690	86,703	86,239	86,438	88,161	85,535	79,329	72,773
Spring	4	86,403	4/21/2015	68,382	65,605	64,200	63,830	64,911	69,719	78,001	82,343	83,736	83,935	84,320	84,296	83,921	83,890	83,283	82,592	82,702	82,617	82,163	82,812	86,403	84,687	78,760	72,707
Spring	4	88,647	4/22/2015	68,497	66,017	65,031	64,750	66,284	71,372	79,929	84,400	85,474	85,925	86,333	86,161	86,081	86,232	85,827	85,289	85,126	85,269	85,151	85,687	88,647	86,940	81,227	75,252
Spring	4	90,110	4/23/2015	71,171	69,155	68,201	68,214	70,127	75,554	84,123	88,358	88,526	88,024	87,977	87,712	87,252	86,547	85,751	85,108	85,018	85,313	85,464	86,636	90,110	88,885	83,597	77,890
Spring	4	91,229	4/24/2015	73,937	71,953	71,128	71,387	73,437	78,786	87,303	91,229	90,992	89,508	88,387	86,928	85,366	84,070	82,627	81,204	80,336	79,736	79,108	79,975	83,762	83,136	79,271	74,274
Spring	4	81,328	4/25/2015	70,103	67,939	67,020	66,547	67,168	69,006	71,703	74,718	78,388	80,573	81,229	80,585	79,254	77,989	76,524	75,846	75,920	76,367	77,196	78,592	81,328	80,481	76,912	72,711
Spring	4	78,641	4/26/2015	68,998	66,733	65,365	65,018	65,196	66,599	68,379	70,283	72,757	73,947	73,737	73,114	72,654	71,834	71,014	70,449	70,912	71,700	72,568	74,385	78,514	78,641	74,635	70,015
Spring	4	87,426	4/27/2015	66,829	65,306	65,049	65,572	68,020	73,824	82,618	86,943	87,212	86,396	85,861	85,461	85,286	85,059	84,062	83,093	83,113	83,284	83,418	84,578	87,426	86,109	80,499	74,689
Spring	4	86,575	4/28/2015	70,614	68,437	67,537	67,680	69,499	75,073	83,214	86,575	86,272	85,291	84,893	84,175	83,715	83,378	82,464	81,662	81,320	81,211	80,504	80,922	84,282	83,723	77,806	71,860
Spring	4	85,392	4/29/2015	67,391	65,158	64,311	64,383	66,049	71,188	79,342	83,688	84,000	83,748	83,865	84,076	84,127	84,055	83,922	83,386	83,441	83,091	82,316	82,238	85,392	84,133	78,015	71,640
Spring	4	84,996	4/30/2015	66,849	64,152	62,745	62,481	63,915	68,405	76,447	81,270	82,950	83,728	84,452	84,410	84,387	84,425	83,849	83,237	82,821	82,483	82,083	82,577	84,996	83,838	78,562	72,475
Spring	5	84,125	5/1/2015	67,925	65,541	64,293	63,867	65,277	69,823	77,465	81,807	83,276	83,756	84,125	83,824	83,361	82,868	81,969	80,993	80,561	79,930	78,987	78,780	80,847	80,526	76,290	70,964
Spring	5	75,726	5/2/2015	66,378	63,540	62,202	61,522	61,931	63,770	65,855	68,676	71,628	73,254	73,979	74,025	73,668	73,165	72,686	72,711	73,028	73,457	73,291	73,458	75,726	75,578	71,584	66,750
Spring	5	81,125	5/3/2015	62,644	60,271	58,750	57,813	57,821	58,950	59,831	62,016	65,391	68,350	69,849	71,140	71,974	72,735	73,210	73,775	75,106	76,746	77,499	78,239	81,125	80,230	74,983	69,060
Spring	5	92,899	5/4/2015	64,540	61,997	60,606	60,204	61,402	66,028	73,401	78,989	81,969	84,177	86,549	88,602	90,012	91,338	91,922	92,491	92,750	92,899	91,749	90,700	92,405	90,468	83,232	75,716
Spring	5	96,658	5/5/2015	69,968	66,622	64,338	63,429	64,362	68,489	75,777	81,251	84,537	86,733	89,433	91,278	92,747	94,514	95,786	96,407	96,658	95,982	94,420	93,357	94,599	92,563	85,276	77,525
Spring	5	97,579	5/6/2015	71,786	68,155	65,868	64,692	65,481	69,509	76,627	81,758	84,877	86,922	89,278	91,502	93,292	95,344	96,519	97,209	97,579	96,860	95,017	93,358	94,003	92,408	85,170	77,204
Spring	5	101,580	5/7/2015	71,157	67,167	65,023	63,894	64,663	68,648	75,632	80,855	84,032	87,168	90,155	92,665	95,317	97,666	99,481	100,677	101,550	101,580	100,019	97,858	97,951	96,136	88,299	79,838
Spring	5	107,010	5/8/2015	73,689	69,553	66,954	65,780	66,138	69,790	76,532	81,986	86,393	90,181	94,013	97,404	100,264	103,303	105,143	106,233	107,010	105,958	103,049	99,044	97,932	95,633	88,849	80,942
Spring	5	93,140	5/9/2015	74,128	69,589	66,760	64,961	64,300	65,202	66,572	69,842	74,863	79,340	82,604	84,856	86,677	88,319	89,907	91,476	92,712	93,140	91,896	89,770	89,922	89,052	84,034	77,384
Spring	5	94,750	5/10/2015	71,651	67,485	64,788	63,222	62,370	62,722	63,344	66,528	72,046	77,401	81,467	84,784	87,382	89,349	91,115	92,730	93,974	94,750	94,252	93,100	91,500	94,148	87,973	80,815
Spring	5	111,596	5/11/2015	74,641	71,036	68,754	67,913	68,731	73,376	80,666	87,222	91,888	95,470	99,525	102,977	106,540	109,327	111,070	111,405	111,596	110,838	108,609	105,271	104,433	101,272	92,715	84,055
Spring	5	105,026	5/12/2015	77,298	73,207	70,769	69,475	69,957	73,793	80,873	86,960	90,807	94,366	97,389	99,718	101,316	103,281	104,183	104,743	105,026	104,066	101,583	98,494	98,107	96,123	88,124	79,371
Spring	5	87,059	5/13/2015	73,032	69,062	66,671	65,400	65,885	69,585	76,120	81,072	83,534	85,033	86,111	86,455	86,531	86,695	86,895	86,734	87,059	86,840	85,538	84,612	85,811	85,308	79,276	72,892
Spring	5	86,168	5/14/2015	68,064	65,303	63,773	63,485	64,559	68,689	75,475	80,365	82,427	83,286	84,133	84,648	84,930	85,639	85,713	85,778	86,036	86,168	84,947	84,128	86,078	85,425	79,046	72,669
Spring	5	90,857	5/15/2015	67,620	64,450	62,980	62,356	63,462	67,467	74,020	78,971	82,076	83,998	85,846	86,978	87,895	89,084	89,727	90,317	90,857	90,617	89,090	87,277	87,661	87,327	82,299	76,078
Spring	5	92,740	5/16/2015	70,432	66,620	64,359	62,842	62,588	63,557	64,712	68,446	73,678	78,206	81,896	84,620	86,961	88,718	90,385	91,896	92,740	92,467	90,839	89,154	89,260	88,347	83,927	77,834
Spring	5	101,303	5/17/2015	72,388	68,525	65,911	64,348	63,620	63,840	64,349	67,069	72,588	77,860	82,231	86,330	89,986	92,866	95,043	97,377	99,760	101,303	101,284	100,035	99,746	98,657	92,177	84,439
Spring	5	113,132	5/18/2015	78,049	73,888	71,312	70,121	70,948	75,168	82,680	89,501	94,815	99,498	104,135	107,892	110,321	112,242	113,132	113,048	112,673	111,145	107,948	104,788	103,136	100,030	91,969	83,468
Spring	5	105,992	5/19/2015	76,822	72,698	70,157	68,832	69,317	73,121	79,731	85,499	88,721	91,453	94,389	96,771	98,696	100,568	102,464	104,373	105,918	105,992	104,140	100,934	99,824	97,994	90,154	81,562
Spring	5	89,431	5/20/2015	74,848	70,237	67,538	66,169	66,540	69,954	76,043	81,435	84,241	85,830	86,905	87,677	87,765	88,398	88,846	89,114	89,431	89,095	87,702	86,318	87,278	86,707	80,609	74,009
Spring	5	85,456	5/21/2015	68,841	65,848	63,961	63,373	64,344	68,459	75,247	80,381	83,156	84,539	85,313	85,456	85,282	85,294	84,832	84,120	84,050	83,910	83,311	83,021	84,083	83,712	78,819	72,482
Spring	5	84,002	5/22/2015	68,052	65,268	63,000	62,273	64,389	68,172	74,144	78,971	81,339	82,459	83,491	83,863	83,882	84,002	83,916	83,678	83,621	83,070	81,688	79,791	80,263	80,615	76,106	70,077
Spring	5	76,960	5/23/2015	65,132	61,893	60,029	59,156	59,110	59,993	60,917	63,823	67,597	70,542	72,110	72,769	72,963	72,986	73,218	74,095	75,506	76,780	76,960	76,104	76,339	76,651	73,015	67,980
Spring	5	83,360	5/24/2015	63,466	60,225	58,382	57,445	57,108	57,332	57,496	60,220	64,396	68,009	70,674	73,140	74,971	76,524	78,204	80,003	81,984	83,360	83,145	81,713	81,367	81,668	77,809	72,450
Spring	5	97,314	5/25/2015	67,314	63,452	61,364	60,081	59,922	60,579	61,169	64,107	69,300	74,713	79,932	84,039	87,462	89,806	91,786	93,846	95,800	97,314	96,753	95,021	94,697	94,304	87,690	80,164
Spring	5	118,081	5/26/2015	73,936	69,582	67,136	65,681	66,543	70,257	77,558	85,172	90,695	95,312	100,163	104,431	108,261	111,842	114,448	116,641	118,081	117,865	115,666	111,833	109,593	106,905	98,693	89,572
Spring	5	117,558	5/27/2015	82,002	77,113	74,119	72,435	72,885	76,724	83,655	90,760	95,691	99,623	103,737	107,873	111,291	114,351	116,475	117,188	117,558	116,788	113,468	109,640	107,408	105,056	97,112	87,745
Spring	5	120,840	5/28/2015	80,305	75,543	72,663	71,021	71,229	74,922	81,471	88,261	93,316	97,941	102,859	107,411	111,245	115,011	117,906	119,688	120,840	120,150	117,258	113,400	110,387	107,854	99,356	89,542
Spring	5	119,894	5/29/2015	81,639	76,301	72,765	71,189	71,233	74,490	80,527	87,410	92,551	97,610	102,315	106,432	109,930	113,615	116,639	118,730	119,894	118,783	115,083	110,053	106,707	104,809	98,197	89,907
Spring	5	108,167	5/30/2015	82,225	77,003	73,418	71,251	70,288	70,571	71,813	76,449	83,336	90,151	96,019	100,461	103,713	105,528	106,607	107,371	108,167	107,473	104,791	100,941	98,513	96,969	91,292	84,203
Spring	5	101,600	5/31/2015	77,739	73,023	69,793	67,564	66,504	66,289	66,602	70,269	76,598	83,199	88,759	93,467	96,915	99,534	100,878	101,600	101,427	101,173	99,371	96,824	95,848	94,186	88,161	81,121
Summer	6	101,491	6/1/2015	75,017	71,286	69,041	67,823	68,848	72,488	79,096	85,395	89,392	92,477	95,504	97,972	99,799	101,341	101,491	101,286	100,059	98,424	96,106	93,987	92,876	90,489	84,450	77,335
Summer	6	89,379	6/2/2015	71,706	68,637	66,709	65,912	66,631	70,304	76,472	81,764	84,822	86,787	88,318	89,117	89,174	89,379	88,665	87,999	87,592	87,327	86,411	85,481	85,813	85,120	80,113	73,559
Summer	6	88,867	6/3/2015	69,726	65,774	63,885	63,236	64,143	67,990	73,961	79,252	82,488	84,292	85,949	86,991	87,300	88,003	88,246	88,377	88,785	88,867	87,967	86,908	87,130	86,968	81,907	75,285
Summer	6	95,895	6/4/2015	69,938	66,778	64,706	63,853	64,697	68,343	74,420	80,106	83,780	86,338	88,779	90,486	91,796	93,540	94,475	95,236	95,895	95,643	94,579	93,241	93,036	92,269	86,977	79,481
Summer	6	97,569	6/5/2015	73,466	69,356	66,977	65,890	66,297	69,767	75,060	80,848	85,020	88,093	90,774	92,860	94,219	95,530	96,619	97,266	97,569	96,824	94,725	92,277	90,886	89,944	84,967	78,115
Summer	6	90,658	6/6/2015	71,784	67,392	64,954	63,633	63,155	63,881	64,947	68,438	73,196	77,817	81,330	83,590	84,994	85,950	86,747	88,048	89,618	90,658	89,675	87,410	85,258	84,710	80,482	74,186
Summer	6	93,701	6/7/2015	68,390	64,541	62,145	60,544	59,877	59,726	59,736	62,915	68,142	73,264	77,149	80,750	83,747	86,042	87,937	89,860	92,016	93,673	93,701	92,445	92,180	92,181	87,158	80,655
Summer	6	113,883	6/8/2015	74,848	71,097	68,845	67,753	68,531	72,334	78,570	85,106	90,263	94,478	98,771	102,209	105,323	108,742	111,215	112,826	113,883	112,546	109,923	106,678	104,236	100,864	93,724	85,348
Summer	6	114,190	6/9/2015	78,463	73,937	71,257	70,002	70,321	73,842	79,825	86,349	90,982	94,651	98,767	102,355	105,600	108,681	110,854	112,549	114,022	114,190	111,983	108,484	105,820	103,738	96,615	87,555
Summer	6	124,478	6/10/2015	80,198	74,925	71,791	70,258	70,202	73,427	79,085	86,068	91,808	97,018	102,298	106,991	111,164	115,425	118,703	121,948	124,053	124,478	121,894	117,521	113,928	111,533	103,804	94,069
Summer	6	131,922	6/11/2015	86,060	80,281	76,695	74,632	74,503	77,484	83,178	90,544	97,029	103,330	109,801	116,103	121,265	125,843	128,698	130,683	131,922	131,167	128,334	124,263	121,149	118,662	110,399	100,433
Summer	6	131,052	6/12/2015	91,964	85,816	81,708	79,276	79,153	81,835	87,408	95,522	103,235	110,463	117,547	123,114	127,188	129,890	131,052	130,533	129,030	126,626	122,150	117,220	114,044	111,986	105,231	96,633
Summer	6	117,700	6/13/2015	88,899	83,581	79,670	76,996	75,431	75,553	76,849	81,790	89,161	95,947	102,010	106,304	109,929	112,486	114,787	116,570	117,700	117,509	115,026	110,864	107,590	105,580	99,753	92,426
Summer	6	120,955	6/14/2015	85,380	80,393	76,724	74,307	72,927	72,322	72,546	76,859	84,337	91,460	100,853	110,441	118,407	123,914	126,955	128,559	130,955	130,657	128,559	125,341	122,736	120,206	103,736	94,644
Summer	6	134,129	6/15/2015	88,475	83,615	80,667	79,105	79,857	83,509	89,887	97,384	103,820	109,522	115,044	119,815	124,166	127,845	130,499	132,956	134,129	133,301	129,935	125,965	122,191	118,663	110,330	100,715
Summer	6	130,241	6/16/2015	92,559	86,853	83,204	80,948	81,006	84,186	90,148	97,487	103,999	109,987	115,427	119,724	122,973	125,939	127,572	129,058	130,241	129,247	126,543	121,863	116,898	113,690	105,614	95,788
Summer	6	112,899	6/17/2015	87,695	81,983	78,246	76,098	75,960	78,468	83,960	90,829	95,946	99,823	103,384	106,510	108,961	111,350	112,597	112,899	112,340	110,515	107,856	105,054	103,857	102,787	96,691	88,906
Summer	6	121,368	6/18/2015	82,238	77,923	75,107	73,868	74,334	78,092	83,673	90,340	95,970	100,691	105,813	110,111	113,783	117,420	119,697	121,368	121,187	118,607	115,406	111,686	108,940	106,534	99,559	91,163
Summer	6	115,405	6/19/2015	84,058	79,168	76,063	74,280	74,438	77,457	82,345	88,738	94,301	99,368	104,487	108,210	111,060	113,166	114,501	115,111	115,405	114,408	111,185	106,935	104,303	102,812	97,250	89,396
Summer	6	105,366	6/20/2015	82,531	77,768	74,335	72,234	71,280	71,763	72,794	76,153	81,919	87,712	92,641	96,525	99,469	101,652	103,291	104,701	105,366	105,275	103,687	101,664	99,795	98,001	93,540	87,305
Summer	6	120,192	6/21/2015	81,238	76,818	74,042	72,203	71,197	71,281	71,411	74,811	81,865	89,287	95,924	101,808	106,667	110,215	113,545	116,619	119,258	120,192	118,801	115,944	113,088	111,877	106,219	97,786
Summer	6	134,545	6/22/2015	89,809	84,263	80,488	78,391	78,109	80,555	85,993	94,547	102,310	108,989	115,659	120,881	124,948	128,331	131,501	133,635	134,381	134,545	133,126	129,542	125,754	123,177	115,142	104,923
Summer	6	137,287	6/23/2015	96,301	90,564	86,884	84,794	84,965	87,695	93,088	100,613	107,711	114,485	121,117	126,594	130,703	134,243	136,118	136,923	137,287	135,895	129,879	123,716	117,865	113,594	106,257	96,906
Summer	6	121,042	6/24/2015	88,719	82,755	78,635	76,028	75,294	77,317	81,933	88,691	94,352	99,048	103,809	107,796	111,449	114,909	117,485	119,727	121,042	120,884	118,516	114,130	109,480	107,124	99,438	90,585
Summer	6	113,915	6/25/2015	82,698	77,570	74,230	72,260	72,615	75,315	80,420	86,987	92,653	97,588	102,229	106,377	109,471	112,107	113,555	113,875	113,915	112,662	110,230	107,256	105,113	103,203	96,610	88,478
Summer	6	109,122	6/26/2015	81,645	76,988	74,043	72,727	75,393	80,176	86,875	92,775	95,273	98,257	102,347	106,307	109,727	107,132	108,512	109,122	109,106	108,072	105,112	101,475	99,026	97,703	91,282	85,084
Summer	6	87,808	6/27/2015	78,578	74,022	71,202	69,370	68,829	69,428	70,710	73,534	77,965	82,270	85,653	87,315	87,752	87,808	87,580	87,166	87,196	87,019	86,398	85,160	84,527	83,817	80,415	75,411
Summer	6	89,123	6/28/2015	70,775	67,441	64,881	63,137	62,718	62,698	62,725	65,450	70,205	74,732	78,296	80,706	83,012	84,566	85,621	86,924	88,145	89,123	88,708	87,685	86,756	87,094	83,013	76,863
Summer	6	103,222	6/29/2015	71,549	67,889	65,822	64,912	65,581	68,546	73,541	79,368	84,296	88,118	91,783	94,760	96,888	99,107	100,633	101,841	102,749	103,222	101,893	99,463	97,270	95,995	90,163	82,550
Summer	6	113,079	6/30/2015	76,166	72,087	69,649	68,496	68,947	72,095	77,172	83,330	88,861	93,408	97,999	102,253	106,118	109,760	111,847	112,568	113,079	112,269	109,317	105,592	103,129	101,356	94,891	86,705
Summer	7	112,608	7/1/2015	79,795	74,937	71,746	70,140	70,177	73,053	77,468	82,983	88,060	92,505	96,910	100,776	104,142	107,446	109,664	111,345	112,608	112,492	109,802	105,608	102,479	100,999	94,477	86,367
Summer	7	99,415	7/2/2015	79,215	74,513	71,408	69,868	70,067	72,643	77,208	82,581	87,014	90,379	93,758	96,084	97,647	99,030	99,415	99,396	99,255	98,987	97,017	94,168	92,210	91,280	86,224	79,226
Summer	7	96,403	7/3/2015	72,916	68,650	65,792	64,162	63,559	64,313	65,609	69,063	73,987	78,946	83,494	87,090	90,106	92,533	94,316	95,844	96,403	96,217	93,853	90,730	89,154	88,012	84,283	78,875
Summer	7	93,336	7/4/2015	73,366	69,160	66,454	64,583	63,673	63,908	63,725	66,124	70

Contains Proprietary Material
Do Not Distribute

Summer	8	127,063	8/14/2015	81,838	77,089	73,811	71,900	71,961	75,018	80,152	85,121	90,743	96,275	101,497	106,389	111,585	116,657	121,239	124,580	126,918	127,063	123,907	117,634	114,105	110,243	102,135	92,759
Summer	8	123,513	8/15/2015	84,704	79,157	75,077	72,649	71,251	71,815	72,932	75,664	82,476	89,911	97,129	103,977	109,787	115,053	119,073	122,007	123,513	123,009	119,954	115,144	111,627	107,898	100,512	92,516
Summer	8	129,803	8/16/2015	85,277	79,683	75,717	72,927	71,338	71,021	71,125	73,390	80,338	89,157	97,914	106,278	113,412	119,027	123,017	126,381	128,776	129,803	128,038	123,469	120,579	116,448	107,753	98,320
Summer	8	139,650	8/17/2015	90,613	85,102	81,652	79,518	79,527	82,905	88,813	94,554	101,653	110,183	119,009	127,178	133,528	137,803	139,650	139,643	139,482	138,100	134,818	130,364	128,109	122,410	112,220	101,998
Summer	8	133,464	8/18/2015	93,824	88,311	84,464	82,218	82,207	85,299	91,561	96,816	102,015	107,555	113,974	120,083	125,076	129,010	131,429	132,550	133,464	132,447	129,073	124,884	123,577	118,596	108,882	99,323
Summer	8	133,354	8/19/2015	91,517	86,621	83,433	81,536	81,891	85,629	92,439	98,092	104,019	110,017	116,353	121,342	126,023	129,856	132,299	133,286	133,354	131,513	127,533	122,725	121,301	116,791	107,867	98,778
Summer	8	121,714	8/20/2015	91,499	86,712	83,609	81,999	82,309	85,808	92,788	97,578	101,805	106,555	110,445	114,120	116,843	119,354	120,721	121,231	121,714	120,806	117,450	113,444	111,354	107,755	99,794	91,599
Summer	8	119,364	8/21/2015	84,669	80,048	76,952	75,043	75,158	78,116	83,710	87,979	92,971	97,638	102,279	105,838	109,070	112,431	115,685	117,557	119,364	118,597	115,041	109,165	105,966	102,033	94,953	86,865
Summer	8	106,985	8/22/2015	79,791	74,846	71,363	69,158	67,964	68,603	69,732	71,922	77,493	83,359	88,327	92,582	95,925	98,739	101,445	104,137	106,428	106,985	104,786	99,895	97,743	94,338	87,991	81,091
Summer	8	109,331	8/23/2015	75,112	70,813	67,935	66,103	64,955	65,178	65,782	67,375	72,521	78,502	83,770	88,826	93,517	97,886	101,652	105,042	107,949	109,331	107,831	104,743	104,263	100,855	93,616	86,336
Summer	8	121,793	8/24/2015	79,945	75,650	72,915	71,496	72,165	75,834	82,307	86,829	91,957	97,321	103,009	108,122	112,778	116,656	119,402	121,094	121,793	120,476	117,070	112,580	111,167	106,605	97,775	89,042
Summer	8	112,073	8/25/2015	82,202	77,933	74,975	73,226	73,427	76,947	83,239	87,567	92,164	96,533	100,830	103,908	106,401	108,725	110,359	111,348	112,073	111,650	108,511	104,557	104,033	99,489	91,425	83,201
Summer	8	102,854	8/26/2015	76,851	73,000	70,181	68,943	69,343	72,949	79,690	84,018	87,672	90,771	93,748	96,229	98,294	100,313	101,341	101,814	102,854	102,435	100,332	97,778	98,138	94,838	87,400	79,886
Summer	8	103,565	8/27/2015	74,215	70,706	68,415	67,340	68,066	71,817	78,634	83,039	86,866	90,405	93,747	96,268	98,455	100,660	101,860	102,551	103,565	103,232	101,037	98,271	98,932	95,491	87,945	80,196
Summer	8	107,563	8/28/2015	74,315	70,349	68,106	66,895	67,350	70,871	77,037	81,943	86,089	90,299	94,363	97,594	100,411	102,956	104,805	106,287	107,563	107,096	103,872	99,640	98,862	95,044	88,688	81,412
Summer	8	106,635	8/29/2015	75,142	70,867	67,931	66,244	65,641	66,389	68,193	70,675	75,890	81,917	87,725	92,662	96,840	100,371	103,032	105,259	106,635	106,373	104,109	100,909	100,812	97,318	91,465	84,599
Summer	8	114,421	8/30/2015	78,551	74,205	70,877	68,786	67,867	68,039	68,724	70,364	75,743	81,957	88,302	94,350	100,289	105,125	109,151	111,741	113,922	114,421	112,298	110,272	110,360	106,059	98,504	90,615
Summer	8	133,453	8/31/2015	84,155	79,596	76,824	75,526	76,197	80,577	88,886	93,754	98,272	103,502	109,716	115,741	120,703	125,016	128,767	131,434	133,380	133,453	130,421	126,187	124,641	118,254	108,015	98,292
Fall	9	138,975	9/1/2015	90,311	84,612	80,837	78,822	78,883	82,719	90,527	95,540	100,839	107,331	115,010	122,123	128,443	133,312	136,369	137,946	138,975	138,619	135,883	131,708	129,729	122,760	112,167	101,938
Fall	9	138,664	9/2/2015	93,316	87,642	83,323	80,874	80,665	84,679	92,515	97,023	101,741	108,078	115,464	122,748	129,233	134,512	137,576	138,664	138,256	136,928	133,723	129,383	127,332	121,240	111,031	100,831
Fall	9	141,210	9/3/2015	92,625	87,254	83,394	81,019	80,862	84,803	92,545	97,414	102,716	109,172	116,962	124,390	131,238	136,556	139,315	140,460	141,210	139,944	136,789	132,566	129,873	122,770	112,688	102,596
Fall	9	133,169	9/4/2015	94,068	88,404	84,514	82,253	81,975	85,068	91,906	96,695	102,006	108,100	114,742	121,345	126,655	130,832	133,022	133,169	132,062	128,910	123,081	118,136	115,484	110,141	102,595	94,320
Fall	9	116,000	9/5/2015	87,003	81,733	77,793	75,297	74,136	74,546	76,119	77,955	83,652	90,209	96,341	101,408	106,039	109,752	112,771	114,757	116,000	115,356	111,861	107,663	106,102	101,364	94,833	87,415
Fall	9	116,818	9/6/2015	80,926	75,752	72,355	70,088	68,781	68,690	69,374	70,523	76,111	83,615	90,800	97,825	103,603	108,479	112,162	114,907	116,604	116,818	113,815	109,278	107,374	102,547	96,018	88,913
Fall	9	128,068	9/7/2015	82,213	77,185	73,453	71,313	70,367	71,055	72,447	73,653	79,187	87,728	96,598	105,116	112,172	117,256	121,382	124,813	127,350	128,068	125,640	122,205	120,970	114,411	105,056	96,069
Fall	9	138,388	9/8/2015	88,600	83,423	80,006	78,077	78,377	82,589	91,042	96,799	102,390	109,208	117,167	124,404	130,507	135,037	136,882	137,554	138,388	137,910	134,995	131,253	129,801	122,120	111,764	101,647
Fall	9	131,701	9/9/2015	93,403	87,823	84,120	82,130	82,431	86,489	95,100	100,338	104,263	109,112	114,910	120,665	125,670	129,663	131,397	131,701	131,320	129,491	126,079	123,711	122,150	115,729	106,244	96,991
Fall	9	111,039	9/10/2015	89,591	84,827	81,550	79,317	79,641	83,626	92,040	96,481	99,198	102,362	105,363	107,599	109,419	110,677	111,017	110,923	111,039	110,341	108,231	106,655	106,095	101,162	93,497	85,550
Fall	9	107,715	9/11/2015	79,064	74,701	72,599	70,914	71,585	75,133	83,096	87,520	90,444	93,660	97,011	99,867	102,196	104,959	106,328	107,369	107,715	106,576	102,658	99,535	98,242	93,818	87,593	81,028
Fall	9	86,446	9/12/2015	75,193	71,049	68,374	66,390	66,000	67,131	69,566	72,239	76,560	80,681	83,896	85,813	86,446	86,344	85,877	85,267	84,940	84,880	84,347	85,279	86,000	83,695	79,054	73,936
Fall	9	83,047	9/13/2015	69,388	66,296	63,908	62,456	61,716	62,273	63,595	64,942	68,423	72,433	75,092	76,837	78,215	79,054	79,182	79,256	79,695	80,399	80,110	81,026	83,047	79,406	74,298	69,315
Fall	9	94,824	9/14/2015	65,519	63,253	61,910	61,549	62,804	66,976	74,594	78,873	81,324	83,719	86,116	87,842	88,967	90,214	91,519	92,802	94,293	94,824	93,710	93,393	93,895	89,197	82,175	75,344
Fall	9	105,341	9/15/2015	70,289	67,020	65,137	64,392	65,397	69,320	76,999	81,406	83,805	86,515	89,530	92,606	94,757	97,497	100,154	102,589	104,792	105,341	102,965	101,010	100,550	94,628	86,386	78,765
Fall	9	112,439	9/16/2015	72,843	69,239	67,138	66,057	66,816	70,705	78,305	82,543	85,335	88,916	92,937	96,644	100,238	103,887	107,312	110,140	112,260	112,439	109,489	107,043	105,609	99,382	90,668	82,525
Fall	9	116,254	9/17/2015	76,037	72,062	69,507	68,149	68,631	72,482	80,199	84,252	87,194	91,093	95,330	99,667	103,636	108,095	111,356	114,327	116,254	115,469	111,414	108,803	107,657	101,733	93,085	84,273
Fall	9	113,052	9/18/2015	77,948	74,130	71,191	69,687	70,102	74,018	81,487	85,310	88,911	92,804	96,969	100,565	104,096	107,559	110,309	112,094	113,052	111,789	107,577	104,994	103,004	98,064	91,388	83,886
Fall	9	100,447	9/19/2015	77,351	72,982	70,145	68,445	67,676	68,332	70,796	73,256	77,880	82,838	87,360	91,389	94,390	96,804	98,646	99,825	100,447	99,929	97,285	95,792	94,660	90,488	84,680	78,250
Fall	9	88,880	9/20/2015	72,917	69,180	66,541	64,825	64,083	64,255	65,421	66,661	70,369	74,366	77,236	79,681	81,658	83,380	84,865	86,522	87,984	88,799	87,503	88,072	88,880	84,006	77,828	72,115
Fall	9	92,517	9/21/2015	67,812	65,047	63,600	62,957	64,142	68,277	76,408	81,177	83,059	85,149	87,514	89,200	90,560	91,618	91,780	91,785	92,300	92,353	91,739	92,517	92,303	87,631	80,880	74,502
Fall	9	95,800	9/22/2015	69,575	66,674	64,906	64,114	65,091	69,185	77,364	81,878	83,730	85,950	88,511	90,052	91,705	93,473	94,287	95,074	95,800	95,704	94,527	94,908	94,845	90,060	82,857	75,985
Fall	9	100,172	9/23/2015	70,732	67,564	65,503	64,578	65,221	69,006	76,806	80,884	83,186	85,844	89,126	91,344	93,107	95,390	97,324	98,814	100,172	100,087	97,772	97,221	96,473	90,737	83,330	76,178
Fall	9	100,534	9/24/2015	70,586	67,369	65,383	64,405	65,243	69,018	77,147	81,553	83,479	85,972	88,725	91,625	94,051	96,320	98,053	99,567	100,534	100,055	97,256	97,424	96,937	91,495	84,372	77,004
Fall	9	93,655	9/25/2015	71,671	68,218	66,201	65,391	66,043	70,247	78,096	82,381	84,629	87,053	89,391	91,027	92,221	93,274	93,655	93,069	92,058	90,554	88,674	89,236	88,373	84,782	79,963	74,260
Fall	9	81,500	9/26/2015	69,184	65,817	63,411	62,110	61,802	62,945	65,593	68,232	71,781	75,274	77,654	78,861	79,412	79,737	79,687	80,064	80,236	80,232	79,774	81,361	81,500	78,778	74,624	69,849
Fall	9	87,012	9/27/2015	65,817	62,805	60,824	59,661	59,296	59,970	61,492	63,473	67,020	70,622	73,164	75,441	77,295	78,636	79,527	80,590	81,609	82,823	83,889	86,833	87,012	83,385	78,158	73,281
Fall	9	104,418	9/28/2015	69,046	66,310	64,776	64,473	65,717	70,263	78,838	84,726	87,118	89,711	92,511	94,966	97,310	99,856	101,620	102,718	103,335	103,336	102,507	104,418	103,342	98,218	90,802	83,254
Fall	9	102,180	9/29/2015	77,282	73,424	71,094	70,108	70,875	75,398	84,200	89,989	92,236	94,662	97,443	99,486	101,000	102,180	101,829	100,927	100,465	100,357	100,653	102,158	100,568	95,643	88,869	81,896
Fall	9	96,535	9/30/2015	76,091	72,649	70,603	69,899	70,628	75,076	83,963	89,436	91,113	93,015	94,632	95,899	96,417	96,535	95,530	94,647	93,785	92,597	91,727	93,321	92,495	87,748	81,082	74,311
Fall	10	86,056	10/1/2015	69,205	65,946	64,021	63,332	64,021	68,012	76,074	80,979	82,251	83,235	84,073	84,295	84,315	84,253	83,761	83,094	82,838	82,914	83,588	86,056	85,629	82,126	76,504	70,931
Fall	10	84,604	10/2/2015	66,564	63,760	62,313	61,661	62,694	66,710	74,480	79,964	81,602	82,878	83,952	84,143	83,995	83,818	83,308	82,474	82,576	82,711	83,336	84,604	83,634	80,564	76,066	71,189
Fall	10	80,819	10/3/2015	67,011	64,314	62,925	62,020	61,948	63,302	66,196	69,762	73,529	77,256	79,438	80,057	79,576	78,658	77,771	77,173	77,326	77,808	79,089	80,819	79,999	77,338	73,564	69,318
Fall	10	80,481	10/4/2015	65,328	62,645	60,838	59,880	59,646	60,476	62,498	64,826	67,822	70,881	72,320	72,969	73,206	72,844	72,535	72,608	73,360	74,823	76,648	80,481	80,446	77,052	72,576	67,748
Fall	10	88,823	10/5/2015	64,415	62,199	61,268	61,103	62,553	66,964	75,600	80,663	81,999	82,673	83,490	83,939	84,394	84,932	84,882	84,600	84,786	84,929	85,569	88,823	87,576	83,347	77,212	71,314
Fall	10	89,818	10/6/2015	66,976	64,225	62,893	62,519	63,636	68,096	76,445	81,353	82,032	82,833	83,987	84,450	85,260	86,012	86,527	86,867	87,058	86,849	86,812	89,818	88,906	84,383	77,914	71,949
Fall	10	90,766	10/7/2015	67,272	64,501	62,974	62,406	63,396	67,646	75,916	80,992	82,052	83,334	84,526	85,696	86,815	87,833	88,569	88,821	89,223	88,773	88,162	90,766	89,366	84,812	78,418	72,185
Fall	10	92,076	10/8/2015	67,290	64,283	62,822	62,131	63,043	67,189	75,324	80,265	81,377	83,043	84,977	86,618	88,152	89,732	90,397	90,457	90,430	89,657	89,453	92,076	90,823	86,530	80,403	73,797
Fall	10	89,459	10/9/2015	68,873	65,936	64,220	63,293	64,027	68,038	75,980	81,248	83,132	85,032	87,002	88,359	88,879	89,305	89,459	89,247	88,467	87,684	86,884	87,483	85,592	82,083	77,095	71,645
Fall	10	76,740	10/10/2015	66,698	63,399	61,412	60,324	59,992	61,175	63,924	67,049	69,839	72,398	73,663	73,839	73,302	72,714	72,295	72,251	72,660	73,057	73,907	76,740	76,155	73,876	70,384	66,540
Fall	10	79,722	10/11/2015	62,916	60,560	59,094	58,397	58,453	59,452	61,672	64,108	66,999	69,249	69,862	70,262	70,604	70,877	71,252	71,876	73,020	74,664	76,129	79,722	79,017	75,501	71,188	66,948
Fall	10	90,150	10/12/2015	63,463	61,276	60,401	60,356	61,881	66,134	73,766	79,024	80,684	82,231	83,814	84,662	85,315	85,959	86,311	86,544	86,997	86,936	87,468	90,150	88,179	83,889	77,610	71,615
Fall	10	89,378	10/13/2015	67,032	64,293	62,826	62,281	63,280	67,501	75,883	81,105	82,063	83,383	84,728	85,526	85,937	86,371	86,140	86,013	85,980	85,987	87,130	89,378	87,760	83,191	77,287	71,266
Fall	10	87,564	10/14/2015	66,914	64,078	62,475	62,127	63,142	67,441	75,746	81,212	82,044	82,592	83,374	83,584	83,924	84,248	84,197	83,717	83,682	83,500	84,710	87,564	86,300	82,368	76,554	71,009
Fall	10	87,090	10/15/2015	66,910	64,078	62,239	61,550	64,395	67,113	77,814	82,996	83,704	83,626	83,736	83,642	83,381	83,467	83,214	83,024	83,045	82,989	84,174	87,090	85,909	82,168	76,764	71,090
Fall	10	83,650	10/16/2015	66,993	64,458	63,224	62,988	64,325	68,707	76,677	81,975	82,759	83,277	83,427	83,179	82,572	82,247	81,507	80,586	80,289	80,212	81,210	83,650	82,613	80,047	76,175	71,595
Fall	10	80,754	10/17/2015	67,558	65,202	63,923	63,612	64,006	66,065	69,479	73,247	75,978	77,356	77,352	76,660	75,854	74,783	73,765	73,278	73,545	74,621	77,277	80,754	80,310	78,554	75,621	72,091
Fall	10	85,294	10/18/2015	69,031	67,140	66,104	65,854	66,458	68,244	70,957	74,033	76,751	77,621	76,723	75,832	75,375	74,957	74,183	73,797	74,653	76,693	80,328	85,238	85,294	82,561	78,857	75,003
Fall	10	94,825	10/19/2015	72,257	71,050	70,644	71,492	73,907	79,396	89,021	94,825	94,732	92,718	90,621	88,779	87,408	86,038	84,696	83,997	83,947	84,954	87,863	91,615	90,571	86,949	81,680	76,228
Fall	10	89,522	10/20/2015	72,284	70,092	69,055	68,978	70,740	75,951	84,352	89,522	88,806	87,631	86,867	85,779	84,895	84,572	84,266	83,890	83,808	83,948	86,059	89,370	87,875	83,639	77,733	72,247
Fall	10	89,211	10/21/2015	68,372	66,304	65,268	65,054	66,690	71,675	80,708	85,925	85,958	85,332	85,227	84,858	84,881	85,276	85,228	85,057	84,937	85,068	86,555	89,211	87,560	83,337	77,580	71,667
Fall	10	89,538	10/22/2015	67,447	65,095	63,872	63,511	64,882	69,475	78,252	83,860	84,291	84,254	84,540	84,739	84,842	85,478	85,713	85,486	85,584	85,372	87,154	89,538	87,563	83,428	77,669	71,711
Fall	10	84,304	10/23/2015	67,253	64,542	63,074	62,525	63,704	67,833	76,173	81,697	82,290	83,068	83,491	83,363	82,914	83,232	82,742	82,240	82,040	81,773	83,058	84,304	82,452	79,668	75,512	70,573
Fall	10	79,462	10/24/2015	66,468	63,858	62,299	61,528	61,937	63,594	66,924	70,645	73,628	75,845	76,903	76,688	75,853	74,820	73,993	73,504	73,958	75,426	78,327	79,462	78,016	75,612	71,977	67,718
Fall	10	80,613	10/25/2015	63,786	61,373	59,776	58,885	58,782	59,564	61,611	64,635	67,563	70,370	71,802	72,245	72,448	72,073	71,597	71,487	72,139	73,429	77,341	80,613	79,589	76,262	72,048	67,958
Fall	10	80,916	10/26/2015	64,792	63,065	62,356	62,444	63,575	69,797	79,074	85,631	86,103	85,885	85,525	84,973	84,123	82,657	82,042	82,275	83,280	87,040	89,916	88,223	84,671	79,270	74,113
Fall	10	91,828	10/27/2015	70,126	68,135	67,004	67,075	68,602	73,563	82,549	88,393	88,406	88,084	87,538	86,991	86,471	86,006	85,323	84,930	85,224	86,875	90,668	91,828	89,662	85,686	79,917	74,165
Fall	10	90,892	10/28/2015	70,098	67,664	66,231	65,644	66,861	70,987	79,229	85,200	86,498	86,962	87,906	88,042	87,899	87,920	87,342	86,772	87,162	87,952	90,302	90,892	88,814	84,859	79,151	73,422
Fall	10	89,137	10/29/2015	68,913	66,354	64,898	64,099	65,449	69,912	78,427	84,510	85,118	85,615	86,253	86,271	85,825	85,266	84,608	83,860	83,540	84,175	87,166	89,137	87,767	84,278	78,646	73,117
Fall	10	87,132	10/30/2015	69,067	66,605	65,565	65,437	66,836	71,286	80,303	86,632	87,132	86,433	86,140	85,303	84,304	83,313	82,271	81,467	81,518	82,227	84,963	86,132	84,773	82,327	78,534	74,007
Fall	10	79,901	10/31/2015	70,279	68,022	66,901	66,459	66,933	68,916	72,295	75,985	78,878	79,885	79,901	78,930	77,556	76,375	75,300	74,840	75,306	75,910	78,077	78,474	77,720	75,980	73,180	69,375
Fall	11	81,554	11/1/2015	65,834		61,163	60,639	60,853	62,471	64,662	67,216	70,568	72,601	72,910	72,639	72,588	72,011	71,736	71,822	73,615	78,987	81,554	80,614	78,728	74,872	70,765	66,840
Fall	11	91,502	11/2/2015	63,935	62,565	61,918	62,121	64,203	69,403	78,163	82,507	83,952	84,796	85,524	85,668	85,491	85,503	84,920	84,452	85,379	89,198	91,502	90,054	87,217	82,923	77,332	71,800
Fall	11	91,924	11/3/2015	68,314	66,371	65,379	65,483	67,527	72,979	80,891	84,433	84,766	84,705	84,985	85,526	85,698	86,218	86,261	86,161	86,305	89,486	91,924	90,251	87,585	83,109	77,069	71,262
Fall	11	92,479	11/4/2015	67,313	65,309	64,140	64,028	65,837	71,019	79,365	83,229	83,922	84,339	84,973	85,545	86,087	86,805	86,957	86,593	86,815	90,792	92,479	90,649	87,695	83,154	77,223	71,625
Fall	11	94,038	11/5/2015	67,445	65,000	63,664	63,484	64,713	69,368	77,930	82,277	84,373	86,069	87,342	88,023	88,593	89,264	89,167	88,777	89,014	92,609	94,038	92,221	89,373	85,042	78,777	73,160
Fall	11	90,735	11/6/2015	68,794	66,200	64,722	64,177	65,160	69,490	77,543	82,579	84,714	86,439	87,801	88,259	88,281	88,125	87,896	87,037	87,096	90,589	90,735	88,412	85,758	82,237	77,327	71,870
Fall	11	81,638	11/7/2015	67,304	64,306	62,628	61,685	61,770	63,465	66,053	69,326	73,166	76,032	77,065	77,360	76,973	75,921	75,048	74,716	76,099	80,202	81,638	80,393	78,963	76,665	73,412	69,729
Fall	11	84,934	11/8/2015	66,579	64,595	63,362	63,157	63,753	65,314	67,997	70,223	72,710	73,745	73,428	72,931	72,570	72,057	71,600	72,103	74,289	81,346	84,934	84,744	83,721	80,867	77,049	73,534
Fall	11	95,207	11/9/2015	71,126	69,769	69,616	70,288	72,716	78,288	87,746	91,868	91,519	90,562	89,863	88,940	88,325	87,889	87,108	86,695	88,700	93,725	95,207	93,612	90,859	86,483	80,568	75,186
Fall	11	92,824	11/10/2015	70,716	68,461	67,329	67,007	68,474	73,051	81,606	86,293	86,704	87,286	88,013	87,767	87,240	86,930	86,243	85,960	87,519	91,553	92,824	91,173	88,582	84,645	79,564	74,253
Fall	11	91,641	11/11/2015	70,708	68,513	67,503	67,506	69,114	73,628	81,245	85,423	86,169	86,213	86,091	85,392	84,603	84,062	83,330	83,095	84,777	90,254	91,641	90,209	88,138	84,588	79,304	74,041
Fall	11	92,782	11/12/2015	70,065	68,053	67,044	66,957	68,479	73,421	81,851	86,536	87,385	87,931	88,405	87,714	87,090	86,727	85,926	85,712	87,351	91,858	92,782	91,284	89,232	85,228	79,579	74,118
Fall	11	90,995	11/13/2015	70,247	68,091	67,145	67,214	68,928	73,687	82,290	86,664	86,890	86,397	86,120	85,309	84,640	83,973	83,270	82,845	84,559	89,872	90,995	89,850	88,429	85,684	81,731	77,028
Fall	11	85,130	11/14/2015	73,344	70,932	70,001	69,644	70,529	72,575	76,081	78,989	81,017	81,774	81,168	79,782	77,900	76,084	74,792	74,702	76,777	82,848	85,130	84,504	83,601	81,888	78,840	75,486
Fall	11	83,733	11/15/2015	72,640	70,870	70,016	69,870	70,555	72,236	74,665	76,811	77,785	77,013	75,498

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	AP South
Max	70,729
Peak Month	7
PST	58,108
Winter	51,170
Spring	43,394
Summer	56,097
Fall	43,262

Source: ABB Velocity Suite
CONFIDENTIAL DATA REDACTED

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	1																										

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Spring	1
Spring	1
Spring	1

Contains Proprietary Material
Do Not Distribute

Summer	1
Summer	1
Summer	1

Contains Proprietary Material
Do Not Distribute

Fall	1																										

Contains Proprietary Material
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	5004/5005
Max	52,190
Peak Month	7
PST	42,368
Winter	36,840
Spring	31,515
Summer	40,748
Fall	31,648

Source: ABB Velocity Suite
CONFIDENTIAL DATA REDACTED

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	1																										

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Spring	1
Spring	1
Spring	1

Contains Proprietary Material
Do Not Distribute

Summer	1
Summer	1
Summer	1

Contains Proprietary Material
Do Not Distribute

Fall	1																										

Contains Proprietary Material
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	PJM East
Max	30,240
Peak Month	7
PST	24,093
Winter	19,303
Spring	16,803
Summer	22,934
Fall	17,326

Source: ABB Velocity Suite
CONFIDENTIAL DATA REDACTED

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	1																										

Contains Proprietary Material
Do Not Distribute

Spring	1
Spring	1
Spring	1

Contains Proprietary Material
Do Not Distribute

Summer	1
Summer	1
Summer	1

Contains Proprietary Material
Do Not Distribute

Fall	1																										

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FERC Form 714 Outages

Month	Planned Outage and Derating (MW)
Dec-14	13,851
Jan15	3,616
Feb15	7,609
Mar15	19,290
Apr15	34,834
May15	24,301
Jun15	4,660
Jul15	4,535
Aug15	3,566
Sep15	3,993
Oct15	46,567
Nov15	23,207

	Planned Outage and Derating (MW)					Generation (MW)			
	Winter	Spring	Summer	Fall	Note	Winter	Spring	Summer	Fall
PJM	8,359	26,142	4,254	24,589	PJM outages	199,600	196,690	183,060	192,785
AP South	3,540	11,141	1,835	10,738	Estimated based on generation ratios	84,538	83,829	78,969	84,193
5004/5005	2,512	7,879	1,297	7,620	Estimated based on generation ratios	59,991	59,282	55,814	59,741
PJM East	1,596	4,972	805	4,813	Estimated based on generation ratios	38,116	37,407	34,630	37,735

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	Operating Reserves					
	PST	Winter	Spring	Summer	Fall	Note
PJM	9,097	8,067	6,367	9,097	6,391	PJM Interconnection, L.L.C., Docket No. AD10-2 Reserves
AP South	2,868	2,552	2,266	2,772	2,230	5.93% of 5004/5005 Load + Dominion share of VACAR Reserves
5004/5005	2,512	2,185	1,869	2,416	1,877	5.93% of 5004/5005 Load
PJM East	1,429	1,145	996	1,360	1,027	5.93% of PJM East Load

Loads				
PST	Winter	Spring	Summer	Fall
121,600	112,390	94,917	117,821	95,173
58,108	51,170	43,394	56,097	43,262
42,368	36,840	31,515	40,748	31,648
24,093	19,303	16,803	22,934	17,326

Methodology
PJM Operating Reserves are based on the August 2016 PJM SIL filing
Submarket Operating Reserves = PJM Op Res * Submarket Load/PJM Load

Attachment 11: PJM Operating Reserves

PJM's Day-Ahead Scheduling Reserve (DASR) requirement is calculated using a 3 year historical average of both a Load Forecast Error (LFE) component, as well as a Forced Outage Rate (FOR) component. The LFE component is a 3 year historical average of the under forecasted load. The FOR is the 3 year historical average of resource forced outages which impacted next-day operations, and which were reported after the day-ahead commitments had been completed. The sum of the LFE and LOF components determine PJM's DASR for the next calendar year, calculated as a percentage of the forecasted peak load. Shown below is the calculation of the 2015 DASR, as well as the applicable reserve amounts which may be used by PJM members when filing a Market Share Analysis.

DASR = LFE + LOF (calculated as a percentage of forecasted peak load)
2015 DASR = 2.15% + 3.78%
2015 DASR = 5.93%

2015 SIL Operating Reserves		
Season	Peak Load (MW)	DASR (MW)
Winter	136,044	8067
Spring	107,372	6367
Summer	153,402	9097
Fall	107,782	6391

Area	Ancillary Service Market Area	Day-ahead Scheduling (Operating)	Contingency (Primary)	Synchronized Reserve
RTO		Annual %	150% Largest Single Contingency	Largest Single Contingency
	Mid-Atlantic & Dominion	N/A	1700 MW	Largest Single Contingency
SERC	Dominion	VACAR ARS%	VACAR ARS%	VACAR ARS%

Effective January 1, ~~2014~~ 2015 the Day-ahead Scheduling Reserve for RFC and EKPC regions of PJM is ~~6.27~~5.93% times Peak Load Forecast for RFC plus EKPC.

http://www.pjm.com/~/media/committees-groups/subcommittees/sos/20141125/20141125-item-06a-manual-13-version-57-2015-da

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PJM Generation Summary

	Modeled Generation MW			
	Winter	**Spring**	**Summer**	**Fall**
PJM	199,600	196,690	183,060	192,785
AP South	84,538	83,829	78,969	84,193
5004-5005	59,991	59,282	55,814	59,741
PJM East	38,116	37,407	34,630	37,735

Operating generation during the study period

	Winter	**Spring**	**Summer**	**Fall**
PJM	189,859	189,859	182,872	192,785
AP South	82,190	82,190	78,969	84,193
5004-5005	57,758	57,758	55,814	59,741
PJM East	35,883	35,883	34,630	37,735

Currently retired generation but operating during the study period

	Winter	**Spring**	**Summer**	**Fall**
PJM	9,741	6,832	189	0
AP South	2,349	1,639	0	0
5004-5005	2,234	1,524	0	0
PJM East	2,234	1,524	0	0

Generation Dataset Including Ventyx Data as of 9/29/2016

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Holding Company Name	Plant Name	Unit	Unit ID	Plant EIA ID	Node	Supplier	East Units

							Unit Capacity (MW)		
5004/5005 Units	AP South Units	Prime Mover Type	Primary Fuel Type	Unit Status	Added During Study Period	Percent Owned %	Name Plate	Summer	Winter

Unit Capacity Adjusted for Ownership and Status (MW)		Modeled Capacity (MW)				Unit Onsite Capacity Use (MW)		Onsite Unit Usa Ownership an
Summer	Winter	Winter	Spring	Summer	Fall	Summer	Winter	Summer

	Modeled Capacity (MW)			
	Winter	Spring	Summer	Fall
PJM	189,859	189,859	182,872	192,785
AP South	82,190	82,190	78,969	84,193
5004/5005	57,758	57,758	55,814	59,741
PJM East	35,883	35,883	34,630	37,735

ge Adjusted for d Status (MW)				
Winter	Online Date	Retirement Date	Proposed Retirement Date	ABB Retirement Date

ABB Retirement Date - Source	Grid Connected (Y/N)	Plant County

Plant State	Unit NERC Region Abbrev	Plant NAICS

PJM Retired Units during the study period

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Unit ID	Holding Company Name	Plant Name	Unit	Plant Aliases	Season	East Units	5004/5005 Units	AP South Units

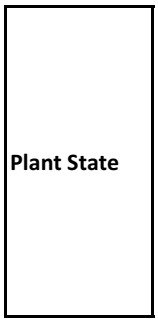
							Modeled Capacity (MW)			Ventyx Data
Retirement Date	ABB Retirement Date	Plant Government ID	Unit NERC Sub Region Abbrev	Unit ISO Name	Unit ISO Zone Name	Percent Owned %	Nameplate	Summer	Winter	Nameplate

		Modeled Capacity (MW)			Capacity t
		Nameplate	Summer	Winter	Winter
PJM	Winter	911	829	905	0
	Spring	2,974	2,751	2,910	2,910
	Summer	6,868	6,509	6,634	6,634
	Fall	196	189	198	198
	Period	10,948	10,278	10,647	9,741
AP South	Winter	698	640	660	0
	Spring	624	570	710	710
	Summer	1,571	1,639	1,639	1,639
	Fall	0	0	0	0
	Period	2,893	2,848	3,008	2,349
5004/5005	Winter	48	45	55	0
	Spring	624	570	710	710
	Summer	1,456	1,524	1,524	1,524
	Fall	0	0	0	0
	Period	2,129	2,138	2,288	2,234
PJM East	Winter	48	45	55	0
	Spring	624	570	710	710
	Summer	1,456	1,524	1,524	1,524
	Fall	0	0	0	0
	Period	2,129	2,138	2,288	2,234

abase Capacity (MW)							
Summer	Winter	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Grid Connected (Y/N)	Plant NAICS Code

o Add Back into Generation (MW)		
Spring	Summer	Fall
0	0	0
0	0	0
6,634	0	0
198	189	0
6,832	189	0
0	0	0
0	0	0
1,639	0	0
0	0	0
1,639	0	0
0	0	0
0	0	0
1,524	0	0
0	0	0
1,524	0	0
0	0	0
0	0	0
1,524	0	0
0	0	0
1,524	0	0

	Ventyx Database EIA Capacity (MW)				
Plant NAICS Description	**Nameplate**	**Summer**	**Winter**	**Plant City**	**Plant County**


Plant State

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Southeast and MISO Generation Summary

	Modeled Generation MW			
	Winter	**Spring**	**Summer**	**Fall**
CPLE	14,696	14,696	13,525	14,720
CPLW	878	878	826	878
DUKE	25,619	25,619	24,632	25,619
LGEE	9,033	8,793	8,838	9,108
MISO	175,367	175,695	168,505	175,039
TVA	37,014	37,014	35,065	36,069

Operating generation during the study period

	Winter	**Spring**	**Summer**	**Fall**
CPLE	14,696	14,696	13,525	14,720
CPLW	878	878	826	878
DUKE	25,619	25,619	24,632	25,619
LGEE	8,301	8,301	8,677	9,108
MISO	174,022	175,003	168,404	175,039
TVA	36,069	36,069	34,127	36,069

Currently retired generation but operating during the study period

	Winter	**Spring**	**Summer**	**Fall**
CPLE	0	0	0	0
CPLW	0	0	0	0
DUKE	0	0	0	0
LGEE	732	492	161	0
MISO	1,345	692	101	0
TVA	945	945	938	0

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Southeast and MISO Retired Units during the study period

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		Modelec
		Modelec
		Nameplate
MISO	Winter	0
MISO	Spring	742
MISO	Summer	642
MISO	Fall	126
MISO	Period	1,510
LGEE	Winter	0
LGEE	Spring	272
LGEE	Summer	373
LGEE	Fall	189
LGEE	Period	833
TVA	Winter	0
TVA	Spring	0
TVA	Summer	0
TVA	Fall	1,125
TVA	Period	1,125

d Capacity (MW)	Ventyx Database Capacity (MW)

d Capacity (MW)		Capacity to Add Back into Generation (MW)			
Summer	Winter	Winter	Spring	Summer	Fall
0	0	0	0	0	0
632	653	653	0	0	0
575	589	589	589	0	0
101	103	103	103	101	0
1,309	1,345	1,345	692	101	0
0	0	0	0	0	0
240	240	240	0	0	0
323	323	323	323	0	0
161	169	169	169	161	0
724	732	732	492	161	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
938	945	945	945	938	0
938	945	945	945	938	0

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Ventyx Database EIA Capacity (MW)

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	MISO	CPLE	CPLW	DUKE	LGEE	TVA
Max	118,332	14,383	1,186	21,101	7,236	32,751
Peak Month	7	2	2	2	2	1
PST	102,563	10,538	869	16,433	5,754	25,981
Winter	86,929	9,332	770	14,053	5,124	22,486
Spring	76,192	7,425	612	11,801	4,348	18,523
Summer	97,947	10,231	844	15,919	5,616	24,974
Fall	80,875	7,487	618	11,970	4,421	18,959

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	91,352	12/1/2014	65,909	64,245	63,482	63,438	64,509	67,485	73,235	80,235	82,680	83,202	83,862	84,202	84,060	84,152	83,896	83,628	84,111	87,614	91,082	91,352	90,226	88,350	84,357	79,529
Winter	12	88,515	12/2/2014	75,587	73,313	71,793	71,051	71,441	73,300	78,278	84,659	86,038	85,836	85,478	85,064	84,245	83,416	83,013	82,205	82,478	85,494	88,419	88,515	87,331	85,357	81,254	76,384
Winter	12	86,783	12/3/2014	72,348	70,047	68,712	68,184	68,790	71,035	76,257	82,751	83,917	83,185	82,266	81,283	80,053	79,320	78,712	78,110	78,714	82,396	86,497	86,783	85,945	84,267	80,626	75,638
Winter	12	86,587	12/4/2014	71,826	69,590	68,297	67,677	68,119	70,352	75,572	81,994	83,755	83,155	82,727	82,354	81,899	81,169	80,992	80,501	80,686	83,744	86,587	86,447	85,347	83,330	79,497	74,490
Winter	12	82,922	12/5/2014	70,181	67,422	65,939	64,837	65,040	67,252	72,299	78,329	80,283	80,481	80,761	80,789	80,431	79,955	79,552	78,755	78,772	81,228	82,922	81,959	80,298	78,718	75,908	71,894
Winter	12	79,699	12/6/2014	68,001	65,246	63,620	62,664	62,694	63,703	65,770	68,993	71,314	73,655	75,179	75,360	74,799	73,858	73,214	72,771	73,236	76,558	79,699	79,246	78,378	76,941	74,640	71,212
Winter	12	82,198	12/7/2014	67,898	65,493	64,203	63,275	63,463	64,105	65,696	68,013	70,208	72,421	73,544	73,321	72,905	72,622	72,219	72,025	73,086	77,840	81,790	82,198	81,417	79,590	76,224	71,919
Winter	12	86,601	12/8/2014	68,360	66,346	65,368	65,138	65,977	68,854	74,726	81,734	83,656	83,241	82,608	81,997	81,064	80,634	79,802	79,467	79,724	82,895	86,297	86,601	85,521	83,870	80,264	75,219
Winter	12	87,447	12/9/2014	71,211	68,881	67,822	67,532	68,119	70,744	76,666	83,657	85,393	84,430	83,725	82,790	81,856	81,083	80,802	80,429	80,884	83,937	87,210	87,447	86,623	85,028	81,180	76,197
Winter	12	88,921	12/10/2014	72,295	70,191	68,932	68,540	69,118	71,656	77,512	84,186	86,000	85,372	84,495	83,724	82,701	81,688	81,234	80,656	81,235	84,854	88,829	88,921	88,027	86,520	82,475	77,468
Winter	12	87,694	12/11/2014	73,472	71,022	69,696	69,318	69,909	72,537	78,180	84,859	85,850	85,191	84,571	83,683	82,340	81,034	80,225	79,357	79,586	83,448	87,399	87,694	87,053	85,488	81,815	76,838
Winter	12	84,572	12/12/2014	72,775	70,436	69,021	68,397	69,011	71,142	76,484	82,884	84,572	83,859	83,201	82,273	81,059	79,970	79,313	78,495	78,655	81,522	83,862	83,036	81,817	80,004	77,117	73,079
Winter	12	76,243	12/13/2014	69,134	66,152	64,478	63,679	63,361	64,226	66,284	69,344	71,859	73,738	74,574	73,907	72,779	71,559	70,545	69,723	70,295	73,266	76,243	75,988	74,717	73,267	70,901	67,494
Winter	12	76,562	12/14/2014	64,072	61,499	60,069	59,264	59,193	59,735	61,248	63,730	66,251	68,213	68,871	68,632	68,374	68,213	67,802	67,719	68,644	72,584	76,245	76,562	75,779	74,029	70,621	66,568
Winter	12	83,910	12/15/2014	63,115	60,943	59,917	59,522	60,224	62,776	68,355	75,393	77,943	78,005	78,452	78,695	78,577	78,253	77,881	77,551	77,868	81,081	83,910	83,909	82,694	80,675	76,801	71,858
Winter	12	87,992	12/16/2014	67,652	65,132	63,654	63,060	63,690	66,002	71,544	78,530	80,993	81,010	81,180	81,098	80,635	80,325	80,165	79,793	80,491	83,578	87,244	87,992	86,932	84,822	82,071	76,530
Winter	12	89,983	12/17/2014	73,704	71,120	70,164	69,764	70,380	73,060	78,957	85,710	87,480	86,632	85,802	84,865	83,590	82,538	82,006	81,664	82,167	85,793	89,601	89,983	89,137	87,570	83,961	78,729
Winter	12	88,469	12/18/2014	74,421	71,913	70,405	69,821	70,224	72,438	77,854	84,271	85,765	85,312	85,022	84,595	83,565	82,937	82,544	82,094	82,624	85,603	88,469	88,186	87,541	85,617	82,131	77,119
Winter	12	87,127	12/19/2014	72,985	70,457	68,928	68,341	68,639	70,762	75,966	82,311	84,561	84,439	84,250	83,758	83,115	82,208	81,900	81,156	81,456	84,715	87,127	86,076	84,723	83,003	80,266	76,256
Winter	12	80,990	12/20/2014	72,176	69,235	67,713	66,754	66,458	67,279	69,540	72,587	75,414	77,644	78,994	78,866	77,808	76,325	75,147	74,368	74,872	77,994	80,990	80,880	79,983	78,735	76,553	73,193
Winter	12	80,003	12/21/2014	70,175	67,566	65,970	65,175	65,044	65,736	67,405	70,266	72,618	74,423	74,868	74,168	73,289	72,432	71,453	70,863	71,866	75,685	79,502	80,003	79,495	78,067	75,420	71,559
Winter	12	83,069	12/22/2014	68,103	65,811	64,447	63,856	64,141	66,307	70,628	76,096	79,142	79,714	80,283	80,458	79,816	79,242	78,660	78,089	78,229	80,697	83,069	82,808	81,656	79,580	76,246	71,534
Winter	12	80,631	12/23/2014	67,324	64,261	62,526	61,487	61,505	63,416	67,420	72,699	75,702	76,777	77,532	77,897	77,299	76,455	76,146	75,401	75,308	77,972	80,631	80,324	79,158	77,391	74,407	69,947
Winter	12	74,745	12/24/2014	65,699	62,666	60,671	59,780	59,762	60,856	63,600	67,592	70,864	72,992	74,318	74,745	73,952	72,738	72,052	71,344	71,384	73,065	74,384	73,319	72,221	71,442	70,239	68,095
Winter	12	70,102	12/25/2014	65,475	63,171	61,496	60,735	60,899	61,725	63,674	66,347	68,834	70,102	70,079	69,119	67,279	64,876	62,839	61,145	61,135	63,634	67,492	68,633	68,911	68,586	67,238	64,783
Winter	12	75,012	12/26/2014	62,058	60,072	59,019	58,720	59,121	60,672	63,732	67,276	69,539	70,812	71,485	71,614	70,706	69,615	68,601	68,089	68,432	71,603	75,012	74,580	73,542	72,064	69,471	66,031
Winter	12	75,252	12/27/2014	62,703	60,131	58,516	57,499	57,351	57,867	59,493	61,871	64,019	66,387	68,828	70,116	70,287	69,872	69,132	68,617	69,517	72,462	75,252	75,068	74,312	73,061	71,006	68,023
Winter	12	80,080	12/28/2014	65,096	62,894	61,689	60,850	61,046	61,713	63,279	65,634	67,610	69,631	71,297	71,889	72,177	71,885	71,384	70,841	71,703	75,197	79,859	80,080	79,686	78,175	75,708	72,282
Winter	12	87,028	12/29/2014	69,260	67,552	66,592	66,301	66,844	68,919	73,112	78,320	80,808	81,885	82,235	82,056	81,176	80,191	79,353	78,551	78,782	82,145	86,760	87,028	86,032	84,138	80,942	76,842
Winter	12	90,469	12/30/2014	73,514	71,394	70,040	69,596	70,045	72,053	76,124	81,024	83,498	84,368	84,835	84,546	83,903	83,068	82,143	81,525	81,699	85,277	89,898	90,469	89,807	88,391	85,600	81,760
Winter	12	87,295	12/31/2014	78,397	76,276	75,084	74,643	74,916	76,608	80,225	84,667	86,756	87,295	87,025	85,912	84,074	82,059	80,547	79,082	78,827	82,019	86,521	85,825	83,749	81,673	79,285	76,651
Winter	1	80,590	1/1/2015	74,302	72,198	70,655	69,594	69,047	69,505	70,688	72,086	72,591	73,799	75,195	75,862	75,617	74,496	73,328	72,634	73,366	76,709	80,590	80,452	79,243	77,643	74,923	71,386
Winter	1	81,261	1/2/2015	68,324	66,213	64,941	64,462	64,877	66,395	69,805	74,000	76,553	77,743	78,710	78,685	77,882	77,066	76,336	75,716	75,650	78,372	81,261	80,693	79,319	77,434	74,774	71,242
Winter	1	78,000	1/3/2015	67,747	65,265	63,545	62,636	62,546	63,060	64,470	66,761	68,893	70,777	72,901	74,102	74,525	74,079	73,399	72,703	72,970	75,211	78,000	77,738	76,632	75,134	72,677	69,718
Winter	1	88,160	1/4/2015	66,815	64,569	63,269	62,669	62,756	63,692	65,269	67,845	70,420	72,812	74,609	75,680	76,385	76,924	76,920	76,852	77,926	81,558	87,218	88,160	87,835	86,160	83,463	80,201
Winter	1	97,062	1/5/2015	77,786	76,794	76,345	76,648	77,844	80,943	86,991	94,113	96,101	95,533	94,776	93,804	92,414	91,114	89,877	88,956	88,955	91,770	95,949	97,062	96,223	94,240	90,584	86,246
Winter	1	94,607	1/6/2015	82,462	80,516	79,482	79,100	79,434	81,993	87,173	93,476	94,607	93,321	91,767	89,979	88,160	86,978	86,046	85,210	85,509	88,393	92,789	94,147	93,489	91,959	88,699	84,845
Winter	1	103,050	1/7/2015	81,808	80,001	79,104	79,045	79,825	82,577	88,014	94,214	96,147	95,821	95,476	95,020	93,982	93,008	92,313	91,688	92,164	95,543	101,268	103,050	102,782	101,355	98,204	94,363
Winter	1	104,733	1/8/2015	91,587	89,965	89,021	88,838	89,549	92,045	96,921	103,269	104,733	103,792	102,669	101,391	100,062	98,460	96,974	95,717	95,635	98,184	102,104	102,707	101,414	99,240	94,998	89,943
Winter	1	98,484	1/9/2015	86,369	83,948	82,888	82,303	83,006	85,109	90,197	96,298	97,923	97,331	96,533	95,815	94,489	93,147	92,205	91,378	91,393	93,851	98,192	98,484	97,424	95,632	92,716	89,166
Winter	1	92,037	1/10/2015	86,101	83,864	82,785	82,410	82,751	83,982	86,075	88,974	90,989	92,037	91,732	90,072	87,668	85,123	83,150	81,626	81,904	84,599	88,922	89,242	88,296	86,686	84,005	80,352
Winter	1	84,899	1/11/2015	77,078	74,723	73,393	72,450	72,131	72,475	73,738	75,947	77,727	79,517	80,161	79,916	79,361	78,775	78,120	77,453	77,853	80,831	84,743	84,899	83,801	81,445	78,260	74,310
Winter	1	93,117	1/12/2015	71,393	69,770	68,736	68,553	69,428	72,078	77,476	84,282	86,621	86,275	86,419	86,475	85,953	85,558	85,017	84,479	84,562	87,357	92,219	93,117	92,436	90,620	87,215	82,936
Winter	1	96,466	1/13/2015	79,616	77,768	76,751	76,570	77,369	80,236	85,850	92,825	94,717	93,706	92,805	91,872	90,383	89,376	88,314	87,440	87,504	90,347	95,340	96,466	95,894	93,830	90,104	85,357
Winter	1	95,412	1/14/2015	81,989	80,251	79,206	78,992	79,599	81,785	87,245	93,841	95,412	94,730	93,678	92,364	90,959	89,446	88,277	87,415	87,502	90,024	94,410	94,848	93,728	91,333	87,180	82,260
Winter	1	91,641	1/15/2015	78,535	76,617	75,452	75,027	75,611	78,008	83,659	89,983	91,641	90,222	88,999	87,713	86,205	84,730	83,493	82,140	81,750	83,499	88,509	90,101	89,692	87,897	84,616	80,135
Winter	1	91,902	1/16/2015	77,038	75,315	74,378	74,371	75,196	77,847	83,400	90,174	91,902	90,292	87,957	85,476	83,050	80,875	79,289	77,748	77,137	78,702	82,884	83,869	83,326	82,173	79,877	76,406
Winter	1	79,190	1/17/2015	73,596	71,663	70,434	69,921	70,000	70,939	73,099	76,072	78,246	79,190	78,448	76,727	74,701	72,680	70,837	69,603	69,628	71,713	75,619	76,388	75,619	74,034	71,944	68,909
Winter	1	75,607	1/18/2015	66,344	64,381	63,340	63,081	63,333	64,080	65,928	68,641	70,904	72,445	72,373	71,107	69,906	68,836	67,756	66,788	66,736	68,786	73,260	75,607	75,217	74,000	72,140	69,439
Winter	1	83,172	1/19/2015	67,323	66,196	65,780	65,958	67,058	69,691	74,798	80,731	83,172	83,113	82,100	80,446	78,647	77,167	75,979	74,939	74,846	76,665	80,374	82,087	81,204	79,346	75,891	71,834
Winter	1	83,665	1/20/2015	68,686	66,927	65,989	65,840	66,388	69,203	75,008	81,896	83,665	82,363	80,985	79,644	78,246	77,176	76,786	76,053	76,096	77,908	81,455	82,536	81,715	79,712	76,444	71,924
Winter	1	84,002	1/21/2015	68,667	66,787	65,823	65,532	66,192	68,784	74,413	81,451	83,300	82,045	80,886	79,995	78,893	78,153	77,792	77,276	77,203	79,063	82,785	84,002	83,032	81,135	77,756	73,368
Winter	1	88,377	1/22/2015	70,050	68,079	66,936	66,631	67,238	69,661	75,204	82,039	83,847	83,226	83,057	82,737	82,004	81,590	81,293	80,895	81,421	83,779	87,711	88,377	87,389	85,374	81,619	76,785
Winter	1	86,266	1/23/2015	73,330	71,253	70,062	69,486	69,981	72,326	77,530	84,236	86,266	85,968	85,926	85,366	84,016	82,694	81,622	80,763	80,526	81,992	85,391	85,849	84,675	83,025	80,133	76,739
Winter	1	79,412	1/24/2015	73,411	71,284	70,052	69,708	69,793	70,803	73,155	76,395	78,592	79,412	78,731	77,029	74,852	72,784	70,751	69,246	68,748	70,329	74,503	76,095	75,604	74,490	72,578	69,661
Winter	1	80,008	1/25/2015	67,091	65,340	64,297	63,766	63,843	64,662	66,398	68,901	71,376	72,970	73,283	72,603	71,953	71,375	70,698	70,135	70,826	73,442	78,088	80,008	79,519	77,948	75,220	71,945
Winter	1	87,302	1/26/2015	69,377	67,901	67,446	67,570	68,736	71,723	77,820	85,325	87,302	86,366	85,468	84,269	82,761	81,575	80,639	79,393	78,982	80,406	84,426	86,456	85,485	83,332	79,728	75,274
Winter	1	85,506	1/27/2015	71,909	70,061	68,932	68,682	69,339	71,778	77,295	84,315	85,506	84,123	82,545	81,249	79,960	79,028	78,338	77,509	77,223	78,532	82,574	84,421	83,788	82,117	78,685	74,574
Winter	1	86,794	1/28/2015	71,441	69,846	69,124	69,112	69,777	72,639	78,667	85,485	86,794	85,010	83,188	81,450	79,767	78,369	77,612	76,787	76,759	78,335	82,357	84,045	82,965	81,192	77,797	73,091
Winter	1	84,553	1/29/2015	69,554	67,422	66,201	65,656	66,003	68,230	73,616	80,383	82,303	81,574	81,311	81,075	80,406	79,996	79,867	79,364	79,397	80,478	83,407	84,553	83,630	81,716	78,340	74,087
Winter	1	85,804	1/30/2015	70,823	68,862	67,873	67,696	68,514	71,202	76,812	83,922	85,804	84,925	83,962	82,631	80,812	79,229	77,649	76,131	75,598	76,686	80,771	82,828	82,353	81,260	79,046	75,809
Winter	1	78,702	1/31/2015	72,826	70,539	69,612	69,138	69,150	70,035	72,127	74,976	77,090	78,690	78,702	77,443	75,558	73,838	72,654	72,085	72,011	73,757	77,066	78,043	76,975	75,622	73,475	70,497
Winter	2	78,886	2/1/2015	67,603	65,501	64,175	63,604	63,357	63,899	65,365	67,467	69,401	71,631	73,262	73,766	74,106	74,235	74,141	73,844	74,302	76,023	78,596	78,886	78,024	77,092	75,838	73,313
Winter	2	92,168	2/2/2015	70,687	69,521	69,230	69,807	71,092	74,085	80,007	87,457	90,063	90,005	89,646	88,456	86,800	85,179	83,837	82,451	82,136	83,921	88,963	92,168	91,676	89,953	86,706	82,153
Winter	2	92,824	2/3/2015	78,999	77,337	76,610	76,339	77,031	79,610	85,145	91,907	92,824	91,519	89,839	88,360	86,404	84,735	83,308	82,285	81,978	83,564	87,769	89,991	89,218	87,232	83,366	78,767
Winter	2	90,369	2/4/2015	75,177	72,966	71,761	71,329	71,860	74,357	79,824	86,481	87,514	86,618	85,816	85,147	84,151	83,596	83,117	82,760	82,958	84,346	88,095	90,369	89,697	88,094	84,790	80,542
Winter	2	92,801	2/5/2015	77,663	75,990	75,477	75,521	76,458	79,062	84,770	91,631	92,801	91,441	89,899	88,350	86,458	84,891	83,615	82,275	81,708	82,882	87,890	91,410	91,457	89,974	86,748	82,619
Winter	2	92,183	2/6/2015	79,608	77,809	76,999	76,535	77,154	79,509	84,836	91,273	92,183	90,723	88,726	86,134	83,629	81,372	79,693	77,961	76,917	77,214	80,362	82,660	82,123	80,991	78,696	75,488
Winter	2	77,785	2/7/2015	72,273	70,441	69,280	68,723	68,760	69,891	72,161	75,245	76,959	77,785	76,649	74,458	72,154	69,903	68,096	66,778	66,517	67,394	70,794	73,139	72,325	71,090	68,925	65,950
Winter	2	75,427	2/8/2015	63,304	61,414	60,354	59,663	59,677	60,263	61,657	63,917	65,753	67,558	68,252	67,748	67,547	67,450	67,149	66,986	67,594	69,463	72,998	75,427	74,867	72,761	70,286	66,782
Winter	2	85,379	2/9/2015	64,249	62,749	62,093	62,009	62,851	65,800	71,678	78,811	80,947	81,230	81,361	81,295	80,858	80,435	80,019	79,358	79,143	80,045	83,209	85,379	84,424	82,396	78,767	74,372
Winter	2	85,866	2/10/2015	71,068	69,223	68,354	68,200	69,032	71,590	77,527	84,377	85,866	85,015	83,918	82,531	81,007	79,479	78,408	77,232	76,661	77,768	81,282	84,452	84,408	82,834	79,400	75,218
Winter	2	85,981	2/11/2015	72,095	70,290	69,301	69,069	69,906	72,454	78,226	85,150	85,981	84,605	83,201	81,820	80,632	79,758	79,136	78,656	78,515	79,680	82,751	85,756	85,375	83,963	80,815	76,710
Winter	2	89,139	2/12/2015	73,681	72,206	71,435	71,462	72,509	75,426	81,456	88,535	89,851	89,088	88,165	86,906	85,476	84,180	83,416	82,460	82,105	83,262	87,086	90,538	90,381	89,196	86,121	82,139
Winter	2	92,340	2/13/2015	78,890	77,144	76,175	76,246	76,963	79,421	84,734	91,110	92,340	91,203	89,747	87,765	85,460	83,263	81,850	80,333	79,610	80,023	82,617	85,300	84,607	83,344	81,029	77,552
Winter	2	83,778	2/14/2015	74,604	72,776	71,596	71,042	71,440	72,524	74,790	77,569	79,686	81,171	81,075	79,991	78,699	77,301	76,185	75,331	75,707	77,016	80,596	83,778	83,234	82,005	80,120	77,411
Winter	2	86,460	2/15/2015	75,144	73,539	72,750	72,441	72,627	73,703	75,288	77,521	79,399	81,094	81,651	80,912	79,981	79,031	77,983	77,099	77,633	79,669	83,763	86,460	85,639	83,970	81,280	78,107
Winter	2	93,857	2/16/2015	75,594	73,982	73,096	73,046	73,663	75,835	80,190	85,097	87,024	88,298	89,216	89,384	88,754	88,077	87,353	86,607	86,527	87,742	91,087	93,857	92,934	90,943	87,706	83,715
Winter	2	94,782	2/17/2015	81,103	79,672	79,002	79,032	79,822	82,379	87,668	93,306	94,667	94,782	93,981	92,700	90,878	89,172	87,516	86,154	85,489	86,550	90,053	93,938	93,792	92,215	88,856	84,738
Winter	2	96,371	2/18/2015	81,861	80,477	79,803	79,946	80,701	83,319	88,880	94,831	96,001	94,745	93,522	92,296	90,812	89,671	88,705	87,714	87,577	88,696	92,401	96,343	96,371	95,287	92,427	88,427
Winter	2	99,150	2/19/2015	85,565	84,135	83,507	83,710	84,608	87,141	92,367	98,171	99,150	98,143	96,569	94,822	92,466	90,626	89,091	87,582	87,272	88,231	91,935	96,220	96,391	95,096	92,162	88,163
Winter	2	95,864	2/20/2015	85,079	83,433	82,504	82,206	82,678	84,639	89,249	94,778	95,864	95,342	94,318	92,893	90,917	89,236	87,990	86,730	86,113	86,432	88,390	89,930	88,390	86,287	82,914	78,789
Winter	2	79,998	2/21/2015	75,319	72,677	70,984	70,110	69,708	69,950	71,760	73,804	75,422	77,591	78,548	78,414	77,447	76,157	74,662	73,379	73,096	74,190	76,918	79,998	79,508	78,239	76,053	73,082
Winter	2	86,490	2/22/2015	70,464	68,720	67,762	67,401	67,392	67,970	69,623	71,655	73,418	75,733	76,947	76,978	76,776	76,714	76,377	76,199	76,832	78,904	82,807	86,490	86,424	84,991	82,641	79,523
Winter	2	98,370	2/23/2015	77,410	76,055	75,708	75,990	77,342	80,356	86,137	92,714	94,542	94,478	94,090	93,577	92,742	91,846	90,648	89,529	89,267	90,703	94,424	98,370	97,812	95,780	91,991	87,424
Winter	2	95,668	2/24/2015	84,151	82,240	81,172	80,802	81,409	83,791	88,793	94,630	95,668	94,948	93,972	92,588	90,900	89,075	87,424	85,627	84,710	85,537	88,492	92,455	92,134	90,084	86,378	81,549
Winter	2	92,598	2/25/2015	78,512	76,813	75,895	75,865	76,677	79,273	84,663	90,596	91,469	90,569	89,907	88,924	87,700	86,476	85,627	84,855	84,689	85,969	88,905	92,598	92,521	90,588	87,184	82,938
Winter	2	95,046	2/26/2015	79,690	77,851	77,162	77,087	77,887	80,625	86,287	92,303	93,453	93,212	92,389	91,173	89,343	87,951	86,995	85,844	85,585	86,778	89,934	94,457	95,046	93,808	90,670	86,743
Winter	2	97,543	2/27/2015	83,852	82,445	81,788	81,933	82,742	85,407	90,958	96,964	97,543	95,926	93,900	91,503	88,977	86,771	85,056	83,415	82,713	83,443	86,150	90,437	90,670	89,674	87,451	84,386
Winter	2	87,028	2/28/2015	81,593	79,796	78,824	78,439	78,632	79,673	81,799	84,116	85,951	87,028	86,323	84,088	81,438	78,946	76,909	75,578	75,545	76,577	79,133	82,341	82,027	80,747	78,349	75,282
Spring	3	81,816	3/1/2015	72,404	70,406	69,130	68,463	68,298	68,682	69,977	71,573	73,090	75,206	75,893	75,744	75,245	74,785	73,957	73,507	73,823	74,978	77,915	81,816	81,652	79,864	76,907	73,553
Spring	3	87,149	3/2

Contains Proprietary Material
Do Not Distribute

Spring	3	70,760	3/29/2015	64,013	62,006	61,052	60,564	60,567	61,138	62,530	64,537	66,107	67,590	68,245	68,115	67,828	67,470	66,807	66,381	66,378	67,455	68,096	68,419	70,102	70,760	68,007	64,300
Spring	3	74,416	3/30/2015	60,934	59,003	57,978	57,620	58,393	60,801	66,133	72,309	73,837	73,772	74,008	73,964	73,806	73,570	73,351	72,887	72,375	72,285	71,917	72,011	74,112	74,416	70,890	65,977
Spring	3	74,274	3/31/2015	61,992	59,301	57,852	57,323	57,647	59,762	64,634	70,682	72,214	72,492	72,836	72,956	72,954	72,912	73,061	72,764	72,353	72,117	71,644	71,351	73,547	74,274	70,698	65,802
Spring	4	73,704	4/1/2015	61,805	59,283	57,906	57,197	57,597	59,600	64,377	70,102	71,504	71,654	72,043	72,302	72,549	72,834	73,161	72,785	72,467	72,052	71,517	71,151	73,211	73,704	70,316	65,582
Spring	4	74,414	4/2/2015	61,224	58,519	56,917	56,025	56,292	58,129	62,475	68,210	70,248	71,475	72,674	73,588	73,977	74,103	74,414	74,095	73,664	73,064	72,395	71,776	72,791	72,941	69,778	65,302
Spring	4	70,792	4/3/2015	61,136	58,207	56,538	55,714	55,538	56,730	59,741	63,763	65,965	68,290	69,915	70,792	70,773	70,691	70,549	70,094	69,527	69,364	68,784	68,189	69,243	70,140	68,017	64,881
Spring	4	65,696	4/4/2015	61,576	59,234	57,569	56,881	56,812	57,455	59,181	61,257	62,818	64,839	65,696	65,215	64,272	63,148	62,016	61,293	61,025	61,305	61,543	61,708	63,993	65,621	64,187	61,402
Spring	4	64,726	4/5/2015	58,506	56,066	54,772	54,043	53,969	54,569	56,039	57,987	59,791	61,749	62,362	61,845	61,130	60,079	58,809	57,867	57,474	57,703	58,394	59,801	63,171	64,726	62,882	59,849
Spring	4	74,499	4/6/2015	57,000	55,351	54,443	54,278	54,910	57,179	61,990	67,611	70,109	71,594	72,881	73,621	74,093	73,963	73,863	73,318	72,862	72,365	72,377	72,631	74,499	74,407	71,087	66,795
Spring	4	76,667	4/7/2015	62,523	59,728	58,156	57,307	57,425	59,098	63,711	69,488	71,903	73,044	74,183	75,291	75,723	75,836	75,932	75,844	75,658	75,951	75,914	75,552	76,667	76,450	72,887	67,932
Spring	4	77,392	4/8/2015	63,854	60,981	59,215	58,222	58,337	60,139	64,570	70,304	72,435	73,606	74,717	75,496	76,200	76,861	77,392	77,175	77,286	77,024	76,771	76,444	77,253	77,300	73,759	68,733
Spring	4	78,300	4/9/2015	64,503	61,702	59,887	58,929	59,065	60,640	65,073	70,808	73,328	74,695	75,954	76,976	77,483	77,833	78,300	78,094	77,946	78,032	77,384	76,691	77,465	77,209	73,631	68,574
Spring	4	74,092	4/10/2015	63,996	61,031	59,230	58,148	58,035	59,646	63,825	69,206	71,547	72,792	73,704	74,092	73,732	73,458	72,830	71,760	70,512	69,520	68,435	67,941	69,066	70,208	68,008	64,350
Spring	4	66,352	4/11/2015	60,640	58,302	56,693	56,127	55,997	56,863	58,811	60,696	62,549	64,549	65,478	65,603	65,225	65,041	64,581	64,236	63,943	63,920	63,830	63,649	64,940	66,352	64,217	60,960
Spring	4	68,400	4/12/2015	57,700	55,393	53,848	53,008	52,796	53,053	54,204	55,473	57,145	59,574	61,122	61,794	62,340	62,711	62,806	62,662	63,057	63,840	64,499	65,275	67,347	68,400	65,569	61,581
Spring	4	73,984	4/13/2015	58,059	55,812	54,348	53,942	54,380	56,607	61,726	67,751	70,214	71,391	72,459	73,389	73,804	73,915	73,956	73,674	73,336	73,143	72,675	72,314	73,312	73,984	70,422	65,594
Spring	4	72,500	4/14/2015	61,296	58,663	57,128	56,223	56,600	58,617	63,847	69,405	71,381	71,944	72,307	72,491	72,191	72,111	71,795	71,204	70,345	70,040	69,797	69,677	71,116	72,500	69,402	64,716
Spring	4	73,732	4/15/2015	60,367	57,730	56,261	55,643	55,737	57,658	62,511	67,866	69,718	70,371	71,143	71,784	71,937	72,504	72,943	72,922	72,607	72,181	71,480	71,134	72,349	73,732	70,601	65,508
Spring	4	74,143	4/16/2015	61,216	58,341	56,730	55,877	56,054	57,805	62,606	68,045	70,257	71,210	72,128	72,538	73,152	73,546	73,819	73,408	73,201	72,942	72,163	71,990	73,296	74,143	70,829	65,845
Spring	4	75,132	4/17/2015	61,403	58,683	56,967	56,053	56,118	57,697	62,113	67,105	69,243	70,524	72,065	73,173	73,720	74,261	74,986	75,132	74,919	74,644	73,550	72,068	71,978	72,801	70,081	65,670
Spring	4	67,219	4/18/2015	61,292	57,899	55,718	54,499	54,000	54,429	55,828	57,307	59,413	62,480	64,617	65,752	66,132	66,097	65,950	65,884	65,671	65,757	65,632	65,253	66,099	67,219	65,021	61,437
Spring	4	69,364	4/19/2015	57,863	55,229	53,413	52,232	51,763	51,970	52,856	53,725	55,925	59,016	61,329	62,836	63,991	64,829	65,424	66,037	66,910	67,905	68,634	68,548	69,322	69,364	66,500	62,386
Spring	4	73,737	4/20/2015	58,673	56,394	55,118	54,547	55,017	56,963	61,954	67,758	70,314	71,617	72,561	73,319	73,609	73,585	73,696	73,039	72,459	72,558	72,439	72,102	72,926	73,737	70,528	65,819
Spring	4	74,218	4/21/2015	61,814	59,102	57,824	57,230	57,315	59,574	64,636	70,007	71,938	72,510	72,630	72,750	72,670	72,694	72,519	72,275	72,046	72,228	71,981	71,784	72,697	74,218	70,997	66,164
Spring	4	75,709	4/22/2015	61,922	59,478	58,312	57,474	57,890	59,745	64,758	69,888	71,849	72,464	72,986	73,667	74,137	74,433	74,748	74,518	74,452	74,097	73,702	73,317	74,200	75,709	72,653	68,164
Spring	4	75,289	4/23/2015	64,171	61,736	60,256	59,589	59,865	62,014	66,954	71,946	73,622	73,927	74,180	74,455	74,416	74,350	74,285	73,778	73,358	73,185	72,491	72,060	73,130	75,289	72,621	67,980
Spring	4	73,650	4/24/2015	63,837	61,360	59,997	59,286	59,544	61,302	65,878	70,610	72,681	73,229	73,566	73,650	73,228	73,018	72,675	71,922	71,324	70,865	70,227	69,770	70,559	71,149	68,909	65,376
Spring	4	68,587	4/25/2015	61,732	59,197	57,436	56,632	56,323	56,871	58,365	60,104	62,734	65,767	67,835	68,587	68,359	67,733	67,032	66,522	66,451	66,598	66,781	66,485	66,734	67,994	66,173	62,638
Spring	4	69,653	4/26/2015	59,211	56,846	55,450	54,648	54,392	54,756	55,714	56,612	58,694	61,179	62,601	63,243	63,799	64,158	64,202	64,476	64,895	65,535	66,101	66,249	67,408	69,653	67,389	63,202
Spring	4	72,204	4/27/2015	59,716	57,528	56,520	56,059	56,597	59,005	64,106	69,225	71,726	72,179	72,204	71,956	71,770	71,719	71,331	70,587	70,156	69,900	69,696	69,755	70,352	72,015	69,423	64,720
Spring	4	71,779	4/28/2015	60,716	58,289	57,053	56,508	56,896	58,892	63,600	68,627	70,622	70,982	71,243	71,504	71,324	71,343	71,358	70,909	70,333	69,994	69,495	69,131	69,928	71,779	68,992	64,136
Spring	4	71,917	4/29/2015	59,911	57,274	56,091	55,509	55,932	58,002	62,897	67,784	69,889	70,246	70,598	70,949	70,958	71,181	71,411	71,183	70,707	70,532	70,191	69,828	70,060	71,917	69,151	64,150
Spring	4	72,715	4/30/2015	59,768	57,253	55,645	54,902	55,232	57,112	61,989	66,933	69,366	70,062	70,679	71,202	71,394	71,568	72,044	72,076	71,988	71,894	71,334	70,842	70,921	72,715	70,296	65,188
Spring	5	72,058	5/1/2015	60,905	57,730	56,073	55,226	55,421	57,428	62,104	66,856	69,056	69,762	70,645	71,083	71,269	71,637	72,058	71,894	71,827	71,075	70,344	69,351	68,735	70,227	67,765	63,459
Spring	5	67,296	5/2/2015	59,068	55,785	53,975	52,841	52,372	52,954	54,596	55,802	58,625	61,575	63,421	64,320	64,903	65,344	65,738	66,104	66,645	67,034	67,113	66,564	65,909	67,296	65,168	61,231
Spring	5	71,682	5/3/2015	57,450	54,723	52,622	51,514	50,698	50,576	51,145	51,768	54,753	58,095	60,973	62,681	64,286	65,738	66,836	67,707	68,693	69,837	70,330	70,000	69,979	71,682	69,111	64,141
Spring	5	79,354	5/4/2015	59,494	56,605	54,872	53,909	54,186	56,029	60,666	66,026	69,476	71,482	73,552	75,398	76,688	78,106	79,059	79,309	79,354	79,134	78,524	77,373	77,140	78,048	74,412	68,502
Spring	5	80,151	5/5/2015	63,067	59,721	57,576	56,437	56,262	57,727	62,252	67,213	70,404	72,414	74,347	76,130	77,644	78,872	79,819	80,151	80,143	79,983	79,228	78,099	77,437	78,274	74,795	69,022
Spring	5	82,568	5/6/2015	63,653	60,633	58,274	56,991	56,915	58,432	62,696	67,486	70,681	72,754	74,726	76,773	78,379	79,869	81,317	82,101	82,519	82,568	81,904	80,785	79,614	80,460	76,970	70,756
Spring	5	85,941	5/7/2015	65,209	61,480	59,051	57,625	57,409	59,027	63,061	67,951	71,707	74,191	76,877	79,536	81,553	83,430	84,851	85,671	85,941	85,731	84,599	82,883	81,857	82,583	78,736	72,624
Spring	5	83,086	5/8/2015	67,087	63,160	60,663	59,055	58,569	59,899	63,660	68,623	72,291	75,027	77,462	79,537	81,055	82,122	83,086	83,025	82,645	82,113	80,472	78,440	77,240	77,509	74,858	70,024
Spring	5	73,826	5/9/2015	65,226	61,526	59,080	57,600	56,730	56,936	57,910	59,348	62,359	65,816	68,379	70,062	71,327	71,974	72,481	72,933	73,483	73,826	73,523	72,361	71,578	72,720	70,914	66,663
Spring	5	74,751	5/10/2015	62,311	59,049	56,779	55,338	54,534	54,545	55,144	55,757	58,912	62,809	65,740	67,889	69,459	70,773	71,665	72,419	73,221	73,754	73,714	73,310	73,582	74,751	72,299	67,616
Spring	5	80,130	5/11/2015	63,226	60,576	58,796	57,904	57,921	59,859	64,525	69,690	73,159	75,060	76,703	78,506	79,562	80,072	80,130	79,804	78,876	78,406	77,588	76,734	75,898	76,695	73,587	68,038
Spring	5	75,704	5/12/2015	63,326	60,329	58,406	57,341	57,331	58,913	63,083	67,972	70,921	72,181	73,314	74,148	74,803	75,267	75,704	75,435	74,945	74,608	73,879	73,140	73,106	74,182	72,017	66,864
Spring	5	75,440	5/13/2015	62,550	59,713	58,051	57,093	57,178	58,935	63,159	67,935	70,647	71,702	72,687	73,528	74,139	74,713	75,362	75,322	75,176	74,953	74,497	73,696	73,477	75,440	72,849	67,599
Spring	5	77,641	5/14/2015	63,055	60,179	58,307	57,224	57,170	58,926	63,099	68,034	70,988	72,213	73,659	74,766	75,661	76,536	77,470	77,641	77,379	77,333	76,828	76,205	76,086	76,978	73,989	68,731
Spring	5	80,591	5/15/2015	64,243	61,140	59,424	58,258	58,094	59,474	63,598	68,499	71,771	74,028	76,160	77,827	79,291	80,256	80,591	80,281	79,513	78,774	77,442	75,733	74,745	75,887	73,711	69,160
Spring	5	75,903	5/16/2015	64,824	61,473	59,358	57,907	57,333	57,549	58,662	60,171	63,436	66,994	70,022	72,043	73,469	74,351	75,070	75,407	75,776	75,903	75,607	74,696	73,636	74,796	73,266	69,216
Spring	5	79,503	5/17/2015	64,981	61,759	59,584	58,043	57,332	57,325	57,539	58,399	61,422	65,531	69,108	71,627	73,724	75,357	76,120	77,250	78,361	79,208	79,503	78,824	77,882	78,821	76,727	71,700
Spring	5	85,504	5/18/2015	66,883	63,514	61,374	60,201	60,068	61,824	66,153	71,455	75,739	78,430	80,619	82,726	84,128	84,881	85,504	85,379	84,774	84,172	83,089	81,580	79,829	79,770	76,615	70,670
Spring	5	77,567	5/19/2015	65,267	61,632	59,935	58,546	58,480	59,809	63,042	67,861	71,031	72,484	73,711	74,870	75,677	76,482	77,189	77,567	77,530	77,550	76,540	75,466	74,990	75,857	73,472	68,584
Spring	5	78,644	5/20/2015	64,196	61,493	59,357	58,487	58,582	59,913	63,764	68,454	71,705	73,454	74,919	76,471	77,297	78,008	78,644	78,252	78,147	78,050	77,633	76,976	76,348	76,979	74,599	69,460
Spring	5	76,160	5/21/2015	64,911	62,209	60,315	59,311	59,003	60,688	64,589	68,720	71,613	73,311	74,622	75,306	75,805	76,160	76,117	75,274	74,203	73,167	72,117	71,334	70,796	72,716	71,463	66,803
Spring	5	74,023	5/22/2015	62,346	59,598	57,728	56,527	56,359	57,861	61,158	65,485	68,614	69,965	71,109	71,983	72,457	72,988	73,456	73,868	74,023	73,787	72,928	71,242	70,098	71,062	69,646	65,155
Spring	5	71,456	5/23/2015	60,592	57,386	55,335	54,061	53,357	53,462	53,995	54,878	58,174	61,815	64,511	66,493	67,974	69,074	69,848	70,414	70,937	71,456	71,305	70,301	68,837	69,610	68,159	64,436
Spring	5	71,318	5/24/2015	60,460	57,160	55,073	53,762	53,046	52,818	52,953	53,598	56,643	60,675	63,849	66,324	68,339	69,623	70,307	70,756	71,098	71,264	71,318	70,460	69,617	70,379	68,738	65,009
Spring	5	76,702	5/25/2015	61,045	57,818	55,929	54,643	54,032	54,290	55,151	55,853	58,449	62,521	66,526	69,816	72,238	73,794	74,642	75,332	76,118	76,702	76,674	75,752	74,962	75,434	73,632	68,788
Spring	5	86,817	5/26/2015	63,918	60,478	58,454	57,262	57,039	58,730	62,702	68,282	72,731	75,505	77,915	80,153	82,066	83,649	84,978	85,681	86,428	86,817	85,955	84,495	82,533	82,048	79,285	73,426
Spring	5	85,857	5/27/2015	68,003	64,172	61,721	60,308	60,028	61,458	64,933	69,746	74,050	76,667	79,077	81,174	82,583	83,450	84,484	85,021	85,554	85,857	85,638	84,623	82,731	82,470	79,862	73,577
Spring	5	92,466	5/28/2015	67,848	63,700	61,015	59,525	58,967	60,217	63,234	68,120	72,726	76,321	79,659	82,901	85,810	88,554	90,865	92,138	92,466	92,350	91,190	89,226	86,876	86,173	83,342	77,038
Spring	5	91,612	5/29/2015	70,933	66,445	63,505	61,874	61,373	62,784	65,871	70,555	75,333	79,054	82,473	85,479	87,800	89,477	90,910	91,422	91,612	90,800	88,863	86,292	83,678	83,132	80,479	75,264
Spring	5	77,808	5/30/2015	69,687	65,466	62,566	60,636	59,618	59,589	60,139	61,351	65,265	69,735	73,476	76,012	77,303	77,808	77,549	77,274	76,664	75,551	73,945	72,304	70,760	70,622	69,244	65,440
Spring	5	67,878	5/31/2015	61,563	58,285	56,038	54,674	53,999	53,809	53,887	54,227	56,981	60,282	62,622	64,449	65,761	66,528	66,718	66,229	66,138	66,541	66,985	67,009	66,866	67,878	66,938	63,263
Summer	6	78,295	6/1/2015	59,293	56,794	55,435	54,746	54,955	56,901	60,747	65,403	68,966	71,486	73,275	74,842	76,016	77,068	77,987	78,205	78,295	78,035	77,491	76,302	75,238	75,468	73,876	68,847
Summer	6	81,231	6/2/2015	63,997	60,620	58,451	57,064	56,958	58,393	61,598	66,039	69,809	72,253	74,742	76,668	78,265	79,581	80,748	81,113	81,231	80,956	80,370	79,072	77,545	77,887	76,005	70,668
Summer	6	84,216	6/3/2015	65,268	61,639	59,322	57,976	57,531	59,020	62,042	66,613	70,573	73,234	75,791	78,002	79,860	81,426	82,866	83,586	84,061	84,216	83,597	82,122	80,466	80,219	78,144	72,558
Summer	6	89,968	6/4/2015	67,114	63,237	60,731	59,291	58,983	60,213	63,514	67,879	72,191	75,438	78,565	81,538	83,751	85,763	87,709	88,860	89,642	89,968	89,308	87,754	85,659	85,196	82,951	76,780
Summer	6	91,874	6/5/2015	70,661	66,266	63,373	61,500	60,769	61,706	64,582	68,877	73,513	77,462	81,191	84,473	87,115	89,039	90,865	91,734	91,874	91,338	89,671	87,277	84,213	82,617	79,938	74,624
Summer	6	82,834	6/6/2015	68,878	64,484	61,193	59,132	57,941	57,867	57,894	59,092	62,635	66,978	70,762	74,041	76,558	78,178	79,642	80,864	82,135	82,834	82,622	81,073	78,888	78,031	76,273	71,607
Summer	6	88,975	6/7/2015	66,647	62,549	59,797	58,052	57,003	56,700	56,556	57,193	60,910	66,221	71,148	75,581	79,073	82,097	84,127	85,494	87,192	88,611	88,975	87,843	85,913	84,716	82,363	77,035
Summer	6	96,644	6/8/2015	71,554	67,473	64,441	62,570	61,984	63,190	66,392	71,080	76,008	80,014	83,823	87,350	90,279	92,800	95,045	95,993	96,558	96,644	95,406	93,158	90,495	88,828	85,605	78,979
Summer	6	98,343	6/9/2015	72,521	68,094	65,076	63,187	62,481	63,552	66,183	70,602	75,548	79,897	83,957	87,993	91,037	93,774	96,195	97,424	98,172	98,343	97,702	95,833	93,255	91,721	88,807	81,934
Summer	6	105,843	6/10/2015	75,330	70,518	66,980	65,023	64,172	65,232	68,091	72,727	77,935	82,828	87,360	91,736	95,890	99,677	102,371	104,318	105,702	105,843	104,473	101,843	98,221	95,680	91,857	84,338
Summer	6	96,995	6/11/2015	77,089	71,924	68,381	66,162	65,154	66,019	68,634	73,109	77,856	81,838	85,979	89,618	92,500	94,536	96,258	96,995	96,872	95,672	93,964	91,974	89,857	88,915	86,330	80,350
Summer	6	93,077	6/12/2015	74,492	70,082	67,144	65,193	64,446	65,633	68,149	72,196	77,108	81,421	85,460	88,450	90,499	91,904	92,771	93,077	92,737	91,821	89,276	86,617	84,219	82,915	80,892	75,801
Summer	6	84,291	6/13/2015	70,561	66,461	63,600	61,870	60,840	60,973	61,708	63,462	67,247	71,862	75,640	79,009	81,245	82,567	83,278	83,511	83,963	84,291	83,559	82,058	80,137	79,884	78,417	74,234
Summer	6	88,888	6/14/2015	69,894	66,049	63,390	61,552	60,522	60,365	60,172	61,021	64,853	69,986	74,455	78,048	81,325	84,159	85,874	86,850	87,568	88,545	88,888	87,927	86,260	85,431	83,723	78,564
Summer	6	99,540	6/15/2015	72,973	68,930	66,101	64,691	64,353	65,786	68,983	74,046	79,556	83,989	88,096	92,010	95,423	97,750	99,308	99,540	99,365	98,805	97,399	95,270	92,831	90,967	88,007	82,126
Summer	6	97,065	6/16/2015	75,777	71,228	68,095	66,117	65,364	66,261	69,181	73,548	78,432	82,479	85,939	89,104	91,664	93,911	95,762	96,957	97,065	96,581	95,035	92,734	89,979	88,568	85,746	79,658
Summer	6	94,520	6/17/2015	73,650	69,271	66,369	64,607	63,882	65,326	68,187	72,365	76,747	80,610	84,277	87,526	90,257	92,269	93,841	94,464	94,520	93,985	92,630	90,939	88,905	88,185	85,998	80,404
Summer	6	95,926	6/18/2015	74,591	70,444	67,652	65,902	65,322	66,494	69,464	73,836	78,603	82,752	86,349	89,628	92,122	94,372	95,618	95,926	95,773	94,947	93,539	91,650	89,333	88,208	86,067	80,497
Summer	6	90,962	6/19/2015	74,385	70,094	67,102	64,989	64,402	65,209	67,870	71,679	75,992	79,467	82,616	85,211	87,175	88,672	90,282	90,907	90,962	90,437	88,890	86,396	84,169	82,897	81,178	76,490
Summer	6	89,737	6/20/2015	71,319	67,111	64,160	62,326	61,288	61,048	61,515	62,682	66,046	70,680	74,992	78,546	81,421	83,670	85,742	87,355	88,781	89,724	89,737	88,379	86,372	84,886	83,147	78,529
Summer	6	93,125	6/21/2015	73,141	68,621	64,996	62,762	61,362	60,811	60,344	61,204	64,917	70,319	75,335	79,379	83,093	86,052	88,413	90,248	91,775	92,941	93,125	92,110	90,097	88,887	87,013	81,561
Summer	6	106,061	6/22/2015	75,480	71,056	68,052	66,187	65,493	66,834	69,971	75,019	80,808	86,140	91,081	95,658	99,295	102,091	104,385	105,379	105,647	106,061	105,889	104,257	101,353	99,404	96,405	89,531
Summer	6	103,253	6/23/2015	82,765	77,140	73,349	70,681	69,450	70,171	72,609	76,933	81,506	85,797	89,704	93,432	96,316	99,352	101,736	102,924	103,253	102,996	101,289	98,821	95,130	92,795	89,878	82,928
Summer	6	99,475	6/24/2015	76,068	71,259	67,881	65,688	64,821	65,740	68,262	72,288	77,262	81,748	85,537	89,315	92,990	95,583	97,481	98,931	99,475	99,464	98,109	95,941	93,098	91,436	88,784	82,391
Summer	6	99,688	6/25/2015	76,148	71,422	68,430	66,424	65,638	66,656	69,746	73,623	78,081	81,983	85,411	88,991	92,396	95,650	98,187	99,304	99,688	99,120	97,795	95,795	92,822	91,095	88,289	82,009
Summer	6	93,149	6/26/2015	75,670	70,957	67,760	65,685	64,939	65,632	68,060	72,003	76,619	80,835	84,320	87,886	90,507	91,854	92,868	93,149	92,911	92,113	90,013	87,419	84,782	83,418	81,370	76,716
Summer	6	83,041	6/27/2015	71,449	67,131	64,185	62,418	61,214	61,087	61,525	62,323	65,645	69,995	73,980	77,033	79,022	80,381	81,332	81,894	82,651	83,041	82,605	81,003	78,915	77,450	75,773	71,552
Summer	6	82,311	6/28/2015	66,989	62,872	60,100	58,314	57,230	56,977	56,488	57,211	60,366	64,657	68,333	71,798	74,674	77,015	78,836	80,224	81,417	82,092	82,311	81,379	79,847	79,186	77,793	73,296
Summer	6	96,660	6/29/2015	68,356	64,713	62,303	60,907	60,705	62,242	65,289	69,517	74,608	79,070	83,038	86,860	90,169	92,538	94,773	96,133	96,549	96,660	95,616	93,635	90,584	88,963	86,020	79,925
Summer	6	94,097	6/30/2015	73,509	69,021	65,855	63,923	63,089	64,192	67,271	71,064	75,303	79,074

Contains Proprietary Material
Do Not Distribute

Summer	8	104,310	8/4/2015	78,853	73,853	70,247	67,944	66,966	67,874	70,802	74,146	78,498	83,093	87,926	92,478	96,416	99,492	102,175	103,701	104,310	103,941	102,433	100,044	96,790	95,393	91,521	84,734
Summer	8	102,044	8/5/2015	78,314	73,895	70,712	68,603	67,829	68,753	71,967	75,408	79,481	83,651	87,953	92,018	95,582	98,887	101,209	101,964	102,044	101,559	100,509	98,183	95,089	94,224	90,463	83,956
Summer	8	101,031	8/6/2015	78,044	73,815	70,646	68,564	67,939	68,996	72,362	75,969	79,264	82,995	86,819	90,309	93,300	95,747	98,383	99,948	100,958	101,031	99,852	97,662	94,759	93,882	90,114	83,970
Summer	8	104,310	8/7/2015	78,079	73,522	70,411	68,260	67,347	68,344	71,568	75,057	79,078	83,468	87,727	91,661	95,151	98,237	101,150	103,047	104,082	104,310	103,027	100,346	96,760	95,311	91,426	85,188
Summer	8	96,706	8/8/2015	79,170	74,309	70,899	68,494	67,004	66,791	67,553	68,136	70,984	76,081	81,104	85,605	89,161	91,875	93,735	94,864	96,038	96,706	96,197	94,112	91,550	91,005	87,788	82,370
Summer	8	98,955	8/9/2015	76,943	72,542	69,520	67,227	65,662	64,825	65,046	65,442	68,127	73,121	77,989	82,294	86,455	90,324	93,219	95,293	97,145	98,658	98,955	97,703	95,673	94,831	91,222	85,302
Summer	8	108,587	8/10/2015	79,304	75,219	72,297	70,438	69,936	71,144	75,122	79,193	83,268	87,819	92,403	96,840	100,743	103,948	106,287	107,189	108,172	108,587	107,475	105,248	101,730	99,780	95,118	87,312
Summer	8	105,165	8/11/2015	80,772	75,848	72,354	70,106	69,167	70,152	73,662	77,368	81,242	85,801	90,379	94,598	98,272	101,056	103,304	104,564	105,165	104,941	103,544	101,056	97,517	95,856	91,104	83,690
Summer	8	105,249	8/12/2015	77,292	72,509	69,267	67,108	66,283	67,149	70,741	74,388	78,209	82,569	86,781	91,353	95,338	98,693	101,633	103,534	104,905	105,249	104,145	101,807	98,204	96,689	91,887	84,564
Summer	8	108,275	8/13/2015	78,100	73,304	70,008	67,912	66,987	67,811	71,544	75,466	79,090	83,559	88,262	93,023	97,328	101,346	104,825	106,925	108,241	108,275	107,204	104,514	101,350	100,255	95,564	88,303
Summer	8	113,010	8/14/2015	81,380	76,404	72,854	70,482	69,300	70,256	74,049	78,203	82,057	86,836	92,026	96,992	101,827	105,899	109,219	111,553	113,010	112,605	110,588	106,746	102,195	99,582	94,690	87,541
Summer	8	106,502	8/15/2015	80,764	75,442	71,526	68,597	66,904	66,417	67,174	67,807	71,634	78,019	84,610	90,808	95,804	99,446	102,186	104,318	105,795	106,502	105,641	102,445	98,288	96,415	92,122	85,570
Summer	8	102,882	8/16/2015	79,201	73,948	70,319	67,546	65,777	65,189	65,335	65,671	69,117	75,519	81,970	87,789	92,730	96,544	99,356	100,987	102,134	102,882	102,334	100,137	97,423	96,195	91,623	85,040
Summer	8	107,374	8/17/2015	78,592	74,211	71,035	69,096	68,265	69,495	74,149	79,003	83,215	87,626	92,439	97,284	101,399	104,806	106,941	107,374	107,062	105,877	103,974	101,183	98,623	97,365	91,908	84,632
Summer	8	102,758	8/18/2015	78,254	73,725	70,798	68,615	68,036	69,333	73,658	78,339	81,708	85,364	89,603	93,975	97,586	100,379	102,328	102,758	102,143	101,063	99,278	96,889	95,098	94,415	89,669	82,918
Summer	8	92,760	8/19/2015	77,236	73,255	70,120	68,439	67,925	69,268	73,299	78,081	81,249	84,320	87,291	89,827	91,350	92,363	92,760	91,949	91,101	90,892	89,876	88,157	87,032	87,125	82,884	76,709
Summer	8	87,614	8/20/2015	71,361	67,687	64,972	63,292	62,774	64,014	67,992	72,182	74,855	77,457	79,826	82,005	83,424	84,782	86,254	87,138	87,332	87,614	86,534	84,973	83,525	83,667	80,177	74,244
Summer	8	91,430	8/21/2015	68,930	65,254	62,990	61,651	61,313	62,550	66,240	70,120	73,392	77,191	80,511	83,582	86,020	88,125	89,859	90,879	91,430	91,293	90,078	87,473	84,922	84,520	80,871	75,396
Summer	8	86,799	8/22/2015	70,272	66,238	63,368	61,558	60,610	60,801	61,693	62,712	65,446	70,176	74,581	78,190	81,235	83,544	85,318	86,114	86,799	86,665	85,891	83,561	81,718	81,410	77,826	72,991
Summer	8	86,515	8/23/2015	68,449	64,759	61,924	60,300	59,278	58,876	59,387	59,925	62,400	67,064	71,496	75,016	77,979	80,460	82,607	84,184	85,471	86,385	86,515	84,890	83,267	82,915	78,713	73,085
Summer	8	89,609	8/24/2015	68,055	64,528	62,229	60,955	60,620	62,035	65,909	70,253	73,382	76,404	79,573	82,467	84,512	86,520	88,197	89,121	89,546	89,609	88,584	86,794	85,551	85,087	80,265	74,431
Summer	8	85,445	8/25/2015	69,147	65,573	63,189	61,614	61,101	62,455	66,436	70,597	72,841	75,400	77,774	80,014	81,598	83,126	84,235	84,847	85,201	85,445	84,813	83,517	82,464	82,139	77,653	71,512
Summer	8	86,983	8/26/2015	66,470	62,993	60,962	59,570	59,341	60,621	64,531	69,081	71,629	74,168	76,633	79,126	81,016	82,669	84,439	85,566	86,575	86,983	86,488	85,006	83,697	83,461	78,865	72,560
Summer	8	88,283	8/27/2015	67,433	63,821	61,500	60,191	59,667	60,899	64,976	69,406	72,107	74,779	77,303	79,844	81,902	84,064	86,102	87,380	88,081	88,283	87,206	85,420	84,373	84,323	79,732	73,682
Summer	8	90,227	8/28/2015	68,403	64,584	62,225	60,667	60,420	61,525	65,461	69,727	72,693	75,622	78,590	81,531	84,048	86,197	88,261	89,525	90,227	89,984	88,357	85,693	84,095	83,049	79,073	73,959
Summer	8	84,600	8/29/2015	68,982	64,983	62,300	60,552	59,697	59,923	61,196	62,558	64,529	68,632	72,883	76,124	78,689	80,729	82,156	83,278	83,984	84,600	84,373	82,978	82,217	81,718	78,601	73,897
Summer	8	92,914	8/30/2015	69,423	65,477	62,828	61,104	60,035	59,605	60,117	60,859	63,040	67,452	71,905	76,261	80,296	84,001	87,095	89,248	91,156	92,575	92,914	91,426	90,355	89,459	84,485	78,014
Summer	8	106,821	8/31/2015	72,336	68,367	65,734	63,900	63,489	65,147	69,837	75,034	78,541	82,464	86,935	91,615	96,152	100,365	103,675	105,713	106,642	106,821	105,392	102,750	100,853	99,152	93,015	85,167
Fall	9	111,632	9/1/2015	78,420	73,827	70,313	68,235	67,365	68,409	72,822	78,415	81,291	85,392	90,310	95,690	100,720	104,757	108,351	110,577	111,488	111,632	110,073	107,298	105,607	103,721	96,819	88,889
Fall	9	110,663	9/2/2015	82,043	76,891	73,395	71,214	70,155	71,091	75,546	81,030	84,395	88,001	92,660	97,880	102,425	105,985	108,893	110,157	110,663	110,315	108,517	105,955	104,011	102,059	95,870	87,878
Fall	9	111,106	9/3/2015	80,737	75,771	72,224	70,067	69,076	70,288	74,795	80,350	83,624	87,848	92,740	97,942	102,825	106,553	108,941	110,206	111,039	111,106	109,440	106,465	104,334	102,403	96,172	88,290
Fall	9	109,524	9/4/2015	81,628	76,316	73,043	70,784	69,690	70,677	74,387	79,340	82,578	86,749	91,788	96,770	100,854	104,451	107,294	108,892	109,524	108,945	106,354	102,530	99,956	97,605	92,303	85,790
Fall	9	102,277	9/5/2015	79,530	74,413	70,758	68,259	66,582	66,075	66,670	67,924	70,353	75,869	81,829	87,581	92,522	96,197	98,968	100,679	101,957	102,277	101,152	97,922	95,713	93,531	88,643	82,953
Fall	9	104,209	9/6/2015	77,376	72,863	69,375	66,927	65,296	64,504	64,734	65,254	67,910	74,037	80,716	86,901	92,516	97,349	100,779	102,996	103,954	104,209	102,938	99,415	96,779	94,050	89,046	82,825
Fall	9	102,318	9/7/2015	76,859	72,320	68,850	66,427	64,992	64,625	65,367	66,041	67,789	73,170	80,081	86,732	92,333	96,381	99,193	100,910	102,029	102,318	101,084	98,690	97,852	95,664	89,599	82,378
Fall	9	106,130	9/8/2015	76,355	72,165	69,271	67,634	67,174	68,608	73,606	79,758	83,147	86,724	91,173	96,159	100,184	103,403	105,838	106,130	105,687	104,504	102,398	99,754	98,539	96,054	89,770	82,402
Fall	9	92,801	9/9/2015	76,249	71,658	68,821	66,964	66,196	67,490	71,983	77,402	79,300	81,331	83,914	86,473	88,606	90,545	91,899	92,489	92,801	92,660	91,413	89,316	88,895	87,351	82,052	75,373
Fall	9	92,195	9/10/2015	69,957	66,339	63,945	62,659	62,396	63,842	68,479	73,979	76,086	78,727	81,865	84,820	87,411	89,526	91,425	92,128	92,195	91,682	90,030	87,674	87,579	85,917	80,719	74,309
Fall	9	80,016	9/11/2015	69,019	65,245	62,948	61,491	60,953	62,362	66,598	71,923	73,952	75,636	77,148	78,348	79,248	79,644	80,016	79,789	78,841	78,022	76,526	74,788	75,139	74,365	71,192	67,099
Fall	9	70,181	9/12/2015	62,829	59,795	57,748	56,347	55,749	56,073	57,320	58,922	60,729	63,777	66,108	67,738	68,771	69,416	69,804	69,853	70,126	70,181	69,781	68,691	69,122	68,674	65,720	61,956
Fall	9	71,867	9/13/2015	58,278	55,511	53,570	52,325	51,603	51,627	52,462	53,378	55,084	58,342	60,598	62,404	63,907	65,096	65,982	67,082	68,693	70,073	70,882	70,578	71,867	71,137	67,437	62,726
Fall	9	85,662	9/14/2015	59,068	56,379	54,984	54,175	54,356	56,268	61,032	66,649	68,905	70,998	73,222	75,594	77,410	79,731	81,896	83,371	84,730	85,662	85,298	83,845	84,707	83,078	78,020	71,982
Fall	9	93,519	9/15/2015	66,924	63,322	61,052	59,761	59,506	61,059	65,570	71,167	73,387	75,567	78,236	81,152	84,093	86,833	89,756	91,841	93,159	93,519	92,250	89,882	89,867	87,533	82,034	75,504
Fall	9	98,663	9/16/2015	69,777	66,032	63,437	61,859	61,393	62,523	66,879	72,525	74,583	77,259	80,889	84,334	87,792	91,420	94,728	96,836	98,043	98,663	97,578	94,933	94,402	91,564	85,740	78,977
Fall	9	99,479	9/17/2015	73,060	68,934	65,929	64,245	63,582	64,849	69,361	75,154	77,804	80,411	83,418	86,931	90,161	93,458	96,254	98,235	99,297	99,479	97,879	95,265	94,582	91,964	86,191	79,196
Fall	9	93,712	9/18/2015	73,131	68,859	65,935	64,212	63,531	64,680	69,136	74,665	76,772	79,274	81,983	84,895	87,591	90,260	92,532	93,319	93,712	93,089	91,210	88,840	88,106	85,570	81,251	75,944
Fall	9	79,364	9/19/2015	70,663	66,533	63,722	61,671	60,500	60,291	61,268	63,229	65,030	68,593	71,669	73,983	75,605	76,810	77,797	78,576	79,135	79,364	78,376	76,400	76,516	74,692	70,951	66,499
Fall	9	77,082	9/20/2015	62,210	59,012	56,909	55,358	54,562	54,473	55,044	56,232	57,644	61,388	64,661	67,167	69,755	71,535	73,123	74,085	75,191	75,937	76,133	75,635	77,082	75,117	71,068	66,233
Fall	9	85,833	9/21/2015	62,395	59,619	57,957	57,023	57,030	58,810	63,518	69,192	71,251	73,261	75,301	77,534	79,177	81,151	82,902	84,205	85,227	85,833	85,281	83,863	84,220	81,609	76,578	70,471
Fall	9	88,788	9/22/2015	65,265	61,720	59,450	58,092	57,883	59,472	63,916	69,632	71,514	73,651	76,243	78,797	81,043	83,518	85,822	87,462	88,645	88,788	87,626	85,669	85,812	82,795	77,465	71,152
Fall	9	90,276	9/23/2015	65,874	62,329	60,044	58,668	58,471	59,871	64,375	70,022	72,139	74,364	77,021	79,911	82,791	85,362	87,737	89,166	90,160	90,276	89,034	86,986	87,012	83,836	78,519	72,201
Fall	9	89,868	9/24/2015	66,940	63,549	61,154	59,805	59,390	60,834	65,378	71,139	73,176	75,259	78,022	80,862	83,330	85,954	88,130	89,414	89,868	89,599	87,893	86,210	86,749	83,918	78,850	72,590
Fall	9	89,764	9/25/2015	67,275	63,738	61,426	59,973	59,549	60,825	65,337	70,795	72,761	74,858	77,545	80,706	83,410	85,925	88,132	89,306	89,764	89,096	86,699	83,687	83,157	80,236	76,103	71,224
Fall	9	78,195	9/26/2015	66,312	62,447	59,814	58,293	57,456	57,447	58,846	60,818	62,310	65,875	69,357	72,043	74,279	76,046	77,206	77,805	78,195	78,053	77,076	76,011	76,793	74,961	71,830	67,634
Fall	9	79,479	9/27/2015	63,528	60,261	58,226	56,748	55,837	55,724	56,511	57,997	59,563	62,743	65,686	68,018	70,329	72,324	73,721	74,737	75,680	76,893	77,385	77,965	79,479	77,332	73,240	68,942
Fall	9	89,185	9/28/2015	64,595	61,793	60,167	59,189	59,219	61,221	66,346	72,839	75,143	77,134	79,470	81,929	84,174	86,457	88,268	89,075	89,185	88,756	87,676	87,388	88,118	85,110	80,627	74,545
Fall	9	82,688	9/29/2015	69,414	65,716	63,233	61,698	61,322	62,936	67,409	73,786	75,820	77,160	78,490	79,662	80,860	81,822	82,688	82,543	82,537	82,222	81,169	80,892	81,760	79,383	74,848	68,941
Fall	9	79,891	9/30/2015	64,315	61,083	59,283	57,996	57,885	59,369	63,969	69,881	71,309	72,592	73,945	75,521	76,925	78,092	79,379	79,817	79,891	79,775	78,618	78,192	79,684	77,232	72,868	67,354
Fall	10	76,578	10/1/2015	62,953	59,937	58,031	56,876	56,731	58,220	62,760	68,576	69,961	70,846	72,032	72,918	73,630	74,584	75,563	75,873	75,914	75,716	74,670	74,728	76,578	74,489	70,399	65,643
Fall	10	72,072	10/2/2015	61,307	58,601	56,828	55,856	55,950	57,368	61,931	67,782	69,366	70,270	70,953	71,497	71,752	71,702	72,072	71,664	71,396	71,147	70,350	70,484	71,756	70,040	67,276	63,287
Fall	10	67,714	10/3/2015	59,443	56,981	55,076	54,166	53,755	54,368	55,962	58,644	60,500	63,147	64,776	65,328	65,380	65,152	64,760	64,440	64,588	65,099	65,268	66,351	67,714	66,291	63,694	60,428
Fall	10	69,642	10/4/2015	57,122	55,022	53,498	52,497	52,042	52,199	53,184	55,257	56,959	59,638	61,408	62,277	62,781	62,965	63,150	62,983	63,383	64,450	65,466	67,257	69,642	67,810	64,783	60,888
Fall	10	78,910	10/5/2015	58,041	55,791	54,623	54,123	54,489	56,700	61,662	67,945	70,321	71,164	72,321	73,365	73,970	74,771	75,608	76,199	76,375	76,496	76,322	77,519	78,910	76,490	72,362	66,934
Fall	10	81,331	10/6/2015	62,466	59,680	57,967	57,028	57,031	58,614	63,350	69,588	71,641	72,815	74,174	75,723	77,184	78,626	79,767	80,439	80,714	80,557	79,823	80,130	81,331	78,527	73,857	68,286
Fall	10	82,337	10/7/2015	63,670	60,811	58,702	57,566	57,435	59,127	63,654	69,769	71,675	72,770	74,409	76,346	78,303	79,953	81,333	82,028	82,337	82,201	81,290	81,414	82,132	79,146	74,617	69,267
Fall	10	83,182	10/8/2015	64,472	61,508	59,307	58,233	58,208	59,806	64,049	70,201	72,212	73,484	75,400	77,567	79,584	81,216	82,836	83,105	83,182	82,996	82,319	82,526	82,929	80,108	75,637	70,158
Fall	10	78,268	10/9/2015	65,504	62,314	60,121	58,782	58,476	60,013	64,201	70,186	72,311	73,394	74,818	76,101	76,918	77,595	78,268	77,883	77,301	76,556	75,433	75,429	75,558	73,429	70,280	66,010
Fall	10	69,535	10/10/2015	62,035	59,123	57,200	55,787	55,336	55,714	57,427	59,833	61,396	63,921	65,766	66,477	66,808	66,901	67,104	67,305	67,771	68,104	67,837	68,616	69,535	67,631	64,749	61,095
Fall	10	74,139	10/11/2015	57,687	55,264	53,481	52,504	51,904	52,163	53,248	55,034	56,559	59,210	61,353	62,744	63,851	65,441	66,786	68,218	69,780	71,223	71,796	72,787	74,139	71,432	67,814	63,535
Fall	10	80,571	10/12/2015	59,822	57,419	55,743	54,982	55,019	56,858	61,354	67,511	69,686	71,448	73,584	75,497	77,097	78,594	79,823	80,122	80,550	80,500	80,138	80,571	80,571	77,607	73,023	67,490
Fall	10	78,617	10/13/2015	62,879	59,694	57,961	56,903	56,783	58,524	63,203	69,403	71,286	72,194	73,413	74,599	75,474	76,424	77,658	78,220	78,383	78,171	77,616	78,121	78,617	75,487	71,073	65,826
Fall	10	78,061	10/14/2015	61,406	58,494	56,896	55,744	55,971	57,872	62,455	68,772	70,532	70,883	71,503	72,439	73,194	74,185	75,481	76,360	76,862	77,095	76,635	77,522	78,061	75,012	70,582	65,498
Fall	10	78,716	10/15/2015	61,104	58,526	56,808	56,007	56,162	57,836	62,516	68,915	70,617	71,270	72,202	73,202	74,316	75,697	77,289	78,240	78,393	78,467	77,772	78,488	78,716	75,965	71,690	66,728
Fall	10	75,109	10/16/2015	62,327	59,598	57,775	56,810	56,848	58,666	63,024	69,261	71,116	71,818	72,708	73,358	73,852	74,209	74,887	75,109	74,893	74,482	73,741	74,413	74,672	72,635	69,677	65,646
Fall	10	68,737	10/17/2015	61,933	59,489	57,630	56,628	56,258	57,022	58,816	61,483	63,486	65,707	67,001	66,981	66,460	65,788	65,489	65,032	64,797	64,925	65,167	67,508	68,737	67,349	64,974	62,141
Fall	10	70,123	10/18/2015	59,163	56,941	55,700	55,053	54,975	55,324	56,617	58,955	60,669	62,712	63,454	63,247	63,034	63,116	62,977	62,897	63,165	64,169	65,339	68,183	70,123	68,173	65,149	61,412
Fall	10	76,516	10/19/2015	58,335	56,662	55,732	55,571	56,097	58,410	63,702	70,595	72,768	72,935	73,190	73,341	73,274	73,171	73,530	73,324	73,402	73,546	73,631	75,841	76,516	74,072	70,058	65,124
Fall	10	77,559	10/20/2015	61,249	58,915	57,327	56,572	56,667	58,646	63,376	69,803	71,765	71,990	72,671	73,436	74,185	74,757	75,434	75,315	75,137	75,134	75,232	77,174	77,559	74,942	71,211	66,428
Fall	10	79,366	10/21/2015	62,139	59,549	57,811	56,994	57,036	58,937	63,516	70,062	72,118	72,579	73,486	74,561	75,669	76,768	77,896	78,145	78,218	78,113	77,710	79,234	79,366	76,616	72,348	67,339
Fall	10	79,133	10/22/2015	62,970	60,223	58,458	57,482	57,279	59,120	63,897	70,163	72,428	72,813	73,702	74,760	75,697	76,695	77,773	78,112	78,047	77,705	77,042	79,050	79,133	76,686	72,772	67,895
Fall	10	75,967	10/23/2015	63,571	60,760	58,798	57,863	57,819	59,551	63,680	69,864	72,291	73,125	74,177	75,080	75,381	75,748	75,967	75,581	75,116	74,607	74,585	75,598	74,831	72,792	69,989	66,241
Fall	10	69,027	10/24/2015	62,228	59,307	57,502	56,229	55,771	56,181	57,864	60,540	63,181	65,434	67,497	68,526	68,823	68,479	67,837	67,132	66,784	66,607	67,216	69,027	68,736	67,111	64,606	61,400
Fall	10	69,414	10/25/2015	58,365	55,775	54,306	53,303	52,670	52,874	54,172	56,302	58,358	60,390	61,977	62,684	63,059	63,162	62,662	62,420	62,520	63,341	65,050	68,821	69,414	67,528	64,747	61,316
Fall	10	75,509	10/26/2015	58,440	56,546	55,548	55,158	55,612	57,844	63,064	69,931	72,608	72,841	73,159	73,261	73,305	73,296	72,903	72,123	71,476	71,428	72,390	75,509	75,245	73,187	69,557	64,910
Fall	10	76,040	10/27/2015	61,063	58,611	57,270	56,470	56,530	58,314	62,975	69,673	72,383	72,360	72,837	73,108	73,183	73,040	72,851	72,407	72,105	72,445	73,794	76,040	75,625	73,431	69,474	64,962
Fall	10	76,930	10/28/2015	61,225	58,790	57,247	56,327	56,284	58,134	62,729	69,099	71,940	72,128	72,946	73,680	73,963	74,339	74,884	74,691	74,787	75,028	75,471	76,930	76,593	74,560	71,079	66,267
Fall	10	76,382	10/29/2015	62,208	59,694	58,036	57,412	57,531	59,518	64,337	71,016	73,338	73,302	73,769	74,235	74,181	74,197	74,391	74,217	74,107	74,162	74,609	76,382	76,223	74,093	70,500	66,054
Fall	10	73,233	10/30/2015	62,253	59,744	58,113	57,474	57,594	59,488	64,382	70,571	73,233	73,203	73,227	73,046	72,530	71,973	71,774	71,000	70,278	69,905	70,279	72,020	71,555	70,173	67,583	64,188
Fall	10	68,826	10/31/2015	60,850	58,349	56,701	55,673	55,570	56,073	57,779	60,349	63,185	65,440	67,545	68,558	68,826	68,146	67,448	66,841	66,431	66,333	66,263	67,059	66,573	65,323	63,190	60,602
Fall	11	69,377	11/1/2015	56,583	53,994	53,051	52,515	52,527	53,165	54,754	56,643	58,713	60,703	61,630	61,891	62,045	62,140	61,979	61,820	62,279	64,388	68,976	69,377	67,950	65,577	62,598	59,365
Fall	11	76,703	11/2/2015	56,632	55,061	54,218	54,056	54,784	57,175	62,538	68,267	70,208	71,212	72,121	72,725	73,007	73,228	73,232	72,804	72,444	73,213	76,344	76,703	74,770	71,855	67,938	63,355
Fall	11	77,048	11/3/2015	59,887	57,605	56,345	55,779	56,252	58,301	63,352	68,846	70,638	71,382	72,384	73,168	73,686	73,890	74,151	73,687	72,920	73,537	76,748	77,048	75,207	72,495	68,313	63,549
Fall	11	78,391	11/4/2015	60,001	57,792	56,451	55,641	55,927	57,876	62,811	68,370	70,262	71,476	72,716	73,855	74,509	74,871	75,611	75,429	75,098	75,638	78,391	78,244	76,110	73,306	69,238	64,696
Fall	11	79,923	11/5/2015	60,639	58,301	56,787	56,063	56,252	58,228	63,171	69,026	71,179	72,554

Contains Proprietary Material
Do Not Distribute

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	8,089	12/1/2014	5,769	5,669	5,723	5,867	6,150	6,813	7,896	8,089	7,755	7,281	6,967	6,712	6,565	6,448	6,383	6,388	6,509	7,169	7,517	7,507	7,389	7,058	6,624	6,099
Winter	12	8,256	12/2/2014	5,748	5,640	5,611	5,661	5,899	6,480	7,444	7,804	7,630	7,546	7,444	7,293	7,170	7,081	7,037	7,079	7,373	8,028	8,256	8,175	8,047	7,652	7,094	6,571
Winter	12	7,836	12/3/2014	6,143	5,938	5,845	5,869	6,025	6,552	7,501	7,704	7,558	7,447	7,347	7,164	6,974	6,835	6,715	6,664	6,846	7,596	7,836	7,801	7,653	7,342	6,826	6,268
Winter	12	8,173	12/4/2014	5,837	5,649	5,592	5,625	5,820	6,405	7,399	7,711	7,593	7,484	7,310	7,114	6,895	6,808	6,705	6,743	7,073	7,844	8,158	8,173	8,110	7,839	7,345	6,833
Winter	12	8,247	12/5/2014	6,386	6,289	6,266	6,294	6,523	7,078	8,019	8,247	8,007	7,740	7,625	7,230	7,001	6,866	6,829	6,663	7,045	7,705	7,777	7,693	7,601	7,368	6,995	6,540
Winter	12	7,247	12/6/2014	6,135	5,906	5,807	5,751	5,788	5,966	6,290	6,572	6,901	7,065	7,031	6,894	6,760	6,629	6,532	6,492	6,756	7,239	7,247	7,097	6,906	6,689	6,358	5,981
Winter	12	8,707	12/7/2014	5,590	5,404	5,371	5,460	5,612	5,923	6,381	6,878	7,457	7,675	7,487	7,181	7,005	6,838	6,738	6,804	7,192	8,109	8,525	8,707	8,700	8,468	8,099	7,678
Winter	12	9,518	12/8/2014	7,433	7,335	7,313	7,416	7,588	8,327	9,295	9,518	9,267	8,988	8,607	8,286	8,109	8,064	8,069	8,215	8,615	9,336	9,461	9,469	9,277	8,881	8,275	7,732
Winter	12	9,522	12/9/2014	7,355	7,245	7,261	7,347	7,597	8,268	9,249	9,522	9,360	9,197	9,058	8,870	8,651	8,486	8,373	8,430	8,739	9,403	9,513	9,423	9,215	8,788	8,124	7,517
Winter	12	9,624	12/10/2014	7,175	7,070	7,102	7,211	7,567	8,305	9,382	9,624	9,279	8,670	8,171	7,857	7,603	7,574	7,574	7,715	8,092	9,040	9,442	9,521	9,527	9,309	8,865	8,419
Winter	12	11,021	12/11/2014	8,246	8,315	8,469	8,678	9,104	9,812	10,778	11,021	10,672	9,876	9,223	8,675	8,180	7,824	7,640	7,648	8,085	9,162	9,753	10,047	10,241	10,148	9,705	9,256
Winter	12	11,252	12/12/2014	9,019	8,962	9,044	9,178	9,500	10,202	11,092	11,252	10,793	9,836	8,966	8,282	7,782	7,424	7,198	7,143	7,440	8,345	8,773	8,944	9,056	9,031	8,785	8,433
Winter	12	9,860	12/13/2014	8,166	8,126	8,114	8,251	8,509	8,910	9,430	9,860	9,823	9,049	8,234	7,568	7,052	6,724	6,526	6,443	6,674	7,591	7,989	8,121	8,268	8,275	8,130	7,847
Winter	12	9,378	12/14/2014	7,727	7,685	7,710	7,819	7,967	8,333	8,772	9,234	9,378	8,733	7,952	7,260	6,910	6,646	6,397	6,381	6,649	7,687	8,217	8,494	8,616	8,503	8,193	7,896
Winter	12	10,791	12/15/2014	7,722	7,756	7,895	8,134	8,565	9,351	10,517	10,791	10,209	9,167	8,311	7,721	7,268	6,644	6,852	6,784	7,089	8,022	8,514	8,676	8,723	8,561	8,100	7,669
Winter	12	9,546	12/16/2014	7,408	7,390	7,452	7,561	7,825	8,506	9,447	9,546	8,968	8,371	7,968	7,694	7,534	7,465	7,345	7,350	7,539	8,185	8,425	8,344	8,184	7,836	7,315	6,770
Winter	12	8,890	12/17/2014	6,415	6,339	6,373	6,497	6,819	7,528	8,583	8,890	8,531	8,000	7,579	7,223	6,915	6,791	6,674	6,669	6,980	7,897	8,384	8,464	8,477	8,283	7,820	7,331
Winter	12	9,883	12/18/2014	7,062	7,031	7,119	7,331	7,683	8,435	9,595	9,883	9,472	8,868	8,317	7,778	7,363	7,153	7,037	7,122	7,454	8,386	8,888	9,017	9,079	8,869	8,389	7,884
Winter	12	9,762	12/19/2014	7,537	7,455	7,450	7,549	7,792	8,435	9,460	9,762	9,402	8,725	8,126	7,639	7,180	6,974	6,831	6,837	7,175	8,095	8,456	8,507	8,533	8,434	8,118	7,708
Winter	12	9,077	12/20/2014	7,386	7,217	7,131	7,148	7,253	7,485	7,848	8,261	8,669	8,951	8,972	8,865	8,640	8,440	8,251	8,199	8,349	8,977	9,077	9,009	8,915	8,764	8,470	8,078
Winter	12	8,877	12/21/2014	7,672	7,471	7,430	7,448	7,528	7,766	8,093	8,505	8,877	8,806	8,340	7,714	7,370	7,109	6,915	6,965	7,316	8,117	8,347	8,359	8,317	8,098	7,697	7,197
Winter	12	9,458	12/22/2014	6,863	6,739	6,747	6,868	7,120	7,613	8,239	8,759	8,941	9,065	9,094	8,948	8,778	8,726	8,678	8,654	8,838	9,387	9,458	9,350	9,180	8,824	8,293	7,710
Winter	12	8,717	12/23/2014	7,324	7,098	7,006	7,024	7,161	7,587	8,176	8,568	8,675	8,717	8,658	8,471	8,227	8,072	7,950	7,872	8,036	8,583	8,578	8,414	8,227	7,948	7,468	6,864
Winter	12	7,039	12/24/2014	6,368	6,045	5,830	5,705	5,738	5,912	6,255	6,543	6,737	6,967	7,039	6,969	6,793	6,625	6,484	6,345	6,460	6,821	6,739	6,519	6,347	6,185	5,909	5,516
Winter	12	6,848	12/25/2014	5,069	4,778	4,614	4,538	4,556	4,731	5,060	5,480	5,915	6,251	6,304	6,218	5,982	5,697	5,477	5,378	5,459	6,009	6,406	6,575	6,759	6,848	6,797	6,661
Winter	12	8,805	12/26/2014	6,569	6,592	6,733	6,962	7,258	7,820	8,372	8,757	8,805	8,189	7,497	6,965	6,528	6,214	6,006	5,927	6,141	6,985	7,480	7,646	7,783	7,751	7,545	7,303
Winter	12	8,782	12/27/2014	7,120	7,114	7,194	7,396	7,612	7,938	8,426	8,738	8,782	8,131	7,434	6,893	6,473	6,130	5,929	5,888	6,055	6,782	7,164	7,191	7,169	6,982	6,727	6,342
Winter	12	6,873	12/28/2014	5,985	5,769	5,664	5,586	5,612	5,688	5,901	6,089	6,359	6,487	6,366	6,160	6,148	6,045	5,941	5,942	6,116	6,667	6,873	6,754	6,613	6,362	5,964	5,492
Winter	12	8,066	12/29/2014	5,140	4,960	4,878	4,874	5,000	5,382	5,927	6,384	6,604	6,847	7,004	7,097	7,063	7,084	7,060	7,067	7,270	7,900	8,066	7,976	7,819	7,524	7,107	6,686
Winter	12	9,716	12/30/2014	6,404	6,260	6,246	6,325	6,533	7,007	7,639	8,144	8,416	8,616	8,766	8,802	8,788	8,757	8,649	8,655	8,813	9,463	9,716	9,677	9,632	9,452	9,151	8,847
Winter	12	10,681	12/31/2014	8,679	8,699	8,809	8,975	9,280	9,746	10,419	10,681	10,558	10,158	9,499	8,729	8,172	7,805	7,574	7,527	7,913	8,894	9,397	9,395	9,434	9,427	9,275	9,138
Winter	1	10,268	1/1/2015	9,069	9,110	9,142	9,277	9,465	9,770	10,112	10,268	10,107	9,396	8,578	7,952	7,458	7,006	6,763	6,700	6,948	7,824	8,233	8,328	8,284	8,104	7,703	7,243
Winter	1	7,862	1/2/2015	6,892	6,649	6,526	6,491	6,595	6,958	7,477	7,823	7,862	7,787	7,609	7,387	7,216	7,071	6,979	6,932	7,109	7,712	7,819	7,668	7,517	7,272	6,931	6,533
Winter	1	7,572	1/3/2015	6,172	5,941	5,830	5,815	5,908	6,078	6,379	6,626	6,902	7,165	7,274	7,243	7,116	6,982	6,871	6,857	6,983	7,463	7,572	7,392	7,237	6,926	6,542	6,145
Winter	1	7,044	1/4/2015	5,706	5,434	5,229	5,108	5,079	5,092	5,218	5,441	5,700	6,046	6,062	6,058	6,111	6,144	6,075	6,099	6,272	6,826	7,044	6,953	6,816	6,425	5,939	5,485
Winter	1	9,066	1/5/2015	5,160	5,027	5,039	5,149	5,468	6,239	7,435	7,897	7,787	7,653	7,473	7,257	7,068	6,984	6,878	6,917	7,237	8,126	8,838	9,039	9,066	8,920	8,535	8,151
Winter	1	11,150	1/6/2015	8,022	8,092	8,252	8,500	8,912	9,724	10,867	11,150	10,583	9,492	8,707	8,077	7,601	7,296	7,123	7,175	7,454	8,230	8,900	9,052	9,071	8,842	8,456	8,066
Winter	1	12,003	1/7/2015	7,931	7,963	8,111	8,370	8,792	9,588	10,699	10,861	10,519	9,816	9,473	9,323	9,248	9,220	9,258	9,462	9,955	10,936	11,483	11,802	11,978	12,003	11,893	11,806
Winter	1	14,519	1/8/2015	11,941	12,150	12,408	12,765	13,141	13,726	14,219	14,519	14,255	14,012	13,107	12,305	11,569	10,995	10,531	10,478	10,905	11,973	12,889	13,210	13,276	13,002	12,548	12,047
Winter	1	12,288	1/9/2015	11,787	11,625	11,533	11,418	11,361	11,639	12,288	12,160	11,844	11,213	10,547	9,740	9,035	8,505	8,100	8,004	8,327	9,207	9,814	9,886	9,883	9,743	9,434	9,082
Winter	1	11,069	1/10/2015	8,935	8,915	9,027	9,287	9,594	9,999	10,519	10,979	11,069	10,727	10,192	9,557	8,988	8,451	8,117	8,027	8,374	9,441	10,279	10,576	10,787	10,697	10,747	10,477
Winter	1	12,102	1/11/2015	10,356	10,478	10,666	10,881	11,088	11,427	11,778	12,102	11,996	11,027	9,924	9,042	8,431	8,010	7,804	7,718	8,011	8,684	8,975	8,925	8,759	8,358	7,829	7,342
Winter	1	8,935	1/12/2015	6,970	6,843	6,840	6,911	7,176	7,766	8,606	8,935	8,711	8,573	8,473	8,353	8,241	8,160	8,025	7,947	8,055	8,510	8,703	8,560	8,282	7,858	7,276	6,732
Winter	1	10,609	1/13/2015	6,381	6,202	6,165	6,258	6,537	7,192	8,262	8,762	8,693	8,827	8,958	9,024	9,108	9,198	9,207	9,361	9,696	10,329	10,609	10,553	10,429	10,051	9,568	9,145
Winter	1	11,537	1/14/2015	8,932	8,907	8,997	9,119	9,416	9,964	10,684	11,273	11,537	11,424	11,187	10,988	10,746	10,574	10,416	10,408	10,591	11,114	11,349	11,198	10,962	10,508	9,899	9,339
Winter	1	10,948	1/15/2015	9,030	8,896	8,847	8,933	9,161	9,731	10,601	10,948	10,808	10,492	10,049	9,630	9,225	9,115	8,996	9,015	9,268	9,795	10,052	10,011	9,804	9,439	8,852	8,282
Winter	1	10,254	1/16/2015	7,929	7,794	7,770	7,852	8,135	8,833	9,877	10,254	9,949	9,337	8,650	8,130	7,663	7,373	7,123	6,990	7,169	7,863	8,526	8,674	8,815	8,817	8,651	8,444
Winter	1	10,012	1/17/2015	8,301	8,336	8,432	8,578	8,783	9,160	9,637	10,010	10,012	9,423	8,727	8,072	7,477	7,038	6,748	6,658	6,900	7,633	8,183	8,244	8,208	8,013	7,694	7,274
Winter	1	7,620	1/18/2015	6,890	6,645	6,546	6,516	6,529	6,620	6,800	7,083	7,402	7,558	7,334	7,012	6,719	6,489	6,295	6,215	6,347	6,934	7,478	7,608	7,620	7,540	7,376	7,105
Winter	1	9,471	1/19/2015	7,017	7,045	7,202	7,408	7,746	8,300	9,042	9,471	9,397	8,757	8,164	7,623	7,209	6,880	6,700	6,567	6,749	7,374	8,046	8,135	8,100	7,888	7,463	7,078
Winter	1	8,933	1/20/2015	6,823	6,754	6,736	6,776	7,039	7,620	8,540	8,933	8,686	8,170	7,686	7,243	6,901	6,703	6,579	6,523	6,635	7,211	7,849	7,886	7,796	7,464	7,030	6,550
Winter	1	8,815	1/21/2015	6,261	6,168	6,143	6,286	6,603	7,329	8,401	8,815	8,529	8,072	7,646	7,230	6,900	6,703	6,559	6,554	6,717	7,317	8,052	8,168	8,182	7,973	7,621	7,286
Winter	1	10,215	1/22/2015	7,124	7,144	7,334	7,590	7,938	8,772	9,891	10,215	9,833	9,142	8,372	7,723	7,236	6,949	6,733	6,730	6,953	7,556	8,255	8,411	8,421	8,276	7,868	7,476
Winter	1	9,436	1/23/2015	7,227	7,193	7,221	7,310	7,469	8,032	8,949	9,241	9,085	8,931	8,834	8,776	8,710	8,718	8,735	8,805	9,001	9,386	9,436	9,153	8,818	8,410	7,878	7,318
Winter	1	8,756	1/24/2015	6,885	6,638	6,488	6,524	6,665	6,946	7,314	7,747	8,161	8,494	8,602	8,512	8,433	8,247	7,976	7,621	7,631	8,028	8,603	8,655	8,756	8,633	8,411	8,108
Winter	1	9,768	1/25/2015	7,913	7,883	7,992	8,166	8,372	8,708	9,198	9,668	9,768	9,037	8,076	7,337	6,912	6,601	6,338	6,291	6,492	7,180	8,000	8,229	8,282	8,115	7,744	7,416
Winter	1	9,387	1/26/2015	7,145	7,071	7,102	7,210	7,506	8,086	9,090	9,387	9,085	8,761	8,459	8,097	7,761	7,593	7,528	7,635	7,958	8,537	8,968	8,978	8,821	8,470	7,972	7,496
Winter	1	10,578	1/27/2015	7,277	7,219	7,336	7,504	7,899	8,662	9,813	10,200	10,091	9,915	9,687	9,429	9,115	8,784	8,528	8,422	8,663	9,303	10,186	10,466	10,578	10,365	9,897	9,494
Winter	1	11,929	1/28/2015	9,308	9,306	9,406	9,538	9,883	10,647	11,704	11,929	11,271	10,662	9,964	9,303	8,747	8,344	8,018	7,901	8,186	8,969	10,078	10,465	10,646	10,542	10,199	9,875
Winter	1	12,626	1/29/2015	9,824	9,907	10,114	10,347	10,708	11,477	12,485	12,626	11,978	10,996	10,012	9,221	8,688	8,411	8,162	8,046	8,337	8,966	9,539	9,603	9,474	9,071	8,498	7,948
Winter	1	9,504	1/30/2015	7,559	7,416	7,347	7,312	7,471	7,942	8,885	9,216	8,970	8,693	8,401	8,169	7,911	7,705	7,486	7,441	7,695	8,403	9,219	9,406	9,504	9,477	9,302	9,063
Winter	1	10,925	1/31/2015	8,952	9,010	9,154	9,351	9,613	10,042	10,510	10,925	10,844	10,306	9,576	8,918	8,242	7,693	7,287	7,143	7,312	7,975	8,885	9,198	9,376	9,346	9,134	8,845
Winter	2	9,135	2/1/2015	8,609	8,434	8,296	8,252	8,247	8,342	8,552	8,868	9,135	8,837	8,301	7,742	7,322	7,116	6,925	6,919	7,128	7,565	7,846	7,632	7,491	7,234	6,891	6,393
Winter	2	9,513	2/2/2015	5,922	5,658	5,558	5,556	5,695	6,232	7,186	7,522	7,366	7,327	7,396	7,358	7,210	7,152	7,139	7,105	7,344	8,051	9,082	9,384	9,513	9,366	9,033	8,707
Winter	2	11,657	2/3/2015	8,589	8,680	8,863	9,139	9,570	10,410	11,416	11,657	11,322	10,584	9,764	9,050	8,465	8,056	7,752	7,634	7,878	8,673	9,772	10,145	10,281	10,109	9,718	9,327
Winter	2	11,696	2/4/2015	9,159	9,169	9,344	9,565	9,897	10,655	11,588	11,696	11,305	10,126	9,095	8,367	7,797	7,520	7,283	7,260	7,485	8,064	8,770	8,796	8,676	8,279	7,690	7,124
Winter	2	10,221	2/5/2015	6,765	6,598	6,568	6,632	6,828	7,517	8,555	8,861	8,703	8,630	8,453	8,187	7,767	7,494	7,301	7,324	7,665	8,488	9,613	10,035	10,221	10,129	9,810	9,494
Winter	2	12,620	2/6/2015	9,423	9,541	9,763	10,045	10,509	11,415	12,424	12,620	12,191	11,201	10,292	9,459	8,847	8,467	8,277	8,322	8,598	9,100	9,683	9,732	9,669	9,504	9,233	8,998
Winter	2	10,559	2/7/2015	8,882	8,876	9,006	9,141	9,381	9,743	10,268	10,559	10,297	9,486	8,634	7,941	7,296	6,850	6,565	6,413	6,490	6,920	7,691	7,823	7,835	7,728	7,474	7,122
Winter	2	7,712	2/8/2015	6,880	6,729	6,680	6,719	6,805	7,011	7,324	7,627	7,712	7,387	6,865	6,388	6,148	5,903	5,722	5,656	5,773	6,121	6,868	7,026	6,954	6,647	6,252	5,816
Winter	2	7,779	2/9/2015	5,516	5,448	5,430	5,544	5,809	6,443	7,485	7,779	7,538	7,239	7,005	6,791	6,610	6,580	6,536	6,573	6,730	7,127	7,621	7,586	7,382	6,995	6,543	6,072
Winter	2	10,271	2/10/2015	5,825	5,727	5,788	6,009	6,348	7,166	8,417	8,995	9,070	9,213	9,376	9,349	9,317	9,315	9,263	9,286	9,393	9,767	10,266	10,271	10,085	9,696	9,119	8,627
Winter	2	10,891	2/11/2015	8,397	8,369	8,451	8,579	8,916	9,589	10,667	10,891	10,473	9,945	9,357	8,719	8,189	7,748	7,379	7,176	7,256	7,784	8,803	9,167	9,335	9,249	8,960	8,591
Winter	2	10,757	2/12/2015	8,354	8,415	8,482	8,625	8,959	9,683	10,695	10,757	9,941	8,887	8,109	7,575	7,197	7,053	7,058	7,242	7,733	8,389	9,278	9,709	9,915	9,866	9,577	9,328
Winter	2	12,006	2/13/2015	9,208	9,332	9,505	9,788	10,192	10,946	11,863	12,006	11,580	11,202	10,586	10,012	9,526	9,170	8,866	8,663	8,755	9,363	10,317	10,684	10,844	10,875	10,723	10,522
Winter	2	11,849	2/14/2015	10,463	10,546	10,692	10,844	11,032	11,361	11,739	11,849	11,331	10,372	9,541	8,752	8,121	7,578	7,219	7,055	7,181	7,680	8,376	8,432	8,291	8,147	8,014	7,992
Winter	2	12,693	2/15/2015	8,203	8,734	9,422	10,037	10,682	11,324	12,049	12,565	12,693	12,470	11,872	11,199	10,678	10,126	9,687	9,490	9,650	10,344	11,399	11,640	11,674	11,561	11,377	11,089
Winter	2	12,451	2/16/2015	10,976	10,902	10,938	10,960	11,117	11,604	12,248	12,383	12,451	12,352	12,049	11,599	11,114	10,849	10,780	10,857	11,222	11,821	12,164	11,983	11,630	11,134	10,746	10,360
Winter	2	11,788	2/17/2015	10,170	10,119	10,101	10,021	10,165	10,537	11,001	11,369	11,615	11,788	11,663	11,358	11,031	10,588	10,306	10,266	10,473	10,984	11,572	11,502	11,323	10,997	10,602	10,277
Winter	2	12,653	2/18/2015	10,203	10,319	10,560	10,785	11,029	11,519	12,263	12,653	12,383	11,535	10,774	10,160	9,741	9,458	9,221	9,203	9,359	9,976	10,801	10,959	11,100	10,914	10,609	10,413
Winter	2	13,704	2/19/2015	10,533	10,816	11,054	11,454	11,950	12,572	13,373	13,704	13,601	13,402	12,905	12,389	11,919	11,506	11,208	11,131	11,411	12,247	13,459	13,563	13,616	13,671	13,586	13,410
Winter	2	15,569	2/20/2015	13,325	13,606	13,863	14,071	14,454	14,950	15,441	15,569	15,181	14,686	13,806	12,922	12,118	11,459	10,848	10,509	10,533	11,121	12,239	12,550	12,638	12,690	12,501	12,283
Winter	2	12,517	2/21/2015	12,111	12,109	12,060	12,127	12,167	12,330	12,517	12,517	12,261	11,803	11,154	10,483	9,862	9,249	8,843	8,615	8,621	8,753	9,113	9,009	8,767	8,420	7,924	7,430
Winter	2	7,889	2/22/2015	7,038	6,866	6,802	6,786	6,850	7,011	7,320	7,553	7,889	7,802	7,524	7,112	6,865	6,697	6,546	6,488	6,557	6,968	7,543	7,698	7,597	7,240	6,810	6,355
Winter	2	10,525	2/23/2015	6,046	5,927	5,890	5,984	6,265	6,886	7,954	8,374	8,471	8,624	8,827	8,979	9,042	9,073	9,039	9,124	9,334	9,717	10,362	10,525	10,504	10,268	9,901	9,490
Winter	2	12,556	2/24/2015	9,294	9,321	9,393	9,569	9,909	10,642	11,607	12,040	12,292	12,491	12,556	12,549	12,476	12,281	12,134	11,993	11,977	12,229	12,549	12,450	12,150	11,622	11,139	10,763
Winter	2	12,266	2/25/2015	10,564	10,565	10,615	10,707	10,897	11,300	11,900	12,266	12,087	11,409	10,637	10,046	9,525	9,178	8,874	8,876	9,368	9,752	10,367	10,362	10,463	10,277	9,918	9,594
Winter	2	11,078	2/26/2015	9,452	9,390	9,293	9,275	9,280	9,553	10,196	10,626	10,809	10,817	10,741	10,566	10,377	10,230	10,066	10,056	10,183	10,486	11,050	11,078	10,921	10,594	10,062	9,680
Winter	2	11,946	2/27/2015	9,504	9,476	9,549	9,738	10,077	10,729	11,626	11,946	11,435	10,465	9,576	8,909	8,349	7,976	7,675	7,496	7,587	8,031	8,939	9,381	9,575	9,623	9,450	9,173
Winter	2	11,156	2/28/2015	9,058	9,126	9,290	9,519	9,820	10,269	10,784	11,112	11,156	10,842	10,258	9,674	9,057	8,579	8,197	8,012	8,156	8,684	9,513	9,833	9,912	9,808	9,501	9,155
Spring	3	10,149	3/1/2015	8,827	8,636	8,627	8,624	8,761	9,015	9,393	9,781	10,116	10,149	9,995	9,655	9,477	9,317	9,129	9,017	9,074	9,292	9,741	9,829	9,638	9,237	8,710	8,183
Spring	3	9,468	3/2/2015	7,854	7,652	7,621	7,661	7,869	8,433	9,356	9,468	9,186	8,848	8,399	7,853	7,379	6,978	6,772	6,600	6,672	6,926	7,769	8,187	8,204	8,016	7,640	7,260
Spring	3	9,822	3/3/2015	7,011	6,953	7,030	7,172	7,470	8,158	9,214	9,531	9,421	9,351	9,281	9,138	9,000	8,922	8,831	8,859	9,070	9,352	9,810	9,822	9,606	9,126	8,470	7,804

Contains Proprietary Material
Do Not Distribute

Spring	4	7,123	4/6/2015	4,844	4,695	4,636	4,706	4,843	5,372	6,005	6,357	6,415	6,358	6,346	6,363	6,312	6,363	6,412	6,461	6,537	6,617	6,655	6,825	7,123	6,765	6,160	5,594
Spring	4	7,309	4/7/2015	5,131	4,862	4,738	4,683	4,759	5,114	5,834	6,155	6,257	6,394	6,512	6,631	6,668	6,696	6,716	6,733	6,770	6,804	6,863	7,017	7,309	6,967	6,402	5,767
Spring	4	8,063	4/8/2015	5,269	5,049	4,885	4,781	4,855	5,204	5,884	6,181	6,325	6,522	6,680	6,931	7,181	7,442	7,664	7,843	8,003	8,051	8,019	7,990	8,063	7,640	6,898	6,145
Spring	4	7,878	4/9/2015	5,572	5,231	4,985	4,927	4,989	5,309	5,899	6,200	6,374	6,540	6,702	6,827	7,026	7,270	7,526	7,759	7,878	7,849	7,784	7,785	7,829	7,388	6,754	6,090
Spring	4	8,091	4/10/2015	5,576	5,286	5,120	5,011	5,063	5,391	5,995	6,286	6,554	6,805	7,094	7,378	7,616	7,783	7,914	8,091	7,955	7,931	7,849	7,702	7,868	7,520	6,953	6,297
Spring	4	6,945	4/11/2015	5,790	5,437	5,234	5,054	4,995	5,044	5,219	5,357	5,721	6,023	6,168	6,270	6,299	6,381	6,527	6,708	6,885	6,945	6,903	6,563	6,775	6,438	5,967	5,432
Spring	4	6,755	4/12/2015	4,981	4,696	4,547	4,471	4,469	4,569	4,747	4,992	5,437	5,663	5,642	5,622	5,721	5,794	5,860	5,935	6,041	6,148	6,180	6,381	6,755	6,445	5,886	5,299
Spring	4	7,600	4/13/2015	4,871	4,659	4,550	4,550	4,696	5,191	6,010	6,266	6,264	6,294	6,457	6,556	6,659	6,809	6,920	6,991	7,123	7,156	7,176	7,304	7,600	7,219	6,561	5,875
Spring	4	7,966	4/14/2015	5,379	5,092	4,935	4,870	4,955	5,364	6,211	6,505	6,574	6,718	6,896	7,082	7,213	7,386	7,506	7,607	7,700	7,710	7,723	7,740	7,966	7,590	6,864	6,109
Spring	4	7,064	4/15/2015	5,590	5,279	5,121	5,079	5,059	5,333	6,183	6,394	6,415	6,405	6,459	6,451	6,396	6,441	6,376	6,295	6,416	6,534	6,697	6,860	7,064	6,723	6,200	5,618
Spring	4	7,124	4/16/2015	5,229	5,034	4,956	4,955	5,081	5,546	6,459	6,742	6,665	6,687	6,711	6,614	6,562	6,508	6,449	6,414	6,465	6,524	6,642	6,826	7,124	6,810	6,236	5,581
Spring	4	7,099	4/17/2015	5,175	4,984	4,871	4,821	4,903	5,276	6,123	6,398	6,437	6,478	6,515	6,551	6,559	6,606	6,647	6,700	6,836	6,884	6,837	6,850	7,099	6,873	6,410	5,848
Spring	4	7,064	4/18/2015	5,340	4,992	4,840	4,706	4,705	4,826	5,048	5,263	5,656	6,025	6,282	6,481	6,614	6,771	6,904	7,016	7,056	7,064	6,960	6,851	7,053	6,773	6,330	5,755
Spring	4	6,907	4/19/2015	5,291	4,995	4,763	4,650	4,597	4,650	4,770	4,981	5,471	5,872	6,098	6,241	6,338	6,402	6,343	6,294	6,317	6,416	6,559	6,751	6,907	6,616	6,128	5,600
Spring	4	7,757	4/20/2015	5,165	4,919	4,807	4,757	4,832	5,234	6,077	6,414	6,488	6,643	6,917	7,130	7,381	7,648	7,757	7,620	7,613	7,532	7,516	7,579	7,736	7,388	6,720	6,039
Spring	4	7,323	4/21/2015	5,496	5,195	5,022	4,929	4,985	5,370	6,085	6,316	6,373	6,436	6,526	6,586	6,621	6,803	6,856	7,001	7,116	7,146	7,097	6,991	7,323	6,994	6,336	5,638
Spring	4	7,329	4/22/2015	5,192	4,951	4,812	4,776	4,907	5,377	6,240	6,493	6,438	6,400	6,440	6,509	6,453	6,562	6,670	6,850	6,983	7,065	7,062	7,021	7,329	7,065	6,409	5,705
Spring	4	6,997	4/23/2015	5,215	4,954	4,821	4,783	4,877	5,284	6,073	6,321	6,345	6,353	6,352	6,349	6,349	6,412	6,470	6,538	6,655	6,639	6,611	6,618	6,997	6,800	6,207	5,571
Spring	4	6,677	4/24/2015	5,199	4,992	4,902	4,887	5,017	5,542	6,380	6,677	6,567	6,445	6,373	6,271	6,205	6,161	6,099	6,102	6,180	6,224	6,166	6,137	6,474	6,331	5,930	5,510
Spring	4	6,416	4/25/2015	5,112	4,900	4,812	4,757	4,780	4,945	5,189	5,439	5,857	6,098	6,245	6,229	6,201	6,115	6,013	5,994	6,036	6,104	6,148	6,222	6,416	6,222	5,860	5,420
Spring	4	6,685	4/26/2015	5,017	4,849	4,720	4,671	4,641	4,729	4,922	5,224	5,715	6,046	6,129	6,075	6,098	6,070	5,973	5,913	5,943	6,065	6,125	6,314	6,685	6,486	6,014	5,528
Spring	4	6,983	4/27/2015	5,169	5,025	4,969	5,022	5,248	5,821	6,713	6,983	6,755	6,518	6,405	6,316	6,268	6,246	6,223	6,247	6,317	6,365	6,386	6,502	6,906	6,699	6,087	5,529
Spring	4	7,025	4/28/2015	5,122	4,942	4,917	4,975	5,203	5,809	6,735	7,025	6,763	6,554	6,382	6,279	6,188	6,186	6,154	6,167	6,275	6,352	6,430	6,505	6,871	6,677	6,071	5,456
Spring	4	6,854	4/29/2015	5,083	4,904	4,839	4,844	5,007	5,532	6,391	6,644	6,511	6,433	6,374	6,349	6,268	6,295	6,301	6,308	6,376	6,452	6,546	6,591	6,854	6,643	6,084	5,500
Spring	4	6,838	4/30/2015	5,061	4,875	4,789	4,781	4,892	5,376	6,206	6,483	6,392	6,324	6,289	6,201	6,127	6,169	6,139	6,150	6,236	6,316	6,443	6,550	6,838	6,609	6,081	5,480
Spring	5	6,480	5/1/2015	5,099	4,892	4,785	4,773	4,893	5,323	6,120	6,424	6,430	6,458	6,480	6,448	6,359	6,302	6,206	6,116	6,095	6,083	6,059	6,106	6,480	6,448	6,126	5,694
Spring	5	6,190	5/2/2015	5,326	5,108	5,024	4,991	5,070	5,274	5,503	5,771	5,951	5,980	5,892	5,812	5,758	5,741	5,725	5,754	5,839	5,942	5,918	5,906	6,190	6,071	5,666	5,211
Spring	5	6,805	5/3/2015	4,779	4,611	4,490	4,437	4,486	4,623	4,755	5,095	5,494	5,645	5,653	5,675	5,805	5,958	6,055	6,220	6,373	6,570	6,624	6,561	6,805	6,594	6,010	5,353
Spring	5	7,741	5/4/2015	4,867	4,607	4,484	4,456	4,573	5,063	5,808	6,117	6,231	6,330	6,530	6,720	6,901	7,169	7,347	7,513	7,673	7,741	7,728	7,570	7,721	7,460	6,711	5,868
Spring	5	8,154	5/5/2015	5,327	4,992	4,803	4,710	4,753	5,170	5,878	6,188	6,292	6,437	6,659	6,873	7,099	7,424	7,685	7,943	8,131	8,154	8,048	7,779	7,830	7,513	6,728	5,906
Spring	5	8,009	5/6/2015	5,312	4,985	4,806	4,720	4,792	5,184	5,878	6,190	6,265	6,495	6,644	6,850	7,098	7,380	7,643	7,853	7,996	8,009	7,887	7,670	7,748	7,428	6,689	5,937
Spring	5	7,944	5/7/2015	5,380	5,073	4,866	4,774	4,870	5,281	6,015	6,309	6,427	6,613	6,807	6,951	7,177	7,380	7,564	7,751	7,942	7,944	7,861	7,678	7,837	7,620	6,894	6,112
Spring	5	7,856	5/8/2015	5,511	5,142	4,938	4,859	4,904	5,248	5,915	6,290	6,487	6,766	7,054	7,274	7,439	7,616	7,705	7,769	7,856	7,835	7,689	7,455	7,525	7,361	6,871	6,229
Spring	5	7,640	5/9/2015	5,665	5,315	5,085	4,950	4,927	5,027	5,141	5,447	5,982	6,426	6,769	7,077	7,274	7,457	7,548	7,602	7,640	7,590	7,403	7,244	7,321	7,222	6,780	6,215
Spring	5	7,257	5/10/2015	5,700	5,351	5,144	5,004	4,954	4,998	5,059	5,416	6,000	6,417	6,625	6,640	6,734	6,755	6,777	6,805	6,856	6,898	6,934	6,978	7,257	7,140	6,649	6,020
Spring	5	9,573	5/11/2015	5,546	5,254	5,123	5,057	5,148	5,576	6,322	6,671	6,864	7,095	7,470	7,836	8,224	8,660	8,980	9,302	9,518	9,573	9,469	9,101	9,029	8,543	7,668	6,818
Spring	5	10,048	5/12/2015	6,204	5,863	5,616	5,489	5,532	5,943	6,627	7,031	7,340	7,786	8,325	8,856	9,346	9,785	9,881	10,040	10,048	10,007	9,879	9,574	9,516	9,067	8,098	7,168
Spring	5	8,971	5/13/2015	6,452	6,027	5,653	5,530	5,490	5,822	6,387	6,662	6,780	6,994	7,282	7,557	7,817	8,184	8,457	8,739	8,950	8,971	8,814	8,366	8,163	7,773	6,944	6,106
Spring	5	7,556	5/14/2015	5,498	5,182	4,965	4,873	4,942	5,255	5,885	6,160	6,257	6,379	6,497	6,632	6,773	7,009	7,177	7,366	7,556	7,556	7,419	7,224	7,407	7,209	6,545	5,798
Spring	5	7,571	5/15/2015	5,269	4,988	4,850	4,796	4,850	5,170	5,805	6,120	6,230	6,358	6,536	6,695	6,833	7,037	7,198	7,341	7,523	7,571	7,462	7,215	7,207	7,076	6,564	5,936
Spring	5	8,421	5/16/2015	5,384	5,068	4,840	4,700	4,685	4,802	4,849	5,143	5,672	6,146	6,520	6,879	7,287	7,647	7,963	8,244	8,409	8,421	8,196	7,854	7,777	7,502	6,927	6,213
Spring	5	9,132	5/17/2015	5,624	5,202	4,902	4,801	4,687	4,716	4,684	5,007	5,601	6,214	6,686	7,163	7,656	8,107	8,484	8,793	9,039	9,132	9,047	8,706	8,587	8,296	7,476	6,652
Spring	5	10,530	5/18/2015	6,030	5,580	5,404	5,276	5,329	5,717	6,391	6,823	7,176	7,622	8,255	8,912	9,450	9,911	10,112	10,352	10,506	10,530	10,381	10,151	9,982	9,441	8,464	7,491
Spring	5	10,287	5/19/2015	6,742	6,283	5,984	5,766	5,760	6,076	6,744	7,212	7,525	7,956	8,478	9,056	9,284	10,087	10,287	10,247	10,242	10,079	9,840	9,514	9,274	8,922	8,047	7,138
Spring	5	10,216	5/20/2015	6,452	6,037	5,741	5,567	5,549	5,852	6,414	6,934	7,279	7,715	8,250	8,695	9,174	9,614	9,953	10,125	10,216	10,197	10,063	9,672	9,375	8,953	8,010	7,112
Spring	5	8,927	5/21/2015	6,405	5,979	5,750	5,602	5,612	5,904	6,535	6,900	7,114	7,403	7,817	8,197	8,594	8,927	8,923	8,751	8,592	8,429	8,166	7,855	7,794	7,590	6,862	6,103
Spring	5	7,520	5/22/2015	5,550	5,218	5,013	4,897	4,924	5,268	5,793	6,097	6,236	6,397	6,531	6,684	6,784	6,961	7,118	7,283	7,446	7,520	7,362	7,055	6,902	6,757	6,282	5,658
Spring	5	7,531	5/23/2015	5,150	4,799	4,594	4,471	4,496	4,597	4,656	4,972	5,405	5,735	5,942	6,147	6,347	6,557	6,811	7,066	7,373	7,531	7,470	7,135	6,942	6,793	6,281	5,687
Spring	5	7,952	5/24/2015	5,167	4,852	4,630	4,512	4,453	4,488	4,462	4,787	5,322	5,818	6,180	6,498	6,794	7,095	7,362	7,613	7,837	7,952	7,823	7,453	7,220	7,074	6,525	5,862
Spring	5	8,878	5/25/2015	5,355	4,969	4,728	4,564	4,545	4,614	4,655	4,953	5,512	6,161	6,689	7,112	7,467	7,832	8,185	8,480	8,702	8,878	8,760	8,425	8,233	7,978	7,223	6,353
Spring	5	10,180	5/26/2015	5,727	5,343	5,097	4,969	5,016	5,335	5,939	6,557	6,946	7,397	7,908	8,416	8,986	9,491	9,842	10,141	10,180	10,130	10,077	9,717	9,595	9,177	8,281	7,398
Spring	5	10,141	5/27/2015	6,682	6,247	5,915	5,808	5,777	6,135	6,781	7,237	7,614	7,979	8,480	8,999	9,380	9,789	10,060	10,141	10,096	10,050	9,778	9,265	9,037	8,752	7,898	7,017
Spring	5	10,125	5/28/2015	6,323	5,914	5,650	5,474	5,484	5,802	6,427	6,920	7,253	7,636	8,095	8,585	9,042	9,537	9,908	10,125	10,112	10,073	9,955	9,562	9,309	8,926	8,037	7,110
Spring	5	10,139	5/29/2015	6,350	5,871	5,591	5,386	5,413	5,722	6,247	6,719	7,197	7,696	8,249	8,717	9,190	9,584	9,929	10,139	10,119	10,038	9,871	9,339	8,952	8,681	7,946	7,185
Spring	5	9,873	5/30/2015	6,470	5,979	5,619	5,389	5,309	5,356	5,385	5,834	6,549	7,286	7,857	8,402	8,826	9,133	9,401	9,661	9,871	9,873	9,676	9,197	8,811	8,545	7,868	7,070
Spring	5	10,103	5/31/2015	6,340	5,880	5,494	5,287	5,165	5,145	5,079	5,529	6,338	7,139	7,729	8,290	8,766	9,283	9,588	9,821	10,031	10,103	9,984	9,559	9,242	8,931	8,113	7,230
Summer	6	10,940	6/1/2015	6,539	6,067	5,787	5,645	5,676	6,000	6,604	7,233	7,748	8,325	8,988	9,602	10,158	10,657	10,881	10,940	10,877	10,657	10,236	9,671	9,408	8,974	8,137	7,266
Summer	6	9,254	6/2/2015	6,577	6,120	5,837	5,687	5,693	6,006	6,602	7,110	7,419	7,793	8,175	8,445	8,664	8,868	9,070	9,254	9,246	9,046	8,804	8,556	8,484	8,156	7,409	6,601
Summer	6	7,677	6/3/2015	6,085	5,782	5,487	5,400	5,398	5,732	6,400	6,683	6,793	6,947	7,068	7,201	7,260	7,366	7,429	7,481	7,621	7,677	7,632	7,571	7,596	7,457	6,923	6,225
Summer	6	8,045	6/4/2015	5,706	5,407	5,237	5,125	5,199	5,569	6,183	6,527	6,688	6,903	7,107	7,297	7,473	7,668	7,813	7,912	8,045	8,009	7,915	7,746	7,743	7,643	7,044	6,314
Summer	6	8,233	6/5/2015	5,769	5,412	5,208	5,134	5,174	5,510	6,055	6,406	6,595	6,788	6,978	7,252	7,435	7,694	7,888	8,054	8,232	8,233	8,088	7,810	7,687	7,606	7,040	6,373
Summer	6	9,680	6/6/2015	5,788	5,409	5,174	4,996	4,949	5,003	5,044	5,416	6,090	6,772	7,448	8,028	8,548	8,939	9,257	9,494	9,653	9,680	9,444	8,975	8,524	8,353	7,677	6,930
Summer	6	9,377	6/7/2015	6,195	5,723	5,435	5,214	5,087	5,063	5,005	5,405	6,064	6,734	7,128	7,578	8,045	8,467	8,806	9,064	9,279	9,377	9,234	8,853	8,548	8,333	7,581	6,737
Summer	6	10,683	6/8/2015	6,093	5,645	5,353	5,196	5,236	5,538	6,104	6,618	7,092	7,617	8,237	8,820	9,343	9,860	10,202	10,456	10,680	10,683	10,484	10,084	9,797	9,474	8,647	7,733
Summer	6	10,451	6/9/2015	7,021	6,599	6,308	6,115	6,087	6,336	6,795	7,309	7,696	8,151	8,637	9,152	9,570	10,006	10,220	10,408	10,451	10,325	10,004	9,559	9,241	8,866	8,092	7,217
Summer	6	10,941	6/10/2015	6,550	6,092	5,865	5,674	5,673	5,951	6,452	6,949	7,293	7,744	8,308	8,948	9,590	10,161	10,612	10,858	10,941	10,874	10,634	10,214	9,886	9,590	8,747	7,795
Summer	6	11,479	6/11/2015	7,110	6,619	6,304	6,062	6,050	6,341	6,799	7,414	8,073	8,772	9,542	10,197	10,735	11,167	11,438	11,428	11,479	11,419	11,298	10,920	10,511	10,198	9,309	8,386
Summer	6	11,092	6/12/2015	7,596	7,022	6,635	6,382	6,299	6,511	6,874	7,538	8,246	8,940	9,646	10,246	10,706	10,945	11,052	11,092	11,068	11,006	10,845	10,413	10,034	9,812	9,096	8,279
Summer	6	11,380	6/13/2015	7,541	7,047	6,696	6,423	6,273	6,259	6,258	6,812	7,710	8,641	9,491	10,186	10,724	11,104	11,325	11,296	11,380	11,359	11,245	10,891	10,454	10,165	9,384	8,520
Summer	6	11,650	6/14/2015	7,730	7,185	6,766	6,450	6,249	6,181	6,095	6,640	7,651	8,684	9,521	10,245	10,806	11,191	11,364	11,498	11,629	11,650	11,552	11,263	10,819	10,470	9,603	8,693
Summer	6	12,722	6/15/2015	7,867	7,317	6,925	6,650	6,603	6,827	7,175	7,960	8,782	9,787	10,791	11,590	12,063	12,409	12,665	12,722	12,651	12,594	12,616	12,420	11,964	11,486	10,414	9,339
Summer	6	12,849	6/16/2015	8,498	7,813	7,478	7,120	7,015	7,157	7,445	8,155	8,941	9,927	10,942	11,713	12,283	12,658	12,816	12,849	12,823	12,766	12,815	12,639	12,174	11,705	10,710	9,670
Summer	6	12,723	6/17/2015	8,853	8,213	7,710	7,372	7,236	7,370	7,664	8,367	9,116	9,917	10,735	11,475	12,042	12,513	12,635	12,723	12,704	12,683	12,549	12,157	11,699	11,273	10,315	9,197
Summer	6	12,639	6/18/2015	8,386	7,827	7,435	7,180	7,107	7,289	7,563	8,071	8,621	9,401	10,262	11,075	11,849	12,416	12,639	12,416	12,280	12,088	11,715	11,195	10,627	10,039	9,163	8,287
Summer	6	12,367	6/19/2015	7,594	7,118	6,785	6,574	6,538	6,759	7,072	7,583	8,217	8,940	9,692	10,464	11,095	11,711	12,116	12,338	12,367	12,107	11,544	10,785	10,233	9,751	9,001	8,080
Summer	6	11,710	6/20/2015	7,320	6,840	6,445	6,205	6,111	6,091	6,111	6,510	7,326	8,329	9,258	10,068	10,759	11,214	11,535	11,710	11,667	11,657	11,465	11,040	10,622	10,299	9,640	8,887
Summer	6	12,095	6/21/2015	8,184	7,608	7,205	6,939	6,795	6,684	6,582	7,135	8,128	9,036	9,706	10,252	10,762	11,160	11,512	11,789	12,015	12,095	11,932	11,526	11,065	10,734	9,897	8,925
Summer	6	12,672	6/22/2015	8,139	7,534	7,180	6,888	6,794	6,951	7,207	7,932	8,722	9,589	10,490	11,252	11,854	12,327	12,672	12,548	12,671	12,588	12,452	12,101	11,654	11,262	10,314	9,329
Summer	6	12,773	6/23/2015	8,540	8,018	7,686	7,388	7,345	7,516	7,787	8,443	9,187	9,948	10,833	11,576	12,176	12,562	12,733	12,577	12,773	12,752	12,670	12,320	11,952	11,625	10,766	9,797
Summer	6	12,719	6/24/2015	9,002	8,464	8,058	7,823	7,680	7,813	8,117	8,688	9,314	10,058	10,879	11,555	11,909	12,472	12,652	12,617	12,719	12,652	12,474	12,072	11,428	11,006	9,999	8,946
Summer	6	12,349	6/25/2015	8,122	7,537	7,167	6,895	6,775	6,929	7,212	7,671	8,111	8,679	9,350	10,027	10,587	11,318	11,805	12,143	12,349	12,341	12,083	11,669	11,235	10,731	9,870	8,941
Summer	6	12,571	6/26/2015	8,194	7,730	7,417	7,163	7,109	7,302	7,593	8,022	8,696	9,470	10,361	11,069	11,623	12,065	12,411	12,571	12,465	12,101	11,560	10,895	10,460	10,008	9,221	8,337
Summer	6	9,836	6/27/2015	7,622	7,080	6,677	6,406	6,268	6,258	6,223	6,577	7,206	7,988	8,669	9,192	9,637	9,800	9,836	9,620	9,628	9,703	9,521	9,187	8,836	8,581	8,047	7,394
Summer	6	9,747	6/28/2015	6,789	6,380	6,167	6,011	5,957	5,958	5,896	6,170	6,802	7,408	7,743	8,106	8,459	8,767	9,101	9,395	9,641	9,747	9,586	9,194	8,709	8,469	7,800	6,943
Summer	6	10,775	6/29/2015	6,259	5,808	5,509	5,373	5,361	5,628	5,919	6,436	7,006	7,618	8,263	8,928	9,462	9,954	10,309	10,580	10,744	10,775	10,609	10,152	9,713	9,391	8,509	7,579
Summer	6	11,757	6/30/2015	6,865	6,308	5,995	5,822	5,792	5,995	6,312	6,917	7,485	8,166	8,927	9,703	10,382	10,975	11,386	11,649	11,757	11,552	11,032	10,417	9,789	9,295	8,478	7,593
Summer	7	10,784	7/1/2015	6,846	6,365	6,064	5,919	5,887	6,131	6,483	6,915	7,317	7,755	8,284	8,880	9,439	9,974	10,388	10,661	10,784	10,727	10,435	9,978	9,717	9,410	8,658	7,795
Summer	7	10,724	7/2/2015	7,115	6,679	6,427	6,274	6,270	6,492	6,811	7,241	7,664	8,147	8,703	9,271	9,753	10,219	10,538	10,667	10,724	10,593	10,066	9,492	9,159	8,883	8,220	7,435
Summer	7	8,793	7/3/2015	6,744	6,263	5,945	5,758	5,713	5,817	5,915	6,197	6,686	7,123	7,512	7,810	8,137	8,401	8,564	8,688	8,776	8,793	8,587	8,302	8,105	8,028	7,591	7,016
Summer	7	9,707	7/4/2015	6,495	6,095	5,821	5,616	5,550	5,543	5,491	5,849	6,587	7,401	8,092	8,646	8,992	9,209	9,250	9,380	9,622	9,707	9,444	8,959	8,583	8,264	7,952	7,471
Summer	7	10,537	7/5/2015	6,839	6,354	6,027	5,792	5,670	5,651	5,501	5,839	6,631	7,454	8,231	8,878	9,521	10,028	10,317	10,482	10,537	10,461	10,115	9,608	9,266	8,962	8,238	7,490
Summer	7	11,515	7/6/2015	6,822	6,373	6,112	5,945	5,966	6,249	6,571	7,078	7,714	8,406	9,147	9,779	10,292	10,755	11,104	11,390	11,515	11,479	11,169	10,649	10,195	9,812	8,993	8,047
Summer	7	11,897	7/7/2015	7,256	6,739	6,412	6,205	6,194	6,443	6,778	7,357	8,011	8,793	9,598	10,343	10,985	11,450	11,612	11,842	11,897	11,845	11,762	11,288	10,894	10,486	9,595	8,651
Summer	7	11,786	7/8/2015	7,862	7,324	6,970	6,715	6,670	6,862	7,210	7,703	8,257	8,924

Contains Proprietary Material
Do Not Distribute

Summer	8	11,150	8/12/2015	6,754	6,305	6,028	5,902	5,895	6,196	6,644	7,007	7,544	8,140	8,778	9,383	9,917	10,418	10,751	11,025	11,150	11,117	10,845	10,251	9,851	9,251	8,309	7,418
Summer	8	10,985	8/13/2015	6,672	6,163	5,884	5,715	5,689	5,933	6,376	6,730	7,263	7,883	8,622	9,294	9,843	10,307	10,671	10,892	10,985	10,856	10,536	10,028	9,768	9,258	8,366	7,515
Summer	8	10,927	8/14/2015	6,799	6,330	6,029	5,842	5,809	6,044	6,457	6,821	7,356	8,054	8,740	9,419	9,942	10,360	10,733	10,867	10,927	10,826	10,468	9,863	9,512	9,007	8,239	7,416
Summer	8	10,663	8/15/2015	6,704	6,209	5,899	5,657	5,568	5,571	5,667	5,889	6,565	7,349	8,149	8,878	9,469	9,874	10,204	10,444	10,629	10,663	10,370	9,794	9,473	8,919	8,247	7,426
Summer	8	10,830	8/16/2015	6,720	6,234	5,888	5,643	5,532	5,510	5,505	5,763	6,538	7,389	8,125	8,811	9,506	10,029	10,414	10,647	10,825	10,830	10,566	10,082	9,865	9,368	8,527	7,677
Summer	8	11,966	8/17/2015	7,017	6,569	6,258	6,073	6,064	6,365	6,849	7,190	7,727	8,445	9,304	10,130	10,868	11,460	11,806	11,966	11,956	11,780	11,393	10,919	10,707	10,086	9,173	8,220
Summer	8	10,010	8/18/2015	7,512	7,059	6,720	6,534	6,526	6,806	7,386	7,638	8,005	8,383	8,874	9,266	9,553	9,786	9,970	10,010	9,926	9,778	9,570	9,291	9,314	8,887	8,020	7,371
Summer	8	11,148	8/19/2015	6,824	6,446	6,273	6,171	6,245	6,550	7,132	7,476	7,838	8,278	8,830	9,372	9,873	10,359	10,707	10,970	11,148	11,144	10,877	10,460	10,188	9,541	8,672	7,881
Summer	8	11,725	8/20/2015	7,299	6,877	6,614	6,451	6,426	6,730	7,326	7,702	8,101	8,576	9,137	9,673	10,119	10,607	11,099	11,468	11,725	11,657	11,316	10,844	10,606	9,979	9,109	8,208
Summer	8	11,416	8/21/2015	7,525	7,062	6,727	6,536	6,487	6,773	7,299	7,589	8,131	8,779	9,498	10,123	10,616	11,021	11,317	11,416	11,397	11,196	10,795	10,216	9,882	9,369	8,595	7,816
Summer	8	10,346	8/22/2015	7,108	6,587	6,193	5,940	5,830	5,882	5,920	6,126	6,750	7,487	8,206	8,799	9,275	9,669	9,992	10,227	10,346	10,321	9,998	9,424	9,155	8,578	7,829	7,093
Summer	8	10,185	8/23/2015	6,406	5,945	5,640	5,352	5,247	5,274	5,304	5,502	6,177	6,899	7,474	7,988	8,572	9,145	9,577	9,863	10,080	10,185	10,037	9,650	9,561	8,959	8,083	7,289
Summer	8	11,309	8/24/2015	6,675	6,291	6,148	6,188	6,243	6,467	7,156	7,392	7,720	8,399	9,216	9,959	10,596	11,147	11,309	11,140	10,979	10,799	10,644	10,295	10,213	9,593	8,625	7,723
Summer	8	11,411	8/25/2015	7,051	6,635	6,345	6,221	6,252	6,645	7,391	7,629	7,882	8,390	8,951	9,592	10,178	10,727	10,895	11,222	11,411	11,320	11,038	10,598	10,465	9,763	8,815	7,913
Summer	8	10,440	8/26/2015	7,244	6,800	6,521	6,305	6,274	6,605	7,309	7,474	7,633	7,992	8,372	8,690	9,018	9,477	9,868	10,212	10,440	10,369	10,084	9,700	9,606	9,010	8,096	7,276
Summer	8	9,506	8/27/2015	6,676	6,265	6,024	5,896	5,924	6,330	7,107	7,254	7,410	7,636	7,986	8,377	8,761	9,131	9,358	9,423	9,506	9,461	9,239	8,969	8,995	8,506	7,644	6,842
Summer	8	10,035	8/28/2015	6,216	5,853	5,600	5,469	5,501	5,835	6,513	6,708	7,031	7,493	7,970	8,410	8,840	9,287	9,644	9,902	10,035	9,918	9,541	8,961	8,745	8,204	7,528	6,806
Summer	8	9,399	8/29/2015	6,148	5,712	5,457	5,277	5,227	5,284	5,385	5,546	6,127	6,706	7,274	7,853	8,333	8,704	8,995	9,225	9,399	9,382	9,073	8,668	8,533	8,096	7,454	6,768
Summer	8	8,824	8/30/2015	6,174	5,763	5,474	5,322	5,217	5,217	5,255	5,488	6,113	6,687	7,139	7,598	8,119	8,544	8,742	8,824	8,747	8,617	8,459	8,400	8,467	8,037	7,342	6,648
Summer	8	9,161	8/31/2015	6,179	5,848	5,690	5,649	5,736	6,192	7,022	7,286	7,440	7,618	7,775	8,015	8,152	8,371	8,576	8,729	8,993	9,125	9,161	9,059	9,117	8,597	7,814	7,011
Fall	9	11,116	9/1/2015	6,441	6,080	5,875	5,789	5,842	6,248	7,071	7,249	7,523	7,968	8,565	9,267	9,853	10,432	10,840	11,027	11,116	11,106	10,999	10,621	10,455	9,642	8,632	7,700
Fall	9	11,855	9/2/2015	6,980	6,567	6,253	6,078	6,043	6,397	7,115	7,344	7,732	8,368	9,172	10,019	10,594	11,210	11,534	11,738	11,855	11,751	11,643	11,237	10,956	10,162	9,105	8,114
Fall	9	11,539	9/3/2015	7,416	6,924	6,580	6,355	6,339	6,661	7,360	7,557	7,866	8,355	8,985	9,578	10,227	10,811	11,230	11,453	11,539	11,364	11,000	10,617	10,432	9,663	8,681	7,782
Fall	9	11,507	9/4/2015	7,072	6,598	6,289	6,108	6,049	6,398	7,079	7,311	7,736	8,424	9,232	10,074	10,759	11,277	11,507	11,414	11,174	10,743	10,182	9,736	9,469	8,881	8,193	7,423
Fall	9	9,745	9/5/2015	6,781	6,345	6,019	5,779	5,768	5,822	5,964	6,107	6,628	7,254	7,843	8,383	8,860	9,283	9,595	9,745	9,610	9,377	8,973	8,643	8,530	8,079	7,508	6,909
Fall	9	8,505	9/6/2015	6,307	5,903	5,666	5,508	5,450	5,470	5,604	5,746	6,272	6,752	7,121	7,442	7,772	8,078	8,306	8,433	8,505	8,480	8,304	8,160	8,070	7,690	7,206	6,675
Fall	9	9,807	9/7/2015	6,175	5,842	5,648	5,546	5,557	5,690	5,872	5,978	6,427	7,085	7,760	8,360	8,842	9,215	9,469	9,725	9,807	9,777	9,488	9,241	9,223	8,598	7,764	6,955
Fall	9	10,961	9/8/2015	6,384	6,025	5,815	5,729	5,813	6,268	7,096	7,429	7,665	8,059	8,693	9,345	9,897	10,388	10,692	10,890	10,961	10,880	10,624	10,360	10,235	9,490	8,594	7,726
Fall	9	11,337	9/9/2015	7,076	6,670	6,409	6,251	6,275	6,655	7,409	7,666	8,046	8,549	9,130	9,690	10,184	10,682	10,965	11,148	11,337	11,304	11,043	10,762	10,589	9,878	8,930	8,089
Fall	9	11,611	9/10/2015	7,468	7,050	6,808	6,662	6,682	7,079	7,843	8,087	8,349	8,801	9,333	9,876	10,406	10,954	11,372	11,611	11,510	11,438	11,065	10,697	10,401	9,636	8,741	7,822
Fall	9	10,128	9/11/2015	7,159	6,724	6,393	6,212	6,173	6,561	7,274	7,484	7,676	8,032	8,448	8,891	9,331	9,700	9,964	10,070	10,128	10,012	9,723	9,437	9,251	8,709	8,061	7,309
Fall	9	8,127	9/12/2015	6,729	6,305	6,051	5,864	5,821	5,871	6,070	6,256	6,719	7,222	7,660	7,893	8,060	8,105	8,127	8,123	8,037	7,993	7,886	7,924	7,908	7,566	7,070	6,529
Fall	9	7,707	9/13/2015	6,008	5,677	5,443	5,263	5,180	5,183	5,271	5,364	5,811	6,269	6,545	6,777	7,041	7,285	7,498	7,605	7,670	7,707	7,498	7,329	7,371	6,855	6,218	5,572
Fall	9	8,087	9/14/2015	5,127	4,860	4,720	4,706	4,804	5,218	5,960	6,174	6,288	6,463	6,649	6,802	6,959	7,247	7,468	7,720	8,005	8,087	7,962	7,824	7,746	7,188	6,436	5,764
Fall	9	8,453	9/15/2015	5,268	5,033	4,884	4,809	4,896	5,299	6,052	6,219	6,345	6,491	6,753	6,977	7,242	7,538	7,832	8,189	8,387	8,453	8,268	8,096	8,008	7,368	6,652	5,953
Fall	9	8,465	9/16/2015	5,420	5,134	4,970	4,866	4,934	5,323	6,054	6,262	6,367	6,541	6,782	7,049	7,315	7,688	7,991	8,287	8,465	8,372	8,229	8,246	8,194	7,655	6,997	6,293
Fall	9	8,821	9/17/2015	5,767	5,463	5,292	5,226	5,300	5,689	6,467	6,673	6,759	6,994	7,296	7,614	7,930	8,289	8,495	8,681	8,821	8,777	8,568	8,462	8,420	7,839	7,128	6,367
Fall	9	9,460	9/18/2015	5,778	5,470	5,286	5,190	5,206	5,581	6,281	6,527	6,680	7,017	7,428	7,875	8,327	8,744	9,128	9,365	9,460	9,387	9,007	8,705	8,498	7,924	7,294	6,633
Fall	9	9,875	9/19/2015	6,060	5,663	5,433	5,288	5,260	5,290	5,491	5,697	6,226	6,888	7,556	8,153	8,655	9,083	9,457	9,728	9,875	9,846	9,460	9,054	8,666	8,032	7,332	6,633
Fall	9	9,824	9/20/2015	5,992	5,569	5,279	5,079	4,987	4,999	5,116	5,269	5,921	6,561	7,150	7,713	8,349	8,946	9,426	9,691	9,824	9,783	9,386	9,258	8,995	8,335	7,534	6,776
Fall	9	9,280	9/21/2015	6,193	5,826	5,602	5,494	5,575	5,993	6,778	7,063	7,208	7,529	7,952	8,354	8,695	9,054	9,188	9,254	9,280	9,177	9,014	9,069	8,804	8,158	7,436	6,728
Fall	9	8,747	9/22/2015	6,194	5,869	5,673	5,591	5,653	6,026	6,837	7,038	7,151	7,345	7,605	7,860	8,015	8,258	8,486	8,649	8,747	8,635	8,452	8,574	8,494	7,952	7,283	6,607
Fall	9	8,271	9/23/2015	6,057	5,745	5,573	5,474	5,517	5,946	6,696	6,905	7,026	7,193	7,453	7,651	7,876	8,094	8,221	8,263	8,271	8,174	8,089	8,269	8,181	7,692	7,015	6,353
Fall	9	7,833	9/24/2015	5,805	5,494	5,330	5,234	5,282	5,649	6,437	6,666	6,748	6,885	7,029	7,199	7,296	7,396	7,473	7,435	7,472	7,456	7,548	7,833	7,744	7,328	6,739	6,164
Fall	9	7,499	9/25/2015	5,691	5,429	5,274	5,242	5,293	5,682	6,467	6,815	6,937	7,056	7,231	7,323	7,332	7,380	7,394	7,348	7,354	7,349	7,341	7,499	7,406	7,109	6,654	6,148
Fall	9	6,957	9/26/2015	5,690	5,409	5,237	5,128	5,114	5,200	5,404	5,619	6,013	6,391	6,662	6,765	6,773	6,719	6,663	6,633	6,653	6,676	6,706	6,957	6,902	6,658	6,298	5,864
Fall	9	7,758	9/27/2015	5,398	5,140	4,964	4,883	4,868	4,947	5,128	5,381	5,813	6,233	6,439	6,618	6,814	6,955	7,041	7,115	7,231	7,347	7,430	7,758	7,681	7,278	6,747	6,199
Fall	9	8,806	9/28/2015	5,726	5,467	5,334	5,270	5,391	5,860	6,703	7,109	7,206	7,416	7,699	7,948	8,173	8,319	8,520	8,538	8,506	8,490	8,515	8,806	8,682	8,188	7,564	6,948
Fall	9	9,711	9/29/2015	6,419	6,143	5,952	5,899	5,984	6,384	7,235	7,588	7,699	7,965	8,336	8,734	9,055	9,418	9,639	9,711	9,636	9,505	9,452	9,639	9,366	8,744	8,029	7,281
Fall	9	9,820	9/30/2015	6,723	6,420	6,170	6,081	6,123	6,543	7,335	7,664	7,808	8,042	8,322	8,700	9,075	9,551	9,679	9,782	9,820	9,686	9,560	9,541	9,050	8,540	7,727	6,955
Fall	10	7,307	10/1/2015	6,389	6,018	5,782	5,619	5,627	5,973	6,758	7,073	7,045	7,105	7,162	7,119	7,058	7,046	6,968	6,923	6,887	6,930	7,070	7,307	7,176	6,778	6,255	5,701
Fall	10	6,942	10/2/2015	5,307	5,067	4,936	4,858	4,951	5,294	6,077	6,431	6,478	6,605	6,657	6,739	6,686	6,688	6,622	6,569	6,631	6,731	6,857	6,942	6,807	6,528	6,107	5,655
Fall	10	7,149	10/3/2015	5,287	5,024	4,908	4,830	4,818	4,942	5,171	5,364	5,784	6,234	6,546	6,769	6,820	6,851	6,826	6,830	6,888	6,917	6,909	7,149	6,995	6,722	6,354	5,946
Fall	10	6,920	10/4/2015	5,551	5,279	5,117	5,016	4,921	4,952	5,081	5,294	5,698	6,046	6,236	6,338	6,420	6,460	6,427	6,371	6,402	6,468	6,628	6,920	6,764	6,399	5,926	5,425
Fall	10	7,157	10/5/2015	5,016	4,804	4,667	4,617	4,724	5,084	5,826	6,177	6,274	6,421	6,567	6,637	6,632	6,630	6,567	6,556	6,593	6,667	6,858	7,157	6,994	6,607	6,090	5,539
Fall	10	7,235	10/6/2015	5,127	4,925	4,810	4,775	4,905	5,300	6,045	6,379	6,404	6,452	6,511	6,543	6,509	6,579	6,629	6,674	6,785	6,803	6,855	7,235	7,133	6,709	6,151	5,561
Fall	10	7,752	10/7/2015	5,179	4,945	4,843	4,814	4,909	5,339	6,093	6,374	6,361	6,446	6,548	6,631	6,766	6,992	7,195	7,434	7,568	7,648	7,603	7,752	7,622	7,111	6,436	5,802
Fall	10	7,921	10/8/2015	5,340	5,088	4,935	4,873	4,971	5,353	6,155	6,379	6,423	6,612	6,858	7,051	7,352	7,682	7,894	7,877	7,921	7,843	7,742	7,831	7,773	7,307	6,652	5,988
Fall	10	7,881	10/9/2015	5,530	5,246	5,063	4,978	5,038	5,380	6,132	6,353	6,444	6,647	6,922	7,200	7,448	7,769	7,817	7,881	7,867	7,774	7,587	7,671	7,598	7,188	6,811	6,235
Fall	10	6,583	10/10/2015	5,694	5,379	5,183	5,063	5,052	5,128	5,326	5,569	5,874	6,233	6,426	6,507	6,501	6,439	6,385	6,295	6,335	6,354	6,420	6,583	6,468	6,197	5,845	5,418
Fall	10	6,842	10/11/2015	5,022	4,769	4,637	4,506	4,475	4,567	4,749	5,003	5,402	5,668	5,752	5,745	5,854	5,966	6,068	6,170	6,311	6,436	6,461	6,842	6,706	6,282	5,782	5,306
Fall	10	7,747	10/12/2015	4,940	4,718	4,612	4,581	4,689	5,100	5,905	6,221	6,299	6,450	6,580	6,681	6,787	6,929	7,050	7,208	7,334	7,357	7,431	7,747	7,490	6,985	6,387	5,758
Fall	10	7,717	10/13/2015	5,323	5,076	4,948	4,888	4,978	5,360	6,186	6,419	6,471	6,581	6,707	6,852	7,036	7,213	7,355	7,484	7,618	7,586	7,570	7,717	7,679	7,174	6,534	5,905
Fall	10	7,619	10/14/2015	5,424	5,168	5,010	4,927	5,007	5,398	6,198	6,390	6,362	6,506	6,665	6,782	6,932	7,166	7,338	7,474	7,577	7,501	7,407	7,619	7,378	6,869	6,249	5,613
Fall	10	7,230	10/15/2015	5,170	4,951	4,808	4,787	4,880	5,325	6,164	6,418	6,403	6,395	6,488	6,492	6,553	6,659	6,728	6,838	6,921	6,904	6,891	7,230	7,075	6,649	6,125	5,510
Fall	10	6,888	10/16/2015	5,160	4,916	4,840	4,821	4,937	5,363	6,197	6,483	6,461	6,483	6,517	6,567	6,602	6,702	6,735	6,782	6,736	6,617	6,676	6,888	6,716	6,449	6,059	5,627
Fall	10	6,484	10/17/2015	5,221	5,020	4,877	4,858	4,929	5,107	5,475	5,802	6,147	6,220	6,178	6,069	5,964	5,907	5,900	5,918	5,996	6,042	6,175	6,484	6,416	6,203	5,892	5,506
Fall	10	7,108	10/18/2015	5,172	5,022	4,965	4,980	5,088	5,311	5,674	6,140	6,646	6,685	6,428	6,184	6,041	5,917	5,785	5,773	5,826	6,052	6,447	7,042	7,108	6,861	6,566	6,186
Fall	10	8,419	10/19/2015	5,969	5,894	5,935	6,061	6,357	7,054	7,952	8,419	8,389	8,015	7,498	7,121	6,804	6,613	6,471	6,398	6,465	6,655	7,092	7,661	7,599	7,325	6,929	6,503
Fall	10	8,419	10/20/2015	6,211	6,160	6,220	6,131	6,573	7,305	8,132	8,419	8,268	7,791	7,267	6,916	6,639	6,516	6,430	6,422	6,486	6,566	6,865	7,280	7,164	6,842	6,347	5,899
Fall	10	7,842	10/21/2015	5,600	5,529	5,524	5,603	5,862	6,526	7,511	7,842	7,609	7,206	6,865	6,640	6,487	6,503	6,518	6,503	6,694	6,769	6,912	7,236	7,077	6,687	6,162	5,643
Fall	10	7,312	10/22/2015	5,273	5,123	5,084	5,085	5,312	5,872	6,833	7,154	7,001	6,791	6,756	6,624	6,600	6,700	6,733	6,890	6,979	6,979	7,078	7,312	7,096	6,673	6,140	5,581
Fall	10	7,086	10/23/2015	5,152	4,962	4,869	4,873	4,985	5,449	6,274	6,584	6,604	6,558	6,581	6,576	6,621	6,772	6,901	7,010	7,086	7,022	6,980	7,067	6,811	6,507	6,078	5,606
Fall	10	6,559	10/24/2015	5,196	4,908	4,690	4,682	4,687	4,815	5,123	5,401	5,709	5,980	6,058	6,050	6,002	6,064	6,048	6,143	6,204	6,224	6,381	6,559	6,390	6,132	5,729	5,296
Fall	10	6,921	10/25/2015	4,927	4,724	4,588	4,498	4,486	4,555	4,783	5,106	5,505	5,784	5,822	5,779	5,845	5,919	6,009	6,079	6,175	6,322	6,674	6,921	6,702	6,299	5,832	5,321
Fall	10	7,323	10/26/2015	4,958	4,712	4,596	4,546	4,650	5,050	5,834	6,253	6,272	6,400	6,484	6,501	6,478	6,461	6,429	6,410	6,490	6,642	7,127	7,323	7,138	6,741	6,212	5,684
Fall	10	7,484	10/27/2015	5,313	5,139	5,056	5,061	5,199	5,683	6,539	6,925	6,824	6,823	6,881	6,880	6,797	6,842	6,811	6,786	6,889	7,049	7,385	7,484	7,236	6,823	6,264	5,732
Fall	10	7,526	10/28/2015	5,314	5,144	5,006	4,967	5,068	5,513	6,308	6,712	6,671	6,764	6,859	6,947	6,936	6,938	6,816	6,844	6,975	7,034	7,401	7,526	7,379	7,017	6,482	5,873
Fall	10	7,544	10/29/2015	5,473	5,218	5,072	4,991	5,069	5,471	6,278	6,624	6,582	6,637	6,805	6,930	7,015	7,131	7,170	7,218	7,209	7,141	7,371	7,544	7,380	6,978	6,398	5,784
Fall	10	6,677	10/30/2015	5,338	5,117	4,933	4,874	4,929	5,353	6,127	6,466	6,402	6,420	6,420	6,371	6,396	6,415	6,447	6,466	6,479	6,452	6,535	6,677	6,525	6,322	5,983	5,608
Fall	10	6,469	10/31/2015	5,283	5,099	5,024	5,013	5,071	5,273	5,622	5,990	6,320	6,469	6,406	6,174	6,041	5,937	5,905	5,919	5,941	5,967	6,075	6,115	6,086	6,007	5,720	5,342
Fall	11	6,902	11/1/2015	4,814	4,707	4,673	4,567	4,582	4,523	5,038	5,268	5,706	5,936	5,984	5,968	6,096	6,099	6,105	5,977	6,381	6,673	6,902	6,674	6,477	6,151	5,562	5,269
Fall	11	7,416	11/2/2015	4,894	4,735	4,645	4,645	4,778	5,278	6,125	6,430	6,569	6,720	6,838	6,877	6,847	6,813	6,714	6,617	6,811	7,249	7,416	7,286	6,956	6,548	6,029	5,523
Fall	11	7,379	11/3/2015	5,188	4,976	4,858	4,849	4,955	5,391	6,217	6,491	6,595	6,634	6,663	6,665	6,563	6,546	6,556	6,611	6,767	7,185	7,379	7,344	7,100	6,597	6,037	5,552
Fall	11	7,457	11/4/2015	5,170	4,987	4,898	4,866	4,993	5,466	6,245	6,450	6,486	6,473	6,550	6,604	6,602	6,624	6,610	6,621	6,837	7,211	7,457	7,332	7,117	6,627	6,117	5,623
Fall	11	7,646	11/5/2015	5,267	5,077	4,947	4,885	5,022	5,457	6,308	6,551	6,616	6,708	6,815	6,836	6,880	6,862	7,000	6,977	7,042	7,413	7,646	7,508	7,255	6,817	6,268	5,701
Fall	11	7,529	11/6/2015	5,307	5,098	4,949	4,926	5,025	5,474	6,252	6,505	6,641	6,781	6,944	7,094	7,210	7,300	7,285	7,211	7,199	7,466	7,529	7,332	7,106	6,810	6,405	5,946
Fall	11	7,315	11/7/2015	5,480	5,231	5,077	4,976	4,976	5,128	5,326	5,625	6,123	6,546	6,854	7,038	7,068	7,116	7,107	7,091	7,082	7,315	7,300	7,071	6,661	6,327	5,904	5,430
Fall	11	6,966	11/8/2015	4,945	4,672	4,521	4,426	4,431	4,554	4,768	5,064	5,561	5,855	5,880	5,853	5,868	5,879	5,902	5,935	6,117	6,793	6,966	6,888	6,726	6,369	5,939	5,509
Fall	11	7,704	11/9/2015	5,212	5,065	5,028	5,043	5,235	5,783	6,700	6,962	6,997	7,057	7,122	7,125	7,079	7,043	6,993	6,964	7,124	7,588	7,704	7,558	7,269	6,840	6,279	5,764
Fall	11	7,247	11/10/2015	5,402	5,219	5,120	5,097	5,244	5,715	6,551	6,776	6,748	6,755	6,755	6,738	6,669	6,661	6,597	6,552	6,581	6,981	7,247	7,106	6,906	6,548	6,137	5,683
Fall	11	7,229	11/11/2015	5,367	5,218	5,181	5,196	5,394	5,811	6,386	6,707	6,738	6,672	6,603	6,495	6,363	6,372	6,358	6,350	6,496	6,927	7,229	7,105	6,967	6,651	6,208	5,765
Fall	11	7,477	11/12/2015	5,492	5,375	5,329	5,403	5,551	6,128	6,982	7,109	6,844	6,642	6,547	6,479	6,459	6,575	6,602	6,645	6,710	7,122	7,477	7,164	7,011	6,605	6,054	5,520
Fall	11	7,063	11/13/2015	5,159	4,961	4,845	4,877	5,027	5,524	6,410	6,656	6,557	6,494	6

Contains Proprietary Material
Do Not Distribute

Winter	12	12,507	12/7/2014	9,423	9,150	9,047	9,045	9,183	9,516	10,054	10,586	11,094	11,045	10,664	10,324	10,129	9,923	9,757	9,777	10,214	11,505	12,206	12,409	12,507	12,212	11,654	11,096
Winter	12	14,800	12/8/2014	10,755	10,623	10,644	10,761	11,154	12,085	13,596	14,214	14,083	13,950	13,866	13,736	13,555	13,471	13,412	13,481	13,776	14,579	14,800	14,658	14,358	13,731	12,856	11,982
Winter	12	14,176	12/9/2014	11,444	11,143	11,017	11,056	11,339	12,157	13,604	14,176	13,890	13,489	12,900	12,362	11,982	11,922	11,929	12,084	12,417	13,309	13,660	13,635	13,454	13,012	12,241	11,476
Winter	12	14,581	12/10/2014	11,153	11,027	11,083	11,230	11,623	12,544	14,079	14,581	14,081	13,274	12,749	12,401	12,067	11,921	11,783	11,815	12,256	13,539	14,203	14,308	14,263	13,924	13,224	12,576
Winter	12	16,083	12/11/2014	12,265	12,243	12,354	12,586	13,087	14,114	15,716	16,083	15,581	14,803	13,796	13,053	12,410	12,026	11,771	11,709	12,088	13,276	14,013	14,297	14,428	14,185	13,525	12,828
Winter	12	15,977	12/12/2014	12,473	12,424	12,468	12,663	13,037	13,951	15,473	15,977	15,408	14,312	13,284	12,446	11,772	11,415	11,102	10,964	11,193	12,226	12,744	12,698	12,773	12,624	12,192	11,681
Winter	12	13,577	12/13/2014	11,277	11,148	11,202	11,334	11,615	12,087	12,807	13,345	13,577	12,909	12,025	11,281	10,666	10,234	9,939	9,853	10,048	10,983	11,467	11,570	11,588	11,495	11,233	10,806
Winter	12	12,787	12/14/2014	10,495	10,400	10,435	10,570	10,799	11,187	11,789	12,413	12,787	12,168	11,197	10,473	10,078	9,752	9,537	9,459	9,757	10,860	11,542	11,752	11,844	11,645	11,167	10,706
Winter	12	15,029	12/15/2014	10,458	10,492	10,605	10,947	11,514	12,610	14,330	15,029	14,606	13,646	12,758	12,066	11,534	11,236	11,010	10,931	11,183	12,269	12,946	13,037	13,038	12,683	12,013	11,222
Winter	12	13,247	12/16/2014	10,755	10,496	10,438	10,452	10,678	11,392	12,699	13,247	12,962	12,759	12,549	12,293	11,964	11,761	11,503	11,349	11,548	12,423	12,849	12,781	12,655	12,237	11,506	10,742
Winter	12	13,974	12/17/2014	10,304	10,191	10,252	10,413	10,835	11,812	13,378	13,974	13,592	12,787	12,142	11,624	11,184	10,974	10,774	10,718	11,015	12,074	12,712	12,759	12,740	12,432	11,805	11,103
Winter	12	14,383	12/18/2014	10,763	10,716	10,802	10,998	11,411	12,374	13,874	14,383	14,022	13,570	13,046	12,498	11,996	11,687	11,418	11,390	11,638	12,595	13,048	13,030	12,906	12,529	11,841	11,095
Winter	12	14,203	12/19/2014	10,609	10,428	10,424	10,604	11,045	11,961	13,510	14,203	13,969	13,164	12,397	11,738	11,284	11,099	10,916	10,899	11,145	12,166	12,565	12,496	12,385	12,166	11,694	11,039
Winter	12	12,667	12/20/2014	10,491	10,170	10,024	9,985	10,106	10,378	10,895	11,513	12,081	12,554	12,667	12,535	12,201	11,890	11,649	11,561	11,746	12,474	12,659	12,514	12,363	12,053	11,502	10,839
Winter	12	11,946	12/21/2014	10,291	9,966	9,801	9,771	9,848	10,076	10,453	11,017	11,564	11,715	11,371	10,928	10,726	10,526	10,349	10,334	10,647	11,592	11,946	11,922	11,819	11,509	10,945	10,291
Winter	12	14,169	12/22/2014	9,836	9,608	9,584	9,737	10,104	10,803	11,856	12,704	12,984	13,257	13,402	13,387	13,289	13,264	13,165	13,170	13,362	14,034	14,169	14,019	13,687	13,191	12,459	11,640
Winter	12	13,041	12/23/2014	11,049	10,685	10,505	10,482	10,666	11,240	12,105	12,776	12,922	13,041	13,033	12,837	12,576	12,467	12,324	12,204	12,275	12,862	12,877	12,613	12,321	11,866	11,178	10,355
Winter	12	11,161	12/24/2014	9,644	9,281	9,062	8,978	9,082	9,394	9,886	10,342	10,672	11,033	11,161	11,029	10,754	10,550	10,362	10,253	10,319	10,684	10,486	10,153	9,894	9,613	9,213	8,672
Winter	12	10,243	12/25/2014	8,188	7,866	7,719	7,729	7,852	8,168	8,669	9,193	9,654	9,693	9,551	9,343	9,033	8,614	8,329	8,194	8,303	9,062	9,665	9,895	10,141	10,243	10,168	9,979
Winter	12	12,760	12/26/2014	9,872	9,930	10,078	10,310	10,681	11,307	12,064	12,636	12,760	12,140	11,272	10,493	9,939	9,454	9,149	9,008	9,247	10,192	10,864	10,916	10,986	10,920	10,550	10,170
Winter	12	11,687	12/27/2014	9,862	9,692	9,727	9,783	10,051	10,380	10,966	11,437	11,687	11,252	10,640	10,028	9,529	9,123	8,868	8,782	8,973	9,824	10,276	10,237	10,119	9,846	9,360	8,809
Winter	12	10,225	12/28/2014	8,353	8,085	7,947	7,905	7,905	8,097	8,419	8,744	9,159	9,467	9,458	9,349	9,325	9,208	9,110	9,056	9,204	9,925	10,225	10,174	9,994	9,632	9,117	8,532
Winter	12	11,821	12/29/2014	8,085	7,815	7,733	7,725	7,929	8,492	9,390	10,114	10,372	10,599	10,820	10,894	10,839	10,766	10,654	10,578	10,756	11,494	11,821	11,669	11,430	11,025	10,436	9,772
Winter	12	13,650	12/30/2014	9,357	9,177	9,114	9,217	9,545	10,220	11,166	12,048	12,327	12,628	12,808	12,825	12,713	12,582	12,368	12,229	12,371	13,166	13,650	13,635	13,570	13,296	12,798	12,223
Winter	12	13,979	12/31/2014	11,847	11,693	11,674	11,742	12,032	12,684	13,432	13,976	13,979	13,781	13,257	12,591	12,079	11,690	11,340	11,214	11,465	12,520	13,150	13,054	12,890	12,654	12,343	12,169
Winter	1	13,649	1/1/2015	11,982	11,991	12,013	12,168	12,430	12,863	13,323	13,611	13,649	13,141	12,311	11,671	11,015	10,526	10,116	9,986	10,278	11,225	11,637	11,598	11,395	11,062	10,527	9,982
Winter	1	11,883	1/2/2015	9,518	9,260	9,134	9,165	9,427	9,986	10,821	11,466	11,666	11,736	11,633	11,475	11,286	11,118	11,056	10,885	11,033	11,768	11,883	11,669	11,421	11,041	10,485	9,887
Winter	1	11,550	1/3/2015	9,405	9,053	8,924	8,852	8,909	9,119	9,567	9,985	10,369	10,887	11,134	11,176	11,063	10,918	10,815	10,840	10,980	11,442	11,550	11,330	11,190	10,780	10,131	9,690
Winter	1	11,023	1/4/2015	9,166	8,869	8,654	8,544	8,561	8,732	9,037	9,444	9,823	10,131	10,153	10,118	10,185	10,171	9,989	9,864	9,950	10,614	11,023	10,899	10,766	10,355	9,863	9,386
Winter	1	13,778	1/5/2015	9,123	9,075	9,209	9,468	9,975	11,048	12,746	13,542	13,335	12,921	12,599	12,210	11,863	11,600	11,340	11,275	11,520	12,544	13,533	13,778	13,736	13,384	12,845	12,335
Winter	1	16,126	1/6/2015	12,063	12,104	12,190	12,483	12,969	13,974	15,543	16,126	15,662	14,578	13,668	12,861	12,216	11,903	11,595	11,596	11,841	12,728	13,641	13,816	13,779	13,429	12,858	12,317
Winter	1	18,179	1/7/2015	12,040	11,981	12,056	12,237	12,659	13,577	15,035	15,494	15,048	14,733	14,477	14,285	14,180	14,150	13,988	14,140	14,867	16,292	17,438	17,857	18,179	18,160	17,790	17,437
Winter	1	20,376	1/8/2015	17,280	17,330	17,469	17,689	17,961	18,525	19,786	20,376	19,942	19,037	18,338	17,500	16,597	15,852	15,263	15,061	15,437	16,636	17,726	17,976	17,944	17,507	16,812	16,092
Winter	1	17,084	1/9/2015	15,564	15,245	15,035	14,987	14,980	15,414	16,629	17,084	16,682	16,023	15,308	14,508	13,782	13,230	12,771	12,569	12,875	13,914	14,742	14,827	14,930	14,773	14,404	13,952
Winter	1	16,484	1/10/2015	13,633	13,627	13,738	13,946	14,324	14,848	15,529	16,217	16,484	15,872	15,106	14,364	13,399	12,704	12,165	11,929	12,257	13,438	14,513	14,789	14,938	14,857	14,684	14,342
Winter	1	16,428	1/11/2015	14,197	14,214	14,382	14,590	14,903	15,271	15,758	16,255	16,428	15,535	14,171	13,123	12,547	12,187	12,021	12,022	12,350	13,161	13,543	13,505	13,295	12,823	12,161	11,557
Winter	1	14,375	1/12/2015	11,161	10,996	11,004	11,113	11,479	12,328	13,729	14,375	14,148	14,057	14,005	13,847	13,668	13,486	13,285	13,158	13,243	13,718	14,044	13,878	13,533	12,818	11,986	11,187
Winter	1	15,348	1/13/2015	10,652	10,352	10,184	10,174	10,444	11,273	12,671	13,452	13,388	13,441	13,598	13,706	13,683	13,767	13,762	13,853	14,151	14,894	15,348	15,234	15,041	14,478	13,705	12,987
Winter	1	15,887	1/14/2015	12,588	12,510	12,479	12,635	12,965	13,809	15,113	15,873	15,887	15,755	15,585	15,236	14,762	14,379	14,083	13,939	14,041	14,659	15,197	15,015	14,814	14,377	13,714	13,128
Winter	1	16,325	1/15/2015	12,773	12,736	12,781	12,973	13,325	14,196	15,654	16,325	16,022	15,603	15,075	14,404	13,896	13,745	13,570	13,514	13,663	14,198	14,664	14,535	14,274	13,745	12,915	12,240
Winter	1	15,661	1/16/2015	11,843	11,849	11,948	12,175	12,553	13,484	14,910	15,661	15,317	14,516	13,585	12,833	12,155	11,691	11,283	11,099	11,128	11,817	12,746	12,864	12,939	12,864	12,558	12,124
Winter	1	14,514	1/17/2015	11,882	11,877	11,987	12,188	12,523	13,016	13,696	14,233	14,514	13,849	12,837	12,068	11,326	10,760	10,335	10,140	10,376	11,129	11,997	12,058	12,066	11,883	11,532	10,965
Winter	1	11,772	1/18/2015	10,474	10,156	9,999	9,941	10,047	10,284	10,739	11,362	11,772	11,669	11,050	10,431	10,124	9,896	9,745	9,629	9,780	10,506	11,375	11,558	11,546	11,366	11,047	10,699
Winter	1	14,036	1/19/2015	10,550	10,523	10,623	10,878	11,312	12,100	13,185	13,987	14,036	13,399	12,751	12,075	11,559	11,165	10,893	10,733	10,819	11,439	12,377	12,474	12,270	11,909	11,292	10,709
Winter	1	13,673	1/20/2015	10,344	10,198	10,180	10,259	10,608	11,451	12,899	13,673	13,456	12,764	12,112	11,586	11,138	10,910	10,701	10,607	10,663	11,250	12,007	12,016	11,830	11,321	10,707	10,016
Winter	1	13,264	1/21/2015	9,569	9,431	9,421	9,560	9,975	10,937	12,474	13,264	12,958	12,360	11,944	11,481	11,145	10,939	10,754	10,636	10,803	11,349	12,297	12,371	12,353	12,071	11,477	10,961
Winter	1	14,946	1/22/2015	10,701	10,688	10,866	11,155	11,651	12,706	14,292	14,946	14,633	13,966	13,112	12,269	11,632	11,331	11,168	11,111	11,250	11,856	12,733	12,846	12,830	12,501	11,903	11,221
Winter	1	14,548	1/23/2015	10,878	10,647	10,563	10,588	10,847	11,609	12,979	13,665	13,604	13,685	13,865	13,917	13,857	13,905	13,845	13,894	14,032	14,455	14,548	14,237	13,892	13,398	12,713	12,042
Winter	1	13,149	1/24/2015	11,556	11,301	11,161	11,115	11,197	11,437	11,865	12,468	12,838	13,135	13,149	12,771	12,043	11,336	10,880	10,612	10,725	11,432	12,474	12,614	12,645	12,522	12,175	11,827
Winter	1	13,873	1/25/2015	11,492	11,418	11,421	11,564	11,864	12,299	12,879	13,535	13,873	13,090	11,937	11,047	10,578	10,165	9,850	9,727	9,859	10,655	11,716	11,909	11,810	11,385	10,796	10,250
Winter	1	13,848	1/26/2015	9,908	9,814	9,842	10,030	10,478	11,374	12,924	13,662	13,400	13,136	12,753	12,479	12,240	12,157	11,975	11,985	12,185	12,827	13,699	13,848	13,752	13,327	12,671	12,055
Winter	1	15,776	1/27/2015	11,750	11,716	11,858	12,065	12,571	13,546	15,105	15,776	15,384	14,908	14,420	13,866	13,207	12,714	12,309	12,162	12,423	13,148	14,430	14,735	14,722	14,327	13,650	13,069
Winter	1	16,850	1/28/2015	12,779	12,771	12,867	13,093	13,577	14,622	16,235	16,850	16,231	15,227	14,384	13,589	12,897	12,456	12,068	11,887	12,052	12,724	13,963	14,322	14,507	14,229	13,663	13,119
Winter	1	16,849	1/29/2015	12,891	12,886	13,031	13,234	13,732	14,743	16,349	16,849	16,260	15,271	14,448	13,828	13,285	13,006	12,870	12,704	12,671	13,106	14,000	14,098	13,991	13,426	12,557	11,771
Winter	1	14,132	1/30/2015	11,184	10,851	10,672	10,740	11,075	11,987	13,488	14,132	13,871	13,559	13,236	12,760	12,308	11,970	11,728	11,587	11,796	12,463	13,576	13,784	13,817	13,677	13,331	12,966
Winter	1	15,454	1/31/2015	12,688	12,688	12,799	13,012	13,438	13,960	14,692	15,284	15,454	14,654	13,663	12,808	11,992	11,327	10,808	10,623	10,742	11,435	12,389	12,561	12,580	12,375	11,992	11,445
Winter	2	12,253	2/1/2015	10,983	10,753	10,658	10,582	10,678	10,857	11,247	11,702	12,248	12,253	11,756	11,260	10,976	10,835	10,721	10,781	10,992	11,442	11,699	11,422	11,201	10,867	10,504	9,884
Winter	2	14,718	2/2/2015	9,299	8,982	8,854	8,824	9,070	9,799	11,151	11,909	11,727	11,741	11,808	11,741	11,734	11,719	11,620	11,643	11,945	12,864	14,259	14,685	14,718	14,403	13,784	13,218
Winter	2	17,471	2/3/2015	12,989	12,961	13,117	13,411	14,001	15,093	16,893	17,471	16,845	15,593	14,535	13,681	12,968	12,526	12,080	11,836	11,951	12,676	13,988	14,433	14,523	14,188	13,595	12,975
Winter	2	16,707	2/4/2015	12,628	12,569	12,699	12,909	13,398	14,395	16,084	16,707	16,105	14,988	13,943	13,031	12,357	11,970	11,662	11,527	11,813	12,484	13,417	13,499	13,414	12,888	12,168	11,480
Winter	2	14,935	2/5/2015	11,067	10,917	10,879	11,042	11,379	12,304	13,838	14,392	13,936	13,421	13,059	12,820	12,407	12,125	11,924	11,827	12,084	12,864	14,268	14,798	14,935	14,664	14,138	13,689
Winter	2	18,345	2/6/2015	13,523	13,609	13,823	14,224	14,841	16,053	17,793	18,345	17,527	16,235	15,064	14,174	13,432	13,047	12,781	12,649	12,687	12,997	13,850	13,957	13,925	13,814	13,484	13,018
Winter	2	14,561	2/7/2015	12,704	12,627	12,640	12,776	12,999	13,458	14,144	14,494	14,561	13,875	13,070	12,215	11,369	10,728	10,221	9,926	9,936	10,363	11,282	11,502	11,455	11,240	10,842	10,357
Winter	2	11,454	2/8/2015	9,990	9,791	9,744	9,758	9,900	10,210	10,665	11,184	11,454	11,073	10,420	9,879	9,536	9,275	9,045	8,946	9,075	9,518	10,455	10,720	10,550	10,099	9,558	8,977
Winter	2	12,469	2/9/2015	8,598	8,381	8,350	8,399	8,711	9,577	11,044	11,758	11,646	11,569	11,521	11,542	11,507	11,493	11,354	11,372	11,464	11,807	12,469	12,376	12,065	11,430	10,656	9,960
Winter	2	13,178	2/10/2015	9,510	9,341	9,283	9,429	9,812	10,720	12,260	12,994	12,837	12,705	12,566	12,362	12,112	11,955	11,626	11,302	11,358	11,729	12,802	13,164	13,178	12,889	12,277	11,697
Winter	2	15,778	2/11/2015	11,396	11,405	11,534	11,833	12,363	13,486	15,196	15,778	15,134	14,041	13,201	12,441	11,811	11,479	11,112	10,904	10,961	11,361	12,434	12,803	12,857	12,597	12,030	11,450
Winter	2	15,473	2/12/2015	11,132	11,068	11,181	11,429	11,931	12,973	14,613	15,125	14,448	13,391	12,605	12,079	11,776	11,770	11,844	12,017	12,351	13,227	14,736	15,367	15,473	15,300	14,684	14,116
Winter	2	16,972	2/13/2015	13,802	13,750	13,796	13,912	14,246	15,131	16,493	16,972	16,697	16,219	15,680	14,952	14,159	13,471	12,823	12,457	12,571	13,077	14,303	14,749	14,915	14,833	14,538	14,103
Winter	2	15,382	2/14/2015	13,805	13,736	13,776	13,917	14,125	14,545	15,094	15,382	15,314	14,659	13,837	12,958	12,093	11,453	10,968	10,912	11,092	11,547	12,280	12,328	12,260	12,027	12,095	12,174
Winter	2	16,841	2/15/2015	12,444	12,914	13,460	13,976	14,546	15,201	16,027	16,623	16,841	16,416	15,681	14,823	14,121	13,461	12,917	12,594	12,643	13,384	14,792	15,375	15,437	15,228	14,824	14,308
Winter	2	17,256	2/16/2015	13,973	13,782	13,703	13,775	14,035	14,729	15,956	16,568	16,630	16,591	16,442	16,187	15,944	15,912	15,888	15,996	16,286	16,781	17,256	16,951	16,460	15,877	15,217	14,627
Winter	2	15,932	2/17/2015	14,134	13,933	13,861	13,918	14,123	14,534	15,121	15,495	15,819	15,932	15,656	15,005	14,440	14,085	13,799	13,684	13,905	14,498	15,353	15,444	15,187	14,715	14,226	13,720
Winter	2	17,424	2/18/2015	13,511	13,509	13,697	13,936	14,463	15,269	16,415	17,158	17,019	16,162	15,525	15,050	14,599	14,480	14,557	14,628	14,858	15,583	16,910	17,418	17,424	17,238	16,872	16,568
Winter	2	19,764	2/19/2015	16,523	16,647	16,898	17,276	17,773	18,438	19,306	19,764	19,664	19,262	18,709	18,056	17,365	16,858	16,390	16,128	16,312	17,216	18,791	19,554	19,735	19,557	19,068	18,684
Winter	2	21,101	2/20/2015	18,554	18,641	18,915	19,143	19,568	20,086	20,767	21,101	20,491	19,678	18,774	17,794	16,795	15,968	15,265	14,761	14,783	15,501	16,590	16,808	16,716	16,407	15,909	15,331
Winter	2	15,980	2/21/2015	14,754	14,661	14,697	14,642	14,636	14,910	15,144	15,423	15,818	15,980	15,724	15,291	14,764	14,171	13,750	13,475	13,445	13,634	14,172	14,149	13,933	13,518	12,985	12,384
Winter	2	12,942	2/22/2015	12,000	11,796	11,704	11,789	11,819	11,984	12,278	12,549	12,942	12,864	12,276	11,824	11,396	10,981	10,555	10,598	10,430	10,889	11,664	11,956	11,828	11,400	10,852	10,272
Winter	2	14,297	2/23/2015	9,932	9,665	9,636	9,739	10,043	10,964	12,417	13,216	13,190	13,206	13,218	13,014	12,600	12,240	11,936	11,745	12,041	12,695	13,811	14,292	14,297	13,863	13,365	12,692
Winter	2	16,739	2/24/2015	12,278	12,238	12,293	12,495	12,957	14,007	15,512	16,225	16,450	16,629	16,631	16,614	16,477	16,315	16,120	15,913	15,930	16,157	16,697	16,739	16,408	15,839	15,088	14,374
Winter	2	17,150	2/25/2015	13,880	13,702	13,674	13,789	14,175	15,069	16,530	17,150	16,622	15,794	15,021	14,358	13,726	13,316	13,089	13,265	13,558	13,974	14,672	14,767	14,602	14,097	13,597	12,959
Winter	2	15,032	2/26/2015	12,561	12,301	12,193	12,209	12,386	12,793	13,385	13,763	14,129	14,229	14,289	14,160	13,954	13,656	13,458	13,402	13,465	13,728	14,609	15,032	14,931	14,519	13,863	13,215
Winter	2	16,143	2/27/2015	12,895	12,766	12,780	12,968	13,406	14,290	15,494	16,143	16,017	15,227	14,316	13,547	12,864	12,414	12,010	11,682	11,666	11,998	13,004	13,579	13,746	13,680	13,405	12,985
Winter	2	14,973	2/28/2015	12,689	12,678	12,795	12,893	13,192	13,535	14,087	14,477	14,973	14,966	14,536	13,880	13,123	12,520	11,998	11,726	11,828	12,229	13,242	13,750	13,805	13,604	13,190	12,652
Spring	3	14,204	3/1/2015	12,196	11,909	11,801	11,801	11,979	12,305	12,816	13,296	13,941	14,204	14,061	13,737	13,485	13,235	12,900	12,684	12,607	12,829	13,465	13,648	13,447	12,910	12,283	11,623
Spring	3	13,797	3/2/2015	11,187	10,981	10,903	10,928	11,204	11,972	13,396	13,797	13,464	12,941	12,351	11,810	11,350	11,078	10,824	10,659	10,622	10,779	11,591	12,127	12,052	11,653	11,048	10,360
Spring	3	14,042	3/3/2015	9,883	9,660	9,606	9,692	10,019	10,867	12,416	13,088	13,073	13,106	13,187	13,155	13,058	13,052	12,923	12,871	12,972	13,323	13,952	14,042	13,782	13,168	12,408	11,501
Spring	3	12,850	3/4/2015	10,912	10,591	10,413	10,445	10,618	11,308	12,548	12,850	12,478	12,137	11,815	11,371	11,098	10,927	10,723	10,613	10,622	10,710	11,302	11,634	11,502	10,979	10,291	9,395
Spring	3	13,797	3/5/2015	8,814	8,469	8,340	8,225	8,400	9,071	10,393	10,977	11,079	11,186	11,378	11,554	11,625	11,728	11,780	11,916	12,209	12,730	13,473	13,780	13,797	13,470	12,896	12,335
Spring	3	16,260	3/6/2015	12,064	12,099	12,319	12,618	13,198	14,241	15,834	16,260	15,842	15,274	14,602	13,870	13,206	12,646	12,163	11,771	11,693	12,054	13,030	13,789	14,026	13,979	13,691	13,302
Spring	3	15,173	3/7/2015	13,054	13,069	13,208	13,509	13,808	14,287	14,899	15,173	14,619	13,570	12,628	11,816	11,057	10,430	10,021	9,749	9,736	9,961	10,664	11,273	11,337	11,238	10,958	10,577
Spring	3	12,350	3/8/2015	10,307	0	10,208	10,258	10,512	10,860	11,377	11,960	12,350	11,853	10,931	10,220	9,802	9,514	9,192	8,979	9,018	9,146	9,359	10,085	10,621	10,313	9,732	9,073
Spring	3	11,714	3/9/2015	8,565	8,331	8,288	8,260	8,553	9,369	10,820	11,714	11,549	11,510	11,534	11,385	11,151	11,002	10,751	10,540	10,389	10,396	10,543	11,218	11,522	11,046	10,310	9,512
Spring	3	11,574	3/10/2015	8,929	8,612	8,446	8,447	8,643	9,381	10,736	11,574	11,344	11,291

Contains Proprietary Material
Do Not Distribute

Spring	4	12,709	4/14/2015	8,783	8,384	8,195	8,096	8,200	8,810	10,192	10,875	10,997	11,137	11,342	11,485	11,630	11,809	11,928	12,071	12,387	12,496	12,441	12,466	12,709	12,095	11,006	9,953
Spring	4	11,451	4/15/2015	9,114	8,631	8,345	8,193	8,275	8,851	10,101	10,653	10,646	10,678	10,858	10,864	10,862	10,893	10,835	10,824	10,891	10,981	11,091	11,222	11,451	11,008	10,196	9,338
Spring	4	11,554	4/16/2015	8,804	8,484	8,330	8,301	8,503	9,208	10,566	11,190	11,254	11,328	11,453	11,377	11,244	11,142	10,993	10,925	10,957	11,049	11,132	11,303	11,554	11,130	10,282	9,440
Spring	4	10,769	4/17/2015	8,912	8,562	8,367	8,283	8,434	9,003	10,209	10,659	10,708	10,731	10,750	10,689	10,593	10,566	10,554	10,542	10,555	10,478	10,378	10,397	10,769	10,489	9,864	9,102
Spring	4	10,884	4/18/2015	8,449	8,040	7,788	7,665	7,658	7,853	8,220	8,496	9,073	9,552	9,927	10,226	10,428	10,580	10,689	10,767	10,783	10,762	10,666	10,571	10,884	10,615	9,988	9,203
Spring	4	10,557	4/19/2015	8,505	8,031	7,762	7,595	7,550	7,653	7,900	8,181	8,820	9,279	9,506	9,632	9,783	9,823	9,771	9,761	9,845	10,031	10,193	10,377	10,557	10,224	9,553	8,836
Spring	4	11,728	4/20/2015	8,276	7,917	7,757	7,734	7,905	8,589	9,305	10,469	10,631	10,852	11,121	11,325	11,551	11,728	11,719	11,577	11,443	11,318	11,240	11,111	11,406	11,062	10,186	9,175
Spring	4	11,213	4/21/2015	8,487	8,100	7,880	7,772	7,879	8,496	9,740	10,335	10,385	10,402	10,478	10,486	10,481	10,610	10,665	10,695	10,787	10,787	10,775	10,743	11,213	10,915	9,984	9,031
Spring	4	11,398	4/22/2015	8,416	8,115	7,987	7,995	8,242	8,969	10,347	10,839	10,759	10,636	10,632	10,611	10,609	10,767	10,834	10,913	10,994	11,018	10,945	10,930	11,398	11,082	10,150	9,180
Spring	4	11,210	4/23/2015	8,537	8,150	7,943	7,860	8,000	8,655	9,884	10,389	10,426	10,414	10,518	10,522	10,528	10,606	10,660	10,746	10,802	10,841	10,787	10,734	11,210	10,910	10,023	9,104
Spring	4	10,940	4/24/2015	8,496	8,206	8,104	8,101	8,322	9,072	10,410	10,940	10,784	10,615	10,478	10,314	10,152	10,159	10,096	10,046	10,098	10,099	9,973	9,892	10,316	10,105	9,493	8,781
Spring	4	10,157	4/25/2015	8,200	7,883	7,695	7,608	7,671	7,877	8,231	8,587	9,184	9,686	9,996	10,107	10,045	9,940	9,784	9,661	9,675	9,752	9,757	9,851	10,157	9,940	9,434	8,813
Spring	4	10,358	4/26/2015	8,243	7,909	7,704	7,640	7,660	7,809	8,092	8,473	9,177	9,600	9,701	9,698	9,790	9,759	9,621	9,520	9,558	9,617	9,641	9,830	10,358	10,154	9,502	8,791
Spring	4	11,046	4/27/2015	8,361	8,122	8,059	8,129	8,412	9,187	10,515	11,046	10,887	10,708	10,660	10,579	10,499	10,513	10,481	10,434	10,510	10,460	10,455	10,495	11,004	10,770	9,940	9,045
Spring	4	11,277	4/28/2015	8,479	8,245	8,182	8,270	8,574	9,395	10,771	11,277	11,027	10,801	10,688	10,553	10,475	10,465	10,434	10,472	10,549	10,576	10,557	10,596	11,099	10,821	9,921	9,031
Spring	4	10,961	4/29/2015	8,452	8,140	8,008	8,017	8,234	8,955	10,187	10,760	10,730	10,639	10,709	10,734	10,711	10,700	10,594	10,545	10,527	10,496	10,479	10,503	10,961	10,779	9,943	9,094
Spring	4	10,993	4/30/2015	8,557	8,296	8,163	8,155	8,357	9,058	10,249	10,726	10,696	10,634	10,619	10,626	10,684	10,813	10,832	10,822	10,827	10,788	10,654	10,587	10,993	10,741	9,928	9,047
Spring	5	10,556	5/1/2015	8,416	8,065	7,931	7,917	8,119	8,767	9,943	10,484	10,542	10,556	10,534	10,463	10,345	10,318	10,189	10,037	10,015	9,933	9,883	9,826	10,208	10,164	9,596	8,936
Spring	5	9,864	5/2/2015	8,365	8,062	7,926	7,889	7,994	8,280	8,612	9,003	9,355	9,476	9,477	9,433	9,388	9,355	9,398	9,511	9,704	9,754	9,759	9,657	9,864	9,721	9,065	8,366
Spring	5	10,694	5/3/2015	7,783	7,486	7,283	7,209	7,239	7,414	7,595	7,993	8,537	8,803	8,907	9,030	9,272	9,489	9,677	9,898	10,176	10,485	10,536	10,425	10,694	10,490	9,649	8,733
Spring	5	12,799	5/4/2015	8,064	7,695	7,519	7,444	7,612	8,294	9,421	10,076	10,317	10,613	11,014	11,358	11,701	12,140	12,380	12,536	12,777	12,799	12,720	12,438	12,465	12,066	10,985	9,820
Spring	5	13,706	5/5/2015	9,007	8,486	8,157	7,993	8,070	8,647	9,703	10,314	10,571	10,875	11,290	11,657	12,067	12,592	13,051	13,431	13,664	13,706	13,518	13,077	12,992	12,523	11,319	9,998
Spring	5	13,958	5/6/2015	9,111	8,583	8,280	8,128	8,170	8,745	9,763	10,259	10,530	10,868	11,315	11,790	12,271	12,834	13,270	13,630	13,931	13,958	13,715	13,222	13,089	12,634	11,361	10,064
Spring	5	13,337	5/7/2015	9,200	8,661	8,336	8,157	8,226	8,771	9,828	10,363	10,634	11,002	11,428	11,882	12,312	12,859	13,167	13,293	13,337	13,190	12,898	12,672	12,784	12,433	11,323	10,112
Spring	5	14,043	5/8/2015	9,246	8,716	8,384	8,177	8,257	8,778	9,697	10,286	10,615	10,956	11,454	11,903	12,345	12,885	13,375	13,760	14,043	13,973	13,569	12,931	12,652	12,190	11,273	10,177
Spring	5	12,850	5/9/2015	9,241	8,627	8,230	8,015	7,926	8,078	8,244	8,721	9,425	10,111	10,668	11,167	11,580	11,990	12,392	12,745	12,850	12,797	12,557	12,131	12,020	11,745	10,972	10,019
Spring	5	12,259	5/10/2015	9,156	8,600	8,220	7,963	7,881	7,948	8,053	8,475	9,356	10,026	10,422	10,650	10,921	11,256	11,543	11,810	12,066	12,259	12,191	11,923	12,064	11,941	11,062	10,021
Spring	5	16,541	5/11/2015	9,209	8,710	8,438	8,289	8,363	8,922	9,966	10,686	11,223	11,902	12,747	13,575	14,375	15,235	15,846	16,280	16,541	16,495	16,110	15,566	15,364	14,661	13,214	11,772
Spring	5	16,063	5/12/2015	10,667	9,985	9,510	9,250	9,233	9,731	10,765	11,443	11,955	12,601	13,319	14,012	14,573	15,109	15,602	15,931	16,063	15,880	15,462	14,836	14,467	13,780	12,424	11,010
Spring	5	14,620	5/13/2015	9,941	9,331	8,903	8,625	8,647	9,134	10,100	10,579	10,789	11,140	11,659	12,088	12,523	13,084	13,593	14,106	14,505	14,620	14,378	13,658	13,179	12,668	11,358	10,097
Spring	5	12,466	5/14/2015	9,171	8,624	8,285	8,146	8,224	8,744	9,675	10,202	10,419	10,610	10,821	11,062	11,275	11,572	11,858	12,095	12,373	12,466	12,295	11,964	12,105	11,853	10,915	9,795
Spring	5	13,224	5/15/2015	9,046	8,567	8,298	8,200	8,279	8,844	9,829	10,390	10,598	10,831	11,120	11,374	11,644	12,097	12,506	12,840	13,170	13,224	12,926	12,415	12,276	12,043	11,164	10,183
Spring	5	13,886	5/16/2015	9,345	8,789	8,410	8,192	8,108	8,213	8,325	8,760	9,516	10,265	11,007	11,682	12,312	12,873	13,319	13,658	13,834	13,886	13,605	12,962	12,685	12,318	11,351	10,544
Spring	5	14,328	5/17/2015	9,529	8,882	8,472	8,173	8,023	8,048	7,998	8,407	9,215	9,881	10,491	11,217	11,991	12,776	13,344	13,753	14,157	14,328	14,158	13,748	13,488	13,115	11,964	10,792
Spring	5	16,802	5/18/2015	9,869	9,311	8,943	8,757	8,858	9,459	10,501	11,236	11,774	12,473	13,484	14,411	15,248	15,934	16,354	16,628	16,802	16,585	15,952	15,376	15,036	14,261	12,914	11,576
Spring	5	16,066	5/19/2015	10,546	9,902	9,501	9,231	9,229	9,700	10,734	11,413	11,783	12,234	12,919	13,678	14,420	15,188	15,714	15,968	16,066	15,921	15,611	15,147	14,761	14,233	12,804	11,403
Spring	5	16,797	5/20/2015	10,355	9,637	9,223	8,992	8,966	9,439	10,334	11,062	11,532	12,121	12,940	13,766	14,490	15,292	15,924	16,422	16,797	16,728	16,370	15,623	15,062	14,446	13,065	11,652
Spring	5	14,559	5/21/2015	10,640	9,949	9,537	9,292	9,339	9,843	10,804	11,384	11,685	12,003	12,441	12,760	13,047	13,430	13,828	14,273	14,559	14,537	14,220	13,640	13,275	12,831	11,562	10,204
Spring	5	12,130	5/22/2015	9,246	8,656	8,320	8,133	8,188	8,653	9,450	10,024	10,286	10,548	10,790	10,917	11,060	11,293	11,574	11,805	12,097	12,130	11,975	11,488	11,099	10,904	10,078	9,108
Spring	5	11,728	5/23/2015	8,333	7,857	7,595	7,459	7,425	7,571	7,636	7,961	8,535	9,024	9,380	9,654	9,906	10,174	10,552	11,003	11,425	11,728	11,665	11,243	10,818	10,620	9,826	8,932
Spring	5	12,264	5/24/2015	8,204	7,680	7,393	7,213	7,153	7,189	7,184	7,598	8,313	8,935	9,365	9,757	10,231	10,674	11,109	11,616	12,010	12,264	12,169	11,673	11,210	10,988	10,262	9,344
Spring	5	13,673	5/25/2015	8,572	8,048	7,713	7,492	7,482	7,590	7,657	8,020	8,707	9,534	10,282	10,902	11,396	11,895	12,425	12,949	13,428	13,673	13,531	13,193	12,925	12,566	11,445	10,363
Spring	5	16,378	5/26/2015	9,515	8,999	8,726	8,572	8,667	9,202	10,211	11,084	11,702	12,431	13,242	13,968	14,584	15,273	15,705	15,964	16,265	16,378	16,075	15,474	15,080	14,403	13,015	11,630
Spring	5	15,630	5/27/2015	10,592	9,884	9,412	9,172	9,179	9,679	10,569	11,280	11,719	12,112	12,621	13,076	13,521	14,115	14,607	15,093	15,519	15,630	15,431	14,779	14,303	13,902	12,611	11,284
Spring	5	16,432	5/28/2015	10,282	9,665	9,256	9,057	9,080	9,578	10,553	11,282	11,757	12,585	13,428	14,236	15,026	15,697	16,156	16,386	16,432	16,153	15,575	14,816	14,484	13,926	12,768	11,463
Spring	5	15,627	5/29/2015	10,476	9,827	9,384	9,102	9,131	9,538	10,393	11,115	11,577	12,136	12,794	13,421	13,992	14,652	15,105	15,454	15,627	15,525	15,015	14,327	13,731	13,323	12,319	11,063
Spring	5	15,108	5/30/2015	10,019	9,358	8,944	8,640	8,517	8,602	8,658	9,209	10,138	11,050	11,943	12,590	13,195	13,708	14,177	14,650	14,970	15,108	14,869	14,266	13,642	13,271	12,333	11,210
Spring	5	15,133	5/31/2015	10,252	9,559	9,107	8,762	8,576	8,535	8,498	8,984	9,920	10,828	11,566	12,332	13,164	13,867	14,359	14,703	14,997	15,133	14,903	14,288	13,768	13,394	12,279	11,059
Summer	6	16,464	6/1/2015	10,160	9,572	9,196	9,018	9,104	9,677	10,618	11,482	12,094	12,796	13,661	14,485	15,187	15,826	16,114	16,364	16,464	16,005	15,298	14,599	14,193	13,704	12,460	11,200
Summer	6	14,311	6/2/2015	10,224	9,617	9,249	9,000	9,066	9,582	10,551	11,264	11,489	11,899	12,286	12,865	13,453	14,055	14,311	14,282	14,231	13,980	13,658	13,202	12,925	12,547	11,505	10,389
Summer	6	11,891	6/3/2015	9,538	9,047	8,744	8,593	8,683	9,196	10,158	10,787	11,056	11,245	11,434	11,585	11,685	11,815	11,846	11,891	11,879	11,801	11,618	11,477	11,627	11,477	10,626	9,676
Summer	6	12,272	6/4/2015	8,987	8,606	8,418	8,274	8,401	8,958	9,907	10,504	10,729	10,975	11,242	11,414	11,442	11,648	11,816	12,050	12,218	12,272	12,161	11,981	12,026	11,953	11,065	10,094
Summer	6	13,832	6/5/2015	9,252	8,737	8,445	8,314	8,418	8,881	9,740	10,381	10,757	11,116	11,519	11,957	12,367	12,881	13,351	13,678	13,832	13,658	13,372	12,873	12,495	12,373	11,542	10,473
Summer	6	15,074	6/6/2015	9,605	9,000	8,596	8,340	8,294	8,379	8,418	8,971	9,887	10,856	11,849	12,668	13,366	13,981	14,458	14,821	15,074	14,984	14,652	14,029	13,437	13,065	12,111	11,018
Summer	6	14,373	6/7/2015	10,070	9,374	8,931	8,588	8,407	8,391	8,361	8,815	9,759	10,690	11,378	12,029	12,704	13,297	13,676	13,938	14,205	14,373	14,190	13,724	13,359	13,111	12,129	11,039
Summer	6	16,486	6/8/2015	10,170	9,597	9,251	9,104	9,165	9,768	10,685	11,575	12,158	12,745	13,446	14,145	14,704	15,476	16,057	16,424	16,486	16,166	15,710	15,102	14,719	14,238	13,075	11,781
Summer	6	16,919	6/9/2015	10,761	10,035	9,585	9,336	9,316	9,806	10,668	11,406	11,863	12,358	13,133	13,937	14,786	15,678	16,272	16,662	16,919	16,646	16,031	15,299	14,683	14,240	13,128	11,789
Summer	6	17,296	6/10/2015	10,793	10,036	9,599	9,334	9,302	9,765	10,528	11,300	11,890	12,628	13,609	14,584	15,415	16,226	16,779	17,116	17,296	17,169	16,777	16,153	15,583	15,162	13,828	12,436
Summer	6	17,632	6/11/2015	11,273	10,559	10,044	9,708	9,697	10,073	10,903	11,809	12,629	13,629	14,681	15,670	16,410	16,958	17,432	17,532	17,632	17,479	17,011	16,375	15,768	15,331	14,033	12,700
Summer	6	17,191	6/12/2015	11,592	10,831	10,362	10,006	9,944	10,311	11,027	11,839	12,660	13,427	14,268	15,084	15,798	16,417	16,833	17,117	17,191	16,974	16,391	15,711	15,107	14,888	13,957	12,754
Summer	6	17,242	6/13/2015	11,726	10,950	10,451	10,013	9,798	9,828	9,820	10,487	11,616	12,903	14,116	15,114	15,810	16,334	16,659	16,916	17,197	17,242	16,978	16,400	15,649	15,219	14,099	12,805
Summer	6	17,480	6/14/2015	11,716	10,884	10,249	9,798	9,506	9,390	9,226	9,879	11,221	12,649	13,868	14,921	15,774	16,425	16,898	17,225	17,441	17,480	17,231	16,660	16,053	15,698	14,522	13,183
Summer	6	19,597	6/15/2015	12,019	11,118	10,596	10,220	10,221	10,554	11,161	12,301	13,380	14,635	15,989	17,149	18,008	18,699	19,185	19,515	19,597	19,522	19,247	18,660	17,809	17,262	15,768	14,156
Summer	6	19,692	6/16/2015	12,911	12,018	11,323	10,894	10,705	11,041	11,584	12,576	13,691	15,008	16,442	17,578	18,387	19,138	19,475	19,595	19,692	19,592	19,430	18,918	18,241	17,670	16,293	14,744
Summer	6	19,977	6/17/2015	13,507	12,578	11,829	11,308	11,160	11,439	11,979	12,919	13,997	15,166	16,465	17,591	18,504	19,157	19,583	19,844	19,977	19,778	19,363	18,656	18,025	17,509	16,133	14,631
Summer	6	19,840	6/18/2015	13,432	12,461	11,845	11,436	11,305	11,553	12,090	12,910	13,930	15,154	16,574	17,848	18,789	19,466	19,813	19,840	19,765	19,401	18,710	17,918	17,274	16,596	15,235	13,817
Summer	6	18,741	6/19/2015	12,666	11,846	11,293	10,941	10,762	11,102	11,512	12,327	13,326	14,373	15,522	16,640	17,501	18,307	18,737	18,741	18,382	17,866	17,148	16,293	15,543	15,218	14,129	12,872
Summer	6	16,831	6/20/2015	11,795	10,993	10,441	10,090	9,891	9,872	9,885	10,417	11,583	12,827	14,186	15,315	16,096	16,623	16,831	16,653	16,685	16,199	15,666	15,213	14,716	14,495	13,668	12,628
Summer	6	17,935	6/21/2015	11,641	10,894	10,366	9,949	9,711	9,618	9,460	10,085	11,357	12,629	13,675	14,617	15,389	16,120	16,747	17,286	17,734	17,935	17,739	17,219	16,439	15,832	14,640	13,200
Summer	6	19,726	6/22/2015	12,030	11,133	10,564	10,226	10,158	10,496	11,061	12,064	13,129	14,406	15,781	17,011	17,961	18,786	19,369	19,726	19,724	19,444	18,695	17,884	17,250	16,736	15,417	13,893
Summer	6	19,827	6/23/2015	12,774	12,013	11,454	11,085	10,954	11,260	11,798	12,739	13,760	15,005	16,446	17,597	18,502	19,172	19,607	19,741	19,688	19,827	19,503	18,976	18,326	17,874	16,582	15,046
Summer	6	20,003	6/24/2015	13,893	12,999	12,351	11,963	11,783	12,107	12,581	13,376	14,456	15,665	16,992	18,093	18,858	19,349	19,778	19,948	20,003	19,860	19,106	18,094	17,292	16,680	15,391	13,945
Summer	6	19,926	6/25/2015	12,817	11,941	11,355	10,987	10,997	11,337	11,915	12,695	13,563	14,524	15,744	16,878	17,871	18,789	19,390	19,809	19,926	19,820	19,317	18,595	17,815	17,228	15,817	14,331
Summer	6	19,443	6/26/2015	13,136	12,291	11,710	11,291	11,170	11,388	11,778	12,492	13,396	14,474	15,614	16,799	17,807	18,612	19,237	19,443	19,348	18,881	17,986	17,046	16,270	15,542	14,208	12,940
Summer	6	15,555	6/27/2015	11,784	11,044	10,505	10,143	9,959	9,990	10,040	10,311	10,888	11,640	12,554	13,434	14,198	14,837	15,356	15,555	15,123	14,492	13,804	13,236	12,908	12,826	12,149	11,246
Summer	6	14,474	6/28/2015	10,376	9,781	9,336	9,024	8,766	8,655	8,467	8,902	9,710	10,409	10,954	11,473	11,983	12,547	13,052	13,607	14,097	14,474	14,344	13,869	13,026	12,662	11,684	10,503
Summer	6	16,140	6/29/2015	9,567	8,922	8,550	8,321	8,377	8,782	9,298	10,071	10,771	11,489	12,361	13,143	13,913	14,678	15,257	15,767	16,050	16,140	15,899	15,243	14,489	14,134	12,966	11,694
Summer	6	17,124	6/30/2015	10,635	9,996	9,525	9,308	9,280	9,655	10,211	11,023	11,853	12,817	13,964	15,061	16,014	16,758	17,119	17,124	16,828	16,255	15,524	14,762	14,128	13,836	12,813	11,595
Summer	7	16,386	7/1/2015	10,612	9,941	9,515	9,273	9,256	9,632	10,215	10,837	11,429	12,118	13,036	13,948	14,801	15,552	16,045	16,386	16,386	16,077	15,482	14,794	14,315	13,968	12,931	11,751
Summer	7	15,147	7/2/2015	10,785	10,156	9,781	9,492	9,483	9,837	10,410	10,975	11,443	12,069	13,016	13,858	14,546	15,001	15,147	15,099	14,837	14,405	13,951	13,384	13,027	12,881	12,053	10,998
Summer	7	13,208	7/3/2015	10,065	9,457	9,120	8,878	8,836	8,986	9,183	9,527	10,068	10,639	11,107	11,438	11,800	12,027	12,356	12,743	13,069	13,208	12,973	12,540	12,196	12,058	11,410	10,595
Summer	7	14,029	7/4/2015	9,857	9,267	8,857	8,559	8,437	8,537	8,487	8,799	9,578	10,440	11,281	11,867	12,263	12,589	12,930	13,406	13,932	14,029	13,637	12,973	12,350	11,953	11,385	10,844
Summer	7	14,253	7/5/2015	10,076	9,448	8,985	8,727	8,567	8,565	8,527	8,869	9,616	10,450	11,171	11,906	12,822	13,629	14,126	14,253	14,209	14,224	14,033	13,577	13,087	12,871	12,025	11,013
Summer	7	17,474	7/6/2015	10,130	9,499	9,128	8,899	8,972	9,475	10,132	10,958	11,788	12,706	13,707	14,704	15,508	16,246	16,851	17,244	17,474	17,463	17,095	16,312	15,567	15,111	13,843	12,472
Summer	7	18,591	7/7/2015	11,313	10,661	10,057	9,737	9,669	9,986	10,599	11,404	12,259	13,250	14,427	15,636	16,615	17,390	17,950	18,349	18,591	18,539	18,176	17,456	16,801	16,282	14,977	13,562
Summer	7	18,766	7/8/2015	12,434	11,642	11,049	10,625	10,584	10,901	11,523	12,204	12,879	13,813	15,133	16,203	17,138	17,964	18,487	18,766	18,746	18,105	17,250	16,511	15,929	15,517	14,368	13,043
Summer	7	19,666	7/9/2015	11,951	11,223	10,750	10,447	10,361	10,691	11,279	12,061	13,059	14,243	15,686	16,931	17,831	18,612	19,140	19,486	19,654	19,666	19,366	18,666	17,827	17,264	15,885	14,352
Summer	7	19,439	7/10/2015	13,045	12,085	11,379	10,863	10,658	10,855	11,193	11,971	13,031	14,279	15,681	16,847	17,735	18,433	18,913	19,239	19,439	19,279	18,850	18,007	16,980	16,378	15,012	13,604
Summer	7	17,589	7/11/2015	12,349	11,423	10,680	10,157	9,930	9,983	10,037	10,339	11,370	12,732	14,063	15,120	15,925	16,559	17,042	17,400	17,589	17,575	17,145	16,466	15,743	15,298	14,197	12,946
Summer	7	16,105	7/12/2015	11,799	10,939	10,267	9,828	9,550	9,449	9,233	9,682	10,712	11,788	12,774	13,703	14,578	15,266	15,687	15,914	16,105	16,087	15,594	15,096	14,657	14,407	13,496	12,323
Summer	7	19,355	7/13/2015	11,400	10,688	10,261	10,028	10,070	10,521	11,261	12,011	12,685	13,317	14,452	15,757	16,908	17,903	18,659	19,201	19,317	19,355	18,844	17,968	17,034	15,741	14,359	12,897
Summer	7	16,505	7/14/2015	11,883	11,063	10,558	10,218	10,192	10,561	11,172	11,909	12,409	12,807	13,198	13,671	13,960	14,470	15,185	15,979	16,444	16,505	16,214	15,672	15,307	14,841	13,782	12,563
Summer	7	17,241	7/15/2015	11,627	11,002	10,602	10,340	10,348	10,688	11,286	12,050	13,001	13,995	15,067	15,864	16,325	16,793	17,031	16,999	17,177	17,241	17,029	16,454	15,706	15,256	14,014	12,584
Summer	7	17,754	7/16/2015	11,567	10,793	10,270	9,980	9,936	10,317	10,893	11,629	12,491	13,261

Contains Proprietary Material
Do Not Distribute

Summer	8	18,237	8/20/2015	11,484	10,910	10,516	10,307	10,312	10,860	11,912	12,458	12,951	13,516	14,278	15,123	15,954	16,871	17,571	18,045	18,237	18,102	17,570	16,760	16,371	15,614	14,300	12,991
Summer	8	17,132	8/21/2015	11,930	11,221	10,728	10,400	10,332	10,701	11,675	12,079	12,674	13,371	14,196	14,928	15,604	16,222	16,711	16,959	17,132	17,032	16,514	15,645	15,208	14,499	13,343	12,131
Summer	8	15,772	8/22/2015	11,116	10,411	9,884	9,572	9,443	9,489	9,686	9,895	10,592	11,430	12,326	13,095	13,815	14,441	14,941	15,352	15,652	15,772	15,450	14,745	14,378	13,724	12,730	11,677
Summer	8	15,010	8/23/2015	10,735	10,059	9,580	9,305	9,111	9,080	9,200	9,300	10,053	10,846	11,526	12,065	12,626	13,104	13,523	14,067	14,601	15,010	14,881	14,497	14,456	13,830	12,702	11,574
Summer	8	18,499	8/24/2015	10,710	10,182	9,823	9,652	9,793	10,397	11,600	12,067	12,715	13,602	14,765	15,806	16,719	17,445	17,922	18,306	18,499	18,370	17,816	17,060	16,698	15,787	14,300	12,900
Summer	8	17,782	8/25/2015	11,925	11,113	10,612	10,303	10,274	10,734	11,735	12,032	12,424	13,039	13,871	14,651	15,455	16,267	16,933	17,440	17,782	17,746	17,330	16,540	16,158	15,122	13,571	12,189
Summer	8	16,119	8/26/2015	11,135	10,416	9,813	9,474	9,447	9,891	11,004	11,283	11,607	12,186	12,697	13,263	13,799	14,457	15,012	15,614	16,065	16,119	15,775	15,086	14,824	14,007	12,764	11,448
Summer	8	15,938	8/27/2015	10,502	9,909	9,482	9,271	9,323	9,795	10,927	11,364	11,567	12,028	12,653	13,278	14,056	14,695	15,256	15,672	15,938	15,797	15,400	14,746	14,559	13,775	12,441	11,304
Summer	8	15,927	8/28/2015	10,308	9,607	9,245	8,980	8,995	9,453	10,509	10,924	11,242	11,779	12,462	13,170	13,840	14,632	15,230	15,675	15,927	15,763	15,237	14,288	13,906	13,124	12,072	10,982
Summer	8	14,444	8/29/2015	9,930	9,292	8,931	8,557	8,443	8,552	8,748	8,944	9,595	10,343	11,103	11,852	12,588	13,273	13,769	14,164	14,444	14,320	13,791	13,318	13,204	12,600	11,736	10,725
Summer	8	12,948	8/30/2015	9,856	9,326	8,909	8,664	8,533	8,583	8,718	8,942	9,636	10,328	10,854	11,367	11,857	12,338	12,538	12,761	12,934	12,948	12,781	12,698	12,818	12,188	11,250	10,330
Summer	8	16,367	8/31/2015	9,591	9,137	8,844	8,757	8,892	9,487	10,760	11,281	11,593	12,168	12,899	13,548	14,245	14,866	15,435	15,981	16,235	16,367	16,079	15,544	15,285	14,376	12,994	11,637
Fall	9	18,059	9/1/2015	10,722	10,011	9,632	9,379	9,375	9,892	11,057	11,420	11,991	12,799	13,989	15,022	15,953	16,805	17,436	17,865	18,059	17,929	17,541	16,856	16,523	15,408	13,913	12,474
Fall	9	18,681	9/2/2015	11,488	10,707	10,210	9,920	9,832	10,398	11,558	11,959	12,454	13,387	14,500	15,723	16,823	17,681	18,210	18,524	18,681	18,518	18,026	17,305	17,001	15,875	14,396	13,067
Fall	9	18,099	9/3/2015	11,986	11,246	10,716	10,411	10,329	10,769	11,859	12,286	12,658	13,430	14,457	15,384	16,300	17,124	17,712	18,018	18,099	17,947	17,394	16,638	16,354	15,318	13,844	12,466
Fall	9	17,909	9/4/2015	11,412	10,669	10,231	9,890	9,824	10,306	11,369	11,758	12,241	13,118	14,380	15,535	16,595	17,432	17,892	17,909	17,485	16,928	16,102	15,176	14,704	13,822	12,670	11,542
Fall	9	14,420	9/5/2015	10,576	9,943	9,469	9,197	9,068	9,117	9,349	9,492	10,158	10,838	11,558	12,389	12,871	13,345	13,842	14,143	14,420	14,378	14,009	13,409	13,277	12,561	11,732	10,729
Fall	9	14,386	9/6/2015	9,880	9,264	8,915	8,642	8,508	8,522	8,656	8,799	9,513	10,270	11,006	11,738	12,402	13,097	13,666	14,068	14,370	14,386	14,050	13,350	13,210	12,501	11,606	10,682
Fall	9	14,838	9/7/2015	9,856	9,261	8,880	8,690	8,625	8,849	9,122	9,194	9,721	10,492	11,276	11,927	12,468	13,056	13,663	14,289	14,693	14,838	14,545	14,068	14,050	13,201	11,973	10,861
Fall	9	16,789	9/8/2015	9,984	9,407	9,039	8,877	8,980	9,598	10,882	11,431	11,910	12,522	13,327	14,136	14,884	15,650	16,180	16,544	16,789	16,718	16,368	15,866	15,772	14,690	13,390	12,000
Fall	9	16,431	9/9/2015	11,094	10,497	10,109	9,907	9,940	10,550	11,768	12,316	12,655	13,220	14,050	14,806	15,506	16,133	16,357	16,431	16,223	15,808	15,379	15,039	14,957	14,132	12,924	11,785
Fall	9	17,150	9/10/2015	10,979	10,406	10,067	9,892	9,943	10,606	11,890	12,385	12,601	13,083	13,832	14,722	15,616	16,460	16,997	17,150	17,032	16,393	15,485	14,962	14,690	13,778	12,597	11,483
Fall	9	15,699	9/11/2015	10,644	10,013	9,655	9,428	9,515	10,051	11,176	11,629	11,965	12,460	13,126	13,733	14,245	14,789	15,173	15,520	15,699	15,535	15,110	14,485	14,219	13,388	12,367	11,365
Fall	9	12,030	9/12/2015	10,419	9,784	9,393	9,116	8,998	9,125	9,462	9,762	10,277	10,816	11,259	11,548	11,731	11,878	11,975	12,007	12,030	12,001	11,859	11,700	11,766	11,263	10,501	9,676
Fall	9	10,862	9/13/2015	8,900	8,397	8,006	7,805	7,691	7,701	7,892	8,003	8,577	9,071	9,386	9,631	9,936	10,189	10,332	10,517	10,725	10,862	10,789	10,644	10,859	10,261	9,440	8,663
Fall	9	12,301	9/14/2015	8,084	7,758	7,608	7,556	7,706	8,331	9,476	9,924	10,113	10,380	10,659	10,827	11,021	11,289	11,562	11,877	12,174	12,301	12,192	11,966	11,971	11,207	10,128	9,176
Fall	9	13,292	9/15/2015	8,523	8,141	7,941	7,867	7,980	8,549	9,734	10,099	10,259	10,534	10,935	11,251	11,595	12,016	12,395	12,847	13,179	13,292	13,096	12,640	12,619	11,684	10,549	9,523
Fall	9	12,711	9/16/2015	8,822	8,430	8,173	8,031	8,168	8,780	9,951	10,352	10,480	10,699	11,092	11,441	11,678	12,037	12,334	12,534	12,711	12,641	12,449	12,399	12,457	11,740	10,726	9,750
Fall	9	14,110	9/17/2015	9,026	8,595	8,365	8,240	8,328	8,904	10,069	10,470	10,629	11,000	11,492	11,964	12,361	12,910	13,375	13,830	14,088	14,110	13,798	13,377	13,281	12,369	11,208	10,105
Fall	9	14,775	9/18/2015	9,283	8,762	8,483	8,331	8,405	8,917	10,058	10,393	10,677	11,117	11,725	12,266	12,772	13,397	13,998	14,481	14,775	14,666	14,062	13,337	12,953	12,089	11,131	10,111
Fall	9	14,420	9/19/2015	9,290	8,672	8,326	8,104	8,026	8,186	8,477	8,713	9,282	9,907	10,671	11,437	12,084	12,787	13,447	13,966	14,352	14,420	13,807	13,163	12,731	11,898	10,878	10,022
Fall	9	14,700	9/20/2015	9,125	8,554	8,199	7,947	7,850	7,879	8,059	8,219	8,934	9,747	10,560	11,413	12,336	13,244	13,953	14,396	14,700	14,700	14,321	14,108	13,833	12,885	11,779	10,758
Fall	9	12,691	9/21/2015	9,959	9,449	9,155	8,971	9,074	9,647	10,910	11,523	11,602	11,764	12,049	12,228	12,389	12,630	12,673	12,691	12,673	12,438	12,204	12,407	12,291	11,603	10,703	9,747
Fall	9	12,296	9/22/2015	9,069	8,634	8,439	8,375	8,510	9,115	10,394	10,992	11,055	11,158	11,328	11,431	11,496	11,675	11,824	12,002	12,138	12,078	11,983	12,175	12,296	11,614	10,732	9,801
Fall	9	13,151	9/23/2015	9,122	8,680	8,410	8,325	8,446	9,030	10,276	10,774	10,886	11,099	11,465	11,709	11,919	12,295	12,620	12,944	13,151	13,052	12,799	12,732	12,717	11,945	10,953	9,954
Fall	9	11,755	9/24/2015	9,196	8,705	8,460	8,323	8,413	8,984	10,157	10,622	10,636	10,790	10,988	11,148	11,230	11,403	11,430	11,451	11,379	11,315	11,293	11,755	11,666	11,075	10,317	9,451
Fall	9	11,088	9/25/2015	8,837	8,441	8,222	8,128	8,239	8,780	9,925	10,566	10,680	10,849	11,068	11,088	11,021	10,979	10,905	10,823	10,804	10,725	10,683	10,919	10,845	10,458	9,822	9,206
Fall	9	10,314	9/26/2015	8,579	8,198	7,986	7,870	7,841	8,032	8,365	8,714	9,168	9,657	9,989	10,138	10,095	10,059	9,979	9,918	9,929	9,952	10,046	10,314	10,252	9,908	9,389	8,760
Fall	9	10,824	9/27/2015	8,205	7,822	7,635	7,479	7,471	7,574	7,822	8,135	8,656	9,084	9,315	9,427	9,602	9,672	9,669	9,722	9,863	10,056	10,300	10,824	10,790	10,392	9,775	9,121
Fall	9	12,940	9/28/2015	8,640	8,301	8,207	8,169	8,376	9,044	10,352	11,136	11,249	11,510	11,793	12,027	12,128	12,247	12,328	12,407	12,483	12,483	12,551	12,940	12,818	12,234	11,357	10,442
Fall	9	13,992	9/29/2015	9,759	9,326	9,138	9,035	9,127	9,760	11,090	11,792	11,941	12,204	12,549	12,824	12,940	13,149	13,327	13,580	13,711	13,711	13,653	13,992	13,842	13,009	11,978	10,953
Fall	9	15,751	9/30/2015	10,194	9,662	9,352	9,194	9,292	9,865	11,134	11,728	11,919	12,194	12,819	13,473	14,171	14,807	15,278	15,566	15,751	15,537	15,059	15,022	14,552	13,529	12,236	11,046
Fall	10	11,551	10/1/2015	10,075	9,492	9,088	8,877	8,856	9,383	10,607	11,238	11,215	11,322	11,480	11,551	11,528	11,507	11,453	11,348	11,282	11,184	11,186	11,545	11,429	10,866	10,025	9,209
Fall	10	10,782	10/2/2015	8,601	8,237	8,070	7,990	8,069	8,597	9,731	10,365	10,454	10,638	10,782	10,773	10,686	10,640	10,513	10,380	10,336	10,322	10,350	10,642	10,495	10,130	9,549	8,933
Fall	10	10,438	10/3/2015	8,387	8,068	7,880	7,737	7,816	8,006	8,416	8,863	9,391	9,932	10,297	10,438	10,378	10,244	10,078	9,980	9,961	9,984	10,038	10,379	10,161	9,784	9,244	8,665
Fall	10	10,363	10/4/2015	8,201	7,846	7,670	7,524	7,492	7,578	7,878	8,244	8,752	9,219	9,355	9,418	9,509	9,540	9,497	9,452	9,555	9,676	9,862	10,363	10,284	9,814	9,182	8,582
Fall	10	11,501	10/5/2015	8,102	7,823	7,665	7,661	7,866	8,542	9,825	10,540	10,543	10,760	10,905	10,938	10,906	10,980	10,940	10,941	10,924	10,894	10,988	11,501	11,344	10,728	9,896	9,060
Fall	10	11,609	10/6/2015	8,503	8,151	8,002	7,953	8,093	8,788	10,047	10,645	10,589	10,626	10,701	10,758	10,803	10,993	11,113	11,282	11,352	11,269	11,160	11,609	11,522	10,874	9,982	9,118
Fall	10	12,441	10/7/2015	8,506	8,209	8,051	7,969	8,131	8,778	10,034	10,649	10,648	10,746	10,947	11,085	11,318	11,693	11,952	12,239	12,441	12,404	12,189	12,371	12,118	11,371	10,335	9,426
Fall	10	12,755	10/8/2015	8,817	8,370	8,112	8,013	8,138	8,734	9,958	10,469	10,508	10,822	11,279	11,598	11,985	12,376	12,593	12,654	12,755	12,693	12,433	12,712	12,484	11,709	10,743	9,793
Fall	10	12,679	10/9/2015	9,026	8,595	8,278	8,184	8,277	8,830	9,996	10,537	10,610	10,915	11,299	11,653	11,914	12,239	12,516	12,650	12,679	12,517	12,143	12,234	11,923	11,408	10,695	9,869
Fall	10	10,277	10/10/2015	9,074	8,599	8,252	8,079	8,047	8,200	8,549	8,984	9,427	9,903	10,209	10,277	10,235	10,101	9,965	9,839	9,818	9,823	9,908	10,106	9,963	9,567	9,093	8,487
Fall	10	10,602	10/11/2015	7,973	7,625	7,434	7,287	7,328	7,462	7,784	8,192	8,707	9,060	9,088	9,132	9,298	9,405	9,518	9,671	9,861	10,057	10,097	10,602	10,479	9,955	9,224	8,525
Fall	10	12,066	10/12/2015	8,049	7,706	7,595	7,558	7,758	8,404	9,673	10,274	10,388	10,604	10,895	11,042	11,274	11,543	11,642	11,704	11,763	11,737	11,668	12,066	11,810	11,092	10,143	9,237
Fall	10	12,399	10/13/2015	8,620	8,223	8,047	7,988	8,115	8,736	9,987	10,655	10,606	10,782	11,004	11,229	11,455	11,832	12,057	12,270	12,399	12,277	12,045	12,348	12,066	11,272	10,244	9,365
Fall	10	11,750	10/14/2015	8,671	8,228	8,005	7,915	8,070	8,725	9,986	10,593	10,563	10,697	10,836	10,981	11,094	11,336	11,502	11,663	11,737	11,628	11,446	11,750	11,508	10,811	9,918	9,078
Fall	10	11,567	10/15/2015	8,482	8,164	7,969	7,938	8,130	8,829	10,132	10,741	10,738	10,784	10,860	10,915	10,932	11,076	11,172	11,216	11,299	11,236	11,152	11,567	11,351	10,752	9,919	9,145
Fall	10	10,898	10/16/2015	8,514	8,187	8,028	8,002	8,138	8,731	9,917	10,559	10,555	10,706	10,803	10,898	10,862	10,847	10,734	10,683	10,699	10,609	10,474	10,771	10,527	10,138	9,552	8,923
Fall	10	10,154	10/17/2015	8,427	8,096	7,969	7,950	8,076	8,412	8,930	9,537	10,066	10,154	10,001	9,763	9,517	9,362	9,232	9,196	9,300	9,370	9,510	10,024	9,945	9,648	9,244	8,782
Fall	10	10,672	10/18/2015	8,379	8,165	8,101	8,147	8,283	8,603	9,132	9,803	10,433	10,413	10,025	9,701	9,520	9,342	9,196	9,152	9,207	9,465	9,795	10,582	10,672	10,319	9,818	9,302
Fall	10	13,072	10/19/2015	9,083	8,969	9,048	9,220	9,668	10,661	12,298	13,072	12,959	12,533	11,952	11,471	11,116	10,922	10,721	10,635	10,581	10,721	11,138	11,887	11,810	11,369	10,619	9,955
Fall	10	13,126	10/20/2015	9,651	9,520	9,525	9,697	10,093	10,960	12,506	13,126	12,921	12,350	11,735	11,280	10,951	10,810	10,650	10,588	10,591	10,634	10,885	11,504	11,312	10,914	10,135	9,438
Fall	10	12,545	10/21/2015	9,059	8,906	8,977	8,992	9,433	10,353	11,852	12,545	12,312	11,831	11,386	11,109	10,872	10,829	10,806	10,868	10,883	10,870	11,008	11,463	11,259	10,724	9,903	9,190
Fall	10	11,789	10/22/2015	8,712	8,491	8,440	8,506	8,829	9,645	11,072	11,789	11,582	11,336	11,062	10,932	10,840	10,928	10,969	11,090	11,142	11,101	11,081	11,507	11,337	10,753	9,966	9,169
Fall	10	11,335	10/23/2015	8,623	8,301	8,194	8,155	8,313	8,910	10,160	10,839	10,852	10,848	10,847	10,855	10,922	11,117	11,228	11,331	11,335	11,227	11,083	11,245	10,893	10,437	9,796	9,107
Fall	10	10,269	10/24/2015	8,453	8,006	7,767	7,652	7,681	7,940	8,356	8,849	9,278	9,628	9,804	9,774	9,734	9,647	9,637	9,665	9,705	9,822	10,001	10,269	10,042	9,734	9,172	8,506
Fall	10	10,878	10/25/2015	7,995	7,624	7,494	7,385	7,408	7,527	7,824	8,365	8,775	9,186	9,295	9,346	9,479	9,647	9,695	9,759	9,901	10,068	10,429	10,878	10,647	10,101	9,444	8,759
Fall	11	11,826	10/26/2015	8,341	7,928	7,737	7,663	7,814	8,450	9,647	10,503	10,603	10,696	10,882	10,919	10,903	10,920	10,802	10,770	10,816	10,960	11,518	11,826	11,559	10,966	10,239	9,415
Fall	11	12,217	10/27/2015	8,906	8,654	8,517	8,539	8,768	9,491	10,783	11,597	11,576	11,597	11,782	11,747	11,774	11,805	11,666	11,671	11,704	11,773	12,176	12,217	11,908	11,264	10,509	9,652
Fall	11	11,801	10/28/2015	9,148	8,786	8,585	8,517	8,663	9,271	10,498	11,257	11,123	11,228	11,318	11,321	11,288	11,295	11,315	11,236	11,252	11,207	11,461	11,801	11,569	11,064	10,185	9,355
Fall	11	11,521	10/29/2015	8,773	8,426	8,208	8,161	8,304	8,947	10,175	10,852	10,837	10,896	11,030	11,076	11,072	11,084	11,005	10,924	10,885	10,856	11,144	11,521	11,346	10,811	10,041	9,250
Fall	11	11,215	10/30/2015	8,688	8,385	8,234	8,258	8,475	9,170	10,420	11,215	11,168	11,006	10,836	10,695	10,417	10,385	10,268	10,194	10,127	10,122	10,258	10,592	10,397	10,133	9,694	9,127
Fall	10	10,430	10/31/2015	8,666	8,399	8,308	8,328	8,419	8,736	9,260	9,818	10,246	10,430	10,358	10,228	10,014	9,733	9,541	9,442	9,465	9,486	9,607	9,692	9,619	9,440	9,046	8,552
Fall	11	10,600	11/1/2015	7,926	7,737	7,687	7,598	7,658	7,855	8,247	8,678	9,296	9,596	9,572	9,519	9,561	9,558	9,539	9,504	9,692	10,360	10,600	10,420	10,150	9,567	8,988	8,446
Fall	11	11,868	11/2/2015	8,061	7,844	7,744	7,748	7,969	8,694	10,051	10,716	10,944	11,155	11,320	11,309	11,268	11,290	11,182	11,164	11,281	11,702	11,868	11,659	11,241	10,583	9,854	9,130
Fall	11	11,816	11/3/2015	8,682	8,379	8,200	8,174	8,342	9,055	10,296	10,811	10,900	11,018	11,129	11,110	11,066	11,059	10,961	10,914	11,016	11,517	11,816	11,661	11,291	10,633	9,790	9,055
Fall	11	11,776	11/4/2015	8,590	8,288	8,122	8,085	8,276	8,954	10,228	10,715	10,826	10,932	11,015	10,981	10,965	10,981	10,913	10,861	10,957	11,467	11,776	11,564	11,225	10,616	9,843	9,082
Fall	11	11,920	11/5/2015	8,542	8,260	8,117	8,076	8,228	8,913	10,163	10,636	10,720	10,826	10,963	11,017	11,055	11,177	11,218	11,247	11,262	11,610	11,920	11,757	11,415	10,839	10,013	9,235
Fall	11	11,560	11/6/2015	8,672	8,347	8,147	8,091	8,260	8,885	10,105	10,637	10,832	11,023	11,172	11,240	11,199	11,198	11,161	11,057	11,035	11,364	11,560	11,284	10,998	10,580	9,992	9,336
Fall	11	10,641	11/7/2015	8,694	8,311	8,078	7,950	8,002	8,232	8,637	8,995	9,610	10,091	10,405	10,512	10,425	10,318	10,216	10,155	10,194	10,629	10,641	10,380	10,009	9,531	8,993	8,356
Fall	11	10,904	11/8/2015	7,845	7,536	7,347	7,300	7,366	7,578	7,985	8,453	9,185	9,573	9,617	9,565	9,581	9,566	9,534	9,574	9,712	10,597	10,904	10,856	10,683	10,211	9,668	9,114
Fall	11	12,815	11/9/2015	8,760	8,567	8,532	8,598	8,918	9,729	11,184	11,845	11,947	12,063	12,198	12,212	12,160	12,154	12,010	11,973	12,122	12,563	12,815	12,574	12,138	11,452	10,643	9,834
Fall	11	11,535	11/10/2015	9,292	8,951	8,765	8,703	8,916	9,620	10,896	11,308	11,154	11,024	10,917	10,820	10,737	10,771	10,711	10,703	10,763	11,142	11,535	11,369	11,068	10,571	10,004	9,353
Fall	11	11,725	11/11/2015	8,990	8,767	8,738	8,842	9,176	9,971	11,150	11,725	11,626	11,333	11,134	10,904	10,755	10,718	10,724	10,757	10,809	11,210	11,628	11,497	11,302	10,799	10,130	9,480
Fall	11	11,612	11/12/2015	9,110	8,875	8,803	8,947	9,121	9,949	11,244	11,583	11,330	11,142	11,057	10,930	10,803	10,802	10,757	10,799	10,807	11,190	11,612	11,448	11,155	10,542	9,796	9,113
Fall	11	11,330	11/13/2015	8,677	8,434	8,384	8,451	8,751	9,561	10,891	11,330	11,181	10,956	10,812	10,622	10,424	10,302	10,178	10,115	10,272	10,891	11,323	11,206	11,086	10,884	10,525	10,048
Fall	11	11,600	11/14/2015	9,653	9,492	9,473	9,598	9,851	10,354	10,972	11,434	11,600	11,215	10,818	10,403	9,996	9,698	9,499	9,464	9,679	10,475	11,002	11,013	10,983	10,819	10,578	10,271
Fall	11	12,199	11/15/2015	10,097	10,082	10,155	10,332	10,604	11,024	11,595	12,075	12,199	11,494	10,634	10,071	9,796	9,575	9,533	9,535	9,800	10,748	11,097	11,101	11,036	10,664	10,165	9,760
Fall	11	13,704	11/16/2015	9,596	9,648	9,833	10,101	10,627	11,645	13,299	13,704	13,219	12,518	11,908	11,408	10,996	10,836	10,659	10,645	10,805	11,551	12,046	12,004	11,741	11,182	10,478	9,791
Fall	11	11,962	11/17/2015	9,413	9,216	9,090	9,123	9,392	10,214	11,618	11,962	11,736	11,485	11,294	11,102	10,856	10,801	10,730	10,756	10,969	11,716	11,910	11,820	11,557	11,026	10,253	9,512
Fall	11	11,929	11/18/2015	9,014	8,754	8,627	8,621	8,833	9,573	10,853	11,318	11,263	11,180	11,206	11,120	10,996	11,085	11,012	10,983	11,142	11,733	11,929	11,698	11,393	10,797	10,015	9,213
Fall	11	11,748	11/19/2015	8,695	8,391	8,203	8,151	8,328	8,993	10,333	10,939	11,051	11,162	11,278	11,266	11,211	11,254	11,202	11,206	11,121	11,429	11,748	11,531	11,204	10,663	9,874	9,179
Fall	11	11,559	11/20/2015	8,695	8,494	8,396	8,458	8,805	9,599	11,052	11,559	11,415	11,194	10,962	10,730	10,520	10,435	10,292	10,242	10,359	10,997	11,361	11,292	11,215	11,016	10,655	10,182
Fall	11	11,984	11/21/2015	9,810	9,715	9,705	9,816	10,092	10,607	11,292	11,864	11,984	11,552

Contains Proprietary Material
Do Not Distribute

Winter	12	4,685	12/15/2014	3,547	3,520	3,455	3,483	3,540	3,786	4,263	4,603	4,682	4,685	4,612	4,504	4,454	4,252	4,208	4,204	4,304	4,529	4,657	4,609	4,568	4,415	4,135	3,880
Winter	12	4,820	12/16/2014	3,642	3,497	3,368	3,396	3,410	3,566	3,961	4,308	4,362	4,420	4,467	4,443	4,478	4,471	4,470	4,465	4,533	4,701	4,820	4,820	4,792	4,649	4,411	4,162
Winter	12	5,201	12/17/2014	3,993	3,843	3,786	3,780	3,888	4,109	4,559	4,884	5,011	5,004	5,060	4,941	4,863	4,766	4,744	4,652	4,726	4,995	5,165	5,144	5,201	5,118	4,875	4,676
Winter	12	5,253	12/18/2014	4,453	4,355	4,290	4,228	4,355	4,542	4,932	5,253	5,223	5,209	5,226	5,091	5,012	5,035	4,936	4,863	4,924	5,042	5,220	5,167	5,177	5,013	4,809	4,566
Winter	12	5,219	12/19/2014	4,393	4,277	4,204	4,216	4,255	4,463	4,901	5,211	5,219	5,120	4,984	4,904	4,829	4,745	4,676	4,607	4,574	4,818	5,046	5,091	5,082	5,043	4,882	4,707
Winter	12	4,781	12/20/2014	4,484	4,355	4,269	4,219	4,194	4,270	4,406	4,597	4,716	4,781	4,738	4,673	4,562	4,421	4,287	4,228	4,243	4,454	4,659	4,663	4,644	4,621	4,528	4,410
Winter	12	4,781	12/21/2014	4,289	4,231	4,235	4,209	4,290	4,404	4,554	4,716	4,781	4,674	4,429	4,185	4,010	3,921	3,795	3,737	3,811	4,133	4,402	4,450	4,508	4,491	4,354	4,171
Winter	12	4,626	12/22/2014	4,050	3,924	3,900	3,848	3,927	4,056	4,383	4,546	4,618	4,626	4,515	4,404	4,336	4,272	4,199	4,127	4,151	4,379	4,407	4,380	4,386	4,239	4,067	3,807
Winter	12	4,224	12/23/2014	3,597	3,462	3,332	3,279	3,275	3,410	3,696	3,980	4,080	4,175	4,224	4,112	4,117	4,057	4,082	4,034	4,010	4,196	4,176	4,066	3,990	3,867	3,672	3,407
Winter	12	3,625	12/24/2014	3,179	3,025	2,926	2,867	2,870	2,934	3,074	3,240	3,361	3,490	3,532	3,528	3,516	3,473	3,449	3,427	3,470	3,605	3,625	3,584	3,557	3,536	3,440	3,318
Winter	12	3,736	12/25/2014	3,191	3,108	3,066	3,055	3,080	3,153	3,261	3,383	3,491	3,598	3,635	3,621	3,556	3,417	3,288	3,183	3,176	3,339	3,577	3,652	3,719	3,736	3,701	3,620
Winter	12	4,177	12/26/2014	3,514	3,471	3,459	3,467	3,540	3,681	3,898	4,103	4,177	4,144	4,006	3,838	3,694	3,555	3,435	3,383	3,404	3,622	3,771	3,787	3,766	3,698	3,583	3,430
Winter	12	3,656	12/27/2014	3,250	3,130	3,086	3,044	3,030	3,077	3,195	3,307	3,399	3,478	3,570	3,588	3,567	3,489	3,372	3,344	3,359	3,580	3,656	3,642	3,568	3,510	3,365	3,201
Winter	12	4,178	12/28/2014	3,095	2,959	2,934	2,926	2,967	3,034	3,160	3,325	3,449	3,608	3,702	3,754	3,802	3,818	3,797	3,804	3,867	4,085	4,178	4,160	4,118	4,012	3,870	3,722
Winter	12	4,660	12/29/2014	3,588	3,522	3,495	3,530	3,615	3,783	4,074	4,367	4,479	4,547	4,585	4,509	4,449	4,374	4,320	4,286	4,317	4,497	4,660	4,630	4,595	4,503	4,331	4,149
Winter	12	4,862	12/30/2014	4,047	3,944	3,923	3,931	3,985	4,199	4,501	4,788	4,862	4,830	4,732	4,614	4,496	4,390	4,285	4,205	4,202	4,469	4,748	4,741	4,735	4,688	4,563	4,406
Winter	12	5,032	12/31/2014	4,283	4,240	4,218	4,235	4,298	4,462	4,724	4,976	4,977	5,032	4,908	4,761	4,601	4,450	4,329	4,205	4,221	4,493	4,732	4,718	4,659	4,593	4,487	4,397
Winter	1	4,469	1/1/2015	4,325	4,263	4,233	4,243	4,271	4,331	4,418	4,469	4,441	4,458	4,456	4,390	4,318	4,146	4,014	3,946	4,042	4,270	4,438	4,412	4,328	4,275	4,090	3,896
Winter	1	4,507	1/2/2015	3,797	3,699	3,609	3,619	3,616	3,740	3,983	4,182	4,278	4,329	4,469	4,463	4,449	4,389	4,336	4,306	4,279	4,441	4,507	4,387	4,349	4,244	4,100	3,890
Winter	1	3,825	1/3/2015	3,758	3,616	3,553	3,479	3,518	3,522	3,555	3,717	3,751	3,810	3,789	3,825	3,738	3,691	3,680	3,593	3,652	3,752	3,805	3,697	3,646	3,507	3,321	3,173
Winter	1	4,431	1/4/2015	3,070	2,917	2,857	2,835	2,784	2,864	2,960	3,111	3,174	3,441	3,482	3,590	3,708	3,747	3,788	3,855	3,981	4,243	4,431	4,426	4,393	4,375	4,267	4,199
Winter	1	5,660	1/5/2015	4,134	4,137	4,223	4,281	4,477	4,745	5,270	5,643	5,660	5,590	5,554	5,365	5,271	5,125	4,977	5,032	4,987	5,228	5,544	5,532	5,501	5,366	5,130	4,926
Winter	1	5,448	1/6/2015	4,743	4,634	4,518	4,434	4,476	4,699	5,094	5,448	5,396	5,363	5,298	5,252	5,168	4,975	4,887	4,877	4,918	5,024	5,231	5,277	5,292	5,217	5,013	4,873
Winter	1	6,588	1/7/2015	4,719	4,645	4,602	4,636	4,773	4,991	5,401	5,726	5,818	5,889	6,012	5,986	6,000	6,081	5,988	6,043	6,084	6,298	6,581	6,588	6,560	6,434	6,355	6,265
Winter	1	6,964	1/8/2015	6,128	6,145	6,094	6,074	6,127	6,406	6,666	6,964	6,957	6,795	6,657	6,499	6,381	6,241	6,158	6,077	5,980	6,002	6,157	6,018	5,899	5,696	5,531	5,292
Winter	1	5,780	1/9/2015	5,128	5,013	4,951	4,901	4,916	5,045	5,339	5,563	5,650	5,639	5,617	5,573	5,466	5,344	5,271	5,178	5,211	5,387	5,665	5,675	5,706	5,780	5,643	5,499
Winter	1	6,097	1/10/2015	5,432	5,401	5,432	5,452	5,538	5,684	5,812	5,965	6,097	5,883	5,729	5,512	5,301	5,030	4,814	4,633	4,664	4,817	5,146	5,166	5,270	5,289	5,155	5,009
Winter	1	4,926	1/11/2015	4,926	4,843	4,801	4,727	4,675	4,678	4,714	4,788	4,777	4,819	4,690	4,615	4,523	4,415	4,399	4,335	4,386	4,568	4,699	4,655	4,611	4,446	4,275	4,057
Winter	1	5,150	1/12/2015	3,932	3,840	3,789	3,785	3,840	4,081	4,500	4,837	4,870	4,898	4,882	4,850	4,815	4,816	4,807	4,814	4,842	4,992	5,150	5,126	5,048	4,980	4,751	4,601
Winter	1	5,571	1/13/2015	4,508	4,380	4,359	4,352	4,414	4,648	5,048	5,367	5,398	5,442	5,461	5,442	5,433	5,399	5,347	5,327	5,313	5,422	5,571	5,557	5,453	5,296	5,084	4,840
Winter	1	5,489	1/14/2015	4,687	4,569	4,439	4,473	4,497	4,698	5,111	5,388	5,473	5,434	5,489	5,431	5,350	5,187	5,113	4,992	4,940	5,129	5,346	5,408	5,340	5,196	4,996	4,762
Winter	1	5,354	1/15/2015	4,607	4,495	4,457	4,416	4,466	4,690	5,103	5,354	5,307	5,343	5,299	5,224	5,153	5,109	4,966	4,953	4,854	4,977	5,249	5,276	5,262	5,094	4,975	4,765
Winter	1	5,490	1/16/2015	4,576	4,562	4,542	4,493	4,598	4,808	5,155	5,490	5,456	5,365	5,103	4,957	4,700	4,559	4,353	4,231	4,185	4,279	4,613	4,658	4,743	4,657	4,534	4,420
Winter	1	4,596	1/17/2015	4,288	4,208	4,165	4,178	4,168	4,240	4,411	4,568	4,596	4,569	4,381	4,256	4,015	3,836	3,743	3,646	3,579	3,757	4,071	4,108	4,057	3,929	3,819	3,705
Winter	1	4,143	1/18/2015	3,507	3,402	3,323	3,346	3,358	3,452	3,589	3,756	3,876	3,956	3,906	3,799	3,777	3,708	3,633	3,588	3,611	3,783	4,063	4,112	4,143	4,107	3,966	3,899
Winter	1	4,975	1/19/2015	3,791	3,804	3,815	3,882	4,027	4,267	4,622	4,862	4,975	4,897	4,695	4,523	4,360	4,157	4,106	3,983	3,874	3,948	4,275	4,424	4,491	4,363	4,247	4,082
Winter	1	4,945	1/20/2015	4,000	3,926	3,893	3,936	3,979	4,249	4,718	4,945	4,914	4,769	4,620	4,388	4,278	4,201	4,102	4,050	3,943	4,148	4,394	4,419	4,393	4,250	4,047	3,865
Winter	1	4,667	1/21/2015	3,709	3,631	3,605	3,610	3,632	3,845	4,329	4,667	4,648	4,602	4,478	4,360	4,267	4,210	4,116	4,007	4,041	4,155	4,457	4,548	4,521	4,469	4,294	4,124
Winter	1	5,138	1/22/2015	3,991	3,965	3,979	3,993	4,115	4,331	4,807	5,138	5,119	5,060	5,005	4,846	4,796	4,683	4,631	4,589	4,607	4,722	4,913	4,909	4,867	4,731	4,557	4,303
Winter	1	5,022	1/23/2015	4,170	4,084	4,027	4,056	4,087	4,313	4,725	4,969	5,022	5,010	5,003	4,960	4,901	4,850	4,802	4,752	4,761	4,875	5,001	4,963	4,905	4,754	4,583	4,382
Winter	1	4,627	1/24/2015	4,226	4,127	4,087	4,075	4,075	4,144	4,308	4,489	4,627	4,622	4,623	4,536	4,391	4,258	4,145	4,171	4,162	4,216	4,516	4,497	4,459	4,387	4,269	4,073
Winter	1	4,338	1/25/2015	3,957	3,867	3,863	3,781	3,805	3,843	3,946	4,061	4,146	4,224	4,190	4,064	4,065	4,009	3,979	3,942	3,998	4,077	4,338	4,329	4,277	4,126	3,980	3,769
Winter	1	5,402	1/26/2015	3,712	3,685	3,700	3,820	3,982	4,296	4,878	5,177	5,336	5,382	5,402	5,321	5,329	5,248	5,212	5,147	5,177	5,205	5,358	5,303	5,272	5,046	4,809	4,590
Winter	1	5,345	1/27/2015	4,430	4,345	4,302	4,240	4,306	4,553	4,933	5,242	5,303	5,345	5,296	5,159	5,125	4,965	4,875	4,831	4,772	4,886	5,157	5,254	5,199	5,148	4,981	4,824
Winter	1	5,765	1/28/2015	4,690	4,630	4,605	4,728	4,812	5,057	5,515	5,765	5,756	5,533	5,319	5,151	4,959	4,816	4,652	4,544	4,486	4,618	4,954	5,011	5,042	4,904	4,763	4,513
Winter	1	4,938	1/29/2015	4,349	4,258	4,191	4,113	4,085	4,240	4,672	4,938	4,904	4,843	4,741	4,622	4,565	4,530	4,461	4,493	4,542	4,652	4,807	4,833	4,832	4,695	4,539	4,331
Winter	1	5,000	1/30/2015	4,209	4,091	4,008	3,993	4,091	4,271	4,664	4,956	4,965	5,000	4,948	4,823	4,729	4,597	4,497	4,389	4,296	4,433	4,803	4,858	4,828	4,788	4,693	4,577
Winter	1	4,970	1/31/2015	4,487	4,532	4,502	4,533	4,584	4,675	4,813	4,911	4,970	4,863	4,660	4,455	4,246	4,153	4,012	3,972	4,051	4,139	4,351	4,359	4,303	4,231	4,073	3,911
Winter	2	4,222	2/1/2015	3,776	3,667	3,649	3,624	3,625	3,660	3,779	3,933	3,983	4,073	4,190	4,147	4,152	4,188	4,151	4,129	4,155	4,183	4,222	4,106	4,019	3,900	3,825	3,660
Winter	2	5,509	2/2/2015	3,538	3,511	3,567	3,615	3,834	4,159	4,710	5,147	5,319	5,437	5,509	5,495	5,441	5,382	5,228	5,189	5,171	5,262	5,456	5,471	5,460	5,291	5,104	4,833
Winter	2	5,581	2/3/2015	4,676	4,579	4,516	4,523	4,642	4,863	5,331	5,581	5,567	5,424	5,253	5,082	4,935	4,747	4,638	4,518	4,449	4,550	4,933	5,059	5,068	4,952	4,759	4,554
Winter	2	5,188	2/4/2015	4,436	4,340	4,239	4,255	4,290	4,556	4,971	5,188	5,133	4,941	4,826	4,602	4,457	4,344	4,228	4,186	4,091	4,245	4,529	4,578	4,582	4,492	4,340	4,209
Winter	2	5,610	2/5/2015	4,170	4,195	4,191	4,280	4,424	4,722	5,233	5,537	5,610	5,569	5,448	5,328	5,162	5,064	4,927	4,761	4,824	4,884	5,202	5,418	5,410	5,354	5,243	5,142
Winter	2	6,065	2/6/2015	5,099	5,062	5,062	5,096	5,191	5,395	5,848	6,065	5,943	5,799	5,686	5,424	5,206	4,924	4,768	4,636	4,544	4,554	4,738	4,819	4,832	4,705	4,589	4,422
Winter	2	4,403	2/7/2015	4,220	4,192	4,116	4,075	4,107	4,151	4,291	4,403	4,380	4,384	4,288	4,105	3,897	3,748	3,643	3,526	3,472	3,503	3,758	3,838	3,833	3,770	3,647	3,482
Winter	2	3,852	2/8/2015	3,361	3,164	3,210	3,196	3,175	3,177	3,319	3,449	3,502	3,627	3,596	3,480	3,533	3,518	3,518	3,494	3,550	3,645	3,851	3,852	3,825	3,660	3,492	3,296
Winter	2	5,022	2/9/2015	3,100	3,055	3,085	3,070	3,098	3,337	3,889	4,237	4,344	4,388	4,500	4,529	4,594	4,611	4,642	4,645	4,667	4,782	5,003	5,022	4,992	4,860	4,727	4,521
Winter	2	5,334	2/10/2015	4,468	4,338	4,310	4,295	4,372	4,548	5,007	5,334	5,313	5,215	5,245	5,128	5,018	4,892	4,772	4,635	4,641	4,677	4,956	5,043	5,012	4,924	4,743	4,611
Winter	2	5,448	2/11/2015	4,541	4,461	4,443	4,478	4,572	4,777	5,211	5,448	5,410	5,286	5,161	4,898	4,736	4,509	4,324	4,300	4,180	4,341	4,619	4,710	4,683	4,534	4,418	4,193
Winter	2	5,696	2/12/2015	4,119	4,038	4,055	4,075	4,147	4,385	4,858	5,198	5,326	5,451	5,513	5,503	5,429	5,426	5,343	5,303	5,300	5,371	5,591	5,696	5,633	5,570	5,343	5,171
Winter	2	5,931	2/13/2015	5,024	4,959	4,932	4,950	4,997	5,224	5,668	5,907	5,931	5,741	5,576	5,290	5,130	4,922	4,798	4,606	4,534	4,624	4,979	5,028	5,075	5,006	4,859	4,691
Winter	2	5,515	2/14/2015	4,504	4,364	4,293	4,254	4,242	4,312	4,429	4,520	4,577	4,679	4,780	4,778	4,741	4,731	4,723	4,665	4,685	4,856	5,221	5,456	5,515	5,515	5,447	5,373
Winter	2	5,678	2/15/2015	5,297	5,122	5,161	5,185	5,320	5,386	5,541	5,661	5,678	5,591	5,459	5,297	5,141	4,957	4,832	4,773	4,758	4,987	5,237	5,406	5,360	5,281	5,133	5,027
Winter	2	6,025	2/16/2015	4,915	4,867	4,864	4,938	5,074	5,242	5,537	5,796	5,869	6,013	5,975	6,025	5,989	5,874	5,816	5,699	5,639	5,711	5,880	5,868	5,734	5,574	5,359	5,260
Winter	2	6,005	2/17/2015	5,190	5,139	5,233	5,191	5,307	5,531	5,720	5,904	6,005	5,916	5,662	5,460	5,311	5,192	5,094	4,998	5,026	5,130	5,461	5,578	5,578	5,496	5,350	5,285
Winter	2	6,381	2/18/2015	5,186	5,115	5,100	5,053	5,115	5,280	5,554	5,661	5,780	5,778	5,843	5,852	5,791	5,745	5,721	5,769	5,792	5,931	6,193	6,365	6,381	6,362	6,252	6,134
Winter	2	6,897	2/19/2015	6,057	6,083	6,137	6,176	6,234	6,460	6,748	6,897	6,865	6,761	6,737	6,644	6,523	6,362	6,260	6,151	6,097	6,187	6,499	6,742	6,742	6,736	6,573	6,557
Winter	2	7,236	2/20/2015	6,574	6,476	6,560	6,586	6,650	6,840	7,102	7,236	7,179	6,981	6,810	6,575	6,314	6,064	5,881	5,792	5,776	5,816	5,988	5,983	5,889	5,728	5,468	5,233
Winter	2	5,013	2/21/2015	5,008	4,868	4,790	4,737	4,642	4,630	4,744	4,741	4,833	4,907	5,009	5,013	4,954	4,880	4,819	4,762	4,829	4,838	4,868	4,920	4,803	4,695	4,552	4,420
Winter	2	4,972	2/22/2015	4,272	4,234	4,191	4,185	4,233	4,330	4,353	4,523	4,594	4,568	4,581	4,525	4,440	4,320	4,332	4,311	4,406	4,575	4,817	4,912	4,972	4,786	4,636	4,514
Winter	2	6,003	2/23/2015	4,447	4,435	4,480	4,547	4,721	5,003	5,419	5,725	5,857	5,802	5,715	5,686	5,538	5,451	5,385	5,299	5,241	5,380	5,678	5,966	5,989	6,003	5,814	5,744
Winter	2	6,399	2/24/2015	5,589	5,566	5,483	5,534	5,529	5,788	6,124	6,399	6,319	6,051	5,823	5,579	5,457	5,308	5,125	5,049	4,982	5,035	5,301	5,592	5,587	5,524	5,306	5,093
Winter	2	5,655	2/25/2015	5,008	4,887	4,880	4,829	4,890	5,025	5,402	5,655	5,544	5,404	5,246	5,036	4,900	4,813	4,765	4,730	4,753	4,873	5,070	5,206	5,151	5,014	4,820	4,615
Winter	2	5,441	2/26/2015	4,521	4,403	4,424	4,461	4,509	4,748	5,140	5,328	5,323	5,231	5,141	4,997	4,834	4,753	4,685	4,670	4,776	4,979	5,211	5,433	5,441	5,415	5,303	5,157
Winter	2	6,090	2/27/2015	5,048	5,040	5,059	5,038	5,152	5,430	5,861	6,090	6,017	5,798	5,604	5,436	5,326	5,177	5,031	4,918	4,862	4,943	5,234	5,462	5,494	5,467	5,325	5,198
Winter	2	5,380	2/28/2015	5,091	5,058	4,992	5,001	5,005	5,022	5,200	5,358	5,380	5,337	5,147	4,936	4,678	4,492	4,323	4,254	4,263	4,359	4,562	4,682	4,636	4,547	4,390	4,220
Spring	3	4,582	3/1/2015	4,123	3,998	4,013	3,959	3,981	4,002	4,072	4,178	4,271	4,415	4,430	4,359	4,281	4,210	4,143	4,140	4,226	4,309	4,491	4,582	4,572	4,432	4,299	4,150
Spring	3	5,213	3/2/2015	4,056	4,025	4,042	4,088	4,200	4,504	4,994	5,191	5,213	5,061	4,966	4,826	4,698	4,589	4,436	4,360	4,343	4,439	4,735	4,966	4,949	4,879	4,746	4,530
Spring	3	4,987	3/3/2015	4,416	4,319	4,214	4,181	4,218	4,409	4,803	4,987	4,946	4,943	4,921	4,782	4,672	4,609	4,513	4,407	4,315	4,323	4,409	4,427	4,389	4,215	4,013	3,781
Spring	3	5,175	3/4/2015	3,586	3,517	3,480	3,512	3,529	3,797	4,126	4,436	4,510	4,556	4,629	4,711	4,714	4,711	4,753	4,880	4,807	4,978	5,092	5,175	5,100	4,983	4,828	4,691
Spring	3	5,456	3/5/2015	4,625	4,528	4,504	4,568	4,630	4,749	4,921	5,075	5,156	5,260	5,240	5,190	5,247	5,161	5,061	4,969	4,868	4,967	5,124	5,407	5,456	5,362	5,315	5,239
Spring	3	6,170	3/6/2015	5,199	5,237	5,269	5,384	5,489	5,652	5,962	6,170	6,085	5,851	5,702	5,452	5,230	5,077	4,980	4,820	4,776	4,757	5,025	5,275	5,286	5,248	5,117	4,988
Spring	3	5,038	3/7/2015	4,895	4,814	4,825	4,792	4,822	4,877	5,008	5,038	4,978	4,810	4,693	4,519	4,381	4,192	4,051	3,892	3,830	3,903	4,081	4,328	4,345	4,286	4,183	4,033
Spring	3	4,274	3/8/2015	3,919	0	3,855	3,846	3,852	3,918	4,067	4,198	4,274	4,257	4,079	3,919	3,798	3,669	3,596	3,520	3,495	3,537	3,638	3,819	4,047	3,965	3,869	3,657
Spring	3	4,639	3/9/2015	3,586	3,490	3,469	3,497	3,569	3,855	4,311	4,613	4,639	4,614	4,551	4,463	4,338	4,215	4,103	4,080	3,961	3,940	3,997	4,115	4,285	4,191	3,934	3,814
Spring	3	4,432	3/10/2015	3,563	3,545	3,381	3,434	3,426	3,654	4,051	4,349	4,385	4,391	4,410	4,416	4,432	4,360	4,339	4,289	4,228	4,181	4,197	4,232	4,282	4,171	3,938	3,672
Spring	3	4,261	3/11/2015	3,476	3,359	3,278	3,252	3,280	3,433	3,892	4,145	4,181	4,226	4,261	4,197	4,119	4,039	4,024	3,937	3,872	3,800	3,820	3,859	4,093	4,036	3,805	3,630
Spring	3	4,342	3/12/2015	3,427	3,371	3,324	3,288	3,356	3,557	4,051	4,342	4,329	4,278	4,301	4,199	4,145	4,040	3,965	3,903	3,750	3,758	3,752	3,852	4,052	3,974	3,814	3,537
Spring	3	4,228	3/13/2015	3,336	3,206	3,161	3,120	3,118	3,302	3,733	4,033	4,082	4,143	4,201	4,210	4,228	4,201	4,114	4,111	4,070	4,030	4,034	4,030	4,078	4,000	3,811	3,661
Spring	3	3,733	3/14/2015	3,420	3,279	3,177	3,142	3,138	3,148	3,310	3,390	3,551	3,641	3,727	3,733	3,725	3,619	3,551	3,503	3,473	3,440	3,406	3,488	3,579	3,566	3,442	3,287
Spring	3	3,638	3/15/2015	3,149	3,053	2,995	2,995	3,061	3,156	3,287	3,453	3,545	3,577	3,500	3,431	3,387	3,318	3,250	3,193	3,209	3,241	3,264	3,359	3,638	3,523	3,428	3,176
Spring	3	4,171	3/16/2015	3,083	3,012	3,007	3,028	3,090	3,295	3,783	4,171	4,108	4,057	4,075	3,994	3,895	3,881	3,928	3,901	3,784	3,725	3,650	3,725	4,001	3,904	3,652	3,423
Spring	3	4,016	3/17/2015	3,193	3,125	3,023	2,933	2,923	3,128	3,561	3,883	3,961	3,971	4,016	3,954	3,991	3,926	3,857	3,788	3,691	3,722	3,689	3,723	3,954	3,899	3,744	3,615
Spring	3	4,636	3/18/2015	3,507	3,388	3,425	3,455	3,514	3,802	4,342	4,636	4,554	4,552

Contains Proprietary Material
Do Not Distribute

Spring	4	3,966	4/22/2015	3,238	3,064	3,051	3,014	3,005	3,252	3,606	3,828	3,896	3,887	3,955	3,950	3,966	3,937	3,912	3,849	3,780	3,711	3,639	3,701	3,859	3,879	3,721	3,440
Spring	4	4,166	4/23/2015	3,310	3,172	3,211	3,175	3,275	3,466	3,943	4,166	4,163	4,100	4,074	4,002	3,985	3,936	3,941	3,795	3,752	3,636	3,680	3,699	3,862	3,906	3,725	3,494
Spring	4	4,203	4/24/2015	3,355	3,318	3,272	3,280	3,316	3,534	3,928	4,203	4,100	4,137	4,036	3,962	3,900	3,828	3,787	3,719	3,651	3,629	3,585	3,582	3,707	3,690	3,483	3,305
Spring	4	3,576	4/25/2015	3,086	2,982	2,904	2,823	2,830	2,894	2,955	3,114	3,241	3,404	3,516	3,576	3,492	3,453	3,433	3,400	3,404	3,425	3,388	3,441	3,485	3,428	3,323	3,134
Spring	4	3,419	4/26/2015	2,934	2,819	2,738	2,705	2,693	2,714	2,784	2,880	3,060	3,194	3,234	3,197	3,155	3,141	3,084	3,052	3,071	3,097	3,128	3,173	3,313	3,419	3,229	3,038
Spring	4	3,906	4/27/2015	2,889	2,823	2,814	2,857	2,957	3,205	3,619	3,866	3,906	3,889	3,884	3,857	3,839	3,821	3,800	3,730	3,682	3,647	3,633	3,609	3,709	3,745	3,531	3,300
Spring	4	3,886	4/28/2015	3,136	2,999	2,983	2,977	3,012	3,252	3,665	3,885	3,886	3,869	3,873	3,839	3,824	3,806	3,778	3,715	3,672	3,647	3,615	3,608	3,699	3,745	3,525	3,223
Spring	4	3,830	4/29/2015	3,069	2,945	2,892	2,878	2,928	3,128	3,428	3,597	3,623	3,619	3,651	3,786	3,822	3,830	3,822	3,809	3,749	3,717	3,661	3,625	3,721	3,740	3,523	3,271
Spring	4	3,796	4/30/2015	3,061	2,921	2,846	2,808	2,821	3,001	3,355	3,587	3,685	3,682	3,757	3,789	3,796	3,787	3,769	3,690	3,664	3,600	3,593	3,580	3,689	3,711	3,578	3,415
Spring	5	3,855	5/1/2015	3,271	3,118	3,083	3,045	3,069	3,245	3,562	3,806	3,855	3,852	3,837	3,815	3,830	3,767	3,760	3,710	3,717	3,691	3,631	3,621	3,684	3,716	3,516	3,297
Spring	5	3,459	5/2/2015	3,105	2,951	2,880	2,807	2,789	2,874	2,932	3,016	3,156	3,279	3,312	3,382	3,335	3,354	3,364	3,397	3,384	3,390	3,429	3,397	3,386	3,459	3,239	3,065
Spring	5	3,847	5/3/2015	2,820	2,752	2,677	2,571	2,602	2,624	2,691	2,720	2,883	3,122	3,206	3,179	3,383	3,395	3,464	3,519	3,681	3,777	3,811	3,796	3,846	3,847	3,602	3,264
Spring	5	4,724	5/4/2015	3,019	2,947	2,827	2,763	2,779	2,974	3,331	3,585	3,865	3,972	4,155	4,217	4,324	4,457	4,592	4,648	4,724	4,695	4,640	4,539	4,548	4,468	4,205	3,828
Spring	5	5,054	5/5/2015	3,530	3,327	3,195	3,061	3,102	3,171	3,515	3,787	3,953	4,152	4,339	4,531	4,704	4,839	4,936	5,037	5,054	5,046	5,022	4,935	4,840	4,724	4,321	3,956
Spring	5	5,252	5/6/2015	3,614	3,396	3,219	3,064	3,071	3,196	3,461	3,668	3,868	4,079	4,331	4,527	4,809	4,948	5,049	5,126	5,225	5,252	5,231	5,103	5,016	4,870	4,531	4,065
Spring	5	5,478	5/7/2015	3,741	3,495	3,283	3,255	3,201	3,311	3,674	3,878	4,083	4,251	4,493	4,744	4,962	5,201	5,385	5,474	5,469	5,478	5,448	5,290	5,171	5,068	4,670	4,225
Spring	5	5,508	5/8/2015	3,843	3,591	3,404	3,265	3,199	3,310	3,588	3,855	4,093	4,342	4,620	4,867	5,125	5,310	5,486	5,491	5,508	5,434	5,306	5,134	4,899	4,839	4,534	4,186
Spring	5	5,042	5/9/2015	3,814	3,598	3,370	3,249	3,194	3,185	3,239	3,308	3,528	3,857	4,143	4,427	4,546	4,690	4,816	4,945	5,042	5,027	4,861	4,719	4,584	4,581	4,284	3,958
Spring	5	4,839	5/10/2015	3,654	3,386	3,235	3,139	3,013	3,019	2,967	3,014	3,373	3,661	3,959	4,139	4,283	4,345	4,457	4,617	4,727	4,839	4,834	4,722	4,658	4,672	4,365	3,935
Spring	5	5,538	5/11/2015	3,641	3,406	3,317	3,152	3,167	3,308	3,658	3,936	4,201	4,409	4,794	5,014	5,324	5,538	5,531	5,506	5,367	5,276	5,145	4,946	4,804	4,687	4,412	4,026
Spring	5	4,539	5/12/2015	3,726	3,459	3,317	3,258	3,224	3,314	3,624	3,831	3,995	4,151	4,231	4,329	4,339	4,452	4,494	4,539	4,473	4,389	4,297	4,186	4,089	4,135	3,849	3,514
Spring	5	4,261	5/13/2015	3,316	3,104	2,999	2,942	2,906	3,116	3,363	3,608	3,728	3,836	3,939	3,987	4,057	4,091	4,152	4,204	4,218	4,261	4,237	4,138	4,116	4,106	3,830	3,504
Spring	5	4,322	5/14/2015	3,276	3,109	2,995	2,910	2,923	3,076	3,395	3,607	3,739	3,844	3,892	3,979	4,082	4,130	4,198	4,289	4,322	4,276	4,212	4,171	4,234	4,232	3,979	3,698
Spring	5	5,271	5/15/2015	3,448	3,261	3,147	3,078	3,085	3,188	3,511	3,742	3,935	4,166	4,378	4,602	4,780	4,945	5,133	5,249	5,229	5,271	5,240	4,975	4,842	4,776	4,502	4,200
Spring	5	4,051	5/16/2015	3,866	3,614	3,473	3,319	3,225	3,235	3,259	3,382	3,593	3,816	3,954	4,051	4,045	3,976	3,968	3,925	4,014	3,997	3,936	3,904	3,931	3,929	3,759	3,487
Spring	5	4,731	5/17/2015	3,265	3,075	2,987	2,915	2,872	2,869	2,921	2,950	3,279	3,638	3,827	4,010	4,194	4,238	4,414	4,479	4,607	4,716	4,731	4,656	4,595	4,560	4,233	3,857
Spring	5	4,834	5/18/2015	3,580	3,384	3,277	3,241	3,200	3,365	3,709	3,950	4,137	4,328	4,505	4,582	4,669	4,730	4,798	4,783	4,761	4,826	4,834	4,658	4,657	4,652	4,288	4,025
Spring	5	4,858	5/19/2015	3,702	3,506	3,330	3,229	3,197	3,280	3,522	3,756	3,964	4,117	4,277	4,426	4,539	4,646	4,778	4,826	4,858	4,837	4,773	4,593	4,457	4,389	4,055	3,690
Spring	5	4,252	5/20/2015	3,404	3,203	3,055	2,977	2,952	3,088	3,385	3,599	3,782	3,876	3,948	4,004	4,080	4,159	4,220	4,252	4,249	4,226	4,100	4,031	4,045	4,030	3,759	3,537
Spring	5	3,919	5/21/2015	3,286	3,090	3,034	2,944	2,943	3,068	3,386	3,577	3,726	3,827	3,882	3,915	3,919	3,892	3,840	3,831	3,766	3,716	3,672	3,686	3,736	3,850	3,667	3,372
Spring	5	3,984	5/22/2015	3,239	3,072	3,043	2,963	3,008	3,158	3,382	3,684	3,726	3,876	3,878	3,943	3,930	3,968	3,960	3,984	3,946	3,922	3,926	3,781	3,780	3,830	3,627	3,370
Spring	5	3,990	5/23/2015	3,113	2,906	2,813	2,745	2,755	2,699	2,765	2,798	2,985	3,133	3,271	3,337	3,446	3,508	3,639	3,735	3,885	3,957	3,990	3,935	3,780	3,742	3,555	3,291
Spring	5	4,493	5/24/2015	3,032	2,807	2,697	2,668	2,627	2,649	2,588	2,730	2,944	3,153	3,334	3,586	3,718	3,932	4,081	4,259	4,422	4,493	4,454	4,373	4,172	4,165	3,949	3,576
Spring	5	4,010	5/25/2015	3,352	3,128	3,022	2,964	2,916	2,911	2,950	2,956	3,111	3,371	3,575	3,755	3,877	3,896	3,933	3,985	3,924	3,938	3,938	3,983	3,947	4,010	3,819	3,513
Spring	5	5,203	5/26/2015	3,228	3,085	3,015	2,986	2,999	3,168	3,495	3,846	4,082	4,336	4,671	4,948	5,074	5,182	5,203	5,135	5,131	5,038	4,822	4,667	4,544	4,476	4,217	3,908
Spring	5	5,096	5/27/2015	3,647	3,396	3,339	3,212	3,183	3,278	3,576	3,881	4,067	4,288	4,484	4,740	4,911	5,075	5,096	5,026	4,910	4,693	4,555	4,406	4,281	4,295	4,070	3,724
Spring	5	5,135	5/28/2015	3,450	3,240	3,079	3,017	2,990	3,126	3,455	3,719	3,926	4,109	4,291	4,465	4,623	4,779	4,940	5,051	5,117	5,135	5,001	4,896	4,773	4,719	4,476	4,096
Spring	5	5,272	5/29/2015	3,747	3,493	3,339	3,224	3,178	3,286	3,537	3,844	4,086	4,328	4,486	4,728	4,959	5,078	5,179	5,227	5,259	5,272	5,197	5,046	4,855	4,771	4,507	4,172
Spring	5	5,013	5/30/2015	3,835	3,570	3,375	3,266	3,171	3,167	3,161	3,312	3,604	3,974	4,310	4,579	4,787	4,870	4,933	5,013	5,013	4,992	4,952	4,767	4,591	4,508	4,263	3,903
Spring	5	4,085	5/31/2015	3,624	3,356	3,196	3,119	3,024	3,002	2,972	3,039	3,249	3,463	3,696	3,754	3,861	3,915	3,990	4,049	4,067	4,085	4,080	3,959	3,846	3,865	3,739	3,460
Summer	6	4,060	6/1/2015	3,203	3,048	2,964	2,962	2,953	3,139	3,366	3,623	3,782	3,901	4,040	4,037	4,060	4,016	4,014	4,013	3,975	3,881	3,892	3,817	3,766	3,841	3,664	3,422
Summer	6	4,027	6/2/2015	3,240	3,096	3,010	2,962	2,941	3,123	3,331	3,565	3,786	3,871	3,950	3,984	4,010	4,014	4,025	4,027	3,943	3,888	3,896	3,871	3,875	3,914	3,725	3,493
Summer	6	4,202	6/3/2015	3,308	3,144	3,037	3,032	2,993	3,139	3,419	3,665	3,771	3,934	3,998	4,039	4,139	4,191	4,198	4,202	4,154	4,147	4,143	4,083	4,053	4,090	3,923	3,619
Summer	6	5,229	6/4/2015	3,365	3,166	3,055	3,008	3,013	3,136	3,324	3,612	3,871	4,027	4,233	4,384	4,620	4,774	4,915	5,077	5,176	5,229	5,193	5,061	4,902	4,801	4,515	4,111
Summer	6	5,492	6/5/2015	3,723	3,425	3,290	3,183	3,138	3,250	3,481	3,685	3,924	4,256	4,521	4,736	4,982	5,156	5,334	5,440	5,492	5,478	5,423	5,251	5,068	4,888	4,662	4,231
Summer	6	5,087	6/6/2015	3,903	3,624	3,445	3,240	3,190	3,134	3,133	3,245	3,515	3,762	4,072	4,299	4,500	4,745	4,867	4,968	5,087	5,070	5,006	4,846	4,631	4,530	4,290	3,939
Summer	6	5,471	6/7/2015	3,605	3,334	3,165	3,027	3,011	2,932	2,912	3,001	3,244	3,677	4,033	4,361	4,689	4,951	5,109	5,250	5,377	5,471	5,381	5,310	5,198	5,030	4,821	4,446
Summer	6	5,203	6/8/2015	4,075	3,858	3,704	3,644	3,614	3,700	3,977	4,235	4,395	4,558	4,698	4,882	4,960	5,073	5,203	5,186	4,983	4,844	4,874	4,773	4,598	4,609	4,391	3,989
Summer	6	5,790	6/9/2015	3,754	3,518	3,364	3,277	3,204	3,347	3,509	3,789	4,094	4,420	4,619	4,970	5,202	5,539	5,634	5,693	5,784	5,790	5,718	5,505	5,300	5,132	4,780	4,378
Summer	6	6,216	6/10/2015	3,944	3,626	3,470	3,344	3,310	3,381	3,559	3,890	4,210	4,527	4,927	5,283	5,581	5,818	6,035	6,204	6,216	6,204	6,112	5,974	5,722	5,578	5,222	4,733
Summer	6	6,441	6/11/2015	4,295	3,965	3,766	3,578	3,499	3,544	3,773	4,055	4,429	4,803	5,224	5,641	5,984	6,209	6,319	6,395	6,441	6,389	6,304	6,143	5,878	5,736	5,450	5,006
Summer	6	6,330	6/12/2015	4,567	4,230	3,990	3,835	3,801	3,883	4,099	4,369	4,762	5,148	5,493	5,827	6,086	6,238	6,302	6,274	6,298	6,330	6,146	5,986	5,804	5,645	5,362	4,990
Summer	6	5,675	6/13/2015	4,614	4,315	4,096	3,893	3,777	3,738	3,718	3,880	4,225	4,541	4,908	5,151	5,330	5,482	5,585	5,587	5,632	5,675	5,552	5,420	5,249	5,102	4,929	4,556
Summer	6	5,817	6/14/2015	4,229	3,982	3,802	3,664	3,583	3,524	3,432	3,560	3,931	4,300	4,703	5,016	5,184	5,408	5,504	5,613	5,655	5,776	5,817	5,693	5,507	5,431	5,161	4,761
Summer	6	6,576	6/15/2015	4,403	4,170	3,981	3,868	3,818	3,937	4,157	4,456	4,930	5,341	5,626	5,943	6,175	6,334	6,475	6,570	6,576	6,539	6,480	6,314	6,100	5,970	5,618	5,188
Summer	6	6,468	6/16/2015	4,768	4,505	4,288	4,151	4,068	4,173	4,344	4,555	4,971	5,297	5,694	5,958	6,158	6,335	6,433	6,468	6,287	6,123	6,014	5,766	5,587	5,521	5,149	4,772
Summer	6	6,426	6/17/2015	4,430	4,138	3,950	3,844	3,787	3,919	4,153	4,373	4,564	4,855	5,209	5,537	5,800	6,096	6,218	6,426	6,397	6,216	5,944	5,741	5,447	5,382	5,067	4,700
Summer	6	6,470	6/18/2015	4,349	4,026	3,891	3,709	3,628	3,809	3,971	4,230	4,676	5,034	5,489	5,866	6,181	6,383	6,430	6,470	6,348	5,978	5,683	5,413	5,234	5,128	4,848	4,495
Summer	6	5,743	6/19/2015	4,126	3,889	3,737	3,626	3,660	3,739	3,994	4,199	4,441	4,667	4,908	5,202	5,436	5,622	5,743	5,731	5,627	5,413	5,145	4,944	4,758	4,767	4,533	4,269
Summer	6	4,819	6/20/2015	3,992	3,732	3,587	3,454	3,439	3,466	3,488	3,589	3,792	3,985	4,198	4,279	4,357	4,378	4,410	4,541	4,652	4,766	4,817	4,819	4,643	4,547	4,358	4,062
Summer	6	5,493	6/21/2015	3,760	3,546	3,376	3,238	3,221	3,188	3,165	3,285	3,572	3,993	4,338	4,715	4,985	5,113	5,256	5,422	5,477	5,493	5,388	5,224	5,052	5,005	4,747	4,464
Summer	6	6,138	6/22/2015	4,003	3,801	3,607	3,458	3,415	3,572	3,786	4,014	4,270	4,588	4,946	5,304	5,573	5,776	5,965	6,039	6,138	6,080	6,049	5,874	5,702	5,604	5,332	4,926
Summer	6	6,386	6/23/2015	4,556	4,297	4,099	3,981	3,932	4,021	4,226	4,458	4,756	5,136	5,488	5,825	6,112	6,307	6,292	6,386	6,365	6,339	6,340	6,164	5,944	5,743	5,407	4,918
Summer	6	5,963	6/24/2015	4,482	4,131	3,847	3,640	3,556	3,613	3,756	3,981	4,214	4,499	4,785	5,079	5,358	5,558	5,756	5,910	5,949	5,963	5,767	5,627	5,368	5,169	4,835	4,430
Summer	6	6,195	6/25/2015	4,062	3,762	3,544	3,409	3,329	3,440	3,655	3,858	4,127	4,351	4,596	4,845	5,121	5,456	5,790	6,023	6,182	6,195	6,100	5,910	5,750	5,664	5,355	4,951
Summer	6	5,961	6/26/2015	4,524	4,217	3,943	3,734	3,630	3,702	3,859	4,044	4,266	4,577	4,842	5,186	5,501	5,704	5,885	5,961	5,948	5,774	5,303	4,942	4,736	4,671	4,453	4,163
Summer	6	4,247	6/27/2015	3,901	3,676	3,487	3,385	3,306	3,335	3,344	3,440	3,649	3,841	3,966	3,997	4,037	4,108	4,117	4,144	4,221	4,231	4,247	4,101	3,898	3,824	3,669	3,408
Summer	6	4,523	6/28/2015	3,146	3,008	2,922	2,739	2,717	2,720	2,700	2,770	2,968	3,281	3,444	3,605	3,834	3,960	4,046	4,258	4,411	4,490	4,523	4,379	4,242	4,155	3,998	3,635
Summer	6	5,214	6/29/2015	3,425	3,155	3,066	2,971	2,989	3,167	3,396	3,529	3,842	4,034	4,269	4,546	4,748	4,918	5,065	5,175	5,214	5,188	5,149	5,009	4,845	4,718	4,499	4,115
Summer	6	5,432	6/30/2015	3,757	3,546	3,331	3,212	3,209	3,338	3,504	3,672	3,942	4,182	4,401	4,678	4,939	5,151	5,358	5,424	5,432	5,416	5,307	5,054	4,820	4,682	4,424	4,067
Summer	7	4,887	7/1/2015	3,761	3,548	3,325	3,173	3,214	3,286	3,519	3,730	3,989	4,186	4,385	4,557	4,712	4,875	4,887	4,834	4,739	4,780	4,691	4,613	4,539	4,560	4,338	4,017
Summer	7	4,893	7/2/2015	3,760	3,546	3,447	3,312	3,307	3,450	3,654	3,830	3,960	4,148	4,323	4,445	4,587	4,719	4,840	4,843	4,825	4,893	4,804	4,664	4,520	4,471	4,302	3,939
Summer	7	4,383	7/3/2015	3,628	3,449	3,298	3,210	3,155	3,187	3,275	3,307	3,491	3,682	3,875	4,000	4,172	4,309	4,383	4,317	4,303	4,273	4,203	4,077	3,952	3,958	3,774	3,554
Summer	7	4,607	7/4/2015	3,335	3,157	2,983	2,915	2,886	2,886	2,916	2,879	3,044	3,299	3,574	3,858	4,058	4,215	4,330	4,482	4,607	4,587	4,475	4,303	4,083	3,966	3,850	3,689
Summer	7	4,469	7/5/2015	3,470	3,255	3,112	2,986	2,939	2,949	2,915	2,992	3,094	3,271	3,491	3,599	3,830	3,937	4,020	4,101	4,237	4,404	4,469	4,434	4,289	4,255	4,028	3,717
Summer	7	5,947	7/6/2015	3,427	3,273	3,153	3,098	3,095	3,229	3,428	3,701	3,992	4,302	4,619	4,959	5,295	5,532	5,743	5,829	5,892	5,947	5,902	5,755	5,513	5,378	5,041	4,634
Summer	7	5,193	7/7/2015	4,289	3,968	3,790	3,656	3,632	3,735	3,934	4,127	4,417	4,665	4,861	5,047	5,147	5,125	5,193	5,169	5,065	4,912	4,840	4,752	4,691	4,664	4,528	4,201
Summer	7	5,374	7/8/2015	3,984	3,688	3,608	3,495	3,456	3,574	3,827	4,059	4,258	4,471	4,639	4,814	4,885	5,035	5,160	5,252	5,210	5,352	5,374	5,240	5,076	5,058	4,783	4,452
Summer	7	5,606	7/9/2015	4,169	3,900	3,721	3,661	3,642	3,777	3,959	4,181	4,440	4,598	4,762	4,907	5,048	5,168	5,371	5,509	5,578	5,606	5,589	5,456	5,312	5,183	4,943	4,515
Summer	7	5,448	7/10/2015	4,160	3,823	3,638	3,528	3,505	3,584	3,798	4,011	4,262	4,615	4,936	5,146	5,246	5,284	5,448	5,409	5,442	5,294	5,087	4,975	4,748	4,663	4,500	4,145
Summer	7	5,284	7/11/2015	3,797	3,556	3,391	3,264	3,191	3,179	3,192	3,287	3,470	3,765	4,038	4,355	4,547	4,780	4,968	5,093	5,222	5,284	5,226	5,092	4,869	4,773	4,503	4,232
Summer	7	5,520	7/12/2015	3,870	3,646	3,490	3,383	3,332	3,331	3,359	3,392	3,443	3,674	3,901	4,183	4,558	4,896	5,131	5,339	5,489	5,520	5,501	5,370	5,196	5,070	4,900	4,497
Summer	7	6,372	7/13/2015	4,128	3,880	3,705	3,595	3,567	3,676	3,887	4,125	4,488	4,918	5,370	5,822	6,124	6,372	6,177	5,778	5,446	5,345	5,279	5,276	5,101	5,056	4,900	4,408
Summer	7	6,296	7/14/2015	4,142	4,016	3,865	3,718	3,629	3,748	3,950	4,120	4,390	4,669	5,044	5,375	5,603	5,816	6,086	6,262	6,296	6,221	6,154	5,899	5,588	5,394	5,104	4,679
Summer	7	5,532	7/15/2015	4,283	3,999	3,789	3,628	3,586	3,620	3,822	4,004	4,244	4,447	4,602	4,808	4,916	5,047	5,238	5,392	5,532	5,494	5,501	5,344	5,191	5,094	4,791	4,422
Summer	7	6,053	7/16/2015	4,048	3,733	3,532	3,456	3,426	3,499	3,688	3,903	4,185	4,466	4,810	5,096	5,337	5,595	5,812	5,974	6,053	6,012	5,958	5,788	5,594	5,416	5,100	4,684
Summer	7	6,476	7/17/2015	4,294	4,002	3,795	3,678	3,592	3,677	3,833	4,098	4,443	4,858	5,316	5,678	5,968	6,240	6,448	6,476	6,468	6,415	6,248	6,097	5,935	5,759	5,405	4,793
Summer	7	6,150	7/18/2015	4,392	4,088	3,865	3,696	3,575	3,593	3,597	3,656	3,988	4,371	4,845	5,232	5,578	5,858	6,026	6,098	6,150	6,105	6,023	5,892	5,717	5,583	5,357	5,040
Summer	7	6,030	7/19/2015	4,683	4,382	4,163	3,938	3,825	3,730	3,734	3,787	4,143	4,553	4,900	5,263	5,613	5,800	5,973	6,030	5,974	5,965	5,865	5,720	5,515	5,431	5,133	4,815
Summer	7	6,172	7/20/2015	4,456	4,173	3,949	3,872	3,873	3,971	4,173	4,477	4,767	5,130	5,400	5,683	5,838	6,058	6,108	6,141	6,108	6,172	6,157	6,047	5,869	5,744	5,375	5,016
Summer	7	6,352	7/21/2015	4,640	4,330	4,089	3,935	3,954	4,004	4,255	4,465	4,773	4,993	5,236	5,591	5,816	6,025	6,240	6,343	6,352	6,293	6,221	5,941	5,689	5,630	5,216	4,800
Summer	7	5,980	7/22/2015	4,364	4,093	3,821	3,719	3,593	3,695	3,880	4,042	4,300	4,550	4,837	5,090	5,362	5,585	5,796	5,958	5,980	5,979	5,889	5,706	5,444	5,268	4,920	4,495
Summer	7	5,858	7/23/2015	4,079	3,815	3,628	3,526	3,495	3,558	3,780	3,959	4,233	4,501	4,805	5,055	5,260	5,490	5,681	5,768	5,833	5,858	5,799	5,593	5,403	5,266	4,962	4,531
Summer	7	6,060	7/24/2015	4,170	3,867	3,659	3,506	3,435	3,528	3,654	3,880	4,197	4,550

Contains Proprietary Material
Do Not Distribute

Summer	8	5,457	8/28/2015	3,502	3,285	3,194	3,116	3,072	3,173	3,545	3,636	3,757	4,076	4,247	4,469	4,645	4,859	5,071	5,264	5,408	5,457	5,365	5,130	4,984	4,741	4,490	4,121
Summer	8	5,472	8/29/2015	3,794	3,532	3,394	3,220	3,168	3,156	3,254	3,296	3,511	3,844	4,252	4,574	4,856	5,100	5,289	5,462	5,458	5,472	5,353	5,117	5,004	4,811	4,439	4,150
Summer	8	5,123	8/30/2015	3,824	3,581	3,415	3,258	3,227	3,191	3,234	3,208	3,481	3,794	4,093	4,333	4,591	4,836	4,967	5,008	5,030	5,123	5,028	4,941	4,875	4,763	4,405	4,058
Summer	8	6,109	8/31/2015	3,803	3,540	3,381	3,294	3,336	3,459	3,854	4,031	4,286	4,553	4,877	5,186	5,494	5,750	5,921	6,057	6,109	6,092	6,054	5,795	5,655	5,402	4,951	4,500
Fall	9	6,204	9/1/2015	4,135	3,863	3,596	3,549	3,478	3,644	3,934	4,115	4,372	4,651	5,022	5,362	5,687	5,890	6,067	6,143	6,204	6,131	6,041	5,953	5,796	5,532	5,087	4,595
Fall	9	6,378	9/2/2015	4,205	3,930	3,720	3,586	3,558	3,656	4,001	4,225	4,455	4,761	5,156	5,515	5,795	6,084	6,224	6,322	6,378	6,364	6,237	6,108	5,960	5,721	5,248	4,764
Fall	9	6,411	9/3/2015	4,441	4,101	3,890	3,693	3,625	3,801	4,115	4,268	4,469	4,841	5,175	5,609	5,994	6,199	6,267	6,350	6,372	6,411	6,320	6,145	6,038	5,693	5,218	4,795
Fall	9	6,461	9/4/2015	4,453	4,094	3,920	3,744	3,724	3,735	4,091	4,291	4,420	4,761	5,212	5,647	5,964	6,213	6,324	6,424	6,461	6,345	6,175	5,981	5,812	5,523	5,053	4,628
Fall	9	5,885	9/5/2015	4,310	3,983	3,716	3,558	3,433	3,414	3,423	3,418	3,567	3,984	4,440	4,816	5,231	5,547	5,730	5,855	5,885	5,867	5,652	5,373	5,236	4,932	4,650	4,242
Fall	9	5,678	9/6/2015	3,902	3,679	3,426	3,355	3,266	3,214	3,268	3,280	3,442	3,866	4,228	4,593	4,976	5,260	5,520	5,582	5,668	5,678	5,523	5,314	5,185	4,942	4,575	4,195
Fall	9	5,795	9/7/2015	3,927	3,652	3,491	3,385	3,337	3,309	3,356	3,327	3,503	3,939	4,366	4,768	5,141	5,393	5,517	5,696	5,795	5,762	5,686	5,466	5,376	5,122	4,773	4,355
Fall	9	6,388	9/8/2015	4,023	3,786	3,628	3,517	3,486	3,639	3,959	4,248	4,498	4,859	5,223	5,592	5,946	6,219	6,310	6,388	6,377	6,372	6,281	6,100	6,029	5,674	5,239	4,799
Fall	9	5,588	9/9/2015	4,450	4,155	3,955	3,853	3,773	3,872	4,255	4,517	4,643	4,849	5,115	5,294	5,377	5,494	5,554	5,588	5,487	5,323	5,231	5,149	5,103	4,950	4,592	4,258
Fall	9	5,658	9/10/2015	3,991	3,725	3,606	3,569	3,525	3,701	4,047	4,308	4,348	4,445	4,653	4,860	5,012	5,204	5,324	5,547	5,634	5,658	5,535	5,327	5,264	5,037	4,592	4,183
Fall	9	5,279	9/11/2015	3,865	3,633	3,376	3,316	3,289	3,411	3,780	3,973	4,122	4,380	4,625	4,894	5,127	5,279	5,278	5,220	5,072	4,800	4,629	4,426	4,425	4,251	3,943	3,695
Fall	9	3,633	9/12/2015	3,402	3,239	3,118	3,026	2,965	2,989	3,082	3,144	3,226	3,378	3,500	3,617	3,593	3,577	3,607	3,561	3,633	3,631	3,539	3,508	3,534	3,418	3,311	3,130
Fall	9	3,652	9/13/2015	2,889	2,810	2,694	2,621	2,609	2,654	2,745	2,757	2,914	3,087	3,186	3,228	3,323	3,369	3,366	3,377	3,452	3,507	3,546	3,551	3,652	3,553	3,310	3,086
Fall	9	4,438	9/14/2015	2,898	2,803	2,765	2,766	2,830	2,958	3,329	3,551	3,679	3,827	3,883	4,027	4,088	4,203	4,266	4,310	4,416	4,438	4,401	4,298	4,338	4,143	3,830	3,518
Fall	9	4,959	9/15/2015	3,289	3,159	3,039	2,923	2,910	3,094	3,439	3,625	3,717	3,856	4,073	4,187	4,292	4,479	4,620	4,754	4,910	4,959	4,920	4,705	4,672	4,450	4,106	3,692
Fall	9	5,235	9/16/2015	3,399	3,203	3,081	2,950	2,986	3,143	3,503	3,644	3,751	3,959	4,194	4,407	4,591	4,781	5,016	5,085	5,220	5,235	5,153	4,884	4,810	4,552	4,130	3,753
Fall	9	5,265	9/17/2015	3,508	3,266	3,127	3,017	3,046	3,173	3,489	3,734	3,816	4,055	4,215	4,340	4,643	4,788	5,007	5,132	5,235	5,265	5,134	4,949	4,915	4,576	4,230	3,866
Fall	9	5,443	9/18/2015	3,556	3,378	3,228	3,116	3,070	3,185	3,577	3,744	3,846	4,085	4,334	4,580	4,855	5,022	5,214	5,377	5,443	5,423	5,318	5,041	5,005	4,767	4,374	4,042
Fall	9	4,517	9/19/2015	3,762	3,548	3,395	3,230	3,150	3,114	3,244	3,319	3,481	3,801	4,041	4,312	4,476	4,509	4,517	4,438	4,387	4,311	4,169	4,089	4,080	3,910	3,676	3,446
Fall	9	3,918	9/20/2015	3,196	2,989	2,836	2,806	2,738	2,740	2,792	2,828	2,942	3,141	3,362	3,461	3,604	3,658	3,680	3,855	3,918	3,902	3,806	3,820	3,904	3,748	3,505	3,228
Fall	9	4,660	9/21/2015	3,032	2,882	2,758	2,735	2,793	3,045	3,406	3,632	3,709	3,854	4,032	4,142	4,291	4,379	4,465	4,581	4,649	4,660	4,642	4,524	4,528	4,254	3,925	3,579
Fall	9	4,898	9/22/2015	3,357	3,217	3,094	2,968	2,960	3,106	3,431	3,673	3,767	3,950	4,091	4,254	4,374	4,532	4,609	4,796	4,830	4,898	4,848	4,660	4,687	4,411	4,004	3,696
Fall	9	5,216	9/23/2015	3,461	3,281	3,145	3,083	3,081	3,174	3,540	3,781	3,838	4,039	4,200	4,337	4,567	4,748	4,942	5,139	5,216	5,213	5,037	4,894	4,765	4,497	4,122	3,776
Fall	9	5,260	9/24/2015	3,484	3,269	3,139	3,046	3,034	3,157	3,499	3,713	3,806	3,988	4,167	4,376	4,627	4,858	5,070	5,196	5,260	5,225	5,079	4,919	4,892	4,608	4,215	3,830
Fall	9	4,317	9/25/2015	3,534	3,325	3,174	3,070	3,020	3,169	3,491	3,740	3,791	3,917	4,066	4,181	4,250	4,310	4,317	4,310	4,247	4,189	4,092	4,065	4,070	3,936	3,726	3,523
Fall	9	3,784	9/26/2015	3,272	3,108	2,958	2,911	2,845	2,848	2,974	3,134	3,253	3,377	3,542	3,602	3,633	3,670	3,699	3,687	3,721	3,752	3,744	3,676	3,784	3,677	3,528	3,319
Fall	9	4,232	9/27/2015	3,130	2,955	2,888	2,764	2,757	2,806	2,775	2,925	3,017	3,241	3,380	3,533	3,669	3,841	3,971	4,096	4,159	4,204	4,148	4,197	4,232	4,082	3,792	3,582
Fall	9	5,257	9/28/2015	3,329	3,170	3,046	3,046	3,080	3,199	3,612	3,870	3,940	4,126	4,366	4,530	4,794	4,992	5,147	5,257	5,223	5,199	5,120	5,115	5,025	4,851	4,489	4,145
Fall	9	4,595	9/29/2015	3,826	3,657	3,526	3,375	3,343	3,543	3,901	4,193	4,299	4,439	4,546	4,540	4,573	4,595	4,587	4,534	4,474	4,538	4,488	4,484	4,534	4,363	4,055	3,733
Fall	9	4,188	9/30/2015	3,573	3,432	3,302	3,159	3,148	3,262	3,634	3,891	3,938	4,072	4,129	4,123	4,188	4,146	4,096	4,057	4,047	3,990	3,992	4,086	4,136	3,945	3,706	3,437
Fall	10	3,986	10/1/2015	3,248	3,071	3,035	2,943	2,965	3,097	3,404	3,678	3,740	3,841	3,909	3,959	3,961	3,968	3,940	3,909	3,880	3,861	3,783	3,913	3,986	3,769	3,654	3,391
Fall	10	3,945	10/2/2015	3,196	3,081	2,988	2,949	2,907	3,066	3,388	3,675	3,758	3,864	3,928	3,900	3,945	3,919	3,879	3,748	3,707	3,758	3,741	3,822	3,801	3,638	3,511	3,317
Fall	10	3,557	10/3/2015	3,157	3,015	2,947	2,903	2,864	2,912	2,970	3,151	3,259	3,439	3,485	3,557	3,542	3,507	3,476	3,431	3,405	3,432	3,427	3,509	3,516	3,413	3,259	3,093
Fall	10	3,857	10/4/2015	2,926	2,800	2,789	2,742	2,677	2,767	2,740	2,856	3,020	3,140	3,154	3,205	3,301	3,273	3,309	3,348	3,506	3,587	3,609	3,700	3,857	3,649	3,445	3,215
Fall	10	4,761	10/5/2015	3,076	2,960	2,859	2,885	2,918	3,042	3,410	3,664	3,736	3,932	4,039	4,197	4,334	4,485	4,597	4,679	4,746	4,761	4,665	4,597	4,531	4,318	4,067	3,723
Fall	10	4,914	10/6/2015	3,463	3,257	3,168	3,100	3,078	3,150	3,461	3,710	3,780	3,978	4,143	4,287	4,432	4,574	4,762	4,893	4,914	4,837	4,758	4,694	4,673	4,382	4,057	3,748
Fall	10	5,005	10/7/2015	3,479	3,262	3,125	3,030	2,994	3,157	3,531	3,729	3,860	3,992	4,135	4,335	4,497	4,715	4,820	4,977	5,005	4,955	4,895	4,768	4,715	4,430	4,093	3,775
Fall	10	5,030	10/8/2015	3,538	3,335	3,211	3,115	3,077	3,212	3,539	3,828	3,908	4,058	4,265	4,395	4,591	4,792	4,872	4,984	5,030	4,930	4,884	4,762	4,708	4,403	4,117	3,818
Fall	10	4,380	10/9/2015	3,496	3,381	3,233	3,149	3,104	3,290	3,552	3,833	3,903	4,097	4,278	4,348	4,380	4,366	4,356	4,228	4,221	4,088	4,034	4,058	3,985	3,832	3,617	3,382
Fall	10	3,538	10/10/2015	3,217	3,068	2,983	2,830	2,867	2,866	2,919	3,043	3,096	3,215	3,327	3,369	3,416	3,428	3,451	3,453	3,538	3,525	3,446	3,499	3,514	3,415	3,177	3,003
Fall	10	3,652	10/11/2015	2,869	2,734	2,694	2,653	2,673	2,653	2,759	2,872	2,971	3,074	3,122	3,195	3,298	3,287	3,336	3,321	3,434	3,572	3,562	3,577	3,652	3,503	3,253	3,070
Fall	10	4,401	10/12/2015	2,923	2,815	2,739	2,709	2,771	2,961	3,420	3,644	3,671	3,816	3,887	3,928	4,053	4,160	4,236	4,279	4,286	4,331	4,281	4,401	4,329	4,122	3,870	3,563
Fall	10	4,144	10/13/2015	3,319	3,145	3,050	2,966	3,001	3,158	3,529	3,810	3,832	3,926	3,967	4,069	4,108	4,144	4,093	4,120	4,072	4,003	3,969	4,095	4,092	3,898	3,636	3,387
Fall	10	4,078	10/14/2015	3,193	3,080	2,983	2,932	2,931	3,117	3,507	3,821	3,768	3,836	3,904	3,989	3,995	4,064	4,078	4,072	4,027	4,004	3,911	4,024	3,973	3,793	3,551	3,334
Fall	10	4,028	10/15/2015	3,175	3,051	2,986	2,928	2,925	3,067	3,531	3,841	3,867	3,864	3,931	3,901	3,948	3,946	4,028	3,980	3,971	3,893	3,872	3,976	3,974	3,836	3,668	3,441
Fall	10	3,924	10/16/2015	3,233	3,118	3,009	2,889	2,910	3,034	3,416	3,644	3,720	3,832	3,899	3,924	3,883	3,891	3,885	3,838	3,795	3,736	3,704	3,752	3,748	3,613	3,515	3,310
Fall	10	3,594	10/17/2015	3,165	3,077	2,988	2,946	2,962	3,049	3,160	3,348	3,510	3,594	3,517	3,498	3,411	3,381	3,310	3,303	3,238	3,287	3,310	3,476	3,532	3,444	3,324	3,241
Fall	10	3,689	10/18/2015	3,102	3,047	3,003	3,056	3,065	3,165	3,295	3,463	3,581	3,627	3,541	3,435	3,390	3,304	3,295	3,234	3,254	3,299	3,410	3,616	3,689	3,605	3,472	3,328
Fall	10	4,370	10/19/2015	3,229	3,126	3,179	3,196	3,313	3,510	4,006	4,356	4,370	4,368	4,245	4,157	4,043	3,974	3,947	3,867	3,848	3,843	3,864	4,040	4,044	3,849	3,674	3,487
Fall	10	4,153	10/20/2015	3,361	3,258	3,176	3,159	3,185	3,361	3,762	4,054	4,077	4,153	4,091	4,083	4,089	4,053	4,034	3,999	3,942	3,954	3,909	4,042	4,015	3,889	3,651	3,454
Fall	10	4,158	10/21/2015	3,284	3,189	3,099	3,092	3,131	3,299	3,715	4,028	4,058	4,021	4,049	3,995	4,021	4,034	4,079	4,056	4,064	4,049	4,012	4,158	4,092	3,981	3,682	3,470
Fall	10	4,349	10/22/2015	3,285	3,094	3,043	2,990	3,021	3,205	3,588	3,867	3,911	3,961	4,041	4,048	4,183	4,177	4,258	4,349	4,316	4,294	4,210	4,336	4,229	4,029	3,744	3,493
Fall	10	4,243	10/23/2015	3,315	3,148	3,032	2,968	2,901	3,068	3,436	3,722	3,815	3,895	4,006	4,076	4,084	4,243	4,143	4,146	4,126	4,055	4,022	4,057	3,977	3,827	3,634	3,417
Fall	10	3,684	10/24/2015	3,247	3,057	2,980	2,870	2,851	2,876	2,996	3,169	3,253	3,412	3,500	3,545	3,524	3,546	3,518	3,520	3,474	3,539	3,616	3,684	3,622	3,457	3,309	3,132
Fall	10	3,562	10/25/2015	2,965	2,817	2,714	2,674	2,628	2,667	2,731	2,870	2,955	3,128	3,209	3,235	3,258	3,236	3,256	3,238	3,269	3,288	3,403	3,562	3,536	3,407	3,245	3,022
Fall	10	4,018	10/26/2015	2,848	2,779	2,722	2,729	2,810	3,082	3,477	3,797	3,818	3,887	3,918	3,951	3,946	3,883	3,868	3,805	3,749	3,815	3,894	4,018	3,968	3,807	3,592	3,362
Fall	10	4,137	10/27/2015	3,188	3,081	2,996	2,939	3,002	3,153	3,563	3,913	3,968	4,036	4,079	4,054	3,995	3,960	3,942	3,937	3,948	3,937	4,069	4,137	4,054	3,889	3,656	3,439
Fall	10	4,031	10/28/2015	3,275	3,148	3,063	3,049	3,024	3,192	3,533	3,830	3,901	3,926	3,977	3,986	3,991	3,964	3,944	3,918	3,851	3,838	3,850	4,031	3,977	3,842	3,606	3,388
Fall	10	3,900	10/29/2015	3,161	3,032	2,927	2,889	2,917	3,102	3,489	3,816	3,841	3,863	3,900	3,866	3,845	3,828	3,794	3,747	3,688	3,626	3,689	3,900	3,899	3,787	3,600	3,435
Fall	10	4,153	10/30/2015	3,371	3,262	3,216	3,190	3,202	3,385	3,841	4,126	4,153	4,145	4,116	4,060	3,957	3,869	3,794	3,754	3,720	3,673	3,703	3,856	3,849	3,730	3,635	3,523
Fall	10	3,611	10/31/2015	3,408	3,285	3,204	3,165	3,124	3,170	3,258	3,373	3,455	3,554	3,611	3,591	3,512	3,434	3,388	3,346	3,325	3,240	3,284	3,432	3,409	3,334	3,208	3,079
Fall	11	3,554	11/1/2015	2,902	2,768	2,722	2,681	2,660	2,705	2,798	2,896	3,086	3,187	3,194	3,182	3,199	3,190	3,183	3,186	3,253	3,392	3,554	3,486	3,508	3,347	3,203	3,029
Fall	11	3,955	11/2/2015	2,909	2,801	2,830	2,855	2,930	3,088	3,501	3,701	3,789	3,898	3,940	3,867	3,857	3,877	3,837	3,800	3,791	3,789	3,955	3,903	3,788	3,614	3,437	3,311
Fall	11	4,194	11/3/2015	3,156	3,045	3,009	2,989	3,000	3,186	3,507	3,725	3,756	3,858	3,917	3,838	3,994	4,053	4,092	4,057	4,063	4,053	4,194	4,106	3,992	3,807	3,555	3,336
Fall	11	4,307	11/4/2015	3,146	3,030	2,933	2,891	2,901	3,117	3,473	3,630	3,722	3,863	3,972	4,020	4,072	4,150	4,191	4,128	4,041	4,136	4,307	4,239	4,121	3,884	3,673	3,385
Fall	11	4,251	11/5/2015	3,220	3,082	2,999	2,945	2,957	3,130	3,492	3,751	3,815	3,956	4,001	4,094	4,155	4,223	4,251	4,202	4,131	4,209	4,247	4,209	4,137	4,003	3,795	3,541
Fall	11	4,091	11/6/2015	3,382	3,221	3,106	3,035	3,014	3,235	3,511	3,739	3,883	3,998	4,091	4,083	4,013	4,029	3,966	3,957	3,843	3,941	3,964	3,770	3,828	3,568	3,430	3,163
Fall	11	3,551	11/7/2015	3,031	2,933	2,796	2,746	2,694	2,771	2,947	3,050	3,204	3,281	3,424	3,329	3,306	3,265	3,234	3,228	3,207	3,377	3,551	3,487	3,496	3,408	3,297	3,138
Fall	11	3,713	11/8/2015	2,999	2,953	2,894	2,865	2,871	3,005	3,122	3,244	3,337	3,382	3,384	3,275	3,278	3,207	3,145	3,128	3,171	3,414	3,675	3,713	3,698	3,586	3,480	3,297
Fall	11	4,194	11/9/2015	3,204	3,175	3,160	3,193	3,241	3,441	3,837	4,107	4,120	4,179	4,139	4,137	4,107	4,023	3,976	3,963	3,907	4,063	4,194	4,113	4,029	3,872	3,636	3,442
Fall	11	4,097	11/10/2015	3,270	3,183	3,104	3,068	3,149	3,298	3,683	3,890	3,965	4,033	4,001	4,005	3,944	3,891	3,835	3,803	3,770	3,852	4,077	4,097	4,049	3,952	3,758	3,582
Fall	11	4,235	11/11/2015	3,482	3,381	3,363	3,341	3,419	3,592	4,046	4,235	4,214	4,166	4,066	3,987	3,922	3,839	3,832	3,828	3,778	3,922	4,127	4,042	3,973	3,817	3,604	3,421
Fall	11	3,987	11/12/2015	3,229	3,114	3,017	2,967	2,992	3,134	3,556	3,705	3,760	3,828	3,890	3,845	3,845	3,766	3,768	3,756	3,710	3,803	3,987	3,983	3,938	3,862	3,651	3,419
Fall	11	4,073	11/13/2015	3,302	3,234	3,171	3,176	3,204	3,427	3,863	4,073	4,068	4,002	4,008	3,951	3,900	3,850	3,793	3,723	3,684	3,826	4,043	3,985	3,948	3,854	3,750	3,621
Fall	11	3,945	11/14/2015	3,516	3,442	3,413	3,433	3,467	3,543	3,727	3,893	3,945	3,848	3,734	3,620	3,473	3,406	3,296	3,259	3,289	3,448	3,646	3,664	3,701	3,654	3,546	3,363
Fall	11	3,650	11/15/2015	3,273	3,270	3,229	3,190	3,325	3,373	3,523	3,607	3,650	3,555	3,435	3,350	3,314	3,241	3,224	3,213	3,262	3,425	3,648	3,645	3,594	3,539	3,482	3,326
Fall	11	4,320	11/16/2015	3,236	3,143	3,143	3,146	3,284	3,567	4,068	4,302	4,320	4,282	4,215	4,136	4,075	4,045	3,998	3,993	3,972	4,123	4,231	4,133	4,094	3,960	3,728	3,547
Fall	11	4,081	11/17/2015	3,356	3,262	3,160	3,135	3,171	3,361	3,753	4,002	4,026	4,059	4,081	4,037	4,024	3,992	3,909	3,844	3,815	4,021	4,076	4,072	3,937	3,830	3,610	3,369
Fall	11	4,124	11/18/2015	3,174	3,074	2,992	2,947	2,975	3,129	3,534	3,800	3,847	3,926	3,963	3,956	3,991	3,995	3,962	3,868	3,894	4,030	4,124	4,018	3,965	3,771	3,514	3,349
Fall	11	4,002	11/19/2015	3,172	3,043	2,938	2,960	2,995	3,213	3,682	3,889	3,878	3,858	3,868	3,858	3,810	3,786	3,771	3,723	3,755	3,745	4,001	4,002	3,999	3,927	3,733	3,536
Fall	11	4,520	11/20/2015	3,457	3,461	3,431	3,426	3,522	3,825	4,257	4,520	4,499	4,332	4,191	4,078	4,018	3,893	3,833	3,768	3,785	3,962	4,161	4,147	4,121	4,045	3,921	3,772
Fall	11	3,996	11/21/2015	3,628	3,520	3,493	3,399	3,404	3,532	3,717	3,820	3,879	3,825	3,740	3,617	3,597	3,555	3,535	3,630	3,777	3,930	3,995	3,996	3,960	3,909	3,820	3,657
Fall	11	4,483	11/22/2015	3,534	3,464	3,460	3,422	3,475	3,602	3,712	3,843	4,028	4,103	4,085	3,996	3,944	3,895	3,819	3,796	3,806	4,108	4,407	4,463	4,483	4,381	4,259	4,155
Fall	11	5,190	11/23/2015	4,098	4,050	4,040	4,140	4,201	4,486	4,851	5,190	5,080	4,894	4,706	4,546	4,366	4,292	4,170	4,104	4,062	4,356	4,535	4,591	4,575	4,417	4,336	4,118
Fall	11	4,803	11/24/2015	4,003	3,932	3,915	3,918	4,006	4,195	4,616	4,803	4,741	4,574	4,384	4,237	4,141	4,031	3,969	3,913	3,873	4,036	4,211	4,224	4,173	4,101	3,920	3,779
Fall	11	4,412	11/25/2015	3,621	3,539	3,566	3,564	3,563	3,800	4,087	4,281	4,412	4,319	4,219	4,063	4,018	3,896	3,811	3,735	3,717	3,817	3,975	3,971	3,928	3,765	3,649	3,396
Fall	11	3,348	11/26/2015	3,166	3,120	2,979	2,935	2,946	2,975	3,071	3,128	3,303	3,348	3,342	3,337	3,218	2,999	2,908	2,852	2,778	2,821	2,968	2,941	2,976	2,903	2,862	2,803
Fall	11	3,384	11/27/2015	2,661	2,645	2,594	2,640	2,628	2,746	2,857	3,013	3,007	3,163	3,203	3,193	3,157	3,103	3,064	3,055	3,062	3,235	3,384	3,341	3,265	3,189	3,115	2,920
Fall	11	3,557	11/28/2015	2,814	2,706	2,658	2,617	2,600	2,680	2,762	2,903	3,063	3,186	3,320	3,285	3,326	3,290	3,251	3,234	3,329	3,471	3,557	3,466	3,402	3,328	3,188	3,026
Fall	11	3,869	11/29/2015	2,865	2,811	2,770	2,736	2,766	2,848	2,961	3,060	3,224	3,377

Contains Proprietary Material
Do Not Distribute

Winter	12	18,383	12/23/2014	14,663	14,262	14,073	13,933	14,242	15,168	16,313	16,749	17,072	17,330	17,421	17,431	17,381	17,306	17,298	17,266	17,980	18,383	18,196	17,889	17,367	16,563	15,572	14,554
Winter	12	17,105	12/24/2014	13,767	13,279	12,909	12,731	12,935	13,503	14,321	14,942	15,503	16,095	16,336	16,337	16,176	16,063	15,967	16,024	16,596	17,105	16,880	16,776	16,654	16,412	15,820	15,192
Winter	12	16,909	12/25/2014	14,707	14,300	14,122	14,253	14,502	15,035	15,807	16,464	16,800	16,672	16,359	15,681	14,735	14,051	13,573	13,529	14,336	15,814	16,252	16,677	16,909	16,829	16,545	16,197
Winter	12	19,181	12/26/2014	16,024	16,097	16,272	16,481	17,050	17,944	18,879	19,181	18,920	18,120	17,478	16,754	16,177	15,789	15,545	15,661	16,537	17,727	17,833	17,769	17,524	17,012	16,254	15,419
Winter	12	16,966	12/27/2014	14,835	14,473	14,288	14,217	14,450	14,866	15,416	15,754	16,226	16,568	16,587	16,418	16,045	15,628	15,524	15,662	16,384	16,966	16,833	16,692	16,366	15,762	14,986	14,185
Winter	12	18,392	12/28/2014	13,647	13,257	13,136	13,103	13,300	13,647	14,370	15,226	15,959	16,387	16,373	16,355	16,442	16,507	16,401	16,663	17,614	18,369	18,392	18,214	17,786	17,182	16,210	15,535
Winter	12	20,459	12/29/2014	15,091	14,810	14,734	14,810	15,211	16,265	17,478	17,900	18,257	18,602	18,869	18,877	18,799	18,748	18,681	18,797	19,541	20,459	20,363	20,089	19,635	18,886	17,931	17,050
Winter	12	21,550	12/30/2014	16,628	16,502	16,482	16,601	16,987	18,134	19,403	19,884	20,113	20,121	19,789	19,371	18,903	18,579	18,316	18,369	19,376	21,070	21,526	21,550	21,340	20,908	20,212	19,527
Winter	12	21,954	12/31/2014	19,235	19,098	19,052	19,092	19,500	20,400	21,555	21,954	21,903	21,472	20,864	20,331	19,718	19,178	18,692	18,710	19,653	21,335	21,517	21,325	21,043	20,645	20,260	19,813
Winter	1	20,120	1/1/2015	19,644	19,554	19,552	19,529	19,685	19,896	20,120	20,078	19,953	19,839	19,585	19,115	18,708	18,387	18,168	18,314	19,011	19,663	19,518	19,108	18,759	18,092	17,342	16,596
Winter	1	19,476	1/2/2015	16,086	15,748	15,623	15,626	15,932	16,748	17,626	18,258	18,583	18,815	19,112	19,011	18,790	18,605	18,391	18,395	18,780	19,476	19,353	18,945	18,482	17,763	16,853	15,974
Winter	1	16,774	1/3/2015	15,323	14,821	14,537	14,444	14,471	14,763	15,142	15,527	15,925	16,173	16,295	16,122	15,869	15,709	15,593	15,693	16,251	16,774	16,564	16,116	15,711	15,087	14,216	13,488
Winter	1	19,314	1/4/2015	12,886	12,515	12,380	12,348	12,459	12,919	13,521	14,319	15,118	15,389	15,367	15,563	15,797	15,974	16,150	16,545	17,528	18,849	19,097	19,314	19,228	18,881	18,274	17,882
Winter	1	23,995	1/5/2015	17,811	17,896	18,144	18,641	19,633	21,475	23,357	23,769	23,361	22,742	22,075	21,431	20,821	20,307	19,779	19,877	21,075	23,123	23,846	23,995	23,855	23,137	22,191	21,506
Winter	1	24,561	1/6/2015	21,162	21,078	21,022	21,019	21,688	23,201	24,561	24,030	22,788	21,758	20,942	20,178	19,683	19,307	18,945	19,177	20,279	21,920	22,696	22,817	22,676	22,050	21,160	20,555
Winter	1	31,334	1/7/2015	20,293	20,245	20,150	20,340	20,938	22,472	24,078	24,321	24,284	24,425	24,660	24,812	24,952	25,222	25,461	26,193	27,909	30,145	30,983	31,334	31,073	30,498	29,844	29,274
Winter	1	32,751	1/8/2015	29,045	29,098	29,337	29,704	30,248	31,332	32,751	32,747	31,453	29,912	28,453	26,919	25,416	24,926	24,121	24,219	25,246	26,903	27,369	27,254	26,806	25,754	24,527	23,584
Winter	1	26,542	1/9/2015	23,116	22,993	23,029	23,285	23,728	25,150	26,542	26,343	25,534	24,567	23,608	22,560	21,833	21,224	20,947	21,166	22,310	24,225	24,748	24,776	24,917	24,811	24,370	23,946
Winter	1	28,007	1/10/2015	23,904	24,137	24,518	25,027	25,660	26,545	27,544	28,007	27,163	25,727	24,309	22,798	21,363	20,450	19,708	19,700	20,831	22,940	23,506	23,818	23,646	23,435	22,782	22,008
Winter	1	21,909	1/11/2015	21,433	21,091	20,745	20,606	20,617	20,909	21,426	21,895	21,909	21,253	20,499	20,007	19,936	19,587	19,361	19,357	19,979	20,977	20,965	20,640	20,071	19,235	18,132	17,276
Winter	1	21,805	1/12/2015	16,793	16,444	16,410	16,512	16,945	18,433	20,038	20,321	19,993	20,027	20,177	19,954	20,017	19,941	19,794	19,894	20,665	21,753	21,805	21,599	21,093	20,357	19,311	18,458
Winter	1	24,397	1/13/2015	18,132	18,035	18,119	18,464	19,144	20,812	22,476	22,742	22,621	22,794	22,878	22,886	22,687	22,585	22,409	22,747	23,456	24,397	24,379	24,060	23,551	22,665	21,381	20,588
Winter	1	23,859	1/14/2015	20,083	19,954	19,881	19,929	20,459	21,957	23,495	23,557	23,216	23,010	22,753	22,225	21,713	21,051	20,616	20,767	21,582	23,258	23,796	23,859	23,693	23,041	22,019	21,431
Winter	1	24,506	1/15/2015	21,184	21,149	21,171	21,215	21,757	23,111	24,506	24,450	23,913	23,503	23,170	22,769	22,424	21,948	21,660	21,748	22,314	23,357	23,716	23,563	23,343	22,578	21,613	20,905
Winter	1	25,153	1/16/2015	20,710	20,752	20,854	21,130	21,883	23,517	25,153	25,098	23,855	22,223	20,944	19,635	18,596	17,937	17,489	17,306	17,991	19,675	20,307	20,526	20,675	20,505	20,165	19,748
Winter	1	22,167	1/17/2015	19,549	19,405	19,521	19,803	20,366	21,003	21,782	22,167	21,581	20,197	18,951	17,917	16,981	16,193	15,697	15,620	16,164	17,764	18,211	18,245	18,066	17,630	17,040	16,386
Winter	1	18,047	1/18/2015	15,779	15,572	15,453	15,400	15,688	16,294	17,033	17,698	17,952	17,384	16,662	16,112	15,804	15,523	15,140	15,166	15,813	17,259	17,945	18,021	18,047	17,857	17,240	16,869
Winter	1	20,586	1/19/2015	16,736	16,771	17,022	17,322	17,946	19,097	20,227	20,586	19,932	18,962	18,283	17,656	17,142	16,640	16,325	16,272	16,679	18,262	18,794	18,813	18,530	17,815	16,862	16,190
Winter	1	20,528	1/20/2015	15,867	15,879	15,854	16,061	16,902	18,760	20,528	20,432	19,395	18,353	17,580	17,026	16,743	16,448	16,258	16,424	16,986	18,313	18,655	18,605	18,259	17,571	16,534	15,886
Winter	1	20,570	1/21/2015	15,694	15,651	15,639	16,138	16,981	18,684	20,570	20,569	19,566	18,380	17,612	16,982	16,685	16,437	16,242	16,242	17,031	18,675	19,386	19,514	19,581	19,117	18,230	17,646
Winter	1	21,778	1/22/2015	17,480	17,483	17,590	17,755	18,428	20,064	21,778	21,606	21,084	20,413	20,118	19,732	19,450	19,191	19,129	19,249	19,985	21,108	21,462	21,358	20,874	20,037	18,902	18,153
Winter	1	21,721	1/23/2015	17,639	17,394	17,328	17,357	17,947	19,583	21,031	21,315	21,260	21,242	21,237	21,046	20,955	20,771	20,718	20,593	21,067	21,721	21,586	21,158	20,820	20,228	19,365	18,590
Winter	1	21,629	1/24/2015	18,148	18,082	18,101	18,292	18,775	19,602	20,551	21,158	21,629	21,278	20,607	19,650	18,621	17,750	17,182	17,039	17,629	19,145	19,797	19,779	19,648	19,371	18,823	18,263
Winter	1	20,096	1/25/2015	17,965	17,946	17,915	18,100	18,428	18,923	19,625	20,096	19,856	18,902	17,735	17,000	16,529	16,304	16,285	16,546	17,326	18,435	18,764	18,709	18,361	17,759	16,903	16,274
Winter	1	23,222	1/26/2015	15,958	15,831	16,078	16,361	17,354	19,203	21,139	21,548	21,610	21,804	21,982	21,914	21,702	21,581	21,193	21,160	21,594	22,832	23,222	22,965	22,459	21,482	20,286	19,467
Winter	1	22,793	1/27/2015	19,039	18,814	18,806	18,816	19,555	21,211	22,793	22,709	22,123	21,434	20,932	20,638	20,427	20,172	20,001	20,104	20,579	21,804	22,413	22,383	21,955	21,169	20,146	19,429
Winter	1	23,918	1/28/2015	19,023	18,873	19,054	19,542	20,429	22,115	23,918	23,697	22,275	21,087	20,194	19,276	18,492	17,927	17,400	17,543	18,170	19,903	20,743	20,913	20,737	20,058	19,083	18,418
Winter	1	21,130	1/29/2015	18,003	17,794	17,656	17,788	18,340	19,733	21,130	20,909	20,225	19,721	19,112	18,301	17,653	17,241	16,894	17,009	17,589	18,927	19,425	19,524	19,263	18,564	17,675	16,993
Winter	1	21,482	1/30/2015	16,807	16,728	16,843	17,067	17,790	19,472	21,297	21,482	21,201	20,660	19,944	19,297	18,625	18,146	17,658	17,640	18,187	19,869	20,677	20,931	20,995	20,773	20,232	19,752
Winter	1	22,281	1/31/2015	19,804	19,848	20,011	20,297	20,640	21,258	21,843	22,281	22,193	21,598	20,421	19,224	18,379	17,684	17,488	17,430	18,051	19,023	19,255	19,165	18,904	18,369	17,635	16,880
Winter	2	18,412	2/1/2015	16,396	16,117	15,942	15,915	15,877	16,367	17,004	17,665	18,315	18,412	18,202	18,033	17,986	17,792	17,549	17,607	17,904	18,171	17,850	17,517	17,124	16,650	16,039	15,402
Winter	2	24,728	2/2/2015	15,158	15,190	15,444	15,935	17,208	19,415	21,677	22,370	22,769	23,113	23,431	23,308	22,903	22,378	22,021	22,175	22,747	24,105	24,728	24,692	24,354	23,603	22,588	21,948
Winter	2	26,710	2/3/2015	21,619	21,752	22,011	22,415	23,169	24,974	26,710	26,340	24,854	23,203	22,019	20,980	19,925	19,155	18,543	18,452	19,082	20,787	22,108	22,507	22,409	21,769	20,868	20,297
Winter	2	24,390	2/4/2015	20,060	20,058	20,198	20,522	21,091	22,777	24,390	24,019	22,672	21,059	19,938	19,046	18,462	17,954	17,749	17,946	18,636	19,931	20,679	20,657	20,451	19,746	18,884	18,145
Winter	2	24,058	2/5/2015	17,850	17,833	18,088	18,524	19,319	21,187	23,262	23,636	23,262	22,672	21,970	21,204	20,650	20,124	19,668	19,692	20,410	22,387	23,686	24,042	24,058	23,497	22,751	22,405
Winter	2	27,603	2/6/2015	22,415	22,601	22,970	23,489	24,342	26,065	27,603	27,109	25,347	23,467	21,946	20,493	19,306	18,549	17,888	17,670	18,005	19,447	20,485	20,671	20,619	20,153	19,583	19,123
Winter	2	20,969	2/7/2015	18,726	18,671	18,743	18,964	19,375	20,019	20,707	20,969	20,308	19,228	18,109	17,188	16,346	15,633	15,151	14,952	15,187	16,288	17,134	17,100	16,992	16,576	15,989	15,410
Winter	2	16,970	2/8/2015	14,933	14,761	14,693	14,860	14,891	15,368	15,921	16,419	16,773	16,621	16,044	15,609	15,474	15,227	15,127	15,155	15,552	16,510	16,970	16,777	16,190	15,487	14,576	13,702
Winter	2	20,915	2/9/2015	13,257	13,111	13,061	13,138	13,823	15,420	17,132	17,396	17,393	17,456	17,655	17,815	17,855	17,885	17,931	18,194	18,946	20,291	20,889	20,915	20,638	19,870	18,965	18,212
Winter	2	22,472	2/10/2015	17,919	17,917	18,019	18,172	18,919	20,649	22,406	22,472	22,309	21,872	21,429	20,709	20,037	19,264	18,636	18,495	18,945	20,521	21,734	21,900	21,845	21,201	20,300	19,669
Winter	2	24,311	2/11/2015	19,570	19,730	20,036	20,348	21,163	22,758	24,311	23,885	22,536	21,002	19,616	18,501	17,844	17,218	16,732	16,609	17,046	18,483	19,649	19,733	19,881	19,355	18,462	17,704
Winter	2	25,279	2/12/2015	17,400	17,273	17,426	17,731	18,510	20,343	22,134	22,294	22,132	22,041	22,171	22,083	21,857	21,458	20,977	21,041	21,798	23,596	24,987	25,279	25,151	24,557	23,652	22,921
Winter	2	26,488	2/13/2015	22,585	22,584	22,585	22,702	23,299	24,913	26,488	26,254	25,288	24,131	22,946	21,813	20,865	20,237	19,745	19,782	20,205	21,576	22,593	22,782	22,680	22,358	21,860	21,291
Winter	2	22,071	2/14/2015	21,028	20,838	20,725	20,759	21,030	21,513	21,982	22,071	21,686	20,944	20,040	18,962	18,265	17,805	17,523	17,682	18,217	19,154	20,211	20,490	20,870	21,215	21,388	21,578
Winter	2	26,623	2/15/2015	22,044	22,556	23,096	23,692	24,418	25,268	26,074	26,623	26,537	25,684	24,535	23,564	22,835	22,197	21,864	22,035	22,743	24,021	24,740	24,481	24,003	23,375	22,635	21,905
Winter	2	25,507	2/16/2015	21,531	21,316	21,206	21,328	21,801	22,773	23,674	24,024	24,457	24,780	25,017	25,099	25,113	24,774	24,476	24,396	24,568	25,407	25,507	24,987	24,360	23,818	23,235	22,777
Winter	2	26,413	2/17/2015	22,828	22,827	23,001	23,284	23,861	24,949	26,042	26,413	26,396	26,009	25,472	24,869	24,105	23,385	22,907	22,865	23,470	24,842	25,909	25,915	25,716	25,198	24,486	24,030
Winter	2	28,354	2/18/2015	23,849	23,846	23,888	23,991	24,259	25,137	26,132	26,409	26,300	25,804	25,412	25,063	24,614	24,351	24,305	24,587	25,329	26,787	28,095	28,354	28,289	28,052	27,619	27,412
Winter	2	32,164	2/19/2015	27,487	27,882	28,371	28,857	29,763	31,175	32,164	31,921	31,069	30,169	29,301	28,206	27,377	26,661	26,110	25,973	26,494	28,270	29,636	29,968	30,085	29,674	28,933	28,283
Winter	2	30,159	2/20/2015	28,129	28,172	28,157	28,326	28,643	29,582	30,159	30,080	29,591	28,852	27,831	26,989	26,364	26,056	25,915	25,931	26,198	27,069	27,257	26,710	25,980	25,033	23,895	22,881
Winter	2	22,960	2/21/2015	22,313	22,170	21,829	21,715	21,687	21,747	22,004	22,224	22,678	22,960	22,861	22,642	22,094	21,493	21,131	20,999	21,043	21,369	21,652	21,279	20,789	20,182	19,422	18,774
Winter	2	22,140	2/22/2015	18,363	18,059	18,024	18,172	18,459	18,872	19,488	20,160	20,768	20,834	20,515	20,165	19,791	19,523	19,395	19,602	20,281	21,379	22,140	22,097	21,821	21,342	20,675	20,126
Winter	2	26,075	2/23/2015	19,961	20,112	20,328	20,773	21,638	23,184	24,595	25,085	25,140	24,795	24,180	23,536	23,016	22,943	23,038	23,211	23,735	24,999	26,075	26,034	25,730	24,963	23,852	23,044
Winter	2	25,894	2/24/2015	22,588	22,428	22,556	22,919	23,502	24,620	25,838	25,894	25,547	25,108	24,605	23,930	23,303	22,682	22,354	22,017	22,223	23,254	24,755	24,959	24,806	24,422	23,665	23,026
Winter	2	26,595	2/25/2015	22,896	22,957	23,111	23,411	24,117	25,460	26,595	26,391	25,302	24,180	23,437	22,815	22,459	22,411	22,295	22,507	22,983	23,714	24,361	23,812	23,324	22,602	21,670	20,909
Winter	2	23,883	2/26/2015	20,519	20,292	20,283	20,483	21,001	21,955	22,874	23,208	22,755	22,288	21,824	21,463	21,044	20,777	20,504	20,757	21,476	22,612	23,676	23,883	23,702	23,125	22,435	21,750
Winter	2	26,135	2/27/2015	21,530	21,491	21,736	22,116	22,894	24,501	25,974	26,135	25,544	24,706	23,676	22,859	21,991	21,197	20,615	20,476	21,014	22,464	23,874	24,169	24,005	23,878	23,145	22,428
Winter	2	23,540	2/28/2015	22,160	21,900	21,782	21,718	22,025	22,627	23,205	23,540	23,526	22,819	21,770	20,503	19,215	18,133	17,539	17,267	17,519	18,624	19,613	19,650	19,483	18,996	18,349	17,734
Spring	3	18,928	3/1/2015	17,168	16,890	16,784	16,851	16,910	17,237	17,758	18,239	18,789	18,627	18,110	17,691	17,510	17,263	17,171	17,264	17,598	18,266	18,911	18,928	18,526	17,896	17,094	16,354
Spring	3	21,084	3/2/2015	16,070	15,883	16,025	16,411	17,222	18,943	20,739	21,084	20,942	20,641	20,306	19,744	19,226	18,660	18,150	18,022	18,415	19,557	20,673	20,680	20,196	19,438	18,456	17,386
Spring	3	19,561	3/3/2015	16,776	16,471	16,355	16,300	16,864	18,288	19,561	19,515	19,128	18,828	18,668	18,373	17,823	17,713	17,488	17,389	17,746	18,405	18,992	18,735	18,157	17,146	15,782	14,819
Spring	3	20,260	3/4/2015	14,290	13,977	13,735	13,620	14,164	15,559	16,929	17,006	16,935	16,999	17,144	17,140	17,310	17,520	17,606	18,015	18,579	19,640	20,260	20,194	19,949	19,370	18,710	18,264
Spring	3	25,938	3/5/2015	18,162	18,310	18,663	19,122	19,920	21,170	22,202	22,709	23,342	23,694	24,002	24,047	24,003	23,849	23,574	23,487	23,727	24,634	25,909	25,938	25,656	25,244	24,590	24,216
Spring	3	27,804	3/6/2015	24,158	24,301	24,612	25,011	25,739	27,140	27,804	27,519	26,238	25,025	23,903	22,842	21,849	20,920	20,092	19,697	19,695	20,758	22,502	22,948	23,093	22,904	22,524	21,966
Spring	3	23,893	3/7/2015	21,880	21,902	22,029	22,312	22,810	23,526	23,893	23,318	22,134	20,824	19,624	18,478	17,406	16,567	16,060	15,733	15,788	16,564	18,073	18,306	18,434	18,259	17,826	17,419
Spring	3	20,150	3/8/2015	17,352	0	19,275	17,715	18,074	18,663	19,599	20,150	19,810	18,450	17,157	16,256	15,680	15,233	14,829	14,877	15,103	15,509	16,269	17,317	17,144	16,712	15,813	14,989
Spring	3	18,491	3/9/2015	14,516	14,381	14,311	14,504	15,050	16,539	18,202	18,491	18,323	18,140	18,040	17,812	17,270	16,928	16,582	16,577	16,719	16,988	17,741	18,435	18,132	17,365	16,328	15,224
Spring	3	17,908	3/10/2015	14,589	14,230	14,202	14,243	14,617	15,848	17,349	17,626	17,264	17,249	17,317	17,308	17,122	16,888	16,600	16,565	16,631	16,866	17,366	17,908	17,394	16,634	15,466	14,452
Spring	3	17,435	3/11/2015	13,728	13,270	13,106	13,070	13,385	14,644	16,248	16,546	16,440	16,497	16,664	16,693	16,594	16,521	16,263	16,208	16,242	16,408	16,778	17,435	17,246	16,643	15,582	14,603
Spring	3	17,485	3/12/2015	14,066	13,717	13,628	13,702	14,254	15,692	17,314	17,485	17,195	16,956	16,777	16,500	16,273	16,117	15,894	15,915	15,849	16,013	16,402	17,098	16,936	16,173	15,081	14,046
Spring	3	17,364	3/13/2015	13,411	13,043	12,744	12,695	13,062	14,369	15,944	16,319	16,360	16,603	16,878	16,825	16,841	16,771	16,655	16,468	16,482	16,669	17,027	17,364	17,027	16,500	15,538	14,606
Spring	3	16,302	3/14/2015	14,036	13,550	13,364	13,267	13,348	13,895	14,400	14,939	15,679	16,221	16,302	16,132	15,765	15,435	15,124	15,039	14,968	15,043	15,346	15,941	15,582	15,091	14,353	13,518
Spring	3	15,747	3/15/2015	12,957	12,665	12,529	12,492	12,767	13,367	14,021	14,766	15,187	14,983	14,412	14,172	14,066	13,756	13,698	13,849	14,046	14,192	14,545	15,747	15,739	15,120	14,092	13,158
Spring	3	17,792	3/16/2015	12,815	12,627	12,865	13,177	13,965	15,725	17,580	17,792	17,252	16,669	16,312	16,169	16,049	15,981	15,998	16,044	16,096	16,092	16,260	17,156	16,954	15,990	14,651	13,532
Spring	3	16,913	3/17/2015	12,831	12,469	12,257	12,303	12,868	14,222	15,749	15,890	15,721	15,560	15,607	15,802	15,920	15,940	15,974	15,914	15,907	15,899	15,992	16,913	16,773	15,897	14,669	13,614
Spring	3	17,794	3/18/2015	13,054	12,785	12,580	12,743	13,477	14,978	16,736	17,082	17,122	17,153	17,081	16,943	16,707	16,326	15,978	16,048	16,239	16,558	17,046	17,794	17,581	16,900	15,699	14,696
Spring	3	17,956	3/19/2015	14,096	13,902	13,757	13,754	14,371	15,768	17,435	17,676	17,654	17,668	17,859	17,571	17,406	17,273	17,009	16,930	16,918	17,019	17,345	17,956	17,707	17,006	15,871	14,945
Spring	3	17,048	3/20/2015	14,333	13,976	13,763	13,655	14,104	15,331	16,833	16,960	16,914	16,907	17,048	17,041	16,738	16,573	16,367	16,156	16,170	16,225	16,398	16,948	16,692	16,145	15,368	14,534
Spring	3	15,992	3/21/2015	13,995	13,526	13,466	13,422	13,731	14,348	15,119	15,607	15,992	15,915	15,559	15,125	14,686	14,380	14,168	14,076	14,188	14,362	14,745	15,555	15,354	14,850	14,118	13,338
Spring	3	16,165	3/22/2015	12,762	12,513	12,344	12,379	12,548	12,889	13,610	14,201	14,994	15,041	14,635	14,492	14,533	14,391	14,190	14,312	14,535	14,839	15,363	16,165	15,989	15,268	14,355	13,569
Spring	3	17,267	3/23/2015	13,099	12,972	12,901	13,145	13,796	15,512	17,112	17,267	16,820	16,413	16,263	15,984	15,916	15,822	15,689	15,719	15,749	15,867	16,017	16,969	16,749	15,763	14,663	13,538
Spring	3	17,131	3/24/2015	13,037	12,760	12,580	12,755	13,416	14,971	16,620	16,692	16,378	16,119	16,010	15,831	15,776	15,902	15,941	16,095	16,160	16,155	16,304	17,131	17,006	16,059	14,812	13,612
Spring	3	17,428	3/25/2015	13,029	12,624	12,424	12,379	12,680	14,005	15,461	15,533	15,553	15,630	15,887	16,063	16,115	16,377	16,487	16,573	16,795	16,758	16,680	17,428	17,303	16,431	15,075	13,845
Spring	3	17,586	3/26/2015	13,108	12,581	12,366	12,255	12,565	13,781	15,220	15,272	15,446	15,665

Contains Proprietary Material
Do Not Distribute

Spring	4	16,645	4/30/2015	12,830	12,427	12,267	12,479	13,124	14,491	15,745	15,924	15,815	15,916	15,947	15,741	15,808	15,964	15,936	15,975	16,008	15,946	15,860	16,143	16,645	15,929	14,576	13,683
Spring	5	16,216	5/1/2015	13,108	12,797	12,698	12,916	13,476	14,912	16,050	16,216	15,963	15,878	15,855	15,666	15,319	15,266	15,303	15,455	15,575	15,479	15,232	15,300	15,858	15,319	14,500	13,551
Spring	5	15,733	5/2/2015	12,840	12,490	12,342	12,376	12,691	13,131	13,433	14,065	14,470	14,609	14,547	14,565	14,534	14,960	15,143	15,495	15,712	15,733	15,591	15,462	15,548	14,858	13,879	12,808
Spring	5	16,884	5/3/2015	12,141	11,694	11,435	11,397	11,547	11,830	12,057	12,968	13,642	13,853	14,074	14,293	14,801	15,276	15,787	16,248	16,679	16,884	16,588	16,579	16,777	15,963	14,551	13,259
Spring	5	19,683	5/4/2015	12,497	11,930	11,821	11,873	12,392	13,697	14,812	15,427	15,815	16,379	17,102	17,591	18,119	18,609	18,998	19,431	19,683	19,682	19,393	18,854	19,102	17,830	15,962	14,478
Spring	5	20,451	5/5/2015	13,562	12,919	12,607	12,452	12,814	13,964	14,977	15,617	16,079	16,689	17,409	18,108	18,739	19,370	19,828	20,205	20,451	20,446	19,946	19,505	19,548	18,292	16,431	14,851
Spring	5	21,328	5/6/2015	13,773	13,100	12,807	12,694	13,002	14,128	15,224	15,782	16,411	17,042	17,786	18,557	19,289	19,944	20,564	21,009	21,328	21,218	20,631	19,889	19,780	18,523	16,696	15,011
Spring	5	21,940	5/7/2015	14,009	13,243	12,786	12,702	13,056	14,224	15,218	15,887	16,516	17,352	18,362	19,162	19,981	20,669	21,163	21,640	21,940	21,774	21,249	20,605	20,410	19,064	17,145	15,435
Spring	5	21,916	5/8/2015	14,299	13,616	13,209	13,115	13,457	14,513	15,544	16,280	17,119	18,149	19,201	19,995	20,547	21,342	21,589	21,916	21,907	21,445	20,702	19,895	19,821	18,647	17,048	15,633
Spring	5	20,790	5/9/2015	14,422	13,622	13,195	12,886	12,838	13,086	13,352	14,416	15,652	16,713	17,645	18,338	18,991	19,696	20,119	20,544	20,790	20,502	19,888	19,414	19,212	18,099	16,694	15,277
Spring	5	21,859	5/10/2015	14,103	13,242	12,923	12,644	12,419	12,476	12,772	13,951	15,317	16,570	17,696	18,762	19,784	20,567	21,179	21,654	21,859	21,651	21,064	20,731	20,591	19,281	17,527	15,797
Spring	5	22,070	5/11/2015	14,716	14,168	13,756	13,632	14,001	15,087	16,292	17,117	17,986	19,105	20,131	20,958	21,618	22,008	21,991	22,070	22,050	21,609	21,093	20,633	20,849	19,541	17,590	15,805
Spring	5	20,076	5/12/2015	14,704	13,998	13,650	13,528	13,802	14,938	16,023	16,703	17,374	17,973	18,463	18,801	19,128	19,483	19,834	20,076	19,930	19,360	18,663	18,368	18,494	17,407	15,654	14,317
Spring	5	19,600	5/13/2015	13,478	12,978	12,662	12,569	13,020	13,970	14,894	15,453	15,648	16,081	16,482	16,846	17,380	17,914	18,581	19,074	19,560	19,600	19,083	18,417	18,611	17,551	15,916	14,508
Spring	5	19,328	5/14/2015	13,539	12,985	12,717	12,631	12,883	14,135	15,385	15,736	16,093	16,498	16,984	17,560	18,011	18,615	19,047	19,278	19,328	19,038	18,803	18,719	19,071	18,109	16,601	15,098
Spring	5	20,966	5/15/2015	14,278	13,710	13,286	13,067	13,433	14,549	15,631	16,487	17,282	18,159	18,913	19,531	20,291	20,878	20,881	20,966	20,919	20,429	19,540	19,054	19,210	18,351	16,857	15,542
Spring	5	18,860	5/16/2015	14,501	13,811	13,382	13,120	13,145	13,290	13,743	14,718	15,943	16,645	17,307	17,662	17,923	18,233	18,546	18,763	18,860	18,735	18,352	18,170	18,244	17,540	16,342	14,893
Spring	5	19,603	5/17/2015	13,938	13,321	12,927	12,642	12,633	12,820	12,884	13,909	15,326	16,311	16,988	17,495	17,903	18,347	18,917	19,313	19,603	19,461	18,973	18,804	18,857	17,838	16,435	15,054
Spring	5	20,806	5/18/2015	14,199	13,565	13,185	13,178	13,637	14,765	16,046	16,816	17,542	18,216	19,123	19,766	20,207	20,597	20,804	20,741	20,806	20,753	20,439	20,050	20,077	18,983	17,380	15,787
Spring	5	22,348	5/19/2015	14,808	14,167	13,745	13,583	14,028	15,107	16,200	16,892	17,447	18,075	18,855	19,551	20,333	21,096	21,784	22,185	22,348	22,057	21,308	20,527	20,448	19,176	17,357	15,701
Spring	5	20,883	5/20/2015	14,531	13,617	13,151	13,083	13,239	14,089	15,075	15,817	16,433	17,227	17,943	18,610	19,348	20,000	20,508	20,827	20,883	20,654	20,107	19,713	19,705	18,599	16,942	15,516
Spring	5	16,732	5/21/2015	14,497	13,927	13,530	13,417	13,673	14,661	15,606	16,138	16,554	16,603	16,732	16,487	16,232	16,117	16,072	15,874	15,817	15,682	15,657	15,799	16,368	15,841	14,734	13,693
Spring	5	16,694	5/22/2015	12,999	12,586	12,423	12,512	12,982	13,918	14,870	15,364	15,575	15,668	15,647	15,702	15,594	15,842	16,142	16,451	16,662	16,694	16,370	15,833	16,194	15,624	14,541	13,471
Spring	5	18,302	5/23/2015	12,641	12,088	11,855	11,798	11,864	11,978	12,282	12,960	13,662	14,240	14,766	15,273	15,773	16,361	17,050	17,656	18,217	18,302	17,986	17,195	17,192	16,442	15,164	13,925
Spring	5	19,620	5/24/2015	13,003	12,401	11,955	11,654	11,701	11,703	11,757	12,826	14,102	15,199	15,899	16,737	17,581	18,316	18,876	19,353	19,620	19,441	18,796	18,161	18,052	17,164	15,781	14,514
Spring	5	18,152	5/25/2015	13,669	13,008	12,601	12,436	12,480	12,493	12,623	13,343	14,305	15,389	16,267	16,755	17,154	17,458	17,642	17,944	18,151	18,152	17,895	17,671	17,878	17,020	15,642	14,601
Spring	5	20,850	5/26/2015	13,743	13,300	12,981	12,882	13,205	14,099	15,185	16,329	17,205	17,907	18,728	19,365	19,920	20,479	20,722	20,818	20,850	20,646	20,285	19,764	19,856	18,976	17,422	15,865
Spring	5	20,877	5/27/2015	14,806	14,115	13,744	13,590	14,032	14,857	15,580	16,616	17,458	18,204	19,328	19,955	20,567	20,831	20,736	20,877	20,845	20,442	19,833	19,350	19,484	18,662	17,155	15,676
Spring	5	22,117	5/28/2015	14,655	14,015	13,642	13,572	13,958	14,688	15,604	16,432	17,193	18,063	18,973	19,612	20,241	21,000	21,602	21,983	22,117	21,889	21,290	20,723	20,872	19,932	18,276	16,588
Spring	5	21,826	5/29/2015	15,550	14,765	14,264	14,042	14,368	15,002	15,935	16,990	17,762	18,722	19,612	20,242	20,809	21,419	21,701	21,826	21,745	21,085	20,221	19,617	19,793	19,008	17,582	16,122
Spring	5	21,182	5/30/2015	15,109	14,167	13,651	13,445	13,407	13,416	13,770	14,928	16,574	17,959	19,105	19,955	20,378	20,859	21,060	21,148	21,182	20,983	20,246	19,480	19,256	18,406	16,993	15,681
Spring	5	18,772	5/31/2015	14,421	13,538	13,069	12,766	12,709	12,693	12,817	13,806	15,113	16,106	16,882	17,682	18,275	18,639	18,772	18,703	18,572	18,405	17,946	17,572	17,645	16,922	15,653	14,429
Summer	6	19,042	6/1/2015	13,677	13,056	12,863	12,806	13,185	13,985	14,937	15,841	16,460	17,017	17,753	18,059	18,362	18,629	18,770	19,042	19,011	18,768	18,411	17,934	18,080	17,408	15,997	14,763
Summer	6	18,320	6/2/2015	13,723	13,174	12,809	12,681	13,150	13,924	14,740	15,599	16,188	16,711	17,229	17,571	17,806	18,141	18,300	18,264	18,320	18,078	17,844	17,578	17,829	17,036	15,730	14,519
Summer	6	19,421	6/3/2015	13,592	13,000	12,693	12,672	13,017	13,615	14,453	15,198	15,726	16,338	17,080	17,586	17,973	18,447	18,936	19,210	19,421	19,313	18,883	18,267	18,295	17,647	16,117	14,766
Summer	6	22,217	6/4/2015	13,728	13,164	12,687	12,480	12,765	13,488	14,478	15,426	16,241	17,123	18,089	18,793	19,694	20,513	21,168	21,799	22,217	22,152	21,487	20,570	20,450	19,552	17,781	16,201
Summer	6	22,811	6/5/2015	15,054	14,240	13,749	13,548	13,774	14,295	15,217	16,465	17,646	18,903	20,214	21,198	21,820	22,298	22,627	22,811	22,729	22,271	21,603	20,805	20,731	19,713	18,121	16,386
Summer	6	23,587	6/6/2015	15,135	14,208	13,653	13,436	13,253	13,294	13,548	14,621	16,165	17,890	19,407	20,553	21,480	22,311	22,832	23,387	23,587	23,344	22,754	21,743	21,165	20,038	18,400	16,653
Summer	6	24,356	6/7/2015	15,337	14,500	14,019	13,460	13,118	12,904	13,230	14,662	16,472	18,298	19,797	21,032	22,236	23,073	23,286	23,792	24,277	24,356	23,779	22,850	22,392	21,144	19,212	17,524
Summer	6	24,006	6/8/2015	16,311	15,531	14,873	14,755	14,885	15,725	16,772	18,159	19,509	21,007	22,387	23,331	23,932	24,006	23,864	23,247	22,446	21,880	21,215	20,613	20,573	19,631	17,926	16,471
Summer	6	25,219	6/9/2015	15,387	14,802	14,361	14,229	14,392	15,071	16,057	17,337	18,377	19,610	21,014	22,135	23,097	23,994	24,736	25,001	25,219	24,958	24,288	23,097	22,618	21,404	19,295	17,467
Summer	6	26,195	6/10/2015	16,176	15,174	14,638	14,264	14,431	15,048	16,104	17,374	18,787	20,362	22,082	23,323	24,267	25,090	25,524	26,009	26,195	25,936	25,356	24,257	23,730	22,426	20,299	18,396
Summer	6	26,351	6/11/2015	16,978	16,025	15,379	15,075	15,272	15,704	16,623	18,118	19,661	21,498	22,914	24,208	25,166	25,793	26,135	26,351	26,240	25,823	25,178	24,050	23,606	22,601	20,496	18,741
Summer	6	25,093	6/12/2015	17,440	16,480	15,776	15,418	15,565	16,030	16,877	18,221	19,687	20,909	22,282	23,318	24,008	24,512	24,968	25,051	25,093	24,824	24,058	22,941	22,535	21,648	19,915	18,311
Summer	6	24,846	6/13/2015	16,881	16,102	15,395	14,963	14,745	14,784	15,215	16,401	18,011	19,509	20,885	21,975	22,935	23,639	24,227	24,587	24,846	24,579	23,860	22,830	22,245	20,933	19,282	17,724
Summer	6	25,286	6/14/2015	16,428	15,543	14,764	14,306	14,162	13,896	14,161	15,627	17,478	19,153	20,585	21,888	22,941	23,767	24,463	24,901	25,286	25,230	24,669	23,618	22,965	21,915	20,075	18,340
Summer	6	27,989	6/15/2015	16,972	16,013	15,452	15,219	15,330	15,921	17,116	18,780	20,570	22,363	24,124	25,447	26,347	27,072	27,572	27,820	27,989	27,593	27,058	25,984	25,426	24,008	21,854	19,824
Summer	6	28,167	6/16/2015	18,326	17,243	16,433	16,093	16,269	16,688	17,679	19,352	21,178	23,121	24,884	26,084	26,980	27,741	28,028	28,082	28,167	27,939	27,283	26,334	25,881	24,534	22,288	20,418
Summer	6	28,542	6/17/2015	18,845	17,725	16,967	16,330	16,404	16,727	17,629	19,102	20,826	22,779	24,594	25,866	26,839	27,693	28,225	28,469	28,542	28,156	27,297	26,018	25,529	24,095	22,057	20,086
Summer	6	26,732	6/18/2015	18,607	17,625	16,789	16,452	16,511	17,004	17,937	19,272	20,876	22,586	24,251	25,440	26,137	26,706	26,732	26,692	26,431	25,942	25,311	24,351	24,172	23,019	21,198	19,365
Summer	6	25,489	6/19/2015	18,080	17,320	16,681	16,292	16,501	17,175	18,002	19,151	20,395	21,786	23,045	24,033	24,822	25,350	25,462	25,489	25,208	24,471	23,350	22,288	22,013	21,224	19,781	18,238
Summer	6	24,317	6/20/2015	17,117	16,345	15,887	15,549	15,447	15,572	15,786	16,682	18,035	19,311	20,575	21,471	22,243	22,966	23,508	24,098	24,317	24,143	23,602	22,703	22,115	21,158	19,654	18,028
Summer	6	26,005	6/21/2015	16,834	15,982	15,376	14,964	14,878	14,750	15,026	16,602	18,575	20,433	22,027	23,405	24,424	25,206	25,640	25,869	26,005	25,618	24,901	23,843	23,311	22,092	20,422	18,708
Summer	6	27,806	6/22/2015	17,472	16,496	15,897	15,667	16,001	16,404	17,407	19,014	20,615	22,500	24,347	25,723	26,773	27,431	27,773	27,806	27,684	27,094	26,100	25,024	24,675	23,475	21,510	19,674
Summer	6	28,865	6/23/2015	18,431	17,463	16,737	16,386	16,639	17,235	18,048	19,555	21,235	22,964	24,608	25,953	26,975	27,830	28,570	28,852	28,865	28,589	27,859	27,073	26,570	25,207	23,143	21,065
Summer	6	27,774	6/24/2015	19,386	18,181	17,379	16,829	16,863	17,392	18,122	19,353	20,893	22,470	24,030	25,093	26,117	26,874	27,482	27,774	27,405	26,750	25,665	24,630	24,145	22,905	20,921	19,072
Summer	6	28,575	6/25/2015	17,924	16,751	16,228	15,836	16,022	16,558	17,383	18,693	20,235	21,827	23,719	25,213	26,440	27,473	27,977	28,500	28,575	28,289	27,659	26,636	26,079	24,771	22,688	20,686
Summer	6	27,694	6/26/2015	19,297	18,200	17,487	17,030	17,093	17,398	18,035	19,321	21,071	23,001	24,826	26,230	27,047	27,597	27,694	27,346	26,583	25,378	23,903	22,672	22,165	20,896	19,436	18,316
Summer	6	20,763	6/27/2015	16,729	15,864	15,452	15,131	14,932	15,130	15,236	16,043	17,041	18,016	18,783	19,354	19,912	20,293	20,564	20,716	20,763	20,660	20,194	19,081	18,882	18,201	16,773	15,370
Summer	6	21,434	6/28/2015	14,229	13,321	12,920	12,557	12,455	12,257	12,570	13,668	15,090	16,249	17,187	17,901	18,861	19,603	20,376	21,007	21,404	21,434	21,007	20,034	19,490	18,554	16,954	15,565
Summer	6	23,955	6/29/2015	14,509	13,852	13,345	13,204	13,596	14,273	15,132	16,065	17,252	18,342	19,411	20,471	21,465	22,343	22,967	23,705	23,955	23,862	23,314	22,479	22,127	21,094	19,258	17,385
Summer	6	23,191	6/30/2015	16,229	15,514	14,923	14,611	14,754	15,348	16,172	17,076	18,163	19,354	20,598	21,489	22,070	22,704	22,989	23,191	23,162	22,698	22,030	21,324	21,205	20,352	18,768	17,273
Summer	7	20,335	7/1/2015	16,142	15,503	14,897	14,661	14,816	15,348	16,078	16,920	17,682	18,515	19,342	19,851	20,236	20,335	20,301	20,266	20,199	19,908	19,574	19,157	19,355	18,915	17,615	16,270
Summer	7	21,279	7/2/2015	15,329	14,726	14,364	14,313	14,529	15,309	15,976	16,815	17,519	18,131	18,856	19,354	19,791	20,315	20,913	21,129	21,279	20,999	20,562	20,002	20,112	19,412	18,109	16,634
Summer	7	18,333	7/3/2015	15,558	14,804	14,327	14,088	14,038	14,151	14,359	15,022	15,858	16,774	17,341	17,685	17,919	18,179	18,292	18,302	18,333	18,174	17,689	17,375	17,506	17,017	16,229	15,096
Summer	7	18,523	7/4/2015	14,223	13,472	12,977	12,904	12,796	12,841	12,913	13,552	14,544	15,702	16,506	17,211	17,771	18,129	18,375	18,523	18,455	18,099	17,522	16,891	16,594	16,194	15,662	14,702
Summer	7	20,767	7/5/2015	13,744	13,127	12,777	12,406	12,261	12,362	12,566	13,441	14,608	15,637	16,581	17,583	18,569	19,282	19,810	20,341	20,672	20,767	20,420	19,724	19,403	18,695	17,340	15,893
Summer	7	24,648	7/6/2015	14,846	14,143	13,630	13,527	13,804	14,494	15,327	16,438	17,444	18,656	19,887	21,036	22,086	23,109	23,769	24,344	24,648	24,504	23,971	23,034	22,689	21,567	19,765	17,979
Summer	7	26,232	7/7/2015	16,774	15,913	15,377	15,037	15,287	15,868	16,722	17,954	19,453	20,876	22,467	23,693	24,715	25,540	26,113	26,232	26,135	25,605	24,570	23,634	23,224	22,147	20,346	18,565
Summer	7	26,910	7/8/2015	17,248	16,301	15,799	15,364	15,385	15,986	16,826	18,071	19,395	21,137	22,825	24,067	24,945	25,889	26,531	26,867	26,910	26,668	25,920	24,782	24,376	23,221	21,236	19,395
Summer	7	27,653	7/9/2015	18,002	17,074	16,448	16,082	16,255	16,842	17,561	19,013	20,636	22,432	24,160	25,243	26,131	26,825	27,337	27,595	27,653	27,382	26,639	25,473	24,873	23,642	21,616	19,578
Summer	7	27,875	7/10/2015	18,141	17,148	16,294	15,913	15,970	16,446	17,264	18,572	20,381	22,307	24,047	25,354	26,392	27,184	27,607	27,833	27,875	27,336	26,511	25,063	24,519	23,442	21,638	19,724
Summer	7	26,552	7/11/2015	18,298	17,264	16,500	15,968	15,713	15,608	15,737	17,012	18,910	20,908	22,816	24,264	25,297	25,972	26,258	26,552	26,436	26,257	25,643	24,582	23,976	22,705	20,979	19,232
Summer	7	26,089	7/12/2015	17,844	16,724	15,974	15,569	15,329	15,137	15,280	16,629	18,648	20,509	22,106	23,151	23,895	24,682	25,217	25,794	26,089	25,965	25,452	24,662	24,105	22,963	21,237	19,570
Summer	7	29,027	7/13/2015	18,283	17,467	16,704	16,371	16,577	17,132	17,951	19,658	21,382	23,331	25,268	26,412	27,544	28,247	28,829	29,027	28,924	28,491	27,671	26,759	26,209	24,969	22,871	21,064
Summer	7	27,681	7/14/2015	19,696	18,696	18,100	17,682	17,835	18,606	19,236	20,486	21,576	22,995	24,214	25,398	26,556	27,482	27,681	27,129	25,778	24,538	23,320	22,314	21,884	20,960	19,480	17,996
Summer	7	26,826	7/15/2015	16,820	16,118	15,704	15,422	15,427	16,138	16,960	18,150	19,409	20,789	22,377	23,601	24,696	25,644	26,320	26,730	26,826	26,422	25,630	24,355	23,851	22,636	20,729	18,846
Summer	7	27,314	7/16/2015	17,419	16,400	15,681	15,428	15,615	16,170	17,047	18,328	19,803	21,513	23,094	24,236	25,271	26,200	26,842	27,253	27,314	27,095	26,615	25,477	24,930	23,595	21,596	19,608
Summer	7	28,743	7/17/2015	18,221	17,201	16,519	16,115	16,294	16,817	17,606	18,842	20,554	22,533	24,547	25,911	26,978	27,831	28,395	28,710	28,743	28,353	27,638	26,444	25,870	24,613	22,589	20,958
Summer	7	27,264	7/18/2015	19,344	18,176	17,346	16,809	16,509	16,428	16,573	17,914	20,082	22,159	24,146	25,540	26,283	26,786	27,150	27,144	27,264	27,051	26,463	25,331	24,818	23,689	22,021	20,269
Summer	7	27,311	7/19/2015	18,851	17,697	16,851	16,287	16,134	15,945	16,066	17,578	19,828	21,834	23,512	24,820	25,723	26,450	26,695	26,950	27,311	27,194	26,705	25,828	25,343	24,117	22,336	20,674
Summer	7	29,018	7/20/2015	19,305	18,307	17,681	17,431	17,579	18,319	19,098	20,236	21,589	23,407	25,297	26,868	27,921	28,751	29,018	28,828	28,158	27,609	26,720	25,788	25,411	24,252	22,380	20,597
Summer	7	27,603	7/21/2015	19,308	18,382	17,789	17,486	17,603	18,274	18,870	20,122	21,353	22,818	24,372	25,537	26,524	27,181	27,603	27,454	27,060	26,687	25,881	24,930	24,562	23,319	21,310	19,479
Summer	7	25,787	7/22/2015	18,024	17,159	16,573	16,324	16,433	17,124	17,793	18,643	19,767	21,161	22,441	23,548	24,481	25,313	25,617	25,787	25,765	25,573	24,757	23,987	23,704	22,456	20,708	19,128
Summer	7	23,227	7/23/2015	17,907	17,221	16,581	16,343	16,553	17,309	18,117	18,874	19,704	20,588	21,437	21,927	22,436	22,526	22,772	23,109	23,227	23,129	22,801	22,202	22,297	21,446	19,874	18,401
Summer	7	27,005	7/24/2015	17,261	16,459	15,962	15,611	15,924	16,587	17,303	18,518	19,730	21,221	22,768	23,987	25,020	26,005	26,605	27,005	26,987	26,675	25,745	24,465	23,910	22,585	20,734	18,935
Summer	7	26,681	7/25/2015	17,571	16,461	15,804	15,369	15,184	15,167	15,203	16,459	18,244	20,066	21,974	23,455	24,598	25,525	26,213	26,585	26,654	26,681	25,834	24,556	23,800	22,255	20,554	18,743
Summer	7	26,380	7/26/2015	17,424	16,399	15,695	15,173	14,910	14,728	14,811	16,299	18,263	20,260	21,946	23,602	24,809	25,672	26,102	26,350	26,380	26,146	25,473	24,523	24,201	22,875	20,969	19,321
Summer	7	28,828	7/27/2015	18,120	17,175	16,687	16,355	16,511	17,177	18,080	19,368	21,079	23,009	25,066	26,592	27,471	28,101	28,351	28,689	28,828	28,684	27,898	26,993	26,566	25,093	23,016	21,218
Summer	7	28,630	7/28/2015	19,795	18,684	17,999	17,571	17,619	18,273	18,901	20,328	22,249	24,025	26,198	27,465	28,111	28,550	28,630	28,372	27,643	26,920	26,259	25,515	25,257	24,146	22,437	20,646
Summer	7	28,970	7/29/2015	19,545	18,143	17,579	17,189	17,203	17,798	18,523	19,575	20,974	22,638	24,309	25,699	26,903	27,710	28,266	28,714	28,970	28,796	28,021	27,077	26,651	25,188	22,998	21,132
Summer	7	27,672	7/30/2015	19,755	18,749	17,961	17,524	17,586	18,198	18,899	19,913	21,130	22,479	23,856	24,978	25,900	26,730	27,316	27,672	27,519	26,931	25,923	24,504	24,016	22,483	20,462	18,481
Summer	7	26,246	7/31/2015	17,099	16,037	15,456	14,956	15,061	15,706	16,229	17,497	18,967	20,432	21,921	23,024	23,931	24,873	25,654	26,156	26,246	25,801	24,893	23,399	22,582	21,259	19,401	17,640
Summer	8	25,969	8/1/2015	16,286	15,266	14,518	14,142	14,127	14,186	14,291	15,447	17,145	19,134

Contains Proprietary Material
Do Not Distribute

Fall	9	25,492	9/5/2015	16,815	15,736	15,161	14,689	14,395	14,485	14,585	15,377	17,123	19,033	20,937	22,706	24,037	24,953	25,473	25,492	25,338	24,652	23,504	22,841	21,777	20,267	18,646	17,138
Fall	9	24,340	9/6/2015	15,891	15,084	14,501	14,011	13,875	13,843	13,999	14,891	16,592	18,230	19,662	21,154	22,403	23,368	23,939	24,289	24,340	23,746	22,543	21,850	20,890	19,470	18,045	16,637
Fall	9	24,597	9/7/2015	15,492	14,630	14,110	13,679	13,632	13,717	13,668	14,300	15,939	17,835	19,837	21,450	22,657	23,553	24,071	24,475	24,597	24,203	23,307	22,849	21,875	20,105	18,265	16,666
Fall	9	25,812	9/8/2015	15,569	14,812	14,250	14,193	14,439	15,629	16,827	17,519	18,714	20,169	21,788	23,094	24,145	25,084	25,439	25,688	25,812	25,480	24,781	24,436	23,521	21,755	19,693	18,042
Fall	9	23,220	9/9/2015	16,830	16,196	15,759	15,527	15,630	16,715	17,903	18,188	18,930	20,098	21,280	22,168	22,888	23,209	23,220	23,068	22,646	21,985	21,380	21,292	20,684	19,340	17,798	16,409
Fall	9	23,227	9/10/2015	15,603	14,989	14,663	14,537	14,878	16,017	17,300	17,568	18,047	18,573	19,206	19,739	20,563	21,465	22,303	22,952	23,227	22,896	22,164	21,885	21,197	19,722	18,046	16,485
Fall	9	22,190	9/11/2015	15,510	14,748	14,296	14,177	14,453	15,583	16,669	17,034	17,850	19,010	20,174	21,030	21,776	22,190	22,011	21,659	21,202	20,270	19,424	19,066	18,543	17,657	16,476	15,221
Fall	9	17,134	9/12/2015	14,216	13,512	13,184	12,926	12,882	13,130	13,380	13,854	14,754	15,463	15,934	16,206	16,462	16,729	17,044	17,134	17,028	16,631	15,994	16,211	15,731	14,919	13,990	12,995
Fall	9	16,297	9/13/2015	12,246	11,789	11,467	11,397	11,373	11,579	11,860	12,471	13,327	13,637	13,879	14,141	14,541	14,841	15,129	15,544	15,913	16,045	15,793	16,297	15,877	14,828	13,670	12,693
Fall	9	18,553	9/14/2015	12,080	11,881	11,628	11,748	12,280	13,586	14,767	15,008	15,374	15,686	16,145	16,338	16,660	17,083	17,567	18,172	18,553	18,426	18,109	18,141	17,584	16,474	15,007	13,666
Fall	9	20,128	9/15/2015	13,031	12,483	12,304	12,297	12,803	13,984	15,073	15,333	15,680	16,125	16,679	17,120	17,733	18,450	19,060	19,729	20,128	19,918	19,320	19,328	18,717	17,439	15,806	14,392
Fall	9	21,122	9/16/2015	13,507	13,007	12,668	12,614	13,030	14,171	15,381	15,423	15,980	16,692	17,444	17,899	18,650	19,467	20,192	20,915	21,122	20,957	20,251	19,965	19,279	17,858	16,233	14,839
Fall	9	22,201	9/17/2015	13,829	13,277	12,867	12,886	13,202	14,449	15,498	15,822	16,393	16,968	17,897	18,648	19,528	20,510	21,280	21,900	22,201	21,863	20,893	20,749	19,921	18,510	16,805	15,194
Fall	9	23,150	9/18/2015	14,166	13,606	13,215	13,068	13,376	14,439	15,650	15,872	16,623	17,544	18,691	19,582	20,546	21,356	22,315	22,927	23,150	22,601	21,284	20,592	19,609	18,408	16,928	15,459
Fall	9	22,168	9/19/2015	14,257	13,700	13,187	12,883	12,807	13,128	13,453	13,999	15,296	16,539	17,749	18,966	20,108	21,115	21,853	22,168	21,978	21,371	20,506	20,178	19,182	17,980	16,698	15,382
Fall	9	20,000	9/20/2015	14,372	13,688	13,110	12,800	12,539	12,658	12,890	13,534	14,656	15,564	16,430	17,335	18,275	19,058	19,482	19,833	20,000	19,473	18,999	19,120	18,167	16,849	15,377	14,193
Fall	9	19,845	9/21/2015	13,454	12,907	12,666	12,636	13,195	14,391	15,709	15,944	16,232	16,614	17,240	17,736	18,200	18,810	19,238	19,690	19,845	19,547	19,108	19,188	18,504	17,177	15,574	14,309
Fall	9	21,219	9/22/2015	13,421	12,865	12,555	12,561	12,941	14,143	15,335	15,490	15,919	16,587	17,236	17,901	18,549	19,359	20,243	20,868	21,219	20,929	20,211	20,033	19,271	17,698	16,137	14,787
Fall	9	22,319	9/23/2015	13,945	13,279	12,933	12,829	13,184	14,269	15,431	15,637	16,130	16,937	17,876	18,742	19,696	20,719	21,415	22,044	22,319	21,947	21,174	20,769	19,767	18,277	16,564	15,196
Fall	9	22,116	9/24/2015	14,325	13,560	13,254	13,030	13,312	14,538	15,722	15,876	16,471	17,312	18,353	19,281	20,110	21,074	21,722	22,116	22,011	21,442	20,861	20,744	19,797	18,349	16,741	15,301
Fall	9	18,290	9/25/2015	14,322	13,639	13,315	13,189	13,647	14,644	16,009	16,177	16,437	16,948	17,471	17,815	18,046	18,187	18,290	18,218	18,042	17,754	17,618	17,578	17,078	16,393	15,509	14,417
Fall	9	17,321	9/26/2015	13,616	13,022	12,685	12,491	12,522	12,871	13,403	13,911	14,743	15,527	16,059	16,393	16,686	16,913	17,049	17,077	17,065	16,841	17,009	17,321	16,899	16,049	15,128	14,127
Fall	9	19,125	9/27/2015	13,313	12,740	12,316	12,330	12,361	12,465	12,922	13,482	14,562	15,359	15,913	16,618	17,385	17,903	18,280	18,478	18,846	18,733	18,747	19,125	18,398	17,158	15,899	14,784
Fall	9	20,157	9/28/2015	13,984	13,474	13,311	13,233	13,735	14,977	16,444	16,897	17,241	17,873	18,440	18,856	19,213	19,519	19,656	19,600	19,605	19,584	19,952	20,157	19,592	18,506	17,150	15,862
Fall	9	20,079	9/29/2015	15,084	14,548	14,184	14,053	14,537	15,863	17,298	17,558	17,828	18,149	18,538	18,827	19,148	19,355	19,664	19,921	20,079	19,851	19,835	19,921	19,170	18,185	16,804	15,483
Fall	9	18,345	9/30/2015	14,619	14,188	13,769	13,750	14,202	15,345	16,745	16,950	17,142	17,475	17,856	17,934	18,074	18,345	18,283	18,220	18,080	17,837	18,124	18,188	17,564	16,677	15,377	14,106
Fall	10	16,967	10/1/2015	13,470	12,976	12,716	12,734	13,112	14,277	15,597	15,697	15,916	16,094	16,242	16,364	16,303	16,235	16,186	16,191	16,223	16,201	16,495	16,967	16,541	15,659	14,529	13,495
Fall	10	15,711	10/2/2015	12,686	12,318	12,130	12,085	12,551	13,784	15,219	15,348	15,480	15,565	15,693	15,711	15,406	15,245	15,110	14,965	14,881	14,934	15,333	15,618	15,374	14,788	13,890	13,061
Fall	10	15,254	10/3/2015	12,391	11,985	11,790	11,726	11,807	12,195	12,813	13,251	13,903	14,531	14,810	14,735	14,643	14,512	14,479	14,345	14,500	14,642	15,156	15,254	15,005	14,355	13,601	12,771
Fall	10	16,298	10/4/2015	12,212	11,799	11,627	11,507	11,629	11,873	12,345	12,958	13,720	14,042	14,076	14,147	14,254	14,192	14,407	14,621	14,909	15,074	15,639	16,298	15,881	14,908	13,819	12,803
Fall	10	19,398	10/5/2015	12,223	11,849	11,703	11,782	12,260	13,391	14,614	15,003	15,562	16,023	16,492	17,121	17,695	18,194	18,708	19,130	19,393	19,200	19,156	19,398	18,676	17,467	15,948	14,517
Fall	10	20,819	10/6/2015	13,706	13,203	12,842	12,781	13,170	14,355	15,483	15,688	16,201	16,851	17,595	18,361	19,219	19,769	20,327	20,811	20,819	20,370	19,996	19,989	19,024	17,840	16,270	14,788
Fall	10	20,783	10/7/2015	13,836	13,168	12,818	12,733	12,942	14,195	15,144	15,254	15,677	16,343	17,119	17,987	18,927	19,674	20,240	20,659	20,783	20,301	19,854	19,473	18,611	17,413	15,996	14,621
Fall	10	20,630	10/8/2015	13,809	13,310	12,996	12,762	13,174	14,477	15,564	15,701	16,242	16,958	17,848	18,619	19,411	19,973	20,630	20,596	20,566	20,072	20,018	19,947	19,185	18,012	16,525	15,208
Fall	10	19,679	10/9/2015	14,276	13,799	13,353	13,195	13,492	14,535	15,788	16,026	16,637	17,245	18,035	18,790	19,395	19,679	19,606	19,313	18,718	18,077	17,882	17,619	17,043	16,206	15,233	13,969
Fall	10	15,575	10/10/2015	13,257	12,730	12,419	12,265	12,215	12,487	13,088	13,488	14,194	14,733	14,963	15,076	14,997	14,953	15,021	15,171	15,257	15,144	15,420	15,575	15,036	14,469	13,502	12,716
Fall	10	16,159	10/11/2015	12,130	11,741	11,487	11,346	11,496	11,803	12,280	12,801	13,570	13,933	13,992	14,125	14,394	14,680	14,953	15,283	15,674	15,662	16,020	16,159	15,595	14,644	13,694	12,912
Fall	10	18,603	10/12/2015	12,200	11,986	11,785	11,768	12,294	13,471	14,782	15,148	15,473	15,865	16,166	16,429	16,704	17,212	17,602	17,995	18,229	18,003	18,432	18,603	17,861	16,760	15,440	14,287
Fall	10	17,379	10/13/2015	13,389	12,828	12,469	12,484	12,817	13,753	14,982	15,083	15,317	15,808	16,304	16,601	16,900	17,024	17,202	17,379	17,375	16,997	17,137	17,342	16,600	15,574	14,320	13,368
Fall	10	17,409	10/14/2015	12,808	12,386	12,264	12,357	12,796	14,114	15,407	15,547	15,714	15,867	16,055	16,232	16,271	16,415	16,688	17,034	17,314	17,091	17,230	17,409	16,839	15,869	14,565	13,601
Fall	10	17,941	10/15/2015	12,985	12,592	12,426	12,477	12,989	14,164	15,490	15,617	15,636	15,828	16,180	16,324	16,617	16,717	17,277	17,758	17,941	17,692	17,773	17,921	17,298	16,295	15,063	13,903
Fall	10	16,018	10/16/2015	13,238	12,789	12,519	12,454	12,901	13,979	15,214	15,432	15,603	15,842	16,018	16,014	16,001	15,844	15,852	15,834	15,722	15,494	15,682	15,871	15,628	15,051	14,255	13,473
Fall	10	15,370	10/17/2015	12,934	12,603	12,530	12,450	12,718	13,181	14,042	14,752	15,226	15,200	14,974	14,816	14,250	14,124	14,000	13,964	14,116	14,231	15,080	15,370	15,157	14,672	14,069	13,451
Fall	10	16,309	10/18/2015	13,054	12,929	12,871	12,953	13,244	13,805	14,505	15,422	15,867	15,442	14,867	14,534	14,271	14,115	13,972	13,994	14,238	14,675	15,828	16,309	15,988	15,306	14,544	13,884
Fall	10	18,518	10/19/2015	13,698	13,637	13,780	14,134	15,005	16,655	18,426	18,518	18,016	17,314	16,966	16,256	16,002	15,562	15,386	15,342	15,458	15,626	16,503	16,952	16,556	15,841	14,732	13,990
Fall	10	17,593	10/20/2015	13,480	13,398	13,380	13,563	14,331	15,973	17,556	17,593	17,055	16,547	16,184	15,901	15,749	15,474	15,412	15,537	15,701	15,705	16,529	16,861	16,355	15,584	14,341	13,507
Fall	10	17,181	10/21/2015	13,053	12,861	12,749	13,007	13,657	15,141	16,680	16,606	16,309	16,147	15,948	15,915	15,853	15,952	16,085	16,372	16,470	16,474	17,028	17,181	16,694	15,735	14,615	13,606
Fall	10	17,538	10/22/2015	12,914	12,656	12,535	12,651	13,353	14,588	16,051	16,091	15,945	15,821	15,998	16,099	16,244	16,476	16,604	16,897	17,053	16,884	17,402	17,538	17,018	15,934	14,641	13,500
Fall	10	16,821	10/23/2015	12,870	12,480	12,384	12,496	13,060	14,373	15,869	16,096	16,041	16,050	16,132	16,326	16,369	16,527	16,628	16,711	16,690	16,359	16,821	16,729	16,307	15,766	14,749	13,741
Fall	10	16,197	10/24/2015	13,192	12,650	12,367	12,207	12,381	12,731	13,371	13,906	14,627	15,143	15,564	15,549	15,544	15,500	15,407	15,395	15,416	15,474	16,197	15,929	15,564	14,908	14,113	13,048
Fall	10	15,802	10/25/2015	12,393	12,018	11,801	11,603	11,629	11,900	12,379	12,982	13,642	13,969	14,149	14,214	14,326	14,346	14,427	14,465	14,709	14,966	15,802	15,736	15,388	14,565	13,557	12,702
Fall	10	16,964	10/26/2015	12,117	11,923	11,792	11,941	12,525	13,843	15,433	15,822	15,884	16,070	16,165	16,221	16,044	15,827	15,660	15,655	15,813	16,263	16,956	16,964	16,498	15,687	14,535	13,575
Fall	10	17,226	10/27/2015	13,061	12,703	12,519	12,556	13,122	14,493	15,865	16,227	16,282	16,628	16,667	16,571	16,397	15,970	15,753	15,857	16,053	16,536	17,226	17,161	16,568	15,716	14,629	13,653
Fall	10	16,758	10/28/2015	13,129	12,839	12,627	12,680	13,159	14,377	15,868	16,145	16,165	16,215	16,284	16,153	16,029	15,783	15,777	15,841	15,903	15,973	16,635	16,758	16,412	15,662	14,464	13,534
Fall	10	16,568	10/29/2015	12,939	12,528	12,394	12,454	12,905	14,229	15,800	15,938	15,760	15,795	15,945	15,824	15,774	15,591	15,493	15,440	15,476	15,488	16,348	16,568	16,295	15,533	14,499	13,564
Fall	10	16,721	10/30/2015	12,918	12,656	12,673	12,790	13,395	14,919	16,627	16,721	16,431	16,054	15,516	15,301	14,985	14,655	14,541	14,377	14,361	14,505	15,278	15,392	15,201	14,722	14,095	13,242
Fall	10	15,058	10/31/2015	12,921	12,552	12,318	12,220	12,422	12,892	13,355	13,946	14,635	15,001	15,058	14,897	14,727	14,565	14,476	14,404	14,416	14,528	14,874	14,640	14,434	13,906	13,187	12,365
Fall	11	15,833	11/1/2015	11,777	11,494	11,223	11,152	11,367	11,614	12,152	13,135	13,881	13,979	13,783	14,033	14,007	14,029	13,986	14,162	14,923	15,833	15,816	15,456	14,794	14,078	13,185	12,429
Fall	11	17,475	11/2/2015	11,936	11,729	11,652	11,586	12,005	13,387	14,724	15,054	15,264	15,452	15,785	16,006	16,053	16,043	16,009	16,092	16,462	17,429	17,475	16,925	16,342	15,369	14,269	13,253
Fall	11	17,840	11/3/2015	12,711	12,367	12,251	12,027	12,359	13,712	14,821	15,057	15,321	15,450	15,956	16,190	16,451	16,569	16,583	16,533	16,845	17,829	17,840	17,406	16,763	15,689	14,550	13,413
Fall	11	17,951	11/4/2015	12,869	12,478	12,231	12,029	12,374	13,665	14,870	15,101	15,380	15,716	16,165	16,388	16,714	16,815	16,735	16,657	16,941	17,951	17,948	17,500	16,917	15,718	14,615	13,608
Fall	11	18,709	11/5/2015	12,933	12,560	12,332	12,218	12,557	13,857	15,143	15,470	15,779	16,150	16,712	17,110	17,454	17,585	17,739	17,721	17,878	18,709	18,632	18,196	17,531	16,637	15,342	14,280
Fall	11	17,590	11/6/2015	13,625	13,328	12,940	12,810	13,032	14,218	15,406	15,731	16,120	16,302	16,725	16,924	16,985	17,012	16,856	16,704	17,044	17,590	17,257	16,771	16,203	15,478	14,539	13,525
Fall	11	15,969	11/7/2015	12,782	12,356	12,056	11,938	12,066	12,469	12,999	13,588	14,441	14,985	15,144	15,080	14,792	14,666	14,608	14,688	15,246	15,969	15,736	15,518	15,088	14,612	13,907	13,214
Fall	11	16,260	11/8/2015	12,682	12,470	12,383	12,324	12,488	12,932	13,455	14,267	14,759	14,678	14,327	14,175	14,151	14,069	13,999	14,188	14,945	16,080	16,260	16,036	15,548	14,828	13,899	13,296
Fall	11	17,867	11/9/2015	12,829	12,508	12,500	12,709	13,088	14,579	16,027	16,185	16,340	16,405	16,553	16,595	16,568	16,481	16,287	16,416	17,008	17,867	17,779	17,434	16,757	15,867	14,730	13,783
Fall	11	17,391	11/10/2015	13,094	12,932	12,837	12,993	13,399	14,814	16,128	16,151	15,986	15,932	15,977	15,973	15,901	15,939	15,849	15,855	16,175	17,309	17,391	17,199	16,618	16,018	15,129	14,431
Fall	11	17,643	11/11/2015	14,086	13,931	13,954	14,081	14,532	16,006	17,083	16,968	16,375	16,055	16,019	16,031	16,084	16,075	16,183	16,201	16,655	17,643	17,596	17,103	16,676	15,836	14,674	13,822
Fall	11	17,368	11/12/2015	13,273	12,918	12,720	12,578	12,931	14,166	15,392	15,590	15,687	15,680	15,963	16,065	15,999	15,968	15,910	15,833	16,166	17,361	17,368	17,245	16,681	15,972	14,948	14,229
Fall	11	17,722	11/13/2015	13,942	13,679	13,802	13,910	14,489	16,198	17,690	17,578	16,983	16,624	16,458	16,162	15,734	15,666	15,629	15,820	16,438	17,722	17,708	17,632	17,519	17,163	16,539	15,959
Fall	11	18,158	11/14/2015	15,533	15,562	15,694	15,982	16,306	17,120	17,732	18,158	17,725	17,078	16,262	15,508	15,225	14,935	14,745	14,684	15,544	16,605	16,888	16,710	16,505	16,214	15,769	15,377
Fall	11	17,278	11/15/2015	15,198	15,149	15,232	15,376	15,640	16,091	16,623	17,143	17,195	16,501	15,815	15,277	14,945	14,650	14,551	14,630	15,755	17,121	17,262	17,278	17,044	16,493	15,675	15,153
Fall	11	18,390	11/16/2015	14,835	14,748	14,800	14,818	15,483	17,120	18,390	18,279	17,921	17,455	17,255	17,048	16,801	16,533	16,445	16,676	17,464	18,360	18,281	17,946	17,183	16,234	15,000	14,149
Fall	11	17,709	11/17/2015	13,667	13,427	13,328	13,280	13,732	15,161	16,468	16,508	16,429	16,278	16,317	16,289	16,330	16,234	16,146	16,279	16,974	17,709	17,629	17,259	16,644	15,792	14,687	13,661
Fall	11	17,965	11/18/2015	13,137	12,896	12,695	12,597	12,871	14,087	15,597	15,905	16,101	16,247	16,494	16,643	16,597	16,603	16,543	16,636	17,085	17,946	17,965	17,581	17,046	16,135	15,168	14,214
Fall	11	17,613	11/19/2015	13,591	13,321	13,196	13,181	13,770	15,364	16,769	16,797	16,502	16,272	16,110	16,003	15,943	15,957	15,824	15,846	16,265	17,412	17,613	17,445	17,161	16,562	15,691	14,918
Fall	11	18,673	11/20/2015	14,597	14,381	14,465	14,831	15,461	17,233	18,673	18,498	17,789	17,253	17,028	16,555	16,298	16,009	15,798	15,831	16,658	17,803	17,952	17,898	17,737	17,388	16,716	16,214
Fall	11	17,774	11/21/2015	15,735	15,554	15,626	15,710	16,000	16,574	17,082	17,329	17,236	16,797	16,502	16,043	15,746	15,596	15,694	15,941	16,710	17,685	17,774	17,698	17,571	17,087	16,649	16,242
Fall	11	20,511	11/22/2015	15,928	15,910	15,931	16,153	16,683	17,345	18,055	18,840	19,010	18,532	17,909	17,377	16,978	16,680	16,567	16,882	18,141	19,768	20,222	20,511	20,344	19,895	19,425	18,990
Fall	11	23,475	11/23/2015	18,904	19,061	19,304	19,631	20,389	21,998	23,475	23,191	22,104	20,603	19,763	18,959	18,351	17,835	17,559	17,580	18,648	20,190	20,619	20,685	20,575	20,156	19,396	18,698
Fall	11	22,218	11/24/2015	18,484	18,411	18,516	18,794	19,507	21,085	22,218	21,945	20,804	19,474	18,670	17,888	17,441	17,090	16,858	16,906	17,824	19,150	19,428	19,315	19,140	18,551	17,701	17,062
Fall	11	19,045	11/25/2015	16,616	16,486	16,299	16,357	16,698	17,792	18,748	19,045	18,638	18,011	17,573	17,075	16,681	16,299	15,953	15,913	16,523	17,534	17,457	17,179	16,923	16,459	15,455	14,470
Fall	11	15,698	11/26/2015	13,818	13,466	13,220	13,250	13,508	14,034	14,545	15,088	15,536	15,698	15,618	14,980	14,082	13,367	12,929	12,666	12,829	13,518	13,479	13,408	13,276	12,996	12,520	11,977
Fall	11	14,889	11/27/2015	11,622	11,427	11,367	11,431	11,682	12,246	12,775	13,148	13,553	13,751	13,824	13,702	13,554	13,439	13,383	13,462	14,228	14,889	14,784	14,561	14,280	13,750	13,063	12,262
Fall	11	15,272	11/28/2015	11,661	11,368	11,240	11,309	11,440	11,872	12,342	12,914	13,676	14,213	14,419	14,414	14,268	14,172	14,083	14,137	14,759	15,272	15,065	15,058	14,713	14,179	13,436	12,614
Fall	11	16,619	11/29/2015	12,057	11,750	11,554	11,466	11,577	12,080	12,548	13,183	13,968	14,352	14,488	14,610	14,797	14,895	14,886	15,234	16,015	16,619	16,585	16,483	15,847	15,241	14,217	13,395
Fall	11	18,331	11/30/2015	12,908	12,584	12,567	12,481	12,930	14,345	15,857	16,036	16,216	16,346	16,547	16,688	16,711	16,732	16,660	16,869	17,634	18,331	18,185	17,923	17,241	16,387	15,065	14,069

Southeast Operating Reserves

VACAR Reserve Sharing Group

Coincident Peak Load Date		Winter Peak Load 02/20/15, Hour 8	Spring Peak Load 03/06/15, Hour 8	Summer Peak Load 06/23/15, Hour 18	Fall Peak Load 09/02/15, Hour 16	Winter Max of mos the largest s
Dominion	VAP	21,651	17,719	18,955	16,640	367
Duke	DUKE	21,101	16,260	19,827	18,524	358
Progress Energy Carolinas	CPL	15,569	11,245	12,752	11,738	264
	CPLE					244
	CPLW					20
SCEG	SCEG	4,970	3,200	4,450	4,185	84
SC	SC	5,869	3,895	4,834	4,214	100
	Total	**69,160**	**52,319**	**60,818**	**55,301**	

Largest Single Unit	Summer	Winter
DUK BAA : Catawba 1	1,140	1,174

http://www.serc1.org/docs/default-source/program-areas/standards-regional-criteria/regional-criteria/serc-reg-criteria_contingency-reserve-policy-r

Wkp - SERC Operating Reserves

TEE Reserve Sharing Group

		Winter Peak Load	Spring Peak Load	Summer Peak Load	Fall Peak Load
Coincident Peak Load Date		01/08/15, Hour 8	03/06/15, Hour 7	07/29/15, Hour 17	09/04/15, Hour 16
TVA	TVA	32,747	27,804	28,970	27,142
LGEE	LGEE	6,964	5,962	6,628	6,424
	Total	**39,711**	**33,766**	**35,598**	**33,566**

Winter
1
1,043
222

Largest Single Unit	Summer	Winter
TVA BAA: Cumberland (TN) 1	1,239	1,265

http://www.serc1.org/docs/default-source/program-areas/standards-regional-criteria/regional-criteria/serc-reg-criteria_contingency-reserve-policy-

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Spring	Summer	Fall
t severe single contingency or 1.0 times ingle resource in the combined systems		
397	355	353
365	372	393
252	239	249
233	221	230
19	18	19
72	83	89
87	91	89

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Wkp - SERC Operating Reserves

Spring	Summer	Fall
x Largest Single Unit, Shared		
1,042	1,008	1,023
223	231	242

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FERC Form 714 Outages

	Planned Outage and Derating (MW)				
Month	MISO	CPL	DUKE	LGEE	TVA
Dec-14	######	2,077	2,316	0	5,939
Jan15	######	5	209	0	1,658
Feb15	######	0	480	0	2,173
Mar15	######	578	3,148	758	4,098
Apr15	######	2,098	3,901	2,504	8,727
May15	######	2,171	4,464	300	5,885
Jun15	8,163	2	247	0	2,271
Jul15	6,429	0	325	0	1,440
Aug15	7,498	50	189	0	1,718
Sep15	7,327	36	417	0	2,717
Oct15	######	2,035	2,902	1,208	8,241
Nov15	######	1,664	3,062	1,467	7,242

	Planned Outage and Derating (MW)				
	Winter	Spring	Summer	Fall	Note
MISO	13,735	24,153	7,363	19,757	MISO outages
CPL	694	1,616	17	1,245	CPL outages
CPLE	655	1,525	16	1,175	Estimated based on generation ratios
CPLW	39	91	1	70	Estimated based on generation ratios
DUKE	1,002	3,838	254	2,127	DUKE outages
LGEE	0	1,187	0	892	LGEE outages
TVA	3,257	6,237	1,810	6,067	TVA outages

Generation (MW)			
Winter	Spring	Summer	Fall
15,574	15,574	14,351	15,598
14,696	14,696	13,525	14,720
878	878	826	878

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Area	PST	Winter	Spring	Summer	Fall
PJM	19,538	16,011	14,104	18,740	15,366
AP South	10,376	8,453	7,202	10,017	8,235
5004-5005	10,376	8,348	7,135	10,017	8,235
PJM East	5,063	3,767	3,417	4,819	3,923
NYISO	1,774	1,053	1,345	1,785	1,610
ISONE	4,000	3,627	3,224	4,080	3,720
CT	1,470	1,012	868	1,304	1,197

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Exhibit NCI-3 (UPDATED)

Generation Owned or Controlled by the CENG Nuclear Entities and their Affiliates in the Northeast Region and Relevant First-Tier Markets

Balancing Authority Area		Plant Name	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share	Owned and Purchased (MW) Summer	Owned and Purchased (MW) Winter
PJM							
Calvert Cliffs Nuclear Power Plant, LLC							
PJM	5004/5005	Calvert Cliffs [1/]	1,707.8	1,768.0	100.0%	1,707.8	1,768.0
Generation affiliated with the CENG Nuclear Entities through Exelon							
PJM		Braidwood	2,361.0	2,416.0	100.0%	2,361.0	2,416.0
PJM		Byron	2,318.0	2,364.0	100.0%	2,318.0	2,364.0
PJM	East	Chester	39.0	54.0	100.0%	39.0	54.0
PJM	East	Conowingo	572.0	572.0	100.0%	572.0	572.0
PJM		Criterion Power	70.0	70.0	100.0%	70.0	70.0
PJM	East	Croydon	392.0	512.0	100.0%	392.0	512.0
PJM	East	Delaware	56.0	74.0	100.0%	56.0	74.0
PJM		Dresden	1,797.0	1,805.0	100.0%	1,797.0	1,805.0
PJM	East	Eddystone	820.0	836.0	100.0%	820.0	836.0
PJM	East	Fairless Hills	60.0	60.0	100.0%	60.0	60.0
PJM	East	Falls	51.0	60.0	100.0%	51.0	60.0
PJM		Fair Wind Facility	30.0	30.0	100.0%	30.0	30.0
PJM		Fourmile Wind	40.0	40.0	100.0%	40.0	40.0
PJM	5004/5005	Gould Street	97.0	97.0	100.0%	97.0	97.0
PJM		Handsome Lake	267.5	267.5	100.0%	267.5	267.5
PJM		La Salle	2,271.6	2,313.0	100.0%	2,271.6	2,313.0
PJM	East	Limerick	2,241.8	2,386.0	100.0%	2,241.8	2,386.0
PJM	East	Moser	51.0	60.0	100.0%	51.0	60.0
PJM	East	Muddy Run	1,070.0	1,070.0	100.0%	1,070.0	1,070.0
PJM	5004/5005	Notch Cliff	116.7	116.7	100.0%	116.7	116.7
PJM	East	Oyster Creek	607.7	637.0	100.0%	607.7	637.0
PJM	5004/5005	Peach Bottom (inc. upgrade)	2,450.4	2,658.0	50.0%	1,225.2	1,329.0
PJM	East	Pennsbury	5.4	5.4	100.0%	5.4	5.4
PJM	5004/5005	Perryman	302.6	302.6	100.0%	302.6	302.6
PJM	5004/5005	Perryman 6	110.0	130.0	100.0%	110.0	130.0
PJM	5004/5005	Philadelphia Road	60.9	60.9	100.0%	60.9	60.9
PJM		Quad Cities	1,819.0	1,819.0	75.0%	1,364.3	1,364.3
PJM	East	Richmond	98.0	132.0	100.0%	98.0	132.0
PJM	5004/5005	Riverside	39.0	39.0	100.0%	39.0	39.0
PJM	East	Salem	2,366.6	2,366.6	42.6%	1,007.9	1,007.9
PJM	East	Schuylkill	30.0	38.0	100.0%	30.0	38.0
PJM		Southeast Chicago	296.0	320.0	100.0%	296.0	320.0
PJM	East	Southwark	52.0	72.0	100.0%	52.0	72.0
PJM	5004/5005	Three Mile Island 1	802.8	829.0	100.0%	802.8	829.0
PJM	5004/5005	Westport	115.8	115.8	100.0%	115.8	115.8
PJM	5004/5005	Bethlehem Renewable Plant	4.7	1.2	100.0%	4.7	1.2
PJM	5004/5005	Eastern LFG	3.0	1.5	100.0%	3.0	1.5
PJM	AP South	Fauquier LFG (retired Jan 2016)	2.0	1.0	100.0%	2.0	1.0

Exhibit NCI-3 (UPDATED)

Balancing Authority Area		Plant Name	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share	Owned and Purchased (MW) Summer	Owned and Purchased (MW) Winter
PJM		Clinton Battery (2016)	10.0	10.0	100.0%	10.0	10.0
Subtotal, PJM						20,858.9	21,599.8
Exelon's Purchases							
PJM		Elwood Energy, LLC [2/]				600.0	768.0
PJM	5004/5005	Calpine Mid Merit LLC				545.0	545.0
PJM		Cordova Energy Company, LLC				521.2	601.2
PJM		Backbone Mountain Windpower LLC				66.0	66.0
PJM		Bellefontaine Gas Producers, LLC				4.5	4.5
PJM		Forward Wind Power LLC				29.4	29.4
PJM		High Trail Wind Farm, LLC				99.0	99.0
PJM		Mill Run Windpower, LLC				15.6	15.6
PJM		Old Trail Wind Farm, LLC				198.0	198.0
PJM		Patton Wind Farm, LLC				16.0	16.0
PJM		Somerset Windpower, LLC				9.0	9.0
PJM		WM Renewable Energy, LLC				10.1	10.1
PJM	AP South	WM Renewable Energy, LLC				3.8	3.8
PJM	5004/5005	Green Gas Pioneer Crossing Energy, LLC				5.0	5.0
PJM	5004/5005	Green Knight Economic Development Corporation				3.3	3.3
PJM	5004/5005	Keystone Solar, L.L.C.				4.9	4.9
PJM	5004/5005	Waymart Wind Farm, L.P.				64.5	64.5
PJM	AP South	Ameresco Stafford, LLC				2.0	2.0
PJM	East	Ameresco Delaware Energy, LLC				7.0	7.0
PJM	East	MF Mesa Lane LLC				3.0	3.0
PJM	East	Chambers Cogeneration				187.6	187.6
PJM	East	Logan Generating				200.0	200.0
PJM		AES Armenia Mountain				50.0	50.0
PJM		Roth Rock				40.0	40.0
PJM		Chestnut Flats				38.0	38.0
Subtotal, PJM						2,722.9	2,970.9
Generation affiliated with the CENG Nuclear Entities through EDF							
PJM		Chestnut Flats [4/]	38.0	38.0	100.0%		
PJM		Kelly Creek Wind	184.0	184.0	100.0%	184.0	184.0
PJM		McHenry Battery Storage	20.0	20.0	100.0%	20.0	20.0
PJM		Pilot Hill Wind	175.0	175.0	100.0%	175.0	175.0
Subtotal, PJM						379.0	379.0
Subtotal, PJM						25,668.6	26,717.7
Subtotal, PJM East						7,551.4	7,973.9
Subtotal, 5004/5005						12,759.6	13,387.3
Subtotal, AP South						12,767.4	13,394.1
NYISO							

Exhibit NCI-3 (UPDATED)

Balancing Authority Area		Plant Name	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share	Owned and Purchased (MW) Summer	Owned and Purchased (MW) Winter
R.E. Ginna Nuclear Power Plant, LLC and Nine Mile Point Nuclear Station, LLC							
NYISO		Nine Mile Point [1/, 3/]	1,692.3	1,703.8	100.00%	1,692.3	1,703.8
NYISO		Ginna [1/]	582.0	583.0	100.00%	582.0	583.0
NYISO		Fitzpatrick	836.8	853.3	100.00%	836.8	853.3
Exelon's Purchases							
NYISO		Purchase (WM Renewable Energy, LLC)				28.8	28.8
Subtotal, NYISO			**3,111.1**	**3,140.1**		**3,139.9**	**3,168.9**
First-Tier Markets							
ISO-NE							
Generation affiliated with the CENG Nuclear Entities Through Exelon							
ISO-NE		Wyman (Yarmouth) 4	602.1	605.8	5.90%	35.5	35.7
ISO-NE		Framingham Jet	31.4	43.4	100.00%	31.4	43.4
ISO-NE		West Medway 1-2	81.8	125.6	100.00%	81.8	125.6
ISO-NE		West Medway 3	42.0	64.0	100.00%	42.0	64.0
ISO-NE		New Boston (L Street Jet)	16.0	21.8	100.00%	16.0	21.8
ISO-NE		Mystic 7	570.8	559.8	100.00%	570.8	559.8
ISO-NE		Mystic 8	703.4	841.5	100.00%	703.4	841.5
ISO-NE		Mystic 9	713.9	858.5	100.00%	713.9	858.5
ISO-NE		Mystic Jet	9.1	14.5	100.00%	9.1	14.5
ISO-NE	CT	Kleen Energy (purchase)				622.0	623.0
ISO-NE		Ameresco Northampton (purchase)				0.8	0.8
Subtotal, ISO-NE			**2,770.5**	**3,134.9**		**2,826.7**	**3,188.6**
Subtotal, CT						**622.0**	**623.0**
MISO							
Generation Affiliated with the CENG Nuclear Entities Through Exelon							
MISO			1,468.2	1,481.2		2,448.6	2,527.6
Generation Affiliated with the CENG Nuclear Entities Through EDF							
MISO			412.0	412.0		412.0	412.0
Subtotal, MISO			1,880.2	1,893.2		2,860.6	2,939.6

Plant ratings based on 2015 EIA-860 data
https://www.eia.gov/electricity/data/eia860/

1/ Reflects 100% of the ownership share attributed to the CENG Nuclear Entities.

2/ The current PPA is only 300 MW PPA. Another PPA was terminated August 16, 2016.

3/ Total capacity reflects 100% of unit 1 and 82% of unit 2. The remaining 18% of unit 2 is owned by Long Island Power Authority. Reflects Uprate for Unit 2

4/ EDF owns Chestnut flats and has a long term PPA with Exelon, which is reflected as owned by Exelon.

Exhibit NCI-11 (UPDATED)

Part I – Pivotal Supplier Analysis

Applicant-> **CENG Nuclear Entities**
Market -> **NYISO**
Data Year -> **Dec 2014-Nov 2015**

Row			
	Generation		**Reference**
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	3,111	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0	
B	Long-Term Firm Purchases (from inside the study area)	29	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	
C	Long-Term Firm Sales (in and outside the study area)	0	
D	Uncommitted Capacity Imports	519	Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	35,554	Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)	0	
F	Long-Term Firm Purchases (from inside the study area)	0	
F1	Long-Term Firm Purchases (from outside the study area)	0	
G	Long-Term Firm Sales (in and outside the study area)	29	Offset Row B
H	Uncommitted Capacity Imports	7,176	Wkp - SILs, less Row D
I	Study Area Reserve Requirement	2,620	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	18,496	
	Load		
L	Balancing Authority Area Annual Peak Load	31,138	Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month	25,244	Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any	1,774	Wkp - Exelon Load Summary
O	Wholesale Load (L-M)	5,894	
P	Net Uncommitted Supply (K-O)	12,602	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,885	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->	7,695	
	% of SIL for Seller's imported capacity ->	0.07	
	% of SIL for Other's imported capacity ->	0.93	
	SIL value ->	7,695	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->	No	

Exhibit NCI-12 (UPDATED)

Part II – Market Share Analysis

Applicant-> **CENG Nuclear Entities**
Study Area -> **NYISO**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled or under LT contract)				
A	Installed Capacity (inside the study area)	3,140	3,140	3,111	3,140
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	29	29	29	29
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
D	Seasonal Average Planned Outages	256	454	59	363
E	Uncommitted Capacity Imports	717	621	565	616
	Capacity Deductions				
F	Average Peak Native Load in the Season	22,045	19,393	24,144	20,374
G	Amount of Line F Attributable to Seller, if any	1,053	1,345	1,785	1,610
H	Amount of Line F Attributable to Non-Affiliates, if any	20,992	18,048	22,359	18,764
I	Study Area Reserve Requirement	2,620	2,620	2,620	2,620
J	Amount of Line I Attributable to Seller, if any	0	0	0	0
K	Amount of Line I Attributable to Non-Affiliates, if any	2,620	2,620	2,620	2,620
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	37,873	37,873	35,554	37,873
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	29	29	29	29
O	Seasonal Average Planned Outages	3,092	5,481	680	4,380
P	Uncommitted Capacity Imports	6,807	6,229	7,130	7,019
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	17,947	17,925	16,997	19,099
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	2,577	1,990	1,860	1,812
S	Total Seasonal Uncommitted Capacity (Q+R)	20,524	19,915	18,857	20,911
T	**Seller's Market Share** (R÷S)	12.6%	10.0%	9.9%	8.7%
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass
U	Total Imports, as filed by Seller (E+P)	7,524	6,850	7,695	7,635
V	SIL value*	7,524	6,850	7,695	7,635
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No

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Reference

Exhibit NCI-3

Exhibit NCI-3

Pro Rata Share of Outages
Wkp - Import Allocation

Wkp - Summary of Inputs Data
Wkp - Exelon Load Summary

Wkp - Summary of Inputs Data

Wkp - Summary of Inputs Data, less Row A

Offset Row B
Wkp - Summary of Inputs Data, less Row D
Wkp - SILs, less Row E

PJM Interconnection 2015 SIL Study

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Market/ Submarket	Exhibit	Pivotal Supplier Analysis	Exhibit	Market Share Analysis			
				Winter	Spring	Summer	Fall
PJM	NCI-5	Pass	NCI-6	12.3%	12.1%	11.3%	11.6%
5004/5005	NCI-7	#REF!	NCI-8	#REF!	#REF!	#REF!	#REF!
AP South	NCI-9	#REF!	NCI-10	#REF!	#REF!	#REF!	#REF!
NYISO	NCI-11	Pass	NCI-12	12.6%	10.0%	9.9%	8.7%

Exhibit NCI-5

Part I – Pivotal Supplier Analysis

Applicant-> **CENG Nuclear Entities**
Market -> **PJM**
Data Year -> **Dec 2014-Nov 2015**

Row			Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	22,946	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0	
B	Long-Term Firm Purchases (from inside the study area)	2,723	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	
C	Long-Term Firm Sales (in and outside the study area)	0	
D	Uncommitted Capacity Imports	335	Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	160,115	Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)	0	
F	Long-Term Firm Purchases (from inside the study area)	0	
F1	Long-Term Firm Purchases (from outside the study area)	0	
G	Long-Term Firm Sales (in and outside the study area)	2,723	Offset Row B
H	Uncommitted Capacity Imports	7,265	Wkp - SILs, less Row D
I	Study Area Reserve Requirement	9,097	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	59,964	
	Load		
L	Balancing Authority Area Annual Peak Load	143,633	Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month	121,600	Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any	19,538	Wkp - Exelon Load Summary
O	Wholesale Load (L-M)	22,033	
P	Net Uncommitted Supply (K-O)	37,931	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	6,465	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->	7,600	
	% of SIL for Seller's imported capacity ->	0.04	
	% of SIL for Other's imported capacity ->	0.96	
	SIL value ->	7,600	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->	No	

Exhibit NCI-6

Part II – Market Share Analysis

Applicant-> **CENG Nuclear Entities**
Study Area -> **PJM**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled or under LT contract)				
A	Installed Capacity (inside the study area)	23,747	23,747	22,946	23,747
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	2,971	2,971	2,723	2,971
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
D	Seasonal Average Planned Outages	994	3,156	533	3,029
E	Uncommitted Capacity Imports	506	475	338	252
	Capacity Deductions				
F	Average Peak Native Load in the Season	112,390	94,917	117,821	95,173
G	Amount of Line F Attributable to Seller, if any	16,011	14,104	18,740	15,366
H	Amount of Line F Attributable to Non-Affiliates, if any	96,379	80,813	99,081	79,807
I	Study Area Reserve Requirement	8,067	6,367	9,097	6,391
J	Amount of Line I Attributable to Seller, if any	0	0	0	0
K	Amount of Line I Attributable to Non-Affiliates, if any	8,067	6,367	9,097	6,391
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	175,853	172,943	160,115	169,038
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	2,971	2,971	2,723	2,971
O	Seasonal Average Planned Outages	7,365	22,986	3,721	21,560
P	Uncommitted Capacity Imports	11,491	12,248	7,262	6,815
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	72,563	72,055	52,755	65,124
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	10,218	9,932	6,733	8,575
S	Total Seasonal Uncommitted Capacity (Q+R)	82,781	81,987	59,489	73,699
T	**Seller's Market Share** (R÷S)	12.3%	12.1%	11.3%	11.6%
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass
U	Total Imports, as filed by Seller (E+P)	11,997	12,723	7,600	7,067
V	SIL value*	11,997	12,723	7,600	7,067
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No

P.

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Reference

Exhibit NCI-3

Exhibit NCI-3

Pro Rata Share of Outages
Wkp - Import Allocation

Wkp - Summary of Inputs Data
Wkp - Exelon Load Summary

Wkp - Summary of Inputs Data

Wkp - Summary of Inputs Data, less Row A

Offset Row B
Wkp - Summary of Inputs Data, less Row D
Wkp - SILs, less Row E

JM Interconnection 2015 SIL Study

2015 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Technology
58962	Fair Wind Power Partners	59147	Fair Wind Power	MD	Garrett	1	Wind
55951	Exelon Nuclear	6022	Braidwood Generation Station	IL	Will	1	Nuclear
55951	Exelon Nuclear	6022	Braidwood Generation Station	IL	Will	1	Nuclear
55951	Exelon Nuclear	6022	Braidwood Generation Station	IL	Will	2	Nuclear
55951	Exelon Nuclear	6023	Byron Generating Station	IL	Ogle	1	Nuclear
55951	Exelon Nuclear	6023	Byron Generating Station	IL	Ogle	2	Nuclear
55951	Exelon Nuclear	6011	Calvert Cliffs Nuclear Power Plant	MD	Calvert	1	Nuclear
55951	Exelon Nuclear	6011	Calvert Cliffs Nuclear Power Plant	MD	Calvert	2	Nuclear
6035	Exelon Power	3157	Chester Generating Station	PA	Chester	7	Liquids
6035	Exelon Power	3157	Chester Generating Station	PA	Chester	8	Liquids
6035	Exelon Power	3157	Chester Generating Station	PA	Chester	9	Liquids
6035	Exelon Power	1574	Conowingo	MD	Harford	1	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	10	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	11	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	2	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	3	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	4	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	5	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	6	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	7	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	8	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	9	Conventio
56661	Criterion Power Partners LLC	57300	Criterion Wind Project	MD	GARRET	1	Onshore
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	11	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	12	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	21	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	22	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	31	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	32	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	41	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	42	Petroleum
6035	Exelon Power	3160	Delaware Generating Station	PA	Philadelph	10	Petroleum
6035	Exelon Power	3160	Delaware Generating Station	PA	Philadelph	11	Petroleum
6035	Exelon Power	3160	Delaware Generating Station	PA	Philadelph	12	Petroleum
6035	Exelon Power	3160	Delaware Generating Station	PA	Philadelph	9	Petroleum
55951	Exelon Nuclear	869	Dresden Generating Station	IL	Grundy	2	Nuclear
55951	Exelon Nuclear	869	Dresden Generating Station	IL	Grundy	3	Nuclear
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	10	Petroleum
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	20	Petroleum
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	3	Petroleum
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	30	Petroleum
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	4	Petroleum
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	40	Petroleum
6035	Exelon Power	57191	Exelon Solar Chicago	IL	Cook	ECS1	PV
6035	Exelon Power	7701	Fairless Hills	PA	Bucks	A	Landfill
6035	Exelon Power	7701	Fairless Hills	PA	Bucks	B	Landfill
6035	Exelon Power	3162	Falls	PA	Bucks	1	Petroleum
6035	Exelon Power	3162	Falls	PA	Bucks	2	Petroleum
6035	Exelon Power	3162	Falls	PA	Bucks	3	Petroleum
4161	Constellation Power Source Gen	1553	Gould Street	MD	Baltimore	3	Natural
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT01	Natural
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT02	Natural
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT03	Natural
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT04	Natural
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT05	Natural
55951	Exelon Nuclear	6026	LaSalle Generating Station	IL	LaSalle	1	Nuclear
55951	Exelon Nuclear	6026	LaSalle Generating Station	IL	LaSalle	2	Nuclear
55951	Exelon Nuclear	6105	Limerick	PA	Montgom	1	Nuclear
55951	Exelon Nuclear	6105	Limerick	PA	Montgom	2	Nuclear
6035	Exelon Power	3163	Moser Generating Station	PA	Montgom	1	Petroleum
6035	Exelon Power	3163	Moser Generating Station	PA	Montgom	2	Petroleum
6035	Exelon Power	3163	Moser Generating Station	PA	Montgom	3	Petroleum
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	1	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	2	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	3	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	4	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	5	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	6	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	7	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	8	Hydroelec
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT1	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT2	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT3	Natural

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Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Technology
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT4	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT5	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT6	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT7	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT8	Natural
55951	Exelon Nuclear	2388	Oyster Creek	NJ	Ocean	1	Nuclear
14432	Panther Creek Power Operating, LLC	50776	Panther Creek Energy Facility	PA	Carbon	GEN1	Conventio
55951	Exelon Nuclear	3166	Peach Bottom	PA	York	2	Nuclear
55951	Exelon Nuclear	3166	Peach Bottom	PA	York	3	Nuclear
6035	Exelon Power	7690	Pennsbury	PA	Bucks	1	Landfill
6035	Exelon Power	7690	Pennsbury	PA	Bucks	2	Landfill
4161	Constellation Power Source Gen	1556	Perryman	MD	Harford	GT1	Petroleum
4161	Constellation Power Source Gen	1556	Perryman	MD	Harford	GT2	Petroleum
4161	Constellation Power Source Gen	1556	Perryman	MD	Harford	GT3	Petroleum
4161	Constellation Power Source Gen	1556	Perryman	MD	Harford	GT4	Petroleum
4161	Constellation Power Source Gen	1556	Perryman	MD	Harford	GT5	Natural
4161	Constellation Power Source Gen	1557	Philadelphia	MD	Baltimore	GT1	Petroleum
4161	Constellation Power Source Gen	1557	Philadelphia	MD	Baltimore	GT2	Petroleum
4161	Constellation Power Source Gen	1557	Philadelphia	MD	Baltimore	GT3	Petroleum
4161	Constellation Power Source Gen	1557	Philadelphia	MD	Baltimore	GT4	Petroleum
55951	Exelon Nuclear	880	Quad Cities Generating Station	IL	Rock	1	Nuclear
55951	Exelon Nuclear	880	Quad Cities Generating Station	IL	Rock	2	Nuclear
6035	Exelon Power	3168	Richmond Generating Station	PA	Philadelph	91	Petroleum
6035	Exelon Power	3168	Richmond Generating Station	PA	Philadelph	92	Petroleum
4161	Constellation Power Source Gen	1559	Riverside (MD)	MD	Baltimore	4	Natural
4161	Constellation Power Source Gen	1559	Riverside (MD)	MD	Baltimore	GT7	Petroleum
4161	Constellation Power Source Gen	1559	Riverside (MD)	MD	Baltimore	GT8	Petroleum
15478	PSEG Nuclear LLC	2410	PSEG Salem Generating Station	NJ	Salem	1	Nuclear
15478	PSEG Nuclear LLC	2410	PSEG Salem Generating Station	NJ	Salem	2	Nuclear
15478	PSEG Nuclear LLC	2410	PSEG Salem Generating Station	NJ	Salem	3	Petroleum
6035	Exelon Power	3169	Schuylkill Generating Station	PA	Philadelph	10	Petroleum
6035	Exelon Power	3169	Schuylkill Generating Station	PA	Philadelph	11	Petroleum
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT05	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT06	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT07	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT08	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT09	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT10	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT11	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT12	Natural
6035	Exelon Power	3170	Southwark	PA	Philadelph	3	Petroleum
6035	Exelon Power	3170	Southwark	PA	Philadelph	4	Petroleum
6035	Exelon Power	3170	Southwark	PA	Philadelph	5	Petroleum
6035	Exelon Power	3170	Southwark	PA	Philadelph	6	Petroleum
55951	Exelon Nuclear	8011	Three Mile Island	PA	Dauphin	1	Nuclear
4161	Constellation Power Source Gen	1560	Westport	MD	Baltimore	GT5	Natural
57311	Constellation Solar Federal LLC	58029	Constellation New Energy Inc	NJ	Burlington	PV1	Solar
57044	Constellation Solar New Jersey, LLC	57733	Benjamin Moore & Co. Solar	NJ	Morris	PV1	Solar
56976	Constellation Solar New Jersey II, LLC	57723	Johnson Matthey, Inc. Solar	NJ	Glouceste	PV1	Solar
56975	Constellation Solar Maryland, LLC	57646	McCormick & Co. Inc. at Belcamp	MD	Harford	PV1	Solar
57065	Constellation Solar Horizons LLC	57758	Mount Saint Mary's	MD	Frederick	PV1	Solar
56976	Constellation Solar New Jersey II, LLC	57647	Toys R Us- DE, Inc. at Mt. Olive, NJ	NJ	Morris	PV1	Solar
57044	Constellation Solar New Jersey, LLC	57745	The City of Vineland at West Vineland	NJ	Cumberla	PV1	Solar
57044	Constellation Solar New Jersey, LLC	57746	The City of Vineland at North Vineland	NJ	Cumberla	PV1	Solar
56975	Constellation Solar Maryland, LLC	59841	General Motors Corp at White Marsh	MD	Baltimore	PV1	Solar
58304	Constellation Solar Maryland II LLC	58329	UMMS at Pocomoke	MD	Somerset	PV1	Solar
56608	Calpine Mid-Merit LLC	55524	York Energy Center	PA	York	CTG1	Gas Fired
56608	Calpine Mid-Merit LLC	55524	York Energy Center	PA	York	CTG2	Gas Fired
56608	Calpine Mid-Merit LLC	55524	York Energy Center	PA	York	CTG3	Gas Fired
56608	Calpine Mid-Merit LLC	55524	York Energy Center	PA	York	STG1	Gas Fired
4210	Cordova Energy Co LLC	55188	Cordova Energy	IL	Island	PT11	Gas Fired
4210	Cordova Energy Co LLC	55188	Cordova Energy	IL	Island	PT21	Gas Fired
4210	Cordova Energy Co LLC	55188	Cordova Energy	IL	Island	PT31	Gas Fired
5259	Elwood Energy LLC	55199	Elwood Energy LLC	IL	Will	GT5	Gas Fired
5259	Elwood Energy LLC	55199	Elwood Energy LLC	IL	Will	GT6	Gas Fired
5259	Elwood Energy LLC	55199	Elwood Energy LLC	IL	Will	GT7	Gas Fired
5259	Elwood Energy LLC	55199	Elwood Energy LLC	IL	Will	GT8	Gas Fired
55951	Exelon Nuclear	6122	R E Ginna Nuclear Power Plant	NY	Wayne	1	Nuclear

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Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Technology
55951	Exelon Nuclear	2589	Nine Mile Point Nuclear Station	NY	Oswego	1	Nuclear
55951	Exelon Nuclear	2589	Nine Mile Point Nuclear Station	NY	Oswego	2	Nuclear
58784	Fourmile Wind Energy, LLC	58904	Fourmile Ridge	MD	Garrett	1	Wind

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Prime Mover	Unit Code	Ownership	Duct Burners	Can Bypass Heat Recovery Steam Generator?	RTO/ISO LMP Node Designation	RTO/ISO Location Designation for Reporting Wholesale Sales Data to FERC	Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Status	Operating Month	Operating Year
WT		S	X	X			30.0		30.0	30.0	OP	11	2015
ST		S	X	X	86031201	86031201	1,224.9	0.900	1,178.0	1,208.0	OP	7	1988
ST		S	X	X	86031201	86031201	1,224.9	0.900	1,183.0	1,208.0	OP	7	1988
ST		S	X	X	86031202	86031202	1,224.9	0.900	1,154.0	1,176.0	OP	10	1988
ST		S	X	X	86041201	86041201	1,224.9	0.900	1,164.0	1,188.0	OP	9	1985
ST		S	X	X	86041202	86041202	1,224.9	0.900	1,136.0	1,158.0	OP	8	1987
ST		J	X	X			918.0	0.900	866.0	890.0	OP	5	1975
ST		J	X	X			910.7	0.900	841.8	878.0	OP	4	1977
GT		S	X	X			18.6	0.850	13.0	18.0	OP	2	1969
GT		S	X	X			18.6	0.850	13.0	18.0	OP	5	1969
GT		S	X	X			18.6	0.850	13.0	18.0	OP	3	1969
HY		S	X	X			45.0	0.900	48.0	48.0	OP	3	1928
HY		S	X	X			55.6	0.900	65.0	65.0	OP	5	1964
HY		S	X	X			55.6	0.900	65.0	65.0	OP	5	1964
HY		S	X	X			36.0	0.900	36.0	36.0	OP	3	1928
HY		S	X	X			48.0	0.900	48.0	48.0	OP	3	1928
HY		S	X	X			47.7	0.900	48.0	48.0	OP	4	1928
HY		S	X	X			36.0	0.900	36.0	36.0	OP	6	1928
HY		S	X	X			47.7	0.900	48.0	48.0	OP	7	1928
HY		S	X	X			48.0	0.900	48.0	48.0	OP	6	1928
HY		S	X	X			55.6	0.900	65.0	65.0	OP	3	1964
HY		S	X	X			55.6	0.900	65.0	65.0	OP	3	1964
WT		S	X	X			70.0		70.0	70.0	OP	12	2010
GT		S	X	X			68.3	0.900	49.0	64.0	OP	6	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	6	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	6	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	6	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	8	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	8	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	7	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	7	1974
GT		S	X	X			18.6	0.850	13.0	18.0	OP	5	1969
GT		S	X	X			18.6	0.850	13.0	18.0	OP	4	1969
GT		S	X	X			18.6	0.850	13.0	18.0	OP	5	1969
GT		S	X	X			21.2	0.850	17.0	20.0	OP	7	1970
ST		S	X	X	86101102	86101102	1,009.3	0.945	902.0	902.0	OP	8	1970
ST		S	X	X	86101103	86101103	1,009.3	0.945	895.0	903.0	OP	10	1971
GT		S	X	X			18.6	0.850	13.0	18.0	OP	5	1967
GT		S	X	X			18.6	0.850	13.0	18.0	OP	10	1967
ST		S	X	X			391.0	0.850	380.0	380.0	OP	9	1974
GT		S	X	X			21.2	0.850	17.0	20.0	OP	3	1970
ST		S	X	X		20060104	391.0	0.850	380.0	380.0	OP	6	1976
GT		S	X	X			21.2	0.850	17.0	20.0	OP	6	1970
	S	N	N			9.0			9.0	9.0	OP	12	2009
ST		S	X	X			30.0	0.850	30.0	30.0	OP	12	1996
ST		S	X	X			30.0	0.800	30.0	30.0	OP	12	1996
GT		S	X	X			21.2	0.850	17.0	20.0	OP	5	1970
GT		S	X	X			21.2	0.850	17.0	20.0	OP	5	1970
GT		S	X	X			21.2	0.850	17.0	20.0	OP	6	1970
ST		S	X	X			103.5	0.850	97.0	97.0	OP	12	1952
GT		S	X	X	1104241	1104241	58.9	0.850	53.5	53.5	OP	8	2001
GT		S	X	X	1104241	1104241	58.9	0.850	53.5	53.5	OP	8	2001
GT		S	X	X	1104241	1104241	58.9	0.850	53.5	53.5	OP	7	2001
GT		S	X	X	1104241	1104241	58.9	0.850	53.5	53.5	OP	7	2001
GT		S	X	X	1104241	1104241	58.9	0.850	53.5	53.5	OP	7	2001
ST		S	X	X	86191101	86191101	1,170.0	0.900	1,135.4	1,152.0	OP	1	1984
ST		S	X	X	86191102	86191102	1,170.0	0.900	1,136.2	1,161.0	OP	10	1984
ST		S	X	X	20021101	20021101	1,138.5	0.900	1,119.7	1,191.0	OP	2	1986
ST		S	X	X	20021102	20021102	1,138.5	0.900	1,122.1	1,195.0	OP	1	1990
GT		S	X	X			21.2	0.850	17.0	20.0	OP	6	1970
GT		S	X	X			21.2	0.850	17.0	20.0	OP	5	1970
GT		S	X	X			21.2	0.850	17.0	20.0	OP	6	1970
PS		S	X	X			134.0	0.900	134.0	134.0	OP	4	1967
PS		S	X	X			134.0	0.900	133.0	133.0	OP	4	1967
PS		S	X	X			134.0	0.900	134.0	134.0	OP	4	1967
PS		S	X	X			134.0	0.900	134.0	134.0	OP	6	1967
PS		S	X	X			134.0	0.900	134.0	134.0	OP	10	1967
PS		S	X	X			134.0	0.900	133.0	133.0	OP	10	1967
PS		S	X	X			134.0	0.900	134.0	134.0	OP	2	1968
PS		S	X	X			134.0	0.900	134.0	134.0	OP	2	1968
GT		S	X	X			18.0	0.850	14.0	14.0	OP	6	1969
GT		S	X	X			18.0	0.850	14.0	14.0	OP	6	1969
GT		S	X	X			18.0	0.850	14.0	14.0	OP	6	1969

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Prime Mover	Unit Code	Ownership	Duct Burners	Can Bypass Heat Recovery Steam Generator?	RTO/ISO LMP Node Designation	RTO/ISO Location Designation for Reporting Wholesale Sales Data to FERC	Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Status	Operating Month	Operating Year
GT		S	X	X			18.0	0.850	14.0	14.0	OP	6	1969
GT		S	X	X			18.0	0.850	14.6	14.6	OP	6	1969
GT		S	X	X			18.0	0.850	15.6	15.6	OP	6	1969
GT		S	X	X			18.0	0.850	14.5	14.5	OP	6	1969
GT		S	X	X			18.0	0.850	16.0	16.0	OP	6	1969
ST		S	X	X	51101101	51101101	550.0	0.800	607.7	637.0	OP	12	1969
ST		S	X	X			94.0	0.850	83.0	83.0	OP	7	1992
ST		J	X	X	20141102	20141102	1,244.8	0.920	1,223.7	1,296.0	OP	7	1974
ST		J	X	X	20141103	20141103	1,377.0	0.900	1,122.7	1,284.0	OP	12	1974
GT		S	X	X			3.0	0.800	2.7	2.7	OP	9	1996
GT		S	X	X			3.0	0.800	2.7	2.7	OP	9	1996
GT		S	X	X			53.1	0.850	52.0	52.0	OP	1	1972
GT		S	X	X			53.1	0.850	51.0	51.0	OP	4	1972
GT		S	X	X			53.1	0.850	51.0	51.0	OP	4	1972
GT		S	X	X			53.1	0.850	52.0	52.0	OP	4	1972
GT		S	X	X			192.0	0.900	147.6	147.6	OP	6	1995
GT		S	X	X			20.7	0.850	15.3	15.3	OP	8	1970
GT		S	X	X			20.7	0.850	16.0	16.0	OP	8	1970
GT		S	X	X			20.7	0.850	14.8	14.8	OP	9	1970
GT		S	X	X			20.7	0.850	14.8	14.8	OP	9	1970
ST		J	X	X	86251101	86251101	1,009.3	0.945	908.0	908.0	OP	12	1972
ST		J	X	X	86251102	86251102	1,009.3	0.945	911.0	911.0	OP	12	1972
GT		S	X	X			65.8	0.900	49.0	66.0	OP	6	1973
GT		S	X	X			65.8	0.900	49.0	66.0	OP	6	1973
ST		S	X	X			72.2	0.850	74.0	74.0	OP	9	1951
GT		S	X	X			25.0	0.850	19.0	19.0	OP	9	1970
GT		S	X	X			25.0	0.850	20.0	20.0	OP	9	1970
ST		J	X	X	50489	SALEM	1,170.0	0.900	1,170.2	1,170.2	OP	6	1977
ST		J	X	X	50490	SALEM	1,170.0	0.900	1,158.0	1,158.0	OP	10	1981
GT		J	X	X	50488	SALEM	41.8	0.900	38.4	38.4	SB	6	1971
GT		S	X	X			18.6	0.850	13.0	18.0	OP	5	1969
GT		S	X	X			21.2	0.850	17.0	20.0	OP	6	1971
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			18.6	0.850	13.0	18.0	OP	6	1967
GT		S	X	X			18.6	0.850	13.0	18.0	OP	10	1967
GT		S	X	X			18.6	0.850	13.0	18.0	OP	7	1967
GT		S	X	X			18.6	0.850	13.0	18.0	OP	11	1968
ST		S	X	X	20111201	20111201	980.8	0.945	802.8	829.0	OP	8	1974
GT		S	X	X			121.5	0.900	115.8	115.8	OP	2	1969
PV		S	X	X			3.9		3.9	3.9	OP	12	2011
PV		S	X	X			1.4		1.4	1.4	OP	12	2010
PV		S	X	X			4.0		4.0	4.0	OP	3	2011
PV		S	X	X			1.4		1.4	1.4	OP	12	2010
PV		S	X	X			13.7		13.7	13.7	OP	7	2012
PV		S	X	X			4.1		4.1	4.1	OP	12	2011
PV		S	X	X			3.7		3.7	3.7	OP	10	2011
PV		S	X	X			2.3		2.3	2.3	OP	10	2011
PV		S	X	X			1.0		1.0	1.0	OP	5	2011
PV		S	X	X			2.8		2.8	2.8	OP	2	2013
CT	CCB1	S	X	N	T	T	120.0	0.850	113.0	113.0	OP	3	2011
CT	CCB1	S	X	N	T	T	120.0	0.850	122.0	122.0	OP	3	2011
CT	CCB1	S	X	N	T	T	120.0	0.850	122.0	122.0	OP	3	2011
CA	CCB1	S	N	X			200.0	0.850	188.0	188.0	OP	3	2011
CT	CC1	S	X	N	32417721	32417721	210.0	0.850	165.0	205.0	OP	6	2001
CT	CC1	S	X	N	32417723	32417723	210.0	0.850	165.0	205.0	OP	6	2001
CA	CC1	S	N	X	32417725	32417725	191.2	0.850	191.2	191.2	OP	6	2001
GT		J	X	X			192.0	0.850	150.0	192.0	OP	7	2001
GT		J	X	X			192.0	0.850	150.0	192.0	OP	7	2001
GT		J	X	X			192.0	0.850	150.0	192.0	OP	8	2001
GT		J	X	X			192.0	0.850	150.0	192.0	OP	8	2001
ST		J	X	X			614.0	0.920	582.0	583.0	OP	7	1970

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Prime Mover	Unit Code	Ownership	Duct Burners	Can Bypass Heat Recovery Steam Generator?	RTO/ISO LMP Node Designation	RTO/ISO Location Designation for Reporting Wholesale Sales Data to FERC	Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Status	Operating Month	Operating Year
ST		J	X	X			641.8	0.850	637.0	637.0	OP	12	1969
ST		J	X	X			1,259.3	0.900	1,287.0	1,301.0	OP	7	1987
WT		S	X	X			40.0		40.0	40.0	OP	12	2014

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2015 Form EIA-860 Data - Schedule 3, 'Generator Data' (Prelim)

Utility ID	Utility Name	Plant Code	Plant Name	State
6035	Exelon Power	59882	Exelon West Medway II LLC	MA
6035	Exelon Power	59882	Exelon West Medway II LLC	MA
55951	Exelon Nuclear	2589	Nine Mile Point Nuclear Station	NY
55951	Exelon Nuclear	2589	Nine Mile Point Nuclear Station	NY
55951	Exelon Nuclear	6122	R E Ginna Nuclear Power Plant	NY
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
6035	Exelon Power	1586	Exelon Framingham LLC	MA
6035	Exelon Power	1586	Exelon Framingham LLC	MA
6035	Exelon Power	1586	Exelon Framingham LLC	MA
6035	Exelon Power	1587	Exelon L Street	MA
6035	Exelon Power	1592	Exelon Medway LLC	MA
6035	Exelon Power	1592	Exelon Medway LLC	MA
6035	Exelon Power	1592	Exelon Medway LLC	MA
31719	FPL Energy Wyman LLC	1507	William F Wyman	ME
55993	Kleen Energy Systems, LLC	56798	Kleen Energy Systems Project	CT
55993	Kleen Energy Systems, LLC	56798	Kleen Energy Systems Project	CT
55993	Kleen Energy Systems, LLC	56798	Kleen Energy Systems Project	CT
5943	Entergy Nuc Fitzpatrick LLC	6110	James A Fitzpatrick	NY

County	Generator ID	Technology	Prime Mover	Unit Code	Ownership	Duct Burners	Can Bypass Heat Recovery Steam Generator?	RTO/ISO LMP Node Designation	RTO/ISO Location Designation for Reporting Wholesale Sales Data to FERC
Norfolk	4	Gas Fired	GT		S	X	X		
Norfolk	5	Gas Fired	GT		S	X	X		
Oswego	1	Nuclear	ST		J	X	X		
Oswego	2	Nuclear	ST		J	X	X		
Wayne	1	Nuclear	ST		J	X	X		
Middlesex	7	m Liquids	ST		S	X	X	MYSTIC	MYSTIC
Middlesex	GT1	m Liquids	GT		S	X	X	MYSTIC	MYSTIC
Middlesex	GT81	Gas Fired	CT	G941	S	X	Y	MYSTIC	MYSTIC
Middlesex	GT82	Gas Fired	CT	G941	S	X	Y	MYSTIC	MYSTIC
Middlesex	GT93	Gas Fired	CT	G942	S	X	Y	MYSTIC	MYSTIC
Middlesex	GT94	Gas Fired	CT	G942	S	X	Y	MYSTIC	MYSTIC
Middlesex	ST85	Gas Fired	CA	G941	S	Y	X	MYSTIC	MYSTIC
Middlesex	ST96	Gas Fired	CA	G942	S	Y	X	MYSTIC	MYSTIC
Norfolk	GT1	m Liquids	GT		S	X	X		
Norfolk	GT2	m Liquids	GT		S	X	X		
Norfolk	GT3	m Liquids	GT		S	X	X		
Suffolk	GT1	m Liquids	GT		S	X	X		
Norfolk	GT1	m Liquids	GT		S	X	X		
Norfolk	GT2	m Liquids	GT		S	X	X		
Norfolk	GT3	m Liquids	GT		S	X	X		
Cumberland	4	Petroleum Liquids	ST		J	X	X		
Middlesex	ST	Gas Fired	CA	CC01	S	Y	X	14614	14614
Middlesex	U1	Gas Fired	CT	CC01	S	X	N	14614	14614
Middlesex	U2	Gas Fired	CT	CC01	S	X	N	14614	14614
Oswego	1	Nuclear	ST		S	X	X	23598	23598

637.0
1055.34

Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Status	Effective Month	Effective Year	Current Month	Current Year	Associated with Combined Heat and Power System
100.0	0.900	97.4	103.5	L	6	2018	6	2018	N
100.0	0.900	97.4	103.5	L	6	2018	6	2018	N
641.8	0.850	637.0	637.0						
1,259.3	0.900	1,287.0	1,301.0						
614.0	0.920	582.0	583.0						
617.0	0.900	570.8	559.8	90.0	N			OP	X
14.2	0.850	9.1	14.5	5.0	N			SB	Y
278.6	0.850	224.6	268.7	140.0	N			OP	X
278.6	0.850	226.7	271.2	140.0	N			OP	X
278.6	0.850	227.9	274.1	140.0	N			OP	X
278.6	0.850	230.1	276.7	140.0	N			OP	X
315.0	0.850	252.1	301.6	75.0	N			OP	X
315.0	0.850	255.9	307.7	75.0	N			OP	X
14.2	0.850	10.2	14.2	5.0	N			OP	X
14.2	0.850	9.9	13.9	5.0	N			OP	X
14.2	0.850	11.3	15.3	5.0	N			OP	X
18.6	0.850	16.0	21.8	6.0	N			OP	X
45.0	0.850	42.0	64.0	20.0	N			OP	X
45.0	0.850	39.8	61.6	20.0	N			OP	X
45.0	0.850	42.0	64.0	20.0	N			OP	X
632.4	0.930	602.1	605.8	60.0	N			OP	X
295.0	1.000	268.0	233.0	177.0	N			OP	X
199.0	1.000	177.0	195.0	120.0	N			OP	X
199.0	1.000	177.0	195.0	120.0	N			OP	X
882.0	0.800	836.8	853.3	0.0	N			OP	X

Sector Name	Sector	Previously Canceled	Energy Source 1	Energy Source 2	Energy Source 3	Energy Source 4	Energy Source 5	Energy Source 6	Turbines, Inverters, or Hydrokinetic Buoys
CHP	2	N	NG	DFO					1
CHP	2	N	NG	DFO					1

6	1975			N	CHP	2	X	RFO	NG
6	1969			N	CHP	2	X	DFO	
4	2003			N	CHP	2	X	NG	
4	2003			N	CHP	2	X	NG	
6	2003			N	CHP	2	X	NG	
6	2003			N	CHP	2	X	NG	
4	2003			N	CHP	2	X	NG	
6	2003			N	CHP	2	X	NG	
3	1970			N	CHP	2	X	DFO	
9	1969			N	CHP	2	X	DFO	
9	1969			N	CHP	2	X	DFO	
9	1966	10	2016	N	CHP	2	X	DFO	
7	1970			N	CHP	2	X	DFO	
3	1971			N	CHP	2	X	DFO	
7	1970			N	CHP	2	X	DFO	
1	1978			N	IPP Non-CHP	2	X	RFO	
7	2011			N	CHP	2	X	NG	DFO
7	2011			N	CHP	2	X	NG	DFO
7	2011			N	CHP	2	X	NG	DFO
8	1976	1	2017	N	IPP Non-CHP	2	X	NUC	

Fluidized Bed Technology?	Pulverized Coal Technology?	Stoker Technology?	Other Combustion Technology?	Subcritical Technology?	Supercritical Technology?	Ultrasupercritical Technology?	Solid Fuel Gasification System?	Carbon Capture Technology?	Switch Between Oil and Natural Gas?
									Y
							N	N	Y

				NG		NG		N	N
				DFO		DFO		N	N
				NG		NG		N	N
				NG				N	N
				NG				N	N
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Cofire Fuels?
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2015 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Technology
55734	Cow Branch	56536	Cow Branch Wind Power LLC	MO	Atchison	1	Wind
55735	Conception	56537	CR Clearing LLC	MO	Nodaway	1	Wind
55736	Loess Hills	56538	Loess Hills Wind Farm LLC	MO	Atchison	1	Wind
55737	Wind Capital Holdings LLC	56555	Wind Capital Holdings LLC	MO	Gentry	1	Wind
54789	AgriWind LLC	56408	Agriwind LLC	IL	BUREAU	AWND1	Wind
56800	Brewster	56210	B&K Energy Systems LLC	MN	Jackson	1	Wind
57158	Ewington Wind Project	56624	BC Energy LLC	MN	Jackson	1	Wind
57397	Beebe Renewable Energy LLC	58020	Beebe Renewable Energy LLC	MI	Gratiot	1	Wind
56807	Moore 1	56580	Blue Breezes LLC	MN	Faribault	1	Wind
56807	Moore 1	56581	Blue Breezes II LLC	MN	Faribault	1	Wind
56808	Norgard 1	56595	Breezy Bucks I LLC	MN	Lincoln	1	Wind
56808	Norgard 1	56582	Breezy Bucks II LLC	MN	Lincoln	1	Wind
56801	Cisco	56709	Christoffer Wind Energy I LLC	MN	Jackson	1	Wind
56801	Cisco	56710	Christoffer Wind Energy II LLC	MN	Jackson	1	Wind
56801	Cisco	56711	Christoffer Wind Energy III LLC	MN	Jackson	1	Wind
56801	Cisco	56712	Christoffer Wind Energy IV LLC	MN	Jackson	1	Wind
56800	Brewster	56207	DL Windy Acres LLC	MN	Jackson	1	Wind
55951	Exelon Nuclear	204	Clinton Power Station	IL	DeWitt	1	Nuclear
57157	Wolf Wind Project	56588	G Flow Wind LLC	MN	Nobles	1	Wind
57157	Wolf Wind Project	56590	Green Acres Breeze LLC	MN	Nobles	1	Wind
55873	Harvest I	56635	Harvest Windfarm LLC	MI	Huron	1	Wind
57256	Harvest II Windfarm LLC	57888	Harvest II Windfarm	MI	Huron	1	Wind
57158	Ewington Wind Project	56626	K&D Energy LLC	MN	Jackson	1	Wind
57158	Ewington Wind Project	56625	KC Energy LLC	MN	Jackson	1	Wind
57158	Ewington Wind Project	56625	KC Energy LLC	MN	Jackson	1	Wind
54800	Michigan Wind 1 LLC	56416	Michigan Wind 1 LLC	MI	Huron	1	Wind
56951	Michigan Wind 2 LLC	56659	Michigan Wind 2	MI	Sanilac	1	Wind
57157	Wolf Wind Project	56587	Minnesota Breeze LLC	MN	Nobles	1	Wind
56805	Exelon Wind LLC	56628	Prairie Wind Power LLC	MN	Jackson	1	Wind
56808	Norgard 1	56578	Roadrunner I LLC	MN	Lincoln	1	Wind
56800	Brewster	56208	S&P Windfarm LLC	MN	Jackson	1	Wind
56808	Norgard 1	56583	Salty Dog I LLC	MN	Lincoln	1	Wind
56808	Norgard 1	56584	Salty Dog II LLC	MN	Lincoln	1	Wind
55832	Cowell	56577	Shane's Wind Machine	MN	Pipestone	1	Wind
57157	Wolf Wind Project	56586	Sunset Breeze LLC	MN	Nobles	1	Wind
56808	Norgard 1	56585	Wallys Wind Farm LLC	MN	LINCOLN	1	Wind
56808	Norgard 1	56579	Windy Dog I LLC	MN	Lincoln	1	Wind
57157	Wolf Wind Project	56589	Wolf Wind Enterprises LLC	MN	Nobles	1	Wind
18611	Tenaska Frontier Partners Ltd	55062	Tenaska Frontier Generation Station	TX	Grimes	GTG1	Gas Fired
18611	Tenaska Frontier Partners Ltd	55062	Tenaska Frontier Generation Station	TX	Grimes	GTG2	Gas Fired
18611	Tenaska Frontier Partners Ltd	55062	Tenaska Frontier Generation Station	TX	Grimes	GTG3	Gas Fired
18611	Tenaska Frontier Partners Ltd	55062	Tenaska Frontier Generation Station	TX	Grimes	STG1	Gas Fired

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Prime Mover	Unit Code	Ownership	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Status	Operating Month	Operating Year	Energy Source 1	Energy Source 2
WT		S		50.4	50.4	OP	4	2008	WND	
WT		S		50.4	50.4	OP	4	2008	WND	
WT		S		5.0	5.0	OP	2	2008	WND	
WT		S		56.7	56.7	OP	6	2007	WND	
WT		S		8.4	8.4	OP	7	2007	WND	
WT		S		2.0	2.0	OP	12	2003	WND	
WT		S		4.0	4.0	OP	1	2008	WND	
WT		S		81.6	81.6	OP	12	2012	WND	
WT		S		1.3	1.3	OP	5	2006	WND	
WT		S		1.3	1.3	OP	5	2006	WND	
WT		S		1.3	1.3	OP	5	2006	WND	
WT		S		1.3	1.3	OP	5	2006	WND	
WT		S		2.1	2.1	OP	2	2008	WND	
WT		S		2.1	2.1	OP	2	2008	WND	
WT		S		2.1	2.1	OP	2	2008	WND	
WT		S		2.1	2.1	OP	2	2008	WND	
WT		S		2.0	2.0	OP	12	2003	WND	
ST		S	0.900	1,065.0	1,078.0	OP	11	1987	NUC	
WT		S		1.3	1.3	OP	5	2006	WND	
WT		S		1.3	1.3	OP	5	2006	WND	
WT		S		52.8	52.8	OP	1	2008	WND	
WT		S		59.4	59.4	OP	11	2012	WND	
WT		S		4.0	4.0	OP	1	2008	WND	
WT		S		4.0	4.0	OP	1	2008	WND	
WT		S		4.0	4.0	OP	1	2008	WND	
WT		S		69.0	69.0	OP	12	2008	WND	
WT		S		90.0	90.0	OP	12	2011	WND	
WT		S		1.3	1.3	OP	5	2006	WND	
WT		S		4.0	4.0	OP	1	2008	WND	
WT		S		1.3	1.3	OP	5	2006	WND	
WT		S		2.0	2.0	OP	12	2003	WND	
WT		S		1.3	1.3	OP	5	2006	WND	
WT		S		1.3	1.3	OP	5	2006	WND	
WT		S		1.3	1.3	OP	7	2006	WND	
WT		S		1.3	1.3	OP	5	2006	WND	
WT		S		1.3	1.3	OP	5	2006	WND	
WT		S		1.3	1.3	OP	5	2006	WND	
WT		S		1.3	1.3	OP	5	2006	WND	
CT	STG1	J	0.900	155.0	177.0	OP	5	2000	NG	
CT	STG1	J	0.900	155.0	177.0	OP	5	2000	NG	
CT	STG1	J	0.900	155.0	177.0	OP	5	2000	NG	
CA	STG1	J	0.900	395.0	395.0	OP	5	2000	NG	

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SIL Values used for the Northeast Region Triennials

Study Period of December 2014 to November 2015

	Study Area	Area Abbr	Winter 2014	Spring 2015	Summer 2015	Fall 2015	SIL Values Source
1	ISO-NE	ISO-NE	4,548	4,548	4,548	4,548	*Simultaneous Import Limit for 2015*, ISO New England Inc., Docket No. AD10-2-00_, (filed Dec. 20, 2016).
2	Connecticut	CT	3,050	3,050	3,050	3,050	
3	Southwest Connecticut	SWCT	2,540	2,370	3,200	3,190	
4	New Brunswick	NBPC	1,768	1,742	1,337	1,305	FERC Accepted Notheast SILs Dec14 to Nov15
5	NYISO	NYISO	7,524	6,850	7,695	7,635	NYISO's Informational Filing Regarding the Simultaneous Import Limitation Study, Docket No. AD10-2. (Filed Dec 19, 2016)
6	New York City	NYC	6,575	6,325	6,325	6,325	
7	Long Island	Long Island	1,760	2,090	2,090	2,090	
8	PJM	PJM	11,997	12,723	7,600	7,067	PJM Interconnection, L.L.C., Docket No. AD10-2
9	PJM East	PJM East	7,502	8,830	6,537	7,859	PJM Interconnection, L.L.C., Docket No. AD10-2
10	AP South	AP South	7,897	8,856	4,455	6,068	PJM Interconnection, L.L.C., Docket No. AD10-2
11	5004/5005	5004/5005	8,104	8,293	6,319	6,103	PJM Interconnection, L.L.C., Docket No. AD10-2

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		PST Summer	Winter	Spring	Summer	Fall
	Allocation of Imports into NYISO					
A	Seller's Uncommitted Capacity in PJM	6,130	9,712	9,457	6,395	8,322
B	Seller's Uncommitted Capacity in ISO-NE	0	0	0	0	0
C	Seller's Uncommitted Capacity in HQT	0	0	0	0	0
D	Seller's Uncommitted Capacity in IESO	0	0	0	0	0
E	**Seller's Uncommitted Capacity (SUM A-F)**	**6,130**	**9,712**	**9,457**	**6,395**	**8,322**
F	Total Uncommitted Capacity in PJM	52,364	70,785	69,265	51,889	66,633
G	Total Uncommitted Capacity in ISO-NE	12,493	14,497	15,302	13,159	14,873
H	Total Uncommitted Capacity in HQT	11,132	7,914	10,905	13,475	15,221
I	Total Uncommitted Capacity in IESO	14,987	8,702	8,820	8,649	6,486
J	**Total Uncommitted Capacity (SUM G-K)**	**90,975**	**101,897**	**104,292**	**87,172**	**103,213**
K	**Seller's Share of Uncommitted Capacity into NYISO (F/K)**	6.7%	9.5%	9.1%	7.3%	8.1%
L	**Imports into NYISO**	7,695	7,524	6,850	7,695	7,635
M	**Seller's Share of Imports into NYISO (L*M)**	519	717	621	565	616

Seller Uncommitted Capacity in all BAAs, Markets or Sub-Markets

Dec 2014-Nov 2015

	Pivotal Supplier Analysis	Market Share Analysis			
PJM Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	25,669	26,718	26,718	25,669	26,718
Average Daily Peak Native Load in Peak Month	(19,538)				
Average Peak Native Load in the Season		(16,011)	(14,104)	(18,740)	(15,366)
Operating Reserves	0	0	0	0	0
Planned Outages		(994)	(3,156)	(533)	(3,029)
Total Uncommitted Capacity in PJM	6,130	9,712	9,457	6,395	8,322

	Pivotal Supplier Analysis	Market Share Analysis			
AP South Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	12,767	13,394	13,394	12,767	13,394
Average Daily Peak Native Load in Peak Month	#REF!				
Average Peak Native Load in the Season		#REF!	#REF!	#REF!	#REF!
Operating Reserves	0	0	0	0	0
Planned Outages		#REF!	#REF!	#REF!	#REF!
Total Uncommitted Capacity in AP South	#REF!	#REF!	#REF!	#REF!	#REF!

	Pivotal Supplier Analysis	Market Share Analysis			
5004/5005 Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	12,760	13,387	13,387	12,760	13,387
Average Daily Peak Native Load in Peak Month	#REF!				
Average Peak Native Load in the Season		#REF!	#REF!	#REF!	#REF!
Operating Reserves	0	0	0	0	0
Planned Outages		#REF!	#REF!	#REF!	#REF!
Total Uncommitted Capacity in 5004/5005	#REF!	#REF!	#REF!	#REF!	#REF!

	Pivotal Supplier Analysis	Market Share Analysis			
NYISO Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	3,140	3,169	3,169	3,140	3,169
Average Daily Peak Native Load in Peak Month	(1,774)				

Average Peak Native Load in the Season		(1,053)	(1,345)	(1,785)	(1,610)
Operating Reserves	0	0	0	0	0
Planned Outages		(256)	(454)	(59)	(363)
Total Uncommitted Capacity in NYISO	1,366	1,860	1,369	1,295	1,196

	Pivotal Supplier Analysis	**Market Share Analysis**			
ISONE Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	2,827	3,189	3,189	2,827	3,189
Average Daily Peak Native Load in Peak Month	(4,000)				
Average Peak Native Load in the Season		(3,627)	(3,224)	(4,080)	(3,720)
Operating Reserves	0	0	0	0	0
Planned Outages		0	0	0	0
Total Uncommitted Capacity in NYISO	0	0	0	0	0

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Total Uncommitted Capacity in all BAAs, Markets or Sub-Markets

Dec 2014-Nov 2015

	Pivotal Supplier		Market Share Analysis				
NBPC Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	4,361	4,427	4,427	4,427	4,361	4,427	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(2,741)	(2,741)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(2,654)	(2,062)	(1,595)	(1,764)	Wkp - Summary of Inputs Data
Operating Reserves	(417)	(417)	(417)	(430)	(441)	(429)	Wkp - Summary of Inputs Data
Planned Outages			(531)	(942)	(1,096)	(895)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in NBPC	1,203	1,269	825	994	1,228	1,339	

	Pivotal Supplier		Market Share Analysis				
NSPI Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	2,659	2,648	2,648	2,648	2,659	2,748	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(2,041)	(2,041)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(1,759)	(1,366)	(1,057)	(1,169)	Wkp - Summary of Inputs Data
Operating Reserves	(276)	(276)	(276)	(285)	(293)	(285)	Wkp - Summary of Inputs Data
Planned Outages			(318)	(563)	(669)	(555)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in NSPI	342		295	433	641	739	

	Pivotal Supplier		Market Share Analysis				
IESO Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	36,740	36,058	36,058	36,428	36,740	36,995	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(20,089)	(20,089)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(19,875)	(16,965)	(17,949)	(17,489)	Wkp - Summary of Inputs Data
Operating Reserves	(1,664)	(1,664)	(1,392)	(1,540)	(1,664)	(1,656)	Wkp - Summary of Inputs Data
Planned Outages			(6,089)	(9,103)	(8,478)	(11,364)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in IESO	14,987	14,305	8,702	8,820	8,649	6,486	

	Pivotal Supplier		Market Share Analysis				
HQT Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	45,936	45,885	45,885	46,280	45,936	46,269	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(33,304)	(33,304)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(32,242)	(25,046)	(19,377)	(21,430)	Wkp - Summary of Inputs Data
Operating Reserves	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	Wkp - Summary of Inputs Data
Planned Outages			(4,230)	(8,830)	(11,584)	(8,117)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in HQT	11,132	11,082	7,914	10,905	13,475	15,221	

	Pivotal Supplier		Market Share Analysis				
NYISO Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	38,665	41,013	41,013	41,013	38,665	41,013	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(25,244)	(25,244)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(22,045)	(19,393)	(24,144)	(20,374)	Wkp - Summary of Inputs Data
Operating Reserves	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	Wkp - Summary of Inputs Data
Planned Outages			(3,348)	(5,935)	(739)	(4,743)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in NYISO	10,800	13,148	12,999	13,065	11,161	13,276	

	Pivotal Supplier		Market Share Analysis				
ISO-NE Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	33,424	35,576	35,576	35,576	33,424	35,576	Wkp - Summary of Inputs Data

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Average Daily Peak Native Load in Peak Month	(19,621)	(19,621)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(18,391)	(15,604)	(18,719)	(16,307)	Wkp - Summary of Inputs Data
Operating Reserves	(1,310)	(1,310)	(1,562)	(1,436)	(1,310)	(1,436)	Wkp - Summary of Inputs Data
Planned Outages			(1,127)	(3,234)	(236)	(2,960)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in ISO-NE	12,493	14,645	14,497	15,302	13,159	14,873	

	Pivotal Supplier		Market Share Analysis				
CT Sub-Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	7,789	8,213	8,213	8,213	7,789	8,213	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(5,054)	(5,054)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(4,497)	(3,789)	(4,827)	(4,005)	Wkp - Summary of Inputs Data
Operating Reserves	(714)	(714)	(363)	(539)	(714)	(539)	Wkp - Summary of Inputs Data
Planned Outages			(260)	(747)	(55)	(683)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in CT	2,020	2,444	3,092	3,139	2,192	2,986	

	Pivotal Supplier		Market Share Analysis				
PJM Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	183,060	199,600	199,600	196,690	183,060	192,785	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(121,600)	(121,600)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(112,390)	(94,917)	(117,821)	(95,173)	Wkp - Summary of Inputs Data
Operating Reserves	(9,097)	(9,097)	(8,067)	(6,367)	(9,097)	(6,391)	Wkp - Summary of Inputs Data
Planned Outages			(8,359)	(26,142)	(4,254)	(24,589)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in PJM	52,364	68,903	70,785	69,265	51,889	66,633	

	Pivotal Supplier		Market Share Analysis				
AP South Sub-Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	78,969	84,538	84,538	83,829	78,969	84,193	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(58,108)	(58,108)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(51,170)	(43,394)	(56,097)	(43,262)	Wkp - Summary of Inputs Data
Operating Reserves	(2,868)	(2,868)	(2,552)	(2,266)	(2,772)	(2,230)	Wkp - Summary of Inputs Data
Planned Outages			(3,540)	(11,141)	(1,835)	(10,738)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in AP South	17,993	23,562	27,276	27,027	18,265	27,963	

	Pivotal Supplier		Market Share Analysis				
5004/5005 Sub-Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	55,814	59,991	59,991	59,282	55,814	59,741	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(42,368)	(42,368)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(36,840)	(31,515)	(40,748)	(31,648)	Wkp - Summary of Inputs Data
Operating Reserves	(2,512)	(2,512)	(2,185)	(1,869)	(2,416)	(1,877)	Wkp - Summary of Inputs Data
Planned Outages			(2,512)	(7,879)	(1,297)	(7,620)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in 5004/5005	10,934	15,111	18,454	18,018	11,353	18,595	

	Pivotal Supplier		Market Share Analysis				
PJM East Sub-Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	34,630	38,116	38,116	37,407	34,630	37,735	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(24,093)	(24,093)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(19,303)	(16,803)	(22,934)	(17,326)	Wkp - Summary of Inputs Data
Operating Reserves	(1,429)	(1,429)	(1,145)	(996)	(1,360)	(1,027)	Wkp - Summary of Inputs Data
Planned Outages			(1,596)	(4,972)	(805)	(4,813)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in PJM East	9,109	12,594	16,072	14,636	9,532	14,569	

	Pivotal Supplier		Market Share Analysis

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MISO Balancing Authority Area	PST Summer	PST Winter	Winter	Spring	Summer	Fall	Reference
Installed Capacity	168,505	175,367	175,367	175,695	168,505	175,039	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(102,563)	(102,563)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(86,929)	(76,192)	(97,947)	(80,875)	Wkp - Summary of Inputs Data
Operating Reserves	(2,438)	(2,438)	(2,440)	(2,439)	(2,438)	(2,440)	Wkp - Summary of Inputs Data
Planned Outages			(13,735)	(24,153)	(7,363)	(19,757)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in MISO	63,504	70,366	72,264	72,912	60,757	71,967	

	Pivotal Supplier		Market Share Analysis				
CPLE Balancing Authority Area	PST Summer	PST Winter	Winter	Spring	Summer	Fall	Reference
Installed Capacity	13,525	14,696	14,696	14,696	13,525	14,720	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(10,538)	(10,538)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(9,332)	(7,425)	(10,231)	(7,487)	Wkp - Summary of Inputs Data
Operating Reserves	(244)	(244)	(244)	(233)	(221)	(230)	Wkp - Summary of Inputs Data
Planned Outages			(655)	(1,525)	(16)	(1,175)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in CPLE	2,743	3,914	4,465	5,514	3,057	5,827	

	Pivotal Supplier		Market Share Analysis				
CPLW Balancing Authority Area	PST Summer	PST Winter	Winter	Spring	Summer	Fall	Reference
Installed Capacity	826	878	878	878	826	878	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(869)	(869)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(770)	(612)	(844)	(618)	Wkp - Summary of Inputs Data
Operating Reserves	(20)	(20)	(20)	(19)	(18)	(19)	Wkp - Summary of Inputs Data
Planned Outages			(39)	(91)	(1)	(70)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in CPLW	0	0	49	155	0	171	

	Pivotal Supplier		Market Share Analysis				
LGEE Balancing Authority Area	PST Summer	PST Winter	Winter	Spring	Summer	Fall	Reference
Installed Capacity	8,838	9,033	9,033	8,793	8,838	9,108	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(5,754)	(5,754)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(5,124)	(4,348)	(5,616)	(4,421)	Wkp - Summary of Inputs Data
Operating Reserves	(222)	(222)	(222)	(223)	(231)	(242)	Wkp - Summary of Inputs Data
Planned Outages			0	(1,187)	0	(892)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in LGEE	2,862	3,057	3,687	3,034	2,991	3,553	

	Pivotal Supplier		Market Share Analysis				
DUKE Balancing Authority Area	PST Summer	PST Winter	Winter	Spring	Summer	Fall	Reference
Installed Capacity	24,632	25,619	25,619	25,619	24,632	25,619	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(16,433)	(16,433)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(14,053)	(11,801)	(15,919)	(11,970)	Wkp - Summary of Inputs Data
Operating Reserves	(358)	(358)	(358)	(365)	(372)	(393)	Wkp - Summary of Inputs Data
Planned Outages			(1,002)	(3,838)	(254)	(2,127)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in DUKE	7,840	8,828	10,207	9,616	8,087	11,129	

	Pivotal Supplier		Market Share Analysis				
TVA Balancing Authority Area	PST Summer	PST Winter	Winter	Spring	Summer	Fall	Reference
Installed Capacity	35,065	37,014	37,014	37,014	35,065	36,069	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(25,981)	(25,981)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(22,486)	(18,523)	(24,974)	(18,959)	Wkp - Summary of Inputs Data
Operating Reserves	(1,043)	(1,043)	(1,043)	(1,042)	(1,008)	(1,023)	Wkp - Summary of Inputs Data
Planned Outages			(3,257)	(6,237)	(1,810)	(6,067)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in TVA	8,040	9,990	10,228	11,213	7,272	10,021	

	Generation (MW)						
	PST	MST					
Markets or Sub-Markets	PSA	Winter	Spring	Summer	Fall	Reference	Markets or Sub-Markets
NBPC	4,427	4,427	4,427	4,361	4,427	Wkp - Canadian BAAs Generation	NBPC
NSPI	2,648	2,648	2,648	2,659	2,748	Wkp - Canadian BAAs Generation	NSPI
IESO	36,058	36,058	36,428	36,740	36,995	Wkp - Canadian BAAs Generation	IESO
HQT	45,885	45,885	46,280	45,936	46,269	Wkp - Canadian BAAs Generation	HQT
NYISO	38,665	41,013	41,013	38,665	41,013	Wkp - NYCA_2015	NYISO
ISO-NE	33,424	35,576	35,576	33,424	35,576	Wkp - ISO-NE CELT	ISO-NE
CT	7,789	8,213	8,213	7,789	8,213	Wkp - ISO-NE CELT	CT
PJM	183,060	199,600	196,690	183,060	192,785	Wkp - PJM Generation Summary	PJM
AP South	78,969	84,538	83,829	78,969	84,193	Wkp - PJM Generation Summary	AP South
5004/5005	55,814	59,991	59,282	55,814	59,741	Wkp - PJM Generation Summary	5004/5005
PJM East	34,630	38,116	37,407	34,630	37,735	Wkp - PJM Generation Summary	PJM East

1st Tiers

CPLE	13,525	14,696	14,696	13,525	14,720	Wkp - SE-MISO Gen Summary	CPLE
CPLW	826	878	878	826	878	Wkp - SE-MISO Gen Summary	CPLW
DUKE	24,632	25,619	25,619	24,632	25,619	Wkp - SE-MISO Gen Summary	DUKE
LGEE	8,838	9,033	8,793	8,838	9,108	Wkp - SE-MISO Gen Summary	LGEE
MISO	168,505	175,367	175,695	168,505	175,039	Wkp - SE-MISO Gen Summary	MISO
TVA	35,065	37,014	37,014	35,065	36,069	Wkp - SE-MISO Gen Summary	TVA

Load (MW)								
PST		MST						PST
Peak	Avg	Winter	Spring	Summer	Fall	Reference	Markets or Sub-Markets	PSA
3,206	2,741	2,654	2,062	1,595	1,764	Wkp - Canadian BAAs Loads	NBPC	417
2,604	2,041	1,759	1,366	1,057	1,169	Wkp - Canadian BAAs Loads	NSPI	276
21,814	20,089	19,875	16,965	17,949	17,489	Wkp - Canadian BAAs Loads	IESO	1,664
38,950	33,304	32,242	25,046	19,377	21,430	Wkp - Canadian BAAs Loads	HQT	1,500
31,138	25,244	22,045	19,393	24,144	20,374	Wkp - NYISO Load	NYISO	2,620
24,437	19,621	18,391	15,604	18,719	16,307	Wkp - ISO-NE Load	ISO-NE	1,310
6,253	5,054	4,497	3,789	4,827	4,005	Wkp - CT Load	CT	714
143,633	121,600	112,390	94,917	117,821	95,173	Wkp - PJM Load	PJM	9,097
70,729	58,108	51,170	43,394	56,097	43,262	Wkp - AP South Load	AP South	2,868
52,190	42,368	36,840	31,515	40,748	31,648	Wkp - 5004 5005 Load	5004/5005	2,512
30,240	24,093	19,303	16,803	22,934	17,326	Wkp - PJM East Load	PJM East	1,429
14,383	10,538	9,332	7,425	10,231	7,487	Wkp - Southeast & MISO Load	CPLE	244
1,186	869	770	612	844	618	Wkp - Southeast & MISO Load	CPLW	20
21,101	16,433	14,053	11,801	15,919	11,970	Wkp - Southeast & MISO Load	DUKE	358
7,236	5,754	5,124	4,348	5,616	4,421	Wkp - Southeast & MISO Load	LGEE	222
118,332	102,563	86,929	76,192	97,947	80,875	Wkp - Southeast & MISO Load	MISO	2,438
32,751	25,981	22,486	18,523	24,974	18,959	Wkp - Southeast & MISO Load	TVA	1,043

Reserves (MW)						Outage	
MST						M	
Winter	Spring	Summer	Fall	Reference	Markets or Sub-Markets	Winter	Spring
417	430	441	429	Wkp - NPCC Outages & Reserves	NBPC	531	942
276	285	293	285	Wkp - NPCC Outages & Reserves	NSPI	318	563
1,392	1,540	1,664	1,656	Wkp - NPCC Outages & Reserves	IESO	6,089	9,103
1,500	1,500	1,500	1,500	Wkp - NPCC Outages & Reserves	HQT	4,230	8,830
2,620	2,620	2,620	2,620	Wkp - NYISO Reserves	NYISO	3,348	5,935
1,562	1,436	1,310	1,436	Wkp - ISO-NE Reserves	ISO-NE	1,127	3,234
363	539	714	539	Wkp - ISO-NE Reserves	CT	260	747
8,067	6,367	9,097	6,391	Wkp - PJM Operating Reserves	PJM	8,359	26,142
2,552	2,266	2,772	2,230	Wkp - PJM Operating Reserves	AP South	3,540	11,141
2,185	1,869	2,416	1,877	Wkp - PJM Operating Reserves	5004/5005	2,512	7,879
1,145	996	1,360	1,027	Wkp - PJM Operating Reserves	PJM East	1,596	4,972
244	233	221	230	Wkp - SERC Operating Reserves	CPLE	655	1,525
20	19	18	19	Wkp - SERC Operating Reserves	CPLW	39	91
358	365	372	393	Wkp - SERC Operating Reserves	DUKE	1,002	3,838
222	223	231	242	Wkp - SERC Operating Reserves	LGEE	0	1,187
2,440	2,439	2,438	2,440	MISO Triennials Data (Dec12 to Nov13)	MISO	13,735	24,153
1,043	1,042	1,008	1,023	Wkp - SERC Operating Reserves	TVA	3,257	6,237

s (MW)		
ST		
Summer	**Fall**	**Reference**
1,096	895	Wkp - NPCC Outages & Reserves
669	555	Wkp - NPCC Outages & Reserves
8,478	11,364	Wkp - NPCC Outages & Reserves
11,584	8,117	Wkp - NPCC Outages & Reserves
739	4,743	Wkp - NYISO Outages
236	2,960	Wkp - ISO-NE Outages
55	683	Wkp - ISO-NE Outages
4,254	24,589	Wkp - PJM Outages
1,835	10,738	Wkp - PJM Outages
1,297	7,620	Wkp - PJM Outages
805	4,813	Wkp - PJM Outages
16	1,175	Wkp -Southeast and MISO Outages
1	70	Wkp -Southeast and MISO Outages
254	2,127	Wkp -Southeast and MISO Outages
0	892	Wkp -Southeast and MISO Outages
7,363	19,757	Wkp -Southeast and MISO Outages
1,810	6,067	Wkp -Southeast and MISO Outages

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Ventyx IESO Load Summary	
Peak	22,516
Peak Month	July
January Peak	21,814
January Avg	20,089
February Peak	21,494
February Avg	20,556
PST	18,815
Winter	19,875
Spring	16,965
Summer	17,949
Fall	17,489

Modeled Loads	
IESO	
January Peak	21,814
Peak Month	Jan
IESO July Peak	22,516
IESO July Avg	18,815
Summer Peak	22,516
PST	20,089
Winter	19,875
Spring	16,965
Summer	17,949
Fall	17,489

Modeled Loads	
Maritimes	
Peak	5,314
Peak Month	Feb
Summer Peak	3,688
PST	4,782
Winter	4,413
Spring	3,428
Summer	2,652
Fall	2,933

Modeled Loads	
NBPC	
Peak	3,206
Peak Month	Jan
NBPC Feb Peak	3,196
NBPC Feb Avg	2,876
PST	2,741
Winter	2,654
Spring	2,062
Summer	1,595
Fall	1,764

Modeled Loads	
NSPI	
Peak	2,604
Peak Month	Feb
PST	2,041
Winter	1,759
Spring	1,366
Summer	1,057
Fall	1,169

Modeled Loads	
HQT BAA	
Peak	38,950
Peak Month	Jan
NBPC Jan Peak	3,206
NBPC Jan Avg	2,741
Summer Peak	20,766
PST	33,304
Winter	32,242
Spring	25,046
Summer	19,377
Fall	21,430

IESO load from ABB, The Velocity Suite
NBPC Load from New Bruswick Power archive website
Maritimes and Hydro Quebec Peak demand from NPCC seasonnal assessment.
NSPI load is assumed to be the difference between the Maritimes and NBPC Loads
https://www.npcc.org/Library/Seasonal%20Assessment/2015-16W_NPCC%20Seasonal%20Assessment%20-%20Final%20Report%20-%20Posted%20NPCC%20Web%20Site%2020151204.pdf
https://www.npcc.org/Library/Seasonal%20Assessment/NPCC_Reliability_Assessment_for_2016_Summer-Final_Report.pdf

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Ontario Balancing Authority Areas Load Data - Source: Ventyx, The Velocity Suite
Dec 2014-Nov 2015 Load

Needle Peak	**IESO**	22,516
Avg July (P Month)	**IESO**	18,815
Winter	**IESO**	19,875
Spring	**IESO**	16,965
Summer	**IESO**	17,949
Fall	**IESO**	17,489

Source: ABB, The Velocity Suite

CONFIDENTIAL DATA REDACTED

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
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Table AP-6 – Québec

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat. (MW)	Req. Reserves (MW)
7-Dec-14	44,681	4,290	1,500
14-Dec-14	44,681	4,394	1,500
21-Dec-14	44,681	4,549	1,500
28-Dec-14	44,681	4,386	1,500
4-Jan-15	44,681	3,924	1,500
11-Jan-15	44,681	3,985	1,500
18-Jan-15	44,681	4,125	1,500
25-Jan-15	44,681	4,142	1,500
1-Feb-15	44,681	4,137	1,500
8-Feb-15	44,681	4,214	1,500
15-Feb-15	44,681	4,284	1,500
22-Feb-15	44,681	4,324	1,500
1-Mar-15	44,681	4,592	1,500
8-Mar-15	44,681	4,756	1,500
15-Mar-15	44,681	4,761	1,500
22-Mar-15	44,681	4,686	1,500
29-Mar-15	44,681	5,301	1,500

Season	Outages Factors (%)
Winter	10%
Winter	10%
Winter	10%
Winter	10%
Winter	9%
Winter	9%
Winter	9%
Winter	9%
Winter	9%
Winter	9%
Winter	10%
Winter	10%
Spring	10%
Spring	11%
Spring	11%
Spring	10%
Spring	12%

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat (MW)	Req. Reserves (MW)
26-Mar-15	44,813	12,693	1,500
2-Apr-15	44,813	12,142	1,500
10-Apr-15	44,813	12,393	1,500
17-Apr-15	44,813	12,637	1,500
24-Apr-15	44,813	13,052	1,500
31-May-15	44,813	11,604	1,500
7-Jun-15	44,813	12,488	1,500
14-Jun-15	44,813	11,837	1,500
21-Jun-15	44,813	10,650	1,500
28-Jun-15	44,813	11,198	1,500
5-Jul-15	44,813	12,299	1,500
12-Jul-15	44,813	11,708	1,500
19-Jul-15	44,813	11,430	1,500
26-Jul-15	44,813	10,731	1,500
2-Aug-15	44,813	10,892	1,500
9-Aug-15	44,813	11,795	1,500
16-Aug-15	44,813	11,605	1,500
23-Aug-15	44,813	11,665	1,500
30-Aug-15	44,813	12,299	1,500
6-Sep-15	44,813	12,287	1,500
13-Sep-15	44,813	11,287	1,500

Season	Outages Factors (%)
Spring	28%
Spring	27%
Spring	28%
Spring	28%
Spring	27%
Spring	26%
Summer	28%
Summer	28%
Summer	24%
Summer	25%
Summer	27%
Summer	28%
Summer	25%
Summer	24%
Summer	24%
Summer	26%
Summer	26%
Summer	27%
Fall	27%
Fall	25%

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat (MW)	Req. Reserves (MW)
27-Nov-15	45,380	4,487	1,500
28-Nov-15	45,380	4,406	1,500

Season	Outages Factors (%)
Fall	10%
Fall	10%

Tables AP-5 – Ontario

Installed Capacity (MW)	Known Maint./Derat. (MW)	Req. Reserves (MW)
34,382	5,888	1,392
34,382	5,853	1,392
34,382	5,063	1,392
34,382	4,565	1,392
34,628	5,379	1,392
34,628	6,148	1,392
34,628	6,120	1,392
38,628	6,142	1,392
35,065	6,585	1,392
35,165	7,119	1,392
35,065	7,156	1,392
35,065	7,050	1,392
35,232	7,288	1,392
35,232	7,436	1,392
35,232	7,456	1,392
35,232	7,513	1,392
35,232	11,368	1,392

Season	Outages Factors (%)
Winter	17%
Winter	17%
Winter	15%
Winter	13%
Winter	16%
Winter	18%
Winter	18%
Winter	18%
Winter	19%
Winter	20%
Winter	20%
Winter	20%
Spring	21%
Spring	21%
Spring	21%
Spring	21%
Spring	32%

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat (MW)	Req. Reserves (MW)
26-Mar-15	35,126	10,754	1,664
2-Apr-15	35,251	10,036	1,664
10-Apr-15	35,251	10,707	1,664
17-Apr-15	35,251	8,738	1,664
24-Apr-15	35,251	8,660	1,664
31-May-15	35,251	9,291	1,664
7-Jun-15	35,251	9,329	1,664
14-Jun-15	35,251	9,273	1,664
21-Jun-15	35,251	8,724	1,664
28-Jun-15	35,251	8,768	1,664
5-Jul-15	35,547	7,851	1,664
12-Jul-15	35,547	7,820	1,664
19-Jul-15	35,547	7,794	1,664
26-Jul-15	35,547	7,848	1,664
2-Aug-15	35,547	8,863	1,664
9-Aug-15	35,547	8,357	1,664
16-Aug-15	35,547	7,637	1,664
23-Aug-15	35,547	8,358	1,664
30-Aug-15	35,845	9,606	1,664
6-Sep-15	35,845	13,618	1,664
13-Sep-15	35,845	13,030	1,632

Season	Outages Factors (%)
Spring	31%
Spring	31%
Spring	30%
Spring	35%
Spring	35%
Spring	36%
Summer	38%
Summer	38%
Summer	25%
Summer	25%
Summer	22%
Summer	22%
Summer	22%
Summer	22%
Summer	25%
Summer	24%
Summer	27%
Fall	38%
Fall	39%

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat (MW)	Req. Reserves (MW)
27-Nov-15	35,748	9,051	1,664
28-Nov-15	35,748	8,875	1,664

Season	Outages Factors (%)
Fall	35%
Fall	35%

Tables AP-2 – Maritimes

Installed Capacity (MW)	Known Maint./Derat. (MW)	Req. Reserves (MW)
7,557	847	693
7,557	847	693
7,557	847	693
7,557	798	693
7,586	820	693
7,586	820	693
7,586	820	693
7,586	836	693
7,618	893	693
7,618	893	693
7,618	877	693
7,639	1,046	693
7,639	1,046	693
7,639	1,046	693
7,639	970	693
7,647	1,187	693

Season	Outages Factors (%)
Winter	11%
Winter	11%
Winter	11%
Winter	11%
Winter	11%
Winter	11%
Winter	11%
Winter	11%
Winter	12%
Winter	12%
Winter	12%
Winter	12%
Spring	14%
Spring	14%
Spring	14%
Spring	13%
Spring	18%

Installed Capacity (MW)	Known Maint./Derat. (MW)	Req. Reserves (MW)
7,693	2,048	734
7,722	2,131	734
7,722	1,978	734
7,722	1,605	734
7,722	1,714	734
7,722	1,784	734
7,723	1,906	734
7,723	1,810	734
7,723	1,644	734
7,723	1,616	734
7,726	1,674	734
7,726	1,671	734
7,726	1,667	734
7,726	1,850	734
7,726	1,615	734
7,726	1,720	734
7,726	2,044	734
7,726	2,065	734
7,726	1,809	734
7,741	1,788	734
7,741	2,115	734

Season	Outages Factors (%)
Spring	27%
Spring	28%
Spring	28%
Spring	21%
Spring	22%
Spring	23%
Summer	29%
Summer	24%
Summer	21%
Summer	21%
Summer	22%
Summer	22%
Summer	22%
Summer	21%
Summer	22%
Summer	28%
Summer	27%
Summer	23%
Fall	23%
Fall	27%

Installed Capacity (MW)	Known Maint./Derat. (MW)	Req. Reserves (MW)
7,741	931	693
7,744	960	693

Season	Outages Factors (%)
Fall	12%
Fall	12%

	Québec				Ontario				Maritimes			
	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Average Outage Factors	9%	26%	26%	18%	18%	26%	24%	32%	11%	20%	23%	19%
Average Outages	4,130	8,830	11,584	8,117	6,089	9,103	8,478	11,364	849	1,565	1,765	1,450
Operating Reserves	1,500	1,500	1,500	1,500	1,392	1,540	1,664	1,656	693	715	734	714

	NBPC Generation				NSPI Generation			
	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Total Generation	4,427	4,427	4,261	4,427	2,648	2,648	2,659	2,748
Share of Maritimes Outages	521	942	1,096	895	328	563	669	555
Share of Operating Reserves	417	430	441	429	276	285	293	285
Total Load	2,654	2,062	1,595	1,764	1,759	1,266	1,057	1,369

Source Links
2020 / www.npcc.org/Library/Seasonal%20Assessment/NPCC%20SEASONAL%20ASSESSMENT%20OF%20ADEQUATE%20POWER%20FOR%20THE%20WINTER%20OF%202015-16.pdf

https://www.npcc.org/Library/Seasonal%20Assessment/20145_NPCC%20Seasonal%20Assessment%20Final%20Report.pdf

https://www.npcc.org/Library/Seasonal%20Assessment/2014-2015_Winter_NPCC%20Seasonal%20Assessment%20Report-Final_20141202.pdf

https://www.npcc.org/Library/Seasonal%20Assessment/2015-16W_NPCC%20Seasonal%20Assessment%20-%20Final%20Report%20-%20Posted%20NPCC%20Web%20Site%2020151204.pdf

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Max	3,206
Max Month	1
PST	2,741
Winter	2,654
Spring	2,062
Summer	1,595
Fall	1,764

Source: New Brunswick Power Website Archive data
http://tso.nbpower.com/Public/en/system_information_archive.aspx

NB Power load assumed to be "NB_DEMAND" +/- "NMISA" +/- "PEI"

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	2,087	12/1/2014	1,586	1,500	1,485	1,469	1,462	1,472	1,528	1,734	1,949	1,936	1,869	1,848	1,825	1,781	1,771	1,782	1,807	1,966	2,087	2,067	2,040	2,005	1,936	1,817
Winter	12	2,586	12/2/2014	1,699	1,616	1,647	1,672	1,697	1,756	1,873	2,087	2,348	2,375	2,295	2,243	2,206	2,154	2,152	2,161	2,234	2,436	2,586	2,543	2,568	2,550	2,461	2,330
Winter	12	2,357	12/3/2014	2,178	2,058	2,009	2,007	1,976	1,991	2,019	2,205	2,357	2,297	2,229	2,181	2,144	2,071	2,022	1,954	1,927	2,013	2,067	2,003	1,972	1,911	1,787	1,635
Winter	12	2,296	12/4/2014	1,555	1,469	1,475	1,495	1,507	1,541	1,617	1,828	2,078	2,074	2,008	1,933	1,903	1,860	1,858	1,876	1,879	2,032	2,250	2,269	2,296	2,284	2,228	2,154
Winter	12	2,729	12/5/2014	2,052	2,001	2,008	2,028	2,037	2,100	2,210	2,451	2,729	2,723	2,642	2,552	2,491	2,400	2,352	2,302	2,318	2,436	2,565	2,546	2,530	2,483	2,429	2,366
Winter	12	2,403	12/6/2014	2,270	2,159	2,094	2,057	2,026	2,019	2,028	2,100	2,209	2,320	2,395	2,403	2,352	2,305	2,259	2,221	2,242	2,332	2,335	2,230	2,121	2,034	1,947	1,877
Winter	12	2,567	12/7/2014	1,763	1,719	1,666	1,663	1,667	1,695	1,751	1,838	1,943	2,077	2,162	2,178	2,180	2,174	2,134	2,107	2,159	2,357	2,520	2,541	2,563	2,567	2,479	2,365
Winter	12	3,009	12/8/2014	2,255	2,207	2,196	2,248	2,300	2,358	2,480	2,701	2,995	3,009	2,922	2,811	2,721	2,579	2,480	2,452	2,494	2,647	2,739	2,696	2,654	2,618	2,528	2,409
Winter	12	2,668	12/9/2014	2,260	2,175	2,123	2,131	2,173	2,186	2,272	2,412	2,642	2,668	2,608	2,531	2,417	2,389	2,367	2,364	2,377	2,481	2,530	2,462	2,430	2,348	2,228	2,052
Winter	12	2,285	#########	1,941	1,742	1,707	1,693	1,698	1,717	1,795	1,972	2,197	2,285	2,186	2,124	2,177	2,192	2,184	2,153	2,143	2,228	2,285	2,211	2,277	2,191	2,120	1,967
Winter	12	2,206	#########	1,767	1,670	1,653	1,636	1,617	1,621	1,681	1,886	2,100	2,064	2,039	2,022	2,013	1,989	1,959	1,939	1,984	2,111	2,206	2,172	2,111	2,052	1,952	1,836
Winter	12	2,199	#########	1,700	1,595	1,594	1,585	1,575	1,644	1,722	1,928	2,167	2,167	2,127	2,118	2,109	2,059	2,064	2,057	2,073	2,164	2,199	2,146	2,079	2,024	1,953	1,862
Winter	12	2,146	#########	1,746	1,704	1,652	1,638	1,649	1,659	1,710	1,823	1,935	2,036	2,049	2,037	1,965	1,963	1,915	1,912	1,979	2,112	2,135	2,146	2,133	2,124	2,064	1,969
Winter	12	2,273	#########	1,873	1,791	1,752	1,723	1,705	1,717	1,768	1,850	1,953	2,064	2,145	2,156	2,153	2,115	2,085	2,073	2,088	2,193	2,273	2,223	2,168	2,128	2,063	1,914
Winter	12	2,352	#########	1,780	1,679	1,656	1,640	1,657	1,696	1,760	1,979	2,198	2,193	2,166	2,107	2,129	2,099	2,085	2,070	2,104	2,245	2,350	2,352	2,286	2,263	2,187	2,044
Winter	12	2,395	#########	1,906	1,797	1,776	1,782	1,798	1,839	1,935	2,157	2,383	2,395	2,332	2,259	2,237	2,194	2,164	2,147	2,184	2,285	2,361	2,372	2,343	2,313	2,224	2,079
Winter	12	2,395	#########	1,929	1,837	1,802	1,795	1,793	1,820	1,908	2,144	2,391	2,395	2,303	2,254	2,228	2,172	2,132	2,139	2,176	2,265	2,355	2,352	2,328	2,324	2,223	2,055
Winter	12	2,455	#########	1,871	1,734	1,679	1,657	1,645	1,664	1,729	1,929	2,178	2,201	2,195	2,195	2,220	2,181	2,174	2,189	2,219	2,337	2,455	2,435	2,418	2,361	2,271	2,123
Winter	12	2,318	#########	1,976	1,823	1,815	1,766	1,771	1,789	1,859	2,039	2,286	2,301	2,253	2,188	2,135	2,074	2,135	2,119	2,165	2,229	2,318	2,278	2,238	2,205	2,149	2,030
Winter	12	2,396	#########	1,913	1,813	1,808	1,809	1,808	1,833	1,875	1,992	2,109	2,233	2,309	2,316	2,289	2,244	2,186	2,164	2,215	2,330	2,396	2,329	2,278	2,236	2,185	2,094
Winter	12	2,399	#########	1,999	1,933	1,891	1,864	1,869	1,874	1,908	1,972	2,092	2,227	2,313	2,331	2,315	2,297	2,259	2,230	2,244	2,322	2,399	2,370	2,342	2,288	2,236	2,124
Winter	12	2,442	#########	2,000	1,926	1,893	1,881	1,898	1,934	2,019	2,192	2,364	2,409	2,420	2,395	2,355	2,280	2,253	2,198	2,241	2,364	2,442	2,416	2,395	2,359	2,293	2,165
Winter	12	2,387	#########	2,036	1,919	1,894	1,895	1,870	1,893	1,974	2,137	2,318	2,374	2,373	2,356	2,332	2,277	2,243	2,217	2,218	2,317	2,387	2,368	2,332	2,286	2,229	2,095
Winter	12	2,239	#########	1,948	1,837	1,774	1,753	1,752	1,775	1,827	1,960	2,106	2,188	2,239	2,228	2,211	2,144	2,087	2,091	2,077	2,096	2,063	1,956	1,881	1,859	1,799	1,728
Winter	12	1,762	#########	1,641	1,588	1,543	1,491	1,476	1,472	1,489	1,542	1,586	1,651	1,706	1,747	1,762	1,741	1,712	1,678	1,655	1,658	1,694	1,671	1,682	1,677	1,657	1,598
Winter	12	1,897	#########	1,568	1,489	1,483	1,467	1,476	1,495	1,552	1,618	1,679	1,750	1,821	1,835	1,802	1,761	1,716	1,670	1,645	1,755	1,897	1,889	1,873	1,833	1,805	1,747
Winter	12	1,999	#########	1,678	1,620	1,559	1,571	1,556	1,564	1,592	1,653	1,738	1,831	1,851	1,865	1,824	1,746	1,679	1,657	1,678	1,802	1,957	1,998	1,999	1,980	1,954	1,889
Winter	12	2,093	#########	1,796	1,756	1,723	1,717	1,731	1,737	1,715	1,802	1,847	1,926	1,968	1,959	1,944	1,921	1,912	1,904	1,916	1,987	2,093	2,053	1,992	1,954	1,889	1,783
Winter	12	2,319	#########	1,696	1,639	1,619	1,612	1,644	1,677	1,752	1,880	1,992	2,051	2,035	2,002	2,009	1,990	1,969	1,928	1,986	2,154	2,292	2,319	2,317	2,284	2,230	2,158
Winter	12	2,788	#########	2,067	1,997	2,027	2,051	2,095	2,147	2,252	2,414	2,603	2,672	2,667	2,583	2,572	2,536	2,499	2,469	2,492	2,653	2,788	2,768	2,760	2,745	2,688	2,551
Winter	12	2,887	#########	2,457	2,399	2,387	2,385	2,418	2,442	2,522	2,670	2,817	2,887	2,885	2,834	2,749	2,611	2,568	2,536	2,557	2,691	2,790	2,736	2,673	2,638	2,579	2,516
Winter	1	2,521	1/1/2015	2,461	2,386	2,371	2,344	2,339	2,349	2,400	2,457	2,475	2,493	2,521	2,481	2,389	2,305	2,247	2,203	2,231	2,356	2,426	2,354	2,356	2,319	2,258	2,146
Winter	1	2,445	1/2/2015	2,033	1,952	1,908	1,889	1,912	1,952	2,058	2,187	2,306	2,308	2,333	2,347	2,282	2,220	2,177	2,139	2,164	2,286	2,445	2,429	2,405	2,386	2,355	2,276
Winter	1	2,804	1/3/2015	2,217	2,169	2,187	2,208	2,246	2,288	2,344	2,435	2,559	2,666	2,691	2,662	2,617	2,599	2,556	2,528	2,533	2,682	2,804	2,797	2,780	2,743	2,693	2,585
Winter	1	2,520	1/4/2015	2,504	2,418	2,378	2,362	2,344	2,333	2,315	2,350	2,400	2,435	2,507	2,517	2,520	2,495	2,429	2,408	2,404	2,469	2,481	2,438	2,413	2,329	2,207	2,037
Winter	1	2,634	1/5/2015	1,913	1,849	1,799	1,750	1,764	1,819	1,906	2,076	2,234	2,254	2,209	2,217	2,211	2,192	2,185	2,185	2,251	2,417	2,578	2,601	2,629	2,634	2,573	2,461
Winter	1	3,067	1/6/2015	2,375	2,319	2,338	2,378	2,415	2,465	2,586	2,819	3,064	3,067	2,955	2,871	2,822	2,747	2,681	2,640	2,728	2,921	3,025	3,010	2,994	2,953	2,863	2,715
Winter	1	3,041	1/7/2015	2,584	2,526	2,535	2,523	2,536	2,580	2,670	2,837	3,041	3,020	2,960	2,845	2,751	2,637	2,549	2,539	2,559	2,664	2,770	2,755	2,746	2,699	2,636	2,513
Winter	1	3,099	1/8/2015	2,414	2,349	2,377	2,430	2,495	2,530	2,616	2,841	3,092	3,099	2,968	2,884	2,806	2,701	2,669	2,641	2,712	2,918	3,091	3,088	3,084	3,046	2,965	2,819
Winter	1	3,023	1/9/2015	2,689	2,573	2,586	2,580	2,591	2,646	2,716	2,879	3,023	2,966	2,915	2,856	2,791	2,653	2,589	2,574	2,552	2,541	2,594	2,578	2,573	2,546	2,488	2,375
Winter	1	2,629	1/10/2015	2,284	2,216	2,219	2,256	2,277	2,319	2,365	2,444	2,549	2,629	2,626	2,540	2,452	2,355	2,279	2,247	2,308	2,434	2,603	2,614	2,611	2,576	2,512	2,412
Winter	1	2,752	1/11/2015	2,312	2,240	2,245	2,272	2,301	2,357	2,390	2,528	2,646	2,752	2,732	2,624	2,480	2,391	2,317	2,306	2,339	2,505	2,634	2,630	2,602	2,545	2,504	2,354
Winter	1	2,688	1/12/2015	2,196	2,125	2,123	2,123	2,110	2,158	2,249	2,471	2,688	2,678	2,628	2,610	2,552	2,504	2,505	2,475	2,491	2,560	2,610	2,572	2,529	2,488	2,398	2,215
Winter	1	2,873	1/13/2015	2,080	1,950	1,924	1,916	1,967	2,049	2,184	2,437	2,701	2,724	2,641	2,541	2,498	2,437	2,384	2,373	2,437	2,606	2,805	2,855	2,873	2,858	2,792	2,622
Winter	1	3,206	1/14/2015	2,575	2,503	2,504	2,508	2,548	2,622	2,732	2,953	3,206	3,191	3,074	2,916	2,788	2,640	2,568	2,522	2,527	2,663	2,801	2,812	2,808	2,758	2,669	2,539
Winter	1	2,956	1/15/2015	2,433	2,330	2,335	2,338	2,346	2,397	2,491	2,739	2,956	2,922	2,827	2,717	2,627	2,520	2,476	2,441	2,469	2,558	2,645	2,647	2,637	2,597	2,509	2,353
Winter	1	2,510	1/16/2015	2,212	2,131	2,076	2,058	2,027	2,098	2,118	2,304	2,510	2,501	2,435	2,372	2,307	2,257	2,234	2,246	2,233	2,329	2,427	2,464	2,465	2,396	2,383	2,313
Winter	1	2,812	1/17/2015	2,236	2,210	2,218	2,273	2,324	2,378	2,447	2,567	2,703	2,811	2,812	2,756	2,669	2,598	2,492	2,429	2,424	2,578	2,768	2,775	2,747	2,681	2,660	2,590
Winter	1	2,632	1/18/2015	2,513	2,505	2,483	2,497	2,507	2,482	2,501	2,548	2,623	2,632	2,610	2,577	2,519	2,442	2,362	2,240	2,236	2,309	2,372	2,318	2,247	2,170	2,065	1,952
Winter	1	2,167	1/19/2015	1,815	1,713	1,644	1,638	1,653	1,672	1,762	1,992	2,154	2,110	2,078	2,074	2,056	2,050	2,023	2,005	2,017	2,087	2,167	2,125	2,087	2,031	1,963	1,865
Winter	1	2,489	1/20/2015	1,772	1,658	1,630	1,640	1,676	1,715	1,819	2,059	2,296	2,336	2,304	2,245	2,233	2,183	2,162	2,123	2,158	2,282	2,424	2,470	2,489	2,480	2,440	2,349
Winter	1	2,852	1/21/2015	2,256	2,185	2,204	2,228	2,253	2,300	2,412	2,626	2,852	2,806	2,666	2,561	2,500	2,411	2,332	2,294	2,302	2,366	2,522	2,571	2,617	2,607	2,562	2,453
Winter	1	2,982	1/22/2015	2,356	2,280	2,279	2,300	2,332	2,394	2,507	2,745	2,982	2,965	2,876	2,776	2,679	2,568	2,519	2,483	2,498	2,575	2,626	2,622	2,622	2,533	2,455	2,309
Winter	1	2,794	1/23/2015	2,196	2,141	2,163	2,205	2,242	2,300	2,363	2,563	2,794	2,781	2,691	2,583	2,454	2,366	2,288	2,235	2,251	2,358	2,485	2,498	2,453	2,406	2,340	2,201
Winter	1	2,374	1/24/2015	2,090	2,018	2,006	2,013	2,024	2,022	2,014	2,095	2,237	2,333	2,371	2,356	2,326	2,268	2,222	2,191	2,164	2,267	2,374	2,345	2,241	2,203	2,137	2,047
Winter	1	2,545	1/25/2015	1,946	1,862	1,850	1,844	1,819	1,845	1,889	1,957	2,067	2,196	2,233	2,162	2,187	2,164	2,112	2,093	2,124	2,251	2,400	2,472	2,540	2,545	2,445	2,339
Winter	1	2,834	1/26/2015	2,242	2,182	2,187	2,211	2,196	2,274	2,391	2,633	2,834	2,824	2,700	2,595	2,510	2,424	2,321	2,295	2,342	2,470	2,650	2,693	2,681	2,670	2,627	2,529
Winter	1	2,817	1/27/2015	2,405	2,357	2,349	2,404	2,398	2,435	2,475	2,585	2,763	2,792	2,816	2,806	2,817	2,801	2,732	2,677	2,649	2,713	2,720	2,665	2,599	2,522	2,411	2,274
Winter	1	2,614	1/28/2015	2,177	2,150	2,119	2,117	2,109	2,132	2,187	2,420	2,588	2,576	2,566	2,558	2,576	2,540	2,502	2,479	2,498	2,577	2,604	2,614	2,587	2,533	2,468	2,335
Winter	1	2,908	1/29/2015	2,245	2,196	2,213	2,241	2,279	2,325	2,435	2,659	2,908	2,850	2,692	2,553	2,452	2,352	2,266	2,230	2,242	2,331	2,457	2,571	2,589	2,581	2,528	2,447
Winter	1	2,915	1/30/2015	2,353	2,280	2,288	2,331	2,361	2,418	2,506	2,719	2,915	2,887	2,809	2,743	2,669	2,590	2,519	2,481	2,486	2,552	2,575	2,572	2,524	2,470	2,401	2,294
Winter	1	2,476	1/31/2015	2,168	2,082	2,050	2,037	2,038	2,053	2,079	2,139	2,202	2,267	2,360	2,396	2,451	2,476	2,404	2,343	2,337	2,409	2,466	2,462	2,431	2,384	2,363	2,242
Winter	2	2,753	2/1/2015	2,194	2,158	2,169	2,185	2,150	2,185	2,237	2,330	2,434	2,539	2,537	2,482	2,447	2,384	2,333	2,298	2,315	2,435	2,628	2,731	2,753	2,739	2,693	2,609
Winter	2	3,169	2/2/2015	2,509	2,403	2,373	2,379	2,447	2,502	2,619	2,900	3,169	3,160	3,120	3,074	3,049	3,014	2,999	3,010	2,990	3,091	3,152	3,125	3,066	2,984	2,861	2,705
Winter	2	2,983	2/3/2015	2,555	2,434	2,438	2,456	2,493	2,529	2,581	2,692	2,846	2,983	2,867	2,798	2,752	2,622	2,547	2,501	2,509	2,645	2,795	2,838	2,837	2,802	2,741	2,631
Winter	2	3,196	2/4/2015	2,550	2,505	2,513	2,539	2,564	2,610	2,733	2,974	3,196	3,132	3,007	2,856	2,726	2,673	2,599	2,575	2,562	2,632	2,691	2,704	2,650	2,542	2,424	2,274
Winter	2	2,562	2/5/2015	2,140	2,060	2,064	2,027	1,986	1,986	2,067	2,217	2,406	2,397	2,404	2,375	2,363	2,342	2,308	2,317	2,374	2,479	2,545	2,562	2,543	2,503	2,442	2,374
Winter	2	2,966	2/6/2015	2,333	2,239	2,237	2,283	2,315	2,381	2,492	2,752	2,966	2,900	2,766	2,658	2,576	2,491	2,430	2,387	2,397	2,492	2,635	2,727	2,733	2,707	2,638	2,573
Winter	2	2,915	2/7/2015	2,494	2,369	2,419	2,438	2,457	2,514	2,564	2,686	2,838	2,915	2,850	2,738	2,622	2,550	2,482	2,462	2,469	2,551	2,682	2,734	2,707	2,667	2,603	2,537
Winter	2	2,859	2/8/2015	2,470	2,411	2,415	2,419	2,426	2,480	2,566	2,660	2,769	2,859	2,836	2,733	2,581	2,500	2,422	2,386	2,415	2,560	2,671	2,755	2,741	2,726	2,650	2,538
Winter	2	3,132	2/9/2015	2,449	2,402	2,406	2,428	2,473	2,521	2,627	2,880	3,132	3,130	3,020	2,937	2,853	2,740	2,681	2,633	2,661	2,779	2,874	2,948	2,952	2,910	2,847	2,701
Winter	2	3,090	2/10/2015	2,590	2,516	2,518	2,537	2,577	2,611	2,710	2,919	3,090	3,075	2,998	2,886	2,797	2,701	2,618	2,569	2,573	2,636	2,694	2,763	2,750	2,756	2,674	2,518
Winter	2	3,044	2/11/2015	2,378	2,355	2,350	2,358	2,391	2,447	2,590	2,791	3,044	2,993	2,844	2,717	2,595	2,495	2,397	2,361	2,422	2,547	2,679	2,799	2,812	2,781	2,692	2,551
Winter	2	2,898	2/12/2015	2,432	2,362	2,352	2,367	2,385	2,417	2,484	2,692	2,898	2,876	2,873	2,718	2,654	2,593	2,628	2,557	2,553	2,643	2,683	2,728	2,702	2,645	2,547	2,462
Winter	2	2,902	2/13/2015	2,331	2,252	2,239	2,256	2,290	2,327	2,425	2,615	2,855	2,902	2,770	2,665	2,559	2,431	2,306	2,279	2,332	2,406	2,541	2,684	2,697	2,648	2,598	2,539
Winter	2	2,952	2/14/2015	2,455	2,424	2,443	2,483	2,532	2,586	2,639	2,779	2,899	2,952	2,931	2,886	2,831	2,732	2,652	2,584	2,577	2,649	2,732	2,789	2,786	2,744	2,677	2,590
Winter	2	2,949	2/15/2015	2,521	2,453	2,420	2,418	2,388	2,390	2,416	2,464	2,565	2,630	2,709	2,771	2,804	2,815	2,816	2,776	2,818	2,895	2,948	2,949	2,917	2,854	2,766	2,647
Winter	2	2,936	2/16/2015	2,556	2,481	2,486	2,483	2,506	2,536	2,620	2,799	2,910	2,936	2,935	2,911	2,900	2,794	2,713	2,673	2,674	2,736	2,789	2,863	2,868	2,798	2,709	2,590
Winter	2	2,937	2/17/2015	2,477	2,430	2,416	2,412	2,417	2,452	2,540	2,744	2,937	2,911	2,783	2,697	2,629	2,519	2,448	2,392	2,407	2,510	2,600	2,709	2,727	2,693	2,634	2,539
Winter	2	3,010	2/18/2015	2,436	2,354	2,365	2,382	2,408	2,456	2,563	2,808	3,010	2,971	2,809	2,615	2,565	2,442	2,388	2,346	2,366	2,437	2,525	2,633	2,656	2,637	2,565	2,443
Winter	2	2,787	2/19/2015	2,345	2,284	2,271	2,277	2,295	2,317	2,400	2,614	2,787	2,759	2,696	2,618	2,550	2,533	2,481	2,462	2,489	2,548	2,518	2,554	2,580	2,518	2,424	2,258
Winter	2	2,626	2/20/2015	2,133	1,987	1,967	1,962	1,961	2,001	2,125	2,308	2,539	2,534	2,449	2,391	2,360	2,325	2,292	2,287	2,321	2,406	2,492	2,591	2,626	2,585	2,516	2,408
Winter	2	2,626	2/21/2015	2,269	2,282	2,199	2,234	2,266	2,314	2,377	2,485	2,600	2,626	2,586	2,520	2,446	2,356	2,273	2,218	2,191	2,278	2,416	2,512	2,498	2,426	2,337	2,208
Winter	2	2,397	2/22/2015	2,120	2,041	1,987	1,962	1,923	1,910	1,940	2,001	2,091	2,189	2,282	2,267	2,232	2,215	2,181	2,150	2,159	2,218	2,278	2,372	2,397	2,358	2,298	2,204
Winter	2	2,671	2/23/2015	2,120	2,067	2,067	2,089	2,096	2,147	2,234	2,467	2,652	2,605	2,504	2,404	2,336	2,288	2,232	2,197	2,214	2,327	2,466	2,612	2,671	2,646	2,641	2,566
Winter	2	3,160	2/24/2015	2,511	2,472	2,509	2,563	2,618	2,669	2,750	2,962	3,160	3,048	2,904	2,823	2,742	2,635	2,572	2,536	2,547	2,624	2,722	2,829	2,852	2,814	2,735	2,591
Winter	2	2,636	2/25/2015	2,489	2,365	2,365	2,348	2,322	2,344	2,340	2,501	2,636	2,627	2,544	2,498	2,519	2,442	2,416	2,368	2,352	2,325	2,330	2,389	2,415	2,364	2,298	2,277
Winter	2	2,711	2/26/2015	2,198	2,064	2,134	2,160	2,194	2,230	2,299	2,529	2,711	2,651	2,547	2,474	2,415	2,394	2,382	2,374	2,431	2,539	2,607	2,686	2,687	2,653	2,588	2,510
Winter	2	2,900	2/27/2015	2,342	2,251	2,243	2,246	2,267	2,329	2,438	2,700	2,900	2,803	2,674	2,590	2,486	2,377	2,308	2,265	2,281	2,348	2,417	2,563	2,592	2,552	2,466	2,447
Winter	2	2,766	2/28/2015	2,384	2,322	2,306	2,321	2,367	2,415	2,495	2,635	2,758	2,766	2,697	2,585	2,462	2,344	2,238	2,139	2,057	2,114	2,205	2,332	2,386	2,350	2,298	2,224
Spring	3	2,553	3/1/2015	2,168	2,123	2,108	2,132	2,190	2,242	2,295	2,395	2,475	2,553	2,534	2,478	2,395	2,340	2,284	2,211	2,193	2,249	2,333	2,412	2,407	2,344	2,260	2,153
Spring	3	2,454	3/2/2015	2,059	1,994	1,948	1,937	1,950	1,967	2,048	2,229	2,387	2,454	2,423	2,395	2,344	2,239	2,205	2,193	2,172	2,272	2,260	2,352	2,372	2,293	2,219	2,117
Spring	3	2,678	3/3/2015	2,120	1,999	2,048	2,094	2,137	2,227	2,334	2,536	2,678	2,609	2,507	2,451	2,394

Contains Proprietary Material
Do Not Distribute

Spring	3	2,495	3/7/2015	2,264	2,176	2,159	2,172	2,195	2,223	2,284	2,380	2,465	2,495	2,429	2,345	2,252	2,159	2,056	1,978	1,960	2,011	2,125	2,271	2,326	2,279	2,213	2,131
Spring	3	2,360	3/8/2015	2,068	2,010		1,995	2,040	2,074	2,085	2,154	2,264	2,360	2,341	2,292	2,226	2,166	2,107	2,065	2,065	2,114	2,180	2,217	2,309	2,354	2,288	2,169
Spring	3	2,701	3/9/2015	2,038	1,938	1,905	1,939	2,015	2,070	2,144	2,401	2,678	2,701	2,586	2,467	2,370	2,258	2,231	2,161	2,195	2,236	2,251	2,239	2,329	2,361	2,312	2,216
Spring	3	2,639	3/10/2015	2,106	2,021	1,993	2,004	2,013	2,062	2,159	2,362	2,634	2,639	2,487	2,335	2,256	2,129	2,042	1,965	1,929	1,971	1,978	2,027	2,111	2,152	2,103	1,954
Spring	3	2,068	3/11/2015	1,815	1,729	1,692	1,668	1,674	1,685	1,738	1,861	2,068	2,060	1,982	1,902	1,827	1,805	1,728	1,642	1,592	1,706	1,702	1,697	1,801	1,880	1,852	1,771
Spring	3	2,375	3/12/2015	1,662	1,605	1,590	1,617	1,633	1,685	1,767	1,989	2,241	2,258	2,183	2,109	2,051	2,015	2,051	2,026	2,029	2,121	2,145	2,177	2,294	2,375	2,325	2,216
Spring	3	2,760	3/13/2015	2,104	2,096	2,090	2,118	2,162	2,213	2,303	2,512	2,755	2,760	2,629	2,508	2,439	2,340	2,270	2,192	2,152	2,151	2,148	2,155	2,274	2,361	2,348	2,276
Spring	3	2,578	3/14/2015	2,168	2,122	2,129	2,155	2,180	2,235	2,300	2,420	2,532	2,578	2,523	2,439	2,343	2,250	2,145	2,072	2,025	2,045	2,081	2,108	2,178	2,192	2,151	2,076
Spring	3	2,435	3/15/2015	1,965	1,832	1,798	1,798	1,805	1,809	1,845	1,953	2,057	2,175	2,303	2,364	2,397	2,391	2,361	2,321	2,329	2,366	2,393	2,372	2,420	2,435	2,354	2,239
Spring	3	2,526	3/16/2015	2,146	2,065	2,037	2,080	2,114	2,149	2,210	2,344	2,500	2,526	2,450	2,391	2,328	2,240	2,171	2,099	2,043	2,051	2,079	2,088	2,179	2,241	2,224	2,137
Spring	3	2,739	3/17/2015	2,040	1,963	1,988	2,020	2,061	2,134	2,229	2,500	2,739	2,710	2,544	2,482	2,423	2,306	2,246	2,194	2,169	2,231	2,252	2,259	2,291	2,323	2,225	2,107
Spring	3	2,445	3/18/2015	2,050	1,920	1,912	1,916	1,942	1,979	2,055	2,234	2,420	2,445	2,426	2,395	2,360	2,284	2,227	2,182	2,203	2,240	2,264	2,294	2,377	2,416	2,320	2,215
Spring	3	2,700	3/19/2015	2,113	2,054	2,080	2,092	2,119	2,159	2,301	2,492	2,700	2,676	2,582	2,488	2,392	2,263	2,189	2,121	2,084	2,100	2,062	2,078	2,187	2,284	2,228	2,129
Spring	3	2,638	3/20/2015	2,032	2,015	1,975	1,992	2,016	2,062	2,147	2,395	2,638	2,570	2,417	2,317	2,237	2,130	2,066	1,994	1,947	1,962	1,946	1,967	2,054	2,131	2,102	2,021
Spring	3	2,246	3/21/2015	1,944	1,888	1,876	1,876	1,895	1,934	1,977	2,070	2,170	2,246	2,245	2,221	2,156	2,075	1,997	1,917	1,877	1,893	1,916	1,933	1,999	2,032	2,003	1,940
Spring	3	2,466	3/22/2015	1,851	1,809	1,786	1,775	1,768	1,774	1,776	1,801	1,870	1,947	2,027	2,068	2,087	2,054	1,993	1,994	2,035	2,128	2,185	2,242	2,361	2,466	2,440	2,336
Spring	3	2,798	3/23/2015	2,257	2,222	2,238	2,259	2,298	2,333	2,412	2,607	2,798	2,795	2,695	2,575	2,456	2,294	2,249	2,175	2,140	2,141	2,127	2,117	2,215	2,317	2,247	2,126
Spring	3	2,611	3/24/2015	2,022	1,969	1,985	2,008	2,030	2,072	2,169	2,391	2,611	2,581	2,446	2,327	2,234	2,098	2,024	1,958	1,938	1,968	1,956	1,955	2,040	2,156	2,117	2,014
Spring	3	2,531	3/25/2015	1,886	1,837	1,884	1,918	1,945	1,992	2,074	2,297	2,531	2,444	2,283	2,160	2,050	1,938	1,868	1,829	1,825	1,854	1,841	1,838	1,913	2,015	1,988	1,887
Spring	3	2,213	3/26/2015	1,820	1,762	1,631	1,620	1,630	1,674	1,772	1,973	2,213	2,201	2,101	2,047	2,013	1,947	1,910	1,867	1,868	1,903	1,920	1,889	1,931	1,970	1,974	1,882
Spring	3	2,212	3/27/2015	1,775	1,697	1,678	1,680	1,686	1,715	1,791	1,986	2,182	2,212	2,180	2,154	2,099	2,006	1,946	1,900	1,871	1,875	1,885	1,875	1,914	1,952	1,924	1,853
Spring	3	2,200	3/28/2015	1,771	1,703	1,687	1,687	1,705	1,739	1,789	1,883	1,997	2,096	2,200	2,194	2,083	2,004	1,928	1,863	1,837	1,853	1,921	1,931	1,977	2,021	1,997	1,937
Spring	3	2,120	3/29/2015	1,864	1,816	1,839	1,791	1,801	1,823	1,867	1,942	2,046	2,120	2,101	2,036	1,979	1,914	1,859	1,800	1,766	1,794	1,811	1,811	1,880	1,986	1,956	1,876
Spring	3	2,368	3/30/2015	1,778	1,703	1,694	1,733	1,769	1,830	1,937	2,164	2,368	2,351	2,256	2,166	2,130	2,063	2,015	1,975	1,965	2,021	2,009	2,019	2,070	2,105	2,006	1,879
Spring	3	2,188	3/31/2015	1,757	1,676	1,662	1,665	1,668	1,702	1,794	2,003	2,188	2,187	2,122	2,083	2,006	1,948	1,916	1,880	1,885	1,934	1,931	1,910	1,950	2,023	1,976	1,868
Spring	4	2,343	4/1/2015	1,752	1,679	1,659	1,669	1,687	1,726	1,819	2,078	2,343	2,286	2,182	2,114	2,047	1,981	1,936	1,889	1,878	1,905	1,873	1,879	1,962	2,077	2,050	1,949
Spring	4	2,433	4/2/2015	1,849	1,775	1,792	1,821	1,848	1,879	1,989	2,237	2,433	2,371	2,248	2,117	2,048	1,954	1,903	1,845	1,848	1,854	1,856	1,876	1,936	2,002	1,963	1,874
Spring	4	1,960	4/3/2015	1,761	1,684	1,646	1,593	1,611	1,623	1,667	1,756	1,841	1,929	1,960	1,957	1,949	1,898	1,828	1,776	1,717	1,706	1,658	1,627	1,652	1,740	1,740	1,693
Spring	4	2,062	4/4/2015	1,630	1,583	1,556	1,550	1,536	1,543	1,592	1,690	1,807	1,926	1,971	1,990	1,984	1,936	1,916	1,901	1,917	1,981	2,037	2,048	2,023	2,062	2,044	1,979
Spring	4	2,122	4/5/2015	1,899	1,868	1,866	1,845	1,865	1,897	1,944	2,021	2,109	2,122	2,108	2,044	2,062	2,026	1,970	1,937	1,924	1,909	1,867	1,870	1,909	2,043	2,063	1,994
Spring	4	2,523	4/6/2015	1,920	1,882	1,906	1,914	1,985	2,084	2,213	2,398	2,523	2,493	2,414	2,338	2,250	2,167	2,090	2,009	1,972	2,009	2,058	2,073	2,099	2,176	2,150	2,044
Spring	4	2,440	4/7/2015	1,946	1,861	1,845	1,843	1,844	1,902	2,005	2,231	2,440	2,428	2,329	2,228	2,132	2,009	1,963	1,932	1,922	1,951	1,939	1,915	1,948	2,042	2,028	1,949
Spring	4	2,397	4/8/2015	1,829	1,778	1,790	1,810	1,850	1,899	1,985	2,221	2,397	2,323	2,210	2,134	2,093	2,019	1,960	1,902	1,886	1,916	1,933	1,918	1,987	2,059	2,038	1,959
Spring	4	2,402	4/9/2015	1,854	1,796	1,783	1,776	1,797	1,850	1,941	2,171	2,402	2,368	2,239	2,119	2,047	1,965	1,913	1,862	1,846	1,868	1,855	1,844	1,887	2,010	1,980	1,900
Spring	4	2,308	4/10/2015	1,812	1,768	1,749	1,744	1,748	1,784	1,865	2,053	2,262	2,308	2,267	2,220	2,189	2,128	2,097	2,050	2,052	2,090	2,041	2,007	1,978	1,987	1,911	1,795
Spring	4	1,802	4/11/2015	1,678	1,579	1,540	1,505	1,510	1,506	1,539	1,618	1,710	1,762	1,794	1,790	1,778	1,759	1,680	1,643	1,627	1,673	1,706	1,691	1,731	1,802	1,776	1,698
Spring	4	1,817	4/12/2015	1,623	1,573	1,551	1,536	1,549	1,582	1,617	1,694	1,755	1,778	1,816	1,781	1,766	1,760	1,712	1,668	1,650	1,693	1,702	1,674	1,713	1,815	1,817	1,721
Spring	4	2,225	4/13/2015	1,634	1,546	1,532	1,560	1,607	1,673	1,784	2,020	2,225	2,170	2,036	1,938	1,855	1,775	1,721	1,669	1,654	1,676	1,648	1,594	1,590	1,644	1,601	1,475
Spring	4	1,865	4/14/2015	1,392	1,366	1,388	1,406	1,426	1,457	1,506	1,660	1,845	1,865	1,842	1,816	1,808	1,740	1,699	1,631	1,625	1,678	1,657	1,623	1,603	1,675	1,658	1,588
Spring	4	1,930	4/15/2015	1,489	1,422	1,438	1,445	1,460	1,481	1,542	1,741	1,930	1,825	1,749	1,769	1,756	1,709	1,710	1,678	1,691	1,729	1,746	1,742	1,773	1,883	1,886	1,771
Spring	4	2,130	4/16/2015	1,658	1,596	1,615	1,650	1,672	1,695	1,727	1,917	2,130	2,047	1,938	1,881	1,821	1,767	1,759	1,703	1,694	1,711	1,700	1,688	1,696	1,846	1,840	1,670
Spring	4	1,975	4/17/2015	1,563	1,519	1,545	1,561	1,571	1,601	1,641	1,799	1,971	1,975	1,944	1,892	1,844	1,780	1,760	1,732	1,682	1,626	1,622	1,579	1,583	1,652	1,650	1,552
Spring	4	1,777	4/18/2015	1,481	1,449	1,372	1,392	1,376	1,407	1,470	1,576	1,675	1,736	1,772	1,777	1,762	1,717	1,668	1,628	1,604	1,630	1,647	1,615	1,643	1,747	1,746	1,672
Spring	4	1,947	4/19/2015	1,608	1,569	1,567	1,574	1,591	1,618	1,635	1,694	1,772	1,907	1,947	1,928	1,879	1,816	1,748	1,680	1,632	1,662	1,668	1,660	1,667	1,760	1,767	1,692
Spring	4	2,124	4/20/2015	1,570	1,492	1,477	1,495	1,535	1,605	1,714	1,960	2,124	2,065	1,988	1,937	1,877	1,800	1,761	1,703	1,697	1,778	1,796	1,786	1,797	1,843	1,782	1,609
Spring	4	1,980	4/21/2015	1,481	1,380	1,390	1,390	1,399	1,428	1,509	1,687	1,946	1,980	1,952	1,911	1,907	1,873	1,849	1,849	1,854	1,916	1,915	1,885	1,876	1,881	1,816	1,685
Spring	4	1,904	4/22/2015	1,573	1,497	1,466	1,467	1,446	1,464	1,490	1,669	1,881	1,904	1,882	1,810	1,766	1,689	1,638	1,619	1,619	1,662	1,660	1,655	1,680	1,798	1,775	1,651
Spring	4	2,034	4/23/2015	1,546	1,490	1,479	1,490	1,505	1,540	1,613	1,816	2,027	2,034	2,022	2,003	1,970	1,921	1,908	1,902	1,901	1,944	1,945	1,911	1,891	1,921	1,849	1,750
Spring	4	2,113	4/24/2015	1,616	1,555	1,547	1,553	1,557	1,594	1,677	1,897	2,110	2,113	2,084	2,051	2,016	1,941	1,923	1,886	1,698	1,709	1,677	1,816	1,847	1,863	1,846	1,760
Spring	4	1,947	4/25/2015	1,664	1,607	1,558	1,553	1,571	1,587	1,619	1,693	1,799	1,905	1,915	1,947	1,931	1,878	1,809	1,734	1,695	1,713	1,718	1,706	1,712	1,770	1,783	1,722
Spring	4	1,828	4/26/2015	1,632	1,569	1,509	1,498	1,515	1,562	1,609	1,660	1,727	1,776	1,819	1,828	1,803	1,785	1,753	1,700	1,704	1,744	1,766	1,761	1,759	1,787	1,731	1,637
Spring	4	1,974	4/27/2015	1,526	1,458	1,445	1,456	1,460	1,467	1,544	1,750	1,974	1,974	1,909	1,854	1,801	1,782	1,763	1,706	1,720	1,824	1,924	1,852	1,890	1,974	1,923	1,786
Spring	4	2,023	4/28/2015	1,657	1,578	1,568	1,566	1,565	1,581	1,649	1,816	2,023	2,005	1,924	1,901	1,903	1,857	1,856	1,809	1,831	1,888	1,903	1,884	1,882	1,894	1,859	1,737
Spring	4	2,099	4/29/2015	1,649	1,586	1,579	1,585	1,588	1,606	1,682	1,880	2,092	2,099	2,059	2,010	1,941	1,858	1,831	1,784	1,844	1,823	1,827	1,826	1,816	1,839	1,769	1,653
Spring	4	2,036	4/30/2015	1,545	1,475	1,454	1,446	1,457	1,504	1,593	1,785	1,999	2,036	2,013	1,999	1,977	1,925	1,900	1,858	1,856	1,880	1,885	1,863	1,874	1,924	1,897	1,782
Spring	5	2,101	5/1/2015	1,675	1,607	1,595	1,592	1,602	1,629	1,713	1,888	2,077	2,101	1,980	1,951	1,906	1,849	1,812	1,736	1,697	1,681	1,654	1,625	1,645	1,743	1,787	1,714
Spring	5	1,848	5/2/2015	1,628	1,583	1,561	1,569	1,587	1,617	1,647	1,723	1,798	1,840	1,848	1,813	1,764	1,694	1,623	1,557	1,517	1,524	1,526	1,508	1,485	1,524	1,550	1,455
Spring	5	1,699	5/3/2015	1,368	1,316	1,314	1,318	1,307	1,344	1,395	1,485	1,557	1,644	1,699	1,693	1,653	1,607	1,548	1,494	1,469	1,450	1,454	1,440	1,464	1,530	1,561	1,444
Spring	5	1,844	5/4/2015	1,363	1,294	1,273	1,280	1,293	1,331	1,432	1,641	1,844	1,826	1,759	1,718	1,676	1,633	1,574	1,531	1,490	1,498	1,470	1,426	1,382	1,417	1,402	1,304
Spring	5	1,415	5/5/2015	1,215	1,164	1,178	1,160	1,156	1,167	1,195	1,206	1,282	1,279	1,406	1,407	1,361	1,307	1,279	1,260	1,257	1,295	1,298	1,283	1,295	1,360	1,415	1,310
Spring	5	1,582	5/6/2015	1,209	1,126	1,128	1,139	1,158	1,179	1,228	1,401	1,582	1,554	1,507	1,436	1,471	1,466	1,447	1,429	1,445	1,507	1,506	1,483	1,520	1,551	1,565	1,465
Spring	5	1,629	5/7/2015	1,346	1,241	1,232	1,199	1,211	1,230	1,284	1,434	1,629	1,611	1,556	1,505	1,495	1,468	1,469	1,445	1,443	1,483	1,471	1,435	1,444	1,506	1,540	1,460
Spring	5	1,812	5/8/2015	1,335	1,261	1,246	1,245	1,224	1,279	1,321	1,508	1,757	1,812	1,808	1,796	1,785	1,740	1,707	1,654	1,614	1,618	1,609	1,592	1,588	1,631	1,661	1,592
Spring	5	1,588	5/9/2015	1,489	1,404	1,381	1,370	1,365	1,370	1,396	1,400	1,466	1,556	1,588	1,568	1,541	1,477	1,411	1,356	1,342	1,369	1,378	1,392	1,374	1,389	1,384	1,308
Spring	5	1,563	5/10/2015	1,240	1,179	1,149	1,111	1,133	1,119	1,167	1,242	1,339	1,452	1,527	1,558	1,563	1,538	1,500	1,465	1,419	1,458	1,467	1,458	1,487	1,525	1,548	1,451
Spring	5	1,619	5/11/2015	1,332	1,242	1,178	1,125	1,148	1,130	1,180	1,352	1,552	1,574	1,546	1,569	1,569	1,563	1,543	1,527	1,529	1,581	1,585	1,567	1,573	1,619	1,597	1,452
Spring	5	1,653	5/12/2015	1,316	1,240	1,207	1,208	1,204	1,215	1,276	1,429	1,648	1,653	1,628	1,620	1,606	1,568	1,557	1,532	1,543	1,596	1,616	1,592	1,556	1,573	1,549	1,422
Spring	5	1,641	5/13/2015	1,316	1,240	1,224	1,206	1,218	1,228	1,258	1,389	1,603	1,598	1,630	1,630	1,641	1,601	1,564	1,524	1,558	1,577	1,554	1,518	1,492	1,550	1,609	1,505
Spring	5	1,744	5/14/2015	1,389	1,334	1,327	1,324	1,340	1,367	1,428	1,586	1,744	1,685	1,645	1,645	1,622	1,591	1,549	1,509	1,502	1,527	1,524	1,495	1,489	1,509	1,566	1,492
Spring	5	1,654	5/15/2015	1,311	1,226	1,225	1,243	1,258	1,298	1,338	1,483	1,627	1,654	1,642	1,610	1,597	1,570	1,546	1,512	1,497	1,491	1,495	1,456	1,427	1,433	1,450	1,371
Spring	5	1,494	5/16/2015	1,247	1,171	1,132	1,121	1,141	1,166	1,194	1,240	1,337	1,427	1,486	1,494	1,480	1,457	1,409	1,362	1,358	1,366	1,376	1,369	1,352	1,357	1,331	1,246
Spring	5	1,542	5/17/2015	1,146	1,099	1,067	1,064	1,045	1,046	1,053	1,087	1,189	1,324	1,430	1,505	1,532	1,542	1,523	1,487	1,494	1,515	1,539	1,521	1,523	1,525	1,517	1,445
Spring	5	1,618	5/18/2015	1,334	1,246	1,240	1,226	1,232	1,255	1,298	1,375	1,463	1,544	1,590	1,618	1,611	1,571	1,516	1,467	1,449	1,474	1,479	1,461	1,457	1,481	1,492	1,356
Spring	5	1,627	5/19/2015	1,192	1,107	1,031	1,024	1,020	1,052	1,095	1,296	1,525	1,566	1,622	1,577	1,583	1,548	1,554	1,540	1,550	1,599	1,627	1,596	1,590	1,609	1,569	1,413
Spring	5	1,546	5/20/2015	1,271	1,154	1,125	1,122	1,147	1,151	1,208	1,378	1,539	1,546	1,501	1,464	1,434	1,401	1,410	1,370	1,370	1,397	1,411	1,402	1,411	1,430	1,463	1,372
Spring	5	1,545	5/21/2015	1,290	1,237	1,219	1,209	1,225	1,234	1,266	1,397	1,545	1,526	1,480	1,454	1,441	1,387	1,401	1,417	1,427	1,473	1,473	1,436	1,415	1,425	1,457	1,370
Spring	5	1,635	5/22/2015	1,226	1,126	1,117	1,114	1,133	1,162	1,214	1,380	1,595	1,635	1,632	1,604	1,599	1,552	1,553	1,455	1,454	1,471	1,515	1,485	1,474	1,491	1,517	1,456
Spring	5	1,629	5/23/2015	1,350	1,267	1,157	1,183	1,216	1,202	1,216	1,289	1,394	1,515	1,604	1,629	1,594	1,570	1,512	1,447	1,447	1,472	1,459	1,382	1,370	1,365	1,462	1,403
Spring	5	1,514	5/24/2015	1,345	1,244	1,242	1,258	1,276	1,280	1,286	1,306	1,381	1,468	1,514	1,480	1,449	1,405	1,344	1,308	1,302	1,337	1,337	1,383	1,408	1,408	1,435	1,376
Spring	5	1,515	5/25/2015	1,237	1,157	1,150	1,142	1,133	1,144	1,200	1,352	1,503	1,515	1,506	1,501	1,470	1,452	1,438	1,419	1,398	1,419	1,439	1,452	1,419	1,403	1,410	1,305
Spring	5	1,450	5/26/2015	1,192	1,056	1,023	1,015	1,010	1,024	1,069	1,221	1,401	1,442	1,447	1,450	1,441	1,395	1,387	1,380	1,404	1,424	1,431	1,442	1,410	1,387	1,385	1,313
Spring	5	1,553	5/27/2015	1,187	1,102	1,060	1,056	1,051	1,058	1,086	1,199	1,398	1,462	1,507	1,549	1,553	1,528	1,512	1,490	1,480	1,501	1,486	1,454	1,433	1,431	1,415	1,312
Spring	5	1,561	5/28/2015	1,206	1,136	1,100	1,067	1,055	1,058	1,044	1,179	1,373	1,448	1,445	1,482	1,527	1,502	1,516	1,483	1,443	1,457	1,488	1,487	1,494	1,530	1,561	1,486
Spring	5	1,590	5/29/2015	1,350	1,218	1,189	1,176	1,177	1,179	1,206	1,350	1,531	1,572	1,589	1,581	1,563	1,548	1,571	1,579	1,579	1,590	1,559	1,541	1,502	1,485	1,480	1,371
Spring	5	1,475	5/30/2015	1,268	1,156	1,142	1,110	1,110	1,112	1,136	1,163	1,271	1,396	1,437	1,458	1,475	1,470	1,442	1,396	1,384	1,398	1,407	1,399	1,392	1,377	1,415	1,382
Spring	5	1,564	5/31/2015	1,303	1,241	1,190	1,144	1,132	1,137	1,138	1,129	1,174	1,256	1,331	1,359	1,329	1,357	1,397	1,454	1,470	1,528	1,564	1,553	1,553	1,554	1,562	1,471
Summer	6	1,715	6/1/2015	1,341	1,253	1,217	1,201	1,204	1,211	1,272	1,446	1,671	1,699	1,709	1,712	1,715	1,692	1,677	1,639	1,618	1,635	1,626	1,595	1,583	1,595	1,596	1,509
Summer	6	1,825	6/2/2015	1,400	1,321	1,284	1,279	1,273	1,290	1,353	1,517	1,717	1,754	1,753	1,758	1,729	1,728	1,725	1,706	1,734	1,800	1,817	1,825	1,815	1,814	1,777	1,637
Summer	6	1,799	6/3/2015	1,503	1,389	1,373	1,347	1,347	1,349	1,394	1,588	1,790	1,799	1,759	1,722	1,702	1,634	1,587	1,570	1,587	1,627	1,628	1,660	1,679	1,684	1,674	1,571
Summer	6	1,766	6/4/2015	1,436	1,351	1,344	1,347	1,322	1,373	1,427	1,607	1,766	1,734	1,681	1,657	1,657	1,618	1,599	1,571	1,559	1,585	1,563	1,534	1,514	1,516	1,535	1,432
Summer	6	1,634	6/5/2015	1,328	1,220	1,171	1,170	1,168	1,203	1,234	1,402	1,603	1,634	1,624	1,590	1,548	1,501	1,493	1,463	1,441	1,439	1,425	1,334	1,301	1,286	1,329	1,276
Summer	6	1,524	6/6/2015	1,217	1,182	1,118	1,075	1,081	1,094	1,087	1,157	1,278	1,406	1,495	1,515	1,524	1,523	1,474	1,420	1,398	1,412	1,415	1,396	1,370	1,378	1,399	1,379
Summer	6	1,462	6/7/2015	1,307	1,236	1,186	1,149	1,124	1,135	1,121	1,173	1,215	1,268	1,354	1,385	1,421	1,412	1,376	1,351	1,362	1,405	1,443	1,423	1,425	1,436	1,462	1,366
Summer	6	1,578	6/8/2015	1,250	1,178	1,152	1,134	1,157	1,187	1,228	1,382	1,524	1,567

Contains Proprietary Material
Do Not Distribute

Summer	6	1,524	6/20/2015	1,310	1,216	1,186	1,167	1,176	1,173	1,178	1,206	1,266	1,371	1,457	1,510	1,524	1,502	1,464	1,429	1,416	1,432	1,429	1,407	1,381	1,355	1,361	1,309
Summer	6	1,528	6/21/2015	1,207	1,122	1,084	1,067	1,071	1,084	1,088	1,121	1,203	1,316	1,423	1,483	1,511	1,516	1,504	1,491	1,480	1,528	1,522	1,503	1,492	1,520	1,503	1,384
Summer	6	1,626	6/22/2015	1,267	1,184	1,160	1,137	1,127	1,132	1,112	1,241	1,424	1,481	1,520	1,589	1,626	1,569	1,541	1,524	1,523	1,541	1,555	1,535	1,502	1,495	1,498	1,416
Summer	6	1,598	6/23/2015	1,279	1,179	1,179	1,188	1,188	1,197	1,234	1,378	1,529	1,527	1,538	1,555	1,573	1,582	1,588	1,574	1,555	1,592	1,598	1,588	1,547	1,515	1,493	1,355
Summer	6	1,514	6/24/2015	1,235	1,161	1,149	1,118	1,106	1,109	1,106	1,226	1,367	1,444	1,484	1,494	1,478	1,491	1,514	1,500	1,492	1,503	1,478	1,467	1,455	1,453	1,494	1,432
Summer	6	1,513	6/25/2015	1,283	1,192	1,199	1,151	1,102	1,118	1,129	1,273	1,419	1,480	1,474	1,513	1,503	1,503	1,482	1,472	1,456	1,497	1,512	1,493	1,447	1,472	1,474	1,423
Summer	6	1,537	6/26/2015	1,291	1,211	1,169	1,148	1,145	1,170	1,196	1,304	1,456	1,517	1,530	1,532	1,537	1,521	1,508	1,476	1,484	1,487	1,476	1,442	1,407	1,416	1,429	1,391
Summer	6	1,484	6/27/2015	1,292	1,213	1,151	1,137	1,124	1,125	1,129	1,173	1,258	1,364	1,445	1,477	1,484	1,472	1,441	1,412	1,404	1,417	1,427	1,401	1,376	1,347	1,326	1,292
Summer	6	1,450	6/28/2015	1,196	1,105	1,120	1,052	1,051	1,019	1,024	1,060	1,155	1,257	1,353	1,415	1,430	1,450	1,438	1,407	1,401	1,441	1,429	1,394	1,384	1,408	1,411	1,285
Summer	6	1,570	6/29/2015	1,191	1,122	1,081	1,045	1,044	1,007	1,019	1,155	1,267	1,439	1,490	1,540	1,557	1,546	1,558	1,537	1,535	1,570	1,547	1,510	1,481	1,452	1,439	1,365
Summer	6	1,568	6/30/2015	1,256	1,137	1,121	1,094	1,082	1,081	1,101	1,214	1,412	1,502	1,526	1,548	1,558	1,533	1,529	1,530	1,531	1,568	1,558	1,516	1,480	1,468	1,469	1,406
Summer	7	1,530	7/1/2015	1,281	1,188	1,138	1,105	1,094	1,102	1,099	1,139	1,262	1,373	1,460	1,517	1,530	1,506	1,466	1,429	1,421	1,443	1,437	1,402	1,386	1,382	1,362	1,268
Summer	7	1,526	7/2/2015	1,180	1,104	1,084	1,057	1,051	1,048	1,074	1,171	1,334	1,409	1,437	1,481	1,518	1,501	1,526	1,495	1,478	1,476	1,457	1,444	1,395	1,404	1,416	1,385
Summer	7	1,514	7/3/2015	1,261	1,154	1,085	1,062	1,042	1,058	1,063	1,153	1,303	1,434	1,463	1,503	1,491	1,506	1,514	1,513	1,474	1,471	1,458	1,429	1,396	1,409	1,399	1,349
Summer	7	1,501	7/4/2015	1,269	1,178	1,122	1,080	1,067	1,024	1,013	1,063	1,170	1,292	1,415	1,462	1,486	1,501	1,483	1,461	1,458	1,470	1,455	1,441	1,421	1,380	1,373	1,319
Summer	7	1,518	7/5/2015	1,222	1,138	1,074	1,061	1,057	1,072	1,070	1,075	1,195	1,329	1,430	1,452	1,495	1,505	1,482	1,475	1,465	1,498	1,518	1,484	1,466	1,465	1,471	1,391
Summer	7	1,656	7/6/2015	1,276	1,191	1,157	1,116	1,095	1,091	1,143	1,287	1,452	1,560	1,590	1,617	1,624	1,614	1,614	1,602	1,618	1,656	1,647	1,608	1,565	1,548	1,548	1,463
Summer	7	1,600	7/7/2015	1,301	1,207	1,153	1,118	1,093	1,109	1,133	1,229	1,326	1,398	1,441	1,494	1,525	1,556	1,600	1,584	1,569	1,565	1,544	1,476	1,414	1,395	1,373	1,303
Summer	7	1,556	7/8/2015	1,174	1,074	1,039	1,022	1,008	1,020	1,051	1,123	1,262	1,343	1,370	1,407	1,473	1,523	1,519	1,484	1,488	1,512	1,556	1,531	1,493	1,473	1,426	1,365
Summer	7	1,632	7/9/2015	1,228	1,158	1,097	1,083	1,098	1,104	1,139	1,259	1,439	1,553	1,592	1,615	1,617	1,625	1,626	1,604	1,596	1,632	1,617	1,577	1,530	1,530	1,560	1,503
Summer	7	1,684	7/10/2015	1,328	1,221	1,183	1,160	1,134	1,133	1,172	1,294	1,462	1,571	1,619	1,669	1,675	1,665	1,684	1,674	1,654	1,666	1,644	1,621	1,545	1,496	1,494	1,426
Summer	7	1,573	7/11/2015	1,326	1,269	1,212	1,191	1,171	1,173	1,179	1,209	1,316	1,428	1,521	1,562	1,573	1,563	1,542	1,536	1,525	1,542	1,545	1,527	1,501	1,464	1,443	1,381
Summer	7	1,566	7/12/2015	1,259	1,178	1,098	1,071	1,041	1,032	1,075	1,043	1,130	1,269	1,389	1,480	1,526	1,550	1,535	1,497	1,513	1,547	1,554	1,540	1,548	1,550	1,566	1,503
Summer	7	1,719	7/13/2015	1,348	1,231	1,156	1,144	1,118	1,125	1,151	1,307	1,459	1,563	1,650	1,698	1,719	1,718	1,688	1,655	1,650	1,671	1,661	1,607	1,556	1,574	1,574	1,485
Summer	7	1,641	7/14/2015	1,306	1,187	1,106	1,093	1,063	1,074	1,100	1,215	1,384	1,509	1,571	1,609	1,641	1,609	1,630	1,608	1,596	1,620	1,613	1,582	1,539	1,490	1,487	1,384
Summer	7	1,680	7/15/2015	1,223	1,123	1,094	1,101	1,099	1,091	1,143	1,261	1,442	1,540	1,609	1,628	1,680	1,655	1,644	1,636	1,612	1,613	1,594	1,589	1,570	1,524	1,489	1,445
Summer	7	1,587	7/16/2015	1,307	1,163	1,132	1,048	1,044	1,058	1,118	1,218	1,387	1,468	1,493	1,519	1,532	1,499	1,503	1,502	1,515	1,574	1,587	1,556	1,544	1,517	1,519	1,438
Summer	7	1,642	7/17/2015	1,272	1,103	1,069	1,058	1,091	1,103	1,137	1,259	1,417	1,526	1,590	1,612	1,642	1,636	1,618	1,566	1,551	1,561	1,565	1,516	1,463	1,429	1,449	1,399
Summer	7	1,494	7/18/2015	1,279	1,164	1,087	1,071	1,048	1,040	1,042	1,079	1,165	1,273	1,400	1,461	1,492	1,494	1,464	1,440	1,438	1,473	1,479	1,460	1,450	1,439	1,426	1,353
Summer	7	1,500	7/19/2015	1,229	1,142	1,093	1,091	1,088	1,076	1,082	1,085	1,154	1,230	1,156	1,156	1,156	1,356	1,500	1,442	1,417	1,442	1,463	1,445	1,437	1,448	1,445	1,371
Summer	7	1,640	7/20/2015	1,243	1,151	1,123	1,093	1,110	1,123	1,149	1,248	1,435	1,522	1,592	1,631	1,640	1,633	1,617	1,579	1,578	1,611	1,582	1,546	1,527	1,499	1,529	1,405
Summer	7	1,592	7/21/2015	1,276	1,175	1,231	1,195	1,203	1,206	1,233	1,292	1,411	1,480	1,527	1,569	1,592	1,578	1,568	1,541	1,530	1,542	1,508	1,485	1,478	1,458	1,442	1,383
Summer	7	1,604	7/22/2015	1,222	1,111	1,066	1,044	1,028	1,048	1,061	1,159	1,325	1,476	1,505	1,567	1,573	1,586	1,567	1,517	1,477	1,564	1,604	1,550	1,504	1,505	1,483	1,420
Summer	7	1,566	7/23/2015	1,301	1,199	1,151	1,154	1,124	1,126	1,172	1,277	1,423	1,495	1,530	1,557	1,552	1,537	1,520	1,492	1,538	1,566	1,549	1,523	1,500	1,477	1,510	1,424
Summer	7	1,552	7/24/2015	1,295	1,186	1,147	1,116	1,105	1,119	1,129	1,252	1,381	1,458	1,531	1,552	1,550	1,507	1,500	1,474	1,456	1,462	1,451	1,407	1,379	1,370	1,396	1,343
Summer	7	1,466	7/25/2015	1,245	1,174	1,130	1,115	1,109	1,107	1,130	1,140	1,220	1,328	1,401	1,451	1,466	1,450	1,413	1,399	1,384	1,415	1,417	1,412	1,377	1,334	1,399	1,319
Summer	7	1,415	7/26/2015	1,220	1,143	1,114	1,078	1,071	1,065	1,082	1,056	1,151	1,258	1,315	1,385	1,411	1,415	1,385	1,354	1,338	1,370	1,387	1,367	1,370	1,359	1,368	1,271
Summer	7	1,591	7/27/2015	1,120	1,041	1,016	1,006	1,006	1,036	1,078	1,174	1,330	1,413	1,482	1,509	1,497	1,496	1,524	1,550	1,533	1,586	1,591	1,535	1,492	1,501	1,511	1,408
Summer	7	1,567	7/28/2015	1,267	1,166	1,135	1,105	1,097	1,088	1,123	1,186	1,316	1,414	1,460	1,536	1,567	1,538	1,519	1,498	1,488	1,514	1,508	1,476	1,483	1,488	1,491	1,418
Summer	7	1,644	7/29/2015	1,289	1,148	1,112	1,079	1,057	1,081	1,138	1,246	1,396	1,526	1,575	1,588	1,593	1,588	1,624	1,623	1,618	1,644	1,628	1,586	1,545	1,522	1,560	1,485
Summer	7	1,644	7/30/2015	1,338	1,211	1,174	1,157	1,131	1,134	1,157	1,251	1,448	1,527	1,597	1,630	1,644	1,629	1,610	1,606	1,613	1,634	1,616	1,582	1,538	1,527	1,540	1,448
Summer	7	1,599	7/31/2015	1,286	1,173	1,093	1,075	1,054	1,055	1,087	1,183	1,337	1,409	1,470	1,540	1,549	1,557	1,585	1,572	1,582	1,599	1,588	1,562	1,491	1,461	1,434	1,358
Summer	8	1,576	8/1/2015	1,255	1,173	1,100	1,090	1,091	1,085	1,093	1,135	1,243	1,395	1,496	1,551	1,574	1,576	1,551	1,514	1,484	1,484	1,494	1,458	1,393	1,376	1,381	1,373
Summer	8	1,510	8/2/2015	1,265	1,201	1,152	1,114	1,096	1,076	1,087	1,097	1,168	1,277	1,427	1,484	1,510	1,499	1,429	1,400	1,390	1,429	1,457	1,443	1,410	1,371	1,398	1,318
Summer	8	1,563	8/3/2015	1,247	1,108	1,072	1,084	1,079	1,079	1,097	1,141	1,215	1,321	1,442	1,504	1,563	1,542	1,520	1,494	1,482	1,515	1,544	1,506	1,454	1,461	1,466	1,387
Summer	8	1,643	8/4/2015	1,268	1,153	1,116	1,087	1,072	1,066	1,089	1,198	1,375	1,459	1,518	1,566	1,626	1,615	1,606	1,617	1,605	1,643	1,622	1,549	1,508	1,469	1,481	1,323
Summer	8	1,634	8/5/2015	1,182	1,106	1,131	1,077	1,067	1,086	1,140	1,257	1,441	1,530	1,577	1,573	1,626	1,634	1,616	1,604	1,561	1,580	1,603	1,552	1,515	1,485	1,493	1,401
Summer	8	1,621	8/6/2015	1,268	1,196	1,135	1,117	1,117	1,140	1,181	1,254	1,418	1,525	1,608	1,609	1,621	1,574	1,582	1,556	1,526	1,541	1,537	1,500	1,481	1,487	1,513	1,391
Summer	8	1,609	8/7/2015	1,236	1,155	1,114	1,086	1,081	1,087	1,130	1,231	1,398	1,498	1,571	1,602	1,609	1,582	1,573	1,563	1,555	1,578	1,567	1,529	1,484	1,451	1,460	1,386
Summer	8	1,531	8/8/2015	1,287	1,201	1,149	1,119	1,158	1,158	1,155	1,154	1,230	1,353	1,445	1,503	1,531	1,509	1,486	1,470	1,439	1,460	1,461	1,437	1,414	1,411	1,405	1,349
Summer	8	1,511	8/9/2015	1,266	1,183	1,118	1,099	1,104	1,104	1,108	1,110	1,164	1,280	1,388	1,451	1,495	1,511	1,479	1,387	1,350	1,380	1,415	1,436	1,459	1,483	1,503	1,410
Summer	8	1,636	8/10/2015	1,283	1,187	1,120	1,098	1,069	1,080	1,134	1,250	1,400	1,467	1,520	1,558	1,569	1,556	1,565	1,581	1,593	1,632	1,636	1,601	1,564	1,559	1,581	1,477
Summer	8	1,622	8/11/2015	1,343	1,230	1,147	1,122	1,121	1,134	1,158	1,276	1,437	1,509	1,570	1,611	1,563	1,593	1,622	1,601	1,620	1,612	1,580	1,564	1,510	1,528	1,512	1,408
Summer	8	1,505	8/12/2015	1,243	1,166	1,157	1,138	1,143	1,125	1,134	1,221	1,347	1,408	1,453	1,477	1,472	1,445	1,461	1,428	1,440	1,490	1,505	1,470	1,470	1,484	1,478	1,363
Summer	8	1,683	8/13/2015	1,235	1,131	1,087	1,077	1,077	1,071	1,132	1,239	1,380	1,504	1,551	1,580	1,610	1,591	1,612	1,573	1,600	1,672	1,683	1,644	1,596	1,594	1,622	1,489
Summer	8	1,699	8/14/2015	1,370	1,261	1,213	1,185	1,181	1,186	1,219	1,310	1,452	1,557	1,627	1,670	1,699	1,680	1,664	1,610	1,603	1,607	1,599	1,560	1,518	1,504	1,520	1,414
Summer	8	1,602	8/15/2015	1,285	1,179	1,137	1,117	1,091	1,080	1,098	1,140	1,246	1,352	1,471	1,531	1,575	1,584	1,576	1,559	1,557	1,588	1,602	1,576	1,545	1,525	1,536	1,447
Summer	8	1,592	8/16/2015	1,345	1,260	1,200	1,157	1,129	1,119	1,143	1,163	1,221	1,351	1,462	1,539	1,585	1,592	1,566	1,535	1,513	1,553	1,578	1,574	1,548	1,561	1,571	1,419
Summer	8	1,766	8/17/2015	1,294	1,189	1,135	1,135	1,130	1,139	1,182	1,304	1,481	1,600	1,697	1,736	1,766	1,757	1,755	1,749	1,755	1,761	1,733	1,694	1,667	1,669	1,669	1,517
Summer	8	1,825	8/18/2015	1,382	1,259	1,213	1,186	1,172	1,189	1,225	1,340	1,513	1,625	1,698	1,776	1,819	1,816	1,825	1,811	1,809	1,811	1,800	1,750	1,728	1,746	1,743	1,590
Summer	8	1,803	8/19/2015	1,457	1,320	1,293	1,243	1,219	1,238	1,272	1,387	1,556	1,652	1,704	1,741	1,786	1,778	1,777	1,769	1,771	1,803	1,789	1,736	1,696	1,697	1,702	1,542
Summer	8	1,765	8/20/2015	1,385	1,269	1,246	1,217	1,197	1,214	1,240	1,355	1,536	1,632	1,684	1,735	1,765	1,734	1,738	1,738	1,739	1,756	1,709	1,668	1,640	1,627	1,620	1,490
Summer	8	1,715	8/21/2015	1,352	1,252	1,229	1,200	1,211	1,188	1,207	1,319	1,486	1,603	1,662	1,676	1,706	1,715	1,676	1,672	1,657	1,657	1,614	1,569	1,567	1,533	1,527	1,430
Summer	8	1,634	8/22/2015	1,310	1,237	1,204	1,176	1,165	1,163	1,189	1,219	1,304	1,429	1,536	1,611	1,634	1,620	1,600	1,595	1,594	1,606	1,616	1,589	1,542	1,576	1,563	1,479
Summer	8	1,618	8/23/2015	1,382	1,302	1,230	1,207	1,199	1,203	1,211	1,222	1,274	1,400	1,506	1,566	1,606	1,618	1,606	1,536	1,536	1,588	1,600	1,591	1,583	1,609	1,605	1,482
Summer	8	1,763	8/24/2015	1,359	1,234	1,201	1,183	1,177	1,188	1,236	1,347	1,522	1,621	1,687	1,738	1,754	1,730	1,729	1,721	1,728	1,763	1,745	1,700	1,640	1,666	1,611	1,468
Summer	8	1,724	8/25/2015	1,340	1,255	1,264	1,245	1,240	1,233	1,264	1,374	1,518	1,610	1,625	1,663	1,690	1,686	1,695	1,685	1,699	1,724	1,706	1,672	1,665	1,668	1,633	1,523
Summer	8	1,660	8/26/2015	1,363	1,253	1,217	1,198	1,191	1,200	1,220	1,305	1,446	1,516	1,553	1,604	1,653	1,625	1,578	1,554	1,588	1,619	1,660	1,654	1,628	1,627	1,574	1,429
Summer	8	1,644	8/27/2015	1,299	1,196	1,165	1,138	1,136	1,145	1,185	1,304	1,469	1,575	1,611	1,626	1,597	1,601	1,586	1,591	1,607	1,644	1,624	1,581	1,553	1,601	1,576	1,466
Summer	8	1,645	8/28/2015	1,358	1,269	1,226	1,202	1,181	1,157	1,218	1,340	1,465	1,529	1,578	1,629	1,645	1,628	1,616	1,600	1,605	1,614	1,603	1,579	1,542	1,565	1,548	1,465
Summer	8	1,558	8/29/2015	1,352	1,240	1,208	1,179	1,155	1,146	1,160	1,218	1,284	1,394	1,490	1,547	1,558	1,542	1,526	1,504	1,467	1,483	1,468	1,441	1,414	1,464	1,448	1,372
Summer	8	1,589	8/30/2015	1,270	1,237	1,169	1,146	1,130	1,136	1,158	1,157	1,217	1,322	1,424	1,487	1,527	1,536	1,515	1,496	1,496	1,538	1,547	1,545	1,532	1,589	1,571	1,443
Summer	8	1,596	8/31/2015	1,307	1,218	1,179	1,127	1,125	1,131	1,177	1,274	1,422	1,487	1,533	1,580	1,596	1,580	1,538	1,521	1,531	1,550	1,529	1,478	1,459	1,492	1,461	1,327
Fall	9	1,559	9/1/2015	1,210	1,142	1,143	1,100	1,060	1,061	1,087	1,198	1,351	1,435	1,465	1,495	1,466	1,450	1,456	1,438	1,437	1,505	1,517	1,499	1,494	1,559	1,515	1,397
Fall	9	1,650	9/2/2015	1,263	1,176	1,158	1,138	1,140	1,137	1,160	1,293	1,420	1,468	1,504	1,547	1,574	1,587	1,611	1,616	1,627	1,650	1,619	1,600	1,593	1,623	1,567	1,452
Fall	9	1,589	9/3/2015	1,295	1,215	1,185	1,144	1,148	1,145	1,170	1,288	1,451	1,532	1,571	1,589	1,588	1,546	1,551	1,536	1,537	1,562	1,547	1,506	1,478	1,489	1,445	1,343
Fall	9	1,571	9/4/2015	1,256	1,154	1,131	1,126	1,102	1,120	1,164	1,285	1,418	1,484	1,517	1,569	1,571	1,543	1,534	1,533	1,519	1,534	1,513	1,483	1,448	1,479	1,464	1,382
Fall	9	1,463	9/5/2015	1,287	1,240	1,183	1,161	1,142	1,129	1,120	1,162	1,247	1,308	1,388	1,463	1,463	1,439	1,406	1,389	1,376	1,401	1,403	1,383	1,360	1,354	1,303	1,226
Fall	9	1,518	9/6/2015	1,178	1,124	1,052	1,049	1,038	1,055	1,096	1,131	1,206	1,311	1,396	1,456	1,507	1,514	1,494	1,473	1,472	1,499	1,518	1,496	1,477	1,508	1,426	1,309
Fall	9	1,548	9/7/2015	1,206	1,119	1,075	1,053	1,035	1,041	1,058	1,054	1,118	1,204	1,292	1,383	1,443	1,462	1,448	1,457	1,472	1,520	1,524	1,503	1,524	1,548	1,469	1,375
Fall	9	1,606	9/8/2015	1,241	1,155	1,146	1,128	1,104	1,177	1,191	1,353	1,502	1,470	1,486	1,560	1,605	1,574	1,588	1,567	1,579	1,605	1,595	1,571	1,570	1,606	1,530	1,391
Fall	9	1,524	9/9/2015	1,285	1,214	1,192	1,162	1,144	1,149	1,199	1,353	1,494	1,501	1,521	1,524	1,491	1,451	1,451	1,450	1,477	1,501	1,470	1,448	1,487	1,509	1,435	1,325
Fall	9	1,571	9/10/2015	1,214	1,166	1,135	1,131	1,111	1,098	1,133	1,295	1,465	1,537	1,571	1,566	1,555	1,541	1,513	1,439	1,452	1,493	1,476	1,443	1,444	1,493	1,425	1,283
Fall	9	1,557	9/11/2015	1,147	1,084	1,058	1,047	1,027	1,043	1,089	1,288	1,465	1,495	1,494	1,546	1,557	1,547	1,542	1,514	1,462	1,453	1,463	1,446	1,384	1,373	1,344	1,286
Fall	9	1,394	9/12/2015	1,198	1,136	1,072	1,018	994	1,002	1,029	1,056	1,119	1,217	1,303	1,376	1,394	1,370	1,334	1,312	1,300	1,351	1,372	1,348	1,344	1,382	1,345	1,312
Fall	9	1,531	9/13/2015	1,205	1,161	1,096	1,063	1,059	1,054	1,067	1,102	1,169	1,283	1,381	1,452	1,488	1,499	1,463	1,432	1,428	1,466	1,481	1,472	1,492	1,531	1,473	1,340
Fall	9	1,566	9/14/2015	1,218	1,144	1,091	1,070	1,069	1,077	1,095	1,228	1,447	1,444	1,487	1,499	1,516	1,527	1,506	1,492	1,527	1,566	1,542	1,506	1,486	1,515	1,437	1,287
Fall	9	1,569	9/15/2015	1,164	1,107	1,058	1,064	1,067	1,076	1,120	1,286	1,482	1,500	1,489	1,447	1,455	1,450	1,475	1,463	1,473	1,541	1,528	1,502	1,522	1,569	1,512	1,356
Fall	9	1,587	9/16/2015	1,227	1,140	1,113	1,101	1,089	1,081	1,121	1,273	1,445	1,457	1,463	1,490	1,520	1,500	1,514	1,514	1,529	1,587	1,567	1,533	1,549	1,577	1,509	1,406
Fall	9	1,588	9/17/2015	1,274	1,183	1,149	1,120	1,136	1,110	1,168	1,301	1,473	1,462	1,488	1,522	1,536	1,535	1,559	1,555	1,529	1,569	1,581	1,537	1,550	1,588	1,509	1,384
Fall	9	1,654	9/18/2015	1,257	1,163	1,135	1,115	1,105	1,117	1,154	1,300	1,490	1,516	1,559	1,591	1,618	1,613	1,629	1,634	1,638	1,654	1,607	1,551	1,545	1,516	1,454	1,364
Fall	9	1,510	9/19/2015	1,264	1,137	1,119	1,083	1,068	1,029	1,034	1,073	1,181	1,309	1,413	1,467	1,497	1,510	1,495	1,436	1,406	1,422	1,426	1,388	1,404	1,383	1,320	1,253
Fall	9	1,395	9/20/2015	1,151	1,061	1,105	1,067	1,032	1,010	1,020	1,068	1,077	1,184	1,278	1,365	1,395	1,383	1,344	1,313	1,316	1,367	1,380	1,383	1,321	1,335	1,285	1,203
Fall	9	1,541	9/21/2015	1,117	1,032	1,021	1,016	1,023	1,045	1,098	1,275	1,477

Contains Proprietary Material
Do Not Distribute

Fall	10	1,555	10/3/2015	1,313	1,238	1,224	1,221	1,246	1,243	1,232	1,301	1,394	1,501	1,551	1,555	1,523	1,496	1,432	1,404	1,376	1,403	1,407	1,415	1,477	1,483	1,492	1,428
Fall	10	1,644	10/4/2015	1,361	1,313	1,309	1,333	1,316	1,341	1,367	1,431	1,518	1,611	1,644	1,631	1,607	1,566	1,501	1,466	1,453	1,481	1,515	1,527	1,616	1,627	1,563	1,456
Fall	10	1,809	10/5/2015	1,361	1,297	1,282	1,270	1,276	1,302	1,378	1,587	1,809	1,799	1,752	1,725	1,686	1,621	1,584	1,543	1,557	1,571	1,587	1,599	1,655	1,635	1,531	1,394
Fall	10	1,727	10/6/2015	1,296	1,219	1,219	1,221	1,229	1,251	1,317	1,518	1,705	1,727	1,665	1,622	1,565	1,514	1,491	1,488	1,497	1,535	1,536	1,536	1,602	1,594	1,499	1,399
Fall	10	1,627	10/7/2015	1,281	1,204	1,188	1,161	1,167	1,209	1,264	1,427	1,627	1,592	1,545	1,509	1,484	1,450	1,432	1,405	1,406	1,445	1,449	1,412	1,436	1,485	1,415	1,265
Fall	10	1,585	10/8/2015	1,153	1,003	1,004	978	989	1,018	1,098	1,245	1,447	1,493	1,489	1,472	1,504	1,458	1,458	1,450	1,446	1,483	1,488	1,517	1,580	1,585	1,512	1,411
Fall	10	1,701	10/9/2015	1,300	1,208	1,216	1,221	1,242	1,273	1,343	1,528	1,663	1,701	1,680	1,654	1,639	1,627	1,669	1,653	1,643	1,678	1,686	1,692	1,687	1,638	1,565	1,463
Fall	10	1,515	#########	1,289	1,213	1,200	1,192	1,198	1,204	1,259	1,344	1,395	1,486	1,515	1,514	1,483	1,438	1,411	1,371	1,358	1,342	1,364	1,391	1,506	1,494	1,438	1,382
Fall	10	1,704	#########	1,332	1,285	1,283	1,287	1,305	1,328	1,305	1,342	1,438	1,593	1,650	1,667	1,658	1,704	1,660	1,592	1,528	1,559	1,531	1,545	1,573	1,522	1,510	1,395
Fall	10	1,684	#########	1,325	1,250	1,199	1,176	1,190	1,211	1,244	1,344	1,427	1,535	1,622	1,673	1,684	1,647	1,608	1,564	1,548	1,539	1,506	1,508	1,595	1,571	1,464	1,299
Fall	10	1,657	#########	1,181	1,112	1,102	1,084	1,057	1,089	1,167	1,353	1,599	1,582	1,574	1,598	1,613	1,568	1,522	1,494	1,530	1,589	1,622	1,628	1,657	1,574	1,469	1,370
Fall	10	1,564	#########	1,261	1,153	1,128	1,112	1,097	1,098	1,137	1,310	1,504	1,499	1,490	1,472	1,466	1,433	1,440	1,428	1,425	1,475	1,472	1,500	1,564	1,528	1,463	1,359
Fall	10	1,742	#########	1,217	1,143	1,110	1,102	1,120	1,163	1,245	1,450	1,728	1,742	1,691	1,705	1,665	1,610	1,604	1,578	1,536	1,568	1,590	1,628	1,709	1,675	1,577	1,458
Fall	10	1,733	#########	1,349	1,278	1,249	1,253	1,272	1,354	1,384	1,550	1,733	1,720	1,675	1,654	1,613	1,559	1,537	1,527	1,562	1,612	1,605	1,619	1,641	1,601	1,549	1,485
Fall	10	1,805	#########	1,396	1,347	1,318	1,322	1,325	1,371	1,449	1,549	1,694	1,805	1,785	1,787	1,771	1,724	1,675	1,641	1,660	1,725	1,767	1,788	1,804	1,778	1,680	1,609
Fall	10	1,777	#########	1,458	1,392	1,406	1,318	1,307	1,347	1,392	1,436	1,532	1,642	1,658	1,659	1,660	1,627	1,590	1,588	1,588	1,623	1,649	1,697	1,763	1,777	1,696	1,612
Fall	10	2,017	#########	1,519	1,466	1,448	1,476	1,487	1,457	1,554	1,797	1,985	2,017	1,950	1,912	1,842	1,780	1,754	1,708	1,708	1,745	1,757	1,843	1,946	1,942	1,854	1,713
Fall	10	1,858	#########	1,584	1,496	1,446	1,425	1,413	1,420	1,493	1,665	1,858	1,837	1,783	1,737	1,720	1,644	1,600	1,560	1,555	1,514	1,524	1,621	1,687	1,684	1,616	1,509
Fall	10	1,805	#########	1,353	1,301	1,310	1,321	1,348	1,388	1,464	1,620	1,805	1,789	1,691	1,622	1,556	1,504	1,473	1,441	1,434	1,479	1,506	1,555	1,661	1,666	1,669	1,575
Fall	10	2,033	#########	1,500	1,456	1,468	1,484	1,494	1,538	1,621	1,837	2,033	2,022	2,008	1,976	1,940	1,903	1,871	1,814	1,800	1,850	1,777	1,750	1,722	1,683	1,592	1,479
Fall	10	1,749	#########	1,372	1,291	1,254	1,218	1,215	1,248	1,311	1,526	1,749	1,747	1,693	1,665	1,630	1,578	1,594	1,592	1,603	1,660	1,642	1,668	1,679	1,657	1,590	1,488
Fall	10	1,786	#########	1,395	1,356	1,335	1,312	1,312	1,339	1,384	1,450	1,580	1,751	1,786	1,751	1,729	1,661	1,612	1,563	1,539	1,571	1,606	1,657	1,713	1,675	1,622	1,534
Fall	10	1,633	#########	1,437	1,359	1,289	1,276	1,278	1,305	1,322	1,377	1,415	1,535	1,563	1,584	1,582	1,588	1,565	1,529	1,530	1,591	1,611	1,630	1,633	1,583	1,520	1,409
Fall	10	1,882	#########	1,302	1,250	1,253	1,269	1,264	1,314	1,391	1,599	1,882	1,853	1,790	1,746	1,732	1,688	1,679	1,634	1,644	1,703	1,688	1,749	1,842	1,849	1,781	1,653
Fall	10	2,126	#########	1,566	1,506	1,508	1,546	1,576	1,583	1,646	1,880	2,126	2,111	2,009	1,930	1,844	1,747	1,684	1,638	1,645	1,686	1,731	1,826	1,862	1,812	1,776	1,636
Fall	10	2,072	#########	1,499	1,443	1,451	1,447	1,449	1,475	1,536	1,801	2,062	2,072	1,989	1,873	1,797	1,732	1,689	1,646	1,655	1,737	1,792	1,851	1,867	1,818	1,750	1,627
Fall	10	1,806	#########	1,512	1,416	1,384	1,374	1,381	1,384	1,439	1,622	1,806	1,725	1,697	1,680	1,685	1,616	1,589	1,528	1,510	1,543	1,558	1,562	1,589	1,556	1,471	1,415
Fall	10	1,673	#########	1,334	1,296	1,279	1,265	1,250	1,276	1,323	1,492	1,673	1,671	1,620	1,599	1,584	1,541	1,523	1,487	1,528	1,548	1,510	1,536	1,626	1,642	1,577	1,539
Fall	10	1,789	#########	1,484	1,387	1,394	1,459	1,475	1,506	1,536	1,612	1,674	1,781	1,789	1,756	1,706	1,664	1,606	1,547	1,534	1,580	1,622	1,668	1,683	1,670	1,633	1,581
Fall	11	1,883	11/1/2015	1,530	1,435	1,412	1,423	1,443	1,479	1,517	1,582	1,704	1,806	1,858	1,836	1,822	1,803	1,790	1,755	1,789	1,841	1,883	1,821	1,714	1,630	1,512	1,428
Fall	11	1,845	11/2/2015	1,338	1,295	1,241	1,228	1,230	1,265	1,347	1,579	1,787	1,742	1,717	1,674	1,647	1,598	1,629	1,621	1,657	1,758	1,841	1,845	1,827	1,819	1,691	1,622
Fall	11	2,060	11/3/2015	1,522	1,429	1,470	1,471	1,490	1,521	1,611	1,820	1,998	1,998	1,981	1,956	1,932	1,904	1,903	1,884	1,907	2,003	2,060	2,027	1,984	1,946	1,852	1,731
Fall	11	1,867	11/4/2015	1,594	1,496	1,495	1,467	1,460	1,496	1,568	1,700	1,867	1,843	1,790	1,749	1,704	1,658	1,623	1,567	1,589	1,645	1,746	1,770	1,738	1,713	1,631	1,537
Fall	11	1,958	11/5/2015	1,453	1,349	1,363	1,380	1,374	1,402	1,478	1,680	1,883	1,886	1,871	1,835	1,860	1,813	1,800	1,777	1,803	1,888	1,948	1,958	1,939	1,890	1,796	1,660
Fall	11	1,841	11/6/2015	1,547	1,429	1,391	1,357	1,354	1,371	1,458	1,579	1,841	1,826	1,795	1,753	1,715	1,661	1,659	1,609	1,622	1,662	1,666	1,612	1,580	1,509	1,435	1,376
Fall	11	1,633	11/7/2015	1,332	1,252	1,242	1,228	1,224	1,230	1,226	1,264	1,278	1,350	1,380	1,386	1,389	1,376	1,366	1,385	1,424	1,544	1,627	1,633	1,599	1,562	1,525	1,475
Fall	11	1,825	11/8/2015	1,399	1,378	1,345	1,365	1,392	1,388	1,435	1,497	1,574	1,687	1,736	1,743	1,739	1,722	1,662	1,622	1,622	1,695	1,819	1,825	1,810	1,787	1,748	1,660
Fall	11	2,018	11/9/2015	1,573	1,542	1,502	1,493	1,502	1,523	1,598	1,820	2,018	1,996	1,918	1,788	1,757	1,697	1,609	1,562	1,561	1,661	1,805	1,817	1,792	1,752	1,677	1,556
Fall	11	1,883	#########	1,438	1,370	1,353	1,391	1,401	1,422	1,516	1,715	1,883	1,838	1,756	1,700	1,655	1,584	1,549	1,543	1,551	1,658	1,798	1,777	1,739	1,692	1,626	1,527
Fall	11	1,873	#########	1,481	1,417	1,405	1,396	1,399	1,418	1,443	1,519	1,628	1,734	1,800	1,807	1,738	1,710	1,704	1,703	1,726	1,808	1,870	1,862	1,873	1,823	1,746	1,623
Fall	11	2,029	#########	1,553	1,493	1,480	1,476	1,502	1,537	1,590	1,842	2,029	2,027	1,958	1,894	1,845	1,773	1,741	1,705	1,746	1,798	1,878	1,893	1,860	1,803	1,711	1,589
Fall	11	1,750	#########	1,480	1,395	1,328	1,337	1,363	1,353	1,407	1,550	1,750	1,739	1,707	1,712	1,675	1,609	1,599	1,562	1,595	1,666	1,735	1,722	1,695	1,661	1,616	1,538
Fall	11	1,800	#########	1,407	1,320	1,277	1,282	1,277	1,306	1,357	1,446	1,565	1,679	1,749	1,697	1,691	1,685	1,662	1,631	1,640	1,720	1,800	1,762	1,730	1,701	1,644	1,575
Fall	11	1,867	#########	1,496	1,446	1,431	1,439	1,450	1,475	1,509	1,562	1,652	1,732	1,774	1,753	1,702	1,663	1,610	1,621	1,662	1,778	1,867	1,854	1,811	1,794	1,743	1,643
Fall	11	2,038	#########	1,496	1,426	1,443	1,443	1,479	1,514	1,586	1,800	1,998	1,973	1,921	1,888	1,867	1,825	1,820	1,822	1,871	1,956	2,038	2,011	1,950	1,883	1,818	1,697
Fall	11	2,014	#########	1,579	1,482	1,504	1,493	1,491	1,521	1,585	1,822	1,999	1,978	1,876	1,829	1,803	1,765	1,744	1,731	1,762	1,890	1,993	2,014	2,008	1,970	1,863	1,730
Fall	11	2,182	#########	1,624	1,548	1,524	1,530	1,529	1,564	1,667	1,920	2,130	2,161	2,103	2,077	2,061	2,023	1,985	1,939	1,921	2,057	2,182	2,162	2,119	2,072	1,970	1,857
Fall	11	2,195	#########	1,725	1,626	1,639	1,611	1,612	1,644	1,734	1,962	2,195	2,160	2,112	2,078	2,050	1,992	1,969	1,912	1,921	2,007	2,094	2,058	2,018	1,962	1,882	1,717
Fall	11	1,877	#########	1,591	1,498	1,477	1,444	1,442	1,443	1,521	1,688	1,877	1,853	1,840	1,843	1,831	1,783	1,756	1,742	1,742	1,799	1,830	1,777	1,732	1,684	1,628	1,551
Fall	11	1,907	#########	1,475	1,424	1,387	1,370	1,367	1,334	1,367	1,447	1,604	1,737	1,778	1,756	1,721	1,724	1,691	1,673	1,700	1,805	1,907	1,881	1,850	1,802	1,740	1,652
Fall	11	1,795	#########	1,560	1,512	1,401	1,391	1,398	1,408	1,392	1,451	1,510	1,594	1,643	1,636	1,630	1,620	1,608	1,612	1,590	1,708	1,782	1,795	1,786	1,772	1,723	1,573
Fall	11	2,014	#########	1,451	1,356	1,346	1,319	1,341	1,395	1,492	1,714	1,824	1,811	1,783	1,783	1,777	1,764	1,766	1,758	1,777	1,921	1,965	2,004	2,014	1,971	1,898	1,792
Fall	11	2,326	#########	1,694	1,611	1,645	1,647	1,652	1,693	1,768	1,982	2,218	2,210	2,169	2,143	2,129	2,093	2,078	2,057	2,101	2,227	2,326	2,289	2,276	2,239	2,148	2,006
Fall	11	2,444	#########	1,885	1,809	1,797	1,817	1,831	1,875	1,994	2,217	2,444	2,383	2,255	2,153	2,076	2,004	1,987	1,963	1,977	2,144	2,285	2,288	2,277	2,247	2,182	2,047
Fall	11	2,443	#########	1,931	1,863	1,876	1,888	1,901	1,926	2,008	2,237	2,443	2,376	2,242	2,133	2,083	2,023	1,964	1,910	1,939	1,997	2,050	2,017	1,971	1,921	1,851	1,716
Fall	11	1,821	#########	1,560	1,455	1,459	1,454	1,458	1,466	1,506	1,673	1,821	1,797	1,751	1,706	1,666	1,623	1,616	1,592	1,619	1,671	1,715	1,698	1,654	1,600	1,556	1,491
Fall	11	2,063	#########	1,422	1,367	1,328	1,310	1,323	1,358	1,417	1,476	1,581	1,727	1,834	1,894	1,926	1,916	1,914	1,900	1,900	2,006	2,063	2,035	2,018	2,006	1,941	1,863
Fall	11	2,173	#########	1,776	1,683	1,674	1,649	1,651	1,675	1,713	1,792	1,895	1,992	2,012	1,993	1,982	1,974	1,929	1,890	1,933	2,055	2,173	2,156	2,147	2,102	2,001	1,904
Fall	11	2,474	#########	1,850	1,794	1,790	1,813	1,827	1,864	1,951	2,222	2,471	2,474	2,384	2,338	2,320	2,259	2,253	2,240	2,286	2,411	2,474	2,428	2,359	2,289	2,178	2,041

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Max	2,974
Max Month	2
PST	2,643
Winter	2,431
Spring	1,898
Summer	1,402
Fall	1,603

Source: ABB, The Velocity Suite
CONFIDENTIAL DATA REDACTED

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12		12/1/2014																								
Winter	12		12/2/2014																								
Winter	12		12/3/2014																								
Winter	12		12/4/2014																								
Winter	12		12/5/2014																								
Winter	12		12/6/2014																								
Winter	12		12/7/2014																								
Winter	12		12/8/2014																								
Winter	12		12/9/2014																								
Winter	12		#########																								
Winter	12		#########																								
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Winter	12		#########																								
Winter	12		#########																								
Winter	12		#########																								
Winter	1		1/1/2015																								
Winter	1		1/2/2015																								
Winter	1		1/3/2015																								
Winter	1		1/4/2015																								
Winter	1		1/5/2015																								
Winter	1		1/6/2015																								
Winter	1		1/7/2015																								
Winter	1		1/8/2015																								
Winter	1		1/9/2015																								
Winter	1		1/10/2015																								
Winter	1		1/11/2015																								
Winter	1		1/12/2015																								
Winter	1		1/13/2015																								
Winter	1		1/14/2015																								
Winter	1		1/15/2015																								
Winter	1		1/16/2015																								
Winter	1		1/17/2015																								
Winter	1		1/18/2015																								
Winter	1		1/19/2015																								
Winter	1		1/20/2015																								
Winter	1		1/21/2015																								
Winter	1		1/22/2015																								
Winter	1		1/23/2015																								
Winter	1		1/24/2015																								
Winter	1		1/25/2015																								
Winter	1		1/26/2015																								
Winter	1		1/27/2015																								
Winter	1		1/28/2015																								
Winter	1		1/29/2015																								
Winter	1		1/30/2015																								
Winter	1		1/31/2015																								
Winter	2		2/1/2015																								
Winter	2		2/2/2015																								
Winter	2		2/3/2015																								
Winter	2		2/4/2015																								
Winter	2		2/5/2015																								
Winter	2		2/6/2015																								
Winter	2		2/7/2015																								
Winter	2		2/8/2015																								
Winter	2		2/9/2015																								
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Winter	2		2/25/2015																								
Winter	2		2/26/2015																								
Winter	2		2/27/2015																								
Winter	2		2/28/2015																								
Spring	3		3/1/2015																								
Spring	3		3/2/2015																								
Spring	3		3/3/2015																								
Spring	3		3/4/2015																								
Spring	3		3/5/2015																								
Spring	3		3/6/2015																								

Contains Proprietary Material
Do Not Distribute

Spring	3		3/7/2015
Spring	3		3/8/2015
Spring	3		3/9/2015
Spring	3		3/10/2015
Spring	3		3/11/2015
Spring	3		3/12/2015
Spring	3		3/13/2015
Spring	3		3/14/2015
Spring	3		3/15/2015
Spring	3		3/16/2015
Spring	3		3/17/2015
Spring	3		3/18/2015
Spring	3		3/19/2015
Spring	3		3/20/2015
Spring	3		3/21/2015
Spring	3		3/22/2015
Spring	3		3/23/2015
Spring	3		3/24/2015
Spring	3		3/25/2015
Spring	3		3/26/2015
Spring	3		3/27/2015
Spring	3		3/28/2015
Spring	3		3/29/2015
Spring	3		3/30/2015
Spring	3		3/31/2015
Spring	4		4/1/2015
Spring	4		4/2/2015
Spring	4		4/3/2015
Spring	4		4/4/2015
Spring	4		4/5/2015
Spring	4		4/6/2015
Spring	4		4/7/2015
Spring	4		4/8/2015
Spring	4		4/9/2015
Spring	4		4/10/2015
Spring	4		4/11/2015
Spring	4		4/12/2015
Spring	4		4/13/2015
Spring	4		4/14/2015
Spring	4		4/15/2015
Spring	4		4/16/2015
Spring	4		4/17/2015
Spring	4		4/18/2015
Spring	4		4/19/2015
Spring	4		4/20/2015
Spring	4		4/21/2015
Spring	4		4/22/2015
Spring	4		4/23/2015
Spring	4		4/24/2015
Spring	4		4/25/2015
Spring	4		4/26/2015
Spring	4		4/27/2015
Spring	4		4/28/2015
Spring	4		4/29/2015
Spring	4		4/30/2015
Spring	5		5/1/2015
Spring	5		5/2/2015
Spring	5		5/3/2015
Spring	5		5/4/2015
Spring	5		5/5/2015
Spring	5		5/6/2015
Spring	5		5/7/2015
Spring	5		5/8/2015
Spring	5		5/9/2015
Spring	5		5/10/2015
Spring	5		5/11/2015
Spring	5		5/12/2015
Spring	5		5/13/2015
Spring	5		5/14/2015
Spring	5		5/15/2015
Spring	5		5/16/2015
Spring	5		5/17/2015
Spring	5		5/18/2015
Spring	5		5/19/2015
Spring	5		5/20/2015
Spring	5		5/21/2015
Spring	5		5/22/2015
Spring	5		5/23/2015
Spring	5		5/24/2015
Spring	5		5/25/2015
Spring	5		5/26/2015
Spring	5		5/27/2015
Spring	5		5/28/2015
Spring	5		5/29/2015
Spring	5		5/30/2015
Spring	5		5/31/2015
Summer	6		6/1/2015
Summer	6		6/2/2015
Summer	6		6/3/2015
Summer	6		6/4/2015
Summer	6		6/5/2015
Summer	6		6/6/2015
Summer	6		6/7/2015
Summer	6		6/8/2015
Summer	6		6/9/2015
Summer	6		6/10/2015
Summer	6		6/11/2015
Summer	6		6/12/2015
Summer	6		6/13/2015
Summer	6		6/14/2015
Summer	6		6/15/2015
Summer	6		6/16/2015
Summer	6		6/17/2015
Summer	6		6/18/2015
Summer	6		6/19/2015

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Summer	6		6/20/2015
Summer	6		6/21/2015
Summer	6		6/22/2015
Summer	6		6/23/2015
Summer	6		6/24/2015
Summer	6		6/25/2015
Summer	6		6/26/2015
Summer	6		6/27/2015
Summer	6		6/28/2015
Summer	6		6/29/2015
Summer	6		6/30/2015
Summer	7		7/1/2015
Summer	7		7/2/2015
Summer	7		7/3/2015
Summer	7		7/4/2015
Summer	7		7/5/2015
Summer	7		7/6/2015
Summer	7		7/7/2015
Summer	7		7/8/2015
Summer	7		7/9/2015
Summer	7		7/10/2015
Summer	7		7/11/2015
Summer	7		7/12/2015
Summer	7		7/13/2015
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Summer	7		7/15/2015
Summer	7		7/16/2015
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Summer	7		7/18/2015
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Summer	7		7/20/2015
Summer	7		7/21/2015
Summer	7		7/22/2015
Summer	7		7/23/2015
Summer	7		7/24/2015
Summer	7		7/25/2015
Summer	7		7/26/2015
Summer	7		7/27/2015
Summer	7		7/28/2015
Summer	7		7/29/2015
Summer	7		7/30/2015
Summer	7		7/31/2015
Summer	8		8/1/2015
Summer	8		8/2/2015
Summer	8		8/3/2015
Summer	8		8/4/2015
Summer	8		8/5/2015
Summer	8		8/6/2015
Summer	8		8/7/2015
Summer	8		8/8/2015
Summer	8		8/9/2015
Summer	8		8/10/2015
Summer	8		8/11/2015
Summer	8		8/12/2015
Summer	8		8/13/2015
Summer	8		8/14/2015
Summer	8		8/15/2015
Summer	8		8/16/2015
Summer	8		8/17/2015
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Summer	8		8/24/2015
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Summer	8		8/26/2015
Summer	8		8/27/2015
Summer	8		8/28/2015
Summer	8		8/29/2015
Summer	8		8/30/2015
Summer	8		8/31/2015
Fall	9		9/1/2015
Fall	9		9/2/2015
Fall	9		9/3/2015
Fall	9		9/4/2015
Fall	9		9/5/2015
Fall	9		9/6/2015
Fall	9		9/7/2015
Fall	9		9/8/2015
Fall	9		9/9/2015
Fall	9		9/10/2015
Fall	9		9/11/2015
Fall	9		9/12/2015
Fall	9		9/13/2015
Fall	9		9/14/2015
Fall	9		9/15/2015
Fall	9		9/16/2015
Fall	9		9/17/2015
Fall	9		9/18/2015
Fall	9		9/19/2015
Fall	9		9/20/2015
Fall	9		9/21/2015
Fall	9		9/22/2015
Fall	9		9/23/2015
Fall	9		9/24/2015
Fall	9		9/25/2015
Fall	9		9/26/2015
Fall	9		9/27/2015
Fall	9		9/28/2015
Fall	9		9/29/2015
Fall	9		9/30/2015
Fall	10		10/1/2015
Fall	10		10/2/2015

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Fall	10		10/3/2015																									
Fall	10		10/4/2015																									
Fall	10		10/5/2015																									
Fall	10		10/6/2015																									
Fall	10		10/7/2015																									
Fall	10		10/8/2015																									
Fall	10		10/9/2015																									
Fall	10		#########

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2.1 Generator List with Existing and Expected Seasonal Claimed Capability (SCC)

- **Generator Information as of January 1, 2015**
- **Summer and Winter SCC as of January 1, 2015, and as of the 2014/15 Winter and 2015 Summer Peaks**

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICI-PANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	Change in Summer SCC from 8/1/14
194	FOUR HILLS LOAD REDUCER	194	FOUR HILLS LOAD REDUCER	IC	LFG		BIO/REFUSE	01-Apr-96	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	55006	0.000	0.000	0.000	0.000	0.000
253	TURNKEY LANDFILL	253	TURNKEY LANDFILL	IC	LFG		BIO/REFUSE	01-Mar-92	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH	54663	0.730	0.732	0.730	0.732	-0.003
321	MANCHESTER 10/10A CC	321	MANCHESTER 10 10A CC	CC	NG	DFO	GAS/OIL COMBINED CYCLE	15-Nov-95	Dominion Energy Marketing, Inc.	DEM	RI	07	RI	RI	3236	170.000	149.000	170.000	159.000	10.000
322	MANCHESTER 11 11A CC	322	MANCHESTER 11 11A CC	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Oct-95	Dominion Energy Marketing, Inc.	DEM	RI	07	RI	RI	3236	170.000	153.594	170.000	159.000	5.406
323	MANCHESTER 9/9A CC	323	MANCHESTER 9 9A CC	CC	NG	DFO	GAS/OIL COMBINED CYCLE	14-Nov-95	Dominion Energy Marketing, Inc.	DEM	RI	07	RI	RI	3236	169.785	148.785	169.785	159.000	10.215
324	CDECCA	324	CDECCA	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Nov-88	Pawtucket Power Holding Company LLC	PPH	CT	03	CT	CT	50498	61.334	49.522	61.334	49.522	-5.732
326	ALTRESCO	326	ALTRESCO	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Sep-90	Pawtucket Power Holding Company LLC	PPH	MA	03	WMA	WCMA	50002	178.879	144.612	178.879	144.612	-6.370
327	AMOSKEAG	327	AMOSKEAG	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-22	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	2354	17.500	16.781	17.500	16.781	0.000
328	GULF ISLAND COMPOSITE	328	GULF ISLAND COMPOSITE Incremental	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-26	Brookfield White Pine Hydro LLC	FPLEMH	ME	01	ME	ME	1480	32.970	32.970	32.970	32.970	0.000
329	ASCUTNEY GT	329	ASCUTNEY GT	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Nov-61	Green Mountain Power Corporation	GMP	VT	27	VT	VT	3708	12.581	8.503	12.581	8.503	-0.143
330	AYERS ISLAND	330	AYERS ISLAND	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-25	Public Service Company of New Hampshire	PSNH	NH	01	NH	NH	2355	9.080	8.474	9.080	8.474	0.000
331	AZISCOHOS HYDRO	331	AZISCOHOS HYDRO	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jul-88	Brookfield Energy Marketing, LP	BEMLP	ME	19	ME	ME	50999	6.800	6.800	6.800	6.800	-0.010
332	BAR HARBOR DIESELS 1-4	332	BAR HARBOR DIESELS 1-4	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-69	Energy New England LLC	ENE	ME	09	BHE	ME	1468	4.000	0.000	4.000	0.000	-3.800
335	BELLOWS FALLS	335	BELLOWS FALLS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-28	TransCanada Power Marketing, Ltd.	TCPM	VT	25	VT	NH	3745	48.540	48.540	48.540	48.540	0.000
336	BERLIN 1 GT	336	BERLIN 1 GT	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-72	Green Mountain Power Corporation	GMP	VT	23	VT	VT	3734	50.409	40.260	50.409	40.260	0.000
337	BETHLEHEM	337	BETHLEHEM	ST	WDS		BIO/REFUSE	01-Dec-86	GDF Suez Energy Marketing NA, Inc.	SUEZ	NH	07	NH	NH	50208	15.321	15.303	15.321	15.303	0.129
340	BRIDGEPORT HARBOR 3	340	BRIDGEPORT HARBOR 3	ST	SUB		COAL STEAM	01-Aug-68	PSEG Energy Resources & Trade LLC	PSEG	CT	01	SWCT	CT	568	384.984	383.426	384.984	383.426	0.000
341	BRIDGEPORT HARBOR 4	341	BRIDGEPORT HARBOR 4	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Oct-67	PSEG Energy Resources & Trade LLC	PSEG	CT	01	SWCT	CT	568	21.924	16.907	21.924	16.907	0.000
345	MEAD	345	MEAD	ST	BIT	OBS	COAL STEAM	01-Feb-90	American PowerNet Management, LP	APNM	ME	17	ME	ME	10495	0.000	0.000	0.000	0.000	-0.485
346	BOLTON FALLS	346	BOLTON FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Green Mountain Power Corporation	GMP	VT	23	VT	VT	7056	3.397	0.000	3.397	0.000	-2.149
348	BOOT MILLS	348	BOOT MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-85	NSTAR Electric Company	NSTAR	MA	17	CMA/NEMA	WCMA	10556	11.400	6.010	11.400	6.010	-6.355
349	WHEELABRATOR BRIDGEPORT, L.P.	349	WHEELABRATOR BRIDGEPORT, L.P.	ST	MSW		BIO/REFUSE	01-Apr-88	Wheelabrator Bridgeport, L.P.	WB	CT	01	SWCT	CT	50883	59.267	59.069	59.267	59.069	0.195
350	BRAYTON PT 1	350	BRAYTON PT 1	ST	BIT	NG	COAL STEAM	01-Aug-63	Brayton Point Energy, LLC	BPE	MA	05	RI	SEMA	1619	241.366	225.230	241.366	225.230	0.000
351	BRAYTON PT 2	351	BRAYTON PT 2	ST	BIT	NG	COAL STEAM	01-Jul-64	Brayton Point Energy, LLC	BPE	MA	05	RI	SEMA	1619	242.455	237.842	242.455	237.842	0.000
352	BRAYTON PT 3	352	BRAYTON PT 3	ST	BIT	NG	COAL STEAM	01-Jul-69	Brayton Point Energy, LLC	BPE	MA	05	RI	SEMA	1619	598.606	596.289	598.606	596.289	-15.195
353	BRAYTON PT 4	353	BRAYTON PT 4	ST	RFO	NG	GAS/OIL STEAM	01-Dec-74	Brayton Point Energy, LLC	BPE	MA	05	RI	SEMA	1619	445.520	434.025	445.520	434.025	0.000
354	BRAYTON DIESELS 1-4	354	Brayton Diesels 1-4 Incremental	IC	DFO		OIL INTERNAL COMBUSTION	01-Mar-67	Brayton Point Energy, LLC	BPE	MA	05	RI	SEMA	1619	0.000	0.000	0.000	0.000	0.000
355	BRANFORD 10	355	BRANFORD 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	540	20.950	15.940	20.950	15.940	0.000
356	BRISTOL REFUSE	356	BRISTOL REFUSE	ST	MSW		BIO/REFUSE	01-May-88	Covanta Energy Marketing, LLC	CEM	CT	03	CT	CT	50648	12.440	12.941	12.440	12.941	0.571
357	BRIDGEWATER	357	BRIDGEWATER	ST	WDS		BIO/REFUSE	01-Sep-87	Bridgewater Power Company L.P.	BPCLP	NH	09	NH	NH	10290	14.395	14.170	14.395	14.170	-0.622
358	BRUNSWICK	358	BRUNSWICK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-82	Brookfield White Pine Hydro LLC	FPLEMH	ME	05	ME	ME	1483	11.107	10.585	11.107	10.585	-3.237
359	J. COCKWELL 1	359	J. COCKWELL 1	PS	WAT		HYDRO (PUMPED STORAGE)	01-Sep-74	Bear Swamp Power Company LLC	BSP	MA	03	WMA	WCMA	8005	292.275	292.275	292.275	292.275	0.000
360	J. COCKWELL 2	360	J. COCKWELL 2	PS	WAT		HYDRO (PUMPED STORAGE)	01-Oct-74	Bear Swamp Power Company LLC	BSP	MA	03	WMA	WCMA	8005	292.113	293.238	292.113	293.238	0.000
362	BULLS BRIDGE	362	BULLS BRIDGE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-03	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	05	SWCT	CT	541	5.470	5.388	5.470	5.388	2.159
363	BURLINGTON GT	363	BURLINGTON GT	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jul-71	Burlington Electric Department	BED	VT	07	VT	VT	3754	23.354	19.104	23.354	19.104	0.000
365	CANAL 1	365	CANAL 1	ST	RFO		OIL STEAM	01-Jul-68	Genon Energy Management, LLC	MET	MA	01	SEMA	SEMA	1599	562.305	565.240	562.305	565.240	565.240
366	CANAL 2	366	CANAL 2	ST	RFO	NG	GAS/OIL STEAM	01-Feb-76	Genon Energy Management, LLC	MET	MA	01	SEMA	SEMA	1599	303.000	558.750	303.000	558.750	0.000
367	CAPE GT 4	367	CAPE GT 4	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jan-70	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1484	20.011	15.487	20.011	15.487	-0.209
368	CAPE GT 5	368	CAPE GT 5	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jan-70	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1484	20.272	15.822	20.272	15.822	0.000
369	CATARACT EAST	369	CATARACT EAST	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-37	Brookfield White Pine Hydro LLC	FPLEMH	ME	31	SME	ME	1486	8.000	7.775	8.000	7.775	0.000
370	COS COB 10	370	COS COB 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	NRG Power Marketing LLC	NRGPM	CT	01	NOR	CT	542	23.000	18.932	23.000	18.932	0.000
371	COS COB 11	371	COS COB 11	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	NRG Power Marketing LLC	NRGPM	CT	01	NOR	CT	542	23.000	18.724	23.000	18.724	0.000
372	COS COB 12	372	COS COB 12	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	NRG Power Marketing LLC	NRGPM	CT	01	NOR	CT	542	23.000	19.082	23.000	19.082	0.000
375	CLEARY 9 9A CC	375	CLEARY 9 9A CC	CC	NG	DFO	GAS COMBINED CYCLE	01-Dec-75	Taunton Municipal Lighting Plant	TMLP	MA	05	SEMA	SEMA	1682	109.931	104.931	109.931	104.931	0.000
376	CLEARY 8	376	CLEARY 8	ST	RFO		OIL STEAM	01-Jan-66	Taunton Municipal Lighting Plant	TMLP	MA	05	SEMA	SEMA	1682	22.253	24.825	22.253	24.825	0.000
379	COBBLE MOUNTAIN	379	COBBLE MOUNTAIN	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-23	Hydro-Quebec Gas & Electric Department	HQE	MA	13	WMA	WCMA	1630	32.480	31.126	32.480	31.126	0.000
380	COMERFORD	380	COMERFORD	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-30	TransCanada Power Marketing, Ltd.	TCPM	NH	09	NH	NH	2349	168.111	166.135	168.111	166.135	0.000
382	MERRIMACK CT1	382	MERRIMACK CT1	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Jul-69	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2364	21.676	16.826	21.676	16.826	0.000
383	MERRIMACK CT2	383	MERRIMACK CT2	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-68	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2364	21.304	16.804	21.304	16.804	0.000
388	DARTMOUTH POWER	388	DARTMOUTH POWER	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-May-92	Consolidated Edison Energy, Inc	CEEI	MA	05	SEMA	SEMA	52026	67.656	60.457	67.656	60.457	-1.692
389	DERBY DAM	389	DERBY DAM	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Mar-89	Connecticut Light and Power Company, The	CLP	CT	01	SWCT	CT	10063	7.050	7.050	7.050	7.050	0.000
393	DEERFIELD 5	393	DEERFIELD 5	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Oct-74	TransCanada Power Marketing, Ltd.	TCPM	MA	11	WMA	WCMA	1620	13.990	13.703	13.990	13.703	0.000
395	DOREEN	395	DOREEN	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	Essential Power Massachusetts, LLC	NAEA-EM	MA	03	WMA	WCMA	1631	20.670	15.820	20.670	15.820	0.000
396	DEVON 10	396	DEVON 10	GT	JF	DFO	OIL COMBUSTION (GAS) TURBINE	01-Apr-88	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	544	18.852	14.407	18.852	14.407	0.000
397	DEVON 11	397	DEVON 11	GT	JF	NG	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	544	38.819	29.299	38.819	29.299	0.000
398	DEVON 12	398	DEVON 12	GT	JF	NG	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	544	38.437	29.227	38.437	29.227	0.000
399	DEVON 13	399	DEVON 13	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	544	38.967	29.967	38.967	29.967	0.000
400	DEVON 14	400	DEVON 14	GT	JF	NG	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	544	40.274	29.704	40.274	29.704	0.000
401	EASTMAN FALLS	401	EASTMAN FALLS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-12	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2356	6.470	5.582	6.470	5.582	0.000
405	ELLSWORTH HYDRO	405	ELLSWORTH HYDRO	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-19	Black Bear Hydro Partners, LLC	BBHP	ME	09	BHE	ME	1469	9.050	9.044	9.050	9.044	0.000
407	EASTPORT DIESELS 1-3	407	EASTPORT DIESELS 1-3	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-48	Energy New England LLC	ENE	ME	29	BHE	ME	1468	2.100	1.800	2.100	1.800	-0.200
410	ESSEX 19 HYDRO	410	ESSEX 19 HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-17	Green Mountain Power Corporation	GMP	VT	07	VT	VT	3737	4.258	2.266	4.258	2.266	-2.918
411	EXETER	411	EXETER	ST	TDF	OBS	BIO/REFUSE	01-Dec-91	ReEnergy Sterling CT Limited Partnership	REENERGY	CT	13	CT	CT	50736	0.000	0.000	0.000	0.000	-20.981
412	FALLS VILLAGE	412	FALLS VILLAGE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-14	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	05	CT	CT	560	4.349	3.939	4.349	3.939	1.561
413	FIFE BROOK	413	FIFE BROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-74	Bear Swamp Power Company LLC	BSP	MA	03	WMA	WCMA	8004	9.900	6.089	9.900	6.089	0.000
417	FRAMINGHAM JET 1	417	FRAMINGHAM JET 1	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	Exelon Generation Company, LLC	EXGC	MA	17	BOSTON	NEMA	1586	14.175	10.145	14.175	10.145	0.000
418	FRAMINGHAM JET 2	418	FRAMINGHAM JET 2	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	Exelon Generation Company, LLC	EXGC	MA	17	BOSTON	NEMA	1586	15.688	9.743	15.688	9.743	0.000
419	FRAMINGHAM JET 3	419	FRAMINGHAM JET 3	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	Exelon Generation Company, LLC	EXGC	MA	17	BOSTON	NEMA	1586	15.250	10.790	15.250	10.790	0.000
420	FRANKLIN DRIVE 10	420	FRANKLIN DRIVE 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Nov-68	NRG Power Marketing LLC	NRGPM	CT	05	CT	CT	561	20.527	15.417	20.527	15.417	0.000
421	FRONT STREET DIESELS 1-3	421	FRONT STREET DIESELS 1-3	IC	DFO		OIL INTERNAL COMBUSTION	01-Dec-80	Chicopee Municipal Lighting Plant	CMLP	MA	13	WMA	WCMA	7396	8.250	7.713	8.250	7.713	0.000
424	GREAT LAKES - MILLINOCKET	424	GREAT LAKES - MILLINOCKET	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Mar-87	Brookfield Energy Marketing, LP	BEMLP	ME	19	BHE	ME	55830	55.317	74.958	55.317	74.958	44.575
426	GORGE 1 DIESEL	426	GORGE 1 DIESEL	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jan-85	Green Mountain Power Corporation	GMP	VT	07	VT	VT	3735	11.000	0.000	11.000	0.000	-7.099
427	GORHAM	427	GORHAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-87	Public Service Company of New Hampshire	PSNH	NH	07	NH	NH	2358	1.518	1.434	1.518	1.434	0.001
432	HARRIS 1	432	HARRIS 1	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-54	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1492	16.776	16.790	16.776	16.790	0.000
433	HARRIS 2	433	HARRIS 2	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-54	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1492	34.500	34.865	34.500	34.865	0.000
434	HARRIS 3	434	HARRIS 3	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-53	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1492	33.905	34.210	33.905	34.210	0.000
435	HARRIMAN	435	HARRIMAN	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-24	TransCanada Power Marketing, Ltd.	TCPM	VT	25	WMA	WCMA	3746	38.663	40.943	38.663	40.943	0.000
436	HEMPHILL 1	436	HEMPHILL 1	ST	WDS		BIO/REFUSE	01-Dec-87	Springfield Power, LLC	SPRING	NH	19	NH	NH	10838	16.764	16.968	16.764	16.968	0.270
440	HIRAM	440	HIRAM	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-17	Brookfield White Pine Hydro LLC	FPLEMH	ME	05	SME	ME	1493	11.600	11.189	11.600	11.189	0.000
445	COVANTA WEST ENFIELD	445	COVANTA WEST ENFIELD	ST	WDS		BIO/REFUSE	01-Nov-87	Covanta Maine, LLC	CM	ME	19	BHE	ME	10766	21.446	20.461	21.446	20.461	0.000
446	COVANTA JONESBORO	446	COVANTA JONESBORO	ST	WDS		BIO/REFUSE	01-Nov-87	Covanta Maine, LLC	CM	ME	29	BHE	ME	10765	20.226	20.226	20.226	20.226	0.000
448	IPSWICH DIESELS	448	IPSWICH DIESELS	IC	DFO	NG	GAS/OIL INTERNAL COMBUSTION	01-Jan-51	Ipswich Municipal Light Department	IMLD	MA	09	BOSTON	NEMA	1670	9.495	9.729	9.495	9.729	-0.511
449	JACKMAN	449	JACKMAN	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Feb-26	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	2360	3.541	3.600	3.541	3.600	0.000
452	KENDALL JET 1	452	KENDALL JET 1	GT	DFO		OIL COMBUSTION (GAS) TURBINE	24-Sep-70	Kendall Green Energy, LLC	KENDALL	MA	17	BOSTON	NEMA	1595	23.000	18.000	23.000	18.000	0.000
457	LAWRENCE HYDRO	457	LAWRENCE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-81	CHI Power Marketing, Inc.	CHIPM	MA	09	CMA/NEMA	WCMA	50545	8.576	6.160	8.576	6.160	-3.318
460	LOCKWOOD	460	LOCKWOOD	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Brookfield Energy Marketing, LP	BEMLP	ME	11	ME	ME	10066	4.113	4.046	4.113	4.046	0.162
461	LENERGIA ENERGY CENTER	12521	Lowell Power Reactivation	CC	NG	DFO	GAS/OIL COMBINED CYCLE	11-Mar-93	EDF Trading North America, LLC	EDFT	MA	17	CMA/NEMA	WCMA	54586	78.446	74.638	78.446	74.638	0.000
462	LISBON RESOURCE RECOVERY	462	LISBON RESOURCE RECOVERY	ST	MSW		BIO/REFUSE	01-Jan-96	Connecticut Light and Power Company, The	CLP	CT	11	CT	CT	54758	13.530	13.325	13.530	13.325	-0.197
463	REENERGY LIVERMORE FALLS	463	AEI LIVERMORE	ST	WDS		BIO/REFUSE	01-Oct-92	ReEnergy Stratton LLC	REH	ME	01	ME	ME	10354	34.430	34.695	34.430	34.695	0.000
464	LOST NATION	464	LOST NATION	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	Public Service Company of New Hampshire	PSNH	NH	07	NH	NH	2362	17.992	13.926	17.992	13.926	0.000
465	DEERFIELD 2/LWR DRFIELD	465	DEERFIELD 2 LWR DRFIELD	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-12	TransCanada Power Marketing, Ltd.	TCPM	MA	11	WMA	WCMA	7, 6083, 6	19.500	19.275	19.500	19.275	0.000
466	L STREET JET	466	L STREET JET	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-66	Exelon Generation Company, LLC	EXGC	MA	25	BOSTON	NEMA	1587	21.770	16.030	21.770	16.030	0.000
467	MARBLEHEAD DIESELS	467	MARBLEHEAD DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	25-Sep-68	Marblehead Municipal Light Department	MMLD	MA	09	BOSTON	NEMA	6586	5.000	5.000	5.000	5.000	0.000
468	MARSHFIELD 6 HYDRO	468	MARSHFIELD 6 HYDRO	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-27	Green Mountain Power Corporation	GMP	VT	23	NH	VT	3739	4.380	4.412	4.380	4.412	0.000
472	M STREET JET	472	M STREET JET	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-78	Massachusetts Bay Transportation Authority	MBTA	MA	25	BOSTON	NEMA	10176	67.200	47.000	67.200	47.000	0.000
473	MCINDOES	473	MCINDOES	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-31	TransCanada Power Marketing, Ltd.	TCPM	NH	09	NH	NH	6483	10.571	10.066	10.571	10.066	0.000
474	J C MCNEIL	474	J C MCNEIL	ST	WDS	NG	BIO/REFUSE	01-Feb-84	Burlington Electric Department	BED	VT	07	VT	VT	589	54.000	52.000	54.000	52.000	0.000
475	MEDWAY DIESELS 1-4	475	MEDWAY DIESELS 1-4	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-68	Energy New England LLC	ENE	ME	19	BHE	ME	1474	6.412	4.029	6.412	4.029	-3.921
478	MIDDLETOWN 10	478	MIDDLETOWN 10	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Jan-66	NRG Power Marketing LLC	NRGPM	CT	07	CT	CT	562	20.015	15.515	20.015	15.515	0.000
480	MIDDLETOWN 2	480	MIDDLETOWN 2	ST	RFO	NG	GAS/OIL STEAM	01-Jan-58	NRG Power Marketing LLC	NRGPM	CT	07	CT	CT	562	120.000	117.000	120.000	117.000	0.000
481	MIDDLETOWN 3	481	MIDDLETOWN 3	ST	RFO	NG	GAS/OIL STEAM	01-Jan-64	NRG Power Marketing LLC	NRGPM	CT	07	CT	CT	562	244.398	233.679	244.398	233.679	0.000
482	MIDDLETOWN 4	482	MIDDLETOWN 4	ST	RFO		OIL STEAM	01-Jun-73	NRG Power Marketing LLC	NRGPM	CT	07	CT	CT	562	402.000	399.923	402.000	399.923	0.000
484	MILLSTONE POINT 2	484	MILLSTONE POINT 2	ST	NUC		NUCLEAR STEAM	01-Dec-75	Dominion Energy Marketing, Inc.	DEM	CT	11	CT	CT	566	875.912	870.855	875.912	870.855	0.000
485	MILLSTONE POINT 3	485	MILLSTONE POINT 3	ST	NUC		NUCLEAR STEAM	01-Apr-86	Dominion Energy Marketing, Inc.	DEM	CT	11	CT	CT	566	1,235.001	1,225.000	1,235.001	1,225.000	0.000
486	MILFORD POWER	486	MILFORD POWER	CC	NG		GAS COMBINED CYCLE	01-Jan-94	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	27	RI	SEMA	54805	170.730	149.000	170.730	149.000	0.000
487	MILLER HYDRO	487	MILLER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-84	Energy New England LLC	ENE	ME	01	ME	ME	50278	9.769	9.428	9.769	9.428	0.002
489	MERRIMACK 1	489	MERRIMACK 1	ST	BIT		COAL STEAM	01-Dec-60	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2364	108.000	108.000	108.000	108.000	0.000
490	MERRIMACK 2	490	MERRIMACK 2	ST	BIT		COAL STEAM	30-Apr-68	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2364	330.513	330.000	330.513	330.000	0.000
492	MONTVILLE 10 and 11	492	MONTVILLE 10 and 11	IC	KER		OIL INTERNAL COMBUSTION	01-Jan-67	NRG Power Marketing LLC	NRGPM	CT	11	CT	CT	546	5.354	5.296	5.354	5.296	0.000
493	MONTVILLE 5	493	MONTVILLE 5	ST	RFO	NG	GAS/OIL STEAM	01-Jan-54	NRG Power Marketing LLC	NRGPM	CT	11	CT	CT	546	81.590	81.000	81.590	81.000	0.000
494	MONTVILLE 6	494	MONTVILLE 6	ST	RFO		OIL STEAM	01-Jul-71	NRG Power Marketing LLC	NRGPM	CT	11	CT	CT	546	406.

Contains Proprietary Material
Do Not Distribute

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 81/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
561	SEARSBURG	561	SEARSBURG	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Mar-22	TransCanada Power Marketing, Ltd.	TCPM	VT	03	WMA	WCMA	6529	4.960	4.755	4.960	4.755	0.000
562	SECREC-PRESTON	562	SECREC-PRESTON	ST	MSW	DFO	BIO/REFUSE	01-Jan-92	Connecticut Light and Power Company, The	CLP	CT	11	CT	CT	10646	16.232	15.857	16.232	15.857	0.044
563	SEMASS 1	563	SEMASS 1	ST	MSW	DFO	BIO/REFUSE	01-Oct-88	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA	50290	50.314	49.185	50.314	49.185	1.171
564	SEMASS 2	564	SEMASS 2	ST	MSW	DFO	BIO/REFUSE	01-May-93	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA	50290	24.878	22.640	24.878	22.640	0.585
565	SHELDON SPRINGS	565	SHELDON SPRINGS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-88	Vermont Electric Power Company, Inc.	VELCO	VT	11	VT	VT	10494	9.370	2.286	9.370	2.286	-6.381
566	SHEPAUG	566	SHEPAUG	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-55	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	09	SWCT	CT	552	42.523	41.511	42.523	41.511	0.000
567	SHERMAN	567	SHERMAN	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Dec-26	TransCanada Power Marketing, Ltd.	TCPM	MA	11	WMA	WCMA	6012	6.220	6.154	6.220	6.154	0.000
568	SHREWSBURY DIESELS	35657	Shrewsbury Diesels	IC	DFO		OIL INTERNAL COMBUSTION	01-May-78	Shrewsbury Electric & Cable Operations	SELP	MA	27	CMA/NEMA	WCMA	6125	13.650	13.750	13.650	13.750	0.000
569	SKELTON	569	SKELTON	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-48	Brookfield White Pine Hydro LLC	FPLEMH	ME	31	SME	ME	1505	19.704	19.704	19.704	21.600	1.896
570	SMITH	570	SMITH	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-48	Public Service Company of New Hampshire	PSNH	NH	07	NH	NH	2368	13.214	8.353	13.214	8.353	-4.787
572	SO. MEADOW 11	572	SO. MEADOW 11	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-70	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	46.921	35.781	46.921	35.781	0.000
573	SO. MEADOW 12	573	SO. MEADOW 12	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-70	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	47.815	37.649	47.815	37.649	0.000
574	SO. MEADOW 13	574	SO. MEADOW 13	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-70	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	47.917	38.317	47.917	38.317	0.000
575	SO. MEADOW 14	575	SO. MEADOW 14	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-70	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	46.346	36.746	46.346	36.746	0.000
580	SO. MEADOW 5	580	SO. MEADOW 5	ST	MSW	NG	BIO/REFUSE	01-Nov-87	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	24.327	26.136	24.327	26.136	4.140
581	SO. MEADOW 6	581	SO. MEADOW 6	ST	MSW	NG	BIO/REFUSE	01-Nov-87	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	22.050	16.623	22.050	16.623	-1.836
583	STONY BROOK 2A	583	STONY BROOK 2A	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Nov-82	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	13	WMA	WCMA	6081	87.400	67.400	87.400	67.400	0.000
584	STONY BROOK 2B	584	STONY BROOK 2B	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Nov-82	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	13	WMA	WCMA	6081	85.300	65.300	85.300	65.300	0.000
587	STEVENSON	587	STEVENSON	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-19	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	01	SWCT	CT	553	28.844	28.311	28.844	28.311	0.000
590	REENERGY STRATTON	590	BORALEX STRATTON ENERGY	ST	WDS		BIO/REFUSE	01-Sep-89	ReEnergy Stratton LLC	REH	ME	07	ME	ME	50650	44.363	45.024	44.363	45.024	0.000
591	S.D. WARREN-WESTBROOK	591	S.D. WARREN-WESTBROOK	ST	WDS	RFO	BIO/REFUSE	01-Nov-97	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	50447	49.103	42.590	49.103	42.590	0.000
592	TAMWORTH	592	TAMWORTH	ST	WDS		BIO/REFUSE	01-Jan-88	GDF Suez Energy Marketing NA, Inc.	SUEZ	NH	03	NH	NH	50739	19.973	20.074	19.973	20.074	0.720
595	TORRINGTON TERMINAL 10	595	TORRINGTON TERMINAL 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Aug-67	NRG Power Marketing LLC	NRGPM	CT	05	CT	CT	565	20.748	15.638	20.748	15.638	0.000
596	TUNNEL 10	596	TUNNEL 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	11	CT	CT	557	21.691	16.257	21.691	16.257	-0.334
598	VERGENNES 5 AND 6 DIESELS	598	VERGENNES 5 and 6 DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-64	Green Mountain Power Corporation	GMP	VT	01	VT	VT	6519	4.240	3.940	4.240	3.940	0.000
599	VERNON	599	VERNON	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-09	TransCanada Power Marketing, Ltd.	TCPM	VT	25	WMA	WCMA	2352	32.000	32.000	32.000	32.000	0.000
612	WATERS RIVER JET 1	612	WATERS RIVER JET 1	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	01-Dec-71	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	09	BOSTON	NEMA	1678	21.974	15.974	21.974	15.974	0.000
613	WATERS RIVER JET 2	613	WATERS RIVER JET 2	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	01-Apr-91	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	09	BOSTON	NEMA	1678	40.000	28.500	40.000	28.500	0.000
614	WATERBURY 22	614	WATERBURY 22	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-53	Green Mountain Power Corporation	GMP	VT	23	VT	VT	6520	5.000	5.000	5.000	5.000	0.000
616	WEST ENFIELD	616	WEST ENFIELD	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-88	New Brunswick Energy Marketing Corporation	NBPGC	ME	19	BHE	ME	10255	10.646	8.818	10.646	8.818	-7.577
617	WESTON	617	WESTON	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-20	Brookfield White Pine Hydro LLC	FPLEMH	ME	17	ME	ME	1509	8.315	10.831	8.315	10.831	1.644
618	DG WHITEFIELD, LLC	618	DG WHITEFIELD, LLC	ST	WDS		BIO/REFUSE	01-Apr-88	Exelon Generation Company, LLC	EXGC	NH	07	NH	NH	10839	15.726	15.603	15.726	15.603	-0.567
619	WHITE LAKE JET	619	WHITE LAKE JET	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-68	Public Service Company of New Hampshire	PSNH	NH	03	NH	NH	2369	22.397	17.447	22.397	17.447	0.000
620	WILDER	620	WILDER	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-50	TransCanada Power Marketing, Ltd.	TCPM	VT	27	VT	NH	2353	40.698	39.083	40.698	39.083	0.000
621	WILLIAMS	621	WILLIAMS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-39	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1510	14.900	14.900	14.900	14.900	0.000
622	WINOOSKI 1	622	WINOOSKI 1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-93	Burlington Electric Department	BED	VT	07	VT	VT	54355	2.614	1.363	2.614	1.363	-1.828
623	COVANTA PROJECTS WALLINGFORD	623	WALLINGFORD REFUSE	ST	MSW	DFO	BIO/REFUSE	01-Mar-89	Covanta Projects of Wallingford, L.P.	CPW	CT	09	SWCT	CT	50664	5.275	5.027	5.275	5.027	-1.542
624	WMI MILLBURY 1	624	WMI MILLBURY 1	ST	MSW		BIO/REFUSE	01-Sep-87	New England Power Company	NEP	MA	27	CMA/NEMA	WCMA	50878	39.891	39.811	39.891	39.811	0.000
625	WEST MEDWAY JET 1	625	WEST MEDWAY JET 1	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jul-70	Exelon Generation Company, LLC	EXGC	MA	21	BOSTON	NEMA	1592	62.915	42.000	62.915	42.000	0.000
626	WEST MEDWAY JET 2	626	WEST MEDWAY JET 2	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Mar-71	Exelon Generation Company, LLC	EXGC	MA	21	BOSTON	NEMA	1592	61.598	39.848	61.598	39.848	0.000
627	WEST MEDWAY JET 3	627	WEST MEDWAY JET 3	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jul-70	Exelon Generation Company, LLC	EXGC	MA	21	RI	SEMA	1592	62.401	42.001	62.401	42.001	6.580
628	WOODLAND ROAD	628	WOODLAND ROAD	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jul-69	Essential Power Massachusetts, LLC	NAEA-EM	MA	03	WMA	WCMA	1643	20.658	15.808	20.658	15.808	0.000
630	WEST SPRINGFIELD 10	630	WEST SPRINGFIELD 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-68	Essential Power Massachusetts, LLC	NAEA-EM	MA	13	WMA	WCMA	1642	21.928	17.143	21.928	17.143	0.000
633	WEST SPRINGFIELD 3	633	WEST SPRINGFIELD 3	ST	NG	RFO	GAS/OIL STEAM	01-Jan-57	Essential Power Massachusetts, LLC	NAEA-EM	MA	13	WMA	WCMA	1642	100.087	94.276	100.087	94.276	0.000
636	WYMAN HYDRO 1	636	WYMAN HYDRO 1	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-30	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1511	27.400	27.362	27.400	27.362	0.000
637	WYMAN HYDRO 2	637	WYMAN HYDRO 2	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-31	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1511	29.900	29.866	29.900	29.866	0.000
638	WYMAN HYDRO 3	638	WYMAN HYDRO 3	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-40	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1511	25.700	25.548	25.700	25.548	0.000
639	YARMOUTH 1	639	YARMOUTH 1	ST	RFO		OIL STEAM	01-Jan-57	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1507	50.065	0.000	50.065	0.000	0.000
640	YARMOUTH 2	640	YARMOUTH 2	ST	RFO		OIL STEAM	01-Jan-58	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1507	52.823	50.045	52.823	50.045	-0.760
641	YARMOUTH 3	641	YARMOUTH 3	ST	RFO		OIL STEAM	01-Jul-65	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1507	114.720	109.040	114.720	109.040	-1.830
642	YARMOUTH 4	642	YARMOUTH 4	ST	RFO		OIL STEAM	01-Dec-78	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1507	605.875	602.050	605.875	602.050	0.000
715	ROCHESTER LANDFILL	715	ROCHESTER LANDFILL	GT	LFG		BIO/REFUSE	01-May-98	New Hampshire Electric Cooperative, Inc.	NHEC	NH	17	NH	NH	2007	2.257	2.192	2.257	2.192	0.048
737	SIMPSON G LOAD REDUCER	737	SIMPSON G LOAD REDUCER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Green Mountain Power Corporation	GMP	VT	09	NH	VT	10608	2.656	2.388	2.656	2.388	-0.620
739	ROCKY RIVER	739	ROCKY RIVER	PS	WAT		HYDRO (PUMPED STORAGE)	01-Jan-28	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	09	SWCT	CT	539	28.127	28.853	28.127	28.853	0.000
754	BAR MILLS	754	BAR MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-56	Brookfield White Pine Hydro LLC	FPLEMH	ME	31	SME	ME	1481	1.586	0.000	1.586	0.000	-2.067
755	BONNY EAGLE/W. BUXTON	755	BONNY EAGLE W. BUXTON	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-10	Brookfield White Pine Hydro LLC	FPLEMH	ME	31	SME	ME	1482, 1508	17.500	16.151	17.500	16.151	0.000
757	HARRIS 4	757	HARRIS 4	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-54	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1492	1.249	1.436	1.249	1.436	0.000
759	MESSALONSKEE COMPOSITE	759	MESSALONSKEE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-17	Messalonskee Stream Hydro, LLC	MESSA	ME	11	ME	ME	1497	4.016	3.948	4.016	3.948	-0.099
760	NORTH GORHAM	760	NORTH GORHAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-25	Brookfield White Pine Hydro LLC	FPLEMH	ME	05	SME	ME	1501	1.121	1.475	1.121	1.475	-0.283
761	SHAWMUT	761	SHAWMUT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-13	Brookfield White Pine Hydro LLC	FPLEMH	ME	11	ME	ME	1504	6.066	7.239	6.066	7.239	0.738
767	SES CONCORD	767	SES CONCORD	ST	MSW		BIO/REFUSE	01-May-89	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	50873	12.397	12.096	12.397	12.096	-0.020
768	GARVINS/HOOKSETT	768	GARVINS HOOKSETT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-02	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2357, 2358	5.844	3.853	5.844	3.853	-3.423
769	HADLEY FALLS 1&2	769	HADLEY FALLS 1&2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-83	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	1605	23.436	20.229	23.436	20.229	2.509
772	NEWPORT HYDRO	772	NEWPORT HYDRO	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-80	Great Bay Power Marketing, Inc	GBPM	VT	19	NH	VT	3731	1.722	1.215	1.722	1.215	-0.912
774	LOWER LAMOILLE COMPOSITE	774	LOWER LAMOILLE COMPOSITE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-48	Green Mountain Power Corporation	GMP	VT	07	VT	VT	3711	16.000	10.106	16.000	10.106	-5.694
775	MIDDLEBURY COMPOSITE	775	MIDDLEBURY COMPOSITE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-17	Green Mountain Power Corporation	GMP	VT	01	VT	VT	3716	5.724	5.678	5.724	5.678	0.078
776	N. RUTLAND COMPOSITE	776	N. RUTLAND COMPOSITE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-80	Green Mountain Power Corporation	GMP	VT	21	VT	VT	3714	4.155	4.503	4.155	4.503	0.000
779	MIDDLESEX 2	779	MIDDLESEX 2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-28	Green Mountain Power Corporation	GMP	VT	23	VT	VT	3740	1.504	0.000	1.504	0.000	-1.368
781	WEST DANVILLE 1	781	WEST DANVILLE 1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-86	Green Mountain Power Corporation	GMP	VT	05	VT	VT	3743	0.000	0.000	0.000	0.000	0.000
783	HIGHGATE FALLS	783	HIGHGATE FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	VT	11	VT	VT	6618	7.895	1.663	7.895	1.663	-2.653
789	CEC 002 PAWTUCKET U5	789	CEC 002 PAWTUCKET U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-85	The Narragansett Electric Company	NEC	RI	07	RI	SEMA	3233	0.556	0.000	0.556	0.000	-0.219
792	CENTENNIAL HYDRO	792	CENTENNIAL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-90	Sterling Municipal Electric Light Department	SMED	MA	17	CMA/NEMA	WCMA	7112	0.554	0.108	0.554	0.108	-0.181
793	METHUEN HYDRO	793	METHUEN HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Aug-88	Sterling Municipal Electric Light Department	SMED	MA	09	BOSTON	NEMA		0.118	0.000	0.118	0.000	0.000
794	MINWAWA	794	MINWAWA	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-92	Littleton Electric Light & Water Department	LELWD	NH	05	VT	NH		0.605	0.190	0.605	0.190	-0.007
795	RIVER MILL HYDRO	795	RIVER MILL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-89	Middleton Municipal Light Department	MMELD	NH	09	VT	NH	3049	0.000	0.000	0.000	0.000	0.000
796	GOODWIN DAM	796	GOODWIN DAM	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Feb-86	Connecticut Light and Power Company, The	CLP	CT	05	CT	CT	54302	3.000	3.000	3.000	3.000	0.000
797	WYRE WYND HYDRO	797	CEC 003 WYRE WYND U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-97	Summit Hydropower, Inc.	SUMMIT	CT	11	CT	CT		0.000	0.079	0.000	0.079	-0.853
798	COLEBROOK	798	COLEBROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-88	Connecticut Light and Power Company, The	CLP	CT	05	CT	CT	54301	0.388	0.948	0.388	0.948	0.190
800	KINNEYTOWN B	800	KINNEYTOWN B	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-86	Connecticut Light and Power Company, The	CLP	CT	09	SWCT	CT	54385	0.523	0.000	0.523	0.000	0.000
801	WILLIMANTIC 1	801	WILLIMANTIC 1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-90	Connecticut Light and Power Company, The	CLP	CT	15	CT	CT		0.343	0.000	0.343	0.000	0.000
802	WILLIMANTIC 2	802	WILLIMANTIC 2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-90	Connecticut Light and Power Company, The	CLP	CT	15	CT	CT		0.191	0.000	0.191	0.000	0.000
803	TOUTANT	803	TOUTANT	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Feb-94	Connecticut Light and Power Company, The	CLP	CT	15	CT	CT		0.396	0.251	0.396	0.251	0.000
804	PUTNAM	804	PUTNAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-87	Putnam Hydropower, Inc.	PUTNAM	CT	15	CT	CT		0.384	0.000	0.384	0.000	-0.185
806	MECHANICSVILLE	806	MECHANICSVILLE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-95	Sterling Municipal Electric Light Department	SMED	CT	15	CT	CT		0.098	0.000	0.098	0.000	-0.033
807	CEC 004 DAYVILLE POND U5	807	CEC 004 DAYVILLE POND U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-95	Connecticut Light and Power Company, The	CLP	CT	15	CT	CT		0.049	0.000	0.049	0.000	0.000
808	SANDY HOOK HYDRO	808	SANDY HOOK HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-89	Connecticut Light and Power Company, The	CLP	CT	05	SWCT	CT		0.070	0.000	0.070	0.000	0.000
809	PINCHBECK	809	PINCHBECK	ST	WDS		BIO/REFUSE	01-Jul-87	Connecticut Light and Power Company, The	CLP	CT	13	CT	CT		0.000	0.000	0.000	0.000	0.000
810	QUINEBAUG	810	QUINEBAUG	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-90	Connecticut Light and Power Company, The	CLP	CT	15	CT	CT	543	0.892	0.040	0.892	0.040	-0.290
811	BANTAM	811	BANTAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-05	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	05	CT	CT	6457	0.085	0.000	0.085	0.000	-0.068
812	BEEBE HOLBROOK	812	BEEBE HOLBROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-48	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	1602	0.000	0.000	0.000	0.000	-0.170
813	TUNNEL	813	TUNNEL	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-19	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	11	CT	CT	557	1.048	0.000	1.048	0.000	-0.746
814	PATCH	814	PATCH	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	21	VT	VT	3719	0.087	0.031	0.087	0.031	0.031
815	CARVER FALLS	815	CARVER FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	25-Sep-98	Green Mountain Power Corporation	GMP	VT	21	VT	VT	6456	0.770	0.000	0.770	0.000	-0.083
816	CAVENDISH	816	CAVENDISH	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	25-Sep-98	Green Mountain Power Corporation	GMP	VT	27	VT	VT	3710	0.457	0.337	0.457	0.337	-0.029
817	TAFTSVILLE VT	817	TAFTSVILLE VT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	27	VT	VT	3727	0.000	0.000	0.000	0.000	0.000
818	PIERCE MILLS	818	PIERCE MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	05	NH	VT	3721	0.135	0.056	0.135	0.056	0.180
819	ARNOLD FALLS	819	ARNOLD FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	25-Sep-98	Green Mountain Power Corporation	GMP	VT	05	NH	VT	3707	0.123	0.000	0.123	0.000	-0.320
820	PASSUMPSIC	820	PASSUMPSIC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	05	NH	VT	3718	0.232	0.077	0.232	0.077	-0.170
821	GAGE	821	GAGE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	05	NH	VT	3713	0.252	0.000	0.252	0.000	-0.401
822	SMITH (CVPS)	822	SMITH (CVPS)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	17	VT	VT	3709	0.460	0.264	0.460	0.264	-0.643
823	EAST BARNET	823	EAST BARNET	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	05	NH	VT	788	0.907	0.399	0.907	0.399	-0.195
824	BATH ELECTRIC HYDRO	824	BATH ELECTRIC HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-85	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.154	0.270	0.154	0.270	-0.036
827	SEARSBURG WIND	827	SEARSBURG WIND	WT	WND		WIND TURBINE	01-Jul-97	Green Mountain Power Corporation	GMP	VT	03	WMA	WCMA	7381	1.123	0.113	1.123	0.113	-0.222
828	BARTON HYDRO	828	BARTON HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-31	Vermont Public Power Supply Authority	VPPSA	VT	19	NH	VT	3753	0.384	0.073	0.384	0.073	-0.371
830	ENOSBURG HYDRO	830	ENOSBURG HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	VT	11	VT	VT	3757	0.315	0.457	0.315	0.457	-0.078
831	VAIL & GREAT FALLS	831	VAIL & GREAT FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	VT	05	NH	VT	3726	0.992	0.196	0.992	0.196	0.067
832	CENTER RUTLAND	832	CENTER RUTLAND	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Aug-01	Green Mountain Power Corporation	GMP	VT	21	VT	VT	6453	0.000	0.096	0.000	0.096	0.096
833	BARNET	833	BARNET	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-01	Green Mountain Power Corporation	GMP	VT	05	VT	VT		0.139	0.000	0.139	0.000	-0.167
834	COMTU FALLS	834	COMPTU FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-82	Green Mountain Power Corporation	GMP	VT	27	VT	VT		0.251	0.214	0.251	0.214	-0.002
835	DEWEY MIL

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Contains Proprietary Material
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ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PAINT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
875	RIVER BEND	875	RIVER BEND	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-86	Massachusetts Municipal Wholesale Electric Company	MMWEC	NH	13	NH	NH		1.218	0.705	1.218	0.705	-0.712
876	ROBERTSVILLE	876	ROBERTSVILLE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-24	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	03	CT	CT	549	0.065	0.000	0.065	0.000	0.000
877	SCOTLAND	877	SCOTLAND	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-37	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	15	CT	CT	551	1.340	0.000	1.340	0.000	0.000
878	SKINNER	878	SKINNER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-24	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	1608	0.000	0.000	0.000	0.000	-0.248
879	TAFTVILLE CT	879	TAFTVILLE CT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-06	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	11	CT	CT	554	0.993	0.000	0.993	0.000	0.000
882	FRANKLIN FALLS	882	FRANKLIN FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-78	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	10109	0.436	0.444	0.436	0.444	-0.198
883	SALMON FALLS HYDRO		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-83	CHI Power Marketing, Inc.	CHIPM	NH	17	SME	ME	50702	0.392	0.000	0.392	0.000	-0.145
884	SWANS FALLS	884	SWANS FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-98	Public Service Company of New Hampshire	PSNH	ME	17	NH	NH	1518	0.280	0.259	0.280	0.259	-0.184
886	COCHECO FALLS	886	COCHECO FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-83	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.223	0.175	0.223	0.175	0.175
887	CHINA MILLS DAM	887	CHINA MILLS DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-81	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	50103	0.344	0.000	0.344	0.000	-0.025
888	NEWFOUND HYDRO	888	NEWFOUND HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-83	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH	50324	0.687	0.237	0.687	0.237	-0.435
889	SUNAPEE HYDRO	889	SUNAPEE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-85	Public Service Company of New Hampshire	PSNH	NH	19	NH	NH		0.328	0.180	0.328	0.180	0.005
890	NASHUA HYDRO	890	NASHUA HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.492	0.287	0.492	0.287	0.287
891	HILLSBORO MILLS	891	HILLSBORO MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-88	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	10036	0.136	0.000	0.136	0.000	0.000
892	LAKEPORT DAM	892	LAKEPORT DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-83	Power Supply Services, LLC	PSS	NH	01	NH	NH		0.136	0.212	0.136	0.212	-0.240
893	WEST HOPKINTON HYDRO	893	WEST HOPKINTON HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-82	CHI Power Marketing, Inc.	CHIPM	NH	13	NH	NH	54384	0.384	0.270	0.384	0.270	-0.139
894	LISBON HYDRO	894	LISBON HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-86	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.203	0.241	0.203	0.241	-0.109
895	LOWER ROBERTSON DAM	895	LOWER ROBERTSON DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-87	Massachusetts Municipal Wholesale Electric Company	MMWEC	NH	05	VT	NH		0.538	0.374	0.538	0.374	-0.130
897	OLD NASH DAM	897	OLD NASH DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	NH	05	VT	NH		0.081	0.041	0.081	0.041	0.007
898	SUGAR RIVER HYDRO	898	SUGAR RIVER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-86	Public Service Company of New Hampshire	PSNH	NH	19	NH	NH		0.119	0.058	0.119	0.058	0.058
900	GREAT FALLS 1 LOWER	900	GREAT FALLS 1 LOWER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-84	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH	50704	0.478	0.168	0.478	0.168	0.100
901	WATERLOOM FALLS	901	WATERLOOM FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-81	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.031	0.000	0.031	0.000	0.000
902	HOSIERY MILL DAM	902	HOSIERY MILL DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-84	Swift River Trading Company LLC	SRTC	NH	11	NH	NH		0.000	0.001	0.000	0.001	0.001
903	WYANDOTTE HYDRO	903	WYANDOTTE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-83	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.034	0.000	0.034	0.000	0.000
904	LOCHMERE DAM	904	LOCHMERE DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Massachusetts Municipal Wholesale Electric Company	MMWEC	NH	01	NH	NH	54572	0.482	0.231	0.482	0.231	-0.220
905	ASHUELOT HYDRO	905	ASHUELOT HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-87	Massachusetts Municipal Wholesale Electric Company	MMWEC	NH	05	VT	NH		0.452	0.392	0.452	0.392	-0.172
906	ROLLINSFORD HYDRO	906	ROLLINSFORD HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-80	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH	54418	0.734	0.178	0.734	0.178	-0.104
908	OTIS MILL HYDRO	908	OTIS MILL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-82	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	50080	0.007	0.000	0.007	0.000	0.000
909	STEELS POND HYDRO	909	STEELS POND HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.000	0.000	0.000	0.000	0.000
910	CAMPTON DAM	910	CAMPTON DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-85	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.091	0.106	0.091	0.106	-0.007
911	KELLEYS FALLS	911	KELLEYS FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-89	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.000	0.000	0.000	0.000	-0.105
913	GOODRICH FALLS	913	GOODRICH FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-81	Public Service Company of New Hampshire	PSNH	NH	03	NH	NH		0.237	0.189	0.237	0.189	-0.099
914	CHAMBERLAIN FALLS	914	CHAMBERLAIN FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-83	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.000	0.000	0.000	0.000	0.000
915	MONADNOCK PAPER MILLS	915	MONADNOCK PAPER MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-75	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.000	0.000	0.000	0.000	0.000
919	HOPKINTON HYDRO	919	HOPKINTON HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Sterling Municipal Electric Light Department	SMED	NH	13	NH	NH		0.151	0.119	0.151	0.119	-0.004
922	NOONE FALLS	922	NOONE FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-85	Public Service Company of New Hampshire	PSNH	NH	11	VT	NH		0.067	0.000	0.067	0.000	0.000
925	OTTER LANE HYDRO	925	OTTER LANE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-84	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH		0.033	0.015	0.033	0.015	-0.004
926	PETERBOROUGH LOWER HYDRO	926	PETERBOROUGH LOWER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-89	Public Service Company of New Hampshire	PSNH	NH	11	VT	NH		0.130	0.037	0.130	0.037	0.001
928	SALMON BROOK STATION 3	928	SALMON BROOK STATION 3	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-85	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH		0.000	0.000	0.000	0.000	-0.117
931	AVERY DAM	931	AVERY DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-85	Public Service Company of New Hampshire	PSNH	NH	01	NH	NH		0.163	0.175	0.163	0.175	-0.073
932	WATSON DAM	932	WATSON DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-85	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.122	0.066	0.122	0.066	-0.004
933	WESTON DAM	933	WESTON DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-87	Public Service Company of New Hampshire	PSNH	NH	07	NH	NH	1509	0.236	0.254	0.236	0.254	-0.060
935	SUNNYBROOK HYDRO 2	935	SUNNYBROOK HYDRO 2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-82	Public Service Company of New Hampshire	PSNH	NH	07	NH	NH		0.004	0.009	0.004	0.009	-0.007
941	PETERBOROUGH UPPER HYDRO	941	PETERBOROUGH UPPER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-90	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.147	0.000	0.147	0.000	-0.051
942	DUNBARTON ROAD LANDFILL	942	DUNBARTON ROAD LANDFILL	IC	LFG		BIO/REFUSE	01-Aug-89	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	55779	0.000	0.000	0.000	0.000	0.000
943	FOUR HILLS LANDFILL	943	FOUR HILLS LANDFILL	IC	LFG		BIO/REFUSE	01-Apr-96	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.723	0.694	0.723	0.694	-0.027
947	RIVERDALE MILLS - QF	947	RIVERDALE MILLS - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-85	Massachusetts Electric Company	MEC	MA	27	RI	SEMA	50601	0.000	0.000	0.000	0.000	0.000
948	PEPPERELL HYDRO COMPANY LLC	948	PEPPERELL HYDRO COMPANY LLC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-20	Swift River Trading Company LLC	SRTC	MA	17	CMA/NEMA	WCMA	10694	0.484	0.446	0.484	0.446	-0.275
949	VALLEY HYDRO - QF	949	VALLEY HYDRO - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-84	The Narragansett Electric Company	NEC	RI	03	RI	RI		0.106	0.000	0.106	0.000	-0.004
950	LP ATHOL - QF	950	LP ATHOL - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-31	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.049	0.055	0.049	0.055	-0.058
951	BALTIC MILLS - QF	951	BALTIC MILLS - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-81	Sterling Municipal Electric Light Department	SMED	NH	09	VT	NH		0.061	0.061	0.061	0.061	0.002
952	PONTIAC ENERGY - QF	952	PONTIAC ENERGY - QF	IC	OBG		BIO/REFUSE	01-Oct-98	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
953	ATTLEBORO LANDFILL - QF	953	ATTLEBORO LANDFILL - QF	IC	OBG		BIO/REFUSE	01-Nov-97	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.105	0.119	0.105	0.119	0.119
954	MM LOWELL LANDFILL - QF	954	MM LOWELL LANDFILL - QF	IC	LFG		BIO/REFUSE	01-Aug-97	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA	55095	0.099	0.077	0.099	0.077	-0.020
957	HG&E HYDRO/CABOT 1-4	957	HG&E HYDRO/CABOT 1-4	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	9864	0.607	0.922	0.607	0.922	-0.863
959	BARTON 1-4 DIESELS	959	BARTON 1-4 DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	01-Jul-56	Vermont Public Power Supply Authority	VPPSA	VT	19	NH	VT	3753	0.000	0.000	0.000	0.000	0.000
969	POWDER MILL HYDRO	969	POWDER MILL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-90	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
970	DUDLEY HYDRO	970	DUDLEY HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-87	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.106	0.000	0.106	0.000	-0.040
973	CONCORD STEAM		No Resource (1)	ST	WDS		BIO/REFUSE	01-Oct-86	Unitil Energy Systems, Inc.	UNITIL-ES	NH	13	NH	NH		0.208	0.000	0.208	0.000	0.000
978	NEW MILFORD	978	NEW MILFORD	IC	OBG	DFO	BIO/REFUSE	01-Aug-91	Connecticut Light and Power Company, The	CLP	CT	05	SWCT	CT	50564	1.282	1.177	1.282	1.177	-0.127
1005	BRIGHTON POWER LLC	1005	BRIGHTON POWER LLC	CC	NG		GAS COMBINED CYCLE	01-May-99	EquiPower Resources Management, LLC	EPRM	MA	05	SEMA	SEMA	55026	185.000	160.539	185.000	160.539	0.000
1028	BUNKER RD #12 GAS TURB	1028	BUNKER RD #12 GAS TURB	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Apr-00	New England Power Company	NEP	MA	19	SEMA	SEMA	1615	3.012	2.351	3.012	2.351	0.000
1029	BUNKER RD #13 GAS TURB	1029	BUNKER RD #13 GAS TURB	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Apr-00	New England Power Company	NEP	MA	19	SEMA	SEMA	1615	3.281	2.806	3.281	2.806	0.000
1030	OAK BLUFFS	1030	OAK BLUFFS	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-70	Genon Energy Management, LLC	MET	MA	07	SEMA	SEMA	1597	8.120	7.471	8.120	7.471	0.000
1031	WEST TISBURY	1031	WEST TISBURY	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-75	Genon Energy Management, LLC	MET	MA	07	SEMA	SEMA	6049	5.142	5.005	5.142	5.005	0.000
1032	BRIDGEPORT ENERGY 1	1032	BRIDGEPORT ENERGY 1	CC	NG		GAS COMBINED CYCLE	01-Aug-98	Emera Energy Services Subsidiary No. 5 LLC	EES5	CT	01	SWCT	CT	55042	519.937	487.000	519.937	487.000	35.736
1034	RIVERSIDE 4-7	1034	RIVERSIDE 4-7	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-21	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	1607	1.477	1.139	1.477	1.139	-0.826
1035	RIVERSIDE 8	1035	RIVERSIDE 8	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-31	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	1607	3.190	3.083	3.190	3.083	-0.211
1047	FAIRFAX	1047	FAIRFAX	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	25-Sep-98	Green Mountain Power Corporation	GMP	VT	11	VT	VT	3712	3.775	1.122	3.775	1.122	-2.629
1048	WARE HYDRO	1048	WARE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-84	Pioneer Hydro Electric Co., Inc.	PHE	MA	15	WMA	WCMA	50419	0.450	0.000	0.450	0.000	-0.273
1049	COLLINS HYDRO	1049	COLLINS HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-82	Swift River Trading Company LLC	SRTC	MA	13	WMA	WCMA	52166	0.660	0.234	0.660	0.234	-0.258
1050	CHICOPEE HYDRO	1050	CHICOPEE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-85	Chicopee Municipal Lighting Plant	CMLP	MA	13	WMA	WCMA	50832	0.989	0.411	0.989	0.411	-0.410
1054	BLACKSTONE HYDRO ASSOC	1054	BLACKSTONE HYDRO ASSOC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-89	The Narragansett Electric Company	NEC	RI	07	RI	RI	3245	0.000	0.000	0.000	0.000	0.000
1057	BLACKSTONE HYDRO LOAD REDUCER	1057	BLACKSTONE HYDRO LOAD REDUCER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-89	Blackstone Hydro, Inc.	BHI	RI	07	RI	RI	50177	0.494	0.104	0.494	0.104	-0.198
1059	BARRE LANDFILL	1059	BARRE LANDFILL	IC	LFG		BIO/REFUSE	01-Jul-96	Dominion Energy Marketing, Inc.	DEM	MA	27	WMA	WCMA	55776	0.592	0.658	0.592	0.658	0.230
1061	MASCOMA HYDRO	1061	MASCOMA HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-89	TransCanada Power Marketing, Ltd.	TCPM	NH	09	VT	NH	54471	0.558	0.000	0.558	0.000	0.380
1062	MWRA COSGROVE	1062	MWRA COSGROVE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Oct-95	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA	10825	0.148	0.834	0.148	0.834	-0.064
1086	BERKSHIRE POWER	1086	BERKSHIRE POWER	CC	NG		GAS COMBINED CYCLE	19-Jun-00	Direct Energy Business Marketing, LLC	DEBM	MA	13	WMA	WCMA	55041	246.279	229.279	246.279	229.279	0.000
1107	SOMERSET	1107	SOMERSET	ST	BLQ	WDS	BIO/REFUSE	01-Jan-76	NextEra Energy Power Marketing, LLC	FPLP	ME	11	ME	ME	50406	0.000	0.000	0.000	0.000	0.000
1109	MMWAC	1109	MMWAC	ST	MSW		BIO/REFUSE	01-Jun-92	Mid-Maine Waste Action Corporation	MMWAC	ME	01	ME	ME	50035	2.039	1.986	2.039	1.986	0.052
1113	BRASSUA HYDRO	1113	BRASSUA HYDRO	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Aug-89	Brookfield Energy Marketing, LP	BEMLP	ME	25	ME	ME	10955	1.071	2.696	1.071	2.696	0.002
1114	MADISON COMPOSITE	1114	MADISON COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-84	Competitive Energy Services, LLC	CESLLC	ME	25	ME	ME	7469	0.000	0.000	0.000	0.000	0.000
1117	GREAT WORKS COMPOSITE	1117	GREAT WORKS COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-84	Blackstone Hydro, Inc.	BHI	ME	31	SME	ME		0.111	0.009	0.111	0.009	-0.039
1119	KENNEBAGO HYDRO	1119	KENNEBAGO HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-88	Exelon Generation Company, LLC	EXGC	ME	29	ME	ME		0.252	0.285	0.252	0.285	0.081
1122	CASCADE-DIAMOND-QF	1122	CASCADE-DIAMOND-QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-19	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.216	0.038	0.216	0.038	-0.182
1165	CADYS FALLS	1165	CADYS FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	VT	15	VT	VT	3765	0.454	0.226	0.454	0.226	0.162
1166	MORRISVILLE PLANT #2	1166	MORRISVILLE PLANT #2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	VT	15	VT	VT	3764	0.579	0.135	0.579	0.135	-0.208
1167	WOLCOTT HYDRO #1	1167	WOLCOTT HYDRO #1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-37	Vermont Public Power Supply Authority	VPPSA	VT	15	VT	VT	6477	0.275	0.136	0.275	0.136	-0.266
1168	H.K. SANDERS	1168	H.K. SANDERS	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-83	Vermont Public Power Supply Authority	VPPSA	VT	15	VT	VT	678	1.715	1.800	1.715	1.800	0.000
1185	STONY BROOK GT1A	1185	STONY BROOK GT1A	CC	DFO	NG	GAS/OIL COMBINED CYCLE	01-Nov-81	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	13	WMA	WCMA	6081	119.000	103.858	119.000	103.858	-0.142
1186	STONY BROOK GT1B	1186	STONY BROOK GT1B	CC	DFO	NG	GAS/OIL COMBINED CYCLE	01-Nov-81	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	13	WMA	WCMA	6081	115.932	99.932	115.932	99.932	0.000
1187	STONY BROOK GT1C	1187	STONY BROOK GT1C	CC	DFO	NG	GAS/OIL COMBINED CYCLE	01-Nov-81	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	13	WMA	WCMA	6081	119.000	100.143	119.000	100.143	-3.857
1209	CRRA HARTFORD LANDFILL	1209	CRRA HARTFORD LANDFILL	IC	LFG		BIO/REFUSE	01-Aug-98	Connecticut Light and Power Company, The	CLP	CT	03	CT	CT	55163	1.285	1.212	1.285	1.212	-0.036
1210	MILLENNIUM	1210	MILLENNIUM	CC	NG		GAS COMBINED CYCLE	06-Apr-01	Consolidated Edison Energy, Inc	CEEI	MA	27	WMA	WCMA	55079	383.904	334.904	383.904	334.904	0.000
1221	ESSEX DIESELS	1221	ESSEX DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-47	Green Mountain Power Corporation	GMP	VT	07	VT	VT	3737	7.246	7.215	7.246	7.215	0.000
1225	TANNERY DAM	1225	TANNERY DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-00	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA	55924	0.000	0.000	0.000	0.000	0.000
1226	TIVERTON POWER	1226	TIVERTON POWER	CC	NG		GAS COMBINED CYCLE	18-Aug-00	Emera Energy Services Subsidiary No. 6 LLC	EES6	RI	05	SEMA	RI	55048	278.756	243.208	278.756	243.208	0.000
1255	RUMFORD POWER	1255	RUMFORD POWER	CC	NG		GAS COMBINED CYCLE	16-Oct-00	Emera Energy Services Subsidiary No. 7 LLC	EES7	ME	17	ME	ME	55100	269.091	244.281	269.091	244.281	0.000
1258	BHE SMALL HYDRO COMPOSITE	1258	BHE SMALL HYDRO COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-82	New Brunswick Energy Marketing Corporation	NBPGC	ME	21	BHE	ME		0.813	0.496	0.813	0.496	-0.473
1266	MARSH POWER	1266	MARSH POWER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-86	Christopher M. Anthony	CMA	ME	27	ME	ME	1469	0.000	0.000	0.000	0.000	0.000
1267	SPARHAWK	1267	SPARHAWK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-85	Union Atlantic Electricity	UNION	ME	05	SME	ME		0.013	0.000	0.013	0.000	0.003
1270	SYSKO STONY BROOK	1270	SYSKO STONY BROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Union Atlantic Electricity	UNION	ME	17	ME	ME		0.016	0.015	0.016	0.015	-0.002
1271	SYSKO WIGHT BROOK	1271	SYSKO WIGHT BROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-84	Union Atlantic Electricity	UNION	ME	17	ME	ME		0.021	0.000	0.021	0.000	0.000
1273	KENNEBEC WATER US	1273	KENNEBEC WATER US	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-95	Messalonskee Stream Hydro, LLC	MESSA	ME	11	ME	ME	54148	0.518	0.512	0.518	0.512	0.512
1286	ANP-BLACKSTONE ENERGY 1	1286	ANP-BLACKSTONE ENERGY CO. #1	CC	NG		GAS COMBINED CYCLE	07-Jun-01	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	27	RI	SEMA	55212	246.947	239.174	246.947	239.174	0.000
1287	ANP-BLACKSTONE ENERGY 2	1287	ANP-BLACKSTONE ENERGY 2	CC	NG		GAS COMBINED CYCLE	13-Jul-01	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	27	RI	SEMA	55212	249.338	234.134	249.338	234.134	0.000

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ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN.5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
2425	SPRINGFIELD REFUSE-NEW	2425	SPRINGFIELD REFUSE-NEW	ST	MSW	DFO	BIO/REFUSE	01-Sep-88	Covanta Energy Marketing, LLC	CEM	MA	13	WMA	WCMA	50273	5.700	6.124	5.700	6.124	0.201
2426	HYDRO KENNEBEC	2426	Hydro Kennebec	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-89	Brookfield Energy Marketing, LP	BEMLP	ME	11	ME	ME	54148	9.520	11.524	9.520	11.524	3.463
2430	BELDENS-NEW	2430	BELDENS-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Green Mountain Power Corporation	GMP	VT	01	VT	VT	6451	1.616	0.906	1.616	0.906	-1.440
2431	DODGE FALLS-NEW	2431	DODGE FALLS-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-90	Vermont Electric Power Company, Inc.	VELCO	NH	09	VT	VT	10526	3.371	3.629	3.371	3.629	-0.672
2432	HUNTINGTON FALLS-NEW	2432	HUNTINGTON FALLS-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-88	Green Mountain Power Corporation	GMP	VT	01	VT	VT	50713	2.008	1.728	2.008	1.728	-1.493
2433	RYEGATE 1-NEW	2433	RYEGATE 1-NEW	ST	WDS		BIO/REFUSE	01-Nov-92	Vermont Electric Power Company, Inc.	VELCO	VT	05	NH	VT	51026	19.920	19.560	19.920	19.560	-0.700
2434	GORGE 18 HYDRO-NEW	2434	GORGE 18 HYDRO-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-28	Green Mountain Power Corporation	GMP	VT	07	VT	VT	6475	1.542	0.000	1.542	0.000	-0.670
2435	VERGENNES HYDRO-NEW	2435	VERGENNES HYDRO-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-12	Green Mountain Power Corporation	GMP	VT	01	VT	VT	6519	1.476	0.923	1.476	0.923	-0.817
2439	BROCKWAY MILLS U5	2439	BROCKWAY MILLS U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-03	Green Mountain Power Corporation	GMP	VT	25	VT	VT		0.196	0.000	0.196	0.000	-0.139
2462	PLAINVILLE GEN GF U5	2462	PLAINVILLE GEN GF U5	IC	OBG		BIO/REFUSE	24-Mar-03	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		2.287	2.106	2.287	2.106	0.001
2466	CHERRY 7	2466	CHERRY 7	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	MA	17	CMA/NEMA	WCMA	9038	2.800	2.800	2.800	2.800	0.000
2467	CHERRY 8	2467	CHERRY 8	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	MA	17	CMA/NEMA	WCMA	9038	3.400	3.400	3.400	3.400	0.000
2468	CHERRY 10	2468	CHERRY 10	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	MA	17	CMA/NEMA	WCMA	9038	2.100	2.100	2.100	2.100	0.000
2469	CHERRY 11	2469	CHERRY 11	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	MA	17	CMA/NEMA	WCMA	9038	2.100	2.100	2.100	2.100	0.000
2470	CHERRY 12	2470	CHERRY 12	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	MA	17	CMA/NEMA	WCMA	9038	4.999	4.999	4.999	4.999	0.000
10308	NECCO COGENERATION FACILITY	10308	NECCO COGENERATION FACILITY	IC	NG		GAS INTERNAL COMBUSTION	01-Oct-03	New England Confectionery Company, Inc	NECCO	MA	25	BOSTON	NEMA	55999	4.939	0.017	4.939	0.017	-4.726
10347	KENDALL STEAM 1	37040	KENDALL STEAM	CC	NG		GAS COMBINED CYCLE	01-Jan-50	Kendall Green Energy, LLC	KENDALL	MA	17	BOSTON	NEMA	1595	14.752	14.505	14.752	14.505	0.000
10348	KENDALL STEAM 2	37040	KENDALL STEAM	CC	NG		GAS COMBINED CYCLE	01-Jan-50	Kendall Green Energy, LLC	KENDALL	MA	17	BOSTON	NEMA	1595	19.669	19.340	19.669	19.340	0.000
10349	KENDALL STEAM 3	37040	KENDALL STEAM	CC	NG		GAS COMBINED CYCLE	01-Jan-50	Kendall Green Energy, LLC	KENDALL	MA	17	BOSTON	NEMA	1595	20.141	19.805	20.141	19.805	0.000
10401	CELLEY MILL U5	10401	CELLEY MILL U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.064	0.031	0.064	0.031	-0.040
10402	PETTYBORO HYDRO U5	10402	PETTYBORO HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	09-May-99	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.000	0.000	0.000	0.000	0.000
10403	EASTMAN BROOK U5	10403	EASTMAN BROOK U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-85	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.030	0.008	0.030	0.008	-0.021
10404	WHEELABRATOR CLAREMONT U5	10404	WHEELABRATOR CLAREMONT U5	ST	MSW		BIO/REFUSE	01-Mar-04	Wheelabrator North Andover Inc	WNE	NH	19	NH	NH	50872	0.000	0.000	0.000	0.000	-3.648
10406	LOWER VALLEY HYDRO U5	10406	LOWER VALLEY HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-04	Green Mountain Power Corporation	GMP	NH	19	NH	NH		0.083	0.000	0.083	0.000	-0.177
10407	WOODSVILLE HYDRO U5	10407	WOODSVILLE HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-87	Green Mountain Power Corporation	GMP	NH	19	NH	NH		0.069	0.166	0.069	0.166	-0.071
10408	LOWER VILLAGE HYDRO U5	10408	LOWER VILLAGE HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-95	Green Mountain Power Corporation	GMP	NH	19	NH	NH	50285	0.000	0.000	0.000	0.000	0.000
10409	SWEETWATER HYDRO U5	10409	SWEETWATER HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-04	Green Mountain Power Corporation	GMP	NH	19	NH	NH		0.257	0.221	0.257	0.221	0.015
10424	GREAT Lakes - Berlin Incremental	10424	Great Lakes - Berlin Incremental	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	22-Jun-04	Brookfield Energy Marketing, LP	BEMLP	NH	07	NH	NH	54639	10.854	9.230	10.854	9.230	-0.364
10451	WESTFIELD #1 U5	10451	WESTFIELD #1 U5	IC	OBG		BIO/REFUSE	01-Mar-04	Westfield Gas and Electric Light Department	WGED	MA	13	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
10615	BLUE SPRUCE FARM	10615	BLUE SPRUCE FARM U5	IC	OBG		BIO/REFUSE	01-Nov-04	Green Mountain Power Corporation	GMP	VT	21	VT			0.296	0.305	0.296	0.305	0.018
10770	WEST SPRINGFIELD HYDRO U5	10770	WEST SPRINGFIELD HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	10-Jan-05	Littleton Electric Light & Water Department	LELWD	MA	13	WMA	WCMA		0.774	0.515	0.774	0.515	-0.074
10801	COVENTRY CLEAN ENERGY	10801	COVENTRY CLEAN ENERGY	IC	LFG		BIO/REFUSE	01-Feb-05	Vermont Public Power Supply Authority	VPPSA	VT	19	NH	VT		3.300	3.268	3.300	3.268	-0.152
10880	GE LYNN EXCESS REPLACEMENT	10880	GE LYNN EXCESS REPLACEMENT	GT	DFO	NG	GAS/OIL COMBUSTION (GAS) TURBINE	11-Oct-05	Constellation NewEnergy, Inc.	CNE	MA	25	BOSTON	NEMA	10029	0.000	0.000	0.000	0.000	0.000
10959	RRIG EXPANSION PHASE 2	10959	RRIG EXPANSION PHASE 2	IC	LFG		BIO/REFUSE	01-Jun-05	Rhode Island Engine Genco, LLC	RRIG	RI	07	RI	RI	50365	0.000	0.000	0.000	0.000	0.000
10998	MASSINNOVATION FITCHBURG	10998	MASSINNOVATION FITCHBURG	PV	SUN		PHOTOVOLTAIC	01-Aug-05	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
11052	GRTR NEW BEDFORD LFG UTIL PROJ	11052	GRTR NEW BEDFORD LFG UTIL PROJ	IC	LFG		BIO/REFUSE	15-Aug-05	Exelon Generation Company, LLC	EXGC	MA	05	SEMA	SEMA		2.458	2.449	2.458	2.449	0.021
11126	NORTH HARTLAND HYDRO	11126	NORTH HARTLAND HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	27-Sep-06	Green Mountain Power Corporation	GMP	VT	27	VT	VT		0.983	1.207	0.983	1.207	0.122
11408	HULL WIND TURBINE II	11408	HULL WIND TURBINE II	WT	WND		WIND TURBINE	27-Sep-05	Hull Municipal Lighting Plant	HULL	MA	23	SEMA	SEMA	56800	0.248	0.075	0.248	0.075	0.038
11424	RUMFORD FALLS	11424	RUMFORD FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	06-Jul-06	Brookfield Energy Marketing, LP	BEMLP	ME	17	ME	ME	10493	30.830	32.470	30.830	32.470	-1.690
11827	PORTSMOUTH ABBEY WIND QF		No Resource (1)	WT	WND		WIND TURBINE	25-Jul-06	The Narragansett Electric Company	NEC	RI	05	SEMA	RI		0.000	0.000	0.000	0.000	0.000
11842	WATERSIDE POWER	11842	WATERSIDE POWER	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-May-04	Waterside Power, LLC	WATERSIDE	CT	01	NOR	CT	56189	71.557	70.017	71.557	70.017	0.000
11889	BEW LOCAL 99 SOLAR QF		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-06	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
11925	BROCKTON BRIGHTFIELDS	11925	BROCKTON BRIGHTFIELDS	PV	SUN		PHOTOVOLTAIC	18-Sep-06	Exelon Generation Company, LLC	EXGC	MA	23	SEMA	SEMA		0.000	0.152	0.000	0.152	0.006
12108	FIEC DIESEL	12108	FIEC DIESEL	IC	DFO		OIL INTERNAL COMBUSTION	01-Dec-06	Vermont Public Power Supply Authority	VPPSA	ME	13	ME	ME		1.596	1.540	1.596	1.540	0.000
12163	PPL GREAT WORKS - RED SHIELD	12163	PPL GREAT WORKS - RED SHIELD	ST	WDS		BIO/REFUSE	24-Jan-07	Competitive Energy Services, LLC	CESLLC	ME	19	BHE	ME	10700	0.000	0.000	0.000	0.000	0.000
12168	HARRIS ENERGY	12168	HARRIS ENERGY	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-06	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	54981	0.000	0.000	0.000	0.000	0.000
12180	BERKSHIRE COW POWER	12180	BERKSHIRE COW POWER	IC	OBG		BIO/REFUSE	06-Dec-06	Vermont Electric Cooperative, Inc.	VEC	VT	11	VT	VT		0.262	0.207	0.262	0.207	-0.004
12274	GREEN MOUNTAIN DAIRY	12274	GREEN MOUNTAIN DAIRY	IC	OBG		BIO/REFUSE	01-Feb-07	Green Mountain Power Corporation	GMP	VT	11	VT	VT		0.220	0.218	0.220	0.218	-0.031
12323	COVENTRY CLEAN ENERGY #4	12323	COVENTRY CLEAN ENERGY #4	IC	LFG		BIO/REFUSE	20-Jan-07	Vermont Public Power Supply Authority	VPPSA	VT	19	NH	VT		2.200	2.179	2.200	2.179	-0.101
12504	DEVON 15	12504	Devon 15-18	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	12-Jul-10	GenConn Energy LLC	GCE	CT	09	SWCT	CT	57070	49.200	46.889	49.200	46.889	0.000
12505	MIDDLETOWN 12-15	12505	Middletown 12-15	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	24-Jun-11	GenConn Energy LLC	GCE	CT	07	CT	CT	57068	49.200	46.900	49.200	46.900	0.000
12509	UNH POWER PLANT	12509	UNH Power Plant	GT	LFG		BIO/REFUSE	20-Oct-09	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH	58180	4.378	3.008	4.378	3.008	0.000
12510	SWANTON GT-1	12510	Swanton Gas Turbine 1	GT	DFO	OBL	OIL COMBUSTION (GAS) TURBINE	12-Feb-10	Vermont Public Power Supply Authority	VPPSA	VT	11	VT	VT		23.954	19.304	23.954	19.304	0.000
12511	SWANTON GT-2	12511	Swanton Gas Turbine 2	GT	DFO	OBL	OIL COMBUSTION (GAS) TURBINE	24-May-10	Vermont Public Power Supply Authority	VPPSA	VT	11	VT	VT		23.839	19.349	23.839	19.349	0.000
12529	HOOSAC WIND		No Resource (1)	WT	WND		WIND TURBINE	27-Dec-12	Iberdrola Renewables, LLC	IR	MA	03	WMA	WCMA	57380	13.627	3.942	13.627	3.942	-1.332
12530	SHEFFIELD WIND PLANT	12530	Sheffield Wind Farm	WT	WND		WIND TURBINE	19-Oct-11	Vermont Wind LLC	VTWIND	VT	05	VT	VT	57080	9.685	3.295	9.685	3.296	0.995
12551	KIBBY WIND POWER	12551	Kibby Wind Power	WT	WND		WIND TURBINE	16-Sep-09	TransCanada Power Marketing, Ltd.	TCPM	ME	07	ME	ME	56829	35.060	18.275	35.060	18.275	0.480
12564	WATERBURY GENERATION FACILITY	12564	Waterbury Generation Facility	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	21-May-09	Waterbury Generation LLC	WATERBURY	CT	09	SWCT	CT	56629	98.128	95.821	98.128	95.821	1.088
13515	PIERCE STATION	12526	Pierce	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-07	Connecticut Municipal Electric Energy Cooperative	CMEEC	CT	09	SWCT	CT	6635	94.590	74.085	94.590	74.085	0.000
13669	EAST WINDSOR NORCAP LFG PLANT	13669	Manchester Methane LLC East Windsor Facility	IC	LFG		BIO/REFUSE	07-May-07	Manchester Methane, LLC	MMLLC	CT	03	CT	CT		0.698	0.783	0.698	0.783	0.000
13673	MATEP (DIESEL)	13673	MATEP (DIESEL)	IC	DFO		OIL INTERNAL COMBUSTION	28-Jun-07	MATEP, LLC	MATEP	MA	25	BOSTON	NEMA	10883	17.460	17.120	17.460	17.120	0.000
13675	MATEP (COMBINED CYCLE)	13675	MATEP (COMBINED CYCLE)	CC	NG	DFO	GAS/OIL COMBINED CYCLE	28-Jun-07	MATEP, LLC	MATEP	MA	25	BOSTON	NEMA	10883	48.275	42.515	48.275	42.515	0.000
13703	VERSO COGEN 1	13703	Verso VCG1	GT	NG	KER	GAS COMBUSTION (GAS) TURBINE	28-Dec-00	Verso Maine Energy LLC	VERSO	ME	07	ME	ME	55031	53.760	42.483	53.760	42.483	0.000
13704	VERSO COGEN 2	13704	Verso VCG2	GT	NG	KER	GAS COMBUSTION (GAS) TURBINE	28-Dec-00	Verso Maine Energy LLC	VERSO	ME	07	ME	ME	55031	56.333	44.314	56.333	44.314	0.000
13705	VERSO COGEN 3	13705	Verso VCG3	GT	NG	KER	GAS COMBUSTION (GAS) TURBINE	28-Dec-00	Verso Maine Energy LLC	VERSO	ME	07	ME	ME	55031	55.123	41.962	55.123	41.962	0.000
13933	UMINY PEAK WIND QF		No Resource (1)	WT	WND		WIND TURBINE	01-Jul-07	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.020	0.000	0.020	0.000	0.000
13975	CORRIVEAU HYDROELECTRIC LLC	13975	Corriveau Hydroelectric LLC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	10-Aug-07	Union Atlantic Electricity	UNION	ME	17	ME	ME		0.053	0.063	0.053	0.063	-0.040
14087	MAT3	14087	MAT3	IC	DFO		OIL INTERNAL COMBUSTION	11-Dec-07	MATEP, LLC	MATEP	MA	25	BOSTON	NEMA	10883	18.630	17.970	18.630	17.970	0.000
14098	FITCHBURG LANDFILL	35485	Fitchburg-FCA-5	IC	LFG		BIO/REFUSE	16-Aug-07	Vermont Public Power Supply Authority	VPPSA	MA	27	WMA	WCMA	56527	3.316	3.093	3.316	3.093	-1.093
14134	MONTAGNE FARM	14134	MONTAGNE FARM	IC	LFG		BIO/REFUSE	17-Sep-07	Green Mountain Power Corporation	GMP	VT	11	VT	VT		0.000	0.000	0.000	0.000	-0.080
14152	COS COB 13	12524	Cos Cob 13&14	GT	KER		OIL COMBUSTION (GAS) TURBINE	29-May-08	NRG Power Marketing LLC	NRGPM	CT	01	NOR	CT	542	22.852	19.053	22.852	19.053	0.000
14158	COS COB 14	12524	Cos Cob 13&14	GT	KER		OIL COMBUSTION (GAS) TURBINE	29-May-08	NRG Power Marketing LLC	NRGPM	CT	01	NOR	CT	542	22.602	19.209	22.602	19.209	0.000
14177	WESTBROOK ENERGY CENTER G1	1345	WESTBROOK	CC	NG		GAS COMBINED CYCLE	13-Apr-01	Calpine Energy Services, LP	CALP	ME	05	SME	ME	55294	281.835	261.204	281.835	261.204	0.268
14178	WESTBROOK ENERGY CENTER G2	1345	WESTBROOK	CC	NG		GAS COMBINED CYCLE	13-Apr-01	Calpine Energy Services, LP	CALP	ME	05	SME	ME	55294	285.063	261.204	285.063	261.204	6.824
14211	INDECK ALEXANDRIA	1631	Indeck-Energy Alexandria, LLC	ST	WDS		BIO/REFUSE	06-Nov-08	Indeck-Energy-Alexandria, L.L.C.	IEA	NH	09	NH	NH		15.200	15.031	15.200	15.031	0.000
14217	NORTHFIELD MOUNTAIN 1	14217	NORTHFIELD MOUNTAIN 1	PS	WAT		HYDRO (PUMPED STORAGE)	30-Nov-72	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	547	270.000	270.000	270.000	270.000	0.000
14218	NORTHFIELD MOUNTAIN 2	14218	NORTHFIELD MOUNTAIN 2	PS	WAT		HYDRO (PUMPED STORAGE)	30-Nov-72	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	547	293.500	293.500	293.500	293.500	0.000
14219	NORTHFIELD MOUNTAIN 3	14219	NORTHFIELD MOUNTAIN 3	PS	WAT		HYDRO (PUMPED STORAGE)	30-Nov-72	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	547	292.000	292.000	292.000	292.000	0.000
14220	NORTHFIELD MOUNTAIN 4	14220	NORTHFIELD MOUNTAIN 4	PS	WAT		HYDRO (PUMPED STORAGE)	30-Nov-72	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	547	274.638	293.500	274.638	293.500	0.000
14271	AMERESCO NORTHAMPTON	14271	Ameresco Northampton	IC	LFG		BIO/REFUSE	01-Nov-07	Exelon Generation Company, LLC	EXGC	MA	15	WMA	WCMA		0.752	0.748	0.752	0.748	0.000
14595	GRANITE RELIABLE POWER, LLC	14595	Granite Reliable Power	WT	WND		WIND TURBINE	15-Feb-12	Granite Reliable Power, LLC	GRP	NH	07	NH	NH	58004	26.748	14.034	26.748	14.034	0.102
14610	PRINCETON WIND FARM PROJECT	14610	Princeton Wind Farm Project	WT	WND		WIND TURBINE	01-Sep-09	Princeton Municipal Light Department	PMLD	MA	27	WMA	WCMA	7501	0.297	0.154	0.297	0.154	0.124
14614	KLEEN ENERGY	14614	Kleen Energy	CC	NG	DFO	GAS/OIL COMBINED CYCLE	12-Jul-11	Exelon Generation Company, LLC	EXGC	CT	07	CT	CT	56798	620.000	620.000	620.000	620.000	0.000
14623	VALLEY HYDRO (STATION NO. 5)	14623	Valley Hydro (Station No. 5)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-08	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA		0.604	0.000	0.604	0.000	-0.552
14652	TEMPLETON WIND TURBINE	14652	Templeton Wind Turbine	WT	WND		WIND TURBINE	18-May-11	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	27	WMA	WCMA		0.157	0.058	0.157	0.058	-0.041
14665	RECORD HILL WIND	14665	Record Hill Wind	WT	WND		WIND TURBINE	31-Jan-12	Record Hill Wind, LLC	RHW	ME	17	ME	ME	57568	12.305	5.168	12.305	5.168	-1.780
14695	ORONO	14695	Orono Hydro Station	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	29-Dec-08	Black Bear Hydro Partners, LLC	BBHP	ME	19	BHE	ME	57184	1.681	1.790	1.681	1.790	1.790
14707	COVANTA HAVERHILL - LF GAS	12553	Covanta Haverhill Landfill Gas Engine	IC	LFG		BIO/REFUSE	05-Dec-07	Covanta Haverhill Associates	CHA	MA	09	BOSTON	NEMA	50661	1.091	1.089	1.091	1.089	-0.099
14767	PINE TREE LFGTE		No Resource (1)	IC	LFG		BIO/REFUSE	01-Jan-08	NextEra Energy Power Marketing, LLC	FPLP	ME	19	BHE	ME		0.000	0.000	0.000	0.000	0.000
14801	CABOT	766	CABOT TURNERS FALLS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-05	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	1629	61.800	61.481	61.800	61.481	0.000
14808	TURNERSFALLS	766	CABOT TURNERS FALLS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-05	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	6388	6.400	6.400	6.400	6.400	0.000
14816	NORDEN 1	16688	Nor1	IC	DFO		OIL INTERNAL COMBUSTION	26-Feb-09	Connecticut Municipal Electric Energy Cooperative	CMEEC	CT	01	NOR	CT	57689	1.958	1.789	1.958	1.789	0.000
14817	NORDEN 2	16750	Norden #2	IC	DFO		OIL INTERNAL COMBUSTION	26-Feb-09	Connecticut Municipal Electric Energy Cooperative	CMEEC	CT	01	NOR	CT	57689	1.947	1.789	1.947	1.789	-0.159
14818	NORDEN 3	16752	Norden #3	IC	DFO		OIL INTERNAL COMBUSTION	26-Feb-09	Connecticut Municipal Electric Energy Cooperative	CMEEC	CT	01	NOR	CT	57689	1.942	1.775	1.942	1.775	-0.167
14823	NORWICH WWTP		No Resource (1)	IC	DFO		OIL INTERNAL COMBUSTION	29-May-08	Connecticut Municipal Electric Energy Cooperative	CMEEC	CT	11	CT	CT	57624	2.000	2.000	2.000	2.000	0.000
14919	DBE-001		No Resource (1)	GT	WDS	DFO	BIO/REFUSE	01-Mar-08	Public Service Company of New Hampshire	PSNH	NH	05	VT	NH		0.000	0.000	0.000	0.000	0.000
14925	ICE HOUSE PARTNERS INC.		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-08	Littleton Electric Light & Water Department	LELWD	MA	17	CMA/NEMA	WCMA		0.093	0.101	0.093	0.101	0.008
14937	UNION GAS STATION	759	MESSALONSKEE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	19-Mar-08	Messalonskee Stream Hydro, LLC	MESSA	ME	11	ME	ME		1.303	1.218	1.303	1.218	-0.113
15097	KIMB ROCKY RIVER PH2	14706	Kimberly-Clark Corp Energy Independence Project	CC	NG		GAS COMBINED CYCLE	15-Jul-08	Kimberly-Clark Corporation	KCC	CT	05	SWCT	CT	58084	14.451	13.853	14.451	13.853	0.837
15115	LEMPSTER WIND	14660	Lempster Wind	WT	WND		WIND TURBINE	24-Sep-08	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	56399	8.224	2.430	8.224	2.430	-0.815
15201	FSKE HYDRO	35593	Fiske Hydro	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-08	Public Service Company of New Hampshire	PSNH	NH	05	VT	NH		0.000	0.000	0.000	0.000	-1.399
15462	HOLY NAME CC JR SR HGH SCHOOL		No Resource (1)	WT	WND		WIND TURBINE	01-Sep-08	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
15464	STETSON WIND FARM		No Resource (1)	WT	WND		WIND TURBINE	09-Dec-08	Stetson Holdings, LLC	STETSON	ME	29	BHE	ME	56989	15.189	6.490	15.189	6.490	-1.103
15477	NEW HAVEN HARBOR UNIT 2	15477	New Haven Harbor Units 2, 3, & 4	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	30-May-12	PSEG New Haven, LLC	PSEG-NH	CT	09	CT	CT	6156	48.600	43.200	48.600	43.200	0.000
15484	THOMAS A. WATSON UNIT #1	12500	Thomas A. Watson	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	22-Apr-09	Braintree Electric Light Department, Town of	BELD	MA	21	SEMA	SEMA	1660	57.400	52.600	57.400	52.600	0.000
15485	THOMAS A. WATSON UNIT #2	12500	Thomas A. Watson	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	14-Apr-09	Braintree Electric Light Department, Town of	BELD	MA	21	SEMA	SEMA	1660	57.400	52.600	57.400	52.600	0.000
15488	MIDDLETON BUILDING SUPPLY		No Resource (1)	ST	WDS		BIO/REFUSE	01-Oct-08	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.000	0.000	0.000	0.000	0.000
15509	PLAINFIELD RENEWABLE ENERGY	15509	Plainfield Renewable Energy	ST	WDS	OBS	BIO/REFUSE	12-Dec-13	Plainfield Renewable Energy, LLC	PRE	CT	15	CT	CT	56847	36.464	35.534	36.464	35.534	0.333
15617	MORETOWN LFGTE	35728	Moretown LG	IC	LFG		BIO/REFUSE	01-Dec-08	Green Mountain

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ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PAINT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
17233	RAINBOW UNIT 1	35658	Rainbow_1	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-80	Connecticut Light and Power Company, The	CLP	CT	03	CT	CT	559	4.100	4.100	4.100	4.100	0.000
17234	RAINBOW UNIT 2	35658	Rainbow_2	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-80	Connecticut Light and Power Company, The	CLP	CT	03	CT	CT	559	4.100	4.100	4.100	4.100	0.000
17259	SEAMAN ENERGY LLC	35442	Seaman Energy	IC	LFG		BIO/REFUSE	31-Mar-10	Templeton Municipal Lighting Plant	TTMLP	MA	27	CMA/NEMA	WCMA		0.249	0.170	0.249	0.170	-0.146
35379	SPAULDING POND HYDRO	35594	Spaulding Pond Hydro	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-10	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.201	0.035	0.201	0.035	-0.028
35555	GMCW	35555	GMCW	WT	WND		WIND TURBINE	31-Dec-12	Burlington Electric Department	BED	VT	07	VT	VT	58238	3.289	0.888	3.289	0.888	0.038
35693	SPRUCE MOUNTAIN WIND	35693	Spruce Mountain Wind	WT	WND		WIND TURBINE	21-Dec-11	Spruce Mountain Wind, LLC	SPRUCE	ME	17	ME	ME	58026	6.873	2.410	6.873	2.410	0.077
35979	KINGDOM COMMUNITY WIND	35979	Kingdom Community Wind	WT	WND		WIND TURBINE	16-Nov-12	Green Mountain Power Corporation	GMP	VT	19	VT	VT	57979	21.720	8.400	21.720	8.400	-1.360
36882	NOTUS WIND I		No Resource (1)	WT	WND		WIND TURBINE	23-Jun-10	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA	57414	0.483	0.280	0.483	0.280	-0.092
37050	GROTON WIND	37050	Groton Wind Project	WT	WND		WIND TURBINE	28-Dec-12	Iberdrola Renewables, LLC	IR	NH	09	NH	NH	58141	8.244	5.019	8.244	5.019	-1.395
37073	SOUTHBRIDGE LANDFILL	38178	Southbridge Landfill Gas to Energy 17-18	IC	LFG		BIO/REFUSE	15-Feb-12	NextEra Energy Power Marketing, LLC	FPLP	MA	27	CMA/NEMA	WCMA	59011	1.506	1.402	1.506	1.402	0.095
37175	ROLLINS WIND PLANT		No Resource (1)	WT	WND		WIND TURBINE	26-Jul-11	Evergreen Wind (II, LLC	EWP3	ME	19	BHE	ME	56990	14.915	6.391	14.915	6.391	-1.383
37224	PATRIOT PL_D FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.038	0.000	0.038	0.002
37225	PATRIOT PL_E FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.000	0.000	0.000	0.000
37226	PATRIOT PL_F FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.042	0.000	0.042	0.003
37227	PATRIOT PL_H FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.023	0.000	0.023	0.003
37228	PATRIOT PL_J FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.038	0.000	0.038	0.005
37229	PATRIOT PL_K FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.033	0.000	0.033	0.001
37230	UNITED NAT. FOODS PROV. RI PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.003	0.000	0.003	0.003
37266	CARLSON ORCH HARVARD MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Nov-10	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.065	0.000	0.065	-0.023
37267	SPRUCE ENV HAVERHILL MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Nov-10	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
37366	MIDDLETOWN 13	12505	Middletown 12-15	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	23-Jun-11	GenConn Energy LLC	GCE	CT	07	CT	CT	57068	49.200	46.900	49.200	46.900	0.000
37367	MIDDLETOWN 14	12505	Middletown 12-15	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	01-Jun-11	GenConn Energy LLC	GCE	CT	07	CT	CT	57068	49.200	46.900	49.200	46.900	0.000
37368	MIDDLETOWN 15	12505	Middletown 12-15	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	01-Jun-11	GenConn Energy LLC	GCE	CT	07	CT	CT	57068	49.200	46.900	49.200	46.900	0.000
37721	ROYAL MILLS WARWICK RI HYDRO		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-10	The Narragansett Electric Company	NEC	RI	03	RI	RI		0.000	0.000	0.000	0.000	0.000
37722	SILVER LAKE SOLAR PV FACILITY	37051	Silver lake PV	PV	SUN		PHOTOVOLTAIC	06-Dec-10	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA	57676	0.000	0.696	0.000	0.696	0.014
37751	NM-UNISTRESS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37752	NM-COUNTRY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37753	NM-HANCOCK		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.017	0.000	0.017	0.010
37754	NM-QUALITY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37755	NM-WOOD		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.014	0.000	0.014	0.002
37756	NM-FOURSTAR		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.020	0.000	0.020	-0.001
37757	NM-ASTRO		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	13	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37758	NM-MARLEY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	15	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37759	NM-STONE		No Resource (1)	WT	WND		WIND TURBINE	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.022	0.000	0.022	0.000	0.000
37760	NM-RIVERVIEW		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.006	0.000	0.006	0.006
37761	NM-PETRICCA		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37823	INDIAN RIVER POWER SUPPLY LLC	37079	Indian River Power Supply LLC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-11	Swift River Trading Company LLC	SRTC	MA	13	WMA	WCMA		0.309	0.280	0.309	0.280	0.096
37955	TRANS MED TYNGSBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.028	0.000	0.028	0.003
37956	PH HENBIL BILLERICA MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.010	0.000	0.010	0.002
37957	CHELM WTR N CHELMSFORD MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.044	0.000	0.044	-0.002
37958	PETER W ELEM LOWELL MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.016	0.000	0.016	0.002
37959	CIRCLE FIN NEWBURYPORT MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Mar-11	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
37965	BIO-DETEK PAWTUCKET RI PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Mar-11	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
37966	LTI HARVARD AP HARVARD MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Mar-11	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
37967	HILLSIDE MARLBOROUGH MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.002	0.000	0.002	0.002
37969	LOW MEM AUD LOWELL MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.026	0.000	0.026	0.000
37972	DARTMOUTHBUSPARK_PV_ID1592		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Mar-11	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA	57473	0.000	0.708	0.000	0.708	0.057
37973	GENERAL MILLS METHUEN MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Mar-11	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.017	0.000	0.017	0.004
38083	ORONO B HYDRO	38083	Orono "B" Hydro	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-13	Black Bear Hydro Partners, LLC	BBHP	ME	19	BHE	ME		3.030	3.290	3.030	3.290	3.290
38084	STILLWATER B HYDRO	38084	Stillwater "B" Hydro	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	20-Sep-13	Black Bear Hydro Partners, LLC	BBHP	ME	19	BHE	ME		1.638	1.487	1.638	1.487	1.487
38172	SADDLEBACK RIDGE WIND		No Resource (1)	WT	WND		WIND TURBINE	19-Dec-14	Spruce Mountain Wind, LLC	SPRUCE	ME	07	ME	ME	58608	0.000	0.000	0.000	0.000	0.000
38287	WMA CHESTER SOLAR 1	38287	WMA Chester Solar 1	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Vermont Public Power Supply Authority	VPPSA	MA	13	WMA	WCMA		0.000	2.078	0.000	2.078	2.078
38302	TOWN_OF_CARVER_PV_1763		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-14	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
39663	BARNSTABLE_DPW_ID1545		No Resource (1)	WT	WND		WIND TURBINE	01-Aug-11	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.020	0.320	0.020	0.320	0.022
39664	DART_BLDG_SUPPLY_ID1476		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-11	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.048	0.000	0.048	0.007
39665	YARMOUTH_ DPW_ID1740		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-11	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.117	0.000	0.117	0.016
39675	TURKEY HILL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-11	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.016	0.000	0.016	0.003
39717	HI GEAR		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-11	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.103	0.000	0.103	0.003
39722	GTR_BOSTON_FOODBANKS_ID1628		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Oct-11	NSTAR Electric Company	NSTAR	MA	25	BOSTON	NEMA		0.000	0.089	0.000	0.089	0.006
39724	EASTERN_AVE_HOLDINGS_PV_ID1652		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Oct-11	NSTAR Electric Company	NSTAR	MA	25	BOSTON	NEMA		0.000	0.089	0.000	0.089	0.007
39738	MWRA_LORING_RD_ID1400		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-11	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.091	0.155	0.091	0.155	-0.021
40015	INDIAN ORCHARD SOLAR FACILITY	38081	Indian Orchard Solar PV	PV	SUN		PHOTOVOLTAIC	01-Dec-11	Western Massachusetts Electric Company	WMECO	MA	13	WMA	WCMA	57674	0.000	0.803	0.000	0.803	-0.075
40050	EXETER AGRI ENERGY		No Resource (1)	IC	OBG		BIO/REFUSE	19-Dec-11	Vermont Public Power Supply Authority	VPPSA	ME	19	BHE	ME		0.935	0.895	0.935	0.895	-0.002
40052	NEW HAVEN HARBOR UNIT 3	15477	New Haven Harbor Units 2, 3, & 4	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	30-May-12	PSEG New Haven, LLC	PSEG-NH	CT	09	CT	CT	6156	48.600	43.200	48.600	43.200	0.000
40053	NEW HAVEN HARBOR UNIT 4	15477	New Haven Harbor Units 2, 3, & 4	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	30-May-12	PSEG New Haven, LLC	PSEG-NH	CT	09	CT	CT	6156	48.600	43.200	48.600	43.200	0.000
40054	JOHNSTON LFG TURBINE PLANT	14599	Rhode Island LFG Genco, LLC - ST	CC	LFG		BIO/REFUSE	25-May-13	Rhode Island Engine Genco, LLC	RRIG	RI	07	RI	RI	59254	27.891	26.430	27.891	26.430	0.067
40060	OLDBARNET_RD_MASHPEE_PV_ID1798		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-12	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.133	0.000	0.133	0.015
40067	MARION_DR_KINGSTON_WT_ID1656		No Resource (1)	WT	WND		WIND TURBINE	16-Jan-12	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.819	0.473	0.819	0.473	-0.409
40085	QUABBIN 1_ORANGE MA PV NET		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Jan-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40086	QUABBIN 2_ORANGE MA PV NET		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Jan-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40116	DELAWARE VALLEY CORP PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	31-Jan-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
40119	WORCESTER STATE COLLEGE PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	31-Jan-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40137	BERKSHIRE EAST WIND		No Resource (1)	WT	WND		WIND TURBINE	03-Feb-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.263	0.000	0.263	-0.038
40176	NFM SOLAR POWER, LLC	38078	NFM Solar Power, LLC	PV	SUN		PHOTOVOLTAIC	18-Feb-12	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	58210	0.000	0.649	0.000	0.649	0.042
40194	MICRON		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Mar-12	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40207	KEZAR UPPER FALLS	786	KEZAR LEDGEMERE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-12	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	7668	0.280	0.118	0.280	0.118	-0.136
40208	KEZAR LOWER FALLS	786	KEZAR LEDGEMERE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-12	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	7668	0.453	0.248	0.453	0.248	-0.188
40209	LEDGEMERE	786	KEZAR LEDGEMERE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-12	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	7668	0.235	0.057	0.235	0.057	-0.095
40225	MILLIPORE PV - BILLERICA		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Mar-12	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.000	0.000	0.000	0.000
40242	TANTASQUA JR HIGH_PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Mar-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	-0.008
40243	SOLAR SHOP LLC BLDG 14_PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Mar-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.038	0.000	0.038	0.000
40244	SOLAR SHOP LLC BLDG 10_PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Mar-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.049	0.000	0.049	0.001
40246	HODGES BADGE CO_WIND		No Resource (1)	WT	WND		WIND TURBINE	30-Mar-12	The Narragansett Electric Company	NEC	RI	05	SEMA	RI		0.000	0.000	0.000	0.000	0.000
40247	QUABBIN BARRE - WIND		No Resource (1)	WT	WND		WIND TURBINE	29-Mar-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.408	0.000	0.406	-0.004
40248	JJ CARROLL WW PLANT_PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Mar-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.205	0.000	0.205	-0.009
40249	WESTBORO SUITES		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Mar-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.006	0.000	0.006	0.000
40250	SHAWS SUPER MARKET		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Mar-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40251	VETERAN HOMESTEAD PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Mar-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.003	0.000	0.003	-0.010
40259	COMMERCE_PK_RD_PV_ID1871		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Apr-12	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.131	0.000	0.131	0.018
40263	MATOUK TEXTILE WORKS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Apr-12	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
40270	TECTA AMERICA		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Apr-12	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.007	0.000	0.007	-0.017
40327	FORE RIVER 11	1691	FORE RIVER-1	CC	NG		GAS COMBINED CYCLE	04-Aug-03	Calpine Energy Services, LP	CALP	MA	21	SEMA	SEMA	55317	416.611	362.997	416.611	362.997	0.000
40328	FORE RIVER 12	1691	FORE RIVER-1	CC	NG		GAS COMBINED CYCLE	04-Aug-03	Calpine Energy Services, LP	CALP	MA	21	SEMA	SEMA	55317	421.500	362.712	421.500	362.712	0.000
40338	MAINE INDEPENDENCE STATION 1	1216	MAINE INDEPENDENCE STATION	CC	NG		GAS COMBINED CYCLE	01-May-00	Dynegy Marketing and Trade, LLC	DMT1	ME	19	BHE	ME	55068	269.138	244.138	269.138	244.138	0.000
40339	MAINE INDEPENDENCE STATION 2	1216	MAINE INDEPENDENCE STATION	CC	NG		GAS COMBINED CYCLE	01-May-00	Dynegy Marketing and Trade, LLC	DMT1	ME	19	BHE	ME	55068	269.138	244.138	269.138	244.138	0.000
40340	NEXAMP CAP-WORCESTER ACADEMY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Apr-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
40342	VERSO BUCKSPORT G5		No Resource (1)	ST	OBS	NG	BIO/REFUSE	15-Nov-12	Verso Maine Energy LLC	VERSO	ME	09	BHE	ME	50243	22.265	0.000	22.265	0.000	-22.494
40343	BULL HILL WIND		No Resource (1)	WT	WND		WIND TURBINE	27-Oct-12	Blue Sky East, LLC	BSE	ME	09	BHE	ME	57083	13.458	6.457	13.458	6.457	1.483
40365	EAST ISLAND COMMUNITY - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Apr-12	Massachusetts Electric Company	MEC	MA	09	CMA/NEMA	WCMA		0.000	0.037	0.000	0.037	0.001
40482	DURFEE UNION MILLS BLDG 9 - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-May-12	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
40483	TYNGSBOROUGH SPORTS PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-May-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
40484	BANCROFT SCHOOL PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-May-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40485	LITCHFIELD LECOMINSTER PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-May-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40520	MANCHESTER-BOSTON REGIONAL PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-May-12	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.000	0.000	0.000	0.000	-0.008
40524	MOUNT WACHUSSETT CC WIND		No Resource (1)	WT	WND		WIND TURBINE	11-May-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA	58025	0.000	0.000	0.000	0.000	0.000
40555	BLACKCOMB WORC MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-May-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.063	0.000	0.063	0.007
41782	PAWTUCKET MEMORIAL ELEM SCH		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-May-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
41783	PHOENIX FINANCE LLC		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-May-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.017	0.000	0.017	-0.005
41784	NANTUCKET HIGH SCHOOL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-May-12	Massachusetts Electric Company	MEC	MA	19	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
41806	NM-PROPEL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.000	0.000	0.000	-0.014
41807	NM-PITTSFIELD WWTP		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA	59060	0.000	0.550	0.000	0.550	-0.103
41808	NM-MASS DEP		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	13	WMA	WCMA		0.000	0.006	0.000	0.006	0.005
41809	NM-GREENFIELD CC		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
41810	NM-FULL BLOOM MARKET		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.033	0.000	0.033	0.033
41811	NM-BERKSHIRE CC		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
41815	TIFFANY AND CO - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Jun-12	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
41816	QUABOAG REGIONAL ELEM - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Jun-12	Massachusetts

Contains Proprietary Material
Do Not Distribute

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
41881	TOWN OF SWAMPSCOTT HS - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jul-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.156	0.000	0.156	-0.069
41882	NEXAMP CAP-NASHOBA VALLEY THS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Jul-12	Massachusetts Electric Company	MEC	MA	17	CMAINEMA	WCMA		0.000	0.000	0.000	0.000	0.000
41921	MSI REALTY JAMES ST - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Jul-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
41922	LIGHTOLIER - WIND		No Resource (1)	WT	WND		WIND TURBINE	23-Jul-12	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.194	0.127	0.194	0.127	0.127
41923	BLACKCOMB SOLAR III-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Jul-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.379	0.000	0.379	0.002
41924	COREMARK-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Jul-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.173	0.000	0.173	0.007
42041	D.D. BEAN		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	02-Aug-12	Constellation NewEnergy, Inc.	CNE	NH	05	VT	NH		0.000	0.000	0.000	0.000	0.000
42043	SWANSEA WATER DISTRICT		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Aug-12	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.000	0.000	0.000	0.000	0.000
42045	NM-GREENFIELD MA LANDFILL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-12	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.635	0.000	0.635	-0.186
42046	ST. MARYS HIGH SCHOOL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Aug-12	Massachusetts Electric Company	MEC	MA	25	BOSTON	NEMA		0.000	0.011	0.000	0.011	0.006
42048	TANTASQUA HIGH- PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Aug-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.012	0.000	0.012	0.012
42050	PETE'S TIRE BARN		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Aug-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.065	0.000	0.065	0.018
42083	CANTON_LANDFILL_PV_ID1726		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Aug-12	NSTAR Electric Company	NSTAR	MA	21	SEMA	SEMA		0.000	2.559	0.000	2.559	0.177
42091	QUABOAG REGIONAL HS - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Aug-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.048	0.000	0.048	0.002
42092	TOWN OF SUTTON MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Aug-12	Massachusetts Electric Company	MEC	MA	27	CMAINEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42104	HYDEPARKSTORPV_ID1919		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	25	BOSTON	NEMA		0.000	0.059	0.000	0.059	-0.016
42105	MILLST_NATICKPV_ID1818		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.070	0.000	0.070	-0.015
42106	SUBURBANATHLETIC2_ID1637		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.036	0.000	0.036	0.000
42107	4M_ALDRINRDPV_ID1856		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.000	0.049	0.000	0.049	0.001
42108	BROADWAY_RENEWABLE_ID1772		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.000	0.382	0.000	0.382	-0.013
42109	COCHITUATERD_FRAMPV_ID1873		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.079	0.000	0.079	0.006
42110	DOUGLAS_SCHOOLPV_ID1464		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.034	0.000	0.034	0.008
42111	HYANNIS_SELF_STOR_ID1946		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.198	0.000	0.198	0.030
42112	POND_ST_ASHLAND_ID1736		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.185	0.000	0.185	0.009
42113	COBSCOOK BAY TEP TGU 1		No Resource (1)	OT	WAT		MISC. OTHER	04-Sep-12	New Brunswick Energy Marketing Corporation	NBPGC	ME	29	BHE	ME		0.000	0.000	0.000	0.000	0.000
42114	PUMPKIN HILL	1258	BHE SMALL HYDRO COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-82	New Brunswick Energy Marketing Corporation	NBPGC	ME	19	BHE	ME	50699	0.000	0.572	0.000	0.572	-0.638
42115	GLC_ACUSHNETLLC_ID1821_1824		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.000	1.861	0.000	1.861	0.025
42116	DSD_REALTY_TRUST_ID1672		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.500	0.000	0.500	-0.003
42117	CONST_SOLAR_NORFOLK_ID1846		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	21	RI	SEMA	57942	0.000	0.649	0.000	0.649	0.003
42118	CONED_HIXVILLERD_ID1862		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	1.123	0.000	1.123	0.071
42123	KEZAR LEDGEMERE COMPOSITE	786	KEZAR LEDGEMERE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-12	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME		0.057	0.076	0.057	0.076	0.010
42135	18 PHOENIX PARK BLDG DEAST & F		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Sep-12	Massachusetts Electric Company	MEC	MA	17	CMAINEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42136	18 PHOENIX PARK BLDG DEAST & J		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Sep-12	Massachusetts Electric Company	MEC	MA	17	CMAINEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42137	18 PHOENIX PARK BLDG DWEST		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Sep-12	Massachusetts Electric Company	MEC	MA	17	CMAINEMA	WCMA		0.000	0.017	0.000	0.017	0.000
42149	FAVORITE FOODS PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-12	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.000	0.000	0.000	0.000	0.000
42155	LEICESTER HS - BWSC RENEWABLE		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Oct-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
42158	UMASS LOWELL LEITCH HALL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Oct-12	Massachusetts Electric Company	MEC	MA	17	CMAINEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42157	MILLBROOK RIVERSIDE LLC		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Oct-12	Massachusetts Electric Company	MEC	MA	27	CMAINEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42158	MOHAWK DRIVE CORPORATION		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Oct-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.036	0.000	0.036	0.004
42193	TRUE NORTH ENERGY A		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59390	0.000	0.601	0.000	0.601	0.073
42194	TRUE NORTH ENERGY B		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59390	0.000	0.458	0.000	0.458	-0.045
42195	TRUE NORTH ENERGY C		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59390	0.000	0.423	0.000	0.423	0.027
42196	TRUE NORTH ENERGY D		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59390	0.000	0.541	0.000	0.541	0.019
42197	TRUE NORTH ENERGY E		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59390	0.000	0.562	0.000	0.562	0.059
42201	MATTHEW KUSS MS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Nov-12	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
42202	DR AMP 100 AMES POND - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Nov-12	Massachusetts Electric Company	MEC	MA	17	CMAINEMA	WCMA		0.000	0.025	0.000	0.025	0.016
42203	WESTFORD SOLAR 3 - PV	38181	Westford Solar	PV	SUN		PHOTOVOLTAIC	08-Nov-12	Massachusetts Electric Company	MEC	MA	17	CMAINEMA	WCMA	58534	0.000	0.463	0.000	0.463	0.007
42204	BPV LOWELL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Nov-12	Massachusetts Electric Company	MEC	MA	17	CMAINEMA	WCMA		0.000	0.033	0.000	0.033	0.003
42205	SALEM STATE UNIVERSITY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
42212	DR AMP 200 AMES POND - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Nov-12	Massachusetts Electric Company	MEC	MA	17	CMAINEMA	WCMA		0.000	0.028	0.000	0.028	-0.004
42213	CUMMINGS PROPERTY E GMR		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.040	0.000	0.040	0.040
42214	ORCHARD MADE PRODUCTS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.012	0.000	0.012	-0.007
42215	WESTBOROUGH TREATMENT PL BD		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Nov-12	Massachusetts Electric Company	MEC	MA	27	CMAINEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42344	CAMELOT_WIND_ID1240		No Resource (1)	WT	WND		WIND TURBINE	01-Dec-12	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA	58958	0.198	0.159	0.198	0.159	-0.004
42346	3 RIVERS PALMER-SPRINGFLD-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Dec-12	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
42347	CONSTELLATION SOLAR-UXBRG-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Dec-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA	57941	0.000	0.830	0.000	0.830	0.059
42349	15 UNION SOLAR LLC-LAWRENCE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Dec-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.075	0.000	0.075	0.037
42350	BARRETT-FRANKLIN-SOLAR		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Dec-12	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.257	0.000	0.257	0.019
42351	OMA GROUP-CHARLTON-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Dec-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.419	0.000	0.419	-0.016
42352	OSG SOLAR 1-ORANGE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Dec-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.439	0.000	0.439	0.006
42353	OSG SOLAR 2-ORANGE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Dec-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.439	0.000	0.439	0.003
42354	OSG SOLAR 3-ORANGE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Dec-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.217	0.000	0.217	0.001
42355	CIL CEDAR-MARLBORO-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Dec-12	Massachusetts Electric Company	MEC	MA	17	CMAINEMA	WCMA		0.000	0.047	0.000	0.047	0.047
42356	LEEWOOD SWIX-HAVERHILL-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Dec-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.125	0.000	0.125	-0.004
42357	UP BLACKSTONE WWTP-MILLBURY-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Dec-12	Massachusetts Electric Company	MEC	MA	27	CMAINEMA	WCMA		0.000	0.126	0.000	0.126	-0.003
42359	FOREKICKS-MARLBORO-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Dec-12	Massachusetts Electric Company	MEC	MA	17	CMAINEMA	WCMA		0.000	0.088	0.000	0.088	0.008
42360	35 LYMAN LLC-NORTHBORO-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Dec-12	Massachusetts Electric Company	MEC	MA	27	CMAINEMA	WCMA		0.000	0.092	0.000	0.092	0.007
42364	CAPITAL GROUP-SOUTHBORO-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Dec-12	Massachusetts Electric Company	MEC	MA	27	CMAINEMA	WCMA		0.000	0.376	0.000	0.376	-0.013
42365	LOFT 27-LOWELL-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Dec-12	Massachusetts Electric Company	MEC	MA	17	CMAINEMA	WCMA		0.000	0.107	0.000	0.107	-0.007
42366	SOLTAS SPECTOR-LAWRENCE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Dec-12	Massachusetts Electric Company	MEC	MA	09	CMAINEMA	WCMA		0.000	0.149	0.000	0.149	0.000
42375	DEXTER 1	392	DEXTER	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-May-90	Algonquin Energy Services Inc.	AESR	CT	03	CT	CT	10567	38.363	37.839	38.363	37.839	0.205
42376	DEXTER 2	392	DEXTER	CC	NG		GAS COMBINED CYCLE	01-May-90	Algonquin Energy Services Inc.	AESR	CT	03	CT	CT	10567	4.833	4.432	4.833	4.432	0.205
42383	SALEM STATE-SALEM-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Dec-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
42384	BJS WHOLESALE CLUB LEOMINSTER		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Dec-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
42385	CORNER BROOK-MILFORD-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Dec-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.056	0.000	0.056	0.001
42394	WINDENERGYDEV-MKINGSTN-WIND		No Resource (1)	WT	WND		WIND TURBINE	02-Jan-13	The Narragansett Electric Company	NEC	RI	09	RI	RI		0.187	0.134	0.187	0.134	0.056
42411	EXTRA SPACE-PLAINVILLE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Jan-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.040	0.000	0.040	0.040
42412	EXTRA SPACE-SAUGUS-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.039	0.000	0.039	0.007
42413	35 LYMAN LLC - ACTIVE		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Jan-13	Massachusetts Electric Company	MEC	MA	27	CMAINEMA	WCMA		0.000	0.023	0.000	0.023	0.023
42414	NE ELECTRO-FALL RIVER-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Jan-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.016	0.000	0.016	-0.010
42424	IPSWICH WIND II		No Resource (1)	WT	WND		WIND TURBINE	09-Jan-13	Ipswich Municipal Light Department	IMLD	MA	09	BOSTON	NEMA	59023	0.313	0.152	0.313	0.152	0.007
42431	SOLECT PLUMBING-NORWELL-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Jan-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.049	0.000	0.049	-0.003
42432	VAUGHN CORP-SALISBURY-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Jan-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.031	0.000	0.031	0.003
42433	BETHANY CHURCH-MENDON-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Jan-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.029	0.000	0.029	-0.001
42438	EXTRA SPACE-NORTHBORO-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jan-13	Massachusetts Electric Company	MEC	MA	27	CMAINEMA	WCMA		0.000	0.038	0.000	0.038	0.005
42439	CITY OF BROCKTON-SWANSEA-PV1		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jan-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.520	0.000	0.520	0.034
42440	CITY OF BROCKTON-SWANSEA-PV2		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jan-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.770	0.000	0.770	0.051
42443	WAL-MART LUN (PV)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Jan-13	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
42444	MRTA (PV)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Jan-13	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.019	0.000	0.019	0.012
42448	CITY OF GLOUCESTER 1 - WIND		No Resource (1)	WT	WND		WIND TURBINE	06-Feb-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.395	0.127	0.395	0.127	0.009
42449	CITY OF GLOUCESTER 2 - WIND		No Resource (1)	WT	WND		WIND TURBINE	06-Feb-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.274	0.106	0.274	0.106	-0.053
42482	CITY_OF_WALTHAM_PV_ID1805		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.072	0.000	0.072	0.016
42483	FIRST_HIGHLAND_PV_ID2021		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	25	BOSTON	NEMA		0.000	0.346	0.000	0.346	-0.043
42484	UNITEDSALVAGE_PV_ID1966		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.213	0.000	0.213	0.082
42485	SOLCHEMY_PV_ID1969		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	07	SEMA	SEMA		0.000	0.118	0.000	0.118	0.030
42486	AIRPORT_WAY_PV_ID1875		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.633	0.000	0.633	0.096
42487	BILL_BENNETT_PV_ID1967		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	07	SEMA	SEMA		0.000	0.387	0.000	0.387	0.141
42495	VARIANSEMICON-GLOUCESTER-WT		No Resource (1)	WT	WND		WIND TURBINE	21-Feb-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
42496	HANOVER SOLAR-LEICESTER-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Feb-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.363	0.000	0.363	-0.077
42497	WESTFORD SOLAR 4- PV	38181	Westford Solar	PV	SUN		PHOTOVOLTAIC	21-Feb-13	Massachusetts Electric Company	MEC	MA	17	CMAINEMA	WCMA	58534	0.000	0.444	0.000	0.444	-0.008
42504	BERKSHIRE SREG-GT BARRGTN-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Feb-13	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
42505	CUMMINGS 1000-BEVERLY-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Feb-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.083	0.000	0.083	-0.002
42597	GPT JACLEN-BEVERLY-CHP		No Resource (1)	IC	NG		GAS INTERNAL COMBUSTION	26-Mar-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
42598	NEW BARRE HYDRO	852	SOUTH BARRE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	02-Apr-13	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	27	WMA	WCMA		0.047	0.000	0.047	0.000	0.000
42599	MAPREMCT-97GREEN-02035-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Apr-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.052	0.000	0.052	0.002
42600	HOSIACWALREG-ORCHARD-01225-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Apr-13	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.000	0.081	0.000	0.081	0.014
42601	CARLSTROMPM-65FISHER-0158-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Apr-13	Massachusetts Electric Company	MEC	MA	27	CMAINEMA	WCMA		0.000	0.200	0.000	0.200	0.007
42602	KEYPOLYMER-1 JACOB-01843-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Apr-13	Massachusetts Electric Company	MEC	MA	09	CMAINEMA	WCMA		0.000	0.112	0.000	0.112	0.049
42603	BARRE1-750BARRE-01005-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Apr-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.343	0.000	0.343	0.016
42611	AUBUCHON-95AUBUCHON-01473-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Apr-13	Massachusetts Electric Company	MEC	MA	27	CMAINEMA	WCMA		0.000	0.116	0.000	0.116	0.022
42612	NPPDEVELOP-370PATRIOT-02035-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Apr-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.229	0.000	0.229	0.013
42613	AMERICOLD-0PEW-01930-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Apr-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
42631	CABRAL-247BAKER-02777-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Apr-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.231	0.000	0.231	0.029
42632	ALPHA GRAINGER-02038PV250NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Apr-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.000	0.000	0.000	0.000
42633	NORTHBORSPORTS-01532PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Apr-13	Massachusetts Electric Company	MEC	MA	27	CMAINEMA	WCMA		0.000	0.061	0.000	0.061	0.033
42641	NATICKMEMORIAL SCHOOL PV_ID1892		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Apr-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.043	0.000	0.043	0.002
42812	PEGASUS_PV_ID1809		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-May-13	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.441	0.000	0.441	0.007
42813	BIG Y FOODS-02038PV250NM		No Resource (1)	PV	SUN		PHOTOV

Contains Proprietary Material
Do Not Distribute

ASSET ID	ASSET NAME	RE SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
43492	NARR BAY - 02903WT4500NM		No Resource (1)	WT	WND		WIND TURBINE	09-Jul-13	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
43509	DOUGLAS SOLAR-01516PV200NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Jul-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA	57934	0.000	1.048	0.000	1.048	0.068
43510	SANDF MGMNT-02725PV623NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Jul-13	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.000	0.239	0.000	0.239	-0.002
43512	WEST GREENWICH - 02817PV2000DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jul-13	The Narragansett Electric Company	NEC	RI	03	RI	RI		0.000	0.934	0.000	0.934	0.067
43527	STUART THOMAS - 02842PV500DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jul-13	The Narragansett Electric Company	NEC	RI	05	SEMA	RI		0.000	0.213	0.000	0.213	0.038
43528	EXTRA SPC MGMT-02035PV102NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Jul-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.026	0.000	0.026	0.000
43529	CREEDON AND CO-01604PV110NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Jul-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.012	0.000	0.012	-0.002
43531	28 HASTINGS - 01756PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Jul-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.038	0.000	0.038	0.022
43556	CALLAHAN - 02324PV110NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.010	0.000	0.010	0.004
43557	BRDGWTR RECYCLE-02324PV96NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.045	0.000	0.045	0.004
43558	COMMERCE GRN-02339PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.032	0.000	0.032	0.000
43572	JDH_SOLAR_SYSTEMS_PV_2221		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-13	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.000	0.242	0.000	0.242	0.035
43573	NEW_ENGLAND_RESINS_PV_2309		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.188	0.000	0.188	0.016
43574	TOWN_OF_FAIRHAVEN_LF_PV_1714		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.189	0.000	0.189	0.053
43575	NE_ELEMENTARY_WALTHAM_PV_1872		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.114	0.000	0.114	0.012
43576	GLC_ACUSHNET_PV_1888		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.507	0.000	0.507	0.028
43577	GLC_ACUSHNET_PV_1889		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.383	0.000	0.383	0.027
43578	GLC_ACUSHNET_PV_1890		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.508	0.000	0.508	0.038
43579	GOIS_SOLAR_ONE_PV_2040		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.386	0.000	0.386	0.011
43586	COMTRAN CABLE-02864PV400DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Aug-13	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.217	0.000	0.217	0.006
43587	TRAVIS_HOSPITALITY_PV_2239		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Aug-13	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.066	0.000	0.066	0.020
43603	WORC GEAR AND RACK-01537PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Aug-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
43604	METRO WST PROVIS-01747PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Aug-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.033	0.000	0.033	0.011
43605	PRECISE PACK-02720PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
43606	CITY NORTHAMPTON-02721PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-13	Massachusetts Electric Company	MEC	MA	15	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
43607	COX PRTSMTH-02871PV500DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-13	The Narragansett Electric Company	NEC	RI	05	RI	RI		0.000	0.235	0.000	0.235	0.235
43608	35 LYMAN LLC-01532PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Aug-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.016	0.000	0.016	0.000
43609	MA CORRECTIONAL-01440WT3300NM		No Resource (1)	WT	WND		WIND TURBINE	05-Sep-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
43623	E BRIDGEWATER-02333PV2000NM	38114	East Bridgewater Solar Energy Project	PV	SUN		PHOTOVOLTAIC	12-Sep-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	1.062	0.000	1.062	1.062
43624	TJ MAXX - 02061PV260NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Sep-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
43643	SUNGEN UXBRIDGE1-01569PV950NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Sep-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.501	0.000	0.501	0.501
43644	SUNGEN UXBRIDGE2-01569PV950NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Sep-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.494	0.000	0.494	0.494
43645	SUNGEN UXBRIDGE3-01569PV950NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Sep-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.479	0.000	0.479	0.479
43652	TWN W BRDGEWTR-02379PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Sep-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.768	0.000	0.768	0.768
43653	40 WASHINGTON LTD-01581PV750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Sep-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.165	0.000	0.165	0.165
43654	3 COUNTY FAIR ASN-01060PV250NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Sep-13	Massachusetts Electric Company	MEC	MA	15	WMA	WCMA		0.000	0.108	0.000	0.108	0.108
43655	SPRING HILL FARM-01835PV229NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Oct-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.073	0.000	0.073	0.073
43656	SVC TIRE TRUCK - 01527PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Oct-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
43657	RIPTA - 02907PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Sep-13	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
43658	TWN LANCASTER-01523PV500GF		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Oct-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.195	0.000	0.195	0.195
43659	TWN OF SCITUATE2-02066PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Oct-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA	59013	0.000	0.810	0.000	0.810	0.810
43678	DISCOVER MARBLE - 01527PV142NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Oct-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
43682	NEXTSUN ENERGY-01516PV3000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Oct-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	1.590	0.000	1.590	1.590
43683	TWN OF SCITUATE1-02066PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Oct-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA	59013	0.000	0.544	0.000	0.544	0.544
43684	KEY BOSTON-02039PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Oct-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.776	0.000	0.776	0.776
43685	CONNNCUT MARINE-02859PV120DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Oct-13	The Narragansett Electric Company	NEC	RI	05	SEMA	RI		0.000	0.049	0.000	0.049	0.049
43686	SHEA CONCRETE-01913PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Oct-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.088	0.000	0.088	0.088
43687	SUNGEN ORANGE1-01364PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Oct-13	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA	58411	0.000	0.654	0.000	0.654	0.654
43688	SUNGEN ORANGE2-01364PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Oct-13	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA	58411	0.000	0.208	0.000	0.208	0.208
43689	BOSTON NORTH TECH-01913PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Oct-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
43690	OXFORD REALTY-01604PV149NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Oct-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.030	0.000	0.030	0.030
43691	CRAFT INC-02703PV285NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Oct-13	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.000	0.037	0.000	0.037	0.037
43695	KOHLS-01906PV252NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Oct-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
43696	STOP AND SHOP-02155PV200NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Oct-13	Massachusetts Electric Company	MEC	MA	17	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
43698	NTHBRDGE SOLAR-01560PV1910NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Oct-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA	58385	0.000	1.125	0.000	1.125	1.125
43706	CITY OF LOWELL1-01364PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Nov-13	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.421	0.000	0.421	0.421
43707	CITY OF LOWELL2-01364PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Nov-13	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.859	0.000	0.859	0.859
43708	HANNAFORD-02061PV135NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Nov-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
43709	CITY OF LOWELL 1-01331PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Nov-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.430	0.000	0.430	0.430
43710	CITY OF LOWELL 2-01331PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Nov-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.487	0.000	0.487	0.487
43711	CITY OF LOWELL 3-01331PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Nov-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.492	0.000	0.492	0.492
43712	PHOENIX FINS-01464PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Nov-13	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
43713	CUMMINGS PROP-01915PV110NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Nov-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.040	0.000	0.040	0.040
43714	EXTRA SPC STOR-02189PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Nov-13	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.031	0.000	0.031	0.031
43715	MILFORD IND-01757PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Nov-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.038	0.000	0.038	0.038
43716	NEXAMP-02852PV2000DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Nov-13	The Narragansett Electric Company	NEC	RI	09	RI	RI		0.000	0.940	0.000	0.940	0.940
43717	ASSUMPTION-01562PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Nov-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	1.034	0.000	1.034	1.034
43729	GRAFTON WATER-01519PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Nov-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA	59394	0.000	0.715	0.000	0.715	0.715
43731	JEFFERSON-02720PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Nov-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.011	0.000	0.011	0.011
43734	TOWN EASTON-02375PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Nov-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA	59134	0.000	0.812	0.000	0.812	0.812
43735	28 HASTINGS-01756PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Nov-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.030	0.000	0.030	0.030
43736	SMITH COLLEGE-01060NG3500QF		No Resource (1)	IC	NG		GAS INTERNAL COMBUSTION	22-Nov-13	Massachusetts Electric Company	MEC	MA	15	WMA	WCMA	58166	0.134	0.000	0.134	0.000	0.000
43747	PARSONS GRP-01581PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Dec-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.027	0.000	0.027	0.027
43748	ACUMEN-01752PV65NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Dec-13	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.033	0.000	0.033	0.033
43749	WILVECO-01821PV62NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Dec-13	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.002	0.000	0.002	0.002
43750	CANTON HIGH SCHOOL 2009		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Dec-13	NSTAR Electric Company	NSTAR	MA	21	SEMA	SEMA		0.000	0.200	0.000	0.200	0.200
43751	EAGLE LEASE-01540PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Dec-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.016	0.000	0.016	0.016
43752	EXTRA SPACE-01607PV91.2NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Dec-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.029	0.000	0.029	0.029
43762	FORBES STREET 1-02914PV3000DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Dec-13	The Narragansett Electric Company	NEC	RI	07	RI	RI	58583	0.012	1.449	0.012	1.449	1.449
43766	EXTRA SPACE-02149PV237NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Dec-13	Massachusetts Electric Company	MEC	MA	17	BOSTON	NEMA		0.000	0.029	0.000	0.029	0.029
43840	SOLVENTERRA-01089PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jan-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.019	0.479	0.019	0.479	0.479
43841	FLAIR ONE-01507PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jan-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.010	0.366	0.010	0.366	0.366
43842	FORRESTALL-01507PV950NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jan-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.009	0.342	0.009	0.342	0.342
43869	FRPV WEST-02720PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Jan-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.025	0.508	0.025	0.508	0.508
43870	FRPV EAST-02720PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Jan-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.030	0.506	0.030	0.506	0.506
43871	SYNAGRO-02886CHP2000QF		No Resource (1)	ST	NG		GAS STEAM	07-Jan-14	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.094	0.000	0.094	0.000
43874	MASS MOCA1-01247PV225NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Jan-14	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
43875	CUMMINGS PROP-01915PV230NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Jan-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.073	0.000	0.073	0.073
43876	KENNEDY CARPET-02189PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Jan-14	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.025	0.000	0.025	0.025
43878	MCI WORLD COMM-01821PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Jan-14	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.000	0.000	0.000	0.000
43884	MASS MOCA3 01247PV177NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-14	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.000	0.049	0.000	0.049	0.049
43885	NM-HP HOOD AND SONS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Feb-14	Western Massachusetts Electric Company	WMECO	MA	13	WMA	WCMA		0.038	0.702	0.038	0.702	0.702
43886	NM-FRANKLIN COUNTY SHERIFF		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Feb-14	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.037	0.617	0.037	0.617	0.617
43887	NM-TOWN OF AGAWAM SOLAR		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Feb-14	Western Massachusetts Electric Company	WMECO	MA	13	WMA	WCMA		0.062	0.739	0.062	0.739	0.739
43892	SYNCARPHA SOLAR-01740PV495NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Jan-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.201	2.516	0.201	2.516	2.516
43893	HUBBARDSTON-01432PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Jan-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.087	1.015	0.087	1.015	1.015
43903	SUNGEN-02720PV2850NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.160	1.748	0.160	1.748	1.748
43904	CITY OF METHUEN-01523PV3000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.176	1.550	0.176	1.550	1.550
43907	PALMER SOLAR-01069PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Feb-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.092	0.917	0.092	0.917	0.917
43908	NEXTSUN ENERGY-02370PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Feb-14	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.076	0.844	0.076	0.844	0.844
43915	CITIZENS-02769PV200NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Feb-14	NSTAR Electric Company	NSTAR	MA	05	RI	SEMA		0.127	1.093	0.127	1.093	1.093
43916	TOWN OF ADAMS-01220PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Feb-14	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.055	0.434	0.055	0.434	0.434
43917	CHEER PACK-02397PV1750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-14	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.195	0.000	0.195	0.195
43918	CITY OF LOWELL-01851PV1333NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-14	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.050	0.615	0.050	0.615	0.615
43919	SOLVENTERRA 1-01535PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.034	0.515	0.034	0.515	0.515
43920	SOLVENTERRA 2-01535PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.039	0.519	0.039	0.519	0.519
43921	COXCOM-02893PV135DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Feb-14	The Narragansett Electric Company	NEC	RI	03	RI	RI		0.009	0.072	0.009	0.072	0.072
43922	SOLVENTERRA 4-01083PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.062	0.552	0.062	0.552	0.552
43923	PLYMOUTH PUBLIC SCHOOLS-#2062		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.278	2.284	0.278	2.284	2.284
43924	TOWN OF DARTMOUTH #1777		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.059	0.575	0.059	0.575	0.575
43927	SOUTHERN SKY-CARVER #1 (1997)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.067	0.509	0.067	0.509	0.509
43928	SOUTHERN SKY-CARVER #2 (1998)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.075	0.502	0.075	0.502	0.502
43929	SOUTHERN SKY-CARVER #4 (2000)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.069	0.478	0.069	0.478	0.478
43930	SOUTHERN SKY-CARVER #5 (2001)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.079	0.504	0.079	0.504	0.504
43932	SOUTHERN SKY-CARVER #3 (1999)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.071	0.464	0.071	0.464	0.464
43936	SOLVENTERRA 1-01083PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.039	0.536	0.039	0.536	0.536
43937	SOLVENTERRA 2-01083PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.060	0.537	0.060	0.537	0.537
43938	SOLVENTERRA 3-01083PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.062	0.552	0.062	0.552	0.552
43948	SUNGEN 1-01810PV950NM		No Resource (1)	PV

Contains Proprietary Material
Do Not Distribute

ASSET ID	ASSET NAME	RE SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
46210	NEXAMP-01475PV1900NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Apr-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.246	0.887	0.246	0.887	0.887
46211	GIGUERE-01524PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Apr-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.006	0.000	0.006	0.006
46212	BODWELL REALTY-02322PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Apr-14	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
46213	PINGREE SCHOOL-01982PV85NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Apr-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.026	0.000	0.026	0.026
46220	BERKELEY-01844PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Apr-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.263	0.921	0.263	0.921	0.921
46221	JP SULLIVAN-01432PV90NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Apr-14	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.025	0.000	0.025	0.025
46267	COTTAGE STREET SOLAR FACILITY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-May-14	Western Massachusetts Electric Company	WMECO	MA	19	WMA	WCMA	58568	0.000	1.635	0.000	1.635	1.635
46268	OLD TIME SPORTS-01952PV150NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-May-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.031	0.000	0.031	0.031
46294	LAWRENCE 1-01840PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-May-14	Massachusetts Electric Company	MEC	MA	09	CMA/NEMA	WCMA		0.000	0.032	0.000	0.032	0.032
46295	LAWRENCE 2-01840PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-May-14	Massachusetts Electric Company	MEC	MA	09	CMA/NEMA	WCMA		0.000	0.034	0.000	0.034	0.034
46479	CANTON_MIDDLE_SCHOOL_2013		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-May-14	NSTAR Electric Company	NSTAR	MA	21	SEMA	SEMA		0.000	0.138	0.000	0.138	0.138
46480	CEDAR_SOLAR1_2411		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-May-14	NSTAR Electric Company	NSTAR	MA	25	BOSTON	NEMA		0.000	0.039	0.000	0.039	0.039
46481	TOWN_OF_MARSHFIELD_1865		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-May-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA	58410	0.000	1.716	0.000	1.716	1.716
46482	NEWBEDFORD_DPI_1843_1844		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-May-14	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	1.676	0.000	1.676	1.676
46483	MILFORD INDUSTRIAL-0175PV52NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-May-14	Massachusetts Electric Company	MEC	MA	09	RI	SEMA		0.000	0.030	0.000	0.030	0.030
46484	WORCESTER SCHL-01602PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-May-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
46485	NPP DEVELOPMENT-02035PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-May-14	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.030	0.000	0.030	0.030
46486	WB HUNT-02176PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jun-14	Massachusetts Electric Company	MEC	MA	17	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
46487	CIDER HILL-01913PV78NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jun-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.030	0.000	0.030	0.030
46537	CUMMINGS-01911PV82NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jun-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.023	0.000	0.023	0.023
46538	SILVIA-02720PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Jun-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
46539	BCC SEA QALIBC-01854PV66NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Jun-14	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.026	0.000	0.026	0.026
46540	NPP DEVELOPMENT-02035PV62NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Jun-14	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.018	0.000	0.018	0.018
46541	TEKNOR APEX-02703PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Jun-14	Massachusetts Electric Company	MEC	MA	23	RI	SEMA		0.000	0.000	0.000	0.000	0.000
46564	EPG SOLAR-01009PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Jun-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.832	0.000	0.832	0.832
46565	CABOT BEVERLY-01915PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Jun-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59242	0.000	1.205	0.000	1.205	1.205
46566	PRECISE PACKAGING-02720PV250NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.082	0.000	0.082	0.082
46567	NORTH BROOKFIELD-01535PV3000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	1.402	0.000	1.402	1.402
46568	GLC-MA SOLAR-01440PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.392	0.000	0.392	0.392
46569	NUGEN NCMC (PV)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.223	0.000	0.223	0.223
46570	NUGEN LUN (PV)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.860	0.000	0.860	0.860
46607	HARVARD SOLAR-01451PV260NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Jul-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.115	0.000	0.115	0.115
46636	GOOSE RIVER HYDRO, INC.		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Aug-14	Goose River Hydro, Inc.	GOOSE	ME	27	ME	ME		0.000	0.037	0.000	0.037	0.037
46641	205 STURBRIDGE-01010PV3000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.000	0.943	0.000	0.943	0.943
46643	EPG SOLAR-01005PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.676	0.000	0.676	0.676
46644	UGT RENEW ENERGY-01540PV2750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Aug-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	1.348	0.000	1.348	1.348
46645	NEXAMP CAPITAL-01007PV1300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-14	Massachusetts Electric Company	MEC	MA	15	WMA	WCMA		0.000	0.595	0.000	0.595	0.595
46646	SOLTAS ENERGY-01010PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Aug-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.000	1.642	0.000	1.642	1.642
46647	BLUEWAVE CAPITAL-02769PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Aug-14	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.000	0.368	0.000	0.368	0.368
46653	WESTBORO SOLAR-01581PV1820NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Aug-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA	59368	0.000	0.054	0.000	0.054	0.054
46657	INDIAN HILL-01069PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Aug-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA	59362	0.000	0.477	0.000	0.477	0.477
46659	BROWN SOLAR-01069PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Aug-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA	59361	0.000	0.325	0.000	0.325	0.325
46660	STATE SOLAR-01069PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Aug-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.000	0.462	0.000	0.462	0.462
46662	DISTRIBUTOR CORP-02148PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-14	Massachusetts Electric Company	MEC	MA	17	BOSTON	NEMA		0.000	0.000	0.000	0.120	0.120
46663	CITY OF LAWRENCE-01841PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-14	Massachusetts Electric Company	MEC	MA	09	CMA/NEMA	WCMA		0.000	0.000	0.000	0.120	0.120
46664	NEXAMP CAPITAL-01543PV4099NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	2.000	2.000
46665	SX INDUSTRIES-02072PV170NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Sep-14	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.000	0.000	0.068	0.068
46666	CUMMINGS-01915PV224NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Sep-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.090	0.090
46667	E NAZARENE-02170PV85NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Sep-14	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.000	0.000	0.034	0.034
46691	CORNERSTONE-01057PV3000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Sep-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.000	0.000	0.000	1.200	1.200
46717	EAST BAY-02915PV70NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Sep-14	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.028	0.028
46718	EXTRA SPACE-02151PV144.3NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Sep-14	Massachusetts Electric Company	MEC	MA	25	BOSTON	NEMA		0.000	0.000	0.000	0.058	0.058
46719	STONEHILL COLL-02356PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Sep-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.800	0.800
46721	ALL AMERICAN-02852PV250DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Sep-14	The Narragansett Electric Company	NEC	RI	09	RI	RI		0.000	0.000	0.000	0.100	0.100
46733	BILLERICA-01821PV499NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Sep-14	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.000	0.000	2.000	2.000
46732	PIONEER SOLAR-01453PV495NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Sep-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.198	0.198
46733	TKS SOLAR-02301PV180NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Sep-14	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.000	0.000	0.072	0.072
46911	NEXTSUN ENERGY-02896PV850DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Dec-14	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.340	0.340
46913	WOONSOCKET-02895PV190DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Dec-14	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.076	0.076
46914	BILLERICA-01523PV2499NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Dec-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	1.000	1.000
46915	NEXAMP-01844PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Dec-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.800	0.800
46916	PHILLIPS-01810PV495NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Dec-14	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.198	0.198
46917	NEWPORT VINEYARDS-02882PV50DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Dec-14	The Narragansett Electric Company	NEC	RI	05	SEMA	RI		0.000	0.000	0.000	0.029	0.029
46918	TOWN OF WESTFORD-01452PV2800NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Dec-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	1.120	1.120
46924	BILLERICA-01523PV2500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Dec-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	1.000	1.000
46925	GLC-MA SOLAR-01440PV1980NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Dec-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.792	0.792
46926	STILLWATER-02917PV56DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Dec-14	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.022	0.022
46947	AMERIPRIDE-01607PV225NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.090	0.090
46948	MILFORD IND-01757PV170NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Jan-15	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.000	0.000	0.068	0.068
46949	NEW SALEM-01452PV675NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Jan-15	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.270	0.270
46952	TOWN OF WENDELL-01876PV260NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-15	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.000	0.000	0.104	0.104
46953	MACHINE INC-02072PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-15	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.000	0.000	0.030	0.030
46954	PROTECTOWIRE-02359PV70NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-15	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.000	0.000	0.028	0.028
46955	MASS FISHERIES-01581PV251NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.100	0.100
46982	GLOBAL LIQUORS-02720PV85NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Jan-15	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.034	0.034
46984	FIVEMILE RIVER1-01503PV750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.300	0.300
46985	FIVEMILE RIVER2-01503PV750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.300	0.300
46986	FIVEMILE RIVER3-01503PV750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.300	0.300
46987	FIVEMILE RIVER4-01503PV750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.300	0.300
46992	RIN LOGISTICS-02720PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Feb-15	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.600	0.600
46993	PARAGON HOLDINGS-01740PV995NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Feb-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.398	0.398
46997	BOLTONVILLE HYDRO		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-15	Green Mountain Power Corporation	GMP	VT	17	VT	VT	50539	0.000	0.000	0.000	0.527	0.527
46998	STEERE ELECTRIC-02814PV72DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Feb-15	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.029	0.029
47002	ONE KENWOOD-02038PV266NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-15	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.000	0.000	0.106	0.106
47003	S SHORE MILLWORK-02766PV648NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-15	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.000	0.000	0.000	0.259	0.259
47004	IRON MOUNTAIN-01532PV760NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.304	0.304
47007	FRANKLIN FORD-02038PV140NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-15	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.000	0.000	0.056	0.056
47008	MCGEE TOYOTA-02339PV85NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-15	Massachusetts Electric Company	MEC	MA	23	RI	SEMA		0.000	0.000	0.000	0.034	0.034
47020	NEXAMP-02898PV499DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Feb-15	The Narragansett Electric Company	NEC	RI	09	RI	RI		0.000	0.000	0.000	0.200	0.200
47032	ABINGTON TARGET-02351PV418NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Feb-15	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.000	0.000	0.167	0.167
47033	HANOVER TARGET-02339PV441NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Feb-15	Massachusetts Electric Company	MEC	MA	23	RI	SEMA		0.000	0.000	0.000	0.176	0.176
47034	MARLBORO TARGET-01752PV441NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Feb-15	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.176	0.176
47035	MILFORD TARGET-01757PV302NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Mar-15	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.000	0.000	0.121	0.121
47036	NORTHBORO WALMART-01532PV368NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Mar-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.147	0.147
47037	LYNN WALMART-01905PV232NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Mar-15	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.093	0.093
47040	BOOTHBAY ENERGY STORAGE		No Resource (1)	OT	OTR		MISC. OTHER	09-Mar-15	Convergent Energy and Power LLC	CONV	ME	15	ME	ME		0.000	0.000	0.000	0.483	0.483
47060	HANNAFORD FOOD-01535PV120NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Mar-15	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.048	0.048
47061	WHITTIER FARMS-01590PV114NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Mar-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.046	0.046
47062	EASTERN BANK-01901PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Mar-15	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.040	0.040
47063	SWISS TURN-01540PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Mar-15	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.040	0.040
47064	1ST CONGREGATION-02176PV90NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Mar-15	Massachusetts Electric Company	MEC	MA	17	BOSTON	NEMA		0.000	0.000	0.000	0.036	0.036
47065	210 UPHAM (PV)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Mar-15	Fitchburg Gas and Electric Lig	FGE	MA	27	WMA	WCMA		0.000	0.000	0.000	0.029	0.029
47066	S.D. WARREN SACCARAPPA HYDRO		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	20-Mar-15	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME		0.000	0.000	0.000	0.540	0.540
46976	BUCKSPORT G3		No Resource (1)	ST	WDS		BIO/REFUSE	16-Apr-15	. Tenaska Power Services Company	TPS	ME	09	BHE	ME	50243	0.000	0.000	0.000	73.000	73.000
	Forecasted Photovoltaic Capacity			PV	SUN		PHOTOVOLTAIC	01-Jul-15								0.000	0.000	0.000	8.248	8.248

Total	32,647	30,494	32,647	30,749	677
CT			5,333	5,163	(43)
NOR			192	170	2
SWCT			2,536	2,320	561

NOTES:

Appendix A - defines the codes used.

Generator details, including Lead Market Participant, as of January 1, 2015.

Additional information and changes to generating asset Lead Participant since January 1, 2015 may be found in the Endnotes following Section 2.1.

The Expected Summer Peak SCC is based on the April 2015 SCC Report and capacity that is expected to be added by August 1st based on the interconnection queue and information provided to ISO-NE by the lead participants. In this table, new capacity consists of one new 73 MW generator and uprates to Manchester Station, Bridgeport Energy, Granite Ridge Energy, and EP Newington Energy totaling approximately 147 MW.

New PV resources that do not yet have an SCC value due to a lack of historical generation data have an assumed SCC of 40 percent of nameplate.

Based on the PV forecast, approximately 8 MW of additional capacity is expected to go commercial by July 1, 2015. See Sec. 3.1.2, "PV in Markets" category for more details on the forecast.

When an alternate fuel is listed, the unit may not necessarily be fully operable on both fuels.

FOOTNOTES:

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Table 3-5
Local Operating Reserve Requirements
Summer 2014 and Winter 2014/2015 Forward Reserve Auctions (MW)

Location Name	Product	Summer 2013	Winter 2013/2014	Summer 2014	Winter 2014/2015
CT	TMOR[a]	747	578	900	363
NEMA/Boston	TMOR[a]	0	0	0	0
SWCT	TMOR[a]	0	155	94	87
Systemwide	TMNSR	1,349	1,532	1,573	1,562
Systemwide	TMOR[a]	723	915	891	831

(a) TMNSR also can be used to satisfy this requirement.

http://www.iso-ne.com/static-assets/documents/2015/05/2014-amr.pdf
http://www.iso-ne.com/static-assets/documents/2016/05/2015_imm_amr_final_5_25_2016.pdf
ISO-NE 2014 Annual Markets Report
ISO-NE 2015 Annual Markets Report

	Winter	Spring	Summer	Fall
ISO-NE	1562	1436	1310	1436
CT	363	538.5	714	538.5
SWCT	87	112.5	138	112.5

Spring, Fall = average of Winter, Summer

Operating Reserves: The bulk power system needs reserve capacity to be able to respond to contingencies, such as those caused by unexpected outages. Operating reserves are provided by the unloaded capacity of generating resources, either online or offline, which can deliver energy within 10 or 30 minutes. The ISO procures both system-wide reserve, and local reserve for import-constrained areas. The system reserve requirement has been relatively constant over the past three years, with a total ten-minute reserve requirement of about 1,700MW and total thirty-minute reserve requirement of about 2,500MW in 2015.

Per ISO-NE ISO New England's Internal Market Monitor 2015 Annual Markets Report Note above, the 2014-2015 reserves are assumed to be the same as the 2013-2014 Reserves.

The TMNSR and TMOR requirements are based on first- and second-contingency losses (refer to Sections 2.1.4 and 2.2.1). The methodology to calculate these requirements is described in OP 8 (Section 2.2.1) and the ISO New England Manual for Forward Reserve (Manual M-36) (December 3, 2013), http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

The Forward Reserve requirements for the New England Control Area are based on expected system operating conditions. The TMNSR purchase amount represents the expected single contingency of the HQ Phase II Interconnection, including a TMNSR bias of 63%. The TMNSR purchase amount is increased to reflect a 20% average fleet-wide historical non-performance of resources called upon after a contingency.[1] The TMOR purchase amount represents the expected single contingency of Seabrook. The Replacement Reserve will be equal to 160 MW.

Forward Reserve Requirements

Reserve Zone	Reserve Category	Local 2nd Contingency MW	External Reserve Support MW	Reserve Requirement MW
New England Control Area	TMNSR	N/A	N/A	1310
New England Control Area	TMOR	N/A	N/A	785
SWCT	TMOR	503	365	138
CT	TMOR	1213	499	714
NEMA/Boston	TMOR	880	549	331

The New England Control Area Forward Reserve Requirements are based on a 1st contingency of 1,664 MW and a 2nd contingency of 1,249 MW.

https://www.iso-ne.com/static-assets/documents/2015/03/forward_reserve_auction_assumptions_summer_2015.docx

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FERC Form 714 Outages

Month	Planned Outage and Derating (MW)
Dec-14	2,033
Jan15	160
Feb15	1,187
Mar15	2,362
Apr15	4,595
May15	2,746
Jun15	627
Jul15	80
Aug15	0
Sep15	482
Oct15	6,598
Nov15	1,801

	Planned Outage and Derating (MW)				
	Winter	Spring	Summer	Fall	Notes
ISO-NE	1,127	3,234	236	2,960	NYISO outages
CT	260	747	55	683	Estimated based on generation ratios

	Generation (MW)			
	Winter	Spring	Summer	Fall
ISO-NE	35,576	35,576	33,424	35,576
CT	8,213	8,213	7,789	8,213

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Needle Peak	24,437
Peak Month	7
PST	19,621
Winter	18,391
Spring	15,604
Summer	18,719
Fall	16,307

Source: ISO NE

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	17,146	12/1/2014	10,753	10,347	10,184	10,211	10,595	11,749	13,695	14,747	14,901	14,876	14,968	14,940	14,880	14,917	14,890	15,129	16,299	17,146	17,055	16,653	16,038	14,961	13,562	12,334
Winter	12	18,415	12/2/2014	11,554	11,158	11,002	11,048	11,468	12,683	14,792	15,870	16,092	16,135	16,194	16,156	16,133	16,233	16,254	16,551	17,736	18,415	18,275	17,865	17,174	15,998	14,422	13,024
Winter	12	17,801	12/3/2014	12,145	11,634	11,401	11,366	11,702	12,775	14,690	15,788	16,039	16,127	16,214	16,229	16,100	16,041	15,967	16,233	17,236	17,801	17,579	17,106	16,462	15,373	13,948	12,668
Winter	12	18,125	12/4/2014	11,869	11,434	11,271	11,311	11,703	12,905	15,005	15,959	15,966	15,847	15,736	15,586	15,404	15,401	15,440	15,752	17,062	18,114	18,125	17,776	17,277	16,131	14,708	13,434
Winter	12	17,857	12/5/2014	12,626	12,189	11,996	12,034	12,438	13,615	15,658	16,657	16,667	16,481	16,328	16,084	15,910	15,930	15,962	16,215	17,364	17,857	17,501	16,969	16,410	15,595	14,406	13,143
Winter	12	16,745	12/6/2014	12,198	11,647	11,305	11,147	11,190	11,592	12,392	13,274	14,339	15,108	15,486	15,575	15,504	15,286	15,172	15,318	16,291	16,745	16,436	15,905	15,375	14,652	13,678	12,620
Winter	12	18,005	12/7/2014	11,795	11,311	11,036	10,952	11,048	11,387	12,054	12,830	13,838	14,534	14,789	14,782	14,712	14,625	14,627	15,043	16,641	17,925	18,005	17,743	17,262	16,268	15,051	13,882
Winter	12	19,843	12/8/2014	12,989	12,586	12,469	12,522	12,986	14,175	16,312	17,492	17,745	17,844	17,984	17,949	17,849	17,801	17,734	17,992	19,134	19,843	19,640	19,189	18,476	17,231	15,564	14,085
Winter	12	19,049	12/9/2014	13,146	12,609	12,312	12,237	12,546	13,615	15,416	16,646	17,066	17,309	17,500	17,597	17,536	17,566	17,493	17,643	18,501	19,049	18,712	18,081	17,196	15,912	14,309	12,952
Winter	12	18,372	12/10/2014	12,049	11,557	11,334	11,312	11,648	12,760	14,719	15,930	16,176	16,330	16,253	16,536	16,537	16,528	16,310	16,561	17,627	18,372	18,217	17,763	17,083	15,941	14,420	12,995
Winter	12	18,636	12/11/2014	12,114	11,611	11,410	11,429	11,776	12,907	14,915	16,078	16,313	16,421	16,519	16,547	16,485	16,465	16,440	16,630	17,789	18,636	18,488	18,094	17,502	16,439	14,903	13,479
Winter	12	18,208	12/12/2014	12,576	12,097	11,875	11,859	12,229	13,362	15,330	16,421	16,594	16,517	16,441	16,328	16,149	16,093	16,091	16,362	17,500	18,208	17,919	17,442	16,861	16,021	14,857	13,600
Winter	12	17,064	12/13/2014	12,601	12,035	11,759	11,680	11,802	12,271	13,105	13,975	14,895	15,361	15,436	15,299	15,026	14,729	14,620	14,901	16,197	17,064	16,849	16,403	15,944	15,280	14,328	13,214
Winter	12	17,219	12/14/2014	12,304	11,741	11,444	11,334	11,390	11,714	12,322	13,006	13,873	14,417	14,556	14,513	14,465	14,339	14,317	14,616	16,076	17,219	17,178	16,861	16,325	15,311	13,968	12,719
Winter	12	18,367	12/15/2014	11,906	11,504	11,355	11,405	11,864	13,101	15,196	16,278	16,300	16,147	16,009	15,830	15,609	15,526	15,447	15,701	17,093	18,362	18,367	17,998	17,383	16,238	14,684	13,283
Winter	12	18,485	12/16/2014	12,358	11,882	11,667	11,660	12,032	13,183	15,241	16,373	16,554	16,604	16,656	16,629	16,478	16,465	16,384	16,634	17,773	18,485	18,303	17,836	17,172	16,013	14,447	12,957
Winter	12	17,878	12/17/2014	11,949	11,436	11,177	11,157	11,486	12,598	14,570	15,783	15,971	15,978	15,976	15,891	15,703	15,653	15,561	15,779	17,025	17,878	17,735	17,340	16,773	15,725	14,231	12,792
Winter	12	18,215	12/18/2014	11,828	11,322	11,102	11,115	11,491	12,684	14,765	15,931	16,092	16,033	15,955	15,924	15,805	15,798	15,737	16,008	17,289	18,215	18,128	17,740	17,208	16,194	14,732	13,275
Winter	12	18,279	12/19/2014	12,343	11,835	11,589	11,569	11,926	13,038	15,030	16,198	16,436	16,531	16,574	16,474	16,258	16,172	16,068	16,287	17,435	18,279	18,065	17,617	17,097	16,293	15,148	13,854
Winter	12	17,569	12/20/2014	12,873	12,324	12,049	11,940	12,060	12,518	13,366	14,320	15,277	15,819	15,985	15,936	15,785	15,603	15,558	15,825	16,932	17,569	17,317	16,837	16,386	15,701	14,695	13,535
Winter	12	17,728	12/21/2014	12,599	11,983	11,676	11,553	11,604	11,922	12,537	13,345	14,371	15,130	15,504	15,650	15,678	15,579	15,534	15,665	16,930	17,728	17,616	17,262	16,711	15,763	14,411	13,109
Winter	12	18,112	12/22/2014	12,199	11,709	11,504	11,503	11,887	12,971	14,837	16,013	16,338	16,364	16,298	16,201	16,035	15,934	15,859	16,080	17,266	18,112	17,994	17,581	16,988	15,964	14,538	13,054
Winter	12	17,711	12/23/2014	12,016	11,426	11,119	11,071	11,400	12,420	14,219	15,510	15,915	16,108	16,218	16,211	16,071	16,010	15,939	16,104	17,106	17,711	17,492	17,048	16,485	15,572	14,232	12,854
Winter	12	16,368	12/24/2014	11,739	11,087	10,746	10,620	10,830	11,575	12,863	14,090	14,956	15,597	15,962	16,011	15,808	15,703	15,667	15,738	16,355	16,368	15,510	14,727	14,238	13,736	13,027	12,105
Winter	12	14,122	12/25/2014	11,160	10,508	10,090	9,896	9,919	10,227	10,811	11,641	12,613	13,374	13,657	13,648	13,374	13,103	12,832	12,755	13,465	14,122	14,047	13,912	13,754	13,324	12,520	11,584
Winter	12	16,379	12/26/2014	10,857	10,411	10,209	10,195	10,453	11,121	12,135	12,929	13,608	14,085	14,327	14,348	14,166	13,954	13,870	14,057	15,221	16,379	16,203	15,790	15,325	14,577	13,535	12,453
Winter	12	15,621	12/27/2014	11,599	11,117	10,840	10,741	10,854	11,222	11,884	12,537	13,296	13,786	13,954	13,875	13,642	13,333	13,168	13,340	14,530	15,621	15,524	15,140	14,737	14,073	13,084	12,052
Winter	12	16,107	12/28/2014	11,188	10,641	10,320	10,166	10,208	10,497	10,977	11,615	12,464	13,284	13,774	13,997	14,073	13,980	13,834	13,974	15,207	16,107	15,994	15,552	15,010	14,229	13,108	12,076
Winter	12	17,910	12/29/2014	11,316	10,879	10,753	10,821	11,226	12,173	13,628	14,689	15,295	15,522	15,550	15,565	15,479	15,418	15,396	15,605	16,763	17,910	17,796	17,338	16,776	15,830	14,543	13,328
Winter	12	18,734	12/30/2014	12,533	12,093	11,928	11,934	12,275	13,216	14,644	15,731	16,298	16,607	16,721	16,585	16,362	16,253	16,187	16,396	17,531	18,734	18,622	18,209	17,662	16,734	15,445	14,229
Winter	12	18,443	12/31/2014	13,381	12,892	12,677	12,660	12,955	13,800	15,097	16,101	16,713	16,902	16,889	16,747	16,540	16,347	16,208	16,291	17,356	18,443	18,037	17,255	16,548	15,844	15,062	14,362
Winter	1	17,326	1/1/2015	13,662	13,069	12,645	12,425	12,454	12,774	13,247	13,537	13,966	14,429	14,771	14,887	14,869	14,796	14,714	14,949	16,151	17,326	17,155	16,688	16,134	15,328	14,227	13,154
Winter	1	17,673	1/2/2015	12,361	11,854	11,618	11,615	11,881	12,616	13,763	14,673	15,267	15,608	15,761	15,808	15,699	15,541	15,407	15,522	16,575	17,673	17,421	16,934	16,394	15,599	14,537	13,486
Winter	1	17,710	1/3/2015	12,648	12,187	11,933	11,864	11,987	12,386	13,125	13,857	14,644	15,217	15,538	15,728	15,731	15,680	15,729	15,958	16,976	17,710	17,486	16,958	16,342	15,468	14,387	13,283
Winter	1	17,000	1/4/2015	12,363	11,763	11,404	11,245	11,217	11,431	11,916	12,527	13,337	14,193	14,805	15,202	15,425	15,448	15,358	15,475	16,379	17,000	16,695	16,058	15,372	14,210	12,960	11,863
Winter	1	19,224	1/5/2015	11,133	10,791	10,672	10,747	11,208	12,419	14,504	15,627	15,772	15,875	16,000	16,031	16,015	16,092	16,146	16,518	17,717	19,163	19,224	18,867	18,277	17,163	15,747	14,529
Winter	1	20,011	1/6/2015	13,743	13,368	13,240	13,287	13,664	14,793	16,749	17,910	18,047	18,216	18,382	18,401	18,273	18,167	18,017	18,100	18,994	20,011	19,956	19,554	18,877	17,745	16,270	15,010
Winter	1	20,439	1/7/2015	14,233	13,824	13,645	13,639	13,951	14,981	16,931	18,016	18,072	17,921	17,812	17,718	17,661	17,670	17,688	17,977	19,062	20,293	20,439	20,159	19,706	18,690	17,348	16,129
Winter	1	20,583	1/8/2015	15,415	15,090	14,955	15,016	15,420	16,446	18,253	19,413	19,647	19,556	19,397	19,188	18,833	18,625	18,406	18,503	19,468	20,583	20,543	20,143	19,473	18,317	16,786	15,442
Winter	1	19,111	1/9/2015	14,646	14,193	13,965	13,884	14,130	15,059	16,816	17,946	18,121	18,341	18,505	18,371	17,933	17,611	17,337	17,315	18,075	19,111	18,928	18,454	17,883	17,046	15,974	14,835
Winter	1	18,376	1/10/2015	14,041	13,582	13,357	13,329	13,486	13,961	14,795	15,640	16,418	16,866	16,959	16,804	16,510	16,330	16,223	16,435	17,363	18,376	18,367	17,899	17,615	16,966	15,998	15,000
Winter	1	18,668	1/11/2015	14,251	13,793	13,576	13,503	13,566	13,862	14,417	15,005	15,779	16,335	16,531	16,660	16,709	16,648	16,626	16,758	17,631	18,668	18,479	17,874	17,154	16,019	14,714	13,568
Winter	1	18,797	1/12/2015	12,794	12,367	12,182	12,231	12,581	13,691	15,497	16,608	16,879	17,130	17,379	17,497	17,486	17,382	17,203	17,233	18,006	18,797	18,577	17,993	17,218	16,036	14,658	13,466
Winter	1	19,614	1/13/2015	12,713	12,310	12,193	12,271	12,718	13,961	16,079	17,241	17,367	17,344	17,323	17,202	17,024	16,993	16,918	17,116	18,103	19,521	19,614	19,307	18,749	17,693	16,314	15,118
Winter	1	19,803	1/14/2015	14,387	14,054	13,938	13,980	14,346	15,423	17,404	18,536	18,656	18,717	18,783	18,699	18,513	18,364	18,171	18,212	18,930	19,803	19,682	19,213	18,524	17,344	15,887	14,612
Winter	1	19,000	1/15/2015	13,803	13,386	13,202	13,205	13,536	14,640	16,591	17,632	17,701	17,707	17,714	17,615	17,413	17,286	17,137	17,174	17,909	19,000	18,942	18,513	17,895	16,845	15,468	14,276
Winter	1	18,650	1/16/2015	13,506	13,164	12,967	12,969	13,316	14,361	16,251	17,227	17,363	17,201	16,969	16,725	16,603	16,636	16,574	16,676	17,469	18,650	18,606	18,219	17,740	16,981	15,968	14,915
Winter	1	18,122	1/17/2015	14,177	13,768	13,600	13,563	13,722	14,237	15,068	15,914	16,726	17,093	17,123	16,893	16,538	16,140	15,898	16,025	16,857	18,122	18,049	17,574	17,054	16,282	15,290	14,289
Winter	1	17,072	1/18/2015	13,515	13,023	12,703	12,554	12,565	12,806	13,277	13,843	14,658	15,353	15,769	15,977	15,990	15,921	15,863	15,904	16,479	17,072	16,675	15,929	15,308	14,502	13,585	12,511
Winter	1	18,025	1/19/2015	11,740	11,321	11,140	11,194	11,509	12,388	13,680	14,651	15,294	15,720	16,054	16,174	16,112	16,028	15,943	16,071	16,794	18,025	17,933	17,443	16,746	15,639	14,306	13,149
Winter	1	18,339	1/20/2015	12,454	12,065	11,892	11,918	12,313	13,466	15,457	16,477	16,467	16,363	16,255	16,088	15,915	15,836	15,813	15,999	16,864	18,261	18,339	17,917	17,294	16,174	14,833	13,644
Winter	1	18,521	1/21/2015	12,944	12,590	12,449	12,513	12,954	14,161	16,230	17,295	17,197	16,967	16,836	16,731	16,569	16,436	16,259	16,379	17,216	18,521	18,520	18,084	17,404	16,239	14,788	13,566
Winter	1	18,058	1/22/2015	12,781	12,371	12,195	12,216	12,601	13,722	15,730	16,787	16,887	16,757	16,582	16,380	16,173	16,070	15,902	15,973	16,664	18,011	18,058	17,687	17,100	16,058	14,695	13,550
Winter	1	17,523	1/23/2015	12,853	12,484	12,360	12,429	12,840	13,965	15,983	17,021	16,997	16,766	16,544	16,290	15,994	15,799	15,616	15,664	16,322	17,523	17,482	17,028	16,461	15,634	14,549	13,454
Winter	1	17,403	1/24/2015	12,625	12,145	11,877	11,755	11,863	12,286	13,079	13,876	14,749	15,523	16,014	16,200	16,191	16,034	15,827	15,805	16,355	17,403	17,183	16,533	15,844	14,990	13,988	13,041
Winter	1	17,425	1/25/2015	12,281	11,829	11,556	11,458	11,521	11,850	12,468	13,101	13,949	14,446	14,622	14,623	14,515	14,341	14,298	14,593	15,570	17,210	17,425	17,125	16,590	15,677	14,562	13,584
Winter	1	19,531	1/26/2015	12,944	12,629	12,541	12,642	13,128	14,408	16,588	17,722	17,899	17,932	17,953	17,896	17,826	17,815	17,737	17,766	18,395	19,531	19,425	18,697	17,769	16,628	15,416	14,359
Winter	1	18,727	1/27/2015	13,622	13,219	13,044	13,053	13,256	13,727	14,443	15,060	15,785	16,399	16,696	16,822	16,870	16,743	16,605	16,628	17,318	18,727	18,632	18,035	17,290	16,299	15,153	14,165
Winter	1	19,361	1/28/2015	13,545	13,239	13,111	13,133	13,457	14,313	15,707	16,734	17,410	17,689	17,831	17,816	17,666	17,477	17,181	17,127	17,711	19,186	19,361	18,896	18,214	17,099	15,764	14,630
Winter	1	18,661	1/29/2015	13,975	13,660	13,544	13,652	14,075	15,201	17,142	18,092	18,089	17,838	17,587	17,272	16,915	16,667	16,451	16,516	17,151	18,521	18,661	18,268	17,611	16,515	15,106	13,840
Winter	1	18,114	1/30/2015	13,077	12,658	12,464	12,435	12,747	13,738	15,519	16,610	16,915	17,105	17,190	17,100	16,917	16,834	16,669	16,626	17,054	18,040	18,114	17,711	17,248	16,531	15,538	14,570
Winter	1	18,686	1/31/2015	13,905	13,544	13,412	13,436	13,639	14,191	15,072	15,951	16,886	17,423	17,505	17,379	17,080	16,700	16,444	16,483	17,075	18,452	18,686	18,292	17,790	17,032	16,051	15,037
Winter	2	17,999	2/1/2015	14,296	13,847	13,621	13,522	13,606	13,894	14,452	15,041	15,750	16,132	16,132	16,037	15,931	15,743	15,713	15,923	16,643	17,999	17,647	16,743	16,265	15,631	15,013	14,306
Winter	2	19,916	2/2/2015	13,458	13,029	12,888	12,959	13,314	14,155	15,354	16,231	17,027	17,719	18,242	18,537	18,613	18,528	18,399	18,379	18,844	19,916	19,911	19,321	18,477	17,310	16,017	14,882
Winter	2	19,599	2/3/2015	14,276	13,964	13,889	13,992	14,372	15,392	16,969	17,957	18,367	18,360	18,282	18,191	17,869	17,638	17,371	17,293	17,754	19,174	19,599	19,320	18,725	17,690	16,286	15,088
Winter	2	18,581	2/4/2015	14,383	14,045	13,886	13,885	14,212	15,246	17,103	18,007	18,021	17,917	17,846	17,648	17,344	17,172	16,971	16,868	17,223	18,401	18,581	18,164	17,487	16,371	14,927	13,711
Winter	2	19,642	2/5/2015	12,892	12,428	12,215	12,201	12,537	13,618	15,452	16,500	16,815	17,092	17,341	17,437	17,383	17,355	17,180	17,149	17,636	19,097	19,642	19,397	18,916	17,944	16,572	15,423
Winter	2	19,112	2/6/2015	14,726	14,403	14,280	14,342	14,710	15,815	17,689	18,577	18,594	18,530	18,484	18,374	18,115	17,848	17,512	17,339	17,695	18,829	19,112	18,773	18,266	17,449	16,368	15,251
Winter	2	17,680	2/7/2015	14,412	13,923	13,637	13,498	13,528	13,897	14,640	15,476	16,271	16,632	16,825	16,721	16,552	16,440	16,320	16,315	16,664	17,643	17,680	17,174	16,607	15,811	14,832	13,861
Winter	2	18,491	2/8/2015	13,125	12,679	12,430	12,317	12,400	12,650	13,160	13,758	14,767	15,558	16,056	16,340	16,466	16,438	16,404	16,607	17,243	18,401	18,491	17,986	17,293	16,326	15,293	14,366
Winter	2	19,658	2/9/2015	13,691	13,324	13,175	13,192	13,529	14,391	15,619	16,507	17,287	17,920	18,386	18,662	18,686	18,537	18,252	18,062	18,413	19,585	19,658	19,057	18,211	17,045	15,698	14,563
Winter	2	18,822	2/10/2015	13,846	13,470	13,294	13,286	13,604	14,543	16,034	17,042	17,546	17,683	17,646	17,506	17,290	17,082	16,843	16,690	17,026	18,296	18,822	18,442	17,802	16,732	15,350	14,196
Winter	2	18,964	2/11/2015	13,476	13,121	12,959	13,046	13,510	14,623	16,527	17,449	17,607	17,560	17,443	17,285	17,083	16,922	16,713	16,721	17,205	18,463	18,964	18,662	18,122	17,116	15,757	14,573
Winter	2	18,792	2/12/2015	13,874	13,477	13,306	13,350	13,674	14,737	16,561	17,499	17,692	17,785	17,782	17,613	17,381	17,264	17,054	17,042	17,454	18,424	18,792	18,492	17,948	16,990	15,671	14,537
Winter	2	19,343	2/13/2015	13,808	13,519	13,480	13,633	14,080	15,292	17,174	18,188	18,390	18,444	18,428	18,256	17,956	17,736	17,480	17,429	17,772	18,826	19,343	19,038	18,623	17,879	16,832	15,792
Winter	2	18,532	2/14/2015	15,034	14,607	14,413	14,354	14,495	14,942	15,698	16,516	17,286	17,685	17,724	17,524	17,269	17,022	16,855	16,895	17,287	18,300	18,532	17,952	17,247	16,326	15,333	14,409
Winter	2	19,590	2/15/2015	13,712	13,338	13,157	13,096	13,169	13,434	13,929	14,514	15,496	16,330	16,886	17,163	17,204	17,074	16,887	16,950	17,471	18,929	19,590	19,179	18,609	17,806	16,889	15,993
Winter	2	20,108	2/16/2015	15,404	15,093	14,989	15,036	15,319	16,029	17,083	17,955	18,664	19,043	19,153	19,037	18,746	18,405	18,131	18,093	18,554	19,713	20,108	19,659	18,989	17,947	16,673	15,508
Winter	2	19,514	2/17/2015	14,780	14,388	14,208	14,215	14,560	15,494	17,047	18,070	18,609	18,839	18,908	18,751	18,433	18,137	17,769	17,643	17,962	19,018	19,514	19,123	18,477	17,421	16,094	14,935
Winter	2	18,763	2/18/2015	14,214	13,876	13,728	13,777	14,171	15,199	16,839	17,786	18,010	17,968	17,830	17,551	17,191	17,006	16,808	16,782	17,174	18,304	18,763	18,380	17,739	16,725	15,414	14,279
Winter	2	19,705	2/19/2015	13,549	13,150	12,999	13,046	13,397	14,407	15,982	16,951	17,283	17,333	17,367	17,451	17,356	17,290	17,192	17,293	17,763	19,007	19,705	19,475	18,954	18,008	16,737	15,669
Winter	2	19,540	2/20/2015	14,988	14,666	14,546	14,610	14,992	16,017	17,575	18,601	18,944	19,022	18,959	18,769	18,478	18,234	17,951	17,789	18,060	18,952	19,540	19,229	18,714	17,903	16,878	15,834
Winter	2	18,223	2/21/2015	15,076	14,746	14,603	14,575	14,748	15,216	15,905	16,679	17,340	17,576	17,499	17,265	17,008	16,864	16,776	16,833	17,156	18,013	18,223	17,679	16,991	16,077	14,980	13,954
Winter	2	17,270	2/22/2015	13,180	12,690	12,392	12,260	12,291	12,553	12,997	13,593	14,450	15,111	15,449	15,499	15,285	14,931	14,668	14,678	15,135	16,476	17,270	16,942	16,306	15,309	14,244	13,274
Winter	2	19,862	2/23/2015	12,653	12,315	12,175	12,224	12,650	13,803	15,699	16,819	17,273	17,466	17,502	17,501	17,305	17,190	17,059	17,185	17,714	18,940	19,862	19,670	19,172	18,190	16,893	15,773
Winter	2	19,983	2/24/2015	15,118	14,851	14,768	14,851	15,246	16,370	18,127	18,962	18,920	18,870	18,674	18,416	18,102	17,876	17,680	17,647	18,106	19,254	19,983	19,649	18,960	17,818	16,325	15,045
Winter	2	18,605	2/25/2015	14,276	13,903	13,730	13,747	14,079	15,163	16,878	17,706	17,669	17,458	17,290	17,026	16,729	16,523	16,292	16,286	16,707	17,763	18,605	18,408	17,835	16,840	15,518	14,393
Winter	2	19,206	2/26/2015	13,691	13,356	13,217	13,278	13,634	14,728	16,525	17,527	17,856	18,044	18,124	18,062	17,834	17,510	17,272	17,360	17,759	18,605	19,206	18,894	18,276	17,198	15,818	14,627
Winter	2	18,313	2/27/2015	13,939	13,626	13,520	13,584	13,975	15,073	16,812	17,653	17,697	17,554	17,382	17,144	16,808	16,587	16,335	16,262	16,587	17,461	18,313	18,029	17,623	16,900	15,897	14,889
Winter	2	17,337	2/28/2015	14,220	13,868	13,724	13,697	13,867	14,367	15,110	15,883	16,454	16,691	16,593	16,298	15,870	15,443	15,150	15,100	15,483	16,452	17,337	17,091	16,703	16,096	15,264	14,418
Spring	3	18,198	3/1/2015	13,805	13,493	13,354	13,314	13,406	13,740	14,163	14,861	15,605	16,039	16,241	16,293	16,151	16,050	16,038	16,233	16,708	17,664	18,198	17,749	17,009	15,882	14,667	13,629
Spring	3	18,586	3/2/2015	12,963	12,621	12,492	12,524	12,901	13,943	15,501	16,491	16,823	16,835	16,823	16,718	16,576	16,454	16,310	16,279	16,664	17,682	18,586	18,308	17,710	16,594	15,221	14,092

Contains Proprietary Material
Do Not Distribute

Spring	3	18,800	3/3/2015	13,422	13,097	12,982	13,053	13,521	14,694	16,484	17,227	17,140	16,987	16,878	16,714	16,543	16,545	16,515	16,629	17,111	18,201	18,800	18,451	17,783	16,568	15,109	13,866
Spring	3	17,706	3/4/2015	13,021	12,549	12,294	12,272	12,601	13,619	15,248	16,169	16,449	16,473	16,400	16,273	16,097	15,963	15,746	15,796	16,223	17,129	17,706	17,345	16,672	15,568	14,195	13,040
Spring	3	18,848	3/5/2015	12,294	11,923	11,769	11,790	12,183	13,320	15,134	16,201	16,620	16,923	17,203	17,293	17,294	17,293	17,136	17,142	17,503	18,306	18,848	18,512	17,948	16,884	15,579	14,474
Spring	3	18,082	3/6/2015	13,870	13,586	13,504	13,596	14,038	15,209	16,904	17,742	17,746	17,559	17,400	17,125	16,752	16,494	16,219	16,123	16,416	17,192	18,082	17,835	17,357	16,577	15,510	14,478
Spring	3	16,572	3/7/2015	13,703	13,283	13,103	13,076	13,268	13,758	14,408	15,177	15,752	15,971	15,884	15,597	15,176	14,762	14,553	14,611	14,983	15,761	16,572	16,265	15,783	15,030	14,107	13,218
Spring	3	16,400	3/8/2015	12,539		12,361	12,183	11,975	11,980	12,198	12,680	13,189	13,928	14,575	14,840	14,870	14,859	14,724	14,432	14,244	14,370	14,806	15,505	16,400	16,129	15,235	14,074
Spring	3	16,717	3/9/2015	12,989	12,301	11,979	11,852	11,923	12,298	13,380	15,325	16,461	16,566	16,083	16,085	15,816	15,508	15,286	14,984	14,782	14,839	15,227	15,830	16,717	16,372	15,394	14,080
Spring	3	16,610	3/10/2015	12,905	12,162	11,778	11,632	11,681	12,028	13,118	15,120	16,188	16,235	15,968	15,715	15,431	15,174	15,003	14,825	14,804	15,063	15,553	16,147	16,610	16,125	15,095	13,700
Spring	3	15,840	3/11/2015	12,498	11,711	11,331	11,105	11,087	11,395	12,406	14,302	15,381	15,334	15,094	15,021	14,884	14,684	14,516	14,267	14,149	14,231	14,577	15,026	15,840	15,583	14,634	13,362
Spring	3	16,839	3/12/2015	12,196	11,446	11,089	10,939	10,988	11,347	12,477	14,529	15,625	15,714	15,617	15,553	15,392	15,170	15,047	14,847	14,741	14,889	15,330	15,941	16,839	16,623	15,735	14,446
Spring	3	16,560	3/13/2015	13,295	12,545	12,203	12,073	12,126	12,472	13,547	15,514	16,541	16,560	16,357	16,122	15,865	15,535	15,247	14,916	14,672	14,725	14,990	15,433	16,101	15,815	15,111	14,042
Spring	3	15,563	3/14/2015	12,969	12,176	11,713	11,468	11,349	11,424	11,784	12,542	13,411	14,364	15,075	15,467	15,563	15,436	15,200	14,978	14,858	14,952	15,191	15,372	15,487	15,092	14,409	13,499
Spring	3	16,279	3/15/2015	12,524	11,761	11,318	11,026	10,899	10,924	11,164	11,706	12,355	13,309	14,049	14,382	14,568	14,597	14,388	14,240	14,334	14,745	15,258	15,699	16,279	15,912	14,977	13,816
Spring	3	16,474	3/16/2015	12,777	12,092	11,773	11,633	11,697	12,116	13,268	15,280	16,247	16,251	16,033	15,850	15,598	15,303	15,141	14,868	14,673	14,723	15,108	15,684	16,474	16,137	15,111	13,751
Spring	3	16,826	3/17/2015	12,569	11,824	11,381	11,177	11,154	11,488	12,558	14,535	15,694	16,000	16,136	16,218	16,079	15,653	15,388	15,158	14,961	15,193	15,575	15,978	16,826	16,612	15,723	14,443
Spring	3	17,853	3/18/2015	13,310	12,588	12,243	12,130	12,199	12,606	13,733	15,743	16,765	16,797	16,615	16,501	16,354	16,163	16,038	15,831	15,773	15,982	16,464	17,005	17,853	17,573	16,564	15,169
Spring	3	17,212	3/19/2015	13,970	13,229	12,886	12,746	12,770	13,161	14,291	16,265	17,198	17,079	16,836	16,692	16,463	16,146	15,904	15,570	15,398	15,511	15,872	16,356	17,212	17,005	16,092	14,793
Spring	3	16,984	3/20/2015	13,602	12,863	12,495	12,362	12,398	12,759	13,849	15,764	16,755	16,984	16,920	16,818	16,599	16,335	16,273	16,151	16,067	16,181	16,389	16,575	16,937	16,548	15,725	14,595
Spring	3	15,695	3/21/2015	13,476	12,662	12,215	11,967	11,823	11,918	12,298	13,068	13,898	14,862	15,504	15,695	15,470	14,961	14,442	14,048	13,828	13,930	14,248	14,576	15,104	14,877	14,260	13,418
Spring	3	16,441	3/22/2015	12,517	11,822	11,416	11,223	11,186	11,340	11,704	12,308	12,982	13,750	14,226	14,465	14,542	14,454	14,234	14,000	13,968	14,217	14,796	15,434	16,441	16,335	15,482	14,346
Spring	3	17,333	3/23/2015	13,326	12,669	12,406	12,343	12,431	12,907	14,122	16,126	17,115	17,076	16,890	16,765	16,549	16,284	16,020	15,696	15,468	15,573	16,008	16,494	17,333	17,118	16,087	14,727
Spring	3	16,945	3/24/2015	13,523	12,812	12,479	12,394	12,428	12,823	13,973	15,963	16,945	16,854	16,456	16,103	15,818	15,509	15,276	14,990	14,847	14,965	15,332	15,730	16,574	16,447	15,465	14,107
Spring	3	16,448	3/25/2015	12,929	12,277	11,961	11,833	11,914	12,335	13,509	15,497	16,363	16,172	15,756	15,441	15,136	14,843	14,648	14,430	14,443	14,767	15,326	15,889	16,448	16,055	15,034	13,646
Spring	3	16,030	3/26/2015	12,455	11,690	11,293	11,084	11,039	11,321	12,378	14,292	15,255	15,420	15,399	15,301	15,192	15,064	15,142	15,112	15,082	15,323	15,645	15,802	16,030	15,598	14,585	13,216
Spring	3	15,683	3/27/2015	12,036	11,288	10,847	10,648	10,643	10,951	11,990	13,947	15,113	15,440	15,621	15,683	15,556	15,322	15,228	15,006	14,879	14,970	15,071	15,112	15,447	15,223	14,485	13,430
Spring	3	15,402	3/28/2015	12,376	11,588	11,140	10,908	10,818	10,923	11,330	12,133	13,068	14,115	14,847	15,208	15,201	15,027	14,762	14,474	14,353	14,431	14,683	14,936	15,402	15,220	14,601	13,738
Spring	3	15,238	3/29/2015	12,817	12,120	11,729	11,510	11,437	11,535	11,857	12,387	13,044	13,743	14,066	14,072	13,929	13,702	13,401	13,117	12,999	13,189	13,708	14,240	15,166	15,238	14,372	13,242
Spring	3	16,512	3/30/2015	12,229	11,589	11,285	11,167	11,230	11,606	12,733	14,708	15,847	16,210	16,353	16,512	16,477	16,302	16,066	15,736	15,396	15,479	15,811	16,008	16,389	16,112	15,086	13,689
Spring	3	15,964	3/31/2015	12,473	11,712	11,317	11,152	11,162	11,545	12,673	14,551	15,447	15,390	15,228	15,089	14,857	14,563	14,458	14,331	14,358	14,620	15,075	15,379	15,964	15,759	14,762	13,374
Spring	4	15,783	4/1/2015	12,231	11,537	11,190	11,066	11,095	11,520	12,694	14,653	15,537	15,467	15,195	15,041	14,876	14,625	14,468	14,205	14,073	14,187	14,537	14,913	15,693	15,783	14,897	13,605
Spring	4	15,818	4/2/2015	12,476	11,765	11,443	11,342	11,381	11,770	12,903	14,787	15,755	15,818	15,717	15,611	15,264	14,847	14,517	14,182	13,952	13,967	14,220	14,528	15,199	15,113	14,239	12,958
Spring	4	14,652	4/3/2015	11,748	10,921	10,474	10,227	10,173	10,415	11,219	12,607	13,565	14,190	14,531	14,652	14,561	14,322	14,197	14,054	13,939	14,017	14,138	14,139	14,404	14,185	13,455	12,432
Spring	4	14,370	4/4/2015	11,397	10,609	10,155	9,888	9,761	9,851	10,217	10,911	11,773	12,811	13,356	13,581	13,608	13,413	13,137	12,887	12,773	12,900	13,224	13,538	14,202	14,370	13,843	13,032
Spring	4	14,278	4/5/2015	12,082	11,261	10,808	10,593	10,510	10,582	10,900	11,414	12,181	12,911	13,337	13,379	13,359	13,223	12,843	12,492	12,336	12,479	12,808	13,234	14,075	14,278	13,562	12,506
Spring	4	15,410	4/6/2015	11,502	10,819	10,521	10,451	10,538	10,959	12,117	14,003	15,067	15,274	15,187	15,106	14,940	14,676	14,517	14,276	14,106	14,165	14,444	14,740	15,410	15,373	14,356	13,014
Spring	4	16,021	4/7/2015	11,814	10,982	10,587	10,407	10,401	10,738	11,830	13,730	14,832	15,091	15,217	15,383	15,379	15,287	15,260	15,096	15,061	15,259	15,601	15,745	16,021	15,744	14,733	13,350
Spring	4	16,441	4/8/2015	12,128	11,363	10,983	10,825	10,841	11,197	12,326	14,156	15,164	15,250	15,134	15,108	15,103	15,077	15,204	15,182	15,257	15,542	15,959	16,159	16,441	16,095	15,138	13,743
Spring	4	16,455	4/9/2015	12,563	11,810	11,396	11,227	11,240	11,576	12,673	14,572	15,699	15,990	16,120	16,223	16,173	16,013	15,890	15,724	15,640	15,747	16,023	16,171	16,455	16,180	15,215	13,830
Spring	4	15,697	4/10/2015	12,592	11,782	11,328	11,103	11,090	11,385	12,398	14,221	15,338	15,599	15,667	15,697	15,581	15,371	15,237	15,045	14,891	14,918	14,959	14,911	15,066	14,871	14,071	12,979
Spring	4	13,799	4/11/2015	11,854	10,993	10,515	10,260	10,173	10,270	10,677	11,317	12,142	12,873	13,312	13,428	13,313	13,057	12,776	12,518	12,359	12,446	12,711	12,967	13,543	13,799	13,241	12,390
Spring	4	13,853	4/12/2015	11,439	10,761	10,361	10,175	10,111	10,203	10,509	10,913	11,545	12,141	12,486	12,558	12,499	12,335	12,092	11,908	11,899	12,143	12,572	12,886	13,573	13,853	12,952	11,813
Spring	4	14,644	4/13/2015	10,732	10,128	9,783	9,647	9,692	10,110	11,255	12,941	13,952	14,129	14,172	14,219	14,161	14,024	13,944	13,783	13,669	13,736	13,949	14,057	14,587	14,644	13,602	12,235
Spring	4	14,745	4/14/2015	11,017	10,290	9,861	9,663	9,645	9,940	10,948	12,646	13,855	14,207	14,314	14,410	14,305	14,161	14,121	13,943	13,833	13,935	14,145	14,298	14,745	14,624	13,617	12,236
Spring	4	14,493	4/15/2015	11,053	10,283	9,881	9,678	9,674	10,015	11,085	12,700	13,683	13,826	13,858	13,867	13,826	13,717	13,713	13,571	13,495	13,535	13,725	13,811	14,272	14,493	13,540	12,205
Spring	4	14,485	4/16/2015	10,989	10,229	9,834	9,650	9,699	10,079	11,184	12,823	13,806	13,908	13,917	13,918	13,835	13,687	13,624	13,442	13,368	13,417	13,620	13,767	14,291	14,485	13,555	12,242
Spring	4	14,781	4/17/2015	11,058	10,265	9,860	9,645	9,619	9,907	10,869	12,532	13,742	14,296	14,629	14,781	14,726	14,533	14,378	14,103	13,865	13,763	13,733	13,649	13,800	13,963	13,225	12,155
Spring	4	13,032	4/18/2015	11,022	10,220	9,747	9,489	9,395	9,477	9,859	10,384	11,234	11,983	12,451	12,541	12,479	12,304	12,117	11,985	11,955	12,131	12,410	12,516	12,752	13,032	12,426	11,501
Spring	4	13,353	4/19/2015	10,579	9,864	9,442	9,194	9,097	9,160	9,417	9,753	10,408	11,153	11,627	11,834	11,853	11,778	11,611	11,476	11,474	11,716	12,147	12,508	13,074	13,353	12,532	11,483
Spring	4	15,288	4/20/2015	10,490	9,858	9,520	9,378	9,394	9,733	10,698	12,116	13,360	14,101	14,589	14,917	15,076	15,124	15,128	14,985	14,897	15,024	15,272	15,276	15,288	14,909	13,846	12,542
Spring	4	14,565	4/21/2015	11,359	10,589	10,172	9,945	9,903	10,191	11,077	12,591	13,742	14,247	14,412	14,545	14,565	14,392	14,277	14,013	13,824	13,820	13,894	13,904	14,220	14,471	13,599	12,290
Spring	4	14,448	4/22/2015	11,116	10,326	9,908	9,730	9,685	10,040	11,005	12,420	13,467	13,759	13,857	13,937	13,934	13,881	13,902	13,796	13,710	13,854	14,123	14,241	14,448	14,431	13,476	12,182
Spring	4	14,939	4/23/2015	11,039	10,281	9,878	9,669	9,674	10,001	11,003	12,431	13,523	13,899	14,074	14,236	14,277	14,250	14,241	14,025	13,910	14,029	14,276	14,436	14,759	14,939	14,107	12,859
Spring	4	14,577	4/24/2015	11,709	10,981	10,560	10,373	10,369	10,665	11,607	12,987	14,052	14,430	14,502	14,529	14,429	14,253	14,118	13,927	13,752	13,769	13,926	14,058	14,381	14,577	13,898	12,883
Spring	4	13,287	4/25/2015	11,826	11,042	10,621	10,385	10,328	10,452	10,835	11,389	12,143	12,748	12,996	12,984	12,795	12,548	12,329	12,101	12,038	12,164	12,467	12,688	12,986	13,287	12,730	11,870
Spring	4	13,679	4/26/2015	10,956	10,283	9,876	9,663	9,580	9,643	9,882	10,227	10,864	11,575	12,029	12,207	12,366	12,417	12,371	12,286	12,317	12,559	12,975	13,231	13,561	13,679	12,788	11,641
Spring	4	14,635	4/27/2015	10,594	9,940	9,567	9,420	9,454	9,801	10,881	12,565	13,727	14,005	14,064	14,123	14,154	14,117	14,090	13,903	13,845	13,970	14,271	14,357	14,536	14,635	13,667	12,281
Spring	4	14,470	4/28/2015	11,079	10,317	9,897	9,715	9,711	10,029	11,068	12,738	13,801	14,022	14,057	14,037	13,797	13,683	13,723	13,566	13,463	13,552	13,725	13,782	14,072	14,470	13,555	12,176
Spring	4	14,357	4/29/2015	10,946	10,157	9,746	9,532	9,520	9,837	10,827	12,474	13,489	13,717	13,756	13,855	13,879	13,792	13,817	13,700	13,565	13,588	13,691	13,737	14,075	14,357	13,442	12,076
Spring	4	14,359	4/30/2015	10,858	10,081	9,657	9,451	9,456	9,767	10,780	12,441	13,573	13,844	13,929	13,967	13,889	13,789	13,773	13,658	13,577	13,617	13,759	13,832	14,129	14,359	13,466	12,163
Spring	5	13,960	5/1/2015	10,940	10,175	9,755	9,551	9,529	9,820	10,754	12,369	13,502	13,853	13,931	13,960	13,884	13,743	13,665	13,491	13,323	13,301	13,298	13,239	13,429	13,807	13,190	12,142
Spring	5	12,974	5/2/2015	11,057	10,249	9,785	9,561	9,484	9,592	9,942	10,566	11,469	12,139	12,369	12,375	12,277	12,130	11,959	11,794	11,759	11,891	12,118	12,217	12,478	12,974	12,443	11,517
Spring	5	13,460	5/3/2015	10,577	9,849	9,467	9,200	9,081	9,132	9,304	9,628	10,343	11,100	11,596	11,835	11,929	11,978	11,920	11,863	11,927	12,146	12,517	12,745	13,043	13,460	12,665	11,433
Spring	5	15,035	5/4/2015	10,330	9,615	9,248	9,084	9,083	9,426	10,389	12,037	13,160	13,566	13,873	14,196	14,425	14,552	14,696	14,677	14,629	14,688	14,751	14,614	14,673	15,035	14,067	12,577
Spring	5	15,037	5/5/2015	11,223	10,355	9,880	9,625	9,540	9,813	10,733	12,386	13,696	14,173	14,441	14,615	14,823	14,863	14,957	14,984	14,981	14,983	14,926	14,716	14,745	15,037	14,070	12,558
Spring	5	14,769	5/6/2015	11,216	10,346	9,869	9,595	9,506	9,732	10,638	12,239	13,446	13,862	14,150	14,352	14,423	14,400	14,463	14,416	14,404	14,480	14,536	14,407	14,391	14,769	13,845	12,382
Spring	5	15,335	5/7/2015	11,030	10,160	9,677	9,430	9,363	9,652	10,491	12,116	13,323	13,806	14,197	14,596	14,838	14,957	15,152	15,214	15,241	15,335	15,277	15,022	14,893	15,202	14,334	12,776
Spring	5	14,887	5/8/2015	11,406	10,490	9,951	9,628	9,527	9,764	10,575	12,139	13,411	13,983	14,385	14,650	14,816	14,833	14,887	14,797	14,715	14,680	14,536	14,232	14,104	14,354	13,661	12,444
Spring	5	13,831	5/9/2015	11,198	10,274	9,758	9,436	9,292	9,357	9,647	10,179	11,127	12,023	12,537	12,685	12,717	12,722	12,681	12,722	12,835	13,000	13,236	13,307	13,408	13,831	13,333	12,341
Spring	5	15,908	5/10/2015	11,239	10,422	9,883	9,567	9,427	9,443	9,557	9,900	10,796	11,868	12,699	13,222	13,559	13,787	14,007	14,246	14,523	14,909	15,256	15,348	15,439	15,908	15,220	13,838
Spring	5	16,955	5/11/2015	12,477	11,528	10,994	10,646	10,520	10,792	11,664	13,347	14,900	15,705	16,313	16,778	16,955	16,934	16,952	16,840	16,764	16,738	16,585	16,289	16,112	16,175	15,094	13,452
Spring	5	17,077	5/12/2015	11,984	11,073	10,572	10,294	10,196	10,460	11,351	12,980	14,278	14,806	15,192	15,688	16,184	16,606	16,955	17,073	17,012	17,077	16,968	16,613	16,344	16,359	15,263	13,486
Spring	5	14,543	5/13/2015	11,858	10,829	10,235	9,905	9,789	10,002	10,757	12,348	13,562	13,991	14,235	14,463	14,543	14,474	14,484	14,358	14,257	14,303	14,302	14,166	14,137	14,464	13,684	12,255
Spring	5	14,510	5/14/2015	10,965	10,127	9,672	9,449	9,433	9,719	10,546	12,179	13,282	13,632	13,860	14,058	14,157	14,127	14,209	14,187	14,195	14,309	14,362	14,245	14,177	14,510	13,781	12,347
Spring	5	14,394	5/15/2015	11,013	10,165	9,693	9,472	9,424	9,705	10,468	12,047	13,202	13,682	13,995	14,245	14,355	14,341	14,394	14,277	14,108	14,123	14,020	13,778	13,674	13,971	13,388	12,244
Spring	5	13,564	5/16/2015	11,070	10,196	9,673	9,389	9,277	9,352	9,618	10,219	11,258	12,230	12,839	13,146	13,215	13,141	13,056	12,980	12,949	13,009	13,164	13,187	13,265	13,564	13,079	12,134
Spring	5	15,349	5/17/2015	11,088	10,278	9,792	9,503	9,361	9,364	9,409	9,798	10,705	11,749	12,577	13,148	13,590	13,869	13,992	14,148	14,388	14,789	15,160	15,262	15,140	15,349	14,591	13,117
Spring	5	15,068	5/18/2015	11,704	10,783	10,263	9,961	9,857	10,103	10,950	12,545	13,770	14,214	14,470	14,678	14,832	14,859	15,006	15,032	15,022	15,066	15,068	14,869	14,757	14,965	14,097	12,632
Spring	5	15,353	5/19/2015	11,264	10,416	9,955	9,710	9,639	9,919	10,775	12,405	13,720	14,223	14,565	14,901	15,050	15,033	15,014	14,978	14,974	15,160	15,346	15,265	15,153	15,353	14,544	13,096
Spring	5	14,297	5/20/2015	11,763	10,823	10,256	9,878	9,730	9,949	10,672	12,309	13,495	13,909	14,098	14,253	14,297	14,246	14,278	14,151	14,007	14,026	14,092	13,982	13,956	14,285	13,651	12,304
Spring	5	14,381	5/21/2015	11,013	10,167	9,747	9,486	9,458	9,752	10,563	12,192	13,326	13,758	13,949	14,161	14,203	14,188	14,212	14,108	14,077	14,106	14,142	14,028	14,027	14,381	13,735	12,359
Spring	5	14,514	5/22/2015	11,069	10,202	9,736	9,489	9,445	9,688	10,494	12,029	13,278	13,787	14,116	14,348	14,472	14,507	14,514	14,368	14,233	14,177	14,128	13,903	13,667	13,824	13,351	12,227
Spring	5	12,796	5/23/2015	11,044	10,137	9,639	9,349	9,220	9,264	9,400	9,979	10,815	11,630	12,101	12,268	12,241	12,129	11,943	11,799	11,799	11,993	12,303	12,455	12,459	12,796	12,516	11,605
Spring	5	13,198	5/24/2015	10,609	9,856	9,411	9,162	9,046	9,083	9,120	9,502	10,241	11,073	11,741	12,091	12,293	12,357	12,350	12,356	12,483	12,713	12,969	12,971	12,872	13,198	12,873	11,942
Spring	5	14,992	5/25/2015	10,910	10,099	9,608	9,317	9,183	9,245	9,380	9,874	10,691	11,761	12,647	13,206	13,623	13,873	13,909	13,923	14,056	14,377	14,720	14,714	14,671	14,992	14,336	12,908
Spring	5	18,470	5/26/2015	11,607	10,745	10,271	10,013	9,967	10,219	11,030	12,769	14,295	15,089	15,794	16,453	16,830	17,088	17,544	17,913	18,229	18,470	18,462	18,130	17,785	17,785	16,890	15,097
Spring	5	19,544	5/27/2015	13,446	12,303	11,643	11,241	11,069	11,277	12,042	13,727	15,168	15,992	16,733	17,514	18,155	18,623	19,109	19,354	19,524	19,544	19,254	18,700	18,211	17,996	16,973	15,225
Spring	5	19,363	5/28/2015	13,615	12,503	11,837	11,405	11,248	11,453	12,241	14,030	15,466	16,175	16,763	17,361	17,900	18,324	18,831	19,143	19,363	19,296	18,925	18,280	17,766	17,654	16,780	14,948
Spring	5	17,854	5/29/2015	13,222	12,028	11,309	10,879	10,673	10,830	11,510	13,169	14,587	15,435	16,055	16,548	16,890	17,071	17,348	17,534	17,738	17,854	17,602	16,928	16,303	16,202	15,546	14,171
Spring	5	17,405	5/30/2015	12,756	11,677	10,986	10,547	10,331	10,334	10,443	11,058	12,103	13,300	14,296	15,076	15,726	16,177	16,484	16,790	17,076	17,324	17,405	17,084	16,494	16,383	15,883	14,655
Spring	5	15,409	5/31/2015	13,343	12,284	11,625	11,201	10,928	10,865	10,855	11,166	11,963	13,000	13,999	14,688	15,162	15,409	15,401	15,141	14,837	14,709	14,768	14,550	14,218	13,963	13,089	11,848
Summer	6	14,984	6/1/2015	10,734	10,030	9,636	9,430	9,422	9,731	10,652	12,270	13,583	14,164	14,504	14,783	14,880	14,801	14,745	14,586	14,532	14,702	14,984	14,953	14,804	14,623	13,697	12,329
Summer	6	14,864	6/2/2015	11,137	10,349	9,923	9,724	9,664	9,940	10,836	12,495	13,773	14,275	14,607	14,820	14,864	14,778	14,721	14,545	14,499	14,637	14,850	14,828	14,684	14,649	13,898	12,508
Summer	6	14,352	6/3/2015	11,246	10,409	9,968	9,755	9,708	10,017	10,798	12,451	13,570	13,890	14,029	14,242	14,302	14,246	14,247	14,157	14,128	14,186	14,261	14,169	14,062	14,352	13,876	12,476
Summer	6	14,460	6/4/2015	11,163	10,272	9,819	9,589	9,563	9,847	10,635	12,273	13,470	13,886

Contains Proprietary Material
Do Not Distribute

Summer	6	19,755	6/12/2015	14,488	13,201	12,351	11,815	11,550	11,661	12,296	13,911	15,309	16,154	16,900	17,631	18,275	18,664	19,224	19,552	19,720	19,755	19,420	18,700	17,983	17,856	17,343	16,049
Summer	6	17,740	6/13/2015	14,618	13,490	12,771	12,323	12,034	11,964	12,008	12,645	13,752	14,842	15,593	16,125	16,497	16,715	16,839	17,033	17,296	17,605	17,740	17,496	16,908	16,562	16,119	14,850
Summer	6	16,648	6/14/2015	13,451	12,304	11,564	11,071	10,766	10,646	10,530	10,946	11,812	12,928	13,962	14,696	15,210	15,570	15,754	15,933	16,182	16,447	16,648	16,502	16,052	16,045	15,440	13,979
Summer	6	15,928	6/15/2015	12,588	11,633	11,037	10,707	10,612	10,875	11,727	13,246	14,542	15,190	15,545	15,844	15,928	15,854	15,806	15,615	15,469	15,496	15,550	15,397	15,192	15,036	14,257	12,919
Summer	6	16,707	6/16/2015	11,679	10,828	10,343	10,137	10,081	10,351	11,098	12,691	14,049	14,725	15,158	15,565	15,835	16,048	16,361	16,426	16,427	16,594	16,707	16,593	16,436	16,412	15,934	14,436
Summer	6	16,423	6/17/2015	12,958	11,898	11,254	10,862	10,668	10,797	11,420	13,078	14,475	15,145	15,493	15,769	15,963	15,997	16,195	16,272	16,385	16,423	16,257	15,862	15,516	15,525	14,977	13,481
Summer	6	16,482	6/18/2015	12,054	11,053	10,471	10,159	10,043	10,249	10,924	12,465	13,776	14,498	15,004	15,426	15,743	15,913	16,156	16,335	16,447	16,482	16,374	15,998	15,684	15,689	15,184	13,819
Summer	6	18,328	6/19/2015	12,439	11,434	10,864	10,568	10,471	10,720	11,463	13,023	14,455	15,355	16,100	16,807	17,393	17,734	18,034	18,230	18,328	18,275	18,034	17,494	16,842	16,445	15,934	14,558
Summer	6	14,307	6/20/2015	13,028	11,841	11,049	10,542	10,258	10,150	10,175	10,762	11,767	12,806	13,572	14,006	14,235	14,307	14,279	14,190	14,129	14,130	14,134	13,995	13,876	13,987	13,694	12,838
Summer	6	16,718	6/21/2015	11,835	11,038	10,531	10,238	10,122	10,148	10,280	10,667	11,511	12,612	13,610	14,338	14,833	15,072	15,164	15,295	15,628	16,107	16,613	16,718	16,506	16,459	16,144	14,793
Summer	6	20,012	6/22/2015	13,354	12,302	11,657	11,239	11,122	11,342	12,066	13,665	15,269	16,405	17,259	17,959	18,511	18,863	19,275	19,518	19,779	20,012	19,999	19,687	19,092	18,653	17,893	16,044
Summer	6	20,923	6/23/2015	14,276	13,008	12,217	11,684	11,518	11,683	12,356	13,932	15,564	16,681	17,601	18,594	19,322	19,543	19,981	20,512	20,923	20,867	20,511	20,008	19,458	19,049	18,272	16,563
Summer	6	19,392	6/24/2015	14,777	13,353	12,500	11,935	11,598	11,630	12,166	13,764	15,317	16,242	16,891	17,511	17,937	18,234	18,565	18,869	19,168	19,392	19,338	18,866	18,199	17,743	17,133	15,471
Summer	6	18,472	6/25/2015	13,778	12,520	11,756	11,267	11,038	11,136	11,661	13,138	14,662	15,634	16,348	17,002	17,513	17,859	18,256	18,452	18,472	18,402	18,178	17,704	17,293	17,190	16,663	15,195
Summer	6	16,993	6/26/2015	13,692	12,599	11,919	11,505	11,321	11,447	11,995	13,259	14,521	15,268	15,763	16,126	16,363	16,516	16,766	16,878	16,921	16,993	16,865	16,427	15,831	15,467	15,050	13,849
Summer	6	14,227	6/27/2015	12,493	11,435	10,775	10,363	10,141	10,107	10,158	10,744	11,748	12,729	13,481	13,935	14,170	14,227	14,115	13,986	13,862	13,846	13,876	13,798	13,701	13,798	13,388	12,492
Summer	6	13,700	6/28/2015	11,470	10,661	10,149	9,871	9,703	9,691	9,798	10,096	10,795	11,740	12,635	13,254	13,587	13,677	13,576	13,405	13,341	13,496	13,700	13,684	13,548	13,502	13,046	11,992
Summer	6	15,859	6/29/2015	10,914	10,196	9,761	9,534	9,514	9,755	10,471	11,801	13,172	13,994	14,565	15,060	15,400	15,558	15,727	15,750	15,693	15,750	15,859	15,676	15,480	15,388	14,957	13,600
Summer	6	17,912	6/30/2015	12,221	11,244	10,667	10,341	10,204	10,390	10,993	12,365	13,870	14,854	15,608	16,300	16,840	17,207	17,645	17,842	17,897	17,912	17,771	17,369	16,881	16,705	16,181	14,775
Summer	7	18,681	7/1/2015	13,268	12,232	11,606	11,258	11,126	11,338	12,061	13,488	14,879	15,792	16,422	16,960	17,323	17,545	17,921	18,202	18,436	18,650	18,681	18,304	17,762	17,403	16,766	15,248
Summer	7	17,682	7/2/2015	13,652	12,460	11,653	11,187	10,962	11,022	11,537	12,861	14,381	15,390	16,103	16,697	17,090	17,345	17,598	17,682	17,585	17,486	17,311	16,845	16,404	16,290	15,833	14,576
Summer	7	16,376	7/3/2015	13,194	12,083	11,330	10,835	10,540	10,487	10,603	11,262	12,309	13,328	14,127	14,677	15,007	15,191	15,379	15,596	15,882	16,230	16,376	15,971	15,323	15,056	14,613	13,632
Summer	7	13,992	7/4/2015	12,529	11,472	10,772	10,342	10,123	10,065	10,057	10,403	11,198	12,143	12,974	13,519	13,817	13,992	13,876	13,631	13,444	13,409	13,510	13,455	13,245	13,173	12,952	12,441
Summer	7	16,692	7/5/2015	11,646	10,807	10,220	9,867	9,693	9,629	9,575	9,866	10,690	11,775	12,797	13,642	14,302	14,824	15,188	15,505	15,895	16,322	16,688	16,692	16,438	16,382	16,068	14,818
Summer	7	20,106	7/6/2015	13,336	12,277	11,592	11,212	11,023	11,195	11,729	13,061	14,642	15,836	16,897	17,863	18,640	19,099	19,494	19,717	19,877	20,058	20,106	19,696	19,126	18,786	18,036	16,273
Summer	7	20,988	7/7/2015	14,563	13,329	12,540	12,091	11,906	12,088	12,777	14,272	15,880	16,967	17,890	18,818	19,588	20,107	20,604	20,868	20,977	20,988	20,903	20,481	20,016	19,803	18,980	17,320
Summer	7	21,638	7/8/2015	15,656	14,457	13,659	13,155	12,898	13,049	13,683	15,233	16,899	17,992	18,721	19,515	20,261	20,808	21,319	21,603	21,638	21,621	21,397	20,866	20,114	19,668	18,748	16,888
Summer	7	17,917	7/9/2015	15,030	13,717	12,783	12,229	11,926	11,998	12,543	13,769	15,080	15,866	16,385	16,859	17,166	17,370	17,729	17,857	17,889	17,917	17,761	17,362	17,059	17,020	16,371	14,926
Summer	7	18,844	7/10/2015	13,530	12,501	11,891	11,551	11,395	11,525	12,107	13,382	14,760	15,737	16,462	17,042	17,575	17,895	18,227	18,461	18,663	18,844	18,800	18,320	17,667	17,272	16,795	15,442
Summer	7	18,602	7/11/2015	13,924	12,678	11,874	11,337	11,026	10,909	10,958	11,483	12,644	13,974	15,117	15,974	16,635	17,054	17,371	17,651	18,025	18,374	18,602	18,434	17,884	17,534	17,058	15,819
Summer	7	20,162	7/12/2015	14,414	13,232	12,428	11,881	11,509	11,331	11,181	11,518	12,494	13,780	15,092	16,279	17,331	18,109	18,650	19,080	19,532	19,915	20,162	19,983	19,574	19,469	18,942	17,334
Summer	7	21,122	7/13/2015	15,595	14,329	13,513	13,016	12,749	12,871	13,508	14,909	16,537	17,709	18,664	19,526	20,171	20,681	21,042	21,122	21,098	21,111	20,992	20,454	19,713	19,239	18,384	16,532
Summer	7	20,048	7/14/2015	14,778	13,526	12,786	12,370	12,177	12,368	13,045	14,483	16,108	17,211	18,090	18,738	19,090	19,338	19,791	20,048	20,048	19,822	19,676	19,516	19,180	19,108	18,436	16,922
Summer	7	21,117	7/15/2015	15,374	14,214	13,513	13,075	12,883	13,057	13,765	15,260	16,913	18,010	18,917	19,752	20,351	20,726	21,094	21,117	20,958	20,755	20,327	19,622	18,826	18,339	17,356	15,643
Summer	7	17,211	7/16/2015	13,947	12,712	11,936	11,410	11,147	11,212	11,729	12,888	14,251	15,015	15,504	15,905	16,171	16,328	16,593	16,752	16,921	17,154	17,211	16,884	16,366	16,170	15,647	14,253
Summer	7	17,773	7/17/2015	12,789	11,705	11,050	10,670	10,523	10,680	11,207	12,434	13,883	14,877	15,586	16,217	16,702	17,002	17,376	17,583	17,686	17,773	17,717	17,170	16,630	16,559	16,082	14,861
Summer	7	16,838	7/18/2015	13,563	12,524	11,904	11,487	11,283	11,268	11,476	11,969	12,878	13,957	14,819	15,359	15,609	15,747	15,885	15,967	16,210	16,549	16,838	16,830	16,646	16,707	16,406	15,422
Summer	7	21,368	7/19/2015	14,223	13,241	12,611	12,222	11,959	11,879	11,915	12,277	13,353	14,896	16,437	17,772	18,898	19,758	20,273	20,478	20,655	21,045	21,368	21,132	20,777	20,677	19,835	18,255
Summer	7	24,437	7/20/2015	16,655	15,498	14,738	14,201	13,972	14,153	14,894	16,293	18,284	19,917	21,243	22,383	23,213	23,689	24,143	24,291	24,357	24,437	24,365	23,813	22,971	22,463	21,343	19,206
Summer	7	22,683	7/21/2015	17,170	15,746	14,727	14,061	13,655	13,685	14,265	15,581	17,027	17,946	18,611	19,325	19,963	20,504	21,207	21,741	22,268	22,683	22,622	22,024	21,236	20,760	19,759	17,865
Summer	7	19,755	7/22/2015	15,969	14,581	13,642	12,967	12,570	12,569	13,082	14,369	15,893	16,886	17,578	18,193	18,657	19,001	19,402	19,631	19,739	19,755	19,595	19,004	18,344	18,037	17,359	15,776
Summer	7	18,942	7/23/2015	14,195	12,975	12,226	11,737	11,466	11,549	12,123	13,420	14,967	16,012	16,757	17,399	17,855	18,206	18,587	18,782	18,834	18,942	18,843	18,432	17,863	17,692	17,050	15,527
Summer	7	18,199	7/24/2015	13,987	12,778	12,010	11,541	11,305	11,413	11,923	13,111	14,634	15,743	16,509	17,155	17,631	17,903	18,127	18,199	18,195	18,152	17,923	17,376	16,759	16,584	16,045	14,764
Summer	7	15,778	7/25/2015	13,402	12,307	11,590	11,132	10,873	10,797	10,910	11,397	12,397	13,456	14,323	14,896	15,240	15,397	15,439	15,483	15,571	15,705	15,778	15,538	15,181	15,280	14,895	13,929
Summer	7	17,080	7/26/2015	12,855	11,965	11,367	10,980	10,796	10,769	10,899	11,189	11,931	12,930	13,869	14,589	15,112	15,568	15,945	16,179	16,414	16,797	17,080	17,044	16,889	16,952	16,456	15,232
Summer	7	20,877	7/27/2015	13,884	12,947	12,356	12,006	11,868	12,104	12,842	14,169	15,720	16,834	17,695	18,456	19,052	19,522	20,056	20,467	20,750	20,877	20,790	20,346	19,740	19,549	18,652	16,939
Summer	7	23,171	7/28/2015	15,298	14,062	13,313	12,856	12,652	12,776	13,473	14,828	16,469	17,725	18,901	20,088	21,071	21,895	22,597	22,989	23,162	23,171	23,032	22,430	21,683	21,364	20,333	18,359
Summer	7	24,437	7/29/2015	16,400	15,009	14,102	13,546	13,245	13,308	13,901	15,262	17,099	18,597	19,966	21,301	22,374	23,094	23,720	24,029	24,216	24,437	24,399	23,946	23,277	22,875	21,801	19,746
Summer	7	23,865	7/30/2015	17,763	16,286	15,333	14,662	14,328	14,404	15,017	16,442	18,181	19,627	20,937	22,041	22,736	23,181	23,626	23,865	23,702	23,297	22,747	21,989	21,326	20,989	20,053	18,334
Summer	7	21,880	7/31/2015	16,633	15,317	14,469	13,857	13,525	13,524	14,019	15,205	16,867	18,186	19,191	20,103	20,707	21,046	21,431	21,690	21,830	21,880	21,649	20,930	19,952	19,330	18,401	16,781
Summer	8	18,939	8/1/2015	15,085	13,769	12,895	12,302	11,982	11,910	12,037	12,529	13,713	15,148	16,445	17,340	18,038	18,588	18,837	18,939	18,932	18,826	18,781	18,530	17,971	17,756	17,123	15,816
Summer	8	19,003	8/2/2015	14,383	13,226	12,404	11,829	11,456	11,243	11,172	11,370	12,288	13,522	14,671	15,598	16,388	16,969	17,412	17,772	18,199	18,670	19,003	18,880	18,380	18,299	17,589	16,122
Summer	8	22,919	8/3/2015	14,660	13,625	12,969	12,530	12,369	12,589	13,323	14,679	16,469	17,852	18,960	19,982	20,820	21,443	22,077	22,476	22,743	22,919	22,715	21,997	21,208	20,936	19,969	18,184
Summer	8	21,920	8/4/2015	16,449	15,205	14,413	13,960	13,743	13,897	14,620	15,695	16,827	17,595	18,531	19,541	20,477	21,137	21,759	21,920	21,549	21,060	20,887	20,374	19,770	19,531	18,490	16,768
Summer	8	20,212	8/5/2015	15,053	13,786	12,953	12,413	12,125	12,184	12,756	13,874	15,374	16,506	17,395	18,103	18,701	19,263	19,774	20,099	20,170	20,212	20,006	19,357	18,604	18,435	17,508	15,795
Summer	8	18,322	8/6/2015	14,126	12,894	12,126	11,627	11,372	11,481	12,105	13,245	14,673	15,705	16,447	17,056	17,501	17,795	18,085	18,263	18,300	18,322	18,163	17,682	17,264	17,314	16,482	15,073
Summer	8	18,025	8/7/2015	13,666	12,543	11,814	11,379	11,161	11,272	11,830	12,926	14,356	15,453	16,231	16,845	17,271	17,572	17,858	17,999	18,025	18,008	17,842	17,290	16,650	16,550	15,852	14,577
Summer	8	15,982	8/8/2015	13,189	12,137	11,451	11,004	10,736	10,679	10,799	11,180	12,205	13,311	14,208	14,816	15,208	15,450	15,535	15,591	15,728	15,916	15,982	15,674	15,362	15,510	14,955	13,928
Summer	8	15,622	8/9/2015	12,761	11,814	11,206	10,775	10,542	10,457	10,517	10,703	11,469	12,519	13,388	13,989	14,376	14,662	14,786	14,854	14,987	15,311	15,622	15,597	15,364	15,527	14,877	13,654
Summer	8	18,988	8/10/2015	12,401	11,529	10,988	10,663	10,560	10,801	11,524	12,691	14,159	15,284	16,142	16,858	17,467	17,914	18,405	18,733	18,901	18,988	18,882	18,386	17,833	17,792	16,793	15,280
Summer	8	17,745	8/11/2015	13,864	12,794	12,192	11,844	11,710	11,950	12,794	14,095	15,452	16,351	16,939	17,391	17,586	17,620	17,676	17,596	17,538	17,616	17,745	17,598	17,494	17,429	16,534	15,148
Summer	8	19,898	8/12/2015	13,834	12,849	12,267	11,895	11,729	11,893	12,631	13,806	15,260	16,407	17,247	18,004	18,585	18,953	19,352	19,573	19,733	19,898	19,834	19,306	18,681	18,510	17,482	15,837
Summer	8	19,250	8/13/2015	14,208	13,065	12,307	11,830	11,601	11,698	12,366	13,450	14,884	15,944	16,730	17,423	17,952	18,293	18,708	18,951	19,111	19,250	19,154	18,647	18,026	17,907	16,950	15,375
Summer	8	20,051	8/14/2015	13,814	12,651	11,912	11,430	11,170	11,287	11,923	12,963	14,413	15,618	16,590	17,388	17,990	18,423	18,980	19,455	19,796	20,051	19,981	19,386	18,652	18,475	17,506	16,035
Summer	8	20,198	8/15/2015	14,556	13,352	12,556	12,045	11,748	11,671	11,861	12,263	13,334	14,680	15,980	17,157	18,157	18,935	19,501	19,851	20,115	20,198	20,056	19,522	18,951	18,761	17,822	16,417
Summer	8	20,923	8/16/2015	15,012	13,908	13,117	12,599	12,255	12,072	12,115	12,270	13,187	14,550	15,864	17,101	18,149	18,958	19,546	19,991	20,367	20,694	20,923	20,673	20,199	20,170	19,103	17,427
Summer	8	24,047	8/17/2015	15,815	14,648	13,885	13,397	13,164	13,279	13,995	15,191	16,835	18,357	19,745	21,068	22,105	22,849	23,502	23,790	23,934	24,047	23,991	23,470	22,857	22,553	21,117	19,100
Summer	8	24,216	8/18/2015	17,163	15,746	14,878	14,281	13,937	13,998	14,698	15,901	17,520	18,898	20,219	21,536	22,642	23,484	24,113	24,216	23,939	23,700	23,295	22,530	21,995	21,731	20,407	18,503
Summer	8	23,624	8/19/2015	16,695	15,481	14,695	14,185	13,958	14,072	14,814	16,056	17,627	18,918	20,002	21,026	21,874	22,510	23,098	23,456	23,598	23,624	23,406	22,664	21,911	21,645	20,362	18,480
Summer	8	22,513	8/20/2015	16,677	15,403	14,591	14,143	13,920	14,084	14,870	16,183	17,662	18,815	19,744	20,628	21,314	21,770	22,252	22,484	22,513	22,468	22,146	21,410	20,828	20,667	19,521	17,879
Summer	8	21,166	8/21/2015	16,296	15,116	14,373	13,931	13,743	13,969	14,794	16,058	17,432	18,414	19,046	19,496	19,811	20,217	20,671	20,940	21,061	21,166	20,935	20,253	19,738	19,494	18,439	16,989
Summer	8	17,706	8/22/2015	15,472	14,291	13,477	12,938	12,582	12,427	12,565	12,870	13,716	14,781	15,748	16,473	16,923	17,179	17,332	17,413	17,541	17,697	17,706	17,423	17,100	17,107	16,326	15,189
Summer	8	17,474	8/23/2015	13,982	13,015	12,367	11,930	11,654	11,567	11,678	11,887	12,548	13,581	14,503	15,262	15,855	16,279	16,507	16,664	16,793	17,061	17,355	17,385	17,374	17,474	16,628	15,358
Summer	8	20,880	8/24/2015	14,100	13,188	12,645	12,364	12,280	12,558	13,462	14,829	16,197	17,212	18,018	18,797	19,404	19,902	20,441	20,707	20,833	20,880	20,856	20,370	19,964	19,793	18,536	16,877
Summer	8	21,733	8/25/2015	15,268	14,110	13,392	12,917	12,721	12,944	13,778	15,155	16,572	17,584	18,447	19,317	19,997	20,542	21,045	21,454	21,660	21,733	21,562	21,003	20,633	20,311	18,965	17,201
Summer	8	20,376	8/26/2015	15,538	14,315	13,515	12,996	12,725	12,819	13,617	14,933	16,144	17,058	17,879	18,655	19,262	19,670	20,085	20,301	20,376	20,334	20,076	19,365	18,848	18,563	17,267	15,567
Summer	8	18,281	8/27/2015	13,936	12,787	12,098	11,656	11,454	11,582	12,280	13,463	14,744	15,703	16,394	17,004	17,459	17,769	18,120	18,274	18,281	18,272	18,185	17,709	17,416	17,311	16,193	14,647
Summer	8	17,691	8/28/2015	13,195	12,156	11,496	11,112	10,924	11,042	11,776	12,939	14,186	15,152	15,866	16,444	16,878	17,147	17,445	17,562	17,595	17,691	17,556	17,054	16,768	16,576	15,614	14,309
Summer	8	16,517	8/29/2015	12,985	11,945	11,288	10,840	10,576	10,530	10,738	11,088	11,962	13,134	14,120	14,773	15,200	15,491	15,704	15,905	16,140	16,410	16,517	16,250	16,139	16,078	15,298	14,227
Summer	8	18,767	8/30/2015	13,096	12,221	11,600	11,210	10,992	10,921	11,019	11,233	11,984	13,162	14,354	15,424	16,391	17,056	17,503	17,840	18,171	18,550	18,767	18,612	18,758	18,710	17,596	16,110
Summer	8	22,568	8/31/2015	14,697	13,634	12,987	12,564	12,400	12,603	13,538	14,981	16,409	17,562	18,637	19,701	20,624	21,298	21,887	22,221	22,419	22,568	22,484	21,898	21,655	21,199	19,624	17,609
Fall	9	21,458	9/1/2015	15,766	14,522	13,684	13,115	12,796	12,885	13,679	15,033	16,250	17,251	18,173	19,040	19,641	20,126	20,702	21,038	21,301	21,458	21,245	20,552	20,231	19,788	18,249	16,370
Fall	9	22,766	9/2/2015	14,655	13,526	12,776	12,326	12,111	12,281	13,186	14,690	15,919	16,851	17,851	18,915	19,911	20,727	21,533	22,072	22,520	22,766	22,595	21,906	21,567	21,011	19,392	17,398
Fall	9	22,759	9/3/2015	15,599	14,359	13,553	13,062	12,785	12,908	13,772	15,264	16,484	17,503	18,541	19,596	20,547	21,351	22,097	22,460	22,707	22,759	22,350	21,714	21,608	21,121	19,658	17,756
Fall	9	18,396	9/4/2015	16,014	14,814	14,019	13,522	13,225	13,301	13,951	15,151	16,106	16,728	17,174	17,595	17,949	18,143	18,333	18,396	18,355	18,343	18,090	17,381	17,115	16,742	15,692	14,314
Fall	9	15,974	9/5/2015	12,956	11,915	11,246	10,809	10,528	10,476	10,674	10,987	11,748	12,815	13,651	14,193	14,537	14,815	15,051	15,291	15,571	15,851	15,974	15,690	15,587	15,359	14,527	13,411
Fall	9	17,102	9/6/2015	12,262	11,364	10,797	10,441	10,233	10,186	10,301	10,480	11,163	12,243	13,166	13,947	14,648	15,228	15,721	16,136	16,584	16,978	17,102	16,719	16,556	16,251	15,359	14,237
Fall	9	20,921	9/7/2015	13,071	12,127	11,500	11,102	10,883	10,868	11,134	11,449	12,176	13,389	14,679	15,884	16,996	17,963	18,800	19,535	20,158	20,699	20,921	20,570	20,664	20,301	18,862	17,000
Fall	9	24,368	9/8/2015	15,383	14,269	13,601	13,194	12,999	13,209	14,192	15,904	17,322	18,527	19,766	21,045	22,186	23,167	23,963	24,291	24,368	24,338	24,032	23,444	23,380	22,570	20,841	18,725
Fall	9	24,275	9/9/2015	16,886	15,577	14,750	14,237	13,974	14,081	14,983	16,547	17,786	18,830	19,918	21,031	21,920	22,706	23,492	23,961	24,199	24,275	23,917	23,267	23,202	22,483	20,960	18,908
Fall	9	19,108	9/10/2015	17,067	15,790	15,021	14,508	14,240	14,291	15,170	16,775	17,806	18,335	18,768	19,048	19,108	19,067	18,947	18,593	18,313	18,198	18,131	17,970	18,003	17,369	16,174	14,838
Fall	9	16,866	9/11/2015	13,504	12,490	11,876	11,490	11,363	11,555	12,429	14,049	15,093	15,632	16,012	16,294	16,418	16,444	16,633	16,729	16,799	16,866	16,764	16,424	16,519	16,094	15,097	13,844
Fall	9	15,638	9/12/2015	12,606	11,652	11,057	10,676	10,498	10,490	10,767	11,244	12,077	13,099	13,878	14,446	14,808	15,056	15,218	15,303	15,397	15,395	15,342	15,364	15,638	15,255	14,471	13,468
Fall	9	15,810	9/13/2015	12,396	11,563	11,028	10,667	10,484	10,437	10,588	10,929	11,535	12,523

Contains Proprietary Material
Do Not Distribute

Fall	9	15,610	9/21/2015	11,104	10,329	9,905	9,681	9,666	9,936	10,890	12,480	13,425	13,852	14,177	14,466	14,653	14,719	14,900	14,913	14,906	14,984	15,068	15,216	15,610	14,930	13,764	12,343
Fall	9	15,611	9/22/2015	11,162	10,384	9,959	9,756	9,717	10,010	10,950	12,692	13,725	14,111	14,454	14,790	14,948	14,984	15,090	15,051	15,047	15,086	15,129	15,219	15,611	14,991	13,844	12,431
Fall	9	15,879	9/23/2015	11,185	10,415	9,986	9,774	9,706	9,958	10,867	12,427	13,389	13,862	14,192	14,534	14,762	14,891	15,103	15,225	15,352	15,526	15,607	15,564	15,879	15,220	14,026	12,574
Fall	9	16,032	9/24/2015	11,332	10,506	10,076	9,833	9,743	10,027	10,965	12,628	13,619	14,108	14,503	14,891	15,165	15,316	15,550	15,621	15,682	15,764	15,715	15,663	16,032	15,399	14,217	12,781
Fall	9	14,817	9/25/2015	11,493	10,658	10,175	9,884	9,797	10,014	10,907	12,496	13,458	13,953	14,264	14,541	14,668	14,653	14,726	14,701	14,613	14,608	14,545	14,595	14,817	14,237	13,369	12,251
Fall	9	13,602	9/26/2015	11,150	10,319	9,826	9,567	9,453	9,501	9,818	10,430	11,206	12,076	12,571	12,746	12,770	12,678	12,534	12,433	12,458	12,635	12,899	13,256	13,602	13,174	12,453	11,523
Fall	9	14,456	9/27/2015	10,577	9,876	9,434	9,192	9,086	9,119	9,355	9,769	10,424	11,259	11,808	12,078	12,253	12,392	12,437	12,489	12,628	13,035	13,511	13,987	14,456	13,827	12,810	11,641
Fall	9	16,780	9/28/2015	10,672	9,966	9,583	9,411	9,392	9,698	10,712	12,487	13,529	14,034	14,478	14,907	15,233	15,486	15,792	15,891	15,938	16,060	16,199	16,475	16,780	16,030	14,790	13,359
Fall	9	18,219	9/29/2015	12,089	11,227	10,738	10,486	10,423	10,725	11,795	13,727	14,882	15,495	16,035	16,558	17,012	17,359	17,670	17,758	17,759	17,791	17,860	18,151	18,219	17,473	16,266	14,757
Fall	9	18,044	9/30/2015	13,422	12,514	12,020	11,760	11,671	11,969	13,031	15,035	16,349	16,991	17,450	17,872	18,044	18,027	17,920	17,589	17,114	16,785	16,685	16,695	16,660	15,895	14,637	13,133
Fall	10	15,367	10/1/2015	11,765	10,835	10,321	10,016	9,930	10,154	11,048	12,813	13,801	14,154	14,346	14,525	14,522	14,481	14,490	14,397	14,369	14,470	14,779	15,260	15,367	14,713	13,675	12,292
Fall	10	14,927	10/2/2015	11,098	10,324	9,874	9,648	9,590	9,828	10,759	12,538	13,599	14,059	14,291	14,447	14,452	14,404	14,364	14,231	14,186	14,293	14,550	14,927	14,844	14,256	13,424	12,332
Fall	10	14,032	10/3/2015	11,226	10,430	9,977	9,695	9,566	9,657	9,995	10,716	11,611	12,569	13,229	13,509	13,519	13,409	13,178	12,990	12,938	13,068	13,418	13,962	14,032	13,583	12,903	11,983
Fall	10	14,440	10/4/2015	11,022	10,263	9,811	9,531	9,400	9,417	9,662	10,126	10,746	11,604	12,145	12,355	12,442	12,413	12,289	12,194	12,295	12,658	13,255	14,047	14,440	13,835	12,833	11,657
Fall	10	15,416	10/5/2015	10,603	9,937	9,595	9,436	9,466	9,825	10,898	12,792	13,803	14,063	14,144	14,253	14,283	14,261	14,280	14,181	14,107	14,250	14,584	15,191	15,416	14,720	13,580	12,193
Fall	10	15,427	10/6/2015	11,039	10,295	9,894	9,692	9,680	9,979	11,005	12,882	13,825	13,989	14,053	14,144	14,190	14,176	14,257	14,203	14,199	14,402	14,704	15,267	15,427	14,740	13,612	12,198
Fall	10	15,509	10/7/2015	10,974	10,200	9,818	9,624	9,590	9,879	10,866	12,744	13,766	13,969	14,091	14,221	14,308	14,297	14,389	14,417	14,456	14,635	14,868	15,343	15,509	14,825	13,693	12,280
Fall	10	15,192	10/8/2015	11,050	10,289	9,855	9,671	9,613	9,884	10,856	12,687	13,643	13,844	13,920	14,024	14,031	14,037	14,104	14,055	14,039	14,178	14,404	14,998	15,192	14,585	13,581	12,233
Fall	10	15,478	10/9/2015	11,009	10,223	9,826	9,633	9,592	9,858	10,784	12,568	13,690	14,206	14,577	14,916	15,056	15,065	15,101	15,010	14,911	15,014	15,237	15,478	15,146	14,487	13,609	12,485
Fall	10	13,613	10/10/2015	11,320	10,460	9,921	9,596	9,445	9,491	9,843	10,540	11,298	12,121	12,540	12,645	12,534	12,346	12,139	11,995	12,031	12,318	12,794	13,495	13,613	13,192	12,547	11,667
Fall	10	13,768	10/11/2015	10,752	10,052	9,645	9,403	9,311	9,351	9,610	10,100	10,696	11,494	12,013	12,192	12,190	12,118	12,031	12,005	12,160	12,553	13,015	13,678	13,768	13,280	12,393	11,452
Fall	10	15,334	10/12/2015	10,525	9,826	9,464	9,265	9,230	9,479	10,175	11,374	12,296	13,006	13,493	13,783	13,908	13,931	13,979	13,989	14,072	14,335	14,727	15,334	15,310	14,545	13,418	12,099
Fall	10	15,855	10/13/2015	10,920	10,158	9,729	9,514	9,485	9,782	10,811	12,691	13,822	14,258	14,596	14,776	14,841	14,904	15,003	14,957	14,881	14,993	15,246	15,855	15,741	14,992	13,858	12,496
Fall	10	15,285	10/14/2015	11,266	10,417	9,945	9,672	9,609	9,863	10,848	12,642	13,595	13,871	14,074	14,293	14,405	14,406	14,416	14,320	14,240	14,311	14,602	15,285	15,273	14,578	13,446	12,086
Fall	10	15,204	10/15/2015	10,909	10,151	9,740	9,513	9,510	9,803	10,852	12,766	13,764	13,924	13,912	13,898	13,850	13,761	13,787	13,731	13,748	13,992	14,380	15,152	15,204	14,605	13,586	12,247
Fall	10	14,673	10/16/2015	11,052	10,273	9,845	9,598	9,571	9,856	10,870	12,730	13,802	14,125	14,259	14,294	14,180	14,021	13,941	13,820	13,718	13,795	14,055	14,673	14,570	14,041	13,277	12,227
Fall	10	14,091	10/17/2015	11,160	10,366	9,917	9,684	9,597	9,694	10,085	10,870	11,737	12,543	12,897	12,973	12,878	12,724	12,527	12,409	12,438	12,740	13,304	14,091	14,035	13,595	12,988	12,135
Fall	10	15,285	10/18/2015	11,212	10,512	10,117	9,888	9,802	9,889	10,210	10,809	11,492	12,326	12,745	12,867	12,945	13,012	13,061	13,055	13,174	13,601	14,328	15,284	15,285	14,776	13,811	12,762
Fall	10	16,227	10/19/2015	11,775	11,025	10,616	10,486	10,523	10,940	12,114	14,174	15,287	15,404	15,260	15,129	14,906	14,635	14,446	14,247	14,198	14,524	15,242	16,227	16,168	15,486	14,375	12,946
Fall	10	15,710	10/20/2015	11,701	10,891	10,472	10,263	10,222	10,515	11,588	13,526	14,514	14,626	14,594	14,622	14,563	14,420	14,349	14,208	14,181	14,397	14,856	15,710	15,579	14,854	13,738	12,352
Fall	10	15,580	10/21/2015	11,147	10,386	9,976	9,754	9,714	10,004	11,011	12,949	14,054	14,331	14,477	14,586	14,569	14,439	14,406	14,292	14,259	14,421	14,847	15,580	15,400	14,715	13,624	12,291
Fall	10	15,656	10/22/2015	11,102	10,342	9,914	9,676	9,645	9,937	10,990	12,925	13,990	14,210	14,359	14,524	14,598	14,568	14,598	14,555	14,509	14,640	15,050	15,656	15,409	14,737	13,675	12,323
Fall	10	14,975	10/23/2015	11,081	10,289	9,795	9,536	9,460	9,763	10,768	12,659	13,740	14,002	14,089	14,112	14,058	13,939	13,865	13,737	13,625	13,810	14,263	14,975	14,778	14,335	13,601	12,589
Fall	10	14,399	10/24/2015	11,518	10,767	10,341	10,104	10,056	10,178	10,603	11,442	12,288	13,182	13,598	13,632	13,534	13,368	13,176	13,044	13,092	13,359	13,934	14,399	14,126	13,624	12,969	12,062
Fall	10	14,578	10/25/2015	11,109	10,367	9,911	9,632	9,507	9,540	9,782	10,304	11,042	11,931	12,739	13,163	13,383	13,455	13,230	13,003	12,905	13,111	13,687	14,578	14,399	13,756	12,768	11,631
Fall	10	15,792	10/26/2015	10,624	9,997	9,670	9,508	9,542	9,933	11,137	13,213	14,342	14,412	14,303	14,251	14,124	13,954	13,864	13,730	13,731	14,034	14,787	15,792	15,638	15,004	14,004	12,653
Fall	10	15,868	10/27/2015	11,496	10,786	10,427	10,280	10,308	10,663	11,822	13,883	14,921	14,956	14,722	14,446	14,330	14,108	14,002	13,862	13,878	14,180	14,916	15,868	15,663	15,021	13,978	12,622
Fall	10	16,247	10/28/2015	11,482	10,755	10,355	10,149	10,140	10,456	11,554	13,562	14,612	14,722	14,797	14,878	14,830	14,817	14,931	14,884	14,943	15,328	16,023	16,247	15,836	15,187	14,111	12,795
Fall	10	15,494	10/29/2015	11,587	10,804	10,352	10,135	10,075	10,312	11,333	13,240	14,525	14,795	14,933	15,008	14,933	14,880	14,898	14,670	14,453	14,396	14,767	15,494	15,244	14,616	13,545	12,273
Fall	10	14,820	10/30/2015	11,151	10,292	9,816	9,552	9,508	9,778	10,783	12,726	13,834	13,985	14,002	14,076	14,028	13,829	13,700	13,503	13,475	13,675	14,158	14,820	14,538	14,049	13,327	12,353
Fall	10	13,708	10/31/2015	11,287	10,569	10,140	9,920	9,838	9,987	10,445	11,267	12,133	12,912	13,234	13,199	12,993	12,784	12,610	12,484	12,515	12,841	13,372	13,708	13,370	13,051	12,540	11,755
Fall	11	14,993	11/1/2015	10,562	9,651	9,384	9,367	9,485	9,836	10,439	11,259	12,189	12,839	13,163	13,278	13,205	13,074	12,956	13,023	13,825	14,993	14,773	14,244	13,542	12,490	11,373	10,491
Fall	11	15,931	11/2/2015	9,937	9,603	9,503	9,557	9,979	11,198	13,009	13,902	14,061	14,076	14,162	14,134	14,093	14,053	14,009	14,088	14,810	15,931	15,723	15,166	14,384	13,310	12,064	11,000
Fall	11	15,937	11/3/2015	10,348	9,989	9,828	9,844	10,229	11,377	13,089	13,924	13,992	14,026	14,110	14,143	14,118	14,218	14,238	14,321	14,866	15,937	15,780	15,220	14,421	13,292	11,976	10,875
Fall	11	15,825	11/4/2015	10,215	9,859	9,677	9,702	10,061	11,186	12,948	13,843	13,926	13,927	14,009	14,038	13,997	14,059	14,054	14,165	14,731	15,825	15,693	15,178	14,432	13,311	12,035	10,929
Fall	11	16,157	11/5/2015	10,242	9,874	9,689	9,694	10,041	11,135	12,906	13,824	14,085	14,254	14,424	14,541	14,576	14,619	14,608	14,610	15,203	16,157	15,917	15,409	14,707	13,614	12,279	11,124
Fall	11	16,006	11/6/2015	10,412	9,981	9,768	9,719	10,024	11,026	12,785	13,840	14,355	14,714	14,943	14,986	14,889	15,006	14,878	14,803	15,313	16,006	15,621	15,011	14,348	13,450	12,357	11,232
Fall	11	14,357	11/7/2015	10,341	9,811	9,528	9,396	9,452	9,853	10,455	11,262	12,127	12,648	12,842	12,851	12,760	12,625	12,596	12,761	13,584	14,357	14,021	13,589	13,044	12,344	11,527	10,686
Fall	11	14,918	11/8/2015	10,024	9,619	9,376	9,318	9,415	9,723	10,214	10,899	11,615	12,036	12,185	12,275	12,336	12,300	12,351	12,609	13,645	14,918	14,783	14,372	13,766	12,796	11,728	10,837
Fall	11	16,203	11/9/2015	10,264	9,972	9,838	9,904	10,344	11,564	13,412	14,297	14,288	14,187	14,159	14,065	13,980	13,980	13,986	14,128	15,073	16,203	16,061	15,550	14,819	13,720	12,395	11,272
Fall	11	16,326	11/10/2015	10,571	10,210	10,031	10,051	10,431	11,567	13,452	14,367	14,562	14,607	14,651	14,618	14,591	14,653	14,612	14,773	15,561	16,326	16,075	15,527	14,826	13,762	12,527	11,403
Fall	11	16,431	11/11/2015	10,648	10,237	10,018	9,998	10,263	11,137	12,514	13,615	14,311	14,726	14,962	15,017	14,939	14,907	14,823	14,912	15,716	16,431	16,092	15,529	14,825	13,721	12,411	11,316
Fall	11	16,415	11/12/2015	10,601	10,210	9,985	10,006	10,332	11,424	13,291	14,303	14,686	14,897	15,049	15,166	15,130	15,122	15,053	15,161	15,848	16,415	16,150	15,620	14,928	13,832	12,485	11,347
Fall	11	15,665	11/13/2015	10,539	10,092	9,863	9,851	10,168	11,205	12,947	13,820	13,992	14,068	14,195	14,164	14,032	14,091	14,058	14,123	14,875	15,665	15,391	14,882	14,293	13,462	12,426	11,381
Fall	11	15,304	11/14/2015	10,625	10,214	9,985	9,881	10,020	10,488	11,207	12,010	12,819	13,265	13,526	13,542	13,354	13,104	13,072	13,326	14,330	15,304	15,058	14,622	14,169	13,469	12,575	11,707
Fall	11	15,262	11/15/2015	11,029	10,589	10,343	10,280	10,353	10,684	11,178	11,758	12,389	12,811	12,940	13,001	12,961	12,830	12,865	13,234	14,364	15,262	15,081	14,448	14,043	13,041	11,884	11,010
Fall	11	16,287	11/16/2015	10,266	9,930	9,813	9,884	10,343	11,519	13,427	14,369	14,444	14,330	14,254	14,231	14,137	14,150	14,114	14,275	15,224	16,287	16,161	15,716	15,009	13,880	12,603	11,464
Fall	11	16,616	11/17/2015	10,819	10,506	10,359	10,422	10,845	12,070	13,987	14,824	14,777	14,586	14,440	14,254	14,114	14,104	14,117	14,422	15,519	16,616	16,570	16,237	15,651	14,553	13,234	12,112
Fall	11	16,647	11/18/2015	11,426	11,100	10,939	10,992	11,415	12,605	14,481	15,317	15,228	15,064	14,855	14,642	14,425	14,391	14,412	14,659	15,780	16,647	16,474	16,075	15,395	14,290	12,878	11,682
Fall	11	16,355	11/19/2015	10,909	10,461	10,254	10,233	10,568	11,672	13,581	14,532	14,759	14,855	14,929	14,939	14,852	14,832	14,804	14,982	15,834	16,355	16,113	15,649	14,952	13,849	12,517	11,378
Fall	11	15,576	11/20/2015	10,617	10,198	9,971	9,912	10,194	11,192	13,011	13,961	14,161	14,207	14,195	14,107	13,936	13,899	13,861	13,982	14,765	15,576	15,279	14,813	14,283	13,504	12,530	11,542
Fall	11	15,124	11/21/2015	10,828	10,433	10,230	10,167	10,341	10,842	11,607	12,418	13,183	13,467	13,391	13,227	13,000	12,842	12,840	13,103	14,191	15,124	14,909	14,487	14,038	13,355	12,497	11,576
Fall	11	15,744	11/22/2015	10,798	10,398	10,093	10,002	10,065	10,375	10,896	11,567	12,489	13,117	13,410	13,660	13,815	13,881	13,905	14,194	15,199	15,744	15,518	15,040	14,425	13,475	12,432	11,467
Fall	11	17,439	11/23/2015	10,832	10,504	10,368	10,469	10,906	12,099	14,108	15,062	15,162	15,033	14,985	14,886	14,745	14,790	14,867	15,191	16,378	17,439	17,362	17,000	16,450	15,408	14,176	13,018
Fall	11	17,211	11/24/2015	12,217	11,728	11,541	11,561	12,008	13,168	15,058	15,941	15,918	15,679	15,504	15,283	15,077	15,016	14,995	15,235	16,289	17,211	17,147	16,861	16,275	15,284	13,986	12,792
Fall	11	16,828	11/25/2015	12,035	11,599	11,421	11,456	11,857	12,911	14,577	15,562	15,764	15,626	15,426	15,184	14,898	14,831	14,786	14,935	15,946	16,828	16,577	16,131	15,563	14,667	13,510	12,301
Fall	11	14,394	11/26/2015	11,412	10,880	10,579	10,460	10,569	10,996	11,667	12,499	13,435	14,013	14,287	14,394	13,997	13,274	12,611	12,235	12,630	12,919	12,812	12,703	12,552	12,120	11,507	10,761
Fall	11	14,683	11/27/2015	10,163	9,832	9,633	9,619	9,796	10,344	11,103	11,684	12,310	12,737	12,847	12,828	12,760	12,688	12,673	12,874	13,961	14,683	14,388	13,912	13,400	12,681	11,786	10,831
Fall	11	14,954	11/28/2015	10,070	9,614	9,331	9,236	9,327	9,685	10,333	11,114	12,150	12,939	13,435	13,654	13,706	13,630	13,497	13,681	14,534	14,954	14,692	14,306	13,880	13,254	12,390	11,486
Fall	11	16,211	11/29/2015	10,735	10,358	10,154	10,103	10,226	10,567	11,167	11,827	12,617	13,069	13,177	13,202	13,183	13,159	13,257	13,673	15,132	16,211	16,201	15,839	15,305	14,351	13,292	12,273
Fall	11	17,692	11/30/2015	11,514	11,108	10,961	11,031	11,486	12,698	14,513	15,600	15,732	15,665	15,599	15,528	15,418	15,481	15,470	15,707	16,831	17,692	17,605	17,189	16,538	15,417	13,969	12,695

Contains Proprietary Material
Do Not Distribute

Max	6,253
Max Month	7
PST	5,054
Winter	4,497
Spring	3,789
Summer	4,827
Fall	4,005

Source: ISONE 2015 SIL Filing

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	4,108	12/1/2014	2,619	2,462	2,403	2,390	2,407	2,552	2,964	3,424	3,536	3,505	3,522	3,526	3,546	3,531	3,534	3,522	3,626	3,992	4,108	4,052	3,927	3,775	3,461	3,112
Winter	12	4,392	12/2/2014	2,813	2,665	2,604	2,578	2,602	2,788	3,204	3,695	3,852	3,860	3,831	3,839	3,811	3,837	3,838	3,868	3,997	4,329	4,392	4,323	4,233	4,009	3,666	3,255
Winter	12	4,285	12/3/2014	2,959	2,808	2,723	2,676	2,700	2,850	3,202	3,669	3,809	3,857	3,885	3,872	3,845	3,839	3,812	3,842	3,970	4,231	4,285	4,196	4,085	3,885	3,576	3,183
Winter	12	4,322	12/4/2014	2,926	2,772	2,694	2,678	2,727	2,891	3,324	3,789	3,887	3,813	3,773	3,729	3,639	3,646	3,656	3,672	3,809	4,237	4,322	4,265	4,171	4,019	3,735	3,370
Winter	12	4,313	12/5/2014	3,089	2,926	2,825	2,843	2,881	3,025	3,458	3,888	4,012	3,958	3,975	3,931	3,868	3,891	3,902	3,895	4,024	4,313	4,312	4,233	4,051	3,867	3,628	3,322
Winter	12	4,023	12/6/2014	3,010	2,827	2,711	2,650	2,618	2,662	2,826	3,058	3,299	3,539	3,680	3,739	3,721	3,711	3,667	3,648	3,729	4,023	3,996	3,892	3,757	3,646	3,440	3,199
Winter	12	4,273	12/7/2014	2,934	2,753	2,638	2,594	2,599	2,649	2,763	2,937	3,150	3,382	3,459	3,479	3,467	3,435	3,418	3,455	3,613	4,166	4,273	4,260	4,181	4,032	3,745	3,431
Winter	12	4,830	12/8/2014	3,183	3,029	2,976	2,970	3,026	3,201	3,618	4,086	4,282	4,314	4,341	4,363	4,313	4,306	4,310	4,299	4,429	4,737	4,830	4,709	4,590	4,390	4,033	3,613
Winter	12	4,627	12/9/2014	3,284	3,076	2,984	2,938	2,932	3,098	3,426	3,837	4,121	4,202	4,256	4,308	4,300	4,325	4,292	4,270	4,320	4,593	4,627	4,525	4,371	4,074	3,796	3,352
Winter	12	4,514	12/10/2014	3,044	2,884	2,783	2,744	2,763	2,915	3,290	3,809	3,916	3,945	3,963	3,947	3,949	3,969	3,923	3,855	4,075	4,443	4,514	4,478	4,367	4,155	3,819	3,422
Winter	12	4,578	12/11/2014	3,118	2,957	2,852	2,826	2,871	3,011	3,425	3,855	4,017	4,043	4,043	4,053	4,027	4,007	4,012	3,987	4,089	4,469	4,578	4,490	4,382	4,203	3,873	3,478
Winter	12	4,427	12/12/2014	3,167	2,992	2,928	2,908	2,944	3,078	3,470	3,967	4,065	4,057	4,059	4,027	3,943	3,950	3,888	3,875	3,969	4,393	4,427	4,331	4,172	4,043	3,813	3,500
Winter	12	4,102	12/13/2014	3,174	2,959	2,870	2,825	2,815	2,872	3,015	3,258	3,476	3,644	3,694	3,649	3,578	3,487	3,452	3,426	3,567	4,021	4,102	4,014	3,905	3,767	3,617	3,353
Winter	12	4,170	12/14/2014	3,062	2,884	2,781	2,717	2,709	2,746	2,834	2,978	3,123	3,383	3,454	3,499	3,498	3,525	3,427	3,461	3,577	4,094	4,170	4,110	4,046	3,853	3,602	3,238
Winter	12	4,443	12/15/2014	2,929	2,794	2,720	2,704	2,742	2,943	3,341	3,833	3,950	3,931	3,856	3,798	3,734	3,721	3,675	3,654	3,781	4,307	4,443	4,385	4,292	4,122	3,803	3,416
Winter	12	4,518	12/16/2014	3,069	2,919	2,841	2,824	2,850	3,030	3,414	3,909	4,054	4,036	4,068	4,062	4,008	4,012	3,979	3,962	4,076	4,438	4,518	4,421	4,289	4,087	3,749	3,332
Winter	12	4,302	12/17/2014	2,970	2,792	2,687	2,635	2,655	2,798	3,164	3,678	3,806	3,789	3,736	3,695	3,660	3,642	3,650	3,679	3,830	4,221	4,302	4,239	4,127	3,926	3,640	3,253
Winter	12	4,439	12/18/2014	2,925	2,746	2,646	2,630	2,660	2,806	3,240	3,728	3,879	3,838	3,862	3,890	3,824	3,764	3,760	3,783	3,897	4,335	4,439	4,365	4,272	4,116	3,821	3,429
Winter	12	4,481	12/19/2014	3,059	2,867	2,796	2,746	2,778	2,929	3,319	3,795	3,979	3,966	3,999	3,940	3,851	3,851	3,808	3,861	3,981	4,369	4,481	4,362	4,225	4,080	3,870	3,565
Winter	12	4,280	12/20/2014	3,223	3,022	2,892	2,859	2,854	2,917	3,054	3,295	3,554	3,772	3,869	3,918	3,947	3,880	3,851	3,847	3,944	4,253	4,280	4,147	4,043	3,917	3,719	3,452
Winter	12	4,295	12/21/2014	3,141	2,958	2,827	2,783	2,660	2,787	2,904	3,067	3,282	3,554	3,657	3,741	3,770	3,769	3,735	3,752	3,844	4,249	4,295	4,258	4,154	3,995	3,710	3,352
Winter	12	4,411	12/22/2014	3,048	2,868	2,784	2,737	2,777	2,916	3,282	3,763	3,927	3,950	3,957	3,928	3,874	3,828	3,795	3,814	3,955	4,338	4,411	4,342	4,207	4,019	3,713	3,333
Winter	12	4,279	12/23/2014	2,998	2,783	2,669	2,634	2,654	2,777	3,140	3,588	3,800	3,839	3,890	3,879	3,871	3,836	3,847	3,817	3,873	4,224	4,279	4,186	4,072	3,919	3,655	3,300
Winter	12	4,005	12/24/2014	2,967	2,725	2,578	2,524	2,543	2,640	2,853	3,197	3,440	3,642	3,792	3,888	3,849	3,853	3,820	3,793	3,841	4,005	3,944	3,677	3,526	3,377	3,249	3,077
Winter	12	3,364	12/25/2014	2,825	2,570	2,435	2,353	2,297	2,341	2,428	2,569	2,815	3,063	3,211	3,209	3,200	3,206	3,135	3,076	3,049	3,338	3,363	3,364	3,347	3,292	3,163	2,935
Winter	12	3,919	12/26/2014	2,729	2,547	2,488	2,466	2,501	2,581	2,776	3,022	3,184	3,345	3,425	3,428	3,400	3,361	3,288	3,270	3,340	3,813	3,919	3,875	3,752	3,644	3,442	3,174
Winter	12	3,726	12/27/2014	2,938	2,767	2,655	2,602	2,608	2,667	2,769	2,932	3,104	3,281	3,356	3,357	3,279	3,219	3,118	3,087	3,188	3,635	3,726	3,680	3,574	3,447	3,301	3,062
Winter	12	3,821	12/28/2014	2,838	2,616	2,497	2,438	2,409	2,432	2,504	2,662	2,794	3,049	3,202	3,321	3,301	3,335	3,272	3,266	3,372	3,770	3,821	3,756	3,645	3,488	3,289	3,006
Winter	12	4,271	12/29/2014	2,793	2,632	2,558	2,538	2,575	2,746	3,014	3,367	3,586	3,711	3,701	3,693	3,701	3,642	3,632	3,625	3,685	4,167	4,271	4,172	4,063	3,884	3,656	3,339
Winter	12	4,547	12/30/2014	3,072	2,885	2,816	2,799	2,838	2,994	3,263	3,606	3,805	3,926	4,028	4,035	3,961	3,933	3,866	3,863	3,959	4,403	4,547	4,452	4,353	4,176	3,931	3,619
Winter	12	4,440	12/31/2014	3,308	3,145	3,067	3,021	3,020	3,146	3,381	3,704	3,893	3,965	4,008	3,988	3,907	3,885	3,837	3,812	3,927	4,364	4,440	4,301	4,104	3,910	3,716	3,551
Winter	1	4,144	1/1/2015	3,394	3,243	3,112	3,032	3,002	3,036	3,127	3,232	3,254	3,371	3,481	3,565	3,569	3,538	3,503	3,501	3,609	4,051	4,144	4,077	3,946	3,796	3,536	3,279
Winter	1	4,208	1/2/2015	3,031	2,889	2,777	2,750	2,767	2,885	3,103	3,367	3,555	3,701	3,762	3,761	3,719	3,724	3,668	3,621	3,692	4,112	4,208	4,089	3,968	3,850	3,650	3,373
Winter	1	4,303	1/3/2015	3,112	2,968	2,866	2,824	2,831	2,899	3,021	3,181	3,358	3,507	3,648	3,698	3,740	3,736	3,772	3,815	3,907	4,266	4,303	4,192	4,021	3,811	3,595	3,317
Winter	1	4,044	1/4/2015	3,018	2,860	2,744	2,678	2,650	2,687	2,746	2,894	3,036	3,289	3,459	3,598	3,685	3,713	3,679	3,660	3,709	4,018	4,044	3,939	3,794	3,543	3,271	2,948
Winter	1	4,690	1/5/2015	2,695	2,560	2,505	2,498	2,531	2,720	3,119	3,644	3,770	3,766	3,817	3,857	3,825	3,838	3,822	3,869	3,998	4,469	4,690	4,650	4,554	4,352	4,037	3,679
Winter	1	4,897	1/6/2015	3,411	3,262	3,218	3,201	3,233	3,375	3,749	4,246	4,361	4,385	4,424	4,435	4,411	4,389	4,375	4,329	4,416	4,751	4,897	4,841	4,767	4,543	4,212	3,835
Winter	1	5,123	1/7/2015	3,568	3,441	3,354	3,318	3,336	3,471	3,837	4,336	4,431	4,374	4,378	4,371	4,344	4,356	4,341	4,417	4,520	4,902	5,123	5,027	5,018	4,869	4,546	4,170
Winter	1	5,110	1/8/2015	3,930	3,831	3,735	3,730	3,782	3,940	4,280	4,735	4,900	4,855	4,765	4,741	4,642	4,564	4,491	4,479	4,555	4,940	5,110	5,039	4,937	4,738	4,402	4,006
Winter	1	4,718	1/9/2015	3,726	3,560	3,466	3,405	3,401	3,533	3,837	4,281	4,437	4,502	4,572	4,591	4,455	4,355	4,301	4,206	4,265	4,575	4,718	4,629	4,476	4,314	4,091	3,792
Winter	1	4,594	1/10/2015	3,525	3,375	3,279	3,264	3,275	3,356	3,498	3,710	3,946	4,114	4,212	4,160	4,126	4,034	3,979	3,937	4,031	4,406	4,594	4,527	4,425	4,307	4,123	3,882
Winter	1	4,549	1/11/2015	3,636	3,468	3,376	3,317	3,330	3,382	3,476	3,608	3,761	3,939	4,003	4,049	4,076	4,082	4,064	4,074	4,081	4,437	4,549	4,430	4,304	4,091	3,770	3,429
Winter	1	4,599	1/12/2015	3,183	3,017	2,970	2,920	2,962	3,110	3,448	3,850	4,009	4,128	4,239	4,299	4,310	4,308	4,261	4,207	4,253	4,542	4,599	4,502	4,333	4,083	3,756	3,412
Winter	1	4,877	1/13/2015	3,134	2,980	2,914	2,885	2,925	3,127	3,547	4,049	4,190	4,170	4,157	4,169	4,129	4,110	4,076	4,064	4,208	4,628	4,877	4,807	4,716	4,562	4,255	3,894
Winter	1	4,863	1/14/2015	3,621	3,584	3,450	3,445	3,468	3,650	4,001	4,512	4,586	4,608	4,638	4,633	4,569	4,527	4,464	4,417	4,477	4,717	4,863	4,813	4,705	4,471	4,144	3,783
Winter	1	4,697	1/15/2015	3,518	3,347	3,286	3,268	3,316	3,473	3,854	4,328	4,417	4,357	4,311	4,276	4,180	4,114	4,091	4,038	4,102	4,444	4,697	4,611	4,523	4,339	4,046	3,665
Winter	1	4,585	1/16/2015	3,406	3,285	3,187	3,153	3,188	3,326	3,691	4,142	4,260	4,199	4,155	4,068	4,007	4,005	3,990	3,994	4,027	4,361	4,585	4,535	4,419	4,273	4,078	3,804
Winter	1	4,429	1/17/2015	3,576	3,425	3,347	3,299	3,335	3,415	3,566	3,772	3,976	4,147	4,198	4,138	4,056	3,951	3,856	3,810	3,883	4,199	4,429	4,327	4,232	4,081	3,880	3,623
Winter	1	4,177	1/18/2015	3,403	3,238	3,145	3,080	3,082	3,103	3,189	3,310	3,473	3,699	3,877	4,005	4,049	4,053	3,994	3,951	3,951	4,174	4,177	4,039	3,852	3,724	3,492	3,211
Winter	1	4,445	1/19/2015	2,969	2,836	2,747	2,733	2,776	2,886	3,152	3,437	3,679	3,805	3,929	3,968	3,941	3,921	3,919	3,907	3,925	4,250	4,445	4,356	4,225	4,021	3,713	3,350
Winter	1	4,437	1/20/2015	3,093	2,951	2,784	2,846	2,874	3,034	3,442	3,923	4,009	3,964	3,930	3,900	3,843	3,854	3,858	3,871	3,873	4,206	4,437	4,386	4,257	4,061	3,760	3,452
Winter	1	4,536	1/21/2015	3,207	3,110	3,020	3,012	3,067	3,247	3,660	4,136	4,226	4,185	4,142	4,120	4,083	4,035	3,938	3,903	3,993	4,322	4,536	4,443	4,346	4,117	3,791	3,438
Winter	1	4,392	1/22/2015	3,174	3,025	2,979	2,936	2,960	3,127	3,485	3,935	4,076	4,084	4,052	3,997	3,918	3,885	3,797	3,769	3,785	4,113	4,392	4,335	4,261	4,081	3,777	3,435
Winter	1	4,261	1/23/2015	3,183	3,073	2,998	2,996	3,029	3,217	3,612	4,071	4,186	4,091	4,053	3,984	3,875	3,798	3,740	3,740	3,779	4,073	4,261	4,182	4,037	3,921	3,657	3,388
Winter	1	4,195	1/24/2015	3,109	2,953	2,846	2,838	2,841	2,902	3,023	3,199	3,349	3,565	3,750	3,867	3,919	3,891	3,822	3,777	3,831	4,079	4,195	4,043	3,899	3,731	3,545	3,279
Winter	1	4,179	1/25/2015	3,045	2,886	2,819	2,764	2,750	2,805	2,891	3,050	3,210	3,398	3,473	3,493	3,478	3,434	3,403	3,426	3,542	3,877	4,173	4,179	4,086	3,944	3,712	3,448
Winter	1	4,859	1/26/2015	3,208	3,093	2,989	2,988	3,057	3,240	3,687	4,173	4,327	4,330	4,363	4,441	4,433	4,475	4,464	4,419	4,409	4,685	4,859	4,674	4,421	4,154	3,896	3,631
Winter	1	4,639	1/27/2015	3,384	3,275	3,206	3,179	3,211	3,269	3,389	3,537	3,647	3,841	3,939	3,964	3,964	3,975	3,950	3,959	4,050	4,387	4,639	4,526	4,364	4,169	3,894	3,628
Winter	1	4,759	1/28/2015	3,415	3,322	3,273	3,237	3,279	3,440	3,745	4,103	4,351	4,441	4,438	4,452	4,366	4,268	4,187	4,117	4,142	4,410	4,759	4,704	4,588	4,390	4,081	3,752
Winter	1	4,606	1/29/2015	3,500	3,393	3,355	3,359	3,381	3,525	3,987	4,422	4,511	4,420	4,358	4,232	4,147	4,081	4,020	4,030	4,106	4,342	4,606	4,521	4,416	4,184	3,882	3,506
Winter	1	4,463	1/30/2015	3,251	3,115	3,031	2,992	3,029	3,159	3,488	3,876	4,065	4,101	4,167	4,106	4,087	4,053	4,029	3,954	3,998	4,213	4,463	4,438	4,357	4,243	4,014	3,789
Winter	1	4,573	1/31/2015	3,542	3,443	3,369	3,395	3,421	3,497	3,681	3,887	4,097	4,285	4,342	4,314	4,248	4,186	4,049	4,018	4,036	4,254	4,573	4,526	4,428	4,331	4,108	3,846
Winter	2	4,341	2/1/2015	3,623	3,470	3,381	3,360	3,346	3,396	3,473	3,600	3,768	3,944	3,960	3,913	3,868	3,788	3,771	3,748	3,827	4,070	4,341	4,125	3,926	3,808	3,648	3,509
Winter	2	4,885	2/2/2015	3,268	3,111	3,018	3,037	3,087	3,220	3,431	3,704	3,891	4,109	4,259	4,387	4,450	4,437	4,465	4,418	4,413	4,590	4,885	4,735	4,623	4,369	4,069	3,777
Winter	2	4,775	2/3/2015	3,562	3,468	3,426	3,429	3,472	3,624	3,941	4,283	4,507	4,567	4,518	4,480	4,372	4,298	4,196	4,158	4,191	4,410	4,775	4,764	4,680	4,506	4,233	3,902
Winter	2	4,536	2/4/2015	3,684	3,471	3,429	3,426	3,438	3,563	3,905	4,355	4,358	4,366	4,368	4,311	4,243	4,173	4,101	4,078	4,060	4,227	4,536	4,513	4,345	4,207	3,857	3,507
Winter	2	4,796	2/5/2015	3,219	3,126	2,968	2,847	2,881	3,091	3,408	3,816	4,086	4,148	4,238	4,256	4,245	4,208	4,137	4,079	4,111	4,374	4,791	4,796	4,705	4,546	4,245	3,920
Winter	2	4,714	2/6/2015	3,720	3,583	3,473	3,484	3,518	3,719	3,985	4,517	4,600	4,520	4,541	4,536	4,493	4,370	4,275	4,217	4,317	4,318	4,714	4,665	4,551	4,401	4,196	3,999
Winter	2	4,314	2/7/2015	3,655	3,497	3,379	3,336	3,307	3,354	3,444	3,682	3,838	4,033	4,090	4,117	4,053	4,107	4,022	3,888	3,948	4,110	4,314	4,243	4,099	3,954	3,732	3,478
Winter	2	4,373	2/8/2015	3,251	3,094	3,028	2,998	2,969	2,963	3,037	3,180	3,344	3,590	3,748	3,823	3,826	3,842	3,810	3,834	3,841	4,131	4,373	4,323	4,218	4,003	3,792	3,549
Winter	2	4,859	2/9/2015	3,339	3,210	3,169	3,156	3,192	3,358	3,589	3,887	4,108	4,198	4,408	4,614	4,562	4,562	4,510	4,423	4,442	4,565	4,859	4,729	4,627	4,382	4,116	3,671
Winter	2	4,567	2/10/2015	3,577	3,350	3,260	3,235	3,249	3,398	3,689	4,021	4,291	4,313	4,258	4,206	4,150	4,093	4,039	3,976	3,964	4,109	4,567	4,497	4,316	4,190	3,949	3,586
Winter	2	4,549	2/11/2015	3,372	3,193	3,133	3,158	3,183	3,358	3,759	4,159	4,314	4,250	4,205	4,121	4,030	3,988	3,920	3,903	3,924	4,127	4,538	4,549	4,419	4,280	3,956	3,755
Winter	2	4,522	2/12/2015	3,432	3,323	3,225	3,228	3,275	3,400	3,680	4,149	4,290	4,257	4,276	4,238	4,138	4,108	4,087	3,900	4,074	4,246	4,522	4,506	4,432	4,277	4,047	3,687
Winter	2	4,763	2/13/2015	3,504	3,412	3,381	3,386	3,468	3,651	4,044	4,421	4,517	4,571	4,575	4,572	4,555	4,447	4,337	4,265	4,277	4,411	4,763	4,746	4,636	4,534	4,327	4,070
Winter	2	4,534	2/14/2015	3,831	3,711	3,673	3,624	3,646	3,696	3,860	4,016	4,218	4,422	4,415	4,257	4,325	4,235	4,121	4,122	4,147	4,276	4,534	4,461	4,310	4,147	3,900	3,719
Winter	2	4,791	2/15/2015	3,450	3,296	3,291	3,241	3,252	3,254	3,385	3,540	3,729	3,966	4,219	4,330	4,319	4,289	4,198	4,130	4,168	4,405	4,791	4,767	4,689	4,661	4,380	4,199
Winter	2	5,029	2/16/2015	3,978	3,860	3,827	3,821	3,860	3,971	4,158	4,438	4,681	4,811	4,882	4,811	4,796	4,703	4,577	4,555	4,572	4,661	5,029	4,971	4,861	4,715	4,401	4,019
Winter	2	4,934	2/17/2015	3,704	3,612	3,565	3,516	3,549	3,701	4,016	4,403	4,580	4,744	4,769	4,675	4,568	4,496	4,355	4,257	4,271	4,521	4,915	4,934	4,792	4,651	4,259	3,935

Contains Proprietary Material
Do Not Distribute

Winter	2	4,716	2/18/2015	3,764	3,616	3,521	3,525	3,634	3,649	4,176	4,566	4,703	4,716	4,544	4,480	4,324	4,253	4,136	4,108	4,084	4,276	4,690	4,662	4,477	4,489	4,059	3,651
Winter	2	5,186	2/19/2015	3,430	3,320	3,271	3,290	3,314	3,434	3,830	4,271	4,463	4,458	4,475	4,379	4,372	4,316	4,292	4,295	4,407	4,655	5,076	5,180	5,186	4,790	4,497	4,196
Winter	2	4,990	2/20/2015	3,946	3,900	3,860	3,840	3,911	4,085	4,441	4,853	4,964	4,966	4,971	4,852	4,804	4,745	4,578	4,540	4,522	4,657	4,976	4,990	4,934	4,792	4,572	4,303
Winter	2	4,671	2/21/2015	3,977	3,805	3,778	3,738	3,748	3,813	3,969	4,099	4,325	4,435	4,476	4,358	4,302	4,313	4,196	4,189	4,240	4,398	4,671	4,569	4,397	4,227	3,947	3,607
Winter	2	4,212	2/22/2015	3,379	3,231	3,106	3,043	3,035	3,066	3,093	3,242	3,393	3,627	3,671	3,780	3,668	3,625	3,562	3,528	3,560	3,729	4,186	4,212	3,978	3,917	3,679	3,360
Winter	2	4,963	2/23/2015	3,167	3,062	2,987	2,961	3,027	3,207	3,568	4,063	4,253	4,364	4,334	4,375	4,305	4,276	4,222	4,209	4,260	4,449	4,903	4,963	4,950	4,794	4,541	4,145
Winter	2	5,107	2/24/2015	3,884	3,786	3,738	3,738	3,829	3,963	4,381	4,735	4,786	4,783	4,754	4,718	4,579	4,488	4,406	4,391	4,490	4,658	5,081	5,107	4,999	4,637	4,295	3,897
Winter	2	4,551	2/25/2015	3,708	3,506	3,483	3,428	3,474	3,642	4,002	4,407	4,521	4,399	4,314	4,295	4,137	4,109	3,928	3,956	4,022	4,158	4,505	4,551	4,496	4,336	4,042	3,618
Winter	2	4,770	2/26/2015	3,420	3,316	3,285	3,228	3,214	3,387	3,778	4,197	4,457	4,423	4,450	4,453	4,419	4,299	4,206	4,183	4,203	4,437	4,769	4,770	4,636	4,417	4,134	3,781
Winter	2	4,529	2/27/2015	3,484	3,404	3,335	3,334	3,399	3,539	3,931	4,341	4,396	4,357	4,343	4,226	4,202	4,095	4,059	4,005	3,992	4,127	4,443	4,529	4,423	4,297	4,131	3,901
Winter	2	4,326	2/28/2015	3,608	3,497	3,435	3,403	3,431	3,516	3,707	3,816	4,070	4,157	4,147	4,121	4,019	3,875	3,810	3,725	3,708	3,860	4,121	4,326	4,200	4,180	4,052	3,773
Spring	3	4,553	3/1/2015	3,600	3,440	3,401	3,340	3,350	3,401	3,399	3,574	3,744	3,909	4,019	4,077	4,071	4,047	4,021	4,060	4,122	4,254	4,553	4,550	4,352	4,156	3,845	3,525
Spring	3	4,538	3/2/2015	3,295	3,180	3,112	3,095	3,126	3,258	3,509	3,848	4,090	4,111	4,061	4,105	4,070	4,018	3,958	3,929	4,010	4,111	4,400	4,538	4,392	4,292	3,956	3,750
Spring	3	4,720	3/3/2015	3,372	3,251	3,187	3,209	3,331	3,425	3,818	4,236	4,266	4,202	4,152	4,129	4,066	4,088	4,073	4,069	4,152	4,367	4,720	4,718	4,544	4,315	3,932	3,559
Spring	3	4,310	3/4/2015	3,217	3,112	3,031	2,989	3,007	3,150	3,460	3,805	3,968	4,052	4,017	3,995	3,955	3,954	3,869	3,868	3,902	4,022	4,310	4,299	4,236	3,970	3,642	3,301
Spring	3	4,645	3/5/2015	3,041	3,002	2,851	2,831	2,896	3,098	3,408	3,687	3,990	4,100	4,238	4,330	4,322	4,350	4,324	4,267	4,287	4,431	4,632	4,645	4,570	4,367	4,003	3,777
Spring	3	4,484	3/6/2015	3,529	3,381	3,361	3,343	3,383	3,543	3,927	4,352	4,423	4,366	4,313	4,271	4,176	4,097	4,019	3,963	3,932	4,069	4,361	4,484	4,376	4,260	4,088	3,754
Spring	3	4,068	3/7/2015	3,480	3,351	3,242	3,261	3,248	3,362	3,531	3,589	3,850	3,962	3,974	3,865	3,848	3,648	3,517	3,602	3,622	3,767	3,984	4,068	3,979	3,815	3,678	3,397
Spring	3	3,918	3/8/2015	3,153	3,043	2,981	2,994	2,919	2,921	2,982	3,123	3,179	3,444	3,543	3,550	3,511	3,503	3,444	3,344	3,383	3,426	3,552	3,785	3,918	3,802	3,597	3,299
Spring	3	4,060	3/9/2015	3,010	2,946	2,906	2,879	2,919	3,076	3,388	3,899	4,060	3,976	3,879	3,794	3,751	3,665	3,590	3,517	3,481	3,547	3,624	3,807	3,969	3,841	3,572	3,254
Spring	3	4,047	3/10/2015	3,054	2,880	2,818	2,812	2,846	3,011	3,362	3,878	4,004	3,922	3,840	3,789	3,731	3,677	3,610	3,592	3,637	3,731	3,860	3,930	4,047	3,884	3,561	3,234
Spring	3	3,779	3/11/2015	2,914	2,784	2,707	2,653	2,674	2,819	3,136	3,644	3,752	3,779	3,740	3,692	3,660	3,622	3,559	3,545	3,483	3,535	3,649	3,689	3,772	3,728	3,373	3,082
Spring	3	3,992	3/12/2015	2,756	2,681	2,626	2,593	2,616	2,732	3,172	3,663	3,809	3,753	3,669	3,707	3,719	3,574	3,537	3,474	3,486	3,551	3,627	3,821	3,992	3,885	3,623	3,304
Spring	3	4,015	3/13/2015	3,073	2,926	2,889	2,848	2,919	3,025	3,401	3,816	4,015	3,952	3,892	3,811	3,749	3,669	3,573	3,530	3,460	3,534	3,613	3,709	3,856	3,746	3,541	3,274
Spring	3	3,765	3/14/2015	3,060	2,895	2,767	2,700	2,696	2,702	2,799	3,076	3,283	3,521	3,689	3,753	3,765	3,690	3,564	3,560	3,472	3,511	3,574	3,653	3,616	3,490	3,294	3,119
Spring	3	3,850	3/15/2015	2,859	2,700	2,617	2,634	2,567	2,569	2,666	2,844	2,974	3,234	3,323	3,339	3,444	3,396	3,341	3,328	3,338	3,499	3,637	3,672	3,850	3,691	3,456	3,190
Spring	3	3,896	3/16/2015	2,909	2,801	2,742	2,731	2,781	2,872	3,302	3,770	3,854	3,746	3,766	3,723	3,615	3,575	3,485	3,492	3,440	3,471	3,602	3,764	3,896	3,752	3,429	3,103
Spring	3	3,991	3/17/2015	2,842	2,663	2,616	2,604	2,611	2,737	3,147	3,617	3,778	3,800	3,787	3,857	3,716	3,573	3,603	3,500	3,523	3,564	3,683	3,756	3,991	3,849	3,620	3,317
Spring	3	4,326	3/18/2015	3,079	2,949	2,858	2,864	2,894	2,953	3,443	3,874	4,025	3,956	3,935	3,925	3,887	3,900	3,807	3,804	3,735	3,786	3,989	4,083	4,326	4,118	3,832	3,471
Spring	3	4,152	3/19/2015	3,403	3,085	3,046	3,034	3,061	3,209	3,638	4,060	4,152	4,086	4,015	3,974	3,884	3,837	3,737	3,649	3,636	3,671	3,741	3,911	4,097	3,991	3,701	3,373
Spring	3	4,199	3/20/2015	3,153	3,013	2,938	2,900	2,973	3,081	3,479	3,915	4,057	4,054	4,047	4,064	4,033	4,041	4,036	3,980	3,999	4,070	4,141	4,146	4,199	4,012	3,793	3,510
Spring	3	3,818	3/21/2015	3,196	3,091	3,000	2,944	2,877	2,937	3,114	3,284	3,520	3,735	3,818	3,805	3,678	3,504	3,410	3,305	3,254	3,303	3,340	3,481	3,587	3,487	3,291	3,183
Spring	3	3,897	3/22/2015	2,834	2,755	2,758	2,667	2,673	2,705	2,819	2,952	3,113	3,327	3,413	3,445	3,415	3,386	3,259	3,264	3,278	3,376	3,502	3,650	3,897	3,806	3,567	3,337
Spring	3	4,184	3/23/2015	3,109	2,977	2,936	2,921	3,023	3,191	3,551	4,001	4,173	4,109	4,041	4,001	3,927	3,860	3,789	3,701	3,669	3,736	3,872	3,963	4,184	4,040	3,764	3,418
Spring	3	4,095	3/24/2015	3,174	3,152	3,010	2,942	2,951	3,110	3,547	4,001	4,095	4,055	3,967	3,892	3,796	3,739	3,680	3,586	3,553	3,581	3,738	3,841	4,055	3,906	3,632	3,260
Spring	3	4,055	3/25/2015	3,060	2,952	2,877	2,898	2,936	3,103	3,430	3,842	4,055	3,933	3,759	3,728	3,643	3,508	3,565	3,492	3,551	3,750	3,895	3,938	3,990	3,813	3,513	3,139
Spring	3	3,813	3/26/2015	2,859	2,738	2,659	2,627	2,635	2,779	3,147	3,582	3,720	3,740	3,730	3,747	3,706	3,688	3,726	3,669	3,687	3,672	3,741	3,813	3,806	3,647	3,327	3,032
Spring	3	3,759	3/27/2015	2,753	2,615	2,524	2,507	2,520	2,676	3,014	3,518	3,627	3,710	3,759	3,747	3,675	3,672	3,619	3,570	3,607	3,569	3,563	3,529	3,713	3,615	3,407	3,101
Spring	3	3,778	3/28/2015	2,926	2,730	2,643	2,597	2,609	2,658	2,797	3,002	3,276	3,529	3,669	3,678	3,693	3,622	3,560	3,500	3,464	3,469	3,549	3,698	3,778	3,657	3,519	3,274
Spring	3	3,497	3/29/2015	3,048	2,929	2,867	2,777	2,776	2,862	2,935	3,066	3,291	3,430	3,462	3,408	3,360	3,260	3,212	3,119	2,984	3,033	3,095	3,240	3,497	3,438	3,210	3,070
Spring	3	3,524	3/30/2015	2,877	2,763	2,717	2,739	2,706	2,640	2,900	3,248	3,430	3,517	3,495	3,524	3,468	3,373	3,249	3,189	3,199	3,187	3,283	3,364	3,372	3,382	3,196	3,126
Spring	3	3,735	3/31/2015	2,820	2,769	2,626	2,636	2,654	2,828	3,096	3,372	3,476	3,473	3,420	3,448	3,364	3,339	3,305	3,366	3,387	3,444	3,574	3,622	3,707	3,735	3,481	3,053
Spring	4	3,387	4/1/2015	2,862	2,742	2,668	2,662	2,684	2,606	2,964	3,247	3,387	3,367	3,280	3,220	3,136	3,107	3,110	3,091	2,999	3,043	3,130	3,230	3,386	3,282	3,203	2,986
Spring	4	3,450	4/2/2015	2,776	2,772	2,756	2,695	2,725	2,908	3,139	3,297	3,450	3,336	3,236	3,211	3,113	3,142	3,037	2,976	2,904	2,966	3,043	3,149	3,198	3,101	3,023	2,709
Spring	4	2,834	4/3/2015	2,614	2,459	2,390	2,358	2,348	2,408	2,447	2,608	2,596	2,629	2,713	2,834	2,726	2,744	2,611	2,618	2,644	2,635	2,691	2,718	2,744	2,572	2,465	2,447
Spring	4	3,371	4/4/2015	2,269	2,418	2,298	2,229	2,216	2,275	2,354	2,557	2,799	3,005	3,080	3,157	3,136	3,029	2,977	2,954	2,934	3,004	3,084	3,136	3,371	3,322	3,245	2,988
Spring	4	3,347	4/5/2015	2,700	2,547	2,503	2,497	2,445	2,473	2,536	2,753	2,921	3,107	3,146	3,156	3,175	3,103	3,042	2,957	2,995	2,991	3,027	3,130	3,347	3,312	3,187	2,855
Spring	4	3,665	4/6/2015	2,629	2,529	2,491	2,499	2,511	2,679	3,099	3,461	3,665	3,644	3,609	3,557	3,491	3,439	3,379	3,309	3,291	3,287	3,386	3,442	3,654	3,559	3,235	2,909
Spring	4	3,763	4/7/2015	2,607	2,473	2,394	2,360	2,364	2,543	2,892	3,299	3,485	3,546	3,627	3,635	3,662	3,642	3,573	3,590	3,614	3,686	3,763	3,737	3,759	3,732	3,384	3,018
Spring	4	3,903	4/8/2015	2,793	2,650	2,582	2,500	2,510	2,658	3,033	3,404	3,668	3,683	3,665	3,711	3,708	3,692	3,653	3,685	3,640	3,726	3,749	3,812	3,903	3,756	3,517	3,146
Spring	4	3,862	4/9/2015	2,839	2,724	2,658	2,623	2,647	2,783	3,153	3,601	3,759	3,788	3,823	3,862	3,821	3,759	3,764	3,707	3,684	3,798	3,828	3,812	3,822	3,747	3,515	3,175
Spring	4	3,741	4/10/2015	2,846	2,676	2,629	2,593	2,604	2,726	3,035	3,472	3,616	3,680	3,703	3,741	3,694	3,660	3,616	3,550	3,431	3,522	3,572	3,532	3,510	3,535	3,230	2,961
Spring	4	3,205	4/11/2015	2,692	2,573	2,437	2,364	2,353	2,381	2,545	2,685	2,884	3,043	3,123	3,084	3,023	2,978	2,905	2,804	2,791	2,824	2,874	2,922	3,205	3,159	2,999	2,752
Spring	4	3,199	4/12/2015	2,562	2,532	2,362	2,343	2,337	2,359	2,497	2,602	2,755	2,858	2,908	2,907	2,851	2,824	2,776	2,728	2,750	2,826	2,871	2,901	3,199	3,084	2,928	2,664
Spring	4	3,587	4/13/2015	2,435	2,355	2,351	2,343	2,392	2,523	2,873	3,219	3,402	3,445	3,485	3,510	3,429	3,401	3,362	3,333	3,281	3,325	3,368	3,362	3,587	3,471	3,191	2,877
Spring	4	3,582	4/14/2015	2,637	2,442	2,370	2,312	2,325	2,443	2,761	3,105	3,343	3,408	3,435	3,582	3,476	3,413	3,400	3,414	3,375	3,385	3,417	3,434	3,564	3,429	3,218	2,829
Spring	4	3,523	4/15/2015	2,598	2,443	2,430	2,316	2,333	2,461	2,813	3,097	3,266	3,360	3,328	3,373	3,349	3,387	3,334	3,300	3,266	3,293	3,313	3,161	3,523	3,438	3,124	2,821
Spring	4	3,509	4/16/2015	2,532	2,522	2,295	2,313	2,328	2,445	2,695	3,183	3,328	3,354	3,384	3,374	3,341	3,301	3,363	3,274	3,243	3,259	3,239	3,302	3,509	3,395	3,134	2,845
Spring	4	3,599	4/17/2015	2,620	2,443	2,366	2,282	2,332	2,458	2,740	3,106	3,321	3,471	3,582	3,599	3,562	3,539	3,484	3,467	3,398	3,330	3,381	3,327	3,351	3,376	3,161	2,916
Spring	4	3,189	4/18/2015	2,578	2,446	2,300	2,294	2,287	2,317	2,461	2,588	2,812	2,985	3,099	3,074	3,056	3,016	2,960	2,971	2,955	3,022	3,048	3,000	3,189	3,164	2,965	2,676
Spring	4	3,314	4/19/2015	2,426	2,400	2,218	2,162	2,142	2,138	2,176	2,337	2,516	2,715	2,813	2,868	2,872	2,844	2,872	2,820	2,826	2,923	2,990	3,107	3,314	3,209	2,978	2,680
Spring	4	3,786	4/20/2015	2,453	2,305	2,265	2,238	2,269	2,444	2,808	3,252	3,470	3,585	3,651	3,721	3,724	3,750	3,672	3,662	3,675	3,705	3,770	3,756	3,786	3,587	3,261	2,912
Spring	4	3,546	4/21/2015	2,600	2,479	2,386	2,358	2,352	2,486	2,780	3,213	3,396	3,454	3,497	3,489	3,445	3,434	3,377	3,323	3,323	3,319	3,321	3,353	3,546	3,473	3,201	2,844
Spring	4	3,580	4/22/2015	2,519	2,385	2,318	2,299	2,303	2,461	2,779	3,227	3,387	3,388	3,398	3,423	3,387	3,376	3,381	3,366	3,369	3,449	3,472	3,528	3,580	3,477	3,161	2,888
Spring	4	3,719	4/23/2015	2,601	2,413	2,327	2,317	2,351	2,492	2,727	3,158	3,431	3,470	3,483	3,494	3,488	3,496	3,448	3,411	3,390	3,486	3,504	3,537	3,719	3,690	3,385	3,053
Spring	4	3,663	4/24/2015	2,729	2,617	2,552	2,508	2,517	2,684	3,037	3,409	3,540	3,576	3,580	3,577	3,556	3,521	3,486	3,452	3,459	3,469	3,478	3,532	3,663	3,611	3,434	3,151
Spring	4	3,239	4/25/2015	2,912	2,715	2,629	2,557	2,595	2,664	2,757	2,943	3,115	3,220	3,239	3,155	3,115	3,053	2,916	2,889	2,860	2,912	2,974	3,014	3,183	3,183	3,034	2,798
Spring	4	3,346	4/26/2015	2,598	2,468	2,385	2,364	2,337	2,412	2,445	2,592	2,767	2,941	3,021	3,013	3,016	3,017	2,977	2,972	2,945	3,041	3,162	3,221	3,346	3,294	3,026	2,748
Spring	4	3,623	4/27/2015	2,565	2,273	2,194	2,191	2,188	2,326	2,677	3,201	3,382	3,386	3,468	3,445	3,395	3,424	3,406	3,375	3,342	3,425	3,477	3,503	3,623	3,496	3,208	2,795
Spring	4	3,429	4/28/2015	2,581	2,443	2,345	2,307	2,339	2,483	2,770	3,288	3,389	3,429	3,373	3,356	3,286	3,361	3,307	3,217	3,217	3,229	3,278	3,243	3,411	3,374	3,118	2,701
Spring	4	3,369	4/29/2015	2,448	2,304	2,231	2,179	2,195	2,341	2,656	3,064	3,240	3,223	3,287	3,299	3,268	3,314	3,353	3,319	3,276	3,295	3,282	3,187	3,369	3,364	3,057	2,725
Spring	4	3,383	4/30/2015	2,421	2,280	2,186	2,169	2,189	2,348	2,578	3,058	3,241	3,249	3,284	3,279	3,290	3,277	3,308	3,240	3,211	3,239	3,229	3,255	3,383	3,346	3,066	2,696
Spring	5	3,364	5/1/2015	2,587	2,267	2,228	2,175	2,200	2,294	2,591	3,041	3,221	3,254	3,265	3,354	3,364	3,266	3,264	3,230	3,163	3,163	3,136	3,154	3,249	3,267	3,029	2,773
Spring	5	3,051	5/2/2015	2,478	2,306	2,222	2,199	2,179	2,226	2,327	2,570	2,748	2,918	2,987	2,937	2,913	2,922	2,838	2,828	2,849	2,859	2,902	2,846	3,011	3,051	2,829	2,639
Spring	5	3,176	5/3/2015	2,421	2,283	2,196	2,146	2,115	2,165	2,176	2,292	2,551	2,689	2,792	2,850	2,860	2,876	2,886	2,875	2,869	2,960	3,022	3,059	3,176	3,143	2,922	2,623
Spring	5	3,585	5/4/2015	2,289	2,243	2,146	2,112	2,129	2,237	2,491	3,051	3,184	3,264	3,359	3,456	3,523	3,558	3,580	3,585	3,539	3,520	3,526	3,472	3,559	3,544	3,214	2,866
Spring	5	3,742	5/5/2015	2,537	2,368	2,267	2,166	2,209	2,328	2,566	3,113	3,302	3,404	3,506	3,589	3,593	3,669	3,697	3,730	3,727	3,724	3,742	3,694	3,737	3,664	3,343	2,924
Spring	5	3,594	5/6/2015	2,642	2,509	2,345	2,306	2,296	2,404	2,668	3,062	3,312	3,369	3,568	3,583	3,569	3,594	3,583	3,553	3,541	3,538	3,555	3,497	3,514	3,572	3,252	2,904
Spring	5	3,810	5/7/2015	2,600	2,514	2,328	2,274	2,276	2,380	2,693	3,109	3,314	3,412	3,498	3,625	3,687	3,721	3,779	3,782	3,810	3,774	3,739	3,666	3,695	3,736	3,344	2,994
Spring	5	4,058	5/8/2015	2,678	2,486	2,418	2,303	2,335	2,420	2,675	3,141	3,327	3,520	3,627	3,757	3,824	3,954	4,016	4,043	4,050	4,058	3,983	3,793	3,764	3,757	3,465	3,087
Spring	5	3,440	5/9/2015	2,775	2,577	2,472	2,321	2,322	2,382	2,439	2,553	2,841	3,116	3,197	3,238	3,252	3,241	3,254	3,255	3,286	3,326	3,341	3,342	3,400	3,440	3,260	2,962
Spring	5	3,961	5/10/2015	2,740	2,538	2,377	2,329	2,343	2,314	2,344	2,495	2,742	3,014	3,191	3,343	3,476	3,521	3,571	3,622	3,713	3,814	3,824	3,799	3,844	3,961	3,568	3,344
Spring	5	4,685	5/11/2015	2,957	2,758	2,629	2,591	2,553	2,673	2,955	3,443	3,771	3,941	4,099	4,264	4,392	4,507	4,575	4,659	4,685	4,684	4,611	4,516	4,466	4,417	4,027	3,559
Spring	5	4,691	5/12/2015	3,158	2,960	2,839	2,756	2,746	2,870	3,176	3,621	3,917	4,064	4,245	4,479	4,626	4,691	4,602	4,577	4,517	4,557	4,484	4,380	4,319	4,220	3,768	3,152
Spring	5	3,578	5/13/2015	2,788	2,549	2,427	2,361	2,333	2,428	2,571	3,118	3,294	3,404	3,481	3,503	3,491	3,523	3,578	3,460	3,415	3,416	3,440	3,384	3,424	3,422	3,139	2,774
Spring	5	3,508	5/14/2015	2,518	2,322	2,190	2,175	2,204	2,327	2,606	3,053	3,227	3,321	3,381	3,428	3,444	3,464	3,485	3,503	3,487	3,507	3,508	3,419	3,461	3,427	3,209	2,801
Spring	5	3,502	5/15/2015	2,488	2,333	2,233	2,213	2,181	2,335	2,500	3,000	3,218	3,309	3,398	3,438	3,443	3,466	3,502	3,470	3,433	3,433	3,367	3,325	3,308	3,338	3,115	2,839
Spring	5	3,249	5/16/2015	2,529	2,347	2,242	2,177	2,164	2,192	2,255	2,429	2,702	2,994	3,123	3,165	3,193	3,213	3,157	3,108	3,137	3,167	3,184	3,164	3,214	3,249	3,086	2,833

Contains Proprietary Material
Do Not Distribute

Spring	5	4,011	5/17/2015	2,557	2,426	2,258	2,234	2,213	2,185	2,181	2,372	2,632	2,945	3,143	3,333	3,499	3,581	3,626	3,717	3,806	3,938	3,947	4,011	3,934	3,974	3,682	3,245
Spring	5	3,886	5/18/2015	2,930	2,681	2,569	2,483	2,482	2,617	2,875	3,294	3,496	3,598	3,683	3,755	3,782	3,847	3,867	3,886	3,842	3,779	3,716	3,655	3,764	3,698	3,401	3,039
Spring	5	3,896	5/19/2015	2,692	2,535	2,412	2,368	2,385	2,526	2,763	3,238	3,490	3,575	3,626	3,644	3,718	3,728	3,742	3,749	3,816	3,896	3,864	3,856	3,886	3,873	3,531	3,166
Spring	5	3,540	5/20/2015	2,866	2,499	2,465	2,398	2,412	2,504	2,725	3,170	3,387	3,492	3,498	3,540	3,395	3,426	3,502	3,463	3,452	3,463	3,464	3,414	3,467	3,519	3,249	2,904
Spring	5	3,525	5/21/2015	2,603	2,436	2,374	2,320	2,332	2,440	2,680	3,115	3,368	3,429	3,499	3,505	3,503	3,525	3,477	3,479	3,473	3,474	3,468	3,439	3,487	3,512	3,250	2,917
Spring	5	3,626	5/22/2015	2,570	2,453	2,335	2,302	2,279	2,403	2,588	3,082	3,307	3,364	3,517	3,539	3,579	3,626	3,584	3,552	3,523	3,491	3,466	3,383	3,336	3,389	3,144	2,872
Spring	5	3,128	5/23/2015	2,699	2,396	2,254	2,267	2,232	2,220	2,270	2,368	2,718	2,839	2,990	3,028	3,011	2,953	2,956	2,946	2,933	2,991	3,048	3,027	3,028	3,128	2,983	2,780
Spring	5	3,260	5/24/2015	2,496	2,370	2,288	2,192	2,181	2,192	2,185	2,293	2,546	2,805	2,878	3,010	3,045	3,069	3,045	3,030	3,104	3,140	3,121	3,058	3,081	3,260	3,100	2,801
Spring	5	3,783	5/25/2015	2,564	2,392	2,305	2,253	2,232	2,272	2,309	2,324	2,676	2,928	3,102	3,252	3,389	3,489	3,536	3,592	3,651	3,721	3,770	3,696	3,669	3,783	3,461	3,116
Spring	5	4,621	5/26/2015	2,759	2,616	2,498	2,340	2,419	2,454	2,784	3,283	3,573	3,806	3,950	4,186	4,353	4,373	4,517	4,621	4,609	4,604	4,503	4,357	4,264	4,259	3,873	3,403
Spring	5	4,673	5/27/2015	3,015	2,791	2,620	2,553	2,533	2,643	2,842	3,362	3,599	3,891	4,095	4,289	4,414	4,521	4,609	4,673	4,669	4,633	4,459	4,364	4,300	4,145	3,746	3,371
Spring	5	4,556	5/28/2015	3,027	2,761	2,624	2,537	2,548	2,678	2,845	3,393	3,666	3,769	3,938	4,051	4,102	4,207	4,498	4,554	4,556	4,511	4,475	4,321	4,247	4,188	3,845	3,344
Spring	5	4,585	5/29/2015	2,983	2,725	2,588	2,432	2,410	2,465	2,644	3,200	3,497	3,677	3,865	4,007	4,109	4,273	4,354	4,435	4,585	4,520	4,437	4,208	4,112	3,966	3,770	3,414
Spring	5	4,358	5/30/2015	2,998	2,816	2,629	2,526	2,483	2,494	2,525	2,759	3,060	3,349	3,605	3,795	3,986	4,093	4,176	4,267	4,312	4,358	4,260	4,106	3,914	3,904	3,762	3,467
Spring	5	3,941	5/31/2015	3,127	2,892	2,765	2,669	2,596	2,609	2,566	2,692	2,962	3,252	3,496	3,666	3,752	3,847	3,926	3,906	3,941	3,876	3,908	3,763	3,691	3,513	3,142	2,884
Summer	6	3,678	6/1/2015	2,616	2,465	2,289	2,331	2,333	2,444	2,709	3,129	3,351	3,506	3,572	3,615	3,644	3,663	3,615	3,567	3,571	3,652	3,678	3,577	3,602	3,531	3,214	2,822
Summer	6	3,628	6/2/2015	2,610	2,492	2,342	2,392	2,344	2,406	2,729	3,149	3,399	3,482	3,582	3,545	3,555	3,628	3,611	3,532	3,548	3,588	3,622	3,580	3,560	3,565	3,253	2,890
Summer	6	3,575	6/3/2015	2,614	2,506	2,372	2,348	2,347	2,477	2,724	3,173	3,335	3,353	3,433	3,385	3,508	3,539	3,480	3,544	3,548	3,565	3,558	3,496	3,482	3,575	3,316	2,914
Summer	6	3,625	6/4/2015	2,603	2,439	2,341	2,299	2,357	2,394	2,696	3,060	3,308	3,423	3,506	3,550	3,594	3,625	3,623	3,617	3,597	3,586	3,604	3,500	3,507	3,569	3,292	2,930
Summer	6	3,287	6/5/2015	2,692	2,459	2,349	2,374	2,317	2,364	2,697	2,814	2,903	2,948	3,045	3,114	3,180	3,234	3,276	3,287	3,236	3,238	3,225	3,053	3,059	2,985	2,911	2,671
Summer	6	3,111	6/6/2015	2,466	2,157	2,023	1,983	1,969	1,939	2,050	2,176	2,425	2,741	2,867	3,026	3,111	3,028	3,067	2,926	2,924	2,992	2,943	2,842	2,778	2,864	2,669	2,534
Summer	6	3,399	6/7/2015	2,278	2,144	2,029	1,889	1,782	1,755	1,871	1,933	1,991	2,364	2,555	2,723	2,635	2,674	2,682	2,721	2,743	2,851	2,884	3,000	3,359	3,399	3,189	2,898
Summer	6	4,011	6/8/2015	2,649	2,403	2,338	2,309	2,323	2,480	2,821	3,154	3,413	3,558	3,710	3,775	3,801	3,779	3,904	3,926	3,947	4,011	3,947	3,846	3,785	3,918	3,560	3,167
Summer	6	4,318	6/9/2015	2,870	2,651	2,566	2,492	2,520	2,632	2,944	3,362	3,658	3,809	3,961	4,020	4,067	4,147	4,160	4,211	4,305	4,318	4,303	4,207	4,147	4,093	3,772	3,353
Summer	6	4,576	6/10/2015	2,929	2,731	2,616	2,514	2,493	2,512	2,857	3,301	3,613	3,773	3,966	4,139	4,148	4,304	4,462	4,469	4,560	4,576	4,499	4,361	4,284	4,298	3,954	3,491
Summer	6	5,262	6/11/2015	3,129	2,942	2,782	2,678	2,703	2,797	3,024	3,497	3,819	3,976	4,201	4,480	4,713	4,813	5,005	5,123	5,262	5,260	5,260	5,155	5,067	5,038	4,651	4,072
Summer	6	5,301	6/12/2015	3,638	3,362	3,149	2,994	2,925	3,018	3,219	3,722	4,038	4,260	4,497	4,682	4,900	5,012	5,198	5,301	5,272	5,224	5,131	4,976	4,763	4,763	4,465	4,069
Summer	6	4,716	6/13/2015	3,656	3,386	3,221	3,097	3,070	3,032	3,029	3,326	3,711	3,880	4,141	4,272	4,340	4,413	4,516	4,552	4,630	4,716	4,622	4,519	4,311	4,282	4,049	3,683
Summer	6	4,686	6/14/2015	3,289	3,019	2,858	2,726	2,631	2,607	2,582	2,757	3,005	3,422	3,651	3,959	4,142	4,264	4,379	4,496	4,589	4,675	4,686	4,513	4,327	4,397	4,053	3,564
Summer	6	4,176	6/15/2015	3,284	2,997	2,847	2,769	2,774	2,867	3,098	3,570	3,820	3,939	4,037	4,145	4,176	4,129	4,066	4,047	3,991	3,991	3,983	3,891	3,851	3,811	3,537	3,169
Summer	6	4,385	6/16/2015	2,871	2,682	2,592	2,529	2,527	2,651	2,839	3,295	3,626	3,786	3,870	3,990	4,043	4,152	4,219	4,179	4,243	4,385	4,381	4,311	4,269	4,309	4,031	3,610
Summer	6	4,450	6/17/2015	3,194	2,975	2,824	2,703	2,660	2,739	2,982	3,395	3,766	3,966	4,093	4,182	4,250	4,338	4,391	4,444	4,450	4,368	4,228	4,063	3,969	4,022	3,690	3,307
Summer	6	4,210	6/18/2015	3,006	2,615	2,477	2,418	2,407	2,515	2,703	3,146	3,414	3,645	3,871	3,960	3,916	4,060	4,078	4,210	4,147	4,066	3,885	3,833	3,852	3,815	3,555	3,212
Summer	6	4,828	6/19/2015	2,958	2,760	2,622	2,571	2,605	2,713	2,955	3,432	3,698	3,958	4,199	4,404	4,585	4,716	4,800	4,828	4,821	4,803	4,772	4,566	4,322	4,341	4,092	3,688
Summer	6	3,627	6/20/2015	3,272	3,019	2,792	2,670	2,589	2,559	2,632	2,686	3,034	3,194	3,475	3,580	3,596	3,627	3,596	3,506	3,339	3,427	3,421	3,424	3,423	3,478	3,299	3,102
Summer	6	4,625	6/21/2015	2,856	2,687	2,661	2,521	2,502	2,517	2,547	2,656	2,921	3,236	3,433	3,635	3,800	3,944	4,083	4,221	4,365	4,537	4,625	4,466	4,318	4,330	4,133	3,715
Summer	6	5,324	6/22/2015	3,344	3,126	2,938	2,861	2,833	2,912	3,219	3,573	3,987	4,290	4,555	4,769	4,883	5,059	5,098	5,221	5,264	5,324	5,264	5,215	4,942	4,888	4,498	3,976
Summer	6	5,776	6/23/2015	3,469	3,239	3,028	2,903	2,922	2,946	3,173	3,610	4,132	4,469	4,830	5,039	5,198	5,425	5,561	5,776	5,684	5,235	5,113	4,981	4,824	4,727	4,457	3,953
Summer	6	4,996	6/24/2015	3,566	3,198	2,994	2,872	2,840	2,843	3,002	3,381	3,867	4,106	4,331	4,493	4,596	4,695	4,796	4,887	4,976	4,996	4,968	4,748	4,563	4,508	4,181	3,730
Summer	6	4,737	6/25/2015	3,283	3,076	2,818	2,696	2,669	2,683	2,895	3,336	3,678	3,884	4,105	4,336	4,463	4,568	4,690	4,737	4,733	4,674	4,602	4,414	4,369	4,325	4,064	3,692
Summer	6	4,575	6/26/2015	3,314	3,074	2,955	2,848	2,818	2,868	3,090	3,484	3,784	3,926	4,127	4,243	4,266	4,378	4,466	4,551	4,575	4,550	4,459	4,272	4,109	4,068	3,831	3,511
Summer	6	3,614	6/27/2015	3,116	2,911	2,736	2,653	2,565	2,578	2,594	2,769	3,063	3,298	3,493	3,555	3,614	3,531	3,495	3,415	3,374	3,398	3,386	3,370	3,354	3,353	3,176	2,909
Summer	6	3,375	6/28/2015	2,640	2,547	2,489	2,398	2,352	2,358	2,383	2,507	2,701	2,965	3,135	3,244	3,293	3,323	3,342	3,264	3,289	3,351	3,375	3,299	3,340	3,365	3,219	2,887
Summer	6	4,095	6/29/2015	2,676	2,542	2,433	2,425	2,397	2,509	2,740	3,076	3,445	3,648	3,756	3,903	3,986	4,032	4,080	4,075	4,067	4,095	4,095	4,057	3,926	3,947	3,687	3,322
Summer	6	4,678	6/30/2015	2,976	2,738	2,678	2,578	2,560	2,661	2,866	3,267	3,583	3,839	4,117	4,322	4,428	4,467	4,598	4,678	4,643	4,609	4,529	4,358	4,259	4,248	3,984	3,632
Summer	7	4,973	7/1/2015	3,291	3,148	2,961	2,900	2,900	3,007	3,276	3,613	3,906	4,003	4,300	4,505	4,623	4,767	4,862	4,931	4,967	4,973	4,922	4,739	4,540	4,503	4,250	3,771
Summer	7	4,596	7/2/2015	3,420	3,121	2,882	2,779	2,714	2,695	2,917	3,312	3,715	3,997	4,169	4,374	4,482	4,569	4,596	4,580	4,492	4,466	4,405	4,215	4,089	4,083	3,872	3,554
Summer	7	4,240	7/3/2015	3,182	2,956	2,751	2,620	2,577	2,573	2,617	2,809	3,071	3,391	3,585	3,686	3,838	3,923	3,974	4,144	4,172	4,240	4,202	4,010	3,823	3,818	3,584	3,379
Summer	7	3,567	7/4/2015	3,064	2,849	2,683	2,573	2,516	2,518	2,552	2,556	2,849	3,104	3,313	3,490	3,532	3,567	3,509	3,466	3,430	3,462	3,498	3,402	3,343	3,405	3,263	3,155
Summer	7	4,399	7/5/2015	2,866	2,705	2,535	2,456	2,441	2,419	2,357	2,525	2,776	3,042	3,350	3,581	3,761	3,868	3,962	4,082	4,216	4,326	4,399	4,289	4,202	4,203	3,997	3,673
Summer	7	5,099	7/6/2015	3,293	3,060	2,876	2,853	2,732	2,819	3,001	3,382	3,742	4,037	4,336	4,631	4,817	4,984	5,046	5,058	5,099	5,083	5,038	4,869	4,677	4,649	4,258	3,874
Summer	7	5,397	7/7/2015	3,493	3,270	3,087	3,021	3,005	3,112	3,363	3,725	4,163	4,381	4,635	4,823	5,028	5,144	5,185	5,349	5,397	5,339	5,263	5,142	5,005	4,909	4,529	4,071
Summer	7	5,504	7/8/2015	3,732	3,409	3,249	3,121	3,084	3,190	3,415	3,893	4,163	4,440	4,561	4,815	5,114	5,323	5,439	5,504	5,496	5,411	5,411	5,307	5,072	5,040	4,701	4,166
Summer	7	4,488	7/9/2015	3,800	3,440	3,219	3,097	3,049	3,099	3,257	3,624	3,925	4,128	4,168	4,316	4,367	4,393	4,480	4,488	4,419	4,433	4,398	4,295	4,256	4,246	3,943	3,599
Summer	7	4,952	7/10/2015	3,258	3,044	2,965	2,877	2,857	2,927	3,132	3,544	3,912	4,077	4,326	4,470	4,576	4,732	4,774	4,867	4,893	4,952	4,880	4,633	4,427	4,391	4,120	3,741
Summer	7	4,802	7/11/2015	3,334	3,075	2,954	2,787	2,698	2,698	2,655	2,905	3,220	3,574	3,950	4,171	4,311	4,527	4,553	4,657	4,714	4,757	4,802	4,610	4,395	4,361	4,103	3,764
Summer	7	5,044	7/12/2015	3,395	3,156	2,967	2,831	2,763	2,689	2,620	2,851	3,089	3,438	3,792	4,113	4,400	4,559	4,720	4,802	4,909	4,930	5,044	4,806	4,740	4,701	4,437	4,013
Summer	7	5,530	7/13/2015	3,605	3,346	3,228	3,046	3,001	3,092	3,300	3,695	4,089	4,338	4,651	4,909	5,158	5,350	5,467	5,530	5,526	5,529	5,492	5,229	4,957	4,808	4,423	3,937
Summer	7	5,175	7/14/2015	3,505	3,365	3,152	3,107	3,068	3,170	3,287	3,786	4,187	4,412	4,692	4,847	4,988	4,990	5,175	5,125	5,008	4,872	4,886	4,824	4,737	4,634	4,397	4,012
Summer	7	5,283	7/15/2015	3,649	3,429	3,289	3,190	3,168	3,233	3,532	3,975	4,303	4,508	4,769	4,940	5,157	5,283	5,269	5,200	5,098	5,094	5,037	4,794	4,605	4,433	4,128	3,688
Summer	7	4,474	7/16/2015	3,293	3,030	2,831	2,723	2,662	2,766	2,887	3,285	3,588	3,752	3,863	4,041	4,125	4,211	4,238	4,412	4,423	4,474	4,455	4,286	4,098	4,101	3,814	3,472
Summer	7	4,613	7/17/2015	3,061	2,840	2,652	2,570	2,549	2,628	2,845	3,226	3,552	3,720	3,916	4,129	4,302	4,403	4,498	4,570	4,599	4,613	4,520	4,256	4,120	4,092	3,867	3,553
Summer	7	4,615	7/18/2015	3,265	2,988	2,904	2,803	2,784	2,794	2,823	2,989	3,285	3,587	3,758	3,946	3,994	4,036	4,120	4,264	4,444	4,567	4,615	4,518	4,388	4,432	4,224	3,927
Summer	7	5,754	7/19/2015	3,625	3,390	3,243	3,124	3,065	3,038	3,003	3,167	3,595	3,955	4,385	4,775	5,101	5,341	5,422	5,560	5,610	5,754	5,683	5,517	5,383	5,412	5,086	4,605
Summer	7	6,419	7/20/2015	4,219	3,992	3,825	3,701	3,651	3,721	3,958	4,385	4,969	5,315	5,651	5,962	6,184	6,220	6,332	6,397	6,419	6,394	6,306	6,122	5,955	5,844	5,389	4,809
Summer	7	5,975	7/21/2015	4,307	3,930	3,693	3,543	3,467	3,499	3,645	4,109	4,346	4,538	4,768	4,990	5,189	5,380	5,648	5,865	5,975	5,971	5,852	5,636	5,293	5,085	4,782	4,241
Summer	7	5,042	7/22/2015	3,745	3,445	3,233	3,055	2,965	2,998	3,156	3,568	3,988	4,138	4,379	4,595	4,613	4,827	4,901	4,990	5,027	5,042	4,983	4,807	4,511	4,465	4,098	3,697
Summer	7	4,918	7/23/2015	3,271	3,021	2,892	2,710	2,694	2,787	2,958	3,316	3,676	3,978	4,178	4,382	4,462	4,597	4,707	4,782	4,886	4,918	4,857	4,707	4,476	4,458	4,082	3,685
Summer	7	4,827	7/24/2015	3,331	3,039	2,864	2,751	2,757	2,780	2,916	3,283	3,682	3,901	4,153	4,346	4,448	4,606	4,602	4,783	4,794	4,827	4,754	4,510	4,258	4,283	4,149	3,677
Summer	7	4,479	7/25/2015	3,324	3,048	2,878	2,769	2,681	2,701	2,669	2,905	3,211	3,546	3,804	4,021	4,149	4,266	4,354	4,414	4,466	4,479	4,429	4,229	4,096	4,115	3,954	3,667
Summer	7	4,563	7/26/2015	3,414	3,135	3,008	2,878	2,834	2,824	2,870	2,847	3,140	3,418	3,691	3,891	4,078	4,278	4,370	4,519	4,546	4,563	4,543	4,440	4,309	4,375	4,131	3,821
Summer	7	5,500	7/27/2015	3,479	3,318	3,155	3,059	3,039	3,172	3,342	3,732	4,005	4,300	4,444	4,609	4,775	4,914	5,071	5,319	5,439	5,500	5,498	5,257	5,074	5,035	4,620	4,187
Summer	7	4,630	7/28/2015	3,827	3,519	3,308	3,224	3,157	3,227	3,429	3,847	4,317	4,630	3,767	3,779	3,729	3,871	3,980	4,059	4,014	4,150	4,057	3,900	3,911	3,883	3,740	3,734
Summer	7	6,266	7/29/2015	3,612	3,458	3,627	3,599	3,608	3,418	3,381	3,366	3,772	4,060	4,174	4,834	5,057	5,982	6,153	6,239	6,266	6,198	6,188	5,988	5,746	5,668	5,239	4,655
Summer	7	5,829	7/30/2015	4,109	3,868	3,666	3,551	3,497	3,569	3,734	4,165	4,598	4,872	5,159	5,341	5,489	5,656	5,829	5,761	5,649	5,447	5,251	5,074	4,820	4,857	4,654	4,193
Summer	7	5,726	7/31/2015	3,703	3,568	3,388	3,244	3,172	3,181	3,363	3,747	4,139	4,564	4,728	4,974	5,168	5,409	5,543	5,640	5,690	5,726	5,584	5,334	4,995	4,802	4,385	4,075
Summer	8	4,984	8/1/2015	3,575	3,334	3,173	3,034	2,970	2,970	2,982	3,150	3,527	3,883	4,265	4,509	4,715	4,857	4,908	4,943	4,984	4,926	4,862	4,712	4,494	4,499	4,213	3,861
Summer	8	4,947	8/2/2015	3,477	3,187	3,031	2,876	2,789	2,734	2,705	2,801	3,165	3,467	3,766	4,049	4,274	4,430	4,557	4,696	4,820	4,947	4,916	4,739	4,633	4,615	4,354	3,898
Summer	8	5,844	8/3/2015	3,582	3,349	3,212	3,091	3,014	3,142	3,331	3,774	4,204	4,569	4,788	5,024	5,280	5,486	5,661	5,750	5,841	5,844	5,741	5,524	5,345	5,361	4,964	4,446
Summer	8	5,925	8/4/2015	4,013	3,729	3,550	3,451	3,410	3,472	3,669	4,007	4,281	4,545	4,873	5,217	5,429	5,642	5,776	5,860	5,925	5,898	5,791	5,590	5,297	5,183	4,712	4,211
Summer	8	5,243	8/5/2015	3,729	3,450	3,236	3,079	3,057	3,004	3,204	3,580	3,975	4,232	4,475	4,600	4,845	5,051	5,165	5,243	5,184	5,165	5,072	4,833	4,555	4,601	4,235	3,762
Summer	8	4,616	8/6/2015	3,372	3,079	2,919	2,821	2,763	2,850	2,951	3,338	3,681	3,930	4,205	4,326	4,369	4,509	4,577	4,616	4,578	4,581	4,524	4,351	4,311	4,268	3,960	3,614
Summer	8	4,748	8/7/2015	3,241	3,026	2,883	2,781	2,727	2,795	2,937	3,307	3,646	3,899	4,119	4,305	4,420	4,528	4,635	4,705	4,748	4,729	4,673	4,455	4,316	4,216	3,947	3,571
Summer	8	4,134	8/8/2015	3,186	3,036	2,848	2,728	2,679	2,664	2,672	2,826	3,084	3,405	3,658	3,815	3,952	3,995	4,044	4,064	4,112	4,134	4,071	3,949	3,917	3,948	3,701	3,422
Summer	8	4,192	8/9/2015	3,144	2,911	2,775	2,654	2,599	2,593	2,563	2,651	2,921	3,233	3,463	3,634	3,776	3,910	4,019	4,065	4,121	4,147	4,192	4,074	3,984	4,074	3,750	3,458
Summer	8	4,898	8/10/2015	3,148	2,933	2,810	2,691	2,703	2,813	3,026	3,369	3,749	3,942	4,138	4,445	4,649	4,725	4,830	4,898	4,898	4,834	4,742	4,525	4,443	4,416	4,134	3,770
Summer	8	4,518	8/11/2015	3,396	3,203	3,079	3,010	2,989	3,101	3,398	3,750	4,008	4,204	4,338	4,433	4,448	4,504	4,487	4,407	4,426	4,470	4,518	4,400	4,403	4,348	4,052	3,655
Summer	8	4,997	8/12/2015	3,355	3,159	3,050	2,898	2,868	2,931	3,150	3,474	3,837	4,077	4,323	4,530	4,633	4,782	4,891	4,958	4,997	4,994	4,960	4,735	4,587	4,523	4,203	3,726

Contains Proprietary Material
Do Not Distribute

Summer	8	4,880	8/13/2015	3,395	3,100	2,996	2,841	2,798	2,853	3,031	3,340	3,717	3,959	4,190	4,315	4,474	4,631	4,726	4,806	4,850	4,880	4,755	4,619	4,435	4,335	4,026	3,669
Summer	8	5,210	8/14/2015	3,147	3,073	2,879	2,779	2,683	2,727	2,957	3,247	3,598	3,894	4,187	4,367	4,561	4,705	4,859	5,033	5,110	5,210	5,003	4,789	4,634	4,564	4,214	3,841
Summer	8	5,319	8/15/2015	3,505	3,225	3,054	2,924	2,859	2,857	2,825	2,999	3,338	3,725	4,092	4,415	4,692	4,846	5,034	5,178	5,262	5,319	5,217	5,012	4,875	4,770	4,477	4,056
Summer	8	5,402	8/16/2015	3,715	3,447	3,260	3,137	3,058	3,025	3,030	2,997	3,376	3,703	4,121	4,501	4,789	5,007	5,162	5,236	5,325	5,390	5,402	5,217	5,112	5,055	4,726	4,245
Summer	8	6,237	8/17/2015	3,856	3,650	3,369	3,283	3,217	3,278	3,497	3,824	4,263	4,712	5,023	5,449	5,661	5,995	6,064	6,160	6,169	6,237	6,155	5,947	5,776	5,617	5,034	4,596
Summer	8	6,200	8/18/2015	4,118	3,814	3,631	3,477	3,367	3,467	3,695	4,012	4,479	4,771	5,150	5,514	5,765	6,030	6,089	6,200	6,097	6,046	5,932	5,643	5,545	5,358	4,879	4,398
Summer	8	6,027	8/19/2015	3,973	3,749	3,656	3,504	3,439	3,506	3,770	4,040	4,481	4,778	5,119	5,428	5,603	5,777	5,933	5,962	6,009	6,027	5,845	5,541	5,389	5,294	4,858	4,407
Summer	8	5,849	8/20/2015	4,002	3,748	3,567	3,473	3,441	3,512	3,791	4,089	4,525	4,896	5,125	5,383	5,396	5,684	5,823	5,849	5,788	5,763	5,570	5,368	5,363	5,115	4,726	4,313
Summer	8	4,996	8/21/2015	3,952	3,710	3,533	3,455	3,430	3,550	3,799	4,075	4,386	4,565	4,624	4,717	4,799	4,812	4,867	4,929	4,983	4,996	4,978	4,753	4,701	4,488	4,284	3,925
Summer	8	4,614	8/22/2015	3,570	3,311	3,084	2,955	2,847	2,771	2,869	2,931	3,223	3,490	3,785	3,972	4,145	4,287	4,420	4,514	4,573	4,614	4,544	4,404	4,337	4,248	3,968	3,652
Summer	8	4,658	8/23/2015	3,345	3,104	3,034	2,867	2,828	2,780	2,791	2,874	3,068	3,272	3,591	3,877	4,062	4,225	4,336	4,439	4,531	4,618	4,658	4,523	4,580	4,500	4,222	3,879
Summer	8	5,635	8/24/2015	3,507	3,328	3,182	3,136	3,113	3,187	3,483	3,850	4,206	4,508	4,718	5,000	5,186	5,391	5,520	5,594	5,635	5,626	5,564	5,288	5,241	5,014	4,557	4,154
Summer	8	5,800	8/25/2015	3,786	3,565	3,256	3,210	3,202	3,312	3,591	3,980	4,290	4,554	4,827	5,111	5,248	5,462	5,617	5,789	5,776	5,800	5,642	5,432	5,338	5,148	4,660	4,142
Summer	8	4,916	8/26/2015	3,770	3,530	3,291	3,108	2,956	2,994	3,331	3,586	3,886	4,088	4,269	4,470	4,653	4,787	4,807	4,878	4,883	4,916	4,840	4,581	4,530	4,236	3,978	3,618
Summer	8	4,482	8/27/2015	3,180	2,921	2,800	2,726	2,696	2,769	2,948	3,341	3,586	3,854	3,996	4,222	4,318	4,385	4,429	4,469	4,469	4,465	4,482	4,274	4,294	4,184	3,760	3,460
Summer	8	4,474	8/28/2015	3,136	2,844	2,702	2,637	2,612	2,679	2,942	3,274	3,549	3,806	3,946	4,110	4,202	4,269	4,339	4,474	4,429	4,459	4,363	4,145	4,141	3,978	3,713	3,405
Summer	8	4,211	8/29/2015	3,033	2,790	2,688	2,579	2,538	2,485	2,589	2,690	2,954	3,278	3,498	3,785	3,834	3,899	4,026	4,077	4,145	4,211	4,175	4,076	4,114	3,991	3,745	3,477
Summer	8	4,956	8/30/2015	3,187	3,012	2,832	2,758	2,692	2,667	2,695	2,645	2,994	3,361	3,726	4,041	4,278	4,516	4,567	4,718	4,825	4,888	4,883	4,853	4,956	4,784	4,376	3,984
Summer	8	5,874	8/31/2015	3,673	3,371	3,232	3,144	3,124	3,209	3,549	3,888	4,276	4,468	4,756	5,036	5,275	5,501	5,632	5,762	5,753	5,874	5,868	5,686	5,628	5,327	4,849	4,283
Fall	9	5,728	9/1/2015	3,855	3,655	3,407	3,268	3,209	3,280	3,586	3,832	4,203	4,470	4,736	5,055	5,191	5,286	5,552	5,666	5,622	5,728	5,616	5,393	5,340	5,058	4,528	4,020
Fall	9	5,966	9/2/2015	3,627	3,360	3,159	3,077	3,038	3,062	3,408	3,703	4,113	4,352	4,676	4,906	5,255	5,480	5,667	5,798	5,920	5,966	5,864	5,571	5,516	5,236	4,689	4,195
Fall	9	5,969	9/3/2015	3,710	3,446	3,298	3,182	3,097	3,181	3,447	3,816	4,162	4,415	4,700	5,068	5,265	5,601	5,809	5,904	5,968	5,969	5,779	5,605	5,637	5,360	4,820	4,342
Fall	9	5,232	9/4/2015	4,003	3,636	3,468	3,357	3,307	3,385	3,730	4,060	4,341	4,515	4,651	4,780	4,921	5,021	5,157	5,208	5,232	5,188	5,024	4,707	4,731	4,499	4,137	3,718
Fall	9	4,194	9/5/2015	3,358	3,093	2,929	2,808	2,696	2,656	2,732	2,781	2,974	3,357	3,494	3,698	3,755	3,894	3,957	4,032	4,148	4,194	4,111	3,978	4,000	3,824	3,528	3,313
Fall	9	4,308	9/6/2015	3,005	2,781	2,629	2,577	2,491	2,480	2,497	2,557	2,763	3,070	3,272	3,535	3,736	3,878	4,015	4,150	4,263	4,308	4,279	4,042	4,059	3,915	3,626	3,395
Fall	9	5,221	9/7/2015	3,137	2,937	2,720	2,595	2,589	2,637	2,711	2,736	2,989	3,310	3,670	3,999	4,302	4,550	4,741	4,954	5,110	5,221	5,174	4,984	5,097	4,866	4,468	4,042
Fall	9	6,332	9/8/2015	3,652	3,387	3,281	3,183	3,162	3,262	3,597	3,997	4,299	4,648	4,997	5,394	5,717	5,999	6,292	6,203	6,328	6,332	6,229	5,997	6,048	5,571	5,076	4,526
Fall	9	6,195	9/9/2015	4,120	3,789	3,603	3,483	3,414	3,511	3,799	4,144	4,478	4,719	5,064	5,399	5,587	5,840	6,040	6,156	6,195	6,174	5,973	5,695	5,730	5,440	4,973	4,475
Fall	9	4,735	9/10/2015	4,052	3,750	3,633	3,494	3,417	3,448	3,828	4,202	4,442	4,515	4,553	4,735	4,677	4,723	4,710	4,631	4,621	4,625	4,610	4,565	4,529	4,300	3,892	3,551
Fall	9	4,409	9/11/2015	3,240	2,977	2,880	2,782	2,767	2,850	3,155	3,467	3,726	3,855	3,981	4,048	4,060	4,121	4,205	4,283	4,320	4,409	4,310	4,200	4,191	4,002	3,774	3,359
Fall	9	3,916	9/12/2015	2,929	2,823	2,749	2,636	2,600	2,568	2,662	2,743	3,084	3,298	3,538	3,739	3,814	3,913	3,912	3,916	3,832	3,798	3,838	3,879	3,892	3,751	3,540	3,276
Fall	9	4,032	9/13/2015	3,116	2,815	2,690	2,604	2,548	2,570	2,591	2,686	2,898	3,189	3,369	3,549	3,668	3,779	3,852	3,908	3,973	4,002	4,008	4,032	3,934	3,780	3,399	3,065
Fall	9	3,909	9/14/2015	2,804	2,600	2,491	2,432	2,442	2,511	2,820	3,127	3,279	3,513	3,577	3,733	3,746	3,822	3,816	3,825	3,805	3,857	3,829	3,776	3,909	3,663	3,274	3,027
Fall	9	4,319	9/15/2015	2,690	2,574	2,470	2,417	2,406	2,534	2,855	3,088	3,456	3,533	3,680	3,841	3,921	4,002	4,174	4,188	4,279	4,319	4,316	4,234	4,260	3,979	3,579	3,312
Fall	9	4,696	9/16/2015	2,854	2,744	2,588	2,533	2,520	2,584	3,027	3,283	3,512	3,709	3,913	4,074	4,174	4,356	4,525	4,601	4,696	4,687	4,694	4,465	4,533	4,181	3,869	3,441
Fall	9	4,955	9/17/2015	3,067	2,919	2,800	2,657	2,601	2,732	3,019	3,362	3,630	3,796	3,996	4,259	4,401	4,604	4,731	4,880	4,955	4,942	4,874	4,656	4,645	4,375	3,956	3,505
Fall	9	4,799	9/18/2015	3,193	2,980	2,813	2,634	2,651	2,775	3,061	3,336	3,575	3,771	4,023	4,243	4,386	4,557	4,686	4,766	4,799	4,792	4,657	4,392	4,425	4,066	3,844	3,506
Fall	9	4,151	9/19/2015	3,132	2,874	2,705	2,603	2,561	2,605	2,706	2,809	3,041	3,417	3,588	3,720	3,886	4,017	4,086	4,150	4,151	4,129	4,024	4,016	4,044	3,923	3,715	3,462
Fall	9	3,756	9/20/2015	3,207	2,991	2,891	2,813	2,731	2,751	2,785	2,757	2,909	3,120	3,200	3,365	3,519	3,547	3,581	3,648	3,654	3,735	3,724	3,705	3,756	3,506	3,145	2,972
Fall	9	3,790	9/21/2015	2,515	2,452	2,411	2,313	2,320	2,470	2,768	3,132	3,318	3,417	3,520	3,579	3,620	3,689	3,719	3,787	3,726	3,772	3,725	3,790	3,779	3,562	3,217	2,851
Fall	9	3,787	9/22/2015	2,530	2,475	2,397	2,318	2,351	2,487	2,778	3,209	3,339	3,435	3,561	3,639	3,642	3,711	3,730	3,711	3,705	3,733	3,727	3,786	3,787	3,551	3,254	2,956
Fall	9	3,943	9/23/2015	2,633	2,500	2,411	2,362	2,342	2,464	2,768	3,031	3,302	3,405	3,507	3,657	3,651	3,807	3,818	3,834	3,880	3,943	3,907	3,912	3,876	3,643	3,372	2,983
Fall	9	4,058	9/24/2015	2,656	2,491	2,409	2,356	2,348	2,459	2,757	3,152	3,316	3,475	3,611	3,727	3,806	3,895	3,959	4,058	4,049	4,052	4,043	4,019	4,053	3,802	3,472	3,110
Fall	9	3,747	9/25/2015	2,771	2,583	2,493	2,435	2,412	2,498	2,830	3,152	3,359	3,494	3,575	3,653	3,651	3,733	3,747	3,708	3,714	3,712	3,626	3,703	3,656	3,463	3,264	2,959
Fall	9	3,290	9/26/2015	2,602	2,415	2,339	2,298	2,339	2,278	2,519	2,511	2,692	3,023	3,071	3,107	3,174	3,181	3,150	3,131	3,116	3,143	3,189	3,290	3,283	3,182	2,955	2,746
Fall	9	3,473	9/27/2015	2,433	2,361	2,320	2,186	2,182	2,182	2,250	2,337	2,548	2,757	2,884	2,986	3,020	3,041	3,068	3,100	3,131	3,277	3,327	3,473	3,473	3,301	3,016	2,764
Fall	9	4,178	9/28/2015	2,476	2,349	2,356	2,233	2,251	2,427	2,781	3,095	3,340	3,436	3,561	3,734	3,790	3,878	3,923	3,946	3,987	4,023	4,010	4,178	4,075	3,877	3,493	3,163
Fall	9	4,604	9/29/2015	2,852	2,661	2,571	2,532	2,510	2,643	3,051	3,473	3,775	3,865	4,036	4,189	4,304	4,445	4,518	4,535	4,542	4,539	4,505	4,604	4,481	4,239	3,911	3,539
Fall	9	4,553	9/30/2015	3,218	3,003	2,964	2,899	2,919	3,037	3,419	3,837	4,159	4,301	4,475	4,553	4,491	4,415	4,276	4,192	4,068	4,109	4,048	4,174	4,044	3,803	3,414	3,072
Fall	10	3,767	10/1/2015	2,681	2,531	2,452	2,377	2,377	2,474	2,808	3,212	3,383	3,386	3,445	3,524	3,516	3,532	3,522	3,500	3,452	3,544	3,595	3,767	3,680	3,506	3,184	2,825
Fall	10	3,638	10/2/2015	2,518	2,408	2,338	2,286	2,303	2,375	2,711	3,083	3,345	3,392	3,475	3,508	3,506	3,512	3,475	3,452	3,444	3,499	3,618	3,638	3,549	3,409	3,197	2,885
Fall	10	3,509	10/3/2015	2,605	2,470	2,376	2,328	2,357	2,424	2,527	2,667	2,960	3,172	3,349	3,402	3,396	3,384	3,328	3,283	3,263	3,267	3,389	3,509	3,414	3,291	3,084	2,844
Fall	10	3,565	10/4/2015	2,723	2,339	2,261	2,246	2,193	2,148	2,262	2,379	2,653	2,896	3,014	2,988	3,117	3,022	2,975	2,944	3,028	3,130	3,259	3,565	3,461	3,283	3,000	2,721
Fall	10	3,672	10/5/2015	2,561	2,266	2,162	2,175	2,215	2,324	2,682	3,121	3,281	3,352	3,413	3,372	3,354	3,338	3,380	3,355	3,310	3,382	3,468	3,672	3,657	3,392	3,143	2,744
Fall	10	3,689	10/6/2015	2,532	2,306	2,274	2,226	2,270	2,358	2,724	3,109	3,268	3,307	3,332	3,387	3,359	3,375	3,409	3,401	3,399	3,471	3,544	3,689	3,574	3,366	3,126	2,751
Fall	10	3,691	10/7/2015	2,402	2,312	2,239	2,192	2,197	2,296	2,671	3,149	3,225	3,307	3,326	3,372	3,380	3,421	3,474	3,452	3,460	3,514	3,520	3,691	3,574	3,374	3,056	2,683
Fall	10	3,596	10/8/2015	2,508	2,304	2,206	2,178	2,202	2,303	2,673	3,131	3,246	3,293	3,332	3,382	3,355	3,398	3,424	3,373	3,410	3,421	3,436	3,596	3,584	3,399	3,050	2,699
Fall	10	3,642	10/9/2015	2,434	2,296	2,242	2,190	2,209	2,317	2,683	3,064	3,251	3,360	3,472	3,520	3,495	3,525	3,552	3,502	3,468	3,570	3,633	3,642	3,504	3,325	3,057	2,812
Fall	10	3,186	10/10/2015	2,527	2,382	2,236	2,156	2,137	2,148	2,293	2,465	2,652	2,899	2,963	2,939	2,907	2,862	2,833	2,890	2,905	2,958	3,010	3,186	3,114	3,003	2,834	2,628
Fall	10	3,260	10/11/2015	2,420	2,293	2,238	2,133	2,073	2,155	2,226	2,342	2,522	2,757	2,840	2,876	2,858	2,849	2,804	2,837	2,890	3,037	3,084	3,260	3,207	3,055	2,835	2,602
Fall	10	3,745	10/12/2015	2,407	2,346	2,272	2,226	2,236	2,249	2,532	2,821	3,076	3,207	3,249	3,378	3,336	3,381	3,399	3,419	3,496	3,404	3,504	3,737	3,745	3,492	3,160	2,910
Fall	10	3,852	10/13/2015	2,521	2,392	2,329	2,293	2,285	2,415	2,817	3,226	3,374	3,443	3,556	3,602	3,615	3,677	3,669	3,683	3,642	3,681	3,730	3,852	3,753	3,567	3,206	2,894
Fall	10	3,670	10/14/2015	2,639	2,452	2,347	2,348	2,305	2,432	2,715	3,148	3,143	3,228	3,456	3,481	3,459	3,493	3,483	3,512	3,371	3,482	3,512	3,670	3,642	3,453	3,068	2,807
Fall	10	3,707	10/15/2015	2,541	2,376	2,263	2,284	2,357	2,403	2,819	3,273	3,363	3,390	3,406	3,420	3,383	3,406	3,371	3,353	3,381	3,430	3,507	3,707	3,628	3,499	3,161	2,827
Fall	10	3,560	10/16/2015	2,557	2,430	2,348	2,303	2,296	2,437	2,782	3,220	3,388	3,392	3,416	3,425	3,439	3,415	3,374	3,367	3,340	3,379	3,439	3,560	3,487	3,311	3,010	2,855
Fall	10	3,409	10/17/2015	2,587	2,431	2,365	2,316	2,246	2,363	2,492	2,651	2,868	3,047	3,133	3,124	3,106	3,076	3,000	2,974	3,002	3,102	3,179	3,409	3,365	3,264	3,105	2,901
Fall	10	3,765	10/18/2015	2,691	2,502	2,412	2,410	2,386	2,438	2,552	2,655	2,850	3,086	3,156	3,129	3,202	3,204	3,165	3,142	3,166	3,369	3,507	3,765	3,689	3,565	3,257	2,945
Fall	10	3,990	10/19/2015	2,767	2,642	2,593	2,531	2,609	2,807	3,174	3,691	3,845	3,814	3,779	3,746	3,642	3,612	3,542	3,513	3,530	3,628	3,750	3,990	3,934	3,750	3,350	3,020
Fall	10	3,794	10/20/2015	2,686	2,646	2,494	2,445	2,524	2,533	2,998	3,396	3,527	3,511	3,516	3,524	3,476	3,451	3,447	3,436	3,436	3,480	3,643	3,794	3,672	3,558	3,160	2,858
Fall	10	3,790	10/21/2015	2,635	2,349	2,244	2,214	2,193	2,325	2,717	3,127	3,283	3,433	3,371	3,432	3,428	3,474	3,541	3,466	3,400	3,478	3,593	3,790	3,714	3,487	3,035	2,898
Fall	10	3,776	10/22/2015	2,544	2,440	2,278	2,295	2,298	2,414	2,878	3,183	3,375	3,413	3,472	3,548	3,493	3,536	3,590	3,489	3,591	3,481	3,719	3,776	3,669	3,499	3,189	2,815
Fall	10	3,582	10/23/2015	2,565	2,409	2,253	2,261	2,244	2,430	2,720	3,213	3,326	3,403	3,415	3,385	3,352	3,361	3,295	3,299	3,272	3,321	3,476	3,582	3,572	3,396	3,210	2,970
Fall	10	3,457	10/24/2015	2,700	2,547	2,454	2,431	2,446	2,507	2,650	2,847	3,085	3,271	3,276	3,250	3,213	3,163	3,133	3,078	3,103	3,200	3,311	3,457	3,337	3,219	3,052	2,736
Fall	10	3,500	10/25/2015	2,571	2,344	2,263	2,195	2,160	2,179	2,261	2,340	2,614	2,829	3,018	3,019	3,113	3,098	2,990	2,967	3,015	3,091	3,305	3,500	3,424	3,214	2,793	2,573
Fall	10	3,808	10/26/2015	2,342	2,259	2,228	2,186	2,221	2,353	2,796	3,283	3,453	3,448	3,484	3,415	3,326	3,309	3,267	3,267	3,368	3,460	3,663	3,808	3,721	3,578	3,246	2,850
Fall	10	3,798	10/27/2015	2,587	2,410	2,459	2,389	2,397	2,554	3,013	3,455	3,484	3,546	3,497	3,434	3,376	3,338	3,294	3,296	3,328	3,429	3,656	3,798	3,713	3,515	3,096	2,792
Fall	10	3,849	10/28/2015	2,648	2,474	2,358	2,310	2,314	2,452	2,830	3,333	3,398	3,465	3,511	3,525	3,531	3,555	3,555	3,541	3,555	3,653	3,849	3,824	3,702	3,495	3,212	2,785
Fall	10	3,596	10/29/2015	2,546	2,427	2,358	2,289	2,312	2,390	2,688	3,201	3,361	3,403	3,467	3,470	3,461	3,445	3,431	3,343	3,300	3,284	3,416	3,596	3,565	3,286	3,024	2,653
Fall	10	3,464	10/30/2015	2,501	2,262	2,168	2,220	2,143	2,268	2,656	3,147	3,275	3,246	3,251	3,296	3,243	3,228	3,172	3,127	3,127	3,206	3,387	3,464	3,371	3,267	3,051	2,840
Fall	10	3,204	10/31/2015	2,544	2,383	2,308	2,300	2,282	2,339	2,481	2,703	2,920	3,083	3,137	3,096	3,052	3,011	2,931	2,905	2,953	3,049	3,204	3,160	3,095	3,028	2,906	2,677
Fall	11	3,513	11/1/2015	2,487	2,323	2,187	2,147	2,101	2,222	2,298	2,395	2,710	2,973	3,007	3,091	3,061	3,054	2,994	2,973	3,028	3,316	3,513	3,405	3,279	3,074	2,831	2,513
Fall	11	3,838	11/2/2015	2,402	2,255	2,199	2,197	2,242	2,413	2,807	3,177	3,300	3,371	3,381	3,368	3,374	3,351	3,322	3,331	3,313	3,636	3,838	3,733	3,547	3,289	3,062	2,746
Fall	11	3,805	11/3/2015	2,511	2,397	2,336	2,303	2,351	2,507	2,847	3,172	3,295	3,338	3,328	3,400	3,360	3,385	3,389	3,377	3,390	3,610	3,805	3,692	3,583	3,319	3,016	2,757
Fall	11	3,844	11/4/2015	2,461	2,332	2,262	2,241	2,314	2,407	2,800	3,176	3,306	3,291	3,325	3,360	3,348	3,378	3,386	3,363	3,355	3,557	3,844	3,701	3,554	3,357	3,030	2,747
Fall	11	3,856	11/5/2015	2,463	2,295	2,260	2,233	2,274	2,404	2,746	3,173	3,365	3,370	3,413	3,481	3,382	3,473	3,478	3,460	3,481	3,735	3,856	3,741	3,630	3,375	3,068	2,748
Fall	11	3,852	11/6/2015	2,501	2,372	2,291	2,231	2,231	2,397	2,768	3,155	3,371	3,439	3,535	3,542	3,541	3,521	3,528	3,495	3,488	3,728	3,852	3,745	3,552	3,301	3,049	2,832
Fall	11	3,474	11/7/2015	2,800	2,706	2,723	2,709	2,682	2,729	2,919	3,059	3,228	3,365	2,969	3,037	3,021	2,997	2,997	2,952	3,063	3,369	3,474	3,316	3,165	2,994	2,752	2,531
Fall	11	3,542	11/8/2015	2,313	2,251	2,152	2,081	2,069	2,130	2,263	2,300	2,517	2,657	2,784	2,696	2,858	2,892	2,784	2,876	2,903	3,385	3,542	3,453	3,319	3,216	2,919	2,633

Contains Proprietary Material
Do Not Distribute

Fall	11	3,947	11/9/2015	2,574	2,514	2,451	2,433	2,439	2,523	2,663	3,130	3,194	3,183	3,394	3,379	3,431	3,408	3,351	3,291	3,303	3,741	3,947	3,779	3,578	3,471	3,135	2,777
Fall	11	3,963	11/10/2015	2,537	2,350	2,358	2,339	2,327	2,601	2,816	3,185	3,428	3,513	3,482	3,432	3,351	3,244	3,540	3,533	3,544	3,888	3,963	3,780	3,689	3,592	3,112	2,935
Fall	11	3,936	11/11/2015	2,595	2,447	2,392	2,340	2,372	2,500	2,747	3,118	3,331	3,472	3,527	3,588	3,515	3,471	3,561	3,488	3,517	3,936	3,920	3,794	3,768	3,532	3,298	3,022
Fall	11	4,046	11/12/2015	2,666	2,609	2,430	2,470	2,379	2,578	2,893	3,317	3,536	3,636	3,681	3,665	3,689	3,709	3,688	3,653	3,770	3,887	4,046	3,914	3,772	3,518	3,206	2,979
Fall	11	3,846	11/13/2015	2,654	2,497	2,452	2,375	2,412	2,508	2,870	3,179	3,369	3,471	3,417	3,412	3,510	3,412	3,435	3,395	3,383	3,715	3,846	3,747	3,576	3,426	3,237	2,949
Fall	11	3,734	11/14/2015	2,713	2,572	2,476	2,447	2,425	2,492	2,622	2,807	3,011	3,197	3,268	3,278	3,203	3,181	3,147	3,175	3,272	3,658	3,734	3,616	3,561	3,463	3,214	2,995
Fall	11	3,742	11/15/2015	2,817	2,661	2,585	2,557	2,514	2,582	2,725	2,802	2,928	3,150	3,173	3,181	3,122	3,102	3,076	3,147	3,215	3,654	3,742	3,647	3,529	3,368	3,088	2,840
Fall	11	3,972	11/16/2015	2,609	2,444	2,410	2,412	2,451	2,631	2,999	3,398	3,510	3,482	3,487	3,505	3,490	3,483	3,464	3,381	3,434	3,880	3,972	3,869	3,715	3,526	3,224	2,893
Fall	11	4,006	11/17/2015	2,677	2,561	2,596	2,508	2,577	2,749	3,044	3,590	3,530	3,555	3,541	3,512	3,465	3,447	3,438	3,456	3,438	3,886	4,006	3,970	3,918	3,690	3,435	3,189
Fall	11	4,038	11/18/2015	2,905	2,766	2,663	2,686	2,706	2,852	3,248	3,619	3,748	3,787	3,728	3,659	3,589	3,623	3,570	3,596	3,636	3,911	4,038	3,927	3,821	3,637	3,352	2,919
Fall	11	3,936	11/19/2015	2,702	2,561	2,473	2,416	2,430	2,560	2,879	3,323	3,491	3,532	3,591	3,639	3,611	3,651	3,552	3,593	3,652	3,876	3,936	3,891	3,737	3,565	3,330	2,984
Fall	11	3,748	11/20/2015	2,675	2,517	2,448	2,368	2,322	2,525	2,853	3,091	3,394	3,369	3,397	3,427	3,368	3,331	3,364	3,346	3,376	3,664	3,748	3,689	3,567	3,440	3,217	2,938
Fall	11	3,643	11/21/2015	2,745	2,599	2,507	2,421	2,499	2,555	2,704	2,843	3,056	3,306	3,311	3,116	3,074	2,997	3,013	3,038	3,136	3,495	3,643	3,607	3,471	3,355	3,105	2,942
Fall	11	3,797	11/22/2015	2,578	2,430	2,340	2,280	2,271	2,284	2,405	2,610	2,775	3,012	3,053	3,138	3,237	3,312	3,297	3,367	3,456	3,699	3,797	3,729	3,582	3,444	3,213	2,947
Fall	11	4,237	11/23/2015	2,761	2,591	2,554	2,545	2,592	2,756	3,149	3,529	3,716	3,705	3,687	3,644	3,584	3,576	3,645	3,625	3,699	4,102	4,237	4,209	4,101	3,959	3,641	3,314
Fall	11	4,213	11/24/2015	3,032	2,894	2,848	2,810	2,827	3,035	3,386	3,838	3,947	3,925	3,861	3,759	3,657	3,657	3,641	3,656	3,784	3,975	4,213	4,160	4,104	3,966	3,648	3,358
Fall	11	4,166	11/25/2015	3,062	2,820	2,887	2,756	2,793	3,101	3,378	3,789	3,878	3,893	3,784	3,846	3,720	3,781	3,711	3,647	3,669	4,084	4,166	4,054	3,940	3,722	3,492	3,263
Fall	11	3,573	11/26/2015	3,084	2,767	2,676	2,587	2,606	2,681	2,783	2,954	3,328	3,406	3,516	3,565	3,573	3,464	3,235	3,127	3,013	3,168	3,160	3,109	3,127	3,092	2,958	2,737
Fall	11	3,551	11/27/2015	2,602	2,439	2,326	2,347	2,362	2,455	2,557	2,749	2,892	3,089	3,172	3,080	3,136	3,076	3,069	3,045	3,115	3,438	3,551	3,452	3,310	3,207	3,018	2,775
Fall	11	3,637	11/28/2015	2,535	2,323	2,302	2,247	2,261	2,259	2,396	2,564	2,780	2,996	3,102	3,252	3,338	3,244	3,280	3,221	3,351	3,567	3,637	3,511	3,433	3,316	3,180	2,934
Fall	11	3,930	11/29/2015	2,690	2,559	2,474	2,505	2,342	2,467	2,549	2,726	2,903	3,103	3,143	3,276	3,185	3,092	3,131	3,197	3,314	3,853	3,930	3,862	3,787	3,581	3,406	3,130
Fall	11	4,287	11/30/2015	2,845	2,600	2,585	2,579	2,627	2,732	3,176	3,646	3,851	3,853	3,793	3,846	3,805	3,749	3,687	3,719	3,813	4,188	4,287	4,240	4,155	3,932	3,630	3,204

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
a	b	c	d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t
1001	Albany Energy LLC	Albany LFGE	F	323615	Albany	001	36	1998-05-01	5.6	4.5	5.6	5.6		IC	MTE			24.3	
1002	Astoria Energy II, LLC	Astoria Energy 2 - CC3	J	323677	Queens	081	36	2011-07-01	330.0	288.0	269.4	312.9		CC	NG	FO2		3,082.5	**(G)**
1003	Astoria Energy II, LLC	Astoria Energy 2 - CC4	J	323678	Queens	081	36	2011-07-01	330.0	288.0	269.4	312.9		CC	NG	FO2			
1004	Astoria Energy, LLC	Astoria East Energy - CC1	J	323581	Queens	081	36	2006-04-01	320.0	278.7	276.9	311.6		CC	NG	FO2		3,496.2	**(G)**
1005	Astoria Energy, LLC	Astoria East Energy - CC2	J	323582	Queens	081	36	2006-04-01	320.0	278.7	276.9	311.6		CC	NG	FO2			
1006	Astoria Generating Company L.P.	Astoria 2 (ReAct. - 12/31/14)	J	24149	Queens	081	36	1954-03-01	180.0	177.0	167.9	166.6		ST	NG			2.4	**(D) (1)**
1007	Astoria Generating Company L.P.	Astoria 3	J	23516	Queens	081	36	1958-09-01	376.0	369.9	376.0	376.4		ST	FO6	NG		188.8	
1008	Astoria Generating Company L.P.	Astoria 5	J	23518	Queens	081	36	1962-05-01	387.0	376.3	381.0	380.6		ST	FO6	NG		993.9	
1009	Astoria Generating Company L.P.	Astoria GT 01	J	23523	Queens	081	36	1967-07-01	16.0	15.7	14.7	18.0		GT	NG			0.7	
1010	Astoria Generating Company L.P.	Gowanus 1-1	J	24077	Brooklyn	047	36	1971-06-01	20.0	19.1	18.2	24.1		GT	FO2			0.1	
1011	Astoria Generating Company L.P.	Gowanus 1-2	J	24078	Brooklyn	047	36	1971-06-01	20.0	17.1	18.5	21.3		GT	FO2			0.2	
1012	Astoria Generating Company L.P.	Gowanus 1-3	J	24079	Brooklyn	047	36	1971-06-01	20.0	17.2	16.3	21.9		GT	FO2			0.2	
1013	Astoria Generating Company L.P.	Gowanus 1-4	J	24080	Brooklyn	047	36	1971-06-01	20.0	17.1	16.0	21.3		GT	FO2			0.1	
1014	Astoria Generating Company L.P.	Gowanus 1-5	J	24084	Brooklyn	047	36	1971-06-01	20.0	16.5	16.1	22.4		GT	FO2			0.2	
1015	Astoria Generating Company L.P.	Gowanus 1-6	J	24111	Brooklyn	047	36	1971-06-01	20.0	18.0	15.6	21.8		GT	FO2			0.2	
1016	Astoria Generating Company L.P.	Gowanus 1-7	J	24112	Brooklyn	047	36	1971-06-01	20.0	17.6	16.7	22.3		GT	FO2			0.2	
1017	Astoria Generating Company L.P.	Gowanus 1-8	J	24113	Brooklyn	047	36	1971-06-01	20.0	16.1	14.6	19.9		GT	FO2			0.2	
1018	Astoria Generating Company L.P.	Gowanus 2-1	J	24114	Brooklyn	047	36	1971-06-01	20.0	17.9	17.3	21.4		GT	FO2	NG		0.7	
1019	Astoria Generating Company L.P.	Gowanus 2-2	J	24115	Brooklyn	047	36	1971-06-01	20.0	18.8	18.3	22.0		GT	FO2	NG		0.6	
1020	Astoria Generating Company L.P.	Gowanus 2-3	J	24116	Brooklyn	047	36	1971-06-01	20.0	20.6	19.1	24.2		GT	FO2	NG		0.5	
1021	Astoria Generating Company L.P.	Gowanus 2-4	J	24117	Brooklyn	047	36	1971-06-01	20.0	19.3	17.4	22.2		GT	FO2	NG		0.5	
1022	Astoria Generating Company L.P.	Gowanus 2-5	J	24118	Brooklyn	047	36	1971-06-01	20.0	18.6	17.0	21.4		GT	FO2	NG		0.6	
1023	Astoria Generating Company L.P.	Gowanus 2-6	J	24119	Brooklyn	047	36	1971-06-01	20.0	20.3	19.1	23.6		GT	FO2	NG		0.7	
1024	Astoria Generating Company L.P.	Gowanus 2-7	J	24120	Brooklyn	047	36	1971-06-01	20.0	19.6	18.5	23.0		GT	FO2	NG		0.6	
1025	Astoria Generating Company L.P.	Gowanus 2-8	J	24121	Brooklyn	047	36	1971-06-01	20.0	17.7	17.0	21.5		GT	FO2	NG		0.3	
1026	Astoria Generating Company L.P.	Gowanus 3-1	J	24122	Brooklyn	047	36	1971-07-01	20.0	17.7	16.9	22.0		GT	FO2	NG		0.4	
1027	Astoria Generating Company L.P.	Gowanus 3-2	J	24123	Brooklyn	047	36	1971-07-01	20.0	17.7	16.9	21.9		GT	FO2	NG		0.4	
1028	Astoria Generating Company L.P.	Gowanus 3-3	J	24124	Brooklyn	047	36	1971-07-01	20.0	19.8	18.0	23.9		GT	FO2	NG		0.5	
1029	Astoria Generating Company L.P.	Gowanus 3-4	J	24125	Brooklyn	047	36	1971-07-01	20.0	17.9	16.3	21.7		GT	FO2	NG		0.4	
1030	Astoria Generating Company L.P.	Gowanus 3-5	J	24126	Brooklyn	047	36	1971-07-01	20.0	19.0	17.3	24.0		GT	FO2	NG		0.5	
1031	Astoria Generating Company L.P.	Gowanus 3-6	J	24127	Brooklyn	047	36	1971-07-01	20.0	17.6	15.4	20.0		GT	FO2	NG		0.8	
1032	Astoria Generating Company L.P.	Gowanus 3-7	J	24128	Brooklyn	047	36	1971-07-01	20.0	18.1	18.0	24.2		GT	FO2	NG		0.4	
1033	Astoria Generating Company L.P.	Gowanus 3-8	J	24129	Brooklyn	047	36	1971-07-01	20.0	19.0	17.6	23.8		GT	FO2	NG		0.3	
1034	Astoria Generating Company L.P.	Gowanus 4-1	J	24130	Brooklyn	047	36	1971-07-01	20.0	16.8	18.6	23.0		GT	FO2			0.2	
1035	Astoria Generating Company L.P.	Gowanus 4-2	J	24131	Brooklyn	047	36	1971-07-01	20.0	17.3	17.4	20.9		GT	FO2			0.2	
1036	Astoria Generating Company L.P.	Gowanus 4-3	J	24132	Brooklyn	047	36	1971-07-01	20.0	17.6	17.1	22.0		GT	FO2			0.2	
1037	Astoria Generating Company L.P.	Gowanus 4-4	J	24133	Brooklyn	047	36	1971-07-01	20.0	17.1	16.5	21.5		GT	FO2			0.1	
1038	Astoria Generating Company L.P.	Gowanus 4-5	J	24134	Brooklyn	047	36	1971-07-01	20.0	17.1	16.2	21.2		GT	FO2			0.2	
1039	Astoria Generating Company L.P.	Gowanus 4-6	J	24135	Brooklyn	047	36	1971-07-01	20.0	18.6	18.0	22.9		GT	FO2			0.2	
1040	Astoria Generating Company L.P.	Gowanus 4-7	J	24136	Brooklyn	047	36	1971-07-01	20.0	16.6	16.4	21.3		GT	FO2			0.1	
1041	Astoria Generating Company L.P.	Gowanus 4-8	J	24137	Brooklyn	047	36	1971-07-01	20.0	19.0	17.0	22.1		GT	FO2			0.2	
1042	Astoria Generating Company L.P.	Narrows 1-1	J	24228	Brooklyn	047	36	1972-05-01	22.0	21.0	19.2	23.6		GT	KER	NG		2.4	
1043	Astoria Generating Company L.P.	Narrows 1-2	J	24229	Brooklyn	047	36	1972-05-01	22.0	19.5	17.2	22.2		GT	KER	NG		2.0	
1044	Astoria Generating Company L.P.	Narrows 1-3	J	24230	Brooklyn	047	36	1972-05-01	22.0	20.4	18.2	23.3		GT	KER	NG		2.1	
1045	Astoria Generating Company L.P.	Narrows 1-4	J	24231	Brooklyn	047	36	1972-05-01	22.0	20.1	19.2	24.2		GT	KER	NG		1.7	
1046	Astoria Generating Company L.P.	Narrows 1-5	J	24232	Brooklyn	047	36	1972-05-01	22.0	19.8	18.5	24.5		GT	KER	NG		1.4	
1047	Astoria Generating Company L.P.	Narrows 1-6	J	24233	Brooklyn	047	36	1972-05-01	22.0	18.9	16.1	21.7		GT	KER	NG		1.4	
1048	Astoria Generating Company L.P.	Narrows 1-7	J	24234	Brooklyn	047	36	1972-05-01	22.0	18.4	16.2	21.7		GT	KER	NG		1.8	
1049	Astoria Generating Company L.P.	Narrows 1-8	J	24235	Brooklyn	047	36	1972-05-01	22.0	19.9	17.2	22.6		GT	KER	NG		1.3	
1050	Astoria Generating Company L.P.	Narrows 2-1	J	24236	Brooklyn	047	36	1972-06-01	22.0	19.4	19.0	24.0		GT	KER	NG		2.1	
1051	Astoria Generating Company L.P.	Narrows 2-2	J	24237	Brooklyn	047	36	1972-06-01	22.0	18.7	17.2	21.0		GT	KER	NG		1.4	
1052	Astoria Generating Company L.P.	Narrows 2-3	J	24238	Brooklyn	047	36	1972-06-01	22.0	18.4	18.1	22.0		GT	KER	NG		1.4	
1053	Astoria Generating Company L.P.	Narrows 2-4	J	24239	Brooklyn	047	36	1972-06-01	22.0	18.4	18.4	21.9		GT	KER	NG		1.7	
1054	Astoria Generating Company L.P.	Narrows 2-5	J	24240	Brooklyn	047	36	1972-06-01	22.0	19.9	17.9	22.8		GT	KER	NG		1.4	
1055	Astoria Generating Company L.P.	Narrows 2-6	J	24241	Brooklyn	047	36	1972-06-01	22.0	18.1	15.8	20.7		GT	KER	NG		1.3	
1056	Astoria Generating Company L.P.	Narrows 2-7	J	24242	Brooklyn	047	36	1972-06-01	22.0	20.7	18.7	23.8		GT	KER	NG		1.4	
1057	Astoria Generating Company L.P.	Narrows 2-8	J	24243	Brooklyn	047	36	1972-06-01	22.0	17.5	16.5	20.8		GT	KER	NG		1.3	
1058	Athens Generating Company, LP	Athens 1	F	23668	Athens	039	36	2004-05-01	441.0	316.6	321.2	398.2		CC	NG	FO2		1,056.8	
1059	Athens Generating Company, LP	Athens 2	F	23670	Athens	039	36	2004-05-01	441.0	315.6	315.5	398.7		CC	NG	FO2		757.8	
1060	Athens Generating Company, LP	Athens 3	F	23677	Athens	039	36	2004-05-01	441.0	312.8	313.2	389.3		CC	NG	FO2		844.7	
1061	Bayonne Energy Center, LLC	Bayonne EC CTG1	J	323682	Bayonne NJ	017	34	2012-06-01	64.0	64.0	58.9	62.9		JE	NG	KER		152.1	
1062	Bayonne Energy Center, LLC	Bayonne EC CTG2	J	323683	Bayonne NJ	017	34	2012-06-01	64.0	64.0	59.0	62.8		JE	NG	KER		182.2	
1063	Bayonne Energy Center, LLC	Bayonne EC CTG3	J	323684	Bayonne NJ	017	34	2012-06-01	64.0	64.0	56.4	62.9		JE	NG	KER		154.7	
1064	Bayonne Energy Center, LLC	Bayonne EC CTG4	J	323685	Bayonne NJ	017	34	2012-06-01	64.0	64.0	56.3	62.8		JE	NG	KER		152.2	
1065	Bayonne Energy Center, LLC	Bayonne EC CTG5	J	323686	Bayonne NJ	017	34	2012-06-01	64.0	64.0	57.0	62.8		JE	NG	KER		149.2	
1066	Bayonne Energy Center, LLC	Bayonne EC CTG6	J	323687	Bayonne NJ	017	34	2012-06-01	64.0	64.0	55.5	62.8		JE	NG	KER		180.6	
1067	Bayonne Energy Center, LLC	Bayonne EC CTG7	J	323688	Bayonne NJ	017	34	2012-06-01	64.0	64.0	57.6	62.9		JE	NG	KER		160.1	
1068	Bayonne Energy Center, LLC	Bayonne EC CTG8	J	323689	Bayonne NJ	017	34	2012-06-01	64.0	64.0	58.9	62.7		JE	NG	KER		169.3	
1069	Binghamton BOP, LLC	Binghamton (ReAct. - 12/16/	C	23790	Binghamton	007	36	2001-03-01	47.7	43.8	45.1	46.9	Yes	CC	NG	KER		0.5	**(D) (2)**
1070	Boralex Hydro Operations Inc	Fourth Branch	F	23824	Waterford	091	36	1987-12-01	3.3	3.5	3.3	3.3		HY	WAT			16.6	
1071	Boralex Hydro Operations Inc	NYS Dam	F	23527	Waterford	091	36	1990-12-01	11.4	11.3	11.4	11.4		HY	WAT			53.1	

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1072	Boralex Hydro Operations Inc	Sissonville		E	23735	Potsdam	089	36	1990-08-01	3.1	3.0	3.1	3.1		HY	WAT			14.6	
1073	Boralex Hydro Operations Inc	Warrensburg		F	23737	Warrensburg	113	36	1988-12-01	2.9	3.0	2.9	2.9		HY	WAT			11.8	
1074	Calpine Energy Services LP	Bethpage		K	23823	Hicksville	059	36	1989-09-01	83.6	54.9	50.0	56.7		CC	NG			295.2	
1075	Calpine Energy Services LP	Bethpage GT4		K	323586	Hicksville	059	36	2002-07-01	60.0	48.2	44.3	46.6		GT	NG			123.6	
1076	Calpine Energy Services LP	KIAC_JFK_GT1		J	23816	Jamaica	081	36	1995-02-01	60.6	58.7	59.9	60.4	YES	CC	NG	FO2		734.3	(G)
1077	Calpine Energy Services LP	KIAC_JFK_GT2		J	23817	Jamaica	081	36	1995-02-01	60.6	58.3	59.7	61.2	YES	CC	NG	FO2			
1078	Canandaigua Power Partners, LLC	Canandaigua Wind Power		C	323617	Avoca	101	36	2008-12-05	125.0	125.0	125.0	125.0		WT	WND			259.5	
1079	Canastota Windpower LLC	Fenner Wind Power		C	24204	Fenner	053	36	2001-12-01	30.0	0.0	0.0	0.0		WT	WND			66.8	
1080	Carr Street Generating Station LP	Carr St.-E. Syr		C	24060	Dewitt	067	36	1993-08-01	122.6	89.0	83.2	105.1		CC	NG	FO2		97.7	
1081	Castleton Power, LLC	Castleton Energy Center		F	23900	Castleton	083	36	1992-01-01	72.0	67.0	60.0	72.0		CC	NG	FO2		229.4	
1082	Cayuga Operating Company, LLC	Cayuga 1		C	23584	Lansing	109	36	1955-09-01	155.3	154.1	153.3	153.7		ST	BIT			408.8	(S)
1083	Cayuga Operating Company, LLC	Cayuga 2		C	23585	Lansing	109	36	1958-10-01	167.2	154.7	151.0	153.6		ST	BIT			507.4	(S)
1084	Cayuga Operating Company, LLC	Cayuga IC 1		C	23629	Lansing	109	36	1967-08-01	2.8	0.0	0.0	0.0		IC	FO2				
1085	Cayuga Operating Company, LLC	Cayuga IC 2		C	23629	Lansing	109	36	1967-08-01	2.8	0.0	0.0	0.0		IC	FO2				
1086	Central Hudson Gas & Elec. Corp.	Coxsackie GT		G	23611	Coxsackie	039	36	1969-12-01	21.6	19.9	19.0	23.3		GT	KER	NG		0.3	
1087	Central Hudson Gas & Elec. Corp.	Dashville 1		G	23610	Rifton	111	36	1920-01-01	2.4	2.7	0.0	0.0		HY	WAT				
1088	Central Hudson Gas & Elec. Corp.	Dashville 2		G	23610	Rifton	111	36	1920-01-01	2.4	2.7	0.0	0.0		HY	WAT				
1089	Central Hudson Gas & Elec. Corp.	DCRRA		G	23765	Poughkeepsie	027	36	1987-09-01	9.2	8.8	7.7	7.4		ST	REF			43.2	
1090	Central Hudson Gas & Elec. Corp.	High Falls		G	23754	Marbletown	111	36	1986-12-01	3.2	3.0	0.0	0.0		HY	WAT				
1091	Central Hudson Gas & Elec. Corp.	Millpond		G	5004	Catskill	039	36	1993-12-01	0.9		0.0	0.0		HY	WAT				
1092	Central Hudson Gas & Elec. Corp.	Montgomery West		G	5005	Montgomery	071	36	1985-11-01	0.2		0.0	0.0		HY	WAT				
1093	Central Hudson Gas & Elec. Corp.	Salisbury Mills		G	5006	Salisbury Mills	071	36	1986-12-01	0.5		0.0	0.0		HY	WAT				
1094	Central Hudson Gas & Elec. Corp.	South Cairo		G	23612	Cairo	039	36	1970-06-01	21.6	17.8	18.2	23.3		GT	KER			0.1	
1095	Central Hudson Gas & Elec. Corp.	Sturgeon 1		G	23609	Rifton	111	36	1924-01-01	4.8	5.0	0.0	0.0		HY	WAT				
1096	Central Hudson Gas & Elec. Corp.	Sturgeon 2		G	23609	Rifton	111	36	1924-01-01	4.8	5.8	0.0	0.0		HY	WAT				
1097	Central Hudson Gas & Elec. Corp.	Sturgeon 3		G	23609	Rifton	111	36	1924-01-01	4.8	5.0	0.0	0.0		HY	WAT				
1098	Central Hudson Gas & Elec. Corp.	Wallkill		G	5007	Shwangunk	111	36	1986-12-01	0.5		0.0	0.0		HY	WAT				
1099	Central Hudson Gas & Elec. Corp.	Wappingers Falls		G	23765	Wappingers	027	36	1988-12-01	2.0	2.0	2.0	2.0		HY	WAT			8.8	
1100	CHI Energy Inc	Goodyear Lake		E	323669	Milford	077	36	1980-07-01	1.4	1.4	0.0	0.0		HY	WAT			4.3	
1101	Consolidated Edison Co. of NY, Inc.	59 St. GT 1		J	24138	Manhattan	061	36	1969-06-01	17.1	15.4	15.1	20.7		GT	KER	NG		0.3	
1102	Consolidated Edison Co. of NY, Inc.	74 St. GT 1		J	24260	Manhattan	061	36	1968-10-01	18.5	19.0	17.7	17.9		GT	KER			0.2	
1103	Consolidated Edison Co. of NY, Inc.	74 St. GT 2		J	24261	Manhattan	061	36	1968-10-01	18.5	20.1	17.4	20.1		GT	KER			0.5	
1104	Consolidated Edison Co. of NY, Inc.	Brooklyn Navy Yard		J	23515	Brooklyn	047	36	1996-11-01	322.0	266.9	261.5	296.1	YES	CC	NG	FO2		1,953.5	
1105	Consolidated Edison Co. of NY, Inc.	East River 1		J	323558	Manhattan	061	36	2005-04-01	185.0	150.5	144.6	180.4		CC	NG	KER		1,058.1	
1106	Consolidated Edison Co. of NY, Inc.	East River 2		J	323559	Manhattan	061	36	2005-04-05	185.0	152.4	144.8	181.8		CC	NG	KER		1,156.7	
1107	Consolidated Edison Co. of NY, Inc.	East River 6		J	23660	Manhattan	061	36	1951-11-01	156.2	134.3	138.3	137.9	YES	ST	FO6	NG		431.5	
1108	Consolidated Edison Co. of NY, Inc.	East River 7		J	23524	Manhattan	061	36	1955-06-01	200.0	184.7	183.6	185.0	YES	ST	FO6	NG		105.9	
1109	Consolidated Edison Co. of NY, Inc.	Hudson Ave 3		J	23810	Brooklyn	047	36	1970-07-01	16.3	16.0	14.8	18.7		GT	KER			0.2	
1110	Consolidated Edison Co. of NY, Inc.	Hudson Ave 4		J	23540	Brooklyn	047	36	1970-07-01	16.3	13.9	13.7	17.5		GT	KER			0.4	
1111	Consolidated Edison Co. of NY, Inc.	Hudson Ave 5		J	23657	Brooklyn	047	36	1970-07-01	16.3	15.1	15.0	18.6		GT	KER			0.5	
1112	Consolidated Edison Energy, Inc.	Broome 2 LFGE		C	323671	Binghamton	007	36	2013-01-31	1.6	1.6	1.6	1.6		IC	MTE			13.1	
1113	Consolidated Edison Energy, Inc.	Massena		D	23902	Massena	089	36	1992-07-01	102.1	82.2	80.3	90.7		CC	NG	FO2		1.7	
1114	Consolidated Edison Energy, Inc.	Rensselaer		F	23796	Rensselaer	083	36	1993-12-01	96.9	79.0	77.0	82.7		CC	NG	FO2		48.0	
1115	Consolidated Edison Energy, Inc.	Roseton 1		G	23587	Newburgh	071	36	1974-12-01	621.0	614.8	610.5	618.7		ST	FO6	NG	FO2	176.4	
1116	Consolidated Edison Energy, Inc.	Roseton 2		G	23588	Newburgh	071	36	1974-09-01	621.0	605.7	597.0	587.2		ST	FO6	NG	FO2	202.0	
1117	Consolidated Hydro New York, Inc.	Groveville Hydro		G	323602	Beacon	027	36	1983-12-01	0.9	0.9	0.0	0.0		HY	WAT			1.6	
1118	Consolidated Hydro New York, Inc.	Walden Hydro		G	24148	Walden	071	36	1983-12-01	2.4	0.0	0.0	0.0		HY	WAT			3.0	
1119	Covanta Niagara, LP	American Ref-Fuel 1		A	24010	Niagara	063	36	1993-05-01	25.0	19.6	18.4	17.5	YES	ST	REF			241.1	(G)
1120	Covanta Niagara, LP	American Ref-Fuel 2		A	24010	Niagara	063	36	1993-05-01	25.0	19.6	18.4	17.5	YES	ST	REF				
1121	Danskammer Energy, LLC	Danskammer 1	(ReAct. - 10/	G	23586	Newburgh	071	36	1951-12-01	72.0	67.0	60.7	60.7		ST	NG	FO6			(D)
1122	Danskammer Energy, LLC	Danskammer 2	(ReAct. - 10/	G	23589	Newburgh	071	36	1954-09-01	73.5	62.7	59.5	59.5		ST	NG	FO6			(D)
1123	Danskammer Energy, LLC	Danskammer 3	(ReAct. - 12/	G	23590	Newburgh	071	36	1959-10-01	147.1	137.2	137.5	137.5		ST	NG			1.2	(D) (3)
1124	Danskammer Energy, LLC	Danskammer 4	(ReAct. - 11/	G	23591	Newburgh	071	36	1967-09-01	239.4	236.2	232.0	178.7		ST	NG			3.1	(D) (4)
1125	Dynegy Danskammer, LLC	Danskammer 5		G	23592	Newburgh	071	36	1967-01-01	2.7	0.0	0.0	0.0		IC	FO2				
1126	Dynegy Danskammer, LLC	Danskammer 6		G	23592	Newburgh	071	36	1967-01-01	2.7	0.0	0.0	0.0		IC	FO2				
1127	Dynegy Marketing and Trade, LLC	Independence		C	23800	Scriba	075	36	1994-11-01	1,254.0	954.4	910.8	1,112.0		CC	NG			6,026.3	
1128	Eagle Creek Hydro Power, LLC	Mongaup 1		G	23641	Forestburg	105	36	1923-07-01	1.0	0.9	1.0	1.0		HY	WAT			10.3	(G)
1129	Eagle Creek Hydro Power, LLC	Mongaup 2		G	23641	Forestburg	105	36	1923-07-01	1.0	1.0	1.0	1.0		HY	WAT				
1130	Eagle Creek Hydro Power, LLC	Mongaup 3		G	23641	Forestburg	105	36	1923-07-01	1.0	1.0	1.0	1.0		HY	WAT				
1131	Eagle Creek Hydro Power, LLC	Mongaup 4		G	23641	Forestburg	105	36	1926-01-01	1.0	1.0	1.0	1.0		HY	WAT				
1132	Eagle Creek Hydro Power, LLC	Rio		G	23641	Glen Spey	105	36	1927-12-01	10.8	10.8	10.4	10.1		HY	WAT			23.0	
1133	Eagle Creek Hydro Power, LLC	Swinging Bridge 2		G	23641	Forestburg	105	36	1930-02-01	7.0	7.9	6.6	6.5		HY	WAT			9.1	
1134	East Coast Power, LLC	Linden Cogen		J	23786	Linden NJ	039	34	1992-05-01	1,034.9	755.3	757.8	800.0	YES	CC	NG	BUT		3,308.3	
1135	Empire Generating Co, LLC	EMPIRE_CC_1		F	323656	Rensselaer	083	36	2010-09-02	335.0	294.2	287.3	335.9		CC	NG	FO2		1,357.3	
1136	Empire Generating Co, LLC	EMPIRE_CC_2		F	323658	Rensselaer	083	36	2010-09-02	335.0	298.2	288.3	335.8		CC	NG	FO2		1,339.2	
1137	Entergy Nuclear Power Marketing LLC	Fitzpatrick 1		C	23598	Scriba	075	36	1975-07-01	882.0	858.9	836.8	842.9		NB	UR			5,828.7	
1138	Entergy Nuclear Power Marketing LLC	Indian Point 2		H	23530	Buchanan	119	36	1973-08-01	1,299.0	1,026.5	1,020.0	1,031.0		NP	UR			8,331.3	
1139	Entergy Nuclear Power Marketing LLC	Indian Point 3		H	23531	Buchanan	119	36	1976-04-01	1,012.0	1,040.4	1,034.8	1,047.0		NP	UR			8,979.0	
1140	Erie Blvd. Hydro - Beaver River	Belfort 1		E	24048	Belfort	049	36	1903-01-01	0.4	0.4	0.4	0.4		HY	WAT			1.8	
1141	Erie Blvd. Hydro - Beaver River	Belfort 2		E	24048	Belfort	049	36	1915-01-01	0.6	0.6	0.6	0.6		HY	WAT			5.1	
1142	Erie Blvd. Hydro - Beaver River	Belfort 3		E	24048	Belfort	049	36	1918-01-01	1.0	1.0	1.0	1.0		HY	WAT			5.2	
1143	Erie Blvd. Hydro - Beaver River	Eagle 1		E	24048	Watson	049	36	1914-01-01	1.3	1.2	1.3	1.3		HY	WAT			10.2	

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1144	Erie Blvd. Hydro - Beaver River	Eagle 2		E	24048	Watson	049	36	1915-01-01	1.4	1.3	1.4	1.4		HY	WAT			9.0	
1145	Erie Blvd. Hydro - Beaver River	Eagle 3		E	24048	Watson	049	36	1919-01-01	1.4	1.3	1.4	1.4		HY	WAT			7.0	
1146	Erie Blvd. Hydro - Beaver River	Eagle 4		E	24048	Watson	049	36	1925-01-01	2.1	2.0	2.1	2.1		HY	WAT			12.2	
1147	Erie Blvd. Hydro - Beaver River	Effley 1		E	24048	Belfort	049	36	1902-01-01	0.4	0.3	0.4	0.4		HY	WAT			2.6	
1148	Erie Blvd. Hydro - Beaver River	Effley 2		E	24048	Belfort	049	36	1907-01-01	0.4	0.3	0.4	0.4		HY	WAT			2.2	
1149	Erie Blvd. Hydro - Beaver River	Effley 3		E	24048	Belfort	049	36	1910-01-01	0.6	0.5	0.6	0.6		HY	WAT			4.3	
1150	Erie Blvd. Hydro - Beaver River	Effley 4		E	24048	Belfort	049	36	1923-01-01	1.6	1.5	1.6	1.6		HY	WAT			9.2	
1151	Erie Blvd. Hydro - Beaver River	Elmer 1		E	24048	Belfort	049	36	1916-01-01	0.8	0.9	0.8	0.8		HY	WAT			5.9	
1152	Erie Blvd. Hydro - Beaver River	Elmer 2		E	24048	Belfort	049	36	1916-01-01	0.8	0.9	0.8	0.8		HY	WAT			7.4	
1153	Erie Blvd. Hydro - Beaver River	High Falls 1		E	24048	Indian River	049	36	1925-01-01	1.6	1.9	1.6	1.6		HY	WAT			12.1	
1154	Erie Blvd. Hydro - Beaver River	High Falls 2		E	24048	Indian River	049	36	1925-01-01	1.6	1.9	1.6	1.6		HY	WAT			9.4	
1155	Erie Blvd. Hydro - Beaver River	High Falls 3		E	24048	Indian River	049	36	1925-01-01	1.6	1.9	1.6	1.6		HY	WAT			13.5	
1156	Erie Blvd. Hydro - Beaver River	Moshier 1		E	24048	Belfort	043	36	1929-01-01	4.0	4.0	4.0	4.0		HY	WAT			28.5	
1157	Erie Blvd. Hydro - Beaver River	Moshier 2		E	24048	Belfort	043	36	1929-01-01	4.0	4.0	4.0	4.0		HY	WAT			18.8	
1158	Erie Blvd. Hydro - Beaver River	Soft Maple 1		E	24048	Croghan	049	36	1925-01-01	7.5	8.0	7.5	7.5		HY	WAT			37.6	
1159	Erie Blvd. Hydro - Beaver River	Soft Maple 2		E	24048	Croghan	049	36	1925-01-01	7.5	8.0	7.5	7.5		HY	WAT			8.0	
1160	Erie Blvd. Hydro - Beaver River	Taylorville 1		E	24048	Belfort	049	36	1913-01-01	1.1	1.0	1.1	1.1		HY	WAT			8.4	
1161	Erie Blvd. Hydro - Beaver River	Taylorville 2		E	24048	Belfort	049	36	1913-01-01	1.1	1.0	1.1	1.1		HY	WAT			5.1	
1162	Erie Blvd. Hydro - Beaver River	Taylorville 3		E	24048	Belfort	049	36	1913-01-01	1.1	1.0	1.1	1.1		HY	WAT			6.8	
1163	Erie Blvd. Hydro - Beaver River	Taylorville 4		E	24048	Belfort	049	36	1927-01-01	1.2	1.1	1.2	1.2		HY	WAT			8.4	
1164	Erie Blvd. Hydro - Black River	Beebee Island 1		E	24047	Watertown	045	36	1963-01-01	4.0	4.4	4.0	4.0		HY	WAT			13.0	
1165	Erie Blvd. Hydro - Black River	Beebee Island 2		E	24047	Watertown	045	36	1968-01-01	4.0	4.4	4.0	4.0		HY	WAT			31.0	
1166	Erie Blvd. Hydro - Black River	Black River 1		E	24047	Black River	045	36	1920-01-01	2.0	2.3	2.0	2.0		HY	WAT			10.8	
1167	Erie Blvd. Hydro - Black River	Black River 2		E	24047	Black River	045	36	1920-01-01	2.0	2.3	2.0	2.0		HY	WAT			15.4	
1168	Erie Blvd. Hydro - Black River	Black River 3		E	24047	Black River	045	36	1920-01-01	2.0	2.3	2.0	2.0		HY	WAT			7.7	
1169	Erie Blvd. Hydro - Black River	Deferiet 1		E	24047	Deferiet	045	36	1925-01-01	3.6	3.7	3.6	3.6		HY	WAT			15.7	
1170	Erie Blvd. Hydro - Black River	Deferiet 2		E	24047	Deferiet	045	36	1925-01-01	3.6	3.7	3.6	3.6		HY	WAT			29.9	
1171	Erie Blvd. Hydro - Black River	Deferiet 3		E	24047	Deferiet	045	36	1925-01-01	3.6	3.7	3.6	3.6		HY	WAT			13.5	
1172	Erie Blvd. Hydro - Black River	Herrings 1		E	24047	Herrings	045	36	1924-01-01	1.8	1.8	1.8	1.8		HY	WAT			4.5	
1173	Erie Blvd. Hydro - Black River	Herrings 2		E	24047	Herrings	045	36	1924-01-01	1.8	1.8	1.8	1.8		HY	WAT			9.6	
1174	Erie Blvd. Hydro - Black River	Herrings 3		E	24047	Herrings	045	36	1924-01-01	1.8	1.8	1.8	1.8		HY	WAT			4.0	
1175	Erie Blvd. Hydro - Black River	Kamargo 1		E	24047	Black River	045	36	1921-01-01	1.8	1.8	1.8	1.8		HY	WAT			7.8	
1176	Erie Blvd. Hydro - Black River	Kamargo 2		E	24047	Black River	045	36	1921-01-01	1.8	1.8	1.8	1.8		HY	WAT			12.8	
1177	Erie Blvd. Hydro - Black River	Kamargo 3		E	24047	Black River	045	36	1921-01-01	1.8	1.8	1.8	1.8		HY	WAT			2.3	
1178	Erie Blvd. Hydro - Black River	Sewalls 1		E	24047	Watertown	045	36	1925-01-01	1.0	1.1	1.0	1.0		HY	WAT			6.2	
1179	Erie Blvd. Hydro - Black River	Sewalls 2		E	24047	Watertown	045	36	1925-01-01	1.0	1.1	1.0	1.0		HY	WAT			4.2	
1180	Erie Blvd. Hydro - East Canada Capita	Beardslee 1		F	24051	Little Falls	043	36	1924-01-01	10.0	9.5	10.0	10.0		HY	WAT			22.6	
1181	Erie Blvd. Hydro - East Canada Capita	Beardslee 2		F	24051	Little Falls	043	36	1924-01-01	10.0	9.5	10.0	10.0		HY	WAT			28.8	
1182	Erie Blvd. Hydro - East Canada Capita	Ephratah 1		F	24051	Caroga Lake	035	36	1920-01-01	1.4	0.7	1.4	1.4		HY	WAT			1.0	
1183	Erie Blvd. Hydro - East Canada Capita	Ephratah 2		F	24051	Caroga Lake	035	36	1911-01-01	1.2	0.6	1.2	1.2		HY	WAT			0.5	
1184	Erie Blvd. Hydro - East Canada Capita	Ephratah 3		F	24051	Caroga Lake	035	36	1911-01-01	1.3	0.0	0.0	0.0		HY	WAT			4.2	
1185	Erie Blvd. Hydro - East Canada Capita	Ephratah 4		F	24051	Caroga Lake	035	36	1911-01-01	1.3	0.7	1.3	1.3		HY	WAT			7.6	
1186	Erie Blvd. Hydro - East Canada Moha	Inghams 1		E	24050	Little Falls	043	36	1912-01-01	3.2	3.5	3.2	3.2		HY	WAT			11.9	
1187	Erie Blvd. Hydro - East Canada Moha	Inghams 2		E	24050	Little Falls	043	36	1912-01-01	3.2	3.5	3.2	3.2		HY	WAT			16.5	
1188	Erie Blvd. Hydro - Lower Hudson	Johnsonville 1		F	24059	Johnsonville	083	36	1909-01-01	1.2	1.3	1.2	1.2		HY	WAT			3.3	
1189	Erie Blvd. Hydro - Lower Hudson	Johnsonville 2		F	24059	Johnsonville	083	36	1909-01-01	1.2	1.3	1.2	1.2		HY	WAT			6.8	
1190	Erie Blvd. Hydro - Lower Hudson	Schaghticoke 1		F	24059	Schaghticoke	083	36	1908-01-01	3.3	4.1	3.3	3.3		HY	WAT			19.9	
1191	Erie Blvd. Hydro - Lower Hudson	Schaghticoke 2		F	24059	Schaghticoke	083	36	1908-01-01	3.3	4.1	3.3	3.3		HY	WAT			8.5	
1192	Erie Blvd. Hydro - Lower Hudson	Schaghticoke 3		F	24059	Schaghticoke	083	36	1908-01-01	3.3	4.1	3.3	3.3		HY	WAT			12.6	
1193	Erie Blvd. Hydro - Lower Hudson	Schaghticoke 4		F	24059	Schaghticoke	083	36	1908-01-01	3.3	4.1	3.3	3.3		HY	WAT			16.4	
1194	Erie Blvd. Hydro - Lower Hudson	School Street 1		F	24059	Cohoes	001	36	1974-01-01	7.2	6.9	7.2	7.2		HY	WAT			39.7	
1195	Erie Blvd. Hydro - Lower Hudson	School Street 2		F	24059	Cohoes	001	36	1915-01-01	7.2	6.9	7.2	7.2		HY	WAT			40.2	
1196	Erie Blvd. Hydro - Lower Hudson	School Street 3		F	24059	Cohoes	001	36	1915-01-01	7.2	6.9	7.2	7.2		HY	WAT			35.2	
1197	Erie Blvd. Hydro - Lower Hudson	School Street 4		F	24059	Cohoes	001	36	1922-01-01	7.2	6.9	7.2	7.2		HY	WAT			31.8	
1198	Erie Blvd. Hydro - Lower Hudson	School Street 5		F	24059	Cohoes	001	36	1924-01-01	10.0	9.6	10.0	10.0		HY	WAT			21.2	
1199	Erie Blvd. Hydro - Lower Hudson	Schuylerville		F	24059	Schuylerville	091	36	1919-01-01	1.2	1.5	1.2	1.2		HY	WAT			7.3	
1200	Erie Blvd. Hydro - Lower Raquette	Colton 1		E	24057	Colton	089	36	1962-01-01	10.0	10.0	10.0	10.0		HY	WAT			64.8	
1201	Erie Blvd. Hydro - Lower Raquette	Colton 2		E	24057	Colton	089	36	1918-01-01	10.0	10.0	10.0	10.0		HY	WAT			56.5	
1202	Erie Blvd. Hydro - Lower Raquette	Colton 3		E	24057	Colton	089	36	1928-01-01	10.0	10.0	10.0	10.0		HY	WAT			68.6	
1203	Erie Blvd. Hydro - Lower Raquette	East Norfolk		E	24057	East Norfolk	089	36	1928-01-01	3.0	4.0	3.0	3.0		HY	WAT			24.9	
1204	Erie Blvd. Hydro - Lower Raquette	Hannawa Falls 1		E	24057	Hannawa Falls	089	36	1914-01-01	3.6	3.7	3.6	3.6		HY	WAT			20.6	
1205	Erie Blvd. Hydro - Lower Raquette	Hannawa Falls 2		E	24057	Hannawa Falls	089	36	1920-01-01	3.6	3.7	3.6	3.6		HY	WAT			26.4	
1206	Erie Blvd. Hydro - Lower Raquette	Higley 1		E	24057	Colton	089	36	1913-01-01	1.2	1.1	1.2	1.2		HY	WAT			8.0	
1207	Erie Blvd. Hydro - Lower Raquette	Higley 2		E	24057	Colton	089	36	1913-01-01	1.2	1.1	1.2	1.2		HY	WAT			7.9	
1208	Erie Blvd. Hydro - Lower Raquette	Higley 3		E	24057	Colton	089	36	1943-01-01	2.1	2.0	2.1	2.1		HY	WAT			10.0	
1209	Erie Blvd. Hydro - Lower Raquette	Higley 4		E	24057	Colton	089	36	1943-01-01	2.1	2.0	2.1	2.1		HY	WAT			7.5	
1210	Erie Blvd. Hydro - Lower Raquette	Norfolk		E	24057	Norfolk	089	36	1928-01-01	4.5	4.8	4.5	4.5		HY	WAT			28.2	
1211	Erie Blvd. Hydro - Lower Raquette	Norwood		E	24057	Norwood	089	36	1928-01-01	2.0	2.2	2.0	2.0		HY	WAT			13.6	
1212	Erie Blvd. Hydro - Lower Raquette	Raymondville		E	24057	Raymondville	089	36	1928-01-01	2.0	2.1	2.0	2.0		HY	WAT			13.1	
1213	Erie Blvd. Hydro - Lower Raquette	Sugar Island 1		E	24057	Potsdam	089	36	1924-01-01	2.6	2.1	2.6	2.6		HY	WAT			9.9	
1214	Erie Blvd. Hydro - Lower Raquette	Sugar Island 2		E	24057	Potsdam	089	36	1924-01-01	2.4	2.0	2.4	2.4		HY	WAT			17.1	
1215	Erie Blvd. Hydro - Lower Raquette	Yaleville 1		E	24057	Norwood	089	36	1940-01-01	0.5	0.2	0.5	0.5		HY	WAT			2.3	

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1216	Erie Blvd. Hydro - Lower Raquette	Yaleville 2		E	24057	Norwood	089	36	1940-01-01	0.2	0.3	0.2	0.2		HY	WAT			0.8	
1217	Erie Blvd. Hydro - North Salmon	Allens Falls		D	24042	Allens Falls	089	36	1927-01-01	4.4	5.0	4.4	4.4		HY	WAT			24.8	
1218	Erie Blvd. Hydro - North Salmon	Chasm 1		D	24042	Chateaugay	033	36	1913-01-01	1.0	1.1	1.0	1.0		HY	WAT			5.2	
1219	Erie Blvd. Hydro - North Salmon	Chasm 2		D	24042	Chateaugay	033	36	1913-01-01	1.0	1.1	1.0	1.0		HY	WAT			2.8	
1220	Erie Blvd. Hydro - North Salmon	Chasm 3		D	24042	Chateaugay	033	36	1926-01-01	1.4	1.6	1.4	1.4		HY	WAT			0.0	
1221	Erie Blvd. Hydro - North Salmon	Franklin 1		D	24042	Franklin	033	36	1911-01-01	1.1	1.1	1.1	1.1		HY	WAT			5.5	
1222	Erie Blvd. Hydro - North Salmon	Franklin 2		D	24042	Franklin	033	36	1926-01-01	1.1	1.1	1.1	1.1		HY	WAT			3.6	
1223	Erie Blvd. Hydro - North Salmon	Hogansburg		D	24042	Hogansburg	033	36	1930-01-01	0.7	0.3	0.7	0.7		HY	WAT			0.7	
1224	Erie Blvd. Hydro - North Salmon	Macomb		D	24042	Malone	033	36	1940-01-01	1.0	0.9	1.0	1.0		HY	WAT			4.4	
1225	Erie Blvd. Hydro - North Salmon	Parishville		D	24042	Parishville	089	36	1925-01-01	2.4	2.3	2.4	2.4		HY	WAT			14.1	
1226	Erie Blvd. Hydro - North Salmon	Piercefield 1		D	24042	Piercefield	089	36	1957-01-01	1.5	1.6	1.5	1.5		HY	WAT			9.5	
1227	Erie Blvd. Hydro - North Salmon	Piercefield 2		D	24042	Piercefield	089	36	1924-01-01	0.6	0.6	0.6	0.6		HY	WAT			3.6	
1228	Erie Blvd. Hydro - North Salmon	Piercefield 3		D	24042	Piercefield	089	36	1924-01-01	0.6	0.6	0.6	0.6		HY	WAT			2.7	
1229	Erie Blvd. Hydro - NYS Barge	Hydraulic Race		A	23848	Lockport	063	36	1942-01-01	4.7	3.1	4.7	4.7		HY	WAT			9.3	
1230	Erie Blvd. Hydro - Oak Orchard	Glenwood 1		B	24046	Medina	073	36	1950-01-01	0.5	0.5	0.5	0.5		HY	WAT			2.7	
1231	Erie Blvd. Hydro - Oak Orchard	Glenwood 2		B	24046	Medina	073	36	1950-01-01	0.5	0.5	0.5	0.5		HY	WAT			3.6	
1232	Erie Blvd. Hydro - Oak Orchard	Glenwood 3		B	24046	Medina	073	36	1950-01-01	0.5	0.5	0.5	0.5		HY	WAT			0.0	
1233	Erie Blvd. Hydro - Oak Orchard	Oak Orchard		B	24046	Waterport	073	36	1941-01-01	0.4	0.3	0.4	0.4		HY	WAT			1.1	
1234	Erie Blvd. Hydro - Oak Orchard	Waterport 1		B	24046	Waterport	073	36	1941-01-01	2.3	1.6	2.3	2.3		HY	WAT			6.6	
1235	Erie Blvd. Hydro - Oak Orchard	Waterport 2		B	24046	Waterport	073	36	1968-01-01	2.5	1.8	2.5	2.5		HY	WAT			7.8	
1236	Erie Blvd. Hydro - Oswegatchie	Browns Falls 1		E	24044	Oswegatchie	089	36	1923-01-01	7.5	8.0	7.5	7.5		HY	WAT			37.9	
1237	Erie Blvd. Hydro - Oswegatchie	Browns Falls 2		E	24044	Oswegatchie	089	36	1923-01-01	7.5	8.0	7.5	7.5		HY	WAT			23.6	
1238	Erie Blvd. Hydro - Oswegatchie	Eel Weir 1		E	24044	Heuvelton	089	36	1928-01-01	0.5	0.3	0.5	0.5		HY	WAT			2.1	
1239	Erie Blvd. Hydro - Oswegatchie	Eel Weir 2		E	24044	Heuvelton	089	36	1938-01-01	1.1	0.8	1.1	1.1		HY	WAT			2.7	
1240	Erie Blvd. Hydro - Oswegatchie	Eel Weir 3		E	24044	Heuvelton	089	36	1938-01-01	1.1	0.8	1.1	1.1		HY	WAT			4.8	
1241	Erie Blvd. Hydro - Oswegatchie	Flat Rock 1		E	24044	Flat Rock	089	36	1924-01-01	3.0	2.6	3.0	3.0		HY	WAT			12.9	
1242	Erie Blvd. Hydro - Oswegatchie	Flat Rock 2		E	24044	Flat Rock	089	36	1924-01-01	3.0	2.6	3.0	3.0		HY	WAT			5.8	
1243	Erie Blvd. Hydro - Oswegatchie	Heuvelton 1		E	24044	Heuvelton	089	36	1924-01-01	0.5	0.4	0.5	0.5		HY	WAT			2.5	
1244	Erie Blvd. Hydro - Oswegatchie	Heuvelton 2		E	24044	Heuvelton	089	36	1924-01-01	0.5	0.4	0.5	0.5		HY	WAT			2.2	
1245	Erie Blvd. Hydro - Oswegatchie	Lower Newton Falls 1		E	24044	Newton Falls	089	36	2002-07-01	0.5	0.6	0.5	0.5		HY	WAT			2.9	
1246	Erie Blvd. Hydro - Oswegatchie	Oswegatchie 1		E	24044	Oswegatchie	089	36	1937-01-01	0.6	1.3	0.6	0.6		HY	WAT			5.3	
1247	Erie Blvd. Hydro - Oswegatchie	Oswegatchie 2		E	24044	Oswegatchie	089	36	1937-01-01	0.2	0.5	0.2	0.2		HY	WAT			2.8	
1248	Erie Blvd. Hydro - Oswegatchie	South Edwards 1		E	24044	South Edwards	089	36	1937-01-01	1.0	1.2	1.0	1.0		HY	WAT			9.3	
1249	Erie Blvd. Hydro - Oswegatchie	South Edwards 2		E	24044	South Edwards	089	36	1937-01-01	1.0	1.2	1.0	1.0		HY	WAT			5.1	
1250	Erie Blvd. Hydro - Oswegatchie	South Edwards 3		E	24044	South Edwards	089	36	1921-01-01	0.7	0.8	0.7	0.7		HY	WAT			4.5	
1251	Erie Blvd. Hydro - Oswegatchie	South Edwards 4		E	24044	South Edwards	089	36	1937-01-01	0.2	0.2	0.2	0.2		HY	WAT			0.0	
1252	Erie Blvd. Hydro - Oswegatchie	Talcville 1		E	24044	Edwards	089	36	1986-12-01	0.5	0.4	0.5	0.5		HY	WAT			3.1	
1253	Erie Blvd. Hydro - Oswegatchie	Talcville 2		E	24044	Edwards	089	36	1986-12-01	0.5	0.4	0.5	0.5		HY	WAT			0.3	
1254	Erie Blvd. Hydro - Oswegatchie	Upper Newton Falls 2		E	24044	Newton Falls	089	36	2002-07-01	0.5	0.4	0.5	0.5		HY	WAT			2.2	
1255	Erie Blvd. Hydro - Oswegatchie	Upper Newton Falls 3		E	24044	Newton Falls	089	36	2002-07-01	0.5	0.4	0.5	0.5		HY	WAT			1.4	
1256	Erie Blvd. Hydro - Oswegatchie	Upper Newton Falls 4		E	24044	Newton Falls	089	36	2002-07-01	0.5	0.4	0.5	0.5		HY	WAT			1.8	
1257	Erie Blvd. Hydro - Seneca Oswego	Baldwinsville 1		C	24041	Baldwinsville	067	36	1927-01-01	0.3	0.2	0.3	0.3		HY	WAT			1.6	
1258	Erie Blvd. Hydro - Seneca Oswego	Baldwinsville 2		C	24041	Baldwinsville	067	36	1927-01-01	0.3	0.2	0.3	0.3		HY	WAT			1.4	
1259	Erie Blvd. Hydro - Seneca Oswego	Granby 1		C	24041	Granby	075	36	1983-05-01	5.0	5.1	5.2	5.2		HY	WAT			22.0	
1260	Erie Blvd. Hydro - Seneca Oswego	Granby 2		C	24041	Granby	075	36	1983-05-01	5.0	5.1	5.2	5.2		HY	WAT			25.8	
1261	Erie Blvd. Hydro - Seneca Oswego	Minetto 2		C	24041	Minetto	075	36	1915-01-01	1.6	1.5	1.7	1.7		HY	WAT			9.3	
1262	Erie Blvd. Hydro - Seneca Oswego	Minetto 3		C	24041	Minetto	075	36	1915-01-01	1.6	1.5	1.7	1.7		HY	WAT			9.2	
1263	Erie Blvd. Hydro - Seneca Oswego	Minetto 4		C	24041	Minetto	075	36	1915-01-01	1.6	1.5	1.7	1.7		HY	WAT			7.8	
1264	Erie Blvd. Hydro - Seneca Oswego	Minetto 5		C	24041	Minetto	075	36	1975-01-01	1.6	1.5	1.7	1.7		HY	WAT			6.9	
1265	Erie Blvd. Hydro - Seneca Oswego	Minetto 6		C	24041	Minetto	075	36	1975-01-01	1.6	1.5	1.7	1.7		HY	WAT			5.5	
1266	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls E 1		C	24041	Oswego	075	36	1914-01-01	1.5	1.5	1.6	1.6		HY	WAT			10.1	
1267	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls E 2		C	24041	Oswego	075	36	1914-01-01	1.5	1.5	1.6	1.6		HY	WAT			6.9	
1268	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls E 3		C	24041	Oswego	075	36	1914-01-01	1.5	1.5	1.6	1.6		HY	WAT			6.4	
1269	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls W 4		C	24041	Oswego	075	36	1914-01-01	0.9	1.0	0.9	0.9		HY	WAT			4.6	
1270	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls W 5		C	24041	Oswego	075	36	1914-01-01	0.9	1.0	0.9	0.9		HY	WAT			5.1	
1271	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls W 6		C	24041	Oswego	075	36	2007-01-01	0.5	0.5	0.5	0.5		HY	WAT			0.1	
1272	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls W 7		C	24041	Oswego	075	36	2007-01-01	0.5	0.5	0.5	0.5		HY	WAT			0.3	
1273	Erie Blvd. Hydro - Seneca Oswego	Varick 2		C	24041	Oswego	075	36	1926-01-01	2.2	1.9	2.3	2.3		HY	WAT			9.9	
1274	Erie Blvd. Hydro - Seneca Oswego	Varick 3		C	24041	Oswego	075	36	1926-01-01	2.2	2.1	2.3	2.3		HY	WAT			5.3	
1275	Erie Blvd. Hydro - Seneca Oswego	Varick 4		C	24041	Oswego	075	36	1926-01-01	2.2	1.9	2.3	2.3		HY	WAT			6.5	
1276	Erie Blvd. Hydro - Seneca Oswego	Varick 5		C	24041	Oswego	075	36	1926-01-01	2.2	1.9	2.3	2.3		HY	WAT			7.1	
1277	Erie Blvd. Hydro - South Salmon	Bennetts Bridge 1		C	24043	Altmar	075	36	1964-01-01	6.4	7.0	6.4	6.4		HY	WAT			7.7	
1278	Erie Blvd. Hydro - South Salmon	Bennetts Bridge 2		C	24043	Altmar	075	36	1966-01-01	6.4	7.0	6.4	6.4		HY	WAT			20.2	
1279	Erie Blvd. Hydro - South Salmon	Bennetts Bridge 3		C	24043	Altmar	075	36	1970-01-01	7.0	7.7	7.0	7.0		HY	WAT			38.1	
1280	Erie Blvd. Hydro - South Salmon	Bennetts Bridge 4		C	24043	Altmar	075	36	1970-01-01	7.0	7.7	7.0	7.0		HY	WAT			38.0	
1281	Erie Blvd. Hydro - South Salmon	Lighthouse Hill 1		C	24043	Altmar	075	36	1930-01-01	3.8	4.1	3.8	3.8		HY	WAT			17.4	
1282	Erie Blvd. Hydro - South Salmon	Lighthouse Hill 2		C	24043	Altmar	075	36	1930-01-01	3.8	4.1	3.8	3.8		HY	WAT			8.0	
1283	Erie Blvd. Hydro - Upper Hudson	E J West 1		F	24058	Hadley	091	36	1930-01-01	10.0	11.9	10.0	10.0		HY	WAT			31.4	
1284	Erie Blvd. Hydro - Upper Hudson	E J West 2		F	24058	Hadley	091	36	1930-01-01	10.0	11.9	10.0	10.0		HY	WAT			35.9	
1285	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 1		F	24058	S Glens Falls	091	36	1924-01-01	1.2	0.9	1.2	1.2		HY	WAT			5.1	
1286	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 2		F	24058	S Glens Falls	091	36	1924-01-01	1.2	0.9	1.2	1.2		HY	WAT			4.3	
1287	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 3		F	24058	S Glens Falls	091	36	1924-01-01	1.2	0.9	1.2	1.2		HY	WAT			4.5	

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1288	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 4		F	24058	S Glens Falls	091	36	1924-01-01	1.2	0.9	1.2	1.2		HY	WAT			6.2	
1289	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 5		F	24058	S Glens Falls	091	36	1924-01-01	1.2	0.9	1.2	1.2		HY	WAT			6.3	
1290	Erie Blvd. Hydro - Upper Hudson	Sherman Island 1		F	24058	Queensbury	113	36	2009-03-01	8.0	0.0	0.0	0.0		HY	WAT			36.2	
1291	Erie Blvd. Hydro - Upper Hudson	Sherman Island 2		F	24058	Queensbury	113	36	1923-01-01	7.2	8.1	7.2	7.2		HY	WAT			39.0	
1292	Erie Blvd. Hydro - Upper Hudson	Sherman Island 3		F	24058	Queensbury	113	36	1923-01-01	8.7	9.7	8.7	8.7		HY	WAT			34.9	
1293	Erie Blvd. Hydro - Upper Hudson	Sherman Island 4		F	24058	Queensbury	113	36	1923-01-01	7.2	8.1	7.2	7.2		HY	WAT			34.0	
1294	Erie Blvd. Hydro - Upper Hudson	Sherman Island 5		F	24058	Queensbury	113	36	1923-01-01	7.2	8.1	7.2	7.2		HY	WAT			19.9	
1295	Erie Blvd. Hydro - Upper Hudson	Sherman Island 6		F	24058	Queensbury	113	36	2009-02-02	1.0	0.0	0.0	0.0		HY	WAT			10.1	
1296	Erie Blvd. Hydro - Upper Hudson	Spier Falls 1		F	24058	Moreau	091	36	1924-01-01	6.8	8.4	6.8	6.8		HY	WAT			56.2	
1297	Erie Blvd. Hydro - Upper Hudson	Spier Falls 2		F	24058	Moreau	091	36	1930-01-01	37.6	46.9	37.6	37.6		HY	WAT			172.6	
1298	Erie Blvd. Hydro - Upper Hudson	Stewarts Bridge		F	24058	Hadley	091	36	1952-01-01	30.0	35.8	30.0	30.0		HY	WAT			113.3	
1299	Erie Blvd. Hydro - Upper Raquette	Blake		E	24056	Stark	089	36	1957-01-01	14.4	15.6	14.4	14.4		HY	WAT			58.1	
1300	Erie Blvd. Hydro - Upper Raquette	Five Falls		E	24056	Colton	089	36	1955-01-01	22.5	24.4	22.5	22.5		HY	WAT			97.7	
1301	Erie Blvd. Hydro - Upper Raquette	Rainbow Falls		E	24056	Colton	089	36	1956-01-01	22.5	24.4	22.5	22.5		HY	WAT			99.4	
1302	Erie Blvd. Hydro - Upper Raquette	South Colton		E	24056	South Colton	089	36	1954-01-01	19.4	20.9	19.4	19.4		HY	WAT			82.3	
1303	Erie Blvd. Hydro - Upper Raquette	Stark		E	24056	Stark	089	36	1957-01-01	22.5	24.6	22.5	22.5		HY	WAT			91.6	
1304	Erie Blvd. Hydro - West Canada	Prospect		E	24049	Prospect	043	36	1959-01-01	17.3	21.7	17.3	17.3		HY	WAT			77.9	
1305	Erie Blvd. Hydro - West Canada	Trenton Falls 5		E	24049	Trenton	065	36	1919-01-01	6.8	9.6	6.8	6.8		HY	WAT			59.5	
1306	Erie Blvd. Hydro - West Canada	Trenton Falls 6		E	24049	Trenton	065	36	1919-01-01	6.4	9.1	6.4	6.4		HY	WAT			54.1	
1307	Erie Blvd. Hydro - West Canada	Trenton Falls 7		E	24049	Trenton	065	36	1922-01-01	6.4	9.1	6.4	6.4		HY	WAT			39.7	
1308	Erie Blvd. Hydropower LP	West Delaware Hydro		G	323627	Grahamsville	105	36	1988-12-01	7.5	7.5	7.5	7.5		HY	WAT			23.0	
1309	Erie Wind, LLC	Erie Wind		A	323693	Lackawanna	029	36	2012-02-01	15.0	0.0	0.0	0.0		WT	WND			39.3	
1310	Exelon Generation Company, LLC	Chaffee		A	323603	Chaffee	029	36	2007-08-09	6.4	6.4	6.4	6.4		IC	MTE			49.4	
1311	Exelon Generation Company, LLC	High Acres 1		C	23767	Fairport	117	36	1991-06-01	3.2	3.2	3.2	3.2		IC	MTE			26.6	
1312	Exelon Generation Company, LLC	High Acres 2		C	23767	Fairport	117	36	2008-02-28	6.4	6.4	6.4	6.4		IC	MTE			51.7	
1313	Exelon Generation Company, LLC	Madison County LF		E	323628	Wampsville	053	36	2010-03-01	1.6	1.6	1.6	1.6		IC	MTE			6.2	
1314	Exelon Generation Company, LLC	Mill Seat		B	323607	Riga	055	36	2007-07-20	6.4	6.4	6.4	6.4		IC	MTE			48.6	
1315	Exelon Generation Company, LLC	Monroe Livingston		B	24207	Scottsville	055	36	1988-11-01	2.4	2.4	2.4	2.4		IC	MTE			8.6	
1316	Exelon Generation Company, LLC	Oneida-Herkimer LFGE		E	323681	Boonville	065	36	2012-04-01	3.2	3.2	3.2	3.2		IC	MTE			24.7	
1317	Exelon Generation Company, LLC	Synergy Biogas		B	323694	Wyoming	121	36	2012-09-01	2.0	2.0	0.0	0.0		IC	MTE			6.2	
1318	Flat Rock Windpower II, LLC	Maple Ridge Wind 2		E	323611	Lowville	049	36	2007-12-01	90.7	90.7	90.8	90.8		WT	WND			225.8	
1319	Flat Rock Windpower, LLC	Maple Ridge Wind 1		E	323574	Lowville	049	36	2006-01-01	231.0	231.0	231.0	231.0		WT	WND			587.4	
1320	Freeport Electric	Freeport 1-2		K	1660	Freeport	059	36	1949-08-01	2.9	2.0	2.5	2.9		IC	FO2			0.0	
1321	Freeport Electric	Freeport 1-3		K	1660	Freeport	059	36	1954-08-01	3.1	2.1	2.7	3.0		IC	FO2			0.0	
1322	Freeport Electric	Freeport 1-4		K	1660	Freeport	059	36	1964-10-01	5.1	4.4	4.5	5.0		IC	FO2			0.2	
1323	Freeport Electric	Freeport 2-3		K	1660	Freeport	059	36	1973-05-01	18.1	18.1	15.8	17.9		GT	KER			0.2	
1324	Freeport Electric	Freeport CT 2		K	23818	Freeport	059	36	2004-03-01	60.5	50.3	48.5	49.9		GT	NG			52.5	
1325	GenOn Energy Management, LLC	Bowline 1		G	23526	West Haverstraw	087	36	1972-09-01	621.0	577.7	579.3	576.7		ST	NG	FO6		1,387.8	
1326	GenOn Energy Management, LLC	Bowline 2		G	23595	West Haverstraw	087	36	1974-05-01	621.0	557.4	183.0	183.0		ST	NG	FO6		99.6	
1327	Hampshire Paper Co., Inc.	Hampshire Paper		E	323593	Gouverneur	089	36	1987-03-01	3.4	3.5	3.4	3.4		HY	WAT			18.8	
1328	Hardscrabble Wind Power LLC	Hardscrabble Wind		E	323673	Fairfield	043	36	2011-02-01	74.0	74.0	74.0	74.0		WT	WND			184.3	
1329	Howard Wind LLC	Howard Wind		C	323690	Howard	101	36	2011-12-01	57.4	57.4	55.4	55.4		WT	WND			133.0	
1330	Indeck Energy Services of Silver Sprir	Indeck-Silver Springs		C	23768	Silver Springs	121	36	1991-04-01	56.6	51.5	50.3	61.3	YES	CC	NG	FO2		36.4	
1331	Indeck-Corinth LP	Indeck-Corinth		F	23802	Corinth	091	36	1995-07-01	147.0	131.2	129.5	132.2	YES	CC	NG	FO2		876.7	
1332	Indeck-Olean LP	Indeck-Olean		A	23982	Olean	009	36	1993-12-01	90.6	79.4	76.0	84.4	YES	CC	NG	FO2		330.0	
1333	Indeck-Oswego LP	Indeck-Oswego		C	23783	Oswego	075	36	1990-05-01	57.4	51.6	48.8	61.5		CC	NG	FO2		65.6	
1334	Indeck-Yerkes LP	Indeck-Yerkes		A	23781	Tonawanda	029	36	1990-02-01	59.9	49.7	47.9	56.2	YES	CC	NG	FO2		68.1	
1335	Innovative Energy Systems, Inc.	Chautauqua LFGE		A	323629	Jamestown	013	36	2010-02-12	9.6	0.0	0.0	0.0		IC	MTE			42.4	
1336	Innovative Energy Systems, Inc.	Clinton LFGE		D	323618	Morrisonville	019	36	2008-10-01	6.4	6.4	6.4	6.4		IC	MTE			39.6	
1337	Innovative Energy Systems, Inc.	Colonie LFGTE		F	323577	Colonie	001	36	2006-03-01	4.8	4.8	4.8	4.8		IC	MTE			37.0	
1338	Innovative Energy Systems, Inc.	DANC LFGE		E	323619	Watertown	045	36	2008-09-08	6.4	6.4	6.4	6.4		IC	MTE			39.4	
1339	Innovative Energy Systems, Inc.	Fulton LFGE		F	323630	Johnstown	035	36	2010-06-04	3.2	0.0	0.0	0.0		IC	MTE			12.4	
1340	Innovative Energy Systems, Inc.	Hyland LFGE		B	323620	Angelica	003	36	2008-09-08	4.8	4.8	4.8	4.8		IC	MTE			31.6	
1341	Innovative Energy Systems, Inc.	Steuben County LF		C	323667	Bath	101	36	2012-08-01	3.2	3.2	3.2	3.2		IC	MTE			22.3	
1342	International Paper Company	Ticonderoga		F	23804	Ticonderoga	031	36	1970-01-01	42.1	7.6	9.5	9.8	YES	ST	FO6			0.0	
1343	Jamestown Board of Public Utilities	Jamestown 5		A	1658	Jamestown	013	36	1951-08-01	28.7	23.0	16.2	16.6	YES	ST	BIT	NG		4.7	
1344	Jamestown Board of Public Utilities	Jamestown 6		A	1658	Jamestown	013	36	1968-08-01	25.0	22.4	14.2	14.7	YES	ST	BIT	NG		45.5	
1345	Jamestown Board of Public Utilities	Jamestown 7		A	1659	Jamestown	013	36	2002-01-01	47.3	40.0	38.6	45.6	YES	GT	NG			174.0	
1346	Lakeside New York, LLC	Beaver Falls		E	23983	Beaver Falls	049	36	1995-03-01	107.8	80.2	81.1	89.3		CC	NG	FO2		1.3	
1347	Lakeside New York, LLC	Syracuse		C	23985	Syracuse	067	36	1993-09-01	102.7	86.8	85.6	97.8		CC	NG	FO2		41.0	
1348	Long Island Power Authority	Babylon (RR)		K	323704	Babylon	103	36	1989-04-01	17.0	15.5	14.3	15.0		ST	REF			109.5	
1349	Long Island Power Authority	Barrett 03		K	23706	Island Park	059	36	1970-06-01	18.0	17.9	17.0	19.2		GT	NG	FO2		2.4	
1350	Long Island Power Authority	Barrett 04		K	23707	Island Park	059	36	1970-07-01	18.0	17.7	17.5	20.4		GT	NG	FO2		6.6	
1351	Long Island Power Authority	Barrett 05		K	23708	Island Park	059	36	1970-07-01	18.0	17.8	17.3	19.9		GT	NG	FO2		2.0	
1352	Long Island Power Authority	Barrett 06		K	23709	Island Park	059	36	1970-07-01	18.0	17.8	17.1	20.1		GT	NG	FO2		3.0	
1353	Long Island Power Authority	Barrett 08		K	23711	Island Park	059	36	1970-07-01	18.0	17.3	17.2	20.4		GT	NG	FO2		2.2	
1354	Long Island Power Authority	Barrett 09		K	23700	Island Park	059	36	1971-06-01	41.8	43.4	39.4	48.2		JE	NG	FO2		9.1	
1355	Long Island Power Authority	Barrett 10		K	23701	Island Park	059	36	1971-06-01	41.8	42.7	39.9	49.4		JE	NG	FO2		24.3	
1356	Long Island Power Authority	Barrett 11		K	23702	Island Park	059	36	1971-06-01	41.8	43.3	39.8	49.5		JE	NG	FO2		14.5	
1357	Long Island Power Authority	Barrett 12		K	23703	Island Park	059	36	1971-06-01	41.8	44.0	40.3	49.5		JE	NG	FO2		23.2	
1358	Long Island Power Authority	Barrett GT 01		K	23704	Island Park	059	36	1970-06-01	18.0	18.1	11.4	0.0		GT	NG	FO2		0.1	
1359	Long Island Power Authority	Barrett GT 02		K	23705	Island Park	059	36	1970-06-01	18.0	17.4	14.7	17.1		GT	NG	FO2		4.7	

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1360	Long Island Power Authority	Barrett ST 01		K	23545	Island Park	059	36	1956-11-01	188.0	200.2	195.2	192.5		ST	NG	FO6		623.4	
1361	Long Island Power Authority	Barrett ST 02		K	23546	Island Park	059	36	1963-10-01	188.0	197.5	196.0	194.8		ST	NG	FO6		804.8	
1362	Long Island Power Authority	Bethpage 3		K	323564	Hicksville	059	36	2005-05-01	96.0	79.9	77.1	77.3		CC	NG			140.6	
1363	Long Island Power Authority	Caithness_CC_1		K	323624	Brookhaven	103	36	2009-08-01	375.0	315.6	306.7	358.6		CC	NG	FO2		2,393.7	
1364	Long Island Power Authority	East Hampton 2		K	23722	E Hampton	103	36	1962-12-01	2.0	2.0	2.0	2.0		IC	FO2			0.4	
1365	Long Island Power Authority	East Hampton 3		K	23722	E Hampton	103	36	1962-12-01	2.0	2.0	2.0	2.0		IC	FO2			0.5	
1366	Long Island Power Authority	East Hampton 4		K	23722	E Hampton	103	36	1962-12-01	2.0	2.0	2.0	2.0		IC	FO2			0.5	
1367	Long Island Power Authority	East Hampton GT 01		K	23717	E Hampton	103	36	1970-12-01	21.3	19.2	19.0	24.4		JE	FO2			5.0	
1368	Long Island Power Authority	Far Rockaway GT1		K	24212	Far Rockaway	081	36	2002-07-01	60.5	53.5	53.9	57.1		JE	NG			225.6	
1369	Long Island Power Authority	Far Rockaway GT2		K	23815	Jamaica Bay	081	36	2003-07-02	60.5	55.4	54.3	53.8		JE	FO2			16.9	
1370	Long Island Power Authority	Freeport CT 1		K	23764	Freeport	059	36	2004-06-01	60.0	48.3	48.3	49.7		GT	NG	FO2		105.5	
1371	Long Island Power Authority	Glenwood GT 01		K	23712	Glenwood	059	36	1967-04-01	16.0	14.6	12.6	17.6		GT	FO2			0.1	
1372	Long Island Power Authority	Glenwood GT 02		K	23688	Glenwood	059	36	1972-06-01	55.0	52.7	50.0	62.0		GT	FO2			2.5	
1373	Long Island Power Authority	Glenwood GT 03		K	23689	Glenwood	059	36	1972-06-01	55.0	52.7	51.2	67.3		GT	FO2			3.1	
1374	Long Island Power Authority	Glenwood GT 04		K	24219	Glenwood	059	36	2002-06-01	53.0	40.3	39.7	46.4		GT	NG	FO2		99.6	
1375	Long Island Power Authority	Glenwood GT 05		K	24220	Glenwood	059	36	2002-06-01	53.0	40.0	38.3	47.2		GT	NG	FO2		97.2	
1376	Long Island Power Authority	Greenport GT1		K	23814	Greenport	103	36	2003-07-02	54.0	51.9	51.3	56.8		JE	FO2			13.9	
1377	Long Island Power Authority	Hempstead (RR)		K	23647	Hempstead	059	36	1989-10-01	78.6	73.7	72.1	73.4		ST	REF			574.6	
1378	Long Island Power Authority	Holtsville 01		K	23690	Holtsville	103	36	1974-07-01	56.7	55.1	53.2	62.6		JE	FO2			3.4	
1379	Long Island Power Authority	Holtsville 02		K	23691	Holtsville	103	36	1974-07-01	56.7	55.3	47.6	59.3		JE	FO2			3.2	
1380	Long Island Power Authority	Holtsville 03		K	23692	Holtsville	103	36	1974-07-01	56.7	52.1	47.4	60.1		JE	FO2			2.4	
1381	Long Island Power Authority	Holtsville 04		K	23693	Holtsville	103	36	1974-07-01	56.7	52.7	51.9	59.0		JE	FO2			2.8	
1382	Long Island Power Authority	Holtsville 05		K	23694	Holtsville	103	36	1974-07-01	56.7	53.3	53.8	66.3		JE	FO2			3.8	
1383	Long Island Power Authority	Holtsville 06		K	23695	Holtsville	103	36	1975-07-01	56.7	53.0	51.2	63.9		JE	FO2			10.6	
1384	Long Island Power Authority	Holtsville 07		K	23696	Holtsville	103	36	1975-07-01	56.7	55.1	52.2	60.1		JE	FO2			1.1	
1385	Long Island Power Authority	Holtsville 08		K	23697	Holtsville	103	36	1975-07-01	56.7	57.4	52.3	68.3		JE	FO2			2.4	
1386	Long Island Power Authority	Holtsville 09		K	23698	Holtsville	103	36	1975-07-01	56.7	57.5	53.2	66.5		JE	FO2			6.9	
1387	Long Island Power Authority	Holtsville 10		K	23699	Holtsville	103	36	1975-07-01	56.7	55.1	52.9	66.1		JE	FO2			2.1	
1388	Long Island Power Authority	Huntington (RR)		K	323705	Huntington	103	36	1991-12-01	28.0	24.7	24.2	24.3		ST	REF			190.1	
1389	Long Island Power Authority	Islip (RR)		K	323679	Ronkonkoma	103	36	1990-03-01	12.5	11.2	8.6	8.7		ST	REF			51.2	
1390	Long Island Power Authority	Long Island Solar Farm		K	323691	Upton	103	36	2011-11-01	31.5	31.5	31.5	31.5		PV	SUN			51.0	
1391	Long Island Power Authority	Northport 1		K	23551	Northport	103	36	1967-07-01	387.0	395.0	399.7	391.3		ST	NG	FO6		356.5	
1392	Long Island Power Authority	Northport 2		K	23552	Northport	103	36	1968-06-01	387.0	396.0	396.5	398.7		ST	NG	FO6		609.8	
1393	Long Island Power Authority	Northport 3		K	23553	Northport	103	36	1972-07-01	387.0	399.2	391.2	382.2		ST	NG	FO6		685.1	
1394	Long Island Power Authority	Northport 4		K	23650	Northport	103	36	1977-12-01	387.0	399.2	391.2	393.2		ST	NG	FO6		1,060.3	
1395	Long Island Power Authority	Northport GT		K	23718	Northport	103	36	1967-03-01	16.0	13.8	11.9	15.4		GT	FO2			0.1	
1396	Long Island Power Authority	Oceanside (LF)		K	5008	Oceanside	059	36	1991-02-01	2.1	1.1	0.0	0.0		IC	MTE				
1397	Long Island Power Authority	Oyster Bay (LF)		K	5009	Bethpage	059	36	1986-07-01	1.3	0.0	0.0	0.0		IC	MTE				
1398	Long Island Power Authority	Pilgrim GT1		K	24216	Brentwood	103	36	2002-08-01	50.0	45.6	45.3	46.5		GT	NG			86.9	
1399	Long Island Power Authority	Pilgrim GT2		K	24217	Brentwood	103	36	2002-08-01	50.0	46.2	45.3	46.3		GT	NG			94.3	
1400	Long Island Power Authority	Pinelawn Power 1		K	323563	Babylon	103	36	2005-06-01	82.0	78.0	76.1	77.8		CC	NG	KER		136.4	
1401	Long Island Power Authority	Port Jefferson 3		K	23555	Port Jefferson	103	36	1958-11-01	188.0	194.5	196.7	195.3		ST	FO6	NG		93.6	
1402	Long Island Power Authority	Port Jefferson 4		K	23616	Port Jefferson	103	36	1960-11-01	188.0	198.7	196.7	198.0		ST	FO6	NG		191.2	
1403	Long Island Power Authority	Port Jefferson GT 01		K	23713	Port Jefferson	103	36	1966-12-01	16.0	14.1	12.9	18.0		GT	FO2			0.1	
1404	Long Island Power Authority	Port Jefferson GT 02		K	24210	Port Jefferson	103	36	2002-07-01	53.0	42.0	41.0	45.9		GT	NG	FO2		93.3	
1405	Long Island Power Authority	Port Jefferson GT 03		K	24211	Port Jefferson	103	36	2002-07-01	53.0	41.1	40.5	46.1		GT	NG	FO2		88.2	
1406	Long Island Power Authority	S Hampton 1		K	23720	South Hampton	103	36	1963-03-01	11.5	10.3	8.3	12.0		GT	FO2			0.1	
1407	Long Island Power Authority	Shoreham 1		K	23715	Shoreham	103	36	1971-07-01	52.9	48.9	48.9	65.6		GT	FO2			0.9	
1408	Long Island Power Authority	Shoreham 2		K	23716	Shoreham	103	36	1984-04-01	18.6	18.5	15.8	20.9		JE	FO2			0.2	
1409	Long Island Power Authority	Shoreham GT3		K	24213	Shoreham	103	36	2002-08-01	50.0	45.1	45.0	45.9		GT	FO2			6.4	
1410	Long Island Power Authority	Shoreham GT4		K	24214	Shoreham	103	36	2002-08-01	50.0	41.9	44.2	45.9		GT	FO2			6.0	
1411	Long Island Power Authority	Smithtown (LF)		K	5010	Smithtown	103	36	1985-12-01	1.1	0.0	0.0	0.0		IC	MTE				
1412	Long Island Power Authority	South Oaks Hosp		K	5011	Amityville	103	36	1990-06-01	1.0	0.0	0.0	0.0		IC	NG				
1413	Long Island Power Authority	Southold 1		K	23719	Southold	103	36	1964-08-01	14.0	12.3	13.0	15.3		GT	FO2			0.2	
1414	Long Island Power Authority	Stony Brook		K	24151	Stony Brook	103	36	1995-04-01	47.0	9.6	17.2	19.0	YES	GT	NG	FO2		283.3	
1415	Long Island Power Authority	Trigen-NDEC		K	323695	Garden City	059	36	1991-03-01	55.0	51.6	43.0	56.4	YES	CC	NG	FO2		343.0	
1416	Long Island Power Authority	Wading River 1		K	23522	Shoreham	103	36	1989-08-01	79.5	81.2	78.8	98.3		GT	FO2			9.7	
1417	Long Island Power Authority	Wading River 2		K	23547	Shoreham	103	36	1989-08-01	79.5	81.3	76.6	96.2		GT	FO2			13.4	
1418	Long Island Power Authority	Wading River 3		K	23601	Shoreham	103	36	1989-08-01	79.5	81.3	73.3	95.5		GT	FO2			8.2	
1419	Long Island Power Authority	West Babylon 4		K	23714	West Babylon	103	36	1971-08-01	52.4	49.0	47.8	66.1		GT	FO2			2.4	
1420	Long Island Power Authority	Yaphank (LF)		K	5012	Yaphank	103	36	1983-09-01	1.6	1.5	0.0	0.0		IC	MTE				
1421	Madison Windpower, LLC	Madison Wind Power		E	24146	Madison	053	36	2000-09-01	11.6	11.5	11.6	11.6		WT	WND			21.0	
1422	Marble River LLC	Marble River Wind		D	323696	Ellenburg	019	36	2012-07-01	215.5	0.0	0.0	0.0		WT	WND			539.2	
1423	Marsh Hill Energy LLC	Marsh Hill Wind Farm		C	323713	Jasper	101	36	2014-12-01	16.2	0.0	0.0	0.0		WT	WND			8.8	**(N) (5)**
1424	Model City Energy LLC	Model City Energy		A	24167	Lewiston	063	36	2001-06-01	5.6	5.6	5.6	5.6		IC	MTE			39.5	
1425	Modern Innovative Energy, LLC	Modern LF		A	323580	Lewiston	063	36	2006-02-01	6.4	6.4	6.4	6.4		IC	MTE			31.5	
1426	New York Power Authority	Ashokan 1		G	23654	Ashokan	111	36	1982-11-01	2.3	1.8	2.3	2.3		HY	WAT			4.7	
1427	New York Power Authority	Ashokan 2		G	23654	Ashokan	111	36	1982-11-01	2.3	1.8	2.3	2.3		HY	WAT			3.0	
1428	New York Power Authority	Astoria CC 1		J	323568	Queens	081	36	2006-01-01	288.0	246.2	229.5	260.0		CC	NG	JF	KER	3,246.7	**(G)**
1429	New York Power Authority	Astoria CC 2		J	323569	Queens	081	36	2006-01-01	288.0	246.2	229.4	260.0		CC	NG	JF	KER		
1430	New York Power Authority	Blenheim - Gilboa 1		F	23756	Gilboa NY	095	36	1973-07-01	290.0	290.7	290.9	292.2		PS	WAT			83.1	
1431	New York Power Authority	Blenheim - Gilboa 2		F	23757	Gilboa NY	095	36	1973-07-01	290.0	291.2	291.6	292.1		PS	WAT			217.1	

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EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date	Name Plate Rating	CRIS Sum Cap (A)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
									YY-MM-DD	(MW)	(MW)									
1432	New York Power Authority	Blenheim - Gilboa 3		F	23758	Gilboa NY	095	36	1973-07-01	290.0	291.7	292.0	291.2		PS	WAT			35.0	
1433	New York Power Authority	Blenheim - Gilboa 4		F	23759	Gilboa NY	095	36	1973-07-01	290.0	291.5	292.7	293.7		PS	WAT			30.9	
1434	New York Power Authority	Brentwood		K	24164	Brentwood	103	36	2001-08-01	50.0	47.1	45.5	46.4		GT	NG			43.2	
1435	New York Power Authority	Crescent 1		F	24018	Crescent	001	36	1991-07-01	2.8	3.2	2.8	2.8		HY	WAT			15.4	
1436	New York Power Authority	Crescent 2		F	24018	Crescent	001	36	1991-07-01	2.8	3.2	2.8	2.8		HY	WAT			15.3	
1437	New York Power Authority	Crescent 3		F	24018	Crescent	001	36	1991-07-01	3.0	3.2	3.0	3.0		HY	WAT			21.0	
1438	New York Power Authority	Crescent 4		F	24018	Crescent	001	36	1991-07-01	3.0	3.2	3.0	3.0		HY	WAT			0.0	
1439	New York Power Authority	Flynn		K	23794	Holtsville	103	36	1994-05-01	170.0	135.5	133.8	162.7		CC	NG	FO2		1,208.0	
1440	New York Power Authority	Gowanus 5		J	24156	Brooklyn	047	36	2001-08-01	50.0	45.4	40.0	40.0		GT	NG			31.3	
1441	New York Power Authority	Gowanus 6		J	24157	Brooklyn	047	36	2001-08-01	50.0	46.1	39.9	39.9		GT	NG			40.1	
1442	New York Power Authority	Grahamsville		G	23607	Grahamsville	105	36	1956-12-01	18.0	16.3	18.0	18.0		HY	WAT			98.8	
1443	New York Power Authority	Greenport IC 4		K	1652	Greenport	103	36	1957-06-06	1.2	1.7	1.0	1.0		IC	FO2			0.0	
1444	New York Power Authority	Greenport IC 5		K	1652	Greenport	103	36	1965-07-08	1.8	1.7	1.5	1.5		IC	FO2			0.0	
1445	New York Power Authority	Greenport IC 6		K	1652	Greenport	103	36	1971-09-17	3.8	2.7	2.5	2.5		IC	FO2			0.0	
1446	New York Power Authority	Harlem River 1		J	24160	Bronx	005	36	2001-08-01	50.0	46.0	39.9	39.9		GT	NG			31.0	
1447	New York Power Authority	Harlem River 2		J	24161	Bronx	005	36	2001-08-01	50.0	45.2	40.0	40.0		GT	NG			23.3	
1448	New York Power Authority	Hellgate 1		J	24158	Bronx	005	36	2001-08-01	50.0	45.0	39.9	39.9		GT	NG			24.7	
1449	New York Power Authority	Hellgate 2		J	24159	Bronx	005	36	2001-08-01	50.0	45.0	40.0	40.0		GT	NG			20.9	
1450	New York Power Authority	Jarvis 1		E	23743	Hinckley	065	36	1991-07-01	4.5	4.5	4.5	4.5		HY	WAT			26.2	
1451	New York Power Authority	Jarvis 2		E	23743	Hinckley	065	36	1991-07-01	4.5	4.5	4.5	4.5		HY	WAT			0.0	
1452	New York Power Authority	Kent		J	24152	Brooklyn	047	36	2001-08-01	50.0	46.9	46.0	46.6		GT	NG			39.8	
1453	New York Power Authority	Lewiston PS (Fleet)		A	23760	Niagara Falls	063	36	1961-01-01	240.0	240.0	240.0	240.0		PS	WAT			483.2	
1454	New York Power Authority	Moses Niagara (Fleet)		A	23760	Niagara Falls	063	36	1961-01-01	2,860.0	2,460.0	2,444.7	2,442.0		HY	WAT			13,211.9	
1455	New York Power Authority	Neversink		G	23608	Grahamsville	105	36	1953-12-01	25.0	22.0	25.0	25.0		HY	WAT			41.4	
1456	New York Power Authority	Pouch		J	24155	Staten Island	085	36	2001-08-01	50.0	47.1	46.0	46.8		GT	NG			40.7	
1457	New York Power Authority	St Lawrence - FDR (Fleet)		D	23600	Massena	089	36	1958-07-01	1,088.0	856.0	843.2	820.8		HY	WAT			7,077.5	
1458	New York Power Authority	Vernon Blvd 2		J	24162	Queens	081	36	2001-08-01	50.0	46.2	40.0	40.0		GT	NG			20.9	
1459	New York Power Authority	Vernon Blvd 3		J	24163	Queens	081	36	2001-08-01	50.0	43.8	39.9	39.9		GT	NG			28.3	
1460	New York Power Authority	Vischer Ferry 1		F	24020	Vischer Ferry	091	36	1991-07-01	2.8	3.2	2.8	2.9		HY	WAT			15.0	
1461	New York Power Authority	Vischer Ferry 2		F	24020	Vischer Ferry	091	36	1991-07-01	2.8	3.2	2.8	2.9		HY	WAT			14.4	
1462	New York Power Authority	Vischer Ferry 3		F	24020	Vischer Ferry	091	36	1991-07-01	3.0	3.2	3.0	2.9		HY	WAT			0.0	
1463	New York Power Authority	Vischer Ferry 4		F	24020	Vischer Ferry	091	36	1991-07-01	3.0	3.2	3.0	2.9		HY	WAT			21.0	
1464	New York State Elec. & Gas Corp.	AA Dairy		C	5013	Ithaca	109	36	1998-06-01	0.1		0.0	0.0		IC	MTE			0.0	
1465	New York State Elec. & Gas Corp.	Alice Falls 1		D	23915	Ausable	019	36	1991-11-01	1.5	1.6	0.0	0.0		HY	WAT			0.0	
1466	New York State Elec. & Gas Corp.	Alice Falls 2		D	23915	Ausable	019	36	1991-11-01	0.6	0.6	0.0	0.0		HY	WAT			0.0	
1467	New York State Elec. & Gas Corp.	Allegheny 8		C	23528	Kittanning PA	005	42	1990-10-01	16.0	14.7	16.0	16.0		HY	WAT			105.8	
1468	New York State Elec. & Gas Corp.	Allegheny 9		C	23528	Kittanning PA	005	42	1990-10-01	22.0	20.2	22.0	22.0		HY	WAT			129.3	
1469	New York State Elec. & Gas Corp.	Auburn - Mill St.		C	5014	Auburn	011	36	1981-10-01	0.4		0.0	0.0		HY	WAT				
1470	New York State Elec. & Gas Corp.	Auburn - No. Div.St		C	5015	Auburn	011	36	1992-12-01	0.8		0.0	0.0		HY	WAT				
1471	New York State Elec. & Gas Corp.	Auburn - State St.		C	24147	Auburn	011	36	1995-01-01	7.4	5.8	5.0	6.9		GT	NG			0.9	
1472	New York State Elec. & Gas Corp.	Broome LFGE		C	323600	Binghamton	007	36	2007-09-01	2.1	2.1	2.1	2.1		IC	MTE			16.9	
1473	New York State Elec. & Gas Corp.	Cadyville 1		D	23628	Schuyler Falls	019	36	1921-08-01	1.2	1.0	1.2	1.2		HY	WAT			5.1	
1474	New York State Elec. & Gas Corp.	Cadyville 2		D	23628	Schuyler Falls	019	36	1921-08-01	1.2	1.0	1.2	1.2		HY	WAT			5.4	
1475	New York State Elec. & Gas Corp.	Cadyville 3		D	23628	Schuyler Falls	019	36	1986-09-01	3.1	2.7	3.1	3.1		HY	WAT			13.2	
1476	New York State Elec. & Gas Corp.	Chasm Hydro		D	5016	Chateaugay	033	36	1982-03-01	1.6		0.0	0.0		HY	WAT				
1477	New York State Elec. & Gas Corp.	Croton Fall Hydro		I	5017	North Salem	119	36	1987-01-01	0.2		0.0	0.0		HY	WAT				
1478	New York State Elec. & Gas Corp.	Harris Lake		D	5018	Newcomb	031	36	1967-08-01	1.7		0.0	0.0		IC	FO2				
1479	New York State Elec. & Gas Corp.	High Falls 1		D	23628	Saranac	019	36	1948-08-01	4.0	4.3	4.0	4.0		HY	WAT			13.1	
1480	New York State Elec. & Gas Corp.	High Falls 2		D	23628	Saranac	019	36	1949-08-01	4.0	4.3	4.0	4.0		HY	WAT			21.7	
1481	New York State Elec. & Gas Corp.	High Falls 3		D	23628	Saranac	019	36	1956-08-01	7.0	8.2	7.0	7.0		HY	WAT			41.0	
1482	New York State Elec. & Gas Corp.	Kent Falls 1		D	23628	Schuyler Falls	019	36	1928-08-01	3.6	3.0	3.6	3.6		HY	WAT			17.5	
1483	New York State Elec. & Gas Corp.	Kent Falls 2		D	23628	Schuyler Falls	019	36	1928-08-01	3.6	3.0	3.6	3.6		HY	WAT			0.0	
1484	New York State Elec. & Gas Corp.	Kent Falls 3		D	23628	Schuyler Falls	019	36	1985-07-01	6.4	6.0	6.4	6.4		HY	WAT			37.5	
1485	New York State Elec. & Gas Corp.	Lower Saranac 1		D	23913	Schuyler Falls	019	36	1990-10-01	3.2	3.5	0.0	0.0		HY	WAT			0.0	
1486	New York State Elec. & Gas Corp.	Lower Saranac 2		D	23913	Schuyler Falls	019	36	1990-10-01	3.2	3.5	0.0	0.0		HY	WAT			0.0	
1487	New York State Elec. & Gas Corp.	Lower Saranac 3		D	23913	Schuyler Falls	019	36	1990-10-01	0.3	2.9	0.0	0.0		HY	WAT			0.0	
1488	New York State Elec. & Gas Corp.	Mechanicville 1		F	23645	Stillwater	091	36	1983-09-01	9.2	10.0	9.2	9.3		HY	WAT			45.7	
1489	New York State Elec. & Gas Corp.	Mechanicville 2		F	23645	Stillwater	091	36	1983-09-01	9.3	10.0	9.3	9.3		HY	WAT			40.0	
1490	New York State Elec. & Gas Corp.	Mill C 1		D	23628	Plattsburgh	019	36	1944-08-01	1.0	0.9	1.0	1.0		HY	WAT			4.9	
1491	New York State Elec. & Gas Corp.	Mill C 2		D	23628	Plattsburgh	019	36	1943-08-01	1.2	1.2	1.2	1.2		HY	WAT			4.8	
1492	New York State Elec. & Gas Corp.	Mill C 3		D	23628	Plattsburgh	019	36	1984-11-01	3.8	3.7	3.8	3.8		HY	WAT			15.8	
1493	New York State Elec. & Gas Corp.	Montville Falls		C	5019	Moravia	011	36	1992-08-01	0.2		0.0	0.0		HY	WAT				
1494	New York State Elec. & Gas Corp.	Rainbow Falls 1		D	23628	Ausable	019	36	1926-08-01	1.3	1.5	1.3	1.3		HY	WAT			0.0	
1495	New York State Elec. & Gas Corp.	Rainbow Falls 2		D	23628	Ausable	019	36	1927-08-01	1.3	1.5	1.3	1.3		HY	WAT			0.0	
1496	New York State Elec. & Gas Corp.	Waterloo 2		C	5020	Waterloo	099	36	1998-06-01	0.5		0.0	0.0		HY	WAT				
1497	New York State Elec. & Gas Corp.	Waterloo 3		C	5021	Waterloo	099	36	1998-06-01	0.5		0.0	0.0		HY	WAT				
1498	New York State Elec. & Gas Corp.	Waterloo 4		C	5022	Waterloo	099	36	1998-06-01	0.5		0.0	0.0		HY	WAT				
1499	Niagara Generation, LLC	Niagara Bio-Gen		A	23895	Niagara Falls	063	36	1991-08-01	56.0	50.5	43.2	37.2		ST	WD			89.3	
1500	Niagara Mohawk Power Corp.	Boralex - Hudson Falls		F	24011	Hudson Falls	115	36	1995-10-01	44.0	43.7	44.0	44.0		HY	WAT			228.5	
1501	Niagara Mohawk Power Corp.	Boralex - South Glens Falls		F	24028	Moreau	091	36	1994-12-01	13.8	14.8	0.0	0.0		HY	WAT			89.9	
1502	Niagara Mohawk Power Corp.	CHI-LaChute		F	1654	Ticonderoga	031	36	1987-12-01	9.0	8.9	0.0	0.0		HY	WAT			33.5	
1503	Niagara Mohawk Power Corp.	Fortis - Dolgeville		E	23807	Dolgeville	043	36	1985-07-01	5.0	6.3	0.0	0.0		HY	WAT			17.4	

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EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1504	Niagara Mohawk Power Corp.	Fortis Energy - Philadelphia	E	1656	Philadelphia	045	36	1986-08-01	3.6	3.2	0.0	0.0		HY	WAT			8.8	
1505	Niagara Mohawk Power Corp.	Fortis Energy - Moose River	E	24016	Moose River	049	36	1987-09-01	12.6	12.0	0.0	0.0		HY	WAT			45.9	
1506	Niagara Mohawk Power Corp.	Fortistar - N.Tonawanda	A	24026	N Tonawanda	029	36	1993-06-01	55.3	57.0	54.9	63.9		CC	NG	FO2		39.8	
1507	Niagara Mohawk Power Corp.	General Mills Inc	A	23808	Buffalo	029	36	1988-12-01	3.8	3.8	0.0	0.0		GT	NG			0.5	
1508	Niagara Mohawk Power Corp.	International Paper - Curtis	F	1655	Corinth	091	36	1986-01-01	9.8	30.8	0.0	0.0		HY	WAT			415.8	(G)
1509	Niagara Mohawk Power Corp.	International Paper - Palmer	F	1655	Corinth	091	36	1986-01-01	49.2	30.8	0.0	0.0		HY	WAT				
1510	Niagara Mohawk Power Corp.	Little Falls Hydro	E	24013	Little Falls	043	36	1987-01-01	13.0	12.6	0.0	0.0		HY	WAT			61.1	
1511	Niagara Mohawk Power Corp.	Onondaga County	C	23987	North Syracuse	067	36	1994-12-01	39.5	32.6	32.1	30.8		ST	REF			187.6	
1512	Niagara Mohawk Power Corp.	Pyrites Assoc.	E	24023	Canton	089	36	1985-12-01	8.2	7.5	0.0	0.0		HY	WAT			29.7	
1513	Niagara Mohawk Power Corp.	Adams Hydro	E	23633	Adams	045	36	1987-11-01	0.2		0.0	0.0		HY	WAT			0.0	
1514	Niagara Mohawk Power Corp.	Algon.-Burt Dam Assoc.	A	23774	Burt	063	36	1987-12-01	0.4		0.0	0.0		HY	WAT			2.2	
1515	Niagara Mohawk Power Corp.	Algon.-Christine.Falls	F	23643	Wells	041	36	1987-12-01	0.8		0.0	0.0		HY	WAT			2.5	
1516	Niagara Mohawk Power Corp.	Algon.-Cranberry. Lake	E	23633	Cranberry Lake	049	36	1987-12-01	0.5		0.0	0.0		HY	WAT			0.0	
1517	Niagara Mohawk Power Corp.	Algon.-Forrestport	E	23633	Forrestport	065	36	1987-12-01	3.4		0.0	0.0		HY	WAT			8.1	
1518	Niagara Mohawk Power Corp.	Algon.-Herkimer	E	23633	Herkimer	043	36	1987-12-01	1.6		0.0	0.0		HY	WAT			0.0	
1519	Niagara Mohawk Power Corp.	Algon.-Hollow Dam Power	E	23633	Saint Lawrence	089	36	1987-12-01	1.0		0.0	0.0		HY	WAT			3.1	
1520	Niagara Mohawk Power Corp.	Algon.-Kayuta	E	23633	Kayuta	065	36	1988-05-01	0.4		0.0	0.0		HY	WAT			0.0	
1521	Niagara Mohawk Power Corp.	Algon.-Ogdensburg	E	23633	Ogdensberg	089	36	1987-12-01	3.5		0.0	0.0		HY	WAT			10.0	
1522	Niagara Mohawk Power Corp.	Algon.-Otter Creek	E	23633	Greig	049	36	1986-11-01	0.5		0.0	0.0		HY	WAT			1.2	
1523	Niagara Mohawk Power Corp.	Allied Frozen Storage	A	23774	Cheektowaga	029	36	2008-05-01	0.1		0.0	0.0		IC	NG			0.1	
1524	Niagara Mohawk Power Corp.	Azure Mnt. Pwr Co	E	23633	St. Regis Falls	033	36	1993-08-01	0.6		0.0	0.0		HY	WAT			1.8	
1525	Niagara Mohawk Power Corp.	Beaver Falls #1	E	23633	Beaver Falls	049	36	1986-01-01	1.5		0.0	0.0		HY	WAT			10.4	
1526	Niagara Mohawk Power Corp.	Beaver Falls #2	E	23633	Beaver Falls	049	36	1986-01-01	1.0		0.0	0.0		HY	WAT			5.7	
1527	Niagara Mohawk Power Corp.	Bellows Towers	E	23633	Malone	033	36	1987-06-01	0.2		0.0	0.0		HY	WAT			0.0	
1528	Niagara Mohawk Power Corp.	Black River Hyd#1	E	23633	Port Leyden	049	36	1984-07-01	1.9		0.0	0.0		HY	WAT			4.9	
1529	Niagara Mohawk Power Corp.	Black River Hyd#2	E	23633	Port Leyden	049	36	1985-12-01	1.6		0.0	0.0		HY	WAT			2.1	
1530	Niagara Mohawk Power Corp.	Black River Hyd#3	E	23633	Port Leyden	049	36	1984-07-01	2.2		0.0	0.0		HY	WAT			14.9	
1531	Niagara Mohawk Power Corp.	Boralex - Middle Falls	F	23643	Easton	115	36	1989-12-01	2.2		0.0	0.0		HY	WAT			13.2	
1532	Niagara Mohawk Power Corp.	Burrstone Energy Center, LLC	E	23633	Utica	065	36	2009-11-01	1.1		0.0	0.0		IC	NG			2.7	
1533	Niagara Mohawk Power Corp.	Burrstone Energy Center, LLC	E	23633	Utica	065	36	2009-11-01	2.2		0.0	0.0		IC	NG			0.1	
1534	Niagara Mohawk Power Corp.	Cal Ban Power	A	23774	Allegany	003	36	1995-06-01	0.1		0.0	0.0		IC	NG			0.1	
1535	Niagara Mohawk Power Corp.	Cellu-Tissue Corp - Natural Di	E	23633	Natural Dam	089	36	1986-01-01	1.0		0.0	0.0		HY	WAT			0.0	
1536	Niagara Mohawk Power Corp.	Champlain Spinner	F	23643	Whitehall	031	36	1992-07-01	0.4		0.0	0.0		HY	WAT			1.2	
1537	Niagara Mohawk Power Corp.	CHI Dexter Hydro	E	23633	Dexter	045	36	1988-01-01	4.2		0.0	0.0		HY	WAT			11.7	
1538	Niagara Mohawk Power Corp.	CHI Diamond Is HY	E	23633	Watertown	045	36	1986-01-01	1.2		0.0	0.0		HY	WAT			6.3	
1539	Niagara Mohawk Power Corp.	CHI Fowler	E	23633	Fowler	049	36	1986-01-01	0.6		0.0	0.0		HY	WAT			1.7	
1540	Niagara Mohawk Power Corp.	CHI Hailsboro #3	E	23633	Hailsboro	089	36	1986-01-01	0.8		0.0	0.0		HY	WAT			4.3	
1541	Niagara Mohawk Power Corp.	CHI Hailsboro #4	E	23633	Hailsboro	089	36	1986-01-01	1.4		0.0	0.0		HY	WAT			11.6	
1542	Niagara Mohawk Power Corp.	CHI Hailsboro #6	E	23633	Hailsboro	089	36	1986-01-01	0.8		0.0	0.0		HY	WAT			5.2	
1543	Niagara Mohawk Power Corp.	CHI Theresa Hydro	E	23633	Theresa	089	36	1986-01-01	1.3		0.0	0.0		HY	WAT			7.5	
1544	Niagara Mohawk Power Corp.	Chittenden Falls	F	23643	Stuyvesant	021	36	1995-12-01	0.6		0.0	0.0		HY	WAT			0.6	
1545	Niagara Mohawk Power Corp.	City of Oswego (H.D.)	C	23634	Oswego	075	36	1994-02-01	11.9		0.0	0.0		HY	WAT			50.0	
1546	Niagara Mohawk Power Corp.	City of Utica - Sand Road	E	23633	Utica	065	36	1993-05-01	0.2		0.0	0.0		HY	WAT			1.6	
1547	Niagara Mohawk Power Corp.	City of Utica -Trenton Falls	E	23633	Utica	065	36	1993-02-01	0.2		0.0	0.0		HY	WAT			0.4	
1548	Niagara Mohawk Power Corp.	City of Watertown	E	23633	Watertown	045	36	1986-01-01	8.1		0.0	0.0		HY	WAT			13.6	
1549	Niagara Mohawk Power Corp.	City of Watervliet	F	23643	Guilderland	001	36	1986-01-01	1.2		0.0	0.0		HY	WAT			3.3	
1550	Niagara Mohawk Power Corp.	Cons. HY-Victory	F	23643	Victory Falls	091	36	1986-12-01	1.7		0.0	0.0		HY	WAT			5.7	
1551	Niagara Mohawk Power Corp.	Copenhagen Assoc.	E	23633	Copenhagen	049	36	1986-01-01	3.3		0.0	0.0		HY	WAT			10.4	
1552	Niagara Mohawk Power Corp.	Cottrell Paper	F	23643	Rock City Falls	091	36	1987-01-01	0.3		0.0	0.0		HY	WAT			0.1	
1553	Niagara Mohawk Power Corp.	Edison Hydro Electric	F	23643	Stottville	021	36	2009-11-01	0.4		0.0	0.0		HY	WAT			1.9	
1554	Niagara Mohawk Power Corp.	Empire HY Partner	E	23633	Port Leyden	049	36	1984-11-01	1.0		0.0	0.0		HY	WAT			5.0	
1555	Niagara Mohawk Power Corp.	Finch Paper LLC - Glens Falls	F	23643	Glens Falls	113	36	2009-11-01	11.8		0.0	0.0		HY	WAT			2.0	
1556	Niagara Mohawk Power Corp.	Finch Pruyn	F	23643	Glens Falls	113	36	1989-12-01	29.0		0.0	0.0		HY	WAT			0.0	
1557	Niagara Mohawk Power Corp.	Fort Miller Assoc	F	23643	Schuylerville	091	36	1985-10-01	5.0		0.0	0.0		HY	WAT			24.3	
1558	Niagara Mohawk Power Corp.	Fortis Energy - Diana	E	23633	Diana	049	36	1985-07-01	1.8		0.0	0.0		HY	WAT			7.1	
1559	Niagara Mohawk Power Corp.	Franklin Hydro	D	24055	Franklin Falls	033	36	1995-03-01	0.3		0.0	0.0		HY	WAT			0.0	
1560	Niagara Mohawk Power Corp.	Green Island Power Authority	F	23643	Green Island	001	36	1971-01-01	6.0		0.0	0.0		HY	WAT			35.7	
1561	Niagara Mohawk Power Corp.	Hewittville Hydro	E	23633	Potsdam	089	36	1984-07-01	3.0		0.0	0.0		HY	WAT			13.5	
1562	Niagara Mohawk Power Corp.	Hollings&Vose-Center	F	23643	Easton	115	36	1986-01-01	0.4		0.0	0.0		HY	WAT			0.2	
1563	Niagara Mohawk Power Corp.	Hollings&Vose-Lower	F	23643	Easton	115	36	1986-01-01	0.4		0.0	0.0		HY	WAT			0.0	
1564	Niagara Mohawk Power Corp.	Hollings&Vose-Upper	F	23643	Easton	115	36	1986-01-01	0.4		0.0	0.0		HY	WAT			4.6	
1565	Niagara Mohawk Power Corp.	Hoosick Falls	F	23643	Hoosick Falls	083	36	1988-08-01	0.6		0.0	0.0		HY	WAT			0.0	
1566	Niagara Mohawk Power Corp.	Hydrocarbon-Algny	A	23774	Allegany	003	36	1992-12-01	0.2		0.0	0.0		IC	NG			0.0	
1567	Niagara Mohawk Power Corp.	Indian Falls HY	E	23633	Theresa	045	36	1986-01-01	0.3		0.0	0.0		HY	WAT			0.6	
1568	Niagara Mohawk Power Corp.	Kings Falls	E	23633	Copenhagen	049	36	1988-05-01	1.6		0.0	0.0		HY	WAT			0.0	
1569	Niagara Mohawk Power Corp.	Laidlaw Energy	A	23774	Ellicottville	009	36	1991-07-01	3.4		0.0	0.0		GT	NG			0.0	
1570	Niagara Mohawk Power Corp.	Laidlaw Energy	A	23774	Ellicottville	009	36	1991-07-01	2.4		0.0	0.0		ST	NG			0.0	
1571	Niagara Mohawk Power Corp.	Laquidara-Long Falls	E	23633	Carthage	045	36	1991-06-01	3.3		0.0	0.0		HY	WAT			5.2	
1572	Niagara Mohawk Power Corp.	Lyonsdale Assoc. (Burrows)	E	23633	Lyons Falls	049	36	1984-07-01	3.0		0.0	0.0		HY	WAT			11.1	
1573	Niagara Mohawk Power Corp.	Mechanicville	F	23643	Mechanicville	091	36	2005-03-01	2.0		0.0	0.0		HY	WAT			17.2	
1574	Niagara Mohawk Power Corp.	Mountainaire Massage Spa	F	23643	Wevertown	113	36	2009-11-01	0.0		0.0	0.0		HY	WAT			0.0	
1575	Niagara Mohawk Power Corp.	Mt. Ida Assoc.	F	23643	Troy	083	36	1986-01-01	6.0		0.0	0.0		HY	WAT			9.1	

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EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1576	Niagara Mohawk Power Corp.	Newport HY Assoc		E	23633	Newport	043	36	1987-12-01	1.7		0.0	0.0		HY	WAT			7.3	
1577	Niagara Mohawk Power Corp.	Nottingham High School		C	23634	Syracuse	067	36	1988-06-01	0.2		0.0	0.0		CC	NG			0.0	
1578	Niagara Mohawk Power Corp.	Oakvale Construction		D	24055	Wilmington	031	36	2009-11-01	0.4		0.0	0.0		HY	WAT			1.6	
1579	Niagara Mohawk Power Corp.	Onondaga Energy Partners		C	23634	Onondaga	067	36	1987-12-01	1.4		0.0	0.0		IC	MTE			0.0	
1580	Niagara Mohawk Power Corp.	Oswego County		C	23634	Oswego	075	36	1986-03-01	3.6		0.0	0.0		ST	REF			5.0	
1581	Niagara Mohawk Power Corp.	Oswego HY Partners (Phoeni		C	23634	Phoenix	067	36	1990-12-01	3.4		0.0	0.0		HY	WAT			11.6	
1582	Niagara Mohawk Power Corp.	Riverrat Glass&Electric		F	23643	Wadhams	031	36	1986-01-01	0.6		0.0	0.0		HY	WAT			2.2	
1583	Niagara Mohawk Power Corp.	Sandy Hollow HY		E	23633	Sandy Hollow	045	36	1986-09-01	0.6		0.0	0.0		HY	WAT			1.5	
1584	Niagara Mohawk Power Corp.	Seneca Limited		C	23634	Syracuse	067	36	1985-12-01	0.2		0.0	0.0		HY	WAT			0.0	
1585	Niagara Mohawk Power Corp.	St. Elizabeth Medical Center		E	23633	Utica	065	36	2012-02-01	0.6		0.0	0.0		IC	NG			0.6	
1586	Niagara Mohawk Power Corp.	Stevens&Thompson Paper Cc		F	23643	Middle Falls	115	36	1987-12-01	10.5		0.0	0.0		HY	WAT			14.3	
1587	Niagara Mohawk Power Corp.	Stillwater Assoc.		E	23633	Webb	043	36	1987-01-01	1.8		0.0	0.0		HY	WAT			7.5	
1588	Niagara Mohawk Power Corp.	Stillwater HY Partners		F	23643	Stillwater	091	36	1993-04-01	3.4		0.0	0.0		HY	WAT			13.6	
1589	Niagara Mohawk Power Corp.	Stuyvesant Falls		F	23643	Stuyvesant	021	36	2013-02-01	7.0		0.0	0.0		HY	WAT			12.7	
1590	Niagara Mohawk Power Corp.	Sustainable Bioelectric LLC		A	23774	Wheeatfield	063	36	2014-03-01	0.6		0.0	0.0		IC	MTE				
1591	Niagara Mohawk Power Corp.	Synergics - Middle Greenwich		F	23643	Greenwich	115	36	1987-12-01	0.2		0.0	0.0		HY	WAT			0.0	
1592	Niagara Mohawk Power Corp.	Synergics - Union Falls		D	24055	Union Falls	019	36	1987-12-01	3.0		0.0	0.0		HY	WAT			13.4	
1593	Niagara Mohawk Power Corp.	Synergics - Upper Greenwich		F	23643	Greenwich	115	36	1987-12-01	0.4		0.0	0.0		HY	WAT			0.0	
1594	Niagara Mohawk Power Corp.	Tannery Island		E	23633	Carthage	045	36	1986-01-01	1.5		0.0	0.0		HY	WAT			9.2	
1595	Niagara Mohawk Power Corp.	Town of Wells		F	23643	Wells	041	36	1987-12-01	0.5		0.0	0.0		HY	WAT			1.6	
1596	Niagara Mohawk Power Corp.	Tri-City JATC		F	23643	Latham	001	36	2009-11-01	0.0		0.0	0.0		IC	NG			0.0	
1597	Niagara Mohawk Power Corp.	Unionville Hydro		E	23633	Potsdam	089	36	1984-07-01	3.0		0.0	0.0		HY	WAT			13.6	
1598	Niagara Mohawk Power Corp.	United States Gypsum		A	23774	Batavia	037	36	2009-11-01	5.8		0.0	0.0		CC	NG			0.9	
1599	Niagara Mohawk Power Corp.	Valatie Falls		F	23643	Valatie	021	36	1992-12-01	0.1		0.0	0.0		HY	WAT			0.5	
1600	Niagara Mohawk Power Corp.	Valley Falls Assoc.		F	23643	Valley Falls	083	36	1985-08-01	2.5		0.0	0.0		HY	WAT			8.2	
1601	Niagara Mohawk Power Corp.	Village of Gouverneur		E	23633	Gouverneur	089	36	1986-01-01	0.1		0.0	0.0		HY	WAT			0.5	
1602	Niagara Mohawk Power Corp.	Village of Potsdam		E	23633	Potsdam	089	36	1986-01-01	0.8		0.0	0.0		HY	WAT			3.1	
1603	Niagara Mohawk Power Corp.	Village of Potsdam 2		E	23633	Potsdam	089	36	2014-04-01	0.5		0.0	0.0		HY	WAT			1.2	
1604	Niagara Mohawk Power Corp.	Village of Saranac Lake		E	23633	Saranac Lake	033	36	1996-12-01	0.2		0.0	0.0		HY	WAT			0.5	
1605	Niagara Mohawk Power Corp.	Wave Hydro LLC		C	23634	Baldwinsville	067	36	2010-02-07	0.8		0.0	0.0		HY	WAT			0.0	
1606	Niagara Mohawk Power Corp.	West End Dam Assoc.		E	23633	Carthage	045	36	1986-01-01	4.4		0.0	0.0		HY	WAT			24.3	
1607	Niagara Wind Power, LLC	Steel Wind		A	323596	Lackawanna	029	36	2007-01-23	20.0	20.0	20.0	20.0		WT	WND			46.6	
1608	Nine Mile Point Nuclear Station, LLC	Nine Mile Point 1		C	23575	Scriba	075	36	1969-11-01	641.8	630.5	636.6	639.7		NB	UR			5,442.1	
1609	Nine Mile Point Nuclear Station, LLC	Nine Mile Point 2		C	23744	Scriba	075	36	1988-08-01	1,259.3	1,246.6	1,290.4	1,296.5		NB	UR			9,797.1	
1610	Noble Altona Windpark, LLC	Altona Wind Power		D	323606	Altona	019	36	2008-09-23	97.5	97.5	97.5	97.5		WT	WND			186.4	
1611	Noble Bliss Windpark, LLC	Bliss Wind Power		A	323608	Bliss	121	36	2008-03-20	100.5	100.5	100.5	100.5		WT	WND			206.6	
1612	Noble Chateaugay Windpark, LLC	Chateaugay Wind Power		D	323614	Chateaugay	033	36	2008-10-07	106.5	106.5	106.5	106.5		WT	WND			200.5	
1613	Noble Clinton Windpark 1, LLC	Clinton Wind Power		D	323605	Clinton	019	36	2008-04-09	100.5	100.5	100.5	100.5		WT	WND			186.2	
1614	Noble Ellenburg Windpark, LLC	Ellenburg Wind Power		D	323604	Ellenburg	019	36	2008-03-31	81.0	81.0	81.0	81.0		WT	WND			176.6	
1615	Noble Wethersfield Windpark, LLC	Wethersfield Wind Power		C	323626	Wethersfield	121	36	2008-12-11	126.0	126.0	126.0	126.0		WT	WND			267.8	
1616	Northbrook Lyons Falls, LLC	Lyons Falls Hydro		E	23570	Lyons Falls	049	36	1986-01-01	8.0	7.3	8.0	8.0		HY	WAT			41.1	
1617	NRG Power Marketing LLC	Arthur Kill GT 1		J	23520	Staten Island	085	36	1970-06-01	20.0	16.5	10.9	11.8		GT	NG			0.3	
1618	NRG Power Marketing LLC	Arthur Kill ST 2		J	23512	Staten Island	085	36	1959-08-01	376.2	357.7	338.3	340.9		ST	NG			788.8	
1619	NRG Power Marketing LLC	Arthur Kill ST 3		J	23513	Staten Island	085	36	1969-06-01	535.5	518.0	503.0	527.1		ST	NG			331.4	
1620	NRG Power Marketing LLC	Astoria GT 05		J	24106	Queens	081	36	1970-06-01	19.2	16.0	12.3	15.8		GT	FO2			0.1	
1621	NRG Power Marketing LLC	Astoria GT 07		J	24107	Queens	081	36	1970-06-01	19.2	15.5	11.5	14.0		GT	FO2			0.1	
1622	NRG Power Marketing LLC	Astoria GT 08		J	24108	Queens	081	36	1970-06-01	19.2	15.3	11.4	14.8		GT	FO2			0.1	
1623	NRG Power Marketing LLC	Astoria GT 10		J	24110	Queens	081	36	1971-01-01	31.8	24.9	18.4	22.6		GT	FO2			0.5	
1624	NRG Power Marketing LLC	Astoria GT 11		J	24225	Queens	081	36	1971-02-01	31.8	23.6	16.5	25.0		GT	FO2			1.0	
1625	NRG Power Marketing LLC	Astoria GT 12		J	24226	Queens	081	36	1971-05-01	31.8	22.7	17.7	22.4		GT	FO2			0.6	
1626	NRG Power Marketing LLC	Astoria GT 13		J	24227	Queens	081	36	1971-05-01	31.8	24.0	16.9	22.1		GT	FO2			0.4	
1627	NRG Power Marketing LLC	Astoria GT 2-1		J	24094	Queens	081	36	1970-06-01	46.5	41.2	35.7	43.9		JE	KER	NG		6.2	
1628	NRG Power Marketing LLC	Astoria GT 2-2		J	24095	Queens	081	36	1970-06-01	46.5	42.4	32.2	42.7		JE	KER	NG		6.8	
1629	NRG Power Marketing LLC	Astoria GT 2-3		J	24096	Queens	081	36	1970-06-01	46.5	41.2	31.8	42.2		JE	KER	NG		3.6	
1630	NRG Power Marketing LLC	Astoria GT 2-4		J	24097	Queens	081	36	1970-06-01	46.5	41.0	32.6	43.4		JE	KER	NG		3.1	
1631	NRG Power Marketing LLC	Astoria GT 3-1		J	24098	Queens	081	36	1970-06-01	46.5	41.2	31.7	41.8		JE	KER	NG		4.1	
1632	NRG Power Marketing LLC	Astoria GT 3-2		J	24099	Queens	081	36	1970-06-01	46.5	43.5	33.7	42.5		JE	KER	NG		3.1	
1633	NRG Power Marketing LLC	Astoria GT 3-3		J	24100	Queens	081	36	1970-06-01	46.5	43.0	32.2	42.3		JE	KER	NG		4.5	
1634	NRG Power Marketing LLC	Astoria GT 3-4		J	24101	Queens	081	36	1970-06-01	46.5	43.0	34.3	42.5		JE	KER	NG		3.1	
1635	NRG Power Marketing LLC	Astoria GT 4-1		J	24102	Queens	081	36	1970-07-01	46.5	42.6	34.3	42.7		JE	KER	NG		6.9	
1636	NRG Power Marketing LLC	Astoria GT 4-2		J	24103	Queens	081	36	1970-07-01	46.5	41.4	33.6	43.6		JE	KER	NG		3.8	
1637	NRG Power Marketing LLC	Astoria GT 4-3		J	24104	Queens	081	36	1970-07-01	46.5	41.1	32.8	42.8		JE	KER	NG		2.6	
1638	NRG Power Marketing LLC	Astoria GT 4-4		J	24105	Queens	081	36	1970-07-01	46.5	42.8	31.6	42.5		JE	KER	NG		3.8	
1639	NRG Power Marketing LLC	Dunkirk 2		A	23564	Dunkirk	013	36	1950-12-01	100.0	97.2	75.0	75.0		ST	BIT			368.5	(S)
1640	NRG Power Marketing LLC	Dunkirk IC 2		A	5050	Dunkirk	013	36	1990-01-01	0.5		0.0	0.0		IC	FO2				
1641	NRG Power Marketing LLC	Huntley 67		A	23561	Tonawanda	029	36	1957-12-01	218.0	196.5	187.9	187.0		ST	BIT			500.0	
1642	NRG Power Marketing LLC	Huntley 68		A	23562	Tonawanda	029	36	1958-12-01	218.0	198.0	189.5	187.2		ST	BIT			703.9	
1643	NRG Power Marketing LLC	Huntley IC 1		A	5051	Tonawanda	029	36	1967-08-01	0.7		0.0	0.0		IC	FO2				
1644	NRG Power Marketing LLC	Oswego 5		C	23606	Oswego	075	36	1976-02-01	901.8	850.3	828.5	825.5		ST	FO6			43.3	
1645	NRG Power Marketing LLC	Oswego 6		C	23613	Oswego	075	36	1980-07-01	901.8	835.2	826.5	832.0		ST	FO6	NG		40.6	
1646	NRG Power Marketing LLC	Oswego IC 1		C	5052	Oswego	075	36	1967-08-01	0.7		0.0	0.0		IC	FO2				
1647	NRG Power Marketing LLC	Oswego IC 2		C	5053	Oswego	075	36	1976-02-01	0.8		0.0	0.0		IC	FO2				

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1648	NRG Power Marketing LLC	Oswego IC 3	C	5054	Oswego	075	36	1980-07-01	0.8		0.0	0.0		IC	FO2				
1649	Orange and Rockland Utilities	Buttermilk Falls	G	5055	Highland Falls	071	36	1986-12-01	0.1		0.0	0.0		HY	WAT				
1650	Orange and Rockland Utilities	Intl. Crossroads	G	5056	Mahwah NJ	003	34	1987-12-01	3.0		0.0	0.0		IC	NG	FO2			
1651	Orange and Rockland Utilities	Landfill G.Part19	G	5057	Goshen	071	36	1988-12-01	2.5		0.0	0.0		IC	MTE				
1652	Orange and Rockland Utilities	Middletown LFG	G	5058	Goshen	071	36	1988-12-01	3.0		0.0	0.0		IC	MTE				
1653	PSEG Energy Resource & Trade, LLC	Bethlehem Energy Center	F	23843	Bethlehem	001	36	2005-07-01	893.1	756.9	762.0	870.3		CC	NG	FO2		4,526.7	
1654	R.E. Ginna Nuclear Power Plant, LLC	Ginna	B	23603	Ontario	117	36	1970-07-01	614.0	582.0	581.4	582.8		NP	UR			4,662.5	
1655	ReEnergy Holdings LLC	Black River	E	23780	Watertown	045	36	2013-05-30	55.5	55.6	50.8	52.4		ST	WD			302.6	
1656	ReEnergy Holdings LLC	Lyonsdale	E	23803	Lyonsdale	049	36	1992-08-01	21.1	20.2	20.3	20.6	YES	ST	WD			146.7	
1657	Rochester Gas and Electric Corp.	Mills Mills	B	5059	Fillmore	003	36	1906-07-01	0.2		0.0	0.0		HY	WAT				
1658	Rochester Gas and Electric Corp.	Mt Morris	B	5060	Mt Morris	051	36	1916-07-01	0.3		0.0	0.0		HY	WAT				
1659	Rochester Gas and Electric Corp.	Station 2 1	B	23604	Rochester	055	36	1913-07-01	8.5	6.5	8.5	8.5		HY	WAT			36.5	
1660	Rochester Gas and Electric Corp.	Station 26 1	B	23604	Rochester	055	36	1952-08-01	3.0	3.0	3.0	3.0		HY	WAT			0.8	
1661	Rochester Gas and Electric Corp.	Station 5 1	B	23604	Rochester	055	36	1918-07-01	14.0	11.8	14.0	14.0		HY	WAT			4.3	
1662	Rochester Gas and Electric Corp.	Station 5 2	B	23604	Rochester	055	36	1918-07-01	13.6	11.8	13.6	13.6		HY	WAT			0.0	
1663	Rochester Gas and Electric Corp.	Station 5 3	B	23604	Rochester	055	36	1918-07-01	18.0	16.5	18.0	18.0		HY	WAT			86.9	
1664	Rochester Gas and Electric Corp.	Wiscoy 1	B	5061	Fillmore	003	36	1922-07-01	0.6		0.0	0.0		HY	WAT				
1665	Rochester Gas and Electric Corp.	Wiscoy 2	B	5062	Fillmore	003	36	1922-07-01	0.5		0.0	0.0		HY	WAT				
1666	Rockville Centre, Village of	Charles P Keller 07	K	1661	Rockville Centre	059	36	1942-09-01	2.0	2.0	2.0	2.0		IC	FO2			0.0	
1667	Rockville Centre, Village of	Charles P Keller 08	K	1661	Rockville Centre	059	36	1950-09-01	2.4	2.8	2.4	2.4		IC	FO2			0.0	
1668	Rockville Centre, Village of	Charles P Keller 09	K	1661	Rockville Centre	059	36	1954-09-01	3.5	3.3	3.5	3.5		IC	FO2	NG		0.0	
1669	Rockville Centre, Village of	Charles P Keller 10	K	1661	Rockville Centre	059	36	1954-09-01	3.5	3.2	3.5	3.5		IC	FO2	NG		0.0	
1670	Rockville Centre, Village of	Charles P Keller 11	K	1661	Rockville Centre	059	36	1962-09-01	5.2	5.2	5.2	5.2		IC	FO2	NG		0.1	
1671	Rockville Centre, Village of	Charles P Keller 12	K	1661	Rockville Centre	059	36	1967-09-01	5.5	5.5	5.5	5.5		IC	FO2	NG		0.0	
1672	Rockville Centre, Village of	Charles P Keller 13	K	1661	Rockville Centre	059	36	1974-09-01	5.5	5.6	5.5	5.5		IC	FO2	NG		0.1	
1673	Rockville Centre, Village of	Charles P Keller 14	K	1661	Rockville Centre	059	36	1994-09-01	6.2	6.3	6.2	6.2		IC	FO2	NG		0.5	
1674	Selkirk Cogen Partners, L.P.	Selkirk-I	F	23801	Selkirk	001	36	1992-03-01	107.2	82.1	76.2	107.6	YES	CC	NG	FO2		287.0	
1675	Selkirk Cogen Partners, L.P.	Selkirk-II	F	23799	Selkirk	001	36	1994-09-01	338.8	291.3	270.4	334.2	YES	CC	NG	FO2		928.6	
1676	Seneca Energy II, LLC	Ontario LFGE	C	23819	Canandaigua	069	36	2003-12-01	11.2	5.6	11.2	11.2		IC	MTE			75.7	
1677	Seneca Energy II, LLC	Seneca Energy 1	C	23797	Seneca Falls	099	36	1996-03-01	8.8	8.8	8.8	8.8		IC	MTE			141.8	**(G)**
1678	Seneca Energy II, LLC	Seneca Energy 2	C	23797	Seneca Falls	099	36	1997-08-01	8.8	8.8	8.8	8.8		IC	MTE				
1679	Seneca Falls Power Corp.	Seneca Falls 1	C	23627	Seneca Falls	099	36	1998-06-01	1.8	1.6	0.0	0.0		HY	WAT			0.0	
1680	Seneca Falls Power Corp.	Seneca Falls 2	C	23627	Seneca Falls	099	36	1998-06-01	1.8	1.6	0.0	0.0		HY	WAT			0.0	
1681	Seneca Falls Power Corp.	Seneca Falls 4	C	23627	Seneca Falls	099	36	1998-06-01	2.0	1.8	0.0	0.0		HY	WAT			0.0	
1682	Seneca Power Partners, L.P.	Allegany	B	23514	Hume	003	36	1995-03-01	67.0	62.9	60.0	61.7	YES	CC	NG			96.5	
1683	Seneca Power Partners, L.P.	Batavia	B	24024	Batavia	037	36	1992-06-01	67.3	57.1	48.8	60.1		CC	NG			10.8	
1684	Seneca Power Partners, L.P.	Carthage Energy	E	23857	Carthage	045	36	1991-08-01	62.9	59.0	55.5	63.6		CC	NG	FO2		11.4	
1685	Seneca Power Partners, L.P.	Hillburn GT	G	23639	Hillburn	087	36	1971-04-01	46.5	37.9	34.8	43.3		JE	KER			0.3	
1686	Seneca Power Partners, L.P.	Shoemaker GT	G	23640	Middletown	071	36	1971-05-01	41.9	33.1	31.6	41.0		JE	KER			0.4	
1687	Seneca Power Partners, L.P.	Sterling	E	23777	Sherrill	065	36	1991-06-01	65.3	57.4	50.1	63.0		CC	NG			22.4	
1688	Sheldon Energy LLC	High Sheldon Wind Farm	C	323625	Sheldon	121	36	2009-02-01	112.5	112.5	112.5	112.5		WT	WND			270.7	
1689	Shell Energy North America (US), L.P	Glen Park Hydro	E	23778	Glen Park	045	36	1986-01-01	32.6	40.4	32.6	32.6		HY	WAT			168.3	
1690	Shell Energy North America (US), L.P	Lockport	A	23791	Lockport	063	36	1992-07-01	221.3	225.2	202.7	220.3		CC	NG	FO2		388.8	
1691	Shell Energy North America (US), L.P	Munnsville Wind Power	E	323609	Bouckville	053	36	2007-08-20	34.5	34.5	34.5	34.5		WT	WND			96.0	
1692	Somerset Operating Company, LLC	Somerset	A	23543	Somerset	063	36	1984-08-01	655.1	686.5	681.5	681.2		ST	BIT			1,786.6	
1693	Stephentown Spindle LLC	Beacon LESR	F	323632	Stephentown	083	36	2010-11-29	20.0	0.0	0.0	0.0		ES	FW			0.0	
1694	Stony Creek Energy LLC	Orangeville Wind Farm	C	323706	Orangeville	121	36	2013-12-01	93.9	88.5	93.9	93.9		WT	WND			274.1	
1695	TC Ravenswood, LLC	Ravenswood 01	J	23729	Queens	081	36	1967-07-01	18.6	8.8	9.3	9.6		GT	NG			0.1	
1696	TC Ravenswood, LLC	Ravenswood 04	J	24252	Queens	081	36	1970-09-01	21.1	15.2	12.9	15.4		GT	KER	NG		0.2	
1697	TC Ravenswood, LLC	Ravenswood 05	J	24254	Queens	081	36	1970-08-01	21.1	15.7	13.6	15.6		GT	KER			0.1	
1698	TC Ravenswood, LLC	Ravenswood 06	J	24253	Queens	081	36	1970-08-01	22.0	16.7	13.4	15.8		GT	KER	NG		0.2	
1699	TC Ravenswood, LLC	Ravenswood 09	J	24257	Queens	081	36	1970-07-01	25.0	21.7	16.9	21.7		JE	KER	NG		1.6	
1700	TC Ravenswood, LLC	Ravenswood 10	J	24258	Queens	081	36	1970-08-01	25.0	21.2	18.0	22.8		JE	KER	NG		0.3	
1701	TC Ravenswood, LLC	Ravenswood 11	J	24259	Queens	081	36	1970-08-01	25.0	20.2	17.2	22.8		JE	KER	NG		1.4	
1702	TC Ravenswood, LLC	Ravenswood 2-1	J	24244	Queens	081	36	1970-12-01	42.9	40.4	32.7	37.4		JE	NG			1.6	
1703	TC Ravenswood, LLC	Ravenswood 2-2	J	24245	Queens	081	36	1970-12-01	42.9	37.6	31.4	43.0		JE	NG			1.5	
1704	TC Ravenswood, LLC	Ravenswood 2-3	J	24246	Queens	081	36	1970-12-01	42.9	39.2	0.0	0.0		JE	NG			0.0	
1705	TC Ravenswood, LLC	Ravenswood 2-4	J	24247	Queens	081	36	1970-12-01	42.9	39.8	32.0	37.5		JE	NG			1.8	
1706	TC Ravenswood, LLC	Ravenswood 3-1	J	24248	Queens	081	36	1970-08-01	42.9	40.5	30.3	40.9		JE	NG			1.4	
1707	TC Ravenswood, LLC	Ravenswood 3-2	J	24249	Queens	081	36	1970-08-01	42.9	38.1	30.6	35.8		JE	NG			1.3	
1708	TC Ravenswood, LLC	Ravenswood 3-3 (MB - 10/3	J	24250	Queens	081	36	1970-08-01	42.9	37.7	0.0	0.0		JE	NG			0.9	**(M) (6)**
1709	TC Ravenswood, LLC	Ravenswood 3-4 (ReAct. - 8	J	24251	Queens	081	36	1970-08-01	42.9	35.8	30.9	38.6		JE	NG			1.5	**(D) (7)**
1710	TC Ravenswood, LLC	Ravenswood CC 04	J	23820	Queens	081	36	2004-05-01	250.0	231.2	216.6	262.9		CC	NG	FO2		1,527.2	
1711	TC Ravenswood, LLC	Ravenswood ST 01	J	23533	Queens	081	36	1963-02-01	400.0	365.1	366.2	363.6		ST	FO6	NG		696.3	
1712	TC Ravenswood, LLC	Ravenswood ST 02	J	23534	Queens	081	36	1963-05-01	400.0	391.6	363.5	373.7		ST	FO6	NG		1,006.0	
1713	TC Ravenswood, LLC	Ravenswood ST 03	J	23535	Queens	081	36	1965-06-01	1,027.0	986.8	969.2	960.1		ST	FO6	NG		1,540.3	
1714	TransAlta Energy Marketing (U.S.) Inc	Saranac Energy	D	23793	Plattsburgh	019	36	1994-06-01	285.6	253.7	244.9	273.4		CC	NG			224.3	
1715	Triton Power Company	Chateaugay High Falls	D	323578	Chateaugay	033	36	1987-12-01	1.7	1.7	0.0	0.0		HY	WAT			4.3	
1716	Western New York Wind Corp.	Western NY Wind Power	B	24143	Wethersfield	121	36	2000-10-01	6.6	0.0	0.0	0.0		WT	WND			9.3	
1717	Wheelabrator Hudson Falls, LLC	Wheelabrator Hudson Falls	F	23798	Hudson Falls	115	36	1991-10-01	14.4	12.7	11.4	11.7		ST	REF			74.9	
1718	Wheelabrator Westchester, LP	Wheelabrator Westchester	H	23653	Peekskill	119	36	1984-04-01	59.7	53.5	52.7	53.6		ST	REF			388.7	
1719																			

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Contains Proprietary Material
Do Not Distribute

TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1720										44,866.1	40,333.7	38,664.5	41,012.8						141,186.6	
1721				J						11,398.8	10,223.4	9,597.0	10,560.6							

Contains Proprietary Material
Do Not Distribute

Max	31,138
Peak Month	7
PST	25,244
Winter	22,045
Spring	19,393
Summer	24,144
Fall	20,374

Source: NYISO

SIL Study
24,893
24,418
31,266
31,179

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	21,185	12/1/2014	14,220	13,616	13,287	13,224	13,497	14,498	16,506	17,769	18,270	18,637	18,888	18,940	18,882	18,884	18,880	19,092	20,181	21,185	21,029	20,601	20,071	19,094	17,738	16,283
Winter	12	21,996	12/2/2014	15,242	14,655	14,333	14,246	14,541	15,635	17,671	18,946	19,413	19,603	19,837	19,833	19,845	19,937	20,024	20,287	21,327	21,996	21,835	21,369	20,649	19,560	17,986	16,471
Winter	12	21,652	12/3/2014	15,318	14,675	14,270	14,138	14,334	15,250	17,166	18,527	19,044	19,407	19,666	19,733	19,721	19,811	19,863	19,865	20,847	21,652	21,389	21,004	20,464	19,490	18,020	16,551
Winter	12	21,613	12/4/2014	15,512	14,928	14,575	14,494	14,762	15,747	17,679	18,896	19,323	19,560	19,572	19,387	19,325	19,267	19,209	19,467	20,446	21,613	21,466	21,085	20,583	19,689	18,278	16,864
Winter	12	21,460	12/5/2014	15,822	15,229	14,954	14,850	15,006	16,053	17,942	19,131	19,557	19,848	19,958	19,960	19,914	19,882	19,901	20,132	20,997	21,460	21,073	20,573	19,992	19,212	18,031	16,660
Winter	12	20,018	12/6/2014	15,536	14,773	14,307	14,084	14,094	14,433	15,170	16,023	16,988	17,791	18,293	18,494	18,523	18,408	18,348	18,490	19,303	20,018	19,855	19,424	19,000	18,380	17,434	16,389
Winter	12	20,968	12/7/2014	15,426	14,738	14,348	14,178	14,207	14,511	15,102	15,697	16,556	17,170	17,486	17,593	17,648	17,629	17,665	17,984	19,296	20,864	20,968	20,770	20,358	19,525	18,319	17,050
Winter	12	23,095	12/8/2014	16,111	15,590	15,329	15,267	15,562	16,598	18,519	19,872	20,452	20,837	21,037	21,023	20,899	20,901	20,864	21,078	22,091	23,095	22,917	22,422	21,725	20,649	19,086	17,449
Winter	12	22,518	12/9/2014	16,176	15,502	15,093	14,964	15,179	16,098	18,003	19,567	20,081	20,496	20,838	20,931	20,877	20,834	20,702	20,817	21,686	22,518	22,242	21,698	20,924	19,879	18,327	16,737
Winter	12	22,828	12/10/2014	15,639	14,986	14,637	14,544	14,775	15,739	17,646	19,107	19,682	20,144	20,359	20,438	20,450	20,467	20,456	20,687	21,765	22,828	22,655	22,190	21,509	20,441	18,901	17,276
Winter	12	22,609	12/11/2014	16,148	15,501	15,141	15,061	15,281	16,239	18,052	19,426	19,965	20,268	20,413	20,417	20,335	20,318	20,306	20,495	21,515	22,609	22,385	21,936	21,334	20,326	18,859	17,292
Winter	12	22,122	12/12/2014	16,167	15,528	15,169	15,041	15,199	16,161	18,080	19,451	19,978	20,349	20,396	20,292	20,106	20,067	19,977	20,100	21,048	22,122	21,854	21,315	20,699	19,923	18,755	17,390
Winter	12	20,486	12/13/2014	16,205	15,449	14,975	14,771	14,767	15,142	15,912	16,689	17,578	18,163	18,441	18,444	18,303	18,141	18,077	18,329	19,410	20,486	20,410	20,025	19,565	18,924	17,974	16,772
Winter	12	20,471	12/14/2014	15,744	14,964	14,502	14,280	14,265	14,498	15,028	15,631	16,480	17,241	17,676	17,854	17,912	17,889	17,850	18,012	19,138	20,471	20,407	20,298	19,829	18,984	17,640	16,327
Winter	12	21,987	12/15/2014	15,278	14,688	14,407	14,317	14,574	15,580	17,568	18,949	19,367	19,631	19,725	19,662	19,475	19,451	19,374	19,543	20,656	21,987	21,889	21,453	20,848	19,872	18,377	16,778
Winter	12	21,968	12/16/2014	15,564	14,900	14,551	14,442	14,687	15,668	17,694	19,133	19,610	19,932	20,075	20,042	19,924	19,834	19,719	19,925	20,985	21,968	21,749	21,330	20,713	19,683	18,172	16,514
Winter	12	21,926	12/17/2014	15,256	14,556	14,201	14,063	14,274	15,187	17,214	18,618	19,068	19,344	19,514	19,476	19,418	19,508	19,587	19,886	20,933	21,926	21,675	21,245	20,671	19,779	18,335	16,819
Winter	12	22,187	12/18/2014	15,628	14,959	14,600	14,512	14,779	15,810	17,781	19,129	19,549	19,847	19,947	19,942	19,840	19,789	19,745	19,999	21,119	22,187	22,014	21,611	21,048	20,109	18,694	17,137
Winter	12	22,134	12/19/2014	16,050	15,391	14,980	14,867	15,132	16,103	17,932	19,353	19,927	20,272	20,419	20,363	20,111	19,962	19,843	20,038	21,027	22,134	21,852	21,436	20,852	20,105	19,004	17,659
Winter	12	21,028	12/20/2014	16,467	15,746	15,308	15,060	15,072	15,429	16,187	17,022	17,966	18,789	19,172	19,272	19,191	19,014	18,948	19,060	20,001	21,028	20,927	20,544	20,110	19,469	18,569	17,390
Winter	12	20,957	12/21/2014	16,310	15,534	15,072	14,780	14,750	14,989	15,540	16,178	17,060	17,907	18,414	18,585	18,640	18,539	18,528	18,769	19,891	20,957	20,943	20,681	20,237	19,458	18,208	16,903
Winter	12	22,074	12/22/2014	15,844	15,128	14,779	14,674	14,896	15,806	17,589	18,981	19,639	20,075	20,265	20,242	20,031	19,964	19,936	20,163	21,078	22,074	21,848	21,353	20,763	19,861	18,478	16,991
Winter	12	21,324	12/23/2014	15,742	14,944	14,520	14,362	14,519	15,356	17,007	18,464	19,175	19,660	19,905	19,917	19,756	19,700	19,595	19,658	20,477	21,324	21,144	20,666	20,071	19,265	17,973	16,495
Winter	12	19,625	12/24/2014	15,187	14,350	13,872	13,647	13,749	14,354	15,564	16,812	17,763	18,590	19,069	19,265	19,135	19,006	18,834	18,731	19,296	19,625	18,899	18,160	17,560	17,058	16,315	15,428
Winter	12	17,507	12/25/2014	14,450	13,720	13,238	12,909	12,866	13,075	13,573	14,232	14,957	15,682	16,015	16,128	16,225	16,184	16,030	16,025	16,620	17,507	17,497	17,358	17,165	16,832	16,125	15,108
Winter	12	19,843	12/26/2014	14,254	13,650	13,287	13,159	13,315	13,962	15,048	16,003	16,797	17,468	17,801	17,892	17,738	17,513	17,326	17,421	18,349	19,843	19,775	19,424	18,976	18,284	17,253	16,101
Winter	12	18,786	12/27/2014	15,021	14,315	13,858	13,648	13,662	13,932	14,598	15,162	15,844	16,467	16,851	16,935	16,801	16,533	16,354	16,399	17,316	18,745	18,786	18,488	18,076	17,447	16,542	15,453
Winter	12	19,288	12/28/2014	14,459	13,733	13,298	13,087	13,070	13,287	13,758	14,326	15,024	15,846	16,471	16,820	17,037	17,039	16,998	17,165	18,228	19,288	19,267	18,939	18,467	17,806	16,795	15,648
Winter	12	21,428	12/29/2014	14,687	14,136	13,815	13,726	13,962	14,858	16,276	17,509	18,349	18,877	19,210	19,343	19,256	19,185	19,140	19,233	20,129	21,428	21,311	20,887	20,289	19,452	18,229	16,832
Winter	12	22,203	12/30/2014	15,741	15,119	14,776	14,683	14,869	15,668	17,076	18,328	19,129	19,669	19,944	20,015	19,949	19,857	19,834	19,956	20,853	22,203	22,084	21,665	21,148	20,310	19,067	17,612
Winter	12	21,953	12/31/2014	16,482	15,744	15,338	15,167	15,314	16,021	17,320	18,408	19,146	19,649	19,904	20,023	19,888	19,775	19,682	19,719	20,473	21,953	21,656	20,900	20,098	19,310	18,552	17,809
Winter	1	20,225	1/1/2015	17,052	16,304	15,759	15,425	15,341	15,530	15,879	16,081	16,454	17,001	17,527	17,843	17,944	17,887	17,784	17,932	18,822	20,225	20,108	19,810	19,410	18,746	17,667	16,518
Winter	1	21,193	1/2/2015	15,636	15,043	14,684	14,495	14,635	15,377	16,494	17,468	18,225	18,904	19,265	19,394	19,322	19,191	19,063	19,148	19,955	21,193	21,023	20,519	19,987	19,206	18,173	17,013
Winter	1	20,642	1/3/2015	15,981	15,332	14,982	14,760	14,784	15,105	15,727	16,396	17,089	17,828	18,435	18,807	18,973	18,966	19,026	19,143	19,878	20,642	20,520	20,081	19,474	18,618	17,601	16,436
Winter	1	19,736	1/4/2015	15,452	14,695	14,170	13,853	13,736	13,924	14,332	14,846	15,516	16,317	16,980	17,419	17,607	17,673	17,692	17,816	18,690	19,736	19,680	19,278	18,711	17,779	16,642	15,526
Winter	1	23,003	1/5/2015	14,657	14,234	14,028	14,020	14,391	15,567	17,647	19,085	19,552	19,957	20,226	20,332	20,377	20,400	20,408	20,624	21,482	22,957	23,003	22,683	22,052	21,005	19,539	18,099
Winter	1	23,632	1/6/2015	17,175	16,600	16,274	16,185	16,441	17,302	19,168	20,670	21,174	21,563	21,844	21,884	21,764	21,715	21,610	21,750	22,433	23,623	23,632	23,256	22,605	21,545	19,957	18,488
Winter	1	24,648	1/7/2015	17,480	16,888	16,544	16,431	16,653	17,553	19,489	20,930	21,418	21,715	21,916	21,974	21,986	22,014	22,054	22,288	23,094	24,514	24,648	24,289	23,709	22,711	21,316	19,864
Winter	1	24,327	1/8/2015	18,913	18,314	17,947	17,835	18,114	19,022	20,738	22,137	22,510	22,895	22,974	22,816	22,572	22,408	22,223	22,292	23,036	24,327	24,322	23,954	23,321	22,234	20,662	19,176
Winter	1	23,069	1/9/2015	18,138	17,564	17,185	17,034	17,194	17,959	19,717	21,187	21,626	22,020	22,190	22,085	21,773	21,575	21,363	21,357	21,901	23,069	22,930	22,414	21,827	21,044	19,927	18,731
Winter	1	22,334	1/10/2015	17,763	17,177	16,819	16,653	16,721	17,096	17,826	18,592	19,469	20,142	20,447	20,478	20,400	20,170	20,007	20,068	20,756	22,142	22,334	21,945	21,514	20,867	19,905	18,871
Winter	1	21,443	1/11/2015	17,924	17,200	16,773	16,525	16,477	16,646	17,125	17,627	18,354	19,016	19,504	19,723	19,700	19,609	19,413	19,402	20,114	21,443	21,431	21,029	20,427	19,475	18,241	17,012
Winter	1	22,559	1/12/2015	16,094	15,607	15,309	15,204	15,466	16,408	18,217	19,685	20,291	20,784	21,107	21,270	21,227	21,159	21,048	21,095	21,704	22,559	22,396	21,874	21,168	20,133	18,796	17,448
Winter	1	23,668	1/13/2015	16,454	15,930	15,665	15,646	15,938	17,080	19,100	20,567	21,021	21,390	21,568	21,456	21,311	21,236	21,149	21,361	22,045	23,465	23,668	23,355	22,720	21,756	20,407	19,062
Winter	1	23,222	1/14/2015	18,120	17,572	17,249	17,160	17,404	18,368	20,286	21,735	22,165	22,383	22,363	22,115	21,799	21,655	21,488	21,500	22,048	23,222	23,207	22,748	22,078	21,087	19,673	18,250
Winter	1	22,679	1/15/2015	17,274	16,739	16,405	16,326	16,567	17,518	19,461	20,838	21,228	21,421	21,397	21,211	20,894	20,736	20,557	20,631	21,300	22,635	22,679	22,314	21,693	20,692	19,168	17,822
Winter	1	22,452	1/16/2015	16,850	16,282	15,933	15,814	16,004	16,879	18,776	20,120	20,542	20,780	20,831	20,758	20,621	20,449	20,425	20,566	21,128	22,309	22,452	22,023	21,523	20,788	19,706	18,524
Winter	1	21,099	1/17/2015	17,608	17,031	16,722	16,579	16,650	17,002	17,782	18,552	19,390	20,007	20,237	20,170	19,835	19,443	19,182	19,143	19,713	20,968	21,099	20,727	20,193	19,510	18,597	17,528
Winter	1	20,222	1/18/2015	16,685	16,041	15,596	15,318	15,264	15,399	15,814	16,338	17,092	17,902	18,513	18,854	18,999	19,019	18,948	19,027	19,515	20,222	20,121	19,690	19,096	18,306	17,328	16,263
Winter	1	21,623	1/19/2015	15,459	14,964	14,658	14,574	14,778	15,473	16,677	17,732	18,604	19,312	19,731	19,899	19,850	19,872	19,886	19,970	20,506	21,623	21,579	21,149	20,477	19,523	18,161	16,881
Winter	1	22,144	1/20/2015	15,940	15,425	15,130	15,052	15,345	16,419	18,424	19,709	20,192	20,437	20,411	20,335	20,183	20,217	20,172	20,247	20,944	22,140	22,144	21,771	21,172	20,282	18,920	17,526
Winter	1	22,439	1/21/2015	16,584	16,119	15,893	15,880	16,220	17,235	19,224	20,552	20,930	21,242	21,367	21,257	20,945	20,701	20,595	20,730	21,260	22,385	22,439	22,013	21,353	20,329	18,943	17,526
Winter	1	22,118	1/22/2015	16,500	15,910	15,612	15,515	15,778	16,748	18,631	20,019	20,454	20,729	20,843	20,691	20,453	20,257	20,081	20,100	20,622	21,923	22,118	21,755	21,192	20,248	18,912	17,528
Winter	1	21,425	1/23/2015	16,523	16,044	15,753	15,664	15,895	16,882	18,800	20,141	20,508	20,756	20,704	20,523	20,208	20,008	19,788	19,778	20,249	21,349	21,425	20,954	20,373	19,561	18,445	17,247
Winter	1	20,458	1/24/2015	16,307	15,650	15,318	15,163	15,212	15,515	16,196	16,942	17,808	18,603	19,122	19,365	19,308	19,068	18,919	18,969	19,455	20,428	20,458	20,060	19,498	18,761	17,830	16,787
Winter	1	20,754	1/25/2015	15,900	15,258	14,849	14,679	14,681	14,957	15,505	16,099	16,960	17,606	17,975	18,107	18,087	17,948	17,891	18,035	18,697	20,263	20,754	20,582	20,165	19,368	18,326	17,309
Winter	1	23,112	1/26/2015	16,491	16,034	15,804	15,788	16,101	17,157	19,074	20,598	21,154	21,635	21,932	22,092	22,092	22,046	21,858	21,705	22,021	23,112	23,105	22,509	21,712	20,671	19,454	18,169
Winter	1	22,964	1/27/2015	17,249	16,686	16,398	16,319	16,505	17,128	18,210	18,983	19,553	20,196	20,607	20,784	20,805	20,697	20,600	20,635	21,175	22,642	22,964	22,575	21,891	20,876	19,535	18,245
Winter	1	23,166	1/28/2015	17,391	16,951	16,719	16,677	16,962	17,922	19,752	21,041	21,561	21,881	21,979	21,781	21,487	21,289	21,039	20,993	21,394	22,749	23,166	22,815	22,225	21,204	19,779	18,429
Winter	1	22,758	1/29/2015	17,516	17,002	16,778	16,713	17,029	17,961	19,879	21,127	21,530	21,736	21,692	21,534	21,312	21,268	21,174	21,246	21,713	22,690	22,758	22,290	21,546	20,429	18,980	17,642
Winter	1	22,613	1/30/2015	16,704	16,122	15,760	15,608	15,792	16,665	18,455	19,844	20,462	20,972	21,207	21,157	21,013	20,879	20,733	20,745	21,109	22,229	22,613	22,243	21,754	21,006	19,925	18,825
Winter	1	22,020	1/31/2015	17,917	17,354	17,055	16,927	17,014	17,363	18,121	18,931	19,835	20,509	20,828	20,763	20,513	20,160	19,916	19,858	20,243	21,483	22,020	21,744	21,233	20,527	19,534	18,476
Winter	2	21,227	2/1/2015	17,551	16,910	16,464	16,233	16,190	16,423	16,849	17,356	18,148	18,688	19,033	19,190	19,206	19,199	19,234	19,448	20,067	21,154	21,227	20,641	20,143	19,547	18,787	17,731
Winter	2	23,654	2/2/2015	16,782	16,287	16,030	15,981	16,203	16,988	18,447	19,665	20,644	21,492	22,008	22,218	22,225	22,262	22,212	22,172	22,393	23,423	23,654	23,242	22,508	21,461	20,200	18,886
Winter	2	23,494	2/3/2015	17,976	17,460	17,215	17,152	17,428	18,352	20,111	21,317	21,924	22,162	22,207	22,091	21,812	21,635	21,410	21,338	21,713	22,921	23,494	23,181	22,519	21,543	20,021	18,595
Winter	2	22,432	2/4/2015	17,576	16,992	16,662	16,520	16,731	17,616	19,431	20,588	21,031	21,325	21,423	21,323	21,150	21,026	20,870	20,745	21,041	22,088	22,432	22,069	21,381	20,294	18,881	17,483
Winter	2	23,633	2/5/2015	16,508	15,903	15,615	15,525	15,792	16,776	18,741	20,153	20,747	21,260	21,495	21,523	21,381	21,294	21,167	21,180	21,650	22,952	23,633	23,459	22,887	21,905	20,549	19,201
Winter	2	22,829	2/6/2015	18,232	17,702	17,427	17,383	17,626	18,598	20,459	21,730	22,129	22,386	22,461	22,421	22,174	21,845	21,481	21,353	21,581	22,463	22,829	22,426	21,847	21,044	19,918	18,628
Winter	2	20,783	2/7/2015	17,605	16,952	16,507	16,273	16,256	16,548	17,224	17,967	18,848	19,553	19,979	20,124	19,944	19,698	19,486	19,315	19,450	20,362	20,783	20,391	19,860	19,169	18,292	17,295
Winter	2	21,114	2/8/2015	16,373	15,772	15,402	15,149	15,156	15,400	15,873	16,373	17,263	18,074	18,602	18,858	19,009	19,025	19,092	19,209	19,726	20,782	21,114	20,787	20,259	19,448	18,374	17,300
Winter	2	23,242	2/9/2015	16,513	16,065	15,804	15,741	16,068	17,006	18,665	19,971	20,767	21,422	21,887	22,041	22,074	22,051	21,885	21,855	22,165	23,050	23,242	22,831	22,050	20,961	19,480	18,081
Winter	2	22,506	2/10/2015	17,090	16,514	16,199	16,101	16,339	17,300	19,123	20,455	21,008	21,200	21,300	21,223	20,947	20,791	20,598	20,635	20,914	21,919	22,506	22,273	21,696	20,732	19,311	17,960
Winter	2	22,529	2/11/2015	16,978	16,513	16,227	16,228	16,492	17,540	19,516	20,798	21,101	21,313	21,284	21,102	20,818	20,589	20,353	20,371	20,764	21,798	22,529	22,222	21,675	20,622	19,264	17,851
Winter	2	22,826	2/12/2015	16,777	16,257	15,910	15,821	16,054	16,953	18,848	20,074	20,602	20,921	21,045	20,972	20,789	20,742	20,584	20,802	21,201	22,164	22,826	22,635	22,188	21,343	20,062	18,903
Winter	2	23,321	2/13/2015	18,061	17,584	17,367	17,387	17,716	18,673	20,514	21,761	22,306	22,680	22,816	22,560	22,209	21,969	21,732	21,586	21,829	22,693	23,321	23,029	22,513	21,744	20,550	19,326
Winter	2	21,698	2/14/2015	18,393	17,756	17,408	17,198	17,158	17,444	18,041	18,657	19,642	20,402	20,731	20,759	20,555	20,354	20,230	20,182	20,362	21,165	21,698	21,398	20,868	20,169	19,192	18,222
Winter	2	23,163	2/15/2015	17,342	16,840	16,655	16,589	16,678	16,969	17,478	18,007	19,121	20,077	20,640	20,812	20,761	20,592	20,363	20,418	20,951	22,151	23,163	22,887	22,341	21,772	20,926	19,919
Winter	2	23,754	2/16/2015	19,081	18,560	18,260	18,131	18,285	18,911	19,955	20,880	21,755	22,353	22,616	22,667	22,402	22,139	21,973	21,941	22,221	23,110	23,754	23,412	22,805	21,888	20,656	19,403
Winter	2	23,397	2/17/2015	18,429	17,857	17,569	17,506	17,785	18,603	19,976	21,174	21,979	22,479	22,688	22,566	22,286	22,014	21,720	21,557	21,785	22,549	23,397	23,091	22,505	21,600	20,319	19,090
Winter	2	22,839	2/18/2015	18,152	17,642	17,351	17,273	17,539	18,413	19,885	21,024	21,710	22,001	21,971	21,690	21,364	21,180	20,994	20,961	21,247	22,175	22,839	22,467	21,848	21,004	19,713	18,452
Winter	2	24,024	2/19/2015	17,496	16,970	16,711	16,679	16,953	17,844	19,384	20,545	21,321	21,760	21,950	22,090	22,083	22,044	21,918	21,938	22,208	23,102	24,024	23,853	23,360	22,541	21,374	20,171
Winter	2	23,746	2/20/2015	19,187	18,608	18,352	18,307	18,542	19,424	20,895	21,981	22,834	23,331	23,471	23,408	23,105	22,828	22,491	22,287	22,438	23,013	23,746	23,483	22,979	22,323	21,246	20,077
Winter	2	22,108	2/21/2015	19,020	18,448	18,050	17,824	17,805	18,126	18,773	19,416	20,252	20,756	21,008	21,025	20,966	20,819	20,802	20,762	21,016	21,679	22,108	21,766	21,142	20,212	19,191	18,142
Winter	2	20,911	2/22/2015	17,285	16,683	16,230	15,977	15,942	16,121	16,567	16,975	17,823	18,509	18,878	18,867	18,695	18,493	18,278	18,359	18,790	19,909	20,911	20,753	20,260	19,422	18,397	17,362
Winter	2	24,144	2/23/2015	16,584	16,109	15,928	15,925	16,109	17,319	19,264	20,572	21,274	21,871	22,168	22,133	22,009	21,810	21,772	21,805	22,282	23,158	24,144	24,071	23,571	22,628	21,339	19,973
Winter	2	23,955	2/24/2015	18,917	18,365	18,096	18,050	18,375	19,365	21,150	22,275	22,665	22,855	22,894	22,636	22,362	22,209	22,028	21,993	22,207	23,062	23,955	23,584	22,936	21,919	20,417	18,905
Winter	2	22,679	2/25/2015	17,939	17,341	17,027	16,915	17,196	18,136	19,894	21,003	21,344	21,484	21,436	21,221	20,951	20,765	20,597	20,600	20,942	21,642	22,679	22,565	21,949	21,062	19,638	18,323
Winter	2	23,331	2/26/2015	17,454	17,003	16,744	16,726	16,969	17,963	19,823	21,058	21,625	22,026	22,187	22,094	21,754	21,495	21,487	21,590	21,929	22,590	23,331	23,050	22,492	21,530	20,175	18,808
Winter	2	22,501	2/27/2015	17,893	17,365	17,079	17,030	17,292	18,321	20,041	21,171	21,564	21,770	21,750	21,578	21,278	21,095	20,865	20,800	21,014	21,573	22,501	22,349	21,903	21,206	20,183	19,041
Winter	2	21,244	2/28/2015	18,150	17,626	17,329	17,215	17,282	17,659	18,314	19,034	19,808	20,275	20,439	20,259	19,933	19,591	19,290	19,133	19,352	20,046	21,244	21,231	20,838	20,277	19,451	18,581
Spring	3	21,805	3/1/2015	17,761	17,217	16,876	16,682	16,663	16,865	17,216	17,662	18,492	19,000	19,388	19,613	19,743	19,826	19,891	19,967	20,339	21,061	21,805	21,547	20,885	19,879	18,698	17,514
Spring	3	22,544	3/2/2015	16,668	16,214	15,959	15,911	16,160	17,139	18,732	19,914	20,686	21,041	21,183	21,135	20,996	20,894	20,665	20,568	20,786	21,449	22,544	22,397	21,833	20,848	19,488	18,126

SI-SSA-0010

Contains Proprietary Material
Do Not Distribute

Spring	3	22,697	3/3/2015	17,203	16,720	16,485	16,451	16,744	17,829	19,550	20,570	21,035	21,285	21,366	21,328	21,248	21,267	21,254	21,293	21,494	22,106	22,697	22,494	21,857	20,737	19,243	17,791
Spring	3	21,683	3/4/2015	16,731	16,124	15,751	15,599	15,815	16,781	18,472	19,651	20,171	20,434	20,544	20,494	20,293	20,126	20,015	20,137	20,426	21,019	21,683	21,421	20,799	19,855	18,521	17,243
Spring	3	23,122	3/5/2015	16,315	15,803	15,505	15,476	15,776	16,775	18,510	19,828	20,655	21,213	21,635	21,769	21,785	21,722	21,536	21,474	21,720	22,313	23,122	22,963	22,318	21,335	20,013	18,716
Spring	3	22,378	3/6/2015	17,960	17,487	17,240	17,257	17,587	18,603	20,060	21,071	21,438	21,720	21,848	21,730	21,420	21,184	20,920	20,806	20,965	21,472	22,378	22,156	21,626	20,882	19,861	18,671
Spring	3	20,390	3/7/2015	17,693	17,156	16,758	16,614	16,654	17,028	17,596	18,317	19,130	19,543	19,647	19,529	19,325	19,106	18,980	18,913	19,123	19,576	20,390	20,266	19,817	19,076	18,118	17,127
Spring	3	19,580	3/8/2015	16,235	0	15,630	15,303	15,120	15,215	15,604	16,039	16,658	17,314	17,692	17,884	17,938	17,860	17,686	17,491	17,548	17,818	18,330	19,505	19,580	18,956	17,918	16,707
Spring	3	20,238	3/9/2015	15,830	15,364	15,113	15,046	15,268	16,133	18,029	19,485	19,833	19,882	19,816	19,657	19,390	19,133	18,874	18,670	18,722	18,956	19,244	20,238	20,091	19,306	18,017	16,664
Spring	3	20,286	3/10/2015	15,673	15,099	14,801	14,746	14,939	15,934	17,892	19,283	19,579	19,615	19,580	19,457	19,259	19,150	19,011	19,065	19,251	19,536	19,815	20,286	19,884	18,970	17,667	16,306
Spring	3	19,534	3/11/2015	15,342	14,733	14,326	14,170	14,300	15,202	17,175	18,559	18,908	19,045	19,072	18,951	18,781	18,628	18,329	18,201	18,318	18,438	18,637	19,534	19,492	18,665	17,400	16,051
Spring	3	20,127	3/12/2015	15,120	14,600	14,304	14,262	14,439	15,444	17,443	18,833	19,246	19,446	19,557	19,460	19,146	19,012	18,832	18,734	18,787	18,990	19,248	20,127	20,074	19,340	18,028	16,723
Spring	3	19,789	3/13/2015	15,800	15,241	14,959	14,924	15,172	16,087	18,045	19,367	19,700	19,789	19,685	19,434	19,068	18,854	18,528	18,363	18,423	18,515	18,770	19,455	19,273	18,612	17,557	16,418
Spring	3	18,772	3/14/2015	15,363	14,735	14,373	14,194	14,179	14,475	15,233	16,119	17,097	17,978	18,525	18,688	18,574	18,334	18,054	17,920	17,992	18,212	18,433	18,772	18,411	17,616	16,924	15,949
Spring	3	19,419	3/15/2015	15,029	14,381	13,961	13,759	13,767	14,028	14,541	15,200	16,151	17,074	17,598	17,840	17,899	17,809	17,791	17,886	18,053	18,449	18,688	19,419	19,266	18,524	17,387	16,167
Spring	3	19,909	3/16/2015	15,325	14,816	14,519	14,456	14,723	15,688	17,697	18,963	19,287	19,509	19,565	19,436	19,209	19,033	18,753	18,522	18,569	18,791	19,097	19,909	19,713	18,792	17,457	15,981
Spring	3	20,268	3/17/2015	14,887	14,262	13,905	13,796	14,046	15,023	17,030	18,510	19,063	19,431	19,584	19,542	19,408	19,263	19,013	18,901	18,985	19,087	19,266	20,169	20,268	19,531	18,221	16,873
Spring	3	20,950	3/18/2015	15,975	15,491	15,220	15,163	15,417	16,407	18,362	19,554	20,037	20,271	20,352	20,279	20,071	19,942	19,737	19,729	19,835	20,040	20,171	20,950	20,883	20,007	18,696	17,344
Spring	3	20,295	3/19/2015	16,338	15,729	15,453	15,437	15,742	16,759	18,728	19,888	20,208	20,295	20,224	20,047	19,791	19,623	19,357	19,161	19,185	19,329	19,451	20,246	20,269	19,533	18,352	17,056
Spring	3	20,490	3/20/2015	15,982	15,423	15,105	14,997	15,209	16,121	17,957	19,291	19,935	20,285	20,490	20,475	20,322	20,280	20,185	20,133	20,086	20,069	20,020	20,385	20,197	19,403	18,376	17,217
Spring	3	18,639	3/21/2015	16,176	15,512	15,090	14,894	14,884	15,171	15,919	16,722	17,701	18,381	18,616	18,577	18,421	18,173	17,896	17,737	17,691	17,712	17,840	18,493	18,639	18,153	17,372	16,408
Spring	3	19,649	3/22/2015	15,537	14,949	14,599	14,463	14,503	14,783	15,369	15,916	16,738	17,336	17,720	17,814	17,815	17,651	17,472	17,401	17,580	17,953	18,382	19,444	19,649	18,968	17,896	16,798
Spring	3	20,914	3/23/2015	16,006	15,604	15,380	15,382	15,667	16,659	18,539	19,757	20,274	20,511	20,622	20,484	20,258	20,121	19,881	19,661	19,709	19,889	20,073	20,883	20,914	20,083	18,827	17,390
Spring	3	20,382	3/24/2015	16,381	15,876	15,626	15,564	15,839	16,819	18,739	19,977	20,332	20,382	20,333	20,194	19,942	19,712	19,359	19,136	19,104	19,189	19,296	20,043	20,238	19,442	18,072	16,766
Spring	3	20,365	3/25/2015	15,846	15,348	15,091	15,048	15,310	16,284	18,217	19,441	19,755	19,746	19,654	19,473	19,207	19,146	19,204	19,453	19,803	20,113	20,189	20,365	19,994	19,095	17,733	16,341
Spring	3	19,864	3/26/2015	15,327	14,758	14,421	14,284	14,499	15,337	17,308	18,530	19,027	19,341	19,546	19,625	19,617	19,536	19,412	19,351	19,487	19,618	19,594	19,864	19,589	18,675	17,318	16,015
Spring	3	19,680	3/27/2015	15,048	14,450	14,120	13,996	14,224	15,183	17,078	18,415	19,058	19,526	19,680	19,633	19,456	19,369	19,215	19,135	19,097	19,011	18,914	19,310	19,233	18,580	17,573	16,409
Spring	3	19,173	3/28/2015	15,500	14,961	14,628	14,460	14,482	14,806	15,590	16,429	17,453	18,204	18,695	18,762	18,620	18,369	18,121	17,944	17,921	18,084	18,316	18,914	19,173	18,758	17,951	17,008
Spring	3	18,596	3/29/2015	16,152	15,583	15,234	15,082	15,082	15,309	15,795	16,255	16,906	17,339	17,568	17,599	17,477	17,239	16,982	16,817	16,852	17,070	17,352	18,187	18,596	17,996	17,043	15,967
Spring	3	20,279	3/30/2015	15,116	14,640	14,382	14,310	14,555	15,491	17,272	18,672	19,461	19,966	20,279	20,234	19,918	19,606	19,345	19,275	19,308	19,351	19,304	19,697	19,826	18,961	17,682	16,314
Spring	3	19,820	3/31/2015	15,268	14,759	14,385	14,264	14,512	15,473	17,184	18,332	18,854	19,126	19,154	19,138	19,064	19,175	19,086	19,063	19,129	19,243	19,412	19,820	19,769	18,978	17,631	16,354
Spring	4	19,178	4/1/2015	15,345	14,818	14,550	14,501	14,752	15,689	17,337	18,513	18,975	19,139	19,113	18,951	18,709	18,522	18,307	18,151	18,145	18,191	18,220	18,823	19,178	18,570	17,374	16,060
Spring	4	18,842	4/2/2015	15,132	14,534	14,275	14,192	14,419	15,367	16,993	18,058	18,633	18,842	18,815	18,606	18,334	18,125	17,895	17,696	17,749	17,860	17,954	18,486	18,449	17,674	16,493	15,255
Spring	4	17,839	4/3/2015	14,187	13,525	13,124	12,950	13,048	13,697	14,859	15,930	16,885	17,489	17,783	17,839	17,687	17,566	17,382	17,288	17,252	17,297	17,228	17,476	17,395	16,792	15,870	14,829
Spring	4	17,567	4/4/2015	13,877	13,300	12,928	12,737	12,777	13,085	13,721	14,416	15,374	16,158	16,576	16,649	16,538	16,297	16,070	15,957	15,996	16,214	16,440	17,070	17,567	17,167	16,391	15,424
Spring	4	17,062	4/5/2015	14,568	13,890	13,507	13,293	13,310	13,610	14,037	14,533	15,216	15,783	16,092	16,152	16,065	15,881	15,758	15,652	15,640	15,678	15,896	16,644	17,062	16,656	15,763	14,771
Spring	4	18,482	4/6/2015	13,995	13,533	13,295	13,219	13,481	14,401	15,916	17,111	17,832	18,226	18,294	18,201	18,010	17,896	17,703	17,574	17,579	17,772	17,868	18,388	18,482	17,604	16,429	15,123
Spring	4	19,026	4/7/2015	14,130	13,529	13,198	13,086	13,304	14,248	15,799	17,022	17,858	18,349	18,596	18,617	18,545	18,487	18,365	18,270	18,397	18,669	18,744	19,026	18,894	18,067	16,815	15,484
Spring	4	19,521	4/8/2015	14,558	13,994	13,671	13,586	13,806	14,691	16,330	17,597	18,374	18,860	19,181	19,267	19,217	19,183	19,071	19,032	19,187	19,318	19,329	19,521	19,316	18,528	17,248	15,903
Spring	4	19,406	4/9/2015	14,941	14,372	14,025	13,877	14,078	14,939	16,512	17,771	18,594	19,038	19,281	19,277	19,173	19,092	18,920	18,775	18,827	18,992	19,124	19,406	19,282	18,448	17,138	15,829
Spring	4	19,020	4/10/2015	14,853	14,260	13,889	13,728	13,926	14,756	16,307	17,465	18,192	18,675	18,978	19,020	18,820	18,706	18,509	18,359	18,292	18,284	18,090	18,123	18,265	17,623	16,514	15,378
Spring	4	17,148	4/11/2015	14,441	13,763	13,332	13,134	13,137	13,473	14,021	14,729	15,583	16,207	16,538	16,605	16,494	16,266	16,022	15,862	15,866	15,928	16,039	16,515	17,148	16,795	16,069	15,156
Spring	4	16,966	4/12/2015	14,281	13,686	13,364	13,175	13,168	13,403	13,727	14,202	14,841	15,269	15,533	15,578	15,468	15,282	15,109	15,023	15,182	15,474	15,693	16,274	16,966	16,338	15,344	14,250
Spring	4	18,208	4/13/2015	13,369	12,886	12,656	12,604	12,859	13,910	15,686	16,930	17,525	17,766	17,809	17,766	17,673	17,679	17,605	17,560	17,566	17,567	17,432	17,864	18,208	17,343	15,972	14,528
Spring	4	18,116	4/14/2015	13,445	12,862	12,524	12,384	12,563	13,494	15,323	16,646	17,406	17,691	17,902	17,861	17,737	17,734	17,650	17,573	17,639	17,715	17,716	17,965	18,116	17,254	15,945	14,541
Spring	4	17,965	4/15/2015	13,464	12,912	12,633	12,561	12,797	13,797	15,436	16,688	17,197	17,422	17,552	17,522	17,411	17,410	17,330	17,302	17,357	17,386	17,247	17,524	17,965	17,194	15,884	14,499
Spring	4	17,892	4/16/2015	13,495	12,944	12,632	12,579	12,831	13,832	15,492	16,719	17,252	17,497	17,602	17,583	17,438	17,379	17,273	17,189	17,249	17,295	17,213	17,540	17,892	17,102	15,763	14,414
Spring	4	18,136	4/17/2015	13,438	12,854	12,557	12,404	12,552	13,443	15,229	16,591	17,341	17,831	18,114	18,136	18,036	17,925	17,692	17,540	17,526	17,371	17,100	17,184	17,504	16,889	15,824	14,552
Spring	4	16,471	4/18/2015	13,547	12,876	12,476	12,273	12,273	12,550	13,007	13,852	14,805	15,400	15,758	15,861	15,889	15,760	15,619	15,533	15,582	15,680	15,681	15,861	16,471	15,993	15,080	14,091
Spring	4	16,663	4/19/2015	13,227	12,597	12,200	12,000	11,981	12,171	12,381	13,015	13,814	14,471	14,853	14,984	15,010	14,924	14,801	14,784	14,961	15,245	15,522	16,142	16,663	16,023	14,958	13,819
Spring	4	18,858	4/20/2015	12,998	12,534	12,288	12,228	12,456	13,449	15,313	16,878	17,688	18,304	18,694	18,858	18,764	18,651	18,480	18,360	18,391	18,486	18,392	18,480	18,434	17,450	16,040	14,597
Spring	4	18,010	4/21/2015	13,624	13,087	12,712	12,589	12,815	13,702	15,354	16,754	17,513	17,912	18,001	17,953	17,824	17,772	17,624	17,562	17,596	17,636	17,432	17,605	18,010	17,239	15,953	14,540
Spring	4	18,397	4/22/2015	13,568	13,009	12,678	12,581	12,816	13,770	15,379	16,652	17,285	17,641	17,862	17,895	17,896	17,947	17,887	18,021	18,254	18,353	18,270	18,234	18,397	17,572	16,245	14,855
Spring	4	18,962	4/23/2015	13,900	13,358	13,060	12,979	13,242	14,212	15,838	17,126	17,759	18,142	18,336	18,417	18,348	18,283	18,187	18,106	18,274	18,490	18,482	18,667	18,962	18,151	16,761	15,417
Spring	4	18,675	4/24/2015	14,435	13,921	13,603	13,520	13,745	14,661	16,292	17,604	18,249	18,532	18,675	18,650	18,522	18,412	18,220	18,081	18,052	18,010	17,844	17,973	18,431	17,932	16,950	15,702
Spring	4	16,668	4/25/2015	14,669	14,043	13,718	13,553	13,584	13,884	14,329	15,094	15,857	16,273	16,389	16,287	16,081	15,808	15,534	15,368	15,375	15,535	15,649	15,939	16,668	16,393	15,605	14,648
Spring	4	17,014	4/26/2015	13,783	13,224	12,906	12,725	12,743	12,928	13,185	13,836	14,558	15,072	15,340	15,477	15,516	15,464	15,403	15,384	15,616	15,930	16,155	16,475	17,014	16,431	15,386	14,261
Spring	4	18,327	4/27/2015	13,392	12,906	12,581	12,517	12,859	13,838	15,458	16,807	17,548	17,870	17,912	17,987	17,977	17,943	17,877	17,783	17,826	17,939	17,899	18,089	18,327	17,534	16,150	14,771
Spring	4	17,910	4/28/2015	13,732	13,185	12,901	12,777	13,031	13,980	15,548	16,762	17,334	17,617	17,730	17,747	17,682	17,658	17,551	17,498	17,558	17,550	17,355	17,380	17,910	17,279	15,893	14,483
Spring	4	17,948	4/29/2015	13,500	12,935	12,614	12,526	12,744	13,617	15,132	16,513	17,123	17,521	17,728	17,873	17,877	17,911	17,879	17,891	17,948	17,875	17,546	17,432	17,916	17,166	15,767	14,317
Spring	4	17,831	4/30/2015	13,373	12,801	12,448	12,318	12,596	13,455	15,014	16,400	17,071	17,420	17,690	17,756	17,668	17,718	17,660	17,615	17,601	17,496	17,267	17,301	17,831	17,166	15,855	14,432
Spring	5	17,580	5/1/2015	13,449	12,836	12,538	12,430	12,626	13,461	15,012	16,397	17,033	17,349	17,580	17,575	17,449	17,416	17,309	17,169	17,090	16,961	16,745	16,771	17,193	16,731	15,667	14,442
Spring	5	16,216	5/2/2015	13,439	12,867	12,516	12,310	12,341	12,624	13,062	13,963	14,843	15,426	15,704	15,782	15,714	15,598	15,420	15,297	15,355	15,511	15,464	15,612	16,216	15,897	15,055	14,028
Spring	5	16,847	5/3/2015	13,209	12,675	12,291	12,059	12,040	12,154	12,345	13,041	13,882	14,498	14,978	15,246	15,429	15,447	15,455	15,533	15,706	15,932	16,023	16,171	16,847	16,319	15,199	13,986
Spring	5	19,209	5/4/2015	13,106	12,593	12,313	12,236	12,411	13,219	14,804	16,298	17,224	17,819	18,355	18,690	18,931	19,081	19,060	19,132	19,209	19,139	18,759	18,671	18,952	18,181	16,704	15,173
Spring	5	19,846	5/5/2015	14,092	13,371	12,952	12,812	12,958	13,733	15,248	16,846	17,761	18,389	18,934	19,192	19,320	19,515	19,695	19,811	19,846	19,609	19,116	18,900	19,085	18,310	16,850	15,328
Spring	5	18,612	5/6/2015	14,226	13,575	13,171	12,998	13,115	13,921	15,526	17,050	17,777	18,228	18,533	18,612	18,591	18,612	18,527	18,499	18,554	18,491	18,152	17,911	18,260	17,686	16,277	14,768
Spring	5	19,603	5/7/2015	13,688	13,022	12,688	12,548	12,714	13,501	14,978	16,490	17,368	18,051	18,551	18,890	19,052	19,250	19,362	19,472	19,603	19,473	18,961	18,579	18,810	18,208	16,722	15,177
Spring	5	20,708	5/8/2015	14,018	13,347	12,944	12,757	12,899	13,637	15,172	16,699	17,809	18,601	19,272	19,765	20,038	20,333	20,516	20,674	20,708	20,522	19,918	19,373	19,359	18,753	17,470	15,990
Spring	5	18,130	5/9/2015	14,750	13,930	13,426	13,150	13,055	13,198	13,539	14,516	15,695	16,533	17,043	17,328	17,478	17,572	17,705	17,839	17,945	17,959	17,922	17,850	18,130	17,802	16,827	15,674
Spring	5	19,286	5/10/2015	14,650	13,820	13,264	12,987	12,937	12,966	13,110	13,910	15,059	16,118	17,009	17,611	18,001	18,290	18,513	18,777	18,938	18,995	18,895	18,803	19,286	18,901	17,707	16,303
Spring	5	23,036	5/11/2015	15,125	14,477	14,075	13,892	14,057	14,899	16,580	18,363	19,491	20,417	21,252	21,854	22,214	22,667	22,862	23,029	23,036	22,872	22,250	21,612	21,564	20,817	19,138	17,396
Spring	5	22,379	5/12/2015	16,095	15,245	14,730	14,501	14,639	15,412	17,084	18,841	19,927	20,657	21,460	21,953	22,239	22,374	22,379	22,239	22,219	21,972	21,289	20,693	20,741	19,942	18,156	16,232
Spring	5	18,671	5/13/2015	14,869	14,041	13,529	13,283	13,336	14,020	15,478	16,924	17,758	18,217	18,495	18,592	18,667	18,671	18,643	18,604	18,585	18,435	18,009	17,773	17,981	17,493	16,156	14,704
Spring	5	18,354	5/14/2015	13,679	13,054	12,682	12,581	12,760	13,520	15,034	16,429	17,166	17,592	17,722	17,880	17,938	18,079	18,191	18,238	18,354	18,317	17,949	17,604	17,882	17,438	16,035	14,600
Spring	5	18,448	5/15/2015	13,557	12,956	12,600	12,457	12,641	13,400	14,922	16,353	17,151	17,652	18,052	18,239	18,276	18,437	18,442	18,448	18,437	18,190	17,734	17,495	17,704	17,235	16,157	14,924
Spring	5	17,576	5/16/2015	13,929	13,264	12,864	12,651	12,592	12,758	13,177	14,119	15,245	16,087	16,682	16,917	17,100	17,140	17,107	17,155	17,311	17,364	17,313	17,308	17,576	17,312	16,391	15,339
Spring	5	20,000	5/17/2015	14,372	13,650	13,194	12,916	12,828	12,826	13,024	13,878	15,116	16,216	17,075	17,815	18,360	18,726	19,001	19,334	19,753	20,000	19,888	19,568	19,788	19,465	18,080	16,675
Spring	5	20,418	5/18/2015	15,541	14,733	14,257	14,047	14,199	15,002	16,440	17,904	18,860	19,491	19,950	20,167	20,268	20,330	20,370	20,360	20,418	20,314	19,833	19,604	19,574	18,793	17,280	15,698
Spring	5	20,718	5/19/2015	14,613	13,896	13,489	13,306	13,437	14,237	15,823	17,402	18,338	18,850	19,324	19,612	19,700	19,844	20,145	20,511	20,713	20,718	20,182	19,570	19,522	18,926	17,535	16,004
Spring	5	18,351	5/20/2015	14,701	13,855	13,314	13,055	13,160	13,820	15,310	16,825	17,683	18,105	18,280	18,351	18,247	18,196	18,091	18,031	18,023	17,950	17,630	17,483	17,797	17,445	16,153	14,733
Spring	5	18,029	5/21/2015	13,717	13,076	12,722	12,604	12,787	13,530	15,040	16,490	17,180	17,684	17,921	18,029	17,964	17,970	17,921	17,851	17,849	17,801	17,588	17,498	17,742	17,270	16,019	14,625
Spring	5	18,182	5/22/2015	13,615	13,022	12,664	12,513	12,673	13,269	14,580	16,023	16,936	17,509	17,877	18,076	18,156	18,182	18,086	17,950	17,830	17,711	17,433	17,160	17,328	17,127	16,080	14,801
Spring	5	16,151	5/23/2015	13,777	13,109	12,724	12,537	12,500	12,535	12,936	13,740	14,649	15,270	15,614	15,707	15,618	15,498	15,364	15,395	15,529	15,750	15,818	15,760	16,088	16,151	15,362	14,361
Spring	5	16,537	5/24/2015	13,528	12,894	12,519	12,332	12,265	12,224	12,426	13,092	14,013	14,800	15,409	15,780	15,988	16,073	16,117	16,190	16,345	16,430	16,341	16,180	16,534	16,537	15,782	14,790
Spring	5	19,529	5/25/2015	13,885	13,242	12,860	12,594	12,585	12,684	12,993	13,753	14,795	15,891	16,775	17,580	18,126	18,456	18,709	19,043	19,314	19,529	19,434	19,254	19,483	19,224	17,915	16,483
Spring	5	24,285	5/26/2015	15,404	14,636	14,193	13,936	14,037	14,713	16,366	18,260	19,641	20,730	21,640	22,340	22,892	23,433	23,790	24,108	24,285	24,070	23,362	22,635	22,373	21,826	20,121	18,277
Spring	5	24,190	5/27/2015	16,892	15,994	15,415	15,113	15,200	15,873	17,587	19,434	20,637	21,477	22,264	22,800	23,046	23,537	23,871	24,094	24,190	23,881	22,968	22,178	21,922	21,226	19,552	17,794
Spring	5	23,754	5/28/2015	16,455	15,649	15,163	14,912	14,979	15,706	17,280	19,023	20,003	20,726	21,209	21,940	22,440	22,988	23,350	23,606	23,754	23,462	22,700	21,997	21,705	21,187	19,467	17,597
Spring	5	23,435	5/29/2015	16,133	15,193	14,611	14,280	14,341	14,862	16,362	18,086	19,347	20,264	21,016	21,608	22,084	22,538	22,908	23,293	23,435	23,017	22,025	21,182	20,837	20,473	19,278	17,777
Spring	5	22,447	5/30/2015	16,476	15,548	14,969	14,625	14,537	14,586	15,113	16,377	17,912	19,248	20,406	21,244	21,755	22,072	22,338	22,423	22,447	22,210	21,646	20,976	20,650	20,324	19,219	17,879
Spring	5	19,841	5/31/2015	16,671	15,724	15,088	14,639	14,376	14,260	14,423	15,138	16,332	17,499	18,444	19,200	19,667	19,841	19,813	19,754	19,508	19,515	19,361	19,215	19,193	18,484	17,165	15,634
Summer	6	19,071	6/1/2015	14,495	13,863	13,486	13,320	13,459	14,195	15,746	17,305	18,070	18,602	18,984	19,071	19,014	18,898	18,732	18,602	18,553	18,582	18,297	18,073	17,979	17,305	15,968	14,586
Summer	6	18,382	6/2/2015	13,606	13,014	12,639	12,490	12,660	13,394	14,911	16,460	17,354	17,896	18,241	18,382	18,339	18,307	18,173	18,093	18,128	18,142	17,942	17,697	17,711	17,314	15,970	14,552
Summer	6	18,600	6/3/2015	13,533	12,954	12,575	12,428	12,620	13,315	14,861	16,296	17,082	17,526	17,794	17,969	18,068	18,292	18,385	18,490	18,600	18,530	18,099	17,721	17,803	17,644	16,278	14,760
Summer	6	18,696	6/4/2015	13,677	13,015	12,629	12,452	12,603	13,210	14,729	16,246	17,151	17,729

Contains Proprietary Material
Do Not Distribute

Summer	6	26,231	6/12/2015	18,513	17,465	16,776	16,284	16,156	16,622	18,113	19,864	21,172	22,220	23,165	23,925	24,387	25,028	25,645	26,231	26,179	25,676	24,883	24,147	23,769	23,265	21,851	20,201
Summer	6	22,589	6/13/2015	18,742	17,831	17,156	16,628	16,366	16,245	16,665	17,793	19,053	20,018	20,631	21,100	21,390	21,600	21,838	22,143	22,467	22,589	22,236	21,515	20,938	20,776	19,707	18,314
Summer	6	22,719	6/14/2015	17,051	16,069	15,425	15,018	14,812	14,626	14,847	15,857	17,263	18,676	19,860	20,823	21,505	21,947	22,247	22,484	22,658	22,719	22,246	21,702	21,732	21,321	19,973	18,329
Summer	6	24,111	6/15/2015	17,116	16,284	15,778	15,547	15,698	16,517	18,107	19,895	21,079	21,897	22,508	23,006	23,531	23,930	24,111	24,017	23,734	23,298	22,558	21,865	21,463	20,961	19,465	17,750
Summer	6	23,396	6/16/2015	16,450	15,626	15,111	14,907	15,061	15,871	17,442	19,254	20,426	21,126	21,702	22,127	22,420	22,691	22,733	22,987	23,396	23,394	22,958	22,554	22,153	21,707	20,048	18,174
Summer	6	22,746	6/17/2015	16,702	15,733	15,099	14,739	14,766	15,230	16,822	18,682	19,974	20,856	21,520	22,035	22,328	22,630	22,746	22,625	22,365	21,849	21,086	20,515	20,322	20,048	18,671	17,096
Summer	6	21,701	6/18/2015	15,837	15,106	14,596	14,346	14,423	15,053	16,551	18,246	19,404	20,145	20,694	21,059	21,339	21,627	21,701	21,664	21,628	21,425	20,897	20,505	20,346	20,021	18,682	17,124
Summer	6	23,993	6/19/2015	15,854	15,143	14,676	14,477	14,573	15,257	16,831	18,607	19,842	20,868	21,688	22,494	23,012	23,396	23,608	23,821	23,993	23,681	22,858	22,001	21,408	21,106	19,937	18,371
Summer	6	18,735	6/20/2015	16,913	15,837	15,114	14,637	14,419	14,270	14,588	15,484	16,641	17,576	18,292	18,604	18,735	18,696	18,633	18,562	18,586	18,685	18,672	18,592	18,711	18,636	17,891	16,901
Summer	6	23,277	6/21/2015	15,922	15,246	14,800	14,550	14,426	14,394	14,616	15,453	16,682	17,954	19,186	20,261	21,172	21,791	22,180	22,594	23,126	23,277	22,728	22,196	21,912	21,962	20,839	19,274
Summer	6	26,544	6/22/2015	17,864	16,876	16,288	15,897	15,885	16,370	17,876	19,782	21,275	22,342	23,247	23,969	24,511	25,132	25,716	26,232	26,544	26,452	25,875	25,136	24,672	24,195	22,491	20,513
Summer	6	28,100	6/23/2015	18,963	17,916	17,334	17,017	17,023	17,650	19,391	21,418	23,251	24,529	25,470	26,474	27,213	27,623	27,987	28,100	27,890	27,726	26,793	25,863	24,981	24,234	22,542	20,639
Summer	6	24,895	6/24/2015	18,896	17,672	16,658	16,033	15,886	16,238	17,684	19,466	20,762	21,729	22,508	23,106	23,521	23,973	24,332	24,684	24,832	24,895	24,254	23,382	22,547	22,157	20,634	18,734
Summer	6	24,007	6/25/2015	17,231	16,211	15,500	15,097	15,051	15,440	16,889	18,720	20,156	21,252	22,115	22,789	23,279	23,731	23,934	24,007	23,856	23,319	22,483	21,901	21,673	21,363	20,124	18,548
Summer	6	23,412	6/26/2015	17,221	16,260	15,652	15,334	15,362	15,874	17,224	18,893	20,224	21,193	21,963	22,339	22,669	22,970	23,226	23,360	23,412	23,170	22,349	21,391	20,735	20,462	19,310	17,800
Summer	6	18,483	6/27/2015	16,514	15,605	15,004	14,612	14,451	14,402	14,771	15,668	16,856	17,658	18,191	18,475	18,483	18,310	18,097	17,872	17,707	17,655	17,549	17,461	17,480	17,152	16,269	15,296
Summer	6	17,787	6/28/2015	14,461	13,844	13,437	13,204	13,127	13,145	13,284	13,850	14,822	15,795	16,534	16,975	17,118	17,105	17,119	17,180	17,349	17,569	17,613	17,583	17,787	17,762	16,852	15,760
Summer	6	20,932	6/29/2015	14,824	14,090	13,606	13,390	13,499	14,049	15,409	17,048	18,367	19,284	19,926	20,319	20,543	20,795	20,904	20,856	20,865	20,932	20,571	20,104	19,780	19,643	18,389	16,839
Summer	6	22,663	6/30/2015	15,596	14,853	14,426	14,202	14,197	14,789	16,151	17,916	19,310	20,340	21,177	21,770	22,002	22,186	22,377	22,660	22,663	22,379	21,772	21,177	20,938	20,721	19,589	18,160
Summer	7	23,804	7/1/2015	16,891	16,027	15,541	15,283	15,304	15,874	17,161	18,690	19,956	20,971	21,849	22,471	22,809	23,260	23,606	23,778	23,804	23,664	22,984	22,262	21,746	21,525	20,149	18,493
Summer	7	22,337	7/2/2015	17,090	16,052	15,356	14,936	14,884	15,314	16,591	18,271	19,470	20,364	21,181	21,714	22,057	22,313	22,337	22,136	21,972	21,717	21,071	20,473	20,195	19,896	18,717	17,352
Summer	7	20,675	7/3/2015	16,108	15,179	14,519	14,107	13,947	13,996	14,541	15,620	16,746	17,752	18,535	19,062	19,430	19,745	20,061	20,435	20,675	20,585	20,138	19,525	19,172	19,034	18,112	16,956
Summer	7	18,211	7/4/2015	15,872	15,036	14,479	14,118	13,930	13,891	14,069	14,758	15,804	16,822	17,572	17,963	18,211	18,192	18,058	17,974	18,087	18,168	17,927	17,503	17,246	17,159	16,777	16,141
Summer	7	21,343	7/5/2015	15,281	14,584	14,057	13,744	13,582	13,440	13,566	14,354	15,567	16,691	17,785	18,706	19,403	19,949	20,348	20,764	21,148	21,343	21,123	20,670	20,539	20,580	19,517	18,130
Summer	7	25,621	7/6/2015	16,923	16,095	15,537	15,261	15,325	15,803	17,065	18,915	20,549	22,019	23,238	24,085	24,614	25,089	25,381	25,580	25,621	25,415	24,683	23,922	23,446	23,139	21,698	19,969
Summer	7	28,172	7/7/2015	18,563	17,683	17,136	16,843	16,974	17,651	19,086	21,006	22,626	23,979	25,154	26,127	26,871	27,642	28,023	28,043	28,172	27,882	27,070	26,232	25,652	25,164	23,422	21,433
Summer	7	26,609	7/8/2015	19,820	18,682	17,953	17,588	17,523	18,064	19,436	21,111	22,320	23,232	24,050	24,785	25,462	26,092	26,609	26,567	26,146	25,603	24,933	24,309	24,012	23,595	22,139	20,337
Summer	7	22,900	7/9/2015	18,834	17,785	17,114	16,565	16,456	16,926	18,037	19,574	20,610	21,271	21,701	22,044	22,253	22,481	22,513	22,624	22,900	22,857	22,253	21,692	21,529	21,057	19,883	18,562
Summer	7	24,406	7/10/2015	17,437	16,648	16,174	15,896	15,858	16,283	17,452	19,155	20,465	21,391	22,189	22,674	23,087	23,491	23,829	24,157	24,406	24,314	23,604	22,764	22,069	21,683	20,442	18,890
Summer	7	23,172	7/11/2015	17,542	16,522	15,829	15,339	15,120	15,003	15,330	16,405	17,807	19,188	20,355	21,167	21,757	22,119	22,434	22,793	23,092	23,172	22,879	22,183	21,652	21,465	20,481	19,160
Summer	7	23,904	7/12/2015	17,903	16,963	16,143	15,664	15,322	15,109	15,214	16,110	17,531	19,027	20,405	21,492	22,278	22,872	23,310	23,713	23,904	23,869	23,592	23,129	22,878	22,811	21,618	20,031
Summer	7	27,754	7/13/2015	18,648	17,678	17,059	16,744	16,749	17,299	18,562	20,485	22,146	23,643	24,805	25,711	26,447	27,045	27,430	27,638	27,754	27,462	26,490	25,448	24,677	24,171	22,533	20,667
Summer	7	25,453	7/14/2015	19,115	18,074	17,407	17,038	17,023	17,647	19,033	20,947	22,425	23,562	24,223	24,749	25,029	25,107	25,085	25,120	25,380	25,453	24,857	24,310	24,079	23,792	22,418	20,657
Summer	7	23,901	7/15/2015	19,250	18,248	17,552	17,163	17,112	17,671	19,059	20,712	21,839	22,736	23,301	23,508	23,527	23,596	23,625	23,729	23,901	23,707	22,940	22,142	21,618	21,151	19,685	17,980
Summer	7	22,715	7/16/2015	16,630	15,663	15,002	14,592	14,540	15,035	16,164	17,749	18,956	19,867	20,492	20,919	21,250	21,705	22,037	22,412	22,689	22,715	22,149	21,361	20,816	20,507	19,174	17,638
Summer	7	23,069	7/17/2015	16,378	15,565	14,909	14,627	14,690	15,234	16,421	18,124	19,464	20,593	21,453	22,002	22,390	22,748	22,915	23,010	23,069	22,853	22,089	21,277	20,997	20,766	19,771	18,450
Summer	7	24,465	7/18/2015	17,358	16,506	15,986	15,683	15,602	15,754	16,144	17,101	18,411	19,591	20,587	21,495	22,173	22,605	23,108	23,766	24,361	24,465	24,179	23,633	23,364	23,158	22,109	20,827
Summer	7	27,776	7/19/2015	19,556	18,598	17,872	17,371	17,088	16,891	16,973	18,035	19,809	21,644	23,480	24,852	25,865	26,574	27,160	27,606	27,776	27,687	27,249	26,653	26,495	26,295	24,962	23,353
Summer	7	30,575	7/20/2015	21,942	20,979	20,325	19,920	19,880	20,439	21,566	23,560	25,433	26,899	28,117	29,064	29,652	30,212	30,449	30,575	30,573	30,329	29,625	28,794	28,220	27,474	25,559	23,448
Summer	7	27,893	7/21/2015	21,655	20,427	19,609	19,135	19,093	19,705	20,945	22,502	23,829	24,820	25,761	26,304	26,704	26,983	27,281	27,668	27,893	27,588	26,718	25,749	24,893	24,331	22,717	20,735
Summer	7	24,949	7/22/2015	19,104	17,869	16,958	16,499	16,382	16,762	17,858	19,575	20,913	21,899	22,666	23,237	23,643	24,129	24,480	24,793	24,949	24,823	23,991	23,010	22,454	22,034	20,643	18,910
Summer	7	24,622	7/23/2015	17,525	16,569	15,857	15,496	15,465	15,978	17,195	18,966	20,338	21,380	22,168	22,759	23,137	23,565	23,998	24,380	24,622	24,525	23,809	22,920	22,272	21,853	20,432	18,680
Summer	7	24,579	7/24/2015	17,289	16,345	15,733	15,399	15,369	15,859	16,947	18,715	20,126	21,213	22,151	22,787	23,230	23,685	24,069	24,370	24,579	24,437	23,687	22,822	22,282	21,885	20,623	19,110
Summer	7	22,978	7/25/2015	17,746	16,742	16,029	15,550	15,331	15,333	15,614	16,676	18,073	19,366	20,448	21,214	21,750	22,110	22,440	22,749	22,978	22,967	22,568	21,933	21,774	21,619	20,700	19,497
Summer	7	24,389	7/26/2015	18,314	17,368	16,694	16,244	16,001	15,951	16,007	16,711	17,934	19,368	20,708	21,810	22,705	23,434	23,936	24,206	24,360	24,389	23,862	23,424	23,420	23,103	21,752	20,232
Summer	7	28,345	7/27/2015	18,901	18,017	17,423	17,098	17,160	17,887	19,037	20,720	22,241	23,602	24,698	25,622	26,406	27,154	27,711	28,106	28,345	28,276	27,555	26,649	26,042	25,460	23,726	21,760
Summer	7	30,434	7/28/2015	20,143	19,034	18,285	17,813	17,765	18,380	19,645	21,638	23,515	25,164	26,621	27,746	28,524	29,215	29,742	30,148	30,434	30,278	29,510	28,442	27,741	27,077	25,258	23,174
Summer	7	31,138	7/29/2015	21,427	20,162	19,264	18,721	18,622	19,144	20,312	22,279	24,149	25,870	27,446	28,617	29,451	30,211	30,687	30,938	31,138	30,975	30,354	29,427	28,851	28,245	26,387	24,267
Summer	7	28,775	7/30/2015	22,465	21,222	20,389	19,934	19,906	20,510	21,763	23,507	24,969	26,030	26,908	27,686	28,307	28,722	28,775	28,435	28,035	27,532	26,886	26,131	25,682	25,224	23,679	21,879
Summer	7	27,615	7/31/2015	20,324	19,228	18,417	17,863	17,689	18,033	19,022	20,802	22,411	23,711	24,823	25,626	26,210	26,774	27,175	27,497	27,615	27,371	26,468	25,350	24,549	23,935	22,526	20,894
Summer	8	24,132	8/1/2015	19,452	18,358	17,554	17,033	16,778	16,771	16,946	18,018	19,623	21,130	22,305	22,994	23,543	23,730	23,880	24,044	24,132	24,034	23,565	22,843	22,465	22,106	20,959	19,550
Summer	8	24,325	8/2/2015	18,278	17,302	16,564	16,039	15,703	15,535	15,494	16,421	17,877	19,320	20,658	21,605	22,316	22,840	23,228	23,678	24,107	24,325	24,028	23,448	23,438	23,242	22,185	20,654
Summer	8	28,275	8/3/2015	19,395	18,419	17,758	17,432	17,440	18,039	19,231	21,058	22,714	24,032	25,138	25,968	26,658	27,369	27,851	28,119	28,275	27,957	27,046	26,177	25,789	25,188	23,519	21,703
Summer	8	27,615	8/4/2015	20,199	19,198	18,545	18,219	17,811	18,155	19,231	20,714	22,064	23,436	24,716	25,664	26,354	26,994	27,356	27,533	27,615	27,289	26,398	25,371	24,885	24,127	22,388	20,524
Summer	8	25,757	8/5/2015	19,066	17,966	17,202	16,832	16,736	17,255	18,364	19,965	21,273	22,411	23,415	24,147	24,663	25,109	25,419	25,656	25,757	25,405	24,504	23,639	23,211	22,673	21,134	19,395
Summer	8	24,049	8/6/2015	17,921	16,881	16,190	15,755	15,730	16,244	17,298	18,926	20,237	21,291	22,071	22,622	22,952	23,376	23,748	24,013	24,049	23,738	22,971	22,308	22,222	21,708	20,394	18,875
Summer	8	24,098	8/7/2015	17,592	16,677	16,056	15,636	15,611	16,151	17,135	18,750	20,155	21,306	22,178	22,793	23,160	23,519	23,734	23,957	24,098	23,931	23,152	22,244	21,809	21,207	19,937	18,465
Summer	8	20,977	8/8/2015	17,221	16,240	15,589	15,162	14,995	15,079	15,321	16,261	17,522	18,674	19,580	20,141	20,412	20,591	20,806	20,945	20,977	20,761	20,330	19,942	20,071	19,843	18,932	17,859
Summer	8	21,862	8/9/2015	16,921	16,114	15,454	15,023	14,804	14,789	14,813	15,612	16,873	17,929	18,919	19,693	20,263	20,675	21,019	21,275	21,640	21,862	21,637	21,055	21,102	20,825	19,653	18,273
Summer	8	25,010	8/10/2015	17,148	16,354	15,865	15,638	15,759	16,469	17,612	19,337	20,818	22,053	23,015	23,753	24,268	24,751	24,992	25,010	24,793	24,351	23,578	23,003	22,913	22,192	20,843	19,391
Summer	8	24,598	8/11/2015	18,180	17,332	16,821	16,582	16,710	17,473	18,858	20,263	21,337	22,141	22,734	23,085	23,339	23,695	23,927	24,301	24,598	24,494	23,972	23,335	23,100	22,453	21,034	19,433
Summer	8	24,960	8/12/2015	18,019	17,012	16,347	16,014	15,978	16,575	17,740	19,383	20,740	21,766	22,630	23,279	23,675	24,119	24,496	24,767	24,960	24,761	23,909	23,054	22,841	22,151	20,659	18,958
Summer	8	24,374	8/13/2015	17,524	16,522	15,850	15,455	15,436	16,027	17,119	18,768	20,149	21,224	22,063	22,671	23,126	23,553	23,872	24,178	24,374	24,262	23,550	22,631	22,455	21,784	20,359	18,706
Summer	8	25,722	8/14/2015	17,390	16,500	15,859	15,495	15,455	16,028	17,146	18,756	20,340	21,588	22,525	23,311	24,014	24,699	25,214	25,560	25,722	25,386	24,506	23,570	23,355	22,668	21,361	19,928
Summer	8	25,348	8/15/2015	18,584	17,565	16,873	16,390	16,152	16,186	16,380	17,416	18,943	20,483	21,908	23,026	23,865	24,472	24,864	25,216	25,348	25,157	24,573	23,791	23,689	23,127	22,013	20,633
Summer	8	25,910	8/16/2015	19,344	18,325	17,562	17,056	16,702	16,633	16,602	17,343	18,874	20,395	21,893	23,256	24,356	25,058	25,434	25,568	25,797	25,910	25,579	24,943	25,040	24,422	23,024	21,380
Summer	8	30,543	8/17/2015	20,047	19,083	18,392	18,006	18,001	18,640	19,771	21,550	23,263	24,967	26,555	27,874	28,941	29,758	30,171	30,382	30,543	30,408	29,558	28,526	28,192	27,047	25,090	23,013
Summer	8	29,569	8/18/2015	21,303	20,146	19,320	18,827	18,775	19,397	20,535	22,236	23,886	25,333	26,807	28,084	28,830	29,381	29,569	29,536	29,354	29,075	28,174	27,298	27,066	26,082	24,277	22,419
Summer	8	29,550	8/19/2015	20,864	19,829	19,112	18,763	18,747	19,433	20,758	22,443	24,142	25,572	26,831	27,784	28,467	29,038	29,371	29,550	29,417	29,038	28,259	27,482	27,382	26,473	24,816	22,911
Summer	8	28,651	8/20/2015	21,428	20,367	19,664	19,289	19,294	20,026	21,273	22,931	24,559	26,003	27,092	27,878	28,276	28,581	28,651	28,557	28,382	27,780	26,823	26,281	26,053	25,248	23,722	21,992
Summer	8	25,483	8/21/2015	20,554	19,449	18,694	18,251	18,164	18,694	19,721	20,866	21,935	22,662	23,389	23,995	24,348	24,739	25,071	25,316	25,483	25,315	24,507	23,683	23,461	22,589	21,160	19,594
Summer	8	22,004	8/22/2015	18,204	17,186	16,476	15,927	15,617	15,631	15,762	16,471	17,834	18,983	19,856	20,498	20,976	21,279	21,591	21,832	21,990	22,004	21,586	20,930	20,932	20,274	19,213	18,020
Summer	8	22,867	8/23/2015	16,962	16,168	15,594	15,254	15,117	15,187	15,240	15,944	17,070	18,284	19,368	20,268	20,996	21,610	21,955	22,239	22,613	22,867	22,644	22,290	22,605	21,972	20,782	19,465
Summer	8	26,483	8/24/2015	18,290	17,491	16,939	16,693	16,794	17,514	18,783	20,318	21,796	22,980	23,957	24,825	25,366	25,903	26,222	26,451	26,483	26,230	25,313	24,584	24,564	23,598	22,024	20,228
Summer	8	27,036	8/25/2015	18,850	17,985	17,363	17,111	17,179	17,941	19,245	20,704	22,159	23,338	24,435	25,206	25,865	26,460	26,848	27,026	27,036	26,747	25,789	25,062	24,754	23,558	21,700	19,726
Summer	8	23,823	8/26/2015	18,162	17,092	16,360	15,918	15,873	16,475	17,576	18,993	20,261	21,261	22,023	22,553	22,990	23,450	23,758	23,823	23,794	23,475	22,702	22,181	22,146	21,222	19,767	18,235
Summer	8	22,374	8/27/2015	17,003	16,169	15,592	15,295	15,309	15,938	17,050	18,453	19,780	20,732	21,426	21,890	22,103	22,160	22,299	22,374	22,368	22,291	21,647	21,136	21,159	20,288	18,880	17,449
Summer	8	22,692	8/28/2015	16,203	15,383	14,847	14,587	14,613	15,231	16,361	17,741	19,012	20,069	20,848	21,360	21,652	22,008	22,279	22,520	22,692	22,480	21,761	21,141	21,035	20,190	18,976	17,625
Summer	8	21,578	8/29/2015	16,348	15,469	14,901	14,560	14,412	14,553	14,861	15,661	17,006	18,248	19,242	19,975	20,416	20,700	20,998	21,313	21,578	21,556	21,088	20,739	20,902	20,240	19,268	18,190
Summer	8	23,452	8/30/2015	17,103	16,246	15,689	15,282	15,077	15,119	15,224	15,814	17,117	18,446	19,736	20,912	21,855	22,552	23,100	23,385	23,452	23,441	23,156	23,129	23,430	22,707	21,525	20,059
Summer	8	28,661	8/31/2015	18,811	17,918	17,400	17,097	17,167	17,995	19,299	20,823	22,397	23,702	24,878	25,842	26,597	27,384	28,060	28,433	28,661	28,426	27,582	27,035	26,879	25,681	23,847	21,904
Fall	9	28,425	9/1/2015	20,324	19,189	18,396	17,925	17,879	18,497	19,828	21,282	22,711	23,975	25,153	26,070	26,776	27,398	27,853	28,205	28,425	28,136	27,104	26,349	26,067	24,727	22,898	20,971
Fall	9	28,978	9/2/2015	19,455	18,383	17,706	17,301	17,318	18,071	19,472	20,917	22,329	23,724	25,027	26,215	27,176	27,968	28,630	28,978	28,961	28,479	27,439	26,854	26,646	25,384	23,567	21,697
Fall	9	29,420	9/3/2015	20,134	19,098	18,377	17,947	17,904	18,593	20,048	21,509	22,921	24,212	25,471	26,582	27,564	28,516	29,176	29,401	29,420	29,082	28,065	27,559	27,255	25,961	24,041	22,080
Fall	9	26,616	9/4/2015	20,508	19,398	18,662	18,151	18,106	18,742	20,024	21,379	22,867	24,133	24,999	25,517	25,772	26,085	26,373	26,590	26,616	26,276	25,217	24,445	23,969	22,818	21,337	19,693
Fall	9	22,888	9/5/2015	18,333	17,335	16,575	16,067	15,828	15,882	16,104	16,822	18,095	19,334	20,320	21,021	21,595	22,015	22,395	22,701	22,888	22,826	22,198	21,681	21,537	20,695	19,525	18,205
Fall	9	22,713	9/6/2015	17,042	16,139	15,525	15,108	14,886	14,888	14,966	15,523	16,834	18,168	19,354	20,378	21,236	21,848	22,256	22,533	22,713	22,589	21,979	21,621	21,539	20,830	19,768	18,559
Fall	9	26,257	9/7/2015	17,476	16,641	16,088	15,740	15,622	15,786	16,036	16,762	18,246	19,843	21,345	22,627	23,655	24,485	25,173	25,778	26,209	26,257	25,765	25,685	25,777	24,675	22,948	21,163
Fall	9	31,058	9/8/2015	19,807	18,847	18,170	17,814	17,819	18,603	20,283	21,801	23,459	25,039	26,526	27,987	29,214	30,173	30,734	31,010	31,058	30,744	29,753	29,370	28,902	27,396	25,141	22,926
Fall	9	29,426	9/9/2015	21,264	20,061	19,326	18,900	18,902	19,794	21,606	23,095	24,421	25,807	26,926	27,880	28,554	29,119	29,325	29,426	29,139	28,604	27,647	27,388	27,166	25,911	23,974	22,051
Fall	9	23,969	9/10/2015	20,459	19,341	18,527	18,134	18,082	18,748	20,374	21,553	22,386	23,056	23,506	23,734	23,795	23,923	23,874	23,928	23,969	23,830	23,362	23,330	23,044	21,980	20,452	18,785
Fall	9	23,351	9/11/2015	17,489	16,567	15,938	15,586	15,613	16,372	18,010	19,205	20,111	20,836	21,386	21,746	22,024	22,464	22,815	23,108	23,351	23,169	22,392	22,137	21,724	20,781	19,509	18,141
Fall	9	20,384	9/12/2015	16,927	16,013	15,417	15,075	14,944	15,131	15,575	16,353	17,666	18,860	19,608	20,024	20,237	20,314	20,265	20,115	20,019	20,114	20,191	20,384	20,115	19,505	18,551	17,433
Fall	9	19,850	9/13/2015	16,419	15,666	15,166	14,823	14,685	14,737	14,972	15,420	16,406	17

Contains Proprietary Material
Do Not Distribute

Fall	9	19,855	9/21/2015	14,418	13,804	13,428	13,269	13,438	14,333	16,059	17,190	17,998	18,593	19,036	19,263	19,442	19,626	19,609	19,558	19,622	19,614	19,491	19,855	19,348	18,263	16,893	15,480
Fall	9	19,802	9/22/2015	14,399	13,691	13,360	13,195	13,384	14,246	16,119	17,357	18,097	18,666	19,086	19,351	19,496	19,636	19,703	19,766	19,802	19,704	19,372	19,725	19,244	18,182	16,852	15,498
Fall	9	20,482	9/23/2015	14,540	13,852	13,446	13,280	13,426	14,199	15,633	16,752	17,627	18,285	18,799	19,115	19,419	19,809	20,045	20,249	20,482	20,362	19,899	20,111	19,610	18,489	17,015	15,641
Fall	9	21,303	9/24/2015	14,649	14,004	13,587	13,349	13,489	14,292	15,933	17,110	18,054	18,777	19,394	19,856	20,197	20,586	20,844	21,102	21,303	21,132	20,580	20,872	20,324	19,208	17,744	16,285
Fall	9	20,140	9/25/2015	15,158	14,417	13,944	13,732	13,839	14,618	16,297	17,473	18,313	18,924	19,405	19,706	19,871	20,078	20,140	20,128	20,002	19,661	19,312	19,508	18,967	18,080	16,880	15,632
Fall	9	17,717	9/26/2015	14,588	13,902	13,454	13,217	13,147	13,388	13,948	14,577	15,593	16,366	16,790	16,966	17,027	17,025	17,018	17,013	17,064	17,105	17,192	17,717	17,405	16,728	15,815	14,845
Fall	9	18,255	9/27/2015	14,021	13,396	12,970	12,758	12,703	12,851	13,164	13,475	14,421	15,184	15,711	16,053	16,271	16,442	16,602	16,773	17,058	17,391	17,643	18,255	17,927	17,043	15,973	14,959
Fall	9	21,354	9/28/2015	14,112	13,585	13,345	13,266	13,481	14,418	16,311	17,667	18,503	19,174	19,646	20,020	20,221	20,430	20,627	20,894	21,072	21,038	20,931	21,354	20,678	19,577	18,185	16,824
Fall	9	22,937	9/29/2015	15,742	15,091	14,736	14,546	14,724	15,626	17,709	19,138	20,158	20,998	21,701	22,236	22,641	22,937	22,843	22,772	22,767	22,758	22,707	22,811	22,125	21,024	19,462	17,882
Fall	9	22,116	9/30/2015	16,700	16,039	15,604	15,292	15,418	16,385	18,377	19,925	20,804	21,490	21,967	22,116	22,065	21,908	21,213	20,724	20,613	20,400	20,191	20,332	19,545	18,357	16,897	15,424
Fall	10	18,899	10/1/2015	14,355	13,711	13,238	12,969	13,088	13,917	15,715	16,925	17,529	17,927	18,177	18,218	18,167	18,151	18,091	18,069	18,132	18,296	18,576	18,899	18,371	17,346	16,042	14,761
Fall	10	18,581	10/2/2015	13,791	13,147	12,791	12,618	12,775	13,633	15,428	16,702	17,380	17,818	18,071	18,130	18,060	18,106	18,033	17,998	18,109	18,236	18,451	18,581	18,041	17,224	16,147	14,964
Fall	10	17,538	10/3/2015	13,905	13,255	12,899	12,703	12,717	13,035	13,684	14,404	15,461	16,268	16,752	16,905	16,909	16,763	16,653	16,589	16,676	16,899	17,302	17,538	17,164	16,594	15,735	14,730
Fall	10	17,444	10/4/2015	13,852	13,198	12,786	12,542	12,493	12,700	13,115	13,553	14,453	15,190	15,576	15,676	15,610	15,526	15,462	15,563	15,766	16,116	16,683	17,444	17,072	16,294	15,220	14,182
Fall	10	18,959	10/5/2015	13,350	12,849	12,591	12,529	12,754	13,684	15,528	16,810	17,392	17,733	17,907	17,966	17,947	17,971	17,904	17,854	17,932	18,090	18,419	18,959	18,431	17,404	16,040	14,702
Fall	10	19,179	10/6/2015	13,696	13,147	12,789	12,645	12,861	13,719	15,556	16,769	17,313	17,671	17,889	17,951	18,023	18,125	18,176	18,273	18,478	18,607	18,873	19,179	18,578	17,538	16,170	14,813
Fall	10	19,323	10/7/2015	13,822	13,197	12,835	12,677	12,830	13,679	15,536	16,760	17,404	17,816	18,043	18,233	18,327	18,474	18,545	18,667	18,790	18,858	19,043	19,323	18,663	17,625	16,251	14,899
Fall	10	19,113	10/8/2015	13,869	13,270	12,885	12,744	12,909	13,817	15,717	16,962	17,543	17,939	18,171	18,256	18,310	18,402	18,382	18,359	18,464	18,470	18,759	19,113	18,524	17,538	16,225	14,853
Fall	10	19,457	10/9/2015	13,866	13,308	12,972	12,854	13,030	13,894	15,725	17,134	18,008	18,603	18,989	19,211	19,256	19,326	19,386	19,364	19,407	19,439	19,457	19,206	18,527	17,667	16,562	15,273
Fall	10	17,043	10/10/2015	14,125	13,404	12,923	12,612	12,563	12,835	13,464	14,127	14,998	15,592	15,858	15,889	15,779	15,634	15,515	15,463	15,642	15,913	16,544	17,043	16,728	16,136	15,335	14,458
Fall	10	17,217	10/11/2015	13,607	12,979	12,551	12,338	12,299	12,494	12,967	13,459	14,235	14,867	15,217	15,357	15,409	15,396	15,403	15,487	15,767	16,106	16,699	17,217	16,830	16,144	15,260	14,280
Fall	10	19,162	10/12/2015	13,420	12,857	12,530	12,406	12,567	13,300	14,585	15,710	16,744	17,439	17,828	18,057	18,206	18,296	18,381	18,448	18,600	18,637	18,923	19,162	18,447	17,435	16,097	14,773
Fall	10	19,571	10/13/2015	13,715	13,102	12,784	12,658	12,838	13,784	15,716	17,105	17,754	18,281	18,698	18,921	19,022	19,054	18,877	18,922	18,936	19,027	19,422	19,571	18,830	17,792	16,393	14,968
Fall	10	18,987	10/14/2015	13,835	13,250	12,873	12,695	12,834	13,662	15,553	16,897	17,482	17,897	18,096	18,177	18,203	18,272	18,255	18,232	18,300	18,390	18,821	18,987	18,350	17,323	15,999	14,614
Fall	10	18,796	10/15/2015	13,607	13,053	12,722	12,603	12,781	13,726	15,644	16,910	17,454	17,766	17,935	17,922	17,847	17,862	17,805	17,817	17,946	18,100	18,627	18,796	18,242	17,256	15,985	14,707
Fall	10	18,206	10/16/2015	13,666	13,059	12,704	12,587	12,782	13,642	15,541	16,843	17,390	17,687	17,889	17,925	17,821	17,764	17,654	17,600	17,675	17,788	18,206	18,201	17,701	16,949	15,880	14,713
Fall	10	17,592	10/17/2015	13,783	13,199	12,835	12,634	12,641	12,975	13,689	14,432	15,361	15,987	16,266	16,281	16,192	16,026	15,902	15,895	16,088	16,468	17,300	17,592	17,212	16,655	15,863	14,895
Fall	10	18,340	10/18/2015	14,043	13,513	13,130	12,925	12,920	13,174	13,684	14,258	15,078	15,723	16,030	16,244	16,345	16,331	16,229	16,264	16,515	16,994	17,983	18,340	17,986	17,211	16,174	15,082
Fall	10	19,695	10/19/2015	14,229	13,757	13,523	13,473	13,763	14,797	16,767	18,047	18,484	18,697	18,770	18,599	18,345	18,261	18,094	18,058	18,238	18,635	19,505	19,695	19,093	18,098	16,709	15,330
Fall	10	19,191	10/20/2015	14,314	13,728	13,366	13,231	13,404	14,312	16,209	17,527	17,985	18,174	18,317	18,241	18,142	18,111	18,060	18,088	18,278	18,556	19,191	19,163	18,477	17,464	16,174	14,828
Fall	10	19,145	10/21/2015	13,733	13,192	12,831	12,721	12,916	13,757	15,662	17,068	17,520	17,882	18,123	18,274	18,323	18,383	18,336	18,338	18,384	18,535	19,145	19,112	18,482	17,477	16,181	14,882
Fall	10	19,278	10/22/2015	13,812	13,207	12,856	12,754	12,911	13,756	15,665	17,036	17,606	17,987	18,224	18,343	18,448	18,533	18,505	18,474	18,584	18,714	19,278	19,213	18,580	17,595	16,297	14,955
Fall	10	18,361	10/23/2015	13,959	13,302	12,929	12,775	12,931	13,749	15,635	16,945	17,488	17,803	17,916	17,867	17,744	17,650	17,549	17,426	17,499	17,701	18,356	18,361	17,859	17,171	16,193	15,064
Fall	10	17,579	10/24/2015	14,134	13,532	13,149	12,990	13,016	13,377	14,082	14,891	15,717	16,312	16,602	16,658	16,592	16,476	16,367	16,315	16,440	16,898	17,579	17,477	17,034	16,481	15,697	14,747
Fall	10	17,587	10/25/2015	13,914	13,328	12,902	12,623	12,538	12,720	13,172	13,781	14,635	15,500	15,999	16,265	16,311	16,208	16,043	16,010	16,168	16,530	17,454	17,587	17,136	16,345	15,326	14,237
Fall	10	19,273	10/26/2015	13,413	12,966	12,700	12,660	12,934	13,979	15,977	17,412	17,858	18,096	18,148	18,056	17,918	17,858	17,769	17,736	17,883	18,288	19,218	19,273	18,679	17,744	16,418	15,102
Fall	10	19,298	10/27/2015	14,148	13,651	13,332	13,255	13,526	14,516	16,505	17,896	18,207	18,343	18,349	18,237	18,086	17,997	17,851	17,809	17,989	18,399	19,298	19,247	18,638	17,697	16,432	15,146
Fall	10	20,088	10/28/2015	14,185	13,596	13,229	13,098	13,282	14,208	16,139	17,646	18,205	18,618	18,878	19,018	19,028	19,030	18,942	19,020	19,372	19,803	20,088	19,706	19,018	18,022	16,698	15,331
Fall	10	19,185	10/29/2015	14,315	13,687	13,306	13,145	13,255	14,093	16,039	17,475	17,973	18,327	18,528	18,668	18,535	18,492	18,316	18,189	18,270	18,592	19,185	18,979	18,394	17,509	16,231	14,907
Fall	10	18,425	10/30/2015	13,912	13,333	12,950	12,799	12,955	13,861	15,733	17,216	17,601	17,834	17,927	17,978	17,786	17,706	17,555	17,460	17,489	17,772	18,425	18,336	17,839	17,174	16,181	15,050
Fall	10	17,137	10/31/2015	14,106	13,511	13,156	12,972	13,002	13,342	14,122	14,938	15,720	16,286	16,512	16,486	16,280	16,085	15,930	15,880	16,077	16,424	17,137	17,005	16,711	16,235	15,481	14,611
Fall	11	17,969	11/1/2015	13,498	12,837	12,617	12,516	12,534	12,816	13,352	14,016	14,984	15,626	15,953	16,093	16,088	16,011	16,001	16,126	16,638	17,944	17,969	17,570	16,992	16,023	15,072	14,110
Fall	11	19,568	11/2/2015	13,421	12,891	12,623	12,591	12,901	13,972	15,888	16,957	17,503	17,835	18,038	18,084	17,981	17,933	17,877	17,902	18,420	19,568	19,491	18,975	18,224	17,211	15,904	14,653
Fall	11	19,615	11/3/2015	13,765	13,259	12,981	12,902	13,195	14,195	15,841	16,872	17,406	17,705	17,932	18,021	18,036	18,124	18,151	18,202	18,534	19,615	19,507	18,911	18,162	17,096	15,816	14,571
Fall	11	19,579	11/4/2015	13,611	13,077	12,794	12,705	12,962	13,934	15,769	16,876	17,444	17,746	18,009	18,123	18,120	18,202	18,200	18,212	18,535	19,579	19,486	18,923	18,216	17,165	15,844	14,578
Fall	11	20,065	11/5/2015	13,663	13,128	12,822	12,720	12,945	13,884	15,709	16,996	17,677	18,160	18,490	18,544	18,580	18,651	18,689	18,741	19,197	20,065	19,842	19,319	18,605	17,629	16,279	15,010
Fall	11	20,071	11/6/2015	14,006	13,403	13,084	12,965	13,167	14,122	15,949	17,368	18,277	18,819	19,087	19,254	19,258	19,209	19,091	19,043	19,337	20,071	19,662	19,026	18,303	17,472	16,394	15,191
Fall	11	17,872	11/7/2015	14,190	13,523	13,109	12,861	12,817	13,098	13,678	14,502	15,516	16,140	16,519	16,638	16,593	16,487	16,382	16,443	17,008	17,872	17,766	17,354	16,907	16,323	15,528	14,621
Fall	11	18,094	11/8/2015	13,785	13,215	12,851	12,647	12,645	12,906	13,326	13,843	14,646	15,190	15,499	15,706	15,754	15,734	15,730	15,902	16,586	17,963	18,094	17,810	17,358	16,536	15,539	14,523
Fall	11	19,805	11/9/2015	13,803	13,362	13,118	13,075	13,413	14,458	16,322	17,425	17,859	18,077	18,102	17,987	17,852	17,844	17,796	17,895	18,594	19,805	19,718	19,300	18,616	17,649	16,340	14,968
Fall	11	20,106	11/10/2015	13,937	13,433	13,100	13,023	13,278	14,232	16,097	17,337	17,983	18,431	18,661	18,750	18,674	18,637	18,583	18,777	19,394	20,106	19,772	19,222	18,464	17,486	16,254	15,030
Fall	11	19,783	11/11/2015	14,072	13,471	13,119	12,995	13,190	13,979	15,235	16,469	17,445	17,987	18,273	18,344	18,279	18,241	18,183	18,240	18,868	19,783	19,617	19,116	18,419	17,482	16,220	14,948
Fall	11	20,173	11/12/2015	13,913	13,358	13,001	12,906	13,160	14,156	15,999	17,352	17,981	18,407	18,681	18,733	18,684	18,743	18,691	18,786	19,390	20,173	19,933	19,348	18,626	17,603	16,346	15,032
Fall	11	19,553	11/13/2015	13,993	13,409	13,019	12,916	13,123	14,031	15,821	17,026	17,602	17,925	18,155	18,192	18,110	18,068	17,970	18,027	18,646	19,553	19,374	18,837	18,204	17,395	16,366	15,180
Fall	11	18,449	11/14/2015	14,265	13,695	13,321	13,139	13,182	13,567	14,224	14,930	15,819	16,474	16,795	16,849	16,779	16,671	16,618	16,700	17,340	18,449	18,373	18,000	17,552	16,862	16,033	15,100
Fall	11	18,177	11/15/2015	14,281	13,736	13,371	13,174	13,177	13,418	13,827	14,280	14,948	15,428	15,677	15,804	15,804	15,767	15,804	15,932	16,711	18,094	18,177	17,807	17,325	16,531	15,458	14,312
Fall	11	19,730	11/16/2015	13,542	13,082	12,854	12,846	13,141	14,139	16,026	17,100	17,557	17,786	17,868	17,854	17,873	17,876	17,859	17,909	18,544	19,730	19,594	19,158	18,517	17,570	16,301	14,962
Fall	11	20,221	11/17/2015	14,052	13,520	13,270	13,242	13,542	14,629	16,598	17,668	18,078	18,186	18,181	18,111	17,981	17,955	17,940	18,085	18,941	20,221	20,112	19,687	19,050	18,076	16,731	15,347
Fall	11	20,098	11/18/2015	14,397	13,852	13,538	13,433	13,681	14,638	16,561	17,721	18,148	18,291	18,283	18,235	18,143	18,187	18,184	18,376	19,244	20,098	19,844	19,317	18,635	17,632	16,310	14,938
Fall	11	20,061	11/19/2015	13,940	13,383	13,066	12,957	13,152	14,060	15,935	17,202	17,800	18,202	18,444	18,531	18,565	18,564	18,535	18,653	19,319	20,061	19,801	19,299	18,611	17,559	16,341	15,018
Fall	11	19,423	11/20/2015	14,034	13,431	13,058	12,922	13,109	13,988	15,825	16,932	17,475	17,775	17,836	17,792	17,701	17,667	17,645	17,705	18,345	19,423	19,171	18,640	18,104	17,353	16,320	15,217
Fall	11	18,314	11/21/2015	14,305	13,713	13,385	13,211	13,285	13,693	14,379	15,101	15,934	16,430	16,641	16,609	16,491	16,334	16,290	16,407	17,232	18,314	18,222	17,810	17,325	16,653	15,796	14,823
Fall	11	18,819	11/22/2015	14,010	13,443	13,041	12,813	12,814	13,029	13,517	14,040	14,876	15,550	16,010	16,303	16,475	16,576	16,659	16,931	17,847	18,819	18,769	18,467	17,974	17,172	16,063	14,983
Fall	11	20,993	11/23/2015	14,194	13,755	13,547	13,528	13,852	14,916	16,854	18,041	18,532	18,758	18,828	18,828	18,731	18,706	18,715	18,900	19,807	20,993	20,913	20,538	19,908	18,885	17,583	16,205
Fall	11	20,739	11/24/2015	15,191	14,605	14,290	14,218	14,473	15,544	17,397	18,622	19,079	19,194	19,154	19,020	18,875	18,823	18,763	18,879	19,692	20,739	20,562	20,177	19,560	18,646	17,373	16,027
Fall	11	20,080	11/25/2015	15,038	14,486	14,143	14,056	14,340	15,264	16,991	18,123	18,657	18,900	18,875	18,742	18,512	18,355	18,249	18,285	19,006	20,080	19,923	19,490	18,903	18,097	16,961	15,731
Fall	11	16,936	11/26/2015	14,679	14,019	13,586	13,370	13,444	13,796	14,372	14,922	15,694	16,373	16,776	16,936	16,811	16,399	15,919	15,576	15,814	16,274	16,119	15,924	15,721	15,452	14,865	14,103
Fall	11	18,286	11/27/2015	13,370	12,911	12,626	12,510	12,676	13,176	14,045	14,785	15,464	16,007	16,358	16,476	16,460	16,361	16,406	16,567	17,419	18,286	18,038	17,588	17,063	16,368	15,465	14,464
Fall	11	18,336	11/28/2015	13,594	13,015	12,662	12,456	12,491	12,850	13,486	14,196	15,146	15,944	16,448	16,754	16,827	16,796	16,763	16,944	17,723	18,336	18,270	17,943	17,529	16,945	16,072	15,049
Fall	11	19,199	11/29/2015	14,196	13,614	13,264	13,054	13,102	13,381	13,915	14,447	15,242	15,920	16,359	16,410	16,414	16,416	16,457	16,760	17,843	19,135	19,199	18,951	18,460	17,621	16,474	15,360
Fall	11	21,086	11/30/2015	14,541	14,076	13,837	13,764	14,099	15,186	17,182	18,457	18,824	19,078	19,162	19,028	18,859	18,759	18,666	18,832	19,869	21,086	21,009	20,549	19,871	18,822	17,369	15,916

Contains Proprietary Material
Do Not Distribute

FERC Form 714 Outages

Month	Planned Outage and Derating (MW)
Dec-14	3,297
Jan15	3,180
Feb15	3,568
Mar15	6,026
Apr15	7,520
May15	4,259
Jun15	1,496
Jul15	440
Aug15	281
Sep15	1,327
Oct15	7,477
Nov15	5,426

	Planned Outage and Derating (MW)				
	Winter	Spring	Summer	Fall	Notes
NYISO	3,348	5,935	739	4,743	NYISO outages
NY-City	862	1,528	183	1,221	Estimated based on generation ratios
Long Island	468	829	101	663	Estimated based on generation ratios

	Generation (MW)			
	Winter	Spring	Summer	Fall
NYISO	41,013	41,013	38,665	41,013
NY-City	10,561	10,561	9,597	10,561
Long Island	5,732	5,732	5,281	5,732

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	PSA	Winter	Spring	Summer	Fall	Notes
NYISO Reserves	2,620	2,620	2,620	2,620	2,620	NYISO Locational Reserve Requirements (30-minute reserves)
NY-City	#REF!	#REF!	#REF!	#REF!	#REF!	Estimated based on load ratios
Long Island	540	540	540	540	540	Maximum LI Locational Reserve Requirements (30-minute reserves)

	Loads				
	PSA	Winter	Spring	Summer	Fall
NYISO	25,244	22,045	19,393	24,144	20,374
NY-City	#REF!	#REF!	#REF!	#REF!	#REF!
Long Island	#REF!	#REF!	#REF!	#REF!	#REF!

http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf

NYISO
Locational Reserve Requirements

The NYISO shall define requirements for Spinning Reserve, which may be met only by Suppliers that are eligible to provide Spinning Reserve; 10-Minute Reserve, which may be met by Suppliers that are eligible to provide either Spinning Reserve or 10-Minute Non-Synchronized Reserve; and 30-Minute Reserve, which may be met by Suppliers that are eligible to provide any Operating Reserve product. The NYISO shall also define locational requirements for Spinning Reserve, 10-Minute Reserve, and 30-Minute Reserve located in East of Central–East (EAST), in Southeastern New York (SENY) and on Long Island (LI) as shown in the following table:

	NYCA	EAST	SENY	LI
A=most severe NYCA Operating Capability Loss (1310 MWs)	Zone A-K	Zone F-K	Zone G-K	Zone K
10 Minute Spinning Reserve	½ A = 655 MWs (I)	¼ A = 330 MWs (IV)	0 MWs	0 MWs
10 Minute Total Reserve	A = 1310 MWs (II)	1200 MWs (V)	0 MWs	$^{1}/_{10}$ V = 120 MWs (VIII)
30 Minute Reserve	2 A = 2620 MWs (III)	1200 MWs (VI)	1300 MWs (VII)	270-540 MWs (IX)

Contains Proprietary Material
Do Not Distribute

Source: PJM

	PJM
Max	143,633
Peak Month	7
PST	121,600
Winter	112,390
Spring	94,917
Summer	117,821
Fall	95,173

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	102,668	12/1/2014	70,381	68,446	67,764	68,161	70,444	76,128	84,884	90,282	91,203	91,189	91,836	91,776	91,829	91,811	91,779	92,445	95,733	101,439	102,668	101,987	100,291	96,470	90,714	84,732
Winter	12	110,873	12/2/2014	80,525	78,286	77,574	77,980	80,090	85,967	95,553	101,320	102,173	102,630	103,122	103,037	102,901	102,911	102,603	103,044	106,193	110,792	110,873	109,348	106,785	101,968	95,298	88,771
Winter	12	106,204	12/3/2014	83,905	81,113	79,602	79,325	81,114	86,183	95,107	100,446	100,367	99,996	99,745	99,041	98,104	97,266	96,052	95,696	98,556	104,849	106,204	105,479	104,054	100,662	94,871	88,963
Winter	12	109,104	12/4/2014	84,723	82,551	81,758	82,124	84,287	90,141	99,955	104,875	104,152	102,630	101,256	99,544	98,606	98,133	97,941	98,533	102,027	108,501	109,104	108,029	106,297	102,316	96,191	89,658
Winter	12	104,351	12/5/2014	84,891	81,949	80,646	80,558	82,192	87,130	96,094	101,346	101,410	101,125	101,214	100,457	99,438	98,682	97,895	97,865	100,427	104,351	103,620	101,486	99,179	95,844	91,032	85,028
Winter	12	96,752	12/6/2014	80,208	76,949	75,150	74,391	74,752	76,530	80,068	83,883	87,393	90,142	91,406	91,509	90,735	89,824	88,960	88,996	91,693	96,170	96,752	95,591	94,358	92,148	88,444	84,077
Winter	12	102,331	12/7/2014	79,958	77,424	76,296	76,130	77,032	79,002	82,258	85,648	88,254	89,170	88,566	87,148	86,119	84,990	84,516	85,364	90,142	99,259	101,864	102,331	101,962	98,965	94,151	88,877
Winter	12	113,955	12/8/2014	85,216	83,506	82,915	83,514	85,975	91,863	101,605	107,058	107,620	107,275	106,802	105,963	104,859	104,117	103,414	103,912	107,321	113,305	113,955	112,514	110,388	106,093	99,412	92,296
Winter	12	110,721	12/9/2014	87,318	84,683	83,420	83,438	85,167	90,647	99,563	105,126	105,422	105,171	104,880	103,946	102,866	102,008	101,037	101,305	104,426	110,215	110,721	109,407	107,222	102,824	96,096	89,371
Winter	12	113,559	12/10/2014	84,508	81,989	80,995	81,151	83,268	88,825	98,226	103,449	103,468	102,684	102,571	102,242	101,639	101,558	101,257	101,841	105,788	112,411	113,559	112,382	110,709	106,921	100,621	93,962
Winter	12	114,045	12/11/2014	89,594	87,225	86,339	86,577	88,735	94,425	104,168	109,511	108,929	107,689	106,446	104,902	103,726	102,882	101,914	102,090	105,641	112,601	114,045	113,234	111,866	108,250	101,952	95,291
Winter	12	109,191	12/12/2014	90,392	87,870	86,702	86,834	88,742	94,114	103,252	108,674	108,384	107,292	105,509	103,484	101,379	100,147	98,801	98,632	101,774	108,575	109,191	107,840	106,268	103,585	98,951	93,203
Winter	12	100,490	12/13/2014	88,294	85,371	84,023	83,775	84,441	86,721	90,223	94,274	96,806	97,313	96,502	94,990	93,191	91,605	90,505	90,632	93,713	99,671	100,490	99,427	98,173	96,027	91,991	87,198
Winter	12	98,486	12/14/2014	82,641	80,025	78,576	77,886	78,015	79,446	82,076	85,015	87,614	88,694	88,521	87,864	87,549	86,491	85,813	86,105	89,557	96,827	98,486	98,159	97,021	93,763	88,793	83,253
Winter	12	105,072	12/15/2014	79,058	76,804	76,020	76,514	78,941	84,785	94,566	100,339	100,184	98,490	96,999	95,206	93,472	92,271	91,027	91,013	94,614	102,884	105,072	104,783	103,565	99,779	93,918	87,114
Winter	12	106,709	12/16/2014	82,294	79,686	78,574	78,654	80,467	85,925	95,301	100,953	100,495	99,400	98,884	98,145	97,445	97,116	97,150	97,648	100,871	106,394	106,709	105,346	103,550	99,760	93,347	86,305
Winter	12	109,307	12/17/2014	81,302	78,612	77,534	77,405	79,395	85,188	94,651	100,406	100,161	98,992	98,337	97,490	96,786	96,686	96,502	96,916	100,687	107,877	109,307	108,659	107,473	104,435	98,828	92,226
Winter	12	113,423	12/18/2014	87,282	85,004	84,127	84,317	86,588	92,352	102,125	107,737	107,287	106,133	105,488	104,426	102,891	102,040	101,581	101,837	105,584	112,361	113,423	112,264	110,939	107,230	100,985	94,134
Winter	12	110,832	12/19/2014	88,924	86,015	84,812	84,921	86,932	92,223	101,340	107,405	107,566	106,809	106,055	104,283	102,547	100,967	99,680	99,657	103,020	109,961	110,832	109,497	108,054	105,391	100,902	95,173
Winter	12	105,010	12/20/2014	90,098	87,297	85,773	85,397	85,878	88,332	91,906	96,297	99,456	101,486	101,848	100,663	98,742	96,702	95,461	95,362	98,267	104,403	105,010	103,880	102,853	100,690	96,674	91,778
Winter	12	104,387	12/21/2014	87,358	84,412	82,846	82,240	82,546	84,158	86,902	90,241	93,210	94,515	93,944	92,596	91,207	89,094	87,922	88,183	92,142	100,729	103,851	104,387	104,095	101,821	97,572	92,569
Winter	12	109,089	12/22/2014	88,412	85,962	85,180	85,311	87,217	91,984	99,540	105,061	106,251	106,052	105,268	104,072	102,539	101,196	100,525	100,327	103,042	108,610	109,089	107,587	105,744	101,813	95,998	89,201
Winter	12	100,145	12/23/2014	83,660	80,274	78,624	77,852	79,136	83,221	90,333	95,691	97,012	97,274	97,163	96,304	94,828	93,806	92,654	92,162	94,428	99,611	100,145	98,523	96,412	92,985	87,818	81,237
Winter	12	88,815	12/24/2014	75,581	71,879	69,800	68,921	69,578	72,287	76,856	81,383	84,298	86,842	88,399	88,352	87,085	85,851	84,852	84,140	85,605	88,815	87,014	84,326	82,595	80,993	78,334	74,445
Winter	12	83,815	12/25/2014	70,175	67,079	65,166	64,390	64,845	66,331	69,161	72,757	75,930	78,240	79,165	79,439	78,810	77,524	76,045	75,231	76,498	81,692	83,346	83,498	83,815	83,249	81,159	77,865
Winter	12	93,069	12/26/2014	74,906	73,058	72,560	73,239	75,198	78,945	84,275	88,555	89,997	89,375	87,724	85,802	83,737	81,728	80,235	79,960	82,713	90,696	93,069	92,554	91,697	89,678	86,012	81,607
Winter	12	88,934	12/27/2014	77,511	75,287	74,125	73,763	74,352	76,209	79,177	82,517	84,509	84,901	84,064	82,770	80,915	79,077	77,752	77,568	80,120	87,269	88,934	88,340	87,299	85,432	81,929	77,593
Winter	12	92,467	12/28/2014	73,533	70,859	69,288	68,585	68,753	70,038	72,252	75,165	77,542	80,060	81,199	81,692	82,016	81,653	81,340	81,673	84,799	90,242	92,467	91,819	90,693	87,979	84,307	79,709
Winter	12	106,148	12/29/2014	76,057	73,839	73,136	73,466	75,375	79,840	86,424	92,427	94,719	96,108	96,824	96,719	95,558	95,083	94,650	94,646	97,087	104,388	106,148	104,906	103,166	99,992	94,934	89,310
Winter	12	110,969	12/30/2014	85,158	82,961	81,918	81,927	83,766	88,076	94,820	100,377	102,214	103,005	102,649	101,217	99,391	98,078	97,027	96,779	99,895	107,912	110,969	110,315	109,205	106,587	102,033	96,808
Winter	12	110,712	12/31/2014	92,824	90,825	90,213	90,391	92,159	96,213	102,039	106,177	106,966	106,284	104,907	103,100	101,041	98,994	97,394	96,911	100,075	108,863	110,712	108,487	105,835	102,991	99,729	96,399
Winter	1	100,418	1/1/2015	94,002	91,930	90,377	89,636	89,869	91,496	93,609	94,661	94,393	93,595	93,037	92,148	90,712	88,937	87,566	87,639	90,579	98,472	100,418	99,622	98,106	95,346	91,232	86,865
Winter	1	102,363	1/2/2015	83,243	81,050	79,966	79,816	81,302	85,142	90,711	95,487	97,348	97,671	97,117	96,171	94,593	93,186	92,091	91,900	94,277	101,121	102,363	101,127	99,669	97,212	93,105	88,464
Winter	1	98,387	1/3/2015	84,415	81,797	80,286	79,699	79,928	81,614	84,139	87,128	89,799	92,616	94,899	95,640	95,306	94,640	93,652	93,100	94,728	98,387	97,974	95,964	93,496	90,264	86,137	81,225
Winter	1	95,931	1/4/2015	76,690	73,582	71,615	70,618	70,505	71,601	73,364	76,032	78,390	80,803	82,444	83,440	84,311	84,568	84,318	84,797	87,843	93,682	95,931	95,028	94,128	90,877	86,854	82,810
Winter	1	119,815	1/5/2015	79,944	78,810	78,898	79,993	82,975	89,652	100,128	106,670	107,140	106,612	106,112	105,633	104,812	104,105	103,709	104,398	108,250	116,660	119,815	119,285	117,705	113,945	108,021	102,163
Winter	1	122,846	1/6/2015	98,195	96,106	95,176	95,196	97,136	102,616	111,077	116,543	116,476	116,026	115,483	114,466	113,053	111,749	110,567	110,015	112,517	120,195	122,846	122,385	120,670	116,843	111,068	105,659
Winter	1	135,639	1/7/2015	101,571	99,579	98,804	99,208	101,335	106,680	114,922	120,461	121,092	120,319	119,993	119,579	119,189	119,289	119,290	120,394	124,240	131,953	135,424	135,639	134,763	131,875	126,616	121,623
Winter	1	134,197	1/8/2015	118,502	117,119	116,828	117,144	119,316	124,060	131,396	136,397	135,305	133,080	130,834	128,427	126,223	124,293	123,179	123,214	125,800	132,509	134,759	133,640	131,229	126,824	120,108	113,728
Winter	1	122,167	1/9/2015	108,949	106,487	105,074	104,539	105,718	109,710	116,898	121,704	121,409	120,176	118,113	115,500	113,330	111,596	110,255	109,958	112,332	119,266	122,167	121,493	120,294	117,981	114,018	109,342
Winter	1	119,065	1/10/2015	106,201	104,570	104,250	104,682	106,176	108,963	113,020	117,234	119,065	118,510	116,514	113,773	110,625	107,315	105,225	104,923	108,084	115,500	119,027	118,968	118,430	116,574	112,914	108,868
Winter	1	109,169	1/11/2015	105,354	103,403	102,366	102,072	102,390	103,729	106,065	108,686	109,169	107,281	104,271	101,458	99,304	97,352	96,045	96,259	99,665	106,626	108,701	107,561	105,704	101,773	96,767	91,716
Winter	1	113,974	1/12/2015	88,199	86,206	85,742	85,963	88,132	93,149	101,131	107,630	109,235	109,643	109,517	109,352	108,528	107,717	106,653	106,492	108,191	112,613	113,974	112,515	110,010	105,613	100,289	94,790
Winter	1	121,214	1/13/2015	90,741	88,452	87,906	88,563	90,994	96,952	106,849	113,166	113,271	112,227	111,242	109,939	108,667	107,583	107,177	107,634	110,467	117,588	121,214	120,989	119,514	115,895	110,058	104,471
Winter	1	121,315	1/14/2015	100,703	98,717	98,152	98,659	100,747	106,284	114,884	120,549	120,956	120,280	119,168	117,851	116,665	114,618	113,150	112,676	114,265	119,266	121,315	120,171	118,253	113,961	107,744	101,669
Winter	1	116,668	1/15/2015	97,651	95,639	94,615	94,862	96,902	102,120	111,013	116,668	115,936	113,989	111,582	109,019	106,641	104,875	103,386	103,077	105,101	111,271	114,737	114,338	113,000	109,335	103,530	97,774
Winter	1	112,992	1/16/2015	94,058	92,038	91,508	91,662	93,894	99,342	107,895	112,992	111,753	108,980	106,918	104,847	102,692	100,980	99,604	99,021	100,724	106,405	109,484	108,652	107,396	104,783	101,042	96,542
Winter	1	104,517	1/17/2015	93,001	91,161	90,606	90,858	92,071	94,552	98,520	102,531	104,517	103,877	101,601	98,712	95,244	92,333	90,257	89,754	92,132	98,326	101,907	101,398	100,108	97,703	93,907	89,613
Winter	1	98,475	1/18/2015	85,813	83,580	81,932	81,296	81,152	82,141	84,235	87,036	89,840	92,376	93,566	93,890	93,746	92,730	91,617	90,892	92,173	96,520	98,475	98,411	96,712	94,174	90,375	86,670
Winter	1	106,188	1/19/2015	83,833	82,395	81,993	82,443	84,445	88,567	95,060	100,413	102,519	102,752	101,668	100,242	98,809	97,682	96,318	95,571	96,982	102,674	106,188	105,974	104,528	101,041	95,610	90,186
Winter	1	108,376	1/20/2015	86,501	84,813	84,408	84,972	87,346	93,404	102,897	108,376	107,518	105,135	101,841	100,571	98,458	97,423	96,288	96,183	98,165	103,602	106,713	106,327	104,953	101,506	96,189	90,689
Winter	1	112,252	1/21/2015	86,648	84,800	84,236	84,413	86,723	92,555	101,982	107,373	106,948	106,060	105,549	104,970	104,012	103,682	103,256	103,142	105,036	109,832	112,252	111,085	109,397	105,245	99,349	93,904
Winter	1	110,280	1/22/2015	89,895	87,720	86,890	87,056	89,116	94,564	103,574	109,259	109,309	108,374	106,946	104,772	102,811	101,250	100,050	99,900	101,676	107,125	110,280	109,759	108,129	104,856	98,994	93,708
Winter	1	110,667	1/23/2015	89,583	87,617	87,243	87,620	89,904	95,666	105,125	110,667	109,670	107,668	105,653	103,553	101,574	100,588	99,815	99,989	101,881	106,038	107,736	106,503	104,633	101,456	96,980	91,868
Winter	1	102,257	1/24/2015	87,741	85,509	83,997	83,517	83,903	85,884	89,002	92,901	95,846	98,614	99,927	99,896	98,513	96,783	95,252	94,231	94,940	99,431	102,257	101,434	99,712	97,115	93,053	88,487
Winter	1	100,769	1/25/2015	84,828	82,421	81,080	80,707	81,178	82,746	85,195	88,046	90,652	91,867	91,642	91,172	90,172	89,171	88,074	88,446	90,950	97,053	100,769	100,557	99,311	96,304	92,046	87,909
Winter	1	118,210	1/26/2015	84,673	83,351	83,095	83,834	86,436	92,550	101,654	108,345	109,803	110,475	111,011	110,530	110,039	109,713	108,977	108,805	110,528	115,330	118,210	116,939	114,359	110,230	104,637	99,354
Winter	1	118,540	1/27/2015	95,260	93,519	92,838	93,228	95,179	100,019	107,895	113,311	114,303	114,021	112,945	111,368	109,458	107,953	106,404	106,023	108,121	114,088	118,540	118,182	116,531	112,922	107,606	102,192
Winter	1	122,273	1/28/2015	99,006	97,919	97,648	98,479	101,236	107,345	116,990	122,273	120,526	116,971	113,732	110,354	107,445	105,272	103,220	102,849	104,827	111,239	116,674	116,963	116,000	112,314	106,679	101,111
Winter	1	118,159	1/29/2015	97,643	96,032	95,629	96,209	98,637	104,453	113,600	118,159	116,433	113,967	111,964	109,936	108,212	107,436	106,541	106,497	108,211	112,391	114,590	113,517	111,117	106,596	100,378	94,385
Winter	1	115,519	1/30/2015	89,969	87,576	86,497	86,566	88,716	94,043	103,096	108,744	108,967	108,411	107,796	106,856	105,577	104,744	103,632	103,241	104,792	110,122	115,228	115,519	114,676	112,601	108,829	104,888
Winter	1	111,797	1/31/2015	101,771	100,336	99,937	100,284	101,337	104,023	107,767	111,409	111,797	111,655	111,352	110,868	109,852	108,825	107,567	107,154	107,590	107,465	106,441	104,318	100,742	96,014	91,242	96,659
Winter	2	103,665	2/1/2015	93,181	91,116	90,027	89,404	89,340	90,417	92,480	94,907	97,059	98,130	97,669	96,915	96,319	95,704	95,189	95,691	98,040	102,508	103,665	101,206	99,217	96,655	93,595	89,116
Winter	2	120,485	2/2/2015	85,143	82,973	82,025	82,271	84,148	89,472	97,673	103,631	104,978	106,049	107,013	107,109	106,628	106,180	105,715	105,671	108,056	113,967	119,733	120,485	119,029	115,425	109,737	104,236
Winter	2	121,191	2/3/2015	101,026	99,518	99,007	99,597	101,976	107,505	116,460	121,191	120,326	118,223	115,519	111,995	108,765	106,495	104,450	103,729	105,380	110,812	116,476	117,036	115,673	111,978	106,275	100,385
Winter	2	114,251	2/4/2015	96,493	94,345	93,552	93,487	95,294	100,693	109,768	114,251	112,409	109,160	106,370	103,676	101,233	99,147	97,636	96,975	98,566	103,397	108,264	108,785	107,499	103,866	98,222	92,661
Winter	2	123,695	2/5/2015	88,862	86,959	86,318	86,913	89,452	95,485	105,344	111,724	112,602	112,617	112,499	111,261	109,696	108,404	107,130	106,823	109,216	115,615	122,417	123,695	123,097	120,228	115,132	110,157
Winter	2	127,381	2/6/2015	106,845	105,644	105,473	105,954	108,312	113,982	122,847	127,381	124,753	121,387	118,524	115,612	112,284	109,722	107,726	106,542	106,712	109,887	113,924	113,325	112,048	108,929	104,658	99,494
Winter	2	102,343	2/7/2015	95,484	93,255	92,148	91,654	91,826	93,432	96,676	100,017	102,023	102,343	100,646	97,412	93,329	89,931	87,475	86,304	86,958	90,717	95,530	95,786	94,665	92,392	88,809	84,969
Winter	2	93,941	2/8/2015	81,514	79,227	78,177	77,599	77,998	79,206	81,612	84,155	86,376	87,349	86,570	85,371	84,201	82,955	82,193	82,323	84,315	88,903	93,684	93,941	92,495	89,170	85,054	80,872
Winter	2	113,055	2/9/2015	77,452	75,751	75,380	76,214	78,904	84,915	94,774	101,065	102,276	103,101	104,038	104,232	104,046	103,830	103,319	103,704	105,606	109,804	113,055	112,567	110,696	106,660	100,806	95,204
Winter	2	114,183	2/10/2015	91,452	89,783	89,329	89,846	91,880	97,629	106,710	112,407	112,838	112,615	112,005	110,371	108,451	106,628	104,777	103,675	104,217	108,378	113,706	114,183	112,810	109,500	103,557	97,862
Winter	2	114,516	2/11/2015	94,031	92,302	91,812	92,309	94,713	100,641	110,188	114,516	112,644	110,164	107,750	104,941	102,105	100,250	98,580	98,164	99,674	104,224	109,821	110,396	109,216	105,705	100,377	94,654
Winter	2	130,851	2/12/2015	96,621	88,703	87,933	88,242	90,575	94,665	106,060	111,368	111,066	110,157	108,294	107,872	107,311	106,596	106,226	106,256	108,128	112,992	119,161	120,450	118,152	113,639	109,090	
Winter	2	128,761	2/13/2015	106,589	105,760	105,817	106,966	109,618	115,318	124,228	128,761	127,115	124,532	121,764	118,647	115,369	112,651	110,147	108,746	109,698	113,889	119,031	119,266	118,181	115,593	111,400	106,437
Winter	2	113,813	2/14/2015	102,598	100,403	99,014	98,250	98,345	99,728	102,497	105,212	107,801	109,548	109,747	108,714	106,818	104,868	103,273	102,426	103,781	107,432	112,534	113,813	113,421	112,731	111,055	109,263
Winter	2	127,475	2/15/2015	108,340	108,384	108,947	109,968	111,591	113,967	117,242	119,757	121,290	121,821	120,710	119,016	116,729	113,986	111,717	110,857	112,599	118,316	125,719	127,475	126,774	124,797	121,472	118,270
Winter	2	134,183	2/16/2015	115,800	114,993	114,643	115,338	116,884	121,072	126,900	130,754	132,213	132,926	132,553	130,548	128,516	127,214	126,349	125,961	127,053	130,389	134,183	133,384	130,682	126,451	120,492	115,177
Winter	2	126,240	2/17/2015	111,777	109,999	109,231	109,579	111,177	115,018	121,233	125,025	126,240	124,877	122,766	119,538	116,639	114,283	112,248	111,380	112,566	117,166	123,265	124,109	122,445	119,115	113,795	109,517
Winter	2	127,107	2/18/2015	106,542	105,692	105,838	106,867	109,221	114,528	123,117	127,107	125,447	121,808	118,853	116,241	114,330	112,921	112,054	112,594	114,785	119,605	125,758	126,798	126,071	123,374	118,885	114,776
Winter	2	140,386	2/19/2015	112,308	111,506	111,882	113,337	116,203	121,808	129,594	133,522	133,056	131,649	129,766	128,346	126,737	125,716	124,944	125,214	127,477	132,392	138,886	140,386	139,399	137,114	132,574	128,428
Winter	2	143,129	2/20/2015	125,665	124,750	124,784	125,840	127,861	132,615	139,530	143,129	141,840	138,982	136,112	132,570	128,896	125,386	122,339	121,024	121,613	125,154	130,983	131,932	130,985	128,469	124,216	119,717
Winter	2	119,441	2/21/2015	115,795	113,625	112,199	111,672	111,824	113,207	115,763	117,517	118,370	119,441	119,436	118,438	116,950	114,880	112,717	111,260	111,438	113,377	116,182	115,007	111,797	107,847	103,335	98,365
Winter	2	106,323	2/22/2015	94,329	91,919	90,713	90,234	90,356	91,571	93,725	95,416	98,060	99,924	99,269	97,105	94,934	92,933	91,393	91,304	93,015	98,054	104,324	106,323	105,586	102,715	98,799	94,819
Winter	2	127,775	2/23/2015	92,310	90,989	90,875	91,421	93,753	100,690	110,049	115,430	117,204	117,039	116,813	115,631	113,922	112,080	110,686	110,451	112,414	117,208	124,876	127,775	127,500	124,785	120,076	115,573
Winter	2	134,132	2/24/2015	113,038	112,293	112,470	113,561	116,332	122,154	130,663	134,132	131,619	127,664	123,917	120,643	117,816	115,732	114,181	113,487	115,094	118,761	123,988	125,187	123,438	119,706	114,019	108,778
Winter	2	122,289	2/25/2015	104,851	103,413	102,938	103,537	105,352	110,699	119,253	122,289	119,043	114,969	111,633	108,481	105,697	103,888	102,247	101,718	103,418	107,515	113,838	115,072	113,933	110,691	105,185	99,941
Winter	2	119,359	2/26/2015	96,185	94,426	93,983	94,535	96,754	102,025	110,488	114,913	116,127	116,135	115,534	113,417	111,170	109,437	108,388	107,999	109,108	112,816	118,000	119,359	118,457	115,205	110,028	104,998
Winter	2	121,067	2/27/2015	101,799	100,213	99,730	100,389	102,570	108,019	116,914	121,067	119,702	116,521	114,083	111,431	109,088	107,330	105,622	104,454	105,326	108,858	115,204	117,755	117,731	115,900	112,363	108,312
Winter	2	114,963	2/28/2015	105,369	104,029	103,695	104,084	105,412	108,302	112,177	114,498	114,963	113,688	110,850	107,153	103,464	99,803	97,302	95,925	96,924	100,770	107,473	109,837	109,554	107,931	104,836	101,028
Spring	3	111,112	3/1/2015	98,093	96,299	95,423	94,705	94,766	95,609	97,359	99,031	101,620	103,803	104,778	104,825	104,833	103,980	103,245	102,798	103,875	106,722	110,320	111,112	108,884	104,867	99,922	95,310
Spring	3	112,134	3/2/2015	91,845	90,213	89,883	90,319	92,327	97,672	105,816	110,085	110,809	108,462	106,375	104,019	101,841	99,943	98,251	97,187	98,253	101,857	109,138	112,134	111,207	108,148	103,227	98,064
Spring	3	114,461	3/3/2015	94,755	93,228	92,644	93,093	95,238	100,687	109,474	112,858

Contains Proprietary Material
Do Not Distribute

Spring	4	92,469	4/2/2015	74,038	72,233	71,643	72,056	74,288	79,817	88,359	92,469	91,936	90,200	89,057	87,695	86,282	85,471	84,304	83,194	82,754	82,645	82,498	84,066	86,135	83,363	78,070	71,975
Spring	4	82,162	4/3/2015	67,345	64,351	62,999	62,433	63,259	66,416	72,127	76,252	78,853	81,016	82,109	82,162	81,518	80,704	80,055	79,272	79,231	79,524	79,296	80,288	81,514	79,574	75,811	71,107
Spring	4	79,892	4/4/2015	66,975	64,476	63,114	62,441	63,048	64,829	67,923	71,194	74,994	77,620	78,339	77,701	76,274	74,511	72,934	71,893	71,859	72,333	72,972	75,596	79,892	79,527	77,064	73,348
Spring	4	76,582	4/5/2015	69,823	67,499	66,641	66,447	67,225	69,067	71,972	74,641	76,582	76,565	74,866	73,114	71,601	69,905	68,020	66,736	66,014	66,174	67,314	70,599	75,660	75,327	72,263	68,471
Spring	4	87,056	4/6/2015	65,718	64,045	64,151	64,880	67,218	72,715	81,173	85,879	87,056	86,730	86,391	85,668	84,849	84,070	83,083	82,149	81,800	82,023	82,041	84,289	87,015	84,186	78,721	72,844
Spring	4	89,290	4/7/2015	68,242	65,555	64,075	63,725	64,986	69,331	77,566	82,792	84,778	85,913	87,166	87,212	87,047	86,874	86,379	85,669	85,659	86,039	86,274	87,898	89,290	85,918	80,036	73,905
Spring	4	91,683	4/8/2015	69,529	66,992	65,670	65,303	66,603	71,332	79,596	84,771	86,795	88,033	89,048	89,164	89,000	88,686	87,903	87,214	87,418	88,003	88,667	90,339	91,683	88,704	83,058	77,153
Spring	4	92,720	4/9/2015	72,761	70,126	68,661	68,444	69,923	74,863	83,615	88,232	89,951	90,805	91,487	91,617	91,531	91,031	90,165	89,619	89,636	90,073	90,415	91,566	92,720	89,818	83,999	77,893
Spring	4	89,432	4/10/2015	73,079	70,467	69,055	68,451	69,649	74,005	82,049	86,831	88,612	89,338	89,432	88,826	87,987	87,058	85,943	84,396	83,531	82,820	81,693	81,875	84,381	82,640	78,136	73,040
Spring	4	77,383	4/11/2015	68,479	66,006	64,527	64,084	64,485	66,488	69,495	72,120	74,798	76,427	76,842	76,103	74,985	73,686	72,287	71,602	71,427	71,758	72,089	73,370	77,383	76,894	73,748	69,829
Spring	4	79,870	4/12/2015	66,217	64,326	63,425	63,383	64,006	65,979	68,500	70,441	72,389	73,011	72,580	71,981	71,350	70,547	69,930	70,015	70,647	71,953	72,998	75,470	79,870	78,068	73,336	68,309
Spring	4	88,036	4/13/2015	64,510	62,577	61,672	61,896	63,756	69,084	78,361	83,252	84,277	84,120	84,856	84,750	84,928	85,348	85,071	84,908	84,942	84,934	84,280	85,074	88,036	84,995	78,846	72,131
Spring	4	86,675	4/14/2015	67,171	64,433	62,776	62,158	63,295	67,770	76,508	81,417	83,410	84,603	85,545	85,568	85,318	84,993	84,321	83,418	83,366	83,444	83,674	84,637	86,675	84,278	78,175	72,132
Spring	4	86,396	4/15/2015	67,842	65,650	64,357	64,321	65,913	70,964	79,577	83,887	84,708	84,781	84,528	84,133	83,758	83,491	82,726	81,983	81,819	81,992	81,677	83,062	86,396	83,764	78,485	72,461
Spring	4	86,192	4/16/2015	68,344	65,813	64,633	64,630	66,067	71,146	79,491	83,804	84,385	84,302	84,577	84,103	83,796	83,567	82,978	82,465	82,293	82,318	82,040	83,433	86,192	84,003	78,153	72,090
Spring	4	85,616	4/17/2015	67,646	64,887	63,574	63,032	64,333	68,658	76,934	81,272	83,153	84,432	85,383	85,334	85,477	85,616	85,139	84,511	84,188	83,451	82,066	81,704	84,057	82,565	77,378	71,253
Spring	4	78,849	4/18/2015	66,218	62,905	61,011	59,934	60,136	61,506	63,922	66,672	70,508	73,520	75,233	75,889	75,987	75,878	75,760	75,921	76,724	77,113	76,472	76,271	78,849	77,651	73,401	68,184
Spring	4	79,522	4/19/2015	63,590	60,461	58,554	57,532	57,390	58,131	59,264	61,280	65,111	68,150	69,682	70,564	71,110	71,077	71,014	71,216	72,233	73,901	75,040	77,195	79,522	77,140	72,623	67,863
Spring	4	88,161	4/20/2015	64,223	62,118	61,169	61,076	62,619	67,388	76,234	81,458	84,122	85,521	86,895	87,414	87,495	87,494	87,333	87,009	86,690	86,703	86,239	86,438	88,161	85,535	79,329	72,773
Spring	4	86,403	4/21/2015	68,382	65,605	64,200	63,830	64,911	69,719	78,001	82,343	83,736	83,935	84,320	84,296	83,921	83,890	83,283	82,592	82,702	82,617	82,163	82,812	86,403	84,687	78,760	72,707
Spring	4	88,647	4/22/2015	68,497	66,017	65,031	64,750	66,284	71,372	79,929	84,400	85,474	85,925	86,333	86,161	86,081	86,232	85,827	85,289	85,126	85,269	85,151	85,687	88,647	86,940	81,227	75,252
Spring	4	90,110	4/23/2015	71,171	69,155	68,201	68,214	70,127	75,554	84,123	88,358	88,526	88,024	87,977	87,712	87,252	86,547	85,751	85,108	85,018	85,313	85,464	86,636	90,110	88,885	83,597	77,890
Spring	4	91,229	4/24/2015	73,937	71,953	71,128	71,387	73,437	78,786	87,303	91,229	90,992	89,508	88,387	86,928	85,366	84,070	82,627	81,204	80,336	79,736	79,108	79,975	83,762	83,136	79,271	74,274
Spring	4	81,328	4/25/2015	70,103	67,939	67,020	66,547	67,168	69,006	71,703	74,718	78,388	80,573	81,229	80,585	79,254	77,989	76,524	75,846	75,920	76,367	77,196	78,592	81,328	80,481	76,912	72,711
Spring	4	78,641	4/26/2015	68,998	66,733	65,365	65,018	65,196	66,599	68,379	70,283	72,757	73,947	73,737	73,114	72,654	71,834	71,014	70,449	70,912	71,700	72,568	74,385	78,514	78,641	74,635	70,015
Spring	4	87,426	4/27/2015	66,829	65,306	65,049	65,572	68,020	73,824	82,618	86,943	87,212	86,396	85,861	85,461	85,286	85,059	84,062	83,093	83,113	83,284	83,418	84,578	87,426	86,109	80,499	74,689
Spring	4	86,575	4/28/2015	70,614	68,437	67,537	67,680	69,499	75,073	83,214	86,575	86,272	85,291	84,893	84,175	83,715	83,378	82,464	81,662	81,320	81,211	80,504	80,922	84,282	83,723	77,806	71,860
Spring	4	85,392	4/29/2015	67,391	65,158	64,311	64,383	66,049	71,188	79,342	83,688	84,000	83,748	83,865	84,076	84,127	84,055	83,922	83,386	83,441	83,091	82,316	82,238	85,392	84,133	78,015	71,640
Spring	4	84,996	4/30/2015	66,849	64,152	62,745	62,481	63,915	68,405	76,447	81,270	82,950	83,728	84,452	84,410	84,387	84,425	83,849	83,237	82,821	82,483	82,083	82,577	84,996	83,838	78,562	72,475
Spring	5	84,125	5/1/2015	67,925	65,541	64,293	63,867	65,277	69,823	77,465	81,807	83,276	83,756	84,125	83,824	83,361	82,868	81,969	80,993	80,561	79,930	78,987	78,780	80,847	80,526	76,290	70,964
Spring	5	75,726	5/2/2015	66,378	63,540	62,202	61,522	61,931	63,770	65,855	68,676	71,628	73,254	73,979	74,025	73,668	73,165	72,686	72,711	73,028	73,457	73,291	73,458	75,726	75,578	71,584	66,750
Spring	5	81,125	5/3/2015	62,644	60,271	58,750	57,813	57,821	58,950	59,831	62,016	65,391	68,350	69,849	71,140	71,974	72,735	73,210	73,775	75,106	76,746	77,499	78,239	81,125	80,230	74,983	69,060
Spring	5	92,899	5/4/2015	64,540	61,997	60,606	60,204	61,402	66,028	73,401	78,989	81,969	84,177	86,549	88,602	90,012	91,338	91,922	92,491	92,750	92,899	91,749	90,700	92,405	90,468	83,232	75,716
Spring	5	96,658	5/5/2015	69,968	66,622	64,338	63,429	64,362	68,489	75,777	81,251	84,537	86,733	89,433	91,278	92,747	94,514	95,786	96,407	96,658	95,982	94,420	93,357	94,599	92,563	85,276	77,525
Spring	5	97,579	5/6/2015	71,786	68,155	65,868	64,692	65,481	69,509	76,627	81,758	84,877	86,922	89,278	91,502	93,292	95,344	96,519	97,209	97,579	96,860	95,017	93,358	94,003	92,408	85,170	77,204
Spring	5	101,580	5/7/2015	71,157	67,167	65,023	63,894	64,663	68,648	75,632	80,855	84,032	87,168	90,155	92,665	95,317	97,666	99,481	100,677	101,550	101,580	100,019	97,858	97,951	96,136	88,299	79,838
Spring	5	107,010	5/8/2015	73,689	69,553	66,954	65,780	66,138	69,790	76,532	81,986	86,393	90,181	94,013	97,404	100,264	103,303	105,143	106,233	107,010	105,958	103,049	99,044	97,932	95,633	88,849	80,942
Spring	5	93,140	5/9/2015	74,128	69,589	66,760	64,961	64,300	65,202	66,572	69,842	74,863	79,340	82,604	84,856	86,677	88,319	89,907	91,476	92,712	93,140	91,896	89,770	89,522	89,052	84,034	77,384
Spring	5	94,750	5/10/2015	71,651	67,485	64,788	63,222	62,370	62,772	63,344	66,528	72,046	77,405	81,467	84,784	87,382	89,349	91,115	92,730	93,974	94,750	94,252	93,100	91,500	94,148	87,973	80,815
Spring	5	111,596	5/11/2015	74,641	71,036	68,754	67,913	68,731	73,376	80,666	87,222	91,888	95,470	99,525	102,977	106,540	109,327	111,070	111,405	111,596	110,838	108,609	105,271	104,433	101,272	92,715	84,055
Spring	5	105,026	5/12/2015	77,298	73,207	70,769	69,475	69,957	73,793	80,873	86,960	90,807	94,366	97,389	99,718	101,316	103,281	104,183	104,743	105,026	104,066	101,583	98,494	98,107	96,123	88,124	79,371
Spring	5	87,059	5/13/2015	73,032	69,062	66,671	65,400	65,885	69,585	76,120	81,072	83,534	85,033	86,111	86,455	86,531	86,695	86,895	86,734	87,059	86,840	85,538	84,612	85,811	85,308	79,276	72,892
Spring	5	86,168	5/14/2015	68,064	65,303	63,773	63,485	64,559	68,689	75,475	80,365	82,427	83,286	84,133	84,648	84,930	85,639	85,713	85,778	86,036	86,168	84,947	84,128	86,078	85,425	79,046	72,669
Spring	5	90,857	5/15/2015	67,620	64,450	62,980	62,356	63,462	67,467	74,020	78,971	82,076	83,998	85,846	86,978	87,895	89,084	89,727	90,317	90,857	90,617	89,090	87,277	87,661	87,327	82,299	76,078
Spring	5	92,740	5/16/2015	70,432	66,620	64,359	62,842	62,588	63,557	64,712	68,446	73,678	78,206	81,896	84,620	86,961	88,718	90,385	91,896	92,740	92,467	90,839	89,154	89,260	88,347	83,927	77,834
Spring	5	101,303	5/17/2015	72,388	68,525	65,911	64,348	63,620	63,840	64,349	67,069	72,588	77,860	82,231	86,330	89,986	92,866	95,043	97,377	99,760	101,303	101,284	100,035	99,746	98,657	92,177	84,439
Spring	5	113,132	5/18/2015	78,049	73,888	71,312	70,121	70,948	75,168	82,680	89,501	94,815	99,498	104,135	107,892	110,321	112,242	113,132	113,048	112,673	111,145	107,948	104,788	103,136	100,030	91,969	83,468
Spring	5	105,992	5/19/2015	76,822	72,698	70,157	68,832	69,317	73,121	79,731	85,499	88,721	91,453	94,389	96,771	98,696	100,568	102,464	104,373	105,918	105,992	104,140	100,934	99,824	97,994	90,154	81,562
Spring	5	89,431	5/20/2015	74,848	70,237	67,538	66,169	66,540	69,954	76,043	81,435	84,241	85,830	86,905	87,677	87,765	88,398	88,846	89,114	89,431	89,095	87,702	86,318	87,278	86,707	80,609	74,009
Spring	5	85,456	5/21/2015	68,841	65,848	63,961	63,373	64,344	68,459	75,247	80,381	83,156	84,539	85,313	85,456	85,282	85,294	84,832	84,120	84,050	83,910	83,311	83,021	84,083	83,712	78,819	72,482
Spring	5	84,002	5/22/2015	68,052	65,268	63,000	62,273	64,389	68,172	74,144	78,971	81,339	82,459	83,491	83,863	83,882	84,002	83,916	83,678	83,621	83,070	81,688	79,791	80,263	80,615	76,106	70,077
Spring	5	76,960	5/23/2015	65,132	61,893	60,029	59,156	59,110	59,993	60,917	63,823	67,597	70,542	72,110	72,769	72,963	72,986	73,218	74,095	75,506	76,780	76,960	76,104	76,339	76,651	73,015	67,980
Spring	5	83,360	5/24/2015	63,466	60,225	58,382	57,445	57,108	57,332	57,496	60,220	64,396	68,009	70,674	73,140	74,971	76,524	78,204	80,003	81,984	83,360	83,145	81,713	81,367	81,668	77,809	72,450
Spring	5	97,314	5/25/2015	67,314	63,452	61,364	60,081	59,922	60,579	61,169	64,107	69,300	74,713	79,932	84,039	87,462	89,806	91,786	93,846	95,800	97,314	96,753	95,021	94,697	94,304	87,690	80,164
Spring	5	118,081	5/26/2015	73,936	69,582	67,136	65,681	66,543	70,257	77,558	85,172	90,695	95,312	100,163	104,431	108,261	111,842	114,448	116,641	118,081	117,865	115,666	111,833	109,593	106,905	98,693	89,572
Spring	5	117,558	5/27/2015	82,002	77,113	74,119	72,435	72,885	76,724	83,655	90,760	95,691	99,623	103,737	107,873	111,291	114,351	116,475	117,188	117,558	116,788	113,468	109,640	107,408	105,056	97,112	87,745
Spring	5	120,840	5/28/2015	80,305	75,543	72,663	71,021	71,229	74,922	81,471	88,261	93,316	97,941	102,859	107,411	111,245	115,011	117,906	119,688	120,840	120,150	117,258	113,400	110,387	107,854	99,356	89,542
Spring	5	119,894	5/29/2015	81,639	76,301	72,765	71,189	71,233	74,490	80,527	87,410	92,551	97,610	102,315	106,432	109,930	113,615	116,639	118,730	119,894	118,783	115,083	110,053	106,707	104,809	98,197	89,907
Spring	5	108,167	5/30/2015	82,225	77,003	73,418	71,251	70,288	70,571	71,813	76,449	83,336	90,151	96,019	100,461	103,713	105,528	106,607	107,371	108,167	107,473	104,791	100,941	98,513	96,969	91,292	84,203
Spring	5	101,600	5/31/2015	77,739	73,023	69,793	67,564	66,504	66,289	66,602	70,269	76,598	83,199	88,759	93,467	96,915	99,534	100,878	101,600	101,427	101,173	99,371	96,824	95,848	94,189	88,161	81,121
Summer	6	101,491	6/1/2015	75,017	71,286	69,041	67,823	68,848	72,488	79,096	85,395	89,392	92,477	95,504	97,972	99,799	101,341	101,491	101,286	100,059	98,424	96,106	93,987	92,876	90,489	84,450	77,335
Summer	6	89,379	6/2/2015	71,706	68,637	66,709	65,912	66,631	70,304	76,472	81,764	84,822	86,787	88,318	89,117	89,174	89,379	88,665	87,999	87,592	87,327	86,411	85,481	85,813	85,120	80,113	73,559
Summer	6	88,867	6/3/2015	69,726	65,774	63,885	63,236	64,143	67,990	73,961	79,252	82,488	84,292	85,949	86,991	87,300	88,003	88,246	88,377	88,785	88,867	87,967	86,908	87,130	86,968	81,907	75,285
Summer	6	95,895	6/4/2015	69,938	66,778	64,706	63,853	64,697	68,343	74,420	80,106	83,780	86,338	88,779	90,486	91,796	93,540	94,475	95,236	95,895	95,643	94,579	93,241	93,036	92,269	86,977	79,481
Summer	6	97,569	6/5/2015	73,466	69,356	66,977	65,890	66,297	69,767	75,060	80,848	85,020	88,093	90,774	92,860	94,219	95,530	96,619	97,266	97,569	96,824	94,725	92,277	90,886	89,944	84,967	78,115
Summer	6	90,658	6/6/2015	71,784	67,392	64,954	63,633	63,155	63,881	64,947	68,438	73,196	77,817	81,330	83,590	84,994	85,950	86,747	88,048	89,618	90,658	89,675	87,410	85,258	84,710	80,482	74,186
Summer	6	93,701	6/7/2015	68,390	64,541	62,145	60,544	59,877	59,726	59,736	62,915	68,142	73,264	77,149	80,750	83,747	86,042	87,937	89,860	92,016	93,673	93,701	92,445	92,180	92,181	87,158	80,655
Summer	6	113,883	6/8/2015	74,848	71,097	68,845	67,753	68,531	72,334	78,570	85,106	90,263	94,478	98,771	102,209	105,323	108,742	111,215	112,826	113,883	112,546	109,923	106,678	104,236	100,864	93,724	85,348
Summer	6	114,190	6/9/2015	78,463	73,937	71,257	70,002	70,321	73,842	79,825	86,349	90,982	94,651	98,767	102,355	105,600	108,681	110,854	112,549	114,022	114,190	111,983	108,484	105,820	103,738	96,615	87,555
Summer	6	124,478	6/10/2015	80,198	74,925	71,791	70,258	70,202	73,427	79,085	86,068	91,808	97,018	102,298	106,991	111,164	115,425	118,703	121,948	124,053	124,478	121,894	117,521	113,928	111,533	103,804	94,069
Summer	6	131,922	6/11/2015	86,060	80,281	76,695	74,632	74,503	77,484	83,178	90,544	97,029	103,330	109,801	116,103	121,265	125,843	128,698	130,683	131,922	131,167	128,334	124,263	121,149	118,662	110,399	100,433
Summer	6	131,052	6/12/2015	91,964	85,816	81,708	79,276	79,153	81,835	87,408	95,522	103,235	110,463	117,547	123,114	127,188	129,890	131,052	130,533	129,030	126,626	122,150	117,220	114,044	111,986	105,231	96,633
Summer	6	117,700	6/13/2015	88,899	83,581	79,670	76,996	75,431	75,553	76,849	81,790	89,161	95,947	102,010	106,304	109,929	112,486	114,787	116,570	117,700	117,509	115,026	110,864	107,590	105,580	99,753	92,426
Summer	6	120,955	6/14/2015	85,380	80,393	76,714	74,307	72,922	72,332	72,546	76,853	84,337	91,792	98,178	103,460	107,853	111,440	114,271	116,594	118,005	120,955	118,559	115,341	112,736	110,206	103,736	96,544
Summer	6	134,129	6/15/2015	88,475	83,615	80,667	79,105	79,857	83,509	89,887	97,384	103,820	109,522	115,044	119,815	124,166	127,845	130,499	132,956	134,129	133,301	129,935	125,965	122,191	118,663	110,330	100,715
Summer	6	130,241	6/16/2015	92,559	86,853	83,204	80,948	81,006	84,186	90,148	97,487	103,999	109,987	115,427	119,724	122,973	125,939	127,572	129,058	130,241	129,247	126,543	121,863	116,898	113,690	105,614	95,788
Summer	6	112,899	6/17/2015	87,695	81,983	78,246	76,098	75,960	78,468	83,960	90,829	95,946	99,823	103,384	106,510	108,961	111,350	112,597	112,899	112,340	110,515	107,856	105,054	103,857	102,787	96,691	88,906
Summer	6	121,368	6/18/2015	82,238	77,923	75,107	73,868	74,334	78,092	83,673	90,340	95,970	100,691	105,813	110,111	113,783	117,420	119,697	121,368	121,187	118,607	115,406	111,686	108,940	106,534	99,559	91,163
Summer	6	115,405	6/19/2015	84,058	79,168	76,063	74,280	74,438	77,457	82,345	88,738	94,301	99,368	104,487	108,210	111,060	113,166	114,501	115,111	115,405	114,408	111,185	106,935	104,303	102,812	97,250	89,396
Summer	6	105,366	6/20/2015	82,531	77,768	74,335	72,234	71,280	71,763	72,794	76,153	81,919	87,712	92,641	96,525	99,469	101,652	103,291	104,701	105,366	105,275	103,687	101,664	99,795	98,001	93,540	87,305
Summer	6	120,192	6/21/2015	81,238	76,818	74,042	72,203	71,197	71,281	71,411	74,811	81,865	89,287	95,924	101,808	106,667	110,215	113,545	116,619	119,258	120,192	118,801	115,944	113,088	111,877	106,219	97,786
Summer	6	134,545	6/22/2015	89,809	84,263	80,488	78,391	78,109	80,555	85,993	94,547	102,310	108,989	115,659	120,881	124,948	128,331	131,501	133,635	134,381	134,545	133,126	129,542	125,754	123,177	115,142	104,923
Summer	6	137,287	6/23/2015	96,301	90,564	86,884	84,794	84,965	87,695	93,088	100,613	107,711	114,485	121,117	126,594	130,703	134,243	136,118	136,923	137,287	135,895	129,879	123,716	117,865	113,594	106,257	96,906
Summer	6	121,042	6/24/2015	88,719	82,755	78,635	76,028	75,294	77,317	81,933	88,691	94,352	99,048	103,809	107,796	111,449	114,909	117,485	119,727	121,042	120,884	118,516	114,130	109,480	107,124	99,438	90,585
Summer	6	113,915	6/25/2015	82,698	77,570	74,230	72,260	72,615	75,315	80,420	86,987	92,653	97,588	102,229	106,377	109,471	112,107	113,555	113,875	113,915	112,662	110,230	107,256	105,113	103,203	96,610	88,478
Summer	6	109,122	6/26/2015	81,645	76,988	74,049	72,727	75,393	80,176	85,816	90,875	95,273	99,251	103,307	107,137	109,967	112,347	113,512	113,122	109,106	108,072	105,112	101,475	99,026	97,703	92,282	85,084
Summer	6	87,808	6/27/2015	78,578	74,022	71,202	69,370	68,829	69,428	70,710	73,534	77,965	82,270	85,653	87,315	87,752	87,808	87,580	87,166	87,196	87,019	86,398	85,160	84,527	83,817	80,415	75,411
Summer	6	89,123	6/28/2015	70,775	67,441	64,881	63,137	62,718	62,698	62,725	65,450	70,205	74,732	78,296	80,706	83,012	84,566	85,621	86,924	88,145	89,123	88,708	87,685	86,756	87,094	83,013	76,863
Summer	6	103,222	6/29/2015	71,549	67,889	65,822	64,912	65,581	68,546	73,541	79,368	84,296	88,118	91,783	94,760	96,888	99,107	100,633	101,841	102,749	103,222	101,893	99,463	97,270	95,995	90,163	82,550
Summer	6	113,079	6/30/2015	76,166	72,087	69,649	68,496	68,947	72,095	77,172	83,330	88,861	93,408	97,999	102,253	106,118	109,760	111,847	112,568	113,079	112,269	109,317	105,592	103,129	101,356	94,891	86,705
Summer	7	112,608	7/1/2015	79,795	74,937	71,746	70,140	70,177	73,053	77,468	82,983	88,060	92,505	96,910	100,776	104,142	107,446	109,664	111,345	112,608	112,492	109,802	105,608	102,479	100,999	94,477	86,367
Summer	7	99,415	7/2/2015	79,215	74,513	71,408	69,868	70,067	72,643	77,208	82,581	87,014	90,379	93,758	96,084	97,647	99,030	99,415	99,396	99,255	98,987	97,017	94,168	92,210	91,280	86,224	79,226
Summer	7	96,403	7/3/2015	72,916	68,650	65,792	64,162	63,559	64,313	65,609	69,063	73,987	78,946	83,494	87,090	90,106	92,533	94,316	95,844	96,403	96,217	93,853	90,730	89,154	88,012	84,283	78,875
Summer	7	93,336	7/4/2015	73,366	69,160	66,454	64,583	63,673	63,908	63,725	66,124	70

Contains Proprietary Material
Do Not Distribute

Summer	8	127,063	8/14/2015	81,838	77,089	73,811	71,900	71,961	75,018	80,152	85,121	90,743	96,275	101,497	106,389	111,585	116,657	121,239	124,580	126,918	127,063	123,907	117,634	114,105	110,243	102,135	92,759
Summer	8	123,513	8/15/2015	84,704	79,157	75,077	72,649	71,251	71,815	72,932	75,664	82,476	89,911	97,129	103,977	109,787	115,053	119,073	122,007	123,513	123,009	119,954	115,144	111,627	107,898	100,512	92,516
Summer	8	129,803	8/16/2015	85,277	79,683	75,717	72,927	71,338	71,021	71,125	73,390	80,338	89,157	97,914	106,278	113,412	119,027	123,017	126,381	128,776	129,803	128,038	123,469	120,579	116,448	107,753	98,320
Summer	8	139,650	8/17/2015	90,613	85,102	81,652	79,518	79,527	82,905	88,813	94,554	101,653	110,183	119,009	127,178	133,528	137,803	139,650	139,643	139,482	138,100	134,818	130,364	128,109	122,410	112,220	101,998
Summer	8	133,464	8/18/2015	93,824	88,311	84,464	82,218	82,207	85,299	91,561	96,816	102,015	107,555	113,974	120,083	125,076	129,010	131,429	132,550	133,464	132,447	129,073	124,884	123,577	118,596	108,882	99,323
Summer	8	133,354	8/19/2015	91,517	86,621	83,433	81,536	81,891	85,629	92,439	98,092	104,019	110,017	116,353	121,342	126,023	129,856	132,299	133,286	133,354	131,513	127,533	122,725	121,301	116,791	107,867	98,778
Summer	8	121,714	8/20/2015	91,499	86,712	83,609	81,999	82,309	85,808	92,788	97,578	101,805	106,555	110,445	114,120	116,843	119,354	120,721	121,231	121,714	120,806	117,450	113,444	111,354	107,755	99,794	91,599
Summer	8	119,364	8/21/2015	84,669	80,048	76,952	75,043	75,158	78,116	83,710	87,979	92,971	97,638	102,279	105,838	109,070	112,431	115,685	117,557	119,364	118,597	115,041	109,165	105,966	102,033	94,953	86,865
Summer	8	106,985	8/22/2015	79,791	74,846	71,363	69,158	67,964	68,603	69,732	71,922	77,493	83,359	88,327	92,582	95,925	98,739	101,445	104,137	106,428	106,985	104,786	99,895	97,743	94,338	87,991	81,091
Summer	8	109,331	8/23/2015	75,112	70,813	67,935	66,103	64,955	65,178	65,782	67,375	72,521	78,502	83,770	88,826	93,517	97,886	101,652	105,042	107,949	109,331	107,831	104,743	104,263	100,855	93,616	86,336
Summer	8	121,793	8/24/2015	79,945	75,650	72,915	71,496	72,165	75,834	82,307	86,829	91,957	97,321	103,009	108,122	112,778	116,656	119,402	121,094	121,793	120,476	117,070	112,580	111,167	106,605	97,775	89,042
Summer	8	112,073	8/25/2015	82,202	77,933	74,975	73,226	73,427	76,947	83,239	87,567	92,164	96,533	100,830	103,908	106,401	108,725	110,359	111,348	112,073	111,650	108,511	104,557	104,033	99,489	91,425	83,201
Summer	8	102,854	8/26/2015	76,851	73,000	70,181	68,943	69,343	72,949	79,690	84,018	87,672	90,771	93,748	96,229	98,294	100,313	101,341	101,814	102,854	102,435	100,332	97,778	98,138	94,838	87,400	79,886
Summer	8	103,565	8/27/2015	74,215	70,706	68,415	67,340	68,066	71,817	78,634	83,039	86,866	90,405	93,747	96,268	98,455	100,660	101,860	102,551	103,565	103,232	101,037	98,271	98,932	95,491	87,945	80,196
Summer	8	107,563	8/28/2015	74,315	70,349	68,106	66,895	67,350	70,871	77,037	81,943	86,089	90,299	94,363	97,594	100,411	102,956	104,805	106,287	107,563	107,096	103,872	99,640	98,862	95,044	88,688	81,412
Summer	8	106,635	8/29/2015	75,142	70,867	67,931	66,244	65,641	66,389	68,193	70,675	75,890	81,917	87,725	92,662	96,840	100,371	103,032	105,259	106,635	106,373	104,109	100,909	100,812	97,318	91,465	84,599
Summer	8	114,421	8/30/2015	78,551	74,205	70,877	68,786	67,867	68,039	68,724	70,364	75,743	81,957	88,302	94,350	100,289	105,125	109,151	111,741	113,922	114,421	112,298	110,272	110,360	106,059	98,504	90,615
Summer	8	133,453	8/31/2015	84,155	79,596	76,824	75,526	76,197	80,577	88,886	93,754	98,272	103,502	109,716	115,741	120,703	125,016	128,767	131,434	133,380	133,453	130,421	126,187	124,641	118,254	108,015	98,292
Fall	9	138,975	9/1/2015	90,311	84,612	80,837	78,822	78,883	82,719	90,527	95,540	100,839	107,331	115,010	122,123	128,443	133,312	136,369	137,946	138,975	138,619	135,883	131,708	129,729	122,760	112,167	101,938
Fall	9	138,664	9/2/2015	93,316	87,642	83,323	80,874	80,665	84,679	92,515	97,023	101,741	108,078	115,464	122,748	129,233	134,512	137,576	138,664	138,256	136,928	133,723	129,383	127,332	121,240	111,031	100,831
Fall	9	141,210	9/3/2015	92,625	87,254	83,394	81,019	80,862	84,803	92,545	97,414	102,716	109,172	116,962	124,390	131,238	136,556	139,315	140,460	141,210	139,944	136,789	132,566	129,873	122,770	112,688	102,596
Fall	9	133,169	9/4/2015	94,068	88,404	84,514	82,253	81,975	85,068	91,906	96,695	102,006	108,100	114,742	121,345	126,655	130,832	133,022	133,169	132,062	128,910	123,081	118,136	115,484	110,141	102,595	94,320
Fall	9	116,000	9/5/2015	87,003	81,733	77,793	75,297	74,136	74,546	76,119	77,955	83,652	90,209	96,341	101,408	106,039	109,752	112,771	114,757	116,000	115,356	111,861	107,663	106,102	101,364	94,833	87,415
Fall	9	116,818	9/6/2015	80,926	75,752	72,355	70,088	68,781	68,690	69,374	70,523	76,111	83,615	90,800	97,825	103,603	108,479	112,162	114,907	116,604	116,818	113,815	109,278	107,374	102,547	96,018	88,913
Fall	9	128,068	9/7/2015	82,213	77,185	73,453	71,313	70,367	71,055	72,447	73,653	79,187	87,728	96,598	105,116	112,172	117,256	121,382	124,813	127,350	128,068	125,640	122,205	120,970	114,411	105,056	96,069
Fall	9	138,388	9/8/2015	88,600	83,423	80,006	78,077	78,377	82,589	91,042	96,799	102,390	109,208	117,167	124,404	130,507	135,037	136,882	137,554	138,388	137,910	134,995	131,253	129,801	122,120	111,764	101,647
Fall	9	131,701	9/9/2015	93,403	87,823	84,120	82,130	82,431	86,489	95,100	100,338	104,263	109,112	114,910	120,665	125,670	129,663	131,397	131,701	131,320	129,491	126,079	123,711	122,150	115,729	106,244	96,991
Fall	9	111,039	9/10/2015	89,591	84,827	81,550	79,317	79,641	83,626	92,040	96,481	99,198	102,362	105,363	107,599	109,419	110,677	111,017	110,923	111,039	110,341	108,231	106,655	106,095	101,162	93,497	85,550
Fall	9	107,715	9/11/2015	79,064	74,701	72,599	70,914	71,585	75,133	83,096	87,520	90,444	93,660	97,011	99,867	102,196	104,959	106,328	107,369	107,715	106,576	102,658	99,535	98,242	93,818	87,593	81,028
Fall	9	86,446	9/12/2015	75,193	71,049	68,374	66,390	66,000	67,131	69,566	72,239	76,560	80,681	83,896	85,813	86,446	86,344	85,877	85,267	84,940	84,880	84,347	85,279	86,000	83,695	79,054	73,936
Fall	9	83,047	9/13/2015	69,388	66,296	63,908	62,456	61,716	62,273	63,595	64,942	68,423	72,433	75,092	76,837	78,215	79,054	79,182	79,256	79,695	80,399	80,110	81,026	83,047	79,406	74,298	69,315
Fall	9	94,824	9/14/2015	65,519	63,253	61,910	61,549	62,804	66,976	74,594	78,873	81,324	83,719	86,116	87,842	88,967	90,214	91,519	92,802	94,293	94,824	93,710	93,393	93,895	89,197	82,175	75,344
Fall	9	105,341	9/15/2015	70,289	67,020	65,137	64,392	65,397	69,320	76,999	81,406	83,805	86,515	89,530	92,606	94,757	97,497	100,154	102,589	104,792	105,341	102,965	101,010	100,550	94,628	86,386	78,765
Fall	9	112,439	9/16/2015	72,843	69,239	67,138	66,057	66,816	70,705	78,305	82,543	85,335	88,916	92,937	96,644	100,238	103,887	107,312	110,140	112,260	112,439	109,489	107,043	105,609	99,382	90,668	82,525
Fall	9	116,254	9/17/2015	76,037	72,062	69,507	68,149	68,631	72,482	80,199	84,252	87,194	91,093	95,330	99,667	103,636	108,095	111,356	114,327	116,254	115,469	111,414	108,803	107,657	101,733	93,085	84,273
Fall	9	113,052	9/18/2015	77,948	74,130	71,191	69,687	70,102	74,018	81,487	85,310	88,911	92,804	96,969	100,565	104,096	107,559	110,309	112,094	113,052	111,789	107,577	104,994	103,004	98,064	91,388	83,886
Fall	9	100,447	9/19/2015	77,351	72,982	70,145	68,445	67,676	68,332	70,796	73,256	77,880	82,838	87,360	91,389	94,390	96,804	98,646	99,825	100,447	99,929	97,285	95,792	94,660	90,488	84,680	78,250
Fall	9	88,880	9/20/2015	72,917	69,180	66,541	64,825	64,083	64,255	65,421	66,661	70,369	74,366	77,236	79,681	81,658	83,380	84,865	86,522	87,984	88,799	87,503	88,072	88,880	84,006	77,828	72,115
Fall	9	92,517	9/21/2015	67,812	65,047	63,600	62,957	64,142	68,277	76,408	81,177	83,059	85,149	87,514	89,209	90,560	91,618	91,780	91,785	92,300	92,353	91,739	92,517	92,303	87,631	80,880	74,502
Fall	9	95,800	9/22/2015	69,575	66,674	64,906	64,114	65,091	69,185	77,364	81,878	83,730	85,950	88,511	90,052	91,705	93,473	94,287	95,074	95,800	95,704	94,527	94,908	94,845	90,060	82,857	75,985
Fall	9	100,172	9/23/2015	70,732	67,564	65,503	64,578	65,221	69,006	76,806	80,884	83,186	85,844	89,126	91,344	93,107	95,390	97,324	98,814	100,172	100,087	97,772	97,221	96,473	90,737	83,330	76,178
Fall	9	100,534	9/24/2015	70,586	67,369	65,383	64,405	65,243	69,018	77,147	81,553	83,479	85,972	88,725	91,625	94,051	96,320	98,053	99,567	100,534	100,055	97,256	97,424	96,937	91,495	84,372	77,004
Fall	9	93,655	9/25/2015	71,671	68,218	66,201	65,391	66,043	70,247	78,096	82,381	84,629	87,053	89,391	91,027	92,221	93,274	93,655	93,069	92,058	90,554	88,674	89,236	88,373	84,782	79,963	74,260
Fall	9	81,500	9/26/2015	69,184	65,817	63,411	62,110	61,802	62,945	65,593	68,232	71,781	75,274	77,654	78,861	79,412	79,737	79,687	80,064	80,236	80,232	79,774	81,361	81,500	78,778	74,624	69,849
Fall	9	87,012	9/27/2015	65,817	62,805	60,824	59,661	59,296	59,970	61,492	63,473	67,020	70,622	73,164	75,441	77,295	78,636	79,527	80,590	81,609	82,823	83,889	86,833	87,012	83,385	78,158	73,281
Fall	9	104,418	9/28/2015	69,046	66,310	64,776	64,473	65,717	70,263	78,838	84,726	87,118	89,711	92,511	94,966	97,310	99,856	101,620	102,718	103,335	103,336	102,507	104,418	103,342	98,218	90,802	83,254
Fall	9	102,180	9/29/2015	77,282	73,424	71,094	70,108	70,875	75,398	84,200	89,989	92,236	94,662	97,443	99,486	101,000	102,180	101,829	100,927	100,465	100,357	100,653	102,158	100,568	95,643	88,869	81,896
Fall	9	96,535	9/30/2015	76,091	72,649	70,603	69,899	70,628	75,076	83,963	89,436	91,113	93,015	94,632	95,899	96,417	96,535	95,530	94,647	93,785	92,597	91,727	93,321	92,495	87,748	81,082	74,311
Fall	10	86,056	10/1/2015	69,205	65,946	64,021	63,332	64,021	68,012	76,074	80,979	82,251	83,235	84,073	84,295	84,315	84,253	83,761	83,094	82,838	82,914	83,588	86,056	85,629	82,126	76,504	70,931
Fall	10	84,604	10/2/2015	66,564	63,760	62,313	61,661	62,694	66,710	74,480	79,964	81,602	82,878	83,952	84,143	83,995	83,818	83,308	82,474	82,576	82,711	83,336	84,604	83,634	80,564	76,066	71,189
Fall	10	80,819	10/3/2015	67,001	64,314	62,925	62,020	61,948	63,302	66,196	69,762	73,529	77,256	79,438	80,057	79,576	78,658	77,771	77,173	77,326	77,808	79,089	80,819	79,999	77,338	73,564	69,318
Fall	10	80,481	10/4/2015	65,328	62,645	60,838	59,880	59,646	60,476	62,498	64,826	67,822	70,881	72,320	72,969	73,206	72,844	72,535	72,608	73,360	74,823	76,648	80,481	80,446	77,052	72,576	67,748
Fall	10	88,823	10/5/2015	64,415	62,199	61,268	61,103	62,553	66,964	75,600	80,663	81,999	82,673	83,490	83,939	84,394	84,932	84,882	84,600	84,786	84,929	85,569	88,823	87,576	83,347	77,212	71,314
Fall	10	89,818	10/6/2015	66,976	64,225	62,893	62,519	63,636	68,096	76,445	81,353	82,032	82,833	83,987	84,450	85,260	86,012	86,527	86,867	87,058	86,849	86,812	89,818	88,906	84,383	77,914	71,949
Fall	10	90,766	10/7/2015	67,272	64,501	62,974	62,406	63,396	67,646	75,916	80,992	82,052	83,334	84,526	85,696	86,815	87,833	88,569	88,821	89,223	88,773	88,162	90,766	89,366	84,812	78,418	72,185
Fall	10	92,076	10/8/2015	67,290	64,283	62,822	62,131	63,043	67,189	75,324	80,265	81,377	83,043	84,977	86,618	88,152	89,732	90,397	90,457	90,430	89,657	89,453	92,076	90,823	86,530	80,403	73,797
Fall	10	89,459	10/9/2015	68,873	65,936	64,220	63,293	64,027	68,038	75,980	81,248	83,132	85,032	87,002	88,359	88,879	89,305	89,459	89,247	88,467	87,684	86,884	87,483	85,592	82,083	77,095	71,645
Fall	10	76,740	10/10/2015	66,698	63,399	61,412	60,324	59,992	61,175	63,924	67,049	69,839	72,398	73,663	73,839	73,302	72,714	72,295	72,251	72,660	73,057	73,907	76,740	76,155	73,876	70,384	66,540
Fall	10	79,722	10/11/2015	62,916	60,560	59,094	58,397	58,453	59,452	61,672	64,108	66,999	69,249	69,862	70,262	70,604	70,877	71,252	71,876	73,020	74,664	76,129	79,722	79,017	75,501	71,188	66,948
Fall	10	90,150	10/12/2015	63,463	61,276	60,401	60,356	61,881	66,134	73,766	79,024	80,684	82,231	83,814	84,662	85,315	85,959	86,311	86,544	86,997	86,936	87,468	90,150	88,179	83,889	77,610	71,615
Fall	10	89,378	10/13/2015	67,032	64,293	62,826	62,281	63,280	67,501	75,883	81,105	82,063	83,383	84,728	85,526	85,937	86,371	86,140	86,013	85,980	85,987	87,130	89,378	87,760	83,191	77,287	71,266
Fall	10	87,564	10/14/2015	66,914	64,078	62,475	62,127	63,142	67,441	75,746	81,212	82,044	82,592	83,374	83,584	83,924	84,248	84,197	83,717	83,682	83,500	84,710	87,564	86,300	82,368	76,554	71,009
Fall	10	87,090	10/15/2015	66,910	64,078	62,239	61,550	64,395	67,113	77,814	82,996	83,704	83,626	83,736	83,642	83,381	83,467	83,214	83,024	83,045	82,989	84,174	87,090	85,909	82,168	76,764	71,090
Fall	10	83,650	10/16/2015	66,993	64,458	63,224	62,988	64,325	68,707	76,677	81,975	82,759	83,277	83,427	83,179	82,572	82,247	81,507	80,586	80,289	80,212	81,210	83,650	82,613	80,047	76,175	71,595
Fall	10	80,754	10/17/2015	67,558	65,202	63,923	63,612	64,006	66,065	69,479	73,247	75,978	77,356	77,352	76,660	75,854	74,783	73,765	73,278	73,545	74,621	77,277	80,754	80,310	78,554	75,621	72,091
Fall	10	85,294	10/18/2015	69,031	67,140	66,104	65,854	66,458	68,244	70,957	74,033	76,751	77,621	76,723	75,832	75,375	74,957	74,183	73,797	74,653	76,693	80,328	85,238	85,294	82,561	78,857	75,003
Fall	10	94,825	10/19/2015	72,257	71,050	70,644	71,492	73,907	79,396	89,021	94,825	94,732	92,718	90,621	88,779	87,408	86,038	84,696	83,997	83,947	84,954	87,863	91,615	90,571	86,949	81,680	76,228
Fall	10	89,522	10/20/2015	72,284	70,092	69,055	68,978	70,740	75,951	84,352	89,522	88,806	87,631	86,867	85,779	84,895	84,572	84,266	83,890	83,808	83,948	86,059	89,370	87,875	83,639	77,733	72,247
Fall	10	89,211	10/21/2015	68,372	66,304	65,268	65,054	66,690	71,675	80,708	85,925	85,958	85,332	85,227	84,858	84,881	85,276	85,228	85,057	84,937	85,068	86,555	89,211	87,560	83,337	77,580	71,667
Fall	10	89,538	10/22/2015	67,447	65,095	63,872	63,511	64,882	69,475	78,252	83,860	84,291	84,254	84,540	84,739	84,842	85,478	85,713	85,486	85,584	85,372	87,154	89,538	87,563	83,428	77,669	71,711
Fall	10	84,304	10/23/2015	67,253	64,542	63,074	62,525	63,704	67,833	76,173	81,697	82,290	83,068	83,491	83,363	82,914	83,232	82,742	82,240	82,040	81,773	83,058	84,304	82,452	79,668	75,512	70,573
Fall	10	79,462	10/24/2015	66,468	63,858	62,299	61,528	61,937	63,594	66,924	70,645	73,628	75,845	76,903	76,688	75,853	74,820	73,993	73,504	73,958	75,426	78,327	79,462	78,016	75,612	71,977	67,718
Fall	10	80,613	10/25/2015	63,786	61,373	59,776	58,885	58,782	59,564	61,611	64,635	67,563	70,370	71,802	72,245	72,448	72,073	71,597	71,487	72,139	73,429	77,341	80,613	79,589	76,262	72,048	67,958
Fall	10	80,916	10/26/2015	64,792	63,065	62,356	62,444	63,575	69,797	79,074	85,631	86,103	85,885	85,525	84,973	84,129	83,423	82,657	82,042	82,275	83,289	87,040	89,916	88,223	84,671	79,270	74,113
Fall	10	91,828	10/27/2015	70,126	68,135	67,004	67,075	68,602	73,563	82,549	88,393	88,406	88,084	87,538	86,991	86,471	86,006	85,323	84,930	85,224	86,875	90,668	91,828	89,662	85,686	79,917	74,165
Fall	10	90,892	10/28/2015	70,098	67,664	66,231	65,644	66,861	70,987	79,229	85,200	86,498	86,962	87,906	88,042	87,899	87,920	87,342	86,772	87,162	87,952	90,302	90,892	88,814	84,859	79,151	73,422
Fall	10	89,137	10/29/2015	68,913	66,354	64,898	64,099	65,449	69,912	78,427	84,510	85,118	85,615	86,253	86,271	85,825	85,266	84,608	83,860	83,540	84,175	87,166	89,137	87,767	84,278	78,646	73,117
Fall	10	87,132	10/30/2015	69,067	66,605	65,565	65,437	66,836	71,286	80,303	86,632	87,132	86,433	86,140	85,303	84,304	83,313	82,271	81,467	81,518	82,227	84,963	86,132	84,773	82,327	78,534	74,007
Fall	10	79,901	10/31/2015	70,279	68,022	66,901	66,459	66,933	68,916	72,295	75,985	78,878	79,885	79,901	78,930	77,556	76,375	75,300	74,840	75,306	75,910	78,077	78,474	77,720	75,980	73,180	69,375
Fall	11	81,554	11/1/2015	65,834		61,163	60,639	60,853	62,471	64,662	67,216	70,568	72,601	72,910	72,639	72,588	72,011	71,736	71,822	73,615	78,987	81,554	80,614	78,728	74,872	70,765	66,840
Fall	11	91,502	11/2/2015	63,935	62,565	61,918	62,121	64,203	69,403	78,163	82,507	83,952	84,796	85,524	85,668	85,491	85,503	84,920	84,452	85,379	89,198	91,502	90,054	87,217	82,923	77,332	71,800
Fall	11	91,924	11/3/2015	68,314	66,371	65,379	65,483	67,527	72,979	80,891	84,433	84,766	84,705	84,985	85,526	85,698	86,218	86,261	86,161	86,305	89,486	91,924	90,251	87,585	83,109	77,069	71,262
Fall	11	92,479	11/4/2015	67,313	65,309	64,140	64,028	65,837	71,019	79,365	83,229	83,922	84,339	84,973	85,545	86,087	86,805	86,957	86,593	86,815	90,792	92,479	90,649	87,695	83,154	77,223	71,625
Fall	11	94,038	11/5/2015	67,445	65,000	63,664	63,484	64,713	69,368	77,930	82,277	84,373	86,069	87,342	88,023	88,593	89,264	89,167	88,777	89,014	92,609	94,038	92,221	89,373	85,042	78,777	73,160
Fall	11	90,735	11/6/2015	68,794	66,200	64,722	64,177	65,160	69,490	77,543	82,579	84,714	86,439	87,801	88,259	88,281	88,125	87,896	87,037	87,096	90,589	90,735	88,412	85,758	82,237	77,327	71,870
Fall	11	81,638	11/7/2015	67,304	64,306	62,628	61,685	61,770	63,465	66,053	69,326	73,166	76,032	77,065	77,360	76,973	75,921	75,048	74,716	76,099	80,202	81,638	80,393	78,963	76,665	73,412	69,729
Fall	11	84,934	11/8/2015	66,579	64,595	63,362	63,157	63,753	65,314	67,997	70,223	72,710	73,745	73,428	72,931	72,570	72,057	71,600	72,103	74,289	81,346	84,934	84,744	83,721	80,867	77,049	73,534
Fall	11	95,207	11/9/2015	71,126	69,769	69,616	70,288	72,716	78,288	87,746	91,868	91,519	90,562	89,863	88,940	88,325	87,889	87,108	86,695	88,700	93,725	95,207	93,612	90,859	86,483	80,568	75,186
Fall	11	92,824	11/10/2015	70,716	68,461	67,329	67,007	68,474	73,051	81,606	86,293	86,704	87,286	88,013	87,767	87,240	86,930	86,243	85,960	87,519	91,553	92,824	91,173	88,582	84,645	79,564	74,253
Fall	11	91,641	11/11/2015	70,708	68,513	67,503	67,506	69,114	73,628	81,245	85,423	86,169	86,213	86,091	85,392	84,603	84,062	83,330	83,095	84,777	90,254	91,641	90,209	88,138	84,588	79,304	74,041
Fall	11	92,782	11/12/2015	70,065	68,053	67,044	66,957	68,479	73,421	81,851	86,536	87,385	87,931	88,405	87,714	87,090	86,727	85,926	85,712	87,351	91,858	92,782	91,284	89,232	85,228	79,579	74,118
Fall	11	90,995	11/13/2015	70,247	68,091	67,145	67,214	68,928	73,687	82,290	86,664	86,890	86,397	86,120	85,309	84,640	83,973	83,270	82,845	84,559	89,872	90,995	89,850	88,429	85,684	81,731	77,028
Fall	11	85,130	11/14/2015	73,344	70,932	70,001	69,644	70,529	72,575	76,081	78,989	81,017	81,774	81,168	79,782	77,900	76,084	74,792	74,702	76,777	82,848	85,130	84,504	83,601	81,888	78,840	75,486
Fall	11	83,733	11/15/2015	72,640	70,870	70,016	69,870	70,555	72,236	74,665	76,811	77,785	77,013

Contains Proprietary Material
Do Not Distribute

	AP South
Max	70,729
Peak Month	7
PST	58,108
Winter	51,170
Spring	43,394
Summer	56,097
Fall	43,262

Source: ABB, The Velocity Suite

CONFIDENTIAL DATA REDACTED

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12		12/1/2014																								
Winter	12		12/2/2014																								
Winter	12		12/3/2014																								
Winter	12		12/4/2014																								
Winter	12		12/5/2014																								
Winter	12		12/6/2014																								
Winter	12		12/7/2014																								
Winter	12		12/8/2014																								
Winter	12		12/9/2014																								
Winter	12		12/10/2014																								
Winter	12		12/11/2014																								
Winter	12		12/12/2014																								
Winter	12		12/13/2014																								
Winter	12		12/14/2014																								
Winter	12		12/15/2014																								
Winter	12		12/16/2014																								
Winter	12		12/17/2014																								
Winter	12		12/18/2014																								
Winter	12		12/19/2014																								
Winter	12		12/20/2014																								
Winter	12		12/21/2014																								
Winter	12		12/22/2014																								
Winter	12		12/23/2014																								
Winter	12		12/24/2014																								
Winter	12		12/25/2014																								
Winter	12		12/26/2014																								
Winter	12		12/27/2014																								
Winter	12		12/28/2014																								
Winter	12		12/29/2014																								
Winter	12		12/30/2014																								
Winter	12		12/31/2014																								
Winter	1		1/1/2015																								
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Winter	1		1/3/2015																								
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Winter	2		2/1/2015																								
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Winter	2		2/26/2015																								
Winter	2		2/27/2015																								
Winter	2		2/28/2015																								
Spring	3		3/1/2015																								

Contains Proprietary Material
Do Not Distribute

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Contains Proprietary Material
Do Not Distribute

Summer	6		6/11/2015
Summer	6		6/12/2015
Summer	6		6/13/2015
Summer	6		6/14/2015
Summer	6		6/15/2015
Summer	6		6/16/2015
Summer	6		6/17/2015
Summer	6		6/18/2015
Summer	6		6/19/2015
Summer	6		6/20/2015
Summer	6		6/21/2015
Summer	6		6/22/2015
Summer	6		6/23/2015
Summer	6		6/24/2015
Summer	6		6/25/2015
Summer	6		6/26/2015
Summer	6		6/27/2015
Summer	6		6/28/2015
Summer	6		6/29/2015
Summer	6		6/30/2015
Summer	7		7/1/2015
Summer	7		7/2/2015
Summer	7		7/3/2015
Summer	7		7/4/2015
Summer	7		7/5/2015
Summer	7		7/6/2015
Summer	7		7/7/2015
Summer	7		7/8/2015
Summer	7		7/9/2015
Summer	7		7/10/2015
Summer	7		7/11/2015
Summer	7		7/12/2015
Summer	7		7/13/2015
Summer	7		7/14/2015
Summer	7		7/15/2015
Summer	7		7/16/2015
Summer	7		7/17/2015
Summer	7		7/18/2015
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Summer	7		7/20/2015
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Summer	7		7/26/2015
Summer	7		7/27/2015
Summer	7		7/28/2015
Summer	7		7/29/2015
Summer	7		7/30/2015
Summer	7		7/31/2015
Summer	8		8/1/2015
Summer	8		8/2/2015
Summer	8		8/3/2015
Summer	8		8/4/2015
Summer	8		8/5/2015
Summer	8		8/6/2015
Summer	8		8/7/2015
Summer	8		8/8/2015
Summer	8		8/9/2015
Summer	8		8/10/2015
Summer	8		8/11/2015
Summer	8		8/12/2015
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Summer	8		8/29/2015
Summer	8		8/30/2015
Summer	8		8/31/2015
Fall	9		9/1/2015
Fall	9		9/2/2015
Fall	9		9/3/2015
Fall	9		9/4/2015
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Fall	9		9/6/2015
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Fall	9		9/9/2015
Fall	9		9/10/2015
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Fall	9		9/16/2015
Fall	9		9/17/2015
Fall	9		9/18/2015
Fall	9		9/19/2015

Contains Proprietary Material
Do Not Distribute

Fall	9		9/20/2015																									
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Fall	11		11/29/2015																									
Fall	11		11/30/2015																									

Contains Proprietary Material
Do Not Distribute

	5004/5005
Max	52,190
Peak Month	7
PST	42,368
Winter	36,840
Spring	31,515
Summer	40,748
Fall	31,648

Source: ABB, The Velocity Suite
CONFIDENTIAL DATA REDACTED

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12		12/1/2014																								
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Winter	12		12/29/2014																								
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Winter	12		12/31/2014																								
Winter	1		1/1/2015																								
Winter	1		1/2/2015																								
Winter	1		1/3/2015																								
Winter	1		1/4/2015																								
Winter	1		1/5/2015																								
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	PJM East
Max	30,240
Peak Month	7
PST	24,093
Winter	19,303
Spring	16,803
Summer	22,934
Fall	17,326

Source: ABB, The Velocity Suite
CONFIDENTIAL DATA REDACTED

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
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FERC Form 714 Outages

Month	Planned Outage and Derating (MW)
Dec-14	13,851
Jan15	3,616
Feb15	7,609
Mar15	19,290
Apr15	34,834
May15	24,301
Jun15	4,660
Jul15	4,535
Aug15	3,566
Sep15	3,993
Oct15	46,567
Nov15	23,207

	Planned Outage and Derating (MW)					Generation (MW)			
	Winter	Spring	Summer	Fall	Note	Winter	Spring	Summer	Fall
PJM	8,359	26,142	4,254	24,589	PJM outages	199,600	196,690	183,060	192,785
AP South	3,540	11,141	1,835	10,738	Estimated based on generation ratios	84,538	83,829	78,969	84,193
5004/5005	2,512	7,879	1,297	7,620	Estimated based on generation ratios	59,991	59,282	55,814	59,741
PJM East	1,596	4,972	805	4,813	Estimated based on generation ratios	38,116	37,407	34,630	37,735

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	Operating Reserves					
	PST	Winter	Spring	Summer	Fall	Note
PJM	9,097	8,067	6,367	9,097	6,391	PJM Interconnection, L.L.C., Docket No. AD10-2 Reserves
AP South	2,868	2,552	2,266	2,772	2,230	5.93% of 5004/5005 Load + Dominion share of VACAR Reserves
5004/5005	2,512	2,185	1,869	2,416	1,877	5.93% of 5004/5005 Load
PJM East	1,429	1,145	996	1,360	1,027	5.93% of PJM East Load

Loads				
PST	Winter	Spring	Summer	Fall
121,600	112,390	94,917	117,821	95,173
58,108	51,170	43,394	56,097	43,262
42,368	36,840	31,515	40,748	31,648
24,093	19,303	16,803	22,934	17,326

Methodology
PJM Operating Reserves are based on the August 2016 PJM SIL filing
Submarket Operating Reserves = PJM Op Res * Submarket Load/PJM Load

Attachment 11: PJM Operating Reserves

PJM's Day-Ahead Scheduling Reserve (DASR) requirement is calculated using a 3 year historical average of both a Load Forecast Error (LFE) component, as well as a Forced Outage Rate (FOR) component. The LFE component is a 3 year historical average of the under forecasted load. The FOR is the 3 year historical average of resource forced outages which impacted next-day operations, and which were reported after the day-ahead commitments had been completed. The sum of the LFE and LOF components determine PJM's DASR for the next calendar year, calculated as a percentage of the forecasted peak load. Shown below is the calculation of the 2015 DASR, as well as the applicable reserve amounts which may be used by PJM members when filing a Market Share Analysis.

DASR = LFE + LOF (calculated as a percentage of forecasted peak load)
2015 DASR = 2.15% + 3.78%
2015 DASR = 5.93%

2015 SIL Operating Reserves		
Season	Peak Load (MW)	DASR (MW)
Winter	136,044	8067
Spring	107,372	6367
Summer	153,402	9097
Fall	107,782	6391

Area	Ancillary Service Market Area	Day-ahead Scheduling (Operating)	Contingency (Primary)	Synchronized Reserve
RTO		Annual %	150% Largest Single Contingency	Largest Single Contingency
	Mid-Atlantic & Dominion	N/A	1700 MW	Largest Single Contingency
SERC	Dominion	VACAR ARS%	VACAR ARS%	VACAR ARS%

Effective January 1, ~~2014~~ 2015 the Day-ahead Scheduling Reserve for RFC and EKPC regions of PJM is ~~6.27~~5.93% times Peak Load Forecast for RFC plus EKPC.

http://www.pjm.com/~/media/committees-groups/subcommittees/sos/20141125/20141125-item-06a-manual-13-version-57-2015-da

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PJM Generation Summary

	Modeled Generation MW			
	Winter	**Spring**	**Summer**	**Fall**
PJM	199,600	196,690	183,060	192,785
AP South	84,538	83,829	78,969	84,193
5004-5005	59,991	59,282	55,814	59,741
PJM East	38,116	37,407	34,630	37,735

Operating generation during the study period

	Winter	**Spring**	**Summer**	**Fall**
PJM	189,859	189,859	182,872	192,785
AP South	82,190	82,190	78,969	84,193
5004-5005	57,758	57,758	55,814	59,741
PJM East	35,883	35,883	34,630	37,735

Currently retired generation but operating during the study period

	Winter	**Spring**	**Summer**	**Fall**
PJM	9,741	6,832	189	0
AP South	2,349	1,639	0	0
5004-5005	2,234	1,524	0	0
PJM East	2,234	1,524	0	0

Generation Dataset Including Ventyx Data as of 9/29/2016

CONFIDENTIAL DATA REDACTED

Holding Company Name	Plant Name	Unit	Unit ID	Plant EIA ID	Node	Supplier	East Units	5004/5005 Units	AP South Units	Prime Mover Type

				Unit Capacity (MW)			Unit Capacity Adjusted for Ownership and Status		Modeled Ca	
Primary Fuel Type	Unit Status	Added During Study Period	Percent Owned %	Name Plate	Summer	Winter	Summer	Winter	Winter	Spring

	Modeled Ca	
	Winter	Spring
PJM	189,859	189,859
AP South	82,190	82,190
5004/5005	57,758	57,758
PJM East	35,883	35,883

pacity (MW)		Unit Onsite Capacity Use (MW)		Onsite Unit Usage Adjusted for Ownership and Status (MW)				
Summer	Fall	Summer	Winter	Summer	Winter	Online Date	Retirement Date	Proposed Retirement Date

pacity (MW)	
Summer	Fall
182,872	192,785
78,969	84,193
55,814	59,741
34,630	37,735

ABB Retirement Date	ABB Retirement Date - Source	Grid Connected (Y/N)	Plant County

Plant State	Unit NERC Region Abbrev	Plant NAICS

PJM Retired Units during the study period

CONFIDENTIAL DATA REDACTED

Unit ID	Holding Company Name	Plant Name	Unit	Plant Aliases	Season	East Units	5004/5005 Units	AP South Units

Retirement Date	ABB Retirement Date	ABB Retirement Date - Source	Plant Government ID	Unit NERC Sub Region Abbrev	Unit ISO Name	Unit ISO Zone Name	Percent Owned %	Modeled Capacity Nameplate	Modeled Capacity Summer

		Modeled Capacity Nameplate	Modeled Capacity Summer
PJM	Winter	911	829
	Spring	2,974	2,751
	Summer	6,868	6,509
	Fall	196	189
	Period	10,948	10,278
AP South	Winter	698	640
	Spring	624	570
	Summer	1,571	1,639
	Fall	0	0
	Period	2,893	2,848
5004/5005	Winter	48	45
	Spring	624	570
	Summer	1,456	1,524
	Fall	0	0
	Period	2,129	2,138
PJM East	Winter	48	45
	Spring	624	570
	Summer	1,456	1,524
	Fall	0	0
	Period	2,129	2,138

(MW)	Ventyx Database Capacity (MW)								
Winter	Nameplate	Summer	Winter	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Grid Connected (Y/N)	Plant NAICS Code

(MW)	Capacity to Add Back into Generation (MW)			
Winter	Winter	Spring	Summer	Fall
905	0	0	0	0
2,910	2,910	0	0	0
6,634	6,634	6,634	0	0
198	198	198	189	0
10,647	9,741	6,832	189	0
660	0	0	0	0
710	710	0	0	0
1,639	1,639	1,639	0	0
0	0	0	0	0
3,008	2,349	1,639	0	0
55	0	0	0	0
710	710	0	0	0
1,524	1,524	1,524	0	0
0	0	0	0	0
2,288	2,234	1,524	0	0
55	0	0	0	0
710	710	0	0	0
1,524	1,524	1,524	0	0
0	0	0	0	0
2,288	2,234	1,524	0	0

	Ventyx Database EIA Capacity (MW)				
Plant NAICS Description	**Nameplate**	**Summer**	**Winter**	**Plant City**	**Plant County**

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Plant State

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Contains Proprietary Material
Do Not Distribute

Southeast and MISO Generation Summary

	Modeled Generation MW			
	Winter	**Spring**	**Summer**	**Fall**
CPLE	14,696	14,696	13,525	14,720
CPLW	878	878	826	878
DUKE	25,619	25,619	24,632	25,619
LGEE	9,033	8,793	8,838	9,108
MISO	175,367	175,695	168,505	175,039
TVA	37,014	37,014	35,065	36,069

Operating generation during the study period

	Winter	**Spring**	**Summer**	**Fall**
CPLE	14,696	14,696	13,525	14,720
CPLW	878	878	826	878
DUKE	25,619	25,619	24,632	25,619
LGEE	8,301	8,301	8,677	9,108
MISO	174,022	175,003	168,404	175,039
TVA	36,069	36,069	34,127	36,069

Currently retired generation but operating during the study period

	Winter	**Spring**	**Summer**	**Fall**
CPLE	0	0	0	0
CPLW	0	0	0	0
DUKE	0	0	0	0
LGEE	732	492	161	0
MISO	1,345	692	101	0
TVA	945	945	938	0

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Southeast and MISO Retired Units CONTAINS PRIVILEGED MATERIAL

CONFIDENTIAL DATA REDACTED DO NOT RELEASE

Unit ID	Holding Company Name	Plant Name	Unit	Plant Aliases	Season	BAA	Retirement Date	ABB Retirement Date

						Modeled Capacity (MW)			Ventyx Dat
ABB Retirement Date - Source	Plant Government ID	Unit NERC Sub Region Abbrev	Unit ISO Name	Unit ISO Zone Name	Percent Owned %	Nameplate	Summer	Winter	Nameplate

		Modeled Capacity (MW)			Capacity t
		Nameplate	Summer	Winter	Winter
MISO	Winter	0	0	0	0
MISO	Spring	742	632	653	653
MISO	Summer	642	575	589	589
MISO	Fall	126	101	103	103
MISO	Period	1,510	1,309	1,345	1,345
LGEE	Winter	0	0	0	0
LGEE	Spring	272	240	240	240
LGEE	Summer	373	323	323	323
LGEE	Fall	189	161	169	169
LGEE	Period	833	724	732	732
TVA	Winter	0	0	0	0
TVA	Spring	0	0	0	0
TVA	Summer	0	0	0	0
TVA	Fall	1,125	938	945	945
TVA	Period	1,125	938	945	945

abase Capacity (MW)							
Summer	Winter	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Grid Connected (Y/N)	Plant NAICS Code

o Add Back into Generation (MW)		
Spring	Summer	Fall
0	0	0
0	0	0
589	0	0
103	101	0
692	101	0
0	0	0
0	0	0
323	0	0
169	161	0
492	161	0
0	0	0
0	0	0
0	0	0
945	938	0
945	938	0

	Ventyx Database EIA Capacity (MW)					
Plant NAICS Description	**Nameplate**	**Summer**	**Winter**	**Plant City**	**Plant County**	**Plant State**

Contains Proprietary Material
Do Not Distribute

	MISO	CPLE	CPLW	DUKE	LGEE	TVA
Max	118,332	14,383	1,186	21,101	7,236	32,751
Peak Month	7	2	2	2	2	1
PST	102,563	10,538	869	16,433	5,754	25,981
Winter	86,929	9,332	770	14,053	5,124	22,486
Spring	76,192	7,425	612	11,801	4,348	18,523
Summer	97,947	10,231	844	15,919	5,616	24,974
Fall	80,875	7,487	618	11,970	4,421	18,959

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	91,352	12/1/2014	65,909	64,245	63,482	63,438	64,509	67,485	73,235	80,235	82,680	83,202	83,862	84,202	84,060	84,152	83,896	83,628	84,111	87,614	91,082	91,352	90,226	88,350	84,357	79,529
Winter	12	88,515	12/2/2014	75,587	73,313	71,793	71,051	71,441	73,300	78,278	84,659	86,038	85,836	85,478	85,064	84,245	83,416	83,013	82,205	82,478	85,494	88,419	88,515	87,331	85,357	81,254	76,384
Winter	12	86,783	12/3/2014	72,348	70,047	68,712	68,184	68,790	71,035	76,257	82,751	83,917	83,185	82,266	81,283	80,053	79,320	78,712	78,110	78,714	82,396	86,497	86,783	85,945	84,267	80,626	75,638
Winter	12	86,587	12/4/2014	71,826	69,590	68,297	67,677	68,119	70,352	75,572	81,994	83,755	83,155	82,727	82,354	81,899	81,169	80,992	80,501	80,686	83,744	86,587	86,447	85,347	83,330	79,497	74,490
Winter	12	82,922	12/5/2014	70,181	67,422	65,939	64,837	65,040	67,252	72,299	78,329	80,283	80,481	80,761	80,789	80,431	79,955	79,552	78,755	78,772	81,228	82,922	81,959	80,298	78,718	75,908	71,894
Winter	12	79,699	12/6/2014	68,001	65,246	63,620	62,664	62,694	63,703	65,770	68,993	71,314	73,655	75,179	75,360	74,799	73,858	73,214	72,771	73,236	76,558	79,699	79,246	78,378	76,941	74,640	71,212
Winter	12	82,198	12/7/2014	67,898	65,493	64,203	63,275	63,463	64,105	65,696	68,013	70,208	72,421	73,544	73,321	72,905	72,622	72,219	72,025	73,086	77,840	81,790	82,198	81,417	79,590	76,224	71,919
Winter	12	86,601	12/8/2014	68,360	66,346	65,368	65,138	65,977	68,854	74,726	81,734	83,656	83,241	82,608	81,997	81,064	80,634	79,802	79,467	79,724	82,895	86,297	86,601	85,521	83,870	80,264	75,219
Winter	12	87,447	12/9/2014	71,211	68,881	67,822	67,532	68,119	70,744	76,666	83,657	85,393	84,430	83,725	82,790	81,856	81,083	80,802	80,429	80,884	83,937	87,210	87,447	86,623	85,028	81,180	76,197
Winter	12	88,921	12/10/2014	72,295	70,191	68,932	68,540	69,118	71,656	77,512	84,186	86,000	85,372	84,495	83,724	82,701	81,688	81,234	80,656	81,235	84,854	88,829	88,921	88,027	86,520	82,475	77,468
Winter	12	87,694	12/11/2014	73,472	71,022	69,696	69,318	69,909	72,537	78,180	84,859	85,850	85,191	84,571	83,683	82,340	81,034	80,225	79,357	79,586	83,448	87,399	87,694	87,053	85,488	81,815	76,838
Winter	12	84,572	12/12/2014	72,775	70,436	69,021	68,397	69,011	71,142	76,484	82,884	84,572	83,859	83,201	82,273	81,059	79,970	79,313	78,495	78,655	81,522	83,862	83,036	81,817	80,004	77,117	73,079
Winter	12	76,243	12/13/2014	69,134	66,152	64,478	63,679	63,361	64,226	66,284	69,344	71,859	73,738	74,574	73,907	72,779	71,559	70,545	69,723	70,295	73,266	76,243	75,988	74,717	73,267	70,901	67,494
Winter	12	76,562	12/14/2014	64,072	61,499	60,069	59,264	59,193	59,735	61,248	63,730	66,251	68,213	68,871	68,632	68,374	68,213	67,802	67,719	68,644	72,584	76,245	76,562	75,779	74,029	70,621	66,568
Winter	12	83,910	12/15/2014	63,115	60,943	59,917	59,522	60,224	62,776	68,355	75,393	77,943	78,005	78,452	78,695	78,577	78,253	77,881	77,551	77,868	81,081	83,910	83,909	82,694	80,675	76,801	71,858
Winter	12	87,992	12/16/2014	67,652	65,132	63,654	63,060	63,690	66,002	71,544	78,530	80,993	81,010	81,180	81,098	80,635	80,325	80,165	79,793	80,491	83,578	87,244	87,992	86,932	84,822	82,071	76,530
Winter	12	89,983	12/17/2014	73,704	71,120	70,164	69,764	70,380	73,060	78,957	85,710	87,480	86,632	85,802	84,865	83,590	82,538	82,006	81,664	82,167	85,793	89,601	89,983	89,137	87,570	83,961	78,729
Winter	12	88,469	12/18/2014	74,421	71,913	70,405	69,821	70,224	72,438	77,854	84,271	85,765	85,312	85,022	84,595	83,565	82,937	82,544	82,094	82,624	85,603	88,469	88,186	87,541	85,617	82,131	77,119
Winter	12	87,127	12/19/2014	72,985	70,457	68,928	68,341	68,639	70,762	75,966	82,311	84,561	84,439	84,250	83,758	83,115	82,208	81,900	81,156	81,456	84,715	87,127	86,076	84,723	83,003	80,266	76,256
Winter	12	80,990	12/20/2014	72,176	69,235	67,713	66,754	66,458	67,279	69,540	72,587	75,414	77,644	78,994	78,866	77,808	76,325	75,147	74,368	74,872	77,994	80,990	80,880	79,983	78,735	76,553	73,193
Winter	12	80,003	12/21/2014	70,175	67,566	65,970	65,175	65,044	65,736	67,405	70,266	72,618	74,423	74,868	74,168	73,289	72,432	71,453	70,863	71,866	75,685	79,502	80,003	79,495	78,067	75,420	71,559
Winter	12	83,069	12/22/2014	68,103	65,811	64,447	63,856	64,141	66,307	70,628	76,096	79,142	79,714	80,283	80,458	79,816	79,242	78,660	78,089	78,229	80,697	83,069	82,808	81,656	79,580	76,246	71,534
Winter	12	80,631	12/23/2014	67,324	64,261	62,526	61,487	61,505	63,416	67,420	72,699	75,702	76,777	77,532	77,897	77,299	76,455	76,146	75,401	75,308	77,972	80,631	80,324	79,158	77,391	74,407	69,947
Winter	12	74,745	12/24/2014	65,699	62,666	60,671	59,780	59,762	60,856	63,600	67,592	70,864	72,992	74,318	74,745	73,952	72,738	72,052	71,344	71,384	73,065	74,384	73,319	72,221	71,442	70,239	68,095
Winter	12	70,102	12/25/2014	65,475	63,171	61,496	60,735	60,899	61,725	63,674	66,347	68,834	70,102	70,079	69,119	67,279	64,876	62,839	61,145	61,135	63,634	67,492	68,633	68,911	68,586	67,238	64,783
Winter	12	75,012	12/26/2014	62,058	60,072	59,019	58,720	59,121	60,672	63,732	67,276	69,539	70,812	71,485	71,614	70,706	69,615	68,601	68,089	68,432	71,603	75,012	74,580	73,542	72,064	69,471	66,031
Winter	12	75,252	12/27/2014	62,703	60,131	58,516	57,499	57,351	57,867	59,493	61,871	64,019	66,387	68,828	70,116	70,287	69,872	69,132	68,617	69,517	72,462	75,252	75,068	74,312	73,061	71,006	68,023
Winter	12	80,080	12/28/2014	65,096	62,894	61,689	60,850	61,046	61,713	63,279	65,634	67,610	69,631	71,297	71,889	72,177	71,885	71,384	70,841	71,703	75,197	79,859	80,080	79,686	78,175	75,708	72,282
Winter	12	87,028	12/29/2014	69,260	67,552	66,592	66,301	66,844	68,919	73,112	78,320	80,808	81,885	82,235	82,056	81,176	80,191	79,353	78,551	78,782	82,145	86,760	87,028	86,032	84,138	80,942	76,842
Winter	12	90,469	12/30/2014	73,514	71,394	70,040	69,596	70,045	72,053	76,124	81,024	83,498	84,368	84,835	84,546	83,903	83,068	82,143	81,525	81,699	85,277	89,898	90,469	89,807	88,391	85,600	81,760
Winter	12	87,295	12/31/2014	78,397	76,276	75,084	74,643	74,916	76,608	80,225	84,667	86,756	87,295	87,025	85,912	84,074	82,059	80,547	79,082	78,827	82,019	86,521	85,825	83,749	81,673	79,285	76,651
Winter	1	80,590	1/1/2015	74,302	72,198	70,655	69,594	69,047	69,505	70,688	72,086	72,591	73,799	75,195	75,862	75,617	74,496	73,328	72,634	73,366	76,709	80,590	80,452	79,243	77,643	74,923	71,386
Winter	1	81,261	1/2/2015	68,324	66,213	64,941	64,462	64,877	66,395	69,805	74,000	76,553	77,743	78,710	78,685	77,882	77,066	76,336	75,716	75,650	78,372	81,261	80,693	79,319	77,434	74,774	71,242
Winter	1	78,000	1/3/2015	67,747	65,265	63,545	62,636	62,546	63,060	64,470	66,761	68,893	70,777	72,901	74,102	74,525	74,079	73,399	72,703	72,970	75,211	78,000	77,738	76,632	75,134	72,677	69,718
Winter	1	88,160	1/4/2015	66,815	64,569	63,269	62,669	62,756	63,692	65,269	67,845	70,420	72,812	74,609	75,680	76,385	76,924	76,920	76,852	77,926	81,558	87,218	88,160	87,835	86,160	83,463	80,201
Winter	1	97,062	1/5/2015	77,786	76,794	76,345	76,648	77,844	80,943	86,991	94,113	96,101	95,533	94,776	93,804	92,414	91,114	89,877	88,956	88,955	91,770	95,949	97,062	96,223	94,240	90,584	86,246
Winter	1	94,607	1/6/2015	82,462	80,516	79,482	79,100	79,434	81,993	87,173	93,476	94,607	93,321	91,767	89,979	88,160	86,978	86,046	85,210	85,509	88,393	92,789	94,147	93,489	91,959	88,699	84,845
Winter	1	103,050	1/7/2015	81,808	80,001	79,104	79,045	79,825	82,577	88,014	94,214	96,147	95,821	95,476	95,020	93,982	93,008	92,313	91,688	92,164	95,543	101,268	103,050	102,782	101,355	98,204	94,363
Winter	1	104,733	1/8/2015	91,587	89,965	89,021	88,838	89,549	92,045	96,921	103,269	104,733	103,792	102,669	101,391	100,062	98,460	96,974	95,717	95,635	98,184	102,104	102,707	101,414	99,240	94,998	89,943
Winter	1	98,484	1/9/2015	86,369	83,948	82,888	82,303	83,006	85,109	90,197	96,298	97,923	97,331	96,533	95,815	94,489	93,147	92,205	91,378	91,393	93,851	98,192	98,484	97,424	95,632	92,716	89,166
Winter	1	92,037	1/10/2015	86,101	83,864	82,785	82,410	82,751	83,982	86,075	88,974	90,989	92,037	91,732	90,072	87,668	85,123	83,150	81,626	81,904	84,599	88,922	89,242	88,296	86,686	84,005	80,352
Winter	1	84,899	1/11/2015	77,078	74,723	73,393	72,450	72,131	72,475	73,738	75,947	77,727	79,517	80,161	79,916	79,361	78,775	78,120	77,453	77,853	80,831	84,743	84,899	83,801	81,445	78,260	74,310
Winter	1	93,117	1/12/2015	71,393	69,770	68,736	68,553	69,428	72,078	77,476	84,282	86,621	86,275	86,419	86,475	85,953	85,558	85,017	84,479	84,562	87,357	92,219	93,117	92,436	90,620	87,215	82,936
Winter	1	96,466	1/13/2015	79,616	77,768	76,751	76,570	77,369	80,236	85,850	92,825	94,717	93,706	92,805	91,872	90,383	89,376	88,314	87,440	87,504	90,347	95,340	96,466	95,894	93,830	90,104	85,357
Winter	1	95,412	1/14/2015	81,989	80,251	79,206	78,992	79,599	81,785	87,245	93,841	95,412	94,730	93,678	92,364	90,959	89,446	88,277	87,415	87,502	90,024	94,410	94,848	93,728	91,333	87,180	82,260
Winter	1	91,641	1/15/2015	78,535	76,617	75,452	75,027	75,611	78,008	83,659	89,983	91,641	90,222	88,999	87,713	86,205	84,730	83,493	82,140	81,750	83,499	88,509	90,101	89,692	87,897	84,616	80,135
Winter	1	91,902	1/16/2015	77,038	75,315	74,378	74,371	75,196	77,847	83,400	90,174	91,902	90,292	87,957	85,476	83,050	80,875	79,289	77,748	77,137	78,702	82,884	83,869	83,326	82,173	79,877	76,406
Winter	1	79,190	1/17/2015	73,596	71,663	70,434	69,921	70,000	70,939	73,099	76,072	78,246	79,190	78,448	76,727	74,701	72,680	70,837	69,603	69,628	71,713	75,619	76,388	75,619	74,034	71,944	68,909
Winter	1	75,607	1/18/2015	66,344	64,381	63,340	63,081	63,333	64,080	65,928	68,641	70,904	72,445	72,373	71,107	69,906	68,836	67,756	66,788	66,736	68,786	73,260	75,607	75,217	74,000	72,140	69,439
Winter	1	83,172	1/19/2015	67,323	66,196	65,780	65,958	67,058	69,691	74,798	80,731	83,172	83,113	82,100	80,446	78,647	77,167	75,979	74,939	74,846	76,665	80,374	82,087	81,204	79,346	75,891	71,834
Winter	1	83,665	1/20/2015	68,686	66,927	65,989	65,840	66,388	69,203	75,008	81,896	83,665	82,363	80,985	79,644	78,246	77,176	76,786	76,053	76,096	77,908	81,455	82,536	81,715	79,712	76,444	71,924
Winter	1	84,002	1/21/2015	68,667	66,787	65,823	65,532	66,192	68,784	74,413	81,451	83,300	82,045	80,886	79,995	78,893	78,153	77,792	77,276	77,203	79,063	82,785	84,002	83,032	81,135	77,756	73,368
Winter	1	88,377	1/22/2015	70,050	68,079	66,936	66,631	67,238	69,661	75,204	82,039	83,847	83,226	83,057	82,737	82,004	81,590	81,293	80,895	81,421	83,779	87,711	88,377	87,389	85,374	81,619	76,785
Winter	1	86,266	1/23/2015	73,330	71,253	70,062	69,486	69,981	72,326	77,530	84,236	86,266	85,968	85,926	85,366	84,016	82,694	81,622	80,763	80,526	81,992	85,391	85,849	84,675	83,025	80,133	76,739
Winter	1	79,412	1/24/2015	73,411	71,284	70,052	69,708	69,793	70,803	73,155	76,395	78,592	79,412	78,731	77,029	74,852	72,784	70,751	69,246	68,748	70,329	74,503	76,095	75,604	74,490	72,578	69,661
Winter	1	80,008	1/25/2015	67,091	65,340	64,297	63,766	63,843	64,662	66,398	68,901	71,376	72,970	73,283	72,603	71,953	71,375	70,698	70,135	70,826	73,442	78,088	80,008	79,519	77,948	75,220	71,945
Winter	1	87,302	1/26/2015	69,377	67,901	67,446	67,570	68,736	71,723	77,820	85,325	87,302	86,366	85,468	84,269	82,761	81,575	80,639	79,393	78,982	80,406	84,426	86,456	85,485	83,332	79,728	75,274
Winter	1	85,506	1/27/2015	71,909	70,061	68,932	68,682	69,339	71,778	77,295	84,315	85,506	84,123	82,545	81,249	79,960	79,028	78,338	77,509	77,223	78,532	82,574	84,421	83,788	82,117	78,685	74,574
Winter	1	86,794	1/28/2015	71,441	69,846	69,124	69,112	69,777	72,639	78,667	85,485	86,794	85,010	83,188	81,450	79,767	78,369	77,612	76,787	76,759	78,335	82,357	84,045	82,965	81,192	77,797	73,091
Winter	1	84,553	1/29/2015	69,554	67,422	66,201	65,656	66,003	68,230	73,616	80,383	82,303	81,574	81,311	81,075	80,406	79,996	79,867	79,364	79,397	80,478	83,407	84,553	83,630	81,716	78,340	74,087
Winter	1	85,804	1/30/2015	70,823	68,862	67,873	67,696	68,514	71,202	76,812	83,922	85,804	84,925	83,962	82,631	80,812	79,229	77,649	76,131	75,598	76,686	80,771	82,828	82,353	81,260	79,046	75,809
Winter	1	78,702	1/31/2015	72,826	70,539	69,612	69,138	69,150	70,035	72,127	74,976	77,090	78,690	78,702	77,443	75,558	73,838	72,654	72,085	72,011	73,757	77,066	78,043	76,975	75,622	73,475	70,497
Winter	2	78,886	2/1/2015	67,603	65,501	64,175	63,604	63,357	63,899	65,365	67,467	69,401	71,631	73,262	73,766	74,106	74,235	74,141	73,844	74,302	76,023	78,596	78,886	78,024	77,092	75,838	73,313
Winter	2	92,168	2/2/2015	70,687	69,521	69,230	69,807	71,092	74,085	80,007	87,457	90,063	90,005	89,646	88,456	86,800	85,179	83,837	82,451	82,136	83,921	88,963	92,168	91,676	89,953	86,706	82,153
Winter	2	92,824	2/3/2015	78,999	77,337	76,610	76,339	77,031	79,610	85,145	91,907	92,824	91,519	89,839	88,360	86,404	84,735	83,308	82,285	81,978	83,564	87,769	89,991	89,218	87,232	83,366	78,767
Winter	2	90,369	2/4/2015	75,177	72,966	71,761	71,329	71,860	74,357	79,824	86,481	87,514	86,618	85,816	85,147	84,151	83,596	83,117	82,760	82,958	84,346	88,095	90,369	89,697	88,094	84,790	80,542
Winter	2	92,801	2/5/2015	77,663	75,990	75,477	75,521	76,458	79,062	84,770	91,631	92,801	91,441	89,899	88,350	86,458	84,891	83,615	82,275	81,708	82,882	87,890	91,410	91,457	89,974	86,748	82,619
Winter	2	92,183	2/6/2015	79,608	77,809	76,999	76,535	77,154	79,509	84,836	91,273	92,183	90,723	88,726	86,134	83,629	81,372	79,693	77,961	76,917	77,214	80,362	82,660	82,123	80,991	78,696	75,488
Winter	2	77,785	2/7/2015	72,273	70,441	69,280	68,723	68,760	69,891	72,161	75,245	76,959	77,785	76,649	74,458	72,154	69,903	68,096	66,778	66,517	67,394	70,794	73,139	72,325	71,090	68,925	65,950
Winter	2	75,427	2/8/2015	63,304	61,414	60,354	59,663	59,677	60,263	61,657	63,917	65,753	67,558	68,252	67,748	67,547	67,450	67,149	66,986	67,594	69,463	72,998	75,427	74,867	72,761	70,286	66,782
Winter	2	85,379	2/9/2015	64,249	62,749	62,093	62,009	62,851	65,800	71,678	78,811	80,947	81,230	81,361	81,295	80,858	80,435	80,019	79,358	79,143	80,045	83,209	85,379	84,424	82,396	78,767	74,372
Winter	2	85,866	2/10/2015	71,068	69,223	68,354	68,200	69,032	71,590	77,527	84,377	85,866	85,015	83,918	82,531	81,007	79,479	78,408	77,232	76,661	77,768	81,282	84,452	84,408	82,834	79,400	75,218
Winter	2	85,981	2/11/2015	72,095	70,290	69,301	69,069	69,906	72,454	78,226	85,150	85,981	84,605	83,201	81,820	80,632	79,758	79,136	78,656	78,515	79,680	82,751	85,756	85,375	83,963	80,815	76,710
Winter	2	90,538	2/12/2015	73,681	72,206	71,435	71,462	72,509	75,426	81,456	88,535	89,851	89,088	88,165	86,906	85,476	84,180	83,416	82,460	82,105	83,262	87,086	90,538	90,381	89,196	86,121	82,139
Winter	2	92,340	2/13/2015	78,890	77,144	76,175	76,246	76,963	79,421	84,734	91,110	92,340	91,203	89,747	87,765	85,460	83,263	81,850	80,333	79,610	80,023	82,617	85,300	84,607	83,344	81,029	77,552
Winter	2	83,778	2/14/2015	74,604	72,776	71,596	71,042	71,440	72,524	74,790	77,569	79,686	81,171	81,075	79,991	78,699	77,301	76,185	75,331	75,707	77,016	80,596	83,778	83,234	82,005	80,120	77,411
Winter	2	86,460	2/15/2015	75,144	73,539	72,750	72,441	72,627	73,703	75,288	77,521	79,399	81,094	81,651	80,912	79,981	79,031	77,983	77,099	77,633	79,669	83,763	86,460	85,639	83,970	81,280	78,107
Winter	2	93,857	2/16/2015	75,594	73,982	73,096	73,046	73,663	75,835	80,190	85,097	87,024	88,298	89,216	89,384	88,754	88,077	87,353	86,607	86,527	87,742	91,087	93,857	92,934	90,943	87,706	83,715
Winter	2	94,782	2/17/2015	81,103	79,672	79,002	79,032	79,822	82,379	87,668	93,306	94,667	94,782	93,981	92,700	90,878	89,172	87,516	86,154	85,489	86,550	90,053	93,938	93,792	92,215	88,856	84,738
Winter	2	96,371	2/18/2015	81,861	80,477	79,803	79,946	80,701	83,319	88,880	94,831	96,001	94,745	93,522	92,296	90,812	89,671	88,705	87,714	87,577	88,696	92,401	96,343	96,371	95,287	92,427	88,427
Winter	2	99,150	2/19/2015	85,565	84,135	83,507	83,710	84,608	87,141	92,367	98,171	99,150	98,143	96,569	94,822	92,466	90,626	89,091	87,582	87,272	88,231	91,935	96,220	96,391	95,096	92,162	88,163
Winter	2	95,864	2/20/2015	85,079	83,433	82,504	82,206	82,678	84,639	89,249	94,778	95,864	95,342	94,318	92,893	90,917	89,236	87,990	86,730	86,113	86,432	88,390	89,930	88,390	86,287	82,914	78,789
Winter	2	79,998	2/21/2015	75,319	72,677	70,984	70,110	69,708	69,950	71,760	73,804	75,422	77,591	78,548	78,414	77,447	76,157	74,662	73,379	73,096	74,190	76,918	79,998	79,508	78,239	76,053	73,082
Winter	2	86,490	2/22/2015	70,464	68,720	67,762	67,401	67,392	67,970	69,623	71,655	73,418	75,733	76,947	76,978	76,776	76,714	76,377	76,199	76,832	78,904	82,807	86,490	86,424	84,991	82,641	79,523
Winter	2	98,370	2/23/2015	77,410	76,055	75,708	75,990	77,342	80,356	86,137	92,714	94,542	94,478	94,090	93,577	92,742	91,846	90,648	89,529	89,267	90,703	94,424	98,370	97,812	95,780	91,991	87,424
Winter	2	95,668	2/24/2015	84,151	82,240	81,172	80,802	81,409	83,791	88,793	94,630	95,668	94,948	93,972	92,588	90,900	89,075	87,424	85,627	84,710	85,537	88,492	92,455	92,134	90,084	86,378	81,549
Winter	2	92,598	2/25/2015	78,512	76,813	75,895	75,865	76,677	79,273	84,663	90,596	91,469	90,569	89,907	88,924	87,700	86,476	85,627	84,855	84,689	85,969	88,905	92,598	92,521	90,588	87,184	82,938
Winter	2	95,046	2/26/2015	79,690	77,851	77,162	77,087	77,887	80,625	86,287	92,303	93,453	93,212	92,389	91,173	89,343	87,951	86,995	85,844	85,585	86,778	89,934	94,457	95,046	93,808	90,670	86,743
Winter	2	97,543	2/27/2015	83,852	82,445	81,788	81,933	82,742	85,407	90,958	96,964	97,543	95,926	93,900	91,503	88,977	86,771	85,056	83,415	82,713	83,443	86,150	90,437	90,670	89,674	87,451	84,386
Winter	2	87,028	2/28/2015	81,593	79,796	78,824	78,439	78,632	79,673	81,799	84,116	85,951	87,028	86,323	84,088	81,438	78,946	76,909	75,578	75,545	76,577	79,133	82,341	82,027	80,747	78,349	75,282
Spring	3	81,816	3/1/2015	72,404	70,406	69,130	68,463	68,298	68,682	69,977	71,573	73,090	75,206	75,893	75,744	75,245	74,785	73,957	73,507	73,823	74,978	77,915	81,816	81,652	79,864	76,907	73,553
Spring	3	87,149	3/2

Contains Proprietary Material
Do Not Distribute

Spring	3	70,760	3/29/2015	64,013	62,006	61,052	60,564	60,567	61,138	62,530	64,537	66,107	67,590	68,245	68,115	67,828	67,470	66,807	66,381	66,378	67,455	68,096	68,419	70,102	70,760	68,007	64,300
Spring	3	74,416	3/30/2015	60,934	59,003	57,978	57,620	58,393	60,801	66,133	72,309	73,837	73,772	74,008	73,964	73,806	73,570	73,351	72,887	72,375	72,285	71,917	72,011	74,112	74,416	70,890	65,977
Spring	3	74,274	3/31/2015	61,992	59,301	57,852	57,323	57,647	59,762	64,634	70,682	72,214	72,492	72,836	72,956	72,954	72,912	73,061	72,764	72,353	72,117	71,644	71,351	73,547	74,274	70,698	65,802
Spring	4	73,704	4/1/2015	61,805	59,283	57,906	57,197	57,597	59,600	64,377	70,102	71,504	71,654	72,043	72,302	72,549	72,834	73,161	72,785	72,467	72,052	71,517	71,151	73,211	73,704	70,316	65,582
Spring	4	74,414	4/2/2015	61,224	58,519	56,917	56,025	56,292	58,129	62,475	68,210	70,248	71,475	72,674	73,588	73,977	74,103	74,414	74,095	73,664	73,064	72,395	71,776	72,791	72,941	69,778	65,302
Spring	4	70,792	4/3/2015	61,136	58,207	56,538	55,714	55,538	56,730	59,741	63,763	65,965	68,290	69,915	70,792	70,773	70,691	70,549	70,094	69,527	69,364	68,784	68,189	69,243	70,140	68,017	64,881
Spring	4	65,696	4/4/2015	61,576	59,234	57,569	56,881	56,812	57,455	59,181	61,257	62,818	64,839	65,696	65,215	64,272	63,148	62,016	61,293	61,025	61,305	61,543	61,708	63,993	65,621	64,187	61,402
Spring	4	64,726	4/5/2015	58,506	56,066	54,772	54,043	53,969	54,503	56,039	57,987	59,791	61,749	62,362	61,845	61,130	60,079	58,809	57,867	57,474	57,703	58,394	59,801	63,171	64,726	62,882	59,849
Spring	4	74,499	4/6/2015	57,000	55,351	54,443	54,278	54,910	57,179	61,990	67,611	70,109	71,594	72,881	73,621	74,093	73,963	73,863	73,318	72,862	72,365	72,377	72,631	74,499	74,407	71,087	66,795
Spring	4	76,667	4/7/2015	62,523	59,728	58,156	57,307	57,425	59,098	63,711	69,488	71,903	73,044	74,183	75,291	75,723	75,836	75,932	75,844	75,658	75,951	75,914	75,552	76,667	76,450	72,887	67,932
Spring	4	77,392	4/8/2015	63,854	60,981	59,215	58,222	58,337	60,139	64,570	70,304	72,435	73,606	74,717	75,496	76,200	76,861	77,392	77,175	77,286	77,024	76,771	76,444	77,253	77,300	73,759	68,733
Spring	4	78,300	4/9/2015	64,503	61,702	59,887	58,929	59,065	60,640	65,073	70,808	73,328	74,695	75,954	76,976	77,483	77,833	78,300	78,094	77,946	78,032	77,384	76,691	77,465	77,209	73,631	68,574
Spring	4	74,092	4/10/2015	63,996	61,031	59,230	58,148	58,035	59,646	63,825	69,206	71,547	72,792	73,704	74,092	73,732	73,458	72,830	71,760	70,512	69,520	68,435	67,941	69,066	70,208	68,008	64,350
Spring	4	66,352	4/11/2015	60,640	58,302	56,693	56,127	55,997	56,863	58,811	60,696	62,549	64,549	65,478	65,603	65,225	65,041	64,581	64,236	63,943	63,920	63,830	63,649	64,940	66,352	64,217	60,960
Spring	4	68,400	4/12/2015	57,700	55,393	53,848	53,008	52,796	53,053	54,204	55,473	57,145	59,574	61,122	61,794	62,340	62,711	62,806	62,662	63,057	63,840	64,499	65,275	67,347	68,400	65,569	61,581
Spring	4	73,984	4/13/2015	58,059	55,812	54,348	53,942	54,380	56,607	61,726	67,751	70,214	71,391	72,459	73,389	73,804	73,915	73,956	73,674	73,336	73,143	72,675	72,314	73,312	73,984	70,422	65,594
Spring	4	72,500	4/14/2015	61,296	58,663	57,128	56,223	56,600	58,617	63,847	69,405	71,381	71,944	72,307	72,491	72,191	72,111	71,795	71,204	70,345	70,040	69,797	69,677	71,116	72,500	69,402	64,716
Spring	4	73,732	4/15/2015	60,367	57,730	56,261	55,643	55,737	57,658	62,511	67,866	69,718	70,371	71,143	71,784	71,937	72,504	72,943	72,922	72,607	72,181	71,480	71,134	72,349	73,732	70,601	65,508
Spring	4	74,143	4/16/2015	61,216	58,341	56,730	55,877	56,054	57,805	62,606	68,045	70,257	71,210	72,128	72,538	73,152	73,546	73,819	73,408	73,201	72,942	72,163	71,990	73,296	74,143	70,829	65,845
Spring	4	75,132	4/17/2015	61,403	58,683	56,967	56,053	56,118	57,697	62,113	67,105	69,243	70,524	72,065	73,173	73,720	74,261	74,986	75,132	74,919	74,644	73,550	72,068	71,978	72,801	70,081	65,670
Spring	4	67,219	4/18/2015	61,292	57,899	55,718	54,499	54,000	54,429	55,828	57,307	59,413	62,480	64,617	65,752	66,132	66,097	65,950	65,884	65,671	65,757	65,632	65,253	66,099	67,219	65,021	61,437
Spring	4	69,364	4/19/2015	57,863	55,229	53,413	52,232	51,763	51,970	52,856	53,725	55,925	59,016	61,329	62,836	63,991	64,829	65,424	66,037	66,910	67,905	68,634	68,548	69,322	69,364	66,500	62,386
Spring	4	73,737	4/20/2015	58,673	56,394	55,118	54,547	55,017	56,963	61,954	67,758	70,314	71,617	72,561	73,319	73,609	73,585	73,696	73,039	72,459	72,558	72,439	72,102	72,926	73,737	70,528	65,819
Spring	4	74,218	4/21/2015	61,814	59,102	57,824	57,230	57,315	59,574	64,636	70,007	71,938	72,510	72,630	72,750	72,670	72,694	72,519	72,275	72,046	72,228	71,981	71,784	72,697	74,218	70,997	66,164
Spring	4	75,709	4/22/2015	61,922	59,478	58,312	57,474	57,890	59,745	64,758	69,888	71,849	72,464	72,986	73,667	74,137	74,433	74,748	74,518	74,452	74,097	73,702	73,317	74,200	75,709	72,653	68,164
Spring	4	75,289	4/23/2015	64,171	61,736	60,256	59,589	59,865	62,014	66,954	71,946	73,622	73,927	74,180	74,455	74,416	74,350	74,285	73,778	73,358	73,185	72,491	72,060	73,130	75,289	72,621	67,980
Spring	4	73,650	4/24/2015	63,837	61,360	59,997	59,286	59,544	61,302	65,878	70,610	72,681	73,229	73,566	73,650	73,228	73,018	72,675	71,922	71,324	70,865	70,227	69,770	70,559	71,149	68,909	65,376
Spring	4	68,587	4/25/2015	61,732	59,197	57,436	56,632	56,323	56,871	58,365	60,104	62,734	65,767	67,835	68,587	68,359	67,733	67,032	66,522	66,451	66,598	66,781	66,485	66,734	67,994	66,173	62,638
Spring	4	69,653	4/26/2015	59,211	56,846	55,450	54,648	54,392	54,756	55,714	56,612	58,694	61,179	62,601	63,243	63,799	64,158	64,202	64,476	64,895	65,535	66,101	66,249	67,408	69,653	67,389	63,202
Spring	4	72,204	4/27/2015	59,716	57,528	56,520	56,059	56,597	59,005	64,106	69,225	71,726	72,179	72,204	71,956	71,770	71,719	71,331	70,587	70,156	69,900	69,696	69,755	70,352	72,015	69,423	64,720
Spring	4	71,779	4/28/2015	60,716	58,289	57,053	56,508	56,896	58,892	63,600	68,627	70,622	70,982	71,243	71,504	71,324	71,343	71,358	70,909	70,333	69,994	69,495	69,131	69,928	71,779	68,992	64,136
Spring	4	71,917	4/29/2015	59,911	57,274	56,091	55,509	55,932	58,002	62,897	67,784	69,889	70,246	70,598	70,949	70,958	71,181	71,411	71,183	70,707	70,532	70,191	69,828	70,060	71,917	69,151	64,150
Spring	4	72,715	4/30/2015	59,768	57,253	55,645	54,902	55,232	57,112	61,989	66,933	69,366	70,062	70,679	71,202	71,394	71,568	72,044	72,076	71,988	71,894	71,334	70,842	70,921	72,715	70,296	65,188
Spring	5	72,058	5/1/2015	60,905	57,730	56,073	55,226	55,421	57,428	62,104	66,856	69,056	69,762	70,645	71,083	71,269	71,637	72,058	71,894	71,827	71,075	70,344	69,351	68,735	70,227	67,765	63,459
Spring	5	67,296	5/2/2015	59,068	55,785	53,975	52,841	52,372	52,954	54,596	55,802	58,625	61,575	63,421	64,320	64,903	65,344	65,738	66,104	66,645	67,034	67,113	66,564	65,909	67,296	65,168	61,231
Spring	5	71,682	5/3/2015	57,450	54,723	52,622	51,514	50,698	50,576	51,145	51,768	54,753	58,095	60,973	62,681	64,286	65,738	66,836	67,707	68,693	69,837	70,330	70,000	69,979	71,682	69,111	64,141
Spring	5	79,354	5/4/2015	59,494	56,605	54,872	53,909	54,186	56,029	60,666	66,026	69,476	71,482	73,552	75,398	76,688	78,106	79,059	79,309	79,354	79,134	78,524	77,373	77,140	78,048	74,412	68,502
Spring	5	80,151	5/5/2015	63,067	59,721	57,576	56,437	56,262	57,727	62,252	67,213	70,404	72,414	74,347	76,130	77,644	78,872	79,819	80,151	80,143	79,983	79,228	78,099	77,437	78,274	74,795	69,022
Spring	5	82,568	5/6/2015	63,653	60,633	58,274	56,991	56,915	58,432	62,696	67,486	70,681	72,754	74,726	76,773	78,379	79,869	81,317	82,101	82,519	82,568	81,904	80,785	79,614	80,460	76,970	70,756
Spring	5	85,941	5/7/2015	65,209	61,480	59,051	57,625	57,409	59,027	63,061	67,951	71,707	74,191	76,877	79,536	81,553	83,430	84,851	85,671	85,941	85,731	84,599	82,883	81,857	82,583	78,736	72,624
Spring	5	83,086	5/8/2015	67,087	63,160	60,663	59,055	58,569	59,899	63,660	68,623	72,291	75,027	77,462	79,537	81,055	82,122	83,086	83,025	82,645	82,113	80,472	78,440	77,240	77,509	74,858	70,024
Spring	5	73,826	5/9/2015	65,226	61,526	59,080	57,600	56,730	56,936	57,910	59,348	62,359	65,816	68,379	70,062	71,327	71,974	72,481	72,933	73,483	73,826	73,523	72,361	71,578	72,720	70,914	66,663
Spring	5	74,751	5/10/2015	62,311	59,049	56,779	55,338	54,534	54,545	55,144	55,757	58,912	62,809	65,740	67,889	69,459	70,773	71,665	72,419	73,221	73,754	73,714	73,310	73,582	74,751	72,299	67,616
Spring	5	80,130	5/11/2015	63,226	60,576	58,796	57,904	57,921	59,859	64,525	69,690	73,159	75,060	76,703	78,506	79,562	80,072	80,130	79,804	78,876	78,406	77,588	76,734	75,898	76,695	73,587	68,038
Spring	5	75,704	5/12/2015	63,326	60,329	58,406	57,341	57,331	58,913	63,083	67,972	70,921	72,181	73,314	74,148	74,803	75,267	75,704	75,435	74,945	74,608	73,879	73,140	73,106	74,182	72,017	66,864
Spring	5	75,440	5/13/2015	62,550	59,713	58,051	57,093	57,178	58,935	63,159	67,935	70,647	71,702	72,687	73,528	74,139	74,713	75,362	75,322	75,176	74,953	74,497	73,696	73,477	75,440	72,849	67,599
Spring	5	77,641	5/14/2015	63,055	60,179	58,307	57,224	57,170	58,926	63,099	68,034	70,988	72,213	73,659	74,766	75,661	76,536	77,470	77,641	77,379	77,333	76,828	76,205	76,086	76,978	73,989	68,731
Spring	5	80,591	5/15/2015	64,243	61,140	59,424	58,258	58,094	59,474	63,598	68,499	71,771	74,028	76,160	77,827	79,291	80,256	80,591	80,281	79,513	78,774	77,442	75,733	74,745	75,887	73,711	69,160
Spring	5	75,903	5/16/2015	64,824	61,473	59,358	57,907	57,333	57,549	58,662	60,171	63,436	66,994	70,022	72,043	73,469	74,351	75,070	75,407	75,776	75,903	75,607	74,696	73,636	74,796	73,266	69,216
Spring	5	79,503	5/17/2015	64,981	61,759	59,584	58,043	57,332	57,325	57,539	58,399	61,422	65,531	69,108	71,627	73,724	75,357	76,120	77,250	78,361	79,208	79,503	78,824	77,882	78,821	76,727	71,700
Spring	5	85,504	5/18/2015	66,883	63,514	61,374	60,201	60,068	61,824	66,153	71,455	75,739	78,430	80,619	82,726	84,128	84,881	85,504	85,379	84,774	84,172	83,089	81,580	79,829	79,770	76,615	70,670
Spring	5	77,567	5/19/2015	65,267	61,632	59,935	58,546	58,480	59,809	63,042	67,861	71,031	72,484	73,711	74,870	75,677	76,482	77,189	77,567	77,530	77,550	76,540	75,466	74,990	75,857	73,472	68,584
Spring	5	78,644	5/20/2015	64,196	61,493	59,357	58,487	58,582	59,913	63,764	68,454	71,705	73,454	74,919	76,471	77,297	78,008	78,644	78,252	78,147	78,050	77,633	76,976	76,348	76,979	74,599	69,460
Spring	5	76,160	5/21/2015	64,911	62,209	60,315	59,311	59,003	60,688	64,589	68,720	71,613	73,311	74,622	75,306	75,805	76,160	76,117	75,274	74,203	73,167	72,117	71,334	70,796	72,716	71,463	66,803
Spring	5	74,023	5/22/2015	62,346	59,598	57,728	56,527	56,359	57,861	61,158	65,485	68,614	69,965	71,109	71,983	72,457	72,988	73,456	73,868	74,023	73,787	72,928	71,242	70,098	71,062	69,646	65,155
Spring	5	71,456	5/23/2015	60,592	57,386	55,335	54,061	53,357	53,462	53,995	54,878	58,174	61,815	64,511	66,493	67,974	69,074	69,848	70,414	70,937	71,456	71,305	70,301	68,837	69,610	68,159	64,436
Spring	5	71,318	5/24/2015	60,460	57,160	55,073	53,762	53,046	52,818	52,953	53,598	56,643	60,675	63,849	66,324	68,339	69,623	70,307	70,756	71,098	71,264	71,318	70,460	69,617	70,379	68,738	65,009
Spring	5	76,702	5/25/2015	61,045	57,818	55,929	54,643	54,032	54,290	55,151	55,853	58,449	62,521	66,526	69,816	72,238	73,794	74,642	75,332	76,118	76,702	76,674	75,752	74,962	75,434	73,632	68,788
Spring	5	86,817	5/26/2015	63,918	60,478	58,454	57,262	57,039	58,730	62,702	68,282	72,731	75,505	77,915	80,153	82,066	83,649	84,978	85,681	86,428	86,817	85,955	84,495	82,533	82,048	79,285	73,426
Spring	5	85,857	5/27/2015	68,003	64,172	61,721	60,308	60,028	61,458	64,933	69,746	74,050	76,667	79,077	81,174	82,583	83,450	84,484	85,021	85,554	85,857	85,638	84,623	82,731	82,470	79,862	73,577
Spring	5	92,466	5/28/2015	67,848	63,700	61,015	59,525	58,967	60,217	63,234	68,120	72,726	76,321	79,659	82,901	85,810	88,554	90,865	92,138	92,466	92,350	91,190	89,226	86,876	86,173	83,342	77,038
Spring	5	91,612	5/29/2015	70,933	66,445	63,505	61,874	61,373	62,784	65,871	70,555	75,333	79,054	82,473	85,479	87,800	89,477	90,910	91,422	91,612	90,800	88,863	86,292	83,678	83,132	80,479	75,264
Spring	5	77,808	5/30/2015	69,687	65,466	62,566	60,636	59,618	59,589	60,139	61,351	65,265	69,735	73,476	76,012	77,303	77,808	77,549	77,274	76,664	75,551	73,945	72,304	70,760	70,622	69,244	65,440
Spring	5	67,878	5/31/2015	61,563	58,285	56,038	54,674	53,999	53,809	53,887	54,227	56,981	60,282	62,622	64,449	65,761	66,528	66,718	66,229	66,138	66,541	66,985	67,009	66,866	67,878	66,938	63,263
Summer	6	78,295	6/1/2015	59,293	56,794	55,435	54,746	54,955	56,901	60,747	65,403	68,966	71,486	73,275	74,842	76,016	77,068	77,987	78,205	78,295	78,035	77,491	76,302	75,238	75,468	73,876	68,847
Summer	6	81,231	6/2/2015	63,997	60,620	58,451	57,064	56,958	58,393	61,598	66,039	69,809	72,253	74,742	76,668	78,265	79,581	80,748	81,113	81,231	80,956	80,370	79,072	77,545	77,887	76,005	70,668
Summer	6	84,216	6/3/2015	65,268	61,639	59,322	57,976	57,531	59,020	62,042	66,613	70,573	73,234	75,791	78,002	79,860	81,426	82,866	83,586	84,061	84,216	83,597	82,122	80,466	80,219	78,144	72,558
Summer	6	89,968	6/4/2015	67,114	63,237	60,731	59,291	58,983	60,213	63,514	67,879	72,191	75,438	78,565	81,538	83,751	85,763	87,709	88,860	89,642	89,968	89,308	87,754	85,659	85,196	82,951	76,780
Summer	6	91,874	6/5/2015	70,661	66,266	63,373	61,500	60,769	61,706	64,582	68,877	73,513	77,462	81,191	84,473	87,115	89,039	90,865	91,734	91,874	91,338	89,671	87,277	84,213	82,617	79,938	74,624
Summer	6	82,834	6/6/2015	68,878	64,484	61,193	59,132	57,941	57,867	57,894	59,092	62,635	66,978	70,762	74,041	76,558	78,178	79,642	80,864	82,135	82,834	82,622	81,073	78,888	78,031	76,273	71,607
Summer	6	88,975	6/7/2015	66,647	62,549	59,797	58,052	57,003	56,700	56,556	57,193	60,910	66,221	71,148	75,581	79,073	82,097	84,127	85,494	87,192	88,611	88,975	87,843	85,913	84,716	82,363	77,035
Summer	6	96,644	6/8/2015	71,554	67,473	64,441	62,570	61,984	63,190	66,392	71,080	76,008	80,014	83,823	87,350	90,279	92,800	95,045	95,993	96,558	96,644	95,406	93,158	90,495	88,828	85,605	78,979
Summer	6	98,343	6/9/2015	72,521	68,094	65,076	63,187	62,481	63,552	66,183	70,602	75,548	79,897	83,957	87,993	91,037	93,774	96,195	97,424	98,172	98,343	97,702	95,833	93,255	91,721	88,807	81,934
Summer	6	105,843	6/10/2015	75,330	70,518	66,980	65,023	64,172	65,232	68,091	72,727	77,935	82,828	87,360	91,736	95,890	99,677	102,371	104,318	105,702	105,843	104,473	101,843	98,221	95,680	91,857	84,338
Summer	6	96,995	6/11/2015	77,089	71,924	68,381	66,162	65,154	66,019	68,634	73,109	77,856	81,838	85,979	89,618	92,500	94,536	96,258	96,995	96,872	95,672	93,964	91,974	89,857	88,915	86,330	80,350
Summer	6	93,077	6/12/2015	74,492	70,082	67,144	65,193	64,446	65,633	68,149	72,196	77,108	81,421	85,460	88,450	90,499	91,904	92,771	93,077	92,737	91,821	89,276	86,617	84,219	82,915	80,892	75,801
Summer	6	84,291	6/13/2015	70,561	66,461	63,600	61,870	60,840	60,973	61,708	63,462	67,247	71,862	75,640	79,009	81,245	82,567	83,278	83,511	83,963	84,291	83,559	82,058	80,137	79,884	78,417	74,234
Summer	6	88,888	6/14/2015	69,894	66,049	63,390	61,552	60,522	60,365	60,172	61,021	64,853	69,986	74,455	78,048	81,325	84,159	85,874	86,850	87,568	88,545	88,888	87,927	86,260	85,431	83,723	78,564
Summer	6	99,540	6/15/2015	72,973	68,930	66,101	64,691	64,353	65,786	68,983	74,046	79,556	83,989	88,096	92,010	95,423	97,750	99,308	99,540	99,365	98,805	97,399	95,270	92,831	90,967	88,007	82,126
Summer	6	97,065	6/16/2015	75,777	71,228	68,095	66,117	65,364	66,261	69,181	73,548	78,432	82,479	85,939	89,104	91,664	93,911	95,762	96,957	97,065	96,581	95,035	92,734	89,979	88,568	85,746	79,658
Summer	6	94,520	6/17/2015	73,650	69,271	66,369	64,607	63,882	65,326	68,187	72,365	76,747	80,610	84,277	87,526	90,257	92,269	93,841	94,464	94,520	93,985	92,630	90,939	88,905	88,185	85,998	80,404
Summer	6	95,926	6/18/2015	74,591	70,444	67,652	65,902	65,322	66,494	69,464	73,836	78,603	82,752	86,349	89,628	92,122	94,372	95,618	95,926	95,773	94,947	93,539	91,650	89,333	88,208	86,067	80,497
Summer	6	90,962	6/19/2015	74,385	70,094	67,102	64,989	64,402	65,209	67,870	71,679	75,992	79,467	82,616	85,211	87,175	88,672	90,282	90,907	90,962	90,437	88,890	86,396	84,169	82,897	81,178	76,490
Summer	6	89,737	6/20/2015	71,319	67,111	64,160	62,326	61,288	61,048	61,515	62,682	66,046	70,680	74,992	78,506	81,421	83,670	85,742	87,355	88,781	89,724	89,737	88,379	86,372	84,886	83,147	78,529
Summer	6	93,125	6/21/2015	73,141	68,621	64,996	62,762	61,362	60,811	60,344	61,204	64,917	70,319	75,335	79,379	83,093	86,052	88,413	90,248	91,775	92,941	93,125	92,110	90,097	88,887	87,013	81,561
Summer	6	106,061	6/22/2015	75,480	71,056	68,052	66,187	65,493	66,834	69,971	75,019	80,808	86,140	91,081	95,658	99,295	102,091	104,385	105,379	105,647	106,061	105,889	104,257	101,353	99,404	96,405	89,531
Summer	6	103,253	6/23/2015	82,765	77,140	73,349	70,681	69,450	70,171	72,609	76,933	81,506	85,797	89,704	93,432	96,316	99,352	101,736	102,924	103,253	102,996	101,289	98,821	95,130	92,795	89,878	82,928
Summer	6	99,475	6/24/2015	76,068	71,259	67,881	65,688	64,821	65,740	68,262	72,288	77,262	81,748	85,537	89,315	92,990	95,583	97,481	98,931	99,475	99,464	98,109	95,941	93,098	91,436	88,784	82,391
Summer	6	99,688	6/25/2015	76,148	71,422	68,430	66,424	65,638	66,656	69,746	73,623	78,081	81,983	85,411	88,991	92,396	95,650	98,187	99,304	99,688	99,120	97,795	95,795	92,822	91,095	88,289	82,009
Summer	6	93,149	6/26/2015	75,670	70,957	67,760	65,685	64,939	65,632	68,060	72,003	76,619	80,835	84,320	87,886	90,507	91,854	92,868	93,149	92,911	92,113	90,013	87,419	84,782	83,418	81,370	76,716
Summer	6	83,041	6/27/2015	71,449	67,131	64,185	62,418	61,214	61,087	61,525	62,323	65,645	69,995	73,980	77,033	79,022	80,381	81,332	81,894	82,651	83,041	82,605	81,003	78,915	77,450	75,773	71,552
Summer	6	82,311	6/28/2015	66,989	62,872	60,100	58,314	57,230	56,977	56,488	57,211	60,366	64,657	68,333	71,798	74,674	77,015	78,836	80,224	81,417	82,092	82,311	81,379	79,847	79,186	77,793	73,296
Summer	6	96,660	6/29/2015	68,356	64,713	62,303	60,907	60,705	62,242	65,289	69,517	74,608	79,070	83,038	86,860	90,169	92,538	94,773	96,133	96,549	96,660	95,616	93,635	90,584	88,963	86,020	79,925
Summer	6	94,097	6/30/2015	73,509	69,021	65,855	63,923	63,089	64,192	67,271	71,064	75,303	79,074

Contains Proprietary Material
Do Not Distribute

Summer	8	104,310	8/4/2015	78,853	73,853	70,247	67,944	66,966	67,874	70,802	74,146	78,498	83,093	87,926	92,478	96,416	99,492	102,175	103,701	104,310	103,941	102,433	100,044	96,790	95,393	91,521	84,734
Summer	8	102,044	8/5/2015	78,314	73,895	70,712	68,603	67,829	68,753	71,967	75,408	79,481	83,651	87,953	92,018	95,582	98,887	101,209	101,964	102,044	101,559	100,509	98,183	95,089	94,224	90,463	83,956
Summer	8	101,031	8/6/2015	78,044	73,815	70,646	68,564	67,939	68,996	72,362	75,969	79,264	82,995	86,819	90,309	93,300	95,747	98,383	99,948	100,958	101,031	99,852	97,662	94,759	93,882	90,114	83,970
Summer	8	104,310	8/7/2015	78,079	73,522	70,411	68,260	67,347	68,344	71,568	75,057	79,078	83,468	87,727	91,661	95,151	98,237	101,150	103,047	104,082	104,310	103,027	100,346	96,760	95,311	91,426	85,188
Summer	8	96,706	8/8/2015	79,170	74,309	70,899	68,494	67,004	66,791	67,553	68,136	70,984	76,081	81,104	85,605	89,161	91,875	93,735	94,864	96,038	96,706	96,197	94,112	91,550	91,005	87,788	82,370
Summer	8	98,955	8/9/2015	76,943	72,542	69,520	67,227	65,662	64,825	65,046	65,442	68,127	73,121	77,989	82,294	86,455	90,324	93,219	95,293	97,145	98,658	98,955	97,703	95,673	94,831	91,222	85,302
Summer	8	108,587	8/10/2015	79,304	75,219	72,297	70,438	69,936	71,144	75,122	79,193	83,268	87,819	92,403	96,840	100,743	103,948	106,287	107,189	108,172	108,587	107,475	105,248	101,730	99,780	95,118	87,312
Summer	8	105,165	8/11/2015	80,772	75,848	72,354	70,036	69,167	70,152	73,662	77,368	81,242	85,801	90,379	94,598	98,272	101,056	103,304	104,564	105,165	104,941	103,544	101,056	97,517	95,856	91,104	83,690
Summer	8	105,249	8/12/2015	77,292	72,509	69,267	67,108	66,283	67,149	70,741	74,388	78,209	82,569	86,781	91,353	95,338	98,693	101,633	103,534	104,905	105,249	104,145	101,807	98,204	96,689	91,887	84,564
Summer	8	108,275	8/13/2015	78,100	73,304	70,008	67,912	66,987	67,811	71,544	75,466	79,090	83,559	88,262	93,023	97,328	101,346	104,825	106,925	108,241	108,275	107,204	104,514	101,350	100,255	95,564	88,303
Summer	8	113,010	8/14/2015	81,380	76,404	72,854	70,482	69,300	70,256	74,049	78,203	82,057	86,836	92,026	96,992	101,827	105,899	109,219	111,553	113,010	112,605	110,588	106,746	102,195	99,582	94,690	87,541
Summer	8	106,502	8/15/2015	80,764	75,442	71,526	68,597	66,904	66,417	67,174	67,807	71,634	78,019	84,610	90,808	95,804	99,446	102,186	104,318	105,795	106,502	105,641	102,445	98,288	96,415	92,122	85,570
Summer	8	102,882	8/16/2015	79,201	73,948	70,319	67,546	65,777	65,189	65,335	65,671	69,117	75,519	81,970	87,789	92,730	96,544	99,356	100,987	102,134	102,882	102,334	100,137	97,423	96,195	91,623	85,040
Summer	8	107,374	8/17/2015	78,592	74,211	71,035	69,096	68,265	69,495	74,149	79,003	83,215	87,626	92,439	97,284	101,399	104,806	106,941	107,374	107,062	105,877	103,974	101,183	98,623	97,365	91,908	84,632
Summer	8	102,758	8/18/2015	78,254	73,725	70,798	68,615	68,036	69,333	73,658	78,339	81,708	85,364	89,603	93,975	97,586	100,379	102,328	102,758	102,143	101,063	99,278	96,889	95,098	94,415	89,669	82,918
Summer	8	92,760	8/19/2015	77,236	73,255	70,120	68,439	67,925	69,268	73,299	78,081	81,249	84,320	87,291	89,827	91,350	92,363	92,760	91,949	91,101	90,892	89,876	88,157	87,032	87,125	82,884	76,709
Summer	8	87,614	8/20/2015	71,361	67,687	64,972	63,292	62,774	64,014	67,992	72,182	74,855	77,457	79,826	82,005	83,424	84,782	86,254	87,138	87,332	87,614	86,534	84,973	83,525	83,667	80,177	74,244
Summer	8	91,430	8/21/2015	68,930	65,254	62,990	61,651	61,313	62,550	66,240	70,120	73,392	77,191	80,511	83,582	86,020	88,125	89,859	90,879	91,430	91,293	90,078	87,473	84,922	84,520	80,871	75,396
Summer	8	86,799	8/22/2015	70,272	66,238	63,368	61,558	60,610	60,801	61,693	62,712	65,446	70,176	74,581	78,190	81,235	83,544	85,318	86,114	86,799	86,665	85,891	83,561	81,718	81,410	77,826	72,991
Summer	8	86,515	8/23/2015	68,449	64,759	61,924	60,300	59,278	58,876	59,387	59,925	62,400	67,064	71,496	75,016	77,979	80,460	82,607	84,184	85,471	86,385	86,515	84,890	83,267	82,915	78,713	73,085
Summer	8	89,609	8/24/2015	68,055	64,528	62,229	60,955	60,620	62,035	65,909	70,253	73,382	76,404	79,573	82,467	84,512	86,520	88,197	89,121	89,546	89,609	88,584	86,794	85,551	85,087	80,265	74,431
Summer	8	85,445	8/25/2015	69,147	65,573	63,189	61,614	61,101	62,455	66,436	70,597	72,841	75,400	77,774	80,014	81,598	83,126	84,235	84,847	85,201	85,445	84,813	83,517	82,464	82,139	77,653	71,512
Summer	8	86,983	8/26/2015	66,470	62,993	60,962	59,570	59,341	60,621	64,531	69,081	71,629	74,168	76,633	79,126	81,016	82,669	84,439	85,566	86,575	86,983	86,488	85,006	83,697	83,461	78,865	72,560
Summer	8	88,283	8/27/2015	67,433	63,821	61,500	60,191	59,667	60,899	64,976	69,406	72,107	74,779	77,303	79,844	81,902	84,064	86,102	87,380	88,081	88,283	87,206	85,420	84,373	84,323	79,732	73,682
Summer	8	90,227	8/28/2015	68,403	64,584	62,225	60,667	60,420	61,525	65,461	69,727	72,693	75,622	78,590	81,531	84,048	86,197	88,261	89,525	90,227	89,984	88,357	85,693	84,095	83,049	79,073	73,959
Summer	8	84,600	8/29/2015	68,982	64,983	62,300	60,552	59,697	59,923	61,196	62,558	64,529	68,632	72,883	76,124	78,689	80,729	82,156	83,278	83,984	84,600	84,373	82,978	82,217	81,718	78,601	73,897
Summer	8	92,914	8/30/2015	69,423	65,477	62,828	61,104	60,035	59,605	60,117	60,859	63,040	67,452	71,905	76,261	80,296	84,001	87,095	89,248	91,156	92,575	92,914	91,426	90,355	89,459	84,485	78,014
Summer	8	106,821	8/31/2015	72,336	68,367	65,734	63,900	63,489	65,147	69,837	75,034	78,541	82,464	86,935	91,615	96,152	100,365	103,675	105,713	106,642	106,821	105,392	102,750	100,853	99,152	93,015	85,167
Fall	9	111,632	9/1/2015	78,420	73,827	70,313	68,235	67,365	68,409	72,822	78,415	81,291	85,392	90,310	95,690	100,720	104,757	108,351	110,577	111,488	111,632	110,073	107,298	105,607	103,721	96,819	88,889
Fall	9	110,663	9/2/2015	82,043	76,891	73,395	71,214	70,155	71,091	75,546	81,030	84,395	88,001	92,660	97,880	102,425	105,985	108,893	110,157	110,663	110,315	108,517	105,955	104,011	102,059	95,870	87,878
Fall	9	111,106	9/3/2015	80,737	75,771	72,224	70,067	69,076	70,288	74,795	80,350	83,624	87,848	92,740	97,942	102,825	106,553	108,941	110,206	111,039	111,106	109,440	106,465	104,334	102,403	96,172	88,290
Fall	9	109,524	9/4/2015	81,628	76,316	73,043	70,784	69,690	70,677	74,387	79,340	82,578	86,749	91,788	96,770	100,854	104,451	107,294	108,892	109,524	108,945	106,354	102,530	99,956	97,605	92,303	85,790
Fall	9	102,277	9/5/2015	79,530	74,413	70,758	68,259	66,582	66,075	66,670	67,924	70,353	75,869	81,829	87,581	92,522	96,197	98,968	100,679	101,957	102,277	101,152	97,922	95,713	93,531	88,643	82,953
Fall	9	104,209	9/6/2015	77,376	72,863	69,375	66,927	65,296	64,504	64,734	65,254	67,910	74,037	80,716	86,901	92,516	97,349	100,779	102,996	103,954	104,209	102,938	99,415	96,779	94,050	89,046	82,825
Fall	9	102,318	9/7/2015	76,859	72,320	68,850	66,427	64,992	64,625	65,367	66,041	67,789	73,170	80,081	86,732	92,333	96,381	99,193	100,910	102,029	102,318	101,084	98,690	97,852	95,664	89,599	82,378
Fall	9	106,130	9/8/2015	76,355	72,165	69,271	67,634	67,174	68,608	73,606	79,758	83,147	86,724	91,173	96,159	100,184	103,403	105,838	106,130	105,687	104,504	102,398	99,754	98,539	96,054	89,770	82,402
Fall	9	92,801	9/9/2015	76,249	71,658	68,821	66,964	66,196	67,490	71,983	77,402	79,300	81,331	83,914	86,473	88,606	90,545	91,899	92,489	92,801	92,660	91,413	89,316	88,895	87,351	82,052	75,373
Fall	9	92,195	9/10/2015	69,957	66,339	63,945	62,659	62,396	63,842	68,479	73,979	76,086	78,727	81,865	84,820	87,411	89,526	91,425	92,128	92,195	91,682	90,030	87,674	87,579	85,917	80,719	74,309
Fall	9	80,016	9/11/2015	69,019	65,245	62,948	61,491	60,953	62,362	66,598	71,923	73,952	75,636	77,148	78,348	79,248	79,644	80,016	79,789	78,841	78,022	76,526	74,788	75,139	74,365	71,192	67,099
Fall	9	70,181	9/12/2015	62,829	59,795	57,748	56,347	55,749	56,073	57,320	58,922	60,729	63,777	66,108	67,738	68,771	69,416	69,804	69,853	70,126	70,181	69,781	68,691	69,122	68,674	65,720	61,956
Fall	9	71,867	9/13/2015	58,278	55,511	53,570	52,325	51,603	51,627	52,462	53,378	55,084	58,342	60,598	62,404	63,907	65,096	65,982	67,082	68,693	70,073	70,882	70,578	71,867	71,137	67,437	62,726
Fall	9	85,662	9/14/2015	59,068	56,379	54,984	54,175	54,356	56,268	61,032	66,649	68,905	70,998	73,222	75,594	77,410	79,731	81,896	83,371	84,730	85,662	85,298	83,845	84,707	83,078	78,020	71,982
Fall	9	93,519	9/15/2015	66,924	63,322	61,052	59,761	59,506	61,059	65,570	71,167	73,387	75,567	78,236	81,152	84,093	86,833	89,756	91,841	93,159	93,519	92,250	89,882	89,867	87,533	82,034	75,504
Fall	9	98,663	9/16/2015	69,777	66,032	63,437	61,859	61,393	62,523	66,879	72,525	74,583	77,259	80,889	84,334	87,792	91,420	94,728	96,836	98,043	98,663	97,578	94,933	94,402	91,564	85,740	78,977
Fall	9	99,479	9/17/2015	73,060	68,934	65,929	64,245	63,582	64,849	69,361	75,154	77,804	80,411	83,418	86,931	90,161	93,458	96,254	98,235	99,297	99,479	97,879	95,265	94,582	91,964	86,191	79,196
Fall	9	93,712	9/18/2015	73,131	68,859	65,935	64,212	63,531	64,680	69,136	74,665	76,772	79,274	81,983	84,895	87,591	90,260	92,532	93,319	93,712	93,089	91,210	88,840	88,106	85,570	81,251	75,944
Fall	9	79,364	9/19/2015	70,663	66,533	63,722	61,671	60,500	60,291	61,268	63,229	65,030	68,593	71,669	73,983	75,605	76,810	77,797	78,576	79,135	79,364	78,376	76,400	76,516	74,692	70,951	66,499
Fall	9	77,082	9/20/2015	62,210	59,012	56,909	55,358	54,562	54,473	55,044	56,232	57,644	61,388	64,661	67,167	69,755	71,535	73,123	74,085	75,191	75,937	76,133	75,635	77,082	75,117	71,068	66,233
Fall	9	85,833	9/21/2015	62,395	59,619	57,957	57,023	57,030	58,810	63,518	69,192	71,251	73,261	75,301	77,534	79,177	81,151	82,902	84,205	85,227	85,833	85,281	83,863	84,220	81,609	76,578	70,471
Fall	9	88,788	9/22/2015	65,265	61,720	59,450	58,092	57,883	59,472	63,916	69,632	71,514	73,651	76,243	78,797	81,043	83,518	85,822	87,462	88,645	88,788	87,626	85,669	85,812	82,795	77,465	71,152
Fall	9	90,276	9/23/2015	65,874	62,329	60,044	58,668	58,471	59,871	64,375	70,022	72,139	74,364	77,021	79,911	82,791	85,362	87,737	89,166	90,160	90,276	89,034	86,986	87,012	83,836	78,519	72,201
Fall	9	89,868	9/24/2015	66,940	63,549	61,154	59,805	59,390	60,834	65,378	71,139	73,176	75,259	78,022	80,862	83,330	85,954	88,130	89,414	89,868	89,599	87,893	86,210	86,749	83,918	78,850	72,590
Fall	9	89,764	9/25/2015	67,275	63,738	61,426	59,973	59,549	60,825	65,337	70,795	72,761	74,858	77,545	80,706	83,410	85,925	88,132	89,306	89,764	89,096	86,699	83,687	83,157	80,236	76,103	71,224
Fall	9	78,195	9/26/2015	66,312	62,447	59,814	58,293	57,456	57,447	58,846	60,818	62,310	65,875	69,357	72,043	74,279	76,046	77,206	77,805	78,195	78,053	77,076	76,011	76,793	74,961	71,830	67,634
Fall	9	79,479	9/27/2015	63,528	60,261	58,226	56,748	55,837	55,724	56,511	57,997	59,563	62,743	65,686	68,018	70,329	72,324	73,721	74,737	75,680	76,893	77,385	77,965	79,479	77,332	73,240	68,942
Fall	9	89,185	9/28/2015	64,595	61,793	60,167	59,189	59,219	61,221	66,346	72,839	75,143	77,134	79,470	81,929	84,174	86,457	88,268	89,075	89,185	88,756	87,676	87,388	88,118	85,110	80,627	74,545
Fall	9	82,688	9/29/2015	69,414	65,716	63,233	61,698	61,322	62,936	67,409	73,786	75,820	77,160	78,490	79,662	80,860	81,822	82,688	82,543	82,537	82,222	81,169	80,892	81,760	79,383	74,848	68,941
Fall	9	79,891	9/30/2015	64,315	61,083	59,283	57,996	57,885	59,369	63,969	69,881	71,309	72,592	73,945	75,521	76,925	78,092	79,379	79,817	79,891	79,775	78,618	78,192	79,684	77,232	72,868	67,354
Fall	10	76,578	10/1/2015	62,953	59,937	58,031	56,876	56,731	58,220	62,760	68,576	69,961	70,846	72,032	72,918	73,630	74,584	75,563	75,873	75,914	75,716	74,670	74,728	76,578	74,489	70,399	65,643
Fall	10	72,072	10/2/2015	61,307	58,601	56,828	55,856	55,950	57,368	61,931	67,782	69,366	70,270	70,953	71,497	71,752	71,702	72,072	71,664	71,396	71,147	70,350	70,484	71,756	70,040	67,276	63,287
Fall	10	67,714	10/3/2015	59,443	56,981	55,076	54,166	53,755	54,368	55,962	58,644	60,500	63,147	64,776	65,328	65,380	65,152	64,760	64,440	64,588	65,099	65,268	66,351	67,714	66,291	63,694	60,428
Fall	10	69,642	10/4/2015	57,122	55,022	53,498	52,497	52,042	52,199	53,184	55,257	56,959	59,638	61,408	62,277	62,781	62,965	63,150	62,983	63,383	64,450	65,466	67,257	69,642	67,810	64,783	60,888
Fall	10	78,910	10/5/2015	58,041	55,791	54,623	54,123	54,489	56,700	61,662	67,945	70,321	71,164	72,321	73,365	73,970	74,771	75,608	76,199	76,375	76,496	76,322	77,519	78,910	76,490	72,362	66,934
Fall	10	81,331	10/6/2015	62,466	59,680	57,967	57,028	57,031	58,614	63,350	69,588	71,641	72,815	74,174	75,723	77,184	78,626	79,767	80,439	80,714	80,557	79,823	80,130	81,331	78,527	73,857	68,286
Fall	10	82,337	10/7/2015	63,670	60,811	58,702	57,566	57,435	59,127	63,654	69,769	71,675	72,770	74,409	76,346	78,303	79,953	81,333	82,028	82,337	82,201	81,290	81,414	82,132	79,146	74,617	69,267
Fall	10	83,182	10/8/2015	64,472	61,508	59,307	58,233	58,208	59,806	64,049	70,201	72,212	73,484	75,400	77,567	79,584	81,216	82,836	83,105	83,182	82,996	82,319	82,526	82,929	80,108	75,637	70,158
Fall	10	78,268	10/9/2015	65,504	62,314	60,121	58,782	58,476	60,013	64,201	70,186	72,311	73,394	74,818	76,101	76,918	77,595	78,268	77,883	77,301	76,556	75,433	75,429	75,558	73,429	70,280	66,010
Fall	10	69,535	10/10/2015	62,035	59,123	57,200	55,787	55,336	55,714	57,427	59,833	61,396	63,921	65,766	66,477	66,808	66,901	67,104	67,305	67,771	68,104	67,837	68,616	69,535	67,631	64,749	61,095
Fall	10	74,139	10/11/2015	57,687	55,264	53,481	52,504	51,904	52,163	53,248	55,034	56,559	59,210	61,353	62,744	63,851	65,441	66,786	68,218	69,780	71,223	71,796	72,787	74,139	71,432	67,814	63,535
Fall	10	80,571	10/12/2015	59,822	57,419	55,743	54,982	55,019	56,858	61,354	67,511	69,686	71,448	73,584	75,497	77,097	78,594	79,823	80,122	80,550	80,500	80,138	80,571	80,571	77,607	73,023	67,490
Fall	10	78,617	10/13/2015	62,879	59,694	57,961	56,903	56,783	58,524	63,203	69,403	71,286	72,194	73,413	74,599	75,474	76,424	77,658	78,220	78,383	78,171	77,616	78,121	78,617	75,487	71,073	65,826
Fall	10	78,061	10/14/2015	61,406	58,494	56,896	55,744	55,971	57,872	62,455	68,772	70,532	70,883	71,503	72,439	73,194	74,185	75,481	76,360	76,862	77,095	76,635	77,522	78,061	75,012	70,582	65,498
Fall	10	78,716	10/15/2015	61,104	58,526	56,808	56,007	56,162	57,836	62,516	68,915	70,617	71,270	72,202	73,202	74,316	75,697	77,289	78,240	78,393	78,467	77,772	78,488	78,716	75,965	71,690	66,728
Fall	10	75,109	10/16/2015	62,327	59,598	57,775	56,810	56,848	58,666	63,024	69,261	71,116	71,818	72,708	73,358	73,852	74,209	74,887	75,109	74,893	74,482	73,741	74,413	74,672	72,635	69,677	65,646
Fall	10	68,737	10/17/2015	61,933	59,489	57,630	56,628	56,258	57,022	58,816	61,483	63,486	65,707	67,001	66,981	66,460	65,788	65,489	65,032	64,797	64,925	65,167	67,508	68,737	67,349	64,974	62,141
Fall	10	70,123	10/18/2015	59,163	56,941	55,700	55,053	54,975	55,324	56,617	58,955	60,669	62,712	63,454	63,247	63,034	63,116	62,977	62,897	63,165	64,169	65,339	68,183	70,123	68,173	65,149	61,412
Fall	10	76,516	10/19/2015	58,335	56,662	55,732	55,571	56,097	58,410	63,702	70,595	72,768	72,935	73,190	73,341	73,274	73,171	73,530	73,324	73,402	73,546	73,631	75,841	76,516	74,072	70,058	65,124
Fall	10	77,559	10/20/2015	61,249	58,915	57,327	56,572	56,667	58,646	63,376	69,803	71,765	71,990	72,671	73,436	74,185	74,757	75,434	75,315	75,137	75,134	75,232	77,174	77,559	74,942	71,211	66,428
Fall	10	79,366	10/21/2015	62,139	59,549	57,811	56,994	57,036	58,937	63,516	70,062	72,118	72,579	73,486	74,561	75,669	76,768	77,896	78,145	78,218	78,113	77,710	79,234	79,366	76,616	72,348	67,339
Fall	10	79,133	10/22/2015	62,970	60,223	58,458	57,482	57,279	59,120	63,897	70,163	72,428	72,813	73,702	74,760	75,697	76,695	77,773	78,112	78,047	77,705	77,042	79,050	79,133	76,686	72,772	67,895
Fall	10	75,967	10/23/2015	63,571	60,760	58,798	57,863	57,819	59,551	63,680	69,864	72,291	73,125	74,177	75,080	75,381	75,748	75,967	75,581	75,116	74,607	74,585	75,598	74,831	72,792	69,989	66,241
Fall	10	69,027	10/24/2015	62,228	59,307	57,502	56,229	55,771	56,181	57,864	60,540	63,181	65,434	67,497	68,526	68,823	68,479	67,837	67,132	66,784	66,607	67,216	69,027	68,736	67,111	64,606	61,400
Fall	10	69,414	10/25/2015	58,365	55,775	54,306	53,303	52,670	52,874	54,172	56,302	58,358	60,390	61,977	62,684	63,059	63,162	62,662	62,420	62,520	63,341	65,050	68,821	69,414	67,528	64,747	61,316
Fall	10	75,509	10/26/2015	58,440	56,546	55,548	55,158	55,612	57,844	63,064	69,931	72,603	72,841	73,159	73,261	73,305	73,296	72,907	72,123	71,476	71,428	72,390	75,509	75,245	73,187	69,557	64,910
Fall	10	76,040	10/27/2015	61,063	58,611	57,270	56,470	56,530	58,314	62,975	69,673	72,383	72,360	72,837	73,108	73,183	73,040	72,851	72,407	72,105	72,445	73,794	76,040	75,625	73,431	69,474	64,962
Fall	10	76,930	10/28/2015	61,225	58,790	57,247	56,327	56,284	58,134	62,729	69,099	71,940	72,128	72,946	73,680	73,963	74,339	74,884	74,691	74,787	75,028	75,471	76,930	76,593	74,560	71,079	66,267
Fall	10	76,382	10/29/2015	62,208	59,694	58,036	57,412	57,531	59,518	64,337	71,016	73,338	73,302	73,769	74,235	74,181	74,197	74,391	74,217	74,107	74,162	74,609	76,382	76,223	74,093	70,500	66,054
Fall	10	73,233	10/30/2015	62,253	59,744	58,113	57,474	57,594	59,488	64,382	70,571	73,233	73,203	73,227	73,046	72,530	71,973	71,774	71,000	70,278	69,905	70,279	72,020	71,555	70,173	67,583	64,188
Fall	10	68,826	10/31/2015	60,850	58,349	56,701	55,673	55,570	56,073	57,779	60,349	63,185	65,440	67,545	68,558	68,826	68,146	67,448	66,841	66,431	66,333	66,263	67,059	66,573	65,323	63,190	60,602
Fall	11	69,377	11/1/2015	56,583	53,994	53,051	52,515	52,527	53,165	54,754	56,643	58,713	60,703	61,630	61,891	62,045	62,140	61,979	61,820	62,279	64,388	68,976	69,377	67,950	65,577	62,598	59,365
Fall	11	76,703	11/2/2015	56,632	55,061	54,218	54,056	54,784	57,175	62,538	68,267	70,208	71,212	72,121	72,725	73,007	73,228	73,232	72,804	72,444	73,213	76,344	76,703	74,770	71,855	67,938	63,355
Fall	11	77,048	11/3/2015	59,887	57,605	56,345	55,779	56,252	58,301	63,352	68,846	70,638	71,382	72,384	73,168	73,686	73,890	74,151	73,687	72,920	73,537	76,748	77,048	75,207	72,495	68,313	63,549
Fall	11	78,391	11/4/2015	60,001	57,792	56,451	55,641	55,927	57,876	62,811	68,370	70,262	71,476	72,716	73,855	74,509	74,871	75,611	75,429	75,098	75,638	78,391	78,244	76,110	73,306	69,238	64,696
Fall	11	79,923	11/5/2015	60,639	58,301	56,787	56,063	56,252	58,228	63,171	69,026	71,179	72

Contains Proprietary Material
Do Not Distribute

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	8,089	12/1/2014	5,769	5,669	5,723	5,867	6,150	6,813	7,896	8,089	7,755	7,281	6,967	6,712	6,565	6,448	6,383	6,388	6,509	7,169	7,517	7,507	7,389	7,058	6,624	6,099
Winter	12	8,256	12/2/2014	5,748	5,640	5,611	5,661	5,899	6,480	7,444	7,804	7,630	7,546	7,444	7,293	7,170	7,081	7,037	7,079	7,373	8,028	8,256	8,175	8,047	7,652	7,094	6,571
Winter	12	7,836	12/3/2014	6,143	5,938	5,845	5,869	6,025	6,552	7,501	7,704	7,558	7,447	7,347	7,164	6,974	6,835	6,715	6,664	6,846	7,596	7,836	7,801	7,653	7,342	6,826	6,268
Winter	12	8,173	12/4/2014	5,837	5,649	5,592	5,625	5,820	6,405	7,399	7,711	7,593	7,484	7,310	7,114	6,895	6,808	6,705	6,743	7,073	7,844	8,158	8,173	8,110	7,839	7,345	6,833
Winter	12	8,247	12/5/2014	6,386	6,289	6,266	6,294	6,523	7,078	8,019	8,247	8,007	7,740	7,625	7,230	7,001	6,866	6,829	6,663	7,045	7,705	7,777	7,693	7,601	7,368	6,995	6,540
Winter	12	7,247	12/6/2014	6,135	5,906	5,807	5,751	5,788	5,966	6,290	6,572	6,901	7,065	7,031	6,894	6,760	6,629	6,532	6,492	6,756	7,239	7,247	7,097	6,906	6,689	6,358	5,981
Winter	12	8,707	12/7/2014	5,590	5,404	5,371	5,460	5,612	5,923	6,381	6,878	7,457	7,675	7,487	7,181	7,005	6,838	6,738	6,804	7,192	8,109	8,525	8,707	8,700	8,468	8,099	7,678
Winter	12	9,518	12/8/2014	7,433	7,335	7,313	7,416	7,588	8,327	9,295	9,518	9,267	8,988	8,607	8,286	8,109	8,064	8,069	8,215	8,615	9,336	9,461	9,469	9,277	8,881	8,275	7,732
Winter	12	9,522	12/9/2014	7,355	7,245	7,261	7,347	7,597	8,268	9,249	9,522	9,360	9,197	9,058	8,870	8,651	8,486	8,373	8,430	8,739	9,403	9,513	9,423	9,215	8,788	8,124	7,517
Winter	12	9,624	12/10/2014	7,175	7,070	7,102	7,211	7,567	8,305	9,382	9,624	9,279	8,670	8,171	7,857	7,603	7,574	7,574	7,715	8,092	9,040	9,442	9,521	9,527	9,309	8,865	8,419
Winter	12	11,021	12/11/2014	8,246	8,315	8,469	8,678	9,104	9,812	10,778	11,021	10,672	9,876	9,223	8,675	8,180	7,824	7,640	7,648	8,085	9,162	9,753	10,047	10,241	10,148	9,705	9,256
Winter	12	11,252	12/12/2014	9,019	8,962	9,044	9,178	9,500	10,202	11,092	11,252	10,793	9,836	8,966	8,282	7,782	7,424	7,198	7,143	7,440	8,345	8,773	8,944	9,056	9,031	8,785	8,433
Winter	12	9,860	12/13/2014	8,166	8,126	8,114	8,251	8,509	8,910	9,430	9,860	9,823	9,049	8,234	7,568	7,052	6,724	6,526	6,443	6,674	7,591	7,989	8,121	8,268	8,275	8,130	7,847
Winter	12	9,378	12/14/2014	7,727	7,685	7,710	7,819	7,967	8,333	8,772	9,234	9,378	8,733	7,952	7,260	6,910	6,646	6,397	6,381	6,649	7,687	8,217	8,494	8,616	8,503	8,193	7,896
Winter	12	10,791	12/15/2014	7,722	7,756	7,895	8,134	8,565	9,351	10,517	10,791	10,209	9,167	8,311	7,721	7,268	6,644	6,852	6,784	7,089	8,022	8,514	8,676	8,723	8,561	8,100	7,669
Winter	12	9,546	12/16/2014	7,408	7,390	7,452	7,561	7,825	8,506	9,447	9,546	8,968	8,371	7,968	7,694	7,534	7,465	7,345	7,350	7,539	8,185	8,425	8,344	8,184	7,836	7,315	6,770
Winter	12	8,890	12/17/2014	6,415	6,339	6,373	6,497	6,819	7,528	8,583	8,890	8,531	8,000	7,579	7,223	6,915	6,791	6,674	6,669	6,980	7,897	8,384	8,464	8,477	8,283	7,820	7,331
Winter	12	9,883	12/18/2014	7,062	7,031	7,119	7,331	7,683	8,435	9,595	9,883	9,472	8,868	8,317	7,778	7,363	7,153	7,037	7,122	7,454	8,386	8,888	9,017	9,079	8,869	8,389	7,884
Winter	12	9,762	12/19/2014	7,537	7,455	7,450	7,549	7,792	8,435	9,460	9,762	9,402	8,725	8,126	7,639	7,180	6,974	6,831	6,837	7,175	8,095	8,456	8,507	8,533	8,434	8,118	7,708
Winter	12	9,077	12/20/2014	7,386	7,217	7,131	7,148	7,253	7,485	7,848	8,261	8,669	8,951	8,972	8,865	8,640	8,440	8,251	8,199	8,349	8,977	9,077	9,009	8,915	8,764	8,470	8,078
Winter	12	8,877	12/21/2014	7,672	7,471	7,430	7,448	7,528	7,766	8,093	8,505	8,877	8,806	8,340	7,714	7,370	7,109	6,915	6,965	7,316	8,117	8,347	8,359	8,317	8,098	7,697	7,197
Winter	12	9,458	12/22/2014	6,863	6,739	6,747	6,868	7,120	7,613	8,239	8,759	8,941	9,065	9,094	8,948	8,778	8,726	8,678	8,654	8,838	9,387	9,458	9,350	9,180	8,824	8,293	7,710
Winter	12	8,717	12/23/2014	7,324	7,098	7,006	7,024	7,161	7,587	8,176	8,568	8,675	8,717	8,658	8,471	8,227	8,072	7,950	7,872	8,036	8,583	8,578	8,414	8,227	7,948	7,468	6,864
Winter	12	7,039	12/24/2014	6,368	6,045	5,830	5,705	5,738	5,912	6,255	6,543	6,737	6,967	7,039	6,969	6,793	6,625	6,484	6,345	6,460	6,821	6,739	6,519	6,347	6,185	5,909	5,516
Winter	12	6,848	12/25/2014	5,069	4,778	4,614	4,538	4,556	4,731	5,060	5,480	5,915	6,251	6,304	6,218	5,982	5,697	5,477	5,378	5,459	6,009	6,406	6,575	6,759	6,848	6,797	6,661
Winter	12	8,805	12/26/2014	6,569	6,592	6,733	6,962	7,258	7,820	8,372	8,757	8,805	8,189	7,497	6,965	6,528	6,214	6,006	5,927	6,141	6,985	7,480	7,646	7,783	7,751	7,545	7,303
Winter	12	8,782	12/27/2014	7,120	7,114	7,194	7,396	7,612	7,938	8,426	8,738	8,782	8,131	7,434	6,893	6,473	6,130	5,929	5,888	6,055	6,782	7,164	7,191	7,169	6,982	6,727	6,342
Winter	12	6,873	12/28/2014	5,985	5,769	5,664	5,586	5,612	5,688	5,901	6,089	6,359	6,487	6,366	6,160	6,148	6,045	5,941	5,942	6,116	6,667	6,873	6,754	6,613	6,362	5,964	5,492
Winter	12	8,066	12/29/2014	5,140	4,960	4,878	4,874	5,000	5,382	5,927	6,384	6,604	6,847	7,004	7,097	7,063	7,084	7,060	7,067	7,270	7,900	8,066	7,976	7,819	7,524	7,107	6,686
Winter	12	9,716	12/30/2014	6,404	6,260	6,246	6,325	6,533	7,007	7,639	8,144	8,416	8,616	8,766	8,802	8,788	8,757	8,649	8,655	8,813	9,463	9,716	9,677	9,632	9,452	9,151	8,847
Winter	12	10,681	12/31/2014	8,679	8,699	8,809	8,975	9,280	9,746	10,419	10,681	10,558	10,158	9,499	8,729	8,172	7,805	7,574	7,527	7,913	8,894	9,397	9,395	9,434	9,427	9,275	9,138
Winter	1	10,268	1/1/2015	9,069	9,110	9,142	9,277	9,465	9,770	10,112	10,268	10,107	9,396	8,578	7,952	7,458	7,006	6,763	6,700	6,948	7,824	8,233	8,328	8,284	8,104	7,703	7,243
Winter	1	7,862	1/2/2015	6,892	6,649	6,526	6,491	6,595	6,958	7,477	7,823	7,862	7,787	7,609	7,387	7,216	7,071	6,979	6,932	7,109	7,712	7,819	7,668	7,517	7,272	6,931	6,533
Winter	1	7,572	1/3/2015	6,172	5,941	5,830	5,815	5,908	6,078	6,379	6,626	6,902	7,165	7,274	7,243	7,116	6,982	6,871	6,857	6,983	7,463	7,572	7,392	7,237	6,926	6,542	6,145
Winter	1	7,044	1/4/2015	5,706	5,434	5,229	5,108	5,079	5,092	5,218	5,441	5,700	6,046	6,062	6,058	6,111	6,144	6,075	6,099	6,272	6,826	7,044	6,953	6,816	6,425	5,939	5,485
Winter	1	9,066	1/5/2015	5,160	5,027	5,039	5,149	5,468	6,239	7,435	7,897	7,787	7,653	7,473	7,257	7,068	6,984	6,878	6,917	7,237	8,126	8,838	9,039	9,066	8,920	8,535	8,151
Winter	1	11,150	1/6/2015	8,022	8,092	8,252	8,500	8,912	9,724	10,867	11,150	10,583	9,492	8,707	8,077	7,601	7,296	7,123	7,175	7,454	8,230	8,900	9,052	9,071	8,842	8,456	8,066
Winter	1	12,003	1/7/2015	7,931	7,963	8,111	8,370	8,792	9,588	10,699	10,861	10,519	9,816	9,473	9,323	9,248	9,220	9,258	9,462	9,955	10,936	11,483	11,802	11,978	12,003	11,893	11,806
Winter	1	14,519	1/8/2015	11,941	12,150	12,408	12,765	13,141	13,726	14,219	14,519	14,255	14,012	13,107	12,305	11,569	10,995	10,531	10,478	10,905	11,973	12,889	13,210	13,276	13,002	12,548	12,047
Winter	1	12,288	1/9/2015	11,787	11,625	11,533	11,418	11,361	11,639	12,288	12,160	11,844	11,213	10,547	9,740	9,035	8,505	8,100	8,004	8,327	9,207	9,814	9,886	9,883	9,743	9,434	9,082
Winter	1	11,069	1/10/2015	8,935	8,915	9,027	9,287	9,594	9,999	10,519	10,979	11,069	10,727	10,192	9,557	8,988	8,451	8,117	8,027	8,374	9,441	10,279	10,576	10,787	10,697	10,747	10,477
Winter	1	12,102	1/11/2015	10,356	10,478	10,666	10,881	11,088	11,427	11,778	12,102	11,996	11,027	9,924	9,042	8,431	8,010	7,804	7,718	8,011	8,684	8,975	8,925	8,759	8,358	7,829	7,342
Winter	1	8,935	1/12/2015	6,970	6,843	6,840	6,911	7,176	7,766	8,606	8,935	8,711	8,573	8,473	8,353	8,241	8,160	8,025	7,947	8,055	8,510	8,703	8,560	8,282	7,858	7,276	6,732
Winter	1	10,609	1/13/2015	6,381	6,202	6,165	6,258	6,537	7,192	8,262	8,762	8,693	8,827	8,958	9,024	9,108	9,198	9,207	9,361	9,696	10,329	10,609	10,553	10,429	10,051	9,568	9,145
Winter	1	11,537	1/14/2015	8,932	8,907	8,997	9,119	9,416	9,964	10,684	11,273	11,537	11,424	11,187	10,988	10,746	10,574	10,416	10,408	10,591	11,114	11,349	11,198	10,962	10,508	9,899	9,339
Winter	1	10,948	1/15/2015	9,030	8,896	8,847	8,933	9,161	9,731	10,601	10,948	10,808	10,492	10,049	9,630	9,225	9,115	8,996	9,015	9,268	9,795	10,052	10,011	9,804	9,439	8,852	8,282
Winter	1	10,254	1/16/2015	7,929	7,794	7,770	7,852	8,135	8,833	9,877	10,254	9,949	9,337	8,650	8,130	7,663	7,373	7,123	6,990	7,169	7,863	8,526	8,674	8,815	8,817	8,651	8,444
Winter	1	10,012	1/17/2015	8,301	8,336	8,432	8,578	8,783	9,160	9,637	10,010	10,012	9,423	8,727	8,072	7,477	7,038	6,748	6,658	6,900	7,633	8,183	8,244	8,208	8,013	7,694	7,274
Winter	1	7,620	1/18/2015	6,890	6,645	6,546	6,516	6,529	6,620	6,800	7,083	7,402	7,558	7,334	7,012	6,719	6,489	6,295	6,215	6,347	6,934	7,478	7,608	7,620	7,540	7,376	7,105
Winter	1	9,471	1/19/2015	7,017	7,045	7,202	7,408	7,746	8,300	9,042	9,471	9,397	8,757	8,164	7,623	7,209	6,880	6,700	6,567	6,749	7,374	8,046	8,135	8,100	7,888	7,463	7,078
Winter	1	8,933	1/20/2015	6,823	6,754	6,736	6,776	7,039	7,620	8,540	8,933	8,686	8,170	7,686	7,243	6,901	6,703	6,579	6,523	6,635	7,211	7,849	7,886	7,796	7,464	7,030	6,550
Winter	1	8,815	1/21/2015	6,261	6,168	6,143	6,286	6,603	7,329	8,401	8,815	8,529	8,072	7,646	7,230	6,900	6,703	6,559	6,554	6,717	7,317	8,052	8,168	8,182	7,973	7,621	7,286
Winter	1	10,215	1/22/2015	7,124	7,144	7,334	7,590	7,938	8,772	9,891	10,215	9,833	9,142	8,372	7,723	7,236	6,949	6,733	6,730	6,953	7,556	8,255	8,411	8,421	8,276	7,868	7,476
Winter	1	9,436	1/23/2015	7,227	7,193	7,221	7,310	7,469	8,032	8,949	9,241	9,085	8,931	8,834	8,776	8,710	8,718	8,735	8,805	9,001	9,386	9,436	9,153	8,818	8,410	7,878	7,318
Winter	1	8,756	1/24/2015	6,885	6,638	6,488	6,524	6,665	6,946	7,314	7,747	8,161	8,494	8,602	8,512	8,433	8,247	7,976	7,621	7,631	8,028	8,603	8,655	8,756	8,633	8,411	8,108
Winter	1	9,768	1/25/2015	7,913	7,883	7,992	8,166	8,372	8,708	9,198	9,668	9,768	9,037	8,076	7,337	6,912	6,601	6,338	6,291	6,492	7,180	8,000	8,229	8,282	8,115	7,744	7,416
Winter	1	9,387	1/26/2015	7,145	7,071	7,102	7,210	7,506	8,086	9,090	9,387	9,085	8,761	8,459	8,097	7,761	7,593	7,528	7,635	7,958	8,537	8,968	8,978	8,821	8,470	7,972	7,496
Winter	1	10,578	1/27/2015	7,277	7,219	7,336	7,504	7,899	8,662	9,813	10,200	10,091	9,915	9,687	9,429	9,115	8,784	8,528	8,422	8,663	9,303	10,186	10,466	10,578	10,365	9,897	9,494
Winter	1	11,929	1/28/2015	9,308	9,306	9,406	9,538	9,883	10,647	11,704	11,929	11,271	10,662	9,964	9,303	8,747	8,344	8,018	7,901	8,186	8,969	10,078	10,465	10,646	10,542	10,199	9,875
Winter	1	12,626	1/29/2015	9,824	9,907	10,114	10,347	10,708	11,477	12,485	12,626	11,978	10,996	10,012	9,221	8,688	8,411	8,162	8,046	8,337	8,966	9,539	9,603	9,474	9,071	8,498	7,948
Winter	1	9,504	1/30/2015	7,559	7,416	7,347	7,312	7,471	7,942	8,885	9,216	8,970	8,693	8,401	8,169	7,911	7,705	7,486	7,441	7,695	8,403	9,219	9,406	9,504	9,477	9,302	9,063
Winter	1	10,925	1/31/2015	8,952	9,010	9,154	9,351	9,613	10,042	10,510	10,925	10,844	10,306	9,576	8,918	8,242	7,693	7,287	7,143	7,312	7,975	8,885	9,198	9,376	9,346	9,134	8,845
Winter	2	9,135	2/1/2015	8,609	8,434	8,296	8,252	8,247	8,342	8,552	8,868	9,135	8,837	8,301	7,742	7,322	7,116	6,925	6,919	7,128	7,565	7,846	7,632	7,491	7,234	6,891	6,393
Winter	2	9,513	2/2/2015	5,922	5,658	5,558	5,556	5,695	6,232	7,186	7,522	7,366	7,327	7,396	7,358	7,210	7,152	7,139	7,105	7,344	8,051	9,082	9,384	9,513	9,366	9,033	8,707
Winter	2	11,657	2/3/2015	8,589	8,680	8,863	9,139	9,570	10,410	11,416	11,657	11,322	10,584	9,764	9,050	8,465	8,056	7,752	7,634	7,878	8,673	9,772	10,145	10,281	10,109	9,718	9,327
Winter	2	11,696	2/4/2015	9,159	9,169	9,344	9,565	9,897	10,655	11,588	11,696	11,305	10,126	9,095	8,367	7,797	7,520	7,283	7,260	7,485	8,064	8,770	8,796	8,676	8,279	7,690	7,124
Winter	2	10,221	2/5/2015	6,765	6,598	6,568	6,632	6,828	7,517	8,555	8,861	8,703	8,630	8,453	8,187	7,767	7,494	7,301	7,324	7,665	8,488	9,613	10,035	10,221	10,129	9,810	9,494
Winter	2	12,620	2/6/2015	9,423	9,541	9,763	10,045	10,509	11,415	12,424	12,620	12,191	11,201	10,292	9,459	8,847	8,467	8,277	8,322	8,598	9,100	9,683	9,732	9,669	9,504	9,233	8,998
Winter	2	10,559	2/7/2015	8,882	8,876	9,006	9,141	9,381	9,743	10,268	10,559	10,297	9,486	8,634	7,941	7,296	6,850	6,565	6,413	6,490	6,920	7,691	7,823	7,835	7,728	7,474	7,122
Winter	2	7,712	2/8/2015	6,880	6,729	6,680	6,719	6,805	7,011	7,324	7,627	7,712	7,387	6,865	6,388	6,148	5,903	5,722	5,656	5,773	6,121	6,868	7,026	6,954	6,647	6,252	5,816
Winter	2	7,779	2/9/2015	5,516	5,448	5,430	5,544	5,809	6,443	7,485	7,779	7,538	7,239	7,005	6,791	6,610	6,580	6,536	6,573	6,730	7,127	7,621	7,586	7,382	6,995	6,543	6,072
Winter	2	10,271	2/10/2015	5,825	5,727	5,788	6,009	6,348	7,166	8,417	8,995	9,070	9,213	9,376	9,349	9,317	9,315	9,263	9,286	9,393	9,767	10,266	10,271	10,085	9,696	9,119	8,627
Winter	2	10,891	2/11/2015	8,397	8,369	8,451	8,579	8,916	9,589	10,667	10,891	10,473	9,945	9,357	8,719	8,189	7,748	7,379	7,176	7,256	7,784	8,803	9,167	9,335	9,249	8,960	8,591
Winter	2	10,757	2/12/2015	8,354	8,415	8,482	8,625	8,959	9,683	10,695	10,757	9,941	8,887	8,109	7,575	7,197	7,053	7,058	7,242	7,733	8,389	9,278	9,709	9,915	9,866	9,577	9,328
Winter	2	12,006	2/13/2015	9,208	9,332	9,505	9,788	10,192	10,946	11,863	12,006	11,580	11,202	10,586	10,012	9,526	9,170	8,866	8,663	8,755	9,363	10,317	10,684	10,844	10,875	10,723	10,522
Winter	2	11,849	2/14/2015	10,463	10,546	10,692	10,844	11,032	11,361	11,739	11,849	11,331	10,372	9,541	8,752	8,121	7,578	7,219	7,055	7,181	7,680	8,376	8,432	8,291	8,147	8,014	7,992
Winter	2	12,693	2/15/2015	8,203	8,734	9,422	10,037	10,682	11,324	12,049	12,565	12,693	12,470	11,872	11,199	10,678	10,126	9,687	9,490	9,650	10,344	11,399	11,640	11,674	11,561	11,377	11,089
Winter	2	12,451	2/16/2015	10,976	10,902	10,938	10,960	11,117	11,604	12,248	12,383	12,451	12,352	12,049	11,599	11,114	10,849	10,780	10,857	11,222	11,821	12,164	11,983	11,630	11,134	10,746	10,360
Winter	2	11,788	2/17/2015	10,170	10,119	10,101	10,021	10,165	10,537	11,001	11,369	11,615	11,788	11,663	11,358	11,031	10,588	10,306	10,266	10,473	10,984	11,572	11,502	11,323	10,997	10,602	10,277
Winter	2	12,653	2/18/2015	10,203	10,319	10,560	10,785	11,029	11,519	12,263	12,653	12,383	11,535	10,774	10,160	9,741	9,458	9,221	9,203	9,359	9,976	10,801	10,959	11,100	10,914	10,609	10,413
Winter	2	13,704	2/19/2015	10,533	10,816	11,054	11,454	11,950	12,572	13,373	13,704	13,601	13,402	12,905	12,389	11,919	11,506	11,208	11,131	11,411	12,247	13,459	13,563	13,616	13,671	13,586	13,410
Winter	2	15,569	2/20/2015	13,325	13,606	13,863	14,071	14,454	14,950	15,441	15,569	15,181	14,686	13,806	12,922	12,118	11,459	10,848	10,509	10,533	11,121	12,239	12,550	12,638	12,690	12,501	12,283
Winter	2	12,517	2/21/2015	12,111	12,109	12,060	12,127	12,167	12,330	12,517	12,517	12,261	11,803	11,154	10,483	9,862	9,249	8,843	8,615	8,621	8,753	9,113	9,009	8,767	8,420	7,924	7,430
Winter	2	7,889	2/22/2015	7,038	6,866	6,802	6,786	6,850	7,011	7,320	7,553	7,889	7,802	7,524	7,112	6,865	6,697	6,546	6,488	6,557	6,968	7,543	7,698	7,597	7,240	6,810	6,355
Winter	2	10,525	2/23/2015	6,046	5,927	5,890	5,984	6,265	6,886	7,954	8,374	8,471	8,624	8,827	8,979	9,042	9,073	9,039	9,124	9,334	9,717	10,362	10,525	10,504	10,268	9,901	9,490
Winter	2	12,556	2/24/2015	9,294	9,321	9,393	9,569	9,909	10,642	11,607	12,040	12,292	12,491	12,556	12,549	12,476	12,281	12,134	11,993	11,977	12,229	12,549	12,450	12,150	11,622	11,139	10,763
Winter	2	12,266	2/25/2015	10,564	10,565	10,615	10,707	10,897	11,300	11,900	12,266	12,087	11,409	10,637	10,046	9,525	9,178	8,874	8,876	9,368	9,752	10,367	10,362	10,463	10,277	9,918	9,594
Winter	2	11,078	2/26/2015	9,452	9,390	9,293	9,275	9,280	9,553	10,196	10,626	10,809	10,817	10,741	10,566	10,377	10,230	10,066	10,056	10,183	10,486	11,050	11,078	10,921	10,594	10,062	9,680
Winter	2	11,946	2/27/2015	9,504	9,476	9,549	9,738	10,077	10,729	11,626	11,946	11,435	10,465	9,576	8,909	8,349	7,976	7,675	7,496	7,587	8,031	8,939	9,381	9,575	9,623	9,450	9,173
Winter	2	11,156	2/28/2015	9,058	9,126	9,290	9,519	9,820	10,269	10,784	11,112	11,156	10,842	10,258	9,674	9,057	8,579	8,197	8,012	8,156	8,684	9,513	9,833	9,912	9,808	9,501	9,155
Spring	3	10,149	3/1/2015	8,827	8,636	8,627	8,624	8,761	9,015	9,393	9,781	10,116	10,149	9,995	9,655	9,477	9,317	9,129	9,017	9,074	9,292	9,741	9,829	9,638	9,237	8,710	8,183
Spring	3	9,468	3/2/2015	7,854	7,652	7,621	7,661	7,869	8,433	9,356	9,468	9,186	8,848	8,399	7,853	7,379	6,978	6,772	6,600	6,672	6,926	7,769	8,187	8,204	8,016	7,640	7,260
Spring	3	9,822	3/3/2015	7,011	6,953	7,030	7,172	7,470	8,158	9,214	9,531	9,421	9,351	9,281	9,138	9,000	8,922	8,831	8,859	9,070	9,352	9,810	9,822	9,606	9,126	8,470	7,804

Contains Proprietary Material
Do Not Distribute

Spring	4	7,123	4/6/2015	4,844	4,695	4,636	4,706	4,843	5,372	6,005	6,357	6,415	6,358	6,346	6,363	6,312	6,363	6,412	6,461	6,537	6,617	6,655	6,825	7,123	6,765	6,160	5,594
Spring	4	7,309	4/7/2015	5,131	4,862	4,738	4,683	4,759	5,114	5,834	6,155	6,257	6,394	6,512	6,631	6,668	6,696	6,716	6,733	6,770	6,804	6,863	7,017	7,309	6,967	6,402	5,767
Spring	4	8,063	4/8/2015	5,269	5,049	4,885	4,781	4,855	5,204	5,884	6,181	6,325	6,522	6,680	6,931	7,181	7,442	7,664	7,843	8,003	8,051	8,019	7,990	8,063	7,640	6,898	6,145
Spring	4	7,878	4/9/2015	5,572	5,231	4,985	4,927	4,989	5,309	5,899	6,200	6,374	6,540	6,702	6,827	7,026	7,270	7,526	7,759	7,878	7,849	7,784	7,785	7,829	7,388	6,754	6,090
Spring	4	8,091	4/10/2015	5,576	5,286	5,120	5,011	5,063	5,391	5,995	6,286	6,554	6,805	7,094	7,378	7,616	7,783	7,914	8,091	7,955	7,931	7,849	7,702	7,868	7,520	6,953	6,297
Spring	4	6,945	4/11/2015	5,790	5,437	5,234	5,054	4,995	5,044	5,219	5,357	5,721	6,023	6,168	6,270	6,299	6,381	6,527	6,708	6,885	6,945	6,903	6,563	6,775	6,438	5,967	5,432
Spring	4	6,755	4/12/2015	4,981	4,696	4,547	4,471	4,469	4,569	4,747	4,992	5,437	5,663	5,642	5,622	5,721	5,794	5,860	5,935	6,041	6,148	6,180	6,381	6,755	6,445	5,886	5,299
Spring	4	7,600	4/13/2015	4,871	4,659	4,550	4,550	4,696	5,191	6,010	6,266	6,264	6,294	6,457	6,556	6,659	6,809	6,920	6,991	7,123	7,156	7,176	7,304	7,600	7,219	6,561	5,875
Spring	4	7,966	4/14/2015	5,379	5,092	4,935	4,870	4,955	5,364	6,211	6,505	6,574	6,718	6,896	7,082	7,213	7,386	7,506	7,607	7,700	7,710	7,723	7,740	7,966	7,590	6,864	6,109
Spring	4	7,064	4/15/2015	5,590	5,279	5,121	5,079	5,059	5,333	6,183	6,394	6,415	6,405	6,459	6,451	6,396	6,441	6,376	6,295	6,416	6,534	6,697	6,860	7,064	6,723	6,200	5,618
Spring	4	7,124	4/16/2015	5,229	5,034	4,956	4,955	5,081	5,546	6,459	6,742	6,665	6,687	6,711	6,614	6,562	6,508	6,449	6,414	6,465	6,524	6,642	6,826	7,124	6,810	6,236	5,581
Spring	4	7,099	4/17/2015	5,175	4,984	4,871	4,821	4,903	5,276	6,123	6,398	6,437	6,478	6,515	6,551	6,559	6,606	6,647	6,700	6,836	6,884	6,837	6,850	7,099	6,873	6,410	5,848
Spring	4	7,064	4/18/2015	5,340	4,992	4,840	4,706	4,705	4,826	5,048	5,263	5,656	6,025	6,282	6,481	6,614	6,771	6,904	7,016	7,056	7,064	6,960	6,851	7,053	6,773	6,330	5,755
Spring	4	6,907	4/19/2015	5,291	4,995	4,763	4,650	4,597	4,650	4,770	4,981	5,471	5,872	6,098	6,241	6,338	6,402	6,343	6,294	6,317	6,416	6,559	6,751	6,907	6,616	6,128	5,600
Spring	4	7,757	4/20/2015	5,165	4,919	4,807	4,757	4,832	5,234	6,077	6,414	6,488	6,643	6,917	7,130	7,381	7,648	7,757	7,620	7,613	7,532	7,516	7,579	7,736	7,388	6,720	6,039
Spring	4	7,323	4/21/2015	5,496	5,195	5,022	4,929	4,985	5,370	6,085	6,316	6,373	6,436	6,526	6,586	6,621	6,803	6,856	7,001	7,116	7,146	7,097	6,991	7,323	6,994	6,336	5,638
Spring	4	7,329	4/22/2015	5,192	4,951	4,812	4,776	4,907	5,377	6,240	6,493	6,438	6,400	6,440	6,509	6,453	6,562	6,670	6,850	6,983	7,065	7,062	7,021	7,329	7,065	6,409	5,705
Spring	4	6,997	4/23/2015	5,215	4,954	4,821	4,783	4,877	5,284	6,073	6,321	6,345	6,353	6,352	6,349	6,349	6,412	6,470	6,538	6,655	6,639	6,611	6,618	6,997	6,800	6,207	5,571
Spring	4	6,677	4/24/2015	5,199	4,992	4,902	4,887	5,017	5,542	6,380	6,677	6,567	6,445	6,373	6,271	6,205	6,161	6,099	6,102	6,180	6,224	6,166	6,137	6,474	6,331	5,930	5,510
Spring	4	6,416	4/25/2015	5,112	4,900	4,812	4,757	4,780	4,945	5,189	5,439	5,857	6,098	6,245	6,229	6,201	6,115	6,013	5,994	6,036	6,104	6,148	6,222	6,416	6,222	5,860	5,420
Spring	4	6,685	4/26/2015	5,017	4,849	4,720	4,671	4,641	4,729	4,922	5,224	5,715	6,046	6,129	6,075	6,098	6,070	5,973	5,913	5,943	6,065	6,125	6,314	6,685	6,486	6,014	5,528
Spring	4	6,983	4/27/2015	5,169	5,025	4,969	5,022	5,248	5,821	6,713	6,983	6,755	6,518	6,405	6,316	6,268	6,246	6,223	6,247	6,317	6,365	6,386	6,502	6,906	6,699	6,087	5,529
Spring	4	7,025	4/28/2015	5,122	4,942	4,917	4,975	5,203	5,809	6,735	7,025	6,763	6,554	6,382	6,279	6,188	6,186	6,154	6,167	6,275	6,352	6,430	6,505	6,871	6,677	6,071	5,456
Spring	4	6,854	4/29/2015	5,083	4,904	4,839	4,844	5,007	5,532	6,391	6,644	6,511	6,433	6,374	6,349	6,268	6,295	6,301	6,308	6,376	6,452	6,546	6,591	6,854	6,643	6,084	5,500
Spring	4	6,838	4/30/2015	5,061	4,875	4,789	4,781	4,892	5,376	6,206	6,483	6,392	6,324	6,289	6,201	6,127	6,169	6,139	6,150	6,236	6,316	6,443	6,550	6,838	6,609	6,081	5,480
Spring	5	6,480	5/1/2015	5,099	4,892	4,785	4,773	4,893	5,323	6,120	6,424	6,430	6,458	6,480	6,448	6,359	6,302	6,206	6,116	6,095	6,083	6,059	6,106	6,480	6,448	6,126	5,694
Spring	5	6,190	5/2/2015	5,326	5,108	5,024	4,991	5,070	5,274	5,503	5,771	5,951	5,980	5,892	5,812	5,758	5,741	5,725	5,754	5,839	5,942	5,918	5,906	6,190	6,071	5,666	5,211
Spring	5	6,805	5/3/2015	4,779	4,611	4,490	4,437	4,486	4,623	4,755	5,095	5,494	5,645	5,653	5,675	5,805	5,958	6,055	6,220	6,373	6,570	6,624	6,561	6,805	6,594	6,010	5,353
Spring	5	7,741	5/4/2015	4,867	4,607	4,484	4,456	4,573	5,063	5,808	6,117	6,231	6,330	6,530	6,720	6,901	7,169	7,347	7,513	7,673	7,741	7,728	7,570	7,721	7,460	6,711	5,868
Spring	5	8,154	5/5/2015	5,327	4,992	4,803	4,710	4,753	5,170	5,878	6,188	6,292	6,437	6,659	6,873	7,099	7,424	7,685	7,943	8,131	8,154	8,048	7,779	7,830	7,513	6,728	5,906
Spring	5	8,009	5/6/2015	5,312	4,985	4,806	4,720	4,792	5,184	5,878	6,190	6,265	6,495	6,644	6,850	7,098	7,380	7,643	7,853	7,996	8,009	7,887	7,670	7,748	7,428	6,689	5,937
Spring	5	7,944	5/7/2015	5,380	5,073	4,866	4,774	4,870	5,281	6,015	6,309	6,427	6,613	6,807	6,951	7,177	7,380	7,564	7,751	7,942	7,944	7,861	7,678	7,837	7,620	6,894	6,112
Spring	5	7,856	5/8/2015	5,511	5,142	4,938	4,859	4,904	5,248	5,915	6,290	6,487	6,766	7,054	7,274	7,439	7,616	7,705	7,769	7,856	7,835	7,689	7,455	7,525	7,361	6,871	6,229
Spring	5	7,640	5/9/2015	5,665	5,315	5,085	4,950	4,927	5,027	5,141	5,447	5,982	6,426	6,769	7,077	7,274	7,457	7,548	7,602	7,640	7,590	7,403	7,244	7,321	7,222	6,780	6,215
Spring	5	7,257	5/10/2015	5,700	5,351	5,144	5,004	4,954	4,998	5,059	5,416	6,000	6,417	6,625	6,640	6,734	6,755	6,777	6,805	6,856	6,898	6,934	6,978	7,257	7,140	6,649	6,020
Spring	5	9,573	5/11/2015	5,546	5,254	5,123	5,057	5,148	5,576	6,322	6,671	6,864	7,095	7,470	7,836	8,224	8,660	8,980	9,302	9,518	9,573	9,469	9,101	9,029	8,543	7,668	6,818
Spring	5	10,048	5/12/2015	6,204	5,863	5,616	5,489	5,532	5,943	6,627	7,031	7,340	7,786	8,325	8,856	9,346	9,785	9,881	10,040	10,048	10,007	9,879	9,574	9,516	9,067	8,098	7,168
Spring	5	8,971	5/13/2015	6,452	6,027	5,653	5,530	5,490	5,822	6,387	6,662	6,780	6,994	7,282	7,557	7,817	8,184	8,457	8,739	8,950	8,971	8,814	8,366	8,163	7,773	6,944	6,106
Spring	5	7,556	5/14/2015	5,498	5,182	4,965	4,873	4,942	5,255	5,885	6,160	6,257	6,379	6,497	6,632	6,773	7,009	7,177	7,366	7,556	7,556	7,419	7,224	7,407	7,209	6,545	5,798
Spring	5	7,571	5/15/2015	5,269	4,988	4,850	4,796	4,850	5,170	5,805	6,120	6,230	6,358	6,536	6,695	6,833	7,037	7,198	7,341	7,523	7,571	7,462	7,215	7,207	7,076	6,564	5,936
Spring	5	8,421	5/16/2015	5,384	5,068	4,840	4,700	4,685	4,802	4,849	5,143	5,672	6,146	6,520	6,879	7,287	7,647	7,963	8,244	8,409	8,421	8,196	7,854	7,777	7,502	6,927	6,213
Spring	5	9,132	5/17/2015	5,624	5,202	4,902	4,801	4,687	4,716	4,684	5,007	5,601	6,214	6,686	7,163	7,656	8,107	8,484	8,793	9,039	9,132	9,047	8,706	8,587	8,296	7,476	6,652
Spring	5	10,530	5/18/2015	6,030	5,580	5,404	5,276	5,329	5,717	6,391	6,823	7,176	7,622	8,255	8,912	9,450	9,911	10,112	10,352	10,506	10,530	10,381	10,151	9,982	9,441	8,464	7,491
Spring	5	10,287	5/19/2015	6,742	6,283	5,984	5,766	5,760	6,076	6,744	7,212	7,525	7,956	8,478	9,056	9,284	10,087	10,287	10,247	10,242	10,079	9,840	9,514	9,274	8,922	8,047	7,138
Spring	5	10,216	5/20/2015	6,452	6,037	5,741	5,567	5,549	5,852	6,414	6,934	7,279	7,715	8,250	8,695	9,174	9,614	9,953	10,125	10,216	10,197	10,063	9,672	9,375	8,953	8,010	7,112
Spring	5	8,927	5/21/2015	6,405	5,979	5,750	5,602	5,612	5,904	6,535	6,900	7,114	7,403	7,817	8,197	8,594	8,927	8,923	8,751	8,592	8,429	8,166	7,855	7,794	7,590	6,862	6,103
Spring	5	7,520	5/22/2015	5,550	5,218	5,013	4,897	4,924	5,268	5,793	6,097	6,236	6,397	6,531	6,684	6,784	6,961	7,118	7,283	7,446	7,520	7,362	7,055	6,902	6,757	6,282	5,658
Spring	5	7,531	5/23/2015	5,150	4,799	4,594	4,471	4,496	4,597	4,656	4,972	5,405	5,735	5,942	6,147	6,347	6,557	6,811	7,066	7,373	7,531	7,470	7,135	6,942	6,793	6,281	5,687
Spring	5	7,952	5/24/2015	5,167	4,852	4,630	4,512	4,453	4,488	4,462	4,787	5,322	5,818	6,180	6,498	6,794	7,095	7,362	7,613	7,837	7,952	7,823	7,453	7,220	7,074	6,525	5,862
Spring	5	8,878	5/25/2015	5,355	4,969	4,728	4,564	4,545	4,614	4,655	4,953	5,512	6,161	6,689	7,112	7,467	7,832	8,185	8,480	8,702	8,878	8,760	8,425	8,233	7,978	7,223	6,353
Spring	5	10,180	5/26/2015	5,727	5,343	5,097	4,969	5,016	5,335	5,939	6,557	6,946	7,397	7,908	8,416	8,986	9,491	9,842	10,141	10,180	10,130	10,077	9,717	9,595	9,177	8,281	7,398
Spring	5	10,141	5/27/2015	6,682	6,247	5,915	5,808	5,777	6,135	6,781	7,237	7,614	7,979	8,480	8,999	9,380	9,789	10,060	10,141	10,096	10,050	9,778	9,265	9,037	8,752	7,898	7,017
Spring	5	10,125	5/28/2015	6,323	5,914	5,650	5,474	5,484	5,802	6,427	6,920	7,253	7,636	8,095	8,585	9,042	9,537	9,908	10,125	10,112	10,073	9,955	9,562	9,309	8,926	8,037	7,110
Spring	5	10,139	5/29/2015	6,350	5,871	5,591	5,386	5,413	5,722	6,247	6,719	7,197	7,696	8,249	8,717	9,190	9,584	9,929	10,139	10,119	10,038	9,871	9,339	8,952	8,681	7,946	7,185
Spring	5	9,873	5/30/2015	6,470	5,979	5,619	5,389	5,309	5,356	5,385	5,834	6,549	7,286	7,857	8,402	8,826	9,133	9,401	9,661	9,871	9,873	9,676	9,197	8,811	8,545	7,868	7,070
Spring	5	10,103	5/31/2015	6,340	5,880	5,494	5,287	5,165	5,145	5,079	5,529	6,338	7,139	7,729	8,290	8,766	9,283	9,588	9,821	10,031	10,103	9,984	9,559	9,242	8,931	8,113	7,230
Summer	6	10,940	6/1/2015	6,539	6,067	5,787	5,645	5,676	6,000	6,604	7,233	7,748	8,325	8,988	9,602	10,158	10,657	10,881	10,940	10,877	10,657	10,236	9,671	9,408	8,974	8,137	7,266
Summer	6	9,254	6/2/2015	6,577	6,120	5,837	5,687	5,693	6,006	6,602	7,110	7,419	7,793	8,175	8,445	8,664	8,868	9,070	9,254	9,246	9,046	8,804	8,556	8,484	8,156	7,409	6,601
Summer	6	7,677	6/3/2015	6,085	5,782	5,487	5,400	5,398	5,732	6,400	6,683	6,793	6,947	7,068	7,201	7,260	7,366	7,428	7,481	7,621	7,677	7,632	7,571	7,596	7,457	6,923	6,225
Summer	6	8,045	6/4/2015	5,706	5,407	5,237	5,125	5,199	5,569	6,183	6,527	6,688	6,903	7,107	7,297	7,473	7,668	7,813	7,912	8,045	8,009	7,915	7,746	7,743	7,643	7,044	6,314
Summer	6	8,233	6/5/2015	5,769	5,412	5,208	5,134	5,174	5,510	6,055	6,406	6,595	6,788	6,978	7,252	7,435	7,694	7,888	8,054	8,232	8,233	8,088	7,810	7,687	7,606	7,040	6,373
Summer	6	9,680	6/6/2015	5,788	5,409	5,174	4,996	4,949	5,003	5,044	5,416	6,090	6,772	7,448	8,028	8,548	8,939	9,257	9,494	9,653	9,680	9,444	8,975	8,524	8,353	7,677	6,930
Summer	6	9,377	6/7/2015	6,195	5,723	5,435	5,214	5,087	5,063	5,005	5,405	6,064	6,734	7,128	7,578	8,045	8,467	8,806	9,064	9,279	9,377	9,234	8,853	8,548	8,333	7,581	6,737
Summer	6	10,683	6/8/2015	6,093	5,645	5,353	5,196	5,236	5,538	6,104	6,618	7,092	7,617	8,237	8,820	9,343	9,860	10,202	10,456	10,680	10,683	10,484	10,084	9,797	9,474	8,647	7,733
Summer	6	10,451	6/9/2015	7,021	6,599	6,308	6,115	6,087	6,336	6,795	7,309	7,696	8,151	8,637	9,152	9,570	10,006	10,220	10,408	10,451	10,325	10,004	9,559	9,241	8,866	8,092	7,217
Summer	6	10,941	6/10/2015	6,550	6,092	5,865	5,674	5,673	5,951	6,452	6,949	7,293	7,744	8,308	8,948	9,590	10,161	10,612	10,858	10,941	10,874	10,634	10,214	9,886	9,590	8,747	7,795
Summer	6	11,479	6/11/2015	7,110	6,619	6,304	6,062	6,050	6,341	6,799	7,414	8,073	8,772	9,542	10,197	10,735	11,167	11,438	11,428	11,479	11,419	11,298	10,920	10,511	10,198	9,309	8,386
Summer	6	11,092	6/12/2015	7,596	7,022	6,635	6,382	6,299	6,511	6,874	7,538	8,246	8,940	9,646	10,246	10,706	10,945	11,052	11,092	11,068	11,006	10,845	10,413	10,034	9,812	9,096	8,279
Summer	6	11,380	6/13/2015	7,541	7,047	6,696	6,423	6,273	6,259	6,258	6,812	7,710	8,641	9,491	10,186	10,724	11,104	11,325	11,296	11,380	11,359	11,245	10,891	10,454	10,165	9,384	8,520
Summer	6	11,650	6/14/2015	7,730	7,185	6,766	6,450	6,249	6,181	6,095	6,640	7,651	8,684	9,521	10,245	10,806	11,191	11,364	11,498	11,629	11,650	11,552	11,263	10,819	10,470	9,603	8,693
Summer	6	12,722	6/15/2015	7,867	7,317	6,925	6,650	6,603	6,827	7,175	7,960	8,782	9,787	10,791	11,590	12,063	12,409	12,665	12,722	12,651	12,594	12,616	12,420	11,964	11,486	10,414	9,339
Summer	6	12,849	6/16/2015	8,498	7,813	7,478	7,120	7,015	7,157	7,445	8,155	8,941	9,927	10,942	11,713	12,283	12,658	12,816	12,849	12,823	12,766	12,815	12,639	12,174	11,705	10,710	9,670
Summer	6	12,723	6/17/2015	8,853	8,213	7,710	7,372	7,236	7,370	7,664	8,367	9,116	9,917	10,735	11,475	12,042	12,513	12,635	12,723	12,704	12,683	12,549	12,157	11,699	11,273	10,315	9,197
Summer	6	12,639	6/18/2015	8,386	7,827	7,435	7,180	7,107	7,289	7,563	8,071	8,621	9,401	10,262	11,075	11,849	12,416	12,639	12,416	12,280	12,088	11,715	11,195	10,627	10,039	9,163	8,287
Summer	6	12,367	6/19/2015	7,594	7,118	6,785	6,574	6,538	6,759	7,072	7,583	8,217	8,940	9,692	10,464	11,095	11,711	12,116	12,338	12,367	12,107	11,544	10,785	10,233	9,751	9,001	8,080
Summer	6	11,710	6/20/2015	7,320	6,840	6,445	6,205	6,111	6,091	6,111	6,510	7,326	8,329	9,258	10,068	10,759	11,214	11,535	11,710	11,667	11,657	11,465	11,040	10,622	10,299	9,640	8,887
Summer	6	12,095	6/21/2015	8,184	7,608	7,205	6,939	6,795	6,684	6,582	7,135	8,128	9,036	9,706	10,252	10,762	11,160	11,512	11,789	12,015	12,095	11,932	11,526	11,065	10,734	9,897	8,925
Summer	6	12,672	6/22/2015	8,139	7,534	7,180	6,888	6,794	6,951	7,207	7,932	8,722	9,589	10,490	11,252	11,854	12,327	12,672	12,548	12,671	12,588	12,452	12,101	11,654	11,262	10,314	9,329
Summer	6	12,773	6/23/2015	8,540	8,018	7,686	7,388	7,345	7,516	7,787	8,443	9,187	9,948	10,833	11,576	12,176	12,562	12,733	12,577	12,773	12,752	12,670	12,320	11,952	11,625	10,766	9,797
Summer	6	12,719	6/24/2015	9,002	8,464	8,058	7,823	7,680	7,813	8,117	8,688	9,314	10,058	10,879	11,555	11,909	12,472	12,652	12,617	12,719	12,652	12,474	12,072	11,428	11,006	9,999	8,946
Summer	6	12,349	6/25/2015	8,122	7,537	7,167	6,895	6,775	6,929	7,212	7,671	8,111	8,679	9,350	10,027	10,587	11,318	11,805	12,143	12,349	12,341	12,083	11,669	11,235	10,731	9,870	8,941
Summer	6	12,571	6/26/2015	8,194	7,730	7,417	7,163	7,109	7,302	7,593	8,022	8,696	9,470	10,361	11,069	11,623	12,065	12,411	12,571	12,465	12,101	11,560	10,895	10,460	10,008	9,221	8,337
Summer	6	9,836	6/27/2015	7,622	7,080	6,677	6,406	6,268	6,258	6,223	6,577	7,206	7,988	8,669	9,192	9,637	9,800	9,836	9,620	9,628	9,703	9,521	9,187	8,836	8,581	8,047	7,394
Summer	6	9,747	6/28/2015	6,789	6,380	6,167	6,011	5,957	5,958	5,896	6,170	6,802	7,408	7,743	8,106	8,459	8,767	9,101	9,395	9,641	9,747	9,586	9,194	8,709	8,469	7,800	6,943
Summer	6	10,775	6/29/2015	6,259	5,808	5,509	5,373	5,361	5,628	5,919	6,436	7,006	7,618	8,263	8,928	9,462	9,954	10,309	10,580	10,744	10,775	10,609	10,152	9,713	9,391	8,509	7,579
Summer	6	11,757	6/30/2015	6,865	6,308	5,995	5,822	5,792	5,995	6,312	6,917	7,485	8,166	8,927	9,703	10,382	10,975	11,386	11,649	11,757	11,552	11,032	10,417	9,789	9,295	8,478	7,593
Summer	7	10,784	7/1/2015	6,846	6,365	6,064	5,919	5,887	6,131	6,483	6,915	7,317	7,755	8,284	8,880	9,439	9,974	10,388	10,661	10,784	10,727	10,435	9,978	9,717	9,410	8,658	7,795
Summer	7	10,724	7/2/2015	7,115	6,679	6,427	6,274	6,270	6,492	6,811	7,241	7,664	8,147	8,703	9,271	9,753	10,219	10,538	10,667	10,724	10,593	10,066	9,492	9,159	8,883	8,220	7,435
Summer	7	8,793	7/3/2015	6,744	6,263	5,945	5,758	5,713	5,817	5,915	6,197	6,686	7,123	7,512	7,810	8,137	8,401	8,564	8,688	8,776	8,793	8,587	8,302	8,105	8,028	7,591	7,016
Summer	7	9,707	7/4/2015	6,495	6,095	5,821	5,616	5,550	5,543	5,491	5,849	6,587	7,401	8,092	8,646	8,992	9,209	9,250	9,380	9,622	9,707	9,444	8,959	8,583	8,264	7,952	7,471
Summer	7	10,537	7/5/2015	6,839	6,354	6,027	5,792	5,670	5,651	5,501	5,839	6,631	7,454	8,231	8,878	9,521	10,028	10,317	10,482	10,537	10,461	10,115	9,608	9,266	8,962	8,238	7,490
Summer	7	11,515	7/6/2015	6,822	6,373	6,112	5,945	5,966	6,249	6,571	7,078	7,714	8,406	9,147	9,779	10,292	10,755	11,104	11,390	11,515	11,479	11,169	10,649	10,195	9,812	8,993	8,047
Summer	7	11,897	7/7/2015	7,256	6,739	6,412	6,205	6,194	6,443	6,778	7,357	8,011	8,793	9,598	10,343	10,985	11,450	11,612	11,842	11,897	11,845	11,762	11,288	10,894	10,486	9,595	8,651
Summer	7	11,786	7/8/2015	7,862	7,324	6,970	6,715	6,670	6,862	7,210	7,703	8,257	8

Contains Proprietary Material
Do Not Distribute

Summer	8	11,150	8/12/2015	6,754	6,305	6,028	5,902	5,895	6,196	6,644	7,007	7,544	8,140	8,778	9,383	9,917	10,418	10,751	11,025	11,150	11,117	10,845	10,251	9,851	9,251	8,309	7,418
Summer	8	10,985	8/13/2015	6,672	6,163	5,884	5,715	5,689	5,933	6,376	6,730	7,263	7,883	8,622	9,294	9,843	10,307	10,671	10,892	10,985	10,856	10,536	10,028	9,768	9,258	8,366	7,515
Summer	8	10,927	8/14/2015	6,799	6,330	6,029	5,842	5,809	6,044	6,457	6,821	7,356	8,054	8,740	9,419	9,942	10,360	10,733	10,867	10,927	10,826	10,468	9,863	9,512	9,007	8,239	7,416
Summer	8	10,663	8/15/2015	6,704	6,209	5,899	5,657	5,568	5,571	5,667	5,889	6,565	7,349	8,149	8,878	9,469	9,874	10,204	10,444	10,629	10,663	10,370	9,794	9,473	8,919	8,247	7,426
Summer	8	10,830	8/16/2015	6,720	6,234	5,888	5,643	5,532	5,510	5,505	5,763	6,538	7,389	8,125	8,811	9,506	10,029	10,414	10,647	10,825	10,830	10,566	10,082	9,865	9,368	8,527	7,677
Summer	8	11,966	8/17/2015	7,017	6,569	6,258	6,073	6,064	6,365	6,849	7,190	7,727	8,445	9,304	10,130	10,868	11,460	11,806	11,966	11,956	11,780	11,393	10,919	10,707	10,086	9,173	8,220
Summer	8	10,010	8/18/2015	7,512	7,059	6,720	6,534	6,526	6,806	7,386	7,638	8,005	8,383	8,874	9,266	9,553	9,786	9,970	10,010	9,926	9,778	9,570	9,291	9,314	8,887	8,020	7,371
Summer	8	11,148	8/19/2015	6,824	6,446	6,273	6,171	6,245	6,550	7,132	7,476	7,838	8,273	8,830	9,372	9,873	10,359	10,707	10,970	11,148	11,144	10,877	10,460	10,188	9,541	8,672	7,881
Summer	8	11,725	8/20/2015	7,299	6,877	6,614	6,451	6,426	6,730	7,326	7,702	8,101	8,576	9,137	9,673	10,119	10,607	11,099	11,468	11,725	11,657	11,316	10,844	10,606	9,979	9,109	8,208
Summer	8	11,416	8/21/2015	7,525	7,062	6,727	6,536	6,487	6,773	7,299	7,589	8,131	8,779	9,498	10,123	10,616	11,021	11,317	11,416	11,397	11,196	10,795	10,216	9,882	9,369	8,595	7,816
Summer	8	10,346	8/22/2015	7,108	6,587	6,193	5,940	5,830	5,882	5,920	6,126	6,750	7,487	8,206	8,799	9,275	9,669	9,992	10,227	10,346	10,321	9,998	9,424	9,155	8,578	7,829	7,093
Summer	8	10,185	8/23/2015	6,406	5,945	5,640	5,352	5,247	5,274	5,304	5,502	6,177	6,899	7,474	7,988	8,572	9,145	9,577	9,863	10,080	10,185	10,037	9,650	9,561	8,959	8,083	7,289
Summer	8	11,309	8/24/2015	6,675	6,291	6,148	6,188	6,243	6,467	7,156	7,392	7,720	8,399	9,216	9,959	10,596	11,147	11,309	11,140	10,979	10,799	10,644	10,295	10,213	9,593	8,625	7,723
Summer	8	11,411	8/25/2015	7,051	6,635	6,345	6,221	6,252	6,645	7,391	7,629	7,882	8,390	8,951	9,592	10,178	10,727	10,895	11,222	11,411	11,320	11,038	10,598	10,465	9,763	8,815	7,913
Summer	8	10,440	8/26/2015	7,244	6,800	6,521	6,305	6,274	6,605	7,309	7,474	7,633	7,992	8,372	8,690	9,018	9,477	9,868	10,212	10,440	10,369	10,084	9,700	9,606	9,010	8,096	7,276
Summer	8	9,506	8/27/2015	6,676	6,265	6,024	5,896	5,924	6,330	7,107	7,254	7,410	7,636	7,986	8,377	8,761	9,131	9,358	9,423	9,506	9,461	9,239	8,969	8,995	8,506	7,644	6,842
Summer	8	10,035	8/28/2015	6,216	5,853	5,600	5,469	5,501	5,835	6,513	6,708	7,031	7,493	7,970	8,410	8,840	9,287	9,644	9,902	10,035	9,918	9,541	8,961	8,745	8,204	7,528	6,806
Summer	8	9,399	8/29/2015	6,148	5,712	5,457	5,277	5,227	5,284	5,385	5,546	6,127	6,706	7,274	7,853	8,333	8,704	8,995	9,225	9,399	9,382	9,073	8,668	8,533	8,096	7,454	6,768
Summer	8	8,824	8/30/2015	6,174	5,763	5,474	5,322	5,217	5,217	5,255	5,488	6,113	6,687	7,139	7,598	8,119	8,544	8,742	8,824	8,747	8,617	8,459	8,400	8,467	8,037	7,342	6,648
Summer	8	9,161	8/31/2015	6,179	5,848	5,690	5,649	5,736	6,192	7,022	7,286	7,440	7,618	7,775	8,015	8,152	8,371	8,576	8,729	8,993	9,125	9,161	9,059	9,117	8,597	7,814	7,011
Fall	9	11,116	9/1/2015	6,441	6,080	5,875	5,789	5,842	6,248	7,071	7,249	7,523	7,968	8,565	9,267	9,853	10,432	10,840	11,027	11,116	11,106	10,999	10,621	10,455	9,642	8,632	7,700
Fall	9	11,855	9/2/2015	6,980	6,567	6,253	6,078	6,043	6,397	7,115	7,344	7,732	8,368	9,172	10,019	10,594	11,210	11,534	11,738	11,855	11,751	11,643	11,237	10,956	10,162	9,105	8,114
Fall	9	11,539	9/3/2015	7,416	6,924	6,580	6,355	6,339	6,661	7,360	7,557	7,866	8,355	8,985	9,578	10,227	10,811	11,230	11,453	11,539	11,364	11,000	10,617	10,432	9,663	8,681	7,782
Fall	9	11,507	9/4/2015	7,072	6,598	6,289	6,108	6,049	6,398	7,079	7,311	7,736	8,424	9,232	10,074	10,759	11,277	11,507	11,414	11,174	10,743	10,182	9,736	9,469	8,881	8,193	7,423
Fall	9	9,745	9/5/2015	6,781	6,345	6,019	5,779	5,768	5,822	5,964	6,107	6,628	7,254	7,843	8,383	8,860	9,283	9,595	9,745	9,610	9,377	8,973	8,643	8,530	8,079	7,508	6,909
Fall	9	8,505	9/6/2015	6,307	5,903	5,666	5,508	5,450	5,470	5,604	5,746	6,272	6,752	7,121	7,442	7,772	8,078	8,306	8,433	8,505	8,480	8,304	8,160	8,070	7,690	7,206	6,675
Fall	9	9,807	9/7/2015	6,175	5,842	5,648	5,546	5,557	5,690	5,872	5,978	6,427	7,085	7,760	8,360	8,842	9,215	9,469	9,725	9,807	9,777	9,488	9,241	9,223	8,598	7,764	6,955
Fall	9	10,961	9/8/2015	6,384	6,025	5,815	5,729	5,813	6,268	7,096	7,429	7,665	8,059	8,693	9,345	9,897	10,388	10,692	10,890	10,961	10,880	10,624	10,360	10,235	9,490	8,594	7,726
Fall	9	11,337	9/9/2015	7,076	6,670	6,409	6,251	6,275	6,655	7,409	7,666	8,046	8,549	9,130	9,690	10,184	10,682	10,965	11,148	11,337	11,304	11,043	10,762	10,589	9,878	8,930	8,089
Fall	9	11,611	9/10/2015	7,468	7,050	6,808	6,662	6,682	7,079	7,843	8,087	8,349	8,801	9,333	9,876	10,406	10,954	11,372	11,611	11,510	11,438	11,065	10,697	10,401	9,636	8,741	7,822
Fall	9	10,128	9/11/2015	7,159	6,724	6,393	6,212	6,173	6,561	7,274	7,484	7,676	8,032	8,448	8,891	9,331	9,700	9,964	10,070	10,128	10,012	9,723	9,437	9,251	8,709	8,061	7,309
Fall	9	8,127	9/12/2015	6,729	6,305	6,051	5,864	5,821	5,871	6,070	6,256	6,719	7,222	7,660	7,893	8,060	8,105	8,127	8,123	8,037	7,993	7,886	7,924	7,908	7,566	7,070	6,529
Fall	9	7,707	9/13/2015	6,008	5,677	5,443	5,263	5,180	5,183	5,271	5,364	5,811	6,269	6,545	6,777	7,041	7,285	7,498	7,605	7,670	7,707	7,498	7,329	7,371	6,855	6,218	5,572
Fall	9	8,087	9/14/2015	5,127	4,860	4,720	4,706	4,804	5,218	5,960	6,174	6,288	6,463	6,649	6,802	6,959	7,247	7,468	7,720	8,005	8,087	7,962	7,824	7,746	7,188	6,436	5,764
Fall	9	8,453	9/15/2015	5,268	5,033	4,884	4,809	4,896	5,299	6,052	6,219	6,345	6,491	6,753	6,977	7,242	7,538	7,832	8,189	8,387	8,453	8,268	8,096	8,008	7,368	6,652	5,953
Fall	9	8,465	9/16/2015	5,420	5,134	4,970	4,866	4,934	5,323	6,054	6,262	6,367	6,541	6,782	7,049	7,315	7,688	7,991	8,287	8,465	8,372	8,229	8,246	8,194	7,655	6,997	6,293
Fall	9	8,821	9/17/2015	5,767	5,463	5,292	5,226	5,300	5,689	6,467	6,673	6,759	6,994	7,296	7,614	7,930	8,289	8,495	8,681	8,821	8,777	8,568	8,462	8,420	7,839	7,128	6,367
Fall	9	9,460	9/18/2015	5,778	5,470	5,286	5,190	5,206	5,581	6,281	6,527	6,680	7,017	7,428	7,875	8,327	8,744	9,128	9,365	9,460	9,387	9,007	8,705	8,498	7,924	7,294	6,633
Fall	9	9,875	9/19/2015	6,060	5,663	5,433	5,288	5,260	5,290	5,491	5,697	6,226	6,888	7,556	8,153	8,655	9,083	9,457	9,728	9,875	9,846	9,460	9,054	8,666	8,032	7,332	6,633
Fall	9	9,824	9/20/2015	5,992	5,569	5,279	5,079	4,987	4,999	5,116	5,269	5,921	6,561	7,150	7,713	8,349	8,946	9,426	9,691	9,824	9,783	9,386	9,258	8,995	8,335	7,534	6,776
Fall	9	9,280	9/21/2015	6,193	5,826	5,602	5,494	5,575	5,993	6,778	7,063	7,208	7,529	7,952	8,354	8,695	9,054	9,188	9,254	9,280	9,177	9,014	9,069	8,804	8,158	7,436	6,728
Fall	9	8,747	9/22/2015	6,194	5,869	5,673	5,591	5,653	6,026	6,837	7,038	7,151	7,345	7,605	7,860	8,015	8,258	8,486	8,649	8,747	8,635	8,452	8,574	8,494	7,952	7,283	6,607
Fall	9	8,271	9/23/2015	6,057	5,745	5,573	5,474	5,517	5,946	6,696	6,905	7,026	7,193	7,453	7,651	7,876	8,094	8,221	8,263	8,271	8,174	8,089	8,269	8,181	7,692	7,015	6,353
Fall	9	7,833	9/24/2015	5,805	5,494	5,330	5,234	5,282	5,649	6,437	6,666	6,748	6,885	7,029	7,199	7,296	7,396	7,473	7,435	7,472	7,456	7,548	7,833	7,744	7,328	6,739	6,164
Fall	9	7,499	9/25/2015	5,691	5,429	5,274	5,242	5,293	5,682	6,467	6,815	6,937	7,056	7,231	7,323	7,332	7,380	7,394	7,348	7,354	7,349	7,341	7,499	7,406	7,109	6,654	6,148
Fall	9	6,957	9/26/2015	5,690	5,409	5,237	5,128	5,114	5,200	5,404	5,619	6,013	6,391	6,662	6,765	6,773	6,719	6,663	6,633	6,653	6,676	6,706	6,957	6,902	6,658	6,298	5,864
Fall	9	7,758	9/27/2015	5,398	5,140	4,964	4,883	4,868	4,947	5,128	5,381	5,813	6,233	6,439	6,618	6,814	6,955	7,041	7,115	7,231	7,347	7,430	7,758	7,681	7,278	6,747	6,199
Fall	9	8,806	9/28/2015	5,726	5,467	5,334	5,270	5,391	5,860	6,703	7,109	7,206	7,416	7,699	7,948	8,173	8,319	8,520	8,538	8,506	8,490	8,515	8,806	8,682	8,188	7,564	6,948
Fall	9	9,711	9/29/2015	6,419	6,143	5,952	5,899	5,984	6,384	7,235	7,588	7,699	7,965	8,336	8,734	9,055	9,418	9,639	9,711	9,636	9,505	9,452	9,639	9,366	8,744	8,029	7,281
Fall	9	9,820	9/30/2015	6,723	6,420	6,170	6,081	6,123	6,543	7,335	7,664	7,808	8,042	8,322	8,700	9,075	9,551	9,679	9,782	9,820	9,686	9,560	9,541	9,050	8,540	7,727	6,955
Fall	10	7,307	10/1/2015	6,389	6,018	5,782	5,619	5,627	5,973	6,758	7,073	7,045	7,105	7,162	7,119	7,058	7,046	6,968	6,923	6,887	6,930	7,070	7,307	7,176	6,778	6,255	5,701
Fall	10	6,942	10/2/2015	5,307	5,067	4,936	4,858	4,951	5,294	6,077	6,431	6,478	6,605	6,657	6,739	6,686	6,688	6,622	6,569	6,631	6,731	6,857	6,942	6,807	6,528	6,107	5,655
Fall	10	7,149	10/3/2015	5,287	5,024	4,908	4,830	4,818	4,942	5,171	5,364	5,784	6,234	6,546	6,769	6,820	6,851	6,826	6,830	6,888	6,917	6,909	7,149	6,995	6,722	6,354	5,946
Fall	10	6,920	10/4/2015	5,551	5,279	5,117	5,016	4,921	4,952	5,081	5,294	5,698	6,046	6,236	6,338	6,420	6,460	6,427	6,371	6,402	6,468	6,628	6,920	6,764	6,399	5,926	5,425
Fall	10	7,157	10/5/2015	5,016	4,804	4,667	4,617	4,724	5,084	5,826	6,177	6,274	6,421	6,567	6,637	6,632	6,630	6,567	6,556	6,593	6,667	6,858	7,157	6,994	6,607	6,090	5,539
Fall	10	7,235	10/6/2015	5,127	4,925	4,810	4,775	4,905	5,300	6,045	6,379	6,404	6,452	6,511	6,543	6,509	6,579	6,629	6,674	6,785	6,803	6,855	7,235	7,133	6,709	6,151	5,561
Fall	10	7,752	10/7/2015	5,179	4,945	4,843	4,814	4,909	5,339	6,093	6,374	6,361	6,446	6,548	6,631	6,766	6,992	7,195	7,434	7,568	7,648	7,603	7,752	7,622	7,111	6,436	5,802
Fall	10	7,921	10/8/2015	5,340	5,088	4,935	4,873	4,971	5,353	6,155	6,379	6,423	6,612	6,858	7,051	7,352	7,682	7,894	7,877	7,921	7,843	7,742	7,831	7,773	7,307	6,652	5,988
Fall	10	7,881	10/9/2015	5,530	5,246	5,063	4,978	5,038	5,380	6,132	6,353	6,444	6,647	6,922	7,200	7,448	7,769	7,817	7,881	7,867	7,774	7,587	7,671	7,598	7,188	6,811	6,235
Fall	10	6,583	10/10/2015	5,694	5,379	5,183	5,063	5,052	5,128	5,326	5,569	5,874	6,233	6,426	6,507	6,501	6,439	6,385	6,295	6,335	6,354	6,420	6,583	6,468	6,197	5,845	5,418
Fall	10	6,842	10/11/2015	5,022	4,769	4,637	4,506	4,475	4,567	4,749	5,003	5,402	5,668	5,752	5,745	5,854	5,966	6,068	6,170	6,311	6,436	6,461	6,842	6,706	6,282	5,782	5,306
Fall	10	7,747	10/12/2015	4,940	4,718	4,612	4,581	4,689	5,100	5,905	6,221	6,299	6,450	6,580	6,681	6,787	6,929	7,050	7,208	7,334	7,357	7,431	7,747	7,490	6,985	6,387	5,758
Fall	10	7,717	10/13/2015	5,323	5,076	4,948	4,888	4,978	5,360	6,186	6,419	6,471	6,581	6,707	6,852	7,036	7,213	7,355	7,484	7,618	7,586	7,570	7,717	7,679	7,174	6,534	5,905
Fall	10	7,619	10/14/2015	5,424	5,168	5,010	4,927	5,007	5,398	6,198	6,390	6,362	6,506	6,665	6,782	6,932	7,166	7,338	7,474	7,577	7,501	7,407	7,619	7,378	6,869	6,249	5,613
Fall	10	7,230	10/15/2015	5,170	4,951	4,808	4,787	4,880	5,325	6,164	6,418	6,403	6,395	6,488	6,492	6,553	6,659	6,728	6,838	6,921	6,904	6,891	7,230	7,075	6,649	6,125	5,510
Fall	10	6,888	10/16/2015	5,160	4,916	4,840	4,821	4,937	5,363	6,197	6,483	6,461	6,483	6,517	6,567	6,602	6,702	6,735	6,782	6,736	6,617	6,676	6,888	6,716	6,449	6,059	5,627
Fall	10	6,484	10/17/2015	5,221	5,020	4,877	4,858	4,929	5,107	5,475	5,802	6,147	6,220	6,178	6,069	5,964	5,907	5,900	5,918	5,996	6,042	6,175	6,484	6,416	6,203	5,892	5,506
Fall	10	7,108	10/18/2015	5,172	5,022	4,965	4,980	5,088	5,311	5,674	6,140	6,646	6,685	6,428	6,184	6,041	5,917	5,785	5,773	5,826	6,052	6,447	7,042	7,108	6,861	6,566	6,186
Fall	10	8,419	10/19/2015	5,969	5,894	5,935	6,061	6,357	7,054	7,952	8,419	8,389	8,015	7,498	7,121	6,804	6,613	6,471	6,398	6,465	6,655	7,092	7,661	7,599	7,325	6,929	6,503
Fall	10	8,419	10/20/2015	6,211	6,160	6,220	6,131	6,573	7,305	8,132	8,419	8,268	7,791	7,267	6,916	6,639	6,516	6,430	6,422	6,486	6,566	6,865	7,280	7,164	6,842	6,347	5,899
Fall	10	7,842	10/21/2015	5,600	5,529	5,524	5,603	5,862	6,526	7,511	7,842	7,609	7,206	6,865	6,640	6,487	6,503	6,518	6,503	6,694	6,769	6,912	7,236	7,077	6,687	6,162	5,643
Fall	10	7,312	10/22/2015	5,273	5,123	5,084	5,085	5,312	5,872	6,833	7,154	7,001	6,791	6,756	6,624	6,600	6,700	6,733	6,890	6,979	6,979	7,078	7,312	7,096	6,673	6,140	5,581
Fall	10	7,086	10/23/2015	5,152	4,962	4,869	4,873	4,985	5,449	6,274	6,584	6,604	6,558	6,581	6,576	6,621	6,772	6,901	7,010	7,086	7,022	6,980	7,067	6,811	6,507	6,078	5,606
Fall	10	6,559	10/24/2015	5,196	4,908	4,690	4,682	4,687	4,815	5,123	5,401	5,709	5,980	6,058	6,050	6,002	6,064	6,048	6,143	6,204	6,224	6,381	6,559	6,390	6,132	5,729	5,296
Fall	10	6,921	10/25/2015	4,927	4,724	4,588	4,498	4,486	4,555	4,783	5,106	5,505	5,784	5,822	5,779	5,845	5,919	6,009	6,079	6,175	6,322	6,674	6,921	6,702	6,299	5,832	5,321
Fall	10	7,323	10/26/2015	4,958	4,712	4,596	4,546	4,650	5,050	5,834	6,253	6,272	6,400	6,484	6,501	6,478	6,461	6,429	6,410	6,490	6,642	7,127	7,323	7,138	6,741	6,212	5,684
Fall	10	7,484	10/27/2015	5,313	5,139	5,056	5,061	5,199	5,683	6,539	6,925	6,824	6,823	6,881	6,880	6,797	6,842	6,811	6,786	6,889	7,049	7,385	7,484	7,236	6,823	6,264	5,732
Fall	10	7,526	10/28/2015	5,314	5,144	5,006	4,967	5,068	5,513	6,308	6,712	6,671	6,764	6,859	6,947	6,936	6,938	6,816	6,844	6,975	7,034	7,401	7,526	7,379	7,017	6,482	5,873
Fall	10	7,544	10/29/2015	5,473	5,218	5,072	4,991	5,069	5,471	6,278	6,624	6,582	6,637	6,805	6,930	7,015	7,131	7,170	7,218	7,209	7,141	7,371	7,544	7,380	6,978	6,398	5,784
Fall	10	6,677	10/30/2015	5,338	5,117	4,933	4,874	4,929	5,353	6,127	6,466	6,402	6,420	6,420	6,371	6,396	6,415	6,447	6,466	6,479	6,452	6,535	6,677	6,525	6,322	5,983	5,608
Fall	10	6,469	10/31/2015	5,283	5,099	5,024	5,013	5,071	5,273	5,622	5,990	6,320	6,469	6,406	6,174	6,041	5,937	5,905	5,919	5,941	5,967	6,075	6,115	6,086	6,007	5,720	5,342
Fall	11	6,902	11/1/2015	4,814	4,707	4,673	4,567	4,582	4,523	5,038	5,268	5,706	5,936	5,984	5,968	6,096	6,099	6,105	5,977	6,381	6,673	6,902	6,674	6,477	6,151	5,562	5,269
Fall	11	7,416	11/2/2015	4,894	4,735	4,645	4,645	4,778	5,278	6,125	6,430	6,569	6,720	6,838	6,877	6,847	6,813	6,714	6,617	6,811	7,249	7,416	7,286	6,956	6,548	6,029	5,523
Fall	11	7,379	11/3/2015	5,188	4,976	4,858	4,849	4,955	5,391	6,217	6,491	6,595	6,634	6,663	6,665	6,563	6,546	6,556	6,611	6,767	7,185	7,379	7,344	7,100	6,597	6,037	5,552
Fall	11	7,457	11/4/2015	5,170	4,987	4,898	4,866	4,993	5,466	6,245	6,450	6,486	6,473	6,550	6,604	6,602	6,624	6,610	6,621	6,837	7,211	7,457	7,332	7,117	6,627	6,117	5,623
Fall	11	7,646	11/5/2015	5,267	5,077	4,947	4,885	5,022	5,457	6,308	6,551	6,616	6,708	6,815	6,836	6,880	6,862	7,000	6,977	7,042	7,413	7,646	7,508	7,255	6,817	6,268	5,701
Fall	11	7,529	11/6/2015	5,307	5,098	4,949	4,926	5,025	5,474	6,252	6,505	6,641	6,781	6,944	7,094	7,210	7,300	7,285	7,211	7,199	7,466	7,529	7,332	7,106	6,810	6,405	5,946
Fall	11	7,315	11/7/2015	5,480	5,231	5,077	4,976	4,976	5,128	5,326	5,625	6,123	6,546	6,854	7,038	7,068	7,116	7,107	7,091	7,082	7,315	7,300	7,071	6,661	6,327	5,904	5,430
Fall	11	6,966	11/8/2015	4,945	4,672	4,521	4,426	4,431	4,554	4,768	5,064	5,561	5,855	5,880	5,853	5,868	5,879	5,902	5,935	6,117	6,793	6,966	6,888	6,726	6,369	5,939	5,509
Fall	11	7,704	11/9/2015	5,212	5,065	5,028	5,043	5,235	5,783	6,700	6,962	6,997	7,057	7,122	7,125	7,079	7,043	6,993	6,964	7,124	7,588	7,704	7,558	7,269	6,840	6,279	5,764
Fall	11	7,247	11/10/2015	5,402	5,219	5,120	5,097	5,244	5,715	6,551	6,776	6,748	6,755	6,755	6,738	6,669	6,661	6,597	6,552	6,581	6,981	7,247	7,106	6,906	6,548	6,137	5,683
Fall	11	7,229	11/11/2015	5,367	5,218	5,181	5,196	5,394	5,811	6,386	6,707	6,738	6,672	6,603	6,495	6,363	6,372	6,358	6,350	6,496	6,927	7,229	7,105	6,967	6,651	6,208	5,765
Fall	11	7,477	11/12/2015	5,492	5,375	5,329	5,403	5,551	6,128	6,982	7,109	6,844	6,642	6,547	6,479	6,459	6,575	6,602	6,645	6,710	7,122	7,477	7,164	7,011	6,605	6,054	5,520
Fall	11	7,063	11/13/2015	5,159	4,961	4,845	4,877	5,027	5,524	6,410	6,656	6,557	6,494	6

Contains Proprietary Material
Do Not Distribute

Winter	12	12,507	12/7/2014	9,423	9,150	9,047	9,045	9,183	9,516	10,054	10,586	11,094	11,045	10,664	10,324	10,129	9,923	9,757	9,777	10,214	11,505	12,206	12,409	12,507	12,212	11,654	11,096
Winter	12	14,800	12/8/2014	10,755	10,623	10,644	10,761	11,154	12,085	13,596	14,214	14,083	13,950	13,866	13,736	13,555	13,471	13,412	13,481	13,776	14,579	14,800	14,658	14,358	13,731	12,856	11,982
Winter	12	14,176	12/9/2014	11,444	11,143	11,017	11,056	11,339	12,157	13,604	14,176	13,890	13,489	12,900	12,362	11,982	11,922	11,929	12,084	12,417	13,309	13,660	13,635	13,454	13,012	12,241	11,476
Winter	12	14,581	12/10/2014	11,153	11,027	11,083	11,230	11,623	12,544	14,079	14,581	14,081	13,274	12,749	12,401	12,067	11,921	11,783	11,815	12,256	13,539	14,203	14,308	14,263	13,924	13,224	12,576
Winter	12	16,083	12/11/2014	12,265	12,243	12,354	12,586	13,087	14,114	15,716	16,083	15,581	14,803	13,796	13,053	12,410	12,026	11,771	11,709	12,088	13,276	14,013	14,297	14,428	14,185	13,525	12,828
Winter	12	15,977	12/12/2014	12,473	12,424	12,468	12,663	13,037	13,951	15,473	15,977	15,408	14,312	13,284	12,446	11,772	11,415	11,102	10,964	11,193	12,226	12,744	12,698	12,773	12,624	12,192	11,681
Winter	12	13,577	12/13/2014	11,277	11,148	11,202	11,334	11,615	12,087	12,807	13,345	13,577	12,909	12,025	11,281	10,666	10,234	9,939	9,853	10,048	10,983	11,467	11,570	11,588	11,495	11,233	10,806
Winter	12	12,787	12/14/2014	10,495	10,400	10,435	10,570	10,799	11,187	11,789	12,413	12,787	12,168	11,195	10,473	10,078	9,752	9,537	9,459	9,757	10,860	11,542	11,752	11,844	11,645	11,167	10,706
Winter	12	15,029	12/15/2014	10,458	10,492	10,605	10,947	11,514	12,610	14,330	15,029	14,606	13,646	12,758	12,066	11,534	11,236	11,010	10,931	11,183	12,269	12,946	13,037	13,038	12,683	12,013	11,222
Winter	12	13,247	12/16/2014	10,755	10,496	10,438	10,452	10,678	11,392	12,699	13,247	12,962	12,759	12,549	12,293	11,964	11,761	11,503	11,349	11,548	12,423	12,849	12,781	12,655	12,237	11,506	10,742
Winter	12	13,974	12/17/2014	10,304	10,191	10,252	10,413	10,835	11,812	13,378	13,974	13,592	12,787	12,142	11,624	11,184	10,974	10,774	10,718	11,015	12,074	12,712	12,759	12,740	12,432	11,805	11,103
Winter	12	14,383	12/18/2014	10,763	10,716	10,802	10,998	11,411	12,374	13,874	14,383	14,022	13,570	13,046	12,498	11,996	11,687	11,418	11,390	11,638	12,595	13,048	13,030	12,906	12,529	11,841	11,095
Winter	12	14,203	12/19/2014	10,609	10,428	10,424	10,604	11,045	11,961	13,510	14,203	13,969	13,164	12,397	11,738	11,284	11,099	10,916	10,899	11,145	12,166	12,565	12,496	12,385	12,166	11,694	11,039
Winter	12	12,667	12/20/2014	10,491	10,170	10,024	9,985	10,106	10,378	10,895	11,513	12,081	12,554	12,667	12,535	12,201	11,890	11,649	11,561	11,746	12,474	12,659	12,514	12,363	12,053	11,502	10,839
Winter	12	11,946	12/21/2014	10,291	9,966	9,801	9,771	9,848	10,076	10,453	11,017	11,564	11,715	11,371	10,928	10,726	10,526	10,349	10,334	10,647	11,592	11,946	11,922	11,819	11,509	10,945	10,291
Winter	12	14,169	12/22/2014	9,836	9,608	9,584	9,737	10,104	10,803	11,856	12,704	12,984	13,257	13,402	13,387	13,289	13,264	13,165	13,170	13,362	14,034	14,169	14,019	13,687	13,191	12,459	11,640
Winter	12	13,041	12/23/2014	11,049	10,685	10,505	10,482	10,666	11,240	12,105	12,776	12,922	13,041	13,033	12,837	12,576	12,467	12,324	12,204	12,275	12,862	12,877	12,613	12,321	11,866	11,178	10,355
Winter	12	11,161	12/24/2014	9,644	9,281	9,062	8,978	9,082	9,394	9,886	10,342	10,672	11,033	11,161	11,029	10,754	10,550	10,362	10,253	10,319	10,684	10,486	10,153	9,894	9,613	9,213	8,672
Winter	12	10,243	12/25/2014	8,188	7,866	7,719	7,729	7,852	8,168	8,669	9,193	9,654	9,693	9,551	9,343	9,033	8,614	8,329	8,194	8,303	9,062	9,665	9,895	10,141	10,243	10,168	9,979
Winter	12	12,760	12/26/2014	9,872	9,930	10,078	10,310	10,681	11,307	12,064	12,636	12,760	12,140	11,272	10,493	9,939	9,454	9,149	9,008	9,247	10,192	10,864	10,916	10,986	10,920	10,550	10,170
Winter	12	11,687	12/27/2014	9,862	9,692	9,727	9,783	10,051	10,380	10,966	11,437	11,687	11,252	10,640	10,028	9,529	9,123	8,868	8,782	8,973	9,824	10,276	10,237	10,119	9,846	9,360	8,809
Winter	12	10,225	12/28/2014	8,353	8,085	7,947	7,905	7,905	8,097	8,419	8,744	9,159	9,467	9,458	9,349	9,325	9,208	9,110	9,056	9,204	9,925	10,225	10,174	9,994	9,632	9,117	8,532
Winter	12	11,821	12/29/2014	8,085	7,815	7,733	7,725	7,929	8,492	9,390	10,114	10,372	10,599	10,820	10,894	10,839	10,766	10,654	10,578	10,756	11,494	11,821	11,669	11,430	11,025	10,436	9,772
Winter	12	13,650	12/30/2014	9,357	9,177	9,114	9,217	9,545	10,220	11,166	12,048	12,327	12,628	12,808	12,825	12,713	12,582	12,368	12,229	12,371	13,166	13,650	13,635	13,570	13,296	12,798	12,223
Winter	12	13,979	12/31/2014	11,847	11,693	11,674	11,742	12,032	12,684	13,432	13,976	13,979	13,781	13,257	12,591	12,079	11,690	11,340	11,214	11,465	12,520	13,150	13,054	12,890	12,654	12,343	12,169
Winter	1	13,649	1/1/2015	11,982	11,991	12,013	12,168	12,430	12,863	13,323	13,611	13,649	13,141	12,311	11,671	11,015	10,526	10,116	9,986	10,278	11,225	11,637	11,598	11,395	11,062	10,527	9,982
Winter	1	11,883	1/2/2015	9,518	9,260	9,134	9,165	9,427	9,986	10,821	11,466	11,666	11,736	11,633	11,475	11,286	11,118	11,056	10,885	11,033	11,768	11,883	11,669	11,421	11,041	10,485	9,887
Winter	1	11,550	1/3/2015	9,405	9,053	8,924	8,852	8,909	9,119	9,567	9,985	10,369	10,887	11,134	11,176	11,063	10,918	10,815	10,840	10,980	11,442	11,550	11,330	11,190	10,780	10,131	9,690
Winter	1	11,023	1/4/2015	9,166	8,869	8,654	8,544	8,561	8,732	9,037	9,444	9,823	10,131	10,153	10,118	10,185	10,171	9,989	9,864	9,950	10,614	11,023	10,899	10,766	10,355	9,863	9,386
Winter	1	13,778	1/5/2015	9,123	9,075	9,209	9,468	9,975	11,048	12,746	13,542	13,335	12,921	12,599	12,210	11,863	11,600	11,340	11,275	11,520	12,544	13,533	13,778	13,736	13,384	12,845	12,335
Winter	1	16,126	1/6/2015	12,063	12,104	12,190	12,483	12,969	13,974	15,543	16,126	15,662	14,578	13,668	12,861	12,216	11,903	11,595	11,596	11,841	12,728	13,641	13,816	13,779	13,429	12,858	12,317
Winter	1	18,179	1/7/2015	12,040	11,981	12,056	12,237	12,659	13,577	15,035	15,494	15,048	14,733	14,477	14,285	14,180	14,150	13,988	14,140	14,867	16,292	17,438	17,857	18,179	18,160	17,790	17,437
Winter	1	20,376	1/8/2015	17,280	17,330	17,469	17,689	17,961	18,525	19,786	20,376	19,942	19,037	18,338	17,500	16,597	15,852	15,263	15,061	15,437	16,636	17,726	17,976	17,944	17,507	16,812	16,092
Winter	1	17,084	1/9/2015	15,564	15,245	15,035	14,987	14,980	15,414	16,629	17,084	16,682	16,023	15,308	14,508	13,782	13,230	12,771	12,569	12,875	13,914	14,742	14,827	14,930	14,773	14,404	13,952
Winter	1	16,484	1/10/2015	13,633	13,627	13,738	13,946	14,324	14,848	15,529	16,217	16,484	15,872	15,106	14,364	13,399	12,704	12,165	11,929	12,257	13,438	14,513	14,789	14,938	14,857	14,684	14,342
Winter	1	16,428	1/11/2015	14,197	14,214	14,382	14,590	14,903	15,271	15,758	16,255	16,428	15,535	14,171	13,123	12,547	12,187	12,021	12,022	12,350	13,161	13,543	13,505	13,295	12,823	12,161	11,557
Winter	1	14,375	1/12/2015	11,161	10,996	11,004	11,113	11,479	12,328	13,729	14,375	14,148	14,057	14,005	13,847	13,668	13,486	13,285	13,158	13,243	13,718	14,044	13,878	13,533	12,818	11,986	11,187
Winter	1	15,348	1/13/2015	10,652	10,352	10,184	10,174	10,444	11,273	12,671	13,452	13,388	13,441	13,598	13,706	13,683	13,767	13,762	13,853	14,151	14,894	15,348	15,234	15,041	14,478	13,705	12,987
Winter	1	15,887	1/14/2015	12,588	12,510	12,479	12,635	12,965	13,809	15,113	15,873	15,887	15,755	15,585	15,236	14,762	14,379	14,083	13,939	14,041	14,659	15,197	15,015	14,814	14,377	13,714	13,128
Winter	1	16,325	1/15/2015	12,773	12,736	12,781	12,973	13,325	14,196	15,654	16,325	16,022	15,603	15,075	14,404	13,896	13,745	13,570	13,514	13,663	14,198	14,664	14,535	14,274	13,745	12,915	12,240
Winter	1	15,661	1/16/2015	11,843	11,849	11,948	12,175	12,553	13,484	14,910	15,661	15,317	14,516	13,585	12,833	12,155	11,691	11,283	11,099	11,128	11,817	12,746	12,864	12,939	12,864	12,558	12,124
Winter	1	14,514	1/17/2015	11,882	11,877	11,987	12,188	12,523	13,016	13,696	14,233	14,514	13,849	12,837	12,068	11,326	10,760	10,335	10,140	10,376	11,129	11,997	12,058	12,066	11,883	11,532	10,965
Winter	1	11,772	1/18/2015	10,474	10,156	9,999	9,941	10,047	10,284	10,739	11,362	11,772	11,669	11,050	10,431	10,124	9,896	9,745	9,629	9,780	10,506	11,375	11,558	11,546	11,366	11,047	10,699
Winter	1	14,036	1/19/2015	10,550	10,523	10,623	10,878	11,312	12,100	13,185	13,987	14,036	13,399	12,751	12,075	11,559	11,165	10,893	10,733	10,819	11,439	12,377	12,474	12,270	11,909	11,292	10,709
Winter	1	13,673	1/20/2015	10,344	10,198	10,180	10,259	10,608	11,451	12,899	13,673	13,456	12,764	12,112	11,586	11,138	10,910	10,701	10,607	10,663	11,250	12,007	12,016	11,830	11,321	10,707	10,016
Winter	1	13,264	1/21/2015	9,569	9,431	9,421	9,560	9,975	10,937	12,474	13,264	12,958	12,360	11,944	11,481	11,145	10,939	10,754	10,636	10,803	11,349	12,297	12,371	12,353	12,071	11,477	10,961
Winter	1	14,946	1/22/2015	10,701	10,688	10,866	11,155	11,651	12,706	14,292	14,946	14,633	13,966	13,112	12,269	11,632	11,331	11,168	11,111	11,250	11,856	12,733	12,846	12,830	12,501	11,903	11,221
Winter	1	14,548	1/23/2015	10,878	10,647	10,563	10,588	10,847	11,609	12,979	13,665	13,604	13,685	13,865	13,917	13,857	13,905	13,845	13,894	14,032	14,455	14,548	14,237	13,892	13,398	12,713	12,042
Winter	1	13,149	1/24/2015	11,556	11,301	11,161	11,115	11,197	11,437	11,865	12,468	12,838	13,135	13,149	12,771	12,043	11,336	10,880	10,612	10,725	11,432	12,474	12,614	12,645	12,522	12,175	11,827
Winter	1	13,873	1/25/2015	11,492	11,418	11,421	11,564	11,864	12,299	12,879	13,535	13,873	13,090	11,937	11,047	10,578	10,165	9,850	9,727	9,859	10,655	11,716	11,909	11,810	11,385	10,796	10,250
Winter	1	13,848	1/26/2015	9,908	9,814	9,842	10,030	10,478	11,374	12,924	13,662	13,400	13,136	12,753	12,479	12,240	12,157	11,975	11,985	12,185	12,827	13,699	13,848	13,752	13,327	12,671	12,055
Winter	1	15,776	1/27/2015	11,750	11,716	11,858	12,065	12,571	13,546	15,105	15,776	15,384	14,908	14,420	13,866	13,207	12,714	12,309	12,162	12,423	13,148	14,430	14,735	14,722	14,327	13,650	13,069
Winter	1	16,850	1/28/2015	12,779	12,771	12,867	13,093	13,577	14,622	16,235	16,850	16,231	15,227	14,384	13,589	12,897	12,456	12,068	11,887	12,052	12,724	13,963	14,322	14,507	14,229	13,663	13,119
Winter	1	16,849	1/29/2015	12,891	12,886	13,031	13,234	13,732	14,743	16,349	16,849	16,260	15,271	14,448	13,828	13,285	13,006	12,870	12,704	12,671	13,106	14,000	14,098	13,991	13,426	12,557	11,771
Winter	1	14,132	1/30/2015	11,184	10,851	10,672	10,740	11,075	11,987	13,488	14,132	13,871	13,559	13,236	12,760	12,308	11,970	11,728	11,587	11,796	12,463	13,576	13,784	13,817	13,677	13,331	12,966
Winter	1	15,454	1/31/2015	12,688	12,688	12,799	13,012	13,438	13,960	14,692	15,284	15,454	14,654	13,663	12,808	11,992	11,327	10,808	10,623	10,742	11,435	12,389	12,561	12,580	12,375	11,992	11,445
Winter	2	12,253	2/1/2015	10,983	10,753	10,658	10,582	10,678	10,857	11,247	11,702	12,248	12,253	11,756	11,260	10,976	10,835	10,721	10,781	10,992	11,442	11,699	11,422	11,201	10,867	10,504	9,884
Winter	2	14,718	2/2/2015	9,299	8,982	8,854	8,824	9,070	9,799	11,151	11,909	11,727	11,741	11,808	11,741	11,734	11,719	11,620	11,643	11,945	12,864	14,259	14,685	14,718	14,403	13,784	13,218
Winter	2	17,471	2/3/2015	12,989	12,961	13,117	13,411	14,001	15,093	16,893	17,471	16,845	15,593	14,535	13,681	12,968	12,526	12,080	11,836	11,951	12,676	13,988	14,433	14,523	14,188	13,595	12,975
Winter	2	16,707	2/4/2015	12,628	12,569	12,699	12,909	13,398	14,395	16,084	16,707	16,105	14,988	13,943	13,031	12,357	11,970	11,662	11,527	11,813	12,484	13,417	13,499	13,414	12,888	12,168	11,480
Winter	2	14,935	2/5/2015	11,067	10,917	10,879	11,042	11,379	12,304	13,838	14,392	13,936	13,421	13,059	12,820	12,407	12,125	11,924	11,827	12,084	12,864	14,268	14,798	14,935	14,664	14,138	13,689
Winter	2	18,345	2/6/2015	13,523	13,609	13,823	14,224	14,841	16,053	17,793	18,345	17,527	16,235	15,064	14,174	13,432	13,047	12,781	12,649	12,687	12,997	13,850	13,957	13,925	13,814	13,484	13,018
Winter	2	14,561	2/7/2015	12,704	12,627	12,640	12,776	12,999	13,458	14,144	14,494	14,561	13,875	13,070	12,215	11,369	10,728	10,221	9,926	9,936	10,363	11,282	11,502	11,455	11,240	10,842	10,357
Winter	2	11,454	2/8/2015	9,990	9,791	9,744	9,758	9,900	10,210	10,665	11,184	11,454	11,073	10,420	9,879	9,536	9,275	9,045	8,946	9,075	9,518	10,455	10,720	10,550	10,099	9,558	8,977
Winter	2	12,469	2/9/2015	8,598	8,381	8,350	8,399	8,711	9,577	11,044	11,758	11,646	11,569	11,521	11,542	11,507	11,493	11,354	11,372	11,464	11,807	12,469	12,376	12,065	11,430	10,656	9,960
Winter	2	13,178	2/10/2015	9,510	9,341	9,283	9,429	9,812	10,720	12,260	12,994	12,837	12,705	12,566	12,362	12,112	11,955	11,626	11,302	11,358	11,729	12,802	13,164	13,178	12,889	12,277	11,697
Winter	2	15,778	2/11/2015	11,396	11,405	11,534	11,833	12,363	13,486	15,196	15,778	15,134	14,041	13,201	12,441	11,811	11,479	11,112	10,904	10,961	11,361	12,434	12,803	12,857	12,597	12,030	11,450
Winter	2	15,473	2/12/2015	11,132	11,068	11,181	11,429	11,931	12,973	14,613	15,125	14,448	13,391	12,605	12,079	11,776	11,770	11,844	12,017	12,351	13,227	14,736	15,367	15,473	15,300	14,684	14,116
Winter	2	16,972	2/13/2015	13,802	13,750	13,796	13,912	14,246	15,131	16,493	16,972	16,697	16,219	15,680	14,952	14,159	13,471	12,823	12,457	12,571	13,077	14,303	14,749	14,915	14,833	14,538	14,103
Winter	2	15,382	2/14/2015	13,805	13,736	13,776	13,917	14,125	14,545	15,094	15,382	15,314	14,659	13,837	12,958	12,093	11,453	10,968	10,912	11,092	11,547	12,280	12,328	12,260	12,027	12,095	12,174
Winter	2	16,841	2/15/2015	12,444	12,914	13,460	13,976	14,546	15,201	16,027	16,623	16,841	16,416	15,681	14,823	14,121	13,461	12,917	12,594	12,643	13,384	14,792	15,375	15,437	15,228	14,824	14,308
Winter	2	17,256	2/16/2015	13,973	13,782	13,703	13,775	14,035	14,729	15,956	16,568	16,630	16,591	16,442	16,187	15,944	15,912	15,888	15,996	16,286	16,781	17,256	16,951	16,460	15,877	15,217	14,627
Winter	2	15,932	2/17/2015	14,134	13,933	13,861	13,918	14,123	14,534	15,121	15,495	15,819	15,932	15,656	15,005	14,440	14,085	13,799	13,684	13,905	14,498	15,353	15,444	15,187	14,715	14,226	13,720
Winter	2	17,424	2/18/2015	13,511	13,509	13,697	13,936	14,463	15,269	16,415	17,158	17,019	16,162	15,525	15,050	14,599	14,480	14,557	14,628	14,858	15,583	16,910	17,418	17,424	17,238	16,872	16,568
Winter	2	19,764	2/19/2015	16,523	16,647	16,898	17,276	17,773	18,438	19,306	19,764	19,664	19,262	18,709	18,056	17,365	16,858	16,390	16,128	16,312	17,216	18,791	19,554	19,735	19,557	19,068	18,684
Winter	2	21,101	2/20/2015	18,554	18,641	18,915	19,143	19,568	20,086	20,767	21,101	20,491	19,678	18,774	17,794	16,795	15,968	15,265	14,761	14,783	15,501	16,590	16,808	16,716	16,407	15,909	15,331
Winter	2	15,980	2/21/2015	14,754	14,661	14,697	14,642	14,636	14,910	15,144	15,423	15,818	15,980	15,724	15,291	14,764	14,171	13,750	13,475	13,445	13,634	14,172	14,149	13,933	13,518	12,985	12,384
Winter	2	12,942	2/22/2015	12,000	11,796	11,704	11,789	11,819	11,984	12,278	12,549	12,942	12,864	12,276	11,824	11,396	10,981	10,555	10,598	10,430	10,889	11,664	11,956	11,828	11,400	10,852	10,272
Winter	2	14,297	2/23/2015	9,932	9,665	9,636	9,739	10,043	10,964	12,417	13,216	13,190	13,206	13,218	13,014	12,600	12,240	11,936	11,745	12,041	12,695	13,811	14,292	14,297	13,863	13,365	12,692
Winter	2	16,739	2/24/2015	12,278	12,238	12,293	12,495	12,957	14,007	15,512	16,225	16,450	16,629	16,631	16,614	16,477	16,315	16,120	15,913	15,930	16,157	16,697	16,739	16,408	15,839	15,088	14,374
Winter	2	17,150	2/25/2015	13,880	13,702	13,674	13,789	14,175	15,069	16,530	17,150	16,622	15,794	15,021	14,358	13,726	13,316	13,089	13,265	13,558	13,974	14,672	14,767	14,602	14,097	13,597	12,959
Winter	2	15,032	2/26/2015	12,561	12,301	12,193	12,209	12,386	12,793	13,385	13,763	14,129	14,229	14,289	14,160	13,954	13,656	13,458	13,402	13,465	13,728	14,609	15,032	14,931	14,519	13,863	13,215
Winter	2	16,143	2/27/2015	12,895	12,766	12,780	12,968	13,406	14,290	15,494	16,143	16,017	15,227	14,316	13,547	12,864	12,414	12,010	11,682	11,666	11,998	13,004	13,579	13,746	13,680	13,405	12,985
Winter	2	14,973	2/28/2015	12,689	12,678	12,795	12,893	13,192	13,535	14,087	14,477	14,973	14,966	14,536	13,880	13,123	12,520	11,998	11,726	11,828	12,229	13,242	13,750	13,805	13,604	13,190	12,652
Spring	3	14,204	3/1/2015	12,196	11,909	11,801	11,801	11,979	12,305	12,816	13,296	13,941	14,204	14,061	13,737	13,485	13,235	12,900	12,684	12,607	12,829	13,465	13,648	13,447	12,910	12,283	11,623
Spring	3	13,797	3/2/2015	11,187	10,981	10,903	10,928	11,204	11,972	13,396	13,797	13,464	12,941	12,351	11,810	11,350	11,078	10,824	10,659	10,622	10,779	11,591	12,127	12,052	11,653	11,048	10,360
Spring	3	14,042	3/3/2015	9,883	9,660	9,606	9,692	10,019	10,867	12,416	13,088	13,073	13,106	13,187	13,155	13,058	13,052	12,923	12,871	12,972	13,323	13,952	14,042	13,782	13,168	12,408	11,501
Spring	3	12,850	3/4/2015	10,912	10,591	10,413	10,445	10,618	11,308	12,548	12,850	12,478	12,137	11,815	11,371	11,098	10,927	10,723	10,613	10,622	10,710	11,302	11,634	11,502	10,979	10,291	9,395
Spring	3	13,797	3/5/2015	8,814	8,469	8,340	8,225	8,400	9,071	10,393	10,977	11,079	11,186	11,378	11,554	11,625	11,728	11,780	11,916	12,209	12,730	13,473	13,780	13,797	13,470	12,896	12,335
Spring	3	16,260	3/6/2015	12,064	12,099	12,319	12,618	13,198	14,241	15,834	16,260	15,842	15,274	14,602	13,870	13,206	12,646	12,163	11,771	11,693	12,054	13,030	13,789	14,026	13,979	13,691	13,302
Spring	3	15,173	3/7/2015	13,054	13,069	13,208	13,509	13,808	14,287	14,899	15,173	14,619	13,570	12,628	11,816	11,057	10,430	10,021	9,749	9,736	9,961	10,664	11,273	11,337	11,238	10,958	10,577
Spring	3	12,350	3/8/2015	10,307	0	10,208	10,258	10,512	10,860	11,377	11,960	12,350	11,853	10,931	10,220	9,802	9,514	9,192	8,979	9,018	9,146	9,359	10,085	10,621	10,313	9,732	9,073
Spring	3	11,714	3/9/2015	8,565	8,331	8,288	8,260	8,553	9,369	10,820	11,714	11,549	11,510	11,534	11,385	11,151	11,002	10,751	10,540	10,389	10,396	10,543	11,218	11,522	11,046	10,310	9,512
Spring	3	11,574	3/10/2015	8,929	8,612	8,446	8,447	8,643	9,381	10,736	11,574	11,344	11,291

Contains Proprietary Material
Do Not Distribute

Spring	4	12,709	4/14/2015	8,783	8,384	8,195	8,096	8,200	8,810	10,192	10,875	10,997	11,137	11,342	11,485	11,630	11,809	11,928	12,071	12,387	12,496	12,441	12,466	12,709	12,095	11,006	9,953
Spring	4	11,451	4/15/2015	9,114	8,631	8,345	8,193	8,275	8,851	10,101	10,653	10,646	10,678	10,858	10,864	10,862	10,893	10,835	10,824	10,891	10,981	11,091	11,222	11,451	11,008	10,196	9,338
Spring	4	11,554	4/16/2015	8,804	8,484	8,330	8,301	8,503	9,208	10,566	11,190	11,254	11,328	11,453	11,377	11,244	11,142	10,993	10,925	10,957	11,049	11,132	11,303	11,554	11,130	10,282	9,440
Spring	4	10,769	4/17/2015	8,912	8,562	8,367	8,283	8,434	9,003	10,209	10,659	10,708	10,731	10,750	10,689	10,593	10,566	10,554	10,542	10,555	10,478	10,378	10,397	10,769	10,489	9,864	9,102
Spring	4	10,884	4/18/2015	8,449	8,040	7,788	7,665	7,658	7,853	8,220	8,496	9,073	9,552	9,927	10,226	10,428	10,580	10,689	10,767	10,783	10,762	10,666	10,571	10,884	10,615	9,988	9,203
Spring	4	10,557	4/19/2015	8,505	8,031	7,762	7,595	7,550	7,653	7,900	8,181	8,820	9,279	9,506	9,632	9,783	9,823	9,771	9,761	9,845	10,031	10,193	10,377	10,557	10,224	9,553	8,836
Spring	4	11,728	4/20/2015	8,276	7,917	7,757	7,734	7,905	8,589	9,905	10,469	10,631	10,852	11,121	11,325	11,551	11,728	11,719	11,577	11,443	11,318	11,240	11,111	11,406	11,062	10,186	9,175
Spring	4	11,213	4/21/2015	8,487	8,100	7,880	7,772	7,879	8,496	9,740	10,335	10,385	10,402	10,478	10,486	10,481	10,610	10,665	10,695	10,787	10,787	10,775	10,743	11,213	10,915	9,984	9,031
Spring	4	11,398	4/22/2015	8,416	8,115	7,987	7,995	8,242	8,969	10,347	10,839	10,759	10,636	10,632	10,611	10,609	10,767	10,834	10,913	10,994	11,018	10,945	10,930	11,398	11,082	10,150	9,180
Spring	4	11,210	4/23/2015	8,537	8,150	7,943	7,860	8,000	8,655	9,884	10,389	10,426	10,414	10,518	10,522	10,528	10,606	10,660	10,746	10,802	10,841	10,787	10,734	11,210	10,910	10,023	9,104
Spring	4	10,940	4/24/2015	8,496	8,206	8,104	8,101	8,322	9,072	10,410	10,940	10,784	10,615	10,478	10,314	10,152	10,159	10,096	10,046	10,098	10,099	9,973	9,892	10,316	10,105	9,493	8,781
Spring	4	10,157	4/25/2015	8,200	7,883	7,695	7,608	7,671	7,877	8,231	8,587	9,184	9,686	9,996	10,107	10,045	9,940	9,784	9,661	9,675	9,752	9,757	9,851	10,157	9,940	9,434	8,813
Spring	4	10,358	4/26/2015	8,243	7,909	7,704	7,640	7,660	7,809	8,092	8,473	9,177	9,600	9,701	9,698	9,790	9,759	9,621	9,520	9,558	9,617	9,641	9,830	10,358	10,154	9,502	8,791
Spring	4	11,046	4/27/2015	8,361	8,122	8,059	8,129	8,412	9,187	10,515	11,046	10,887	10,708	10,660	10,579	10,499	10,513	10,481	10,434	10,510	10,460	10,455	10,495	11,004	10,770	9,940	9,045
Spring	4	11,277	4/28/2015	8,479	8,245	8,182	8,270	8,574	9,395	10,771	11,277	11,027	10,801	10,688	10,553	10,475	10,465	10,434	10,472	10,549	10,576	10,557	10,596	11,099	10,821	9,921	9,031
Spring	4	10,961	4/29/2015	8,452	8,140	8,008	8,017	8,234	8,955	10,187	10,760	10,730	10,639	10,709	10,734	10,711	10,700	10,594	10,545	10,527	10,496	10,479	10,503	10,961	10,779	9,943	9,094
Spring	4	10,993	4/30/2015	8,557	8,296	8,163	8,155	8,357	9,058	10,249	10,726	10,696	10,634	10,619	10,626	10,684	10,813	10,832	10,822	10,827	10,788	10,654	10,587	10,993	10,741	9,928	9,047
Spring	5	10,556	5/1/2015	8,416	8,065	7,931	7,917	8,119	8,767	9,943	10,484	10,542	10,556	10,534	10,463	10,345	10,318	10,189	10,037	10,015	9,933	9,883	9,826	10,208	10,164	9,596	8,936
Spring	5	9,864	5/2/2015	8,365	8,062	7,926	7,889	7,994	8,280	8,612	9,003	9,355	9,476	9,477	9,433	9,388	9,355	9,398	9,511	9,704	9,754	9,759	9,657	9,864	9,721	9,065	8,366
Spring	5	10,694	5/3/2015	7,783	7,486	7,283	7,209	7,239	7,414	7,595	7,993	8,537	8,803	8,907	9,030	9,272	9,489	9,677	9,898	10,176	10,485	10,536	10,425	10,694	10,490	9,649	8,733
Spring	5	12,799	5/4/2015	8,064	7,695	7,519	7,444	7,612	8,294	9,421	10,076	10,317	10,613	11,014	11,358	11,701	12,140	12,380	12,536	12,777	12,799	12,720	12,438	12,465	12,066	10,985	9,820
Spring	5	13,706	5/5/2015	9,007	8,486	8,157	7,993	8,070	8,647	9,703	10,314	10,571	10,875	11,290	11,657	12,067	12,592	13,051	13,431	13,664	13,706	13,518	13,077	12,992	12,523	11,319	9,998
Spring	5	13,958	5/6/2015	9,111	8,583	8,280	8,128	8,170	8,745	9,763	10,259	10,530	10,868	11,315	11,790	12,271	12,834	13,270	13,630	13,931	13,958	13,715	13,222	13,089	12,634	11,361	10,064
Spring	5	13,337	5/7/2015	9,200	8,661	8,336	8,157	8,226	8,771	9,828	10,363	10,634	11,002	11,428	11,882	12,312	12,859	13,167	13,293	13,337	13,190	12,898	12,672	12,784	12,433	11,323	10,112
Spring	5	14,043	5/8/2015	9,246	8,716	8,384	8,177	8,257	8,778	9,697	10,286	10,615	10,956	11,454	11,903	12,345	12,885	13,375	13,760	14,043	13,973	13,569	12,931	12,652	12,190	11,273	10,177
Spring	5	12,850	5/9/2015	9,241	8,627	8,230	8,015	7,926	8,078	8,244	8,721	9,425	10,111	10,668	11,167	11,580	11,990	12,392	12,745	12,850	12,797	12,557	12,131	12,020	11,745	10,972	10,019
Spring	5	12,259	5/10/2015	9,156	8,600	8,220	7,963	7,881	7,948	8,053	8,475	9,356	10,026	10,422	10,650	10,921	11,256	11,543	11,810	12,066	12,259	12,191	11,923	12,064	11,941	11,062	10,021
Spring	5	16,541	5/11/2015	9,209	8,710	8,438	8,289	8,363	8,922	9,966	10,686	11,223	11,902	12,747	13,575	14,375	15,235	15,846	16,280	16,541	16,495	16,110	15,566	15,364	14,661	13,214	11,772
Spring	5	16,063	5/12/2015	10,667	9,985	9,510	9,250	9,233	9,731	10,765	11,443	11,955	12,601	13,319	14,012	14,573	15,109	15,602	15,931	16,063	15,880	15,462	14,836	14,467	13,780	12,424	11,010
Spring	5	14,620	5/13/2015	9,941	9,331	8,903	8,625	8,647	9,134	10,100	10,579	10,789	11,140	11,659	12,088	12,523	13,084	13,593	14,106	14,505	14,620	14,378	13,658	13,179	12,668	11,358	10,097
Spring	5	12,466	5/14/2015	9,171	8,624	8,285	8,146	8,224	8,744	9,675	10,202	10,419	10,610	10,821	11,062	11,275	11,572	11,858	12,095	12,373	12,466	12,295	11,964	12,105	11,853	10,915	9,795
Spring	5	13,224	5/15/2015	9,046	8,567	8,298	8,200	8,279	8,844	9,829	10,390	10,598	10,831	11,120	11,374	11,644	12,097	12,506	12,840	13,170	13,224	12,926	12,415	12,276	12,043	11,164	10,183
Spring	5	13,886	5/16/2015	9,345	8,789	8,410	8,192	8,108	8,213	8,325	8,760	9,516	10,265	11,007	11,682	12,312	12,873	13,319	13,658	13,834	13,886	13,605	12,962	12,685	12,318	11,351	10,544
Spring	5	14,328	5/17/2015	9,529	8,882	8,472	8,173	8,023	8,048	7,998	8,407	9,215	9,881	10,491	11,217	11,991	12,776	13,344	13,753	14,157	14,328	14,158	13,748	13,488	13,115	11,964	10,792
Spring	5	16,802	5/18/2015	9,869	9,311	8,943	8,757	8,858	9,459	10,501	11,236	11,774	12,473	13,484	14,411	15,248	15,934	16,354	16,628	16,802	16,585	15,952	15,376	15,036	14,261	12,914	11,576
Spring	5	16,066	5/19/2015	10,546	9,902	9,501	9,231	9,229	9,700	10,734	11,413	11,783	12,234	12,919	13,678	14,420	15,188	15,714	15,968	16,066	15,921	15,611	15,147	14,761	14,233	12,804	11,403
Spring	5	16,797	5/20/2015	10,355	9,637	9,223	8,992	8,966	9,439	10,334	11,062	11,532	12,121	12,940	13,766	14,490	15,292	15,924	16,422	16,797	16,728	16,370	15,623	15,062	14,446	13,065	11,652
Spring	5	14,559	5/21/2015	10,640	9,949	9,537	9,292	9,339	9,843	10,804	11,384	11,685	12,003	12,441	12,760	13,047	13,430	13,828	14,273	14,559	14,537	14,220	13,640	13,275	12,831	11,562	10,204
Spring	5	12,130	5/22/2015	9,246	8,656	8,320	8,133	8,188	8,653	9,450	10,024	10,286	10,548	10,790	10,917	11,060	11,293	11,574	11,805	12,097	12,130	11,975	11,488	11,099	10,904	10,078	9,108
Spring	5	11,728	5/23/2015	8,333	7,857	7,595	7,459	7,425	7,571	7,636	7,961	8,535	9,024	9,380	9,654	9,906	10,174	10,552	11,003	11,425	11,728	11,665	11,243	10,818	10,620	9,826	8,932
Spring	5	12,264	5/24/2015	8,204	7,680	7,393	7,213	7,153	7,189	7,184	7,598	8,313	8,935	9,365	9,757	10,231	10,674	11,109	11,616	12,010	12,264	12,169	11,673	11,210	10,988	10,262	9,344
Spring	5	13,673	5/25/2015	8,572	8,048	7,713	7,492	7,482	7,590	7,657	8,020	8,707	9,534	10,282	10,902	11,396	11,895	12,425	12,949	13,428	13,673	13,531	13,193	12,925	12,566	11,445	10,363
Spring	5	16,378	5/26/2015	9,515	8,999	8,726	8,572	8,667	9,202	10,211	11,084	11,702	12,431	13,242	13,968	14,584	15,273	15,705	15,964	16,265	16,378	16,075	15,474	15,080	14,403	13,015	11,630
Spring	5	15,630	5/27/2015	10,592	9,884	9,412	9,172	9,179	9,679	10,569	11,280	11,719	12,112	12,621	13,076	13,521	14,115	14,607	15,093	15,519	15,630	15,431	14,779	14,303	13,902	12,611	11,284
Spring	5	16,432	5/28/2015	10,282	9,665	9,256	9,057	9,080	9,578	10,553	11,282	11,757	12,585	13,428	14,236	15,026	15,697	16,156	16,386	16,432	16,153	15,575	14,816	14,484	13,926	12,768	11,463
Spring	5	15,627	5/29/2015	10,476	9,827	9,384	9,102	9,131	9,538	10,393	11,115	11,577	12,136	12,794	13,421	13,992	14,652	15,105	15,454	15,627	15,525	15,015	14,327	13,731	13,323	12,319	11,063
Spring	5	15,108	5/30/2015	10,019	9,358	8,944	8,640	8,517	8,602	8,658	9,209	10,138	11,050	11,943	12,590	13,195	13,708	14,177	14,650	14,970	15,108	14,869	14,266	13,642	13,271	12,333	11,210
Spring	5	15,133	5/31/2015	10,252	9,559	9,107	8,762	8,576	8,535	8,498	8,984	9,920	10,828	11,566	12,332	13,164	13,867	14,359	14,703	14,997	15,133	14,903	14,288	13,768	13,394	12,279	11,059
Summer	6	16,464	6/1/2015	10,160	9,572	9,196	9,018	9,104	9,677	10,618	11,482	12,094	12,796	13,661	14,485	15,187	15,826	16,114	16,364	16,464	16,005	15,298	14,599	14,193	13,704	12,460	11,200
Summer	6	14,311	6/2/2015	10,224	9,617	9,249	9,000	9,066	9,582	10,551	11,264	11,489	11,899	12,286	12,865	13,453	14,055	14,311	14,282	14,231	13,980	13,658	13,202	12,925	12,547	11,505	10,389
Summer	6	11,891	6/3/2015	9,538	9,047	8,744	8,593	8,683	9,196	10,158	10,787	11,056	11,245	11,434	11,585	11,685	11,815	11,846	11,891	11,879	11,801	11,618	11,477	11,627	11,477	10,626	9,676
Summer	6	12,272	6/4/2015	8,987	8,606	8,418	8,274	8,401	8,958	9,907	10,504	10,729	10,975	11,242	11,414	11,442	11,648	11,816	12,050	12,218	12,272	12,161	11,981	12,026	11,953	11,065	10,094
Summer	6	13,832	6/5/2015	9,252	8,737	8,445	8,314	8,418	8,881	9,740	10,381	10,757	11,116	11,519	11,957	12,367	12,881	13,351	13,678	13,832	13,658	13,372	12,873	12,495	12,373	11,542	10,473
Summer	6	15,074	6/6/2015	9,605	9,000	8,596	8,340	8,294	8,379	8,418	8,971	9,887	10,856	11,849	12,668	13,366	13,981	14,458	14,821	15,074	14,984	14,652	14,029	13,437	13,065	12,111	11,018
Summer	6	14,373	6/7/2015	10,070	9,374	8,931	8,588	8,407	8,391	8,361	8,815	9,759	10,690	11,378	12,029	12,704	13,297	13,676	13,938	14,205	14,373	14,190	13,724	13,359	13,111	12,129	11,039
Summer	6	16,486	6/8/2015	10,170	9,597	9,251	9,104	9,165	9,768	10,685	11,575	12,158	12,745	13,446	14,145	14,704	15,476	16,057	16,424	16,486	16,166	15,710	15,102	14,719	14,238	13,075	11,781
Summer	6	16,919	6/9/2015	10,761	10,035	9,585	9,336	9,316	9,806	10,668	11,406	11,863	12,358	13,133	13,937	14,786	15,678	16,272	16,662	16,919	16,646	16,031	15,299	14,683	14,240	13,128	11,789
Summer	6	17,296	6/10/2015	10,793	10,036	9,599	9,334	9,302	9,765	10,528	11,300	11,890	12,628	13,609	14,584	15,415	16,226	16,779	17,116	17,296	17,169	16,777	16,153	15,583	15,162	13,828	12,436
Summer	6	17,632	6/11/2015	11,273	10,559	10,044	9,708	9,697	10,073	10,903	11,809	12,629	13,629	14,681	15,670	16,410	16,958	17,432	17,532	17,632	17,479	17,011	16,375	15,768	15,331	14,033	12,700
Summer	6	17,191	6/12/2015	11,592	10,831	10,362	10,006	9,944	10,311	11,027	11,839	12,660	13,427	14,268	15,084	15,798	16,417	16,833	17,117	17,191	16,974	16,391	15,711	15,107	14,888	13,957	12,754
Summer	6	17,242	6/13/2015	11,726	10,950	10,451	10,013	9,798	9,828	9,820	10,487	11,616	12,903	14,116	15,114	15,810	16,334	16,659	16,916	17,197	17,242	16,978	16,400	15,649	15,219	14,099	12,805
Summer	6	17,480	6/14/2015	11,716	10,884	10,249	9,798	9,506	9,390	9,226	9,879	11,221	12,649	13,868	14,921	15,774	16,425	16,898	17,225	17,441	17,480	17,231	16,660	16,053	15,698	14,522	13,183
Summer	6	19,597	6/15/2015	12,019	11,118	10,596	10,220	10,221	10,554	11,161	12,301	13,380	14,635	15,989	17,149	18,008	18,699	19,185	19,515	19,597	19,522	19,247	18,660	17,809	17,262	15,768	14,156
Summer	6	19,692	6/16/2015	12,911	12,018	11,323	10,894	10,705	11,041	11,584	12,576	13,691	15,008	16,442	17,578	18,387	19,138	19,475	19,595	19,692	19,592	19,430	18,918	18,241	17,670	16,293	14,744
Summer	6	19,977	6/17/2015	13,507	12,578	11,829	11,308	11,160	11,439	11,979	12,919	13,997	15,166	16,465	17,591	18,504	19,157	19,583	19,844	19,977	19,778	19,363	18,656	18,025	17,509	16,133	14,631
Summer	6	19,840	6/18/2015	13,432	12,461	11,845	11,436	11,305	11,553	12,090	12,910	13,930	15,154	16,574	17,848	18,789	19,466	19,813	19,840	19,765	19,401	18,710	17,918	17,274	16,596	15,235	13,817
Summer	6	18,741	6/19/2015	12,666	11,846	11,293	10,941	10,762	11,102	11,512	12,327	13,326	14,373	15,522	16,640	17,501	18,307	18,737	18,741	18,382	17,866	17,148	16,293	15,543	15,218	14,129	12,872
Summer	6	16,831	6/20/2015	11,795	10,993	10,441	10,090	9,891	9,872	9,885	10,417	11,583	12,827	14,186	15,315	16,096	16,623	16,831	16,653	16,685	16,199	15,666	15,213	14,716	14,495	13,668	12,628
Summer	6	17,935	6/21/2015	11,641	10,894	10,366	9,949	9,711	9,618	9,460	10,085	11,357	12,629	13,675	14,617	15,389	16,120	16,747	17,286	17,734	17,935	17,739	17,219	16,439	15,832	14,640	13,200
Summer	6	19,726	6/22/2015	12,030	11,133	10,564	10,226	10,158	10,496	11,061	12,064	13,129	14,406	15,781	17,011	17,961	18,786	19,369	19,726	19,724	19,444	18,695	17,884	17,250	16,736	15,417	13,893
Summer	6	19,827	6/23/2015	12,774	12,013	11,454	11,085	10,954	11,260	11,798	12,739	13,760	15,005	16,446	17,597	18,502	19,172	19,607	19,741	19,688	19,827	19,503	18,976	18,326	17,874	16,582	15,046
Summer	6	20,003	6/24/2015	13,893	12,999	12,351	11,963	11,783	12,107	12,581	13,376	14,456	15,665	16,992	18,093	18,858	19,349	19,778	19,948	20,003	19,860	19,106	18,094	17,292	16,680	15,391	13,945
Summer	6	19,926	6/25/2015	12,817	11,941	11,355	10,987	10,997	11,337	11,915	12,695	13,563	14,524	15,744	16,878	17,871	18,789	19,390	19,809	19,926	19,820	19,317	18,595	17,815	17,228	15,817	14,331
Summer	6	19,443	6/26/2015	13,136	12,291	11,710	11,291	11,170	11,388	11,778	12,492	13,396	14,474	15,614	16,799	17,807	18,612	19,237	19,443	19,348	18,881	17,986	17,046	16,270	15,542	14,208	12,940
Summer	6	15,555	6/27/2015	11,784	11,044	10,505	10,143	9,959	9,990	10,040	10,311	10,888	11,640	12,554	13,434	14,198	14,837	15,356	15,555	15,123	14,492	13,804	13,236	12,908	12,826	12,149	11,246
Summer	6	14,474	6/28/2015	10,376	9,781	9,336	9,024	8,766	8,655	8,467	8,902	9,710	10,409	10,954	11,473	11,983	12,547	13,052	13,607	14,097	14,474	14,344	13,869	13,026	12,662	11,684	10,503
Summer	6	16,140	6/29/2015	9,567	8,922	8,550	8,321	8,377	8,782	9,298	10,071	10,771	11,489	12,361	13,143	13,913	14,678	15,257	15,767	16,050	16,140	15,899	15,243	14,489	14,134	12,966	11,694
Summer	6	17,124	6/30/2015	10,635	9,996	9,525	9,308	9,280	9,655	10,211	11,023	11,853	12,817	13,964	15,061	16,014	16,758	17,119	17,124	16,828	16,255	15,524	14,762	14,128	13,836	12,813	11,595
Summer	7	16,386	7/1/2015	10,612	9,941	9,515	9,273	9,256	9,632	10,215	10,837	11,429	12,118	13,036	13,948	14,801	15,552	16,045	16,386	16,386	16,077	15,482	14,794	14,315	13,968	12,931	11,751
Summer	7	15,147	7/2/2015	10,785	10,156	9,781	9,492	9,483	9,837	10,410	10,975	11,443	12,069	13,016	13,858	14,546	15,001	15,147	15,099	14,837	14,405	13,951	13,384	13,027	12,881	12,053	10,998
Summer	7	13,208	7/3/2015	10,065	9,457	9,120	8,878	8,836	8,986	9,183	9,527	10,068	10,639	11,107	11,438	11,800	12,027	12,356	12,743	13,069	13,208	12,973	12,540	12,196	12,058	11,410	10,595
Summer	7	14,029	7/4/2015	9,857	9,267	8,857	8,559	8,437	8,537	8,487	8,799	9,578	10,440	11,281	11,867	12,263	12,589	12,930	13,406	13,932	14,029	13,637	12,973	12,350	11,953	11,385	10,844
Summer	7	14,253	7/5/2015	10,076	9,448	8,985	8,727	8,567	8,565	8,527	8,869	9,616	10,450	11,171	11,906	12,822	13,629	14,126	14,253	14,209	14,224	14,033	13,577	13,087	12,871	12,025	11,013
Summer	7	17,474	7/6/2015	10,130	9,499	9,128	8,899	8,972	9,475	10,132	10,958	11,788	12,706	13,707	14,704	15,508	16,246	16,851	17,244	17,474	17,463	17,095	16,312	15,567	15,111	13,843	12,472
Summer	7	18,591	7/7/2015	11,313	10,661	10,057	9,737	9,669	9,986	10,599	11,404	12,259	13,250	14,427	15,636	16,615	17,390	17,950	18,349	18,591	18,539	18,176	17,456	16,801	16,282	14,977	13,562
Summer	7	18,766	7/8/2015	12,434	11,642	11,049	10,625	10,584	10,901	11,523	12,204	12,879	13,813	15,133	16,203	17,138	17,964	18,487	18,766	18,746	18,105	17,250	16,511	15,929	15,517	14,368	13,043
Summer	7	19,666	7/9/2015	11,951	11,223	10,750	10,447	10,361	10,691	11,279	12,061	13,059	14,243	15,686	16,931	17,831	18,612	19,140	19,486	19,654	19,666	19,366	18,666	17,827	17,264	15,885	14,352
Summer	7	19,439	7/10/2015	13,045	12,085	11,379	10,863	10,658	10,855	11,193	11,971	13,031	14,279	15,681	16,847	17,735	18,433	18,913	19,239	19,439	19,279	18,850	18,007	16,980	16,378	15,012	13,604
Summer	7	17,589	7/11/2015	12,349	11,423	10,680	10,157	9,930	9,983	10,037	10,339	11,370	12,732	14,063	15,120	15,925	16,559	17,042	17,400	17,589	17,575	17,145	16,466	15,743	15,298	14,197	12,946
Summer	7	16,105	7/12/2015	11,799	10,939	10,267	9,828	9,550	9,449	9,233	9,682	10,712	11,788	12,774	13,703	14,578	15,266	15,687	15,914	16,105	16,087	15,594	15,096	14,657	14,407	13,496	12,323
Summer	7	19,355	7/13/2015	11,400	10,688	10,261	10,028	10,070	10,521	11,261	12,011	12,685	13,317	14,452	15,757	16,908	17,903	18,659	19,201	19,317	19,355	18,844	17,968	17,034	15,741	14,359	12,897
Summer	7	16,505	7/14/2015	11,883	11,063	10,558	10,218	10,192	10,561	11,172	11,909	12,409	12,807	13,198	13,671	13,960	14,470	15,185	15,979	16,444	16,505	16,214	15,672	15,307	14,841	13,782	12,563
Summer	7	17,241	7/15/2015	11,627	11,002	10,602	10,340	10,348	10,688	11,286	12,050	13,001	13,995	15,067	15,864	16,325	16,793	17,031	16,999	17,177	17,241	17,029	16,454	15,706	15,256	14,014	12,584
Summer	7	17,754	7/16/2015	11,567	10,793	10,270	9,980	9,936	10,317	10,893	11,629	12,491	13

Contains Proprietary Material
Do Not Distribute

Summer	8	18,237	8/20/2015	11,484	10,910	10,516	10,307	10,312	10,860	11,912	12,458	12,951	13,516	14,278	15,123	15,954	16,871	17,571	18,045	18,237	18,102	17,570	16,760	16,371	15,614	14,300	12,991
Summer	8	17,132	8/21/2015	11,930	11,221	10,728	10,400	10,332	10,701	11,675	12,079	12,674	13,371	14,196	14,928	15,604	16,222	16,711	16,959	17,132	17,032	16,514	15,645	15,208	14,499	13,343	12,131
Summer	8	15,772	8/22/2015	11,116	10,411	9,884	9,572	9,443	9,489	9,686	9,895	10,592	11,430	12,326	13,095	13,815	14,441	14,941	15,352	15,652	15,772	15,450	14,745	14,378	13,724	12,730	11,677
Summer	8	15,010	8/23/2015	10,735	10,059	9,580	9,305	9,111	9,080	9,200	9,300	10,053	10,846	11,526	12,065	12,626	13,104	13,523	14,067	14,601	15,010	14,881	14,497	14,456	13,830	12,702	11,574
Summer	8	18,499	8/24/2015	10,710	10,182	9,823	9,652	9,793	10,397	11,600	12,067	12,715	13,602	14,765	15,806	16,719	17,445	17,922	18,306	18,499	18,370	17,816	17,060	16,698	15,787	14,300	12,900
Summer	8	17,782	8/25/2015	11,925	11,113	10,612	10,303	10,274	10,734	11,735	12,032	12,424	13,039	13,871	14,651	15,455	16,267	16,933	17,440	17,782	17,746	17,330	16,540	16,158	15,122	13,571	12,189
Summer	8	16,119	8/26/2015	11,135	10,416	9,813	9,474	9,447	9,891	11,004	11,283	11,607	12,186	12,697	13,263	13,799	14,457	15,012	15,614	16,065	16,119	15,775	15,086	14,824	14,007	12,764	11,448
Summer	8	15,938	8/27/2015	10,502	9,909	9,482	9,271	9,323	9,795	10,927	11,364	11,567	12,028	12,663	13,278	14,056	14,695	15,256	15,672	15,938	15,797	15,400	14,746	14,559	13,775	12,441	11,304
Summer	8	15,927	8/28/2015	10,308	9,607	9,245	8,980	8,995	9,453	10,509	10,924	11,242	11,779	12,462	13,170	13,840	14,632	15,230	15,675	15,927	15,763	15,237	14,288	13,906	13,124	12,072	10,982
Summer	8	14,444	8/29/2015	9,930	9,292	8,931	8,557	8,443	8,552	8,748	8,944	9,595	10,343	11,103	11,852	12,588	13,273	13,769	14,164	14,444	14,320	13,791	13,318	13,204	12,600	11,736	10,725
Summer	8	12,948	8/30/2015	9,856	9,326	8,909	8,664	8,533	8,583	8,718	8,942	9,636	10,328	10,854	11,367	11,857	12,338	12,538	12,761	12,934	12,948	12,781	12,698	12,818	12,188	11,250	10,330
Summer	8	16,367	8/31/2015	9,591	9,137	8,844	8,757	8,892	9,487	10,760	11,281	11,593	12,168	12,899	13,548	14,245	14,866	15,435	15,981	16,235	16,367	16,079	15,544	15,285	14,376	12,994	11,637
Fall	9	18,059	9/1/2015	10,722	10,011	9,632	9,379	9,375	9,892	11,057	11,420	11,991	12,799	13,989	15,022	15,953	16,805	17,436	17,865	18,059	17,929	17,541	16,856	16,523	15,408	13,913	12,474
Fall	9	18,681	9/2/2015	11,488	10,707	10,210	9,920	9,832	10,398	11,558	11,959	12,454	13,387	14,500	15,723	16,823	17,681	18,210	18,524	18,681	18,518	18,026	17,305	17,001	15,875	14,396	13,067
Fall	9	18,099	9/3/2015	11,986	11,246	10,716	10,411	10,329	10,769	11,859	12,286	12,658	13,430	14,457	15,384	16,300	17,124	17,712	18,018	18,099	17,947	17,394	16,638	16,354	15,318	13,844	12,466
Fall	9	17,909	9/4/2015	11,412	10,669	10,231	9,890	9,824	10,306	11,369	11,758	12,241	13,118	14,380	15,535	16,595	17,432	17,892	17,909	17,485	16,928	16,102	15,176	14,704	13,822	12,670	11,542
Fall	9	14,420	9/5/2015	10,576	9,943	9,469	9,197	9,068	9,117	9,349	9,492	10,158	10,838	11,558	12,389	12,871	13,345	13,842	14,143	14,420	14,378	14,009	13,409	13,277	12,561	11,732	10,729
Fall	9	14,386	9/6/2015	9,880	9,264	8,915	8,642	8,508	8,522	8,656	8,799	9,513	10,270	11,006	11,738	12,402	13,097	13,666	14,068	14,370	14,386	14,050	13,350	13,210	12,501	11,606	10,682
Fall	9	14,838	9/7/2015	9,856	9,261	8,880	8,690	8,625	8,849	9,122	9,194	9,721	10,492	11,276	11,927	12,468	13,056	13,663	14,289	14,693	14,838	14,545	14,068	14,050	13,201	11,973	10,861
Fall	9	16,789	9/8/2015	9,984	9,407	9,039	8,877	8,980	9,598	10,882	11,431	11,910	12,522	13,327	14,136	14,884	15,650	16,180	16,544	16,789	16,718	16,368	15,866	15,772	14,690	13,390	12,000
Fall	9	16,431	9/9/2015	11,094	10,497	10,109	9,907	9,940	10,550	11,768	12,316	12,655	13,220	14,050	14,806	15,506	16,133	16,357	16,431	16,223	15,808	15,379	15,039	14,957	14,132	12,924	11,785
Fall	9	17,150	9/10/2015	10,979	10,406	10,067	9,892	9,943	10,606	11,890	12,385	12,601	13,083	13,832	14,722	15,616	16,460	16,997	17,150	17,032	16,393	15,485	14,962	14,690	13,778	12,597	11,483
Fall	9	15,699	9/11/2015	10,644	10,013	9,655	9,428	9,515	10,051	11,176	11,629	11,965	12,460	13,126	13,733	14,245	14,789	15,173	15,520	15,699	15,535	15,110	14,485	14,219	13,388	12,367	11,365
Fall	9	12,030	9/12/2015	10,419	9,784	9,393	9,116	8,998	9,125	9,462	9,762	10,277	10,816	11,259	11,548	11,731	11,878	11,975	12,007	12,030	12,001	11,859	11,700	11,766	11,263	10,501	9,676
Fall	9	10,862	9/13/2015	8,900	8,397	8,006	7,805	7,691	7,701	7,892	8,003	8,577	9,071	9,386	9,631	9,936	10,189	10,332	10,517	10,725	10,862	10,789	10,644	10,859	10,261	9,440	8,663
Fall	9	12,301	9/14/2015	8,084	7,758	7,608	7,556	7,706	8,331	9,476	9,924	10,113	10,380	10,659	10,827	11,021	11,289	11,562	11,877	12,174	12,301	12,192	11,966	11,971	11,207	10,128	9,176
Fall	9	13,292	9/15/2015	8,523	8,141	7,941	7,867	7,980	8,549	9,734	10,099	10,259	10,534	10,935	11,251	11,595	12,016	12,395	12,847	13,179	13,292	13,096	12,640	12,619	11,684	10,549	9,523
Fall	9	12,711	9/16/2015	8,822	8,430	8,173	8,031	8,168	8,780	9,951	10,352	10,480	10,699	11,092	11,441	11,678	12,037	12,334	12,534	12,711	12,641	12,449	12,399	12,457	11,740	10,726	9,750
Fall	9	14,110	9/17/2015	9,026	8,595	8,365	8,240	8,328	8,904	10,069	10,470	10,629	11,000	11,492	11,964	12,361	12,910	13,375	13,830	14,088	14,110	13,798	13,377	13,281	12,369	11,208	10,105
Fall	9	14,775	9/18/2015	9,283	8,762	8,483	8,331	8,405	8,917	10,058	10,393	10,677	11,117	11,725	12,266	12,772	13,397	13,998	14,481	14,775	14,666	14,062	13,337	12,953	12,089	11,131	10,111
Fall	9	14,420	9/19/2015	9,290	8,672	8,326	8,104	8,026	8,186	8,477	8,713	9,282	9,907	10,671	11,437	12,084	12,787	13,447	13,966	14,352	14,420	13,807	13,163	12,731	11,898	10,878	10,022
Fall	9	14,700	9/20/2015	9,125	8,554	8,199	7,947	7,850	7,879	8,059	8,219	8,934	9,747	10,560	11,413	12,336	13,244	13,953	14,396	14,700	14,700	14,321	14,108	13,833	12,885	11,779	10,758
Fall	9	12,691	9/21/2015	9,959	9,449	9,155	8,971	9,074	9,647	10,910	11,523	11,602	11,764	12,049	12,228	12,389	12,630	12,673	12,691	12,673	12,438	12,204	12,407	12,291	11,603	10,703	9,747
Fall	9	12,296	9/22/2015	9,069	8,634	8,439	8,375	8,510	9,115	10,394	10,992	11,055	11,158	11,328	11,431	11,496	11,675	11,824	12,002	12,138	12,078	11,983	12,175	12,296	11,614	10,732	9,801
Fall	9	13,151	9/23/2015	9,122	8,680	8,410	8,325	8,446	9,030	10,276	10,774	10,886	11,099	11,465	11,709	11,919	12,295	12,620	12,944	13,151	13,052	12,799	12,732	12,717	11,945	10,953	9,954
Fall	9	11,755	9/24/2015	9,196	8,705	8,460	8,323	8,413	8,984	10,157	10,622	10,636	10,790	10,988	11,148	11,230	11,403	11,430	11,451	11,379	11,315	11,293	11,755	11,666	11,075	10,317	9,451
Fall	9	11,088	9/25/2015	8,837	8,441	8,222	8,128	8,239	8,780	9,925	10,566	10,680	10,849	11,068	11,088	11,021	10,979	10,905	10,823	10,804	10,725	10,683	10,919	10,845	10,458	9,822	9,206
Fall	9	10,314	9/26/2015	8,579	8,198	7,986	7,870	7,841	8,032	8,365	8,714	9,168	9,657	9,989	10,138	10,095	10,059	9,979	9,918	9,929	9,952	10,046	10,314	10,252	9,908	9,389	8,760
Fall	9	10,824	9/27/2015	8,205	7,822	7,635	7,479	7,471	7,574	7,822	8,135	8,656	9,084	9,315	9,427	9,602	9,672	9,669	9,722	9,863	10,056	10,300	10,824	10,790	10,392	9,775	9,121
Fall	9	12,940	9/28/2015	8,640	8,301	8,207	8,169	8,376	9,044	10,352	11,136	11,249	11,510	11,793	12,027	12,128	12,247	12,328	12,407	12,483	12,483	12,551	12,940	12,818	12,234	11,357	10,442
Fall	9	13,992	9/29/2015	9,759	9,326	9,138	9,035	9,127	9,760	11,090	11,792	11,941	12,204	12,549	12,824	12,940	13,149	13,327	13,580	13,711	13,711	13,653	13,992	13,842	13,009	11,978	10,953
Fall	9	15,751	9/30/2015	10,194	9,662	9,352	9,194	9,292	9,865	11,134	11,728	11,919	12,194	12,819	13,473	14,171	14,807	15,278	15,566	15,751	15,537	15,059	15,022	14,552	13,529	12,236	11,046
Fall	10	11,551	10/1/2015	10,075	9,492	9,088	8,877	8,856	9,383	10,607	11,238	11,215	11,322	11,480	11,551	11,528	11,507	11,453	11,348	11,282	11,184	11,186	11,545	11,429	10,866	10,025	9,209
Fall	10	10,782	10/2/2015	8,601	8,237	8,070	7,990	8,069	8,597	9,731	10,365	10,454	10,638	10,782	10,773	10,686	10,640	10,513	10,380	10,336	10,322	10,350	10,642	10,495	10,130	9,549	8,933
Fall	10	10,438	10/3/2015	8,387	8,068	7,880	7,737	7,816	8,006	8,416	8,863	9,391	9,932	10,297	10,438	10,378	10,244	10,078	9,980	9,961	9,984	10,038	10,379	10,161	9,784	9,244	8,665
Fall	10	10,363	10/4/2015	8,201	7,846	7,670	7,524	7,492	7,578	7,878	8,244	8,752	9,219	9,355	9,418	9,509	9,540	9,497	9,452	9,555	9,676	9,862	10,363	10,284	9,814	9,182	8,582
Fall	10	11,501	10/5/2015	8,102	7,823	7,665	7,661	7,866	8,542	9,825	10,540	10,543	10,760	10,905	10,938	10,906	10,980	10,940	10,941	10,924	10,894	10,988	11,501	11,344	10,728	9,896	9,060
Fall	10	11,609	10/6/2015	8,503	8,151	8,002	7,953	8,093	8,788	10,047	10,645	10,589	10,626	10,701	10,758	10,803	10,993	11,113	11,282	11,352	11,269	11,160	11,609	11,522	10,874	9,982	9,118
Fall	10	12,441	10/7/2015	8,506	8,209	8,051	7,969	8,131	8,778	10,034	10,649	10,648	10,746	10,947	11,085	11,318	11,693	11,952	12,239	12,441	12,404	12,189	12,371	12,118	11,371	10,335	9,426
Fall	10	12,755	10/8/2015	8,817	8,370	8,112	8,013	8,138	8,734	9,958	10,469	10,508	10,822	11,279	11,598	11,985	12,376	12,593	12,654	12,755	12,693	12,433	12,712	12,484	11,709	10,743	9,793
Fall	10	12,679	10/9/2015	9,026	8,595	8,278	8,184	8,277	8,830	9,996	10,537	10,610	10,915	11,299	11,653	11,914	12,239	12,516	12,650	12,679	12,517	12,143	12,234	11,923	11,408	10,695	9,869
Fall	10	10,277	10/10/2015	9,074	8,599	8,252	8,079	8,047	8,200	8,549	8,984	9,427	9,903	10,209	10,277	10,235	10,101	9,965	9,839	9,818	9,823	9,908	10,106	9,963	9,567	9,093	8,487
Fall	10	10,602	10/11/2015	7,973	7,625	7,434	7,287	7,328	7,462	7,784	8,192	8,707	9,060	9,088	9,132	9,298	9,405	9,518	9,671	9,861	10,057	10,097	10,602	10,479	9,955	9,224	8,525
Fall	10	12,066	10/12/2015	8,049	7,706	7,595	7,558	7,758	8,404	9,673	10,274	10,388	10,604	10,895	11,042	11,274	11,543	11,642	11,704	11,763	11,737	11,668	12,066	11,810	11,092	10,143	9,237
Fall	10	12,399	10/13/2015	8,620	8,223	8,047	7,988	8,115	8,736	9,987	10,655	10,606	10,782	11,004	11,229	11,455	11,832	12,057	12,270	12,399	12,277	12,045	12,348	12,066	11,272	10,244	9,365
Fall	10	11,750	10/14/2015	8,671	8,228	8,005	7,915	8,070	8,725	9,986	10,593	10,563	10,697	10,836	10,981	11,094	11,336	11,502	11,663	11,737	11,628	11,446	11,750	11,508	10,811	9,918	9,078
Fall	10	11,567	10/15/2015	8,482	8,164	7,969	7,938	8,130	8,829	10,132	10,741	10,738	10,784	10,860	10,915	10,932	11,076	11,172	11,216	11,299	11,236	11,152	11,567	11,351	10,752	9,919	9,145
Fall	10	10,898	10/16/2015	8,514	8,187	8,028	8,002	8,138	8,731	9,917	10,559	10,555	10,706	10,803	10,898	10,862	10,847	10,734	10,683	10,699	10,609	10,474	10,771	10,527	10,138	9,552	8,923
Fall	10	10,154	10/17/2015	8,427	8,096	7,969	7,950	8,076	8,412	8,930	9,537	10,066	10,154	10,001	9,763	9,517	9,362	9,232	9,196	9,300	9,370	9,510	10,024	9,945	9,648	9,244	8,782
Fall	10	10,672	10/18/2015	8,379	8,165	8,101	8,147	8,283	8,603	9,132	9,803	10,433	10,413	10,025	9,701	9,520	9,342	9,196	9,152	9,207	9,465	9,795	10,582	10,672	10,319	9,818	9,302
Fall	10	13,072	10/19/2015	9,083	8,969	9,048	9,220	9,668	10,661	12,298	13,072	12,959	12,533	11,952	11,471	11,116	10,922	10,721	10,635	10,581	10,721	11,138	11,887	11,810	11,369	10,619	9,955
Fall	10	13,126	10/20/2015	9,651	9,520	9,525	9,697	10,093	10,960	12,506	13,126	12,921	12,350	11,735	11,280	10,951	10,810	10,650	10,588	10,591	10,634	10,885	11,504	11,312	10,914	10,135	9,438
Fall	10	12,545	10/21/2015	9,059	8,906	8,977	8,992	9,433	10,353	11,852	12,545	12,312	11,831	11,386	11,109	10,872	10,829	10,806	10,868	10,883	10,870	11,008	11,463	11,259	10,724	9,903	9,190
Fall	10	11,789	10/22/2015	8,712	8,491	8,440	8,506	8,829	9,645	11,072	11,789	11,582	11,336	11,062	10,932	10,840	10,928	10,969	11,090	11,142	11,101	11,081	11,507	11,337	10,753	9,966	9,169
Fall	11	11,335	10/23/2015	8,623	8,301	8,194	8,155	8,313	8,910	10,160	10,839	10,852	10,848	10,847	10,855	10,922	11,117	11,228	11,331	11,335	11,227	11,083	11,245	10,893	10,437	9,796	9,107
Fall	10	10,269	10/24/2015	8,453	8,006	7,767	7,652	7,681	7,940	8,356	8,849	9,278	9,628	9,804	9,774	9,734	9,647	9,637	9,665	9,705	9,822	10,001	10,269	10,042	9,734	9,172	8,506
Fall	10	10,878	10/25/2015	7,995	7,624	7,494	7,385	7,408	7,527	7,824	8,365	8,775	9,186	9,295	9,346	9,479	9,647	9,695	9,759	9,901	10,068	10,429	10,878	10,647	10,101	9,444	8,759
Fall	11	11,826	10/26/2015	8,341	7,928	7,737	7,663	7,814	8,450	9,647	10,503	10,603	10,696	10,882	10,919	10,903	10,920	10,802	10,770	10,816	10,960	11,518	11,826	11,559	10,966	10,239	9,415
Fall	10	12,217	10/27/2015	8,906	8,654	8,517	8,539	8,768	9,491	10,783	11,597	11,576	11,597	11,782	11,747	11,774	11,805	11,666	11,671	11,704	11,773	12,176	12,217	11,908	11,264	10,509	9,652
Fall	10	11,801	10/28/2015	9,148	8,786	8,585	8,517	8,663	9,271	10,498	11,257	11,123	11,228	11,318	11,321	11,288	11,295	11,315	11,236	11,252	11,207	11,461	11,801	11,569	11,064	10,185	9,355
Fall	10	11,521	10/29/2015	8,773	8,426	8,208	8,161	8,304	8,947	10,175	10,852	10,837	10,896	11,030	11,076	11,072	11,084	11,005	10,924	10,885	10,856	11,144	11,521	11,346	10,811	10,041	9,250
Fall	10	11,215	10/30/2015	8,688	8,385	8,234	8,258	8,475	9,170	10,420	11,215	11,168	11,006	10,836	10,695	10,417	10,385	10,268	10,194	10,127	10,122	10,258	10,592	10,397	10,133	9,694	9,127
Fall	10	10,430	10/31/2015	8,666	8,399	8,308	8,328	8,419	8,736	9,260	9,818	10,246	10,430	10,358	10,228	10,014	9,733	9,541	9,442	9,465	9,486	9,607	9,692	9,619	9,440	9,046	8,552
Fall	11	10,600	11/1/2015	7,926	7,737	7,687	7,598	7,658	7,855	8,247	8,678	9,296	9,596	9,572	9,519	9,561	9,558	9,539	9,504	9,692	10,360	10,600	10,420	10,150	9,567	8,988	8,446
Fall	11	11,868	11/2/2015	8,061	7,844	7,744	7,748	7,969	8,694	10,051	10,716	10,944	11,155	11,320	11,309	11,268	11,290	11,182	11,164	11,281	11,702	11,868	11,659	11,241	10,583	9,854	9,130
Fall	11	11,816	11/3/2015	8,682	8,379	8,200	8,174	8,342	9,055	10,296	10,811	10,900	11,018	11,129	11,110	11,066	11,059	10,961	10,914	11,016	11,517	11,816	11,661	11,291	10,633	9,790	9,055
Fall	11	11,776	11/4/2015	8,590	8,288	8,122	8,085	8,276	8,954	10,228	10,715	10,826	10,932	11,015	10,981	10,965	10,981	10,913	10,861	10,957	11,467	11,776	11,564	11,225	10,616	9,843	9,082
Fall	11	11,920	11/5/2015	8,542	8,260	8,117	8,076	8,228	8,913	10,163	10,636	10,720	10,826	10,963	11,017	11,055	11,177	11,218	11,247	11,262	11,610	11,920	11,757	11,415	10,839	10,013	9,235
Fall	11	11,560	11/6/2015	8,672	8,347	8,147	8,091	8,260	8,885	10,105	10,637	10,832	11,023	11,172	11,240	11,199	11,198	11,161	11,057	11,035	11,364	11,560	11,284	10,998	10,580	9,992	9,336
Fall	11	10,641	11/7/2015	8,694	8,311	8,078	7,950	8,002	8,232	8,637	8,995	9,610	10,091	10,405	10,512	10,425	10,318	10,216	10,155	10,194	10,629	10,641	10,380	10,009	9,531	8,993	8,356
Fall	11	10,904	11/8/2015	7,845	7,536	7,347	7,300	7,366	7,578	7,985	8,453	9,185	9,573	9,617	9,565	9,581	9,566	9,534	9,574	9,712	10,597	10,904	10,856	10,683	10,211	9,668	9,114
Fall	11	12,815	11/9/2015	8,760	8,567	8,532	8,598	8,918	9,729	11,184	11,845	11,947	12,063	12,198	12,212	12,160	12,154	12,010	11,973	12,122	12,563	12,815	12,574	12,138	11,452	10,643	9,834
Fall	11	11,535	11/10/2015	9,292	8,951	8,765	8,703	8,916	9,620	10,896	11,308	11,154	11,024	10,917	10,820	10,737	10,771	10,711	10,703	10,763	11,142	11,535	11,369	11,068	10,571	10,004	9,353
Fall	11	11,725	11/11/2015	8,990	8,767	8,738	8,842	9,176	9,971	11,150	11,725	11,626	11,333	11,134	10,904	10,755	10,718	10,724	10,757	10,809	11,210	11,628	11,497	11,302	10,799	10,130	9,480
Fall	11	11,612	11/12/2015	9,110	8,875	8,803	8,947	9,121	9,949	11,244	11,583	11,330	11,142	11,057	10,930	10,803	10,802	10,757	10,799	10,807	11,190	11,612	11,448	11,155	10,542	9,796	9,113
Fall	11	11,330	11/13/2015	8,677	8,434	8,384	8,451	8,751	9,561	10,891	11,330	11,181	10,956	10,812	10,622	10,424	10,302	10,178	10,115	10,272	10,891	11,323	11,206	11,086	10,884	10,525	10,048
Fall	11	11,600	11/14/2015	9,653	9,492	9,473	9,598	9,851	10,354	10,972	11,434	11,600	11,215	10,818	10,403	9,996	9,698	9,499	9,464	9,679	10,475	11,002	11,013	10,983	10,819	10,578	10,271
Fall	11	12,199	11/15/2015	10,097	10,082	10,155	10,332	10,604	11,024	11,595	12,075	12,199	11,494	10,634	10,071	9,796	9,575	9,533	9,535	9,800	10,748	11,097	11,101	11,036	10,664	10,165	9,760
Fall	11	13,704	11/16/2015	9,596	9,648	9,833	10,101	10,627	11,645	13,299	13,704	13,219	12,518	11,908	11,408	10,996	10,836	10,659	10,645	10,805	11,551	12,046	12,004	11,741	11,182	10,478	9,791
Fall	11	11,962	11/17/2015	9,413	9,216	9,090	9,123	9,392	10,214	11,618	11,962	11,736	11,485	11,294	11,102	10,856	10,801	10,730	10,756	10,969	11,716	11,910	11,820	11,557	11,026	10,253	9,512
Fall	11	11,929	11/18/2015	9,014	8,754	8,627	8,621	8,833	9,573	10,853	11,318	11,263	11,180	11,206	11,120	10,996	11,085	11,012	10,983	11,142	11,733	11,929	11,698	11,393	10,797	10,015	9,213
Fall	11	11,748	11/19/2015	8,695	8,391	8,203	8,151	8,328	8,993	10,333	10,939	11,051	11,162	11,278	11,266	11,211	11,254	11,202	11,206	11,121	11,429	11,748	11,531	11,204	10,663	9,874	9,179
Fall	11	11,559	11/20/2015	8,695	8,494	8,396	8,458	8,805	9,599	11,052	11,559	11,415	11,194	10,962	10,730	10,520	10,435	10,292	10,242	10,359	10,997	11,361	11,292	11,215	11,016	10,655	10,182
Fall	11	11,984	11/21/2015	9,810	9,715	9,705	9,816	10,092	10,607	11,292	11,864	11,984	11,552

Contains Proprietary Material
Do Not Distribute

Winter	12	4,685	12/15/2014	3,547	3,520	3,455	3,483	3,540	3,786	4,263	4,603	4,682	4,685	4,612	4,504	4,454	4,252	4,208	4,204	4,304	4,529	4,657	4,609	4,568	4,415	4,135	3,880
Winter	12	4,820	12/16/2014	3,642	3,497	3,368	3,396	3,410	3,566	3,961	4,308	4,362	4,420	4,467	4,443	4,478	4,471	4,470	4,465	4,533	4,701	4,820	4,820	4,792	4,649	4,411	4,162
Winter	12	5,201	12/17/2014	3,993	3,843	3,786	3,780	3,888	4,109	4,559	4,884	5,011	5,004	5,060	4,941	4,863	4,766	4,744	4,652	4,726	4,995	5,165	5,144	5,201	5,118	4,875	4,676
Winter	12	5,253	12/18/2014	4,453	4,355	4,290	4,228	4,355	4,542	4,932	5,253	5,223	5,209	5,226	5,091	5,012	5,035	4,936	4,863	4,924	5,042	5,220	5,167	5,177	5,013	4,809	4,566
Winter	12	5,219	12/19/2014	4,393	4,277	4,204	4,216	4,255	4,463	4,901	5,211	5,219	5,120	4,984	4,904	4,829	4,745	4,676	4,607	4,574	4,818	5,046	5,091	5,082	5,043	4,882	4,707
Winter	12	4,781	12/20/2014	4,484	4,355	4,269	4,219	4,194	4,270	4,406	4,597	4,716	4,781	4,738	4,673	4,562	4,421	4,287	4,228	4,243	4,454	4,659	4,663	4,644	4,621	4,528	4,410
Winter	12	4,781	12/21/2014	4,289	4,231	4,235	4,209	4,290	4,404	4,554	4,716	4,781	4,674	4,429	4,185	4,010	3,921	3,795	3,737	3,811	4,133	4,402	4,450	4,508	4,491	4,354	4,171
Winter	12	4,626	12/22/2014	4,050	3,924	3,900	3,848	3,927	4,056	4,383	4,546	4,618	4,626	4,515	4,404	4,336	4,272	4,199	4,127	4,151	4,379	4,407	4,380	4,386	4,239	4,067	3,907
Winter	12	4,224	12/23/2014	3,597	3,462	3,332	3,279	3,275	3,410	3,696	3,980	4,080	4,175	4,224	4,112	4,117	4,057	4,082	4,034	4,010	4,196	4,176	4,066	3,990	3,867	3,672	3,407
Winter	12	3,625	12/24/2014	3,179	3,025	2,926	2,867	2,870	2,934	3,074	3,240	3,361	3,490	3,532	3,528	3,516	3,473	3,449	3,427	3,470	3,605	3,625	3,584	3,557	3,536	3,440	3,318
Winter	12	3,736	12/25/2014	3,191	3,108	3,066	3,055	3,080	3,153	3,261	3,383	3,491	3,598	3,635	3,621	3,556	3,417	3,288	3,183	3,176	3,339	3,577	3,652	3,719	3,736	3,701	3,620
Winter	12	4,177	12/26/2014	3,514	3,471	3,459	3,467	3,540	3,681	3,898	4,103	4,177	4,144	4,006	3,838	3,694	3,555	3,435	3,383	3,404	3,622	3,771	3,787	3,766	3,698	3,583	3,430
Winter	12	3,656	12/27/2014	3,250	3,130	3,086	3,044	3,030	3,077	3,195	3,307	3,399	3,478	3,570	3,588	3,567	3,489	3,372	3,344	3,359	3,580	3,656	3,642	3,568	3,510	3,365	3,201
Winter	12	4,178	12/28/2014	3,095	2,959	2,934	2,926	2,967	3,034	3,160	3,325	3,449	3,608	3,702	3,754	3,802	3,818	3,797	3,804	3,867	4,085	4,178	4,160	4,118	4,012	3,870	3,722
Winter	12	4,660	12/29/2014	3,588	3,522	3,495	3,530	3,615	3,783	4,074	4,367	4,479	4,547	4,585	4,509	4,449	4,374	4,320	4,286	4,317	4,497	4,660	4,630	4,595	4,503	4,331	4,149
Winter	12	4,862	12/30/2014	4,047	3,944	3,923	3,931	3,985	4,199	4,501	4,788	4,862	4,830	4,732	4,614	4,496	4,390	4,285	4,205	4,202	4,469	4,748	4,741	4,735	4,688	4,563	4,406
Winter	12	5,032	12/31/2014	4,283	4,240	4,218	4,235	4,298	4,462	4,724	4,976	4,977	5,032	4,908	4,761	4,601	4,450	4,329	4,205	4,221	4,493	4,732	4,718	4,659	4,593	4,487	4,397
Winter	1	4,469	1/1/2015	4,325	4,263	4,233	4,243	4,271	4,331	4,418	4,469	4,441	4,458	4,456	4,390	4,318	4,146	4,014	3,946	4,042	4,270	4,438	4,412	4,328	4,275	4,090	3,896
Winter	1	4,507	1/2/2015	3,797	3,699	3,609	3,619	3,616	3,740	3,983	4,182	4,278	4,329	4,469	4,463	4,449	4,389	4,336	4,306	4,279	4,441	4,507	4,387	4,349	4,244	4,100	3,890
Winter	1	3,825	1/3/2015	3,758	3,616	3,553	3,479	3,518	3,522	3,555	3,717	3,751	3,810	3,789	3,825	3,738	3,691	3,680	3,593	3,652	3,752	3,805	3,697	3,646	3,507	3,321	3,173
Winter	1	4,431	1/4/2015	3,070	2,917	2,857	2,835	2,784	2,864	2,960	3,111	3,174	3,441	3,482	3,590	3,708	3,747	3,788	3,855	3,981	4,243	4,431	4,426	4,393	4,375	4,267	4,199
Winter	1	5,660	1/5/2015	4,134	4,137	4,223	4,281	4,477	4,745	5,270	5,643	5,660	5,590	5,554	5,365	5,271	5,125	4,977	5,032	4,987	5,228	5,544	5,532	5,501	5,366	5,130	4,926
Winter	1	5,448	1/6/2015	4,743	4,634	4,518	4,434	4,476	4,699	5,094	5,448	5,396	5,363	5,298	5,252	5,168	4,975	4,887	4,877	4,918	5,024	5,231	5,277	5,292	5,217	5,013	4,873
Winter	1	6,588	1/7/2015	4,719	4,645	4,602	4,636	4,773	4,991	5,401	5,726	5,818	5,889	6,012	5,986	6,000	6,081	5,988	6,043	6,084	6,298	6,581	6,588	6,560	6,434	6,355	6,265
Winter	1	6,964	1/8/2015	6,128	6,145	6,094	6,074	6,127	6,406	6,666	6,964	6,957	6,795	6,657	6,499	6,381	6,241	6,158	6,077	5,980	6,002	6,157	6,018	5,899	5,696	5,531	5,292
Winter	1	5,780	1/9/2015	5,128	5,013	4,951	4,901	4,916	5,045	5,339	5,563	5,650	5,639	5,617	5,573	5,466	5,344	5,271	5,178	5,211	5,387	5,665	5,675	5,706	5,780	5,643	5,499
Winter	1	6,097	1/10/2015	5,432	5,401	5,432	5,452	5,538	5,684	5,812	5,965	6,097	5,883	5,729	5,512	5,301	5,030	4,814	4,633	4,664	4,817	5,146	5,166	5,270	5,289	5,155	5,009
Winter	1	4,926	1/11/2015	4,926	4,843	4,801	4,727	4,675	4,678	4,714	4,788	4,777	4,819	4,690	4,615	4,523	4,415	4,399	4,335	4,386	4,568	4,699	4,655	4,611	4,446	4,275	4,057
Winter	1	5,150	1/12/2015	3,932	3,840	3,789	3,785	3,840	4,081	4,500	4,837	4,870	4,898	4,882	4,850	4,815	4,816	4,807	4,814	4,842	4,992	5,150	5,126	5,048	4,980	4,751	4,601
Winter	1	5,571	1/13/2015	4,508	4,380	4,359	4,352	4,414	4,648	5,048	5,367	5,398	5,442	5,461	5,442	5,433	5,399	5,347	5,327	5,313	5,422	5,571	5,557	5,453	5,296	5,084	4,840
Winter	1	5,489	1/14/2015	4,687	4,569	4,439	4,473	4,497	4,698	5,111	5,388	5,473	5,434	5,489	5,431	5,350	5,187	5,113	4,992	4,940	5,129	5,346	5,408	5,340	5,196	4,996	4,762
Winter	1	5,354	1/15/2015	4,607	4,495	4,457	4,416	4,466	4,690	5,103	5,354	5,307	5,343	5,299	5,224	5,153	5,109	4,966	4,953	4,854	4,977	5,249	5,276	5,262	5,094	4,975	4,765
Winter	1	5,490	1/16/2015	4,576	4,562	4,542	4,493	4,598	4,808	5,155	5,490	5,456	5,365	5,103	4,957	4,700	4,559	4,353	4,231	4,185	4,279	4,613	4,658	4,743	4,657	4,534	4,420
Winter	1	4,596	1/17/2015	4,288	4,208	4,165	4,178	4,168	4,240	4,411	4,568	4,596	4,569	4,381	4,256	4,015	3,836	3,743	3,646	3,579	3,757	4,071	4,108	4,057	3,929	3,819	3,705
Winter	1	4,143	1/18/2015	3,507	3,402	3,323	3,346	3,358	3,452	3,589	3,756	3,876	3,956	3,906	3,799	3,777	3,708	3,633	3,588	3,611	3,783	4,063	4,112	4,143	4,107	3,966	3,899
Winter	1	4,975	1/19/2015	3,791	3,804	3,815	3,882	4,027	4,267	4,622	4,862	4,975	4,897	4,695	4,523	4,360	4,157	4,106	3,983	3,874	3,948	4,275	4,424	4,491	4,363	4,247	4,082
Winter	1	4,945	1/20/2015	4,000	3,926	3,893	3,936	3,979	4,249	4,718	4,945	4,914	4,769	4,620	4,388	4,278	4,201	4,102	4,050	3,943	4,148	4,394	4,419	4,393	4,250	4,047	3,865
Winter	1	4,667	1/21/2015	3,709	3,631	3,605	3,610	3,632	3,845	4,329	4,667	4,648	4,602	4,478	4,360	4,267	4,210	4,116	4,007	4,041	4,155	4,457	4,548	4,521	4,469	4,294	4,124
Winter	1	5,138	1/22/2015	3,991	3,965	3,979	3,993	4,115	4,331	4,807	5,138	5,119	5,060	5,005	4,846	4,796	4,683	4,631	4,589	4,607	4,722	4,913	4,909	4,867	4,731	4,557	4,303
Winter	1	5,022	1/23/2015	4,170	4,084	4,027	4,056	4,087	4,313	4,725	4,969	5,022	5,010	5,003	4,960	4,901	4,850	4,802	4,752	4,761	4,875	5,001	4,963	4,905	4,754	4,583	4,382
Winter	1	4,627	1/24/2015	4,226	4,127	4,087	4,075	4,075	4,144	4,308	4,489	4,627	4,622	4,623	4,536	4,391	4,258	4,145	4,171	4,162	4,216	4,516	4,497	4,459	4,387	4,269	4,073
Winter	1	4,338	1/25/2015	3,957	3,867	3,863	3,781	3,805	3,843	3,946	4,061	4,146	4,224	4,190	4,064	4,065	4,009	3,979	3,942	3,998	4,077	4,338	4,329	4,277	4,126	3,980	3,769
Winter	1	5,402	1/26/2015	3,712	3,685	3,700	3,820	3,982	4,296	4,878	5,177	5,336	5,382	5,402	5,321	5,329	5,248	5,212	5,147	5,177	5,205	5,358	5,303	5,272	5,046	4,809	4,590
Winter	1	5,345	1/27/2015	4,430	4,345	4,302	4,240	4,306	4,553	4,933	5,242	5,303	5,345	5,296	5,159	5,125	4,965	4,875	4,831	4,772	4,886	5,157	5,254	5,199	5,148	4,981	4,824
Winter	1	5,765	1/28/2015	4,690	4,630	4,605	4,728	4,812	5,057	5,515	5,765	5,756	5,533	5,319	5,151	4,959	4,816	4,652	4,544	4,486	4,618	4,954	5,011	5,042	4,904	4,763	4,513
Winter	1	4,938	1/29/2015	4,349	4,258	4,191	4,113	4,085	4,240	4,672	4,938	4,904	4,843	4,741	4,622	4,565	4,530	4,461	4,493	4,542	4,652	4,807	4,833	4,832	4,695	4,539	4,331
Winter	1	5,000	1/30/2015	4,209	4,091	4,008	3,993	4,091	4,271	4,664	4,956	4,965	5,000	4,948	4,823	4,729	4,597	4,497	4,389	4,296	4,433	4,803	4,858	4,828	4,788	4,693	4,577
Winter	1	4,970	1/31/2015	4,487	4,532	4,502	4,533	4,584	4,675	4,813	4,911	4,970	4,863	4,660	4,455	4,246	4,153	4,012	3,972	4,051	4,139	4,351	4,359	4,303	4,231	4,073	3,911
Winter	2	4,222	2/1/2015	3,776	3,667	3,649	3,624	3,625	3,660	3,779	3,933	3,983	4,073	4,190	4,147	4,152	4,188	4,151	4,129	4,155	4,183	4,222	4,106	4,019	3,900	3,825	3,660
Winter	2	5,509	2/2/2015	3,538	3,511	3,567	3,615	3,834	4,159	4,710	5,147	5,319	5,437	5,509	5,495	5,441	5,382	5,228	5,189	5,171	5,262	5,456	5,471	5,460	5,291	5,104	4,833
Winter	2	5,581	2/3/2015	4,676	4,579	4,516	4,523	4,642	4,863	5,331	5,581	5,567	5,424	5,253	5,082	4,935	4,747	4,638	4,518	4,449	4,550	4,933	5,059	5,068	4,952	4,759	4,554
Winter	2	5,188	2/4/2015	4,436	4,340	4,239	4,255	4,290	4,556	4,971	5,188	5,133	4,941	4,826	4,602	4,457	4,344	4,228	4,186	4,091	4,245	4,529	4,578	4,582	4,492	4,340	4,209
Winter	2	5,610	2/5/2015	4,170	4,195	4,191	4,280	4,424	4,722	5,233	5,537	5,610	5,569	5,448	5,328	5,162	5,064	4,927	4,761	4,824	4,884	5,202	5,418	5,410	5,354	5,243	5,142
Winter	2	6,065	2/6/2015	5,099	5,062	5,062	5,096	5,191	5,395	5,848	6,065	5,943	5,799	5,686	5,424	5,206	4,924	4,768	4,636	4,544	4,554	4,738	4,819	4,832	4,705	4,589	4,422
Winter	2	4,403	2/7/2015	4,220	4,192	4,116	4,075	4,107	4,151	4,291	4,403	4,380	4,384	4,288	4,105	3,897	3,748	3,643	3,526	3,472	3,503	3,758	3,838	3,833	3,770	3,647	3,482
Winter	2	3,852	2/8/2015	3,361	3,164	3,210	3,196	3,175	3,177	3,319	3,449	3,502	3,627	3,596	3,480	3,533	3,518	3,518	3,494	3,550	3,645	3,851	3,852	3,825	3,660	3,492	3,296
Winter	2	5,022	2/9/2015	3,100	3,055	3,085	3,070	3,098	3,337	3,889	4,237	4,344	4,388	4,500	4,529	4,594	4,611	4,642	4,645	4,667	4,782	5,003	5,022	4,992	4,860	4,727	4,521
Winter	2	5,334	2/10/2015	4,468	4,338	4,310	4,295	4,372	4,548	5,007	5,334	5,313	5,315	5,245	5,128	5,018	4,892	4,772	4,635	4,641	4,677	4,956	5,043	5,012	4,924	4,743	4,611
Winter	2	5,448	2/11/2015	4,541	4,461	4,443	4,478	4,572	4,777	5,211	5,448	5,410	5,286	5,161	4,898	4,736	4,509	4,324	4,300	4,180	4,341	4,619	4,710	4,683	4,534	4,418	4,193
Winter	2	5,696	2/12/2015	4,119	4,038	4,055	4,075	4,147	4,385	4,858	5,198	5,326	5,451	5,513	5,503	5,429	5,426	5,343	5,303	5,300	5,371	5,591	5,696	5,633	5,570	5,343	5,171
Winter	2	5,931	2/13/2015	5,024	4,959	4,932	4,950	4,997	5,224	5,668	5,907	5,931	5,741	5,576	5,290	5,130	4,922	4,798	4,606	4,534	4,624	4,979	5,028	5,075	5,006	4,859	4,691
Winter	2	5,515	2/14/2015	4,504	4,364	4,293	4,254	4,242	4,312	4,429	4,520	4,577	4,679	4,780	4,778	4,741	4,731	4,723	4,665	4,685	4,856	5,221	5,456	5,515	5,515	5,447	5,373
Winter	2	5,678	2/15/2015	5,297	5,122	5,161	5,185	5,320	5,386	5,541	5,661	5,678	5,591	5,459	5,297	5,141	4,957	4,832	4,773	4,758	4,987	5,237	5,406	5,360	5,281	5,133	5,027
Winter	2	6,025	2/16/2015	4,915	4,867	4,864	4,938	5,074	5,242	5,537	5,796	5,869	6,013	5,975	6,025	5,989	5,874	5,816	5,699	5,639	5,711	5,880	5,868	5,734	5,574	5,359	5,260
Winter	2	6,005	2/17/2015	5,190	5,139	5,233	5,191	5,307	5,531	5,720	5,904	6,005	5,916	5,662	5,460	5,311	5,192	5,094	4,998	5,026	5,130	5,461	5,578	5,578	5,496	5,350	5,285
Winter	2	6,381	2/18/2015	5,186	5,115	5,100	5,053	5,115	5,280	5,554	5,661	5,780	5,778	5,843	5,852	5,791	5,745	5,721	5,769	5,792	5,931	6,193	6,365	6,381	6,362	6,252	6,134
Winter	2	6,897	2/19/2015	6,057	6,083	6,137	6,176	6,234	6,460	6,748	6,897	6,865	6,761	6,737	6,644	6,523	6,362	6,260	6,151	6,097	6,187	6,499	6,742	6,742	6,736	6,573	6,557
Winter	2	7,236	2/20/2015	6,574	6,476	6,560	6,586	6,650	6,840	7,102	7,236	7,179	6,981	6,810	6,575	6,314	6,064	5,881	5,792	5,776	5,816	5,988	5,983	5,889	5,728	5,468	5,233
Winter	2	5,013	2/21/2015	5,008	4,868	4,790	4,737	4,642	4,630	4,744	4,741	4,833	4,907	5,009	5,013	4,954	4,880	4,819	4,762	4,829	4,838	4,868	4,920	4,803	4,695	4,552	4,420
Winter	2	4,972	2/22/2015	4,272	4,234	4,191	4,185	4,233	4,330	4,353	4,523	4,594	4,568	4,581	4,525	4,440	4,320	4,332	4,311	4,406	4,575	4,817	4,912	4,972	4,786	4,636	4,514
Winter	2	6,003	2/23/2015	4,447	4,435	4,480	4,547	4,721	5,003	5,419	5,725	5,857	5,802	5,715	5,686	5,538	5,451	5,385	5,299	5,241	5,380	5,678	5,966	5,989	6,003	5,814	5,744
Winter	2	6,399	2/24/2015	5,589	5,566	5,483	5,534	5,529	5,788	6,124	6,399	6,319	6,051	5,823	5,579	5,457	5,308	5,125	5,049	4,982	5,035	5,301	5,592	5,587	5,524	5,306	5,093
Winter	2	5,655	2/25/2015	5,008	4,887	4,880	4,829	4,890	5,025	5,402	5,655	5,544	5,404	5,246	5,036	4,900	4,813	4,765	4,730	4,753	4,873	5,070	5,206	5,151	5,014	4,820	4,615
Winter	2	5,441	2/26/2015	4,521	4,403	4,424	4,461	4,509	4,748	5,140	5,328	5,323	5,231	5,141	4,997	4,834	4,753	4,685	4,670	4,776	4,979	5,211	5,433	5,441	5,415	5,303	5,157
Winter	2	6,090	2/27/2015	5,048	5,040	5,059	5,038	5,152	5,430	5,861	6,090	6,017	5,798	5,604	5,436	5,326	5,177	5,031	4,918	4,862	4,943	5,234	5,462	5,494	5,467	5,325	5,198
Winter	2	5,380	2/28/2015	5,091	5,058	4,992	5,001	5,005	5,022	5,200	5,358	5,380	5,337	5,147	4,936	4,678	4,492	4,323	4,254	4,263	4,359	4,562	4,682	4,636	4,547	4,390	4,220
Spring	3	4,582	3/1/2015	4,123	3,998	4,013	3,959	3,981	4,002	4,072	4,178	4,271	4,415	4,430	4,359	4,281	4,210	4,143	4,140	4,226	4,309	4,491	4,582	4,572	4,432	4,299	4,150
Spring	3	5,213	3/2/2015	4,056	4,025	4,042	4,088	4,200	4,504	4,994	5,191	5,213	5,061	4,966	4,826	4,698	4,589	4,436	4,360	4,343	4,439	4,735	4,966	4,949	4,879	4,746	4,530
Spring	3	4,987	3/3/2015	4,416	4,319	4,214	4,181	4,218	4,409	4,803	4,987	4,946	4,943	4,921	4,782	4,672	4,609	4,513	4,407	4,315	4,323	4,409	4,427	4,389	4,215	4,013	3,781
Spring	3	5,175	3/4/2015	3,586	3,517	3,480	3,512	3,529	3,797	4,126	4,436	4,510	4,556	4,629	4,711	4,714	4,711	4,753	4,880	4,807	4,978	5,092	5,175	5,100	4,983	4,828	4,691
Spring	3	5,456	3/5/2015	4,625	4,528	4,504	4,568	4,630	4,749	4,921	5,075	5,156	5,260	5,240	5,190	5,247	5,161	5,061	4,969	4,868	4,967	5,124	5,407	5,456	5,362	5,315	5,239
Spring	3	6,170	3/6/2015	5,199	5,237	5,269	5,384	5,489	5,652	5,962	6,170	6,085	5,851	5,702	5,452	5,230	5,077	4,980	4,820	4,776	4,757	5,025	5,275	5,286	5,248	5,117	4,988
Spring	3	5,038	3/7/2015	4,895	4,814	4,825	4,792	4,822	4,877	5,008	5,038	4,978	4,810	4,693	4,519	4,381	4,192	4,051	3,892	3,830	3,903	4,081	4,328	4,345	4,286	4,183	4,033
Spring	3	4,274	3/8/2015	3,919	0	3,855	3,846	3,852	3,918	4,067	4,198	4,274	4,257	4,079	3,919	3,798	3,669	3,596	3,520	3,495	3,537	3,638	3,819	4,047	3,965	3,869	3,657
Spring	3	4,639	3/9/2015	3,586	3,490	3,469	3,497	3,569	3,855	4,311	4,613	4,639	4,614	4,551	4,463	4,338	4,215	4,103	4,080	3,961	3,940	3,997	4,115	4,285	4,191	3,934	3,814
Spring	3	4,432	3/10/2015	3,563	3,545	3,381	3,434	3,426	3,654	4,051	4,349	4,385	4,391	4,410	4,416	4,432	4,360	4,339	4,289	4,228	4,181	4,197	4,232	4,282	4,171	3,938	3,672
Spring	3	4,261	3/11/2015	3,476	3,359	3,278	3,252	3,280	3,433	3,892	4,145	4,181	4,226	4,261	4,197	4,119	4,039	4,024	3,937	3,872	3,800	3,820	3,859	4,093	4,036	3,805	3,630
Spring	3	4,342	3/12/2015	3,427	3,371	3,324	3,288	3,356	3,557	4,051	4,342	4,329	4,278	4,301	4,199	4,145	4,040	3,965	3,903	3,750	3,758	3,752	3,852	4,052	3,974	3,814	3,537
Spring	3	4,228	3/13/2015	3,336	3,206	3,161	3,120	3,118	3,302	3,733	4,033	4,082	4,143	4,201	4,210	4,228	4,201	4,114	4,111	4,070	4,030	4,034	4,030	4,078	4,000	3,811	3,661
Spring	3	3,733	3/14/2015	3,420	3,279	3,177	3,142	3,138	3,148	3,310	3,390	3,551	3,641	3,727	3,733	3,725	3,619	3,551	3,503	3,473	3,440	3,406	3,488	3,579	3,566	3,442	3,287
Spring	3	3,638	3/15/2015	3,149	3,053	2,995	2,995	3,061	3,156	3,287	3,453	3,545	3,577	3,500	3,431	3,387	3,318	3,250	3,193	3,209	3,241	3,264	3,359	3,638	3,523	3,428	3,176
Spring	3	4,171	3/16/2015	3,083	3,012	3,007	3,028	3,090	3,295	3,783	4,171	4,108	4,057	4,075	3,994	3,895	3,881	3,928	3,901	3,784	3,725	3,650	3,725	4,001	3,904	3,652	3,423
Spring	3	4,016	3/17/2015	3,193	3,125	3,023	2,933	2,923	3,128	3,561	3,883	3,961	3,971	4,016	3,954	3,991	3,926	3,857	3,788	3,691	3,722	3,689	3,723	3,954	3,899	3,744	3,615
Spring	3	4,636	3/18/2015	3,507	3,388	3,425	3,455	3,514	3,802	4,342	4,636	4,554	4,552

Contains Proprietary Material
Do Not Distribute

Spring	4	4,966	4/22/2015	3,238	3,064	3,051	3,014	3,005	3,252	3,606	3,828	3,896	3,887	3,955	3,950	3,966	3,937	3,912	3,849	3,780	3,711	3,639	3,701	3,859	3,879	3,721	3,440
Spring	4	4,166	4/23/2015	3,310	3,172	3,211	3,175	3,275	3,466	3,943	4,166	4,163	4,100	4,074	4,002	3,985	3,936	3,941	3,795	3,752	3,636	3,680	3,699	3,862	3,906	3,725	3,494
Spring	4	4,203	4/24/2015	3,355	3,318	3,272	3,280	3,316	3,534	3,928	4,203	4,100	4,137	4,036	3,962	3,900	3,828	3,787	3,719	3,651	3,629	3,585	3,582	3,707	3,690	3,483	3,305
Spring	4	3,576	4/25/2015	3,086	2,982	2,904	2,823	2,830	2,894	2,955	3,114	3,241	3,404	3,516	3,576	3,492	3,453	3,433	3,400	3,404	3,425	3,388	3,441	3,485	3,428	3,323	3,134
Spring	4	3,419	4/26/2015	2,934	2,819	2,738	2,705	2,693	2,714	2,784	2,880	3,060	3,194	3,234	3,197	3,155	3,141	3,084	3,052	3,071	3,097	3,128	3,173	3,313	3,419	3,229	3,038
Spring	4	3,906	4/27/2015	2,889	2,823	2,814	2,857	2,957	3,205	3,619	3,866	3,906	3,889	3,884	3,857	3,839	3,821	3,800	3,730	3,682	3,647	3,633	3,609	3,709	3,745	3,531	3,300
Spring	4	3,886	4/28/2015	3,136	2,999	2,983	2,977	3,012	3,252	3,665	3,885	3,886	3,869	3,873	3,839	3,824	3,806	3,778	3,715	3,672	3,647	3,615	3,608	3,699	3,745	3,525	3,223
Spring	4	3,830	4/29/2015	3,069	2,945	2,892	2,878	2,928	3,128	3,428	3,597	3,623	3,619	3,651	3,786	3,822	3,830	3,822	3,809	3,749	3,717	3,661	3,625	3,721	3,740	3,523	3,271
Spring	4	3,796	4/30/2015	3,061	2,921	2,846	2,808	2,821	3,001	3,355	3,587	3,685	3,682	3,757	3,789	3,796	3,787	3,769	3,690	3,664	3,600	3,593	3,580	3,689	3,711	3,578	3,415
Spring	5	3,855	5/1/2015	3,271	3,118	3,083	3,045	3,069	3,245	3,562	3,806	3,855	3,852	3,837	3,815	3,830	3,767	3,760	3,710	3,717	3,691	3,631	3,621	3,684	3,716	3,516	3,297
Spring	5	3,459	5/2/2015	3,105	2,951	2,880	2,807	2,789	2,874	2,932	3,016	3,156	3,279	3,312	3,382	3,335	3,354	3,364	3,397	3,384	3,390	3,429	3,397	3,386	3,459	3,239	3,065
Spring	5	3,847	5/3/2015	2,820	2,752	2,677	2,571	2,602	2,624	2,691	2,720	2,883	3,122	3,206	3,179	3,383	3,395	3,464	3,519	3,681	3,777	3,811	3,796	3,846	3,847	3,602	3,264
Spring	5	4,724	5/4/2015	3,019	2,947	2,827	2,763	2,779	2,974	3,331	3,585	3,865	3,972	4,155	4,217	4,324	4,457	4,592	4,648	4,724	4,695	4,640	4,539	4,548	4,468	4,205	3,828
Spring	5	5,054	5/5/2015	3,530	3,327	3,195	3,061	3,102	3,171	3,515	3,787	3,953	4,152	4,339	4,531	4,704	4,839	4,936	5,037	5,054	5,046	5,022	4,935	4,840	4,724	4,321	3,956
Spring	5	5,252	5/6/2015	3,614	3,396	3,219	3,064	3,071	3,196	3,461	3,668	3,868	4,079	4,331	4,527	4,809	4,948	5,049	5,126	5,225	5,252	5,231	5,103	5,016	4,870	4,531	4,065
Spring	5	5,478	5/7/2015	3,741	3,495	3,283	3,255	3,201	3,311	3,674	3,878	4,083	4,251	4,493	4,744	4,962	5,201	5,385	5,474	5,469	5,478	5,448	5,290	5,171	5,068	4,670	4,225
Spring	5	5,508	5/8/2015	3,843	3,591	3,404	3,265	3,199	3,310	3,588	3,855	4,093	4,342	4,620	4,867	5,125	5,310	5,486	5,491	5,508	5,434	5,306	5,134	4,899	4,839	4,534	4,186
Spring	5	5,042	5/9/2015	3,814	3,598	3,370	3,249	3,194	3,185	3,239	3,308	3,528	3,857	4,143	4,427	4,546	4,690	4,816	4,945	5,042	5,027	4,861	4,719	4,584	4,581	4,284	3,958
Spring	5	4,839	5/10/2015	3,654	3,386	3,235	3,139	3,013	3,019	2,967	3,014	3,373	3,661	3,959	4,139	4,283	4,345	4,457	4,617	4,727	4,839	4,834	4,722	4,658	4,672	4,365	3,935
Spring	5	5,538	5/11/2015	3,641	3,406	3,317	3,152	3,167	3,308	3,658	3,936	4,201	4,409	4,794	5,014	5,324	5,538	5,531	5,506	5,367	5,276	5,145	4,946	4,804	4,687	4,412	4,026
Spring	5	4,539	5/12/2015	3,726	3,459	3,317	3,258	3,224	3,314	3,624	3,831	3,995	4,151	4,231	4,329	4,339	4,452	4,494	4,539	4,473	4,389	4,297	4,186	4,089	4,135	3,849	3,514
Spring	5	4,261	5/13/2015	3,316	3,104	2,999	2,942	2,906	3,116	3,363	3,608	3,728	3,836	3,939	3,987	4,057	4,091	4,152	4,204	4,218	4,261	4,237	4,138	4,116	4,106	3,830	3,504
Spring	5	4,322	5/14/2015	3,276	3,109	2,995	2,910	2,923	3,076	3,395	3,607	3,739	3,844	3,892	3,979	4,082	4,130	4,198	4,289	4,322	4,276	4,212	4,171	4,234	4,232	3,979	3,698
Spring	5	5,271	5/15/2015	3,448	3,261	3,147	3,078	3,085	3,188	3,511	3,742	3,935	4,166	4,378	4,602	4,780	4,945	5,133	5,249	5,229	5,271	5,240	4,975	4,842	4,776	4,502	4,200
Spring	5	4,051	5/16/2015	3,866	3,614	3,473	3,319	3,225	3,235	3,259	3,382	3,593	3,816	3,954	4,051	4,045	3,976	3,968	3,925	4,014	3,997	3,936	3,904	3,931	3,929	3,759	3,487
Spring	5	4,731	5/17/2015	3,265	3,075	2,987	2,915	2,872	2,869	2,921	2,950	3,279	3,638	3,827	4,010	4,194	4,238	4,414	4,479	4,607	4,716	4,731	4,656	4,595	4,560	4,233	3,857
Spring	5	4,834	5/18/2015	3,580	3,384	3,277	3,241	3,200	3,365	3,709	3,950	4,137	4,328	4,505	4,582	4,669	4,730	4,798	4,783	4,761	4,826	4,834	4,658	4,657	4,652	4,288	4,025
Spring	5	4,858	5/19/2015	3,702	3,506	3,330	3,229	3,197	3,280	3,522	3,756	3,964	4,117	4,277	4,426	4,539	4,646	4,778	4,826	4,858	4,837	4,773	4,593	4,457	4,389	4,055	3,690
Spring	5	4,252	5/20/2015	3,404	3,203	3,055	2,977	2,952	3,088	3,385	3,599	3,782	3,876	3,948	4,004	4,080	4,159	4,220	4,252	4,249	4,226	4,100	4,031	4,045	4,030	3,759	3,537
Spring	5	3,919	5/21/2015	3,286	3,090	3,034	2,944	2,943	3,068	3,386	3,577	3,726	3,827	3,882	3,915	3,919	3,892	3,840	3,831	3,766	3,716	3,672	3,686	3,736	3,850	3,667	3,372
Spring	5	3,984	5/22/2015	3,239	3,072	3,043	2,963	3,008	3,158	3,382	3,684	3,726	3,876	3,878	3,943	3,930	3,968	3,960	3,984	3,946	3,922	3,926	3,781	3,780	3,830	3,627	3,370
Spring	5	3,990	5/23/2015	3,113	2,906	2,813	2,745	2,755	2,699	2,765	2,798	2,985	3,133	3,271	3,337	3,446	3,508	3,639	3,735	3,885	3,957	3,990	3,935	3,780	3,742	3,555	3,291
Spring	5	4,493	5/24/2015	3,032	2,807	2,697	2,668	2,627	2,649	2,588	2,730	2,944	3,153	3,334	3,586	3,718	3,932	4,081	4,259	4,422	4,493	4,454	4,373	4,172	4,165	3,949	3,576
Spring	5	4,010	5/25/2015	3,352	3,128	3,022	2,964	2,916	2,911	2,950	2,956	3,111	3,371	3,575	3,755	3,877	3,896	3,933	3,985	3,924	3,938	3,938	3,983	3,947	4,010	3,819	3,513
Spring	5	5,203	5/26/2015	3,228	3,085	3,015	2,986	2,999	3,168	3,495	3,846	4,082	4,336	4,671	4,948	5,074	5,182	5,203	5,135	5,131	5,038	4,822	4,667	4,544	4,476	4,217	3,908
Spring	5	5,096	5/27/2015	3,647	3,396	3,339	3,212	3,183	3,278	3,576	3,881	4,067	4,288	4,484	4,740	4,911	5,075	5,096	5,026	4,910	4,693	4,555	4,406	4,281	4,295	4,070	3,724
Spring	5	5,135	5/28/2015	3,450	3,240	3,079	3,017	2,990	3,126	3,455	3,719	3,926	4,109	4,291	4,465	4,623	4,779	4,940	5,051	5,117	5,135	5,001	4,896	4,773	4,719	4,476	4,096
Spring	5	5,272	5/29/2015	3,747	3,493	3,339	3,224	3,178	3,286	3,537	3,844	4,086	4,328	4,486	4,728	4,959	5,078	5,179	5,227	5,259	5,272	5,197	5,046	4,855	4,771	4,507	4,172
Spring	5	5,013	5/30/2015	3,835	3,570	3,375	3,266	3,171	3,167	3,161	3,312	3,604	3,974	4,310	4,579	4,787	4,870	4,933	5,013	5,013	4,992	4,952	4,767	4,591	4,508	4,263	3,903
Spring	5	4,085	5/31/2015	3,624	3,356	3,196	3,119	3,024	3,002	2,972	3,039	3,249	3,463	3,696	3,754	3,861	3,915	3,990	4,049	4,067	4,085	4,080	3,959	3,846	3,865	3,739	3,460
Summer	6	4,060	6/1/2015	3,203	3,048	2,964	2,962	2,953	3,139	3,366	3,623	3,782	3,901	4,040	4,037	4,060	4,016	4,014	4,013	3,975	3,881	3,892	3,817	3,766	3,841	3,664	3,422
Summer	6	4,027	6/2/2015	3,240	3,096	3,010	2,962	2,941	3,123	3,331	3,565	3,786	3,871	3,950	3,984	4,010	4,014	4,025	4,027	3,943	3,888	3,896	3,871	3,875	3,914	3,725	3,493
Summer	6	4,202	6/3/2015	3,308	3,144	3,037	3,032	2,993	3,139	3,419	3,665	3,771	3,934	3,998	4,039	4,139	4,191	4,198	4,202	4,154	4,147	4,143	4,083	4,053	4,090	3,923	3,619
Summer	6	5,229	6/4/2015	3,365	3,166	3,055	3,008	3,013	3,136	3,324	3,612	3,871	4,027	4,233	4,384	4,620	4,774	4,915	5,077	5,176	5,229	5,193	5,061	4,902	4,801	4,515	4,111
Summer	6	5,492	6/5/2015	3,723	3,425	3,290	3,183	3,138	3,250	3,481	3,685	3,924	4,256	4,521	4,736	4,982	5,156	5,334	5,440	5,492	5,478	5,423	5,251	5,068	4,888	4,662	4,231
Summer	6	5,087	6/6/2015	3,903	3,624	3,445	3,240	3,190	3,134	3,133	3,245	3,515	3,762	4,072	4,299	4,500	4,745	4,867	4,968	5,087	5,070	5,006	4,846	4,631	4,530	4,290	3,939
Summer	6	5,471	6/7/2015	3,605	3,334	3,165	3,027	3,011	2,932	2,912	3,001	3,244	3,677	4,033	4,361	4,689	4,951	5,109	5,250	5,377	5,471	5,381	5,310	5,198	5,030	4,821	4,446
Summer	6	5,203	6/8/2015	4,075	3,858	3,704	3,644	3,614	3,700	3,977	4,235	4,395	4,558	4,698	4,882	4,960	5,073	5,203	5,186	4,983	4,844	4,874	4,773	4,598	4,609	4,391	3,989
Summer	6	5,790	6/9/2015	3,754	3,518	3,364	3,277	3,204	3,347	3,509	3,789	4,094	4,420	4,619	4,970	5,202	5,539	5,634	5,693	5,784	5,790	5,718	5,505	5,300	5,132	4,780	4,378
Summer	6	6,216	6/10/2015	3,944	3,626	3,470	3,344	3,310	3,381	3,559	3,890	4,210	4,527	4,927	5,283	5,581	5,818	6,035	6,204	6,216	6,204	6,112	5,974	5,722	5,578	5,222	4,733
Summer	6	6,441	6/11/2015	4,295	3,965	3,766	3,578	3,499	3,544	3,773	4,055	4,429	4,803	5,224	5,641	5,984	6,209	6,319	6,395	6,441	6,389	6,304	6,143	5,878	5,736	5,450	5,006
Summer	6	6,330	6/12/2015	4,567	4,230	3,990	3,835	3,801	3,883	4,099	4,369	4,762	5,148	5,493	5,827	6,086	6,238	6,302	6,274	6,298	6,330	6,146	5,986	5,804	5,645	5,362	4,990
Summer	6	5,675	6/13/2015	4,614	4,315	4,096	3,893	3,777	3,738	3,718	3,880	4,225	4,541	4,908	5,151	5,330	5,482	5,585	5,587	5,632	5,675	5,552	5,420	5,249	5,102	4,929	4,556
Summer	6	5,817	6/14/2015	4,229	3,982	3,802	3,664	3,583	3,524	3,432	3,560	3,931	4,300	4,703	5,016	5,184	5,408	5,504	5,613	5,655	5,776	5,817	5,693	5,507	5,431	5,161	4,761
Summer	6	6,576	6/15/2015	4,403	4,170	3,981	3,868	3,818	3,937	4,157	4,456	4,930	5,341	5,626	5,943	6,175	6,334	6,475	6,570	6,576	6,539	6,480	6,314	6,100	5,970	5,618	5,188
Summer	6	6,468	6/16/2015	4,768	4,505	4,288	4,151	4,068	4,173	4,344	4,555	4,971	5,297	5,694	5,958	6,158	6,335	6,433	6,468	6,287	6,123	6,014	5,766	5,587	5,521	5,149	4,772
Summer	6	6,426	6/17/2015	4,430	4,138	3,950	3,844	3,787	3,919	4,153	4,373	4,564	4,855	5,209	5,537	5,800	6,096	6,218	6,426	6,397	6,216	5,944	5,741	5,447	5,382	5,067	4,700
Summer	6	6,470	6/18/2015	4,349	4,026	3,891	3,709	3,628	3,809	3,971	4,230	4,676	5,034	5,489	5,866	6,181	6,383	6,430	6,470	6,348	5,978	5,683	5,413	5,234	5,128	4,848	4,495
Summer	6	5,743	6/19/2015	4,126	3,889	3,737	3,626	3,660	3,739	3,994	4,199	4,441	4,667	4,908	5,202	5,436	5,622	5,743	5,731	5,627	5,413	5,145	4,944	4,758	4,767	4,533	4,269
Summer	6	4,819	6/20/2015	3,992	3,732	3,587	3,454	3,439	3,466	3,488	3,589	3,792	3,985	4,198	4,279	4,357	4,378	4,410	4,441	4,652	4,766	4,817	4,819	4,643	4,547	4,358	4,062
Summer	6	5,493	6/21/2015	3,760	3,546	3,376	3,238	3,221	3,188	3,165	3,285	3,572	3,993	4,338	4,715	4,985	5,113	5,256	5,422	5,477	5,493	5,388	5,224	5,052	5,005	4,747	4,464
Summer	6	6,138	6/22/2015	4,003	3,801	3,607	3,458	3,415	3,572	3,786	4,014	4,270	4,588	4,946	5,304	5,573	5,776	5,965	6,039	6,138	6,080	6,049	5,874	5,702	5,604	5,332	4,926
Summer	6	6,386	6/23/2015	4,556	4,297	4,099	3,981	3,932	4,021	4,226	4,458	4,756	5,136	5,488	5,825	6,112	6,307	6,292	6,386	6,365	6,339	6,340	6,164	5,944	5,743	5,407	4,918
Summer	6	5,963	6/24/2015	4,482	4,131	3,847	3,640	3,556	3,613	3,756	3,981	4,214	4,499	4,785	5,079	5,358	5,558	5,756	5,910	5,949	5,963	5,767	5,627	5,368	5,169	4,835	4,430
Summer	6	6,195	6/25/2015	4,062	3,762	3,544	3,409	3,329	3,440	3,655	3,858	4,127	4,351	4,596	4,845	5,121	5,456	5,790	6,023	6,182	6,195	6,100	5,910	5,750	5,664	5,355	4,951
Summer	6	5,961	6/26/2015	4,524	4,217	3,943	3,734	3,630	3,702	3,859	4,044	4,266	4,577	4,842	5,186	5,501	5,704	5,885	5,961	5,948	5,774	5,303	4,942	4,736	4,671	4,453	4,163
Summer	6	4,247	6/27/2015	3,901	3,676	3,487	3,385	3,306	3,335	3,344	3,440	3,649	3,841	3,966	3,997	4,037	4,108	4,117	4,144	4,221	4,231	4,247	4,101	3,898	3,824	3,669	3,408
Summer	6	4,523	6/28/2015	3,146	3,008	2,922	2,739	2,717	2,720	2,700	2,770	2,968	3,281	3,444	3,605	3,834	3,960	4,046	4,258	4,411	4,490	4,523	4,379	4,242	4,155	3,998	3,635
Summer	6	5,214	6/29/2015	3,425	3,155	3,066	2,971	2,989	3,167	3,396	3,529	3,842	4,034	4,269	4,546	4,748	4,918	5,065	5,175	5,214	5,188	5,149	5,009	4,845	4,718	4,499	4,115
Summer	6	5,432	6/30/2015	3,757	3,546	3,331	3,212	3,209	3,338	3,504	3,672	3,942	4,182	4,401	4,678	4,939	5,151	5,358	5,424	5,432	5,416	5,307	5,054	4,820	4,682	4,424	4,067
Summer	7	4,887	7/1/2015	3,761	3,548	3,325	3,173	3,214	3,286	3,519	3,730	3,989	4,186	4,385	4,557	4,712	4,875	4,887	4,834	4,739	4,780	4,691	4,613	4,539	4,560	4,338	4,017
Summer	7	4,893	7/2/2015	3,760	3,546	3,447	3,312	3,307	3,450	3,654	3,830	3,960	4,148	4,323	4,445	4,587	4,719	4,840	4,843	4,825	4,893	4,804	4,664	4,520	4,471	4,302	3,939
Summer	7	4,383	7/3/2015	3,628	3,449	3,298	3,210	3,155	3,187	3,275	3,307	3,491	3,682	3,875	4,000	4,172	4,309	4,383	4,317	4,303	4,273	4,203	4,077	3,952	3,958	3,774	3,554
Summer	7	4,607	7/4/2015	3,335	3,157	2,983	2,915	2,886	2,886	2,916	2,879	3,044	3,299	3,574	3,858	4,058	4,215	4,330	4,482	4,607	4,587	4,475	4,303	4,083	3,966	3,850	3,689
Summer	7	4,469	7/5/2015	3,470	3,255	3,112	2,986	2,939	2,949	2,915	2,992	3,094	3,271	3,491	3,599	3,830	3,937	4,020	4,101	4,237	4,404	4,469	4,434	4,289	4,255	4,028	3,717
Summer	7	5,947	7/6/2015	3,427	3,273	3,153	3,098	3,095	3,229	3,428	3,701	3,992	4,302	4,619	4,959	5,295	5,532	5,743	5,829	5,892	5,947	5,902	5,755	5,513	5,378	5,041	4,634
Summer	7	5,193	7/7/2015	4,289	3,968	3,790	3,656	3,632	3,735	3,934	4,127	4,417	4,665	4,861	5,047	5,147	5,125	5,193	5,169	5,065	4,912	4,840	4,752	4,691	4,664	4,528	4,201
Summer	7	5,374	7/8/2015	3,984	3,688	3,608	3,495	3,456	3,574	3,827	4,059	4,258	4,471	4,639	4,814	4,885	5,035	5,160	5,252	5,210	5,352	5,374	5,240	5,076	5,058	4,783	4,452
Summer	7	5,606	7/9/2015	4,169	3,900	3,721	3,661	3,642	3,777	3,959	4,181	4,440	4,598	4,762	4,907	5,048	5,168	5,371	5,509	5,578	5,606	5,589	5,456	5,312	5,183	4,943	4,515
Summer	7	5,448	7/10/2015	4,160	3,823	3,638	3,528	3,505	3,584	3,798	4,011	4,262	4,615	4,936	5,146	5,246	5,284	5,448	5,409	5,442	5,294	5,087	4,975	4,748	4,663	4,500	4,145
Summer	7	5,284	7/11/2015	3,797	3,556	3,391	3,264	3,191	3,179	3,192	3,287	3,470	3,765	4,038	4,355	4,547	4,780	4,968	5,093	5,222	5,284	5,226	5,092	4,869	4,773	4,503	4,232
Summer	7	5,520	7/12/2015	3,870	3,646	3,490	3,383	3,332	3,331	3,359	3,392	3,443	3,674	3,901	4,183	4,558	4,896	5,131	5,339	5,489	5,520	5,501	5,370	5,196	5,070	4,900	4,497
Summer	7	6,372	7/13/2015	4,128	3,880	3,705	3,595	3,567	3,676	3,887	4,125	4,488	4,918	5,370	5,822	6,124	6,372	6,177	5,778	5,446	5,345	5,279	5,276	5,101	5,056	4,900	4,408
Summer	7	6,296	7/14/2015	4,142	4,016	3,865	3,718	3,629	3,748	3,950	4,120	4,390	4,669	5,044	5,375	5,603	5,816	6,086	6,262	6,296	6,221	6,154	5,899	5,588	5,394	5,104	4,679
Summer	7	5,532	7/15/2015	4,283	3,999	3,789	3,628	3,586	3,620	3,822	4,004	4,244	4,447	4,602	4,808	4,916	5,047	5,238	5,392	5,532	5,494	5,501	5,344	5,191	5,094	4,791	4,422
Summer	7	6,053	7/16/2015	4,048	3,733	3,532	3,456	3,426	3,499	3,688	3,903	4,185	4,466	4,810	5,096	5,337	5,595	5,812	5,974	6,053	6,012	5,958	5,788	5,594	5,416	5,100	4,684
Summer	7	6,476	7/17/2015	4,294	4,002	3,795	3,678	3,592	3,677	3,833	4,098	4,443	4,858	5,316	5,678	5,968	6,240	6,448	6,476	6,468	6,415	6,248	6,097	5,935	5,759	5,405	4,793
Summer	7	6,150	7/18/2015	4,392	4,088	3,865	3,696	3,575	3,593	3,597	3,656	3,988	4,371	4,845	5,232	5,578	5,858	6,026	6,098	6,150	6,105	6,023	5,892	5,717	5,583	5,357	5,040
Summer	7	6,030	7/19/2015	4,683	4,382	4,163	3,938	3,825	3,730	3,734	3,787	4,143	4,553	4,900	5,263	5,613	5,800	5,973	6,030	5,974	5,965	5,865	5,720	5,515	5,431	5,133	4,815
Summer	7	6,172	7/20/2015	4,456	4,173	3,949	3,872	3,873	3,971	4,173	4,477	4,767	5,130	5,400	5,683	5,838	6,058	6,108	6,141	6,108	6,172	6,157	6,047	5,869	5,744	5,375	5,016
Summer	7	6,352	7/21/2015	4,640	4,330	4,089	3,935	3,954	4,004	4,255	4,465	4,773	4,993	5,236	5,591	5,816	6,025	6,240	6,343	6,352	6,293	6,221	5,941	5,689	5,630	5,216	4,800
Summer	7	5,980	7/22/2015	4,364	4,093	3,821	3,719	3,593	3,695	3,880	4,042	4,300	4,550	4,837	5,090	5,362	5,585	5,796	5,958	5,980	5,979	5,889	5,706	5,444	5,268	4,920	4,495
Summer	7	5,858	7/23/2015	4,079	3,815	3,628	3,526	3,495	3,558	3,780	3,959	4,233	4,501	4,805	5,055	5,260	5,490	5,681	5,768	5,833	5,858	5,799	5,593	5,403	5,266	4,962	4,531
Summer	7	6,060	7/24/2015	4,170	3,867	3,659	3,506	3,435	3,528	3,654	3,880	4,197	4

Contains Proprietary Material
Do Not Distribute

Summer	8	5,457	8/28/2015	3,502	3,285	3,194	3,116	3,072	3,173	3,545	3,636	3,757	4,076	4,247	4,469	4,645	4,859	5,071	5,264	5,408	5,457	5,365	5,130	4,984	4,741	4,490	4,121
Summer	8	5,472	8/29/2015	3,794	3,532	3,394	3,220	3,168	3,156	3,254	3,296	3,511	3,844	4,252	4,574	4,856	5,100	5,289	5,462	5,458	5,472	5,353	5,117	5,004	4,811	4,439	4,150
Summer	8	5,123	8/30/2015	3,824	3,581	3,415	3,258	3,227	3,191	3,234	3,208	3,481	3,794	4,093	4,333	4,591	4,836	4,967	5,008	5,030	5,123	5,028	4,941	4,875	4,763	4,405	4,058
Summer	8	6,109	8/31/2015	3,803	3,540	3,381	3,294	3,336	3,459	3,854	4,031	4,286	4,553	4,877	5,186	5,494	5,750	5,921	6,057	6,109	6,092	6,054	5,795	5,655	5,402	4,951	4,500
Fall	9	6,204	9/1/2015	4,135	3,863	3,596	3,549	3,478	3,644	3,934	4,115	4,372	4,651	5,022	5,362	5,687	5,890	6,067	6,143	6,204	6,131	6,041	5,953	5,796	5,532	5,087	4,595
Fall	9	6,378	9/2/2015	4,205	3,930	3,720	3,586	3,558	3,656	4,001	4,225	4,455	4,761	5,156	5,515	5,795	6,084	6,224	6,322	6,378	6,364	6,237	6,108	5,960	5,721	5,248	4,764
Fall	9	6,411	9/3/2015	4,441	4,101	3,890	3,693	3,625	3,801	4,115	4,268	4,469	4,841	5,175	5,609	5,994	6,199	6,267	6,350	6,372	6,411	6,320	6,145	6,038	5,693	5,218	4,795
Fall	9	6,461	9/4/2015	4,453	4,094	3,920	3,744	3,724	3,735	4,091	4,291	4,420	4,761	5,212	5,647	5,964	6,213	6,324	6,424	6,461	6,345	6,175	5,981	5,812	5,523	5,053	4,628
Fall	9	5,885	9/5/2015	4,310	3,983	3,716	3,558	3,433	3,414	3,423	3,418	3,567	3,984	4,440	4,816	5,231	5,547	5,730	5,855	5,885	5,867	5,652	5,373	5,236	4,932	4,650	4,242
Fall	9	5,678	9/6/2015	3,902	3,679	3,426	3,355	3,266	3,214	3,268	3,280	3,442	3,866	4,228	4,593	4,976	5,260	5,520	5,582	5,668	5,678	5,523	5,314	5,185	4,942	4,575	4,195
Fall	9	5,795	9/7/2015	3,927	3,652	3,491	3,385	3,337	3,309	3,356	3,327	3,503	3,939	4,366	4,768	5,141	5,393	5,517	5,696	5,795	5,762	5,686	5,466	5,376	5,122	4,773	4,355
Fall	9	6,388	9/8/2015	4,023	3,786	3,628	3,517	3,486	3,639	3,959	4,248	4,498	4,859	5,223	5,592	5,946	6,219	6,310	6,388	6,377	6,372	6,281	6,100	6,029	5,674	5,239	4,799
Fall	9	5,588	9/9/2015	4,450	4,155	3,955	3,853	3,773	3,872	4,255	4,517	4,643	4,849	5,115	5,294	5,377	5,494	5,554	5,588	5,487	5,323	5,231	5,149	5,103	4,950	4,592	4,258
Fall	9	5,658	9/10/2015	3,991	3,725	3,606	3,569	3,525	3,701	4,047	4,308	4,348	4,445	4,653	4,860	5,012	5,204	5,324	5,547	5,634	5,658	5,535	5,327	5,264	5,037	4,592	4,183
Fall	9	5,279	9/11/2015	3,865	3,633	3,376	3,316	3,289	3,411	3,780	3,973	4,122	4,380	4,625	4,894	5,127	5,279	5,278	5,220	5,072	4,800	4,629	4,426	4,425	4,251	3,943	3,695
Fall	9	3,633	9/12/2015	3,402	3,239	3,118	3,026	2,965	2,989	3,082	3,144	3,226	3,378	3,500	3,617	3,593	3,577	3,607	3,561	3,633	3,631	3,539	3,508	3,534	3,418	3,311	3,130
Fall	9	3,652	9/13/2015	2,889	2,810	2,694	2,621	2,609	2,654	2,745	2,757	2,914	3,087	3,186	3,228	3,323	3,369	3,366	3,377	3,452	3,507	3,546	3,551	3,652	3,553	3,310	3,086
Fall	9	4,438	9/14/2015	2,898	2,803	2,765	2,766	2,830	2,958	3,329	3,551	3,679	3,827	3,883	4,027	4,088	4,203	4,266	4,310	4,416	4,438	4,401	4,298	4,338	4,143	3,830	3,518
Fall	9	4,959	9/15/2015	3,289	3,159	3,039	2,923	2,910	3,094	3,439	3,625	3,717	3,856	4,073	4,187	4,292	4,479	4,620	4,754	4,910	4,959	4,920	4,705	4,672	4,450	4,106	3,692
Fall	9	5,235	9/16/2015	3,399	3,203	3,081	2,950	2,986	3,143	3,503	3,644	3,751	3,959	4,194	4,407	4,591	4,781	5,016	5,085	5,220	5,235	5,153	4,884	4,810	4,552	4,130	3,753
Fall	9	5,265	9/17/2015	3,508	3,266	3,127	3,017	3,046	3,173	3,489	3,734	3,816	4,055	4,215	4,340	4,643	4,788	5,007	5,132	5,235	5,265	5,134	4,949	4,915	4,576	4,230	3,866
Fall	9	5,443	9/18/2015	3,556	3,378	3,228	3,116	3,070	3,185	3,577	3,744	3,846	4,085	4,334	4,580	4,855	5,022	5,214	5,377	5,443	5,423	5,318	5,041	5,005	4,767	4,374	4,042
Fall	9	4,517	9/19/2015	3,762	3,548	3,395	3,230	3,150	3,114	3,244	3,319	3,481	3,801	4,041	4,312	4,476	4,509	4,517	4,438	4,387	4,311	4,169	4,089	4,080	3,910	3,676	3,446
Fall	9	3,918	9/20/2015	3,196	2,989	2,836	2,806	2,738	2,740	2,792	2,828	2,942	3,141	3,362	3,461	3,604	3,658	3,680	3,855	3,918	3,902	3,806	3,820	3,904	3,748	3,505	3,228
Fall	9	4,660	9/21/2015	3,032	2,882	2,758	2,735	2,793	3,045	3,406	3,632	3,709	3,854	4,032	4,142	4,291	4,379	4,465	4,581	4,649	4,660	4,642	4,524	4,528	4,254	3,925	3,579
Fall	9	4,898	9/22/2015	3,357	3,217	3,094	2,968	2,960	3,106	3,431	3,673	3,767	3,950	4,091	4,254	4,374	4,532	4,609	4,796	4,830	4,898	4,848	4,660	4,687	4,411	4,004	3,696
Fall	9	5,216	9/23/2015	3,461	3,281	3,145	3,083	3,081	3,174	3,540	3,781	3,838	4,039	4,200	4,337	4,567	4,748	4,942	5,139	5,216	5,213	5,037	4,894	4,765	4,497	4,122	3,776
Fall	9	5,260	9/24/2015	3,484	3,269	3,139	3,046	3,034	3,157	3,499	3,713	3,806	3,988	4,167	4,376	4,627	4,858	5,070	5,196	5,260	5,225	5,079	4,919	4,892	4,608	4,215	3,830
Fall	9	4,317	9/25/2015	3,534	3,325	3,174	3,070	3,020	3,169	3,491	3,740	3,791	3,917	4,066	4,181	4,250	4,310	4,317	4,310	4,247	4,189	4,092	4,065	4,070	3,936	3,726	3,523
Fall	9	3,784	9/26/2015	3,272	3,108	2,958	2,911	2,845	2,848	2,974	3,134	3,253	3,377	3,542	3,602	3,633	3,670	3,699	3,687	3,721	3,752	3,744	3,676	3,784	3,677	3,528	3,319
Fall	9	4,232	9/27/2015	3,130	2,955	2,888	2,764	2,757	2,806	2,775	2,925	3,017	3,241	3,380	3,533	3,669	3,841	3,971	4,096	4,159	4,204	4,148	4,197	4,232	4,082	3,792	3,582
Fall	9	5,257	9/28/2015	3,329	3,170	3,046	3,046	3,080	3,199	3,612	3,870	3,940	4,126	4,366	4,530	4,794	4,992	5,147	5,257	5,223	5,199	5,120	5,115	5,025	4,851	4,489	4,145
Fall	9	4,595	9/29/2015	3,826	3,657	3,526	3,375	3,343	3,543	3,901	4,193	4,299	4,439	4,546	4,540	4,573	4,595	4,587	4,534	4,474	4,538	4,488	4,484	4,534	4,363	4,055	3,733
Fall	9	4,188	9/30/2015	3,573	3,432	3,302	3,159	3,148	3,262	3,634	3,891	3,938	4,072	4,129	4,123	4,188	4,146	4,096	4,057	4,047	3,990	3,992	4,086	4,136	3,945	3,706	3,437
Fall	10	3,986	10/1/2015	3,248	3,071	3,035	2,943	2,965	3,097	3,404	3,678	3,740	3,841	3,909	3,959	3,961	3,968	3,940	3,909	3,880	3,861	3,783	3,913	3,986	3,769	3,654	3,391
Fall	10	3,945	10/2/2015	3,196	3,081	2,988	2,949	2,907	3,066	3,388	3,675	3,758	3,864	3,928	3,900	3,945	3,919	3,879	3,748	3,707	3,758	3,741	3,822	3,801	3,638	3,511	3,317
Fall	10	3,557	10/3/2015	3,157	3,015	2,947	2,903	2,864	2,912	2,970	3,151	3,259	3,439	3,485	3,557	3,542	3,507	3,476	3,431	3,405	3,432	3,427	3,509	3,516	3,413	3,259	3,093
Fall	10	3,857	10/4/2015	2,926	2,800	2,789	2,742	2,677	2,767	2,740	2,856	3,020	3,140	3,154	3,205	3,301	3,273	3,309	3,348	3,506	3,587	3,609	3,700	3,857	3,649	3,445	3,215
Fall	10	4,761	10/5/2015	3,076	2,960	2,859	2,885	2,918	3,042	3,410	3,664	3,736	3,932	4,039	4,197	4,334	4,485	4,597	4,679	4,746	4,761	4,665	4,597	4,531	4,318	4,067	3,723
Fall	10	4,914	10/6/2015	3,463	3,257	3,168	3,100	3,078	3,150	3,461	3,710	3,780	3,978	4,143	4,287	4,432	4,574	4,762	4,893	4,914	4,837	4,758	4,694	4,673	4,382	4,057	3,748
Fall	10	5,005	10/7/2015	3,479	3,262	3,125	3,030	2,994	3,157	3,531	3,729	3,860	3,992	4,135	4,335	4,497	4,715	4,820	4,977	5,005	4,955	4,895	4,768	4,715	4,430	4,093	3,775
Fall	10	5,030	10/8/2015	3,538	3,335	3,211	3,115	3,077	3,212	3,539	3,828	3,908	4,058	4,265	4,395	4,591	4,792	4,872	4,984	5,030	4,930	4,884	4,762	4,708	4,403	4,117	3,818
Fall	10	4,380	10/9/2015	3,496	3,381	3,233	3,149	3,104	3,290	3,552	3,833	3,903	4,097	4,278	4,348	4,380	4,366	4,356	4,228	4,221	4,088	4,034	4,058	3,985	3,832	3,617	3,382
Fall	10	3,538	10/10/2015	3,217	3,068	2,983	2,830	2,867	2,866	2,919	3,043	3,096	3,215	3,327	3,369	3,416	3,428	3,451	3,453	3,538	3,525	3,446	3,499	3,514	3,415	3,177	3,003
Fall	10	3,652	10/11/2015	2,869	2,734	2,694	2,653	2,673	2,653	2,759	2,872	2,971	3,074	3,122	3,195	3,298	3,287	3,336	3,321	3,434	3,572	3,562	3,577	3,652	3,503	3,253	3,070
Fall	10	4,401	10/12/2015	2,923	2,815	2,739	2,709	2,771	2,961	3,420	3,644	3,671	3,816	3,887	3,928	4,053	4,160	4,236	4,279	4,286	4,331	4,281	4,401	4,329	4,122	3,870	3,563
Fall	10	4,144	10/13/2015	3,319	3,145	3,050	2,966	3,001	3,158	3,529	3,810	3,832	3,926	3,967	4,069	4,108	4,144	4,093	4,120	4,072	4,003	3,969	4,095	4,092	3,898	3,636	3,387
Fall	10	4,078	10/14/2015	3,193	3,080	2,983	2,932	2,931	3,117	3,507	3,821	3,768	3,836	3,904	3,989	3,995	4,064	4,078	4,072	4,027	4,004	3,911	4,024	3,973	3,793	3,551	3,334
Fall	10	4,028	10/15/2015	3,175	3,051	2,986	2,928	2,925	3,067	3,531	3,841	3,867	3,864	3,931	3,901	3,948	3,946	4,028	3,980	3,971	3,893	3,872	3,976	3,974	3,836	3,668	3,441
Fall	10	3,924	10/16/2015	3,233	3,118	3,009	2,889	2,910	3,034	3,416	3,644	3,720	3,832	3,899	3,924	3,883	3,891	3,885	3,838	3,795	3,736	3,704	3,752	3,748	3,613	3,515	3,310
Fall	10	3,594	10/17/2015	3,165	3,077	2,988	2,946	2,962	3,049	3,160	3,348	3,510	3,594	3,517	3,498	3,411	3,381	3,310	3,303	3,238	3,287	3,310	3,476	3,532	3,444	3,324	3,241
Fall	10	3,689	10/18/2015	3,102	3,047	3,003	3,056	3,065	3,165	3,295	3,463	3,581	3,627	3,541	3,435	3,390	3,304	3,295	3,234	3,254	3,299	3,410	3,616	3,689	3,605	3,472	3,328
Fall	10	4,370	10/19/2015	3,229	3,126	3,179	3,196	3,313	3,510	4,006	4,356	4,370	4,368	4,245	4,157	4,043	3,974	3,947	3,867	3,848	3,843	3,864	4,040	4,044	3,849	3,674	3,487
Fall	10	4,153	10/20/2015	3,361	3,258	3,176	3,159	3,185	3,361	3,762	4,054	4,077	4,153	4,091	4,083	4,089	4,053	4,034	3,999	3,942	3,954	3,909	4,042	4,015	3,889	3,651	3,454
Fall	10	4,158	10/21/2015	3,284	3,189	3,099	3,092	3,131	3,299	3,715	4,028	4,058	4,021	4,049	3,995	4,021	4,034	4,079	4,056	4,064	4,049	4,012	4,158	4,092	3,981	3,682	3,470
Fall	10	4,349	10/22/2015	3,285	3,094	3,043	2,990	3,021	3,205	3,588	3,867	3,911	3,961	4,041	4,048	4,183	4,177	4,258	4,349	4,316	4,294	4,210	4,336	4,229	4,029	3,744	3,493
Fall	10	4,243	10/23/2015	3,315	3,148	3,032	2,968	2,901	3,068	3,436	3,722	3,815	3,895	4,006	4,076	4,084	4,243	4,143	4,146	4,126	4,055	4,022	4,057	3,977	3,827	3,634	3,417
Fall	10	3,684	10/24/2015	3,247	3,057	2,980	2,870	2,851	2,876	2,996	3,169	3,253	3,412	3,500	3,545	3,524	3,546	3,518	3,520	3,474	3,539	3,616	3,684	3,622	3,457	3,309	3,132
Fall	10	3,562	10/25/2015	2,965	2,817	2,714	2,674	2,628	2,667	2,731	2,870	2,955	3,128	3,209	3,235	3,258	3,236	3,256	3,238	3,269	3,288	3,403	3,562	3,536	3,407	3,245	3,022
Fall	10	4,018	10/26/2015	2,848	2,779	2,722	2,729	2,810	3,082	3,477	3,797	3,818	3,887	3,918	3,951	3,946	3,883	3,868	3,805	3,749	3,815	3,894	4,018	3,968	3,807	3,592	3,362
Fall	10	4,137	10/27/2015	3,188	3,081	2,996	2,939	3,002	3,153	3,563	3,913	3,968	4,036	4,079	4,054	3,995	3,960	3,942	3,937	3,948	3,937	4,069	4,137	4,054	3,889	3,656	3,439
Fall	10	4,031	10/28/2015	3,275	3,148	3,063	3,049	3,024	3,192	3,533	3,830	3,901	3,926	3,977	3,986	3,991	3,964	3,944	3,918	3,851	3,838	3,850	4,031	3,977	3,842	3,606	3,388
Fall	10	3,900	10/29/2015	3,161	3,032	2,927	2,889	2,917	3,102	3,489	3,816	3,841	3,863	3,900	3,866	3,845	3,828	3,794	3,747	3,688	3,626	3,689	3,900	3,899	3,787	3,600	3,435
Fall	10	4,153	10/30/2015	3,371	3,262	3,216	3,190	3,202	3,385	3,841	4,126	4,153	4,145	4,116	4,060	3,957	3,869	3,794	3,754	3,720	3,673	3,703	3,856	3,849	3,730	3,635	3,523
Fall	10	3,611	10/31/2015	3,408	3,285	3,204	3,165	3,124	3,170	3,258	3,373	3,455	3,554	3,611	3,591	3,512	3,434	3,388	3,346	3,325	3,240	3,284	3,432	3,409	3,334	3,208	3,079
Fall	11	3,554	11/1/2015	2,902	2,768	2,722	2,681	2,660	2,705	2,798	2,896	3,086	3,187	3,194	3,182	3,199	3,190	3,183	3,186	3,253	3,392	3,554	3,486	3,508	3,347	3,203	3,029
Fall	11	3,955	11/2/2015	2,909	2,801	2,830	2,855	2,930	3,088	3,501	3,701	3,789	3,898	3,940	3,867	3,857	3,877	3,837	3,800	3,791	3,789	3,955	3,903	3,788	3,614	3,437	3,311
Fall	11	4,194	11/3/2015	3,156	3,045	3,009	2,989	3,000	3,186	3,507	3,725	3,756	3,858	3,917	3,838	3,994	4,053	4,092	4,057	4,063	4,053	4,194	4,106	3,992	3,807	3,555	3,336
Fall	11	4,307	11/4/2015	3,146	3,030	2,933	2,891	2,901	3,117	3,473	3,630	3,722	3,863	3,972	4,020	4,072	4,150	4,191	4,128	4,041	4,136	4,307	4,239	4,121	3,884	3,673	3,385
Fall	11	4,251	11/5/2015	3,220	3,082	2,999	2,945	2,957	3,130	3,492	3,751	3,815	3,956	4,001	4,094	4,155	4,223	4,251	4,202	4,131	4,209	4,247	4,209	4,137	4,003	3,795	3,541
Fall	11	4,091	11/6/2015	3,382	3,221	3,106	3,035	3,014	3,235	3,511	3,739	3,883	3,998	4,091	4,083	4,013	4,029	3,966	3,957	3,843	3,941	3,964	3,770	3,828	3,568	3,430	3,163
Fall	11	3,551	11/7/2015	3,031	2,933	2,796	2,746	2,694	2,771	2,947	3,050	3,204	3,281	3,424	3,329	3,306	3,265	3,234	3,228	3,207	3,377	3,551	3,487	3,496	3,408	3,297	3,138
Fall	11	3,713	11/8/2015	2,999	2,953	2,894	2,865	2,871	3,005	3,122	3,244	3,337	3,382	3,384	3,275	3,278	3,207	3,145	3,128	3,171	3,414	3,675	3,713	3,698	3,586	3,480	3,297
Fall	11	4,194	11/9/2015	3,204	3,175	3,160	3,193	3,241	3,441	3,837	4,107	4,120	4,179	4,139	4,137	4,107	4,023	3,976	3,963	3,907	4,063	4,194	4,113	4,029	3,872	3,636	3,442
Fall	11	4,097	11/10/2015	3,270	3,183	3,104	3,068	3,149	3,298	3,683	3,890	3,965	4,033	4,001	4,005	3,944	3,891	3,835	3,803	3,770	3,852	4,077	4,097	4,049	3,952	3,758	3,582
Fall	11	4,235	11/11/2015	3,482	3,381	3,363	3,341	3,419	3,592	4,046	4,235	4,214	4,166	4,066	3,987	3,922	3,839	3,832	3,828	3,778	3,922	4,127	4,042	3,973	3,817	3,604	3,421
Fall	11	3,987	11/12/2015	3,229	3,114	3,017	2,967	2,992	3,134	3,556	3,705	3,760	3,828	3,890	3,845	3,845	3,766	3,768	3,756	3,710	3,803	3,987	3,983	3,938	3,862	3,651	3,419
Fall	11	4,073	11/13/2015	3,302	3,234	3,171	3,176	3,204	3,427	3,863	4,073	4,068	4,002	4,008	3,951	3,900	3,850	3,793	3,723	3,684	3,826	4,043	3,985	3,948	3,854	3,750	3,621
Fall	11	3,945	11/14/2015	3,516	3,442	3,413	3,433	3,467	3,543	3,727	3,893	3,945	3,848	3,734	3,620	3,473	3,406	3,296	3,259	3,289	3,448	3,646	3,664	3,701	3,654	3,546	3,363
Fall	11	3,650	11/15/2015	3,273	3,270	3,229	3,190	3,325	3,373	3,523	3,607	3,650	3,555	3,435	3,350	3,314	3,241	3,224	3,213	3,262	3,425	3,648	3,645	3,594	3,539	3,482	3,326
Fall	11	4,320	11/16/2015	3,236	3,143	3,143	3,146	3,284	3,567	4,068	4,302	4,320	4,282	4,215	4,136	4,075	4,045	3,998	3,993	3,972	4,123	4,231	4,133	4,094	3,960	3,728	3,547
Fall	11	4,081	11/17/2015	3,356	3,262	3,160	3,135	3,171	3,361	3,753	4,002	4,026	4,059	4,081	4,037	4,024	3,992	3,909	3,844	3,815	4,021	4,076	4,072	3,937	3,830	3,610	3,369
Fall	11	4,124	11/18/2015	3,174	3,074	2,992	2,947	2,975	3,129	3,534	3,800	3,847	3,926	3,963	3,956	3,991	3,995	3,962	3,868	3,894	4,030	4,124	4,018	3,965	3,771	3,514	3,349
Fall	11	4,002	11/19/2015	3,172	3,043	2,938	2,960	2,995	3,213	3,682	3,889	3,878	3,858	3,868	3,858	3,810	3,786	3,771	3,723	3,755	3,745	4,001	4,002	3,999	3,927	3,733	3,536
Fall	11	4,520	11/20/2015	3,457	3,461	3,431	3,426	3,522	3,825	4,257	4,520	4,499	4,332	4,191	4,078	4,018	3,893	3,833	3,768	3,785	3,962	4,161	4,147	4,121	4,045	3,921	3,772
Fall	11	3,996	11/21/2015	3,628	3,520	3,493	3,399	3,404	3,532	3,717	3,820	3,879	3,825	3,740	3,617	3,597	3,555	3,535	3,630	3,777	3,930	3,995	3,996	3,960	3,909	3,820	3,657
Fall	11	4,483	11/22/2015	3,534	3,464	3,460	3,422	3,475	3,602	3,712	3,843	4,028	4,103	4,085	3,996	3,944	3,895	3,819	3,796	3,806	4,108	4,407	4,463	4,483	4,381	4,259	4,155
Fall	11	5,190	11/23/2015	4,098	4,050	4,040	4,140	4,201	4,486	4,851	5,190	5,080	4,894	4,706	4,546	4,366	4,292	4,170	4,104	4,062	4,356	4,535	4,591	4,575	4,417	4,336	4,118
Fall	11	4,803	11/24/2015	4,003	3,932	3,915	3,918	4,006	4,195	4,616	4,803	4,741	4,574	4,384	4,237	4,141	4,031	3,969	3,913	3,873	4,036	4,211	4,224	4,173	4,101	3,920	3,779
Fall	11	4,412	11/25/2015	3,621	3,539	3,566	3,564	3,563	3,800	4,087	4,281	4,412	4,319	4,219	4,063	4,018	3,896	3,811	3,735	3,717	3,817	3,975	3,971	3,928	3,765	3,649	3,396
Fall	11	3,348	11/26/2015	3,166	3,120	2,979	2,935	2,946	2,975	3,071	3,128	3,303	3,348	3,342	3,337	3,218	2,999	2,908	2,852	2,778	2,821	2,968	2,941	2,976	2,903	2,862	2,803
Fall	11	3,384	11/27/2015	2,661	2,645	2,594	2,640	2,628	2,746	2,857	3,013	3,007	3,163	3,203	3,193	3,157	3,103	3,064	3,055	3,062	3,235	3,384	3,341	3,265	3,189	3,115	2,920
Fall	11	3,557	11/28/2015	2,814	2,706	2,658	2,617	2,600	2,680	2,762	2,903	3,063	3,186	3,320	3,285	3,326	3,290	3,251	3,234	3,329	3,471	3,557	3,466	3,402	3,328	3,188	3,026
Fall	11	3,869	11/29/2015	2,865	2,811	2,770	2,736	2,766	2,848	2,961	3,060	3,224	3,377

Contains Proprietary Material
Do Not Distribute

Winter	12	18,383	12/23/2014	14,663	14,262	14,073	13,933	14,242	15,168	16,313	16,749	17,072	17,330	17,421	17,431	17,381	17,306	17,298	17,266	17,980	18,383	18,196	17,889	17,367	16,563	15,572	14,554
Winter	12	17,105	12/24/2014	13,767	13,279	12,909	12,731	12,935	13,503	14,321	14,942	15,503	16,095	16,336	16,337	16,176	16,063	15,967	16,024	16,596	17,105	16,880	16,776	16,654	16,412	15,820	15,192
Winter	12	16,909	12/25/2014	14,707	14,300	14,122	14,253	14,502	15,035	15,807	16,464	16,800	16,672	16,359	15,681	14,735	14,051	13,573	13,529	14,336	15,814	16,252	16,677	16,909	16,829	16,545	16,197
Winter	12	19,181	12/26/2014	16,024	16,097	16,272	16,481	17,050	17,944	18,879	19,181	18,920	18,120	17,478	16,754	16,177	15,789	15,545	15,661	16,537	17,727	17,833	17,769	17,524	17,012	16,254	15,419
Winter	12	16,966	12/27/2014	14,835	14,473	14,288	14,217	14,450	14,866	15,416	15,754	16,226	16,568	16,587	16,418	16,045	15,628	15,524	15,662	16,384	16,966	16,833	16,692	16,366	15,762	14,986	14,185
Winter	12	18,392	12/28/2014	13,647	13,257	13,136	13,103	13,300	13,647	14,370	15,226	15,959	16,387	16,373	16,355	16,442	16,507	16,401	16,663	17,614	18,369	18,392	18,214	17,786	17,182	16,210	15,535
Winter	12	20,459	12/29/2014	15,091	14,810	14,734	14,810	15,211	16,265	17,478	17,900	18,257	18,602	18,869	18,877	18,799	18,748	18,681	18,797	19,541	20,459	20,363	20,089	19,635	18,886	17,931	17,050
Winter	12	21,550	12/30/2014	16,628	16,502	16,482	16,601	16,987	18,134	19,403	19,884	20,113	20,121	19,789	19,371	18,903	18,579	18,316	18,369	19,376	21,070	21,526	21,550	21,340	20,908	20,212	19,527
Winter	12	21,954	12/31/2014	19,235	19,098	19,052	19,092	19,500	20,400	21,555	21,954	21,903	21,472	20,864	20,331	19,718	19,178	18,692	18,710	19,653	21,335	21,517	21,325	21,043	20,645	20,260	19,813
Winter	1	20,120	1/1/2015	19,644	19,554	19,552	19,529	19,685	19,896	20,120	20,078	19,953	19,839	19,585	19,115	18,708	18,387	18,168	18,314	19,011	19,663	19,518	19,108	18,759	18,092	17,342	16,596
Winter	1	19,476	1/2/2015	16,086	15,748	15,623	15,626	15,932	16,748	17,626	18,258	18,583	18,815	19,112	19,011	18,790	18,605	18,391	18,395	18,780	19,476	19,353	18,945	18,482	17,763	16,853	15,974
Winter	1	16,774	1/3/2015	15,323	14,821	14,537	14,444	14,471	14,763	15,142	15,527	15,925	16,173	16,295	16,122	15,869	15,709	15,593	15,693	16,251	16,774	16,564	16,116	15,711	15,087	14,216	13,488
Winter	1	19,314	1/4/2015	12,886	12,515	12,380	12,348	12,459	12,919	13,521	14,319	15,118	15,389	15,367	15,563	15,797	15,974	16,150	16,545	17,528	18,849	19,097	19,314	19,228	18,881	18,274	17,882
Winter	1	23,995	1/5/2015	17,811	17,896	18,144	18,641	19,633	21,475	23,357	23,769	23,361	22,742	22,075	21,431	20,821	20,307	19,779	19,877	21,075	23,123	23,846	23,995	23,855	23,137	22,191	21,506
Winter	1	24,561	1/6/2015	21,162	21,078	21,022	21,019	21,688	23,201	24,561	24,030	22,788	21,758	20,942	20,178	19,683	19,307	18,945	19,177	20,279	21,920	22,696	22,817	22,676	22,050	21,160	20,555
Winter	1	31,334	1/7/2015	20,293	20,245	20,150	20,340	20,938	22,472	24,078	24,321	24,284	24,425	24,660	24,812	24,952	25,222	25,461	26,193	27,909	30,145	30,983	31,334	31,073	30,498	29,844	29,274
Winter	1	32,751	1/8/2015	29,045	29,098	29,337	29,704	30,248	31,332	32,751	32,747	31,453	29,912	28,453	26,919	25,416	24,926	24,121	24,219	25,246	26,903	27,369	27,254	26,806	25,754	24,527	23,584
Winter	1	26,542	1/9/2015	23,116	22,993	23,029	23,285	23,728	25,150	26,542	26,343	25,534	24,567	23,608	22,560	21,833	21,224	20,947	21,166	22,310	24,225	24,748	24,776	24,917	24,811	24,370	23,946
Winter	1	28,007	1/10/2015	23,904	24,137	24,518	25,027	25,660	26,545	27,544	28,007	27,163	25,727	24,309	22,798	21,363	20,450	19,708	19,700	20,831	22,940	23,506	23,818	23,646	23,435	22,782	22,008
Winter	1	21,909	1/11/2015	21,433	21,091	20,745	20,606	20,617	20,909	21,426	21,895	21,909	21,253	20,499	20,007	19,936	19,587	19,361	19,357	19,979	20,977	20,965	20,640	20,071	19,235	18,132	17,276
Winter	1	21,805	1/12/2015	16,793	16,444	16,410	16,512	16,945	18,433	20,038	20,321	19,993	20,027	20,177	19,954	20,017	19,941	19,794	19,894	20,665	21,753	21,805	21,599	21,093	20,357	19,311	18,458
Winter	1	24,397	1/13/2015	18,132	18,035	18,119	18,464	19,144	20,812	22,476	22,742	22,621	22,794	22,878	22,886	22,687	22,585	22,409	22,747	23,456	24,397	24,379	24,060	23,551	22,665	21,381	20,588
Winter	1	23,859	1/14/2015	20,083	19,954	19,881	19,929	20,459	21,957	23,495	23,557	23,216	23,010	22,753	22,225	21,713	21,051	20,616	20,767	21,582	23,258	23,796	23,859	23,693	23,041	22,019	21,431
Winter	1	24,506	1/15/2015	21,184	21,149	21,171	21,215	21,757	23,111	24,506	24,450	23,913	23,503	23,170	22,769	22,424	21,948	21,660	21,748	22,314	23,357	23,716	23,563	23,343	22,578	21,613	20,905
Winter	1	25,153	1/16/2015	20,710	20,752	20,854	21,130	21,883	23,517	25,153	25,098	23,855	22,223	20,944	19,635	18,596	17,937	17,489	17,306	17,991	19,675	20,307	20,526	20,675	20,505	20,165	19,748
Winter	1	22,167	1/17/2015	19,549	19,405	19,521	19,803	20,366	21,003	21,782	22,167	21,581	20,197	18,951	17,917	16,981	16,193	15,697	15,620	16,164	17,764	18,211	18,245	18,066	17,630	17,040	16,386
Winter	1	18,047	1/18/2015	15,779	15,572	15,453	15,400	15,688	16,294	17,033	17,698	17,952	17,384	16,662	16,112	15,804	15,523	15,140	15,166	15,813	17,259	17,945	18,021	18,047	17,857	17,240	16,869
Winter	1	20,586	1/19/2015	16,736	16,771	17,022	17,322	17,946	19,097	20,227	20,586	19,932	18,962	18,283	17,656	17,142	16,640	16,325	16,272	16,679	18,262	18,794	18,813	18,530	17,815	16,862	16,190
Winter	1	20,528	1/20/2015	15,867	15,879	15,854	16,061	16,902	18,760	20,528	20,432	19,395	18,353	17,580	17,026	16,743	16,448	16,258	16,424	16,986	18,313	18,655	18,605	18,259	17,571	16,534	15,886
Winter	1	20,570	1/21/2015	15,694	15,651	15,639	16,138	16,981	18,684	20,570	20,569	19,566	18,380	17,612	16,982	16,685	16,437	16,242	16,242	17,031	18,675	19,386	19,514	19,581	19,117	18,230	17,646
Winter	1	21,778	1/22/2015	17,480	17,483	17,590	17,755	18,428	20,064	21,778	21,606	21,084	20,413	20,118	19,732	19,450	19,191	19,129	19,249	19,985	21,108	21,462	21,358	20,874	20,037	18,902	18,153
Winter	1	21,721	1/23/2015	17,639	17,394	17,328	17,357	17,947	19,583	21,031	21,315	21,260	21,242	21,237	21,046	20,955	20,771	20,718	20,593	21,067	21,721	21,586	21,158	20,820	20,228	19,365	18,590
Winter	1	21,629	1/24/2015	18,148	18,082	18,101	18,292	18,775	19,602	20,551	21,158	21,629	21,278	20,607	19,650	18,621	17,750	17,182	17,039	17,629	19,145	19,797	19,779	19,648	19,371	18,823	18,263
Winter	1	20,096	1/25/2015	17,965	17,946	17,915	18,100	18,428	18,923	19,625	20,096	19,856	18,902	17,735	17,000	16,529	16,304	16,285	16,546	17,326	18,435	18,764	18,709	18,361	17,759	16,903	16,274
Winter	1	23,222	1/26/2015	15,958	15,831	16,078	16,361	17,354	19,203	21,139	21,548	21,610	21,804	21,982	21,914	21,702	21,581	21,193	21,160	21,594	22,832	23,222	22,965	22,459	21,482	20,286	19,467
Winter	1	22,793	1/27/2015	19,039	18,814	18,806	18,816	19,555	21,211	22,793	22,709	22,123	21,434	20,932	20,638	20,427	20,172	20,001	20,104	20,579	21,804	22,413	22,383	21,955	21,169	20,146	19,429
Winter	1	23,918	1/28/2015	19,023	18,873	19,054	19,542	20,429	22,115	23,918	23,697	22,275	21,087	20,194	19,276	18,492	17,927	17,400	17,543	18,170	19,903	20,743	20,913	20,737	20,058	19,083	18,418
Winter	1	21,130	1/29/2015	18,003	17,794	17,656	17,788	18,340	19,733	21,130	20,909	20,225	19,721	19,112	18,301	17,653	17,241	16,894	17,009	17,589	18,927	19,425	19,524	19,263	18,564	17,675	16,993
Winter	1	21,482	1/30/2015	16,807	16,728	16,843	17,067	17,790	19,472	21,297	21,482	21,201	20,660	19,944	19,297	18,625	18,146	17,658	17,640	18,187	19,869	20,677	20,931	20,995	20,773	20,232	19,752
Winter	1	22,281	1/31/2015	19,804	19,848	20,011	20,297	20,640	21,258	21,843	22,281	22,193	21,598	20,421	19,224	18,379	17,684	17,488	17,430	18,051	19,023	19,255	19,165	18,904	18,369	17,635	16,880
Winter	2	18,412	2/1/2015	16,396	16,117	15,942	15,915	15,877	16,367	17,004	17,665	18,315	18,412	18,202	18,033	17,986	17,792	17,549	17,607	17,904	18,171	17,850	17,517	17,124	16,650	16,039	15,402
Winter	2	24,728	2/2/2015	15,158	15,190	15,444	15,935	17,208	19,415	21,677	22,370	22,769	23,113	23,431	23,308	22,903	22,378	22,021	22,175	22,747	24,105	24,728	24,692	24,354	23,603	22,588	21,948
Winter	2	26,710	2/3/2015	21,619	21,752	22,011	22,415	23,169	24,974	26,710	26,340	24,854	23,203	22,019	20,980	19,925	19,155	18,543	18,452	19,082	20,787	22,108	22,507	22,409	21,769	20,868	20,297
Winter	2	24,390	2/4/2015	20,060	20,058	20,198	20,522	21,091	22,777	24,390	24,019	22,672	21,059	19,938	19,046	18,462	17,954	17,749	17,946	18,636	19,931	20,679	20,657	20,451	19,746	18,884	18,145
Winter	2	24,058	2/5/2015	17,850	17,833	18,088	18,524	19,319	21,187	23,262	23,636	23,262	22,672	21,970	21,204	20,650	20,124	19,668	19,692	20,410	22,387	23,686	24,042	24,058	23,497	22,751	22,405
Winter	2	27,603	2/6/2015	22,415	22,601	22,970	23,489	24,342	26,065	27,603	27,109	25,347	23,467	21,946	20,493	19,306	18,549	17,888	17,670	18,005	19,447	20,485	20,671	20,619	20,153	19,583	19,123
Winter	2	20,969	2/7/2015	18,726	18,671	18,743	18,964	19,375	20,019	20,707	20,969	20,308	19,228	18,109	17,188	16,346	15,633	15,151	14,952	15,187	16,288	17,134	17,100	16,992	16,576	15,989	15,410
Winter	2	16,970	2/8/2015	14,933	14,761	14,693	14,860	14,891	15,368	15,921	16,419	16,773	16,621	16,044	15,609	15,474	15,227	15,127	15,155	15,552	16,510	16,970	16,777	16,190	15,487	14,576	13,702
Winter	2	20,915	2/9/2015	13,257	13,111	13,061	13,138	13,823	15,420	17,132	17,396	17,393	17,456	17,655	17,815	17,855	17,885	17,931	18,194	18,946	20,291	20,889	20,915	20,638	19,870	18,965	18,212
Winter	2	22,472	2/10/2015	17,919	17,917	18,019	18,172	18,919	20,649	22,406	22,472	22,309	21,872	21,429	20,709	20,037	19,264	18,636	18,495	18,945	20,521	21,734	21,900	21,845	21,201	20,300	19,669
Winter	2	24,311	2/11/2015	19,570	19,730	20,036	20,348	21,163	22,758	24,311	23,885	22,536	21,002	19,616	18,501	17,844	17,218	16,732	16,609	17,046	18,483	19,649	19,733	19,881	19,355	18,462	17,704
Winter	2	25,279	2/12/2015	17,400	17,273	17,426	17,731	18,510	20,343	22,134	22,294	22,132	22,041	22,171	22,083	21,857	21,458	20,977	21,041	21,798	23,596	24,987	25,279	25,151	24,557	23,652	22,921
Winter	2	26,488	2/13/2015	22,585	22,584	22,585	22,702	23,299	24,913	26,488	26,254	25,288	24,131	22,946	21,813	20,865	20,237	19,745	19,782	20,205	21,576	22,593	22,782	22,680	22,358	21,860	21,291
Winter	2	22,071	2/14/2015	21,028	20,838	20,725	20,759	21,030	21,513	21,982	22,071	21,686	20,944	20,040	18,962	18,265	17,805	17,523	17,682	18,217	19,154	20,211	20,490	20,870	21,215	21,388	21,578
Winter	2	26,623	2/15/2015	22,044	22,556	23,096	23,692	24,418	25,268	26,074	26,623	26,537	25,684	24,535	23,564	22,835	22,197	21,864	22,035	22,743	24,021	24,740	24,481	24,003	23,375	22,635	21,905
Winter	2	25,507	2/16/2015	21,531	21,316	21,206	21,328	21,801	22,773	23,674	24,024	24,457	24,780	25,017	25,099	25,113	24,774	24,476	24,396	24,568	25,407	25,507	24,987	24,360	23,818	23,235	22,777
Winter	2	26,413	2/17/2015	22,828	22,827	23,001	23,284	23,861	24,949	26,042	26,413	26,396	26,009	25,472	24,869	24,105	23,385	22,907	22,865	23,470	24,842	25,909	25,915	25,716	25,198	24,486	24,030
Winter	2	28,354	2/18/2015	23,849	23,846	23,888	23,991	24,259	25,137	26,132	26,403	26,300	25,804	25,412	25,063	24,614	24,351	24,305	24,587	25,329	26,787	28,095	28,354	28,289	28,052	27,619	27,412
Winter	2	32,164	2/19/2015	27,487	27,882	28,371	28,857	29,763	31,175	32,164	31,921	31,069	30,169	29,301	28,206	27,377	26,661	26,110	25,973	26,494	28,270	29,636	29,968	30,085	29,674	28,933	28,283
Winter	2	30,159	2/20/2015	28,129	28,172	28,157	28,326	28,643	29,582	30,159	30,080	29,591	28,852	27,831	26,989	26,364	26,056	25,915	25,931	26,198	27,069	27,257	26,710	25,980	25,033	23,895	22,881
Winter	2	22,960	2/21/2015	22,313	22,170	21,829	21,715	21,687	21,747	22,004	22,224	22,678	22,960	22,861	22,642	22,094	21,493	21,131	20,999	21,043	21,369	21,652	21,279	20,789	20,182	19,422	18,774
Winter	2	22,140	2/22/2015	18,363	18,059	18,024	18,172	18,459	18,872	19,488	20,160	20,768	20,834	20,515	20,165	19,791	19,523	19,395	19,602	20,281	21,379	22,140	22,097	21,821	21,342	20,675	20,126
Winter	2	26,075	2/23/2015	19,961	20,112	20,328	20,773	21,638	23,184	24,595	25,085	25,140	24,795	24,180	23,536	23,016	22,943	23,038	23,211	23,735	24,999	26,075	26,034	25,730	24,963	23,852	23,044
Winter	2	25,894	2/24/2015	22,588	22,428	22,556	22,919	23,502	24,620	25,838	25,894	25,547	25,108	24,605	23,930	23,303	22,682	22,354	22,017	22,223	23,254	24,755	24,959	24,806	24,422	23,665	23,026
Winter	2	26,595	2/25/2015	22,896	22,957	23,111	23,411	24,117	25,460	26,595	26,391	25,302	24,180	23,437	22,815	22,459	22,411	22,295	22,507	22,983	23,714	24,361	23,812	23,324	22,602	21,670	20,909
Winter	2	23,883	2/26/2015	20,519	20,292	20,283	20,483	21,001	21,955	22,874	23,208	22,755	22,288	21,824	21,463	21,044	20,777	20,504	20,757	21,476	22,612	23,676	23,883	23,702	23,125	22,435	21,750
Winter	2	26,135	2/27/2015	21,530	21,491	21,736	22,116	22,894	24,501	25,974	26,135	25,544	24,706	23,676	22,859	21,991	21,197	20,615	20,476	21,014	22,464	23,874	24,169	24,005	23,878	23,145	22,428
Winter	2	23,540	2/28/2015	22,160	21,900	21,782	21,718	22,025	22,627	23,205	23,540	23,526	22,819	21,770	20,503	19,215	18,133	17,539	17,267	17,519	18,624	19,613	19,650	19,483	18,996	18,349	17,734
Spring	3	18,928	3/1/2015	17,168	16,890	16,784	16,851	16,910	17,237	17,758	18,239	18,789	18,627	18,110	17,691	17,510	17,263	17,171	17,264	17,598	18,266	18,911	18,928	18,526	17,896	17,094	16,354
Spring	3	21,084	3/2/2015	16,070	15,883	16,025	16,411	17,222	18,943	20,739	21,084	20,942	20,641	20,306	19,744	19,226	18,660	18,150	18,022	18,415	19,557	20,673	20,680	20,196	19,438	18,456	17,386
Spring	3	19,561	3/3/2015	16,776	16,471	16,355	16,300	16,864	18,288	19,561	19,515	19,128	18,828	18,668	18,373	17,823	17,713	17,488	17,389	17,746	18,405	18,992	18,735	18,157	17,146	15,782	14,819
Spring	3	20,260	3/4/2015	14,290	13,977	13,735	13,620	14,164	15,559	16,929	17,006	16,935	16,999	17,144	17,140	17,310	17,520	17,606	18,015	18,579	19,640	20,260	20,194	19,949	19,370	18,710	18,264
Spring	3	25,938	3/5/2015	18,162	18,310	18,663	19,122	19,920	21,170	22,202	22,709	23,342	23,694	24,002	24,047	24,003	23,849	23,574	23,487	23,727	24,634	25,909	25,938	25,656	25,244	24,590	24,216
Spring	3	27,804	3/6/2015	24,158	24,301	24,612	25,011	25,739	27,140	27,804	27,519	26,238	25,025	23,903	22,842	21,849	20,920	20,092	19,697	19,695	20,758	22,502	22,948	23,093	22,904	22,524	21,966
Spring	3	23,893	3/7/2015	21,880	21,902	22,029	22,312	22,810	23,526	23,893	23,318	22,134	20,824	19,624	18,478	17,406	16,567	16,060	15,733	15,788	16,564	18,073	18,306	18,434	18,259	17,826	17,419
Spring	3	20,150	3/8/2015	17,352	0	19,275	17,715	18,074	18,663	19,599	20,150	19,810	18,450	17,157	16,256	15,680	15,233	14,829	14,877	15,103	15,509	16,269	17,317	17,144	16,712	15,813	14,989
Spring	3	18,491	3/9/2015	14,516	14,381	14,311	14,504	15,050	16,539	18,202	18,491	18,323	18,140	18,040	17,812	17,270	16,928	16,582	16,577	16,719	16,988	17,741	18,435	18,132	17,365	16,328	15,224
Spring	3	17,908	3/10/2015	14,589	14,230	14,202	14,243	14,617	15,848	17,349	17,626	17,264	17,249	17,317	17,308	17,122	16,888	16,600	16,565	16,631	16,866	17,366	17,908	17,394	16,634	15,466	14,452
Spring	3	17,435	3/11/2015	13,728	13,270	13,106	13,070	13,385	14,644	16,248	16,546	16,440	16,497	16,664	16,693	16,594	16,521	16,263	16,208	16,242	16,408	16,778	17,435	17,246	16,643	15,582	14,603
Spring	3	17,485	3/12/2015	14,066	13,717	13,628	13,702	14,254	15,692	17,314	17,485	17,195	16,956	16,777	16,500	16,273	16,117	15,894	15,915	15,849	16,013	16,402	17,098	16,936	16,173	15,081	14,046
Spring	3	17,364	3/13/2015	13,411	13,043	12,744	12,695	13,062	14,369	15,944	16,319	16,360	16,603	16,878	16,825	16,841	16,771	16,655	16,468	16,482	16,669	17,027	17,364	17,027	16,500	15,538	14,606
Spring	3	16,302	3/14/2015	14,036	13,550	13,364	13,267	13,348	13,895	14,400	14,939	15,679	16,221	16,302	16,132	15,765	15,435	15,124	15,039	14,968	15,043	15,346	15,941	15,582	15,091	14,353	13,518
Spring	3	15,747	3/15/2015	12,957	12,665	12,529	12,492	12,767	13,367	14,021	14,766	15,187	14,983	14,412	14,172	14,066	13,756	13,698	13,849	14,046	14,192	14,545	15,747	15,739	15,120	14,092	13,158
Spring	3	17,792	3/16/2015	14,627	12,865	13,177	13,965	15,725	17,580	17,792	17,252	16,669	16,312	16,169	16,049	15,981	15,998	16,044	16,096	16,092	16,260	17,156	17,156	16,954	15,990	14,651	13,532
Spring	3	16,913	3/17/2015	12,831	12,469	12,257	12,303	12,868	14,222	15,749	15,890	15,721	15,560	15,607	15,802	15,920	15,940	15,974	15,914	15,907	15,899	15,992	16,913	16,773	15,897	14,669	13,614
Spring	3	17,794	3/18/2015	13,054	12,785	12,580	12,743	13,477	14,978	16,736	17,082	17,122	17,153	17,081	16,943	16,707	16,326	15,978	16,048	16,239	16,558	17,046	17,794	17,581	16,900	15,699	14,696
Spring	3	17,956	3/19/2015	14,096	13,902	13,757	13,754	14,371	15,768	17,435	17,676	17,654	17,668	17,859	17,571	17,406	17,273	17,009	16,930	16,918	17,019	17,345	17,956	17,707	17,006	15,871	14,945
Spring	3	17,048	3/20/2015	14,333	13,976	13,763	13,655	14,104	15,331	16,833	16,960	16,914	16,907	17,048	17,041	16,738	16,573	16,367	16,156	16,170	16,225	16,398	16,948	16,692	16,145	15,368	14,534
Spring	3	15,992	3/21/2015	13,995	13,526	13,466	13,422	13,731	14,348	15,119	15,607	15,992	15,915	15,559	15,125	14,686	14,380	14,168	14,076	14,188	14,362	14,745	15,555	15,354	14,850	14,118	13,338
Spring	3	16,165	3/22/2015	12,762	12,513	12,344	12,379	12,548	12,889	13,610	14,201	14,994	15,041	14,635	14,492	14,533	14,391	14,190	14,312	14,535	14,839	15,363	16,165	15,989	15,268	14,355	13,569
Spring	3	17,267	3/23/2015	13,099	12,972	12,901	13,145	13,796	15,512	17,112	17,267	16,820	16,413	16,263	15,984	15,916	15,822	15,689	15,719	15,749	15,867	16,017	16,969	16,749	15,763	14,663	13,538
Spring	3	17,131	3/24/2015	13,037	12,760	12,580	12,755	13,416	14,971	16,620	16,692	16,378	16,119	16,010	15,831	15,776	15,902	15,941	16,095	16,160	16,155	16,304	17,131	17,006	16,059	14,812	13,612
Spring	3	17,428	3/25/2015	13,029	12,624	12,424	12,379	12,680	14,005	15,461	15,533	15,553	15,630	15,887	16,063	16,115	16,377	16,487	16,573	16,795	16,758	16,680	17,428	17,303	16,431	15,075	13,845
Spring	3	17,586	3/26/2015	13,108	12,581	12,366	12,255	12,565	13,781	15,220	15,272	15,446	15,665

Contains Proprietary Material
Do Not Distribute

Spring	4	16,645	4/30/2015	12,830	12,427	12,267	12,479	13,124	14,491	15,745	15,924	15,815	15,916	15,947	15,741	15,808	15,964	15,936	15,975	16,008	15,946	15,860	16,143	16,645	15,929	14,576	13,683
Spring	5	16,216	5/1/2015	13,108	12,797	12,698	12,916	13,476	14,912	16,050	16,216	15,963	15,878	15,855	15,666	15,319	15,266	15,303	15,455	15,575	15,479	15,232	15,300	15,858	15,319	14,500	13,551
Spring	5	15,733	5/2/2015	12,840	12,490	12,342	12,376	12,691	13,131	13,433	14,065	14,470	14,609	14,547	14,565	14,534	14,960	15,143	15,495	15,712	15,733	15,591	15,462	15,548	14,858	13,879	12,808
Spring	5	16,884	5/3/2015	12,141	11,694	11,435	11,397	11,547	11,830	12,057	12,968	13,642	13,853	14,074	14,293	14,801	15,276	15,787	16,248	16,679	16,884	16,588	16,579	16,777	15,963	14,551	13,259
Spring	5	19,683	5/4/2015	12,497	11,930	11,821	11,873	12,392	13,697	14,812	15,427	15,815	16,379	17,102	17,591	18,119	18,609	18,998	19,431	19,683	19,682	19,393	18,854	19,102	17,830	15,962	14,478
Spring	5	20,451	5/5/2015	13,562	12,919	12,607	12,452	12,814	13,964	14,977	15,617	16,079	16,689	17,409	18,108	18,739	19,370	19,828	20,205	20,451	20,446	19,946	19,505	19,548	18,292	16,431	14,851
Spring	5	21,328	5/6/2015	13,773	13,100	12,807	12,694	13,002	14,128	15,224	15,782	16,411	17,042	17,786	18,557	19,289	19,944	20,564	21,009	21,328	21,218	20,631	19,889	19,780	18,523	16,696	15,011
Spring	5	21,940	5/7/2015	14,009	13,243	12,786	12,702	13,056	14,224	15,218	15,887	16,516	17,352	18,362	19,162	19,981	20,669	21,163	21,640	21,940	21,774	21,249	20,605	20,410	19,064	17,145	15,435
Spring	5	21,916	5/8/2015	14,299	13,616	13,209	13,115	13,457	14,513	15,544	16,280	17,119	18,149	19,201	19,995	20,547	21,342	21,589	21,916	21,907	21,445	20,702	19,895	19,821	18,647	17,048	15,633
Spring	5	20,790	5/9/2015	14,422	13,622	13,195	12,886	12,838	13,086	13,352	14,416	15,652	16,713	17,645	18,338	18,991	19,696	20,119	20,544	20,790	20,502	19,888	19,414	19,212	18,099	16,694	15,277
Spring	5	21,859	5/10/2015	14,103	13,242	12,923	12,644	12,419	12,476	12,772	13,951	15,317	16,570	17,696	18,762	19,784	20,567	21,179	21,654	21,859	21,651	21,064	20,731	20,591	19,281	17,527	15,797
Spring	5	22,070	5/11/2015	14,716	14,168	13,756	13,632	14,001	15,087	16,292	17,117	17,986	19,105	20,131	20,958	21,618	22,008	21,991	22,070	22,050	21,609	21,093	20,633	20,849	19,541	17,590	15,805
Spring	5	20,076	5/12/2015	14,704	13,998	13,650	13,528	13,802	14,938	16,023	16,703	17,374	17,973	18,463	18,801	19,128	19,483	19,834	20,076	19,930	19,360	18,663	18,368	18,494	17,407	15,654	14,317
Spring	5	19,600	5/13/2015	13,478	12,978	12,662	12,569	13,020	13,970	14,894	15,453	15,648	16,081	16,482	16,846	17,380	17,914	18,581	19,074	19,560	19,600	19,083	18,417	18,611	17,551	15,916	14,508
Spring	5	19,328	5/14/2015	13,539	12,985	12,717	12,631	12,883	14,135	15,385	15,736	16,093	16,498	16,984	17,560	18,011	18,615	19,047	19,278	19,328	19,038	18,803	18,719	19,071	18,109	16,601	15,098
Spring	5	20,966	5/15/2015	14,278	13,710	13,286	13,067	13,433	14,549	15,631	16,487	17,282	18,159	18,913	19,531	20,291	20,878	20,881	20,966	20,919	20,429	19,540	19,054	19,210	18,351	16,857	15,542
Spring	5	18,860	5/16/2015	14,501	13,811	13,382	13,120	13,145	13,290	13,743	14,718	15,943	16,645	17,307	17,662	17,923	18,233	18,546	18,763	18,860	18,735	18,352	18,170	18,244	17,540	16,342	14,893
Spring	5	19,603	5/17/2015	13,938	13,321	12,927	12,642	12,633	12,820	12,884	13,909	15,326	16,311	16,988	17,495	17,903	18,347	18,917	19,313	19,603	19,461	18,973	18,804	18,857	17,838	16,435	15,054
Spring	5	20,806	5/18/2015	14,199	13,565	13,185	13,178	13,637	14,765	16,046	16,816	17,542	18,216	19,123	19,766	20,207	20,597	20,804	20,741	20,806	20,753	20,439	20,050	20,077	18,983	17,380	15,787
Spring	5	22,348	5/19/2015	14,808	14,167	13,745	13,583	14,028	15,107	16,200	16,892	17,447	18,075	18,855	19,551	20,333	21,096	21,784	22,185	22,348	22,057	21,308	20,527	20,448	19,176	17,357	15,701
Spring	5	20,883	5/20/2015	14,531	13,617	13,151	13,083	13,239	14,089	15,075	15,817	16,433	17,227	17,943	18,610	19,348	20,000	20,508	20,827	20,883	20,654	20,107	19,713	19,705	18,599	16,942	15,516
Spring	5	16,732	5/21/2015	14,497	13,927	13,530	13,417	13,673	14,661	15,606	16,138	16,554	16,603	16,732	16,487	16,232	16,117	16,072	15,874	15,817	15,682	15,657	15,799	16,368	15,841	14,734	13,693
Spring	5	16,694	5/22/2015	12,999	12,586	12,423	12,512	12,982	13,918	14,870	15,364	15,575	15,668	15,647	15,702	15,594	15,842	16,142	16,451	16,662	16,694	16,370	15,833	16,194	15,624	14,541	13,471
Spring	5	18,302	5/23/2015	12,641	12,088	11,855	11,798	11,864	11,978	12,282	12,960	13,662	14,240	14,766	15,273	15,773	16,361	17,050	17,656	18,217	18,302	17,986	17,195	17,192	16,442	15,164	13,925
Spring	5	19,620	5/24/2015	13,003	12,401	11,955	11,654	11,701	11,703	11,757	12,826	14,102	15,199	15,899	16,737	17,581	18,316	18,876	19,353	19,620	19,441	18,796	18,161	18,052	17,164	15,781	14,514
Spring	5	18,152	5/25/2015	13,669	13,008	12,601	12,436	12,480	12,493	12,623	13,343	14,305	15,389	16,267	16,755	17,154	17,458	17,642	17,944	18,151	18,152	17,895	17,671	17,878	17,020	15,642	14,601
Spring	5	20,850	5/26/2015	13,743	13,300	12,981	12,882	13,205	14,099	15,185	16,329	17,205	17,907	18,728	19,365	19,920	20,479	20,722	20,818	20,850	20,646	20,285	19,764	19,856	18,976	17,422	15,865
Spring	5	20,877	5/27/2015	14,806	14,115	13,744	13,590	14,032	14,857	15,580	16,616	17,458	18,204	19,328	19,955	20,567	20,831	20,736	20,877	20,845	20,442	19,833	19,350	19,484	18,662	17,155	15,676
Spring	5	22,117	5/28/2015	14,655	14,015	13,642	13,572	13,958	14,688	15,604	16,432	17,193	18,063	18,973	19,612	20,241	21,000	21,602	21,983	22,117	21,889	21,290	20,723	20,872	19,932	18,276	16,588
Spring	5	21,826	5/29/2015	15,550	14,765	14,264	14,042	14,368	15,002	15,935	16,990	17,762	18,722	19,612	20,242	20,809	21,419	21,701	21,826	21,745	21,085	20,221	19,617	19,793	19,008	17,582	16,122
Spring	5	21,182	5/30/2015	15,109	14,167	13,651	13,445	13,407	13,416	13,770	14,928	16,574	17,959	19,105	19,955	20,378	20,859	21,060	21,148	21,182	20,983	20,246	19,480	19,256	18,406	16,993	15,681
Spring	5	18,772	5/31/2015	14,421	13,538	13,069	12,766	12,709	12,693	12,817	13,806	15,113	16,106	16,882	17,682	18,275	18,639	18,772	18,703	18,572	18,405	17,946	17,572	17,645	16,922	15,653	14,429
Summer	6	19,042	6/1/2015	13,677	13,056	12,863	12,806	13,185	13,985	14,937	15,841	16,460	17,017	17,753	18,059	18,362	18,629	18,770	19,042	19,011	18,768	18,411	17,934	18,080	17,408	15,997	14,763
Summer	6	18,320	6/2/2015	13,723	13,174	12,809	12,681	13,150	13,924	14,740	15,599	16,188	16,711	17,229	17,571	17,806	18,141	18,300	18,264	18,320	18,078	17,844	17,578	17,829	17,036	15,730	14,519
Summer	6	19,421	6/3/2015	13,592	13,000	12,693	12,672	13,017	13,615	14,453	15,198	15,726	16,338	17,080	17,586	17,973	18,447	18,936	19,210	19,421	19,313	18,883	18,267	18,295	17,647	16,117	14,766
Summer	6	22,217	6/4/2015	13,728	13,164	12,687	12,480	12,765	13,488	14,478	15,426	16,241	17,123	18,089	18,793	19,694	20,513	21,168	21,799	22,217	22,152	21,487	20,570	20,450	19,552	17,781	16,201
Summer	6	22,811	6/5/2015	15,054	14,240	13,749	13,548	13,774	14,295	15,217	16,465	17,646	18,903	20,214	21,198	21,820	22,298	22,627	22,811	22,729	22,271	21,603	20,805	20,731	19,713	18,121	16,386
Summer	6	23,587	6/6/2015	15,135	14,208	13,653	13,436	13,253	13,294	13,548	14,621	16,165	17,890	19,407	20,553	21,480	22,311	22,832	23,387	23,587	23,344	22,754	21,743	21,165	20,038	18,400	16,653
Summer	6	24,356	6/7/2015	15,337	14,500	14,019	13,460	13,118	12,904	13,230	14,662	16,472	18,298	19,797	21,032	22,236	23,073	23,286	23,792	24,277	24,356	23,779	22,850	22,392	21,144	19,212	17,524
Summer	6	24,006	6/8/2015	16,311	15,531	14,873	14,755	14,885	15,725	16,772	18,159	19,509	21,007	22,387	23,331	23,932	24,006	23,864	23,247	22,446	21,880	21,215	20,613	20,573	19,631	17,926	16,471
Summer	6	25,219	6/9/2015	15,387	14,802	14,361	14,229	14,392	15,071	16,057	17,337	18,377	19,610	21,014	22,135	23,097	23,994	24,736	25,001	25,219	24,958	24,288	23,097	22,618	21,404	19,295	17,467
Summer	6	26,195	6/10/2015	16,176	15,174	14,638	14,264	14,431	15,048	16,104	17,374	18,787	20,362	22,082	23,323	24,267	25,090	25,524	26,009	26,195	25,936	25,356	24,257	23,730	22,426	20,299	18,396
Summer	6	26,351	6/11/2015	16,978	16,025	15,379	15,075	15,272	15,704	16,623	18,118	19,661	21,498	22,914	24,208	25,166	25,793	26,135	26,351	26,240	25,823	25,178	24,050	23,606	22,601	20,496	18,741
Summer	6	25,093	6/12/2015	17,440	16,480	15,776	15,418	15,565	16,030	16,877	18,221	19,687	20,909	22,282	23,318	24,008	24,512	24,968	25,051	25,093	24,824	24,058	22,941	22,535	21,648	19,915	18,311
Summer	6	24,846	6/13/2015	16,881	16,102	15,395	14,963	14,745	14,784	15,215	16,401	18,011	19,509	20,885	21,975	22,935	23,639	24,227	24,587	24,846	24,579	23,860	22,830	22,245	20,933	19,282	17,724
Summer	6	25,286	6/14/2015	16,428	15,543	14,764	14,306	14,162	13,896	14,161	15,627	17,478	19,153	20,585	21,888	22,941	23,767	24,463	24,901	25,286	25,230	24,669	23,618	22,965	21,915	20,075	18,340
Summer	6	27,989	6/15/2015	16,972	16,013	15,452	15,219	15,330	15,921	17,116	18,780	20,570	22,363	24,124	25,447	26,347	27,072	27,572	27,820	27,989	27,593	27,058	25,984	25,426	24,008	21,854	19,824
Summer	6	28,167	6/16/2015	18,326	17,243	16,433	16,093	16,269	16,688	17,679	19,352	21,178	23,121	24,884	26,084	26,980	27,741	28,028	28,082	28,167	27,939	27,283	26,334	25,881	24,534	22,288	20,418
Summer	6	28,542	6/17/2015	18,845	17,725	16,967	16,330	16,404	16,727	17,629	19,102	20,826	22,779	24,594	25,866	26,839	27,693	28,225	28,469	28,542	28,156	27,297	26,018	25,529	24,095	22,057	20,086
Summer	6	26,732	6/18/2015	18,607	17,625	16,789	16,452	16,511	17,004	17,937	19,272	20,876	22,586	24,251	25,440	26,137	26,706	26,732	26,692	26,431	25,942	25,311	24,351	24,172	23,019	21,198	19,365
Summer	6	25,489	6/19/2015	18,080	17,320	16,681	16,292	16,501	17,175	18,002	19,151	20,395	21,786	23,045	24,033	24,822	25,350	25,462	25,489	25,208	24,471	23,350	22,288	22,013	21,224	19,781	18,238
Summer	6	24,317	6/20/2015	17,117	16,345	15,887	15,549	15,447	15,572	15,786	16,682	18,035	19,311	20,575	21,471	22,243	22,966	23,508	24,098	24,317	24,143	23,602	22,703	22,115	21,158	19,654	18,028
Summer	6	26,005	6/21/2015	16,834	15,982	15,376	14,964	14,878	14,750	15,026	16,602	18,575	20,433	22,027	23,405	24,424	25,206	25,640	25,869	26,005	25,618	24,901	23,843	23,311	22,092	20,422	18,708
Summer	6	27,806	6/22/2015	17,472	16,496	15,897	15,667	16,001	16,404	17,407	19,014	20,615	22,500	24,347	25,723	26,773	27,431	27,773	27,806	27,684	27,094	26,100	25,024	24,675	23,475	21,510	19,674
Summer	6	28,865	6/23/2015	18,431	17,463	16,737	16,386	16,639	17,235	18,048	19,555	21,235	22,964	24,608	25,953	26,975	27,830	28,570	28,852	28,865	28,589	27,859	27,073	26,570	25,207	23,143	21,065
Summer	6	27,774	6/24/2015	19,386	18,181	17,379	16,829	16,863	17,392	18,122	19,353	20,893	22,470	24,030	25,093	26,117	26,874	27,482	27,774	27,405	26,750	25,665	24,630	24,145	22,905	20,921	19,072
Summer	6	28,575	6/25/2015	17,924	16,751	16,228	15,836	16,022	16,558	17,383	18,693	20,235	21,827	23,719	25,213	26,440	27,473	27,977	28,500	28,575	28,289	27,659	26,636	26,079	24,771	22,688	20,686
Summer	6	27,694	6/26/2015	19,297	18,200	17,487	17,030	17,093	17,398	18,035	19,321	21,071	23,001	24,826	26,230	27,047	27,597	27,694	27,346	26,583	25,378	23,903	22,672	22,165	20,896	19,436	18,316
Summer	6	20,763	6/27/2015	16,729	15,864	15,452	15,131	14,932	15,130	15,236	16,043	17,041	18,016	18,783	19,354	19,912	20,293	20,564	20,716	20,763	20,660	20,194	19,081	18,882	18,201	16,773	15,370
Summer	6	21,434	6/28/2015	14,229	13,321	12,920	12,557	12,455	12,257	12,570	13,668	15,090	16,249	17,187	17,901	18,861	19,603	20,376	21,007	21,404	21,434	21,007	20,034	19,490	18,554	16,954	15,565
Summer	6	23,955	6/29/2015	14,509	13,852	13,345	13,204	13,596	14,273	15,132	16,065	17,252	18,342	19,411	20,471	21,465	22,343	22,967	23,705	23,955	23,862	23,314	22,479	22,127	21,094	19,258	17,385
Summer	6	23,191	6/30/2015	16,229	15,514	14,923	14,611	14,754	15,348	16,172	17,076	18,163	19,354	20,598	21,489	22,070	22,704	22,989	23,191	23,162	22,698	22,030	21,324	21,205	20,352	18,768	17,273
Summer	7	20,335	7/1/2015	16,142	15,503	14,897	14,661	14,816	15,348	16,078	16,920	17,682	18,515	19,342	19,851	20,236	20,335	20,301	20,266	20,199	19,908	19,574	19,157	19,355	18,915	17,615	16,270
Summer	7	21,279	7/2/2015	15,329	14,726	14,364	14,313	14,529	15,309	15,976	16,815	17,519	18,131	18,856	19,354	19,791	20,315	20,913	21,129	21,279	20,999	20,562	20,002	20,112	19,412	18,109	16,634
Summer	7	18,333	7/3/2015	15,558	14,804	14,327	14,088	14,038	14,151	14,359	15,022	15,858	16,774	17,341	17,685	17,919	18,179	18,292	18,302	18,333	18,174	17,689	17,375	17,506	17,017	16,229	15,096
Summer	7	18,523	7/4/2015	14,223	13,472	12,977	12,904	12,796	12,841	12,913	13,552	14,544	15,702	16,506	17,211	17,771	18,129	18,375	18,523	18,455	18,099	17,522	16,891	16,584	16,194	15,662	14,702
Summer	7	20,767	7/5/2015	13,744	13,127	12,777	12,406	12,261	12,362	12,566	13,441	14,608	15,637	16,581	17,583	18,569	19,282	19,810	20,341	20,672	20,767	20,420	19,724	19,403	18,695	17,340	15,893
Summer	7	24,648	7/6/2015	14,846	14,143	13,630	13,527	13,804	14,494	15,327	16,438	17,444	18,656	19,887	21,036	22,086	23,109	23,769	24,344	24,648	24,504	23,971	23,034	22,689	21,567	19,765	17,979
Summer	7	26,232	7/7/2015	16,774	15,913	15,377	15,037	15,287	15,868	16,722	17,954	19,453	20,876	22,467	23,693	24,715	25,540	26,113	26,232	26,135	25,605	24,570	23,634	23,224	22,147	20,346	18,565
Summer	7	26,910	7/8/2015	17,248	16,301	15,799	15,364	15,385	15,986	16,826	18,071	19,395	21,137	22,825	24,067	24,945	25,889	26,531	26,867	26,910	26,668	25,920	24,782	24,376	23,221	21,236	19,395
Summer	7	27,653	7/9/2015	18,002	17,074	16,448	16,082	16,255	16,842	17,561	19,013	20,636	22,432	24,160	25,243	26,131	26,825	27,337	27,595	27,653	27,382	26,639	25,473	24,873	23,642	21,616	19,578
Summer	7	27,875	7/10/2015	18,141	17,148	16,294	15,913	15,970	16,446	17,264	18,572	20,381	22,307	24,047	25,354	26,392	27,184	27,607	27,833	27,875	27,336	26,511	25,063	24,519	23,442	21,638	19,724
Summer	7	26,552	7/11/2015	18,298	17,264	16,500	15,968	15,713	15,608	15,737	17,012	18,910	20,908	22,816	24,264	25,297	25,972	26,258	26,552	26,436	26,257	25,643	24,582	23,976	22,705	20,979	19,232
Summer	7	26,089	7/12/2015	17,844	16,724	15,974	15,569	15,329	15,137	15,280	16,629	18,648	20,509	22,106	23,151	23,895	24,682	25,217	25,794	26,089	25,965	25,452	24,662	24,105	22,963	21,237	19,570
Summer	7	29,027	7/13/2015	18,283	17,467	16,704	16,371	16,577	17,132	17,951	19,658	21,382	23,331	25,268	26,412	27,544	28,247	28,829	29,027	28,924	28,491	27,671	26,759	26,209	24,969	22,871	21,064
Summer	7	27,681	7/14/2015	19,696	18,696	18,100	17,682	17,835	18,606	19,236	20,486	21,576	22,995	24,214	25,398	26,556	27,482	27,681	27,129	25,778	24,538	23,320	22,314	21,884	20,960	19,480	17,996
Summer	7	26,826	7/15/2015	16,820	16,118	15,704	15,422	15,427	16,138	16,960	18,150	19,409	20,789	22,377	23,601	24,696	25,644	26,320	26,730	26,826	26,422	25,630	24,355	23,851	22,636	20,729	18,846
Summer	7	27,314	7/16/2015	17,419	16,400	15,681	15,428	15,615	16,170	17,047	18,328	19,803	21,513	23,094	24,236	25,271	26,200	26,842	27,253	27,314	27,095	26,615	25,477	24,930	23,595	21,596	19,608
Summer	7	28,743	7/17/2015	18,221	17,201	16,519	16,115	16,294	16,817	17,606	18,842	20,554	22,533	24,547	25,911	26,978	27,831	28,395	28,710	28,743	28,353	27,638	26,444	25,870	24,613	22,589	20,958
Summer	7	27,264	7/18/2015	19,344	18,176	17,346	16,809	16,509	16,428	16,573	17,914	20,082	22,159	24,146	25,540	26,283	26,786	27,150	27,144	27,264	27,051	26,463	25,331	24,818	23,689	22,021	20,269
Summer	7	27,311	7/19/2015	18,851	17,697	16,851	16,287	16,134	15,945	16,066	17,578	19,828	21,834	23,512	24,820	25,723	26,450	26,695	26,950	27,311	27,194	26,705	25,828	25,343	24,117	22,336	20,674
Summer	7	29,018	7/20/2015	19,305	18,307	17,681	17,431	17,579	18,319	19,098	20,236	21,589	23,407	25,297	26,868	27,921	28,751	29,018	28,828	28,158	27,609	26,720	25,788	25,411	24,252	22,380	20,597
Summer	7	27,603	7/21/2015	19,308	18,382	17,789	17,486	17,603	18,274	18,870	20,122	21,353	22,818	24,372	25,537	26,524	27,181	27,603	27,454	27,060	26,687	25,881	24,930	24,562	23,319	21,310	19,479
Summer	7	25,787	7/22/2015	18,024	17,159	16,573	16,324	16,433	17,124	17,793	18,643	19,767	21,161	22,441	23,548	24,481	25,313	25,617	25,787	25,765	25,573	24,757	23,987	23,708	22,456	20,708	19,128
Summer	7	23,227	7/23/2015	17,907	17,221	16,581	16,343	16,553	17,309	18,117	18,874	19,704	20,588	21,437	21,927	22,436	22,526	22,772	23,109	23,227	23,129	22,801	22,202	22,297	21,446	19,874	18,401
Summer	7	27,005	7/24/2015	17,261	16,459	15,962	15,611	15,924	16,587	17,303	18,518	19,730	21,221	22,768	23,987	25,020	26,005	26,605	27,005	26,987	26,675	25,745	24,465	23,910	22,585	20,734	18,935
Summer	7	26,681	7/25/2015	17,571	16,461	15,804	15,369	15,184	15,167	15,203	16,459	18,244	20,066	21,974	23,455	24,598	25,525	26,213	26,585	26,654	26,681	25,834	24,556	23,800	22,255	20,554	18,743
Summer	7	26,380	7/26/2015	17,424	16,399	15,695	15,173	14,910	14,728	14,811	16,299	18,263	20,260	21,946	23,602	24,809	25,672	26,102	26,350	26,380	26,146	25,473	24,523	24,201	22,875	20,969	19,321
Summer	7	28,828	7/27/2015	18,120	17,175	16,687	16,355	16,511	17,177	18,080	19,368	21,079	23,009	25,066	26,592	27,471	28,101	28,351	28,689	28,828	28,684	27,898	26,993	26,566	25,093	23,016	21,218
Summer	7	28,630	7/28/2015	19,795	18,684	17,999	17,571	17,619	18,273	18,901	20,328	22,249	24,025	26,198	27,465	28,111	28,550	28,630	28,372	27,643	26,920	26,259	25,515	25,257	24,146	22,437	20,646
Summer	7	28,970	7/29/2015	19,545	18,143	17,579	17,189	17,203	17,798	18,523	19,575	20,974	22,638	24,309	25,699	26,903	27,710	28,266	28,714	28,970	28,796	28,021	27,077	26,651	25,188	22,998	21,132
Summer	7	27,672	7/30/2015	19,755	18,749	17,961	17,524	17,586	18,198	18,899	19,913	21,130	22,479	23,856	24,978	25,900	26,730	27,316	27,672	27,519	26,931	25,923	24,504	24,016	22,483	20,462	18,481
Summer	7	26,246	7/31/2015	17,099	16,037	15,456	14,956	15,061	15,706	16,229	17,497	18,967	20,432	21,921	23,024	23,931	24,873	25,654	26,156	26,246	25,801	24,893	23,399	22,582	21,259	19,401	17,640
Summer	8	25,969	8/1/2015	16,286	15,266	14,518	14,142	14,127	14,186	14,291	15,447	17,145	19,134

Contains Proprietary Material
Do Not Distribute

Fall	9	25,492	9/5/2015	16,815	15,736	15,161	14,689	14,395	14,485	14,585	15,377	17,123	19,033	20,937	22,706	24,037	24,953	25,473	25,492	25,338	24,652	23,504	22,841	21,777	20,267	18,646	17,138
Fall	9	24,340	9/6/2015	15,891	15,084	14,501	14,011	13,875	13,843	13,999	14,891	16,592	18,230	19,662	21,154	22,403	23,368	23,939	24,289	24,340	23,746	22,543	21,850	20,890	19,470	18,045	16,637
Fall	9	24,597	9/7/2015	15,492	14,630	14,110	13,679	13,632	13,717	13,668	14,300	15,939	17,835	19,837	21,450	22,657	23,553	24,071	24,475	24,597	24,203	23,307	22,849	21,875	20,105	18,265	16,666
Fall	9	25,812	9/8/2015	15,569	14,812	14,250	14,193	14,439	15,629	16,827	17,519	18,714	20,169	21,788	23,094	24,145	25,084	25,439	25,688	25,812	25,480	24,781	24,436	23,521	21,755	19,693	18,042
Fall	9	23,220	9/9/2015	16,830	16,196	15,759	15,527	15,630	16,715	17,903	18,188	18,930	20,098	21,280	22,168	22,888	23,209	23,220	23,068	22,646	21,985	21,380	21,292	20,684	19,340	17,798	16,409
Fall	9	23,227	9/10/2015	15,603	14,989	14,663	14,537	14,878	16,017	17,300	17,568	18,047	18,573	19,206	19,739	20,563	21,465	22,303	22,952	23,227	22,896	22,164	21,885	21,197	19,722	18,046	16,485
Fall	9	22,190	9/11/2015	15,510	14,748	14,296	14,177	14,453	15,583	16,669	17,034	17,850	19,010	20,174	21,030	21,776	22,190	22,011	21,659	21,202	20,270	19,424	19,066	18,543	17,657	16,476	15,221
Fall	9	17,134	9/12/2015	14,216	13,512	13,184	12,926	12,882	13,130	13,380	13,854	14,754	15,463	15,934	16,206	16,462	16,729	17,044	17,134	17,028	16,631	15,994	16,211	15,731	14,919	13,990	12,995
Fall	9	16,297	9/13/2015	12,246	11,789	11,467	11,397	11,373	11,579	11,860	12,471	13,327	13,637	13,879	14,141	14,541	14,841	15,129	15,544	15,913	16,045	15,793	16,297	15,877	14,828	13,670	12,693
Fall	9	18,553	9/14/2015	12,080	11,881	11,628	11,748	12,280	13,586	14,767	15,008	15,374	15,686	16,145	16,338	16,660	17,083	17,567	18,172	18,553	18,426	18,109	18,141	17,584	16,474	15,007	13,666
Fall	9	20,128	9/15/2015	13,031	12,483	12,304	12,297	12,803	13,984	15,073	15,333	15,680	16,125	16,679	17,120	17,733	18,450	19,060	19,729	20,128	19,918	19,320	19,328	18,717	17,439	15,806	14,392
Fall	9	21,122	9/16/2015	13,507	13,007	12,668	12,614	13,030	14,171	15,381	15,423	15,980	16,692	17,444	17,899	18,650	19,467	20,192	20,915	21,122	20,957	20,251	19,965	19,279	17,858	16,233	14,839
Fall	9	22,201	9/17/2015	13,829	13,277	12,867	12,886	13,202	14,449	15,498	15,822	16,393	16,968	17,897	18,648	19,528	20,510	21,280	21,900	22,201	21,863	20,893	20,749	19,921	18,510	16,805	15,194
Fall	9	23,150	9/18/2015	14,166	13,606	13,215	13,068	13,376	14,439	15,650	15,872	16,623	17,544	18,691	19,582	20,546	21,356	22,315	22,927	23,150	22,601	21,284	20,592	19,609	18,408	16,928	15,459
Fall	9	22,168	9/19/2015	14,257	13,700	13,187	12,883	12,807	13,128	13,453	13,999	15,296	16,539	17,749	18,966	20,108	21,115	21,853	22,168	21,978	21,371	20,506	20,178	19,182	17,980	16,698	15,382
Fall	9	20,000	9/20/2015	14,372	13,688	13,110	12,800	12,539	12,658	12,890	13,534	14,656	15,564	16,430	17,335	18,275	19,058	19,482	19,833	20,000	19,473	18,999	19,120	18,167	16,849	15,377	14,193
Fall	9	19,845	9/21/2015	13,454	12,907	12,666	12,636	13,195	14,391	15,709	15,944	16,232	16,614	17,240	17,736	18,200	18,810	19,238	19,690	19,845	19,547	19,108	19,188	18,504	17,177	15,574	14,309
Fall	9	21,219	9/22/2015	13,421	12,865	12,555	12,561	12,941	14,143	15,335	15,490	15,919	16,587	17,236	17,901	18,549	19,359	20,243	20,868	21,219	20,929	20,211	20,033	19,271	17,698	16,137	14,787
Fall	9	22,319	9/23/2015	13,945	13,279	12,933	12,829	13,184	14,269	15,431	15,637	16,130	16,937	17,876	18,742	19,696	20,719	21,415	22,044	22,319	21,947	21,174	20,769	19,767	18,277	16,564	15,196
Fall	9	22,116	9/24/2015	14,325	13,560	13,254	13,030	13,312	14,538	15,722	15,876	16,471	17,312	18,353	19,281	20,110	21,074	21,722	22,116	22,011	21,442	20,861	20,744	19,797	18,349	16,741	15,301
Fall	9	18,290	9/25/2015	14,322	13,639	13,315	13,189	13,647	14,644	16,009	16,177	16,437	16,948	17,471	17,815	18,046	18,187	18,290	18,218	18,042	17,754	17,618	17,578	17,078	16,393	15,509	14,417
Fall	9	17,321	9/26/2015	13,616	13,022	12,685	12,491	12,522	12,871	13,403	13,911	14,743	15,527	16,059	16,393	16,686	16,913	17,049	17,077	17,065	16,841	17,009	17,321	16,899	16,049	15,128	14,127
Fall	9	19,125	9/27/2015	13,313	12,740	12,316	12,330	12,361	12,465	12,922	13,482	14,562	15,359	15,913	16,618	17,385	17,903	18,280	18,478	18,846	18,733	18,747	19,125	18,398	17,158	15,899	14,784
Fall	9	20,157	9/28/2015	13,984	13,474	13,311	13,233	13,735	14,977	16,444	16,897	17,241	17,873	18,440	18,856	19,213	19,519	19,656	19,600	19,605	19,584	19,952	20,157	19,592	18,506	17,150	15,862
Fall	9	20,079	9/29/2015	15,084	14,548	14,184	14,053	14,537	15,863	17,298	17,558	17,828	18,149	18,538	18,827	19,148	19,355	19,664	19,921	20,079	19,851	19,835	19,921	19,170	18,185	16,804	15,483
Fall	9	18,345	9/30/2015	14,619	14,188	13,769	13,750	14,202	15,345	16,745	16,950	17,142	17,475	17,856	17,934	18,074	18,345	18,283	18,220	18,080	17,837	18,124	18,188	17,564	16,677	15,377	14,106
Fall	10	16,967	10/1/2015	13,470	12,976	12,716	12,734	13,112	14,277	15,597	15,697	15,916	16,094	16,242	16,364	16,303	16,235	16,186	16,191	16,223	16,201	16,495	16,967	16,541	15,659	14,529	13,495
Fall	10	15,711	10/2/2015	12,686	12,318	12,130	12,085	12,551	13,784	15,219	15,348	15,480	15,565	15,693	15,711	15,406	15,245	15,110	14,965	14,881	14,934	15,333	15,618	15,374	14,788	13,890	13,061
Fall	10	15,254	10/3/2015	12,391	11,985	11,790	11,726	11,807	12,195	12,813	13,251	13,903	14,531	14,810	14,735	14,643	14,512	14,479	14,345	14,500	14,642	15,156	15,254	15,005	14,355	13,601	12,771
Fall	10	16,298	10/4/2015	12,212	11,799	11,627	11,507	11,629	11,873	12,345	12,958	13,720	14,042	14,076	14,147	14,254	14,192	14,407	14,621	14,909	15,074	15,639	16,298	15,881	14,908	13,819	12,803
Fall	10	19,398	10/5/2015	12,223	11,849	11,703	11,782	12,260	13,391	14,614	15,003	15,562	16,023	16,492	17,121	17,695	18,194	18,708	19,130	19,393	19,200	19,156	19,398	18,676	17,467	15,948	14,517
Fall	10	20,819	10/6/2015	13,706	13,203	12,842	12,781	13,170	14,355	15,483	15,688	16,201	16,851	17,595	18,361	19,219	19,769	20,327	20,811	20,819	20,370	19,996	19,989	19,024	17,840	16,270	14,788
Fall	10	20,783	10/7/2015	13,836	13,168	12,818	12,733	12,942	14,195	15,144	15,254	15,677	16,343	17,119	17,987	18,927	19,674	20,240	20,659	20,783	20,301	19,854	19,473	18,611	17,413	15,996	14,621
Fall	10	20,630	10/8/2015	13,809	13,310	12,996	12,762	13,174	14,477	15,564	15,701	16,242	16,958	17,848	18,619	19,411	19,973	20,630	20,596	20,566	20,072	20,018	19,947	19,185	18,012	16,525	15,208
Fall	10	19,679	10/9/2015	14,276	13,799	13,353	13,195	13,492	14,535	15,788	16,026	16,637	17,245	18,035	18,790	19,395	19,679	19,606	19,313	18,718	18,077	17,882	17,619	17,043	16,206	15,233	13,969
Fall	10	15,575	10/10/2015	13,257	12,730	12,419	12,265	12,215	12,487	13,088	13,488	14,194	14,733	14,963	15,076	14,997	14,953	15,021	15,171	15,257	15,144	15,420	15,575	15,036	14,469	13,502	12,716
Fall	10	16,159	10/11/2015	12,130	11,741	11,487	11,346	11,496	11,803	12,280	12,801	13,570	13,933	13,992	14,125	14,394	14,680	14,953	15,283	15,674	15,662	16,020	16,159	15,595	14,644	13,694	12,912
Fall	10	18,603	10/12/2015	12,200	11,986	11,785	11,768	12,294	13,471	14,782	15,148	15,473	15,865	16,166	16,429	16,704	17,212	17,602	17,995	18,229	18,003	18,432	18,603	17,861	16,760	15,440	14,287
Fall	10	17,379	10/13/2015	13,389	12,828	12,469	12,484	12,817	13,753	14,982	15,083	15,317	15,808	16,304	16,601	16,900	17,024	17,202	17,379	17,375	16,997	17,137	17,342	16,600	15,574	14,320	13,368
Fall	10	17,409	10/14/2015	12,808	12,386	12,264	12,357	12,796	14,114	15,407	15,547	15,714	15,867	16,055	16,232	16,271	16,415	16,688	17,034	17,314	17,091	17,230	17,409	16,839	15,869	14,565	13,601
Fall	10	17,941	10/15/2015	12,985	12,592	12,426	12,477	12,989	14,164	15,490	15,617	15,636	15,828	16,180	16,324	16,617	16,717	17,277	17,758	17,941	17,692	17,773	17,921	17,298	16,295	15,063	13,903
Fall	10	16,018	10/16/2015	13,238	12,789	12,519	12,454	12,901	13,979	15,214	15,432	15,603	15,842	16,018	16,014	16,001	15,844	15,852	15,834	15,722	15,494	15,682	15,871	15,628	15,051	14,255	13,473
Fall	10	15,370	10/17/2015	12,934	12,603	12,530	12,450	12,718	13,181	14,042	14,752	15,226	15,200	14,974	14,816	14,250	14,124	14,000	13,964	14,116	14,231	15,080	15,370	15,157	14,672	14,069	13,451
Fall	10	16,309	10/18/2015	13,054	12,929	12,871	12,953	13,244	13,805	14,505	15,422	15,867	15,442	14,867	14,534	14,271	14,115	13,972	13,994	14,238	14,675	15,828	16,309	15,988	15,306	14,544	13,884
Fall	10	18,518	10/19/2015	13,698	13,637	13,780	14,134	15,005	16,655	18,426	18,518	18,016	17,314	16,966	16,256	16,002	15,562	15,386	15,342	15,458	15,626	16,503	16,952	16,556	15,841	14,732	13,990
Fall	10	17,593	10/20/2015	13,480	13,398	13,380	13,563	14,331	15,973	17,556	17,593	17,055	16,547	16,184	15,901	15,749	15,474	15,412	15,537	15,701	15,705	16,529	16,861	16,355	15,584	14,341	13,507
Fall	10	17,181	10/21/2015	13,053	12,861	12,749	13,007	13,657	15,141	16,680	16,606	16,309	16,147	15,948	15,915	15,853	15,952	16,085	16,372	16,470	16,474	17,028	17,181	16,694	15,735	14,615	13,606
Fall	10	17,538	10/22/2015	12,914	12,656	12,535	12,651	13,353	14,588	16,051	16,091	15,945	15,821	15,998	16,099	16,244	16,476	16,604	16,897	17,053	16,884	17,402	17,538	17,018	15,934	14,641	13,500
Fall	10	16,821	10/23/2015	12,870	12,480	12,384	12,496	13,060	14,373	15,869	16,096	16,041	16,050	16,132	16,326	16,369	16,527	16,628	16,711	16,690	16,359	16,821	16,729	16,307	15,766	14,749	13,741
Fall	10	16,197	10/24/2015	13,192	12,650	12,367	12,207	12,381	12,731	13,371	13,906	14,627	15,143	15,564	15,549	15,544	15,500	15,407	15,395	15,416	15,474	16,197	15,929	15,564	14,908	14,113	13,048
Fall	10	15,802	10/25/2015	12,393	12,018	11,801	11,603	11,629	11,900	12,379	12,982	13,642	13,969	14,149	14,214	14,326	14,346	14,427	14,465	14,709	14,966	15,802	15,736	15,388	14,565	13,557	12,702
Fall	10	16,964	10/26/2015	12,117	11,923	11,792	11,941	12,525	13,843	15,433	15,822	15,884	16,070	16,165	16,221	16,044	15,827	15,660	15,655	15,813	16,263	16,956	16,964	16,498	15,687	14,535	13,575
Fall	10	17,226	10/27/2015	13,061	12,703	12,519	12,556	13,122	14,493	15,865	16,227	16,282	16,628	16,667	16,571	16,397	15,970	15,753	15,857	16,053	16,536	17,226	17,161	16,568	15,716	14,629	13,653
Fall	10	16,758	10/28/2015	13,129	12,839	12,627	12,680	13,159	14,377	15,868	16,145	16,165	16,215	16,284	16,153	16,029	15,783	15,777	15,841	15,903	15,973	16,635	16,758	16,412	15,662	14,464	13,534
Fall	10	16,568	10/29/2015	12,939	12,528	12,394	12,454	12,905	14,229	15,800	15,938	15,760	15,795	15,945	15,824	15,774	15,591	15,493	15,440	15,476	15,488	16,348	16,568	16,295	15,533	14,499	13,564
Fall	10	16,721	10/30/2015	12,918	12,656	12,673	12,790	13,395	14,919	16,627	16,721	16,431	16,054	15,516	15,301	14,985	14,655	14,541	14,377	14,361	14,505	15,278	15,392	15,201	14,722	14,095	13,242
Fall	10	15,058	10/31/2015	12,921	12,552	12,318	12,220	12,422	12,892	13,355	13,946	14,635	15,001	15,058	14,897	14,727	14,565	14,476	14,404	14,416	14,528	14,874	14,640	14,434	13,906	13,187	12,365
Fall	11	15,833	11/1/2015	11,777	11,494	11,223	11,152	11,367	11,614	12,152	13,135	13,881	13,979	13,783	14,033	14,007	14,029	13,986	14,162	14,923	15,833	15,816	15,456	14,794	14,078	13,185	12,429
Fall	11	17,475	11/2/2015	11,936	11,729	11,652	11,586	12,005	13,387	14,724	15,054	15,264	15,452	15,785	16,006	16,053	16,043	16,009	16,092	16,462	17,429	17,475	16,925	16,342	15,369	14,269	13,253
Fall	11	17,840	11/3/2015	12,711	12,367	12,251	12,027	12,359	13,712	14,821	15,057	15,321	15,450	15,956	16,190	16,451	16,569	16,583	16,533	16,845	17,829	17,840	17,406	16,763	15,689	14,550	13,413
Fall	11	17,951	11/4/2015	12,869	12,478	12,231	12,029	12,374	13,665	14,870	15,101	15,380	15,716	16,165	16,388	16,714	16,815	16,735	16,657	16,941	17,951	17,948	17,500	16,917	15,718	14,615	13,608
Fall	11	18,709	11/5/2015	12,933	12,560	12,332	12,218	12,557	13,857	15,143	15,470	15,779	16,150	16,712	17,110	17,454	17,585	17,739	17,721	17,878	18,709	18,632	18,196	17,531	16,637	15,342	14,280
Fall	11	17,590	11/6/2015	13,625	13,328	12,940	12,810	13,032	14,218	15,406	15,731	16,120	16,302	16,725	16,924	16,985	17,012	16,856	16,704	17,044	17,590	17,257	16,771	16,203	15,478	14,539	13,525
Fall	11	15,969	11/7/2015	12,782	12,356	12,056	11,938	12,066	12,469	12,999	13,588	14,441	14,985	15,144	15,080	14,792	14,666	14,608	14,688	15,246	15,969	15,736	15,518	15,088	14,612	13,907	13,214
Fall	11	16,260	11/8/2015	12,682	12,470	12,383	12,324	12,488	12,932	13,455	14,267	14,759	14,678	14,327	14,175	14,151	14,069	13,999	14,188	14,945	16,080	16,260	16,036	15,548	14,828	13,899	13,296
Fall	11	17,867	11/9/2015	12,829	12,508	12,500	12,709	13,088	14,579	16,027	16,185	16,340	16,405	16,553	16,595	16,568	16,481	16,287	16,416	17,008	17,867	17,779	17,434	16,757	15,867	14,730	13,783
Fall	11	17,391	11/10/2015	13,094	12,932	12,837	12,993	13,399	14,814	16,128	16,151	15,986	15,932	15,977	15,973	15,901	15,939	15,849	15,855	16,175	17,309	17,391	17,199	16,618	16,018	15,129	14,431
Fall	11	17,643	11/11/2015	14,086	13,931	13,954	14,081	14,532	16,006	17,083	16,968	16,375	16,055	16,019	16,031	16,084	16,075	16,183	16,201	16,655	17,643	17,596	17,103	16,676	15,836	14,674	13,822
Fall	11	17,368	11/12/2015	13,273	12,918	12,720	12,578	12,931	14,166	15,392	15,590	15,687	15,680	15,963	16,065	15,999	15,968	15,910	15,833	16,166	17,361	17,368	17,245	16,681	15,972	14,948	14,229
Fall	11	17,722	11/13/2015	13,942	13,679	13,802	13,910	14,489	16,198	17,690	17,578	16,983	16,624	16,458	16,162	15,734	15,666	15,629	15,820	16,438	17,722	17,708	17,632	17,519	17,163	16,539	15,959
Fall	11	18,158	11/14/2015	15,533	15,562	15,694	15,982	16,306	17,120	17,732	18,158	17,725	17,078	16,262	15,508	15,225	14,935	14,745	14,684	15,544	16,605	16,888	16,710	16,505	16,214	15,769	15,377
Fall	11	17,278	11/15/2015	15,198	15,149	15,232	15,376	15,640	16,091	16,623	17,143	17,195	16,501	15,815	15,277	14,945	14,650	14,551	14,630	15,755	17,121	17,262	17,278	17,044	16,493	15,675	15,153
Fall	11	18,390	11/16/2015	14,835	14,748	14,800	14,818	15,483	17,120	18,390	18,279	17,921	17,455	17,255	17,048	16,801	16,533	16,445	16,676	17,464	18,360	18,281	17,946	17,183	16,234	15,000	14,149
Fall	11	17,709	11/17/2015	13,667	13,427	13,328	13,280	13,732	15,161	16,468	16,508	16,429	16,278	16,317	16,289	16,330	16,234	16,146	16,279	16,974	17,709	17,629	17,259	16,644	15,792	14,687	13,661
Fall	11	17,965	11/18/2015	13,137	12,896	12,695	12,597	12,871	14,087	15,597	15,905	16,101	16,247	16,494	16,643	16,597	16,603	16,543	16,636	17,085	17,946	17,965	17,581	17,046	16,135	15,168	14,214
Fall	11	17,613	11/19/2015	13,591	13,321	13,196	13,181	13,770	15,364	16,769	16,797	16,502	16,272	16,110	16,003	15,943	15,957	15,824	15,846	16,265	17,412	17,613	17,445	17,161	16,562	15,691	14,918
Fall	11	18,673	11/20/2015	14,597	14,381	14,465	14,831	15,461	17,233	18,673	18,498	17,789	17,253	17,028	16,555	16,298	16,009	15,798	15,831	16,658	17,803	17,952	17,898	17,737	17,388	16,716	16,214
Fall	11	17,774	11/21/2015	15,735	15,554	15,626	15,710	16,000	16,574	17,082	17,329	17,236	16,797	16,502	16,043	15,746	15,596	15,694	15,941	16,710	17,685	17,774	17,698	17,571	17,087	16,649	16,242
Fall	11	20,511	11/22/2015	15,928	15,910	15,931	16,153	16,683	17,345	18,055	18,840	19,010	18,532	17,909	17,377	16,978	16,680	16,567	16,882	18,141	19,768	20,222	20,511	20,344	19,895	19,425	18,990
Fall	11	23,475	11/23/2015	18,904	19,061	19,304	19,631	20,389	21,998	23,475	23,191	22,104	20,603	19,763	18,959	18,351	17,835	17,559	17,580	18,648	20,190	20,619	20,685	20,575	20,156	19,396	18,698
Fall	11	22,218	11/24/2015	18,484	18,411	18,516	18,794	19,507	21,085	22,218	21,945	20,804	19,474	18,670	17,888	17,441	17,090	16,858	16,906	17,824	19,150	19,428	19,315	19,140	18,551	17,701	17,062
Fall	11	19,045	11/25/2015	16,616	16,486	16,299	16,357	16,698	17,792	18,748	19,045	18,638	18,011	17,573	17,075	16,681	16,299	15,953	15,913	16,523	17,534	17,457	17,179	16,923	16,459	15,455	14,470
Fall	11	15,698	11/26/2015	13,818	13,466	13,220	13,250	13,508	14,034	14,545	15,088	15,536	15,698	15,618	14,980	14,082	13,367	12,929	12,666	12,829	13,518	13,479	13,408	13,276	12,996	12,520	11,977
Fall	11	14,889	11/27/2015	11,622	11,427	11,367	11,431	11,682	12,246	12,775	13,148	13,553	13,751	13,824	13,702	13,554	13,439	13,383	13,462	14,228	14,889	14,784	14,561	14,280	13,750	13,063	12,262
Fall	11	15,272	11/28/2015	11,661	11,368	11,240	11,309	11,440	11,872	12,342	12,914	13,676	14,213	14,419	14,414	14,268	14,172	14,083	14,137	14,759	15,272	15,065	15,058	14,713	14,179	13,436	12,614
Fall	11	16,619	11/29/2015	12,057	11,750	11,554	11,466	11,577	12,080	12,548	13,183	13,968	14,352	14,488	14,610	14,797	14,895	14,886	15,234	16,015	16,619	16,585	16,483	15,847	15,241	14,217	13,395
Fall	11	18,331	11/30/2015	12,908	12,584	12,567	12,481	12,930	14,345	15,857	16,036	16,216	16,346	16,547	16,688	16,711	16,732	16,660	16,869	17,634	18,331	18,185	17,923	17,241	16,387	15,065	14,069

Southeast Operating Reserves

VACAR Reserve Sharing Group

Coincident Peak Load Date		Winter Peak Load 02/20/15, Hour 8	Spring Peak Load 03/06/15, Hour 8	Summer Peak Load 06/23/15, Hour 18	Fall Peak Load 09/02/15, Hour 16	Winter Max of mos the largest s
Dominion	VAP	21,651	17,719	18,955	16,640	367
Duke	DUKE	21,101	16,260	19,827	18,524	358
Progress Energy Carolinas	CPL	15,569	11,245	12,752	11,738	264
	CPLE					244
	CPLW					20
SCEG	SCEG	4,970	3,200	4,450	4,185	84
SC	SC	5,869	3,895	4,834	4,214	100
	Total	**69,160**	**52,319**	**60,818**	**55,301**	

Largest Single Unit	Summer	Winter
DUK BAA : Catawba 1	1,140	1,174

http://www.serc1.org/docs/default-source/program-areas/standards-regional-criteria/regional-criteria/serc-reg-criteria_contingency-reserve-policy-r

Wkp - SERC Operating Reserves

TEE Reserve Sharing Group

		Winter Peak Load	Spring Peak Load	Summer Peak Load	Fall Peak Load
Coincident Peak Load Date		01/08/15, Hour 8	03/06/15, Hour 7	07/29/15, Hour 17	09/04/15, Hour 16
TVA	TVA	32,747	27,804	28,970	27,142
LGEE	LGEE	6,964	5,962	6,628	6,424
	Total	**39,711**	**33,766**	**35,598**	**33,566**

Winter
1
1,043
222

Largest Single Unit	Summer	Winter
TVA BAA: Cumberland (TN) 1	1,239	1,265

http://www.serc1.org/docs/default-source/program-areas/standards-regional-criteria/regional-criteria/serc-reg-criteria_contingency-reserve-policy-

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Spring	Summer	Fall
t severe single contingency or 1.0 times ingle resource in the combined systems		
397	355	353
365	372	393
252	239	249
233	221	230
19	18	19
72	83	89
87	91	89

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Wkp - SERC Operating Reserves

Spring	Summer	Fall
x Largest Single Unit, Shared		
1,042	1,008	1,023
223	231	242

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FERC Form 714 Outages

	Planned Outage and Derating (MW)				
Month	MISO	CPL	DUKE	LGEE	TVA
Dec-14	######	2,077	2,316	0	5,939
Jan15	######	5	209	0	1,658
Feb15	######	0	480	0	2,173
Mar15	######	578	3,148	758	4,098
Apr15	######	2,098	3,901	2,504	8,727
May15	######	2,171	4,464	300	5,885
Jun15	8,163	2	247	0	2,271
Jul15	6,429	0	325	0	1,440
Aug15	7,498	50	189	0	1,718
Sep15	7,327	36	417	0	2,717
Oct15	######	2,035	2,902	1,208	8,241
Nov15	######	1,664	3,062	1,467	7,242

	Planned Outage and Derating (MW)				
	Winter	Spring	Summer	Fall	Note
MISO	13,735	24,153	7,363	19,757	MISO outages
CPL	694	1,616	17	1,245	CPL outages
CPLE	655	1,525	16	1,175	Estimated based on generation ratios
CPLW	39	91	1	70	Estimated based on generation ratios
DUKE	1,002	3,838	254	2,127	DUKE outages
LGEE	0	1,187	0	892	LGEE outages
TVA	3,257	6,237	1,810	6,067	TVA outages

Generation (MW)			
Winter	Spring	Summer	Fall
15,574	15,574	14,351	15,598
14,696	14,696	13,525	14,720
878	878	826	878

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Area	PST	Winter	Spring	Summer	Fall
PJM	19,538	16,011	14,104	18,740	15,366
AP South	10,376	8,453	7,202	10,017	8,235
5004-5005	10,376	8,348	7,135	10,017	8,235
PJM East	5,063	3,767	3,417	4,819	3,923
NYISO	1,774	1,053	1,345	1,785	1,610
ISONE	4,000	3,627	3,224	4,080	3,720
CT	1,470	1,012	868	1,304	1,197

CONFIDENTIAL DATA REDACTED

Electric Generating Facilities and Assets

Asset Appendix: Generation Assets - April 2017

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned by**	**Controlled by**	**Date Control Transferred**	**Location**		**In-Service Date**	**Capacity Rating: Nameplate (MW)**	**Capacity Rating: Used in Filing (MW)**	**Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative**	**End Note Number (Enter text in End Note Tab)**
						Market / Balancing Authority Area	**Geographic Region**					
Beebe 1B Renewable Energy, LLC	ER14-2144	Beebe 1b WF	Beebe 1B Renewable Energy, LLC	Beebe 1B Renewable Energy, LLC	N/A	MISO	Central	12/12/2014	50.40	50.40	S	
Beebe Renewable Energy, LLC	ER12-2311	Beebe 1a WF	Beebe Renewable Energy, LLC	Beebe Renewable Energy, LLC	N/A	MISO	Central	1/17/2013	81.60	81.60	S	
Exelon Generation Company, LLC	ER00-3251	Clinton	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	MISO	Central	11/1/1987	1138.30	1065.00	S	
Harvest II Windfarm, LLC	ER12-2201 QF12-522	Harvest 2 WF	Harvest II Windfarm, LLC	Harvest II Windfarm, LLC	N/A	MISO	Central	11/28/2012	59.40	59.40	S	
Harvest Windfarm, LLC	ER07-1246 QF07-29	Harvest 1 WF	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	2/28/2008	52.80	52.80	S	
Michigan Wind 1, LLC	ER05-1511 QF05-228	Michigan Wind 1 WF	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	12/16/2008	69.00	69.00	S	
Michigan Wind 2, LLC	ER11-3989	Michigan Wind 2 WF	Michigan Wind 2, LLC	Michigan Wind 2, LLC	N/A	MISO	Central	1/5/2012	90.00	90.00	S	
Atlantic City Electric Company	ER96-1361	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Commonwealth Edison Company	ER98-1734	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Energy Commodities Group Maine, LLC	ER02-699	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Energy Services of New York, Inc.	ER07-651	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Energy Services, Inc.	ER07-650	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation NewEnergy, Inc.	ER96-1387	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Delmarva Power & Light Company	ER96-2571	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
PECO Energy Company	ER01-1147	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Potomac Electric Power Company	ER98-4138	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Mystic Power, LLC	ER10-2281	Mystic 7	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/1975	617.00	574.55	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	278.60	228.77	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	278.60	229.97	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	315.00	244.58	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	278.60	232.36	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	278.60	233.47	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	315.00	248.07	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic Jet	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/1969	14.20	8.95	S	
Exelon Framingham LLC	ER98-1943	Framingham Jet 1	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	3/1/1970	14.20	9.62	S	
Exelon Framingham LLC	ER98-1943	Framingham Jet 2	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/1969	14.20	10.13	S	
Exelon Framingham LLC	ER98-1943	Framingham Jet 3	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/1969	14.20	10.22	S	
Exelon New Boston, LLC	ER98-1943	New Boston Jet	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	9/1/1966	18.60	16.00	S	1
Exelon West Medway II, LLC	ER16-2708	West Medway 4	Exelon West Medway II, LLC	Exelon West Medway II, LLC	N/A	ISO-NE	Northeast	6/1/2018	100.00	97.40	S	
Exelon West Medway II, LLC	ER16-2708	West Medway 5	Exelon West Medway II, LLC	Exelon West Medway II, LLC	N/A	ISO-NE	Northeast	6/1/2018	100.00	97.40	S	
Exelon West Medway, LLC	ER98-1943	West Medway Jet 1	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/1970	45.00	42.00	S	
Exelon West Medway, LLC	ER98-1943	West Medway Jet 2	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	3/1/1971	45.00	39.85	S	
Exelon West Medway, LLC	ER98-1943	West Medway Jet 3	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/1970	45.00	42.00	S	
Exelon Wyman, LLC	ER98-1943	Wyman 4	Exelon Wyman, LLC (5.9%)	FPL Energy Wyman IV LLC	N/A	ISO-NE	Northeast	1/1/1978	632.40	602.00	S	2
Exelon Generation Company, LLC	ER00-3251	Fitzpatrick 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	NYISO	Northeast	7/1/1975	917.00	837.50	S	
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 1	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	12/1/1969	641.80	626.10	S	
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 2	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	8/1/1988	1428.45	1289.60	S	3
R. E. Ginna Nuclear Power Plant, LLC	ER04-485	Ginna	R. E. Ginna Nuclear Power Plant, LLC	R. E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	7/1/1970	614.00	582.00	S	
Clinton Battery Utility, LLC	ER16-2194	Clinton Battery Project	Clinton Battery Utility, LLC	Clinton Battery Utility, LLC	N/A	PJM	Northeast	10/14/2016	10.00	10.00	S	
Criterion Power Partners, LLC	ER10-1443	Criterion WF	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	2/4/2011	70.00	70.00	S	
Exelon Generation Company, LLC	ER00-3251	Braidwood 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/1/1988	1224.90	1183.00	S	
Exelon Generation Company, LLC	ER00-3251	Braidwood 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1988	1224.90	1154.00	S	
Exelon Generation Company, LLC	ER00-3251	Byron 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/1/1985	1224.90	1164.00	S	
Exelon Generation Company, LLC	ER00-3251	Byron 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/1987	1224.90	1136.00	S	
Exelon Generation Company, LLC	ER00-3251	Dresden 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/1970	1009.00	902.00	S	
Exelon Generation Company, LLC	ER00-3251	Dresden 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1971	1009.00	895.00	S	
Exelon Generation Company, LLC	ER00-3251	LaSalle 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	1/1/1984	1170.00	1130.00	S	
Exelon Generation Company, LLC	ER00-3251	LaSalle 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1984	1170.00	1133.90	S	
Exelon Generation Company, LLC	ER00-3251	Quad Cities 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1972	1009.30	908.00	S	4
Exelon Generation Company, LLC	ER00-3251	Quad Cities 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1972	1009.30	911.00	S	5
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Fair Wind Power Partners, LLC	ER15-2293	Fair Wind WF	Fair Wind Power Partners, LLC	Fair Wind Power Partners, LLC	N/A	PJM	Northeast	11/24/2015	30.00	30.00	S	
Fourmile Wind Energy, LLC	ER14-2145 QF14-721	Fourmile Ridge WF	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	1/15/2015	40.00	40.00	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 1	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	

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Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned by	Controlled by	Date Control Transferred	Location		In-Service Date	Capacity Rating: Nameplate (MW)	Capacity Rating: Used in Filing (MW)	Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative	End Note Number (Enter text in End Note Tab)
						Market / Balancing Authority Area	Geographic Region					
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 2	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 3	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 4	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 5	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 1	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM 5004/5005	Northeast	5/1/1975	918.00	866.00	S	
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 2	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM 5004/5005	Northeast	4/1/1977	910.70	841.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Gould Street 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	12/1/1952	103.50	97.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.60	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	15.60	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.50	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	16.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	1/1/1972	53.10	52.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	4/1/1972	53.10	51.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	4/1/1972	53.10	52.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 51	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1995	192.00	147.60	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/28/2015	141.00	109.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	8/1/1970	20.70	15.30	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	8/1/1970	20.70	16.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	20.70	14.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	20.70	14.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Riverside 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	25.00	19.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Riverside 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	25.00	20.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Westport 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	2/1/1969	121.50	115.80	S	
Exelon Generation Company, LLC	ER00-3251	TMI 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM 5004/5005	Northeast	9/2/1974	980.90	802.80	S	
Exelon Generation Company, LLC	ER00-3251	Chester 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/7/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Chester 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/20/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Chester 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/6/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/1/1928	45.00	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/25/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/4/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/1/1928	36.00	36.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/6/1928	48.00	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/5/1928	47.70	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1928	36.00	36.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/1/1928	47.70	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1928	48.00	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/10/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/25/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 21	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 22	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 31	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	8/6/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 32	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	8/8/1974	68.30	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 41	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 42	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/7/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/19/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/12/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/20/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 20	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/24/1974	391.00	380.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 30	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/7/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/29/1976	391.00	380.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 40	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/21/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Fairless Hills A	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1996	30.00	30.00	S	
Exelon Generation Company, LLC	ER00-3251	Fairless Hills B	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1996	30.00	30.00	S	

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Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned by	Controlled by	Date Control Transferred	Location		In-Service Date	Capacity Rating: Nameplate (MW)	Capacity Rating: Used in Filing (MW)	Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative	End Note Number (Enter text in End Note Tab)
						Market / Balancing Authority Area	Geographic Region					
Exelon Generation Company, LLC	ER00-3251	Falls 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/22/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Falls 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/10/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Falls 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/28/1970	21.10	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Limerick 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/1/1986	1138.50	1119.70	S	
Exelon Generation Company, LLC	ER00-3251	Limerick 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	1/1/1990	1138.50	1122.10	S	
Exelon Generation Company, LLC	ER00-3251	Moser 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/9/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Moser 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/29/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Moser 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/11/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/10/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/10/1967	134.00	133.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	134.00	133.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/10/1968	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/10/1968	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Oyster Creek 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1969	550.00	607.70	S	
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/5/1974	1244.80	1223.70	S	6
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/23/1974	1377.00	1226.70	S	7
Exelon Generation Company, LLC	ER00-3251	Pennsbury 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/1/1996	3.00	3.00	S	
Exelon Generation Company, LLC	ER00-3251	Pennsbury 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/1/1996	3.00	3.00	S	
Exelon Generation Company, LLC	ER00-3251	Richmond 91	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/7/1973	65.80	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Richmond 92	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/7/1973	65.80	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Salem 1	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	6/30/1977	1251.40	1173.99	S	8
Exelon Generation Company, LLC	ER00-3251	Salem 2	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	10/13/1981	1216.40	1158.02	S	9
Exelon Generation Company, LLC	ER00-3251	Salem 3	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	6/17/1971	41.80	37.57	S	10
Exelon Generation Company, LLC	ER00-3251	Schuylkill 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/30/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Schuylkill 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/11/1971	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/14/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/9/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/26/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	11/7/1968	18.60	13.00	S	
Cassia Gulch Wind Park LLC	ER10-75 QF05-180	Cassia Gulch WF	Cassia Gulch Wind Park LLC	Cassia Gulch Wind Park LLC	N/A	IPCO	Northwest	3/31/2009	18.90	18.90	S	
High Mesa Energy, LLC	ER12-2528 QF13-77	High Mesa WF	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	IPCO	Northwest	8/28/2012	39.90	39.90	S	
Tuana Springs Energy, LLC	ER10-87 QF08-742	Tuana Springs WF	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	IPCO	Northwest	7/27/2010	16.80	16.80	S	
Cow Branch Wind Power, LLC	ER07-1223 QF07-253	Cow Branch WF	Cow Branch Wind Power, L.L.C.	Cow Branch Wind Power, L.L.C.	N/A	AECI	Southeast	3/3/2008	50.40	50.40	S	
CR Clearing, LLC	ER07-1222 QF07-248	Conception WF	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	5/1/2008	50.40	50.40	S	
Wind Capital Holdings, LLC	ER07-1208 QF07-222	Bluegrass Ridge WF	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	5/14/2007	56.70	56.70	S	
Albany Green Energy, LLC	ER17-615	Albany Green Energy 1	Albany Green Energy, LLC	Albany Green Energy, LLC	N/A	SOCO	Southeast	6/1/2017	54.00	50.00	S	
CER Generation, LLC	ER10-662	Hillabee GT1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	258.40	234.40	S	
CER Generation, LLC	ER10-662	Hillabee GT2	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	258.40	234.40	S	
CER Generation, LLC	ER10-662	Hillabee STG1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	306.00	283.90	S	
AV Solar Ranch 1, LLC	ER12-2178	Antelope Valley SF	AV Solar Ranch 1, LLC	AV Solar Ranch 1, LLC	N/A	CAISO	Southwest	12/28/2012	253.00	241.50	S	
Luz Solar Partners Ltd, IV	ER17-823	SEGS IV SF	Luz Solar Partners Ltd, IV	Luz Solar Partners Ltd, IV	N/A	CAISO	Southwest	12/1/1986	34.78	36.00	S	
Bluestem Wind Energy, LLC	ER16-2363	Bluestem WF	Bluestem Wind Energy, LLC	Bluestem Wind Energy, LLC	N/A	SPP	SPP	12/16/2016	198.00	198.00	S	
Exelon Wind 4, LLC	ER07-1202 QF03-13	Exelon Wind 4 WF	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	2/2/2007	79.80	79.80	S	
Shooting Star Wind Project, LLC	ER12-1829	Shooting Star WF	Shooting Star Wind Project, LLC	Shooting Star Wind Project, LLC	N/A	SPP	SPP	9/29/2012	104.00	104.00	S	
Wildcat Wind, LLC	ER12-1223 QF12-412	Wildcat WF	Wildcat Wind, LLC	Wildcat Wind, LLC	N/A	SPP	SPP	7/1/2012	27.30	837.50	S	

Asset Appendix: Long-Term Purchase Agreements - April 2017

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
			Location						
Filing Entity and its Energy Affiliates	**Seller Name**	**Amount of PPA (MW)**	**Market / Balancing Authority Area (Source)**	**Market / Balancing Authority Area (Sink)**	**Geographic Region (Sink)**	**Start Date (mo/da/yr)**	**End Date (mo/da/yr)**	**Type of PPA (Unit or System)**	**End Note Number (Enter text in End Note Tab)**
Exelon Generation Company, LLC	Pioneer Trail Wind Farm, LLC	110	MISO	MISO	Central	2/15/2012	7/1/2020	Unit	11
Exelon Generation Company, LLC	Tenaska Frontier Partners Ltd	160	MISO	MISO	Central	9/20/2000	8/31/2020	Unit	12
Exelon Generation Company, LLC	Tenaska Frontier Partners Ltd	160	MISO	MISO	Central	9/20/2000	8/31/2020	Unit	13
Exelon Generation Company, LLC	Tenaska Frontier Partners Ltd	160	MISO	MISO	Central	9/20/2000	8/31/2020	Unit	14
Exelon Generation Company, LLC	Tenaska Frontier Partners Ltd	390	MISO	MISO	Central	9/20/2000	8/31/2020	Unit	15
EcoMaine	EcoMaine	11	ISO-NE	ISO-NE	Northeast	2/1/2017	1/31/2018	Unit	16
Exelon Generation Company, LLC	Ameresco Northampton, Inc	1	ISO-NE	ISO-NE	Northeast	3/13/2008	12/31/2017	Unit	17
Exelon Generation Company, LLC	Kleen Energy Systems, LLC	186	ISO-NE Connecticut	ISO-NE Connecticut	Northeast	7/23/2011	12/31/2017	Unit	18
Exelon Generation Company, LLC	Kleen Energy Systems, LLC	188	ISO-NE Connecticut	ISO-NE Connecticut	Northeast	7/23/2011	12/31/2017	Unit	19
Exelon Generation Company, LLC	Kleen Energy Systems, LLC	246	ISO-NE Connecticut	ISO-NE Connecticut	Northeast	7/23/2011	12/31/2017	Unit	20
Exelon Generation Company, LLC	WM Renewable Energy, LLC	6	NYISO	NYISO	Northeast	1/1/2012	12/31/2017	Unit	21
Exelon Generation Company, LLC	WM Renewable Energy, LLC	3	NYISO	NYISO	Northeast	1/1/2012	12/31/2017	Unit	22
Exelon Generation Company, LLC	WM Renewable Energy, LLC	6	NYISO	NYISO	Northeast	1/1/2012	12/31/2017	Unit	23
Exelon Generation Company, LLC	WM Renewable Energy, LLC	2	NYISO	NYISO	Northeast	1/1/2012	12/31/2017	Unit	24
Exelon Generation Company, LLC	WM Renewable Energy, LLC	6	NYISO	NYISO	Northeast	1/1/2012	12/31/2017	Unit	25
Exelon Generation Company, LLC	WM Renewable Energy, LLC	2	NYISO	NYISO	Northeast	1/1/2012	12/31/2017	Unit	26
Exelon Generation Company, LLC	WM Renewable Energy, LLC	3	NYISO	NYISO	Northeast	2/1/2013	12/31/2017	Unit	27
Delmarva Power & Light Company	AES Armenia Mountain Wind LLC	50	PJM	PJM	Northeast	12/18/2009	12/19/2024	Unit	28
Delmarva Power & Light Company	Chestnut Flats Lessee, LLC	38	PJM	PJM	Northeast	12/31/2011	12/29/2031	Unit	29
Delmarva Power & Light Company	Roth Rock Wind Farm LLC	40	PJM	PJM	Northeast	12/31/2010	8/3/2031	Unit	30
Exelon Generation Company, LLC	Backbone Mountain Windpower LLC	66	PJM	PJM	Northeast	12/20/2002	12/31/2022	Unit	31
Exelon Generation Company, LLC	Bellefontaine Gas Producers, LLC	5	PJM	PJM	Northeast	3/5/2009	3/31/2019	Unit	32
Exelon Generation Company, LLC	Cordova Energy Company, LLC	165	PJM	PJM	Northeast	12/30/2005	12/31/2019	Unit	33
Exelon Generation Company, LLC	Cordova Energy Company, LLC	165	PJM	PJM	Northeast	12/30/2005	12/31/2019	Unit	34
Exelon Generation Company, LLC	Cordova Energy Company, LLC	191	PJM	PJM	Northeast	12/30/2005	12/31/2019	Unit	35
Exelon Generation Company, LLC	Elwood Energy, LLC	150	PJM	PJM	Northeast	6/15/2006	8/31/2017	Unit	36
Exelon Generation Company, LLC	Elwood Energy, LLC	150	PJM	PJM	Northeast	6/15/2006	8/31/2017	Unit	37
Exelon Generation Company, LLC	Forward Windpower LLC	29	PJM	PJM	Northeast	4/11/2008	12/31/2017	Unit	38
Exelon Generation Company, LLC	High Trail Wind Farm, LLC	99	PJM	PJM	Northeast	1/1/2010	12/31/2017	Unit	39
Exelon Generation Company, LLC	Mill Run Windpower, LLC	16	PJM	PJM	Northeast	12/20/2001	12/31/2021	Unit	40
Exelon Generation Company, LLC	Old Trail Wind Farm, LLC	198	PJM	PJM	Northeast	9/1/2008	12/31/2022	Unit	41
Exelon Generation Company, LLC	Patton Wind Farm, LLC	16	PJM	PJM	Northeast	1/1/2013	12/31/2032	Unit	42
Exelon Generation Company, LLC	Somerset Windpower, LLC	9	PJM	PJM	Northeast	12/19/2001	12/31/2021	Unit	43
Exelon Generation Company, LLC	WM Renewable Energy, LLC	4	PJM	PJM	Northeast	3/1/2012	12/31/2019	Unit	44
Exelon Generation Company, LLC	WM Renewable Energy, LLC	6	PJM	PJM	Northeast	6/1/2012	12/31/2019	Unit	45
Exelon Generation Company, LLC	Green Gas Pioneer Crossing Energy, LLC	5	PJM 5004/5005	PJM 5004/5005	Northeast	11/10/2008	11/30/2021	Unit	46
Exelon Generation Company, LLC	Green Knight Economic Development Corporation	6	PJM 5004/5005	PJM 5004/5005	Northeast	1/1/2012	12/31/2019	Unit	47
Exelon Generation Company, LLC	Keystone Solar, LLC	5	PJM 5004/5005	PJM 5004/5005	Northeast	5/4/2011	10/1/2027	Unit	48
Exelon Generation Company, LLC	Waymart Wind Farm, L.P.	65	PJM 5004/5005	PJM 5004/5005	Northeast	10/20/2003	10/31/2023	Unit	49
Exelon Generation Company, LLC	Ameresco Stafford, LLC	2	PJM AP South	PJM AP South	Northeast	5/19/2009	5/1/2019	Unit	50
Exelon Generation Company, LLC	WM Renewable Energy, LLC	4	PJM AP South	PJM AP South	Northeast	12/1/2007	12/31/2019	Unit	51
Atlantic City Electric Company	Chambers Cogeneration LP	188	PJM-East	PJM-East	Northeast	3/1/1994	3/15/2024	Unit	52
Atlantic City Electric Company	Logan Generating Co LP	200	PJM-East	PJM-East	Northeast	9/1/1994	9/22/2024	Unit	53
Exelon Generation Company, LLC	Calpine Mid Merit LLC	118	PJM-East	PJM-East	Northeast	6/1/2011	5/31/2017	Unit	54

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
			Location						
Filing Entity and its Energy Affiliates	**Seller Name**	**Amount of PPA (MW)**	**Market / Balancing Authority Area (Source)**	**Market / Balancing Authority Area (Sink)**	**Geographic Region (Sink)**	**Start Date (mo/da/yr)**	**End Date (mo/da/yr)**	**Type of PPA (Unit or System)**	**End Note Number (Enter text in End Note Tab)**
Exelon Generation Company, LLC	Calpine Mid Merit LLC	127	PJM-East	PJM-East	Northeast	6/1/2011	5/31/2017	Unit	55
Exelon Generation Company, LLC	Calpine Mid Merit LLC	127	PJM-East	PJM-East	Northeast	6/1/2011	5/31/2017	Unit	56
Exelon Generation Company, LLC	Calpine Mid Merit LLC	193	PJM-East	PJM-East	Northeast	6/1/2011	5/31/2017	Unit	57
Exelon Generation Company, LLC	MF Mesa Lane LLC	3	PJM-East	PJM-East	Northeast	12/1/2008	11/30/2028	Unit	58
Exelon Generation Company, LLC	Sagebrush Power Partners, LLC	101	BPA	BPA	Northwest	9/1/2012	12/31/2018	Unit	59
Exelon Generation Company, LLC	Public Utility District No. 1 of Chelan County, Washington	47	CHPD	GRID	Northwest	2/16/2012	12/31/2017	Unit	60
Exelon Generation Company, LLC	Public Utility District No. 1 of Chelan County, Washington	98	CHPD	GRID	Northwest	2/16/2012	12/31/2017	Unit	61
Exelon Generation Company, LLC	TGP Energy Management, LLC	6	CAISO	CAISO	Southwest	1/1/2017	12/31/2018	System	62
Exelon Generation Company, LLC	TGP Energy Management, LLC	6	CAISO	CAISO	Southwest	1/1/2017	12/31/2018	System	63
Exelon Generation Company, LLC	Wind Power Partners 1993, LLC	17	CAISO	CAISO	Southwest	2/15/2012	12/31/2024	Unit	64
Exelon Generation Company, LLC	Wind Power Partners 1993, LLC	6	CAISO	CAISO	Southwest	2/15/2012	12/31/2024	Unit	65
Exelon Generation Company, LLC	Wind Power Partners 1993, LLC	9	CAISO	CAISO	Southwest	2/15/2012	12/31/2024	Unit	66
Exelon Generation Company, LLC	Wind Power Partners 1993, LLC	11	CAISO	CAISO	Southwest	2/15/2012	12/31/2024	Unit	67
Exelon Generation Company, LLC	Wind Power Partners 1993, LLC	8	CAISO	CAISO	Southwest	2/15/2012	12/31/2024	Unit	68
Exelon Generation Company, LLC	Green Country Energy, LLC	261	SPP	SPP	SPP	2/11/2002	12/28/2021	Unit	69
Exelon Generation Company, LLC	Green Country Energy, LLC	261	SPP	SPP	SPP	2/11/2002	12/28/2021	Unit	70
Exelon Generation Company, LLC	Green Country Energy, LLC	261	SPP	SPP	SPP	2/11/2002	12/28/2021	Unit	71

Asset Appendix: Transmission Assets/Natural Gas Asset - April 2017

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
						Location			
Filing Entity and its Energy Affiliates	**Cite to order accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO**	**Asset Name and Use**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Market / Balancing Authority Area**	**Geographic Region**	**Size: (length and kV)**	**End Note Number (Enter text in End Note Tab)**
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	709.29 combined miles 115kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	54.82 combined miles 138kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	330.97 combined miles 230kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	217.94 combined miles 500kV lines	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Transportation	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	161.4 combined miles	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Storage (LNG)	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	1,056 mmcf	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Distribution	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	13,398 combined miles	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	90 combined miles 765kV lines	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	2,656 combined miles 345kV lines	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	2,897 combined miles 138kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	446 combined miles 500kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	549 combined miles 230kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	156 combined miles 138kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	200 combined miles 69kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	0.47 combined miles 13.2kV lines	
PECO Energy Company	N/A	Intrastate Gas Transportation	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	30 combined miles	
PECO Energy Company	N/A	Intrastate Gas Storage (LNG)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	1,200 mmcf	
PECO Energy Company	N/A	Intrastate Gas Stogare (LP)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	125 mmcf	
PECO Energy Company	N/A	Intrastate Gas Distribution	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	13,046 combined miles	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	281 combined miles 500kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	223 combined miles 230kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	242 combined miles 138kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	636 combined miles 69kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	297 combined miles 500kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	470 combined miles 230kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	557 combined miles 138kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	580 combined miles 69kV lines	
Delmarva Power & Light Company	N/A	Intrastate Gas Transportation	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	111 combined miles	
Delmarva Power & Light Company	N/A	Intrastate Gas Storage (LNG)	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	248 mmcf	
Delmarva Power & Light Company	N/A	Intrastate Gas Distribution	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	3,279 combined miles	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	142.04 combined miles 500kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	773.85 combined miles 230kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	60.37 combined miles 138kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	38.07 combined miles 115kV lines	

Asset Appendix: End Notes - April, 2017

[A] [B] [C]

End Note Number	Sheet (Generation, PPA or Transmission)	Explanatory Note
1	Generation	The plant was decommissioned in October 2016
2	Generation	Exelon owns only 5.9% of the Wyman 4 generating unit
3	Generation	Nine Mile Point Nuclear Stations, LLC owns only 82% of Unit 2
4	Generation	Exelon owns only 75% of the Quad Cities 1 generating unit
5	Generation	Exelon owns only 75% of the Quad Cities 2 generating unit
6	Generation	Exelon owns only 50% of the Peach Bottom 2 generating unit
7	Generation	Exelon owns only 50% of the Peach Bottom 3 generating unit
8	Generation	Exelon owns only 42.59% of the Salem 1 generating unit
9	Generation	Exelon owns only 42.59% of the Salem 2 generating unit
10	Generation	Exelon owns only 42.59% of the Salem 3 generating unit
11	PPA	Pioneer Trail WF
12	PPA	Frontier GT1
13	PPA	Frontier GT2
14	PPA	Frontier GT3
15	PPA	Frontier ST
16	PPA	EcoMaine 1
17	PPA	Northampton
18	PPA	Kleen GT1
19	PPA	Kleen GT2
20	PPA	Kleen STG1
21	PPA	Chaffee Landfill
22	PPA	High Acres-I Landfill
23	PPA	High Acres-II Landfill
24	PPA	Madison County Landfill
25	PPA	Mill Seat Landill
26	PPA	Monroe-Livingston Landfill
27	PPA	Oneida/Herkimer Landfill
28	PPA	Armenia Mountain WF II
29	PPA	Chestnut Flats WF I
30	PPA	Roth Rock WF I
31	PPA	Mountaineer WF
32	PPA	Bellefontaine Landfill
33	PPA	Cordova GT1
34	PPA	Cordova GT2
35	PPA	Cordova STG1
36	PPA	Elwood CEG 7
37	PPA	Elwood CEG 8
38	PPA	Forward Wind WF
39	PPA	High Trail WF
40	PPA	Mill Run WF
41	PPA	Old Trail WF
42	PPA	Patton WF
43	PPA	Somerset WF
44	PPA	Arden Landfill
45	PPA	Lakeview Landfill
46	PPA	Pioneer Crossing Landfill
47	PPA	Grand Central Landfill
48	PPA	Keystone Solar SF
49	PPA	Waymart WF
50	PPA	Stafford Landfill
51	PPA	Bethel Landfill
52	PPA	Carney Point
53	PPA	Logan Generating Plant

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Asset Appendix: End Notes - April, 2017

[A] [B] [C]

End Note Number	Sheet (Generation, PPA or Transmission)	Explanatory Note
54	PPA	York Delta GT1
55	PPA	York Delta GT2
56	PPA	York Delta GT3
57	PPA	York Delta STG1
58	PPA	Falls Solar SF
59	PPA	Kittitas Valley WF
60	PPA	Rock Island
61	PPA	Rocky Reach
62	PPA	Block Energy Deal ECP0LS0
63	PPA	Block Energy Deal ECP0LS1
64	PPA	Palm Springs Buckwind WF
65	PPA	Palm Springs Carter WF
66	PPA	Palm Springs Garnet WF
67	PPA	Palm Springs Renwind WF
68	PPA	Palm Springs Triad WF
69	PPA	Green Country 1
70	PPA	Green Country 2
71	PPA	Green Country 3

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A	B	C	D	E
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**
EDF Trading North America, LLC	ER03-774	N/A	EDF Trading Holdings LLC	EDF Trading Holdings LLC
EDF Industrial Power Services (CA), LLC	ER12-1825	N/A	EDF Trading North America, LLC	EDF Trading North America, LLC
EDF Energy Services, LLC	ER14-2672	N/A	EDF Trading North America LLC	EDF Trading North America LLC
Anahau Energy, LLC	ER13-415	N/A	N/A	N/A
Allendale Biomass, LLC	N/A	N/A	Allendale Biomass	Allendale Biomass
Bellevue Solar, LLC	ER11-4380-000	N/A	Bellevue Solar	Bellevue Solar
Catalina Solar Lessee, LLC	ER13-1562-000	N/A	Catalina Solar, LLC	Catalina Solar Lessee
Champepadan Wind Power Partners, LLC	QF02-3	N/A	Champepadan	Champepadan
Chestnut Flats Lessee, LLC	ER13-1641-000	N/A	Chestnut Flats Wind, LLC	Chestnut Flats Lessee
Dorchester Biomass, LLC	QF13-648	N/A	Dorchester Biomass	Dorchester Biomass
EDF Renewable Wind Farm V, Inc.	QF90-57	N/A	EDF Renewable Wind Farm V	EDF Renewable Wind Farm V
Fenton Power Partners I, LLC	ER07-357-000	N/A	Fenton Power Partners	Fenton Power Partners
Great Western Wind Energy, LLC	ER16-2360	N/A	Great Western Wind	Great Western Wind
Hoosier Wind Project, LLC	ER09-1181-000	N/A	Hoosier Wind Project	Hoosier Wind Project
Kelly Creek Wind, LLC	ER16-2227	N/A	Kelly Creek Wind	Kelly Creek Wind

McHenry Battery Storage, LLC	ER16-2226	N/A	McHenry Battery Storage	McHenry Battery Storage
Milo Wind Project, LLC	ER15-2131-000	N/A	Milo Wind Project, LLC	Milo Wind Project, LLC
Moulton Wind Power Partners, LLC	QF04-7	N/A	Moulton Wind	Moulton Wind
Oasis Power Partners, LLC	ER05-41-000	N/A	Oasis Power	Oasis Power
Pacific Wind Lessee, LLC	ER12-1931-000	N/A	Pacific Wind, LLC	Pacific Wind Lessee, LLC
Pilot Hill Wind, LLC	ER15-1045-000	N/A	Pilot Hill Wind, LLC	Pilot Hill Wind, LLC
Roosevelt Wind Project, LLC	ER15-2130-000	N/A	Roosevelt Wind Project, LLC	Roosevelt Wind Project, LLC
Sacramento Soleil, LLC	QF08-630	N/A	Sacramento Soleil	Sacramento Soleil
Shiloh Wind Project 2, LLC	ER08-1237-000	N/A	Shiloh 2	Shiloh 2
Shiloh III Lessee, LLC	ER12-610-009	N/A	Shiloh III Wind Project, LLC	Shiloh III Lessee
Shiloh IV Lessee, LLC	ER13-338-000	N/A	Shiloh IV Wind Project	Shiloh IV Lessee
Slate Creek Wind Project, LLC	ER15-2129-000	N/A	Slate Creek Wind Project, LLC	Slate Creek Wind Project, LLC
Spearville 3, LLC	ER12-2037-000	N/A	Spearville 3, LLC	Spearville 3, LLC
Spinning Spur Wind LLC	ER12-2314	N/A	Spinning Spur Wind LLC	Spinning Spur Wind LLC
Wapsipinicon Wind Project, LLC	ER08-1288-000	N/A	Wapsipinicon	Wapsipinicon
Yamhill Solar, LLC	ER11-4381-000	N/A	Yamhill Solar	Yamhill Solar
Calvert Cliffs Nuclear Power Plant LLC	ER00-2917-000	Calvert Cliffs Nuclear Power Plant (Unit 1)	Calvert Cliffs Nuclear Power Plant LLC	Calvert Cliffs Nuclear Power Plant LLC
Calvert Cliffs Nuclear Power Plant LLC	ER00-2917-000	Calvert Cliffs Nuclear Power Plant (Unit 2)	Calvert Cliffs Nuclear Power Plant LLC	Calvert Cliffs Nuclear Power Plant LLC
R.E. Ginna Unit 1 Nuclear Power Plant, LLC	ER04-485-000	Ginna	R.E. Ginna Unit 1 Nuclear Power Plant, LLC	R.E. Ginna Unit 1 Nuclear Power Plant, LLC
Nine Mile Point Nuclear Station, LLC	ER01-1654-000	Nine Mile Point (Unit 1)	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC
Nine Mile Point Nuclear Station, LLC	ER01-1654-000	Nine Mile Point (Unit 2)	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC

Asset Appendix: Generation Assets

F	G	H	I	J	K
Date Control Transferred	Location		In-service Date	Capacity rating: Nameplate (MW)	Capacity Rating: Used in Filing (MW)
	Market/Balancing Authority Area	Geographic Region			
10/31/2008	N/A	N/A	N/A	N/A	
N/A	N/A	N/A	N/A	N/A	
N/A	N/A	N/A	N/A	N/A	
N/A	N/A	N/A	N/A	N/A	
N/A	Santee Cooper	Southeast	10/1/2013	19.3	19.3
N/A	PGE	Northwest	10/26/2011	1.66	1.66
N/A	CAISO	Southwest	2013	110	110
N/A	MISO	Central	12/19/2001	1.98	1.98
9/30/2013	PJM	Northeast	12/29/2011	38	38
N/A	Santee Cooper	Southeast	10/1/2013	19.3	19.3
N/A	CAISO	Southwest	1989	16.2	16.2
N/A	MISO	Central	11/13/2007	205.5	205.5
N/A	SPP	SPP	Oct-16	225	225
N/A	MISO	Central	Nov-09	106	106
N/A	PJM	Northeast	Oct-16	184	184

N/A	PJM	Northeast	Dec-15	20	20
N/A	SPP	SPP	Dec-15	49.65	49.65
N/A	MISO	Central	12/19/2001	1.98	1.98
N/A	CAISO	Southwest	12/24/2004	60	60
N/A	CAISO	Southwest	8/16/2012	140	140
N/A	PJM	Northeast	Sep-15	176.9	176.9
N/A	SPP	SPP	12/14/2015	250	250
N/A	CAISO	Southwest	7/14/2008	1	1
N/A	CAISO	Southwest	1/30/2009	150	150
N/A	CAISO	Southwest	12/22/2011	100	100
N/A	CAISO	Southwest	12/21/2012	102.5	102.5
N/A	SPP	SPP	Dec-15	150	150
N/A	SPP	SPP	10/1/2012	100.8	100.8
N/A	SPP	SPP	12/20/2012	161	161
N/A	MISO	Central	2/20/2009	100.5	100.5
N/A	PGE	Northwest	10/26/2011	1.19	1.19
11/6/2009	PJM	Northeast	5/1/1975	918	866
11/6/2009	PJM	Northeast	4/1/1977	910.7	841.8
11/6/2009	NYISO	Northeast	7/1/1970	614	582
11/6/2009	NYISO	Northeast	12/1/1969	641.8	626.1
11/6/2009	NYISO	Northeast	8/1/1988	1428.45	1289.6

L	M
Capacity Rating: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative	**End Note Number (Enter text in End Notes Sheet)**
	1
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Asset Appendix: Long-Term Purchased Power Agreements (PP

A	B	C	D
Filing Entity and its Energy Affiliates	Seller Name	Amount of PPA (MW)	Market/Balancing Authority Area (Source)
N/A			

'A)

E		F	G	H	I	J
Location			Start Date	End Date	Type of PPA (Unit or System)	End Note Number (Enter text in End Notes Sheet)
Market/Balancing Authority Area (Sink)		Geographic Region	(mo/da/yr)	(mo/da/yr)		

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A	B	C	D	E	F
Filing Entity and its Energy Affiliates	**Cite to Order accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO**	**Asset Name and Use**	**Owned By**	**Controlled By**	**Date Control Transferred**
N/A					

ıl Gas Assets

G	H		I	J
Location			Size	End Note Number (Enter text in End Notes Sheet)
Market/Balancing Authority Area		Geographic Region		
				1

End Notes for Entries in the Generation, Long-term

A	B
End Note Number	**Sheet (Generation, PPA, or Transmission)**
1	Generation, Transmission
2	Generation

PPA and Transmission Lists

C
Explanatory Note
Table excludes assets outside the continential U.S. and in ERCOT
Excluded from market-power analysis per Order No. 816

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August 7, 2017

VIA ELECTRONIC FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Beebe 1B Renewable Energy, LLC, Docket No. ER14-2144-___
Beebe Renewable Energy, LLC, Docket No. ER12-2311-___
Bluestem Wind Energy, LLC, Docket No. ER16-2363-____
Cassia Gulch Wind Park LLC, Docket No. ER11-2016-___
Cow Branch Wind Power, LLC, Docket No. ER11-2014-___
CR Clearing, LLC, Docket No. ER11-2013-___
Criterion Power Partners, LLC, Docket No. ER10-3308-___
Fourmile Wind Energy, LLC, Docket No. ER14-2145-___
Harvest Windfarm, LLC, Docket No. ER11-2011-___
Harvest II Windfarm, LLC, Docket No. ER12-2201-___
High Mesa Energy, LLC, Docket No. ER12-2528-___
Michigan Wind 1, LLC, Docket No. ER11-2009-___
Michigan Wind 2, LLC, Docket No. ER11-3989-___
Shooting Star Wind Project, LLC, Docket No. ER12-1829-___
Tuana Springs Energy, LLC, Docket No. ER11-2007-___
Wildcat Wind, LLC, Docket No. ER12-1223-___
Wind Capital Holdings, LLC, Docket No. ER11-2005-___

Notice of Change in Status

Dear Secretary Bose:

Pursuant to the requirements of section 35.42 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[1] Beebe 1B Renewable Energy, LLC ("Beebe 1B"), Beebe Renewable Energy, LLC ("Beebe"), Bluestem Wind Energy, LLC ("Bluestem"), Cassia Gulch Wind Park LLC ("Cassia Gulch"), Cow Branch Wind Power, LLC ("Cow Branch"), CR Clearing, LLC ("CR Clearing"), Criterion Power Partners, LLC ("Criterion"), Fourmile Wind Energy, LLC ("Fourmile"), Harvest Windfarm, LLC ("Harvest"), Harvest II Windfarm, LLC ("Harvest II"), High Mesa Energy, LLC ("High

[1] 18 C.F.R. § 35.42 (2017).

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Mesa"), Michigan Wind 1, LLC ("Michigan Wind 1"), Michigan Wind 2, LLC ("Michigan Wind 2"), Shooting Star Wind Project, LLC ("Shooting Star"), Tuana Springs Energy, LLC ("Tuana Springs"), Wildcat Wind, LLC ("Wildcat"), and Wind Capital Holdings, LLC ("WCH") (collectively, "Exelon Sellers") submit this notice of change in status ("Notice"). The Exelon Sellers are direct or indirect subsidiaries of ExGen Renewables Partners, LLC ("ExGen Renewables"), which is an indirect subsidiary of Exelon Generation Company, LLC ("Exelon Generation"). On June 6, 2017, the Commission authorized pursuant to section 203 of the Federal Power Act a transaction pursuant to which John Hancock Life Insurance Company (U.S.A.) ("John Hancock") acquired certain passive, non-managing interests in ExGen Renewables ("Transaction").[2] The Exelon Sellers file this Notice to report to the Commission the consummation of the Transaction on July 6, 2017. As demonstrated below, the Transaction does not materially change the facts and circumstances that the Commission relied upon in granting market-based rate authority to the Exelon Sellers.

I. Communications

Communications with regard to this Notice should be addressed to:

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FERCeFilings@exeloncorp.com

II. Description of the Exelon Sellers

The Exelon Sellers own and operate wind generation facilities located in the balancing authority areas ("BAAs") of PJM Interconnection, L.L.C. ("PJM"), Midcontinent Independent System Operator, Inc. ("MISO"), Associated Electric Cooperative, Inc. ("AECI"), Southwest Power Pool, Inc. ("SPP"), and Idaho Power Company ("IPCO"). Each of the Exelon Sellers has market-based rate authority and is either an exempt wholesale generator ("EWG") under the Public Utility Holding Company Act of 2005 ("PUHCA") or

[2] *Beebe 1B Renewable Energy, LLC, et al.*, 159 FERC ¶ 62,247 (2017).

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the owner of a qualifying small power production facility ("QF") under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Except for Fourmile, each of the Exelon Sellers sells its entire output to an unaffiliated third party pursuant to a long-term contract.[3]

A. Exelon Sellers Located in the PJM BAA

The Exelon Sellers located in PJM are:

- Criterion Power Partners, LLC: Criterion owns and operates an approximately 70 MW wind generation facility located in Garrett County, Maryland. Criterion is an EWG[4] and has market-based rate authority.[5] Criterion sells its entire output to Old Dominion Electric Cooperative pursuant to a long-term agreement that terminates in 2030.

- Fourmile Wind Energy, LLC: Fourmile owns and operates an approximately 40 MW wind-powered QF located in Garrett County, Maryland.[6] Fourmile has market-based rate authority.[7]

B. Exelon Sellers Located in the MISO BAA

The Exelon Sellers located in MISO are:

- Beebe 1B Renewable Energy, LLC: Beebe 1B owns and operates an approximately 50 MW (summer) wind generation facility located in Gratiot County, Michigan. Beebe 1B is an EWG[8] and has market-based rate authority.[9] Beebe 1B sells its entire output to the Lansing Board of Water and Light and the Michigan Public Power Agency pursuant to long-term agreements that terminate in 2034.

- Beebe Renewable Energy, LLC: Beebe owns and operates an approximately 81.60 MW (summer) wind generation facility located in Gratiot County,

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[3] As explained below, Beebe, Harvest II, Michigan Wind 1, and Michigan Wind 2 sell their output under contracts that contemplate an annual cap on the amount of energy sold to the offtaker under the agreement. If and when the cap is reached, any energy generated in excess of the cap is sold into the market.

[4] *See* Notice of Effectiveness of Exempt Wholesale Generator Status, Docket No. EG10-70-000 (Dec. 1, 2010).

[5] *Criterion Power Partners, LLC*, Letter Order, Docket Nos. ER10-1443-000, *et al.* (Aug. 9, 2010).

[6] *See* Form 556, Notice of Self-Certification of Qualifying Facility Status, Docket No. QF14-721-000 (Aug. 13, 2014).

[7] *Fourmile Wind Energy, LLC*, 148 FERC ¶ 61,104 (2014).

[8] *See* Notice of Effectiveness of Exempt Wholesale Generator Status, Docket No. EG14-60-000 (Sept 11, 2014).

[9] *Beebe 1B Renewable Energy, LLC*, 148 FERC ¶ 61,099 (2014).

Michigan. Beebe is an EWG[10] and has market-based rate authority.[11] Beebe sells its entire output to Consumers Energy Company ("Consumers") pursuant to a long-term agreement that terminates in 2032.[12]

- Harvest Windfarm, LLC: Harvest owns and operates an approximately 52.8 MW (summer) wind-powered QF located in Huron County, Michigan.[13] Harvest has market-based rate authority[14] and sells its entire output to Wolverine Power Supply Cooperative, Inc. pursuant to a long-term agreement that terminates in 2028.

- Harvest II Windfarm, LLC: Harvest II owns and operates an approximately 59.40 MW (summer) wind-powered QF located in Huron County, Michigan.[15] Harvest II has market-based rate authority[16] and sells its entire output to Consumers pursuant to a long-term agreement that terminates in 2032.[17]

- Michigan Wind 1, LLC: Michigan 1 owns and operates an approximately 69 MW (summer) wind-powered QF located in Huron County, Michigan.[18] Michigan 1 has market-based rate authority[19] and sells its entire output to Consumers pursuant to long-term agreements that do not terminate before December 2018.[20]

- Michigan Wind 2, LLC: Michigan 2 owns and operates an approximately 90 MW (summer) wind generation facility located in Sanilac County, Michigan.

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[10] *See* Notice of Effectiveness of Exempt Wholesale Generator Status, Docket No. EG12-92-000 (Oct. 15, 2012).

[11] *Beebe Renewable Energy, LLC*, Letter Order, Docket Nos. ER12-2311-000, *et al.* (Sept. 20, 2012).

[12] Consumers purchases the output up to an annual energy cap. If and when the cap is reached, any energy generated in excess of the cap is sold into the MISO market.

[13] *See* Form 556, Notice of Self-Certification of Qualifying Facility Status, Docket No. QF07-29-000 (Nov. 8, 2006).

[14] *Harvest Windfarm, LLC*, Letter Order, Docket No. ER07-1246-000 (Aug. 31, 2007).

[15] *See* Form 556, Notice of Self-Certification of Qualifying Facility Status, Docket No. QF12-522-000 (Sept. 13, 2012).

[16] *Harvest II Windfarm, LLC*, Letter Order, Docket No. ER12-2201-000 (Sept. 14, 2012).

[17] Consumers purchases the output up to an annual energy cap. If and when the cap is reached, any energy generated in excess of the cap is sold into the MISO market.

[18] *See* Form 556, Notice of Self-Certification of Qualifying Facility Status, Docket No. QF05-228-000 (Sept. 28, 2005). Michigan Wind 1 is also an EWG. *Noble Thumb Windpark I, LLC*, 113 FERC ¶ 62,073 (2005).

[19] *Noble Thumb Windpark I, LLC*, 113 FERC ¶ 61,156 (2005).

[20] Consumers purchases the output up to an annual energy cap. If and when the cap is reached, any energy generated in excess of the cap is sold into the MISO market.

Michigan 2 is an EWG[21] and has market-based rate authority.[22] Michigan 2 sells its entire output to Consumers pursuant to a long-term agreement that terminates in 2031.[23]

C. Exelon Sellers Located in the AECI BAA

The Exelon Sellers located in the AECI BAA are:

- Cow Branch Wind Power, LLC: Cow Branch owns and operates an approximately 50.4 MW (summer) wind-powered QF located in Atchison County, Missouri.[24] Cow Branch has market-based rate authority[25] and sells its entire output to AECI pursuant to a long-term agreement that terminates in 2027.

- CR Clearing, LLC: CR Clearing owns and operates an approximately 50.4 MW (summer) wind-powered QF located in Nodaway Country, Missouri.[26] CR Clearing has market-based rate authority[27] and sells its entire output to AECI pursuant to a long-term agreement that terminates in 2027.

- Wind Capital Holdings, LLC: WCH owns and operates an approximately 56.7 MW (summer) wind-powered QF located in Gentry County, Missouri.[28] WCH has market-based rate authority[29] and sells its entire output to AECI pursuant to a long-term agreement that terminates in 2027.

D. Exelon Sellers Located in the SPP BAA

The Exelon Sellers located in SPP are:

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[21] *See* Notice of Effectiveness of Exempt Wholesale Generator Status, Docket No. EG11-100-000 (Oct. 17, 2011).

[22] *Michigan Wind 2, LLC*, Letter Order, Docket Nos. ER11-3989-000, *et al.* (Sept. 1, 2011).

[23] Consumers purchases the output up to an annual energy cap. If and when the cap is reached, any energy generated in excess of the cap is sold into the MISO market.

[24] *See* Form 556, Notice of Self-Certification of Qualifying Facility Status, Docket No. QF07-253-000 (July 23, 2007).

[25] *CR Clearing, LLC and Cow Branch Wind Power, LLC*, Letter Order, Docket Nos. ER07-1222-000 and ER07-1223-000 (Aug 31, 2007).

[26] *See* Form 556, Notice of Self-Certification of Qualifying Facility Status, Docket No. QF07-248-000 (July 23, 2007).

[27] *CR Clearing, LLC and Cow Branch Wind Power, LLC*, Letter Order, Docket Nos. ER07-1222-000 and ER07-1223-000 (Aug 31, 2007).

[28] *See* Form 556, Notice of Self-Certification of Qualifying Facility Status, Docket No. QF07-222-000 (July 19, 2007).

[29] *Wind Capital Holdings, LLC*, 120 FERC ¶ 61,276 (2007).

- Bluestem Wind Energy, LLC: Bluestem owns and operates an approximately 198 MW (summer) wind generation facility located in Beaver County, Oklahoma. Bluestem is an EWG[30] and has market-based rate authority.[31] Bluestem sells its entire output to Google Energy LLC pursuant to a long-term agreement that terminates in 2031.

- Shooting Star Wind Project, LLC: Shooting Star owns and operates an approximately 104 MW (summer) wind generation facility located in Kiowa County, Kansas. Shooting Star is an EWG[32] and has market-based rate authority.[33] Shooting Star sells its entire output to Mid-Kansas Electric Company, LLC pursuant to a long-term agreement that terminates in 2032.

- Wildcat Wind, LLC: Wildcat owns and operates an approximately 27.3 MW (summer) wind-powered QF located in Lea County, New Mexico.[34] Wildcat has market-based rate authority[35] and sells its entire output to Western Farmers Electric Cooperative pursuant to a long-term agreement that terminates in 2032.

E. Exelon Sellers Located in the IPCO BAA

The Exelon Sellers located in the IPCO BAA are:

- Cassia Gulch Wind Park LLC: Cassia Gulch owns and operates an approximately 18.9 MW (summer) wind-powered QF located in Twin Falls County, Idaho.[36] Cassia Gulch has market-based rate authority[37] and sells its entire output to Idaho Power Company pursuant to a long-term agreement that terminates in 2030.

- High Mesa Energy, LLC: High Mesa owns and operates an approximately 39.9 MW (summer) wind-powered QF located in Elmore County, Idaho.[38] High Mesa

[30] *See* Notice of Effectiveness of Exempt Wholesale Generator Status, Docket No. EG17-15-000 (Jan. 5, 2017).

[31] *Bluestem Wind Energy, LLC*, Letter Order, Docket No. ER16-2363-000 (Sept. 15, 2016).

[32] *See* Notice of Effectiveness of Exempt Wholesale Generator Status, Docket No. EG12-69-000 (Aug. 6, 2012).

[33] *Shooting Star Wind Project, LLC*, Letter Order, Docket No. ER12-1829-000 (July 18, 2012).

[34] *See* Form 556, Notice of Self-Certification of Qualifying Facility Status, Docket No. QF12-412-000 (June 15, 2012).

[35] *Wildcat Wind, LLC*, Letter Order, Docket No. ER12-1223-001 (Apr. 30, 2012).

[36] *See* Form 556, Notice of Self-Certification of Qualifying Facility Status, Docket No. QF05-180-000 (Aug. 4, 2005).

[37] *Cassia Gulch Wind Park LLC and Tuana Springs Energy, LLC*, Letter Order, Docket Nos. ER10-75-000 and ER10-87-000 (Nov. 30, 2009).

[38] *See* Form 556, Notice of Self-Certification of Qualifying Facility Status, Docket No. QF13-77-000 (Nov. 8, 2012).

has market-based rate authority[39] and sells its entire output to Idaho Power Company pursuant to a long-term agreement that terminates in 2032.

- Tuana Springs Energy, LLC: Tuana Springs owns and operates an approximately 16.8 MW (summer) wind-powered QF located in Twin Falls County, Idaho.[40] Tuana Springs has market-based rate authority[41] and sells its entire output to Idaho Power Company pursuant to a long-term agreement that terminates in 2030.

III. Description of the Transaction

The Exelon Sellers are direct or indirect subsidiaries of ExGen Renewables. Prior to the Transaction, ExGen Renewables was a direct wholly owned subsidiary of ExGen Renewables Holdings, LLC ("ExGen Renewables Holdings"), which is an indirect subsidiary of Exelon Generation. Pursuant to the Transaction, John Hancock acquired from ExGen Renewables Holdings a 49 percent of the membership interests in ExGen Renewables, which was then converted into Class B non-managing membership interests. In addition, ExGen Renewables Holdings' 51 percent membership interests in ExGen Renewables were converted into Class A managing membership interests and ExGen Renewables Holdings was appointed as the managing member of ExGen Renewables.

As a result of the Transaction, Exelon Generation indirectly owns, through ExGen Renewables Holdings, all of the Class A managing membership interests in ExGen Renewables and continues to have, through its subsidiaries, day-to-day control over the Exelon Sellers and their jurisdictional activities. As Class B member of ExGen Renewables, John Hancock does not have the right or authority to manage ExGen Renewables or the Exelon Sellers and is entitled only to receive certain tax benefits, cash distributions, and rights to cash (or other assets) upon liquidation. As a passive investor, John Hancock has only limited rights with respect to the actions of ExGen Renewables and the Exelon Sellers, such as consent rights necessary for John Hancock to protect its economic investment interests, including, but not limited to: the sale, lease or disposition of significant assets; the incurrence of significant indebtedness; participation by ExGen Renewables or the Exelon Sellers in any business or activity not within their purpose or change in such purpose; mergers; the settlement of significant litigation; and the cancellation, suspension or termination of any material contract. At all times, Exelon Generation, through its subsidiaries, retains day-to-day control of the Exelon Sellers. Accordingly, John Hancock has only non-controlling, passive equity interests in ExGen Renewables and the Exelon Sellers.

As demonstrated by the information in Attachment A hereto, the limited consent rights attached to the Class B membership interests held by John Hancock are substantially

[39] *High Mesa Energy, LLC*, Letter Order, Docket No. ER12-2528-000 (Oct. 16, 2012).

[40] *See* Form 556, Notice of Self-Certification of Qualifying Facility Status, Docket No. QF08-742-000 (Sept. 8, 2008).

[41] *Cassia Gulch Wind Park LLC and Tuana Springs Energy, LLC*, Letter Order, Docket Nos. ER10-75-000 and ER10-87-000 (Nov. 30, 2009).

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similar to the consent rights held by passive tax equity investors in *AES Creative Resources*.[42] In *AES Creative Resources* the Commission held that passive tax equity investors with limited consent rights with respect to major decisions of electric generation companies were not affiliates of such electric generation companies for purposes of the Commission's market power analysis. Accordingly, as the holder of Class B passive membership interests in ExGen Renewables, John Hancock is not affiliated with the Exelon Sellers under the Commission's regulations.[43] Therefore, the Transaction does not raise any horizontal or vertical market power concerns.

For the reasons set forth above, the Transaction did not materially change the facts and circumstances that the Commission relied upon in granting market-based rate authority to the Exelon Sellers. Therefore, the Exelon Sellers respectfully request that the Commission accept for filing this Notice and find that no further inquiry is necessary.

Respectfully submitted,

/s/ Vincenzo Franco
Vincenzo Franco
Associate General Counsel
Exelon Corporation

Enclosures

[42] *AES Creative Resources, L.P.*, 129 FERC ¶ 61,239 (2009). Confidential Exhibit 1 to Attachment A includes relevant excerpts from ExGen Renewables' Amended and Restated Limited Liability Company Agreement, which demonstrate that John Hancock's interests in ExGen Renewables are passive, non-managing interests with limited consent rights. Pursuant to 18 C.F.R. § 388.112, the Exelon Sellers request confidential treatment of Exhibit 1 to Attachment A, because it contains sensitive commercial information that is privileged and not otherwise publicly available. The information in Exhibit 1 to Attachment A is provided for use by Commission Staff only and should not be released to the public. A proposed form of protective agreement is attached as Attachment B.

[43] The Exelon Sellers provide herewith a current asset appendix in the format set forth in Appendix B to 18 C.F.R. Part 35, Subpart H.

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ATTACHMENT A

ExGen Renewables Partners, LLC - Demonstration of Passive Investment

The Exelon Sellers[44] are public utilities with market-based rate authority that are direct or indirect subsidiaries of ExGen Renewables Partners, LLC ("ExGen Renewables"). Consistent with Commission's precedent in *AES Creative Resources, L.P.,* 129 FERC ¶ 61,239 (2000) and the practice followed in other proceedings involving passive equity investments, the Exelon Sellers provide the following information regarding the passive nature of the Class B membership interests in ExGen Renewables held by John Hancock Life Insurance Company (U.S.A.) ("John Hancock").

1. **Please clarify whether any of the passive interests include voting rights (i.e., common stock or the equivalent of common stock).**

   The Class B membership interests in ExGen Renewables held by John Hancock do not confer full voting rights. The Class B membership interests only provide for limited consent or approval rights under specific circumstances with respect to certain material actions and events in order to protect John Hancock's economic investment and do not confer rights to control or manage the day-to-day activities of ExGen Renewables or the Exelon Sellers. The limited consent rights attached to John Hancock's interests are described below and in confidential Exhibit 1 to this Attachment.

2. **If the passive interests are non-voting, please clarify the following:**

[44] The Exelon Sellers are: Beebe 1B Renewable Energy, LLC, Beebe Renewable Energy, LLC, Bluestem Wind Energy, LLC, Cassia Gulch Wind Park LLC, Cow Branch Wind Power, LLC, CR Clearing, LLC, Criterion Power Partners, LLC, Fourmile Wind Energy, LLC, Harvest Windfarm, LLC, Harvest II Windfarm, LLC, High Mesa Energy, LLC, Michigan Wind 1, LLC, Michigan Wind 2, LLC, Shooting Star Wind Project, LLC, Tuana Springs Energy, LLC, Wildcat Wind, LLC, and Wind Capital Holdings, LLC

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A. Do they represent a separate class of security in [the Public Utility's] ownership structure?

Yes. ExGen Renewables has two classes of membership interests. Class A managing membership interests are held by ExGen Renewables Holdings, LLC ("ExGen Renewables Holdings"), which is the managing member of ExGen Renewables. Class B passive, non-managing membership interests are held by John Hancock.

1. If so, do such securities confer on the holder limited consent/veto rights over major corporate actions that could affect the value of the holder's investment?

Yes. Confidential Exhibit 1 to this Attachment contains relevant excerpts from ExGen Renewables' Amended and Restated Limited Liability Company Agreement ("LLC Agreement"). Such excerpts show that John Hancock's limited consent rights relate to major corporate actions that could affect the value of John Hancock's investment.

B. Is there a list describing the major corporate actions over which the holders of the passive or non-voting securities have consent/veto rights?

Under the LLC Agreement, John Hancock has consent/veto rights over the following major corporate actions: issuance of new membership interests or modification of the rights associated with existing ones; corporate mergers or consolidations; acquisition of equity interests or assets other than in the ordinary course of business; sale, lease or disposition of equity interests or any significant asset; execution of contracts involving significant payments or expenditures; modification or termination of any material contract; incurrence of significant indebtness; issuance of significant guarantees; changes to the tax

entity classification and to other tax treatments or accounting practices; requests for additional capital contributions; institution or commencement of bankruptcy proceedings; commencement or settlement of significant litigation; changes to corporate names, corporate business, or corporate structures; and initial public offering or listing of shares.

1. If so, please file a publicly available exhaustive list describing the major corporate actions over which the holders of the passive or non-voting securities have consent/veto rights.

See above.

C. Do the holders of the asserted passive or non-voting securities have any power to remove the manager (e.g., the general partner if a partnership, or managing member if a manager-managed limited liability company) of the facility?

Under the LLC Agreement, removal of the managing member of ExGen Renewables requires unanimous consent of the members (other than any member who is, or is an affiliate of, the managing member). Therefore removal of the managing member requires the consent of John Hancock as the holder of Class B passive membership interests. Removal of the managing member may occur only if the managing member engaged in fraud, is dissolved, ceases business or is bankrupt, or if the managing member engaged in gross negligence or willful misconduct which could reasonably be expected to have a material adverse effect on ExGen Renewables.

1. If so, is their power to remove limited to "cause," i.e. situations such as criminal activity/fraud on the part of the manager?

The managing member may be removed only for cause. See above.

2. Or, under what circumstances can they remove the manager?

N/A.

D. If it is asserted that the securities in question confer only limited approval/veto rights, who exercises day-to-day control over [the Public Utility's] jurisdictional facilities?

ExGen Renewables holds the Class A membership interests in ExGen Renewables and is the managing member. The LLC Agreement provides that the managing member conducts, directs and exercises day-to-day control over all activities of ExGen Renewables and the Exelon Sellers.

E. Do the holders of the asserted passive or non-voting securities have any day-to-day input or control over the facility?

No. John Hancock does not have any day-to-day input or control over the electric generation facilities owned by the Exelon Sellers.

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EXHIBIT 1 TO ATTACHMENT A

Public Version

CUI/PRIV Information Has Been Removed

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ATTACHMENT B

Protective Agreement

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Beebe 1B Renewable Energy, LLC	**)**	**Docket No.**	**ER14-2144-___**
Beebe Renewable Energy, LLC	**)**	**Docket No.**	**ER12-2311-___**
Bluestem Wind Energy, LLC	**)**	**Docket No.**	**ER16-2363-____**
Cassia Gulch Wind Park LLC	**)**	**Docket No.**	**ER11-2016-___**
Cow Branch Wind Power, LLC	**)**	**Docket No.**	**ER11-2014-___**
CR Clearing, LLC	**)**	**Docket No.**	**ER11-2013-___**
Criterion Power Partners, LLC	**)**	**Docket No.**	**ER10-3308-___**
Fourmile Wind Energy, LLC	**)**	**Docket No.**	**ER14-2145-___**
Harvest Windfarm, LLC	**)**	**Docket No.**	**ER11-2011-___**
Harvest II Windfarm, LLC	**)**	**Docket No.**	**ER12-2201-___**
High Mesa Energy, LLC	**)**	**Docket No.**	**ER12-2528-___**
Michigan Wind 1, LLC	**)**	**Docket No.**	**ER11-2009-___**
Michigan Wind 2, LLC	**)**	**Docket No.**	**ER11-3989-___**
Shooting Star Wind Project, LLC	**)**	**Docket No.**	**ER12-1829-___**
Tuana Springs Energy, LLC	**)**	**Docket No.**	**ER11-2007-___**
Wildcat Wind, LLC	**)**	**Docket No.**	**ER12-1223-___**
Wind Capital Holdings, LLC	**)**	**Docket No.**	**ER11-2005-___**

PROTECTIVE AGREEMENT

This Protective Agreement ("Agreement") is entered into this ___ day of _____, 20__ by and between _____ ("Applicant") and _____ ("Intervenor"), and shall govern the use of all Protected Materials produced by Applicant to Intervenor, or vice versa, in connection with the proceeding before the Federal Energy Regulatory Commission (the "Commission") in Docket No. ER__-___-___. Applicant and Intervenor are sometimes referred to herein individually as a "Party" or jointly as the "Parties."

1. Applicant filed Protected Materials in the captioned Commission proceeding and Intervenor is a Participant in such proceeding, as the term Participant is defined in 18 C.F.R. § 382.102(b), or has filed a motion to intervene or a notice of intervention in such proceeding. Applicant and Intervenor enter into this Agreement in accordance with their respective rights and obligations set forth in 18 C.F.R. § 388.112(b)(2). Notwithstanding any order terminating such proceeding, this Agreement shall remain in effect until specifically modified or terminated by the Commission or court of competent jurisdiction.

2. This Agreement applies to the following two categories of Protected Materials: (A) a Party may designate as protected those materials which customarily are treated by that Party as sensitive or proprietary, which are not available to the public, and which, if disclosed freely, would subject that Party or its customers to risk of competitive disadvantage or other business injury; and (B) a Party shall designate as protected those materials which contain critical energy infrastructure information, as defined in 18 C.F.R. § 388.113(c)(1) ("Critical Energy Infrastructure Information").

3. Definitions – For purposes of this Order:

(a) (1) The term "Protected Materials" means (A) materials provided by a Party in association with this proceeding and designated by such Party as protected; (B) any information contained in or obtained from such designated materials; (C) any other materials that are made subject to this Protective Order by the Commission, by any court or other body having appropriate authority, or by agreement of the Participants; (D) notes of Protected Materials; and (E) copies of Protected Materials. The Party producing the Protected Materials shall physically mark them on each page as "PROTECTED MATERIALS" or with words of similar import as long as the term "Protected Materials" is included in that designation to indicate that they are Protected Materials. If the Protected Materials contain Critical Energy Infrastructure Information, the Party producing such information shall additionally mark on each page containing such information the words "Contains Critical Energy Infrastructure Information—"Do Not Release."

(2) The term "Notes of Protected Materials" means memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses materials described in Paragraph 3(a)(1). Notes of Protected Materials are subject to the same restrictions provided in this Agreement for Protected Materials except as specifically provided in this Agreement.

(3) Protected Materials shall not include (A) any information or document contained in the publicly available files of the Commission or of any other federal or state agency, or any federal or state court, unless the information or document has been determined to be protected by such agency or court, or (B) information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Agreement, or (C) any information or document labeled as "Non-Internet Public" by a Party, in accordance with Paragraph 30 of FERC Order No. 630, FERC Stats. & Regs. ¶ 31,140 (2003). Protected Materials do include any information or documents contained in the files of the Commission that have been designated as Critical Energy Infrastructure Information.

(b) The term "Non-Disclosure Certificate" shall mean the certificate annexed hereto by which Reviewing Representatives have been granted access to Protected Materials shall certify their understanding that such access to Protected Materials is provided pursuant to the terms and restrictions of this Agreement, and that they have read the Agreement and agree to be bound by it. Each Party shall provide a copy of the Non-Disclosure Certificate(s) executed by its Reviewing Representative(s) to the other Party prior to such Reviewing Representative(s) receiving access to any Protected Materials.

(c) The term "Reviewing Representative" shall mean a person who has signed a Non-Disclosure Certificate and who is:

(1) an attorney retained by a Party for purposes of this proceeding;

(2) attorneys, paralegals, and other employees associated for purposes of this proceeding with an attorney described in Paragraph (3)(c)(1);

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(3) an expert or an employee of an expert retained by a Party for the purpose of advising, preparing for or testifying in this proceeding;

(4) a person designated as a Reviewing Representative by order of the Commission; or

(5) employees or other representatives of a Party with significant responsibility for matters involving this proceeding.

4. Protected Materials shall be made available under the terms of this Agreement only to Parties and only through their Reviewing Representative(s) as provided in Paragraphs 7–9.

5. Protected Materials shall remain available to a Party until the later of the date that an order terminating this proceeding becomes no longer subject to judicial review, or the date that any other Commission proceeding relating to the Protected Material is concluded and no longer subject to judicial review. If requested to do so in writing after that date, the Party shall, within fifteen days of such request, return the Protected Materials (excluding Notes of Protected Materials) to the Party that produced them, or shall destroy the materials, except that copies of filings, official transcripts and exhibits in this proceeding that contain Protected Materials, and Notes of Protected Materials may be retained, if they are maintained in accordance with Paragraph 6, below. Within such time period the Party, if requested to do so, shall also submit to the producing Party an affidavit stating that, to the best of its knowledge, all Protected Materials and all Notes of Protected Materials have been returned or have been destroyed or will be maintained in accordance with Paragraph 6. To the extent Protected Materials are not returned or destroyed, they shall remain subject to this Agreement.

6. All Protected Materials shall be maintained by the Party in a secure place. Access to those materials shall be limited to those Reviewing Representatives specifically authorized pursuant to Paragraphs 8–9.

7. Protected Materials shall be treated as confidential by the Party and its Reviewing Representative(s) in accordance with the certificate executed pursuant to Paragraph 9. Protected Materials shall not be used except as necessary for the conduct of this proceeding, nor shall they be disclosed in any manner to any person except a Reviewing Representative who is engaged in the conduct of this proceeding and who needs to know the information in order to carry out that person's responsibilities in this proceeding. Reviewing Representatives may make copies of Protected Materials, but such copies become Protected Materials. Reviewing Representatives may make notes of Protected Materials, which shall be treated as Notes of Protected Materials if they disclose the contents of Protected Materials.

8. (a) If a Reviewing Representative's scope of employment includes the marketing of energy or the buying or selling of electric generation or transmission assets, the direct supervision of any employee or employees whose duties include the foregoing, the provision of consulting services to any person whose duties include the foregoing, or the direct supervision of any employee or employees whose duties include the foregoing, such Reviewing Representative may not use information contained in any Protected Materials

obtained through this proceeding to give any Party or any competitor of any Party a commercial advantage.

(b) In the event that a Party wishes to designate as a Reviewing Representative a person not described in Paragraph 3(c) above, the Party shall seek agreement from the Party providing the Protected Materials. If an agreement is reached that person shall be a Reviewing Representative pursuant to Paragraphs 3(c) above with respect to those materials. If no agreement is reached, the Party shall submit the disputed designation to the Commission for resolution.

9. (a) A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Protected Materials pursuant to this Agreement unless that Reviewing Representative has first executed a Non-Disclosure Certificate; provided, that if an attorney qualified as a Reviewing Representative has executed such a certificate, the paralegals, secretarial and clerical personnel under the attorney's instruction, supervision or control need not do so. A copy of each Non- Disclosure Certificate shall be provided to counsel for the Party asserting confidentiality prior to disclosure of any Protected Material to that Reviewing Representative.

(b) Attorneys qualified as Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this Agreement.

10. Any Reviewing Representative may disclose Protected Materials to any other Reviewing Representative as long as the disclosing Reviewing Representative and the receiving Reviewing Representative both have executed a Non-Disclosure Certificate. In the event that any Reviewing Representative to whom the Protected Materials are disclosed ceases to be engaged in these proceedings, or is employed or retained for a position whose occupant is not qualified to be a Reviewing Representative under Paragraph 3(c), access to Protected Materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Non-Disclosure Certificate shall continue to be bound by the provisions of this Agreement and the certification.

11. Subject to Paragraph 18, the Commission shall resolve any disputes arising under this Agreement. Prior to presenting any dispute under this Agreement to the Commission, the parties to the dispute shall use their best efforts to resolve it. If a Party contests the designation of materials as protected, it shall notify the Party that provided the Protected Materials by specifying in writing the materials whose designation is contested. This Agreement shall automatically cease to apply to such materials five (5) business days after the notification is made unless the Party, within said 5-day period, files a motion with the Commission, with supporting affidavits, demonstrating that the materials should continue to be protected. In any challenge to the designation of materials as protected, the burden of proof shall be on the Party seeking protection. If the Commission finds that the materials at issue are not entitled to protection, the procedures of Paragraph 18 shall apply. The procedures described above shall not apply to Protected Materials designated by a Party as Critical Energy Infrastructure Information. Materials so designated shall remain protected and subject to the provisions of this Agreement unless a Party requests and obtains a

determination from the Commission's Critical Energy Infrastructure Information Coordinator that such materials need not remain protected.

12. All copies of all documents reflecting Protected Materials, including the portion of any hearing testimony, exhibits, transcripts, briefs and other documents which refer to Protected Materials, shall be filed and served in sealed envelopes or by other appropriate means endorsed to the effect that they are protected pursuant to this Agreement. Such documents shall be marked "PROTECTED MATERIALS" and shall be filed under seal and served under seal upon the Commission and all Reviewing Representatives who are on the service list. Such documents containing Critical Energy Infrastructure Information shall be additionally marked "Contains Critical Energy Infrastructure Information Do Not Release." For anything filed under seal, redacted versions or, where an entire document is protected, a letter indicating such, will also be filed with the Commission and served on all parties on the service list. Counsel for the producing Party shall, upon the request of a Party, provide a list of Reviewing Representatives who are entitled to receive such material. Counsel shall take all reasonable precautions necessary to assure that Protected Materials are not distributed to unauthorized persons.

13. If any Party desires to include, utilize or refer to any Protected Materials or information derived therefrom in pleadings, testimony or exhibits to these proceedings in such a manner that might require disclosure of such material to persons other than Reviewing Representatives, such Party shall first notify both counsel for the disclosing Party and the Commission of such desire, identifying with particularity each of the Protected Materials. Thereafter, use of such Protected Materials will be governed by procedures determined by the Commission.

14. Nothing in this Agreement shall be construed as precluding any Party from objecting to the use of Protected Materials on any legal grounds.

15. Nothing in this Agreement shall preclude any Party from requesting the Commission or any other body having appropriate authority to find that this Agreement should not apply to all or any materials previously designated as Protected Materials pursuant to this Agreement. The Commission may alter or amend this Agreement as circumstances warrant at any time during the course of this proceeding.

16. The Parties may amend this Agreement only by mutual consent and in writing; provided, however, that a Party has the right to seek changes to this Agreement as appropriate from the Commission.

17. All Protected Materials filed with the Commission or any other judicial or administrative body, in support of, or as a part of, a motion, other pleading, brief, or other document, shall be filed and served in sealed envelopes or other appropriate means bearing prominent markings indicating that the contents include Protected Materials subject to this Agreement. Such documents containing Critical Energy Infrastructure Information shall be additionally marked "Contains Critical Energy Infrastructure Information – Do Not Release."

18. If the Commission finds at any time in the course of this proceeding that all or part of the Protected Materials need not be protected, those materials shall, nevertheless, be subject to the protection afforded by this Agreement for three (3) business days from the date of issuance of the Commission's decision, and if the Party seeking protection files an interlocutory appeal or requests that the issue be certified to the Commission, for an additional seven (7) business days. No Party waives its rights to seek additional administrative or judicial remedies after the Commission's decision respecting Protected Materials or Reviewing Representatives, or the Commission's denial of any appeal thereof. The provisions of 18 C.F.R. §§ 388.112 and 388.113 shall apply to any requests for Protected Materials in the files of the Commission under the Freedom of Information Act (5 U.S.C. § 552).

19. Nothing in this Agreement shall be deemed to preclude any Party from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced in this proceeding under this Agreement.

20. No Party waives the right to pursue any other legal or equitable remedies that may be available in the event of actual or anticipated disclosure of Protected Materials.

21. The contents of Protected Materials or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with this Agreement and shall be used only in connection with this proceeding. Any violation of this Agreement and of any Non-Disclosure Certificate executed hereunder shall constitute a violation of an order of the Commission.

IN WITNESS WHEREOF, the Parties each have caused this Protective Agreement to be signed by their respective duly authorized representatives as of the date first set forth above.

By:	By:
Name:	Name:
Title:	Title:
Representing Applicant	Representing Intervenor

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Beebe 1B Renewable Energy, LLC	**)**	**Docket No.**	**ER14-2144-___**
Beebe Renewable Energy, LLC	**)**	**Docket No.**	**ER12-2311-___**
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High Mesa Energy, LLC	**)**	**Docket No.**	**ER12-2528-___**
Michigan Wind 1, LLC	**)**	**Docket No.**	**ER11-2009-___**
Michigan Wind 2, LLC	**)**	**Docket No.**	**ER11-3989-___**
Shooting Star Wind Project, LLC	**)**	**Docket No.**	**ER12-1829-___**
Tuana Springs Energy, LLC	**)**	**Docket No.**	**ER11-2007-___**
Wildcat Wind, LLC	**)**	**Docket No.**	**ER12-1223-___**
Wind Capital Holdings, LLC	**)**	**Docket No.**	**ER11-2005-___**

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Protected Materials is provided to me pursuant to the terms and restrictions of the Protective Agreement dated _____ by and between [Applicant] and [Intervenor] concerning materials in Federal Energy Regulatory Commission Docket No. _____, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by it. I understand that the contents of the Protected Materials, any notes or other memoranda, or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with that Protective Agreement. I acknowledge that a violation of this certificate constitutes a violation of an order of the Federal Energy Regulatory Commission.

By: _____
Name: _____
Title: _____
Representing: _____

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CERTIFICATE OF SERVICE

I hereby certify that this day I have caused to be served the foregoing document upon each person designated on the official service lists compiled by the Secretary in this proceeding.

Dated at Baltimore, MD this 7th day of August, 2017.

/s/ Vincenzo Franco
Vincenzo Franco
Associate General Counsel
Exelon Corporation
1310 Point Street, 8th Floor
Baltimore, MD 21231
(410) 470-2593
vincenzo.franco@exeloncorp.com

Electric Generating Facilities and Assets

Asset Appendix: Generation Assets - July 2017

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned by**	**Controlled by**	**Date Control Transferred**	**Location**		**In-Service Date**	**Capacity Rating: Nameplate (MW)**	**Capacity Rating: Used in Filing (MW)**	**Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative**	**End Note Number (Enter text in End Note Tab)**
						Market / Balancing Authority Area	**Geographic Region**					
Beebe 1B Renewable Energy, LLC	ER14-2144	Beebe 1b WF	Beebe 1B Renewable Energy, LLC	Beebe 1B Renewable Energy, LLC	N/A	MISO	Central	12/12/2014	50.40	50.40	S	
Beebe Renewable Energy, LLC	ER12-2311	Beebe 1a WF	Beebe Renewable Energy, LLC	Beebe Renewable Energy, LLC	N/A	MISO	Central	1/17/2013	81.60	81.60	S	
Exelon Generation Company, LLC	ER00-3251	Clinton	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	MISO	Central	11/1/1987	1138.30	1065.00	S	
Harvest II Windfarm, LLC	ER12-2201 QF12-522	Harvest 2 WF	Harvest II Windfarm, LLC	Harvest II Windfarm, LLC	N/A	MISO	Central	11/28/2012	59.40	59.40	S	
Harvest Windfarm, LLC	ER07-1246 QF07-29	Harvest 1 WF	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	2/28/2008	52.80	52.80	S	
Michigan Wind 1, LLC	ER05-1511 QF05-228	Michigan Wind 1 WF	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	12/16/2008	69.00	69.00	S	
Michigan Wind 2, LLC	ER11-3989	Michigan Wind 2 WF	Michigan Wind 2, LLC	Michigan Wind 2, LLC	N/A	MISO	Central	1/5/2012	90.00	90.00	S	
Atlantic City Electric Company	ER96-1361	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Commonwealth Edison Company	ER98-1734	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Energy Commodities Group Maine, LLC	ER02-699	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Energy Services, Inc.	ER07-650	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation NewEnergy, Inc.	ER96-1387	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Delmarva Power & Light Company	ER96-2571	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Exelon FitzPatrick, LLC	ER17-2201	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
PECO Energy Company	ER01-1147	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Potomac Electric Power Company	ER98-4138	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Mystic Power, LLC	ER10-2281	Mystic 7	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/1975	617.00	574.55	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	278.60	228.77	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	278.60	229.97	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	315.00	244.58	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	278.60	232.36	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	278.60	233.47	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	315.00	248.07	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic Jet	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/1969	14.20	8.95	S	
Exelon Framingham LLC	ER98-1943	Framingham Jet 1	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	3/1/1970	14.20	9.62	S	
Exelon Framingham LLC	ER98-1943	Framingham Jet 2	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/1969	14.20	10.13	S	
Exelon Framingham LLC	ER98-1943	Framingham Jet 3	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/1969	14.20	10.22	S	
Exelon New Boston, LLC	ER98-1943	New Boston Jet	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	9/1/1966	18.60	16.00	S	1
Exelon West Medway II, LLC	ER16-2708	West Medway 4	Exelon West Medway II, LLC	Exelon West Medway II, LLC	N/A	ISO-NE	Northeast	6/1/2018	100.00	97.40	S	
Exelon West Medway II, LLC	ER16-2708	West Medway 5	Exelon West Medway II, LLC	Exelon West Medway II, LLC	N/A	ISO-NE	Northeast	6/1/2018	100.00	97.40	S	
Exelon West Medway, LLC	ER98-1943	West Medway Jet 1	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/1970	45.00	42.00	S	
Exelon West Medway, LLC	ER98-1943	West Medway Jet 2	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	3/1/1971	45.00	39.85	S	
Exelon West Medway, LLC	ER98-1943	West Medway Jet 3	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/1970	45.00	42.00	S	
Exelon Wyman, LLC	ER98-1943	Wyman 4	Exelon Wyman, LLC (5.9%)	FPL Energy Wyman IV LLC	N/A	ISO-NE	Northeast	1/1/1978	632.40	602.00	S	2
Exelon Generation Company, LLC	ER00-3251	Fitzpatrick 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	NYISO	Northeast	7/1/1975	883.30	837.50	S	
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 1	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	12/1/1969	641.80	626.10	S	
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 2	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	8/1/1988	1428.45	1289.60	S	3
R. E. Ginna Nuclear Power Plant, LLC	ER04-485	Ginna	R. E. Ginna Nuclear Power Plant, LLC	R. E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	7/1/1970	614.00	582.00	S	
Clinton Battery Utility, LLC	ER16-2194	Clinton Battery Project	Clinton Battery Utility, LLC	Clinton Battery Utility, LLC	N/A	PJM	Northeast	10/14/2016	10.00	10.00	S	
Criterion Power Partners, LLC	ER10-1443	Criterion WF	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	2/4/2011	70.00	70.00	S	
Exelon Generation Company, LLC	ER00-3251	Braidwood 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/1/1988	1224.90	1183.00	S	
Exelon Generation Company, LLC	ER00-3251	Braidwood 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1988	1224.90	1154.00	S	
Exelon Generation Company, LLC	ER00-3251	Byron 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/1/1985	1224.90	1164.00	S	
Exelon Generation Company, LLC	ER00-3251	Byron 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/1987	1224.90	1136.00	S	
Exelon Generation Company, LLC	ER00-3251	Dresden 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/1970	1009.00	902.00	S	
Exelon Generation Company, LLC	ER00-3251	Dresden 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1971	1009.00	895.00	S	
Exelon Generation Company, LLC	ER00-3251	LaSalle 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	1/1/1984	1170.00	1130.00	S	
Exelon Generation Company, LLC	ER00-3251	LaSalle 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1984	1170.00	1133.90	S	
Exelon Generation Company, LLC	ER00-3251	Quad Cities 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1972	1009.30	908.00	S	4
Exelon Generation Company, LLC	ER00-3251	Quad Cities 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1972	1009.30	911.00	S	5
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Fair Wind Power Partners, LLC	ER15-2293	Fair Wind WF	Fair Wind Power Partners, LLC	Fair Wind Power Partners, LLC	N/A	PJM	Northeast	11/24/2015	30.00	30.00	S	
Fourmile Wind Energy, LLC	ER14-2145 QF14-721	Fourmile Ridge WF	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	1/15/2015	40.00	40.00	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 1	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	

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Electric Generating Facilities and Assets

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned by	Controlled by	Date Control Transferred	Location		In-Service Date	Capacity Rating: Nameplate (MW)	Capacity Rating: Used in Filing (MW)	Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative	End Note Number (Enter text in End Note Tab)
						Market / Balancing Authority Area	Geographic Region					
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 2	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 3	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 4	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 5	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 1	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM 5004/5005	Northeast	5/1/1975	918.00	866.00	S	
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 2	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM 5004/5005	Northeast	4/1/1977	910.70	841.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Gould Street 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	12/1/1952	103.50	97.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.60	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	15.60	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.50	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	16.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	1/1/1972	53.10	52.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	4/1/1972	53.10	51.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	4/1/1972	53.10	52.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 51	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1995	192.00	139.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/28/2015	141.00	109.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	8/1/1970	20.70	15.30	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	8/1/1970	20.70	16.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	20.70	14.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	20.70	14.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Riverside 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	25.00	19.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Riverside 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	25.00	20.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Westport 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	2/1/1969	121.50	115.80	S	
Exelon Generation Company, LLC	ER00-3251	TMI 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM 5004/5005	Northeast	9/2/1974	980.90	802.80	S	
Exelon Generation Company, LLC	ER00-3251	Chester 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/7/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Chester 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/20/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Chester 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/6/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/1/1928	45.00	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/25/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/4/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/1/1928	36.00	36.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/6/1928	48.00	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/5/1928	47.70	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1928	36.00	36.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/1/1928	47.70	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1928	48.00	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/10/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/25/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 21	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 22	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 31	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	8/6/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 32	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	8/8/1974	68.30	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 41	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 42	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/7/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/19/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/12/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/20/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 20	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/24/1974	391.00	380.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 30	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/7/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/29/1976	391.00	380.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 40	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/21/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Fairless Hills A	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1996	30.00	30.00	S	
Exelon Generation Company, LLC	ER00-3251	Fairless Hills B	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1996	30.00	30.00	S	

Electric Generating Facilities and Assets

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Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned by	Controlled by	Date Control Transferred	Location		In-Service Date	Capacity Rating: Nameplate (MW)	Capacity Rating: Used in Filing (MW)	Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative	End Note Number (Enter text in End Note Tab)
						Market / Balancing Authority Area	Geographic Region					
Exelon Generation Company, LLC	ER00-3251	Falls 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/22/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Falls 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/10/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Falls 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/28/1970	21.10	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Limerick 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/1/1986	1138.50	1119.70	S	
Exelon Generation Company, LLC	ER00-3251	Limerick 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	1/1/1990	1138.50	1122.10	S	
Exelon Generation Company, LLC	ER00-3251	Moser 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/9/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Moser 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/29/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Moser 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/11/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/10/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/10/1967	134.00	133.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	134.00	133.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/10/1968	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/10/1968	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Oyster Creek 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1969	550.00	607.70	S	
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/5/1974	1244.80	1223.70	S	6
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/23/1974	1377.00	1226.70	S	7
Exelon Generation Company, LLC	ER00-3251	Pennsbury 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/1/1996	3.00	3.00	S	
Exelon Generation Company, LLC	ER00-3251	Pennsbury 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/1/1996	3.00	3.00	S	
Exelon Generation Company, LLC	ER00-3251	Richmond 91	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/7/1973	65.80	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Richmond 92	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/7/1973	65.80	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Salem 1	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	6/30/1977	1251.40	1173.99	S	8
Exelon Generation Company, LLC	ER00-3251	Salem 2	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	10/13/1981	1216.40	1158.02	S	9
Exelon Generation Company, LLC	ER00-3251	Salem 3	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	6/17/1971	41.80	37.57	S	10
Exelon Generation Company, LLC	ER00-3251	Schuylkill 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/30/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Schuylkill 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/11/1971	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/14/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/9/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/26/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	11/7/1968	18.60	13.00	S	
Cassia Gulch Wind Park LLC	ER10-75 QF05-180	Cassia Gulch WF	Cassia Gulch Wind Park LLC	Cassia Gulch Wind Park LLC	N/A	IPCO	Northwest	3/31/2009	18.90	18.90	S	
High Mesa Energy, LLC	ER12-2528 QF13-77	High Mesa WF	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	IPCO	Northwest	12/21/2012	39.90	39.90	S	
Tuana Springs Energy, LLC	ER10-87 QF08-742	Tuana Springs WF	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	IPCO	Northwest	7/27/2010	16.80	16.80	S	
Cow Branch Wind Power, LLC	ER07-1223 QF07-253	Cow Branch WF	Cow Branch Wind Power, L.L.C.	Cow Branch Wind Power, L.L.C.	N/A	AECI	Southeast	3/3/2008	50.40	50.40	S	
CR Clearing, LLC	ER07-1222 QF07-248	Conception WF	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	5/1/2008	50.40	50.40	S	
Wind Capital Holdings, LLC	ER07-1208 QF07-222	Bluegrass Ridge WF	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	5/14/2007	56.70	56.70	S	
Albany Green Energy, LLC	ER17-615 QF17-889	Albany Green Energy 1	Albany Green Energy, LLC	Albany Green Energy, LLC	N/A	SOCO	Southeast	7/6/2017	53.94	46.03	S	
CER Generation, LLC	ER10-662	Hillabee GT1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	258.40	234.40	S	
CER Generation, LLC	ER10-662	Hillabee GT2	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	258.40	234.40	S	
CER Generation, LLC	ER10-662	Hillabee STG1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	306.00	283.90	S	
AV Solar Ranch 1, LLC	ER12-2178	Antelope Valley SF	AV Solar Ranch 1, LLC	AV Solar Ranch 1, LLC	N/A	CAISO	Southwest	12/28/2012	253.00	241.50	S	
Luz Solar Partners Ltd, IV	ER17-823	SEGS IV SF	Luz Solar Partners Ltd, IV	Luz Solar Partners Ltd, IV	N/A	CAISO	Southwest	12/1/1986	34.78	36.00	S	
Bluestem Wind Energy, LLC	ER16-2363	Bluestem WF	Bluestem Wind Energy, LLC	Bluestem Wind Energy, LLC	N/A	SPP	SPP	12/16/2016	198.00	198.00	S	
Exelon Wind 4, LLC	ER07-1202 QF03-13	Exelon Wind 4 WF	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	2/2/2007	79.80	79.80	S	
Shooting Star Wind Project, LLC	ER12-1829	Shooting Star WF	Shooting Star Wind Project, LLC	Shooting Star Wind Project, LLC	N/A	SPP	SPP	9/29/2012	104.00	104.00	S	
Wildcat Wind, LLC	ER12-1223 QF12-412	Wildcat WF	Wildcat Wind, LLC	Wildcat Wind, LLC	N/A	SPP	SPP	7/1/2012	27.30	27.30	S	

Asset Appendix: Transmission Assets/Natural Gas Asset - July 2017

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
						Location			
Filing Entity and its Energy Affiliates	**Cite to order accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO**	**Asset Name and Use**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Market / Balancing Authority Area**	**Geographic Region**	**Size: (length and kV)**	**End Note Number (Enter text in End Note Tab)**
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	709.29 combined miles 115kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	54.82 combined miles 138kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	330.97 combined miles 230kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	217.94 combined miles 500kV lines	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Transportation	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	161.4 combined miles	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Storage (LNG)	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	1,056 mmcf	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Distribution	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	13,398 combined miles	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	90 combined miles 765kV lines	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	2,656 combined miles 345kV lines	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	2,897 combined miles 138kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	446 combined miles 500kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	549 combined miles 230kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	156 combined miles 138kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	200 combined miles 69kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	0.47 combined miles 13.2kV lines	
PECO Energy Company	N/A	Intrastate Gas Transportation	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	30 combined miles	
PECO Energy Company	N/A	Intrastate Gas Storage (LNG)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	1,200 mmcf	
PECO Energy Company	N/A	Intrastate Gas Stogare (LP)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	125 mmcf	
PECO Energy Company	N/A	Intrastate Gas Distribution	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	13,046 combined miles	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	281 combined miles 500kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	223 combined miles 230kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	242 combined miles 138kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	636 combined miles 69kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	297 combined miles 500kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	470 combined miles 230kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	557 combined miles 138kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	580 combined miles 69kV lines	
Delmarva Power & Light Company	N/A	Intrastate Gas Transportation	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	111 combined miles	
Delmarva Power & Light Company	N/A	Intrastate Gas Storage (LNG)	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	248 mmcf	
Delmarva Power & Light Company	N/A	Intrastate Gas Distribution	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	3,279 combined miles	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	142.04 combined miles 500kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	773.85 combined miles 230kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	60.37 combined miles 138kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	38.07 combined miles 115kV lines	

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December 19, 2017

VIA ELECTRONIC FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: ***Exelon Fitzpatrick, LLC*, Docket No. ER17-2201-___**
***Exelon Generation Company, LLC*, Docket No. ER13-1536-___**
***Constellation Energy Commodities Group Maine, LLC*, Docket No. ER10-2192-__**
***Constellation NewEnergy, Inc.*, Docket No. ER10-2178-___**
***Nine Mile Point Nuclear Station, LLC*, Docket No. ER10-2181-___**
***R.E. Ginna Nuclear Power Plant, LLC*, Docket No. ER10-2182-___**

Notice of Non-Material Change in Status

Dear Secretary Bose:

Pursuant to the requirements of section 35.42 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[1] Exelon Fitzpatrick, LLC ("Exelon Fitzpatrick"), Exelon Generation Company, LLC ("Exelon Generation"), Constellation Energy Commodities Group Maine, LLC ("CECG Maine"), Constellation NewEnergy, Inc. ("CNE," and with Exelon Fitzpatrick, Exelon Generation, CECG Maine, the "Exelon Sellers"), Nine Mile Point Nuclear Station, LLC ("Nine Mile"), and R.E. Ginna Nuclear Power Plant, LLC ("Ginna," and with Nine Mile, the "CENG Sellers") submit this notice of change in status ("Notice"). The Exelon Sellers are wholly-owned subsidiaries of Exelon Corporation. The CENG Sellers are indirect, wholly owned subsidiaries of Constellation Energy Nuclear Group, LLC ("CENG"), which is a joint venture between Exelon Generation and EDF Inc.

On October 13, 2017, the Commission authorized Exelon Fitzpatrick to acquire the James A. FitzPatrick Nuclear Power Plant and associated interconnection equipment (the "Fitzpatrick Facility") from Exelon Generation (the "Transaction").[2] The Fitzpatrick Facility is located in the balancing authority area operated by the New York Independent System Operator, Inc. ("NYISO"). Exelon Generation previously acquired the Fitzpatrick Facility

[1] 18 C.F.R. § 35.42 (2017).

[2] *Exelon Generation Company, LLC, et al.*, 161 FERC ¶ 62,031 (2017).

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from Entergy Nuclear FitzPatrick, LLC.[3] This Notice is filed as a result of the consummation of the Transaction on November 30, 2017.[4]

The Transaction did not change the facts and circumstances that the Commission relied upon in granting market-based rate authority to the Exelon Sellers and the CENG Sellers. The Commission order granting Exelon Fitzpatrick market-based rate authority analyzed Exelon Fitzpatrick's ownership of the Fitzpatrick Facility and found that Exelon Fitzpatrick lacks horizontal or vertical market power and satisfies the Commission's requirements for market-based rates.[5] In addition, in a Notice of Change in Status filed with the Commission on May 1, 2017, Exelon Generation and its affiliates had previously demonstrated that they continued to pass the Commission's pivotal supplier and market share screens following the acquisition of the Fitzpatrick Facility by Exelon Generation.[6]

Therefore, the Exelon Sellers and the CENG Sellers respectfully request that the Commission accept for filing this Notice and find that no further inquiry is necessary. Provided herewith are copies of the asset appendices for Exelon Corporation, reporting affiliates of the Exelon Sellers and the CENG Sellers, and for EDF Inc., reporting additional affiliates of the CENG Sellers.

Respectfully submitted,

/s/ Vincenzo Franco
Vincenzo Franco
Associate General Counsel
Exelon Corporation

[3] *See Entergy Nuclear FitzPatrick, LLC, et al.*, 157 FERC ¶ 61,183 (2016); *Entergy Nuclear FitzPatrick, LLC, et al.*, Notice of Consummation, Docket No. EC16-169-000 (filed April 7, 2017).

[4] *See Exelon Generation Company, LLC, et al.*, Notice of Consummation, Docket No. EC17-142-000 (filed Dec. 11, 2017).

[5] *Exelon Fitzpatrick, LLC*, 160 FERC ¶ 61,136 (2017).

[6] *Exelon Generation Company, LLC, et al.*, Notice of Change in Status, Docket Nos. ER13-1536-013, *et al.* (filed May 1, 2017).

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CERTIFICATE OF SERVICE

I hereby certify that this day I have caused to be served the foregoing document upon each person designated on the official service lists compiled by the Secretary in these proceedings.

Dated at Baltimore, MD this 19th day of December, 2017.

/s/ Vincenzo Franco
Vincenzo Franco
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Electric Generating Facilities and Assets

Asset Appendix: Generation Assets - December 2017

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned by**	**Controlled by**	**Date Control Transferred**	**Location**		**In-Service Date**	**Capacity Rating: Nameplate (MW)**	**Capacity Rating: Used in Filing (MW)**	**Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative**	**End Note Number (Enter text in End Note Tab)**
						Market / Balancing Authority Area	**Geographic Region**					
Beebe 1B Renewable Energy, LLC	ER14-2144	Beebe 1b WF	Beebe 1B Renewable Energy, LLC	Beebe 1B Renewable Energy, LLC	N/A	MISO	Central	12/12/2014	50.40	50.40	S	0
Beebe Renewable Energy, LLC	ER12-2311	Beebe 1a WF	Beebe Renewable Energy, LLC	Beebe Renewable Energy, LLC	N/A	MISO	Central	1/17/2013	81.60	81.60	S	0
Exelon Generation Company, LLC	ER00-3251	Clinton	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	MISO	Central	11/1/1987	1138.30	1065.00	S	0
Harvest II Windfarm, LLC	ER12-2201 QF12-522	Harvest 2 WF	Harvest II Windfarm, LLC	Harvest II Windfarm, LLC	N/A	MISO	Central	11/28/2012	59.40	59.40	S	0
Harvest Windfarm, LLC	ER07-1246 QF07-29	Harvest 1 WF	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	2/28/2008	52.80	52.80	S	0
Michigan Wind 1, LLC	ER05-1511 QF05-228	Michigan Wind 1 WF	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	12/16/2008	69.00	69.00	S	0
Michigan Wind 2, LLC	ER11-3989	Michigan Wind 2 WF	Michigan Wind 2, LLC	Michigan Wind 2, LLC	N/A	MISO	Central	1/5/2012	90.00	90.00	S	0
Atlantic City Electric Company	ER96-1361	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0
Commonwealth Edison Company	ER98-1734	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0
Constellation Energy Commodities Group Maine, LLC	ER02-699	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0
Constellation NewEnergy, Inc.	ER96-1387	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0
Delmarva Power & Light Company	ER96-2571	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0
PECO Energy Company	ER01-1147	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0
Potomac Electric Power Company	ER98-4138	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0
Constellation Mystic Power, LLC	ER10-2281	Mystic 7	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/1975	617.00	574.55	S	0
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	278.60	228.77	S	0
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	278.60	229.97	S	0
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	315.00	244.58	S	0
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	278.60	232.36	S	0
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	278.60	233.47	S	0
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	315.00	248.07	S	0
Constellation Mystic Power, LLC	ER10-2281	Mystic Jet	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/1969	14.20	8.95	S	0
Exelon Framingham LLC	ER98-1943	Framingham Jet 1	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	3/1/1970	14.20	9.62	S	0
Exelon Framingham LLC	ER98-1943	Framingham Jet 2	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/1969	14.20	10.13	S	0
Exelon Framingham LLC	ER98-1943	Framingham Jet 3	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/1969	14.20	10.22	S	0
Exelon New Boston, LLC	ER98-1943	New Boston Jet	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	9/1/1966	18.60	16.00	S	1
Exelon West Medway II, LLC	ER16-2708	West Medway 4	Exelon West Medway II, LLC	Exelon West Medway II, LLC	N/A	ISO-NE	Northeast	6/1/2018	100.00	97.40	S	0
Exelon West Medway II, LLC	ER16-2708	West Medway 5	Exelon West Medway II, LLC	Exelon West Medway II, LLC	N/A	ISO-NE	Northeast	6/1/2018	100.00	97.40	S	0
Exelon West Medway, LLC	ER98-1943	West Medway Jet 1	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/1970	45.00	42.00	S	0
Exelon West Medway, LLC	ER98-1943	West Medway Jet 2	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	3/1/1971	45.00	39.85	S	0
Exelon West Medway, LLC	ER98-1943	West Medway Jet 3	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/1970	45.00	42.00	S	0
Exelon Wyman, LLC	ER98-1943	Wyman 4	Exelon Wyman, LLC (5.9%)	FPL Energy Wyman IV LLC	N/A	ISO-NE	Northeast	1/1/1978	632.40	602.00	S	2
Exelon Fitzpatrick, LLC	ER17-2201	Fitzpatrick 1	Exelon Fitzpatrick, LLC	Exelon Fitzpatrick, LLC	N/A	NYISO	Northeast	7/1/1975	883.30	837.50	S	0
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 1	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	12/1/1969	641.80	626.10	S	0
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 2	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	8/1/1988	1259.30	1289.60	S	3
R. E. Ginna Nuclear Power Plant, LLC	ER04-485	Ginna	R. E. Ginna Nuclear Power Plant, LLC	R. E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	7/1/1970	614.00	582.00	S	0
Clinton Battery Utility, LLC	ER16-2194	Clinton Battery Project	Clinton Battery Utility, LLC	Clinton Battery Utility, LLC	N/A	PJM	Northeast	10/14/2016	10.00	10.00	N	0
Criterion Power Partners, LLC	ER10-1443	Criterion WF	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	2/4/2011	70.00	70.00	S	0
Exelon Generation Company, LLC	ER00-3251	Braidwood 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/1/1988	1224.90	1183.00	S	0
Exelon Generation Company, LLC	ER00-3251	Braidwood 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1988	1224.90	1154.00	S	0
Exelon Generation Company, LLC	ER00-3251	Byron 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/1/1985	1224.90	1164.00	S	0
Exelon Generation Company, LLC	ER00-3251	Byron 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/1987	1224.90	1136.00	S	0
Exelon Generation Company, LLC	ER00-3251	Dresden 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/1970	1009.00	902.00	S	0
Exelon Generation Company, LLC	ER00-3251	Dresden 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1971	1009.00	895.00	S	0
Exelon Generation Company, LLC	ER00-3251	LaSalle 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	1/1/1984	1170.00	1130.00	S	0
Exelon Generation Company, LLC	ER00-3251	LaSalle 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1984	1170.00	1133.90	S	0
Exelon Generation Company, LLC	ER00-3251	Quad Cities 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1972	1009.30	908.00	S	4
Exelon Generation Company, LLC	ER00-3251	Quad Cities 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1972	1009.30	911.00	S	5
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	0
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	0
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	0
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	0
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	0
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	0
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	0
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	0
Fair Wind Power Partners, LLC	ER15-2293	Fair Wind WF	Fair Wind Power Partners, LLC	Fair Wind Power Partners, LLC	N/A	PJM	Northeast	11/24/2015	30.00	30.00	S	0
Fourmile Wind Energy, LLC	ER14-2145 QF14-721	Fourmile Ridge WF	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	1/15/2015	40.00	40.00	S	0
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 1	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	0
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 2	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	0
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 3	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	0

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Electric Generating Facilities and Assets

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned by	Controlled by	Date Control Transferred	Location		In-Service Date	Capacity Rating: Nameplate (MW)	Capacity Rating: Used in Filing (MW)	Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative	End Note Number (Enter text in End Note Tab)
						Market / Balancing Authority Area	Geographic Region					
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 4	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	0
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 5	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	0
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 1	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM 5004/5005	Northeast	5/1/1975	918.00	866.00	S	0
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 2	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM 5004/5005	Northeast	4/1/1977	910.70	841.80	S	0
Constellation Power Source Generation, LLC	ER00-1598	Gould Street 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	12/1/1952	103.50	97.00	S	0
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	0
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	0
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	0
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	0
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.60	S	0
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	15.60	S	0
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.50	S	0
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	16.00	S	0
Constellation Power Source Generation, LLC	ER00-1598	Perryman 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	1/1/1972	53.10	52.00	S	0
Constellation Power Source Generation, LLC	ER00-1598	Perryman 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	4/1/1972	53.10	51.00	S	0
Constellation Power Source Generation, LLC	ER00-1598	Perryman 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	4/1/1972	53.10	52.00	S	0
Constellation Power Source Generation, LLC	ER00-1598	Perryman 51	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1995	192.00	139.00	S	0
Constellation Power Source Generation, LLC	ER00-1598	Perryman 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/28/2015	141.00	109.80	S	0
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	8/1/1970	20.70	15.30	S	0
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	8/1/1970	20.70	16.00	S	0
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	20.70	14.80	S	0
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	20.70	14.80	S	0
Constellation Power Source Generation, LLC	ER00-1598	Riverside 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	25.00	19.00	S	0
Constellation Power Source Generation, LLC	ER00-1598	Riverside 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	25.00	20.00	S	0
Constellation Power Source Generation, LLC	ER00-1598	Westport 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	2/1/1969	121.50	115.80	S	0
Exelon Generation Company, LLC	ER00-3251	TMI 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM 5004/5005	Northeast	9/2/1974	980.90	802.80	S	0
Exelon Generation Company, LLC	ER00-3251	Chester 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/7/1969	18.60	13.00	S	0
Exelon Generation Company, LLC	ER00-3251	Chester 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/20/1969	18.60	13.00	S	0
Exelon Generation Company, LLC	ER00-3251	Chester 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/6/1969	18.60	13.00	S	0
Exelon Generation Company, LLC	ER00-3251	Conowingo 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/1/1928	45.00	48.00	S	0
Exelon Generation Company, LLC	ER00-3251	Conowingo 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/25/1964	55.60	65.00	S	0
Exelon Generation Company, LLC	ER00-3251	Conowingo 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/4/1964	55.60	65.00	S	0
Exelon Generation Company, LLC	ER00-3251	Conowingo 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/1/1928	36.00	36.00	S	0
Exelon Generation Company, LLC	ER00-3251	Conowingo 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/6/1928	48.00	48.00	S	0
Exelon Generation Company, LLC	ER00-3251	Conowingo 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/5/1928	47.70	48.00	S	0
Exelon Generation Company, LLC	ER00-3251	Conowingo 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1928	36.00	36.00	S	0
Exelon Generation Company, LLC	ER00-3251	Conowingo 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/1/1928	47.70	48.00	S	0
Exelon Generation Company, LLC	ER00-3251	Conowingo 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1928	48.00	48.00	S	0
Exelon Generation Company, LLC	ER00-3251	Conowingo 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/10/1964	55.60	65.00	S	0
Exelon Generation Company, LLC	ER00-3251	Conowingo 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/25/1964	55.60	65.00	S	0
Exelon Generation Company, LLC	ER00-3251	Croydon 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	0
Exelon Generation Company, LLC	ER00-3251	Croydon 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	0
Exelon Generation Company, LLC	ER00-3251	Croydon 21	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	0
Exelon Generation Company, LLC	ER00-3251	Croydon 22	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	0
Exelon Generation Company, LLC	ER00-3251	Croydon 31	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	8/6/1974	68.30	49.00	S	0
Exelon Generation Company, LLC	ER00-3251	Croydon 32	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	8/8/1974	68.30	48.00	S	0
Exelon Generation Company, LLC	ER00-3251	Croydon 41	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1974	68.30	49.00	S	0
Exelon Generation Company, LLC	ER00-3251	Croydon 42	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1974	68.30	49.00	S	0
Exelon Generation Company, LLC	ER00-3251	Delaware 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/7/1969	18.60	13.00	S	0
Exelon Generation Company, LLC	ER00-3251	Delaware 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/19/1969	18.60	13.00	S	0
Exelon Generation Company, LLC	ER00-3251	Delaware 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/12/1969	18.60	13.00	S	0
Exelon Generation Company, LLC	ER00-3251	Delaware 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1970	21.20	17.00	S	0
Exelon Generation Company, LLC	ER00-3251	Eddystone 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/20/1967	18.60	13.00	S	0
Exelon Generation Company, LLC	ER00-3251	Eddystone 20	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	18.60	13.00	S	0
Exelon Generation Company, LLC	ER00-3251	Eddystone 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/24/1974	391.00	380.00	S	0
Exelon Generation Company, LLC	ER00-3251	Eddystone 30	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/7/1970	21.20	17.00	S	0
Exelon Generation Company, LLC	ER00-3251	Eddystone 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/29/1976	391.00	380.00	S	0
Exelon Generation Company, LLC	ER00-3251	Eddystone 40	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/21/1970	21.20	17.00	S	0
Exelon Generation Company, LLC	ER00-3251	Fairless Hills A	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1996	30.00	30.00	S	0
Exelon Generation Company, LLC	ER00-3251	Fairless Hills B	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1996	30.00	30.00	S	0
Exelon Generation Company, LLC	ER00-3251	Falls 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/22/1970	21.20	17.00	S	0
Exelon Generation Company, LLC	ER00-3251	Falls 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/10/1970	21.20	17.00	S	0

Electric Generating Facilities and Assets

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned by	Controlled by	Date Control Transferred	Location		In-Service Date	Capacity Rating: Nameplate (MW)	Capacity Rating: Used in Filing (MW)	Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative	End Note Number (Enter text in End Note Tab)
						Market / Balancing Authority Area	Geographic Region					
Exelon Generation Company, LLC	ER00-3251	Falls 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/28/1970	21.10	17.00	S	0
Exelon Generation Company, LLC	ER00-3251	Limerick 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/1/1986	1138.50	1119.70	S	0
Exelon Generation Company, LLC	ER00-3251	Limerick 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	1/1/1990	1138.50	1122.10	S	0
Exelon Generation Company, LLC	ER00-3251	Moser 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/9/1970	21.20	17.00	S	0
Exelon Generation Company, LLC	ER00-3251	Moser 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/29/1970	21.20	17.00	S	0
Exelon Generation Company, LLC	ER00-3251	Moser 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/11/1970	21.20	17.00	S	0
Exelon Generation Company, LLC	ER00-3251	Muddy Run 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/10/1967	134.00	134.00	S	0
Exelon Generation Company, LLC	ER00-3251	Muddy Run 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/10/1967	134.00	133.00	S	0
Exelon Generation Company, LLC	ER00-3251	Muddy Run 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1967	134.00	134.00	S	0
Exelon Generation Company, LLC	ER00-3251	Muddy Run 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1967	134.00	134.00	S	0
Exelon Generation Company, LLC	ER00-3251	Muddy Run 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	134.00	134.00	S	0
Exelon Generation Company, LLC	ER00-3251	Muddy Run 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	134.00	133.00	S	0
Exelon Generation Company, LLC	ER00-3251	Muddy Run 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/10/1968	134.00	134.00	S	0
Exelon Generation Company, LLC	ER00-3251	Muddy Run 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/10/1968	134.00	134.00	S	0
Exelon Generation Company, LLC	ER00-3251	Oyster Creek 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1969	550.00	607.70	S	0
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/5/1974	1244.80	1223.70	S	6
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/23/1974	1377.00	1226.70	S	7
Exelon Generation Company, LLC	ER00-3251	Pennsbury 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/1/1996	3.00	3.00	S	0
Exelon Generation Company, LLC	ER00-3251	Pennsbury 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/1/1996	3.00	3.00	S	0
Exelon Generation Company, LLC	ER00-3251	Richmond 91	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/7/1973	65.80	49.00	S	0
Exelon Generation Company, LLC	ER00-3251	Richmond 92	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/7/1973	65.80	49.00	S	0
Exelon Generation Company, LLC	ER00-3251	Salem 1	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	6/30/1977	1251.40	1173.99	S	8
Exelon Generation Company, LLC	ER00-3251	Salem 2	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	10/13/1981	1216.40	1158.02	S	9
Exelon Generation Company, LLC	ER00-3251	Salem 3	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	6/17/1971	41.80	38.40	S	10
Exelon Generation Company, LLC	ER00-3251	Schuylkill 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/30/1969	18.60	13.00	S	0
Exelon Generation Company, LLC	ER00-3251	Schuylkill 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/11/1971	21.20	17.00	S	0
Exelon Generation Company, LLC	ER00-3251	Southwark 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/14/1967	18.60	13.00	S	0
Exelon Generation Company, LLC	ER00-3251	Southwark 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/9/1967	18.60	13.00	S	0
Exelon Generation Company, LLC	ER00-3251	Southwark 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/26/1967	18.60	13.00	S	0
Exelon Generation Company, LLC	ER00-3251	Southwark 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	11/7/1968	18.60	13.00	S	0
Cassia Gulch Wind Park LLC	ER10-75 QF05-180	Cassia Gulch WF	Cassia Gulch Wind Park LLC	Cassia Gulch Wind Park LLC	N/A	IPCO	Northwest	3/31/2009	18.90	18.90	S	0
High Mesa Energy, LLC	ER12-2528 QF13-77	High Mesa WF	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	IPCO	Northwest	12/21/2012	39.90	39.90	S	0
Tuana Springs Energy, LLC	ER10-87 QF08-742	Tuana Springs WF	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	IPCO	Northwest	7/27/2010	16.80	16.80	S	0
Cow Branch Wind Power, LLC	ER07-1223 QF07-253	Cow Branch WF	Cow Branch Wind Power, L.L.C.	Cow Branch Wind Power, L.L.C.	N/A	AECI	Southeast	3/3/2008	50.40	50.40	S	0
CR Clearing, LLC	ER07-1222 QF07-248	Conception WF	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	5/1/2008	50.40	50.40	S	0
Wind Capital Holdings, LLC	ER07-1208 QF07-222	Bluegrass Ridge WF	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	5/14/2007	56.70	56.70	S	0
Albany Green Energy, LLC	ER17-615 QF17-889	Albany Green Energy 1	Albany Green Energy, LLC	Albany Green Energy, LLC	N/A	SOCO	Southeast	7/6/2017	53.94	46.03	S	0
CER Generation, LLC	ER10-662	Hillabee GT1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	258.40	234.40	S	0
CER Generation, LLC	ER10-662	Hillabee GT2	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	258.40	234.40	S	0
CER Generation, LLC	ER10-662	Hillabee STG1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	306.00	283.90	S	0
AV Solar Ranch 1, LLC	ER12-2178	Antelope Valley SF	AV Solar Ranch 1, LLC	AV Solar Ranch 1, LLC	N/A	CAISO	Southwest	12/28/2012	253.00	241.50	S	0
Luz Solar Partners Ltd, IV	ER17-823	SEGS IV SF	Luz Solar Partners Ltd, IV	Luz Solar Partners Ltd, IV	N/A	CAISO	Southwest	12/1/1986	34.78	36.00	S	0
Bluestem Wind Energy, LLC	ER16-2363	Bluestem WF	Bluestem Wind Energy, LLC	Bluestem Wind Energy, LLC	N/A	SPP	SPP	12/16/2016	198.00	198.00	S	0
Exelon Wind 4, LLC	ER07-1202 QF03-13	Exelon Wind 4 WF	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	2/2/2007	79.80	79.80	S	0
Shooting Star Wind Project, LLC	ER12-1829	Shooting Star WF	Shooting Star Wind Project, LLC	Shooting Star Wind Project, LLC	N/A	SPP	SPP	9/29/2012	104.00	104.00	S	0
Wildcat Wind, LLC	ER12-1223 QF12-412	Wildcat WF	Wildcat Wind, LLC	Wildcat Wind, LLC	N/A	SPP	SPP	7/1/2012	27.30	27.30	S	0

Asset Appendix: Transmission Assets/Natural Gas Asset - December 2017

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
						Location			
Filing Entity and its Energy Affiliates	**Cite to order accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO**	**Asset Name and Use**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Market / Balancing Authority Area**	**Geographic Region**	**Size: (length and kV)**	**End Note Number (Enter text in End Note Tab)**
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	709.29 combined miles 115kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	54.82 combined miles 138kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	330.97 combined miles 230kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	217.94 combined miles 500kV lines	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Transportation	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	161.4 combined miles	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Storage (LNG)	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	1,056 mmcf	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Distribution	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	13,398 combined miles	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	90 combined miles 765kV lines	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	2,656 combined miles 345kV lines	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	2,897 combined miles 138kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	446 combined miles 500kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	549 combined miles 230kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	156 combined miles 138kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	200 combined miles 69kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	0.47 combined miles 13.2kV lines	
PECO Energy Company	N/A	Intrastate Gas Transportation	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	30 combined miles	
PECO Energy Company	N/A	Intrastate Gas Storage (LNG)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	1,200 mmcf	
PECO Energy Company	N/A	Intrastate Gas Stogare (LP)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	125 mmcf	
PECO Energy Company	N/A	Intrastate Gas Distribution	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	13,046 combined miles	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	281 combined miles 500kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	223 combined miles 230kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	242 combined miles 138kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	636 combined miles 69kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	297 combined miles 500kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	470 combined miles 230kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	557 combined miles 138kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	580 combined miles 69kV lines	
Delmarva Power & Light Company	N/A	Intrastate Gas Transportation	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	111 combined miles	
Delmarva Power & Light Company	N/A	Intrastate Gas Storage (LNG)	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	248 mmcf	
Delmarva Power & Light Company	N/A	Intrastate Gas Distribution	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	3,279 combined miles	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	142.04 combined miles 500kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	773.85 combined miles 230kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	60.37 combined miles 138kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	38.07 combined miles 115kV lines	

A	B	C	D	E	F	G	H	I	J	K	L	M
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned By	Controlled By	Date Control Transferred	Location		In-service Date	Capacity rating: Nameplate (MW)	Capacity Rating: Used in Filing (MW)	Capacity Rating: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative	End Note Number (Enter text in End Notes Sheet)
						Market/Balancing Authority Area	Geographic Region					
EDF Trading North America, LLC	ER03-774	N/A	EDF Trading Holdings LLC	EDF Trading Holdings LLC	10/31/2008	N/A	N/A	N/A	N/A			1
EDF Industrial Power Services (CA), LLC	ER12-1825	N/A	EDF Trading North America, LLC	EDF Trading North America, LLC	N/A	N/A	N/A	N/A	N/A			
EDF Energy Services, LLC	ER14-2672	N/A	EDF Trading North America LLC	EDF Trading North America LLC	N/A	N/A	N/A	N/A	N/A			
Anahau Energy, LLC	ER13-415	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			
Allendale Biomass, LLC	N/A	N/A	Allendale Biomass	Allendale Biomass	N/A	Santee Cooper	Southeast	10/1/2013	19.3	19.3	N	
Bellevue Solar, LLC	ER11-4380-000	N/A	Bellevue Solar	Bellevue Solar	N/A	PGE	Northwest	10/26/2011	1.66	1.66	N	
Catalina Solar Lessee, LLC	ER13-1562-000	N/A	Catalina Solar LLC	Catalina Solar Lessee	N/A	CAISO	Southwest	2013	110	110	N	
Champepadan Wind Power Partners, LLC	QF02-3	N/A	Champepadan	Champepadan	N/A	MISO	Central	12/19/2001	1.98	1.98	N	2
Chestnut Flats Lessee, LLC	ER13-1641-000	N/A	Chestnut Flats Wind, LLC	Chestnut Flats Lessee	9/30/2013	PJM	Northeast	12/29/2011	38	38	N	
Dorchester Biomass, LLC	QF13-648	N/A	Dorchester Biomass	Dorchester Biomass	N/A	Santee Cooper	Southeast	10/1/2013	19.3	19.3	N	2
EDF Renewable Wind Farm V, Inc.	QF90-57	N/A	EDF Renewable Wind Farm V	EDF Renewable Wind Farm V	N/A	CAISO	Southwest	1989	16.2	16.2	N	2
Fenton Power Partners I, LLC	ER07-357-000	N/A	Fenton Power Partners	Fenton Power Partners	N/A	MISO	Central	11/13/2007	205.5	205.5	N	
Great Western Wind Energy, LLC	ER16-2360	N/A	Great Western Wind	Great Western Wind	N/A	SPP	SPP	Oct-16	225	225	N	
Hoosier Wind Project, LLC	ER09-1181-000	N/A	Hoosier Wind Project	Hoosier Wind Project	N/A	MISO	Central	Nov-09	106	106	N	
Kelly Creek Wind, LLC	ER16-2227	N/A	Kelly Creek Wind	Kelly Creek Wind	N/A	PJM	Northeast	Oct-16	184	184	N	
McHenry Battery Storage, LLC	ER16-2226	N/A	McHenry Battery Storage	McHenry Battery Storage	N/A	PJM	Northeast	Dec-15	20	20	N	
Milo Wind Project, LLC	ER15-2131-000	N/A	Milo Wind Project, LLC	Milo Wind Project, LLC	N/A	SPP	SPP	Dec-15	49.65	49.65	N	
Moulton Wind Power Partners, LLC	QF04-7	N/A	Moulton Wind	Moulton Wind	N/A	MISO	Central	12/19/2001	1.98	1.98	N	2
Oasis Power Partners, LLC	ER05-41-000	N/A	Oasis Power	Oasis Power	N/A	CAISO	Southwest	12/24/2004	60	60	N	
Pacific Wind Lessee, LLC	ER12-1931-000	N/A	Pacific Wind, LLC	Pacific Wind Lessee, LLC	N/A	CAISO	Southwest	8/16/2012	140	140	N	
Pilot Hill Wind, LLC	ER15-1045-000	N/A	Pilot Hill Wind, LLC	Pilot Hill Wind, LLC	N/A	PJM	Northeast	Sep-15	176.9	176.9	N	
Playa Solar 1, LLC	ER17-1522-000	N/A	Playa Solar 1, LLC	Playa Solar 1, LLC	30-Jun-17	NV Energy	Southwest	Jul-17	81.7	79	N	
Playa Solar 2, LLC	ER17-1324-000	N/A	Playa Solar 2, LLC	Playa Solar 2, LLC	30-Jun-17	NV Energy	Southwest	6/6/17	104.7	100	N	
Red Pine Wind Project, LLC	ER17-1666-000	N/A	Red Pine Wind Project, LLC	Red Pine Wind Project, LLC	N/A	SPP	Southwest	Projected Q4 2017	200	200	N	
Rock Falls Wind Farm LLC	ER17-2258-000	N/A	Rock Falls Wind Farm LLC	Rock Falls Wind Farm LLC	N/A	SPP	SPP	N/A	154	154	N	
Roosevelt Wind Project, LLC	ER15-2130-000	N/A	Roosevelt Wind Project, LLC	Roosevelt Wind Project, LLC	N/A	SPP	SPP	12/14/2015	250	250	N	
Sacramento Soleil, LLC	QF08-630	N/A	Sacramento Soleil	Sacramento Soleil	N/A	CAISO	Southwest	7/14/2008	1	1	N	2
Shiloh Wind Project 2, LLC	ER08-1237-000	N/A	Shiloh 2	Shiloh 2	N/A	CAISO	Southwest	1/30/2009	150	150	N	
Shiloh III Lessee, LLC	ER12-610-009	N/A	Shiloh III Wind Project, LLC	Shiloh III Lessee	N/A	CAISO	Southwest	12/22/2011	100	100	N	
Shiloh IV Lessee, LLC	ER13-338-000	N/A	Shiloh IV Wind Project	Shiloh IV Lessee	N/A	CAISO	Southwest	12/21/2012	102.5	102.5	N	
Slate Creek Wind Project, LLC	ER15-2129-000	N/A	Slate Creek Wind Project, LLC	Slate Creek Wind Project, LLC	N/A	SPP	SPP	Dec-15	150	150	N	
Spearville 3, LLC	ER12-2037-000	N/A	Spearville 3, LLC	Spearville 3, LLC	N/A	SPP	SPP	10/1/2012	100.8	100.8	N	
Spinning Spur Wind LLC	ER12-2314	N/A	Spinning Spur Wind LLC	Spinning Spur Wind LLC	N/A	SPP	SPP	12/20/2012	161	161	N	
Wapsipinicon Wind Project, LLC	ER08-1288-000	N/A	Wapsipinicon	Wapsipinicon	N/A	MISO	Central	2/20/2009	100.5	100.5	N	
Yamhill Solar, LLC	ER11-4381-000	N/A	Yamhill Solar	Yamhill Solar	N/A	PGE	Northwest	10/26/2011	1.19	1.19	N	
Calvert Cliffs Nuclear Power Plant LLC	ER00-2917-000	Calvert Cliffs Nuclear Power Plant (Unit 1)	Calvert Cliffs Nuclear Power Plant LLC	Calvert Cliffs Nuclear Power Plant LLC	11/6/2009	PJM	Northeast	5/1/1975	918	866	S	
Calvert Cliffs Nuclear Power Plant LLC	ER00-2917-000	Calvert Cliffs Nuclear Power Plant (Unit 2)	Calvert Cliffs Nuclear Power Plant LLC	Calvert Cliffs Nuclear Power Plant LLC	11/6/2009	PJM	Northeast	4/1/1977	910.7	841.8	S	
R.E. Ginna Unit 1 Nuclear Power Plant, LLC	ER04-485-000	Ginna	R.E. Ginna Unit 1 Nuclear Power Plant, LLC	R.E. Ginna Unit 1 Nuclear Power Plant, LLC	11/6/2009	NYISO	Northeast	7/1/1970	614	582	S	
Nine Mile Point Nuclear Station, LLC	ER01-1654-000	Nine Mile Point (Unit 1)	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	11/6/2009	NYISO	Northeast	12/1/1969	641.8	626.1	S	
Nine Mile Point Nuclear Station, LLC	ER01-1654-000	Nine Mile Point (Unit 2)	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	11/6/2009	NYISO	Northeast	8/1/1988	1428.45	1289.6	S	

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Asset Appendix: Long-Term Purchased Power Agreements (PPA)

A	B	C	D	E	F	G	H	I	J
Filing Entity and its Energy Affiliates	Seller Name	Amount of PPA (MW)	Location			Start Date (mo/da/yr)	End Date (mo/da/yr)	Type of PPA (Unit or System)	End Note Number (Enter text in End Notes Sheet)
			Market/Balancing Authority Area (Source)	Market/Balancing Authority Area (Sink)	Geographic Region				
N/A									

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A	B	C	D	E	F
Filing Entity and its Energy Affiliates	Cite to Order accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO	Asset Name and Use	Owned By	Controlled By	Date Control Transferred
N/A					

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G	H		I	J
Location			Size	End Note Number (Enter text in End Notes Sheet)
Market/Balancing Authority Area		Geographic Region		
				1

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End Notes for Entries in the Generation, Long-term PPA and Transmission Lists

A	B	C
End Note Number	**Sheet (Generation, PPA, or Transmission)**	**Explanatory Note**
1	Generation, Transmission	Table excludes assets outside the continential U.S. and in ERCOT
2	Generation	Excluded from market-power analysis per Order No. 816

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January 25, 2017

VIA eTARIFF FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: ***Constellation Power Source Generation, LLC*, Docket No. ER17-801-001;**
***Exelon Generation Company, LLC*, Docket No. ER17-802-001;**
***Handsome Lake Energy, LLC*, Docket No. ER17-803-001;**
Amended Cost Support and Amended Rate Schedules

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA")[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission ("FERC" or the "Commission"),[2] Constellation Power Source Generation, LLC ("CPSG"), Exelon Generation Company, LLC ("Exelon Generation"), and Handsome Lake Energy, LLC ("Handsome Lake") (collectively, the "Applicants") hereby submit for filing amended Exhibit No. EXE-3 and Exhibit No. EXE-4 ("Amended Exhibits") for their cost-based revenue requirements for Reactive Supply and Voltage Control from Generation Sources Service ("Reactive Service"), together with amended rate schedules to reflect the amended cost support, consisting of (i) CPSG's amended FERC Rate Schedule No. 2 ("Amended CPSG Rate Schedule"), which sets forth the amended annual revenue requirement ("Amended CPSG ARR"); (ii) Exelon Generation's amended FERC Rate Schedule No. 22 ("Amended ExGen Rate Schedule"), which sets forth the amended annual revenue requirement ("Amended ExGen ARR"); and (iii) Handsome Lake's amended Rate Schedule FERC No. 2 ("Amended HLE Rate Schedule"), which sets forth the amended annual revenue requirement ("Amended HLE ARR") (collectively, the "Amended Rate Schedules").[3]

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1 16 U.S.C. § 824d (2012).

2 18 C.F.R. Pt. 35 (2016).

3 Because the amended cost support for the Amended CPSG ARR, Amended ExGen ARR, and Amended HLE ARR include cost allocations common to all of the generation facilities, the Applicants prepared a single filing consisting of this letter and the accompanying attachments (the "Filing"). The Filing is being submitted in accordance with the Commission's eTariff guidelines concurrently in the

(Continued…)

The Amended Exhibits and the Amended Rate Schedules replace the corresponding documents filed in the above-referenced proceedings on January 17, 2017.[4]

CPSG, Exelon Generation, and Handsome Lake respectfully request that the Commission accept respectively the Amended CPSG Rate Schedule, Amended ExGen Rate Schedule, and Amended HLE Rate Schedule for filing on or before March 26, 2017, and grant any necessary waivers to permit an effective date for the Rate Schedules of March 1, 2017.[5]

I. DOCUMENTS SUBMITTED

This filing consists of the following:

1. Transmittal Letter;

2. Clean amended Constellation Power Source Generation, LLC FERC Rate Schedule No. 2 for Reactive Supply and Voltage Control from Generation Sources Service (Attachment A);

3. Redline Constellation Power Source Generation, LLC FERC Rate Schedule No. 2 for Reactive Supply and Voltage Control from Generation Sources Service (Attachment B);[6]

4. Amended Exelon Generation Company, LLC FERC Rate Schedule No. 22 for Reactive Supply and Voltage Control from Generation Sources Service (Attachment C);[7]

CPSG, Exelon Generation, and Handsome Lake dockets, with the filing entity's corresponding eTariff record.

4 Reactive Service Rate Schedule Filings, Docket Nos. ER17-801-000, ER17-802-000, and ER17-803-000 (filed Jan. 17, 2017) (collectively, the "January 17 Filings").

5 PJM typically incorporates reactive service revenue requirements into Schedule 2 of the PJM Tariff effective the first day of the month in which the Commission accepts or approves the revenue requirement. In order to prevent retroactive billing, PJM interprets Schedule 2 to require effective dates no earlier than the first day of the month in which the Commission approves the revenue requirement. *See, e.g.,* Motion for Leave to Intervene Out of Time and Comments of PJM Interconnection, L.L.C. at 3, Docket No. EL05-20-000 (filed Dec. 1, 2004). The Commission has granted similar effective dates for other reactive power revenue requirements incorporated into Schedule 2 of the PJM Tariff. *See Ameren Energy Generating Co*., Docket No. ER09-337-000 (Mar. 30, 2009) (unreported) (establishing a March 1, 2009 effective date); *York Generation Co. LLC*, Docket No. ER07-1351-000 (Oct. 26, 2007) (unreported) (establishing an October 1, 2007 effective date); *see also Calpine Mid Merit, LLC*, 138 FERC ¶ 61,232 at P 1 (2012) (establishing a March 1, 2012 effective date).

6 The redline documents included as Attachment B and Attachment E compare the amended rate schedules to those currently in effect and not those in the January 17 Filings.

5. Clean amended Handsome Lake Energy, LLC Rate Schedule FERC No. 2 for Reactive Supply and Voltage Control from Generation Sources Service (Attachment D);

6. Redline Handsome Lake Energy, LLC Rate Schedule FERC No. 2 for Reactive Supply and Voltage Control from Generation Sources Service (Attachment E);

7. Amended Exhibit No. EXE-3 and amended Exhibit No. EXE-4 (Attachment F); and

8. The attestation of Alan C. Heintz (Attachment G).

II. BACKGROUND AND AMENDED EXHIBITS

Subsequent to the filing of the January 17 Filings, the Applicants became aware that certain data in an input file failed to correctly transfer to Schedule 3 of Exhibit No. EXE-4 included in the January 17 Filings and, as a result, was not reflected in the cost support. This data transfer error is corrected in Schedule 3 of Exhibit No. EXE-4 of the Amended Exhibits, with the impact of that correction reflected in the Amended Exhibits. Other than the substitution of the Amended Exhibits for the corresponding exhibits attached to the Prepared Direct Testimony of Alan C. Heintz included in the January 17 Filings, there are no revisions to the testimony of Mr. Heintz.

III. EFFECTIVE DATE

Pursuant to the January 17 Filings, the Applicants request an effective date for the Amended Rate Schedules of March 1, 2017. As discussed in the January 17 Filings, pursuant to PJM Tariff Schedule 2 the Applicants will be eligible to begin recovering their cost of providing reactive power within PJM on the first day of the month in which the Commission accepts or approves the revenue requirement. The Commission has regularly granted waiver of its notice requirements establishing effective dates less than sixty days after filing a new rate schedule when the filing is made prior to the requested effective date.[8] The Applicants thus respectfully

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[7] As discussed in Section III.B of the January 17 Filings, while Exelon Generation currently receives Reactive Service compensation, that compensation is not set forth in an existing Exelon Generation rate schedule. Accordingly, unlike for CPSG and Handsome Lake, a redline of the Exelon Generation amended FERC Rate Schedule No. 22 is not included herein.

[8] *See, e.g., DeSoto County Generating Co., LLC,* 142 FERC ¶ 61,006 (2013) (effective date of filing fifty-six days after filing made); *Calpine Mid Merit,* LLC, 138 FERC ¶ 61,232 (2012) (effective date of filing thirty days after filing made); *Las Vegas Power Co., LLC*, 137 FERC ¶ 61,161 (2011) (effective date of filing one day after filing made); *Union Power Partners, L.P.*, 112 FERC ¶ 61,065 (effective date of filing one day after filing made), *on reh'g*, 113 FERC ¶ 61,272 (2005); *Hot Spring Power Co.*, *LP*, 113 FERC ¶ 61,088 (2005) (effective date of filing one day after filing made), *on reh'g*, (Continued…)

request Commission action by March 26, 2017, to establish an effective date of March 1, 2017, under Schedule 2 of the PJM Tariff.

IV. CONCLUSION

WHEREFORE, for the foregoing reasons, the Applicants respectfully request that the Commission (i) accept their Amended Rate Schedules to become effective on March 1, 2017, and (ii) grant the waivers requested herein.

Respectfully submitted,

CONSTELLATION POWER SOURCE GENERATION, LLC
EXELON GENERATION COMPANY, LLC
HANDSOME LAKE ENERGY, LLC

By: */s/ Neil L. Levy*
Neil L. Levy
Bruce L. Richardson

Counsel for
Constellation Power Source Generation, LLC, Exelon Generation Company, LLC, and Handsome Lake Energy, LLC

Attachments

cc: Official Service Lists

115 FERC ¶ 61,027, *on clarification*, 116 FERC ¶ 61,223 (2006); *Rockingham Power, L.L.C.*, 93 FERC ¶ 61,310 (2000) (effective date of filing one day after filing made).

Attachment A

Constellation Power Source Generation, LLC

FERC Rate Schedule No. 2
(Clean)

CONSTELLATION POWER SOURCE GENERATION, LLC
FERC RATE SCHEDULE NO. 2

Reactive Supply and Voltage Control from Generation Sources Service

Constellation Power Source Generation, LLC ("CPSG") provides Reactive Supply and Voltage Control from Generation Sources Service ("Reactive Supply Service") from certain generation facilities ("Facilities") within the Baltimore Gas and Electricity Company zone under the operational control of PJM Interconnection, L.L.C. This FERC Rate Schedule No. 2 sets forth CPSG's revenue requirement for Reactive Supply Service from the Facilities. This Rate Schedule shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

CPSG's monthly fixed revenue requirement consists of the sum of the charges for the Facilities specified below.

REVENUE REQUIREMENT:

Generation Facility	Monthly Revenue Requirement
Gould Street 3	$2,719.31
Notch Cliff CT 1	$3,535.34
Notch Cliff CT 2	$2,721.39
Notch Cliff CT 3	$2,721.39
Notch Cliff CT 4	$2,721.39
Notch Cliff CT 5	$3,661.08
Notch Cliff CT 6	$2,721.39
Notch Cliff CT 7	$2,721.39
Notch Cliff CT 8	$2,721.39
Perryman CT 1	$11,873.32
Perryman CT 3	$11,873.32
Perryman CT 4	$11,873.32
Perryman CT 6	$33,659.76
Perryman 51	$26,105.29
Philadelphia Road CT 1	$3,640.06
Philadelphia Road CT 2	$3,304.30
Philadelphia Road CT 3	$3,304.30
Philadelphia Road CT 4	$3,304.30
Riverside CT 7	$10,101.69
Riverside CT 8	$8,666.28
Westport CT 5	$10,144.03
Total Monthly Revenue Requirement	**$164,094.04**
Total Annual (Filed)	**$1,969,128.51**

PARTIAL MONTH REVENUE REQUIREMENT:

When a unit deactivation date is other than the first day of the month, the revenue requirement shall be a blended revenue requirement for the month of service in which the deactivation occurred ("Deactivation Month") as follows: the sum of (i) the total monthly revenue requirement prior to the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the number of days in the Deactivation Month prior to the unit deactivation date and (ii) the total monthly revenue requirement after the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the remaining number of days in the Deactivation Month from and including the unit deactivation date.

Attachment B

Constellation Power Source Generation, LLC

FERC Rate Schedule No. 2
(Redline)

CONSTELLATION POWER SOURCE GENERATION, LLC
FERC RATE SCHEDULE NO. 2

Reactive Supply and Voltage Control from Generation Sources Service

Constellation Power Source Generation, LLC ("CPSG") provides Reactive Supply and Voltage Control from Generation Sources Service ("Reactive Supply Service") from certain generation facilities ("Facilities") within the Baltimore Gas and Electricity Company zone under the operational control of PJM Interconnection, L.L.C. This FERC Rate Schedule No. 2 sets forth CPSG's revenue requirement for Reactive Supply Service from the Facilities. This Rate Schedule shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

CPSG's monthly fixed revenue requirement consists of the sum of the charges for the Facilities specified below.

REVENUE REQUIREMENT:

Generation Facility	**Monthly Revenue Requirement**
Gould Street 3	$~~13,312.97~~2,719.31
Notch Cliff CT 1	$~~2,399.79~~3,535.34
Notch Cliff CT 2	$~~2,399.79~~2,721.39
Notch Cliff CT 3	$~~2,399.79~~2,721.39
Notch Cliff CT 4	$~~2,399.79~~2,721.39
Notch Cliff CT 5	$~~2,399.79~~3,661.08
Notch Cliff CT 6	$~~2,399.79~~2,721.39
Notch Cliff CT 7	$~~2,399.79~~2,721.39
Notch Cliff CT 8	$~~2,399.79~~2,721.39
Perryman CT 1	$~~5,998.49~~11,873.32
Perryman CT ~~2~~3	$~~5,998.49~~11,873.32
Perryman CT ~~3~~4	$~~5,998.49~~11,873.32
Perryman CT ~~4~~6	$~~5,998.49~~33,659.76
Perryman 51	$~~27,465.53~~26,105.29
Philadelphia Road CT 1	$~~2,258.44~~3,640.06
Philadelphia Road CT 2	$~~2,258.44~~3,304.30
Philadelphia Road CT 3	$~~2,258.44~~3,304.30
Philadelphia Road CT 4	$~~2,258.44~~3,304.30
~~Riverside 4~~	~~$5,843.69~~
~~Riverside CT 6~~	~~$6,885.29~~
Riverside CT 7	$~~2,996.44~~10,101.69
Riverside CT 8	$~~2,996.44~~8,666.28
Westport CT 5	$~~10,356.87~~10,144.03
Total Monthly Revenue Requirement	**~~$122,083.25~~164,094.04**
Total Annual (~~Total Monthly x 12~~Filed)	**~~$1,464,999.00~~1,969,128.51**
~~**Without Riverside CT 6 and Perryman CT 2 Effective February 1, 2016**~~	

~~**Total Monthly Revenue Requirement**~~	~~**$109,199.47**~~
~~**Total Annual (Total Monthly x 12)**~~	~~**$1,310,393.64**~~
~~**Without Riverside 4**~~ ~~**Effective June 1, 2016**~~	
~~**Total Monthly Revenue Requirement**~~	~~**$103,355.78**~~
~~**Total Annual (Total Monthly x 12)**~~	~~**$1,240,269.32**~~

PARTIAL MONTH REVENUE REQUIREMENT:

When a unit deactivation date is other than the first day of the month, the revenue requirement shall be a blended revenue requirement for the month of service in which the deactivation occurred ("Deactivation Month") as follows: the sum of (i) the total monthly revenue requirement prior to the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the number of days in the Deactivation Month prior to the unit deactivation date and (ii) the total monthly revenue requirement after the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the remaining number of days in the Deactivation Month from and including the unit deactivation date.

Attachment C

Exelon Generation Company, LLC

FERC Rate Schedule No. 22
(Clean)

EXELON GENERATION COMPANY, LLC
FERC RATE SCHEDULE NO. 22

Reactive Supply and Voltage Control from Generation Sources Service

Exelon Generation Company, LLC ("ExGen") provides Reactive Supply and Voltage Control from Generation Sources Service ("Reactive Supply Service") from certain generation facilities ("Facilities") within the ComEd, JCPL, MetEd, PECO, and PSEG zones under the operational control of PJM Interconnection, L.L.C. This Rate Schedule FERC No. 22 sets forth ExGen's revenue requirement for Reactive Supply Service from the Facilities. This Rate Schedule shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

ExGen's revenue requirements for the ComEd, JCPL, MetEd, PECO, and PSEG zones are set forth below.

REVENUE REQUIREMENT:

Zone	Generation Facility	Monthly Revenue Requirement
ComEd	Braidwood 1	$197,160.96
	Braidwood 2	$216,903.96
	Byron 1	$165,509.87
	Byron 2	$185,417.69
	Dresden 2	$212,266.27
	Dresden 3	$209,705.49
	LaSalle 1	$135,845.20
	LaSalle 2	$162,151.91
	Quad Cities 1 (75%)	$114,487.25
	Quad Cities 2 (75%)	$120,181.66
	Southeast Chicago 5	$9,051.66
	Southeast Chicago 6	$9,051.66
	Southeast Chicago 7	$9,051.66
	Southeast Chicago 8	$9,051.66
	Southeast Chicago 9	$9,051.66
	Southeast Chicago 10	$9,051.66
	Southeast Chicago 11	$9,051.66
	Southeast Chicago 12	$9,051.66
	ComEd Zone Total Monthly Revenue Requirement	**$1,792,043.55**
	ComEd Zone Total Annual (Filed)	**$21,504,522.60**

JCPL	Oyster Creek 1	$203,074.78
	JCPL Zone Total Monthly Revenue Requirement	**$203,074.78**
	JCPL Zone Total Annual (Filed)	**$2,436,897.35**
MetEd	TMI	$26,449.62
	MetEd Zone Total Monthly Revenue Requirement	**$26,449.62**
	MetEd Zone Total Annual (Filed)	**$317,395.38**
PECO	Chester 7	$1,257.83
	Chester 8	$1,263.81
	Chester 9	$1,307.30
	Conowingo 1	$2,840.51
	Conowingo 2	$2,567.12
	Conowingo 3	$2,708.19
	Conowingo 4	$2,567.12
	Conowingo 5	$1,838.96
	Conowingo 6	$2,797.30
	Conowingo 7	$2,797.30
	Conowingo 8	$908.77
	Conowingo 9	$1,148.65
	Conowingo 10	$1,405.39
	Conowingo 11	$1,074.73
	Croydon 11	$3,410.10
	Croydon 12	$3,138.53
	Croydon 21	$3,623.76
	Croydon 22	$3,623.76
	Croydon 31	$3,623.76
	Croydon 32	$3,623.76
	Croydon 41	$3,623.76
	Croydon 42	$3,623.76
	Delaware 9	$1,338.12
	Delaware 10	$1,555.72
	Delaware 11	$1,543.69
	Delaware 12	$1,543.69
	Eddystone 3	$16,369.68
	Eddystone 4	$14,282.00

	Eddystone 10	$1,188.19
	Eddystone 20	$1,219.62
	Eddystone 30	$1,165.16
	Eddystone 40	$1,165.16
	Fairless Hills A	$7,107.78
	Fairless Hills B	$7,107.78
	Falls 1	$1,122.57
	Falls 2	$1,136.72
	Falls 3	$1,126.13
	Limerick 1	$117,425.96
	Limerick 2	$110,306.86
	Moser 1	$1,370.85
	Moser 2	$1,374.32
	Moser 3	$1,342.63
	Muddy Run 1	$4,658.52
	Muddy Run 2	$4,930.03
	Muddy Run 3	$4,338.87
	Muddy Run 4	$4,448.45
	Muddy Run 5	$4,977.46
	Muddy Run 6	$4,632.88
	Muddy Run 7	$4,632.88
	Muddy Run 8	$4,282.85
	Peach Bottom 2 (50%)	$114,618.36
	Peach Bottom 3 (50%)	$131,487.66
	Pennsbury 1	$362.54
	Pennsbury 2	$362.54
	Richmond 91	$2,714.45
	Richmond 92	$2,730.24
	Schuylkill 10	$2,246.06
	Schuylkill 11	$2,092.87
	Southwark 3	$2,032.57
	Southwark 4	$1,842.23
	Southwark 5	$1,996.14
	Southwark 6	$1,850.63
	PECO Zone Total Monthly Revenue Requirement	**$646,805.00**
	PECO Zone Total Annual (Filed)	**$7,761,660.05**

PSEG	Salem 1 (43%)	$16,704.87
	Salem 2 (43%)	$18,612.43
	PSEG Zone Total Monthly Revenue Requirement	**$35,317.30**
	PSEG Zone Total Annual (Filed)	**$423,807.58**
All Zones	**Total Monthly Revenue Requirement**	**$2,703,690.25**
	Total Annual (Filed)	**$32,444,282.95**

PARTIAL MONTH REVENUE REQUIREMENT:

When a unit deactivation date is other than the first day of the month, the revenue requirement shall be a blended revenue requirement for the month of service in which the deactivation occurred ("Deactivation Month") as follows: the sum of (i) the total monthly revenue requirement prior to the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the number of days in the Deactivation Month prior to the unit deactivation date and (ii) the total monthly revenue requirement after the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the remaining number of days in the Deactivation Month from and including the unit deactivation date.

Attachment D

Handsome Lake Energy, LLC

Rate Schedule FERC No. 2
(Clean)

HANDSOME LAKE ENERGY, LLC
RATE SCHEDULE FERC NO. 2

Reactive Supply and Voltage Control from Generation Sources Service

Handsome Lake Energy, LLC ("Handsome Lake") provides Reactive Supply and Voltage Control from Generation Sources Service ("Reactive Supply Service") from its natural-gas fueled electric generating facility located in Venango County, Pennsylvania ("Facility") within the Penelec zone under the operational control of PJM Interconnection, L.L.C. This Rate Schedule FERC No. 2 sets forth Handsome Lake's revenue requirement for Reactive Supply Service from the Facility. This Rate Schedule shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

Handsome Lake's monthly fixed revenue requirement consists of the charges set forth below.

REVENUE REQUIREMENT:

Generation Facility	**Monthly Revenue Requirement**
Handsome Lake 1	$3,595.28
Handsome Lake 2	$3,595.28
Handsome Lake 3	$3,595.28
Handsome Lake 4	$3,595.28
Handsome Lake 5	$3,595.28
Total Monthly Revenue Requirement	**$17,976.40**
Total Annual (Filed)	**$215,716.75**

PARTIAL MONTH REVENUE REQUIREMENT:

When a unit deactivation date is other than the first day of the month, the revenue requirement shall be a blended revenue requirement for the month of service in which the deactivation occurred ("Deactivation Month") as follows: the sum of (i) the total monthly revenue requirement prior to the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the number of days in the Deactivation Month prior to the unit deactivation date and (ii) the total monthly revenue requirement after the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the remaining number of days in the Deactivation Month from and including the unit deactivation date.

Attachment E

Handsome Lake Energy, LLC

Rate Schedule FERC No. 2
(Redline)

HANDSOME LAKE ENERGY, LLC
RATE SCHEDULE FERC NO. 2

Reactive ~~Power~~Supply and Voltage Control from Generation Sources Service

Handsome Lake Energy, LLC ("Handsome Lake") provides Reactive ~~Power~~Supply and Voltage Control from Generation Sources Service ("Reactive ~~Power~~Supply Service") from its natural-gas fueled electric generating facility located in Venango County, Pennsylvania ("Facility") ~~in~~within the ~~PJM~~Penelec zone under the operational control ~~area administered by the~~ of PJM Interconnection, L.L.C. ~~("PJM") in order to assist in maintaining transmission voltages within acceptable limits on the PJM transmission system.~~ This Rate Schedule FERC No. 2 sets forth Handsome Lake's revenue ~~requirements for the provision of Reactive Power, as contemplated by the revised Schedule 2 of the PJM Open Access Transmission Tariff, filed in Docket No. ER00-3327-000, which provides that PJM will pay generation owners their monthly revenue~~ requirement for Reactive ~~Power.~~

~~Handsome Lake's monthly revenue requirement consists of the sum of the charges for the following: (1) Fixed Capability Component; and (2) Heating Losses Component. Total charges for any 12-month period will not be less than the sum of the annual charges specified below.~~Supply Service from the Facility. This Rate Schedule ~~FERC No. 2~~ shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

~~**MONTHLY**~~ Handsome Lake's monthly fixed revenue requirement consists of the charges set forth below.

REVENUE REQUIREMENT:

~~**1) FIXED CAPABILITY COMPONENT**~~

~~The annual revenue requirement of the Fixed Capability Component is $362,659.~~
~~The monthly charge to PJM is $362,659/12 = $30,222.~~

~~**2) HEATING LOSSES COMPONENT**~~

~~The annual revenue requirement for the Heating Losses Component is $7,645~~
~~The monthly charge to PJM is $7,645/12 = $637.~~

Generation Facility	**Monthly Revenue Requirement**
Handsome Lake 1	$3,595.28
Handsome Lake 2	$3,595.28
Handsome Lake 3	$3,595.28
Handsome Lake 4	$3,595.28
Handsome Lake 5	$3,595.28
Total Monthly Revenue Requirement	**$17,976.40**
Total Annual (Filed)	**$215,716.75**

PARTIAL MONTH REVENUE REQUIREMENT:

When a unit deactivation date is other than the first day of the month, the revenue requirement shall be a blended revenue requirement for the month of service in which the deactivation occurred ("Deactivation Month") as follows: the sum of (i) the total monthly revenue requirement prior to the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the number of days in the Deactivation Month prior to the unit deactivation date and (ii) the total monthly revenue requirement after the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the remaining number of days in the Deactivation Month from and including the unit deactivation date.

Attachment F

Exhibit EXE-3 and Exhibit EXE-4

Exhibit No. EXE-3

Revenue Requirements by Generating Station

	Name	Type	Interconnected TO	Fixed Revenue Requirement	Losses	Total
1	Braidwood 1 & 2	Nuclear	ComEd	$ 4,870,192	$ 98,587	$ 4,968,779
2	Byron 1 & 2	Nuclear	ComEd	$ 4,138,876	$ 72,254	$ 4,211,131
3	Dresden 2&3	Nuclear	ComEd	$ 5,020,319	$ 43,342	$ 5,063,661
4	LaSalle 1 & 2	Nuclear	ComEd	$ 3,526,110	$ 49,855	$ 3,575,965
5	Quad Cities 1 & 2 (75%)	Nuclear	ComEd	$ 2,721,668	$ 94,359	$ 2,816,027
6	SE Chicago 5-12	NG	ComEd	$ 868,959		$ 868,959
7	Perryman 6	NG	BGE	$ 403,917		$ 403,917
8	Gould Street 3	NG	BGE	$ 32,632		$ 32,632
9	Notch Cliff 1-8	Oil	BGE	$ 282,297		$ 282,297
10	Perryman 1,3,4,51 (excl. Unit 2)	Oil,NG	BGE	$ 740,703		$ 740,703
11	Philadelphia Rd 1-4	Oil	BGE	$ 162,635		$ 162,635
12	Riverside 7&8	Oil,NG	BGE	$ 225,216		$ 225,216
13	Westport 5	NG	BGE	$ 121,728		$ 121,728
14	Salem 1 & 2 (43%)	Nuclear	PSEG	$ 423,808		$ 423,808
15	Handsome Lake	NG	Penelec	$ 215,717		$ 215,717
16	TMI	Nuclear	MetEd	$ 317,011	$ 385	$ 317,395
17	Oyster Creek	Nuclear	JCPL	$ 2,421,025	$ 15,872	$ 2,436,897
18	Limerick 1 & 2	Nuclear	PECO	$ 2,724,271	$ 8,523	$ 2,732,794
19	Peach Bottom 2&3 (50%)	Nuclear	PECO	$ 2,942,232	$ 11,040	$ 2,953,272
20	Chester 7-9	Oil	PECO	$ 45,947		$ 45,947
21	Conowingo 1-11	Hydro	PECO	$ 271,848		$ 271,848
22	Croydon 11,12,21,22,31,32,41,42	Oil	PECO	$ 339,494		$ 339,494
23	Delaware 9-12	Oil	PECO	$ 71,775		$ 71,775
24	Eddystone 3,4,10,20,30,40	Oil	PECO	$ 424,678		$ 424,678
25	Fairless Hills A&B	NG	PECO	$ 170,587		$ 170,587
26	Falls1-3	Oil	PECO	$ 40,625		$ 40,625
27	Moser 1-3	Oil	PECO	$ 49,054		$ 49,054
28	Muddy Run 1-8	Pump.Stor.	PECO	$ 442,823		$ 442,823
29	Pennsbury 1&2	NG	PECO	$ 8,701		$ 8,701
30	Richmond 91&92	Oil	PECO	$ 65,336		$ 65,336
31	Schuylkill10&11	Oil	PECO	$ 52,067		$ 52,067
32	Southwark 3-6	NG	PECO	$ 92,659		$ 92,659
33	Total			$ 34,234,911	$ 394,217	$ 34,629,128

Reactive Revenue Requirement by Unit

Constellation Power Source Generation, LLC
Zone
BGE

Monthly Revenue Requirement	Gould Street	Notch Cliff	Perryman 1,3,4,6 51 (Excludes Unit 2)	Philadelphia Rd	Riverside	Westport	Total
Unit1		$ 3,535.34	$ 11,873.32	$ 3,640.06			
Unit 2		$ 2,721.39		$ 3,304.30			
Unit 3	$ 2,719.31	$ 2,721.39	$ 11,873.32	$ 3,304.30			
Unit 4		$ 2,721.39	$ 11,873.32	$ 3,304.30			
Unit 5		$ 3,661.08				$ 10,144.03	
Unit 6		$ 2,721.39	$ 33,659.76				
Unit 7		$ 2,721.39			$ 10,101.69		
Unit 8		$ 2,721.39			$ 8,666.28		
Unit 51			$ 26,105.29				
Total Monthly Revenue Requirement	$ 2,719.31	$ 23,524.76	$ 95,385.02	$ 13,552.95	$ 18,767.97	$ 10,144.03	$ 164,094.04
Total Annual Revenue Requirement							$ 1,969,128.51

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Reactive Revenue Requirement by Unit

Exelon Generation Company, LLC
Zone
Monthly Revenue Requirement

ComEd	Braidwood	Byron	Dresden	LaSalle	Quad Cities	SE Chicago	Total
Unit1	$ 197,160.96	$ 165,509.87		$ 135,845.20	$ 114,487.25		
Unit 2	$ 216,903.96	$ 185,417.69	$ 212,266.27	$ 162,151.91	$ 120,181.66		
Unit 3			$ 209,705.49				
Unit 4							
Unit 5						$ 9,051.66	
Unit 6						$ 9,051.66	
Unit 7						$ 9,051.66	
Unit 8						$ 9,051.66	
Unit 9						$ 9,051.66	
Unit 10						$ 9,051.66	
Unit 11						$ 9,051.66	
Unit 12						$ 9,051.66	
Total	$ 414,064.92	$ 350,927.56	$ 421,971.77	$ 297,997.11	$ 234,668.91	$ 72,413.29	$ 1,792,043.55
Total Zone Annual							$ 21,504,522.60

PECO	Limerick	Peach Bottom	Chester	Conowingo	Croydon	Delaware	Eddystone	Fairless Hills	Falls	Moser	Muddy Run	Pennsbury	Richmond	Schuylkill	Southwark	Total
Unit1	$ 117,425.96			$ 2,840.51					$ 1,122.57	$ 1,370.85	$ 4,658.52	$ 362.54				
Unit 2	$ 110,306.86	$ 114,618.36		$ 2,567.12					$ 1,136.72	$ 1,374.32	$ 4,930.03	$ 362.54				
Unit 3		$ 131,487.66		$ 2,708.19			$ 16,369.68		$ 1,126.13	$ 1,342.63	$ 4,338.87				$ 2,032.57	
Unit 4				$ 2,567.12			$ 14,282.00				$ 4,448.45				$ 1,842.23	
Unit 5				$ 1,838.96							$ 4,977.46				$ 1,996.14	
Unit 6				$ 2,797.30							$ 4,632.88				$ 1,850.63	
Unit 7			$ 1,257.83	$ 2,797.30							$ 4,632.88					
Unit 8			$ 1,263.81	$ 908.77							$ 4,282.85					
Unit 9			$ 1,307.30	$ 1,148.65		$ 1,338.12										
Unit 10				$ 1,405.39		$ 1,555.72	$ 1,188.19							$ 2,246.06		
Unit 11				$ 1,074.73	$ 3,410.10	$ 1,543.69								$ 2,092.87		
Unit 12					$ 3,138.53	$ 1,543.69										
Unit 21					$ 3,623.76											
Unit 22					$ 3,623.76											
Unit 31					$ 3,623.76											
Unit 32					$ 3,623.76											
Unit 41					$ 3,623.76											
Unit 42					$ 3,623.76											
Unit 20							$ 1,219.62									
Unit 30							$ 1,165.16									
Unit 40							$ 1,165.16									
Unit 91													$ 2,714.45			
Unit 92													$ 2,730.24			
Unit A								$ 7,107.78								
Unit B								$ 7,107.78								
Total	$ 227,732.82	$ 246,106.03	$ 3,828.94	$ 22,654.04	$ 28,291.16	$ 5,981.22	$ 35,389.82	$ 14,215.56	$ 3,385.41	$ 4,087.80	$ 36,901.95	$ 725.07	$ 5,444.70	$ 4,338.93	$ 7,721.56	$ 646,805.00
Total Zone Annual																$ 7,761,660.05

PSE&G	Salem
Unit1	$ 16,704.87
Unit 2	$ 18,612.43
Total	$ 35,317.30
Total Zone Annual	$ 423,807.58

MetEd	TMI
Unit 2	$ 26,449.62
Total	$ 26,449.62
Total Zone Annual	$ 317,395.38

JCP&L	Oyster Creek
Unit1	$ 203,074.78
Total	$ 203,074.78
Total Zone Annual	$ 2,436,897.35

All Zones	
Total Monthly Revenue Requirement	$ 2,703,690.25
Total Annual Revenue Requirement	$ 32,444,282.95

SI-SSA-0010-2485

Reactive Revenue Requirement by Unit

Handsome Lake Energy, LLC
Zone
Penelec

Monthly Revenue Requirement		Handsome Lake
Unit1	$	3,595.28
Unit 2	$	3,595.28
Unit 3	$	3,595.28
Unit 4	$	3,595.28
Unit 5	$	3,595.28
Total Monthly Revenue Requirement	$	17,976.40
Total Annual Revenue Requirement	$	215,716.75

SI-SSA-0010-2486

Nuclear Generating Losses

		Braidwood		Byron		Dresden			LaSalle	
		BWD 1	BWD 2	BYR 1	BYR 2	DRE 2		LAS 1	LAS 2	
	Fuel Cost ($ / MW Hr)	**$6.48**	**$7.09**	**$7.03**	**$6.92**	**$6.96**	**$6.65**	**$6.56**	**$6.98**	
1	Gen Field Annual Loss (MW Hr)	5,346	5,602	4,160	3,647	1,101	2,049	2,431		2,808
2	Gen Armature Annual Loss (MW Hr)	1,215	1,310	920	780	1,001	1,687	732		620
3	GSU Annual Loss (MW Hr)	616	431	466	381			347		415
4	Total Annual Loss (MW Hr)	7,177	7,343	5,546	4,807	2,331	4,079	3,510		3,843
5	Cost of Heating Loss (Annual)	$ 46,519	$ 52,068	$ 39,002	$ 33,252	$ 16,220	$ 27,123	$ 23,036	$	26,819

		Limerick		Oyster Creek	Peach Bottom		Quad Cities		Three Mile Isl	
		LIM 1	LIM 2	OYS	PEA 2	PEA 3	QDE 1	QDE 2	TMI	
	Fuel Cost ($ / MW Hr)	**$5.95**	**$6.00**	**$6.18**	**$6.63**	**$6.41**	**$6.67**	**$6.73**	**$6.82**	
6	Gen Field Annual Loss (MW Hr)	361	721	1,100	203	250	1,716	1,898		35
7	Gen Armature Annual Loss (MW Hr)	81	175	1,037	419	728	4,400	4,698		11
8	GSU Annual Loss (MW Hr)	27	59	430	33	66	658	703		10
9	Total Annual Loss (MW Hr)	470	955	2,567	655	1,045	6,775	7,298		56
10	Cost of Heating Loss (Annual)	$ 2,794	$ 5,728	$ 15,872	$ 4,343	$ 6,697	$ 45,211	$ 49,148	$	385

Exhibit No. EXE-3
Schedule 3
Page 1

Unit Name: Braidwood 1 & 2 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 276,982,389	
2	Investment Generator & Exciter	Inputs Tab	41,547,358	
3	Reactive Allocator	(Line 71)	16.49%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**6,850,549**	
5				
6	GSU Transformer Investment	Inputs Tab	49,633,067	
7	Reactive Allocator	(Line 71)	16.49%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**8,183,764**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	2,482,481	
11	Reactive Allocator	(Line 71)	16.49%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**409,325**	
13				
14	Total Cost of Power Plant	Inputs Tab	1,484,090,250	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	1,390,427,343	
16	Balance of Plant Allocator	(Line 79)	0.1358%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	1,888,844	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	17,332,483	
19	Reactive Fixed Charge Rate	(Line 14(h))	28.0986%	
20	**Annual Reactive Rev Req**	(Line 14 * 18)	**4,870,192**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 4,870,192**	
23				
24				
25				
26				

	(e)		(f)	(g)	(h)
	Fixed Charge Rate for Reactive Plant				
			Calculated Amt	Plant	FCR % (f) / (g)
	Electric Expenses	Line 140	382,031		
	Other Expenses		156,675		
	O&M	(sum line 1 & 2)	538,705	17,332,483	3.1081%
	A&G		165,025,553	1,484,090,250	11.1196%
	CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.1975%
	Working Capital	Line 216	33,666,939	1,484,090,250	2.2685%
	General Plant		-	1,484,090,250	0.0000%
	Other Taxes	Line 196(c)	24,988,247	1,484,090,250	1.6837%
	Depreciation	Line 168(c)			0.0814%
					8.1350%
	Taxes (Federal/State/Local)	Line 180			2.9692%
	ADIT	-Line 233(k)	($21,733,067)	1,484,090,250	-1.4644%
			(Sum Lines 1 to 11 , Col. (h))		28.0986%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								

Real Power Capability (MW)		
	1,258.00	
	1,220.00	
Total	2,478.00	(Sum Lines 31 to 33)
Nominal Power Factor (pf)		
	0.92	
	0.90	
Total	0.91	(Line 38 / 58)
MVA Capability (MVA)		
	1,362.95	(Line 31 / 41)
	1,349.56	(Line 32 / 42)
Total	2,712.50	(Sum Lines 51 to 53)
Reactive Power Capability (MVAR)		
(MVA^2 - MW^2)^0.5		
	524.46	(SQRT (Line 51^2 - Line 31^2))
	576.98	(SQRT (Line 52^2 - Line 32^2))
Total	1,101.44	(Sum Lines 62 to 64)
Reactive Allocator	16.5%	(Line 69^2 / Line 58^2)
	ComEd is TO Fleet	
Max. MVAr	2,187	
Nameplate MVAr	4,856	
Exciter MW	35	
Generator MW	11,447	
Balance of Plant Allocator	0.1358%	(Line 75 / Line 76) * (Line 77 / Line 78)

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ 734,651	15%	$ 110,198
	Control&Power Cabling	$ 175,303,902	1%	$ 1,753,039
	Switch Board Equipment	$ 51,974,311	1%	$ 519,743
	Switching Equipment	$ 7,843,655	1%	$ 78,437
	Transformers	$ 702,163	3%	$ 21,065
	Aux Generator	$ 21,664,522	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	50%	$ -
	Structure	$ -	0%	$ -
	Misc	$ 19,860,488	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	1%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 278,083,692		$ 2,482,481

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	$ 32,492,207		
	Coolants and Water (Nuclear Plants Only)	$ 3,183,689		
	Steam Expenses	$ 19,969,572	19,969,572	
	Steam From Other Sources	$ -		
	Electric Expenses	$ -	-	
	Misc Steam (or Nuclear) Power Expenses	$ 2,040,158		
	Rents	$ 56,408,634	56,408,634	
	Allowances	$ 4,476,155	4,476,155	
	Maintenance Supervision and Engineering	$ -		
	Maintenance of Structures	$ 5,994,248	5,994,248	
	Maintenance of Boiler (or reactor) Plant	$ 467,205		
	Maintenance of Electric Plant	$ 15,446,317		
	Maintenance of Misc Steam (or Nuclear) Plant	$ 9,921,805	9,921,805	
	Other Power Production, & Other Expenses	$ 18,561,772	18,561,772	
	Total NonFuel Expenses	168,961,761	115,332,187	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		68.26%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation

	Plant Var Allocators						
	Electric Expense Allocator	2.4733%	Line 4(c) / 1(c))				
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)				
	Other Demand Expense Allocator	0.1358%	Line 79				
	Production Plant Expenses						
	Total NonFuel Expenses	168,961,761	Line 116				
	Allowances	4,476,155	Line 109				
	Non-Fuel Production O&M	164,485,606	(Line 126 - 127)				
	Operating Expenses						
	Operations Supervision & Engineering	0	Line 102(c)				
	Electric Expenses	0	Line 106(c)				
	Maintenance of Electric Plant	15,446,317	Line 113(b)				
	Other Demand Related Expenses	115,332,187	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)				
	Total	130,778,503	(Sum Lines 131 to 134)				
						$	82,500
				Allocator	Allocated Amount		
	Maintenance of Electric Plant	15,446,317	Line 113(b)				
	Electric Expenses	0	Line 106(c)				
	Total Electric Expenses	15,446,317	(Line 138 + 139)	2.4733%	382,031	(Line 140(b) * (d))	
				Line 121			
	Other Demand Related Expenses	115,332,187	(Line 134)	0.1358%	156,675		
				Line 123			
	Balance of Plant Fixed Expenses				130,239,798.34	(Line 135(b) - Line 140(e) - Line 142(e))	

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Exhibit No. EXE-3
Schedule 3
Page 4

	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		124,367,412	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		40,658,141	(allocated on plant labor)	
	Total		165,025,553		
Depreciation					
	Annual Depreciation Exp ...DE	25,369,064			
	Gross Production Plant Cost ... F	1,484,090,250	Line 14		
	SLDP=DE/F	1.7094%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	59			
	SFDP=(R/((1+R)^n-1)		0.0814%		
Income Taxes					
	Income Tax Calculation; (2015 Est Tax Rate)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.679%			
	e) Federal Income Tax Rate ("FIT")	35.000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.679%			
	g) Gross-Up Tax Factor ("GTF")	61.321%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.969%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	0.4500	0.0500	0.0225	
	Preferred Stock				
	Common Stock	0.5500	0.1070	0.0589	
	Total Cost of Capital "R"	1.0000	R=	0.0814	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		20,026,176		
	Payroll Taxes	7,269,439			
	Percentage Fixed O&M Excluding Allowances	68.2593%	Line 117		
	Fixed Payroll Taxes		4,962,071	(Line 193 * 194)	
	Total Other Taxes		24,988,247	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	Percentage Fixed O&M Excluding Allowances	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9692%				
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	2,488,211				
		100.000%				
	Production Related Prepayments	2,488,211	(Line 209 * 210)			
	Unit Specific M&S	300,703,432				
	Total	303,191,643	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9692%				
	Working Capital Costs	33,666,939	(Line 213 * 214)			

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Accumulated Deferred Income Taxes

Investment	1,484,090,250	Line 14
Asset Service Life	59	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 264,508,102

Yr.	(a)	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized
		Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	PMT of NPV col. (j)
	1	25,154,072	3.750%	55,653,384	11,796,829	11,796,829	694,243	265,429	425,717	1,385,389	21,733,067
	2	25,154,072	7.219%	107,136,475	31,709,974	43,506,803	2,560,375	978,903	1,570,048	5,109,326	21,733,067
	3	25,154,072	6.677%	99,092,706	28,598,724	72,105,527	4,243,410	1,622,374	2,602,102	8,467,886	21,733,067
	4	25,154,072	6.177%	91,672,255	25,728,568	97,834,095	5,757,536	2,201,267	3,530,579	11,489,383	21,733,067
	5	25,154,072	5.713%	84,786,076	23,065,063	120,899,158	7,114,915	2,720,231	4,362,937	14,198,084	21,733,067
	6	25,154,072	5.285%	78,434,170	20,608,209	141,507,367	8,327,709	3,183,916	5,106,634	16,618,258	21,733,067
	7	25,154,072	4.888%	72,542,331	18,329,305	159,836,671	9,406,388	3,596,325	5,768,091	18,770,804	21,733,067
	8	25,154,072	4.522%	67,110,561	16,228,350	176,065,022	10,361,427	3,961,463	6,353,730	20,676,620	21,733,067
	9	25,154,072	4.462%	66,220,107	15,883,932	191,948,954	11,296,196	4,318,851	6,926,940	22,541,988	21,733,067
	10	25,154,072	4.461%	66,205,266	15,878,191	207,827,145	12,230,627	4,676,111	7,499,943	24,406,681	21,733,067
	11	25,154,072	4.462%	66,220,107	15,883,932	223,711,077	13,165,397	5,033,499	8,073,153	26,272,049	21,733,067
	12	25,154,072	4.461%	66,205,266	15,878,191	239,589,268	14,099,828	5,390,759	8,646,156	28,136,743	21,733,067
	13	25,154,072	4.462%	66,220,107	15,883,932	255,473,200	15,034,598	5,748,147	9,219,366	30,002,110	21,733,067
	14	25,154,072	4.461%	66,205,266	15,878,191	271,351,391	15,969,029	6,105,406	9,792,368	31,866,804	21,733,067
	15	25,154,072	4.462%	66,220,107	15,883,932	287,235,323	16,903,799	6,462,795	10,365,578	33,732,172	21,733,067
	16	25,154,072	4.461%	66,205,266	15,878,191	303,113,514	17,838,230	6,820,054	10,938,581	35,596,866	21,733,067
	17	25,154,072	4.462%	66,220,107	15,883,932	318,997,446	18,773,000	7,177,443	11,511,791	37,462,233	21,733,067
	18	25,154,072	4.461%	66,205,266	15,878,191	334,875,637	19,707,431	7,534,702	12,084,794	39,326,927	21,733,067
	19	25,154,072	4.462%	66,220,107	15,883,932	350,759,568	20,642,201	7,892,090	12,658,004	41,192,295	21,733,067
	20	25,154,072	4.461%	66,205,266	15,878,191	366,637,760	21,576,632	8,249,350	13,231,007	43,056,988	21,733,067
	21	25,154,072	2.231%	33,110,053	3,077,294	369,715,054	21,757,731	8,318,589	13,342,058	43,418,378	21,733,067
	22	25,154,072	0.000%	0	-9,729,344	359,985,710	21,185,159	8,099,678	12,990,951	42,275,789	21,733,067
	23	25,154,072	0.000%	0	-9,729,344	350,256,367	20,612,587	7,880,768	12,639,845	41,133,200	21,733,067
	24	25,154,072	0.000%	0	-9,729,344	340,527,023	20,040,015	7,661,858	12,288,738	39,990,611	21,733,067
	25	25,154,072	0.000%	0	-9,729,344	330,797,680	19,467,443	7,442,948	11,937,631	38,848,022	21,733,067
	26	25,154,072	0.000%	0	-9,729,344	321,068,336	18,894,872	7,224,038	11,586,524	37,705,433	21,733,067
	27	25,154,072	0.000%	0	-9,729,344	311,338,993	18,322,300	7,005,127	11,235,417	36,562,844	21,733,067
	28	25,154,072	0.000%	0	-9,729,344	301,609,649	17,749,728	6,786,217	10,884,311	35,420,256	21,733,067
	29	25,154,072	0.000%	0	-9,729,344	291,880,306	17,177,156	6,567,307	10,533,204	34,277,667	21,733,067
	30	25,154,072	0.000%	0	-9,729,344	282,150,962	16,604,584	6,348,397	10,182,097	33,135,078	21,733,067
	31	25,154,072	0.000%	0	-9,729,344	272,421,619	16,032,012	6,129,486	9,830,990	31,992,489	21,733,067
	32	25,154,072	0.000%	0	-9,729,344	262,692,275	15,459,440	5,910,576	9,479,883	30,849,900	21,733,067
	33	25,154,072	0.000%	0	-9,729,344	252,962,932	14,886,869	5,691,666	9,128,777	29,707,311	21,733,067
	34	25,154,072	0.000%	0	-9,729,344	243,233,588	14,314,297	5,472,756	8,777,670	28,564,722	21,733,067
	35	25,154,072	0.000%	0	-9,729,344	233,504,245	13,741,725	5,253,846	8,426,563	27,422,133	21,733,067
	36	25,154,072	0.000%	0	-9,729,344	223,774,901	13,169,153	5,034,935	8,075,456	26,279,544	21,733,067
	37	25,154,072	0.000%	0	-9,729,344	214,045,558	12,596,581	4,816,025	7,724,349	25,136,956	21,733,067
	38	25,154,072	0.000%	0	-9,729,344	204,316,214	12,024,009	4,597,115	7,373,243	23,994,367	21,733,067
	39	25,154,072	0.000%	0	-9,729,344	194,586,870	11,451,437	4,378,205	7,022,136	22,851,778	21,733,067
	40	25,154,072	0.000%	0	-9,729,344	184,857,527	10,878,865	4,159,294	6,671,029	21,709,189	21,733,067
	41	25,154,072	0.000%	0	-9,729,344	175,128,183	10,306,294	3,940,384	6,319,922	20,566,600	21,733,067
	42	25,154,072	0.000%	0	-9,729,344	165,398,840	9,733,722	3,721,474	5,968,816	19,424,011	21,733,067
	43	25,154,072	0.000%	0	-9,729,344	155,669,496	9,161,150	3,502,564	5,617,709	18,281,422	21,733,067
	44	25,154,072	0.000%	0	-9,729,344	145,940,153	8,588,578	3,283,653	5,266,602	17,138,833	21,733,067
	45	25,154,072	0.000%	0	-9,729,344	136,210,809	8,016,006	3,064,743	4,915,495	15,996,244	21,733,067
	46	25,154,072	0.000%	0	-9,729,344	126,481,466	7,443,434	2,845,833	4,564,388	14,853,656	21,733,067
	47	25,154,072	0.000%	0	-9,729,344	116,752,122	6,870,862	2,626,923	4,213,282	13,711,067	21,733,067
	48	25,154,072	0.000%	0	-9,729,344	107,022,779	6,298,291	2,408,013	3,862,175	12,568,478	21,733,067
	49	25,154,072	0.000%	0	-9,729,344	97,293,435	5,725,719	2,189,102	3,511,068	11,425,889	21,733,067
	50	25,154,072	0.000%	0	-9,729,344	87,564,092	5,153,147	1,970,192	3,159,961	10,283,300	21,733,067
	51	25,154,072	0.000%	0	-9,729,344	77,834,748	4,580,575	1,751,282	2,808,854	9,140,711	21,733,067
	52	25,154,072	0.000%	0	-9,729,344	68,105,405	4,008,003	1,532,372	2,457,748	7,998,122	21,733,067
	53	25,154,072	0.000%	0	-9,729,344	58,376,061	3,435,431	1,313,461	2,106,641	6,855,533	21,733,067
	54	25,154,072	0.000%	0	-9,729,344	48,646,718	2,862,859	1,094,551	1,755,534	5,712,944	21,733,067
	55	25,154,072	0.000%	0	-9,729,344	38,917,374	2,290,287	875,641	1,404,427	4,570,356	21,733,067
	56	25,154,072	0.000%	0	-9,729,344	29,188,031	1,717,716	656,731	1,053,320	3,427,767	21,733,067
	57	25,154,072	0.000%	0	-9,729,344	19,458,687	1,145,144	437,820	702,214	2,285,178	21,733,067
	58	25,154,072	0.000%	0	-9,729,344	9,729,344	572,572	218,910	351,107	1,142,589	21,733,067
	59	25,154,072	0.000%	0	-9,729,344	0	0	0	0	0	21,733,067

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Unit Name: Byron 1 & 2 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 326,545,555	
2	Investment Generator & Exciter	Inputs Tab	48,981,833	
3	Reactive Allocator	(Line 71)	16.19%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**7,932,428**	
5				
6	GSU Transformer Investment	Inputs Tab	21,644,926	
7	Reactive Allocator	(Line 71)	16.19%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**3,505,316**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	2,870,875	
11	Reactive Allocator	(Line 71)	16.19%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**464,928**	
13				
14	Total Cost of Power Plant	Inputs Tab	1,391,617,170	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	1,318,119,535	
16	Balance of Plant Allocator	(Line 79)	0.1358%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	1,790,617	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	13,693,289	
19	Reactive Fixed Charge Rate	(Line 14(h))	30.2256%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**4,138,876**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 4,138,876**	
23				
24				
25				
26				

(e)		(f)	(g)	(h)
Fixed Charge Rate for Reactive Plant				
		Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 140	396,890		
Other Expenses		165,722		
O&M	(sum line 1 & 2)	562,613	13,693,289	4.1087%
A&G		156,485,976	1,391,617,170	11.2449%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.2132%
Working Capital	Line 216	29,115,524	1,391,617,170	2.0922%
General Plant		-	1,391,617,170	0.0000%
Other Taxes	Line 196(c)	39,504,797	1,391,617,170	2.8388%
Depreciation	Line 168(c)			0.0814%
				8.1350%
Taxes (Federal/State/Local)	Line 180			2.9758%
ADIT	-Line 233(k)	($20,378,888)	1,391,617,170	-1.4644%
		(Sum Lines 1 to 11 , Col. (h))		30.2256%

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	(a)	(b)	(c)
Allocators			
	Real Power Capability (MW)		
		1,248.00	
		1,205.00	
		-	
	Total	2,453.00	(Sum Lines 31 to 33)
	Nominal Power Factor (pf)		
		0.93	
		0.90	
		-	
	Total	0.92	(Line 38 / 58)
	MVA Capability (MVA)		
		1,347.73	(Line 31 / 41)
		1,333.01	(Line 32 / 42)
		-	
	Total	2,680.75	(Sum Lines 51 to 53)
	Reactive Power Capability (MVAR)		
	(MVA^2 - MW^2)^0.5		
		508.80	(SQRT (Line 51^2 - Line 31^2))
		570.00	(SQRT (Line 52^2 - Line 32^2))
		-	
	Total	1,078.80	(Sum Lines 62 to 64)
	Reactive Allocator	16.2%	(Line 69^2 / Line 58^2)
		ComEd is TO Fleet	
	Max. MVAr	2,187	
	Nameplate MVAr	4,856	
	Exciter MW	35	
	Generator MW	11,447	
	Balance of Plant Allocator	0.1358%	(Line 75 / Line 76) * (Line 77 / Line 78)

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ 1,036,178	15%	$ 155,427
	Control&Power Cabling	$ 185,037,012	1%	$ 1,850,370
	Switch Board Equipment	$ 65,474,820	1%	$ 654,748
	Switching Equipment	$ 14,828,319	1%	$ 148,283
	Transformers	$ 1,267,080	3%	$ 38,012
	Aux Generator	$ 30,867,315	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ 48,068	50%	$ 24,034
	Structure	$ -	0%	$ -
	Misc	$ 18,414,787	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	1%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 316,973,581		$ 2,870,875

		Total Non-Fuel	**Fixed O&M**	
O&M				
	Production Expenses: Oper, Supv, & Engr	34,368,626	34,368,626	
	Coolants and Water (Nuclear Plants Only)	3,367,547		
	Steam Expenses	21,122,811	21,122,811	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	2,157,976		
	Rents	59,666,223	59,666,223	
	Allowances	4,734,652	4,734,652	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	6,340,415	6,340,415	
	Maintenance of Boiler (or reactor) Plant	494,186		
	Maintenance of Electric Plant	16,338,339		
	Maintenance of Misc Steam (or Nuclear) Plant	10,494,787	10,494,787	
	Other Power Production, & Other Expenses	19,633,712	19,633,712	
	Total NonFuel Expenses	178,719,274	156,361,227	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	2.4292%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.1358%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	178,719,274	Line 116			
	Allowances	4,734,652	Line 109			
	Non-Fuel Production O&M	173,984,622	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	34,368,626	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	0	Line 113(b)			
	Other Demand Related Expenses	121,992,601	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	156,361,227	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	16,338,339	Line 114(b)			
	Electric Expenses	0	Line 107(c)			
	Total Electric Expenses	16,338,339	(Line 138 + 139)	2.4292%	396,890	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	121,992,601	(Line 134)	0.1358%	165,722	
				Line 123		
	Balance of Plant Fixed Expenses				155,798,614	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		119,205,155	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		37,280,822	(allocated on plant labor)	
	Total		156,485,976		
Depreciation					
	Annual Depreciation Exp ...DE	23,586,732			
	Gross Production Plant Cost ... F	1,391,617,170	Line 14		
	SLDP=DE/F	1.6949%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	59			
	SFDP=(R/((1+R)^n-1)		0.0814%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.976%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		33,153,706		
	Payroll Taxes	7,259,232			
		0 87.4899%	Line 117		
	Fixed Payroll Taxes		6,351,091	(Line 193 * 194)	
	Total Other Taxes		39,504,797	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9758%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	2,333,171				
		100.000%				
	Production Related Prepayments	2,333,171	(Line 209 * 210)			
	Unit Specific M&S	259,714,161				
	Total	262,047,333	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9758%				
	Working Capital Costs	29,115,524	(Line 213 * 214)			

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Accumulated Deferred Income Taxes

Investment	1,391,617,170	Line 14
Asset Service Life	59	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 248,026,706

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	23,586,732	3.750%	52,185,644	11,061,773	11,061,773	650,985	248,890	399,191	1,299,066	20,378,888
2	23,586,732	7.219%	100,460,843	29,734,138	40,795,911	2,400,839	917,908	1,472,219	4,790,966	20,378,888
3	23,586,732	6.677%	92,918,278	26,816,749	67,612,660	3,979,005	1,521,285	2,439,966	7,940,256	20,378,888
4	23,586,732	6.177%	85,960,193	24,125,431	91,738,091	5,398,787	2,064,107	3,310,590	10,773,484	20,378,888
5	23,586,732	5.713%	79,503,089	21,627,888	113,365,979	6,671,588	2,550,735	4,091,084	13,313,407	20,378,888
6	23,586,732	5.285%	73,546,967	19,324,120	132,690,098	7,808,812	2,985,527	4,788,442	15,582,781	20,378,888
7	23,586,732	4.888%	68,022,247	17,187,213	149,877,311	8,820,280	3,372,240	5,408,684	17,601,203	20,378,888
8	23,586,732	4.522%	62,928,928	15,217,168	165,094,480	9,715,810	3,714,626	5,957,832	19,388,268	20,378,888
9	23,586,732	4.462%	62,093,958	14,894,210	179,988,690	10,592,334	4,049,746	6,495,325	21,137,405	20,378,888
10	23,586,732	4.461%	62,080,042	14,888,827	194,877,517	11,468,542	4,384,744	7,032,625	22,885,911	20,378,888
11	23,586,732	4.462%	62,093,958	14,894,210	209,771,727	12,345,066	4,719,864	7,570,118	24,635,048	20,378,888
12	23,586,732	4.461%	62,080,042	14,888,827	224,660,555	13,221,274	5,054,862	8,107,417	26,383,553	20,378,888
13	23,586,732	4.462%	62,093,958	14,894,210	239,554,765	14,097,798	5,389,982	8,644,911	28,132,691	20,378,888
14	23,586,732	4.461%	62,080,042	14,888,827	254,443,592	14,974,005	5,724,981	9,182,210	29,881,196	20,378,888
15	23,586,732	4.462%	62,093,958	14,894,210	269,337,802	15,850,530	6,060,101	9,719,703	31,630,334	20,378,888
16	23,586,732	4.461%	62,080,042	14,888,827	284,226,630	16,726,737	6,395,099	10,257,003	33,378,839	20,378,888
17	23,586,732	4.462%	62,093,958	14,894,210	299,120,840	17,603,261	6,730,219	10,794,496	35,127,976	20,378,888
18	23,586,732	4.461%	62,080,042	14,888,827	314,009,667	18,479,469	7,065,218	11,331,795	36,876,482	20,378,888
19	23,586,732	4.462%	62,093,958	14,894,210	328,903,878	19,355,993	7,400,337	11,869,289	38,625,619	20,378,888
20	23,586,732	4.461%	62,080,042	14,888,827	343,792,705	20,232,201	7,735,336	12,406,588	40,374,124	20,378,888
21	23,586,732	2.231%	31,046,979	2,885,549	346,678,254	20,402,015	7,800,261	12,510,720	40,712,996	20,378,888
22	23,586,732	0.000%	0	-9,123,112	337,555,142	19,865,120	7,594,991	12,181,490	39,641,601	20,378,888
23	23,586,732	0.000%	0	-9,123,112	328,432,030	19,328,225	7,389,721	11,852,261	38,570,207	20,378,888
24	23,586,732	0.000%	0	-9,123,112	319,308,918	18,791,330	7,184,451	11,523,031	37,498,812	20,378,888
25	23,586,732	0.000%	0	-9,123,112	310,185,806	18,254,435	6,979,181	11,193,802	36,427,417	20,378,888
26	23,586,732	0.000%	0	-9,123,112	301,062,694	17,717,540	6,773,911	10,864,572	35,356,023	20,378,888
27	23,586,732	0.000%	0	-9,123,112	291,939,582	17,180,644	6,568,641	10,535,343	34,284,628	20,378,888
28	23,586,732	0.000%	0	-9,123,112	282,816,470	16,643,749	6,363,371	10,206,114	33,213,233	20,378,888
29	23,586,732	0.000%	0	-9,123,112	273,693,359	16,106,854	6,158,101	9,876,884	32,141,839	20,378,888
30	23,586,732	0.000%	0	-9,123,112	264,570,247	15,569,959	5,952,831	9,547,655	31,070,444	20,378,888
31	23,586,732	0.000%	0	-9,123,112	255,447,135	15,033,064	5,747,561	9,218,425	29,999,050	20,378,888
32	23,586,732	0.000%	0	-9,123,112	246,324,023	14,496,169	5,542,291	8,889,196	28,927,655	20,378,888
33	23,586,732	0.000%	0	-9,123,112	237,200,911	13,959,274	5,337,020	8,559,966	27,856,260	20,378,888
34	23,586,732	0.000%	0	-9,123,112	228,077,799	13,422,378	5,131,750	8,230,737	26,784,866	20,378,888
35	23,586,732	0.000%	0	-9,123,112	218,954,687	12,885,483	4,926,480	7,901,507	25,713,471	20,378,888
36	23,586,732	0.000%	0	-9,123,112	209,831,575	12,348,588	4,721,210	7,572,278	24,642,076	20,378,888
37	23,586,732	0.000%	0	-9,123,112	200,708,463	11,811,693	4,515,940	7,243,048	23,570,682	20,378,888
38	23,586,732	0.000%	0	-9,123,112	191,585,351	11,274,798	4,310,670	6,913,819	22,499,287	20,378,888
39	23,586,732	0.000%	0	-9,123,112	182,462,239	10,737,903	4,105,400	6,584,589	21,427,893	20,378,888
40	23,586,732	0.000%	0	-9,123,112	173,339,127	10,201,008	3,900,130	6,255,360	20,356,498	20,378,888
41	23,586,732	0.000%	0	-9,123,112	164,216,015	9,664,112	3,694,860	5,926,130	19,285,103	20,378,888
42	23,586,732	0.000%	0	-9,123,112	155,092,903	9,127,217	3,489,590	5,596,901	18,213,709	20,378,888
43	23,586,732	0.000%	0	-9,123,112	145,969,791	8,590,322	3,284,320	5,267,671	17,142,314	20,378,888
44	23,586,732	0.000%	0	-9,123,112	136,846,679	8,053,427	3,079,050	4,938,442	16,070,919	20,378,888
45	23,586,732	0.000%	0	-9,123,112	127,723,567	7,516,532	2,873,780	4,609,213	14,999,525	20,378,888
46	23,586,732	0.000%	0	-9,123,112	118,600,455	6,979,637	2,668,510	4,279,983	13,928,130	20,378,888
47	23,586,732	0.000%	0	-9,123,112	109,477,343	6,442,742	2,463,240	3,950,754	12,856,736	20,378,888
48	23,586,732	0.000%	0	-9,123,112	100,354,231	5,905,847	2,257,970	3,621,524	11,785,341	20,378,888
49	23,586,732	0.000%	0	-9,123,112	91,231,120	5,368,951	2,052,700	3,292,295	10,713,946	20,378,888
50	23,586,732	0.000%	0	-9,123,112	82,108,008	4,832,056	1,847,430	2,963,065	9,642,552	20,378,888
51	23,586,732	0.000%	0	-9,123,112	72,984,896	4,295,161	1,642,160	2,633,836	8,571,157	20,378,888
52	23,586,732	0.000%	0	-9,123,112	63,861,784	3,758,266	1,436,890	2,304,606	7,499,762	20,378,888
53	23,586,732	0.000%	0	-9,123,112	54,738,672	3,221,371	1,231,620	1,975,377	6,428,368	20,378,888
54	23,586,732	0.000%	0	-9,123,112	45,615,560	2,684,476	1,026,350	1,646,147	5,356,973	20,378,888
55	23,586,732	0.000%	0	-9,123,112	36,492,448	2,147,581	821,080	1,316,918	4,285,579	20,378,888
56	23,586,732	0.000%	0	-9,123,112	27,369,336	1,610,685	615,810	987,688	3,214,184	20,378,888
57	23,586,732	0.000%	0	-9,123,112	18,246,224	1,073,790	410,540	658,459	2,142,789	20,378,888
58	23,586,732	0.000%	0	-9,123,112	9,123,112	536,895	205,270	329,229	1,071,395	20,378,888
59	23,586,732	0.000%	0	-9,123,112	0	0	0	0	0	20,378,888

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Unit Name: Chester 7-9 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 4,695,512	
2	Investment Generator & Exciter	Inputs Tab	704,327	
3	Reactive Allocator	(Line 71)	35.06%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**246,936**	
5				
6	GSU Transformer Investment	Inputs Tab	-	
7	Reactive Allocator	(Line 71)	35.06%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	502,862	
11	Reactive Allocator	(Line 71)	35.06%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**176,303**	
13				
14	Total Cost of Power Plant	Inputs Tab	9,133,168	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	7,925,979	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	4,294	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	427,533	
19	Reactive Fixed Charge Rate	(Line 14(h))	10.7471%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**45,947**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 45,947**	
23				
24				
25				
26				

(e)		(f)	(g)	(h)
Fixed Charge Rate for Reactive Plant				
		Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 140	352		
Other Expenses		52		
O&M	(sum line 1 & 2)	403	427,533	0.0944%
A&G		71,811	9,133,168	0.7863%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0123%
Working Capital	Line 216	10,340	9,133,168	0.1132%
General Plant		-	9,133,168	0.0000%
Other Taxes	Line 196(c)	5,780	9,133,168	0.0633%
Depreciation	Line 168(c)			0.0549%
				8.1350%
Taxes (Federal/State/Local)	Line 180			3.0241%
ADIT	-Line 233(k)	($140,315)	9,133,168	-1.5363%
		(Sum Lines 1 to 11 , Col. (h))		10.7471%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		15.14						
		15.16						
		14.48						
	Total	44.78	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.81						
		0.81						
		0.80						
	Total	0.81	(Line 38 / 58)					
	MVA Capability (MVA)							
		18.65	(Line 31 / 41)					
		18.72	(Line 32 / 42)					
		18.21	(Line 33 / 43)					
	Total	55.58	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		10.88	(SQRT (Line 51^2 - Line 31^2))					
		10.98	(SQRT (Line 52^2 - Line 32^2))					
		11.05	(SQRT (Line 53^2 - Line 33^2))					
	Total	32.91	(Sum Lines 62 to 64)					
	Reactive Allocator	35.1%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ 12,262	50%	$ 6,131
	Control&Power Cabling	$ 360,640	50%	$ 180,320
	Switch Board Equipment	$ -	50%	$ -
	Switching Equipment	$ 791,028	40%	$ 316,411
	Transformers	$ -	10%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ -	0%	$ -
	Misc	$ 560,700	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 1,724,631		$ 502,862

O&M		**Total Non-Fuel**	**Fixed O&M**		
	Production Expenses: Oper, Supv, & Engr	38,422	38,422		
	Coolants and Water (Nuclear Plants Only)	0			
	Steam Expenses	9,925	9,925		
	Steam From Other Sources	19,178			
	Electric Expenses	0	-		
	Misc Steam (or Nuclear) Power Expenses	5,876			
	Rents	35,759	35,759		
	Allowances	1,445	1,445		
	Maintenance Supervision and Engineering	0			
	Maintenance of Structures	14,987	14,987		
	Maintenance of Boiler (or reactor) Plant	6,427			
	Maintenance of Electric Plant	6,686			
	Maintenance of Misc Steam (or Nuclear) Plant	8,322	8,322		
	Other Power Production, & Other Expenses	25,242	25,242		
	Total NonFuel Expenses	172,268	134,102	(Sum Lines 102 to 115)	
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))	

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	5.2590%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	172,268	Line 116			
	Allowances	1,445	Line 109			
	Non-Fuel Production O&M	170,823	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	38,422	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	6,686	Line 113(b)			
	Other Demand Related Expenses	95,679	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	140,788	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	6,686	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	6,686	(Line 138 + 139)	5.2590%	352	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	95,679	(Line 134)	0.0542%	52	
				Line 123		
	Balance of Plant Fixed Expenses				140,384	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		8,214	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		63,597	(allocated on plant labor)	
	Total		71,811		
Depreciation					
	Annual Depreciation Exp ...DE	142,706			
	Gross Production Plant Cost ... F	9,133,168	Line 14		
	SLDP=DE/F	1.5625%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	64			
	SFDP=(R/((1+R)^n-1)		0.0549%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.024%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		5,780	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		5,780	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	3.0241%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
	Prepayments	68,701	
		100.000%	
	Production Related Prepayments	68,701	(Line 209 * 210)
	Unit Specific M&S	23,962	
	Total	92,663	(Line 211 + 212)
	Return on Working Capital	8.1350%	
	Taxes on Working Capital	3.0241%	
	Working Capital Costs	10,340	(Line 213 * 214)

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(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)

Accumulated Deferred Income Taxes

Investment	9,133,168	Line 14		NPV of Col (j)>	1,713,273
Asset Service Life	64	Line 167			
Composite Tax Rate	38.6790%	Line 177			

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity = (f) *	Interest	Income Taxes = (g) *	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	= (f) * (Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	142,706	3.750%	342,494	77,276	77,276	4,548	1,739	2,789	9,075	140,315
2	142,706	7.219%	659,323	199,823	277,099	16,307	6,235	10,000	32,542	140,315
3	142,706	6.677%	609,822	180,676	457,774	26,940	10,300	16,520	53,760	140,315
4	142,706	6.177%	564,156	163,013	620,787	36,533	13,968	22,403	72,904	140,315
5	142,706	5.713%	521,778	146,621	767,408	45,162	17,267	27,694	90,122	140,315
6	142,706	5.285%	482,688	131,502	898,910	52,901	20,225	32,439	105,566	140,315
7	142,706	4.888%	446,429	117,477	1,016,387	59,814	22,869	36,679	119,362	140,315
8	142,706	4.522%	413,002	104,548	1,120,935	65,967	25,221	40,452	131,640	140,315
9	142,706	4.462%	407,522	102,428	1,223,363	71,995	27,526	44,148	143,669	140,315
10	142,706	4.461%	407,431	102,393	1,325,756	78,021	29,830	47,843	155,693	140,315
11	142,706	4.462%	407,522	102,428	1,428,185	84,049	32,134	51,539	167,722	140,315
12	142,706	4.461%	407,431	102,393	1,530,577	90,074	34,438	55,235	179,747	140,315
13	142,706	4.462%	407,522	102,428	1,633,006	96,102	36,743	58,931	191,776	140,315
14	142,706	4.461%	407,431	102,393	1,735,399	102,128	39,046	62,626	203,801	140,315
15	142,706	4.462%	407,522	102,428	1,837,827	108,156	41,351	66,322	215,830	140,315
16	142,706	4.461%	407,431	102,393	1,940,220	114,182	43,655	70,018	227,854	140,315
17	142,706	4.462%	407,522	102,428	2,042,648	120,210	45,960	73,714	239,883	140,315
18	142,706	4.461%	407,431	102,393	2,145,041	126,236	48,263	77,409	251,908	140,315
19	142,706	4.462%	407,522	102,428	2,247,469	132,264	50,568	81,105	263,937	140,315
20	142,706	4.461%	407,431	102,393	2,349,862	138,289	52,872	84,800	275,962	140,315
21	142,706	2.231%	203,761	23,616	2,373,478	139,679	53,403	85,653	278,735	140,315
22	142,706	0.000%	0	-55,197	2,318,281	136,431	52,161	83,661	272,253	140,315
23	142,706	0.000%	0	-55,197	2,263,083	133,182	50,919	81,669	265,771	140,315
24	142,706	0.000%	0	-55,197	2,207,886	129,934	49,677	79,677	259,288	140,315
25	142,706	0.000%	0	-55,197	2,152,689	126,686	48,436	77,685	252,806	140,315
26	142,706	0.000%	0	-55,197	2,097,492	123,437	47,194	75,693	246,324	140,315
27	142,706	0.000%	0	-55,197	2,042,295	120,189	45,952	73,701	239,842	140,315
28	142,706	0.000%	0	-55,197	1,987,098	116,941	44,710	71,709	233,360	140,315
29	142,706	0.000%	0	-55,197	1,931,901	113,692	43,468	69,717	226,877	140,315
30	142,706	0.000%	0	-55,197	1,876,703	110,444	42,226	67,725	220,395	140,315
31	142,706	0.000%	0	-55,197	1,821,506	107,196	40,984	65,733	213,913	140,315
32	142,706	0.000%	0	-55,197	1,766,309	103,947	39,742	63,742	207,431	140,315
33	142,706	0.000%	0	-55,197	1,711,112	100,699	38,500	61,750	200,949	140,315
34	142,706	0.000%	0	-55,197	1,655,915	97,451	37,258	59,758	194,466	140,315
35	142,706	0.000%	0	-55,197	1,600,718	94,202	36,016	57,766	187,984	140,315
36	142,706	0.000%	0	-55,197	1,545,520	90,954	34,774	55,774	181,502	140,315
37	142,706	0.000%	0	-55,197	1,490,323	87,706	33,532	53,782	175,020	140,315
38	142,706	0.000%	0	-55,197	1,435,126	84,457	32,290	51,790	168,537	140,315
39	142,706	0.000%	0	-55,197	1,379,929	81,209	31,048	49,798	162,055	140,315
40	142,706	0.000%	0	-55,197	1,324,732	77,960	29,806	47,806	155,573	140,315
41	142,706	0.000%	0	-55,197	1,269,535	74,712	28,565	45,814	149,091	140,315
42	142,706	0.000%	0	-55,197	1,214,337	71,464	27,323	43,822	142,609	140,315
43	142,706	0.000%	0	-55,197	1,159,140	68,215	26,081	41,830	136,126	140,315
44	142,706	0.000%	0	-55,197	1,103,943	64,967	24,839	39,838	129,644	140,315
45	142,706	0.000%	0	-55,197	1,048,746	61,719	23,597	37,847	123,162	140,315
46	142,706	0.000%	0	-55,197	993,549	58,470	22,355	35,855	116,680	140,315
47	142,706	0.000%	0	-55,197	938,352	55,222	21,113	33,863	110,198	140,315
48	142,706	0.000%	0	-55,197	883,155	51,974	19,871	31,871	103,715	140,315
49	142,706	0.000%	0	-55,197	827,957	48,725	18,629	29,879	97,233	140,315
50	142,706	0.000%	0	-55,197	772,760	45,477	17,387	27,887	90,751	140,315
51	142,706	0.000%	0	-55,197	717,563	42,229	16,145	25,895	84,269	140,315
52	142,706	0.000%	0	-55,197	662,366	38,980	14,903	23,903	77,787	140,315
53	142,706	0.000%	0	-55,197	607,169	35,732	13,661	21,911	71,304	140,315
54	142,706	0.000%	0	-55,197	551,972	32,484	12,419	19,919	64,822	140,315
55	142,706	0.000%	0	-55,197	496,774	29,235	11,177	17,927	58,340	140,315
56	142,706	0.000%	0	-55,197	441,577	25,987	9,935	15,935	51,858	140,315
57	142,706	0.000%	0	-55,197	386,380	22,738	8,694	13,943	45,375	140,315
58	142,706	0.000%	0	-55,197	331,183	19,490	7,452	11,952	38,893	140,315
59	142,706	0.000%	0	-55,197	275,986	16,242	6,210	9,960	32,411	140,315
60	142,706	0.000%	0	-55,197	220,789	12,993	4,968	7,968	25,929	140,315
61	142,706	0.000%	0	-55,197	165,591	9,745	3,726	5,976	19,447	140,315
62	142,706	0.000%	0	-55,197	110,394	6,497	2,484	3,984	12,964	140,315
63	142,706	0.000%	0	-55,197	55,197	3,248	1,242	1,992	6,482	140,315
64	142,706	0.000%	0	-55,197	0	0	0	0	0	140,315

Unit Name: Conowingo 1 - 11 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 143,524,274		Electric Expenses	Line 156	31,568		
2	Investment Generator & Exciter	Inputs Tab	$ 21,528,641		Other Expenses		1,249		
3	Reactive Allocator	(Line 87)	6.00%		O&M	(sum line 1 & 2)	32,817	2,023,182	1.6221%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**1,291,445**						
5					A&G		7,967,029	380,084,794	2.0961%
6	GSU Transformer Investment	Inputs Tab	6,792,649		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0532%
7	Reactive Allocator	(Line 87)	6.00%		Working Capital	Line 222	582,080	380,084,794	0.1531%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**407,473**		General Plant		-	380,084,794	0.0000%
9					Other Taxes	Line 202(c)	-	380,084,794	0.0000%
10	Allocated Acc Elec Equipment	(Line 115 , Column d)	2,248,765		Depreciation	Line 174(c)			0.0009%
11	Reactive Allocator	(Line 87)	6.00%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**134,897**		Taxes (Federal/State/Local)	Line 186			3.3191%
13					ADIT	-Line 239(k)	($7,384,692)	380,084,794	-1.9429%
14	Total Cost of Power Plant	Inputs Tab	380,084,794				(Sum Lines 1 to 11 , Col. (h))		13.4367%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	349,514,738						
16	Balance of Plant Allocator	(Line 79)	0.0542%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	189,366						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	2,023,182						
19	Reactive Fixed Charge Rate	(Line 14(h))	13.4367%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**271,848**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 271,848**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		40.20						
		48.00						
		42.20						
		48.00						
		37.10						
		44.60						
		44.10						
		110.90						
		108.40						
		114.50						
		112.20						
	Total	750.20	(Sum Lines 31 to 41)					
	Nominal Power Factor (pf)							
		0.88						
		0.90						
		0.89						
		0.90						
		0.95						
		0.88						
		0.88						
		1.00						
		0.99						
		0.99						
		0.99						
	Total	0.95	(Line 42 / 55)					
	MVA Capability (MVA)							
		45.89	(Line 31 / 45)					
		53.33	(Line 32 / 46)					
		47.52	(Line 33 / 47)					
		53.33	(Line 33 / 47)					
		39.05	(Line 33 / 47)					
		50.68	(Line 33 / 47)					
		50.11	(Line 33 / 47)					
		111.46	(Line 33 / 47)					
		109.27	(Line 33 / 47)					
		115.89	(Line 33 / 47)					
		112.99	(Line 33 / 47)					
	Total	789.54	(Sum Lines 59 to 69)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		22.13	(SQRT (Line 59^2 - Line 31^2))					
		23.25	(SQRT (Line 60^2 - Line 32^2))					
		21.85	(SQRT (Line 61^2 - Line 33^2))					
		23.25	(SQRT (Line 62^2 - Line 34^2))					
		12.19	(SQRT (Line 63^2 - Line 35^2))					
		24.07	(SQRT (Line 64^2 - Line 36^2))					
		23.80	(SQRT (Line 65^2 - Line 37^2))					
		11.13	(SQRT (Line 66^2 - Line 38^2))					
		13.79	(SQRT (Line 67^2 - Line 39^2))					
		17.90	(SQRT (Line 68^2 - Line 40^2))					
		13.35	(SQRT (Line 69^2 - Line 41^2))					
	Total	193.38	(Sum Lines 74 to 84)					
	Reactive Allocator	6.0%	(Line 85^2 / Line 70^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 91 / Line 92) * (Line 93 / Line 94)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Hydro & Steam**	**Allocated Amt**
	Storage Batteries	$ 136,064	30%	$ 40,819
	Control&Power Cabling	$ 3,179,427	15%	$ 476,914
	Switch Board Equipment	$ 1,973,492	30%	$ 592,048
	Switching Equipment	$ 2,017,595	20%	$ 403,519
	Transformers	$ 6,318,929	5%	$ 315,946
	Aux Generator	$ 101,173	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ 390,726	75%	$ 293,044
	Structure	$ 270,434	0%	$ -
	Misc	$ 15,212,502	0%	$ -
	Exciter & PPT	$ 126,475	100%	$ 126,475
	Station Grounding	$ -	0%	$ -
	Bus & Insulators	$ -	60%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 29,726,815		$ 2,248,765

O&M		**Total Non-Fuel**	**Fixed O&M**	
	(535) Operation Supervision and Engineering	1,036,292	1,036,292	
		0		
	(536) Water for Power	855,810	855,810	
	(537) Hydraulic Expenses	5,098,303		
	(538) Electric Expenses	1,685,208	1,685,208	
	(539) Miscellaneous Hydraulic Power Generation Ex	1,684,113		
	(540) Rents	243,307	243,307	
		0	-	
	(541) Mainentance Supervision and Engineering	575,100		
	(542) Maintenance of Structures	691,360	691,360	
	(543) Maintenance of Reservoirs, Dams, and Waterv	2,545,004		
	(544) Maintenance of Electric Plant	1,823,125		
	(545) Maintenance of Miscellaneous Hydraulic Plant	514,507	514,507	
			-	
	Total NonFuel Expenses	16,752,129	5,026,484	(Sum Lines 118 to 131)
	Percentage Fixed O&M Excluding Allowances		31.07%	(Line 132(c) / (Line 132(b) - Line 126(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	0.8998%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.4029%	(Col. (c) Line 139 * Line 148 + Line 137 * Line 148 / (Line148 + 150)			
	Other Demand Expense Allocator	0.0542%	Line 95			
	Production Plant Expenses					
	Total NonFuel Expenses	16,752,129	Line 132			
	Allowances	0	Line 125			
	Non-Fuel Production O&M	16,752,129	(Line 142 - 143)			
	Operating Expenses					
	Operations Supervision & Engineering	1,036,292	Line 118(c)			
	Electric Expenses	1,685,208	Line 122(c)			
	Maintenance of Electric Plant	1,823,125	Line 129(b)			
	Other Demand Related Expenses	2,304,983	Col. (c) Line 132 - Col (b) Line 148 - Col. (b) Line 147)			
	Total	6,849,608	(Sum Lines 147 to 150)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	1,823,125	Line 129(b)			
	Electric Expenses	1,685,208	Line 122(c)			
	Total Electric Expenses	3,508,333	(Line 154 + 155)	0.8998%	31,568	(Line 156(b) * (d))
				Line 137		
	Other Demand Related Expenses	2,304,983	(Line 150)	0.0542%	1,249	
				Line 139		
	Balance of Plant Fixed Expenses				6,816,791	(Line 151(b) - Line 156(e) - Line 158(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		2,067,560	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		5,899,470	(allocated on plant labor)	
	Total		7,967,029		
Depreciation					
	Annual Depreciation Exp ...DE	3,276,593			
	Gross Production Plant Cost ... F	380,084,794	Line 14		
	SLDP=DE/F	0.8621%	(Line 170 / 171)		
	Depreciable years (n)=1/SLDP	116			
	SFDP=(R/((1+R)^n-1)		0.0009%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.319%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 191 to 193)
Other Taxes					
	Property Taxes		0	<Includes Payroll	
	Payroll Taxes	-			
		31.0717%	Line 133		
	Fixed Payroll Taxes		-	(Line 199 * 200)	
	Total Other Taxes		-	(Line 198 + 201)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		
	Fixed General Plant	-		-		(Lines 206 * 207)
	Return on General Plant	8.1350%	Line 194			
	Taxes on General Plant	3.3191%	Line 195			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 208 * 209)	-	-	
Working Capital						
	Prepayments	2,859,063				
		100.000%				
	Production Related Prepayments	2,859,063	(Line 215 * 216)			
	Unit Specific M&S	2,222,784				
	Total	5,081,847	(Line 217 + 218)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	3.3191%				
	Working Capital Costs	582,080	(Line 219 * 220)			

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Accumulated Deferred Income Taxes

Investment	380,084,794	Line 14
Asset Service Life	116	Line 173
Composite Tax Rate	38.6790%	Line 183

NPV of Col (j)> 90,766,369

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized
	Line 230 / 231		(b) * (c)	((d) - (b)) * Line 183	Accum. (e)	= (f) * (Line192+193)	= (f) * (Line191)	= (g) * (Line184)	(g) + (h) + (i)	PMT of NPV col. (j)
1	3,276,593	3.750%	14,253,180	4,245,634	4,245,634	249,856	95,527	153,214	498,596	7,384,692
2	3,276,593	7.219%	27,438,321	9,345,515	13,591,149	799,839	305,801	490,469	1,596,109	7,384,692
3	3,276,593	6.677%	25,378,262	8,548,704	22,139,853	1,302,930	498,147	798,970	2,600,047	7,384,692
4	3,276,593	6.177%	23,477,838	7,813,639	29,953,493	1,762,763	673,954	1,080,944	3,517,661	7,384,692
5	3,276,593	5.713%	21,714,244	7,131,499	37,084,992	2,182,452	834,412	1,338,301	4,355,165	7,384,692
6	3,276,593	5.285%	20,087,481	6,502,283	43,587,275	2,565,111	980,714	1,572,952	5,118,777	7,384,692
7	3,276,593	4.888%	18,578,545	5,918,642	49,505,917	2,913,423	1,113,883	1,786,540	5,813,847	7,384,692
8	3,276,593	4.522%	17,187,434	5,380,574	54,886,491	3,230,070	1,234,946	1,980,711	6,445,727	7,384,692
9	3,276,593	4.462%	16,959,383	5,292,367	60,178,858	3,541,526	1,354,024	2,171,699	7,067,249	7,384,692
10	3,276,593	4.461%	16,955,583	5,290,896	65,469,754	3,852,895	1,473,069	2,362,634	7,688,598	7,384,692
11	3,276,593	4.462%	16,959,383	5,292,367	70,762,121	4,164,351	1,592,148	2,553,622	8,310,120	7,384,692
12	3,276,593	4.461%	16,955,583	5,290,896	76,053,017	4,475,720	1,711,193	2,744,556	8,931,469	7,384,692
13	3,276,593	4.462%	16,959,383	5,292,367	81,345,384	4,787,176	1,830,271	2,935,544	9,552,991	7,384,692
14	3,276,593	4.461%	16,955,583	5,290,896	86,636,280	5,098,545	1,949,316	3,126,479	10,174,340	7,384,692
15	3,276,593	4.462%	16,959,383	5,292,367	91,928,647	5,410,001	2,068,395	3,317,467	10,795,862	7,384,692
16	3,276,593	4.461%	16,955,583	5,290,896	97,219,543	5,721,370	2,187,440	3,508,401	11,417,211	7,384,692
17	3,276,593	4.462%	16,959,383	5,292,367	102,511,910	6,032,826	2,306,518	3,699,389	12,038,733	7,384,692
18	3,276,593	4.461%	16,955,583	5,290,896	107,802,806	6,344,195	2,425,563	3,890,324	12,660,082	7,384,692
19	3,276,593	4.462%	16,959,383	5,292,367	113,095,172	6,655,651	2,544,641	4,081,312	13,281,604	7,384,692
20	3,276,593	4.461%	16,955,583	5,290,896	118,386,069	6,967,020	2,663,687	4,272,246	13,902,953	7,384,692
21	3,276,593	2.231%	8,479,692	2,012,507	120,398,575	7,085,456	2,708,968	4,344,873	14,139,297	7,384,692
22	3,276,593	0.000%	0	-1,267,353	119,131,222	7,010,872	2,680,452	4,299,137	13,990,462	7,384,692
23	3,276,593	0.000%	0	-1,267,353	117,863,869	6,936,289	2,651,937	4,253,402	13,841,627	7,384,692
24	3,276,593	0.000%	0	-1,267,353	116,596,515	6,861,705	2,623,422	4,207,666	13,692,793	7,384,692
25	3,276,593	0.000%	0	-1,267,353	115,329,162	6,787,121	2,594,906	4,161,931	13,543,958	7,384,692
26	3,276,593	0.000%	0	-1,267,353	114,061,808	6,712,537	2,566,391	4,116,195	13,395,123	7,384,692
27	3,276,593	0.000%	0	-1,267,353	112,794,455	6,637,954	2,537,875	4,070,460	13,246,288	7,384,692
28	3,276,593	0.000%	0	-1,267,353	111,527,101	6,563,370	2,509,360	4,024,724	13,097,454	7,384,692
29	3,276,593	0.000%	0	-1,267,353	110,259,748	6,488,786	2,480,844	3,978,989	12,948,619	7,384,692
30	3,276,593	0.000%	0	-1,267,353	108,992,395	6,414,202	2,452,329	3,933,253	12,799,784	7,384,692
31	3,276,593	0.000%	0	-1,267,353	107,725,041	6,339,619	2,423,813	3,887,518	12,650,950	7,384,692
32	3,276,593	0.000%	0	-1,267,353	106,457,688	6,265,035	2,395,298	3,841,782	12,502,115	7,384,692
33	3,276,593	0.000%	0	-1,267,353	105,190,334	6,190,451	2,366,783	3,796,047	12,353,280	7,384,692
34	3,276,593	0.000%	0	-1,267,353	103,922,981	6,115,867	2,338,267	3,750,311	12,204,446	7,384,692
35	3,276,593	0.000%	0	-1,267,353	102,655,627	6,041,284	2,309,752	3,704,576	12,055,611	7,384,692
36	3,276,593	0.000%	0	-1,267,353	101,388,274	5,966,700	2,281,236	3,658,840	11,906,776	7,384,692
37	3,276,593	0.000%	0	-1,267,353	100,120,921	5,892,116	2,252,721	3,613,105	11,757,941	7,384,692
38	3,276,593	0.000%	0	-1,267,353	98,853,567	5,817,532	2,224,205	3,567,369	11,609,107	7,384,692
39	3,276,593	0.000%	0	-1,267,353	97,586,214	5,742,949	2,195,690	3,521,634	11,460,272	7,384,692
40	3,276,593	0.000%	0	-1,267,353	96,318,860	5,668,365	2,167,174	3,475,898	11,311,437	7,384,692
41	3,276,593	0.000%	0	-1,267,353	95,051,507	5,593,781	2,138,659	3,430,163	11,162,603	7,384,692
42	3,276,593	0.000%	0	-1,267,353	93,784,153	5,519,197	2,110,143	3,384,427	11,013,768	7,384,692
43	3,276,593	0.000%	0	-1,267,353	92,516,800	5,444,614	2,081,628	3,338,692	10,864,933	7,384,692
44	3,276,593	0.000%	0	-1,267,353	91,249,447	5,370,030	2,053,113	3,292,956	10,716,099	7,384,692
45	3,276,593	0.000%	0	-1,267,353	89,982,093	5,295,446	2,024,597	3,247,221	10,567,264	7,384,692
46	3,276,593	0.000%	0	-1,267,353	88,714,740	5,220,862	1,996,082	3,201,485	10,418,429	7,384,692
47	3,276,593	0.000%	0	-1,267,353	87,447,386	5,146,279	1,967,566	3,155,750	10,269,594	7,384,692
48	3,276,593	0.000%	0	-1,267,353	86,180,033	5,071,695	1,939,051	3,110,014	10,120,760	7,384,692
49	3,276,593	0.000%	0	-1,267,353	84,912,680	4,997,111	1,910,535	3,064,279	9,971,925	7,384,692
50	3,276,593	0.000%	0	-1,267,353	83,645,326	4,922,527	1,882,020	3,018,543	9,823,090	7,384,692
51	3,276,593	0.000%	0	-1,267,353	82,377,973	4,847,944	1,853,504	2,972,808	9,674,256	7,384,692
52	3,276,593	0.000%	0	-1,267,353	81,110,619	4,773,360	1,824,989	2,927,072	9,525,421	7,384,692
53	3,276,593	0.000%	0	-1,267,353	79,843,266	4,698,776	1,796,473	2,881,337	9,376,586	7,384,692
54	3,276,593	0.000%	0	-1,267,353	78,575,912	4,624,192	1,767,958	2,835,601	9,227,752	7,384,692
55	3,276,593	0.000%	0	-1,267,353	77,308,559	4,549,609	1,739,443	2,789,866	9,078,917	7,384,692

294	56	3,276,593	0.000%	0	-1,267,353	76,041,206	4,475,025	1,710,927	2,744,130	8,930,082	7,384,692
295	57	3,276,593	0.000%	0	-1,267,353	74,773,852	4,400,441	1,682,412	2,698,395	8,781,247	7,384,692
296	58	3,276,593	0.000%	0	-1,267,353	73,506,499	4,325,857	1,653,896	2,652,659	8,632,413	7,384,692
297	59	3,276,593	0.000%	0	-1,267,353	72,239,145	4,251,274	1,625,381	2,606,924	8,483,578	7,384,692
298	60	3,276,593	0.000%	0	-1,267,353	70,971,792	4,176,690	1,596,865	2,561,188	8,334,743	7,384,692
299	61	3,276,593	0.000%	0	-1,267,353	69,704,438	4,102,106	1,568,350	2,515,453	8,185,909	7,384,692
300	62	3,276,593	0.000%	0	-1,267,353	68,437,085	4,027,522	1,539,834	2,469,717	8,037,074	7,384,692
301	63	3,276,593	0.000%	0	-1,267,353	67,169,732	3,952,939	1,511,319	2,423,982	7,888,239	7,384,692
302	64	3,276,593	0.000%	0	-1,267,353	65,902,378	3,878,355	1,482,804	2,378,246	7,739,405	7,384,692
303	65	3,276,593	0.000%	0	-1,267,353	64,635,025	3,803,771	1,454,288	2,332,511	7,590,570	7,384,692
304	66	3,276,593	0.000%	0	-1,267,353	63,367,671	3,729,187	1,425,773	2,286,775	7,441,735	7,384,692
305	67	3,276,593	0.000%	0	-1,267,353	62,100,318	3,654,604	1,397,257	2,241,040	7,292,900	7,384,692
306	68	3,276,593	0.000%	0	-1,267,353	60,832,964	3,580,020	1,368,742	2,195,304	7,144,066	7,384,692
307	69	3,276,593	0.000%	0	-1,267,353	59,565,611	3,505,436	1,340,226	2,149,569	6,995,231	7,384,692
308	70	3,276,593	0.000%	0	-1,267,353	58,298,258	3,430,852	1,311,711	2,103,833	6,846,396	7,384,692
309	71	3,276,593	0.000%	0	-1,267,353	57,030,904	3,356,269	1,283,195	2,058,098	6,697,562	7,384,692
310	72	3,276,593	0.000%	0	-1,267,353	55,763,551	3,281,685	1,254,680	2,012,362	6,548,727	7,384,692
311	73	3,276,593	0.000%	0	-1,267,353	54,496,197	3,207,101	1,226,164	1,966,627	6,399,892	7,384,692
312	74	3,276,593	0.000%	0	-1,267,353	53,228,844	3,132,517	1,197,649	1,920,891	6,251,057	7,384,692
313	75	3,276,593	0.000%	0	-1,267,353	51,961,490	3,057,934	1,169,134	1,875,156	6,102,223	7,384,692
314	76	3,276,593	0.000%	0	-1,267,353	50,694,137	2,983,350	1,140,618	1,829,420	5,953,388	7,384,692
315	77	3,276,593	0.000%	0	-1,267,353	49,426,784	2,908,766	1,112,103	1,783,685	5,804,553	7,384,692
316	78	3,276,593	0.000%	0	-1,267,353	48,159,430	2,834,182	1,083,587	1,737,949	5,655,719	7,384,692
317	79	3,276,593	0.000%	0	-1,267,353	46,892,077	2,759,599	1,055,072	1,692,214	5,506,884	7,384,692
318	80	3,276,593	0.000%	0	-1,267,353	45,624,723	2,685,015	1,026,556	1,646,478	5,358,049	7,384,692
319	81	3,276,593	0.000%	0	-1,267,353	44,357,370	2,610,431	998,041	1,600,743	5,209,215	7,384,692
320	82	3,276,593	0.000%	0	-1,267,353	43,090,016	2,535,847	969,525	1,555,007	5,060,380	7,384,692
321	83	3,276,593	0.000%	0	-1,267,353	41,822,663	2,461,264	941,010	1,509,272	4,911,545	7,384,692
322	84	3,276,593	0.000%	0	-1,267,353	40,555,310	2,386,680	912,494	1,463,536	4,762,710	7,384,692
323	85	3,276,593	0.000%	0	-1,267,353	39,287,956	2,312,096	883,979	1,417,801	4,613,876	7,384,692
324	86	3,276,593	0.000%	0	-1,267,353	38,020,603	2,237,512	855,464	1,372,065	4,465,041	7,384,692
325	87	3,276,593	0.000%	0	-1,267,353	36,753,249	2,162,929	826,948	1,326,330	4,316,206	7,384,692
326	88	3,276,593	0.000%	0	-1,267,353	35,485,896	2,088,345	798,433	1,280,594	4,167,372	7,384,692
327	89	3,276,593	0.000%	0	-1,267,353	34,218,542	2,013,761	769,917	1,234,859	4,018,537	7,384,692
328	90	3,276,593	0.000%	0	-1,267,353	32,951,189	1,939,177	741,402	1,189,123	3,869,702	7,384,692
329	91	3,276,593	0.000%	0	-1,267,353	31,683,836	1,864,594	712,886	1,143,388	3,720,868	7,384,692
330	92	3,276,593	0.000%	0	-1,267,353	30,416,482	1,790,010	684,371	1,097,652	3,572,033	7,384,692
331	93	3,276,593	0.000%	0	-1,267,353	29,149,129	1,715,426	655,855	1,051,917	3,423,198	7,384,692
332	94	3,276,593	0.000%	0	-1,267,353	27,881,775	1,640,842	627,340	1,006,181	3,274,363	7,384,692
333	95	3,276,593	0.000%	0	-1,267,353	26,614,422	1,566,259	598,824	960,446	3,125,529	7,384,692
334	96	3,276,593	0.000%	0	-1,267,353	25,347,069	1,491,675	570,309	914,710	2,976,694	7,384,692
335	97	3,276,593	0.000%	0	-1,267,353	24,079,715	1,417,091	541,794	868,975	2,827,859	7,384,692
336	98	3,276,593	0.000%	0	-1,267,353	22,812,362	1,342,507	513,278	823,239	2,679,025	7,384,692
337	99	3,276,593	0.000%	0	-1,267,353	21,545,008	1,267,924	484,763	777,504	2,530,190	7,384,692
338	100	3,276,593	0.000%	0	-1,267,353	20,277,655	1,193,340	456,247	731,768	2,381,355	7,384,692
339	101	3,276,593	0.000%	0	-1,267,353	19,010,301	1,118,756	427,732	686,033	2,232,521	7,384,692
340	102	3,276,593	0.000%	0	-1,267,353	17,742,948	1,044,172	399,216	640,297	2,083,686	7,384,692
341	103	3,276,593	0.000%	0	-1,267,353	16,475,595	969,589	370,701	594,562	1,934,851	7,384,692
342	104	3,276,593	0.000%	0	-1,267,353	15,208,241	895,005	342,185	548,826	1,786,016	7,384,692
343	105	3,276,593	0.000%	0	-1,267,353	13,940,888	820,421	313,670	503,091	1,637,182	7,384,692
344	106	3,276,593	0.000%	0	-1,267,353	12,673,534	745,837	285,155	457,355	1,488,347	7,384,692
345	107	3,276,593	0.000%	0	-1,267,353	11,406,181	671,254	256,639	411,620	1,339,512	7,384,692
346	108	3,276,593	0.000%	0	-1,267,353	10,138,827	596,670	228,124	365,884	1,190,678	7,384,692
347	109	3,276,593	0.000%	0	-1,267,353	8,871,474	522,086	199,608	320,149	1,041,843	7,384,692
348	110	3,276,593	0.000%	0	-1,267,353	7,604,121	447,502	171,093	274,413	893,008	7,384,692
349	111	3,276,593	0.000%	0	-1,267,353	6,336,767	372,919	142,577	228,678	744,174	7,384,692
350	112	3,276,593	0.000%	0	-1,267,353	5,069,414	298,335	114,062	182,942	595,339	7,384,692
351	113	3,276,593	0.000%	0	-1,267,353	3,802,060	223,751	85,546	137,207	446,504	7,384,692
352	114	3,276,593	0.000%	0	-1,267,353	2,534,707	149,167	57,031	91,471	297,669	7,384,692
353	115	3,276,593	0.000%	0	-1,267,353	1,267,353	74,584	28,515	45,736	148,835	7,384,692
354	116	3,276,593	0.000%	0	-1,267,353	0	0	0	0	0	7,384,692

Unit Name: Croydon 11,12,21,22,31,32,41,42 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 72,348,001		Electric Expenses	Line 143	2,671		
2	Investment Generator & Exciter	Inputs Tab	$ 10,852,200		Other Expenses		768		
3	Reactive Allocator	(Line 74)	17.98%		O&M	(sum line 1 & 2)	3,439	2,584,833	0.1330%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**1,950,882**						
5					A&G		1,022,909	107,412,068	0.9523%
6	GSU Transformer Investment	Inputs Tab	1,420,756		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0151%
7	Reactive Allocator	(Line 74)	17.98%		Working Capital	Line 219	2,389,456	107,412,068	2.2246%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**255,407**		General Plant		-	107,412,068	0.0000%
9					Other Taxes	Line 199(c)	87,293	107,412,068	0.0813%
10	Allocated Acc Elec Equipment	(Line 102 , Column d)	1,824,495		Depreciation	Line 171(c)			0.0814%
11	Reactive Allocator	(Line 74)	17.98%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**327,986**		Taxes (Federal/State/Local)	Line 183			2.9758%
13					ADIT	-Line 236(k)	($1,572,946)	107,412,068	-1.4644%
14	Total Cost of Power Plant	Inputs Tab	107,412,068				(Sum Lines 1 to 11 , Col. (h))		13.1341%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	93,314,617						
16	Balance of Plant Allocator	(Line 79)	0.0542%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	50,558						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	2,584,833						
19	Reactive Fixed Charge Rate	(Line 14(h))	13.1341%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**339,494**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 339,494**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		51.00						
		56.60						
		68.30						
		68.30						
		68.30						
		68.30						
		-						
		-						
	Total	380.80	(Sum Lines 31 to 38)					
	Nominal Power Factor (pf)							
		0.91						
		0.93						
		0.90						
		0.90						
		0.90						
		0.90						
		-						
		-						
	Total	0.91	(Line 38 / 60)					
	MVA Capability (MVA)							
			55.92	(Line 31 / 41)				
			61.12	(Line 32 / 42)				
			75.89	(Line 33 / 43)				
			75.89	(Line 34 / 44)				
			75.89	(Line 35 / 45)				
			75.89	(Line 36 / 46)				
			-					
			-					
	Total		420.60	(Sum Lines 52 to 59)				
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
			22.94	(SQRT (Line 52^2 - Line 31^2))				
			23.08	(SQRT (Line 53^2 - Line 32^2))				
			33.08	(SQRT (Line 54^2 - Line 33^2))				
			33.08	(SQRT (Line 55^2 - Line 34^2))				
			33.08	(SQRT (Line 56^2 - Line 35^2))				
			33.08	(SQRT (Line 57^2 - Line 36^2))				
			-					
			-					
	Total		178.33	(Sum Lines 64 to 71)				
	Reactive Allocator		18.0%	(Line 72^2 / Line 60^2)				
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 78 / Line 79) * (Line 80 / Line 81)					

	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ 64,719	50%	$ 32,360
	Control&Power Cabling	$ 2,578,451	50%	$ 1,289,225
	Switch Board Equipment	$ 239,413	50%	$ 119,706
	Switching Equipment	$ 745,807	40%	$ 298,323
	Transformers	$ 247,743	10%	$ 24,774
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ 56,420	0%	$ -
	Misc	$ 5,030,779	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ 75,133	80%	$ 60,107
	Capacitor Bank	$ -	0%	$ -
	Total	$ 9,038,464		$ 1,824,495

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	569,237	569,237	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	147,038	147,038	
	Steam From Other Sources	284,134		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	87,051		
	Rents	529,786	529,786	
	Allowances	21,408	21,408	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	222,036	222,036	
	Maintenance of Boiler (or reactor) Plant	95,213		
	Maintenance of Electric Plant	99,056		
	Maintenance of Misc Steam (or Nuclear) Plant	123,289	123,289	
	Other Power Production, & Other Expenses	373,967	373,967	
	Total NonFuel Expenses	2,552,217	1,986,762	(Sum Lines 105 to 118)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 119(c) / (Line 119(b) - Line 113(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	2.6965%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 126 * Line 135 + Line 124 * Line 135 / (Line135 + 137)			
	Other Demand Expense Allocator	0.0542%	Line 82			
	Production Plant Expenses					
	Total NonFuel Expenses	2,552,217	Line 119			
	Allowances	21,408	Line 112			
	Non-Fuel Production O&M	2,530,809	(Line 129 - 130)			
	Operating Expenses					
	Operations Supervision & Engineering	569,237	Line 105(c)			
	Electric Expenses	0	Line 109(c)			
	Maintenance of Electric Plant	99,056	Line 116(b)			
	Other Demand Related Expenses	1,417,525	Col. (c) Line 119 - Col (b) Line 135 - Col. (b) Line 134)			
	Total	2,085,818	(Sum Lines 134 to 137)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	99,056	Line 116(b)			
	Electric Expenses	0	Line 109(c)			
	Total Electric Expenses	99,056	(Line 141 + 142)	2.6965%	2,671	(Line 143(b) * (d))
				Line 124		
	Other Demand Related Expenses	1,417,525	(Line 137)	0.0542%	768	
				Line 126		
	Balance of Plant Fixed Expenses				2,082,379	(Line 138(b) - Line 143(e) - Line 145(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		127,260	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		895,649	(allocated on plant labor)	
	Total		1,022,909		
Depreciation					
	Annual Depreciation Exp ...DE	1,820,544			
	Gross Production Plant Cost ... F	107,412,068	Line 14		
	SLDP=DE/F	1.6949%	(Line 167 / 168)		
	Depreciable years (n)=1/SLDP	59			
	SFDP=(R/((1+R)^n-1)		0.0814%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.976%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 188 to 190)
Other Taxes					
	Property Taxes		87,293	<Includes Payroll	
	Payroll Taxes				
	0	77.8446%	Line 120		
	Fixed Payroll Taxes		-	(Line 196 * 197)	
	Total Other Taxes		87,293	(Line 195 + 198)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 162
	Fixed General Plant	-		-		(Lines 203 *204)
	Return on General Plant	8.1350%	Line 191			
	Taxes on General Plant	2.9758%	Line 192			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 205 * 206)	-	-	
Working Capital						
	Prepayments	807,972				
		100.000%				
	Production Related Prepayments	807,972	(Line 212 * 213)			
	Unit Specific M&S	20,697,756				
	Total	21,505,728	(Line 214 + 215)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9758%				
	Working Capital Costs	2,389,456	(Line 216 * 217)			

Accumulated Deferred Income Taxes

Investment	107,412,068	Line 14	NPV of Col (j)> 19,143,959
Asset Service Life	59	Line 170	
Composite Tax Rate	38.6790%	Line 180	

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity = (f) *	(h) Interest = (f) *	(i) Income Taxes = (g) *	(j) Rev Req Impact	(k) Levelized PMT of NPV
	Line 227 / 228		(b) * (c)	((d) - (b)) * Line 180	Accum. (e)	(Line189+190)	(Line188)	(Line181)	(g) + (h) + (i)	col. (j)
1	1,820,544	3.750%	4,027,953	853,804	853,804	50,246	19,211	30,812	100,268	1,572,946
2	1,820,544	7.219%	7,754,077	2,295,031	3,148,835	185,309	70,849	113,633	369,791	1,572,946
3	1,820,544	6.677%	7,171,904	2,069,853	5,218,688	307,120	117,420	188,329	612,869	1,572,946
4	1,820,544	6.177%	6,634,843	1,862,123	7,080,811	416,706	159,318	255,528	831,552	1,572,946
5	1,820,544	5.713%	6,136,451	1,669,350	8,750,161	514,947	196,879	315,771	1,027,596	1,572,946
6	1,820,544	5.285%	5,676,728	1,491,534	10,241,694	602,724	230,438	369,596	1,202,758	1,572,946
7	1,820,544	4.888%	5,250,302	1,326,596	11,568,291	680,794	260,287	417,470	1,358,550	1,572,946
8	1,820,544	4.522%	4,857,174	1,174,538	12,742,829	749,915	286,714	459,856	1,496,485	1,572,946
9	1,820,544	4.462%	4,792,726	1,149,611	13,892,440	817,570	312,580	501,342	1,631,492	1,572,946
10	1,820,544	4.461%	4,791,652	1,149,195	15,041,635	885,200	338,437	542,814	1,766,451	1,572,946
11	1,820,544	4.462%	4,792,726	1,149,611	16,191,245	952,855	364,303	584,300	1,901,458	1,572,946
12	1,820,544	4.461%	4,791,652	1,149,195	17,340,441	1,020,485	390,160	625,772	2,036,416	1,572,946
13	1,820,544	4.462%	4,792,726	1,149,611	18,490,051	1,088,140	416,026	667,258	2,171,424	1,572,946
14	1,820,544	4.461%	4,791,652	1,149,195	19,639,246	1,155,770	441,883	708,730	2,306,382	1,572,946
15	1,820,544	4.462%	4,792,726	1,149,611	20,788,857	1,223,424	467,749	750,216	2,441,390	1,572,946
16	1,820,544	4.461%	4,791,652	1,149,195	21,938,052	1,291,054	493,606	791,687	2,576,348	1,572,946
17	1,820,544	4.462%	4,792,726	1,149,611	23,087,663	1,358,709	519,472	833,174	2,711,355	1,572,946
18	1,820,544	4.461%	4,791,652	1,149,195	24,236,858	1,426,339	545,329	874,645	2,846,314	1,572,946
19	1,820,544	4.462%	4,792,726	1,149,611	25,386,469	1,493,994	571,196	916,132	2,981,321	1,572,946
20	1,820,544	4.461%	4,791,652	1,149,195	26,535,664	1,561,624	597,052	957,603	3,116,280	1,572,946
21	1,820,544	2.231%	2,396,363	222,721	26,758,385	1,574,731	602,064	965,641	3,142,435	1,572,946
22	1,820,544	0.000%	0	-704,168	26,054,217	1,533,291	586,220	940,229	3,059,740	1,572,946
23	1,820,544	0.000%	0	-704,168	25,350,049	1,491,850	570,376	914,818	2,977,044	1,572,946
24	1,820,544	0.000%	0	-704,168	24,645,881	1,450,410	554,532	889,406	2,894,348	1,572,946
25	1,820,544	0.000%	0	-704,168	23,941,713	1,408,970	538,689	863,994	2,811,653	1,572,946
26	1,820,544	0.000%	0	-704,168	23,237,545	1,367,530	522,845	838,583	2,728,957	1,572,946
27	1,820,544	0.000%	0	-704,168	22,533,377	1,326,089	507,001	813,171	2,646,261	1,572,946
28	1,820,544	0.000%	0	-704,168	21,829,209	1,284,649	491,157	787,760	2,563,566	1,572,946
29	1,820,544	0.000%	0	-704,168	21,125,041	1,243,209	475,313	762,348	2,480,870	1,572,946
30	1,820,544	0.000%	0	-704,168	20,420,873	1,201,768	459,470	736,936	2,398,174	1,572,946
31	1,820,544	0.000%	0	-704,168	19,716,705	1,160,328	443,626	711,525	2,315,479	1,572,946
32	1,820,544	0.000%	0	-704,168	19,012,537	1,118,888	427,782	686,113	2,232,783	1,572,946
33	1,820,544	0.000%	0	-704,168	18,308,369	1,077,448	411,938	660,702	2,150,087	1,572,946
34	1,820,544	0.000%	0	-704,168	17,604,201	1,036,007	396,095	635,290	2,067,392	1,572,946
35	1,820,544	0.000%	0	-704,168	16,900,033	994,567	380,251	609,878	1,984,696	1,572,946
36	1,820,544	0.000%	0	-704,168	16,195,865	953,127	364,407	584,467	1,902,000	1,572,946
37	1,820,544	0.000%	0	-704,168	15,491,697	911,686	348,563	559,055	1,819,305	1,572,946
38	1,820,544	0.000%	0	-704,168	14,787,529	870,246	332,719	533,644	1,736,609	1,572,946
39	1,820,544	0.000%	0	-704,168	14,083,361	828,806	316,876	508,232	1,653,913	1,572,946
40	1,820,544	0.000%	0	-704,168	13,379,193	787,365	301,032	482,820	1,571,218	1,572,946
41	1,820,544	0.000%	0	-704,168	12,675,025	745,925	285,188	457,409	1,488,522	1,572,946
42	1,820,544	0.000%	0	-704,168	11,970,857	704,485	269,344	431,997	1,405,826	1,572,946
43	1,820,544	0.000%	0	-704,168	11,266,689	663,045	253,500	406,586	1,323,131	1,572,946
44	1,820,544	0.000%	0	-704,168	10,562,520	621,604	237,657	381,174	1,240,435	1,572,946
45	1,820,544	0.000%	0	-704,168	9,858,352	580,164	221,813	355,762	1,157,739	1,572,946
46	1,820,544	0.000%	0	-704,168	9,154,184	538,724	205,969	330,351	1,075,044	1,572,946
47	1,820,544	0.000%	0	-704,168	8,450,016	497,283	190,125	304,939	992,348	1,572,946
48	1,820,544	0.000%	0	-704,168	7,745,848	455,843	174,282	279,528	909,652	1,572,946
49	1,820,544	0.000%	0	-704,168	7,041,680	414,403	158,438	254,116	826,957	1,572,946
50	1,820,544	0.000%	0	-704,168	6,337,512	372,963	142,594	228,704	744,261	1,572,946
51	1,820,544	0.000%	0	-704,168	5,633,344	331,522	126,750	203,293	661,565	1,572,946
52	1,820,544	0.000%	0	-704,168	4,929,176	290,082	110,906	177,881	578,870	1,572,946
53	1,820,544	0.000%	0	-704,168	4,225,008	248,642	95,063	152,470	496,174	1,572,946
54	1,820,544	0.000%	0	-704,168	3,520,840	207,201	79,219	127,058	413,478	1,572,946
55	1,820,544	0.000%	0	-704,168	2,816,672	165,761	63,375	101,646	330,783	1,572,946
56	1,820,544	0.000%	0	-704,168	2,112,504	124,321	47,531	76,235	248,087	1,572,946
57	1,820,544	0.000%	0	-704,168	1,408,336	82,881	31,688	50,823	165,391	1,572,946
58	1,820,544	0.000%	0	-704,168	704,168	41,440	15,844	25,412	82,696	1,572,946
59	1,820,544	0.000%	0	-704,168	0	0	0	0	0	1,572,946

Unit Name: Delaware 9-12 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 6,730,407	
2	Investment Generator & Exciter	Inputs Tab	$ 1,009,561	
3	Reactive Allocator	(Line 71)	36.88%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**372,362**	
5				
6	GSU Transformer Investment	Inputs Tab	-	
7	Reactive Allocator	(Line 71)	36.88%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	655,447	
11	Reactive Allocator	(Line 71)	36.88%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**241,752**	
13				
14	Total Cost of Power Plant	Inputs Tab	13,528,361	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	11,863,353	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	6,428	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	620,541	
19	Reactive Fixed Charge Rate	(Line 14(h))	11.5665%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**71,775**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 71,775**	
23				
24				
25				
26				

(e)		(f)	(g)	(h)
Fixed Charge Rate for Reactive Plant				
		Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 140	785		
Other Expenses		110		
O&M	(sum line 1 & 2)	895	620,541	0.1442%
A&G		146,504	13,528,361	1.0829%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0171%
Working Capital	Line 216	60,440	13,528,361	0.4468%
General Plant		-	13,528,361	0.0000%
Other Taxes	Line 196(c)	27,880	13,528,361	0.2061%
Depreciation	Line 168(c)			0.0507%
				8.1350%
Taxes (Federal/State/Local)	Line 180			3.0332%
ADIT	-Line 233(k)	($209,633)	13,528,361	-1.5496%
		(Sum Lines 1 to 11 , Col. (h))		11.5665%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		16.90						
		13.40						
		13.70						
		13.40						
	Total	57.40	(Sum Lines 31 to 34)					
	Nominal Power Factor (pf)							
		0.84						
		0.77						
		0.78						
		0.78						
	Total	0.79	(Line 38 / 58)					
	MVA Capability (MVA)							
		20.17	(Line 31 / 41)					
		17.34	(Line 32 / 42)					
		17.63	(Line 33 / 43)					
		17.25	(Line 34 / 44)					
	Total	72.38	(Sum Lines 51 to 54)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		11.00	(SQRT (Line 51^2 - Line 31^2))					
		11.00	(SQRT (Line 52^2 - Line 32^2))					
		11.10	(SQRT (Line 53^2 - Line 33^2))					
		10.86	(SQRT (Line 54^2 - Line 34^2))					
	Total	43.96	(Sum Lines 62 to 65)					
	Reactive Allocator	36.9%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ 28,741	50%	$ 14,370
	Control&Power Cabling	$ 344,611	50%	$ 172,306
	Switch Board Equipment	$ 19,874	50%	$ 9,937
	Switching Equipment	$ 1,147,085	40%	$ 458,834
	Transformers	$ -	10%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ -	0%	$ -
	Misc	$ 370,485	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 1,910,796		$ 655,447

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	81,528	81,528	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	21,059	21,059	
	Steam From Other Sources	40,694		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	12,468		
	Rents	75,877	75,877	
	Allowances	3,066	3,066	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	31,801	31,801	
	Maintenance of Boiler (or reactor) Plant	13,637		
	Maintenance of Electric Plant	14,187		
	Maintenance of Misc Steam (or Nuclear) Plant	17,658	17,658	
	Other Power Production, & Other Expenses	53,560	53,560	
	Total NonFuel Expenses	365,535	284,549	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation

	Plant Var Allocators		
	Electric Expense Allocator	5.5325%	Line 4(c) / 1(c))
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)
	Other Demand Expense Allocator	0.0542%	Line 79
	Production Plant Expenses		
	Total NonFuel Expenses	365,535	Line 116
	Allowances	3,066	Line 109
	Non-Fuel Production O&M	362,469	(Line 126 - 127)
	Operating Expenses		
	Operations Supervision & Engineering	81,528	Line 102(c)
	Electric Expenses	0	Line 106(c)
	Maintenance of Electric Plant	14,187	Line 113(b)
	Other Demand Related Expenses	203,021	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)
	Total	298,736	(Sum Lines 131 to 134)

				Allocator	Allocated Amount	
	Maintenance of Electric Plant	14,187	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	14,187	(Line 138 + 139)	5.5325%	785	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	203,021	(Line 134)	0.0542%	110	
				Line 123		
	Balance of Plant Fixed Expenses				297,841	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		18,226	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		128,277	(allocated on plant labor)	
	Total		146,504		
Depreciation					
	Annual Depreciation Exp ...DE	208,129			
	Gross Production Plant Cost ... F	13,528,361	Line 14		
	SLDP=DE/F	1.5385%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	65			
	SFDP=(R/((1+R)^n-1)		0.0507%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.033%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		27,880	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		27,880	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	3.0332%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
	Prepayments	101,763	
		100.000%	
	Production Related Prepayments	101,763	(Line 209 * 210)
	Unit Specific M&S	439,420	
	Total	541,183	(Line 211 + 212)
	Return on Working Capital	8.1350%	
	Taxes on Working Capital	3.0332%	
	Working Capital Costs	60,440	(Line 213 * 214)

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Accumulated Deferred Income Taxes

Investment	13,528,361	Line 14
Asset Service Life	65	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 2,560,954

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity = (f) *	(h) Interest = (f) *	(i) Income Taxes = (g) *	(j) Rev Req Impact	(k) Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	(Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	208,129	3.750%	507,314	115,722	115,722	6,810	2,604	4,176	13,590	209,633
2	208,129	7.219%	976,612	297,242	412,964	24,303	9,292	14,903	48,497	209,633
3	208,129	6.677%	903,289	268,881	681,844	40,127	15,342	24,606	80,074	209,633
4	208,129	6.177%	835,647	242,718	924,562	54,410	20,803	33,365	108,578	209,633
5	208,129	5.713%	772,875	218,438	1,143,001	67,266	25,718	41,248	134,231	209,633
6	208,129	5.285%	714,974	196,043	1,339,043	78,803	30,128	48,323	157,254	209,633
7	208,129	4.888%	661,266	175,269	1,514,312	89,117	34,072	54,648	177,837	209,633
8	208,129	4.522%	611,752	156,118	1,670,430	98,305	37,585	60,281	196,171	209,633
9	208,129	4.462%	603,635	152,978	1,823,408	107,308	41,027	65,802	214,136	209,633
10	208,129	4.461%	603,500	152,926	1,976,334	116,307	44,468	71,321	232,096	209,633
11	208,129	4.462%	603,635	152,978	2,129,312	125,310	47,910	76,841	250,061	209,633
12	208,129	4.461%	603,500	152,926	2,282,238	134,310	51,350	82,360	268,020	209,633
13	208,129	4.462%	603,635	152,978	2,435,216	143,312	54,792	87,881	285,985	209,633
14	208,129	4.461%	603,500	152,926	2,588,142	152,312	58,233	93,399	303,945	209,633
15	208,129	4.462%	603,635	152,978	2,741,120	161,315	61,675	98,920	321,910	209,633
16	208,129	4.461%	603,500	152,926	2,894,045	170,315	65,116	104,439	339,869	209,633
17	208,129	4.462%	603,635	152,978	3,047,024	179,317	68,558	109,959	357,835	209,633
18	208,129	4.461%	603,500	152,926	3,199,949	188,317	71,999	115,478	375,794	209,633
19	208,129	4.462%	603,635	152,978	3,352,927	197,320	75,441	120,998	393,759	209,633
20	208,129	4.461%	603,500	152,926	3,505,853	206,319	78,882	126,517	411,718	209,633
21	208,129	2.231%	301,818	36,238	3,542,091	208,452	79,697	127,825	415,974	209,633
22	208,129	0.000%	0	-80,502	3,461,589	203,715	77,886	124,920	406,520	209,633
23	208,129	0.000%	0	-80,502	3,381,087	198,977	76,074	122,015	397,066	209,633
24	208,129	0.000%	0	-80,502	3,300,585	194,239	74,263	119,110	387,612	209,633
25	208,129	0.000%	0	-80,502	3,220,083	189,502	72,452	116,204	378,158	209,633
26	208,129	0.000%	0	-80,502	3,139,581	184,764	70,641	113,299	368,704	209,633
27	208,129	0.000%	0	-80,502	3,059,079	180,027	68,829	110,394	359,250	209,633
28	208,129	0.000%	0	-80,502	2,978,577	175,289	67,018	107,489	349,796	209,633
29	208,129	0.000%	0	-80,502	2,898,075	170,552	65,207	104,584	340,342	209,633
30	208,129	0.000%	0	-80,502	2,817,572	165,814	63,395	101,679	330,888	209,633
31	208,129	0.000%	0	-80,502	2,737,070	161,077	61,584	98,774	321,434	209,633
32	208,129	0.000%	0	-80,502	2,656,568	156,339	59,773	95,869	311,981	209,633
33	208,129	0.000%	0	-80,502	2,576,066	151,602	57,961	92,964	302,527	209,633
34	208,129	0.000%	0	-80,502	2,495,564	146,864	56,150	90,058	293,073	209,633
35	208,129	0.000%	0	-80,502	2,415,062	142,126	54,339	87,153	283,619	209,633
36	208,129	0.000%	0	-80,502	2,334,560	137,389	52,528	84,248	274,165	209,633
37	208,129	0.000%	0	-80,502	2,254,058	132,651	50,716	81,343	264,711	209,633
38	208,129	0.000%	0	-80,502	2,173,556	127,914	48,905	78,438	255,257	209,633
39	208,129	0.000%	0	-80,502	2,093,054	123,176	47,094	75,533	245,803	209,633
40	208,129	0.000%	0	-80,502	2,012,552	118,439	45,282	72,628	236,349	209,633
41	208,129	0.000%	0	-80,502	1,932,050	113,701	43,471	69,723	226,895	209,633
42	208,129	0.000%	0	-80,502	1,851,548	108,964	41,660	66,818	217,441	209,633
43	208,129	0.000%	0	-80,502	1,771,046	104,226	39,849	63,912	207,987	209,633
44	208,129	0.000%	0	-80,502	1,690,543	99,488	38,037	61,007	198,533	209,633
45	208,129	0.000%	0	-80,502	1,610,041	94,751	36,226	58,102	189,079	209,633
46	208,129	0.000%	0	-80,502	1,529,539	90,013	34,415	55,197	179,625	209,633
47	208,129	0.000%	0	-80,502	1,449,037	85,276	32,603	52,292	170,171	209,633
48	208,129	0.000%	0	-80,502	1,368,535	80,538	30,792	49,387	160,717	209,633
49	208,129	0.000%	0	-80,502	1,288,033	75,801	28,981	46,482	151,263	209,633
50	208,129	0.000%	0	-80,502	1,207,531	71,063	27,169	43,577	141,809	209,633
51	208,129	0.000%	0	-80,502	1,127,029	66,326	25,358	40,672	132,355	209,633
52	208,129	0.000%	0	-80,502	1,046,527	61,588	23,547	37,766	122,901	209,633
53	208,129	0.000%	0	-80,502	966,025	56,851	21,736	34,861	113,447	209,633
54	208,129	0.000%	0	-80,502	885,523	52,113	19,924	31,956	103,994	209,633
55	208,129	0.000%	0	-80,502	805,021	47,375	18,113	29,051	94,540	209,633
56	208,129	0.000%	0	-80,502	724,519	42,638	16,302	26,146	85,086	209,633
57	208,129	0.000%	0	-80,502	644,017	37,900	14,490	23,241	75,632	209,633
58	208,129	0.000%	0	-80,502	563,514	33,163	12,679	20,336	66,178	209,633
59	208,129	0.000%	0	-80,502	483,012	28,425	10,868	17,431	56,724	209,633
60	208,129	0.000%	0	-80,502	402,510	23,688	9,056	14,526	47,270	209,633
61	208,129	0.000%	0	-80,502	322,008	18,950	7,245	11,620	37,816	209,633
62	208,129	0.000%	0	-80,502	241,506	14,213	5,434	8,715	28,362	209,633
63	208,129	0.000%	0	-80,502	161,004	9,475	3,623	5,810	18,908	209,633
64	208,129	0.000%	0	-80,502	80,502	4,738	1,811	2,905	9,454	209,633
65	208,129	0.000%	0	-80,502	0	0	0	0	0	209,633

Unit Name: Dresden 2 & 3 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)		
					Fixed Charge Rate for Reactive Plant						
							Calculated Amt	Plant	FCR % (f) / (g)		
	Annual Revenue Requirement										
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 507,917,628		Electric Expenses	Line 140	294,104				
2	Investment Generator & Exciter	Inputs Tab	76,187,644		Other Expenses		146,200				
3	Reactive Allocator	(Line 71)	13.60%		O&M	(sum line 1 & 2)	440,304	17,543,922	2.5097%	**3.61%**	-1.0984%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**10,363,834**								
5					A&G		151,648,021	1,359,267,568	11.1566%	**9.00%**	2.1552%
6	GSU Transformer Investment	Inputs Tab	36,227,984		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.1900%	**0.18%**	0.0147%
7	Reactive Allocator	(Line 71)	13.60%		Working Capital	Line 216	37,136,087	1,359,267,568	2.7321%	**2.75%**	-0.0195%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**4,928,106**		General Plant		-	1,359,267,568	0.0000%		0.0000%
9					Other Taxes	Line 196(c)	31,410,713	1,359,267,568	2.3109%	**2.31%**	0.0051%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	4,144,738		Depreciation	Line 168(c)			0.0752%	**0.0752%**	0.0000%
11	Reactive Allocator	(Line 71)	13.60%						8.1350%	**8.14%**	0.0000%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**563,810**		Taxes (Federal/State/Local)	Line 180			2.9859%	**2.99%**	0.0000%
13					ADIT	-Line 233(k)	($20,111,563)	1,359,267,568	-1.4796%	**-1.48%**	0.0000%
14	Total Cost of Power Plant	Inputs Tab	1,359,267,568				(Sum Lines 1 to 11 , Col. (h))		28.6157%		
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	1,242,707,203								
16	Balance of Plant Allocator	(Line 79)	0.1358%								
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	1,688,172								
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	17,543,922								
19	Reactive Fixed Charge Rate	(Line 14(h))	28.6157%								
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**5,020,319**								
21											
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 5,020,319**								
23											
24											
25											
26											

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		948.00						
		944.00						
		-						
	Total	1,892.00	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.93						
		0.93						
		-						
	Total	0.93	(Line 38 / 58)					
	MVA Capability (MVA)							
		1,020.45	(Line 31 / 41)					
		1,015.05	(Line 32 / 42)					
		-						
	Total	2,035.51	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		377.65	(SQRT (Line 51^2 - Line 31^2))					
		373.09	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	750.74	(Sum Lines 62 to 64)					
	Reactive Allocator	13.6%	(Line 69^2 / Line 58^2)					
		ComEd is TO Fleet						
	Max. MVAr	2,187						
	Nameplate MVAr	4,856						
	Exciter MW	35						
	Generator MW	11,447						
	Balance of Plant Allocator	0.1358%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ 1,984,353	15%	$ 297,653
	Control&Power Cabling	$ 4,946,860	1%	$ 49,469
	Switch Board Equipment	$ -	1%	$ -
	Switching Equipment	$ 4,661,842	1%	$ 46,618
	Transformers	$ 12,219,855	3%	$ 366,596
	Aux Generator	$ 5,052,411	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ 153,468	50%	$ 76,734
	Structure	$ 31,844	0%	$ -
	Misc	$ 63,976,359	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ 4,948	1%	$ 49
	Bus & Insulators	$ 4,134,523	80%	$ 3,307,619
	Capacitor Bank	$ -	0%	$ -
	Total	$ 97,166,463		$ 4,144,738

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	30,319,889	30,319,889	
	Coolants and Water (Nuclear Plants Only)	2,970,838		
	Steam Expenses	18,634,475	18,634,475	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	1,903,760		
	Rents	52,637,346	52,637,346	
	Allowances	4,176,895	4,176,895	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	5,593,493	5,593,493	
	Maintenance of Boiler (or reactor) Plant	435,969		
	Maintenance of Electric Plant	14,413,629		
	Maintenance of Misc Steam (or Nuclear) Plant	9,258,467	9,258,467	
	Other Power Production, & Other Expenses	17,320,796	17,320,796	
	Total NonFuel Expenses	157,665,557	137,941,361	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	2.0405%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.1358%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	157,665,557	Line 116			
	Allowances	4,176,895	Line 109			
	Non-Fuel Production O&M	153,488,662	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	30,319,889	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	14,413,629	Line 113(b)			
	Other Demand Related Expenses	107,621,472	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	152,354,990	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	14,413,629	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	14,413,629	(Line 138 + 139)	2.0405%	294,104	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	107,621,472	(Line 134)	0.1358%	146,200	
				Line 123		
	Balance of Plant Fixed Expenses				151,914,687	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		113,729,176	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		37,918,846	(allocated on plant labor)	
	Total		151,648,021		
Depreciation					
	Annual Depreciation Exp ...DE	22,654,459			
	Gross Production Plant Cost ... F	1,359,267,568	Line 14		
	SLDP=DE/F	1.6667%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	60			
	SFDP=(R/((1+R)^n-1)		0.0752%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.986%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		25,219,637		
	Payroll Taxes	7,076,336			
		0 87.4899%	Line 117		
	Fixed Payroll Taxes		6,191,076	(Line 193 * 194)	
	Total Other Taxes		31,410,713	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9859%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	2,278,934				
		100.000%				
	Production Related Prepayments	2,278,934	(Line 209 * 210)			
	Unit Specific M&S	331,652,931				
	Total	333,931,865	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9859%				
	Working Capital Costs	37,136,087	(Line 213 * 214)			

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Accumulated Deferred Income Taxes

Investment	1,359,267,568	Line 14
Asset Service Life	60	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 244,957,426

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	PMT of NPV col. (j)
1	22,654,459	3.750%	50,972,534	10,953,148	10,953,148	644,593	246,446	395,271	1,286,309	20,111,563
2	22,654,459	7.219%	98,125,526	29,191,454	40,144,602	2,362,510	903,254	1,448,715	4,714,478	20,111,563
3	22,654,459	6.677%	90,758,296	26,341,883	66,486,484	3,912,730	1,495,946	2,399,325	7,808,000	20,111,563
4	22,654,459	6.177%	83,961,958	23,713,127	90,199,612	5,308,247	2,029,491	3,255,070	10,592,809	20,111,563
5	22,654,459	5.713%	77,654,956	21,273,642	111,473,254	6,560,201	2,508,148	4,022,781	13,091,130	20,111,563
6	22,654,459	5.285%	71,837,291	19,023,427	130,496,681	7,679,730	2,936,175	4,709,287	15,325,192	20,111,563
7	22,654,459	4.888%	66,440,999	16,936,196	147,432,877	8,676,425	3,317,240	5,320,470	17,314,135	20,111,563
8	22,654,459	4.522%	61,466,079	15,011,946	162,444,823	9,559,878	3,655,009	5,862,213	19,077,099	20,111,563
9	22,654,459	4.462%	60,650,519	14,696,496	177,141,319	10,424,767	3,985,680	6,392,571	20,803,017	20,111,563
10	22,654,459	4.461%	60,636,926	14,691,238	191,832,557	11,289,346	4,316,233	6,922,740	22,528,318	20,111,563
11	22,654,459	4.462%	60,650,519	14,696,496	206,529,053	12,154,235	4,646,904	7,453,098	24,254,237	20,111,563
12	22,654,459	4.461%	60,636,926	14,691,238	221,220,292	13,018,814	4,977,457	7,983,267	25,979,538	20,111,563
13	22,654,459	4.462%	60,650,519	14,696,496	235,916,787	13,883,703	5,308,128	8,513,625	27,705,456	20,111,563
14	22,654,459	4.461%	60,636,926	14,691,238	250,608,026	14,748,282	5,638,681	9,043,794	29,430,757	20,111,563
15	22,654,459	4.462%	60,650,519	14,696,496	265,304,521	15,613,171	5,969,352	9,574,153	31,156,675	20,111,563
16	22,654,459	4.461%	60,636,926	14,691,238	279,995,760	16,477,750	6,299,905	10,104,321	32,881,976	20,111,563
17	22,654,459	4.462%	60,650,519	14,696,496	294,692,256	17,342,639	6,630,576	10,634,680	34,607,895	20,111,563
18	22,654,459	4.461%	60,636,926	14,691,238	309,383,494	18,207,219	6,961,129	11,164,849	36,333,196	20,111,563
19	22,654,459	4.462%	60,650,519	14,696,496	324,079,990	19,072,107	7,291,800	11,695,207	38,059,114	20,111,563
20	22,654,459	4.461%	60,636,926	14,691,238	338,771,228	19,936,687	7,622,353	12,225,376	39,784,415	20,111,563
21	22,654,459	2.231%	30,325,259	2,966,989	341,738,217	20,111,294	7,689,110	12,332,447	40,132,851	20,111,563
22	22,654,459	0.000%	0	-8,762,518	332,975,698	19,595,620	7,491,953	12,016,230	39,103,803	20,111,563
23	22,654,459	0.000%	0	-8,762,518	324,213,180	19,079,946	7,294,797	11,700,013	38,074,756	20,111,563
24	22,654,459	0.000%	0	-8,762,518	315,450,662	18,564,271	7,097,640	11,383,797	37,045,708	20,111,563
25	22,654,459	0.000%	0	-8,762,518	306,688,143	18,048,597	6,900,483	11,067,580	36,016,661	20,111,563
26	22,654,459	0.000%	0	-8,762,518	297,925,625	17,532,923	6,703,327	10,751,364	34,987,613	20,111,563
27	22,654,459	0.000%	0	-8,762,518	289,163,107	17,017,249	6,506,170	10,435,147	33,958,566	20,111,563
28	22,654,459	0.000%	0	-8,762,518	280,400,588	16,501,575	6,309,013	10,118,931	32,929,518	20,111,563
29	22,654,459	0.000%	0	-8,762,518	271,638,070	15,985,900	6,111,857	9,802,714	31,900,471	20,111,563
30	22,654,459	0.000%	0	-8,762,518	262,875,551	15,470,226	5,914,700	9,486,497	30,871,424	20,111,563
31	22,654,459	0.000%	0	-8,762,518	254,113,033	14,954,552	5,717,543	9,170,281	29,842,376	20,111,563
32	22,654,459	0.000%	0	-8,762,518	245,350,515	14,438,878	5,520,387	8,854,064	28,813,329	20,111,563
33	22,654,459	0.000%	0	-8,762,518	236,587,996	13,923,204	5,323,230	8,537,848	27,784,281	20,111,563
34	22,654,459	0.000%	0	-8,762,518	227,825,478	13,407,529	5,126,073	8,221,631	26,755,234	20,111,563
35	22,654,459	0.000%	0	-8,762,518	219,062,960	12,891,855	4,928,917	7,905,415	25,726,186	20,111,563
36	22,654,459	0.000%	0	-8,762,518	210,300,441	12,376,181	4,731,760	7,589,198	24,697,139	20,111,563
37	22,654,459	0.000%	0	-8,762,518	201,537,923	11,860,507	4,534,603	7,272,981	23,668,091	20,111,563
38	22,654,459	0.000%	0	-8,762,518	192,775,404	11,344,833	4,337,447	6,956,765	22,639,044	20,111,563
39	22,654,459	0.000%	0	-8,762,518	184,012,886	10,829,158	4,140,290	6,640,548	21,609,996	20,111,563
40	22,654,459	0.000%	0	-8,762,518	175,250,368	10,313,484	3,943,133	6,324,332	20,580,949	20,111,563
41	22,654,459	0.000%	0	-8,762,518	166,487,849	9,797,810	3,745,977	6,008,115	19,551,902	20,111,563
42	22,654,459	0.000%	0	-8,762,518	157,725,331	9,282,136	3,548,820	5,691,898	18,522,854	20,111,563
43	22,654,459	0.000%	0	-8,762,518	148,962,812	8,766,462	3,351,663	5,375,682	17,493,807	20,111,563
44	22,654,459	0.000%	0	-8,762,518	140,200,294	8,250,787	3,154,507	5,059,465	16,464,759	20,111,563
45	22,654,459	0.000%	0	-8,762,518	131,437,776	7,735,113	2,957,350	4,743,249	15,435,712	20,111,563
46	22,654,459	0.000%	0	-8,762,518	122,675,257	7,219,439	2,760,193	4,427,032	14,406,664	20,111,563
47	22,654,459	0.000%	0	-8,762,518	113,912,739	6,703,765	2,563,037	4,110,816	13,377,617	20,111,563
48	22,654,459	0.000%	0	-8,762,518	105,150,221	6,188,090	2,365,880	3,794,599	12,348,569	20,111,563
49	22,654,459	0.000%	0	-8,762,518	96,387,702	5,672,416	2,168,723	3,478,382	11,319,522	20,111,563
50	22,654,459	0.000%	0	-8,762,518	87,625,184	5,156,742	1,971,567	3,162,166	10,290,475	20,111,563
51	22,654,459	0.000%	0	-8,762,518	78,862,665	4,641,068	1,774,410	2,845,949	9,261,427	20,111,563
52	22,654,459	0.000%	0	-8,762,518	70,100,147	4,125,394	1,577,253	2,529,733	8,232,380	20,111,563
53	22,654,459	0.000%	0	-8,762,518	61,337,629	3,609,719	1,380,097	2,213,516	7,203,332	20,111,563
54	22,654,459	0.000%	0	-8,762,518	52,575,110	3,094,045	1,182,940	1,897,299	6,174,285	20,111,563
55	22,654,459	0.000%	0	-8,762,518	43,812,592	2,578,371	985,783	1,581,083	5,145,237	20,111,563
56	22,654,459	0.000%	0	-8,762,518	35,050,074	2,062,697	788,627	1,264,866	4,116,190	20,111,563
57	22,654,459	0.000%	0	-8,762,518	26,287,555	1,547,023	591,470	948,650	3,087,142	20,111,563
58	22,654,459	0.000%	0	-8,762,518	17,525,037	1,031,348	394,313	632,433	2,058,095	20,111,563
59	22,654,459	0.000%	0	-8,762,518	8,762,518	515,674	197,157	316,217	1,029,047	20,111,563
60	22,654,459	0.000%	0	-8,762,518	0	0	0	0	0	20,111,563

Unit Name: Eddystone 3,4,10,20,30,40 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 62,382,060	
2	Investment Generator & Exciter	Inputs Tab	$ 9,357,309	
3	Reactive Allocator	(Line 71)	15.53%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**1,453,008**	
5				
6	GSU Transformer Investment	Inputs Tab	6,411,560	
7	Reactive Allocator	(Line 71)	15.53%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**995,590**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	3,656,031	
11	Reactive Allocator	(Line 71)	15.53%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**567,710**	
13				
14	Total Cost of Power Plant	Inputs Tab	400,131,998	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	380,707,098	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	206,266	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	3,222,574	
19	Reactive Fixed Charge Rate	(Line 14(h))	13.1782%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**424,678**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 424,678**	
23				
24				
25				
26				

(e)		(f)	(g)	(h)
Fixed Charge Rate for Reactive Plant				
		Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 140	15,169		
Other Expenses		5,049		
O&M	(sum line 1 & 2)	20,218	3,222,574	0.6274%
A&G		5,944,558	400,131,998	1.4856%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0295%
Working Capital	Line 216	2,296,730	400,131,998	0.5740%
General Plant		-	400,131,998	0.0000%
Other Taxes	Line 196(c)	3,170,443	400,131,998	0.7923%
Depreciation	Line 168(c)			0.0507%
				8.1350%
Taxes (Federal/State/Local)	Line 180			3.0332%
ADIT	-Line 233(k)	($6,200,365)	400,131,998	-1.5496%
		(Sum Lines 1 to 11 , Col. (h))		13.1782%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		400.00						
		400.00						
		14.20						
		13.60						
		18.00						
		18.00						
		-						
	Total	863.80	(Sum Lines 31 to 37)					
	Nominal Power Factor (pf)							
		0.92						
		0.94						
		0.79						
		0.78						
		0.85						
		0.85						
		-						
	Total	0.92	(Line 38 / 58)					
	MVA Capability (MVA)							
		437.16	(Line 31 / 41)					
		427.35	(Line 32 / 42)					
		18.02	(Line 33 / 43)					
		17.55	(Line 34 / 44)					
		21.20	(Line 35 / 45)					
		21.20	(Line 36 / 46)					
	Total	942.48	(Sum Lines 51 to 57)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		176.37	(SQRT (Line 51^2 - Line 31^2))					
		150.43	(SQRT (Line 52^2 - Line 32^2))					
		11.09	(SQRT (Line 53^2 - Line 33^2))					
		11.09	(SQRT (Line 54^2 - Line 34^2))					
		11.20	(SQRT (Line 55^2 - Line 35^2))					
		11.20	(SQRT (Line 56^2 - Line 36^2))					
	Total	371.39	(Sum Lines 62 to 68)					
	Reactive Allocator	15.5%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Hydro & Steam**	**Allocated Amt**
	Storage Batteries	$ 351,463	**30%**	$ 105,439
	Control&Power Cabling	$ 19,978,318	**15%**	$ 2,996,748
	Switch Board Equipment	$ 484,897	**30%**	$ 145,469
	Switching Equipment	$ 2,041,877	**20%**	$ 408,375
	Transformers	$ -	**5%**	$ -
	Aux Generator	$ -	**0%**	$ -
	Fire Protection System	$ -	**0%**	$ -
	HVAC	$ -	**0%**	$ -
	Regulating Equipment	$ -	**75%**	$ -
	Structure	$ 167,065	**0%**	$ -
	Misc	$ 7,066,463	**0%**	$ -
	Exciter & PPT	$ -	**100%**	$ -
	Station Grounding	$ -	**0%**	$ -
	Bus & Insulators	$ -	**60%**	$ -
	Capacitor Bank	$ -	**0%**	$ -
	Total	$ 30,090,084		$ 3,656,031

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	3,742,503	3,742,503	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	966,716	966,716	
	Steam From Other Sources	1,868,066		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	572,328		
	Rents	3,483,129	3,483,129	
	Allowances	140,748	140,748	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	1,459,799	1,459,799	
	Maintenance of Boiler (or reactor) Plant	625,988		
	Maintenance of Electric Plant	651,254		
	Maintenance of Misc Steam (or Nuclear) Plant	810,576	810,576	
	Other Power Production, & Other Expenses	2,458,680	2,458,680	
	Total NonFuel Expenses	16,779,786	13,062,151	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	2.3292%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	16,779,786	Line 116			
	Allowances	140,748	Line 109			
	Non-Fuel Production O&M	16,639,038	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	3,742,503	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	651,254	Line 113(b)			
	Other Demand Related Expenses	9,319,648	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	13,713,405	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	651,254	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	651,254	(Line 138 + 139)	2.3292%	15,169	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	9,319,648	(Line 134)	0.0542%	5,049	
				Line 123		
	Balance of Plant Fixed Expenses				13,693,187	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		1,076,796	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		4,867,763	(allocated on plant labor)	
	Total		5,944,558		
Depreciation					
	Annual Depreciation Exp ...DE	6,155,877			
	Gross Production Plant Cost ... F	400,131,998	Line 14		
	SLDP=DE/F	1.5385%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	65			
	SFDP=(R/((1+R)^n-1)		0.0507%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.033%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		3,170,443	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		3,170,443	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	3.0332%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
	Prepayments	3,009,862	
		100.000%	
	Production Related Prepayments	3,009,862	(Line 209 * 210)
	Unit Specific M&S	17,555,085	
	Total	20,564,947	(Line 211 + 212)
	Return on Working Capital	8.1350%	
	Taxes on Working Capital	3.0332%	
	Working Capital Costs	2,296,730	(Line 213 * 214)

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Accumulated Deferred Income Taxes

Investment	400,131,998	Line 14
Asset Service Life	65	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 75,746,042

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity = (f) *	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	6,155,877	3.750%	15,004,950	3,422,733	3,422,733	201,428	77,011	123,518	401,957	6,200,365
2	6,155,877	7.219%	28,885,529	8,791,602	12,214,335	718,814	274,823	440,784	1,434,420	6,200,365
3	6,155,877	6.677%	26,716,813	7,952,765	20,167,100	1,186,834	453,760	727,778	2,368,372	6,200,365
4	6,155,877	6.177%	24,716,154	7,178,929	27,346,029	1,609,314	615,286	986,847	3,211,447	6,200,365
5	6,155,877	5.713%	22,859,541	6,460,810	33,806,839	1,989,532	760,654	1,220,001	3,970,188	6,200,365
6	6,155,877	5.285%	21,146,976	5,798,407	39,605,247	2,330,769	891,118	1,429,251	4,651,138	6,200,365
7	6,155,877	4.888%	19,558,452	5,183,982	44,789,229	2,635,846	1,007,758	1,616,327	5,259,931	6,200,365
8	6,155,877	4.522%	18,093,969	4,617,535	49,406,763	2,907,588	1,111,652	1,782,962	5,802,202	6,200,365
9	6,155,877	4.462%	17,853,890	4,524,674	53,931,438	3,173,865	1,213,457	1,946,246	6,333,568	6,200,365
10	6,155,877	4.461%	17,849,888	4,523,127	58,454,564	3,440,051	1,315,228	2,109,474	6,864,753	6,200,365
11	6,155,877	4.462%	17,853,890	4,524,674	62,979,239	3,706,328	1,417,033	2,272,758	7,396,119	6,200,365
12	6,155,877	4.461%	17,849,888	4,523,127	67,502,366	3,972,514	1,518,803	2,435,985	7,927,303	6,200,365
13	6,155,877	4.462%	17,853,890	4,524,674	72,027,040	4,238,791	1,620,608	2,599,269	8,458,669	6,200,365
14	6,155,877	4.461%	17,849,888	4,523,127	76,550,167	4,504,977	1,722,379	2,762,497	8,989,853	6,200,365
15	6,155,877	4.462%	17,853,890	4,524,674	81,074,841	4,771,254	1,824,184	2,925,781	9,521,219	6,200,365
16	6,155,877	4.461%	17,849,888	4,523,127	85,597,968	5,037,440	1,925,954	3,089,009	10,052,404	6,200,365
17	6,155,877	4.462%	17,853,890	4,524,674	90,122,642	5,303,717	2,027,759	3,252,293	10,583,770	6,200,365
18	6,155,877	4.461%	17,849,888	4,523,127	94,645,769	5,569,903	2,129,530	3,415,521	11,114,954	6,200,365
19	6,155,877	4.462%	17,853,890	4,524,674	99,170,443	5,836,181	2,231,335	3,578,804	11,646,320	6,200,365
20	6,155,877	4.461%	17,849,888	4,523,127	103,693,570	6,102,367	2,333,105	3,742,032	12,177,504	6,200,365
21	6,155,877	2.231%	8,926,945	1,071,821	104,765,391	6,165,443	2,357,221	3,780,711	12,303,376	6,200,365
22	6,155,877	0.000%	0	-2,381,032	102,384,360	6,025,320	2,303,648	3,694,786	12,023,754	6,200,365
23	6,155,877	0.000%	0	-2,381,032	100,003,328	5,885,196	2,250,075	3,608,861	11,744,132	6,200,365
24	6,155,877	0.000%	0	-2,381,032	97,622,297	5,745,072	2,196,502	3,522,936	11,464,510	6,200,365
25	6,155,877	0.000%	0	-2,381,032	95,241,265	5,604,948	2,142,928	3,437,010	11,184,887	6,200,365
26	6,155,877	0.000%	0	-2,381,032	92,860,233	5,464,825	2,089,355	3,351,085	10,905,265	6,200,365
27	6,155,877	0.000%	0	-2,381,032	90,479,202	5,324,701	2,035,782	3,265,160	10,625,643	6,200,365
28	6,155,877	0.000%	0	-2,381,032	88,098,170	5,184,577	1,982,209	3,179,235	10,346,021	6,200,365
29	6,155,877	0.000%	0	-2,381,032	85,717,138	5,044,454	1,928,636	3,093,309	10,066,399	6,200,365
30	6,155,877	0.000%	0	-2,381,032	83,336,107	4,904,330	1,875,062	3,007,384	9,786,776	6,200,365
31	6,155,877	0.000%	0	-2,381,032	80,955,075	4,764,206	1,821,489	2,921,459	9,507,154	6,200,365
32	6,155,877	0.000%	0	-2,381,032	78,574,044	4,624,082	1,767,916	2,835,534	9,227,532	6,200,365
33	6,155,877	0.000%	0	-2,381,032	76,193,012	4,483,959	1,714,343	2,749,608	8,947,910	6,200,365
34	6,155,877	0.000%	0	-2,381,032	73,811,980	4,343,835	1,660,770	2,663,683	8,668,288	6,200,365
35	6,155,877	0.000%	0	-2,381,032	71,430,949	4,203,711	1,607,196	2,577,758	8,388,665	6,200,365
36	6,155,877	0.000%	0	-2,381,032	69,049,917	4,063,588	1,553,623	2,491,833	8,109,043	6,200,365
37	6,155,877	0.000%	0	-2,381,032	66,668,885	3,923,464	1,500,050	2,405,907	7,829,421	6,200,365
38	6,155,877	0.000%	0	-2,381,032	64,287,854	3,783,340	1,446,477	2,319,982	7,549,799	6,200,365
39	6,155,877	0.000%	0	-2,381,032	61,906,822	3,643,216	1,392,903	2,234,057	7,270,177	6,200,365
40	6,155,877	0.000%	0	-2,381,032	59,525,791	3,503,093	1,339,330	2,148,132	6,990,555	6,200,365
41	6,155,877	0.000%	0	-2,381,032	57,144,759	3,362,969	1,285,757	2,062,206	6,710,932	6,200,365
42	6,155,877	0.000%	0	-2,381,032	54,763,727	3,222,845	1,232,184	1,976,281	6,431,310	6,200,365
43	6,155,877	0.000%	0	-2,381,032	52,382,696	3,082,722	1,178,611	1,890,356	6,151,688	6,200,365
44	6,155,877	0.000%	0	-2,381,032	50,001,664	2,942,598	1,125,037	1,804,430	5,872,066	6,200,365
45	6,155,877	0.000%	0	-2,381,032	47,620,632	2,802,474	1,071,464	1,718,505	5,592,444	6,200,365
46	6,155,877	0.000%	0	-2,381,032	45,239,601	2,662,351	1,017,891	1,632,580	5,312,821	6,200,365
47	6,155,877	0.000%	0	-2,381,032	42,858,569	2,522,227	964,318	1,546,655	5,033,199	6,200,365
48	6,155,877	0.000%	0	-2,381,032	40,477,538	2,382,103	910,745	1,460,729	4,753,577	6,200,365
49	6,155,877	0.000%	0	-2,381,032	38,096,506	2,241,979	857,171	1,374,804	4,473,955	6,200,365
50	6,155,877	0.000%	0	-2,381,032	35,715,474	2,101,856	803,598	1,288,879	4,194,333	6,200,365
51	6,155,877	0.000%	0	-2,381,032	33,334,443	1,961,732	750,025	1,202,954	3,914,711	6,200,365
52	6,155,877	0.000%	0	-2,381,032	30,953,411	1,821,608	696,452	1,117,028	3,635,088	6,200,365
53	6,155,877	0.000%	0	-2,381,032	28,572,379	1,681,485	642,879	1,031,103	3,355,466	6,200,365
54	6,155,877	0.000%	0	-2,381,032	26,191,348	1,541,361	589,305	945,178	3,075,844	6,200,365
55	6,155,877	0.000%	0	-2,381,032	23,810,316	1,401,237	535,732	859,253	2,796,222	6,200,365
56	6,155,877	0.000%	0	-2,381,032	21,429,285	1,261,113	482,159	773,327	2,516,600	6,200,365
57	6,155,877	0.000%	0	-2,381,032	19,048,253	1,120,990	428,586	687,402	2,236,977	6,200,365
58	6,155,877	0.000%	0	-2,381,032	16,667,221	980,866	375,012	601,477	1,957,355	6,200,365
59	6,155,877	0.000%	0	-2,381,032	14,286,190	840,742	321,439	515,552	1,677,733	6,200,365
60	6,155,877	0.000%	0	-2,381,032	11,905,158	700,619	267,866	429,626	1,398,111	6,200,365
61	6,155,877	0.000%	0	-2,381,032	9,524,126	560,495	214,293	343,701	1,118,489	6,200,365
62	6,155,877	0.000%	0	-2,381,032	7,143,095	420,371	160,720	257,776	838,867	6,200,365
63	6,155,877	0.000%	0	-2,381,032	4,762,063	280,247	107,146	171,851	559,244	6,200,365
64	6,155,877	0.000%	0	-2,381,032	2,381,032	140,124	53,573	85,925	279,622	6,200,365
65	6,155,877	0.000%	0	-2,381,032	0	0	0	0	0	6,200,365

Unit Name: Fairless Hills A&B **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 20,090,347		Electric Expenses	Line 140	12,361		
2	Investment Generator & Exciter	Inputs Tab	$ 3,013,552		Other Expenses		2,302		
3	Reactive Allocator	(Line 71)	27.75%		O&M	(sum line 1 & 2)	14,664	883,698	1.6594%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**836,261**						
5					A&G		3,484,428	61,729,219	5.6447%
6	GSU Transformer Investment	Inputs Tab	51,347		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0974%
7	Reactive Allocator	(Line 71)	27.75%		Working Capital	Line 216	156,107	61,729,219	0.2529%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**14,249**		General Plant		-	61,729,219	0.0000%
9					Other Taxes	Line 196(c)	263,599	61,729,219	0.4270%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	5,071		Depreciation	Line 168(c)			1.1202%
11	Reactive Allocator	(Line 71)	27.75%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**1,407**		Taxes (Federal/State/Local)	Line 180			2.5332%
13					ADIT	-Line 233(k)	($349,408)	61,729,219	-0.5660%
14	Total Cost of Power Plant	Inputs Tab	61,729,219				(Sum Lines 1 to 11 , Col. (h))		19.3037%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	58,659,250						
16	Balance of Plant Allocator	(Line 79)	0.0542%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	31,781						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	883,698						
19	Reactive Fixed Charge Rate	(Line 14(h))	19.3037%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**170,587**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 170,587**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		30.00						
		30.00						
		-						
		-						
		-						
		-						
		-						
	Total	60.00	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.85						
		0.85						
		-						
		-						
		-						
		-						
		-						
	Total	0.85	(Line 38 / 58)					
	MVA Capability (MVA)							
		35.29	(Line 31 / 41)					
		35.29	(Line 32 / 42)					
		-						
	Total	70.59	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		18.59	(SQRT (Line 51^2 - Line 31^2))					
		18.59	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	37.18	(Sum Lines 62 to 64)					
	Reactive Allocator	27.8%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Hydro & Steam**	**Allocated Amt**
	Storage Batteries	$ 16,787	30%	$ 5,036
	Control&Power Cabling	$ 230	15%	$ 34
	Switch Board Equipment	$ -	30%	$ -
	Switching Equipment	$ -	20%	$ -
	Transformers	$ -	5%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ -	0%	$ -
	Misc	$ 154,657	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	0%	$ -
	Bus & Insulators	$ -	60%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 171,673		$ 5,071

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	1,706,571	1,706,571	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	440,820	440,820	
	Steam From Other Sources	851,833		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	260,980		
	Rents	1,588,297	1,588,297	
	Allowances	64,181	64,181	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	665,664	665,664	
	Maintenance of Boiler (or reactor) Plant	285,449		
	Maintenance of Electric Plant	296,970		
	Maintenance of Misc Steam (or Nuclear) Plant	369,620	369,620	
	Other Power Production, & Other Expenses	1,121,151	1,121,151	
	Total NonFuel Expenses	7,651,534	5,956,303	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	4.1625%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	7,651,534	Line 116			
	Allowances	64,181	Line 109			
	Non-Fuel Production O&M	7,587,353	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	1,706,571	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	296,970	Line 113(b)			
	Other Demand Related Expenses	4,249,732	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	6,253,273	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	296,970	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	296,970	(Line 138 + 139)	4.1625%	12,361	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	4,249,732	(Line 134)	0.0542%	2,302	
				Line 123		
	Balance of Plant Fixed Expenses				6,238,609	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		833,095	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		2,651,333	(allocated on plant labor)	
	Total		3,484,428		
Depreciation					
	Annual Depreciation Exp ...DE	2,286,267			
	Gross Production Plant Cost ... F	61,729,219	Line 14		
	SLDP=DE/F	3.7037%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	27			
	SFDP=(R/((1+R)^n-1)		1.1202%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.533%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		263,599	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		263,599	(Line 192 + 195)	

	Plant		Depreciation	Total	
General Plant	-		-		
	0.000%		0.000%		Line 159
Fixed General Plant	-		-		(Lines 200 * 201)
Return on General Plant	8.1350%	Line 188			
Taxes on General Plant	2.5332%	Line 189			
General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
Prepayments	464,338		
	100.000%		
Production Related Prepayments	464,338	(Line 209 * 210)	
Unit Specific M&S	998,961		
Total	1,463,299	(Line 211 + 212)	
Return on Working Capital	8.1350%		
Taxes on Working Capital	2.5332%		
Working Capital Costs	156,107	(Line 213 * 214)	

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(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Accumulated Deferred Income Taxes										
Investment		61,729,219	Line 14					NPV of Col (j)>	3,775,258	
Asset Service Life		27	Line 167							
Composite Tax Rate		38.6790%	Line 177							
Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity = (f) *	Interest = (f) *	Income Taxes = (g) *	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	(Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	2,286,267	3.750%	2,314,846	11,054	11,054	651	249	399	1,298	349,408
2	2,286,267	7.219%	4,456,232	839,321	850,375	50,045	19,133	30,688	99,866	349,408
3	2,286,267	6.677%	4,121,660	709,912	1,560,286	91,823	35,106	56,307	183,236	349,408
4	2,286,267	6.177%	3,813,014	590,530	2,150,816	126,576	48,393	77,617	252,586	349,408
5	2,286,267	5.713%	3,526,590	479,745	2,630,561	154,809	59,188	94,930	308,926	349,408
6	2,286,267	5.285%	3,262,389	377,554	3,008,115	177,028	67,683	108,555	353,265	349,408
7	2,286,267	4.888%	3,017,324	282,765	3,290,880	193,668	74,045	118,759	386,472	349,408
8	2,286,267	4.522%	2,791,395	195,378	3,486,259	205,166	78,441	125,810	409,417	349,408
9	2,286,267	4.462%	2,754,358	181,053	3,667,312	215,821	82,515	132,344	430,680	349,408
10	2,286,267	4.461%	2,753,740	180,814	3,848,126	226,462	86,583	138,869	451,914	349,408
11	2,286,267	4.462%	2,754,358	181,053	4,029,178	237,117	90,657	145,403	473,176	349,408
12	2,286,267	4.461%	2,753,740	180,814	4,209,992	247,758	94,725	151,928	494,411	349,408
13	2,286,267	4.462%	2,754,358	181,053	4,391,045	258,413	98,799	158,461	515,673	349,408
14	2,286,267	4.461%	2,753,740	180,814	4,571,859	269,054	102,867	164,987	536,907	349,408
15	2,286,267	4.462%	2,754,358	181,053	4,752,911	279,709	106,941	171,520	558,170	349,408
16	2,286,267	4.461%	2,753,740	180,814	4,933,725	290,350	111,009	178,045	579,404	349,408
17	2,286,267	4.462%	2,754,358	181,053	5,114,778	301,005	115,083	184,579	600,666	349,408
18	2,286,267	4.461%	2,753,740	180,814	5,295,592	311,646	119,151	191,104	621,901	349,408
19	2,286,267	4.462%	2,754,358	181,053	5,476,645	322,301	123,225	197,638	643,163	349,408
20	2,286,267	4.461%	2,753,740	180,814	5,657,459	332,941	127,293	204,163	664,397	349,408
21	2,286,267	2.231%	1,377,179	-351,626	5,305,832	312,248	119,381	191,474	623,103	349,408
22	2,286,267	0.000%	0	-884,305	4,421,527	260,207	99,484	159,561	519,253	349,408
23	2,286,267	0.000%	0	-884,305	3,537,221	208,165	79,587	127,649	415,402	349,408
24	2,286,267	0.000%	0	-884,305	2,652,916	156,124	59,691	95,737	311,552	349,408
25	2,286,267	0.000%	0	-884,305	1,768,611	104,083	39,794	63,825	207,701	349,408
26	2,286,267	0.000%	0	-884,305	884,305	52,041	19,897	31,912	103,851	349,408
27	2,286,267	0.000%	0	-884,305	0	0	0	0	0	349,408

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Unit Name: Falls 1-3 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 5,518,050	
2	Investment Generator & Exciter	Inputs Tab	$ 827,708	
3	Reactive Allocator	(Line 71)	27.18%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**224,966**	
5				
6	GSU Transformer Investment	Inputs Tab	-	
7	Reactive Allocator	(Line 71)	27.18%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	312,817	
11	Reactive Allocator	(Line 71)	27.18%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**85,022**	
13				
14	Total Cost of Power Plant	Inputs Tab	7,829,474	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	6,688,950	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	3,624	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	313,612	
19	Reactive Fixed Charge Rate	(Line 14(h))	12.9539%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**40,625**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 40,625**	
23				
24				
25				
26				

(e)		(f)	(g)	(h)
Fixed Charge Rate for Reactive Plant				
		Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 140	527		
Other Expenses		100		
O&M	(sum line 1 & 2)	627	313,612	0.1999%
A&G		133,423	7,829,474	1.7041%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0265%
Working Capital	Line 216	93,281	7,829,474	1.1914%
General Plant		-	7,829,474	0.0000%
Other Taxes	Line 196(c)	11,386	7,829,474	0.1454%
Depreciation	Line 168(c)			0.0594%
				8.1350%
Taxes (Federal/State/Local)	Line 180			3.0148%
ADIT	-Line 233(k)	($119,220)	7,829,474	-1.5227%
		(Sum Lines 1 to 11 , Col. (h))		12.9539%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		18.46						
		18.08						
		18.26						
	Total	54.80	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.86						
		0.85						
		0.85						
	Total	0.85	(Line 38 / 58)					
	MVA Capability (MVA)							
		21.59	(Line 31 / 41)					
		21.25	(Line 32 / 42)					
		21.38	(Line 33 / 43)					
	Total	64.22	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		11.20	(SQRT (Line 51^2 - Line 31^2))					
		11.16	(SQRT (Line 52^2 - Line 32^2))					
		11.12	(SQRT (Line 53^2 - Line 33^2))					
	Total	33.48	(Sum Lines 62 to 64)					
	Reactive Allocator	27.2%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ 33,793	50%	$ 16,896
	Control&Power Cabling	$ 142,003	50%	$ 71,002
	Switch Board Equipment	$ -	50%	$ -
	Switching Equipment	$ 562,170	40%	$ 224,868
	Transformers	$ 512	10%	$ 51
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ 8,093	0%	$ -
	Misc	$ 380,300	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 1,126,870		$ 312,817

O&M		**Total Non-Fuel**	**Fixed O&M**		
	Production Expenses: Oper, Supv, & Engr	74,248	74,248		
	Coolants and Water (Nuclear Plants Only)	0			
	Steam Expenses	19,179	19,179		
	Steam From Other Sources	37,061			
	Electric Expenses	0	-		
	Misc Steam (or Nuclear) Power Expenses	11,355			
	Rents	69,103	69,103		
	Allowances	2,792	2,792		
	Maintenance Supervision and Engineering	0			
	Maintenance of Structures	28,961	28,961		
	Maintenance of Boiler (or reactor) Plant	12,419			
	Maintenance of Electric Plant	12,920			
	Maintenance of Misc Steam (or Nuclear) Plant	16,081	16,081		
	Other Power Production, & Other Expenses	48,778	48,778		
	Total NonFuel Expenses	332,898	259,143	(Sum Lines 102 to 115)	
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))	

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	4.0769%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	332,898	Line 116			
	Allowances	2,792	Line 109			
	Non-Fuel Production O&M	330,106	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	74,248	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	12,920	Line 113(b)			
	Other Demand Related Expenses	184,895	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	272,063	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	12,920	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	12,920	(Line 138 + 139)	4.0769%	527	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	184,895	(Line 134)	0.0542%	100	
				Line 123		
	Balance of Plant Fixed Expenses				271,436	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		16,599	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		116,824	(allocated on plant labor)	
	Total		133,423		
Depreciation					
	Annual Depreciation Exp ...DE	124,277			
	Gross Production Plant Cost ... F	7,829,474	Line 14		
	SLDP=DE/F	1.5873%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	63			
	SFDP=(R/((1+R)^n-1)		0.0594%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.015%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		11,386	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		11,386	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	3.0148%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	58,895				
		100.000%				
	Production Related Prepayments	58,895	(Line 209 * 210)			
	Unit Specific M&S	777,716				
	Total	836,611	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	3.0148%				
	Working Capital Costs	93,281	(Line 213 * 214)			

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(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)

Accumulated Deferred Income Taxes

Investment		7,829,474	Line 14					NPV of Col (j)>	1,454,902	
Asset Service Life		63	Line 167							
Composite Tax Rate		38.6790%	Line 177							

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity = (f) *	Interest	Income Taxes = (g) *	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	= (f) * (Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	124,277	3.750%	293,605	65,494	65,494	3,854	1,474	2,364	7,691	119,220
2	124,277	7.219%	565,210	170,548	236,043	13,891	5,311	8,518	27,720	119,220
3	124,277	6.677%	522,774	154,135	390,177	22,962	8,779	14,080	45,821	119,220
4	124,277	6.177%	483,627	138,993	529,170	31,142	11,906	19,096	62,144	119,220
5	124,277	5.713%	447,298	124,941	654,111	38,494	14,717	23,605	76,817	119,220
6	124,277	5.285%	413,788	111,980	766,091	45,084	17,237	27,646	89,968	119,220
7	124,277	4.888%	382,705	99,957	866,048	50,967	19,486	31,253	101,706	119,220
8	124,277	4.522%	354,049	88,873	954,921	56,197	21,486	34,461	112,143	119,220
9	124,277	4.462%	349,351	87,056	1,041,977	61,320	23,444	37,602	122,367	119,220
10	124,277	4.461%	349,273	87,026	1,129,003	66,442	25,403	40,743	132,587	119,220
11	124,277	4.462%	349,351	87,056	1,216,060	71,565	27,361	43,884	142,811	119,220
12	124,277	4.461%	349,273	87,026	1,303,086	76,687	29,319	47,025	153,031	119,220
13	124,277	4.462%	349,351	87,056	1,390,142	81,810	31,278	50,167	163,255	119,220
14	124,277	4.461%	349,273	87,026	1,477,168	86,931	33,236	53,307	173,475	119,220
15	124,277	4.462%	349,351	87,056	1,564,224	92,055	35,195	56,449	183,698	119,220
16	124,277	4.461%	349,273	87,026	1,651,250	97,176	37,153	59,589	193,919	119,220
17	124,277	4.462%	349,351	87,056	1,738,306	102,299	39,112	62,731	204,142	119,220
18	124,277	4.461%	349,273	87,026	1,825,332	107,421	41,070	65,872	214,362	119,220
19	124,277	4.462%	349,351	87,056	1,912,389	112,544	43,029	69,013	224,586	119,220
20	124,277	4.461%	349,273	87,026	1,999,415	117,666	44,987	72,154	234,806	119,220
21	124,277	2.231%	174,676	19,494	2,018,908	118,813	45,425	72,857	237,095	119,220
22	124,277	0.000%	0	-48,069	1,970,839	115,984	44,344	71,122	231,450	119,220
23	124,277	0.000%	0	-48,069	1,922,770	113,155	43,262	69,388	225,805	119,220
24	124,277	0.000%	0	-48,069	1,874,700	110,326	42,181	67,653	220,160	119,220
25	124,277	0.000%	0	-48,069	1,826,631	107,497	41,099	65,918	214,515	119,220
26	124,277	0.000%	0	-48,069	1,778,562	104,668	40,018	64,184	208,870	119,220
27	124,277	0.000%	0	-48,069	1,730,493	101,839	38,936	62,449	203,225	119,220
28	124,277	0.000%	0	-48,069	1,682,423	99,011	37,855	60,714	197,579	119,220
29	124,277	0.000%	0	-48,069	1,634,354	96,182	36,773	58,980	191,934	119,220
30	124,277	0.000%	0	-48,069	1,586,285	93,353	35,691	57,245	186,289	119,220
31	124,277	0.000%	0	-48,069	1,538,216	90,524	34,610	55,510	180,644	119,220
32	124,277	0.000%	0	-48,069	1,490,147	87,695	33,528	53,776	174,999	119,220
33	124,277	0.000%	0	-48,069	1,442,077	84,866	32,447	52,041	169,354	119,220
34	124,277	0.000%	0	-48,069	1,394,008	82,037	31,365	50,306	163,709	119,220
35	124,277	0.000%	0	-48,069	1,345,939	79,208	30,284	48,571	158,064	119,220
36	124,277	0.000%	0	-48,069	1,297,870	76,380	29,202	46,837	152,418	119,220
37	124,277	0.000%	0	-48,069	1,249,800	73,551	28,121	45,102	146,773	119,220
38	124,277	0.000%	0	-48,069	1,201,731	70,722	27,039	43,367	141,128	119,220
39	124,277	0.000%	0	-48,069	1,153,662	67,893	25,957	41,633	135,483	119,220
40	124,277	0.000%	0	-48,069	1,105,593	65,064	24,876	39,898	129,838	119,220
41	124,277	0.000%	0	-48,069	1,057,523	62,235	23,794	38,163	124,193	119,220
42	124,277	0.000%	0	-48,069	1,009,454	59,406	22,713	36,429	118,548	119,220
43	124,277	0.000%	0	-48,069	961,385	56,577	21,631	34,694	112,903	119,220
44	124,277	0.000%	0	-48,069	913,316	53,749	20,550	32,959	107,257	119,220
45	124,277	0.000%	0	-48,069	865,246	50,920	19,468	31,224	101,612	119,220
46	124,277	0.000%	0	-48,069	817,177	48,091	18,386	29,490	95,967	119,220
47	124,277	0.000%	0	-48,069	769,108	45,262	17,305	27,755	90,322	119,220
48	124,277	0.000%	0	-48,069	721,039	42,433	16,223	26,020	84,677	119,220
49	124,277	0.000%	0	-48,069	672,969	39,604	15,142	24,286	79,032	119,220
50	124,277	0.000%	0	-48,069	624,900	36,775	14,060	22,551	73,387	119,220
51	124,277	0.000%	0	-48,069	576,831	33,946	12,979	20,816	67,742	119,220
52	124,277	0.000%	0	-48,069	528,762	31,118	11,897	19,082	62,096	119,220
53	124,277	0.000%	0	-48,069	480,692	28,289	10,816	17,347	56,451	119,220
54	124,277	0.000%	0	-48,069	432,623	25,460	9,734	15,612	50,806	119,220
55	124,277	0.000%	0	-48,069	384,554	22,631	8,652	13,878	45,161	119,220
56	124,277	0.000%	0	-48,069	336,485	19,802	7,571	12,143	39,516	119,220
57	124,277	0.000%	0	-48,069	288,415	16,973	6,489	10,408	33,871	119,220
58	124,277	0.000%	0	-48,069	240,346	14,144	5,408	8,673	28,226	119,220
59	124,277	0.000%	0	-48,069	192,277	11,315	4,326	6,939	22,581	119,220
60	124,277	0.000%	0	-48,069	144,208	8,487	3,245	5,204	16,935	119,220
61	124,277	0.000%	0	-48,069	96,138	5,658	2,163	3,469	11,290	119,220
62	124,277	0.000%	0	-48,069	48,069	2,829	1,082	1,735	5,645	119,220
63	124,277	0.000%	0	-48,069	0	0	0	0	0	119,220

Unit Name: Gould Street 3 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 4,694,859	
2	Investment Generator & Exciter	Inputs Tab	$ 704,229	
3	Reactive Allocator	(Line 71)	18.64%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**131,265**	
5				
6	GSU Transformer Investment	Inputs Tab	3,114	
7	Reactive Allocator	(Line 71)	18.64%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**580**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	107,738	
11	Reactive Allocator	(Line 71)	18.64%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**20,082**	
13				
14	Total Cost of Power Plant	Inputs Tab	18,406,803	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	17,591,722	
16	Balance of Plant Allocator	(Line 79)	0.0154%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	2,701	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	154,629	
19	Reactive Fixed Charge Rate	(Line 14(h))	21.1032%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**32,632**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 32,632**	
23				
24				
25				
26				

(e)		(f)	(g)	(h)
Fixed Charge Rate for Reactive Plant				
		Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 140	2,816		
Other Expenses		221		
O&M	(sum line 1 & 2)	3,037	154,629	1.9641%
A&G		1,052,467	18,406,803	5.7178%
CWC	From Col. (h): ((lines 3 + 5) * .125 * (lines 11 + 12)			0.1079%
Working Capital	Line 216	27,640	18,406,803	0.1502%
General Plant		-	18,406,803	0.0000%
Other Taxes	Line 196(c)	653,648	18,406,803	3.5511%
Depreciation	Line 168(c)			0.0250%
				8.1350%
Taxes (Federal/State/Local)	Line 180			3.1068%
ADIT	-Line 233(k)	($304,590)	18,406,803	-1.6548%
		(Sum Lines 1 to 11 , Col. (h))		21.1032%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		102.70						
		-						
		-						
	Total	102.70	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.90						
		-						
	Total	0.90	(Line 38 / 58)					
	MVA Capability (MVA)							
		113.86	(Line 31 / 41)					
		-						
		-						
	Total	113.86	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		49.16	(SQRT (Line 51^2 - Line 31^2))					
		-						
		-						
	Total	49.16	(Sum Lines 62 to 64)					
	Reactive Allocator	18.6%	(Line 69^2 / Line 58^2)					
		BGE is TO Fleet						
	Max. MVAr	27.50						
	Nameplate MVAr	571.22						
	Exciter MW	3.08						
	Generator MW	965.46						
	Balance of Plant Allocator	0.0154%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Hydro & Steam**	**Allocated Amt**
	Storage Batteries	$ 353,658	**30%**	$ 106,097
	Control&Power Cabling	$ 10,940	**15%**	$ 1,641
	Switch Board Equipment	$ -	**30%**	$ -
	Switching Equipment	$ -	**20%**	$ -
	Transformers	$ -	**5%**	$ -
	Aux Generator	$ -	**0%**	$ -
	Fire Protection System	$ -	**0%**	$ -
	HVAC	$ -	**0%**	$ -
	Regulating Equipment	$ -	**75%**	$ -
	Structure	$ -	**0%**	$ -
	Misc	$ -	**0%**	$ -
	Exciter & PPT	$ -	**100%**	$ -
	Station Grounding	$ -	**0%**	$ -
	Bus & Insulators	$ -	**60%**	$ -
	Capacitor Bank	$ -	**0%**	$ -
	Total	$ 364,598		$ 107,738

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	578,737	578,737	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	149,492	149,492	
	Steam From Other Sources	288,876		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	88,504		
	Rents	538,628	538,628	
	Allowances	21,765	21,765	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	225,742	225,742	
	Maintenance of Boiler (or reactor) Plant	96,802		
	Maintenance of Electric Plant	100,709		
	Maintenance of Misc Steam (or Nuclear) Plant	125,347	125,347	
	Other Power Production, & Other Expenses	380,208	380,208	
	Total NonFuel Expenses	2,594,809	2,019,918	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	2.7959%	Line 4(c) / 1(c))			
	Operations Supvr & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0154%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	2,594,809	Line 116			
	Allowances	21,765	Line 109			
	Non-Fuel Production O&M	2,573,044	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	578,737	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	100,709	Line 113(b)			
	Other Demand Related Expenses	1,441,181	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	2,120,627	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	100,709	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	100,709	(Line 138 + 139)	2.7959%	2,816	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	1,441,181	(Line 134)	0.0154%	221	
				Line 123		
	Balance of Plant Fixed Expenses				2,117,590	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		767,400	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		285,067	(allocated on plant labor)	
	Total		1,052,467		
Depreciation					
	Annual Depreciation Exp ...DE	248,741			
	Gross Production Plant Cost ... F	18,406,803	Line 14		
	SLDP=DE/F	1.3514%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	74			
	SFDP=(R/((1+R)^n-1)		0.0250%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.107%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		653,648	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		653,648	(Line 192 + 195)	

	Plant		Depreciation	Total	
General Plant	-		-		
	0.000%		0.000%		Line 159
Fixed General Plant	-		-		(Lines 200 *201)
Return on General Plant	8.1350%	Line 188			
Taxes on General Plant	3.1068%	Line 189			
General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
Prepayments	138,459		
	100.000%		
Production Related Prepayments	138,459	(Line 209 * 210)	
Unit Specific M&S	107,407		
Total	245,866	(Line 211 + 212)	
Return on Working Capital	8.1350%		
Taxes on Working Capital	3.1068%		
Working Capital Costs	27,640	(Line 213 * 214)	

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Accumulated Deferred Income Taxes

Investment	18,406,803	Line 14	
Asset Service Life	74	Line 167	
Composite Tax Rate	38.6790%	Line 177	

NPV of Col (j)> 3,732,719

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	248,741	3.750%	690,255	170,773	170,773	10,050	3,842	6,163	20,055	304,590
2	248,741	7.219%	1,328,787	417,751	588,525	34,635	13,242	21,238	69,115	304,590
3	248,741	6.677%	1,229,022	379,163	967,688	56,948	21,773	34,921	113,643	304,590
4	248,741	6.177%	1,136,988	343,565	1,311,253	77,167	29,503	47,320	153,990	304,590
5	248,741	5.713%	1,051,581	310,531	1,621,784	95,442	36,490	58,526	190,458	304,590
6	248,741	5.285%	972,800	280,059	1,901,842	111,923	42,791	68,633	223,347	304,590
7	248,741	4.888%	899,725	251,794	2,153,636	126,742	48,457	77,719	252,917	304,590
8	248,741	4.522%	832,356	225,736	2,379,373	140,026	53,536	85,865	279,427	304,590
9	248,741	4.462%	821,312	221,465	2,600,838	153,059	58,519	93,857	305,436	304,590
10	248,741	4.461%	821,128	221,394	2,822,231	166,088	63,500	101,847	331,436	304,590
11	248,741	4.462%	821,312	221,465	3,043,696	179,122	68,483	109,839	357,444	304,590
12	248,741	4.461%	821,128	221,394	3,265,089	192,151	73,465	117,829	383,444	304,590
13	248,741	4.462%	821,312	221,465	3,486,554	205,184	78,447	125,821	409,452	304,590
14	248,741	4.461%	821,128	221,394	3,707,948	218,213	83,429	133,810	435,452	304,590
15	248,741	4.462%	821,312	221,465	3,929,412	231,246	88,412	141,802	461,460	304,590
16	248,741	4.461%	821,128	221,394	4,150,806	244,275	93,393	149,792	487,460	304,590
17	248,741	4.462%	821,312	221,465	4,372,271	257,308	98,376	157,784	513,468	304,590
18	248,741	4.461%	821,128	221,394	4,593,664	270,337	103,357	165,773	539,468	304,590
19	248,741	4.462%	821,312	221,465	4,815,129	283,370	108,340	173,766	565,476	304,590
20	248,741	4.461%	821,128	221,394	5,036,523	296,399	113,322	181,755	591,476	304,590
21	248,741	2.231%	410,656	62,627	5,099,150	300,085	114,731	184,015	598,831	304,590
22	248,741	0.000%	0	-96,210	5,002,939	294,423	112,566	180,543	587,532	304,590
23	248,741	0.000%	0	-96,210	4,906,729	288,761	110,401	177,071	576,234	304,590
24	248,741	0.000%	0	-96,210	4,810,519	283,099	108,237	173,599	564,935	304,590
25	248,741	0.000%	0	-96,210	4,714,308	277,437	106,072	170,127	553,636	304,590
26	248,741	0.000%	0	-96,210	4,618,098	271,775	103,907	166,655	542,337	304,590
27	248,741	0.000%	0	-96,210	4,521,887	266,113	101,742	163,183	531,039	304,590
28	248,741	0.000%	0	-96,210	4,425,677	260,451	99,578	159,711	519,740	304,590
29	248,741	0.000%	0	-96,210	4,329,467	254,789	97,413	156,239	508,441	304,590
30	248,741	0.000%	0	-96,210	4,233,256	249,127	95,248	152,767	497,143	304,590
31	248,741	0.000%	0	-96,210	4,137,046	243,465	93,084	149,295	485,844	304,590
32	248,741	0.000%	0	-96,210	4,040,836	237,803	90,919	145,823	474,545	304,590
33	248,741	0.000%	0	-96,210	3,944,625	232,141	88,754	142,351	463,247	304,590
34	248,741	0.000%	0	-96,210	3,848,415	226,479	86,589	138,879	451,948	304,590
35	248,741	0.000%	0	-96,210	3,752,204	220,817	84,425	135,407	440,649	304,590
36	248,741	0.000%	0	-96,210	3,655,994	215,155	82,260	131,935	429,350	304,590
37	248,741	0.000%	0	-96,210	3,559,784	209,493	80,095	128,463	418,052	304,590
38	248,741	0.000%	0	-96,210	3,463,573	203,831	77,930	124,991	406,753	304,590
39	248,741	0.000%	0	-96,210	3,367,363	198,169	75,766	121,519	395,454	304,590
40	248,741	0.000%	0	-96,210	3,271,153	192,507	73,601	118,047	384,156	304,590
41	248,741	0.000%	0	-96,210	3,174,942	186,845	71,436	114,575	372,857	304,590
42	248,741	0.000%	0	-96,210	3,078,732	181,183	69,271	111,103	361,558	304,590
43	248,741	0.000%	0	-96,210	2,982,522	175,521	67,107	107,631	350,260	304,590
44	248,741	0.000%	0	-96,210	2,886,311	169,859	64,942	104,159	338,961	304,590
45	248,741	0.000%	0	-96,210	2,790,101	164,197	62,777	100,688	327,662	304,590
46	248,741	0.000%	0	-96,210	2,693,890	158,535	60,613	97,216	316,364	304,590
47	248,741	0.000%	0	-96,210	2,597,680	152,873	58,448	93,744	305,065	304,590
48	248,741	0.000%	0	-96,210	2,501,470	147,211	56,283	90,272	293,766	304,590
49	248,741	0.000%	0	-96,210	2,405,259	141,550	54,118	86,800	282,467	304,590
50	248,741	0.000%	0	-96,210	2,309,049	135,888	51,954	83,328	271,169	304,590
51	248,741	0.000%	0	-96,210	2,212,839	130,226	49,789	79,856	259,870	304,590
52	248,741	0.000%	0	-96,210	2,116,628	124,564	47,624	76,384	248,571	304,590
53	248,741	0.000%	0	-96,210	2,020,418	118,902	45,459	72,912	237,273	304,590
54	248,741	0.000%	0	-96,210	1,924,207	113,240	43,295	69,440	225,974	304,590
55	248,741	0.000%	0	-96,210	1,827,997	107,578	41,130	65,968	214,675	304,590
56	248,741	0.000%	0	-96,210	1,731,787	101,916	38,965	62,496	203,377	304,590
57	248,741	0.000%	0	-96,210	1,635,576	96,254	36,800	59,024	192,078	304,590
58	248,741	0.000%	0	-96,210	1,539,366	90,592	34,636	55,552	180,779	304,590
59	248,741	0.000%	0	-96,210	1,443,156	84,930	32,471	52,080	169,480	304,590
60	248,741	0.000%	0	-96,210	1,346,945	79,268	30,306	48,608	158,182	304,590
61	248,741	0.000%	0	-96,210	1,250,735	73,606	28,142	45,136	146,883	304,590
62	248,741	0.000%	0	-96,210	1,154,524	67,944	25,977	41,664	135,584	304,590
63	248,741	0.000%	0	-96,210	1,058,314	62,282	23,812	38,192	124,286	304,590
64	248,741	0.000%	0	-96,210	962,104	56,620	21,647	34,720	112,987	304,590
65	248,741	0.000%	0	-96,210	865,893	50,958	19,483	31,248	101,688	304,590
66	248,741	0.000%	0	-96,210	769,683	45,296	17,318	27,776	90,390	304,590
67	248,741	0.000%	0	-96,210	673,473	39,634	15,153	24,304	79,091	304,590
68	248,741	0.000%	0	-96,210	577,262	33,972	12,988	20,832	67,792	304,590
69	248,741	0.000%	0	-96,210	481,052	28,310	10,824	17,360	56,493	304,590
70	248,741	0.000%	0	-96,210	384,841	22,648	8,659	13,888	45,195	304,590
71	248,741	0.000%	0	-96,210	288,631	16,986	6,494	10,416	33,896	304,590
72	248,741	0.000%	0	-96,210	192,421	11,324	4,329	6,944	22,597	304,590
73	248,741	0.000%	0	-96,210	96,210	5,662	2,165	3,472	11,299	304,590
74	248,741	0.000%	0	-96,210	0	0	0	0	0	304,590

Unit Name: Handsome Lake **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 42,347,182		Electric Expenses	Line 140	3,767		
2	Investment Generator & Exciter	Inputs Tab	$ 6,352,077		Other Expenses		-		
3	Reactive Allocator	(Line 71)	27.75%		O&M	(sum line 1 & 2)	3,767	1,762,701	0.2137%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**1,762,701**						
5					A&G		1,302,381	85,825,302	1.5175%
6	GSU Transformer Investment	Inputs Tab	-		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0235%
7	Reactive Allocator	(Line 71)	27.75%		Working Capital	Line 216	94,367	85,825,302	0.1100%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**		General Plant		-	85,825,302	0.0000%
9					Other Taxes	Line 196(c)	163,782	85,825,302	0.1908%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	-		Depreciation	Line 168(c)			0.3725%
11	Reactive Allocator	(Line 71)	27.75%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**0**		Taxes (Federal/State/Local)	Line 180			2.7413%
13					ADIT	-Line 233(k)	($915,275)	85,825,302	-1.0664%
14	Total Cost of Power Plant	Inputs Tab	85,825,302				(Sum Lines 1 to 11 , Col. (h))		12.2378%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	79,473,225						
16	Balance of Plant Allocator	(Line 79)	0.0000%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	0						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	1,762,701						
19	Reactive Fixed Charge Rate	(Line 14(h))	12.2378%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**215,717**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 215,717**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		59.00						
		59.00						
		59.00						
		59.00						
		59.00						
		-						
		-						
	Total	295.00	(Sum Lines 31 to 37)					
	Nominal Power Factor (pf)							
		0.85						
		0.85						
		0.85						
		0.85						
		0.85						
		-						
		-						
	Total	0.85	(Line 38 / 58)					
	MVA Capability (MVA)							
		69.41	(Line 31 / 41)					
		69.41	(Line 32 / 42)					
		69.41	(Line 33 / 43)					
		69.41	(Line 34 / 44)					
		69.41	(Line 35 / 45)					
	Total	347.06	(Sum Lines 51 to 57)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		36.56	(SQRT (Line 51^2 - Line 31^2))					
		36.56	(SQRT (Line 52^2 - Line 32^2))					
		36.56	(SQRT (Line 53^2 - Line 33^2))					
		36.56	(SQRT (Line 54^2 - Line 34^2))					
		36.56	(SQRT (Line 55^2 - Line 35^2))					
	Total	182.82	(Sum Lines 62 to 68)					
	Reactive Allocator	27.8%	(Line 69^2 / Line 58^2)					
		PENELEC is TO Fleet						
	Max. MVAr	-						
	Nameplate MVAr	182.82						
	Exciter MW	1.03						
	Generator MW	295.00						
	Balance of Plant Allocator	0.0000%	(Line 75 / Line 76) * (Line 77 / Line 78)					

	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Hydro & Steam**	**Allocated Amt**
	Storage Batteries	$ -	**30%**	$ -
	Control&Power Cabling	$ -	**15%**	$ -
	Switch Board Equipment	$ -	**30%**	$ -
	Switching Equipment	$ -	**20%**	$ -
	Transformers	$ -	**5%**	$ -
	Aux Generator	$ -	**0%**	$ -
	Fire Protection System	$ -	**0%**	$ -
	HVAC	$ -	**0%**	$ -
	Regulating Equipment	$ -	**75%**	$ -
	Structure	$ -	**0%**	$ -
	Misc	$ -	**0%**	$ -
	Exciter & PPT	$ -	**100%**	$ -
	Station Grounding	$ -	**0%**	$ -
	Bus & Insulators	$ -	**60%**	$ -
	Capacitor Bank	$ -	**0%**	$ -
	Total	$ -		$ -

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	520,067	520,067	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	134,337	134,337	
	Steam From Other Sources	259,591		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	79,532		
	Rents	484,024	484,024	
	Allowances	19,559	19,559	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	202,857	202,857	
	Maintenance of Boiler (or reactor) Plant	86,989		
	Maintenance of Electric Plant	90,500		
	Maintenance of Misc Steam (or Nuclear) Plant	112,639	112,639	
	Other Power Production, & Other Expenses	341,664	341,664	
	Total NonFuel Expenses	2,331,757	1,815,146	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	4.1625%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0000%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	2,331,757	Line 116			
	Allowances	19,559	Line 109			
	Non-Fuel Production O&M	2,312,198	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	520,067	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	90,500	Line 113(b)			
	Other Demand Related Expenses	1,295,079	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	1,905,646	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	90,500	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	90,500	(Line 138 + 139)	4.1625%	3,767	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	1,295,079	(Line 134)	0.0000%	-	
				Line 123		
	Balance of Plant Fixed Expenses				1,901,879	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		713,054	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		589,327	(allocated on plant labor)	
	Total		1,302,381		
Depreciation					
	Annual Depreciation Exp ...DE	2,145,633			
	Gross Production Plant Cost ... F	85,825,302	Line 14		
	SLDP=DE/F	2.5000%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	40			
	SFDP=(R/((1+R)^n-1)		0.3725%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.741%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		163,782	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		163,782	(Line 192 + 195)	

	Plant		Depreciation	Total	
General Plant	-		-		
	0.000%		0.000%		Line 159
Fixed General Plant	-		-		(Lines 200 * 201)
Return on General Plant	8.1350%	Line 188			
Taxes on General Plant	2.7413%	Line 189			
General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
Prepayments	645,593		
	100.000%		
Production Related Prepayments	645,593	(Line 209 * 210)	
Unit Specific M&S	222,045		
Total	867,638	(Line 211 + 212)	
Return on Working Capital	8.1350%		
Taxes on Working Capital	2.7413%		
Working Capital Costs	94,367	(Line 213 * 214)	

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Accumulated Deferred Income Taxes

Investment	85,825,302	Line 14
Asset Service Life	40	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 10,758,427

(a) Yr.	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity = (f) *	Interest = (f) * (Line185)	Income Taxes = (g) *	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)		(Line178)	(g) + (h) + (i)	col. (j)
1	2,145,633	3.750%	3,218,449	414,955	414,955	24,420	9,336	14,975	48,731	915,275
2	2,145,633	7.219%	6,195,729	1,566,537	1,981,491	116,611	44,584	71,507	232,701	915,275
3	2,145,633	6.677%	5,730,555	1,386,612	3,368,104	198,213	75,782	121,546	395,541	915,275
4	2,145,633	6.177%	5,301,429	1,220,630	4,588,734	270,047	103,247	165,596	538,889	915,275
5	2,145,633	5.713%	4,903,200	1,066,599	5,655,333	332,816	127,245	204,086	664,148	915,275
6	2,145,633	5.285%	4,535,867	924,519	6,579,852	387,224	148,047	237,450	772,721	915,275
7	2,145,633	4.888%	4,195,141	792,729	7,372,582	433,876	165,883	266,057	865,817	915,275
8	2,145,633	4.522%	3,881,020	671,231	8,043,812	473,378	180,986	290,280	944,644	915,275
9	2,145,633	4.462%	3,829,525	651,313	8,695,125	511,708	195,640	313,785	1,021,133	915,275
10	2,145,633	4.461%	3,828,667	650,981	9,346,106	550,018	210,287	337,277	1,097,582	915,275
11	2,145,633	4.462%	3,829,525	651,313	9,997,418	588,348	224,942	360,781	1,174,071	915,275
12	2,145,633	4.461%	3,828,667	650,981	10,648,399	626,658	239,589	384,273	1,250,520	915,275
13	2,145,633	4.462%	3,829,525	651,313	11,299,712	664,988	254,244	407,777	1,327,009	915,275
14	2,145,633	4.461%	3,828,667	650,981	11,950,693	703,298	268,891	431,270	1,403,458	915,275
15	2,145,633	4.462%	3,829,525	651,313	12,602,005	741,628	283,545	454,774	1,479,947	915,275
16	2,145,633	4.461%	3,828,667	650,981	13,252,986	779,938	298,192	478,266	1,556,396	915,275
17	2,145,633	4.462%	3,829,525	651,313	13,904,299	818,268	312,847	501,770	1,632,885	915,275
18	2,145,633	4.461%	3,828,667	650,981	14,555,280	856,578	327,494	525,262	1,709,334	915,275
19	2,145,633	4.462%	3,829,525	651,313	15,206,593	894,908	342,148	548,767	1,785,823	915,275
20	2,145,633	4.461%	3,828,667	650,981	15,857,573	933,218	356,795	572,259	1,862,272	915,275
21	2,145,633	2.231%	1,914,762	-89,298	15,768,275	927,963	354,786	569,036	1,851,785	915,275
22	2,145,633	0.000%	0	-829,909	14,938,366	879,123	336,113	539,087	1,754,323	915,275
23	2,145,633	0.000%	0	-829,909	14,108,457	830,283	317,440	509,138	1,656,861	915,275
24	2,145,633	0.000%	0	-829,909	13,278,547	781,443	298,767	479,188	1,559,398	915,275
25	2,145,633	0.000%	0	-829,909	12,448,638	732,602	280,094	449,239	1,461,936	915,275
26	2,145,633	0.000%	0	-829,909	11,618,729	683,762	261,421	419,290	1,364,473	915,275
27	2,145,633	0.000%	0	-829,909	10,788,820	634,922	242,748	389,341	1,267,011	915,275
28	2,145,633	0.000%	0	-829,909	9,958,911	586,082	224,075	359,391	1,169,549	915,275
29	2,145,633	0.000%	0	-829,909	9,129,001	537,242	205,403	329,442	1,072,086	915,275
30	2,145,633	0.000%	0	-829,909	8,299,092	488,402	186,730	299,493	974,624	915,275
31	2,145,633	0.000%	0	-829,909	7,469,183	439,561	168,057	269,543	877,161	915,275
32	2,145,633	0.000%	0	-829,909	6,639,274	390,721	149,384	239,594	779,699	915,275
33	2,145,633	0.000%	0	-829,909	5,809,365	341,881	130,711	209,645	682,237	915,275
34	2,145,633	0.000%	0	-829,909	4,979,455	293,041	112,038	179,696	584,774	915,275
35	2,145,633	0.000%	0	-829,909	4,149,546	244,201	93,365	149,746	487,312	915,275
36	2,145,633	0.000%	0	-829,909	3,319,637	195,361	74,692	119,797	389,850	915,275
37	2,145,633	0.000%	0	-829,909	2,489,728	146,520	56,019	89,848	292,387	915,275
38	2,145,633	0.000%	0	-829,909	1,659,818	97,680	37,346	59,899	194,925	915,275
39	2,145,633	0.000%	0	-829,909	829,909	48,840	18,673	29,949	97,462	915,275
40	2,145,633	0.000%	0	-829,909	0	0	0	0	0	915,275

Unit Name: LaSalle 1 & 2 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 322,991,066	
2	Investment Generator & Exciter	Inputs Tab	48,448,660	
3	Reactive Allocator	(Line 71)	16.38%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**7,938,051**	
5				
6	GSU Transformer Investment	Inputs Tab	4,672,421	
7	Reactive Allocator	(Line 71)	16.38%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**765,551**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	5,186,913	
11	Reactive Allocator	(Line 71)	16.38%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**849,848**	
13				
14	Total Cost of Power Plant	Inputs Tab	1,412,906,574	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	1,354,598,580	
16	Balance of Plant Allocator	(Line 79)	0.1358%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	1,840,172	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	11,393,621	
19	Reactive Fixed Charge Rate	(Line 14(h))	30.9481%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**3,526,110**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 3,526,110**	
23				
24				
25				
26				

	(e)		(f)	(g)	(h)
	Fixed Charge Rate for Reactive Plant				
			Calculated Amt	Plant	FCR % (f) / (g)
	Electric Expenses	Line 140	356,089		
	Other Expenses		146,963		
	O&M	(sum line 1 & 2)	503,052	11,393,621	4.4152%
	A&G		157,591,099	1,412,906,574	11.1537%
	CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.2164%
	Working Capital	Line 216	49,177,288	1,412,906,574	3.4806%
	General Plant		-	1,412,906,574	0.0000%
	Other Taxes	Line 196(c)	27,773,747	1,412,906,574	1.9657%
	Depreciation	Line 168(c)			0.0752%
					8.1350%
	Taxes (Federal/State/Local)	Line 180			2.9859%
	ADIT	-Line 233(k)	($20,905,199)	1,412,906,574	-1.4796%
			(Sum Lines 1 to 11 , Col. (h))		30.9481%

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	(a)	(b)	(c)
Allocators			
	Real Power Capability (MW)		
		1,194.00	
		1,183.00	
		-	
	Total	2,377.00	(Sum Lines 31 to 33)
	Nominal Power Factor (pf)		
		0.93	
		0.90	
		-	
	Total	0.91	(Line 38 / 58)
	MVA Capability (MVA)		
		1,286.87	(Line 31 / 41)
		1,314.44	(Line 32 / 42)
		-	
	Total	2,601.32	(Sum Lines 51 to 53)
	Reactive Power Capability (MVAR)		
	(MVA^2 - MW^2)^0.5		
		480.00	(SQRT (Line 51^2 - Line 31^2))
		572.95	(SQRT (Line 52^2 - Line 32^2))
		-	
	Total	1,052.95	(Sum Lines 62 to 64)
	Reactive Allocator	16.4%	(Line 69^2 / Line 58^2)
		ComEd is TO Fleet	
	Max. MVAr	2,187	
	Nameplate MVAr	4,856	
	Exciter MW	35	
	Generator MW	11,447	
	Balance of Plant Allocator	0.1358%	(Line 75 / Line 76) * (Line 77 / Line 78)

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ 1,944,786	15%	$ 291,718
	Control&Power Cabling	$ 23,115,092	1%	$ 231,151
	Switch Board Equipment	$ 6,488,908	1%	$ 64,889
	Switching Equipment	$ 6,572,575	1%	$ 65,726
	Transformers	$ 2,026,797	3%	$ 60,804
	Aux Generator	$ 10,275,282	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	50%	$ -
	Structure	$ 445,431	0%	$ -
	Misc	$ 85,054,019	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	1%	$ -
	Bus & Insulators	$ 5,590,781	80%	$ 4,472,625
	Capacitor Bank	$ -	0%	$ -
	Total	$ 141,513,673		$ 5,186,913

O&M	**Total Non-Fuel**	**Fixed O&M**	
Production Expenses: Oper, Supv, & Engr	30,478,210	30,478,210	
Coolants and Water (Nuclear Plants Only)	2,986,351		
Steam Expenses	18,731,778	18,731,778	
Steam From Other Sources	0		
Electric Expenses	0	-	
Misc Steam (or Nuclear) Power Expenses	1,913,700		
Rents	52,912,201	52,912,201	
Allowances	4,198,705	4,198,705	
Maintenance Supervision and Engineering	0		
Maintenance of Structures	5,622,700	5,622,700	
Maintenance of Boiler (or reactor) Plant	438,245		
Maintenance of Electric Plant	14,488,892		
Maintenance of Misc Steam (or Nuclear) Plant	9,306,811	9,306,811	
Other Power Production, & Other Expenses	17,411,239	17,411,239	
Total NonFuel Expenses	158,488,835	138,661,645	(Sum Lines 102 to 115)
Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation

Plant Var Allocators		
Electric Expense Allocator	2.4577%	Line 4(c) / 1(c))
Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)
Other Demand Expense Allocator	0.1358%	Line 79
Production Plant Expenses		
Total NonFuel Expenses	158,488,835	Line 116
Allowances	4,198,705	Line 109
Non-Fuel Production O&M	154,290,130	(Line 126 - 127)
Operating Expenses		
Operations Supervision & Engineering	30,478,210	Line 102(c)
Electric Expenses	0	Line 106(c)
Maintenance of Electric Plant	14,488,892	Line 113(b)
Other Demand Related Expenses	108,183,436	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)
Total	153,150,538	(Sum Lines 131 to 134)

			Allocator	Allocated Amount	
Maintenance of Electric Plant	14,488,892	Line 113(b)			
Electric Expenses	0	Line 106(c)			
Total Electric Expenses	14,488,892	(Line 138 + 139)	2.4577%	356,089	(Line 140(b) * (d))
			Line 121		
Other Demand Related Expenses	108,183,436	(Line 134)	0.1358%	146,963	
			Line 123		
Balance of Plant Fixed Expenses				152,647,486	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		118,779,529	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		38,811,570	(allocated on plant labor)	
	Total		157,591,099		
Depreciation					
	Annual Depreciation Exp ...DE	23,548,443			
	Gross Production Plant Cost ... F	1,412,906,574	Line 14		
	SLDP=DE/F	1.6667%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	60			
	SFDP=(R/((1+R)^n-1)		0.0752%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.986%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		21,480,427		
	Payroll Taxes	7,193,199			
		0 87.4899%	Line 117		
	Fixed Payroll Taxes		6,293,320	(Line 193 * 194)	
	Total Other Taxes		27,773,747	(Line 192 + 195)	
		Plant		**Depreciation**	**Total**
General Plant		-		-	
		0 0.000%		0.000%	Line 159
	Fixed General Plant	-		-	(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188		
	Taxes on General Plant	2.9859%	Line 189		
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-
Working Capital					
	Prepayments	2,368,865			
		100.000%			
	Production Related Prepayments	2,368,865	(Line 209 * 210)		
	Unit Specific M&S	439,838,836			
	Total	442,207,701	(Line 211 + 212)		
	Return on Working Capital	8.1350%			
	Taxes on Working Capital	2.9859%			
	Working Capital Costs	49,177,288	(Line 213 * 214)		

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Accumulated Deferred Income Taxes

Investment	1,412,906,574	Line 14
Asset Service Life	60	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 254,623,862

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	23,548,443	3.750%	52,983,997	11,385,378	11,385,378	670,029	256,171	410,869	1,337,069	20,905,199
2	23,548,443	7.219%	101,997,726	30,343,398	41,728,776	2,455,738	938,897	1,505,883	4,900,519	20,905,199
3	23,548,443	6.677%	94,339,772	27,381,378	69,110,154	4,067,133	1,554,978	2,494,006	8,116,117	20,905,199
4	23,548,443	6.177%	87,275,239	24,648,887	93,759,041	5,517,720	2,109,578	3,383,521	11,010,819	20,905,199
5	23,548,443	5.713%	80,719,353	22,113,136	115,872,178	6,819,078	2,607,124	4,181,527	13,607,728	20,905,199
6	23,548,443	5.285%	74,672,112	19,774,124	135,646,302	7,982,785	3,052,042	4,895,124	15,929,950	20,905,199
7	23,548,443	4.888%	69,062,873	17,604,527	153,250,828	9,018,811	3,448,144	5,530,425	17,997,380	20,905,199
8	23,548,443	4.522%	63,891,635	15,604,343	168,855,172	9,937,127	3,799,241	6,093,546	19,829,914	20,905,199
9	23,548,443	4.462%	63,043,891	15,276,444	184,131,616	10,836,146	4,142,961	6,644,833	21,623,940	20,905,199
10	23,548,443	4.461%	63,029,762	15,270,980	199,402,596	11,734,843	4,486,558	7,195,923	23,417,324	20,905,199
11	23,548,443	4.462%	63,043,891	15,276,444	214,679,040	12,633,862	4,830,278	7,747,210	25,211,350	20,905,199
12	23,548,443	4.461%	63,029,762	15,270,980	229,950,020	13,532,559	5,173,875	8,298,300	27,004,734	20,905,199
13	23,548,443	4.462%	63,043,891	15,276,444	245,226,464	14,431,577	5,517,595	8,849,588	28,798,760	20,905,199
14	23,548,443	4.461%	63,029,762	15,270,980	260,497,444	15,330,275	5,861,192	9,400,678	30,592,145	20,905,199
15	23,548,443	4.462%	63,043,891	15,276,444	275,773,888	16,229,293	6,204,912	9,951,965	32,386,171	20,905,199
16	23,548,443	4.461%	63,029,762	15,270,980	291,044,868	17,127,990	6,548,510	10,503,055	34,179,555	20,905,199
17	23,548,443	4.462%	63,043,891	15,276,444	306,321,312	18,027,009	6,892,230	11,054,342	35,973,581	20,905,199
18	23,548,443	4.461%	63,029,762	15,270,980	321,592,292	18,925,706	7,235,827	11,605,432	37,766,965	20,905,199
19	23,548,443	4.462%	63,043,891	15,276,444	336,868,736	19,824,725	7,579,547	12,156,720	39,560,991	20,905,199
20	23,548,443	4.461%	63,029,762	15,270,980	352,139,716	20,723,422	7,923,144	12,707,810	41,354,376	20,905,199
21	23,548,443	2.231%	31,521,946	3,084,071	355,223,787	20,904,920	7,992,535	12,819,106	41,716,561	20,905,199
22	23,548,443	0.000%	0	-9,108,302	346,115,485	20,368,896	7,787,598	12,490,411	40,646,906	20,905,199
23	23,548,443	0.000%	0	-9,108,302	337,007,182	19,832,873	7,582,662	12,161,716	39,577,250	20,905,199
24	23,548,443	0.000%	0	-9,108,302	327,898,880	19,296,849	7,377,725	11,833,021	38,507,595	20,905,199
25	23,548,443	0.000%	0	-9,108,302	318,790,578	18,760,826	7,172,788	11,504,326	37,437,939	20,905,199
26	23,548,443	0.000%	0	-9,108,302	309,682,276	18,224,802	6,967,851	11,175,631	36,368,284	20,905,199
27	23,548,443	0.000%	0	-9,108,302	300,573,974	17,688,778	6,762,914	10,846,936	35,298,629	20,905,199
28	23,548,443	0.000%	0	-9,108,302	291,465,671	17,152,755	6,557,978	10,518,241	34,228,973	20,905,199
29	23,548,443	0.000%	0	-9,108,302	282,357,369	16,616,731	6,353,041	10,189,546	33,159,318	20,905,199
30	23,548,443	0.000%	0	-9,108,302	273,249,067	16,080,708	6,148,104	9,860,851	32,089,662	20,905,199
31	23,548,443	0.000%	0	-9,108,302	264,140,765	15,544,684	5,943,167	9,532,156	31,020,007	20,905,199
32	23,548,443	0.000%	0	-9,108,302	255,032,462	15,008,660	5,738,230	9,203,461	29,950,351	20,905,199
33	23,548,443	0.000%	0	-9,108,302	245,924,160	14,472,637	5,533,294	8,874,766	28,880,696	20,905,199
34	23,548,443	0.000%	0	-9,108,302	236,815,858	13,936,613	5,328,357	8,546,071	27,811,041	20,905,199
35	23,548,443	0.000%	0	-9,108,302	227,707,556	13,400,590	5,123,420	8,217,376	26,741,385	20,905,199
36	23,548,443	0.000%	0	-9,108,302	218,599,253	12,864,566	4,918,483	7,888,681	25,671,730	20,905,199
37	23,548,443	0.000%	0	-9,108,302	209,490,951	12,328,542	4,713,546	7,559,986	24,602,074	20,905,199
38	23,548,443	0.000%	0	-9,108,302	200,382,649	11,792,519	4,508,610	7,231,291	23,532,419	20,905,199
39	23,548,443	0.000%	0	-9,108,302	191,274,347	11,256,495	4,303,673	6,902,595	22,462,764	20,905,199
40	23,548,443	0.000%	0	-9,108,302	182,166,045	10,720,472	4,098,736	6,573,900	21,393,108	20,905,199
41	23,548,443	0.000%	0	-9,108,302	173,057,742	10,184,448	3,893,799	6,245,205	20,323,453	20,905,199
42	23,548,443	0.000%	0	-9,108,302	163,949,440	9,648,425	3,688,862	5,916,510	19,253,797	20,905,199
43	23,548,443	0.000%	0	-9,108,302	154,841,138	9,112,401	3,483,926	5,587,815	18,184,142	20,905,199
44	23,548,443	0.000%	0	-9,108,302	145,732,836	8,576,377	3,278,989	5,259,120	17,114,487	20,905,199
45	23,548,443	0.000%	0	-9,108,302	136,624,533	8,040,354	3,074,052	4,930,425	16,044,831	20,905,199
46	23,548,443	0.000%	0	-9,108,302	127,516,231	7,504,330	2,869,115	4,601,730	14,975,176	20,905,199
47	23,548,443	0.000%	0	-9,108,302	118,407,929	6,968,307	2,664,178	4,273,035	13,905,520	20,905,199
48	23,548,443	0.000%	0	-9,108,302	109,299,627	6,432,283	2,459,242	3,944,340	12,835,865	20,905,199
49	23,548,443	0.000%	0	-9,108,302	100,191,325	5,896,259	2,254,305	3,615,645	11,766,210	20,905,199
50	23,548,443	0.000%	0	-9,108,302	91,083,022	5,360,236	2,049,368	3,286,950	10,696,554	20,905,199
51	23,548,443	0.000%	0	-9,108,302	81,974,720	4,824,212	1,844,431	2,958,255	9,626,899	20,905,199
52	23,548,443	0.000%	0	-9,108,302	72,866,418	4,288,189	1,639,494	2,629,560	8,557,243	20,905,199
53	23,548,443	0.000%	0	-9,108,302	63,758,116	3,752,165	1,434,558	2,300,865	7,487,588	20,905,199
54	23,548,443	0.000%	0	-9,108,302	54,649,813	3,216,142	1,229,621	1,972,170	6,417,932	20,905,199
55	23,548,443	0.000%	0	-9,108,302	45,541,511	2,680,118	1,024,684	1,643,475	5,348,277	20,905,199
56	23,548,443	0.000%	0	-9,108,302	36,433,209	2,144,094	819,747	1,314,780	4,278,622	20,905,199
57	23,548,443	0.000%	0	-9,108,302	27,324,907	1,608,071	614,810	986,085	3,208,966	20,905,199
58	23,548,443	0.000%	0	-9,108,302	18,216,604	1,072,047	409,874	657,390	2,139,311	20,905,199
59	23,548,443	0.000%	0	-9,108,302	9,108,302	536,024	204,937	328,695	1,069,655	20,905,199
60	23,548,443	0.000%	0	-9,108,302	0	0	0	0	0	20,905,199

Unit Name: Limerick 1 & 2 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 195,863,167		Electric Expenses	Line 140	240,476		
2	Investment Generator & Exciter	Inputs Tab	29,379,475		Other Expenses		53,964		
3	Reactive Allocator	(Line 71)	12.02%		O&M	(sum line 1 & 2)	294,440	9,164,142	3.2130%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**3,530,844**						
5					A&G		156,553,695	1,222,406,959	12.8070%
6	GSU Transformer Investment	Inputs Tab	41,192,118		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.2224%
7	Reactive Allocator	(Line 71)	12.02%		Working Capital	Line 216	35,602,957	1,222,406,959	2.9125%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**4,950,494**		General Plant		-	1,222,406,959	0.0000%
9					Other Taxes	Line 196(c)	10,408,455	1,222,406,959	0.8515%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	491,006		Depreciation	Line 168(c)			0.0814%
11	Reactive Allocator	(Line 71)	12.02%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**59,009**		Taxes (Federal/State/Local)	Line 180			2.9692%
13					ADIT	-Line 233(k)	($17,900,968)	1,222,406,959	-1.4644%
14	Total Cost of Power Plant	Inputs Tab	1,222,406,959				(Sum Lines 1 to 11 , Col. (h))		29.7275%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	1,151,344,360						
16	Balance of Plant Allocator	(Line 79)	0.0542%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	623,795						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	9,164,142						
19	Reactive Fixed Charge Rate	(Line 14(h))	29.7275%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**2,724,271**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 2,724,271**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		1,182.00						
		1,143.00						
		-						
	Total	2,325.00	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.93						
		0.94						
		-						
	Total	0.94	(Line 38 / 58)					
	MVA Capability (MVA)							
		1,265.52	(Line 31 / 41)					
		1,213.38	(Line 32 / 42)					
		-						
	Total	2,478.90	(Sum Lines 51 to 52)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		452.14	(SQRT (Line 51^2 - Line 31^2))					
		407.22	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	859.36	(Sum Lines 62 to 64)					
	Reactive Allocator	12.0%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ 1,414,202	15%	$ 212,130
	Control&Power Cabling	$ 23,319,901	1%	$ 233,199
	Switch Board Equipment	$ 1,188,580	1%	$ 11,886
	Switching Equipment	$ 228,627	1%	$ 2,286
	Transformers	$ 1,050,152	3%	$ 31,505
	Aux Generator	$ 5,506,158	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	50%	$ -
	Structure	$ 301,814	0%	$ -
	Misc	$ 76,645,785	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	1%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 109,655,219		$ 491,006

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	28,060,813	28,060,813	
	Coolants and Water (Nuclear Plants Only)	2,749,487		
	Steam Expenses	17,246,057	17,246,057	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	1,761,914		
	Rents	48,715,440	48,715,440	
	Allowances	3,865,683	3,865,683	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	5,176,733	5,176,733	
	Maintenance of Boiler (or reactor) Plant	403,486		
	Maintenance of Electric Plant	13,339,698		
	Maintenance of Misc Steam (or Nuclear) Plant	8,568,637	8,568,637	
	Other Power Production, & Other Expenses	16,030,257	16,030,257	
	Total NonFuel Expenses	145,918,204	127,663,619	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	1.8027%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	145,918,204	Line 116			
	Allowances	3,865,683	Line 109			
	Non-Fuel Production O&M	142,052,522	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	28,060,813	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	13,339,698	Line 113(b)			
	Other Demand Related Expenses	99,602,806	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131			
	Total	141,003,317	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	13,339,698	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	13,339,698	(Line 138 + 139)	1.8027%	240,476	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	99,602,806	(Line 134)	0.0542%	53,964	
				Line 123		
	Balance of Plant Fixed Expenses				140,708,877	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		116,605,447	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		39,948,249	(allocated on plant labor)	
	Total		156,553,695		

Depreciation				
	Annual Depreciation Exp ...DE	20,895,845		
	Gross Production Plant Cost ... F	1,222,406,959	Line 14	
	SLDP=DE/F	1.7094%	(Line 164 / 165)	
	Depreciable years (n)=1/SLDP	59		
	SFDP=(R/((1+R)^n-1)		0.0814%	
Income Taxes				
	Income Tax Calculation; (Co's Sch. 2)			
	a) State Income Tax Rate ("SIT")	5.6600%		
	b) City/Local Income Tax Rate ("LIT")	0.0000%		
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%		
	d) Net of Fdrl tax SIT	3.6790%		
	e) Federal Income Tax Rate ("FIT")	35.0000%		
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%		
	g) Gross-Up Tax Factor ("GTF")	61.3210%		
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.969%	

				Weighted Cost	
Rate of Return					
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)

Other Taxes					
	Property Taxes		3,969,570		
	Payroll Taxes	7,359,580			
	0	87.4899%	Line 117		
	Fixed Payroll Taxes		6,438,885	(Line 193 * 194)	
	Total Other Taxes		10,408,455	(Line 192 + 195)	

		Plant		**Depreciation**	**Total**	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9692%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
	Prepayments	2,049,475	
		100.000%	
	Production Related Prepayments	2,049,475	(Line 209 * 210)
	Unit Specific M&S	318,577,209	
	Total	320,626,684	(Line 211 + 212)
	Return on Working Capital	8.1350%	
	Taxes on Working Capital	2.9692%	
	Working Capital Costs	35,602,957	(Line 213 * 214)

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Accumulated Deferred Income Taxes

Investment	1,222,406,959	Line 14
Asset Service Life	59	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 217,868,519

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	PMT of NPV col. (j)
1	20,718,762	3.750%	45,840,261	9,716,745	9,716,745	571,830	218,627	350,652	1,141,109	17,900,968
2	20,718,762	7.219%	88,245,558	26,118,690	35,835,434	2,108,915	806,297	1,293,208	4,208,421	17,900,968
3	20,718,762	6.677%	81,620,113	23,556,033	59,391,468	3,495,188	1,336,308	2,143,284	6,974,780	17,900,968
4	20,718,762	6.177%	75,508,078	21,191,959	80,583,427	4,742,335	1,813,127	2,908,047	9,463,509	17,900,968
5	20,718,762	5.713%	69,836,110	18,998,099	99,581,526	5,860,373	2,240,584	3,593,639	11,694,596	17,900,968
6	20,718,762	5.285%	64,604,208	16,974,452	116,555,977	6,859,319	2,622,509	4,206,203	13,688,032	17,900,968
7	20,718,762	4.888%	59,751,252	15,097,377	131,653,354	7,747,800	2,962,200	4,751,028	15,461,029	17,900,968
8	20,718,762	4.522%	55,277,243	13,366,875	145,020,229	8,534,440	3,262,955	5,233,404	17,030,800	17,900,968
9	20,718,762	4.462%	54,543,799	13,083,186	158,103,415	9,304,386	3,557,327	5,705,543	18,567,255	17,900,968
10	20,718,762	4.461%	54,531,574	13,078,458	171,181,873	10,074,053	3,851,592	6,177,510	20,103,156	17,900,968
11	20,718,762	4.462%	54,543,799	13,083,186	184,265,059	10,843,999	4,145,964	6,649,648	21,639,611	17,900,968
12	20,718,762	4.461%	54,531,574	13,078,458	197,343,516	11,613,666	4,440,229	7,121,616	23,175,511	17,900,968
13	20,718,762	4.462%	54,543,799	13,083,186	210,426,702	12,383,611	4,734,601	7,593,754	24,711,967	17,900,968
14	20,718,762	4.461%	54,531,574	13,078,458	223,505,160	13,153,279	5,028,866	8,065,722	26,247,867	17,900,968
15	20,718,762	4.462%	54,543,799	13,083,186	236,588,346	13,923,224	5,323,238	8,537,860	27,784,322	17,900,968
16	20,718,762	4.461%	54,531,574	13,078,458	249,666,803	14,692,891	5,617,503	9,009,828	29,320,222	17,900,968
17	20,718,762	4.462%	54,543,799	13,083,186	262,749,989	15,462,837	5,911,875	9,481,966	30,856,678	17,900,968
18	20,718,762	4.461%	54,531,574	13,078,458	275,828,447	16,232,504	6,206,140	9,953,934	32,392,578	17,900,968
19	20,718,762	4.462%	54,543,799	13,083,186	288,911,633	17,002,450	6,500,512	10,426,072	33,929,033	17,900,968
20	20,718,762	4.461%	54,531,574	13,078,458	301,990,091	17,772,117	6,794,777	10,898,040	35,464,934	17,900,968
21	20,718,762	2.231%	27,271,899	2,534,688	304,524,779	17,921,283	6,851,808	10,989,510	35,762,601	17,900,968
22	20,718,762	0.000%	0	-8,013,810	296,510,969	17,449,671	6,671,497	10,700,312	34,821,480	17,900,968
23	20,718,762	0.000%	0	-8,013,810	288,497,159	16,978,058	6,491,186	10,411,115	33,880,359	17,900,968
24	20,718,762	0.000%	0	-8,013,810	280,483,349	16,506,445	6,310,875	10,121,917	32,939,238	17,900,968
25	20,718,762	0.000%	0	-8,013,810	272,469,539	16,034,832	6,130,565	9,832,720	31,998,117	17,900,968
26	20,718,762	0.000%	0	-8,013,810	264,455,729	15,563,220	5,950,254	9,543,522	31,056,995	17,900,968
27	20,718,762	0.000%	0	-8,013,810	256,441,919	15,091,607	5,769,943	9,254,324	30,115,874	17,900,968
28	20,718,762	0.000%	0	-8,013,810	248,428,109	14,619,994	5,589,632	8,965,127	29,174,753	17,900,968
29	20,718,762	0.000%	0	-8,013,810	240,414,299	14,148,381	5,409,322	8,675,929	28,233,632	17,900,968
30	20,718,762	0.000%	0	-8,013,810	232,400,489	13,676,769	5,229,011	8,386,731	27,292,511	17,900,968
31	20,718,762	0.000%	0	-8,013,810	224,386,679	13,205,156	5,048,700	8,097,534	26,351,390	17,900,968
32	20,718,762	0.000%	0	-8,013,810	216,372,869	12,733,543	4,868,390	7,808,336	25,410,269	17,900,968
33	20,718,762	0.000%	0	-8,013,810	208,359,059	12,261,931	4,688,079	7,519,138	24,469,148	17,900,968
34	20,718,762	0.000%	0	-8,013,810	200,345,249	11,790,318	4,507,768	7,229,941	23,528,027	17,900,968
35	20,718,762	0.000%	0	-8,013,810	192,331,439	11,318,705	4,327,457	6,940,743	22,586,906	17,900,968
36	20,718,762	0.000%	0	-8,013,810	184,317,629	10,847,092	4,147,147	6,651,546	21,645,785	17,900,968
37	20,718,762	0.000%	0	-8,013,810	176,303,819	10,375,480	3,966,836	6,362,348	20,704,664	17,900,968
38	20,718,762	0.000%	0	-8,013,810	168,290,009	9,903,867	3,786,525	6,073,150	19,763,543	17,900,968
39	20,718,762	0.000%	0	-8,013,810	160,276,199	9,432,254	3,606,214	5,783,953	18,822,421	17,900,968
40	20,718,762	0.000%	0	-8,013,810	152,262,389	8,960,642	3,425,904	5,494,755	17,881,300	17,900,968
41	20,718,762	0.000%	0	-8,013,810	144,248,579	8,489,029	3,245,593	5,205,557	16,940,179	17,900,968
42	20,718,762	0.000%	0	-8,013,810	136,234,769	8,017,416	3,065,282	4,916,360	15,999,058	17,900,968
43	20,718,762	0.000%	0	-8,013,810	128,220,959	7,545,803	2,884,972	4,627,162	15,057,937	17,900,968
44	20,718,762	0.000%	0	-8,013,810	120,207,149	7,074,191	2,704,661	4,337,965	14,116,816	17,900,968
45	20,718,762	0.000%	0	-8,013,810	112,193,339	6,602,578	2,524,350	4,048,767	13,175,695	17,900,968
46	20,718,762	0.000%	0	-8,013,810	104,179,530	6,130,965	2,344,039	3,759,569	12,234,574	17,900,968
47	20,718,762	0.000%	0	-8,013,810	96,165,720	5,659,353	2,163,729	3,470,372	11,293,453	17,900,968
48	20,718,762	0.000%	0	-8,013,810	88,151,910	5,187,740	1,983,418	3,181,174	10,352,332	17,900,968
49	20,718,762	0.000%	0	-8,013,810	80,138,100	4,716,127	1,803,107	2,891,976	9,411,211	17,900,968
50	20,718,762	0.000%	0	-8,013,810	72,124,290	4,244,514	1,622,797	2,602,779	8,470,090	17,900,968
51	20,718,762	0.000%	0	-8,013,810	64,110,480	3,772,902	1,442,486	2,313,581	7,528,969	17,900,968
52	20,718,762	0.000%	0	-8,013,810	56,096,670	3,301,289	1,262,175	2,024,383	6,587,848	17,900,968
53	20,718,762	0.000%	0	-8,013,810	48,082,860	2,829,676	1,081,864	1,735,186	5,646,726	17,900,968
54	20,718,762	0.000%	0	-8,013,810	40,069,050	2,358,064	901,554	1,445,988	4,705,605	17,900,968
55	20,718,762	0.000%	0	-8,013,810	32,055,240	1,886,451	721,243	1,156,791	3,764,484	17,900,968
56	20,718,762	0.000%	0	-8,013,810	24,041,430	1,414,838	540,932	867,593	2,823,363	17,900,968
57	20,718,762	0.000%	0	-8,013,810	16,027,620	943,225	360,621	578,395	1,882,242	17,900,968
58	20,718,762	0.000%	0	-8,013,810	8,013,810	471,613	180,311	289,198	941,121	17,900,968
59	20,718,762	0.000%	0	-8,013,810	0	0	0	0	0	17,900,968

Unit Name: Moser 1-3 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 5,376,210	
2	Investment Generator & Exciter	Inputs Tab	$ 806,431	
3	Reactive Allocator	(Line 71)	32.04%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**258,383**	
5				
6	GSU Transformer Investment	Inputs Tab	-	
7	Reactive Allocator	(Line 71)	32.04%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	371,713	
11	Reactive Allocator	(Line 71)	32.04%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**119,098**	
13				
14	Total Cost of Power Plant	Inputs Tab	8,301,032	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	7,122,888	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	3,859	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	381,340	
19	Reactive Fixed Charge Rate	(Line 14(h))	12.8635%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**49,054**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 49,054**	
23				
24				
25				
26				

	(e)		(f)	(g)	(h)
	Fixed Charge Rate for Reactive Plant				
			Calculated Amt	Plant	FCR % (f) / (g)
	Electric Expenses	Line 140	621		
	Other Expenses		100		
	O&M	(sum line 1 & 2)	721	381,340	0.1891%
	A&G		133,423	8,301,032	1.6073%
	CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0250%
	Working Capital	Line 216	101,135	8,301,032	1.2183%
	General Plant		-	8,301,032	0.0000%
	Other Taxes	Line 196(c)	11,386	8,301,032	0.1372%
	Depreciation	Line 168(c)			0.0594%
					8.1350%
	Taxes (Federal/State/Local)	Line 180			3.0148%
	ADIT	-Line 233(k)	($126,401)	8,301,032	-1.5227%
			(Sum Lines 1 to 11 , Col. (h))		12.8635%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		16.00						
		16.38						
		16.50						
	Total	48.88	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.82						
		0.82						
		0.83						
	Total	0.82	(Line 38 / 58)					
	MVA Capability (MVA)							
		19.46	(Line 31 / 41)					
		19.95	(Line 32 / 42)					
		19.88	(Line 33 / 43)					
	Total	59.30	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		11.08	(SQRT (Line 51^2 - Line 31^2))					
		11.39	(SQRT (Line 52^2 - Line 32^2))					
		11.09	(SQRT (Line 53^2 - Line 33^2))					
	Total	33.56	(Sum Lines 62 to 64)					
	Reactive Allocator	32.0%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ 9,365	50%	$ 4,683
	Control&Power Cabling	$ 262,801	50%	$ 131,401
	Switch Board Equipment	$ -	50%	$ -
	Switching Equipment	$ 589,074	40%	$ 235,629
	Transformers	$ -	10%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ 13,093	0%	$ -
	Misc	$ 490,974	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 1,365,306		$ 371,713

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	74,248	74,248	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	19,179	19,179	
	Steam From Other Sources	37,061		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	11,355		
	Rents	69,103	69,103	
	Allowances	2,792	2,792	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	28,961	28,961	
	Maintenance of Boiler (or reactor) Plant	12,419		
	Maintenance of Electric Plant	12,920		
	Maintenance of Misc Steam (or Nuclear) Plant	16,081	16,081	
	Other Power Production, & Other Expenses	48,778	48,778	
	Total NonFuel Expenses	332,898	259,143	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation				
	Plant Var Allocators			
	Electric Expense Allocator	4.8060%	Line 4(c) / 1(c))	
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)	
	Other Demand Expense Allocator	0.0542%	Line 79	
	Production Plant Expenses			
	Total NonFuel Expenses	332,898	Line 116	
	Allowances	2,792	Line 109	
	Non-Fuel Production O&M	330,106	(Line 126 - 127)	
	Operating Expenses			
	Operations Supervision & Engineering	74,248	Line 102(c)	
	Electric Expenses	0	Line 106(c)	
	Maintenance of Electric Plant	12,920	Line 113(b)	
	Other Demand Related Expenses	184,895	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)	
	Total	272,063	(Sum Lines 131 to 134)	

				Allocator	Allocated Amount	
	Maintenance of Electric Plant	12,920	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	12,920	(Line 138 + 139)	4.8060%	621	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	184,895	(Line 134)	0.0542%	100	
				Line 123		
	Balance of Plant Fixed Expenses				271,342	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		16,599	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		116,824	(allocated on plant labor)	
	Total		133,423		
Depreciation					
	Annual Depreciation Exp ...DE	131,762			
	Gross Production Plant Cost ... F	8,301,032	Line 14		
	SLDP=DE/F	1.5873%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	63			
	SFDP=(R/((1+R)^n-1)		0.0594%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.015%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		11,386	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		11,386	(Line 192 + 195)	
		Plant		**Depreciation**	**Total**
General Plant		-		-	
		0.000%		0.000%	Line 159
	Fixed General Plant	-		-	(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188		
	Taxes on General Plant	3.0148%	Line 189		
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-
Working Capital					
	Prepayments	62,442			
		100.000%			
	Production Related Prepayments	62,442	(Line 209 * 210)		
	Unit Specific M&S	844,613			
	Total	907,055	(Line 211 + 212)		
	Return on Working Capital	8.1350%			
	Taxes on Working Capital	3.0148%			
	Working Capital Costs	101,135	(Line 213 * 214)		

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Accumulated Deferred Income Taxes

Investment	8,301,032	Line 14
Asset Service Life	63	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 1,542,529

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	PMT of NPV col. (j)
1	131,762	3.750%	311,289	69,439	69,439	4,086	1,562	2,506	8,155	126,401
2	131,762	7.219%	599,252	180,820	250,259	14,728	5,631	9,031	29,390	126,401
3	131,762	6.677%	554,260	163,418	413,677	24,345	9,308	14,929	48,581	126,401
4	131,762	6.177%	512,755	147,364	561,041	33,017	12,623	20,247	65,887	126,401
5	131,762	5.713%	474,238	132,466	693,507	40,813	15,604	25,027	81,444	126,401
6	131,762	5.285%	438,710	118,724	812,231	47,800	18,275	29,311	95,386	126,401
7	131,762	4.888%	405,754	105,977	918,208	54,037	20,660	33,136	107,832	126,401
8	131,762	4.522%	375,373	94,226	1,012,435	59,582	22,780	36,536	118,898	126,401
9	131,762	4.462%	370,392	92,300	1,104,734	65,014	24,857	39,867	129,737	126,401
10	131,762	4.461%	370,309	92,267	1,197,002	70,444	26,933	43,197	140,573	126,401
11	131,762	4.462%	370,392	92,300	1,289,301	75,875	29,009	46,528	151,412	126,401
12	131,762	4.461%	370,309	92,267	1,381,569	81,305	31,085	49,857	162,248	126,401
13	131,762	4.462%	370,392	92,300	1,473,868	86,737	33,162	53,188	173,087	126,401
14	131,762	4.461%	370,309	92,267	1,566,136	92,167	35,238	56,518	183,923	126,401
15	131,762	4.462%	370,392	92,300	1,658,435	97,599	37,315	59,849	194,762	126,401
16	131,762	4.461%	370,309	92,267	1,750,703	103,029	39,391	63,178	205,598	126,401
17	131,762	4.462%	370,392	92,300	1,843,002	108,461	41,468	66,509	216,437	126,401
18	131,762	4.461%	370,309	92,267	1,935,270	113,891	43,544	69,839	227,273	126,401
19	131,762	4.462%	370,392	92,300	2,027,569	119,322	45,620	73,170	238,112	126,401
20	131,762	4.461%	370,309	92,267	2,119,837	124,752	47,696	76,499	248,948	126,401
21	131,762	2.231%	185,196	20,668	2,140,504	125,969	48,161	77,245	251,375	126,401
22	131,762	0.000%	0	-50,964	2,089,540	122,969	47,015	75,406	245,390	126,401
23	131,762	0.000%	0	-50,964	2,038,575	119,970	45,868	73,567	239,405	126,401
24	131,762	0.000%	0	-50,964	1,987,611	116,971	44,721	71,728	233,420	126,401
25	131,762	0.000%	0	-50,964	1,936,647	113,972	43,575	69,889	227,435	126,401
26	131,762	0.000%	0	-50,964	1,885,682	110,972	42,428	68,049	221,450	126,401
27	131,762	0.000%	0	-50,964	1,834,718	107,973	41,281	66,210	215,465	126,401
28	131,762	0.000%	0	-50,964	1,783,753	104,974	40,134	64,371	209,479	126,401
29	131,762	0.000%	0	-50,964	1,732,789	101,975	38,988	62,532	203,494	126,401
30	131,762	0.000%	0	-50,964	1,681,825	98,975	37,841	60,693	197,509	126,401
31	131,762	0.000%	0	-50,964	1,630,860	95,976	36,694	58,854	191,524	126,401
32	131,762	0.000%	0	-50,964	1,579,896	92,977	35,548	57,014	185,539	126,401
33	131,762	0.000%	0	-50,964	1,528,932	89,978	34,401	55,175	179,554	126,401
34	131,762	0.000%	0	-50,964	1,477,967	86,978	33,254	53,336	173,569	126,401
35	131,762	0.000%	0	-50,964	1,427,003	83,979	32,108	51,497	167,584	126,401
36	131,762	0.000%	0	-50,964	1,376,038	80,980	30,961	49,658	161,598	126,401
37	131,762	0.000%	0	-50,964	1,325,074	77,981	29,814	47,818	155,613	126,401
38	131,762	0.000%	0	-50,964	1,274,110	74,981	28,667	45,979	149,628	126,401
39	131,762	0.000%	0	-50,964	1,223,145	71,982	27,521	44,140	143,643	126,401
40	131,762	0.000%	0	-50,964	1,172,181	68,983	26,374	42,301	137,658	126,401
41	131,762	0.000%	0	-50,964	1,121,216	65,984	25,227	40,462	131,673	126,401
42	131,762	0.000%	0	-50,964	1,070,252	62,984	24,081	38,623	125,688	126,401
43	131,762	0.000%	0	-50,964	1,019,288	59,985	22,934	36,783	119,703	126,401
44	131,762	0.000%	0	-50,964	968,323	56,986	21,787	34,944	113,717	126,401
45	131,762	0.000%	0	-50,964	917,359	53,987	20,641	33,105	107,732	126,401
46	131,762	0.000%	0	-50,964	866,395	50,987	19,494	31,266	101,747	126,401
47	131,762	0.000%	0	-50,964	815,430	47,988	18,347	29,427	95,762	126,401
48	131,762	0.000%	0	-50,964	764,466	44,989	17,200	27,588	89,777	126,401
49	131,762	0.000%	0	-50,964	713,501	41,990	16,054	25,748	83,792	126,401
50	131,762	0.000%	0	-50,964	662,537	38,990	14,907	23,909	77,807	126,401
51	131,762	0.000%	0	-50,964	611,573	35,991	13,760	22,070	71,822	126,401
52	131,762	0.000%	0	-50,964	560,608	32,992	12,614	20,231	65,836	126,401
53	131,762	0.000%	0	-50,964	509,644	29,993	11,467	18,392	59,851	126,401
54	131,762	0.000%	0	-50,964	458,679	26,993	10,320	16,553	53,866	126,401
55	131,762	0.000%	0	-50,964	407,715	23,994	9,174	14,713	47,881	126,401
56	131,762	0.000%	0	-50,964	356,751	20,995	8,027	12,874	41,896	126,401
57	131,762	0.000%	0	-50,964	305,786	17,996	6,880	11,035	35,911	126,401
58	131,762	0.000%	0	-50,964	254,822	14,996	5,733	9,196	29,926	126,401
59	131,762	0.000%	0	-50,964	203,858	11,997	4,587	7,357	23,941	126,401
60	131,762	0.000%	0	-50,964	152,893	8,998	3,440	5,518	17,955	126,401
61	131,762	0.000%	0	-50,964	101,929	5,999	2,293	3,678	11,970	126,401
62	131,762	0.000%	0	-50,964	50,964	2,999	1,147	1,839	5,985	126,401
63	131,762	0.000%	0	-50,964	0	0	0	0	0	126,401

Unit Name: Muddy Run 1-8 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 105,729,817	
2	Investment Generator & Exciter	Inputs Tab	$ 15,859,473	
3	Reactive Allocator	(Line 71)	16.69%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**2,647,720**	
5				
6	GSU Transformer Investment	Inputs Tab	4,657,845	
7	Reactive Allocator	(Line 71)	16.69%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**777,622**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	2,914,002	
11	Reactive Allocator	(Line 71)	16.69%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**486,489**	
13				
14	Total Cost of Power Plant	Inputs Tab	261,421,690	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	237,990,370	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	128,942	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	4,040,774	
19	Reactive Fixed Charge Rate	(Line 14(h))	10.9589%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**442,823**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 442,823**	
23				
24				
25				
26				

	(e)		(f)	(g)	(h)
			Fixed Charge Rate for Reactive Plant		
			Calculated Amt	Plant	FCR % (f) / (g)
	Electric Expenses	Line 140	10,946		
	Other Expenses		156		
	O&M	(sum line 1 & 2)	11,102	4,040,774	0.2748%
	A&G		1,887,948	261,421,690	0.7222%
	CWC	From Col. (h): ((lines 3 + 5) * .125 * (lines 11 + 12)			0.0140%
	Working Capital	Line 216	221,491	261,421,690	0.0847%
	General Plant		-	261,421,690	0.0000%
	Other Taxes	Line 196(c)	692,571	261,421,690	0.2649%
	Depreciation	Line 168(c)			0.0198%
					8.1350%
	Taxes (Federal/State/Local)	Line 180			3.1285%
	ADIT	-Line 233(k)	($4,404,884)	261,421,690	-1.6850%
			(Sum Lines 1 to 11 , Col. (h))		10.9589%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		122.10						
		123.70						
		124.00						
		125.00						
		122.00						
		117.00						
	Total	733.80	(Sum Lines 31 to 36)					
	Nominal Power Factor (pf)							
		0.91						
		0.90						
		0.93						
		0.92						
		0.90						
		0.91						
	Total	0.91	(Line 38 / 58)					
	MVA Capability (MVA)							
		133.73	(Line 31 / 41)					
		137.14	(Line 32 / 42)					
		134.05	(Line 33 / 43)					
		135.72	(Line 34 / 44)					
		135.56	(Line 35 / 45)					
		128.01	(Line 36 / 46)					
	Total	804.22	(Sum Lines 51 to 56)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		54.56	(SQRT (Line 51^2 - Line 31^2))					
		59.21	(SQRT (Line 52^2 - Line 32^2))					
		50.94	(SQRT (Line 53^2 - Line 33^2))					
		52.87	(SQRT (Line 54^2 - Line 34^2))					
		59.09	(SQRT (Line 55^2 - Line 35^2))					
		51.93	(SQRT (Line 56^2 - Line 36^2))					
	Total	328.60	(Sum Lines 62 to 67)					
	Reactive Allocator	16.7%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Hydro & Steam**	**Allocated Amt**
	Storage Batteries	$ 129,233	**30%**	$ 38,770
	Control&Power Cabling	$ 4,929,960	**15%**	$ 739,494
	Switch Board Equipment	$ 1,669,534	**30%**	$ 500,860
	Switching Equipment	$ 6,130,553	**20%**	$ 1,226,111
	Transformers	$ 589,215	**5%**	$ 29,461
	Aux Generator	$ 120,583	**0%**	$ -
	Fire Protection System	$ -	**0%**	$ -
	HVAC	$ -	**0%**	$ -
	Regulating Equipment	$ 505,742	**75%**	$ 379,306
	Structure	$ -	**0%**	$ -
	Misc	$ 29,526,543	**0%**	$ -
	Exciter & PPT	$ -	**100%**	$ -
	Station Grounding	$ 181,000	**0%**	$ -
	Bus & Insulators	$ -	**60%**	$ -
	Capacitor Bank	$ -	**0%**	$ -
	Total	$ 43,782,362		$ 2,914,002

O&M		**Total Non-Fuel**	**Fixed O&M**	
	(535) Operation Supervision and Engineering	129,116	129,116	
		0		
	(536) Water for Power	106,629	106,629	
	(537) Hydraulic Expenses	635,221		
	(538) Electric Expenses	209,968	209,968	
	(539) Miscellaneous Hydraulic Power Generation Expen	209,831		
	(540) Rents	30,315	30,315	
		0	-	
	(541) Mainentance Supervision and Engineering	71,654		
	(542) Maintenance of Structures	86,140	86,140	
	(543) Maintenance of Reservoirs, Dams, and Waterways	317,094		
	(544) Maintenance of Electric Plant	227,151		
	(545) Maintenance of Miscellaneous Hydraulic Plant	64,105	64,105	
	Total NonFuel Expenses	2,087,224	626,272	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		31.07%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	2.5042%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	1.0805%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	2,087,224	Line 116			
	Allowances	0	Line 109			
	Non-Fuel Production O&M	2,087,224	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	129,116	Line 102(c)			
	Electric Expenses	209,968	Line 106(c)			
	Maintenance of Electric Plant	227,151	Line 113(b)			
	Other Demand Related Expenses	287,188	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	853,424	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	227,151	Line 113(b)			
	Electric Expenses	209,968	Line 106(c)			
	Total Electric Expenses	437,119	(Line 138 + 139)	2.5042%	10,946	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	287,188	(Line 134)	0.0542%	156	
				Line 123		
	Balance of Plant Fixed Expenses				842,322	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		1,887,948	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		0	(allocated on plant labor)	
	Total		1,887,948		
Depreciation					
	Annual Depreciation Exp ...DE	3,395,087			
	Gross Production Plant Cost ... F	261,421,690	Line 14		
	SLDP=DE/F	1.2987%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	77			
	SFDP=(R/((1+R)^n-1)		0.0198%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.128%		
Rate of Return					
	Rate Of Return = R	Weight	Cost Rate	Weighted Cost (b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		692,571	<Includes Payroll	
	Payroll Taxes				
		31.0717%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		692,571	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	3.1285%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital				
	Prepayments	1,966,459		
		100.000%		
	Production Related Prepayments	1,966,459	(Line 209 * 210)	
	Unit Specific M&S	-		
	Total	1,966,459	(Line 211 + 212)	
	Return on Working Capital	8.1350%		
	Taxes on Working Capital	3.1285%		
	Working Capital Costs	221,491	(Line 213 * 214)	

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Accumulated Deferred Income Taxes

Investment	261,421,690	Line 14	NPV of Col (j)> 54,016,043
Asset Service Life	77	Line 167	
Composite Tax Rate	38.6790%	Line 177	

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity = (f) *	(h) Interest = (f) *	(i) Income Taxes = (g) *	(j) Rev Req Impact	(k) Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	(f) * (Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	3,395,087	3.750%	9,803,313	2,478,638	2,478,638	145,868	55,769	89,448	291,085	4,404,884
2	3,395,087	7.219%	18,872,032	5,986,328	8,464,965	498,163	190,462	305,479	994,104	4,404,884
3	3,395,087	6.677%	17,455,126	5,438,283	13,903,248	818,206	312,823	501,732	1,632,761	4,404,884
4	3,395,087	6.177%	16,148,018	4,932,706	18,835,954	1,108,496	423,809	679,741	2,212,046	4,404,884
5	3,395,087	5.713%	14,935,021	4,463,531	23,299,485	1,371,175	524,238	840,818	2,736,231	4,404,884
6	3,395,087	5.285%	13,816,136	4,030,758	27,330,243	1,608,385	614,930	986,278	3,209,593	4,404,884
7	3,395,087	4.888%	12,778,292	3,629,330	30,959,573	1,821,971	696,590	1,117,251	3,635,812	4,404,884
8	3,395,087	4.522%	11,821,489	3,259,248	34,218,821	2,013,778	769,923	1,234,869	4,018,570	4,404,884
9	3,395,087	4.462%	11,664,636	3,198,579	37,417,400	2,202,014	841,891	1,350,297	4,394,202	4,404,884
10	3,395,087	4.461%	11,662,022	3,197,568	40,614,968	2,390,191	913,837	1,465,689	4,769,717	4,404,884
11	3,395,087	4.462%	11,664,636	3,198,579	43,813,546	2,578,427	985,805	1,581,117	5,145,349	4,404,884
12	3,395,087	4.461%	11,662,022	3,197,568	47,011,114	2,766,604	1,057,750	1,696,509	5,520,863	4,404,884
13	3,395,087	4.462%	11,664,636	3,198,579	50,209,693	2,954,840	1,129,718	1,811,938	5,896,496	4,404,884
14	3,395,087	4.461%	11,662,022	3,197,568	53,407,261	3,143,017	1,201,663	1,927,330	6,272,010	4,404,884
15	3,395,087	4.462%	11,664,636	3,198,579	56,605,839	3,331,254	1,273,631	2,042,758	6,647,643	4,404,884
16	3,395,087	4.461%	11,662,022	3,197,568	59,803,407	3,519,431	1,345,577	2,158,150	7,023,157	4,404,884
17	3,395,087	4.462%	11,664,636	3,198,579	63,001,986	3,707,667	1,417,545	2,273,578	7,398,790	4,404,884
18	3,395,087	4.461%	11,662,022	3,197,568	66,199,554	3,895,844	1,489,490	2,388,970	7,774,304	4,404,884
19	3,395,087	4.462%	11,664,636	3,198,579	69,398,132	4,084,080	1,561,458	2,504,399	8,149,937	4,404,884
20	3,395,087	4.461%	11,662,022	3,197,568	72,595,700	4,272,257	1,633,403	2,619,791	8,525,451	4,404,884
21	3,395,087	2.231%	5,832,318	942,697	73,538,397	4,327,735	1,654,614	2,653,810	8,636,159	4,404,884
22	3,395,087	0.000%	0	-1,313,186	72,225,211	4,250,454	1,625,067	2,606,421	8,481,942	4,404,884
23	3,395,087	0.000%	0	-1,313,186	70,912,025	4,173,173	1,595,521	2,559,031	8,327,724	4,404,884
24	3,395,087	0.000%	0	-1,313,186	69,598,840	4,095,892	1,565,974	2,511,642	8,173,507	4,404,884
25	3,395,087	0.000%	0	-1,313,186	68,285,654	4,018,611	1,536,427	2,464,252	8,019,290	4,404,884
26	3,395,087	0.000%	0	-1,313,186	66,972,468	3,941,330	1,506,881	2,416,863	7,865,073	4,404,884
27	3,395,087	0.000%	0	-1,313,186	65,659,283	3,864,049	1,477,334	2,369,473	7,710,856	4,404,884
28	3,395,087	0.000%	0	-1,313,186	64,346,097	3,786,768	1,447,787	2,322,084	7,556,639	4,404,884
29	3,395,087	0.000%	0	-1,313,186	63,032,911	3,709,487	1,418,241	2,274,694	7,402,422	4,404,884
30	3,395,087	0.000%	0	-1,313,186	61,719,726	3,632,206	1,388,694	2,227,305	7,248,205	4,404,884
31	3,395,087	0.000%	0	-1,313,186	60,406,540	3,554,925	1,359,147	2,179,915	7,093,988	4,404,884
32	3,395,087	0.000%	0	-1,313,186	59,093,354	3,477,644	1,329,600	2,132,526	6,939,770	4,404,884
33	3,395,087	0.000%	0	-1,313,186	57,780,169	3,400,363	1,300,054	2,085,137	6,785,553	4,404,884
34	3,395,087	0.000%	0	-1,313,186	56,466,983	3,323,082	1,270,507	2,037,747	6,631,336	4,404,884
35	3,395,087	0.000%	0	-1,313,186	55,153,797	3,245,801	1,240,960	1,990,358	6,477,119	4,404,884
36	3,395,087	0.000%	0	-1,313,186	53,840,612	3,168,520	1,211,414	1,942,968	6,322,902	4,404,884
37	3,395,087	0.000%	0	-1,313,186	52,527,426	3,091,239	1,181,867	1,895,579	6,168,685	4,404,884
38	3,395,087	0.000%	0	-1,313,186	51,214,241	3,013,958	1,152,320	1,848,189	6,014,468	4,404,884
39	3,395,087	0.000%	0	-1,313,186	49,901,055	2,936,677	1,122,774	1,800,800	5,860,251	4,404,884
40	3,395,087	0.000%	0	-1,313,186	48,587,869	2,859,396	1,093,227	1,753,410	5,706,033	4,404,884
41	3,395,087	0.000%	0	-1,313,186	47,274,684	2,782,115	1,063,680	1,706,021	5,551,816	4,404,884
42	3,395,087	0.000%	0	-1,313,186	45,961,498	2,704,834	1,034,134	1,658,631	5,397,599	4,404,884
43	3,395,087	0.000%	0	-1,313,186	44,648,312	2,627,553	1,004,587	1,611,242	5,243,382	4,404,884
44	3,395,087	0.000%	0	-1,313,186	43,335,127	2,550,272	975,040	1,563,852	5,089,165	4,404,884
45	3,395,087	0.000%	0	-1,313,186	42,021,941	2,472,991	945,494	1,516,463	4,934,948	4,404,884
46	3,395,087	0.000%	0	-1,313,186	40,708,755	2,395,710	915,947	1,469,073	4,780,731	4,404,884
47	3,395,087	0.000%	0	-1,313,186	39,395,570	2,318,429	886,400	1,421,684	4,626,514	4,404,884
48	3,395,087	0.000%	0	-1,313,186	38,082,384	2,241,148	856,854	1,374,295	4,472,296	4,404,884
49	3,395,087	0.000%	0	-1,313,186	36,769,198	2,163,867	827,307	1,326,905	4,318,079	4,404,884
50	3,395,087	0.000%	0	-1,313,186	35,456,013	2,086,586	797,760	1,279,516	4,163,862	4,404,884
51	3,395,087	0.000%	0	-1,313,186	34,142,827	2,009,305	768,214	1,232,126	4,009,645	4,404,884
52	3,395,087	0.000%	0	-1,313,186	32,829,641	1,932,024	738,667	1,184,737	3,855,428	4,404,884
53	3,395,087	0.000%	0	-1,313,186	31,516,456	1,854,743	709,120	1,137,347	3,701,211	4,404,884
54	3,395,087	0.000%	0	-1,313,186	30,203,270	1,777,462	679,574	1,089,958	3,546,994	4,404,884
55	3,395,087	0.000%	0	-1,313,186	28,890,084	1,700,181	650,027	1,042,568	3,392,777	4,404,884
56	3,395,087	0.000%	0	-1,313,186	27,576,899	1,622,900	620,480	995,179	3,238,560	4,404,884
57	3,395,087	0.000%	0	-1,313,186	26,263,713	1,545,620	590,934	947,789	3,084,342	4,404,884
58	3,395,087	0.000%	0	-1,313,186	24,950,527	1,468,339	561,387	900,400	2,930,125	4,404,884
59	3,395,087	0.000%	0	-1,313,186	23,637,342	1,391,058	531,840	853,010	2,775,908	4,404,884
60	3,395,087	0.000%	0	-1,313,186	22,324,156	1,313,777	502,294	805,621	2,621,691	4,404,884
61	3,395,087	0.000%	0	-1,313,186	21,010,970	1,236,496	472,747	758,231	2,467,474	4,404,884
62	3,395,087	0.000%	0	-1,313,186	19,697,785	1,159,215	443,200	710,842	2,313,257	4,404,884
63	3,395,087	0.000%	0	-1,313,186	18,384,599	1,081,934	413,653	663,453	2,159,040	4,404,884
64	3,395,087	0.000%	0	-1,313,186	17,071,414	1,004,653	384,107	616,063	2,004,823	4,404,884
65	3,395,087	0.000%	0	-1,313,186	15,758,228	927,372	354,560	568,674	1,850,605	4,404,884
66	3,395,087	0.000%	0	-1,313,186	14,445,042	850,091	325,013	521,284	1,696,388	4,404,884
67	3,395,087	0.000%	0	-1,313,186	13,131,857	772,810	295,467	473,895	1,542,171	4,404,884
68	3,395,087	0.000%	0	-1,313,186	11,818,671	695,529	265,920	426,505	1,387,954	4,404,884
69	3,395,087	0.000%	0	-1,313,186	10,505,485	618,248	236,373	379,116	1,233,737	4,404,884
70	3,395,087	0.000%	0	-1,313,186	9,192,300	540,967	206,827	331,726	1,079,520	4,404,884
71	3,395,087	0.000%	0	-1,313,186	7,879,114	463,686	177,280	284,337	925,303	4,404,884
72	3,395,087	0.000%	0	-1,313,186	6,565,928	386,405	147,733	236,947	771,086	4,404,884
73	3,395,087	0.000%	0	-1,313,186	5,252,743	309,124	118,187	189,558	616,868	4,404,884
74	3,395,087	0.000%	0	-1,313,186	3,939,557	231,843	88,640	142,168	462,651	4,404,884
75	3,395,087	0.000%	0	-1,313,186	2,626,371	154,562	59,093	94,779	308,434	4,404,884
76	3,395,087	0.000%	0	-1,313,186	1,313,186	77,281	29,547	47,389	154,217	4,404,884
77	3,395,087	0.000%	0	-1,313,186	0	0	0	0	0	4,404,884

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Unit Name: Notch Cliff 1-8 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 20,738,180	
2	Investment Generator & Exciter	Inputs Tab	$ 3,110,727	
3	Reactive Allocator	(Line 75)	33.78%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**1,050,691**	
5				
6	GSU Transformer Investment	Inputs Tab	-	
7	Reactive Allocator	(Line 75)	33.78%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**	
9				
10	Allocated Acc Elec Equipment	(Line 103 , Column d)	4,014,649	
11	Reactive Allocator	(Line 75)	33.78%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**1,356,003**	
13				
14	Total Cost of Power Plant	Inputs Tab	41,084,404	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	33,959,028	
16	Balance of Plant Allocator	(Line 79)	0.0154%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	5,215	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	2,411,909	
19	Reactive Fixed Charge Rate	(Line 14(h))	11.7043%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**282,297**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 282,297**	
23				
24				
25				
26				

(e)		(f)	(g)	(h)
Fixed Charge Rate for Reactive Plant				
		Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 144	1,914		
Other Expenses		83		
O&M	(sum line 1 & 2)	1,997	2,411,909	0.0828%
A&G		498,913	41,084,404	1.2144%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0180%
Working Capital	Line 215	49,132	41,084,404	0.1196%
General Plant		-	41,084,404	0.0000%
Other Taxes	Line 195(c)	222,581	41,084,404	0.5418%
Depreciation	Line 167(c)			0.0814%
				8.1350%
Taxes (Federal/State/Local)	Line 179			2.9758%
ADIT	-Line 232(k)	($601,641)	41,084,404	-1.4644%
		(Sum Lines 1 to 11 , Col. (h))		11.7043%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		12.80						
		18.00						
		18.00						
		18.00						
		12.50						
		18.00						
		18.00						
		18.00						
	Total	133.30	(Sum Lines 31 to 38)					
	Nominal Power Factor (pf)							
		0.66						
		0.85						
		0.85						
		0.85						
		0.64						
		0.85						
		0.85						
		0.85						
	Total	0.80	(Line 39 / 61)					
	MVA Capability (MVA)							
		19.34	(Line 31 / 42)					
		21.18	(Line 32 / 43)					
		21.18	(Line 33 / 44)					
		21.18	(Line 34 / 45)					
		19.53	(Line 35 / 46)					
		21.18	(Line 36 / 47)					
		21.18	(Line 37 / 48)					
		21.18	(Line 38 / 49)					
	Total	165.93	(Sum Lines 53 to 60)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		14.49	(SQRT (Line 53^2 - Line 31^2))					
		11.16	(SQRT (Line 54^2 - Line 32^2))					
		11.16	(SQRT (Line 55^2 - Line 33^2))					
		11.16	(SQRT (Line 56^2 - Line 34^2))					
		15.01	(SQRT (Line 57^2 - Line 35^2))					
		11.16	(SQRT (Line 58^2 - Line 36^2))					
		11.16	(SQRT (Line 59^2 - Line 37^2))					
		11.16	(SQRT (Line 60^2 - Line 38^2))					
	Total	96.43	(Sum Lines 65 to 72)					
	Reactive Allocator	33.8%	(Line 73^2 / Line 61^2)					
		BGE is TO Fleet						
	Max. MVAr	27.50						
	Nameplate MVAr	571.22						
	Exciter MW	3.08						
	Generator MW	965.46						
	Balance of Plant Allocator	0.0154%	(Line 79 / Line 80) * (Line 81 / Line 82)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ -	50%	$ -
	Control&Power Cabling	$ 33,556	50%	$ 16,778
	Switch Board Equipment	$ 237,988	50%	$ 118,994
	Switching Equipment	$ 981,137	40%	$ 392,455
	Transformers	$ 57,272	10%	$ 5,727
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ 4,640,268	75%	$ 3,480,201
	Structure	$ 6,922	0%	$ -
	Misc	$ 118,909	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ 9,880	5%	$ 494
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 6,085,933		$ 4,014,649

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	217,043	217,043	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	56,064	56,064	
	Steam From Other Sources	108,337		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	33,192		
	Rents	202,000	202,000	
	Allowances	8,163	8,163	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	84,660	84,660	
	Maintenance of Boiler (or reactor) Plant	36,303		
	Maintenance of Electric Plant	37,769		
	Maintenance of Misc Steam (or Nuclear) Plant	47,008	47,008	
	Other Power Production, & Other Expenses	142,589	142,589	
	Total NonFuel Expenses	973,126	757,526	(Sum Lines 106 to 119)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 120(c) / (Line 120(b) - Line 114(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	5.0665%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 127 * Line 136 + Line 125 * Line 136 / (Line136 + 138)			
	Other Demand Expense Allocator	0.0154%	Line 83			
	Production Plant Expenses					
	Total NonFuel Expenses	973,126	Line 120			
	Allowances	8,163	Line 113			
	Non-Fuel Production O&M	964,964	(Line 130 - 131)			
	Operating Expenses					
	Operations Supervision & Engineering	217,043	Line 106(c)			
	Electric Expenses	0	Line 110(c)			
	Maintenance of Electric Plant	37,769	Line 117(b)			
	Other Demand Related Expenses	540,483	Col. (c) Line 120 - Col (b) Line 136 - Col. (b) Line 135			
	Total	795,295	(Sum Lines 135 to 138)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	37,769	Line 117(b)			
	Electric Expenses	0	Line 110(c)			
	Total Electric Expenses	37,769	(Line 142 + 143)	5.0665%	1,914	(Line 144(b) * (d))
				Line 125		
	Other Demand Related Expenses	540,483	(Line 138)	0.0154%	83	
				Line 127		
	Balance of Plant Fixed Expenses				793,298	(Line 139(b) - Line 144(e) - Line 146(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		145,511	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		353,402	(allocated on plant labor)	
	Total		498,913		
Depreciation					
	Annual Depreciation Exp ...DE	696,346			
	Gross Production Plant Cost ... F	41,084,404	Line 14		
	SLDP=DE/F	1.6949%	(Line 163 / 164)		
	Depreciable years (n)=1/SLDP	59			
	SFDP=(R/((1+R)^n-1)		0.0814%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.976%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 184 to 186)
Other Taxes					
	Property Taxes		222,581	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 121		
	Fixed Payroll Taxes		-	(Line 192 * 193)	
	Total Other Taxes		222,581	(Line 191 + 194)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 158
	Fixed General Plant	-		-		(Lines 199 *200)
	Return on General Plant	8.1350%	Line 187			
	Taxes on General Plant	2.9758%	Line 188			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 201 * 202)	-	-	
Working Capital						
	Prepayments	309,044				
		100.000%				
	Production Related Prepayments	309,044	(Line 208 * 209)			
	Unit Specific M&S	133,154				
	Total	442,198	(Line 210 + 211)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9758%				
	Working Capital Costs	49,132	(Line 212 * 213)			

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Accumulated Deferred Income Taxes

Investment	41,084,404	Line 14
Asset Service Life	59	Line 166
Composite Tax Rate	38.6790%	Line 176

NPV of Col (j)> 7,322,437

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized
	Line 223 / 224		(b) * (c)	((d) - (b)) * Line 176	Accum. (e)	= (f) * (Line185+186)	= (f) * (Line184)	= (g) * (Line177)	(g) + (h) + (i)	PMT of NPV col. (j)
1	696,346	3.750%	1,540,665	326,574	326,574	19,219	7,348	11,785	38,352	601,641
2	696,346	7.219%	2,965,883	877,834	1,204,409	70,879	27,099	43,464	141,443	601,641
3	696,346	6.677%	2,743,206	791,705	1,996,113	117,471	44,913	72,035	234,418	601,641
4	696,346	6.177%	2,537,784	712,250	2,708,363	159,387	60,938	97,738	318,063	601,641
5	696,346	5.713%	2,347,152	638,515	3,346,879	196,964	75,305	120,780	393,049	601,641
6	696,346	5.285%	2,171,311	570,502	3,917,380	230,538	88,141	141,368	460,047	601,641
7	696,346	4.888%	2,008,206	507,414	4,424,794	260,399	99,558	159,679	519,636	601,641
8	696,346	4.522%	1,857,837	449,253	4,874,048	286,838	109,666	175,892	572,396	601,641
9	696,346	4.462%	1,833,186	439,718	5,313,766	312,715	119,560	191,760	624,035	601,641
10	696,346	4.461%	1,832,775	439,560	5,753,326	338,583	129,450	207,623	675,656	601,641
11	696,346	4.462%	1,833,186	439,718	6,193,044	364,461	139,343	223,491	727,295	601,641
12	696,346	4.461%	1,832,775	439,560	6,632,604	390,329	149,234	239,353	778,916	601,641
13	696,346	4.462%	1,833,186	439,718	7,072,322	416,206	159,127	255,222	830,555	601,641
14	696,346	4.461%	1,832,775	439,560	7,511,881	442,074	169,017	271,084	882,176	601,641
15	696,346	4.462%	1,833,186	439,718	7,951,600	467,952	178,911	286,953	933,815	601,641
16	696,346	4.461%	1,832,775	439,560	8,391,159	493,820	188,801	302,815	985,436	601,641
17	696,346	4.462%	1,833,186	439,718	8,830,878	519,697	198,695	318,683	1,037,075	601,641
18	696,346	4.461%	1,832,775	439,560	9,270,437	545,565	208,585	334,546	1,088,696	601,641
19	696,346	4.462%	1,833,186	439,718	9,710,156	571,443	218,479	350,414	1,140,336	601,641
20	696,346	4.461%	1,832,775	439,560	10,149,715	597,311	228,369	366,277	1,191,956	601,641
21	696,346	2.231%	916,593	85,189	10,234,905	602,324	230,285	369,351	1,201,961	601,641
22	696,346	0.000%	0	-269,340	9,965,565	586,474	224,225	359,631	1,170,330	601,641
23	696,346	0.000%	0	-269,340	9,696,226	570,623	218,165	349,912	1,138,700	601,641
24	696,346	0.000%	0	-269,340	9,426,886	554,772	212,105	340,192	1,107,069	601,641
25	696,346	0.000%	0	-269,340	9,157,546	538,922	206,045	330,472	1,075,439	601,641
26	696,346	0.000%	0	-269,340	8,888,207	523,071	199,985	320,752	1,043,808	601,641
27	696,346	0.000%	0	-269,340	8,618,867	507,220	193,925	311,033	1,012,177	601,641
28	696,346	0.000%	0	-269,340	8,349,528	491,370	187,864	301,313	980,547	601,641
29	696,346	0.000%	0	-269,340	8,080,188	475,519	181,804	291,593	948,916	601,641
30	696,346	0.000%	0	-269,340	7,810,848	459,668	175,744	281,873	917,286	601,641
31	696,346	0.000%	0	-269,340	7,541,509	443,818	169,684	272,154	885,655	601,641
32	696,346	0.000%	0	-269,340	7,272,169	427,967	163,624	262,434	854,025	601,641
33	696,346	0.000%	0	-269,340	7,002,830	412,117	157,564	252,714	822,394	601,641
34	696,346	0.000%	0	-269,340	6,733,490	396,266	151,504	242,994	790,764	601,641
35	696,346	0.000%	0	-269,340	6,464,150	380,415	145,443	233,274	759,133	601,641
36	696,346	0.000%	0	-269,340	6,194,811	364,565	139,383	223,555	727,503	601,641
37	696,346	0.000%	0	-269,340	5,925,471	348,714	133,323	213,835	695,872	601,641
38	696,346	0.000%	0	-269,340	5,656,132	332,863	127,263	204,115	664,241	601,641
39	696,346	0.000%	0	-269,340	5,386,792	317,013	121,203	194,395	632,611	601,641
40	696,346	0.000%	0	-269,340	5,117,452	301,162	115,143	184,676	600,980	601,641
41	696,346	0.000%	0	-269,340	4,848,113	285,311	109,083	174,956	569,350	601,641
42	696,346	0.000%	0	-269,340	4,578,773	269,461	103,022	165,236	537,719	601,641
43	696,346	0.000%	0	-269,340	4,309,434	253,610	96,962	155,516	506,089	601,641
44	696,346	0.000%	0	-269,340	4,040,094	237,760	90,902	145,797	474,458	601,641
45	696,346	0.000%	0	-269,340	3,770,754	221,909	84,842	136,077	442,828	601,641
46	696,346	0.000%	0	-269,340	3,501,415	206,058	78,782	126,357	411,197	601,641
47	696,346	0.000%	0	-269,340	3,232,075	190,208	72,722	116,637	379,567	601,641
48	696,346	0.000%	0	-269,340	2,962,736	174,357	66,662	106,917	347,936	601,641
49	696,346	0.000%	0	-269,340	2,693,396	158,506	60,601	97,198	316,305	601,641
50	696,346	0.000%	0	-269,340	2,424,056	142,656	54,541	87,478	284,675	601,641
51	696,346	0.000%	0	-269,340	2,154,717	126,805	48,481	77,758	253,044	601,641
52	696,346	0.000%	0	-269,340	1,885,377	110,954	42,421	68,038	221,414	601,641
53	696,346	0.000%	0	-269,340	1,616,038	95,104	36,361	58,319	189,783	601,641
54	696,346	0.000%	0	-269,340	1,346,698	79,253	30,301	48,599	158,153	601,641
55	696,346	0.000%	0	-269,340	1,077,358	63,403	24,241	38,879	126,522	601,641
56	696,346	0.000%	0	-269,340	808,019	47,552	18,180	29,159	94,892	601,641
57	696,346	0.000%	0	-269,340	538,679	31,701	12,120	19,440	63,261	601,641
58	696,346	0.000%	0	-269,340	269,340	15,851	6,060	9,720	31,631	601,641
59	696,346	0.000%	0	-269,340	0	0	0	0	0	601,641

Unit Name: Oyster Creek **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 30,406,806		Electric Expenses	Line 140	251,050		
2	Investment Generator & Exciter	Inputs Tab	4,561,021		Other Expenses		89,230		
3	Reactive Allocator	(Line 71)	17.55%		O&M	(sum line 1 & 2)	340,280	4,703,710	7.2343%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**800,623**						
5					A&G		101,659,795	360,225,425	28.2212%
6	GSU Transformer Investment	Inputs Tab	19,820,373		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.4880%
7	Reactive Allocator	(Line 71)	17.55%		Working Capital	Line 216	12,182,966	360,225,425	3.3820%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**3,479,189**		General Plant		-	360,225,425	0.0000%
9					Other Taxes	Line 196(c)	8,192,927	360,225,425	2.2744%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	16,976		Depreciation	Line 168(c)			0.1663%
11	Reactive Allocator	(Line 71)	17.55%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**2,980**		Taxes (Federal/State/Local)	Line 180			2.8753%
13					ADIT	-Line 233(k)	($4,704,150)	360,225,425	-1.3059%
14	Total Cost of Power Plant	Inputs Tab	360,225,425				(Sum Lines 1 to 11 , Col. (h))		51.4705%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	335,827,055						
16	Balance of Plant Allocator	(Line 79)	0.1253%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	420,918						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	4,703,710						
19	Reactive Fixed Charge Rate	(Line 14(h))	51.4705%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**2,421,025**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 2,421,025**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		621.20						
		-						
		-						
	Total	621.20	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.91						
		-						
		-						
	Total	0.91	(Line 38 / 58)					
	MVA Capability (MVA)							
		684.14	(Line 31 / 41)					
		-						
		-						
	Total	684.14	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		286.63	(SQRT (Line 51^2 - Line 31^2))					
		-						
		-						
	Total	286.63	(Sum Lines 62 to 64)					
	Reactive Allocator	17.6%	(Line 69^2 / Line 58^2)					
		JCPL is TO Fleet						
	Max. MVAr	112.60						
	Nameplate MVAr	286.63						
	Exciter MW	1.98						
	Generator MW	621.20						
	Balance of Plant Allocator	0.1253%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ -	**15%**	$ -
	Control&Power Cabling	$ -	**1%**	$ -
	Switch Board Equipment	$ -	**1%**	$ -
	Switching Equipment	$ -	**1%**	$ -
	Transformers	$ 565,862	**3%**	$ 16,976
	Aux Generator	$ -	**0%**	$ -
	Fire Protection System	$ -	**0%**	$ -
	HVAC	$ -	**0%**	$ -
	Regulating Equipment	$ -	**50%**	$ -
	Structure	$ -	**0%**	$ -
	Misc	$ 8,662,556	**0%**	$ -
	Exciter & PPT	$ -	**100%**	$ -
	Station Grounding	$ -	**1%**	$ -
	Bus & Insulators	$ -	**80%**	$ -
	Capacitor Bank	$ -	**0%**	$ -
	Total	$ 9,228,418		$ 16,976

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	20,056,606	20,056,606	
	Coolants and Water (Nuclear Plants Only)	1,965,210		
	Steam Expenses	12,326,705	12,326,705	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	1,259,337		
	Rents	34,819,603	34,819,603	
	Allowances	2,763,016	2,763,016	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	3,700,095	3,700,095	
	Maintenance of Boiler (or reactor) Plant	288,393		
	Maintenance of Electric Plant	9,534,615		
	Maintenance of Misc Steam (or Nuclear) Plant	6,124,475	6,124,475	
	Other Power Production, & Other Expenses	11,457,706	11,457,706	
	Total NonFuel Expenses	104,295,761	91,248,206	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	2.6330%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.1253%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	104,295,761	Line 116			
	Allowances	2,763,016	Line 109			
	Non-Fuel Production O&M	101,532,745	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	20,056,606	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	9,534,615	Line 113(b)			
	Other Demand Related Expenses	71,191,600	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	100,782,821	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	9,534,615	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	9,534,615	(Line 138 + 139)	2.6330%	251,050	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	71,191,600	(Line 134)	0.1253%	89,230	
				Line 123		
	Balance of Plant Fixed Expenses				100,442,541	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		75,639,559	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		26,020,236	(allocated on plant labor)	
	Total		101,659,795		
Depreciation					
	Annual Depreciation Exp ...DE	7,204,508			
	Gross Production Plant Cost ... F	360,225,425	Line 14		
	SLDP=DE/F	2.0000%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	50			
	SFDP=(R/((1+R)^n-1)		0.1663%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.875%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		3,465,238		
	Payroll Taxes	5,403,699			
		0 87.4899%	Line 117		
	Fixed Payroll Taxes		4,727,688	(Line 193 * 194)	
	Total Other Taxes		8,192,927	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 * 201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.8753%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	603,950				
		100.000%				
	Production Related Prepayments	603,950	(Line 209 * 210)			
	Unit Specific M&S	110,046,662				
	Total	110,650,613	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.8753%				
	Working Capital Costs	12,182,966	(Line 213 * 214)			

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(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Accumulated Deferred Income Taxes										
Investment		360,225,425	Line 14					NPV of Col (j)>	56,667,797	
Asset Service Life		50	Line 167							
Composite Tax Rate		38.6790%	Line 177							
Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	7,204,508	3.750%	13,508,453	2,438,303	2,438,303	143,494	54,862	87,992	286,348	4,704,150
2	7,204,508	7.219%	26,004,673	7,271,716	9,710,019	571,435	218,475	350,409	1,140,319	4,704,150
3	7,204,508	6.677%	24,052,252	6,516,539	16,226,557	954,933	365,098	585,574	1,905,605	4,704,150
4	7,204,508	6.177%	22,251,124	5,819,881	22,046,438	1,297,433	496,045	795,599	2,589,077	4,704,150
5	7,204,508	5.713%	20,579,679	5,173,382	27,219,820	1,601,886	612,446	982,293	3,196,625	4,704,150
6	7,204,508	5.285%	19,037,914	4,577,043	31,796,863	1,871,245	715,429	1,147,466	3,734,141	4,704,150
7	7,204,508	4.888%	17,607,819	4,023,896	35,820,759	2,108,052	805,967	1,292,678	4,206,697	4,704,150
8	7,204,508	4.522%	16,289,394	3,513,943	39,334,702	2,314,847	885,031	1,419,487	4,619,365	4,704,150
9	7,204,508	4.462%	16,073,258	3,430,344	42,765,046	2,516,723	962,214	1,543,280	5,022,216	4,704,150
10	7,204,508	4.461%	16,069,656	3,428,950	46,193,996	2,718,517	1,039,365	1,667,022	5,424,903	4,704,150
11	7,204,508	4.462%	16,073,258	3,430,344	49,624,340	2,920,392	1,116,548	1,790,814	5,827,754	4,704,150
12	7,204,508	4.461%	16,069,656	3,428,950	53,053,290	3,122,186	1,193,699	1,914,556	6,230,441	4,704,150
13	7,204,508	4.462%	16,073,258	3,430,344	56,483,634	3,324,062	1,270,882	2,038,348	6,633,292	4,704,150
14	7,204,508	4.461%	16,069,656	3,428,950	59,912,585	3,525,856	1,348,033	2,162,090	7,035,979	4,704,150
15	7,204,508	4.462%	16,073,258	3,430,344	63,342,928	3,727,731	1,425,216	2,285,882	7,438,829	4,704,150
16	7,204,508	4.461%	16,069,656	3,428,950	66,771,879	3,929,525	1,502,367	2,409,624	7,841,516	4,704,150
17	7,204,508	4.462%	16,073,258	3,430,344	70,202,223	4,131,401	1,579,550	2,533,416	8,244,367	4,704,150
18	7,204,508	4.461%	16,069,656	3,428,950	73,631,173	4,333,195	1,656,701	2,657,158	8,647,054	4,704,150
19	7,204,508	4.462%	16,073,258	3,430,344	77,061,517	4,535,070	1,733,884	2,780,950	9,049,905	4,704,150
20	7,204,508	4.461%	16,069,656	3,428,950	80,490,467	4,736,864	1,811,036	2,904,692	9,452,592	4,704,150
21	7,204,508	2.231%	8,036,629	321,856	80,812,323	4,755,805	1,818,277	2,916,307	9,490,390	4,704,150
22	7,204,508	0.000%	0	-2,786,632	78,025,692	4,591,812	1,755,578	2,815,745	9,163,135	4,704,150
23	7,204,508	0.000%	0	-2,786,632	75,239,060	4,427,819	1,692,879	2,715,183	8,835,880	4,704,150
24	7,204,508	0.000%	0	-2,786,632	72,452,428	4,263,825	1,630,180	2,614,620	8,508,625	4,704,150
25	7,204,508	0.000%	0	-2,786,632	69,665,796	4,099,832	1,567,480	2,514,058	8,181,371	4,704,150
26	7,204,508	0.000%	0	-2,786,632	66,879,164	3,935,839	1,504,781	2,413,496	7,854,116	4,704,150
27	7,204,508	0.000%	0	-2,786,632	64,092,532	3,771,846	1,442,082	2,312,933	7,526,861	4,704,150
28	7,204,508	0.000%	0	-2,786,632	61,305,901	3,607,852	1,379,383	2,212,371	7,199,606	4,704,150
29	7,204,508	0.000%	0	-2,786,632	58,519,269	3,443,859	1,316,684	2,111,809	6,872,351	4,704,150
30	7,204,508	0.000%	0	-2,786,632	55,732,637	3,279,866	1,253,984	2,011,246	6,545,096	4,704,150
31	7,204,508	0.000%	0	-2,786,632	52,946,005	3,115,872	1,191,285	1,910,684	6,217,842	4,704,150
32	7,204,508	0.000%	0	-2,786,632	50,159,373	2,951,879	1,128,586	1,810,122	5,890,587	4,704,150
33	7,204,508	0.000%	0	-2,786,632	47,372,741	2,787,886	1,065,887	1,709,559	5,563,332	4,704,150
34	7,204,508	0.000%	0	-2,786,632	44,586,109	2,623,893	1,003,187	1,608,997	5,236,077	4,704,150
35	7,204,508	0.000%	0	-2,786,632	41,799,478	2,459,899	940,488	1,508,435	4,908,822	4,704,150
36	7,204,508	0.000%	0	-2,786,632	39,012,846	2,295,906	877,789	1,407,873	4,581,568	4,704,150
37	7,204,508	0.000%	0	-2,786,632	36,226,214	2,131,913	815,090	1,307,310	4,254,313	4,704,150
38	7,204,508	0.000%	0	-2,786,632	33,439,582	1,967,919	752,391	1,206,748	3,927,058	4,704,150
39	7,204,508	0.000%	0	-2,786,632	30,652,950	1,803,926	689,691	1,106,186	3,599,803	4,704,150
40	7,204,508	0.000%	0	-2,786,632	27,866,318	1,639,933	626,992	1,005,623	3,272,548	4,704,150
41	7,204,508	0.000%	0	-2,786,632	25,079,687	1,475,940	564,293	905,061	2,945,293	4,704,150
42	7,204,508	0.000%	0	-2,786,632	22,293,055	1,311,946	501,594	804,499	2,618,039	4,704,150
43	7,204,508	0.000%	0	-2,786,632	19,506,423	1,147,953	438,895	703,936	2,290,784	4,704,150
44	7,204,508	0.000%	0	-2,786,632	16,719,791	983,960	376,195	603,374	1,963,529	4,704,150
45	7,204,508	0.000%	0	-2,786,632	13,933,159	819,966	313,496	502,812	1,636,274	4,704,150
46	7,204,508	0.000%	0	-2,786,632	11,146,527	655,973	250,797	402,249	1,309,019	4,704,150
47	7,204,508	0.000%	0	-2,786,632	8,359,896	491,980	188,098	301,687	981,764	4,704,150
48	7,204,508	0.000%	0	-2,786,632	5,573,264	327,987	125,398	201,125	654,510	4,704,150
49	7,204,508	0.000%	0	-2,786,632	2,786,632	163,993	62,699	100,562	327,255	4,704,150
50	7,204,508	0.000%	0	-2,786,632	0	0	0	0	0	4,704,150

Unit Name: Peach Bottom 2 & 3 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 324,475,609	
2	Investment Generator & Exciter	Inputs Tab	48,671,341	
3	Reactive Allocator	(Line 71)	16.72%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**8,135,921**	
5				
6	GSU Transformer Investment	Inputs Tab	41,363,873	
7	Reactive Allocator	(Line 71)	16.72%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**6,914,401**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	636,592	
11	Reactive Allocator	(Line 71)	16.72%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**106,413**	
13				
14	Total Cost of Power Plant	Inputs Tab	1,360,681,860	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	1,270,010,053	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	688,087	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	15,844,823	
19	Reactive Fixed Charge Rate	(Line 14(h))	18.5690%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**2,942,232**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 2,942,232**	
23				
24				
25				
26				

	(e)		(f)	(g)	(h)
	Fixed Charge Rate for Reactive Plant				
			Calculated Amt	Plant	FCR % (f) / (g)
	Electric Expenses	Line 140	190,062		
	Other Expenses		30,664		
	O&M	(sum line 1 & 2)	220,727	15,844,823	1.3931%
	A&G		73,265,206	1,360,681,860	5.3844%
	CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0942%
	Working Capital	Line 216	23,058,146	1,360,681,860	1.6946%
	General Plant		-	1,360,681,860	0.0000%
	Other Taxes	Line 196(c)	3,982,382	1,360,681,860	0.2927%
	Depreciation	Line 168(c)			0.0752%
					8.1350%
	Taxes (Federal/State/Local)	Line 180			2.9795%
	ADIT	-Line 233(k)	($20,132,488)	1,360,681,860	-1.4796%
			(Sum Lines 1 to 11 , Col. (h))		18.5690%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		1,150.00						
		1,195.40						
		-						
	Total	2,345.40	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.93						
		0.90						
		-						
	Total	0.91	(Line 38 / 58)					
	MVA Capability (MVA)							
		1,243.24	(Line 31 / 41)					
		1,328.22	(Line 32 / 42)					
		-						
	Total	2,571.47	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		472.39	(SQRT (Line 51^2 - Line 31^2))					
		578.96	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	1,051.35	(Sum Lines 62 to 64)					
	Reactive Allocator	16.7%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ 2,015,820	15%	$ 302,373
	Control&Power Cabling	$ 19,695,956	1%	$ 196,960
	Switch Board Equipment	$ 11,507,453	1%	$ 115,075
	Switching Equipment	$ 625,734	1%	$ 6,257
	Transformers	$ 1,862,746	3%	$ 55,882
	Aux Generator	$ 129,640	0%	$ -
	Fire Protection System	$ 126,725	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ 794	50%	$ 397
	Structure	$ 25,625	0%	$ -
	Misc	$ 28,280,047	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ 20,693	1%	$ 207
	Bus & Insulators	$ (50,699)	80%	$ (40,559)
	Capacitor Bank	$ -	0%	$ -
	Total	$ 64,240,533		$ 636,592

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	15,945,051	15,945,051	
	Coolants and Water (Nuclear Plants Only)	1,562,346		
	Steam Expenses	9,799,760	9,799,760	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	1,001,176		
	Rents	27,681,670	27,681,670	
	Allowances	2,196,604	2,196,604	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	2,941,585	2,941,585	
	Maintenance of Boiler (or reactor) Plant	229,273		
	Maintenance of Electric Plant	7,580,042		
	Maintenance of Misc Steam (or Nuclear) Plant	4,868,973	4,868,973	
	Other Power Production, & Other Expenses	9,108,904	9,108,904	
	Total NonFuel Expenses	82,915,386	72,542,547	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	2.5074%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	82,915,386	Line 116			
	Allowances	2,196,604	Line 109			
	Non-Fuel Production O&M	80,718,781	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	15,945,051	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	7,580,042	Line 113(b)			
	Other Demand Related Expenses	56,597,497	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	80,122,590	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	7,580,042	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	7,580,042	(Line 138 + 139)	2.5074%	190,062	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	56,597,497	(Line 134)	0.0542%	30,664	
				Line 123		
	Balance of Plant Fixed Expenses				79,901,863	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		54,201,596	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		19,063,610	(allocated on plant labor)	
	Total		73,265,206		
Depreciation					
	Annual Depreciation Exp ...DE	22,868,603			
	Gross Production Plant Cost ... F	1,360,681,860	Line 14		
	SLDP=DE/F	1.6807%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	60			
	SFDP=(R/((1+R)^n-1)		0.0752%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.979%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		862,588		
	Payroll Taxes	3,565,892			
	0	87.4899%	Line 117		
	Fixed Payroll Taxes		3,119,794	(Line 193 * 194)	
	Total Other Taxes		3,982,382	(Line 192 + 195)	
		Plant		**Depreciation**	**Total**
General Plant		-		-	
	0	0.000%		0.000%	Line 159
	Fixed General Plant	-		-	(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188		
	Taxes on General Plant	2.9795%	Line 189		
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-
Working Capital					
	Prepayments	2,281,305			
		100.000%			
	Production Related Prepayments	2,281,305	(Line 209 * 210)		
	Unit Specific M&S	205,179,355			
	Total	207,460,660	(Line 211 + 212)		
	Return on Working Capital	8.1350%			
	Taxes on Working Capital	2.9795%			
	Working Capital Costs	23,058,146	(Line 213 * 214)		

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Accumulated Deferred Income Taxes

Investment	1,360,681,860	Line 14
Asset Service Life	60	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 245,212,300

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	22,678,031	3.750%	51,025,570	10,964,545	10,964,545	645,263	246,702	395,682	1,287,648	20,132,488
2	22,678,031	7.219%	98,227,623	29,221,827	40,186,371	2,364,968	904,193	1,450,222	4,719,383	20,132,488
3	22,678,031	6.677%	90,852,728	26,369,291	66,555,662	3,916,801	1,497,502	2,401,821	7,816,125	20,132,488
4	22,678,031	6.177%	84,049,318	23,737,800	90,293,463	5,313,770	2,031,603	3,258,457	10,603,830	20,132,488
5	22,678,031	5.713%	77,735,755	21,295,777	111,589,240	6,567,027	2,510,758	4,026,966	13,104,751	20,132,488
6	22,678,031	5.285%	71,912,036	19,043,221	130,632,460	7,687,720	2,939,230	4,714,187	15,341,138	20,132,488
7	22,678,031	4.888%	66,510,129	16,953,817	147,586,278	8,685,452	3,320,691	5,326,006	17,332,150	20,132,488
8	22,678,031	4.522%	61,530,034	15,027,566	162,613,844	9,569,825	3,658,811	5,868,312	19,096,948	20,132,488
9	22,678,031	4.462%	60,713,625	14,711,787	177,325,631	10,435,613	3,989,827	6,399,222	20,824,663	20,132,488
10	22,678,031	4.461%	60,700,018	14,706,524	192,032,155	11,301,092	4,320,723	6,929,943	22,551,759	20,132,488
11	22,678,031	4.462%	60,713,625	14,711,787	206,743,943	12,166,881	4,651,739	7,460,853	24,279,473	20,132,488
12	22,678,031	4.461%	60,700,018	14,706,524	221,450,467	13,032,360	4,982,636	7,991,573	26,006,569	20,132,488
13	22,678,031	4.462%	60,713,625	14,711,787	236,162,254	13,898,149	5,313,651	8,522,484	27,734,283	20,132,488
14	22,678,031	4.461%	60,700,018	14,706,524	250,868,778	14,763,628	5,644,548	9,053,204	29,461,379	20,132,488
15	22,678,031	4.462%	60,713,625	14,711,787	265,580,566	15,629,416	5,975,563	9,584,114	31,189,093	20,132,488
16	22,678,031	4.461%	60,700,018	14,706,524	280,287,090	16,494,895	6,306,460	10,114,835	32,916,189	20,132,488
17	22,678,031	4.462%	60,713,625	14,711,787	294,998,877	17,360,684	6,637,475	10,645,745	34,643,904	20,132,488
18	22,678,031	4.461%	60,700,018	14,706,524	309,705,401	18,226,163	6,968,372	11,176,465	36,371,000	20,132,488
19	22,678,031	4.462%	60,713,625	14,711,787	324,417,189	19,091,952	7,299,387	11,707,376	38,098,714	20,132,488
20	22,678,031	4.461%	60,700,018	14,706,524	339,123,713	19,957,431	7,630,284	12,238,096	39,825,810	20,132,488
21	22,678,031	2.231%	30,356,812	2,970,076	342,093,789	20,132,219	7,697,110	12,345,278	40,174,608	20,132,488
22	22,678,031	0.000%	0	-8,771,636	333,322,153	19,616,009	7,499,748	12,028,733	39,144,490	20,132,488
23	22,678,031	0.000%	0	-8,771,636	324,550,518	19,099,798	7,302,387	11,712,187	38,114,372	20,132,488
24	22,678,031	0.000%	0	-8,771,636	315,778,882	18,583,587	7,105,025	11,395,642	37,084,254	20,132,488
25	22,678,031	0.000%	0	-8,771,636	307,007,246	18,067,376	6,907,663	11,079,096	36,054,135	20,132,488
26	22,678,031	0.000%	0	-8,771,636	298,235,611	17,551,166	6,710,301	10,762,550	35,024,017	20,132,488
27	22,678,031	0.000%	0	-8,771,636	289,463,975	17,034,955	6,512,939	10,446,005	33,993,899	20,132,488
28	22,678,031	0.000%	0	-8,771,636	280,692,340	16,518,744	6,315,578	10,129,459	32,963,781	20,132,488
29	22,678,031	0.000%	0	-8,771,636	271,920,704	16,002,533	6,118,216	9,812,914	31,933,663	20,132,488
30	22,678,031	0.000%	0	-8,771,636	263,149,068	15,486,323	5,920,854	9,496,368	30,903,545	20,132,488
31	22,678,031	0.000%	0	-8,771,636	254,377,433	14,970,112	5,723,492	9,179,822	29,873,426	20,132,488
32	22,678,031	0.000%	0	-8,771,636	245,605,797	14,453,901	5,526,130	8,863,277	28,843,308	20,132,488
33	22,678,031	0.000%	0	-8,771,636	236,834,161	13,937,690	5,328,769	8,546,731	27,813,190	20,132,488
34	22,678,031	0.000%	0	-8,771,636	228,062,526	13,421,480	5,131,407	8,230,186	26,783,072	20,132,488
35	22,678,031	0.000%	0	-8,771,636	219,290,890	12,905,269	4,934,045	7,913,640	25,752,954	20,132,488
36	22,678,031	0.000%	0	-8,771,636	210,519,255	12,389,058	4,736,683	7,597,094	24,722,836	20,132,488
37	22,678,031	0.000%	0	-8,771,636	201,747,619	11,872,847	4,539,321	7,280,549	23,692,718	20,132,488
38	22,678,031	0.000%	0	-8,771,636	192,975,983	11,356,637	4,341,960	6,964,003	22,662,599	20,132,488
39	22,678,031	0.000%	0	-8,771,636	184,204,348	10,840,426	4,144,598	6,647,458	21,632,481	20,132,488
40	22,678,031	0.000%	0	-8,771,636	175,432,712	10,324,215	3,947,236	6,330,912	20,602,363	20,132,488
41	22,678,031	0.000%	0	-8,771,636	166,661,077	9,808,004	3,749,874	6,014,366	19,572,245	20,132,488
42	22,678,031	0.000%	0	-8,771,636	157,889,441	9,291,794	3,552,512	5,697,821	18,542,127	20,132,488
43	22,678,031	0.000%	0	-8,771,636	149,117,805	8,775,583	3,355,151	5,381,275	17,512,009	20,132,488
44	22,678,031	0.000%	0	-8,771,636	140,346,170	8,259,372	3,157,789	5,064,730	16,481,890	20,132,488
45	22,678,031	0.000%	0	-8,771,636	131,574,534	7,743,161	2,960,427	4,748,184	15,451,772	20,132,488
46	22,678,031	0.000%	0	-8,771,636	122,802,899	7,226,951	2,763,065	4,431,638	14,421,654	20,132,488
47	22,678,031	0.000%	0	-8,771,636	114,031,263	6,710,740	2,565,703	4,115,093	13,391,536	20,132,488
48	22,678,031	0.000%	0	-8,771,636	105,259,627	6,194,529	2,368,342	3,798,547	12,361,418	20,132,488
49	22,678,031	0.000%	0	-8,771,636	96,487,992	5,678,318	2,170,980	3,482,002	11,331,300	20,132,488
50	22,678,031	0.000%	0	-8,771,636	87,716,356	5,162,108	1,973,618	3,165,456	10,301,182	20,132,488
51	22,678,031	0.000%	0	-8,771,636	78,944,720	4,645,897	1,776,256	2,848,910	9,271,063	20,132,488
52	22,678,031	0.000%	0	-8,771,636	70,173,085	4,129,686	1,578,894	2,532,365	8,240,945	20,132,488
53	22,678,031	0.000%	0	-8,771,636	61,401,449	3,613,475	1,381,533	2,215,819	7,210,827	20,132,488
54	22,678,031	0.000%	0	-8,771,636	52,629,814	3,097,265	1,184,171	1,899,274	6,180,709	20,132,488
55	22,678,031	0.000%	0	-8,771,636	43,858,178	2,581,054	986,809	1,582,728	5,150,591	20,132,488
56	22,678,031	0.000%	0	-8,771,636	35,086,542	2,064,843	789,447	1,266,182	4,120,473	20,132,488
57	22,678,031	0.000%	0	-8,771,636	26,314,907	1,548,632	592,085	949,637	3,090,354	20,132,488
58	22,678,031	0.000%	0	-8,771,636	17,543,271	1,032,422	394,724	633,091	2,060,236	20,132,488
59	22,678,031	0.000%	0	-8,771,636	8,771,636	516,211	197,362	316,546	1,030,118	20,132,488
60	22,678,031	0.000%	0	-8,771,636	0	0	0	0	0	20,132,488

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Unit Name: Pennsbury 1&2 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 568,704		Electric Expenses	Line 140	1,706		
2	Investment Generator & Exciter	Inputs Tab	$ 85,306		Other Expenses		318		
3	Reactive Allocator	(Line 71)	27.75%		O&M	(sum line 1 & 2)	2,024	28,093	7.2049%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**23,672**						
5					A&G		447,267	3,820,667	11.7065%
6	GSU Transformer Investment	Inputs Tab	-		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.2603%
7	Reactive Allocator	(Line 71)	27.75%		Working Capital	Line 216	17,742	3,820,667	0.4644%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**		General Plant		-	3,820,667	0.0000%
9					Other Taxes	Line 196(c)	55,959	3,820,667	1.4646%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	8,655		Depreciation	Line 168(c)			0.1663%
11	Reactive Allocator	(Line 71)	27.75%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**2,402**		Taxes (Federal/State/Local)	Line 180			2.8753%
13					ADIT	-Line 233(k)	($49,894)	3,820,667	-1.3059%
14	Total Cost of Power Plant	Inputs Tab	3,820,667				(Sum Lines 1 to 11 , Col. (h))		30.9714%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	3,726,706						
16	Balance of Plant Allocator	(Line 79)	0.0542%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	2,019						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	28,093						
19	Reactive Fixed Charge Rate	(Line 14(h))	30.9714%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**8,701**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 8,701**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		2.50						
		2.50						
		-						
	Total	5.00	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.85						
		0.85						
		-						
	Total	0.85	(Line 38 / 58)					
	MVA Capability (MVA)							
		2.94	(Line 31 / 41)					
		2.94	(Line 32 / 42)					
		-						
	Total	5.88	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		1.55	(SQRT (Line 51^2 - Line 31^2))					
		1.55	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	3.10	(Sum Lines 62 to 64)					
	Reactive Allocator	27.8%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ -	50%	$ -
	Control&Power Cabling	$ 17,310	50%	$ 8,655
	Switch Board Equipment	$ -	50%	$ -
	Switching Equipment	$ -	40%	$ -
	Transformers	$ -	10%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ -	0%	$ -
	Misc	$ 224,796	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 242,106		$ 8,655

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	235,561	235,561	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	60,847	60,847	
	Steam From Other Sources	117,580		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	36,024		
	Rents	219,236	219,236	
	Allowances	8,859	8,859	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	91,883	91,883	
	Maintenance of Boiler (or reactor) Plant	39,401		
	Maintenance of Electric Plant	40,991		
	Maintenance of Misc Steam (or Nuclear) Plant	51,019	51,019	
	Other Power Production, & Other Expenses	154,755	154,755	
	Total NonFuel Expenses	1,056,155	822,159	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation			
	Plant Var Allocators		
	Electric Expense Allocator	4.1625%	Line 4(c) / 1(c))
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)
	Other Demand Expense Allocator	0.0542%	Line 79
	Production Plant Expenses		
	Total NonFuel Expenses	1,056,155	Line 116
	Allowances	8,859	Line 109
	Non-Fuel Production O&M	1,047,296	(Line 126 - 127)
	Operating Expenses		
	Operations Supervision & Engineering	235,561	Line 102(c)
	Electric Expenses	0	Line 106(c)
	Maintenance of Electric Plant	40,991	Line 113(b)
	Other Demand Related Expenses	586,598	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)
	Total	863,151	(Sum Lines 131 to 134)

				Allocator	Allocated Amount	
	Maintenance of Electric Plant	40,991	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	40,991	(Line 138 + 139)	4.1625%	1,706	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	586,598	(Line 134)	0.0542%	318	
				Line 123		
	Balance of Plant Fixed Expenses				861,127	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		95,853	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		351,414	(allocated on plant labor)	
	Total		447,267		
Depreciation					
	Annual Depreciation Exp ...DE	76,413			
	Gross Production Plant Cost ... F	3,820,667	Line 14		
	SLDP=DE/F	2.0000%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	50			
	SFDP=(R/((1+R)^n-1)		0.1663%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.875%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		55,959	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		55,959	(Line 192 + 195)	

	Plant		Depreciation	Total	
General Plant	-		-		
	0.000%		0.000%		Line 159
Fixed General Plant	-		-		(Lines 200 *201)
Return on General Plant	8.1350%	Line 188			
Taxes on General Plant	2.8753%	Line 189			
General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
Prepayments	28,740		
	100.000%		
Production Related Prepayments	28,740	(Line 209 * 210)	
Unit Specific M&S	132,405		
Total	161,144	(Line 211 + 212)	
Return on Working Capital	8.1350%		
Taxes on Working Capital	2.8753%		
Working Capital Costs	17,742	(Line 213 * 214)	

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Accumulated Deferred Income Taxes

Investment	3,820,667	Line 14
Asset Service Life	50	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 601,037

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	PMT of NPV col. (j)
1	76,413	3.750%	143,275	25,861	25,861	1,522	582	933	3,037	49,894
2	76,413	7.219%	275,814	77,126	102,988	6,061	2,317	3,717	12,095	49,894
3	76,413	6.677%	255,106	69,117	172,104	10,128	3,872	6,211	20,211	49,894
4	76,413	6.177%	236,003	61,728	233,832	13,761	5,261	8,438	27,461	49,894
5	76,413	5.713%	218,275	54,871	288,702	16,990	6,496	10,419	33,904	49,894
6	76,413	5.285%	201,922	48,546	337,248	19,847	7,588	12,170	39,606	49,894
7	76,413	4.888%	186,754	42,679	379,927	22,359	8,548	13,711	44,618	49,894
8	76,413	4.522%	172,771	37,270	417,197	24,552	9,387	15,056	48,994	49,894
9	76,413	4.462%	170,478	36,383	453,580	26,693	10,206	16,369	53,267	49,894
10	76,413	4.461%	170,440	36,369	489,948	28,833	11,024	17,681	57,538	49,894
11	76,413	4.462%	170,478	36,383	526,332	30,975	11,842	18,994	61,811	49,894
12	76,413	4.461%	170,440	36,369	562,700	33,115	12,661	20,306	66,082	49,894
13	76,413	4.462%	170,478	36,383	599,084	35,256	13,479	21,619	70,355	49,894
14	76,413	4.461%	170,440	36,369	635,452	37,396	14,298	22,932	74,626	49,894
15	76,413	4.462%	170,478	36,383	671,836	39,538	15,116	24,245	78,899	49,894
16	76,413	4.461%	170,440	36,369	708,204	41,678	15,935	25,557	83,170	49,894
17	76,413	4.462%	170,478	36,383	744,587	43,819	16,753	26,870	87,442	49,894
18	76,413	4.461%	170,440	36,369	780,956	45,959	17,572	28,183	91,713	49,894
19	76,413	4.462%	170,478	36,383	817,339	48,100	18,390	29,496	95,986	49,894
20	76,413	4.461%	170,440	36,369	853,708	50,241	19,208	30,808	100,257	49,894
21	76,413	2.231%	85,239	3,414	857,122	50,442	19,285	30,931	100,658	49,894
22	76,413	0.000%	0	-29,556	827,566	48,702	18,620	29,865	97,187	49,894
23	76,413	0.000%	0	-29,556	798,010	46,963	17,955	28,798	93,716	49,894
24	76,413	0.000%	0	-29,556	768,454	45,224	17,290	27,732	90,245	49,894
25	76,413	0.000%	0	-29,556	738,898	43,484	16,625	26,665	86,774	49,894
26	76,413	0.000%	0	-29,556	709,342	41,745	15,960	25,598	83,303	49,894
27	76,413	0.000%	0	-29,556	679,786	40,005	15,295	24,532	79,832	49,894
28	76,413	0.000%	0	-29,556	650,230	38,266	14,630	23,465	76,361	49,894
29	76,413	0.000%	0	-29,556	620,674	36,527	13,965	22,399	72,890	49,894
30	76,413	0.000%	0	-29,556	591,118	34,787	13,300	21,332	69,419	49,894
31	76,413	0.000%	0	-29,556	561,562	33,048	12,635	20,265	65,948	49,894
32	76,413	0.000%	0	-29,556	532,006	31,309	11,970	19,199	62,477	49,894
33	76,413	0.000%	0	-29,556	502,451	29,569	11,305	18,132	59,006	49,894
34	76,413	0.000%	0	-29,556	472,895	27,830	10,640	17,066	55,536	49,894
35	76,413	0.000%	0	-29,556	443,339	26,090	9,975	15,999	52,065	49,894
36	76,413	0.000%	0	-29,556	413,783	24,351	9,310	14,932	48,594	49,894
37	76,413	0.000%	0	-29,556	384,227	22,612	8,645	13,866	45,123	49,894
38	76,413	0.000%	0	-29,556	354,671	20,872	7,980	12,799	41,652	49,894
39	76,413	0.000%	0	-29,556	325,115	19,133	7,315	11,733	38,181	49,894
40	76,413	0.000%	0	-29,556	295,559	17,394	6,650	10,666	34,710	49,894
41	76,413	0.000%	0	-29,556	266,003	15,654	5,985	9,599	31,239	49,894
42	76,413	0.000%	0	-29,556	236,447	13,915	5,320	8,533	27,768	49,894
43	76,413	0.000%	0	-29,556	206,891	12,176	4,655	7,466	24,297	49,894
44	76,413	0.000%	0	-29,556	177,335	10,436	3,990	6,400	20,826	49,894
45	76,413	0.000%	0	-29,556	147,780	8,697	3,325	5,333	17,355	49,894
46	76,413	0.000%	0	-29,556	118,224	6,957	2,660	4,266	13,884	49,894
47	76,413	0.000%	0	-29,556	88,668	5,218	1,995	3,200	10,413	49,894
48	76,413	0.000%	0	-29,556	59,112	3,479	1,330	2,133	6,942	49,894
49	76,413	0.000%	0	-29,556	29,556	1,739	665	1,067	3,471	49,894
50	76,413	0.000%	0	-29,556	0	0	0	0	0	49,894

Unit Name: Perryman 1,3,4,51 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 177,706,677		Electric Expenses	Line 140	9,996		
2	Investment Generator & Exciter	Inputs Tab	$ 26,656,002		Other Expenses		598		
3	Reactive Allocator	(Line 71)	24.50%		O&M	(sum line 1 & 2)	10,593	6,796,562	0.1559%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**6,531,683**						
5					A&G		3,246,876	250,720,971	1.2950%
6	GSU Transformer Investment	Inputs Tab	784,897		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0199%
7	Reactive Allocator	(Line 71)	24.50%		Working Capital	Line 216	1,682,364	250,720,971	0.6710%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**192,328**		General Plant		-	250,720,971	0.0000%
9					Other Taxes	Line 196(c)	2,143,070	250,720,971	0.8548%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	156,257		Depreciation	Line 168(c)			0.2483%
11	Reactive Allocator	(Line 71)	24.50%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**38,289**		Taxes (Federal/State/Local)	Line 180			2.8113%
13					ADIT	-Line 233(k)	($2,999,980)	250,720,971	-1.1965%
14	Total Cost of Power Plant	Inputs Tab	250,720,971				(Sum Lines 1 to 11 , Col. (h))		12.9946%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	223,123,816						
16	Balance of Plant Allocator	(Line 79)	0.0154%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	34,263						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	6,796,562						
19	Reactive Fixed Charge Rate	(Line 14(h))	12.9946%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**883,183**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 883,183**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		53.00						
		53.00						
		53.00						
		53.00						
		144.90						
	Total	356.90	(Sum Lines 31 to 35)					
	Nominal Power Factor (pf)							
		0.85						
		0.85						
		0.85						
		0.85						
		0.90						
	Total	0.87	(Line 38 / 58)					
	MVA Capability (MVA)							
		62.35	(Line 31 / 41)					
		62.35	(Line 32 / 42)					
		62.35	(Line 33 / 43)					
		62.35	(Line 34 / 44)					
		161.90	(Line 35 / 45)					
	Total	411.31	(Sum Lines 51 to 55)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		32.85	(SQRT (Line 51^2 - Line 31^2))					
		32.85	(SQRT (Line 52^2 - Line 32^2))					
		32.85	(SQRT (Line 53^2 - Line 33^2))					
		32.85	(SQRT (Line 54^2 - Line 34^2))					
		72.22	(SQRT (Line 55^2 - Line 35^2))					
	Total	203.60	(Sum Lines 62 to 66)					
	Reactive Allocator	24.5%	(Line 69^2 / Line 58^2)					
		BGE is TO Fleet						
	Max. MVAr	27.50						
	Nameplate MVAr	571.22						
	Exciter MW	3.08						
	Generator MW	965.46						
	Balance of Plant Allocator	0.0154%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ -	**50%**	$ -
	Control&Power Cabling	$ -	**50%**	$ -
	Switch Board Equipment	$ -	**50%**	$ -
	Switching Equipment	$ 59,681	**40%**	$ 23,872
	Transformers	$ -	**10%**	$ -
	Aux Generator	$ -	**0%**	$ -
	Fire Protection System	$ -	**0%**	$ -
	HVAC	$ -	**0%**	$ -
	Regulating Equipment	$ 176,513	**75%**	$ 132,385
	Structure	$ -	**0%**	$ -
	Misc	$ 21,318,503	**0%**	$ -
	Exciter & PPT	$ -	**100%**	$ -
	Station Grounding	$ -	**5%**	$ -
	Bus & Insulators	$ -	**80%**	$ -
	Capacitor Bank	$ -	**0%**	$ -
	Total	$ 21,554,696		$ 156,257

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	1,562,813	1,562,813	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	403,686	403,686	
	Steam From Other Sources	780,076		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	238,995		
	Rents	1,454,502	1,454,502	
	Allowances	58,774	58,774	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	609,590	609,590	
	Maintenance of Boiler (or reactor) Plant	261,403		
	Maintenance of Electric Plant	271,954		
	Maintenance of Misc Steam (or Nuclear) Plant	338,484	338,484	
	Other Power Production, & Other Expenses	1,026,708	1,026,708	
	Total NonFuel Expenses	7,006,986	5,454,558	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	3.6755%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0154%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	7,006,986	Line 116			
	Allowances	58,774	Line 109			
	Non-Fuel Production O&M	6,948,212	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	1,562,813	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	271,954	Line 113(b)			
	Other Demand Related Expenses	3,891,745	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	5,726,511	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	271,954	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	271,954	(Line 138 + 139)	3.6755%	9,996	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	3,891,745	(Line 134)	0.0154%	598	
				Line 123		
	Balance of Plant Fixed Expenses				5,715,918	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		757,586	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		2,489,290	(allocated on plant labor)	
	Total		3,246,876		
Depreciation					
	Annual Depreciation Exp ...DE	5,571,577			
	Gross Production Plant Cost ... F	250,720,971	Line 14		
	SLDP=DE/F	2.2222%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	45			
	SFDP=(R/((1+R)^n-1)		0.2483%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.811%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		2,143,070	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		2,143,070	(Line 192 + 195)	

	Plant		Depreciation	Total	
General Plant	-		-		
	0.000%		0.000%		Line 159
Fixed General Plant	-		-		(Lines 200 *201)
Return on General Plant	8.1350%	Line 188			
Taxes on General Plant	2.8113%	Line 189			
General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
Prepayments	1,885,966		
	100.000%		
Production Related Prepayments	1,885,966	(Line 209 * 210)	
Unit Specific M&S	13,483,260		
Total	15,369,227	(Line 211 + 212)	
Return on Working Capital	8.1350%		
Taxes on Working Capital	2.8113%		
Working Capital Costs	1,682,364	(Line 213 * 214)	

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Accumulated Deferred Income Taxes

Investment	250,720,971	Line 14
Asset Service Life	45	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 35,785,300

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	PMT of NPV col. (j)
1	5,571,577	3.750%	9,402,036	1,481,583	1,481,583	87,191	33,336	53,467	173,993	2,999,980
2	5,571,577	7.219%	18,099,547	4,845,693	6,327,277	372,360	142,364	228,335	743,059	2,999,980
3	5,571,577	6.677%	16,740,639	4,320,082	10,647,358	626,597	239,566	384,236	1,250,398	2,999,980
4	5,571,577	6.177%	15,487,034	3,835,200	14,482,558	852,299	325,858	522,638	1,700,794	2,999,980
5	5,571,577	5.713%	14,323,689	3,385,229	17,867,787	1,051,519	402,025	644,802	2,098,347	2,999,980
6	5,571,577	5.285%	13,250,603	2,970,171	20,837,958	1,226,314	468,854	751,988	2,447,156	2,999,980
7	5,571,577	4.888%	12,255,241	2,585,174	23,423,132	1,378,451	527,020	845,280	2,750,752	2,999,980
8	5,571,577	4.522%	11,337,602	2,230,241	25,653,373	1,509,701	577,201	925,764	3,012,666	2,999,980
9	5,571,577	4.462%	11,187,170	2,172,055	27,825,428	1,637,526	626,072	1,004,148	3,267,746	2,999,980
10	5,571,577	4.461%	11,184,662	2,171,085	29,996,513	1,765,295	674,922	1,082,496	3,522,713	2,999,980
11	5,571,577	4.462%	11,187,170	2,172,055	32,168,569	1,893,120	723,793	1,160,880	3,777,793	2,999,980
12	5,571,577	4.461%	11,184,662	2,171,085	34,339,654	2,020,889	772,642	1,239,229	4,032,760	2,999,980
13	5,571,577	4.462%	11,187,170	2,172,055	36,511,709	2,148,714	821,513	1,317,613	4,287,840	2,999,980
14	5,571,577	4.461%	11,184,662	2,171,085	38,682,794	2,276,482	870,363	1,395,962	4,542,807	2,999,980
15	5,571,577	4.462%	11,187,170	2,172,055	40,854,849	2,404,308	919,234	1,474,346	4,797,888	2,999,980
16	5,571,577	4.461%	11,184,662	2,171,085	43,025,935	2,532,076	968,084	1,552,694	5,052,854	2,999,980
17	5,571,577	4.462%	11,187,170	2,172,055	45,197,990	2,659,902	1,016,955	1,631,078	5,307,935	2,999,980
18	5,571,577	4.461%	11,184,662	2,171,085	47,369,075	2,787,670	1,065,804	1,709,427	5,562,901	2,999,980
19	5,571,577	4.462%	11,187,170	2,172,055	49,541,130	2,915,495	1,114,675	1,787,811	5,817,982	2,999,980
20	5,571,577	4.461%	11,184,662	2,171,085	51,712,215	3,043,264	1,163,525	1,866,160	6,072,949	2,999,980
21	5,571,577	2.231%	5,593,585	8,512	51,720,728	3,043,765	1,163,716	1,866,467	6,073,948	2,999,980
22	5,571,577	0.000%	0	-2,155,030	49,565,697	2,916,941	1,115,228	1,788,698	5,820,867	2,999,980
23	5,571,577	0.000%	0	-2,155,030	47,410,667	2,790,118	1,066,740	1,710,928	5,567,786	2,999,980
24	5,571,577	0.000%	0	-2,155,030	45,255,637	2,663,294	1,018,252	1,633,159	5,314,705	2,999,980
25	5,571,577	0.000%	0	-2,155,030	43,100,606	2,536,471	969,764	1,555,389	5,061,624	2,999,980
26	5,571,577	0.000%	0	-2,155,030	40,945,576	2,409,647	921,275	1,477,620	4,808,542	2,999,980
27	5,571,577	0.000%	0	-2,155,030	38,790,546	2,282,824	872,787	1,399,850	4,555,461	2,999,980
28	5,571,577	0.000%	0	-2,155,030	36,635,515	2,156,000	824,299	1,322,081	4,302,380	2,999,980
29	5,571,577	0.000%	0	-2,155,030	34,480,485	2,029,177	775,811	1,244,311	4,049,299	2,999,980
30	5,571,577	0.000%	0	-2,155,030	32,325,455	1,902,353	727,323	1,166,542	3,796,218	2,999,980
31	5,571,577	0.000%	0	-2,155,030	30,170,424	1,775,529	678,835	1,088,772	3,543,136	2,999,980
32	5,571,577	0.000%	0	-2,155,030	28,015,394	1,648,706	630,346	1,011,003	3,290,055	2,999,980
33	5,571,577	0.000%	0	-2,155,030	25,860,364	1,521,882	581,858	933,234	3,036,974	2,999,980
34	5,571,577	0.000%	0	-2,155,030	23,705,333	1,395,059	533,370	855,464	2,783,893	2,999,980
35	5,571,577	0.000%	0	-2,155,030	21,550,303	1,268,235	484,882	777,695	2,530,812	2,999,980
36	5,571,577	0.000%	0	-2,155,030	19,395,273	1,141,412	436,394	699,925	2,277,731	2,999,980
37	5,571,577	0.000%	0	-2,155,030	17,240,243	1,014,588	387,905	622,156	2,024,649	2,999,980
38	5,571,577	0.000%	0	-2,155,030	15,085,212	887,765	339,417	544,386	1,771,568	2,999,980
39	5,571,577	0.000%	0	-2,155,030	12,930,182	760,941	290,929	466,617	1,518,487	2,999,980
40	5,571,577	0.000%	0	-2,155,030	10,775,152	634,118	242,441	388,847	1,265,406	2,999,980
41	5,571,577	0.000%	0	-2,155,030	8,620,121	507,294	193,953	311,078	1,012,325	2,999,980
42	5,571,577	0.000%	0	-2,155,030	6,465,091	380,471	145,465	233,308	759,244	2,999,980
43	5,571,577	0.000%	0	-2,155,030	4,310,061	253,647	96,976	155,539	506,162	2,999,980
44	5,571,577	0.000%	0	-2,155,030	2,155,030	126,824	48,488	77,769	253,081	2,999,980
45	5,571,577	0.000%	0	-2,155,030	0	0	0	0	0	2,999,980

Unit Name: Perryman 6 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 88,242,961		Electric Expenses	Line 140	-		
2	Investment Generator & Exciter	Inputs Tab	$ 13,236,444		Other Expenses		-		
3	Reactive Allocator	(Line 71)	27.75%		O&M	(sum line 1 & 2)	-	3,688,910	0.0000%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**3,673,113**						
5					A&G		-	116,109,159	0.0000%
6	GSU Transformer Investment	Inputs Tab	-		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0000%
7	Reactive Allocator	(Line 71)	27.75%		Working Capital	Line 216	93,619	116,109,159	0.0806%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**		General Plant		-	116,109,159	0.0000%
9					Other Taxes	Line 196(c)	-	116,109,159	0.0000%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	-		Depreciation	Line 168(c)			0.8611%
11	Reactive Allocator	(Line 71)	27.75%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**0**		Taxes (Federal/State/Local)	Line 180			2.5840%
13					ADIT	-Line 233(k)	($825,789)	116,109,159	-0.7112%
14	Total Cost of Power Plant	Inputs Tab	116,109,159				(Sum Lines 1 to 11 , Col. (h))		10.9495%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	102,872,715						
16	Balance of Plant Allocator	(Line 79)	0.0154%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	15,797						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	3,688,910						
19	Reactive Fixed Charge Rate	(Line 14(h))	10.9495%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**403,917**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 403,917**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		141.06						
		-						
		-						
	Total	141.06	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.85						
		-						
		-						
	Total	0.85	(Line 38 / 58)					
	MVA Capability (MVA)							
		165.95	(Line 31 / 41)					
		-						
		-						
	Total	165.95	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		87.42	(SQRT (Line 51^2 - Line 31^2))					
		-						
		-						
	Total	87.42	(Sum Lines 62 to 64)					
	Reactive Allocator	27.8%	(Line 69^2 / Line 58^2)					
		BGE is TO Fleet						
	Max. MVAr	27.50						
	Nameplate MVAr	571.22						
	Exciter MW	3.08						
	Generator MW	965.46						
	Balance of Plant Allocator	0.0154%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ -	50%	$ -
	Control&Power Cabling	$ -	50%	$ -
	Switch Board Equipment	$ -	50%	$ -
	Switching Equipment	$ -	40%	$ -
	Transformers	$ -	10%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ -	0%	$ -
	Misc	$ -	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ -		$ -

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	1	1	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	0	-	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	0		
	Rents	0	-	
	Allowances	0	-	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	0	-	
	Maintenance of Boiler (or reactor) Plant	0		
	Maintenance of Electric Plant	0		
	Maintenance of Misc Steam (or Nuclear) Plant	0	-	
	Other Power Production, & Other Expenses	0	-	
	Total NonFuel Expenses	1	1	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		100.00%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation			
	Plant Var Allocators		
	Electric Expense Allocator	4.1625%	Line 4(c) / 1(c))
	Operations Suprv & Engrg Allocator	#DIV/0!	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)
	Other Demand Expense Allocator	0.0154%	Line 79
	Production Plant Expenses		
	Total NonFuel Expenses	1	Line 116
	Allowances	0	Line 109
	Non-Fuel Production O&M	1	(Line 126 - 127)
	Operating Expenses		
	Operations Supervision & Engineering	1	Line 102(c)
	Electric Expenses	0	Line 106(c)
	Maintenance of Electric Plant	0	Line 113(b)
	Other Demand Related Expenses	0	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)
	Total	1	(Sum Lines 131 to 134)

				Allocator	Allocated Amount	
	Maintenance of Electric Plant	0	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	0	(Line 138 + 139)	4.1625%	-	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	0	(Line 134)	0.0154%	-	
				Line 123		
	Balance of Plant Fixed Expenses				1	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		0	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		0	(allocated on plant labor)	
	Total		0		
Depreciation					
	Annual Depreciation Exp ...DE	3,870,305			
	Gross Production Plant Cost ... F	116,109,159	Line 14		
	SLDP=DE/F	3.3333%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	30			
	SFDP=(R/((1+R)^n-1)		0.8611%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.584%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		0	<Includes Payroll	
	Payroll Taxes				
		100.0000%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		-	(Line 192 + 195)	

	Plant		Depreciation	Total	
General Plant	-		-		
	0.000%		0.000%		Line 159
Fixed General Plant	-		-		(Lines 200 * 201)
Return on General Plant	8.1350%	Line 188			
Taxes on General Plant	2.5840%	Line 189			
General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
Prepayments	873,393		
	100.000%		
Production Related Prepayments	873,393	(Line 209 * 210)	
Unit Specific M&S	-		
Total	873,393	(Line 211 + 212)	
Return on Working Capital	8.1350%		
Taxes on Working Capital	2.5840%		
Working Capital Costs	93,619	(Line 213 * 214)	

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Accumulated Deferred Income Taxes

Investment	116,109,159	Line 14
Asset Service Life	30	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 9,179,383

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	3,870,305	3.750%	4,354,093	187,124	187,124	11,012	4,210	6,753	21,975	825,789
2	3,870,305	7.219%	8,381,920	1,745,048	1,932,172	113,708	43,474	69,727	226,909	825,789
3	3,870,305	6.677%	7,752,609	1,501,636	3,433,808	202,080	77,261	123,917	403,258	825,789
4	3,870,305	6.177%	7,172,063	1,277,087	4,710,895	277,236	105,995	170,004	553,235	825,789
5	3,870,305	5.713%	6,633,316	1,068,705	5,779,600	340,129	130,041	208,571	678,741	825,789
6	3,870,305	5.285%	6,136,369	876,491	6,656,091	391,711	149,762	240,201	781,674	825,789
7	3,870,305	4.888%	5,675,416	698,199	7,354,289	432,800	165,472	265,397	863,669	825,789
8	3,870,305	4.522%	5,250,456	533,829	7,888,118	464,216	177,483	284,662	926,360	825,789
9	3,870,305	4.462%	5,180,791	506,883	8,395,000	494,046	188,888	302,954	985,887	825,789
10	3,870,305	4.461%	5,179,630	506,434	8,901,434	523,849	200,282	321,230	1,045,361	825,789
11	3,870,305	4.462%	5,180,791	506,883	9,408,317	553,679	211,687	339,522	1,104,888	825,789
12	3,870,305	4.461%	5,179,630	506,434	9,914,750	583,483	223,082	357,798	1,164,363	825,789
13	3,870,305	4.462%	5,180,791	506,883	10,421,633	613,313	234,487	376,090	1,223,890	825,789
14	3,870,305	4.461%	5,179,630	506,434	10,928,066	643,117	245,881	394,366	1,283,364	825,789
15	3,870,305	4.462%	5,180,791	506,883	11,434,949	672,947	257,286	412,658	1,342,891	825,789
16	3,870,305	4.461%	5,179,630	506,434	11,941,382	702,750	268,681	430,934	1,402,365	825,789
17	3,870,305	4.462%	5,180,791	506,883	12,448,265	732,580	280,086	449,226	1,461,892	825,789
18	3,870,305	4.461%	5,179,630	506,434	12,954,699	762,384	291,481	467,502	1,521,366	825,789
19	3,870,305	4.462%	5,180,791	506,883	13,461,581	792,214	302,886	485,794	1,580,893	825,789
20	3,870,305	4.461%	5,179,630	506,434	13,968,015	822,018	314,280	504,069	1,640,367	825,789
21	3,870,305	2.231%	2,590,395	-495,056	13,472,958	792,884	303,142	486,204	1,582,229	825,789
22	3,870,305	0.000%	0	-1,496,995	11,975,963	704,785	269,459	432,181	1,406,426	825,789
23	3,870,305	0.000%	0	-1,496,995	10,478,968	616,687	235,777	378,159	1,230,623	825,789
24	3,870,305	0.000%	0	-1,496,995	8,981,972	528,589	202,094	324,136	1,054,820	825,789
25	3,870,305	0.000%	0	-1,496,995	7,484,977	440,491	168,412	270,113	879,016	825,789
26	3,870,305	0.000%	0	-1,496,995	5,987,982	352,393	134,730	216,091	703,213	825,789
27	3,870,305	0.000%	0	-1,496,995	4,490,986	264,295	101,047	162,068	527,410	825,789
28	3,870,305	0.000%	0	-1,496,995	2,993,991	176,196	67,365	108,045	351,607	825,789
29	3,870,305	0.000%	0	-1,496,995	1,496,995	88,098	33,682	54,023	175,803	825,789
30	3,870,305	0.000%	0	-1,496,995	0	0	0	0	0	825,789

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Unit Name: Philadelphia Rd 1-4 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 16,996,875		Electric Expenses	Line 140	1,210		
2	Investment Generator & Exciter	Inputs Tab	$ 2,549,531		Other Expenses		57		
3	Reactive Allocator	(Line 71)	31.36%		O&M	(sum line 1 & 2)	1,266	1,216,879	0.1040%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**799,423**						
5					A&G		189,779	18,270,877	1.0387%
6	GSU Transformer Investment	Inputs Tab	-		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0158%
7	Reactive Allocator	(Line 71)	31.36%		Working Capital	Line 216	178,629	18,270,877	0.9777%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**		General Plant		-	18,270,877	0.0000%
9					Other Taxes	Line 196(c)	264,526	18,270,877	1.4478%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	1,324,305		Depreciation	Line 168(c)			0.1117%
11	Reactive Allocator	(Line 71)	31.36%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**415,245**		Taxes (Federal/State/Local)	Line 180			2.9334%
13					ADIT	-Line 233(k)	($255,638)	18,270,877	-1.3992%
14	Total Cost of Power Plant	Inputs Tab	18,270,877				(Sum Lines 1 to 11 , Col. (h))		13.3650%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	14,397,041						
16	Balance of Plant Allocator	(Line 79)	0.0154%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	2,211						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	1,216,879						
19	Reactive Fixed Charge Rate	(Line 14(h))	13.3650%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**162,635**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 162,635**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		13.40						
		18.00						
		18.00						
		18.00						
	Total	67.40	(Sum Lines 31 to 34)					
	Nominal Power Factor (pf)							
		0.74						
		0.85						
		0.85						
		0.85						
	Total	0.82	(Line 38 / 58)					
	MVA Capability (MVA)							
		18.18	(Line 31 / 41)					
		21.18	(Line 32 / 42)					
		21.18	(Line 33 / 43)					
		21.18	(Line 34 / 44)					
	Total	81.71	(Sum Lines 51 to 54)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		12.29	(SQRT (Line 51^2 - Line 31^2))					
		11.16	(SQRT (Line 52^2 - Line 32^2))					
		11.16	(SQRT (Line 53^2 - Line 33^2))					
		11.16	(SQRT (Line 54^2 - Line 34^2))					
	Total	45.76	(Sum Lines 62 to 65)					
	Reactive Allocator	31.4%	(Line 69^2 / Line 58^2)					
		BGE is TO Fleet						
	Max. MVAr	27.50						
	Nameplate MVAr	571.22						
	Exciter MW	3.08						
	Generator MW	965.46						
	Balance of Plant Allocator	0.0154%	(Line 75 / Line 76) * (Line 77 / Line 78)					

	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ -	50%	$ -
	Control&Power Cabling	$ -	50%	$ -
	Switch Board Equipment	$ 2,648,610	50%	$ 1,324,305
	Switching Equipment	$ -	40%	$ -
	Transformers	$ -	10%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ -	0%	$ -
	Misc	$ 412,515	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 3,061,125		$ 1,324,305

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	147,788	147,788	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	38,175	38,175	
	Steam From Other Sources	73,768		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	22,601		
	Rents	137,546	137,546	
	Allowances	5,558	5,558	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	57,646	57,646	
	Maintenance of Boiler (or reactor) Plant	24,720		
	Maintenance of Electric Plant	25,717		
	Maintenance of Misc Steam (or Nuclear) Plant	32,009	32,009	
	Other Power Production, & Other Expenses	97,091	97,091	
	Total NonFuel Expenses	662,620	515,814	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation				
	Plant Var Allocators			
	Electric Expense Allocator	4.7034%	Line 4(c) / 1(c))	
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)	
	Other Demand Expense Allocator	0.0154%	Line 79	
	Production Plant Expenses			
	Total NonFuel Expenses	662,620	Line 116	
	Allowances	5,558	Line 109	
	Non-Fuel Production O&M	657,062	(Line 126 - 127)	
	Operating Expenses			
	Operations Supervision & Engineering	147,788	Line 102(c)	
	Electric Expenses	0	Line 106(c)	
	Maintenance of Electric Plant	25,717	Line 113(b)	
	Other Demand Related Expenses	368,025	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)	
	Total	541,531	(Sum Lines 131 to 134)	

				Allocator	Allocated Amount	
	Maintenance of Electric Plant	25,717	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	25,717	(Line 138 + 139)	4.7034%	1,210	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	368,025	(Line 134)	0.0154%	57	
				Line 123		
	Balance of Plant Fixed Expenses				540,265	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		70,095	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		119,683	(allocated on plant labor)	
	Total		189,779		
Depreciation					
	Annual Depreciation Exp ...DE	332,198			
	Gross Production Plant Cost ... F	18,270,877	Line 14		
	SLDP=DE/F	1.8182%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	55			
	SFDP=(R/((1+R)^n-1)		0.1117%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.933%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		264,526	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		264,526	(Line 192 + 195)	

	Plant		Depreciation	Total	
General Plant	-		-		
	0.000%		0.000%		Line 159
Fixed General Plant	-		-		(Lines 200 * 201)
Return on General Plant	8.1350%	Line 188			
Taxes on General Plant	2.9334%	Line 189			
General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
Prepayments	137,437		
	100.000%		
Production Related Prepayments	137,437	(Line 209 * 210)	
Unit Specific M&S	1,476,433		
Total	1,613,870	(Line 211 + 212)	
Return on Working Capital	8.1350%		
Taxes on Working Capital	2.9334%		
Working Capital Costs	178,629	(Line 213 * 214)	

Accumulated Deferred Income Taxes

Investment	18,270,877	Line 14
Asset Service Life	55	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 3,099,870

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	332,198	3.750%	685,158	136,521	136,521	8,034	3,072	4,927	16,033	255,638
2	332,198	7.219%	1,318,975	381,675	518,197	30,496	11,659	18,700	60,856	255,638
3	332,198	6.677%	1,219,946	343,372	861,569	50,703	19,385	31,092	101,180	255,638
4	332,198	6.177%	1,128,592	308,037	1,169,607	68,831	26,316	42,208	137,356	255,638
5	332,198	5.713%	1,043,815	275,247	1,444,853	85,030	32,509	52,141	169,680	255,638
6	332,198	5.285%	965,616	245,000	1,689,853	99,448	38,022	60,982	198,452	255,638
7	332,198	4.888%	893,080	216,944	1,906,797	112,215	42,903	68,811	223,929	255,638
8	332,198	4.522%	826,209	191,079	2,097,875	123,460	47,202	75,707	246,369	255,638
9	332,198	4.462%	815,247	186,838	2,284,714	134,455	51,406	82,449	268,311	255,638
10	332,198	4.461%	815,064	186,768	2,471,481	145,447	55,608	89,189	290,244	255,638
11	332,198	4.462%	815,247	186,838	2,658,320	156,442	59,812	95,932	312,186	255,638
12	332,198	4.461%	815,064	186,768	2,845,088	167,433	64,014	102,672	334,120	255,638
13	332,198	4.462%	815,247	186,838	3,031,926	178,429	68,218	109,414	356,062	255,638
14	332,198	4.461%	815,064	186,768	3,218,694	189,420	72,421	116,154	377,995	255,638
15	332,198	4.462%	815,247	186,838	3,405,532	200,416	76,624	122,897	399,937	255,638
16	332,198	4.461%	815,064	186,768	3,592,300	211,407	80,827	129,637	421,870	255,638
17	332,198	4.462%	815,247	186,838	3,779,138	222,402	85,031	136,379	443,812	255,638
18	332,198	4.461%	815,064	186,768	3,965,906	233,394	89,233	143,119	465,746	255,638
19	332,198	4.462%	815,247	186,838	4,152,745	244,389	93,437	149,862	487,688	255,638
20	332,198	4.461%	815,064	186,768	4,339,512	255,380	97,639	156,602	509,621	255,638
21	332,198	2.231%	407,623	29,174	4,368,686	257,097	98,295	157,655	513,047	255,638
22	332,198	0.000%	0	-128,491	4,240,196	249,536	95,404	153,018	497,958	255,638
23	332,198	0.000%	0	-128,491	4,111,705	241,974	92,513	148,381	482,868	255,638
24	332,198	0.000%	0	-128,491	3,983,214	234,412	89,622	143,744	467,778	255,638
25	332,198	0.000%	0	-128,491	3,854,723	226,850	86,731	139,107	452,689	255,638
26	332,198	0.000%	0	-128,491	3,726,232	219,289	83,840	134,470	437,599	255,638
27	332,198	0.000%	0	-128,491	3,597,742	211,727	80,949	129,833	422,509	255,638
28	332,198	0.000%	0	-128,491	3,469,251	204,165	78,058	125,196	407,420	255,638
29	332,198	0.000%	0	-128,491	3,340,760	196,604	75,167	120,559	392,330	255,638
30	332,198	0.000%	0	-128,491	3,212,269	189,042	72,276	115,922	377,241	255,638
31	332,198	0.000%	0	-128,491	3,083,779	181,480	69,385	111,286	362,151	255,638
32	332,198	0.000%	0	-128,491	2,955,288	173,919	66,494	106,649	347,061	255,638
33	332,198	0.000%	0	-128,491	2,826,797	166,357	63,603	102,012	331,972	255,638
34	332,198	0.000%	0	-128,491	2,698,306	158,795	60,712	97,375	316,882	255,638
35	332,198	0.000%	0	-128,491	2,569,815	151,234	57,821	92,738	301,792	255,638
36	332,198	0.000%	0	-128,491	2,441,325	143,672	54,930	88,101	286,703	255,638
37	332,198	0.000%	0	-128,491	2,312,834	136,110	52,039	83,464	271,613	255,638
38	332,198	0.000%	0	-128,491	2,184,343	128,549	49,148	78,827	256,524	255,638
39	332,198	0.000%	0	-128,491	2,055,852	120,987	46,257	74,190	241,434	255,638
40	332,198	0.000%	0	-128,491	1,927,362	113,425	43,366	69,553	226,344	255,638
41	332,198	0.000%	0	-128,491	1,798,871	105,864	40,475	64,917	211,255	255,638
42	332,198	0.000%	0	-128,491	1,670,380	98,302	37,584	60,280	196,165	255,638
43	332,198	0.000%	0	-128,491	1,541,889	90,740	34,693	55,643	181,075	255,638
44	332,198	0.000%	0	-128,491	1,413,399	83,179	31,801	51,006	165,986	255,638
45	332,198	0.000%	0	-128,491	1,284,908	75,617	28,910	46,369	150,896	255,638
46	332,198	0.000%	0	-128,491	1,156,417	68,055	26,019	41,732	135,807	255,638
47	332,198	0.000%	0	-128,491	1,027,926	60,493	23,128	37,095	120,717	255,638
48	332,198	0.000%	0	-128,491	899,435	52,932	20,237	32,458	105,627	255,638
49	332,198	0.000%	0	-128,491	770,945	45,370	17,346	27,821	90,538	255,638
50	332,198	0.000%	0	-128,491	642,454	37,808	14,455	23,184	75,448	255,638
51	332,198	0.000%	0	-128,491	513,963	30,247	11,564	18,548	60,358	255,638
52	332,198	0.000%	0	-128,491	385,472	22,685	8,673	13,911	45,269	255,638
53	332,198	0.000%	0	-128,491	256,982	15,123	5,782	9,274	30,179	255,638
54	332,198	0.000%	0	-128,491	128,491	7,562	2,891	4,637	15,090	255,638
55	332,198	0.000%	0	-128,491	0	0	0	0	0	255,638

Unit Name: Quad Cities 1 & 2 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 345,327,838	
2	Investment Generator & Exciter	Inputs Tab	51,799,176	
3	Reactive Allocator	(Line 71)	10.98%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**5,688,558**	
5				
6	GSU Transformer Investment	Inputs Tab	25,326,658	
7	Reactive Allocator	(Line 71)	10.98%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**2,781,360**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	2,665,593	
11	Reactive Allocator	(Line 71)	10.98%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**292,734**	
13				
14	Total Cost of Power Plant	Inputs Tab	1,046,110,329	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	966,318,902	
16	Balance of Plant Allocator	(Line 79)	0.1358%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	1,312,709	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	10,075,360	
19	Reactive Fixed Charge Rate	(Line 14(h))	27.0131%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**2,721,668**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 2,721,668**	
23				
24				
25				
26				

	(e)		(f)	(g)	(h)
	Fixed Charge Rate for Reactive Plant				
			Calculated Amt	Plant	FCR % (f) / (g)
	Electric Expenses	Line 140	170,624		
	Other Expenses		105,061		
	O&M	(sum line 1 & 2)	275,686	10,075,360	2.7362%
	A&G		109,645,685	1,046,110,329	10.4813%
	CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.1837%
	Working Capital	Line 216	30,066,107	1,046,110,329	2.8741%
	General Plant		-	1,046,110,329	0.0000%
	Other Taxes	Line 196(c)	10,683,702	1,046,110,329	1.0213%
	Depreciation	Line 168(c)			0.0752%
					8.1350%
	Taxes (Federal/State/Local)	Line 180			2.9859%
	ADIT	-Line 233(k)	($15,478,125)	1,046,110,329	-1.4796%
			(Sum Lines 1 to 11 , Col. (h))		27.0131%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		961.00						
		980.00						
		-						
	Total	1,941.00	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.95						
		0.94						
		-						
	Total	0.94	(Line 38 / 58)					
	MVA Capability (MVA)							
		1,016.93	(Line 31 / 41)					
		1,040.34	(Line 32 / 42)					
		-						
	Total	2,057.27	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		332.61	(SQRT (Line 51^2 - Line 31^2))					
		349.15	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	681.76	(Sum Lines 62 to 64)					
	Reactive Allocator	11.0%	(Line 69^2 / Line 58^2)					
		ComEd is TO Fleet						
	Max. MVAr	2,187						
	Nameplate MVAr	4,856						
	Exciter MW	35						
	Generator MW	11,447						
	Balance of Plant Allocator	0.1358%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ 2,133,713	15%	$ 320,057
	Control&Power Cabling	$ 7,403,630	1%	$ 74,036
	Switch Board Equipment	$ 2,898,057	1%	$ 28,981
	Switching Equipment	$ 3,872,699	1%	$ 38,727
	Transformers	$ 8,262,803	3%	$ 247,884
	Aux Generator	$ 3,321,149	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	50%	$ -
	Structure	$ 133,041	0%	$ -
	Misc	$ 35,712,768	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ 2,051	1%	$ 21
	Bus & Insulators	$ 2,444,859	80%	$ 1,955,887
	Capacitor Bank	$ -	0%	$ -
	Total	$ 66,184,772		$ 2,665,593

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	21,788,348	21,788,348	
	Coolants and Water (Nuclear Plants Only)	2,134,891		
	Steam Expenses	13,391,026	13,391,026	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	1,368,072		
	Rents	37,826,023	37,826,023	
	Allowances	3,001,582	3,001,582	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	4,019,572	4,019,572	
	Maintenance of Boiler (or reactor) Plant	313,294		
	Maintenance of Electric Plant	10,357,860		
	Maintenance of Misc Steam (or Nuclear) Plant	6,653,280	6,653,280	
	Other Power Production, & Other Expenses	12,446,996	12,446,996	
	Total NonFuel Expenses	113,300,945	99,126,828	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	1.6473%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.1358%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	113,300,945	Line 116			
	Allowances	3,001,582	Line 109			
	Non-Fuel Production O&M	110,299,363	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	21,788,348	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	10,357,860	Line 113(b)			
	Other Demand Related Expenses	77,338,479	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	109,484,688	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	10,357,860	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	10,357,860	(Line 138 + 139)	1.6473%	170,624	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	77,338,479	(Line 134)	0.1358%	105,061	
				Line 123		
	Balance of Plant Fixed Expenses				109,209,002	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		82,058,738	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		27,586,946	(allocated on plant labor)	
	Total		109,645,685		

Depreciation				
	Annual Depreciation Exp ...DE	17,435,172	Reflects life extension to 2032	
	Gross Production Plant Cost ... F	1,046,110,329	Line 14	
	SLDP=DE/F	1.6667%	(Line 164 / 165)	
	Depreciable years (n)=1/SLDP	60		
	SFDP=(R/((1+R)^n-1)		0.0752%	
Income Taxes				
	Income Tax Calculation; (Co's Sch. 2)			
	a) State Income Tax Rate ("SIT")	5.6600%		
	b) City/Local Income Tax Rate ("LIT")	0.0000%		
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%		
	d) Net of Fdrl tax SIT	3.6790%		
	e) Federal Income Tax Rate ("FIT")	35.0000%		
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%		
	g) Gross-Up Tax Factor ("GTF")	61.3210%		
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.986%	

				Weighted Cost	
Rate of Return					
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)

Other Taxes					
	Property Taxes		6,042,855		
	Payroll Taxes	5,304,440			
	0	87.4899%	Line 117		
	Fixed Payroll Taxes		4,640,846	(Line 193 * 194)	
	Total Other Taxes		10,683,702	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9859%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
	Prepayments	1,753,898	
		100.000%	
	Production Related Prepayments	1,753,898	(Line 209 * 210)
	Unit Specific M&S	268,603,913	
	Total	270,357,811	(Line 211 + 212)
	Return on Working Capital	8.1350%	
	Taxes on Working Capital	2.9859%	
	Working Capital Costs	30,066,107	(Line 213 * 214)

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Accumulated Deferred Income Taxes

Investment	1,046,110,329	Line 14
Asset Service Life	60	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 188,522,481

(a) Yr.	(b)	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized PMT of NPV
	SL Deprec Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	17,435,172	3.750%	39,229,137	8,429,688	8,429,688	496,087	189,668	304,206	989,961	15,478,125
2	17,435,172	7.219%	75,518,705	22,466,130	30,895,817	1,818,219	695,156	1,114,950	3,628,325	15,478,125
3	17,435,172	6.677%	69,848,787	20,273,062	51,168,879	3,011,289	1,151,300	1,846,552	6,009,141	15,478,125
4	17,435,172	6.177%	64,618,235	18,249,937	69,418,816	4,085,297	1,561,923	2,505,145	8,152,366	15,478,125
5	17,435,172	5.713%	59,764,283	16,372,477	85,791,293	5,048,818	1,930,304	3,095,985	10,075,107	15,478,125
6	17,435,172	5.285%	55,286,931	14,640,682	100,431,975	5,910,422	2,259,719	3,624,330	11,794,471	15,478,125
7	17,435,172	4.888%	51,133,873	13,034,320	113,466,295	6,677,491	2,552,992	4,094,705	13,325,188	15,478,125
8	17,435,172	4.522%	47,305,109	11,553,393	125,019,688	7,357,409	2,812,943	4,511,637	14,681,988	15,478,125
9	17,435,172	4.462%	46,677,443	11,310,618	136,330,306	8,023,039	3,067,432	4,919,807	16,010,278	15,478,125
10	17,435,172	4.461%	46,666,982	11,306,572	147,636,878	8,688,430	3,321,830	5,327,832	17,338,092	15,478,125
11	17,435,172	4.462%	46,677,443	11,310,618	158,947,496	9,354,060	3,576,319	5,736,003	18,666,382	15,478,125
12	17,435,172	4.461%	46,666,982	11,306,572	170,254,067	10,019,452	3,830,717	6,144,028	19,994,196	15,478,125
13	17,435,172	4.462%	46,677,443	11,310,618	181,564,685	10,685,082	4,085,205	6,552,199	21,322,486	15,478,125
14	17,435,172	4.461%	46,666,982	11,306,572	192,871,257	11,350,473	4,339,603	6,960,224	22,650,301	15,478,125
15	17,435,172	4.462%	46,677,443	11,310,618	204,181,875	12,016,103	4,594,092	7,368,395	23,978,590	15,478,125
16	17,435,172	4.461%	46,666,982	11,306,572	215,488,446	12,681,495	4,848,490	7,776,420	25,306,405	15,478,125
17	17,435,172	4.462%	46,677,443	11,310,618	226,799,064	13,347,125	5,102,979	8,184,590	26,634,694	15,478,125
18	17,435,172	4.461%	46,666,982	11,306,572	238,105,636	14,012,517	5,357,377	8,592,615	27,962,509	15,478,125
19	17,435,172	4.462%	46,677,443	11,310,618	249,416,254	14,678,147	5,611,866	9,000,786	29,290,798	15,478,125
20	17,435,172	4.461%	46,666,982	11,306,572	260,722,825	15,343,538	5,866,264	9,408,811	30,618,613	15,478,125
21	17,435,172	2.231%	23,338,721	2,283,434	263,006,259	15,477,918	5,917,641	9,491,214	30,886,773	15,478,125
22	17,435,172	0.000%	0	-6,743,750	256,262,509	15,081,049	5,765,906	9,247,850	30,094,805	15,478,125
23	17,435,172	0.000%	0	-6,743,750	249,518,759	14,684,179	5,614,172	9,004,485	29,302,836	15,478,125
24	17,435,172	0.000%	0	-6,743,750	242,775,008	14,287,309	5,462,438	8,761,121	28,510,868	15,478,125
25	17,435,172	0.000%	0	-6,743,750	236,031,258	13,890,440	5,310,703	8,517,756	27,718,899	15,478,125
26	17,435,172	0.000%	0	-6,743,750	229,287,508	13,493,570	5,158,969	8,274,392	26,926,931	15,478,125
27	17,435,172	0.000%	0	-6,743,750	222,543,758	13,096,700	5,007,235	8,031,027	26,134,962	15,478,125
28	17,435,172	0.000%	0	-6,743,750	215,800,007	12,699,830	4,855,500	7,787,663	25,342,994	15,478,125
29	17,435,172	0.000%	0	-6,743,750	209,056,257	12,302,961	4,703,766	7,544,299	24,551,025	15,478,125
30	17,435,172	0.000%	0	-6,743,750	202,312,507	11,906,091	4,552,031	7,300,934	23,759,057	15,478,125
31	17,435,172	0.000%	0	-6,743,750	195,568,757	11,509,221	4,400,297	7,057,570	22,967,088	15,478,125
32	17,435,172	0.000%	0	-6,743,750	188,825,007	11,112,352	4,248,563	6,814,205	22,175,119	15,478,125
33	17,435,172	0.000%	0	-6,743,750	182,081,256	10,715,482	4,096,828	6,570,841	21,383,151	15,478,125
34	17,435,172	0.000%	0	-6,743,750	175,337,506	10,318,612	3,945,094	6,327,476	20,591,182	15,478,125
35	17,435,172	0.000%	0	-6,743,750	168,593,756	9,921,743	3,793,360	6,084,112	19,799,214	15,478,125
36	17,435,172	0.000%	0	-6,743,750	161,850,006	9,524,873	3,641,625	5,840,747	19,007,245	15,478,125
37	17,435,172	0.000%	0	-6,743,750	155,106,255	9,128,003	3,489,891	5,597,383	18,215,277	15,478,125
38	17,435,172	0.000%	0	-6,743,750	148,362,505	8,731,133	3,338,156	5,354,018	17,423,308	15,478,125
39	17,435,172	0.000%	0	-6,743,750	141,618,755	8,334,264	3,186,422	5,110,654	16,631,340	15,478,125
40	17,435,172	0.000%	0	-6,743,750	134,875,005	7,937,394	3,034,688	4,867,289	15,839,371	15,478,125
41	17,435,172	0.000%	0	-6,743,750	128,131,254	7,540,524	2,882,953	4,623,925	15,047,402	15,478,125
42	17,435,172	0.000%	0	-6,743,750	121,387,504	7,143,655	2,731,219	4,380,560	14,255,434	15,478,125
43	17,435,172	0.000%	0	-6,743,750	114,643,754	6,746,785	2,579,484	4,137,196	13,463,465	15,478,125
44	17,435,172	0.000%	0	-6,743,750	107,900,004	6,349,915	2,427,750	3,893,832	12,671,497	15,478,125
45	17,435,172	0.000%	0	-6,743,750	101,156,254	5,953,046	2,276,016	3,650,467	11,879,528	15,478,125
46	17,435,172	0.000%	0	-6,743,750	94,412,503	5,556,176	2,124,281	3,407,103	11,087,560	15,478,125
47	17,435,172	0.000%	0	-6,743,750	87,668,753	5,159,306	1,972,547	3,163,738	10,295,591	15,478,125
48	17,435,172	0.000%	0	-6,743,750	80,925,003	4,762,436	1,820,813	2,920,374	9,503,623	15,478,125
49	17,435,172	0.000%	0	-6,743,750	74,181,253	4,365,567	1,669,078	2,677,009	8,711,654	15,478,125
50	17,435,172	0.000%	0	-6,743,750	67,437,502	3,968,697	1,517,344	2,433,645	7,919,686	15,478,125
51	17,435,172	0.000%	0	-6,743,750	60,693,752	3,571,827	1,365,609	2,190,280	7,127,717	15,478,125
52	17,435,172	0.000%	0	-6,743,750	53,950,002	3,174,958	1,213,875	1,946,916	6,335,748	15,478,125
53	17,435,172	0.000%	0	-6,743,750	47,206,252	2,778,088	1,062,141	1,703,551	5,543,780	15,478,125
54	17,435,172	0.000%	0	-6,743,750	40,462,501	2,381,218	910,406	1,460,187	4,751,811	15,478,125
55	17,435,172	0.000%	0	-6,743,750	33,718,751	1,984,349	758,672	1,216,822	3,959,843	15,478,125
56	17,435,172	0.000%	0	-6,743,750	26,975,001	1,587,479	606,938	973,458	3,167,874	15,478,125
57	17,435,172	0.000%	0	-6,743,750	20,231,251	1,190,609	455,203	730,093	2,375,906	15,478,125
58	17,435,172	0.000%	0	-6,743,750	13,487,500	793,739	303,469	486,729	1,583,937	15,478,125
59	17,435,172	0.000%	0	-6,743,750	6,743,750	396,870	151,734	243,364	791,969	15,478,125
60	17,435,172	0.000%	0	-6,743,750	0	0	0	0	0	15,478,125

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Unit Name: Richmond 91&92 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 20,218,692	
2	Investment Generator & Exciter	Inputs Tab	$ 3,032,804	
3	Reactive Allocator	(Line 71)	15.82%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**479,754**	
5				
6	GSU Transformer Investment	Inputs Tab	355,663	
7	Reactive Allocator	(Line 71)	15.82%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**56,262**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	305,256	
11	Reactive Allocator	(Line 71)	15.82%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**48,288**	
13				
14	Total Cost of Power Plant	Inputs Tab	29,467,537	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	25,773,814	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	13,964	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	598,268	
19	Reactive Fixed Charge Rate	(Line 14(h))	10.9209%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**65,336**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 65,336**	
23				
24				
25				
26				

(e)		(f)	(g)	(h)
Fixed Charge Rate for Reactive Plant				
		Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 140	589		
Other Expenses		192		
O&M	(sum line 1 & 2)	782	598,268	0.1306%
A&G		256,381	29,467,537	0.8700%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0139%
Working Capital	Line 216	34,057	29,467,537	0.1156%
General Plant		-	29,467,537	0.0000%
Other Taxes	Line 196(c)	21,879	29,467,537	0.0742%
Depreciation	Line 168(c)			0.0752%
				8.1350%
Taxes (Federal/State/Local)	Line 180			2.9859%
ADIT	-Line 233(k)	($435,998)	29,467,537	-1.4796%
		(Sum Lines 1 to 11 , Col. (h))		10.9209%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		53.30						
		52.80						
		-						
	Total	106.10	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.92						
		0.92						
		-						
	Total	0.92	(Line 38 / 58)					
	MVA Capability (MVA)							
		58.06	(Line 31 / 41)					
		57.58	(Line 32 / 42)					
		-						
	Total	115.64	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		23.03	(SQRT (Line 51^2 - Line 31^2))					
		22.97	(SQRT (Line 52^2 - Line 32^2))					
	Total	45.99	(Sum Lines 62 to 64)					
	Reactive Allocator	15.8%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ 110,173	50%	$ 55,087
	Control&Power Cabling	$ 376,173	50%	$ 188,087
	Switch Board Equipment	$ 31,046	50%	$ 15,523
	Switching Equipment	$ 98,992	40%	$ 39,597
	Transformers	$ 69,638	10%	$ 6,964
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ 41,045	0%	$ -
	Misc	$ 2,183,819	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 2,910,886		$ 305,256

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	142,673	142,673	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	36,854	36,854	
	Steam From Other Sources	71,215		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	21,819		
	Rents	132,785	132,785	
	Allowances	5,366	5,366	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	55,651	55,651	
	Maintenance of Boiler (or reactor) Plant	23,864		
	Maintenance of Electric Plant	24,827		
	Maintenance of Misc Steam (or Nuclear) Plant	30,901	30,901	
	Other Power Production, & Other Expenses	93,731	93,731	
	Total NonFuel Expenses	639,686	497,961	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation

	Plant Var Allocators					
	Electric Expense Allocator	2.3728%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	639,686	Line 116			
	Allowances	5,366	Line 109			
	Non-Fuel Production O&M	634,320	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	142,673	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	24,827	Line 113(b)			
	Other Demand Related Expenses	355,288	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	522,788	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	24,827	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	24,827	(Line 138 + 139)	2.3728%	589	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	355,288	(Line 134)	0.0542%	192	
				Line 123		
	Balance of Plant Fixed Expenses				522,007	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		31,896	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		224,485	(allocated on plant labor)	
	Total		256,381		
Depreciation					
	Annual Depreciation Exp ...DE	491,126			
	Gross Production Plant Cost ... F	29,467,537	Line 14		
	SLDP=DE/F	1.6667%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	60			
	SFDP=(R/((1+R)^n-1)		0.0752%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.986%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		21,879	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		21,879	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9859%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	221,660				
		100.000%				
	Production Related Prepayments	221,660	(Line 209 * 210)			
	Unit Specific M&S	84,581				
	Total	306,241	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9859%				
	Working Capital Costs	34,057	(Line 213 * 214)			

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Accumulated Deferred Income Taxes

Investment	29,467,537	Line 14	NPV of Col (j)> 5,310,428
Asset Service Life	60	Line 167	
Composite Tax Rate	38.6790%	Line 177	

(a) Yr.	(b)	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized
	SL Deprec Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	PMT of NPV col. (j)
1	491,126	3.750%	1,105,033	237,453	237,453	13,974	5,343	8,569	27,886	435,998
2	491,126	7.219%	2,127,262	632,841	870,294	51,217	19,582	31,407	102,205	435,998
3	491,126	6.677%	1,967,547	571,065	1,441,359	84,824	32,431	52,015	169,270	435,998
4	491,126	6.177%	1,820,210	514,076	1,955,436	115,077	43,997	70,567	229,641	435,998
5	491,126	5.713%	1,683,480	461,191	2,416,627	142,218	54,374	87,210	283,802	435,998
6	491,126	5.285%	1,557,359	412,409	2,829,035	166,489	63,653	102,093	332,235	435,998
7	491,126	4.888%	1,440,373	367,159	3,196,195	188,096	71,914	115,342	375,353	435,998
8	491,126	4.522%	1,332,522	325,444	3,521,638	207,248	79,237	127,087	413,572	435,998
9	491,126	4.462%	1,314,842	318,605	3,840,243	225,998	86,405	138,584	450,988	435,998
10	491,126	4.461%	1,314,547	318,491	4,158,735	244,742	93,572	150,078	488,391	435,998
11	491,126	4.462%	1,314,842	318,605	4,477,340	263,491	100,740	161,576	525,807	435,998
12	491,126	4.461%	1,314,547	318,491	4,795,831	282,235	107,906	173,069	563,210	435,998
13	491,126	4.462%	1,314,842	318,605	5,114,436	300,985	115,075	184,567	600,626	435,998
14	491,126	4.461%	1,314,547	318,491	5,432,927	319,728	122,241	196,060	638,029	435,998
15	491,126	4.462%	1,314,842	318,605	5,751,532	338,478	129,409	207,558	675,445	435,998
16	491,126	4.461%	1,314,547	318,491	6,070,023	357,221	136,576	219,051	712,848	435,998
17	491,126	4.462%	1,314,842	318,605	6,388,628	375,971	143,744	230,549	750,264	435,998
18	491,126	4.461%	1,314,547	318,491	6,707,119	394,714	150,910	242,043	787,667	435,998
19	491,126	4.462%	1,314,842	318,605	7,025,724	413,464	158,079	253,540	825,083	435,998
20	491,126	4.461%	1,314,547	318,491	7,344,215	432,207	165,245	265,034	862,486	435,998
21	491,126	2.231%	657,421	64,321	7,408,537	435,992	166,692	267,355	870,039	435,998
22	491,126	0.000%	0	-189,962	7,218,574	424,813	162,418	260,500	847,731	435,998
23	491,126	0.000%	0	-189,962	7,028,612	413,634	158,144	253,644	825,422	435,998
24	491,126	0.000%	0	-189,962	6,838,649	402,455	153,870	246,789	803,113	435,998
25	491,126	0.000%	0	-189,962	6,648,687	391,275	149,595	239,934	780,805	435,998
26	491,126	0.000%	0	-189,962	6,458,724	380,096	145,321	233,079	758,496	435,998
27	491,126	0.000%	0	-189,962	6,268,762	368,917	141,047	226,223	736,187	435,998
28	491,126	0.000%	0	-189,962	6,078,799	357,737	136,773	219,368	713,878	435,998
29	491,126	0.000%	0	-189,962	5,888,837	346,558	132,499	212,513	691,570	435,998
30	491,126	0.000%	0	-189,962	5,698,874	335,379	128,225	205,658	669,261	435,998
31	491,126	0.000%	0	-189,962	5,508,912	324,199	123,951	198,802	646,952	435,998
32	491,126	0.000%	0	-189,962	5,318,949	313,020	119,676	191,947	624,644	435,998
33	491,126	0.000%	0	-189,962	5,128,987	301,841	115,402	185,092	602,335	435,998
34	491,126	0.000%	0	-189,962	4,939,024	290,662	111,128	178,237	580,026	435,998
35	491,126	0.000%	0	-189,962	4,749,062	279,482	106,854	171,381	557,718	435,998
36	491,126	0.000%	0	-189,962	4,559,099	268,303	102,580	164,526	535,409	435,998
37	491,126	0.000%	0	-189,962	4,369,137	257,124	98,306	157,671	513,100	435,998
38	491,126	0.000%	0	-189,962	4,179,175	245,944	94,031	150,816	490,791	435,998
39	491,126	0.000%	0	-189,962	3,989,212	234,765	89,757	143,960	468,483	435,998
40	491,126	0.000%	0	-189,962	3,799,250	223,586	85,483	137,105	446,174	435,998
41	491,126	0.000%	0	-189,962	3,609,287	212,407	81,209	130,250	423,865	435,998
42	491,126	0.000%	0	-189,962	3,419,325	201,227	76,935	123,395	401,557	435,998
43	491,126	0.000%	0	-189,962	3,229,362	190,048	72,661	116,539	379,248	435,998
44	491,126	0.000%	0	-189,962	3,039,400	178,869	68,386	109,684	356,939	435,998
45	491,126	0.000%	0	-189,962	2,849,437	167,689	64,112	102,829	334,631	435,998
46	491,126	0.000%	0	-189,962	2,659,475	156,510	59,838	95,974	312,322	435,998
47	491,126	0.000%	0	-189,962	2,469,512	145,331	55,564	89,118	290,013	435,998
48	491,126	0.000%	0	-189,962	2,279,550	134,152	51,290	82,263	267,704	435,998
49	491,126	0.000%	0	-189,962	2,089,587	122,972	47,016	75,408	245,396	435,998
50	491,126	0.000%	0	-189,962	1,899,625	111,793	42,742	68,553	223,087	435,998
51	491,126	0.000%	0	-189,962	1,709,662	100,614	38,467	61,697	200,778	435,998
52	491,126	0.000%	0	-189,962	1,519,700	89,434	34,193	54,842	178,470	435,998
53	491,126	0.000%	0	-189,962	1,329,737	78,255	29,919	47,987	156,161	435,998
54	491,126	0.000%	0	-189,962	1,139,775	67,076	25,645	41,132	133,852	435,998
55	491,126	0.000%	0	-189,962	949,812	55,896	21,371	34,276	111,544	435,998
56	491,126	0.000%	0	-189,962	759,850	44,717	17,097	27,421	89,235	435,998
57	491,126	0.000%	0	-189,962	569,887	33,538	12,822	20,566	66,926	435,998
58	491,126	0.000%	0	-189,962	379,925	22,359	8,548	13,711	44,617	435,998
59	491,126	0.000%	0	-189,962	189,962	11,179	4,274	6,855	22,309	435,998
60	491,126	0.000%	0	-189,962	0	0	0	0	0	435,998

Unit Name: Riverside 7&8 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 13,013,142		Electric Expenses	Line 140	1,042		
2	Investment Generator & Exciter	Inputs Tab	$ 1,951,971		Other Expenses		35		
3	Reactive Allocator	(Line 71)	43.26%		O&M	(sum line 1 & 2)	1,078	1,856,869	0.0580%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**844,385**						
5					A&G		316,854	39,227,656	0.8077%
6	GSU Transformer Investment	Inputs Tab	350,500		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0120%
7	Reactive Allocator	(Line 71)	43.26%		Working Capital	Line 216	196,945	39,227,656	0.5021%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**151,620**		General Plant		-	39,227,656	0.0000%
9					Other Taxes	Line 196(c)	379,744	39,227,656	0.9681%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	1,977,658		Depreciation	Line 168(c)			0.1117%
11	Reactive Allocator	(Line 71)	43.26%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**855,497**		Taxes (Federal/State/Local)	Line 180			2.9334%
13					ADIT	-Line 233(k)	($548,855)	39,227,656	-1.3992%
14	Total Cost of Power Plant	Inputs Tab	39,227,656				(Sum Lines 1 to 11 , Col. (h))		12.1288%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	34,947,527						
16	Balance of Plant Allocator	(Line 79)	0.0154%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	5,367						
18		(Line 4 + 8 + 12 + 17)	1,856,869						
19	Reactive Fixed Charge Rate	(Line 14(h))	12.1288%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**225,216**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 225,216**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		24.30						
		21.30						
		-						
	Total	45.60	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.75						
		0.76						
		-						
	Total	0.75	(Line 38 / 58)					
	MVA Capability (MVA)							
		32.40	(Line 31 / 41)					
		28.14	(Line 32 / 42)					
		-						
	Total	60.54	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		21.43	(SQRT (Line 51^2 - Line 31^2))					
		18.39	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	39.82	(Sum Lines 62 to 64)					
	Reactive Allocator	43.3%	(Line 69^2 / Line 58^2)					
		BGE is TO Fleet						
	Max. MVAr	27.50						
	Nameplate MVAr	571.22						
	Exciter MW	3.08						
	Generator MW	965.46						
	Balance of Plant Allocator	0.0154%	(Line 75 / Line 76) * (Line 77 / Line 78)					

	(a)	(b)	(c)	(d)	
Accessory Equip Allocator					
		Investment	**Cumb. Turbine**	**Allocated Amt**	
	Storage Batteries	$ 61,893	50%	$ 30,947	
	Control&Power Cabling	$ 2,209,028	50%	$ 1,104,514	
	Switch Board Equipment	$ 738,213	50%	$ 369,107	
	Switching Equipment	$ 518,931	40%	$ 207,572	
	Transformers	$ 98,872	10%	$ 9,887	
	Aux Generator	$ -	0%	$ -	
	Fire Protection System	$ 7,984	0%	$ -	
	HVAC	$ -	0%	$ -	
	Regulating Equipment	$ 306,814	75%	$ 230,110	
	Structure	$ 4,701	0%	$ -	
	Misc	$ -	0%	$ -	
	Exciter & PPT	$ 15,989	100%	$ 15,989	
	Station Grounding	$ 190,636	5%	$ 9,532	
	Bus & Insulators	$ -	80%	$ -	
	Capacitor Bank	$ -	0%	$ -	
	Total	$ 4,153,061		$ 1,977,658	

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	92,302	92,302	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	23,842	23,842	
	Steam From Other Sources	46,073		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	14,115		
	Rents	85,905	85,905	
	Allowances	3,471	3,471	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	36,003	36,003	
	Maintenance of Boiler (or reactor) Plant	15,439		
	Maintenance of Electric Plant	16,062		
	Maintenance of Misc Steam (or Nuclear) Plant	19,991	19,991	
	Other Power Production, & Other Expenses	60,639	60,639	
	Total NonFuel Expenses	413,844	322,155	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	6.4887%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0154%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	413,844	Line 116			
	Allowances	3,471	Line 109			
	Non-Fuel Production O&M	410,372	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	92,302	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	16,062	Line 113(b)			
	Other Demand Related Expenses	229,853	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	338,217	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	16,062	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	16,062	(Line 138 + 139)	6.4887%	1,042	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	229,853	(Line 134)	0.0154%	35	
				Line 123		
	Balance of Plant Fixed Expenses				337,139	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		240,209	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		76,645	(allocated on plant labor)	
	Total		316,854		
Depreciation					
	Annual Depreciation Exp ...DE	713,230			
	Gross Production Plant Cost ... F	39,227,656	Line 14		
	SLDP=DE/F	1.8182%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	55			
	SFDP=(R/((1+R)^n-1)		0.1117%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.933%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		379,744	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		379,744	(Line 192 + 195)	

	Plant		Depreciation	Total	
General Plant	-		-		
	0.000%		0.000%		Line 159
Fixed General Plant	-		-		(Lines 200 * 201)
Return on General Plant	8.1350%	Line 188			
Taxes on General Plant	2.9334%	Line 189			
General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
Prepayments	295,077		
	100.000%		
Production Related Prepayments	295,077	(Line 209 * 210)	
Unit Specific M&S	1,484,268		
Total	1,779,345	(Line 211 + 212)	
Return on Working Capital	8.1350%		
Taxes on Working Capital	2.9334%		
Working Capital Costs	196,945	(Line 213 * 214)	

Accumulated Deferred Income Taxes

Investment	39,227,656	Line 14
Asset Service Life	55	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 6,655,435

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity = (f) * (Line186+187)	(h) Interest = (f) * (Line185)	(i) Income Taxes = (g) * (Line178)	(j) Rev Req Impact (g) + (h) + (i)	(k) Levelized PMT of NPV col. (j)
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)					
1	713,230	3.750%	1,471,037	293,112	293,112	17,250	6,595	10,578	34,422	548,855
2	713,230	7.219%	2,831,845	819,459	1,112,571	65,475	25,033	40,150	130,657	548,855
3	713,230	6.677%	2,619,231	737,222	1,849,793	108,860	41,620	66,754	217,235	548,855
4	713,230	6.177%	2,423,092	661,358	2,511,151	147,781	56,501	90,621	294,903	548,855
5	713,230	5.713%	2,241,076	590,956	3,102,106	182,559	69,797	111,947	364,303	548,855
6	713,230	5.285%	2,073,182	526,016	3,628,122	213,515	81,633	130,930	426,077	548,855
7	713,230	4.888%	1,917,448	465,779	4,093,901	240,926	92,113	147,738	480,777	548,855
8	713,230	4.522%	1,773,875	410,247	4,504,148	265,069	101,343	162,543	528,955	548,855
9	713,230	4.462%	1,750,338	401,143	4,905,291	288,676	110,369	177,019	576,065	548,855
10	713,230	4.461%	1,749,946	400,991	5,306,282	312,275	119,391	191,490	623,156	548,855
11	713,230	4.462%	1,750,338	401,143	5,707,425	335,882	128,417	205,966	670,265	548,855
12	713,230	4.461%	1,749,946	400,991	6,108,416	359,480	137,439	220,437	717,357	548,855
13	713,230	4.462%	1,750,338	401,143	6,509,559	383,088	146,465	234,913	764,466	548,855
14	713,230	4.461%	1,749,946	400,991	6,910,550	406,686	155,487	249,384	811,557	548,855
15	713,230	4.462%	1,750,338	401,143	7,311,693	430,293	164,513	263,860	858,666	548,855
16	713,230	4.461%	1,749,946	400,991	7,712,685	453,891	173,535	278,331	905,758	548,855
17	713,230	4.462%	1,750,338	401,143	8,113,828	477,499	182,561	292,807	952,867	548,855
18	713,230	4.461%	1,749,946	400,991	8,514,819	501,097	191,583	307,278	999,958	548,855
19	713,230	4.462%	1,750,338	401,143	8,915,962	524,704	200,609	321,754	1,047,067	548,855
20	713,230	4.461%	1,749,946	400,991	9,316,953	548,303	209,631	336,225	1,094,159	548,855
21	713,230	2.231%	875,169	62,636	9,379,589	551,989	211,041	338,485	1,101,515	548,855
22	713,230	0.000%	0	-275,870	9,103,719	535,754	204,834	328,530	1,069,117	548,855
23	713,230	0.000%	0	-275,870	8,827,849	519,519	198,627	318,574	1,036,720	548,855
24	713,230	0.000%	0	-275,870	8,551,979	503,284	192,420	308,619	1,004,322	548,855
25	713,230	0.000%	0	-275,870	8,276,108	487,049	186,212	298,663	971,925	548,855
26	713,230	0.000%	0	-275,870	8,000,238	470,814	180,005	288,708	939,527	548,855
27	713,230	0.000%	0	-275,870	7,724,368	454,579	173,798	278,752	907,130	548,855
28	713,230	0.000%	0	-275,870	7,448,497	438,344	167,591	268,797	874,732	548,855
29	713,230	0.000%	0	-275,870	7,172,627	422,109	161,384	258,842	842,335	548,855
30	713,230	0.000%	0	-275,870	6,896,757	405,874	155,177	248,886	809,937	548,855
31	713,230	0.000%	0	-275,870	6,620,887	389,639	148,970	238,931	777,540	548,855
32	713,230	0.000%	0	-275,870	6,345,016	373,404	142,763	228,975	745,142	548,855
33	713,230	0.000%	0	-275,870	6,069,146	357,169	136,556	219,020	712,745	548,855
34	713,230	0.000%	0	-275,870	5,793,276	340,934	130,349	209,064	680,347	548,855
35	713,230	0.000%	0	-275,870	5,517,406	324,699	124,142	199,109	647,950	548,855
36	713,230	0.000%	0	-275,870	5,241,535	308,464	117,935	189,153	615,552	548,855
37	713,230	0.000%	0	-275,870	4,965,665	292,229	111,727	179,198	583,155	548,855
38	713,230	0.000%	0	-275,870	4,689,795	275,994	105,520	169,243	550,757	548,855
39	713,230	0.000%	0	-275,870	4,413,924	259,759	99,313	159,287	518,360	548,855
40	713,230	0.000%	0	-275,870	4,138,054	243,524	93,106	149,332	485,962	548,855
41	713,230	0.000%	0	-275,870	3,862,184	227,290	86,899	139,376	453,565	548,855
42	713,230	0.000%	0	-275,870	3,586,314	211,055	80,692	129,421	421,167	548,855
43	713,230	0.000%	0	-275,870	3,310,443	194,820	74,485	119,465	388,770	548,855
44	713,230	0.000%	0	-275,870	3,034,573	178,585	68,278	109,510	356,372	548,855
45	713,230	0.000%	0	-275,870	2,758,703	162,350	62,071	99,554	323,975	548,855
46	713,230	0.000%	0	-275,870	2,482,832	146,115	55,864	89,599	291,577	548,855
47	713,230	0.000%	0	-275,870	2,206,962	129,880	49,657	79,644	259,180	548,855
48	713,230	0.000%	0	-275,870	1,931,092	113,645	43,450	69,688	226,782	548,855
49	713,230	0.000%	0	-275,870	1,655,222	97,410	37,242	59,733	194,385	548,855
50	713,230	0.000%	0	-275,870	1,379,351	81,175	31,035	49,777	161,987	548,855
51	713,230	0.000%	0	-275,870	1,103,481	64,940	24,828	39,822	129,590	548,855
52	713,230	0.000%	0	-275,870	827,611	48,705	18,621	29,866	97,192	548,855
53	713,230	0.000%	0	-275,870	551,741	32,470	12,414	19,911	64,795	548,855
54	713,230	0.000%	0	-275,870	275,870	16,235	6,207	9,955	32,397	548,855
55	713,230	0.000%	0	-275,870	0	0	0	0	0	548,855

Unit Name: Salem 1 & 2 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 80,714,327	
2	Investment Generator & Exciter	Inputs Tab	12,107,149	
3	Reactive Allocator	(Line 71)	8.55%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**1,035,096**	
5				
6	GSU Transformer Investment	Inputs Tab	14,618,814	
7	Reactive Allocator	(Line 71)	8.55%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**1,249,830**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	4,591	
11	Reactive Allocator	(Line 71)	8.55%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**393**	
13				
14	Total Cost of Power Plant	Inputs Tab	583,671,743	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	556,941,189	
16	Balance of Plant Allocator	(Line 79)	0.0824%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	458,977	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	2,744,296	
19	Reactive Fixed Charge Rate	(Line 14(h))	35.9145%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**985,599**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 985,599**	
23				
24				
25				
26				

	(e)		(f)	(g)	(h)
	Fixed Charge Rate for Reactive Plant				
			Calculated Amt	Plant	FCR % (f) / (g)
	Electric Expenses	Line 140	105,622		
	Other Expenses		50,679		
	O&M	(sum line 1 & 2)	156,301	2,744,296	5.6955%
	A&G		88,205,514	583,671,743	15.1122%
	CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.2890%
	Working Capital	Line 216	17,567,796	583,671,743	3.0099%
	General Plant		-	583,671,743	0.0000%
	Other Taxes	Line 196(c)	12,141,110	583,671,743	2.0801%
	Depreciation	Line 168(c)			0.0814%
					8.1350%
	Taxes (Federal/State/Local)	Line 180			2.9758%
	ADIT	-Line 233(k)	($8,547,308)	583,671,743	-1.4644%
			(Sum Lines 1 to 11 , Col. (h))		35.9145%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		1,236.80						
		1,190.00						
		-						
	Total	2,426.80	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.96						
		0.95						
		-						
	Total	0.96	(Line 38 / 58)					
	MVA Capability (MVA)							
		1,285.65	(Line 31 / 41)					
		1,252.63	(Line 32 / 42)					
		-						
	Total	2,538.29	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		351.05	(SQRT (Line 51^2 - Line 31^2))					
		391.13	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	742.18	(Sum Lines 62 to 64)					
	Reactive Allocator	8.5%	(Line 69^2 / Line 58^2)					
		PSEG is TO Fleet						
	Max. MVAr	287.66						
	Nameplate MVAr	742.18						
	Exciter MW	5.16						
	Generator MW	2,426.80						
	Balance of Plant Allocator	0.0824%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ -	15%	$ -
	Control&Power Cabling	$ 459,119	1%	$ 4,591
	Switch Board Equipment	$ -	1%	$ -
	Switching Equipment	$ -	1%	$ -
	Transformers	$ -	3%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ 22,085,749	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	50%	$ -
	Structure	$ -	0%	$ -
	Misc	$ 16,168,621	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	1%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 38,713,489		$ 4,591

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	17,325,181	17,325,181	
	Coolants and Water (Nuclear Plants Only)	1,697,576		
	Steam Expenses	10,647,982	10,647,982	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	1,087,833		
	Rents	30,077,667	30,077,667	
	Allowances	2,386,732	2,386,732	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	3,196,195	3,196,195	
	Maintenance of Boiler (or reactor) Plant	249,118		
	Maintenance of Electric Plant	8,236,136		
	Maintenance of Misc Steam (or Nuclear) Plant	5,290,409	5,290,409	
	Other Power Production, & Other Expenses	9,897,329	9,897,329	
	Total NonFuel Expenses	90,092,158	78,821,495	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	1.2824%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0824%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	90,092,158	Line 116			
	Allowances	2,386,732	Line 109			
	Non-Fuel Production O&M	87,705,426	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	17,325,181	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	8,236,136	Line 113(b)			
	Other Demand Related Expenses	61,496,314	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131			
	Total	87,057,631	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	8,236,136	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	8,236,136	(Line 138 + 139)	1.2824%	105,622	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	61,496,314	(Line 134)	0.0824%	50,679	
				Line 123		
	Balance of Plant Fixed Expenses				86,901,330	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		64,855,997	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		23,349,517	(allocated on plant labor)	
	Total		88,205,514		
Depreciation					
	Annual Depreciation Exp ...DE	9,892,741			
	Gross Production Plant Cost ... F	583,671,743	Line 14		
	SLDP=DE/F	1.6949%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	59			
	SFDP=(R/((1+R)^n-1)		0.0814%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.976%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		8,570,246		
	Payroll Taxes	4,081,461			
		0 87.4899%	Line 117		
	Fixed Payroll Taxes		3,570,864	(Line 193 * 194)	
	Total Other Taxes		12,141,109.84	(Line 192 + 195)	
		Plant		**Depreciation**	**Total**
General Plant		-		-	
		0 0.000%		0.000%	Line 159
	Fixed General Plant	-		-	(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188		
	Taxes on General Plant	2.9758%	Line 189		
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-
Working Capital					
	Prepayments	-			
		100.000%			
	Production Related Prepayments	-	(Line 209 * 210)		
	Unit Specific M&S	158,114,762			
	Total	158,114,762	(Line 211 + 212)		
	Return on Working Capital	8.1350%			
	Taxes on Working Capital	2.9758%			
	Working Capital Costs	17,567,796	(Line 213 * 214)		

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Accumulated Deferred Income Taxes

Investment	583,671,743	Line 14	NPV of Col (j)> 104,027,302
Asset Service Life	59	Line 167	
Composite Tax Rate	38.6790%	Line 177	

(a) Yr.	(b) SL Deprec Line 224 / 225	(c) MACRS	(d) Tax Deprec (b) * (c)	(e) Def Inc Taxes ((d) - (b)) * Line 177	(f) ADIT Accum. (e)	(g) Return on Equity = (f) * (Line186+187)	(h) Interest = (f) * (Line185)	(i) Income Taxes = (g) * (Line178)	(j) Rev Req Impact (g) + (h) + (i)	(k) Levelized PMT of NPV col. (j)
1	9,892,741	3.750%	21,887,690	4,639,526	4,639,526	273,036	104,389	167,428	544,854	8,547,308
2	9,892,741	7.219%	42,135,263	12,471,085	17,110,611	1,006,959	384,989	617,478	2,009,426	8,547,308
3	9,892,741	6.677%	38,971,762	11,247,474	28,358,086	1,668,873	638,057	1,023,370	3,330,300	8,547,308
4	9,892,741	6.177%	36,053,404	10,118,683	38,476,768	2,264,358	865,727	1,388,527	4,518,612	8,547,308
5	9,892,741	5.713%	33,345,167	9,071,164	47,547,932	2,798,196	1,069,828	1,715,882	5,583,906	8,547,308
6	9,892,741	5.285%	30,847,052	8,104,918	55,652,849	3,275,170	1,252,189	2,008,367	6,535,726	8,547,308
7	9,892,741	4.888%	28,529,875	7,208,657	62,861,506	3,699,400	1,414,384	2,268,509	7,382,292	8,547,308
8	9,892,741	4.522%	26,393,636	6,382,381	69,243,887	4,075,003	1,557,987	2,498,832	8,131,823	8,547,308
9	9,892,741	4.462%	26,043,433	6,246,926	75,490,813	4,442,634	1,698,543	2,724,268	8,865,445	8,547,308
10	9,892,741	4.461%	26,037,596	6,244,668	81,735,482	4,810,133	1,839,048	2,949,622	9,598,803	8,547,308
11	9,892,741	4.462%	26,043,433	6,246,926	87,982,408	5,177,765	1,979,604	3,175,057	10,332,426	8,547,308
12	9,892,741	4.461%	26,037,596	6,244,668	94,227,076	5,545,263	2,120,109	3,400,411	11,065,784	8,547,308
13	9,892,741	4.462%	26,043,433	6,246,926	100,474,003	5,912,895	2,260,665	3,625,846	11,799,406	8,547,308
14	9,892,741	4.461%	26,037,596	6,244,668	106,718,671	6,280,394	2,401,170	3,851,200	12,532,764	8,547,308
15	9,892,741	4.462%	26,043,433	6,246,926	112,965,597	6,648,025	2,541,726	4,076,636	13,266,387	8,547,308
16	9,892,741	4.461%	26,037,596	6,244,668	119,210,266	7,015,524	2,682,231	4,301,990	13,999,745	8,547,308
17	9,892,741	4.462%	26,043,433	6,246,926	125,457,192	7,383,156	2,822,787	4,527,425	14,733,367	8,547,308
18	9,892,741	4.461%	26,037,596	6,244,668	131,701,860	7,750,654	2,963,292	4,752,779	15,466,725	8,547,308
19	9,892,741	4.462%	26,043,433	6,246,926	137,948,786	8,118,286	3,103,848	4,978,214	16,200,348	8,547,308
20	9,892,741	4.461%	26,037,596	6,244,668	144,193,455	8,485,785	3,244,353	5,203,568	16,933,706	8,547,308
21	9,892,741	2.231%	13,021,717	1,210,256	145,403,711	8,557,008	3,271,583	5,247,243	17,075,835	8,547,308
22	9,892,741	0.000%	0	-3,826,413	141,577,298	8,331,824	3,185,489	5,109,158	16,626,471	8,547,308
23	9,892,741	0.000%	0	-3,826,413	137,750,884	8,106,640	3,099,395	4,971,072	16,177,107	8,547,308
24	9,892,741	0.000%	0	-3,826,413	133,924,471	7,881,455	3,013,301	4,832,987	15,727,743	8,547,308
25	9,892,741	0.000%	0	-3,826,413	130,098,057	7,656,271	2,927,206	4,694,902	15,278,379	8,547,308
26	9,892,741	0.000%	0	-3,826,413	126,271,644	7,431,086	2,841,112	4,556,816	14,829,015	8,547,308
27	9,892,741	0.000%	0	-3,826,413	122,445,230	7,205,902	2,755,018	4,418,731	14,379,651	8,547,308
28	9,892,741	0.000%	0	-3,826,413	118,618,817	6,980,717	2,668,923	4,280,646	13,930,286	8,547,308
29	9,892,741	0.000%	0	-3,826,413	114,792,403	6,755,533	2,582,829	4,142,560	13,480,922	8,547,308
30	9,892,741	0.000%	0	-3,826,413	110,965,990	6,530,349	2,496,735	4,004,475	13,031,558	8,547,308
31	9,892,741	0.000%	0	-3,826,413	107,139,577	6,305,164	2,410,640	3,866,390	12,582,194	8,547,308
32	9,892,741	0.000%	0	-3,826,413	103,313,163	6,079,980	2,324,546	3,728,304	12,132,830	8,547,308
33	9,892,741	0.000%	0	-3,826,413	99,486,750	5,854,795	2,238,452	3,590,219	11,683,466	8,547,308
34	9,892,741	0.000%	0	-3,826,413	95,660,336	5,629,611	2,152,358	3,452,134	11,234,102	8,547,308
35	9,892,741	0.000%	0	-3,826,413	91,833,923	5,404,426	2,066,263	3,314,048	10,784,738	8,547,308
36	9,892,741	0.000%	0	-3,826,413	88,007,509	5,179,242	1,980,169	3,175,963	10,335,374	8,547,308
37	9,892,741	0.000%	0	-3,826,413	84,181,096	4,954,057	1,894,075	3,037,878	9,886,010	8,547,308
38	9,892,741	0.000%	0	-3,826,413	80,354,682	4,728,873	1,807,980	2,899,792	9,436,646	8,547,308
39	9,892,741	0.000%	0	-3,826,413	76,528,269	4,503,689	1,721,886	2,761,707	8,987,282	8,547,308
40	9,892,741	0.000%	0	-3,826,413	72,701,855	4,278,504	1,635,792	2,623,622	8,537,918	8,547,308
41	9,892,741	0.000%	0	-3,826,413	68,875,442	4,053,320	1,549,697	2,485,536	8,088,553	8,547,308
42	9,892,741	0.000%	0	-3,826,413	65,049,029	3,828,135	1,463,603	2,347,451	7,639,189	8,547,308
43	9,892,741	0.000%	0	-3,826,413	61,222,615	3,602,951	1,377,509	2,209,366	7,189,825	8,547,308
44	9,892,741	0.000%	0	-3,826,413	57,396,202	3,377,766	1,291,415	2,071,280	6,740,461	8,547,308
45	9,892,741	0.000%	0	-3,826,413	53,569,788	3,152,582	1,205,320	1,933,195	6,291,097	8,547,308
46	9,892,741	0.000%	0	-3,826,413	49,743,375	2,927,398	1,119,226	1,795,109	5,841,733	8,547,308
47	9,892,741	0.000%	0	-3,826,413	45,916,961	2,702,213	1,033,132	1,657,024	5,392,369	8,547,308
48	9,892,741	0.000%	0	-3,826,413	42,090,548	2,477,029	947,037	1,518,939	4,943,005	8,547,308
49	9,892,741	0.000%	0	-3,826,413	38,264,134	2,251,844	860,943	1,380,853	4,493,641	8,547,308
50	9,892,741	0.000%	0	-3,826,413	34,437,721	2,026,660	774,849	1,242,768	4,044,277	8,547,308
51	9,892,741	0.000%	0	-3,826,413	30,611,308	1,801,475	688,754	1,104,683	3,594,913	8,547,308
52	9,892,741	0.000%	0	-3,826,413	26,784,894	1,576,291	602,660	966,597	3,145,549	8,547,308
53	9,892,741	0.000%	0	-3,826,413	22,958,481	1,351,107	516,566	828,512	2,696,184	8,547,308
54	9,892,741	0.000%	0	-3,826,413	19,132,067	1,125,922	430,472	690,427	2,246,820	8,547,308
55	9,892,741	0.000%	0	-3,826,413	15,305,654	900,738	344,377	552,341	1,797,456	8,547,308
56	9,892,741	0.000%	0	-3,826,413	11,479,240	675,553	258,283	414,256	1,348,092	8,547,308
57	9,892,741	0.000%	0	-3,826,413	7,652,827	450,369	172,189	276,171	898,728	8,547,308
58	9,892,741	0.000%	0	-3,826,413	3,826,413	225,184	86,094	138,085	449,364	8,547,308
59	9,892,741	0.000%	0	-3,826,413	0	0	0	0	0	8,547,308

Unit Name: Schuylkill 10&11 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 4,345,038		Electric Expenses	Line 140	559		
2	Investment Generator & Exciter	Inputs Tab	$ 651,756		Other Expenses		93		
3	Reactive Allocator	(Line 71)	31.02%		O&M	(sum line 1 & 2)	652	262,479	0.2485%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**202,172**						
5					A&G		525,773	5,934,123	8.8602%
6	GSU Transformer Investment	Inputs Tab	-		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.1269%
7	Reactive Allocator	(Line 71)	31.02%		Working Capital	Line 216	42,809	5,934,123	0.7214%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**		General Plant		-	5,934,123	0.0000%
9					Other Taxes	Line 196(c)	11,465	5,934,123	0.1932%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	185,511		Depreciation	Line 168(c)			0.0594%
11	Reactive Allocator	(Line 71)	31.02%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**57,545**		Taxes (Federal/State/Local)	Line 180			3.0148%
13					ADIT	-Line 233(k)	($90,359)	5,934,123	-1.5227%
14	Total Cost of Power Plant	Inputs Tab	5,934,123				(Sum Lines 1 to 11 , Col. (h))		19.8367%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	5,096,857						
16	Balance of Plant Allocator	(Line 79)	0.0542%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	2,761						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	262,479						
19	Reactive Fixed Charge Rate	(Line 14(h))	19.8367%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**52,067**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 52,067**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		14.30						
		19.00						
		-						
	Total	33.30	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.79						
		0.86						
		-						
	Total	0.83	(Line 38 / 58)					
	MVA Capability (MVA)							
		18.22	(Line 31 / 41)					
		22.02	(Line 32 / 42)					
		-						
	Total	40.23	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		11.29	(SQRT (Line 51^2 - Line 31^2))					
		11.12	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	22.41	(Sum Lines 62 to 64)					
	Reactive Allocator	31.0%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ 8,355	50%	$ 4,178
	Control&Power Cabling	$ 207,889	50%	$ 103,944
	Switch Board Equipment	$ 8,299	50%	$ 4,150
	Switching Equipment	$ 183,098	40%	$ 73,239
	Transformers	$ -	10%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ 41,588	0%	$ -
	Misc	$ 104,130	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 553,360		$ 185,511

O&M	**Total Non-Fuel**	**Fixed O&M**	
Production Expenses: Oper, Supv, & Engr	69,047	69,047	
Coolants and Water (Nuclear Plants Only)	0		
Steam Expenses	17,835	17,835	
Steam From Other Sources	34,465		
Electric Expenses	0	-	
Misc Steam (or Nuclear) Power Expenses	10,559		
Rents	64,262	64,262	
Allowances	2,597	2,597	
Maintenance Supervision and Engineering	0		
Maintenance of Structures	26,932	26,932	
Maintenance of Boiler (or reactor) Plant	11,549		
Maintenance of Electric Plant	12,015		
Maintenance of Misc Steam (or Nuclear) Plant	14,955	14,955	
Other Power Production, & Other Expenses	45,361	45,361	
Total NonFuel Expenses	309,577	240,989	(Sum Lines 102 to 115)
Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation

Plant Var Allocators		
Electric Expense Allocator	4.6529%	Line 4(c) / 1(c))
Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)
Other Demand Expense Allocator	0.0542%	Line 79
Production Plant Expenses		
Total NonFuel Expenses	309,577	Line 116
Allowances	2,597	Line 109
Non-Fuel Production O&M	306,980	(Line 126 - 127)
Operating Expenses		
Operations Supervision & Engineering	69,047	Line 102(c)
Electric Expenses	0	Line 106(c)
Maintenance of Electric Plant	12,015	Line 113(b)
Other Demand Related Expenses	171,942	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)
Total	253,004	(Sum Lines 131 to 134)

			Allocator	Allocated Amount	
Maintenance of Electric Plant	12,015	Line 113(b)			
Electric Expenses	0	Line 106(c)			
Total Electric Expenses	12,015	(Line 138 + 139)	4.6529%	559	(Line 140(b) * (d))
			Line 121		
Other Demand Related Expenses	171,942	(Line 134)	0.0542%	93	
			Line 123		
Balance of Plant Fixed Expenses				252,352	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		395,698	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		130,074	(allocated on plant labor)	
	Total		525,773		
Depreciation					
	Annual Depreciation Exp ...DE	94,192			
	Gross Production Plant Cost ... F	5,934,123	Line 14		
	SLDP=DE/F	1.5873%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	63			
	SFDP=(R/((1+R)^n-1)		0.0594%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.015%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		11,465	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		11,465	(Line 192 + 195)	
		Plant		**Depreciation**	**Total**
General Plant		-		-	
		0.000%		0.000%	Line 159
	Fixed General Plant	-		-	(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188		
	Taxes on General Plant	3.0148%	Line 189		
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-
Working Capital					
	Prepayments	44,637			
		100.000%			
	Production Related Prepayments	44,637	(Line 209 * 210)		
	Unit Specific M&S	339,302			
	Total	383,940	(Line 211 + 212)		
	Return on Working Capital	8.1350%			
	Taxes on Working Capital	3.0148%			
	Working Capital Costs	42,809	(Line 213 * 214)		

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Accumulated Deferred Income Taxes

Investment	5,934,123	Line 14
Asset Service Life	63	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 1,102,701

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	PMT of NPV col. (j)
1	94,192	3.750%	222,530	49,640	49,640	2,921	1,117	1,791	5,830	90,359
2	94,192	7.219%	428,384	129,262	178,902	10,528	4,025	6,456	21,010	90,359
3	94,192	6.677%	396,221	116,822	295,723	17,403	6,654	10,672	34,729	90,359
4	94,192	6.177%	366,551	105,345	401,069	23,603	9,024	14,474	47,100	90,359
5	94,192	5.713%	339,016	94,695	495,764	29,176	11,155	17,891	58,221	90,359
6	94,192	5.285%	313,618	84,872	580,636	34,170	13,064	20,954	68,188	90,359
7	94,192	4.888%	290,060	75,760	656,396	38,629	14,769	23,688	77,085	90,359
8	94,192	4.522%	268,341	67,359	723,755	42,593	16,284	26,118	84,996	90,359
9	94,192	4.462%	264,781	65,982	789,736	46,476	17,769	28,500	92,745	90,359
10	94,192	4.461%	264,721	65,959	855,695	50,358	19,253	30,880	100,491	90,359
11	94,192	4.462%	264,781	65,982	921,677	54,241	20,738	33,261	108,239	90,359
12	94,192	4.461%	264,721	65,959	987,636	58,122	22,222	35,641	115,985	90,359
13	94,192	4.462%	264,781	65,982	1,053,618	62,005	23,706	38,022	123,734	90,359
14	94,192	4.461%	264,721	65,959	1,119,577	65,887	25,190	40,403	131,480	90,359
15	94,192	4.462%	264,781	65,982	1,185,558	69,770	26,675	42,784	139,229	90,359
16	94,192	4.461%	264,721	65,959	1,251,517	73,652	28,159	45,164	146,975	90,359
17	94,192	4.462%	264,781	65,982	1,317,499	77,535	29,644	47,545	154,724	90,359
18	94,192	4.461%	264,721	65,959	1,383,458	81,416	31,128	49,925	162,470	90,359
19	94,192	4.462%	264,781	65,982	1,449,440	85,300	32,612	52,307	170,218	90,359
20	94,192	4.461%	264,721	65,959	1,515,398	89,181	34,096	54,687	177,964	90,359
21	94,192	2.231%	132,390	14,775	1,530,173	90,051	34,429	55,220	179,700	90,359
22	94,192	0.000%	0	-36,433	1,493,740	87,907	33,609	53,905	175,421	90,359
23	94,192	0.000%	0	-36,433	1,457,308	85,763	32,789	52,590	171,142	90,359
24	94,192	0.000%	0	-36,433	1,420,875	83,618	31,970	51,276	166,864	90,359
25	94,192	0.000%	0	-36,433	1,384,442	81,474	31,150	49,961	162,585	90,359
26	94,192	0.000%	0	-36,433	1,348,010	79,330	30,330	48,646	158,307	90,359
27	94,192	0.000%	0	-36,433	1,311,577	77,186	29,510	47,331	154,028	90,359
28	94,192	0.000%	0	-36,433	1,275,144	75,042	28,691	46,017	149,750	90,359
29	94,192	0.000%	0	-36,433	1,238,711	72,898	27,871	44,702	145,471	90,359
30	94,192	0.000%	0	-36,433	1,202,279	70,754	27,051	43,387	141,193	90,359
31	94,192	0.000%	0	-36,433	1,165,846	68,610	26,232	42,072	136,914	90,359
32	94,192	0.000%	0	-36,433	1,129,413	66,466	25,412	40,758	132,635	90,359
33	94,192	0.000%	0	-36,433	1,092,981	64,322	24,592	39,443	128,357	90,359
34	94,192	0.000%	0	-36,433	1,056,548	62,178	23,772	38,128	124,078	90,359
35	94,192	0.000%	0	-36,433	1,020,115	60,034	22,953	36,813	119,800	90,359
36	94,192	0.000%	0	-36,433	983,683	57,890	22,133	35,499	115,521	90,359
37	94,192	0.000%	0	-36,433	947,250	55,746	21,313	34,184	111,243	90,359
38	94,192	0.000%	0	-36,433	910,817	53,602	20,493	32,869	106,964	90,359
39	94,192	0.000%	0	-36,433	874,385	51,458	19,674	31,554	102,685	90,359
40	94,192	0.000%	0	-36,433	837,952	49,313	18,854	30,240	98,407	90,359
41	94,192	0.000%	0	-36,433	801,519	47,169	18,034	28,925	94,128	90,359
42	94,192	0.000%	0	-36,433	765,086	45,025	17,214	27,610	89,850	90,359
43	94,192	0.000%	0	-36,433	728,654	42,881	16,395	26,295	85,571	90,359
44	94,192	0.000%	0	-36,433	692,221	40,737	15,575	24,980	81,293	90,359
45	94,192	0.000%	0	-36,433	655,788	38,593	14,755	23,666	77,014	90,359
46	94,192	0.000%	0	-36,433	619,356	36,449	13,936	22,351	72,736	90,359
47	94,192	0.000%	0	-36,433	582,923	34,305	13,116	21,036	68,457	90,359
48	94,192	0.000%	0	-36,433	546,490	32,161	12,296	19,721	64,178	90,359
49	94,192	0.000%	0	-36,433	510,058	30,017	11,476	18,407	59,900	90,359
50	94,192	0.000%	0	-36,433	473,625	27,873	10,657	17,092	55,621	90,359
51	94,192	0.000%	0	-36,433	437,192	25,729	9,837	15,777	51,343	90,359
52	94,192	0.000%	0	-36,433	400,760	23,585	9,017	14,462	47,064	90,359
53	94,192	0.000%	0	-36,433	364,327	21,441	8,197	13,148	42,786	90,359
54	94,192	0.000%	0	-36,433	327,894	19,297	7,378	11,833	38,507	90,359
55	94,192	0.000%	0	-36,433	291,462	17,153	6,558	10,518	34,228	90,359
56	94,192	0.000%	0	-36,433	255,029	15,008	5,738	9,203	29,950	90,359
57	94,192	0.000%	0	-36,433	218,596	12,864	4,918	7,889	25,671	90,359
58	94,192	0.000%	0	-36,433	182,163	10,720	4,099	6,574	21,393	90,359
59	94,192	0.000%	0	-36,433	145,731	8,576	3,279	5,259	17,114	90,359
60	94,192	0.000%	0	-36,433	109,298	6,432	2,459	3,944	12,836	90,359
61	94,192	0.000%	0	-36,433	72,865	4,288	1,639	2,630	8,557	90,359
62	94,192	0.000%	0	-36,433	36,433	2,144	820	1,315	4,279	90,359
63	94,192	0.000%	0	-36,433	0	0	0	0	0	90,359

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Unit Name: SE Chicago 5-12 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 9,173,232	
2	Investment Generator & Exciter	Inputs Tab	$ 19,802,693	
3	Reactive Allocator	(Line 76)	27.75%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**5,495,247**	
5				
6	GSU Transformer Investment	Inputs Tab	4,873,891	
7	Reactive Allocator	(Line 76)	27.75%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**1,352,505**	
9				
10	Allocated Acc Elec Equipment	(Line 104 , Column d)	-	
11	Reactive Allocator	(Line 76)	27.75%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**0**	
13				
14	Total Cost of Power Plant	Inputs Tab	187,439,853	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	162,763,269	
16	Balance of Plant Allocator	(Line 79)	0.1358%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	221,108	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	7,068,860	
19	Reactive Fixed Charge Rate	(Line 14(h))	12.2928%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**868,959**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 868,959**	
23				
24				
25				
26				

	(e)		(f)	(g)	(h)
			Fixed Charge Rate for Reactive Plant		
			Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 145		47,928		
Other Expenses			1,555		
O&M	(sum line 1 & 2)		49,483	7,068,860	0.7000%
A&G			996,937	187,439,853	0.5319%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)				0.0165%
Working Capital	Line 215		178,678	187,439,853	0.0953%
General Plant			-	187,439,853	0.0000%
Other Taxes	Line 195(c)		150,320	187,439,853	0.0802%
Depreciation	Line 167(c)				0.8611%
					8.1350%
Taxes (Federal/State/Local)	Line 179				2.5840%
ADIT	-Line 232(k)		($1,333,105)	187,439,853	-0.7112%
			(Sum Lines 1 to 11 , Col. (h))		12.2928%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		38.30						
		38.30						
		38.30						
		38.30						
		38.30						
		38.30						
		38.30						
		38.30						
	Total	306.40	(Sum Lines 31 to 38)					
	Nominal Power Factor (pf)							
		0.85						
		0.85						
		0.85						
		0.85						
		0.85						
		0.85						
		0.85						
		0.85						
	Total	0.85	(Line 40 / 62)					
	MVA Capability (MVA)							
		45.06	(Line 31 / 43)					
		45.06	(Line 32 / 44)					
		45.06	(Line 33 / 45)					
		45.06	(Line 34 / 46)					
		45.06	(Line 35 / 47)					
		45.06	(Line 36 / 48)					
		45.06	(Line 37 / 49)					
		45.06	(Line 38 / 50)					
	Total	360.47	(Sum Lines 54 to 61)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		23.74	(SQRT (Line 54^2 - Line 31^2))					
		23.74	(SQRT (Line 55^2 - Line 32^2))					
		23.74	(SQRT (Line 56^2 - Line 33^2))					
		23.74	(SQRT (Line 57^2 - Line 34^2))					
		23.74	(SQRT (Line 58^2 - Line 35^2))					
		23.74	(SQRT (Line 59^2 - Line 36^2))					
		23.74	(SQRT (Line 60^2 - Line 37^2))					
		23.74	(SQRT (Line 61^2 - Line 38^2))					
	Total	189.89	(Sum Lines 66 to 73)					
	Reactive Allocator	27.8%	(Line 74^2 / Line 62^2)					
		ComEd is TO Fleet						
	Max. MVAr	2,187						
	Nameplate MVAr	4,856						
	Exciter MW	35						
	Generator MW	11,447						
	Balance of Plant Allocator	0.1358%	(Line 80 / Line 81) * (Line 82 / Line 83)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ -	50%	$ -
	Control&Power Cabling	$ -	50%	$ -
	Switch Board Equipment	$ -	50%	$ -
	Switching Equipment	$ -	40%	$ -
	Transformers	$ -	10%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ -	0%	$ -
	Misc	$ 9,173,232	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 9,173,232		$ -

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	459,763	459,763	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	118,760	118,760	
	Steam From Other Sources	229,490		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	70,310		
	Rents	427,899	427,899	
	Allowances	17,291	17,291	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	179,335	179,335	
	Maintenance of Boiler (or reactor) Plant	76,902		
	Maintenance of Electric Plant	80,006		
	Maintenance of Misc Steam (or Nuclear) Plant	99,578	99,578	
	Other Power Production, & Other Expenses	302,046	302,046	
	Total NonFuel Expenses	2,061,381	1,604,673	(Sum Lines 107 to 120)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 121(c) / (Line 121(b) - Line 115(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	59.9052%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 128 * Line 137 + Line 126 * Line 137 / (Line137 + 139)			
	Other Demand Expense Allocator	0.1358%	Line 84			
	Production Plant Expenses					
	Total NonFuel Expenses	2,061,381	Line 121			
	Allowances	17,291	Line 114			
	Non-Fuel Production O&M	2,044,090	(Line 131 - 132)			
	Operating Expenses					
	Operations Supervision & Engineering	459,763	Line 107(c)			
	Electric Expenses	0	Line 111(c)			
	Maintenance of Electric Plant	80,006	Line 118(b)			
	Other Demand Related Expenses	1,144,910	Col. (c) Line 121 - Col (b) Line 137 - Col. (b) Line 136)			
	Total	1,684,679	(Sum Lines 136 to 139)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	80,006	Line 118(b)			
	Electric Expenses	0	Line 111(c)			
	Total Electric Expenses	80,006	(Line 143 + 144)	59.9052% Line 126	47,928	(Line 145(b) * (d))
	Other Demand Related Expenses	1,144,910	(Line 139)	0.1358% Line 128	1,555	
	Balance of Plant Fixed Expenses				1,635,196	(Line 140(b) - Line 145(e) - Line 147(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		314,901	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		682,036	(allocated on plant labor)	
	Total		996,937		
Depreciation					
	Annual Depreciation Exp ...DE	6,247,995			
	Gross Production Plant Cost ... F	187,439,853	Line 14		
	SLDP=DE/F	3.3333%	(Line 163 / 164)		
	Depreciable years (n)=1/SLDP	30			
	SFDP=(R/((1+R)^n-1)		0.8611%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.584%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 184 to 186)
Other Taxes					
	Property Taxes		150,320	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 122		
	Fixed Payroll Taxes		-	(Line 192 * 193)	
	Total Other Taxes		150,320	(Line 191 + 194)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 158
	Fixed General Plant	-		-		(Lines 199 * 200)
	Return on General Plant	8.1350%	Line 187			
	Taxes on General Plant	2.5840%	Line 188			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 201 * 202)	-	-	
Working Capital						
	Prepayments	1,409,955				
		100.000%				
	Production Related Prepayments	1,409,955	(Line 208 * 209)			
	Unit Specific M&S	256,975				
	Total	1,666,930	(Line 210 + 211)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.5840%				
	Working Capital Costs	178,678	(Line 212 * 213)			

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Accumulated Deferred Income Taxes

Investment	187,439,853	Line 14
Asset Service Life	30	Line 166
Composite Tax Rate	38.6790%	Line 176

NPV of Col (j)> 14,818,660

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized PMT of NPV
	Line 223 / 224		(b) * (c)	((d) - (b)) * Line 176	Accum. (e)	= (f) * (Line185+186)	= (f) * (Line184)	= (g) * (Line177)	(g) + (h) + (i)	col. (j)
1	6,247,995	3.750%	7,028,994	302,083	302,083	17,778	6,797	10,901	35,476	1,333,105
2	6,247,995	7.219%	13,531,283	2,817,103	3,119,186	183,564	70,182	112,563	366,309	1,333,105
3	6,247,995	6.677%	12,515,359	2,424,154	5,543,339	326,226	124,725	200,045	650,995	1,333,105
4	6,247,995	6.177%	11,578,160	2,061,654	7,604,994	447,554	171,112	274,445	893,111	1,333,105
5	6,247,995	5.713%	10,708,439	1,725,255	9,330,249	549,085	209,931	336,704	1,095,720	1,333,105
6	6,247,995	5.285%	9,906,196	1,414,956	10,745,204	632,355	241,767	387,767	1,261,889	1,333,105
7	6,247,995	4.888%	9,162,060	1,127,131	11,872,336	698,687	267,128	428,442	1,394,256	1,333,105
8	6,247,995	4.522%	8,476,030	861,782	12,734,117	749,403	286,518	459,541	1,495,462	1,333,105
9	6,247,995	4.462%	8,363,566	818,282	13,552,399	797,559	304,929	489,071	1,591,559	1,333,105
10	6,247,995	4.461%	8,361,692	817,557	14,369,956	845,672	323,324	518,574	1,687,570	1,333,105
11	6,247,995	4.462%	8,363,566	818,282	15,188,237	893,828	341,735	548,104	1,783,667	1,333,105
12	6,247,995	4.461%	8,361,692	817,557	16,005,794	941,941	360,130	577,608	1,879,679	1,333,105
13	6,247,995	4.462%	8,363,566	818,282	16,824,076	990,097	378,542	607,137	1,975,776	1,333,105
14	6,247,995	4.461%	8,361,692	817,557	17,641,633	1,038,210	396,937	636,641	2,071,788	1,333,105
15	6,247,995	4.462%	8,363,566	818,282	18,459,915	1,086,366	415,348	666,170	2,167,885	1,333,105
16	6,247,995	4.461%	8,361,692	817,557	19,277,471	1,134,479	433,743	695,674	2,263,896	1,333,105
17	6,247,995	4.462%	8,363,566	818,282	20,095,753	1,182,635	452,154	725,204	2,359,993	1,333,105
18	6,247,995	4.461%	8,361,692	817,557	20,913,310	1,230,748	470,549	754,707	2,456,005	1,333,105
19	6,247,995	4.462%	8,363,566	818,282	21,731,592	1,278,904	488,961	784,237	2,552,102	1,333,105
20	6,247,995	4.461%	8,361,692	817,557	22,549,148	1,327,017	507,356	813,740	2,648,114	1,333,105
21	6,247,995	2.231%	4,181,783	-799,190	21,749,958	1,279,985	489,374	784,900	2,554,259	1,333,105
22	6,247,995	0.000%	0	-2,416,662	19,333,296	1,137,764	434,999	697,689	2,270,452	1,333,105
23	6,247,995	0.000%	0	-2,416,662	16,916,634	995,544	380,624	610,477	1,986,646	1,333,105
24	6,247,995	0.000%	0	-2,416,662	14,499,972	853,323	326,249	523,266	1,702,839	1,333,105
25	6,247,995	0.000%	0	-2,416,662	12,083,310	711,103	271,874	436,055	1,419,033	1,333,105
26	6,247,995	0.000%	0	-2,416,662	9,666,648	568,882	217,500	348,844	1,135,226	1,333,105
27	6,247,995	0.000%	0	-2,416,662	7,249,986	426,662	163,125	261,633	851,420	1,333,105
28	6,247,995	0.000%	0	-2,416,662	4,833,324	284,441	108,750	174,422	567,613	1,333,105
29	6,247,995	0.000%	0	-2,416,662	2,416,662	142,221	54,375	87,211	283,807	1,333,105
30	6,247,995	0.000%	0	-2,416,662	0	0	0	0	0	1,333,105

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Unit Name: Southwark 3-6 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 6,463,264		Electric Expenses	Line 140	761		
2	Investment Generator & Exciter	Inputs Tab	$ 969,490		Other Expenses		102		
3	Reactive Allocator	(Line 71)	38.50%		O&M	(sum line 1 & 2)	863	724,193	0.1192%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**373,301**						
5					A&G		136,039	10,963,535	1.2408%
6	GSU Transformer Investment	Inputs Tab	2,616		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0183%
7	Reactive Allocator	(Line 71)	38.50%		Working Capital	Line 216	59,159	10,963,535	0.5396%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**1,007**		General Plant		-	10,963,535	0.0000%
9					Other Taxes	Line 196(c)	11,609	10,963,535	0.1059%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	895,880		Depreciation	Line 168(c)			0.7901%
11	Reactive Allocator	(Line 71)	38.50%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**344,957**		Taxes (Federal/State/Local)	Line 180			2.6006%
13					ADIT	-Line 233(k)	($82,733)	10,963,535	-0.7546%
14	Total Cost of Power Plant	Inputs Tab	10,963,535				(Sum Lines 1 to 11 , Col. (h))		12.7948%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	9,095,550						
16	Balance of Plant Allocator	(Line 79)	0.0542%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	4,928						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	724,193						
19	Reactive Fixed Charge Rate	(Line 14(h))	12.7948%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**92,659**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 92,659**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		12.80						
		14.88						
		12.88						
		14.66						
	Total	55.22	(Sum Lines 31 to 34)					
	Nominal Power Factor (pf)							
		0.76						
		0.81						
		0.77						
		0.80						
	Total	0.78	(Line 38 / 58)					
	MVA Capability (MVA)							
		16.93	(Line 31 / 41)					
		18.48	(Line 32 / 42)					
		16.81	(Line 33 / 43)					
		18.26	(Line 34 / 44)					
	Total	70.49	(Sum Lines 51 to 54)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		11.08	(SQRT (Line 51^2 - Line 31^2))					
		10.97	(SQRT (Line 52^2 - Line 32^2))					
		10.81	(SQRT (Line 53^2 - Line 33^2))					
		10.88	(SQRT (Line 54^2 - Line 34^2))					
	Total	43.74	(Sum Lines 62 to 65)					
	Reactive Allocator	38.5%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)	
Accessory Equip Allocator					
		Investment	**Cumb. Turbine**	**Allocated Amt**	
	Storage Batteries	$ 40,019	50%	$ 20,009	
	Control&Power Cabling	$ 65,482	50%	$ 32,741	
	Switch Board Equipment	$ 1,638,273	50%	$ 819,137	
	Switching Equipment	$ 59,982	40%	$ 23,993	
	Transformers	$ -	10%	$ -	
	Aux Generator	$ -	0%	$ -	
	Fire Protection System	$ -	0%	$ -	
	HVAC	$ -	0%	$ -	
	Regulating Equipment	$ -	75%	$ -	
	Structure	$ 11,054	0%	$ -	
	Misc	$ 781,212	0%	$ -	
	Exciter & PPT	$ -	100%	$ -	
	Station Grounding	$ -	5%	$ -	
	Bus & Insulators	$ -	80%	$ -	
	Capacitor Bank	$ -	0%	$ -	
	Total	$ 2,596,022		$ 895,880	

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	75,704	75,704	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	19,555	19,555	
	Steam From Other Sources	37,788		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	11,577		
	Rents	70,458	70,458	
	Allowances	2,847	2,847	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	29,529	29,529	
	Maintenance of Boiler (or reactor) Plant	12,663		
	Maintenance of Electric Plant	13,174		
	Maintenance of Misc Steam (or Nuclear) Plant	16,397	16,397	
	Other Power Production, & Other Expenses	49,735	49,735	
	Total NonFuel Expenses	339,425	264,224	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	5.7757%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	339,425	Line 116			
	Allowances	2,847	Line 109			
	Non-Fuel Production O&M	336,578	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	75,704	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	13,174	Line 113(b)			
	Other Demand Related Expenses	188,520	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	277,398	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	13,174	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	13,174	(Line 138 + 139)	5.7757%	761	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	188,520	(Line 134)	0.0542%	102	
				Line 123		
	Balance of Plant Fixed Expenses				276,535	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		16,925	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		119,114	(allocated on plant labor)	
	Total		136,039		
Depreciation					
	Annual Depreciation Exp ...DE	353,662			
	Gross Production Plant Cost ... F	10,963,535	Line 14		
	SLDP=DE/F	3.2258%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	31			
	SFDP=(R/((1+R)^n-1)		0.7901%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.601%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		11,609	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		11,609	(Line 192 + 195)	

	Plant		Depreciation	Total	
General Plant	-		-		
	0.000%		0.000%		Line 159
Fixed General Plant	-		-		(Lines 200 *201)
Return on General Plant	8.1350%	Line 188			
Taxes on General Plant	2.6006%	Line 189			
General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
Prepayments	82,470		
	100.000%		
Production Related Prepayments	82,470	(Line 209 * 210)	
Unit Specific M&S	468,585		
Total	551,055	(Line 211 + 212)	
Return on Working Capital	8.1350%		
Taxes on Working Capital	2.6006%		
Working Capital Costs	59,159	(Line 213 * 214)	

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Accumulated Deferred Income Taxes

Investment	10,963,535	Line 14
Asset Service Life	31	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 926,978

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity = (f) *	(h) Interest = (f) *	(i) Income Taxes = (g) *	(j) Rev Req Impact	(k) Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	(Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	353,662	3.750%	411,133	22,229	22,229	1,308	500	802	2,611	82,733
2	353,662	7.219%	791,458	169,335	191,564	11,274	4,310	6,913	22,497	82,733
3	353,662	6.677%	732,035	146,351	337,914	19,886	7,603	12,194	39,684	82,733
4	353,662	6.177%	677,218	125,148	463,062	27,251	10,419	16,711	54,381	82,733
5	353,662	5.713%	626,347	105,472	568,534	33,458	12,792	20,517	66,767	82,733
6	353,662	5.285%	579,423	87,322	655,856	38,597	14,757	23,668	77,022	82,733
7	353,662	4.888%	535,898	70,487	726,343	42,745	16,343	26,212	85,300	82,733
8	353,662	4.522%	495,771	54,966	781,309	45,980	17,579	28,195	91,755	82,733
9	353,662	4.462%	489,193	52,422	833,731	49,065	18,759	30,087	97,911	82,733
10	353,662	4.461%	489,083	52,379	886,110	52,148	19,937	31,977	104,062	82,733
11	353,662	4.462%	489,193	52,422	938,532	55,233	21,117	33,869	110,219	82,733
12	353,662	4.461%	489,083	52,379	990,911	58,315	22,296	35,759	116,370	82,733
13	353,662	4.462%	489,193	52,422	1,043,333	61,400	23,475	37,651	122,526	82,733
14	353,662	4.461%	489,083	52,379	1,095,713	64,483	24,654	39,541	128,678	82,733
15	353,662	4.462%	489,193	52,422	1,148,134	67,568	25,833	41,433	134,834	82,733
16	353,662	4.461%	489,083	52,379	1,200,514	70,650	27,012	43,323	140,985	82,733
17	353,662	4.462%	489,193	52,422	1,252,936	73,735	28,191	45,215	147,142	82,733
18	353,662	4.461%	489,083	52,379	1,305,315	76,818	29,370	47,105	153,293	82,733
19	353,662	4.462%	489,193	52,422	1,357,737	79,903	30,549	48,997	159,449	82,733
20	353,662	4.461%	489,083	52,379	1,410,116	82,985	31,728	50,887	165,600	82,733
21	353,662	2.231%	244,596	-42,186	1,367,931	80,503	30,778	49,365	160,646	82,733
22	353,662	0.000%	0	-136,793	1,231,138	72,452	27,701	44,429	144,582	82,733
23	353,662	0.000%	0	-136,793	1,094,345	64,402	24,623	39,492	128,517	82,733
24	353,662	0.000%	0	-136,793	957,552	56,352	21,545	34,556	112,452	82,733
25	353,662	0.000%	0	-136,793	820,759	48,302	18,467	29,619	96,388	82,733
26	353,662	0.000%	0	-136,793	683,965	40,251	15,389	24,683	80,323	82,733
27	353,662	0.000%	0	-136,793	547,172	32,201	12,311	19,746	64,259	82,733
28	353,662	0.000%	0	-136,793	410,379	24,151	9,234	14,810	48,194	82,733
29	353,662	0.000%	0	-136,793	273,586	16,101	6,156	9,873	32,129	82,733
30	353,662	0.000%	0	-136,793	136,793	8,050	3,078	4,937	16,065	82,733
31	353,662	0.000%	0	-136,793	0	0	0	0	0	82,733

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Unit Name: TMI **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 13,661,046	
2	Investment Generator & Exciter	Inputs Tab	2,049,157	
3	Reactive Allocator	(Line 71)	12.76%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**261,563**	
5				
6	GSU Transformer Investment	Inputs Tab	-	
7	Reactive Allocator	(Line 71)	12.76%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	797,453	
11	Reactive Allocator	(Line 71)	12.76%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**101,790**	
13				
14	Total Cost of Power Plant	Inputs Tab	1,001,621,380	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	998,774,770	
16	Balance of Plant Allocator	(Line 79)	0.0082%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	81,504	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	444,856	
19	Reactive Fixed Charge Rate	(Line 14(h))	71.2614%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**317,011**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 317,011**	
23				
24				
25				
26				

(e)		(f)	(g)	(h)
Fixed Charge Rate for Reactive Plant				
		Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 140	203,229		
Other Expenses		6,467		
O&M	(sum line 1 & 2)	209,696	444,856	47.1379%
A&G		111,580,115	1,001,621,380	11.1399%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.8101%
Working Capital	Line 216	18,368,466	1,001,621,380	1.8339%
General Plant		-	1,001,621,380	0.0000%
Other Taxes	Line 196(c)	6,240,261	1,001,621,380	0.6230%
Depreciation	Line 168(c)			0.0752%
				8.1350%
Taxes (Federal/State/Local)	Line 180			2.9859%
ADIT	-Line 233(k)	($14,819,872)	1,001,621,380	-1.4796%
		(Sum Lines 1 to 11 , Col. (h))		71.2614%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		888.00						
		-						
		-						
	Total	888.00	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.93						
		-						
		-						
	Total	0.93	(Line 38 / 58)					
	MVA Capability (MVA)							
		950.75	(Line 31 / 41)					
		-						
		-						
	Total	950.75	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		339.68	(SQRT (Line 51^2 - Line 31^2))					
		-						
		-						
	Total	339.68	(Sum Lines 62 to 64)					
	Reactive Allocator	12.8%	(Line 69^2 / Line 58^2)					
		MetEd is TO Fleet						
	Max. MVAr	15.32						
	Nameplate MVAr	339.68						
	Exciter MW	1.61						
	Generator MW	888.00						
	Balance of Plant Allocator	0.0082%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ -	15%	$ -
	Control&Power Cabling	$ -	1%	$ -
	Switch Board Equipment	$ -	1%	$ -
	Switching Equipment	$ -	1%	$ -
	Transformers	$ 1,804,433	3%	$ 54,133
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ 194,043	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ 1,486,640	50%	$ 743,320
	Structure	$ -	0%	$ -
	Misc	$ 10,382,696	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	1%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 13,867,813		$ 797,453

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	22,327,877	22,327,877	
	Coolants and Water (Nuclear Plants Only)	2,187,756		
	Steam Expenses	13,722,618	13,722,618	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	1,401,948		
	Rents	38,762,682	38,762,682	
	Allowances	3,075,908	3,075,908	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	4,119,106	4,119,106	
	Maintenance of Boiler (or reactor) Plant	321,052		
	Maintenance of Electric Plant	10,614,344		
	Maintenance of Misc Steam (or Nuclear) Plant	6,818,030	6,818,030	
	Other Power Production, & Other Expenses	12,755,212	12,755,212	
	Total NonFuel Expenses	116,106,533	101,581,433	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	1.9147%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0082%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	116,106,533	Line 116			
	Allowances	3,075,908	Line 109			
	Non-Fuel Production O&M	113,030,625	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	22,327,877	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	10,614,344	Line 113(b)			
	Other Demand Related Expenses	79,253,555	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131			
	Total	112,195,777	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	10,614,344	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	10,614,344	(Line 138 + 139)	1.9147%	203,229	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	79,253,555	(Line 134)	0.0082%	6,467	
				Line 123		
	Balance of Plant Fixed Expenses				111,986,081	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		80,763,143	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		30,816,972	(allocated on plant labor)	
	Total		111,580,115		

Depreciation				
	Annual Depreciation Exp ...DE	16,693,690		
	Gross Production Plant Cost ... F	1,001,621,380	Line 14	
	SLDP=DE/F	1.6667%	(Line 164 / 165)	
	Depreciable years (n)=1/SLDP	60		
	SFDP=(R/((1+R)^n-1)		0.0752%	
Income Taxes				
	Income Tax Calculation; (Co's Sch. 2)			
	a) State Income Tax Rate ("SIT")	5.6600%		
	b) City/Local Income Tax Rate ("LIT")	0.0000%		
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%		
	d) Net of Fdrl tax SIT	3.6790%		
	e) Federal Income Tax Rate ("FIT")	35.0000%		
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%		
	g) Gross-Up Tax Factor ("GTF")	61.3210%		
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.986%	

Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)

Other Taxes					
	Property Taxes		1,186,903		
	Payroll Taxes	5,775,935			
	0	87.4899%	Line 117		
	Fixed Payroll Taxes		5,053,357	(Line 193 * 194)	
	Total Other Taxes		6,240,261	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9859%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
	Prepayments	1,679,308	
		100.000%	
	Production Related Prepayments	1,679,308	(Line 209 * 210)
	Unit Specific M&S	163,491,998	
	Total	165,171,306	(Line 211 + 212)
	Return on Working Capital	8.1350%	
	Taxes on Working Capital	2.9859%	
	Working Capital Costs	18,368,466	(Line 213 * 214)

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Accumulated Deferred Income Taxes

Investment	1,001,621,380	Line 14	NPV of Col (j)> 180,505,002
Asset Service Life	60	Line 167	
Composite Tax Rate	38.6790%	Line 177	

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	PMT of NPV col. (j)
1	16,693,690	3.750%	37,560,802	8,071,190	8,071,190	474,990	181,602	291,268	947,860	14,819,872
2	16,693,690	7.219%	72,307,047	21,510,691	29,581,881	1,740,894	665,592	1,067,533	3,474,019	14,819,872
3	16,693,690	6.677%	66,878,260	19,410,890	48,992,771	2,883,225	1,102,337	1,768,022	5,753,584	14,819,872
4	16,693,690	6.177%	61,870,153	17,473,804	66,466,575	3,911,558	1,495,498	2,398,606	7,805,662	14,819,872
5	16,693,690	5.713%	57,222,629	15,676,189	82,142,763	4,834,102	1,848,212	2,964,319	9,646,633	14,819,872
6	16,693,690	5.285%	52,935,690	14,018,043	96,160,807	5,659,063	2,163,618	3,470,194	11,292,876	14,819,872
7	16,693,690	4.888%	48,959,253	12,479,997	108,640,804	6,393,511	2,444,418	3,920,565	12,758,494	14,819,872
8	16,693,690	4.522%	45,293,319	11,062,051	119,702,854	7,044,513	2,693,314	4,319,766	14,057,593	14,819,872
9	16,693,690	4.462%	44,692,346	10,829,600	130,532,455	7,681,835	2,936,980	4,710,578	15,329,393	14,819,872
10	16,693,690	4.461%	44,682,330	10,825,726	141,358,181	8,318,929	3,180,559	5,101,250	16,600,738	14,819,872
11	16,693,690	4.462%	44,692,346	10,829,600	152,187,781	8,956,251	3,424,225	5,492,063	17,872,539	14,819,872
12	16,693,690	4.461%	44,682,330	10,825,726	163,013,507	9,593,345	3,667,804	5,882,735	19,143,884	14,819,872
13	16,693,690	4.462%	44,692,346	10,829,600	173,843,107	10,230,667	3,911,470	6,273,547	20,415,684	14,819,872
14	16,693,690	4.461%	44,682,330	10,825,726	184,668,834	10,867,761	4,155,049	6,664,220	21,687,029	14,819,872
15	16,693,690	4.462%	44,692,346	10,829,600	195,498,434	11,505,083	4,398,715	7,055,032	22,958,829	14,819,872
16	16,693,690	4.461%	44,682,330	10,825,726	206,324,160	12,142,177	4,642,294	7,445,704	24,230,175	14,819,872
17	16,693,690	4.462%	44,692,346	10,829,600	217,153,760	12,779,499	4,885,960	7,836,516	25,501,975	14,819,872
18	16,693,690	4.461%	44,682,330	10,825,726	227,979,486	13,416,593	5,129,538	8,227,189	26,773,320	14,819,872
19	16,693,690	4.462%	44,692,346	10,829,600	238,809,087	14,053,915	5,373,204	8,618,001	28,045,120	14,819,872
20	16,693,690	4.461%	44,682,330	10,825,726	249,634,813	14,691,009	5,616,783	9,008,673	29,316,465	14,819,872
21	16,693,690	2.231%	22,346,173	2,186,324	251,821,137	14,819,674	5,665,976	9,087,572	29,573,222	14,819,872
22	16,693,690	0.000%	0	-6,456,952	245,364,184	14,439,682	5,520,694	8,854,558	28,814,934	14,819,872
23	16,693,690	0.000%	0	-6,456,952	238,907,232	14,059,691	5,375,413	8,621,543	28,056,646	14,819,872
24	16,693,690	0.000%	0	-6,456,952	232,450,280	13,679,699	5,230,131	8,388,528	27,298,358	14,819,872
25	16,693,690	0.000%	0	-6,456,952	225,993,328	13,299,707	5,084,850	8,155,514	26,540,071	14,819,872
26	16,693,690	0.000%	0	-6,456,952	219,536,376	12,919,716	4,939,568	7,922,499	25,781,783	14,819,872
27	16,693,690	0.000%	0	-6,456,952	213,079,423	12,539,724	4,794,287	7,689,484	25,023,495	14,819,872
28	16,693,690	0.000%	0	-6,456,952	206,622,471	12,159,732	4,649,006	7,456,470	24,265,208	14,819,872
29	16,693,690	0.000%	0	-6,456,952	200,165,519	11,779,741	4,503,724	7,223,455	23,506,920	14,819,872
30	16,693,690	0.000%	0	-6,456,952	193,708,567	11,399,749	4,358,443	6,990,440	22,748,632	14,819,872
31	16,693,690	0.000%	0	-6,456,952	187,251,614	11,019,758	4,213,161	6,757,426	21,990,344	14,819,872
32	16,693,690	0.000%	0	-6,456,952	180,794,662	10,639,766	4,067,880	6,524,411	21,232,057	14,819,872
33	16,693,690	0.000%	0	-6,456,952	174,337,710	10,259,774	3,922,598	6,291,396	20,473,769	14,819,872
34	16,693,690	0.000%	0	-6,456,952	167,880,758	9,879,783	3,777,317	6,058,381	19,715,481	14,819,872
35	16,693,690	0.000%	0	-6,456,952	161,423,806	9,499,791	3,632,036	5,825,367	18,957,193	14,819,872
36	16,693,690	0.000%	0	-6,456,952	154,966,853	9,119,799	3,486,754	5,592,352	18,198,906	14,819,872
37	16,693,690	0.000%	0	-6,456,952	148,509,901	8,739,808	3,341,473	5,359,337	17,440,618	14,819,872
38	16,693,690	0.000%	0	-6,456,952	142,052,949	8,359,816	3,196,191	5,126,323	16,682,330	14,819,872
39	16,693,690	0.000%	0	-6,456,952	135,595,997	7,979,824	3,050,910	4,893,308	15,924,042	14,819,872
40	16,693,690	0.000%	0	-6,456,952	129,139,044	7,599,833	2,905,629	4,660,293	15,165,755	14,819,872
41	16,693,690	0.000%	0	-6,456,952	122,682,092	7,219,841	2,760,347	4,427,279	14,407,467	14,819,872
42	16,693,690	0.000%	0	-6,456,952	116,225,140	6,839,849	2,615,066	4,194,264	13,649,179	14,819,872
43	16,693,690	0.000%	0	-6,456,952	109,768,188	6,459,858	2,469,784	3,961,249	12,890,892	14,819,872
44	16,693,690	0.000%	0	-6,456,952	103,311,236	6,079,866	2,324,503	3,728,235	12,132,604	14,819,872
45	16,693,690	0.000%	0	-6,456,952	96,854,283	5,699,875	2,179,221	3,495,220	11,374,316	14,819,872
46	16,693,690	0.000%	0	-6,456,952	90,397,331	5,319,883	2,033,940	3,262,205	10,616,028	14,819,872
47	16,693,690	0.000%	0	-6,456,952	83,940,379	4,939,891	1,888,659	3,029,191	9,857,741	14,819,872
48	16,693,690	0.000%	0	-6,456,952	77,483,427	4,559,900	1,743,377	2,796,176	9,099,453	14,819,872
49	16,693,690	0.000%	0	-6,456,952	71,026,474	4,179,908	1,598,096	2,563,161	8,341,165	14,819,872
50	16,693,690	0.000%	0	-6,456,952	64,569,522	3,799,916	1,452,814	2,330,147	7,582,877	14,819,872
51	16,693,690	0.000%	0	-6,456,952	58,112,570	3,419,925	1,307,533	2,097,132	6,824,590	14,819,872
52	16,693,690	0.000%	0	-6,456,952	51,655,618	3,039,933	1,162,251	1,864,117	6,066,302	14,819,872
53	16,693,690	0.000%	0	-6,456,952	45,198,666	2,659,941	1,016,970	1,631,103	5,308,014	14,819,872
54	16,693,690	0.000%	0	-6,456,952	38,741,713	2,279,950	871,689	1,398,088	4,549,726	14,819,872
55	16,693,690	0.000%	0	-6,456,952	32,284,761	1,899,958	726,407	1,165,073	3,791,439	14,819,872
56	16,693,690	0.000%	0	-6,456,952	25,827,809	1,519,967	581,126	932,059	3,033,151	14,819,872
57	16,693,690	0.000%	0	-6,456,952	19,370,857	1,139,975	435,844	699,044	2,274,863	14,819,872
58	16,693,690	0.000%	0	-6,456,952	12,913,904	759,983	290,563	466,029	1,516,575	14,819,872
59	16,693,690	0.000%	0	-6,456,952	6,456,952	379,992	145,281	233,015	758,288	14,819,872
60	16,693,690	0.000%	0	-6,456,952	0	0	0	0	0	14,819,872

Unit Name: Westport 5 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 31,650,720		Electric Expenses	Line 140	750		
2	Investment Generator & Exciter	Inputs Tab	4,747,608		Other Expenses		75		
3	Reactive Allocator	(Line 71)	14.62%		O&M	(sum line 1 & 2)	825	911,476	0.0905%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**694,214**						
5					A&G		484,574	38,050,323	1.2735%
6	GSU Transformer Investment	Inputs Tab	337,384		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0188%
7	Reactive Allocator	(Line 71)	14.62%		Working Capital	Line 216	45,779	38,050,323	0.1203%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**49,334**		General Plant		-	38,050,323	0.0000%
9					Other Taxes	Line 196(c)	775,741	38,050,323	2.0387%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	1,114,980		Depreciation	Line 168(c)			0.1309%
11	Reactive Allocator	(Line 71)	14.62%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**163,037**		Taxes (Federal/State/Local)	Line 180			2.9108%
13					ADIT	-Line 233(k)	($518,834)	38,050,323	-1.3635%
14	Total Cost of Power Plant	Inputs Tab	38,050,323				(Sum Lines 1 to 11 , Col. (h))		13.3551%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	31,850,350						
16	Balance of Plant Allocator	(Line 79)	0.0154%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	4,891						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	911,476						
19	Reactive Fixed Charge Rate	(Line 14(h))	13.3551%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**121,728**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 121,728**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		118.50						
		-						
		-						
	Total	118.50	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.92						
		-						
		-						
	Total	0.92	(Line 38 / 58)					
	MVA Capability (MVA)							
		128.25	(Line 31 / 41)					
		-	(Line 32 / 42)					
		-						
	Total	128.25	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		49.04	(SQRT (Line 51^2 - Line 31^2))					
		-	(SQRT (Line 52^2 - Line 32^2))					
		-	(SQRT (Line 53^2 - Line 33^2))					
	Total	49.04	(Sum Lines 62 to 64)					
	Reactive Allocator	14.6%	(Line 69^2 / Line 58^2)					
		BGE is TO Fleet						
	Max. MVAr	27.50						
	Nameplate MVAr	571.22						
	Exciter MW	3.08						
	Generator MW	965.46						
	Balance of Plant Allocator	0.0154%	(Line 75 / Line 76) * (Line 77 / Line 78)					

	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ -	50%	$ -
	Control&Power Cabling	-	50%	$ -
	Switch Board Equipment	-	50%	$ -
	Switching Equipment	-	40%	$ -
	Transformers	-	10%	$ -
	Aux Generator	-	0%	$ -
	Fire Protection System	-	0%	$ -
	HVAC	-	0%	$ -
	Regulating Equipment	1,486,640	75%	$ 1,114,980
	Structure	-	0%	$ -
	Misc	217,121	0%	$ -
	Exciter & PPT	-	100%	$ -
	Station Grounding	-	5%	$ -
	Bus & Insulators	-	80%	$ -
	Capacitor Bank	-	0%	$ -
	Total	$ 1,703,761		$ 1,114,980

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	196,400	196,400	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	50,732	50,732	
	Steam From Other Sources	98,033		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	30,035		
	Rents	182,789	182,789	
	Allowances	7,386	7,386	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	76,608	76,608	
	Maintenance of Boiler (or reactor) Plant	32,851		
	Maintenance of Electric Plant	34,177		
	Maintenance of Misc Steam (or Nuclear) Plant	42,538	42,538	
	Other Power Production, & Other Expenses	129,027	129,027	
	Total NonFuel Expenses	880,575	685,480	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation				
	Plant Var Allocators			
	Electric Expense Allocator	2.1934%	Line 4(c) / 1(c))	
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)	
	Other Demand Expense Allocator	0.0154%	Line 79	
	Production Plant Expenses			
	Total NonFuel Expenses	880,575	Line 116	
	Allowances	7,386	Line 109	
	Non-Fuel Production O&M	873,189	(Line 126 - 127)	
	Operating Expenses			
	Operations Supervision & Engineering	196,400	Line 102(c)	
	Electric Expenses	0	Line 106(c)	
	Maintenance of Electric Plant	34,177	Line 113(b)	
	Other Demand Related Expenses	489,079	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)	
	Total	719,656	(Sum Lines 131 to 134)	

				Allocator	Allocated Amount	
	Maintenance of Electric Plant	34,177	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	34,177	(Line 138 + 139)	2.1934%	750	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	489,079	(Line 134)	0.0154%	75	
				Line 123		
	Balance of Plant Fixed Expenses				718,832	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		144,258	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		340,317	(allocated on plant labor)	
	Total		484,574		
Depreciation					
	Annual Depreciation Exp ...DE	717,931			
	Gross Production Plant Cost ... F	38,050,323	Line 14		
	SLDP=DE/F	1.8868%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	53			
	SFDP=(R/((1+R)^n-1)		0.1309%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.911%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		775,741	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		775,740.9	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9108%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	286,221				
		100.000%				
	Production Related Prepayments	286,221	(Line 209 * 210)			
	Unit Specific M&S	128,223				
	Total	414,445	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9108%				
	Working Capital Costs	45,779	(Line 213 * 214)			

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(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)

Accumulated Deferred Income Taxes

Investment	38,050,323	Line 14		NPV of Col (j)>	6,276,766
Asset Service Life	53	Line 167			
Composite Tax Rate	38.6790%	Line 177			

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity = (f) * (Line186+187)	Interest = (f) * (Line185)	Income Taxes = (g) * (Line178)	Rev Req Impact (g) + (h) + (i)	Levelized PMT of NPV col. (j)
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)					
1	717,931	3.750%	1,426,887	274,217	274,217	16,138	6,170	9,896	32,203	518,834
2	717,931	7.219%	2,746,853	784,767	1,058,984	62,321	23,827	38,216	124,364	518,834
3	717,931	6.677%	2,540,620	704,998	1,763,982	103,810	39,690	63,658	207,157	518,834
4	717,931	6.177%	2,350,368	631,411	2,395,393	140,969	53,896	86,444	281,309	518,834
5	717,931	5.713%	2,173,815	563,121	2,958,514	174,109	66,567	106,765	347,440	518,834
6	717,931	5.285%	2,010,960	500,131	3,458,645	203,541	77,820	124,814	406,174	518,834
7	717,931	4.888%	1,859,900	441,702	3,900,347	229,535	87,758	140,753	458,047	518,834
8	717,931	4.522%	1,720,636	387,836	4,288,183	252,360	96,484	154,749	503,593	518,834
9	717,931	4.462%	1,697,805	379,006	4,667,189	274,664	105,012	168,427	548,103	518,834
10	717,931	4.461%	1,697,425	378,859	5,046,048	296,960	113,536	182,099	592,595	518,834
11	717,931	4.462%	1,697,805	379,006	5,425,054	319,264	122,064	195,776	637,104	518,834
12	717,931	4.461%	1,697,425	378,859	5,803,912	341,560	130,588	209,448	681,596	518,834
13	717,931	4.462%	1,697,805	379,006	6,182,918	363,865	139,116	223,125	726,106	518,834
14	717,931	4.461%	1,697,425	378,859	6,561,776	386,161	147,640	236,798	770,598	518,834
15	717,931	4.462%	1,697,805	379,006	6,940,782	408,465	156,168	250,475	815,107	518,834
16	717,931	4.461%	1,697,425	378,859	7,319,641	430,761	164,692	264,147	859,600	518,834
17	717,931	4.462%	1,697,805	379,006	7,698,647	453,065	173,220	277,824	904,109	518,834
18	717,931	4.461%	1,697,425	378,859	8,077,505	475,361	181,744	291,496	948,601	518,834
19	717,931	4.462%	1,697,805	379,006	8,456,511	497,666	190,271	305,174	993,111	518,834
20	717,931	4.461%	1,697,425	378,859	8,835,370	519,961	198,796	318,846	1,037,603	518,834
21	717,931	2.231%	848,903	50,659	8,886,028	522,943	199,936	320,674	1,043,552	518,834
22	717,931	0.000%	0	-277,688	8,608,340	506,601	193,688	310,653	1,010,941	518,834
23	717,931	0.000%	0	-277,688	8,330,651	490,259	187,440	300,632	978,330	518,834
24	717,931	0.000%	0	-277,688	8,052,963	473,917	181,192	290,611	945,719	518,834
25	717,931	0.000%	0	-277,688	7,775,275	457,575	174,944	280,590	913,108	518,834
26	717,931	0.000%	0	-277,688	7,497,586	441,233	168,696	270,568	880,497	518,834
27	717,931	0.000%	0	-277,688	7,219,898	424,891	162,448	260,547	847,886	518,834
28	717,931	0.000%	0	-277,688	6,942,210	408,549	156,200	250,526	815,275	518,834
29	717,931	0.000%	0	-277,688	6,664,521	392,207	149,952	240,505	782,664	518,834
30	717,931	0.000%	0	-277,688	6,386,833	375,865	143,704	230,484	750,053	518,834
31	717,931	0.000%	0	-277,688	6,109,144	359,523	137,456	220,463	717,442	518,834
32	717,931	0.000%	0	-277,688	5,831,456	343,181	131,208	210,442	684,831	518,834
33	717,931	0.000%	0	-277,688	5,553,768	326,839	124,960	200,421	652,220	518,834
34	717,931	0.000%	0	-277,688	5,276,079	310,497	118,712	190,400	619,609	518,834
35	717,931	0.000%	0	-277,688	4,998,391	294,155	112,464	180,379	586,998	518,834
36	717,931	0.000%	0	-277,688	4,720,702	277,813	106,216	170,358	554,387	518,834
37	717,931	0.000%	0	-277,688	4,443,014	261,471	99,968	160,337	521,776	518,834
38	717,931	0.000%	0	-277,688	4,165,326	245,129	93,720	150,316	489,165	518,834
39	717,931	0.000%	0	-277,688	3,887,637	228,787	87,472	140,295	456,554	518,834
40	717,931	0.000%	0	-277,688	3,609,949	212,445	81,224	130,274	423,943	518,834
41	717,931	0.000%	0	-277,688	3,332,261	196,104	74,976	120,253	391,332	518,834
42	717,931	0.000%	0	-277,688	3,054,572	179,762	68,728	110,232	358,721	518,834
43	717,931	0.000%	0	-277,688	2,776,884	163,420	62,480	100,211	326,110	518,834
44	717,931	0.000%	0	-277,688	2,499,195	147,078	56,232	90,189	293,499	518,834
45	717,931	0.000%	0	-277,688	2,221,507	130,736	49,984	80,168	260,888	518,834
46	717,931	0.000%	0	-277,688	1,943,819	114,394	43,736	70,147	228,277	518,834
47	717,931	0.000%	0	-277,688	1,666,130	98,052	37,488	60,126	195,666	518,834
48	717,931	0.000%	0	-277,688	1,388,442	81,710	31,240	50,105	163,055	518,834
49	717,931	0.000%	0	-277,688	1,110,754	65,368	24,992	40,084	130,444	518,834
50	717,931	0.000%	0	-277,688	833,065	49,026	18,744	30,063	97,833	518,834
51	717,931	0.000%	0	-277,688	555,377	32,684	12,496	20,042	65,222	518,834
52	717,931	0.000%	0	-277,688	277,688	16,342	6,248	10,021	32,611	518,834
53	717,931	0.000%	0	-277,688	0	0	0	0	0	518,834

Input Data For Schedule 3

Ownership for Jointly Owned Plants

	Description		Source	Total		Braidwood 1 & 2	Byron 1 & 2	Dresden 2 & 3	LaSalle 1 & 2
1	Turbogenerator, GUS and Accessory Electric Investment:				TO and Gen count>	ComEd (2)	ComEd (2)	ComEd (2)	ComEd (2)
2	Included TurboGenerator Investment	2015 Actual Data	Account 314,323, 333, 343 or 344	3,410,284,358		276,982,389	326,545,555	507,917,628	322,991,066
3	Investment Generator & Exciter	2015 Actual Data	15%	511,542,654		41,547,358	48,981,833	76,187,644	48,448,660
4	Value of GSU Transformers	2015 Actual Data		280,542,456		49,633,067	21,644,926	$ 36,227,984	$ 4,672,421
5	Total Accessory Elec Equipment - Gross Investment	2015 Actual Data	Account 315, 324, 334, 345	1,327,863,081	From row 144, below>	$ 278,083,692	$ 316,973,581	$ 97,166,463	$ 141,513,673
6	Installed Cost of Power Plant (excluding Nuclear ARC; Steam ARC)	2015 Actual Data	2015 Actual Data	13,317,492,271		$ 1,484,090,250	$ 1,391,617,170	$ 1,359,267,568	$ 1,412,906,574
7	Investment Generator & Exciter / Turbogenerator					15.000%	15.000%	15.000%	15.000%
8	Investment Generation & Exciter / Installed Cost of Power Plant					3.344%	3.520%	5.605%	3.429%
9						Source for Nucs: Excel file "1A - Unit PP&E Balances Dec 31 2015 (Legacy EXC)"			
10	**Allocators**								
11									
12	**Real Power Demonstrated Capability (gross MW)**								
13	Generator 1				Source: "Reactive Test Results - Excel.xlxs"	1,258.00	1,248.00	948.00	1,194.00
14	Generator 2					1,220.00	1,205.00	944.00	1,183.00
15	Generator 3								
16	Generator 4								
17	Generator 5								
18	Generator 6								
19	Generator 7								
20	Generator 8								
21	Generator 9								
22	Generator 10								
23	Generator 11								
24									
25	Total					2,478.00	2,453.00	1,892.00	2,377.00
26									
27	**Nominal Power Factor (pf)**								
28	Generator 1				Source: "Reactive Test Results - Excel.xlxs"	0.92	0.93	0.93	0.93
29	Generator 2				Tested Capability or Name Plate	0.90	0.90	0.93	0.90
30	Generator 3								
31	Generator 4								
32	Generator 5								
33	Generator 6								
34	Generator 7								
35	Generator 8								
36	Generator 9								
37	Generator 10								
38	Generator 11								
39									
40									
41	**Nameplate MVAr**								
42	Generator 1	(Nameplates, sqrt(MVA^2-MW^2))				524.46	508.80	377.65	480.00
43	Generator 2	(Nameplates, sqrt(MVA^2-MW^2))				576.98	570.00	373.09	572.95
44	Generator 3	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
45	Generator 4	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
46	Generator 5	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
47	Generator 6	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
48	Generator 7	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
49	Generator 8	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
50	Generator 9	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
51	Generator 10	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
52	Generator 11	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
53									
54									
55	Total					1,101.44	1,078.80	750.74	1,052.95
56									
57	**Exciter MW**								
58	Generator 1	Exciter Rating				4.41	4.41	1.96	3.48
59	Generator 1	Exciter Rating				4.82	4.82	1.99	3.27
60	Generator 2	Exciter Rating							
61	Generator 3	Exciter Rating							
62	Generator 4	Exciter Rating							
63	Generator 5	Exciter Rating							
64	Generator 6	Exciter Rating							
65	Generator 7	Exciter Rating							
66	Generator 8	Exciter Rating							
67	Generator 9	Exciter Rating							
68	Generator 10	Exciter Rating							
69	Generator 11	Exciter Rating				9.23	9.23	3.95	6.74
70									

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Input Data For Schedule 3

Ownership for Jointly Owned Plants

	Description	Source	Total	Braidwood 1 & 2	Byron 1 & 2	Dresden 2 & 3	LaSalle 1 & 2
71	**Generator MW**						
72	Generator 1	(pf*MVA)		1,258.00	1,248.00	948.00	1,194.00
73	Generator 2	(pf*MVA)		1,220.00	1,205.00	944.00	1,183.00
74	Generator 3	(pf*MVA)		-	-	-	-
75	Generator 4	(pf*MVA)		-	-	-	-
76	Generator 5	(pf*MVA)		-	-	-	-
77	Generator 6	(pf*MVA)		-	-	-	-
78	Generator 7	(pf*MVA)		-	-	-	-
79	Generator 8	(pf*MVA)		-	-	-	-
80	Generator 9	(pf*MVA)		-	-	-	-
81	Generator 10	(pf*MVA)		-	-	-	-
82	Generator 11	(pf*MVA)		-	-	-	-
83	Total			2,478.00	2,453.00	1,892.00	2,377.00
84							
85	**Generator MVA**						
86	Generator 1	MW/pf if not stated	Source: "Reactive Test Results - Excel.xlxs"	1,362.95	1,347.73	1,020.45	1,286.87
87	Generator 2	MW/pf if not stated		1,349.56	1,333.01	1,015.05	1,314.44
88	Generator 3	MW/pf if not stated					
89	Generator 4	MW/pf if not stated					
90	Generator 5	MW/pf if not stated					
91	Generator 6	MW/pf if not stated					
92	Generator 7	MW/pf if not stated					
93	Generator 8	MW/pf if not stated					
94	Generator 9	MW/pf if not stated					
95	Generator 10	MW/pf if not stated					
96	Generator 11	MW/pf if not stated					
97							
98	Total			2,712.50	2,680.75	2,035.51	2,601.32

99	Peak Hour	18	18	16	8	18	8	19	17				
100	Peak Day	9/3/2015	9/3/2015	7/20/2015	2/20/2015	7/20/2015	2/20/2015	2/19/2015	7/20/2015	ComEd (2)	ComEd (2)	ComEd (2)	ComEd (2)
101		**Average**	**ComEd**	**PECO**	**BG&E**	**JCPL**	**MetEd**	**Penelec**	**PSEG**				
102	Max. MVAr	2,991	2,187	361	27	113	15	-	288				
103	Nameplate MVAr	9,831	4,856	2,853	571	287	340	183	742	1,101.4	1,078.8	750.7	1,053.0
104	Exciter MW	76	35	29	3	2	2	1	5	9.2	9.2	3.9	6.7
105	Generator MW	23,359	11,447	6,715	965	621	888	295	2,427	2,478	2,453	1,892	2,377
106		**0.0992%**	**0.1358%**	**0.0542%**	**0.0154%**	**0.1253%**	**0.0082%**	**0.0000%**	**0.0824%**				
107					**Account 315, 324, 334, 345**								
108	**Accessory Equip Allocator**									**Full 315 Account Costs**			
109	Item		**Nuclear**	**Cumb. Turbine**	**Hydro & Steam**					**nuclear**	**nuclear**	**nuclear**	**nuclear**
110	Storage Batteries		15%	50%	30%					$ 110,198	$ 155,427	$ 297,653	$ 291,718
111	Control&Power Cabling		1%	50%	15%					$ 1,753,039	$ 1,850,370	$ 49,469	$ 231,151
112	Switch Board Equipment		1%	50%	30%					$ 519,743	$ 654,748	$ -	$ 64,889
113	Switching Equipment		1%	40%	20%					$ 78,437	$ 148,283	$ 46,618	$ 65,726
114	Transformers		3%	10%	5%					$ 21,065	$ 38,012	$ 366,596	$ 60,804
115	Aux Generator		0%	0%	0%					$ -	$ -	$ -	$ -
116	Fire Protection System		0%	0%	0%					$ -	$ -	$ -	$ -
117	HVAC		0%	0%	0%					$ -	$ -	$ -	$ -
118	Regulating Equipment		50%	75%	75%					$ -	$ 24,034	$ 76,734	$ -
119	Structure		0%	0%	0%					$ -	$ -	$ -	$ -
120	Misc		0%	0%	0%					$ -	$ -	$ -	$ -
121	Exciter & PPT		100%	100%	100%					$ -	$ -	$ -	$ -
122	Station Grounding		1%	5%	0%					$ -	$ -	$ 49	$ -
123	Bus & Insulators		80%	80%	60%					$ -	$ -	$ 3,307,619	$ 4,472,625
124	Capacitor Bank		0%	0%	0%					$ -	$ -	$ -	$ -
125										$ 2,482,481	$ 2,870,875	$ 4,144,738	$ 5,186,913
126			EXE-4, Sch 5 Allocation factors development							1%	1%	4%	4%

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Input Data For Schedule 3

Ownership for Jointly Owned Plants

	Description	Source	Total		Braidwood 1 & 2	Byron 1 & 2	Dresden 2 & 3	LaSalle 1 & 2
127	**Item**				**315 Account Costs**			
128	Storage Batteries	Actual 2015			$ 734,651	$ 1,036,178	$ 1,984,353	$ 1,944,786
129	Control&Power Cabling	Actual 2015			$ 175,303,902	$ 185,037,012	$ 4,946,860	$ 23,115,092
130	Switch Board Equipment	Actual 2015			$ 51,974,311	$ 65,474,820	$ -	$ 6,488,908
131	Switching Equipment	Actual 2015			$ 7,843,655	$ 14,828,319	$ 4,661,842	$ 6,572,575
132	Transformers	Actual 2015			$ 702,163	$ 1,267,080	$ 12,219,855	$ 2,026,797
133	Aux Generator	Actual 2015			$ 21,664,522	$ 30,867,315	$ 5,052,411	$ 10,275,282
134	Fire Protection System	Actual 2015			$ -	$ -	$ -	$ -
135	HVAC	Actual 2015			$ -	$ -	$ -	$ -
136	Regulating Equipment	Actual 2015			$ -	$ 48,068	$ 153,468	$ -
137	Structure	Actual 2015			$ -	$ -	$ 31,844	$ 445,431
138	Misc	Actual 2015			$ 19,860,488	$ 18,414,787	$ 63,976,359	$ 85,054,019
139	Exciter & PPT	Actual 2015			$ -	$ -	$ -	$ -
140	Station Grounding	Actual 2015			$ -	$ -	$ 4,948	$ -
141	Bus & Insulators	Actual 2015			$ -	$ -	$ 4,134,523	$ 5,590,781
142	Capacitor Bank	Actual 2015			$ -	$ -	$ -	$ -
143								
144	Total	$ 1,327,863,081	<ties to "Accessory Electric" excluding "Comm. Cumbust"		$ 278,083,692	$ 316,973,581	$ 97,166,463	$ 141,513,673
145								
146	**O&M Calculation**							
147	Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546			$ 32,492,207	$ 34,368,626	$ 30,319,889	$ 30,478,210
148	Coolants and Water (Nuclear Plants Only)	FERC Account 519			$ 3,183,689	$ 3,367,547	$ 2,970,838	$ 2,986,351
149	Steam Expenses	FERC Account 502, 520			$ 19,969,572	$ 21,122,811	$ 18,634,475	$ 18,731,778
150	Steam From Other Sources	FERC Account 503			$ -	$ -	$ -	$ -
151	Electric Expenses	FERC Account 505, 523 - Allocated based on			$ -	$ -	$ -	$ -
152	Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524 - Reduced from actual			$ 2,040,158	$ 2,157,976	$ 1,903,760	$ 1,913,700
153	Rents	FERC Account 507			$ 56,408,634	$ 59,666,223	$ 52,637,346	$ 52,912,201
154	Allowances	FERC Account 509			$ 4,476,155	$ 4,734,652	$ 4,176,895	$ 4,198,705
155	Maintenance Supervision and Engineering	FERC Account 510, 528			$ -	$ -	$ -	$ -
156	Maintenance of Structures	FERC Account 511, 529, 552			$ 5,994,248	$ 6,340,415	$ 5,593,493	$ 5,622,700
157	Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530			$ 467,205	$ 494,186	$ 435,969	$ 438,245
158	Maintenance of Electric Plant	FERC Account 513, 531, 554			$ 15,446,317	$ 16,338,339	$ 14,413,629	$ 14,488,892
159	Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532			$ 9,921,805	$ 10,494,787	$ 9,258,467	$ 9,306,811
160	Other Power Production, & Other Expenses	FERC Account 548-553; 557			$ 18,561,772	$ 19,633,712	$ 17,320,796	$ 17,411,239
161	TOTAL	Grand Total O&M	$ 1,382,760,846		$ 168,961,761	$ 178,719,274	$ 157,665,557	$ 158,488,835
162					$ 1,316,464,415	<ties to O&M total on "Sum Nucs"		
163	**A&G and Overhead Expenses**							
164	Plant specific A&G		$ 959,951,435		$ 124,367,412	$ 119,205,155	$ 113,729,176	$ 118,779,529
165					$ 950,205,753	<<ties to total on "Sum nucs"		
166	Nuclear Overhead Expenses ("OH" tab)		$ 480,915,543	Allocated on "Nuc. Labor" tab	$ 40,658,141	$ 37,280,822	$ 37,918,846	$ 38,811,570
167	Non-nuclear Overhead Expenses ("OH" tab)		$ 48,249,902	Allocated on "Sum non-nucs" tab				
168	Total		$ 529,165,445		$ 165,025,553	$ 156,485,976	$ 151,648,021	$ 157,591,099
169								
170								
171								
172								
173								
174								
175								
176	**Depreciation Exp**				Source of Lives: EXE4, Sch 2,"Plant Service Lives.xlsx"			
177				Project Life (yrs)>>>	58.5	59.0	60.0	60.0
178	Production Plant in Service Depreciation Expense		$ 229,249,849		$ 25,369,064	$ 23,586,732	$ 22,654,459	$ 23,548,443
179				= line 14 / line 177				
180	**Other Taxes**	Total	Allocator					
181	Plant Related & Property Taxes (Nucs only)	$ 123,977,347	Directly Assigned		$ 20,026,176	$ 33,153,706	$ 25,219,637	$ 21,480,427
182	Payroll Taxes (Nucs Only)	$ 60,289,214	Directly Assigned		$ 7,269,439	$ 7,259,232	$ 7,076,336	$ 7,193,199
183	Other Taxes (Pay & Property) (Non-Nucs)	$ 9,124,663	Directly Assigned					
184	Total Other Taxes	$ 193,391,223			$ 27,295,615	$ 40,412,937	$ 32,295,973	$ 28,673,627
185								
186								
187								
188								
189								
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191								
192								
193								
194								

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Input Data For Schedule 3

Ownership for Jointly Owned Plants

	Description	Source		Total		Braidwood 1 & 2	Byron 1 & 2	Dresden 2 & 3	LaSalle 1 & 2
195									
196									
197	**Prepayments**	Nuclear	17,837,119	10,638,927,515	Allocated on gross plant (except Salem and Calvert)	$ 2,488,211	$ 2,333,171	$ 2,278,934	$ 2,368,865
198		Fossil	50,151,394	6,667,142,786	Allocated on gross plant for Fossil Fleet				
199	Total		67,988,512			$ 2,488,211	$ 2,333,171	$ 2,278,934	$ 2,368,865
200									
201	**M&S**					Source: 2 - Unit Fuel Inventory (Nuc only)			
202	M&S - Fuel		$ 2,060,965,166	Directly Assigned	(use DR 2 and DR 3)	223,530,653	195,107,342	274,522,795	361,375,368
203	M&S - Fuel (undistributed)					-	-	-	-
204	M&S - Fossil Production		18,179,451	Allocated on "Sum non-nucs" tab					
205	M&S - Nuclear Production		$ 549,110,881	DA -- M&S for Nucs only		77,172,779	64,606,819	57,130,136	78,463,468
206	**TOTAL M&S**		$ 2,628,255,498			$ 300,703,432	$ 259,714,161	$ 331,652,931	$ 439,838,836
207									
208									
209	**RETURN (R)**								
210									

		$/mil	%	Cost	Weighted	
211						
212						
213	Long Term Debt	0.45	45.0%	5.00%	0.0225	=WCLTD <<Per ACH 9-29-16 (See below)
214	Proprietary Capital	0.55	55.0%	10.70%	0.0589	
215	Total (sum lines 22-23)	1.00	100%		0.0814	=R
216						
217						
218	**Income Taxes**					
219	State Marginal Rate (multi-state)	5.6600% <<Per ACH 9-29-16				
220						

		2016	2017 - 2020
221			
222	Jurisdiction1		
223			
224	Federal	35.00%	35.00%
	FIT on SIT	-1.65%	-1.98%
	Illinois2	0.72%	0.90%
	IL on SIT	-0.03%	-0.04%
	Pennsylvania2	1.10%	1.40%
	Maryland	0.54%	0.50%
	Other Separate	1.07%	1.30%
	NYS	0.00%	0.00%
	Other Unitary	1.31%	1.60%
	Marginal Tax Rate	38.06%	38.68%
	Effective State Rate	4.71%	5.66%

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Input Data For Schedule 3

	Description		Source	Limerick 1 & 2	Oyster Creek	Peach Bottom 2 & 3	Quad Cities 1 & 2	Salem 1 & 2	TMI	Chester 7-9	Conowingo 1 - 11	Croydon 11,12,21,22,31, 32,41,42
						50%	75%	42.59%				
1	Turbogenerator, GUS and Accessory Electric Investment:			PECO (2)	JCPL (1)	PECO (2)	ComEd (2)	PSEG (2)	MetEd (1)	PECO (3)	PECO (11)	PECO (8)
2	Included TurboGenerator Investment	2015 Actual Data	Account 314,323, 333, 34	195,863,167	30,406,806	324,475,609	345,327,838	80,714,327	13,661,046	4,695,512	143,524,274	72,348,001
3	Investment Generator & Exciter	2015 Actual Data	15%	29,379,475	4,561,021	48,671,341	51,799,176	12,107,149	2,049,157	704,327	21,528,641	10,852,200
4	Value of GSU Transformers	2015 Actual Data		$ 41,192,118	$ 19,820,373	$ 41,363,873	$ 25,326,658	$ 14,618,814	$ -	$ -	$ 6,792,649	$ 1,420,756
5	Total Accessory Elec Equipment - Gross Investment	2015 Actual Data	Account 315, 324, 334, 34	$ 109,655,219	$ 9,228,418	$ 64,240,533	$ 66,184,772	$ 38,713,489	$ 13,867,813	$ 1,724,631	$ 29,726,815	$ 9,038,464
6	Installed Cost of Power Plant (excluding Nuclear ARC; Steam ARC)	2015 Actual Data	2015 Actual Data	$ 1,222,406,959	$ 360,225,425	$ 1,360,681,860	$ 1,046,110,329	$ 583,671,743	$ 1,001,621,380	$ 9,133,168	$ 380,084,794	$ 107,412,068
7	Investment Generator & Exciter / Turbogenerator			15.000%	15.000%	15.000%	15.000%	15.000%	15.000%	15.000%	15.000%	15.000%
8	Investment Generation & Exciter / Installed Cost of Power Plant			2.403%	1.266%	3.577%	4.952%	2.074%	0.205%	7.712%	5.664%	10.103%
9												
10	**Allocators**									$ 2,094,893,014		
11												
12	**Real Power Demonstrated Capability (gross MW)**											
13	Generator 1			1,182.00	621.20	1,150.00	961.00	1,236.80	888.00	15.14	40.20	51.00
14	Generator 2			1,143.00	-	1,195.40	980.00	1,190.00	-	15.16	48.00	56.60
15	Generator 3									14.48	42.20	68.30
16	Generator 4										48.00	68.30
17	Generator 5										37.10	68.30
18	Generator 6										44.60	68.30
19	Generator 7										44.10	68.30
20	Generator 8										110.90	68.30
21	Generator 9										108.40	
22	Generator 10										114.50	
23	Generator 11										112.20	
24											-	
25	Total			2,325.00	621.20	2,345.40	1,941.00	2,426.80	888.00	44.78	750.20	517.40
26												
27	**Nominal Power Factor (pf)**											
28	Generator 1			0.93	0.91	0.93	0.95	0.96	0.93	0.81	0.88	0.91
29	Generator 2			0.94	-	0.90	0.94	0.95		0.81	0.90	0.93
30	Generator 3									0.80	0.89	0.90
31	Generator 4										0.90	0.90
32	Generator 5										0.95	0.90
33	Generator 6										0.88	0.90
34	Generator 7										0.88	0.90
35	Generator 8										1.00	0.90
36	Generator 9										0.99	-
37	Generator 10										0.9880	
38	Generator 11										0.9930	
39												
40												
41	**Nameplate MVAr**											
42	Generator 1	(Nameplates, sqrt(MVA^2-MW^2))		451.95	286.63	206.70	332.61	351.05	339.68	12.77	19.29	31.13
43	Generator 2	(Nameplates, sqrt(MVA^2-MW^2))		424.55	-	237.12	349.15	391.13	-	12.83	17.44	28.65
44	Generator 3	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	13.27	18.39	33.08
45	Generator 4	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	17.44	33.08
46	Generator 5	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	12.49	33.08
47	Generator 6	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	19.00	33.08
48	Generator 7	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	19.00	33.08
49	Generator 8	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	6.17	33.08
50	Generator 9	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	7.80	-
51	Generator 10	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	9.55	-
52	Generator 11	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	7.30	-
53												
54												
55	Total			876.50	286.63	443.83	681.76	742.18	339.68	38.87	153.86	258.25
56												
57	**Exciter MW**											
58	Generator 1	Exciter Rating		3.81	1.98	2.97	2.28	6.00	1.61	0.09	0.28	0.12
59	Generator 1	Exciter Rating		3.81		4.43	2.28	6.00		0.09	0.28	0.12
60	Generator 2	Exciter Rating								0.09	0.28	0.12
61	Generator 3	Exciter Rating									0.28	0.12
62	Generator 4	Exciter Rating									0.28	0.12
63	Generator 5	Exciter Rating									0.28	0.12
64	Generator 6	Exciter Rating									0.28	0.12
65	Generator 7	Exciter Rating									0.28	0.12
66	Generator 8	Exciter Rating									0.36	
67	Generator 9	Exciter Rating									0.36	
68	Generator 10	Exciter Rating									0.36	
69	Generator 11	Exciter Rating		7.61	1.98	7.40	4.56	12.00	1.61	0.26	3.29	0.98
70												

Input Data For Schedule 3

							50%	75%	42.59%			
	Description		**Source**	Limerick 1 & 2	Oyster Creek	Peach Bottom 2 & 3	Quad Cities 1 & 2	Salem 1 & 2	TMI	Chester 7-9	Conowingo 1 - 11	Croydon 11,12,21,22,31, 32,41,42
71	**Generator MW**							What is it?				
72	Generator 1	(pf*MVA)		1,181.51	621.20	503.20	961.00	1,236.80	888.00	17.76	35.04	69.21
73	Generator 2	(pf*MVA)		1,191.63	-	489.60	980.00	1,190.00	-	17.72	36.00	70.27
74	Generator 3	(pf*MVA)		-	-	-	-	-	-	17.39	35.52	68.30
75	Generator 4	(pf*MVA)		-	-	-	-	-	-	-	36.00	68.30
76	Generator 5	(pf*MVA)		-	-	-	-	-	-	-	38.00	68.30
77	Generator 6	(pf*MVA)		-	-	-	-	-	-	-	35.20	68.30
78	Generator 7	(pf*MVA)		-	-	-	-	-	-	-	35.20	68.30
79	Generator 8	(pf*MVA)		-	-	-	-	-	-	-	61.49	68.30
80	Generator 9	(pf*MVA)		-	-	-	-	-	-	-	61.31	-
81	Generator 10	(pf*MVA)		-	-	-	-	-	-	-	61.06	-
82	Generator 11	(pf*MVA)		-	-	-	-	-	-	-	61.37	-
83	Total			2,373.14	621.20	992.80	1,941.00	2,426.80	888.00	52.87	496.18	549.28
84												
85	**Generator MVA**											
86	Generator 1	MW/pf if not stated		1,265.00	684.14	544.00	1,016.93	1,285.65	950.75	21.88	40.00	75.89
87	Generator 2	MW/pf if not stated		1,265.00		544.00	1,040.34	1,252.63		21.88	40.00	75.89
88	Generator 3	MW/pf if not stated								21.88	40.00	75.89
89	Generator 4	MW/pf if not stated									40.00	75.89
90	Generator 5	MW/pf if not stated									40.00	75.89
91	Generator 6	MW/pf if not stated									40.00	75.89
92	Generator 7	MW/pf if not stated									40.00	75.89
93	Generator 8	MW/pf if not stated									61.80	75.89
94	Generator 9	MW/pf if not stated									61.80	
95	Generator 10	MW/pf if not stated									61.80	
96	Generator 11	MW/pf if not stated									61.80	
97												
98	Total			2,530.00	684.14	1,088.00	2,057.27	2,538.29	950.75	65.63	527.20	607.11

99	Peak Hour	18	18	16						2		
100	Peak Day	9/3/2015	9/3/2015	7/20/2015	PECO (2)	JCPL (1)	PECO (2)	ComEd (2)	PSEG (2)	MetEd (1)	PECO (3)	PECO (11)	PECO (8)
101		**Average**	**ComEd**	**PECO**						Page 2			
102	Max. MVAr	2,991	2,187	361									
103	Nameplate MVAr	9,831	4,856	2,853	876.5	286.6	443.8	681.8	742.2	339.7	38.9	153.9	258.3
104	Exciter MW	76	35	29	7.6	2.0	7.4	4.6	12.0	1.6	0.3	3.3	1.0
105	Generator MW	23,359	11,447	6,715	2,373	621	993	1,941	2,427	888	53	496	549
106		**0.0992%**	**0.1358%**	**0.0542%**									
107													

108	**Accessory Equip Allocator**													
109	Item	**Nuclear**	**Cumb. Turbine**	**nuclear**	**nuclear**	**nuclear**	**nuclear**	**nuclear**	**nuclear**	**comb. Tur.**	**Hydro**	**comb. Tur.**
110	Storage Batteries	15%	50%	$ 212,130	$ -	$ 302,373	$ 320,057	$ -	$ -	$ 6,131	$ 40,819	$ 32,360
111	Control&Power Cabling	1%	50%	$ 233,199	$ -	$ 196,960	$ 74,036	$ 4,591	$ -	$ 180,320	$ 476,914	$ 1,289,225
112	Switch Board Equipment	1%	50%	$ 11,886	$ -	$ 115,075	$ 28,981	$ -	$ -	$ -	$ 592,048	$ 119,706
113	Switching Equipment	1%	40%	$ 2,286	$ -	$ 6,257	$ 38,727	$ -	$ -	$ 316,411	$ 403,519	$ 298,323
114	Transformers	3%	10%	$ 31,505	$ 16,976	$ 55,882	$ 247,884	$ -	$ 54,133	$ -	$ 315,946	$ 24,774
115	Aux Generator	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
116	Fire Protection System	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
117	HVAC	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
118	Regulating Equipment	50%	75%	$ -	$ -	$ 397	$ -	$ -	$ 743,320	$ -	$ 293,044	$ -
119	Structure	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
120	Misc	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
121	Exciter & PPT	100%	100%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 126,475	$ -
122	Station Grounding	1%	5%	$ -	$ -	$ 207	$ 21	$ -	$ -	$ -	$ -	$ -
123	Bus & Insulators	80%	80%	$ -	$ -	$ (40,559)	$ 1,955,887	$ -	$ -	$ -	$ -	$ 60,107
124	Capacitor Bank	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
125				$ 491,006	$ 16,976	$ 636,592	$ 2,665,593	$ 4,591	$ 797,453	$ 502,862	$ 2,248,765	$ 1,824,495
126			EXE-4, Sch 5 Allocation factors develop	0%	0%	1%	4%	0%	6%	29%	8%	20%

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Input Data For Schedule 3

	Description	Source		Limerick 1 & 2	Oyster Creek	Peach Bottom 2 & 3	Quad Cities 1 & 2	Salem 1 & 2	TMI	Chester 7-9	Conowingo 1 - 11	Croydon 11,12,21,22,31, 32,41,42
						50%	75%	42.59%				
127	**Item**											
128	Storage Batteries	Actual 2015	$ 1,414,202	$ -	$ 2,015,820	$ 2,133,713	$ -	$ -	$ 12,262	$ 136,064	$ 64,719
129	Control&Power Cabling	Actual 2015	$ 23,319,901	$ -	$ 19,695,956	$ 7,403,630	$ 459,119	$ -	$ 360,640	$ 3,179,427	$ 2,578,451
130	Switch Board Equipment	Actual 2015	$ 1,188,580	$ -	$ 11,507,453	$ 2,898,057	$ -	$ -	$ -	$ 1,973,492	$ 239,413
131	Switching Equipment	Actual 2015	$ 228,627	$ -	$ 625,734	$ 3,872,699	$ -	$ -	$ 791,028	$ 2,017,595	$ 745,807
132	Transformers	Actual 2015	$ 1,050,152	$ 565,862	$ 1,862,746	$ 8,262,803	$ -	$ 1,804,433	$ -	$ 6,318,929	$ 247,743
133	Aux Generator	Actual 2015	$ 5,506,158	$ -	$ 129,640	$ 3,321,149	$ -	$ -	$ -	$ 101,173	$ -
134	Fire Protection System	Actual 2015	$ -	$ -	$ 126,725	$ -	$ 22,085,749	$ 194,043	$ -	$ -	$ -
135	HVAC	Actual 2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
136	Regulating Equipment	Actual 2015	$ -	$ -	$ 794	$ -	$ -	$ 1,486,640	$ -	$ 390,726	$ -
137	Structure	Actual 2015	$ 301,814	$ -	$ 25,625	$ 133,041	$ -	$ -	$ -	$ 270,434	$ 56,420
138	Misc	Actual 2015	$ 76,645,785	$ 8,662,556	$ 28,280,047	$ 35,712,768	$ 16,168,621	$ 10,382,696	$ 560,700	$ 15,212,502	$ 5,030,779
139	Exciter & PPT	Actual 2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 126,475	$ -
140	Station Grounding	Actual 2015	$ -	$ -	$ 20,693	$ 2,051	$ -	$ -	$ -	$ -	$ -
141	Bus & Insulators	Actual 2015	$ -	$ -	$ (50,699)	$ 2,444,859	$ -	$ -	$ -	$ -	$ 75,133
142	Capacitor Bank	Actual 2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
143											
144	Total	$ 1,327,863,081 <ties to "Accessory Electr	$ 109,655,219	$ 9,228,418	$ 64,240,533	$ 66,184,772	$ 38,713,489	$ 13,867,813	$ 1,724,631	$ 29,726,815	$ 9,038,464
145											
146	**O&M Calculation**									Hydro Distribution	
147	Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546	$ 28,060,813	$ 20,056,606	$ 15,945,051	$ 21,788,348	$ 17,325,181	$ 22,327,877	$ 38,422	$ 1,036,292	$ 569,237
148	Coolants and Water (Nuclear Plants Only)	FERC Account 519	$ 2,749,487	$ 1,965,210	$ 1,562,346	$ 2,134,891	$ 1,697,576	$ 2,187,756	$ -	$ -	$ -
149	Steam Expenses	FERC Account 502, 520	$ 17,246,057	$ 12,326,705	$ 9,799,760	$ 13,391,026	$ 10,647,982	$ 13,722,618	$ 9,925	$ 855,810	$ 147,038
150	Steam From Other Sources	FERC Account 503	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,178	$ 5,098,303	$ 284,134
151	Electric Expenses	FERC Account 505, 523 - Allocated based on	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,685,208	$ -
152	Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524 - Reduced from actual	$ 1,761,914	$ 1,259,337	$ 1,001,176	$ 1,368,072	$ 1,087,833	$ 1,401,948	$ 5,876	$ 1,684,113	$ 87,051
153	Rents	FERC Account 507	$ 48,715,440	$ 34,819,603	$ 27,681,670	$ 37,826,023	$ 30,077,667	$ 38,762,682	$ 35,759	$ 243,307	$ 529,786
154	Allowances	FERC Account 509	$ 3,865,683	$ 2,763,016	$ 2,196,604	$ 3,001,582	$ 2,386,732	$ 3,075,908	$ 1,445	$ -	$ 21,408
155	Maintenance Supervision and Engineering	FERC Account 510, 528	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 575,100	$ -
156	Maintenance of Structures	FERC Account 511, 529, 552	$ 5,176,733	$ 3,700,095	$ 2,941,585	$ 4,019,572	$ 3,196,195	$ 4,119,106	$ 14,987	$ 691,360	$ 222,036
157	Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530	$ 403,486	$ 288,393	$ 229,273	$ 313,294	$ 249,118	$ 321,052	$ 6,427	$ 2,545,004	$ 95,213
158	Maintenance of Electric Plant	FERC Account 513, 531, 554	$ 13,339,698	$ 9,534,615	$ 7,580,042	$ 10,357,860	$ 8,236,136	$ 10,614,344	$ 6,686	$ 1,823,125	$ 99,056
159	Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532	$ 8,568,637	$ 6,124,475	$ 4,868,973	$ 6,653,280	$ 5,290,409	$ 6,818,030	$ 8,322	$ 514,507	$ 123,289
160	Other Power Production, & Other Expenses	FERC Account 548-553; 557	$ 16,030,257	$ 11,457,706	$ 9,108,904	$ 12,446,996	$ 9,897,329	$ 12,755,212	$ 25,242	$ -	$ 373,967
161	TOTAL	Grand Total O&M	$ 145,918,204	$ 104,295,761	$ 82,915,386	$ 113,300,945	$ 90,092,158	$ 116,106,533	$ 172,268	$ 16,752,129	$ 2,552,217
162									$ 66,296,431		
163	**A&G and Overhead Expenses**										
164	Plant specific A&G		$ 116,605,447	$ 75,639,559	$ 54,201,596	$ 82,058,738	$ 64,855,997	$ 80,763,143	$ 8,214	$ 2,067,560	$ 127,260
165									$ 9,745,682		
166	Nuclear Overhead Expenses ("OH" tab)		$ 39,948,249	$ 26,020,236	$ 19,063,610	$ 27,586,946	$ 23,349,517	$ 30,816,972			
167	Non-nuclear Overhead Expenses ("OH" tab)								$ 63,597	$ 5,899,470	$ 895,649
168	Total		$ 156,553,695	$ 101,659,795	$ 73,265,206	$ 109,645,685	$ 88,205,514	$ 111,580,115	$ 71,811	$ 7,967,029	$ 1,022,909
169											
170											
171											
172											
173											
174											
175								Schedule 6			
176	**Depreciation Exp**							Page 3			
177				58.5	50.0	59.5	60.0	59.0	60.0	64	116	59
178	Production Plant in Service Depreciation Expense		$ 20,895,845	$ 7,204,508	$ 22,868,603	$ 17,435,172	$ 9,892,741	$ 16,693,690	$ 142,706	$ 3,276,593	$ 1,820,544
179									$ 39,100,591		$ 0
180	**Other Taxes**	Total							0.01866472	53.57701706	
181	Plant Related & Property Taxes (Nucs only)	$ 123,977,347	$ 3,969,570	$ 3,465,238	$ 862,588	$ 6,042,855	$ 8,570,246	$ 1,186,903			
182	Payroll Taxes (Nucs Only)	$ 60,289,214	$ 7,359,580	$ 5,403,699	$ 3,565,892	$ 5,304,440	$ 4,081,461	$ 5,775,935			
183	Other Taxes (Pay & Property) (Non-Nucs)	$ 9,124,663							$ 5,780	$ -	$ 87,293
184	Total Other Taxes	$ 193,391,223	$ 11,329,150	$ 8,868,938	$ 4,428,481	$ 11,347,295	$ 12,651,707	$ 6,962,839	$ 5,780	$ -	$ 87,293
185											
186											
187											
188											
189											
190											
191											
192											
193											
194											

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Input Data For Schedule 3

	Description	Source	Limerick 1 & 2	Oyster Creek	Peach Bottom 2 & 3 (50%)	Quad Cities 1 & 2 (75%)	Salem 1 & 2 (42.59%)	TMI	Chester 7-9	Conowingo 1 - 11	Croydon 11,12,21,22,31, 32,41,42
195											
196											
197	**Prepayments**	Nuclear	$ 2,049,475	$ 603,950	$ 2,281,305	$ 1,753,898		$ 1,679,308			
198		Fossil							$ 68,701	$ 2,859,063	$ 807,972
199	Total		$ 2,049,475	$ 603,950	$ 2,281,305	$ 1,753,898	$ -	$ 1,679,308	$ 68,701	$ 2,859,063	$ 807,972
200											
201	**M&S**								Source: Fuels Inventory 2015 (see Dec 2015 tab) -- column M		
202	M&S - Fuel		240,511,541	84,615,318	169,273,105	218,443,011	112,762,574	126,670,672			20,360,296
203	M&S - Fuel (undistributed)		-	-	-	-	-	-	-	-	-
204	M&S - Fossil Production								23,962	2,222,784	337,460
205	M&S - Nuclear Production		78,065,668	25,431,344	35,906,250	50,160,902	45,352,188	36,821,326			
206	**TOTAL M&S**		$ 318,577,209	$ 110,046,662	$ 205,179,355	$ 268,603,913	$ 158,114,762	$ 163,491,998	$ 23,962	$ 2,222,784	$ 20,697,756
207											
208											
209	**RETURN (R)**										
210											
211											

		$/mil	%
212			
213	Long Term Debt	0.45	45.0%
214	Proprietary Capital	0.55	55.0%
215	Total (sum lines 22-23)	1.00	100%
216			
217			
218	**Income Taxes**		
219	State Marginal Rate (multi-state)	5.6600% <<Per ACH 9-29-16	
220			
221			
222		Jurisdiction1	
223			
224		Federal	
		FIT on SIT	
		Illinois2	
		IL on SIT	
		Pennsylvania2	
		Maryland	
		Other Separate	
		NYS	
		Other Unitary	
		Marginal Tax Rate	
		Effective State Rate	

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Input Data For Schedule 3

	Description		Source	Delaware 9-12	Eddystone 3,4,10,20,30,40	Fairless Hills A&B	Falls 1-3	Gould Street 3	Handsome Lake	Moser 1-3	Muddy Run 1-8
1	Turbogenerator, GUS and Accessory Electric Investment:			PECO (4)	PECO (6)	PECO (2)	PECO (3)	BGE (1)	PENELEC (5)	PECO (3)	PECO (8)
2	Included TurboGenerator Investment	2015 Actual Data	Account 314,323, 333, 34	6,730,407	62,382,060	20,090,347	5,518,050	4,694,859	42,347,182	5,376,210	105,729,817
3	Investment Generator & Exciter	2015 Actual Data	15%	1,009,561	9,357,309	3,013,552	827,708	704,229	6,352,077	806,431	15,859,473
4	Value of GSU Transformers	2015 Actual Data		$ -	$ 6,411,560	$ 51,347	$ -	$ 3,114	$ -	$ -	$ 4,657,845
5	Total Accessory Elec Equipment - Gross Investment	2015 Actual Data	Account 315, 324, 334, 34	$ 1,910,796	$ 30,090,084	$ 171,673	$ 1,126,870	$ 364,598	$ -	$ 1,365,306	$ 43,782,362
6	Installed Cost of Power Plant (excluding Nuclear ARC; Steam ARC)	2015 Actual Data	2015 Actual Data	$ 13,528,361	$ 400,131,998	61,729,219	7,829,474	$ 18,406,803	$ 85,825,302	$ 8,301,032	$ 261,421,690
7	Investment Generator & Exciter / Turbogenerator			15.000%	15.000%	15.000%		15.000%	15.000%	15.000%	15.000%
8	Investment Generation & Exciter / Installed Cost of Power Plant			7.463%	2.339%	4.882%		3.826%	7.401%	9.715%	6.067%
9											
10	**Allocators**										
11											
12	**Real Power Demonstrated Capability (gross MW)**										
13	Generator 1			16.90	400.00	30.00	18.46	102.70	59.00	16.00	122.10
14	Generator 2			13.40	400.00	30.00	18.08		59.00	16.38	123.70
15	Generator 3			13.70	14.20		18.26		59.00	16.50	124.00
16	Generator 4			13.40	13.60				59.00		125.00
17	Generator 5				18.00				59.00		122.00
18	Generator 6				18.00						117.00
19	Generator 7										126.00
20	Generator 8										126.00
21	Generator 9										
22	Generator 10										
23	Generator 11										
24											
25	Total			57.40	863.80	60.00	54.80	102.70	295.00	48.88	985.80
26											
27	**Nominal Power Factor (pf)**										
28	Generator 1			0.84	0.92	0.85	0.86	0.90	0.85	0.82	0.91
29	Generator 2			0.77	0.94	0.85	0.85		0.85	0.82	0.90
30	Generator 3			0.78	0.79		0.85		0.85	0.83	0.93
31	Generator 4			0.78	0.78				0.85		0.92
32	Generator 5				0.85				0.85		0.90
33	Generator 6				0.85						0.91
34	Generator 7										0.91
35	Generator 8										0.93
36	Generator 9										
37	Generator 10										
38	Generator 11										
39											
40											
41	**Nameplate MVAr**										
42	Generator 1	(Nameplates, sqrt(MVA^2-MW^2))		11.94	185.59	18.59	12.97	49.16	36.56	14.24	45.28
43	Generator 2	(Nameplates, sqrt(MVA^2-MW^2))		13.88	161.92	18.59	13.13	-	36.56	14.27	47.92
44	Generator 3	(Nameplates, sqrt(MVA^2-MW^2))		13.77	13.47	-	13.01	-	36.56	13.94	42.18
45	Generator 4	(Nameplates, sqrt(MVA^2-MW^2))		13.77	13.83	-	-	-	36.56	-	43.24
46	Generator 5	(Nameplates, sqrt(MVA^2-MW^2))		-	13.21	-	-	-	36.56	-	48.38
47	Generator 6	(Nameplates, sqrt(MVA^2-MW^2))		-	13.21	-	-	-	-	-	45.03
48	Generator 7	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	45.03
49	Generator 8	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	41.63
50	Generator 9	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	-
51	Generator 10	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	-
52	Generator 11	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	-
53											
54											
55	Total			53.37	401.23	37.18	39.10	49.16	182.82	42.45	358.71
56				per ACH 10-10 email							
57	**Exciter MW**			same as Chester	same as Chester						
58	Generator 1	Exciter Rating		0.09	0.09	0.10	0.09	0.30	0.21	0.09	0.53
59	Generator 1	Exciter Rating		0.09	0.09	0.13	0.09		0.21	0.09	0.53
60	Generator 2	Exciter Rating		0.09	0.09		0.09		0.21	0.09	0.53
61	Generator 3	Exciter Rating		0.09	0.09				0.21		0.53
62	Generator 4	Exciter Rating			1.70				0.21		0.53
63	Generator 5	Exciter Rating			1.70						0.53
64	Generator 6	Exciter Rating									0.53
65	Generator 7	Exciter Rating									
66	Generator 8	Exciter Rating									
67	Generator 9	Exciter Rating									
68	Generator 10	Exciter Rating									
69	Generator 11	Exciter Rating		0.34	3.74	0.23	0.26	0.30	1.03	0.26	3.68
70											

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	Description		Source	Delaware 9-12	Eddystone 3,4,10,20,30,40	Fairless Hills A&B	Falls 1-3	Gould Street 3	Handsome Lake	Moser 1-3	Muddy Run 1-8
71	**Generator MW**										
72	Generator 1	(pf*MVA)		18.34	420.90	30.00	21.38	102.70	59.00	20.55	101.34
73	Generator 2	(pf*MVA)		16.91	430.56	30.00	21.28	-	59.00	20.53	100.12
74	Generator 3	(pf*MVA)		17.00	17.24	-	21.35	-	59.00	20.75	102.68
75	Generator 4	(pf*MVA)		17.00	16.96	-	-	-	59.00	-	102.23
76	Generator 5	(pf*MVA)		-	21.23	-	-	-	59.00	-	99.90
77	Generator 6	(pf*MVA)		-	21.23	-	-	-	-	-	101.45
78	Generator 7	(pf*MVA)		-	-	-	-	-	-	-	101.45
79	Generator 8	(pf*MVA)		-	-	-	-	-	-	-	102.90
80	Generator 9	(pf*MVA)		-	-	-	-	-	-	-	-
81	Generator 10	(pf*MVA)		-	-	-	-	-	-	-	-
82	Generator 11	(pf*MVA)		-	-	-	-	-	-	-	-
83	Total			69.25	928.11	60.00	64.00	102.70	295.00	61.83	812.08
84											
85	**Generator MVA**										
86	Generator 1	MW/pf if not stated		21.88	460.00	35.29	25.00	113.86	69.41	25.00	111.00
87	Generator 2	MW/pf if not stated		21.88	460.00	35.29	25.00		69.41	25.00	111.00
88	Generator 3	MW/pf if not stated		21.88	21.88		25.00		69.41	25.00	111.00
89	Generator 4	MW/pf if not stated		21.88	21.88				69.41		111.00
90	Generator 5	MW/pf if not stated			25.00				69.41		111.00
91	Generator 6	MW/pf if not stated			25.00						111.00
92	Generator 7	MW/pf if not stated									111.00
93	Generator 8	MW/pf if not stated									111.00
94	Generator 9	MW/pf if not stated									
95	Generator 10	MW/pf if not stated									
96	Generator 11	MW/pf if not stated									
97											
98	Total			87.52	1,013.76	70.59	75.00	113.86	347.06	75.00	888.00

99	Peak Hour	18	18	16							
100	Peak Day	9/3/2015	9/3/2015	7/20/2015	PECO (4)	PECO (6)	PECO (2)	PECO (3)	BGE (1)	PENELEC (5)	PECO (3)	PECO (8)
101		**Average**	**ComEd**	**PECO**								
102	Max. MVAr	2,991	2,187	361								
103	Nameplate MVAr	9,831	4,856	2,853	53.4	401.2	37.2	39.1	49.2	182.8	42.5	358.7
104	Exciter MW	76	35	29	0.3	3.7	0.2	0.3	0.3	1.0	0.3	3.7
105	Generator MW	23,359	11,447	6,715	69	928	60	64	103	295	62	812
106		**0.0992%**	**0.1358%**	**0.0542%**								

107																					
108	**Accessory Equip Allocator**																				
109	Item	**Nuclear**	**Cumb. Turbine**		**comb. Tur.**		**steam**		**steam**		**comb. Tur.**		**steam**		**comb. Tur**		**comb. Tur.**		**hydro**		
110	Storage Batteries	15%	50%	$	14,370	$	105,438.80	$	8,394	$	16,896	$	176,829	$	-	$	4,683	$	38,770		
111	Control&Power Cabling	1%	50%	$	172,306	$	2,996,747.75	$	115	$	71,002	$	5,470	$	-	$	131,401	$	739,494		
112	Switch Board Equipment	1%	50%	$	9,937	$	145,469.23	$	-	$	-	$	-	$	-	$	-	$	500,860		
113	Switching Equipment	1%	40%	$	458,834	$	408,375.42	$	-	$	224,868	$	-	$	-	$	235,629	$	1,226,111		
114	Transformers	3%	10%	$	-	$	-	$	-	$	51	$	-	$	-	$	-	$	29,461		
115	Aux Generator	0%	0%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-		
116	Fire Protection System	0%	0%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-		
117	HVAC	0%	0%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-		
118	Regulating Equipment	50%	75%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	379,306		
119	Structure	0%	0%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-		
120	Misc	0%	0%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-		
121	Exciter & PPT	100%	100%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-		
122	Station Grounding	1%	5%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-		
123	Bus & Insulators	80%	80%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-		
124	Capacitor Bank	0%	0%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-		
125				$	655,447	$	3,656,031	$	8,508	$	312,817	$	182,299	$	-	$	371,713	$	2,914,002		
126		EXE-4, Sch 5 Allocation factors develop			34%		12%		5%		28%		50%		#DIV/0!		27%		7%		

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	Description	Source		Delaware 9-12	Eddystone 3,4,10,20,30,40	Fairless Hills A&B	Falls 1-3	Gould Street 3	Handsome Lake	Moser 1-3	Muddy Run 1-8
127	**Item**							Nothing in the detailed accounting			
128	Storage Batteries	Actual 2015		$ 28,741	$ 351,463	$ 16,787	$ 33,793	$ 353,658	$ -	$ 9,365	$ 129,233
129	Control&Power Cabling	Actual 2015		$ 344,611	$ 19,978,318	$ 230	$ 142,003	$ 10,940	$ -	$ 262,801	$ 4,929,960
130	Switch Board Equipment	Actual 2015		$ 19,874	$ 484,897	$ -	$ -	$ -	$ -	$ -	$ 1,669,534
131	Switching Equipment	Actual 2015		$ 1,147,085	$ 2,041,877	$ -	$ 562,170	$ -	$ -	$ 589,074	$ 6,130,553
132	Transformers	Actual 2015		$ -	$ -	$ -	$ 512	$ -	$ -	$ -	$ 589,215
133	Aux Generator	Actual 2015		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 120,583
134	Fire Protection System	Actual 2015		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
135	HVAC	Actual 2015		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
136	Regulating Equipment	Actual 2015		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 505,742
137	Structure	Actual 2015		$ -	$ 167,065	$ -	$ 8,093	$ -	$ -	$ 13,093	$ -
138	Misc	Actual 2015		$ 370,485	$ 7,066,463	$ 154,657	$ 380,300	$ -	$ -	$ 490,974	$ 29,526,543
139	Exciter & PPT	Actual 2015		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
140	Station Grounding	Actual 2015		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 181,000
141	Bus & Insulators	Actual 2015		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
142	Capacitor Bank	Actual 2015		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
143											
144	Total	$ 1,327,863,081	<ties to "Accessory Electr	$ 1,910,796	$ 30,090,084	$ 171,673	$ 1,126,870	$ 364,598	$ -	$ 1,365,306	$ 43,782,362
145											
146	**O&M Calculation**										Hydro Distribution
147	Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546		$ 81,528	$ 3,742,503	$ 1,706,571	$ 74,248	$ 578,737	$ 520,067	$ 74,248	$ 129,116
148	Coolants and Water (Nuclear Plants Only)	FERC Account 519		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
149	Steam Expenses	FERC Account 502, 520		$ 21,059	$ 966,716	$ 440,820	$ 19,179	$ 149,492	$ 134,337	$ 19,179	$ 106,629
150	Steam From Other Sources	FERC Account 503		$ 40,694	$ 1,868,066	$ 851,833	$ 37,061	$ 288,876	$ 259,591	$ 37,061	$ 635,221
151	Electric Expenses	FERC Account 505, 523 - Allocated based on		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 209,968
152	Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524 - Reduced from actual		$ 12,468	$ 572,328	$ 260,980	$ 11,355	$ 88,504	$ 79,532	$ 11,355	$ 209,831
153	Rents	FERC Account 507		$ 75,877	$ 3,483,129	$ 1,588,297	$ 69,103	$ 538,628	$ 484,024	$ 69,103	$ 30,315
154	Allowances	FERC Account 509		$ 3,066	$ 140,748	$ 64,181	$ 2,792	$ 21,765	$ 19,559	$ 2,792	$ -
155	Maintenance Supervision and Engineering	FERC Account 510, 528		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 71,654
156	Maintenance of Structures	FERC Account 511, 529, 552		$ 31,801	$ 1,459,799	$ 665,664	$ 28,961	$ 225,742	$ 202,857	$ 28,961	$ 86,140
157	Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530		$ 13,637	$ 625,988	$ 285,449	$ 12,419	$ 96,802	$ 86,989	$ 12,419	$ 317,094
158	Maintenance of Electric Plant	FERC Account 513, 531, 554		$ 14,187	$ 651,254	$ 296,970	$ 12,920	$ 100,709	$ 90,500	$ 12,920	$ 227,151
159	Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532		$ 17,658	$ 810,576	$ 369,620	$ 16,081	$ 125,347	$ 112,639	$ 16,081	$ 64,105
160	Other Power Production, & Other Expenses	FERC Account 548-553; 557		$ 53,560	$ 2,458,680	$ 1,121,151	$ 48,778	$ 380,208	$ 341,664	$ 48,778	$ -
161	TOTAL	Grand Total O&M		$ 365,535	$ 16,779,786	$ 7,651,534	$ 332,898	$ 2,594,809	$ 2,331,757	$ 332,898	$ 2,087,224
162											
163	**A&G and Overhead Expenses**										
164	Plant specific A&G			$ 18,226	$ 1,076,796	$ 833,095	$ 16,599	$ 767,400	$ 713,054	$ 16,599	$ 1,887,948
165											
166	Nuclear Overhead Expenses ("OH" tab)										
167	Non-nuclear Overhead Expenses ("OH" tab)			$ 128,277	$ 4,867,763	$ 2,651,333	$ 116,824	$ 285,067	589,327	$ 116,824	$ -
168	Total			$ 146,504	$ 5,944,558	$ 3,484,428	$ 133,423	$ 1,052,467	$ 1,302,381	$ 133,423	$ 1,887,948
169											
170											
171											
172											
173											
174											
175											
176	**Depreciation Exp**										
177				65	65	27	63	74	40	63	77
178	Production Plant in Service Depreciation Expense			$ 208,129	$ 6,155,877	$ 2,286,267	$ 124,277	$ 248,741	$ 2,145,633	$ 131,762	$ 3,395,087
179				$ 0	$ 0	$ 0	$ -	$ 0	$ 0	$ 0	$ 0
180	**Other Taxes**	Total									
181	Plant Related & Property Taxes (Nucs only)	$ 123,977,347									
182	Payroll Taxes (Nucs Only)	$ 60,289,214									
183	Other Taxes (Pay & Property) (Non-Nucs)	$ 9,124,663		$ 27,880	$ 3,170,443	$ 263,599	$ 11,386	$ 653,648	$ 163,782	$ 11,386	$ 692,571
184	Total Other Taxes	$ 193,391,223		$ 27,880	$ 3,170,443	$ 263,599	$ 11,386	$ 653,648	$ 163,782	$ 11,386	$ 692,571
185											
186											
187											
188											
189											
190											
191											
192											
193											
194											

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	Description	Source	Delaware 9-12	Eddystone 3,4,10,20,30,40	Fairless Hills A&B	Falls 1-3	Gould Street 3	Handsome Lake	Moser 1-3	Muddy Run 1-8
195										
196										
197	**Prepayments**	Nuclear								
198		Fossil	$ 101,763	$ 3,009,862	$ 464,338	$ 58,895	$ 138,459	$ 645,593	$ 62,442	$ 1,966,459
199	Total		$ 101,763	$ 3,009,862	$ 464,338	$ 58,895	$ 138,459	$ 645,593	$ 62,442	$ 1,966,459
200										
201	**M&S**									
202	M&S - Fuel		391,088	15,721,025		733,700			800,596	
203	M&S - Fuel (undistributed)		-	-	-	-	-	-	-	-
204	M&S - Fossil Production		48,332	1,834,061	998,961	44,017	107,407	222,045	44,017	-
205	M&S - Nuclear Production									
206	**TOTAL M&S**		$ 439,420	$ 17,555,085	$ 998,961	$ 777,716	$ 107,407	$ 222,045	$ 844,613	$ -
207										
208										
209	**RETURN (R)**									
210										
211										
212		$/mil	%							
213	Long Term Debt	0.45	45.0%							
214	Proprietary Capital	0.55	55.0%							
215	Total (sum lines 22-23)	1.00	100%							
216										
217										
218	**Income Taxes**									
219	State Marginal Rate (multi-state)	5.6600% <<Per ACH 9-29-16								
220										
221										
222		Jurisdiction1								
223										
224		Federal								
		FIT on SIT								
		Illinois2								
		IL on SIT								
		Pennsylvania2								
		Maryland								
		Other Separate								
		NYS								
		Other Unitary								
		Marginal Tax Rate								
		Effective State Rate								

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Input Data For Schedule 3

	Description		Source	Notch Cliff 1-8	Pennsbury 1&2	Perryman 1,3,4,51	Perryman 6	Philadelphia Rd 1-4	Richmond 91&92	Riverside 7&8	Schuylkill 10&11
1	Turbogenerator, GUS and Accessory Electric Investment:			BGE (8)	PECO (2)	BGE (5)	BGE (1)	BGE (4)	PECO (2)	BGE (2)	PECO (2)
2	Included TurboGenerator Investment	2015 Actual Data	Account 314,323, 333, 34	20,738,180	568,704	177,706,677	88,242,961	16,996,875	20,218,692	13,013,142	4,345,038
3	Investment Generator & Exciter	2015 Actual Data	15%	3,110,727	85,306	26,656,002	13,236,444	2,549,531	3,032,804	1,951,971	651,756
4	Value of GSU Transformers	2015 Actual Data		$ -	$ -	$ 784,897	$ -	$ -	$ 355,663	$ 350,500	-
5	Total Accessory Elec Equipment - Gross Investment	2015 Actual Data	Account 315, 324, 334, 34	$ 6,085,933	$ 242,106	$ 21,554,696	$ 20,899,649	$ 3,061,125	$ 2,910,886	$ 4,153,061	$ 553,360
6	Installed Cost of Power Plant (excluding Nuclear ARC; Steam ARC)	2015 Actual Data	2015 Actual Data	$ 41,084,404	$ 3,820,667	$ 250,720,971	$ 116,109,159	$ 18,270,877	$ 29,467,537	$ 39,227,656	5,934,123
7	Investment Generator & Exciter / Turbogenerator			15.000%	15.000%	15.000%	15.000%	15.000%	15.000%	15.000%	15.000%
8	Investment Generation & Exciter / Installed Cost of Power Plant			7.572%	2.233%	10.632%	11.400%	13.954%	10.292%	4.976%	10.983%
9											
10	**Allocators**										
11											
12	**Real Power Demonstrated Capability (gross MW)**										
13	Generator 1			12.80	2.50	53.00	141.06	13.40	53.30	24.30	14.30
14	Generator 2			18.00	2.50	53.00		18.00	52.80	21.30	19.00
15	Generator 3			18.00		53.00		18.00			
16	Generator 4			18.00		53.00		18.00			
17	Generator 5			12.50		144.90					
18	Generator 6			18.00							
19	Generator 7			18.00							
20	Generator 8			18.00							
21	Generator 9										
22	Generator 10										
23	Generator 11										
24											
25	Total			133.30	5.00	356.90	141.06	67.40	106.10	45.60	33.30
26											
27	**Nominal Power Factor (pf)**										
28	Generator 1			0.66	0.85	0.85	0.85	0.74	0.92	0.75	0.79
29	Generator 2			0.85	0.85	0.85		0.85	0.92	0.76	0.86
30	Generator 3			0.85		0.85		0.85			
31	Generator 4			0.85		0.85		0.85			
32	Generator 5			0.64		0.90					
33	Generator 6			0.85							
34	Generator 7			0.85							
35	Generator 8			0.85							
36	Generator 9										
37	Generator 10										
38	Generator 11										
39											
40											
41	**Nameplate MVAr**										
42	Generator 1	(Nameplates, sqrt(MVA^2-MW^2))		14.49	1.55	32.85	87.42	12.29	28.78	21.43	13.55
43	Generator 2	(Nameplates, sqrt(MVA^2-MW^2))		11.16	1.55	32.85		11.16	28.94	18.39	12.63
44	Generator 3	(Nameplates, sqrt(MVA^2-MW^2))		11.16	-	32.85		11.16	-	-	-
45	Generator 4	(Nameplates, sqrt(MVA^2-MW^2))		11.16	-	32.85		11.16	-	-	-
46	Generator 5	(Nameplates, sqrt(MVA^2-MW^2))		15.01	-	72.22		-	-	-	-
47	Generator 6	(Nameplates, sqrt(MVA^2-MW^2))		11.16	-	-		-	-	-	-
48	Generator 7	(Nameplates, sqrt(MVA^2-MW^2))		11.16	-	-		-	-	-	-
49	Generator 8	(Nameplates, sqrt(MVA^2-MW^2))		11.16	-	-		-	-	-	-
50	Generator 9	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-		-	-	-	-
51	Generator 10	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-		-	-	-	-
52	Generator 11	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-		-	-	-	-
53											
54											
55	Total			96.43	3.10	203.60	87.42	45.76	57.72	39.82	26.18
56											
57	**Exciter MW**										same as Chester
58	Generator 1	Exciter Rating		0.05		0.08	0.29	0.05	0.11	0.14	0.09
59	Generator 1	Exciter Rating		0.05		0.08		0.05	0.11	0.14	0.09
60	Generator 2	Exciter Rating		0.05		0.08		0.05			
61	Generator 3	Exciter Rating		0.05		0.08		0.05			
62	Generator 4	Exciter Rating		0.05		0.61					
63	Generator 5	Exciter Rating		0.05		0.29					
64	Generator 6	Exciter Rating		0.05							
65	Generator 7	Exciter Rating		0.05							
66	Generator 8	Exciter Rating		0.05							
67	Generator 9	Exciter Rating									
68	Generator 10	Exciter Rating									
69	Generator 11	Exciter Rating		0.49	-	1.21	0.29	0.20	0.22	0.28	0.17
70											

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	Description		Source	Notch Cliff 1-8	Pennsbury 1&2	Perryman 1,3,4,51	Perryman 6	Philadelphia Rd 1-4	Richmond 91&92	Riverside 7&8	Schuylkill 10&11
71	**Generator MW**										
72	Generator 1	(pf*MVA)		12.80	2.50	53.00	141.06	13.40	66.61	24.30	17.18
73	Generator 2	(pf*MVA)		18.00	2.50	53.00		18.00	66.54	21.30	21.58
74	Generator 3	(pf*MVA)		18.00	-	53.00		18.00	-	-	-
75	Generator 4	(pf*MVA)		18.00	-	53.00		18.00	-	-	-
76	Generator 5	(pf*MVA)		12.50	-	144.90		-	-	-	-
77	Generator 6	(pf*MVA)		18.00	-	-		-	-	-	-
78	Generator 7	(pf*MVA)		18.00	-	-		-	-	-	-
79	Generator 8	(pf*MVA)		18.00	-	-		-	-	-	-
80	Generator 9	(pf*MVA)		-	-	-		-	-	-	-
81	Generator 10	(pf*MVA)		-	-	-		-	-	-	-
82	Generator 11	(pf*MVA)		-	-	-		-	-	-	-
83	Total			133.30	5.00	356.90	141.06	67.40	133.15	45.60	38.75
84											
85	**Generator MVA**										
86	Generator 1	MW/pf if not stated		19.34	2.94	62.35	165.95	18.18	72.56	32.40	21.88
87	Generator 2	MW/pf if not stated		21.18	2.94	62.35		21.18	72.56	28.14	25.00
88	Generator 3	MW/pf if not stated		21.18		62.35		21.18			
89	Generator 4	MW/pf if not stated		21.18		62.35		21.18			
90	Generator 5	MW/pf if not stated		19.53		161.90					
91	Generator 6	MW/pf if not stated		21.18							
92	Generator 7	MW/pf if not stated		21.18							
93	Generator 8	MW/pf if not stated		21.18							
94	Generator 9	MW/pf if not stated									
95	Generator 10	MW/pf if not stated									
96	Generator 11	MW/pf if not stated									
97											
98	Total			165.93	5.88	411.31	165.95	81.71	145.12	60.54	46.88

99	Peak Hour	18	18	16							
100	Peak Day	9/3/2015	9/3/2015	7/20/2015	BGE (8)	PECO (2)	BGE (5)		BGE (4)	PECO (2)	BGE (2)	PECO (2)
101		**Average**	**ComEd**	**PECO**								
102	Max. MVAr	2,991	2,187	361								
103	Nameplate MVAr	9,831	4,856	2,853	96.4	3.1	203.6	87.4	45.8	57.7	39.8	26.2
104	Exciter MW	76	35	29	0.5	-	1.2	0.3	0.2	0.2	0.3	0.2
105	Generator MW	23,359	11,447	6,715	133	5	357	141	67	133	46	39
106		**0.0992%**	**0.1358%**	**0.0542%**								
107												

108	**Accessory Equip Allocator**										
109	Item	**Nuclear**	**Cumb. Turbine**	**comb. Tur.**	**comb. Tur.**	**comb. Tur.**	**comb. Tur.**	**comb. Tur.**	**comb. Tur.**	**comb. Tur.**	**comb. Tur.**
110	Storage Batteries	15%	50%	$ -	$ -	$ -		$ -	$ 55,087	$ 30,947	$ 4,178
111	Control&Power Cabling	1%	50%	$ 16,778	$ 8,655	$ -		$ -	$ 188,087	$ 1,104,514	$ 103,944
112	Switch Board Equipment	1%	50%	$ 118,994	$ -	$ -		$ 1,324,305	$ 15,523	$ 369,107	$ 4,150
113	Switching Equipment	1%	40%	$ 392,455	$ -	$ 23,872		$ -	$ 39,597	$ 207,572	$ 73,239
114	Transformers	3%	10%	$ 5,727	$ -	$ -		$ -	$ 6,964	$ 9,887	$ -
115	Aux Generator	0%	0%	$ -	$ -	$ -		$ -	$ -	$ -	$ -
116	Fire Protection System	0%	0%	$ -	$ -	$ -		$ -	$ -	$ -	$ -
117	HVAC	0%	0%	$ -	$ -	$ -		$ -	$ -	$ -	$ -
118	Regulating Equipment	50%	75%	$ 3,480,201	$ -	$ 132,385		$ -	$ -	$ 230,110	$ -
119	Structure	0%	0%	$ -	$ -	$ -		$ -	$ -	$ -	$ -
120	Misc	0%	0%	$ -	$ -	$ -		$ -	$ -	$ -	$ -
121	Exciter & PPT	100%	100%	$ -	$ -	$ -		$ -	$ -	$ 15,989	$ -
122	Station Grounding	1%	5%	$ 494	$ -	$ -		$ -	$ -	$ 9,532	$ -
123	Bus & Insulators	80%	80%	$ -	$ -	$ -		$ -	$ -	$ -	$ -
124	Capacitor Bank	0%	0%	$ -	$ -	$ -		$ -	$ -	$ -	$ -
125				$ 4,014,649	$ 8,655	$ 156,257	$ 2,089,965	$ 1,324,305	$ 305,256	$ 1,977,658	$ 185,511
126			EXE-4, Sch 5 Allocation factors develop	66%	4%	1%	10%	43%	10%	48%	34%

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	Description	Source		Notch Cliff 1-8	Pennsbury 1&2	Perryman 1,3,4,51	Perryman 6	Philadelphia Rd 1-4	Richmond 91&92	Riverside 7&8	Schuylkill 10&11
127	**Item**										
128	Storage Batteries	Actual 2015		$ -	$ -	$ -		$ -	$ 110,173	$ 61,893	$ 8,355
129	Control&Power Cabling	Actual 2015		$ 33,556	$ 17,310	$ -		$ -	$ 376,173	$ 2,209,028	$ 207,889
130	Switch Board Equipment	Actual 2015		$ 237,988	$ -	$ -		$ 2,648,610	$ 31,046	$ 738,213	$ 8,299
131	Switching Equipment	Actual 2015		$ 981,137	$ -	$ 59,681		$ -	$ 98,992	$ 518,931	$ 183,098
132	Transformers	Actual 2015		$ 57,272	$ -	$ -		$ -	$ 69,638	$ 98,872	$ -
133	Aux Generator	Actual 2015		$ -	$ -	$ -		$ -	$ -	$ -	$ -
134	Fire Protection System	Actual 2015		$ -	$ -	$ -		$ -	$ -	$ 7,984	$ -
135	HVAC	Actual 2015		$ -	$ -	$ -		$ -	$ -	$ -	$ -
136	Regulating Equipment	Actual 2015		$ 4,640,268	$ -	$ 176,513		$ -	$ -	$ 306,814	$ -
137	Structure	Actual 2015		$ 6,922	$ -	$ -		$ -	$ 41,045	$ 4,701	$ 41,588
138	Misc	Actual 2015		$ 118,909	$ 224,796	$ 21,318,503		$ 412,515	$ 2,183,819	$ -	$ 104,130
139	Exciter & PPT	Actual 2015		$ -	$ -	$ -		$ -	$ -	$ 15,989	$ -
140	Station Grounding	Actual 2015		$ 9,880	$ -	$ -		$ -	$ -	$ 190,636	$ -
141	Bus & Insulators	Actual 2015		$ -	$ -	$ -		$ -	$ -	$ -	$ -
142	Capacitor Bank	Actual 2015		$ -	$ -	$ -		$ -	$ -	$ -	$ -
143											
144	Total	$ 1,327,863,081	<ties to "Accessory Electr	$ 6,085,933	$ 242,106	$ 21,554,696	$ 20,899,649	$ 3,061,125	$ 2,910,886	$ 4,153,061	$ 553,360
145											
146	**O&M Calculation**										
147	Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546		$ 217,043	$ 235,561	$ 1,562,813	$ 1	$ 147,788	$ 142,673	$ 92,302	$ 69,047
148	Coolants and Water (Nuclear Plants Only)	FERC Account 519		$ -	$ -	$ -		$ -	$ -	$ -	$ -
149	Steam Expenses	FERC Account 502, 520		$ 56,064	$ 60,847	$ 403,686		$ 38,175	$ 36,854	$ 23,842	$ 17,835
150	Steam From Other Sources	FERC Account 503		$ 108,337	$ 117,580	$ 780,076		$ 73,768	$ 71,215	$ 46,073	$ 34,465
151	Electric Expenses	FERC Account 505, 523 - Allocated based on		$ -	$ -	$ -		$ -	$ -	$ -	$ -
152	Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524 - Reduced from actual		$ 33,192	$ 36,024	$ 238,995		$ 22,601	$ 21,819	$ 14,115	$ 10,559
153	Rents	FERC Account 507		$ 202,000	$ 219,236	$ 1,454,502		$ 137,546	$ 132,785	$ 85,905	$ 64,262
154	Allowances	FERC Account 509		$ 8,163	$ 8,859	$ 58,774		$ 5,558	$ 5,366	$ 3,471	$ 2,597
155	Maintenance Supervision and Engineering	FERC Account 510, 528		$ -	$ -	$ -		$ -	$ -	$ -	$ -
156	Maintenance of Structures	FERC Account 511, 529, 552		$ 84,660	$ 91,883	$ 609,590		$ 57,646	$ 55,651	$ 36,003	$ 26,932
157	Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530		$ 36,303	$ 39,401	$ 261,403		$ 24,720	$ 23,864	$ 15,439	$ 11,549
158	Maintenance of Electric Plant	FERC Account 513, 531, 554		$ 37,769	$ 40,991	$ 271,954		$ 25,717	$ 24,827	$ 16,062	$ 12,015
159	Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532		$ 47,008	$ 51,019	$ 338,484		$ 32,009	$ 30,901	$ 19,991	$ 14,955
160	Other Power Production, & Other Expenses	FERC Account 548-553; 557		$ 142,589	$ 154,755	$ 1,026,708		$ 97,091	$ 93,731	$ 60,639	$ 45,361
161	TOTAL	Grand Total O&M		$ 973,126	$ 1,056,155	$ 7,006,986	$ 1	$ 662,620	$ 639,686	$ 413,844	$ 309,577
162											
163	**A&G and Overhead Expenses**										
164	Plant specific A&G			$ 145,511	$ 95,853	$ 757,586	$ -	$ 70,095	$ 31,896	$ 240,209	$ 395,698
165											
166	Nuclear Overhead Expenses ("OH" tab)										
167	Non-nuclear Overhead Expenses ("OH" tab)			$ 353,402	$ 351,414	$ 2,489,290	$ -	$ 119,683	$ 224,485	$ 76,645	$ 130,074
168	Total			$ 498,913	$ 447,267	$ 3,246,876	$ -	$ 189,779	$ 256,381	$ 316,854	$ 525,773
169											
170											
171											
172											
173											
174											
175											
176	**Depreciation Exp**										
177				59	50	45	30	55	60	55	63
178	Production Plant in Service Depreciation Expense			$ 696,346	$ 76,413	$ 5,571,577	$ 3,870,305	$ 332,198	$ 491,126	$ 713,230	$ 94,192
179				$ 0	$ 0	0	0	$ 0	$ 0	$ 0	0
180	**Other Taxes**	Total									
181	Plant Related & Property Taxes (Nucs only)	$ 123,977,347									
182	Payroll Taxes (Nucs Only)	$ 60,289,214									
183	Other Taxes (Pay & Property) (Non-Nucs)	$ 9,124,663	$	222,581	$ 55,959	$ 2,143,070	$ -	$ 264,526	$ 21,879	$ 379,744	$ 11,465
184	Total Other Taxes	$ 193,391,223	$	222,581	$ 55,959	$ 2,143,070	$ -	$ 264,526	$ 21,879	$ 379,744	$ 11,465
185											
186											
187											
188											
189											
190											
191											
192											
193											
194											

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	Description	Source	Notch Cliff 1-8	Pennsbury 1&2	Perryman 1,3,4,51	Perryman 6	Philadelphia Rd 1-4	Richmond 91&92	Riverside 7&8	Schuylkill 10&11
195										
196										
197	**Prepayments**	Nuclear								
198		Fossil	$ 309,044	$ 28,740	$ 1,885,966	$ 873,393	$ 137,437	$ 221,660	$ 295,077	$ 44,637
199	Total		$ 309,044	$ 28,740	$ 1,885,966	$ 873,393	$ 137,437	$ 221,660	$ 295,077	$ 44,637
200										
201	**M&S**									
202	M&S - Fuel				12,545,353	-	1,431,339		1,455,390	290,293
203	M&S - Fuel (undistributed)		-	-	-		-	-	-	-
204	M&S - Fossil Production		133,154	132,405	937,907	-	45,094	84,581	28,878	49,009
205	M&S - Nuclear Production									
206	**TOTAL M&S**		$ 133,154	$ 132,405	$ 13,483,260	$ -	$ 1,476,433	$ 84,581	$ 1,484,268	$ 339,302
207										
208										
209	**RETURN (R)**									
210										
211										
212		$/mil	%							
213	Long Term Debt	0.45	45.0%							
214	Proprietary Capital	0.55	55.0%							
215	Total (sum lines 22-23)	1.00	100%							
216										
217										
218	**Income Taxes**									
219	State Marginal Rate (multi-state)	5.6600% <<Per ACH 9-29-16								
220										
221										
222		Jurisdiction1								
223										
224		Federal								
		FIT on SIT								
		Illinois2								
		IL on SIT								
		Pennsylvania2								
		Maryland								
		Other Separate								
		NYS								
		Other Unitary								
		Marginal Tax Rate								
		Effective State Rate								

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	Description		Source	SE Chicago 5-12	Southwark 3-6	Westport 5
1	Turbogenerator, GUS and Accessory Electric Investment:			ComEd (8)	PECO (4)	BGE (1)
2	Included TurboGenerator Investment	2015 Actual Data	Account 314,323, 333, 34	132,017,953	6,463,264	31,650,720
3	Investment Generator & Exciter	2015 Actual Data	15%	19,802,693	969,490	4,747,608
4	Value of GSU Transformers	2015 Actual Data		$ 4,873,891	$ 2,616	$ 337,384
5	Total Accessory Elec Equipment - Gross Investment	2015 Actual Data	Account 315, 324, 334, 34	$ 9,173,232	$ 2,596,022	$ 1,703,761
6	Installed Cost of Power Plant (excluding Nuclear ARC; Steam ARC)	2015 Actual Data	2015 Actual Data	$ 187,439,853	$ 10,963,535	38,050,323
7	Investment Generator & Exciter / Turbogenerator			15.000%	15.000%	15.000%
8	Investment Generation & Exciter / Installed Cost of Power Plant			10.565%	8.843%	12.477%
9						
10	**Allocators**					
11						
12	**Real Power Demonstrated Capability (gross MW)**					
13	Generator 1			38.30	12.80	118.50
14	Generator 2			38.30	14.88	
15	Generator 3			38.30	12.88	
16	Generator 4			38.30	14.66	
17	Generator 5			38.30		
18	Generator 6			38.30		
19	Generator 7			38.30		
20	Generator 8			38.30		
21	Generator 9					
22	Generator 10					
23	Generator 11					
24						
25	Total			306.40	55.22	118.50
26						
27	**Nominal Power Factor (pf)**					
28	Generator 1			0.85	0.76	0.92
29	Generator 2			0.85	0.81	
30	Generator 3			0.85	0.77	
31	Generator 4			0.85	0.80	
32	Generator 5			0.85		
33	Generator 6			0.85		
34	Generator 7			0.85		
35	Generator 8			0.85		
36	Generator 9					
37	Generator 10					
38	Generator 11					
39						
40						
41	**Nameplate MVAr**					
42	Generator 1	(Nameplates, sqrt(MVA^2-MW^2))		23.74	16.36	49.04
43	Generator 2	(Nameplates, sqrt(MVA^2-MW^2))		23.74	14.83	-
44	Generator 3	(Nameplates, sqrt(MVA^2-MW^2))		23.74	16.07	-
45	Generator 4	(Nameplates, sqrt(MVA^2-MW^2))		23.74	14.90	-
46	Generator 5	(Nameplates, sqrt(MVA^2-MW^2))		23.74	-	-
47	Generator 6	(Nameplates, sqrt(MVA^2-MW^2))		23.74	-	-
48	Generator 7	(Nameplates, sqrt(MVA^2-MW^2))		23.74	-	-
49	Generator 8	(Nameplates, sqrt(MVA^2-MW^2))		23.74	-	-
50	Generator 9	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-
51	Generator 10	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-
52	Generator 11	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-
53						
54						
55	Total			189.89	62.17	49.04
56						
57	**Exciter MW**				same as Chester	
58	Generator 1	Exciter Rating		0.10	0.09	0.31
59	Generator 1	Exciter Rating		0.10	0.09	
60	Generator 2	Exciter Rating		0.10	0.09	
61	Generator 3	Exciter Rating		0.10	0.09	
62	Generator 4	Exciter Rating		0.10		
63	Generator 5	Exciter Rating		0.10		
64	Generator 6	Exciter Rating		0.10		
65	Generator 7	Exciter Rating		0.10		
66	Generator 8	Exciter Rating				
67	Generator 9	Exciter Rating				
68	Generator 10	Exciter Rating				
69	Generator 11	Exciter Rating		0.82	0.34	0.31
70						

	Description		Source	SE Chicago 5-12	Southwark 3-6	Westport 5
71	**Generator MW**					
72	Generator 1	(pf*MVA)		38.30	18.90	118.50
73	Generator 2	(pf*MVA)		38.30	20.13	-
74	Generator 3	(pf*MVA)		38.30	19.15	-
75	Generator 4	(pf*MVA)		38.30	20.08	-
76	Generator 5	(pf*MVA)		38.30	-	-
77	Generator 6	(pf*MVA)		38.30	-	-
78	Generator 7	(pf*MVA)		38.30	-	-
79	Generator 8	(pf*MVA)		38.30	-	-
80	Generator 9	(pf*MVA)		-	-	-
81	Generator 10	(pf*MVA)		-	-	-
82	Generator 11	(pf*MVA)		-	-	-
83	Total			306.40	78.25	118.50
84						
85	**Generator MVA**					
86	Generator 1	MW/pf if not stated		45.06	25.00	128.25
87	Generator 2	MW/pf if not stated		45.06	25.00	
88	Generator 3	MW/pf if not stated		45.06	25.00	
89	Generator 4	MW/pf if not stated		45.06	25.00	
90	Generator 5	MW/pf if not stated		45.06		
91	Generator 6	MW/pf if not stated		45.06		
92	Generator 7	MW/pf if not stated		45.06		
93	Generator 8	MW/pf if not stated		45.06		
94	Generator 9	MW/pf if not stated				
95	Generator 10	MW/pf if not stated				
96	Generator 11	MW/pf if not stated				
97						
98	Total			360.47	100.00	128.25

99	Peak Hour	18	18	16				
100	Peak Day	9/3/2015	9/3/2015	7/20/2015	ComEd (8)		PECO (4)	BGE (1)
101		**Average**	**ComEd**	**PECO**				
102	Max. MVAr	2,991	2,187	361				
103	Nameplate MVAr	9,831	4,856	2,853	189.9		62.2	49.0
104	Exciter MW	76	35	29	0.8		0.3	0.3
105	Generator MW	23,359	11,447	6,715	306		78	119
106		**0.0992%**	**0.1358%**	**0.0542%**				
107								
108	**Accessory Equip Allocator**							
109	Item		**Nuclear**	**Cumb. Turbine**	**comb. Tur.**		**comb. Tur.**	**comb. Tur.**
110	Storage Batteries		15%	50%	$ -	$	20,009	$ -
111	Control&Power Cabling		1%	50%	$ -	$	32,741	$ -
112	Switch Board Equipment		1%	50%	$ -	$	819,137	$ -
113	Switching Equipment		1%	40%	$ -	$	23,993	$ -
114	Transformers		3%	10%	$ -	$	-	$ -
115	Aux Generator		0%	0%	$ -	$	-	$ -
116	Fire Protection System		0%	0%	$ -	$	-	$ -
117	HVAC		0%	0%	$ -	$	-	$ -
118	Regulating Equipment		50%	75%	$ -	$	-	$ 1,114,980
119	Structure		0%	0%	$ -	$	-	$ -
120	Misc		0%	0%	$ -	$	-	$ -
121	Exciter & PPT		100%	100%	$ -	$	-	$ -
122	Station Grounding		1%	5%	$ -	$	-	$ -
123	Bus & Insulators		80%	80%	$ -	$	-	$ -
124	Capacitor Bank		0%	0%	$ -	$	-	$ -
125					$ -	$	895,880	$ 1,114,980
126			EXE-4, Sch 5 Allocation factors develop		0%		35%	65%

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	Description	Source		SE Chicago 5-12	Southwark 3-6	Westport 5
127	**Item**					
128	Storage Batteries	Actual 2015		$ -	$ 40,019	$ -
129	Control&Power Cabling	Actual 2015		$ -	$ 65,482	$ -
130	Switch Board Equipment	Actual 2015		$ -	$ 1,638,273	$ -
131	Switching Equipment	Actual 2015		$ -	$ 59,982	$ -
132	Transformers	Actual 2015		$ -	$ -	$ -
133	Aux Generator	Actual 2015		$ -	$ -	$ -
134	Fire Protection System	Actual 2015		$ -	$ -	$ -
135	HVAC	Actual 2015		$ -	$ -	$ -
136	Regulating Equipment	Actual 2015		$ -	$ -	$ 1,486,640
137	Structure	Actual 2015		$ -	$ 11,054	$ -
138	Misc	Actual 2015		$ 9,173,232	$ 781,212	$ 217,121
139	Exciter & PPT	Actual 2015		$ -	$ -	$ -
140	Station Grounding	Actual 2015		$ -	$ -	$ -
141	Bus & Insulators	Actual 2015		$ -	$ -	$ -
142	Capacitor Bank	Actual 2015		$ -	$ -	$ -
143						
144	Total	$ 1,327,863,081	<ties to "Accessory Electr	$ 9,173,232	$ 2,596,022	$ 1,703,761
145						
146	**O&M Calculation**					
147	Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546		$ 459,763	$ 75,704	$ 196,400
148	Coolants and Water (Nuclear Plants Only)	FERC Account 519		$ -	$ -	$ -
149	Steam Expenses	FERC Account 502, 520		$ 118,760	$ 19,555	$ 50,732
150	Steam From Other Sources	FERC Account 503		$ 229,490	$ 37,788	$ 98,033
151	Electric Expenses	FERC Account 505, 523 - Allocated based on		$ -	$ -	$ -
152	Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524 - Reduced from actual		$ 70,310	$ 11,577	$ 30,035
153	Rents	FERC Account 507		$ 427,899	$ 70,458	$ 182,789
154	Allowances	FERC Account 509		$ 17,291	$ 2,847	$ 7,386
155	Maintenance Supervision and Engineering	FERC Account 510, 528		$ -	$ -	$ -
156	Maintenance of Structures	FERC Account 511, 529, 552		$ 179,335	$ 29,529	$ 76,608
157	Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530		$ 76,902	$ 12,663	$ 32,851
158	Maintenance of Electric Plant	FERC Account 513, 531, 554		$ 80,006	$ 13,174	$ 34,177
159	Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532		$ 99,578	$ 16,397	$ 42,538
160	Other Power Production, & Other Expenses	FERC Account 548-553; 557		$ 302,046	$ 49,735	$ 129,027
161	TOTAL	Grand Total O&M		$ 2,061,381	$ 339,425	$ 880,575
162						
163	**A&G and Overhead Expenses**					
164	Plant specific A&G			$ 314,901	$ 16,925	$ 144,258
165						
166	Nuclear Overhead Expenses ("OH" tab)					
167	Non-nuclear Overhead Expenses ("OH" tab)			$ 682,036	$ 119,114	$ 340,317
168	Total			$ 996,937	$ 136,039	$ 484,574
169						
170						
171						
172						
173						
174						
175						
176	**Depreciation Exp**					
177				30	31	53
178	Production Plant in Service Depreciation Expense			$ 6,247,995	$ 353,662	$ 717,931
179				$ 0	$ 0	$ 0
180	**Other Taxes**		Total			
181	Plant Related & Property Taxes (Nucs only)		$ 123,977,347			
182	Payroll Taxes (Nucs Only)		$ 60,289,214			
183	Other Taxes (Pay & Property) (Non-Nucs)		$ 9,124,663	$ 150,320	$ 11,609	$ 775,741
184	Total Other Taxes		$ 193,391,223	$ 150,320	$ 11,609	$ 775,741
185						
186						
187						
188						
189						
190						
191						
192						
193						
194						

	Description	Source	SE Chicago 5-12	Southwark 3-6	Westport 5
195					
196					
197	**Prepayments**	Nuclear			
198		Fossil	$ 1,409,955	$ 82,470	$ 286,221
199	Total		$ 1,409,955	$ 82,470	$ 286,221
200					
201	**M&S**				
202	M&S - Fuel			423,706	
203	M&S - Fuel (undistributed)		-	-	-
204	M&S - Fossil Production		256,975	44,880	128,223
205	M&S - Nuclear Production				
206	**TOTAL M&S**		$ 256,975	$ 468,585	$ 128,223
207					
208					
209	**RETURN (R)**				
210					
211					

		$/mil	%
212			
213	Long Term Debt	0.45	45.0%
214	Proprietary Capital	0.55	55.0%
215	Total (sum lines 22-23)	1.00	100%

216			
217			
218	**Income Taxes**		
219	State Marginal Rate (multi-state)	5.6600%	<<Per ACH 9-29-16
220			
221			
222		Jurisdiction1	
223			
224		Federal	
		FIT on SIT	
		Illinois2	
		IL on SIT	
		Pennsylvania2	
		Maryland	
		Other Separate	
		NYS	
		Other Unitary	
		Marginal Tax Rate	
		Effective State Rate	

Total Plant and GSU

Exhibit No. EXE-3
Schedule 5
Page 1

	RTO	PJM		RTO	PJM								
	Abv Long Discription	(Multiple Items)		Sum of Book Cost	Column Labels					GSU investment Not booked	GSU investment From		
	Row Labels	Sum of Book Cost		Row Labels	321	322	344	346	353	to Access Elect Eq	Access Elect Equi	Total GSU	
1	Braidwood	1,484,090,250		Braidwood						-	49,633,067	49,633,067	
2	Byron	1,391,617,170		Byron						-	21,644,926	21,644,926	
3	Chester	9,133,168		Chester						-	-	-	
4	Common Combustions	604,207		Common Combustions						-	-	-	
5	Conemaugh	-	Sold	Conowingo						-	6,792,649	6,792,649	
6	Conowingo	380,084,794		Croydon						-	1,420,756	1,420,756	
7	Crane	5,147,586	Solar Exclude	Delaware						-	-	-	
8	Cromby	1,281,727	Retired	Dresden						-	36,227,984	36,227,984	
9	Croydon	107,412,068		Eddystone						-	6,411,560	6,411,560	
10	Delaware	13,528,361								-	51,347	51,347	
11	Dresden	1,359,267,568		Falls						-	-	-	
12	Eddystone	400,131,998		Fort Smallwood						-	-	-	
13	Fairless Hills	61,729,219		Gould St						-	3,114	3,114	
14	Falls	7,829,474		Handsome Lake						-	-	-	
15	Fort Smallwood	1,659,201		LaSalle	6,184					6,184	4,666,236	4,672,421	
16	Gould St	18,406,803		Limerick						-	41,192,118	41,192,118	
17	Handsome Lake	85,825,302		Moser						-	-	-	
18	LaSalle	1,412,906,574		Muddy Run						-	4,657,845	4,657,845	
19	Limerick	1,222,406,959		Notch Cliff						-	-	-	
20	Merrill Ck	1,614,923	Not a gen.	Oyster Ck						-	19,820,373	19,820,373	
21	Moser	8,301,032		Peach Bottom						-	41,363,873	41,363,873	
22	Muddy Run	261,421,690		Pennsbury						-	-	-	
23	Notch Cliff	41,084,404		Perryman						-	784,897	784,897	
24	Oyster Ck	360,225,425		Philadelphia Rd						-	-	-	
25	Peach Bottom	1,360,681,860		Quad Cities	217,244					217,244	25,109,413	25,326,658	
26	Pennsbury	3,820,667		Richmond						-	355,663	355,663	
27	Perryman	254,874,882		Riverside			21,939			21,939	328,562	350,500	
28	Philadelphia Rd	18,270,877		Salem						-	14,618,814	14,618,814	
29	Quad Cities	1,046,110,329		Schuylkill						-	-	-	
30	Richmond	29,467,537		SE Chicago				249,688		249,688	4,624,203	4,873,891	
31	Riverside	39,227,656		Southwark						-	2,616	2,616	
32	Salem	583,671,743		TMI						-	-	-	
33	Schuylkill	5,934,123		Westport					48,771	48,771	288,614	337,384	
34	SE Chicago	187,439,853		Grand Total	223,429	-	21,939	249,688	48,771	543,826	279,998,630	280,542,456	
35	Southwark	10,963,535											
36	TMI	1,001,621,380											
37	Westport	38,050,323											
38	Grand Total	14,625,578,846											
39		14,617,534,609	less Crumby & Merrill Creek & Crane										

Turbogenerator Investment

		TurboGen Investment	From Accessory Electric Acct	Total
1	Braidwood	276,982,389	-	276,982,389
2	Byron	326,517,030	28,526	326,545,555
3	Chester	4,695,512	-	4,695,512
4	Common Combustions	292,357	-	292,357
5	Conowingo	143,524,274	-	143,524,274
6	Croydon	72,348,001	-	72,348,001
7	Delaware	6,730,407	-	6,730,407
8	Dresden	507,917,628	-	507,917,628
9	Eddystone	62,382,060	-	62,382,060
10	Fairless Hills	20,090,347	-	20,090,347
11	Falls	5,518,050	-	5,518,050
12	Fort Smallwood	3,771	-	3,771
13	Gould St	4,694,859	-	4,694,859
14	Handsome Lake	42,347,182	-	42,347,182
15	LaSalle	322,991,066	-	322,991,066
16	Limerick	195,863,167	-	195,863,167
17	Moser	5,376,210	-	5,376,210
18	Muddy Run	105,729,817	-	105,729,817
19	Notch Cliff	20,738,180	-	20,738,180
20	Oyster Ck	30,406,806	-	30,406,806
21	Peach Bottom	324,475,609	-	324,475,609
22	Pennsbury	568,704	-	568,704
23	Perryman	177,835,602	-	177,835,602
24	Philadelphia Rd	11,650,034	5,346,841	16,996,875
25	Quad Cities	345,327,838	-	345,327,838
26	Richmond	20,218,692	-	20,218,692
27	Riverside	13,013,142	-	13,013,142
28	Salem	80,714,327	-	80,714,327
29	Schuylkill	4,345,038	-	4,345,038
30	SE Chicago	132,017,953	-	132,017,953
31	Southwark	6,463,264	-	6,463,264
32	TMI	13,661,046	-	13,661,046
33	Westport	31,650,720	-	31,650,720
		3,317,091,083		
		-		
		3,317,091,083		

	RTO	PJM							
	Detailed Book Cost	Column Labels							
	Row Labels	314	323	333	343	344	Grand Total	Excluded	Included
*	Braidwood								276,982,389
*	Byron								326,517,030
*	Chester								4,695,512
*	Common Combustions								292,357
*	Conowingo								143,524,274
*	Croydon								72,348,001
*	Delaware								6,730,407
*	Dresden								507,917,628
*	Eddystone								62,382,060
*	Fairless Hills								20,090,347
*	Falls								5,518,050
*	Fort Smallwood								3,771
*	Gould St								4,694,859
*	Handsome Lake								42,347,182
*	LaSalle								322,991,066
*	Limerick								195,863,167
*	Moser								5,376,210
*	Muddy Run								105,729,817
*	Notch Cliff								20,738,180
*	Oyster Ck								30,406,806
*	Peach Bottom								324,475,609
*	Pennsbury								568,704
*	Perryman								177,835,602
*	Philadelphia Rd								11,650,034
*	Quad Cities								345,327,838
*	Richmond								20,218,692
*	Riverside								13,013,142
*	Salem								80,714,327
*	Schuylkill								4,345,038
*	SE Chicago								132,017,953
*	Southwark								6,463,264
*	TMI								13,661,046
*	Westport								31,650,720
*	Total								3,317,091,083

ACCESSORY ELECTRICAL EQUIPMENT

	Row Labels	Grand Total	TurboGen	GSU	Storage Batteries	Control&Power Cabling	Switch Board Equipment	Switching Equipment	Transformers	Aux Generator
1	Braidwood	134,750,783	-	49,633,067	734,651	175,303,902	51,974,311	7,843,655	702,163	21,664,522
2	Byron	112,229,473	28,526	21,644,926	1,036,178	185,037,012	65,474,820	14,828,319	1,267,080	30,867,315
3	Chester	1,724,631	-	-	12,262	360,640	-	791,028	-	-
4	Common Combustions	44,507	-	-	-	-		-	-	-
5	Conowingo	38,570,503	-	6,792,649	136,064	3,179,427	1,973,492	2,017,595	6,318,929	101,173
6	Crane	1,763,925	-	-	-	-		-	-	-
7	Croydon	10,459,221	-	1,420,756	64,719	2,578,451	239,413	745,807	247,743	-
8	Delaware	1,910,796	-	-	28,741	344,611	19,874	1,147,085	-	-
9	Dresden	121,457,544	-	36,227,984	1,984,353	4,946,860		4,661,842	12,219,855	5,052,411
10	Eddystone	37,516,746	-	6,411,560	351,463	19,978,318	484,897	2,041,877	-	-
11	Fairless Hills	559,367	-	51,347	16,787	230	-	-	-	-
12	Falls	1,296,752	-	-	33,793	142,003		562,170	512	-
13	Fort Smallwood	229,561	-	-	-	257,127	3,425	-	-	-
14	Gould St	120,655	-	3,114	353,658	10,940	-	-	-	-
15	Handsome Lake	9,841	-	-	-			-	-	-
16	LaSalle	91,943,066	-	4,666,236	1,944,786	23,115,092	6,488,908	6,572,575	2,026,797	10,275,282
17	Limerick	152,931,562	-	41,192,118	1,414,202	23,319,901	1,188,580	228,627	1,050,152	5,506,158
18	Moser	1,539,315	-	-	9,365	262,801		589,074	-	-
19	Muddy Run	49,533,204	-	4,657,845	129,233	4,929,960	1,669,534	6,130,553	589,215	120,583
20	Notch Cliff	5,115,261	-	-	-	33,556	237,988	981,137	57,272	-
21	Oyster Ck	29,048,791	-	19,820,373	-	-	-	-	565,862	-
22	Peach Bottom	112,905,096	-	41,363,873	2,015,820	19,695,956	11,507,453	625,734	1,862,746	129,640
23	Pennsbury	242,106	-	-	-	17,310	-	-	-	-
24	Perryman	22,843,595	5,346,841	784,897	-	-	-	59,681	-	-
25	Philadelphia Rd	2,100,938	-	-	-	-	2,648,610	-	-	-
26	Quad Cities	76,259,093	-	25,109,413	2,133,713	7,403,630	2,898,057	3,872,699	8,262,803	3,321,149
27	Richmond	3,266,852	-	355,663	110,173	376,173	31,046	98,992	69,638	-
28	Riverside	4,370,438	-	328,562	61,893	2,209,028	738,213	518,931	98,872	-
29	Salem	57,321,438	-	14,618,814	-	459,119	-	-	-	-
30	Schuylkill	553,360	-	-	8,355	207,889	8,299	183,098	-	-
31	SE Chicago	13,797,435	-	4,624,203	-	-	-	-	-	-
32	Southwark	2,598,638	-	2,616	40,019	65,482	1,638,273	59,982	-	-
33	TMI	12,600,036	-	-	-	-	-	-	1,804,433	-
34	Westport	2,063,236	-	288,614	-	-	-	-	-	-
35	Total	1,103,677,764	5,375,366	279,998,630	12,620,227	474,235,420	149,225,194	54,560,461	37,144,073	77,038,233

	Detailed Row Labels	Grand Total	TurboGen	GSU	Storage Batteries	Control&Power Cabling	Switch Board Equipment	Switching Equipment	Transformers	Aux Generator
*	Braidwood	134,750,783	-	49,633,067	734,651	175,303,902	51,974,311	7,843,655	702,163	21,664,522
*	Byron	112,229,473	28,526	21,644,926	1,036,178	185,037,012	65,474,820	14,828,319	1,267,080	30,867,315
*	Chester	1,724,631	-	-	12,262	360,640	-	791,028	-	-
*	Common Combustions	44,507	-	-	-	-	-	-	-	-
*	Conowingo	38,570,503	-	6,792,649	136,064	3,179,427	1,973,492	2,017,595	6,318,929	101,173
*	Crane	1,763,925	-	-	-	-	-	-	-	-
*	Croydon	10,459,221	-	1,420,756	64,719	2,578,451	239,413	745,807	247,743	-
*	Delaware	1,910,796	-	-	28,741	344,611	19,874	1,147,085	-	-
*	Dresden	121,457,544	-	36,227,984	1,984,353	4,946,860	3,310,657	4,661,842	12,219,855	5,052,411
*	Eddystone	37,516,746	-	6,411,560	351,463	19,978,318	484,897	2,041,877	-	-
*	Fairless Hills	559,367	-	51,347	16,787	230	-	-	-	-
*	Falls	1,296,752	-	-	33,793	142,003	169,882	562,170	512	-
*	Fort Smallwood	229,561	-	-	-	257,127	3,425	-	-	-
*	Gould St	120,655	-	3,114	353,658	10,940	-	-	-	-
*	Handsome Lake	9,841	-	-	-	-	-	-	-	-
*	LaSalle	91,943,066	-	4,666,236	1,944,786	23,115,092	6,488,908	6,572,575	2,026,797	10,275,282
*	Limerick	152,931,562	-	41,192,118	1,414,202	23,319,901	1,188,580	228,627	1,050,152	5,506,158
*	Moser	1,539,315	-	-	9,365	262,801	174,009	589,074	-	-
*	Muddy Run	49,533,204	-	4,657,845	129,233	4,929,960	1,669,534	6,130,553	589,215	120,583
*	Notch Cliff	5,115,261	-	-	-	33,556	237,988	981,137	57,272	-
*	Oyster Ck	29,048,791	-	19,820,373	-	-	-	-	565,862	-
*	Peach Bottom	112,905,096	-	41,363,873	2,015,820	19,695,956	11,507,453	625,734	1,862,746	129,640
*	Pennsbury	242,106	-	-	-	17,310	-	-	-	-
*	Perryman	22,843,595	5,346,841	784,897	-	-	-	59,681	-	-
*	Philadelphia Rd	2,100,938	-	-	-	-	2,648,610	-	-	-
*	Quad Cities	76,259,093	-	25,109,413	2,133,713	7,403,630	2,898,057	3,872,699	8,262,803	3,321,149
*	Richmond	3,266,852	-	355,663	110,173	376,173	31,046	98,992	69,638	-
*	Riverside	4,370,438	-	328,562	61,893	2,209,028	738,213	518,931	98,872	-
*	Salem	57,321,438	-	14,618,814	-	459,119	-	-	-	-
*	Schuylkill	553,360	-	-	8,355	207,889	8,299	183,098	-	-
*	SE Chicago	13,797,435	-	4,624,203	-	-	-	-	-	-
*	Southwark	2,598,638	-	2,616	40,019	65,482	1,638,273	59,982	-	-
*	TMI	12,600,036	-	-	-	-	-	-	1,804,433	-
*	Westport	2,063,236	-	288,614	-	-	-	-	-	-

ACCESSORY ELECTRICAL EQUIPMENT

	Row Labels	Fire Protection System	HVAC	Regulating Equipment	Structure	Misc.	Exciter & PPT	Station Grounding	Bus & Insulators	Capacitor Bank
1	Braidwood	-	-	-	-	19,860,488	-	-	-	-
2	Byron	-	-	48,068	-	18,414,787	-	-	-	-
3	Chester	-	-	-	-	560,700	-	-	-	-
4	Common Combustions	-	-	-	-	44,507	-	-	-	-
5	Conowingo	-	-	390,726	270,434	15,212,502	126,475	-	-	-
6	Crane	-	-	-	-	-	-	-	-	-
7	Croydon	-	-	-	56,420	5,030,779	-	-	75,133	-
8	Delaware	-	-	-	-	370,485	-	-	-	-
9	Dresden	-	-	153,468	31,844	63,976,359	-	4,948	4,134,523	-
10	Eddystone	-	-	-	167,065	7,066,463	-	-	-	-
11	Fairless Hills	-	-	-	-	154,657	-	-	-	-
12	Falls	-	-	-	8,093	380,300	-	-	-	-
13	Fort Smallwood	-	-	-	-	24,461	-	-	-	-
14	Gould St	-	-	-	-	-	-	-	-	-
15	Handsome Lake	-	-	-	-	-	-	-	-	-
16	LaSalle	-	-	-	445,431	85,054,019	-	-	5,590,781	-
17	Limerick	-	-	-	301,814	76,645,785	-	-	-	-
18	Moser	-	-	-	13,093	490,974	-	-	-	-
19	Muddy Run	-	-	505,742	-	29,526,543	-	181,000	-	-
20	Notch Cliff	-	-	4,640,268	6,922	118,909	-	9,880	-	-
21	Oyster Ck	-	-	-	-	8,662,556	-	-	-	-
22	Peach Bottom	126,725	-	794	25,625	28,280,047	-	20,693	(50,699)	-
23	Pennsbury	-	-	-	-	224,796	-	-	-	-
24	Perryman	-	-	176,513	-	21,318,503	-	-	-	-
25	Philadelphia Rd	-	-	-	-	412,515	-	-	-	-
26	Quad Cities	-	-	-	133,041	35,712,768	-	2,051	2,444,859	-
27	Richmond	-	-	-	41,045	2,183,819	-	-	-	-
28	Riverside	7,984	-	306,814	4,701	-	15,989	190,636	-	-
29	Salem	22,085,749	-	-	-	16,168,621	-	-	-	-
30	Schuylkill	-	-	-	41,588	104,130	-	-	-	-
31	SE Chicago	-	-	-	-	9,173,232	-	-	-	-
32	Southwark	-	-	-	11,054	781,212	-	-	-	-
33	TMI	194,043	-	-	-	10,382,696	-	-	-	-
34	Westport	-	-	1,486,640	-	217,121	-	-	-	-
35	Total	22,414,501	-	7,709,033	1,558,170	456,554,732	142,463	409,208	12,194,598	-

ACCESSORY ELECTRICAL EQUIPMENT

	Detailed Row Labels	Fire Protection System	HVAC	Regulating Equipment	Structure	Misc.	Exciter & PPT	Station Grounding	Bus & Insulators	Capacitor Bank
*	Braidwood	-	-	-	-	19,860,488	-	-	-	-
*	Byron	-	-	48,068	-	18,414,787	-	-	-	-
*	Chester	-	-	-	-	560,700	-	-	-	-
*	Common Combustions	-	-	-	-	44,507	-	-	-	-
*	Conowingo	-	-	390,726	270,434	15,212,502	126,475	-	-	-
*	Crane	-	-	-	-	-	-	-	-	-
*	Croydon	-	-	-	56,420	5,030,779	-	-	75,133	-
*	Delaware	-	-	-	-	370,485	-	-	-	-
*	Dresden	-	-	153,468	31,844	63,976,359	-	4,948	4,134,523	-
*	Eddystone	-	-	-	167,065	7,066,463	-	-	-	-
*	Fairless Hills	-	-	-	-	154,657	-	-	-	-
*	Falls	-	-	-	8,093	380,300	-	-	-	-
*	Fort Smallwood	-	-	-	-	24,461	-	-	-	-
*	Gould St	-	-	-	-	-	-	-	-	-
*	Handsome Lake	-	-	-	-	-	-	-	-	-
*	LaSalle	-	-	-	445,431	85,054,019	-	-	5,590,781	-
*	Limerick	-	-	-	301,814	76,645,785	-	-	-	-
*	Moser	-	-	-	13,093	490,974	-	-	-	-
*	Muddy Run	-	-	505,742	-	29,526,543	-	181,000	-	-
*	Notch Cliff	-	-	4,640,268	6,922	118,909	-	9,880	-	-
*	Oyster Ck	-	-	-	-	8,662,556	-	-	-	-
*	Peach Bottom	126,725	-	794	25,625	28,280,047	-	20,693	(50,699)	-
*	Pennsbury	-	-	-	-	224,796	-	-	-	-
*	Perryman	-	-	176,513	-	21,318,503	-	-	-	-
*	Philadelphia Rd	-	-	-	-	412,515	-	-	-	-
*	Quad Cities	-	-	-	133,041	35,712,768	-	2,051	2,444,859	-
*	Richmond	-	-	-	41,045	2,183,819	-	-	-	-
*	Riverside	7,984	-	306,814	4,701	-	15,989	190,636	-	-
*	Salem	22,085,749	-	-	-	16,168,621	-	-	-	-
*	Schuylkill	-	-	-	41,588	104,130	-	-	-	-
*	SE Chicago	-	-	-	-	9,173,232	-	-	-	-
*	Southwark	-	-	-	11,054	781,212	-	-	-	-
*	TMI	194,043	-	-	-	10,382,696	-	-	-	-
*	Westport	-	-	1,486,640	-	217,121	-	-	-	-

Nuclear O&M Summary

			Braidwood 1 & 2	Byron 1 & 2	Dresden 1 & 2	LaSalle 1 & 2	Limerick 1 & 2	Oyster Creek	Peach Bottom 1 & 2	Quad Cities 1 & 2	Salem 1 & 2 (43%) calculated distribution	TMI
	Actual Expenses											
1	Base Payroll-	O&M	81,450,672	81,108,827	80,164,265	81,600,844	84,313,954	60,913,807	81,687,586	79,370,819	46,153,924.79	64,952,235
2	Stock Comp	O&M	1,317,081	1,303,487	1,101,284	1,207,840	1,673,407	1,077,097	1,790,154	904,370	759,317.92	1,246,508
3	Other Premium-	O&M	2,943,203	3,062,667	3,156,797	4,009,934		4,698,364	3,114,732	3,561,854	1,796,616.67	2,465,069
4	Overtime --	O&M	11,993,688	11,310,015	11,077,125	12,914,844	13,309,556	6,895,440	9,771,487	9,359,575	6,340,510.65	6,062,675
5	Contracting - Operations.	O&M	41,650,145	54,103,838	37,296,828	48,436,886	44,395,567	12,614,103	37,509,342	35,587,992	22,805,380.03	20,746,805
6	Contracting - Non-Operations.	O&M	8,976,034	6,962,858	7,261,212	6,660,558		10,617,668	11,172,140	6,873,256	4,283,307.08	9,316,811
7	Contracting - Outsourced.	O&M	1,357,861	1,505,001	1,091,113	3,285,717	1,425,522	405,221	1,371,239	1,122,938	846,405.26	831,536
8	Staff Augmentation.	O&M	337,894	45,705	268,522	372,212	800,199	320,339	851,129	(5,713)	218,856.79	351,596
9	Materials and Tools	O&M	18,935,184	19,316,877	16,248,410			6,753,723	18,562,963	14,292,834	6,887,838.97	10,133,298
10	Licensing and Telecom.	A&G	32,239	34,907	19,312	20,679	81,222	23,436	42,289	20,241	20,077.62	100,110
11	Regulatory Fees and Permits	A&G	19,831,531	19,662,343	19,971,004	19,970,543	17,519,098	13,663,846	17,220,208	20,018,016	10,821,511.78	12,073,062
12	Transportation & Fleet Service	A&G	276,041	256,581	214,130	239,946		-	572,164	163,723	126,074.73	31,160
13	Facilities, Rentals & Utils	A&G	1,150,629	1,081,940	762,047	913,307	277,986	867,972	31,916	341,442	397,215.60	780,689
14	Office Expense.	A&G	993,879	690,122	763,170	923,958	701,345	504,988	593,094	318,285	401,724.16	235,517
15	Charity and Contributions	A&G	139,115	31,998	26,957	86,181	50,645	40,421	28,400	29,415	31,700.64	30,064
16	Memberships, Dues & Subscrip	A&G	12,669	11,700	13,092	14,669	15,948	7,190	17,984	11,506	7,667.12	30,884
17	Seminars and Training.	A&G	35,204	78,086	115,188	106,393	107,267	81,876	53,320	56,748	46,407.91	12,296
18	Travel, Entertainment & Reimb.	A&G	2,043,258	2,564,261	1,620,295	2,116,449	2,678,097	1,570,009	2,143,327	2,008,466	1,225,492.48	1,601,189
19	InterCompany.	A&G	2,955,342	1,833,864	3,348,948	3,667,776	2,862,789	910,077	1,861,828	763,729	1,332,362.88	2,040,554
20												
21	Total Depreciation	Depreciation	39,203,314	38,603,318	62,194,479	39,145,902	33,598,920	37,290,080	45,507,821	43,271,711	17,015,247	38,072,513
22	Total Insurance	A&G	4,844,360	4,808,976	4,336,015	4,795,414	5,186,848	2,746,321	1,818,626	2,718,756	2,287,552.77	2,627,838
23	Payroll Taxes..	Other Tax	7,269,439	7,259,232	7,076,336	7,193,199	7,359,580	5,403,699	7,131,785	7,072,586	4,081,460.78	5,775,935
24	Property Taxes	Other Tax	20,026,176	33,153,706	25,219,637	21,480,427	3,904,607	2,350,996	1,715,677	8,057,140	8,483,245.57	1,135,951
25	Other Taxes	Other Tax	-	-	-	-	64,962	1,114,242	9,499	-	87,000.32	50,952
26	Pension.	A&G	20,936,860	20,518,770	19,902,343	20,444,497	20,527,026	10,591,350	19,635,722	20,127,780	11,174,851.65	11,438,570
27	Fringe Benefits.	A&G	14,211,257	14,149,184	13,782,272	14,070,516	14,335,773	10,143,334	14,024,640	13,835,682	7,944,886.85	10,853,347
28	Incentive-	A&G	13,817,545	13,710,077	13,099,747	13,424,324	13,493,665	8,847,381	13,380,470	13,216,515	7,537,739.83	9,472,036
29	Allocated O&M	A&G	31,233,648	28,639,186	29,129,317	29,815,109	30,688,308	19,988,786	29,289,390	28,256,448	16,616,899.65	23,673,646
30	BSC Services-	A&G	7,396,232	6,843,306	6,956,360	7,976,336	7,392,990	6,144,197	7,928,675	7,645,090	4,265,702.19	6,453,857
31	Non Nuclear Expense	A&G	2,002	-	-	-	-	-	-	-	146.52	-
32	Other Expenses--	A&G	4,455,601	4,289,853	(331,022)	193,433	686,440	(491,623)	(238,860)	(120,190)	617,982.95	(691,674)
33												
34	Total		359,828,102	376,940,685	365,885,185	345,087,893	307,451,721	226,094,338	328,598,746	318,881,015	184,615,109	241,905,028

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Nuclear O&M Summary

Proxy - Average of 5 Nuclear Units		Nuclear	< "Fossil & Hydro & Nuclear O&M Proxy Breakout.xlsx"		84,020,036	82,961,325	
Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546	19.23%			1,818,626	2,718,756	
Coolants and Water (Nuclear Plants Only)	FERC Account 519	1.88%			85,838,662	85,680,080	
Steam Expenses	FERC Account 502, 520	11.82%					
Steam From Other Sources	FERC Account 503	0.00%					
Electric Expenses	FERC Account 505, 523	0.00%					
Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524	1.21%					
Rents	FERC Account 507	33.39%					
Allowances	FERC Account 509	2.65%					
Maintenance Supervision and Engineering	FERC Account 510, 528	0.00%					
Maintenance of Structures	FERC Account 511, 529, 552	3.55%					
Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530	0.28%					
Maintenance of Electric Plant	FERC Account 513, 531, 554	9.14%					
Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532	5.87%					
Other Power Production, & Other Expenses	FERC Account 548-553; 557	10.99%					
Total O&M		100.00%					

Componentized O&M

		Braidwood 1 & 2	Byron 1 & 2	Dresden 1 & 2	LaSalle 1 & 2	Limerick 1 & 2	Oyster Creek	Peach Bottom 1 & 2	Quad Cities 1 & 2	Salem 1 & 2 (43%)	TMI
Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546	32,492,207	34,368,626	30,319,889	30,478,210	28,060,813	20,056,606	31,890,101	29,051,131	17,325,181	22,327,877
Coolants and Water (Nuclear Plants Only)	FERC Account 519	3,183,689	3,367,547	2,970,838	2,986,351	2,749,487	1,965,210	3,124,693	2,846,522	1,697,576	2,187,756
Steam Expenses	FERC Account 502, 520	19,969,572	21,122,811	18,634,475	18,731,778	17,246,057	12,326,705	19,599,521	17,854,702	10,647,982	13,722,618
Steam From Other Sources	FERC Account 503	-	-	-	-	-	-	-	-	-	-
Electric Expenses	FERC Account 505, 523	-	-	-	-	-	-	-	-	-	-
Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524	2,040,158	2,157,976	1,903,760	1,913,700	1,761,914	1,259,337	2,002,352	1,824,095	1,087,833	1,401,948
Rents	FERC Account 507	56,408,634	59,666,223	52,637,346	52,912,201	48,715,440	34,819,603	55,363,339	50,434,698	30,077,667	38,762,682
Allowances	FERC Account 509	4,476,155	4,734,652	4,176,895	4,198,705	3,865,683	2,763,016	4,393,209	4,002,110	2,386,732	3,075,908
Maintenance Supervision and Engineering	FERC Account 510, 528	-	-	-	-	-	-	-	-	-	-
Maintenance of Structures	FERC Account 511, 529, 552	5,994,248	6,340,415	5,593,493	5,622,700	5,176,733	3,700,095	5,883,170	5,359,429	3,196,195	4,119,106
Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530	467,205	494,186	435,969	438,245	403,486	288,393	458,547	417,725	249,118	321,052
Maintenance of Electric Plant	FERC Account 513, 531, 554	15,446,317	16,338,339	14,413,629	14,488,892	13,339,698	9,534,615	15,160,085	13,810,480	8,236,136	10,614,344
Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532	9,921,805	10,494,787	9,258,467	9,306,811	8,568,637	6,124,475	9,737,946	8,871,039	5,290,409	6,818,030
Other Power Production, & Other Expenses	FERC Account 548-553; 557	18,561,772	19,633,712	17,320,796	17,411,239	16,030,257	11,457,706	18,217,809	16,595,995	9,897,329	12,755,212
O&M	Sum lines 53-66	168,961,761	178,719,274	157,665,557	158,488,835	145,918,204	104,295,761	165,830,771	151,067,926	90,092,158	116,106,533
A&G	Sum A&G lines above	124,367,412	119,205,155	113,729,176	118,779,529	116,605,447	75,639,559	108,403,193	109,411,651	64,855,997	80,763,143
Depreciation	Line 21	39,203,314	38,603,318	62,194,479	39,145,902	33,598,920	37,290,080	45,507,821	43,271,711	17,015,247	38,072,513
Property Tax and Other Tax	Line 24 & 25	20,026,176	33,153,706	25,219,637	21,480,427	3,969,570	3,465,238	1,725,176	8,057,140	8,570,246	1,186,903
Payroll	Line 23	7,269,439	7,259,232	7,076,336	7,193,199	7,359,580	5,403,699	7,131,785	7,072,586	4,081,461	5,775,935
Total O&M	Sum lines 67-71	359,828,102	376,940,685	365,885,185	345,087,893	307,451,721	226,094,338	328,598,746	318,881,015	184,615,109	241,905,028

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Exhibit No. EXE-3
Schedule 8
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Non-nuclear O&M Summary

			Total	Chester	Conowingo	Croyden	Delaware Station	Eddystone	Fairless Hills
1	O&M	$	66,296,430	$ 172,268	$ 16,752,129	$ 2,552,217	$ 365,535	$ 16,779,786	$ 7,651,534
2	A&G	$	9,745,682	$ 8,214	$ 2,067,560	$ 127,260	$ 18,226	$ 1,076,796	$ 833,095
3	DEPR	$	47,190,561	$ 7,267	$ 6,605,136	$ 129,843	$ 18,596	$ 6,764,751	$ 3,643,397
4	OTR TX	$	13,072,583	$ 5,780	$ 3,947,920	$ 87,293	$ 27,880	$ 3,170,443	$ 263,599
		$	136,305,256	$ 193,529	$ 29,372,744	$ 2,896,613	$ 430,238	$ 27,791,776	$ 12,391,625
				$ 136,305,256					
	LABOR -- These plants	$	28,471,791	$ 88,325	$ 8,193,348	$ 1,243,903	$ 178,155	$ 6,760,484	$ 3,682,245
	LABOR -- Other fossil plants	$	38,539,019	< Source: "2015 Exelon Power Adjusted O&M View (recast SMM 9-2 control total.xlxs"					
	TOTAL non-nuc labor	$	67,010,810						
	Non-nuclear allocators (these plants)			0.001318076	0.12226905	0.018562715	0.002658599	0.100886474	0.05495002

	Average of Units		Fossil	
5	Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546	22.30%	(535) Operation Supervision and Engineering
6	Coolants and Water (Nuclear Plants Only)	FERC Account 519	0.00%	
7	Steam Expenses	FERC Account 502, 520	5.76%	(536) Water for Power
8	Steam From Other Sources	FERC Account 503	11.13%	(537) Hydraulic Expenses
9	Electric Expenses	FERC Account 505, 523	0.00%	(538) Electric Expenses
10	Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524	3.41%	(539) Miscellaneous Hydraulic Power Generation Expenses
11	Rents	FERC Account 507	20.76%	(540) Rents
12	Allowances	FERC Account 509	0.84%	
13	Maintenance Supervision and Engineering	FERC Account 510, 528	0.00%	(541) Maintenance Supervision and Engineering
14	Maintenance of Structures	FERC Account 511, 529, 552	8.70%	(542) Maintenance of Structures
15	Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530	3.73%	(543) Maintenance of Reservoirs, Dams, and Waterways
16	Maintenance of Electric Plant	FERC Account 513, 531, 554	3.88%	(544) Maintenance of Electric Plant
17	Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532	4.83%	(545) Maintenance of Miscellaneous Hydraulic Plant
18	Other Power Production, & Other Expenses	FERC Account 548-553; 557	14.65%	
19	Total O&M		100.00%	

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Non-nuclear O&M Summary

	Componentized O&M		Chester	Conowingo	Croyden	Delaware Station	Eddy 3&4	Fairless Hills
20	Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546	38,422	3,736,335	569,237	81,528	3,742,503	1,706,571
21	Coolants and Water (Nuclear Plants Only)	FERC Account 519	-	-	-	-	-	-
22	Steam Expenses	FERC Account 502, 520	9,925	965,123	147,038	21,059	966,716	440,820
23	Steam From Other Sources	FERC Account 503	19,178	1,864,987	284,134	40,694	1,868,066	851,833
24	Electric Expenses	FERC Account 505, 523	-	-	-	-	-	-
25	Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524	5,876	571,384	87,051	12,468	572,328	260,980
26	Rents	FERC Account 507	35,759	3,477,388	529,786	75,877	3,483,129	1,588,297
27	Allowances	FERC Account 509	1,445	140,516	21,408	3,066	140,748	64,181
28	Maintenance Supervision and Engineering	FERC Account 510, 528	-	-	-	-	-	-
29	Maintenance of Structures	FERC Account 511, 529, 552	14,987	1,457,393	222,036	31,801	1,459,799	665,664
30	Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530	6,427	624,956	95,213	13,637	625,988	285,449
31	Maintenance of Electric Plant	FERC Account 513, 531, 554	6,686	650,181	99,056	14,187	651,254	296,970
32	Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532	8,322	809,240	123,289	17,658	810,576	369,620
33	Other Power Production, & Other Expenses	FERC Account 548-553; 557	25,242	2,454,627	373,967	53,560	2,458,680	1,121,151
34	Total O&M	Sum lines 20-33	172,268	16,752,129	2,552,217	365,535	16,779,786	7,651,534
35	A&G	Line 2	8,214	2,067,560	127,260	18,226	1,076,796	833,095
36	Depreciation	Line 3	7,267	6,605,136	129,843	18,596	6,764,751	3,643,397
37	Property, Payroll and Other Taxes	Line 4	5,780		87,293	27,880	3,170,443	263,599
		Total	193,529	25,424,824	2,896,613	430,238	27,791,776	12,391,625

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Non-nuclear O&M Summary

		Falls	Gould St.	Handsome Lake	Moser	Muddy Run	Notch Cliff	Pennsbury	Perryman
1	O&M	$ 332,898	$ 2,594,809	$ 2,331,757	$ 332,898	$ 2,087,224	$ 973,126	$ 1,056,155	$ 7,006,986
2	A&G	$ 16,599	$ 767,400	$ 713,054	$ 16,599	$ 1,887,948	$ 145,511	$ 95,853	$ 757,586
3	DEPR	$ 16,936	$ 1,041,577	$ 3,405,815	$ 16,936	$ 3,638,807	$ 2,297,886	$ 194,037	$ 7,335,545
4	OTR TX	$ 11,386	$ 653,648	$ 163,782	$ 11,386	$ 692,571	$ 222,581	$ 55,959	$ 2,143,070
		$ 377,819	$ 5,057,434	$ 6,614,408	$ 377,819	$ 8,306,550	$ 3,639,105	$ 1,402,004	$ 17,243,187
	LABOR -- These plants	$ 162,248	$ 395,908	$ 818,474	$ 162,248	$ -	$ 490,815	$ 488,053	$ 3,457,195
	LABOR -- Other fossil plants								
	TOTAL non-nuc labor								
	Non-nuclear allocators (these plants)	0.002421224	0.005908128	0.012214064	0.002421224	0	0.007324409	0.0072832	0.051591602

	Average of Units	Hydro	Conowingo	Muddy Run
5	Production Expenses: Oper, Supv, & Engr	6.19%	1,036,292	129,116
6	Coolants and Water (Nuclear Plants Only)		-	-
7	Steam Expenses	5.11%	855,810	106,629
8	Steam From Other Sources	30.43%	5,098,303	635,221
9	Electric Expenses	10.06%	1,685,208	209,968
10	Misc Steam (or Nuclear) Power Expenses	10.05%	1,684,113	209,831
11	Rents	1.45%	243,307	30,315
12	Allowances		-	-
13	Maintenance Supervision and Engineering	3.43%	575,100	71,654
14	Maintenance of Structures	4.13%	691,360	86,140
15	Maintenance of Boiler (or reactor) Plant	15.19%	2,545,004	317,094
16	Maintenance of Electric Plant	10.88%	1,823,125	227,151
17	Maintenance of Misc Steam (or Nuclear) Plant	3.07%	514,507	64,105
18	Other Power Production, & Other Expenses			
19	Total O&M	100.00%	16,752,129	2,087,224

NOTE: Fossil and Hydro expense distribution shares
&M

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Non-nuclear O&M Summary

	Componentized O&M	Falls	Gould St.	Handsome Lake	Moser	Muddy Run	Notch Cliff	Pennsbury	Perryman
20	Production Expenses: Oper, Supv, & Engr	74,248	578,737	520,067	74,248	465,527	217,043	235,561	1,562,813
21	Coolants and Water (Nuclear Plants Only)	-	-	-	-	-	-	-	-
22	Steam Expenses	19,179	149,492	134,337	19,179	120,249	56,064	60,847	403,686
23	Steam From Other Sources	37,061	288,876	259,591	37,061	232,367	108,337	117,580	780,076
24	Electric Expenses	-	-	-	-	-	-	-	-
25	Misc Steam (or Nuclear) Power Expenses	11,355	88,504	79,532	11,355	71,191	33,192	36,024	238,995
26	Rents	69,103	538,628	484,024	69,103	433,264	202,000	219,236	1,454,502
27	Allowances	2,792	21,765	19,559	2,792	17,508	8,163	8,859	58,774
28	Maintenance Supervision and Engineering	-	-	-	-	-	-	-	-
29	Maintenance of Structures	28,961	225,742	202,857	28,961	181,583	84,660	91,883	609,590
30	Maintenance of Boiler (or reactor) Plant	12,419	96,802	86,989	12,419	77,866	36,303	39,401	261,403
31	Maintenance of Electric Plant	12,920	100,709	90,500	12,920	81,009	37,769	40,991	271,954
32	Maintenance of Misc Steam (or Nuclear) Plant	16,081	125,347	112,639	16,081	100,827	47,008	51,019	338,484
33	Other Power Production, & Other Expenses	48,778	380,208	341,664	48,778	305,833	142,589	154,755	1,026,708
34	Total O&M	332,898	2,594,809	2,331,757	332,898	2,087,224	973,126	1,056,155	7,006,986
35	A&G	16,599	767,400	713,054	16,599	1,887,948	145,511	95,853	757,586
36	Depreciation	16,936	1,041,577	3,405,815	16,936	3,638,807	2,297,886	194,037	7,335,545
37	Property, Payroll and Other Taxes	11,386	653,648	163,782	11,386	692,571	222,581	55,959	2,143,070
		377,819	5,057,434	6,614,408	377,819	8,306,550	3,639,105	1,402,004	17,243,187

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Non-nuclear O&M Summary

		Philadelphia Road	Richmond	Riverside	Schuylkill	SCEP	Southwark	Westport
1	O&M	$ 662,620	$ 639,686	$ 413,844	$ 309,577	$ 2,061,381	$ 339,425	$ 880,575
2	A&G	$ 70,095	$ 31,896	$ 240,209	$ 395,698	$ 314,901	$ 16,925	$ 144,258
3	DEPR	$ 893,706	$ 32,544	$ 1,911,250	$ 9,250	$ 6,252,881	$ 17,268	$ 2,957,132
4	OTR TX	$ 264,526	$ 21,879	$ 379,744	$ 11,465	$ 150,320	$ 11,609	$ 775,741
		$ 1,890,947	$ 726,005	$ 2,945,046	$ 725,990	$ 8,779,484	$ 385,227	$ 4,757,705
	LABOR -- These plants	$ 166,220	$ 311,771	$ 106,446	$ 180,651	$ 947,230	$ 165,430	$ 472,641
	LABOR -- Other fossil plants							
	TOTAL non-nuc labor							
	Non-nuclear allocators (these plants)	0.002480492	0.004652548	0.001588492	0.002695846	0.014135483	0.002468699	0.007053208
	Average of Units							
5	Production Expenses: Oper, Supv, & Engr							
6	Coolants and Water (Nuclear Plants Only)							
7	Steam Expenses							
8	Steam From Other Sources							
9	Electric Expenses							
10	Misc Steam (or Nuclear) Power Expenses							
11	Rents							
12	Allowances							
13	Maintenance Supervision and Engineering							
14	Maintenance of Structures							
15	Maintenance of Boiler (or reactor) Plant							
16	Maintenance of Electric Plant							
17	Maintenance of Misc Steam (or Nuclear) Plant							
18	Other Power Production, & Other Expenses							
19	Total O&M							

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Non-nuclear O&M Summary

	Componentized O&M	Philadelphia Road	Richmond	Riverside	Schuylkill	SCEP	Southwark	Westport
20	Production Expenses: Oper, Supv, & Engr	147,788	142,673	92,302	69,047	459,763	75,704	196,400
21	Coolants and Water (Nuclear Plants Only)	-	-	-	-	-	-	-
22	Steam Expenses	38,175	36,854	23,842	17,835	118,760	19,555	50,732
23	Steam From Other Sources	73,768	71,215	46,073	34,465	229,490	37,788	98,033
24	Electric Expenses	-	-	-	-	-	-	-
25	Misc Steam (or Nuclear) Power Expenses	22,601	21,819	14,115	10,559	70,310	11,577	30,035
26	Rents	137,546	132,785	85,905	64,262	427,899	70,458	182,789
27	Allowances	5,558	5,366	3,471	2,597	17,291	2,847	7,386
28	Maintenance Supervision and Engineering	-	-	-	-	-	-	-
29	Maintenance of Structures	57,646	55,651	36,003	26,932	179,335	29,529	76,608
30	Maintenance of Boiler (or reactor) Plant	24,720	23,864	15,439	11,549	76,902	12,663	32,851
31	Maintenance of Electric Plant	25,717	24,827	16,062	12,015	80,006	13,174	34,177
32	Maintenance of Misc Steam (or Nuclear) Plant	32,009	30,901	19,991	14,955	99,578	16,397	42,538
33	Other Power Production, & Other Expenses	97,091	93,731	60,639	45,361	302,046	49,735	129,027
34	Total O&M	662,620	639,686	413,844	309,577	2,061,381	339,425	880,575
35	A&G	70,095	31,896	240,209	395,698	314,901	16,925	144,258
36	Depreciation	893,706	32,544	1,911,250	9,250	6,252,881	17,268	2,957,132
37	Property, Payroll and Other Taxes	264,526	21,879	379,744	11,465	150,320	11,609	775,741
		1,890,947	726,005	2,945,046	725,990	8,779,484	385,227	4,757,705

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Exhibit No. EXE-4

FOSSIL/HYDRO/NUCLEAR O AND M PROXY BREAKDOWN

Exhibit No. EXE-4
Schedule 1
Page 1

Fossil Proxy	%		Carpenter Common	Carpenter 1	Carpenter 2	Hot Spring E.	Lake Catheri	Lake Catherine	Mabelvale 1	Mabelvale 3	Remmel Cor	Remmel 1	Remmel 2	Remmel 3	White Bluff Co	White Bluff 1	White Bluff 2
92,922,409	22%	Production Expenses: Oper, Supv, & Engr	-	-	-	23,995	949,514	797,611	42,786	42,786	-	-	-	-	796,056	1,003,971	1,035,494
-	0%	Coolants and Water (Nuclear Plants Only)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24,002,539	6%	Steam Expenses	-	-	-	-		860,221	-	-	-	-	-	-	1,246,088	-	-
46,382,102	11%	Steam From Other Sources	118,335	2,033	3,651	-	-	-	-	-	129,832	374	48	64	-	-	-
-	0%	Steam Transferred (Cr)	-	-	-	-		-	-	-	-	-	-	-	-	-	-
14,210,289	3%	Electric Expenses	-	-	-	316,765	27,006	565,700	30,207	30,183	-	-	-	-	214,442	194,990	194,113
86,482,428	21%	Misc Steam (or Nuclear) Power Expenses	-	-	-	2,645	689,447	476,171	29,921	29,921	3,036	4,283	19,364	7,463	1,698,964	649,818	807,491
3,494,622	1%	Rents	152,778	1,373	1,420	23,898		19,394	3,590	2,912	109,982	189	142	189	67,422	22,304	22,960
-	0%	Allowances	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36,245,280	9%	Maintenance Supervision and Engineering	8,862	3,825	3,957	-	-	-	-	-	8,164	528	396	528	-	-	-
15,542,612	4%	Maintenance of Structures	81,679	-	-	23,814		20,833	26,654	12,628	6,101	-	-	-	533,515	26,579	26,160
16,169,950	4%	Maintenance of Boiler (or reactor) Plant	283,897	2,744	4,328	-	44,352	2,096,552	(31)	(31)	304,173	5,385	-	-	583,832	4,024,905	5,071,956
20,125,738	5%	Maintenance of Electric Plant	170,139	9,220	74,290	510	26,124	412,117	35,637	16,421	175,123	7,951	2,380	2,042	838,699	715,649	844,637
61,046,422	15%	Maintenance of Misc Steam (or Nuclear) Plant	63,031	2,899	2,999			27,817	(2,533)	(2,750)	219,066	6,081	300	400	1,097,751	(57,327)	(63,665)
416,624,391	100%																

Hydro Proxyy			Consumers		Appalachian		Penn. Power	
		C. Hydraulic Power Generation	1997	1996	1997	1996	1997	1996
	%	Operation						
3,757,027	7%	(535) Operation Supervision and Engineering	711614	650528	746048	845655	363490	439692
2,309,333	4%	(536) Water for Power	1014382	953299	12446	12594	171398	145214
19,420,852	35%	(537) Hydraulic Expenses	3487080	15259456	360910	550028	-236622	0
4,873,395	9%	(538) Electric Expenses	1377354	1410986	575818	431396	536990	540851
5,582,448	10%	(539) Miscellaneous Hydraulic Power Generation Expens	1035844	940865	1431736	1600768	345141	228094
940,895	2%	(540) Rents	-477	4251	366701	432695	68094	69631
1,898,369	3%	(541) Maintenance Supervision and Engineering	308118	307982	700537	508305	29419	44008
1,972,053	4%	(542) Maintenance of Structures	467378	841226	351287	267448	19903	24811
8,439,384	15%	(543) Maintenance of Reservoirs, Dams, and Waterways	2704111	2474125	545912	487416	2106109	121711
5,750,867	10%	(544) Maintenance of Electric Plant	886409	2354650	1119041	1071545	141498	177724
1,271,565	2%	(545) Maintenance of Miscellaneous Hydraulic Plant	463708	186369	203717	310246	46843	60682
56,216,188	100%							

Nuclear Proxy

row_literal	2013	2014	2015		
Plant Name	Prairie Island	Prairie Island	Prairie Island		
Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear	Nuclear	Nuclear		
Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional	Conventional		
Year Originally Constructed	1973	1973	1973		
Year Last Unit was Installed	1974	1974	1974		
Total Installed Cap (Max Gen Name Plate Ratings-MW)	1186.20	1186.20	1186.20		
Net Peak Demand on Plant - MW (60 minutes)	1106	1112	1109		
Plant Hours Connected to Load	8760	8760	8760		
Net Continuous Plant Capability (Megawatts)	1092	1092	1092		
When Not Limited by Condenser Water	1092	1092	1092		
When Limited by Condenser Water	1040	1040	1040		
Average Number of Employees	723	735	673		
Net Generation, Exclusive of Plant Use - KWh	7,714,143,000	8,383,200,000	7,374,711,000		
Cost of Plant: Land and Land Rights	361,732	361,732	361,732		
Structures and Improvements	244,334,949	272,770,914	302,394,576		
Equipment Costs	1,412,694,111	1,473,681,172	1,624,594,259		
Asset Retirement Costs	8,904,951		174,529,690		
Total Cost	1,666,295,743	1,921,343,508	2,101,880,257		
Cost per KW of Installed Capacity (line 17/5) Including	1,405	1,620	1,772		
Production Expenses: Oper, Supv, & Engr	46,343,435	47,983,862	40,006,456	44,777,918	19.23%
Coolants and Water (Nuclear Plants Only)	4,078,764	4,556,348	4,527,336	4,387,483	1.88%
Steam Expenses	25,788,024	29,153,538	27,619,391	27,520,318	11.82%
Steam From Other Sources	0	0	0	0	0.00%
Steam Transferred (Cr)	0	0	0	0	0.00%
Electric Expenses	2,813,977	3,438,751	2,181,969	2,811,566	1.21%
Misc Steam (or Nuclear) Power Expenses	74,225,075	80,830,743	78,156,514	77,737,444	33.39%
Rents	5,990,962	6,344,104	6,170,870	6,168,645	2.65%
Allowances	0	0	0	0	0.00%
Maintenance Supervision and Engineering	12,240,482	8,175,195	4,366,565	8,260,747	3.55%
Maintenance of Structures	599,086	646,661	685,835	643,861	0.28%
Maintenance of Boiler (or reactor) Plant	19,004,939	22,018,742	22,836,604	21,286,762	9.14%
Maintenance of Electric Plant	11,427,245	14,595,954	14,996,893	13,673,364	5.87%
Maintenance of Misc Steam (or Nuclear) Plant	19,359,524	25,519,990	31,861,122	25,580,212	10.99%
Total Production Expenses	301,006,168	321,890,212	298,442,774	232,848,319	100.00%

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FOSSIL/HYDRO/NUCLEAR O AND M PROXY BREAKDOWN

Independenc	Independenc	Independence	Lewis Creek C	Lewis Creek 1	Lewis Creek 2	Sabine Comr	Sabine 1	Sabine 2	Sabine 3	Sabine 4	Sabine 5	Attala Commor	Attala 1	Baxter Wilson (	Baxter Wilson '	Baxter Wilson 2	Gerald Andrus	Hinds	Rex Brown C	Rex Brown 3
589,763	180,315	186,810	1,022,737	280,436	276,310	572,066	1,011,112	327,866	228,084	667,875	529,098	384,027	462,483	1,725,269	491,166	646,639	2,030,826	383,104	475,043	66,184
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
400,540	9,328	10,293	176,623	158,475	158,476	1,576	2,140,696	239,126	9,258	256,020	1,320	-	-	1,095,523	604	3,404	210,897	-	698,609	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
655,554	64,921	69,433	159,070	321,056	321,089	(7,397)	822,176	17,900	193	8,681	11,204	138,346	105,307	880,997	351	492	6,739	287	237,196	49
927,195	166,199	210,269	1,526,917	474,071	439,983	255,145	2,340,189	140,684	116,882	214,632	259,115	1,959,873	1,844,598	1,018,238	325,619	440,534	1,414,611	375,707	485,621	47,908
17,889	4,956	4,987	22,550	12,414	10,127	13,965	14,562	8,023	8,023	10,572	12,426	84,056	48,599	20,956	15,359	15,545	52,020	7,026	21,313	1,187
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	189,901	103,719	105,694	77,860	113,135	39,170	77,595	116,195	88,561	125,727	19,903	112,435	95,032	45,119	394,213	5,136	105,942	3,136
235,432	12,201	20,167	391,586	6,999	3,602	17,085	758,600	20,840	2,683	1,264	5,575	25,394	129,021	203,785	16,656	9,830	319,219	321	454,505	2,804
313,768	572,775	1,945,625	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
178,895	465,873	1,744,069	391,586	6,999	3,602	17,085	758,600	20,840	2,683	1,264	5,575	25,394	129,021	203,785	16,656	9,830	319,219	321	454,505	2,804
511,970	98,824	132,334	47,577	1,291,036	354,581	578,463	194,439	569,732	602,192	1,041,243	2,718,114	-	-	448,944	1,702,939	2,074,040	1,799,798	-	294,660	108,184

SI-SSA-0010-2685

FOSSIL/HYDRO/NUCLEAR O AND M PROXY BREAKDOWN

Rex Brown 4	Rex Brown	Ouachita Common	Ouachita 1 EAI	Ouachita 2 EAI	Calcasieu Common	Calcasieu 1	Calcasieu 2	Nelson Common	Nelson 4 EGSL	Nelson 6 EGSL	Ouachita EGSL Common	Ouachita 3 EGSL	Riverbend 1 EGSL	Willow Glen Common	Willow Glen 2 EGSL	Willow Glen 4 EGSL	Acadia	Buras 8 ELL	Little Gypsy Common	Little Gypsy 1 ELL
243,458	15,119	1,243,949	193,536	200,288	84,155	220,634	236,629	12,543	732,073	791,446	623,144	523,647	21,554,396	1,103,665	301,890	718,995	835,641	19,620	1,094,367	249,299
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	128	139	(186,124)	709,982	592,307	-	195	6,418,645	990,682	20,604	11,232	-	29	816,413	11,197
-	-	-	-	-	-	-	-	-	-	-	-	-	22,033,918	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
148	7	90,723	221,279	182,824	496,832	4,105	4,463	(97,967)	1,351,266	1,101,362	45,807	222,897	-	25,904	10,237	86,879	-	245	827,310	3,149
132,992	5,924	969,428	183,384	188,438	243,019	296,338	166,808	149,631	564,742	91,503	482,236	400,403	22,852,424	1,102,933	199,890	509,228	1,940,062	42,508	1,158,356	141,206
10,621	172	17,412	13,424	11,752	13,525	4,170	4,534	4,631	18,895	16,061	7,151	11,980	767,496	18,849	16,892	19,375	2,331	312	18,581	9,615
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61,001	126	169,602	45,054	43,108	11,040	4,802	5,221	350,339	57,336	278,877	76,959	10,339	12,455,781	36	28,187	23,212	-	3,971	396,549	61,043
34,980	8	108,270	56,631	77,836	6,311	9,904	1,388	13,704	38,322	328,334	54,284	16,827	4,639,802	560,525	20,867	25,538	-	14	171,360	124,101
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)	(0)
34,980	8	-	-	-	6,311	9,904	1,388	13,704	38,322	328,334	54,284	16,827	4,639,802	560,525	20,867	25,538	-	14	171,360	124,101
402,633	-	-	-	-	-	51	56	185,358	1,332,439	4,116,476	-	79	11,187,705	282,786	1,225,725	662,140	-	(3)	564,882	655,899

SI-SSA-0010-2686

FOSSIL/HYDRO/NUCLEAR O AND M PROXY BREAKDOWN

Little Gypsy 2 ELL	Little Gypsy 3 ELL	Ninemile Common	Ninemile 3 ELL	Ninemile 4 ELL	Ninemile 5 ELL	Perryville Common	Perryville 1 ELL	Perryville 2 ELL	Sterlington 7 ELL	Waterford 1 & 2 Common	Waterford 1 ELL	Waterford 2 ELL	Waterford 3 ELL	Waterford 4 ELL	Michoud Common	Michoud 2 ENO	Michoud 3 ENO	Total ETI	Nelson 6 Common	Nelson 6 ETI
418,399	570,591	1,113,948	135,336	777,399	823,047	700,420	530,535	160,405	383,483	359,408	545,536	391,600	27,120,515	801	2,619,608	550,298	646,480	-	148,012	529,536
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
654	29,281	1,061,075	3,199	16,033	3,459	-	843	234	31,931	769,722	617	617	4,132,587	-	96,677	2,223	47,036	-	2,312	410,685
-	-	-	-	-	-	-	-	-	-	-	-	-	24,093,846	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5,626	7,394	1,369,061	2,219	13,141	10,931	622,018	7,252	29,452	19,863	690,320	5,303	5,303	-	4,886	101,758	19,179	43,596	-	(183)	788,865
256,565	333,546	1,286,836	155,467	457,885	431,989	2,561,721	315,945	89,925	336,009	747,398	302,441	231,056	23,345,613	22	745,467	197,328	359,587	-	234,335	970,340
12,773	19,110	30,932	2,220	19,073	19,320	31,500	9,332	2,565	19,785	16,478	17,102	13,531	1,320,801	-	15,636	11,443	17,511	-	11,379	9,394
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47,232	69,891	568,013	23,955	67,341	65,466	323,255	30,920	12,552	54,449	154,107	133,902	25,018	18,201,375	-	249,100	47,640	52,779	-	3,702	187,269
58,260	156,785	1,227,675	10,069	237,706	86,888	65,958	410	1,375	145,593	184,768	22,846	15,699	1,975,554	2,828	468,685	15,137	65,270	-	90,052	241,281
(0)	(0)	(3)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(5)	(0)	-	-	-	-	-	-
58,260	156,784	1,227,671	10,069	237,705	86,887	65,958	410	1,375	145,593	184,767	22,846	15,699	1,975,549	2,828	468,685	15,137	65,270	-	-	-
283,612	915,059	644,926	211,751	2,364,175	2,444,491	-	(97)	(27)	63,382	638,489	436,526	415,039	8,308,669	-	110,861	1,727,417	1,892,220	-	10,805	3,019,347

SI-SSA-0010-2687

SERVICE LIVES OF GENERATING STATIONS

		Commer.	Retr. Or License	Yrs	Avg	
Braidwood	#1	7/88		2046	58	58.5
	#2	10/88		2047	59	
Byron	#1	9/85		2044	59	59
	#2	8/87		2046	59	
Dresden	#2		1970	2030	60	60
	#3		1971	2031	60	
LaSalle	#1	1/84				60
	#2	10/84				
Limerick	#1	2/86		2044	58	58.5
	#2	1/90		2049	59	
Oyster Ck	#1	12/69		2019		50
			(Exelon stated ret. date)			
Peach Bottom	#2	7/74		2033	59	59.5
	#3	12/74		2034	60	
Quad Cities	#1	12/72		2018	46	46
	#2	12/72		2018	46	
			(Exelon stated ret. date)			
Salem	#1	6/77		2036	59	59
	#2	10/81		2040	59	
TMI	#1	9/74		2034	60	60
Chester			1969	2033	64	
Conowingo			1929	2045	116	116
Croydon			1974	2033	59	
Delaware			1968	2033	65	
Eddystone			1968	2033	65	
Fairless Hills			1996	2023	27	
Falls			1970	2033	63	
Gould St	#3		1951	2025	74	
Handsome Lake			2001	2041	40	
Moser			1970	2033	63	
Muddy Run			1968	2045	77	77
Notch Cliff			1969	2028	59	
Pennsbury					50 (est)	
Perryman	1- 4		1972	2033	61	
Perryman		5	1995	2033	38	45
Perryman		6	2015	2055	40	
Perryman Ave					41	
Philadelphia Rd			1970	2025	55	
Richmond			1973	2033	60	
Riverside	#5		1970	2025	55	
Schuylkill			1970	2033	63	
SE Chicago	8-NG		2002	2032	30	
Southwark			2002	2033	31	
Westport			1969	2022	53	

		2015
ExGen Corp Operating Expenses - Before Co-Owner Billing Credits	$	431,826,224
Adjustments:		
UK	$	(6,405,867)
ENP	$	(4,135,773)
Exclusions	$	12,996,813
ExGen Corp. to Allocate	**$**	**434,281,397**
Constellation Unit-Related OH to Allocate	**$**	**164,975,502**
Constellation Wholesale - Unit Related	$	92,544,129
Constellation Wholesale - Not-Unit Related	$	68,977,996
Constellation Retail	$	204,635,410
Power Site	$	122,670,995
Nuclear Site	$	1,222,684,098
UK	$	601,754
ENP	$	2,520,783
Total Labor	**$**	**1,714,635,165**
% Unit-Related		83.9%
% Non-Unit-Related		16.1%
ExGen Corp OH to Allocate	$	434,281,397
Amount Allocated to Power	$	33,207,250
Amount Allocated to Nuclear	$	330,982,693
Total ExGen Corp. OH Allocated to Generation Units	$	364,189,943
Constellation Unit-Related OH to Allocate	$	164,975,502
Amount Allocated to Power	$	15,042,652.42
Amount Allocated to Nuclear	$	149,932,850
Total Constellation Unit-Related OH Allocated to Generation Units	$	164,975,502
Amount Allocated to Power	$	48,249,902
Amount Allocated to Nuclear	$	480,915,543
Total Allocated to Generation Units	$	529,165,445

A

PA Maintenance (58502, 58722)	% of Effort - MW	% of Effort - MWh	Management Estimate %	FTE Equivalent
Eddystone	37%	57%	60%	
Fairless/Pennsbury	18%	17%	20%	
PA CT's/Lamokin	45%	26%	20%	
SCEP	0%	0%	0%	0
Handsome Lake	0%	0%	0%	0
Total	100%	100%	100%	0

PA Maintenance – PA maintenance Staff & related expenses

B

PA Admin (58720)	% of Effort - MW	% of Effort - MWh	Management Estimate %	FTE Equivalent
Eddystone	24%	26%	30%	
Fairless/Pennsbury	2%	8%	15%	
PA CTs	28%	12%	5%	
SCEP	9%	5%	0%	
Handsome Lake	8%	5%	5%	
MD CTs & GS	29%	44%	45%	
Total	100%	100%	100%	0%

PA Admin – Peaking Administrative Support & Overhead

C

MD Admin/Maintenance (58711, 83023, 83093, 83095, 83098)	% of Effort - MW	% of Effort - MWh	Management Estimate %	FTE Equivalent
MD Gas (incl GS3)	36%	36%	20%	
MD Oil	33%	6%	10%	
Perryman 51/6	30%	58%	60%	
SCEP (Admin only)			10%	
Total	100%	100%	100%	0%

MD Admin – MD Headcount and Support. Roughly 35 FTEs

NEW ALLOCATORS (A, B, C MAPPED TO "D")

A

PA Maintenance (58502, 58722)	% of Effort - MW	% of Effort - MWh	Management Estimate %	FTE Equivalent
Eddystone	37%	57%	60.00%	
Fairless/Pennsbury	18%	17%	20.00%	
Croydon	16%	12%	8.81%	
Chester	2%	1%	0.88%	
Delaware	3%	1%	1.26%	
Eddystone CTs	4%	1%	1.35%	
Falls	3%	1%	1.15%	
Moser	3%	1%	1.15%	
Southwark	3%	1%	1.17%	
Richmond	6%	3%	2.21%	
Schuylkill	2%	1%	0.67%	
SCEP	0%	0%	0.00%	0
Handsome Lake	0%	0%	0.00%	0
Total	96%	97%	98.65%	0

<Less than 100% because Lamokin excluded

B

PA Admin (58720)	% of Effort - MW	% of Effort - MWh	Management Estimate %	FTE Equivalent
Eddystone	24%	26%	30.00%	
Fairless/Pennsbury	2%	8%	15.00%	
Croydon	12%		2.20%	
Chester	1%	0%	0.22%	
Delaware	2%	1%	0.32%	
Eddystone CTs	2%	1%	0.34%	
Falls	2%	1%	0.29%	
Moser	2%	1%	0.29%	
Southwark	2%	1%	0.29%	
Richmond	3%	1%	0.55%	
Schuylkill	1%	0%	0.17%	
SCEP	9%	5%	0.00%	
Handsome Lake	8%	5%	5.00%	
Perryman 1-4			14.59%	
Phila Rd			4.31%	
Riverside 7/8			2.76%	
Westport 5			8.20%	
Gould St 3			6.87%	
Notch Cliff			8.26%	
MD CTs & GS	29%	44%	0.00%	
Total	98%	93%	99.66%	0%

<Spread on MW

<Less than 100% because Lamokin excluded

CALCULATED VALUES

MD Admin/Maint Calculated (incl share of PA Admin)	MW	% of Effort - MW	% of Effort - MWh	Calculated Weight	FTE Equivalent
Perryman 1-4	206	23%	4%	6.73%	
Perryman 51	147.6	16%	28%	31.79%	
Perryman 6	131	14%	30%	28.21%	
Phila Rd	60.9	7%	1%	1.99%	
Riverside 7/8	39	4%	1%	1.27%	
Westport 5	115.8	13%	14%	7.03%	
Gould St 3	97	11%	13%	5.89%	
Notch Cliff	116.7	13%	9%	7.08%	
Total	914	100%	100%	90.00%	
SCEP		*0%*	*0%*	*10.00%*	

PA CTs Share of PA Maintenance	MW	% of Effort - MW	% of Effort - MWh	Calculated Weight	FTE Equivalent
Croydon	391	16%	12%	8.81%	
Chester	39	2%	1%	0.88%	
Delaware	56	3%	1%	1.26%	
Eddystone CTs	60	4%	1%	1.35%	
Falls	51	3%	1%	1.15%	
Moser	51	3%	1%	1.15%	
Southwark	52	3%	1%	1.17%	
Richmond	98	6%	3%	2.21%	
Schuylkill	30	2%	1%	0.67%	
Lamokin	60	4%	3%	1.35%	
Total	888	45%	26%	20.00%	0%
Eddystone 3/4 and Fairless		*55%*	*74%*	*80%*	

D

PA CTs Share of PA Admin	MW	% of Effort - MW	% of Effort - MWh	Calculated Weight	FTE Equivalent
Croydon	391	12%	5%	2.20%	
Chester	39	1%	0%	0.22%	
Delaware	56	2%	1%	0.32%	
Eddystone CTs	60	2%	1%	0.34%	
Falls	51	2%	1%	0.29%	
Moser	51	2%	1%	0.29%	
Southwark	52	2%	1%	0.29%	
Richmond	98	3%	1%	0.55%	
Schuylkill	30	1%	0%	0.17%	
Lamokin	60	2%	2%	0.34%	
Total	888	28%	12%	5.00%	0%
Eddystone 3/4, Fairless, SCEP, Handsome Lake, MD CT/GS		*72%*	*88%*	*95%*	

PA CTs Share of PA CT Ops	MW	% of Effort - MW	% of Effort - MWh	Calculated Weight	FTE Equivalent
Croydon	391	47%	52%	47%	
Chester	39	5%	4%	5%	
Delaware	56	7%	6%	7%	
Eddystone	60	7%	6%	7%	
Falls	51	6%	5%	6%	
Moser	51	6%	5%	6%	
Southwark	52	6%	5%	6%	
Richmond	98	12%	14%	12%	
Schuylkill	30	4%	3%	4%	
Total	828	100%	100%	100%	0%

MD Admin/Maintenance (58711, 83023, 83093, 83095, 83098)		% of Effort - MW	% of Effort - MWh	Management Estimate %	FTE Equivalent
Perryman 1-4	206	23%	4%	6.73%	
Perryman 51	147.6	16%	28%	31.79%	
Perryman 6	131	14%	30%	28.21%	
Phila Rd	60.9	7%	1%	1.99%	
Riverside 7/8	39	4%	1%	1.27%	
Westport 5	115.8	13%	14%	7.03%	
Gould St 3	97	11%	13%	5.89%	
Notch Cliff	116.7	13%	9%	7.08%	
SCEP (Admin only)				10.00%	
Total		100%	100%	100.00%	0%

Accessory Equip Allocator Account 315, 324, 334, 345
NUCLEAR FLEET
The following allocation factors pertain to the nuclear fleet. The values are based on a very general assessment of plant design and a subjective interpretation of the category definitions using Exhibit A-38 as guidance. There was no review performed of actual design information or plant accounting dollars to support the development of the allocation factors provided below.

Item		Comment
Storage Batteries	15%	A large portion of storage station battery capacity is dedicated to nuclear safety-related functions such as numerous valve actuators, back-up inverters and relaying/ annunciators/controls. The remaining balance-of-plant battery capacity would be largely dedicated to the seal oil and lube oil backup pumps.
Control&Power Cabling	1%	AVR/ generator / exciter cabling is very small when compared to the overall control and power cable systems in a nuclear generating facility.
Switch Board Equipment	1%	The nuclear plant control rooms contain a vast array of switchboard equipment dedicated to plant functions not associated with vendor supplied package systems. The allocation to AVR, exciter, and generator would be a relatively small component of the non-packaged systems.
Switching Equipment	1%	This category excludes main generator breakers. The remaining switching equipment associated with generator / exciter is fraction of the large switching network in a nuclear facility. The largest would be the seal oil pumps (AC and DC), lube oil pumps (AC and DC), stator water pumps, and AVR contactor / field circuit breaker. The transmission system operators (PECo, ComEd, etc.) on the PJM system own the Exelon nuclear plant output circuit breakers, with the exception of TMI and Nine Mile Point whose breakers are Exelon owned.
Transformers	3%	As instructed during the 8/5/16 telecon, this account does not include the main transformer (GSU). The excitation system power is self-fed from the turbine generator such that no significant auxiliary transformer power is used. Aux power is supplied to the lube oil, seal oil and stator water pumps, and miscellaneous equipment. The capacity is no more than 3% of the total auxiliary power.
Aux Generator	0%	The main generator and exciter would be off-line when the emergency and station black out diesel generators are in use. They do not contribute to main generator power generation.
Fire Protection System	0%	As instructed during the 8/5/16 telecon, the fire deluge system to mitigate shaft seal oil and hydrogen fires is not in this account.
HVAC	0%	As instructed during the 8/5/16 telecon, HVAC is not allocated in this account.
Regulating Equipment	50%	The main generator Automatic Voltage Regulator (AVR) used to control excitation (and VAR generation) is significant, but its allocation factor is reduced by other regulating systems such as the Reactor Recirc ASDs, battery inverters, etc.
Structure	0%	As instructed during the 8/5/16 telecon, HVAC is not allocated in this account.
Misc.	0%	None
Exciter & PPT	100%	The AVR, exciter, and subsystems are control reactive power generation
Station Grounding	1%	The AVR / Exciter Generator is relatively simple and a small subset of all equipment grounding in the plant. The generator armature uses a distribution transformer to achieve grounding, but the overall allocation of capital for this system is small when compared to the grounding installations through in the plant.
Bus & Insulators	80%	The IsoPhase bus and switchyard high voltage insulator systems comprise a major portion of this category when compared to the remaining plant buses.
Capacitor Bank	0%	Capacitor banks are used to control reactive power. However, they are the property of the transmission system owner.

Accessory Equipment Allocator -- FOSSIL & HYDRO

	CTs	Notes (Combustion Turbine Units)	Hydro & Steam Units	Notes (Hydro & Steam Units)
Storage Batteries	50%	Battery load is split between equipment directly related to power production (generator emergency lube oil, seal oil pump) and auxiliary load (fire pump, relays, etc.)	30%	A significant percentage of battery load at Hydro and Steam units relates to plant auxiliary equipment (fire pump, auxiliary dc circuits, relays, etc.).
Control & Power Cabling	50%	This percentage most likely reflects DCS, exciter, AVR, and breaker DC load as compared to total control and power cabling load. Other load reflects control and powering of auxiliary equipment such as annunciators, fuel valves, fire protection, auxiliary breaker, etc. as well as any cabling associated with 480V AC systems.	15%	A significant percentage of control and power cabling at Hydro and Steam sites is associated with auxiliary systems. 15% is assumed to be the load related directly to power generation.
Switch Board Equipment	50%	This portion is made up of relaying, annunciators, exciter, AVR, or DCS controls relating to generator or transformer as compared to plant auxiliaries.	30%	This portion is made up of relaying, annunciators, exciter, AVR, or DCS controls relating to generator or transformer as compared to plant auxiliaries.
Switching Equipment	40%	This percentage is made up of generator breakers and auxiliary breakers supplying power to equipment such as lube oil pumps.	20%	This percentage is made up of generator breakers and auxiliary breakers supplying power to equipment such as lube oil pumps.
Transformers	10%	Most of the auxiliary load that transformers serve does not relate directly to power production, such as water treatment, fire pump, CEMS module distribution power, etc. This number excludes GSUs.	5%	This is assumed to be the portion of total transformer investment serving load relatable to power production (oil pumps, etc.) This number excludes GSUs.
Aux. Generator	0%	None present directly for power generation - only for backup power.	0%	None present directly for power generation - only for backup power.
Fire Protection System	0%	No direct contribution towards power generation.	0%	No direct contribution towards power generation.
HVAC	0%	No direct contribution towards power generation.	0%	No direct contribution towards power generation.
Regulating Equipment	75%	The Automatic Voltage Regulator (AVR) is directly attributed towards power production, but Static Frequency Converters (SFCs), including static start systems, or motor control equipment are not.	75%	The Automatic Voltage Regulator (AVR) is directly attributed towards power production, but Static Frequency Converters (SFCs), including static start systems, or motor control equipment are not.
Structure	0%	No direct contribution towards power generation.	0%	No direct contribution towards power generation.
Misc.	0%	No direct contribution towards power generation.	0%	No direct contribution towards power generation.
Exciter & PPT	100%	All such equipment used for control of power produced (MVARs).	100%	All such equipment used for control of power produced (MVARs).
Station Grounding	5%	5% is assumed to be the cost of generator and transformer neutral grounding as compared to the entire site grounding system.	0%	Generator and transformer neutral grounding is a very small percentage of total grounding at Hydro and Steam sites.
Bus & Insulators	80%	The majority of bus-work in Combustion Turbine (CT) sites runs from generator to generator breaker and towards to point-of-interconnection.	60%	This is an estimate of bus-work running from generator to point-of-interconnection as compared to other bus-work that exists on site.
Capacitor Bank	0%	Item not owned by Generation.	0%	Item not owned by Generation.

Perryman 6 General Ledger Balances

Company	Utility Account	Retirement Unit	Major Location	Gl Account	Month	Book Cost	Ldg Work Order Number
20028 Constell Power Src Gen	GEN 341.03 CMBT-Str & Impvm-Gas	Non-unitized	Perryman - Unit 6	106000 Complete const not class	Dec-16	$1,161,091.54	028C13013
20028 Constell Power Src Gen	GEN 342.03 CMBT-Fuel Holdrs-Gas	Non-unitized	Perryman - Unit 6	106000 Complete const not class		$1,161,091.54	028C13013
20028 Constell Power Src Gen	GEN 344.03 CMBT-Generators-Gas T	Non-unitized	Perryman - Unit 6	106000 Complete const not class	Dec-16	$88,242,960.94	028C13013
20028 Constell Power Src Gen	GEN 345.03 CMBT-Acces Elec-Gas T	Non-unitized	Perryman - Unit 6	106000 Complete const not class		$20,899,648.61	028C13013
20028 Constell Power Src Gen	GEN 346.03 CMBT-Misc Pwr Plt-Gas	Non-unitized	Perryman - Unit 6	106000 Complete const not class	Dec-16	$4,644,366.29	028C13013
20028 Constell Power Src Gen	GEN 346.09 CCGT-Misc Equip	Non-unitized	Perryman - Unit 6	106000 Complete const not class	Dec-16	$0.00	028C13013
						$116,109,158.92	

Summary of Heating Losses

	BWD 1	BWD 2	BYR 1	BYR 2	DRE 2	DRE 3	LAS 1	LAS 2	LIM 1	LIM 2	OYS	PEA 2	PEA 3	QDE 1	QDE 2	TMI	Fleet Total
Fuel Cost ($ / MW Hr)	**$6.48**	**$7.09**	**$7.03**	**$6.92**	**$6.96**	**$6.65**	**$6.56**	**$6.98**	**$5.95**	**$6.00**	**$6.18**	**$6.63**	**$6.41**	**$6.67**	**$6.73**	**$6.82**	
	Based on Individual Hour Computations - Negative VARs Excluded																
Gen Field Annual Loss (MW Hr)	5,345.88	5,602.13	4,159.74	3,646.64	1,101.13	2,048.68	2,430.62	2,808.18	360.73	721.05	1,099.61	202.87	249.84	1,716.19	1,897.71	35.04	
Gen Armature Annual Loss (MW Hr)	1,214.95	1,309.73	920.12	779.96	1,001.02	1,686.71	732.18	619.69	81.33	175.06	1,037.40	419.16	728.47	4,399.95	4,697.61	11.12	
GSU Annual Loss (MW Hr)	616.43	431.05	466.34	380.66	228.99	343.48	347.20	415.05	27.46	59.25	430.45	33.10	66.25	658.41	702.78	10.26	
Total Annual Loss (MW Hr)	7,177.27	7,342.91	5,546.20	4,807.26	2,331.14	4,078.87	3,510.00	3,842.91	469.52	955.36	2,567.46	655.12	1,044.56	6,774.55	7,298.09	56.41	
Cost of Heating Loss (Annual)	46,518.74	52,067.84	39,001.98	33,252.30	16,219.62	27,122.87	23,036.50	26,818.93	2,794.47	5,728.05	15,872.31	4,343.33	6,696.68	45,210.61	49,148.25	384.63	394,217.11

SI-SSA-0010-2694

Attachment G

Attestation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Constellation Power Source Generation, LLC	)	**Docket No. ER17-801-001**
Exelon Generation Company, LLC	)	**Docket No. ER17-802-001**
Handsome Lake Energy, LLC	)	**Docket No. ER17-803-001**

ATTESTATION OF ALAN C. HEINTZ

I, Alan C. Heintz, being duly sworn, do depose and say that I am a Vice President of Brown, Williams, Moorhead & Quinn, Inc., that I am acting on behalf of Constellation Power Source Generation, LLC, Exelon Generation Company, LLC, and Handsome Lake Energy, LLC in the above-referenced proceedings, that I have reviewed amended Exhibit No. EXE-3 and amended Exhibit No. EXE-4 submitted herewith, and that to the best of my knowledge, information, and belief, the cost of service data in the amended exhibits is true and accurate.

Dated at the District of Columbia this 25th day of January, 2017.

Alan C. Heintz

Subscribed and sworn before me
this 25th day of January, 2017

Notary Public

My Commission expires:

STEPHANIE J. WILKERSON
NOTARY PUBLIC DISTRICT OF COLUMBIA
My Commission Expires June 30, 2019

STEPHANIE J. WILKERSON NOTARY PUBLIC MY COMMISSION EXPIRES 6/30/2019 DISTRICT OF COLUMBIA

Exelon

March 27, 2017

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Docket Nos. RM05-15-000; RM94-14

Enclosed please find our annual Federal Energy Regulatory Commission (FERC) financial report as produced by our trustee, The Northern Trust Company. The Exelon Generation Company, LLC units are reported as follows:

- those formerly owned by Commonwealth Edison Company (Braidwood 1 & 2, Byron 1 & 2, Dresden 1, 2 & 3, LaSalle 1& 2, Zion 1& 2 and Quad Cities 1 & 2) – the reports are consolidated for the Tax Qualified and Non-Tax Qualified Trusts;

- those formerly owned by PECO Energy Company (Limerick 1 & 2, Salem 1 & 2, and Peach Bottom 1, 2 & 3) - the reports are consolidated for the Tax Qualified and Non-Tax Qualified Trusts; and

- those formerly owned by AmerGen Energy Company, LLC the reports are provided separately for each of the three units (TMI, Oyster Creek and Clinton) and the reports are consolidated for Tax Qualified and Non-Tax Qualified Trusts.

In 2016, there were no decommissioning expenses paid out of any Exelon units and only the legacy PECO units received rate payer contributions.

The FERC Jurisdictional allocation has been incorporated into our annual filing.

There has not been an opinion expressed on any of the attached reports by an independent public accountant, therefore none is enclosed.

If you have any questions, please contact me at (312) 394-3956.

Sincerely,

Brian E. Andersen

Brian E. Andersen
Managing Director, Public Markets and NDT Investments

Clinton

SI-SSA-0010-2698

Change in Book and Market Value

	Cost	Market value	For more information
Opening balance	399,965,055.65	485,059,663.65	Beginning Balance / Assets
Miscellaneous Cash Receipts	1,577,365.21	1,577,365.21	See funding & disbursement summary
Interportfolio Transfers In	109,218,074.80	109,218,074.80	See funding & disbursement summary
Security Receipts	0.00	0.00	See funding & disbursement summary
Total receipts	110,795,440.01	110,795,440.01	See funding & disbursement summary
Miscellaneous Cash Disbursements	- 1,577,365.21	- 1,577,365.21	See funding & disbursement summary
Interportfolio Transfers Out	- 116,517,498.53	- 116,517,498.53	See funding & disbursement summary
Total disbursements	- 118,094,863.74	- 118,094,863.74	See funding & disbursement summary
Income received	10,900,842.19	10,900,842.19	See income & expense summary, cash activity detail
Expenses paid Fund expenses / taxes	- 6,978,773.76	- 6,978,773.76	See income & expense summary
Unrealized gain/loss change	0.00	22,923,745.70	See asset summary
Realized gain/loss Gain / Loss	2,634,481.89	2,634,481.89	See realized gain/loss summary
Accrued income change	- 211,940.30	- 211,940.30	See income & expense summary
Total amortization expense	- 1,181,580.56	- 1,181,580.56	See fixed income amortization
Total OID/MKT accretion income	408,407.56	408,407.56	See fixed income amortization
Return of capital	- 86,040.58	- 86,040.58	See capital change detail
Closing balance	398,151,028.36	506,169,382.06	Ending Assets

No Rate Payer Contributions
No Decommissioning expense

SI-SSA-0010-2699

◆ Change in Cash Value

	Market value	Cost	For more information
Opening balance	7,102,111.58	7,102,286.87	
Miscellaneous cash receipts	1,577,365.21	1,577,365.21	See funding & disbursement summary
Interportfolio transfers in	109,218,074.80	109,218,074.80	See funding & disbursement summary
Total receipts	110,795,440.01	110,795,440.01	See funding & disbursement summary
Miscellaneous cash disbursements	- 1,577,365.21	- 1,577,365.21	See funding & disbursement summary
Interportfolio transfers out	- 116,517,498.53	- 116,517,498.53	See funding & disbursement summary
Total disbursements	- 118,094,863.74	- 118,094,863.74	See funding & disbursement summary
Income received	10,900,330.51	10,900,330.51	See income & expense summary, cash activity detail
Expenses paid	- 6,978,773.76	- 6,978,773.76	See income & expense summary
Capital changes	6,916,517.05	6,916,517.05	See capital change detail
Foreign currency bought	5,413,976.62	5,413,976.62	See foreign exchange summary
Foreign currency sold	- 5,413,976.62	- 5,413,976.62	See foreign exchange summary
Realized gain/loss	- 2,869.70	- 2,869.70	See realized gain/loss summary
Unrealized gain/loss	- 2,307.22	0.00	See asset summary
Securities bought Purchases	- 133,808,569.14	- 133,808,569.14	See investment transaction summary
Securities sold Sales	130,604,148.47	130,604,148.47	See investment transaction summary
Principal paydowns	109,326.47	109,326.47	See investment transaction summary
Closing balance	7,540,490.53	7,542,973.04	

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Adjustments To Cash								
Pending trade purchases			Beginning liability					
Pending trade purchases	0.00	- 1,597,099.33	- 1,597,100.31	0.00	0.98	0.98	-1,597,099.33	- 0.329%
Total pending trade purchases	**0.00**	**- 1,597,099.33**	**- 1,597,100.31**	**0.00**	**0.98**	**0.98**	**-1,597,099.33**	**- 0.329%**
Pending trade sales								
Pending trade sales	0.00	2,008,993.77	2,008,993.77	0.00	0.00	0.00	2,008,993.77	0.414%
Total pending trade sales	**0.00**	**2,008,993.77**	**2,008,993.77**	**0.00**	**0.00**	**0.00**	**2,008,993.77**	**0.414%**
Total adjustments to cash	**0.00**	**411,895.74**	**411,893.46**	**0.00**	**2.28**	**2.28**	**411,895.74**	**0.085%**
Total Unrealized Gains						**103,871,414.73**		
Total Unrealized Losses						**- 18,776,806.73**		
Total	**1,727,843.69**	**483,331,819.96**	**398,237,211.96**	**89,126,974.44**	**-4,034,366.44**	**85,094,608.00**	**485,059,663.65**	**100.000%**

Total Cost incl. Accruals **399,965,055.65**

SI-SSA-0010-2701

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Translation	Total	Market value incl. accruals	%
All Other								
Recoverable taxes								
Recoverable taxes	58,622.56	0.00	0.00	0.00	0.00	0.00	58,622.56	0.012%
Total recoverable taxes	**58,622.56**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**58,622.56**	**0.012%**
Total all other	**58,622.56**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**58,622.56**	**0.012%**
Cash and Cash Equivalents								
Funds - short term investment								
Funds - Short Term Investment	1,483.58	5,203,673.44	5,203,673.44	0.00	0.00	0.00	5,205,157.02	1.028%
Total funds - short term investment	**1,483.58**	**5,203,673.44**	**5,203,673.44**	**0.00**	**0.00**	**0.00**	**5,205,157.02**	**1.028%**
Cash								
Cash	- 13.43	151,263.83	153,746.34	0.00	-2,482.51	- 2,482.51	151,250.40	0.030%
Total cash	**- 13.43**	**151,263.83**	**153,746.34**	**0.00**	**-2,482.51**	**- 2,482.51**	**151,250.40**	**0.030%**
Invested cash								
Invested cash	408.90	2,185,553.26	2,185,553.26	0.00	0.00	0.00	2,185,962.16	0.432%
Total invested cash	**408.90**	**2,185,553.26**	**2,185,553.26**	**0.00**	**0.00**	**0.00**	**2,185,962.16**	**0.432%**
Total cash and cash equivalents	**1,879.05**	**7,540,490.53**	**7,542,973.04**	**0.00**	**-2,482.51**	**- 2,482.51**	**7,542,369.58**	**1.490%**
Adjustments To Cash								
Pending trade purchases		Ending liability						
Pending trade purchases	0.00	- 424,601.71	- 424,601.71	0.00	0.00	0.00	-424,601.71	- 0.084%
Total pending trade purchases	**0.00**	**- 424,601.71**	**- 424,601.71**	**0.00**	**0.00**	**0.00**	**-424,601.71**	**- 0.084%**
Pending trade sales								
Pending trade sales	0.00	134,147.68	134,147.68	0.00	0.00	0.00	134,147.68	0.027%
Total pending trade sales	**0.00**	**134,147.68**	**134,147.68**	**0.00**	**0.00**	**0.00**	**134,147.68**	**0.027%**
Total adjustments to cash	**0.00**	**- 290,454.03**	**- 290,454.03**	**0.00**	**0.00**	**0.00**	**-290,454.03**	**- 0.057%**

Oyster Creek

SI-SSA-0010-2703

◆ Change in Book and Market Value

	Cost	Market value	For more information
Opening balance	692,603,313.01	836,445,774.29	Beginning Assets
Interportfolio Transfers In	276,847,265.03	276,847,265.03	See funding & disbursement summary
Security Receipts	0.00	0.00	See funding & disbursement summary
Total receipts	276,847,265.03	276,847,265.03	See funding & disbursement summary
Interportfolio Transfers Out	- 289,434,525.03	- 289,434,525.03	See funding & disbursement summary
Security Deliveries	0.00	0.00	See funding & disbursement summary
Total disbursements	- 289,434,525.03	- 289,434,525.03	See funding & disbursement summary
Income received	19,062,581.47	19,062,581.47	See income & expense summary, cash activity detail
Expenses paid Fund expenses / taxes	- 7,503,606.09	- 7,503,606.09	See income & expense summary
Unrealized gain/loss change	0.00	36,172,566.91	See asset summary
Realized gain/loss Gain / loss	2,186,840.98	2,186,840.98	See realized gain/loss summary
Accrued income change	- 315,789.16	- 315,789.16	See income & expense summary
Total amortization expense	- 648,851.16	- 648,851.16	See fixed income amortization
Total OID/MKT accretion income	3,243,660.85	3,243,660.85	See fixed income amortization
Closing balance	696,040,889.90	876,055,918.09	Ending Assets

No rate Contributions
No decommissioning expense

SI-SSA-0010-2704

◆ Change in Cash Value

	Market value	Cost	For more information
Opening balance	48,611,662.51	48,613,679.07	
Miscellaneous cash receipts	1,038,372.88	1,038,372.88	See funding & disbursement summary
Interportfolio transfers in	276,847,265.03	276,847,265.03	See funding & disbursement summary
Total receipts	277,885,637.91	277,885,637.91	See funding & disbursement summary
Interportfolio transfers out	- 289,434,525.03	- 289,434,525.03	See funding & disbursement summary
Total disbursements	- 289,434,525.03	- 289,434,525.03	See funding & disbursement summary
Income received	19,065,825.02	19,065,825.02	See income & expense summary, cash activity detail
Expenses paid	- 7,503,606.09	- 7,503,606.09	See income & expense summary
Capital changes	5,318,868.98	5,318,868.98	See capital change detail
Foreign currency bought	14,703,457.31	14,703,457.31	See foreign exchange summary
Foreign currency sold	- 14,703,457.31	- 14,703,457.31	See foreign exchange summary
Realized gain/loss	- 124,433.31	- 124,433.31	See realized gain/loss summary
Unrealized gain/loss	272.16	0.00	See asset summary
Securities bought Purchases	- 586,778,899.61	- 586,778,899.61	See investment transaction summary
Securities sold Sales	545,573,331.87	545,573,331.87	See investment transaction summary
Principal paydowns	2,117,442.29	2,117,442.29	See investment transaction summary
Closing balance	14,731,576.70	14,733,321.10	

SI-SSA-0010-2705

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Adjustments To Cash								
Pending trade purchases			Ending Liability					
Pending trade purchases	0.00	- 2,194,406.40	- 2,194,406.40	0.00	0.00	0.00	-2,194,406.40	- 0.250%
Total pending trade purchases	**0.00**	**- 2,194,406.40**	**- 2,194,406.40**	**0.00**	**0.00**	**0.00**	**-2,194,406.40**	**- 0.250%**
Pending trade sales								
Pending trade sales	0.00	1,254,989.42	1,254,989.42	0.00	0.00	0.00	1,254,989.42	0.143%
Total pending trade sales	**0.00**	**1,254,989.42**	**1,254,989.42**	**0.00**	**0.00**	**0.00**	**1,254,989.42**	**0.143%**
Other payables								
Other Payables	0.00	- 1,038,372.88	- 1,038,372.88	0.00	0.00	0.00	-1,038,372.88	- 0.119%
Total other payables	**0.00**	**- 1,038,372.88**	**- 1,038,372.88**	**0.00**	**0.00**	**0.00**	**-1,038,372.88**	**- 0.119%**
Total adjustments to cash	**0.00**	**- 1,977,789.86**	**- 1,977,789.86**	**0.00**	**0.00**	**0.00**	**-1,977,789.86**	**- 0.226%**
Total Unrealized Gains						**195,567,638.81**		
Total Unrealized Losses						**- 15,552,610.62**		
Total	**2,083,953.16**	**873,971,964.93**	**693,956,936.74**	**185,057,097.82**	**-5,042,069.63**	**180,015,028.19**	**876,055,918.09**	**100.000%**
Total Cost Incl. Accruals			**696,040,889.90**					

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Funds - short term investment								
Funds - Short Term Investment	431.03	45,442,822.67	45,442,822.67	0.00	0.00	0.00	45,443,253.70	5.433%
Total funds - short term investment	**431.03**	**45,442,822.67**	**45,442,822.67**	**0.00**	**0.00**	**0.00**	**45,443,253.70**	**5.433%**
Cash								
Cash	- 8.38	125,503.83	127,520.39	0.00	-2,016.56	- 2,016.56	125,495.45	0.015%
Total cash	**- 8.38**	**125,503.83**	**127,520.39**	**0.00**	**-2,016.56**	**- 2,016.56**	**125,495.45**	**0.015%**
Invested cash								
Invested cash	19.24	3,043,336.01	3,043,336.01	0.00	0.00	0.00	3,043,355.25	0.364%
Total invested cash	**19.24**	**3,043,336.01**	**3,043,336.01**	**0.00**	**0.00**	**0.00**	**3,043,355.25**	**0.364%**
Total cash and cash equivalents	**441.89**	**48,611,662.51**	**48,613,679.07**	**0.00**	**-2,016.56**	**- 2,016.56**	**48,612,104.40**	**5.812%**
Adjustments To Cash								
Pending foreign exchange purchases Beginning Liability								
Pending foreign exchange purchases	0.00	23,608.30	23,749.57	0.00	-141.27	- 141.27	23,608.30	0.003%
Total pending foreign exchange purchases	**0.00**	**23,608.30**	**23,749.57**	**0.00**	**-141.27**	**- 141.27**	**23,608.30**	**0.003%**
Pending foreign exchange sales								
Pending foreign exchange sales	0.00	- 23,749.57	- 23,749.57	0.00	0.00	0.00	-23,749.57	- 0.003%
Total pending foreign exchange sales	**0.00**	**- 23,749.57**	**- 23,749.57**	**0.00**	**0.00**	**0.00**	**-23,749.57**	**- 0.003%**
Pending trade purchases Beginning Liability								
Pending trade purchases	0.00	- 14,708,549.64	- 14,708,780.71	0.00	231.07	231.07	-14,708,549.64	- 1.758%
Total pending trade purchases	**0.00**	**- 14,708,549.64**	**- 14,708,780.71**	**0.00**	**231.07**	**231.07**	**-14,708,549.64**	**- 1.758%**
Pending trade sales								
Pending trade sales	0.00	14,621,566.72	14,621,566.72	0.00	0.00	0.00	14,621,566.72	1.748%
Total pending trade sales	**0.00**	**14,621,566.72**	**14,621,566.72**	**0.00**	**0.00**	**0.00**	**14,621,566.72**	**1.748%**
Total adjustments to cash	**0.00**	**- 87,124.19**	**- 87,213.99**	**0.00**	**89.80**	**89.80**	**-87,124.19**	**- 0.010%**

TMI

SI-SSA-0010-2708

◆ Change in Book and Market Value

	Cost	Market value	For more information
Opening balance	499,320,313.46	590,139,290.06	Beginning Assets
Interportfolio Transfers In	166,812,951.39	166,812,951.39	See funding & disbursement summary
Security Receipts	0.00	0.00	See funding & disbursement summary
Total receipts	166,812,951.39	166,812,951.39	See funding & disbursement summary
Interportfolio Transfers Out	- 175,693,666.39	- 175,693,666.39	See funding & disbursement summary
Security Deliveries	0.00	0.00	See funding & disbursement summary
Total disbursements	- 175,693,666.39	- 175,693,666.39	See funding & disbursement summary
Income received	12,425,941.54	12,425,941.54	See income & expense summary, cash activity detail
Expenses paid Funding expenses/taxes	- 6,102,668.97	- 6,102,668.97	See income & expense summary
Unrealized gain/loss change	0.00	17,902,573.97	See asset summary
Realized gain/loss Gain/Loss	10,111,747.01	10,111,747.01	See realized gain/loss summary
Accrued income change	- 36,690.57	- 36,690.57	See income & expense summary
Total amortization expense	- 419,654.61	- 419,654.61	See fixed income amortization
Total OID/MKT accretion income	1,992,181.00	1,992,181.00	See fixed income amortization
Closing balance	508,410,453.86	617,132,004.43	Ending Assets

No rate payer contributions
No decommissioning expenses

SI-SSA-0010-2709

◆ Change in Cash Value

	Market value	Cost	For more information
Opening balance	20,914,816.11	20,916,448.25	
Interportfolio transfers in	166,812,951.39	166,812,951.39	See funding & disbursement summary
Total receipts	166,812,951.39	166,812,951.39	See funding & disbursement summary
Interportfolio transfers out	- 175,693,666.39	- 175,693,666.39	See funding & disbursement summary
Total disbursements	- 175,693,666.39	- 175,693,666.39	See funding & disbursement summary
Income received	12,429,932.94	12,429,932.94	See income & expense summary, cash activity detail
Expenses paid	- 6,102,668.97	- 6,102,668.97	See income & expense summary
Capital changes	3,783,552.80	3,783,552.80	See capital change detail
Foreign currency bought	6,272,743.20	6,272,743.20	See foreign exchange summary
Foreign currency sold	- 6,272,743.20	- 6,272,743.20	See foreign exchange summary
Realized gain/loss	- 44,290.56	- 44,290.56	See realized gain/loss summary
Unrealized gain/loss	1,075.35	0.00	See asset summary
Securities bought Purchases	- 369,510,451.38	- 369,510,451.38	See investment transaction summary
Securities sold Sales	354,012,109.98	354,012,109.98	See investment transaction summary
Principal paydowns	1,398,533.86	1,398,533.86	See investment transaction summary
Closing balance	8,001,895.13	8,002,451.92	

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Adjustments To Cash								
Pending trade purchases		Ending liability						
Pending trade purchases	0.00	- 874,387.63	- 874,387.63	0.00	0.00	0.00	-874,387.63	- 0.142%
Total pending trade purchases	**0.00**	**- 874,387.63**	**- 874,387.63**	**0.00**	**0.00**	**0.00**	**-874,387.63**	**- 0.142%**
Pending trade sales								
Pending trade sales	0.00	159,945.32	159,945.32	0.00	0.00	0.00	159,945.32	0.026%
Total pending trade sales	**0.00**	**159,945.32**	**159,945.32**	**0.00**	**0.00**	**0.00**	**159,945.32**	**0.026%**
Total adjustments to cash	**0.00**	**- 714,442.31**	**- 714,442.31**	**0.00**	**0.00**	**0.00**	**-714,442.31**	**- 0.116%**
Total Unrealized Gains						**119,670,906.01**		
Total Unrealized Losses						**- 10,949,355.44**		
Total	**1,506,959.03**	**615,625,045.40**	**506,903,494.83**	**112,166,041.72**	**-3,444,491.15**	**108,721,550.57**	**617,132,004.43**	**100.000%**

Total Cost incl. Accruals **508,410,453.86**

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Funds - short term investment								
Funds - Short Term Investment	192.05	18,704,355.03	18,704,355.03	0.00	0.00	0.00	18,704,547.08	3.170%
Total funds - short term investment	**192.05**	**18,704,355.03**	**18,704,355.03**	**0.00**	**0.00**	**0.00**	**18,704,547.08**	**3.170%**
Cash								
Cash	24.25	65,135.43	66,767.57	0.00	-1,632.14	- 1,632.14	65,159.68	0.011%
Total cash	**24.25**	**65,135.43**	**66,767.57**	**0.00**	**-1,632.14**	**- 1,632.14**	**65,159.68**	**0.011%**
Invested cash								
Invested cash	17.46	2,145,325.65	2,145,325.65	0.00	0.00	0.00	2,145,343.11	0.364%
Total invested cash	**17.46**	**2,145,325.65**	**2,145,325.65**	**0.00**	**0.00**	**0.00**	**2,145,343.11**	**0.364%**
Total cash and cash equivalents	**233.76**	**20,914,816.11**	**20,916,448.25**	**0.00**	**-1,632.14**	**- 1,632.14**	**20,915,049.87**	**3.544%**
Adjustments To Cash								
Pending foreign exchange purchases		Beginning liability						
Pending foreign exchange purchases	0.00	45,308.88	45,454.69	0.00	-145.81	- 145.81	45,308.88	0.008%
Total pending foreign exchange purchases	**0.00**	**45,308.88**	**45,454.69**	**0.00**	**-145.81**	**- 145.81**	**45,308.88**	**0.008%**
Pending foreign exchange sales								
Pending foreign exchange sales	0.00	- 45,454.69	- 45,454.69	0.00	0.00	0.00	-45,454.69	- 0.008%
Total pending foreign exchange sales	**0.00**	**- 45,454.69**	**- 45,454.69**	**0.00**	**0.00**	**0.00**	**-45,454.69**	**- 0.008%**
Pending trade purchases		Beginning liability						
Pending trade purchases	0.00	- 4,976,857.62	- 4,976,983.99	0.00	126.37	126.37	-4,976,857.62	- 0.843%
Total pending trade purchases	**0.00**	**- 4,976,857.62**	**- 4,976,983.99**	**0.00**	**126.37**	**126.37**	**-4,976,857.62**	**- 0.843%**
Pending trade sales								
Pending trade sales	0.00	5,784,876.27	5,784,876.27	0.00	0.00	0.00	5,784,876.27	0.980%
Total pending trade sales	**0.00**	**5,784,876.27**	**5,784,876.27**	**0.00**	**0.00**	**0.00**	**5,784,876.27**	**0.980%**
Total adjustments to cash	**0.00**	**807,872.84**	**807,892.28**	**0.00**	**-19.44**	**- 19.44**	**807,872.84**	**0.137%**

Legacy PECO

◆ Change in Book and Market Value

	Cost	Market value	For more information
Opening balance	1,442,445,195.10	1,762,170,746.07	Beginning Assets
Sponsor Contributions (Rate Payer Cont.)	23,454,732.96	23,454,732.96	See funding & disbursement summary
Interportfolio Transfers In	677,667,841.97	677,667,841.97	See funding & disbursement summary
Security Receipts	0.00	0.00	See funding & disbursement summary
Total receipts	701,122,574.93	701,122,574.93	See funding & disbursement summary
Interportfolio Transfers Out	- 699,883,058.73	- 699,883,058.73	See funding & disbursement summary
Security Deliveries	0.00	0.00	See funding & disbursement summary
Total disbursements	- 699,883,058.73	- 699,883,058.73	See funding & disbursement summary
Income received	41,133,616.21	41,133,616.21	See income & expense summary, cash activity detail
Expenses paid (Fund Expenses / taxes)	- 11,985,851.12	- 11,985,851.12	See income & expense summary
Unrealized gain/loss change	0.00	43,331,725.02	See asset summary
Realized gain/loss (Gain / loss)	38,089,886.40	38,089,886.40	See realized gain/loss summary
Accrued income change	- 1,262,715.13	- 1,262,715.13	See income & expense summary
Total amortization expense	- 3,064,865.85	- 3,064,865.85	See fixed income amortization
Total OID/MKT accretion income	3,726,981.25	3,726,981.25	See fixed income amortization
Closing balance	1,510,321,763.06	1,873,379,039.05	Ending Assets

No decommissioning expense

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◆ Change in Cash Value

	Market value	Cost	For more information
Opening balance	37,556,982.02	37,557,163.16	
Sponsor contributions	23,454,732.96	23,454,732.96	See funding & disbursement summary
Interportfolio transfers in	677,667,841.97	677,667,841.97	See funding & disbursement summary
Total receipts	701,122,574.93	701,122,574.93	See funding & disbursement summary
Interportfolio transfers out	- 699,883,058.73	- 699,883,058.73	See funding & disbursement summary
Total disbursements	- 699,883,058.73	- 699,883,058.73	See funding & disbursement summary
Income received	41,139,056.33	41,139,056.33	See income & expense summary, cash activity detail
Expenses paid	- 11,985,851.12	- 11,985,851.12	See income & expense summary
Capital changes	15,785,141.35	15,785,141.35	See capital change detail
Foreign currency bought	853,825.05	853,825.05	See foreign exchange summary
Foreign currency sold	- 853,825.05	- 853,825.05	See foreign exchange summary
Realized gain/loss	- 2,109.99	- 2,109.99	See realized gain/loss summary
Unrealized gain/loss	- 645.62	0.00	See asset summary
Securities bought Purchases	- 1,295,740,445.61	- 1,295,740,445.61	See investment transaction summary
Securities sold Sales	1,226,208,343.82	1,226,208,343.82	See investment transaction summary
Principal paydowns	4,348,918.21	4,348,918.21	See investment transaction summary
Closing balance	18,548,905.59	18,549,732.35	

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Translation	Total	Market value incl. accruals	%
Adjustments To Cash								
Pending trade purchases			Ending Liability					
Pending trade purchases	0.00	- 4,451,789.31	- 4,451,789.31	0.00	0.00	0.00	-4,451,789.31	- 0.238%
Total pending trade purchases	**0.00**	**- 4,451,789.31**	**- 4,451,789.31**	**0.00**	**0.00**	**0.00**	**-4,451,789.31**	**- 0.238%**
Pending trade sales								
Pending trade sales	0.00	443,719.24	443,719.24	0.00	0.00	0.00	443,719.24	0.024%
Total pending trade sales	**0.00**	**443,719.24**	**443,719.24**	**0.00**	**0.00**	**0.00**	**443,719.24**	**0.024%**
Total adjustments to cash	**0.00**	**- 4,008,070.07**	**- 4,008,070.07**	**0.00**	**0.00**	**0.00**	**-4,008,070.07**	**- 0.214%**
Total Unrealized Gains						**380,454,126.50**		
Total Unrealized Losses						**- 17,396,850.51**		
Total	**4,589,252.34**	**1,868,789,786.71**	**1,505,732,510.72**	**364,289,650.25**	**-1,232,374.26**	**363,057,275.99**	**1,873,379,039.05**	**100.000%**

Total Cost incl. Accruals **1,510,321,763.06**

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Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Cash								
Cash	- 11.46	32,046.87	32,228.01	0.00	-181.14	- 181.14	32,035.41	0.002%
Total cash	**- 11.46**	**32,046.87**	**32,228.01**	**0.00**	**-181.14**	**- 181.14**	**32,035.41**	**0.002%**
Invested cash								
Invested cash	45.39	9,653,641.61	9,653,641.61	0.00	0.00	0.00	9,653,687.00	0.548%
Total invested cash	**45.39**	**9,653,641.61**	**9,653,641.61**	**0.00**	**0.00**	**0.00**	**9,653,687.00**	**0.548%**
Total cash and cash equivalents	**388.45**	**37,556,982.02**	**37,557,163.16**	**0.00**	**-181.14**	**- 181.14**	**37,557,370.47**	**2.131%**
Adjustments To Cash								
Pending trade purchases		Beginning Liability						
Pending trade purchases	0.00	- 18,353,707.94	- 18,353,765.23	0.00	57.29	57.29	-18,353,707.94	- 1.042%
Total pending trade purchases	**0.00**	**- 18,353,707.94**	**- 18,353,765.23**	**0.00**	**57.29**	**57.29**	**-18,353,707.94**	**- 1.042%**
Pending trade sales								
Pending trade sales	0.00	16,191,725.78	16,191,725.78	0.00	0.00	0.00	16,191,725.78	0.919%
Total pending trade sales	**0.00**	**16,191,725.78**	**16,191,725.78**	**0.00**	**0.00**	**0.00**	**16,191,725.78**	**0.919%**
Total adjustments to cash	**0.00**	**- 2,161,982.16**	**- 2,162,039.45**	**0.00**	**57.29**	**57.29**	**-2,161,982.16**	**- 0.123%**
Total Unrealized Gains						**342,838,204.96**		
Total Unrealized Losses						**- 23,112,653.99**		
Total	**5,851,967.47**	**1,756,318,778.60**	**1,436,593,227.63**	**320,831,061.12**	**-1,105,510.15**	**319,725,550.97**	**1,762,170,746.07**	**100.000%**

Total Cost Incl. Accruals **1,442,445,195.10**

SI-SSA-0010-2717

Legacy ComEd

◆ Change in Book and Market Value

	Cost	Market value	For more information
Opening balance	3,491,628,585.38	4,629,538,247.27	Beginning assets
Interportfolio Transfers In	1,799,763,508.27	1,799,763,508.27	See funding & disbursement summary
Total receipts	1,799,763,508.27	1,799,763,508.27	See funding & disbursement summary
Interportfolio Transfers Out	- 1,799,763,508.27	- 1,799,763,508.27	See funding & disbursement summary
Total disbursements	- 1,799,763,508.27	- 1,799,763,508.27	See funding & disbursement summary
Income received	119,010,988.02	119,010,988.02	See income & expense summary, cash activity detail
Expenses paid	31,039,141.22	- 31,039,141.22	See income & expense summary
Unrealized gain/loss change	0.00	194,087,870.82	See asset summary
Realized gain/loss	49,246,577.04	49,246,577.04	See realized gain/loss summary
Accrued income change	- 5,881,160.42	- 5,881,160.42	See income & expense summary
Total amortization expense	- 6,454,960.95	- 6,454,960.95	See fixed income amortization
Total OID/MKT accretion income	2,732,442.31	2,732,442.31	See fixed income amortization
Return of capital	- 19,843.29	- 19,843.29	See capital change detail
Closing balance	3,619,223,486.87	4,951,221,019.58	

Fund expenses / taxes

Gain / loss

Ending assets

No rate payer contributions
No decommissioning expenses

◆ Change in Cash Value

	Market value	Cost	For more information
Opening balance	114,582,116.18	114,612,599.16	
Interportfolio transfers in	1,788,263,508.27	1,788,263,508.27	See funding & disbursement summary
Total receipts	1,788,263,508.27	1,788,263,508.27	See funding & disbursement summary
Interportfolio transfers out	- 1,788,263,508.27	- 1,788,263,508.27	See funding & disbursement summary
Total disbursements	- 1,788,263,508.27	- 1,788,263,508.27	See funding & disbursement summary
Income received	118,588,163.80	118,588,163.80	See income & expense summary, cash activity detail
Expenses paid	- 31,039,141.22	- 31,039,141.22	See income & expense summary
Capital changes	85,467,997.42	85,467,997.42	See capital change detail
Foreign currency bought	1,758,086,602.37	1,758,086,602.37	See foreign exchange summary
Foreign currency sold	- 1,758,086,602.37	- 1,758,086,602.37	See foreign exchange summary
Realized gain/loss	4,266,087.08	4,266,087.08	See realized gain/loss summary
Mark-to-markets	4,220,625.17	4,220,625.17	See realized gain/loss summary
Unrealized gain/loss	- 7,431.66	0.00	See asset summary
Securities bought Purchases	- 3,233,511,850.61	- 3,233,511,850.61	See investment transaction summary
Securities sold Sales	2,966,913,276.17	2,966,913,276.17	See investment transaction summary
Principal paydowns	6,200,329.13	6,200,329.13	See investment transaction summary
Intra portfolio transfer	0.00	0.00	
Closing balance	35,680,171.46	35,718,086.10	

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Derivative Offsets								
Cash & cash equiv - margined options								
Total cash & cash equiv - margined options	**0.00**	**0.00**	**- 4,153.93**	**3,544.77**	**609.16**	**4,153.93**	**0.00**	**0.000%**
Fixed income futures								
Germany - EUR	0.00	1,928,452.10	1,879,120.44	59,456.25	-10,124.59	49,331.66	1,928,452.10	0.039%
United Kingdom - GBP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000%
United States - USD	0.00	- 74,062,539.06	- 74,279,719.52	217,180.46	0.00	217,180.46	-74,062,539.06	- 1.496%
Total fixed income futures	**0.00**	**- 72,134,086.96**	**- 72,400,599.08**	**276,636.71**	**-10,124.59**	**266,512.12**	**-72,134,086.96**	**- 1.457%**
Total derivative offsets	**0.00**	**- 56,842,686.96**	**- 57,119,993.54**	**286,822.01**	**-9,515.43**	**277,306.58**	**-56,842,686.96**	**- 1.148%**
Hedge Fund								
Hedge equity								
United States - USD	0.00	198,754,398.76	197,924,008.76	830,390.00	0.00	830,390.00	198,754,398.76	4.014%
Total hedge equity	**0.00**	**198,754,398.76**	**197,924,008.76**	**830,390.00**	**0.00**	**830,390.00**	**198,754,398.76**	**4.014%**
Total hedge fund	**0.00**	**198,754,398.76**	**197,924,008.76**	**830,390.00**	**0.00**	**830,390.00**	**198,754,398.76**	**4.014%**
Liabilities - Ending								
Swap liabilities								
China - CNY	0.00	- 34,466.86	0.00	- 34,466.86	0.00	- 34,466.86	-34,466.86	- 0.001%
European Union - EUR	0.00	- 145,479.22	- 60,864.31	- 86,283.93	1,669.02	- 84,614.91	-145,479.22	- 0.003%
Mexico - MXN	0.00	- 3,163.15	0.00	- 3,163.15	0.00	- 3,163.15	-3,163.15	- 0.000%
United Kingdom - GBP	0.00	- 562,251.59	- 449,272.94	- 121,108.90	8,130.25	- 112,978.65	-562,251.59	- 0.011%
United States - USD	0.00	- 1,109,750.52	- 1,304,061.93	194,311.41	0.00	194,311.41	-1,109,750.52	- 0.022%
Total swap liabilities	**0.00**	**- 1,855,111.34**	**- 1,814,199.18**	**- 50,711.43**	**9,799.27**	**- 40,912.16**	**-1,855,111.34**	**- 0.037%**
Obligation to return cash collateral hld								
United States - USD	0.00	- 300,000.00	- 300,000.00	0.00	0.00	0.00	-300,000.00	- 0.006%
Total obligation to return cash collateral hld	**0.00**	**- 300,000.00**	**- 300,000.00**	**0.00**	**0.00**	**0.00**	**-300,000.00**	**- 0.006%**

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Liabilities - Ending								
Exchange cleared swap liabilities								
Australia - AUD	0.00	- 384,784.94	- 470,874.46	- 21,829.64	107,919.16	86,089.52	-384,784.94	- 0.008%
Brazil - BRL	0.00	- 1,476.06	- 20,309.48	19,997.17	-1,163.75	18,833.42	-1,476.06	- 0.000%
Canada - CAD	0.00	- 13,032.18	- 20,953.27	6,260.17	1,660.92	7,921.09	-13,032.18	- 0.000%
European Union - EUR	0.00	- 738,046.57	- 358,625.96	- 428,237.11	48,816.50	- 379,420.61	-738,046.57	- 0.015%
Japan - JPY	0.00	- 84,135.10	- 56,386.37	- 30,721.94	2,973.21	- 27,748.73	-84,135.10	- 0.002%
Mexico - MXN	0.00	- 250,658.33	- 854.81	- 249,918.05	114.53	- 249,803.52	-250,658.33	- 0.005%
South Africa - ZAR	0.00	- 1,076.30	0.00	- 1,076.30	0.00	- 1,076.30	-1,076.30	- 0.000%
United Kingdom - GBP	0.00	- 988,243.14	- 95,978.41	- 905,645.14	13,380.41	- 892,264.73	-988,243.14	- 0.020%
United States - USD	0.00	- 2,355,982.95	- 1,801,365.15	- 554,617.80	0.00	- 554,617.80	-2,355,982.95	- 0.048%
Total exchange cleared swap liabilities	**0.00**	**- 4,817,435.57**	**- 2,825,347.91**	**- 2,165,788.64**	**173,700.98**	**- 1,992,087.66**	**-4,817,435.57**	**- 0.097%**
Total liabilities	**0.00**	**- 6,972,546.91**	**- 4,939,547.09**	**- 2,216,500.07**	**183,500.25**	**- 2,032,999.82**	**-6,972,546.91**	**- 0.141%**
All Other								
Recoverable taxes								
Recoverable taxes	32,031.57	0.00	0.00	0.00	0.00	0.00	32,031.57	0.001%
Total recoverable taxes	**32,031.57**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**32,031.57**	**0.001%**
Total all other	**32,031.57**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**32,031.57**	**0.001%**
Cash and Cash Equivalents								
Repurchase agreements								
United States - USD	- 37,751.77	- 28,505,500.00	- 28,505,500.00	0.00	0.00	0.00	-28,543,251.77	- 0.576%
Total repurchase agreements	**- 37,751.77**	**- 28,505,500.00**	**- 28,505,500.00**	**0.00**	**0.00**	**0.00**	**-28,543,251.77**	**- 0.576%**
Funds - short term investment								
United States - USD	0.00	45,499,546.89	45,505,519.35	- 5,972.46	0.00	- 5,972.46	45,499,546.89	0.919%
Total funds - short term investment	**0.00**	**45,499,546.89**	**45,505,519.35**	**- 5,972.46**	**0.00**	**- 5,972.46**	**45,499,546.89**	**0.919%**

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Cash (externally held)								
Cash (externally held)	0.00	1,419,000.00	1,419,000.00	0.00	0.00	0.00	1,419,000.00	0.029%
Total cash (externally held)	**0.00**	**1,419,000.00**	**1,419,000.00**	**0.00**	**0.00**	**0.00**	**1,419,000.00**	**0.029%**
Variation margin								
Variation Margin	0.00	140,217.10	139,934.58	0.00	282.52	282.52	140,217.10	0.003%
Total variation margin	**0.00**	**140,217.10**	**139,934.58**	**0.00**	**282.52**	**282.52**	**140,217.10**	**0.003%**
Cash collateral due to/from ccp broker								
Cash Collateral Due to/from CCP Broker	0.00	1,526,856.01	1,566,651.80	0.00	-39,795.79	- 39,795.79	1,526,856.01	0.031%
Total cash collateral due to/from ccp broker	**0.00**	**1,526,856.01**	**1,566,651.80**	**0.00**	**-39,795.79**	**- 39,795.79**	**1,526,856.01**	**0.031%**
Total cash and cash equivalents	**- 28,247.99**	**37,967,890.30**	**38,005,147.81**	**2,543.23**	**-39,800.74**	**- 37,257.51**	**37,939,642.31**	**0.766%**
Adjustments To Cash								
Pending foreign exchange purchases Ending liability								
Pending foreign exchange purchases	0.00	137,976,738.00	137,522,869.30	0.00	453,868.70	453,868.70	137,976,738.00	2.787%
Total pending foreign exchange purchases	**0.00**	**137,976,738.00**	**137,522,869.30**	**0.00**	**453,868.70**	**453,868.70**	**137,976,738.00**	**2.787%**
Pending foreign exchange sales								
Pending foreign exchange sales	0.00	- 137,713,786.30	- 137,522,869.30	0.00	-190,917.00	- 190,917.00	-137,713,786.30	- 2.781%
Total pending foreign exchange sales	**0.00**	**- 137,713,786.30**	**- 137,522,869.30**	**0.00**	**-190,917.00**	**- 190,917.00**	**-137,713,786.30**	**- 2.781%**
Pending trade purchases Ending liability								
Pending trade purchases	0.00	- 125,046,491.45	- 125,046,491.45	0.00	0.00	0.00	-125,046,491.45	- 2.526%
Total pending trade purchases	**0.00**	**- 125,046,491.45**	**- 125,046,491.45**	**0.00**	**0.00**	**0.00**	**-125,046,491.45**	**- 2.526%**
Pending trade sales								
Pending trade sales	0.00	94,760,587.34	94,760,587.34	0.00	0.00	0.00	94,760,587.34	1.914%
Total pending trade sales	**0.00**	**94,760,587.34**	**94,760,587.34**	**0.00**	**0.00**	**0.00**	**94,760,587.34**	**1.914%**
Total adjustments to cash	**0.00**	**- 30,022,952.41**	**- 30,285,904.11**	**0.00**	**262,951.70**	**262,951.70**	**-30,022,952.41**	**- 0.606%**

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Derivative Offsets								
Equity futures								
Total equity futures	**0.00**	**- 590,625.00**	**- 590,340.62**	**- 284.38**	**0.00**	**- 284.38**	**-590,625.00**	**- 0.013%**
Fixed income futures								
Germany - EUR	0.00	- 6,306,101.97	- 6,272,826.02	- 48,133.95	14,858.00	- 33,275.95	-6,306,101.97	- 0.136%
United States - USD	0.00	- 160,061,023.44	- 160,351,104.63	290,081.19	0.00	290,081.19	-160,061,023.44	- 3.457%
Total fixed income futures	**0.00**	**- 166,367,125.41**	**- 166,623,930.65**	**241,947.24**	**14,858.00**	**256,805.24**	**-166,367,125.41**	**- 3.594%**
Total derivative offsets	**0.00**	**- 70,710,271.72**	**- 70,912,203.41**	**185,963.61**	**15,968.08**	**201,931.69**	**-70,710,271.72**	**- 1.527%**
Hedge Fund								
Hedge equity								
United States - USD	0.00	58,600,000.00	58,600,000.00	0.00	0.00	0.00	58,600,000.00	1.266%
Total hedge equity	**0.00**	**58,600,000.00**	**58,600,000.00**	**0.00**	**0.00**	**0.00**	**58,600,000.00**	**1.266%**
Total hedge fund	**0.00**	**58,600,000.00**	**58,600,000.00**	**0.00**	**0.00**	**0.00**	**58,600,000.00**	**1.266%**
Liabilities — Beginning								
Swap liabilities								
Brazil - BRL	0.00	- 345,064.84	- 23,474.26	- 321,668.55	77.97	- 321,590.58	-345,064.84	- 0.007%
European Union - EUR	0.00	- 80,501.91	- 115,566.15	28,599.04	6,465.20	35,064.24	-80,501.91	- 0.002%
Japan - JPY	0.00	- 166,619.38	- 31,775.14	- 140,414.53	5,570.29	- 134,844.24	-166,619.38	- 0.004%
Mexico - MXN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000%
United Kingdom - GBP	0.00	- 8,447.24	- 35,563.92	24,790.14	2,326.54	27,116.68	-8,447.24	- 0.000%
United States - USD	0.00	- 3,272,695.89	- 968,790.52	- 2,303,905.37	0.00	- 2,303,905.37	-3,272,695.89	- 0.071%
Total swap liabilities	**0.00**	**- 3,873,329.26**	**- 1,175,169.99**	**- 2,712,599.27**	**14,440.00**	**- 2,698,159.27**	**-3,873,329.26**	**- 0.084%**
Obligation to return cash collateral hld								
United States - USD	0.00	- 2,300,000.00	- 2,300,000.00	0.00	0.00	0.00	-2,300,000.00	- 0.050%
Total obligation to return cash collateral hld	**0.00**	**- 2,300,000.00**	**- 2,300,000.00**	**0.00**	**0.00**	**0.00**	**-2,300,000.00**	**- 0.050%**

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Liabilities								
Exchange cleared swap liabilities	–	Beginning						
Australia - AUD	0.00	- 456,263.28	- 470,874.46	- 91,578.68	106,189.86	14,611.18	-456,263.28	- 0.010%
Canada - CAD	0.00	- 33,184.51	- 20,953.27	- 14,559.50	2,328.26	- 12,231.24	-33,184.51	- 0.001%
European Union - EUR	0.00	- 528,920.00	- 488,694.37	- 76,485.65	36,260.02	- 40,225.63	-528,920.00	- 0.011%
Japan - JPY	0.00	- 101,073.90	- 34,671.10	- 71,566.22	5,163.42	- 66,402.80	-101,073.90	- 0.002%
Mexico - MXN	0.00	- 109,617.68	- 68,679.46	- 51,590.42	10,652.20	- 40,938.22	-109,617.68	- 0.002%
United Kingdom - GBP	0.00	- 342,048.57	- 257,250.74	- 91,697.24	6,899.41	- 84,797.83	-342,048.57	- 0.007%
United States - USD	0.00	- 6,850,501.71	- 3,743,748.95	- 3,106,752.76	0.00	- 3,106,752.76	-6,850,501.71	- 0.148%
Total exchange cleared swap liabilities	**0.00**	**- 8,421,609.65**	**- 5,084,872.35**	**- 3,504,230.47**	**167,493.17**	**- 3,336,737.30**	**-8,421,609.65**	**- 0.182%**
Total liabilities	**0.00**	**- 14,594,938.91**	**- 8,560,042.34**	**- 6,216,829.74**	**181,933.17**	**- 6,034,896.57**	**-14,594,938.91**	**- 0.315%**
All Other								
Recoverable taxes								
Recoverable taxes	44,740.86	0.00	0.00	0.00	0.00	0.00	44,740.86	0.001%
Total recoverable taxes	**44,740.86**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**44,740.86**	**0.001%**
Total all other	**44,740.86**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**44,740.86**	**0.001%**
Cash and Cash Equivalents								
Repurchase agreements								
United States - USD	- 22,650.87	- 51,509,713.00	- 51,509,713.00	0.00	0.00	0.00	-51,532,363.87	- 1.113%
Total repurchase agreements	**- 22,650.87**	**- 51,509,713.00**	**- 51,509,713.00**	**0.00**	**0.00**	**0.00**	**-51,532,363.87**	**- 1.113%**
Cash & cash equivalent deriv. - futures								
United States - USD	0.00	- 96,280,687.50	- 96,333,402.11	52,714.61	0.00	52,714.61	-96,280,687.50	- 2.080%
Total cash & cash equivalent deriv. - futures	**0.00**	**- 96,280,687.50**	**- 96,333,402.11**	**52,714.61**	**0.00**	**52,714.61**	**-96,280,687.50**	**- 2.080%**
Cash & cash equiv deriv-margined options								
United Kingdom - GBP	0.00	33,208.81	31,334.25	2,984.64	-1,110.08	1,874.56	33,208.81	0.001%

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Variation margin								
Variation Margin	0.00	139,559.09	139,559.63	0.00	-0.54	- 0.54	139,559.09	0.003%
Total variation margin	**0.00**	**139,559.09**	**139,559.63**	**0.00**	**-0.54**	**- 0.54**	**139,559.09**	**0.003%**
Cash collateral due to/from ccp broker								
Cash Collateral Due to/from CCP Broker	0.00	6,367,923.19	6,366,879.44	0.00	1,043.75	1,043.75	6,367,923.19	0.138%
Total cash collateral due to/from ccp broker	**0.00**	**6,367,923.19**	**6,366,879.44**	**0.00**	**1,043.75**	**1,043.75**	**6,367,923.19**	**0.138%**
Total cash and cash equivalents	**- 21,454.12**	**- 33,210,494.46**	**- 33,253,881.70**	**74,980.30**	**-31,593.06**	**43,387.24**	**-33,231,948.58**	**- 0.718%**
Adjustments To Cash								
Pending foreign exchange purchases		Beginning liability						
Pending foreign exchange purchases	0.00	196,131,515.45	196,609,908.81	0.00	-478,393.36	- 478,393.36	196,131,515.45	4.237%
Total pending foreign exchange purchases	**0.00**	**196,131,515.45**	**196,609,908.81**	**0.00**	**-478,393.36**	**- 478,393.36**	**196,131,515.45**	**4.237%**
Pending foreign exchange sales								
Pending foreign exchange sales	0.00	- 195,798,186.85	- 196,609,908.81	0.00	811,721.96	811,721.96	-195,798,186.85	- 4.229%
Total pending foreign exchange sales	**0.00**	**- 195,798,186.85**	**- 196,609,908.81**	**0.00**	**811,721.96**	**811,721.96**	**-195,798,186.85**	**- 4.229%**
Pending trade purchases		Beginning liability						
Pending trade purchases	0.00	- 34,325,787.18	- 34,629,917.16	0.00	304,129.98	304,129.98	-34,325,787.18	- 0.741%
Total pending trade purchases	**0.00**	**- 34,325,787.18**	**- 34,629,917.16**	**0.00**	**304,129.98**	**304,129.98**	**-34,325,787.18**	**- 0.741%**
Pending trade sales								
Pending trade sales	0.00	32,030,480.58	32,030,480.58	0.00	0.00	0.00	32,030,480.58	0.692%
Total pending trade sales	**0.00**	**32,030,480.58**	**32,030,480.58**	**0.00**	**0.00**	**0.00**	**32,030,480.58**	**0.692%**
Total adjustments to cash	**0.00**	**- 1,961,978.00**	**- 2,599,436.58**	**0.00**	**637,458.58**	**637,458.58**	**-1,961,978.00**	**- 0.042%**

FERC Jurisdictional

FERCNDT TC Allocation

01 JAN 16 - 31 DEC 16 Annual Schedule

FERC Jurisdictional Rates

◆ Allocation Schedule - Market Value

		-401- FERC Jurisdictional Rates	-402- Non-FERC Jurisdictional Rates	PLAN TOTALS
Beginning Totals	Balance	**18,927,530.00**	**367,212,981.85**	**386,140,511.85**
Period Totals	Sponsor Contributions	(588,819.11)	1,680,864.44	1,092,045.33
	Estimated Tax Payment	(122,543.01)	(2,377,456.99)	(2,500,000.00)
		(711,362.12)	**(696,592.55)**	**(1,407,954.67)**
Earnings	Interest Earned	202,934.33	3,937,669.34	4,140,603.67
	Dividends Earned	214,656.64	4,166,000.52	4,380,657.16
	Oid/Market Accretion Income	57,224.23	1,110,272.41	1,167,496.64
	Unrealized Gain/Loss Change	539,582.44	10,472,078.94	11,011,661.38
	Realized Gain/Loss	345,783.52	6,708,155.72	7,053,939.24
	Fees And Expenses	(16,092.08)	(312,221.25)	(328,313.33)
	Oid/Market Amortization Expense	(29,878.78)	(579,678.19)	(609,556.97)
		1,314,210.30	**25,502,277.49**	**26,816,487.79**
Miscellaneous	Sponsor Contributions	588,819.11	11,423,679.52	12,012,498.63
		588,819.11	**11,423,679.52**	**12,012,498.63**
Ending Totals	Balance	**20,119,197.29**	**403,442,346.31**	**423,561,543.60**
	Percent	**4.75001%**	**95.24999%**	**100.00000%**

The Plan Total reflects the total of underlying plan balances, and may not be equal to the sum of displayed columns.

Although this report has been prepared using information believed to be reliable, it may contain information provided by third parties or derived from third party information, and/or information that may have been obtained from, categorized or otherwise reported based upon client direction. The Northern Trust Company does not guarantee the accuracy, timeliness or completeness of any such information. The information included in this report is intended to assist clients with their financial reporting needs, but you must consult with your accountants, auditors and/or legal counsel to ensure your accounting and financial reporting complies with applicable laws, regulations and accounting guidance. The Northern Trust Company and its affiliates shall have no responsibility for the consequences of investment decisions made in reliance on information contained in this report.

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Adrian D. Newall
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email: Adrian.newall@pseg.com

PSEG
Services Corporation

March 29, 2018

VIA ELECTRONIC FILING

Kimberly D. Bose, Secretary
Nathaniel J. Davis, Sr., Deputy Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Annual Financial Report on Nuclear Plant Decommissioning Trust Funds - Order No. 658
Docket Nos. RM 94-14-000 and RM05-15-000

Dear Secretary Bose and Deputy Secretary Davis:

In accordance with 18 CFR § 35.33(d), attached is the financial reports furnished by our trustee, Mellon Bank, for PSEG Nuclear LLC's ("PSEG") Qualified and Non-Qualified Nuclear Decommissioning Trust Funds for the year ending December 31, 2017.

On December 31, 2017 assets in the trust funds totaled $2,083,558.499.16, included in this balance are amounts collected through FERC jurisdictional rates totaling $20,670,858.09. This total represents the contributions and earnings on the funds since its inception in 1988. During 2017, there were no contributions made to the PSEG trust funds.

If you have any questions, or would like to see the detailed information that comprises the numbers shown on the Mellon Bank statements, please contact Bradley Barazani at (973) 430-7096.

Very truly yours,

Adrian D. Newall

PSEG Nuclear LLC
FERC ASSET Allocation
As of December 31, 2017

Account Names	Percentage	Total Trust Market Values	Non-FERC Assets	FERC Assets
Q Hope Creek	33.5%	$ 579,091,308.56	$578,301,490.17	$789,818.39
Q PB 2	14.9%	$ 257,717,912.23	$254,359,401.25	$3,358,510.98
Q PB 3	15.9%	$ 275,382,341.36	$272,007,204.01	$3,375,137.35
Q Salem 1	17.0%	$ 293,132,206.95	$286,841,535.86	$6,290,671.09
Q Salem 2	18.6%	$ 321,642,956.78	$316,208,457.25	$5,434,499.53
PSEG Nuclear LLC Qual. Plans	G716275	$ 1,726,966,725.88		
Non-Q Salem 1	36.8%	$ 131,241,763.97	$130,915,503.31	$326,260.66
Non-Q Salem 2	12.0%	$ 42,752,648.15	$42,595,100.10	$157,548.05
Non-Q PB 2	26.5%	$ 94,420,738.40	$93,951,232.55	$469,505.85
Non-Q PB 3	21.0%	$ 74,736,681.46	$74,267,775.27	$468,906.19
Non-Q Hope Creek	3.8%	$ 13,439,941.30	$13,439,941.30	$ -
PSEG Nuclear LLC Non Qual. Plans	G716277	$ 356,591,773.28		
Totals		$ 2,083,558,499.16	$2,062,887,641.07	$20,670,858.09
			99.01%	0.99%

SI-SSA-0010-2730

BNY MELLON

TRDPSB PSBG71627500 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

INVESTMENT DETAIL PAGE: 1

PSB G716275 31 DECEMBER 2017 M1101

PSEG NUCLEAR LLC QUAL. PLANS

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	PSE&G QUALIFIED MTU				
211,330,968.7940	HOPE CREEK QUAL	507,639,291.62	2.7364	578,301,490.17	70,662,198.55
92,951,547.9400	PEACH BOTTOM #2 Q	225,479,159.33	2.7364	254,359,401.25	28,880,241.92
99,400,653.3260	PEACH BOTTOM #3 Q	241,046,292.13	2.7364	272,007,204.01	30,960,911.88
104,821,621.0660	SALEM Q UNIT 1	256,544,142.19	2.7364	286,841,535.86	30,297,393.67
115,553,289.6710	SALEM Q UNIT 2	283,123,693.00	2.7364	316,208,457.25	33,084,764.25
2,298,824.4690	SALEM Q #1 FERC	6,415,729.22	2.7364	6,290,671.09	125,058.13-
1,985,950.3560	SALEM Q #2 FERC	5,391,749.73	2.7364	5,434,499.53	42,749.80
1,227,313.7660	PB#2 Q FERC	3,387,854.26	2.7364	3,358,510.98	29,343.28-
1,233,389.6050	PB#3 Q FERC	3,411,713.63	2.7364	3,375,137.35	36,576.28-
288,626.4160	HOPE CREEK QUAL FERC	886,850.57	2.7364	789,818.39	97,032.18-
631,092,185.4090		1,533,326,475.68		1,726,966,725.88	193,640,250.20
TOTAL INVESTMENTS UNIT OF PARTICIPATION		1,533,326,475.68		1,726,966,725.88	193,640,250.20
TOTAL INVESTMENT		1,533,326,475.68		1,726,966,725.88	193,640,250.20

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BNY MELLON

PSB G716277 31 DECEMBER 2017 M1101
PSEG NUCLEAR LLC NQ PLANS

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	PSE&G NON-QUALIFIED MTU				
4,397,995.9250	HOPE CREEK NONQUAL	9,271,428.96	3.0559	13,439,941.30	4,168,512.34
30,743,968.9440	PEACH BOTTOM #2 NQ	65,443,355.30	3.0559	93,951,232.55	28,507,877.25
24,302,886.8740	PEACH BOTTOM #3 NQ	51,841,911.17	3.0559	74,267,775.27	22,425,864.10
42,839,908.0980	SALEM NQ UNIT 1	91,040,873.84	3.0559	130,915,503.31	39,874,629.47
13,938,533.8450	SALEM NQ UNIT 2	29,567,841.89	3.0559	42,595,100.10	13,027,258.21
106,763.3430	SALEM NQ #1 FERC	236,248.99	3.0559	326,260.66	90,011.67
51,554.9650	SALEM NQ #2 FERC	114,082.30	3.0559	157,548.05	43,465.75
153,637.9330	PB#2 NQ FERC	339,977.81	3.0559	469,505.85	129,528.04
153,441.7060	PB#3 NQ FERC	339,543.36	3.0559	468,906.19	129,362.83
116,688,691.6330		248,195,263.62		356,591,773.28	108,396,509.66
TOTAL INVESTMENTS UNIT OF PARTICIPATION		248,195,263.62		356,591,773.28	108,396,509.66
TOTAL INVESTMENT		248,195,263.62		356,591,773.28	108,396,509.66

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Non-FERC

Qualified Reports

BNY MELLON

TRDPSB PSBF09287902 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092879 31 DECEMBER 2017 NC100

PSEG NUCLEAR HOPE CREEK QUAL

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 576,185,488.62		$ 524,448,253.59
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 270,288.61		$ 907,665.59	
UNREALIZED GAIN/LOSS-INVESTMENT	8,151,755.64-		13,474,070.39	
		7,881,467.03-		14,381,735.98
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		80,253.21	
MASTER TRUST ALLOCATED EXPENSES	588,372.24-		2,597,308.72-	
MASTER TRUST CHANGE IN REALIZED G/L	11,490,468.33		36,108,969.71	
MASTER TRUST INTEREST INCOME EARNED	722,112.41		8,134,217.70	
MASTER TRUST DIVIDEND INCOME EARNED	349,260.08		4,503,368.70	
		11,973,468.58		46,229,500.60
TOTAL RECEIPTS		4,092,001.55		60,611,236.58
DISBURSEMENTS:				
UBTI TAX EXPENSE	1,976,000.00		6,758,000.00	
		1,976,000.00		6,758,000.00
TOTAL DISBURSEMENTS		1,976,000.00		6,758,000.00
NET ASSETS - END OF PERIOD		$ 578,301,490.17		$ 578,301,490.17

BNY MELLON

TRDPSB PSBF09288202 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PAGE: 1

PSB F092882 31 DECEMBER 2017 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 253,439,580.42		$ 230,705,950.05
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 112,728.31		$ 377,066.03	
UNREALIZED GAIN/LOSS-INVESTMENT	3,585,457.96-		5,927,494.26	
		3,472,729.65-		6,304,560.29
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		35,301.75	
MASTER TRUST ALLOCATED EXPENSES	258,788.91-		1,142,475.45-	
MASTER TRUST CHANGE IN REALIZED G/L	5,060,108.26		15,905,094.54	
MASTER TRUST INTEREST INCOME EARNED	317,613.01		3,578,038.63	
MASTER TRUST DIVIDEND INCOME EARNED	153,618.12		1,980,931.44	
		5,272,550.48		20,356,890.91
TOTAL RECEIPTS		1,799,820.83		26,661,451.20
DISBURSEMENTS:				
UBTI TAX EXPENSE	880,000.00		3,008,000.00	
		880,000.00		3,008,000.00
TOTAL DISBURSEMENTS		880,000.00		3,008,000.00
NET ASSETS - END OF PERIOD		$ 254,359,401.25		$ 254,359,401.25

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BNY MELLON

TRDPSB PSBF09288402 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PAGE: 1

PSB F092884 31 DECEMBER 2017 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 271,022,509.16		$ 246,697,872.89
RECEIPTS:				
INVESTMENT INCOME:				
INTEREST	$ 0.00		$ 400.64	
REALIZED GAIN/LOSS	120,681.59		403,852.74	
UNREALIZED GAIN/LOSS-INVESTMENT	3,834,221.91-		6,338,327.25	
		3,713,540.32-		6,742,580.63
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		37,749.79	
MASTER TRUST ALLOCATED EXPENSES	276,744.04-		1,221,712.88-	
MASTER TRUST CHANGE IN REALIZED G/L	5,411,053.44		17,007,760.83	
MASTER TRUST INTEREST INCOME EARNED	339,649.42		3,826,194.46	
MASTER TRUST DIVIDEND INCOME EARNED	164,276.35		2,118,310.29	
		5,638,235.17		21,768,302.49
TOTAL RECEIPTS		1,924,694.85		28,510,883.12
DISBURSEMENTS:				
UBTI TAX EXPENSE	940,000.00		3,201,552.00	
		940,000.00		3,201,552.00
TOTAL DISBURSEMENTS		940,000.00		3,201,552.00
NET ASSETS - END OF PERIOD		$ 272,007,204.01		$ 272,007,204.01

SI-SSA-0010-2736

BNY MELLON

TRDPSB PSBF09288602 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PAGE: 1

PSB F092886 31 DECEMBER 2017 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 285,811,874.81		$ 260,194,394.42
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 120,151.48		$ 400,870.56	
UNREALIZED GAIN/LOSS-INVESTMENT	4,043,327.11-		6,685,389.20	
		3,923,175.63-		7,086,259.76
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		39,812.96	
MASTER TRUST ALLOCATED EXPENSES	291,836.70-		1,288,439.11-	
MASTER TRUST CHANGE IN REALIZED G/L	5,713,265.24		17,961,236.78	
MASTER TRUST INTEREST INCOME EARNED	358,172.73		4,035,215.94	
MASTER TRUST DIVIDEND INCOME EARNED	173,235.41		2,234,055.11	
		5,952,836.68		22,981,881.68
TOTAL RECEIPTS		2,029,661.05		30,068,141.44
DISBURSEMENTS:				
UBTI TAX EXPENSE	1,000,000.00		3,421,000.00	
		1,000,000.00		3,421,000.00
TOTAL DISBURSEMENTS		1,000,000.00		3,421,000.00
NET ASSETS - END OF PERIOD		$ 286,841,535.86		$ 286,841,535.86

SI-SSA-0010-2737

BNY MELLON

TRDPSB PSBF09288802 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092888 31 DECEMBER 2017 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 315,068,998.90		$ 286,801,737.53
RECEIPTS:				
INVESTMENT INCOME:				
INTEREST	$ 0.00		$ 455.13	
REALIZED GAIN/LOSS	130,832.20		436,073.71	
UNREALIZED GAIN/LOSS-INVESTMENT	4,457,284.15-		7,369,041.94	
		4,326,451.95-		7,805,570.78
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		43,887.19	
MASTER TRUST ALLOCATED EXPENSES	321,715.03-		1,420,298.30-	
MASTER TRUST CHANGE IN REALIZED G/L	6,299,811.46		19,805,480.80	
MASTER TRUST INTEREST INCOME EARNED	394,842.56		4,448,149.63	
MASTER TRUST DIVIDEND INCOME EARNED	190,971.31		2,462,662.62	
		6,563,910.30		25,339,881.94
TOTAL RECEIPTS		2,237,458.35		33,145,452.72
DISBURSEMENTS:				
UBTI TAX EXPENSE	1,098,000.00		3,738,733.00	
		1,098,000.00		3,738,733.00
TOTAL DISBURSEMENTS		1,098,000.00		3,738,733.00
NET ASSETS - END OF PERIOD		$ 316,208,457.25		$ 316,208,457.25

SI-SSA-0010-2738

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FERC Qualified Reports

BNY MELLON

TRDPSB PSBF09319702 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PAGE: 1

PSB F093197 31 DECEMBER 2017 NC100

PSEG NUCLEAR HOPE CREEK QUAL

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 784,229.72		$ 707,665.79
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 11,133.31-		$ 18,105.79	
		11,133.31-		18,105.79
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		108.64	
MASTER TRUST ALLOCATED EXPENSES	803.57-		3,525.81-	
MASTER TRUST CHANGE IN REALIZED G/L	16,062.32		50,331.60	
MASTER TRUST INTEREST INCOME EARNED	986.23		11,030.82	
MASTER TRUST DIVIDEND INCOME EARNED	477.00		6,101.56	
		16,721.98		64,046.81
TOTAL RECEIPTS		5,588.67		82,152.60
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 789,818.39		$ 789,818.39

SI-SSA-0010-2740

BNY MELLON

TRDPSB PSBF09319502 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093195 31 DECEMBER 2017 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 3,334,746.51		$ 3,009,176.98
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 47,341.67-		$ 76,990.62	
		47,341.67-		76,990.62
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		462.01	
MASTER TRUST ALLOCATED EXPENSES	3,417.00-		14,992.75-	
MASTER TRUST CHANGE IN REALIZED G/L	68,301.11		214,035.06	
MASTER TRUST INTEREST INCOME EARNED	4,193.69		46,893.63	
MASTER TRUST DIVIDEND INCOME EARNED	2,028.34		25,945.43	
		71,106.14		272,343.38
TOTAL RECEIPTS		23,764.47		349,334.00
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 3,358,510.98		$ 3,358,510.98

SI-SSA-0010-2741

BNY MELLON

TRDPSB PSBF09319602 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PAGE: 1

PSB F093196 31 DECEMBER 2017 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 3,351,255.23		$ 3,024,073.97
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 47,576.04-		$ 77,371.79	
		47,576.04-		77,371.79
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		464.31	
MASTER TRUST ALLOCATED EXPENSES	3,433.91-		15,067.01-	
MASTER TRUST CHANGE IN REALIZED G/L	68,639.23		215,092.97	
MASTER TRUST INTEREST INCOME EARNED	4,214.46		47,127.43	
MASTER TRUST DIVIDEND INCOME EARNED	2,038.38		26,073.89	
		71,458.16		273,691.59
TOTAL RECEIPTS		23,882.12		351,063.38
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 3,375,137.35		$ 3,375,137.35

SI-SSA-0010-2742

BNY MELLON

TRDPSB PSBF09319302 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093193 31 DECEMBER 2017 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 6,246,158.95		$ 5,636,349.79
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 88,673.49-		$ 144,207.56	
		88,673.49-		144,207.56
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		865.38	
MASTER TRUST ALLOCATED EXPENSES	6,400.22-		28,082.25-	
MASTER TRUST CHANGE IN REALIZED G/L	127,931.63		400,898.35	
MASTER TRUST INTEREST INCOME EARNED	7,855.02		87,835.04	
MASTER TRUST DIVIDEND INCOME EARNED	3,799.20		48,597.22	
		133,185.63		510,113.74
TOTAL RECEIPTS		44,512.14		654,321.30
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 6,290,671.09		$ 6,290,671.09

SI-SSA-0010-2743

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093194 31 DECEMBER 2017 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 5,396,045.57		$ 4,869,232.52
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 76,604.87-		$ 124,580.63	
		76,604.87-		124,580.63
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		747.60	
MASTER TRUST ALLOCATED EXPENSES	5,529.14-		24,260.19-	
MASTER TRUST CHANGE IN REALIZED G/L	110,519.91		346,335.58	
MASTER TRUST INTEREST INCOME EARNED	6,785.94		75,880.33	
MASTER TRUST DIVIDEND INCOME EARNED	3,282.12		41,983.06	
		115,058.83		440,686.38
TOTAL RECEIPTS		38,453.96		565,267.01
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 5,434,499.53		$ 5,434,499.53

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Non-FERC

Non-Qualified Reports

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092885 31 DECEMBER 2017 NC100

PSEG NUCLEAR SALEM NONQUAL

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 129,507,141.34		$ 108,501,320.68
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 1,373,453.12		$ 20,183,420.11	
		1,373,453.12		20,183,420.11
MASTER TRUST INVESTMENT GAIN/LOSS	172.83		12,361.75	
MASTER TRUST ALLOCATED EXPENSES	125,022.90-		517,319.65-	
MASTER TRUST CHANGE IN REALIZED G/L	1,939.43-		461,260.04	
MASTER TRUST INTEREST INCOME EARNED	35,758.46		420,396.31	
MASTER TRUST DIVIDEND INCOME EARNED	125,939.89		1,854,064.07	
		34,908.85		2,230,762.52
TOTAL RECEIPTS		1,408,361.97		22,414,182.63
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 130,915,503.31		$ 130,915,503.31

BNY MELLON

TRDPSB PSBF09288702 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092887 31 DECEMBER 2017 NC100

PSEG NUCLEAR SALEM NONQUAL

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 42,136,870.80		$ 35,302,347.69
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 446,871.23		$ 6,566,944.17	
		446,871.23		6,566,944.17
MASTER TRUST INVESTMENT GAIN/LOSS	56.23		4,022.07	
MASTER TRUST ALLOCATED EXPENSES	40,677.86-		168,316.85-	
MASTER TRUST CHANGE IN REALIZED G/L	631.02-		150,077.09	
MASTER TRUST INTEREST INCOME EARNED	11,634.50		136,781.55	
MASTER TRUST DIVIDEND INCOME EARNED	40,976.22		603,244.38	
		11,358.07		725,808.24
TOTAL RECEIPTS		458,229.30		7,292,752.41
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 42,595,100.10		$ 42,595,100.10

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BNY MELLON

TRDPSB PSBF09288102 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092881 31 DECEMBER 2017 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 92,940,524.57		$ 77,865,742.05
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 985,655.70		$ 14,484,588.51	
		985,655.70		14,484,588.51
MASTER TRUST INVESTMENT GAIN/LOSS	124.03		8,871.38	
MASTER TRUST ALLOCATED EXPENSES	89,722.41-		371,253.34-	
MASTER TRUST CHANGE IN REALIZED G/L	1,391.83-		331,022.29	
MASTER TRUST INTEREST INCOME EARNED	25,661.99		301,696.53	
MASTER TRUST DIVIDEND INCOME EARNED	90,380.50		1,330,565.13	
		25,052.28		1,600,901.99
TOTAL RECEIPTS		1,010,707.98		16,085,490.50
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 93,951,232.55		$ 93,951,232.55

BNY MELLON

TRDPSB PSBF09288302 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092883 31 DECEMBER 2017 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 73,468,817.86		$ 61,552,310.43
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 779,153.78		$ 11,449,963.32	
		779,153.78		11,449,963.32
MASTER TRUST INVESTMENT GAIN/LOSS	98.04		7,012.77	
MASTER TRUST ALLOCATED EXPENSES	70,924.93-		293,473.09-	
MASTER TRUST CHANGE IN REALIZED G/L	1,100.23-		261,670.77	
MASTER TRUST INTEREST INCOME EARNED	20,285.62		238,488.92	
MASTER TRUST DIVIDEND INCOME EARNED	71,445.13		1,051,802.15	
		19,803.63		1,265,501.52
TOTAL RECEIPTS		798,957.41		12,715,464.84
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 74,267,775.27		$ 74,267,775.27

BNY MELLON

TRDPSB PSBF09288002 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092880 31 DECEMBER 2017 NC100

PSEG NUCLEAR HOPE CREEK

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 13,295,357.18		$ 11,138,874.65
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 141,000.33		$ 2,072,053.91	
		141,000.33		2,072,053.91
MASTER TRUST INVESTMENT GAIN/LOSS	17.74		1,269.06	
MASTER TRUST ALLOCATED EXPENSES	12,835.00-		53,108.64-	
MASTER TRUST CHANGE IN REALIZED G/L	199.10-		47,353.53	
MASTER TRUST INTEREST INCOME EARNED	3,671.01		43,158.36	
MASTER TRUST DIVIDEND INCOME EARNED	12,929.14		190,340.43	
		3,583.79		229,012.74
TOTAL RECEIPTS		144,584.12		2,301,066.65
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 13,439,941.30		$ 13,439,941.30

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FERC Non-Qualified Reports

BNY MELLON

TRDPSB PSBF09336202 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

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PSB F093362 31 DECEMBER 2017 NC100

PSEG NUCLEAR SALEM NON-QUAL

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 322,750.82		$ 270,401.23
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 3,422.83		$ 50,299.96	
		3,422.83		50,299.96
MASTER TRUST INVESTMENT GAIN/LOSS	0.43		30.82	
MASTER TRUST ALLOCATED EXPENSES	311.58-		1,289.23-	
MASTER TRUST CHANGE IN REALIZED G/L	4.83-		1,149.53	
MASTER TRUST INTEREST INCOME EARNED	89.13		1,047.74	
MASTER TRUST DIVIDEND INCOME EARNED	313.86		4,620.61	
		87.01		5,559.47
TOTAL RECEIPTS		3,509.84		55,859.43
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 326,260.66		$ 326,260.66

SI-SSA-0010-2752

BNY MELLON

TRDPSB PSBF09336302 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093363 31 DECEMBER 2017 NC100

PSEG NUCLEAR SALEM NON-QUAL

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 155,853.19		$ 130,574.08
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 1,652.85		$ 24,289.39	
		1,652.85		24,289.39
MASTER TRUST INVESTMENT GAIN/LOSS	0.21		14.89	
MASTER TRUST ALLOCATED EXPENSES	150.46-		622.55-	
MASTER TRUST CHANGE IN REALIZED G/L	2.33-		554.99	
MASTER TRUST INTEREST INCOME EARNED	43.03		506.01	
MASTER TRUST DIVIDEND INCOME EARNED	151.56		2,231.24	
		42.01		2,684.58
TOTAL RECEIPTS		1,694.86		26,973.97
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 157,548.05		$ 157,548.05

SI-SSA-0010-2753

BNY MELLON

TRDPSB PSBF09336402 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

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PSB F093364 31 DECEMBER 2017 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 464,455.00		$ 389,121.25
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 4,925.66		$ 72,384.40	
		4,925.66		72,384.40
MASTER TRUST INVESTMENT GAIN/LOSS	0.62		44.33	
MASTER TRUST ALLOCATED EXPENSES	448.37-		1,855.29-	
MASTER TRUST CHANGE IN REALIZED G/L	6.96-		1,654.23	
MASTER TRUST INTEREST INCOME EARNED	128.24		1,507.66	
MASTER TRUST DIVIDEND INCOME EARNED	451.66		6,649.27	
		125.19		8,000.20
TOTAL RECEIPTS		5,050.85		80,384.60
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 469,505.85		$ 469,505.85

SI-SSA-0010-2754

BNY MELLON

TRDPSB PSBF09336502 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PAGE: 1

PSB F093365 31 DECEMBER 2017 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 463,861.80		$ 388,624.26
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 4,919.36		$ 72,291.93	
		4,919.36		72,291.93
MASTER TRUST INVESTMENT GAIN/LOSS	0.62		44.26	
MASTER TRUST ALLOCATED EXPENSES	447.80-		1,852.90-	
MASTER TRUST CHANGE IN REALIZED G/L	6.95-		1,652.13	
MASTER TRUST INTEREST INCOME EARNED	128.07		1,505.72	
MASTER TRUST DIVIDEND INCOME EARNED	451.09		6,640.79	
		125.03		7,990.00
TOTAL RECEIPTS		5,044.39		80,281.93
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 468,906.19		$ 468,906.19

SI-SSA-0010-2755

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Document Content(s)

Order 658.PDF.....1-27

Alexander C. Stern
Associate General Regulatory Counsel

Law Department
80 Park Plaza, T5G, Newark, NJ 07102-4194
tel: 973.430.5754 fax: 973.430.5983
email: alexander.stern@pseg.com

PSEG
Services Corporation

January 11, 2013

VIA E- FILING

Kimberly D. Bose, Secretary
Nathaniel J. Davis, Sr., Deputy Secretary
Federal Energy Regulatory Commission
888 1st Street, N.E., Room 1A
Washington, D.C. 20426

Re: Order No. 580
Docket No. RM 94-14-000

Dear Secretary Bose and Deputy Secretary Davis:

In accordance with 18 CFR § 35.33(d), attached is the financial reports furnished by our trustee, Mellon Bank, for PSEG Nuclear LLC's ("PSEG") Qualified and Non-Qualified Nuclear Decommissioning Trust Funds for the year ending December 31, 2012.

On December 31, 2012 assets in the trust funds totaled $1,505,604,227.68, included in this balance are amounts collected through FERC jurisdictional rates totaling $14,694,132.34. This total represents the contributions and earnings on the funds since its inception in 1988. During 2011, there were no contributions made to the PSEG trust funds.

If you have any questions, or would like to see the detailed information that comprise the numbers shown on the Mellon Bank statements, please contact Peter Caruso at (973) 430-5222.

Sincerely,

Alexander C, Stern

Alexander C. Stern

ACS/jb
Enclosure(s)

PSEG Nuclear LLC
FERC ASSET Allocation
As of December 31, 2012

Account Names	Percentage	Total Trust Market Values	Non-FERC Assets	FERC Assets
Q Hope Creek	33.5%	$ 441,553,084.25	$440,981,066.52	$572,017.73
Q PB 2	14.9%	$ 196,479,797.38	$194,047,436.05	$2,432,361.33
Q PB 3	15.9%	$ 209,945,931.86	$207,501,529.04	$2,444,402.82
Q Salem 1	17.0%	$ 223,468,610.35	$218,912,667.16	$4,555,943.19
Q Salem 2	18.6%	$ 245,223,576.06	$241,287,704.85	$3,935,871.21
PSEG Nuclear LLC Qual. Plans	G716275	$ 1,316,670,999.90		
Non-Q Salem 1	36.8%	$ 69,535,900.56	$69,363,037.68	$172,862.88
Non-Q Salem 2	12.0%	$ 22,651,660.58	$22,568,186.80	$83,473.78
Non-Q PB 2	26.5%	$ 50,026,995.04	$49,778,236.48	$248,758.56
Non-Q PB 3	21.0%	$ 39,597,779.64	$39,349,338.80	$248,440.84
Non-Q Hope Creek	3.8%	$ 7,120,891.96	$7,120,891.96	$ -
PSEG Nuclear LLC Non Qual. Plans	G716277	$ 188,933,227.78		
Totals		$ 1,505,604,227.68	$1,490,910,095.34	$14,694,132.34
			99.02%	0.98%

SI-SSA-0010-2758

THE BANK OF NEW YORK MELLON.

TRDPSB PSBG71627500 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

INVESTMENT DETAIL PAGE: 1

PSB G716275 31 DECEMBER 2012 M1101

PSEG NUCLEAR LLC QUAL. PLANS

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	PSE&G QUALIFIED MTU				
222,508,462.5060	HOPE CREEK QUAL	385,136,043.97	1.9818	440,981,066.52	55,845,022.55
97,911,679.0430	PEACH BOTTOM #2 Q	171,686,913.92	1.9818	194,047,436.05	22,360,522.13
104,700,291.4640	PEACH BOTTOM #3 Q	183,512,010.54	1.9818	207,501,529.04	23,989,518.50
110,458,077.8860	SALEM Q UNIT 1	195,970,112.18	1.9818	218,912,667.16	22,942,554.98
121,747,984.9000	SALEM Q UNIT 2	216,309,941.06	1.9818	241,287,704.85	24,977,763.79
2,298,819.5910	SALEM Q #1 FERC	4,834,461.98	1.9818	4,555,943.19	278,518.79-
1,985,946.1490	SALEM Q #2 FERC	4,025,695.96	1.9818	3,935,871.21	89,824.75-
1,227,311.1520	PB#2 Q FERC	2,543,635.47	1.9818	2,432,361.33	111,274.14-
1,233,386.9960	PB#3 Q FERC	2,563,315.52	1.9818	2,444,402.82	118,912.70-
288,626.4160	HOPE CREEK QUAL FERC	688,317.49	1.9818	572,017.73	116,299.76-
664,360,586.1030		1,167,270,448.09		1,316,670,999.90	149,400,551.81
TOTAL INVESTMENTS UNIT OF PARTICIPATION		1,167,270,448.09		1,316,670,999.90	149,400,551.81
TOTAL INVESTMENT		1,167,270,448.09		1,316,670,999.90	149,400,551.81

SI-SSA-0010-2759

THE BANK OF NEW YORK MELLON.

TRDPSB PSBG71627700 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

INVESTMENT DETAIL PAGE: 1

PSB G716277 31 DECEMBER 2012 M1101

PSEG NUCLEAR LLC NQ PLANS

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	PSE&G NON-QUALIFIED MTU				
4,397,995.9250	HOPE CREEK NONQUAL	6,603,610.81	1.6191	7,120,891.96	517,281.15
30,743,968.9440	PEACH BOTTOM #2 NQ	46,794,106.27	1.6191	49,778,236.48	2,984,130.21
24,302,886.8740	PEACH BOTTOM #3 NQ	37,099,813.63	1.6191	39,349,338.80	2,249,525.17
42,839,908.0980	SALEM NQ UNIT 1	65,054,244.90	1.6191	69,363,037.68	4,308,792.78
13,938,533.8450	SALEM NQ UNIT 2	21,112,746.71	1.6191	22,568,186.80	1,455,440.09
106,763.3430	SALEM NQ #1 FERC	171,486.30	1.6191	172,862.88	1,376.58
51,554.9650	SALEM NQ #2 FERC	82,809.07	1.6191	83,473.78	664.71
153,637.9330	PB#2 NQ FERC	246,781.37	1.6191	248,758.56	1,977.19
153,441.7060	PB#3 NQ FERC	246,465.84	1.6191	248,440.84	1,975.00
116,688,691.6330		177,412,064.90		188,933,227.78	11,521,162.88
TOTAL INVESTMENTS UNIT OF PARTICIPATION		177,412,064.90		188,933,227.78	11,521,162.88
TOTAL INVESTMENT		177,412,064.90		188,933,227.78	11,521,162.88

SI-SSA-0010-2760

FERC Non-Qualified Reports

SI-SSA-0010-2761

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09287902 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092879 31 DECEMBER 2012 NC100

PSEG NUCLEAR HOPE CREEK QUAL

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 437,199,251.97		$ 397,965,333.67
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 58,139.27		$ 251,809.61	
UNREALIZED GAIN/LOSS-INVESTMENT	2,779,376.71		30,385,569.31	
		2,837,515.98		30,637,378.92
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		127,695.46	
MASTER TRUST ALLOCATED EXPENSES	69,817.54-		2,150,761.87-	
MASTER TRUST CHANGE IN REALIZED G/L	636,509.37		5,708,628.65	
MASTER TRUST INTEREST INCOME EARNED	548,044.75		7,088,138.05	
MASTER TRUST DIVIDEND INCOME EARNED	308,561.99		4,032,787.08	
		1,423,298.57		14,806,487.37
TRANSFERS IN:				
CASH	0.00		9,866.56	
		0.00		9,866.56
TOTAL RECEIPTS		4,260,814.55		45,453,732.85
DISBURSEMENTS:				
UBTI TAX EXPENSE	479,000.00		2,438,000.00	
		479,000.00		2,438,000.00
TOTAL DISBURSEMENTS		479,000.00		2,438,000.00
NET ASSETS - END OF PERIOD		$ 440,981,066.52		$ 440,981,066.52

SI-SSA-0010-2762

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09288202 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092882 31 DECEMBER 2012 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 192,382,525.31		$ 175,151,831.16
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 23,073.17		$ 101,191.17	
UNREALIZED GAIN/LOSS-INVESTMENT	1,223,025.13		13,370,637.09	
		1,246,098.30		13,471,828.26
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		56,198.12	
MASTER TRUST ALLOCATED EXPENSES	30,722.22-		945,026.81-	
MASTER TRUST CHANGE IN REALIZED G/L	282,597.07		2,522,091.87	
MASTER TRUST INTEREST INCOME EARNED	241,159.28		3,119,379.24	
MASTER TRUST DIVIDEND INCOME EARNED	135,778.31		1,774,791.93	
		628,812.44		6,527,434.35
TRANSFERS IN:				
CASH	0.00		4,342.28	
		0.00		4,342.28
TOTAL RECEIPTS		1,874,910.74		20,003,604.89
DISBURSEMENTS:				
UBTI TAX EXPENSE	210,000.00		1,108,000.00	
		210,000.00		1,108,000.00
TOTAL DISBURSEMENTS		210,000.00		1,108,000.00
NET ASSETS - END OF PERIOD		$ 194,047,436.05		$ 194,047,436.05

SI-SSA-0010-2763

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09288402 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092884 31 DECEMBER 2012 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 205,720,623.16		$ 187,294,145.91
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 24,697.09		$ 108,481.62	
UNREALIZED GAIN/LOSS-INVESTMENT	1,307,822.40		14,298,957.13	
		1,332,519.49		14,407,438.75
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		60,094.20	
MASTER TRUST ALLOCATED EXPENSES	32,852.31-		1,011,923.80-	
MASTER TRUST CHANGE IN REALIZED G/L	302,166.50		2,696,659.41	
MASTER TRUST INTEREST INCOME EARNED	257,879.83		3,335,638.12	
MASTER TRUST DIVIDEND INCOME EARNED	145,192.37		1,897,833.12	
		672,386.39		6,978,301.05
TRANSFERS IN:				
CASH	0.00		4,643.33	
		0.00		4,643.33
TOTAL RECEIPTS		2,004,905.88		21,390,383.13
DISBURSEMENTS:				
UBTI TAX EXPENSE	224,000.00		1,183,000.00	
		224,000.00		1,183,000.00
TOTAL DISBURSEMENTS		224,000.00		1,183,000.00
NET ASSETS - END OF PERIOD		$ 207,501,529.04		$ 207,501,529.04

SI-SSA-0010-2764

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09288602 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092886 31 DECEMBER 2012 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 217,031,505.42		$ 197,644,297.34
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 23,248.69		$ 104,520.20	
UNREALIZED GAIN/LOSS-INVESTMENT	1,379,743.53		15,087,478.37	
		1,402,992.22		15,191,998.57
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		63,412.07	
MASTER TRUST ALLOCATED EXPENSES	34,658.96-		1,067,868.06-	
MASTER TRUST CHANGE IN REALIZED G/L	321,590.12		2,855,710.54	
MASTER TRUST INTEREST INCOME EARNED	272,061.42		3,519,650.11	
MASTER TRUST DIVIDEND INCOME EARNED	153,176.94		2,002,566.77	
		712,169.52		7,373,471.43
TRANSFERS IN:				
CASH	0.00		4,899.82	
		0.00		4,899.82
TOTAL RECEIPTS		2,115,161.74		22,570,369.82
DISBURSEMENTS:				
UBTI TAX EXPENSE	234,000.00		1,302,000.00	
		234,000.00		1,302,000.00
TOTAL DISBURSEMENTS		234,000.00		1,302,000.00
NET ASSETS - END OF PERIOD		$ 218,912,667.16		$ 218,912,667.16

SI-SSA-0010-2765

THE BANK OF NEW YORK MELLON.

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFITS
31 DECEMBER 2012

PSB F092888
PSEG NUCLEAR SALEM QUAL UNIT
NC100

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 239,220,352.69		$ 217,782,940.67
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 25,886.79		$ 108,388.71	
UNREALIZED GAIN/LOSS-INVESTMENT	1,520,766.95		16,628,707.11	
		1,546,653.74		16,737,095.82
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		69,876.76	
MASTER TRUST ALLOCATED EXPENSES	38,201.45-		1,178,410.88-	
MASTER TRUST CHANGE IN REALIZED G/L	354,197.96		3,153,338.66	
MASTER TRUST INTEREST INCOME EARNED	299,868.78		3,878,674.79	
MASTER TRUST DIVIDEND INCOME EARNED	168,833.13		2,206,789.90	
		784,698.42		8,130,269.23
TRANSFERS IN:				
CASH	0.00		5,399.13	
		0.00		5,399.13
TOTAL RECEIPTS		2,331,352.16		24,872,764.18
DISBURSEMENTS:				
UBTI TAX EXPENSE	264,000.00		1,368,000.00	
		264,000.00		1,368,000.00
TOTAL DISBURSEMENTS		264,000.00		1,368,000.00
NET ASSETS - END OF PERIOD		$ 241,287,704.85		$ 241,287,704.85

SI-SSA-0010-2766

FERC Qualified Reports

SI-SSA-0010-2767

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09319702 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093197 31 DECEMBER 2012 NC100

PSEG NUCLEAR HOPE CREEK QUAL

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 566,490.82		$ 513,275.90
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 3,605.26		$ 148,921.91-	
		3,605.26		148,921.91-
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		165.06	
MASTER TRUST ALLOCATED EXPENSES	90.56-		185,418.78	
MASTER TRUST CHANGE IN REALIZED G/L	901.06		7,701.34	
MASTER TRUST INTEREST INCOME EARNED	710.90		9,165.66	
MASTER TRUST DIVIDEND INCOME EARNED	400.25		5,212.90	
		1,921.65		207,663.74
TOTAL RECEIPTS		5,526.91		58,741.83
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 572,017.73		$ 572,017.73

SI-SSA-0010-2768

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09319502 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093195 31 DECEMBER 2012 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 2,408,859.55		$ 2,182,525.22
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 15,330.48		$ 5,180.15	
		15,330.48		5,180.15
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		701.82	
MASTER TRUST ALLOCATED EXPENSES	385.10-		150,011.76	
MASTER TRUST CHANGE IN REALIZED G/L	3,831.54		32,747.61	
MASTER TRUST INTEREST INCOME EARNED	3,022.90		38,974.26	
MASTER TRUST DIVIDEND INCOME EARNED	1,701.96		22,166.28	
		8,171.30		244,601.73
TRANSFERS IN:				
CASH	0.00		54.23	
		0.00		54.23
TOTAL RECEIPTS		23,501.78		249,836.11
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 2,432,361.33		$ 2,432,361.33

SI-SSA-0010-2769

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09319602 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093196 31 DECEMBER 2012 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 2,420,784.69		$ 2,193,329.87
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 15,406.37		$ 2,933.90-	
		15,406.37		2,933.90-
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		705.32	
MASTER TRUST ALLOCATED EXPENSES	387.01-		158,894.09	
MASTER TRUST CHANGE IN REALIZED G/L	3,850.51		32,909.70	
MASTER TRUST INTEREST INCOME EARNED	3,037.87		39,167.24	
MASTER TRUST DIVIDEND INCOME EARNED	1,710.39		22,275.99	
		8,211.76		253,952.34
TRANSFERS IN:				
CASH	0.00		54.51	
		0.00		54.51
TOTAL RECEIPTS		23,618.13		251,072.95
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 2,444,402.82		$ 2,444,402.82

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THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09319302 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093193 31 DECEMBER 2012 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 4,511,923.10		$ 4,087,986.73
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 28,714.79		$ 31,061.30-	
		28,714.79		31,061.30-
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		1,314.61	
MASTER TRUST ALLOCATED EXPENSES	721.31-		321,744.01	
MASTER TRUST CHANGE IN REALIZED G/L	7,176.68		61,337.98	
MASTER TRUST INTEREST INCOME EARNED	5,662.06		73,000.91	
MASTER TRUST DIVIDEND INCOME EARNED	3,187.87		41,518.65	
		15,305.30		498,916.16
TRANSFERS IN:				
CASH	0.00		101.60	
		0.00		101.60
TOTAL RECEIPTS		44,020.09		467,956.46
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 4,555,943.19		$ 4,555,943.19

SI-SSA-0010-2771

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09319402 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093194 31 DECEMBER 2012 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 3,897,842.32		$ 3,531,604.45
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 24,806.67		$ 118,924.37	
		24,806.67		118,924.37
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		1,135.69	
MASTER TRUST ALLOCATED EXPENSES	623.14-		132,195.95	
MASTER TRUST CHANGE IN REALIZED G/L	6,199.92		52,989.78	
MASTER TRUST INTEREST INCOME EARNED	4,891.44		63,065.32	
MASTER TRUST DIVIDEND INCOME EARNED	2,754.00		35,867.88	
		13,222.22		285,254.62
TRANSFERS IN:				
CASH	0.00		87.77	
		0.00		87.77
TOTAL RECEIPTS		38,028.89		404,266.76
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 3,935,871.21		$ 3,935,871.21

SI-SSA-0010-2772

Non-FERC
Qualified Reports

SI-SSA-0010-2773

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09288502 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092885 31 DECEMBER 2012 NC100

PSEG NUCLEAR SALEM NONQUAL

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 69,203,973.10		$ 60,792,399.99
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 206,236.25-		$ 4,403,764.37-	
		206,236.25-		4,403,764.37-
MASTER TRUST INVESTMENT GAIN/LOSS	38.33		58,029.32	
MASTER TRUST ALLOCATED EXPENSES	81,564.54-		232,707.84-	
MASTER TRUST CHANGE IN REALIZED G/L	268,994.36		10,861,547.21	
MASTER TRUST INTEREST INCOME EARNED	93.97		380.09	
MASTER TRUST DIVIDEND INCOME EARNED	177,738.71		2,287,153.28	
		365,300.83		12,974,402.06
TOTAL RECEIPTS		159,064.58		8,570,637.69
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 69,363,037.68		$ 69,363,037.68

SI-SSA-0010-2774

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09288702 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092887 31 DECEMBER 2012 NC100

PSEG NUCLEAR SALEM NONQUAL

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 22,516,433.02		$ 19,779,615.84
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 67,101.70-		$ 1,432,823.30-	
		67,101.70-		1,432,823.30-
MASTER TRUST INVESTMENT GAIN/LOSS	12.47		18,880.63	
MASTER TRUST ALLOCATED EXPENSES	26,538.11-		75,714.62-	
MASTER TRUST CHANGE IN REALIZED G/L	87,520.89		3,533,948.84	
MASTER TRUST INTEREST INCOME EARNED	30.58		123.66	
MASTER TRUST DIVIDEND INCOME EARNED	57,829.65		744,155.75	
		118,855.48		4,221,394.26
TOTAL RECEIPTS		51,753.78		2,788,570.96
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 22,568,186.80		$ 22,568,186.80

SI-SSA-0010-2775

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09288102 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092881 31 DECEMBER 2012 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 49,664,084.13		$ 43,627,536.57
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 148,005.02-		$ 3,160,352.14-	
		148,005.02-		3,160,352.14-
MASTER TRUST INVESTMENT GAIN/LOSS	27.51		41,644.65	
MASTER TRUST ALLOCATED EXPENSES	58,534.62-		167,002.30-	
MASTER TRUST CHANGE IN REALIZED G/L	193,043.23		7,794,766.25	
MASTER TRUST INTEREST INCOME EARNED	67.44		272.76	
MASTER TRUST DIVIDEND INCOME EARNED	127,553.81		1,641,370.69	
		262,157.37		9,311,052.05
TOTAL RECEIPTS		114,152.35		6,150,699.91
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 49,778,236.48		$ 49,778,236.48

SI-SSA-0010-2776

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09288302 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092883 31 DECEMBER 2012 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 39,259,102.18		$ 34,487,254.65
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 116,996.88-		$ 2,498,235.68-	
		116,996.88-		2,498,235.68-
MASTER TRUST INVESTMENT GAIN/LOSS	21.75		32,919.79	
MASTER TRUST ALLOCATED EXPENSES	46,271.21-		132,014.13-	
MASTER TRUST CHANGE IN REALIZED G/L	152,599.28		6,161,706.78	
MASTER TRUST INTEREST INCOME EARNED	53.31		215.62	
MASTER TRUST DIVIDEND INCOME EARNED	100,830.37		1,297,491.77	
		207,233.50		7,360,319.83
TOTAL RECEIPTS		90,236.62		4,862,084.15
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 39,349,338.80		$ 39,349,338.80

SI-SSA-0010-2777

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09288002 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092880
31 DECEMBER 2012
NC100

PSEG NUCLEAR HOPE CREEK

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 7,104,562.20		$ 6,241,020.10
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 21,172.47-		$ 452,095.69-	
		21,172.47-		452,095.69-
MASTER TRUST INVESTMENT GAIN/LOSS	3.94		5,957.38	
MASTER TRUST ALLOCATED EXPENSES	8,373.51-		23,890.07-	
MASTER TRUST CHANGE IN REALIZED G/L	27,615.28		1,115,059.36	
MASTER TRUST INTEREST INCOME EARNED	9.65		39.01	
MASTER TRUST DIVIDEND INCOME EARNED	18,246.87		234,801.87	
		37,502.23		1,331,967.55
TOTAL RECEIPTS		16,329.76		879,871.86
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 7,120,891.96		$ 7,120,891.96

SI-SSA-0010-2778

Non-FERC
Non-Qualified Reports

SI-SSA-0010-2779

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09336202 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093362 31 DECEMBER 2012 NC100

PSEG NUCLEAR SALEM NON-QUAL

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 172,466.47		$ 151,503.59
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 513.97-		$ 10,974.81-	
		513.97-		10,974.81-
MASTER TRUST INVESTMENT GAIN/LOSS	0.10		144.63	
MASTER TRUST ALLOCATED EXPENSES	203.27-		579.94-	
MASTER TRUST CHANGE IN REALIZED G/L	670.37		27,068.56	
MASTER TRUST INTEREST INCOME EARNED	0.23		0.93	
MASTER TRUST DIVIDEND INCOME EARNED	442.95		5,699.92	
		910.38		32,334.10
TOTAL RECEIPTS		396.41		21,359.29
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 172,862.88		$ 172,862.88

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THE BANK OF NEW YORK MELLON.

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFITS
31 DECEMBER 2012

PSB F093363
PSEG NUCLEAR SALEM NON-QUAL
NC100

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 83,282.35		$ 73,159.59
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 248.19-		$ 5,299.66-	
		248.19-		5,299.66-
MASTER TRUST INVESTMENT GAIN/LOSS	0.05		69.85	
MASTER TRUST ALLOCATED EXPENSES	98.16-		280.04-	
MASTER TRUST CHANGE IN REALIZED G/L	323.72		13,071.15	
MASTER TRUST INTEREST INCOME EARNED	0.11		0.44	
MASTER TRUST DIVIDEND INCOME EARNED	213.90		2,752.45	
		439.62		15,613.85
TOTAL RECEIPTS		191.43		10,314.19
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 83,473.78		$ 83,473.78

SI-SSA-0010-2781

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09336402 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093364 31 DECEMBER 2012 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 248,188.10		$ 218,021.45
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 739.63-		$ 15,793.38-	
		739.63-		15,793.38-
MASTER TRUST INVESTMENT GAIN/LOSS	0.14		208.11	
MASTER TRUST ALLOCATED EXPENSES	292.52-		834.57-	
MASTER TRUST CHANGE IN REALIZED G/L	964.70		38,953.06	
MASTER TRUST INTEREST INCOME EARNED	0.34		1.41	
MASTER TRUST DIVIDEND INCOME EARNED	637.43		8,202.48	
		1,310.09		46,530.49
TOTAL RECEIPTS		570.46		30,737.11
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 248,758.56		$ 248,758.56

SI-SSA-0010-2782

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09336502 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093365 31 DECEMBER 2012 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 247,871.11		$ 217,742.99
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 738.68-		$ 15,773.11-	
		738.68-		15,773.11-
MASTER TRUST INVESTMENT GAIN/LOSS	0.13		207.82	
MASTER TRUST ALLOCATED EXPENSES	292.14-		833.49-	
MASTER TRUST CHANGE IN REALIZED G/L	963.47		38,903.31	
MASTER TRUST INTEREST INCOME EARNED	0.34		1.34	
MASTER TRUST DIVIDEND INCOME EARNED	636.61		8,191.98	
		1,308.41		46,470.96
TOTAL RECEIPTS		569.73		30,697.85
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 248,440.84		$ 248,440.84

SI-SSA-0010-2783

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Alexander C. Stern
Associate General Regulatory Counsel

Law Department
80 Park Plaza, T5G, Newark, NJ 07102-4194
tel: 973.430.5754 fax: 973.430.5983
email: alexander.stern@pseg.com

PSEG
Services Corporation

March 5, 2014

VIA E- FILING

Kimberly D. Bose, Secretary
Nathaniel J. Davis, Sr., Deputy Secretary
Federal Energy Regulatory Commission
888 1st Street, N.E., Room 1A
Washington, D.C. 20426

Re: Order No. 580
Docket No. RM 94-14-000

Dear Secretary Bose and Deputy Secretary Davis:

In accordance with 18 CFR § 35.33(d), attached is the financial reports furnished by our trustee, Mellon Bank, for PSEG Nuclear LLC's ("PSEG") Qualified and Non-Qualified Nuclear Decommissioning Trust Funds for the year ending December 31, 2013.

On December 31, 2013 assets in the trust funds totaled $1,703,771,097.57, included in this balance are amounts collected through FERC jurisdictional rates totaling $16,659,970.75. This total represents the contributions and earnings on the funds since its inception in 1988. During 2013, there were no contributions made to the PSEG trust funds.

If you have any questions, or would like to see the detailed information that comprises the numbers shown on the Mellon Bank statements, please contact Peter Caruso at (973) 430-5222.

Sincerely,

Alexander C. Stern

Alexander C. Stern

ACS/jb
Enclosure(s)

PSEG Nuclear LLC
FERC ASSET Allocation
As of December 31, 2013

Account Names	Percentage	Total Trust Market Values	Non-FERC Assets	FERC Assets
Q Hope Creek	33.5%	$ 491,569,394.21	$490,924,732.39	$644,661.82
Q PB 2	14.9%	$ 218,740,799.48	$215,999,532.64	$2,741,266.84
Q PB 3	15.9%	$ 233,731,662.34	$230,976,824.77	$2,754,837.57
Q Salem 1	17.0%	$ 248,797,996.88	$243,663,457.12	$5,134,539.76
Q Salem 2	18.6%	$ 273,003,352.49	$268,567,632.75	$4,435,719.74
PSEG Nuclear LLC Qual. Plans	G716275	$ 1,465,843,205.40		
Non-Q Salem 1	36.8%	$ 87,568,134.23	$87,350,444.09	$217,690.14
Non-Q Salem 2	12.0%	$ 28,525,749.11	$28,420,628.69	$105,120.42
Non-Q PB 2	26.5%	$ 63,000,127.72	$62,686,860.44	$313,267.28
Non-Q PB 3	21.0%	$ 49,866,380.61	$49,553,513.43	$312,867.18
Non-Q Hope Creek	3.8%	$ 8,967,500.50	$8,967,500.50	$ -
PSEG Nuclear LLC Non Qual. Plans	G716277	$ 237,927,892.17		
Totals		$ 1,703,771,097.57	$1,687,111,126.82	$16,659,970.75
			99.02%	0.98%

SI-SSA-0010-2785

BNY MELLON

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	PSE&G QUALIFIED MTU				
219,795,622.4830	HOPE CREEK QUAL	410,686,404.78	2.2335	490,924,732.39	80,238,327.61
96,706,783.3400	PEACH BOTTOM #2 Q	182,905,596.29	2.2335	215,999,532.64	33,093,936.35
103,412,380.0030	PEACH BOTTOM #3 Q	195,509,682.03	2.2335	230,976,824.77	35,467,142.74
109,092,408.0620	SALEM Q UNIT 1	208,612,364.76	2.2335	243,663,457.12	35,051,092.36
120,242,444.7670	SALEM Q UNIT 2	230,243,736.79	2.2335	268,567,632.75	38,323,895.96
2,298,823.6020	SALEM Q #1 FERC	5,159,763.27	2.2335	5,134,539.76	25,223.51-
1,985,949.6120	SALEM Q #2 FERC	4,306,723.07	2.2335	4,435,719.74	128,996.67
1,227,313.2950	PB#2 Q FERC	2,717,309.72	2.2335	2,741,266.84	23,957.12
1,233,389.1520	PB#3 Q FERC	2,737,849.61	2.2335	2,754,837.57	16,987.96
288,626.4160	HOPE CREEK QUAL FERC	729,159.31	2.2335	644,661.82	84,497.49-
656,283,740.7320		1,243,608,589.63		1,465,843,205.40	222,234,615.77
TOTAL INVESTMENTS UNIT OF PARTICIPATION		1,243,608,589.63		1,465,843,205.40	222,234,615.77
TOTAL INVESTMENT		1,243,608,589.63		1,465,843,205.40	222,234,615.77

SI-SSA-0010-2786

BNY MELLON

TRDPSB PSBG71627700 MONTHLY FINAL 234633 2013-12-31 CYCLE A 23:46:33 RUN DATE: 07-JAN-14

INVESTMENT DETAIL PAGE: 1

PSB G716277 31 DECEMBER 2013 M1101

PSEG NUCLEAR LLC NQ PLANS

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	PSE&G NON-QUALIFIED MTU				
4,397,995.9250	HOPE CREEK NONQUAL	7,120,194.91	2.0389	8,967,500.50	1,847,305.59
30,743,968.9440	PEACH BOTTOM #2 NQ	50,405,261.44	2.0389	62,686,860.44	12,281,599.00
24,302,886.8740	PEACH BOTTOM #3 NQ	39,954,405.89	2.0389	49,553,513.43	9,599,107.54
42,839,908.0980	SALEM NQ UNIT 1	70,086,176.78	2.0389	87,350,444.09	17,264,267.31
13,938,533.8450	SALEM NQ UNIT 2	22,749,952.62	2.0389	28,420,628.69	5,670,676.07
106,763.3430	SALEM NQ #1 FERC	184,026.63	2.0389	217,690.14	33,663.51
51,554.9650	SALEM NQ #2 FERC	88,864.67	2.0389	105,120.42	16,255.75
153,637.9330	PB#2 NQ FERC	264,827.52	2.0389	313,267.28	48,439.76
153,441.7060	PB#3 NQ FERC	264,488.95	2.0389	312,867.18	48,378.23
116,688,691.6330		191,118,199.41		237,927,892.17	46,809,692.76
TOTAL INVESTMENTS UNIT OF PARTICIPATION		191,118,199.41		237,927,892.17	46,809,692.76
TOTAL INVESTMENT		191,118,199.41		237,927,892.17	46,809,692.76

SI-SSA-0010-2787

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Non-FERC

Qualified Reports

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFITS
31 DECEMBER 2013

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 488,206,765.46		$ 440,981,066.52
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 322,324.10		$ 859,666.13	
UNREALIZED GAIN/LOSS-INVESTMENT	963,361.30		24,393,305.06	
		1,285,685.40		25,252,971.19
MASTER TRUST INVESTMENT GAIN/LOSS	8,323.30		132,278.35	
MASTER TRUST ALLOCATED EXPENSES	202,409.87-		2,339,054.63-	
MASTER TRUST CHANGE IN REALIZED G/L	2,584,098.06		22,061,827.95	
MASTER TRUST INTEREST INCOME EARNED	551,760.37		6,625,409.38	
MASTER TRUST DIVIDEND INCOME EARNED	475,509.67		3,993,470.53	
		3,417,281.53		30,473,931.58
TRANSFERS IN:				
CASH	0.00		763.65	
		0.00		763.65
TOTAL RECEIPTS		4,702,966.93		55,727,666.42
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		0.55	
UBTI TAX EXPENSE	1,985,000.00		5,784,000.00	
		1,985,000.00		5,784,000.55
TOTAL DISBURSEMENTS		1,985,000.00		5,784,000.55
NET ASSETS - END OF PERIOD		$ 490,924,732.39		$ 490,924,732.39

SI-SSA-0010-2789

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S
31 DECEMBER 2013

PSB F092882
PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 214,813,297.59		$ 194,047,436.05
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 134,291.84		$ 354,468.97	
UNREALIZED GAIN/LOSS-INVESTMENT	423,864.56		10,733,414.22	
		558,156.40		11,087,883.19
MASTER TRUST INVESTMENT GAIN/LOSS	3,662.13		58,278.74	
MASTER TRUST ALLOCATED EXPENSES	89,057.31-		1,029,232.68-	
MASTER TRUST CHANGE IN REALIZED G/L	1,144,490.40		9,731,324.31	
MASTER TRUST INTEREST INCOME EARNED	242,766.30		2,915,302.60	
MASTER TRUST DIVIDEND INCOME EARNED	209,217.13		1,757,205.72	
		1,511,078.65		13,432,878.69
TRANSFERS IN:				
CASH	0.00		334.95	
		0.00		334.95
TOTAL RECEIPTS		2,069,235.05		24,521,096.83
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		0.24	
UBTI TAX EXPENSE	883,000.00		2,569,000.00	
		883,000.00		2,569,000.24
TOTAL DISBURSEMENTS		883,000.00		2,569,000.24
NET ASSETS - END OF PERIOD		$ 215,999,532.64		$ 215,999,532.64

SI-SSA-0010-2790

BNY MELLON

TRDPSB PSBF09288402 MONTHLY FINAL 234633 2013-12-31 CYCLE A 23:46:33 RUN DATE: 07-JAN-14

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092884

31 DECEMBER 2013

NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 229,708,110.07		$ 207,501,529.04
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 143,891.78		$ 379,858.03	
UNREALIZED GAIN/LOSS-INVESTMENT	453,255.10		11,477,624.24	
		597,146.88		11,857,482.27
MASTER TRUST INVESTMENT GAIN/LOSS	3,916.05		62,319.37	
MASTER TRUST ALLOCATED EXPENSES	95,232.50-		1,100,595.44-	
MASTER TRUST CHANGE IN REALIZED G/L	1,223,560.54		10,405,249.47	
MASTER TRUST INTEREST INCOME EARNED	259,599.59		3,117,438.97	
MASTER TRUST DIVIDEND INCOME EARNED	223,724.14		1,879,043.17	
		1,615,567.82		14,363,455.54
TRANSFERS IN:				
CASH	0.00		358.18	
		0.00		358.18
TOTAL RECEIPTS		2,212,714.70		26,221,295.99
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		0.26	
UBTI TAX EXPENSE	944,000.00		2,746,000.00	
		944,000.00		2,746,000.26
TOTAL DISBURSEMENTS		944,000.00		2,746,000.26
NET ASSETS - END OF PERIOD		$ 230,976,824.77		$ 230,976,824.77

SI-SSA-0010-2791

BNY MELLON

TRDPSB PSBF09288602 MONTHLY FINAL 234633 2013-12-31 CYCLE A 23:46:33 RUN DATE: 07-JAN-14

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092886 31 DECEMBER 2013 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 242,334,206.86		$ 218,912,667.16
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 143,379.70		$ 373,453.52	
UNREALIZED GAIN/LOSS-INVESTMENT	478,150.58		12,108,537.38	
		621,530.28		12,481,990.90
MASTER TRUST INVESTMENT GAIN/LOSS	4,131.15		65,746.40	
MASTER TRUST ALLOCATED EXPENSES	100,463.23-		1,161,107.77-	
MASTER TRUST CHANGE IN REALIZED G/L	1,299,181.30		11,004,598.38	
MASTER TRUST INTEREST INCOME EARNED	273,858.35		3,288,832.86	
MASTER TRUST DIVIDEND INCOME EARNED	236,012.41		1,982,351.59	
		1,712,719.98		15,180,421.46
TRANSFERS IN:				
CASH	0.00		377.87	
		0.00		377.87
TOTAL RECEIPTS		2,334,250.26		27,662,790.23
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		0.27	
UBTI TAX EXPENSE	1,005,000.00		2,912,000.00	
		1,005,000.00		2,912,000.27
TOTAL DISBURSEMENTS		1,005,000.00		2,912,000.27
NET ASSETS - END OF PERIOD		$ 243,663,457.12		$ 243,663,457.12

SI-SSA-0010-2792

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFITS
31 DECEMBER 2013

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 267,097,805.16		$ 241,287,704.85
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 156,084.97		$ 407,850.82	
UNREALIZED GAIN/LOSS-INVESTMENT	527,021.06		13,346,132.17	
		683,106.03		13,753,982.99
MASTER TRUST INVESTMENT GAIN/LOSS	4,553.38		72,465.65	
MASTER TRUST ALLOCATED EXPENSES	110,731.31-		1,279,766.82-	
MASTER TRUST CHANGE IN REALIZED G/L	1,433,916.24		12,132,958.71	
MASTER TRUST INTEREST INCOME EARNED	301,848.66		3,624,930.81	
MASTER TRUST DIVIDEND INCOME EARNED	260,134.59		2,184,940.36	
		1,889,721.56		16,735,528.71
TRANSFERS IN:				
CASH	0.00		416.50	
		0.00		416.50
TOTAL RECEIPTS		2,572,827.59		30,489,928.20
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		0.30	
UBTI TAX EXPENSE	1,103,000.00		3,210,000.00	
		1,103,000.00		3,210,000.30
TOTAL DISBURSEMENTS		1,103,000.00		3,210,000.30
NET ASSETS - END OF PERIOD		$ 268,567,632.75		$ 268,567,632.75

SI-SSA-0010-2793

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FERC Qualified Reports

BNY MELLON

TRDPSB PSBF09319302 MONTHLY FINAL 234633 2013-12-31 CYCLE A 23:46:33 RUN DATE: 07-JAN-14

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093193

31 DECEMBER 2013

NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 5,085,351.83		$ 4,555,943.19
RECEIPTS:				
REALIZED GAIN/LOSS	$ 0.00		$ 0.28	
UNREALIZED GAIN/LOSS-INVESTMENT	10,075.71		253,295.28	
		10,075.71		253,295.56
MASTER TRUST INVESTMENT GAIN/LOSS	87.05		1,370.86	
MASTER TRUST ALLOCATED EXPENSES	2,116.99-		24,265.88-	
MASTER TRUST CHANGE IN REALIZED G/L	30,398.02		237,976.28	
MASTER TRUST INTEREST INCOME EARNED	5,770.82		68,774.02	
MASTER TRUST DIVIDEND INCOME EARNED	4,973.32		41,437.88	
		39,112.22		325,293.16
TRANSFERS IN:				
CASH	0.00		7.86	
		0.00		7.86
TOTAL RECEIPTS		49,187.93		578,596.58
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		0.01	
		0.00		0.01
TOTAL DISBURSEMENTS		0.00		0.01
NET ASSETS - END OF PERIOD		$ 5,134,539.76		$ 5,134,539.76

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BNY MELLON

TRDPSB PSBF09319402 MONTHLY FINAL 234633 2013-12-31 CYCLE A 23:46:33 RUN DATE: 07-JAN-14

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093194

31 DECEMBER 2013

NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 4,393,226.38		$ 3,935,871.21
RECEIPTS:				
REALIZED GAIN/LOSS	$ 0.00		$ 0.24	
UNREALIZED GAIN/LOSS-INVESTMENT	8,704.38		218,821.42	
		8,704.38		218,821.66
MASTER TRUST INVESTMENT GAIN/LOSS	75.21		1,184.28	
MASTER TRUST ALLOCATED EXPENSES	1,828.87-		20,963.28-	
MASTER TRUST CHANGE IN REALIZED G/L	26,260.80		205,587.29	
MASTER TRUST INTEREST INCOME EARNED	4,985.40		59,413.71	
MASTER TRUST DIVIDEND INCOME EARNED	4,296.44		35,798.09	
		33,788.98		281,020.09
TRANSFERS IN:				
CASH	0.00		6.79	
		0.00		6.79
TOTAL RECEIPTS		42,493.36		499,848.54
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		0.01	
		0.00		0.01
TOTAL DISBURSEMENTS		0.00		0.01
NET ASSETS - END OF PERIOD		$ 4,435,719.74		$ 4,435,719.74

SI-SSA-0010-2796

BNY MELLON

TRDPSB PSBF09319502 MONTHLY FINAL 234633 2013-12-31 CYCLE A 23:46:33 RUN DATE: 07-JAN-14

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093195

31 DECEMBER 2013

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PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 2,715,006.01		$ 2,432,361.33
RECEIPTS:				
REALIZED GAIN/LOSS	$ 0.00		$ 0.15	
UNREALIZED GAIN/LOSS-INVESTMENT	5,379.30		135,231.26	
		5,379.30		135,231.41
MASTER TRUST INVESTMENT GAIN/LOSS	46.48		731.89	
MASTER TRUST ALLOCATED EXPENSES	1,130.23-		12,955.26-	
MASTER TRUST CHANGE IN REALIZED G/L	16,229.12		127,052.55	
MASTER TRUST INTEREST INCOME EARNED	3,080.97		36,717.58	
MASTER TRUST DIVIDEND INCOME EARNED	2,655.19		22,123.15	
		20,881.53		173,669.91
TRANSFERS IN:				
CASH	0.00		4.20	
		0.00		4.20
TOTAL RECEIPTS		26,260.83		308,905.52
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		0.01	
		0.00		0.01
TOTAL DISBURSEMENTS		0.00		0.01
NET ASSETS - END OF PERIOD		$ 2,741,266.84		$ 2,741,266.84

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BNY MELLON

TRDPSB PSBF09319602 MONTHLY FINAL 234633 2013-12-31 CYCLE A 23:46:33 RUN DATE: 07-JAN-14

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093196

31 DECEMBER 2013

NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 2,728,446.75		$ 2,444,402.82
RECEIPTS:				
REALIZED GAIN/LOSS	$ 0.00		$ 0.15	
UNREALIZED GAIN/LOSS-INVESTMENT	5,405.93		135,900.66	
		5,405.93		135,900.81
MASTER TRUST INVESTMENT GAIN/LOSS	46.70		735.50	
MASTER TRUST ALLOCATED EXPENSES	1,135.83-		13,019.41-	
MASTER TRUST CHANGE IN REALIZED G/L	16,309.47		127,681.56	
MASTER TRUST INTEREST INCOME EARNED	3,096.22		36,899.38	
MASTER TRUST DIVIDEND INCOME EARNED	2,668.33		22,232.69	
		20,984.89		174,529.72
TRANSFERS IN:				
CASH	0.00		4.22	
		0.00		4.22
TOTAL RECEIPTS		26,390.82		310,434.75
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 2,754,837.57		$ 2,754,837.57

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BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFITS
31 DECEMBER 2013

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 638,486.08		$ 572,017.73
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 1,265.05		$ 31,802.27	
		1,265.05		31,802.27
MASTER TRUST INVESTMENT GAIN/LOSS	10.93		172.12	
MASTER TRUST ALLOCATED EXPENSES	265.79-		3,046.66-	
MASTER TRUST CHANGE IN REALIZED G/L	3,816.59		29,878.86	
MASTER TRUST INTEREST INCOME EARNED	724.54		8,634.81	
MASTER TRUST DIVIDEND INCOME EARNED	624.42		5,202.69	
		4,910.69		40,841.82
TOTAL RECEIPTS		6,175.74		72,644.09
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 644,661.82		$ 644,661.82

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Non-FERC

Non-Qualified Reports

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S
31 DECEMBER 2013

PSB F092880
PSEG NUCLEAR HOPE CREEK

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 8,770,549.44		$ 7,120,891.96
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 71,347.18		$ 1,330,024.44	
		71,347.18		1,330,024.44
MASTER TRUST INVESTMENT GAIN/LOSS	215.22		4,053.65	
MASTER TRUST ALLOCATED EXPENSES	11,055.85-		44,926.97-	
MASTER TRUST CHANGE IN REALIZED G/L	122,113.17		342,084.56	
MASTER TRUST INTEREST INCOME EARNED	246.14		348.19	
MASTER TRUST DIVIDEND INCOME EARNED	14,085.20		215,024.67	
		125,603.88		516,584.10
TOTAL RECEIPTS		196,951.06		1,846,608.54
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 8,967,500.50		$ 8,967,500.50

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BNY MELLON

PSB F092881
PSEG NUCLEAR PEACH BOTTOM #2

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S
31 DECEMBER 2013

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 61,310,084.03		$ 49,778,236.48
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 498,748.87		$ 9,297,468.79	
		498,748.87		9,297,468.79
MASTER TRUST INVESTMENT GAIN/LOSS	1,504.45		28,336.82	
MASTER TRUST ALLOCATED EXPENSES	77,285.41-		314,059.74-	
MASTER TRUST CHANGE IN REALIZED G/L	853,625.98		2,391,324.90	
MASTER TRUST INTEREST INCOME EARNED	1,720.63		2,434.06	
MASTER TRUST DIVIDEND INCOME EARNED	98,461.89		1,503,119.13	
		878,027.54		3,611,155.17
TOTAL RECEIPTS		1,376,776.41		12,908,623.96
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 62,686,860.44		$ 62,686,860.44

SI-SSA-0010-2802

BNY MELLON

TRDPSB PSBF09288302 MONTHLY FINAL 234633 2013-12-31 CYCLE A 23:46:33 RUN DATE: 07-JAN-14

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092883

31 DECEMBER 2013

NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 48,465,181.55		$ 39,349,338.80
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 394,257.41		$ 7,349,582.37	
		394,257.41		7,349,582.37
MASTER TRUST INVESTMENT GAIN/LOSS	1,189.26		22,400.05	
MASTER TRUST ALLOCATED EXPENSES	61,093.56-		248,261.98-	
MASTER TRUST CHANGE IN REALIZED G/L	674,785.21		1,890,325.16	
MASTER TRUST INTEREST INCOME EARNED	1,360.14		1,924.12	
MASTER TRUST DIVIDEND INCOME EARNED	77,833.42		1,188,204.91	
		694,074.47		2,854,592.26
TOTAL RECEIPTS		1,088,331.88		10,204,174.63
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 49,553,513.43		$ 49,553,513.43

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BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFITS
31 DECEMBER 2013

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 85,431,987.33		$ 69,363,037.68
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 694,977.15		$ 12,955,474.53	
		694,977.15		12,955,474.53
MASTER TRUST INVESTMENT GAIN/LOSS	2,096.36		39,485.68	
MASTER TRUST ALLOCATED EXPENSES	107,692.64-		437,623.70-	
MASTER TRUST CHANGE IN REALIZED G/L	1,189,477.47		3,332,170.25	
MASTER TRUST INTEREST INCOME EARNED	2,397.59		3,391.72	
MASTER TRUST DIVIDEND INCOME EARNED	137,200.83		2,094,507.93	
		1,223,479.61		5,031,931.88
TOTAL RECEIPTS		1,918,456.76		17,987,406.41
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 87,350,444.09		$ 87,350,444.09

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S
31 DECEMBER 2013

PSB F092887
PSEG NUCLEAR SALEM NONQUAL

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 27,796,433.27		$ 22,568,186.80
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 226,120.05		$ 4,215,235.98	
		226,120.05		4,215,235.98
MASTER TRUST INVESTMENT GAIN/LOSS	682.08		12,847.18	
MASTER TRUST ALLOCATED EXPENSES	35,039.24-		142,386.72-	
MASTER TRUST CHANGE IN REALIZED G/L	387,012.32		1,084,165.90	
MASTER TRUST INTEREST INCOME EARNED	780.09		1,103.54	
MASTER TRUST DIVIDEND INCOME EARNED	44,640.12		681,476.01	
		398,075.37		1,637,205.91
TOTAL RECEIPTS		624,195.42		5,852,441.89
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 28,420,628.69		$ 28,420,628.69

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FERC Non-Qualified Reports

BNY MELLON

	CURRENT PERIOD 01-DEC-13	31-DEC-13	YEAR TO DATE 01-JAN-13	31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 212,909.06		$ 172,862.88
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 1,732.00		$ 32,286.93	
		1,732.00		32,286.93
MASTER TRUST INVESTMENT GAIN/LOSS	5.22		98.41	
MASTER TRUST ALLOCATED EXPENSES	268.39-		1,090.62-	
MASTER TRUST CHANGE IN REALIZED G/L	2,964.35		8,304.27	
MASTER TRUST INTEREST INCOME EARNED	5.98		8.45	
MASTER TRUST DIVIDEND INCOME EARNED	341.92		5,219.82	
		3,049.08		12,540.33
TOTAL RECEIPTS		4,781.08		44,827.26
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 217,690.14		$ 217,690.14

SI-SSA-0010-2807

BNY MELLON

TRDPSB PSBF09336302 MONTHLY FINAL 234633 2013-12-31 CYCLE A 23:46:33 RUN DATE: 07-JAN-14

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093363
PSEG NUCLEAR SALEM NON-QUAL

31 DECEMBER 2013

NC100

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 102,811.68		$ 83,473.78
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 836.37		$ 15,591.04	
		836.37		15,591.04
MASTER TRUST INVESTMENT GAIN/LOSS	2.52		47.53	
MASTER TRUST ALLOCATED EXPENSES	129.60-		526.64-	
MASTER TRUST CHANGE IN REALIZED G/L	1,431.46		4,010.04	
MASTER TRUST INTEREST INCOME EARNED	2.88		4.06	
MASTER TRUST DIVIDEND INCOME EARNED	165.11		2,520.61	
		1,472.37		6,055.60
TOTAL RECEIPTS		2,308.74		21,646.64
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 105,120.42		$ 105,120.42

SI-SSA-0010-2808

BNY MELLON

TRDPSB PSBF09336402 MONTHLY FINAL 234633 2013-12-31 CYCLE A 23:46:33 RUN DATE: 07-JAN-14

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093364

31 DECEMBER 2013

NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 306,387.07		$ 248,758.56
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 2,492.41		$ 46,462.57	
		2,492.41		46,462.57
MASTER TRUST INVESTMENT GAIN/LOSS	7.52		141.60	
MASTER TRUST ALLOCATED EXPENSES	386.22-		1,569.49-	
MASTER TRUST CHANGE IN REALIZED G/L	4,265.85		11,950.25	
MASTER TRUST INTEREST INCOME EARNED	8.60		12.21	
MASTER TRUST DIVIDEND INCOME EARNED	492.05		7,511.58	
		4,387.80		18,046.15
TOTAL RECEIPTS		6,880.21		64,508.72
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 313,267.28		$ 313,267.28

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BNY MELLON

PSB F093365
PSEG NUCLEAR PEACH BOTTOM #3

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFITS
31 DECEMBER 2013

	CURRENT PERIOD 01-DEC-13	CURRENT PERIOD 31-DEC-13	YEAR TO DATE 01-JAN-13	YEAR TO DATE 31-DEC-13
NET ASSETS - BEGINNING OF PERIOD		$ 305,995.75		$ 248,440.84
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 2,489.22		$ 46,403.23	
		2,489.22		46,403.23
MASTER TRUST INVESTMENT GAIN/LOSS	7.51		141.42	
MASTER TRUST ALLOCATED EXPENSES	385.72-		1,567.43-	
MASTER TRUST CHANGE IN REALIZED G/L	4,260.41		11,935.01	
MASTER TRUST INTEREST INCOME EARNED	8.59		12.12	
MASTER TRUST DIVIDEND INCOME EARNED	491.42		7,501.99	
		4,382.21		18,023.11
TOTAL RECEIPTS		6,871.43		64,426.34
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 312,867.18		$ 312,867.18

SI-SSA-0010-2810

20140305-5198 FERC PDF (Unofficial) 3/5/2014 4:27:07 PM

Document Content(s)

2014-03-05 PSEG Nuclear Order No 580.PDF.....1-27

David K. Richter
Associate General Regulatory Counsel

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PSEG
Services Corporation

March 27, 2015

VIA ELECTRONIC FILING

Kimberly D. Bose, Secretary
Nathaniel J. Davis, Sr., Deputy Secretary
Attention FERC 561
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Order No. 580
Docket No. RM 94-14-000

Dear Secretary Bose and Deputy Secretary Davis:

In accordance with 18 CFR § 35.33(d), attached is the financial reports furnished by our trustee, Mellon Bank, for PSEG Nuclear LLC's ("PSEG") Qualified and Non-Qualified Nuclear Decommissioning Trust Funds for the year ending December 31, 2014.

On December 31, 2014 assets in the trust funds totaled $1,788,158,948.50, included in this balance are amounts collected through FERC jurisdictional rates totaling $17,623,368.29. This total represents the contributions and earnings on the funds since its inception in 1988. During 2014, there were no contributions made to the PSEG trust funds.

If you have any questions, or would like to see the detailed information that comprises the numbers shown on the Mellon Bank statements, please contact Bradley Barazani at (973) 430-7096.

Very truly yours,

David K. Richter

David K. Richter

PSEG Nuclear LLC
FERC ASSET Allocation
As of December 31, 2014

Account Names	Percentage	Total Trust Market Values	Non-FERC Assets	FERC Assets
Q Hope Creek	33.5%	$ 509,912,676.77	$509,233,328.40	$679,348.37
Q PB 2	14.9%	$ 226,930,106.80	$224,041,342.80	$2,888,764.00
Q PB 3	15.9%	$ 242,472,604.55	$239,569,539.67	$2,903,064.88
Q Salem 1	17.0%	$ 258,113,654.39	$252,702,844.57	$5,410,809.82
Q Salem 2	18.6%	$ 283,204,160.56	$278,529,771.61	$4,674,388.95
PSEG Nuclear LLC Qual. Plans	G716275	$ 1,520,633,203.07		
Non-Q Salem 1	36.8%	$ 98,461,471.54	$98,216,701.10	$244,770.44
Non-Q Salem 2	12.0%	$ 32,074,307.16	$31,956,109.93	$118,197.23
Non-Q PB 2	26.5%	$ 70,837,243.92	$70,485,006.68	$352,237.24
Non-Q PB 3	21.0%	$ 56,069,679.44	$55,717,892.08	$351,787.36
Non-Q Hope Creek	3.8%	$ 10,083,043.37	$10,083,043.37	$ -
PSEG Nuclear LLC Non Qual. Plans	G716277	$ 267,525,745.43		
Totals		$ 1,788,158,948.50	$1,770,535,580.21	$17,623,368.29
			99.01%	0.99%

SI-SSA-0010-2813

BNY MELLON

TRDPSB PSBG71627500 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

INVESTMENT DETAIL PAGE: 1

PSB G716275 31 DECEMBER 2014 M1101

PSEG NUCLEAR LLC QUAL. PLANS

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	PSE&G QUALIFIED MTU				
216,351,724.6050	HOPE CREEK QUAL	442,607,673.63	2.3537	509,233,328.40	66,625,654.77
95,185,700.1370	PEACH BOTTOM #2 Q	196,936,492.50	2.3537	224,041,342.80	27,104,850.30
101,782,974.8760	PEACH BOTTOM #3 Q	210,506,871.72	2.3537	239,569,539.67	29,062,667.95
107,362,761.2060	SALEM Q UNIT 1	224,407,323.91	2.3537	252,702,844.57	28,295,520.66
118,335,531.2390	SALEM Q UNIT 2	247,652,051.21	2.3537	278,529,771.61	30,877,720.40
2,298,824.4690	SALEM Q #1 FERC	5,580,216.32	2.3537	5,410,809.82	169,406.50-
1,985,950.3560	SALEM Q #2 FERC	4,669,951.67	2.3537	4,674,388.95	4,437.28
1,227,313.7660	PB#2 Q FERC	2,941,784.38	2.3537	2,888,764.00	53,020.38-
1,233,389.6050	PB#3 Q FERC	2,963,435.52	2.3537	2,903,064.88	60,370.64-
288,626.4160	HOPE CREEK QUAL FERC	781,948.57	2.3537	679,348.37	102,600.20-
646,052,796.6750		1,339,047,749.43		1,520,633,203.07	181,585,453.64
TOTAL INVESTMENTS UNIT OF PARTICIPATION		1,339,047,749.43		1,520,633,203.07	181,585,453.64
TOTAL INVESTMENT		1,339,047,749.43		1,520,633,203.07	181,585,453.64

BNY MELLON

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	PSE&G NON-QUALIFIED MTU				
4,397,995.9250	HOPE CREEK NONQUAL	9,016,113.65	2.2926	10,083,043.37	1,066,929.72
30,743,968.9440	PEACH BOTTOM #2 NQ	63,658,586.28	2.2926	70,485,006.68	6,826,420.40
24,302,886.8740	PEACH BOTTOM #3 NQ	50,431,064.10	2.2926	55,717,892.08	5,286,827.98
42,839,908.0980	SALEM NQ UNIT 1	88,553,903.49	2.2926	98,216,701.10	9,662,797.61
13,938,533.8450	SALEM NQ UNIT 2	28,758,673.05	2.2926	31,956,109.93	3,197,436.88
106,763.3430	SALEM NQ #1 FERC	230,050.96	2.2926	244,770.44	14,719.48
51,554.9650	SALEM NQ #2 FERC	111,089.34	2.2926	118,197.23	7,107.89
153,637.9330	PB#2 NQ FERC	331,058.82	2.2926	352,237.24	21,178.42
153,441.7060	PB#3 NQ FERC	330,635.69	2.2926	351,787.36	21,151.67
116,688,691.6330		241,421,175.38		267,525,745.43	26,104,570.05
TOTAL INVESTMENTS UNIT OF PARTICIPATION		241,421,175.38		267,525,745.43	26,104,570.05
TOTAL INVESTMENT		241,421,175.38		267,525,745.43	26,104,570.05

Non-FERC

Qualified Reports

BNY MELLON

TRDPSB PSBF09287902 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092879 31 DECEMBER 2014 NC100

PSEG NUCLEAR HOPE CREEK QUAL

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 512,723,815.12		$ 490,924,732.39
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 407,805.42		$ 1,223,944.30	
UNREALIZED GAIN/LOSS-INVESTMENT	5,824,640.64-		13,612,672.84-	
		5,416,835.22-		12,388,728.54-
MASTER TRUST INVESTMENT GAIN/LOSS	646.28		55,300.36	
MASTER TRUST ALLOCATED EXPENSES	12.93-		2,186,232.41-	
MASTER TRUST CHANGE IN REALIZED G/L	3,946,254.64		29,603,498.75	
MASTER TRUST INTEREST INCOME EARNED	520,563.64		6,913,900.37	
MASTER TRUST DIVIDEND INCOME EARNED	344,896.87		4,327,657.77	
		4,812,348.50		38,714,124.84
TOTAL RECEIPTS		604,486.72-		26,325,396.30
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		3.84	
UBTI TAX EXPENSE	2,886,000.00		8,016,796.45	
		2,886,000.00		8,016,800.29
TOTAL DISBURSEMENTS		2,886,000.00		8,016,800.29
NET ASSETS - END OF PERIOD		$ 509,233,328.40		$ 509,233,328.40

SI-SSA-0010-2817

BNY MELLON

TRDPSB PSBF09288202 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092882 31 DECEMBER 2014 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 225,592,291.64		$ 215,999,532.64
RECEIPTS:				
INVESTMENT INCOME:				
INTEREST	$ 0.00		$ 156.91	
REALIZED GAIN/LOSS	168,989.25		509,444.01	
UNREALIZED GAIN/LOSS-INVESTMENT	2,562,598.00-		5,989,086.05-	
		2,393,608.75-		5,479,485.13-
MASTER TRUST INVESTMENT GAIN/LOSS	284.34		24,331.49	
MASTER TRUST ALLOCATED EXPENSES	5.69-		1,623,601.97-	
MASTER TRUST CHANGE IN REALIZED G/L	1,746,614.87		13,715,876.80	
MASTER TRUST INTEREST INCOME EARNED	229,026.21		3,042,034.10	
MASTER TRUST DIVIDEND INCOME EARNED	151,740.18		1,904,119.42	
		2,127,659.91		17,062,759.84
TOTAL RECEIPTS		265,948.84-		11,583,274.71
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		1.69	
UBTI TAX EXPENSE	1,285,000.00		3,541,462.86	
		1,285,000.00		3,541,464.55
TOTAL DISBURSEMENTS		1,285,000.00		3,541,464.55
NET ASSETS - END OF PERIOD		$ 224,041,342.80		$ 224,041,342.80

SI-SSA-0010-2818

BNY MELLON

TRDPSB PSBF09288402 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092884 31 DECEMBER 2014 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 241,226,921.30		$ 230,976,824.77
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 181,013.59		$ 545,409.50	
UNREALIZED GAIN/LOSS-INVESTMENT	2,740,210.43-		6,404,474.79-	
		2,559,196.84-		5,859,065.29-
MASTER TRUST INVESTMENT GAIN/LOSS	304.04		26,017.94	
MASTER TRUST ALLOCATED EXPENSES	6.08-		975,039.91-	
MASTER TRUST CHANGE IN REALIZED G/L	1,867,360.13		13,905,191.03	
MASTER TRUST INTEREST INCOME EARNED	244,899.90		3,252,957.96	
MASTER TRUST DIVIDEND INCOME EARNED	162,257.22		2,036,146.71	
		2,274,815.21		18,245,273.73
TOTAL RECEIPTS		284,381.63-		12,386,208.44
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		1.81	
UBTI TAX EXPENSE	1,373,000.00		3,793,491.73	
		1,373,000.00		3,793,493.54
TOTAL DISBURSEMENTS		1,373,000.00		3,793,493.54
NET ASSETS - END OF PERIOD		$ 239,569,539.67		$ 239,569,539.67

SI-SSA-0010-2819

BNY MELLON

TRDPSB PSBF09288602 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092886 31 DECEMBER 2014 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 254,463,816.13		$ 243,663,457.12
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 179,053.65		$ 542,460.76	
UNREALIZED GAIN/LOSS-INVESTMENT	2,890,429.95-		6,755,571.70-	
		2,711,376.30-		6,213,110.94-
MASTER TRUST INVESTMENT GAIN/LOSS	320.71		27,445.81	
MASTER TRUST ALLOCATED EXPENSES	6.41-		1,028,563.49-	
MASTER TRUST CHANGE IN REALIZED G/L	1,981,612.79		14,678,070.67	
MASTER TRUST INTEREST INCOME EARNED	258,325.42		3,431,519.82	
MASTER TRUST DIVIDEND INCOME EARNED	171,152.23		2,171,065.93	
		2,411,404.74		19,279,538.74
TOTAL RECEIPTS		299,971.56-		13,066,427.80
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		1.91	
UBTI TAX EXPENSE	1,461,000.00		4,027,038.44	
		1,461,000.00		4,027,040.35
TOTAL DISBURSEMENTS		1,461,000.00		4,027,040.35
NET ASSETS - END OF PERIOD		$ 252,702,844.57		$ 252,702,844.57

SI-SSA-0010-2820

BNY MELLON

TRDPSB PSBF09288802 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092888 31 DECEMBER 2014 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 280,463,401.08		$ 268,567,632.75
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 194,691.67		$ 590,436.02	
UNREALIZED GAIN/LOSS-INVESTMENT	3,185,839.84-		7,446,175.56-	
		2,991,148.17-		6,855,739.54-
MASTER TRUST INVESTMENT GAIN/LOSS	353.49		30,250.95	
MASTER TRUST ALLOCATED EXPENSES	7.07-		1,195,984.20-	
MASTER TRUST CHANGE IN REALIZED G/L	2,186,800.84		16,273,445.94	
MASTER TRUST INTEREST INCOME EARNED	284,726.99		3,782,222.11	
MASTER TRUST DIVIDEND INCOME EARNED	188,644.45		2,367,432.29	
		2,660,518.70		21,257,367.09
TOTAL RECEIPTS		330,629.47-		14,401,627.55
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		2.10	
UBTI TAX EXPENSE	1,603,000.00		4,439,486.59	
		1,603,000.00		4,439,488.69
TOTAL DISBURSEMENTS		1,603,000.00		4,439,488.69
NET ASSETS - END OF PERIOD		$ 278,529,771.61		$ 278,529,771.61

SI-SSA-0010-2821

FERC Qualified Reports

SI-SSA-0010-2822

BNY MELLON

TRDPSB PSBF09319302 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093193 31 DECEMBER 2014 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 5,417,232.73		$ 5,134,539.76
RECEIPTS:				
REALIZED GAIN/LOSS	$ 0.00		$ 2.01	
UNREALIZED GAIN/LOSS-INVESTMENT	61,889.16-		144,182.99-	
		61,889.16-		144,180.98-
MASTER TRUST INVESTMENT GAIN/LOSS	6.87		583.47	
MASTER TRUST ALLOCATED EXPENSES	0.14-		21,787.24-	
MASTER TRUST CHANGE IN REALIZED G/L	46,263.65		323,402.19	
MASTER TRUST INTEREST INCOME EARNED	5,531.20		72,730.29	
MASTER TRUST DIVIDEND INCOME EARNED	3,664.67		45,522.37	
		55,466.25		420,451.08
TOTAL RECEIPTS		6,422.91-		276,270.10
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		0.04	
		0.00		0.04
TOTAL DISBURSEMENTS		0.00		0.04
NET ASSETS - END OF PERIOD		$ 5,410,809.82		$ 5,410,809.82

SI-SSA-0010-2823

BNY MELLON

TRDPSB PSBF09319402 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093194 31 DECEMBER 2014 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 4,679,937.69		$ 4,435,719.74
RECEIPTS:				
REALIZED GAIN/LOSS	$ 0.00		$ 1.72	
UNREALIZED GAIN/LOSS-INVESTMENT	53,465.92-		124,559.39-	
		53,465.92-		124,557.67-
MASTER TRUST INVESTMENT GAIN/LOSS	5.93		504.05	
MASTER TRUST ALLOCATED EXPENSES	0.12-		18,821.95-	
MASTER TRUST CHANGE IN REALIZED G/L	39,967.08		279,386.56	
MASTER TRUST INTEREST INCOME EARNED	4,778.39		62,831.55	
MASTER TRUST DIVIDEND INCOME EARNED	3,165.90		39,326.70	
		47,917.18		363,226.91
TOTAL RECEIPTS		5,548.74-		238,669.24
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		0.03	
		0.00		0.03
TOTAL DISBURSEMENTS		0.00		0.03
NET ASSETS - END OF PERIOD		$ 4,674,388.95		$ 4,674,388.95

SI-SSA-0010-2824

BNY MELLON

TRDPSB PSBF09319502 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093195 31 DECEMBER 2014 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 2,892,193.12		$ 2,741,266.84
RECEIPTS:				
REALIZED GAIN/LOSS	$ 0.00		$ 1.09	
UNREALIZED GAIN/LOSS-INVESTMENT	33,041.86-		76,977.50-	
		33,041.86-		76,976.41-
MASTER TRUST INVESTMENT GAIN/LOSS	3.66		311.50	
MASTER TRUST ALLOCATED EXPENSES	0.07-		11,631.93-	
MASTER TRUST CHANGE IN REALIZED G/L	24,699.59		172,660.41	
MASTER TRUST INTEREST INCOME EARNED	2,953.04		38,829.79	
MASTER TRUST DIVIDEND INCOME EARNED	1,956.52		24,303.82	
		29,612.74		224,473.59
TOTAL RECEIPTS		3,429.12-		147,497.18
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		0.02	
		0.00		0.02
TOTAL DISBURSEMENTS		0.00		0.02
NET ASSETS - END OF PERIOD		$ 2,888,764.00		$ 2,888,764.00

SI-SSA-0010-2825

BNY MELLON

TRDPSB PSBF09319602 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093196 31 DECEMBER 2014 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 2,906,510.97		$ 2,754,837.57
RECEIPTS:				
REALIZED GAIN/LOSS	$ 0.00		$ 1.05	
UNREALIZED GAIN/LOSS-INVESTMENT	33,205.44-		77,358.60-	
		33,205.44-		77,357.55-
MASTER TRUST INVESTMENT GAIN/LOSS	3.69		313.05	
MASTER TRUST ALLOCATED EXPENSES	0.07-		11,689.53-	
MASTER TRUST CHANGE IN REALIZED G/L	24,821.86		173,515.18	
MASTER TRUST INTEREST INCOME EARNED	2,967.66		39,022.06	
MASTER TRUST DIVIDEND INCOME EARNED	1,966.21		24,424.12	
		29,759.35		225,584.88
TOTAL RECEIPTS		3,446.09-		148,227.33
DISBURSEMENTS:				
TRUSTEE/CUSTODIAN	0.00		0.02	
		0.00		0.02
TOTAL DISBURSEMENTS		0.00		0.02
NET ASSETS - END OF PERIOD		$ 2,903,064.88		$ 2,903,064.88

SI-SSA-0010-2826

BNY MELLON

TRDPSB PSBF09319702 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PAGE: 1

PSB F093197 31 DECEMBER 2014 NC100

PSEG NUCLEAR HOPE CREEK QUAL

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 680,154.79		$ 644,661.82
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 7,770.41-		$ 18,102.71-	
		7,770.41-		18,102.71-
MASTER TRUST INVESTMENT GAIN/LOSS	0.86		73.26	
MASTER TRUST ALLOCATED EXPENSES	0.02-		2,735.48-	
MASTER TRUST CHANGE IN REALIZED G/L	5,808.58		40,604.40	
MASTER TRUST INTEREST INCOME EARNED	694.46		9,131.55	
MASTER TRUST DIVIDEND INCOME EARNED	460.11		5,715.53	
		6,963.99		52,789.26
TOTAL RECEIPTS		806.42-		34,686.55
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 679,348.37		$ 679,348.37

SI-SSA-0010-2827

Non-FERC

Non-Qualified Reports

BNY MELLON

TRDPSB PSBF09288002 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092880 31 DECEMBER 2014 NC100

PSEG NUCLEAR HOPE CREEK

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 10,083,839.40		$ 8,967,500.50
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 1,473,850.23-		$ 780,375.87-	
		1,473,850.23-		780,375.87-
MASTER TRUST INVESTMENT GAIN/LOSS	420.90		1,136.98	
MASTER TRUST ALLOCATED EXPENSES	8.42-		23,943.17-	
MASTER TRUST CHANGE IN REALIZED G/L	1,457,411.23		1,682,348.23	
MASTER TRUST INTEREST INCOME EARNED	2,906.51		26,973.90	
MASTER TRUST DIVIDEND INCOME EARNED	12,323.98		209,402.80	
		1,473,054.20		1,895,918.74
TOTAL RECEIPTS		796.03-		1,115,542.87
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 10,083,043.37		$ 10,083,043.37

BNY MELLON

TRDPSB PSBF09288102 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092881 31 DECEMBER 2014 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 70,490,571.34		$ 62,686,860.44
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 10,302,875.85-		$ 5,455,178.60-	
		10,302,875.85-		5,455,178.60-
MASTER TRUST INVESTMENT GAIN/LOSS	2,942.27		7,948.16	
MASTER TRUST ALLOCATED EXPENSES	58.85-		167,373.29-	
MASTER TRUST CHANGE IN REALIZED G/L	10,187,959.81		11,760,370.60	
MASTER TRUST INTEREST INCOME EARNED	20,317.78		188,559.63	
MASTER TRUST DIVIDEND INCOME EARNED	86,150.18		1,463,819.74	
		10,297,311.19		13,253,324.84
TOTAL RECEIPTS		5,564.66-		7,798,146.24
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 70,485,006.68		$ 70,485,006.68

SI-SSA-0010-2830

BNY MELLON

TRDPSB PSBF09288302 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092883 31 DECEMBER 2014 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 55,722,290.90		$ 49,553,513.43
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 8,144,349.46-		$ 4,312,279.56-	
		8,144,349.46-		4,312,279.56-
MASTER TRUST INVESTMENT GAIN/LOSS	2,325.85		6,282.97	
MASTER TRUST ALLOCATED EXPENSES	46.52-		132,307.39-	
MASTER TRUST CHANGE IN REALIZED G/L	8,053,509.14		9,296,488.60	
MASTER TRUST INTEREST INCOME EARNED	16,061.07		149,055.03	
MASTER TRUST DIVIDEND INCOME EARNED	68,101.10		1,157,139.00	
		8,139,950.64		10,476,658.21
TOTAL RECEIPTS		4,398.82-		6,164,378.65
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 55,717,892.08		$ 55,717,892.08

SI-SSA-0010-2831

BNY MELLON

TRDPSB PSBF09288502 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092885 31 DECEMBER 2014 NC100

PSEG NUCLEAR SALEM NONQUAL

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 98,224,455.12		$ 87,350,444.09
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 14,356,450.08-		$ 7,601,469.70-	
		14,356,450.08-		7,601,469.70-
MASTER TRUST INVESTMENT GAIN/LOSS	4,099.89		11,075.32	
MASTER TRUST ALLOCATED EXPENSES	81.99-		233,224.86-	
MASTER TRUST CHANGE IN REALIZED G/L	14,196,321.34		16,387,383.07	
MASTER TRUST INTEREST INCOME EARNED	28,311.63		262,746.71	
MASTER TRUST DIVIDEND INCOME EARNED	120,045.19		2,039,746.47	
		14,348,696.06		18,467,726.71
TOTAL RECEIPTS		7,754.02-		10,866,257.01
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 98,216,701.10		$ 98,216,701.10

SI-SSA-0010-2832

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092887 31 DECEMBER 2014 NC100

PSEG NUCLEAR SALEM NONQUAL

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 31,958,632.80		$ 28,420,628.69
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 4,671,061.95-		$ 2,473,239.19-	
		4,671,061.95-		2,473,239.19-
MASTER TRUST INVESTMENT GAIN/LOSS	1,333.95		3,603.48	
MASTER TRUST ALLOCATED EXPENSES	26.68-		75,882.79-	
MASTER TRUST CHANGE IN REALIZED G/L	4,618,961.94		5,331,853.00	
MASTER TRUST INTEREST INCOME EARNED	9,211.57		85,488.11	
MASTER TRUST DIVIDEND INCOME EARNED	39,058.30		663,658.63	
		4,668,539.08		6,008,720.43
TOTAL RECEIPTS		2,522.87-		3,535,481.24
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 31,956,109.93		$ 31,956,109.93

FERC Non-Qualified Reports

SI-SSA-0010-2834

BNY MELLON

TRDPSB PSBF09336202 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093362 31 DECEMBER 2014 NC100

PSEG NUCLEAR SALEM NON-QUAL

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 244,789.77		$ 217,690.14
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 35,778.39-		$ 18,944.03-	
		35,778.39-		18,944.03-
MASTER TRUST INVESTMENT GAIN/LOSS	10.22		27.60	
MASTER TRUST ALLOCATED EXPENSES	0.20-		581.21-	
MASTER TRUST CHANGE IN REALIZED G/L	35,379.32		40,839.78	
MASTER TRUST INTEREST INCOME EARNED	70.55		654.80	
MASTER TRUST DIVIDEND INCOME EARNED	299.17		5,083.36	
		35,759.06		46,024.33
TOTAL RECEIPTS		19.33-		27,080.30
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 244,770.44		$ 244,770.44

SI-SSA-0010-2835

BNY MELLON

TRDPSB PSBF09336302 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093363 31 DECEMBER 2014 NC100

PSEG NUCLEAR SALEM NON-QUAL

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 118,206.56		$ 105,120.42
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 17,277.02-		$ 9,147.86-	
		17,277.02-		9,147.86-
MASTER TRUST INVESTMENT GAIN/LOSS	4.93		13.32	
MASTER TRUST ALLOCATED EXPENSES	0.10-		280.68-	
MASTER TRUST CHANGE IN REALIZED G/L	17,084.32		19,721.13	
MASTER TRUST INTEREST INCOME EARNED	34.07		316.20	
MASTER TRUST DIVIDEND INCOME EARNED	144.47		2,454.70	
		17,267.69		22,224.67
TOTAL RECEIPTS		9.33-		13,076.81
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 118,197.23		$ 118,197.23

SI-SSA-0010-2836

BNY MELLON

TRDPSB PSBF09336402 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093364 31 DECEMBER 2014 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 352,265.05		$ 313,267.28
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 51,486.93-		$ 27,261.34-	
		51,486.93-		27,261.34-
MASTER TRUST INVESTMENT GAIN/LOSS	14.70		39.72	
MASTER TRUST ALLOCATED EXPENSES	0.30-		836.45-	
MASTER TRUST CHANGE IN REALIZED G/L	50,912.66		58,770.53	
MASTER TRUST INTEREST INCOME EARNED	101.54		942.30	
MASTER TRUST DIVIDEND INCOME EARNED	430.52		7,315.20	
		51,459.12		66,231.30
TOTAL RECEIPTS		27.81-		38,969.96
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 352,237.24		$ 352,237.24

SI-SSA-0010-2837

BNY MELLON

TRDPSB PSBF09336502 MONTHLY FINAL 121853 2014-12-31 CYCLE 3 12:18:52 RUN DATE: 14-JAN-15

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093365 31 DECEMBER 2014 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-14	CURRENT PERIOD 31-DEC-14	YEAR TO DATE 01-JAN-14	YEAR TO DATE 31-DEC-14
NET ASSETS - BEGINNING OF PERIOD		$ 351,815.13		$ 312,867.18
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 51,421.17-		$ 27,226.56-	
		51,421.17-		27,226.56-
MASTER TRUST INVESTMENT GAIN/LOSS	14.69		39.68	
MASTER TRUST ALLOCATED EXPENSES	0.29-		835.33-	
MASTER TRUST CHANGE IN REALIZED G/L	50,847.63		58,695.44	
MASTER TRUST INTEREST INCOME EARNED	101.40		941.11	
MASTER TRUST DIVIDEND INCOME EARNED	429.97		7,305.84	
		51,393.40		66,146.74
TOTAL RECEIPTS		27.77-		38,920.18
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 351,787.36		$ 351,787.36

SI-SSA-0010-2838

20160428-5214 FERC PDF (Unofficial) 4/28/2016 1:24:37 PM

David K. Richter
Associate General Regulatory Counsel

Law Department
80 Park Plaza, T5G, Newark, NJ 07102
tel: 973.430.6451 fax: 973.430.5983
David.Richter@PSEG.com

PSEG
Services Corporation

April 28, 2016

VIA ELECTRONIC FILING

Kimberly D. Bose, Secretary
Nathaniel J. Davis, Sr., Deputy Secretary
Attention FERC 561
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Order No. 580
Docket No. RM 94-14-000

Dear Secretary Bose and Deputy Secretary Davis:

In accordance with 18 CFR § 35.33(d), attached is the financial reports furnished by our trustee, Mellon Bank, for PSEG Nuclear LLC's ("PSEG") Qualified and Non-Qualified Nuclear Decommissioning Trust Funds for the year ending December 31, 2015.

On December 31, 2015 assets in the trust funds totaled $1,760,843,474.35, included in this balance are amounts collected through FERC jurisdictional rates totaling $17,401,392.14. This total represents the contributions and earnings on the funds since its inception in 1988. During 2015, there were no contributions made to the PSEG trust funds.

If you have any questions, or would like to see the detailed information that comprises the numbers shown on the Mellon Bank statements, please contact Bradley Barazani at (973) 430-7096.

Very truly yours,

David K. Richter

David K. Richter

PSEG Nuclear LLC
FERC ASSET Allocation
As of December 31, 2015

Account Names	Percentage	Total Trust Market Values	Non-FERC Assets	FERC Assets
Q Hope Creek	33.5%	$ 500,182,861.51	$499,512,899.28	$669,962.23
Q PB 2	14.9%	$ 222,600,476.99	$219,751,625.23	$2,848,851.76
Q PB 3	15.9%	$ 237,846,446.64	$234,983,491.59	$2,862,955.05
Q Salem 1	17.0%	$ 253,189,643.52	$247,853,591.47	$5,336,052.05
Q Salem 2	18.6%	$ 277,800,129.74	$273,190,323.90	$4,609,805.84
PSEG Nuclear LLC Qual. Plans	G716275	$ 1,491,619,558.40		
Non-Q Salem 1	36.8%	$ 99,086,474.45	$98,840,150.28	$246,324.17
Non-Q Salem 2	12.0%	$ 32,277,904.92	$32,158,957.41	$118,947.51
Non-Q PB 2	26.5%	$ 71,286,896.79	$70,932,423.66	$354,473.13
Non-Q PB 3	21.0%	$ 56,425,592.39	$56,071,571.99	$354,020.40
Non-Q Hope Creek	3.8%	$ 10,147,047.40	$10,147,047.40	$ -
PSEG Nuclear LLC Non Qual. Plans	G716277	$ 269,223,915.95		
Totals		$ 1,760,843,474.35	$1,743,442,082.21	$17,401,392.14
			99.01%	0.99%

SI-SSA-0010-2840

BNY MELLON

TRDPSB PSBG71627500 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

INVESTMENT DETAIL PAGE: 1

PSB G716275 31 DECEMBER 2015 M1101

PSEG NUCLEAR LLC QUAL. PLANS

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	PSE&G QUALIFIED MTU				
215,195,141.5300	HOPE CREEK QUAL	459,903,360.23	2.3212	499,512,899.28	39,609,539.05
94,671,193.0010	PEACH BOTTOM #2 Q	204,531,890.14	2.3212	219,751,625.23	15,219,735.09
101,233,233.0240	PEACH BOTTOM #3 Q	218,629,771.98	2.3212	234,983,491.59	16,353,719.61
106,777,800.4780	SALEM Q UNIT 1	232,963,058.67	2.3212	247,853,591.47	14,890,532.80
117,693,117.6400	SALEM Q UNIT 2	257,087,937.29	2.3212	273,190,323.90	16,102,386.61
2,298,824.4690	SALEM Q #1 FERC	5,794,078.96	2.3212	5,336,052.05	458,026.91-
1,985,950.3560	SALEM Q #2 FERC	4,854,707.14	2.3212	4,609,805.84	244,901.30-
1,227,313.7660	PB#2 Q FERC	3,055,962.92	2.3212	2,848,851.76	207,111.16-
1,233,389.6050	PB#3 Q FERC	3,078,179.34	2.3212	2,862,955.05	215,224.29-
288,626.4160	HOPE CREEK QUAL FERC	808,799.90	2.3212	669,962.23	138,837.67-
642,604,590.2850		1,390,707,746.57		1,491,619,558.40	100,911,811.83
TOTAL INVESTMENTS UNIT OF PARTICIPATION		1,390,707,746.57		1,491,619,558.40	100,911,811.83
TOTAL INVESTMENT		1,390,707,746.57		1,491,619,558.40	100,911,811.83

BNY MELLON

TRDPSB PSBG71627700 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

INVESTMENT DETAIL PAGE: 1

PSB G716277 31 DECEMBER 2015 M1101

PSEG NUCLEAR LLC NQ PLANS

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	PSE&G NON-QUALIFIED MTU				
4,397,995.9250	HOPE CREEK NONQUAL	8,925,226.77	2.3071	10,147,047.40	1,221,820.63
30,743,968.9440	PEACH BOTTOM #2 NQ	63,023,246.21	2.3071	70,932,423.66	7,909,177.45
24,302,886.8740	PEACH BOTTOM #3 NQ	49,928,832.31	2.3071	56,071,571.99	6,142,739.68
42,839,908.0980	SALEM NQ UNIT 1	87,668,594.50	2.3071	98,840,150.28	11,171,555.78
13,938,533.8450	SALEM NQ UNIT 2	28,470,626.03	2.3071	32,158,957.41	3,688,331.38
106,763.3430	SALEM NQ #1 FERC	227,844.67	2.3071	246,324.17	18,479.50
51,554.9650	SALEM NQ #2 FERC	110,023.95	2.3071	118,947.51	8,923.56
153,637.9330	PB#2 NQ FERC	327,883.75	2.3071	354,473.13	26,589.38
153,441.7060	PB#3 NQ FERC	327,464.75	2.3071	354,020.40	26,555.65
116,688,691.6330		239,009,742.94		269,223,915.95	30,214,173.01
TOTAL INVESTMENTS UNIT OF PARTICIPATION		239,009,742.94		269,223,915.95	30,214,173.01
TOTAL INVESTMENT		239,009,742.94		269,223,915.95	30,214,173.01

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Non-FERC

Qualified Reports

BNY MELLON

TRDPSB PSBF09287902 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092879 31 DECEMBER 2015 NC100

PSEG NUCLEAR HOPE CREEK QUAL

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 506,478,812.36		$ 509,233,328.40
RECEIPTS:				
INVESTMENT INCOME:				
INTEREST	$ 0.00		$ 8.17	
REALIZED GAIN/LOSS	16,068.74		358,541.96	
UNREALIZED GAIN/LOSS-INVESTMENT	6,896,049.65-		27,016,115.72-	
		6,879,980.91-		26,657,565.59-
MASTER TRUST INVESTMENT GAIN/LOSS	4,927.35		38,168.06	
MASTER TRUST ALLOCATED EXPENSES	88,366.52-		2,569,241.65-	
MASTER TRUST CHANGE IN REALIZED G/L	759,822.45-		10,841,032.80	
MASTER TRUST INTEREST INCOME EARNED	630,250.99		7,158,088.80	
MASTER TRUST DIVIDEND INCOME EARNED	302,078.46		4,227,088.46	
		89,067.83		19,695,136.47
TOTAL RECEIPTS		6,790,913.08-		6,962,429.12-
DISBURSEMENTS:				
UBTI TAX EXPENSE	175,000.00		2,758,000.00	
		175,000.00		2,758,000.00
TOTAL DISBURSEMENTS		175,000.00		2,758,000.00
NET ASSETS - END OF PERIOD		$ 499,512,899.28		$ 499,512,899.28

SI-SSA-0010-2844

BNY MELLON

TRDPSB PSBF09288202 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092882 31 DECEMBER 2015 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 222,817,164.07		$ 224,041,342.80
RECEIPTS:				
INVESTMENT INCOME:				
INTEREST	$ 0.00		$ 0.01	
REALIZED GAIN/LOSS	6,389.88		147,675.81	
UNREALIZED GAIN/LOSS-INVESTMENT	3,033,791.78-		11,885,115.21-	
		3,027,401.90-		11,737,439.39-
MASTER TRUST INVESTMENT GAIN/LOSS	2,167.70		16,791.70	
MASTER TRUST ALLOCATED EXPENSES	38,875.24-		1,130,309.66-	
MASTER TRUST CHANGE IN REALIZED G/L	333,590.81-		4,779,450.61	
MASTER TRUST INTEREST INCOME EARNED	277,267.48		3,149,121.40	
MASTER TRUST DIVIDEND INCOME EARNED	132,893.93		1,859,665.22	
		39,863.06		8,674,719.27
TOTAL RECEIPTS		2,987,538.84-		3,062,720.12-
DISBURSEMENTS:				
UBTI TAX EXPENSE	78,000.00		1,226,997.45	
		78,000.00		1,226,997.45
TOTAL DISBURSEMENTS		78,000.00		1,226,997.45
NET ASSETS - END OF PERIOD		$ 219,751,625.23		$ 219,751,625.23

SI-SSA-0010-2845

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092884 31 DECEMBER 2015 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 238,261,108.73		$ 239,569,539.67
RECEIPTS:				
INVESTMENT INCOME:				
INTEREST	$ 0.00		$ 0.01	
REALIZED GAIN/LOSS	6,827.04		158,190.17	
UNREALIZED GAIN/LOSS-INVESTMENT	3,244,076.07-		12,708,948.34-	
		3,237,249.03-		12,550,758.16-
MASTER TRUST INVESTMENT GAIN/LOSS	2,317.95		17,955.58	
MASTER TRUST ALLOCATED EXPENSES	41,569.82-		1,208,654.55-	
MASTER TRUST CHANGE IN REALIZED G/L	356,707.58-		5,110,444.65	
MASTER TRUST INTEREST INCOME EARNED	296,485.99		3,367,397.16	
MASTER TRUST DIVIDEND INCOME EARNED	142,105.35		1,988,564.48	
		42,631.89		9,275,707.32
TOTAL RECEIPTS		3,194,617.14-		3,275,050.84-
DISBURSEMENTS:				
UBTI TAX EXPENSE	83,000.00		1,310,997.24	
		83,000.00		1,310,997.24
TOTAL DISBURSEMENTS		83,000.00		1,310,997.24
NET ASSETS - END OF PERIOD		$ 234,983,491.59		$ 234,983,491.59

SI-SSA-0010-2846

BNY MELLON

TRDPSB PSBF09288602 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092886 31 DECEMBER 2015 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 251,311,178.52		$ 252,702,844.57
RECEIPTS:				
INVESTMENT INCOME:				
INTEREST	$ 0.00		$ 0.01	
REALIZED GAIN/LOSS	6,412.29		155,473.54	
UNREALIZED GAIN/LOSS-INVESTMENT	3,421,754.84-		13,404,987.86-	
		3,415,342.55-		13,249,514.31-
MASTER TRUST INVESTMENT GAIN/LOSS	2,444.90		18,939.42	
MASTER TRUST ALLOCATED EXPENSES	43,846.62-		1,274,871.93-	
MASTER TRUST CHANGE IN REALIZED G/L	375,455.87-		5,401,789.96	
MASTER TRUST INTEREST INCOME EARNED	312,724.60		3,551,884.94	
MASTER TRUST DIVIDEND INCOME EARNED	149,888.49		2,097,515.47	
		45,755.50		9,795,257.86
TOTAL RECEIPTS		3,369,587.05-		3,454,256.45-
DISBURSEMENTS:				
UBTI TAX EXPENSE	88,000.00		1,394,996.65	
		88,000.00		1,394,996.65
TOTAL DISBURSEMENTS		88,000.00		1,394,996.65
NET ASSETS - END OF PERIOD		$ 247,853,591.47		$ 247,853,591.47

SI-SSA-0010-2847

BNY MELLON

TRDPSB PSBF09288802 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092888 31 DECEMBER 2015 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 277,001,365.62		$ 278,529,771.61
RECEIPTS:				
INVESTMENT INCOME:				
INTEREST	$ 0.00		$ 0.01	
REALIZED GAIN/LOSS	6,959.43		169,038.11	
UNREALIZED GAIN/LOSS-INVESTMENT	3,771,542.34-		14,775,333.79-	
		3,764,582.91-		14,606,295.67-
MASTER TRUST INVESTMENT GAIN/LOSS	2,694.84		20,875.33	
MASTER TRUST ALLOCATED EXPENSES	48,328.84-		1,405,187.33-	
MASTER TRUST CHANGE IN REALIZED G/L	413,728.34-		5,956,287.59	
MASTER TRUST INTEREST INCOME EARNED	344,692.76		3,914,951.61	
MASTER TRUST DIVIDEND INCOME EARNED	165,210.77		2,311,916.90	
		50,541.19		10,798,844.10
TOTAL RECEIPTS		3,714,041.72-		3,807,451.57-
DISBURSEMENTS:				
UBTI TAX EXPENSE	97,000.00		1,531,996.14	
		97,000.00		1,531,996.14
TOTAL DISBURSEMENTS		97,000.00		1,531,996.14
NET ASSETS - END OF PERIOD		$ 273,190,323.90		$ 273,190,323.90

SI-SSA-0010-2848

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BNY MELLON

TRDPSB PSBF09319702 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093197 31 DECEMBER 2015 NC100

PSEG NUCLEAR HOPE CREEK QUAL

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 679,070.42		$ 679,348.37
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 9,249.22-		$ 36,237.47-	
		9,249.22-		36,237.47-
MASTER TRUST INVESTMENT GAIN/LOSS	6.61		51.07	
MASTER TRUST ALLOCATED EXPENSES	118.51-		3,439.71-	
MASTER TRUST CHANGE IN REALIZED G/L	997.54-		14,999.60	
MASTER TRUST INTEREST INCOME EARNED	845.31		9,582.82	
MASTER TRUST DIVIDEND INCOME EARNED	405.16		5,657.55	
		141.03		26,851.33
TOTAL RECEIPTS		9,108.19-		9,386.14-
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 669,962.23		$ 669,962.23

SI-SSA-0010-2850

BNY MELLON

TRDPSB PSBF09319502 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093195 31 DECEMBER 2015 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 2,887,582.10		$ 2,888,764.00
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 39,329.95-		$ 154,090.78-	
		39,329.95-		154,090.78-
MASTER TRUST INVESTMENT GAIN/LOSS	28.10		217.15	
MASTER TRUST ALLOCATED EXPENSES	503.98-		14,626.64-	
MASTER TRUST CHANGE IN REALIZED G/L	4,241.82-		63,782.14	
MASTER TRUST INTEREST INCOME EARNED	3,594.48		40,748.52	
MASTER TRUST DIVIDEND INCOME EARNED	1,722.83		24,057.37	
		599.61		114,178.54
TOTAL RECEIPTS		38,730.34-		39,912.24-
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 2,848,851.76		$ 2,848,851.76

BNY MELLON

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 2,901,877.13		$ 2,903,064.88
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 39,524.67-		$ 154,853.65-	
		39,524.67-		154,853.65-
MASTER TRUST INVESTMENT GAIN/LOSS	28.24		218.22	
MASTER TRUST ALLOCATED EXPENSES	506.47-		14,699.08-	
MASTER TRUST CHANGE IN REALIZED G/L	4,262.82-		64,097.92	
MASTER TRUST INTEREST INCOME EARNED	3,612.28		40,950.27	
MASTER TRUST DIVIDEND INCOME EARNED	1,731.36		24,176.49	
		602.59		114,743.82
TOTAL RECEIPTS		38,922.08-		40,109.83-
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 2,862,955.05		$ 2,862,955.05

BNY MELLON

TRDPSB PSBF09319302 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093193 31 DECEMBER 2015 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 5,408,596.05		$ 5,410,809.82
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 73,667.12-		$ 288,620.41-	
		73,667.12-		288,620.41-
MASTER TRUST INVESTMENT GAIN/LOSS	52.64		406.74	
MASTER TRUST ALLOCATED EXPENSES	943.98-		27,396.47-	
MASTER TRUST CHANGE IN REALIZED G/L	7,945.16-		119,467.38	
MASTER TRUST INTEREST INCOME EARNED	6,732.66		76,324.22	
MASTER TRUST DIVIDEND INCOME EARNED	3,226.96		45,060.77	
		1,123.12		213,862.64
TOTAL RECEIPTS		72,544.00-		74,757.77-
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 5,336,052.05		$ 5,336,052.05

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BNY MELLON

TRDPSB PSBF09319402 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093194 31 DECEMBER 2015 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 4,672,476.48		$ 4,674,388.95
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 63,640.90-		$ 249,338.58-	
		63,640.90-		249,338.58-
MASTER TRUST INVESTMENT GAIN/LOSS	45.47		351.36	
MASTER TRUST ALLOCATED EXPENSES	815.50-		23,667.79-	
MASTER TRUST CHANGE IN REALIZED G/L	6,863.81-		103,207.64	
MASTER TRUST INTEREST INCOME EARNED	5,816.34		65,936.33	
MASTER TRUST DIVIDEND INCOME EARNED	2,787.76		38,927.93	
		970.26		184,755.47
TOTAL RECEIPTS		62,670.64-		64,583.11-
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 4,609,805.84		$ 4,609,805.84

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Non-FERC

Non-Qualified Reports

BNY MELLON

TRDPSB PSBF09288502 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092885 31 DECEMBER 2015 NC100

PSEG NUCLEAR SALEM NONQUAL

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 100,177,826.41		$ 98,216,701.10
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 869,671.22-		$ 1,508,758.17	
		869,671.22-		1,508,758.17
MASTER TRUST INVESTMENT GAIN/LOSS	538.45		3,215.39	
MASTER TRUST ALLOCATED EXPENSES	13,991.20-		552,314.30-	
MASTER TRUST CHANGE IN REALIZED G/L	623,977.59-		2,297,834.95-	
MASTER TRUST INTEREST INCOME EARNED	33,012.42		387,219.59	
MASTER TRUST DIVIDEND INCOME EARNED	136,413.01		1,574,405.28	
		468,004.91-		885,308.99-
TOTAL RECEIPTS		1,337,676.13-		623,449.18
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 98,840,150.28		$ 98,840,150.28

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BNY MELLON

TRDPSB PSBF09288702 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092887 31 DECEMBER 2015 NC100

PSEG NUCLEAR SALEM NONQUAL

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 32,594,188.13		$ 31,956,109.93
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 282,959.12-		$ 490,894.50	
		282,959.12-		490,894.50
MASTER TRUST INVESTMENT GAIN/LOSS	175.19		1,046.16	
MASTER TRUST ALLOCATED EXPENSES	4,552.21-		179,702.80-	
MASTER TRUST CHANGE IN REALIZED G/L	203,019.41-		747,631.16-	
MASTER TRUST INTEREST INCOME EARNED	10,741.04		125,987.06	
MASTER TRUST DIVIDEND INCOME EARNED	44,383.79		512,253.72	
		152,271.60-		288,047.02-
TOTAL RECEIPTS		435,230.72-		202,847.48
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 32,158,957.41		$ 32,158,957.41

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BNY MELLON

TRDPSB PSBF09288102 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092881 31 DECEMBER 2015 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 71,892,404.09		$ 70,485,006.68
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 624,117.70-		$ 1,082,757.05	
		624,117.70-		1,082,757.05
MASTER TRUST INVESTMENT GAIN/LOSS	386.42		2,307.52	
MASTER TRUST ALLOCATED EXPENSES	10,040.74-		396,367.14-	
MASTER TRUST CHANGE IN REALIZED G/L	447,796.20-		1,649,036.35-	
MASTER TRUST INTEREST INCOME EARNED	23,691.29		277,887.33	
MASTER TRUST DIVIDEND INCOME EARNED	97,896.50		1,129,868.57	
		335,862.73-		635,340.07-
TOTAL RECEIPTS		959,980.43-		447,416.98
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 70,932,423.66		$ 70,932,423.66

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BNY MELLON

TRDPSB PSBF09288302 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092883 31 DECEMBER 2015 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 56,830,429.63		$ 55,717,892.08
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 493,360.56-		$ 855,911.70	
		493,360.56-		855,911.70
MASTER TRUST INVESTMENT GAIN/LOSS	305.46		1,824.07	
MASTER TRUST ALLOCATED EXPENSES	7,937.14-		313,325.37-	
MASTER TRUST CHANGE IN REALIZED G/L	353,979.68-		1,303,551.42-	
MASTER TRUST INTEREST INCOME EARNED	18,727.80		219,667.91	
MASTER TRUST DIVIDEND INCOME EARNED	77,386.48		893,153.02	
		265,497.08-		502,231.79-
TOTAL RECEIPTS		758,857.64-		353,679.91
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 56,071,571.99		$ 56,071,571.99

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BNY MELLON

TRDPSB PSBF09288002 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092880 31 DECEMBER 2015 NC100

PSEG NUCLEAR HOPE CREEK

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 10,284,374.82		$ 10,083,043.37
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 89,281.47-		$ 154,890.91	
		89,281.47-		154,890.91
MASTER TRUST INVESTMENT GAIN/LOSS	55.28		330.10	
MASTER TRUST ALLOCATED EXPENSES	1,436.36-		56,701.24-	
MASTER TRUST CHANGE IN REALIZED G/L	64,058.28-		235,898.46-	
MASTER TRUST INTEREST INCOME EARNED	3,389.09		39,752.42	
MASTER TRUST DIVIDEND INCOME EARNED	14,004.32		161,630.30	
		48,045.95-		90,886.88-
TOTAL RECEIPTS		137,327.42-		64,004.03
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 10,147,047.40		$ 10,147,047.40

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FERC Non-Qualified Reports

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093362 31 DECEMBER 2015 NC100

PSEG NUCLEAR SALEM NON-QUAL

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 249,657.86		$ 244,770.44
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 2,167.36-		$ 3,760.02	
		2,167.36-		3,760.02
MASTER TRUST INVESTMENT GAIN/LOSS	1.34		8.01	
MASTER TRUST ALLOCATED EXPENSES	34.87-		1,376.45-	
MASTER TRUST CHANGE IN REALIZED G/L	1,555.04-		5,726.54-	
MASTER TRUST INTEREST INCOME EARNED	82.28		965.03	
MASTER TRUST DIVIDEND INCOME EARNED	339.96		3,923.66	
		1,166.33-		2,206.29-
TOTAL RECEIPTS		3,333.69-		1,553.73
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 246,324.17		$ 246,324.17

SI-SSA-0010-2862

BNY MELLON

TRDPSB PSBF09336302 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093363 31 DECEMBER 2015 NC100

PSEG NUCLEAR SALEM NON-QUAL

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 120,557.32		$ 118,197.23
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 1,046.58-		$ 1,815.67	
		1,046.58-		1,815.67
MASTER TRUST INVESTMENT GAIN/LOSS	0.65		3.87	
MASTER TRUST ALLOCATED EXPENSES	16.84-		664.66-	
MASTER TRUST CHANGE IN REALIZED G/L	750.92-		2,765.28-	
MASTER TRUST INTEREST INCOME EARNED	39.72		465.98	
MASTER TRUST DIVIDEND INCOME EARNED	164.16		1,894.70	
		563.23-		1,065.39-
TOTAL RECEIPTS		1,609.81-		750.28
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 118,947.51		$ 118,947.51

SI-SSA-0010-2863

BNY MELLON

TRDPSB PSBF09336402 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093364 31 DECEMBER 2015 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 359,270.48		$ 352,237.24
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 3,118.92-		$ 5,410.96	
		3,118.92-		5,410.96
MASTER TRUST INVESTMENT GAIN/LOSS	1.93		11.52	
MASTER TRUST ALLOCATED EXPENSES	50.18-		1,980.79-	
MASTER TRUST CHANGE IN REALIZED G/L	2,237.79-		8,240.79-	
MASTER TRUST INTEREST INCOME EARNED	118.39		1,388.68	
MASTER TRUST DIVIDEND INCOME EARNED	489.22		5,646.31	
		1,678.43-		3,175.07-
TOTAL RECEIPTS		4,797.35-		2,235.89
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 354,473.13		$ 354,473.13

SI-SSA-0010-2864

BNY MELLON

TRDPSB PSBF09336502 MONTHLY FINAL 093713 2015-12-31 CYCLE 2 09:37:14 RUN DATE: 13-JAN-16

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093365 31 DECEMBER 2015 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-15	CURRENT PERIOD 31-DEC-15	YEAR TO DATE 01-JAN-15	YEAR TO DATE 31-DEC-15
NET ASSETS - BEGINNING OF PERIOD		$ 358,811.61		$ 351,787.36
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 3,114.94-		$ 5,403.98	
		3,114.94-		5,403.98
MASTER TRUST INVESTMENT GAIN/LOSS	1.93		11.53	
MASTER TRUST ALLOCATED EXPENSES	50.11-		1,978.24-	
MASTER TRUST CHANGE IN REALIZED G/L	2,234.93-		8,230.27-	
MASTER TRUST INTEREST INCOME EARNED	118.24		1,386.93	
MASTER TRUST DIVIDEND INCOME EARNED	488.60		5,639.11	
		1,676.27-		3,170.94-
TOTAL RECEIPTS		4,791.21-		2,233.04
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 354,020.40		$ 354,020.40

SI-SSA-0010-2865

20160428-5214 FERC PDF (Unofficial) 4/28/2016 1:24:37 PM

Document Content(s)

Order No. 580 Submission 2016.PDF.....1-27

20170331-5099 FERC PDF (Unofficial) 3/31/2017 9:50:15 AM

David K. Richter
Associate General Regulatory Counsel &
Property Counsel

Law Department
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David.Richter@PSEG.com

PSEG
Services Corporation

March 31, 2017

VIA ELECTRONIC FILING

Kimberly D. Bose, Secretary
Nathaniel J. Davis, Sr., Deputy Secretary
Attention FERC 561
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Order No. 580 and Order No. 658
Docket Nos. RM 94-14-000 and RM05-15-000

Dear Secretary Bose and Deputy Secretary Davis:

In accordance with 18 CFR § 35.33(d), attached is the financial reports furnished by our trustee, Mellon Bank, for PSEG Nuclear LLC's ("PSEG") Qualified and Non-Qualified Nuclear Decommissioning Trust Funds for the year ending December 31, 2016.

On December 31, 2016 assets in the trust funds totaled $1,861,634,023.85, included in this balance are amounts collected through FERC jurisdictional rates totaling $18,425,219.87. This total represents the contributions and earnings on the funds since its inception in 1988. During 2016, there were no contributions made to the PSEG trust funds.

If you have any questions, or would like to see the detailed information that comprises the numbers shown on the Mellon Bank statements, please contact Bradley Barazani at (973) 430-7096.

Very truly yours,

David K. Richter

David K. Richter

PSEG Nuclear LLC
FERC ASSET Allocation
As of December 31, 2016

Account Names	Percentage	Total Trust Market Values	Non-FERC Assets	FERC Assets
Q Hope Creek	33.5%	$ 525,155,919.38	$524,448,253.59	$707,665.79
Q PB 2	14.9%	$ 233,715,127.03	$230,705,950.05	$3,009,176.98
Q PB 3	15.9%	$ 249,721,946.86	$246,697,872.89	$3,024,073.97
Q Salem 1	17.0%	$ 265,830,744.21	$260,194,394.42	$5,636,349.79
Q Salem 2	18.6%	$ 291,670,970.05	$286,801,737.53	$4,869,232.52
PSEG Nuclear LLC Qual. Plans	G716275	$ 1,566,094,707.53		
Non-Q Salem 1	36.8%	$ 108,771,721.91	$108,501,320.68	$270,401.23
Non-Q Salem 2	12.0%	$ 35,432,921.77	$35,302,347.69	$130,574.08
Non-Q PB 2	26.5%	$ 78,254,863.30	$77,865,742.05	$389,121.25
Non-Q PB 3	21.0%	$ 61,940,934.69	$61,552,310.43	$388,624.26
Non-Q Hope Creek	3.8%	$ 11,138,874.65	$11,138,874.65	$ -
PSEG Nuclear LLC Non Qual. Plans	G716277	$ 295,539,316.32		
Totals		$ 1,861,634,023.85	$1,843,208,803.98	$18,425,219.87
			99.01%	0.99%

SI-SSA-0010-2868

BNY MELLON

PSB G716275 31 DECEMBER 2016 M1101
PSEG NUCLEAR LLC QUAL. PLANS

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	PSE&G QUALIFIED MTU				
213,899,868.5030	HOPE CREEK QUAL	467,260,125.43	2.4518	524,448,253.59	57,188,128.16
94,095,026.6110	PEACH BOTTOM #2 Q	207,753,202.39	2.4518	230,705,950.05	22,952,747.66
100,617,443.5910	PEACH BOTTOM #3 Q	222,075,288.26	2.4518	246,697,872.89	24,622,584.63
106,122,093.7810	SALEM Q UNIT 1	236,582,389.95	2.4518	260,194,394.42	23,612,004.47
116,974,083.7610	SALEM Q UNIT 2	261,086,015.22	2.4518	286,801,737.53	25,715,722.31
2,298,824.4690	SALEM Q #1 FERC	5,905,615.48	2.4518	5,636,349.79	269,265.69-
1,985,950.3560	SALEM Q #2 FERC	4,951,063.35	2.4518	4,869,232.52	81,830.83-
1,227,313.7660	PB#2 Q FERC	3,115,510.88	2.4518	3,009,176.98	106,333.90-
1,233,389.6050	PB#3 Q FERC	3,138,022.04	2.4518	3,024,073.97	113,948.07-
288,626.4160	HOPE CREEK QUAL FERC	822,803.76	2.4518	707,665.79	115,137.97-
638,742,620.8590		1,412,690,036.76		1,566,094,707.53	153,404,670.77
TOTAL INVESTMENTS UNIT OF PARTICIPATION		1,412,690,036.76		1,566,094,707.53	153,404,670.77
TOTAL INVESTMENT		1,412,690,036.76		1,566,094,707.53	153,404,670.77

SI-SSA-0010-2869

BNY MELLON

PSB G716277 31 DECEMBER 2016 M1101
PSEG NUCLEAR LLC NQ PLANS

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	PSE&G NON-QUALIFIED MTU				
4,397,995.9250	HOPE CREEK NONQUAL	9,042,416.22	2.5327	11,138,874.65	2,096,458.43
30,743,968.9440	PEACH BOTTOM #2 NQ	63,842,453.31	2.5327	77,865,742.05	14,023,288.74
24,302,886.8740	PEACH BOTTOM #3 NQ	50,576,409.65	2.5327	61,552,310.43	10,975,900.78
42,839,908.0980	SALEM NQ UNIT 1	88,810,111.32	2.5327	108,501,320.68	19,691,209.36
13,938,533.8450	SALEM NQ UNIT 2	28,842,033.65	2.5327	35,302,347.69	6,460,314.04
106,763.3430	SALEM NQ #1 FERC	230,689.52	2.5327	270,401.23	39,711.71
51,554.9650	SALEM NQ #2 FERC	111,397.72	2.5327	130,574.08	19,176.36
153,637.9330	PB#2 NQ FERC	331,977.61	2.5327	389,121.25	57,143.64
153,441.7060	PB#3 NQ FERC	331,553.36	2.5327	388,624.26	57,070.90
116,688,691.6330		242,119,042.36		295,539,316.32	53,420,273.96
TOTAL INVESTMENTS UNIT OF PARTICIPATION		242,119,042.36		295,539,316.32	53,420,273.96
TOTAL INVESTMENT		242,119,042.36		295,539,316.32	53,420,273.96

SI-SSA-0010-2870

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Non-FERC Qualified Reports

BNY MELLON

TRDPSB PSBF09287902 MONTHLY FINAL 093523 2016-12-31 CYCLE 2 09:35:21 RUN DATE: 05-JAN-17

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092879 31 DECEMBER 2016 NC100

PSEG NUCLEAR HOPE CREEK QUAL

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 519,462,100.82		$ 499,512,899.28
RECEIPTS:				
INVESTMENT INCOME:				
INTEREST	$ 0.00		$ 242.93	
REALIZED GAIN/LOSS	77,006.23		254,861.72	
UNREALIZED GAIN/LOSS-INVESTMENT	3,852,369.90		17,578,589.11	
		3,929,376.13		17,833,693.76
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		7,866.43	
MASTER TRUST ALLOCATED EXPENSES	153.48-		2,129,981.30-	
MASTER TRUST CHANGE IN REALIZED G/L	914,148.75		258,088.07	
MASTER TRUST INTEREST INCOME EARNED	601,861.06		7,608,668.09	
MASTER TRUST DIVIDEND INCOME EARNED	290,920.31		4,391,502.26	
		1,806,776.64		10,136,143.55
TOTAL RECEIPTS		5,736,152.77		27,969,837.31
DISBURSEMENTS:				
UBTI TAX EXPENSE	750,000.00		3,034,483.00	
		750,000.00		3,034,483.00
TOTAL DISBURSEMENTS		750,000.00		3,034,483.00
NET ASSETS - END OF PERIOD		$ 524,448,253.59		$ 524,448,253.59

SI-SSA-0010-2872

BNY MELLON

TRDPSB PSBF09288202 MONTHLY FINAL 093523 2016-12-31 CYCLE 2 09:35:21 RUN DATE: 05-JAN-17

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092882 31 DECEMBER 2016 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 228,515,603.72		$ 219,751,625.23
RECEIPTS:				
INVESTMENT INCOME:				
INTEREST	$ 0.00		$ 98.23	
REALIZED GAIN/LOSS	30,977.93		99,824.07	
UNREALIZED GAIN/LOSS-INVESTMENT	1,694,666.08		7,733,012.57	
		1,725,644.01		7,832,934.87
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		3,460.53	
MASTER TRUST ALLOCATED EXPENSES	67.53-		937,004.07-	
MASTER TRUST CHANGE IN REALIZED G/L	405,033.34		125,743.04	
MASTER TRUST INTEREST INCOME EARNED	264,760.02		3,347,160.94	
MASTER TRUST DIVIDEND INCOME EARNED	127,976.49		1,931,882.51	
		797,702.32		4,471,242.95
TOTAL RECEIPTS		2,523,346.33		12,304,177.82
DISBURSEMENTS:				
UBTI TAX EXPENSE	333,000.00		1,349,853.00	
		333,000.00		1,349,853.00
TOTAL DISBURSEMENTS		333,000.00		1,349,853.00
NET ASSETS - END OF PERIOD		$ 230,705,950.05		$ 230,705,950.05

SI-SSA-0010-2873

BNY MELLON

TRDPSB PSBF09288402 MONTHLY FINAL 093523 2016-12-31 CYCLE 2 09:35:21 RUN DATE: 05-JAN-17

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092884 31 DECEMBER 2016 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 244,355,614.91		$ 234,983,491.59
RECEIPTS:				
INVESTMENT INCOME:				
INTEREST	$ 0.00		$ 115.98	
REALIZED GAIN/LOSS	33,232.39		107,129.95	
UNREALIZED GAIN/LOSS-INVESTMENT	1,812,135.81		8,268,865.02	
		1,845,368.20		8,376,110.95
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		3,700.37	
MASTER TRUST ALLOCATED EXPENSES	72.21-		1,001,946.36-	
MASTER TRUST CHANGE IN REALIZED G/L	433,002.03		134,103.63	
MASTER TRUST INTEREST INCOME EARNED	283,112.48		3,579,141.78	
MASTER TRUST DIVIDEND INCOME EARNED	136,847.48		2,065,772.93	
		852,889.78		4,780,772.35
TOTAL RECEIPTS		2,698,257.98		13,156,883.30
DISBURSEMENTS:				
UBTI TAX EXPENSE	356,000.00		1,442,502.00	
		356,000.00		1,442,502.00
TOTAL DISBURSEMENTS		356,000.00		1,442,502.00
NET ASSETS - END OF PERIOD		$ 246,697,872.89		$ 246,697,872.89

SI-SSA-0010-2874

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092886 31 DECEMBER 2016 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 257,727,518.23		$ 247,853,591.47
RECEIPTS:				
INVESTMENT INCOME:				
INTEREST	$ 0.00		$ 111.26	
REALIZED GAIN/LOSS	31,911.91		99,518.60	
UNREALIZED GAIN/LOSS-INVESTMENT	1,911,275.43		8,721,471.67	
		1,943,187.34		8,821,101.53
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		3,902.90	
MASTER TRUST ALLOCATED EXPENSES	76.16-		1,056,788.58-	
MASTER TRUST CHANGE IN REALIZED G/L	459,829.59		154,837.02	
MASTER TRUST INTEREST INCOME EARNED	298,601.19		3,775,066.29	
MASTER TRUST DIVIDEND INCOME EARNED	144,334.23		2,178,854.79	
		902,688.85		5,055,872.42
TOTAL RECEIPTS		2,845,876.19		13,876,973.95
DISBURSEMENTS:				
UBTI TAX EXPENSE	379,000.00		1,536,171.00	
		379,000.00		1,536,171.00
TOTAL DISBURSEMENTS		379,000.00		1,536,171.00
NET ASSETS - END OF PERIOD		$ 260,194,394.42		$ 260,194,394.42

BNY MELLON

TRDPSB PSBF09288802 MONTHLY FINAL 093523 2016-12-31 CYCLE 2 09:35:21 RUN DATE: 05-JAN-17

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092888 31 DECEMBER 2016 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 284,080,843.53		$ 273,190,323.90
RECEIPTS:				
INVESTMENT INCOME:				
INTEREST	$ 0.00		$ 122.08	
REALIZED GAIN/LOSS	34,572.36		107,276.34	
UNREALIZED GAIN/LOSS-INVESTMENT	2,106,721.44		9,613,335.70	
		2,141,293.80		9,720,734.12
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		4,301.99	
MASTER TRUST ALLOCATED EXPENSES	83.94-		1,164,847.04-	
MASTER TRUST CHANGE IN REALIZED G/L	507,454.37		173,120.12	
MASTER TRUST INTEREST INCOME EARNED	329,136.00		4,161,064.87	
MASTER TRUST DIVIDEND INCOME EARNED	159,093.77		2,401,643.57	
		995,600.20		5,575,283.51
TOTAL RECEIPTS		3,136,894.00		15,296,017.63
DISBURSEMENTS:				
UBTI TAX EXPENSE	416,000.00		1,684,604.00	
		416,000.00		1,684,604.00
TOTAL DISBURSEMENTS		416,000.00		1,684,604.00
NET ASSETS - END OF PERIOD		$ 286,801,737.53		$ 286,801,737.53

SI-SSA-0010-2876

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FERC Qualified Reports

BNY MELLON

TRDPSB PSBF09319702 MONTHLY FINAL 093523 2016-12-31 CYCLE 2 09:35:21 RUN DATE: 05-JAN-17

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093197 31 DECEMBER 2016 NC100

PSEG NUCLEAR HOPE CREEK QUAL

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 699,925.70		$ 669,962.23
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 5,198.21		$ 23,699.70	
		5,198.21		23,699.70
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		10.61	
MASTER TRUST ALLOCATED EXPENSES	0.21-		2,868.43-	
MASTER TRUST CHANGE IN REALIZED G/L	1,337.42		705.23	
MASTER TRUST INTEREST INCOME EARNED	812.12		10,243.61	
MASTER TRUST DIVIDEND INCOME EARNED	392.55		5,912.84	
		2,541.88		14,003.86
TOTAL RECEIPTS		7,740.09		37,703.56
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 707,665.79		$ 707,665.79

SI-SSA-0010-2878

BNY MELLON

TRDPSB PSBF09319502 MONTHLY FINAL 093523 2016-12-31 CYCLE 2 09:35:21 RUN DATE: 05-JAN-17

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093195 31 DECEMBER 2016 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 2,976,264.11		$ 2,848,851.76
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 22,104.11		$ 100,777.26	
		22,104.11		100,777.26
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		45.06	
MASTER TRUST ALLOCATED EXPENSES	0.88-		12,197.27-	
MASTER TRUST CHANGE IN REALIZED G/L	5,687.04		2,998.85	
MASTER TRUST INTEREST INCOME EARNED	3,453.36		43,558.40	
MASTER TRUST DIVIDEND INCOME EARNED	1,669.24		25,142.92	
		10,808.76		59,547.96
TOTAL RECEIPTS		32,912.87		160,325.22
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 3,009,176.98		$ 3,009,176.98

SI-SSA-0010-2879

BNY MELLON

TRDPSB PSBF09319602 MONTHLY FINAL 093523 2016-12-31 CYCLE 2 09:35:21 RUN DATE: 05-JAN-17

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093196 31 DECEMBER 2016 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 2,990,998.16		$ 2,862,955.05
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 22,213.55		$ 101,276.22	
		22,213.55		101,276.22
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		45.26	
MASTER TRUST ALLOCATED EXPENSES	0.89-		12,257.66-	
MASTER TRUST CHANGE IN REALIZED G/L	5,715.20		3,013.72	
MASTER TRUST INTEREST INCOME EARNED	3,470.45		43,774.02	
MASTER TRUST DIVIDEND INCOME EARNED	1,677.50		25,267.36	
		10,862.26		59,842.70
TOTAL RECEIPTS		33,075.81		161,118.92
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 3,024,073.97		$ 3,024,073.97

SI-SSA-0010-2880

BNY MELLON

TRDPSB PSBF09319302 MONTHLY FINAL 093523 2016-12-31 CYCLE 2 09:35:21 RUN DATE: 05-JAN-17

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093193 31 DECEMBER 2016 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 5,574,702.21		$ 5,336,052.05
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 41,402.19		$ 188,761.22	
		41,402.19		188,761.22
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		84.40	
MASTER TRUST ALLOCATED EXPENSES	1.65-		22,846.15-	
MASTER TRUST CHANGE IN REALIZED G/L	10,652.14		5,617.03	
MASTER TRUST INTEREST INCOME EARNED	6,468.32		81,587.21	
MASTER TRUST DIVIDEND INCOME EARNED	3,126.58		47,094.03	
		20,245.39		111,536.52
TOTAL RECEIPTS		61,647.58		300,297.74
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 5,636,349.79		$ 5,636,349.79

SI-SSA-0010-2881

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093194 31 DECEMBER 2016 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 4,815,975.29		$ 4,609,805.84
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 35,767.28		$ 163,070.47	
		35,767.28		163,070.47
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		72.91	
MASTER TRUST ALLOCATED EXPENSES	1.43-		19,736.73-	
MASTER TRUST CHANGE IN REALIZED G/L	9,202.36		4,852.51	
MASTER TRUST INTEREST INCOME EARNED	5,587.97		70,483.06	
MASTER TRUST DIVIDEND INCOME EARNED	2,701.05		40,684.46	
		17,489.95		96,356.21
TOTAL RECEIPTS		53,257.23		259,426.68
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 4,869,232.52		$ 4,869,232.52

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Non-Qualified Reports

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFITS

PSB F092885 31 DECEMBER 2016 NC100

PSEG NUCLEAR SALEM NONQUAL

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 107,048,405.20		$ 98,840,150.28
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 1,586,462.50		$ 8,519,653.58	
		1,586,462.50		8,519,653.58
MASTER TRUST INVESTMENT GAIN/LOSS	903.93		4,790.11	
MASTER TRUST ALLOCATED EXPENSES	79,821.57-		382,070.85-	
MASTER TRUST CHANGE IN REALIZED G/L	208,590.58-		547,467.20-	
MASTER TRUST INTEREST INCOME EARNED	34,068.49		400,037.15	
MASTER TRUST DIVIDEND INCOME EARNED	119,892.71		1,666,227.61	
		133,547.02-		1,141,516.82
TOTAL RECEIPTS		1,452,915.48		9,661,170.40
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 108,501,320.68		$ 108,501,320.68

BNY MELLON

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 34,829,622.31		$ 32,158,957.41
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 516,176.69		$ 2,771,982.66	
		516,176.69		2,771,982.66
MASTER TRUST INVESTMENT GAIN/LOSS	294.10		1,558.52	
MASTER TRUST ALLOCATED EXPENSES	25,971.01-		124,311.86-	
MASTER TRUST CHANGE IN REALIZED G/L	67,867.72-		178,125.75-	
MASTER TRUST INTEREST INCOME EARNED	11,084.63		130,157.41	
MASTER TRUST DIVIDEND INCOME EARNED	39,008.69		542,129.30	
		43,451.31-		371,407.62
TOTAL RECEIPTS		472,725.38		3,143,390.28
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 35,302,347.69		$ 35,302,347.69

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFITS

PSB F092881 31 DECEMBER 2016 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 76,823,060.34		$ 70,932,423.66
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 1,138,521.46		$ 6,114,111.29	
		1,138,521.46		6,114,111.29
MASTER TRUST INVESTMENT GAIN/LOSS	648.70		3,437.59	
MASTER TRUST ALLOCATED EXPENSES	57,283.78-		274,192.33-	
MASTER TRUST CHANGE IN REALIZED G/L	149,694.59-		392,888.66-	
MASTER TRUST INTEREST INCOME EARNED	24,449.17		287,085.83	
MASTER TRUST DIVIDEND INCOME EARNED	86,040.75		1,195,764.67	
		95,839.75-		819,207.10
TOTAL RECEIPTS		1,042,681.71		6,933,318.39
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 77,865,742.05		$ 77,865,742.05

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BNY MELLON

TRDPSB PSBF09288302 MONTHLY FINAL 093523 2016-12-31 CYCLE 2 09:35:21 RUN DATE: 05-JAN-17

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092883 31 DECEMBER 2016 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 60,728,078.02		$ 56,071,571.99
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 899,993.06		$ 4,833,161.10	
		899,993.06		4,833,161.10
MASTER TRUST INVESTMENT GAIN/LOSS	512.79		2,717.40	
MASTER TRUST ALLOCATED EXPENSES	45,282.43-		216,747.09-	
MASTER TRUST CHANGE IN REALIZED G/L	118,332.50-		310,575.65-	
MASTER TRUST INTEREST INCOME EARNED	19,326.90		226,939.29	
MASTER TRUST DIVIDEND INCOME EARNED	68,014.59		945,243.39	
		75,760.65-		647,577.34
TOTAL RECEIPTS		824,232.41		5,480,738.44
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 61,552,310.43		$ 61,552,310.43

SI-SSA-0010-2887

BNY MELLON

TRDPSB PSBF09288002 MONTHLY FINAL 093523 2016-12-31 CYCLE 2 09:35:21 RUN DATE: 05-JAN-17

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092880 31 DECEMBER 2016 NC100

PSEG NUCLEAR HOPE CREEK

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 10,989,716.62		$ 10,147,047.40
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 162,868.13		$ 874,637.80	
		162,868.13		874,637.80
MASTER TRUST INVESTMENT GAIN/LOSS	92.80		491.76	
MASTER TRUST ALLOCATED EXPENSES	8,194.58-		39,223.85-	
MASTER TRUST CHANGE IN REALIZED G/L	21,414.16-		56,203.63-	
MASTER TRUST INTEREST INCOME EARNED	3,497.51		41,068.28	
MASTER TRUST DIVIDEND INCOME EARNED	12,308.33		171,056.89	
		13,710.10-		117,189.45
TOTAL RECEIPTS		149,158.03		991,827.25
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 11,138,874.65		$ 11,138,874.65

SI-SSA-0010-2888

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FERC Non-Qualified Reports

BNY MELLON

TRDPSB PSBF09336202 MONTHLY FINAL 093523 2016-12-31 CYCLE 2 09:35:21 RUN DATE: 05-JAN-17

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093362 31 DECEMBER 2016 NC100

PSEG NUCLEAR SALEM NON-QUAL

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 266,780.35		$ 246,324.17
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 3,953.70		$ 21,232.21	
		3,953.70		21,232.21
MASTER TRUST INVESTMENT GAIN/LOSS	2.25		11.94	
MASTER TRUST ALLOCATED EXPENSES	198.93-		952.18-	
MASTER TRUST CHANGE IN REALIZED G/L	519.84-		1,364.36-	
MASTER TRUST INTEREST INCOME EARNED	84.91		996.96	
MASTER TRUST DIVIDEND INCOME EARNED	298.79		4,152.49	
		332.82-		2,844.85
TOTAL RECEIPTS		3,620.88		24,077.06
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 270,401.23		$ 270,401.23

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BNY MELLON

TRDPSB PSBF09336302 MONTHLY FINAL 093523 2016-12-31 CYCLE 2 09:35:21 RUN DATE: 05-JAN-17

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093363 31 DECEMBER 2016 NC100

PSEG NUCLEAR SALEM NON-QUAL

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 128,825.60		$ 118,947.51
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 1,909.20		$ 10,252.80	
		1,909.20		10,252.80
MASTER TRUST INVESTMENT GAIN/LOSS	1.09		5.76	
MASTER TRUST ALLOCATED EXPENSES	96.06-		459.78-	
MASTER TRUST CHANGE IN REALIZED G/L	251.03-		658.84-	
MASTER TRUST INTEREST INCOME EARNED	41.00		481.44	
MASTER TRUST DIVIDEND INCOME EARNED	144.28		2,005.19	
		160.72-		1,373.77
TOTAL RECEIPTS		1,748.48		11,626.57
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 130,574.08		$ 130,574.08

SI-SSA-0010-2891

BNY MELLON

TRDPSB PSBF09336402 MONTHLY FINAL 093523 2016-12-31 CYCLE 2 09:35:21 RUN DATE: 05-JAN-17

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093364 31 DECEMBER 2016 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 383,910.62		$ 354,473.13
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 5,689.58		$ 30,554.26	
		5,689.58		30,554.26
MASTER TRUST INVESTMENT GAIN/LOSS	3.24		17.19	
MASTER TRUST ALLOCATED EXPENSES	286.27-		1,370.22-	
MASTER TRUST CHANGE IN REALIZED G/L	748.07-		1,963.39-	
MASTER TRUST INTEREST INCOME EARNED	122.18		1,434.65	
MASTER TRUST DIVIDEND INCOME EARNED	429.97		5,975.63	
		478.95-		4,093.86
TOTAL RECEIPTS		5,210.63		34,648.12
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 389,121.25		$ 389,121.25

SI-SSA-0010-2892

BNY MELLON

TRDPSB PSBF09336502 MONTHLY FINAL 093523 2016-12-31 CYCLE 2 09:35:21 RUN DATE: 05-JAN-17

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093365 31 DECEMBER 2016 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-16	CURRENT PERIOD 31-DEC-16	YEAR TO DATE 01-JAN-16	YEAR TO DATE 31-DEC-16
NET ASSETS - BEGINNING OF PERIOD		$ 383,420.29		$ 354,020.40
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 5,682.30		$ 30,515.25	
		5,682.30		30,515.25
MASTER TRUST INVESTMENT GAIN/LOSS	3.24		17.15	
MASTER TRUST ALLOCATED EXPENSES	285.90-		1,368.48-	
MASTER TRUST CHANGE IN REALIZED G/L	747.12-		1,960.90-	
MASTER TRUST INTEREST INCOME EARNED	122.02		1,432.84	
MASTER TRUST DIVIDEND INCOME EARNED	429.43		5,968.00	
		478.33-		4,088.61
TOTAL RECEIPTS		5,203.97		34,603.86
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 388,624.26		$ 388,624.26

SI-SSA-0010-2893

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Document Content(s)

Order No. 580 Submission 2016.PDF.....1-27

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Adrian D. Newall
Senior Counsel- Law Department

Regulatory Department
80 Park Plaza, T5C, Newark, NJ 07102-4194
tel: 973.430.5146 fax: 973.430.5983
email: Adrian.newall@pseg.com

PSEG
Services Corporation

March 29, 2018

VIA ELECTRONIC FILING

Kimberly D. Bose, Secretary
Nathaniel J. Davis, Sr., Deputy Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Annual Financial Report on Nuclear Plant Decommissioning Trust Funds - Order No. 658
Docket Nos. RM 94-14-000 and RM05-15-000

Dear Secretary Bose and Deputy Secretary Davis:

In accordance with 18 CFR § 35.33(d), attached is the financial reports furnished by our trustee, Mellon Bank, for PSEG Nuclear LLC's ("PSEG") Qualified and Non-Qualified Nuclear Decommissioning Trust Funds for the year ending December 31, 2017.

On December 31, 2017 assets in the trust funds totaled $2,083,558.499.16, included in this balance are amounts collected through FERC jurisdictional rates totaling $20,670,858.09. This total represents the contributions and earnings on the funds since its inception in 1988. During 2017, there were no contributions made to the PSEG trust funds.

If you have any questions, or would like to see the detailed information that comprises the numbers shown on the Mellon Bank statements, please contact Bradley Barazani at (973) 430-7096.

Very truly yours,

Adrian D. Newall

PSEG Nuclear LLC
FERC ASSET Allocation
As of December 31, 2017

Account Names	Percentage	Total Trust Market Values	Non-FERC Assets	FERC Assets
Q Hope Creek	33.5%	$ 579,091,308.56	$578,301,490.17	$789,818.39
Q PB 2	14.9%	$ 257,717,912.23	$254,359,401.25	$3,358,510.98
Q PB 3	15.9%	$ 275,382,341.36	$272,007,204.01	$3,375,137.35
Q Salem 1	17.0%	$ 293,132,206.95	$286,841,535.86	$6,290,671.09
Q Salem 2	18.6%	$ 321,642,956.78	$316,208,457.25	$5,434,499.53
PSEG Nuclear LLC Qual. Plans	G716275	$ 1,726,966,725.88		
Non-Q Salem 1	36.8%	$ 131,241,763.97	$130,915,503.31	$326,260.66
Non-Q Salem 2	12.0%	$ 42,752,648.15	$42,595,100.10	$157,548.05
Non-Q PB 2	26.5%	$ 94,420,738.40	$93,951,232.55	$469,505.85
Non-Q PB 3	21.0%	$ 74,736,681.46	$74,267,775.27	$468,906.19
Non-Q Hope Creek	3.8%	$ 13,439,941.30	$13,439,941.30	$ -
PSEG Nuclear LLC Non Qual. Plans	G716277	$ 356,591,773.28		
Totals		$ 2,083,558,499.16	$2,062,887,641.07	$20,670,858.09
			99.01%	0.99%

SI-SSA-0010-2896

BNY MELLON

TRDPSB PSBG71627500 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

INVESTMENT DETAIL PAGE: 1

PSB G716275 31 DECEMBER 2017 M1101

PSEG NUCLEAR LLC QUAL. PLANS

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	PSE&G QUALIFIED MTU				
211,330,968.7940	HOPE CREEK QUAL	507,639,291.62	2.7364	578,301,490.17	70,662,198.55
92,951,547.9400	PEACH BOTTOM #2 Q	225,479,159.33	2.7364	254,359,401.25	28,880,241.92
99,400,653.3260	PEACH BOTTOM #3 Q	241,046,292.13	2.7364	272,007,204.01	30,960,911.88
104,821,621.0660	SALEM Q UNIT 1	256,544,142.19	2.7364	286,841,535.86	30,297,393.67
115,553,289.6710	SALEM Q UNIT 2	283,123,693.00	2.7364	316,208,457.25	33,084,764.25
2,298,824.4690	SALEM Q #1 FERC	6,415,729.22	2.7364	6,290,671.09	125,058.13-
1,985,950.3560	SALEM Q #2 FERC	5,391,749.73	2.7364	5,434,499.53	42,749.80
1,227,313.7660	PB#2 Q FERC	3,387,854.26	2.7364	3,358,510.98	29,343.28-
1,233,389.6050	PB#3 Q FERC	3,411,713.63	2.7364	3,375,137.35	36,576.28-
288,626.4160	HOPE CREEK QUAL FERC	886,850.57	2.7364	789,818.39	97,032.18-
631,092,185.4090		1,533,326,475.68		1,726,966,725.88	193,640,250.20
TOTAL INVESTMENTS UNIT OF PARTICIPATION		1,533,326,475.68		1,726,966,725.88	193,640,250.20
TOTAL INVESTMENT		1,533,326,475.68		1,726,966,725.88	193,640,250.20

SI-SSA-0010-2897

BNY MELLON

INVESTMENT DETAIL

PSB G716277 31 DECEMBER 2017 M1101

PSEG NUCLEAR LLC NQ PLANS

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	PSE&G NON-QUALIFIED MTU				
4,397,995.9250	HOPE CREEK NONQUAL	9,271,428.96	3.0559	13,439,941.30	4,168,512.34
30,743,968.9440	PEACH BOTTOM #2 NQ	65,443,355.30	3.0559	93,951,232.55	28,507,877.25
24,302,886.8740	PEACH BOTTOM #3 NQ	51,841,911.17	3.0559	74,267,775.27	22,425,864.10
42,839,908.0980	SALEM NQ UNIT 1	91,040,873.84	3.0559	130,915,503.31	39,874,629.47
13,938,533.8450	SALEM NQ UNIT 2	29,567,841.89	3.0559	42,595,100.10	13,027,258.21
106,763.3430	SALEM NQ #1 FERC	236,248.99	3.0559	326,260.66	90,011.67
51,554.9650	SALEM NQ #2 FERC	114,082.30	3.0559	157,548.05	43,465.75
153,637.9330	PB#2 NQ FERC	339,977.81	3.0559	469,505.85	129,528.04
153,441.7060	PB#3 NQ FERC	339,543.36	3.0559	468,906.19	129,362.83
116,688,691.6330		248,195,263.62		356,591,773.28	108,396,509.66
TOTAL INVESTMENTS UNIT OF PARTICIPATION		248,195,263.62		356,591,773.28	108,396,509.66
TOTAL INVESTMENT		248,195,263.62		356,591,773.28	108,396,509.66

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Non-FERC

Qualified Reports

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFITS

PSB F092879 31 DECEMBER 2017 NC100

PSEG NUCLEAR HOPE CREEK QUAL

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 576,185,488.62		$ 524,448,253.59
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 270,288.61		$ 907,665.59	
UNREALIZED GAIN/LOSS-INVESTMENT	8,151,755.64-		13,474,070.39	
		7,881,467.03-		14,381,735.98
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		80,253.21	
MASTER TRUST ALLOCATED EXPENSES	588,372.24-		2,597,308.72-	
MASTER TRUST CHANGE IN REALIZED G/L	11,490,468.33		36,108,969.71	
MASTER TRUST INTEREST INCOME EARNED	722,112.41		8,134,217.70	
MASTER TRUST DIVIDEND INCOME EARNED	349,260.08		4,503,368.70	
		11,973,468.58		46,229,500.60
TOTAL RECEIPTS		4,092,001.55		60,611,236.58
DISBURSEMENTS:				
UBTI TAX EXPENSE	1,976,000.00		6,758,000.00	
		1,976,000.00		6,758,000.00
TOTAL DISBURSEMENTS		1,976,000.00		6,758,000.00
NET ASSETS - END OF PERIOD		$ 578,301,490.17		$ 578,301,490.17

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092882 31 DECEMBER 2017 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 253,439,580.42		$ 230,705,950.05
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 112,728.31		$ 377,066.03	
UNREALIZED GAIN/LOSS-INVESTMENT	3,585,457.96-		5,927,494.26	
		3,472,729.65-		6,304,560.29
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		35,301.75	
MASTER TRUST ALLOCATED EXPENSES	258,788.91-		1,142,475.45-	
MASTER TRUST CHANGE IN REALIZED G/L	5,060,108.26		15,905,094.54	
MASTER TRUST INTEREST INCOME EARNED	317,613.01		3,578,038.63	
MASTER TRUST DIVIDEND INCOME EARNED	153,618.12		1,980,931.44	
		5,272,550.48		20,356,890.91
TOTAL RECEIPTS		1,799,820.83		26,661,451.20
DISBURSEMENTS:				
UBTI TAX EXPENSE	880,000.00		3,008,000.00	
		880,000.00		3,008,000.00
TOTAL DISBURSEMENTS		880,000.00		3,008,000.00
NET ASSETS - END OF PERIOD		$ 254,359,401.25		$ 254,359,401.25

SI-SSA-0010-2901

BNY MELLON

TRDPSB PSBF09288402 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092884 31 DECEMBER 2017 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 271,022,509.16		$ 246,697,872.89
RECEIPTS:				
INVESTMENT INCOME:				
INTEREST	$ 0.00		$ 400.64	
REALIZED GAIN/LOSS	120,681.59		403,852.74	
UNREALIZED GAIN/LOSS-INVESTMENT	3,834,221.91-		6,338,327.25	
		3,713,540.32-		6,742,580.63
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		37,749.79	
MASTER TRUST ALLOCATED EXPENSES	276,744.04-		1,221,712.88-	
MASTER TRUST CHANGE IN REALIZED G/L	5,411,053.44		17,007,760.83	
MASTER TRUST INTEREST INCOME EARNED	339,649.42		3,826,194.46	
MASTER TRUST DIVIDEND INCOME EARNED	164,276.35		2,118,310.29	
		5,638,235.17		21,768,302.49
TOTAL RECEIPTS		1,924,694.85		28,510,883.12
DISBURSEMENTS:				
UBTI TAX EXPENSE	940,000.00		3,201,552.00	
		940,000.00		3,201,552.00
TOTAL DISBURSEMENTS		940,000.00		3,201,552.00
NET ASSETS - END OF PERIOD		$ 272,007,204.01		$ 272,007,204.01

SI-SSA-0010-2902

BNY MELLON

TRDPSB PSBF09288602 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092886 31 DECEMBER 2017 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 285,811,874.81		$ 260,194,394.42
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 120,151.48		$ 400,870.56	
UNREALIZED GAIN/LOSS-INVESTMENT	4,043,327.11-		6,685,389.20	
		3,923,175.63-		7,086,259.76
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		39,812.96	
MASTER TRUST ALLOCATED EXPENSES	291,836.70-		1,288,439.11-	
MASTER TRUST CHANGE IN REALIZED G/L	5,713,265.24		17,961,236.78	
MASTER TRUST INTEREST INCOME EARNED	358,172.73		4,035,215.94	
MASTER TRUST DIVIDEND INCOME EARNED	173,235.41		2,234,055.11	
		5,952,836.68		22,981,881.68
TOTAL RECEIPTS		2,029,661.05		30,068,141.44
DISBURSEMENTS:				
UBTI TAX EXPENSE	1,000,000.00		3,421,000.00	
		1,000,000.00		3,421,000.00
TOTAL DISBURSEMENTS		1,000,000.00		3,421,000.00
NET ASSETS - END OF PERIOD		$ 286,841,535.86		$ 286,841,535.86

BNY MELLON

TRDPSB PSBF09288802 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092888 31 DECEMBER 2017 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 315,068,998.90		$ 286,801,737.53
RECEIPTS:				
INVESTMENT INCOME:				
INTEREST	$ 0.00		$ 455.13	
REALIZED GAIN/LOSS	130,832.20		436,073.71	
UNREALIZED GAIN/LOSS-INVESTMENT	4,457,284.15-		7,369,041.94	
		4,326,451.95-		7,805,570.78
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		43,887.19	
MASTER TRUST ALLOCATED EXPENSES	321,715.03-		1,420,298.30-	
MASTER TRUST CHANGE IN REALIZED G/L	6,299,811.46		19,805,480.80	
MASTER TRUST INTEREST INCOME EARNED	394,842.56		4,448,149.63	
MASTER TRUST DIVIDEND INCOME EARNED	190,971.31		2,462,662.62	
		6,563,910.30		25,339,881.94
TOTAL RECEIPTS		2,237,458.35		33,145,452.72
DISBURSEMENTS:				
UBTI TAX EXPENSE	1,098,000.00		3,738,733.00	
		1,098,000.00		3,738,733.00
TOTAL DISBURSEMENTS		1,098,000.00		3,738,733.00
NET ASSETS - END OF PERIOD		$ 316,208,457.25		$ 316,208,457.25

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BNY MELLON

TRDPSB PSBF09319702 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

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PSB F093197 31 DECEMBER 2017 NC100

PSEG NUCLEAR HOPE CREEK QUAL

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 784,229.72		$ 707,665.79
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 11,133.31-		$ 18,105.79	
		11,133.31-		18,105.79
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		108.64	
MASTER TRUST ALLOCATED EXPENSES	803.57-		3,525.81-	
MASTER TRUST CHANGE IN REALIZED G/L	16,062.32		50,331.60	
MASTER TRUST INTEREST INCOME EARNED	986.23		11,030.82	
MASTER TRUST DIVIDEND INCOME EARNED	477.00		6,101.56	
		16,721.98		64,046.81
TOTAL RECEIPTS		5,588.67		82,152.60
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 789,818.39		$ 789,818.39

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BNY MELLON

TRDPSB PSBF09319502 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

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PSB F093195 31 DECEMBER 2017 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 3,334,746.51		$ 3,009,176.98
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 47,341.67-		$ 76,990.62	
		47,341.67-		76,990.62
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		462.01	
MASTER TRUST ALLOCATED EXPENSES	3,417.00-		14,992.75-	
MASTER TRUST CHANGE IN REALIZED G/L	68,301.11		214,035.06	
MASTER TRUST INTEREST INCOME EARNED	4,193.69		46,893.63	
MASTER TRUST DIVIDEND INCOME EARNED	2,028.34		25,945.43	
		71,106.14		272,343.38
TOTAL RECEIPTS		23,764.47		349,334.00
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 3,358,510.98		$ 3,358,510.98

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BNY MELLON

TRDPSB PSBF09319602 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

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PSB F093196 31 DECEMBER 2017 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 3,351,255.23		$ 3,024,073.97
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 47,576.04-		$ 77,371.79	
		47,576.04-		77,371.79
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		464.31	
MASTER TRUST ALLOCATED EXPENSES	3,433.91-		15,067.01-	
MASTER TRUST CHANGE IN REALIZED G/L	68,639.23		215,092.97	
MASTER TRUST INTEREST INCOME EARNED	4,214.46		47,127.43	
MASTER TRUST DIVIDEND INCOME EARNED	2,038.38		26,073.89	
		71,458.16		273,691.59
TOTAL RECEIPTS		23,882.12		351,063.38
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 3,375,137.35		$ 3,375,137.35

BNY MELLON

TRDPSB PSBF09319302 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093193 31 DECEMBER 2017 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 6,246,158.95		$ 5,636,349.79
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 88,673.49-		$ 144,207.56	
		88,673.49-		144,207.56
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		865.38	
MASTER TRUST ALLOCATED EXPENSES	6,400.22-		28,082.25-	
MASTER TRUST CHANGE IN REALIZED G/L	127,931.63		400,898.35	
MASTER TRUST INTEREST INCOME EARNED	7,855.02		87,835.04	
MASTER TRUST DIVIDEND INCOME EARNED	3,799.20		48,597.22	
		133,185.63		510,113.74
TOTAL RECEIPTS		44,512.14		654,321.30
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 6,290,671.09		$ 6,290,671.09

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BNY MELLON

TRDPSB PSBF09319402 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093194 31 DECEMBER 2017 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 5,396,045.57		$ 4,869,232.52
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 76,604.87-		$ 124,580.63	
		76,604.87-		124,580.63
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		747.60	
MASTER TRUST ALLOCATED EXPENSES	5,529.14-		24,260.19-	
MASTER TRUST CHANGE IN REALIZED G/L	110,519.91		346,335.58	
MASTER TRUST INTEREST INCOME EARNED	6,785.94		75,880.33	
MASTER TRUST DIVIDEND INCOME EARNED	3,282.12		41,983.06	
		115,058.83		440,686.38
TOTAL RECEIPTS		38,453.96		565,267.01
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 5,434,499.53		$ 5,434,499.53

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Non-Qualified Reports

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092885 31 DECEMBER 2017 NC100

PSEG NUCLEAR SALEM NONQUAL

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 129,507,141.34		$ 108,501,320.68
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 1,373,453.12		$ 20,183,420.11	
		1,373,453.12		20,183,420.11
MASTER TRUST INVESTMENT GAIN/LOSS	172.83		12,361.75	
MASTER TRUST ALLOCATED EXPENSES	125,022.90-		517,319.65-	
MASTER TRUST CHANGE IN REALIZED G/L	1,939.43-		461,260.04	
MASTER TRUST INTEREST INCOME EARNED	35,758.46		420,396.31	
MASTER TRUST DIVIDEND INCOME EARNED	125,939.89		1,854,064.07	
		34,908.85		2,230,762.52
TOTAL RECEIPTS		1,408,361.97		22,414,182.63
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 130,915,503.31		$ 130,915,503.31

BNY MELLON

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092887 31 DECEMBER 2017 NC100

PSEG NUCLEAR SALEM NONQUAL

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 42,136,870.80		$ 35,302,347.69
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 446,871.23		$ 6,566,944.17	
		446,871.23		6,566,944.17
MASTER TRUST INVESTMENT GAIN/LOSS	56.23		4,022.07	
MASTER TRUST ALLOCATED EXPENSES	40,677.86-		168,316.85-	
MASTER TRUST CHANGE IN REALIZED G/L	631.02-		150,077.09	
MASTER TRUST INTEREST INCOME EARNED	11,634.50		136,781.55	
MASTER TRUST DIVIDEND INCOME EARNED	40,976.22		603,244.38	
		11,358.07		725,808.24
TOTAL RECEIPTS		458,229.30		7,292,752.41
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 42,595,100.10		$ 42,595,100.10

BNY MELLON

TRDPSB PSBF09288102 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092881 31 DECEMBER 2017 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 92,940,524.57		$ 77,865,742.05
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 985,655.70		$ 14,484,588.51	
		985,655.70		14,484,588.51
MASTER TRUST INVESTMENT GAIN/LOSS	124.03		8,871.38	
MASTER TRUST ALLOCATED EXPENSES	89,722.41-		371,253.34-	
MASTER TRUST CHANGE IN REALIZED G/L	1,391.83-		331,022.29	
MASTER TRUST INTEREST INCOME EARNED	25,661.99		301,696.53	
MASTER TRUST DIVIDEND INCOME EARNED	90,380.50		1,330,565.13	
		25,052.28		1,600,901.99
TOTAL RECEIPTS		1,010,707.98		16,085,490.50
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 93,951,232.55		$ 93,951,232.55

BNY MELLON

TRDPSB PSBF09288302 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092883 31 DECEMBER 2017 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 73,468,817.86		$ 61,552,310.43
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 779,153.78		$ 11,449,963.32	
		779,153.78		11,449,963.32
MASTER TRUST INVESTMENT GAIN/LOSS	98.04		7,012.77	
MASTER TRUST ALLOCATED EXPENSES	70,924.93-		293,473.09-	
MASTER TRUST CHANGE IN REALIZED G/L	1,100.23-		261,670.77	
MASTER TRUST INTEREST INCOME EARNED	20,285.62		238,488.92	
MASTER TRUST DIVIDEND INCOME EARNED	71,445.13		1,051,802.15	
		19,803.63		1,265,501.52
TOTAL RECEIPTS		798,957.41		12,715,464.84
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 74,267,775.27		$ 74,267,775.27

BNY MELLON

TRDPSB PSBF09288002 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092880 31 DECEMBER 2017 NC100

PSEG NUCLEAR HOPE CREEK

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 13,295,357.18		$ 11,138,874.65
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 141,000.33		$ 2,072,053.91	
		141,000.33		2,072,053.91
MASTER TRUST INVESTMENT GAIN/LOSS	17.74		1,269.06	
MASTER TRUST ALLOCATED EXPENSES	12,835.00-		53,108.64-	
MASTER TRUST CHANGE IN REALIZED G/L	199.10-		47,353.53	
MASTER TRUST INTEREST INCOME EARNED	3,671.01		43,158.36	
MASTER TRUST DIVIDEND INCOME EARNED	12,929.14		190,340.43	
		3,583.79		229,012.74
TOTAL RECEIPTS		144,584.12		2,301,066.65
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 13,439,941.30		$ 13,439,941.30

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FERC Non-Qualified Reports

BNY MELLON

TRDPSB PSBF09336202 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

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PSB F093362

31 DECEMBER 2017

NC100

PSEG NUCLEAR SALEM NON-QUAL

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 322,750.82		$ 270,401.23
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 3,422.83		$ 50,299.96	
		3,422.83		50,299.96
MASTER TRUST INVESTMENT GAIN/LOSS	0.43		30.82	
MASTER TRUST ALLOCATED EXPENSES	311.58-		1,289.23-	
MASTER TRUST CHANGE IN REALIZED G/L	4.83-		1,149.53	
MASTER TRUST INTEREST INCOME EARNED	89.13		1,047.74	
MASTER TRUST DIVIDEND INCOME EARNED	313.86		4,620.61	
		87.01		5,559.47
TOTAL RECEIPTS		3,509.84		55,859.43
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 326,260.66		$ 326,260.66

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BNY MELLON

TRDPSB PSBF09336302 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093363 31 DECEMBER 2017 NC100

PSEG NUCLEAR SALEM NON-QUAL

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 155,853.19		$ 130,574.08
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 1,652.85		$ 24,289.39	
		1,652.85		24,289.39
MASTER TRUST INVESTMENT GAIN/LOSS	0.21		14.89	
MASTER TRUST ALLOCATED EXPENSES	150.46-		622.55-	
MASTER TRUST CHANGE IN REALIZED G/L	2.33-		554.99	
MASTER TRUST INTEREST INCOME EARNED	43.03		506.01	
MASTER TRUST DIVIDEND INCOME EARNED	151.56		2,231.24	
		42.01		2,684.58
TOTAL RECEIPTS		1,694.86		26,973.97
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 157,548.05		$ 157,548.05

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BNY MELLON

TRDPSB PSBF09336402 MONTHLY FINAL 093923 2017-12-31 CYCLE 2 09:39:22 RUN DATE: 04-JAN-18

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093364 31 DECEMBER 2017 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 464,455.00		$ 389,121.25
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 4,925.66		$ 72,384.40	
		4,925.66		72,384.40
MASTER TRUST INVESTMENT GAIN/LOSS	0.62		44.33	
MASTER TRUST ALLOCATED EXPENSES	448.37-		1,855.29-	
MASTER TRUST CHANGE IN REALIZED G/L	6.96-		1,654.23	
MASTER TRUST INTEREST INCOME EARNED	128.24		1,507.66	
MASTER TRUST DIVIDEND INCOME EARNED	451.66		6,649.27	
		125.19		8,000.20
TOTAL RECEIPTS		5,050.85		80,384.60
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 469,505.85		$ 469,505.85

BNY MELLON

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STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093365 31 DECEMBER 2017 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-17	CURRENT PERIOD 31-DEC-17	YEAR TO DATE 01-JAN-17	YEAR TO DATE 31-DEC-17
NET ASSETS - BEGINNING OF PERIOD		$ 463,861.80		$ 388,624.26
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 4,919.36		$ 72,291.93	
		4,919.36		72,291.93
MASTER TRUST INVESTMENT GAIN/LOSS	0.62		44.26	
MASTER TRUST ALLOCATED EXPENSES	447.80-		1,852.90-	
MASTER TRUST CHANGE IN REALIZED G/L	6.95-		1,652.13	
MASTER TRUST INTEREST INCOME EARNED	128.07		1,505.72	
MASTER TRUST DIVIDEND INCOME EARNED	451.09		6,640.79	
		125.03		7,990.00
TOTAL RECEIPTS		5,044.39		80,281.93
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 468,906.19		$ 468,906.19

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)	Docket No. RM18-1-000

COMMENTS OF EXELON CORPORATION

Exelon welcomes the opportunity to comment on this important proposed rule. During the last seven years, we have cautioned that failure to evolve wholesale markets to ensure that they value the reliable, clean and affordable energy produced by the nation's nuclear fleet would lead to premature retirements of the most cost-effective fuel-secure and emissions-free generation on the system. Regrettably, that has occurred. Between 2002 and 2016, 4,666 MW of nuclear generating capacity announced retirement, approximately 4.7 percent of the U.S. total.[1] Another eight nuclear reactors with 7,167 MW of capacity have announced retirement plans since 2016.[2] According to Bloomberg, more than half of the nation's nuclear power plants are losing money.[3] The retirement of nuclear units—the most resilient and reliable generators on the system—and their replacement by resources that are neither fuel secure nor emissions-free will have a strongly negative impact on the grid's resilience, not to mention the environment.

[1] United States Department of Energy, Staff Report to the Secretary on Electricity Markets and Reliability 29 (August 2017), *available at* https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf ("DOE Staff Report").

[2] *Id*. at 30.

[3] Jim Polson, *More Than Half of America's Nuclear Reactors Are Losing Money*, Bloomberg, June 15, 2017, *available at* https://www.bloomberg.com/news/articles/2017-06-14/half-of-america-s-nuclear-power-plants-seen-as-money-losers.

The Commission has not yet taken sufficient action to ensure the resiliency of the grid against threats that are increasingly salient. While the Commission has permitted two RTOs to impose material performance-based penalties on capacity resources, it has not been presented with a reform that would *require* wholesale markets to select resources based on a demonstrated ability to insulate customers from fuel security risks (or from the impacts of carbon and air emissions). Through his proposed rule, the Secretary of Energy has begun to do just that. He is asking whether wholesale markets in PJM, NYISO, and ISO-NE—which are designed to ensure we have *enough* megawatts to serve load—should also be designed to ensure we have the *right* megawatts to serve load: those that have a stable source of fuel that will enable the system to withstand interruptions that could dramatically interfere with the ability of the system to power our economy and society. We have begun to address the implications of risks from spare transformer shortages, EMP and GMD events, and physical and cyberattacks on the transmission system. But as stakeholders, we have been slow to appreciate and address the increasing risk profile of interruptions to and attacks on to the fuel delivery system *behind* the megawatts we are using to power our economy. The Commission should use this proceeding to change that.

Against the backdrop of this increasing risk profile, the supply of electricity is shifting quickly toward natural gas fired generators that lack on-site fuel. In the PJM region, 90 percent of the new installed generation over the last five years has been gas-fueled, and more than 90 percent of planned generation in the interconnection queue is as well.[4] New nuclear plants are no longer

[4] For the PJM RPM auctions from 2015/16 through 2020/21, 90% of new cleared installed capacity has been either natural gas-fired combustion turbines or combined-cycle generators (approximately 32.4 out of 36.2 total GW of new build, reactivated, or uprated capacity). *See* PJM Interconnection L.L.C., *2020/21 RPM Base Residual Auction Results*, Table 8, http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx?la=en.

being built in market regions (where, other than renewable portfolio standards, there is little resource planning). So, with each retirement, the system irretrievably will lose the fuel security it enjoys today. This has exposed the American public to a new and grave danger—the potential for multistate blackouts lasting weeks or months resulting from natural gas supply disruptions.[5]

Natural gas generators rely on a pipeline network that can be disrupted by natural or human forces.[6] A study by PJM Interconnection, L.L.C. ("PJM") has revealed that a ***single*** gas pipeline in that region serves more than 11,000 MW of generation powering our Nation's most populated areas.[7] A disruption to that amount of generation could, in turn, further disrupt the gas pipeline network, leading to the potential of even more widespread generation outages. A prolonged outage (especially one where more than one pipeline is disrupted) would be catastrophic, leading to widespread loss of life and severe economic harm.[8] Water treatment plants, the food distribution system, the medical system, and communications networks all depend on a working electric grid, and these systems are not designed to withstand prolonged outages.[9] Moreover, as the transportation sector shifts its fuel source from gasoline to electricity, the cost of a widespread blackout become even more severe.

These risks extend beyond the civilian sector. Because the nation's military facilities depend on the availability of power, long duration outages could pose serious risks for national

[5] Testimony of Paul Stockton, attached as Exhibit A, at 9 ("Stockton Testimony").

[6] *Id.* at 12-14.

[7] *Id.* at 18; PJM Reliability Analysis Update (Sept. 14, 2017), *available at* http://pjm.com/-/media/committees-groups/committees/teac/20170914/20170914-reliability-analysis-updates.ashx, pp. 8-11.

[8] Stockton Testimony at 10-11.

[9] *Id.* at 10-11.

security.[10] As a result, the nation's energy infrastructure is a target for hostile foreign powers and terrorist organizations.[11]

The Department of Energy ("DOE") should be commended for taking this risk seriously. Fuel security is an essential aspect of grid resiliency, and action must be taken to prevent an overreliance on a single type of generation resource vulnerable to fuel supply disruption. Some have argued that there is a greater need than ever before for flexible resources because of increased renewable penetration. The present demand for power, however, does not require that every resource on the system be flexible. Even in the most low-demand hours, PJM demand does not fall below about 60 GW (or about 40% of peak)[12], indicating that there is substantial room to accommodate resources that are optimized to produce low cost power at full output 24 hours per day, seven days per week without ramping. When operated in this fashion, these firm-fuel resources are low cost and provide the system with an important hedge against the possibility of natural gas supply disruption. Put another way, there are diminishing returns to flexibility as more flexible units are added to the system, and beyond this point of diminishing returns (about 60% of peak load in PJM), the key determinants of the value provided by resources are found in baseload operation and contribution to resiliency and system diversity. These firm-fuel resources provide the system with a necessary hedge against the possibility of natural gas supply disruption. Yet they increasingly face economic distress and are in danger of retirement.

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[10] *Id.* at 6.

[11] *Id.* at 5.

[12] For calendar years 2015 and 2016, PJM load did not fall below 57 (2015) or 58 (2016) gigawatts in any hour, or approximately 40% (2015) or 38% (2016) of peak demand in each respective year. *See* PJM hourly metered load data at http://www.pjm.com/markets-and-operations/ops-analysis/historical-load-data.aspx

This state of affairs is leading to rates that are not just and reasonable. The organized markets were not designed to address resilience to fuel supply interruptions, and as a result customers have been left exposed to catastrophic risks. As a result, the organized markets are no longer producing just and reasonable market outcomes, and they need modification in order to comply with the Federal Power Act. In particular, market rules undervalue the resilience benefits that nuclear units provide to consumers.

Below, we outline short-term, medium-term, and longer-term steps the Commission can take to address resilience in a way that appropriately balances its value to customers with the cost of achieving it.

First, the Commission should act immediately under Section 206 to correct energy price formation in PJM. Doing so will not by itself ensure that the generation mix in PJM remains resilient, but flawed energy pricing is exacerbating the economic stress faced by resilient firm-fuel units, and hastening their exit from the market. To summarize the problem: Resilient, firm-fuel resources in PJM are providing generation needed to serve customers, yet they are not paid for their cost of doing so. Resilient firm-fuel units operating at their economic minimum are not permitted to set the locational marginal price, even when they are the marginal resource and their output is needed to serve load. Consequently, in low-load conditions, energy prices often fall below the marginal cost of operating these units. Indeed, energy prices can be negative for extended periods of time, typically at night, even though resilient firm-fuel resources are serving load during those times and incur costs to do so. In such situations, energy prices do not reflect the true marginal cost of serving load. That is unjust and unreasonable, and is economically untenable for these resources.

The Commission can correct this problem now by acting under Section 206 of the Federal Power Act. PJM has identified this problem in the record developed as part of the Commission's May 2017 technical conference on state policies and wholesale markets. DOE has endorsed immediate action to move forward with energy price formation as a step toward improving the resilience of the grid. Addressing energy price formation is an immediate-term action the Commission can take to mitigate the economic distress faced by resilient units, while it evaluates what must be done to ensure resiliency and how best to achieve it.

Second, the Commission should not take action that would imperil irreplaceable firm-fuel resources, while it simultaneously considers how best to compensate the resilience they provide. Accordingly, the Commission should issue a policy statement declaring that units benefitting from state programs designed to preserve the operation of resilient nuclear resources by compensating them for their emissions-free attributes—such as the New York and Illinois Zero Emissions Credit programs—will not have their offers mitigated in FERC's markets. Having recognized the value of resilience and the significant contribution that nuclear plants make to achieving it, the mitigation of state programs intended to preserve those units would be myopic and counterproductive. Additionally, should a particular unit faced with imminent retirement be able to demonstrate its contribution to resiliency, the Commission should consider, on a unit-specific basis, taking steps that would allow that unit to continue operating, while the Commission considers more comprehensive solutions.

Third, the Commission should direct the organized markets covered by DOE's Notice of Proposed Rulemaking ("NOPR")[13] to report on other market-based reforms that could help to foster resiliency. For example, RTOs should examine the process for setting operating reserves

[13] Dep't of Energy, Grid Resiliency Pricing Rule, 82 Fed. Reg. 46,940 (2017) ("DOE NOPR").

procurement quantities in light of the possibility of a major natural gas pipeline outage. To take another example, NYISO is considering the inclusion of a carbon price in its energy market. Doing so not only would appropriately price the negative externality associated with carbon-emitting generation, but would also have the side benefit of providing support to resilient nuclear resources.

On the capacity side, interim improvements may also be possible. PJM and ISO-NE have adopted pay-for-performance capacity regimes and should be encouraged to closely scrutinize those market rules to ensure that the performance penalties are sufficiently rigorous. Additionally, the Commission has previously approved as just and reasonable short-term reliability measures in New England to ensure that units with on-site fuel receive incentives to maintain that capability in the winter. RTOs should report on whether those market rules could be adapted to provide interim support to resilient units while the Commission considers its options.

Finally, before adopting a final rule in this proceeding, the Commission should require the RTOs covered by the NOPR to submit detailed information that can be used to develop a richer understanding of where our grid's vulnerabilities lie; how those vulnerabilities match up against the intelligence community's threat assessments; and what steps must be taken to ensure a sufficient degree of resiliency to protect the nation from known and credible national security threats. With that design basis threat analysis in hand, the Commission can then identify which solutions will address the identified deficiencies in the most cost-effective manner.

Market-based solutions may certainly be developed to address this issue. The organized markets established by the Commission remain an extraordinary success. They have ensured that customers enjoy a plentiful supply of electricity at just and reasonable prices, but they have done so with prescriptive requirements (such as reserve margins and administratively-set demand curves) that mandate a physical expectation and use market forces to drive the most cost-effective

solution. Once we determine a design basis threat around which the system should be planned, it may be possible to develop a fuel-neutral resiliency product that can place appropriate value on fuel-secure resources so as to ensure the requisite level of grid resiliency. Exelon believes that RTOs should be given the opportunity to propose such market reforms. But, given the urgency of the problem, we need to "get it right" the first time. So the Commission should also consider the efficacy of alternative remedies, including non-market approaches, particularly if those have the potential to achieve the goal at a lower overall system cost. The safety and security of the American people must remain the paramount concern, and the Nation should use whichever tools best address that concern.

The Capacity Performance ("CP") reforms in PJM are not a substitute for Commission action addressing resiliency. First, CP was intended to incentivize unit-specific investments to enhance reliable operations at the unit level. The resiliency challenges faced by the grid are systemic—and CP does not and cannot address the possibility that multiple generators with firm service on the same pipeline are simultaneously unable to perform. Second, the frequency and duration of expected penalty hours used to calibrate the non-performance penalty and associated penalty "caps" were focused on weather-related system stress, not intentional disruptions to fuel supply that could last longer than 30 hours. Simply put, CP was not intended to address the emerging national security threats discussed by Dr. Stockton in his testimony. Third, unlike weather events, it may not be possible to probabilistically determine the likelihood of malicious attacks or quantify the extent of the harm that would be caused. For example, what is the probability of a cyber or physical attack by a rogue nation or terrorist? How do we quantify the harm occasioned by the loss of military capability? Value of Lost Load (VLL) metrics may be less helpful in establishing the appropriate design standard here than in the case of CP. In any

event, CP most certainly did not address these issues, and a more prescriptive approach may be needed.

The Commission should proceed expeditiously with this work. Nuclear retirements are irreversible; once customers lose the fuel security benefits these plants provide, those benefits are gone forever. Moreover, unless market conditions change in unforeseen ways, the threat to these units will persist. Low natural gas prices and slow load growth will continue to drive out resilient nuclear resources unless the Commission modifies the markets to appropriately value the benefits they provide.[14] If the Commission does not act expeditiously, the loss of these units will increase the risks to Americans' physical security and economic well-being.

I. The Commission Should Act under Section 206 to Correct Price Formation in PJM.

While the Commission considers the broader issues of resilience raised by the Notice of Proposed Rulemaking, it should take immediate action to correct a flaw in the PJM market. Currently, energy prices in PJM violate a fundamental principle of good market design – they do not reflect the true cost of producing energy, particularly at night or in other low-load conditions. Firm-fuel units are required to run at prices that do not cover their marginal costs. Because firm-fuel units have long start-up times and are needed to provide power during peak hours, they must also run during off-peak hours. Most of these firm-fuel units are also needed during off-peak hours, but not all of them. So, during these off-peak hours, many of the units are required to run at minimum load and PJM market rules do not permit these units to set energy market prices. Only the dispatchable portion of units can set LMP. As a result, firm-fuel units must operate at a loss

[14] DOE Staff Report at 57 ("[U]nless natural gas prices or electricity demand rise significantly faster than projected, the economic conditions of baseload generators are not projected to change significantly in the near term.").

SI-SSA-0010-2931

because their costs exceed the LMP.[15] This flaw in energy price formation affects a significant fraction of the generation in PJM, including the vast majority of firm-fuel units. In 2016, over 60% of PJM generation was self-scheduled primarily due to long start up times and was exposed to the possibility that their revenues might not support their variable costs.[16]

The Commission can correct this problem today. PJM has clearly identified the problem and it merits a conclusion under Section 206 that existing tariff provisions are not just and reasonable. In the comments submitted as part of the May 2017 Technical Conference, a broad group of stakeholders agreed on the need for energy market reforms to ensure proper price formation.[17] Moreover, PJM has already identified a just and reasonable solution that is consistent with changes that the Commission already has largely accepted in MISO. Directing PJM to adopt that solution is consistent with the Federal Power Act and principles of good market design, and would provide immediate support to units that are needed for a resilient grid.

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[15] This result is particularly harsh when prices become negative and these units have to pay money to operate. Negative prices are now occurring in certain areas of PJM in as many as 10% of the hours. "[N]uclear generation hubs located in Western Illinois have faced negative prices as much as 10-11% of the hours during the year in 2015/16." Maheen Bajwa and Joseph Cavicchi, *Growing Evidence of Increased Frequency of Negative Electricity Prices in U.S. Wholesale Electricity Markets*, IAEE Energy Forum, Fourth Quarter 2017, *available at* www.iaee.org/en/publications/newsletterdl.aspx?id=444.

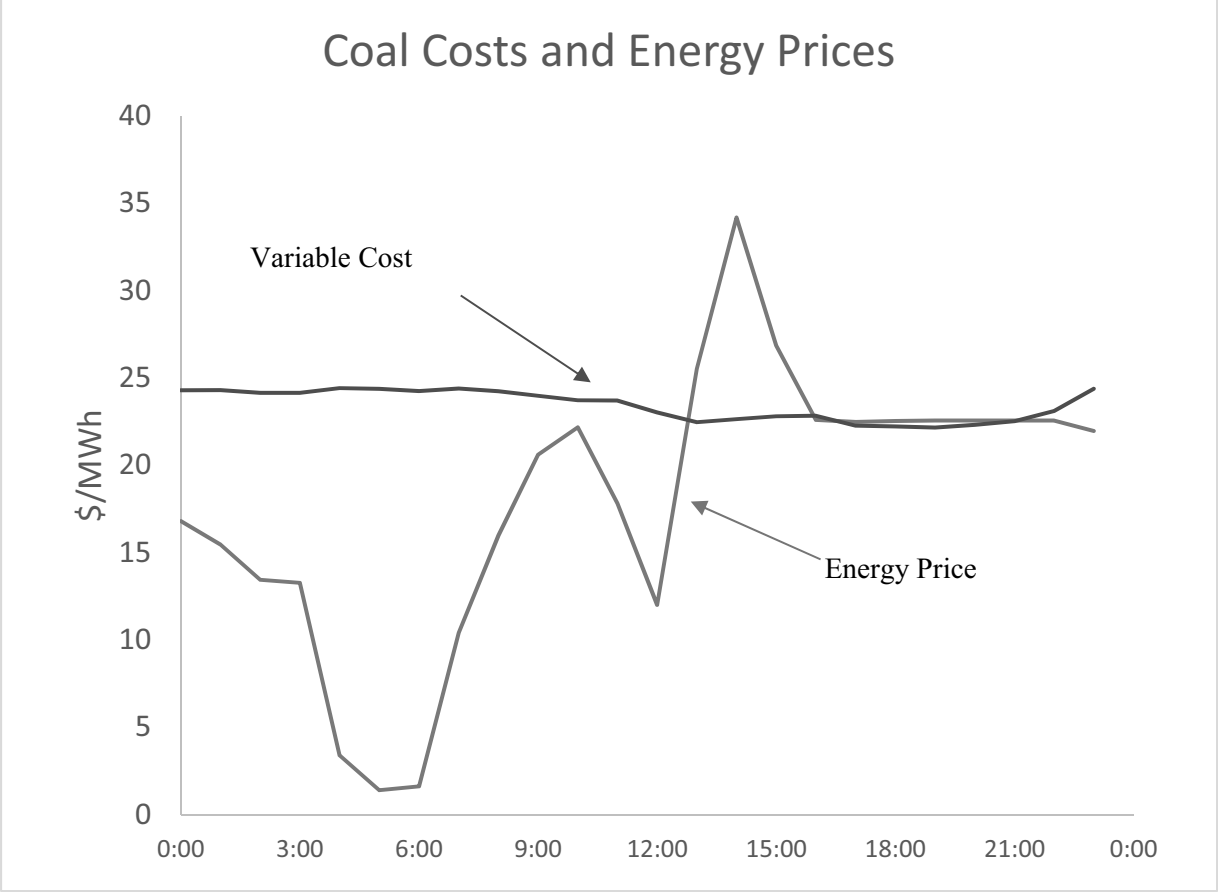
[16] PJM Independent Market Monitor, *2016 State of the Market Report*, at 194 ("[I]n 2016, 61.8 percent in day ahead and 60.6 percent in real time of the total generation was self-scheduled.").

[17] *State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.*, Docket No. AD17-11-000, Comments of Edison Electric Institute at 5-6; Comments of Electric Power Supply Association at 10-12; Comments of NRG Energy, Inc. at 15-17; Comments of Nuclear Energy Institute at 13-14; Comments of PJM Interconnection, L.L.C. at 4-5; Comments of PSEG Companies at 12-14.

SI-SSA-0010-2932

A. PJM's Tariff is Not Just and Reasonable Because Prices Do Not Support Unit Commitment and Dispatch.

PJM's energy pricing regime violates the Federal Power Act because prices do not support unit commitment and dispatch when firm-fuel units operate at their economic minimum but are nevertheless the marginal resources for serving load. Consider the following example reflecting the operation, over the course of a day, of a typical coal unit in PJM with variable costs of approximately $25/MWh.

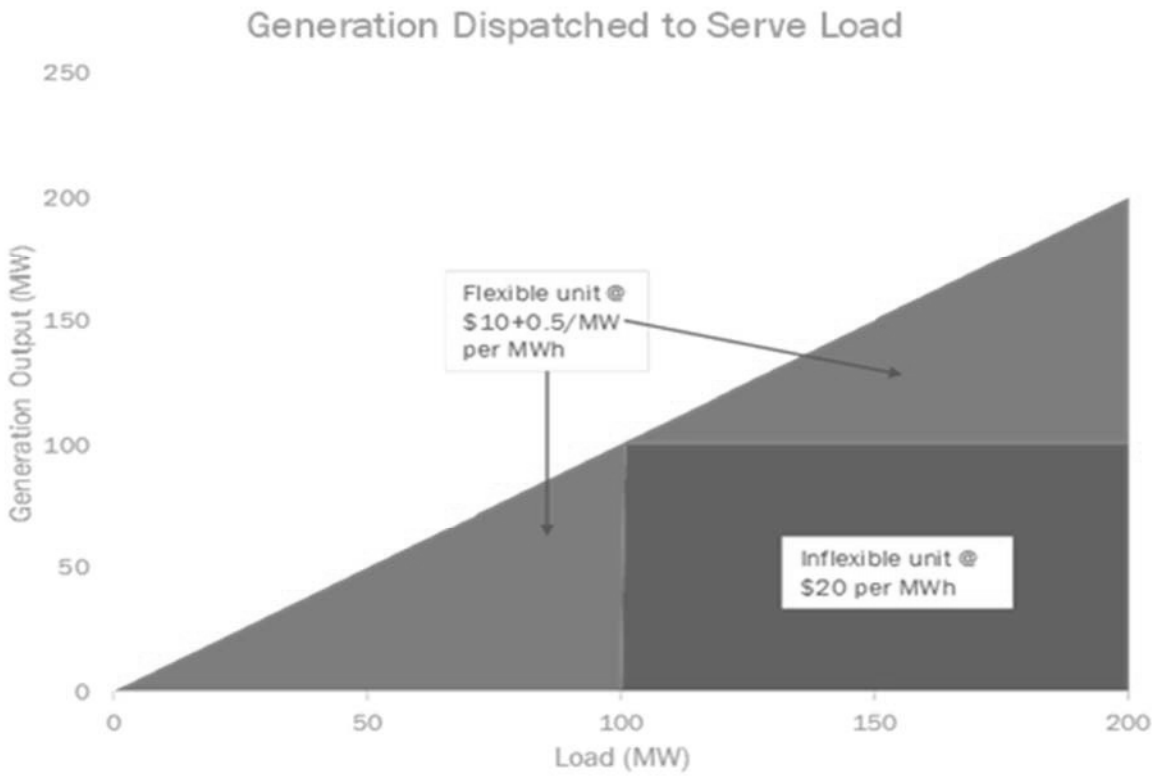


During the morning hours, energy prices fall below the unit's variable cost and it operates at a loss. However, it cannot reduce its output to zero. The unit will be needed later in the day when it will

be called to serve load during peak hours. This unit also does not have the flexibility to quickly shut down and restart. If it shuts down, it will not be able to return to operation in time to ramp up later in the day. Instead, it reduces its output to its economic minimum, the point at which it will no longer be able to reduce output in response to dispatch instructions. RTO market rules do not currently allow units operating at their economic minimum to set price.[18] As a result, energy prices fall below $25 and the generator does not cover its variable costs.

Worse still, units operating at their economic minimum cannot set price even at times they *are* called to serve load, if only a portion of their output is needed. For example, consider a market with two units: a baseload unit (shown in blue below) with a fixed output of 100 MW and variable costs of $20/MWh, and a flexible unit (shown in red) which can vary its output between 1 and 100 MW with an offer price starting at $10 at 1 MW of output and increasing by $.05 for each additional MW.

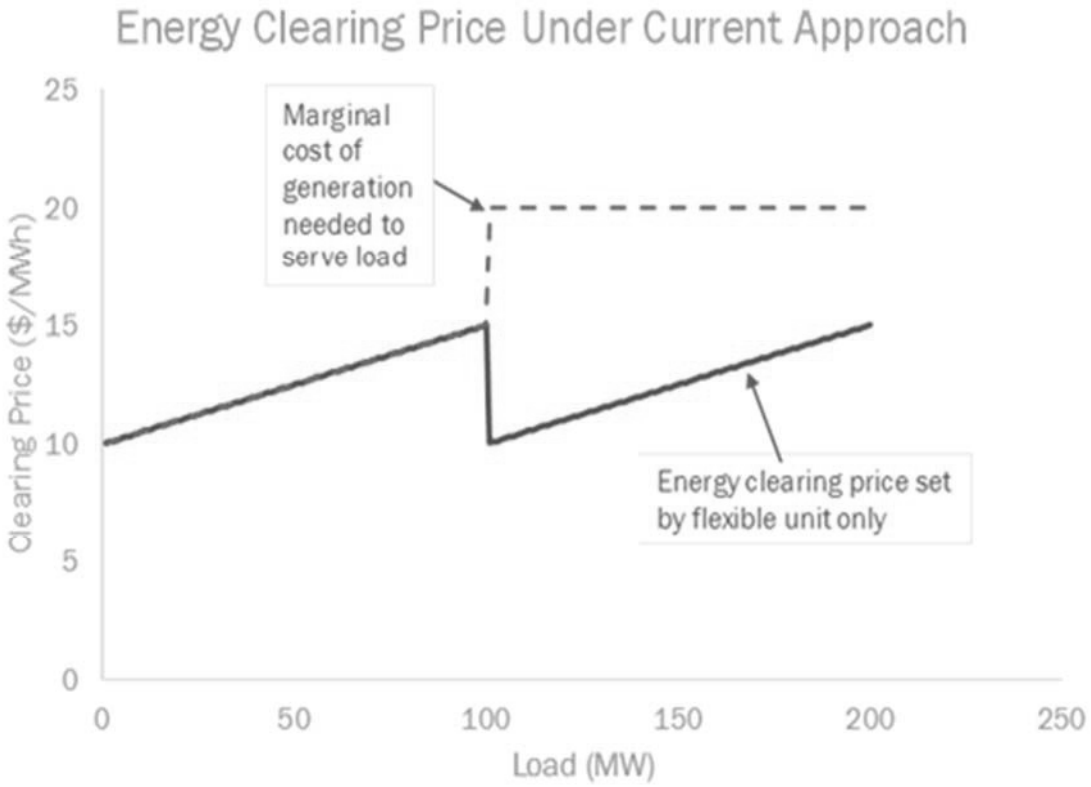
[18] *See Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, 153 FERC ¶ 61,221 at P 9-10 (2015) ("[Inflexible resources typically cannot set LMPs because the market pricing software does not treat these resources as dispatchable or as able to meet the next increment of load. . . [O]nly resources that can be dispatched up or down in response to changes in system conditions are eligible to set LMPs").



In this example, the baseload unit will be needed to serve load once demand exceeds 100 MW. Still, though, it will not be permitted to set the price—even when demand exceeds 100 MW—if only a portion of its power output is needed. The more flexible resource is dispatched down to make room, and under the current PJM rules, the energy price is set at the marginal cost of the unit displaced.

For example, as shown in the chart below, the energy clearing price increases from $10/MWh to $15/MWh as load increases, until demand exceeds 100 MW. At that point, the baseload unit becomes marginal. The energy price *should* equal the baseload unit's marginal costs ($20/MWh), since that is the cost needed to serve load. But instead, under current market rules, the energy clearing price is based on the marginal cost of the flexible resource that is turned down. Thus, if load increases from 100 MW to 101 MW, then the flexible resource is dispatched down to 1 MW to make room for the baseload resource. When this occurs, and the energy price falls

from $15/MWh (the marginal cost of the flexible unit to generate 100 MW) to $10/MWh (the marginal cost of the flexible unit to generate 1 MW)—even though the true marginal cost of serving load has increased to $20/MWh (the marginal cost of the baseload unit).



That result is not just and reasonable. The energy clearing price falls as load increases, and the marginal unit receives a price that is less than its marginal cost. Neither should occur in a well-functioning market. In effect, current market rules allow consumers to benefit from the energy generated by firm-fuel units – not to mention the resiliency benefits these units provide – but do not fully compensate those units for the costs they incur in providing those benefits. The locational marginal price remains below the baseload unit's marginal cost, and the unit loses money. The clearing price in the market thus does not support the least-cost commitment and dispatch needed

to serve load, because absent any other source of revenue the baseload unit would not seek to participate.

A market rule "patch" to pay only the baseload unit an uplift payment to ensure it recovers $20/MWH is not a solution. While in this example there are only two generators in the market, in the real world, every generator in the market (except for the uplift generator) would be undercompensated under the current price setting rules. This is clearly discriminatory and deprives fuel secure resources of energy market revenues to which they are entitled.[19]

In sum, these market rules result in the chronic under-compensation of firm-fuel generators. Plainly, it not sustainable for these generators to continue to operate at a loss. And once they exit the market, they will largely be replaced by gas generation[20] that may be more flexible, but which would compound the resiliency vulnerabilities now facing the fleet.

The current market rules were originally well-intentioned. The energy markets operate in a two-step process. The markets first must determine the appropriate security-constrained economic unit commitment and dispatch; next they must set prices based on that dispatch. The Commission must create market rules to ensure that the prices it sets are consistent with the unit commitment and dispatch. These prices must achieve two goals. Units must have the correct

[19] The Commission has already recognized that the reliance on uplift payments creates market distortions that can support acting under Section 206. *See, e.g.*, *Fast-Start Pricing in Markets Offered by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,213, at P 3 (2016) (finding RTO practices preliminarily not to be just and reasonable because they "potentially creating unnecessary uplift payments").

[20] The overwhelming majority of generators in the PJM interconnection queue are new gas-fired units. *See* Operationalizing Gas Pipeline Contingencies Normal and Conservative Operations, PJM Operating Committee, October 10, 2017 at 4, *available at* http://www.pjm.com/-/media/committees-groups/committees/oc/20171010/20171010-item-16-gas-electric-contingencies-update.ashx

incentives to adjust their output in response to those price signals and LMP must provide sufficient compensation to cover the marginal cost of committed units.

When a baseload unit is marginal, however, the market design requires a trade-off. By limiting price-setting eligibility to flexible units, PJM achieves the goal of ensuring that prices send the correct dispatch signal to flexible units, but the energy price no longer reflects the marginal cost of serving load. This trade-off historically has been masked in PJM.[21] When renewable generation was uncommon and gas prices were high, off-peak energy prices seldom fell below the level necessary to cover the variable costs of firm-fuel units throughout the day. However, increased penetration of renewables, low load growth, and historically low gas prices have produced a combination of extremely low energy prices that are frequently below the variable costs of firm-fuel units that are needed to serve load. This change in circumstances has made the PJM energy market no longer just and reasonable: energy prices no longer reflect the marginal cost of serving load.

B. The Commission Already Has the Record Necessary to Find That the Current Tariff Is Not Just and Reasonable.

The Commission already has the record necessary to act under Section 206 to fix this market design flaw. As the DOE Notice of Proposed Rulemaking outlines, the Commission has been considering price formation for some time.[22] The particular problem discussed above has been highlighted in the record of those proceedings. On June 15, 2017, PJM issued its white paper

[21] *See* Comments of Andrew Ott, AD17-11-000, Transcript of May 1, 2017 Technical Conference at 291-292 (May 1, 2017).

[22] *See Grid Resiliency Pricing Rule*, Notice of Proposed Rulemaking, 82 Fed. Reg. 46,940, 46,944 (Oct. 10, 2017).

on this subject and entered it into the record of the May 2017 technical conference.[23] The white paper clearly describes this problem and highlights the need to reform pricing rules to allow firm-fuel units to set LMP. The DOE Staff Report endorses expediting price formation as a partial solution to the threat to resiliency from the loss of firm-fuel resources.[24] In fact, the DOE Staff Report specifically identified this proposal from PJM as a reform for the Commission to consider.[25]

The record before the Commission establishes that the current market structure does not produce just and reasonable rates for multiple reasons previously accepted by the Commission. For one, a foundational principle of locational marginal pricing is ensuring that the energy price "reflects the marginal cost of serving load at the specific location."[26] The Commission has repeatedly recognized that energy prices are not just and reasonable if they do not reflect the true marginal cost of production. The Commission has viewed the alignment of prices and marginal cost as a priority in the recent price formation proceedings. "LMPs and market-clearing prices used in energy and ancillary services markets ideally would reflect the true marginal cost of production, taking into account all physical system constraints, and these prices would fully compensate all resources for the variable cost of providing service."[27] The Commission has also

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[23] *Initial Post-Technical Conference Comments of PJM Interconnection*, L.L.C., AD-17-11-000, "Initiative 3" at PDF pages 32-37 (June 22, 2017) ("PJM White Paper").

[24] *See* DOE Staff Report at 126 ("FERC should expedite its efforts with states, RTO/ISOs, and other stakeholders to improve energy price formation in centrally-organized wholesale electricity markets.")

[25] *Id.* & n.467 ("After several years of fact finding and technical conferences, the record now supports energy price formation reform, such as the proposals laid out by PJM.") (citing PJM's June 15, 2017 white paper).

[26] Federal Energy Regulatory Commission, Energy Primer: A Handbook of Energy Market Basics 60 (Nov. 2015).

[27] *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,115, at P 7 (2016) (internal quotations omitted)

taken action under Section 206 on this basis. For example, the Commission relied on the failure of energy prices to fully reflect marginal cost as a reason to exercise its Section 206 authority and raise the offer caps in the organized markets.[28]

Additionally, the Commission has already recognized a version of this *specific* market flaw as a basis to declare that RTO tariffs are not just and reasonable. In December 2016, the Commission issued a Notice of Proposed Rulemaking on pricing of fast-start resources.[29] That Notice preliminarily concluded that pricing for fast-start resources is not just and reasonable because they cannot set price when operated at their economic minimum. The Commission stated:

> Fast-start resources are often required to be dispatched at their economic minimum operating limit or are block-loaded. Because the system may need fewer megawatts (MW) than the fast-start resource's economic minimum operating limit to meet load, other resources must be dispatched down. The resources that were dispatched down become the most economic option to serve the next increment of load. Therefore, *despite the fact that a fast-start resource is essentially marginal, this restriction prevents a fast-start resource dispatched at its economic minimum operating limit from setting the LMP*.[30]

The Commission preliminarily found that these market rules lead to pricing that is not just and reasonable because market prices "fail to accurately reflect the marginal cost of serving load."[31]

The same reasons support a comparable Section 206 conclusion here, but for units that are operationally-constrained. Just like fast-start resources, units operating at their economic minimum "are inappropriately prevented from setting prices."[32] Even when they are the marginal

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[28] *Id.* at P 15 (concluding that offer caps are not just and reasonable).

[29] *Fast-Start Pricing in Markets Offered by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,213 (2016).

[30] *Id.* at P 8 (emphasis added).

[31] *Id.* at P 36.

[32] *Id.* at P 37.

unit, market prices do not reflect their marginal costs. Just as the fast-start rules require revision, so too these market rules are no longer just and reasonable.

Like any flaw in price formation, the current flawed market design leads market participants to make inefficient short and long-term decisions. In the short term, the wrong units choose to participate in the market. Low-cost baseload units may decide not to participate in the market because they will be forced to operate at a loss in low-load conditions. In their place, other higher-cost units will be inefficiently dispatched. In the longer term, units that cannot even consistently recover their variable costs (let alone their fixed costs) will exit the market.

Many commissioners, current and past, have recently reiterated their support for markets. However, for markets to work, they must adhere to basic market principles such as marginal cost pricing and appropriate compensation for all attributes. Markets that do not follow such rules are markets in name only. The Commission has also recognized the need to adjust market rules when technological and market changes reveal that rules predicated on particular operational assumptions have grown outdated. For example, in Order 764, the Commission recognized the need to change market rules designed for traditional generation in response to the increased penetration of renewables. In response, it acted under Section 206 to adjust rules relating to transmission scheduling and other practices to ensure rates remained just and reasonable.[33] Similarly, in Order 719, the organized markets were required to adjust their rules to ensure that demand response resources could participate in the markets and have the market rules recognize

[33] *Integration of Variable Energy Resources*, Order No. 764, 77 FR 41,482 (July 13, 2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61,232 (2012), *order on reh'g*, Order No. 764-B, 144 FERC ¶ 61,222 (2013).

their unique operational characteristics.[34] More recently, the Commission issued a Notice of Proposed Rulemaking relating to the participation of storage resources.[35] This NOPR seeks to adjust market rules to reflect the physical and operational characteristics of electric storage to facilitate its participation in the market.[36]

All of these rulemakings rest on the same theory: Different technologies have different physical and operational characteristics. Technological change thus places pressure on market rules. Market rules that fail to adapt to technological changes or changes in other market inputs can become unjust and unreasonable. The same flaw exists here. These market rules are a relic of a different era. When energy prices were consistently high, the inability of these resources to set LMP was irrelevant. The marginal cost of firm-fuel units rarely exceeded the energy revenues that those units received throughout the day. Now, however, because tax-subsidized renewables and low gas prices have driven down the energy prices in low-load conditions, the market flaw has become apparent and the existing rules are no longer just and reasonable.

C. PJM Has Proposed a Just and Reasonable Solution for Setting LMP.

When taking action under Section 206, the Commission must replace the invalid rules with an alternative that is just and reasonable.[37] Here, PJM has proposed a straightforward solution to the pricing problem. It "would … allow the inflexible unit to set LMP, thereby transparently

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[34] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), order on reh'g, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 (2009), order on reh'g, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[35] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,121 (2016).

[36] *Id.* at PP 9-10.

[37] *City of Anaheim v. FERC*, 558 F.3d 521, 523 (D.C. Cir. 2009) ("When the Commission finds a rate unreasonable, it shall determine the just and reasonable rate to be thereafter observed and in force.") (internal quotations omitted).

indicating the cost of the most expensive unit necessary to economically serve the load."[38] This change is the natural resolution to the market flaw identified above. This pricing strategy allows all units to set price regardless of the physical and operational characteristics, reduces or eliminates the need for uplift, and ensures that the energy price reflects the true marginal cost of serving load.

This pricing strategy is also consistent with the goals that FERC has emphasized throughout the price formation proceedings. The Commission has highlighted four objectives:

> The goals of the price formation proceeding are to: (1) maximize market surplus for consumers and suppliers; (2) provide correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability; (3) provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system; and (4) ensure that all suppliers have an opportunity to recover their costs.[39]

The proposal to let baseload units set LMP furthers all four of these goals. Total market surplus is improved when market prices permit efficient unit dispatch and commitment and send accurate entry and exit signals. This scheme sets prices transparently and reflects the true cost of serving load, rather than disguising costs through uplift payments or ignoring the costs completely. Finally, by allowing all resources to set price, market revenues will compensate resources participating in the market for their marginal costs.

The Commission has already accepted a version of this proposal as just and reasonable. In December 2011, MISO recognized that a similar flaw existed in its pricing algorithm and proposed a very similar solution under Section 205. MISO faced the same issue that these units were unable to set energy prices and, when those units operated at their economic minimum, the locational

[38] PJM White Paper at 3.

[39] *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Final Rule, 157 FERC ¶ 61,115, at P 4 (2016).

marginal price was below their marginal costs.[40] The Commission recognized that this pricing mechanism "may produce an inaccurate price signal."[41] It then accepted MISO's proposed solution to permit block-loaded fast-start resources to set the energy price.[42] The same approach should be adopted in PJM.

In selecting this market design, the Commission need not sacrifice the goal of ensuring that market prices send the right signals to resources. The Commission should also direct PJM to report on its efforts to ensure that this market change does not eliminate the incentives for flexible units to follow dispatch instructions. As discussed above, the strongest argument for the current pricing mechanism is that flexible units have the correct economic incentive to reduce output when a baseload unit comes on-line. If energy prices rise to the variable cost of the marginal baseload unit, inframarginal flexible units will see an energy price greater than their marginal cost and will have an incentive to continue to run. To address that incentive, PJM has discussed proposing an additional product that would compensate the flexible resource for turning down in response to the dispatch signal. The price of that product must be at least equal in value to the difference between the energy price and the flexible resource's marginal cost for the megawatts where the baseload unit is marginal and is setting the price. PJM should be encouraged to complete its discussions on the design attributes of this product and to report its progress to the Commission as soon as possible.[43]

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[40] S*ee Midwest Indep. Transmission Sys. Operator, Inc.,* 140 FERC ¶ 61,067, at P 4 (2012) (noting that MISO justified its filing on the grounds that block loaded resources cannot set LMP and the energy price reflects the cost of the unit backed down instead).

[41] *Id.* at P 38.

[42] *Id.*

[43] Initiating a Section 206 action in PJM would not necessarily require changes to any other tariff. While the record exists to take action in PJM, the evidence is less clear in the other RTOs. Each RTO has different energy and capacity market structures as well as a different mix of policies

II. The Commission Should Take Other Interim Steps to Protect Resiliency in the Markets.

While correcting the PJM energy market is important in the short term, the Commission should take other interim steps as well to protect resources needed for resiliency, while the Commission undergoes a longer-term process of developing more permanent compensation mechanisms. *First*, while it considers next steps, the Commission should ensure that state programs to support resilient nuclear units, including the New York and Illinois Zero Emission Credit programs, are not impeded. The Commission should issue a policy statement clarifying that these programs will not lead to mitigation. *Second*, the Commission should request RTOs to report on various other reforms that help protect the resiliency of the grid, such as changes to the operating reserves and capacity markets. While some efforts are underway, requiring the RTOs to report on these efforts would provide a more complete understanding of the risk to resiliency and current RTO efforts to protect the grid.

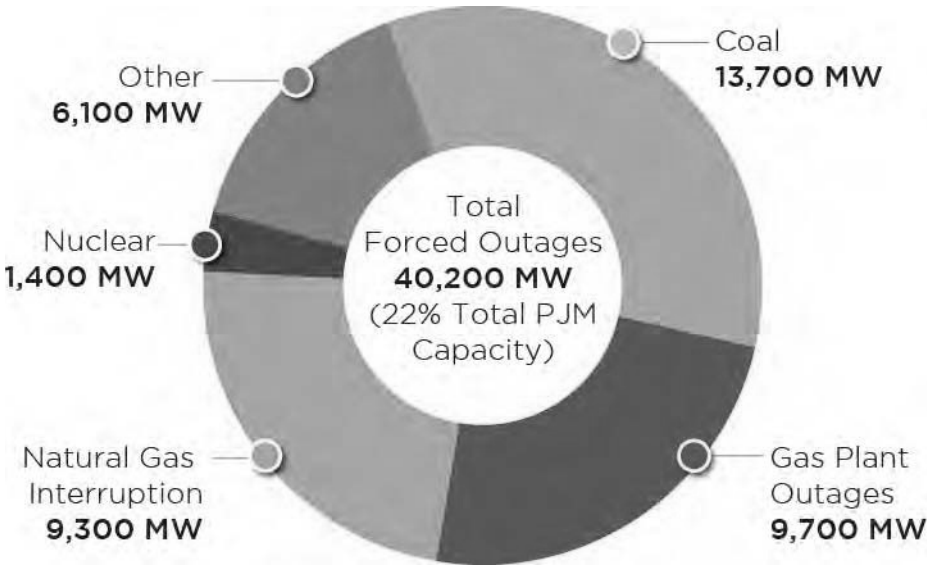
A. Existing Nuclear Units Provide Unique Resiliency Benefits to the System.

The DOE Notice of Proposed Rulemaking describes a current threat to the resiliency of the electric grid. While the Commission considers its longer-term options to respond to that threat, its first priority should be to do no additional harm to the viability of the resilient units that remain in the organized markets. In that regard, nuclear units in particular have proven their worth as resilient and dependable generators, particularly in times of extreme system stress. Their performance relative to other types of resources during the 2014 Polar Vortex – a reliability event DOE itself cited as an example of resiliency problems with the electricity grid – offers a good

providing support for resilient resources. To the extent that the Commission believes that pricing in another RTO may raise similar concerns, the Commission could consider requiring that RTO to report on the problem.

example of the resiliency benefits nuclear units provide.[44] As the chart below demonstrates, during the critical evening of January 7, 2014, nuclear units had by far the least forced outages and were only responsible for 3% of the total outages in PJM.[45]

Figure 17: Outages by Primary Fuel – January 7, 7:00 p.m.[46]



[44] *See* DOE NOPR, 82 Fed. Reg. at 46,942.

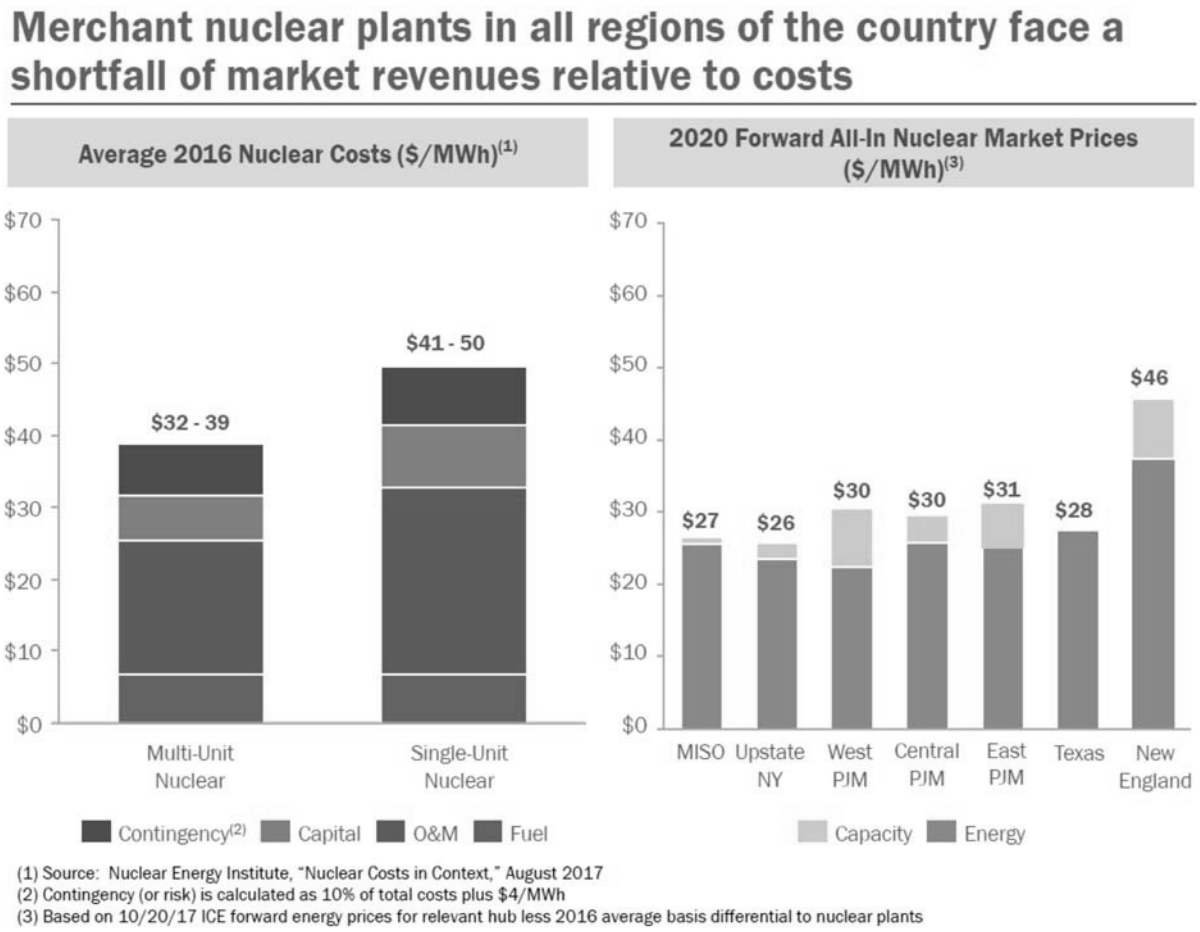
[45] The Polar Vortex is not the only time when the system relied on nuclear generation to keep the lights on during extreme weather conditions. For example, in 1994, extreme cold weather led to fuel supply disruptions in PJM, necessitating rolling blackouts. Subsequent analysis identified frozen coal and coal handling equipment, fuel oil delivery problems, and the interruption of natural gas supplies as prime causes. The stress placed on the system would have been all the more extreme if nuclear generation had been replaced by gas generation. *See* NERC, *Report on Electric Utilities' Response to the Cold Wave of January 1994* (Apr. 11, 1994), *available at* http://www.nerc.com/pa/rrm/ea/February%202011%20Southwest%20Cold%20Weather%20Event/NERC%201994%20Cold%20Wave%20Report.pdf; NERC, *Assessment of Previous Severe Winter Weather Reports 1983-2011* (July 2013), at 7, *available at* http://www.nerc.com/pa/rrm/ea/February%202011%20Southwest%20Cold%20Weather%20Event/Final_Draft_Assessment_of_Previous_Severe_Winter_Weather_Report.pdf.

[46] Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events, PJM Interconnection (May 8, 2014), available at http://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx, at 26.

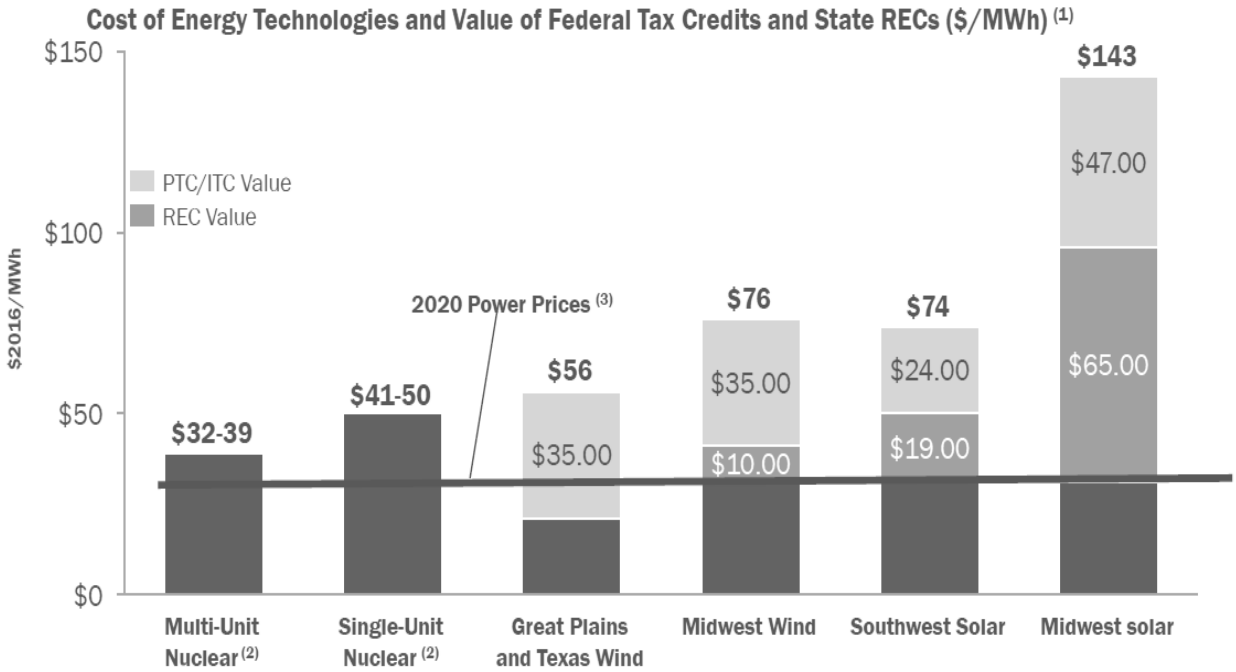
Moreover, of all generation, nuclear is alone in having a separate regulator – the Nuclear Regulatory Commission – that imposes safety and cybersecurity standards and engages in constant monitoring. Thus, from a resiliency perspective, the nuclear fleet is among the most "hardened" and prepared for adverse events and is constantly engaged in safety and reliability enhancements.

Yet nuclear plants have not been compensated for the resiliency value they provide to the system. As a result, many have retired prematurely—more than 10 GW of nuclear capacity has either retired or announced retirement plans—and many other nuclear units are in economic distress. Indeed, Bloomberg estimates that more than half of the nation's nuclear units are losing money.[47] As shown below, throughout the country, merchant nuclear plants face a shortfall of revenue relative to costs:

[47] Jim Polson, *More Than Half of America's Nuclear Reactors Are Losing Money*, Bloomberg, (June 15, 2017), *available at* https://www.bloomberg.com/news/articles/2017-06-14/half-of-america-s-nuclear-power-plants-seen-as-money-losers.



Without corrections to the market and full compensation for the attributes offered by this vital energy source, which produces over 60% of the nation's zero emission energy, the nation will suffer a massive wave of premature retirements. Yet ensuring the continued operation of nuclear plants is the most cost-effective way to achieve resiliency while also reducing emissions:



(1) Source: Nuclear Energy Institute, "Nuclear Costs in Context," August 2017; EIA AEO 2017 Levelized Cost of New Generation Resources
(2) Nuclear costs are comprised of fuel, O&M, capital expenditures and contingency. Contingency (or risk) is calculated as 10% of total costs plus $4/MWh
(3) Based on 10/20/17 ICE 2020 forward energy prices for relevant hub less 2016 average basis differential to nuclear plants

B. The Commission Should Issue a Policy Statement Declaring That Nuclear Facilities Receiving State Support Should Not Have Their Offers Mitigated on Account of That Support.

Given the vital role nuclear energy plays in providing resiliency and emissions-free energy for our customers, the failure of markets to adequately compensate nuclear generators for these attributes, and the irreplaceability of nuclear resources if they retire, the Commission should announce that it will not impede state efforts to support nuclear plants at risk of retirement. Both New York and Illinois have adopted state Zero-Emission Credit programs to provide additional revenue to nuclear units located within their boundaries. While the primary goal of these programs was environmental, the programs have the additional benefit of preserving units needed for system resiliency. These programs benefit nuclear units within the organized markets covered by the DOE NOPR and are targeted at units that otherwise would permanently retire. Ensuring these units'

viability by protecting these state-supported revenue streams is thus consistent with the goals of the DOE proposal and the needs of a resilient electric grid.

Accordingly, the Commission should make clear that units receiving this type of support should not have their capacity or energy offers subject to mitigation. Natural gas generators have argued for mitigation of these state support programs to enhance their market position and to move the grid toward greater reliance on natural gas units. FERC should be mindful that natural gas and oil receive tens of billions of dollars annually in tax and other subsidies,[48] and additionally enjoy the benefit of using the atmosphere on a mostly unrestricted basis as a place to release carbon and other pollutants. Indeed, those who complain most vigorously about the need to preserve "free markets" are in fact the largest beneficiaries of tax and other subsidies. Some of the largest subsidies are shown in the table below:[49]

[48] Dirty Energy Dominance: Dependent on Denial, *Oil Change International* (Oct. 3, 2017), *available at* http://priceofoil.org/content/uploads/2017/10/OCI_US-Fossil-Fuel-Subs-2015-16_Final_Oct2017.pdf.

[49] The table below is excerpted from *id.* at 24-26, "Appendix 1: Complete List of U.S. Federal and State Fossil Fuel Production Subsidies." In total, federal oil and gas subsidies amount to $11 billion annually—not counting the implied of subsidy of being allowed to pollute without paying for the costs imposed on society.

Table 1: Federal Fossil Fuel Production Subsidies, 2015 to 2016

Subsidy Name & Description	Subsidy Type	Targeted Energy Source	Targeted Stage	2015 Estimate (in millions)	2016 Estimate (in millions)	Estimated Annual Average, 2015-2016 (in millions)
Federal Oil & Gas Production Subsidies						
Deduction for Intangible Drilling Costs* – 100% tax deduction for costs not directly part of the final operating of an oil or gas well	Tax expenditure	Oil & Gas	Exploration and field development	2,317	2,267	2,292
Last-In, First-Out (LIFO) Accounting for Fossil Fuel Companies* – allows companies to undervalue their inventory, reducing taxable income; oil and gas companies account for over one-third of LIFO benefits	Tax expenditure	Oil & Gas	Cross-cutting	1,453	1,927	1,690[a]
Corporate Tax Exemption for Fossil Fuel Master Limited Partnerships* – allows companies to pay zero corporate income tax	Tax expenditure	Oil & Gas	Cross-cutting	755	2,473	1,614
Excess of Percentage Over Cost Depletion* – independent producers can deduct a percentage of gross income from production, rather than reflecting the value of the reserve depleted	Tax expenditure	Oil & Gas	Cross-cutting	1,502	1,118	1,310
Lost Royalties on Offshore Drilling for Leases Issued from 1996 through 2000 (Outer Continental Shelf Deep Water Royalty Relief Act)	Royalty relief	Oil & Gas	Extraction	1,072	1,072	1,072
Domestic Manufacturing Deduction for Oil & Gas* – allows oil & gas producers to claim a tax break intended for the manufacturing of goods	Tax expenditure	Oil & Gas	Cross-cutting	963	647	805
Dual Capacity Taxpayer Deduction* – allows oil and gas companies operating abroad to deduct royalty payments to foreign governments from U.S. income taxes	Tax expenditure	Oil & Gas	Remediation	527	533	530[b]

Accepting requests for mitigation from entities currently benefiting to this extent from fuel-specific subsidies would obviously be counterproductive as the Commission considers additional ways to improve the resilience of the grid. To the extent that the states are already taking steps to further the goals that DOE and FERC seek to accomplish, by preserving resilient and irreplaceable nuclear resource, their work should continue unimpeded.

C. FERC Should Direct the RTOs to Make A Filing Describing Other Measures that They Can Take to Support Resilient Units.

While the Commission considers how to design a market-based resiliency product, it should in the meantime direct the RTOs to consider other potential steps that would help to support a resilient grid.

For example, the RTOs should be encouraged to examine their method of procuring operating reserves. They may be able to take action, consistent with their tariffs, to increase operating reserves as needed to address the risk of disruption to the gas supply. Weather-related threats to the gas supply can pose a significant risk of economic harm and loss of life.[50] Similarly, a major pipeline outage from natural or human causes could have significant consequences in both the short and long-term.[51] Procuring adequate operating reserves to plan for these contingencies is a straightforward mechanism to reduce these risks as the Commission considers other possibilities.

PJM has already begun the process of considering changes along these lines. On October 10, 2017, PJM made a presentation to the Operating Committee outlining a proposed approach.[52] In brief, the RTO is considering changes to how it procures operating reserves to take in consideration the location of natural gas generators and the sources of their gas supply. In certain situations, the reserve market may choose not to dispatch certain units to avoid overreliance on particular natural gas pipelines. The Commission should require the RTOs to report on these efforts and to expedite their consideration.

The RTOs should also report on potential capacity market modifications. Certain markets covered by the Notice of Proposed Rulemaking have already recognized the need for enhanced capacity market designs to ensure that resources have an incentive to make investments to improve

[50] *See Grid Resiliency Pricing Rule*, 82 Fed. Reg. 46,940 at 46,945 (discussing the Polar Vortex and Hurricanes Harvey, Irma, and Maria).

[51] Stockton Testimony at 10-11.

[52] *See Operationalizing Gas Pipeline Contingencies Normal and Conservative Operations*, Presentation dated October 10, 2017, *available at* http://www.pjm.com/-/media/committees-groups/committees/oc/20171010/20171010-item-16-gas-electric-contingencies-update.ashx.

their level of performance. In 2014, ISO-NE adopted its pay-for-performance scheme.[53] In 2015, the Commission approved the implementation of capacity performance in PJM.[54] Although these reforms were aimed at reliability, not resiliency—a distinction discussed further below—these reforms nevertheless help to support resilient units and therefore promote the goals set forth in the DOE NOPR. In these markets, the RTOs should consider whether the current penalty structure provides appropriate incentives to invest in performance. For example, in the Capacity Performance Order, FERC ordered PJM to revisit regularly the penalty rate and adjust it as needed to ensure performance.[55] The penalty rate was based on an assumption of 30 penalty hours per year, an estimate that was based on expected extreme weather (not manmade threats) and in any event appears to have been too high as recent years have had no penalty hours assessed. The Commission should urge PJM to consider changes to these and other capacity market features to protect the resilience of the electric grid.

RTOs can also explore tariff changes aimed at other problems—for example, carbon emissions—that would have the side benefit of supporting resilient resources. For example, a stakeholder process is underway in the NYISO market to discuss carbon pricing in that RTO's energy market.[56] That solution would provide additional revenue to resilient nuclear units while not disturbing the overall structure of that market.

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[53] *See ISO New England Inc.*, 149 FERC ¶ 61,009 (2014); *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172 (2014).

[54] *See PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (2015).

[55] *Id.* at 163.

[56] *See* Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals, August 10, 2017, *available at* http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Studies/Market_Studies/Pricing_Carbon_into_NYISOs_Wholesale_Energy_Market.pdf.

Organized markets have also adopted short-term structures in the past that have been used to ensure the availability of resilient resources in times of extreme conditions. The winter reliability programs in New England for oil and LNG storage have provided an adequate supply of power in that region for several years.[57] The Commission has approved those programs as just and reasonable as a transitional measure to a more robust permanent market design. Similarly, the Commission approved transitional auctions in PJM to move from a base capacity model to the capacity performance framework. To the extent organized markets need to take interim steps to retain resilient units while a broader process is underway, these programs can serve as a model of narrowly tailored solutions the Commission has previously approved. The Commission should direct the RTOs to report on whether programs such as these would be a just and reasonable interim mechanism of protecting the resilience of the grid. Additionally, if faced with the imminent retirement of a resource that can demonstrate its contribution to grid resiliency, the Commission should consider taking steps, on a unit-specific basis, to enable that unit's continued operation until the Commission can adopt a more comprehensive solution to address resiliency.

III. Before Determining the Solution, FERC Must Identify With Greater Specificity What Problem It Is Trying to Solve.

In order to identify the best and most cost-effective way to ensure a resilient grid, the Commission must first learn in greater detail what vulnerabilities the grid faces and, based on intelligence community assessments, which threats are the most important to mitigate. Once a Design Basis Threat analysis is complete,[58] then the Commission can identify the steps that must

[57] *ISO New England Inc. and New England Power Pool Participants Committee*, 152 FERC ¶ 61,190 (2015).

[58] *See* Nuclear Regulatory Commission Glossary, Design Basis Threat; https://www.nrc.gov/reading-rm/basic-ref/glossary/design-basis-threat-dbt.html (defining a design basis threat); 10 CFR § 73.1(a) (outlining particular threats).

be taken to address the threat, and the best and most cost-effective means for carrying out those steps. The rigorous analysis that must be the predicate for policy has not yet been done. As an initial step, the Commission should require the markets covered by the NOPR—PJM, NYISO, and ISO-NE—to expedite their planning efforts and report promptly on their readiness to respond to different types of significant systemic failure.

A. The Threat of A Black Sky Event Is Real and the Consequences Would Be Disastrous.

In its NOPR, DOE correctly notes the serious threat posed to the nation's electric grid by generation units that are insufficiently resilient, whether due to a fuel supply vulnerable to disruption, inability to operate in adverse weather conditions, or other factors that render units unable to provide energy at times of critical system need.[59] This threat is real, and it is immediate: Dr. Stockton's testimony outlines at length the critical danger to the bulk power system posed by "growing interdependencies" between natural gas and electric utilities.[60] These interdependencies increase the risk of mutually-reinforcing failures of *both* systems, in which disruption of the natural gas supply will interrupt the supply of electricity, which in turn will lead to further disruption in the ability of pipelines to deliver natural gas, and so on.[61] The result of such a combined failure—which could occur either because of malicious human action (either physical or cyber) or because

[59] *See* DOE NOPR, 82 Fed. Reg. at 46,941 ("The resiliency of the nation's electric grid is threatened by the premature retirements of power plants that can withstand major fuel supply disruptions caused by natural or man-made disasters and, in those critical times, continue to provide electric energy, capacity, and essential grid reliability services.").

[60] Stockton Testimony at 12.

[61] *Id.* at 11-13.

of a natural disaster—could lead to a "black sky" power outage, in which multiple regions throughout the country could suffer a sustained loss of power lasting a month or more.[62]

The human and economic consequences of such an event would be devastating. As Dr. Stockton notes, it would constitute an unprecedented natural emergency. America is not prepared for such a sustained blackout:

> Many critical infrastructure systems and facilities have backup power generators and stored on-site fuel to keep them operating for a few days in a limited power outage. However, in a black sky event, the extensive length and geographic scope of power outages would soon produce failures in emergency power assets and the infrastructure system that rely on them. Blackouts of this severity would cause cascading failures across multiple critical infrastructure sectors..[63]

The damage would spread throughout other components of the economy that depend on electric power. A black sky event would cripple sectors crucial for the preservation of human life. The American public would lose access to food and clean water, health care, and basic sanitation. Even basic forms of communication would become virtually impossible:

> Hospitals would exhaust their ability to rely on backup power. Food manufacturing and distribution networks would cease to function. Other critical infrastructure sectors would also likely collapse. For example, water, wastewater, and cellular systems rely on a functioning power grid and are not currently prepared for such an event. A black sky event would likely disable those systems for sustained periods of time leaving them unavailable to the public.[64]

As the nation becomes increasingly dependent on electricity for transportation through vehicle electrification, we risk disrupting our ability to move people as well. Potentially even more serious, the event would cause a crisis of national security and might incapacitate the defensive capacity of the United States military:

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[62] *Id.* at 9.

[63] *Id.* at 10.

[64] *Id* at 11.

> [N]ational defense installations would begin to fail. Domestic military facilities can operate without power for short periods of time but are not designed to be independent of the electric grid for extended periods of time. Electric power is necessary to keep them in operation because they require access to transportation fuel, communication networks, water and wastewater systems that need electricity to operate.[65]

As Dr. Stockton concludes, "[a] black sky power outage would inflict immense disruption of national security."[66]

B. The Commission Should Require the Three RTOs to Report on Their Status.

The Commission has an essential role to play in preventing the disaster to the nation that a black sky event would entail. It must ensure a robust generation fleet that can overcome threats to resiliency, and doing so requires a thorough examination of where our vulnerabilities lie, which vulnerabilities are the most important to address, what needs to be done to address them, and the most cost-effective means of doing so.

To begin that process. the Commission should issue an order requiring that the three RTOs identified by the Secretary of Energy—PJM, NYISO, and ISO-NE—provide key data regarding the ability of their regions to survive the type of catastrophic high intensity low frequency events that Dr. Stockton describes in his testimony. Beginning with a focus on these three RTOs is appropriate, as all three have capacity structures that select the lowest cost resources without regard to resiliency, driving those markets toward a gas monoculture. Moreover, in those markets, states have largely not used their own regulatory authority to promote resiliency. Other RTOs lack capacity structures causing that particular resiliency issue, in part because they have more robust integrated resource planning overseen by state commissions.

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[65] *Id.*

[66] *Id.* at 10.

Specifically, these three organized markets should provide the Commission with the following information in the following time periods:[67]

Within **30 days**, an inventory of all fuel supply for all generation within in their footprint including, for each generator:

- For the primary fuel source:
    - Fuel source type.
    - On-site inventory reported as average days based on continuous full output.
    - The nature of the fuel supply arrangement (e.g., firm gas, long-term coal contract, purchases of oil on the spot market, etc.).
    - The primary method of fuel delivery (e.g., firm pipeline transportation, rail, barge, truck, etc.).
    - Environmental permitting limitations.
- For the secondary or back-up fuel (if any):
    - Fuel source type.
    - On-site inventory reported as average days based on continuous full output. For oil and diesel this should include both the actual inventory and the maximum potential that can be stored on-site.
    - The nature of the fuel supply arrangement, including the existence of firm resupply contracts, if any.
    - The primary method of fuel delivery.
    - Environmental permitting limitations.

Within **60 days**:

- A fuel reliance analysis detailing the impact on the organized market's ability to serve load if the supply of a particular fuel type is interrupted, or if the supply of a combination of fuel types is interrupted. The analysis should include:

[67] *See* Order Directing Reports, *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, 153 FERC ¶ 61,221, at P 7 n.7 (2015); Federal Power Act §§ 301(b), 309.

- How much load would not be served if a particular fuel type were unavailable for any reason.
- How long primary inventories would last at generators.
- How long secondary inventories would last at generators.
- A generator's ability to resupply from existing secondary fuel inventories that are not on site.
- The market's ability to increase production of remaining fuels, including diesel fuel, to meet increased need for the fuel in light of other demands for that fuel.

- A load impact analysis detailing the consequences if load is unable to be served for a prolonged period of time. This analysis should detail multiple disruption and time combinations (e.g., 50% of load for one week, 75% of load for two weeks, etc). The analysis should include:
  - The financial impact to economy of the region.
  - The security of the region (e.g., loss of other critical infrastructure and life sustaining services).
- A contingency analysis detailing the ability of the system to withstand (for both short- and long-term) electric and gas failures. This analysis should model both existing and future generation mixes. The analysis should include:
  - Single gas pipeline failure.
  - Multiple gas pipeline failures (including shared right of ways and crossings).
  - Coordinated attacks on multiple gas pipelines supplying the majority of an organized market's gas.
  - Loss of all pipelines controlled by single company whether as a result of a physical or cyberattack.
  - Coordinated gas pipeline/electric failures.
- An assessment of the adequacy of existing capacity constructs in light of the resiliency findings, and suggestions of what changes need to be made.[68]

[68] *See* Stockton Testimony at 19-21,

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PJM has already begun a component of this process and started to consider the consequences of the loss of a single pipeline standing alone. This study indicated that in PJM, more than 11 GW of generation is connected to a single pipeline.[69] A disruption of that pipeline would be catastrophic. While PJM is ahead of other RTOs in initiating a planning process,[70] its analysis needs to more robust. For example, PJM should consider the loss of multiple pipelines simultaneously because of the real risk that terrorists or foreign governments might target multiple infrastructure components simultaneously,[71] as well as the risk that an attack on the pipeline system could be accompanied by an attack on components of the electric system. It should also consider the increased risk that will occur if more coal and nuclear units retire and leave the grid even more dependent on natural gas. The reporting requirements outlined above will help improve that planning process.

The other two RTOs need to rapidly advance and expand the planning process as well. NYISO has begun to study whether its system has adequate fuel assurance, recently seeking comment on an evaluation it commissioned the Analysis Group to perform.[72] Unfortunately, while ISO-NE similarly has been evaluating the fuel security of its region, and has "identified fuel security as one of the potential risks to future system reliability," it has nevertheless decided to

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[69] *See supra* note 7.

[70] Stockton Testimony at 18-19.

[71] *Id.* at 19.

[72] *See* Analysis Group, *Capacity Resource Performance in NYISO Markets, An Assessment of Wholesale Market Options*, at 18, 26 (Sept. 2017), *available at* http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2017-09-28/Analysis%20Group%20Draft%20Capacity%20Resource%20Performance%209-26-17.pdf (noting that "[t]he potential for growing future reliance on gas-fired resources suggests that further attention to fuel-related performance may be important to preventatively addressing potential system reliability risks").

"delay finalizing the study until the FERC has provided direction to the industry on how to interpret the DOE NOPR," suggesting that it will release the study "once the NOPR is sufficiently resolved."[73] ISO-NE's decision to delay its release of data is difficult to understand and unfortunate because it deprives commenters and experts in this proceeding of relevant data that would be highly relevant to FERC's response to the NOPR.

The Commission should urge PJM and NYISO to expeditiously complete their studies, and should not countenance ISO-NE's decision to shield its evaluation from public view. Rather, the Commission should order the RTOs to report promptly on their progress in conducting these types of planning efforts.

C. A Final Rule Is Urgently Needed, But Further Action Should Be Informed by a Design Basis Threat Analysis.

Before adopting a final rule to address the need to ensure resilience, the Commission should collaborate with other federal agencies to conduct a design basis threat analysis to measure the resiliency of the grid.[74] Exelon believes DOE might be well-situated to spearhead this analysis given its access to information, its expertise, and its relationship with the intelligence community. Here, such an analysis would help identify what vulnerabilities exist and must be addressed to ensure resiliency. The assessment should account for likelihood that a natural or manmade interruption in the energy sector might disrupt multiple pipelines simultaneously as well as other serious risks.[75]

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[73] ISO New England, Study on Regional Fuel Security to be Delayed Pending Resolution of DOE Proposal on Grid Resiliency Pricing (Oct. 13, 2017), https://www.iso-ne.com/static-assets/documents/2017/10/20171013_fuel_security_analysis_delay_final.pdf.

[74] As Dr. Stockton explains, the Nuclear Regulatory Commission provides its licensees with such a threat assessment to help safeguard nuclear reactors. Stockton Testimony at 22.

[75] *Id.* at 19.

Once the Commission has a more detailed understanding of the bulk power system's vulnerabilities, and which of those vulnerabilities most urgently need to be addressed, it will be able to decide what steps must be taken to counter those threats and the best means of doing so. It can then order the organized markets to adopt tariffs that address this threat, and ensure that generators that provide vital and needed resiliency are able to do so in the years ahead. In considering whatever final action it decides to take, the Commission will need to solicit commentary and analysis from a wide array of stakeholders and market participants. But, regardless of whatever process the Commission deems necessary in coming to a final rule, it should act quickly and not allow the critical resiliency deficiencies that currently endanger the bulk power system to persist.

There are undoubtedly numerous ways markets could be reformed once the appropriate design basis is identified, and the Commission should expect the RTOs to develop solutions that best harmonize with their existing market designs. Key among these is providing sufficient financial support to units that currently make important contributions to system-wide resiliency, so that these units can continue operations and are not forced into retirement. As Dr. Stockton explains,

> Increased dependence on a single type of fuel heightens the risks of common mode failures: that is, the danger that a single attack vector (especially via cyber means) could enable the adversary to disrupt fuel supplies for power generation across major portions of the United States. A significant interruption of the natural gas supply available for electric generation can dramatically reduce the supply of electricity available to serve load. For example, a large-scale disruption of a natural gas pipeline would prevent that pipeline from delivering natural gas to the generators it serves. It would also incapacitate any downstream pipeline dependent on it as a source of gas. Because gas is delivered close in time to its use as a fuel for electric generation, the system would have little time to respond to the loss of a pipeline. Preserving a diverse generation mix that relies on multiple sources of fuel is essential to reducing this risk.[76]

[76] Stockton Testimony at 9.

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The Commission should ensure, however, that market reforms achieve the Design Basis Threat with a high degree of certainty and minimize total system costs in doing so. It may be the case, for example, that compensating an existing resilient unit for its costs of operation is less expensive than building new plants or retrofitting an existing plant to be equally resilient. In other words, providing cost of service payments may be in customers' best interests.

In conclusion, Exelon applauds DOE's focus on the threat posed to consumers and the bulk power system by insufficiently resilient generation. The wholesale markets have a long history of successfully delivering reliable and reasonably priced power to consumers at just and reasonable rates. But they need reform to ensure that the grid retains its most resilient resources.

CONCLUSION

The risks of non-action are real and potentially grave. The declining fuel security of the power system and increased reliance on a vulnerable natural gas pipeline system has created a real possibility of widespread, long-duration blackouts that would have catastrophic consequences. The American public cannot afford to take that risk. Fortunately, solutions exist if we have the stimulus to pursue them. We look forward to working with the Commission to develop those solutions.

SI-SSA-0010-2963

October 23, 2017

Respectfully submitted,

/s/ Matthew E. Price

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SI-SSA-0010-2964

Exhibit A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	**)**	**Docket No. RM18-1-000**

PREPARED DIRECT TESTIMONY OF

DR. PAUL STOCKTON

ON BEHALF OF

EXELON CORPORATION

OCTOBER 23, 2017

I. BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Paul Stockton. My business address is 325 7th Street NW, Suite 250, Washington D.C. 20004.

Q. DR. STOCKTON, BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am the Managing Director of Sonecon LLC, a security and economic advisory firm in Washington, DC.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS, EMPLOYMENT EXPERIENCE, AND EDUCATIONAL BACKGROUND

A. I graduated with a Bachelor of Arts degree s*umma cum laude* from Dartmouth College and received a Ph.D. from Harvard University. From June 2009 until January 2013, I served as the Assistant Secretary of Defense for Homeland Defense and Americas' Security Affairs. In that position, I was responsible for Defense Critical Infrastructure Protection and led the creation of the Department's Mission Assurance Strategy. I also served as the Domestic Crisis Manager for the Department of Defense (DOD) and was responsible for Defense continuity of operations. I was the principal civilian advisor to the Secretary of Defense for providing Defense support to Federal Emergency Management Agency, the Department of Energy (DOE) and other Federal departments in Superstorm Sandy, Hurricane Irene, and other disasters. In addition, I was responsible for developing and overseeing the implementation of DOD security policy in the Western Hemisphere, including U.S.-Canada

cooperation on Defense-related issues concerning energy sector resilience. From January 2012 until January 2017, I served as a Special Government Employee for the Department of Defense, and helped conduct studies to strengthen deterrence of cyberattacks, counter insider threats, and meet other infrastructure resilience challenges. I was twice awarded the DOD Medal for Distinguished Public Service, the Pentagon's highest civilian honor, and a Distinguished Public Service Medal from the Department of Homeland Security.

Q. WHO IS SPONSORING YOUR TESTIMONY?

A. My testimony is sponsored by Exelon. My testimony reflects my informed opinion and does not necessarily reflect the perspectives and policies of the Department of Defense or any other government department or agency.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. In June 2016, I testified at the Commission's Reliability Technical Conference in Docket AD16-15-000.

Q. PLEASE DESCRIBE THE BASIS FOR YOUR FAMILIARITY WITH GRID RESLIANCE PLANNING EFFORTS.

A. In addition to my professional experience, I am the author of multiple works that examine the severe threats to energy sector resilience, and analyze measures that policymakers and stakeholders can take to reduce those risks. In 2016, I authored *Superstorm Sandy: Implications for Designing a Post-Cyber Attack Power Restoration System*, published by Johns Hopkins University Applied Physics Laboratory; *Electric Grid Protection Handbook*

II, Volume 1: Resilient Fuel Resources for Power Generation in Black Sky Events, published by the Electric Infrastructure Security Council; and co-authored the Homeland Security Advisory Council's *Final Report by the Cybersecurity Subcommittee: Incident Response.* I am also widely published on other issues of homeland security, national defense and infrastructure resilience, including *Resilience for Black Sky Days: Supplementing Reliability Metrics for Extraordinary and Hazardous Events*, prepared for the National Association of Regulatory Utility Commissioners.

II. PURPOSE OF TESTIMONY AND CONCLUSIONS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I examine how the increased reliance on natural gas for power generation is creating new risks to electric grid resilience, and analyze the implications for U.S. national security. I evaluate the adequacy of current measures to assess and mitigate these risks. I also propose measures to strengthen the resilience of the grid, and meet the challenges highlighted by the Department of Energy.

Q. COULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS?

A. I believe that this proceeding provides an opportunity to address the risks created by the growing dependence of the electric grid on natural gas as a fuel source. My testimony addresses three overall findings. *First*, the growing dependence of power generation on natural gas poses potential risks to U.S. national security. *Second*, current initiatives to identify and mitigate risks arising from gas-electric system interdependencies are not adequate. *Third*, before the Commission can decide on appropriate actions to help

strengthen fuel resilience, I believe that significant additional analysis will first be required to clarify the attributes of fuel resilience, develop metrics to assess them, and specify the threat against which fuel resilience should be measured. In particular, I recommend that a government agency (in consultation with appropriate Bulk Power System (BPS) entities) establish a Design Basis Threat (DBT) to help assess fuel resilience for power generation and that FERC gather additional data on the current status of resilience efforts. Finally, the Commission, in conjunction with other agencies, should implement measures that will ensure that resiliency is preserved.

Q. PLEASE SUMMARIZE YOUR FIRST FINDING. WHAT ARE THE POTENTIAL RISKS TO U.S. SECURITY POSED BY EMERGING THREATS TO ELECTRIC AND GAS SYSTEMS?

A. Russia, China, North Korea, and other potential adversaries may seek to disrupt U.S. defense capabilities by attacking the critical infrastructure on which our military bases rely. DOD's Mission Assurance Strategy emphasizes that "The Department of Defense's ability to ensure the performance of its Mission-Essential Functions (MEFs) is at growing risk. Potential adversaries are seeking asymmetric means to cripple our force projection, warfighting, and sustainment capabilities by targeting critical Defense and supporting civilian capabilities and assets – within the United States and abroad –on which our forces depend."[1]

[1] Department of Defense, *Mission Assurance Strategy*, April 2012, p. 1, http://policy.defense.gov/Portals/11/Documents/MA_Strategy_Final_7May12.pdf.

The power grid and fuel supplies for power generation are potential targets for these adversaries. While military installations and other national security facilities are strengthening their emergency power capabilities to serve their critical loads, long duration, wide area power outages could jeopardize their ability to execute their MEFs. We must assume that adversaries know this – and, accordingly, that in future conflicts they will attack the power grid and the flow of gas on which power generation increasingly relies.

Q. PLEASE SUMMARIZE YOUR SECOND FINDING. ARE CURRENT EFFORTS TO IDENTIFY AND MITIGATE RISKS STEMMING FROM INCREASED RELIANCE ON NATURAL GAS ADEQUATE TO ENSURE RESILIENCE?

A. No. Existing BPS reliability standards focus on protecting and maintaining the reliability of BPS systems and functions. These standards do not apply to the gas systems that are increasingly vital for power generation. Indeed, no mandatory standards exist for gas system reliability that are remotely equivalent to those that help strengthen the BPS against attack. Current efforts to provide dual-fuel capability for natural gas plants are not sufficient. While some planning efforts have begun, they do not go far enough.

Q. PLEASE SUMMARIZE YOUR THIRD FINDING. HOW CAN THE COMMISSION BEST ADVANCE GRID RESILIENCE?

A. As measures go forward to strengthen fuel resilience, and thereby bolster U.S. security, Commissioners should take a holistic approach that will involve collaboration with a range of government and private sector entities. Work should begin immediately to develop a detailed assessment of the risks being created by increasing gas-electric system

interdependencies. In my testimony that follows, I highlight a number of requirements for further analysis, including reporting requirements for RTOs to understand the current state of resiliency.

The Commission also should seek the creation of a DBT to help assess the resilience of fuel supplies for power generation and the potential value of measures taken to improve that resilience. Modelled on the approach of the Nuclear Regulatory Commission, a DBT should consider the type, composition, and nature of risks to resiliency including both catastrophic natural and manmade hazards.[2] That DBT should account for the risk –indeed, the likelihood – that if a major power decides to attack the U.S. energy sector, they will not merely strike a single pipeline, but seek to disrupt *all* major pipelines in a given region. Finally, implementation measures should be taken to ensure that the threat is appropriately mitigated and resiliency is preserved.

III. EMERGING RISKS TO RESILIENCY

Q. DID THE DEPARTMENT OF ENERGY FIND A RISK TO RESILIENCY FROM RELIANCE ON NATURAL GAS?

A. Yes. DOE's Notice of Proposed Rulemaking takes a crucial step forward to clarify these risks and highlight the value of measures to mitigate them. From 2002 until 2016, the share of electricity generated by gas-fired units increased from 18% to about 34% while the share

[2] *See* Nuclear Regulatory Commission Glossary, Design Basis Threat; https://www.nrc.gov/reading-rm/basic-ref/glossary/design-basis-threat-dbt.html (defining a design basis threat); 10 CFR § 73.1(a) (outlining particular threats).

generated by coal fell from about 50% to about 30%.[3] Risks of mutually-reinforcing failures between gas and electric systems have grown accordingly. DOE found that "the electric sector's growing reliance on natural gas raises concerns regarding the ability to maintain BPS reliability when facing constraints on the natural gas delivery systems."[4] Other key BPS stakeholders have reached similar conclusions. For example, Gerry Cauley, President and CEO of NERC, emphasizes that "[g]rowing reliance on natural gas continues to raise reliability concerns regarding the ability of both gas and electric infrastructures to maintain the BPS reliability at acceptable levels."[5]

Q. WHAT SPECIFIC RISKS DO YOU SEE?

A. In addition to the risks specified in the Notice, I would call the Commission's attention to three specific challenges: *First*, reliance on a single fuel creates the danger of "common-mode failures" where a lack of natural gas incapacitates multiple generators at the same time. *Second*, such failures could help create "black sky" power outages, which would entail outages lasting a month or more over multiple regions of the United States.[6] *Third*, rising gas-electric interdependencies create dangers of mutually-reinforcing failures.

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[3] United States Department of Energy, Staff Report to the Secretary on Electricity Markets and Reliability 90 (August 2017).

[4] North American Electric Reliability Corporation, *Short-Term Special Assessment: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation*, May 2016, p. 12.

[5] Gerry Cauley letter to Energy Secretary Rick Perry, May 9, 2017.

[6] Paul Stockton, *Resilience for Black Sky Days: Supplementing Reliability Metrics for Extraordinary and Hazardous Events*, at 3, National Association of Regulatory Utility Commissioners (2014).

Q. PLEASE DESCRIBE HOW RELIANCE ON A SINGLE FUEL CAN MAGNIFY RISKS OF COMMON-MODE FAILURES.

A. Increased dependence on a single type of fuel heightens the risks of common mode failures: that is, the danger that a single attack vector (especially via cyber means) could enable the adversary to disrupt fuel supplies for power generation across major portions of the United States. A significant interruption of the natural gas supply available for electric generation can dramatically reduce the supply of electricity available to serve load. For example, a large-scale disruption of a natural gas pipeline would prevent that pipeline from delivering natural gas to the generators it serves. It would also incapacitate any downstream pipeline dependent on it as a source of gas. Because gas is delivered close in time to its use as a fuel for electric generation, the system would have little time to respond to the loss of a pipeline. Preserving a diverse generation mix that relies on multiple sources of fuel is essential to reducing this risk.

Q. WHAT WOULD BE THE CONSEQUENCES OF A "BLACK SKY" OUTAGE?

A. A black sky power outage would inflict immense disruption on national security, the U. S. economy, and public health and safety.

Q. WHY WOULD THE HARM BE SO SEVERE?

A. Many critical infrastructure systems and facilities have backup power generators and stored on-site fuel to keep them operating for a few days in a limited power outage. However, in a black sky event, the extensive length and geographic scope of power outages would soon produce failures in emergency power assets and the infrastructure system that rely on them.

Blackouts of this severity would cause cascading failures across multiple critical infrastructure sectors. As highlighted in recent hurricane events, generators will quickly break down through overuse. Demand for replacing them in a wide-area outage will rapidly outstrip available supplies, given the vast number of facilities that will require such replacements. Moreover, on-site fuel supplies for emergency generators will quickly be depleted. Massive, multi-sector requirements for fuel resupply will emerge. Contractors responsible for sustain resupply operations will be unable to meet these requirements, especially since transportation systems, refinery operations, and other systems on which these contractors depend will also be disrupted in a black sky outage. Hospitals would exhaust their ability to rely on backup power. Food manufacturing and distribution networks would cease to function. Other critical infrastructure sectors would also likely collapse. For example, water, wastewater, and cellular systems rely on a functioning power grid and are not currently prepared for such an event. A black sky event would likely disable those systems for sustained periods of time leaving them unavailable to the public. Finally, national defense installations would begin to fail. Domestic military facilities can operate without power for short periods of time but most are not designed to be independent of the electric grid for extended periods of time. Electric power is necessary to keep them in operation because they require access to transportation fuel, communication networks, water and wastewater systems that need electricity to operate. The net result: black sky outages will have catastrophic effects on national security, the U.S. economy, and public safety. Adversaries seeking to achieve such effects will therefore be all the more tempted to build capabilities to create black sky events, and exploit the gas-electric interdependencies that could contribute to the severity of future blackouts..

Q. HOW COULD GAS-ELECTRIC INTERDEPENDENCIES CREATE MUTUALLY REINFORCING FAILURES?

As natural gas has become an increasingly important fuel for electric generation, natural gas pipelines have also come to rely on electricity to function. Key components of gas pipeline systems, including the compressors and industrial control systems that keep gas flowing to power generators and other users, are more reliant on electric power. Gas pipeline systems need compression pumps to sustain the flow of gas. Historically, these compressors were fueled with gas taken from the pipelines themselves. However, in many regions of the United States, these compressors are being replaced by variable speed electric-powered units to reduce onsite methane emissions and increase compressor efficiency. Black sky outages could interrupt the flow of electricity to these units, and (in a classic case of spiraling effects) magnify those outages by disrupting gas deliveries to power generators essential for power restoration.[7] Some compression stations do have emergency power generators and at least some on-site fuel to sustain operations in a blackout. However, as noted above, fuel resupply operations for these stations will be at risk of catastrophic disruption in long duration, wide area outages. These growing interdependencies create risks of cascading, mutually-reinforcing failures across both the electricity and oil and natural gas energy subsectors.[8] Because of the need for generators to receive natural gas

[7] Electric Infrastructure Protection (EPRO) Handbook II (Vol 1 – Fuel), July 18, 2016, at 24, http://www.eiscouncil.com/App_Data/Upload/149e7a61-5d8e-4af3-bdbf-68dce1b832b0.pdf.s

[8] Electric Infrastructure Protection (EPRO) Handbook II (Vol 1 – Fuel), July 18, 2016, at 21, http://www.eiscouncil.com/App_Data/Upload/149e7a61-5d8e-4af3-bdbf-68dce1b832b0.pdf.s

fuel and the need for electricity by natural gas pipelines to deliver that fuel, a significant interruption of the supply of natural gas can start a chain of events that result in interruption of electricity, which can cause the loss of power to gas compressors, which can cause further interruptions of generator fuel supply, cascading toward a broader system outage. The result: *gas and electric systems will be vulnerable to mutually-reinforcing failures when such outages begin.*

Q. WHAT TYPES OF HAZARDS COULD CAUSE THESE FAILURES?

A. Both natural and manmade hazards pose risks. While I describe a few such potential vulnerabilities below, the Commission, in coordination with other knowledgeable agencies, should consider as many other such threats as possible and similarly develop and implement measures to ensure they are understood.

Q. WHAT ARE THE NATURAL HAZARDS THAT COULD CREATE SUCH MUTUALLY REINFORCING GAS-ELECTRIC SYSTEM FAILURES?

A. Catastrophic earthquakes could inflict massive damage on gas and electric infrastructure, and foster mutually-reinforcing failures between them that produce black sky outages. For example, a catastrophic earthquake in the New Madrid Seismic Zone would pose significant risks to PJM. Similar seismically active regions pose risks elsewhere. Other catastrophic natural hazards could also create such risks. Moreover, once a naturally-induced blackout was underway, adversaries could also exploit the resulting disruptions in gas-electric system interdependencies, and exacerbate the interruption of natural gas flows for power generation.

Q. WHAT ARE THE MANMADE RISKS?

A. In recent months, potential adversaries have staged sophisticated, multi-phase intrusion campaigns against the energy sector to insert Advanced Persistent Threats into our energy systems.[9] These efforts are part of a long-term trend towards increased severity in the cyber threats confronting electric and gas systems –a trend that is certain to continue. Coordinated physical attacks on critical gas and electric system infrastructure components pose an additional threat. Such attacks could come from the type of kinetic threats seen in the 2013 attack on the Metcalf substation in California[10], but also from unmanned aerial vehicles carrying advanced payloads and other non-traditional attack vectors. Combined cyber-physical attacks could magnify such risks of disruption.

Q. IN ADDITION TO THE CHANGE IN THE GENERATION MIX, WHAT ADDITIONAL FACTORS HAVE HEIGHTENED THE RISKS?

A. Electricity plays an increasingly important role in the operation of all other infrastructure sectors. DOE notes that "[t]he reliability of the electric system underpins virtually every sector of the modern U.S. economy, which depends on electricity – including sectors from food production to banking to health care. Electricity is at the center of key infrastructure systems that support these activities –transportation, oil and gas production, water, finance,

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[9] U.S. Computer Emergency Readiness Team, "Advanced Persistent Threat Activity Targeting Energy and Other Critical Infrastructure Sectors, October 21, 2017, at https://www.us-cert.gov/ncas/alerts/TA17-293A

[10] Rebecca Smith, *Assault on California Power Station Raises Alarm on Potential for Terrorism,* Wall St. J., Feb. 5, 2014.

and information and communications technology. Electricity-dependent critical infrastructures represent the core underlying lifeline framework that supports the American economy and society."[11] This "electrification of everything" heightens the potential payoff to adversaries of attacking the grid and its fuel supplies, and reinforces the imperative to mitigate the risks of increased reliance on natural gas for power generation.

IV. CURRENT EFFORTS TO IDENTIFY AND MITIGATE RISKS TO RESILIENCY

Q. WHICH STAKEHOLDERS HAVE A ROLE TO PLAY IN PRESERVING THE RESILIENCY OF THE GRID?

A. By issuing the proposed rule, the Department of Energy has taken a critical step forward to facilitate progress on resilience. Other key stakeholders include the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation (NERC), the Regional Transmission Organizations and Independent System Operators overseen by FERC, and other BPS entities. Commissioners and other entities may also wish to consult with the Department of Homeland Security, the Department of Transportation, and the Department of Defense, and other federal and state agencies.

Q. HAVE THE RELEVANT STAKEHOLDERS ADQUATELY CONSIDERED THE RISKS TO RESILIENCY?

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[11] Department of Energy, *Quadrennial Energy Review – Transforming the Nation's Electricity System: Second Installment of the QER*, January 2017, p. 7-3.

A. Stakeholders are making progress, but significant gaps remain in assessing risks to resilience and developing mitigation options. In particular, stakeholders need to account for the growing severity of the threat and the implications for adversary exploitation of gas-electric interdependencies. To the best of my knowledge, for example, no RTO has performed a comprehensive analysis of whether the system can survive the disruption of multiple natural gas pipelines system for an extended period of time.

Q. FERC HAS APPROVED MANDATORY RELIABILITY STANDARDS FOR THE BULK ELECTRIC SYSTEM. DO THE RELIABILITY STANDARDS AIM TO ENSURE RESILIENCY?

A. No. As noted above, NERC reliability standards apply to electric infrastructure, not gas transmission lines and other fuel systems on which the grid depends. Moreover, these standards focus on reliability, not resilience. Studies conducted for the National Association of Regulatory Commissioners and other studies have highlighted significant ways in which resilience differs from reliability. These studies have also examined why traditional metrics for assessing reliability are inadequate for resilience.[12]

Q. DO EFFORTS TO PROVIDE DUAL-FUEL CAPABILITIES TO NATURAL GAS UNITS PROVIDE ADEQUATE RESILIENCE AGAINST THIS THREAT?

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[12] *Resilience for Black Sky Days: Supplementing Reliability Metrics for Extraordinary and Hazardous Events*, National Association of Regulatory Utility Commissioners, February 2014), available at http://www.sonecon.com/docs/studies/Resilience_for_Black_Sky_Days_Stockton_Sonecon_FINAL_ONLINE_Feb5.pdf; Sayanti Mukhopadhyay, Public Utility Commissions to Foster Resilience Investment in Power Grid Infrastructure, available at http://www.sciencedirect.com/science/article/pii/S1877042816300052

A. Not yet. Generators that are able to utilize a secondary source of fuel if natural gas supplies are interrupted can provide a critical bulwark against cross-sector failure. Given that value, some markets have developed financial incentives to encourage the construction and retention of dual-fuel generators. However, there are indications that existing incentives may not be adequate. Moreover, these generators typically have enough secondary feel stored on site to operate for very limited periods. After that, fuel resupply will be essential to sustain their operations if natural gas flows remain interrupted. However, the same factors that will disrupt the resupply of fuel for emergency power generators will apply to resupply of the secondary fuels typically employed for dual-fuel generators. Demand for such fuel in a long duration, wide area outage will be vastly greater than the capacity of contractors to conduct resupply operations. This is especially true since such operations would need to go forward in severely disrupted environments, especially in terms of refining and transportation system functionality.

Q. HOW IMPORTANT IS ON-SITE FUEL STORAGE FOR ENSURING GENERATION RESILIENCE, AND WHAT ARE THE APPROPRIATE STANDARDS FOR RESILIENCE PRICING ELIGIBILITY?

A. Nuclear power plants can operate for many months between refueling operations. Accordingly, they can make special contributions to grid resilience. The proposed Rule also makes the case that because coal generators typically have many weeks of fuel supplies stored on-site, they are also highly resilient. However, much more comprehensive and systematic analysis of such issues should go forward before final decisions are made on eligibility and market design changes. Moreover, as these criteria design options are

developed, it will be vital to avoid crafting them in ways that favor one source of generation over another for reasons irrelevant to grid resilience.

Q. WHAT CURRENT ANALYTIC INITIATIVES ARE UNDERWAY THAT COULD HELP ASSESS CURRENT FUEL RESILIENCE AND REQUIREMENTS FOR PROGRESS UNDER THE NOPR?

A. Valuable studies have already been conducted on the risks that interruptions in gas supplies pose to BPS reliability.[13] NERC is now conducting a much-needed special reliability assessment to determine impacts of a single point of disruption of natural gas facilities.[14] Along with other industry initiatives, PJM is conducting especially important studies of the potential risks created by increased reliance on natural gas, including in its *Natural Gas Contingency Scenario Analysis*.[15] I commend PJM for taking these critical steps forward. These and other industry studies analysis can provide a useful model for BPS entities

[13] See: North American Electric Reliability Corporation, *Short-Term Special Assessment: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation*, May 2016; Federal Energy Regulatory Commission, *Gas-Electric Coordination Quarterly Report to the Commission*, Docket No. AD12-12-000, December 18, 2014; Department of Energy, *Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector*, February 2015; American Electric Power, *Gas-Electric Harmonization: An AEP Perspective*, 2014; Midcontinent Independent System Operator, *Electric-Gas Coordination*, February 2015; and Eastern Interconnection Planning Collaborative, *Gas-Electric System Interface Study*, December 2014.

[14] *See* Agenda Item 3a, Special Assessment: Single Points of Disruption on Natural Gas Infrastructure, MRC Informational Session (April 13, 2017), *available at* http://www.nerc.com/gov/bot/MRC/Agenda%20Highlights%20nad%20Minutes%202013/MRC_Informational_Session_Conference_Call_and_Webinar_Agenda_April_13_2017.pdf.

[15] http://pjm.com/-/media/committees-groups/committees/teac/20170914/20170914-reliability-analysis-updates.ashx

nationwide to adapt to meet their own assessment requirements and fuel resilience challenges. However, as I discuss below, I believe other efforts are necessary.

V. ADVANCING GRID RESILIENCE

Q. WHAT ACTIONS SHOULD THE COMMISSION TAKE?

A. The Commission should obtain the analyses necessary to determine what actions to take next. For one, relevant information from the RTOs covered by the NOPR would help in this determination. Next, the Commission should collaborate with other agencies to conduct a DBT analysis.

Q. WHAT ADDITIONAL INFORMATION WOULD BE HELPFUL FROM THE RTOS?

A. PJM's analysis provides an extremely useful starting point, but it should be expanded. For example, analysis by RTOs should consider the loss of multiple pipelines simultaneously, as might occur in a coordinated physical or cyberattack. As noted above, any major power willing to take the risks of attacking a single U.S. pipeline may well decide to strike on a much more massive scale to disrupt U.S. defense capabilities, and seek to disrupt all flows of gas for power generation in a given RTO or ISO service area.

Useful additional information would include data from each generator on:

- For the primary fuel source:
    - Fuel source type.
    - On-site inventory reported as average days based on continuous full output.

- The nature of the fuel supply arrangement (e.g., firm gas, long-term coal contract, purchases of oil on the spot market, etc.).
- The primary method of fuel delivery (e.g., firm pipeline transportation, rail, barge, truck, etc.).
- Environmental permitting limitations.

- For the secondary or back-up fuel (if any):
  - Fuel source type.
  - On-site inventory reported as average days based on continuous full output. For oil and diesel this should include both the actual inventory and the maximum potential that can be stored on-site.
  - The nature of the fuel supply arrangement.
  - The primary method of fuel delivery.
  - Environmental permitting limitations.

The RTOs should also conduct a series of studies:

- A fuel reliance analysis detailing the impact on the organized market's ability to serve load if the supply of a particular fuel type is interrupted, or if the supply of a combination of fuel types is interrupted. The analysis should include:
  - How much load would not be served if a particular fuel type were unavailable for any reason.
  - How long primary inventories would last at generators' full output
  - How long secondary inventories would last at generators' full output
  - A generator's ability to resupply from existing secondary fuel inventories that are not on site.
  - The market's ability to increase production of remaining fuels, including diesel fuel, to meet increased need for the fuel in light of other demands for that fuel.

- A load impact analysis detailing the consequences if load is unable to be served for a prolonged period of time. This analysis should detail multiple disruption and time combinations (e.g., 50% of load for one week, 75% of load for two weeks, etc). The analysis should include:

- The financial impact to economy of the region.
- The impact to the security of the region (e.g., loss of other critical infrastructure and life sustaining services).

- A contingency analysis detailing the ability of the system to withstand (for both short- and long-term) electric and gas failures. This analysis should model both existing and future generation mixes. The analysis should include:
  - Single gas pipeline failure.
  - Multiple gas pipeline failures (including shared right of ways and crossings).
  - Coordinated attacks on the organized market's 3 of 4 biggest pipelines.
  - Loss of all pipelines controlled by single company whether as a result of a physical or cyber attack.
  - Coordinated gas pipeline/electric failures.
- The RTOs should also conduct an assessment of the adequacy of existing capacity constructs in light of the resiliency findings, and suggestions of what changes need to be made.

Q. DO THE RELIABILITY STANDARDS SUGGEST THAT THIS ANALYSIS IS APPROPRIATE?

A. NERC Reliability Standard TPL-001-4 directs transmission planners to assess the impact of extreme events, and if the analysis determines that such events cause cascading outages, the transmission planner should evaluate possible actions to reduce the likelihood or mitigate the consequences and adverse impacts to reliability.[16] I recommend that large-scale disruptions of gas supplies be included in such analysis. I also propose that planners

[16] *See* Requirements R 3.2 and R 3.5 of Standard TPL-001-4 – Transmission System Planning Requirements.

include contingency analysis of severe disruptions in secondary fuel resupply for dual fuel generators, and disruption of fuel resupply for backup power generators that serve critical natural gas compression stations and other key gathering and transmission infrastructure. Finally, planners should conduct sensitivity analysis on the degree to which retaining a mix of fuel-resilient generation assets, including nuclear assets, can help reinforce the resilience of the BPS as a whole.

Q. HOW COULD A DESIGN BASIS THREAT ASSIST THE COMMISSION?

A. At present, BPS entities lack a government-approved assessment of the threat against which they should measure the resilience of their fuel supplies. The Nuclear Regulatory Commission provides its licensees with a DBT to help design safeguard systems for the U.S. nuclear fleet. Fuel resilience issues pose a very different range of challenges. A DBT would help the Commission support analysis and mitigation of risks to fuel resilience. That effort should be led by a U.S. agency with access to appropriate threat information. The development of a DBT should also go forward in full consultation with the electric power industry, NERC, the E-ISAC, and other key sources of expertise. The design of the DBT should also leverage "best practices" developed by the NRC, and draw lessons learned from the NRC's past efforts that can help accelerate and improve the creation of a DBT for resilience.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)	RM18-1-000

DECLARATION OF DR. PAUL STOCKTON

I, Paul Stockton, declare under penalty of perjury that the foregoing Prepared Direct Testimony of Dr. Paul Stockton on Behalf of Exelon Corporation is true and correct.

Executed: October 23, 2017

Paul Stockton

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)	Docket No. RM18-1-000

REPLY COMMENTS OF EXELON CORPORATION[1]

The Commission should follow a three-step approach to address the generation resilience concern identified by the Secretary of Energy. *First*, the Commission should take immediate action to ensure that unjust and unreasonable market rules do not send inaccurate price signals to fuel-secure resources that are critical to any long-term solution to system resilience. This includes (a) directing PJM to complete energy market reforms within 90 days and (b) declaring that units receiving Zero Emissions Credits or other support payments, which preserve existing nuclear units in economic distress, will not have their capacity market bids mitigated. These actions will not fully solve the problem of resilience, but will help alleviate the immediate economic challenges to nuclear units and other fuel-secure resources.

There is widespread support among commenters for the prioritization of energy price formation issues.[2] Moreover, there is already a record that would allow the Commission to

[1] In addition to these comments, Exelon has prepared answers to certain of the questions placed in the docket by FERC Staff. These answers are attached to the conclusion of these reply comments.

[2] *See, e.g.*, United States Department of Energy, Staff Report to the Secretary on Electricity Markets and Reliability 107-117 (August 2017), *available at* https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf ("DOE Staff Report"); Comments of Edison Electric Institute, Docket No. RM18-1 (Oct. 23, 2017) ("EEI Comments") at 4-6; Initial Comments of the Electric Power Supply Association, Docket No. RM18-1 (Oct. 23, 2017) at 51-53; Initial Comments of PJM Interconnection, L.L.C. on the United States Department of Energy Proposed Rule, Docket No. RM18-1 (Oct. 23, 2017) ("PJM Comments") at 39-49; Letter of Professor Willian W. Hogan

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determine under Section 206 that the current market rules are not just and reasonable in PJM.[3] The Commission should so find and direct PJM to adopt a solution within 90 days. PJM's energy markets are based on the economic principle that the marginal cost of the unit of supply needed to satisfy demand should set the price. Yet the current market rules violate this basic economic principle because units like coal and nuclear are not necessarily permitted to set the locational marginal price, even when they are needed to serve load. The rules thus are not just and reasonable and must be revised.[4]

Second, the Commission should create a process for gathering and assessing data from RTOs that will shed light on the system's vulnerabilities and potential impacts resulting from those vulnerabilities. No commenter disputes, in particular, the system's increasing vulnerability to gas pipeline interruptions, as nuclear and coal resources retire and are largely replaced by gas resources. And no one disputes the extreme toll to our society that would result from a prolonged and widespread outage resulting from a high impact, low frequency ("HILF") event, such as an interruption to multiple gas pipelines. Accordingly, the problem warrants further study. In its opening comments, Exelon provided a detailed list of the information that should be requested and proposed time frames for RTO responses.

Third, the Commission should use that data, together with threat analysis from the national security and intelligence communities, to establish a design basis threat ("DBT") that can inform

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to Mr. Stu Bresler, Attachment B to PJM Comments at 2-3; Comments of NRG Energy, Inc., Docket No. RM18-1 (Oct. 23, 2017) at 10-11.

[3] PJM Comments at 48.

[4] Further, given that PJM has so plainly acknowledged price formation as a problem in PJM, a point with which many commenters and economists agree, the Commission would be justified in ordering PJM to develop and implement price formation improvements as set forth in PJM's Comments.

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cost-effective market reforms. Stakeholders largely agree that resilience is a concept distinct from reliability or resource adequacy. Resilience refers to the system's ability to prepare for, operate through, and recover from HILF events.[5] But as many stakeholders point out, the Commission lacks metrics to evaluate resilience.[6] A DBT will provide a benchmark against which resilience can be measured, and a basis for developing specific solutions for the RTOs to implement. Once that work is complete, Exelon supports PJM's proposal for the Commission to direct each RTO to submit specific reforms to address any resilience-related issues identified in an RTO, with a "deadline that is in the near term."[7] Exelon proposes a deadline of 90 days from the time the Commission establishes a design basis threat.

Each of these steps is moderate in scope and can be accomplished quickly. And the Commission should pursue them expeditiously. Our system's vulnerability is real and the threats grave, and the potential consequences of inaction are unimaginable. Hostile actors are constantly

[5] PJM Comments at 18-19. HILF events are frequently referred to as Black Swan events because the probability of the event occurring is difficult to determine. Unlike traditional reliability events based upon weather or forced outage rates which can be probabilistically determined based upon historical data, a HILF event (for example, a cyber-attack by a nation-state or other malicious actor) may not be forecastable. For this reason, HILF events not only encompass incidents that are expected to occur infrequently, but also events that cannot be forecasted because of significant unknowns. Resilience also differs from reliability in having to account for the underlying nature of man-made threats, which differ from hurricanes and other familiar natural hazards. Unlike hurricanes, adversaries are intelligent and adaptable. Adversaries will also be able to selectively target points of special vulnerability in energy systems, including those related to fuel resilience and gas-electric system interdependencies. Initiatives to define the attributes of resilience and assess measures to strengthen them will need to incorporate these non-traditional risk factors.

[6] Comments of PJM at 20; Initial Comments of AES on the United States Department of Energy Proposed Rule, Docket No. RM18-1 (Oct. 23, 2017) at 13; Initial Comments of the Energy Storage Association on the United States Department of Energy Proposed Rule, Docket No. RM18-1 (Oct. 23, 2017) at 10; Initial Comments of Large Public Power Council on the United States Department of Energy Proposed Rule, Docket No. RM18-1 (Oct. 23, 2017) at 3; Initial Comments of Environmental Defense Fund on the United States Department of Energy Proposed Rule, Docket No. RM18-1 (Oct. 23, 2017) at 40-41.

[7] Comments of PJM at 48.

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probing for weaknesses in our electric grid. A single successful attack that leaves large swaths of the United States without power for an extended period would destroy our Nation's ability to ensure law and order, leave tens of millions of Americans without access to safe drinking water, food, or medical care, devastate our military capabilities, and result in an untold number of deaths.

Together, these steps are essential to achieving a resilient grid at the least cost for consumers. The first step strengthens markets by ensuring that they operate efficiently and consistent with basic economic principles, and that fuel-secure resources are not disadvantaged by flawed market rules. The second two steps do not prejudge what type of solution might be necessary or most cost-effective. Instead, they are focused on understanding the nature of the problem we face and developing a design standard around which solutions can be framed. Once the Commission has sufficient information before it to identify the vulnerabilities that must be addressed, it should consider a range of potential solutions for the design basis threat that can achieve resilience at least cost to customers. RTOs may be able to propose appropriate market-based solutions to accomplish those goals—and they should be encouraged to do so. But in the event that market-based solutions are unworkable or too costly, the Commission should not foreclose the possibility of other solutions. If a market-based solution is unavailable, the stakes are too high to reject a cost-based alternative simply on account of loyalty to a pro-market ideology.[8]

[8] *See, e.g.*, *ISO-New England Inc.,* 144 FERC ¶ 61,204, PP 9-11 (2013) (order conditionally accepting ISO-NE's out of market Winter Reliability Program oil procurement).

I. Grid Resilience is an Urgent Problem in the Eastern RTOs That Prior Reforms Have Not Addressed.

A. The Resource Mix in the Eastern RTOs Is Changing as Fuel-Secure Resources Retire, Creating New Vulnerabilities.

The resource mix in the eastern RTOs is changing rapidly, as many gigawatts of nuclear and coal capacity retire and are replaced largely by gas generation. In the PJM region, 90 percent of the new installed generation over the last five years has been gas-fueled, as is more than 90 percent of planned generation in the interconnection queue.[9] As gas generators enter, resilient baseload units leave.[10] Exelon noted in its initial comments that the loss of nuclear generation in particular has been dramatic. Between 2002 and 2016, 4,666 MW of nuclear generating capacity announced retirement, approximately 4.7 percent of the U.S. total.[11] Another eight nuclear reactors with 7,167 MW of capacity have announced retirement plans since 2016.[12]

The growing prevalence of gas generators, many of which are dependent upon a small number of pipelines for fuel, creates new risks to the system. As Dr. Stockton explains in his attached Supplemental Testimony (attached as Exhibit A), the emerging resource mix in the Eastern RTOs is increasingly susceptible to "common mode failure," in which a large fraction of

[9] For the PJM RPM auctions from 2015/16 through 2020/21, 90% of new cleared installed capacity has been either natural gas-fired combustion turbines or combined-cycle generators (approximately 32.4 out of 36.2 total GW of new build, reactivated, or uprated capacity). *See* PJM Interconnection L.L.C., *2020/21 RPM Base Residual Auction Results*, Table 8, http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx?la=en.

[10] Comments of FirstEnergy Service Company *et al.* in Support of the Grid Reliability and Resilience Pricing Notice of Proposed Rulemaking, Docket No. RM18-1 (Oct. 23, 2017) ("FirstEnergy Comments") at 24-28 (listing recent retirements of baseload units); Comments of ClearPath Foundation, Docket No. RM18-1 (Oct. 23, 2017) at 9.

[11] DOE Staff Report at 29.

[12] *Id*. at 30.

generation resources are susceptible to the same vulnerability.[13] In PJM, 11,000 MW of gas generation is dependent upon a single pipeline.[14] Thus, a single disruptive event—whether it is a physical attack by terrorists, a cyber-attack by a foreign government, or an adverse weather event—can undermine a significant share of the generating capacity serving the Nation's most populous region. Moreover, because pipelines are increasingly dependent upon electricity to function properly, a widespread outage could result in further fuel supply disruptions, leading to an even more widespread outage. Coordinated attacks on multiple pipelines would have far more severe consequences.

No steps have been taken to address the grid's increasing vulnerability due to the growing interdependence of gas supply and electric generation. The Secretary of Energy identified these risks in the NOPR that initiated this proceeding.[15] Other experts concur. According to NERC, "[n]atural gas-fired generation faces greater susceptibility to fuel supply chain disruption than coal and nuclear generation."[16] A disruption of the pipeline network could dramatically reduce the quantity of natural gas available for generators. Using a power-flow simulation, NERC found that "that 18 out of 19 areas studied experience transmission or operational challenges during an extreme event" involving disruption to natural gas supply facilities.[17] ISO-NE likewise

[13] Supplemental Testimony of Paul Stockton, attached as Exhibit A, at 12 ("Stockton Supplemental Testimony").

[14] PJM Reliability Analysis Update (Sept. 14, 2017), *available at* http://pjm.com/-/media/committees-groups/committees/teac/20170914/20170914-reliability-analysis-updates.ashx, pp. 8-11.

[15] Dep't of Energy, Grid Resiliency Pricing Rule, 82 Fed. Reg. 46,940, 46,941 (2017) ("DOE NOPR").

[16] NERC Comments at 9.

[17] NERC November 9, 2017 Board of Trustees Agenda, Item 8c, available at http://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_Meeting_November_9_2017_Agenda_Package.pdf.

highlighted this concern at the October 2017 Commission open meeting when it presented its Winter 2017-2018 Operations and Market Performance update. It noted that "*the ability to meet energy needs is at risk if gas cannot be supplied to gas-fired generators.*"[18] ISO-NE repeated these concerns in comments in this docket.[19] PJM, meanwhile, is studying the effects of a single gas pipeline outage, but that is not enough: PJM should also consider the effects of multiple pipeline failures occurring simultaneously.[20]

Currently, generation developers and owners have no economic incentive to consider the systemic consequences of their investment decisions.[21] RTOs have not attempted to place an economic value on a resource's contribution to system resiliency.[22] Moreover, PJM's market

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[18] Presentation of ISO-NE, October 19, 2017, available at https://www.ferc.gov/CalendarFiles/20171019125657-6-ISONE.pdf.

[19] Comments of ISO-NE Inc., Docket No. RM18-1 (Oct. 23, 2017) at 8-9 ("ISO-NE is concerned about the region's gas dependence").

[20] *See generally* NERC 2016 Long-Term Reliability Assessment, at p. 21 (Dec. 2016) ("As part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electric reliability."); NERC, *Severe Impact Resilience: Considerations and Recommendations*, May 2012, p. 1; NERC and the Department of Energy, *High-Impact, Low-Frequency Event Risk to the North American Bulk Power System*, June 2010.

[21] As Chairman Chatterjee noted as his press conference on October 13, 2017, "Accurately valuing resilience is not a zero-sum game. Compensating base-load generation does not equate to destruction of markets. On the contrary, I think it's a step toward accurately pricing contributions of all market participants."

[22] Comments of Kinder Morgan, Inc. on the Rule Proposed by the Secretary of the Department of Energy, Docket No. RM18-1 (Oct. 23, 2017) at 6-7; Comments of the National Rural Electric Cooperative Association, Docket No. RM18-1 (Oct. 23, 2017) at 3; Comments of the PSEG Companies, Docket No. RM18-1 (Oct. 23, 2017) at 5-7; FirstEnergy Comments at 22-30; Comments of Invenergy Renewables LLC and Invenergy Thermal Development LLC, Docket No. RM18-1 (Oct. 23, 2017), at 5; Comments of Algonquin Gas Transmission, LLC, Docket No. RM18-1 (Oct. 23, 2017) at 4-6; Comments of the National Rural Electric Cooperative Association, Docket No. RM18-1 (Oct. 23, 2017) at 13-14; Rulemaking Comments of the Nuclear Energy Institute, Docket No. RM18-1 (Oct. 23, 2017) ("NEI Comments") at 13-17; Initial Comments of Talen Energy Corporation, Docket No. RM18-1 (Oct. 23, 2017) at 5-11; Motion to Intervene and Comments of Peabody Energy Corporation, Docket No. RM18-1 (Oct. 23, 2017) at 3-8;

design has aggravated the problem, by systematically undercompensating fuel-secure, baseload resources in the energy markets. As a result, private investment decisions are not aligned with the public interest in homeland security. The Commission cannot afford to ignore this issue, which could have devastating consequences for our society, as described above and in Dr. Stockton's testimony.

B. The Commission Should Reject Commenters' Arguments for Inaction.

Commenters opposed to action advance four basic arguments. *First*, some claim there is no reason to be concerned about resiliency—either because the threats are unproven, or because the Commission has already taken steps, such as the Capacity Performance ("CP") reforms in PJM, to enhance reliability, making further steps unnecessary. *Second*, some contend that the Commission should ignore generation-related vulnerabilities because there are also transmission- and distribution-related vulnerabilities that need to be addressed. *Third*, some commenters argue that the costs of implementing the DOE proposal will be very high.[23] *Fourth*, the PJM Independent Market Monitor ("PJM IMM"), using cherry-picked and misleadingly presented data, asserts that the potential changes to the resource mix are overstated, because nuclear generators by and large recover their costs from the markets. Each of these arguments should be rejected.

Comments of Murray Energy Corporation in Support of Proposed Rule, Docket No. RM18-1 (Oct. 23, 2017) at 2-7.

[23] *See, e.g.*, Comments of Rockland Capital, LLC, *et al.*, Docket No. RM18-1 (Oct. 23, 2017) at 12-13; Comments of the PJM Independent Market Monitor, Docket No. RM18-1 (Oct. 23, 2017) ("PJM IMM Comments") at 4-8; Evaluation of the DOE's Proposed Grid Resiliency Pricing Rule, Attachment A to Joint Industry Comments Opposing the DOE Proposal, Docket No. RM18-1 (Oct. 23, 2017) at 24-25.

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1. Resiliency Threats Are Real, and Neither the Capacity Performance Reforms Nor High Reserve Margins Address Resiliency.

Some commenters oppose the DOE's proposal on the ground that there is no genuine threat to resiliency. The Commission should reject this view. Those with expertise concur that resiliency must be made a priority. NERC, the entity whose statutory mandate is to "conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America,"[24] has emphasized the resilient and reliable generation furnished by coal and nuclear units, and the threat to the stability of the bulk power system resulting from those units' retirements. Specifically, NERC explained that "[b]urgeoning reliance on natural gas-fired generation as a replacement for coal and nuclear generation decreases fuel diversity and increases single source fuel dependency."[25] Thus, "[t]he electric sector's growing reliance on natural gas raises concerns regarding the ability to maintain BPS reliability when facing constraints on the natural gas delivery systems."[26] Not only are gas-fueled resources susceptible to supply interruptions that can affect numerous generators simultaneously, but the nuclear and coal generators that are being replaced "provide substantial essential reliability services as a function of large spinning generators and governor control settings, along with reactive support for voltage control."[27]

Dr. Paul Stockton's testimony, submitted with Exelon's initial comments, confirms NERC's observations.[28] Dr. Stockton is one of the country's leading experts on grid resiliency

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[24] 16 U.S.C. §§ 824o(g).

[25] *See* NERC Comments at 10.

[26] *Id.* at 11 (quoting NERC*, Short-Term Special Assessment: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation*, at pp. 10-11 (May 2016), *available at* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC% at 12).

[27] *See* NERC Comments at 8.

[28] Ex. A to Comments of Exelon ("Stockton Initial Testimony").

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and national security. From June 2009 until January 2013, he was the Assistant Secretary of Defense for Homeland Defense and Americas' Security Affairs. He was responsible for Defense Critical Infrastructure Protection and led the creation of the Department's Mission Assurance Strategy. He served as the Domestic Crisis Manager for the Department of Defense (DOD) and was responsible for Defense continuity of operations. He also was the principal civilian advisor to the Secretary of Defense for providing Defense support to Federal Emergency Management Agency, the Department of Energy (DOE) and other Federal departments in Superstorm Sandy, Hurricane Irene, and other disasters.[29]

Dr. Stockton outlined the existing risk to national security from overreliance on natural gas. He concluded that "[r]isks of mutually-reinforcing failures between gas and electric systems have grown."[30] These risks create the possibility of a "black sky" power outage which "would inflict immense disruption on national security, the U. S. economy, and public health and safety."[31] He recommends that the Commission take immediate efforts to study the problem and develop a design basis threat to help evaluate the risk.[32]

Other industry commenters also concur. PSEG, for example, supports the DOE's efforts "to immediately address the erosion of resiliency of our electric grid due to the risk of premature retirements of baseload generation."[33] This trend, particularly in PJM, is resulting in a resource mix placing "greater reliance on natural gas-fired generating resources and exposing the power

[29] *Id.* at 2.

[30] *Id.* at 8.

[31] *Id.* at 9.

[32] *Id.* at 18-19.

[33] PSEG Comments at 2.

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supply portfolio to a greater risk of single mode failure."[34] As PSEG notes, maintaining a resilient and diverse electric grid has important consequences for both human health and national security.[35] AEMA encourages the Commission to "[o]pen a proceeding on resilience with the objectives of defining the needs of resilience on a regional basis and how those needs have evolved."[36] ISO-NE's recently-released 2017 Regional System Plan makes much the same point, noting that "[p]reserving the reliable operation of the system will become increasingly challenging with potential retirements, the increased reliance on natural gas resources" [37]—which are estimated to rise from 44.5% of New England's 2017 summer fuel mix to 56% in 2026.[38] Thus, the Commission should take seriously the need to ensure our electric grid is resilient to the various threats—both human and natural—that could have devastating consequences.

Several commenters contend that the Commission has already taken sufficient action by approving the Capacity Performance product in PJM and the pay-for-performance reforms to the ISO-New England capacity market.[39] Other commenters contend that the Eastern RTOs have large reserve margins, and suggest that these reserve margins resolve any concern about resilience.[40]

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[34] *Id.* at 7. *See also, e.g.,*, FirstEnergy Comments at 18-22; NEI Comments at 13-17; DOE Staff Report at 92-94.

[35] PSEG Comments at 2, 11-12.

[36] Reply Comments of Advanced Energy Management Alliance, Docket No. RM18-1 (Nov. 7, 2017) at 3.

[37] ISO-New England, *2017 Regional System Plan* at 65.

[38] *Id.* at 8.

[39] *See Comments* of LS Power Development on Notice of Proposed Rulemaking, Docket No. RM18-1 (Oct. 23, 2017), at 8-9, 11; Comments of Joint Consumer Advocates of the PJM Region, Docket No. RM18-1 (Oct. 23, 2017) ("PJM Joint Consumer Advocates Comments") at 13-18; PJM IMM Comments at 26-27; PA PUC at 15-19.

[40] *See* Comments of the Advanced, Renewable and Storage Energy Industry Associations at 12-13; Comments of the Midcontinent System Operator, Inc. at 12-13; Comments of the Pennsylvania Public Utilities Commission, Docket No. RM18-1 (Oct. 23, 2017) at 14; Joint Industry Comments

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The Commission should reject these contentions, which erroneously conflate the concept of reliability with the concept of resilience. Existing capacity markets are targeted toward ensuring resource adequacy—in other words, that sufficient generation resources are available on the system to serve peak load in a wide range of operating conditions. The CP reforms were adopted to address a specific problem: although units had committed to provide capacity, they had not made the investments necessary to ensure that they were actually capable of operating during extreme and adverse weather conditions. The Commission adopted penalties for non-performance which were intended to incentivize the investments necessary to ensure unit performance.[41] This is certainly important, and, separate from its consideration of resilience, the Commission and PJM should evaluate whether the current penalty rate is high enough to provide the desired incentive.[42] Indeed, the first auction procuring only Capacity Performance resources has already been held, but clearing prices are too low to reflect investment by gas facilities in dual-fuel capability.

In all events, however, the CP and pay-for-performance reforms did not address the system-wide vulnerability to HILF events that results from the increasing interdependence of the gas and electric systems, which is aggravated by the retirement of fuel-secure resources like nuclear that do not rely on the gas supply system. To put it another way: the CP reforms focused on unit-level investments to improve unit-level performance, but did not address the system's increasing exposure to a common mode failure (such as an attack on the gas pipeline system) that would cause an entire class of generation of resources to fail simultaneously. Resiliency, in contrast to reliability, concerns this type of systemic threat. Making a system resilient to such threats ensures

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Opposing the DOE Proposal, Docket No. RM18-1 (Oct. 23, 2017) at 7; PJM Joint Consumer Advocates Comments at 4-5.

[41] *PJM Interconnection, L.L.C*, 151 FERC ¶ 61,208, at P 158 (2015).

[42] Exelon Comments at 31.

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that the system is capable of "operating through, and recovering from a high-impact, low-frequency event" to the system as a whole.[43] Thus, as PJM recognizes, "a heavy reliance on one resource type … *could* raise questions about system resilience."[44]

For similar reasons, the Commission should find no comfort in the Eastern RTOs' large reserve margins. Of course, large reserve margins help support resource adequacy and help keep prices low for consumers. But the question is whether the reserves on the system are the right kind of resources to help sustain the grid in the event of a HILF event. Simply pointing to a large reserve margin fails to engage with that crucial question. The Commission has previously recognized as much. When approving ISO-NE's first winter reliability program, the Commission underscored the distinction between (on the one hand) resource adequacy and (on the other hand) resiliency against system-wide threats. The Commission explained: "[R]esource adequacy would be unlikely to reflect the unpredictability of fuel shortages and the likelihood that outage result from fuel shortages will simultaneously affect multiple resources."[45] Indeed, in markets where natural gas-based generators increasingly dominate, large reserve margins can provide a false sense of security, since the system's overdependence on just a few pipelines could make the system particularly vulnerable in the case of an attack.

Equally off the mark is the Rhodium Group's analysis, cited by various commenters.[46] According to the Rhodium Group, "[b]etween 2012 and 2016, there were roughly 3.4 billion customer-hours impacted by major electricity disruptions. Of that, 2,382 hours, or 0.00007% of

[43] PJM Comments at 18-19.

[44] *Id.* at 19.

[45] *ISO New England Inc.*, 147 FERC ¶ 61,026, at P 17 (2014).

[46] *See* Houser, Larsen, and Marsters, The Real Electricity Reliability Crisis (Oct. 3, 2017) available at http://rhg.com/notes/the-real-electricity-reliability-crisis.

the total, was due to fuel supply problems."[47] But that analysis, even if true, fails to appreciate the point of this proceeding. Experts are telling the Commission that there is a risk of a fuel supply disruption that could have disastrous consequences for our society. As Dr. Stockton describes in his comments, a HILF event that causes a cascading failure of the gas and electric infrastructure for a significant portion of the Nation's power grid for a prolonged period would have horrific consequences. Clean water would be unavailable and sewage systems would fail for weeks or months causing widespread risk of disease and ultimately jeopardize human lives. Food distribution would be sharply curtailed or stop entirely. Communication and transportation networks would collapse. Hospitals, nursing homes, and other medical facilities would lose their backup power and be unable to provide services to vulnerable members of the public.[48] Defense installations would gradually lose their ability to carry out their essential military function, making the nation significantly more vulnerable to attack from nation-state adversaries and terrorists and risking a collapse of law and order. It would be irresponsible to wait until after a HILF event has occurred to begin preparing for one. We have not experienced outages caused by massive cyber or physical attacks on the transmission and distribution system, either, but we still plan for them.[49]

Simply put, the Rhodium Group does not address the bulk power system's ability to withstand such an event. It does not even attempt to analyze, for example, what the consequences would be if the *single* gas pipeline serving more than 11,000 MW of generation in PJM were disrupted, let alone if multiple gas pipelines were disrupted. Nor does it assess the degree to which

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[47] *Id.*

[48] Stockton Initial Testimony at 9-10; Comments of Center for Security Policy, Docket No. RM18-1 (Oct. 23, 2017) at 1-2.

[49] *See, e.g.*, *Physical Security Reliability Standard*, 149 FERC ¶ 61,140, at P 18 (2014); *Revised Critical Infrastructure Protection Reliability Standards*, 154 FERC ¶ 61,037 (2106).

our vulnerability to such attacks would increase as the resource mix continues to move away from fuel-secure resources. Those who cite the Rhodium Group's elementary analysis as a reason for inaction would have the Commission wait for a catastrophe to happen before assessing whether something could have been done to address it.

2. The Fact That the Distribution and Transmission Systems Also Need Hardening Is No Reason for Inaction.

Some commenters argue that the Commission should ignore generation-related vulnerabilities because there are also transmission- and distribution-related vulnerabilities that need to be addressed. The fact that there are multiple vulnerabilities is no reason for inaction. The Commission does not need to choose between potential risks. It can and should address all system-level vulnerabilities that are capable of being addressed.

Indeed, it has already taken many steps to make the transmission system more resilient. For example, it directed NERC to address supply chain risks to certain cyber assets; it directed NERC to develop physical security standards in the wake of the April 2013 attack on the Metcalf Transmission Substation; and it directed NERC to develop standards governing planning and operations with respect to a 1-in-a-100-year solar storm. Stakeholders have also invested in making transmission and distribution systems more resilient. Utilities have increased acquisition of critical spare equipment.[50] Under the auspices of the Edison Electric Institute ("EEI"), utilities have instituted a Spare Transformer Equipment Program, and the industry is developing additional

[50] U.S. Department of Energy, Strategic Transformer Reserve Report to Congress at 6 (Mar. 2017) ("utilities report they are purchasing additional spares").

equipment sharing programs, including Grid Assurance[51] and RESTORE.[52] Utilities have also hardened transmission systems against adverse weather events and flooding, and they are investing in microgrids. NERC and stakeholders also conduct large-scale exercises and simulations to practice their response to various HILF-type events. [53]

All of these developments are valuable and should not only be encouraged, but also expanded. The Commission, RTOs, NERC, states, and industry more broadly should continue to assess the resiliency of the Nation's transmission and distribution system and make further policy changes as appropriate.

In tandem with those efforts, the Commission should *also* assess the resiliency of the generation fleet. In contrast with the transmission and distribution systems, where already much work has been done analyzing vulnerabilities and taking steps to address them, nothing has yet been done with respect to the risk to the generation fleet posed by HILF events.

The Commission is also uniquely positioned to address vulnerabilities arising from the generation fleet in the Eastern RTOs, in which states generally engage in little integrated resource planning and in which generation resources largely sell at wholesale. The Commission has all the authority it needs to ensure that generation owners and developers have the economic incentives to account for the impact of their investment decisions on system resiliency. In contrast, efforts to

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[51] *See* Grid Assurance, available at http://www.gridassurance.com/equipment-subscribers/.

[52] Utility Dive, *28 Utilities Join RESTORE Program to Boost Grid Resilience, Reliability* (Oct, 4, 2017), *available at*: https://www.utilitydive.com/news/28-utilities-join-restore-program-to-boost-grid-resilience-reliability/506400/.

[53] For example, NERC will be conducting GridEx IV, its biennial exercise, November 16-17, 2017. GridEx IV will allow utilities to demonstrate how they would respond to and recover from a simulated coordinated cyber and physical attack. *See* http://www.nerc.com/pa/CI/CIPOutreach/Documents/TLP_WHITE_GridEx%20IV%20Fact%20Sheet_20161202.docx.

enhance the resiliency of the transmission system and gas pipeline network by siting new transmission lines and pipelines, and to enhance the resiliency of local distribution networks, all require the involvement of other regulatory authorities.

3. Discussion of Costs and Benefits Is Premature.

Several commenters emphasize the costs of DOE's comprehensive cost-of-service proposal to ensure resilience. But their studies are silent on the potential benefits of addressing resilience, and policymakers must always consider costs and benefits together. In any event, it is premature to discuss costs and benefits. Exelon does not advocate immediately providing cost-of-service contracts to every coal and nuclear plant in the eastern RTOs. The Commission must first understand the scope and urgency of the Nation's vulnerabilities. Once the Commission has that data, it can establish a design basis threat and identify cost-effective solutions tailored to address it.

4. The Commission Cannot Afford to Delay Taking Action.

According to the PJM IMM, urgent Commission action to address the resiliency of the generation fleet is not necessary because nuclear plants are not actually under any economic distress and are not in danger of retirement. [54] The PJM IMM's analysis is deeply flawed. As discussed below and in the attached testimony from Michael Schnitzer (attached as Exhibit B), as few as 6% of nuclear units in PJM fully recover their avoidable costs.[55] Unless market conditions change, or these units are compensated for the resiliency they provide to the system, many nuclear units currently in operation are likely to retire in the coming years.

In contending otherwise, the PJM IMM attempts to compare the market revenues of these units—revenues earned from the markets for energy, ancillary services and capacity—to their

[54] PJM IMM Comments at 18, 20.

[55] Testimony of Michael Schnitzer, attached as Exhibit B, at 5 ("Schnitzer Testimony").

avoidable costs. He claims that these revenues are sufficient to cover costs and these units are actually profitable.[56] The PJM IMM's analysis is premised on a dramatic understatement of the costs nuclear units face, and, as a result, draws entirely the wrong conclusions. Mr. Schnitzer has corrected the improper omission of these costs, and the data demonstrate that most nuclear generators throughout PJM do not currently earn market revenues sufficient to cover their costs.[57] As a result, these units are at risk of retirement absent improvements to the market or other measures and the electric grid is at risk of losing the resiliency benefits these units provide.

There are two key flaws in the PJM IMM's analysis of costs. *First*, the PJM IMM excludes the on-going capital expenditures that nuclear units incur annually. This error is inexplicable. Nuclear units are complicated machines that are pervasively regulated. Every year, owners must invest significant amounts of capital to keep nuclear units operational and comply with their regulatory obligations. The PJM IMM's own sources clearly show these costs. He draws cost data from a recent report of the Nuclear Energy Institute ("NEI") outlining the average costs of nuclear units.[58] The NEI data clearly shows that these units have significant ongoing capital expenditures.[59] Obviously, these ongoing capital expenditures can be avoided by retiring a unit.

Indeed, the PJM IMM himself treats ongoing to-go nuclear capital expenditures as an avoidable cost when reviewing Avoidable Cost Rate calculations for nuclear units. And for good

[56] PJM IMM Comments at 18-20.

[57] Schnitzer Testimony at 5-11.

[58] Nuclear Energy Institute, *Nuclear Costs in Context*, August 2017, at 2-3, *available at* https://www.nei.org/CorporateSite/media/filefolder/Policy/Papers/Nuclear-Costs-in-Context.pdf?ext=.pdf

[59] *Id.*; Schnitzer Testimony at 6.

reason: the PJM tariff includes such capital expenditures as avoidable costs.[60] Yet the IMM inexplicably departs from that settled treatment of capital expenditures in his comments here.

The PJM IMM is aware that his analysis is deceptive, but the omission is buried in a footnote and justified with the following cursory explanation: "Capital expenditures are generally sunk costs and appropriately excluded from this analysis. To the extent that there are additional annual avoidable costs, the results could differ."[61] The first sentence of this footnote is false; the second sentence is a massive understatement. The NEI report shows that these expenditures are not "sunk." Because they occur predictably every year, owners of nuclear units can avoid them by retiring units. Retirement decisions are inherently forward-looking—resource owners must ask themselves: Will it be profitable for these units to continue to operate if current market conditions continue? In that context, using 2016 or 2015 revenues as a proxy for future revenues and comparing them to going forward costs, capital additions are clearly avoidable.[62] No reasonable business owner would disregard such foreseeable and sizeable costs. And when these costs are considered, the results *do* differ—dramatically. Including these costs increases the total cost of operating units by approximately one-third over the PJM IMM's estimates.[63]

Second, the PJM IMM disregards the market and operational risk associated with operating a nuclear unit, risks that can be avoided by retiring a unit.[64] For example, nuclear units face energy market risks resulting from unexpected forced outages. If an unexpected outage occurs, these units face a loss of revenue from the energy markets, as well as the need to purchase energy on the

[60] PJM Tariff, Att. DD § 6.8.

[61] PJM IMM Comments at 19, n.17.

[62] Schnitzer Testimony at 9-10.

[63] *Id.* at 6-7.

[64] *Id.* at 7-8.

market at a high spot price in order to cover a forward market sale. The costs of covering forward energy sales can be significant. For example, when Exelon's Calvert Cliffs plant experienced an unexpected five day outage in January 2014, Exelon was forced to cover the plant's forward energy sales at a significant loss with replacement energy purchases made from the real-time and day-ahead energy markets. The loss was equal to about 35 percent of the total capacity revenue for the year.

Units also face risks arising from energy price volatility. Market prices are unpredictable and, given the size of nuclear generators, the market for the energy is often not liquid at the point of sale. Congestion can arise on the system due to forced transmission outages or transmission maintenance and upgrades, which can significantly impact the energy price received. For example, during outages for construction at a substation in the western portion of the ComEd system in the Fall of 2016, Byron and Quad Cities saw significant increases in congestion cost, on some days exceeding $30/MWh.[65] Owners of nuclear units are required to self-insure against this risk and bear these costs. For baseload plants, which receive most of the revenue from the energy markets, the risk of energy price volatility can be particularly significant. A nuclear plant, for example, can expect to recover as much as 75 percent of its going-forward costs through energy market revenues. Thus, a ten percent drop in energy prices can require a 30 percent increase in the capacity revenues needed to cover going-forward costs. As this example demonstrates, volatile energy prices present

[65] Similarly, disturbances on the transmission system can cause generators to unexpectedly trip offline. *See* NERC, *Washington, DC, Area Low Voltage Disturbance Event of April 7, 2015* (Sept. 2015), *available at* http://www.nerc.com/pa/rrm/April%202015%20Washington%20DC%20Area%20LowVoltage%20Disturban/Washington_DC_Area_Low-Voltage_Disturbance_Event_of_April_7_2015_final.pdf (describing a low voltage transmission problem experienced in the Washington, DC area that caused several generators, including Calvert Cliffs, to trip).

a significant commercial risk, and this risk, too, must be considered when determining the capacity revenues needed to cover going-forward costs.

Exelon is not alone in noting the risks and attendant costs faced by nuclear units. In its comments in the Capacity Performance docket, Exelon proposed tariff language addressing the energy market risks faced by nuclear units.[66] In that docket, PJM explicitly supported Exelon's requested tariff clarifications, noting that "[g]iven the importance of these risk premiums to reasonably reflecting a seller's costs of committing as a Capacity Performance Resource, and the inherent challenges in quantify such risks, these are reasonable modifications."[67]

Other companies who actually own and operate nuclear generators agree with Exelon that these plants face significant economic challenges. FirstEnergy has stated that its three nuclear power stations "are all in danger of closing within the next two years due to economic reasons … [and that] '[o]ur plants have been losing money. We've continued to operate them at a loss. But at some point, those economics don't make sense.'"[68] PSEG likewise states, "Nuclear plants are being financially challenged by current and expected market conditions."[69]

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[66] *See* Motion to Submit Reply Comments and Reply Comments of Exelon Corp., Docket No. ER15-623-000 (Feb. 4, 2015) at 28-31 (proposing specific tariff language); Comments of Exelon Corp. Regarding PJM Interconnection, L.L.C.'s April 10, 2015 Response to the Commission's Deficiency Letter, Docket No. ER15-623-000 (Apr. 24, 2015) at 3-7 (reiterating tariff language).

[67] *See* Answer of PJM Interconnection, L.L.C., Docket No. ER15-623-000 (Feb. 13, 2015) at 89-90.

[68] FirstEnergy Comments at 24-25.

[69] PSEG Comments at 5; *see also* http://www.njspotlight.com/stories/17/10/31/pseg-backs-trump-administration-plan-to-spur-nuclear-industry/ (recent statements by Ralph Izzo); s*ee also Order Adopting A Clean Energy Standard*, Case Nos. 15-E-0302, 16-E-0270, 2016 WL 4129243, at *70 (N.Y. P.S.C. Aug. 1, 2017) (the New York State Public Service Commission analyzed the finances of the upstate New York nuclear plants in the course of approving the Zero Emissions Credit program, and made a determination that these units were financially distressed).

In sum, in recent years the majority of nuclear units in PJM have not earned sufficient market revenues to cover their avoidable costs, indicating that they are financially challenged and at risk of existing the market. For single unit nuclear generators, the PJM IMM estimates an average avoidable cost of $25.95/MWh. The cost of ongoing capital expenditures is $8.67/MWh and an appropriate measure of market and operational risk is $8.14/MWh, increasing the avoidable cost to $42.78/MWh. The costs from multi-unit sites similarly increases from the IMM's estimate of $18.73/MWh to $32.02/MWh.[70] Once the true costs of operating these units are accounted for, virtually all of the nuclear units in PJM are challenged and are at risk of retirement.[71]

II. The Commission Should Take Three Steps: Take Immediate Action to Ensure that the PJM Market Rules Do Not Cause Economic Stress to Fuel-Secure Resources, Gather and Assess Data from RTOs Regarding Bulk Power System Vulnerabilities, and Establish a Design Basis Threat That Can Serve as the Foundation for Specific Reforms.

The Commission should take a three-step approach to addressing the concern expressed by the Secretary, as described further below.

A. The Commission Should Take Immediate Action to Ensure That Unjust and Unreasonable Market Rules Do Not Send Inaccurate Prices Signals to Fuel-Secure Resources.

The Commission can take action in the immediate term to reduce the likelihood of further retirements by fuel-secure resources, while it gathers additional information regarding our vulnerabilities and considers how best to ensure generation resilience. *First*, the Commission should make clear that it will not mitigate the capacity market bids of fuel-secure units that receive state compensation intended to prevent their premature retirement. For example, New York and Illinois have adopted Zero Emissions Credit programs which place value on the carbon-free

[70] Schnitzer Testimony at 9.

[71] *Id.* at 9-10.

environmental attributes of nuclear generation, and focus their compensation on units whose attributes would be lost absent state support. Mitigating the capacity market bids of these units would undermine the state programs and run counter to the Secretary's goal of sustaining fuel-secure resources.

Second, Exelon endorses PJM's proposal for the Commission to create a pathway for PJM to correct a well-understood flaw in its energy markets that results in the systematic under compensation of units serving off-peak load.[72] Simply put, energy prices do not reflect the cost of producing power, as Michael Schnitzer explains in the attached testimony.[73] PJM's energy market has two stages. PJM first determines the security constrained economic commitment and dispatch for generation resources. That is, it decides which combination of units are able to serve load at the lowest cost. Next, PJM examines the dispatch and sets energy prices based on the short-run marginal cost of the units. To be economically efficient, energy prices must be set at a level that is consistent with the cost of the energy produced. In other words, prices should be set at a level sufficient to allow all generators that are operating to at least recover their variable costs, and the dispatch instruction for each generator should be profit-maximizing given the prices.[74]

PJM's current approach fails this test, as Mr. Schnitzer explains.[75] Baseload generators must often stay on overnight in order to meet load during peak hours. These generators cannot turn down below a certain level, but they are ineligible to set energy prices when operating at their minimum. As a result, energy prices during off-peak periods often do not reflect the production costs of generators operating during these periods, despite the fact that these generators are serving

[72] PJM Comments at 48.

[73] Schnitzer Testimony at 11-34.

[74] *Id.* at 15.

[75] *Id.* at 11-18, 25-30.

load and are part of the least-cost set of resources to do so. Instead, the energy price is set based on the short-run marginal cost of a different, cheaper unit. At night, these resources are sometimes wind units, which are willing to generate at very low or even negative LMPs in order to benefit from production tax credits; other times, they are the lowest cost combined-cycle gas units. At such times, the offers of these flexible units, rather than the cost of the baseload unit that is truly marginal, determines the locational marginal price. As a result, the baseload unit does not recover its costs, and energy prices do not reflect the true cost of serving load.[76]

Right now, PJM attempts to mitigate this problem through uplift to certain units. The self-scheduled coal and nuclear units needed for grid resiliency, though, are generally not eligible for uplift. Uplift also is not a long-term solution. As the Commission has repeatedly recognized, uplift payments should be reduced whenever possible. A central goal of the current price formation efforts is to move away from uplift as a solution to pricing errors. More fundamentally, these uplift payments undermine the notion of a single market-clearing price. Most generators receive one price—the market price—for the energy they produce. Certain generators, though, receive a different, higher price that is a combination of the market price and the uplift payment.[77]

This flaw in market design has severe consequences for nuclear units, which are always on and which typically self-schedule, so are ineligible to set price. At some times and in some locations, these nuclear units are the marginal resource, but LMP is set by flexible wind units willing to bid below zero. In these conditions, nuclear units are losing money every hour they operate, even though they are part of the least-cost set of resources needed to serve load. Even when LMPs are not negative, however, they are often lower than the marginal cost of serving load.

[76] *Id.* at 11-14.

[77] *Id.* at 14, 16.

For example, when a blockloaded coal plant is the marginal resource, it will not be allowed to set LMP, and so energy prices will be insufficient to support the dispatch.[78] Because nuclear units have very large fixed costs—higher fixed costs than they are able to recover from the capacity market—they depend upon energy margins in order to remain profitable.[79] When energy prices are lower than they ought to be, due to flawed price formation rules, nuclear units are no longer able to earn the revenues necessary to remain in operation.[80]

These nuclear resources are part of any reasonable least-cost portfolio over the long-run, particularly given their zero-emission characteristics, and any retirement of such a resource represents a permanent loss for customers and society at large. The units will not return and instead, they will be replaced by natural gas units that are, over the long term, more expensive. A system that already is over-dependent on natural gas will further lose resilient units and more gas-fired generation will be added to the system. Properly valuing the energy that these units produce thus not only will improve the efficiency and functioning of the market, but will also advance the Secretary's goal of preventing the further retirement of resilient resources.

PJM itself has recognized that this specific flaw in its approach to energy price formation is a problem that needs correction.[81] So too has the Commission. For inflexible peaking units, the Commission has declared market rules unjust and unreasonable in the Notice of Proposed

[78] *Id.* at 17-19.

[79] *Id.* at 6, 20-21.

[80] *Id.* at 17-19.

[81] PJM Comments at 43.

Rulemaking relating to fast-start pricing.[82] The Commission should make the same determination here.

To solve this problem in a manner consistent with principles of economics and good market design, PJM proposes to "relax" the price-setting constraints to better allow the costs of the power being produced to be reflected in the locational marginal price.[83] When an inflexible unit that is part of the least-cost set of resources is operating at its minimum, it will be allowed to set the energy market clearing price. This energy price formation proposal preserves the current security constrained economic dispatch and commitment. It simply sets prices in a manner that is consistent with actual operations—energy prices will reflect the true marginal costs of serving load. PJM's proposal will thus over time produce a lower-cost mix of resources that correctly balances low-cost baseload with more flexible (but usually more expensive) resources.

Additional work on this proposal still needs to be completed. In particular, certain committed units will be paid to ramp down to ensure that generation matches load.[84] Under the current approach to pricing, these units reduce their output in response to a lower energy price. Because energy prices will no longer be suppressed under the PJM proposal, these flexible units will need to receive an additional payment to follow the dispatch signal as large units become the marginal resource. The Commission should find the existing market rules unjust and unreasonable under Section 206, and direct PJM to adopt revisions within 90 days.

The PJM IMM has criticized these changes, even going as far as to suggest that PJM is proposing them to placate Exelon. The PJM IMM's unfortunate insinuation that PJM's integrity

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[82] *Fast-Start Pricing in Markets Offered by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,213 (2016).

[83] PJM Comments at 45.

[84] *Id.* at 39

and independence are in question is belied by a decade of academic commentary noting the very issue PJM has identified.[85] The reforms are supported not only by PJM, but also by many other economists and PJM stakeholders.[86] The weaknesses in the PJM IMM's technical objections, discussed further below, cannot be masked by taking a cheap shot at PJM.

The PJM IMM presents four major criticisms, each of which the Commission should dismiss.[87] First, he claims the proposal would raise costs to consumers without corresponding benefits. Second, he argues that the pricing change is not consistent with efficient dispatch. Third, he states that PJM's proposal inappropriately extends the theory behind the fast-start NOPR. Finally, he believes the proposal will have unintended consequences in the markets. The first three criticisms are not valid and the final one is premature.[88]

First, the concern about costs to consumers is both wrong and misses the point. Correcting the pricing error would produce long term savings by avoiding uneconomic retirement of units as well as incentivizing new, more efficient units to enter the market.[89] Additionally, because of their operational constraints, many units with long-lead times or high start-up costs cannot make commitment decisions within a 24-hour window. Because they cannot effectively participate in

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[85] William W. Hogan and Brendan J. Ring, *On Minimum-Uplift Pricing for Electricity Markets* (Mar. 19, 2003); Paul R. Gribik, William W. Hogan, and Susan L. Pope, *Market-Clearing Electricity Prices and Energy Uplift* (Dec. 31, 2007); Brendan J. Ring, "Dispatch Based Pricing in Decentralized Power Systems," Ph.D. thesis, Department of Management, University of Canterbury, Christchurch, New Zealand, 1995.

[86] *See, e.g.*, Initial Comments of the Electric Power Supply Association, Docket No. RM18-1 (Oct. 23, 2017) at 51-53; Comments of NRG at 4; Comments of PSEG at 25; Comments of Calpine at 22; *see also State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.*, Docket No. AD17-11-000, Comments of Edison Electric Institute at 5-6.

[87] PJM IMM Comments at 36-37.

[88] Schnitzer Testimony at 22-23.

[89] *Id.*

the day-ahead market, they self-commit instead. These self-commitment decisions are made in light of the predicted energy price and, to the extent that the energy price is not set optimally, the decision to self-commit is also not optimal.[90]

Equally important, a cost/benefit framework is misplaced here. The Commission needs to determine whether the pricing model is just and reasonable. Because the current pricing structure does not support the actual cost of production, basic principles of good market design are violated.[91] Specifically, locational *marginal* pricing, the basic principle that underlies energy market pricing, is violated given that a number of resources that are operating are prohibited from setting the clearing price. Units that are needed are not covering their variable costs. In such a model, while low prices produce "savings" for consumers, those savings are generated by undercompensating units that are needed to serve load. This pricing model is not sustainable and consumers do not benefit in the long-term.

Second, the PJM IMM does not describe PJM's proposal correctly when claiming that it would be inconsistent with efficient dispatch.[92] Under the proposal, the dispatch of units in PJM would be the same as it is today.[93] But energy market prices would allow *all* units needed to serve load to cover their costs.[94] To be sure, higher prices will mean that flexible resources will have an incentive to increase their output, but these resources would receive an additional payment

[90] *Id.* at 23.

[91] *Id.* at 22.

[92] PJM IMM Comments at 39.

[93] Schnitzer Testimony at 23.

[94] *Id.* at 23-25.

designed to compensate it for the opportunity cost of following dispatch instructions.[95] This payment would resolve the incentive concerns raised by the PJM IMM.

Third, contrary to the PJM IMM"s assertions, PJM's proposal is also in fact a natural extension of the fast start NOPR.[96] PJM's energy market faces the same pricing problem whether the unit involved is a baseload inflexible unit or a fast-start inflexible unit. In either case, the relevant generator is part of a least-cost commitment and dispatch solution but it not permitted to set price. The LMP that results from the pricing run is not sufficient to cover the costs of the marginal unit and the pricing model does not support the dispatch. The same reasons that led the Commission to act under Section 206 in that rulemaking likewise warrant a finding here that PJM's energy pricing rules are no longer just and reasonable.

Fourth, the claim the proposal will produce unintended consequences is premature.[97] The PJM IMM claims that "no financial incentive supports the unit producing at the efficient dispatch level" and argues that resources will begin to self-commit at higher rates if the Commission approves the pricing proposal.[98] As PJM acknowledges, it will need to design an appropriate compensation mechanism to ensure that resources reduce their output in response to dispatch instructions. While this will be an important component of the proposal, it should be straightforward to design and mange. More fundamentally, this problem already exists in PJM. Without the current out-of-market payments to inflexible units, those units would not have the

[95] *Id.* at 24-25, 30-31.

[96] *Id.* at 25-30; PJM Comments at 44-46; *see also* Initial Post-Technical Conference Comments of PJM Interconnection, L.L.C., AD17-11, (June 22, 2017) at 4-5.

[97] Schnitzer Testimony at 32-33.

[98] PJM IMM Comments at 39.

appropriate incentives. PJM's proposal reduces this uplift and reduces the overall amount of out-of-market compensation needed to induce units to follow dispatch instructions.[99]

The argument that units will begin to self-commit inefficiently is also premature.[100] If designed correctly, self-commitment decisions will be improved. The core concept behind the proposal is that all units that are part of the least-cost solution should be permitted to set price, whether they are pool-scheduled or self-scheduled. Self-scheduled resources that are not part of the least-cost solution should not be allowed to set price. This approach should improve the incentives around self-commitment. Units that are part of a least-cost solution will have an incentive to self-commit when appropriate because they will be able to set price and recover their costs.[101]

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Issuing a policy statement that fuel-secure units receiving state compensation will not have their capacity bids mitigated on account of that compensation, and fixing the well-understood flaw in PJM's energy markets, will not of course fully solve the problem of resilience. But these steps will improve the market's efficiency while also helping to prevent the further retirement of fuel-secure resources while FERC considers solutions more broadly targeted at resilience.

B. The Commission Must Gather Information from the Relevant RTOs That Will Enable It to Assess the System's Vulnerability.

In its initial comments in this docket, Exelon urged the Commission expeditiously to order the three eastern RTOs covered by DOE's NOPR to provide various critical pieces of information

[99] Schnitzer Testimony at 32-33.

[100] *Id.* at 33.

[101] *Id.* at 33.

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about the current resiliency of the electric systems they administer.[102] Within 30 days, the RTOs should provide the Commission with a comprehensive inventory of all fuel supply for all generation within their footprint, by generator.[103] This information, which should not be difficult for the RTOs to gather, is necessary to allow the Commission to assess the fuel security within each RTO and the vulnerability of each individual generator to disruption should its fuel supply be cut off. Within 60 days, the RTOs should provide the Commission with a comprehensive fuel reliance analysis, detailing the consequences to load should the supply of particular types of fuel, or a combination of fuel types, be interrupted.[104] This analysis should be detailed, and include not only a discussion of how much load will be unserved, but also the financial and security impacts of prolonged blackouts.[105] In addition, given that natural gas-based generation is peculiarly vulnerable to common mode failures, the RTOs should analyze and report to the Commission on their ability to continue to serve load even in the event of a multi-pipeline outage, and the time it would take to repair a significant pipeline outage.[106] This body of information will allow the Commission to order the changes necessary to ensure that the organized markets can sustain whatever threats DOE and others identify in the design basis threat analysis Exelon believes must also be immediately undertaken.[107]

[102] *See* Exelon Comments at 35-39.

[103] *Id.* at 36.

[104] *Id.*

[105] *Id.* at 37.

[106] *Id.*

[107] *Id.* at 39-41.

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C. The Commission Should Work with Other Government Entities to Establish a Design Basis Threat.

Once the Commission receives the data from RTOs, it needs to be able to evaluate it. Right now, the Commission and the entities it regulates simply cannot assess the resilience of the electric grid against the threat of serious disruptions to the natural gas fuel supply. Because no description of the threat exists, the risk is uncertain and policy solutions are unclear. Exelon recommends that the Commission take action to remove this uncertainty by partnering with other federal agencies to develop a design basis threat. While DOE may be the appropriate agency to take the lead in developing a DBT, the Commission and other agencies have an important role to play.

As Dr. Paul Stockton outlined in his testimony attached to Exelon's initial comments and supplemented by additional testimony submitted with these reply comments (Exhibit A),[108] the DBT is a well-understood regulatory tool used by the Nuclear Regulatory Commission in order to provide guidance to owners of commercial nuclear generators. It identifies the threat to the units and allows owners of the units to develop strategies to mitigate the risk.[109] DBTs are also used by the Department of Homeland Security and the DOD to address threats to other critical infrastructure.[110]

A version of this model could serve a valuable purpose in guiding the analysis of the resilience of our power supply. Right now, RTOs and other entities are considering the risks of over-dependence on natural gas, but are doing so on their own. This approach means that the planning assumptions by these entities are not coordinated and are not necessarily consistent.

[108] Stockton Supplemental Testimony at 2.

[109] *Id.* at 7-8.

[110] *Id.*

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Moreover, the lack of involvement from national security agencies limits the opportunities for intelligence-related input from the DOE and other partner federal agencies.[111]

DOE need not start from scratch to develop a DBT for fuel resilience. NERC and other entities have already produced studies that could serve as the foundation of such a DBT. Dr. Stockton identifies three studies from NERC that touch on issues relating to the proposed DBT. First, NERC conducted a joint analysis in 2010 with the DOE on high impact, low frequency events.[112] This study warned that coordinated attacks on multiple vulnerable points on the system are possible and could produce extended, widespread outages.[113] Next, NERC came to a similar conclusion in 2012 in its *Severe Impact Resilience* study and recognized the risk of coordinated attacks on the grid.[114] Finally, NERC focused specifically on the risks of a cyberattack and also emphasized the risks of system collapse and widespread blackouts.[115] These studies, as well as others,[116] show the feasibility of assessing these risks in a DBT.

As it develops such a DBT, the DOE should consider a range of risks to resiliency. Dr. Stockton recommends analyzing potential large scale disruptions to the gas supply. Both natural and manmade threats could cause such disruptions. [117] International actors, as well as terrorist groups, could conduct physical or cyberattacks that disable natural gas infrastructure needed to

[111] *Id.* at 8.

[112] *Id.* at 9.

[113] *Id.* at 10.

[114] *Id.*

[115] *Id.* at 11.

[116] *Id.*

[117] *Id.* at 12.

supply fuel for generation. Earthquakes and other natural disasters can have similar effects. Additionally, natural catastrophes could create weaknesses that can be exploited by adversaries.[118]

With a DBT in hand, the Commission will then be able to devise solutions that address the threat. In doing so, the Commission should not allow itself to be hide-bound by an ideological commitment to either markets or command-and-control regulation. It should offer RTOs the opportunity to propose market-based solutions, but should remain open to adopting non-market solutions if necessary. The Commission's ultimate priority must be to secure the Nation's electric grid—and to achieve that goal in the manner that is least burdensome to customers.

CONCLUSION

The deluge of comments the Commission has received in this docket is only further evidence, if any was needed, that the issue of grid resiliency is one of overarching importance, and that Commission action will have widespread consequences for the bulk power system and the nation as a whole. Exelon believes the Commission must expeditiously gather necessary information from the RTOs, and clearly define the resiliency threat it seeks to counter, before it develops a long-term solution. But these actions should not prevent the Commission from taking the immediate steps it can, today, to halt the retirements of baseload nuclear units that are among the most resilient in the generation fleet. The price formation proceedings already underway in PJM, and other state-based initiatives to support zero-emissions generators, are important steps towards that goal.

[118] *Id.* at 13.

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Respectfully submitted,

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EXELON'S ANSWERS TO SELECTED QUESTIONS
POSED BY COMMISSION STAFF (OCT. 4, 2017)

Need for Reform

Question 1: *What is resilience, how is it measured, and how is it different from reliability? What levels of resilience and reliability are appropriate? How are reliability and resilience valued, or not valued, inside RTOs/ISOs? Do RTO/ISO energy and/or capacity markets properly value reliability and resilience? What resources can address reliability and resilience, and in what ways?*

Resiliency and reliability are fundamentally different concepts. Reliability concerns (1) resource adequacy, namely whether there exists sufficient generation resources to serve load at all times throughout a wide range of operating conditions; and (2) operational security, that is, the ability of the electric system to serve load notwithstanding disturbances. Resiliency, by contrast, refers to the system's ability to prepare for, absorb, and rapidly recover from high-impact, low-frequency or unknown-frequency ("HILF") events. Unlike traditional reliability events based upon weather or forced outage rates which can be probabilistically determined based upon historical data, a HILF event (for example, a cyber-attack by a nation-state or other malicious actor) may not be forecastable. For this reason, HILF events not only encompass incidents that are expected to occur infrequently, but also events that cannot be forecasted because of significant unknowns. Resilience also differs from reliability in having to account for the underlying nature of man-made threats, which differ from hurricanes and other familiar natural hazards. Unlike hurricanes, adversaries are intelligent and adaptable. Adversaries will also be able to selectively target points of special vulnerability in energy systems, including those related to fuel resilience and gas-electric system interdependencies. Initiatives to define the attributes of resilience and assess measures to strengthen them will need to incorporate these non-traditional risk factors.

The eastern RTO capacity markets generally value reliability by giving units a financial incentive to be capable of generating power whenever called upon. Because the capacity markets focus on unit level commitments, they do not account for "common mode failure"—that is, the risk that multiple units will fail due to a common cause external to the units, such as a gas supply interruption. Resiliency concerns systemic threats such as these. However, the RTOs/ISOs do not value a unit's contribution to system resiliency, and until this proceeding resiliency has not been a focus for either the organized markets or the Commission.

The Commission should take certain immediate steps to ensure that fuel-secure resources that contribute significantly to system resiliency are being appropriately compensated for the resiliency they provide. As Exelon, PJM, and others have explained in their comments, flaws in PJM's energy market design systematically undercompensate such units, exacerbating the economic pressures these units face and contributing to their retirements. The Commission should create a process for PJM to address this flaw in its energy market. The Commission should also gather information from RTOs to identify the bulk power system's vulnerabilities to HILF events. Using that information, the Commission should establish a design basis threat, which can serve as a reference point for the adoption of market reforms intended to value resiliency.

Question 2: *The proposed rule references the events of the 2014 Polar Vortex, citing the event as an example of the need for the proposed reform. Do commenters agree? Were the changes both operationally and to the RTO/ISO markets in response to these events effective in addressing issues identified during the 2014 Polar Vortex?*

The 2014 Polar Vortex was a significant event because it exposed serious reliability deficiencies within PJM and ISO-New England. Generators that had committed to perform during harsh winter weather were unable to perform, and their failure exposed the organized markets' failure to adequately incentivize generators to provide reliable service. PJM has not faced another weather event as extreme as the 2014 Polar Vortex, and so it is difficult to assess whether the Capacity Performance reforms have succeeded in incentivizing owners to make the investments necessary to ensure performance. Exelon continues to believe that the penalty rate in PJM for a generator's failure to perform remains too low, and, as a result, important investments have not been made. For example, capacity clearing prices have been too low to support the development of dual-fuel capability by gas-fired units.

In all events, however, the issues raised in this docket are quite different from those addressed by the Commission in the wake of the Polar Vortex. The Commission's focus post-Polar Vortex was on creating financial incentives that would lead unit owners to make investments in the performance of their units. This docket, by contrast, concerns systemic threats to the grid external to any particular unit—threats which could affect many units simultaneously. For example, the CP reforms were intended to incentivize owners of gas-fueled plants to enter firm fuel arrangements so their supply could not be curtailed during extreme cold weather. But the CP reforms were not intended to address the possibility that—notwithstanding firm supply arrangements—there might be a gas supply disruption due to a physical or cyber attack on key pipelines. Such a supply disruption would affect numerous units simultaneously. A resilient grid is one that can withstand that type of event.

Question 3: *The proposed rule also references the impacts of other extreme weather events, specifically hurricanes Irma, Harvey, Maria, and superstorm Sandy. Do commenters agree with the proposed rule's characterization of these events? For extreme events like hurricanes, earthquakes, terrorist attacks, or geomagnetic disturbances, what impact would the proposed rule have on the time required for system restoration, particularly if there is associated severe damage to the transmission or distribution system?*

Certainly some extreme weather events, earthquakes, terrorist attacks, or geomagnetic disturbances can properly be characterized as HILF events and are and should be the subject of resiliency planning. Exelon believes it is premature to settle on precise list of events that resiliency planning should address. Likewise, while it is commonly understood that nuclear units can significantly contribute to swift system restoration,[119] Exelon believes it is premature to

[119] Nuclear units are resilient during extreme weather conditions. During Hurricane Sandy, most of the nuclear units in the path of the storm stayed operational throughout the storm. Units that

settle on a particular "solution" to the problem. As Exelon indicated in its comments, the first critical step for the Commission is to work with DOE and others to establish a design basis threat that encapsulates the resiliency deficiencies that need to be addressed. Once this has occurred, the Commission should consider a variety of potential solutions and evaluate which ones will meet the design basis threat in the most cost-effective manner. The proposal in the NOPR may be part of the solution, but Exelon believes further analysis and study is required before that conclusion can be reached.

Question 4: *The proposed rule references the retirement of coal and nuclear resources and a concern from Congress about the potential further loss of valuable generation resources as a basis for action. What impact has the retirement of these resources had on reliability and resilience in RTOs/ISOs to date? What impact on reliability and resilience in RTOs/ISOs can be anticipated under current market constructs?*

As Exelon has noted in its comments, many experts – including NERC – have correctly concluded that retirements of resilient baseload generation is a serious problem. Increasing reliance on gas generation creates the danger that a common mode failure—such as a gas pipeline disruption—could wipe out a large quantity of generation all at once. Fuel-secure units such as nuclear stations provide a valuable hedge against that risk. Moreover, the retirement of a nuclear plant is irreversible. Once the resiliency benefits of these plants are lost, they cannot be regained. The Commission should direct RTOs to provide data to assess the impact that the retirement of these resources had had on reliability and resilience. In its comments, Exelon identified a number of categories of data that RTOs should be directed to provide to the Commission, so that the Commission can accurately assess what impact these retirements will likely have on resiliency and what reforms are needed.[120] ISO-NE likewise highlighted its concern about the disruption of the natural gas supply at the October 2017 Commission open meeting when it presented its Winter 2017-2018 Operations and Market Performance update. It noted that "the ability to meet energy needs is at risk if gas cannot be supplied to gas-fired generators."[121] ISO-NE repeated these concerns in its comments in this docket.[122]

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were required to shut down restarted quickly when the storm ended. Because such units are safely taken offline during an event, they can return to service quickly after an event to allow the grid to resume operation. That quality would be crucial in the face of a major disruption to the natural gas supply. *See* Nuclear Energy Institute, *Nuclear Energy Facilities Prove Resilience During Hurricane Sandy*, October 30, 2012, *available at* https://www.nei.org/News-Media/Media-Room/News-Releases/Nuclear-Energy-Facilities-Prove-Resilience-During

[120] Exelon Comments at 36-37.

[121] Presentation of ISO-NE, October 19, 2017, available at https://www.ferc.gov/CalendarFiles/20171019125657-6-ISONE.pdf

[122] Comments of ISO-NE at 8-9 ("ISO-NE is concerned about the region's gas dependence").

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Question 5: *Is fuel diversity within a region or market itself important for resilience? If so, has the changing resource mix had a measurable impact on fuel diversity, or on resilience and reliability?*

There is no question that the changing resource mix has had a detrimental impact on the fuel diversity within RTOs/ISOs, and that declining fuel diversity in turn has made the system more susceptible to a common mode failure, such as a gas supply disruption. A diverse generation mix provides an extremely valuable hedge against that risk.

Other

Question 3: *Please describe any alternative approaches that could be taken to accomplish the stated goals of the proposed rule.*

As Exelon has noted in its comments, there are immediate steps the Commission should take to reduce the risk of further imminent retirements of nuclear resources and to gather the information needed to formulate comprehensive market reforms. These steps include: (1) providing a means for PJM to adopt energy market reforms intended to ensure that energy prices are sufficient to support dispatch; (2) issuing a policy statement declaring that nuclear units receiving compensation from state programs like the Illinois and New York Zero Emissions Credit programs, which have averted the retirement of nuclear resources, will not have their capacity market bids mitigated; (3) requiring RTOs/ISOs to submit information regarding their susceptibility to fuel-supply interruption and the potential impact of such interruption on the RTO/ISO's ability to serve load; and (4) establishing a design basis threat that can serve as a reference point for specific reforms.

Question 4: *What impact would the proposed rule have on consumers?*

As discussed in Dr. Stockton's testimony, the consequences to consumers of a black sky outage would be devastating. Preventing this by increasing the resiliency of the bulk power system is essential.

EXHIBIT A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	**)**	**Docket No. RM18-1-000**

SUPPLEMENTAL TESTIMONY OF

DR. PAUL STOCKTON

ON BEHALF OF

EXELON CORPORATION

November 7, 2017

My name is Paul Stockton. I am the Managing Director of Sonecon, LLC, a security and economic advisory firm in Washington, D.C. I submitted initial testimony in this docket on behalf of Exelon outlining the risks to the resilience of fuel supplies for power generation, especially those related to natural gas, and proposed steps to mitigate those risks. This additional testimony is designed to expand on my earlier submission.

Bulk Power System (BPS) entities cannot adequately assess the resilience of their fuel supplies for power generation because they lack the necessary analytic framework. In particular, neither the Department of Energy (DOE) nor any other Federal agency has provided BPS entities with a description of the threat against which fuel resilience should be measured. Without the ability to anticipate the likely scope and severity of an attack on natural gas pipelines and other sources of fuel, the Federal Energy Regulatory Commission (FERC) and the entities it regulates cannot measure the adequacy of current fuel resilience measures, or evaluate the potential benefits of additional mitigation options.

In my initial testimony,[1] I recommended the establishment of a Design Basis Threat (DBT) to support such assessments. Government-vetted DBTs already provide descriptions of threats to other infrastructure sectors to help guide their evaluation of security requirements and mitigation measures. For example, the Nuclear Regulatory Commission (NRC) provides a DBT to owners of commercial nuclear generators to help them ensure the adequacy of their security measures against manmade threats. In this testimony, I examine how a DBT for fuel resilience might provide unique benefits for assessing the current status of that resilience, and for evaluating options to mitigate gaps that may emerge against increasingly severe threats. My

[1] Testimony of Paul Stockton at p. 4-5.

testimony presents three overall findings on why developing a DBT is so vital for addressing fuel resilience and recommendations on how that development process should go forward.

First, I explain the need for a DBT. Without a government-vetted DBT, RTOs and other BPS entities are left to develop their own characterizations of the threat, leading to disparate analytic frameworks for assessing the scale and potential impact of fuel interruptions.

Second, I recommend an approach to determine the threat characteristics that the DBT should comprise. The DBT established by the Nuclear Regulatory Commission for commercial nuclear power reactors provide a useful precedent and model for developing a DBT focused on fuel resilience. DBTs provided by the Department of Homeland Security (DHS), the Department of Defense (DOD), and other Federal departments and agencies provide additional models for consideration. However, a fuel resilience DBT would need to focus on specific threats of fuel supply interruption, including those related to gas-electric system interdependencies and the risks of cascading fuel-related infrastructure failures that adversaries could create. Those threat characterizations should also account for both natural and manmade hazards that could inflict the simultaneous disruption of multiple gas pipelines and other fuel supply systems in multi-state regions. Analytic efforts conducted by NERC, entities at the direction of the Electricity Subsector Coordinating Council (ESCC), and BPS entities can also help identify the key threat characteristics that the fuel resilience DBT should encompass.

Third, I discuss the path forward to develop a DBT for fuel resilience. One promising option would be for the Department of Energy to lead the development of the DBT, in close coordination with the Commission, other Federal departments and agencies, BPS entities, the ESCC, NERC, and additional stakeholders in grid resilience with expertise on emerging threats. Such a DBT could also be structured in a "tiered" fashion, with a baseline DBT provided to all

BPS entities at the level of "For Official Use Only" and supplementary DBTs provided as needed at higher levels of classification to cleared industry personnel.

I. The Need for a DBT

The Department of Energy's *Staff Report to the Secretary on Electricity Markets and Reliability* (August 2017) highlights the need to "develop policy metrics and tools for evaluating BPS-wide provision of resilience and considering all aspects of the electricity system that contribute to resilience," including fuel supply and storage, and other factors critical to grid reliability and resilience.[2]

A growing number of RTOs and other BPS entities are developing and applying such evaluative tools. In particular, these entities are either assessing or planning to assess potential risks to their fuel supplies, especially natural gas, and the potential impact of fuel interruptions on grid reliability. PJM, for example, has conducted pioneering studies of the potential risks created by increased reliance on natural gas, including in its *Natural Gas Contingency Scenario Analysis*.[3] These studies are essential to address the resilience challenges identified in the NOPR.

However, the DOE Staff Report also identifies a critical gap for conducting such assessments. The Report cites PJM's finding that "criteria for resilience are not explicitly defined or quantified today."[4] The Report goes on to recommend that "Each RTO/ISO should strive to explicitly define resilience on its system and conduct resource diversity assessments to more

[2] Department of Energy, *Staff Report to the Secretary on Electricity Markets and Reliability*, August 2017, p. 128.
[3] Transmission Expansion Advisory Committee, "Reliability Analysis Update," *PJM Interconnection*, September 14, 2017, http://pjm.com/-/media/committees-groups/committees/teac/20170914/20170914-reliability-analysis-updates.ashx.
[4] PJM Interconnection, *PJM's Evolving Resource Mix and System Reliability*, March 2017, p. 6.

fully understand the resilience of different resource portfolios. Federal, state, and local work to define and support system-wide resilience is also needed."[5]

Providing a DBT offers a uniquely valuable opportunity for such Federal support. The Federal government currently leaves RTOs and ISOs largely on their own to characterize threats to their fuel resilience. This approach is likely to produce disparate planning assumptions regarding the scale and severity of such threats. The government's "hands off" approach also limits opportunities for appropriate intelligence-related input from the Department of Energy and other Federal departments and agencies to support the development of a vetted, appropriately informed DBT. This lack of Federal support is especially notable given the risk that fuel supply interruptions could jeopardize the flow of power on which military bases and other national security assets depend. To help strengthen U.S. security, the Federal government should work with BPS entities and other resilience stakeholders to develop a vetted, intelligence-informed DBT for assessing and mitigating risks fuel resilience.

A DBT of this kind would also help RTO and ISO efforts to meet the underlying assessment problems posed by the proposed Rule. In commenting on the Rule, David Patton, Market Monitor for MISO, NYISO and ISO-NE, noted that "Without first identifying in detail the contingencies and associated reliability risks to the system, there is no way to quantify a resilience requirement."[6] Filling this gap with a DBT will be essential for establishing the objective, analytically sound assessment system needed to achieve the goals of the proposed

[5] Department of Energy, *Staff Report to the Secretary on Electricity Markets and Reliability*, August 2017, p. 128.
[6] Comments of Potomac Economics, Ltd., Docket No. RM18-1 (Oct. 20, 2017) at 5; Michael Kuser, Tom Kleckner, Rory D. Sweeney, Amanda Durish Cook, "RTOs Reject NOPR; Say Fuel Risks Exaggerated," *RTO Insider*, October 24, 2017, https://www.rtoinsider.com/market-monitor-nuclear-coal-nopr-iso-ne-78297/.

Rule. The need for a consistent, government-vetted DBT is further highlighted by the threat assumptions that undergird recent fuel resilience studies. While excellent as far as they go, these studies typically focus on assessing the consequences of the interruption of a single major gas pipeline. That is helpful but not sufficient. Any major power willing to accept the risks associated with attacking a single U.S. pipeline may well decide to strike on a much more massive scale, and seek to disrupt all flows of gas for power generation in a given RTO or ISO service area. Specifying the extent of such anticipated fuel interruptions will be essential to provide a foundation for assessing BPS fuel resilience, and for analyzing the cost-effectiveness of various options to mitigate the emerging threat.

II. Existing DBT Models and Special Requirements for a Fuel Resilience DBT

To accelerate the development of a DBT for fuel resilience, one promising approach would be to borrow from existing DBT models and adapt them to the special fuel-related challenges posed by catastrophic natural and manmade hazards. Most significantly, the NRC has created a DBT for nuclear power plants and related facilities.[7] The requirement to establish this DBT and the basic threats it should comprise are specified in the *Energy Policy Act* of 2005.[8] These threats include "multiple, coordinated groups of attackers, suicide attacks and cyber threats," as well as other potential attack vectors.[9]

[7] The NRC's DBT provide performance-based requirements which allow each facility to develop site-specific strategies. It applies to commercial nuclear power reactors and Category I Fuel Cycle Facilities. See: "Frequently Asked Questions About NRC's Design Basis Threat Final Rule," United States Nuclear Regulatory Commission, last updated August 11, 2017, https://www.nrc.gov/security/faq-dbtfr.html.
[8] 42 USC § 2210e (2005), https://www.ferc.gov/enforcement/enforce-res/EPAct2005.pdf.
[9] 10 CFR § 73.1 (2010), https://www.gpo.gov/fdsys/pkg/CFR-2010-title10-vol2/pdf/CFR-2010-title10-vol2-sec73-1.pdf.

The NRC also regularly reviews and revises the DBT to keep pace with evolving threats. In particular, the NRC monitors domestic and foreign threat intelligence in an attempt to stay ahead of potential adversaries, issues periodic threat advisories and annual reviews, and will use this information to update the DBT as required.[10] While the DBT focuses on manmade threats, the NRC also provides earthquake engineering criteria for nuclear power plants and other guidance related to natural hazards.[11]

The NRC DBT scheme offers valuable models for establishing a fuel resilience DBT. For example, given the evolving threat to gas pipelines and other fuel supplies, it will be essential that the fuel resilience DBT be periodically updated as well. The nuclear DBT also provides a model of the appropriate level of detail for characterizing key threat vectors in an unclassified manner. In addition, existing mechanisms for the Department of Energy to share classified information with BPS entities could also be used to supplement unclassified DBT descriptions. Finally, just as the NRC sets standards for both natural and manmade hazards, the fuel resilience DBT should as well.

Even when Congress has not established statutory requirements for DBTs, Federal departments have issued them to help strengthen resilience and security across a range of critical facilities and functions. For example, DOD provides DBTs to support anti-terrorism and force protection standards, and mitigation measures based on requirements generated internally by the Department.[12] DHS also provides a DBT that establishes "the type, composition, and capabilities

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[10] "Threat Assessment," *United States Nuclear Regulatory Commission*, last updated August 14, 2017, https://www.nrc.gov/security/domestic/phys-protect/threat.html.
[11] "Appendix S to Part 50—Earthquake Engineering Criteria for Nuclear Power Plants," *United States Nuclear Regulatory Commission*, last updated August 29, 2017, https://www.nrc.gov/reading-rm/doc-collections/cfr/part050/part050-apps.html.
[12] *See* Department of Defense, DOD Security Engineering Facilities Planning Manual, September 2008, https://www.wbdg.org/FFC/DOD/UFC/ufc_4_020_01_2008.pdf

of adversaries" who might threaten Federal facilities. DHS uses the best available intelligence information and other relevant sources of data to develop and maintain the DBT. The baseline DBT provided by DHS is designated For Official Use Only (FOUO). In addition, DHS provides supplementary information as needed on specific threats and mitigation options, including at higher levels of classification.[13] A similar tiered approach to provide both an FOUO DBT and other threat assessments at higher levels of classification (to be provided to cleared BPS personnel) might also offer a useful design model for a fuel resilience DBT.

While these models from other departments are useful, a fuel-oriented DBT will need to focus on a different set of resilience challenges and threat vectors than those for nuclear power plants or Federal facilities. NERC Reliability Standard TPL-001-4 provides a valuable starting point. TPL-001-4 directs Transmission planners to assess the impact of extreme events, and if the analysis determines that such events could cause cascading outages, the Transmission planner should evaluate possible actions to reduce their likelihood or mitigate the consequences and adverse impacts to reliability.[14] To ensure that those assessments account for the risks posed by increasing reliance on gas for power generation, NERC is now considering a recommendation that "NERC registered entities should consider the loss of key natural gas infrastructure in their planning studies."[15] A DBT for fuel resilience could provide valuable support for such analysis

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[13] See: Department of Homeland Security, *The Risk Management Process for Federal Facilities: An Interagency Security Committee Standard: 2nd Edition*, November 2016, https://www.dhs.gov/publication/isc-risk-management-process.

[14] *See* Requirements R 3.2 and R 3.5 of Standard TPL-001-4 – Transmission System Planning Requirements.

[15] Thomas Coleman, "Special Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System" (presentation at NERC Board of Trustees Meeting, New Orleans, LA November 9, 2017). http://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Presentations_November_2017.pdf.

by specifying the scope and severity of the gas infrastructure losses that entities should use in their studies.

However, no such DBT exists today. Only limited guidance exists on the scale and characteristics of the extreme events that should be used as a basis for assessing the impact of fuel system interruptions on grid reliability and resilience.[16] BPS entities would benefit from far more extensive support. In particular, using appropriate intelligence sources, it would be helpful if the Federal government could provide these entities with an assessment of the scale and nature of attacks that they must be prepared to confront. Such an assessment could also help entities account for specific risks to fuel resilience, including the risk that adversaries will target their attacks to exploit interdependencies between gas and electric infrastructure.

As a starting point to develop a Design Basis Threat for fuel resilience, NERC and other industry stakeholders have already produced studies that highlight key resilience challenges to address in such a DBT. In particular, three NERC studies have examined both the characteristics of natural and manmade hazards that could cause catastrophic outages, as well as possible mitigation measures to adopt against the risks they pose.[17] These and other studies are useful starting points, but also have gaps in terms of characterizing the threat to fuel supplies. Filling those gaps will be necessary for developing a fuel resilience DBT.

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[16] *See*, *e.g.*, NERC, *2016 Long-Term Reliability Assessment*, December 2016, p. 21. The assessment notes that "As part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electric reliability."

[17] NERC noted that coordinated cyber or physical attacks "could damage or destroy key system components, significantly degrade system operating conditions, and, in extreme cases, result in prolonged outages to large parts of the system." See: NERC, *2015 Long Term Reliability Assessment*, December 2015, p. 27.

The first NERC study is a joint analysis with the Department of Energy to examine the risk of high impact, low frequency events. Particularly useful is the study's analysis of coordinated cyber/physical attacks to the BPS.[18] The report warns that coordinated cyber/physical attacks will purposefully target multiple vulnerable points on the system, and that sophisticated adversaries will adapt to protective measures to maximize disruptions. Such attacks "could result in long-term (irreparable) damage to key system components in multiple simultaneous or near-simultaneous strikes… quickly bring[ing] the system outside the protection provided by current planning and operating practices."[19]A coordinated cyber/physical attack, as described, would likely result in extended outages over a wide geographic area.

The second study examines severe disruptions to the BPS, and stems from the work of the *High Impact, Low Frequency* report. Much like that report, the *Severe Impact Resilience* study focuses primarily on coordinated cyber and physical attacks.[20] The study cautions that a coordinated physical attack on critical nodes in the grid can cause extensive damage to equipment that is difficult to replace, with significant impact to the system as a whole. Similarly, coordinated cyberattacks could cause simultaneous disruptions or misoperation that could be detrimental to system integrity.[21] While *Severe Impact Resilience* treats cyber and physical attacks as separate threats, a future Design Basis Threat should assume advanced adversaries will conduct attacks in both domains near-simultaneously.

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[18] The study also assesses the risks of pandemic illness and geomagnetic/electromagnetic disturbances. For more information, see: NERC and the Department of Energy, *High-Impact, Low-Frequency (HILF) Event Risk to the North American Bulk Power System*, June 2010.
[19] HILF Report, p. 26
[20] Like the *High Impact, Low Frequency* report, it also includes geomagnetic disturbances among the key threats for particularly severe events. See: NERC, *Severe Impact Resilience: Considerations and Recommendations*, May 2012, p. 1.
[21] NERC, *Severe Impact Resilience: Considerations and Recommendations*, May 2012, p. 1.

In a third study, NERC examined the cyberattack scenario in greater detail in a parallel effort from a cyber-focused task force. This study focuses on two primary attack vectors: 1) a coordinated attack which disables or impairs multiple control systems; and 2) intruders gaining control to purposefully misoperate the system, causing outages and/or damage. The potential ramifications are severe. If successful, adversaries could inflict losses of load and generation that cause system instability, and, ultimately, system collapse and widespread blackouts.[22]

Other industry initiatives could also be leveraged to create a DBT for fuel resilience. For example, NERC Standard CIP-014-2, *Physical Security*, provides a methodology for Transmission owners and operators to conduct their own assessment of potential physical threats and vulnerabilities.[23] NERC's *Geomagnetic Disturbance Planning Guide* provides yet another approach to assessing potential threats and system design requirements.[24] While neither of these guiding documents establishes a Design Basis Threat, they do provide useful methodological approaches that might be valuable in developing a DBT for fuel resilience.

The Department of Energy has also sponsored a study by ICF International to establish a 'baseline' of adversarial threats to the North American electric grid. The report provides an in-depth examination of an array of physical and cyber threats, including combined cyber-physical events.[25]

However, none of these studies provides a detailed analysis of the fuel resilience challenges identified in the NOPR. Nor are any of them adequate to capture the risks created by

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[22] NERC, *Cyber Attack Task Force: Final Report,* May 2012, p. 2.
[23] *See* NERC Standard CIP-014-2, *Physical Security*, May 2015, http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=CIP-014-2&title=Physical%20Security&jurisdiction=United%20States.
[24] NERC, *Geomagnetic Disturbance Planning Guide*, December 2013, p. 9.
[25] ICF International, *Electric Grid Security and Resilience: Establishing a Baseline for Adversarial Threats*, June 2016, p. 19.

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gas-electric interdependencies, common failure modes,[26] duel-fuel resupply challenges and other threats I examined in my previous testimony. The threat of common failure modes is particularly concerning, as an increasing number of gas generators depend on a limited number of pipelines to deliver fuel required for power generation. Pipeline disruptions that lead to a shortage and/or outage of natural gas could therefore incapacitate multiple generators at the same time, increasing the scope and severity of the resulting power outages A single attack vector (especially via cyber means) could enable the adversary to disrupt fuel supplies for power generation across major portions of the United States. A DBT that can help BPS entities assess resilience against these threats will need to go far beyond any previous study of interruption scenarios.

As I outlined in my original testimony, the DBT should study both natural and manmade risks the system. Manmade risks could include threats from international actors, such as Russia or China, as well as terrorist organizations. The DBT should account for both physical and cybersecurity risks. For physical attacks, the DBT should encompass both familiar attack vectors as well as threats emerging from new technologies, such as unmanned aerial vehicles carrying advanced payloads. Finally, the DBT should account for the possibility that adversaries will combine cyber and physical attacks to create especially significant challenges to fuel supply systems.

[26] NERC will be presenting a Special Assessment: Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System to its Board for approval on Nov. 9, 2017. *See* Item 8c, Agenda, Board of Trustees, Nov. 9, 2017; Special Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System, Preliminary Findings, Board of Trustees, Nov. 9, 2017, located at http://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Presentations_November_2017.pdf.

Catastrophic earthquakes and other natural hazards can also inflict catastrophic damage on fuel infrastructure. Accordingly, I recommend that the DBT include both manmade and natural hazards. Given the importance of dual fuel generators as an option to mitigate the risks posed by gas system disruptions, I also propose that planners include contingency analysis of severe disruptions in secondary fuel supplies for dual fuel generators, and disruption of fuel resupply for backup power generators that serve critical natural gas compression stations and other key gathering and Transmission infrastructure. Finally, planners should conduct sensitivity analysis on the degree to which retaining a mix of fuel-resilient generation assets, including nuclear assets, can help reinforce the resilience of the BPS as a whole.

III. The Path to a Fuel Resilience DBT

Developing a DBT will require the input of multiple stakeholders. I recommend the Department of Energy lead a multistage effort in consultation with the Commission and other grid resilience stakeholders. As the Sector-Specific Agency (SSA) for the energy sector, including both the electricity and oil and natural gas (ONG) subsectors, DOE is especially well positioned to serve as the government lead for this effort. Close coordination with other Federal departments and agencies will also be required, especially those with: 1) SSA responsibilities concerning specific fuel supplies; and 2) information on the evolving threat that could supplement DOE's own extensive expertise. The ESCC, NERC, BPS asset owners and operators, and other resilience stakeholders could also play valuable roles in guiding this process.

Most important, close coordination will also be required with BPS entities to ensure that the DBT incorporates their own analytic priorities and requirements for support. The ESCC and other appropriate entities might support this BPS engagement process as well.

Given the increasing severity of threats to fuel resilience and the need for timely assessments of those challenges, I also recommend that the development of the DBT go forward in a phased process. DOE might first bring stakeholders together to produce a rapidly-available, top-level assessment of threat vectors and characteristics, equivalent to that which the NRC provides to the nuclear fleet in its publicly-available DBT descriptions. For example, this basic DBT could specify the percentage of gas pipelines that BPS entities should assume will be disrupted (and for how long). Follow-on DBTs could then address the more detailed challenges raised by gas-electric interdependencies and the threat vectors by which adversaries may seek to exploit them.

I also recommend that the fuel resilience DBT be structured in a "tiered" fashion, with a baseline DBT provided to BPS entities at the level of "For Official Use Only" and supplementary DBTs provided as needed at higher levels of classification to cleared industry personnel.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)	**Docket No. RM18-1-000**

DECLARATION OF PAUL STOCKTON

I declare, under penalty of perjury, that the foregoing Supplemental Testimony is true and correct.

Executed: November 7, 2017

Washington, DC

Paul Stockton

SI-SSA-0010-3042

EXHIBIT B

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)	Docket No. RM18-1-000

PREPARED TESTIMONY OF MICHAEL M. SCHNITZER

ON BEHALF OF EXELON CORPORATION

I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A. My name is Michael M. Schnitzer. My business address is 30 Monument Square, Concord MA 01742.

Q. MR. SCHNITZER, BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a Director of The NorthBridge Group, Inc. ("NorthBridge"). NorthBridge is a consulting firm that provides economic and strategic advice to the electric and natural gas industries.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND EMPLOYMENT EXPERIENCE

A. In 1992, I co-founded NorthBridge. Before that, I was a Managing Director of Putnam, Hayes & Bartlett, which I joined in 1979. I have experience working with private sector

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clients in the electric utility, natural gas, and private power industries, as well as with public and nonprofit agencies. My electric industry work has focused on regulatory policy, finance, and market structure issues.

I have testified before the Commission on a number of matters, and have participated in Commission technical conferences and workshops on capacity market and energy market design issues. I have also testified before the public utility commissions of Arkansas, California, Delaware, Illinois, Indiana, Maine, Maryland, Massachusetts, Mississippi, New Hampshire, New Mexico, New Orleans, New York, Ohio, Pennsylvania, Rhode Island, Texas, Vermont, and Wisconsin.

Q. WHO IS SPONSORING YOUR TESTIMONY?

A. My testimony is sponsored by Exelon Corporation ("Exelon" or "the Company").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. On October 23, 2016, the PJM Independent Market Monitor (IMM), Dr. Joseph Bowring, filed extensive comments in this docket on several topics related to the DOE NOPR.[1] The IMM's comments included an analysis that purports to address the economics of nuclear plants in PJM[2] as well as a multi-paged critique of an energy price formation "white paper" published by PJM in June of this year.[3] The IMM concludes that the

[1] Comments of the Independent Market Monitor for PJM, October 23, 2017. ("IMM Comments")
[2] *Ibid.* at 18-20.
[3] *Ibid.* at 34-41. Also see PJM Interconnection LLC, "Energy Price Formation and Valuing Flexibility," June 15, 2017 (the "PJM White Paper").

overwhelming majority of nuclear units have been able to recover their going-forward costs of operation from market revenues in each of the last two years. The IMM further concludes that the price formation proposal outlined in the PJM white paper is unnecessary and counter-productive, and that the existing market is functioning well.

The purpose of my testimony is to respond to the IMM's analysis and critique and explain the errors contained therein. With respect to the IMM's analysis of nuclear plant economics, I correct several fundamental errors in the analysis and explain why the IMM's conclusions are incorrect. With respect to the IMM's criticism of PJM's energy price formation proposal, I first explain why, contrary to the IMM's conclusion, the current energy pricing approach in PJM is flawed and results in both efficiency losses and discrimination. I then explain why the central feature of PJM's proposal that the IMM appears to find so objectionable – separate pricing and dispatch solutions - can address both the efficiency and discrimination problems with the current approach.

Q. COULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS?

A. Yes. First, the IMM's conclusion that the overwhelming majority of nuclear units have been able to recover their costs in the last two years is not correct. The IMM's analysis erroneously omits two categories of costs that should have been included: going-forward capital expenditures as well as the cost of certain operating and market risks that are borne by owners/operators of nuclear units. When these components of going-forward cost are included, the data from the last two years indicate that the

overwhelming majority of nuclear units have failed to cover their costs and are at risk of retirement – the exact opposite of the IMM's conclusion.

Second, as to energy price formation, the IMM's conclusion rests on the false premise that the current market dispatch solution produces the least cost dispatch and prices that are consistent with that solution. It does not. While the current market dispatch solution can produce a least cost physical commitment and dispatch in the short-term (assuming the level of self-commitment is economic), the resulting prices are not necessarily consistent with that physical solution. As a result, the prices from the current market dispatch solution cannot be said to be efficient, which means they do not promote either economic retention or entry. The current prices are also discriminatory in that certain resources are paid a higher energy price than other resources. The price formation approach that PJM described in its October 23 comments is designed to address the flaws in the current pricing rules and to produce prices that support economic commitment and dispatch of generation. Given the number of nuclear units that are at risk of retirement due, in large part, to insufficient energy margins, the PJM proposal should be brought before the Commission without delay.

II. CONTRARY TO THE IMM'S ASSERTION, THE OVERWHELMING MAJORITY OF PJM NUCLEAR UNITS HAVE FAILED TO RECOVER THEIR COSTS IN RECENT YEARS AND ARE AT RISK OF RETIREMENT

Q. PLEASE SUMMARIZE THE IMM'S CONCLUSIONS WITH RESPECT TO THE FINANCIAL VIABILITY OF PJM NUCLEAR PLANTS.

A. The IMM concludes that 90 and 74 percent of all nuclear units in PJM fully recovered avoidable (or going-forward) costs in 2015 and 2016 respectively and then goes on to claim that "there are very few nuclear units in PJM that are at risk [of retirement]."[4]

Q. DO YOU AGREE WITH THE IMM'S CONCLUSIONS?

A. No.

Q. WHY NOT?

A. The IMM's analysis significantly under-states nuclear going-forward costs. When properly analyzed, the same data relied on by the IMM indicate that as few as 6 percent of PJM nuclear units fully recovered going-forward costs in 2016 and therefore many units are at risk of retirement.

Q. HOW DOES THE IMM UNDERSTATE GOING-FORWARD COSTS?

[4] *Ibid.* at 18 and 20.

A. The IMM assumes that nuclear going-forward costs (excluding fuel) are $25.83/MWh for single-unit sites and $18.73/MWh for multi-unit sites, based on national average actual cost data for 2016 published by the Nuclear Energy Institute ("NEI").[5] These values correspond to the operating cost for nuclear generators in 2016, but completely exclude two additional components of going-forward cost: ongoing capital expenditures and compensation for operational and market risk.

With regard to ongoing capital expenditures, the same NEI data indicate that in addition to operating costs, nuclear generators also incurred annual ongoing capital expenditure costs of $8.67/MWh and $6.15/MWh for single- and multi-unit sites respectively in 2016. Excluding these costs is not appropriate. These additional costs are avoidable if a nuclear unit retires. The capital costs reported by NEI do not represent recovery of sunk capital expenditures incurred in prior years. Rather, they are capital expenditures incurred in the present year. Further, the data demonstrate that these expenditures are ongoing and significant in every year tracked, and can be expected to continue at a similar level going out into the future.[6] Ongoing capital expenditures are critical to maintaining the operating condition of nuclear plants; the industry consistently incurs these capital investments, year in and year out, to maintain safe, reliable operations.

[5] Nuclear Energy Institute, "Nuclear Costs in Context," at 2 ("NEI"). Attached as Exhibit A. The IMM includes fuel in his analysis as an offset to revenue, rather than as a component of avoidable cost (*see* IMM comments, footnote 16). The IMM does not provide his estimate of fuel costs. In correcting the IMM analysis, I utilized the fuel costs published by NEI ($6.77 and $6.75/MWh for single- and multi-unit sites, respectively).
[6] NEI at 3.

Thus, ongoing capital expenditures would be avoided if the plant were to retire and are an appropriate component of going-forward costs.

Q. WHY DID THE IMM EXCLUDE THESE COSTS?

A. In a footnote, the IMM observes that, in an operating year, these capital additions are largely sunk costs, and therefore should not be treated as going forward costs.[7] That explanation completely misses the point. Retirement decisions are inherently forward-looking decisions, not backward-looking. If the IMM's analysis is to have any value, it is to provide an answer to the following question: if nuclear owners think that future market conditions will be similar to 2016 (or 2015), will it be profitable for them to continue to operate? In that context, using 2016 or 2015 revenues as a proxy for future revenues and comparing them to going forward costs, capital additions are clearly avoidable. My corrected analysis provides the correct answer to the question, which is "no". Unless market revenues increase relative to 2016 levels, it will not be profitable to continue to operate a large fraction of the PJM nuclear fleet. The retirement risk is real.

Q. WHAT RISKS ARE BORNE BY OWNERS OF OPERATING NUCLEAR PLANTS?

A. Nuclear plant owners incur significant operational and market risks in continuing to operate merchant nuclear plants. These risks include the risk of higher-than-expected operating costs, lower-than-expected production due to outages, the risk of needing to cover liquidated damages forward sales at a very high spot price in the event of a forced

[7] IMM Comments at footnote 17.

outage, the risk of higher-than-expected performance penalties when serving as a capacity resource in PJM's recently-reformed capacity market, and the ongoing market risk of lower-than-expected forward and spot sales prices for energy and capacity. These ongoing risks make owning and operating a nuclear plant on simply a cash breakeven basis an untenable proposition for investors. Rather, on an ongoing basis, investors will require that plant owners either realize compensation for these risks above simple ongoing avoidable cash costs or avoid these risks by retiring the plant. Exelon has in previous proceedings supported an overall level of operational and risk compensation equal to ten percent of operating costs, capital expenditures, and fuel costs plus four dollars per megawatt-hour.[8] I adopt this value in correcting the IMM's analysis and show the range of nuclear profitability between simple breakeven versus cash going-forward costs only, and the same with this measure of risk compensation included as well.

My corrections to the IMM's nuclear going-forward cost information are summarized below:

[8] New York Department of Public Service Case 15-E-0302, Comments of Constellation Energy Nuclear Group LLC Concerning Staff White Paper on Clean Energy Standard, April 22, 2016, at 19-28.

($/MWh)	Single-Unit Sites	Multi-Unit Sites
Operating Cost (per NEI)	$25.95	$18.73
IMM estimate of Going-Forward Cost[9]	$25.83	$18.73
Plus Correction to Operating Cost[10]	$0.12	--
Plus Ongoing Capital Expenditures (per NEI)[11]	$8.67	$6.15
Corrected Going-Forward Cost without Risk	$34.62	$24.88
Plus Market and Operational Risk[12]	$8.14	$7.16
Corrected Going-Forward Cost with Risk	$42.78	$32.02

With corrections, the appropriate going-forward cost for a single-unit site is between $34.62 and $42.78/MWh, rather than $25.83/MWh (excluding fuel) and between $24.88 and $32.02/MWh for a multi-unit site, rather than $18.73/MWh (also excluding fuel).

Q. HOW DOES THE UNDERSTATEMENT OF GOING-FORWARD COSTS AFFECT THE RESULTS OF THE IMM'S NUCLEAR FINANCIAL VIABILITY ANALYSIS?

A. The IMM's analysis of the economics of PJM nuclear generators rests on a comparison of the market revenues of these units to their going-forward costs. Because going-forward costs are greatly understated, the extent to which nuclear market revenues exceed going-forward costs is dramatically overstated. The IMM's comments presents data that purport to show that 90 percent of PJM nuclear units covered their going-forward costs in 2015 and 74 percent covered their going-forward costs in 2016. When the same analysis is performed using corrected going-forward costs, including ongoing

[9] IMM Comments at 18.
[10] The IMM miss-states the operating cost of Single Unit Sites published in the NEI data. The actual published cost is $25.95/MWh, rather than $25.83/MWh. *See* NEI at 2.
[11] NEI at 2.
[12] Market and operational risk equal to 10% of total cost (including fuel) plus $4/MWh.

capital expenditures and market and operational risk, only 19 and 6 percent of PJM nuclear units covered their going-forward costs in 2015[13] and 2016 respectively when risk compensation is included as a going-forward cost. Even without including any risk compensation in going forward costs, only 61 and 32 percent of PJM nuclear units covered their cash going-forward costs in the same years.

	Percent of Nuclear Units with Full Avoidable Cost Recovery from All Markets[14]	
	2015	2016
IMM Analysis[15]	90%	74%
Corrected Analysis excluding risk compensation	61%	32%
Corrected Analysis including risk compensation	19%	6%

Q. WHAT CONCLUSIONS DO YOU DRAW WITH RESPECT TO NUCLEAR FINANCIAL VIABILITY IN PJM FROM THIS ANALYSIS?

A. The corrected analysis does not support the conclusion reached by the IMM; rather it supports the opposite conclusion. Virtually all of PJM nuclear units are financially-challenged and therefore many are at risk of retirement. Energy margins, the principal source of going forward cost recovery for nuclear plants, have fallen to a level which is not adequate for many units. This underscores the urgency of addressing flaws in

[13] For the 2015 analysis, I used single- and multi-unit nuclear avoidable costs from NEI's earlier report on 2015 nuclear costs. *See* Nuclear Energy Institute, Nuclear Costs in Context, April 2016, at 2.

[14] In calculating the percentage of nuclear units covering their avoidable costs from all markets, I estimated energy revenues based on unit-level day-ahead locational marginal prices for the relevant year, capacity revenues based on actual cleared RPM capacity prices for the relevant years and I further assumed that all nuclear units cleared as Capacity Performance resources in the relevant CP transition auctions. I assumed that nuclear units did not earn any ancillary services revenues. For each year, I compared these revenue estimates to the appropriate measure of going-forward costs.

[15] Extracted from IMM Comments, Table 9.

energy price formation in PJM which contribute to nuclear unit financial stress, which I discuss in the next section of my testimony.

III. PJM's CURRENT MARKET DISPATCH SOLUTION DOES NOT PRODUCE PRICES THAT ARE CONSISTENT WITH THAT SOLUTION.

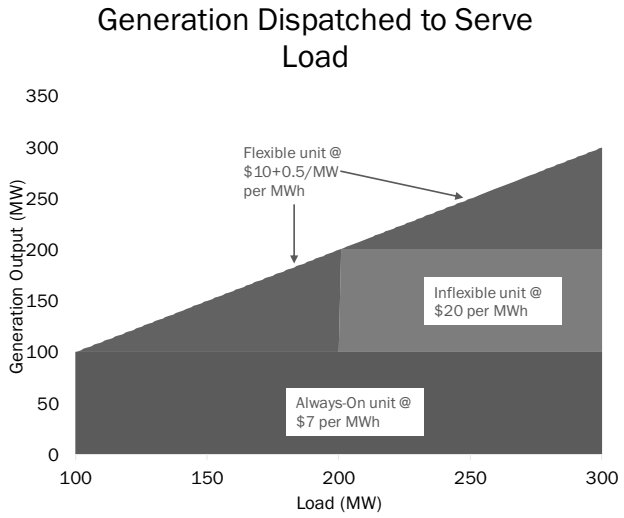
Q. PLEASE EXPLAIN WHY YOU DISAGREE WITH THE IMM ABOUT WHETHER THE CURRENT SYSTEM PRODUCES PRICES CONSISTENT WITH THE DISPATCH SOLUTION.

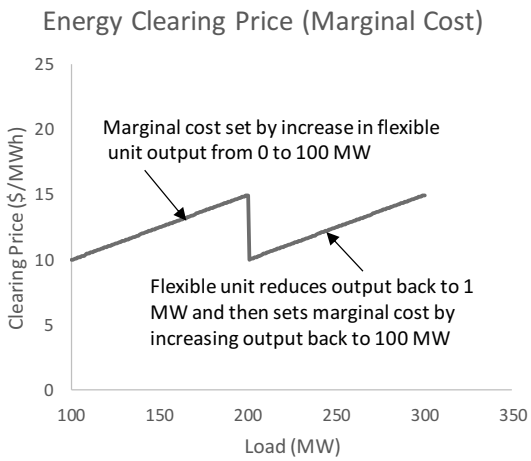
A. As I stated above, the contention that the current PJM market dispatch solution produces the least cost dispatch and prices that are consistent with that solution is central to the IMM's argument.[16] In effect, the IMM is arguing that the current system is not broken, and therefore does not need to be fixed. But a simple example illustrates that this is not the case, and that under the current system, prices are not always consistent with the dispatch.

Consider an electricity market with three generators: the first must always operate at a fixed output level of 100 MW and costs $7/MWh to operate (the "always-on unit"), the second can be either committed or offline but if committed must operate at a fixed level of 100 MW with variable costs of $20/MWh (the "inflexible unit"), and the third that can flexibly produce between 1 MW and 100 MW of output with an incremental cost of $10/MWh plus $0.05/MWh for each incremental MW of output (the "flexible unit").

[16] IMM Comments at 37.

The figures below show the economic dispatch solution at loads between 100 and 300 MW, and the associated energy clearing price under the current pricing regime.





As the dispatch chart illustrates, the least cost dispatch solution is to rely on the always-on and flexible units until load reaches 200 MW, to "back down" the flexible unit to 1 MW and bring on the inflexible unit when load is 201 MW, and then ramp the flexible unit back up as load increases from 201 to 300 MW.

What about the prices? As the price chart shows, energy prices increase and then decrease, and then increase again. From 100 to 200 MW the system marginal cost is defined by the marginal cost of the flexible unit and increases from $10 to $15/MWh. At 201 MW, the inflexible unit is committed but does not set the system marginal cost at that point. This is because, under PJM's current pricing methodology, the system marginal cost is set by the lowest-cost available source of incremental supply than can expand output in the very short term to supply an infinitesimal increase in demand.

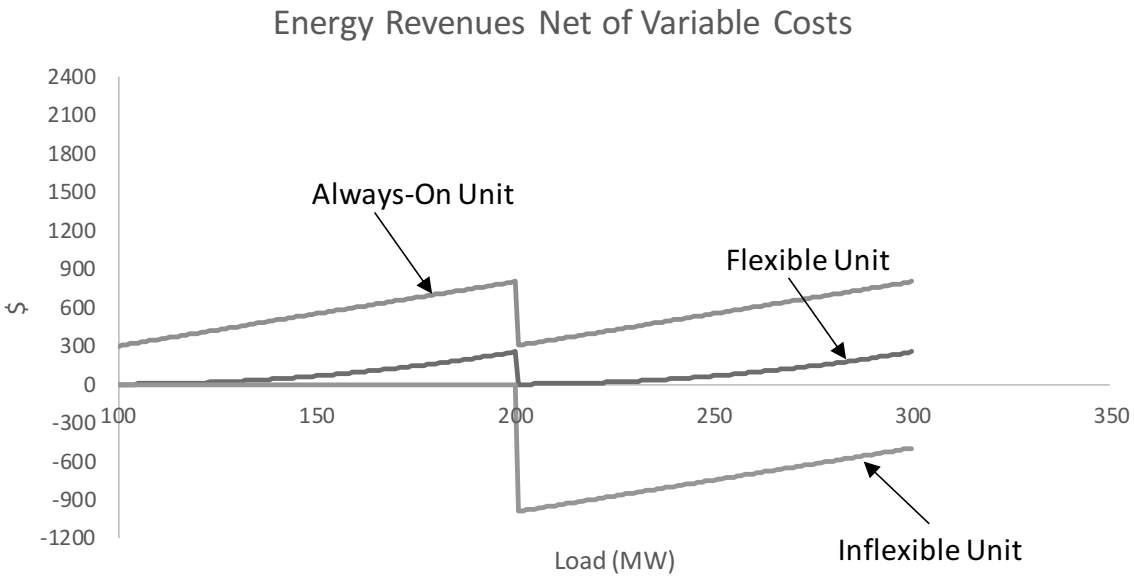
Thus, at 201 MW the inflexible unit is online at a fixed output level and cannot further increase output to supply any further increase in demand, however small, and the system marginal cost is set instead by the flexible unit at an output level of 1 MW, or $10/MWh. Thus, the system marginal cost (and energy clearing price) falls from $15/MWh at 200 MW of load to $10/MWh at 201 MW of load notwithstanding an increase in load. Basic micro-economic theory is based on the assumption that marginal supply costs increase as demand grows. But, as I will discuss in more detail below, electricity supply is different because of what economists refer to as a non-convexity, where the incremental cost of production is not continuously increasing with demand.[17] The failure of the existing pricing methodology to account for non-convexity causes a pricing anomaly where the clearing price goes down as demand increases. In my example, at load levels from 201 MW to 299 MW, the current PJM pricing methodology produces an anomaly where prices are not consistent with the physical dispatch.

Q. HOW DOES THIS ANOMALY IMPACT THE ABILITY OF DISPATCHED UNITS TO RECOVER THEIR VARIABLE COSTS?

A. The chart below shows the energy margin (energy revenues net of variable costs) of each of the generators at each load level. While the always-on and flexible units earn a positive energy margin at every load level, the inflexible unit is unable to cover its variable costs at every load level at which it is committed. Thus, at load levels up to 200

[17] *See* e.g., Richard P. O'Neill, Paul M. Sotkiewicz, Benjamin F. Hobbs, Michael H. Rothkopf, William R. Stewart, Jr., "Efficient Market-Clearing Prices in Markets with Nonconvexities," December 9, 2002.

MW, the energy prices are consistent with the dispatch. But, above 200 MW, the prices do not support the economic dispatch.



Recognizing that a generator cannot be compelled to operate at a loss, under the current system, PJM "solves" the pricing problem with an out of market uplift payment to the inflexible generator that offsets the losses it would sustain if it only received the prevailing market price. In the example, the uplift payment to the inflexible generator would result in it effectively receiving a price of $20 per MWh, split between the prevailing energy price of between $10 and $15 per MWh and whatever additional compensation is needed to move the compensation to the unit's breakeven point of $20 per MWh. But there are two problems with this solution: it does not produce "efficient" market clearing prices, and it is discriminatory.

Q. WHY ARE THESE PRICES NOT "EFFICIENT"? AND SHOULD THE COMMISSION BE CONCERNED?

A. In competitive markets, efficient prices are those that promote both productive and allocative efficiency. Productive efficiency is achieved when the quantity demanded is produced at the lowest possible cost. Allocative efficiency is achieved when the quantity demanded reflects the proper tradeoff of the cost of producing (and consuming) one product versus another.

In RTO energy markets, the commitment and dispatch solution is designed to achieve short-run productive efficiency – that is to produce the quantity demanded at each interval and across intervals at the lowest variable cost. Efficient prices must be consistent with that physical commitment and dispatch. If a unit that is economically dispatched does not receive energy market revenues that cover its variable costs, then the prices are not consistent with the dispatch. For prices to be completely consistent with the dispatch, each generator on the system has to be performing at an economic level, given the prices, and not be able to increase its profits by changing its output level up or down.

As I discussed above, and as illustrated by the simple example, the current energy pricing in PJM fails this simple test. There are both productive and allocative efficiency losses associated with this pricing failure – and that is why the Commission should be concerned.

Q. PLEASE EXPLAIN.

A. In economic terms, the current energy pricing regime in PJM is analogous to the pricing behavior of a partially discriminating monopsonist. I am using monopsony as an economic analogy here and I am not implying that PJM has any perverse intent. PJM, on behalf of the load in the footprint, buys the energy from the lowest cost producers, but it does not pay them all the same price for the energy they produce at the same time. Up to a point, all generators get the same price (the energy price, as calculated currently). But, some of the most expensive generators required to achieve a least cost dispatch, of which there might be one, ten or twenty or more on a given day, are each paid a different price that is in each case higher than the generally available energy price. In the example, the inflexible unit receives an effective price, including out of market uplift payments, of $20 per MWh, while the always-on and flexible units only receive the energy market clearing price of $10 to $15 per MWh.

Economics tells us what happens when this type of price discrimination occurs and why it is inefficient: what would and should be producer surplus under efficient pricing is instead converted to consumer surplus. All of the generators that just receive energy prices under-recover the efficient level of energy margin for every hour and day when the pricing does not support the dispatch. In the short run, a day or a month, this may not result in a significant productive efficiency penalty. But over the medium and longer

term, some of the otherwise economic generators that are harmed by this discrimination will leave the market.

As an illustration, we can return to the previous three-unit example. In this example, it is the always-on and flexible units that suffer from the inefficient price as those units effectively receive a lower price than the inflexible unit. Further, if there were other units running at the time, they would also receive the lower, inefficient price. To the extent that any of these generators withdraw from the market and would have remained in the market with efficient energy pricing, the retirement is "uneconomic" and increases the total cost of serving load, ultimately harming customers in the long run. In particular, the always-on unit, whose economics are analogous to a nuclear unit, would be particularly at risk of uneconomic retirement given that it has high fixed costs of operation that must largely be recovered through energy revenues. As I discussed in the first section of my testimony, many of the nuclear units in PJM are at risk of retirement as a result of the low level of energy margins, and the pricing inefficiency contributes to this retirement risk. Thus, the productive efficiency penalty could be quite substantial over time, and can be avoided through improved energy pricing.

Q. THUS FAR YOU HAVE JUST DISCUSSED THE POTENTIAL FOR PRODUCTIVE EFFICIENCY LOSSES. ARE THERE POTENTIAL ALLOCATIVE EFFICIENCY LOSSES, AS WELL?

A. Yes. In electricity energy markets, allocative efficiency is achieved when the "right" amount of electricity is consumed at the "right" time, consistent with efficient pricing.

As customer technology improves and becomes less expensive, sending efficient price signals on an hourly, fifteen minute, and five minute basis will become increasingly important to achieving allocative efficiency. While the amount of load that currently responds to hourly or real-time prices is not very large today, that proportion will likely grow substantially. So, by improving price formation to achieve prices that are consistent with the dispatch, the Commission should expect to realize both productive and allocative efficiency benefits over time.

Q. HASN'T THIS ENERGY PRICING INEFFICIENCY BEEN PRESENT FROM THE INCEPTION OF COMPETITIVE ENERGY MARKETS? WHY ARE CHANGES TO CORRECT ENERGY PRICE FORMATION ONLY BEING PROPOSED NOW?

A. It is correct that that this price formation inefficiency has been present since the inception of competitive markets. It is not true, however, that the problem is newly-identified, or that solutions to it have not been proposed previously. In fact, the problem of non-convexity in power markets has been well described since the inception of competitive power markets, and solutions to it have been proposed in that time frame as well, and in fact have served as the basis for a partial solution (Extended LMP) implemented in the Midcontinent ISO.[18]

[18] *See*, e.g. William W. Hogan and Brendan J. Ring, "On Minimum Uplift Pricing in Electricity Markets," March 19, 2003.

However, the problem of non-convexity has become more prevalent and apparent in recent years because of changes in market fundamentals, including very low natural gas prices, increased penetration by intermittent renewable resources, and low load growth. In prior years, higher gas prices and fewer low load / high renewables hours tended to mask the underlying problem. In recent years the flexible units setting prices during off-peak hours in PJM are more likely to be either renewables (which can vary their output via curtailment) which usually bid at either a zero or negative level, or natural gas combined-cycles with very low delivered natural gas prices. For example, between 2007 and 2012, the average PJM real-time energy price was below $20/MWH only about 3% of the hours, but the frequency of sub $20/MWH prices increased to 20% of the hours by 2016.[19] The frequency of very low prices is much higher at particular nodes – for example, at the Quad Cities nuclear plant, the real-time LMP was below $20/MWH for 47% of the hours in 2016.

Q. WHY DOES IT MATTER IF ENERGY PRICES DROP BELOW $20/MWH MORE FREQUENTLY?

A. That level of pricing would not be troubling if in fact, the marginal unit serving load during those hours was below $20/MWh. In PJM, however, there are numerous coal units, which have variable costs around or above $20/MWh, online in every hour of the

[19] Monitoring Analytics, LLC, *2016 State of the Market Report for PJM*, Table C-4.

year.[20] Thus, during hours where the price falls below $20/MWh the system will typically be relying on units whose variable costs exceed this level.

Q. WON'T ENERGY REVENUE SHORTFALLS FOR UNITS AFFECTED BY THIS INEFFICIENCY ULTIMATELY JUST BE RECOVERED THROUGH THE PJM CAPACITY MARKET?

A. No. Capacity markets, including PJM's Reliability Pricing Model ("RPM") are designed to procure sufficient capacity to ensure reliable supply during periods of peak demand at least cost. They are not, on their own, designed to produce an efficient least-cost mix of energy resources in all hours. That is primarily the role of the energy market, and, as I discussed, if the energy market is not producing efficient prices, it will not produce the least-cost mix of resources.

The demand curve in the RPM is calibrated based on the capacity revenues that a new peaking unit (a reference natural gas combustion turbine) needs to cover its costs, net of expected energy and ancillary services revenues. This energy offset calculation reflects only those high demand hours when such a unit would typically run, which are not typically the intervals when the pricing inefficiency results in prices that are too low. That is because the impact of the pricing inefficiency tends to be most prevalent and significant during low-load, off-peak hours when such a peaking unit would be offline. So the demand curve itself has not been "inflated" in any way due to the pricing

[20] I have analyzed publicly-available data on hourly unit-level output from the U.S. Environmental Protection Agency's Continuous Emission Monitoring System ("CEMS"). This data indicates that coal units were operating and producing output in every hour in PJM in 2015 and 2016.

inefficiency. In terms of the potential effect on capacity offers, many marginal supply bids in the RPM will be from peaking or intermediate resources such as combustion turbines and demand response whose energy margins, and hence capacity offers, are not significantly affected by the pricing inefficiency. To the extent that some marginal supply bids in the RPM are from resources impacted by the pricing inefficiency during certain hours (e.g., combined cycles), this could have some impact on the clearing price. The overall result of this is that RPM clearing prices based on the intersection of the peaker-calibrated demand curve and a supply curve reflecting the bids of many peaking resources will at most reflect only a portion of the energy revenue shortfalls borne by units affected by the pricing inefficiency, and will thus not offset these shortfalls. Over time, this will result in a bias in favor of peaking units at the expense of units which tend to run in all hours, which is not likely to produce the least cost mix of energy resources.

IV. THE IMM'S CRITICISMS OF PJM'S PROPOSAL ARE EITHER INCORRECT OR PREMATURE

Q. PLEASE SUMMARIZE THE IMM'S CRITICISMS OF PJM'S WHITE PAPER PROPOSAL.

A. The IMM has four major criticisms: 1) the PJM proposal would raise the cost to consumers with no counteracting decrease to production cost;[21] 2) the PJM proposed pricing solution is a fictitious solution that produces higher prices that are not consistent with the efficient dispatch of the market;[22] 3) the proposed pricing solution represents

[21] IMM Comments at 36.
[22] *Ibid.* at 37.

an "inappropriate" extension of the Commission's Fast Start Pricing NOPR;[23] and 4) the PJM proposal will have unintended consequences with respect to the incentives for flexible resources and for adverse economic behavior.[24]

Q. HOW DO YOU RESPOND?

A. As I explain below, none of the IMM's first three criticisms are valid. And the fourth is impossible to evaluate until more of the details of what PJM will propose are known.

There are two problems with the IMM's first criticism that the PJM proposal would raise costs to consumers without any offsetting production cost benefits. The first problem is that a comparison of cost increases to consumers against production cost savings is simply the wrong standard. The question presented by the price formation issue is whether energy prices that are inconsistent with economic commitment and dispatch are unjust and unreasonable and unduly discriminatory. If they are, then no "cost/benefit" test or comparison is required. This is merely a matter of ensuring that PJM's energy market is consistent with the basic economic theory on which it is based.

The second flaw in the IMM's argument is that the claim that there would be no production cost savings is simply untrue. As the preceding discussion of the productive efficiency benefits makes clear, lower production costs through avoided uneconomic retirement would be realized over time. In addition, efficient pricing could change the

[23] *Ibid.* at 36.
[24] *Ibid.* 40-41.

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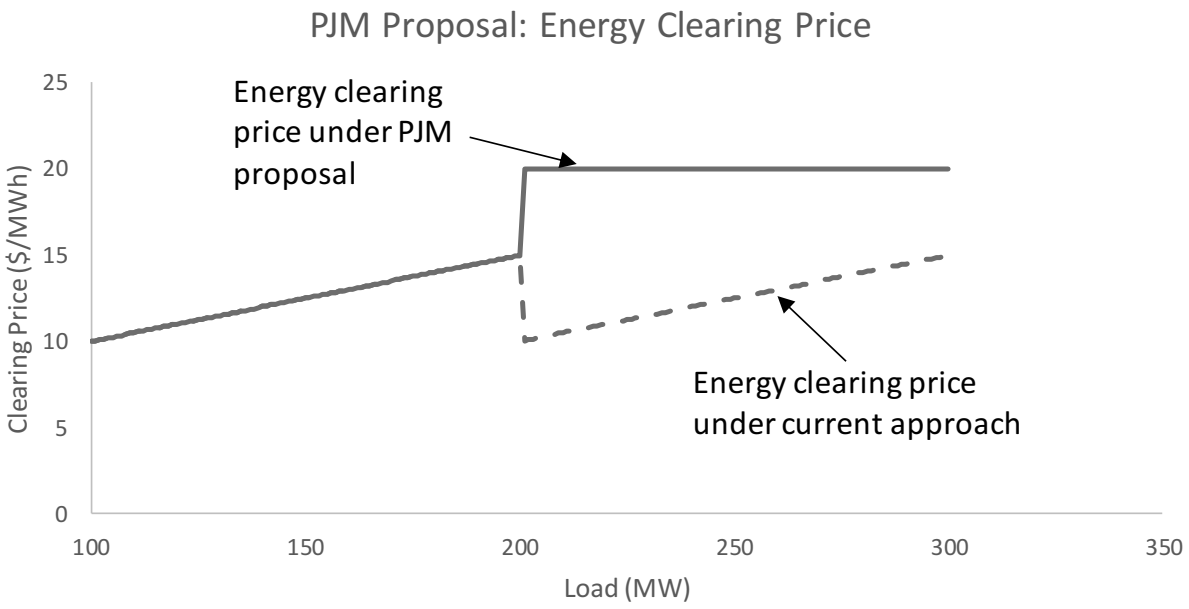
timing and mix of new supply, yielding additional productive efficiency benefits. Finally, it is possible that short-term production cost savings could also be realized, related to self-committed units. As the IMM observes, a number of long lead time or high startup cost units do not fit well into PJM's 24-hour day-ahead commitment, and self-commit instead. While that is rational way for these units to participate in the market, it is not without risk, and may not be optimal. Owners of these units must forecast prices over a multi-day period to decide when/whether to self-commit. To the extent energy prices are "too low" to support the dispatch for the reasons discussed above, the level of self-commitment may, in fact, be less than would otherwise be optimal. Under those circumstances, improved price formation could result in a more economic level of self-commitment, and lower production costs.

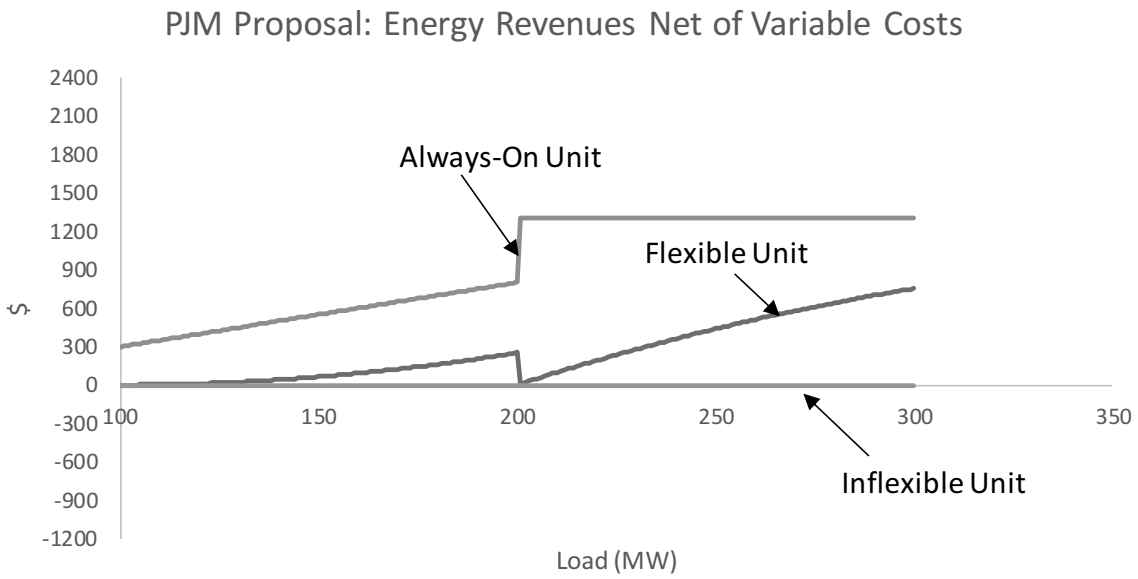
Q. WHAT ABOUT THE IMM'S SECOND CRITICISM THAT THE PJM PROPOSAL WOULD PRODUCE HIGHER PRICES THAT ARE NOT CONSISTENT WITH EFFICIENT DISPATCH?

A. I disagree. As I understand the approach that PJM is currently contemplating, the prices could sometimes be higher, but they would be consistent with the efficient dispatch, and would not be discriminatory. Let me illustrate this point by returning to the previous three-unit example discussed above. Under PJM's proposal, the dispatch would be the same as it is today. In the separate pricing run, the inflexible 100 MW unit with a variable cost of $20 per MWh would be represented as a flexible unit with a $20 per MWh variable cost. The prices that would result from this approach are shown below, together with the prices that result from the current approach.



From 100 MW through 200 MW of load, system marginal cost increases from $10 to $15 per MWh just as it would under the current pricing approach, following the marginal cost of the inflexible unit. At 201 MW and above, however, the inflexible unit is partially committed at an increasing rate, and thus sets the system marginal cost at $20/MWh.

The resulting energy clearing prices allow all three units to cover their variable costs at all load levels:



Because the price is $20/MWh over the range where the inflexible unit is committed, the inflexible unit breaks even, while the always-on and flexible units earn a positive energy margin. Thus, under PJM's proposal, the energy prices fully support the least-cost unit commitment.

However, from the load level of 201 MW to 299 MW (where the price of $20/MWh exceeds its variable cost), the flexible unit could increase its profits by dispatching at a higher level. Because of this, the flexible unit must be compensated for its lost opportunity cost to induce it to reduce its output to the level needed to avoid over generation. I discuss this out-of-market payment further below.

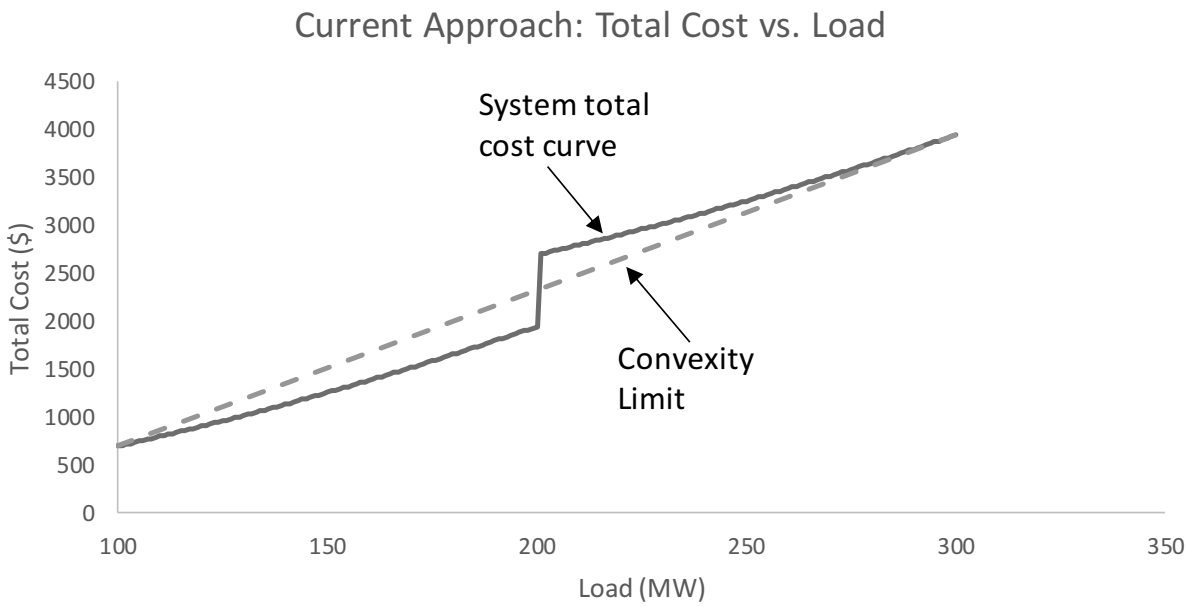
Q. TURNING TO THE IMM'S THIRD CRITICISM, IS PJM'S PROPOSAL AN INAPPROPRIATE EXTENSION OF THE FAST START NOPR PROPOSAL?

A. No. The Fast Start NOPR relates to the treatment of combustion turbines which can start quickly, but then typically must run at full output due to the physical characteristics of the unit. So, once the combustion turbine comes on, another unit must ramp down and becomes the "marginal" unit under PJM's current pricing approach. This is similar to the inflexible unit in my previous example, but a combustion turbine would typically have costs higher than $20/MWH. The solution discussed in the Fast Start NOPR is also similar to PJM's proposed solution which is to effectively let the inflexible resource set price.

The IMM believes that extending the Fast Start NOPR concepts to other inflexible units is inappropriate. I disagree. The pricing problem created by both inflexible fast start resources and inflexible baseload units is, in fact, the same problem. In both cases, we have a unit, or a portion of a unit which is either on or off, but which is part of a least cost commitment and dispatch. In both cases, the resulting prices under the current pricing rules are not sufficient to recover the variable costs of the inflexible unit, and hence are not consistent with the dispatch. In both cases, the pricing is inefficient. The only difference is that it is easier to "see" when the peaker was needed as part of the economic commitment and dispatch – it was needed when it was committed. But the key issue is not whether we know exactly when it was needed, but rather that we know it was part of an economic commitment and dispatch. In that respect, the minimum load portion of a coal unit can be thought of as a "slow start" peaker with a longer minimum run time. When it is economic to commit the slow start peaker, prices should

be consistent with that commitment just as the Fast Start NOPR would have prices consistent with the quick start peaker commitment.

The basic issue, which is common to both the slow start peaker and the fast start peaker is that the total cost of serving increasing levels of load, due to "on/off" segments, is not a smooth curve. To illustrate this point, let's return to my previous three-unit example. The total variable cost of production based on the efficient commitment and dispatch is shown in the chart below:



The minimum load level of 100 MW is served by the always-on unit at a cost of $700. From 100 MW to 200 MW of load, the flexible unit ramps up from 1 to 100 MW, with each incremental MW costing $0.05/MW more than the last MW to the point where total costs are $1950 at 200 MW, and marginal cost is $15/MWh. At 201 MW of load, however, a discontinuity appears because the inflexible unit is now needed to serve

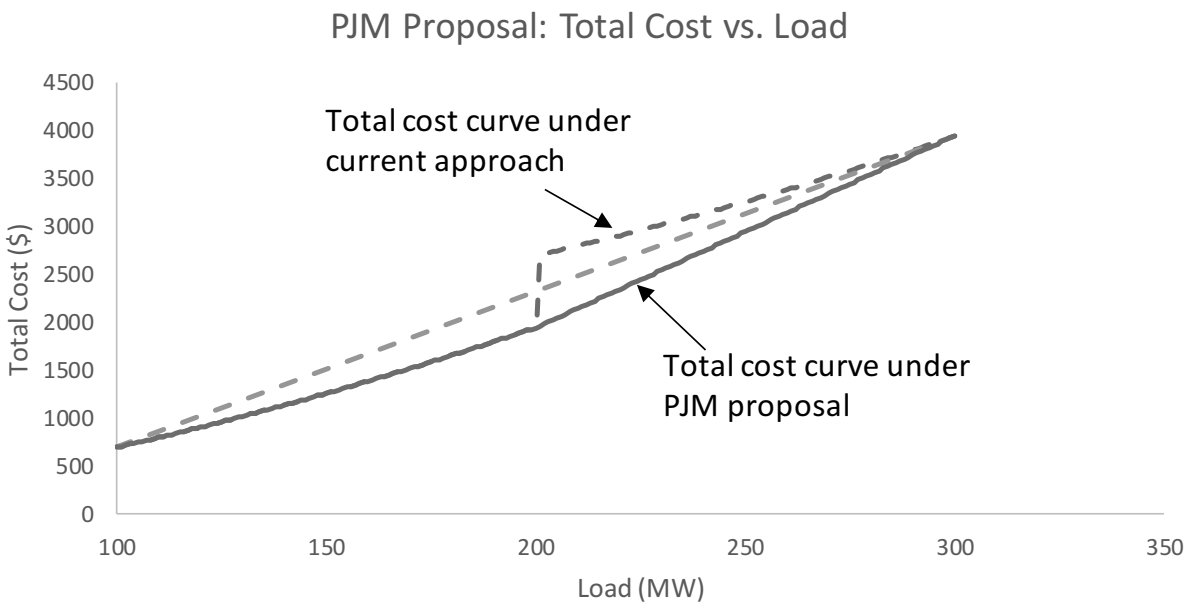
load. At this point the inflexible unit produces a fixed 100 MW of output and the flexible unit must ramp down to 1 MW of output to meet load. Total costs jump from $1950 at 200 MW to $2710 at 201 MW ($700 for the always-on unit, $2000 for the inflexible unit and $10 for the flexible unit). Moving from 201 to 202 MW the incremental cost falls back down to just over $10/MWh because the flexible unit returns to ramping up from 1 to 2 MW. This is indicative of what economists refer to as a non-convexity: the incremental cost of production is not continuously increasing with demand. Graphically, this can be seen by comparing the total cost curve to the straight line drawn between zero production and maximum production (shown in dashed red on the chart above). If any point on the total cost curve is above this line, the cost curve is non-convex. And if the total cost curve is non-convex, it means as system output increases, at some point marginal costs will decline, and prices based on marginal costs will not support the dispatch.

Much of micro-economic theory, and in particular the conclusion that short-term marginal cost is the efficient market price, is only valid under the assumption of a convex cost curve. But the electricity production cost curve is not convex because of operating constraints such as an on/off peaker or the minimum segment of an inflexible baseload unit. Despite significant economic literature on this point,[25] the IMM argues

[25] *See* e.g., Paul R. Gribik, William W. Hogan, and Susan L. Pope, "Market-Clearing Prices and Energy Uplift," Dec 31, 2007 ("Gribik et. al.").

that short-term marginal costs are always the right price and non-convexity should be selectively addressed rather than considered more broadly.

PJM's proposed energy price reform correctly considers all of the sources of non-convexity, not just on/off peakers, and would "relax" the on/off unit commitment decision for all inflexible units that are part of the economic commitment and dispatch, allowing the units to be partially committed in the pricing run and thus able to set price even when physically operating at their minimum output level. This change results in a convex total variable cost curve as shown below for the three-unit example:



The cost curve looks the same as the status quo through the 200 MW load point – the always-on unit serves the minimum 100 MW of load and then the lower cost flexible unit is committed first in either case – but at 201 MW load, rather than fully committing

the inflexible unit and ramping the flexible unit back to 1 MW, the pricing model partially commits the inflexible unit at an output level of 1 MW and leaves the inflexible unit at 100 MW. As a result, total costs increase from $1950 to $1970 as load moves from 200 to 201 MW, and continue to increase at $20/MW, the marginal cost of the inflexible unit, thereafter. Thus, the marginal cost curve, and energy clearing prices, are either increasing or constant with load level. This general approach of reforming the non-convex supply curve to be convex for purposes of setting prices has been well-established in the economic literature for over a decade and is the core economic concept underlying MISO's implementation of Extended Locational Pricing.[26] Given this history, the IMM's claim that "no economic theory supports allowing inflexible, baseload units to set price"[27] is surprising, and wrong. There is, in fact, a sound economic theory for allowing inflexible baseload units that are part of an economic commitment and dispatch to set price.

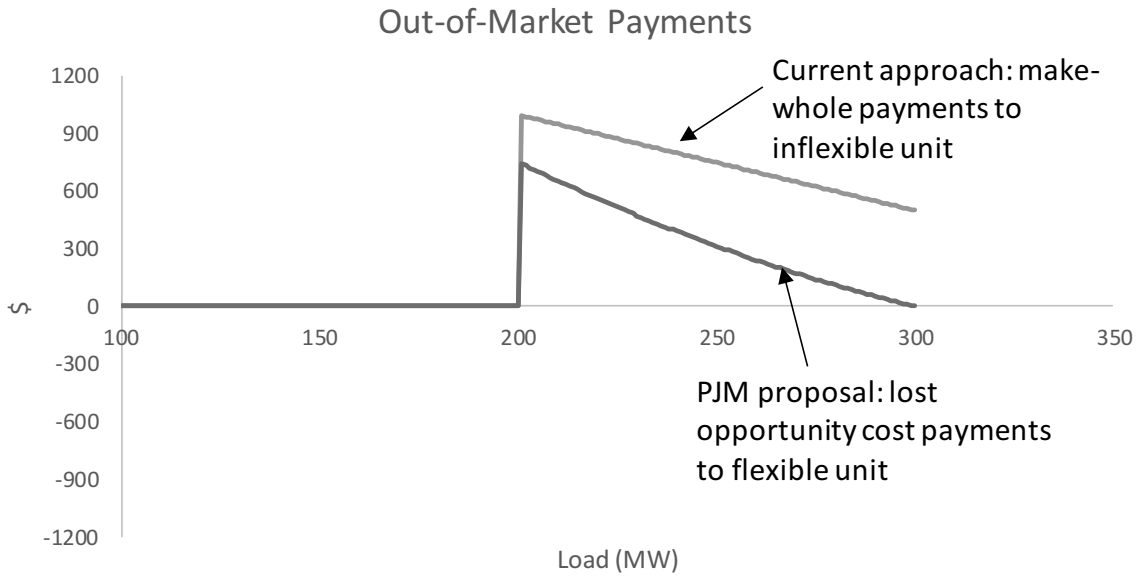
Q. WILL PJM'S PROPOSED APPROACH ELIMINATE OUT-OF-MARKET PAYMENTS?

A. PJM's approach should reduce, but will not eliminate out-of-market payments. Returning to the three-unit example, from the load level of 201 MW to 299 MW (where the price of $20/MWh exceeds its variable cost), the flexible unit could earn increased energy margin by increasing its output to its maximum level of 100 MW, as discussed

[26] *See* Gribik et. al. and Paul Gribik, Li Zhang, "Extended Locational Marginal Pricing (Convex Hull Pricing)," presentation at FERC Technical Conference on Unit Commitment Software, June 2-3, 2010, at 10-13. Available at https://www.ferc.gov/CalendarFiles/20100530130229-Gribik,%20Zhang,%20Midwest%20ISO%20-%20Extended%20LMP.pdf

[27] IMM Comments at 38.

above. While the flexible unit must be compensated for this lost opportunity cost to induce it to reduce its output to the level needed to avoid over-generation, these payments are lower than the payments which would need to be made to the inflexible unit under the status quo approach, as shown below.



Since out of market payments are required under the proposed PJM approach, it could be said that the prices are not completely consistent with the dispatch. But under PJM's proposed approach, units that are part of an economic commitment and dispatch will receive energy market revenues that are sufficient to cover their variable costs. Further, in contrast to the current pricing approach, the out of market payments are non-discriminatory in that all generating units receive revenues consistent with the same market clearing price. As a result, the efficiency losses associated with uneconomic retirement are avoided.

Q. DOES THE PJM PROPOSAL RESULT IN UNINTENDED CONSEQUENCES WITH RESPECT TO FLEXIBLE RESOURCES, AS SUGGESTED BY THE IMM?

A. The IMM suggests that the PJM Proposal "removes the economic incentive for the marginal resource to follow the dispatch signal."[28] This concern is speculative and premature because such incentives will be driven by design elements that PJM has not yet described in detailed terms. Further, in all likelihood, PJM's proposal will ultimately enhance, rather than reduce, incentives for generation to follow dispatch signals.

As noted previously, PJM's proposal will require out-of-market lost opportunity cost payments to induce certain generators to reduce output below their economically-optimal level to avoid physical over-generation. In its comments, PJM acknowledges the need for an appropriately-designed compensation mechanism to achieve this outcome, but does not at this point specify a solution. While care will be needed in designing such a compensation mechanism, the simple baseline lost opportunity cost payment ensures that resources will not have a disincentive to follow dispatch, and numerous options exist to provide an affirmative incentive for resources to follow the precise dispatch signal, such as penalties for failing to follow dispatch (or bonuses for doing so). Similar lost opportunity cost compensation mechanisms exist today in PJM's markets, such as in the synchronized reserve market and as uplift payments to resources scheduled in the day-ahead market but not committed in real-time, or to resources whose output level is restricted due to a reliability issue. While this will be an important element of PJM's

[28] *Ibid.* at 39.

ultimate proposal, it is a tractable issue and one that PJM has ample experience managing.

More fundamentally, the core problem with following dispatch raised by the IMM already exists in PJM's current market design, and PJM's proposal will make the problem better, rather than worse. As noted previously, in the current market, many inflexible units would generate less than the economic amount absent the out-of-market compensation paid to commit their units. This is the mirror image of the problem that the IMM describes, just applied to a different class of units. The PJM proposal largely eliminates the need for this type of uplift while reducing, but not eliminating, the overall amount of out-of-market compensation needed to induce units to follow dispatch. Thus, when viewed through this more holistic lens, the PJM Proposal improves, rather than reduces, the system-wide incentives for units to follow dispatch signals.

Q. DOES THE PJM PROPOSAL CREATE ADVERSE ECONOMIC INCENTIVES FOR SELF-COMMITMENT, AS SUGGESTED BY THE IMM?

A. The IMM suggests that the higher energy prices resulting from PJM's Proposal will lead to an inappropriate incentive for units to self-commit in the energy market, resulting in increased out-of-market payments and further price inefficiency. While PJM's Proposal lacks sufficient detail at this point to fully evaluate this concern, a properly-designed proposal will improve self-commitment incentives relative to the current pricing approach.

As noted previously, the core design principle underpinning PJM's proposal is the notion that all resources that are part of the least-cost solution should be eligible to set price, and the resulting market prices should support the least-cost solution. This principle should apply to both pool-scheduled resources[29] and self-scheduled resources that are part of the least-cost solution. It should not, however, apply to self-scheduled resources that are not part of the least-cost solution, and, by extension, if such resources were nonetheless self-committed, they should not be eligible to set price when running at minimum load. The key distinction here is the difference between economic and uneconomic resources, not the difference between pool-scheduled and self-scheduled resources. If a unit is part of the economic solution, it should be permitted to set price.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[29] PJM's Tariff defines pool-scheduled resources as "those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which [PJM] scheduled in the Day-ahead Energy Market as well as generators committed by [PJM] subsequent to the Day-ahead Energy Market." See PJM OATT, Section 1.10.2.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)	Docket No. RM18-1-000

DECLARATION OF MICHAEL M. SCHNITZER

I declare under penalty of perjury that the foregoing Prepared Testimony is true and correct.

Executed: November 7, 2017

Washington, DC

Michael M. Schnitzer

EXHIBIT A

white paper

Nuclear Costs in Context

Prepared by the

Nuclear Energy Institute

August 2017

NUCLEAR ENERGY INSTITUTE

The Nuclear Energy Institute is the nuclear energy industry's policy organization.

This white paper and additional information about nuclear energy are available at *nei.org*.

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Total Generating Costs

In 2016, the average total generating cost for nuclear energy was $33.93 per MWh (megawatt-hour). Total generating costs include *capital, fuel and operating costs* – all the costs necessary to produce electricity from a nuclear power plant. Cost information for the U.S. nuclear fleet is collected by the Electric Utility Cost Group (EUCG) with prior years converted to 2016 dollars for accurate historical comparisons.[1]

2016 Cost Summary ($/MWh)

Category	Number of Plants / Sites	Fuel	Capital	Operating	Total Operating (Fuel + Operating)	Total Generating (Fuel + Capital + Operating)
All U.S.	60*	6.76	6.74	20.43	27.19	33.93
Plant Size						
Single-Unit	25	6.77	8.67	25.95	32.72	41.39
Multi-Unit	35	6.75	6.15	18.73	25.48	31.63
Operator						
Single	12	7.18	8.19	21.20	28.38	36.57
Fleet	48	6.63	6.32	20.21	26.84	33.16

**Costs exclude shutdown plants.*
Source: Electric Utility Cost Group (EUCG)

Approximately 80 percent of the electricity generated from nuclear power in the U.S. comes from plants with multiple reactors. The economies of scale allow plant operators to spread costs more over multi-unit sites, resulting in a lower total generating cost. In 2016, the average total generating cost at multi-unit plants was $31.63 per MWh compared to $41.39 per MWh for single-unit plants.[2] This separation is driven by operations and capital costs as there is not a meaningful difference in fuel costs.

The 2016 total generating costs were 6 percent lower than in 2015 and more than 15 percent below the 2012 costs. Prior to the 2012 peak, nuclear generating costs had increased steadily over the previous decade, for various reasons. Between 2002 and 2016,

[1] EUCG data are collected to perform benchmarking comparisons by companies that operate nuclear plants. The total generating cost does not include considerations for risk management or returns on investment that would be key factors in business decisions affecting a particular station.
[2] The data provided are averages across the operating fleet. Individual plants may vary notably from the average due to factors such as geographic location, local labor costs and the timing of refueling outages.

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fuel costs increased by 16 percent, capital expenditures by nearly 70 percent, and operating costs by more than 8 percent (in 2016 dollars per megawatt-hour). Total generating costs have increased by more than 18 percent in the last 14 years.

U.S. Nuclear Plant Costs (2016 $/MWh):

Year	Fuel	Capital	Operating	Total
2002	5.80	3.97	18.85	28.62
2005	5.09	5.88	19.21	30.18
2010	6.85	9.28	20.92	37.05
2011	7.19	10.20	22.18	39.58
2012	7.57	10.91	21.77	40.25
2013	7.84	8.32	21.22	37.37
2014	7.31	8.29	21.21	36.81
2015	6.95	8.07	21.11	36.13
2016	6.76	6.74	20.43	33.93
2002-2016 Change	**16.6%**	**69.8%**	**8.4%**	**18.6%**
2012-2016 Change	**-10.7%**	**-38.2%**	**-6.2%**	**-15.7%**

Capital Costs

Industry-wide, capital spending in 2016 decreased to $5.4 billion from $6.3 billion in 2015, compared to the peak of $8.8 billion in 2012 (all in 2016 dollars).

Capital investment saw a step-change increase around 2003 followed by steady increases until another step-change increase in 2009 and finally peaking in 2012. Capital costs have declined in each of the last four years. These inflections are the result of a few major items: a series of vessel head replacements, steam generator replacements and other upgrades as companies prepared their plants for operation after the initial 40-year license, and power uprates to increase output from existing plants. As a result of these investments, 84 of the 99 operating reactors have received twenty-year license renewals[3] and 92 of the operating reactors have been approved for uprates[4] that have added over 7,300 megawatts of capacity.

Capital spending on uprates and items necessary for operation beyond 40 years has moderated as most plants are completing these efforts. Investments in uprates peaked at $2.5 billion in 2012 but declined to $114 million in 2016. Some of this decline has been

[3] Nuclear Regulatory Commission: License Renewals Granted for Operating Nuclear Power Reactors. December 2016. https://www.nrc.gov/images/reading-rm/doc-collections/maps/power-reactors-license-renewals.png
[4] Nuclear Energy Institute: US Nuclear Power Uprates by Plant. June 2016. https://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants/US-Nuclear-Power-Uprates-by-Plant

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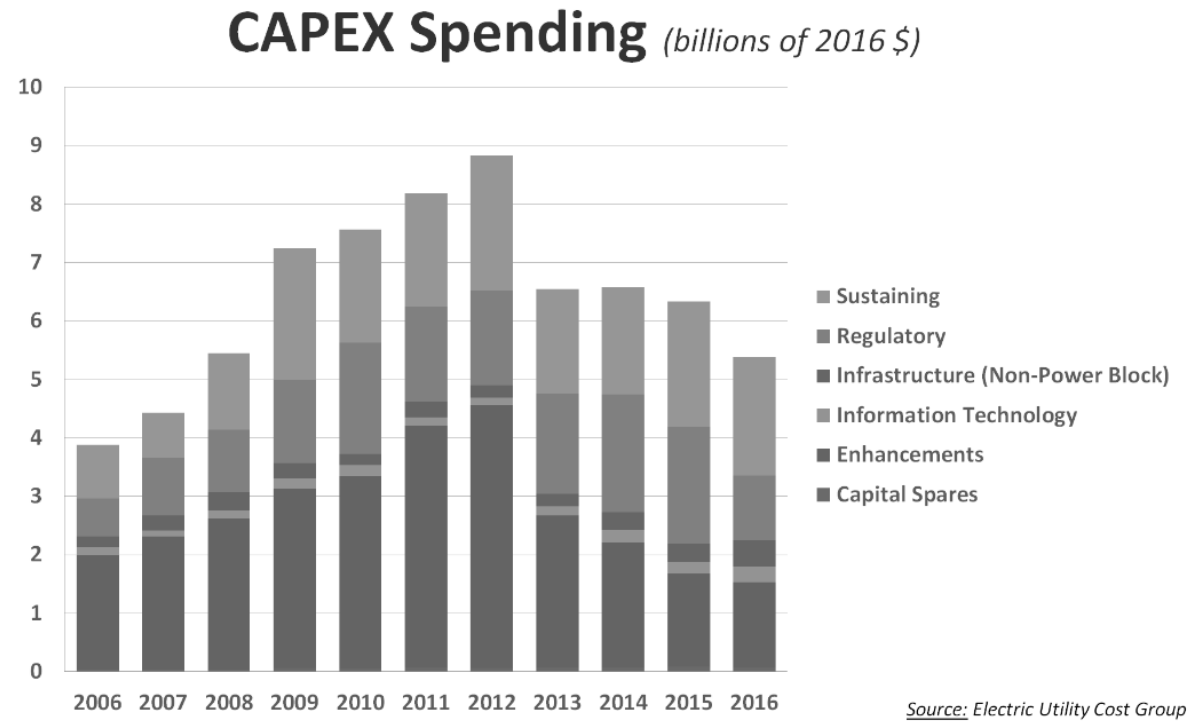
offset in other areas where spending has increased, however capital spending decreased notably in 2016 over 2015. Capital spending to meet regulatory requirements increased from approximately $1 billion in 2007 to approximately $1.9 billion in 2010 and peaked at $2 billion in 2014, before dropping to $1.1 billion in 2016 (all numbers in 2016 dollars). This increase began with significant investments post-9/11 to enhance security, followed by expenditures for post-Fukushima items, which peaked at $1.4 billion in 2015, before falling to $373 million in 2016. As the Fukushima-related safety upgrades are nearly completed, regulatory capex should also moderate, and revert toward 2007-2008 levels.

The chart below breaks down capital costs over the last decade.



Operations

Operations costs increased over the last twelve years from $18.85 per megawatt-hour in 2002 to $20.43 per megawatt-hour in 2016. Operations costs have declined 8 percent from the peak in 2011.

This increase in operations costs was not driven by any single category. Operations costs in the 2002-2008 period are similar to where money was being spent in the 2009-2016 period. However, operations costs have remained flat compared to the past decade. Between 2002 and 2010, operations costs increased 11 percent while, over the past five years, operations costs have decreased by 6 percent.

The chart below breaks down operations spending over the last decade.

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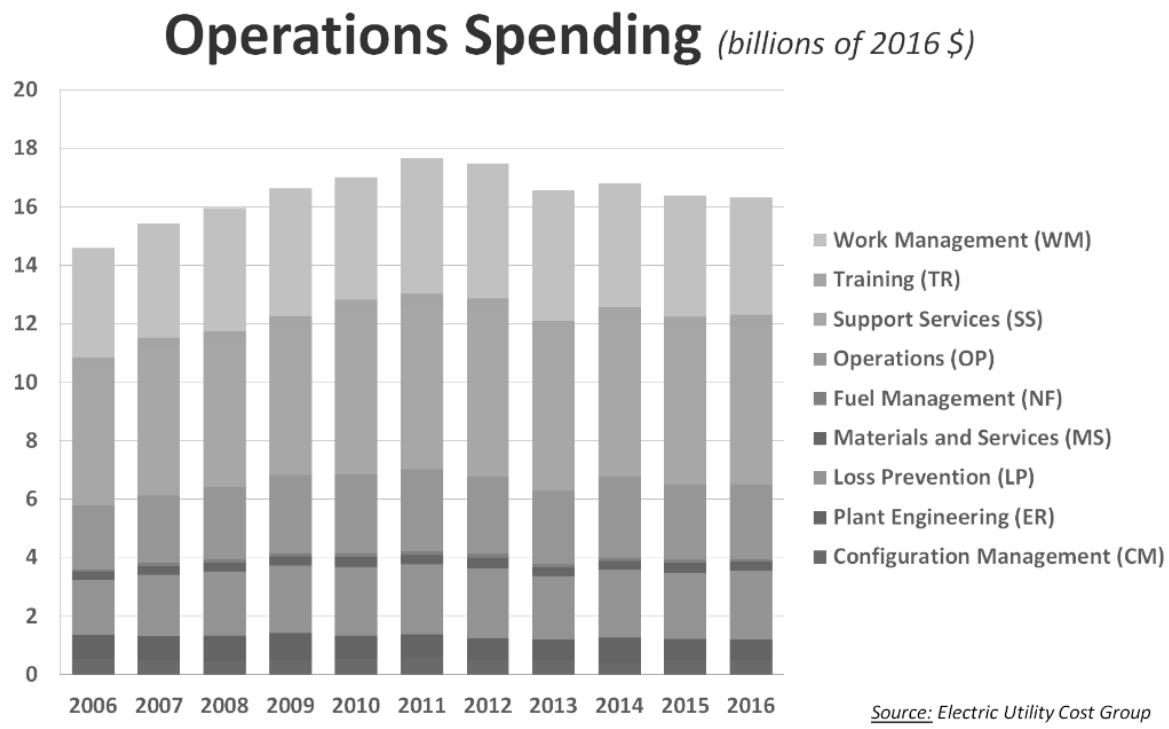

Fuel

Fuel costs represent 15-20 percent of the total generating cost. Fuel costs experienced a relatively rapid increase from 2009 to 2013. This was largely the result of an escalation in uranium prices, which peaked in 2008. Since uranium is purchased far in advance of refueling and resides in the reactor for four to six years, the effect of this commodity price spike persisted for a long time after the price increase actually occurred.

Economic Pressures Facing Nuclear Plants

Since 2013, six nuclear reactors (Crystal River 3 in Florida, San Onofre 2 and 3 in California, Kewaunee in Wisconsin, Vermont Yankee, and Fort Calhoun in Nebraska) have shut down permanently. Entergy announced in October 2015 that it would close its Pilgrim plant in Massachusetts by June 2019. In June 2016, Pacific Gas & Electric announced it would close both Diablo Canyon units by August 2025. In December 2016, Entergy announced it would close its Palisades plant in 2018. A month later, Entergy announced it would close Indian Point 2 and 3 by April 2021. In May 2017, Exelon announced that Three Mile Island would cease operations in 2019.

Crystal River and San Onofre shut down due to failed steam generator replacements – unique situations that are unlikely to be repeated. Since the Surry nuclear power plant in Virginia replaced its steam generators in the early 1980s, it has become a routine practice.

Diablo Canyon is retiring due to a combination policy and market pressures that created a situation where the plant could not optimally operate. Kewaunee, Vermont Yankee, Fort Calhoun, Palisades, Pilgrim and Indian Point, Three Mile Island – all in competitive markets

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– succumbed to a combination of market-related factors (and, in some cases, a combination of several factors), including:

- Sustained low natural gas prices, which are suppressing prices in wholesale power markets, and will continue to do so.
- Relatively low growth (in some markets, no growth) in electricity demand due partly to subpar U.S. economic performance since the 2008 recession, partly to greater efficiency.
- Federal and state mandates for renewable generation, which suppress prices, particularly during off-peak hours (when wind generation is highest and the electricity is needed the least). For example, the federal production tax credit allows wind producers to bid negative prices, which places baseload plants at a disadvantage. Some nuclear plants in Illinois see negative prices as much as 10-11 percent of the off-peak hours and 5-6 percent of all hours.
- Transmission constraints, which require a power plant to pay a congestion charge or penalty to move its power on to the grid. Certain nuclear plants at particularly congested points on the grid pay a penalty of $6-9 per megawatt-hour to move their power out.
- Market designs that do not compensate the baseload nuclear plants for the value they provide to the grid, and market policies and practices – e.g., reliance on out-of-market revenues – that tend to suppress prices.

In the face of these pressures, additional plants will face the prospect of early closure unless policies are put in place to better reflect the value of the benefits provided by nuclear energy. New York and Illinois have enacted policies that will compensate nuclear plants for their environmental attributes, ensuring that a total of seven reactors in those two states will not be forced to shut down prematurely.

Economic Impact of Nuclear Plant Closures

The plants that have closed or announced closure were all highly reliable plants with high capacity factors and relatively low generating costs. Allowing these facilities to close will have long-term economic consequences: replacement generating capacity, when needed, will produce more costly electricity, fewer jobs that will pay less, and more pollution.

In 2016, on average, U.S. nuclear power plants produced electricity for less than $34 per megawatt-hour. The smaller single-unit plants like Kewaunee, Vermont Yankee and Fort Calhoun were a little more costly – about $41 per megawatt-hour. The larger, multi-unit sites were less costly – less than $32 per megawatt-hour range. The electricity these plants produce will likely be replaced with combined cycle gas-fired capacity at a levelized cost of $49 per megawatt-hour[5] according to the U.S. Energy Information Administration

■

[5] U.S. Energy Information Administration: Annual Energy Outlook 2017 Levelized Costs – Appendix A. April 2017. https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

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PUBLIC VERSION

Pursuant to the Commission's Regulations Regarding Requests for Privileged Treatment of Documents, 18 C.F.R. § 388.112, Certain Information Contained in Attachment A of This Submission Constitutes Privileged, Protected, and Confidential Information and Has Been Redacted from This Public Version

December 30, 2013

BY ELECTRONIC FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: AV Solar Ranch 1, LLC, Docket No. ER12-2178-___
Baltimore Gas and Electric Company, Docket No. ER10-2172-___
Cassia Gulch Wind Park, LLC, Docket No. ER11-2016-___
CER Generation, LLC, Docket No. ER10-2184-___
CER Generation II, LLC, Docket No. ER10-2183-___
Commonwealth Edison Company, Docket No. ER10-1048-___
Constellation Energy Commodities Group Maine, LLC, Docket No. ER10-2192-___
Constellation Mystic Power, LLC, Docket No. ER11-2056-___
Constellation NewEnergy, Inc., Docket No. ER10-2178-___
Constellation Power Source Generation, Inc., Docket No. ER10-2174-___
Cow Branch Wind Power, LLC, Docket No. ER11-2014-___
CR Clearing, LLC, Docket No. ER11-2013-___
Criterion Power Partners, LLC, Docket No. ER10-3308-___
Exelon Framingham, LLC, Docket No. ER10-1020-___
Exelon Generation Company, LLC, Docket No. ER13-1536-___
Exelon New Boston, LLC, Docket No. ER10-1078-___
Exelon West Medway, LLC, Docket No. ER10-1080-___
Exelon Wind 4, LLC, Docket No. ER11-2010-___
Exelon Wyman, LLC, Docket No. ER10-1081-___
Handsome Lake Energy, LLC, Docket No. ER10-2180-___

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Harvest Windfarm, LLC, Docket No. ER11-2011-___
High Mesa Energy, LLC, Docket No. ER12-2528-___
Michigan Wind 1, LLC, Docket No. ER11-2009-___
PECO Energy Company, Docket No. ER10-1143-___
Tuana Springs Energy, LLC, Docket No. ER11-2007-___
Wind Capital Holdings, LLC, Docket No. ER11-2005-___

Updated Market Power Analysis for the Northeast Region

Dear Secretary Bose:

The above-referenced entities (collectively, the "Exelon MBR Entities") hereby submit for filing this joint updated market power analysis for the Northeast ("NE") Region pursuant to Section 35.37 of the Federal Energy Regulatory Commission's ("Commission") regulations[1] and Order Nos. 697 and 697-A.[2]

The instant filing is the Exelon MBR Entities' first updated market power analysis filing for the NE Region following the March 12, 2012, Commission-approved merger of Exelon Corporation ("Exelon") and Constellation Energy Group, Inc. ("Constellation"). The Exelon MBR Entities are now all subsidiaries of Exelon, a public utility holding company.[3] The Commission has authorized each of the Exelon MBR Entities to make sales at market-based rates and has designated each of them as a "Category 2 Seller" in the NE Region. The Exelon MBR Entities submit their updated market power analysis in a consolidated manner for administrative efficiency.[4]

As discussed below, the Exelon MBR Entities continue to lack market power in the NE Region. Pursuant to Order No. 697, which provides for the submission of an updated market power analysis on a regional basis, the Exelon MBR Entities' enclosed analysis focuses on the NE Region and specifically the following balancing authority areas ("BAAs") where the Exelon MBR Entities own or control, or are affiliated with, generating facilities as described in greater detail herein: New York Independent System Operator, Inc. ("NYISO"), ISO New England, Inc.

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1 18 C.F.R. § 35.37 (2013).

2 *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied*, 133 S. Ct. 26 (2012).

3 *Exelon Corp.*, 138 FERC ¶ 61,167 (2012) (Order Conditionally Authorizing Merger and Disposition of Jurisdictional Facilities) ("*Merger Order*"); *Exelon Corp.*, Docket Nos. EC11-83-000, *et al.*, Notice of Consummation (filed Mar. 19, 2012).

4 On December 20, 2013, certain of the Exelon MBR Entities filed revisions to their respective market-based rate tariffs under separate cover in compliance with Order No. 784, *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, FERC Stats. & Regs. ¶ 31,349 (2013), *reh'g pending*.

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("ISO-NE"), and PJM Interconnection, L.L.C. ("PJM"). The Exelon MBR Entities respectfully request that the Commission accept their updated market power analysis for filing and grant the waivers requested herein.

In addition, the Exelon MBR Entities include a notice of change in status regarding a tolling agreement through which Exelon Generation Company, LLC ("ExGen") will acquire control over the Granite Ridge generating facility located in the ISO-NE BAA beginning on January 1, 2014. Lastly, certain of the Exelon MBR Entities request waiver of the Commission's open access requirements with respect to their limited and discrete generator interconnection facilities, as explained in Section VII below.

I. REQUEST FOR PRIVILEGED TREATMENT

The Exelon MBR Entities request privileged treatment pursuant to Section 388.112 of the Commission's regulations[5] for the Exelon MBR Entities' 2012 hourly load data. All the information for which privileged treatment is sought is contained in the work papers of Julie Solomon, submitted as part of Attachment A. The work papers contain information about confidential, commercially sensitive load data that could harm the Exelon MBR Entities if publicly released. Pursuant to Section 35.37(f) of the Commission's regulations,[6] a proposed protective order is included herewith as Attachment C.[7] Communications concerning this request for privileged treatment should be directed to Jane Rueger at 202-626-6534 or Caileen Gamache at 202-626-3671.

II. DOCUMENTS SUBMITTED

A. This Transmittal Letter.

B. Affidavit of Julie R. Solomon, Managing Director of Navigant Consulting, Inc. including exhibits and work papers (**Attachment A**).

C. Appendices required by Order No. 697 listing (1) all affiliates that have market-based rate authority and identifying all generation assets owned or controlled by the corporate family by balancing authority area and geographic region; and (2) all electric transmission and natural gas intrastate pipelines and/or gas storage facilities owned or controlled by the corporate family (**Attachment B**).

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5 18 C.F.R. § 388.112.

6 *Id.* § 35.37(f).

7 The attached proposed protective order is a version of the Commission's Model Protective Order modified to apply to all documents in the proceeding, both those provided in discovery and those filed with the Commission, and to provide for additional protection for documents marked as "Highly Sensitive Protected Materials" from review by in-house personnel who may gain a competitive advantage through access to such information. The Model Protective Order was further modified to assure that the right to review, and the protections against disclosure, extend to review by any member of the Commission's staff, not just trial staff. However, Commission advisory staff are specifically exempt from the obligation to sign and return a non-disclosure agreement prior to viewing the materials.

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D. Proposed protective order (**Attachment C**).

III. COMMUNICATIONS

The Exelon MBR Entities request that all communications regarding this filing be sent to the following persons:

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Deputy General Counsel – Regulatory
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* Persons denoted with an asterisk are those designated for service pursuant to 18 C.F.R. § 385.2010. The Exelon MBR Entities respectfully request waiver of 18 C.F.R. § 385.2010(k) so that they may designate three persons to receive service on their behalf.

IV. DESCRIPTION OF THE EXELON MBR ENTITIES' AND THEIR AFFILIATES' GENERATION INTERESTS IN THE NORTHEAST REGION

The Exelon MBR Entities and their affiliates described below own or control generation, transmission and/or inputs to electric power production[8] in the NE Region. The Exelon MBR Entities also include in Attachment B the required appendices listing all affiliates that have market-based rate authority and identifying all generation assets owned or controlled by the corporate family by balancing authority area and geographic region, in accordance with Order No. 697.[9] Similarly, an appendix reflecting all electric transmission and natural gas intrastate pipelines and/or gas storage facilities owned or controlled by the corporate family is provided in Attachment B.[10]

[8] As defined in 18 C.F.R. § 35.36(a)(4) of the Commission's regulations.

[9] Order No. 697 at P 894.

[10] *See id.* at P 895.

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A. ***Exelon Generation Company, LLC***. ExGen, an indirect, wholly owned subsidiary of Exelon, has a diverse generation portfolio consisting of approximately 45,227 MW of directly owned and/or controlled capacity nationwide. ExGen serves as a supplier of energy to, among others, utilities and municipalities to meet their native load obligations. Through various subsidiaries, ExGen is also a retail competitive energy provider. ExGen's generation assets in the various FERC-defined geographic regions are listed in the Asset Appendix in Attachment B. In the NE Region, ExGen directly, or indirectly through its subsidiaries, owns and/or controls approximately 30,000 MW of capacity. ExGen's subsidiaries that own and/or control generation in the NE Region are further described below.[11] The Commission has granted ExGen market-based rate authority.[12]

i. **Calvert Cliffs Nuclear Power Plant, LLC ("CCNPP")**.[13] CCNPP is an indirect, wholly owned subsidiary of Constellation Energy Nuclear Group, Inc. ("CENG"), which is a joint venture between Exelon and EDF Inc. ("EDF").[14] EDF is not an affiliate of Exelon. CCNPP owns and operates the Calvert Cliffs Nuclear Power Plant in Lusby, Maryland, which has a generating capacity of approximately 1,735 MW.[15] The Calvert Cliffs Nuclear Power Plant is located in the PJM BAA. The Commission has granted CCNPP market-based rate authority.[16]

ii. **Constellation Mystic Power, LLC ("Mystic")**. Mystic is a Delaware limited liability company that has been granted market-based rate authority.[17] Mystic owns the following generating facilities and related interconnection facilities, all of which are located in the ISO-NE BAA: (a) Mystic Unit 7, an approximately 575 MW oil- and

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[11] Unless otherwise stated, each subsidiary is a wholly owned subsidiary of ExGen.

[12] *Exelon Generation Co.*, 93 FERC ¶ 61,140 (2000), *reh'g denied*, 95 FERC ¶ 61,309 (2001).

[13] CCNPP is filing a Market Power Update under separate cover.

[14] On November 1, 2013, the Commission issued a letter order accepting for filing a Nuclear Operating Services Agreement ("NOSA") among ExGen, CENG and CENG's wholly owned subsidiaries, CCNPP, Nine Mile Point Nuclear Station, LLC, and R.E. Ginna Nuclear Power Plant, LLC (CENG and its subsidiaries collectively, the "CENG Nuclear Plant Owners"). *Exelon Generation Co.*, Docket Nos. ER13-2105-000, *et al*. (unpublished delegated letter order issued Nov. 1, 2013). The NOSA "provides for ExGen's assumption of the operations of the nuclear generating facilities and related jurisdictional transmission facilities owned by the CENG Nuclear Plant Owners." *Id.* at 2. The Commission stated that the effective date of the NOSA will be the date that the Nuclear Regulatory Commission "issues the conforming license amendments to implement the approval of the transfer from the CENG Nuclear Plant Owners to ExGen of the operating authority" of the CENG Nuclear Plant Owners' relevant facilities. *Id.* The NOSA will not affect control of the nuclear generating facilities for purposes of the Commission's market power analyses because the Exelon MBR Entities already attributed 100% of the ownership share of the relevant facilities due to their affiliation with CENG. As noted in Exhibit JRS-2 to Ms. Solomon's affidavit, Ms. Solomon also includes as a long-term sale by the Exelon MBR Entities the long-term agreement under which EDF markets 15% of the output of these facilities.

[15] Unless otherwise specified, unit ratings are summer season ratings.

[16] *Calvert Cliffs Nuclear Power Plant, Inc.*, 92 FERC ¶ 62,161 (2000).

[17] *Constellation Mystic Power, LLC*, Docket Nos. ER10-2281-000, *et al.* (unpublished delegated letter order issued Oct. 27, 2010).

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natural gas-fired facility in Everett, Massachusetts; (b) Mystic Jet, an approximately 9 MW distillate fuel oil facility in Everett, Massachusetts; (c) Mystic Units 8 (at approximately 704 MW) and 9 (at approximately 714 MW), natural gas-fired facilities located in Everett, Massachusetts, with a total capacity of approximately 1,418 MW; and (d) the Fore River facility, an approximately 700 MW natural gas-fired facility in North Weymouth, Massachusetts.

iii. **Constellation Power, Inc. ("CPI")**. CPI indirectly holds a 25% ownership interest in the approximately 104 MW Colver qualifying cogeneration facility in the PJM BAA. Power from the Colver facility is sold pursuant to a contract that was executed on or before March 17, 2006, and therefore market-based rate authority is not necessary to make such sales.[18]

iv. **Constellation Power Source Generation, Inc. ("CPSG")**. CPSG owns and/or operates multiple generation facilities in the PJM BAA with a total capacity of approximately 972 MW. The Commission has granted CPSG market-based rate authority.[19] On or before December 31, 2013, CPSG is expected to be merged into Constellation Power Source Generation, LLC ("CPSGL"), a newly formed entity that currently does not engage in any jurisdictional activities.[20]

v. **Criterion Power Partners, LLC ("CPP")**. CPP owns an approximately 70 MW wind farm located in western Maryland. The facility is in the PJM BAA. The Commission has granted CPP market-based rate authority.[21]

vi. **Exelon Framingham, LLC ("EFL")**. EFL owns and operates three fossil fueled peaking plants with a combined capacity of approximately 33.08 MW in Framingham, Massachusetts, in the ISO-NE BAA. The Commission has granted EFL market-based rate authority.[22]

vii. **Exelon New Boston, LLC ("Exelon New Boston")**. Exelon New Boston owns and operates an approximately 16.03 MW fossil fueled peaking plant in the ISO-NE BAA. The Commission has granted Exelon New Boston market-based rate authority.[23]

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[18] 18 C.F.R. § 292.601(c)(1).

[19] *AmerGen Vt., LLC*, 90 FERC ¶ 61,307, *reh'g denied sub nom. Baltimore Gas & Elec. Co.*, 91 FERC ¶ 61,270 (2000).

[20] Upon consummation of the transaction, CPSGL will file a Notice of Succession with respect to its succession to CPSG's market-based rate tariff pursuant to 18 C.F.R. § 35.16.

[21] *Criterion Power Partners, LLC*, Docket Nos. ER10-1443-000, *et al.* (unpublished delegated letter order issued Aug 9, 2010).

[22] *Exelon Framingham, LLC*, Docket No. ER01-513-024 (unpublished delegated letter order issued Sept. 2, 2009).

[23] *Exelon New Boston, LLC*, Docket No. ER01-513-024 (unpublished delegated letter order issued Sept. 2, 2009).

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viii. **Exelon Solar Chicago LLC ("Exelon Solar")**. Exelon Solar owns an approximately 8 MW qualifying small power production solar energy facility in Cook County, Illinois, located in the PJM BAA.[24]

ix. **Exelon West Medway, LLC ("Exelon West Medway")**. Exelon West Medway owns the following three fossil fueled peaking plants located in the ISO-NE BAA: Jet 1, with a capacity of approximately 42 MW; Jet 2, with an approximate capacity of 39.85 MW; and Jet 3, with a capacity of approximately 35.44 MW, for a combined total of approximately 117.29 MW. The Commission has granted Exelon West Medway market-based rate authority.[25]

x. **Exelon Wyman, LLC ("Wyman")**. Wyman owns a 5.89% interest in a fossil fueled peaking plant with a total capacity of approximately 610 MW in the ISO-NE BAA. The facility is operated by FPL Wyman Energy, LLC, which is a subsidiary of Florida Power & Light Company and is not an affiliate of Exelon. The Commission has granted Wyman market-based rate authority.[26]

xi. **Handsome Lake Energy, LLC ("Handsome Lake")**. Handsome Lake owns an approximately 267.5 MW natural gas-fired generating facility located in Venango County, Pennsylvania. The facility is located in the PJM BAA. The Commission has granted Handsome Lake market-based rate authority.[27]

xii. **Holyoke Solar LLC ("Holyoke Solar")**. Holyoke Solar owns two qualifying small power production solar energy facilities located in Hampden, Massachusetts. One facility has a net power production of approximately 2.95 MW, and the other has a net power production of approximately 0.87 MW. The facilities are located in the ISO-NE BAA.

xiii. **Nine Mile Point Nuclear Station, LLC ("Nine Mile Point")**.[28] Nine Mile Point is an indirect, wholly owned subsidiary of CENG. Nine Mile Point owns 100% of an approximately 630 MW unit ("Unit 1") and an 82% share of an approximately 1,287 MW unit ("Unit 2") of a nuclear generation facility located in

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[24] *Exelon Solar Chicago LLC*, Docket No. QF10-174-000 (filed Dec. 9, 2009) (Notice of Self-Certification of QF Status).

[25] *Exelon West Medway, LLC*, Docket No. ER01-513-024 (unpublished delegated letter order issued Sept. 2, 2009).

[26] *Exelon Wyman, LLC*, Docket No. ER01-513-024 (unpublished delegated letter order issued Sept. 2, 2009).

[27] *Constellation Power Source*, *Inc.*, Docket Nos. ER01-556-000, *et al.* (unpublished delegated letter order issued Jan. 19, 2001).

[28] Nine Mile Point is filing a Market Power Update under separate cover.

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Scriba, New York. The facility is located in the NYISO BAA. The Commission has granted Nine Mile Point market-based rate authority. [29]

xiv. **R.E. Ginna Nuclear Power Plant, LLC ("Ginna")**.[30] Ginna is an indirect, wholly owned subsidiary of CENG. Ginna owns an approximately 581.5 MW nuclear generation facility located in Ontario, New York. The facility is located in the NYISO BAA. Ginna sells approximately 90% of its entitlement to capacity, energy, and ancillary services from the facility to the former owners of the facility pursuant to long-term power purchase agreements. The Commission has granted Ginna market-based rate authority.[31]

xv. **Safe Harbor Water Power Corporation ("Safe Harbor")**. ExGen indirectly owns 66 2/3% of Safe Harbor.[32] Safe Harbor owns and operates an approximately 416.5 MW hydroelectric generation facility located on the Susquehanna River in Conestoga, Pennsylvania. The facility is located in the PJM BAA. The Commission has granted Safe Harbor market-based rate authority.[33]

B. ***Net-Metered Affiliates***. Certain individual project company subsidiaries of Exelon ("Retail QF Subsidiaries") install, own and operate very small solar generating facilities on property controlled by their commercial, industrial or governmental electric customers. These generating facilities each qualify as a small power production qualifying facility pursuant to Section 292.203(a) of FERC's regulations and are included on the Asset Appendix in Attachment B. The Retail QF Subsidiaries sell all electricity from such generating facilities behind-the-meter, directly to their on-site, end-use customers, and do not participate in the wholesale markets. Therefore, the Retail QF Subsidiaries' generation is not included in the market power analyses of the relevant wholesale markets in the NE Region.

C. ***Franchised Public Utility Affiliates.***

i. **Baltimore Gas and Electric Company ("BGE")**. BGE is a combination electric and natural gas utility engaged in the transmission and distribution of electricity and natural gas to residential, commercial and industrial customers in central Maryland. BGE provides retail electric service to approximately 1.2 million customers and provides retail gas service to approximately 655,000 customers in all or part of 10 counties in central Maryland and the City of Baltimore, Maryland. BGE serves as the default service provider for those gas and electric customers who do not choose competitive suppliers or whose competitive supplier has

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29 *Nine Mile Point Nuclear Station, LLC*, 95 FERC ¶ 61,202 (2001).

30 Ginna is filing a Market Power Update under separate cover.

31 *R.E. Ginna Nuclear Power Plant, LLC*, Docket No. ER04-485-000 (unpublished delegated letter order issued Mar. 24, 2004).

32 The remaining interest in Safe Harbor is owned by LSP Safe Harbor Holdings, LLC, an unaffiliated entity.

33 *Safe Harbor Water Power Corp*., Docket Nos. ER08-537-000, *et al.* (unpublished delegated letter order issued May 6, 2008).

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failed to deliver electric or gas supply. The Commission has granted BGE market-based rate authority.[34]

BGE neither owns nor operates any electric generating facilities, having transferred its generation assets to its affiliates, CPSG and CCNPP in 2000.[35] BGE engages in limited sales of capacity credits associated with the PJM Active Load Management load response program.

Subject to the direction and control of PJM, BGE owns and operates jurisdictional transmission facilities that are used in the transmission of wholesale bulk power to load serving entities within PJM and neighboring regions. BGE is a member of PJM and has made its transmission facilities available for service pursuant to PJM's open access transmission tariff ("OATT").

In addition, BGE operates natural gas distribution facilities in its service territory in Maryland and also operates a liquefied natural gas ("LNG") facility for the liquefaction and storage of natural gas on its distribution system, as well as a captive propane-air facility with a mined cavern. Both the LNG facility and the captive propane-air facility are associated with BGE's distribution activities and do not offer services to third parties.

ii. **Commonwealth Edison Company ("ComEd")**. ComEd is primarily engaged in the purchase, transmission, distribution, and sale of electricity to residential, commercial, industrial, and wholesale customers in Northern Illinois.[36] ComEd has approximately 3.8 million retail electricity customers. ComEd serves as the default service provider for electric generation supply to customers who do not choose a competitive supplier or whose competitive supplier has failed to deliver electric supply. The Commission has granted ComEd market-based rate authority.[37]

ComEd does not own or operate any electric generating facilities, but instead obtains all of its energy requirements for retail customers from market sources pursuant to the Illinois Commerce Commission-approved procurement process.[38] Subject to the direction and control of PJM, ComEd owns and operates jurisdictional transmission facilities that it uses to supply retail electric service to its service territory. ComEd is also a member of PJM and has made its transmission facilities available for service pursuant to PJM's OATT.

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[34] *Green Power Partners I LLC*, 88 FERC ¶ 61,005 (1999).

[35] *See Baltimore Gas & Elec. Co.*, 90 FERC ¶ 62,222 (2000).

[36] Commonwealth Edison Company of Indiana, Inc., a wholly owned subsidiary of ComEd, owns a small amount of electric transmission property in Indiana. As with ComEd, the transmission facilities owned by ComEd of Indiana, Inc. are under the operational control of PJM.

[37] *Commonwealth Edison Co.*, 82 FERC ¶ 61,317 (1998).

[38] ComEd makes a small amount of purchases from Qualifying Facilities under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). 16 U.S.C. §§ 2601-2645.

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iii. **PECO Energy Company ("PECO")**. PECO is primarily engaged in the purchase, transmission, distribution, and sale of electricity and natural gas to residential, commercial, and industrial customers in southeastern Pennsylvania. PECO provides electric delivery service to approximately 1.6 million customers and also provides natural gas service to approximately 500,500 customers. PECO serves as the default service provider for electric generation supply to customers who do not choose a competitive supplier or whose competitive supplier has failed to deliver electric supply. The Commission has granted PECO market-based rate authority.[39]

PECO does not own any generation, but instead purchases the power needed to satisfy its electric service obligations through a competitive procurement process approved by the Pennsylvania Public Utility Commission. PECO is a member of PJM and has made its transmission facilities available for service pursuant to PJM's OATT.

PECO has an LNG facility located in West Conshohocken, Pennsylvania, which has a storage capacity of 1,200 mmcf and a send-out capacity of 157 mmcf/day and a propane-air plant located in Chester, Pennsylvania, with a tank storage capacity of 1,980,000 gallons and a peaking capability of 25 mmcf/day. In addition PECO owns 31 natural gas city gate stations at various locations throughout its gas service territory. Both the LNG facility and the propane-air facility are associated with PECO's distribution activities and do not offer services to third parties.

V. THE EXELON MBR ENTITIES SATISFY THE COMMISSION'S STANDARD FOR AUTHORITY TO SELL POWER AT MARKET-BASED RATES

As explained in the attached Affidavit of Julie R. Solomon from the consulting firm Navigant Consulting Inc., the Exelon MBR Entities continue to satisfy the Commission's test for determining whether to grant a public utility market-based rate authority. This test includes evaluating horizontal (generation) market power and vertical market power, which the Commission defined in Order No. 697 to include both transmission market power and the ability to erect barriers to entry in the relevant markets.[40]

Using the Commission's current standards for evaluating horizontal market power, as set forth in Order No. 697 and subsequent orders, Ms. Solomon concludes that the Exelon MBR Entities pass the pivotal supplier and market share screens in all the relevant markets and submarkets and are therefore presumed not to have horizontal market power in the NE Region.[41] Likewise, Ms. Solomon concludes that the Exelon MBR Entities satisfy the Commission's requirements with respect to transmission market power and the ability to erect barriers to entry. Therefore, the Exelon MBR Entities continue to qualify for market-based rate authority. In

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39 *Exelon Cos.*, 94 FERC ¶ 61,259 (2001).

40 Order No. 697 at P 399.

41 *Id.* at P 62.

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addition, as explained below, the Exelon MBR Entities continue to qualify for waiver of the code of conduct requirement.

A. The Exelon MBR Entities Lack Horizontal Market Power

In Order No. 697, the Commission retained two "indicative" screens for assessing generation market power in the relevant geographic markets: a pivotal supplier screen and a market share screen.[42] If the seller passes both indicative screens, there is a rebuttable presumption that the seller does not possess market power in generation, and no further analysis is required.

The pivotal supplier screen "measures the ability of a firm to dominate the market at peak periods."[43] If demand in a specific market can be met without at least some power from a supplier, that supplier passes the pivotal supplier screen.[44] The Commission's required analysis under the pivotal supplier screen measures the uncommitted capacity of the supplier seeking market-based rate authorization, determined by adding the total nameplate or seasonal capacity of generation owned or controlled through contract and firm purchases, less the supplier's long-term firm sales, operating reserves and native load commitments.[45] The supplier's uncommitted capacity is deemed available for wholesale transactions.[46] The same methodology used in the pivotal supplier screen to calculate an applicant's uncommitted capacity is applied to measure competing suppliers' uncommitted capacity.[47]

The market share screen addresses on a seasonal basis "whether a seller has a dominant position in the market based on the number of megawatts of uncommitted capacity owned or controlled by the seller as compared to the uncommitted capacity of the entire relevant market."[48] If the applicant has less than a 20% market share in all four seasons, it passes the market share screen.[49]

The relevant geographic markets where the Exelon MBR Entities own or control generation are PJM (as well as the following submarkets within PJM: PJM East, AP South, and

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42 *Id.*

43 *Id.* at P 65; *see also AEP Power Mktg., Inc.*, 107 FERC ¶ 61,018, at P 71 (2004) ("*AEP Power Marketing*").

44 *AEP Power Marketing* at P 72.

45 Order No. 697 at P 38. Pursuant to Order No. 697-A, the applicable study period for this triennial is December 1, 2011 to November 30, 2012. The capacity ratings of some of the entities in Ms. Solomon's Affidavit may therefore vary slightly from the capacity reflected in Section IV of this filing and the Asset Appendix in Attachment B, as the ratings in Section IV and the Asset Appendix reflect current data from 2013 ISO/RTO ratings.

46 *Id.* at P 42; *AEP Power Marketing* at P 99.

47 In Order No. 697, the Commission adopted the same native load proxy for the market share screen as is employed in the pivotal supplier screen. Order No. 697 at P 135.

48 *Id.* at P 43.

49 *Id.* at PP 44, 89.

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5004/5005), ISO-NE (as well as the CT submarket), and NYISO.[50] Ms. Solomon has analyzed each of these relevant geographic markets, although she explains that PJM East and 5004/5005 may be of lesser relevance to the market power analysis because constraints on the interfaces with those submarkets have significantly declined since the Commission began reviewing them as separate submarkets.[51] Ms. Solomon provides a "Congestion Event Summary (Event Hours)" table that demonstrates that in the relevant test period, constraints on the PJM East interface occurred in only about 2% of hours in day-ahead and in only five hours in real-time. Likewise, constraints on the 5004/5005 interface occurred in only about 2% of hours in day-ahead and in about 1% of hours in real-time.

Ms. Solomon attributes to the Exelon MBR Entities the generation owned or controlled by the Exelon MBR Entities and their affiliates in each of the relevant markets and submarkets as well as a pro rata share of imports from affiliated uncommitted capacity in relevant first-tier markets.[52] Ms. Solomon deducts 500 MW[53] from the Exelon MBR Entities' uncommitted capacity in PJM and the 5004/5005 submarket that is associated with Exelon's commitment at the time of the Exelon-Constellation merger to enter into fixed-price power sales contracts to sell 500 MW per hour of around-the-clock baseload energy into the 5004/5005 submarket through December 31, 2014.[54]

With respect to load, Ms. Solomon attributes to the Exelon MBR Entities load they served in PJM and ISO-NE during the study period.[55] This load includes wholesale load directly supplied by ExGen such as net physical sales to parties that primarily serve load[56] as well as sales under certain long-term inter-company agreements by which ExGen sells energy, capacity and other electric products to several retail electric supplier affiliates that are necessary to meet those affiliates' retail load obligations in the relevant markets.[57] Under ExGen's long-term contracts with its retail electric supplier affiliates, ExGen is obligated to supply sufficient quantities to satisfy the physical retail supply obligations of each retail electric supplier affiliate. Indeed, one of the rationales for the Exelon-Constellation merger was that owning generation in

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50 Solomon Aff. at 7.

51 *Id.* at 8.

52 *Id.* at 12.

53 *Id.* at Exhibit JRS-2.

54 *Merger Order*, 138 FERC ¶ 61,167, at P 52.

55 Ms. Solomon explains that her Total Uncommitted Capacity determination in each RTO market and submarket is "extremely conservative" because her "analysis assumes that every MW of generation is 'committed' to the extent there is load, even though in reality every MW of generation is not necessarily committed by ownership or contractual commitment to serving a specific load." Solomon Aff. at 11. As Ms. Solomon notes, some parties rely on short-term purchases from the RTO markets to meet load obligations and thus competing uncommitted capacity is conservatively low in her analysis.

56 *Id.* at 10-11 & n.28 (citing Order No. 697 at P 155).

57 As noted in the Solomon Affidavit at n.29, the Commission permits sellers to deduct "long-term load following contracts to the extent that the seller has included in its total capacity a corresponding generating unit or long-term firm purchase contract that will be used to meet the obligation." (Citing Order No. 697 at P 154.)

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the same markets as that in which the retail electric supplier affiliates do business would provide Exelon with a physical hedge against market variations. Therefore, the deduction of these sales in the load calculation is consistent with the Commission's permitted deductions in Order No. 697 as well as the load calculations used in Exelon's 2010 updated market power analysis that was accepted by the Commission on June 22, 2011.[58]

As demonstrated in Ms. Solomon's analysis in Attachment A, the Exelon MBR Entities pass the pivotal supplier screen and market share screen in each of the relevant markets and submarkets. Ms. Solomon's results are summarized in the following table:

Market/ Submarket	Exhibit No.	Pivotal Supplier	Exhibit No.	Market Share Analysis			
				Winter	Spring	Summer	Fall
PJM	JRS-4	PASS	JRS-5	11.1%	10.8%	12.4%	12.3%
PJM East	JRS-6	PASS	JRS-7	15.3%	15.1%	14.0%	14.9%
5004/5005	JRS-8	PASS	JRS-9	13.8%	13.5%	12.5%	14.0%
AP South	JRS-10	PASS	JRS-11	10.1%	9.9%	9.3%	10.5%
ISO-NE	JRS-12	PASS	JRS-13	5.3%	4.9%	4.0%	7.1%
CT	JRS-14	PASS	JRS-15	0.0%	0.0%	0.0%	0.0%
NYISO	JRS-16	PASS	JRS-17	11.2%	10.5%	14.3%	11.1%

Because the Exelon MBR Entities pass both screens in all the relevant markets and submarkets, they are entitled to a presumption that they cannot exercise horizontal market power.[59] Ms. Solomon also notes several additional protections in the relevant markets that ensure that the Exelon MBR Entities cannot exercise market power. First, as Ms. Solomon explains, PJM, ISO-NE and NYISO are subject to extensive Commission-approved market monitoring and mitigation, and the Commission previously has found that such market monitoring and mitigation generally results in transparent pricing and mitigates any attempts to exercise market power.[60] Second, Ms. Solomon notes that Exelon's hedging strategy also reduces its ability or incentive to exercise market power; as of the end of 2012, expected generation was more than 90% hedged for 2013 and more than 60% hedged for 2014.[61]

Third, the Exelon MBR Entities are subject to certain additional behavioral commitments in PJM, entered into via a Settlement Agreement with the PJM Market Monitor at the time of the merger between Exelon and Constellation.[62] These behavioral commitments include (i)

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58 *Commonwealth Edison Co.*, Docket Nos. ER10-1048-002, *et al.*, Updated Market Power Analysis, Solomon Affidavit at 10 (filed Dec. 30, 2010, as supplemented Mar. 21, 2011) (accepted by unpublished delegated letter order issued June 22, 2011).

59 Order No. 697 at P 62.

60 Solomon Aff. at 3 (citing Order No. 697 at PP 241-242).

61 Solomon Aff. at 4.

62 *Id.* at 18.

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notification procedures for planned retirements; (ii) prescribed rules on energy market offers specific to nuclear generation, peaking generation and other types of generation; and (iii) agreement with respect to bidding ancillary services. The PJM Market Monitor stated that, together with the PJM market rules, these behavioral conditions will ensure "the Market Monitor will have the information needed to monitor compliance" and "satisfy the Market Monitor's concerns regarding the merger."[63] In the *Merger Order*, the Commission found "that the behavioral commitments, when monitored, are an effective tool in limiting anti-competitive conduct."[64] Thus, these additional behavioral commitments further strengthen the general market monitoring and mitigation in place in PJM.[65]

In sum, Ms. Solomon concludes that the Exelon MBR Entities do not have market power in any of the relevant markets and submarkets in the NE Region.

B. The Exelon MBR Entities and Their Affiliates Lack Vertical Market Power

In evaluating vertical market power, the Commission considers both transmission market power and the ability of the seller and its affiliates to erect barriers to entry in the relevant markets.[66] As explained below, the Exelon MBR Entities continue to lack vertical market power.

1. Transmission Market Power

In order to receive market-based rate authorization, the seller and its affiliates must lack, or have adequately mitigated, transmission market power. The Exelon MBR Entities are affiliated with PECO, BGE, and ComEd (the "Franchised Public Utilities") through which Exelon distributes electricity to approximately 6.6 million customers in Illinois, Maryland and Pennsylvania. The Franchised Public Utilities have each transferred operational control over their transmission systems to PJM, and transmission service over those facilities is provided by PJM under its OATT. None of the other Exelon MBR Entities nor their affiliates own or control any transmission facilities in the NE Region other than certain limited interconnection facilities necessary to interconnect their generating facilities to the electric grid. The Commission has previously ruled that such limited interconnection facilities do not convey transmission market power.[67] Accordingly, the Exelon MBR Entities and their affiliates lack transmission market power.

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63 *Exelon Corp.*, Docket No. EC11-83-000, Letter to Chairman Wellinghoff and Chairman Nazarian from Joseph E. Bowring, Independent Market Monitor for PJM (submitted Oct. 11, 2011) (forwarding the settlement terms and conditions agreed to between the Independent Market Monitor for PJM, Exelon, and Constellation Energy Group).

64 *Merger Order*, 138 FERC ¶ 61,167, at P 100.

65 Solomon Aff. at 16.

66 Order No. 697 at P 399.

67 *See, e.g.*, *AES Huntington Beach, LLC*, 111 FERC ¶ 61,079, at P 43 (2005); *Zond Dev. Corp.*, 80 FERC ¶ 61,051, at 61,153 (1997).

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2. Barriers to Entry

The Commission also considers whether a company that is authorized to sell at market-based rates can erect barriers to entry by competing wholesale power suppliers in the relevant geographic markets by exercising control over "intrastate natural gas transportation; intrastate natural gas storage or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies such as barges and rail cars."[68]

As noted in Section III.C above, BGE provides retail gas service to approximately 655,000 customers in all or part of 10 counties in central Maryland and the City of Baltimore, Maryland. PECO also provides retail gas service to approximately 500,500 customers located in southeastern Pennsylvania, adjacent to the city of Philadelphia. In addition, both BGE and PECO operate natural gas distribution facilities in their respective service territories. PECO owns 31 natural gas city gate stations at various locations throughout its gas service territory. In addition, both BGE and PECO operate their own propane-air facilities and LNG facilities for the liquefaction and storage of natural gas. The LNG facilities and the propane-air facilities are associated with BGE's and PECO's distribution activities and do not offer services to third parties.

Aside from sites previously reported pursuant to Order No. 697-D, the Exelon MBR Entities and their affiliates do not own or control any sites for generation capacity development in the NE Region other than sites on which their existing generation facilities are located.

In Order No. 697, the Commission adopted a

> rebuttable presumption that sellers cannot erect barriers to entry with regard to the ownership or control of, or affiliation with any entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies such as barges and rail cars.[69]

The Exelon MBR Entities affirmatively state that they have not erected barriers to entry in the relevant markets and will not erect barriers to entry into the relevant markets.[70] Thus, the Exelon MBR Entities have demonstrated that they lack the ability to erect barriers to entry.

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[68] Order No. 697 at P 446. The Commission no longer considers ownership or control of natural gas supply, interstate natural gas transportation (including interstate natural gas storage), oil supply or oil transportation in its barriers to entry analysis. *Id.* at P 442.

[69] *Id.* at P 446.

[70] *Id.* at P 448.

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C. The Exelon MBR Entities and Their Affiliates Continue to Qualify for Waiver of the Affiliate Restrictions

The affiliate restrictions govern the relationship between franchised public utilities with captive customers and their market-regulated power sales affiliates, which include wholesale power sales by a market-based rate seller to its franchised public utility affiliates, as well as transactions involving non-power goods and services between the franchised public utility and its marketing affiliate.[71] The only franchised public utilities affiliated with the Exelon MBR Entities are the Franchised Public Utilities, and the Commission has previously found that the establishment of a code of conduct governing the relationship between the Franchised Public Utilities and their market-regulated power sales affiliates was not necessary because the Franchised Public Utilities do not have any captive wholesale or retail customers.[72] Consistent with Commission precedent, waiver of the affiliate restrictions with respect to the Exelon MBR Entities remains appropriate because, as explained below, the Franchised Public Utilities continue to have no captive wholesale or retail customers.

The regulations define "Franchised public utility" to mean "a public utility with a franchised service obligation under state law"[73] and "Captive customers" to mean "any wholesale or retail electric energy customers served by a franchised public utility under cost-based regulation."[74] None of the Franchised Public Utilities have any wholesale electric energy customers served under cost-based rates. While the Franchised Public Utilities serve retail electric energy customers under cost-based rates in the states of Illinois, Pennsylvania and Maryland, all of their retail customers have the option to choose a competitive retail electric supplier. The Commission clarified in Order No. 697 that

> the definition of "captive customers" does not include those customers who have retail choice, *i.e.* the ability to select a retail supplier based on the rates, terms and conditions of service offered. Retail customers who choose to be served under cost-based rates but have the ability, by virtue of state law, to choose one retail supplier over another, are not considered to be under "cost-based regulation" and therefore are not "captive."[75]

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71 18 C.F.R. § 35.39; *see also id.* § 35.44.

72 *Exelon Generation Co.*, 126 FERC ¶ 61,031, at PP 43-48 (2009); *Baltimore Gas & Elec. Co.*, Docket Nos. ER99-2948-012, *et al.* (unpublished delegated letter order issued Sept. 16, 2008). Waiver of the code of conduct was originally granted in *Exelon Generation Co.*, 93 FERC ¶ 61,140, at 61,425-26 (2000), *reh'g denied*, 95 FERC ¶ 61,309 (2001) and *AmerGen Vt., LLC*, 90 FERC ¶ 61,307, at 61,995, *reh'g denied sub nom.*, *Baltimore Gas & Elec. Co.*, 91 FERC ¶ 61,270 (2000).

73 18 C.F.R. § 35.36(a)(5).

74 *Id.* § 35.36(a)(6).

75 Order No. 697 at P 479.

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Thus, the Franchised Public Utilities do not have any retail captive customers. Because the Franchised Public Utilities do not have any wholesale or retail captive customers, continuation of the waiver of the affiliate restrictions is appropriate.

VI. NOTICE OF CHANGE IN STATUS

ExGen has entered into a one-year tolling agreement pursuant to which it will acquire control over the approximately 661 MW Granite Ridge generating facility, located in the ISO-NE BAA, beginning January 1, 2014. Ms. Solomon has included with her Affidavit an additional analysis demonstrating that the Exelon MBR Entities will continue to pass both indicative screens in the ISO-NE BAA once the tolling agreement commences.[76] Thus, acquisition of control over the Granite Ridge facility for the one-year term of the tolling agreement does not constitute a material departure from the characteristics the Commission relied upon in granting the Exelon MBR Entities market-based rate authority. As stated above, the Exelon MBR Entities confirm that they have not erected barriers to entry into the relevant markets and will not erect barriers to entry into the relevant markets. The Exelon MBR Entities respectfully request that the Commission accept this notice of change in status.

VII. REQUEST FOR WAIVER OF OPEN ACCESS REQUIREMENTS

Certain of the Exelon MBR Entities own or control generation facilities and corresponding limited and discrete interconnection facilities designed to interconnect the generation facilities to the grid (the "Project Company Sellers").[77] The Project Company Sellers do not own or control transmission facilities other than the interconnection facilities.[78] Nonetheless, the Commission has recently indicated that, absent a waiver, entities that only own generator interconnection facilities may also be subject to the requirements of Order Nos. 888,[79]

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[76] Solomon Aff. at 2, 21 and Exhibits JRS-12 (CIS) and JRS-13 (CIS).

[77] Specifically, the Project Company Sellers are: Cassia Gulch Wind Park, LLC; CER Generation, LLC; CER Generation II, LLC; Mystic; CPI; CPSG; CPP; EFL; Exelon New Boston; Exelon Solar; Exelon West Medway; Handsome Lake; Holyoke Solar; Cow Branch Wind Power, LLC; CR Clearing, LLC; ExGen; Exelon Wind 4, LLC; Harvest Windfarm, LLC; High Mesa Energy, LLC; Michigan Wind 1, LLC; Tuana Springs Energy, LLC; Wind Capital Holdings, LLC; and Wyman. The Project Company Sellers do not include Exelon MBR Entities that have already received Open Access Waivers. *See, e.g.*, *AV Solar Ranch 1, LLC*, 140 FERC ¶ 61,159 (2012) (Order Granting AV Solar Ranch 1, LLC Market-Based Rate Authority and Request for Waivers).

[78] *See, e.g.*, *Baltimore Gas & Elec. Co.*, Docket Nos. ER10-2172-001, *et al.*, Triennial Filing at 15 (filed Dec. 29, 2010) ("Other than BGE, neither the Constellation MBR Entities nor their affiliates own or control any transmission facilities other than certain limited interconnection facilities necessary to interconnect their generating facilities to the electric grid."); *Commonwealth Edison Co.*, Docket Nos. ER10-1048-003, *et al.*, Triennial Filing at 6 (filed Dec. 30, 2010) (stating that the facilities owned by PECO and ComEd "are the only transmission assets owned by the transmission assets owned MBR Companies or their affiliates other than those necessary to connect their generation to the grid").

[79] *Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No.

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889,[80] 890,[81] their implementing regulations at Section 35.28 and Part 37, and the requirements of Part 358[82] (collectively, the "Open Access Requirements").[83] The Project Company Sellers therefore request, out of an abundance of caution, that the Commission grant them waivers of the Open Access Requirements.

The generator interconnection facilities that the Project Company Sellers own ("Interconnection Facilities") are each limited and discrete facilities that do not form an integrated transmission grid.[84] The Interconnection Facilities consist of discrete, radial interconnection facilities used solely to interconnect the Project Company Sellers' respective generation facilities to the grid. The Commission has routinely granted waiver of its Open Access Requirements for similar limited and discrete interconnection facilities unless and until an owner of such facilities receives a request for transmission service.[85] Therefore, the Project Company Sellers request that the Commission grant them waiver of the Open Access Requirements.

888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[80] *Open-Access Same Time Information System and Standards of Conduct*, Order No. 889, FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049 (1997), *reh'g denied*, Order No. 889-B, 81 FERC ¶ 61,253 (1997).

[81] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,341, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[82] 18 C.F.R. § 35.28 and Parts 37 and 358.

[83] *See, e.g.*, *Coram Cal. Dev., L.P.*, 138 FERC ¶ 61,070 (2012); *see also Open Access and Priority Rights on Interconnection Facilities*, 139 FERC ¶ 61,051, Notice of Inquiry, at P 1 (2012) (stating that "[i]n a series of cases that have come before the Commission in recent years, the Commission has treated certain interconnection facilities as transmission facilities for purposes of open access policies") (footnote omitted).

[84] *Silver State Solar Power North, LLC*, 139 FERC ¶ 61,088, at PP 24-25 (2012) ("*Silver State*"); *Detroit Edison Co.*, 136 FERC ¶ 61,210, at PP 14-19 (2011) ("*Detroit Edison*"); *Black Creek Hydro, Inc.*, 77 FERC ¶ 61,232, at 61,940-41 (1996).

[85] *See, e.g.*, *Silver State*; *Detroit Edison*; *Evergreen Wind Power III, LLC*, 135 FERC ¶ 61,030 (2011); *Ashtabula Wind, LLC,* 127 FERC ¶ 61,215 (2009).

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VIII. CONCLUSION

Based upon the foregoing, the Exelon MBR Entities respectfully request that the Commission accept for filing this joint updated market power analysis for the NE Region, accept the change in status notice regarding the Granite Ridge tolling agreement and grant the Project Company Sellers the requested waiver of the Open Access Requirements.

Respectfully submitted,

/s/ Jane E. Rueger

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Attachments

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ATTACHMENT A

Affidavit of Julie R. Solomon

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

AV Solar Ranch 1, LLC	)	**Docket No. ER12-2178-____**
Baltimore Gas and Electric Company	)	**Docket No. ER10-2172-____**
Cassia Gulch Wind Park LLC	)	**Docket No. ER11-2016-____**
CER Generation, LLC	)	**Docket No. ER10-2184-____**
CER Generation II, LLC	)	**Docket No. ER10-2183-____**
Commonwealth Edison Company	)	**Docket No. ER10-1048-____**
Constellation Energy Commodities Group Maine, LLC	)	**Docket No. ER10-2192-____**
Constellation Mystic Power, LLC	)	**Docket No. ER11-2056-____**
Constellation NewEnergy, Inc.	)	**Docket No. ER10-2178-____**
Constellation Power Source Generation, Inc.	)	**Docket No. ER10-2174-____**
Cow Branch Wind Power, L.L.C.	)	**Docket No. ER11-2014-____**
CR Clearing, LLC	)	**Docket No. ER11-2013-____**
Criterion Power Partners, LLC	)	**Docket No. ER10-3308-____**
Exelon Framingham, LLC	)	**Docket No. ER10-1020-____**
Exelon Generation Company, LLC	)	**Docket No. ER13-1536-____**
Exelon New Boston, LLC	)	**Docket No. ER10-1078-____**
Exelon West Medway, LLC	)	**Docket No. ER10-1080-____**
Exelon Wind 4, LLC	)	**Docket No. ER11-2010-____**
Exelon Wyman, LLC	)	**Docket No. ER10-1081-____**
Handsome Lake Energy, LLC	)	**Docket No. ER10-2180-____**
Harvest Windfarm, LLC	)	**Docket No. ER11-2011-____**
High Mesa Energy, LLC	)	**Docket No. ER12-2528-____**
Michigan Wind 1, LLC	)	**Docket No. ER11-2009-____**
PECO Energy Company	)	**Docket No. ER10-1143-____**
Tuana Springs Energy, LLC	)	**Docket No. ER11-2007-____**
Wind Capital Holdings, LLC	)	**Docket No. ER11-2005-____**

AFFIDAVIT OF
JULIE R. SOLOMON

I. INTRODUCTION

My name is Julie R. Solomon. I am a Managing Director of Navigant Consulting, Inc. My business address is 1200 19th Street, N.W., Suite 700, Washington, DC 20036. A large portion of my consulting activities involves electric utility industry restructuring and the transition from regulation to competition. I have been involved extensively in consulting on market power issues

concerning mergers, other asset transactions and market-based rate applications. I have filed a number of affidavits before the Federal Energy Regulatory Commission (the "Commission") in connection with electric utility mergers, the purchase and sale of jurisdictional assets, applications for market-based rates, and triennial updates. Included among these, I have filed a number of affidavits with the Commission on behalf of relevant affiliates of Exelon Corporation ("Exelon") with market-based rate authority in connection with past triennial updates. My resume is attached as Exhibit JRS-1.

I have been asked by counsel for the above-captioned subsidiaries of Exelon with market-based rate authority (the "Exelon MBR Entities" or "Sellers") to perform an analysis of market power in compliance with the Commission's guidelines contained in *Order No. 697*.[1] Here I provide an evaluation of horizontal and vertical market power issues for the relevant markets in the Northeast Region[2] in which the Exelon MBR Entities are transmission owners and/or own or control generation facilities.

This affidavit and accompanying exhibits also contain an additional horizontal market power screen analysis relevant to a notice of change in status that will occur on January 1, 2014, with respect to a one-year tolling agreement under which one of the Exelon MBR Entities will "control" the output of the Granite Ridge generating facility in ISO-NE.

II. SUMMARY OF CONCLUSIONS

Based on the analyses discussed herein, I find that, under the Commission's guidelines, the Exelon MBR Entities satisfy the Commission's horizontal market power screens. The Exelon MBR Entities also do not have vertical market power in the relevant markets.

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1 *Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity and Ancillary Servs. by Pub. Utils.*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g and clarification*, Order No. 697-A, FERC Stats. & Regs ¶ 31,268, *order on reh'g and clarification*, 124 FERC ¶ 61,055, *order on reh'g and clarification*, Order No. 697-B, FERC Stats. & Regs ¶ 31,285 (2008), *order on reh'g and clarification*, Order No. 697-C, FERC Stats. & Regs ¶ 31,291 (2009), *order on reh'g and clarification*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305, *order on clarification*, 131 FERC ¶ 61,021, *reh'g denied*, 134 FERC ¶ 61,046 (2010), *appeal docketed sub nom. Mont. Consumer Counsel v. FERC,* Nos. 08-71827, *et al.* (9th Cir. filed May 1, 2008) (collectively, "Order No. 697") (codified at 18 C.F.R. pt. 35).

2 The Northeast Region includes PJM Interconnection, LLC ("PJM"), New York Independent System Operator, Inc. ("NYISO"), and ISO New England Inc. ("ISO-NE"). *Order No. 697*, Appendix D.

The analysis I have conducted is consistent with *Order No. 697* and related orders. I have performed the two indicative horizontal market power screens required by the Commission, namely a pivotal supplier analysis based on the annual peak demand of the relevant market ("Pivotal Supplier Analysis") and a market share analysis ("Market Share Analysis") applied on a seasonal basis for the relevant study period of December 2011-November 2012. Here I provide an evaluation of market power for the default relevant geographic markets in which the Exelon MBR Entities own generation in the Northeast Region, namely PJM and relevant submarkets (PJM East, AP South, and 5004/5005),[3] ISO-NE and a relevant submarket (Connecticut ("CT")), and NYISO (the "Northeast Region RTOs").[4]

The Exelon MBR Entities pass the Pivotal Supplier Analysis and Market Share Analysis in all relevant markets and submarkets, and hence are presumed not to have horizontal market power in the Northeast Region. Additionally, there are other protections in place that further prevent market power concerns. First, *Order No. 697* contemplates that Commission-approved market monitoring and mitigation in RTO markets or submarkets be considered as part of market power analysis.[5] Each of the relevant Northeast Region markets and submarkets is subject to extensive Commission-approved market monitoring and mitigation that generally results in transparent pricing and mitigates attempts to exercise market power.[6] Second, the Exelon MBR Entities are subject to additional behavioral commitments in PJM, entered into as part of the transaction between Exelon Corporation and Constellation Energy Group, Inc. (*see* Docket No. EC11-83-000) (the "Exelon-Constellation merger") that mitigate any horizontal market power.[7] Further, Exelon's hedging strategy limits exposure to risk but also reduces its ability or incentive to exercise market power. Exelon Generation Company, LLC ("Exelon Generation") maintains hedge percentage

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3 Although not described in Order No. 697, the Commission has adopted the convention that AP South and 5004/5005 submarkets are relevant submarkets in PJM. *See, e.g.*, *Exelon Corp.*, 138 FERC ¶ 61,167 (2012).

4 While the Commission has identified submarkets in NYISO, none of the Exelon MBR Entities own or control generation in those submarkets so none of them are relevant to my analysis.

5 *See Order No. 697* at PP 241-242.

6 Order No. 697 at P 241.

7 *See* Answer of Exelon Corporation and Constellation Energy Group, Inc., Docket No. EC11-83-000 (filed Oct. 11, 2011) ("Section 203 Amendment") (describing the behavioral commitments). A copy of the Section 203 Amendment was provided in Attachment A-2 to the Exelon MBR Entities' April 11, 2012 Change in Status Filing in the captioned dockets.

targets for its entire generation fleet, and as of the end of 2012 expected generation was more than 90 percent hedged for 2013 and more than 60 percent hedged for 2014.

The Exelon MBR Entities also lack vertical market power. Commonwealth Edison Company ("ComEd"), PECO Energy Company ("PECO"), and Baltimore Gas and Electric ("BGE") each own transmission facilities in PJM, but such facilities are under the functional control of PJM and are subject to the terms and conditions of the PJM Open Access Transmission Tariff ("OATT"). Outside of PJM, the only transmission facilities owned or controlled by the Exelon MBR Entities or their affiliates consist of those necessary to connect their generating facilities to the grid and thus do not raise any vertical market power concerns.

The Exelon MBR Entities cannot erect barriers to entry in relevant markets. They have no ownership or control of intrastate natural gas transportation or intrastate natural gas storage. PECO and BGE operate natural gas distribution facilities in PJM and have liquefied natural gas ("LNG") facilities that are used to provide peak gas to their customers, but ownership of these assets is subject to the Commission's rebuttable presumption that such ownership does not allow a seller to raise entry barriers.[8] Hence, no vertical concerns are present with respect to the Exelon MBR Entities' owned natural gas distribution and LNG facilities.

The Exelon MBR Entities do not own or control any sites for generation capacity development that can be used to create barriers to entry in relevant markets. The Exelon MBR Entities do not own or control sources of coal supplies (except via coal supply contracts in PJM) or transportation of coal supplies other than private rail cars for transportation of coal supplies in PJM. Here again, these assets would be subject to the rebuttable presumption that such ownership or control does not allow a seller to raise entry barriers. There are no other issues that raise any relevant competitive concerns.

I understand that an affirmative statement on behalf of the Exelon MBR Entities is included in their submission to the effect that they have not erected barriers to entry and will not erect barriers to entry.

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[8] *Order No. 697* at P 22.

III. DESCRIPTION OF EXELON MBR ENTITIES

For purposes of my analysis, Exhibit JRS-2 details the generation owned or controlled by the Exelon MBR Entities in the relevant markets in the Northeast Region, and also reflects generation owned or controlled in relevant first-tier markets. A more detailed description of the Exelon MBR Entities is provided in the submittal letter.

IV. HORIZONTAL MARKET POWER

In *Order No. 697*, the Commission codified a methodology for assessing market power to be used by applicants requesting market-based rate authority under Section 205 of the Federal Power Act or making their required triennial market power update filings. The Commission applies two screens – the Pivotal Supplier Analysis and the Market Share Analysis – intended to demonstrate a lack of horizontal market power. If an entity fails to pass either of the screens, there is a presumption of horizontal market power and further analysis is required.

In *Order No. 697*, the Commission defines the default relevant market as the balancing area authority ("BAA") in which the applicant is physically located. Where a generator is interconnected to a non-affiliate owned transmission system, the only relevant market is the BAA in which the generator is located.[9] Sellers located in, and members of, RTOs may use the geographic region under the control of the RTO as the default relevant geographic market.[10] If the Commission has made specific findings of submarkets within an RTO/ISO, the default relevant market becomes the submarket(s) of the RTO/ISO.[11]

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9 *Order No.697* at P 232 n.217.

10 *Id.* at P 235.

11 *Id.* at PP 236, 246; *Order No. 697-A* at P 90. The relevant submarket in PJM that was identified in *Order No. 697* and related orders was PJM East. The AP South and 5004/5005 submarkets also have been reviewed by the Commission as relevant submarkets in PJM. *Exelon Corp.*, 138 FERC ¶ 61,167 (2012). (See page 8 and note 15 for a discussion of the current state of intra-RTO constraints in PJM.) Submarkets in ISO-NE identified in *Order No. 697* include CT (where the Exelon MBR Entities control generation) and SWCT (where the Exelon MBR Entities do not own or control generation). There are two submarkets in NYISO (New York City and Long Island), but the Exelon MBR Entities do not own or control generation in either of these submarkets.

Pivotal Supplier Analysis

The Pivotal Supplier Analysis seeks to determine if load can be served without an applicant's generation. *Order No. 697-A* specifies a number of calculations for the Pivotal Supplier Analysis.[12]

First, Total Uncommitted Supply is calculated based on installed capacity (adjusted for long-term firm purchases and sales) plus imports less the reserve requirement (*i.e.*, operating reserves) less the average daily peak native load for the peak month.

Second, Wholesale Load is calculated based on the difference between the annual peak load (needle peak) and the average daily peak native load for the peak month.

Third, Net Uncommitted Supply is calculated based on the difference between Total Uncommitted Supply and Wholesale Load. Seller's Uncommitted Capacity is based on Seller's Total Uncommitted Capacity less its average daily peak native load.

If Seller's Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Analysis is passed.

Market Share Analysis

The Market Share Analysis evaluates, for each of the four seasons, whether the seller has a dominant position in the market, with dominance defined as a market share in excess of 20 percent.

Order No. 697 specifies a number of calculations for the market share screen.[13]

First, Seller and Affiliate Capacity is calculated based on installed capacity (adjusted for long-term firm purchases and sales) plus imports less planned outages. Non-Affiliate Capacity is calculated in a similar manner.

Second, Capacity Deductions are calculated based on average peak native load in the season (averaged over all days)[14] plus operating reserves.

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[12] *See Order No. 697-A* at Appendix A to Subpart H.

[13] *See id.*

Third, Seller's Uncommitted Capacity is calculated by subtracting the Capacity Deductions attributed to Seller from Seller and Affiliate Capacity, and Total Competing Supply is calculated by subtracting the Capacity Deductions attributed to others from Non-Affiliate Capacity. Total Seasonal Uncommitted Capacity is the sum of Seller's Uncommitted Capacity and Total Competing Supply.

Finally, Seller's Market Share is calculated as Seller's Uncommitted Capacity as a percentage of Total Seasonal Uncommitted Capacity.

If Seller's Market Share is less than 20 percent in all seasons, the Market Share Analysis is passed.

Assumptions

Relevant Geographic Markets. My analysis is focused on PJM (including PJM East, AP South, and 5004/5005), ISO-NE (including CT) and NYISO as the relevant geographic markets because those are the markets and submarkets in which the Exelon MBR Entities own or control generation. While the analysis I conduct of PJM is consistent with the Commission's current view of PJM submarkets, I note that submarkets cannot always be viewed as a static determination. Market conditions (generation, load patterns, transmission) change, including changes in response to such constraints. Constraints on the PJM East interface, in particular, are not nearly as significant as they have been historically and, likewise, constraints on the 5004/5005 interface have declined in recent years. In contrast, constraints on the AP South interface have increased.

The table below presents a summary of the number of hours in day-ahead and real-time that congestion occurred since 2010, and compares them to levels in 2005.[15]

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[14] Consistent with the *Clarification Order* at P 12(a), I used the following seasons for my analysis: Winter (December-February), Spring (March-May), Summer (June-August) and Fall (September-November).

[15] These data are from the annual or quarterly PJM State of the Market Reports. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013.shtml.

Congestion Event Summary (Event Hours)										
	2005		2010		2011		2012		2013 (Jan-Sept)	
Interface	Day-Ahead	Real-Time	Day-Ahead	Real-Time	Day-Ahead	Real-Time	Day-Ahead	Real-Time	Day-Ahead	Real-Time
PJM East	1,371	148	256	8	522	22	209	5	254	0
5004/5005	1,906	782	1,644	605	905	470	191	128	505	150
AP South	441	39	4,645	1,528	4,111	1,013	2,586	351	4,757	915

As shown, in 2012 (consistent with the study period of the indicative screens), constraints on the PJM East interface occurred in only about 2 percent of hours in day-ahead (209 hours) and in only 5 hours in real-time. Constraints on the 5004/5005 interface in 2012 also were less than 200 hours in both day-ahead and real-time. Thus, day-ahead constraints on the PJM East and 5004/5005 interfaces declined significantly since 2005, when constraints occurred in almost 16 percent and 22 percent of hours in day-ahead, respectively. Some increase in constraints on the 5004/5005 interface have been experienced in 2013 to-date, but constraints on the PJM East interface remain low. By comparison, constraints on the AP South interface in 2012 occurred in almost 30 percent of hours in day-ahead, and 4 percent of hours in real-time, much greater than experienced in 2005, and continued to increase in 2013 to-date. These data suggest that the PJM East and 5004/5005 submarkets may be of relatively lesser relevance in the context of the instant analysis.

Study Period. My analysis is based on a December 2011-November 2012 study period.

Generating Capacity. For PJM installed capacity, I relied on data reported by Energy Velocity based on seasonal EIA-860 ratings.[16] For the PJM submarkets, I relied on the same installed capacity data, identifying generating units in the submarkets consistent with the submarket definitions outlined by PJM in its 2012 Simultaneous Import Limit ("SIL") Study.[17]

For ISO-NE installed capacity, I relied on capacity ratings reported by ISO-NE.[18]

For NYISO installed capacity, I relied on capacity ratings reported by NYISO.[19]

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16 http://www.eia.gov/cneaf/electricity/page/eia860.html.

17 *See 2012 Simultaneous Import Limit Study*, PJM, Docket No. AD10-002, October 2, 2013.

18 For ISO-NE: *2012-2021 Forecast Report of Capacity, Energy, Loads and Transmission*, System Planning, ISO New England, May 1, 2012, http://www.iso-ne.com/trans/celt/report/2012/2012_celt_report.xls.

I use each of these sources for seasonal ratings for the generation owned or controlled by the Exelon MBR Entities and their affiliates. Also, while affiliates of the Exelon MBR Entities own certain small, behind-the-meter generating facilities in the Northeast Region that sell directly to their on-site, end-use customers, I do not include these facilities in my analyses because they do not participate in the wholesale markets.[20]

For the Pivotal Supplier Analysis, I use summer ratings, consistent with the time of annual peak. For the Market Share Analysis, I use summer ratings for the Summer season, and winter ratings for all other seasons.

Operating Reserves. I calculated operating reserves for PJM and its relevant submarkets based on *PJM Manual 13 (Emergency Operations)*.[21] Day-ahead scheduling (operating) reserves in 2012 were based on 7.03 percent of the peak load forecast for the portion of PJM within the NERC Reliability*First* Corporation region. For the Dominion zone, the operating reserve requirement is based on Dominion's share of the Virginia-Carolinas ("VACAR") reserve sharing requirement.[22] I conservatively did not assign any operating reserves to the Exelon MBR Entities.

Operating reserves for ISO-NE are based on its operating procedures.[23] For this purpose, I used the actual average the 30-minute system-wide reserve requirements reported by the ISO-NE

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19 *2012 Load and Capacity Data Report* 2012 ("Gold Book"), NYISO, April 2012, http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2012_GoldBook_V3.pdf.

20 I understand that these behind-the-meter facilities are shown in the Exelon MBR Entities' asset appendix.

21 The current version of Manual 13 can be found at http://www.pjm.com/documents/~/media/documents/manuals/m13.ashx.

22 *See Manual 13* and http://www.serc1.org/Documents/SERC%20Standing%20Committee%20Documents/Regional%20Criteria/SERC%20Reg%20Criteria_Contingency%20Reserve%20Policy_Rev%205%20(10-07-11).pdf

23 *ISO New England Operating Procedure No. 8*, Operating Reserve and Regulation, Effective Date: March 11, 2013, Revision No. 8, http://www.iso-ne.com/rules_proceds/operating/isone/op8/op8_rto_final.pdf.

external market monitor.[24] For CT, operating reserves are based on ISO-NE's local operating reserve requirements.[25]

Operating reserves for NYISO are based on its reported locational reserve requirements for the "NYCA" control area, based on 30-minute reserves.[26]

Load Data. I used hourly load data reported on the websites for the Northeast Region RTOs.

The PJM submarkets are defined based on the following transmission zones:

Transmission Zones		PJM East	5004/5005	AP South
AE	Atlantic City Electric Company	x	x	x
DP&L	Delmarva Power & Light	x	x	x
JCP&L	Jersey Central Power & Light Company	x	x	x
PE	PECO Energy Company	x	x	x
PSE&G	Public Service Electric & Gas Company	x	x	x
RECO	Rockland Electric Company	x	x	x
ME	Metropolitan Edison Company		x	x
PPL	PPL Electric Utilities		x	x
BGE	Baltimore Gas & Electric		x	x
PEPCO	Potomac Electric Power Company		x	x
UGI	UGI Utilities, Inc.		x	x
VAP	Virginia Electric & Power (Dominion)			x

The Exelon MBR Entities provided me with data on the load they served in the relevant markets during the study period. This includes load directly supplied by Exelon Generation,[27] including net

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24 *2012 Assessment Of the ISO New England Electricity Markets*, Potomac Economics, May 2013 at p. 38, http://www.iso-ne.com/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2012_emm_rprt_final.pdf.

25 *See 2012 Regional System Plan*, ISO-NE, November 2, 2012, Table 4-9, Representative Future Operating-Reserve Requirements in Major New England Import Areas (MW), http://www.iso-ne.com/trans/rsp/2012/rsp_final_110212.docx.

26 NYISO, *Locational Reserve Requirements*, http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf.

27 On March 12, 2012, Constellation Energy Group, Inc. ("CEG") was merged into Exelon. Between March 12, 2012, and February 1, 2013, Exelon had two subsidiaries, Constellation Energy Commodities Group, Inc. ("CCG") and Exelon Generation, that were active participants in the wholesale energy markets, which included physical sales to parties that primarily serve load, as well as sales to retail affiliates in support of their load

physical sales to parties that primarily serve load,[28] as well as sales by Exelon Generation to retail affiliates of the Exelon MBR Entities in support of their load obligations.[29]

Other Load and Generation Commitments. I note that the Total Uncommitted Capacity determined in each of the RTO markets and submarkets is extremely conservative, because no attempt has been made to match load commitments (and, correspondingly, generation commitments) attributable to individual parties, other than the Exelon MBR Entities, in the RTOs. Under the Market Share Analysis, for example, the amount of load attributable to "others" is simply the difference between the total average peak native load in the season and the amount attributable to the seller (in this case, the Exelon MBR Entities). The result is conservative in that it assumes all load in the market is met with specific generation committed to serving it via ownership or contractual commitment, which is not an accurate reflection of the facts in a market where some parties rely on short-term market purchases from the RTO to meet load obligations. In other words, my analysis assumes that every MW of generation is "committed" to the extent there is load, even though in reality every MW of generation is not necessarily committed by ownership or contractual commitment to serving a specific load. Thus, the Total Competing (Uncommitted) Supply that is assumed to compete with Exelon MBR Entities' Uncommitted Capacity in my analysis is conservatively low.

Planned Outages. I calculated average planned outages for each of the seasons based on outages at time of monthly peaks reported in the PJM, ISO-NE and NYISO FERC Form No. 714s.[30] For the

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obligations. As part of ongoing corporate reorganization, CCG was merged wholly and fully into Exelon Generation effective February 1, 2013, which effectively consolidated the wholesale energy operations into a single entity, which is Exelon Generation. For purposes of this filing any reference to Exelon Generation also covers the activity of CCG during the period between March 12, 2012, and February 1, 2013.

28 The Commission allows market-based rate sellers to consider their sales to load-serving entities on a short-term basis when computing their uncommitted capacity ("We will allow IPPs to deduct short term native load obligations if they can show that the power sold to the utility was used to meet native load." *Order No. 697* at P 155). For purposes of my screen calculations, I considered only sales by the Exelon MBR Entities to load-serving entities that are subject to contracts for the sale of physical energy while simultaneously netting out purchases from the same load-serving entities.

29 Sellers may deduct "long-term load following contracts to the extent that the seller has included in its total capacity a corresponding generating unit or long-term firm purchase contract that will be used to meet the obligation." *Order No. 697* at P 154.

30 *Order No. 697* indicates that planned outages should be consistent with those reported in FERC Form No. 714, and that "[t]o determine the amount of planned outages for a given season, the total number of MW-days of outages is

submarkets, I estimated outages based on the submarket's share of generation relative to total RTO generation. For the Exelon MBR Entities, I estimated outages based on their share of generation relative to total generation in the relevant market or submarket.

Simultaneous Import Limits ("SIL"). For PJM, I relied on the PJM 2012 Simultaneous Import Limit Study Report.[31] For ISO-NE, I relied on its 2012 Simultaneous Import Limit Study Report.[32] For NYISO, I relied on its 2012 Simultaneous Import Limit Study.[33]

Allocating Imports. I allocated imports to the Exelon MBR Entities in a manner consistent with the *Order No. 697-A Clarification Order*, which states that "market-based rate sellers, after accounting for the firm transmission rights held by the sellers and their affiliates, may allocate simultaneous transmission import capability on a *pro rata* basis (*i.e.*, based on the relative shares of the market-based rate seller's (and its affiliates') and competing suppliers' uncommitted generation capacity in first-tier markets when performing the indicative screens."[34] Based on the Exelon MBR Entities' share of uncommitted capacity in markets first-tier to the relevant markets (or submarkets) being analyzed, I allocated a pro rata share of the SIL to them. The remainder of the SIL was assumed to be Non-Affiliate Capacity.

Results of Analysis

Exhibit JRS-3 summarizes the results, as excerpted below. As shown, the Exelon MBR Entities pass the Pivotal Supplier Analysis and the Market Share Analysis in each of the relevant markets.

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divided by the total number of days in the season." *Order No. 697* at P 43. However, the FERC Form No. 714 reports planned outages only at time of peak for the month, and hence it is not possible to determine the total number of MW-days of outages from these data.

31 *2012 Simultaneous Import Limit Study*, PJM, Docket No. AD10-2, October 2, 2013.

32 *2012 Simultaneous Import Limit Study*, ISO New England Inc., Docket No. AD10-2, November 20, 2013.

33 *2012 Simultaneous Transmission Import Limit Study*, New York Independent System Operator, Inc., Docket No. AD10-2, December 19, 2013.

34 *Order No. 697-A Clarification Order* at Ordering Paragraph (A).

Market/ Submarket	Exhibit No.	Pivotal Supplier	Exhibit No.	Market Share Analysis			
				Winter	Spring	Summer	Fall
PJM	JRS-4	PASS	JRS-5	11.1%	10.8%	12.4%	12.3%
PJM East	JRS-6	PASS	JRS-7	15.3%	15.1%	14.0%	14.9%
5004/5005	JRS-8	PASS	JRS-9	13.8%	13.5%	12.5%	14.0%
AP South	JRS-10	PASS	JRS-11	10.1%	9.9%	9.3%	10.5%
ISO-NE	JRS-12	PASS	JRS-13	5.3%	4.9%	4.0%	7.1%
CT	JRS-14	PASS	JRS-15	0.0%	0.0%	0.0%	0.0%
NYISO	JRS-16	PASS	JRS-17	11.2%	10.5%	14.3%	11.1%

Exhibits JRS-4 through JRS-11 contain the detailed results of the Pivotal Supplier Analysis and the Market Share Analysis in PJM and the PJM submarkets. Exhibits JRS-12 through JRS-15 contain the detailed results in ISO-NE and the CT submarket. Exhibits JRS-16 through JRS-17 contain the detailed results in NYISO. Exhibits JRS-12 (CIS) and Exhibit JRS-13 (CIS) reflect detailed results in connection with the change in status arising from the Granite Ridge toll in ISO-NE.

PJM

In PJM, the Exelon MBR Entities own or control 25,677 MW of capacity, as shown in Exhibit JRS-2. This includes 1,666 MW of generation purchased or controlled under long-term contract, and 757 MW of long-term sales commitments.[35]

Pivotal Supplier Analysis. The Exelon MBR Entities' Installed Capacity is 24,255 MW, their Long-Term Firm Purchases are 1,666 MW and their Long-Term Sales are 757 MW. They are attributed 382 MW of imports. They are assigned 17,201 MW of load. Thus, Sellers' Uncommitted Capacity is 8,345 MW.

Total Uncommitted Supply is 63,975 MW. Wholesale Load is 20,871 MW, and Net Uncommitted Supply is 43,104 MW.

[35] As appropriate, the seasonal results reflect the retirement of the Cromby and Eddystone generating units (December 2011 and May 2012, respectively) during the study period.

Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Screen is passed. See Exhibit JRS-4.

Market Share Analysis. The Exelon MBR Entities' Installed Capacity ranges from 24,255 MW to 25,138 MW. Their Long-Term Firm Purchases range from 1,666 MW to 1,914 MW, and their Long-Term Firm Sales range from 757 to 760 MW. They are attributed 214 MW to 3,582 MW of planned outages, 12,838 MW to 16,198 MW of load, and 168 MW to 347 MW of imports. Thus, Sellers' Uncommitted Capacity ranges from 9,099 MW to 11,060 MW.

Total Seasonal Uncommitted Capacity ranges from 73,493 MW to 98,338 MW.

Sellers' Market Share ranges from 10.8 to 12.4 percent. Because Sellers' Market Share is less than 20 percent in all seasons, the Market Share Screen is passed. See Exhibit JRS-5.

Thus, on the basis of the Commission's screens, the Exelon MBR Entities do not have horizontal market power in PJM.

PJM East

In PJM East, the Exelon MBR Entities own or control 7,926 MW of capacity (some of which was retired during the study period), as shown in Exhibit JRS-2.

Pivotal Supplier Analysis. The Exelon MBR Entities' Installed Capacity is 7,414 MW. They are attributed 1,085 MW of imports. They are assigned 6,599 MW of load. Thus, Sellers' Uncommitted Capacity is 1,899 MW.

Total Uncommitted Supply is 13,644 MW. Wholesale Load is 6,481 MW, and Net Uncommitted Supply is 7,162 MW.

Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Screen is passed. See Exhibit JRS-6.

Market Share Analysis. The Exelon MBR Entities' Installed Capacity ranges from 7,414 MW to 8,122 MW. They are attributed 63 MW to 1,107 MW of planned outages, 4,623 MW to 6,115 MW of load, and 479 MW to 1,014 MW of imports. Thus, Sellers' Uncommitted Capacity ranges from 2,221 MW to 3,507 MW.

Total Seasonal Uncommitted Capacity ranges from 15,906 MW to 23,432 MW.

Sellers' Market Share ranges from 14.9 to 15.3 percent. Because Sellers' Market Share is less than 20 percent in all seasons, the Market Share Screen is passed. See Exhibit JRS-7.

Thus, on the basis of the Commission's screens, the Exelon MBR Entities do not have horizontal market power in PJM East.

5004/5005

In PJM 5004/5005, the Exelon MBR Entities own or control 12,611 MW of capacity (some of which was retired during the study period), as shown in Exhibit JRS-2. This includes 545 MW of generation purchased or controlled under long-term contract, and 757 MW of long-term sales commitments.

Pivotal Supplier Analysis. The Exelon MBR Entities' Installed Capacity is 12,311 MW, their Long-Term Firm Purchases are 545 MW, and their Long-Term Sales are 757 MW. They are attributed 1,318 MW of imports. They are assigned 11,091 MW of load. Thus, Sellers' Uncommitted Capacity is 2,325 MW.

Total Uncommitted Supply is 19,479 MW. Wholesale Load is 10,014 MW, and Net Uncommitted Supply is 9,465 MW.

Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Screen is passed. See Exhibit JRS-8.

Market Share Analysis. The Exelon MBR Entities' Installed Capacity ranges from 12,311 MW to 13,083 MW, their Long-Term Firm Purchases are 545 MW and their Long-Term Sales range from 757 MW to 760 MW. They are attributed 103 MW to 1,753 MW of planned outages, 7,805 MW to 10,288 MW of load and 578 MW to 1,175 MW of imports. Thus, Sellers' Uncommitted Capacity ranges from 2,882 MW to 4,623 MW.

Total Seasonal Uncommitted Capacity ranges from 23,115 MW to 33,618 MW.

Sellers' Market Share ranges from 12.5 to 14.0 percent. Because Sellers' Market Share is less than 20 percent in all seasons, the Market Share Screen is passed. See Exhibit JRS-9.

Thus, on the basis of the Commission's screens, the Exelon MBR Entities do not have horizontal market power in 5004/5005.

AP South

In AP South, the Exelon MBR Entities own or control 12,611 MW of capacity (some of which was retired during the study period), as shown in Exhibit JRS-2. This includes 545 MW of generation purchased or controlled under long-term contract, and 757 MW of long-term sales commitments.

Pivotal Supplier Analysis. The Exelon MBR Entities' Installed Capacity is 12,311 MW, their Long-Term Firm Purchases are 545 MW, and their Long-Term Sales are 757MW. They are attributed 1,351 MW of imports. They are attributed 11,186 MW of load. Thus, Sellers' Uncommitted Capacity is 2,263 MW.

Total Uncommitted Supply is 25,964 MW. Wholesale Load is 12,317 MW, and Net Uncommitted Supply is 13,647 MW.

Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Screen is passed. See Exhibit JRS-10.

Market Share Analysis. The Exelon MBR Entities' Installed Capacity ranges from 12,311 MW to 13,083 MW, their Long-Term Firm Purchases are 545 MW and their Long-Term Sales range from 757 MW to 760 MW. They are attributed 103 MW to 1,753 MW of planned outages, 7,866 MW to 10,372 MW of load and 501 MW to 1,212 MW of imports. Thus, Sellers' Uncommitted Capacity ranges from 2,848 MW to 4,437 MW.

Total Seasonal Uncommitted Capacity ranges from 30,717 MW to 42,227 MW.

Sellers' Market Share ranges from 9.3 to 10.5 percent. Because Sellers' Market Share is less than 20 percent in all seasons, the Market Share Screen is passed. See Exhibit JRS-11.

Thus, on the basis of the Commission's screens, the Exelon MBR Entities do not have horizontal market power in AP South.

Because the Exelon MBR Entities pass the indicative screens in the PJM market and each of the relevant submarkets, the Exelon MBR Entities are presumed not to have horizontal market power in these markets.

Market Mitigation. As I noted earlier, there are other protections in place that further prevent market power concerns. *Order No. 697* specifically considers that Commission-approved market monitoring and mitigation in RTO/ISO markets or submarkets are relevant to the market power analysis. In *Order No. 697*, the Commission stated that it "believe[s] the added protections provided in structured markets with market monitoring and mitigation generally result in a market where prices are transparent and attempts to exercise of market power will be sufficiently mitigated."[36]

PJM – as well as the other Northeast Region RTOs – is subject to extensive Commission-approved market monitoring and mitigation, and the Commission previously has found that such market monitoring and mitigation is sufficient to address any potential market power concerns in PJM and submarkets.[37]

Further, the Exelon MBR Entities also are subject to additional behavioral commitments in PJM entered into as part of the Exelon-Constellation merger that further mitigate any horizontal market power that the Exelon MBR Entities might be deemed to possess in PJM and relevant submarkets. These behavioral commitments include (i) notification procedures for planned retirements; (ii) prescribed rules on energy market offers specific to nuclear generation, peaking generation and other types of generation; and (iii) agreement with respect to bidding ancillary services.[38] In connection with these commitments, the PJM Independent Market Monitor ("IMM") concluded that "[t]he commitments made by the Applicants in the Settlement…would alleviate the Market Monitor's concerns about the effects of the merger on PJM markets. Based on the information that the Applicants will provide to the Market Monitor…and the information available

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36 *See Order No. 697* at PP 241-242.

37 *See*, *Baltimore Gas and Electric et al.*, Docket Nos. ER10-2172-007 *et al*., (Nov 1, 2012) (unpublished letter order), also citing to *PSEG Energy Resources & Trade*, 125 FERC ¶ 61,073 (2008).

38 *See* note 7.

to the Market Monitor under the PJM market rules, the Market Monitor will have the information needed to monitor compliance…"

Thus, the existing market monitoring and mitigation in place generally in PJM is further strengthened by the behavioral commitments agreed upon to the Exelon MBR Entities.

ISO-NE

In ISO-NE, the Exelon MBR Entities own or control 3,463 MW of capacity, as shown in Exhibit JRS-2. This includes 620 MW of generation purchased or controlled under long-term contract.

Pivotal Supplier Analysis. The Exelon MBR Entities' Installed Capacity is 2,843 MW, and their Long-Term Firm Purchases are 620 MW. They are attributed 829 MW of imports. They are assigned 3,589 MW of load. Thus, Sellers' Uncommitted Capacity is 704 MW.

Total Uncommitted Supply is 13,171 MW. Wholesale Load is 4,963 MW, and Net Uncommitted Supply is 8,207 MW.

Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Screen is passed. See Exhibit JRS-12.

Market Share Analysis. The Exelon MBR Entities' Installed Capacity ranges from 2,843 MW to 3,363 MW, and their Long-Term Firm Purchases are 620 MW. They are attributed 17 MW to 446 MW of planned outages, 2,764 MW to 3,518 MW of load and 347 MW to 636 MW of imports. Thus, Sellers' Uncommitted Capacity ranges from 565 MW to 1,149 MW.

Total Seasonal Uncommitted Capacity ranges from 14,167 MW to 18,406 MW.

Sellers' Market Share ranges from 4.0 to 7.1 percent. Because Sellers' Market Share is less than 20 percent in all seasons, the Market Share Screen is passed. See Exhibit JRS-13.

Thus, on the basis of the Commission's screens, the Exelon MBR Entities do not have horizontal market power in ISO-NE.

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CT

In CT, the Exelon MBR Entities control 620 MW of capacity under long-term contract, as shown in Exhibit JRS-2.

Pivotal Supplier Analysis. The Exelon MBR Entities' Installed Capacity is zero, and their Long-Term Firm Purchases are 620 MW. They are assigned 1,495 MW of load and are allocated 821 MW of imports. Thus, Sellers' Uncommitted Capacity is zero.

Total Uncommitted Supply is 4,323 MW. Wholesale Load is 1,530 MW, and Net Uncommitted Supply is 2,792 MW.

Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Screen is passed. See Exhibit JRS-14.

Market Share Analysis. The Exelon MBR Entities' Installed Capacity is zero, and their Long-Term Firm Purchases are 620 MW. They are attributed 3 MW to 69 MW of planned outages, 1,117 MW to 1,399 MW of load and 221 MW to 262 MW of imports. Thus, Sellers' Uncommitted Capacity is zero.

Total Seasonal Uncommitted Capacity ranges from 5,185 MW to 5,831 MW.

Sellers' Market Share is zero in all seasons. Because Sellers' Market Share is less than 20 percent in all seasons, the Market Share Screen is passed. See Exhibit JRS-15.

Thus, on the basis of the Commission's screens, the Exelon MBR Entities do not have horizontal market power in CT.

Because the Exelon MBR Entities pass the indicative screens in ISO-NE and the relevant submarkets, the Exelon MBR Entities are presumed not to have horizontal market power in these markets.

Market Mitigation in ISO-NE. ISO-NE also is subject to extensive Commission-approved market monitoring and mitigation, and the Commission previously has found that such market

monitoring and mitigation is sufficient to provide protection against market power concerns in ISO-NE and submarkets.[39]

NYISO

In NYISO, the Exelon MBR Entities own or control 1,926 MW of capacity, including 322 MW of Long-Term Sales, as shown in Exhibit JRS-2.

Pivotal Supplier Analysis. The Exelon MBR Entities' Installed Capacity is 2,266 MW. Their Long-Term Firm Sales are 340 MW. They are allocated 1,142 MW of imports. Thus, Sellers' Uncommitted Capacity is 3,068 MW.

Total Uncommitted Supply is 17,433 MW. Wholesale Load is 5,116 MW, and Net Uncommitted Supply is 12,318 MW.

Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Screen is passed. See Exhibit JRS-16.

Market Share Analysis. The Exelon MBR Entities' Installed Capacity is 2,266 MW to 2,268 MW and their Long-Term Firm Sales are 340 MW. They are attributed 44 MW to 277 MW of planned outages, and 599 MW to 798 MW of imports. Thus, Sellers' Uncommitted Capacity ranges from 2,249 MW to 2,626 MW.

Total Seasonal Uncommitted Capacity ranges from 18,358 MW to 22,761 MW.

Sellers' Market Share ranges from 10.5 to 14.3 percent. Because Sellers' Market Share is less than 20 percent in all seasons, the Market Share Screen is passed. See Exhibit JRS-17.

Thus, on the basis of the Commission's screens, the Exelon MBR Entities do not have horizontal market power in NYISO.

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[39] "As the Commission has previously found, the ISO-NE market monitoring and mitigation rules are sufficient to address market power concerns in the ISO-NE market and Connecticut submarket." (citing to *Dominion Energy Marketing, Inc.*, 125 FERC ¶ 61,070 at P 27 (2008); *NRG Power Marketing LLC*, Docket No. ER97-4281-018 (April 27, 2009) (delegated letter order)). *Dominion Energy Marketing, Inc.*, Docket No. ER01-468-012 (July 28, 2011) (unpublished letter order).

Market Mitigation in NYISO. NYISO also is subject to extensive Commission-approved market monitoring and mitigation, and the Commission previously has found that such market monitoring and mitigation is sufficient to provide protection against market power concerns in NYISO and submarkets.[40]

Change in Status (Granite Ridge)

Effective January 1, 2014, for a one-year period, Exelon Generation has entered into a tolling agreement under which it will "control" the output of the 661 MW (summer rating) Granite Ridge generating facility in ISO-NE. In anticipation of a notice of change in status that would otherwise be due within 30 days of the effective date of the tolling agreement, I include an analysis of the effect of this additional generation that will be controlled by the Exelon MBR Entities. Exhibits JRS-12 (CIS) and JRS-13 (CIS) reflect the impact of the inclusion of the Granite Ridge facility on the ISO-NE indicative screens for ISO-NE. As summarized in Exhibit JRS-3, the Market Share Analysis is passed in ISO-NE, with the Exelon MBR Entities' market share remaining below 20 percent in all seasons. The ISO-NE market also is subject to Commission-approved market monitoring and mitigation that is relevant in the context of this analysis.

Transmission

ComEd, PECO and BGE each own transmission facilities located in PJM, but those facilities are under the functional control of PJM and subject to the terms and conditions of the PJM OATT, which the Commission has deemed to mitigate a seller's transmission market power.[41] The Exelon MBR Entities own no transmission in other relevant markets other than the equipment necessary to connect their generation to the grid and thus there are no vertical concerns in relation to these facilities.

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[40] The Commission "will consider any existing Commission-approved market monitoring and mitigation regime already in place within the RTO/ISO that provides for mitigation of the submarket…We find that the NYISO market monitoring and mitigation rules are sufficient to address market power concerns in the New York City submarket." *Canandaigua Power Partners, LLC*, 141 FERC ¶ 61,210, P 17 (2012), also citing to *Niagara Mohawk Power Corp.*, 123 FERC ¶ 61,175, at P 35 (2008).

[41] *Order No. 697* at P 21.

Barriers to Entry

The Exelon MBR Entities have no ownership or control of intrastate natural gas transportation or intrastate natural gas storage, but as described above some of them do operate natural gas distribution facilities in PJM, and have LNG facilities that are used to provide peak gas to their customers. As the Commission has determined, there is rebuttable presumption that such ownership does not allow a seller to raise entry barriers.[42] Hence, no vertical concerns are present with respect to the Exelon MBR Entities' owned natural gas distribution company.

The Exelon MBR Entities do not own or control any sites for generation capacity development that can be used to erect barriers to entry in relevant markets.[43] The Exelon MBR Entities do not own or control sources of coal supplies (except via coal supply contracts) or the transportation of coal supplies other than private rail cars for the transport of coal supplies in PJM. Here again, the Commission has determined that there is a rebuttable presumption that such ownership or control does not allow a seller to raise entry barriers. There are no other issues that raise any relevant competitive concerns.

I understand that an affirmative statement on behalf of the Exelon MBR Entities is included in their submission that they have not erected barriers to entry and will not erect barriers to entry.

Based on these facts, the Exelon MBR Entities have demonstrated a lack of vertical market power.

Since the Exelon MBR Entities lack both horizontal and vertical market power, I conclude that they satisfy the Commission's tests for market-based rate authority.

V. CONCLUSION

On the basis of the foregoing analysis, the Exelon MBR Entities satisfy the Commission's horizontal and vertical market power tests for market-based rate authority in the relevant markets.

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42 *Id.* at P 22.

43 New plant sites owned or controlled by the Exelon MBR Entities in relevant markets and meeting the Commission's reporting thresholds have been reported by the Exelon MBR Entities in accordance with the reporting requirements of Order No. 697-C.

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NAVIGANT

Exhibit JRS-1

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Professional History

- Managing Director, Navigant Consulting - 2010-Present
- Vice President, Charles River Associates - 2001-2010
- Senior Vice President, Putnam, Hayes and Bartlett, Inc. and PHB Hagler Bailly, Inc., Washington, DC - 1986-2000
- Economist, Economic Consulting Services, Inc., Washington, DC - 1979-1986
- Economist, U.S. Department of Labor, Washington, DC - 1976-1979

Education

- M.B.A. Finance, The Wharton School University of Pennsylvania
- B.A. Economics, Connecticut College

Testimony

- Written testimony provided in more than 150 regulatory proceedings

Julie Solomon is a Managing Director at Navigant Consulting, Inc. in the Energy Practice's Power Systems, Markets & Pricing group. She has more than 20 years of consulting experience, specializing in the areas of regulatory and utility economics, financial analysis and business valuation. Ms. Solomon has participated in analysis of proposed regulatory reforms, supply options and utility industry restructuring in the gas and electric industries. She also has advised utility clients in corporate strategy and corporate restructuring, and consulted to legal counsel on a variety of litigation and regulatory matters, including antitrust litigation and contract disputes. She has filed testimony in numerous proceedings before the Federal Energy Regulatory Commission. Much of her current practice focuses on regulatory and market power issues concerning mergers and acquisitions and compliance filings in the electricity market.

» Advised clients in the electric and gas utility industry on competition issues, including the impact of mergers on competition. Directed a large number of analytic studies relating to obtaining merger approval from regulatory authorities.

» Advised clients in the electric utility industry on restructuring strategies, including potential mergers and acquisitions, functional unbundling and cost savings.

» Consulted in the electric and gas utility industries in a variety of regulatory and competition matters, including rate proceedings, prudence reviews, proposed regulatory reforms, analysis of supply options, privatization and restructuring.

» Advised utility and non-utility clients on many aspects of the competitive independent power industry, including strategic and financial consulting assignments.

» Consulted legal counsel on a variety of litigation matters, including the development of expert testimony on liability issues and the calculation of damages in a variety of industries.

» Provided strategic and economic analyses for clients in trade regulatory proceedings such as dumping and subsidies.

» Provided financial and business valuation analyses in a number of transactions, including fair market value for taxation purposes and valuation of family-owned businesses.

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Professional Experience

Electric and Gas Utilities

Mergers and Acquisitions (Market Power and Competition Issues)

» Advised clients and conducted analytic studies in connection with a large number of major electric and electric-gas mergers and asset transactions of regulated companies. Provided testimony to FERC for a number of these types of transactions.

» Advised clients and provided confidential pre-screening analyses for potential mergers and acquisitions.

» Conducted numerous analytic studies in connection with FERC market-based rate applications and compliance filings for electricity sellers. Provided testimony to FERC for a number of these types of transactions.

» Conducted numerous analytic studies in connection with FERC market-based rate applications and compliance filings for gas storage facilities. Provided testimony to FERC for a number of these types of transactions.

Utility Restructuring and Stranded Cost

» Conducted analytic studies and provided litigation support in connection with state stranded cost proceedings in Ohio (Cincinnati Gas & Electric and Dayton Power & Light); West Virginia (Monongahela Power and Potomac Edison); Maryland (Potomac Edison) and Pennsylvania (West Penn Power).

» Provided analytic support evaluating the benefits of Public Service of Colorado's proposed DC transmission line between Colorado and Kansas in support of a regulatory proceeding.

» Assisted in studies relating to privatization of the electricity industry in the United Kingdom, including development of a computer model to simulate electricity dispatch and project future prices, capacity needs and utility revenues under various scenarios. During temporary assignment to London office.

» Participated in antitrust litigation involving a utility and a cogenerator, including preparation of an expert report on liability and damage issues, preparation of expert witnesses for deposition, and assistance in preparation for depositions of opposing expert and in-house witnesses.

» Assisted in the valuation of the interests of several firms in various cogeneration projects for the purpose of combining these interests into a new entity or selling interests to third parties.

» Analyzed the financial feasibility and viability of a large number of cogeneration projects, assisted in the preparation of presentations and filings and presented testimony to the relevant public utility commission. Ms. Solomon also assisted in the development of a PC-based financial model to analyze various cogeneration projects.

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» Participated in a study to analyze the financial effects of a variety of restructuring options for a utility, including transfer and/or sale of assets and subsequent sale-leasebacks, and debt restructuring alternatives. In addition, she developed a PC-based financial model with applications to utility restructuring plans.

» Provided litigation support in major utility rate proceedings, including assisting in the preparation of responses to interrogatories and data requests, preparation of company and outside expert witnesses for deposition and hearings, and assistance in the deposition and cross-examination of intervenor witnesses.

» Participated in proceedings involving regulation of an oil pipeline, which included evaluating the business risks faced by the company.

Business Valuation

» Participated in a valuation study involving the fair market value of a privately held company for purposes of an IRS proceeding.

» Participated in a valuation study in a divorce proceeding, where the assets being valued included a privately held business.

» Participated in two strategic engagements that developed business plans and identified potential acquisition candidates for the client.

» Provided advice to a client concerning the benefits and potential risks of developing a partnership with a competitor.

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Testimony or Expert Report Experience

- Supplemental Affidavit on behalf of MidAmerican Energy (Silver Merger Sub, Inc.), Docket No. EC13-128, application for authorization of disposition of jurisdictional facilities, August 17, 2013.
- Affidavit on behalf of Desert Sunlight 250, LLC and Desert Sunlight 300, LLC, Docket Nos. ER13-1991-2, market-based rate applications, July 17, 2013.
- Affidavit on behalf of MidAmerican Energy (Silver Merger Sub, Inc.), Docket No. EC13-128, application for authorization of disposition of jurisdictional facilities, July 12, 2013.
- Affidavit on behalf of Calpine Southwest MBR Sellers, Docket No. ER10-1942, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of NextEra Companies, Docket No. ER10-1847, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of Wayzata Entities, Docket No. ER10-1777, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of AES MBR Affiliates, Docket No. ER10-3415, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of Sierra Pacific Power Company, *et al.* under ER10-2474, Docket No. ER10-24744, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of NorthWestern Corporation, Docket No. ER11-1858, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of SGOC Southwest MBR Sellers, Docket No. ER10-2864, market-based rate triennial filing, June 28, 2013.
- Affidavit on behalf of GWF Energy LLC, et al. Docket No. ER10-3301, market-based rate triennial filing, June 28, 2013.
- Affidavit on behalf of NV Energy, Inc., application for approval of internal reorganization, Docket No. EC13-113, May 31, 2013.
- Affidavit on behalf of Midwest Generation, LLC, Docket No. EC13-103, application for authorization of disposition of jurisdictional facilities, May 6, 2013.
- Affidavit of behalf of Nevada Power Company (with Matthew E. Arenchild), Docket No. EC13-96, application for authorization of disposition of jurisdictional facilities, April 17, 2013.
- Affidavit of behalf of Dynegy Inc., Docket No. EC13-93, application for authorization of disposition of jurisdictional facilities, April 16, 2013.
- Application on behalf of Florida Power & Light Company, Docket No. EC13-91, application for authorization of disposition of jurisdictional facilities, April 12, 2013.
- Affidavit on behalf of Blythe Energy LLC, et al., Docket No. EC13-89, application for authorization of disposition of jurisdictional facilities, April 2, 2013.

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- Affidavit on behalf of New Harquahala Generating Company, LLC, Docket No. ER10-3310, market-based rate triennial filing, March 29, 2013.
- Affidavit on behalf of Dominion Energy Brayton Point, et al., Docket No. EC13-82, application for authorization of disposition of jurisdictional facilities, March 21, 2013.
- Affidavit on behalf of Duke Energy Carolinas, LLC et al., Docket No. ER10-2566, et al., notice of change in status, January 29, 2013.
- Affidavit on behalf of CCI Roseton LLC, Docket No. ER13-773, market-based rate application, January 17, 2013.
- Affidavit on behalf of CCI Roseton LLC, Docket No. EC13-63, application for authorization of disposition of jurisdictional facilities, January 16, 2013.
- Affidavit on behalf of Calpine Oneta Power, LLC, Docket No. ER11-3777, et al., market-based rate triennial filing, December 31, 2012.
- Affidavit on behalf of NextEra Energy Companies, Docket No. ER12-569, et al., market-based rate triennial filing, December 27, 2012.
- Affidavit on behalf of Nevada Power Company, Docket No. ER10-2474, market-based rate triennial filing, December 26, 2012.
- Testimony on behalf of Powerex Corp re Puget Sound Energy, Inc v. All Jurisdictional Sellers of Energy & Capacity, Docket No. EL01-10, December 17, 2012.
- Affidavit on behalf of AES Beaver Valley, LLC, Docket No. ER13-442, market-based rate application, November 21, 2012.
- Affidavit on behalf of Broad River Energy LLC, et al., Docket No. EC13-42, application for authorization of disposition of jurisdictional facilities, November 16, 2012.
- Affidavit on behalf of Westar Energy, Inc., Docket No. ER10-2507, notice of change in status, October 29, 2012.
- Affidavit on behalf of Homer City Generation, L.P., Docket No. ER13-55, market-based rate application, October 9, 2012.
- Affidavit on behalf of Homer City Generation, L.P., et al., Docket No. EC13-9, application for authorization of disposition of jurisdictional facilities, October 9, 2012.
- Affidavit on behalf of GenOn Marsh Landing, LLC, Docket No. ER12-2545, market-based rate application, August 29, 2012.
- Affidavit on behalf of High Mesa Energy, LLC, Docket No. ER12-2528, market-based rate application, August 27, 2012.
- Affidavit on behalf of Brandon Shores LLC, et al., Docket No. EC12-137, application for authorization of disposition of jurisdictional facilities, August 23, 2012.
- Affidavit on behalf of North Sky River Energy, LLC, Docket No. ER12-2444, market-based rate application, August 14, 2012.

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- Affidavit on behalf of Duke Energy Carolinas, LLC et al., Docket No. ER10-2566, et al., notice of change in status, August 1, 2012.
- Affidavit on behalf of Canandaigua Power Partners, LLC et al., Docket No. ER10-2460, notice of change in status, July 16, 2012.
- Affidavit on behalf of Limon Wind I and Limon Wind II, LLC, Docket Nos. ER12-2225 and -2226, market-based rate application, July 10, 2012.
- Affidavit on behalf of Ensign Wind, LLC, Docket No. ER12-2227, market-based rate application, July 10, 2012.
- Affidavit on behalf of NextEra Energy Companies, Docket No. ER10-1836, et al., market-based rate triennial filing, July 2, 2012.
- Affidavit on behalf of Iberdrola Renewables, LLC, et al., Docket No. ER10-2994, et al., market-based rate triennial filing, June 29, 2012.
- Affidavit on behalf of The Empire District Electric Company, Docket No. ER10-2738, market-based rate triennial filing, June 29, 2012.
- Affidavit on behalf of Wisconsin Electric Power Company, Docket No. ER10-2563, market-based rate triennial filing, June 29, 2012.
- Affidavit on behalf of Baltimore Gas and Electric Company, et al., Docket No. ER10-2172, et al., market-based rate triennial filing, June 29, 2012.
- Affidavit on behalf of Westar Energy, Inc., Docket No. ER12-2124, market-based rate triennial filing, June 28, 2012.
- Affidavit on behalf of Duke Energy Beckjord, LLC, et al., Docket No. ER12-1946 et al., market-based rate application, June 5, 2012.
- Affidavit on behalf of Minco Wind III, LLC, Docket No. ER12-1880, market-based rate application, May 31, 2012.
- Affidavit on behalf of Tuscola Bay Wind, LLC, Docket No. ER12-1660, market-based rate application, April 30, 2012.
- Affidavit on behalf of Powerex Corp., Docket No. ER11-2664, notice of change in status, April 13, 2012.
- Affidavit on behalf of Safe Harbor Water Power Corporation, Docket No. ER11-2780, notice of change in status, April 11, 2012.
- Affidavit on behalf of Hot Spring Power Company, LLC, Docket No. EC12-87, application for authorization of disposition of jurisdictional facilities, March 28, 2012.
- Affidavit on behalf of High Majestic Wind II, LLC, Docket No. ER12-1228, market-based rate application, March 8, 2012.
- Affidavit on behalf of Duke Energy Indiana, Inc. et al., Docket No. ER10-2034 et al., notice of change in status, January 31, 2012.

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- Affidavit on behalf of CPV Cimarron Renewable Energy Company, LLC, Docket No. ER12-775, market-based rate application, January 6, 2012.
- Affidavit on behalf of LS Power Marketing, LLC, et al., Docket No. ER10-2739, et al., market-based rate triennial filing, January 3, 2012.
- Affidavit on behalf of Auburndale Peaker Energy Center, LLC, et al., Docket No. ER10-1945, et al., market-based rate triennial filing, January 3, 2012.
- Affidavit on behalf of Duke Energy Indiana, Inc., et al., Docket No. ER10-2034, et al., market-based rate triennial filing, December 28, 2011.
- Affidavit on behalf of Northern Indiana Public Service Company, Docket No. ER10-1781, market-based rate triennial filing, December 28, 2011.
- Affidavit on behalf of Baltimore Gas and Electric Company, et al., Docket No. ER10-2172, et al., market-based rate triennial filing, December 28, 2011.
- Affidavit on behalf of Duke Energy Carolinas, LLC Docket No. ER10-2566, notice of change in status, December 27, 2011.
- Affidavit on behalf of AEE2, L.L.C., et al., Docket No. ER10-3142, et al., market-based rate triennial filing, December 23, 2011.
- Affidavit on behalf of Exelon Generation Company, LLC, et al., Docket No. ER10-1144, et al., market-based rate triennial filing, December 23, 2011.
- Affidavit on behalf of AEE2, L.L.C., et al., Docket No. ER10-3142, et al., notice of change in status, December 23, 2011.
- Affidavit on behalf of Perrin Ranch, LLC, Docket No. ER12-676, market-based rate application, December 22, 2011.
- Affidavit on behalf of GenOn Energy Management, LLC, et al., Docket No. ER10-1869, et al., market-based rate triennial filing, December 16, 2011.
- Affidavit on behalf of Blackwell Wind, LLC, Docket No. ER12-569, market-based rate application, December 7, 2011.
- Affidavit on behalf of Bluegrass Generation Company, L.L.C. et al., Docket No. EC12-29, application for authorization of disposition of jurisdictional facilities, November 14, 2011.
- Affidavit on behalf of Dynegy Danskammer, L.L.C., et al., Docket No. EC12-27, application for authorization of disposition of jurisdictional facilities, November 8, 2011.
- Affidavit on behalf of LSP Energy Limited Partnership, et al., Docket No. EC12-19, application for authorization of disposition of jurisdictional facilities, November 1, 2011.
- Affidavit on behalf of Tenaska Power Management, LLC, Docket No. ER12-60, market-based rate application, October 11, 2011.
- Testimony on behalf of Florida Power & Light Company, Docket No. ER12-46, October 7, 2011.
- Affidavit on behalf of Montezuma Wind II, LLC and Vasco Winds, LLC, Docket No. ER11-4677 and ER11-4678, market-based rate applications, September 28, 2011.

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- Affidavit of Amsterdam Generating Company, LLC, et al. under Docket No. EC11-118, application for authorization of disposition of jurisdictional facilities, September 9, 2011.
- Affidavit on behalf of Minco Wind II, LLC, Docket No. ER11-4428, market-based rate application, September 2, 2011.
- Affidavit on behalf of Osage Wind, LLC, Docket No. ER11-4363, market-based rate application, August 24, 2011.
- Affidavit on behalf of Baltimore Gas and Electric Company, et al., Docket No. ER10-2172, et al. and Calvert Cliffs Nuclear Power Plant, LLC, et al. Docket No. ER10-2179, et al. Notice of Change in Status, August 19, 2011.
- Affidavit on behalf of Michigan Wind II, LLC, Docket No. ER11-3989, market-based rate application, August 17, 2011.
- Affidavit on behalf of Morgan Stanley Capital Group, Docket No. EC11-97, application for authorization of disposition of jurisdictional facilities, July 22, 2011.
- Affidavit on behalf of Calpine Energy Services, L.P., et al., Docket No. ER10-2042, et al., Supplemental market-based rate filing, July 22, 2011.
- Affidavit on behalf of South Carolina Electric & Gas Co, Docket No. ER10-2498, market-based rate triennial filing, July 14, 2011.
- Affidavit on behalf of Duke Energy Carolinas, LLC, Docket No. ER10-2566, market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of North Allegheny Wind, LLC, Docket No. ER10-1330, et al.., market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of NextEra Energy Companies, Docket No. ER10-1838, market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of NextEra Energy Companies, Docket No. ER10-1852, market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of AES MBR Affiliates, Docket No. ER10-3142 et al., market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of MATEP Limited Partnership, Docket No. ER10-3194, market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of Morgan Stanley Capital Group Inc., Docket No. ER94-1384 et al., market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of Louisville Gas and Electric Company et al., Docket No. ER10-1511 et al., market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of Progress Companies, Docket No. ER10-1760 et al., market-based rate triennial filing, June 30, 2011.
- Affidavit on behalf of Mojave Solar, LLC, Docket No. ER11-3917, market-based rate application, June 29, 2011.

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- Affidavit on behalf of GDF SUEZ Northeast MBR Sellers, Docket No. ER10-2670 et al., market-based rate triennial filing, June 24, 2011.
- Affidavit on behalf of Alcoa Companies, Docket No. ER10-3069 et al., market-based rate triennial filing, June 23, 2011.
- Affidavit on behalf of Northwestern Corporation, Docket No. EC11-88, application for authorization of disposition of jurisdictional facilities, June 6, 2011.
- Testimony, with Joe D. Pace, on behalf of Exelon Corporation and Constellation Energy Group, Inc., Docket No. EC11-83, merger application, May 20, 2011.
- Affidavit on behalf of The AES Corporation and DPL Inc., Docket No. EC11-81, application for authorization of disposition of jurisdictional facilities, May 18, 2011.
- Affidavit on behalf of Wildcat Power Holdings, LLC, Docket No. ER11-3336, market-based rate application, April 15, 2011.
- Affidavit on behalf of TPF Generation Holdings, LLC, University Park Energy, LLC, and LSP Park Generating, LLC, Docket No. EC11-61, application for authorization of disposition of jurisdictional facilities, April 4, 2011.
- Affidavit on behalf of Entegra Power Group LLC, Gila River Power, L.P., and Wildcat Power Holdings, LLC, Docket No. EC11-54, application for authorization of disposition of jurisdictional facilities, May 22, 2011.
- Affidavit on behalf of Safe Harbor Water Power Corporation, Docket No. ER11-2780, market-based rate triennial filing, January 28, 2011.
- Supplemental Affidavit on behalf of NorthWestern Corp et al., Docket No. ER03-329-010 et al., triennial market-based rate update, January 21, 2011.
- Affidavit on behalf of Mountain View Power Partners IV, LLC, Docket No. ER11-2701, market-based rate application, January 19, 2011.
- Affidavit on behalf of Calpine Energy Services, L.P., et al., Docket No. ER10-2042, et al., market-based rate triennial filing, January 3, 2011.
- Affidavit on behalf of J.P. Morgan Ventures Energy Corporation, Docket No. ER05-1232, market-based rate triennial filing, December 31, 2010.
- Affidavit on behalf of the Exelon MBR Companies, Docket No. ER10-1048, et al., market-based rate triennial filing, December 30, 2010.
- Affidavit on behalf of First Wind Energy Marketing, LLC, et al., Docket No. ER09-1549, et al. , market-based rate application, December 30, 2010.
- Affidavit on behalf of the IRI MBR Companies, Docket No. ER11-2462, et al., market-based rate triennial filing, December 29, 2010.
- Affidavit on behalf of Green Mountain Power Corporation, Docket No. ER01-989, market-based rate triennial filing, December 29, 2010.

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- Affidavit on behalf of Baltimore Gas and Electric Company et al., Docket Nos. ER10-2172 et al., market-based rate triennial filing, December 29, 2010.
- Affidavit on behalf of Dominion Resources Services, Inc., on behalf of Virginia Electric and Power Company and affiliates, Docket No. ER01-468, et al., market-based rate triennial filing, December 27, 2010.
- Affidavit on behalf of NextEra Companies, Docket No. ER98-2494, et al., market-based rate triennial filing, December 27, 2010.
- Affidavit on behalf of Atlantic City Electric Company et al., Docket No. ER96-1351 et al., market-based rate triennial filing, December 27, 2010.
- Affidavit on behalf of Allegheny Companies, Docket No. ER11-2481 et al., market-based rate triennial filing, December 27, 2010.
- Affidavit on behalf of Red Mesa Wind, LLC, Docket No. ER11-2192, market-based rate application, November 25, 2010.
- Affidavit on behalf of Duke Energy Vermillion II, LLC; Duke Energy Hanging Rock II, LLC; Duke Energy Lee II, LLC; Duke Energy Washington II, LLC; Duke Energy Fayette II, LLC; Docket Nos. ER11- 2063-6 and 2069, market-based rate application, November 10, 2010.
- Affidavit on behalf of Elk City II Wind, LLC, Docket No. ER11-2037, market-based rate application, November 5, 2010.
- Affidavit on behalf of AES Laurel Mountain, LLC, Docket No. ER11-2036, market-based rate application, November 5, 2010.
- Supplemental Affidavit on behalf of GDF SUEZ S.A. and International Power Plc, Docket No. EC10-98, application for authorization of disposition of jurisdictional facilities, October 29, 2010.
- Supplemental Affidavit on behalf of NorthWestern Corp et al., Docket No. ER03-329-010 et al., triennial market-based rate update, October 18, 2010.
- Supplemental Affidavit on behalf of Fore River Development, LLC, et al., Docket No. EC10-85, application for authorization of disposition of jurisdictional facilities, October 8, 2010.
- Affidavit on behalf of Harbor Gen Holdings, LLC, et al., Docket No. EC11-3, application for authorization of disposition of jurisdictional facilities, October 6, 2010.
- Affidavit on behalf of Ashtabula Wind III, LLC, Docket No. ER11-26, market-based rate application, October 5, 2010.
- Affidavit on behalf of LSP Safe Harbor Holdings, LLC, Docket No. ER11-27, market-based rate application, October 5, 2010.
- Affidavit on behalf of Exelon Corporation, et al., Docket No. EC10-105, application for authorization of disposition of jurisdictional facilities, September 30, 2010.
- Supplemental Affidavit on behalf of Constellation Mystic Power, LLC, Docket No. ER10-2281, September 23, 2010.

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- Affidavit on behalf of GDF SUEZ S.A. and International Power Plc, Docket No. EC10-98, application for authorization of disposition of jurisdictional facilities, September 23, 2010.
- Affidavit on behalf of Minco Wind, LLC, Docket No. ER10-2720, market-based rate application, September 17, 2010.
- Affidavit on behalf of Baldwin Wind, LLC, Docket No. ER10-2551, market-based rate application, September 7, 2010.
- Affidavit on behalf of Fore River Development, LLC, et al., Docket No. EC10-85, application for authorization of disposition of jurisdictional facilities, August 18, 2010.
- Affidavit on behalf of Constellation Mystic Power, LLC, Docket No. ER10-2281, market-based rate application, August 18, 2010.
- Affidavit on behalf of Calpine Mid-Atlantic Marketing, LLC, Docket No. ER10-2029, market-based rate application, July 29, 2010.
- Affidavit on behalf of Sundevil Power Holdings, LLC, Docket No. ER10-1777, market-based rate application, July 14, 2010.
- Supplemental affidavit on behalf of Shell Energy North America (US), Docket No. ER08-656, triennial market-based rate update, July 9, 2010.
- Affidavit on behalf of NextEra Companies, Docket No. ER02-2018 et al., triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of NorthWestern Corp et al., Docket No. ER03-329 et al., triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of Mirant, Docket No. ER01-1270 et al., triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of CalPeak Entities and Tyr Energy, LLC, Docket No. ER06-1331, et al., triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of Starwood Power-Midway, Docket No. LLC under ER08-110, triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of J.P. Morgan Ventures Energy Corporation and BE CA LLC in ER05-1232, et al., triennial market-based rate update, June 30, 2010.
- Affidavit on behalf of AES 2, L.L.C., et al. Docket No. ER99-2284, et al., triennial market-based rate update, June 29, 2010.
- Affidavit on behalf of Sierra Pacific Power Company and Nevada Power Company, Docket No. ER01-1527 et al., triennial market-based rate update, June 28, 2010.
- Affidavit on behalf of Dynegy Marketing and Trade, LLC, et al., Docket No. ER09-629, et al., triennial market power update, June 23, 2010.
- Affidavit on behalf of Mirant Corporation and RRI Energy, Inc., application for authorization to transfer jurisdictional facilities, Docket No. EC10-70, May 14, 2010.

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- Affidavit on behalf of New Development Holdings, LLC et al., application for authorization to transfer jurisdictional facilities, Docket No. EC10-64, May 6, 2010.
- Supplemental affidavit on behalf of JPMorgan Chase, Docket No. ER07-1358 et al., notice of change in status regarding market-based rate authorization, April 16, 2010.
- Supplemental affidavit on behalf of Shell Energy North America (US), Docket No. ER08-656, triennial market-based rate update, April 12, 2010.
- Supplemental affidavit on behalf of Dogwood Energy LLC, Docket No. ER07-312, triennial market-based rate update, April 9, 2010.
- Affidavit on behalf of Big Horn Wind Project LLC and Juniper Canyon Wind Power LLC, Docket Nos. ER10-974 and 975, market-based rate application, March 31, 2010.
- Affidavit on behalf of CER Generation, LLC Docket No. ER10-662, market-based rate application, March 19, 2010.
- Affidavit on behalf of Calpine Corporation, Docket No. ER00-3562 et al., triennial market-based rate update, March 16, 2010.
- Affidavit on behalf of NV Energy, Docket No. ER01-1529 et al., triennial market-based rate update, March 8, 2010.
- Affidavit on behalf of Day County Wind, LLC, Docket No. ER10-825, market-based rate application, March 4, 2010.
- Affidavit on behalf of Dogwood Energy LLC, Docket No. ER07-312, triennial market-based rate update, March 1, 2010.
- Affidavit on behalf of NextEra Companies, Docket No. ER10-149 et al., triennial market-based rate update, March 1, 2010.
- Supplemental affidavit on behalf of The Empire District Company, Docket No. ER99-1757, triennial market-based rate update, February 22, 2010.
- Supplemental affidavit on behalf of Oklahoma Gas and Electric Company & OGE Energy Resources, Inc., Docket No. ER98-511 and ER97-4345, triennial market-based rate update, February 19, 2010.
- Supplemental affidavit on behalf of Westar Energy, Inc., ER98-2157 et al., triennial market-based rate update, February 18, 2010.
- Affidavit on behalf of AES ES Westover, LLC, Docket No. ER10-712, market-based rate application, February 5, 2010.
- Affidavit on behalf of RRI Florida MBR Companies, Docket No ER09-1110 et al. notice of change in status regarding market-based rate authorization, February 1, 2010.
- Affidavit on behalf of Wolverine Power Supply Cooperative, Inc. and FirstEnergy Generation Corp., Docket No. EC10-41, January 21, 2010.
- Affidavit on behalf of FPL Energy Illinois Wind, LLC, Docket No. ER10-402, market-based rate application, December 10, 2009.

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- Affidavit on behalf of NextEra Companies, Docket No. ER09-832, et al., notice of change in status regarding market-based rate authorization, December 7, 2009.
- Affidavit on behalf of Garden Wind, LLC, Docket No. ER10-296 and Crystal Lake Wind III, LLC, Docket No. ER10-297, market-based rate application, November 23, 2009.
- Affidavit on behalf of Stateline II, LLC, Docket No. ER10-256, market-based rate application, November 16, 2009.
- Affidavit on behalf of Elk City Wind, LLC, Docket No. ER10-149, market-based rate application, November 2, 2009.
- Affidavit on behalf of Alcoa Power Generating, Inc. et al., Docket No. ER07-496 et al., triennial market-based rate update, October 30, 2009.
- Affidavit on behalf of CPV Keenan II Renewable Energy Co, LLC, Docket No. ER10-64, market-based rate application, October 16, 2009.
- Supplemental Affidavit on behalf of Florida Power & Light Co et al., Docket No. ER97-3359 et al., triennial market-based rate update, October 7, 2009.
- Affidavit on behalf of High Majestic Wind Energy Center, LLC, Butler Ridge Wind Energy Center, LLC, and Wessington Wind Energy Center, LLC, Docket Nos. ER10-1-3, market-based rate applications, October 6, 2009.
- Affidavit on behalf of Powerex Corp. in State of California, ex rel. Lockyer v. British Columbia Power Exchange Corp., et al., Docket No. EL02-71, September 17, 2009.
- Affidavit on behalf of Alcoa Power Generating, Inc. et al., Docket No. ER07-496 et al., triennial market-based rate update, September 14, 2009.
- Affidavit on behalf of Powerex Corp. in State of California, ex rel. Edmund G. Brown, Attorney General for the State of California v. Powerex Corp. (f/k/a British Columbia Power Exchange Corp.), et al., Docket No. EL09-56, September 3, 2009.
- Affidavit on behalf of Ashtabula Wind II, LLC, Docket No. ER09-1656, market-based rate application, September 1, 2009.
- Affidavit on behalf of Oklahoma Gas and Electric Company et al., Docket No. ER98-511 et al., triennial market power update, July 30, 2009.
- Affidavit on behalf of Westar Energy, Inc & Kansas Gas and Electric Company, Docket No. ER98-2157 et al., triennial market power update, July 30, 2009.
- Affidavit on behalf of The Empire District Electric Company, Docket No .ER99-1757, triennial market power update, July 30, 2009.
- Affidavit on behalf of NextEra Companies, Docket No. ER08-1297, et al., triennial market power update, June 30, 2009.
- Affidavit on behalf of Calpine Energy Services, L.P., et al., Docket No. ER00-3562, et al. triennial market power update, June 30, 2009.

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- Affidavit on behalf of Dominion Energy Kewaunee, Inc., Docket No. ER04-318, triennial market power update, June 30, 2009.
- Affidavit on behalf of CinCap IV, LLC, Docket No. ER05-1372 et al., triennial market power update, June 30, 2009.
- Affidavit on behalf of Wisconsin Electric Power Company, Docket No. ER98-855, triennial market power update, June 30, 2009.
- Affidavit on behalf of J.P. Morgan Ventures Energy Corporation, et al., Docket No. ER05-1232, et al., triennial market power update, June 30, 2009.
- Affidavit on behalf of Iberdrola Renewables, Inc et al., Docket No. ER08-912 et al., triennial market power update, June 30, 2009.
- Affidavit on behalf of Exelon Generation Co, LLC et al., Docket No. ER00-3251 et al., triennial market power update, June 30, 2009.
- Affidavit on behalf of Dynegy Marketing and Trade, LLC, et al., Docket No. ER09-629, et al., triennial market power update, June 26, 2009.
- Affidavit on behalf of GenConn Middletown, LLC and GenConn Devon, LLC, Docket Nos. ER09-1300-1301, market-based rate application, June 15, 2009.
- Affidavit on behalf of Northern Colorado Wind Energy, Docket No. ER09-1297, market-based rate application, June 12, 2009.
- Affidavit on behalf of Fox Energy Company LLC, Docket No. ER03-983, triennial market power update, June 3, 2009.
- Affidavit on behalf of the KGen Companies, Docket No .ER04-1181 et al., market-based rate change in status filing, April 2, 2009.
- Affidavit on behalf of Victory Garden Phase IV, LLC, Sky River LLC, FPL Energy Cabazon Wind LLC, Docket Nos. ER09-900-902, market-based rate application, April 1, 2009.
- Affidavit on behalf of the KGen Companies, Docket No. EC07-30 et al., March 31, 2009.
- Affidavit on behalf of TransAlta Energy Marketing Corporation, Docket No. ER09-884, market-based rate application, March 25, 2009.
- Affidavit on behalf of NorthWestern Energy, Docket No. ER03-329, triennial market-based rate update, December 30, 2008.
- Affidavit on behalf of Calpine Corporation re Broad River Energy LLC et al., Docket No. ER00-38 et al., triennial market-based rate update, December 30, 2008.
- Affidavit on behalf of Constellation MBR Entities, Docket No. ER99-2948 et al., triennial market-based rate update, December 30, 2008.
- Affidavit on behalf of LS Power Marketing, LLC, Docket No. ER96-1947 et al., triennial market-based rate update, December 29, 2008.
- Affidavit on behalf of Tenaska Alabama Partners, L.P., et al., Docket No. ER00-840 et al., triennial market-based rate update, December 24, 2008.

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- Affidavit on behalf of Bluegrass Generation Company, LLC., et al., Docket No. ER02-506 et al., triennial market-based rate update, December 24, 2008
- Affidavit on behalf of KGen Hinds, LLC, et al., Docket No. ER04-1181 et al., triennial market-based rate update, December 23, 2008
- Affidavit on behalf of Reliant SE MBR Entities, FERC Docket No. ER05-143 et al., triennial market-based rate update, December 23, 2008.
- Affidavit on behalf of Exelon Generation Company, LLC, Docket No. ER00-3251 triennial market-based rate update, December 18, 2008.
- Affidavit on behalf of Northern Indiana Public Service Co. et al., Docket No. ER00-2173 et al., triennial market-based rate update, December 18, 2008.
- Affidavit on behalf of Duke Energy Indiana, Inc., et al., Docket No. ER07-189 et al., triennial market-based rate update, December 17, 2008.
- Affidavit on behalf of Shady Hills Power Company, LLC, Docket No. ER02-527, triennial market-based rate update, December 4, 2008.
- Affidavit on behalf of Farmers City Wind, LLC, Docket No. ER09-31, market-based rate application, October 6, 2008.
- Affidavit on behalf of Elm Creek Wind, LLC, Docket No. ER09-30, market-based rate application, October 6, 2008.
- Affidavit on behalf of Dynegy Marketing and Trade, Docket No. ER09-20, market-based rate application, October 6, 2008.
- Affidavit on behalf of LS Power Development, LLC and Luminus Management, LLC, Docket No. EC08-126, September 24, 2008.
- Affidavit on behalf of Public Utility District 2 of Grant County, WA, in NorthWestern Corporation, in connection with market-based rates for ancillary services, Docket No. ER08-1529, September 12, 2008.
- Affidavit on behalf of LG&E Energy Marketing Inc. et al., Docket No. ER94-1188 et al., triennial market-based rate update, September 2, 2008.
- Affidavit on behalf of Alcoa Power Generating, Inc. et al., Docket No. ER07-496 et al., triennial market-based rate update, September 2, 2008.
- Affidavit on behalf of Calpine Corporation re Bethpage Energy Center 3, LLC et al., Docket No. ER04-1099 et al., September 2, 2008.
- Supplemental Affidavit on behalf of Virginia Electric and Power Co. et al., Docket No. ER01-468 et al., triennial market-based rate update, September 2, 2008.
- Affidavit on behalf of South Carolina Electric & Gas Company, Docket No. ER96-1085, triennial market-based rate update, September 2, 2008.
- Affidavit on behalf of Florida Power & Light Co et al., Docket No. ER97-3359 et al., triennial market-based rate update, September 2, 2008.

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- Affidavit on behalf of Progress Energy Inc. et al., Docket No. ER99-2311 et al., triennial market-based rate update, September 2, 2008.
- Affidavit on behalf of the EME Companies, Docket No. ER96-2652 et al., triennial market-based rate update, August 29, 2008.
- Affidavit on behalf of Bridgeport Energy, LLC et al., Docket No. ER98-2783. triennial market-based rate update, August 29, 2008.
- Affidavit on behalf of Duke Energy Carolinas, LLC, Docket No. ER07-188, triennial market-based rate update, August 29, 2008.
- Supplemental Affidavit on behalf of PHI Entities, Docket No. ER96-1361 et al., triennial market-based rate update, August 21, 2008.
- Supplemental Affidavit on behalf of Constellation MBR Entities, Docket No. ER99-2948 et al., triennial market-based rate update, August 18, 2008.
- Supplemental Affidavit on behalf of Exelon MBR Companies, Docket No. ER00-3251 et al., triennial market-based rate update, August 15, 2008.
- Affidavit on behalf of Fowler Ridge Wind Farm, LLC, Docket No. ER08-1323, application for market-based rates, August 1, 2008.
- Affidavit on behalf of FPL Energy, LLC, Docket No. ER08-1300 et al., application for market-based rates, July 24, 2008.
- Affidavit on behalf of Naturener Montana Wind Energy, LLC, Docket No. ER08-1261, application for market-based rates, July 15, 2008.
- Affidavit on behalf of FPLE Companies, FERC Docket No. ER02-2559 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Duke Energy MBR Companies, FERC Docket No. ER07-189 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Bear Energy LP et al., FERC Docket No. ER06-864 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Reliant NE MBR Entities, FERC Docket No. ER00-2129 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Noble Altona Windpark, LLC et al., FERC Docket No. ER06-1409 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of NRG Companies, FERC Docket No. ER97-4281 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of BG Dighton Power, LLC et al., FERC Docket No. ER06-1367 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Mirant Canal, LLC et al., FERC Docket No. ER01-1268 et al., triennial market-based rate update, June 30, 2008.

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- Affidavit on behalf of CPV Liberty, LLC, FERC Docket No. ER07-1193, triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Tenaska Energy, Inc. et al., FERC Docket No. ER02-24 et al., triennial market-based rate update, June 30, 2008.
- Affidavit on behalf of Birchwood Power Partners LP et al., FERC Docket No. ER07-501 et al., triennial market-based rate update, June 27, 2008.
- Affidavit on behalf of Wisconsin Electric Power Company, FERC Docket No. ER08-1176, application for market-based rates, June 27, 2008.
- Affidavit on behalf of New Athens Generating Co., LLC and Millennium Power Partners, LP, triennial market-based rate update, FERC Docket No. ER98-830 et al., June 27, 2008.
- Affidavit on behalf of Granite Ridge Energy, LLC, FERC Docket No. ER05-287, triennial market-based rate update, June 27, 2008.
- Affidavit on behalf of Astoria Generating Co. LP et al., FERC Docket No. ER99-3168 et al., triennial market-based rate update, June 24, 2008.
- Affidavit on behalf of Duke Energy Carolinas, LLC, FERC Docket No. EC08-94, application for sale of jurisdictional assets, May 30, 2008.
- Supplemental Affidavit on behalf of Allegheny Energy Supply Company, LLC et al., triennial market-based rate update, FERC Docket No. ER98-1466, April 21, 2008.
- Supplemental Affidavit on behalf of Baltimore Gas and Electric Company et al., triennial market-based rate update, FERC Docket No. ER99-2948, April 21, 2008.
- Affidavit on behalf of JPMorgan Chase & Co. and The Bear Stearns Companies Inc., application for sale of jurisdictional assets, FERC Docket No. EC08-66, March 31, 2008.
- Affidavit on behalf of Oklahoma Gas & Electric Company, et al., application for sale of jurisdictional assets, FERC Docket No. EC08-58, March 20, 2008.
- Affidavit on behalf of NRG Southaven, LLC et al., FERC Docket No. EC08-57, March 20, 2008.
- Affidavit on behalf of Shell Energy North America (US), LP, application for market-based rates, FERC Docket No. ER08-656, March 11, 2008.
- Affidavit on behalf of EFS Parlin Holdings, LLC, application for market-based rates, FERC Docket No. ER08-649, March 10, 2008.
- Affidavit on behalf of Safe Harbor Power Corporation, application for market-based rates, FERC Docket No. ER08-537, February 5, 2008.
- Affidavit on behalf of Auburndale Peaker Energy Center, LLC et al., FERC Docket No. ER02-1633, change in status, January 31, 2008.
- Affidavit on behalf of Calpine Corp. and LS Power Development, LLC et al., FERC Docket No. EC08-39-000, January 22, 2008.
- Supplemental Affidavit on behalf of Langdon Wind, LLC, application for market-based rate authority, FERC Docket No. ER08-250-000, January 15, 2008.

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- Affidavit on behalf of AES Western Wind MV Acquisition, Docket No. EC08-37, January 15, 2008.
- Affidavit on behalf of Dominion Energy Marketing, Inc. et al., application for market-based rate authority, FERC Docket No. ER01-468, January 14, 2008.
- Affidavit on behalf of Baltimore Gas and Electric Company et al., updated market-based rate filing, FERC Docket No. ER99-2948, January 14, 2008.
- Affidavit on behalf of Allegheny Energy Supply Company, LLC et al., updated market-based rate filing, FERC Docket No. ER98-1466, January 14, 2008.
- Affidavit on behalf of Exelon Generation Company, LLC et al., updated market-based rate filing, FERC Docket No. ER00-3251, January 14, 2008.
- Affidavit on behalf of Pepco Holdings, Inc., et al., updated market-based rate filing, FERC Docket No. ER96-1361, January 14, 2008.
- Affidavit on behalf of Green Mountain Power Corporation, updated market-based rate filing, FERC Docket No. ER01-0989, January 14, 2008.
- Affidavit on behalf of Duquesne Light Company et al., updated market-based rate filing, FERC Docket No. ER98-4159 et al., January 11, 2008.
- Affidavit on behalf of Central Hudson Gas and Electric Corporation, updated market-based rate filing, FERC Docket No. Docket No. ER97-2872 et al., January 11, 2008.
- Affidavit on behalf of Bicent (California) Malburg, LLC, application for market-based rate authority, FERC Docket No. ER08-314-000, December 7, 2007.
- Affidavit on behalf of Northern Indiana Public Service Co. and Broadway Gen Funding, LLC, application and related exhibits requesting authorization for a transaction to transfer a generating facility, FERC Docket No. EC08-21-000, December 6, 2007.
- Affidavit on behalf of Langdon Wind, LLC, application for market-based rate authority, FERC Docket No. ER08-250-000, November 21, 2007.
- Affidavit on behalf of Calpine Corp. and Harbinger Capital Partners Master Fund I, Ltd. et al., joint application for approval of the proposed distribution of common stock of a reorganized Calpine to Acquirors, FERC Docket No. EC08-15-000, November 16, 2007.
- Affidavit on behalf of Waterbury Generation, LLC, application for market-based rate authority, FERC Docket No. ER08-200-000, November 9, 2007.
- Affidavit on behalf of FPL Energy Oliver Wind II, LLC, application for market-based rate authority, FERC Docket No. ER08-197-000, November 8, 2007.
- Affidavit on behalf of Central Power & Lime, Inc., application for market-based rate authority, FERC Docket No. ER08-148-000, November 1, 2007.
- Affidavit on behalf of Gilberton Power Company, application for market-based rate authority, FERC Docket No. ER08-83-000, October 23, 2007.
- Affidavit on behalf of Black Bayou Storage, LLC, application for market-based rate authority for a natural gas storage facility, FERC Docket No. CP07-451, September 25, 2007.

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- Affidavit on behalf of NedPower Mount Storm, LLC, application for market-based rate authority, FERC Docket No. ER07-1306-000, August 23, 2007.
- Affidavit on behalf of Sempra Energy Trading Corp. in connection with market-based rate authority, FERC Docket No. ER03-1413-005, July 25, 2007.
- Affidavit on behalf of KGen Acquisition I, LLC et al., application for disposition of jurisdictional facilities, FERC Docket No. EC07-116-000, July 13, 2007.
- Supplemental Affidavit on behalf of Williams Power Company, Inc., application for market-based rate authority, FERC Docket No. EC07-106-000, June 28, 2007.
- Affidavit on behalf of Williams Power Co, Inc and Bear Energy LP, joint application for authorization of the disposition of jurisdictional facilities, FERC Docket No. EC07-106-000, June 14, 2007.
- Affidavit on behalf of Bluegrass Generation Company, LLC et al., notice of non-material change in status, FERC Docket No. ER02-506-008 et al., May 31, 2007.
- Affidavit on behalf of BG Dighton Power, LLC et al., notice of non-material change in status, FERC Docket Nos. ER06-1367-003 et al., May 30, 2007.
- Affidavit on behalf of FPL Energy Point Beach, LLC, application for market-based rate authority, FERC Docket No. ER07-904-000, May 16, 2007.
- Affidavit on behalf of Copiah Storage, LLC, application for market-based rate authority for a natural gas storage facility, FERC Docket No, CP02-24, March 29, 2007.
- Affidavit on behalf of NRG Power Marketing, Inc. and thirty-one affiliates most of which own generating facilities, triennial market power update and notice of change in status, FERC Docket Nos. ER97-4281-016 et al., March 26, 2007.
- Affidavit on behalf of Egan Hub Storage, application for market-based rate authority for a natural gas storage facility, FERC Docket No. CP07-88, February 20, 2007.
- Affidavit on behalf of Wisconsin Electric Power Co. and FPL Energy Point Beach, LLC, joint application for authorization to dispose of jurisdictional facilities, FERC Docket No. EC07-57-000, February 1, 2007.
- Affidavit on behalf of Lake Road Generating Company, LP et al., joint application for authorization of the disposition of jurisdictional facilities pursuant to Section 203 of the Federal Power Act, FERC Docket No. EC07-50-000, January 22, 2007.
- Affidavit on behalf of Exelon Generation Company, LLC et al., notice of non-material change in status, FERC Docket Nos. ER00-3251-013 et al., December 15, 2006.
- Revised Affidavit on behalf of Calpine Energy Services, LP, triennial market analysis, FERC Docket No. ER00-3562-004, December 13, 2006.
- Affidavit on behalf of Dynegy Entities and LSP Entities, notice of non-material change in status, FERC Docket Nos. ER02-506-007 et al., November 2, 2006.

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- Affidavit on behalf of Wisconsin Energy Corp.'s, Wisconsin Electric Power Co. et al. for authorization to dispose of jurisdictional facilities, FERC Docket No. ER07-14-000, November 2, 2006.
- Affidavit on behalf of Calpine Energy Services, LP, updated triennial market power analysis, FERC Docket No. ER00-3562-004, October 30, 2006.
- Affidavit on behalf of Dynegy, application for authorization of transactions pursuant to Section 203 of the Federal Power Act, FERC Docket No. EC07-9-000, October 26, 2006.
- Affidavit on behalf of Coral Power, LLC et al., triennial updated market analysis, FERC Docket Nos. ER96-25-028 et al., October 23, 2006.
- Affidavit on behalf of Westar Energy, Inc. and Kansas Gas and Electric, request for rehearing, FERC Docket Nos. ER03-9-007 et al., October 6, 2006.
- Affidavit on behalf of The Empire District Electric, request for rehearing, FERC Docket Nos. ER99-1757-011 et al., September 14, 2006.
- Joint Affidavit (with William H. Hieronymus) on behalf of Powerex Corp., errata to its 7/31/06 triennial market power update, FERC Docket No. ER01-48-007, September 11, 2006.
- Affidavit on behalf of FPLE Companies, joint triennial market power update, FERC Docket Nos. ER02-2559-007 et al., August 28, 2006.
- Affidavit on behalf of FPL Energy Oliver Wind, LLC application for market-based rates, FERC Docket No. ER06-1392-000, August 23, 2006.
- Affidavit on behalf of The Constellation MBR Entities, errata to their joint triennial market power update submitted on 8/14/06, FERC Docket Nos. ER99-2948-009 et al., August 16, 2006.
- Affidavit on behalf of Constellation MBR Entities, joint triennial market power update, FERC Docket Nos. ER99-2948-009 et al., August 14, 2006.
- Affidavit on behalf of Sempra Energy Trading Corp., updated market analysis, FERC Docket No. ER03-1413-005, August 1, 2006.
- Joint Affidavit (with William H. Hieronymus) on behalf of Powerex Corp, triennial market power analysis in support of its continued authority to sell power at market-based rates, FERC Docket No. ER01-48-007, July 31, 2006.
- Affidavit on behalf of Reliant Energy Power Supply, LLC, application for market-based rates, FERC Docket No. ER06-1272-000, July 20-21, 2006.
- Affidavit on behalf of Lincoln Generating Facility, LLC, fka Allegheny Energy Supply, updated generation market power study, FERC Docket No. ER05-524-001, June 19, 2006.
- Affidavit on behalf of Alcoa Power Generating, Inc & Alcoa Power Marketing, Inc., amendment to triennial, updated market analysis under ER02-2074 et al., FERC Docket Nos. ER02-2074-002 et al., May 17, 2006.
- Affidavit on behalf of Alcoa Power Generating, Inc. and Alcoa Power Marketing, Inc., updated market analysis of the triennial review of market-based rate authority, FERC Docket Nos. ER02-2074-002 et al., April 13, 2006.

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- Affidavit on behalf of Morgan Energy Center, LLC et al., Calpine Gilroy Cogen, LP, Los Medanos Energy Center, LLC, and KIAC Partners et al., market-based rate filings, FERC Docket Nos. ER06-741-000 et al., March 16, 2006.
- Affidavit on behalf of Midland Cogeneration Venture Limited Partnership, market-based rate application, FERC Docket No. ER06-733-000, March 15, 2006.
- Affidavit on behalf of Duke Power Co, LLC et al., notice of change in status filing, FERC Docket Nos. ER96-110-020 et al., March 1, 2006.
- Affidavit on behalf of Westar Energy Inc & ONEOK Energy Services Co, LP, answer to protests filed by Oklahoma Municipal Power Authority et al., FERC Docket No. ER06-48-000, February 21, 2006.
- Affidavit on behalf of Edgecombe Genco, LLC and Spruance Genco, LLC, market-based rate application, FERC Docket No. ER06-635-000 and ER06-634-000, February 13, 2006.
- Affidavit on behalf of NRG Energy, Inc. et al., joint application for authorization under Section 203 of the Federal Power Act to transfer jurisdictional facilities, FERC Docket No. EC06-66-000, January 20, 2006.
- Affidavit on behalf of Westar Energy, Inc. et al. joint application for authorization under Section 203 of the Federal Power Act for the disposition of jurisdictional facilities, FERC Docket No. EC06-48-000, December 21, 2005.
- Affidavit on behalf of Calpine Energy Center, LLC, joint updated market power analysis, FERC Docket Nos. ER02-2227-003 et al., August 30, 2005.
- Affidavit on behalf of Allegheny Power, Allegheny Energy Supply Co., LLC, Allegheny Energy Supply Gleason Generating Facility, Inc et al., combined triennial market power report, FERC Docket Nos. ER98-1466-003 et al., August 11, 2005.
- Affidavit on behalf of Hermiston Power Partnership et al., joint updated market power analysis, filed on 5/3/05, FERC Docket Nos. ER02-1257-003 et al., August 5, 2005.
- Affidavit on behalf of MidAmerican Energy Co., in connection with market-based rate update, FERC Docket No. ER96-719-006, August 1, 2005.
- Affidavit on behalf of Occidental Power Services Inc., updated market power analysis, FERC Docket No. ER02-1947-006, August 1, 2005.
- Affidavit on behalf of FPL Energy Duane Arnold LLC, joint application for approval of disposition of jurisdictional facilities, FERC Docket Nos. EC05-114-000 et al., July 29, 2005.
- Affidavit on behalf of FPL Energy Duane Arnold, LLC, authorization to sell at market-based rates, FERC Docket No. ER05-1281-000, July 29, 2005.
- Affidavit on behalf of MidAmerican Energy Holdings Co. et al., application for approval of disposition of jurisdictional facilities under Section 203 of the Federal Power Act, FERC Docket No. EC05-110-000, July 22, 2005.
- Affidavit on behalf of Calpine Entities, joint updated market power analysis, FERC Docket Nos. EC02-1367-003 et al., July 18, 2005.

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- Affidavit on behalf of Bayonne Plant Holding, LLC, as successor in interest of Cogen Technologies NJ Venture et al.,, as successor in interest to Camden Cogen et al., triennial updated market analysis, FERC Docket Nos. EC02-1486-003 et al., July 15, 2005.
- Affidavit on behalf of Cabazon Wind Partners, LLC & Whitewater Hill Wind Partners, consolidated triennial updated market analysis, FERC Docket Nos. ER02-1695-003 et al., June 24, 2005.
- Affidavit on behalf of TransAlta Energy Marketing (U.S.) Inc. et al., in connection with market-based rate authority, FERC Docket Nos. ER05-1014-000 et al., May 24, 2005.
- Affidavit on behalf of Minergy Neenah, LLC, updated triennial market power analysis, FERC Docket No. ER99-3125-001, May 16, 2005.
- Affidavit on behalf of Hermiston Power Partnership et al., joint updated market power analysis, FERC Docket Nos. ER02-1257-002 et al., May 3, 2005.
- Affidavit on behalf of CES Marketing VI, LLC et al., market-based rate application, FERC Docket Nos. ER05-816-000 et al., April 13, 2005.
- Affidavit on behalf of Onondaga Cogeneration Limited Partnership, triennial updated market analysis, FERC Docket No. ER00-895-006, March 24, 2005.
- Affidavit on behalf of The Williams Entities' (Williams Power Co. Inc. et al.), joint triennial market power update, FERC Docket Nos. ER03-1331-004 et al., March 24, 2005.
- Affidavit on behalf of J Aron & Co and Power Receivable Finance LLC, errata to triennial updated market analysis submitted on 12/30/04, FERC Docket Nos. ER02-237-003 et al., February 25, 2005.
- Affidavit on behalf of Delta Energy Center, LLC, updated power analysis, FERC Docket No. ER02-600-003, February 14, 2005.
- Affidavit on behalf of Wisconsin Electric Power Company, market-based rate filing, FERC Docket No. ER05-540-000, February 4, 2005.
- Affidavit on behalf of J Aron & Co. and Power Receivable Finance, LLC, consolidated triennial updated market analysis, December 30, 2004.
- Affidavit on behalf MidAmerican Energy Co., supplement to 10/29/04 market-power update filing, FERC Docket No. ER96-719-004, November 23, 2004.
- Affidavit in connection with Comments of Cinergy Services, Inc. re Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority under RM04-14, FERC Docket No. RM04-14-000, November 15, 2004.
- Affidavit on behalf of Metcalf Energy Center, LLC and Pastoria Energy Center, LLC, market-based rate application, FERC Docket No. ER05-68-000 and ER05-67-000, October 25, 2004.
- Affidavit on behalf Calpine Bethpage 3, LLC and TBG Cogen Partners, market-based rate filing, FERC Docket No. ER05-48-000 and ER04-1100-000, August 4, 2004.
- Affidavit on behalf of The Empire District Electric Co., updated market power analysis, FERC Docket No. ER99-1757-005, September 27, 2004.

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- Affidavit on behalf of Wisconsin Electric Power Co, revised generation market power portion of its pending three-year market power update, FERC Docket No. ER98-855-004, September 27, 2004.
- Affidavit on behalf of Duke Power, a Division of Duke Energy Corp., market power analysis, FERC Docket No. ER96-110-010, August 11, 2004.
- Affidavit on behalf of Virginia Electric & Power Co et al., application for the proposed transfer of substantially all of the assets of Multitrade to Dominion Power, FERC Docket No. EC04-139-000, July 30, 2004.
- Affidavit on behalf of Goldendale Energy Center, market-based rate application, FERC Docket No. ER04-1038-000, July 23, 2004.
- Affidavit on behalf of Calumet Energy Team, LLC, updated triennial market power analysis, FERC Docket No. ER01-389-001, July 20, 2004.
- Affidavit on behalf of Calpine Parlin, LLC, market-based rate filing, FERC Docket No. ER04-832-000, May 11, 2004.
- Affidavit on behalf of Calpine Newark, LLC, market-based rate filing, FERC Docket No. ER04-831-000, May 11, 2004.
- Affidavit on behalf of Virginia Electric & Power Co, application for market-based rates, FERC Docket No. ER04-834-000, May 11, 2004.
- Affidavit on behalf of Virginia Electric and Power Co., UAE Mecklenburg Cogeneration, LP et al., authorization for the proposed transfer of 100% of the ownership interests of Cogenco etc., FERC Docket No. EC04-104-000, May 6, 2004.
- Affidavit on behalf of Occidental Power Marketing, LP, triennial market power analysis, FERC Docket No. ER99-3665-004, April 14-15, 2004.
- Affidavit on behalf of The Williams Entities, joint triennial market power update, FERC Docket Nos. ER03-1331-003 et al., March 12, 2004.
- Affidavit on behalf of Wisconsin Electric Power Co., updated triennial market-power analysis, FERC Docket No. ER98-855-003, January 29, 2004.
- Affidavit on behalf of GEN~SYS Energy, triennial update market power analysis, FERC Docket No. ER97-4335-006, October 17, 2003.
- Affidavit on behalf of Calpine Energy Services LP, updated market power analysis, FERC Docket No. ER00-3562-001, September 22, 2003.
- Affidavit on behalf of Rocky Mountain Energy Center, LLC, application for market-based rates, FERC Docket No. ER03-1288-000, September 3, 2003.
- Affidavit on behalf of Fox Energy Co, LLC, application for market-based rates, FERC Docket No. ER03-983-000, June 24, 2003.
- Affidavit on behalf of Chehalis Power Generating Limited Partnership, application for market-based rates etc., FERC Docket No. ER03-717-000, April 7, 2003.

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- Affidavit on behalf of Calpine Northbrook Energy Marketing, LLC, triennial updated market power analysis, FERC Docket No. ER03-717-000, October 23, 2002.
- Affidavit on behalf of Choctaw Generation Limited Partnership, updated triennial market power analysis, FERC Docket No. ER98-3774-001, October 17, 2002.
- Affidavit on behalf of Riverside Energy Center, LLC, market-based rate filing, FERC Docket No. ER03-49-000, October 16, 2002.
- Affidavit on behalf of Blue Spruce Energy Center, LLC, market-based rate filing, FERC Docket No. ER03-25-000, October 8, 2002.
- Prepared Responsive Testimony on behalf of Calpine Energy Services, LP et al. re: San Diego Gas & Electric Co. v. Sellers of Energy & Ancillary Services etc. under EL00-95 et al., FERC Docket Nos. EL00-95-045 et al., September 27, 2002.
- Affidavit on behalf of Duke Power Co., a division of Duke Energy Corp., market-based rate filing, FERC Docket No. ER96-110-007, December 17, 2001.

Generation Owned or Controlled by Exelon in the Northeast Region and Relevant First-Tier Markets

RTO	Submarket	Plant Name	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share	Owned/Controlled Interest (MW) Summer	Owned/Controlled Interest (MW) Winter
PJM							
PJM		Braidwood	2,330.0	2,384.0	100.0%	2,330.0	2,384.0
PJM		Byron	2,300.0	2,346.0	100.0%	2,300.0	2,346.0
PJM	5004/5005	Calvert Cliffs [1/]	1,716.0	1,734.0	50.0%	1,716.0	1,734.0
PJM	East	Chester	39.0	54.0	100.0%	39.0	54.0
PJM		Colver Power	110.0	110.0	25.0%	27.5	27.5
PJM		Conemaugh	1,711.2	1,711.2	31.3%	535.3	535.3
PJM	East	Conowingo	572.0	572.0	100.0%	572.0	572.0
PJM		Criterion Power	70.0	70.0	100.0%	70.0	70.0
PJM	East	Croydon	392.0	512.0	100.0%	392.0	512.0
PJM	East	Delaware	56.0	74.0	100.0%	56.0	74.0
PJM		Dresden	1,750.0	1,700.0	100.0%	1,750.0	1,700.0
PJM	East	Eddystone	820.0	836.0	100.0%	820.0	836.0
PJM		Exelon Solar Chicago	9.0	9.0	100.0%	9.0	9.0
PJM	East	Fairless Hills	60.0	60.0	100.0%	60.0	60.0
PJM	East	Falls	51.0	60.0	100.0%	51.0	60.0
PJM	5004/5005	Gould Street	97.0	97.0	100.0%	97.0	97.0
PJM		Handsome Lake	267.5	267.5	100.0%	267.5	267.5
PJM		Keystone	1,711.2	1,711.2	42.0%	718.4	718.4
PJM		La Salle	2,277.0	2,313.0	100.0%	2,277.0	2,313.0
PJM	East	Limerick	2,296.0	2,386.0	100.0%	2,296.0	2,386.0
PJM	East	Moser	51.0	60.0	100.0%	51.0	60.0
PJM	East	Muddy Run	1,070.0	1,070.0	100.0%	1,070.0	1,070.0
PJM	5004/5005	Notch Cliff	116.7	116.7	100.0%	116.7	116.7
PJM	East	Oyster Creek	614.5	637.0	100.0%	614.5	637.0
PJM	East	Panther Creek	83.0	83.0	50.0%	41.5	41.5
PJM	5004/5005	Peach Bottom	2,250.6	2,296.0	50.0%	1,125.3	1,148.0
PJM	East	Pennsbury	5.4	5.4	100.0%	5.4	5.4
PJM	5004/5005	Perryman	353.6	353.6	100.0%	353.6	353.6
PJM	5004/5005	Philadelphia Road	60.9	60.9	100.0%	60.9	60.9
PJM		Quad Cities	1,819.0	1,819.0	75.0%	1,364.3	1,364.3
PJM	East	Richmond	98.0	132.0	100.0%	98.0	132.0
PJM	5004/5005	Riverside	228.0	228.0	100.0%	228.0	228.0
PJM	5004/5005	Safe Harbor	417.5	417.5	66.7%	278.5	278.5
PJM	East	Salem	2,326.0	2,387.8	42.6%	990.6	1,017.0
PJM	East	Schuylkill	30.0	38.0	100.0%	30.0	38.0
PJM		Southeast Chicago	296.0	320.0	100.0%	296.0	320.0
PJM	East	Southwark	52.0	72.0	100.0%	52.0	72.0
PJM	East	The City of Vineland at North Vineland	2.3	2.3	100.0%	2.3	2.3
PJM	East	The City of Vineland at West Vineland	3.7	3.7	100.0%	3.7	3.7
PJM	5004/5005	Three Mile Island 1	805.0	829.0	100.0%	805.0	829.0
PJM	5004/5005	Westport	115.8	115.8	100.0%	115.8	115.8

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RTO	Submarket	Plant Name	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share	Owned/Controlled Interest (MW) Summer	Owned/Controlled Interest (MW) Winter
Purchases							
PJM		Elwood 5-8 (Toll)				600.0	768.0
PJM	5004/5005	Delta/York (Toll)				545.0	545.0
PJM		Cordova (Toll)				521.2	601.2
Retired (During and Post-Study Period)							
PJM	East	Cromby (December 2011)	203.7	213.7	100.0%	203.7	213.7
PJM	East	Eddystone (May 2012)	309.0	311.0	100.0%	309.0	311.0
PJM	East	Schuylkill (December 2012)	168.7	177.7	100.0%	168.7	177.7
Sales							
PJM	5004/5005	Calvert Cliffs (share marketed by EDF) [1/]				(257.4)	(260.1)
PJM	5004/5005	Sale per Merger Mitigation				(500.0)	(500.0)
PJM, Subtotal						25,676.9	26,505.7
PJM East, Subtotal						7,926.4	8,335.3
PJM 5004/5005, Subtotal						12,610.8	13,081.6
PJM AP South, Subtotal						12,610.8	13,081.6

Adjustments to Installed Capacity for Retirements	Winter	Spring	Summer	Fall
(Cromby, Eddystone)	(213.7)	(213.7)	(512.7)	(524.7)

NYISO [2/]							
NYISO		Ginna [1/]	580.8	582.1	50.0%	580.8	582.1
NYISO		Nine Mile Point 1 [1/]	629.7	630.0	50.0%	629.7	630.0
NYISO		Nine Mile Point 2 [1/]	1,287.2	1,287.2	41.0%	1,055.5	1,055.5
Sales							
NYISO		Ginna, Nine Mile Point (share marketed by EDF) [1/]				(339.9)	(340.1)
NYISO, Subtotal						1,926.1	1,927.5
ISO-NE [3/]							
ISO-NE		Wyman (Yarmouth) 4	603.2	610.4	5.9%	35.5	36.0
ISO-NE		Framingham Jet	31.3	43.3	100.0%	31.3	43.3
ISO-NE		West Medway 1-2	65.5	107.9	100.0%	65.5	107.9
ISO-NE		West Medway 3	35.4	55.8	100.0%	35.4	55.8
ISO-NE		L Street Jet	16.0	21.8	100.0%	16.0	21.8
ISONE		Mystic 7	560.5	559.8	100.0%	560.5	559.8
ISONE		Mystic 8	703.3	841.6	100.0%	703.3	841.6
ISONE		Mystic 9	695.2	844.0	100.0%	695.2	844.0
ISONE		Mystic Jet	8.6	12.7	100.0%	8.6	12.7
ISONE		Fore River	688.3	836.6	100.0%	688.3	836.6
ISONE		Holyoke Solar LLC	0.9	0.9	100.0%	0.9	0.9
ISONE		Holyoke Solar LLC	3.0	3.0	100.0%	3.0	3.0
ISONE	CT	Kleen Energy				620.0	620.0
ISO-NE, Subtotal						3,463.5	3,983.3
CT, Subtotal						620.0	620.0

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RTO	Submarket	Plant Name	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share	Owned/Controlled Interest (MW) Summer	Owned/Controlled Interest (MW) Winter
First-Tier Markets							
MISO		Clinton	1,065.0	1,078.0	100.0%	1,065.0	1,078.0
MISO		Agriwind	8.4	8.4	100.0%	8.4	8.4
MISO		Beebe	81.6	81.6	100.0%	81.6	81.6
MISO		B&K Energy Systems	2.0	2.0	100.0%	2.0	2.0
MISO		BC Energy	4.0	4.0	100.0%	4.0	4.0
MISO		CP Windfarm	4.2	4.2	100.0%	4.2	4.2
MISO		Blue Breezes I + II	2.6	2.6	100.0%	2.6	2.6
MISO		Breezy Bucks I + II	2.6	2.6	100.0%	2.6	2.6
MISO		Christoffer Wind I - IV	8.4	8.4	100.0%	8.4	8.4
MISO		DL Windy Acres	2.0	2.0	100.0%	2.0	2.0
MISO		G-Flow Wind	1.3	1.3	100.0%	1.3	1.3
MISO		Green Acres Breeze	1.3	1.3	100.0%	1.3	1.3
MISO		K&D Energy	4.0	4.0	100.0%	4.0	4.0
MISO		KC Energy	4.0	4.0	100.0%	4.0	4.0
MISO		KSS Turbines	4.0	4.0	100.0%	4.0	4.0
MISO		Harvest I + II	112.2	112.2	100.0%	112.2	112.2
MISO		Michigan Wind 1 + 2	159.0	159.0	100.0%	159.0	159.0
MISO		Minnesota Breeze	1.3	1.3	100.0%	1.3	1.3
MISO		Prairie Wind Power	4.0	4.0	100.0%	4.0	4.0
MISO		Roadrunner I	1.3	1.3	100.0%	1.3	1.3
MISO		Salty Dog I + II	2.6	2.6	100.0%	2.6	2.6
MISO		S & P Windfarm	2.0	2.0	100.0%	2.0	2.0
MISO		Shane's Wind Machine	1.3	1.3	100.0%	1.3	1.3
MISO		Sunset Breeze	1.3	1.3	100.0%	1.3	1.3
MISO		Wally's Wind Farm	1.3	1.3	100.0%	1.3	1.3
MISO		Windy Dog I	1.3	1.3	100.0%	1.3	1.3
MISO		Wolf Wind Enterprises	1.3	1.3	100.0%	1.3	1.3
First-Tier Markets to PJM, Subtotal						1,484.3	1,497.3

Note: Generation ratings are based on EIA-860, unless otherwise indicated.
http://www.eia.gov/cneaf/electricity/page/eia860.html

1/ Reflects Exelon's "control" over the nuclear plants owned by its affiliate, Constellation Energy Nuclear Group, LLC ("CENG"), and the long-term agreement under which EDF Inc., the joint-owner of CENG, markets 15% of the output. Reflects uprate for Nine Mile Point 2.

2/ Ratings based on NYISO 2012 Load and Capacity Data ("Gold Book") (ratings as of 2012).
http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2012_GoldBook_V3.pdf

3/ Capacity ratings based on ISO-NE CELT data.
http://www.iso-ne.com/trans/celt/report/2012/2012_celt_report.xls.

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Summary Results

Market/ Submarket	Exhibit No.	Pivotal Supplier	Exhibit No.	Market Share Analysis			
				Winter	Spring	Summer	Fall
PJM	JRS-4	PASS	JRS-5	11.1%	10.8%	12.4%	12.3%
PJM East	JRS-6	PASS	JRS-7	15.3%	15.1%	14.0%	14.9%
5004/5005	JRS-8	PASS	JRS-9	13.8%	13.5%	12.5%	14.0%
AP South	JRS-10	PASS	JRS-11	10.1%	9.9%	9.3%	10.5%
ISO-NE	JRS-12	PASS	JRS-13	5.3%	4.9%	4.0%	7.1%
CT	JRS-14	PASS	JRS-15	0.0%	0.0%	0.0%	0.0%
NYISO	JRS-16	PASS	JRS-17	11.2%	10.5%	14.3%	11.1%
Change in Status (Granite Ridge)							
ISO-NE	JRS-12 (CIS)	PASS	JRS-13 (CIS)	9.6%	8.9%	8.6%	11.4%

Part I -- Pivotal Supplier Analysis

Row	Generation	PJM MW	Reference (December '11 - November '12)
	Seller and Affiliate Capacity		
A	Installed Capacity	24,255	Exhibit JRS-2
B	Long-Term Firm Purchases	1,666	Exhibit JRS-2
C	Long-Term Firm Sales	(757)	Exhibit JRS-2
D	Imported Power	382	Wkp-Import Allocation
	Non-Affiliate Capacity		
E	Installed Capacity	173,305	Wkp-PJM Generation less Row A above
F	Long-Term Firm Purchases	757	Offset, Row C
G	Long-Term Firm Sales	(1,666)	Offset, Row B
H	Imported Power	8,052	PJM SIL Study less Row D above
I	Balancing Authority Area Reserve Requirement	(8,551)	Wkp-PJM Oper Reserves
J	Amount of Line I Attributable to Seller, if any	-	
K	Total Uncommitted Capacity	63,975	SUM (A,B,C,D,E,F,G,H,I,M)
	Load		
L	Balancing Authority Area Annual Peak Load	154,339	Wkp-PJM Load Data
M	Average Daily Peak Native Load in Peak Month	(133,467)	Wkp-PJM Load Data
N	Amount of Line M Attributable to Seller, if any	(17,201)	Wkp-Exelon PJM Load
O	Wholesale Load	20,871	(L+M)
P	Net Uncommitted Supply	43,104	(K-O)
Q	Seller's Uncommitted Capacity	8,345	SUM (A,B,C,D,J,N)
R	Result of Pivotal Supplier Screen	**PASS**	(Pass if (Q < P); (Fail if Q > P)

Part II -- Market Share Analysis

Row		PJM Winter (MW)	PJM Spring (MW)	PJM Summer (MW)	PJM Fall (MW)	Reference December '11 - November '12
	Seller and Affiliate Capacity					
A	Installed Capacity	25,138	25,138	24,255	24,827	Exhibit JRS-2
B	Long-Term Firm Purchases	1,914	1,914	1,666	1,914	Exhibit JRS-2
C	Long-Term Firm Sales	(760)	(760)	(757)	(760)	Exhibit JRS-2
D	Seasonal Average Planned Outages	(1,342)	(3,582)	(214)	(2,384)	Pro Rata Share of Outages
E	Imported Power	280	168	347	301	Wkp-Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	(101,272)	(91,726)	(122,914)	(94,588)	Wkp-PJM Load Data
G	Amount of Line F Attributable to Seller, if any	(14,351)	(13,541)	(16,198)	(12,838)	Wkp-Exelon PJM Load
H	Amount of Line F Attributable to Others, if any	(86,921)	(78,185)	(106,716)	(81,750)	
I	Balancing Authority Area Reserve Requirement, if any	(6,591)	(6,028)	(7,909)	(6,180)	Wkp-PJM Oper Reserves
J	Amount of Line I Attributable to Seller, if any	-	-	-	-	
K	Amount of Line I Attributable to Others, if any	(6,591)	(6,028)	(7,909)	(6,180)	
	Non-Affiliate Capacity					
L	Installed Capacity	181,410	181,588	173,305	177,562	Wkp-PJM Generation less Row A above
M	Long-Term Firm Purchases	760	760	757	760	Offset, Row C
N	Long-Term Firm Sales	(1,914)	(1,914)	(1,666)	(1,914)	Offset, Row B
O	Local Seasonal Average Planned Outages	(9,198)	(24,586)	(1,465)	(16,189)	Wkp-Outages less Row D above
P	Uncommitted Capacity Imports	9,914	5,474	8,087	6,728	PJM SIL Study less Row E above
	Supply Calculation					
Q	Total Competing Supply	87,459	77,110	64,394	79,017	SUM (L,M,N,O,P,H,K)
R	Seller's Uncommitted Capacity	10,879	9,337	9,099	11,060	SUM (A,B,C,D,E,G,J)
S	Total Seasonal Uncommitted Capacity	98,338	86,446	73,493	90,076	SUM (Q,R)
T	**Seller's Market Share**	11.1%	10.8%	12.4%	12.3%	(R/S)
	Results	**PASS**	**PASS**	**PASS**	**PASS**	Pass if T <20%; Fail if T > 20%

Part I -- Pivotal Supplier Analysis

		PJM East	
Row	**Generation**	**MW**	**Reference** (December '11 - November '12)
	Seller and Affiliate Capacity		
A	Installed Capacity	7,414	Exhibit JRS-2
B	Long-Term Firm Purchases	-	
C	Long-Term Firm Sales	-	
D	Imported Power	1,085	Wkp-Import Allocation
	Non-Affiliate Capacity		
E	Installed Capacity	27,130	Wkp-PJM Generation less Row A above
F	Long-Term Firm Purchases	-	
G	Long-Term Firm Sales	-	
H	Imported Power	5,908	PJM SIL Study less Row D above
I	Balancing Authority Area Reserve Requirement	(1,832)	Wkp-PJM Oper Reserves
J	Amount of Line I Attributable to Seller, if any	-	
K	Total Uncommitted Capacity	13,644	SUM (A,B,C,D,E,F,G,H,I,M)
	Load		
L	Balancing Authority Area Annual Peak Load	32,542	Wkp-PJM Load Data
M	Average Daily Peak Native Load in Peak Month	(26,061)	Wkp-PJM Load Data
N	Amount of Line M Attributable to Seller, if any	(6,599)	Wkp-Exelon PJM Load
O	Wholesale Load	6,481	(L+M)
P	Net Uncommitted Supply	7,162	(K-O)
Q	Seller's Uncommitted Capacity	1,899	SUM (A,B,C,D,J,N)
R	Result of Pivotal Supplier Screen	**PASS**	(Pass if (Q < P); (Fail if Q > P)

Part II -- Market Share Analysis

Row		PJM East Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference December '11 - November '12
	Seller and Affiliate Capacity					
A	Installed Capacity	8,122	8,122	7,414	7,811	Exhibit JRS-2
B	Long-Term Firm Purchases	-	-	-	-	
C	Long-Term Firm Sales	-	-	-	-	
D	Seasonal Average Planned Outages	(414)	(1,107)	(63)	(717)	Pro Rata Share of Outages
E	Imported Power	810	479	986	1,014	Wkp-Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	(18,066)	(16,335)	(23,672)	(17,055)	Wkp-PJM Load Data
G	Amount of Line F Attributable to Seller, if any	(5,010)	(4,648)	(6,115)	(4,623)	Wkp-Exelon PJM Load
H	Amount of Line F Attributable to Others, if any	(13,057)	(11,687)	(17,557)	(12,432)	
I	Balancing Authority Area Reserve Requirement, if any	(1,270)	(1,148)	(1,664)	(1,199)	Wkp-PJM Oper Reserves
J	Amount of Line I Attributable to Seller, if any	-	-	-	-	
K	Amount of Line I Attributable to Others, if any	(1,270)	(1,148)	(1,664)	(1,199)	
	Non-Affiliate Capacity					
L	Installed Capacity	28,765	28,700	27,130	28,875	Wkp-PJM Generation less Row A above
M	Long-Term Firm Purchases	-	-	-	-	
N	Long-Term Firm Sales	-	-	-	-	
O	Local Seasonal Average Planned Outages	(1,468)	(3,911)	(231)	(2,650)	Wkp-Outages less Row D above
P	Uncommitted Capacity Imports	6,457	4,091	6,007	7,354	PJM SIL Study less Row E above
	Supply Calculation					
Q	Total Competing Supply	19,428	16,044	13,685	19,948	SUM (L,M,N,O,P,H,K)
R	Seller's Uncommitted Capacity	3,507	2,847	2,221	3,485	SUM (A,B,C,D,E,G,J)
S	Total Seasonal Uncommitted Capacity	22,935	18,891	15,906	23,432	SUM (Q,R)
T	**Seller's Market Share**	15.3%	15.1%	14.0%	14.9%	(R/S)
	Results	**PASS**	**PASS**	**PASS**	**PASS**	Pass if T <20%; Fail if T > 20%

Part I -- Pivotal Supplier Analysis

PJM 5004/5005

Row	Generation	MW	Reference (December '11 - November '12)
	Seller and Affiliate Capacity		
A	Installed Capacity	12,311	Exhibit JRS-2
B	Long-Term Firm Purchases	545	Exhibit JRS-2
C	Long-Term Firm Sales	(757)	Exhibit JRS-2
D	Imported Power	1,318	Wkp-Import Allocation
	Non-Affiliate Capacity		
E	Installed Capacity	48,601	Wkp-PJM Generation less Row A above
F	Long-Term Firm Purchases	757	Offset, Row C
G	Long-Term Firm Sales	(545)	Offset, Row B
H	Imported Power	6,638	PJM SIL Study less Row D above
I	Balancing Authority Area Reserve Requirement	(3,244)	Wkp-PJM Oper Reserves
J	Amount of Line I Attributable to Seller, if any	-	
K	Total Uncommitted Capacity	19,479	SUM (A,B,C,D,E,F,G,H,I,M)
	Load		
L	Balancing Authority Area Annual Peak Load	56,158	Wkp-PJM Load Data
M	Average Daily Peak Native Load in Peak Month	(46,144)	Wkp-PJM Load Data
N	Amount of Line M Attributable to Seller, if any	(11,091)	Wkp-Exelon PJM Load
O	Wholesale Load	10,014	(L+M)
P	Net Uncommitted Supply	9,465	(K-O)
Q	Seller's Uncommitted Capacity	2,325	SUM (A,B,C,D,J,N)
R	Result of Pivotal Supplier Screen	**PASS**	(Pass if (Q < P); (Fail if Q > P)

Part II -- Market Share Analysis

PJM 5004/5005

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference December '11 - November '12
	Seller and Affiliate Capacity					
A	Installed Capacity	13,083	13,083	12,311	12,772	Exhibit JRS-2
B	Long-Term Firm Purchases	545	545	545	545	Exhibit JRS-2
C	Long-Term Firm Sales	(760)	(760)	(757)	(760)	Exhibit JRS-2
D	Seasonal Average Planned Outages	(657)	(1,753)	(103)	(1,152)	Pro Rata Share of Outages
E	Imported Power	998	578	1,175	983	Wkp-Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	(34,193)	(30,414)	(42,263)	(31,762)	Wkp-Exelon PJM Load
G	Amount of Line F Attributable to Seller, if any	(8,586)	(7,805)	(10,288)	(7,981)	Wkp-Exelon Load Data
H	Amount of Line F Attributable to Others, if any	(25,607)	(22,609)	(31,975)	(23,781)	
I	Balancing Authority Area Reserve Requirement, if any	(2,404)	(2,138)	(2,971)	(2,233)	Wkp-PJM Oper Reserves
J	Amount of Line I Attributable to Seller, if any	-	-	-	-	
K	Amount of Line I Attributable to Others, if any	(2,404)	(2,138)	(2,971)	(2,233)	
	Non-Affiliate Capacity					
L	Installed Capacity	51,561	51,500	48,601	50,310	Wkp-PJM Generation less Row A above
M	Long-Term Firm Purchases	760	760	757	760	Offset, Row C
N	Long-Term Firm Sales	(545)	(545)	(545)	(545)	Offset, Row B
O	Local Seasonal Average Planned Outages	(2,642)	(7,047)	(415)	(4,637)	Wkp-Outages less Row D above
P	Uncommitted Capacity Imports	7,871	4,939	6,781	7,088	PJM SIL Study less Row E above
	Supply Calculation					
Q	Total Competing Supply	28,994	24,861	20,233	26,962	SUM (L,M,N,O,P,H,K)
R	Seller's Uncommitted Capacity	4,623	3,888	2,882	4,406	SUM (A,B,C,D,E,G,J)
S	Total Seasonal Uncommitted Capacity	33,618	28,748	23,115	31,369	SUM (Q,R)
T	**Seller's Market Share**	13.8%	13.5%	12.5%	14.0%	(R/S)
	Results	**PASS**	**PASS**	**PASS**	**PASS**	Pass if T <20%; Fail if T > 20%

Part I -- Pivotal Supplier Analysis

AP South

Row	Generation	MW	Reference (December '11 - November '12)
	Seller and Affiliate Capacity		
A	Installed Capacity	12,311	Exhibit JRS-2
B	Long-Term Firm Purchases	545	Exhibit JRS-2
C	Long-Term Firm Sales	(757)	Exhibit JRS-2
D	Imported Power	1,351	Wkp-Import Allocation
	Non-Affiliate Capacity		
E	Installed Capacity	72,496	Wkp-PJM Generation less Row A above
F	Long-Term Firm Purchases	757	Offset, Row C
G	Long-Term Firm Sales	(545)	Offset, Row B
H	Imported Power	6,138	PJM SIL Study less Row D above
I	Balancing Authority Area Reserve Requirement	(3,580)	Wkp-PJM Oper Reserves
J	Amount of Line I Attributable to Seller, if any	-	
K	Total Uncommitted Capacity	25,964	SUM (A,B,C,D,E,F,G,H,I,M)
	Load		
L	Balancing Authority Area Annual Peak Load	75,068	Wkp-PJM Load Data
M	Average Daily Peak Native Load in Peak Month	(62,751)	Wkp-PJM Load Data
N	Amount of Line M Attributable to Seller, if any	(11,186)	Wkp-Exelon PJM Load
O	Wholesale Load	12,317	(L+M)
P	Net Uncommitted Supply	13,647	(K-O)
Q	Seller's Uncommitted Capacity	2,263	SUM (A,B,C,D,J,N)
R	Result of Pivotal Supplier Screen	**PASS**	(Pass if (Q < P); (Fail if Q > P)

Part II -- Market Share Analysis

AP South

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference December '11 - November '12
	Seller and Affiliate Capacity					
A	Installed Capacity	13,083	13,083	12,311	12,772	Exhibit JRS-2
B	Long-Term Firm Purchases	545	545	545	545	Exhibit JRS-2
C	Long-Term Firm Sales	(760)	(760)	(757)	(760)	Exhibit JRS-2
D	Seasonal Average Planned Outages	(657)	(1,753)	(103)	(1,152)	Pro Rata Share of Outages
E	Imported Power	594	506	1,225	1,078	Wkp-Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	(46,542)	(41,447)	(57,545)	(43,419)	Wkp-PJM Load Data
G	Amount of Line F Attributable to Seller, if any	(8,672)	(7,866)	(10,372)	(8,046)	Wkp-Exelon PJM Load
H	Amount of Line F Attributable to Others, if any	(37,870)	(33,581)	(47,173)	(35,372)	
I	Balancing Authority Area Reserve Requirement, if any	(2,744)	(2,493)	(3,313)	(2,583)	Wkp-PJM Oper Reserves
J	Amount of Line I Attributable to Seller, if any	-	-	-	-	
K	Amount of Line I Attributable to Others, if any	(2,744)	(2,493)	(3,313)	(2,583)	
	Non-Affiliate Capacity					
L	Installed Capacity	76,830	76,776	72,496	75,598	Wkp-PJM Generation less Row A above
M	Long-Term Firm Purchases	760	760	757	760	Offset, Row C
N	Long-Term Firm Sales	(545)	(545)	(545)	(545)	Offset, Row B
O	Local Seasonal Average Planned Outages	(3,931)	(10,491)	(618)	(6,957)	Wkp-Outages less Row D above
P	Uncommitted Capacity Imports	4,294	3,840	6,264	6,890	PJM SIL Study less Row E above
	Supply Calculation					
Q	Total Competing Supply	36,794	34,266	27,868	37,790	SUM (L,M,N,O,P,H,K)
R	Seller's Uncommitted Capacity	4,133	3,755	2,848	4,437	SUM (A,B,C,D,E,G,J)
S	Total Seasonal Uncommitted Capacity	40,928	38,021	30,717	42,227	SUM (Q,R)
T	**Seller's Market Share**	10.1%	9.9%	9.3%	10.5%	(R/S)
	Results	**PASS**	**PASS**	**PASS**	**PASS**	Pass if T <20%; Fail if T > 20%

Part I -- Pivotal Supplier Analysis

		ISO-NE	
Row	**Generation**	**MW**	**Reference** (December '11 - November '12)
	Seller and Affiliate Capacity		
A	Installed Capacity	2,843	Exhibit JRS-2
B	Long-Term Firm Purchases	620	Exhibit JRS-2
C	Long-Term Firm Sales	-	
D	Imported Power	829	Wkp-Import Allocation
	Non-Affiliate Capacity		
E	Installed Capacity	29,126	Wkp-ISO-NE Capacity less Row A above
F	Long-Term Firm Purchases	-	
G	Long-Term Firm Sales	(620)	Offset, Row B
H	Imported Power	3,719	ISO-NE SIL Study less Row D above
I	Balancing Authority Area Reserve Requirement	(2,430)	Wkp-ISO-NE Oper Reserves
J	Amount of Line I Attributable to Seller, if any	-	
K	Total Uncommitted Capacity	13,171	SUM (A,B,C,D,E,F,G,H,I,M)
	Load		
L	Balancing Authority Area Annual Peak Load	25,880	Wkp-ISO-NE Load Data
M	Average Daily Peak Native Load in Peak Month	(20,917)	Wkp-ISO-NE Load Data
N	Amount of Line M Attributable to Seller, if any	(3,589)	Wkp-Exelon ISO-NE Load Data
O	Wholesale Load	4,963	(L+M)
P	Net Uncommitted Supply	8,207	(K-O)
Q	Seller's Uncommitted Capacity	704	SUM (A,B,C,D,J,N)
R	Result of Pivotal Supplier Screen	**PASS**	(Pass if (Q < P); (Fail if Q > P)

Part II -- Market Share Analysis

Row		ISO-NE Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference December '11 - November '12
	Seller and Affiliate Capacity					
A	Installed Capacity	3,363	3,363	2,843	3,363	Exhibit JRS-2
B	Long-Term Firm Purchases	620	620	620	620	Exhibit JRS-2
C	Long-Term Firm Sales	-	-	-	-	
D	Seasonal Average Planned Outages	(147)	(347)	(17)	(446)	Pro Rata Share of Outages
E	Imported Power	442	347	636	375	Wkp-Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	(17,779)	(15,490)	(19,767)	(16,420)	Wkp-ISO-NE Load Data
G	Amount of Line F Attributable to Seller, if any	(3,326)	(3,080)	(3,518)	(2,764)	Wkp-Exelon ISO-NE Load Data
H	Amount of Line F Attributable to Others, if any	(14,453)	(12,410)	(16,249)	(13,656)	
I	Balancing Authority Area Reserve Requirement, if any	(2,060)	(2,060)	(2,430)	(2,430)	Wkp-ISO-NE Oper Reserves
J	Amount of Line I Attributable to Seller, if any	-	-	-	-	
K	Amount of Line I Attributable to Others, if any	(2,060)	(2,060)	(2,430)	(2,430)	
	Non-Affiliate Capacity					
L	Installed Capacity	31,045	31,045	29,126	31,045	Wkp-ISO-NE Capacity less Row A above
M	Long-Term Firm Purchases	-	-	-	-	
N	Long-Term Firm Sales	(620)	(620)	(620)	(620)	Offset, Row B
O	Local Seasonal Average Planned Outages	(1,124)	(2,653)	(137)	(3,405)	Wkp-Outages less Row D above
P	Uncommitted Capacity Imports	4,106	4,201	3,912	4,173	ISO-NE SIL Study less Row E above
	Supply Calculation					
Q	Total Competing Supply	16,895	17,504	13,602	15,106	SUM (L,M,N,O,P,H,K)
R	Seller's Uncommitted Capacity	952	903	565	1,149	SUM (A,B,C,D,E,G,J)
S	Total Seasonal Uncommitted Capacity	17,847	18,406	14,167	16,254	SUM (Q,R)
T	**Seller's Market Share**	5.3%	4.9%	4.0%	7.1%	(R/S)
	Results	**PASS**	**PASS**	**PASS**	**PASS**	Pass if T <20%; Fail if T > 20%

Part I -- Pivotal Supplier Analysis

		ISO-NE	
Row	**Generation**	**MW**	**Reference** (December '11 - November '12)
	Seller and Affiliate Capacity		
A	Installed Capacity	2,843	Exhibit JRS-2
B	Long-Term Firm Purchases	1,281	Exhibit JRS-2 (plus Granite Ridge)
C	Long-Term Firm Sales	-	
D	Imported Power	829	Wkp-Import Allocation
	Non-Affiliate Capacity		
E	Installed Capacity	29,126	Wkp-ISO-NE Capacity less Row A above
F	Long-Term Firm Purchases	-	
G	Long-Term Firm Sales	(1,281)	Offset, Row B
H	Imported Power	3,719	ISO-NE SIL Study less Row D above
I	Balancing Authority Area Reserve Requirement	(2,430)	Wkp-ISO-NE Oper Reserves
J	Amount of Line I Attributable to Seller, if any	-	
K	Total Uncommitted Capacity	13,171	SUM (A,B,C,D,E,F,G,H,I,M)
	Load		
L	Balancing Authority Area Annual Peak Load	25,880	Wkp-ISO-NE Load Data
M	Average Daily Peak Native Load in Peak Month	(20,917)	Wkp-ISO-NE Load Data
N	Amount of Line M Attributable to Seller, if any	(3,589)	Wkp-Exelon ISO-NE Load Data
O	Wholesale Load	4,963	(L+M)
P	Net Uncommitted Supply	8,207	(K-O)
Q	Seller's Uncommitted Capacity	1,365	SUM (A,B,C,D,J,N)
R	Result of Pivotal Supplier Screen	**PASS**	(Pass if (Q < P); (Fail if Q > P)

Part II -- Market Share Analysis

Row		ISO-NE Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference December '11 - November '12
	Seller and Affiliate Capacity					
A	Installed Capacity	3,363	3,363	2,843	3,363	Exhibit JRS-2
B	Long-Term Firm Purchases	1,419	1,419	1,281	1,419	Exhibit JRS-2 (plus Granite Ridge)
C	Long-Term Firm Sales	-	-	-	-	
D	Seasonal Average Planned Outages	(177)	(417)	(20)	(535)	Pro Rata Share of Outages
E	Imported Power	442	347	636	375	Wkp-Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	(17,779)	(15,490)	(19,767)	(16,420)	Wkp-ISO-NE Load Data
G	Amount of Line F Attributable to Seller, if any	(3,326)	(3,080)	(3,518)	(2,764)	Wkp-Exelon ISO-NE Load Data
H	Amount of Line F Attributable to Others, if any	(14,453)	(12,410)	(16,249)	(13,656)	
I	Balancing Authority Area Reserve Requirement, if any	(2,060)	(2,060)	(2,430)	(2,430)	Wkp-ISO-NE Oper Reserves
J	Amount of Line I Attributable to Seller, if any	-	-	-	-	
K	Amount of Line I Attributable to Others, if any	(2,060)	(2,060)	(2,430)	(2,430)	
	Non-Affiliate Capacity					
L	Installed Capacity	31,045	31,045	29,126	31,045	Wkp-ISO-NE Capacity less Row A above
M	Long-Term Firm Purchases	-	-	-	-	
N	Long-Term Firm Sales	(1,419)	(1,419)	(1,281)	(1,419)	Offset, Row B
O	Local Seasonal Average Planned Outages	(1,094)	(2,583)	(134)	(3,316)	Wkp-Outages less Row D above
P	Uncommitted Capacity Imports	4,106	4,201	3,912	4,173	ISO-NE SIL Study less Row E above
	Supply Calculation					
Q	Total Competing Supply	16,125	16,774	12,944	14,396	SUM (L,M,N,O,P,H,K)
R	Seller's Uncommitted Capacity	1,722	1,632	1,223	1,859	SUM (A,B,C,D,E,G,J)
S	Total Seasonal Uncommitted Capacity	17,847	18,406	14,167	16,254	SUM (Q,R)
T	**Seller's Market Share**	9.6%	8.9%	8.6%	11.4%	(R/S)
	Results	**PASS**	**PASS**	**PASS**	**PASS**	Pass if T <20%; Fail if T > 20%

Part I -- Pivotal Supplier Analysis

CT

Row	Generation	MW	Reference (December '11 - November '12)
	Seller and Affiliate Capacity		
A	Installed Capacity	-	
B	Long-Term Firm Purchases	620	Exhibit JRS-2
C	Long-Term Firm Sales	-	
D	Imported Power	821	Wkp-Import Allocation
	Non-Affiliate Capacity		
E	Installed Capacity	7,979	Wkp-ISO-NE Capacity less Row A above
F	Long-Term Firm Purchases	-	
G	Long-Term Firm Sales	(620)	Offset, Row B
H	Imported Power	1,679	ISO-NE SIL Study less Row D above
I	Balancing Authority Area Reserve Requirement	(765)	Wkp-ISO-NE Oper Reserves
J	Amount of Line I Attributable to Seller, if any	-	
K	Total Uncommitted Capacity	4,323	SUM (A,B,C,D,E,F,G,H,I,M)
	Load		
L	Balancing Authority Area Annual Peak Load	6,922	Wkp-ISO-NE Load Data
M	Average Daily Peak Native Load in Peak Month	(5,392)	Wkp-ISO-NE Load Data
N	Amount of Line M Attributable to Seller, if any	(1,495)	Wkp-Exelon ISO-NE Load Data
O	Wholesale Load	1,530	(L+M)
P	Net Uncommitted Supply	2,792	(K-O)
Q	Seller's Uncommitted Capacity	-	SUM (A,B,C,D,J,N)
R	Result of Pivotal Supplier Screen	**PASS**	(Pass if (Q < P); (Fail if Q > P)

Part II -- Market Share Analysis

Row		CT Winter (MW)	CT Spring (MW)	CT Summer (MW)	CT Fall (MW)	Reference December '11 - November '12
	Seller and Affiliate Capacity					
A	Installed Capacity	-	-	-	-	
B	Long-Term Firm Purchases	620	620	620	620	Exhibit JRS-2
C	Long-Term Firm Sales	-	-	-	-	
D	Seasonal Average Planned Outages	(23)	(54)	(3)	(69)	Pro Rata Share of Outages
E	Imported Power	230	221	262	262	Wkp-Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	(4,292)	(3,733)	(5,011)	(3,970)	Wkp-ISO-NE Load Data
G	Amount of Line F Attributable to Seller, if any	(1,330)	(1,125)	(1,399)	(1,117)	Wkp-Exelon ISO-NE Load Data
H	Amount of Line F Attributable to Others, if any	(2,963)	(2,608)	(3,612)	(2,853)	
I	Balancing Authority Area Reserve Requirement, if any	(837)	(837)	(765)	(837)	Wkp-ISO-NE Oper Reserves
J	Amount of Line I Attributable to Seller, if any	-	-	-	-	
K	Amount of Line I Attributable to Others, if any	(837)	(837)	(765)	(837)	
	Non-Affiliate Capacity					
L	Installed Capacity	8,263	8,263	7,979	8,263	Wkp-ISO-NE Capacity less Row A above
M	Long-Term Firm Purchases	-	-	-	-	
N	Long-Term Firm Sales	(620)	(620)	(620)	(620)	Offset, Row B
O	Local Seasonal Average Planned Outages	(282)	(666)	(35)	(855)	Wkp-Outages less Row D above
P	Uncommitted Capacity Imports	2,270	2,279	2,238	2,238	ISO-NE SIL Study less Row E above
	Supply Calculation					
Q	Total Competing Supply	5,831	5,810	5,185	5,334	SUM (L,M,N,O,P,H,K)
R	Seller's Uncommitted Capacity	-	-	-	-	SUM (A,B,C,D,E,G,J)
S	Total Seasonal Uncommitted Capacity	5,831	5,810	5,185	5,334	SUM (Q,R)
T	**Seller's Market Share**	0.0%	0.0%	0.0%	0.0%	(R/S)
	Results	**PASS**	**PASS**	**PASS**	**PASS**	Pass if T <20%; Fail if T > 20%

Part I -- Pivotal Supplier Analysis

NYISO

Row	Generation	MW	Reference (December '11 - November '12)
	Seller and Affiliate Capacity		
A	Installed Capacity	2,266	Exhibit JRS-2
B	Long-Term Firm Purchases		
C	Long-Term Firm Sales	(340)	Exhibit JRS-2
D	Imported Power	1,142	Wkp-Import Allocation
	Non-Affiliate Capacity		
E	Installed Capacity	36,636	Wkp-NYISO Capacity less Row A above
F	Long-Term Firm Purchases	340	Offset, Row C
G	Long-Term Firm Sales	-	
H	Imported Power	6,678	NYISO SIL Study less Row D above
I	Balancing Authority Area Reserve Requirement	(1,965)	Wkp-NYISO Oper Reserves
J	Amount of Line I Attributable to Seller, if any	-	
K	Total Uncommitted Capacity	17,433	SUM (A,B,C,D,E,F,G,H,I,M)
	Load		
L	Balancing Authority Area Annual Peak Load	32,439	Wkp-NYISO Load Data
M	Average Daily Peak Native Load in Peak Month	(27,324)	Wkp-NYISO Load Data
N	Amount of Line M Attributable to Seller, if any	-	
O	Wholesale Load	5,116	(L+M)
P	Net Uncommitted Supply	12,318	(K-O)
Q	Seller's Uncommitted Capacity	3,068	SUM (A,B,C,D,J,N)
R	Result of Pivotal Supplier Screen	**PASS**	(Pass if (Q < P); (Fail if Q > P)

Part II -- Market Share Analysis

Row		NYISO Winter (MW)	NYISO Spring (MW)	NYISO Summer (MW)	NYISO Fall (MW)	Reference December '11 - November '12
	Seller and Affiliate Capacity					
A	Installed Capacity	2,268	2,268	2,266	2,268	Exhibit JRS-2
B	Long-Term Firm Purchases					
C	Long-Term Firm Sales	(340)	(340)	(340)	(340)	Exhibit JRS-2
D	Seasonal Average Planned Outages	(187)	(277)	(44)	(204)	Pro Rata Share of Outages
E	Imported Power	748	599	744	798	Wkp - Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	(21,340)	(19,352)	(25,513)	(20,367)	Wkp-NYISO Load Data
G	Amount of Line F Attributable to Seller, if any	-	-	-	-	
H	Amount of Line F Attributable to Others, if any	(21,340)	(19,352)	(25,513)	(20,367)	
I	Balancing Authority Area Reserve Requirement, if any	(1,965)	(1,965)	(1,965)	(1,965)	Wkp-NYISO Oper Reserves
J	Amount of Line I Attributable to Seller, if any	-	-	-	-	
K	Amount of Line I Attributable to Others, if any	(1,965)	(1,965)	(1,965)	(1,965)	
	Non-Affiliate Capacity					
L	Installed Capacity	39,080	39,080	36,636	39,080	Wkp-NYISO Capacity less Row A above
M	Long-Term Firm Purchases	340	340	340	340	Offset, Row C
N	Long-Term Firm Sales					
O	Local Seasonal Average Planned Outages	(3,823)	(5,671)	(842)	(4,180)	Wkp-Outages less Row D above
P	Uncommitted Capacity Imports	7,351	6,761	7,076	7,332	NYISO SIL Study less Row E above
	Supply Calculation					
Q	Total Competing Supply	19,643	19,194	15,732	20,240	SUM (L,M,N,O,P,H,K)
R	Seller's Uncommitted Capacity	2,488	2,249	2,626	2,521	SUM (A,B,C,D,E,G,J)
S	Total Seasonal Uncommitted Capacity	22,131	21,442	18,358	22,761	SUM (Q,R)
T	**Seller's Market Share**	11.2%	10.5%	14.3%	11.1%	(R/S)
	Results	**PASS**	**PASS**	**PASS**	**PASS**	Pass if T <20%; Fail if T > 20%

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

AV Solar Ranch 1, LLC	)	Docket No. ER12-2178-____
Baltimore Gas and Electric Company	)	Docket No. ER10-2172-____
Cassia Gulch Wind Park LLC	)	Docket No. ER11-2016-____
CER Generation, LLC	)	Docket No. ER10-2184-____
CER Generation II, LLC	)	Docket No. ER10-2183-____
Commonwealth Edison Company	)	Docket No. ER10-1048-____
Constellation Energy Commodities Group Maine, LLC	)	Docket No. ER10-2192-____
Constellation Mystic Power, LLC	)	Docket No. ER11-2056-____
Constellation NewEnergy, Inc.	)	Docket No. ER10-2178-____
Constellation Power Source Generation, Inc.	)	Docket No. ER10-2174-____
Cow Branch Wind Power, L.L.C.	)	Docket No. ER11-2014-____
CR Clearing, LLC	)	Docket No. ER11-2013-____
Criterion Power Partners, LLC	)	Docket No. ER10-3308-____
Exelon Framingham, LLC	)	Docket No. ER10-1020-____
Exelon Generation Company, LLC	)	Docket No. ER13-1536-____
Exelon New Boston, LLC	)	Docket No. ER10-1078-____
Exelon West Medway, LLC	)	Docket No. ER10-1080-____
Exelon Wind 4, LLC	)	Docket No. ER11-2010-____
Exelon Wyman, LLC	)	Docket No. ER10-1081-____
Handsome Lake Energy, LLC	)	Docket No. ER10-2180-____
Harvest Windfarm, LLC	)	Docket No. ER11-2011-____
High Mesa Energy, LLC	)	Docket No. ER12-2528-____
Michigan Wind 1, LLC	)	Docket No. ER11-2009-____
PECO Energy Company	)	Docket No. ER10-1143-____
Tuana Springs Energy, LLC	)	Docket No. ER11-2007-____
Wind Capital Holdings, LLC	)	Docket No. ER11-2005-____

AFFIDAVIT

	§
District of Columbia	§
	§

JULIE R. SOLOMON being duly sworn, deposes and states: that she prepared the Affidavit and Exhibits of Julie R. Solomon and that the statements contained therein and the Exhibits attached hereto are true and correct to the best of her knowledge and belief.

Julie R. Solomon

SUBSCRIBED AND SWORN TO BEFORE ME, this the 20 day of December 2013.

Janet P. Cashion
Notary Public, District of Columbia

JANET P. CASHION NOTARY PUBLIC MY COMMISSION EXPIRES 7/14/2017 DISTRICT OF COLUMBIA

Printed Name: Janet P. Cashion

My Commission Expires: July 14, 2017

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ATTACHMENT B

Order No. 697 Appendices

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Electric Generating Facilitates Affiliates and Assets

Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
AgriWind LLC	N/A[3]	AgriWind	AgriWind LLC	AgriWind LLC	N/A	Midcontinent Independent System Operator, Inc. ("MISO")	Central	2007	2.1[4]
AgriWind Project L.L.C.	N/A[3]	AgriWind Project	AgriWind Project L.L.C.	AgriWind Project L.L.C.	N/A	MISO	Central	2007	6.3[4]
B & K Energy Systems, LLC	N/A[3]	B & K Energy Systems	B & K Energy Systems, LLC	B & K Energy Systems, LLC	N/A	MISO	Central	2003	1.9[4]
BC Energy LLC	N/A[3]	BC Energy	BC Energy LLC	BC Energy LLC	N/A	MISO	Central	2007	4.2[4]
Beebe Renewable Energy, LLC	ER12-2311	Beebe Renewable Energy	Beebe Renewable Energy, LLC	Beebe Renewable Energy, LLC	N/A	MISO	Central	2012	81.6[4]
Blue Breezes, L.L.C.	N/A [3]	Blue Breezes	Blue Breezes, L.L.C.	Blue Breezes, L.L.C.	N/A	MISO	Central	2006	1.25[4]
Blue Breezes II, L.L.C.	N/A[3]	Blue Breezes II	Blue Breezes II, L.L.C.	Blue Breezes II, L.L.C.	N/A	MISO	Central	2006	1.25[4]
Breezy Bucks-I LLC	N/A[3]	Breezy Bucks-I	Breezy Bucks-I LLC	Breezy Bucks-I LLC	N/A	MISO	Central	2006	1.25[4]
Breezy Bucks-II LLC	N/A[3]	Breezy Bucks-II	Breezy Bucks-II LLC	Breezy Bucks-II LLC	N/A	MISO	Central	2006	1.25[4]
Christoffer Wind Energy I LLC	N/A[3]	Christoffer Wind Energy I	Christoffer Wind Energy I LLC	Christoffer Wind Energy I LLC	N/A	MISO	Central	2008	2.1[4]
Christoffer Wind Energy II LLC	N/A[3]	Christoffer Wind Energy II	Christoffer Wind Energy H LLC	Christoffer Wind Energy II LLC	N/A	MISO	Central	2008	2.1[4]
Christoffer Wind Energy III LLC	N/A[3]	Christoffer Wind Energy III	Christoffer Wind Energy III LLC	Christoffer Wind Energy HI LLC	N/A	MISO	Central	2008	2.1[4]

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
Christoffer Wind Energy IV LLC	N/A[3]	Christoffer Wind Energy IV	Christoffer Wind Energy IV LLC	Christoffer Wind Energy IV LLC	N/A	MISO	Central	2008	2.1[4]
Constellation Solar Ohio, LLC	N/A[8]	University of Toledo (Solar) Scott Park Campus of Energy & Innovation	Constellation Solar Ohio, LLC	Constellation Solar Ohio, LLC	N/A	MISO	Central	2010	0.88
Constellation Solar Ohio, LLC	N/A[8]	University of Toledo (Wind) Scott Park Campus of Energy & Innovation	Constellation Solar Ohio, LLC	Constellation Solar Ohio, LLC	N/A	MISO	Central	2010	0.07
CP Windfarm, LLC	N/A[3]	CP Windfarm	CP Windfarm, LLC	CP Windfarm, LLC	N/A	MISO	Central	2008	4.2[4]
DL Windy Acres, LLC	N/A[3]	DL Windy Acres	DL Windy Acres, LLC	DL Windy Acres, LLC	N/A	MISO	Central	2003	1.9[4]
Exelon Generation Company, LLC ("ExGen")	ER00-3251	Clinton	ExGen	ExGen	N/A	MISO	Central	1987	1,055
G-Flow Wind, LLC	N/A[3]	G-Flow Wind	G-Flow Wind, LLC	G-Flow Wind, LLC	N/A	MISO	Central	2006	1.25[4]
Green Acres Breeze, LLC	N/A[3]	Green Acres Breeze	Green Acres Breeze, LLC	Green Acres Breeze, LLC	N/A	MISO	Central	2006	1.25[4]
Harvest Windfarm, LLC	ER07-1246	Harvest Windfarm	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	2007	52.8[4]
Harvest II Windfarm, LLC	ER12-2201	Harvest II Windfarm	Harvest II	Harvest II	N/A	MISO	Central	2012	59.4[4]
K & D Energy LLC	N/A[3]	K & D Energy	K & D Energy LLC	K & D Energy LLC	N/A	MISO	Central	2007	4[4]
KC Energy LLC	N/A[3]	KC Energy	KC Energy LLC	KC Energy LLC	N/A	MISO	Central	2007	4[4]
KSS Turbines LLC	N/A[3]	KSS Turbines	KSS Turbines LLC	KSS Turbines LLC	N/A	MISO	Central	2007	4[4]

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
Michigan Wind 1, LLC	ER05-1511	Michigan Wind 1	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	2008	69[4]
Michigan Wind 2, LLC	ER11-3989	Michigan Wind 2	Michigan Wind 2, LLC	Michigan Wind 2, LLC	N/A	MISO	Central	2011	90[4]
Minnesota Breeze, LLC	N/A[3]	Minnesota Breeze	Minnesota Breeze, LLC	Minnesota Breeze, LLC	N/A	MISO	Central	2006	1.25[4]
Prairie Wind Power LLC	N/A[3]	Prairie Wind Power	Prairie Wind Power LLC	Prairie Wind Power LLC	N/A	MISO	Central	2007	4[4]
Roadrunner-I LLC	N/A [3]	Roadrunner-I	Roadrunner-I LLC	Roadrunner-I LLC	N/A	MISO	Central	2006	1.25[4]
S & P Windfarm, LLC	N/A[3]	S & P Windfarm	S & P Windfarm, LLC	S & P Windfarm, LLC	N/A	MISO	Central	2003	1.9[4]
Salty Dog-I LLC	N/A[3]	Salty Dog-I	Salty Dog-I LLC	Salty Dog-I LLC	N/A	MISO	Central	2006	1.25[4]
Salty Dog-II LLC	N/A[3]	Salty Dog-II	Salty Dog-II LLC	Salty Dog-II LLC	N/A	MISO	Central	2006	1.25[4]
Shane's Wind Machine LLC	N/A[3]	Shane's Wind Machine	Shane's Wind Machine LLC	Shane's Wind Machine LLC	N/A	MISO	Central	2006	2[4]
Sunset Breeze, LLC	N/A[3]	Sunset Breeze	Sunset Breeze, LLC	Sunset Breeze, LLC	N/A	MISO	Central	2006	1.25[4]
Wally's Wind Farm LLC	N/A[3]	Wally's Wind Farm	Wally's Wind Farm LLC	Wally's Wind Farm LLC	N/A	MISO	Central	2006	1.25[4]
Windy Dog-I LLC	N/A[3]	Windy Dog-I	Windy Dog-I LLC	Windy Dog-I LLC	N/A	MISO	Central	2006	1.25[4]
Wolf Wind Enterprises, LLC	N/A[3]	Wolf Wind Enterprises	Wolf Wind Enterprises, LLC	Wolf Wind Enterprises, LLC	N/A	MISO	Central	2006	1.25[4]

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
Marshall Wind 2, LLC	N/A[3]	Marshall Wind 2	Marshall Wind 2, LLC	Marshall Wind 2, LLC	N/A	Western Area Power Administration - Upper Great Plains East ("WAUE")	Central	2007	4.2[4]
Marshall Wind 3, LLC	N/A[3]	Marshall Wind 3	Marshall Wind 3, LLC	Marshall Wind 3, LLC	N/A	WAUE	Central	2007	4.2[4]
Marshall Wind 4, LLC	N/A[3]	Marshall Wind 4	Marshall Wind 4, LLC	Marshall Wind 4, LLC	N/A	WAUE	Central	2007	4.2[4]
Marshall Wind 5, LLC	N/A[3]	Marshall Wind 5	Marshall Wind 5, LLC	Marshall Wind 5, LLC	N/A	WAUE	Central	2007	2.1[4]
Marshall Wind 6, LLC	N/A[3]	Marshall Wind 6	Marshall Wind 6, LLC	Marshall Wind 6 LLC	N/A	WAUE	Central	2007	2.1[4]
Marshall Wind 1, LLC	N/A[3]	Marshall Wind 1	Marshall Wind 1, LLC	Marshall Wind 1, LLC	N/A	WAUE	Central	2007	2.1[4]
ExGen	ER97-2261	Kleen	Kleen Energy Systems, LLC	ExGen	2011	ISO New England Inc. ("ISO-NE")	Northeast	2011	620
Constellation Mystic Power, LLC ("Constellation Mystic")	ER10-2281	Mystic - 7	Constellation Mystic	Constellation Mystic	2011	ISO-NE	Northeast	1975	575.48
Constellation Mystic	ER10-2281	Mystic - 8	Constellation Mystic	Constellation Mystic	2011	ISO-NE	Northeast	2003	704
Constellation Mystic	ER10-2281	Mystic – 9	Constellation Mystic	Constellation Mystic	2011	ISO-NE	Northeast	2003	703
Constellation Mystic	ER10-2281	Mystic - Jet	Constellation Mystic	Constellation Mystic	2011	ISO-NE	Northeast	1969	9.07
Constellation Mystic	ER10-2281	Fore River	Constellation Mystic	Constellation Mystic	2011	ISO-NE	Northeast	2003	688

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
Constellation Solar Connecticut, LLC	N/A[8]	Parker Hannifin Corp at New Britain	Constellation Solar Connecticut, LLC	Constellation Solar Connecticut, LLC	N/A	ISO-NE	Northeast	2008	0.18
Constellation Solar Connecticut, LLC	N/A[8]	East Lyme Bd of Ed at East Lyme HS	Constellation Solar Connecticut, LLC	Constellation Solar Connecticut, LLC	N/A	ISO-NE	Northeast	2009	0.41
Constellation Solar Massachusetts, LLC ("CSMA")	N/A[8]	Kollmorgen Corp at Kollmorgen Electro-Optical HQ Bldg	CSMA	CSMA	N/A	ISO-NE	Northeast	2011	0.17
CSMA	N/A[8]	Majilite Corp	CSMA	CSMA	N/A	ISO-NE	Northeast	2009	0.35
CSMA	N/A[8]	NPP Development, LLC at Patriot Place	CSMA	CSMA	N/A	ISO-NE	Northeast	2010	0.45
CSMA	N/A[8]	Town of Norfolk	CSMA	CSMA	N/A	ISO-NE	Northeast	2012	1.35
CSMA	N/A[8]	Town of Swampscott	CSMA	CSMA	N/A	ISO-NE	Northeast	2012	0.32
Constellation Solar Net Metering, LLC	N/A[8]	Town of Uxbridge	Constellation Solar Net Metering, LLC	Constellation Solar Net Metering, LLC	N/A	ISO-NE	Northeast	2012	1.93
Exelon Framingham LLC	ER01-513	Framingham Jet 1-3	Exelon Framingham, LLC	Exelon Framingham, LLC	N/A	ISO-NE	Northeast	1969	33.08
Exelon New Boston, LLC ("Exelon New Boston")	ER01-513	New Boston GT (L Street)	Exelon New Boston	Exelon New Boston	N/A	ISO-NE	Northeast	1966	16.03
Exelon West Medway LLC ("Exelon West Medway")	ER01-513	West Medway Jet 2	Exelon West Medway	Exelon West Medway	N/A	ISO-NE	Northeast	1971	39.85
Exelon West Medway	ER01-513	West Medway Jet 3	Exelon West Medway	Exelon West Medway	N/A	ISO-NE	Northeast	1970	35.44

Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
Exelon West Medway	ER01-513	West Medway Jet 1	Exelon West Medway	Exelon West Medway	N/A	ISO-NE	Northeast	1970	42.00
Exelon Wyman, LLC	ER01-513	Wyman 4	Exelon Wyman, LLC (5.89%)	FPL Wyman Energy, LLC	N/A	ISO-NE	Northeast	1978	610[7]
Holyoke Solar LLC	N/A [3]	City of Holyoke G & E Dept at Mueller	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	2012	2.95
Holyoke Solar LLC	N/A [3]	City of Holyoke G & E Dept at Meadow	Holyoke Solar LLC	Holyoke Solar LLC	N/A	ISO-NE	Northeast	2011	0.87
Residential Solar II, LLC ("RS II")	N/A[8]	Residential Solar	RS II	RS II	N/A	ISO-NE	Northeast	N/A	2.68
Nine Mile Point Nuclear Station, LLC ("Nine Mile Point")	ER01-1654	Nine Mile Point - 1	Nine Mile Point	Nine Mile Point	2010	New York Independent System Operator, Inc. ("NYISO")	Northeast	1969	626.9[7]
Nine Mile Point	ER01-1654	Nine Mile Point - 2	Nine Mile Point (82%)	Nine Mile Point	2010	NYISO	Northeast	1988	1, 287.2[7]
R.E. Ginna Nuclear Power Plant, LLC ("Ginna")	ER04-485	Ginna	Ginna	Ginna	2010	NYISO	Northeast	1970	581.5[7]
RS II	N/A[8]	Residential Solar	RS II	RS II	N/A	NYISO	Northeast	N/A	1.08
Constellation Solar New York, LLC ("CSNY")	N/A[8]	Owens Corning at Bethlehem, NY	CSNY	CSNY	N/A	NYISO	Northeast	2013	2.21
Calvert Cliffs Nuclear Power Plant, LLC ("Calvert Cliffs")	ER00-2917	Calvert Cliffs - 2	Calvert Cliffs	Calvert Cliffs	2010	PJM Interconnection, L.L.C. ("PJM")	Northeast	1977	862[7]
Calvert Cliffs	ER00-2917	Calvert Cliffs - 1	Calvert Cliffs	Calvert Cliffs	2010	PJM	Northeast	1975	873[7]
ExGen	ER97-2261	York Delta	Calpine Mid Merit LLC	ExGen	2011	PJM	Northeast	2011	565

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
ExGen	ER97-2261	Cordova Purchase - 1	Cordova Energy, LLC	ExGen	2005	PJM	Northeast	N/A	475
ExGen	ER97-2261	Elwood Purchase – 1	Elwood Energy, LLC	ExGen	2006	PJM	Northeast	N/A	600
Constellation Solar Federal LLC	N/A[3]	Constellation New Energy, Inc. at US Dept. of State	Constellation Solar Federal LLC	Constellation Solar Federal LLC	N/A	PJM	Northeast	2011	4.23
Constellation Solar Horizons, LLC	N/A[8]	Mount St. Mary's University at Emmitsburg	Constellation Solar Horizons, LLC	Constellation Solar Horizons, LLC	N/A	PJM	Northeast	2012	1.42
Constellation Solar Horizons, LLC	N/A[3]	MD Generating Clean Horizons MSM I	Constellation Solar Horizons, LLC	Constellation Solar Horizons, LLC	N/A	PJM	Northeast	2012	13.61
Constellation Solar New Jersey LLC ("CSNJ")	N/A[3]	The City of Vineland at North Vineland	CSNJ	CSNJ	NA	PJM	Northeast	2011	2.54
CSNJ	N/A[3]	The City of Vineland at West Vineland	CSNJ	CSNJ	N/A	PJM	Northeast	2011	4.06
CSNJ	N/A[8]	Benjamin Moore & Co at Flanders NJ	CSNJ	CSNJ	N/A	PJM	Northeast	2011	1.50
CSNJ	N/A[8]	Jet Aviation Teterboro, LP at Teterboro Airport	CSNJ	CSNJ	N/A	PJM	Northeast	2008	0.15
Constellation Solar New Jersey II, LLC ("CSNJ II")	N/A[8]	Johnson Matthey, Inc at West Deptford	CSNJ II	CSNJ II	N/A	PJM	Northeast	2011	4.41
Constellation Solar New Jersey II	N/A[8]	Toys-R-Us Delaware, Inc at Mt Olive	CSNJ II	CSNJ II	N/A	PJM	Northeast	2011	4.57

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
Constellation Solar New Jersey III, LLC ("CSNJ III")	N/A[8]	Middle Township Elem School 1	CSNJ III	CSNJ III	N/A	PJM	Northeast	2011	0.17
CSNJ III	N/A[8]	Middle Township Elem School 2	CSNJ III	CSNJ III	N/A	PJM	Northeast	2011	0.39
CSNJ III	N/A[8]	Middle Township High School	CSNJ III	CSNJ III	N/A	PJM	Northeast	2011	0.69
Constellation Power, Inc. ("CPI")	N/A[5]	Colver	Inter-Power/Ahlcon Partners (Colver)	Inter-Power/Ahlcon Partners (Colver)	N/A	PJM	Northeast	1995	104[7]
CPS Gen	ER00-1598	Gould Street - 3	CPS Gen	CPS Gen	N/A	PJM	Northeast	2008	97
CPS Gen	ER00-1598	Notch Cliff 1-8	CPS Gen	CPS Gen	N/A	PJM	Northeast	1969	118
CPS Gen	ER00-1598	Perryman - 1	CPS Gen	CPS Gen	N/A	PJM	Northeast	1972	52
CPS Gen	ER00-1598	Perryman - 51	CPS Gen	CPS Gen	N/A	PJM	Northeast	1995	147
CPS Gen	ER00-1598	Perryman 2-4	CPS Gen	CPS Gen	N/A	PJM	Northeast	1972	154
CPS Gen	ER00-1598	Philadelphia Road 1-2	CPS Gen	CPS Gen	N/A	PJM	Northeast	1970	31
CPS Gen	ER00-1598	Philadelphia Road 3-4	CPS Gen	CPS Gen	N/A	PJM	Northeast	1970	30
CPS Gen	ER00-1598	Riverside - 4	CPS Gen	CPS Gen	N/A	PJM	Northeast	1951	74
CPS Gen	ER00-1598	Riverside - 6	CPS Gen	CPS Gen	N/A	PJM	Northeast	1970	115
CPS Gen	ER00-1598	Riverside 7-8	CPS Gen	CPS Gen	N/A	PJM	Northeast	1970	39
CPS Gen	ER00-1598	Westport - 5	CPS Gen	CPS Gen	N/A	PJM	Northeast	1969	115
Exelon Solar Chicago LLC	N/A[3]	Chicago City Solar	Exelon Solar Chicago LLC	Exelon Solar Chicago LLC	N/A	PJM	Northeast	2010	8
Constellation Solar Maryland, LLC ("CSMD")	N/A[8]	AA County, MD at Shared Svcs Complex	CSMD	CSMD	N/A	PJM	Northeast	2011	0.63
CSMD	N/A[8]	Coppin State Univ at Coppin State Univ - PEC	CSMD	CSMD	N/A	PJM	Northeast	2011	0.42

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
CSMD	N/A[8]	CPSG Fort Smallwood Road Complex	CSMD	CSMD	N/A	PJM	Northeast	2011	0.78
CSMD	N/A[8]	GM Allison Plant-I	CSMD	CSMD	N/A	PJM	Northeast	2011	1.04
CSMD	N/A[8]	Maryland Science Center	CSMD	CSMD	N/A	PJM	Northeast	2011	0.09
CSMD	N/A[8]	McCormick & Co, Inc at Belcamp	CSMD	CSMD	N/A	PJM	Northeast	2011	1.56
CSMD	N/A[8]	McCormick & Co, Inc at Hunt Valley	CSMD	CSMD	N/A	PJM	Northeast	2009	0.78
CSMD	N/A[8]	McCormick & Co, Inc Corporate HQ	CSMD	CSMD	N/A	PJM	Northeast	2011	0.08
CSMD	N/A[8]	MD Env Service at MES Headquarters	CSMD	CSMD	N/A	PJM	Northeast	2008	0.25
Constellation Solar Maryland II, LLC	N/A[8]	UMMS (U of MD Medical System)	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	2013	3.09
Constellation Solar Maryland II, LLC	N/A[8]	UMMS - CRE	Constellation Solar Maryland II, LLC	Constellation Solar Maryland II, LLC	N/A	PJM	Northeast	2013	0.35
Criterion Power Partners, LLC	ER10-1443	Criterion 1-28	Criterion Power Partners, LLC	Criterion Power Partners, LLC	2010	PJM	Northeast	2010	70
ExGen	ER00-3251	Braidwood 1	ExGen	ExGen	N/A	PJM	Northeast	1988	1,178
ExGen	ER00-3251	Braidwood 2	ExGen	ExGen	N/A	PJM	Northeast	1988	1,152
ExGen	ER00-3251	Byron 1	ExGen	ExGen	N/A	PJM	Northeast	1985	1,164
ExGen	ER00-3251	Byron 2	ExGen	ExGen	N/A	PJM	Northeast	1987	1,136
ExGen	ER00-3251	Chester 7	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Chester 8	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Chester 9	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Conemaugh 1	ExGen (31.22%)	ExGen	N/A	PJM	Northeast	1970	850[7]

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
ExGen	ER00-3251	Conemaugh 2	ExGen (31.22%)	ExGen	N/A	PJM	Northeast	1970	850[7]
ExGen	ER00-3251	Conemaugh A-D	ExGen (31.22%)	ExGen	N/A	PJM	Northeast	1970	10.8[7]
ExGen	ER00-3251	Conowingo 1	ExGen	ExGen	N/A	PJM	Northeast	1928	48
ExGen	ER00-3251	Conowingo 2	ExGen	ExGen	N/A	PJM	Northeast	1928	36
ExGen	ER00-3251	Conowingo 3	ExGen	ExGen	N/A	PJM	Northeast	1928	48
ExGen	ER00-3251	Conowingo 4	ExGen	ExGen	N/A	PJM	Northeast	1928	48
ExGen	ER00-3251	Conowingo 5	ExGen	ExGen	N/A	PJM	Northeast	1928	36
ExGen	ER00-3251	Conowingo 6	ExGen	ExGen	N/A	PJM	Northeast	1928	48
ExGen	ER00-3251	Conowingo 7	ExGen	ExGen	N/A	PJM	Northeast	1928	48
ExGen	ER00-3251	Conowingo 8	ExGen	ExGen	N/A	PJM	Northeast	1964	65
ExGen	ER00-3251	Conowingo 9	ExGen	ExGen	N/A	PJM	Northeast	1964	65
ExGen	ER00-3251	Conowingo 10	ExGen	ExGen	N/A	PJM	Northeast	1964	65
ExGen	ER00-3251	Conowingo 11	ExGen	ExGen	N/A	PJM	Northeast	1964	65
ExGen	ER00-3251	Croydon 11	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 12	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 21	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 22	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 31	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 32	ExGen	ExGen	N/A	PJM	Northeast	1974	48
ExGen	ER00-3251	Croydon 41	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Croydon 42	ExGen	ExGen	N/A	PJM	Northeast	1974	49
ExGen	ER00-3251	Delaware 9	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Delaware 10	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Delaware 11	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Delaware 12	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Dresden 2	ExGen	ExGen	N/A	PJM	Northeast	1970	883.5
ExGen	ER00-3251	Dresden 3	ExGen	ExGen	N/A	PJM	Northeast	1971	903
ExGen	ER00-3251	Eddystone 3	ExGen	ExGen	N/A	PJM	Northeast	1974	380
ExGen	ER00-3251	Eddystone 4	ExGen	ExGen	N/A	PJM	Northeast	1976	380
ExGen	ER00-3251	Eddystone 10	ExGen	ExGen	N/A	PJM	Northeast	1967	13

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
ExGen	ER00-3251	Eddystone 20	ExGen	ExGen	N/A	PJM	Northeast	1967	13
ExGen	ER00-3251	Eddystone 30	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Eddystone 40	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Fairless Hills A	ExGen	ExGen	N/A	PJM	Northeast	1996	30
ExGen	ER00-3251	Fairless Hills B	ExGen	ExGen	N/A	PJM	Northeast	1996	30
ExGen	ER00-3251	Falls 1	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Falls 2	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Falls 3	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Keystone 1	ExGen (41.98%)	ExGen	N/A	PJM	Northeast	1967	850[7]
ExGen	ER00-3251	Keystone 2	ExGen (41.98%)	ExGen	N/A	PJM	Northeast	1968	850
ExGen	ER00-3251	Keystone 3-6	ExGen (41.98%)	ExGen	N/A	PJM	Northeast	1968	10.8[7]
ExGen	ER00-3251	LaSalle 1	ExGen	ExGen	N/A	PJM	Northeast	1984	1,137
ExGen	ER00-3251	LaSalle 2	ExGen	ExGen	N/A	PJM	Northeast	1984	1,140
ExGen	ER00-3251	Limerick 1	ExGen	ExGen	N/A	PJM	Northeast	1986	1,146
ExGen	ER00-3251	Limerick 2	ExGen	ExGen	N/A	PJM	Northeast	1990	1,150
ExGen	ER00-3251	Moser 1	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Moser 2	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Moser 3	ExGen	ExGen	N/A	PJM	Northeast	1970	17
ExGen	ER00-3251	Muddy Run 1	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Muddy Run 2	ExGen	ExGen	N/A	PJM	Northeast	1967	133
ExGen	ER00-3251	Muddy Run 3	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Muddy Run 4	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Muddy Run 5	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Muddy Run 6	ExGen	ExGen	N/A	PJM	Northeast	1967	133
ExGen	ER00-3251	Muddy Run 7	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Muddy Run 8	ExGen	ExGen	N/A	PJM	Northeast	1967	134
ExGen	ER00-3251	Oyster Creek	ExGen	ExGen	N/A	PJM	Northeast	1969	614.5
ExGen	ER00-3251	Peach Bottom 2	ExGen (50%)	ExGen	N/A	PJM	Northeast	1974	1,125.4[7]
ExGen	ER00-3251	Peach Bottom 3	ExGen (50%)	ExGen	N/A	PJM	Northeast	1974	1,125.4[7]

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
ExGen	ER00-3251	Pennsbury 1	ExGen	ExGen	N/A	PJM	Northeast	1996	2.67
ExGen	ER00-3251	Pennsbury 2	ExGen	ExGen	N/A	PJM	Northeast	1996	2.67
ExGen	ER00-3251	Quad Cities 1	ExGen (75%)	ExGen	N/A	PJM	Northeast	1972	908[7]
ExGen	ER00-3251	Quad Cities 2	ExGen (75%)	ExGen	N/A	PJM	Northeast	1972	911[7]
ExGen	ER00-3251	Richmond 91	ExGen	ExGen	N/A	PJM	Northeast	1973	49
ExGen	ER00-3251	Richmond 92	ExGen	ExGen	N/A	PJM	Northeast	1973	49
ExGen	ER00-3251	Salem 1	ExGen (42.59%)	PSEG	N/A	PJM	Northeast	1977	1,174[7]
ExGen	ER00-3251	Salem 2	ExGen (42.59%)	PSEG	N/A	PJM	Northeast	1981	1,158[7]
ExGen	ER00-3251	Salem 3	ExGen (42.59%)	PSEG	N/A	PJM	Northeast	1971	37.57[7]
ExGen	ER00-3251	Schuylkill 10	ExGen	ExGen	N/A	PJM	Northeast	1969	13
ExGen	ER00-3251	Schuylkill 11	ExGen	ExGen	N/A	PJM	Northeast	1971	17
ExGen	ER00-3251	Southeast Chicago Energy Project 5	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 6	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 7	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 8	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 9	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 10	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 11	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southeast Chicago Energy Project 12	ExGen	ExGen	N/A	PJM	Northeast	2002	37
ExGen	ER00-3251	Southwark 3	ExGen	ExGen	N/A	PJM	Northeast	1967	13
ExGen	ER00-3251	Southwark 4	ExGen	ExGen	N/A	PJM	Northeast	1967	13

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
ExGen	ER00-3251	Southwark 5	ExGen	ExGen	N/A	PJM	Northeast	1967	13
ExGen	ER00-3251	Southwark 6	ExGen	ExGen	N/A	PJM	Northeast	1968	13
ExGen	ER00-3251	TMI # 1	ExGen	ExGen	N/A	PJM	Northeast	1974	805
Handsome Lake Energy, LLC ("Handsome Lake")	ER01-556	Handsome Lake 3-5	Handsome Lake	Handsome Lake	N/A	PJM	Northeast	2001	160.5
Handsome Lake	ER01-556	Handsome Lake 1-2	Handsome Lake	Handsome Lake	N/A	PJM	Northeast	2001	107
RS II	N/A[8]	Residential Solar	RS II	RS II	N/A	PJM	Northeast	N/A	3.56
Safe Harbor Water Power Corporation ("Safe Harbor")	ER08-537	Safe Harbor - 10	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1985	38.5
Safe Harbor	ER08-537	Safe Harbor - 11	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1986	38[7]
Safe Harbor	ER08-537	Safe Harbor - 12	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1985	38.5[7]
Safe Harbor	ER08-537	Safe Harbor - 2	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1934	32[7]
Safe Harbor	ER08-537	Safe Harbor - 7	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1933	32.5[7]
Safe Harbor	ER08-537	Safe Harbor - 8	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1985	37.5[7]
Safe Harbor	ER08-537	Safe Harbor - 9	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1986	38.5[7]
Safe Harbor	ER08-537	Safe Harbor 3-4	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1931	64.5[7]
Safe Harbor	ER08-537	Safe Harbor 5-6	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1932	64.5[7]
Safe Harbor	ER08-537	Safe Harbor - 1	Safe Harbor	Safe Harbor	N/A	PJM	Northeast	1940	32[7]
Denver Airport Solar, LCC	N/A[8]	City & County of Denver at Denver International Airport	Denver Airport Solar, LCC	Denver Airport Solar, LCC	N/A	Public Service Co. of Colorado (Xcel Energy)	Northwest	2011	3.77
Bennett Creek, LLC	N/A[5]	Mountain Home	Bennett Creek, LLC	Bennett Creek, LLC	N/A	Idaho Power	Northwest	2008	21[4]
Cassia Gulch Wind Park LLC	ER10-75	Cassia Gulch	Cassia Gulch Wind Park LLC	Cassia Gulch Wind Park LLC	N/A	Idaho Power	Northwest	2009	18.9[4]
Cassia Wind Farm LLC	N/A[3]	Cassia Wind	Cassia Wind Farm LLC	Cassia Wind Farm LLC	N/A	Idaho Power	Northwest	2009	10.5[4]
High Mesa Energy,	ER12-2528	High Mesa	High Mesa	High Mesa	N/A	Idaho Power	Northwest	2012	40[4]

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
LLC			Energy, LLC	Energy, LLC					
Hot Springs Windfarm, LLC	N/A[5]	Mountain Home	Hot Springs Windfarm, LLC	Hot Springs Windfarm, LLC	N/A	Idaho Power	Northwest	2008	21[4]
Tuana Springs Energy, LLC	ER10-87	Tuana Springs	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	Idaho Power	Northwest	2010	16.8[4]
CER Generation II, LLC	ER08-860	West Valley 1-5	CER Generation-II, LLC	CER Generation-II, LLC	2008	PacifiCorp East	Northwest	2002	200
Big Top, LLC	N/A[3]	Big Top	Big Top, LLC	Big Top, LLC	N/A	PacifiCorp West	Northwest	2009	1.65[4]
Butter Creek Power, LLC	N/A[3]	Butter Creek Power	Butter Creek Power, LLC	Butter Creek Power, LLC	N/A	PacifiCorp West	Northwest	2009	4.95[4]
Sunnyside Cogeneration Assoc.	N/A[5]	Sunnyside Cogen	Sunnyside Cogeneration Assoc.	Sunnyside Cogeneration Assoc.	N/A	PacifiCorp West	Northwest	1993	51
Four Corners Windfarm, LLC	N/A[3]	Four Corners Windfarm	Four Corners Windfarm, LLC	Four Corners Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	10[4]
Four Mile Canyon Windfarm, LLC	N/A [3]	Four Mile Canyon Windfarm	Four Mile Canyon Windfarm, LLC	Four Mile Canyon Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	10[4]
Oregon Trail Windfarm, LLC	N/A[3]	Oregon Trail Windfarm	Oregon Trail Windfarm, LLC	Oregon Trail Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	9.9[4]
Pacific Canyon Windfarm, LLC	N/A [3]	Pacific Canyon Windfarm	Pacific Canyon Windfarm, LLC	Pacific Canyon Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	8.25[4]
Sand Ranch Windfarm, LLC	N/A[3]	Sand Ranch Windfarm	Sand Ranch Windfarm, LLC	Sand Ranch Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	9.9[4]
Threemile Canyon Wind I, LLC	N/A[3]	Threemile Canyon	Threemile Canyon Wind I, LLC	Threemile Canyon Wind I, LLC	N/A	PacifiCorp West	Northwest	2009	9.9[4]
Wagon Trail, LLC	N/A[3]	Wagon Trail	Wagon Trail, LLC	Wagon Trail, LLC	N/A	PacifiCorp West	Northwest	2009	3.3[4]

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
Ward Butte Windfarm, LLC	N/A[3]	Ward Butte Windfarm	Ward Butte Windfarm, LLC	Ward Butte Windfarm, LLC	N/A	PacifiCorp West	Northwest	2009	6.6[4]
Outback Solar, LLC	N/A[3]	Outback Solar	Outback Solar, LLC	Outback Solar, LLC	N/A	Bonneville Power Administration	Northwest	2012	4.8
Cow Branch Wind Power, L.L.C.	ER07-1223	Cow Branch	Cow Branch Wind Power, L.L.C.	Cow Branch Wind Power, L.L.C.	N/A	AEC	Southeast	2008	50.4[4]
CR Clearing, LLC	ER07-1222	Conception	CR Clearing, LLC	CR Clearing, LLC	N/A	AEC	Southeast	2008	50.4[4]
Loess Hills Wind Farm, LLC	N/A[3]	Loess Hills	Loess Hills Wind Farm, LLC	Loess Hills Wind Farm, LLC	N/A	AEC	Southeast	2007	5[4]
Wind Capital Holdings, LLC	ER07-1208	Bluegrass Ridge	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AEC	Southeast	2007	56.7[4]
ExGen	ER00-3251	Tenaska Frontier Generation Station	Tenaska Frontier Partners Ltd	ExGen	N/A	ERCOT/Entergy Services, Inc.	Southeast	2001	860[7]
ExGen	ER97-2261	Sowega 1	Georgia Energy Cooperative ("GEC")	ExGen	2011	Southern Company Services, Inc. ("SOCO")	Southeast	2000	48
ExGen	ER97-2261	Sowega 2	GEC	ExGen	2011	SOCO	Southeast	2000	48
ExGen	ER97-2261	Effingham - 1	Effingham County Power, LLC	Effingham County Power, LLC	2007	SOCO	Southeast	2003	502
ExGen	ER97-2261	Washington 1 & 4	Washington County Power, LLC	Washington County Power, LLC	2007	SOCO	Southeast	N/A	307
ExGen	ER97-2261	Franklin - 1	Southern Power Company	Southern Power Company	2007	SOCO	Southeast	N/A	621
CER Generation, LLC	ER10-662	Hillabee	CER Generation, LLC	CER Generation, LLC	2008	SOCO	Southeast	2010	684

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
ExGen	ER00-325 I	Heard	Tenaska Georgia Partners LP	ExGen	N/A	SOCO	Southeast	2001	945[7]
AV Solar Ranch 1, LLC ("AV Solar")	ER12-2178	Antelope Valley	AV Solar	AV Solar	N/A	California Independent System Operator Corporation ("CAISO")	Southwest	2012	230
Luz Solar Partners IV	N/A[5]	SEGS IV	Luz Solar Partners IV	Luz Solar Partners IV	N/A	CAISO	Southwest	1986	33
Luz Solar Partners IV	N/A[5]	SEGS V	Luz Solar Partners V	Luz Solar Partners V	N/A	CAISO	Southwest	1987	24
Luz Solar Partners IV	N/A[5]	SEGS VI	Luz Solar Partners VI	Luz Solar Partners VI	N/A	CAISO	Southwest	1988	34
Malacha Hydro Limited Partnership	N/A[5]	Malacha (Muck Valley Hydro)	Malacha Hydro Limited Partnership	Malacha Hydro Limited Partnership	N/A	CAISO	Southwest	1988	29.9
Constellation Solar California, LLC	N/A[8]	GSA, PBS, Pacific Service Center at Sacramento, Ca.	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	2008	0.44
Constellation Solar California, LLC	N/A[8]	Kawneer Co., Inc. (Alcoa)	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	2007	0.50
Constellation Solar California, LLC	N/A[8]	General Motors Corp. at Fontana, Ca.	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	2007	0.80
Constellation Solar California, LLC	N/A[8]	Univ of San Francisco at Univ of San Francisco	Constellation Solar California, LLC	Constellation Solar California, LLC	N/A	CAISO	Southwest	2008	0.42
Sacramento PV Energy, LLC ("Sacramento PV Energy")	N/A[3]	Sacramento Municipal Utility District at Fleshman	Sacramento PV Energy	Sacramento PV Energy	N/A	CAISO	Southwest	2011	3.08
Sacramento PV	N/A[3]	Sacramento Municipal	Sacramento PV	Sacramento PV	N/A	CAISO	Southwest	2011	18.5

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						Balancing Authority Area[2]	Geographic Region (per App. D)		
Energy		Utility District at Grundman	Energy	Energy					
Sacramento PV Energy	N/A[3]	Sacramento Municipal Utility District at Lawrence	Sacramento PV Energy	Sacramento PV Energy	N/A	CAISO	Southwest	2011	1.03
Sacramento PV Energy	N/A[3]	Sacramento Municipal Utility District at VanConnet	Sacramento PV Energy	Sacramento PV Energy	N/A	CAISO	Southwest	2011	3.08
California PV Energy, LLC ("CAPV")	N/A[8]	California PV Energy	CAPV	CAPV	N/A	CAISO	Southwest	N/A	3.3
Constellation Solar Arizona, LLC ("CSAZ")	N/A[8]	Buckeye Union High School District 201	CSAZ	CSAZ	N/A	AZPS	Southwest	2011	3.62
CSAZ	N/A[8]	Casa Grande at Casa Verde High School	CSAZ	CSAZ	N/A	AZPS	Southwest	2012	0.35
CSAZ	N/A[8]	Casa Grande at Union High School	CSAZ	CSAZ	N/A	AZPS	Southwest	2012	1.79
CSAZ	N/A[8]	Casa Grande at Vista Grande High School	CSAZ	CSAZ	N/A	AZPS	Southwest	2012	1.54
CSAZ	N/A[8]	Miami School District	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.36
CSAZ	N/A[8]	Somerton School District at Orange Grove	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.18
CSAZ	N/A[8]	Somerton School District at Tierra del Sol	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.23
CSAZ	N/A[8]	Somerton School District at Valle del Encanto	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.17
CSAZ	N/A[8]	Somerton School District at Desert Sonora	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.29

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
CSAZ	N/A[8]	Somerton School District at Somerton Middle School	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.47
CSAZ	N/A[8]	Vail School District at Andrada Polytechnic High School	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.33
CSAZ	N/A[8]	Vail School District at Mesquite Elementary School	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.23
CSAZ	N/A[8]	Vail School District at Old Vail Middle School	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.25
CSAZ	N/A[8]	Dysart School District	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	8.8
CSAZ	N/A[8]	Marana School District	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	3.18
CSAZ	N/A[8]	Peoria School District	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	5.05
CSAZ	N/A[8]	Crane School District at Mesquite	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.17
CSAZ	N/A[8]	Crane School District at Gary A. Knox	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.19
CSAZ	N/A[8]	Crane School District at Centennial	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.38
CSAZ	N/A[8]	Crane School District at Valley Horizon	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.27
CSAZ	N/A[8]	Crane School District at Crane	CSAZ	CSAZ	N/A	AZPS	Southwest	2013	0.38
ExGen	ER00-3251	Green Country 1-3	Green Country OP Services LLC	ExGen	N/A	Central and Southwest	Southwest Power Pool ("SPP")	2002	785[6]

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
Exelon Wind 1, LLC	N/A[3]	Exelon Wind 1	Exelon Wind 1, LLC	Exelon Wind 1, LLC	N/A	Xcel/ Southwestern Public Service Co. ("SPS")	SPP	2005	10[4]
Exelon Wind 10, LLC	N/A[3]	Exelon Wind 10	Exelon Wind 10, LLC	Exelon Wind 10, LLC	N/A	SPS	SPP	2008	10[4]
Exelon Wind 11, LLC	N/A[3]	Exelon Wind 11	Exelon Wind 11, LLC	Exelon Wind 11, LLC	N/A	SPS	SPP	2008	10[4]
Exelon Wind 2, LLC	N/A[3]	Exelon Wind 2	Exelon Wind 2, LLC	Exelon Wind 2, LLC	N/A	SPS	SPP	2005	10[4]
Exelon Wind 3, LLC	N/A[3]	Exelon Wind 3	Exelon Wind 3, LLC	Exelon Wind 3, LLC	N/A	SPS	SPP	2005	10[4]
Exelon Wind 4, LLC	ER07-1202	Exelon Wind 4	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPS	SPP	2007	79.8[4]
Exelon Wind 5, LLC	N/A[3]	Exelon Wind 5	Exelon Wind 5, LLC	Exelon Wind 5, LLC	N/A	SPS	SPP	2006	10[4]
Exelon Wind 6, LLC	N/A[3]	Exelon Wind 6	Exelon Wind 6, LLC	Exelon Wind 6, LLC	N/A	SPS	SPP	2006	10[4]
Exelon Wind 7, LLC	N/A[3]	Exelon Wind 7	Exelon Wind 7, LLC	Exelon Wind 7, LLC	N/A	SPS	SPP	2008	10[4]
Exelon Wind 8, LLC	N/A[3]	Exelon Wind 8	Exelon Wind 8, LLC	Exelon Wind 8, LLC	N/A	SPS	SPP	2008	10[4]
Exelon Wind 9, LLC	N/A[3]	Exelon Wind 9	Exelon Wind 9, LLC	Exelon Wind 9, LLC	N/A	SPS	SPP	2008	10[4]
High Plains Wind Power, LLC	N/A[3]	High Plains	High Plains Wind Power, LLC	High Plains Wind Power, LLC	N/A	SPS	SPP	2008	10[4]
Wildcat Wind, LLC	ER12-1223	Wildcat Wind	Wildcat Wind, LLC	Wildcat Wind, LLC	N/A	SPS	SPP	2012	27.3[4]

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Filing Entities and their Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned by	Controlled by	Date Control Transferred or Start of Contract Term	Location		In-service date	Nameplate and/or Seasonal Rating (MW)[1]
						Balancing Authority Area[2]	Geographic Region (per App. D)		
Greensburg Wind Farm, LLC	N/A[3]	Greensburg	Greensburg Wind Farm, LLC	Greensburg Wind Farm, LLC	N/A	Sunflower Electric Power Corp. ("Sunflower")	SPP	2010	12.5[4]
Shooting Star Wind Project, LLC	ER12-1829	Shooting Star	Shooting Star Wind Project, LLC	Shooting Star Wind Project, LLC	N/A	Sunflower	SPP	2012	1044
Baltimore Gas and Electric Company ("BGE")	ER99-2948	N/A	N/A	N/A	NA	N/A	N/A	N/A	NA
Commonwealth Edison Company ("ComEd")	ER98-1734	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Constellation Energy Commodities Group Maine, LLC	ER02-699	N/A	N/A	N/A	NA	N/A	N/A	N/A	NA
Constellation NewEnergy, Inc.	ER96-1387	N/A	N/A	N/A	NA	N/A	N/A	N/A	NA
PECO Energy Company ("PECO")	ER01-1147	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas Storage Facilities

Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
BGE	Combined 115kV Lines	BGE	PJM	1998	PJM	Northeast	695.85 combined miles
BGE	Combined 138kV Lines	BGE	PJM	1998	PJM	Northeast	54.44 combined miles
BGE	Combined 230kV Lines	BGE	PJM	1998	PJM	Northeast	320.97 combined miles
BGE	Combined 500kV Lines	BGE	PJM	1998	PJM	Northeast	217.42 combined miles
ComEd	Electric Transmission Combined 765 kV Lines	ComEd	ComEd/PJM	N/A	PJM	Northeast	89.59 combined miles
ComEd	Electric Transmission Combined 345 kV Lines	ComEd	ComEd/PJM	N/A	PJM	Northeast	2,634.29 combined miles
ComEd	Electric Transmission Combined 138 kV Lines	ComEd	ComEd/PJM	N/A	PJM	Northeast	2,877.02 combined miles
PECO	Electric Transmission 500 kV Lines	PECO	PECO/PJM	N/A	PJM	Northeast	316.23 combined miles
PECO	Electric Transmission Combined 200/220 kV Lines	PECO	PECO/PJM	N/A	PJM	Northeast	503.05 combined miles
PECO	Electric Transmission Combined 132 kV Lines	PECO	PECO/PJM	N/A	PJM	Northeast	127.70 combined miles
PECO	Electric Transmission Combined 66 kV Lines	PECO	PECO/PJM	N/A	PJM	Northeast	169.54 combined miles
PECO	Electric Transmission Combined 13.2 kV	PECO	PECO/PJM	N/A	PJM	Northeast	0.47 combined miles

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Filing Entities and their Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per App. D)	
	Lines						
PECO	Intrastate Gas Transmission	PECO	PECO	N/A	PJM	Northeast	31 combined miles
PECO	Intrastate Gas Storage (LNG)	PECO	PECO	N/A	PJM	Northeast	1,200 mmcf

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1 Unless otherwise indicated, generation capacity ratings (megawatts) are based on the summer seasonal ratings.

2 Facilities solely in the region administered by the Electric Reliability Council of Texas ("ERCOT") are not included herein.

3 MBR authority was not obtained for this entity, because it is a qualifying facility with a capacity of less than 20 MW *(see* 18 C.F.R. § 292.601(c)(1)).

4 The capacity rating for this entity is based on its nameplate capacity.

5 MBR authority was not obtained for this entity, because it is a qualifying facility that sells power pursuant to a PURPA contract or pursuant to a contract executed on or before March 17, 2006 *(see* 18 C.F.R. § 292.601(c)(1)).

6 ExGen has a tolling agreement for 795 MW from Green Country.

7 This generation rating reflects the full plant rating, not just Exelon's ownership share.

8 This row pertains to one or more behind-the-meter facilities that sell entirely at retail and therefore do not participate in the wholesale market.

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ATTACHMENT C

Proposed Protective Order

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

AV Solar Ranch I, LLC	)	**Docket No. ER12-2178-____**
Baltimore Gas and Electric Company	)	**Docket No. ER10-2172-____**
Cassia Gulch Wind Park LLC	)	**Docket No. ER11-2016-____**
CER Generation, LLC	)	**Docket No. ER10-2184-____**
CER Generation II, LLC	)	**Docket No. ER10-2183-____**
Commonwealth Edison Company	)	**Docket No. ER10-1048-____**
Constellation Energy Commodities Group Maine, LLC	)	**Docket No. ER10-2192-____**
Constellation Mystic Power, LLC	)	**Docket No. ER11-2056-____**
Constellation NewEnergy, Inc.	)	**Docket No. ER10-2178-____**
Constellation Power Source Generation, Inc.	)	**Docket No. ER10-2174-____**
Cow Branch Wind Power, L.L.C.	)	**Docket No. ER11-2014-____**
CR Clearing, LLC	)	**Docket No. ER11-2013-____**
Criterion Power Partners, LLC	)	**Docket No. ER10-3308-____**
Exelon Framingham LLC	)	**Docket No. ER10-1020-____**
Exelon Generation Company, LLC	)	**Docket No. ER13-1536-____**
Exelon New Boston, LLC	)	**Docket No. ER10-1078-____**
Exelon West Medway, LLC	)	**Docket No. ER10-1080-____**
Exelon Wind 4, LLC	)	**Docket No. ER11-2010-____**
Exelon Wyman, LLC	)	**Docket No. ER10-1081-____**
Handsome Lake Energy, LLC	)	**Docket No. ER10-2180-____**
Harvest Windfarm, LLC	)	**Docket No. ER11-2011-____**
High Mesa Energy, LLC	)	**Docket No. ER12-2528-____**
Michigan Wind 1, LLC	)	**Docket No. ER11-2009-____**
PECO Energy Company	)	**Docket No. ER10-1143-____**
Tuana Springs Energy, LLC	)	**Docket No. ER11-2007-____**
Wind Capital Holdings, LLC	)	**Docket No. ER11-2005-____**

PROTECTIVE ORDER

(Issued December __, 2013)

1. This Protective Order shall govern the use of all Protected Materials produced by, or on behalf of, any Participant. Notwithstanding any order terminating this proceeding, this Protective Order shall remain in effect until specifically modified or terminated by the Presiding Administrative Law Judge ("Presiding Judge") or the Federal Energy Regulatory Commission ("Commission").

2. This Protective Order applies to the following two categories of materials: (A) A Participant may designate as protected those materials which customarily are treated by that Participant as sensitive or proprietary, which are not available to the public, and

which, if disclosed freely, would subject that Participant or its customers to risk of competitive disadvantage or other business injury; and (B) A Participant shall designate as protected those materials which contain critical energy infrastructure information, as defined in 18 C.F.R. § 388.113(c)(1) ("Critical Energy Infrastructure Information").

3. Definitions -- For purposes of this Order:

(a) The term "Participant" shall mean a Participant as defined in 18 C.F.R. § 385.102(b).

(b)(1) The term "Protected Materials" means (A) materials (including depositions) provided by a Participant in response to discovery requests and/or filed with the Commission and, in each case, designated by such Participant as protected; (B) any information contained in or obtained from such designated materials; (C) any other materials which are made subject to this Protective Order by the Presiding Judge, by the Commission, by any court or other body having appropriate authority, or by agreement of the Participants; (D) notes of Protected Materials; and (E) copies of Protected Materials. The Participant producing the Protected Materials shall physically mark them on each page as "PROTECTED MATERIALS" or with words of similar import as long as the term "Protected Materials" is included in that designation to indicate that they are Protected Materials. If the Protected Materials contain Critical Energy Infrastructure Information, the Participant producing such information shall additionally mark on each page containing such information the words "Contains Critical Energy Infrastructure Information — Do Not Release." In addition if the Protected Materials contain market sensitive information, public disclosure of which the disclosing Participant believes in good faith would competitively harm the Participant, the disclosing Participant shall additionally mark on each page containing such information the words "HIGHLY SENSITIVE PROTECTED MATERIALS." Except for the more limited list of persons who qualify as Reviewing Representatives for purposes of reviewing Highly Sensitive Protected Materials, such materials are subject to the same provisions in the Protective Order as Protected Materials.

(2) The term "Notes of Protected Materials" means memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses materials described in Paragraph 3(b)(1). Notes of Protected Materials are subject to the same restrictions provided in this order for Protected Materials except as specifically provided in this order.

(3) Protected Materials shall not include (A) any information or document contained in the files of the Commission (other than pursuant to this Protective Order), or any other federal or state agency, or any federal or state court, unless the information or document has been determined to be protected by such agency or court, or (B) information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Protective Order, or (C) any information or document labeled as "Non-Internet Public" by a Participant, in accordance with Paragraph 30 of FERC Order No. 630, FERC Stat. & Reg. & 31,140. Protected Materials

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do include any information or document contained in the files of the Commission that has been designated as Critical Energy Infrastructure Information.

(c) The term "Non-Disclosure Certificate" shall mean the certificate annexed hereto by which Participants who have been granted access to Protected Materials shall certify their understanding that such access to Protected Materials is provided pursuant to the terms and restrictions of this Protective Order, and that such Participants have read the Protective Order and agree to be bound by it. All Non-Disclosure Certificates shall be served on all parties on the official service list maintained by the Secretary in this proceeding.

(d) The term "Reviewing Representative" shall mean a person who has signed a Non-Disclosure Certificate (to the extent required by Section 9) and:

(i) For purposes of reviewing Protected Materials (other than Highly Sensitive Protected Materials), who is

(1) Commission Staff ("Staff");

(2) an attorney who has made an appearance in this proceeding for a Participant;

(3) attorneys, paralegals, and other employees associated for purposes of this case with an attorney described in Subparagraph (2);

(4) an expert or an employee of an expert retained by a Participant for the purpose of advising, preparing for or testifying in this proceeding;

(5) a person designated as a Reviewing Representative by order of the Presiding Judge or the Commission; or

(6) employees or other representatives of Participants appearing in this proceeding with significant responsibility for this docket.

(ii) For purposes of reviewing Highly Sensitive Protected Materials, who is:

(1) Staff;

(2) Members or staff of any state or local utilities commission which is a Participant;

(3) An outside attorney who has made an appearance in this proceeding for a Participant;

(4) Attorneys, paralegals, and other employees of the firm of the outside attorney described in Paragraph 3(d)(ii)(3) working with such outside attorney for purposes of this case;

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(5) An outside expert or an employee of an outside expert retained by a Participant for the purpose of advising, preparing for or testifying in this proceeding who is working under the direction of an attorney described in Paragraph 3(d)(ii)(2) or 3(d)(ii)(3);

(6) If, after a good faith effort, parties fail to agree on designating a specifically-named inside employee(s) of a non-governmental Participant as a Reviewing Representative for the review of specific Highly Sensitive Protected Material(s), a party may request that the Presiding Judge so-designate such a specifically-named inside employee(s) who, for example, is not directly involved in, or having direct or supervisory responsibilities over, the purchase, sale, or marketing of electricity (including transmission service) at retail or wholesale, the negotiation or development of participation or cost-sharing arrangements for transmission or generation facilities, or other activities or transactions of a type with respect to which the disclosure of Highly Sensitive Protected Materials may present an unreasonable risk of harm; or

(7) A person designated as a Reviewing Representative by order of the Presiding Judge or the Commission specifically ruling on and indicating each such person by name.

4. Protected Materials shall be made available under the terms of this Protective Order only to Participants and only through their Reviewing Representatives as provided in Paragraphs 7-9.

5. Protected Materials shall remain available to Participants until the later of the date that an order terminating this proceeding becomes no longer subject to judicial review, or the date that any other Commission proceeding relating to the Protected Material is concluded and no longer subject to judicial review. If requested to do so in writing after that date, the Participants shall, within fifteen days of such request, return the Protected Materials (excluding Notes of Protected Materials) to the Participant that produced them, or shall destroy the materials, except that copies of filings, official transcripts and exhibits in this proceeding that contain Protected Materials, and Notes of Protected Material may be retained, if they are maintained in accordance with Paragraph 6, below. Within such time period each Participant, if requested to do so, shall also submit to the producing Participant an affidavit stating that, to the best of its knowledge, all Protected Materials and all Notes of Protected Materials have been returned or have been destroyed or will be maintained in accordance with Paragraph 6. To the extent Protected Materials are not returned or destroyed, they shall remain subject to the Protective Order.

6. All Protected Materials shall be maintained by the Participant in a secure place. Access to those materials shall be limited to those Reviewing Representatives specifically authorized pursuant to Paragraphs 8-9. The Secretary shall place any Protected Materials filed with the Commission in a non-public file. By placing such documents in a non-

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public file, the Commission is not making a determination of any claim of privilege. The Commission retains the right to make determinations regarding any claim of privilege and the discretion to release information necessary to carry out its jurisdictional responsibilities. For documents submitted to Staff, Staff shall follow the notification procedures of 18 C.F.R. § 388.112 before making public any Protected Materials.

7. Protected Materials shall be treated as confidential by each Participant and by the Reviewing Representative in accordance with the certificate executed pursuant to Paragraph 9. Protected Materials shall not be used except as necessary for the conduct of this proceeding, nor shall they be disclosed in any manner to any person except a Reviewing Representative who is engaged in the conduct of this proceeding and who needs to know the information in order to carry out that person's responsibilities in this proceeding. Reviewing Representatives may make copies of Protected Materials, but such copies become Protected Materials. Reviewing Representatives may make notes of Protected Materials, which shall be treated as Notes of Protected Materials if they disclose the contents of Protected Materials.

8. (a) If a Reviewing Representative's scope of employment includes the marketing of energy, the direct supervision of any employee or employees whose duties include the marketing of energy, the provision of consulting services to any person whose duties include the marketing of energy, or the direct supervision of any employee or employees whose duties include the marketing of energy, such Reviewing Representative may not use information contained in any Protected Materials obtained through this proceeding to give any Participant or any competitor of any Participant a commercial advantage.

(b) In the event that a Participant wishes to designate as a Reviewing Representative a person not described in Paragraph 3 (d) above, the Participant shall seek agreement from the Participant providing the Protected Materials. If an agreement is reached that person shall be a Reviewing Representative pursuant to Paragraphs 3(d) above with respect to those materials. If no agreement is reached, the Participant shall submit the disputed designation to the Presiding Judge for resolution.

9. (a) A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Protected Materials pursuant to this Protective Order unless that Reviewing Representative has first executed a Non-Disclosure Certificate; provided, that if an attorney qualified as a Reviewing Representative has executed such a certificate, the paralegals, secretarial and clerical personnel under the attorney's instruction, supervision or control need not do so. A copy of each Non-Disclosure Certificate shall be provided to counsel for the Participant asserting confidentiality prior to disclosure of any Protected Material to that Reviewing Representative. NOTWITHSTANDING THE FOREGOING, A MEMBER OF THE COMMISSION'S ADVISORY STAFF REVIEWING PROTECTED MATERIAL OR HIGHLY SENSITIVE PROTECTED MATERIAL SUBJECT TO THIS AGREEMENT IN CONNECTION WITH ITS REVIEW OF APPLICANT'S MARKET-BASED RATE AUTHORIZATION SHALL NOT BE REQUIRED TO SIGN OR RETURN A NON-DISCLOSURE CERTIFICATE.

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(b) Attorneys qualified as Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this order.

10. Any Reviewing Representative may disclose Protected Materials to any other Reviewing Representative as long as the disclosing Reviewing Representative and the receiving Reviewing Representative both have executed a Non-Disclosure Certificate. In the event that any Reviewing Representative to whom the Protected Materials are disclosed ceases to be engaged in these proceedings, or is employed or retained for a position whose occupant is not qualified to be a Reviewing Representative under Paragraph 3(d), access to Protected Materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Non-Disclosure Certificate shall continue to be bound by the provisions of this Protective Order and the certification.

11. Subject to Paragraph 18, the Presiding Administrative Law Judge shall resolve any disputes arising under this Protective Order. Prior to presenting any dispute under this Protective Order to the Presiding Administrative Law Judge, the parties to the dispute shall use their best efforts to resolve it. Any participant that contests the designation of materials as protected shall notify the party that provided the protected materials by specifying in writing the materials the designation of which is contested. This Protective Order shall automatically cease to apply to such materials five (5) business days after the notification is made unless the designator, within said 5-day period, files a motion with the Presiding Administrative Law Judge, with supporting affidavits, demonstrating that the materials should continue to be protected. In any challenge to the designation of materials as protected, the burden of proof shall be on the participant seeking protection. If the Presiding Administrative Law Judge finds that the materials at issue are not entitled to protection, the procedures of Paragraph 18 shall apply. The procedures described above shall not apply to protected materials designated by a Participant as Critical Energy Infrastructure Information. Materials so designated shall remain protected and subject to the provisions of this Protective Order, unless a Participant requests and obtains a determination from the Commission's Critical Energy Infrastructure Information Coordinator that such materials need not remain protected.

12. All copies of all documents reflecting Protected Materials, including the portion of the hearing testimony, exhibits, transcripts, briefs and other documents which refer to Protected Materials, shall be filed and served in sealed envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Protective Order. Such documents shall be marked “PROTECTED MATERIALS” and shall be filed under seal and served under seal upon the Presiding Judge and all Reviewing Representatives who are on the service list. Such documents containing Critical Energy Infrastructure Information shall be additionally marked “Contains Critical Energy Infrastructure Information — Do Not Release.” For anything filed under seal, redacted versions or, where an entire document is protected, a letter indicating such, will also be filed with the Commission and served on all parties on the service list and the Presiding Judge. Counsel for the producing Participant shall provide to all Participants who request the

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same, a list of Reviewing Representatives who are entitled to receive such material. Counsel shall take all reasonable precautions necessary to assure that Protected Materials are not distributed to unauthorized persons.

13. If any Participant desires to include, utilize or refer to any Protected Materials or information derived therefrom in testimony or exhibits during the hearing in these proceedings in such a manner that might require disclosure of such material to persons other than reviewing representatives, such participant shall first notify both counsel for the disclosing participant and the Presiding Judge of such desire, identifying with particularity each of the Protected Materials. Thereafter, use of such Protected Material will be governed by procedures determined by the Presiding Judge.

14. Nothing in this Protective Order shall be construed as precluding any Participant from objecting to the use of Protected Materials on any legal grounds.

15. Nothing in this Protective Order shall preclude any Participant from requesting the Presiding Judge, the Commission, or any other body having appropriate authority, to find that this Protective Order should not apply to all or any materials previously designated as Protected Materials pursuant to this Protective Order. The Presiding Judge may alter or amend this Protective Order as circumstances warrant at any time during the course of this proceeding.

16. Each party governed by this Protective Order has the right to seek changes in it as appropriate from the Presiding Judge or the Commission.

17. All Protected Materials filed with the Commission, the Presiding Judge, or any other judicial or administrative body, in support of, or as a part of, a motion, other pleading, brief, or other document, shall be filed and served in sealed envelopes or other appropriate containers bearing prominent markings indicating that the contents include Protected Materials subject to this Protective Order. Such documents containing Critical Energy Infrastructure Information shall be additionally marked "Contains Critical Energy Infrastructure Information – Do Not Release."

18. If the Presiding Judge finds at any time in the course of this proceeding that all or part of the Protected Materials need not be protected, those materials shall, nevertheless, be subject to the protection afforded by this Protective Order for three (3) business days from the date of issuance of the Presiding Judge's determination, and if the Participant seeking protection files an interlocutory appeal or requests that the issue be certified to the Commission, for an additional seven (7) business days. None of the Participants waives its rights to seek additional administrative or judicial remedies after the Presiding Judge's decision respecting Protected Materials or Reviewing Representatives, or the Commission's denial of any appeal thereof. The provisions of 18 C.F.R. §§ 388.112 and 388.113 shall apply to any requests under the Freedom of Information Act. (5 U.S.C. ¶ 552) for Protected Materials in the files of the Commission.

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19. Nothing in this Protective Order shall be deemed to preclude any Participant from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced in this proceeding under this Protective Order.

20. None of the Participants waives the right to pursue any other legal or equitable remedies that may be available in the event of actual or anticipated disclosure of Protected Materials.

21. The contents of Protected Materials or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with this Protective Order and shall be used only in connection with this (these) proceeding(s). Any violation of this Protective Order and of any Non-Disclosure Certificate executed hereunder shall constitute a violation of an order of the Commission.

_____

Presiding Administrative Law Judge

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

AV Solar Ranch I, LLC	**)**	**Docket No. ER12-2178-____**
Baltimore Gas and Electric Company	**)**	**Docket No. ER10-2172-____**
Cassia Gulch Wind Park LLC	**)**	**Docket No. ER11-2016-____**
CER Generation, LLC	**)**	**Docket No. ER10-2184-____**
CER Generation II, LLC	**)**	**Docket No. ER10-2183-____**
Commonwealth Edison Company	**)**	**Docket No. ER10-1048-____**
Constellation Energy Commodities Group Maine, LLC	**)**	**Docket No. ER10-2192-____**
Constellation Mystic Power, LLC	**)**	**Docket No. ER11-2056-____**
Constellation NewEnergy, Inc.	**)**	**Docket No. ER10-2178-____**
Constellation Power Source Generation, Inc.	**)**	**Docket No. ER10-2174-____**
Cow Branch Wind Power, L.L.C.	**)**	**Docket No. ER11-2014-____**
CR Clearing, LLC	**)**	**Docket No. ER11-2013-____**
Criterion Power Partners, LLC	**)**	**Docket No. ER10-3308-____**
Exelon Framingham LLC	**)**	**Docket No. ER10-1020-____**
Exelon Generation Company, LLC	**)**	**Docket No. ER13-1536-____**
Exelon New Boston, LLC	**)**	**Docket No. ER10-1078-____**
Exelon West Medway, LLC	**)**	**Docket No. ER10-1080-____**
Exelon Wind 4, LLC	**)**	**Docket No. ER11-2010-____**
Exelon Wyman, LLC	**)**	**Docket No. ER10-1081-____**
Handsome Lake Energy, LLC	**)**	**Docket No. ER10-2180-____**
Harvest Windfarm, LLC	**)**	**Docket No. ER11-2011-____**
High Mesa Energy, LLC	**)**	**Docket No. ER12-2528-____**
Michigan Wind 1, LLC	**)**	**Docket No. ER11-2009-____**
PECO Energy Company	**)**	**Docket No. ER10-1143-____**
Tuana Springs Energy, LLC	**)**	**Docket No. ER11-2007-____**
Wind Capital Holdings, LLC	**)**	**Docket No. ER11-2005-____**

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Protected Materials is provided to me pursuant to the terms and restrictions of the Protective Order in this proceeding, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by it. I understand that the contents of the Protected Materials, any notes or other memoranda, or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with that Protective Order. I acknowledge that a violation of this certificate constitutes a violation of an order of the Federal Energy Regulatory Commission.

By: _____
Title: _____
Representing: _____
Date: _____

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service lists compiled by the Secretary in these proceedings.

Dated at Washington, D.C., this 30th day of December, 2013.

/s/ Caileen N. Gamache

Caileen N. Gamache
White & Case LLP
701 Thirteenth Street, NW
Washington, D.C. 20005
Tel.: (202) 626-3671

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

AV Solar Ranch 1, LLC	**)**	**Docket No. ER12-2178-____**
Baltimore Gas and Electric Company	**)**	**Docket No. ER10-2172-____**
Cassia Gulch Wind Park LLC	**)**	**Docket No. ER11-2016-____**
CER Generation, LLC	**)**	**Docket No. ER10-2184-____**
CER Generation II, LLC	**)**	**Docket No. ER10-2183-____**
Commonwealth Edison Company	**)**	**Docket No. ER10-1048-____**
Constellation Energy Commodities Group Maine, LLC	**)**	**Docket No. ER10-2192-____**
Constellation Mystic Power, LLC	**)**	**Docket No. ER11-2056-____**
Constellation NewEnergy, Inc.	**)**	**Docket No. ER10-2178-____**
Constellation Power Source Generation, Inc.	**)**	**Docket No. ER10-2174-____**
Cow Branch Wind Power, L.L.C.	**)**	**Docket No. ER11-2014-____**
CR Clearing, LLC	**)**	**Docket No. ER11-2013-____**
Criterion Power Partners, LLC	**)**	**Docket No. ER10-3308-____**
Exelon Framingham, LLC	**)**	**Docket No. ER10-1020-____**
Exelon Generation Company, LLC	**)**	**Docket No. ER13-1536-____**
Exelon New Boston, LLC	**)**	**Docket No. ER10-1078-____**
Exelon West Medway, LLC	**)**	**Docket No. ER10-1080-____**
Exelon Wind 4, LLC	**)**	**Docket No. ER11-2010-____**
Exelon Wyman, LLC	**)**	**Docket No. ER10-1081-____**
Handsome Lake Energy, LLC	**)**	**Docket No. ER10-2180-____**
Harvest Windfarm, LLC	**)**	**Docket No. ER11-2011-____**
High Mesa Energy, LLC	**)**	**Docket No. ER12-2528-____**
Michigan Wind 1, LLC	**)**	**Docket No. ER11-2009-____**
PECO Energy Company	**)**	**Docket No. ER10-1143-____**
Tuana Springs Energy, LLC	**)**	**Docket No. ER11-2007-____**
Wind Capital Holdings, LLC	**)**	**Docket No. ER11-2005-____**

WORKPAPERS OF
JULIE R. SOLOMON

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Generation

Wkp-Exelon Generation

UTILITY_ID	UTILITY_NAME	PLANT_CODE	PLANT_NAME	STATE	COUNTY	GENERATOR_ID	PRIME_MOVER	STATUS	NAMEPLATE	SUMMER_CAPABILITY	WINTER_CAPABILITY	UNIT_CODE	OPERATING_MONTH	OPERATING_YEAR	ENERGY_SOURCE_1	ENERGY_SOURCE_2	ENERGY_SOURCE_3
55951	Exelon Nuclear	6022	Braidwood Generation Station	IL	Will	1	ST	OP	1224.9	1178	1208		7	1988	NUC		
55951	Exelon Nuclear	6022	Braidwood Generation Station	IL	Will	2	ST	OP	1224.9	1152	1176		10	1988	NUC		
55951	Exelon Nuclear	6023	Byron Generating Station	IL	Ogle	1	ST	OP	1224.9	1164	1188		9	1985	NUC		
55951	Exelon Nuclear	6023	Byron Generating Station	IL	Ogle	2	ST	OP	1224.9	1136	1158		8	1987	NUC		
2876	Calvert Cliffs Nuclear PP LLC	6011	Calvert Cliffs Nuclear Power Plant	MD	Calvert	1	ST	OP	918	866	872		5	1975	NUC		
2876	Calvert Cliffs Nuclear PP LLC	6011	Calvert Cliffs Nuclear Power Plant	MD	Calvert	2	ST	OP	910.7	850	862		4	1977	NUC		
6035	Exelon Power	3157	Chester Generating Station	PA	Chester	7	GT	OP	18.6	13	18		2	1969	DFO		
6035	Exelon Power	3157	Chester Generating Station	PA	Chester	8	GT	OP	18.6	13	18		5	1969	DFO		
6035	Exelon Power	3157	Chester Generating Station	PA	Chester	9	GT	OP	18.6	13	18		3	1969	DFO		
9379	Inter-Power/AhlCon Partners, L.P.	10143	Colver Power Project	PA	Cambria	COLV	ST	OP	118	110	110		2	1995	WC	PG	
15873	GenOn Northeast Management Company	3118	Conemaugh	PA	Indiana	1	ST	OP	936	850	850		5	1970	BIT		
15873	GenOn Northeast Management Company	3118	Conemaugh	PA	Indiana	2	ST	OP	936	850	850		5	1971	BIT		
15873	GenOn Northeast Management Company	3118	Conemaugh	PA	Indiana	A	IC	SB	3	2.8	2.8		2	1970	DFO		
15873	GenOn Northeast Management Company	3118	Conemaugh	PA	Indiana	B	IC	SB	3	2.8	2.8		2	1970	DFO		
15873	GenOn Northeast Management Company	3118	Conemaugh	PA	Indiana	C	IC	SB	3	2.8	2.8		2	1970	DFO		
15873	GenOn Northeast Management Company	3118	Conemaugh	PA	Indiana	D	IC	SB	3	2.8	2.8		2	1970	DFO		
6035	Exelon Power	1574	Conowingo	MD	Harford	1	HY	OP	45	48	48		3	1928	WAT		
6035	Exelon Power	1574	Conowingo	MD	Harford	10	HY	OP	55.6	65	65		5	1964	WAT		
6035	Exelon Power	1574	Conowingo	MD	Harford	11	HY	OP	55.6	65	65		5	1964	WAT		
6035	Exelon Power	1574	Conowingo	MD	Harford	2	HY	OP	36	36	36		3	1928	WAT		

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Wkp-Exelon Generation

UTILITY_ID	UTILITY_NAME	PLANT_CODE	PLANT_NAME	STATE	COUNTY	GENERATOR_ID	PRIME_MOVER	STATUS	NAMEPLATE	SUMMER_CAPABILITY	WINTER_CAPABILITY	UNIT_CODE	OPERATING_MONTH	OPERATING_YEAR	ENERGY_SOURCE_1	ENERGY_SOURCE_2	ENERGY_SOURCE_3
6035	Exelon Power	1574	Conowingo	MD	Harford	3	HY	OP	48	48	48		3	1928	WAT		
6035	Exelon Power	1574	Conowingo	MD	Harford	4	HY	OP	47.7	48	48		4	1928	WAT		
6035	Exelon Power	1574	Conowingo	MD	Harford	5	HY	OP	36	36	36		6	1928	WAT		
6035	Exelon Power	1574	Conowingo	MD	Harford	6	HY	OP	47.7	48	48		7	1928	WAT		
6035	Exelon Power	1574	Conowingo	MD	Harford	7	HY	OP	48	48	48		6	1928	WAT		
6035	Exelon Power	1574	Conowingo	MD	Harford	8	HY	OP	55.6	65	65		3	1964	WAT		
6035	Exelon Power	1574	Conowingo	MD	Harford	9	HY	OP	55.6	65	65		3	1964	WAT		
56661	Criterion Power Partners LLC	57300	Criterion Wind Project	MD	GARRETT	1	WT	OP	70	70	70		12	2010	WND		
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	11	GT	OP	68.3	49	64		6	1974	DFO		
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	12	GT	OP	68.3	49	64		6	1974	DFO		
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	21	GT	OP	68.3	49	64		6	1974	DFO		
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	22	GT	OP	68.3	49	64		6	1974	DFO		
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	31	GT	OP	68.3	49	64		8	1974	DFO		
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	32	GT	OP	68.3	49	64		8	1974	DFO		
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	41	GT	OP	68.3	49	64		7	1974	DFO		
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	42	GT	OP	68.3	49	64		7	1974	DFO		
6035	Exelon Power	3160	Delaware Generating Station	PA	ia	10	GT	OP	18.6	13	18		5	1969	DFO		
6035	Exelon Power	3160	Delaware Generating Station	PA	ia	11	GT	OP	18.6	13	18		4	1969	DFO		
6035	Exelon Power	3160	Delaware Generating Station	PA	ia	12	GT	OP	18.6	13	18		5	1969	DFO		
6035	Exelon Power	3160	Delaware Generating Station	PA	ia	9	GT	OP	21.2	17	20		7	1970	DFO		
55951	Exelon Nuclear	869	Dresden Generating Station	IL	Grundy	2	ST	OP	1009.3	883	833		8	1970	NUC		
55951	Exelon Nuclear	869	Dresden Generating Station	IL	Grundy	3	ST	OP	1009.3	867	867		10	1971	NUC		
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	10	GT	OP	18.6	13	18		5	1967	DFO		
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	20	GT	OP	18.6	13	18		10	1967	DFO		
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	3	ST	OP	391	380	380		9	1974	RFO	NG	DFO
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	30	GT	OP	21.2	17	20		3	1970	DFO		
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	4	ST	OP	391	380	380		6	1976	RFO	NG	
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	40	GT	OP	21.2	17	20		6	1970	DFO		
6035	Exelon Power	57191	Exelon Solar Chicago	IL	Cook	ECS1	PV	OP	9	9	9		12	2009	SUN		
6035	Exelon Power	7701	Fairless Hills	PA	Bucks	A	ST	OP	30	30	30		12	1996	LFG	NG	DFO
6035	Exelon Power	7701	Fairless Hills	PA	Bucks	B	ST	OP	30	30	30		12	1996	LFG	NG	DFO
6035	Exelon Power	3162	Falls	PA	Bucks	1	GT	OP	21.2	17	20		5	1970	DFO		
6035	Exelon Power	3162	Falls	PA	Bucks	2	GT	OP	21.2	17	20		5	1970	DFO		

Wkp-Exelon Generation

UTILITY_ID	UTILITY_NAME	PLANT_CODE	PLANT_NAME	STATE	COUNTY	GENERATOR_ID	PRIME_MOVER	STATUS	NAMEPLATE	SUMMER_CAPABILITY	WINTER_CAPABILITY	UNIT_CODE	OPERATING_MONTH	OPERATING_YEAR	ENERGY_SOURCE_1	ENERGY_SOURCE_2	ENERGY_SOURCE_3
6035	Exelon Power	3162	Falls	PA	Bucks	3	GT	OP	21.2	17	20		6	1970	DFO		
4161	Source Gen	1553	Gould Street	MD	City	3	ST	OP	103.5	97	97		12	1952	NG		
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT01	GT	OP	58.9	53.5	53.5		8	2001	NG		
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT02	GT	OP	58.9	53.5	53.5		8	2001	NG		
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT03	GT	OP	58.9	53.5	53.5		7	2001	NG		
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT04	GT	OP	58.9	53.5	53.5		7	2001	NG		
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT05	GT	OP	58.9	53.5	53.5		7	2001	NG		
15873	GenOn Northeast Management Company	3136	Keystone	PA	Armstrong	1	ST	OP	936	850	850		8	1967	BIT		
15873	GenOn Northeast Management Company	3136	Keystone	PA	Armstrong	2	ST	OP	936	850	850		7	1968	BIT		
15873	GenOn Northeast Management Company	3136	Keystone	PA	Armstrong	3	IC	OP	3	2.8	2.8		11	1968	DFO		
15873	GenOn Northeast Management Company	3136	Keystone	PA	Armstrong	4	IC	OP	3	2.8	2.8		11	1968	DFO		
15873	GenOn Northeast Management Company	3136	Keystone	PA	Armstrong	5	IC	OP	3	2.8	2.8		11	1968	DFO		
15873	GenOn Northeast Management Company	3136	Keystone	PA	Armstrong	6	IC	OP	3	2.8	2.8		11	1968	DFO		
55951	Exelon Nuclear	6026	LaSalle Generating Station	IL	La Salle	1	ST	OP	1170	1137	1152		1	1984	NUC		
55951	Exelon Nuclear	6026	LaSalle Generating Station	IL	La Salle	2	ST	OP	1170	1140	1161		10	1984	NUC		
55951	Exelon Nuclear	6105	Limerick	PA	ry	1	ST	OP	1138.5	1146	1191		2	1986	NUC		
55951	Exelon Nuclear	6105	Limerick	PA	ry	2	ST	OP	1138.5	1150	1195		1	1990	NUC		
6035	Exelon Power	3163	Moser Generating Station	PA	ry	1	GT	OP	21.2	17	20		6	1970	DFO		
6035	Exelon Power	3163	Moser Generating Station	PA	ry	2	GT	OP	21.2	17	20		5	1970	DFO		
6035	Exelon Power	3163	Moser Generating Station	PA	ry	3	GT	OP	21.2	17	20		6	1970	DFO		

Wkp-Exelon Generation

UTILITY_ID	UTILITY_NAME	PLANT_CODE	PLANT_NAME	STATE	COUNTY	GENERATOR_ID	PRIME_MOVER	STATUS	NAMEPLATE	SUMMER_CAPABILITY	WINTER_CAPABILITY	UNIT_CODE	OPERATING_MONTH	OPERATING_YEAR	ENERGY_SOURCE_1	ENERGY_SOURCE_2	ENERGY_SOURCE_3
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	1	PS	OP	134	134	134		4	1967	WAT		
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	2	PS	OP	134	133	133		4	1967	WAT		
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	3	PS	OP	134	134	134		4	1967	WAT		
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	4	PS	OP	134	134	134		6	1967	WAT		
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	5	PS	OP	134	134	134		10	1967	WAT		
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	6	PS	OP	134	133	133		10	1967	WAT		
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	7	PS	OP	134	134	134		2	1968	WAT		
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	8	PS	OP	134	134	134		2	1968	WAT		
4161	Source Gen	1555	Notch Cliff	MD	Baltimore	GT1	GT	OP	18	14	14		6	1969	NG		
4161	Source Gen	1555	Notch Cliff	MD	Baltimore	GT2	GT	OP	18	14	14		6	1969	NG		
4161	Source Gen	1555	Notch Cliff	MD	Baltimore	GT3	GT	OP	18	14	14		6	1969	NG		
4161	Source Gen	1555	Notch Cliff	MD	Baltimore	GT4	GT	OP	18	14	14		6	1969	NG		
4161	Source Gen	1555	Notch Cliff	MD	Baltimore	GT5	GT	OP	18	14.6	14.6		6	1969	NG		
4161	Source Gen	1555	Notch Cliff	MD	Baltimore	GT6	GT	OP	18	15.6	15.6		6	1969	NG		
4161	Source Gen	1555	Notch Cliff	MD	Baltimore	GT7	GT	OP	18	14.5	14.5		6	1969	NG		
4161	Source Gen	1555	Notch Cliff	MD	Baltimore	GT8	GT	OP	18	16	16		6	1969	NG		
55951	Exelon Nuclear	2388	Oyster Creek	NJ	Ocean	1	ST	OP	550	614.5	637		12	1969	NUC		
14432	Panther Creek Power Operating, LLC	50776	Panther Creek Energy Facility	PA	Carbon	GEN1	ST	OP	94	83	83		7	1992	WC		
55951	Exelon Nuclear	3166	Peach Bottom	PA	York	2	ST	OP	1159.7	1125.2	1148		7	1974	NUC		
55951	Exelon Nuclear	3166	Peach Bottom	PA	York	3	ST	OP	1159.7	1125.4	1148		12	1974	NUC		
6035	Exelon Power	7690	Pennsbury	PA	Bucks	1	GT	OP	3	2.7	2.7		9	1996	LFG		
6035	Exelon Power	7690	Pennsbury	PA	Bucks	2	GT	OP	3	2.7	2.7		9	1996	LFG		
4161	Source Gen	1556	Perryman	MD	Harford	GT1	GT	OP	53.1	52	52		1	1972	DFO		
4161	Source Gen	1556	Perryman	MD	Harford	GT2	GT	OP	53.1	51	51		4	1972	DFO		
4161	Source Gen	1556	Perryman	MD	Harford	GT3	GT	OP	53.1	51	51		4	1972	DFO		
4161	Source Gen	1556	Perryman	MD	Harford	GT4	GT	OP	53.1	52	52		4	1972	DFO		
4161	Source Gen	1556	Perryman	MD	Harford	GT5	GT	OP	192	147.6	147.6		6	1995	NG	DFO	
4161	Source Gen	1557	Philadelphia	MD	City	GT1	GT	OP	20.7	15.3	15.3		8	1970	DFO		
4161	Source Gen	1557	Philadelphia	MD	City	GT2	GT	OP	20.7	16	16		8	1970	DFO		
4161	Source Gen	1557	Philadelphia	MD	City	GT3	GT	OP	20.7	14.8	14.8		9	1970	DFO		
4161	Source Gen	1557	Philadelphia	MD	City	GT4	GT	OP	20.7	14.8	14.8		9	1970	DFO		
55951	Exelon Nuclear	880	Quad Cities Generating Station	IL	Island	1	ST	OP	1009.3	908	908		12	1972	NUC		
55951	Exelon Nuclear	880	Quad Cities Generating Station	IL	Island	2	ST	OP	1009.3	911	911		12	1972	NUC		

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Wkp-Exelon Generation

UTILITY_ID	UTILITY_NAME	PLANT_CODE	PLANT_NAME	STATE	COUNTY	GENERATOR_ID	PRIME_MOVER	STATUS	NAMEPLATE	SUMMER_CAPABILITY	WINTER_CAPABILITY	UNIT_CODE	OPERATING_MONTH	OPERATING_YEAR	ENERGY_SOURCE_1	ENERGY_SOURCE_2	ENERGY_SOURCE_3
6035	Exelon Power	3168	Richmond Generating Station	PA	ia	91	GT	OP	65.8	49	66		6	1973	DFO		
6035	Exelon Power	3168	Richmond Generating Station	PA	ia	92	GT	OP	65.8	49	66		6	1973	DFO		
4161	Source Gen	1559	Riverside	MD	Baltimore	4	ST	OP	72.2	74	74		9	1951	NG		
4161	Source Gen	1559	Riverside	MD	Baltimore	GT6	GT	OP	135	115	115		4	1970	NG	KER	
4161	Source Gen	1559	Riverside	MD	Baltimore	GT7	GT	OP	25	19	19		9	1970	DFO		
4161	Source Gen	1559	Riverside	MD	Baltimore	GT8	GT	OP	25	20	20		9	1970	DFO		
16537	Safe Harbor Water Power Corp	3175	Safe Harbor	PA	Lancaster	1	HY	OP	33	33	33		10	1940	WAT		
16537	Safe Harbor Water Power Corp	3175	Safe Harbor	PA	Lancaster	10	HY	OP	37.5	37.5	37.5		6	1985	WAT		
16537	Safe Harbor Water Power Corp	3175	Safe Harbor	PA	Lancaster	11	HY	OP	37.5	37.5	37.5		4	1986	WAT		
16537	Safe Harbor Water Power Corp	3175	Safe Harbor	PA	Lancaster	12	HY	OP	37.5	37.5	37.5		9	1985	WAT		
16537	Safe Harbor Water Power Corp	3175	Safe Harbor	PA	Lancaster	2	HY	OP	33	33	33		11	1934	WAT		
16537	Safe Harbor Water Power Corp	3175	Safe Harbor	PA	Lancaster	3	HY	OP	32	32	32		12	1931	WAT		
16537	Safe Harbor Water Power Corp	3175	Safe Harbor	PA	Lancaster	4	HY	OP	32	32	32		12	1931	WAT		
16537	Safe Harbor Water Power Corp	3175	Safe Harbor	PA	Lancaster	41	HY	OP	2	2	2		12	1931	WAT		
16537	Safe Harbor Water Power Corp	3175	Safe Harbor	PA	Lancaster	42	HY	OP	2	2	2		12	1931	WAT		
16537	Safe Harbor Water Power Corp	3175	Safe Harbor	PA	Lancaster	5	HY	OP	32	32	32		1	1932	WAT		
16537	Safe Harbor Water Power Corp	3175	Safe Harbor	PA	Lancaster	6	HY	OP	32	32	32		1	1932	WAT		
16537	Safe Harbor Water Power Corp	3175	Safe Harbor	PA	Lancaster	7	HY	OP	32	32	32		10	1933	WAT		
16537	Safe Harbor Water Power Corp	3175	Safe Harbor	PA	Lancaster	8	HY	OP	37.5	37.5	37.5		4	1985	WAT		
16537	Safe Harbor Water Power Corp	3175	Safe Harbor	PA	Lancaster	9	HY	OP	37.5	37.5	37.5		2	1986	WAT		
15478	PSEG Nuclear LLC	2410	PSEG Salem Generating Station	NJ	Salem	1	ST	OP	1170	1167.9	1194.2		6	1977	NUC		

Wkp-Exelon Generation

UTILITY_ID	UTILITY_NAME	PLANT_CODE	PLANT_NAME	STATE	COUNTY	GENERATOR_ID	PRIME_MOVER	STATUS	NAMEPLATE	SUMMER_CAPABILITY	WINTER_CAPABILITY	UNIT_CODE	OPERATING_MONTH	OPERATING_YEAR	ENERGY_SOURCE_1	ENERGY_SOURCE_2	ENERGY_SOURCE_3
15478	PSEG Nuclear LLC	2410	PSEG Salem Generating Station	NJ	Salem	2	ST	OP	1170	1158.1	1193.6		10	1981	NUC		
15478	PSEG Nuclear LLC	2410	PSEG Salem Generating Station	NJ	Salem	3	GT	OP	41.8	39.7	51.5		6	1971	DFO		
6035	Exelon Power	3169	Schuylkill Generating Station	PA	ia	10	GT	OP	18.6	13	18		5	1969	DFO		
6035	Exelon Power	3169	Schuylkill Generating Station	PA	ia	11	GT	OP	21.2	17	20		6	1971	DFO		
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT05	GT	OP	50.9	37	40		6	2002	NG		
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT06	GT	OP	50.9	37	40		6	2002	NG		
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT07	GT	OP	50.9	37	40		6	2002	NG		
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT08	GT	OP	50.9	37	40		6	2002	NG		
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT09	GT	OP	50.9	37	40		6	2002	NG		
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT10	GT	OP	50.9	37	40		6	2002	NG		
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT11	GT	OP	50.9	37	40		6	2002	NG		
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT12	GT	OP	50.9	37	40		6	2002	NG		
6035	Exelon Power	3170	Southwark	PA	ia	3	GT	OP	18.6	13	18		6	1967	DFO		
6035	Exelon Power	3170	Southwark	PA	ia	4	GT	OP	18.6	13	18		10	1967	DFO		
6035	Exelon Power	3170	Southwark	PA	ia	5	GT	OP	18.6	13	18		7	1967	DFO		
6035	Exelon Power	3170	Southwark	PA	ia	6	GT	OP	18.6	13	18		11	1968	DFO		
57044	Jersey, LLC	57746	The City of Vineland at North Vineland	NJ	nd	PV1	PV	OP	2.3	2.3	2.3		10	2011	SUN		
57044	Jersey, LLC	57745	The City of Vineland at West Vineland	NJ	nd	PV1	PV	OP	3.7	3.7	3.7		10	2011	SUN		
55951	Exelon Nuclear	8011	Three Mile Island	PA	Dauphin	1	ST	OP	975.6	805	829		8	1974	NUC		
4161	Source Gen	1560	Westport	MD	City	GT5	GT	OP	121.5	115.8	115.8		2	1969	NG		
57311	Federal LLC	58029	Constellation New Energy Inc	NJ	Burlington	PV1	PV	OP	3.9	3.9	3.9		12	2011	SUN		
57044	Jersey, LLC	57733	Benjamin Moore & Co. Solar	NJ	Flanders	PV1	PV	OP	1.4	1.4	1.4		12	2010	SUN		
56976	Jersey II, LLC	57723	Johnson Matthey, Inc. Solar	NJ	r	PV1	PV	OP	4	4	4		3	2011	SUN		
56975	Maryland, LLC	57646	McCormick & Co. Inc. at Belcamp	MD	Hartford	PV1	PV	OP	1.4	1.4	1.4		12	2010	SUN		
57065	Horizons LLC	57758	Mount Saint Mary's	MD	Frederick	PV1	PV	OP	13.7	13.7	13.7		7	2012	SUN		
56976	Jersey II, LLC	57647	Toys R Us- DE, Inc. at Mt. Olive, NJ	NJ	Flanders	PV1	PV	OP	2.4	2.4	2.4		12	2011	SUN		
56608	Calpine Mid-Merit LLC	55524	York Energy Center	PA	York	CTG1	CT	OP	120	113	113		3	2011	NG	DFO	
56608	Calpine Mid-Merit LLC	55524	York Energy Center	PA	York	CTG2	CT	OP	120	122	122		3	2011	NG	DFO	

Wkp-Exelon Generation

UTILITY_ID	UTILITY_NAME	PLANT_CODE	PLANT_NAME	STATE	COUNTY	GENERATOR_ID	PRIME_MOVER	STATUS	NAMEPLATE	SUMMER_CAPABILITY	WINTER_CAPABILITY	UNIT_CODE	OPERATING_MONTH	OPERATING_YEAR	ENERGY_SOURCE_1	ENERGY_SOURCE_2	ENERGY_SOURCE_3
56608	Calpine Mid-Merit LLC	55524	York Energy Center	PA	York	CTG3	CT	OP	120	122	122		3	2011	NG	DFO	
56608	Calpine Mid-Merit LLC	55524	York Energy Center	PA	York	STG1	CA	OP	200	188	188		3	2011	NG	DFO	
4210	Cordova Energy Co LLC	55188	Cordova Energy	IL	Rock Island	PT11	CT	OP	210	165	205		6	2001	NG		
4210	Cordova Energy Co LLC	55188	Cordova Energy	IL	Rock Island	PT21	CT	OP	210	165	205		6	2001	NG		
4210	Cordova Energy Co LLC	55188	Cordova Energy	IL	Island	PT31	CA	OP	191.2	191.2	191.2		6	2001	NG		
5259	Dominion Elwood Services Co	55199	Elwood Energy LLC	IL	Will	GT5	GT	OP	192	150	192		7	2001	NG		
5259	Dominion Elwood Services Co	55199	Elwood Energy LLC	IL	Will	GT6	GT	OP	192	150	192		7	2001	NG		
5259	Dominion Elwood Services Co	55199	Elwood Energy LLC	IL	Will	GT7	GT	OP	192	150	192		8	2001	NG		
5259	Dominion Elwood Services Co	55199	Elwood Energy LLC	IL	Will	GT8	GT	OP	192	150	192		8	2001	NG		
50100	R.E. Ginna Nuclear Power Plant, LLC	6122	R E Ginna Nuclear Power Plant	NY	Wayne	1	ST	OP	614	580.8	582.1		7	1970	NUC		
13606	Nine Mile Point Nuclear Sta LLC	2589	Nine Mile Point Nuclear Station	NY	Oswego	1	ST	OP	641.8	629.7	630		12	1969	NUC		
13606	Nine Mile Point Nuclear Sta LLC	2589	Nine Mile Point Nuclear Station	NY	Oswego	2	ST	OP	1259.3	1143.5	1155		7	1987	NUC		
NYISO Gold Book																	
			Nine Mile Point Nuclear Station, LLC	Nine Mile Pt	C					629.7	630.0						
			Nine Mile Point Nuclear Station, LLC	Nine Mile Pt	C					1,143.5	1,155.0						
			R.E. Ginna Nuclear Power Plant, LLC	Ginna	B					580.8	582.2						
57318	Metering LLC	57941	Town of Uxbridge MA at Commerce Dr	MA	Worcester	PV1	PV	OP	1.8	1.8	1.8		6	2012	SUN		
57319	Massachusetts LLC	57942	Town of Norfolk MA at Medway Branch	MA	Norfolk	PV1	PV	OP	1.2	1.2	1.2		6	2012	SUN		
6035	Exelon Power	1586	Exelon Framingham LLC	MA	Norfolk	GT1	GT	OP	14.2	10.2	14.2		3	1970	DFO		
6035	Exelon Power	1586	Exelon Framingham LLC	MA	Norfolk	GT2	GT	OP	14.2	9.9	13.9		9	1969	DFO		
6035	Exelon Power	1586	Exelon Framingham LLC	MA	Norfolk	GT3	GT	OP	14.2	11.3	15.3		9	1969	DFO		
6035	Exelon Power	1587	Exelon L Street	MA	Suffolk	GT1	GT	OP	18.6	16	21.8		9	1966	DFO		
6035	Exelon Power	1592	Exelon Medway LLC	MA	Nolfork	GT1	GT	OP	45	42	64		7	1970	DFO		

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UTILITY_ID	UTILITY_NAME	PLANT_CODE	PLANT_NAME	STATE	COUNTY	GENERATOR_ID	PRIME_MOVER	STATUS	NAMEPLATE	SUMMER_CAPABILITY	WINTER_CAPABILITY	UNIT_CODE	OPERATING_MONTH	OPERATING_YEAR	ENERGY_SOURCE_1	ENERGY_SOURCE_2	ENERGY_SOURCE_3
6035	Exelon Power	1592	Exelon Medway LLC	MA	Nolfork	GT2	GT	OP	45	39.8	61.6		3	1971	DFO		
6035	Exelon Power	1592	Exelon Medway LLC	MA	Nolfork	GT3	GT	OP	45	35.4	55.8		7	1970	DFO		
49965	Power LLC	1588	Mystic Generating Station	MA	Middlesex	7	ST	OP	617	560.5	559.8		6	1975	NG	RFO	
49965	Power LLC	1588	Mystic Generating Station	MA	Middlesex	GT1	GT	SB	14.2	7.7	11.8		6	1969	DFO		
49965	Power LLC	1588	Mystic Generating Station	MA	Middlesex	GT81	CT	OP	278.6	224.6	268.7	G941	4	2003	NG		
49965	Power LLC	1588	Mystic Generating Station	MA	Middlesex	GT82	CT	OP	278.6	226.7	271.3		4	2003	NG		
49965	Power LLC	1588	Mystic Generating Station	MA	Middlesex	GT93	CT	OP	278.6	227.7	275.8		6	2003	NG		
49965	Power LLC	1588	Mystic Generating Station	MA	Middlesex	GT94	CT	OP	278.6	227.4	275.5		6	2003	NG		
49965	Power LLC	1588	Mystic Generating Station	MA	Middlesex	ST85	CA	OP	315	252.3	301.6		4	2003	NG		
49965	Power LLC	1588	Mystic Generating Station	MA	Middlesex	ST96	CA	OP	315	248.3	300.8		6	2003	NG		
49965	Power LLC	55317	Fore River Generating Station	MA	Norfolk	GT11	CT	OP	278.6	223.9	272.1	G942	8	2003	NG		
49965	Power LLC	55317	Fore River Generating Station	MA	Norfolk	GT12	CT	OP	278.6	225.1	273.6	G942	8	2003	NG		
49965	Power LLC	55317	Fore River Generating Station	MA	Norfolk	ST15	CA	OP	315	239.4	290.9	G942	8	2003	NG		
ISO-NE CELT																	

				PRIM FUEL TYPE	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER			As of 2011/12 Winter and 2012 Summer Peaks: EXPECTED SUMMER PEAK SCC AUG 1, 2012	As of 2011/12 Winter and 2012 Summer Peaks: WINTER PEAK SCC JAN 4, 2012
			FRAMINGHAM JET 1	DFO	BOSTON	NEMA	1586			10.145	14.175
			FRAMINGHAM JET 2	DFO	BOSTON	NEMA	1586			9.914	13.914
			FRAMINGHAM JET 3	DFO	BOSTON	NEMA	1586			11.250	15.250
			L STREET JET	DFO	BOSTON	NEMA	1587			16.030	21.770
			MYSTIC 7	NG	BOSTON	NEMA	1588			560.469	559.775
			MYSTIC JET	DFO	BOSTON	NEMA	1588			8.589	12.739
			YARMOUTH 4	RFO	SME	ME	1507			603.225	610.375
			MYSTIC 8	NG	BOSTON	NEMA	1588			703.324	841.564
			MYSTIC 9	NG	BOSTON	NEMA	1588			695.190	843.950
			FORE RIVER-1	NG	SEMA	SEMA	55317			688.297	836.632
			KLEEN ENERGY	NG	CT	CT	56798			620.000	620.000
			WEST MEDWAY JET 1	DFO	BOSTON	NEMA				30.762	55.012
			WEST MEDWAY JET 2	DFO	BOSTON	NEMA				34.732	52.932
			WEST MEDWAY JET 3	DFO	RI	SEMA				35.441	55.841

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UTILITY_ID	UTILITY_NAME	PLANT_CODE	PLANT_NAME	STATE	COUNTY	GENERATOR_ID	PRIME_MOVER	STATUS	NAMEPLATE	SUMMER_CAPABILITY	WINTER_CAPABILITY	UNIT_CODE	OPERATING_MONTH	OPERATING_YEAR	ENERGY_SOURCE_1	ENERGY_SOURCE_2	ENERGY_SOURCE_3
			GRANITE RIDGE ENERGY	CC	NG	NH	NH			799.322	661.322						
55951	Exelon Nuclear	204	Clinton Power Station	IL	De Witt	1	ST	OP	1138.3	1065	1078		11	1987	NUC		
54789	AgriWind LLC	56408	Agriwind LLC	IL	BUREAU	AWND1	WT	OP	8.4	8.4	8.4		7	2007	WND		
57397	Beebe Renewable Energy LLC	58020	Beebe Renewable Energy LLC	MI	Gratiot	1	WT	OP	81.6	81.6	81.6		12	2012	WND		
56800	Brewster	56210	B&K Energy Systems LLC	MN	Jackson	1	WT	OP	2	2	2		12	2003	WND		
57158	Ewington Wind Project	56624	BC Energy LLC	MN	Jackson	1	WT	OP	4	4	4		1	2008	WND		
56807	Moore 1	56580	Blue Breezes LLC	MN	Faribault	1	WT	OP	1.3	1.3	1.3		5	2006	WND		
56807	Moore 1	56581	Blue Breezes II LLC	MN	Faribault	1	WT	OP	1.3	1.3	1.3		5	2006	WND		
56808	Norgard 1	56595	Breezy Bucks I LLC	MN	Lincoln	1	WT	OP	1.3	1.3	1.3		5	2006	WND		
56808	Norgard 1	56582	Breezy Bucks II LLC	MN	Lincoln	1	WT	OP	1.3	1.3	1.3		5	2006	WND		
56801	Cisco	56709	Christoffer Wind Energy I LLC	MN	Jackson	1	WT	OP	2.1	2.1	2.1		2	2008	WND		
56801	Cisco	56710	Christoffer Wind Energy II LLC	MN	Jackson	1	WT	OP	2.1	2.1	2.1		2	2008	WND		
56801	Cisco	56711	Christoffer Wind Energy III LLC	MN	Jackson	1	WT	OP	2.1	2.1	2.1		2	2008	WND		
56801	Cisco	56712	Christoffer Wind Energy IV LLC	MN	Jackson	1	WT	OP	2.1	2.1	2.1		2	2008	WND		
56800	Brewster	56207	DL Windy Acres LLC	MN	Jackson	1	WT	OP	2	2	2		12	2003	WND		
57157	Wolf Wind Project	56588	G Flow Wind LLC	MN	Nobles	1	WT	OP	1.3	1.3	1.3		5	2006	WND		
57157	Wolf Wind Project	56590	Green Acres Breeze LLC	MN	Nobles	1	WT	OP	1.3	1.3	1.3		5	2006	WND		
57158	Ewington Wind Project	56625	KC Energy LLC	MN	Jackson	1	WT	OP	4	4	4		1	2008	WND		

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Wkp-Exelon Generation

UTILITY_ID	UTILITY_NAME	PLANT_CODE	PLANT_NAME	STATE	COUNTY	GENERATOR_ID	PRIME_MOVER	STATUS	NAMEPLATE	SUMMER_CAPABILITY	WINTER_CAPABILITY	UNIT_CODE	OPERATING_MONTH	OPERATING_YEAR	ENERGY_SOURCE_1	ENERGY_SOURCE_2	ENERGY_SOURCE_3
57158	Ewington Wind Project	56626	K&D Energy LLC	MN	Jackson	1	WT	OP	4	4	4		1	2008	WND		
57158	Ewington Wind Project	56627	KSS Turbines LLC	MN	Jackson	1	WT	OP	4	4	4		1	2008	WND		
55873	Harvest I	56635	Harvest Windfarm LLC	MI	Huron	1	WT	OP	52.8	52.8	52.8		1	2008	WND		
57256	Harvest II Windfarm LLC	57888	Harvest II Windfarm	MI	Huron	1	WT	OP	59.4	59.4	59.4		11	2012	WND		
54800	Michigan Wind 1 LLC	56416	Michigan Wind 1 LLC	MI	Huron	1	WT	OP	69	69	69		12	2008	WND		
56951	Michigan Wind 2 LLC	56659	Michigan Wind 2	MI	Sanilac	1	WT	OP	90	90	90		12	2011	WND		
57157	Wolf Wind Project	56587	Minnesota Breeze LLC	MN	Nobles	1	WT	OP	1.3	1.3	1.3		5	2006	WND		
56805	Exelon Wind LLC	56628	Prairie Wind Power LLC	MN	Jackson	1	WT	OP	4	4	4		1	2008	WND		
56808	Norgard 1	56578	Roadrunner I LLC	MN	Lincoln	1	WT	OP	1.3	1.3	1.3		5	2006	WND		
56808	Norgard 1	56583	Salty Dog I LLC	MN	Lincoln	1	WT	OP	1.3	1.3	1.3		5	2006	WND		
56808	Norgard 1	56584	Salty Dog II LLC	MN	Lincoln	1	WT	OP	1.3	1.3	1.3		5	2006	WND		
56800	Brewster	56208	S&P Windfarm LLC	MN	Jackson	1	WT	OP	2	2	2		12	2003	WND		
55832	Cowell	56577	Shane's Wind Machine	MN	Pipestone	1	WT	OP	1.3	1.3	1.3		7	2006	WND		
57157	Wolf Wind Project	56586	Sunset Breeze LLC	MN	Nobles	1	WT	OP	1.3	1.3	1.3		5	2006	WND		
56808	Norgard 1	56585	Wallys Wind Farm LLC	MN	LINCOLN	1	WT	OP	1.3	1.3	1.3		5	2006	WND		
56808	Norgard 1	56579	Windy Dog I LLC	MN	Lincoln	1	WT	OP	1.3	1.3	1.3		5	2006	WND		
57157	Wolf Wind Project	56589	Wolf Wind Enterprises LLC	MN	Nobles	1	WT	OP	1.3	1.3	1.3		5	2006	WND		

Retirements

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UTILITY_ID	UTILITY_NAME	PLANT_CODE	PLANT_NAME	STATE	COUNTY	GENERATOR_ID	PRIME_MOVER	STATUS	NAMEPLATE	SUMMER_CAPABILITY	WINTER_CAPABILITY	UNIT_CODE	OPERATING_MONTH	OPERATING_YEAR	ENERGY_SOURCE_1	ENERGY_SOURCE_2	ENERGY_SOURCE_3

2012 Form EIA-860 Data - Schedule 3, 'Generator Data' (Retired & Canceled Units Only)

UTILITY_ID	UTILITY_NAME	PLANT_CODE	PLANT_NAME	STATE	COUNTY	GENERATOR_ID	PRIME_MOVER	STATUS	NAMEPLATE	SUMMER_CAPABILITY	WINTER_CAPABILITY	UNIT_CODE	OPERATING_MONTH	OPERATING_YEAR	RETIREMENT_MONTH	RETIREMENT_YEAR	ENERGY_SOURCE_1
6035	Exelon Power	3159	Cromby Generating Station	PA	Chester	2	ST	RE	230	201	211		9	1955	12	2011	RFO
6035	Exelon Power	3159	Cromby Generating Station	PA	Chester	ICI	IC	RE	2.7	2.7	2.7		5	1967	12	2011	DFO
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	2	ST	RE	353.6	309	311		10	1960	5	2012	BIT
6035	Exelon Power	3169	Schuylkill Generating Station	PA	Philadelphia	1	ST	RE	190.4	166	175		7	1958	12	2012	RFO
6035	Exelon Power	3169	Schuylkill Generating Station	PA	Philadelphia	IC1	IC	RE	2.7	2.7	2.7		7	1967	12	2012	DFO

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Ventyx Data

	Winter	Spring	Summer	Fall
PJM	206,548	206,726	197,560	202,389
PJM East	36,887	36,821	34,543	36,685
5004/5005	64,644	64,583	60,911	63,082
AP South	89,913	89,859	84,806	88,370

All Periods	Winter	Spring	Summer	Fall
PJM	198,482	198,482	190,181	198,482
PJM East	36,121	36,121	33,990	36,121
5004/5005	62,325	62,325	59,415	62,325
AP South	87,585	87,585	83,283	87,585

Additions	Winter	Spring	Summer	Fall
PJM	1,030	2,095	3,097	3,710
PJM East	64	111	530	564
5004/5005	78	129	550	596
AP South	88	145	577	625

Retirements	Winter	Spring	Summer	Fall
PJM	7,037	6,150	4,282	197
PJM East	701	589	23	-
5004/5005	2,241	2,129	946	161
AP South	2,241	2,129	946	161

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	American Capital Energy	American Capital Energy	American Capital Energy	ACE Vineland Solar	PV1	100	4	4	4	9/30/11	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Pepco Energy Services Inc	Pepco Holdings Inc	Pepco Energy Services Inc	Atlantic City Conventior	PV1	100	0.5	0.5	0.5	3/5/09	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Pepco Energy Services Inc	Pepco Holdings Inc	Pepco Energy Services Inc	Atlantic City Conventior	PV2	100	0.5	0.5	0.5	3/5/09	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Pepco Energy Services Inc	Pepco Holdings Inc	Pepco Energy Services Inc	Atlantic City Conventior	PV3	100	0.5	0.5	0.5	3/5/09	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Pepco Energy Services Inc	Pepco Holdings Inc	Pepco Energy Services Inc	Atlantic City Conventior	PV4	100	0.5	0.5	0.5	3/5/09	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	RC Cape May	Rockland Capital	RC Cape May	B L England	1	100	136	113	113	10/1/62	ST	BIT	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	RC Cape May	Rockland Capital	RC Cape May	B L England	2	100	163.2	155	155	11/1/64	ST	BIT	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	RC Cape May	Rockland Capital	RC Cape May	B L England	IC2	100	2	2	2	8/1/61	IC	DFO	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	RC Cape May	Rockland Capital	RC Cape May	B L England	3	100	176.4	148	148	12/1/74	ST	RFO	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	RC Cape May	Rockland Capital	RC Cape May	B L England	IC3	100	2	2	2	8/1/61	IC	DFO	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	RC Cape May	Rockland Capital	RC Cape May	B L England	IC1	100	2	2	2	8/1/61	IC	DFO	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	RC Cape May	Rockland Capital	RC Cape May	B L England	IC4	100	2	2	2	8/1/61	IC	DFO	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine New Jersey Generati	Calpine Corp	Calpine New Jersey Generatio	Carlls Corner	CA1	100	41.9	37.4	45.3	4/1/73	GT	NG	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine New Jersey Generati	Calpine Corp	Calpine New Jersey Generatio	Carlls Corner	CA2	100	41.9	41.2	49.8	5/1/73	GT	NG	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Chambers Cogeneration LP	Energy Investors Funds Gr	Chambers Cogeneration LP	Carneys Point Generati	GEN1	100	285	262	262	12/1/93	ST	BIT	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine New Jersey Generati	Calpine Corp	Calpine New Jersey Generatio	Cedar Station	CED1	100	46	42.7	52.8	6/1/72	GT	KER	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine New Jersey Generati	Calpine Corp	Calpine New Jersey Generatio	Cedar Station	CED2	100	21.2	22.7	27.8	6/1/72	GT	KER	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine New Jersey Generati	Calpine Corp	Calpine New Jersey Generatio	Cumberland (NJ)	GT2	100	131.8	96.5	102	6/1/09	GT	NG	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine New Jersey Generati	Calpine Corp	Calpine New Jersey Generatio	Cumberland (NJ)	CUMB	100	99.4	86.6	104.1	5/1/90	GT	NG	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	PPL New Jersey Biogas LLC	PPL Corp	PPL New Jersey Biogas LLC	Cumberland County Lar	IC1	100	1.6	1.6	1.6	11/1/08	IC	LFG	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	PPL New Jersey Biogas LLC	PPL Corp	PPL New Jersey Biogas LLC	Cumberland County Lar	IC2	100	1.6	1.6	1.6	11/1/08	IC	LFG	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	PPL New Jersey Biogas LLC	PPL Corp	PPL New Jersey Biogas LLC	Cumberland County Lar	IC3	100	1.6	1.6	1.6	11/1/08	IC	LFG	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine New Jersey Generati	Calpine Corp	Calpine New Jersey Generatio	Deepwater (NJ)	6	100	73.5	81.2	82	12/1/54	ST	NG	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine New Jersey Generati	Calpine Corp	Calpine New Jersey Generatio	Deepwater (NJ)	1	100	81.6	78.9	79.5	12/1/58	ST	NG	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	AC Landfill Energy LLC	DCO Energy LLC	AC Landfill Energy LLC	Egg Harbor Landfill	UNIT1	100	1.6	1.5	1.5	3/31/05	IC	LFG	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	AC Landfill Energy LLC	DCO Energy LLC	AC Landfill Energy LLC	Egg Harbor Landfill	UNIT2	100	1.9	1.8	1.8	8/17/06	IC	LFG	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	AC Landfill Energy LLC	DCO Energy LLC	AC Landfill Energy LLC	Egg Harbor Landfill	UNIT3	100	1.9	1.8	1.8	12/3/07	IC	LFG	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Atlantic County Utilities Autl	Atlantic County Utilities Au	Jersey Atlantic Wind LLC	Jersey Atlantic Wind Fa	PV1	100	0.277	0.277	0.277	12/19/05	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Atlantic County Utilities Autl	Atlantic County Utilities Au	Jersey Atlantic Wind LLC	Jersey Atlantic Wind Fa	PV2	100	0.223	0.223	0.223	7/1/06	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Jersey Atlantic Wind LLC	Infigen Energy	Jersey Atlantic Wind LLC	Jersey Atlantic Wind Fa	WT1 5	100	7.5	7.5	7.5	1/8/06	WT	WND	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Logan Generating Co LP	Energy Investors Funds Gr	Logan Generating Co LP	Logan Generating Plant	GEN1	100	242.3	219	219	10/1/94	ST	BIT	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Mannington Mills Inc	Mannington Mills Inc	Mannington Mills Inc	Mannington Mills Coge	IC1	100	2.8	2.666	2.8	1/1/04	IC	NG	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Mannington Mills Inc	Mannington Mills Inc	Mannington Mills Inc	Mannington Mills Coge	IC2	100	2.8	2.666	2.8	1/1/04	IC	NG	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Mannington Mills Inc	Mannington Mills Inc	Mannington Mills Inc	Mannington Mills Coge	IC3	100	2.8	2.666	2.8	1/1/04	IC	NG	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	NFI Solar Inc	Nfi	NFI Solar Inc	Maple Solar	P1	100	1.6	1.6	1.6	5/1/11	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	NFI Solar Inc	Nfi	NFI Solar Inc	Maple Solar	P2	100	0.8	0.8	0.8	9/1/11	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Marina Energy LLC	South Jersey Industries Inc	Marina Energy LLC	Marina Energy	IC1	100	2	2	2	9/30/03	IC	DSL	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Marina Energy LLC	South Jersey Industries Inc	Marina Energy LLC	Marina Energy	IC2	100	2	2	2	9/30/03	IC	DSL	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Marina Energy LLC	South Jersey Industries Inc	Marina Energy LLC	Marina Energy	IC3	100	2	2	2	9/30/03	IC	DSL	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Marina Energy LLC	South Jersey Industries Inc	Marina Energy LLC	Marina Energy	IC4	100	2	2	2	9/30/03	IC	DSL	Operating	Y	1

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Backup - PJM Generation Data

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Marina Energy LLC	South Jersey Industries Inc	Marina Energy LLC	McKee City Solar	PV1	100	0.651	0.651	0.651	12/31/09	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine New Jersey Generati	Calpine Corp	Calpine New Jersey Generatio	Mickleton Station	MICK	100	71.2	64.9	78	6/1/74	GT	NG	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine New Jersey Generati	Calpine Corp	Calpine New Jersey Generatio	Middle Station	MID1	100	21.2	19.2	24.2	6/1/70	GT	KER	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine New Jersey Generati	Calpine Corp	Calpine New Jersey Generatio	Middle Station	MID2	100	21.2	19.4	24.4	6/1/70	GT	KER	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine New Jersey Generati	Calpine Corp	Calpine New Jersey Generatio	Middle Station	MID3	100	37.2	34.8	44.9	5/1/71	GT	KER	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine New Jersey Generati	Calpine Corp	Calpine New Jersey Generatio	Missouri Avenue	MISC	100	18.6	20.5	23.8	1/1/69	GT	KER	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine New Jersey Generati	Calpine Corp	Calpine New Jersey Generatio	Missouri Avenue	MISD	100	18.6	20.5	23.8	2/1/69	GT	KER	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine New Jersey Generati	Calpine Corp	Calpine New Jersey Generatio	Missouri Avenue	MISB	100	18.6	18.5	23.6	5/1/69	GT	KER	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	NFI Solar Inc	Nfi	NFI Solar Inc	NFI Vineland Solar	PV1	100	1.1	1.1	1.1	6/11/11	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Constellation Solar New Jers	Exelon Corp	Constellation NewEnergy Inc	North Vineland Solar	PV1	100	2.3	2.3	2.3	11/9/11	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Nautilus Solar Ocean City On	Nautilus Solar Ocean City C	Nautilus Solar Ocean City One	Ocean City One Cultura	PV	100	0.3	0.3	0.3	12/16/08	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Nautilus Solar Ocean City On	Nautilus Solar Ocean City C	Nautilus Solar Ocean City One	Ocean City One Sports (	PV	100	0.1	0.07	0.07	12/16/08	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Paulsboro Refining Co LLC	PBF Holding Co LLC	Paulsboro Refining Co LLC	Paulsboro Refinery	CC	100	57	43.6	47.5	9/1/91	CC	NG	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Paulsboro Refining Co LLC	PBF Holding Co LLC	Paulsboro Refining Co LLC	Paulsboro Refinery	OT1	100	18	11.6	11.6	11/1/06	NA	WH	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Pedricktown Cogeneration C	Morris Energy Group	Pedricktown Cogeneration Co	Pedricktown Cogenerat	CC	100	134.5	117.9	130.5	3/1/92	CC	NG	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Pilesgrove Solar LLC	Pilesgrove Solar LLC	Consolidated Edison Energy In	Pilesgrove Solar	PV1	100	18	17.7	17.7	9/30/11	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Repauno Products LLC	Repauno Products LLC	Repauno Products LLC	Repauno Products	GT1	100	1.7	1.7	1.7	4/8/02	GT	NG	Operating	Y	1
PJM ISO	AECO	Public Service Elect	PJM East	5004/5005	AP South	Riverside Renewable Energy	Terminal Holdings LP	Riverside Renewable Energy LI	Riverside Renewable Er	PV1	100	7.5	7.499	7.499	9/1/11	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Clean Harbors Environmenta	Clean Harbors Environmen	Clean Harbors Environmental	Rollins Environmental S	PV1	100	1.5	1.5	1.5	1/31/11	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	SC Landfill Energy LLC	South Jersey Industries Inc	SC Landfill Energy LLC	Salem County Landfill	IC	100	1.9	1.7	1.7	12/1/08	IC	LFG	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Santa Sweets Inc	Santa Sweets Inc	Santa Sweets Inc	Santa Sweets NJ Solar	PV1	100	2	2	2	10/13/10	PV	SUN	Operating	Y	1
PJM ISO	AECO	Delmarva Power &	PJM East	5004/5005	AP South	SBS Energy Partners LLC	DCO Energy LLC	SBS Energy Partners LLC	Seabrook Farms Solar	PV1	100	3.2	3.2	3.2	12/31/10	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine New Jersey Generati	Calpine Corp	Calpine New Jersey Generatio	Sherman Avenue	SEHR	100	112.8	82.4	99	5/1/91	GT	NG	Standby	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Richard Stockton College of I	Richard Stockton College o	Richard Stockton College of Ne	Stockton Athletic Cente	2LOT7	100	0.5	0.5	0.5	10/1/09	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Richard Stockton College of I	Richard Stockton College o	Richard Stockton College of Ne	Stockton Athletic Cente	LOT7	100	0.2	0.2	0.2	4/1/09	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Richard Stockton College of I	Richard Stockton College o	Richard Stockton College of Ne	Stockton Athletic Cente	LOT7B	100	0.2	0.2	0.2	4/1/09	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Richard Stockton College of I	Richard Stockton College o	Richard Stockton College of Ne	Stockton Athletic Cente	SAC	100	0.3	0.3	0.3	2/1/09	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	SunE KHL989 Manahawkin L	SunEdison	SunE KHL989 Manahawkin LLC	SunE KHL989 Manahaw	PV	100	0.3	0.2	0.2	5/20/08	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	SunE WG6902 Millville LLC	SunEdison	SunE WG6902 Millville LLC	SunE WG6902 Millville	PV	100	0.037	0.028	0.028	3/24/09	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	NJR Clean Energy Ventures	New Jersey Resources Corp	NJR Clean Energy Ventures	Vineland Mays Landing	PV1	100	4.3	5.7	2.8	9/30/11	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine Vineland Solar LLC	Calpine Corp	Calpine Vineland Solar LLC	Vineland Solar One	PV1	100	2.3	2.3	2.3	9/21/09	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Calpine Vineland Solar LLC	Calpine Corp	Calpine Vineland Solar LLC	Vineland Solar One	PV2	100	1.8	1.8	1.8	12/15/09	PV	SUN	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Vineland NJ (City of)	Vineland NJ (City of)	Vineland NJ (City of)	West Station	1	100	27	26	32	6/1/72	GT	DFO	Operating	Y	1
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Constellation Solar New Jers	Exelon Corp	Constellation NewEnergy Inc	West Vineland Solar	PV1	100	3.7	3.7	3.7	11/9/11	PV	SUN	Operating	Y	1
PJM ISO	AEP	American Electric Power				AEP Generating Co	American Electric Power C	AEP Generating Co	AEP Generating Co Law	CC1	100	616	540	564	2/15/04	CC	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				AEP Generating Co	American Electric Power C	AEP Generating Co	AEP Generating Co Law	CC2	100	616	540	540	2/15/04	CC	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Elkem Metals Co	Elkem Asa	Elkem Metals Co	Alloy Steam	GEN3	100	40	38	39	7/1/50	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Woodsfield Board of Public A	Woodsfield Board of Public	Woodsfield Board of Public Af	Anadarko (OH)	10	100	1.2	1.2	1.2	1/1/83	IC	DFO	Standby	Y	1
PJM ISO	AEP	American Electric Power				Woodsfield Board of Public A	Woodsfield Board of Public	Woodsfield Board of Public Af	Anadarko (OH)	11	100	1.2	1.2	1.2	1/1/83	IC	DFO	Standby	Y	1
PJM ISO	AEP	American Electric Power				Woodsfield Board of Public A	Woodsfield Board of Public	Woodsfield Board of Public Af	Anadarko (OH)	6	100	0.6	0.6	0.6	1/1/49	IC	DFO	Standby	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	AEP	American Electric Power				Woodsfield Board of Public A	Woodsfield Board of Publi	Woodsfield Board of Public Af	Anadarko (OH)	7	100	1.2	1.2	1.2	1/1/57	IC	DFO	Standby	Y	1
PJM ISO	AEP	American Electric Power				Woodsfield Board of Public A	Woodsfield Board of Publi	Woodsfield Board of Public Af	Anadarko (OH)	8	100	1.5	1.5	1.5	1/1/65	IC	DFO	Standby	Y	1
PJM ISO	AEP	American Electric Power				Woodsfield Board of Public A	Woodsfield Board of Publi	Woodsfield Board of Public Af	Anadarko (OH)	9	100	2.1	2.1	2.1	1/1/71	IC	DFO	Standby	Y	1
PJM ISO	AEP	American Electric Power				Indiana Municipal Power Ag	Indiana Municipal Power A	Indiana Municipal Power Agen	Anderson	GT1	100	41.4	34	42	6/1/92	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Municipal Power Ag	Indiana Municipal Power A	Indiana Municipal Power Agen	Anderson	GT2	100	41.4	34	42	6/1/92	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Municipal Power Ag	Indiana Municipal Power A	Indiana Municipal Power Agen	Anderson	GT3	100	85.9	72	90	4/12/04	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Bayer Cropscience	Bayer Cropscience	Bayer Cropscience	Bayer Cropscience Insti	ST1	100	6.3	6.3	6.3	5/1/58	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Bayer Cropscience	Bayer Cropscience	Bayer Cropscience	Bayer Cropscience Insti	ST2	100	6.3	6.3	6.3	4/1/61	ST	BIT	Operating	Y	1
PJM ISO	AEP	Allegheny Power				Beech Ridge Energy LLC	Invenergy LLC	Beech Ridge Energy LLC	Beech Ridge Wind Farm	WT1 56	100	84	84	84	7/27/10	WT	WND	Operating	Y	1
PJM ISO	AEP	Allegheny Power				Beech Ridge Energy LLC	Invenergy LLC	Beech Ridge Energy LLC	Beech Ridge Wind Farm	WT57 67	100	16.5	16.5	16.5	8/15/10	WT	WND	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Municipal Electric Gene	Cuyahoga Falls OH (City of)	American Municipal Power Inc	Belleville	1	100	21	21	21	4/1/99	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Municipal Electric Gene	Cuyahoga Falls OH (City of)	American Municipal Power Inc	Belleville	2	100	21	21	21	5/1/99	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Berrien Springs	1A	100	0.6	0.2	0.2	10/10/08	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Berrien Springs	10	100	0.6	0.2	0.2	10/10/08	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Berrien Springs	11	100	0.6	0.2	0.2	10/10/08	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Berrien Springs	12	100	0.6	0.2	0.2	10/10/08	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Berrien Springs	2A	100	0.6	0.2	0.2	10/10/08	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Berrien Springs	3A	100	0.6	0.2	0.2	10/10/08	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Berrien Springs	4A	100	0.6	0.2	0.2	10/10/08	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Berrien Springs	5	100	0.6	0.2	0.2	10/10/08	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Berrien Springs	6	100	0.6	0.2	0.2	10/10/08	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Berrien Springs	7	100	0.6	0.2	0.2	10/10/08	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Berrien Springs	8	100	0.6	0.2	0.2	10/10/08	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Berrien Springs	9	100	0.6	0.2	0.2	10/10/08	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Georgia Pacific Corp	Koch Industries Inc	Georgia Pacific Corp	Big Island	BHG1	100	0.2	0.19	0.18	6/1/20	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Georgia Pacific Corp	Koch Industries Inc	Georgia Pacific Corp	Big Island	BHG2	100	0.2	0.19	0.18	6/1/20	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Georgia Pacific Corp	Koch Industries Inc	Georgia Pacific Corp	Big Island	CHG1	100	0.5	0.48	0.46	6/1/83	HY	WAT	Standby	Y	1
PJM ISO	AEP	American Electric Power				Georgia Pacific Corp	Koch Industries Inc	Georgia Pacific Corp	Big Island	CHG2	100	0.5	0.48	0.46	6/1/83	HY	WAT	Standby	Y	1
PJM ISO	AEP	American Electric Power				Georgia Pacific Corp	Koch Industries Inc	Georgia Pacific Corp	Big Island	CHG3	100	0.5	0.48	0.46	6/1/83	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Georgia Pacific Corp	Koch Industries Inc	Georgia Pacific Corp	Big Island	GEN1	100	7.5	6.5	7	6/1/65	ST	WDS	Operating	Y	1
PJM ISO	AEP	American Electric Power				Georgia Pacific Corp	Koch Industries Inc	Georgia Pacific Corp	Big Island	HHG1	100	0.6	0.57	0.55	6/1/20	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Georgia Pacific Corp	Koch Industries Inc	Georgia Pacific Corp	Big Island	HHG2	100	0.6	0.57	0.55	6/1/20	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Georgia Pacific Corp	Koch Industries Inc	Georgia Pacific Corp	Big Island	HHG3	100	0.6	0.57	0.55	6/1/20	HY	WAT	Standby	Y	1
PJM ISO	AEP	American Electric Power				Kentucky Power Co	American Electric Power C	Kentucky Power Co	Big Sandy	2	100	816.3	800	800	10/1/69	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Kentucky Power Co	American Electric Power C	Kentucky Power Co	Big Sandy	1	100	280.5	260	260	1/1/63	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Big Sandy Peaker Plant LLC	Tenaska Inc	Big Sandy Peaker Plant LLC	Big Sandy Peaker	GT1	100	57	50	57	8/1/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Big Sandy Peaker Plant LLC	Tenaska Inc	Big Sandy Peaker Plant LLC	Big Sandy Peaker	GT2	100	57	50	57	8/1/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Big Sandy Peaker Plant LLC	Tenaska Inc	Big Sandy Peaker Plant LLC	Big Sandy Peaker	GT3	100	57	50	57	8/1/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Big Sandy Peaker Plant LLC	Tenaska Inc	Big Sandy Peaker Plant LLC	Big Sandy Peaker	GT4	100	57	50	57	8/1/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Big Sandy Peaker Plant LLC	Tenaska Inc	Big Sandy Peaker Plant LLC	Big Sandy Peaker	GT5	100	57	50	57	8/1/01	GT	NG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	AEP	American Electric Power				Big Sandy Peaker Plant LLC	Tenaska Inc	Big Sandy Peaker Plant LLC	Big Sandy Peaker	GT6	100	57	50	57	8/1/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Buchanan (MI)	1	100	0.4	0.209	0.218	1/1/19	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Buchanan (MI)	10	100	0.5	0.261	0.273	1/3/27	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Buchanan (MI)	2	100	0.4	0.209	0.218	1/1/19	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Buchanan (MI)	3	100	0.4	0.209	0.218	1/1/19	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Buchanan (MI)	4	100	0.4	0.209	0.218	1/1/19	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Buchanan (MI)	5	100	0.4	0.209	0.218	1/1/19	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Buchanan (MI)	6	100	0.4	0.209	0.218	1/1/19	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Buchanan (MI)	7	100	0.5	0.261	0.273	1/3/27	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Buchanan (MI)	8	100	0.5	0.261	0.273	1/3/27	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Buchanan (MI)	9	100	0.5	0.261	0.273	1/3/27	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Buchanan County Gene	1	50	22	20	21.5	6/25/02	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				CONSOL Energy Inc	CONSOL Energy Inc	Allegheny Energy Supply Co LL	Buchanan County Gene	1	50	22	20	21.5	6/25/02	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Buchanan County Gene	2	50	22	20	21.5	6/25/02	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				CONSOL Energy Inc	CONSOL Energy Inc	Allegheny Energy Supply Co LL	Buchanan County Gene	2	50	22	20	21.5	6/25/02	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Buck (VA)	1	100	2.8	2.8	2.8	1/1/12	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Buck (VA)	2	100	2.8	2.8	2.8	1/1/12	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Buck (VA)	3	100	2.8	2.8	2.8	1/1/12	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Byllesby 2	1	100	5.4	7.9	4.4	1/1/12	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Byllesby 2	2	100	5.4	7.9	4.4	1/1/12	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Byllesby 2	3	100	5.4	7.9	4.4	1/1/12	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Byllesby 2	4	100	5.4	7.9	4.4	1/1/12	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Cardinal	1	100	615.2	580	580	2/1/67	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Buckeye Power Inc	Buckeye Power Inc	Ohio Power Co	Cardinal	2	100	615.2	590	590	7/1/67	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Buckeye Power Inc	Buckeye Power Inc	Ohio Power Co	Cardinal	3	100	650	630	630	9/1/77	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Central Soya Co Inc	Bunge Limited	Central Soya Co Inc	Central Soya Co Inc	3516	100	2	2.2	2.2	12/1/50	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Ceredo Generating Station	Ceredo Generating Plar	GT1	100	86.5	75	86	6/15/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Ceredo Generating Station	Ceredo Generating Plar	GT2	100	86.5	75	86	6/15/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Ceredo Generating Station	Ceredo Generating Plar	GT3	100	86.5	75	86	6/15/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Ceredo Generating Station	Ceredo Generating Plar	GT4	100	86.5	75	88.6	6/15/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Ceredo Generating Station	Ceredo Generating Plar	GT5	100	86.5	75	86	6/15/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Ceredo Generating Station	Ceredo Generating Plar	GT6	100	86.5	75	86	6/15/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Charleston Clean Energy LLC	Sindicatum Carbon Capital	Charleston Clean Energy LLC	Charleston Landfill	IC 2	100	1.1	1.1	1.1	1/24/11	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Sindicatum Carbon Capital A	Sindicatum Carbon Capital	Charleston Clean Energy LLC	Charleston Landfill	IC 1	100	1.1	1.1	1.1	1/24/11	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				P H Glatfelter Co	P H Glatfelter Co	P H Glatfelter Co	Chillicothe (OH)	T 10	100	10.6	9	5.3	2/1/52	ST	BLQ	Operating	Y	1
PJM ISO	AEP	American Electric Power				P H Glatfelter Co	P H Glatfelter Co	P H Glatfelter Co	Chillicothe (OH)	T 11	100	24	10.1	13.2	2/1/58	ST	BLQ	Operating	Y	1
PJM ISO	AEP	American Electric Power				P H Glatfelter Co	P H Glatfelter Co	P H Glatfelter Co	Chillicothe (OH)	T 12	100	31	16.6	18.8	2/1/67	ST	BLQ	Operating	Y	1
PJM ISO	AEP	American Electric Power				P H Glatfelter Co	P H Glatfelter Co	P H Glatfelter Co	Chillicothe (OH)	T 13	100	27.2	16.8	19.3	7/1/78	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Claytor	1	100	18.7	14.7	28.2	8/1/39	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Claytor	2	100	18.7	14.7	28.2	8/1/39	HY	WAT	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Claytor	3	100	18.7	14.7	28.2	8/1/39	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Claytor	4	100	18.7	14.7	28.2	8/1/39	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Kentucky Electric Co	American Electric Power Co	Indiana Kentucky Electric Corp	Clifty Creek	1	100	217.3	200.5	204.7	2/1/55	ST	SUB	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Kentucky Electric Co	American Electric Power Co	Indiana Kentucky Electric Corp	Clifty Creek	2	100	217.3	200.5	204.7	5/1/55	ST	SUB	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Kentucky Electric Co	American Electric Power Co	Indiana Kentucky Electric Corp	Clifty Creek	3	100	217.3	200.5	204.7	7/1/55	ST	SUB	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Kentucky Electric Co	American Electric Power Co	Indiana Kentucky Electric Corp	Clifty Creek	4	100	217.3	200.5	204.7	10/1/55	ST	SUB	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Kentucky Electric Co	American Electric Power Co	Indiana Kentucky Electric Corp	Clifty Creek	5	100	217.3	200.5	204.7	11/1/55	ST	SUB	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Kentucky Electric Co	American Electric Power Co	Indiana Kentucky Electric Corp	Clifty Creek	6	100	217.3	200.5	204.7	3/1/56	ST	SUB	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Clinch River	1	100	237.5	230	235	9/1/58	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Clinch River	2	100	237.5	230	235	12/1/58	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Clinch River	3	100	237.5	230	235	12/1/61	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Conesville	5	100	443.9	375	375	11/1/76	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Conesville	6	100	443.9	375	375	6/1/78	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Dayton Power & Light Co (Th	AES Corp (The)	Ohio Power Co	Conesville	4	16.5	138.848	128.7	128.7	6/1/73	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Duke Energy Ohio	Duke Energy Corp	Ohio Power Co	Conesville	4	40	336.6	312	312	6/1/73	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Conesville	4	43.5	366.053	339.3	339.3	6/1/73	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Constantine	1	100	0.3	0.3	0.3	1/1/23	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Constantine	2	100	0.3	0.3	0.3	1/1/23	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Constantine	3	100	0.3	0.3	0.3	1/3/29	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Constantine	4	100	0.3	0.3	0.3	1/1/23	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				RockTenn CP LLC	Rock Tenn Co	RockTenn CP LLC	Coshocton Mill	GEN1	100	16.5	12	14.2	11/1/81	ST	WDS	Operating	Y	1
PJM ISO	AEP	American Electric Power				Sturgis MI (City of)	Sturgis MI (City of)	Sturgis MI (City of)	Diesel Plant (MI STURGI	6	100	6	6	6	12/1/81	IC	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Columbus OH (City of)	Columbus OH (City of)	Columbus OH (City of)	Dodge Park	7	100	2	1.8	1.8	1/1/08	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Donald C Cook	1	100	1171.12	1009	1084	8/1/75	NP	URA	Restarted	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Donald C Cook	2	100	1153.7	1060	1107	7/1/78	NP	URA	Restarted	Y	1
PJM ISO	AEP	American Electric Power				Dover OH (City of)	Dover OH (City of)	Dover OH (City of)	Dover (OH)	3	100	8	8	8	1/1/54	ST	BIT	Standby	Y	1
PJM ISO	AEP	American Electric Power				Dover OH (City of)	Dover OH (City of)	Dover OH (City of)	Dover (OH)	4	100	19.5	15.2	15.2	6/1/68	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Dover OH (City of)	Dover OH (City of)	Dover OH (City of)	Dover (OH)	5	100	2.6	2.4	2.4	6/1/66	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Dover OH (City of)	Dover OH (City of)	Dover OH (City of)	Dover (OH)	6	100	19.5	15.3	15.3	9/1/92	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Dover Peaking	1	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Dover Peaking	2	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Dover Peaking	3	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Dover Peaking	4	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Dover Peaking	5	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Dover Peaking	6	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Wabash Valley Power Associ	Wabash Valley Power Asso	Wabash Valley Power Associat	Earthmovers Landfill	IC1	100	0.8	0.8	0.8	10/28/10	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Wabash Valley Power Associ	Wabash Valley Power Asso	Wabash Valley Power Associat	Earthmovers Landfill	IC2	100	0.8	0.8	0.8	10/28/10	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Wabash Valley Power Associ	Wabash Valley Power Asso	Wabash Valley Power Associat	Earthmovers Landfill	IC3	100	0.8	0.8	0.8	10/28/10	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Wabash Valley Power Associ	Wabash Valley Power Asso	Wabash Valley Power Associat	Earthmovers Landfill	IC4	100	0.8	0.8	0.8	10/28/10	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Wabash Valley Power Associ	Wabash Valley Power Asso	Wabash Valley Power Associat	Earthmovers Landfill	IC5	100	0.8	0.8	0.8	10/28/10	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	AEP	American Electric Power				Wabash Valley Power Associ	Wabash Valley Power Asso	Wabash Valley Power Associat	Earthmovers Landfill	IC6	100	0.8	0.8	0.8	10/28/10	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Elkhart (IN)	1	100	1.4	1.6	2.1	1/1/13	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Elkhart (IN)	2	100	1	0.7	0.7	1/3/21	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Elkhart (IN)	3	100	1	0.7	0.7	1/3/21	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Fowler Ridge III Wind Farm L	BP plc	Fowler Ridge Wind LLC	Fowler Ridge Wind Farr	WT183 222	100	100	100	100	12/31/08	WT	WND	Operating	Y	1
PJM ISO	AEP	American Electric Power				Fowler Ridge Wind LLC	Dominion Resources Inc	Fowler Ridge Wind LLC	Fowler Ridge Wind Farr	WT1 182	100	300.3	300.3	300.3	12/31/08	WT	WND	Operating	Y	1
PJM ISO	AEP	American Electric Power				Fowler Ridge II Wind Farm LI	Dominion Resources Inc	Fowler Ridge Wind LLC	Fowler Ridge Wind Farr	WT223 355	50	100	100	100	12/23/09	WT	WND	Operating	Y	1
PJM ISO	AEP	American Electric Power				Sempra Generation	Sempra Energy	Fowler Ridge Wind LLC	Fowler Ridge Wind Farr	WT223 355	50	100	100	100	12/23/09	WT	WND	Operating	Y	1
PJM ISO	AEP	FirstEnergy ATSI				American Municipal Power I	American Municipal Powe	American Municipal Power Inc	Fremont Energy Center	CC	100	739.5	667.3	716.3	9/27/11	CC	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				French Paper Co	French Paper Co	French Paper Co	French Paper Co Hydro	1	100	0.3	0.3	0.3	1/1/22	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				French Paper Co	French Paper Co	French Paper Co	French Paper Co Hydro	2	100	0.4	0.4	0.4	1/1/27	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				French Paper Co	French Paper Co	French Paper Co	French Paper Co Hydro	3	100	0.4	0.3	0.3	1/1/30	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				French Paper Co	French Paper Co	French Paper Co	French Paper Co Hydro	4	100	0.2	0.2	0.2	1/1/38	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Aquenergy Systems Inc	Enel SpA	Aquenergy Systems Inc	Fries Hydro	GEN1	100	2	2	2	1/1/33	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Aquenergy Systems Inc	Enel SpA	Aquenergy Systems Inc	Fries Hydro	GEN2	100	0.8	0.76	0.74	1/1/33	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Aquenergy Systems Inc	Enel SpA	Aquenergy Systems Inc	Fries Hydro	GEN3	100	0.2	0.2	0.2	1/1/33	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Aquenergy Systems Inc	Enel SpA	Aquenergy Systems Inc	Fries Hydro	GEN4	100	2.4	2	2	1/1/81	HY	WAT	Operating	Y	1
PJM ISO	AEP	FirstEnergy ATSI				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Galion (OH AMP OH)	1	100	1.8	1.8	1.8	7/1/01	IC	DFO	Operating	Y	1
PJM ISO	AEP	FirstEnergy ATSI				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Galion (OH AMP OH)	2	100	1.8	1.8	1.8	7/1/01	IC	DFO	Operating	Y	1
PJM ISO	AEP	FirstEnergy ATSI				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Galion (OH AMP OH)	3	100	1.8	1.8	1.8	7/1/01	IC	DFO	Operating	Y	1
PJM ISO	AEP	FirstEnergy ATSI				American Municipal Power I	American Municipal Powe	American Municipal Power Inc	Galion Generating Stati	CT1	100	33	26	33	6/1/00	GT	NG	Operating	Y	1
PJM ISO	AEP	FirstEnergy ATSI				American Municipal Power I	American Municipal Powe	American Municipal Power Inc	Galion Generating Stati	CT2	100	16.5	12	16.5	6/1/00	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Gauley River Power Partners	Enel SpA	Gauley River Power Partners L	Gauley	GEN1	100	40	40	25	7/1/01	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Gauley River Power Partners	Enel SpA	Gauley River Power Partners L	Gauley	GEN2	100	40	40	25	7/1/01	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power C	Ohio Power Co	Gavin	1	100	1300	1299	1299	10/1/74	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power C	Ohio Power Co	Gavin	2	100	1300	1299	1299	7/1/75	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Columbus & Franklin County	Columbus & Franklin Coun	Columbus & Franklin County N	Glacier Ridge Wind & Sc	PV1 2	100	0.002	0.002	0.002	7/1/04	PV	SUN	Operating	Y	1
PJM ISO	AEP	American Electric Power				Columbus & Franklin County	Columbus & Franklin Coun	Columbus & Franklin County N	Glacier Ridge Wind & Sc	WT	100	0.006	0.006	0.006	12/1/02	WT	WND	Operating	Y	1
PJM ISO	AEP	American Electric Power				Brookfield Renewable Energ	Brookfield Asset Managem	Elkem Metals Co	Glen Ferris Hydro	GEN1	100	0.4	0.4	0.4	1/1/12	HY	WAT	Restarted	Y	1
PJM ISO	AEP	American Electric Power				Brookfield Renewable Energ	Brookfield Asset Managem	Elkem Metals Co	Glen Ferris Hydro	GEN2	100	0.4	0.4	0.4	1/1/12	HY	WAT	Restarted	Y	1
PJM ISO	AEP	American Electric Power				Brookfield Renewable Energ	Brookfield Asset Managem	Elkem Metals Co	Glen Ferris Hydro	GEN3	100	0.4	0.4	0.4	1/1/12	HY	WAT	Restarted	Y	1
PJM ISO	AEP	American Electric Power				Brookfield Renewable Energ	Brookfield Asset Managem	Elkem Metals Co	Glen Ferris Hydro	GEN4	100	0.4	0.4	0.4	1/1/12	HY	WAT	Restarted	Y	1
PJM ISO	AEP	American Electric Power				Brookfield Renewable Energ	Brookfield Asset Managem	Elkem Metals Co	Glen Ferris Hydro	GEN5	100	0.4	0.4	0.4	1/1/12	HY	WAT	Restarted	Y	1
PJM ISO	AEP	American Electric Power				Brookfield Renewable Energ	Brookfield Asset Managem	Elkem Metals Co	Glen Ferris Hydro	GEN6	100	0.4	0.4	0.4	1/1/12	HY	WAT	Restarted	Y	1
PJM ISO	AEP	American Electric Power				Brookfield Renewable Energ	Brookfield Asset Managem	Elkem Metals Co	Glen Ferris Hydro	GEN7	100	1.9	1.9	1.9	1/1/17	HY	WAT	Restarted	Y	1
PJM ISO	AEP	American Electric Power				Brookfield Renewable Energ	Brookfield Asset Managem	Elkem Metals Co	Glen Ferris Hydro	GEN8	100	1.9	1.9	1.9	1/1/17	HY	WAT	Restarted	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power C	Appalachian Power Co	Glen Lyn	5	100	100	90	95	6/1/44	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power C	Appalachian Power Co	Glen Lyn	6	100	237.5	235	240	5/1/57	ST	BIT	Operating	Y	1
PJM ISO	AEP	East Kentucky Power Coop.				East Kentucky Power Coop	East Kentucky Power Coop	East Kentucky Power Coop	Green Valley Landfill	1	100	0.8	0.8	0.8	10/1/03	IC	LFG	Operating	Y	1
PJM ISO	AEP	East Kentucky Power Coop.				East Kentucky Power Coop	East Kentucky Power Coop	East Kentucky Power Coop	Green Valley Landfill	2	100	0.8	0.8	0.8	10/1/03	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	AEP	East Kentucky Power Coop.				East Kentucky Power Coop	East Kentucky Power Coop	East Kentucky Power Coop	Green Valley Landfill	3	100	0.8	0.8	0.8	10/1/03	IC	LFG	Operating	Y	1
PJM ISO	AEP	East Kentucky Power Coop.				East Kentucky Power Coop	East Kentucky Power Coop	East Kentucky Power Coop	Green Valley Landfill	4	100	0.8	0.8	0.8	12/31/10	IC	LFG	Operating	Y	1
PJM ISO	AEP	East Kentucky Power Coop.				Hamilton Dept of Public Utili	Hamilton Dept of Public Ut	Hamilton Dept of Public Utilitie	Greenup Hydro	1	100	23.4	23.4	23.4	12/1/82	HY	WAT	Operating	Y	1
PJM ISO	AEP	East Kentucky Power Coop.				Hamilton Dept of Public Utili	Hamilton Dept of Public Ut	Hamilton Dept of Public Utilitie	Greenup Hydro	2	100	23.4	23.4	23.4	12/1/82	HY	WAT	Operating	Y	1
PJM ISO	AEP	East Kentucky Power Coop.				Hamilton Dept of Public Utili	Hamilton Dept of Public Ut	Hamilton Dept of Public Utilitie	Greenup Hydro	3	100	23.4	23.4	23.4	12/1/82	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Duke Energy Hanging Rock II	Duke Energy Corp	Duke Energy Hanging Rock II LI	Hanging Rock Energy Fa	CC1	100	644.1	626	648	6/12/03	CC	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Duke Energy Hanging Rock II	Duke Energy Corp	Duke Energy Hanging Rock II LI	Hanging Rock Energy Fa	CC2	100	644.1	626	648	8/7/03	CC	NG	Operating	Y	1
PJM ISO	AEP	Virginia Power Company			AP South	Central Virginia Electric Coop	Central Virginia Electric Co	Central Virginia Electric Coop	Harris Bridge	1	100	0.4	0.4	0.4	1/1/21	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Haverhill Cogeneration Co LL	Sun Coke Intl Inc	Haverhill Cogeneration Co LLC	Haverhill North Cogene	ST	100	67	53	53	9/2/08	ST	WH	Operating	Y	1
PJM ISO	AEP	American Electric Power				Brookfield Renewable Energ	Brookfield Asset Managem	Elkem Metals Co	Hawks Nest Hydro	GEN1	100	25.5	24.23	23.46	6/1/36	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Brookfield Renewable Energ	Brookfield Asset Managem	Elkem Metals Co	Hawks Nest Hydro	GEN2	100	25.5	24.23	23.46	6/1/36	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Brookfield Renewable Energ	Brookfield Asset Managem	Elkem Metals Co	Hawks Nest Hydro	GEN3	100	25.5	24.23	23.46	6/1/36	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Brookfield Renewable Energ	Brookfield Asset Managem	Elkem Metals Co	Hawks Nest Hydro	GEN4	100	25.5	24.23	23.46	6/1/36	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Hoge Lumber Co	Hoge Lumber Co	Hoge Lumber Co	Hoge Lumber Co	AC3M	100	3	1.2	0.8	12/1/85	ST	WDS	Standby	Y	1
PJM ISO	AEP	American Electric Power				Hoge Lumber Co	Hoge Lumber Co	Hoge Lumber Co	Hoge Lumber Co	W750	100	0.7	0.3	0.2	1/1/72	ST	WDS	Standby	Y	1
PJM ISO	AEP	Virginia Power Company			AP South	Owens Illinois Inc	Owens Illinois Inc	Holcomb Rock Co	Holcomb Rock	HG1	100	0.6	0.2	0.2	6/1/20	HY	WAT	Operating	Y	1
PJM ISO	AEP	Virginia Power Company			AP South	Owens Illinois Inc	Owens Illinois Inc	Holcomb Rock Co	Holcomb Rock	HG3	100	0.6	0.2	0.2	6/1/20	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Sturgis MI (City of)	Sturgis MI (City of)	Sturgis MI (City of)	Hydro Plant	1	100	0.4	0.4	0.4	1/3/11	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Sturgis MI (City of)	Sturgis MI (City of)	Sturgis MI (City of)	Hydro Plant	2	100	0.4	0.4	0.4	1/3/11	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Sturgis MI (City of)	Sturgis MI (City of)	Sturgis MI (City of)	Hydro Plant	3	100	0.7	0.7	0.7	4/1/83	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Sturgis MI (City of)	Sturgis MI (City of)	Sturgis MI (City of)	Hydro Plant	4	100	0.7	0.7	0.7	4/1/83	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Jackson	12	100	3.6	3.6	3.6	12/1/90	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Jackson CNTR Peaking	1	100	1.8	1.8	1.8	6/1/99	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	John E Amos	1	100	816.3	800	800	9/1/71	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	John E Amos	2	100	816.3	800	800	6/1/72	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	John E Amos	3	33.3	432.9	432.9	432.567	10/1/73	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Appalachian Power Co	John E Amos	3	66.7	867.1	867.1	866.433	10/1/73	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Kammer	1	100	237.5	200	210	7/1/58	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Kammer	2	100	237.5	200	210	11/1/58	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Kammer	3	100	237.5	200	210	3/1/59	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Kanawha River	1	100	219.6	200	200	7/1/53	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Kanawha River	2	100	219.6	200	200	12/1/53	ST	BIT	Operating	Y	1
PJM ISO	AEP	Virginia Power Company			AP South	Danville Power & Light Dept	Danville Power & Light Dep	Danville Power & Light Dept	Kentuck	GEN1	100	1.8	1.2	1.2	7/1/05	IC	DFO	Standby	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Domtar Paper Co LLC Kingspo	Domtar Corp	Domtar Paper Co LLC Kingspor	Kingsport Mill	NO1	100	50	46.5	47	10/1/06	ST	BLQ	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Valley Electric Corp	American Electric Power Co	Ohio Valley Electric Corp	Kyger Creek	1	100	217.3	194	198.7	2/1/55	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Valley Electric Corp	American Electric Power Co	Ohio Valley Electric Corp	Kyger Creek	2	100	217.3	192.2	198	6/1/55	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Valley Electric Corp	American Electric Power Co	Ohio Valley Electric Corp	Kyger Creek	3	100	217.3	192.2	198	9/1/55	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Valley Electric Corp	American Electric Power Co	Ohio Valley Electric Corp	Kyger Creek	4	100	217.3	192.2	198	11/1/55	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Valley Electric Corp	American Electric Power Co	Ohio Valley Electric Corp	Kyger Creek	5	100	217.3	192.2	198	12/1/55	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Leesville	1	100	20	25	25	2/1/64	HY	WAT	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Leesville	2	100	20	25	25	3/1/64	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	London	1	100	4.4	2.3	3.83	12/1/35	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	London	2	100	4.8	2.3	3.83	12/1/35	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	London	3	100	4.8	2.3	3.83	12/1/35	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Marmet	1	100	4.8	1.867	3.767	12/1/35	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Marmet	2	100	4.8	1.867	3.767	12/1/35	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Marmet	3	100	4.8	1.867	3.767	12/1/35	HY	WAT	Operating	Y	1
PJM ISO	AEP	Virginia Power Company			AP South	Martinsville VA (City of)	Martinsville VA (City of)	Martinsville VA (City of)	Martinsville	1	100	0.3	0.3	0.3	5/1/32	HY	WAT	Operating	Y	1
PJM ISO	AEP	Virginia Power Company			AP South	Martinsville VA (City of)	Martinsville VA (City of)	Martinsville VA (City of)	Martinsville	2	100	1	1	1	5/1/32	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Meadow Lake Wind Farm IV	Energias de Portugal SA	EDP Renewables North Americ	Meadow Lake Wind Far	WT257 303	100	98.7	98.7	98.7	10/31/10	WT	WND	Operating	Y	1
PJM ISO	AEP	American Electric Power				Meadow Lake Wind Farm II I	Energias de Portugal SA	EDP Renewables North Americ	Meadow Lake Wind Far	WT122 187	100	101	101	101	8/1/10	WT	WND	Operating	Y	1
PJM ISO	AEP	American Electric Power				Meadow Lake Wind Farm III	Energias de Portugal SA	EDP Renewables North Americ	Meadow Lake Wind Far	WT188 256	100	103.5	103.5	103.5	9/30/10	WT	WND	Operating	Y	1
PJM ISO	AEP	American Electric Power				Meadow Lake Wind Farm LL	Energias de Portugal SA	EDP Renewables North Americ	Meadow Lake Wind Far	WT1 121	100	199.65	199.65	199.65	10/1/09	WT	WND	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ae Operations LLC	Thermagen Power Group L	Ae Operations LLC	Mingo Junction	GEN1	100	32	30	28	8/1/98	ST	BFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Mitchell (WV)	1	100	816.3	770	770	5/1/71	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Mitchell (WV)	2	100	816.3	790	790	5/1/71	ST	BIT	Operating	Y	1
PJM ISO	AEP	Dayton Power & Light Co.				Energy Developments Inc	Energy Developments	Energy Developments Inc	Model (OH)	1	100	1.4	1.4	1.4	3/1/01	IC	LFG	Operating	Y	1
PJM ISO	AEP	Dayton Power & Light Co.				Energy Developments Inc	Energy Developments	Energy Developments Inc	Model (OH)	2	100	1.4	1.4	1.4	3/1/01	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				DPL Energy LLC	AES Corp (The)	DPL Energy LLC	Montpelier Electric Ger	GT1	100	59	45	59	6/5/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				DPL Energy LLC	AES Corp (The)	DPL Energy LLC	Montpelier Electric Ger	GT2	100	59	45	59	6/5/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				DPL Energy LLC	AES Corp (The)	DPL Energy LLC	Montpelier Electric Ger	GT3	100	59	45	59	6/11/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				DPL Energy LLC	AES Corp (The)	DPL Energy LLC	Montpelier Electric Ger	GT4	100	59	45	59	6/11/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Mottville	1	100	0.4	0.15	0.225	1/1/23	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Mottville	2	100	0.4	0.15	0.225	1/1/23	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Mottville	3	100	0.4	0.15	0.225	1/1/23	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Mottville	4	100	0.4	0.15	0.225	8/1/23	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Mountaineer	1	100	1300	1299	1299	9/1/80	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Muskingum River	3	100	237.5	205	215	12/1/57	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Muskingum River	4	100	237.5	205	215	5/1/58	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Muskingum River	1	100	219.6	190	205	12/1/53	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Muskingum River	2	100	219.6	190	205	6/1/54	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Muskingum River	5	100	615.2	585	585	10/1/68	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Narrows LLC	Duke Energy Corp	Narrows LLC	Narrows (VA)	GEN1	100	6	6	6	1/1/42	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Narrows LLC	Duke Energy Corp	Narrows LLC	Narrows (VA)	GEN2	100	6	6	6	1/1/42	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Narrows LLC	Duke Energy Corp	Narrows LLC	Narrows (VA)	GEN3	100	6	6	6	1/1/44	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Narrows LLC	Duke Energy Corp	Narrows LLC	Narrows (VA)	GEN4	100	9.2	9.2	9.2	1/1/66	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Eagle Natrium LLC	Georgia Gulf Corp	Eagle Natrium LLC	Natrium Plant	GEN3	100	7.5	7.5	7.5	1/1/43	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Eagle Natrium LLC	Georgia Gulf Corp	Eagle Natrium LLC	Natrium Plant	GEN4	100	7.5	7.5	7.5	1/1/43	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Eagle Natrium LLC	Georgia Gulf Corp	Eagle Natrium LLC	Natrium Plant	GEN7	100	82	82	82	1/1/66	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Eagle Natrium LLC	Georgia Gulf Corp	Eagle Natrium LLC	Natrium Plant	GEN6	100	26	26	26	1/1/54	ST	BIT	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	AEP	Virginia Power Company		AP South		Danville Power & Light Dept	Danville Power & Light Dep	Danville Power & Light Dept	New Design	GEN1	100	1.8	1.2	1.2	7/1/05	IC	DFO	Standby	Y	1
PJM ISO	AEP	American Electric Power				New Knoxville Light Dept	New Knoxville Light Dept	New Knoxville Light Dept	New Knoxville	1	100	1.1	1	1	9/1/00	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Niagara (VA)	1	100	2.4	0.6	1.4	6/1/54	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Niagara (VA)	2	100	1.2	1.2	1.2	6/1/54	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Nexgen Energy Partners LLC	Nexgen Energy Partners LL	Nexgen Energy Partners LLC	Ohio Northern Universi	WT1 3	100	1.2	1.2	1.2	5/21/10	WT	WND	Operating	Y	1
PJM ISO	AEP	American Electric Power				Orrville OH (City of)	Orrville OH (City of)	Orrville OH (City of)	Orrville	10	100	25	23	23	1/1/71	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Orrville OH (City of)	Orrville OH (City of)	Orrville OH (City of)	Orrville	11	100	25	23	23	1/1/71	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Orrville OH (City of)	Orrville OH (City of)	Orrville OH (City of)	Orrville	9	100	22	20	20	1/1/61	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Orrville Peaking	1	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Orrville Peaking	2	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Orrville Peaking	3	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Columbus OH (City of)	Columbus OH (City of)	Columbus OH (City of)	Oshaughnessy Hydro	1	100	1.3	1.3	1.3	9/1/88	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Columbus OH (City of)	Columbus OH (City of)	Columbus OH (City of)	Oshaughnessy Hydro	2	100	3.9	3.9	3.9	9/1/88	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Phil Sporn	1	100	152.5	145	150	1/1/50	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Appalachian Power Co	Phil Sporn	2	100	152.5	145	150	7/1/50	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Phil Sporn	3	100	152.5	145	150	8/1/51	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Appalachian Power Co	Phil Sporn	4	100	152.5	145	150	2/1/52	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				USACE Wilmington District	U S Army Corps of Enginee	USACE Wilmington District	Philpott Lake	1	100	6.7	7.5	7.5	8/1/53	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				USACE Wilmington District	U S Army Corps of Enginee	USACE Wilmington District	Philpott Lake	2	100	6.7	7.5	7.5	8/1/53	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				USACE Wilmington District	U S Army Corps of Enginee	USACE Wilmington District	Philpott Lake	3	100	0.6	0.6	0.6	8/1/53	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Picway	5	100	106.2	95	100	11/1/55	ST	BIT	Operating	Y	1
PJM ISO	AEP	Virginia Power Company		AP South		Danville Power & Light Dept	Danville Power & Light Dep	Danville Power & Light Dept	Pinnacles (VA)	1	100	3.7	3.5	3.5	6/1/38	HY	WAT	Restarted	Y	1
PJM ISO	AEP	Virginia Power Company		AP South		Danville Power & Light Dept	Danville Power & Light Dep	Danville Power & Light Dept	Pinnacles (VA)	2	100	3.7	3.5	3.5	6/1/38	HY	WAT	Restarted	Y	1
PJM ISO	AEP	Virginia Power Company		AP South		Danville Power & Light Dept	Danville Power & Light Dep	Danville Power & Light Dept	Pinnacles (VA)	3	100	3.7	3.5	3.5	6/1/38	HY	WAT	Restarted	Y	1
PJM ISO	AEP	Virginia Power Company		AP South		Danville Power & Light Dept	Danville Power & Light Dep	Danville Power & Light Dept	Pinnacles (VA)	4	100	0.75	0.75	0.75	11/1/00	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Racine	1	100	23.7	10	13	1/1/83	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Racine	2	100	23.7	10	13	9/1/82	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Radford VA (City of)	Radford VA (City of)	Radford VA (City of)	Radford	1	100	1	1	1	10/1/34	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				U S Army Radford	United States Army	U S Army Radford	Radford Army Ammunit	GEN1	100	6	5.62	5.64	1/1/90	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				U S Army Radford	United States Army	U S Army Radford	Radford Army Ammunit	GEN2	100	6	5.62	5.64	1/1/90	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				U S Army Radford	United States Army	U S Army Radford	Radford Army Ammunit	GEN3	100	6	5.62	5.64	1/1/90	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				U S Army Radford	United States Army	U S Army Radford	Radford Army Ammunit	GEN4	100	6	5.62	5.64	1/1/90	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Performance Services	Performance Services	Performance Services	Randolph Eastern Schoo	WT1	100	1	1	1	12/31/10	WT	WND	Operating	Y	1
PJM ISO	AEP	Dayton Power & Light Co.				Columbus OH (City of)	Columbus OH (City of)	Columbus OH (City of)	Renick Run 03 04	IC1	100	1.4	1.1	1.1	9/1/06	IC	DFO	Operating	Y	1
PJM ISO	AEP	Dayton Power & Light Co.				Columbus OH (City of)	Columbus OH (City of)	Columbus OH (City of)	Renick Run 03 04	IC2	100	1.4	1.1	1.1	9/1/06	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Reusens	1	100	2.5	2.5	2.5	1/1/03	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Reusens	2	100	2.5	2.5	2.5	1/1/03	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Reusens	3	100	2.5	2.5	2.5	1/1/03	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Reusens	4	100	2.5	2.5	2.5	1/1/03	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Reusens	5	100	2.5	2.5	2.5	1/1/03	HY	WAT	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	AEP	American Electric Power				Indiana Municipal Power Ag	Indiana Municipal Power A	Indiana Municipal Power Agen	Richmond (IN)	RCT1	100	41.4	34	42	5/1/92	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Municipal Power Ag	Indiana Municipal Power A	Indiana Municipal Power Agen	Richmond (IN)	RCT2	100	41.4	34	42	5/1/92	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Foothills Generating Co LLC	LS Power Group	Riverside Generating Co LLC	Riverside Generating Cc	GTG4	100	230	165	190	6/1/02	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Foothills Generating Co LLC	LS Power Group	Riverside Generating Co LLC	Riverside Generating Cc	GTG5	100	230	165	190	6/1/02	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Riverside Generating Co LLC	LS Power Group	Riverside Generating Co LLC	Riverside Generating Cc	GTG1	100	230	165	190	7/21/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Riverside Generating Co LLC	LS Power Group	Riverside Generating Co LLC	Riverside Generating Cc	GTG2	100	230	165	190	7/21/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Riverside Generating Co LLC	LS Power Group	Riverside Generating Co LLC	Riverside Generating Cc	GTG3	100	230	165	190	7/21/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				National Power Coop Inc	National Power Coop Inc	National Power Coop Inc	Robert P Mone Plant	1	100	198	151.7	184.9	7/10/02	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				National Power Coop Inc	National Power Coop Inc	National Power Coop Inc	Robert P Mone Plant	2	100	198	149.5	183.1	7/10/02	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				National Power Coop Inc	National Power Coop Inc	National Power Coop Inc	Robert P Mone Plant	3	100	198	149.4	183.7	7/10/02	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				AEP Generating Co	American Electric Power Cc	Indiana Michigan Power Co	Rockport	1	50	650	650	649.5	12/1/84	ST	SUB	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Cc	Indiana Michigan Power Co	Rockport	1	50	650	650	649.5	12/1/84	ST	SUB	Operating	Y	1
PJM ISO	AEP	American Electric Power				AEP Generating Co	American Electric Power Cc	Indiana Michigan Power Co	Rockport	2	50	650	650	649.5	12/1/89	ST	SUB	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Cc	Indiana Michigan Power Co	Rockport	2	50	650	650	649.5	12/1/89	ST	SUB	Operating	Y	1
PJM ISO	AEP	American Electric Power				Rolling Hills Generating LLC	Tenaska Inc	Rolling Hills Generating LLC	Rolling Hills Generating	GT1	100	195.5	165	180	6/5/03	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Rolling Hills Generating LLC	Tenaska Inc	Rolling Hills Generating LLC	Rolling Hills Generating	GT2	100	195.5	165	180	6/5/03	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Rolling Hills Generating LLC	Tenaska Inc	Rolling Hills Generating LLC	Rolling Hills Generating	GT3	100	195.5	165	180	6/5/03	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Rolling Hills Generating LLC	Tenaska Inc	Rolling Hills Generating LLC	Rolling Hills Generating	GT4	100	195.5	165	180	6/5/03	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Rolling Hills Generating LLC	Tenaska Inc	Rolling Hills Generating LLC	Rolling Hills Generating	GT5	100	195.5	165	180	6/5/03	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Salem VA (City of)	Salem VA (City of)	Salem VA (City of)	Salem Electric Dept	IC1	100	1.3	1.3	1.3	12/1/07	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Salem VA (City of)	Salem VA (City of)	Salem VA (City of)	Salem Street Dept	1	100	1.8	2	2	1/1/05	IC	DFO	Standby	Y	1
PJM ISO	AEP	American Electric Power				Salem VA (City of)	Salem VA (City of)	Salem VA (City of)	Salem Water Plant	1	100	2	2	2	1/1/03	IC	DFO	Standby	Y	1
PJM ISO	AEP	American Electric Power				Sauder Woodworking Co	Sauder Woodworking Co	Sauder Woodworking Co	Sauder	UNT1	100	3.6	3.6	3.6	10/1/93	ST	WDS	Operating	Y	1
PJM ISO	AEP	American Electric Power				Sauder Woodworking Co	Sauder Woodworking Co	Sauder Woodworking Co	Sauder	UNT2	100	3.6	3.6	3.6	10/1/93	ST	WDS	Operating	Y	1
PJM ISO	AEP	Virginia Power Company			AP South	STS HydroPower Ltd	Energy Investors Funds Gr	STS HydroPower Ltd	Schoolfield Dam	SCH1	100	1.5	1.5	1.5	10/1/90	HY	WAT	Operating	Y	1
PJM ISO	AEP	Virginia Power Company			AP South	STS HydroPower Ltd	Energy Investors Funds Gr	STS HydroPower Ltd	Schoolfield Dam	SCH2	100	1.5	1.5	1.5	11/1/90	HY	WAT	Operating	Y	1
PJM ISO	AEP	Virginia Power Company			AP South	STS HydroPower Ltd	Energy Investors Funds Gr	STS HydroPower Ltd	Schoolfield Dam	SCH3	100	1.5	1.5	1.5	12/1/90	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Shelby Dept of Utilities	Shelby Dept of Utilities	Shelby Dept of Utilities	Shelby Munic Light Plar	IC1	100	3	3	3	6/1/63	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				American Municipal Power I	American Municipal Powe	American Municipal Power Inc	Shelby North	1	100	1.8	1.8	1.8	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Shelby Dept of Utilities	Shelby Dept of Utilities	Shelby Dept of Utilities	Shelby South	1	100	1.8	1.7	1.8	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Cc	Appalachian Power Co	Smith Mountain	1	100	66	66	66	12/1/65	PS	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Cc	Appalachian Power Co	Smith Mountain	2	100	150.1	174	174	12/1/65	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Cc	Appalachian Power Co	Smith Mountain	3	100	115.3	106	106	6/1/80	PS	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Cc	Appalachian Power Co	Smith Mountain	4	100	150.1	174	174	2/1/66	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Cc	Appalachian Power Co	Smith Mountain	5	100	66	66	66	2/1/66	PS	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Bedford County Public Servic	Bedford County Public Ser	Bedford County Public Service	Snowden	4	100	2.5	2.5	2.5	8/1/87	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Bedford County Public Servic	Bedford County Public Ser	Bedford County Public Service	Snowden	5	100	2.5	2.5	2.5	8/1/87	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				North American Natural Res	North American Natural Re	North American Natural Resou	Southeast Berrien Land	IC1	100	1.6	1.6	1.6	7/31/09	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				North American Natural Res	North American Natural Re	North American Natural Resou	Southeast Berrien Land	IC2	100	1.6	1.6	1.6	7/31/09	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				North American Natural Res	North American Natural Re	North American Natural Resou	Southeast Berrien Land	IC3	100	1.6	1.6	1.6	7/31/09	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	AEP	American Electric Power				Columbus OH (City of)	Columbus OH (City of)	Columbus OH (City of)	St 1a 0006	6	100	1.3	1.1	1.1	1/1/08	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Columbus OH (City of)	Columbus OH (City of)	Columbus OH (City of)	St 8 0005	5	100	2	1.8	1.8	1/1/08	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	Saint Marys OH (City of)	St Marys (OH)	GT1	100	11	10.4	10.4	12/1/99	GT	NG	Standby	Y	1
PJM ISO	AEP	American Electric Power				Saint Marys OH (City of)	Saint Marys OH (City of)	Saint Marys OH (City of)	St Marys (OH)	7	100	14	12	12	8/1/92	GT	DFO	Standby	Y	1
PJM ISO	AEP	American Electric Power				Waste Management Inc	Waste Management Inc	Waste Management Inc	Suburban Landfill	IC1	100	0.8	0.8	0.8	1/14/11	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Waste Management Inc	Waste Management Inc	Waste Management Inc	Suburban Landfill	IC2	100	0.8	0.8	0.8	1/14/11	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Waste Management Inc	Waste Management Inc	Waste Management Inc	Suburban Landfill	IC3	100	0.8	0.8	0.8	1/14/11	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Waste Management Inc	Waste Management Inc	Waste Management Inc	Suburban Landfill	IC4	100	0.8	0.8	0.8	1/14/11	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Waste Management Inc	Waste Management Inc	Waste Management Inc	Suburban Landfill	IC5	100	0.8	0.8	0.8	1/14/11	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Waste Management Inc	Waste Management Inc	Waste Management Inc	Suburban Landfill	IC6	100	0.8	0.8	0.8	1/14/11	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Waste Management Inc	Waste Management Inc	Waste Management Inc	Suburban Landfill	IC7	100	0.8	0.8	0.8	1/14/11	IC	LFG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Tanners Creek	1	100	152.5	145	145	3/1/51	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Tanners Creek	2	100	152.5	145	145	11/1/52	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Tanners Creek	3	100	215.4	200	205	12/1/54	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Tanners Creek	4	100	579.7	500	500	7/1/64	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TG16	100	10.4	10.4	10.4	7/1/66	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TG17	100	10.4	10.4	10.4	10/1/66	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TGO7	100	6	6	6	9/1/36	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TG18	100	10.4	10.4	10.4	7/1/67	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TGO8	100	6	6	6	9/1/39	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TG19	100	10.4	10.4	10.4	3/1/70	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TGO9	100	6	6	6	7/1/41	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TG10	100	6	6	6	2/1/46	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TG11	100	6	6	6	5/1/49	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TG12	100	6	6	6	2/1/53	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TG13	100	7	7	7	1/1/60	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TG14	100	10	10	10	4/1/62	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TG15	100	7.5	7.5	7.5	10/1/63	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TG20	100	10.4	10.4	10.4	4/1/72	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TG21	100	15	15	15	7/1/69	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TG24	100	16.8	16.8	16.8	7/1/83	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TG25	100	18	18	18	12/1/94	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TG22	100	15.4	15.4	15.4	9/1/82	ST	BIT	Operating	Y	1
PJM ISO	AEP	Tennessee Valley Authority				Eastman Chemical Co	Eastman Chemical Co	Eastman Chemical Co	Tenn Eastman Division ,	TG26	100	16.6	16.6	16.6	10/1/94	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Grande Pointe Power Corp	Grande Pointe Power Corp	Grande Pointe Power Corp	Three Rivers Hydroelect	HY	100	0.9	0.9	0.9	1/1/13	HY	WAT	Mothballed	Y	1
PJM ISO	AEP	American Electric Power				Paulding Wind Farm II LLC	Energias de Portugal SA	Paulding Wind Farm II LLC	Timber Road Wind Farm	WT1 55	100	99	99	99	7/22/11	WT	WND	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Twin Branch	H1E	100	0.6	2.9	3.6	5/1/89	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Twin Branch	H1W	100	0.6	0.363	0.45	5/1/89	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Twin Branch	H2W	100	0.6	0.363	0.45	5/1/89	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power C	Indiana Michigan Power Co	Twin Branch	H3W	100	0.6	0.363	0.45	5/1/89	HY	WAT	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Twin Branch	H4W	100	0.6	0.363	0.45	5/1/89	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Twin Branch	H5W	100	0.6	0.363	0.45	5/1/89	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Twin Branch	H6E	100	0.6	0.363	0.45	5/1/89	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Indiana Michigan Power Co	American Electric Power Co	Indiana Michigan Power Co	Twin Branch	H6W	100	0.6	0.363	0.45	5/1/89	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Union Carbide C & P Charles	Dow Chemical Co (The)	Union Carbide C & P Charlesto	Union Carbide South Ch	GEN8	100	6	5.58	5.64	11/1/53	ST	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Performance Services	Performance Services	Performance Services	Union City Wind	WT1	100	1	1	1	12/31/10	WT	WND	Operating	Y	1
PJM ISO	AEP	American Electric Power				University of Notre Dame	University of Notre Dame	University of Notre Dame	Univ of Notre Dame	GEN1	100	3	3	3	6/1/62	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				University of Notre Dame	University of Notre Dame	University of Notre Dame	Univ of Notre Dame	GEN10	100	1.9	1.7	1.8	10/1/06	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				University of Notre Dame	University of Notre Dame	University of Notre Dame	Univ of Notre Dame	GEN2	100	1.7	1.7	1.7	7/1/52	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				University of Notre Dame	University of Notre Dame	University of Notre Dame	Univ of Notre Dame	GEN3	100	1	1	1	7/1/52	IC	DFO	Standby	Y	1
PJM ISO	AEP	American Electric Power				University of Notre Dame	University of Notre Dame	University of Notre Dame	Univ of Notre Dame	GEN4	100	1	1	1	7/1/52	IC	DFO	Standby	Y	1
PJM ISO	AEP	American Electric Power				University of Notre Dame	University of Notre Dame	University of Notre Dame	Univ of Notre Dame	GEN5	100	2	2	2	9/1/56	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				University of Notre Dame	University of Notre Dame	University of Notre Dame	Univ of Notre Dame	GEN6	100	5	5	5	2/1/67	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				University of Notre Dame	University of Notre Dame	University of Notre Dame	Univ of Notre Dame	GEN7	100	9.4	9.4	9.4	3/1/00	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				University of Notre Dame	University of Notre Dame	University of Notre Dame	Univ of Notre Dame	GEN8	100	1.9	1.7	1.8	10/1/06	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				University of Notre Dame	University of Notre Dame	University of Notre Dame	Univ of Notre Dame	GEN9	100	1.9	1.7	1.8	10/1/06	IC	DFO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Virginia Polytechnic Institute	Virginia Polytechnic Institu	Virginia Polytechnic Institute &	Virginia Tech Power Pla	WG01	100	6.3	2.5	6.3	3/1/76	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Duke Energy Washington II L	Duke Energy Corp	Duke Energy Washington II LL	Washington Energy Fac	CC1	100	714.9	626	648	7/26/02	CC	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power Co	Ohio Power Co	Waterford Energy Facili	CC1	100	921.6	810	850	8/11/03	CC	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Richmond Power & Light	Richmond Power & Light	Richmond Power & Light	Whitewater Valley	1	100	33	34.7	34.7	3/1/55	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Richmond Power & Light	Richmond Power & Light	Richmond Power & Light	Whitewater Valley	2	100	60.9	65	65	8/1/73	ST	BIT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Winfield (WV)	1	100	14.7	8.9	14.5	1/1/38	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Winfield (WV)	2	100	4.9	4.9	4.9	1/1/38	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Appalachian Power Co	American Electric Power Co	Appalachian Power Co	Winfield (WV)	3	100	4.9	4.9	4.9	1/1/38	HY	WAT	Operating	Y	1
PJM ISO	AEP	American Electric Power				Wolf Hills Energy LLC (Tenasl	Tenaska Inc	Wolf Hills Energy LLC (Tenaska	Wolf Hills Energy	WHG1	100	57	50	57	7/1/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Wolf Hills Energy LLC (Tenasl	Tenaska Inc	Wolf Hills Energy LLC (Tenaska	Wolf Hills Energy	WHG2	100	57	50	57	7/1/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Wolf Hills Energy LLC (Tenasl	Tenaska Inc	Wolf Hills Energy LLC (Tenaska	Wolf Hills Energy	WHG3	100	57	50	57	7/1/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Wolf Hills Energy LLC (Tenasl	Tenaska Inc	Wolf Hills Energy LLC (Tenaska	Wolf Hills Energy	WHG4	100	57	50	57	7/1/01	GT	NG	Operating	Y	1
PJM ISO	AEP	American Electric Power				Wolf Hills Energy LLC (Tenasl	Tenaska Inc	Wolf Hills Energy LLC (Tenaska	Wolf Hills Energy	WHG5	100	57	50	57	7/1/01	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				AES Warrior Run Inc	AES Corp (The)	AES Warrior Run Inc	AES Warrior Run Cogen	GEN1	100	229	180	180	8/1/99	AB	BIT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Allegheny Energy Unit 8	UNT8	100	43.8	44	44	11/1/00	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Allegheny Energy Unit 8	UNT9	100	43.8	44	44	11/1/00	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Allegheny Energy Units	UNT1	100	43.8	44	44	12/1/99	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Allegheny Energy Units	UNT2	100	43.8	44	44	12/1/99	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power	5004/5005	AP South		Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Allegheny Energy Units	UN12	100	43.8	44	44	12/1/01	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power	5004/5005	AP South		Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Allegheny Energy Units	UN13	100	43.8	44	44	12/1/01	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Allegheny Energy Units	CC	100	556	509	550	7/14/03	CC	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Hydro LP	FirstEnergy Corp	Allegheny Hydro LP	Allegheny Hydro Partne	GEN1	100	4.6	3	5	10/1/88	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Hydro LP	FirstEnergy Corp	Allegheny Hydro LP	Allegheny Hydro Partne	GEN2	100	4.6	3	5	10/1/88	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny No 6 Hydro Partne	FirstEnergy Corp	Allegheny No 6 Hydro Partners	Allegheny No 6 Hydro P	GEN1	100	4.6	4	6	11/1/88	HY	WAT	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	APS	Allegheny Power				Allegheny No 6 Hydro Partne	FirstEnergy Corp	Allegheny No 6 Hydro Partners	Allegheny No 6 Hydro P	GEN2	100	4.6	4	6	11/1/88	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Arden Landfill	GEN1	100	0.8	0.8	0.8	3/31/09	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Arden Landfill	GEN2	100	0.8	0.8	0.8	3/31/09	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Arden Landfill	GEN3	100	0.8	0.8	0.8	3/31/09	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Arden Landfill	GEN4	100	0.8	0.8	0.8	3/31/09	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Arden Landfill	GEN5	100	0.8	0.8	0.8	3/31/09	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Arden Landfill	GEN6	100	0.8	0.8	0.8	3/31/09	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power		5004/5005	AP South	Armstrong Energy LP LLLP (IF	International Power	Armstrong Energy LP LLLP (IP p	Armstrong (PA)	1	100	172	146	169	6/21/02	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power		5004/5005	AP South	Armstrong Energy LP LLLP (IF	International Power	Armstrong Energy LP LLLP (IP p	Armstrong (PA)	2	100	172	146	169	6/21/02	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power		5004/5005	AP South	Armstrong Energy LP LLLP (IF	International Power	Armstrong Energy LP LLLP (IP p	Armstrong (PA)	3	100	172	146	169	6/21/02	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power		5004/5005	AP South	Armstrong Energy LP LLLP (IF	International Power	Armstrong Energy LP LLLP (IP p	Armstrong (PA)	4	100	172	146	169	6/21/02	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Chambersburg PA (Borough	Chambersburg PA (Boroug	Chambersburg PA (Borough of	Chambersburg Diesel	5	100	2	2.1	2.1	12/1/67	IC	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Chambersburg PA (Borough	Chambersburg PA (Boroug	Chambersburg PA (Borough of	Chambersburg Diesel	6	100	2	2.1	2.1	12/1/67	IC	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Chambersburg PA (Borough	Chambersburg PA (Boroug	Chambersburg PA (Borough of	Chambersburg Diesel	7	100	3.2	2.9	2.9	6/1/01	IC	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Criterion Power Partners LLC	Exelon Corp	Criterion Power Partners LLC	Criterion Wind Power G	WT1 28	100	70	70	70	2/4/11	WT	WND	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Dam 4	1	100	0.5	0.474	0.5	1/1/09	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Dam 4	2	100	0.5	0.474	0.5	1/1/09	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Dam 4	3	100	0.9	0.853	0.9	9/1/91	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Dam 5	1	100	0.5	0.5	0.5	1/1/19	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Dam 5	2	100	0.5	0.5	0.5	1/1/19	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Duke Energy Fayette II LLC	Duke Energy Corp	Duke Energy Fayette II LLC	Fayette Energy Facility	CC1	100	677	600.5	634.5	6/1/03	CC	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Keenan Development	Keenan Development Grou	Chevron Energy Solutions	Fort Detrick Power Plan	GT1	100	6	6	6	5/9/08	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Keenan Development	Keenan Development Grou	Chevron Energy Solutions	Fort Detrick Power Plan	GT2	100	6	6	6	5/9/08	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Keenan Development	Keenan Development Grou	Chevron Energy Solutions	Fort Detrick Power Plan	GT3	100	6	6	6	5/9/08	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Keenan Development	Keenan Development Grou	Chevron Energy Solutions	Fort Detrick Power Plan	GT4	100	6	6	6	5/9/08	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Keenan Development	Keenan Development Grou	Chevron Energy Solutions	Fort Detrick Power Plan	GT5	100	6	6	6	5/9/08	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Monongahela Power Co	FirstEnergy Corp	Monongahela Power Co	Fort Martin	1	100	576	552	552	10/1/67	ST	BIT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Monongahela Power Co	FirstEnergy Corp	Monongahela Power Co	Fort Martin	2	100	576	555	555	12/1/68	ST	BIT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Frederick County Dept of Pul	Frederick County Dept of P	Frederick County Dept of Publi	Frederick County Lfgte	GEN1	100	1	1	1	10/12/10	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Frederick County Dept of Pul	Frederick County Dept of P	Frederick County Dept of Publi	Frederick County Lfgte	GEN2	100	1	1	1	10/12/10	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				American Bituminous Power	Edison International	American Bituminous Power L	Grant Town Power Plan	GEN1	100	95.7	80	80	7/1/92	AB	WC	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Monongahela Power Co	Harrison (WV)	1	79.5	543.78	518.34	526.29	12/1/72	ST	BIT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Monongahela Power Co	FirstEnergy Corp	Monongahela Power Co	Harrison (WV)	1	20.5	140.22	133.66	135.71	12/1/72	ST	BIT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Monongahela Power Co	Harrison (WV)	2	79.5	543.78	517.545	525.495	12/1/73	ST	BIT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Monongahela Power Co	FirstEnergy Corp	Monongahela Power Co	Harrison (WV)	2	20.5	140.22	133.455	135.505	12/1/73	ST	BIT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Monongahela Power Co	Harrison (WV)	3	79.5	543.78	517.545	525.495	12/1/74	ST	BIT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Monongahela Power Co	FirstEnergy Corp	Monongahela Power Co	Harrison (WV)	3	20.5	140.22	133.455	135.505	12/1/74	ST	BIT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Hatfields Ferry Power S	1	100	576	530	570	11/1/69	ST	BIT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Hatfields Ferry Power S	2	100	576	530	570	10/1/70	ST	BIT	Restarted	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Hatfields Ferry Power S	3	100	576	530	570	12/1/71	ST	BIT	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Lake Lynn	1	100	12.8	13	13	9/1/26	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Lake Lynn	2	100	12.8	13	13	7/1/26	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Lake Lynn	3	100	12.8	13	13	6/1/26	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Lake Lynn	4	100	12.8	13	13	5/1/26	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				AES Laurel Mountain LLC	AES Corp (The)	AES Laurel Mountain LLC	Laurel Mountain Wind I	ES1 8	100	0	0	0	10/28/11	ES	OTH	Operating	Y	1
PJM ISO	APS	Allegheny Power				AES Laurel Mountain LLC	AES Corp (The)	AES Laurel Mountain LLC	Laurel Mountain Wind I	WT1 65	100	97.6	97.6	97.6	6/30/11	WT	WND	Operating	Y	1
PJM ISO	APS	Allegheny Power				Luke Paper Co	Cerberus Capital Managem	Luke Paper Co	Luke Mill	GEN1	100	35	32	26	1/1/58	ST	BIT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Luke Paper Co	Cerberus Capital Managem	Luke Paper Co	Luke Mill	GEN2	100	30	28	24	1/1/79	ST	BIT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Luray	1	100	0.6	0.375	0.6	1/1/27	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Luray	2	100	0.4	0.25	0.4	1/1/27	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Luray	3	100	0.6	0.4	0.6	1/1/27	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Mill Run Windpower LLC	NextEra Energy Inc	Mill Run Windpower LLC	Mill Run Windpower	WT1 10	100	15	15	15	10/24/01	WT	WND	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Millville	1	100	0.8	0.6	0.8	1/1/13	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Millville	2	100	1	0.8	1	1/3/39	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Millville	3	100	1	1	1.2	1/3/38	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Mitchell Power Station	2	100	74.7	82	82	10/1/49	ST	DFO	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Allegheny Energy Supply Co LL	Mitchell Power Station	3	100	299.2	278	288	8/1/63	ST	BIT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Morgantown Energy Associa	Dominion Resources Inc	Morgantown Energy Associate	Morgantown Energy As	GEN1	100	68.9	50	50	11/1/91	ST	WC	Operating	Y	1
PJM ISO	APS	Allegheny Power				NedPower Mount Storm Inc	Dominion Resources Inc	Shell Wind Energy	Mount Storm NedPowe	WT1 82	100	164	164	164	5/1/08	WT	WND	Operating	Y	1
PJM ISO	APS	Allegheny Power				NedPower Mount Storm Inc	Dominion Resources Inc	Shell Wind Energy	Mount Storm NedPowe	WT83 132	100	100	100	100	10/1/08	WT	WND	Operating	Y	1
PJM ISO	APS	Allegheny Power				Backbone Mountain Windpc	NextEra Energy Inc	Backbone Mountain Windpow	Mountaineer Wind Ene	WT1 44	100	66	66	66	12/31/02	WT	WND	Operating	Y	1
PJM ISO	APS	Allegheny Power				Covanta New Martinsville Hy	Covanta Holding Corp	Covanta New Martinsville Hyd	New Martinsville Hydro	UNT1	100	18.7	18.7	18.7	8/1/88	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Covanta New Martinsville Hy	Covanta Holding Corp	Covanta New Martinsville Hyd	New Martinsville Hydro	UNT2	100	18.7	18.7	18.7	7/1/88	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Newport (VA)	1	100	0.4	0.3	0.4	1/1/23	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Newport (VA)	2	100	0.4	0.5	0.5	1/1/23	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Newport (VA)	3	100	0.6	0.51	0.64	1/1/23	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Chambersburg PA (Borough	Chambersburg PA (Boroug	Chambersburg PA (Borough of	Orchard Park Generatin	10	100	5.8	5.8	5.8	12/5/03	IC	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Chambersburg PA (Borough	Chambersburg PA (Boroug	Chambersburg PA (Borough of	Orchard Park Generatin	11	100	5.8	5.8	5.8	12/5/03	IC	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Chambersburg PA (Borough	Chambersburg PA (Boroug	Chambersburg PA (Borough of	Orchard Park Generatin	8	100	5.8	5.8	5.8	12/5/03	IC	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Chambersburg PA (Borough	Chambersburg PA (Boroug	Chambersburg PA (Borough of	Orchard Park Generatin	9	100	5.8	5.8	5.8	12/5/03	IC	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Monongahela Power Co	Pleasants	1	92.3	631.332	594.412	599.95	4/1/79	ST	BIT	Restarted	Y	1
PJM ISO	APS	Allegheny Power				Monongahela Power Co	FirstEnergy Corp	Monongahela Power Co	Pleasants	1	7.7	52.668	49.588	50.05	4/1/79	ST	BIT	Restarted	Y	1
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	FirstEnergy Corp	Monongahela Power Co	Pleasants	2	92.3	631.332	594.412	599.95	12/1/80	ST	BIT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Monongahela Power Co	FirstEnergy Corp	Monongahela Power Co	Pleasants	2	7.7	52.668	49.588	50.05	12/1/80	ST	BIT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Pleasants Energy LLC (IP plc)	International Power	Pleasants Energy LLC (IP plc)	Pleasants Energy LLC	1	100	172	160.2	160.2	5/1/02	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Pleasants Energy LLC (IP plc)	International Power	Pleasants Energy LLC (IP plc)	Pleasants Energy LLC	2	100	172	163.7	163.7	5/1/02	GT	NG	Operating	Y	1
PJM ISO	APS	Allegheny Power				FC Landfill Energy LLC	South Jersey Industries Inc	FC Landfill Energy LLC	Reichs Ford Landfill	GT1	100	1.1	1.1	1.1	6/1/10	GT	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				FC Landfill Energy LLC	South Jersey Industries Inc	FC Landfill Energy LLC	Reichs Ford Landfill	GT2	100	1.1	1.1	1.1	6/1/10	GT	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				Roth Rock Wind Farm LLC	Gestamp Corp	enXco Service Corp	Roth Rock Wind Power	WT1 16	100	40	40	40	1/25/11	WT	WND	Operating	Y	1
PJM ISO	APS	Allegheny Power				Roth Rock Wind Farm LLC	Gestamp Corp	enXco Service Corp	Roth Rock Wind Power	WT17 20	100	10	10	10	1/25/11	WT	WND	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Shenandoah (VA)	1	100	0.9	0.2	0.4	1/1/25	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Shenandoah (VA)	2	100	0.25	0.25	0.25	1/1/25	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Shenandoah (VA)	3	100	0.25	0.25	0.25	1/1/25	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Shenandoah (VA)	4	100	0.112	0.112	0.112	1/1/25	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				SunEdison	SunEdison	SunEdison	Staples Hagerstown Sol	PV1	100	1.5	1.5	1.5	9/21/10	PV	SUN	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Warren (VA)	1	100	0.3	0.3	0.3	1/1/24	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Warren (VA)	2	100	0.25	0.25	0.25	1/1/24	HY	WAT	Operating	Y	1
PJM ISO	APS	Allegheny Power				Potomac Edison Co (The)	FirstEnergy Corp	Potomac Edison Co (The)	Warren (VA)	3	100	0.25	0.25	0.25	1/1/24	HY	WAT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Ashtabula	5	100	256	244	244	12/1/58	ST	SUB	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				DTE Ashtabula LLC	DTE Energy Co	DTE Ashtabula LLC	Ashtabula (CINERGY/TR	5	100	4.9	4.4	5.4	2/1/01	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Bryan Municipal Utilities	Bryan OH (City of)	Bryan Municipal Utilities	Auglaize Hydro	1	100	0.7	0.8	0.8	12/1/86	HY	WAT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Bryan Municipal Utilities	Bryan OH (City of)	Bryan Municipal Utilities	Auglaize Hydro	2A	100	0.9	0.9	0.8	6/1/04	HY	WAT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Bryan Municipal Utilities	Bryan OH (City of)	Bryan Municipal Utilities	Auglaize Hydro	3A	100	0.9	0.9	0.8	6/1/04	HY	WAT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Bryan Municipal Utilities	Bryan OH (City of)	Bryan Municipal Utilities	Auglaize Hydro	4	100	0.5	0.8	0.8	1/1/87	HY	WAT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Bryan Municipal Utilities	Bryan OH (City of)	Bryan Municipal Utilities	Auglaize Hydro	5	100	0.5	0.7	0.7	6/1/88	HY	WAT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Bryan Municipal Utilities	Bryan OH (City of)	Bryan Municipal Utilities	Auglaize Hydro	6	100	0.1	0.1	0.1	6/1/04	HY	WAT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				NRG Power Midwest LP	NRG Energy Inc	NRG Power Midwest LP	Avon Lake	10	100	29	30	30	1/1/68	GT	DFO	Standby	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				NRG Power Midwest LP	NRG Energy Inc	NRG Power Midwest LP	Avon Lake	7	100	86	70	70	1/1/49	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				NRG Power Midwest LP	NRG Energy Inc	NRG Power Midwest LP	Avon Lake	9	100	680	640	640	1/1/70	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Bay Shore	GT1	100	16	16	17	8/1/67	GT	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Bay Shore	1	100	140.6	136	136	8/1/55	AB	PC	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Bio Gas Technologies	Bio Gas Technologies Ltd	Bio Gas Technologies	Bio Gas Project	IC1	100	1.6	1.6	1.6	12/31/09	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Bio Gas Technologies	Bio Gas Technologies Ltd	Bio Gas Technologies	Bio Gas Project	IC2	100	1.8	1.8	1.8	12/31/09	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Powe	American Municipal Power Inc	Bowling Green (AMP)	GT 1	100	33	26	33	6/1/00	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Powe	American Municipal Power Inc	Bowling Green (AMP)	GT 2	100	16.5	12	16.5	6/1/00	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Powe	American Municipal Power Inc	Bowling Green Peaking	1	100	32	29	32	6/1/00	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Powe	Bowling Green OH (City of)	Bowling Green Wind Fa	1	100	1.6	1.6	1.6	10/1/93	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Powe	Bowling Green OH (City of)	Bowling Green Wind Fa	2	100	7.2	7.2	7.2	8/1/95	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Omega Joint Venture 6	American Municipal Powe	Bowling Green OH (City of)	Bowling Green Wind Fa	WT1	100	1.8	1.8	1.8	11/6/03	WT	WND	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Omega Joint Venture 6	American Municipal Powe	Bowling Green OH (City of)	Bowling Green Wind Fa	WT2	100	1.8	1.8	1.8	11/6/03	WT	WND	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Omega Joint Venture 6	American Municipal Powe	Bowling Green OH (City of)	Bowling Green Wind Fa	WT3	100	1.8	1.8	1.8	11/19/04	WT	WND	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Omega Joint Venture 6	American Municipal Powe	Bowling Green OH (City of)	Bowling Green Wind Fa	WT4	100	1.8	1.8	1.8	11/19/04	WT	WND	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Bridgewater Dairy	Bridgewater Dairy	Bridgewater Dairy	Bridgewater Dairy Proje	IC1	100	0.6	0.6	0.6	8/28/08	IC	OBG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Bridgewater Dairy	Bridgewater Dairy	Bridgewater Dairy	Bridgewater Dairy Proje	IC2	100	0.6	0.6	0.6	8/28/08	IC	OBG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Bruce Mansfield	1	100	913.7	830	830	4/1/76	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Bruce Mansfield	2	100	913.7	830	830	10/1/77	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Bruce Mansfield	3	100	913.7	850	850	9/1/80	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Powe	American Municipal Power Inc	Bryan Peaking	1	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Powe	American Municipal Power Inc	Bryan Peaking	2	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Powe	American Municipal Power Inc	Bryan Peaking	3	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Bryan Peaking	4	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Bryan Peaking	5	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Bryan Peaking	6	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Bryan Municipal Utilities	Bryan OH (City of)	Bryan Municipal Utilities	Bryan(OH)	1	100	15.8	12.5	19.5	7/1/70	GT	NG	Standby	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Bryan Municipal Utilities	Bryan OH (City of)	Bryan Municipal Utilities	Bryan(OH)	2	100	16	12.5	19.5	7/1/88	GT	NG	Standby	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Bryan Municipal Utilities	Bryan OH (City of)	Bryan Municipal Utilities	Bryan(OH)	5	100	2.5	2.5	2.5	5/1/48	IC	DFO	Standby	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Bryan Municipal Utilities	Bryan OH (City of)	Bryan Municipal Utilities	Bryan(OH)	6	100	5	4	6	7/1/63	GT	NG	Standby	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				International Steel Group Inc	Mittal Steel Co N V	ISG Cleveland Inc	Cleveland (OH ISGCLVLI	GEN3	100	10	10	10	1/1/65	ST	BFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				International Steel Group Inc	Mittal Steel Co N V	ISG Cleveland Inc	Cleveland (OH ISGCLVLI	GEN5	100	10	10	10	1/1/65	ST	BFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				International Steel Group Inc	Mittal Steel Co N V	ISG Cleveland Inc	Cleveland (OH ISGCLVLI	GENA	100	15	15	15	1/1/50	ST	BFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				International Steel Group Inc	Mittal Steel Co N V	ISG Cleveland Inc	Cleveland (OH ISGCLVLI	GENB	100	10	10	10	1/1/65	ST	BFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				International Steel Group Inc	Mittal Steel Co N V	ISG Cleveland Inc	Cleveland (OH ISGCLVLI	GENC	100	23	23	23	2/1/10	ST	BFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Cleveland Peaking	1	100	1.8	1.8	1.8	7/1/00	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Cleveland Peaking	2	100	1.8	1.8	1.8	7/1/00	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Cleveland Peaking	3	100	1.8	1.8	1.8	7/1/00	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Cleveland Peaking	4	100	1.8	1.8	1.8	7/1/00	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Cleveland Peaking	5	100	1.8	1.8	1.8	7/1/00	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Cleveland Peaking	6	100	1.8	1.8	1.8	7/1/00	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				IPS Energy Ventures	Ips Energy Ventures	IPS Energy Ventures	Collins Park Solar	PV1	100	1	1	1	8/11/11	PV	SUN	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Cleveland Public Power	Cleveland Public Power	Cleveland Public Power	Collinwood	3	100	16	16	18	2/1/71	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				MM Cuyohega Energy LLC	FORTISTAR	MM Cuyohega Energy LLC	Cuyahoga Regional Lan	UNT1	100	1.9	1.8	1.8	2/1/99	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				MM Cuyohega Energy LLC	FORTISTAR	MM Cuyohega Energy LLC	Cuyahoga Regional Lan	UNT2	100	1.9	1.8	1.8	2/1/99	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Nuclear Generati	FirstEnergy Corp	FirstEnergy Nuclear Operating	Davis Besse	1	100	970	894	908	11/1/77	NP	URA	Restarted	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Eastlake (OH)	6	100	32	24	29	12/1/73	GT	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Eastlake (OH)	1	100	123	132	132	9/1/53	ST	SUB	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Eastlake (OH)	2	100	123	132	132	12/1/53	ST	SUB	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Eastlake (OH)	3	100	123	132	132	8/1/54	ST	SUB	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	Cuyahoga Falls OH (City of)	Engle	16	100	9	9	9	8/1/89	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Genoa (Village of)	Genoa (Village of)	Genoa (Village of)	Genoa Diesel Generatir	IC 1	100	2	2	2	9/1/03	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Genoa (Village of)	Genoa (Village of)	Genoa (Village of)	Genoa Diesel Generatir	IC2	100	2	2	2	9/1/03	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Genoa (Village of)	Genoa (Village of)	Genoa (Village of)	Genoa Diesel Generatir	IC3	100	2	2	2	9/1/03	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Lake Shore	IC1	100	2	2	2	6/1/66	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Lake Shore	IC2	100	2	2	2	6/1/66	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Lake Shore	18	100	256	245	245	6/1/62	ST	SUB	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Lincoln Electric Co	Lincoln Electric Co	Lincoln Electric Co	Lincoln Electric Wind (C	WT1	100	2.5	2.5	2.5	6/27/11	WT	WND	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Lowellville	IC1	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Lowellville	IC10	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Lowellville	IC11	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Lowellville	IC12	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Lowellville	IC13	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Lowellville	IC14	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Lowellville	IC15	100	1.4	1.4	1.4	4/1/11	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Lowellville	IC16	100	1.4	1.4	1.4	4/1/11	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Lowellville	IC2	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Lowellville	IC3	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Lowellville	IC4	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Lowellville	IC5	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Lowellville	IC6	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Lowellville	IC7	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Lowellville	IC8	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Lowellville	IC9	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Mad River	CTA	100	27	25	30	8/1/72	GT	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Mad River	CTB	85.6	23.112	21.4	25.68	9/1/72	GT	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Pennsylvania Power Co	FirstEnergy Corp	FirstEnergy Generation, LLC	Mad River	CTB	14.4	3.888	3.6	4.32	9/1/72	GT	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Montpelier	1	100	1.8	1.8	1.8	7/1/00	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Montpelier	2	100	1.8	1.8	1.8	7/1/00	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Montpelier	3	100	1.8	1.8	1.8	7/1/00	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Montpelier	4	100	1.8	1.8	1.8	7/1/00	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Montpelier	5	100	1.8	1.8	1.8	7/1/00	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Montpelier	6	100	1.8	1.8	1.8	7/1/00	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Morton International Inc	Dow Chemical Co (The)	Morton International Inc	Morton Salt Rittman	GEN1	100	1.5	1.5	1.5	10/1/78	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	Napoleon OH (City of)	Napoleon (City)	IC1	100	1.8	1.8	1.8	12/1/90	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	Napoleon OH (City of)	Napoleon (City)	IC2	100	1.8	1.8	1.8	12/1/90	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	Napoleon OH (City of)	Napoleon (City)	IC3	100	1.8	1.8	1.8	12/1/90	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Napoleon Peaking GT (A	GT 1	100	33	26	33	6/1/00	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Napoleon Peaking GT (A	GT 2	100	16.5	12	16.5	6/1/00	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Ohio Municipal Electric Gen	Cuyahoga Falls OH (City of)	American Municipal Power Inc	Napoleon Peaking IC (A	4	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Ohio Municipal Electric Gen	Cuyahoga Falls OH (City of)	American Municipal Power Inc	Napoleon Peaking IC (A	5	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Ohio Municipal Electric Gen	Cuyahoga Falls OH (City of)	American Municipal Power Inc	Napoleon Peaking IC (A	6	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				NRG Power Midwest LP	NRG Energy Inc	NRG Power Midwest LP	New Castle Plant	3	100	98	88	93	9/1/52	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				NRG Power Midwest LP	NRG Energy Inc	NRG Power Midwest LP	New Castle Plant	4	100	114	87	92	8/1/58	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				NRG Power Midwest LP	NRG Energy Inc	NRG Power Midwest LP	New Castle Plant	5	100	136	130	135	6/1/64	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				NRG Power Midwest LP	NRG Energy Inc	NRG Power Midwest LP	New Castle Plant	EMDA	100	3.2	2.5	2.5	12/1/68	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	Niles OH (City of)	Niles (OH NILES)	13	100	5.4	5.4	5.4	12/1/90	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				NRG Power Midwest LP	NRG Energy Inc	NRG Power Midwest LP	Niles (OH ORION)	GT1	100	27	25	30	7/1/72	GT	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Oberlin OH (City of)	Oberlin OH (City of)	Oberlin OH (City of)	Oberlin (OH)	1	100	1.1	1	1	1/1/48	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Oberlin OH (City of)	Oberlin OH (City of)	Oberlin OH (City of)	Oberlin (OH)	10	100	0.5	0.5	0.5	1/1/90	IC	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Oberlin OH (City of)	Oberlin OH (City of)	Oberlin OH (City of)	Oberlin (OH)	2A	100	3.1	3.1	3.1	6/1/01	IC	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Oberlin OH (City of)	Oberlin OH (City of)	Oberlin OH (City of)	Oberlin (OH)	3A	100	3.1	3.1	3.1	6/1/01	IC	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Oberlin OH (City of)	Oberlin OH (City of)	Oberlin OH (City of)	Oberlin (OH)	5	100	2	2	2	1/1/51	IC	NG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	ATSI	FirstEnergy ATSI				Oberlin OH (City of)	Oberlin OH (City of)	Oberlin OH (City of)	Oberlin (OH)	6	100	2.5	2	2	1/1/58	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Oberlin OH (City of)	Oberlin OH (City of)	Oberlin OH (City of)	Oberlin (OH)	7	100	2.6	2.65	2.65	1/1/61	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Oberlin OH (City of)	Oberlin OH (City of)	Oberlin OH (City of)	Oberlin (OH)	8	100	3	3	3	1/1/66	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Oberlin OH (City of)	Oberlin OH (City of)	Oberlin OH (City of)	Oberlin (OH)	9	100	0.4	0.4	0.4	1/1/90	IC	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Oberlin OH (City of)	Oberlin OH (City of)	Oberlin OH (City of)	Oberlin (OH)	GT4	100	2.1	2.1	2.1	1/1/97	IC	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Oberlin OH (City of)	Oberlin OH (City of)	Oberlin OH (City of)	Oberlin (OH)	IC4	100	2.1	2.1	2.1	6/1/96	IC	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Oberlin Landfill	1	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Oberlin Landfill	2	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Oberlin Landfill	3	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Oberlin Landfill	4	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Oberlin Landfill	5	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Oberlin Landfill	6	100	1.4	1.4	1.4	12/14/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Oberlin Landfill	7	100	1.4	1.4	1.4	7/1/03	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Ltd	Energy Developments	Energy Developments Ltd	Oberlin Landfill	8	100	1.4	1.4	1.4	7/1/03	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Inc	Energy Developments	Energy Developments Inc	Ottawa County Landfill	1	100	1.4	1.4	1.4	3/1/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Inc	Energy Developments	Energy Developments Inc	Ottawa County Landfill	2	100	1.4	1.4	1.4	3/1/01	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Energy Developments Inc	Energy Developments	Energy Developments Inc	Ottawa County Landfill	3	100	1.4	1.4	1.4	5/1/04	IC	LFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Painesville Electric Light Dep	Painesville Electric Light De	Painesville Electric Light Dept	Painesville	3	100	7.5	7	7	1/1/53	ST	BIT	Standby	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Painesville Electric Light Dep	Painesville Electric Light De	Painesville Electric Light Dept	Painesville	5	100	16.5	15.5	15.5	1/1/65	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Painesville Electric Light Dep	Painesville Electric Light De	Painesville Electric Light Dept	Painesville	7	100	22	17.5	17.5	2/1/90	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Painesville Electric Light Dep	Painesville Electric Light De	Painesville Electric Light Dept	Painesville	ST2	100	7.5	7	7	1/1/49	ST	BIT	Standby	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Painesville Electric Light Dep	Painesville Electric Light De	Painesville Electric Light Dept	Painesville	WPCP1	100	2	2	2	2/1/10	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Painesville IC	1	100	6	6	6	7/1/00	IC	FO2	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Nuclear Generati	FirstEnergy Corp	FirstEnergy Nuclear Operating	Perry (OH)	1	87.42	1147.388	1084.01	1108.486	11/1/87	NB	URA	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Ohio Edison Co	FirstEnergy Corp	FirstEnergy Nuclear Operating	Perry (OH)	1	12.58	165.113	155.992	159.514	11/1/87	NB	URA	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Prospect Municipal	1	100	1.8	1.8	1.8	2/1/98	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Ohio Edison Co	FirstEnergy Corp	FirstEnergy Generation, LLC	R E Burger	A1	100	2.5	2	2	5/1/72	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Ohio Edison Co	FirstEnergy Corp	FirstEnergy Generation, LLC	R E Burger	B1	100	2.5	2	2	5/1/72	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Ohio Edison Co	FirstEnergy Corp	FirstEnergy Generation, LLC	R E Burger	B2	100	2.5	3	3	5/1/72	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Richland Stryker Generation	Quintana Infrastructure &	Richland Stryker Generation LL	Richland	1	100	15	11	14	12/1/65	GT	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Richland Stryker Generation	Quintana Infrastructure &	Richland Stryker Generation LL	Richland	2	100	15	11	14	2/1/66	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Richland Stryker Generation	Quintana Infrastructure &	Richland Stryker Generation LL	Richland	3	100	15	11	14	2/1/66	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Richland Stryker Generation	Quintana Infrastructure &	Richland Stryker Generation LL	Richland	4	100	135	112	130	3/1/01	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Richland Stryker Generation	Quintana Infrastructure &	Richland Stryker Generation LL	Richland	5	100	135	112	130	3/1/01	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Richland Stryker Generation	Quintana Infrastructure &	Richland Stryker Generation LL	Richland	6	100	135	112	130	3/1/01	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Caraustar Industries Inc	Caraustar Industries Inc	Caraustar Industries Inc	Rittman Paperboard	GEN1	100	3	3	3	1/1/28	ST	BIT	Standby	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Caraustar Industries Inc	Caraustar Industries Inc	Caraustar Industries Inc	Rittman Paperboard	GEN2	100	5	5	5	1/1/40	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Caraustar Industries Inc	Caraustar Industries Inc	Caraustar Industries Inc	Rittman Paperboard	GEN3	100	6	6	6	6/1/46	ST	BIT	Standby	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Seville	1	100	1.8	1.8	1.8	6/1/01	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Seville	2	100	1.8	1.8	1.8	6/1/01	IC	DFO	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	ATSI	FirstEnergy ATSI				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Seville	3	100	1.8	1.8	1.8	6/1/01	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Richland Stryker Generation	Quintana Infrastructure &	Richland Stryker Generation LL	Stryker	1	100	19	17	18	2/1/68	GT	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Sunoco Inc	Sunoco Inc	Sunoco Inc	Toledo PRT	GEN1	100	6	6	6	6/1/86	GT	PC	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Troy Energy LLC	International Power	Troy Energy LLC	Troy (OH)	1	100	172	146	169	6/21/02	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Troy Energy LLC	International Power	Troy Energy LLC	Troy (OH)	2	100	172	146	169	6/21/02	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Troy Energy LLC	International Power	Troy Energy LLC	Troy (OH)	3	100	172	146	169	6/21/02	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Troy Energy LLC	International Power	Troy Energy LLC	Troy (OH)	4	100	172	146	169	6/21/02	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Constellation Solar Ohio LLC	Exelon Corp	Constellation NewEnergy Inc	University of Toledo	PV1	100	1.041	1.041	1.041	12/31/09	PV	SUN	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Constellation Solar Ohio LLC	Exelon Corp	Constellation NewEnergy Inc	University of Toledo	WT1	100	0.08	0.08	0.08	12/31/09	WT	WND	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				US Coking Group	US Coking Group	US Coking Group	US Coking Cogeneratior	1	100	135	135	135	1/1/11	ST	WH	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	W H Sammis	A1	100	2.5	3	3	3/1/72	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	W H Sammis	B1	100	2.5	3	3	3/1/72	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	W H Sammis	B2	100	2.5	3	3	3/1/72	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	W H Sammis	B3	100	2.5	2	2	3/1/72	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	W H Sammis	B4	100	2.5	2	2	3/1/72	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	W H Sammis	3	100	190.4	180	180	7/1/61	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	W H Sammis	4	100	190.4	180	180	11/1/62	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	W H Sammis	6	100	680	600	600	4/1/69	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	W H Sammis	7	100	680	600	600	9/1/71	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	W H Sammis	1	100	190.4	180	180	8/1/59	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	W H Sammis	2	100	190.4	180	180	7/1/60	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	W H Sammis	5	100	334	300	300	12/1/67	ST	BIT	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	Wadsworth OH (City of)	Wadsworth	13	100	5.4	5.4	5.4	12/1/90	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Severatal Warren Inc	Severstal North America	Severatal Warren Inc	Wci Steel Inc	GEN1	100	3	2.79	2.82	10/1/34	ST	BFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Severatal Warren Inc	Severstal North America	Severatal Warren Inc	Wci Steel Inc	GEN2	100	7.5	6.98	7.05	3/1/40	ST	BFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Severatal Warren Inc	Severstal North America	Severatal Warren Inc	Wci Steel Inc	GEN3	100	10	9.3	9.4	12/1/81	ST	BFG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Wellington (OH)	1	100	1	1	1	2/1/98	IC	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Cleveland Public Power	Cleveland Public Power	Cleveland Public Power	West 41ST Street	1	100	16	16	18	3/1/70	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				Cleveland Public Power	Cleveland Public Power	Cleveland Public Power	West 41ST Street	2	100	16	16	18	3/1/70	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	West Lorain	1A	100	65.3	57	60	6/1/83	GT	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	West Lorain	1B	100	65.3	57	60	6/1/73	GT	DFO	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	West Lorain	1D	100	85	85	85	6/5/01	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	West Lorain	1E	100	85	85	85	6/5/01	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	West Lorain	1F	100	85	85	85	6/5/01	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	West Lorain	1G	100	85	85	85	6/5/01	GT	NG	Operating	Y	1
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	West Lorain	1H	100	85	85	85	6/5/01	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Baltimore Sun Co Inc	Tribune Co	Baltimore Sun Co Inc	Baltimore Sun	IC1	100	2	2	2	4/30/07	IC	DSL	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Baltimore Sun Co Inc	Tribune Co	Baltimore Sun Co Inc	Baltimore Sun	IC2	100	2	2	2	4/30/07	IC	DSL	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Raven Power Holdings	Riverstone Holdings LLC	Raven Power Holdings	Brandon Shores	2	100	685	638	638	5/1/91	ST	BIT	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Brandon Shores LLC	Riverstone Holdings LLC	Raven Power Holdings	Brandon Shores	1	100	685	635	635	5/1/84	ST	BIT	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		CP Crane LLC	Riverstone Holdings LLC	Raven Power Holdings	C P Crane	1	100	190.4	190	190	7/1/61	ST	BIT	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Raven Power Holdings	Riverstone Holdings LLC	Raven Power Holdings	C P Crane	2	100	209.4	195	195	2/1/63	ST	BIT	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Raven Power Holdings	Riverstone Holdings LLC	Raven Power Holdings	C P Crane	GT1	100	16	14	14	7/1/67	GT	DFO	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Calvert Cliffs Nuclear Power	Exelon Corp	Calvert Cliffs Nuclear Power Pl	Calvert Cliffs Nuclear Pc	2	100	960.97	850	862	4/1/77	NP	URA	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Calvert Cliffs Nuclear Power	Exelon Corp	Calvert Cliffs Nuclear Power Pl	Calvert Cliffs Nuclear Pc	1	100	1050	866	872	5/1/75	NP	URA	Restarted	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		American Sugar Refining Co	Florida Crystals Corp	American Sugar Refining Co (T	Domino Sugar Baltimor	GEN1	100	5	5	5	6/1/59	ST	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		American Sugar Refining Co	Florida Crystals Corp	American Sugar Refining Co (T	Domino Sugar Baltimor	GEN2	100	2.5	2.5	2.5	6/1/55	ST	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		American Sugar Refining Co	Florida Crystals Corp	American Sugar Refining Co (T	Domino Sugar Baltimor	GEN4	100	10	10	10	6/1/01	ST	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Eastern Landfill Gas LLC	Pepco Holdings Inc	Eastern Landfill Gas LLC	Eastern Sanitary Landfil	1	100	1	1	1	10/26/06	IC	LFG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Eastern Landfill Gas LLC	Pepco Holdings Inc	Eastern Landfill Gas LLC	Eastern Sanitary Landfil	2	100	1	1	1	10/26/06	IC	LFG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Eastern Landfill Gas LLC	Pepco Holdings Inc	Eastern Landfill Gas LLC	Eastern Sanitary Landfil	3	100	1	1	1	10/26/06	IC	LFG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Solar Maryland	Exelon Corp	Constellation NewEnergy Inc	General Motors Allison	PV1	100	1.236	1.044	1.044	5/22/11	PV	SUN	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Gould Street	3	100	103.5	97	97	12/1/52	ST	NG	Restarted	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Raven Power Holdings	Riverstone Holdings LLC	Raven Power Holdings	Herbert A Wagner	GT1	100	16	12.9	12.9	8/1/67	GT	DFO	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Ha Wagner LLC	Riverstone Holdings LLC	Raven Power Holdings	Herbert A Wagner	1	100	132.8	126	126	2/1/56	ST	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Raven Power Holdings	Riverstone Holdings LLC	Raven Power Holdings	Herbert A Wagner	2	100	136	135	135	1/1/59	ST	BIT	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Raven Power Holdings	Riverstone Holdings LLC	Raven Power Holdings	Herbert A Wagner	3	100	359	305	305	8/1/66	ST	BIT	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Raven Power Holdings	Riverstone Holdings LLC	Raven Power Holdings	Herbert A Wagner	4	100	414.7	397	397	8/1/72	ST	RFO	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Tri Generating Cinergy Soluti	National Industrialization C	Tri Generating Cinergy Solutio	Inner Harbor East Heati	1	100	2.1	2.1	2.1	9/1/04	IC	NG	Operating	Y	1
PJM ISO	BGE	Delmarva Power & Light Compan	5004/5005	AP South		Constellation Energy Group	Exelon Corp	Constellation Energy Group	McCormick Belcamp So	PV1	100	1.4	1.4	1.4	12/31/10	PV	SUN	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Group	Exelon Corp	Constellation Energy Group	McCormick Hunt Valley	PV1	100	1	1	1	1/21/09	PV	SUN	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Tri Generating Cinergy Soluti	National Industrialization C	Tri Generating Cinergy Solutio	Millennium Hawkins Po	1A	100	1.5	1.1	1.5	5/1/00	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Tri Generating Cinergy Soluti	National Industrialization C	Tri Generating Cinergy Solutio	Millennium Hawkins Po	1B	100	1.5	1.1	1.5	5/1/00	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Tri Generating Cinergy Soluti	National Industrialization C	Tri Generating Cinergy Solutio	Millennium Hawkins Po	2A	100	1.5	1.1	1.5	5/1/00	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Tri Generating Cinergy Soluti	National Industrialization C	Tri Generating Cinergy Solutio	Millennium Hawkins Po	2B	100	1.5	1.1	1.5	5/1/00	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Tri Generating Cinergy Soluti	National Industrialization C	Tri Generating Cinergy Solutio	Millennium Hawkins Po	3A	100	1.5	1.1	1.5	5/1/00	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Tri Generating Cinergy Soluti	National Industrialization C	Tri Generating Cinergy Solutio	Millennium Hawkins Po	3B	100	1.5	1.1	1.5	5/1/02	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Tri Generating Cinergy Soluti	National Industrialization C	Tri Generating Cinergy Solutio	Millennium Hawkins Po	ST1	100	1.5	0.5	1	8/1/00	ST	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Notch Cliff	GT1	100	18	14	14	6/1/69	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Notch Cliff	GT2	100	18	14	14	6/1/69	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Notch Cliff	GT3	100	18	14	14	6/1/69	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Notch Cliff	GT4	100	18	14	14	6/1/69	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Notch Cliff	GT5	100	18	14.6	14.6	6/1/69	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Notch Cliff	GT6	100	18	15.6	15.6	6/1/69	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Notch Cliff	GT7	100	18	14.5	14.5	6/1/69	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Notch Cliff	GT8	100	18	16	16	6/1/69	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Perryman	GT1	100	53.1	52	52	1/1/72	GT	DFO	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Perryman	GT2	100	53.1	51	51	4/1/72	GT	DFO	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Perryman	GT3	100	53.1	51	51	4/1/72	GT	DFO	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Perryman	GT4	100	53.1	52	52	4/1/72	GT	DFO	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Perryman	GT5	100	192	147.6	147.6	6/1/95	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Philadelphia Road	GT1	100	20.7	15.3	15.3	8/1/70	GT	DFO	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Philadelphia Road	GT2	100	20.7	16	16	8/1/70	GT	DFO	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Philadelphia Road	GT3	100	20.7	14.8	14.8	9/1/70	GT	DFO	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Philadelphia Road	GT4	100	20.7	14.8	14.8	9/1/70	GT	DFO	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Riverside (MD)	GT6	100	135	115	115	4/1/70	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Riverside (MD)	GT7	100	25	19	19	9/1/70	GT	DFO	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Riverside (MD)	GT8	100	25	20	20	9/1/70	GT	DFO	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Riverside (MD)	4	100	72.2	74	74	9/1/51	ST	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		SunEdison	SunEdison	SunEdison	Staples Hanover Solar	1	100	1.01	1.01	1.01	1/6/10	PV	SUN	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Trigen Cinergy Solutions Swe	Trigen Energy Corp	Trigen Cinergy Solutions Swee	Sweetheart Cup Owings	1	100	5.6	5.6	5.6	6/1/02	IC	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Trigen Cinergy Solutions Swe	Trigen Energy Corp	Trigen Cinergy Solutions Swee	Sweetheart Cup Owings	2	100	5.6	5.6	5.6	6/1/02	IC	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Northeast Maryland Waste D	Northeast Maryland Waste	Energy Recovery Operations Ir	Waste Energy Partners	1	100	1.2	1.12	1.13	12/1/87	ST	MSW	Standby	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Constellation Energy Commc	Exelon Corp	Constellation Energy Commod	Westport	GT5	100	121.5	115.8	115.8	2/1/69	GT	NG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Wheelabrator Baltimore Inc	Waste Management Inc	Wheelabrator Baltimore Inc	Wheelabrator Baltimor	GEN1	100	60.2	57	57	11/1/84	ST	MSW	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		Wheelabrator Baltimore Inc	Waste Management Inc	Wheelabrator Baltimore Inc	Wheelabrator Baltimor	GEN2	100	4.3	4.3	4.3	1/1/01	ST	MSW	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		United States Coast Guard	United States Coast Guard	United States Coast Guard	Yards Landfill Gas Co Ge	IC	100	1.125	1.125	1.125	4/22/09	IC	LFG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		United States Coast Guard	United States Coast Guard	United States Coast Guard	Yards Landfill Gas Co Ge	IC2	100	1.125	1.125	1.125	4/22/09	IC	LFG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		United States Coast Guard	United States Coast Guard	United States Coast Guard	Yards Landfill Gas Co Ge	IC3	100	1.125	1.125	1.125	4/22/09	IC	LFG	Operating	Y	1
PJM ISO	BGE	Baltimore Gas & Electric Compan	5004/5005	AP South		United States Coast Guard	United States Coast Guard	United States Coast Guard	Yards Landfill Gas Co Ge	IC4	100	1.125	1.125	1.125	4/22/09	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rochelle Municipal Utilities	Rochelle Municipal Utilities	Rochelle Municipal Utilities	1515 S Caron Road	GT1	100	4.2	3	3.5	5/1/00	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Adkins Energy LLC	Pearl City Elevator LLC	Adkins Energy LLC	Adkins Energy	GT1	100	5	5	5	8/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				NRG Wholesale Generation I	NRG Energy Inc	NRG Wholesale Generation LP	Aurora	CT10	100	71	45	69.58	6/1/01	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				NRG Wholesale Generation I	NRG Energy Inc	NRG Wholesale Generation LP	Aurora	CTG5	100	71	42	47	5/1/01	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				NRG Wholesale Generation I	NRG Energy Inc	NRG Wholesale Generation LP	Aurora	CTG6	100	71	42	47	5/1/01	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				NRG Wholesale Generation I	NRG Energy Inc	NRG Wholesale Generation LP	Aurora	CTG7	100	71	42	47	6/1/01	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				NRG Wholesale Generation I	NRG Energy Inc	NRG Wholesale Generation LP	Aurora	CTG8	100	71	42	47	5/1/01	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				NRG Wholesale Generation I	NRG Energy Inc	NRG Wholesale Generation LP	Aurora	CTG9	100	71	45	69.6	6/1/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				NRG Wholesale Generation I	NRG Energy Inc	NRG Wholesale Generation LP	Aurora	CTG1	100	213	145	180	5/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				NRG Wholesale Generation I	NRG Energy Inc	NRG Wholesale Generation LP	Aurora	CTG2	100	213	145	180	6/1/01	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				NRG Wholesale Generation I	NRG Energy Inc	NRG Wholesale Generation LP	Aurora	CTG3	100	210	145	180	6/1/01	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				NRG Wholesale Generation I	NRG Energy Inc	NRG Wholesale Generation LP	Aurora	CTG4	100	213	145	180	5/1/01	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				CSL Behring	Armour Pharmaceutical Co	Avenis Behring LLC	Aventis Behring LLC	GEN1	100	4.2	4.2	5.3	5/1/93	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Falls Electrical Dept	Rock Falls Electrical Dept	Rock Falls Electrical Dept	Avenue A Generating Se	1	100	1.8	1.8	1.8	9/1/00	GT	DFO	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Falls Electrical Dept	Rock Falls Electrical Dept	Rock Falls Electrical Dept	Avenue A Generating Se	2	100	1.8	1.8	1.8	9/1/00	GT	DFO	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Beecher Energy LLC	Beecher Energy LLC	Sexton Energy LLC	Beecher LFG	IC1	100	1.1	1.1	1.1	6/7/06	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Beecher Energy LLC	Beecher Energy LLC	Sexton Energy LLC	Beecher LFG	IC2	100	1.1	1.1	1.1	6/7/06	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Beecher Energy LLC	Beecher Energy LLC	Sexton Energy LLC	Beecher LFG	IC3	100	1.1	1.1	1.1	10/1/08	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Big Sky Wind LLC	Edison International	Big Sky Wind LLC	Big Sky Wind Farm	WT1 114	100	239.4	239.4	239.4	2/1/11	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Resource Technology Corp	Resource Technology Corp	Resource Technology Corp	Biodyne Lyons	2	100	0.9	0.9	0.9	12/1/97	IC	LFG	Standby	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	COMED	Commonwealth Edison Co.				Resource Technology Corp	Resource Technology Corp	Resource Technology Corp	Biodyne Lyons	4	100	0.9	0.9	0.9	12/1/97	IC	LFG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				BP Naperville Complex	BP plc	BP Naperville Complex	BP Naperville Cogenera	GEN1	100	8.3	7	12	12/1/90	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Braidwood Generation	1	100	1286.25	1178	1208	7/1/88	NP	URA	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Braidwood Generation	2	100	1261.75	1152	1176	10/1/88	NP	URA	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bunge Foods	Bunge Limited	Bunge Foods	Bunge Oil	1	100	3.5	2.8	4	1/1/90	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Byron Generating Static	1	100	1286.15	1164	1188	9/1/85	NP	URA	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Byron Generating Static	2	100	1286.15	1136	1158	8/1/87	NP	URA	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Cadbury Adams USA LLC	Kraft Foods Inc	Cadbury Adams USA LLC	Cadbury Adams - Rockfo	GEN1	100	4.7	5	3	2/1/95	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				J Calumet Energy Team LLC	International Power	IPA Operations Inc	Calumet Energy Team L	CT11	100	156.4	157.2	165	6/18/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				J Calumet Energy Team LLC	International Power	IPA Operations Inc	Calumet Energy Team L	CT12	100	156.4	164	165	6/18/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Camp Grove Wind Farm LLC	General Electric Co	enXco Service Corp	Camp Grove Wind Farm	WT1 100	100	150	150	150	12/31/07	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bio Energy Partners	Waste Management Inc	Waste Management Illinois Re	Cid Gas Recovery	GEN2	100	3	2.9	3.3	3/1/89	GT	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Cordova Energy Co LLC	Berkshire Hathaway Inc	Cordova Energy Co LLC	Cordova Energy Center	CC	100	611.2	521.2	601.2	6/12/01	CC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Corn Products International	Corn Products Intl Inc	Corn Products International In	Corn Products Internati	TGO1	100	22.5	21.08	21.15	5/1/91	ST	BIT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Corn Products International	Corn Products Intl Inc	Corn Products International In	Corn Products Internati	TGO2	100	22.5	21.08	21.15	5/1/91	ST	BIT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Solar Turbines Inc	Caterpillar Inc	Corn Products International In	Corn Products Internati	TG03	100	4.8	4.4	4.8	2/1/96	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Solar Turbines Inc	Caterpillar Inc	Corn Products International In	Corn Products Internati	TG04	100	4.8	4.4	4.8	2/1/96	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Crescent Ridge Wind LLC	Infigen Energy	Crescent Ridge Wind LLC	Crescent Ridge Wind (E	WT1 33	100	53	53	53	12/1/05	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Crete Energy Venture LLC	Tenaska Inc	DTE Crete Operations LLC	Crete Energy Park	GT1	100	89	75	87.2	5/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Crete Energy Venture LLC	Tenaska Inc	DTE Crete Operations LLC	Crete Energy Park	GT2	100	89	75	87.2	5/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Crete Energy Venture LLC	Tenaska Inc	DTE Crete Operations LLC	Crete Energy Park	GT3	100	89	75	87.2	5/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Crete Energy Venture LLC	Tenaska Inc	DTE Crete Operations LLC	Crete Energy Park	GT4	100	89	75	87.2	5/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Sexton Energy LLC	Sexton Companies	Sexton Energy LLC	Des Plaines Landfill	DP1	100	1.8	1.8	1.8	10/1/04	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Sexton Energy LLC	Sexton Companies	Sexton Energy LLC	Des Plaines Landfill	DP2	100	1.8	1.8	1.8	10/1/04	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				STS HydroPower Ltd	Energy Investors Funds Gr	STS HydroPower Ltd	Dixon Hydro Dam	1	100	0.6	0.6	0.6	6/1/25	HY	WAT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				STS HydroPower Ltd	Energy Investors Funds Gr	STS HydroPower Ltd	Dixon Hydro Dam	2	100	0.6	0.6	0.6	6/1/25	HY	WAT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				STS HydroPower Ltd	Energy Investors Funds Gr	STS HydroPower Ltd	Dixon Hydro Dam	3	100	0.6	0.6	0.6	6/1/25	HY	WAT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				STS HydroPower Ltd	Energy Investors Funds Gr	STS HydroPower Ltd	Dixon Hydro Dam	4	100	0.6	0.6	0.6	6/1/25	HY	WAT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				STS HydroPower Ltd	Energy Investors Funds Gr	STS HydroPower Ltd	Dixon Hydro Dam	5	100	0.6	0.6	0.6	6/1/25	HY	WAT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Illinois Electrical Generating	U S Energy Systems Inc	Illinois Electrical Generating Pa	Dixon/Lee Energy Partn	DX1	100	1.1	0.9	0.9	6/1/99	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Illinois Electrical Generating	U S Energy Systems Inc	Illinois Electrical Generating Pa	Dixon/Lee Energy Partn	DX2	100	1.1	0.9	0.9	6/1/99	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Illinois Electrical Generating	U S Energy Systems Inc	Illinois Electrical Generating Pa	Dixon/Lee Energy Partn	DX3	100	1.1	0.9	0.9	6/1/99	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Illinois Electrical Generating	U S Energy Systems Inc	Illinois Electrical Generating Pa	Dixon/Lee Energy Partn	DX4	100	1.1	0.9	0.9	6/1/99	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Dresden	2	100	908.315	883	833	6/1/70	NB	URA	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Dresden	3	100	912	867	867	11/1/71	NB	URA	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Dupage IL (County Of)	Dupage IL (County Of)	Dupage IL (County Of)	Dupage County Region	FM01	100	1.5	1.5	1.5	4/1/96	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Duraco Products Inc	Duraco Products Inc	Duraco Products Inc	Duraco Products Inc	GEN1	100	0.7	0.7	0.7	11/1/93	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Duraco Products Inc	Duraco Products Inc	Duraco Products Inc	Duraco Products Inc	GEN2	100	0.7	0.7	0.7	11/1/93	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				EcoGrove Wind LLC	Acciona Energia	EcoGrove Wind LLC	EcoGrove Wind Farm	WT1 67	100	100.5	100.5	100.5	8/28/09	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				AmerenEnergy Generating C	Ameren Corp	AmerenEnergy Generating Co	Elgin Energy Center	CT01	100	135	115	114	9/1/02	GT	NG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	COMED	Commonwealth Edison Co.				AmerenEnergy Generating C	Ameren Corp	AmerenEnergy Generating Co	Elgin Energy Center	CT02	100	135	115	114	10/18/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				AmerenEnergy Generating C	Ameren Corp	AmerenEnergy Generating Co	Elgin Energy Center	CT03	100	135	115	114	10/31/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				AmerenEnergy Generating C	Ameren Corp	AmerenEnergy Generating Co	Elgin Energy Center	CT04	100	135	115	114	11/15/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Elwood Energy LLC	Energy Capital Partners	Elwood Energy LLC	Elwood Energy	GT1	100	192	150	192	7/1/99	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Elwood Energy LLC	Energy Capital Partners	Elwood Energy LLC	Elwood Energy	GT2	100	192	150	192	7/1/99	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Elwood Energy LLC	Energy Capital Partners	Elwood Energy LLC	Elwood Energy	GT3	100	192	150	192	7/1/99	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Elwood Energy LLC	Energy Capital Partners	Elwood Energy LLC	Elwood Energy	GT4	100	192	150	192	7/1/99	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Elwood Energy LLC	Energy Capital Partners	Elwood Energy LLC	Elwood Energy	GT5	100	192	150	192	7/18/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Elwood Energy LLC	Energy Capital Partners	Elwood Energy LLC	Elwood Energy	GT6	100	192	150	192	7/18/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Elwood Energy LLC	Energy Capital Partners	Elwood Energy LLC	Elwood Energy	GT7	100	192	150	192	7/18/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Elwood Energy LLC	Energy Capital Partners	Elwood Energy LLC	Elwood Energy	GT8	100	192	150	192	7/18/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Elwood Energy LLC	Energy Capital Partners	Elwood Energy LLC	Elwood Energy	GT9	100	192	150	192	7/18/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Evanston Board of Educatior	Evanston Board of Educatic	Evanston Board of Education	Evanston Township Hig	GEN1	100	0.8	0.8	0.8	12/1/92	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Evanston Board of Educatior	Evanston Board of Educatic	Evanston Board of Education	Evanston Township Hig	GEN2	100	0.8	0.8	0.8	12/1/92	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Evanston Board of Educatior	Evanston Board of Educatic	Evanston Board of Education	Evanston Township Hig	GEN3	100	0.8	0.8	0.8	12/1/92	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Exelon Corp	Exelon Corp	Exelon Corp	Exelon Chicago Solar	PV1	100	9	9	9	12/1/09	PV	SUN	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Fisk Street	311	100	38	25.4	34	7/1/68	GT	KER	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Fisk Street	312	100	38	23.7	31.6	7/1/68	GT	KER	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Fisk Street	321	100	38	25.4	34	7/1/68	GT	KER	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Fisk Street	322	100	38	25.4	34	7/1/68	GT	KER	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Fisk Street	331	100	38	23.7	31.6	7/1/68	GT	KER	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Fisk Street	332	100	38	25.4	34	7/1/68	GT	KER	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Fisk Street	341	100	38	25.4	34	7/1/68	GT	KER	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Fisk Street	342	100	22.8	22.8	30.5	7/1/68	GT	KER	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Five Oaks Gas Recovery	GEN1	100	0.8	0.8	0.8	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Five Oaks Gas Recovery	GEN2	100	0.8	0.8	0.8	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Five Oaks Gas Recovery	GEN3	100	0.8	0.8	0.8	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Five Oaks Gas Recovery	GEN4	100	0.8	0.8	0.8	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Fox Metro Water Reclamatic	Fox Metro Water Reclamat	Fox Metro Water Reclamation	Fox Metro Water Recla	RU3	100	1.1	1.07	1.09	12/1/88	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Fox Metro Water Reclamatic	Fox Metro Water Reclamat	Fox Metro Water Reclamation	Fox Metro Water Recla	RU4	100	1.1	1.07	1.09	12/1/88	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				General Mills Inc	General Mills Inc	General Mills Inc	General Mills West Chic	1	100	0.8	0.8	0.8	4/1/94	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				General Mills Inc	General Mills Inc	General Mills Inc	General Mills West Chic	2	100	0.8	0.8	0.8	4/1/94	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				General Mills Inc	General Mills Inc	General Mills Inc	General Mills West Chic	3	100	0.8	0.8	0.8	4/1/94	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				General Mills Inc	General Mills Inc	General Mills Inc	General Mills West Chic	4	100	0.8	0.8	0.8	4/1/94	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				General Mills Inc	General Mills Inc	General Mills Inc	General Mills West Chic	5	100	0.8	0.8	0.8	4/1/94	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				General Mills Inc	General Mills Inc	General Mills Inc	General Mills West Chic	6	100	0.8	0.8	0.8	4/1/94	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				General Mills Inc	General Mills Inc	General Mills Inc	General Mills West Chic	7	100	0.8	0.8	0.8	4/1/94	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				General Mills Inc	General Mills Inc	General Mills Inc	General Mills West Chic	8	100	0.8	0.8	0.8	4/1/94	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Geneva (City of)	Geneva (City of)	Geneva (City of)	Geneva Township	IC1	100	5.9	5.4	5.8	12/17/04	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Geneva (City of)	Geneva (City of)	Geneva (City of)	Geneva Township	IC2	100	5.9	5.4	5.8	12/17/04	IC	NG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	COMED	Commonwealth Edison Co.				Geneva (City of)	Geneva (City of)	Geneva (City of)	Geneva Township	IC3	100	5.9	5.4	5.8	12/17/04	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Geneva (City of)	Geneva (City of)	Geneva (City of)	Geneva Township	IC4	100	5.9	5.4	5.8	12/17/04	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Geneva (City of)	Geneva (City of)	Geneva (City of)	Geneva Township	IC5	100	5.9	5.4	5.8	12/17/04	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Grand Ridge Energy II LLC	Invenergy LLC	Grand Ridge Energy LLC	Grand Ridge Wind Farm	WT67 100	100	51	51	51	10/30/09	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Grand Ridge Energy III LLC	Invenergy LLC	Grand Ridge Energy LLC	Grand Ridge Wind Farm	WT134 140	100	49.5	49.5	49.5	10/30/09	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Grand Ridge Energy IV LLC	Invenergy LLC	Grand Ridge Energy LLC	Grand Ridge Wind Farm	WT141 147	100	10.5	10.5	10.5	12/31/09	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Grand Ridge Energy LLC	Invenergy LLC	Grand Ridge Energy LLC	Grand Ridge Wind Farm	WT1 66	100	99	99	99	10/15/08	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bio Energy Partners	Waste Management Inc	Bio Energy Partners	Greene Valley Gas Reco	GEN1	100	3.3	2.9	3.3	5/1/96	GT	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bio Energy Partners	Waste Management Inc	Bio Energy Partners	Greene Valley Gas Reco	GEN2	100	3.3	2.9	3.3	5/1/96	GT	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				GSG 7 LLC	GSG Wind	GSG 7 LLC	GSG 7 Wind	WT 1	100	2.6	2.6	2.6	4/30/09	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics	GEN1	100	0.8	0.8	0.8	4/1/92	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics	GEN2	100	0.8	0.8	0.8	4/1/92	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics	GEN3	100	0.8	0.8	0.8	4/1/92	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics	GEN4	100	0.8	0.8	0.8	4/1/92	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics	GEN5	100	0.8	0.8	0.8	4/1/92	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics	GEN6	100	0.8	0.8	0.8	4/1/92	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics	GEN7	100	0.8	0.8	0.8	4/1/92	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics	GEN8	100	0.8	0.8	0.8	4/1/92	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics Inc	Hoffer Plastics	GEN9	100	0.8	0.8	0.8	4/1/95	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Illinois Institute Technology	Illinois Institute Technolog	Illinois Institute Technology	Ilt Cogeneration	GEN1	100	3.7	3.5	3.7	5/1/91	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Illinois Institute Technology	Illinois Institute Technolog	Illinois Institute Technology	Ilt Cogeneration	GEN2	100	3.7	3.5	3.7	5/1/91	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Falls Electrical Dept	Rock Falls Electrical Dept	Rock Falls Electrical Dept	Industrial Park	3	100	1.8	1.5	1.7	7/1/01	GT	DFO	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Falls Electrical Dept	Rock Falls Electrical Dept	Rock Falls Electrical Dept	Industrial Park	4	100	1.8	1.5	1.7	7/1/01	GT	DFO	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Falls Electrical Dept	Rock Falls Electrical Dept	Rock Falls Electrical Dept	Industrial Park	5	100	1.8	1.5	1.7	7/1/01	GT	DFO	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Falls Electrical Dept	Rock Falls Electrical Dept	Rock Falls Electrical Dept	Industrial Park	6	100	1.8	1.5	1.7	6/1/02	GT	DFO	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Falls Electrical Dept	Rock Falls Electrical Dept	Rock Falls Electrical Dept	Industrial Park	7	100	1.8	1.5	1.7	6/1/02	GT	DFO	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Ingersoll Milling Machine Co	Camozzi Group	Ingersoll Milling Machine Co (T	Ingersoll Milling Machir	71	100	0.6	0.6	0.6	7/1/88	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Ingersoll Milling Machine Co	Camozzi Group	Ingersoll Milling Machine Co (T	Ingersoll Milling Machir	72	100	0.6	0.6	0.6	7/1/88	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Ingersoll Milling Machine Co	Camozzi Group	Ingersoll Milling Machine Co (T	Ingersoll Milling Machir	73	100	0.6	0.6	0.6	7/1/88	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Ingersoll Milling Machine Co	Camozzi Group	Ingersoll Milling Machine Co (T	Ingersoll Milling Machir	74	100	0.6	0.6	0.6	7/1/88	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Ingersoll Milling Machine Co	Camozzi Group	Ingersoll Milling Machine Co (T	Ingersoll Milling Machir	75	100	0.6	0.6	0.6	7/1/88	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Ingersoll Milling Machine Co	Camozzi Group	Ingersoll Milling Machine Co (T	Ingersoll Milling Machir	76	100	0.8	0.7	0.7	7/1/88	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Ingersoll Milling Machine Co	Camozzi Group	Ingersoll Milling Machine Co (T	Ingersoll Milling Machir	77	100	0.8	0.7	0.7	7/1/88	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				John Deere Harvester Works	Deere & Co	John Deere Harvester Works C	John Deere Harvester W	GEN2	100	2	2	2	10/1/40	ST	BIT	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				John Deere Harvester Works	Deere & Co	John Deere Harvester Works C	John Deere Harvester W	GEN4	100	2.5	2.5	2.5	4/1/49	ST	BIT	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				John Deere Harvester Works	Deere & Co	John Deere Harvester Works C	John Deere Harvester W	GEN5	100	3	3	3	11/1/51	ST	BIT	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Joliet 29	7	100	660	518	522	4/1/65	ST	SUB	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Joliet 29	8	100	660	518	522	3/1/66	ST	SUB	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Joliet 9	6	100	360.4	314	314	6/1/59	ST	SUB	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Joliet 9	UNIT 9	100	11	11	11	1/1/80	IC	DSL	Standby	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	COMED	Commonwealth Edison Co.				ExxonMobil Oil Corp	ExxonMobil Corp	ExxonMobil Oil Corp	Joliet Refinery	CC	100	39.6	39.7	39.7	11/1/87	CC	OG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bio Energy Partners	Waste Management Inc	Bio Energy Partners	Kankakee Gas Recovery	GEN1	100	0.8	0.8	0.8	6/1/92	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bio Energy Partners	Waste Management Inc	Bio Energy Partners	Kankakee Gas Recovery	GEN2	100	0.8	0.8	0.8	6/1/92	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Kankakee (City of)	Kankakee (City of)	Kankakee (City of)	Kankakee Hydro	1	100	0.4	0.4	0.4	7/1/91	HY	WAT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Kankakee (City of)	Kankakee (City of)	Kankakee (City of)	Kankakee Hydro	2	100	0.4	0.4	0.4	7/1/91	HY	WAT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Kankakee (City of)	Kankakee (City of)	Kankakee (City of)	Kankakee Hydro	3	100	0.4	0.4	0.4	7/1/91	HY	WAT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Dynegy Kendall Energy LLC	Dynegy Inc	Dynegy Kendall Energy LLC	Kendall County Generat	CC1	100	314	285	315	3/1/02	CC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Dynegy Kendall Energy LLC	Dynegy Inc	Dynegy Kendall Energy LLC	Kendall County Generat	CC2	100	314	285	315	4/1/02	CC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Dynegy Kendall Energy LLC	Dynegy Inc	Dynegy Kendall Energy LLC	Kendall County Generat	CC3	100	314	285	315	4/1/02	CC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Dynegy Kendall Energy LLC	Dynegy Inc	Dynegy Kendall Energy LLC	Kendall County Generat	CC4	100	314	285	315	5/1/02	CC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Kincaid Generation LLC	Energy Capital Partners	Kincaid Generation LLC	Kincaid Generation LLC	1	100	659.5	579	579	6/1/67	ST	SUB	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Kincaid Generation LLC	Energy Capital Partners	Kincaid Generation LLC	Kincaid Generation LLC	2	100	659.5	579	579	6/1/68	ST	SUB	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock River Water Reclamatic	Rock River Water Reclama	Rock River Water Reclamation	Kishwaukee CHP Plant	1	100	1	1	1	1/1/10	IC	OBG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock River Water Reclamatic	Rock River Water Reclama	Rock River Water Reclamation	Kishwaukee CHP Plant	2	100	1	1	1	1/1/10	IC	OBG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock River Water Reclamatic	Rock River Water Reclama	Rock River Water Reclamation	Kishwaukee CHP Plant	3	100	1	1	1	1/1/10	IC	OBG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bio Energy Partners	Waste Management Inc	Bio Energy Partners	Lake Gas Recovery	GEN2	100	3	2.9	3.3	8/1/93	GT	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bio Energy Partners	Waste Management Inc	Bio Energy Partners	Lake Gas Recovery	GEN3	100	3	2.9	3.3	8/1/93	GT	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	LaSalle	1	100	1243	1137	1152	8/1/82	NB	URA	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	LaSalle	2	100	1243	1140	1161	4/1/84	NB	URA	Restarted	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Duke Energy Lee II LLC	Duke Energy Corp	Duke Energy Lee II LLC	Lee Energy Facility	CT1	100	101.8	71	89.5	6/15/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Duke Energy Lee II LLC	Duke Energy Corp	Duke Energy Lee II LLC	Lee Energy Facility	CT2	100	101.8	71	89.5	6/15/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Duke Energy Lee II LLC	Duke Energy Corp	Duke Energy Lee II LLC	Lee Energy Facility	CT3	100	101.8	71	89.5	6/15/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Duke Energy Lee II LLC	Duke Energy Corp	Duke Energy Lee II LLC	Lee Energy Facility	CT4	100	101.8	71	89.5	6/15/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Duke Energy Lee II LLC	Duke Energy Corp	Duke Energy Lee II LLC	Lee Energy Facility	CT5	100	101.8	71	89.5	5/1/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Duke Energy Lee II LLC	Duke Energy Corp	Duke Energy Lee II LLC	Lee Energy Facility	CT6	100	101.8	71	89.5	5/1/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Duke Energy Lee II LLC	Duke Energy Corp	Duke Energy Lee II LLC	Lee Energy Facility	CT7	100	101.8	71	89.5	6/15/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Duke Energy Lee II LLC	Duke Energy Corp	Duke Energy Lee II LLC	Lee Energy Facility	CT8	100	101.8	71	89.5	6/15/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Lincoln Generating Facility LI	Tenaska Inc	Lincoln Generating Facility LLC	Lincoln Energy Center	CTG1	100	86.5	77.5	93.3	6/1/00	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Lincoln Generating Facility LI	Tenaska Inc	Lincoln Generating Facility LLC	Lincoln Energy Center	CTG2	100	86.5	77.8	93.4	6/1/00	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Lincoln Generating Facility LI	Tenaska Inc	Lincoln Generating Facility LLC	Lincoln Energy Center	CTG3	100	86.5	78	94.7	6/1/00	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Lincoln Generating Facility LI	Tenaska Inc	Lincoln Generating Facility LLC	Lincoln Energy Center	CTG4	100	86.5	78	93.8	6/1/00	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Lincoln Generating Facility LI	Tenaska Inc	Lincoln Generating Facility LLC	Lincoln Energy Center	CTG5	100	86.5	77.5	92.2	6/1/00	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Lincoln Generating Facility LI	Tenaska Inc	Lincoln Generating Facility LLC	Lincoln Energy Center	CTG6	100	86.5	77.3	92.8	6/1/00	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Lincoln Generating Facility LI	Tenaska Inc	Lincoln Generating Facility LLC	Lincoln Energy Center	CTG7	100	86.5	78.2	92.8	6/1/00	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Lincoln Generating Facility LI	Tenaska Inc	Lincoln Generating Facility LLC	Lincoln Energy Center	CTG8	100	86.5	78.6	94.1	6/1/00	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Metro Water Reclamation D	Metro Water Reclamation	Metro Water Reclamation Dist	Lockport Powerhouse	1GEN	100	8	6	6	2/1/99	HY	WAT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Metro Water Reclamation D	Metro Water Reclamation	Metro Water Reclamation Dist	Lockport Powerhouse	2GEN	100	8	6	6	12/1/01	HY	WAT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Loyola University Health Sys	Loyola University Health S	Loyola University Health Syste	Loyola University Healt	UNIT1	100	5.3	3.9	5.6	1/1/05	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Loyola University Health Sys	Loyola University Health S	Loyola University Health Syste	Loyola University Healt	UNIT2	100	5.3	3.9	5.6	1/1/05	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				M & M Mars Inc	Mars Inc	M & M Mars Inc	M & M Mars Chicago	1	100	3.5	3	3.8	5/1/87	GT	NG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	COMED	Commonwealth Edison Co.				Gas Recovery Services IL Inc	Clean Power Income Fund	Gas Recovery Services IL Inc	Mallard Lake Electric	CC	100	20	15.2	16.8	10/1/97	CC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Mendota Hills LLC	Gamesa Corporación Tecn	Infigen Wind Partners US LLC	Mendota Hills LLC	WT1 63	100	50.4	50.4	50.4	11/24/03	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Moose International	Moose Intl	Moose International	Mooseheart Power Hou	GEN1	100	0.5	0.49	0.49	8/1/86	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Moose International	Moose Intl	Moose International	Mooseheart Power Hou	GEN2	100	0.5	0.49	0.49	8/1/86	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Moose International	Moose Intl	Moose International	Mooseheart Power Hou	GEN3	100	0.3	0.29	0.29	8/1/86	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Moose International	Moose Intl	Moose International	Mooseheart Power Hou	GEN4	100	0.5	0.49	0.49	8/1/86	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Morris Cogeneration LLC	Atlantic Power Corp	Morris Cogeneration LLC	Morris Power Plant	CC1	100	179	176	179	6/1/00	CC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Museum of Science & Indust	Museum of Science & Indu	Museum of Science & Industry	Museum of Science & In	GT	100	1.75	1.715	1.715	12/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				FPL Energy Illinois Wind	NextEra Energy Inc	FPL Energy Illinois Wind	Nextera Dekalb County	WT1 150	100	225	225	225	12/31/09	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Nicor Gas	AGL Resources Inc	Nicor Gas	Nicor Gas	1	100	0.6	0.95	0.75	10/1/87	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Nicor Gas	AGL Resources Inc	Nicor Gas	Nicor Gas	2	100	0.6	0.95	0.75	10/1/87	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Nicor Gas	AGL Resources Inc	Nicor Gas	Nicor Gas	3	100	0.6	0.95	0.75	10/1/87	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Nicor Gas	AGL Resources Inc	Nicor Gas	Nicor Gas	4	100	0.6	0.59	0.59	10/1/87	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Amalgamated Bank of Chica	Amalgamated Bank of Chic	Energy Systems Group	North Chicago Energy C	GT1	100	5.2	5.2	5	10/1/03	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Amalgamated Bank of Chica	Amalgamated Bank of Chic	Energy Systems Group	North Chicago Energy C	GT2	100	7.2	7.1	6.5	1/1/05	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rochelle Municipal Utilities	Rochelle Municipal Utilitie	Rochelle Municipal Utilities	North Ninth Street	10	100	2.5	2	2	5/1/89	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rochelle Municipal Utilities	Rochelle Municipal Utilitie	Rochelle Municipal Utilities	North Ninth Street	3	100	2.5	2	2	7/1/56	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rochelle Municipal Utilities	Rochelle Municipal Utilitie	Rochelle Municipal Utilities	North Ninth Street	6	100	2.5	2	2	4/1/54	IC	NG	Restarted	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rochelle Municipal Utilities	Rochelle Municipal Utilitie	Rochelle Municipal Utilities	North Ninth Street	7	100	3.8	3.5	3.5	2/1/67	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rochelle Municipal Utilities	Rochelle Municipal Utilitie	Rochelle Municipal Utilities	North Ninth Street	9	100	3.5	3	3	5/1/89	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rochelle Municipal Utilities	Rochelle Municipal Utilitie	Rochelle Municipal Utilities	North Ninth Street	1	100	0.9	0.6	0.6	10/1/40	IC	DFO	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rochelle Municipal Utilities	Rochelle Municipal Utilitie	Rochelle Municipal Utilities	North Ninth Street	4	100	1	0.7	0.7	10/1/46	IC	DFO	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rochelle Municipal Utilities	Rochelle Municipal Utilitie	Rochelle Municipal Utilities	North Ninth Street	8	100	1	0.5	0.5	6/1/49	IC	DFO	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Haviland Plastic Products Co	Haviland Plastic Products C	Haviland Plastic Products Co	Northeastern Illinois Ur	GEN1	100	0.8	0.8	0.8	1/1/95	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Haviland Plastic Products Co	Haviland Plastic Products C	Haviland Plastic Products Co	Northeastern Illinois Ur	GEN2	100	0.8	0.8	0.8	1/1/95	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Haviland Plastic Products Co	Haviland Plastic Products C	Haviland Plastic Products Co	Northeastern Illinois Ur	GEN3	100	0.8	0.8	0.8	1/1/95	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Haviland Plastic Products Co	Haviland Plastic Products C	Haviland Plastic Products Co	Northeastern Illinois Ur	GEN4	100	0.8	0.8	0.8	1/1/95	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Ondeo Nalco Co	Nalco Co	Ondeo Nalco Co	Ondeo Nalco	CC	100	4.7	3.7	4.2	11/1/85	CC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Panduit Corp	Panduit Corp	Panduit Corp	Panduit Corp Tinley Par	GEN1	100	0.7	0.7	0.7	5/1/94	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Panduit Corp	Panduit Corp	Panduit Corp	Panduit Corp Tinley Par	GEN2	100	0.7	0.7	0.7	5/1/94	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Powerton	5	100	892.8	769	769	9/1/72	ST	SUB	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Powerton	6	100	892.8	769	769	12/1/75	ST	SUB	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				LSP University Park LLC	LS Power Group	LSP University Park LLC	PPL University Park Pov	1	100	45	42	45	6/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				LSP University Park LLC	LS Power Group	LSP University Park LLC	PPL University Park Pov	10	100	45	42	45	7/25/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				LSP University Park LLC	LS Power Group	LSP University Park LLC	PPL University Park Pov	11	100	45	42	45	7/25/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				LSP University Park LLC	LS Power Group	LSP University Park LLC	PPL University Park Pov	12	100	45	42	45	7/25/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				LSP University Park LLC	LS Power Group	LSP University Park LLC	PPL University Park Pov	2	100	45	42	45	6/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				LSP University Park LLC	LS Power Group	LSP University Park LLC	PPL University Park Pov	3	100	45	42	45	6/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				LSP University Park LLC	LS Power Group	LSP University Park LLC	PPL University Park Pov	4	100	45	42	45	6/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				LSP University Park LLC	LS Power Group	LSP University Park LLC	PPL University Park Pov	5	100	45	42	45	6/1/02	GT	NG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	COMED	Commonwealth Edison Co.				LSP University Park LLC	LS Power Group	LSP University Park LLC	PPL University Park Pov	6	100	45	42	45	6/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				LSP University Park LLC	LS Power Group	LSP University Park LLC	PPL University Park Pov	7	100	45	42	45	6/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				LSP University Park LLC	LS Power Group	LSP University Park LLC	PPL University Park Pov	8	100	45	42	45	6/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				LSP University Park LLC	LS Power Group	LSP University Park LLC	PPL University Park Pov	9	100	45	42	45	6/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Providence Heights Wind LL	Iberdrola SA	Providence Heights Wind LLC	Providence Heights Pro	WT1 36	100	72	72	72	9/23/08	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Quad Cities (EXELON)	1	75	756.975	681	681	12/1/72	NB	URA	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				MidAmerican Energy Co	Berkshire Hathaway Inc	Exelon Generation Co LLC	Quad Cities (EXELON)	1	25	252.325	227	227	12/1/72	NB	URA	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Quad Cities (EXELON)	2	75	756.975	683.25	683.25	12/1/72	NB	URA	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				MidAmerican Energy Co	Berkshire Hathaway Inc	Exelon Generation Co LLC	Quad Cities (EXELON)	2	25	252.325	227.75	227.75	12/1/72	NB	URA	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Robin J Miller	Robin J Miller	Robin J Miller	Robin J Miller Wind	WT	100	0.006	0.006	0.006	12/1/08	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Island IL (City of)	Rock Island IL (City of)	Rock Island IL (City of)	Rock Island Hydroelectr	HY1	100	0.4	0.3	0.3	11/1/85	HY	WAT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Island IL (City of)	Rock Island IL (City of)	Rock Island IL (City of)	Rock Island Hydroelectr	HY2	100	0.4	0.3	0.3	7/1/86	HY	WAT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Island IL (City of)	Rock Island IL (City of)	Rock Island IL (City of)	Rock Island Hydroelectr	HY3	100	0.3	0.3	0.3	9/30/09	HY	WAT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Island IL (City of)	Rock Island IL (City of)	Rock Island IL (City of)	Rock Island Hydroelectr	HY4	100	0.3	0.3	0.3	9/30/09	HY	WAT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Tenn Co	Rock Tenn Co	Rock Tenn Co	Rock Tenn Co	E 1	100	0.7	0.7	0.7	6/1/92	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Tenn Co	Rock Tenn Co	Rock Tenn Co	Rock Tenn Co	E2 A	100	0.7	0.7	0.7	6/1/92	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Tenn Co	Rock Tenn Co	Rock Tenn Co	Rock Tenn Co	E2 B	100	0.7	0.7	0.7	6/1/92	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Tenn Co	Rock Tenn Co	Rock Tenn Co	Rock Tenn Co	E3	100	0.8	0.8	0.8	6/1/92	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				NRG Rockford LLC	NRG Energy Inc	NRG Rockford LLC	Rockford I	1	100	158	149.8	149.8	6/1/00	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				NRG Rockford LLC	NRG Energy Inc	NRG Rockford LLC	Rockford I	2	100	158	151.3	151.3	6/1/00	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				NRG Rockford II LLC	NRG Energy Inc	NRG Rockford II LLC	Rockford II Energy Cent	GT3	100	168	155.8	155.8	6/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rocky Road Power LLC	LS Power Group	Rocky Road Power LLC	Rocky Road Power LLC	T4	100	122.4	104.9	108.9	6/1/00	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rocky Road Power LLC	LS Power Group	Rocky Road Power LLC	Rocky Road Power LLC	TG1	100	125.8	95.2	108.4	6/1/99	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rocky Road Power LLC	LS Power Group	Rocky Road Power LLC	Rocky Road Power LLC	TG2	100	125.8	102.2	108.3	6/1/99	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rocky Road Power LLC	LS Power Group	Rocky Road Power LLC	Rocky Road Power LLC	TG3	100	41.5	25	28.6	6/1/99	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Alliant Energy Integ Ser Coge	Alliant Energy Corp	Treetop Midstream Service LL	SBG 9805 Rockford Proc	GEN1	100	0.8	0.8	0.8	8/1/99	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Alliant Energy Integ Ser Coge	Alliant Energy Corp	Treetop Midstream Service LL	SBG 9805 Rockford Proc	GEN2	100	0.8	0.8	0.8	8/1/99	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Alliant Energy Integ Ser Coge	Alliant Energy Corp	Treetop Midstream Service LL	SBG 9805 Rockford Proc	GEN3	100	0.8	0.8	0.8	8/1/99	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Alliant Energy Integ Ser Coge	Alliant Energy Corp	Treetop Midstream Service LL	SBG 9805 Rockford Proc	GEN4	100	0.8	0.8	0.8	8/1/99	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Alliant Energy Integ Ser Coge	Alliant Energy Corp	Treetop Midstream Service LL	SBG 9805 Rockford Proc	GEN5	100	0.8	0.8	0.8	8/1/99	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Alliant Energy Integ Ser Coge	Alliant Energy Corp	Treetop Midstream Service LL	SBG 9805 Rockford Proc	GEN6	100	0.8	0.8	0.8	8/1/99	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bio Energy Partners	Waste Management Inc	Bio Energy Partners	Settlers Hill Gas Recove	GEN1	100	3	2.9	3.3	10/1/88	GT	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bio Energy Partners	Waste Management Inc	Bio Energy Partners	Settlers Hill Gas Recove	GEN2	100	3	2.9	3.3	5/1/98	GT	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				GSG LLC	Babcock & Brown	GSG LLC	Shady Oaks Wind Farm	WT1 40	100	80	80	80	9/30/07	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rochelle Municipal Utilities	Rochelle Municipal Utilitie	Rochelle Municipal Utilities	South Main Street	1	100	2.5	1.6	1.6	9/1/67	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rochelle Municipal Utilities	Rochelle Municipal Utilitie	Rochelle Municipal Utilities	South Main Street	2	100	2.5	2	2	9/1/67	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Southeast Chicago Energy Pr	Exelon Corp	Southeast Chicago Energy Proj	Southeast Chicago	GT10	100	50.9	37	40	7/31/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Southeast Chicago Energy Pr	Exelon Corp	Southeast Chicago Energy Proj	Southeast Chicago	GT11	100	50.9	37	40	7/31/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Southeast Chicago Energy Pr	Exelon Corp	Southeast Chicago Energy Proj	Southeast Chicago	IC1	100	2	2	2	3/18/04	IC	DSL	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Southeast Chicago Energy Pr	Exelon Corp	Southeast Chicago Energy Proj	Southeast Chicago	GT12	100	50.9	37	40	7/31/02	GT	NG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	COMED	Commonwealth Edison Co.				Southeast Chicago Energy Pr	Exelon Corp	Southeast Chicago Energy Proj	Southeast Chicago	IC2	100	2	2	2	3/18/04	IC	DSL	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Southeast Chicago Energy Pr	Exelon Corp	Southeast Chicago Energy Proj	Southeast Chicago	IC3	100	2	2	2	3/18/04	IC	DSL	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Southeast Chicago Energy Pr	Exelon Corp	Southeast Chicago Energy Proj	Southeast Chicago	GT05	100	50.9	37	40	7/31/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Southeast Chicago Energy Pr	Exelon Corp	Southeast Chicago Energy Proj	Southeast Chicago	GT06	100	50.9	37	40	7/31/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Southeast Chicago Energy Pr	Exelon Corp	Southeast Chicago Energy Proj	Southeast Chicago	GT07	100	50.9	37	40	7/31/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Southeast Chicago Energy Pr	Exelon Corp	Southeast Chicago Energy Proj	Southeast Chicago	GT08	100	50.9	37	40	7/31/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Southeast Chicago Energy Pr	Exelon Corp	Southeast Chicago Energy Proj	Southeast Chicago	GT09	100	50.9	37	40	7/31/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Resurrection Health Care Co	Resurrection Health Care C	Resurrection Health Care Corp	St Mary of Nazareth Ho	GEN1	100	0.8	0.8	0.8	8/1/93	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Resurrection Health Care Co	Resurrection Health Care C	Resurrection Health Care Corp	St Mary of Nazareth Ho	GEN2	100	0.8	0.8	0.8	8/1/93	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Resurrection Health Care Co	Resurrection Health Care C	Resurrection Health Care Corp	St Mary of Nazareth Ho	GEN3	100	0.8	0.8	0.8	8/1/93	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Illinois Electrical Generating	U S Energy Systems Inc	Illinois Electrical Generating Pa	Streator	ST1	100	1.1	0.9	0.9	12/1/99	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Streator Cayuga Ridge Wind	Iberdrola SA	Outland Energy Services LLC	Streator Cayuga Ridge \	WT1 150	100	300	300	300	3/27/10	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bio Energy Partners	Waste Management Inc	Bio Energy Partners	Tazewell Gas Recovery	GEN1	100	0.8	0.8	0.8	7/1/89	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bio Energy Partners	Waste Management Inc	Bio Energy Partners	Tazewell Gas Recovery	GEN2	100	0.8	0.8	0.8	7/1/89	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bio Energy Partners	Waste Management Inc	Bio Energy Partners	Tazewell Gas Recovery	GEN3	100	0.8	0.8	0.8	5/1/99	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Thorton Township School Di	Thorton Township School [	Thorton Township School Distr	Thornridge High School	1	100	0.5	0.5	0.4	3/1/96	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Thorton Township School Di	Thorton Township School [	Thorton Township School Distr	Thornridge High School	2	100	0.5	0.5	0.4	3/1/96	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Thorton Township School Di	Thorton Township School [	Thorton Township School Distr	Thornwood High Schoo	1	100	0.7	0.7	0.5	9/1/96	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Thorton Township School Di	Thorton Township School [	Thorton Township School Distr	Thornwood High Schoo	2	100	0.7	0.7	0.5	9/1/96	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Blackstone Wind Farm II LLC	Energias de Portugal SA	Blackstone Wind Farm LLC	Top Crop Wind Farm	WT69 200	100	198	198	198	8/31/10	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Blackstone Wind Farm LLC	Energias de Portugal SA	Blackstone Wind Farm LLC	Top Crop Wind Farm	WT1 68	100	102	102	102	10/31/09	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				MPEA Energy Center	GDF SUEZ SA	MPEA Energy Center	Trigen Peoples District	GEN1	100	1.1	1.1	1.1	1/1/97	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				MPEA Energy Center	GDF SUEZ SA	MPEA Energy Center	Trigen Peoples District	GEN2	100	1.1	1.1	1.1	1/1/97	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				MPEA Energy Center	GDF SUEZ SA	MPEA Energy Center	Trigen Peoples District	GEN3	100	1.1	1.1	1.1	1/1/97	GT	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				High Trail Wind Farm LLC	Energias de Portugal SA	High Trail Wind Farm LLC	Twin Groves I Wind Far	WT1 120	100	198	198	198	3/1/07	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Old Trail Wind Farm LLC	Energias de Portugal SA	Old Trail Wind Farm LLC	Twin Groves II Wind Fa	WT1 120	100	198	198	198	9/28/07	WT	WND	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				University of Illinois	University of Illinois	University of Illinois	University of Illinois Co	CT1	100	7.8	6.4	7.8	1/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				University of Illinois	University of Illinois	University of Illinois	University of Illinois Co	CT2	100	7.8	6.4	7.8	1/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				University of Illinois	University of Illinois	University of Illinois	University of Illinois Co	CT3	100	7.8	6.4	7.8	1/1/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				University of Illinois	University of Illinois	University of Illinois	University of Illinois Co	GEN1	100	6.3	6.3	6.3	4/1/93	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				University of Illinois	University of Illinois	University of Illinois	University of Illinois Co	GEN2	100	6.3	6.3	6.3	5/1/93	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				University of Illinois	University of Illinois	University of Illinois	University of Illinois Co	GEN3	100	3.7	3.7	3.7	7/1/00	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				University of Illinois	University of Illinois	University of Illinois	University of Illinois Co	GEN4	100	3.7	3.7	3.7	7/1/00	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				University of Illinois	University of Illinois	University of Illinois	University of Illinois Co	RE1	100	5.5	5.5	5.5	1/1/02	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				University of Illinois	University of Illinois	University of Illinois	University of Illinois Co	RE2	100	5.5	5.5	5.5	1/1/02	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				University of Illinois	University of Illinois	University of Illinois	University of Illinois Co	RE3	100	5.5	5.5	5.5	1/1/02	IC	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				University Park Energy LLC	Tenaska Inc	University Park Energy LLC	University Park Energy	UPG1	100	57	50	56	7/6/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				University Park Energy LLC	Tenaska Inc	University Park Energy LLC	University Park Energy	UPG2	100	57	50	56	7/6/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				University Park Energy LLC	Tenaska Inc	University Park Energy LLC	University Park Energy	UPG6	100	57	50	56	7/6/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				University Park Energy LLC	Tenaska Inc	University Park Energy LLC	University Park Energy	UPG3	100	57	50	56	7/6/01	GT	NG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	COMED	Commonwealth Edison Co.				University Park Energy LLC	Tenaska Inc	University Park Energy LLC	University Park Energy	UPG4	100	57	50	56	7/6/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				University Park Energy LLC	Tenaska Inc	University Park Energy LLC	University Park Energy	UPG5	100	57	50	56	7/6/01	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Illinois Electrical Generating	U S Energy Systems Inc	Illinois Electrical Generating Pa	Upper Rock	UR1	100	1.1	0.9	0.9	4/1/00	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Illinois Electrical Generating	U S Energy Systems Inc	Illinois Electrical Generating Pa	Upper Rock	UR2	100	1.1	0.9	0.9	4/1/00	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Illinois Electrical Generating	U S Energy Systems Inc	Illinois Electrical Generating Pa	Upper Rock	UR3	100	1.1	0.9	0.9	4/1/00	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Illinois Electrical Generating	U S Energy Systems Inc	Illinois Electrical Generating Pa	Upper Rock	UR4	100	1.1	0.9	0.9	4/1/03	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Falls Electrical Dept	Rock Falls Electrical Dept	Rock Falls Electrical Dept	Upper Sterling	1	100	1.1	1	1	6/1/88	HY	WAT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Rock Falls Electrical Dept	Rock Falls Electrical Dept	Rock Falls Electrical Dept	Upper Sterling	2	100	1.1	1	1	6/1/88	HY	WAT	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Waukegan	311	100	28	24.6	33.9	6/1/68	GT	DFO	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Waukegan	312	100	28	28.5	37.4	6/1/68	GT	DFO	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Waukegan	321	100	28	28	37.4	6/1/68	GT	DFO	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Waukegan	322	100	28	26.7	35	6/1/68	GT	DFO	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Waukegan	7	100	326.4	328	328	6/1/58	ST	SUB	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Waukegan	8	100	355.3	361	361	7/1/62	ST	SUB	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Wells Manufacturing Co	United Technologies Corp	Wells Manufacturing Co	Wells Manufacturing Dı	1A	100	1	0.9	1	4/1/92	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Wells Manufacturing Co	United Technologies Corp	Wells Manufacturing Co	Wells Manufacturing Dı	1B	100	1	0.9	1	4/1/92	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Wells Manufacturing Co	United Technologies Corp	Wells Manufacturing Co	Wells Manufacturing Dı	2A	100	1	0.9	1	4/1/92	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Wells Manufacturing Co	United Technologies Corp	Wells Manufacturing Co	Wells Manufacturing Dı	2B	100	1	0.9	1	4/1/92	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Wells Manufacturing Co	United Technologies Corp	Wells Manufacturing Co	Wells Manufacturing Dı	3A	100	1	0.9	1	4/1/92	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Wells Manufacturing Co	United Technologies Corp	Wells Manufacturing Co	Wells Manufacturing Dı	3B	100	1	0.9	1	4/1/92	IC	NG	Standby	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Sexton Energy LLC	Sexton Companies	Sexton Energy LLC	Westchester Landfill	W1	100	1.8	1.8	1.8	9/1/04	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Sexton Energy LLC	Sexton Companies	Sexton Energy LLC	Westchester Landfill	W2	100	1.8	1.8	1.8	9/1/04	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Will County	3	100	299.2	251	262	6/1/57	ST	SUB	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Edison International	Midwest Generations EME LLC	Will County	4	100	598.4	510	520	6/1/63	ST	SUB	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Winnebago Energy LLC	Integrys Energy Group Inc	Winnebago Energy LLC	Winnebago Energy Cen	1	100	1.6	1.55	1.55	12/21/07	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Winnebago Energy LLC	Integrys Energy Group Inc	Winnebago Energy LLC	Winnebago Energy Cen	2	100	1.6	1.55	1.55	12/21/07	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Winnebago Energy LLC	Integrys Energy Group Inc	Winnebago Energy LLC	Winnebago Energy Cen	3	100	1.6	1.55	1.55	12/21/07	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Winnebago Energy LLC	Integrys Energy Group Inc	Winnebago Energy LLC	Winnebago Energy Cen	4	100	1.6	1.55	1.55	12/21/07	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Winnetka IL (Village of)	Winnetka IL (Village of)	Winnetka IL (Village of)	Winnetka	4	100	9.4	9.4	9.4	1/3/53	ST	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Winnetka IL (Village of)	Winnetka IL (Village of)	Winnetka IL (Village of)	Winnetka	6	100	6.3	6.3	6.3	1/1/48	ST	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Winnetka IL (Village of)	Winnetka IL (Village of)	Winnetka IL (Village of)	Winnetka	7	100	12.5	12.5	12.5	1/3/60	ST	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Winnetka IL (Village of)	Winnetka IL (Village of)	Winnetka IL (Village of)	Winnetka	8	100	2.6	2.6	2.6	1/3/79	IC	DFO	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Winnetka IL (Village of)	Winnetka IL (Village of)	Winnetka IL (Village of)	Winnetka	9	100	2.6	2.6	2.6	1/3/79	IC	DFO	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bio Energy Partners	Waste Management Inc	Bio Energy Partners	Woodland Landfill Gas I	GEN1	100	0.8	0.8	0.8	5/1/92	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bio Energy Partners	Waste Management Inc	Bio Energy Partners	Woodland Landfill Gas I	GEN2	100	0.8	0.8	0.8	5/1/92	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bio Energy Partners	Waste Management Inc	Bio Energy Partners	Woodland Landfill Gas I	GEN3	100	1.6	1.6	1.6	5/31/10	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Bio Energy Partners	Waste Management Inc	Bio Energy Partners	Woodland Landfill Gas I	GEN4	100	1.6	1.6	1.6	5/31/10	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Calpine Corp	Calpine Corp	Zion Energy LLC	Zion Energy Center	CTG1	100	198.9	152	181	7/5/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Calpine Corp	Calpine Corp	Zion Energy LLC	Zion Energy Center	CTG2	100	198.9	152	181	7/5/02	GT	NG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Calpine Corp	Calpine Corp	Zion Energy LLC	Zion Energy Center	CTG3	100	198.9	152	181	6/26/03	GT	NG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DAY	Dayton Power & Light Co.				Arcanum OH (City of)	Arcanum OH (City of)	Arcanum OH (City of)	Arcanum	1	100	0.7	0.8	0.8	9/1/51	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Arcanum OH (City of)	Arcanum OH (City of)	Arcanum OH (City of)	Arcanum	2	100	0.5	0.6	0.6	10/1/46	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Arcanum Peaking	1	100	1.8	1.8	1.8	6/1/99	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Bellefontaine Gas Producers	DTE Energy Co	Bellefontaine Gas Producers LI	Bellefontaine Landfill	IC1	100	1.6	1.6	1.6	3/5/09	IC	LFG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Bellefontaine Gas Producers	DTE Energy Co	Bellefontaine Gas Producers LI	Bellefontaine Landfill	IC2	100	1.6	1.6	1.6	3/5/09	IC	LFG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Bellefontaine Gas Producers	DTE Energy Co	Bellefontaine Gas Producers LI	Bellefontaine Landfill	IC3	100	1.6	1.6	1.6	3/5/09	IC	LFG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Power Co	American Electric Power C	Ohio Power Co	Darby Electric Generati	GT1	100	94	72.5	84.5	5/11/01	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Power Co	American Electric Power C	Ohio Power Co	Darby Electric Generati	GT2	100	94	72.5	84.5	5/11/01	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Power Co	American Electric Power C	Ohio Power Co	Darby Electric Generati	GT3	100	94	72.5	84.5	5/23/01	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Power Co	American Electric Power C	Ohio Power Co	Darby Electric Generati	GT4	100	94	72.5	84.5	5/23/01	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Power Co	American Electric Power C	Ohio Power Co	Darby Electric Generati	GT5	100	94	72.5	84.5	5/24/02	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Power Co	American Electric Power C	Ohio Power Co	Darby Electric Generati	GT6	100	94	72.5	84.5	5/24/02	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Frank M Tait	GT1	100	103.5	88	100	4/1/95	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Frank M Tait	IC1	100	2.7	2.5	2.5	5/1/67	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Frank M Tait	IC4	100	2.7	2.5	2.5	5/1/67	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Frank M Tait	GT2	100	106.1	89	102	12/1/96	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Frank M Tait	IC2	100	2.7	2.5	2.5	5/1/67	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Frank M Tait	GT3	100	84.2	79	102	12/1/98	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Frank M Tait	IC3	100	2.7	2.5	2.5	5/1/67	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Buckeye Power Inc	Buckeye Power Inc	Buckeye Power Inc	Greenville Electric Gene	GT1	100	59	51.9	61.3	6/28/00	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Buckeye Power Inc	Buckeye Power Inc	Buckeye Power Inc	Greenville Electric Gene	GT2	100	59	50.3	59.8	6/28/00	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Buckeye Power Inc	Buckeye Power Inc	Buckeye Power Inc	Greenville Electric Gene	GT3	100	59	50	59.5	6/28/00	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Buckeye Power Inc	Buckeye Power Inc	Buckeye Power Inc	Greenville Electric Gene	GT4	100	59	49.3	58.8	6/28/00	GT	NG	Operating	Y	1
PJM ISO	DAY	FirstEnergy ATSI				Wright Patterson Afb	Wright Patterson Afb	Wright Patterson Afb	Heat Plant 770	HP	100	1.2	1.2	1.2	4/1/03	ST	BIT	Operating	Y	1
PJM ISO	DAY	FirstEnergy ATSI				Wright Patterson Afb	Wright Patterson Afb	Wright Patterson Afb	Heat Plant 770	LP	100	0.8	0.8	0.8	4/1/03	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	J M Stuart	1	35	213.57	201.95	201.95	5/1/71	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Duke Energy Ohio	Duke Energy Corp	Dayton Power & Light Co (The	J M Stuart	1	39	237.978	225.03	225.03	5/1/71	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Power Co	American Electric Power C	Dayton Power & Light Co (The	J M Stuart	1	26	158.652	150.02	150.02	5/1/71	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	J M Stuart	2	35	213.57	201.95	201.95	10/1/70	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Duke Energy Ohio	Duke Energy Corp	Dayton Power & Light Co (The	J M Stuart	2	39	237.978	225.03	225.03	10/1/70	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Power Co	American Electric Power C	Dayton Power & Light Co (The	J M Stuart	2	26	158.652	150.02	150.02	10/1/70	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	J M Stuart	3	35	213.57	201.95	201.95	5/1/72	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Duke Energy Ohio	Duke Energy Corp	Dayton Power & Light Co (The	J M Stuart	3	39	237.978	225.03	225.03	5/1/72	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Power Co	American Electric Power C	Dayton Power & Light Co (The	J M Stuart	3	26	158.652	150.02	150.02	5/1/72	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	J M Stuart	4	35	213.57	201.95	201.95	6/1/74	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Duke Energy Ohio	Duke Energy Corp	Dayton Power & Light Co (The	J M Stuart	4	39	237.978	225.03	225.03	6/1/74	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Power Co	American Electric Power C	Dayton Power & Light Co (The	J M Stuart	4	26	158.652	150.02	150.02	6/1/74	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	J M Stuart	D1	35	0.945	0.77	0.77	10/1/69	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Duke Energy Ohio	Duke Energy Corp	Dayton Power & Light Co (The	J M Stuart	D1	39	1.053	0.858	0.858	10/1/69	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Power Co	American Electric Power C	Dayton Power & Light Co (The	J M Stuart	D1	26	0.702	0.572	0.572	10/1/69	IC	DFO	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	J M Stuart	D3	35	0.945	0.77	0.77	10/1/69	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Duke Energy Ohio	Duke Energy Corp	Dayton Power & Light Co (The	J M Stuart	D3	39	1.053	0.858	0.858	10/1/69	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Power Co	American Electric Power C	Dayton Power & Light Co (The	J M Stuart	D3	26	0.702	0.572	0.572	10/1/69	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	J M Stuart	D4	35	0.945	0.77	0.77	10/1/69	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Duke Energy Ohio	Duke Energy Corp	Dayton Power & Light Co (The	J M Stuart	D4	39	1.053	0.858	0.858	10/1/69	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Power Co	American Electric Power C	Dayton Power & Light Co (The	J M Stuart	D4	26	0.702	0.572	0.572	10/1/69	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	J M Stuart	D2	35	0.945	0.77	0.77	10/1/69	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Duke Energy Ohio	Duke Energy Corp	Dayton Power & Light Co (The	J M Stuart	D2	39	1.053	0.858	0.858	10/1/69	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Power Co	American Electric Power C	Dayton Power & Light Co (The	J M Stuart	D2	26	0.702	0.572	0.572	10/1/69	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Killen Station	GT1	67	19.229	12.06	16.08	4/1/82	GT	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Duke Energy Ohio	Duke Energy Corp	Dayton Power & Light Co (The	Killen Station	GT1	33	9.471	5.94	7.92	4/1/82	GT	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Killen Station	2	67	442.602	402	402	6/1/82	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Duke Energy Ohio	Duke Energy Corp	Dayton Power & Light Co (The	Killen Station	2	33	217.998	198	198	6/1/82	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Louis M Meyer	Louis M Meyer	Louis M Meyer	Meyer Wind	WT	100	0.002	0.002	0.002	9/30/08	WT	WND	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Monument	1	100	2.7	2.4	2.4	6/1/68	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Monument	2	100	2.7	2.4	2.4	6/1/68	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Monument	3	100	2.7	2.4	2.4	6/1/68	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Monument	4	100	2.7	2.4	2.4	6/1/68	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Monument	5	100	2.7	2.4	2.4	6/1/68	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	O H Hutchings	1	100	69	58	59	7/1/48	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	O H Hutchings	2	100	69	55	56	3/1/49	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	O H Hutchings	3	100	69	63	64	12/1/50	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	O H Hutchings	5	100	69	63	64	11/1/52	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	O H Hutchings	6	100	69	63	64	8/1/53	ST	BIT	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	O H Hutchings	7	100	32.6	25	33	11/1/68	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Piqua Municipal Power Syste	Piqua Municipal Power Sys	Piqua Municipal Power System	Piqua	11	100	16.3	16.5	16.5	12/1/89	GT	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Piqua Municipal Power Syste	Piqua Municipal Power Sys	Piqua Municipal Power System	Piqua	8	100	20	20	20	1/1/72	GT	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Sidney	1	100	2.7	2.4	2.4	7/1/68	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Sidney	2	100	2.7	2.4	2.4	7/1/68	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Sidney	3	100	2.7	2.4	2.4	7/1/68	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Sidney	4	100	2.7	2.4	2.4	7/1/68	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Sidney	5	100	2.7	2.4	2.4	7/1/68	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Columbus OH (City of)	Columbus OH (City of)	Columbus OH (City of)	Solid Waste R F	COBE1	100	1	0.9	0.9	12/1/10	IC	OBG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				DPL Energy LLC	AES Corp (The)	DPL Energy LLC	Tait Electric Generating	GT4	100	94	85	94	6/1/02	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				DPL Energy LLC	AES Corp (The)	DPL Energy LLC	Tait Electric Generating	GT5	100	94	85	94	6/1/02	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				DPL Energy LLC	AES Corp (The)	DPL Energy LLC	Tait Electric Generating	GT6	100	94	85	94	6/1/02	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				DPL Energy LLC	AES Corp (The)	DPL Energy LLC	Tait Electric Generating	GT7	100	94	85	94	6/1/02	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Versailles Peaking	1	100	1.8	1.8	1.8	6/1/99	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Versailles Peaking	2	100	1.8	1.8	1.8	6/1/99	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Versailles Peaking	3	100	1.8	1.8	1.8	6/1/99	IC	DFO	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DAY	Dayton Power & Light Co.				Darryl Watson	Darrylwatson	Darryl Watson	Watson Wind	WT	100	0.002	0.002	0.002	5/1/09	WT	WND	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Wenning Poultry	Wenning Poultry	Wenning Poultry	Wenning Poultry Bioma	GT1	100	1.8	1.8	1.8	2/5/09	GT	OBG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Yankee Street	1	100	18.5	19.5	22	7/1/69	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Yankee Street	2	100	18.5	19.5	22	7/1/69	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Yankee Street	3	100	18.5	19.3	22	7/1/69	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Yankee Street	YS1	100	1.1	1.1	1.1	6/22/10	PV	SUN	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Yankee Street	4	100	17.5	11	11	11/1/70	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Yankee Street	5	100	17.5	8	8	11/1/70	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Yankee Street	6	100	17.5	12	12	11/1/70	GT	NG	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	Yankee Street	7	100	17.5	11	11	11/1/70	GT	NG	Restarted	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Melink Corp	Melink Corp	Melink Corp	Cincinnati Zoo Solar	PV1	100	1.56	1.56	1.56	5/9/11	PV	SUN	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Dicks Creek	1	100	100	92	110	9/1/65	GT	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Dicks Creek	3	100	16.5	14.2	19.5	6/1/69	GT	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Dicks Creek	4	100	21.3	15	21.4	10/1/69	GT	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Dicks Creek	5	100	21.3	15	21.4	10/1/69	GT	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Kentucky				Dayton Power & Light Co (Th	AES Corp (The)	Duke Energy Kentucky	East Bend	2	31	207.483	186	186	3/1/81	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Kentucky				Duke Energy Kentucky	Duke Energy Corp	Duke Energy Kentucky	East Bend	2	69	461.817	414	414	3/1/81	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				University of Cincinnati	University of Cincinnati	University of Cincinnati	East Campus Utility Plar	P007	100	2	1.7	1.7	7/1/06	IC	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				University of Cincinnati	University of Cincinnati	University of Cincinnati	East Campus Utility Plar	P008	100	1.5	1.5	1.5	7/1/06	IC	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				University of Cincinnati	University of Cincinnati	University of Cincinnati	East Campus Utility Plar	STG	100	1.3	1.2	1.2	11/1/10	ST	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Edgerton	1	100	1.8	1.8	1.8	8/1/00	IC	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Ohio Municipal Electric Ager	Hamilton Dept of Public Ut	American Municipal Power Inc	Edgerton	2	100	1.8	1.8	1.8	8/1/00	IC	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Hamilton Dept of Public Utili	Hamilton Dept of Public Ut	Hamilton Dept of Public Utilitie	Hamilton	5	100	10	10	10	3/1/54	ST	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Hamilton Dept of Public Utili	Hamilton Dept of Public Ut	Hamilton Dept of Public Utilitie	Hamilton	7	100	25	25	25	5/1/60	ST	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Hamilton Dept of Public Utili	Hamilton Dept of Public Ut	Hamilton Dept of Public Utilitie	Hamilton	8	100	25	25	25	6/1/65	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Hamilton Dept of Public Utili	Hamilton Dept of Public Ut	Hamilton Dept of Public Utilitie	Hamilton	9	100	50.6	51	50	10/1/75	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Hamilton Dept of Public Utili	Hamilton Dept of Public Ut	Hamilton Dept of Public Utilitie	Hamilton	GT2	100	16.3	12	16	6/1/71	GT	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Hamilton Dept of Public Utili	Hamilton Dept of Public Ut	Hamilton Dept of Public Utilitie	Hamilton (HYDRO)	3	100	1.1	0.97	0.97	5/1/94	HY	WAT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Hamilton Dept of Public Utili	Hamilton Dept of Public Ut	Hamilton Dept of Public Utilitie	Hamilton (HYDRO)	4	100	1.1	0.97	0.97	5/1/94	HY	WAT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				American Municipal Power I	American Municipal Power	American Municipal Power Inc	Hamilton Peaking	1	100	32	29	32	6/1/00	GT	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Procter & Gamble Co	Procter & Gamble Co (The)	Procter & Gamble Co	Ivorydale	GEN1	100	12.5	11.71	11.75	11/1/65	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Lebanon Municipal Electric L	Lebanon Municipal Electric	Lebanon Municipal Electric Uti	Lebanon	5	100	2	2	2	1/1/55	IC	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Lebanon Municipal Electric L	Lebanon Municipal Electric	Lebanon Municipal Electric Uti	Lebanon	6	100	3	3	3	1/1/61	IC	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Lebanon Municipal Electric L	Lebanon Municipal Electric	Lebanon Municipal Electric Uti	Lebanon	7	100	6	6	6	1/1/66	GT	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Lebanon Municipal Electric L	Lebanon Municipal Electric	Lebanon Municipal Electric Uti	Lebanon	8	100	5.6	5.6	5.6	1/1/70	IC	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Lebanon Municipal Electric L	Lebanon Municipal Electric	Lebanon Municipal Electric Uti	Lebanon	9	100	14	14	14	11/1/86	GT	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Lebanon Municipal Electric L	Lebanon Municipal Electric	Lebanon Municipal Electric Uti	Lebanon	1	100	0.7	0.7	0.7	1/1/40	IC	DFO	Standby	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Indiana	Duke Energy Corp	Duke Energy Indiana	Madison (OH)	CT1	100	85.4	72	88	4/1/00	GT	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Indiana	Duke Energy Corp	Duke Energy Indiana	Madison (OH)	CT2	100	85.4	72	88	4/1/00	GT	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Indiana	Duke Energy Corp	Duke Energy Indiana	Madison (OH)	CT3	100	85.4	72	88	4/1/00	GT	NG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Indiana	Duke Energy Corp	Duke Energy Indiana	Madison (OH)	CT4	100	85.4	72	88	4/1/00	GT	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Indiana	Duke Energy Corp	Duke Energy Indiana	Madison (OH)	CT5	100	85.4	72	88	4/1/00	GT	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Indiana	Duke Energy Corp	Duke Energy Indiana	Madison (OH)	CT6	100	85.4	72	88	4/1/00	GT	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Indiana	Duke Energy Corp	Duke Energy Indiana	Madison (OH)	CT7	100	85.4	72	88	4/1/00	GT	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Indiana	Duke Energy Corp	Duke Energy Indiana	Madison (OH)	CT8	100	85.4	72	88	4/1/00	GT	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Miami Fort	GT3	100	16.5	14.2	19.5	7/1/71	GT	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Miami Fort	GT4	100	16.5	14.2	19.5	8/1/71	GT	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Miami Fort	GT5	100	16.5	14.2	19.5	9/1/71	GT	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Miami Fort	GT6	100	16.5	14.2	19.5	10/1/71	GT	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Kentucky	Duke Energy Corp	Duke Energy Ohio	Miami Fort	6	100	163.2	163	163	11/1/60	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Dayton Power & Light Co (Th	AES Corp (The)	Duke Energy Ohio	Miami Fort	7	36	200.556	183.6	183.6	5/1/75	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Miami Fort	7	64	356.544	326.4	326.4	5/1/75	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Dayton Power & Light Co (Th	AES Corp (The)	Duke Energy Ohio	Miami Fort	8	36	200.772	183.6	183.6	2/1/78	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Miami Fort	8	64	356.928	326.4	326.4	2/1/78	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Miller Coors LLC	Molson Coors Brewing Co	Miller Coors LLC	Millercoors Trenton Bre	GE	100	13.8	8	10	1/1/92	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Kentucky				Energy Equipment Leasing LI	DTE Energy Co	DTE Silver Grove LLC	Silver Grove	CG1	100	5.2	4.3	5	1/1/02	CS	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				University of Cincinnati	University of Cincinnati	University of Cincinnati	Univ of Cincinnati	CC1	100	45.3	41.6	43	4/1/04	CC	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				University of Cincinnati	University of Cincinnati	University of Cincinnati	Univ of Cincinnati	IC1	100	1.9	1.9	1.9	6/1/04	IC	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Dayton Power & Light Co (Th	AES Corp (The)	Duke Energy Ohio	W H Zimmer	ST1	28.1	400.594	365.3	365.3	3/1/91	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	W H Zimmer	ST1	46.5	662.904	604.5	604.5	3/1/91	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Ohio Power Co	American Electric Power C	Duke Energy Ohio	W H Zimmer	ST1	25.4	362.102	330.2	330.2	3/1/91	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Dayton Power & Light Co (Th	AES Corp (The)	Duke Energy Ohio	Walter C Beckjord	6	50	230.4	207	210	7/1/69	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Walter C Beckjord	6	37.5	172.8	155.25	157.5	7/1/69	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Ohio Power Co	American Electric Power C	Duke Energy Ohio	Walter C Beckjord	6	12.5	57.6	51.75	52.5	7/1/69	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Walter C Beckjord	GT1	100	52.9	46.6	61.2	4/1/72	GT	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Walter C Beckjord	GT2	100	52.9	46.6	61.2	4/1/72	GT	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Walter C Beckjord	GT3	100	52.9	46.6	61.2	6/1/72	GT	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Walter C Beckjord	GT4	100	52.9	46.6	61.2	6/1/72	GT	DFO	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Walter C Beckjord	2	100	112.5	94	94	10/1/53	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Walter C Beckjord	3	100	125	128	128	11/1/54	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Walter C Beckjord	4	100	163.2	150	150	7/1/58	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Corp	Duke Energy Ohio	Walter C Beckjord	5	100	244.8	238	238	12/1/62	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Wausau Paper Middletown	Wausau Paper Corp	Wausau Paper Middletown	Wausau Paper Middlet	G3	100	7.5	1	1.5	4/1/86	ST	BIT	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Kentucky	Duke Energy Corp	Duke Energy Kentucky	Woodsdale	GT1	100	81.6	77	94	5/1/93	GT	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Kentucky	Duke Energy Corp	Duke Energy Kentucky	Woodsdale	GT2	100	81.6	77	94	7/1/92	GT	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Kentucky	Duke Energy Corp	Duke Energy Kentucky	Woodsdale	GT3	100	81.6	77	94	5/1/92	GT	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Kentucky	Duke Energy Corp	Duke Energy Kentucky	Woodsdale	GT4	100	81.6	77	94	7/1/92	GT	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Kentucky	Duke Energy Corp	Duke Energy Kentucky	Woodsdale	GT5	100	81.6	77	94	5/1/92	GT	NG	Operating	Y	1
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Kentucky	Duke Energy Corp	Duke Energy Kentucky	Woodsdale	GT6	100	81.6	77	94	5/1/92	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Robert A Lodi	Robert A Lodi	Robert A Lodi	Advance Mills	1	100	0.1	0.1	0.1	11/1/84	HY	WAT	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company			AP South	Elizabeth City NC (City of)	Elizabeth City NC (City of)	Elizabeth City NC (City of)	Albemarle District Jail	IC1	100	1.1	1.1	1.1	8/1/08	IC	FO2	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Albemarle Hospital	Albemarle Hospital	Albemarle Hospital	Albemarle Hospital Cog	JE	100	0.55	0.55	0.55	12/1/07	JE	FO2	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Westmoreland Coal Co	Altavista Power Station	1	100	51	63	63	2/1/92	ST	WDS	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Ameresco Stafford LLC	Ameresco Inc	Ameresco Stafford LLC	Ameresco Stafford LLC I	IC1	100	1.07	1.07	1.07	9/17/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Ameresco Stafford LLC	Ameresco Inc	Ameresco Stafford LLC	Ameresco Stafford LLC I	IC2	100	1.07	1.07	1.07	9/17/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	DuPont Fabros Technology	E I DuPont de Nemours & (	DuPont Fabros Technology	Ashburn Corporate Cen	ACC2	100	10.4	10.4	10.4	1/1/01	IC	DSL	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	DuPont Fabros Technology	E I DuPont de Nemours & (	DuPont Fabros Technology	Ashburn Corporate Cen	ACC3	100	13.9	13.9	13.9	1/1/01	IC	DSL	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	DuPont Fabros Technology	E I DuPont de Nemours & (	DuPont Fabros Technology	Ashburn Corporate Cen	ACC4	100	36.4	36.4	36.4	1/1/07	IC	DSL	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	DuPont Fabros Technology	E I DuPont de Nemours & (	DuPont Fabros Technology	Ashburn Corporate Cen	ACC5	100	36.4	36.4	36.4	12/31/09	IC	DSL	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	DuPont Fabros Technology	E I DuPont de Nemours & (	DuPont Fabros Technology	Ashburn Corporate Cen	ACC6I	100	13	13	13	9/14/11	IC	DSL	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Allegheny Generating Co (Th	FirstEnergy Corp	Virginia Electric & Power Co	Bath County	1	40	184.8	200	200	12/1/85	PS	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Bath County	1	60	277.2	300	300	12/1/85	PS	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Allegheny Generating Co (Th	FirstEnergy Corp	Virginia Electric & Power Co	Bath County	2	40	184.8	200	200	12/1/85	PS	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Bath County	2	60	277.2	300	300	12/1/85	PS	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Allegheny Generating Co (Th	FirstEnergy Corp	Virginia Electric & Power Co	Bath County	3	40	184.8	200.8	200.8	12/1/85	PS	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Bath County	3	60	277.2	301.2	301.2	12/1/85	PS	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Allegheny Generating Co (Th	FirstEnergy Corp	Virginia Electric & Power Co	Bath County	4	40	184.8	200	200	12/1/85	PS	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Bath County	4	60	277.2	300	300	12/1/85	PS	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Allegheny Generating Co (Th	FirstEnergy Corp	Virginia Electric & Power Co	Bath County	5	40	184.8	200.4	200.4	12/1/85	PS	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Bath County	5	60	277.2	300.6	300.6	12/1/85	PS	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Allegheny Generating Co (Th	FirstEnergy Corp	Virginia Electric & Power Co	Bath County	6	40	184.8	200	200	12/1/85	PS	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Bath County	6	60	277.2	300	300	12/1/85	PS	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Greenwood Ironworks Inc	Greenwood Ironworks Inc	Virginia Electric & Power Co	Battersea Dam	1	100	0.6	0.1	0.1	12/1/90	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Bear Garden Generatin	CC 2	100	559	589	589	5/24/11	CC	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Bellmeade	CC	100	330	267	267	2/1/97	CC	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Bethel Landfill	IC1	100	0.8	0.8	0.8	10/25/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Bethel Landfill	IC2	100	0.8	0.8	0.8	10/25/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Bethel Landfill	IC3	100	0.8	0.8	0.8	10/25/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Bethel Landfill	IC4	100	0.8	0.8	0.8	10/25/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Bethel Landfill	IC5	100	0.8	0.8	0.8	10/25/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Bethel Landfill	IC6	100	0.8	0.8	0.8	10/25/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Birchwood Power Partners L	General Electric Co	Birchwood Power Partners LP	Birchwood Power Facili	1	100	258.3	243.5	247.4	11/1/96	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN1	100	0.3	0.3	0.3	6/1/93	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN10	100	0.3	0.3	0.3	6/1/93	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN2	100	0.3	0.3	0.3	6/1/93	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN3	100	0.3	0.3	0.3	6/1/93	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN4	100	0.3	0.3	0.3	6/1/93	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN5	100	0.3	0.3	0.3	6/1/93	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN6	100	0.3	0.3	0.3	6/1/93	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN7	100	0.3	0.3	0.3	6/1/93	IC	WO	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN8	100	0.3	0.3	0.3	6/1/93	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN9	100	0.3	0.3	0.3	6/1/93	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN11	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN12	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN13	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN14	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN15	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN16	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN17	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN18	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN19	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN20	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN21	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN22	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN23	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN24	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN25	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN26	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN27	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN28	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN29	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN30	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN31	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN32	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN33	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Dinwiddie Power Inc	INGENCO	Dinwiddie Power Inc	Boydton Plank Road Co	GEN34	100	0.3	0.3	0.3	5/1/00	IC	WO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Appomattox River Associate	Appomattox River Associat	Appomattox River Associates L	Brasfield	1	100	2.9	2.9	2.9	9/1/93	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Bremo Bluff	3	100	69	71	74	6/1/50	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Bremo Bluff	4	100	185.2	156	161	8/1/58	ST	BIT	Operating	Y	1
PJM ISO	DOM	Progress Energy Carolinas East		AP South		North Carolina Electric Mem	North Carolina Electric Me	North Carolina Electric Membe	Buxton	1A	100	3	3	3	4/1/91	IC	DFO	Operating	Y	1
PJM ISO	DOM	Progress Energy Carolinas East		AP South		North Carolina Electric Mem	North Carolina Electric Me	North Carolina Electric Membe	Buxton	2A	100	3	3	3	4/1/91	IC	DFO	Operating	Y	1
PJM ISO	DOM	Progress Energy Carolinas East		AP South		North Carolina Electric Mem	North Carolina Electric Me	North Carolina Electric Membe	Buxton	3A	100	3	3	3	4/1/91	IC	DFO	Operating	Y	1
PJM ISO	DOM	Progress Energy Carolinas East		AP South		North Carolina Electric Mem	North Carolina Electric Me	North Carolina Electric Membe	Buxton	4A	100	3	3	3	4/1/91	IC	DFO	Operating	Y	1
PJM ISO	DOM	Progress Energy Carolinas East		AP South		North Carolina Electric Mem	North Carolina Electric Me	North Carolina Electric Membe	Buxton	5A	100	3	3	3	4/1/91	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Shenandoah Hydro Co	Shenandoah Hydro Co	Virginia Electric & Power Co	Chapman Dam	1	100	0.3	0.1	0.1	10/1/84	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Chesapeake	GT1	100	18.5	15	20	12/1/67	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Chesapeake	6	100	16.3	12	16	7/1/69	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Chesapeake	GT2	100	16.3	12	17	3/1/69	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Chesapeake	GT4	100	16.3	12	16	5/1/69	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Chesapeake	ST1	100	112.5	111	111	6/1/53	ST	BIT	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Chesapeake	ST2	100	112.5	111	111	12/1/54	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Chesapeake	3	100	185.2	156	162	6/1/59	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Chesapeake	ST4	100	239.3	217	221	5/1/62	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Chesterfield	3	100	112.5	97.5	101.5	12/1/52	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Chesterfield	CC7	100	219.4	197	226	6/1/90	CC	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Chesterfield	CC8	100	227.2	200	236	5/1/92	CC	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Chesterfield	4	100	187.5	162.5	167.5	6/1/60	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Chesterfield	5	100	378	336	342	8/1/64	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Chesterfield	6	100	693.9	657	690	12/1/69	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Church Street Plant	C1	100	1	1	1	10/1/79	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Church Street Plant	C2	100	1	1	1	10/1/79	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Church Street Plant	C3A	100	1.1	1	1	6/1/96	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Church Street Plant	C4	100	1	1	1	10/1/79	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Church Street Plant	C5	100	1.6	1.5	1.5	2/1/87	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Church Street Plant	C6	100	1.6	1.5	1.5	2/1/87	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Citys Plant (Harrisonbu	ST 1	100	2.5	2.7	2.7	9/1/97	ST	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Old Dominion Electric Coop	Old Dominion Electric Coo	Virginia Electric & Power Co	Clover	1	50	212	215.5	217.5	10/1/95	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Clover	1	50	212	215.5	217.5	10/1/95	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Old Dominion Electric Coop	Old Dominion Electric Coo	Virginia Electric & Power Co	Clover	2	50	212	217	219	3/1/96	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Clover	2	50	212	217	219	3/1/96	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	James River Genco LLC	Carlyle Group (The)	James River Genco LLC	Cogentrix Hopewell	GEN1	100	57.4	46.3	46.3	10/1/87	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	James River Genco LLC	Carlyle Group (The)	James River Genco LLC	Cogentrix Hopewell	GEN2	100	57.4	46.3	46.3	11/1/87	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Spruance Genco LLC	Energy Investors Funds Gr	Spruance Genco LLC	Cogentrix of Richmond	GEN1	100	57.4	52.5	52.5	5/1/92	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Spruance Genco LLC	Energy Investors Funds Gr	Spruance Genco LLC	Cogentrix of Richmond	GEN2	100	57.4	52.5	52.5	5/1/92	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Spruance Genco LLC	Energy Investors Funds Gr	Spruance Genco LLC	Cogentrix of Richmond	GEN3	100	57.4	42.5	42.5	8/1/92	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Spruance Genco LLC	Energy Investors Funds Gr	Spruance Genco LLC	Cogentrix of Richmond	GEN4	100	57.4	42.5	42.5	8/1/92	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Corolla Companies 1 Inc	Corolla Companies 1 Inc	Corolla Companies 1 Inc	Corolla 1 Wind	WT	100	0.002	0.002	0.002	7/25/08	WT	WND	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Covanta Alexandria/Arlingto	Covanta Holding Corp	Covanta Alexandria/Arlington	Covanta Alexandria/Arl	GEN1	100	14.5	14.5	14.5	10/1/87	ST	MSW	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Covanta Alexandria/Arlingto	Covanta Holding Corp	Covanta Alexandria/Arlington	Covanta Alexandria/Arl	GEN2	100	14.5	14.5	14.5	10/1/87	ST	MSW	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Westvaco Corp	Newpage Group Inc	Westvaco Corp	Covington	GEN1	100	10.5	10.5	10.5	1/1/39	ST	BLQ	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Westvaco Corp	Newpage Group Inc	Westvaco Corp	Covington	GEN2	100	10.5	10.5	10.5	1/1/46	ST	BLQ	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Westvaco Corp	Newpage Group Inc	Westvaco Corp	Covington	GEN3	100	10.5	10.5	10.5	1/1/51	ST	BLQ	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Westvaco Corp	Newpage Group Inc	Westvaco Corp	Covington	GEN4	100	34	32.5	32.5	9/1/80	ST	BLQ	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Westvaco Corp	Newpage Group Inc	Westvaco Corp	Covington	GEN5	100	34	32.5	32.5	9/1/89	ST	BLQ	Operating	Y	1
PJM ISO	DOM	Progress Energy Carolinas East			AP South	Craven County Wood Energy	CMS Energy Corp	CMS Generation Operating Co	Craven County Wood E	1UNI	100	50	48	48	11/1/90	ST	WDS	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Cushaw	1	100	1.5	0.4	0.4	1/1/30	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Cushaw	2	100	1.5	0.4	0.4	1/1/30	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Cushaw	3	100	1.5	0.4	0.4	1/1/30	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Cushaw	4	100	1.5	0.4	0.4	1/1/30	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Cushaw	5	100	1.5	0.4	0.4	1/1/30	HY	WAT	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Darbytown	1	100	92.1	84	98	5/1/90	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Darbytown	2	100	92.1	84	97	5/1/90	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Darbytown	3	100	92.1	84	95	4/1/90	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Darbytown	4	100	92.1	84	97	4/1/90	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Dean Drive	PG1	100	1.6	1.6	1.6	4/1/07	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Dean Drive	PG2	100	1.6	1.6	1.6	4/1/07	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Old Dominion Electric Coop	Old Dominion Electric Coo	Old Dominion Electric Coop	Diesel Group 2	1	100	4	4	4	12/1/02	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Old Dominion Electric Coop	Old Dominion Electric Coo	Old Dominion Electric Coop	Diesel Group 3	1	100	4	4	4	11/1/02	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Dominion/Lo Mar Gene	DOM1	100	12	11.1	11.1	8/1/97	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Dominion/Lo Mar Gene	DOM2	100	1.8	1.7	1.7	8/1/97	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Dominion/Lo Mar Gene	LOM1	100	1.8	1.7	1.7	8/1/97	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Dominion/Lo Mar Gene	LOM2	100	1.8	1.7	1.7	8/1/97	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Dominion/Lo Mar Gene	LOM3	100	1.8	1.7	1.7	8/1/97	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Doswell LP	LS Power Group	Doswell LP	Doswell Combined Cycl	CC1	100	376	332.4	376	12/1/91	CC	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Doswell LP	LS Power Group	Doswell LP	Doswell Combined Cycl	CC2	100	376	332.4	376	1/1/92	CC	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Doswell LP	LS Power Group	Doswell LP	Doswell Combined Cycl	GEN7	100	187	149	187	3/1/01	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Franklin Electric Dept	Franklin Electric Dept	Franklin Electric Dept	Downtown	1	100	1.6	1.56	1.58	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Franklin Electric Dept	Franklin Electric Dept	Franklin Electric Dept	Downtown	2	100	1.6	1.56	1.58	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Progress Energy Carolinas East		AP South		DSM Pharmaceuticals Inc	DSM	DSM Pharmaceuticals Inc	DSM Pharmecueticals I	GEN1	100	4	3.5	4	8/1/93	GT	DFO	Standby	Y	1
PJM ISO	DOM	Progress Energy Carolinas East		AP South		DSM Pharmaceuticals Inc	DSM	DSM Pharmaceuticals Inc	DSM Pharmecueticals I	GEN2	100	0.3	0.3	0.3	10/1/94	IC	DFO	Standby	Y	1
PJM ISO	DOM	Progress Energy Carolinas East		AP South		DSM Pharmaceuticals Inc	DSM	DSM Pharmaceuticals Inc	DSM Pharmecueticals I	GEN3	100	1.1	1.1	1.1	7/1/94	IC	DFO	Standby	Y	1
PJM ISO	DOM	Progress Energy Carolinas East		AP South		DSM Pharmaceuticals Inc	DSM	DSM Pharmaceuticals Inc	DSM Pharmecueticals I	GEN4	100	1.2	1.2	1.2	8/1/87	IC	DFO	Standby	Y	1
PJM ISO	DOM	Progress Energy Carolinas East		AP South		DSM Pharmaceuticals Inc	DSM	DSM Pharmaceuticals Inc	DSM Pharmecueticals I	GEN5	100	1	1	1	7/1/99	IC	DFO	Standby	Y	1
PJM ISO	DOM	Progress Energy Carolinas East		AP South		DSM Pharmaceuticals Inc	DSM	DSM Pharmaceuticals Inc	DSM Pharmecueticals I	GEN6	100	1.2	1.17	1.18	11/1/03	IC	DFO	Standby	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Edgecombe Genco LLC	Goldman Sachs Group Inc (	Edgecombe Genco LLC	Dwayne Collier Battle C	GEN1	100	57.4	57.8	57.8	8/1/90	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Edgecombe Genco LLC	Goldman Sachs Group Inc (	Edgecombe Genco LLC	Dwayne Collier Battle C	GEN2	100	57.4	57.8	57.8	8/1/90	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Edenton NC (Town of)	Edenton NC (Town of)	Edenton NC (Town of)	Edenton Generators	1	100	1.2	1.2	1.2	12/1/88	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Edenton NC (Town of)	Edenton NC (Town of)	Edenton NC (Town of)	Edenton Generators	2	100	1.2	1.2	1.2	12/1/88	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Culpeper VA (Town of)	Culpeper VA (Town of)	Culpeper VA (Town of)	Electric Avenue	IC1	100	1.8	1.8	1.8	12/1/04	IC	DFO	Standby	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Culpeper VA (Town of)	Culpeper VA (Town of)	Culpeper VA (Town of)	Electric Avenue	IC2	100	1.8	1.8	1.8	12/1/04	IC	DFO	Standby	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Culpeper VA (Town of)	Culpeper VA (Town of)	Culpeper VA (Town of)	Electric Avenue	IC3	100	1.8	1.8	1.8	12/1/04	IC	DFO	Standby	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Elizabeth River Combus	GEN1	100	129.6	116	121	5/1/92	GT	NG	Standby	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Elizabeth River Combus	GEN2	100	129.6	116	120	5/1/92	GT	NG	Standby	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Elizabeth River Combus	GEN3	100	129.6	116	124	5/1/92	GT	NG	Standby	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Merck & Co Inc	Merck & Co Inc	Merck & Co Inc	Elkton	GEN1	100	6.2	6.2	6.2	6/1/82	ST	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Merck & Co Inc	Merck & Co Inc	Merck & Co Inc	Elkton	GEN2	100	0.9	0.8	0.8	6/1/82	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Emporia Hydropower LP	Ridgewood US Hydro Corp	Ridgewood Power Manageme	Emporia	GEN1	100	2	1.9	1.84	1/1/86	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Emporia Hydropower LP	Ridgewood US Hydro Corp	Ridgewood Power Manageme	Emporia	GEN2	100	0.5	0.5	0.5	1/1/86	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Fauquier Landfill Gas LLC	Pepco Holdings Inc	Fauquier Landfill Gas LLC	Fauquier Landfill	IC1	100	1	1	1	4/15/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Fauquier Landfill Gas LLC	Pepco Holdings Inc	Fauquier Landfill Gas LLC	Fauquier Landfill	IC2	100	1	1	1	4/15/04	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company			AP South	Jack Forsythe	Jack Forsythe	Jack Forsythe	Forsythe Solar	PV	100	0.004	0.004	0.004	2/28/08	PV	SUN	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Gaston	1	100	44.4	55	55	3/1/63	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Gaston	2	100	44.4	55	55	2/1/63	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Gaston	3	100	44.4	55	55	2/1/63	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Gaston	4	100	44.4	55	55	2/1/63	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Gastonia NC (City of)	Gastonia NC (City of)	Gastonia NC (City of)	Gaston Memorial Hospi	GMH1	100	1.8	1.8	1.8	5/1/06	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Gateway Generating	1	100	1.8	1.7	1.7	3/1/96	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Gateway Generating	2	100	1.8	1.7	1.7	6/1/09	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Godwin Drive Plant	C10	100	1.5	1.5	1.5	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Godwin Drive Plant	C7	100	1.6	1.5	1.5	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Godwin Drive Plant	C8	100	1.6	1.5	1.5	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Godwin Drive Plant	C9	100	1.6	1.5	1.5	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Progress Energy Carolinas East			AP South	Claudia Goettler	Claudia Goettler	Claudia Goettler	Goettler Solar	PV	100	0.002	0.002	0.002	8/1/07	PV	SUN	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Gordonsville Energy LP	Edison International	Virginia Electric & Power Co	Gordonsville Energy LP	CC1	100	150.2	109	135	3/1/94	CC	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Gordonsville Energy LP	Edison International	Virginia Electric & Power Co	Gordonsville Energy LP	CC2	100	150.2	109	133	3/1/94	CC	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Gravel Neck	1	100	16.3	12	15	8/1/70	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Gravel Neck	3	100	91.9	85	98	10/1/89	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Gravel Neck	2	100	23.8	16	23	12/1/70	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Gravel Neck	4	100	91.9	85	97	7/1/89	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Gravel Neck	5	100	91.9	85	98	7/1/89	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Gravel Neck	6	100	91.9	85	97	11/1/89	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Synergics Inc	Synergics Inc	Synergics Inc	Halifax (VA)	GEN1	100	0.8	0.8	0.8	1/1/15	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Synergics Inc	Synergics Inc	Synergics Inc	Halifax (VA)	GEN2	100	0.4	0.38	0.37	1/1/15	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Synergics Inc	Synergics Inc	Synergics Inc	Halifax (VA)	GEN3	100	0.4	0.38	0.37	1/1/15	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Westmoreland Coal Co	Hopewell	1	100	71.1	63	63	7/1/92	ST	BIT	Restarted	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Hopewell Cogeneration Ltd	International Power	Hopewell Cogeneration Ltd	Hopewell Cogeneration	CC	100	399	348.3	399	3/1/90	CC	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	RockTenn CP LLC	Rock Tenn Co	RockTenn CP LLC	Hopewell Mill	GEN1	100	47.6	40.7	40.7	12/1/80	ST	BLQ	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Covanta Fairfax Inc	Covanta Holding Corp	Covanta Fairfax Inc	I 95 Energy Resource Re	GEN1	100	62	49	49	3/1/90	ST	MSW	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Covanta Fairfax Inc	Covanta Holding Corp	Covanta Fairfax Inc	I 95 Energy Resource Re	GEN2	100	62	49	49	3/1/90	ST	MSW	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Landfill Energy Systems	Energy Investors Funds Gr	Landfill Energy Systems	I 95 Landfill Phase I	UNT1	100	0.8	0.8	0.8	1/1/92	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Landfill Energy Systems	Energy Investors Funds Gr	Landfill Energy Systems	I 95 Landfill Phase I	UNT2	100	0.8	0.8	0.8	1/1/92	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Landfill Energy Systems	Energy Investors Funds Gr	Landfill Energy Systems	I 95 Landfill Phase I	UNT3	100	0.8	0.8	0.8	1/1/92	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Landfill Energy Systems	Energy Investors Funds Gr	Landfill Energy Systems	I 95 Landfill Phase I	UNT4	100	0.8	0.8	0.8	1/1/92	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Landfill Energy Systems	Energy Investors Funds Gr	Landfill Energy Systems	I 95 Landfill Phase II	UNT1	100	0.8	0.8	0.8	3/1/93	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Landfill Energy Systems	Energy Investors Funds Gr	Landfill Energy Systems	I 95 Landfill Phase II	UNT2	100	0.8	0.8	0.8	3/1/93	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Landfill Energy Systems	Energy Investors Funds Gr	Landfill Energy Systems	I 95 Landfill Phase II	UNT3	100	0.8	0.8	0.8	3/1/93	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Landfill Energy Systems	Energy Investors Funds Gr	Landfill Energy Systems	I 95 Landfill Phase II	UNT4	100	0.8	0.8	0.8	3/1/93	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	International Paper Co	International Paper Co	International Paper Co	International Paper	GE10	100	46.4	38	59.5	11/1/97	GT	NG	Restarted	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	International Paper Co	International Paper Co	International Paper Co	International Paper	GEN1	100	5	4.69	4.7	11/1/37	ST	BLQ	Restarted	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	International Paper Co	International Paper Co	International Paper Co	International Paper	GEN2	100	3.7	3.7	3.7	11/1/37	ST	BLQ	Restarted	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company			AP South	International Paper Co	International Paper Co	International Paper Co	International Paper	GEN3	100	2.5	2.5	2.5	1/1/42	ST	BLQ	Restarted	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	International Paper Co	International Paper Co	International Paper Co	International Paper	GEN6	100	9.3	9.3	9.3	11/1/50	ST	BLQ	Restarted	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	International Paper Co	International Paper Co	International Paper Co	International Paper	GEN7	100	15.6	15.6	15.6	3/1/58	ST	BLQ	Restarted	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	International Paper Co	International Paper Co	International Paper Co	International Paper	GEN8	100	27.5	27.5	27.5	3/1/70	ST	BLQ	Restarted	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	International Paper Co	International Paper Co	International Paper Co	International Paper	GEN9	100	36.1	36.1	36.1	11/1/77	ST	BLQ	Restarted	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	USACE Wilmington District	U S Army Corps of Enginee	USACE Wilmington District	John H Kerr	2	100	13.8	13.8	13.8	12/1/52	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	USACE Wilmington District	U S Army Corps of Enginee	USACE Wilmington District	John H Kerr	1	100	46.8	46.8	46.8	11/1/52	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	USACE Wilmington District	U S Army Corps of Enginee	USACE Wilmington District	John H Kerr	3	100	46.8	46.8	46.8	1/1/53	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	USACE Wilmington District	U S Army Corps of Enginee	USACE Wilmington District	John H Kerr	4	100	46.8	46.8	46.8	3/1/53	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	USACE Wilmington District	U S Army Corps of Enginee	USACE Wilmington District	John H Kerr	5	100	46.8	46.8	46.8	9/1/53	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	USACE Wilmington District	U S Army Corps of Enginee	USACE Wilmington District	John H Kerr	6	100	46.8	46.8	46.8	10/1/53	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	USACE Wilmington District	U S Army Corps of Enginee	USACE Wilmington District	John H Kerr	7	100	46.8	46.8	46.8	12/1/53	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	King George County Lar	GT1	100	3.3	2.8	3.2	5/17/10	GT	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	King George County Lar	GT2	100	3.3	2.8	3.2	5/17/10	GT	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	King George County Lar	GT3	100	3.125	3.1	3.1	5/17/10	GT	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	King George County Lar	GT4	100	3.3	2.9	3.3	6/3/11	GT	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Ladysmith	1	100	178.5	151	183	5/31/01	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Ladysmith	2	100	178.5	151	183	5/31/01	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Ladysmith	3	100	178.5	161	183	8/13/08	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Ladysmith	4	100	178.5	160	183	8/13/08	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Ladysmith	5	100	178.5	160	183	4/30/09	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Old Dominion Electric Coop	Old Dominion Electric Coo	Pic Energy Services	Louisa Generating	1	100	84.5	76.5	92	8/29/03	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Old Dominion Electric Coop	Old Dominion Electric Coo	Pic Energy Services	Louisa Generating	2	100	84.5	77	92	8/29/03	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Old Dominion Electric Coop	Old Dominion Electric Coo	Pic Energy Services	Louisa Generating	3	100	84.5	77	92	8/29/03	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Old Dominion Electric Coop	Old Dominion Electric Coo	Pic Energy Services	Louisa Generating	4	100	84.5	77	92	8/29/03	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Old Dominion Electric Coop	Old Dominion Electric Coo	Pic Energy Services	Louisa Generating	5	100	171.1	158	187	8/29/03	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Low Moor	GT1	100	20.7	12	17	7/1/71	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Low Moor	GT2	100	20.7	12	16	7/1/71	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Low Moor	GT3	100	20.7	12	15	8/1/71	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Low Moor	GT4	100	20.7	12	17	8/1/71	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Old Dominion Electric Coop	Old Dominion Electric Coo	Pic Energy Services	Marsh Run Generating	GT1	100	171.1	160.8	187	9/15/04	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Old Dominion Electric Coop	Old Dominion Electric Coo	Pic Energy Services	Marsh Run Generating	GT2	100	171.1	159.3	187	9/15/04	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Old Dominion Electric Coop	Old Dominion Electric Coo	Pic Energy Services	Marsh Run Generating	GT3	100	171.1	160	187	9/15/04	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Central Virginia Electric Coop	Central Virginia Electric Co	Central Virginia Electric Coop	Martins Store Genset	1	100	1.6	1.6	1.6	1/1/93	IC	OIL	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Central Virginia Electric Coop	Central Virginia Electric Co	Central Virginia Electric Coop	Martins Store Genset	2	100	1.6	1.6	1.6	1/1/93	IC	OIL	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Central Virginia Electric Coop	Central Virginia Electric Co	Central Virginia Electric Coop	Martins Store Genset	3	100	1.6	1.6	1.6	1/1/93	IC	OIL	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Mecklenburg Cogenera	GEN1	100	69.9	69	69	8/1/92	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Mecklenburg Cogenera	GEN2	100	69.9	69	69	8/1/92	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Middle Peninsula Landf	IC1	100	0.8	0.75	0.75	10/23/09	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Middle Peninsula Landf	IC2	100	0.8	0.75	0.75	10/23/09	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Middle Peninsula Landf	IC3	100	0.8	0.75	0.75	10/23/09	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Middle Peninsula Landf	IC4	100	0.8	0.75	0.75	10/23/09	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Middle Peninsula Landf	IC5	100	0.8	0.75	0.75	10/23/09	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Middle Peninsula Landf	IC6	100	0.8	0.75	0.75	10/23/09	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Middle Peninsula Landf	IC7	100	0.8	0.75	0.75	10/23/09	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Middle Peninsula Landf	IC8	100	0.8	0.75	0.75	10/23/09	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Moomaws Dam Hydroelectr	Moomaws Dam Hydroelec	Virginia Electric & Power Co	Moomaws Dam	1	100	0.5	0.3	0.3	2/1/85	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Mount Clinton	D 2	100	2	2	2	9/1/02	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Mount Clinton	D 3	100	2	2	2	9/1/02	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Mount Clinton	D 5	100	2	2	2	4/1/04	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Mount Clinton	MC 1	100	14	9	12	5/1/99	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company				Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	MT Storm	JF1	100	18.5	11	15	10/1/67	GT	JF	Operating	Y	1
PJM ISO	DOM	Virginia Power Company				Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	MT Storm	1	100	595.666	524	539	9/1/65	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company				Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	MT Storm	2	100	595.666	555	570	7/1/66	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company				Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	MT Storm	3	100	522	520	537	12/1/73	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Old Dominion Electric Coop	Old Dominion Electric Coo	Virginia Electric & Power Co	North Anna	1	11.6	116.661	109.388	113.1	6/1/78	NP	URA	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	North Anna	1	88.4	889.039	833.612	861.9	6/1/78	NP	URA	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	North Anna	HC1	100	1	1	1	12/1/87	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Old Dominion Electric Coop	Old Dominion Electric Coo	Virginia Electric & Power Co	North Anna	2	11.6	121.997	109.388	113.1	12/1/80	NP	URA	Restarted	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	North Anna	2	88.4	929.703	833.612	861.9	12/1/80	NP	URA	Restarted	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Northern Neck	GT1	100	20.7	12	18	7/1/71	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Northern Neck	GT2	100	20.7	11	17	8/1/71	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Northern Neck	GT3	100	20.7	12	17	7/1/71	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Northern Neck	GT4	100	20.7	12	18	8/1/71	GT	DFO	Operating	Y	1
PJM ISO	DOM	Progress Energy Carolinas East				North Carolina Electric Mem	North Carolina Electric Me	North Carolina Electric Membe	Ocracoke	IC2	100	3	3	3	4/1/91	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Park 500 Philip Morris USA	Altria Group Inc	Park 500 Philip Morris USA	Park 500 Philip Morris L	TG2	100	6.1	2	5.5	4/1/84	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Park 500 Philip Morris USA	Altria Group Inc	Park 500 Philip Morris USA	Park 500 Philip Morris L	TG3	100	13	10.5	11.5	9/1/83	ST	BIT	Operating	Y	1
PJM ISO	DOM	Progress Energy Carolinas East				PCS Phosphate Co Inc	Potash Corp of Saskatchew	PCS Phosphate Co Inc	PCS Phosphate Co Inc T	GEN1	100	50.4	50	47.9	12/1/84	ST	OTH	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Pittsylvania Power Stati	GEN1	100	45	41.5	41.5	3/1/94	ST	WDS	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Pittsylvania Power Stati	GEN2	100	45	41.5	41.5	3/1/94	ST	WDS	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Pleasant Valley	D 4	100	2	2	2	9/1/02	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Pleasant Valley	D 6	100	2	2	2	9/1/06	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Pleasant Valley	PV 1	100	16.5	9	13	4/1/97	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Weyerhaeuser Co	Weyerhaeuser Co	Weyerhaeuser Co	Plymouth (NC)	TG10	100	72	74	74	6/1/78	ST	WDS	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Weyerhaeuser Co	Weyerhaeuser Co	Weyerhaeuser Co	Plymouth (NC)	TG7	100	7.5	7.5	7.5	9/1/52	ST	BLQ	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Weyerhaeuser Co	Weyerhaeuser Co	Weyerhaeuser Co	Plymouth (NC)	TG8	100	25	23.8	23.8	6/1/64	ST	BLQ	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Weyerhaeuser Co	Weyerhaeuser Co	Weyerhaeuser Co	Plymouth (NC)	TG9	100	42	40.8	40.8	9/1/76	ST	BLQ	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Portsmouth Genco LLC	Carlyle Group (The)	Portsmouth Genco LLC	Portsmouth Cogenerati	GEN1	100	57.4	57.5	57.5	4/1/88	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Portsmouth Genco LLC	Carlyle Group (The)	Portsmouth Genco LLC	Portsmouth Cogenerati	GEN2	100	57.4	57.5	57.5	5/1/88	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Possum Point	3NG	100	113.6	96	100	6/1/55	ST	NG	Operating	Y	1

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PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Possum Point	GT3	100	16	12	16	5/1/68	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Possum Point	GT2	100	16	12	17	5/1/68	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Possum Point	GT5	100	16	12	17	5/1/68	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Possum Point	GT6	100	16	12	19	5/1/68	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Possum Point	CC	100	613	559	615	5/1/03	CC	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Possum Point	GT1	100	16	12	19	5/1/68	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Possum Point	4NG	100	239.3	220	225	4/1/62	ST	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Possum Point	GT4	100	16	12	18	5/1/68	GT	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Possum Point	5	100	882	786	805	6/1/75	ST	RFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Franklin Electric Dept	Franklin Electric Dept	Franklin Electric Dept	Pretlow	1	100	1.6	1.56	1.58	4/1/01	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Franklin Electric Dept	Franklin Electric Dept	Franklin Electric Dept	Pretlow	2	100	1.6	1.56	1.58	4/1/01	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	MM Prince William Energy L	FORTISTAR	Fortistar Services LLC	Prince William County L	UNT1	100	0.9	0.89	0.89	11/1/98	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	MM Prince William Energy L	FORTISTAR	Fortistar Services LLC	Prince William County L	UNT2	100	0.9	0.89	0.89	11/1/98	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	QVC Inc	QVC Inc	QVC Inc	QVC Inc Solar	PV	100	1	1.1	1.1	11/17/08	PV	SUN	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Melvin R Hall	Melvin R Hall	Melvin R Hall	Rapidan Mill	1	100	0.105	0.105	0.105	1/1/80	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Remington	1	100	178.5	153	187	6/1/00	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Remington	2	100	170	151	187	6/1/00	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Remington	3	100	178.5	152	187	7/1/00	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Remington	4	100	178.5	152	187	7/1/00	GT	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Richmond LLC	FORTISTAR	Richmond LLC	Richmond	1	100	1	0.9	0.9	8/1/93	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Richmond LLC	FORTISTAR	Richmond LLC	Richmond	2	100	1	0.9	0.9	8/1/93	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Richmond LLC	FORTISTAR	Richmond LLC	Richmond	3	100	1	0.9	0.9	8/1/93	IC	LFG	Restarted	Y	1
PJM ISO	DOM	Potomac Electric Power Compan	5004/5005		AP South	River Farm Management LLC	River Farm Management L	River Farm Management LLC	River Farm Solar	PV	100	0.008	0.008	0.008	2/28/09	PV	SUN	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Roanoke Rapids	1	100	25	24	24	12/1/55	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Roanoke Rapids	2	100	25	24	24	10/1/55	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Roanoke Rapids	3	100	25	24	24	9/1/55	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Roanoke Rapids	4	100	25	23	23	9/1/55	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Kapstone Kraft Paper Corp	Kapstone Paper	Kapstone Kraft Paper Corp	Roanoke Rapids North (	GEN1	100	22.5	30	30	1/1/66	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Westmoreland Energy Inc	Westmoreland Coal Co	Westmoreland Energy Inc	Roanoke Valley 1	GEN1	100	182.3	165	167.2	3/1/94	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Westmoreland Energy Inc	Westmoreland Coal Co	Westmoreland Energy Inc	Roanoke Valley II	GEN2	100	57.8	44	45.1	2/1/95	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Rosemary Power Statio	CC	100	180	165	186	11/1/90	CC	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Rivanna Water & Sewer Autl	Rivanna Water & Sewer Au	Rivanna Water & Sewer Autho	South Rivanna	1	100	1.07	1.07	1.07	4/1/88	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Westmoreland Coal Co	Southampton	1	100	71.1	63	63	3/1/92	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Wheelabrator Portsmouth Ir	Waste Management Inc	Wheelabrator Portsmouth Inc	SPSA WTE	1410	100	20	15.5	15.3	10/1/87	ST	MSW	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Wheelabrator Portsmouth Ir	Waste Management Inc	Wheelabrator Portsmouth Inc	SPSA WTE	1420	100	20	15.5	15.3	3/1/87	ST	MSW	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Wheelabrator Portsmouth Ir	Waste Management Inc	Wheelabrator Portsmouth Inc	SPSA WTE	1430	100	20	15.5	15.3	2/1/87	ST	MSW	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Suffolk Energy Partners LP	Suffolk Energy Partners LP	Zapco Energy Tactics Corp	Suffolk Energy Partners	SU1	100	0.8	0.7	0.7	11/1/94	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Suffolk Energy Partners LP	Suffolk Energy Partners LP	Zapco Energy Tactics Corp	Suffolk Energy Partners	SU2	100	0.8	0.7	0.7	11/1/94	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Suffolk Energy Partners LP	Suffolk Energy Partners LP	Zapco Energy Tactics Corp	Suffolk Energy Partners	SU3	100	0.8	0.7	0.7	11/1/94	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Suffolk Energy Partners LP	Suffolk Energy Partners LP	Zapco Energy Tactics Corp	Suffolk Energy Partners	SU4	100	0.8	0.7	0.7	11/1/94	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Surry	1	100	928.086	838	875	12/1/72	NP	URA	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Surry	2	100	928.086	838	875	5/1/73	NP	URA	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Gary Swanner	Gary Swanner	Gary Swanner	Swanner Solar	PV1	100	0.002	0.002	0.002	4/25/08	PV	SUN	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harbert Power LLC	Harbert Management Corp	Tenaska Virginia Partners LP	Tenaska Virginia Genera	CC1	0.1	0.946	0.926	0.958	3/1/04	CC	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Tenaska V Inc	Tenaska Inc	Tenaska Virginia Partners LP	Tenaska Virginia Genera	CC1	0.9	8.515	8.336	8.624	3/1/04	CC	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Tenaska Virginia Partners LP	Tenaska Inc	Tenaska Virginia Partners LP	Tenaska Virginia Genera	CC1	99	936.639	916.938	948.618	3/1/04	CC	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Blackstone VA (Town of)	Blackstone VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V10	4.44	0.071	0.067	0.067	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Blackstone VA (Town of)	Blackstone VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V3	4.44	0.071	0.067	0.067	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Blackstone VA (Town of)	Blackstone VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V4	4.44	0.071	0.067	0.067	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Blackstone VA (Town of)	Blackstone VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V5	4.44	0.071	0.067	0.067	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Blackstone VA (Town of)	Blackstone VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V6	4.44	0.071	0.067	0.067	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Blackstone VA (Town of)	Blackstone VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V7	4.44	0.071	0.067	0.067	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Blackstone VA (Town of)	Blackstone VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V8	4.44	0.071	0.067	0.067	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Blackstone VA (Town of)	Blackstone VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V9-1	4.44	0.089	0.08	0.08	4/1/09	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Culpeper VA (Town of)	Culpeper VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V10	3.29	0.053	0.049	0.049	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Culpeper VA (Town of)	Culpeper VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V3	3.29	0.053	0.049	0.049	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Culpeper VA (Town of)	Culpeper VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V4	3.29	0.053	0.049	0.049	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Culpeper VA (Town of)	Culpeper VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V5	3.29	0.053	0.049	0.049	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Culpeper VA (Town of)	Culpeper VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V6	3.29	0.053	0.049	0.049	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Culpeper VA (Town of)	Culpeper VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V7	3.29	0.053	0.049	0.049	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Culpeper VA (Town of)	Culpeper VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V8	3.29	0.053	0.049	0.049	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Culpeper VA (Town of)	Culpeper VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V9-1	3.29	0.066	0.059	0.059	4/1/09	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Elkton VA (Town of)	Elkton VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V10	1.94	0.031	0.029	0.029	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Elkton VA (Town of)	Elkton VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V3	1.94	0.031	0.029	0.029	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Elkton VA (Town of)	Elkton VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V4	1.94	0.031	0.029	0.029	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Elkton VA (Town of)	Elkton VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V5	1.94	0.031	0.029	0.029	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Elkton VA (Town of)	Elkton VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V6	1.94	0.031	0.029	0.029	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Elkton VA (Town of)	Elkton VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V7	1.94	0.031	0.029	0.029	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Elkton VA (Town of)	Elkton VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V8	1.94	0.031	0.029	0.029	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Elkton VA (Town of)	Elkton VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V9-1	1.94	0.039	0.035	0.035	4/1/09	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Franklin Electric Dept	Franklin Electric Dept	Manassas VA (City of)	VMEA 1 Credit Generati	V10	13.62	0.218	0.204	0.204	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Franklin Electric Dept	Franklin Electric Dept	Manassas VA (City of)	VMEA 1 Credit Generati	V3	13.62	0.218	0.204	0.204	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Franklin Electric Dept	Franklin Electric Dept	Manassas VA (City of)	VMEA 1 Credit Generati	V4	13.62	0.218	0.204	0.204	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Franklin Electric Dept	Franklin Electric Dept	Manassas VA (City of)	VMEA 1 Credit Generati	V5	13.62	0.218	0.204	0.204	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Franklin Electric Dept	Franklin Electric Dept	Manassas VA (City of)	VMEA 1 Credit Generati	V6	13.62	0.218	0.204	0.204	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Franklin Electric Dept	Franklin Electric Dept	Manassas VA (City of)	VMEA 1 Credit Generati	V7	13.62	0.218	0.204	0.204	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Franklin Electric Dept	Franklin Electric Dept	Manassas VA (City of)	VMEA 1 Credit Generati	V8	13.62	0.218	0.204	0.204	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Franklin Electric Dept	Franklin Electric Dept	Manassas VA (City of)	VMEA 1 Credit Generati	V9-1	13.62	0.272	0.245	0.245	4/1/09	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Manassas VA (City of)	VMEA 1 Credit Generati	V10	48.58	0.777	0.729	0.729	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Manassas VA (City of)	VMEA 1 Credit Generati	V3	48.58	0.777	0.729	0.729	5/1/90	IC	DFO	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Manassas VA (City of)	VMEA 1 Credit Generati	V4	48.58	0.777	0.729	0.729	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Manassas VA (City of)	VMEA 1 Credit Generati	V5	48.58	0.777	0.729	0.729	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Manassas VA (City of)	VMEA 1 Credit Generati	V6	48.58	0.777	0.729	0.729	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Manassas VA (City of)	VMEA 1 Credit Generati	V7	48.58	0.777	0.729	0.729	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Manassas VA (City of)	VMEA 1 Credit Generati	V8	48.58	0.777	0.729	0.729	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Manassas VA (City of)	VMEA 1 Credit Generati	V9-1	48.58	0.972	0.874	0.874	4/1/09	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	VMEA 1 Credit Generati	V10	26.95	0.431	0.404	0.404	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	VMEA 1 Credit Generati	V3	26.95	0.431	0.404	0.404	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	VMEA 1 Credit Generati	V4	26.95	0.431	0.404	0.404	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	VMEA 1 Credit Generati	V5	26.95	0.431	0.404	0.404	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	VMEA 1 Credit Generati	V6	26.95	0.431	0.404	0.404	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	VMEA 1 Credit Generati	V7	26.95	0.431	0.404	0.404	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	VMEA 1 Credit Generati	V8	26.95	0.431	0.404	0.404	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	VMEA 1 Credit Generati	V9-1	26.95	0.539	0.485	0.485	4/1/09	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Wakefield VA (Town of)	Wakefield VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V10	1.18	0.019	0.018	0.018	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Wakefield VA (Town of)	Wakefield VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V3	1.18	0.019	0.018	0.018	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Wakefield VA (Town of)	Wakefield VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V4	1.18	0.019	0.018	0.018	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Wakefield VA (Town of)	Wakefield VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V5	1.18	0.019	0.018	0.018	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Wakefield VA (Town of)	Wakefield VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V6	1.18	0.019	0.018	0.018	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Wakefield VA (Town of)	Wakefield VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V7	1.18	0.019	0.018	0.018	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Wakefield VA (Town of)	Wakefield VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V8	1.18	0.019	0.018	0.018	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Wakefield VA (Town of)	Wakefield VA (Town of)	Manassas VA (City of)	VMEA 1 Credit Generati	V9-1	1.18	0.024	0.021	0.021	4/1/09	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Blackstone VA (Town of)	Blackstone VA (Town of)	Manassas VA (City of)	Vmea Peaking Generati	V1	4	0.064	0.06	0.06	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Blackstone VA (Town of)	Blackstone VA (Town of)	Manassas VA (City of)	Vmea Peaking Generati	V11	4	0.064	0.06	0.06	7/1/93	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Blackstone VA (Town of)	Blackstone VA (Town of)	Manassas VA (City of)	Vmea Peaking Generati	V12	4	0.064	0.06	0.06	7/1/93	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Blackstone VA (Town of)	Blackstone VA (Town of)	Manassas VA (City of)	Vmea Peaking Generati	V2	4	0.064	0.06	0.06	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Culpeper VA (Town of)	Culpeper VA (Town of)	Manassas VA (City of)	Vmea Peaking Generati	V1	4.4	0.07	0.066	0.066	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Culpeper VA (Town of)	Culpeper VA (Town of)	Manassas VA (City of)	Vmea Peaking Generati	V11	4.4	0.07	0.066	0.066	7/1/93	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Culpeper VA (Town of)	Culpeper VA (Town of)	Manassas VA (City of)	Vmea Peaking Generati	V12	4.4	0.07	0.066	0.066	7/1/93	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Culpeper VA (Town of)	Culpeper VA (Town of)	Manassas VA (City of)	Vmea Peaking Generati	V2	4.4	0.07	0.066	0.066	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Elkton VA (Town of)	Elkton VA (Town of)	Manassas VA (City of)	Vmea Peaking Generati	V1	1.97	0.032	0.03	0.03	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Elkton VA (Town of)	Elkton VA (Town of)	Manassas VA (City of)	Vmea Peaking Generati	V11	1.97	0.032	0.03	0.03	7/1/93	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Elkton VA (Town of)	Elkton VA (Town of)	Manassas VA (City of)	Vmea Peaking Generati	V12	1.97	0.032	0.03	0.03	7/1/93	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Elkton VA (Town of)	Elkton VA (Town of)	Manassas VA (City of)	Vmea Peaking Generati	V2	1.97	0.032	0.03	0.03	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Franklin Electric Dept	Franklin Electric Dept	Manassas VA (City of)	Vmea Peaking Generati	V1	12.69	0.203	0.19	0.19	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Franklin Electric Dept	Franklin Electric Dept	Manassas VA (City of)	Vmea Peaking Generati	V11	12.69	0.203	0.19	0.19	7/1/93	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Franklin Electric Dept	Franklin Electric Dept	Manassas VA (City of)	Vmea Peaking Generati	V12	12.69	0.203	0.19	0.19	7/1/93	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Franklin Electric Dept	Franklin Electric Dept	Manassas VA (City of)	Vmea Peaking Generati	V2	12.69	0.203	0.19	0.19	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Manassas VA (City of)	Vmea Peaking Generati	V1	47.35	0.758	0.71	0.71	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Harrisonburg VA (City of)	Harrisonburg VA (City of)	Manassas VA (City of)	Vmea Peaking Generati	V11	47.35	0.758	0.71	0.71	7/1/93	IC	DFO	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company		AP South		Harrisonburg VA (City of)	Harrisonburg VA (City of)	Manassas VA (City of)	Vmea Peaking Generati	V12	47.35	0.758	0.71	0.71	7/1/93	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Harrisonburg VA (City of)	Harrisonburg VA (City of)	Manassas VA (City of)	Vmea Peaking Generati	V2	47.35	0.758	0.71	0.71	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Vmea Peaking Generati	V1	28.67	0.459	0.43	0.43	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Vmea Peaking Generati	V11	28.67	0.459	0.43	0.43	7/1/93	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Vmea Peaking Generati	V12	28.67	0.459	0.43	0.43	7/1/93	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Vmea Peaking Generati	V2	28.67	0.459	0.43	0.43	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Wakefield VA (Town of)	Wakefield VA (Town of)	Manassas VA (City of)	Vmea Peaking Generati	V1	0.92	0.015	0.014	0.014	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Wakefield VA (Town of)	Wakefield VA (Town of)	Manassas VA (City of)	Vmea Peaking Generati	V11	0.92	0.015	0.014	0.014	7/1/93	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Wakefield VA (Town of)	Wakefield VA (Town of)	Manassas VA (City of)	Vmea Peaking Generati	V12	0.92	0.015	0.014	0.014	7/1/93	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Wakefield VA (Town of)	Wakefield VA (Town of)	Manassas VA (City of)	Vmea Peaking Generati	V2	0.92	0.015	0.014	0.014	11/1/92	IC	DFO	Operating	Y	1
PJM ISO	DOM	Progress Energy Carolinas East		AP South		Karen & AL Wagner	Karen & AL Wagner	Karen & AL Wagner	Wagner Solar	PV	100	0.004	0.004	0.004	1/12/09	PV	SUN	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Manassas VA (City of)	Manassas VA (City of)	Manassas VA (City of)	Water Treatment Plant	WP1	100	1.8	1.7	1.7	4/1/07	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		RockTenn CP LLC	Rock Tenn Co	RockTenn CP LLC	West Point Mill	GEN8	100	5	5	5	1/1/54	ST	BLQ	Standby	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		RockTenn CP LLC	Rock Tenn Co	RockTenn CP LLC	West Point Mill	GEN9	100	10	10	10	10/1/60	ST	BLQ	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		RockTenn CP LLC	Rock Tenn Co	RockTenn CP LLC	West Point Mill	GN10	100	25	25	25	12/1/68	ST	BLQ	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		RockTenn CP LLC	Rock Tenn Co	RockTenn CP LLC	West Point Mill	GN11	100	15	15	15	8/1/77	ST	BLQ	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		RockTenn CP LLC	Rock Tenn Co	RockTenn CP LLC	West Point Mill	GN12	100	46	46	46	10/1/85	ST	BLQ	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Culpeper VA (Town of)	Culpeper VA (Town of)	Culpeper VA (Town of)	West Spring Street	7	100	1.5	1.5	1.5	2/1/97	IC	DFO	Standby	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Danville Power & Light Dept	Danville Power & Light Dep	Danville Power & Light Dept	Westover	GEN1	100	1.8	1.2	1.2	7/1/05	IC	DFO	Standby	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Rockfish Corp	Rockfish Corp	Rockfish Corp	Whittles Mill	1	100	0.28	0.28	0.28	6/1/86	HY	WAT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Yorktown	2	100	187.5	164	165	1/1/59	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Yorktown	1	100	187.5	159	162	7/1/57	ST	BIT	Operating	Y	1
PJM ISO	DOM	Virginia Power Company		AP South		Virginia Electric & Power Co	Dominion Resources Inc	Virginia Electric & Power Co	Yorktown	3	100	882	818	820	12/1/74	ST	RFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Bayview	BAYV	100	2	2.1	2.1	10/1/63	IC	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Bayview	BYV2	100	2	2.1	2.1	10/1/63	IC	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Bayview	BYV3	100	2	2.1	2.1	10/1/63	IC	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Bayview	BYV4	100	2	2.1	2.1	10/1/63	IC	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Bayview	BYV5	100	2	2.1	2.1	10/1/63	IC	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Bayview	BYV6	100	2	2.1	2.1	10/1/63	IC	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Berlin MD (Town of)	Berlin MD (Town of)	Berlin MD (Town of)	Berlin	1A	100	1.1	1.1	1.1	1/3/61	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Berlin MD (Town of)	Berlin MD (Town of)	Berlin MD (Town of)	Berlin	2A	100	1.8	1.8	1.8	7/1/99	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Berlin MD (Town of)	Berlin MD (Town of)	Berlin MD (Town of)	Berlin	4A	100	1.8	1.8	1.8	7/1/00	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Berlin MD (Town of)	Berlin MD (Town of)	Berlin MD (Town of)	Berlin	5A	100	2.5	2.5	2.5	12/1/89	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Ameresco Inc	Ameresco Inc	Ameresco Inc	Central Landfill	1C	100	1	1	1	11/15/06	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Ameresco Inc	Ameresco Inc	Ameresco Inc	Central Landfill	2C	100	1	1	1	11/15/06	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Ameresco Inc	Ameresco Inc	Ameresco Inc	Central Landfill	3C	100	1	1	1	11/15/06	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Christiana	11	100	26.64	22.5	25	6/1/73	GT	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Christiana	14	100	28	22.5	25	6/1/73	GT	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Commonwealth Chesapeake	ITOCHU Corp	Commonwealth Chesapeake C	Commonwealth Chesap	UNT1	100	57.5	45.5	48.1	8/1/00	GT	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Commonwealth Chesapeake	ITOCHU Corp	Commonwealth Chesapeake C	Commonwealth Chesap	UNT2	100	57.5	44.1	47.8	9/1/00	GT	DFO	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Commonwealth Chesapeake	ITOCHU Corp	Commonwealth Chesapeake C	Commonwealth Chesap	UNT3	100	57.5	44.8	48.3	9/1/00	GT	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Commonwealth Chesapeake	ITOCHU Corp	Commonwealth Chesapeake C	Commonwealth Chesap	UNT4	100	57.5	46.2	48.6	6/1/01	GT	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Commonwealth Chesapeake	ITOCHU Corp	Commonwealth Chesapeake C	Commonwealth Chesap	UNT5	100	57.5	45.6	48.6	6/1/01	GT	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Commonwealth Chesapeake	ITOCHU Corp	Commonwealth Chesapeake C	Commonwealth Chesap	UNT6	100	57.5	44.9	48.7	6/1/01	GT	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Commonwealth Chesapeake	ITOCHU Corp	Commonwealth Chesapeake C	Commonwealth Chesap	UNT7	100	57.5	45.2	48.6	8/1/01	GT	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Crisfield	CRIS	100	2.9	2.6	2.6	5/1/68	IC	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Crisfield	CRS2	100	2.9	2.6	2.6	5/1/68	IC	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Crisfield	CRS3	100	2.9	2.6	2.6	5/1/68	IC	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Crisfield	CRS4	100	2.9	2.6	2.6	5/1/68	IC	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Delaware City (Conectiv	DC10	100	18.5	16	18	4/1/68	GT	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Delaware City Refining Co LL	Blackstone Group (The)	Delaware City Refining Co LLC	Delaware City Refinery	G1	100	27.5	29.5	29.5	10/1/56	ST	OG	Restarted	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Delaware City Refining Co LL	Blackstone Group (The)	Delaware City Refining Co LLC	Delaware City Refinery	G2	100	27.5	29.5	29.5	10/1/56	ST	OG	Restarted	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Delaware City Refining Co LL	Blackstone Group (The)	Delaware City Refining Co LLC	Delaware City Refinery	G3	100	75	66	66	11/1/61	ST	OG	Restarted	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Delaware City Refining Co LL	Blackstone Group (The)	Delaware City Refining Co LLC	Delaware City Refinery	G4	100	10	10	10	6/1/82	ST	OG	Restarted	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Delaware City Refining Co LL	Blackstone Group (The)	Delaware City Refining Co LLC	Delaware City Refinery	GT1	100	92	65	72	5/1/00	GT	NG	Restarted	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Delaware City Refining Co LL	Blackstone Group (The)	Delaware City Refining Co LLC	Delaware City Refinery	GT2	100	92	65	72	5/1/00	GT	NG	Restarted	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Old Dominion Electric Coop	Old Dominion Electric Coo	Old Dominion Electric Coop	Diesel Group 1	1	100	12	12	12	7/1/02	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	NRG Energy Center Dover	NRG Energy Inc	NRG Energy Center Dover	Dover Energy (NRG)	GT1	100	50	44	50	6/1/01	GT	NG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	White Oak Solar Energy LLC	LS Power Group	White Oak Solar Energy LLC	Dover SUN Park	PV1	100	10	10	10	7/1/11	PV	SUN	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Maryland Dept of Public Safe	Maryland Dept of Public Sa	Maryland Environmental Servi	Eastern Correctional Ins	1147	100	1.9	1.3	0.8	8/1/87	ST	WDS	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Maryland Dept of Public Safe	Maryland Dept of Public Sa	Maryland Environmental Servi	Eastern Correctional Ins	1148	100	1.9	1.3	0.8	10/1/87	ST	WDS	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Maryland Dept of Public Safe	Maryland Dept of Public Sa	Maryland Environmental Servi	Eastern Correctional Ins	DG1	100	1	0.98	0.99	11/1/88	IC	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Maryland Dept of Public Safe	Maryland Dept of Public Sa	Maryland Environmental Servi	Eastern Correctional Ins	DG2	100	1	0.98	0.99	11/1/88	IC	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton	10	100	3.5	3.5	3.5	5/1/66	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton	101	100	1.5	1.5	1.5	12/1/95	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton	102	100	1.5	1.5	1.5	12/1/95	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton	11	100	3.8	3.6	3.6	6/1/68	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton	12	100	4.1	4.1	4.1	7/1/70	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton	13	100	5.6	5.6	5.6	7/1/73	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton	14	100	5.6	5.6	5.6	7/1/73	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton	7	100	2.5	2	2	11/1/54	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton	8	100	2.5	2	2	5/1/57	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton	9	100	3	2.5	2.5	12/1/61	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton 2	201	100	1.5	1.5	1.5	5/1/95	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton 2	202	100	1.5	1.5	1.5	5/1/95	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton 2	21	100	6.2	6.2	6.2	3/1/78	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton 2	22	100	6.2	6.2	6.2	3/1/78	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton 2	23	100	6.3	6.25	6.25	6/1/89	IC	RFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton 2	24	100	6.3	6.25	6.25	6/1/89	IC	RFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South	Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton 2	G203	100	5.4	4.5	5.1	11/30/04	GT	FO2	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Easton Utilities Commission	Easton Utilities	Easton Utilities Commission	Easton 2	G204	100	5.4	4.5	5.1	11/30/04	GT	FO2	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Edge Moor	EM10	100	12.5	13	15	6/1/63	GT	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Edge Moor	EM3	100	75	86	86	12/1/54	ST	NG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Edge Moor	EM4	100	176.8	174	174	4/1/66	ST	NG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Edge Moor	EM5	100	446	450	450	8/1/73	ST	NG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Hay Road	CC1	100	566	565	542	5/1/93	CC	NG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Hay Road	CC2	100	627	565	540	5/17/02	CC	NG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		First State Marine Wind	Gamesa Corporación Tecn	First State Marine Wind	Hugh R Sharp Campus \	WT1	100	2	2	2	6/11/10	WT	WND	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Indian River Power LLC	NRG Energy Inc	NRG Indian River Operations	Indian River Generating	10	100	18.6	16.4	20.4	6/1/67	GT	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Indian River Power LLC	NRG Energy Inc	NRG Indian River Operations	Indian River Generating	3	100	176.8	153	153	3/1/70	ST	BIT	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Indian River Power LLC	NRG Energy Inc	NRG Indian River Operations	Indian River Generating	4	100	442.4	430	430	10/1/80	ST	BIT	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		SunEdison	SunEdison	SunEdison	Maryland Eastern Shore	PV	100	2.1	2.1	2.1	3/9/11	PV	SUN	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Dover DE (City of)	Dover DE (City of)	Duke Fluor Daniels Operating	McKee Run	1	100	18.8	17	17	1/1/62	ST	NG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Dover DE (City of)	Dover DE (City of)	Duke Fluor Daniels Operating	McKee Run	2	100	18.8	17	17	3/1/62	ST	NG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Dover DE (City of)	Dover DE (City of)	Duke Fluor Daniels Operating	McKee Run	3	100	113.6	102	102	5/1/75	ST	NG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Washington Gas Energy Serv	WGL Holdings Inc	Washington Gas Energy Servic	Perdue Bridgeville Solar	PV1	100	1.3	1.3	1.3	8/8/11	PV	SUN	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Washington Gas Energy Serv	WGL Holdings Inc	Washington Gas Energy Servic	Perdue Salisbury Solar	PV1	100	1.38	1.38	1.38	10/7/11	PV	SUN	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Kent County Levy Court Dept	Kent County Levy Court De	Kent County Levy Court Dept c	Plant 1 (DE)	PV1	100	1.2	1.2	1.2	3/1/11	PV	SUN	Operating	Y	1
PJM ISO	DPL	Delmarva Power & Light Compan	5004/5005	AP South		Old Dominion Electric Coop	Old Dominion Electric Coo	CED Operating Co LP	Rock Springs Generatin	1	100	198.9	161.7	187	6/19/03	GT	NG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & Light Compan	5004/5005	AP South		Old Dominion Electric Coop	Old Dominion Electric Coo	CED Operating Co LP	Rock Springs Generatin	2	100	175.9	161	187	6/19/03	GT	NG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & Light Compan	5004/5005	AP South		NAEA Rock Springs LLC	Industry Super Holding	CED Operating Co LP	Rock Springs Generatin	3	100	198.9	167.4	189.1	6/1/03	GT	NG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & Light Compan	5004/5005	AP South		NAEA Rock Springs LLC	Industry Super Holding	CED Operating Co LP	Rock Springs Generatin	4	100	198.9	167.9	188.3	6/1/03	GT	NG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Southeastern Chester Count	Southeastern Chester Cou	Southeastern Chester County I	Seccra Community Lanc	1	100	0.9	0.9	0.9	1/1/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Southeastern Chester Count	Southeastern Chester Cou	Southeastern Chester County I	Seccra Community Lanc	3	100	1.6	1.6	1.6	11/1/10	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		A & N Electric Coop	A & N Electric Coop	A & N Electric Coop	Smith Island (MD)	2	100	0.5	0.4	0.4	12/1/69	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		A & N Electric Coop	A & N Electric Coop	A & N Electric Coop	Smith Island (MD)	3	100	1.2	1.2	1.2	3/1/94	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Ameresco Delaware South	Ameresco Inc	Ameresco Delaware South	Southern Landfill	1	100	1	1	1	11/15/06	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Ameresco Delaware South	Ameresco Inc	Ameresco Delaware South	Southern Landfill	2	100	1	1	1	11/15/06	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Ameresco Delaware South	Ameresco Inc	Ameresco Delaware South	Southern Landfill	3	100	1	1	1	11/15/06	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Ameresco Delaware South	Ameresco Inc	Ameresco Delaware South	Southern Landfill	4	100	1	1	1	11/15/06	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Ameresco Delaware South	Ameresco Inc	Ameresco Delaware South	Southern Landfill	5	100	1	1	1	6/30/10	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		A & N Electric Coop	A & N Electric Coop	A & N Electric Coop	Tangier	3	100	0.7	0.6	0.6	5/1/74	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		A & N Electric Coop	A & N Electric Coop	A & N Electric Coop	Tangier	4	100	1	0.8	0.8	9/1/74	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		A & N Electric Coop	A & N Electric Coop	A & N Electric Coop	Tangier	5	100	1.2	1.2	1.2	12/1/93	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		A & N Electric Coop	A & N Electric Coop	A & N Electric Coop	Tangier	6	100	1.2	1.2	1.2	12/1/93	IC	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	Tasley	TAS	100	27	31	40.3	6/1/72	GT	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Dover DE (City of)	Dover DE (City of)	Duke Fluor Daniels Operating	Van Sant Station (DE)	1	100	45.1	39	39	5/1/91	GT	NG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Vienna Power LLC	NRG Energy Inc	Vienna Operations Inc	Vienna	10	100	21	17	17	1/1/68	GT	DFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Vienna Power LLC	NRG Energy Inc	Vienna Operations Inc	Vienna	8	100	162	153	153	1/1/71	ST	RFO	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Delaware Municipal Electric	Delaware Municipal Electri	Delaware Municipal Electric C	Warren F Sam Beasley (	GT1	100	45	48	48	1/1/02	GT	NG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Calpine Mid Atlantic Genera	Calpine Corp	Calpine Mid Atlantic Generatic	West Substation	WEST	100	20	15	19	6/1/64	GT	DFO	Standby	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Worcester County Renewabl	Worcester County Renewa	Worcester County Renewable	Worcester County Rene	IC1	100	1	0.85	0.85	7/9/08	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Worcester County Renewabl	Worcester County Renewa	Worcester County Renewable	Worcester County Rene	IC2	100	1	0.85	0.85	1/21/09	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power & PJM East	5004/5005	AP South		Worcester County Renewabl	Worcester County Renewa	Worcester County Renewable	Worcester County Rene	IC3	100	1	0.85	0.85	3/27/09	IC	LFG	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				AES Beaver Valley LLC	AES Corp (The)	AES Beaver Valley LLC	AES Beaver Valley Partr	GEN2	100	35	32	31.5	7/1/87	ST	BIT	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				AES Beaver Valley LLC	AES Corp (The)	AES Beaver Valley LLC	AES Beaver Valley Partr	GEN3	100	114	114	120	7/1/87	ST	BIT	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				FirstEnergy Nuclear Generati	FirstEnergy Corp	FirstEnergy Nuclear Operating	Beaver Valley	1	100	1011.23	892	911	9/1/76	NP	URA	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				FirstEnergy Nuclear Generati	FirstEnergy Corp	FirstEnergy Nuclear Operating	Beaver Valley	2	60.08	607.547	549.131	560.546	11/1/87	NP	URA	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				Ohio Edison Co	FirstEnergy Corp	FirstEnergy Nuclear Operating	Beaver Valley	2	21.66	219.032	197.972	202.088	11/1/87	NP	URA	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				Toledo Edison Co (The)	FirstEnergy Corp	FirstEnergy Nuclear Operating	Beaver Valley	2	18.26	184.651	166.896	170.366	11/1/87	NP	URA	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				Beaver Valley Power Co	Enel SpA	Beaver Valley Power Co	Beaver Valley Pattersor	GEN1	100	0.4	0.38	0.37	9/1/82	HY	WAT	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				Beaver Valley Power Co	Enel SpA	Beaver Valley Power Co	Beaver Valley Pattersor	GEN2	100	0.4	0.38	0.37	9/1/82	HY	WAT	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				Beaver Valley Power Co	Enel SpA	Beaver Valley Power Co	Beaver Valley Pattersor	GEN3	100	0.4	0.38	0.37	9/1/82	HY	WAT	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				NRG Power Midwest LP	NRG Energy Inc	NRG Power Midwest LP	Brunot Island	1A	100	25.5	15	15	3/1/72	GT	DFO	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				NRG Power Midwest LP	NRG Energy Inc	NRG Power Midwest LP	Brunot Island	CC	100	339.9	198	235	9/1/02	CC	NG	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				NRG Power Midwest LP	NRG Energy Inc	NRG Power Midwest LP	Cheswick Power Plant	1	100	637	563	563	6/1/70	ST	BIT	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				US Steel Clairton	United States Steel Corp	US Steel Clairton	Clairton Works	GEN1	100	21	16	18	1/1/55	ST	OG	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				US Steel Clairton	United States Steel Corp	US Steel Clairton	Clairton Works	GEN3	100	10	6	9.4	1/1/55	ST	OG	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				NRG Power Midwest LP	NRG Energy Inc	NRG Power Midwest LP	Elrama Power Plant	UNT4	100	185	171	175	10/1/60	ST	BIT	Mothballed	Y	1
PJM ISO	DUQ	Duquesne Light Company				Zinc Corp of America	Zinc Corp of America	Cinergy Corp	G F Weaton Power Stati	GEN1	100	60	56	60	8/1/58	ST	SUB	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				Zinc Corp of America	Zinc Corp of America	Cinergy Corp	G F Weaton Power Stati	GEN2	100	60	56	60	5/1/58	ST	SUB	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				PPG Monroeville Chemicals (	PPG Industries Inc	PPG Monroeville Chemicals Ce	PPG Monroeville Chemi	2	100	0.3	0.3	0.3	1/1/00	IC	DFO	Standby	Y	1
PJM ISO	DUQ	Duquesne Light Company				PPG Monroeville Chemicals (	PPG Industries Inc	PPG Monroeville Chemicals Ce	PPG Monroeville Chemi	3	100	0.8	0.8	0.8	10/1/98	IC	DFO	Standby	Y	1
PJM ISO	DUQ	Duquesne Light Company				PPG Industries Inc	PPG Industries Inc	PPG Industries Inc	PPG Place	EG 1	100	0.9	0.9	0.9	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				PPG Industries Inc	PPG Industries Inc	PPG Industries Inc	PPG Place	EG 2	100	0.9	0.9	0.9	5/1/90	IC	DFO	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				PPG Industries Inc	PPG Industries Inc	PPG Industries Inc	PPG Place	EG 3	100	0.5	0.5	0.5	6/1/98	IC	DFO	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				Beaver Falls Municipal Autho	Beaver Falls Municipal Aut	Beaver Falls Municipal Authori	Townsend Hydro	GEN1	100	2.6	2.1	2.1	10/1/87	HY	WAT	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				Beaver Falls Municipal Autho	Beaver Falls Municipal Aut	Beaver Falls Municipal Authori	Townsend Hydro	GEN2	100	2.6	2.1	2.1	10/1/87	HY	WAT	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				US Steel Mon Valley	United States Steel Corp	US Steel Mon Valley	Uss Corp Mon Valley W	GEN1	100	25	28	30	6/1/43	ST	BFG	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				US Steel Mon Valley	United States Steel Corp	US Steel Mon Valley	Uss Corp Mon Valley W	GEN2	100	25	28	30	6/1/43	ST	BFG	Operating	Y	1
PJM ISO	DUQ	Duquesne Light Company				US Steel Mon Valley	United States Steel Corp	US Steel Mon Valley	Uss Corp Mon Valley W	GEN3	100	2.5	1.9	1.9	2/1/02	ST	BFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow PJM East	5004/5005	AP South		Asbury Park Press Inc	Gannett Co Inc	Asbury Park Press Inc	Asbury Park Press Inc	ENG1	100	0.7	0.7	0.7	5/1/87	IC	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow PJM East	5004/5005	AP South		Asbury Park Press Inc	Gannett Co Inc	Asbury Park Press Inc	Asbury Park Press Inc	ENG2	100	0.7	0.7	0.7	5/1/87	IC	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow PJM East	5004/5005	AP South		Aventis Pharmaceuticals Inc	Aventis	Aventis Pharmaceuticals Inc	Aventis Pharmaceutical	2	100	5	4	4.5	11/1/02	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow PJM East	5004/5005	AP South		Ocean County Utilities Autho	Ocean County Utilities Aut	Ocean County Utilities Authori	Bayville Central Facility	COG1	100	0.3	0.29	0.3	9/1/88	IC	OBG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow PJM East	5004/5005	AP South		Ocean County Utilities Autho	Ocean County Utilities Aut	Ocean County Utilities Authori	Bayville Central Facility	COG2	100	0.3	0.29	0.3	9/1/88	IC	OBG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow PJM East	5004/5005	AP South		Ocean County Utilities Autho	Ocean County Utilities Aut	Ocean County Utilities Authori	Bayville Central Facility	COG3	100	0.3	0.29	0.3	9/1/88	IC	OBG	Restarted	Y	1
PJM ISO	JCPL	Jersey Central Pow PJM East	5004/5005	AP South		Ocean County Utilities Autho	Ocean County Utilities Aut	Ocean County Utilities Authori	Bayville Central Facility	COG4	100	1.5	1.5	1.5	5/1/02	IC	DFO	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow PJM East	5004/5005	AP South		Ocean County Utilities Autho	Ocean County Utilities Aut	Ocean County Utilities Authori	Bayville Central Facility	COG5	100	1.5	1.5	1.5	5/1/02	IC	DFO	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow PJM East	5004/5005	AP South		Ocean County Utilities Autho	Ocean County Utilities Aut	Ocean County Utilities Authori	Bayville Central Facility	COG6	100	1.5	1.5	1.5	5/1/02	IC	DFO	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Ocean County Utilities Authc	Ocean County Utilities Autl	Ocean County Utilities Authori	Bayville Central Facility	COG7	100	1.5	1.5	1.5	5/1/02	IC	DFO	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Ocean County Utilities Authc	Ocean County Utilities Autl	Ocean County Utilities Authori	Bayville Central Facility	CPV1	100	0.2	0.2	0.1	5/1/07	PV	SUN	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Consolidated Edison Develop	Consolidated Edison Inc	Consolidated Edison Developn	Bell Lab Solar	PV1	100	1.23	1.23	1.23	6/9/11	PV	SUN	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Constellation Solar New Jers	Exelon Corp	Constellation NewEnergy Inc	Benjamin Moore Flande	PV1	100	1.4	1.4	1.4	12/31/10	PV	SUN	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	EFS Parlin Holdings LLC	General Electric Co	EFS Parlin Holdings LLC	Calpine Parlin Inc	CC1	100	69.4	59	65.5	6/1/91	CC	NG	Restarted	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	EFS Parlin Holdings LLC	General Electric Co	EFS Parlin Holdings LLC	Calpine Parlin Inc	CC2	100	70.4	59	65.5	6/1/91	CC	NG	Restarted	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Camden County Energy Recc	Foster Wheeler Ag	Camden County Energy Recov	Camden Resource Reco	TGA	100	17.5	15	16.8	3/1/91	ST	MSW	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Camden County Energy Recc	Foster Wheeler Ag	Camden County Energy Recov	Camden Resource Reco	TGB	100	17.5	15	16.8	3/1/91	ST	MSW	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Great Bear Hydropower Inc	Great Bear Hydropower In	Great Bear Hydropower Inc	Columbia Dam (NJ)	1	100	0.05	0.05	0.05	1/15/86	HY	WAT	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Forked River Power LLC	Maxim Power Corp	Forked River Power LLC	Forked River	1	100	38.4	34	44	6/1/89	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Forked River Power LLC	Maxim Power Corp	Forked River Power LLC	Forked River	2	100	38.4	31	41	7/1/89	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Neo Freehold Generating LL	NRG Energy Inc	Neo Freehold Generating LLC	Freehold Ashbury Park	UNT1	100	1.1	1.07	1.09	10/1/97	IC	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Neo Freehold Generating LL	NRG Energy Inc	Neo Freehold Generating LLC	Freehold Ashbury Park	UNT2	100	1.1	1.07	1.09	10/1/97	IC	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Frenchtown II Solar LLC	Consolidated Edison Inc	Consolidated Edison Developn	Frenchtown II Solar	PV1	100	3	3	3	7/28/11	PV	SUN	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Gilbert	C1	100	24	20	25	7/1/70	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Gilbert	C2	100	24	22	28	10/1/70	GT	NG	Standby	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Gilbert	C3	100	24	22	28	8/1/70	GT	NG	Standby	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Gilbert	C4	100	24	22	28	7/1/70	GT	NG	Standby	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	RRI Energy New Jersey Holdi	NRG Energy Inc	NRG Rema LLC	Gilbert	CC	100	351	280	360	5/1/77	CC	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Gilbert	9	100	161	150	167	7/1/96	GT	NG	Standby	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Glenn Gardner	1	100	20	18	18	6/1/71	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Glenn Gardner	2	100	20	18	18	6/1/71	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Glenn Gardner	3	100	19.6	18	18	6/1/71	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Glenn Gardner	4	100	20	18	18	6/1/71	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Glenn Gardner	5	100	20	18	18	7/1/71	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Glenn Gardner	6	100	20	18	18	7/1/71	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Glenn Gardner	7	100	20	18	18	7/1/71	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Glenn Gardner	8	100	20	18	18	7/1/71	GT	NG	Operating	Y	1
PJM ISO	JCPL	Public Service Elect	PJM East	5004/5005	AP South	Wheelabrator Gloucester Co	Waste Management Inc	Wheelabrator Gloucester Co L	Gloucester (NJ)	GEN1	100	14	12	12	1/1/90	ST	MSW	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Nautilus Solar Hazlet BOE LL	Nautilus Energy LLC	Nautilus Solar Hazlet BOE LLC	Hazlet BOE Solar	PV1	100	1.339	1.295	1.295	5/17/11	PV	SUN	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Hunterdon Cogeneration LP	United Technologies Corp	Hunterdon Cogeneration LP	Hunterdon Cogeneratic	1	100	4.1	4.1	4.1	11/1/93	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	E F Kenilworth	Atlantic Power Corp	E F Kenilworth	Kenilworth Energy	CC	100	28.8	28.8	28.8	4/1/89	CC	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	High Bridge (Borough of)	High Bridge (Borough of)	High Bridge (Borough of)	Lake Solitude Hydro	HY	100	0.5	0.5	0.5	1/1/11	HY	WAT	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NAEA Lakewood Cogeneratic	Industry Super Holding	NAEA Operating Co LLC	Lakewood Cogeneratio	CC	80	190.8	174.48	188.8	4/1/94	CC	NG	Standby	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Osaka Gas Energy America C	Osaka Gas Co Ltd	NAEA Operating Co LLC	Lakewood Cogeneratio	CC	20	47.7	43.62	47.2	4/1/94	CC	NG	Standby	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NJR Clean Energy Ventures	New Jersey Resources Corp	NJR Clean Energy Ventures	Manalapan Village Sola	PV1	100	3.5	4.6	2.3	9/30/11	PV	SUN	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	PSEG Hackettstown LLC	Public Service Enterprise G	Juwi Solar	Mars Solar Garden	PV1	100	2.2	2.2	2.2	11/9/09	PV	SUN	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	M & M Mars Inc	Mars Inc	M & M Mars Inc	Masterfoods USA	CC	100	10.2	10.7	8.7	5/1/89	CC	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Middlesex Generating Co LL	Middlesex Generating Co L	Middlesex Generating Co LLC	Melrose Wastewater Pl	CC1	100	22.5	18.8	20.4	10/1/01	CC	OBG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Dome Tech Inc	United Technologies Corp	Dome Tech Inc	Merck & Co Headquarte	PV1	100	1	1	1	4/15/09	PV	SUN	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Monmouth Energy Inc	Blue Wolf Capital Manager	Monmouth Energy Inc	Monmouth Landfill	GEN1	100	4.9	3.3	4.1	7/1/98	GT	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Monmouth Energy Inc	Blue Wolf Capital Manager	Monmouth Energy Inc	Monmouth Landfill	GEN2	100	4.9	3.3	4.1	7/1/98	GT	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Manchester Renewable Pow	Manchester Renewable Po	Manchester Renewable Power	Ocean County Landfill	UNT1	100	0.8	0.8	0.8	2/1/97	IC	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Manchester Renewable Pow	Manchester Renewable Po	Manchester Renewable Power	Ocean County Landfill	UNT2	100	0.8	0.8	0.8	2/1/97	IC	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Manchester Renewable Pow	Manchester Renewable Po	Manchester Renewable Power	Ocean County Landfill	UNT3	100	0.8	0.8	0.8	2/1/97	IC	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Manchester Renewable Pow	Manchester Renewable Po	Manchester Renewable Power	Ocean County Landfill	UNT4	100	0.8	0.8	0.8	2/1/97	IC	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Manchester Renewable Pow	Manchester Renewable Po	Manchester Renewable Power	Ocean County Landfill	UNT5	100	0.8	0.8	0.8	2/1/97	IC	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Manchester Renewable Pow	Manchester Renewable Po	Manchester Renewable Power	Ocean County Landfill	UNT6	100	0.8	0.8	0.8	2/1/97	IC	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Ocean Energy Inc	Devon Energy Corp	Landfill Energy Systems	Ocean Energy	IC1	100	1.6	1.55	1.55	3/1/07	IC	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Ocean Energy Inc	Devon Energy Corp	Landfill Energy Systems	Ocean Energy	IC2	100	1.6	1.55	1.55	3/1/07	IC	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Ocean Energy Inc	Devon Energy Corp	Landfill Energy Systems	Ocean Energy	IC3	100	1.6	1.55	1.55	3/1/07	IC	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Ocean Energy Inc	Devon Energy Corp	Landfill Energy Systems	Ocean Energy	IC4	100	1.6	1.55	1.55	3/1/07	IC	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Ocean Energy Inc	Devon Energy Corp	Landfill Energy Systems	Ocean Energy	IC5	100	1.6	1.55	1.55	3/1/07	IC	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Ocean Energy Inc	Devon Energy Corp	Landfill Energy Systems	Ocean Energy	IC6	100	1.6	1.55	1.55	3/1/07	IC	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NAEA Ocean Peaking Power	Industry Super Holding	NAEA Ocean Peaking Power LL	Ocean Peaking Power L	GT1	100	191.5	162.8	187.7	5/1/03	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NAEA Ocean Peaking Power	Industry Super Holding	NAEA Ocean Peaking Power LL	Ocean Peaking Power L	GT2	100	191.5	162.8	187.7	5/1/03	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Exelon Nuclear	Exelon Corp	Exelon Nuclear	Oyster Creek (NJ)	1	100	550	614.5	637	12/1/69	NB	URA	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Red Oak Power LLC	Energy Capital Partners	Red Oak Power LLC	Red Oak	CC	100	966	765.9	823.1	4/1/02	CC	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Sayreville	GT1	100	53	50	70	3/1/72	GT	DFO	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Sayreville	GT2	100	53	50	70	3/1/72	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Sayreville	GT3	100	53	50	70	6/1/72	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Sayreville	GT4	100	53	50	70	10/1/72	GT	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	North Jersey Energy Associat	NextEra Energy Inc	North Jersey Energy Associates	Sayreville Cogeneration	CC	100	430.2	271	315	8/1/91	CC	NG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Shore Point Solar LLC	Shore Point Solar LLC	Shore Point Solar LLC	Shore Point Solar	PV1	100	1.2	1.2	1.2	9/1/11	PV	SUN	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	PPL New Jersey Solar LLC	PPL Corp	PPL New Jersey Solar LLC	Summit Solar	PV1	100	1.7	1.7	1.7	4/1/09	PV	SUN	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	SunE ST8 Monroe LLC	SunEdison	SunE ST8 Monroe LLC	SunE ST8 Monroe	PV	100	0.6	0.5	0.5	3/24/08	PV	SUN	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	SX Landfill Energy LLC	South Jersey Industries Inc	SX Landfill Energy LLC	SX Renewable Energy G	IC1	100	1.6	1.5	1.5	4/27/11	IC	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	SX Landfill Energy LLC	South Jersey Industries Inc	SX Landfill Energy LLC	SX Renewable Energy G	IC2	100	1.6	1.5	1.5	4/27/11	IC	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Constellation Solar New Jers	Exelon Corp	Constellation NewEnergy Inc	Toys R US Distribution C	PV1	100	2.4	2.4	2.4	8/11/11	PV	SUN	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	WC Landfill Energy LLC	DCO Energy LLC	DCO Energy LLC	Warren County Landfill	GT1	100	2	1.6	1.6	11/1/06	GT	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	WC Landfill Energy LLC	DCO Energy LLC	DCO Energy LLC	Warren County Landfill	GT2	100	1.9	1.9	1.9	11/1/06	GT	LFG	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Covanta Warren Energy Resc	Covanta Holding Corp	Covanta Warren Energy Resou	Warren Energy Resourc	NA	100	13.5	10	10.5	9/1/88	ST	MSW	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Werner	GT1	100	53	46	66	3/1/72	GT	DFO	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Werner	GT4	100	53	46	66	6/1/72	GT	DFO	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Werner	GT3	100	53	46	66	5/1/72	GT	DFO	Restarted	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Werner	GT2	100	53	46	66	4/1/72	GT	DFO	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Jersey Central Power & Light	FirstEnergy Corp	Jersey Central Power & Light C	Yards Creek	1	50	75.5	70	70	11/1/65	PS	WAT	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	Jersey Central Power & Light C	Yards Creek	1	50	75.5	70	70	11/1/65	PS	WAT	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Jersey Central Power & Light	FirstEnergy Corp	Jersey Central Power & Light C	Yards Creek	2	50	75.5	70	70	12/1/65	PS	WAT	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	Jersey Central Power & Light C	Yards Creek	2	50	75.5	70	70	12/1/65	PS	WAT	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	Jersey Central Power & Light	FirstEnergy Corp	Jersey Central Power & Light C	Yards Creek	3	50	75.5	60	60	9/1/65	PS	WAT	Operating	Y	1
PJM ISO	JCPL	Jersey Central Pow	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	Jersey Central Power & Light C	Yards Creek	3	50	75.5	60	60	9/1/65	PS	WAT	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		PPL Ironwood LLC	PPL Corp	PPL Prescott LLC	AES Ironwood	CC	100	777.6	660.1	660.1	12/31/01	CC	NG	Operating	Y	1
PJM ISO	METED	Jersey Central Power & Light Company				PPL Corp	PPL Corp	PPL Corp	Crayola Solar Park	PV1	50	0.5	0.5	0.5	5/1/10	PV	SUN	Operating	Y	1
PJM ISO	METED	Jersey Central Power & Light Company				UGI Energy Services Inc	UGI Corp	PPL Corp	Crayola Solar Park	PV1	50	0.5	0.5	0.5	5/1/10	PV	SUN	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		Chrin Brothers Inc	Chrin Brothers Inc	Millennium Design Builders	Glendon Green Energy I	IC1	100	1.6	1.6	1.6	6/1/11	IC	LFG	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		Chrin Brothers Inc	Chrin Brothers Inc	Millennium Design Builders	Glendon Green Energy I	IC2	100	1.6	1.6	1.6	6/1/11	IC	LFG	Operating	Y	1
PJM ISO	METED	Metropolitan Edisc	PJM East	5004/5005	AP South	Green Knight Economic Deve	Green Knight Economic De	Waste Management Inc	Green Knight	TG1	100	3.3	2.4	2.9	2/1/01	GT	LFG	Operating	Y	1
PJM ISO	METED	Metropolitan Edisc	PJM East	5004/5005	AP South	Green Knight Economic Deve	Green Knight Economic De	Waste Management Inc	Green Knight	TG2	100	3.3	2.4	2.9	2/1/01	GT	LFG	Operating	Y	1
PJM ISO	METED	Metropolitan Edisc	PJM East	5004/5005	AP South	Green Knight Economic Deve	Green Knight Economic De	Waste Management Inc	Green Knight	TG3	100	3.3	2.4	2.9	2/1/01	GT	LFG	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		GlaxoSmithKline	GlaxoSmithKline	GlaxoSmithKline	GSK NE Regional Distrib	1	100	2.6	1.5	1	1/1/11	PV	SUN	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		GlaxoSmithKline	GlaxoSmithKline	GlaxoSmithKline	GSK NE Regional Distrib	2	100	1	0.3	0.2	1/1/11	PV	SUN	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		GlaxoSmithKline	GlaxoSmithKline	GlaxoSmithKline	GSK NE Regional Distrib	3	100	1	0.3	0.2	1/1/11	PV	SUN	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		GlaxoSmithKline	GlaxoSmithKline	GlaxoSmithKline	GSK NE Regional Distrib	4	100	1	0.3	0.2	1/1/11	PV	SUN	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		GlaxoSmithKline	GlaxoSmithKline	GlaxoSmithKline	GSK NE Regional Distrib	5	100	1	0.3	0.2	1/1/11	PV	SUN	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Hamilton (PA)	1	100	19.6	18	24	6/1/71	GT	DFO	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		NRG Wholesale Generation I	NRG Energy Inc	NRG Wholesale Generation LP	Hunterstown	1	100	20	18	25	5/1/71	GT	DFO	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		NRG Wholesale Generation I	NRG Energy Inc	NRG Wholesale Generation LP	Hunterstown	2	100	20	17	25	5/1/71	GT	DFO	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		NRG Wholesale Generation I	NRG Energy Inc	NRG Wholesale Generation LP	Hunterstown	3	100	20	18	25	5/1/71	GT	DFO	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		NRG Wholesale Generation I	NRG Energy Inc	NRG Wholesale Generation LP	Hunterstown	CC1	100	898	758	810	7/15/03	CC	NG	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		Lancaster County Solid Wast	Lancaster County Solid Wa	Covanta Lancaster Inc	Lancaster County Resou	GEN1	100	35.7	32.4	32.4	12/1/90	ST	MSW	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		PPL Renewable Energy	PPL Corp	Lebanon Methane Recovery In	Lebanon Methane Recc	GEN3	100	1.6	1.6	1.6	9/20/07	IC	LFG	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		PPL Renewable Energy	PPL Corp	Lebanon Methane Recovery In	Lebanon Methane Recc	GEN4	100	1.6	1.6	1.6	9/20/07	IC	LFG	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		Modern Power LLC	Republic Service Inc	Modern Power LLC	Modern Landfill Produc	GEN2	100	3	3	3	5/1/98	IC	LFG	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		Modern Power LLC	Republic Service Inc	Modern Power LLC	Modern Landfill Produc	GEN3	100	3	3	3	5/1/98	IC	LFG	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		Modern Power LLC	Republic Service Inc	Modern Power LLC	Modern Landfill Produc	GEN4	100	3	3	3	5/1/98	IC	LFG	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Mountain	1	100	27	18	25	6/1/72	GT	DFO	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Mountain	2	100	27	18	25	6/1/72	GT	DFO	Operating	Y	1
PJM ISO	METED	Metropolitan Edisc	PJM East	5004/5005	AP South	Ontelaunee Power Operatin	Dynegy Inc	Ontelaunee Power Operating	Ontelaunee Energy Cen	CC	100	728	465.7	591.4	8/24/02	CC	NG	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Orrtanna	1	100	27	18	26	5/1/71	GT	DFO	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		P H Glatfelter Co	P H Glatfelter Co	P H Glatfelter Co	P H Glatfelter Co	GEN1	100	6	5	5	7/1/48	ST	BIT	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		P H Glatfelter Co	P H Glatfelter Co	P H Glatfelter Co	P H Glatfelter Co	GEN2	100	5.9	4	3.9	4/1/75	ST	BIT	Standby	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		P H Glatfelter Co	P H Glatfelter Co	P H Glatfelter Co	P H Glatfelter Co	GEN3	100	5.1	4	4.3	5/1/48	ST	BIT	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		P H Glatfelter Co	P H Glatfelter Co	P H Glatfelter Co	P H Glatfelter Co	GEN4	100	7.5	8.7	8	8/1/62	ST	BIT	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		P H Glatfelter Co	P H Glatfelter Co	P H Glatfelter Co	P H Glatfelter Co	GEN5	100	45.9	36.1	33.1	5/1/89	AB	BIT	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South		P H Glatfelter Co	P H Glatfelter Co	P H Glatfelter Co	P H Glatfelter Co	GEN6	100	39.1	31.2	28.8	1/1/94	ST	BLQ	Operating	Y	1
PJM ISO	METED	Metropolitan Edisc	PJM East	5004/5005	AP South	Panther Creek Power Operat	ArcLight Capital Partners LI	Panther Creek Power Operatin	Panther Creek	GEN1	100	94	83	83	7/1/92	AB	WC	Operating	Y	1
PJM ISO	METED	Metropolitan Edisc	PJM East	5004/5005	AP South	Green Gas Pioneer Crossing	Green Gas DPB	Green Gas Pioneer Crossing Er	Pioneer Crossing Landfi	IC1	100	1.6	1.6	1.6	10/6/08	IC	LFG	Operating	Y	1
PJM ISO	METED	Metropolitan Edisc	PJM East	5004/5005	AP South	Green Gas Pioneer Crossing	Green Gas DPB	Green Gas Pioneer Crossing Er	Pioneer Crossing Landfi	IC2	100	1.6	1.6	1.6	10/6/08	IC	LFG	Operating	Y	1
PJM ISO	METED	Metropolitan Edisc	PJM East	5004/5005	AP South	Green Gas Pioneer Crossing	Green Gas DPB	Green Gas Pioneer Crossing Er	Pioneer Crossing Landfi	IC3	100	1.6	1.6	1.6	10/6/08	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	METED	Metropolitan Ediso	PJM East	5004/5005	AP South	Green Gas Pioneer Crossing	Green Gas DPB	Green Gas Pioneer Crossing Er	Pioneer Crossing Landfi	IC4	100	1.6	1.6	1.6	10/6/08	IC	LFG	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Portland (PA)	3	100	18	13	16	12/1/67	GT	DFO	Operating	Y	1	
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Portland (PA)	4	100	20	17	20	5/1/71	GT	DFO	Operating	Y	1	
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Portland (PA)	5	100	156	134	155	4/1/97	GT	DFO	Standby	Y	1	
PJM ISO	METED	Metropolitan Ediso	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Portland (PA)	1	100	172	141	141	10/1/58	ST	BIT	Operating	Y	1
PJM ISO	METED	Metropolitan Ediso	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Portland (PA)	2	100	255	194	194	9/1/62	ST	BIT	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South	Reading Hospital & Medical	Reading Hospital & Medica	Reading Hospital & Medical Ce	Reading Hospital Power	GT1	100	5	5	5	4/5/11	GT	NG	Operating	Y	1	
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South	Reading Hospital & Medical	Reading Hospital & Medica	Reading Hospital & Medical Ce	Reading Hospital Power	GT2	100	5	5	5	4/5/11	GT	NG	Operating	Y	1	
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South	Evergreen Community Powe	Interstate Resources Inc	Evergreen Community Power I	Reading Plant	ECP	100	33	25	25	3/14/10	AB	WDS	Operating	Y	1	
PJM ISO	METED	Metropolitan Ediso	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Shawnee (PA)	1	100	20	17	24	6/1/72	GT	DFO	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South	Snyders of Hanover Inc	Snyders of Hanover Inc	Snyders of Hanover Inc	Snyders Lance Solar	PV	100	3.5	3.5	3.5	6/21/11	PV	SUN	Operating	Y	1	
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South	Exelon Nuclear	Exelon Corp	Exelon Nuclear	Three Mile Island	1	100	975.6	805	829	8/1/74	NP	URA	Operating	Y	1	
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Titus	4	100	18	13	17	12/1/67	GT	DFO	Operating	Y	1	
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Titus	5	100	18	14	18	8/1/70	GT	DFO	Operating	Y	1	
PJM ISO	METED	Metropolitan Ediso	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Titus	1	100	75	72	72	3/1/51	ST	BIT	Operating	Y	1
PJM ISO	METED	Metropolitan Ediso	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Titus	2	100	75	72	72	6/1/51	ST	BIT	Operating	Y	1
PJM ISO	METED	Metropolitan Ediso	PJM East	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Titus	3	100	75	72	72	4/1/53	ST	BIT	Operating	Y	1
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Tolna	1	100	27	18	25	6/1/72	GT	DFO	Standby	Y	1	
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South	NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Tolna	2	100	27	18	25	6/1/72	GT	DFO	Standby	Y	1	
PJM ISO	METED	Pennsylvania Power & Light Com	5004/5005	AP South	Westwood Generation LLC	Olympus Holdings LLC	Westwood Generation LLC	Westwood	GEN1	100	36	30	30	6/1/87	AB	WC	Operating	Y	1	
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South	York Generation Co LLC	Morris Energy Group	York Generation Co LLC	York Cogeneration Facil	CC	100	26.1	24.1	27.1	8/1/89	CC	NG	Operating	Y	1	
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South	York Generation Co LLC	Morris Energy Group	York Generation Co LLC	York Cogeneration Facil	CC2	100	26.1	24.4	28	8/1/89	CC	NG	Operating	Y	1	
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South	York County Solid Waste Aut	Covanta Holding Corp	York County Solid Waste Auth	York County Resource R	GEN1	100	36.5	28.9	29.5	11/1/89	ST	MSW	Operating	Y	1	
PJM ISO	METED	Metropolitan Edison Company	5004/5005	AP South	York Haven Power Co	Olympus Holdings LLC	York Haven Power Co	York Haven	1	100	19.6	19	19	12/1/05	HY	WAT	Operating	Y	1	
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Bear Group	Bear Group	Bear Group	Aurora 5	IC	100	1	0.94	0.94	11/2/11	IC	OBG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Chester Generating Stat	7	100	18.6	13	18	2/1/69	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Chester Generating Stat	8	100	18.6	13	18	5/1/69	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Chester Generating Stat	9	100	18.6	13	18	3/1/69	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Kimberly Clark Corp	Kimberly Clark Corp	Kimberly Clark Corp	Chester Ops	NO 5	100	67	67	67	5/1/86	AB	WC	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Susquehanna Electric Co	Exelon Corp	Susquehanna Electric Co	Conowingo	10	100	55.6	65	65	5/1/64	HY	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Susquehanna Electric Co	Exelon Corp	Susquehanna Electric Co	Conowingo	11	100	55.6	65	65	5/1/64	HY	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Susquehanna Electric Co	Exelon Corp	Susquehanna Electric Co	Conowingo	1	100	48	48	48	3/1/28	HY	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Susquehanna Electric Co	Exelon Corp	Susquehanna Electric Co	Conowingo	2	100	36	36	36	3/1/28	HY	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Susquehanna Electric Co	Exelon Corp	Susquehanna Electric Co	Conowingo	3	100	48	48	48	3/1/28	HY	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Susquehanna Electric Co	Exelon Corp	Susquehanna Electric Co	Conowingo	4	100	48	48	48	4/1/28	HY	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Susquehanna Electric Co	Exelon Corp	Susquehanna Electric Co	Conowingo	5	100	36	36	36	6/1/28	HY	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Susquehanna Electric Co	Exelon Corp	Susquehanna Electric Co	Conowingo	6	100	47.7	48	48	7/1/28	HY	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Susquehanna Electric Co	Exelon Corp	Susquehanna Electric Co	Conowingo	8	100	55.6	65	65	3/1/64	HY	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Susquehanna Electric Co	Exelon Corp	Susquehanna Electric Co	Conowingo	9	100	55.6	65	65	3/1/64	HY	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Susquehanna Electric Co	Exelon Corp	Susquehanna Electric Co	Conowingo	7	100	47.7	48	48	6/1/28	HY	WAT	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Croydon CT Generating	11	100	68.3	49	64	6/1/74	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Croydon CT Generating	12	100	68.3	49	64	6/1/74	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Croydon CT Generating	21	100	68.3	49	64	6/1/74	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Croydon CT Generating	22	100	68.3	49	64	6/1/74	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Croydon CT Generating	31	100	68.3	49	64	8/1/74	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Croydon CT Generating	32	100	68.3	49	64	8/1/74	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Croydon CT Generating	41	100	68.3	49	64	7/1/74	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Croydon CT Generating	42	100	68.3	49	64	7/1/74	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Delaware Generating St	9	100	21.2	17	20	7/1/70	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Delaware Generating St	10	100	18.6	13	18	5/1/69	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Delaware Generating St	11	100	18.6	13	18	4/1/69	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Delaware Generating St	12	100	18.6	13	18	5/1/69	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Covanta Delaware Valley LP	Covanta Holding Corp	Covanta Delaware Valley LP	Delaware Valley	GEN1	100	90	80	80	4/1/91	ST	MSW	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Eddystone Generating S	10	100	18.6	13	18	5/1/67	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Eddystone Generating S	20	100	18.6	13	18	10/1/67	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Eddystone Generating S	30	100	21.2	17	20	3/1/70	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Eddystone Generating S	40	100	21.2	17	20	6/1/70	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Eddystone Generating S	3	100	391	380	380	9/1/74	ST	RFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Eddystone Generating S	4	100	391	380	380	6/1/76	ST	RFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	MF Mesa Lane LLC	Epuron	MF Mesa Lane LLC	Exelon Epuron Solar En	PV	100	3	1.5	1.1	11/24/08	PV	SUN	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Dominion Energy Services Cc	Dominion Resources Inc	Fairless Energy LLC	Fairless Energy Center	CC1	100	669	597.2	637.7	6/1/04	CC	NG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Dominion Energy Services Cc	Dominion Resources Inc	Fairless Energy LLC	Fairless Energy Center	CC2	100	669	614	638.7	6/28/04	CC	NG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Fairless Hills	A	100	30	30	30	12/1/97	ST	LFG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Fairless Hills	B	100	30	30	30	12/1/97	ST	LFG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Falls (PA PECO)	1	100	21.2	17	20	5/1/70	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Falls (PA PECO)	2	100	21.2	17	20	5/1/70	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Falls (PA PECO)	3	100	21.2	17	20	6/1/70	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Grays Ferry Cogeneration Pa	Veolia Environnement SA	Grays Ferry Cogeneration Part	Grays Ferry Cogeneratic	CC	100	192.6	150	150	10/1/97	CC	NG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	PPL Renewable Energy	PPL Corp	PPL Renewable Energy	Hill At Whitemarsh (The	CGE	100	1.6	1.6	1.6	5/1/07	IC	NG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Aqua Pennsylvania Inc	Aqua America Inc	Aqua Pennsylvania Inc	Ingrams Mill Farm	PV1	100	1.1	0.4	0.3	3/9/11	PV	SUN	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Liberty Electric Power LLC	LEP Holdings LLC	North American Energy Service	Liberty Electric Power L	CC	100	614	541	541	2/1/02	CC	NG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Limerick	1	100	1211.9	1146	1191	2/1/86	NB	URA	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Limerick	2	100	1211.9	1150	1195	1/1/90	NB	URA	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Ecogy Pennsylvania Systems	Ecogy Pennsylvania Syster	Ecogy Pennsylvania Systems LL	Longwood Gardens	1	100	1.3	1.3	1.3	5/1/10	PV	SUN	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Ecogy Pennsylvania Systems	Ecogy Pennsylvania Syster	Ecogy Pennsylvania Systems LL	Longwood Gardens	PV2	100	0.3	0.3	0.3	6/30/11	PV	SUN	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	FMC Corp	FMC Corp	FMC Corp	Marcus Hook	1	100	17.5	17.5	17.5	1/1/70	ST	COL	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	FPL Energy Marcus Hook LP	NextEra Energy Inc	FPL Energy Marcus Hook LP	Marcus Hook Refinery (	CC	100	836.1	726.5	808.4	1/1/05	CC	NG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	FPL Energy Marcus Hook 50	NextEra Energy Inc	FPL Energy Marcus Hook LP	Marcus Hook Refinery (	GEN1	100	50.5	50	50	11/1/87	GT	NG	Standby	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Southern Energy Manageme	Southern Energy Manager	Southern Energy Management	Marlboro Mushrooms S	PV1	100	1.13	1.13	1.13	11/30/11	PV	SUN	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Moser Generating Stati	1	100	21.2	17	20	6/1/70	GT	DFO	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Moser Generating Stati	2	100	21.2	17	20	5/1/70	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Moser Generating Stati	3	100	21.2	17	20	6/1/70	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Muddy Run	1	100	110	134	134	4/1/67	PS	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Muddy Run	2	100	134	133	133	4/1/67	PS	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Muddy Run	3	100	134	134	134	4/1/67	PS	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Muddy Run	4	100	134	134	134	6/1/67	PS	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Muddy Run	5	100	134	134	134	10/1/67	PS	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Muddy Run	6	100	133	133	133	10/1/67	PS	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Muddy Run	7	100	134	134	134	2/1/68	PS	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Muddy Run	8	100	134	134	134	2/1/68	PS	WAT	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Newman & Co Inc	Newman & Co Inc	Newman & Co Inc	Newman Co Inc	1	100	1.8	1.8	1.8	5/1/64	ST	NG	Operating	Y	1
PJM ISO	PECO	PECO Energy Company		5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Peach Bottom	2	50	614.477	562.6	574	7/1/74	NB	URA	Operating	Y	1
PJM ISO	PECO	PECO Energy Company		5004/5005	AP South	PSEG Nuclear LLC	Public Service Enterprise G	Exelon Generation Co LLC	Peach Bottom	2	50	614.477	562.6	574	7/1/74	NB	URA	Operating	Y	1
PJM ISO	PECO	PECO Energy Company		5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Peach Bottom	3	50	614.477	562.7	574	12/1/74	NB	URA	Operating	Y	1
PJM ISO	PECO	PECO Energy Company		5004/5005	AP South	PSEG Nuclear LLC	Public Service Enterprise G	Exelon Generation Co LLC	Peach Bottom	3	50	614.477	562.7	574	12/1/74	NB	URA	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Pennsbury	1	100	3	2.67	2.67	9/1/96	GT	LFG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Pennsbury	2	100	3	2.67	2.67	9/1/96	GT	LFG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Sunoco Refining & Supply Cc	Sunoco Inc	Sunoco Refining & Supply Co	Philadelphia Refinery	GEN1	100	10	5.5	6.6	1/1/52	ST	OG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Sunoco Refining & Supply Cc	Sunoco Inc	Sunoco Refining & Supply Co	Philadelphia Refinery	GEN2	100	10	6.7	6	1/1/52	ST	OG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Sunoco Refining & Supply Cc	Sunoco Inc	Sunoco Refining & Supply Co	Philadelphia Refinery	GEN3	100	10	7.3	6.8	1/1/52	ST	OG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	AES Energy Storage LLC	AES Corp (The)	AES Energy Storage LLC	PJM Service Center	ES1	100	0	0	0	9/30/08	ES	OTH	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Covanta Plymouth Renewab	Covanta Holding Corp	Covanta Plymouth Renewable	Plymouth Facility	TGI	100	32.1	28	28	12/1/91	ST	MSW	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Richmond Generating S	91	100	65.8	49	66	6/1/73	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Richmond Generating S	92	100	65.8	49	66	6/1/73	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Schuylkill Generating St	10	100	18.6	13	18	5/1/69	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Schuylkill Generating St	11	100	21.2	17	20	6/1/71	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Trigen Philadelphia Energy C	GDF SUEZ SA	Trigen Philadelphia Energy Cor	Schuylkill Turbine	GEN1	100	55	51.15	51.7	10/1/37	ST	NG	Restarted	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Southwark Generating S	3	100	18.6	13	18	6/1/67	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Southwark Generating S	4	100	18.6	13	18	10/1/67	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Southwark Generating S	5	100	18.6	13	18	7/1/67	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Southwark Generating S	6	100	18.6	13	18	11/1/68	GT	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Bio Energy Partners	Waste Management Inc	Bio Energy Partners	Stowe Power Productio	GEN2	100	3	2.9	3	5/1/91	GT	LFG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Merck & Co Inc	Merck & Co Inc	Merck & Co Inc	West Point Facility	COG3	100	38.4	38.5	40	4/1/01	GT	NG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Merck & Co Inc	Merck & Co Inc	Merck & Co Inc	West Point Facility	GEN1	100	3	3	3	12/1/87	ST	NG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Merck & Co Inc	Merck & Co Inc	Merck & Co Inc	West Point Facility	GEN2	100	32.3	24.5	26	1/1/89	GT	NG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Merck & Co Inc	Merck & Co Inc	Merck & Co Inc	West Point Facility	GEN3	100	2.5	2.44	2.47	1/1/72	IC	DFO	Standby	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Merck & Co Inc	Merck & Co Inc	Merck & Co Inc	West Point Facility	GEN4	100	1.7	1.66	1.68	6/1/95	IC	NG	Standby	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Merck & Co Inc	Merck & Co Inc	Merck & Co Inc	West Point Facility	GEN5	100	1.2	1.17	1.18	6/1/94	IC	DFO	Standby	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Merck & Co Inc	Merck & Co Inc	Merck & Co Inc	West Point Facility	GEN6	100	1.2	1.17	1.18	6/1/93	IC	DFO	Standby	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Merck & Co Inc	Merck & Co Inc	Merck & Co Inc	West Point Facility	GEN7	100	0.7	0.68	0.69	6/1/94	IC	NG	Standby	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Merck & Co Inc	Merck & Co Inc	Merck & Co Inc	West Point Facility	GEN8	100	1	0.98	0.99	8/1/99	IC	NG	Standby	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Merck & Co Inc	Merck & Co Inc	Merck & Co Inc	West Point Facility	GEN9	100	1.3	0.9	0.9	2/1/04	IC	NG	Standby	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Merck & Co Inc	Merck & Co Inc	Merck & Co Inc	West Point Facility	GN10	100	1.3	0.9	0.9	2/1/04	IC	NG	Standby	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Merck & Co Inc	Merck & Co Inc	Merck & Co Inc	West Point Facility	GN11	100	1	0.9	0.9	11/1/10	IC	DFO	Standby	Y	1
PJM ISO	PECO	PECO Energy Company		5004/5005	AP South	Calpine Mid Merit LLC	Calpine Corp	Calpine Mid Merit LLC	York Energy Center	CC1	100	560	545	545	3/3/11	CC	NG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Allegheny Ridge Wind Farm	Infigen Energy	Allegheny Ridge Wind Farm LL	Allegheny Ridge Wind F	WT1 40	100	80	80	80	6/1/07	WT	WND	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				DEGS Wind I LLC	Duke Energy Corp	Allegheny Ridge Wind Farm LL	Allegheny Ridge Wind F	WT41 75	100	70	70	70	5/1/09	WT	WND	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Power & Light Company				Lycoming County Resource M	Lycoming County Resource	Lycoming County Resource Ma	Allentown LFG Project	IC1	100	0.5	0.5	0.5	1/1/93	IC	LFG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Power & Light Company				Lycoming County Resource M	Lycoming County Resource	Lycoming County Resource Ma	Allentown LFG Project	IC2	100	0.5	0.5	0.5	1/1/93	IC	LFG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				AES Armenia Mountain Win	AES Corp (The)	AES Wind Generation Inc	Armenia Mountain	WT1 10	100	15	15	15	12/18/09	WT	WND	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				AES Armenia Mountain Win	AES Corp (The)	AES Wind Generation Inc	Armenia Mountain	WT11 67	100	85.5	85.5	85.5	12/18/09	WT	WND	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Blossburg	1	100	24	16	24	5/1/71	GT	NG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Cambria Cogeneration Co	UBS AG	Cambria Cogeneration Co	Cambria Cogeneration	GEN1	100	98	87.5	87.5	3/1/91	AB	WC	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Casselman Windpower LLC	Iberdrola SA	Casselman Windpower LLC	Casselman Wind	WT1 23	100	34.5	34.5	34.5	12/31/07	WT	WND	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Inter Power/Ahlcon Partners	UBS AG	Inter Power/Ahlcon Partners L	Colver Power Project	COLV	100	118	110	110	2/1/95	AB	WC	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Constellation Energy Comm	Exelon Corp	NRG Rema LLC	Conemaugh	A	10.56	0.296	0.296	0.296	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Constellation Energy Comm	Exelon Corp	NRG Rema LLC	Conemaugh	B	10.56	0.296	0.296	0.296	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Constellation Energy Comm	Exelon Corp	NRG Rema LLC	Conemaugh	C	10.56	0.296	0.296	0.296	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Constellation Energy Comm	Exelon Corp	NRG Rema LLC	Conemaugh	D	10.56	0.296	0.296	0.296	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Duquesne Conemaugh LLC	Macquarie Power Income I	NRG Rema LLC	Conemaugh	A	3.83	0.107	0.107	0.107	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Duquesne Conemaugh LLC	Macquarie Power Income I	NRG Rema LLC	Conemaugh	B	3.83	0.107	0.107	0.107	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Duquesne Conemaugh LLC	Macquarie Power Income I	NRG Rema LLC	Conemaugh	C	3.83	0.107	0.107	0.107	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Duquesne Conemaugh LLC	Macquarie Power Income I	NRG Rema LLC	Conemaugh	D	3.83	0.107	0.107	0.107	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Exelon Generation Co LLC	Exelon Corp	NRG Rema LLC	Conemaugh	A	20.72	0.58	0.58	0.58	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Exelon Generation Co LLC	Exelon Corp	NRG Rema LLC	Conemaugh	B	20.72	0.58	0.58	0.58	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Exelon Generation Co LLC	Exelon Corp	NRG Rema LLC	Conemaugh	C	20.72	0.58	0.58	0.58	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Exelon Generation Co LLC	Exelon Corp	NRG Rema LLC	Conemaugh	D	20.72	0.58	0.58	0.58	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Energy (Keystone)	NRG Energy Inc	NRG Rema LLC	Conemaugh	A	3.71	0.104	0.104	0.104	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Energy (Keystone)	NRG Energy Inc	NRG Rema LLC	Conemaugh	B	3.71	0.104	0.104	0.104	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Energy (Keystone)	NRG Energy Inc	NRG Rema LLC	Conemaugh	C	3.71	0.104	0.104	0.104	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Energy (Keystone)	NRG Energy Inc	NRG Rema LLC	Conemaugh	D	3.71	0.104	0.104	0.104	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Conemaugh	A	16.45	0.461	0.461	0.461	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Conemaugh	B	16.45	0.461	0.461	0.461	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Conemaugh	C	16.45	0.461	0.461	0.461	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Conemaugh	D	16.45	0.461	0.461	0.461	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PPL Montour LLC	PPL Corp	NRG Rema LLC	Conemaugh	A	16.25	0.455	0.455	0.455	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PPL Montour LLC	PPL Corp	NRG Rema LLC	Conemaugh	B	16.25	0.455	0.455	0.455	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PPL Montour LLC	PPL Corp	NRG Rema LLC	Conemaugh	C	16.25	0.455	0.455	0.455	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PPL Montour LLC	PPL Corp	NRG Rema LLC	Conemaugh	D	16.25	0.455	0.455	0.455	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PSEG Fossil LLC	Public Service Enterprise G	NRG Rema LLC	Conemaugh	A	22.5	0.63	0.63	0.63	2/1/70	IC	DFO	Standby	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	PENELE	Pennsylvania Electric Company				PSEG Fossil LLC	Public Service Enterprise G	NRG Rema LLC	Conemaugh	B	22.5	0.63	0.63	0.63	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PSEG Fossil LLC	Public Service Enterprise G	NRG Rema LLC	Conemaugh	C	22.5	0.63	0.63	0.63	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PSEG Fossil LLC	Public Service Enterprise G	NRG Rema LLC	Conemaugh	D	22.5	0.63	0.63	0.63	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				UGI Utilities Inc	UGI Corp	NRG Rema LLC	Conemaugh	A	5.98	0.167	0.167	0.167	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				UGI Utilities Inc	UGI Corp	NRG Rema LLC	Conemaugh	B	5.98	0.167	0.167	0.167	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				UGI Utilities Inc	UGI Corp	NRG Rema LLC	Conemaugh	C	5.98	0.167	0.167	0.167	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				UGI Utilities Inc	UGI Corp	NRG Rema LLC	Conemaugh	D	5.98	0.167	0.167	0.167	2/1/70	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Constellation Energy Commc	Exelon Corp	NRG Rema LLC	Conemaugh	1	10.56	98.842	89.76	89.76	5/1/70	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Duquesne Conemaugh LLC	Macquarie Power Income I	NRG Rema LLC	Conemaugh	1	3.83	35.849	32.555	32.555	5/1/70	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Exelon Generation Co LLC	Exelon Corp	NRG Rema LLC	Conemaugh	1	20.72	193.939	176.12	176.12	5/1/70	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Energy (Keystone)	NRG Energy Inc	NRG Rema LLC	Conemaugh	1	3.71	34.726	31.535	31.535	5/1/70	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Conemaugh	1	16.45	153.972	139.825	139.825	5/1/70	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PPL Montour LLC	PPL Corp	NRG Rema LLC	Conemaugh	1	16.25	152.1	138.125	138.125	5/1/70	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PSEG Fossil LLC	Public Service Enterprise G	NRG Rema LLC	Conemaugh	1	22.5	210.6	191.25	191.25	5/1/70	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				UGI Utilities Inc	UGI Corp	NRG Rema LLC	Conemaugh	1	5.98	55.973	50.83	50.83	5/1/70	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Constellation Energy Commc	Exelon Corp	NRG Rema LLC	Conemaugh	2	10.56	98.842	89.76	89.76	5/1/71	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Duquesne Conemaugh LLC	Macquarie Power Income I	NRG Rema LLC	Conemaugh	2	3.83	35.849	32.555	32.555	5/1/71	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Exelon Generation Co LLC	Exelon Corp	NRG Rema LLC	Conemaugh	2	20.72	193.939	176.12	176.12	5/1/71	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Energy (Keystone)	NRG Energy Inc	NRG Rema LLC	Conemaugh	2	3.71	34.726	31.535	31.535	5/1/71	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Conemaugh	2	16.45	153.972	139.825	139.825	5/1/71	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PPL Montour LLC	PPL Corp	NRG Rema LLC	Conemaugh	2	16.25	152.1	138.125	138.125	5/1/71	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PSEG Fossil LLC	Public Service Enterprise G	NRG Rema LLC	Conemaugh	2	22.5	210.6	191.25	191.25	5/1/71	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				UGI Utilities Inc	UGI Corp	NRG Rema LLC	Conemaugh	2	5.98	55.973	50.83	50.83	5/1/71	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Conemaugh Hydro Station	Conemaugh Hydro Station	Pennsylvania Renewable Reso	Conemaugh Hydro	GEN1	49.5	3.713	0.99	1.98	2/1/89	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Conemaugh Hydro Station	Conemaugh Hydro Station	Pennsylvania Renewable Reso	Conemaugh Hydro	GEN2	49.5	3.713	0.99	1.98	2/1/89	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRR Conemaugh Inc	NRR Conemaugh Inc	Pennsylvania Renewable Reso	Conemaugh Hydro	GEN1	1	0.075	0.02	0.04	2/1/89	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRR Conemaugh Inc	NRR Conemaugh Inc	Pennsylvania Renewable Reso	Conemaugh Hydro	GEN2	1	0.075	0.02	0.04	2/1/89	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PSEG Power LLC	Public Service Enterprise G	Pennsylvania Renewable Reso	Conemaugh Hydro	GEN1	49.5	3.713	0.99	1.98	2/1/89	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PSEG Power LLC	Public Service Enterprise G	Pennsylvania Renewable Reso	Conemaugh Hydro	GEN2	49.5	3.713	0.99	1.98	2/1/89	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Brookfield Renewable Energ	Brookfield Asset Managem	Brookfield Renewable Energy	Deep Creek (MD)	1	100	10	9	9	7/1/25	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Brookfield Renewable Energ	Brookfield Asset Managem	Brookfield Renewable Energy	Deep Creek (MD)	2	100	10	9	9	7/1/25	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Babcock & Wilcox Co (The)	McDermott International I	Ebensburg Power Co	Ebensburg Power Co	GEN1	50	28.8	28.5	28.5	11/1/90	AB	WC	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Ebensburg Investors LP	Ebensburg Investors LP	Ebensburg Power Co	Ebensburg Power Co	GEN1	50	28.8	28.5	28.5	11/1/90	AB	WC	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Erie Coke Corp	Erie Coke Corp	Erie Coke Corp	Erie Coke Corp	1	100	2.5	1	1.26	1/1/53	ST	OG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Forward Windpower LLC	Generation Resources Hol	Forward Windpower LLC	Forward Windpower	WT1 14	100	27	27	27	6/30/08	WT	WND	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				General Electric Co	General Electric Co	General Electric Co	General Electric Co	REGN	100	4.4	4.3	4.2	6/1/84	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				FPL Energy Pennsylvania Wir	NextEra Energy Inc	American National Wind Powe	Green Mountain Wind I	N60	100	10.4	10.4	10.4	5/1/00	WT	WND	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Handsome Lake Energy LLC	Exelon Corp	Handsome Lake Energy LLC	Handsome Lake Energy	GT01	100	58.9	53.5	53.5	7/31/01	GT	NG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Handsome Lake Energy LLC	Exelon Corp	Handsome Lake Energy LLC	Handsome Lake Energy	GT02	100	58.9	53.5	53.5	7/31/01	GT	NG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Handsome Lake Energy LLC	Exelon Corp	Handsome Lake Energy LLC	Handsome Lake Energy	GT03	100	58.9	53.5	53.5	7/31/01	GT	NG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	PENELE	Pennsylvania Electric Company				Handsome Lake Energy LLC	Exelon Corp	Handsome Lake Energy LLC	Handsome Lake Energy	GT04	100	58.9	53.5	53.5	7/31/01	GT	NG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Handsome Lake Energy LLC	Exelon Corp	Handsome Lake Energy LLC	Handsome Lake Energy	GT05	100	58.9	53.5	53.5	7/31/01	GT	NG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Krayn Wind LLC	Terra Firma Capital Partne	Krayn Wind LLC	Highland Wind Project	WT1 25	100	62.5	62.5	62.5	5/1/09	WT	WND	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Homer City Generation LP	General Electric Co	Homer City Generation LP	Homer City Station	1	100	660	620	650	6/1/69	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Homer City Generation LP	General Electric Co	Homer City Generation LP	Homer City Station	2	100	660	614	614	8/1/69	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Homer City Generation LP	General Electric Co	Homer City Generation LP	Homer City Station	3	100	692	650	650	11/1/77	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Indiana University of Pennsy	Indiana University of Penn	Indiana University of Pennsylv	Indiana University of Pe	GEN1	100	6.1	6	6	3/1/88	IC	NG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Indiana University of Pennsy	Indiana University of Penn	Indiana University of Pennsylv	Indiana University of Pe	GEN2	100	6.1	6	6	3/1/88	IC	NG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Indiana University of Pennsy	Indiana University of Penn	Indiana University of Pennsylv	Indiana University of Pe	GEN3	100	6.1	6	6	3/1/88	IC	NG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Indiana University of Pennsy	Indiana University of Penn	Indiana University of Pennsylv	Indiana University of Pe	GEN4	100	6.1	6	6	3/1/88	IC	NG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Domtar LLC	Domtar Corp	Domtar LLC	Johnsonburg Mill	PT1	100	54	49	49	2/1/93	ST	BLQ	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Norfolk Southern Corp	Norfolk Southern Corp	Norfolk Southern Corp	Juniata Locomotive Sho	GEN1	100	2	0.4	0.5	8/1/55	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Norfolk Southern Corp	Norfolk Southern Corp	Norfolk Southern Corp	Juniata Locomotive Sho	GEN2	100	2	0.3	0.7	8/1/55	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Constellation Energy Comm	Exelon Corp	NRG Rema LLC	Keystone (PA)	1	20.99	196.466	178.415	178.415	8/1/67	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Constellation Energy Comm	Exelon Corp	NRG Rema LLC	Keystone (PA)	4	20.99	0.63	0.588	0.588	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Duquesne Keystone LLC	Macquarie Power Income I	NRG Rema LLC	Keystone (PA)	1	2.47	23.119	20.995	20.995	8/1/67	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Duquesne Keystone LLC	Macquarie Power Income I	NRG Rema LLC	Keystone (PA)	4	2.47	0.074	0.069	0.069	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Exelon Generation Co LLC	Exelon Corp	NRG Rema LLC	Keystone (PA)	1	20.99	196.466	178.415	178.415	8/1/67	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Exelon Generation Co LLC	Exelon Corp	NRG Rema LLC	Keystone (PA)	4	20.99	0.63	0.588	0.588	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Energy (Keystone)	NRG Energy Inc	NRG Rema LLC	Keystone (PA)	1	3.7	34.632	31.45	31.45	8/1/67	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Energy (Keystone)	NRG Energy Inc	NRG Rema LLC	Keystone (PA)	4	3.7	0.111	0.104	0.104	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Keystone (PA)	1	16.67	156.031	141.695	141.695	8/1/67	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Keystone (PA)	4	16.67	0.5	0.467	0.467	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PPL Montour LLC	PPL Corp	NRG Rema LLC	Keystone (PA)	1	12.34	115.502	104.89	104.89	8/1/67	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PPL Montour LLC	PPL Corp	NRG Rema LLC	Keystone (PA)	4	12.34	0.37	0.346	0.346	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PSEG Fossil LLC	Public Service Enterprise G	NRG Rema LLC	Keystone (PA)	1	22.84	213.782	194.14	194.14	8/1/67	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PSEG Fossil LLC	Public Service Enterprise G	NRG Rema LLC	Keystone (PA)	4	22.84	0.685	0.64	0.64	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Constellation Energy Comm	Exelon Corp	NRG Rema LLC	Keystone (PA)	2	20.99	196.466	178.415	178.415	7/1/68	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Constellation Energy Comm	Exelon Corp	NRG Rema LLC	Keystone (PA)	5	20.99	0.63	0.588	0.588	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Duquesne Keystone LLC	Macquarie Power Income I	NRG Rema LLC	Keystone (PA)	2	2.47	23.119	20.995	20.995	7/1/68	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Duquesne Keystone LLC	Macquarie Power Income I	NRG Rema LLC	Keystone (PA)	5	2.47	0.074	0.069	0.069	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Exelon Generation Co LLC	Exelon Corp	NRG Rema LLC	Keystone (PA)	2	20.99	196.466	178.415	178.415	7/1/68	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Exelon Generation Co LLC	Exelon Corp	NRG Rema LLC	Keystone (PA)	5	20.99	0.63	0.588	0.588	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Energy (Keystone)	NRG Energy Inc	NRG Rema LLC	Keystone (PA)	2	3.7	34.632	31.45	31.45	7/1/68	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Energy (Keystone)	NRG Energy Inc	NRG Rema LLC	Keystone (PA)	5	3.7	0.111	0.104	0.104	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Keystone (PA)	2	16.67	156.031	141.695	141.695	7/1/68	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Keystone (PA)	5	16.67	0.5	0.467	0.467	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PPL Montour LLC	PPL Corp	NRG Rema LLC	Keystone (PA)	2	12.34	115.502	104.89	104.89	7/1/68	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PPL Montour LLC	PPL Corp	NRG Rema LLC	Keystone (PA)	5	12.34	0.37	0.346	0.346	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PSEG Fossil LLC	Public Service Enterprise G	NRG Rema LLC	Keystone (PA)	2	22.84	213.782	194.14	194.14	7/1/68	ST	BIT	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	PENELE	Pennsylvania Electric Company				PSEG Fossil LLC	Public Service Enterprise G	NRG Rema LLC	Keystone (PA)	5	22.84	0.685	0.64	0.64	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Constellation Energy Commc	Exelon Corp	NRG Rema LLC	Keystone (PA)	3	20.99	0.63	0.588	0.588	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Constellation Energy Commc	Exelon Corp	NRG Rema LLC	Keystone (PA)	6	20.99	0.63	0.588	0.588	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Duquesne Keystone LLC	Macquarie Power Income I	NRG Rema LLC	Keystone (PA)	3	2.47	0.074	0.069	0.069	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Duquesne Keystone LLC	Macquarie Power Income I	NRG Rema LLC	Keystone (PA)	6	2.47	0.074	0.069	0.069	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Exelon Generation Co LLC	Exelon Corp	NRG Rema LLC	Keystone (PA)	3	20.99	0.63	0.588	0.588	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Exelon Generation Co LLC	Exelon Corp	NRG Rema LLC	Keystone (PA)	6	20.99	0.63	0.588	0.588	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Energy (Keystone)	NRG Energy Inc	NRG Rema LLC	Keystone (PA)	3	3.7	0.111	0.104	0.104	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Energy (Keystone)	NRG Energy Inc	NRG Rema LLC	Keystone (PA)	6	3.7	0.111	0.104	0.104	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Keystone (PA)	3	16.67	0.5	0.467	0.467	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Keystone (PA)	6	16.67	0.5	0.467	0.467	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PPL Montour LLC	PPL Corp	NRG Rema LLC	Keystone (PA)	3	12.34	0.37	0.346	0.346	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PPL Montour LLC	PPL Corp	NRG Rema LLC	Keystone (PA)	6	12.34	0.37	0.346	0.346	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PSEG Fossil LLC	Public Service Enterprise G	NRG Rema LLC	Keystone (PA)	3	22.84	0.685	0.64	0.64	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				PSEG Fossil LLC	Public Service Enterprise G	NRG Rema LLC	Keystone (PA)	6	22.84	0.685	0.64	0.64	11/1/68	IC	DFO	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Lakeview Gas Recovery	GEN1	100	3	3	3	5/1/97	IC	LFG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				WM Renewable Energy LLC	Waste Management Inc	WM Renewable Energy LLC	Lakeview Gas Recovery	GEN2	100	3	3	3	6/1/97	IC	LFG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Lookout Windpower LLC	Edison International	Lookout Windpower LLC	Lookout Windpower	WT1 18	100	37.8	37.8	37.8	12/31/08	WT	WND	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electi	PJM East	5004/5005	AP South	Procter & Gamble Paper Pro	Procter & Gamble Co (The)	Procter & Gamble Paper Produ	Mehoopany	GEN1	100	53.6	53.6	53.6	6/1/85	GT	NG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Procter & Gamble Paper Pro	Procter & Gamble Co (The)	Procter & Gamble Paper Produ	Mehoopany	GEN2	100	2.6	0.9	1.6	10/1/84	ST	NG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Meyersdale Windpower LLC	NextEra Energy Inc	Meyersdale Windpower LLC	Meyersdale Wind Energ	WT1 20	100	30	30	30	12/31/03	WT	WND	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Northern Tier Solid Waste A	PPL Corp	Northern Tier Solid Waste Aut	Northern Tier Landfill	IC	100	1.6	1.6	1.6	1/1/09	IC	LFG	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Brookfield Renewable Energ	Brookfield Asset Managem	Brookfield Renewable Energy	Piney	1	100	10	9	9	6/1/24	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Brookfield Renewable Energ	Brookfield Asset Managem	Brookfield Renewable Energy	Piney	2	100	12	9	9	7/1/24	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Brookfield Renewable Energ	Brookfield Asset Managem	Brookfield Renewable Energy	Piney	3	100	10	9	10	2/1/28	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Colmac Clarion Inc	American Consumer Indust	Colmac Clarion Inc	Piney Creek	GEN1	100	36.2	32.5	32.5	11/1/92	AB	WC	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Loyalhanna Watershed Asso	Loyalhanna Watershed Ass	Loyalhanna Watershed Associa	Saxman Run Mine Drair	HY	100	0.01	0.01	0.01	6/1/10	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Scrubgrass Generating Co LP	Energy Investors Funds Gr	Scrubgrass Generating Co LP	Scrubgrass Generating (	GEN1	100	94.7	84.3	84.8	1/1/93	AB	WC	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Seneca	1	100	220	218	218	1/1/70	PS	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Seneca	2	100	220	203	203	1/1/70	PS	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				FirstEnergy Generation, LLC	FirstEnergy Corp	FirstEnergy Generation, LLC	Seneca	3	100	29	30	30	1/1/70	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Wholesale Generation I	NRG Energy Inc	NRG Wholesale Generation LP	Seward Generating Stat	FB1	100	585	521	521	10/30/04	AB	WC	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Shawville Lessor GenOn LLC	NRG Energy Inc	NRG Rema LLC	Shawville	1	100	125	118	124	8/1/54	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Shawville Lessor GenOn LLC	NRG Energy Inc	NRG Rema LLC	Shawville	2	100	125	121	126	3/1/54	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Shawville Lessor GenOn LLC	NRG Energy Inc	NRG Rema LLC	Shawville	3	100	188	163	169	12/1/59	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Shawville Lessor GenOn LLC	NRG Energy Inc	NRG Rema LLC	Shawville	4	100	188	163	169	4/1/60	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Shawville Lessor GenOn LLC	NRG Energy Inc	NRG Rema LLC	Shawville	5	100	2	2	2	4/1/60	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Shawville Lessor GenOn LLC	NRG Energy Inc	NRG Rema LLC	Shawville	6	100	2	2	2	4/1/60	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Shawville Lessor GenOn LLC	NRG Energy Inc	NRG Rema LLC	Shawville	7	100	2	2	2	4/1/60	IC	DFO	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Somerset Windpower LLC	NextEra Energy Inc	Somerset Windpower LLC	Somerset Windpower	WT1 6	100	9	9	9	10/15/01	WT	WND	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	PENELE	Pennsylvania Electric Company				Stony Creek Wind Farm LLC	E.ON Group	General Electric Co	Stony Creek Wind Farm	WT1 35	100	52.5	52.5	52.5	11/18/09	WT	WND	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				CraftMaster Manufacturing I	CraftMaster Manufacturin	CraftMaster Manufacturing In	Towanda Mill	ST1	100	0.675	0.66	0.66	7/31/11	ST	WD	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				CraftMaster Manufacturing I	CraftMaster Manufacturin	CraftMaster Manufacturing In	Towanda Mill	ST2	100	0.675	0.66	0.66	7/31/11	ST	WD	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				American Eagle Paper Mills	Team Ten LLC	American Eagle Paper Mills	Tyrone (PA)	TG3	100	2.5	2.5	2.5	1/1/29	ST	BIT	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				American Eagle Paper Mills	Team Ten LLC	American Eagle Paper Mills	Tyrone (PA)	TG4	100	4.5	4.5	4.5	1/1/30	ST	BIT	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				American Eagle Paper Mills	Team Ten LLC	American Eagle Paper Mills	Tyrone (PA)	TG5	100	3	3	3	1/1/36	ST	BIT	Standby	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				American Eagle Paper Mills	Team Ten LLC	American Eagle Paper Mills	Tyrone (PA)	TG6	100	7.5	7.03	7.05	1/1/58	ST	BIT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				NRG Rema LLC	NRG Energy Inc	NRG Rema LLC	Warren (PA)	3	100	53.1	46	57	9/1/72	GT	DFO	Restarted	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				American Hydro Power Co	American Hydro Power Co	American Hydro Power Co	Warrior Ridge Hydro	L 1	100	0.7	0.7	0.7	12/1/85	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				American Hydro Power Co	American Hydro Power Co	American Hydro Power Co	Warrior Ridge Hydro	L 2	100	0.7	0.7	0.7	12/1/85	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				American Hydro Power Co	American Hydro Power Co	American Hydro Power Co	Warrior Ridge Hydro	L 4	100	0.7	0.7	0.7	12/1/85	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				American Hydro Power Co	American Hydro Power Co	American Hydro Power Co	Warrior Ridge Hydro	L 5	100	0.7	0.7	0.7	12/1/85	HY	WAT	Restarted	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Allegheny Electric Coop Inc	Allegheny Electric Coop Inc	Allegheny Electric Coop Inc	William F Matson Gene	1	100	7	2.4	7.2	6/1/88	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				Allegheny Electric Coop Inc	Allegheny Electric Coop Inc	Allegheny Electric Coop Inc	William F Matson Gene	2	100	14.7	5.2	14.8	6/1/88	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				D/R Hydro Co	D/R Hydro Co	D/R Hydro Co	Yough Hydro	GEN1	100	6.1	6.1	5	12/1/89	HY	WAT	Operating	Y	1
PJM ISO	PENELE	Pennsylvania Electric Company				D/R Hydro Co	D/R Hydro Co	D/R Hydro Co	Yough Hydro	GEN2	100	6.1	6.1	5	12/1/89	HY	WAT	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Bethesda Triangle LLC	Bethesda Triangle LLC	Bethesda Triangle LLC	Bethesda Triangle Proje	IC1	100	1.8	1.8	1.8	12/31/04	IC	DSL	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Alternative Energy Associate	Alternative Energy Associa	Alternative Energy Associates	Brighton Dam	1	100	0.48	0.48	0.48	1/1/86	HY	WAT	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		US General Services Adminis	US General Services Admin	US General Services Administr	Central Heating & Refri	GT1	100	5.4	5	5	6/30/04	GT	NG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		US General Services Adminis	US General Services Admin	US General Services Administr	Central Heating & Refri	GT2	100	5.4	5	5	6/30/04	GT	NG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		NRG Chalk Point LLC	NRG Energy Inc	NRG Chalk Point LLC	Chalk Point	GT2	100	35	22	27	6/1/74	GT	DFO	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		NRG Chalk Point LLC	NRG Energy Inc	NRG Chalk Point LLC	Chalk Point	GT3	100	103	73	92	6/1/91	GT	DFO	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		NRG Chalk Point LLC	NRG Energy Inc	NRG Chalk Point LLC	Chalk Point	GT4	100	103	73	92	6/1/91	GT	DFO	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		NRG Chalk Point LLC	NRG Energy Inc	NRG Chalk Point LLC	Chalk Point	GT5	100	125	81	107	6/1/91	GT	DFO	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		NRG Chalk Point LLC	NRG Energy Inc	NRG Chalk Point LLC	Chalk Point	GT6	100	125	81	107	6/1/91	GT	DFO	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		NRG Chalk Point LLC	NRG Energy Inc	NRG Chalk Point LLC	Chalk Point	ST1	100	364	331	331	8/1/64	ST	BIT	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		NRG Chalk Point LLC	NRG Energy Inc	NRG Chalk Point LLC	Chalk Point	ST2	100	364	336	337	3/1/65	ST	BIT	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		NRG Chalk Point LLC	NRG Energy Inc	NRG Chalk Point LLC	Chalk Point	3	100	659	582	582	5/1/75	ST	RFO	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		NRG Chalk Point LLC	NRG Energy Inc	NRG Chalk Point LLC	Chalk Point	4	100	659	582	582	12/1/81	ST	RFO	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		NRG Chalk Point LLC	NRG Energy Inc	NRG Chalk Point LLC	Chalk Point	GT1	100	16	16	16	4/1/67	GT	DFO	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		NRG Chalk Point LLC	NRG Energy Inc	NRG Chalk Point LLC	Chalk Point	SGT1	100	94	71	90	6/1/90	GT	DFO	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		GenOn Mid Atlantic LLC	NRG Energy Inc	GenOn Mid Atlantic LLC	Dickerson	2	100	196	179	179	4/1/60	ST	BIT	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		GenOn Mid Atlantic LLC	NRG Energy Inc	GenOn Mid Atlantic LLC	Dickerson	ST1	100	196	179	179	6/1/59	ST	BIT	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		GenOn Mid Atlantic LLC	NRG Energy Inc	GenOn Mid Atlantic LLC	Dickerson	GT2	100	163	139	167	6/1/92	GT	NG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		GenOn Mid Atlantic LLC	NRG Energy Inc	GenOn Mid Atlantic LLC	Dickerson	3	100	196	179	179	3/1/62	ST	BIT	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		GenOn Mid Atlantic LLC	NRG Energy Inc	GenOn Mid Atlantic LLC	Dickerson	GT3	100	163	139	167	6/1/93	GT	NG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		GenOn Mid Atlantic LLC	NRG Energy Inc	GenOn Mid Atlantic LLC	Dickerson	GT1	100	16	18	18	3/1/67	GT	DFO	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Sempra Energy	Sempra Energy	Sempra Energy	Federal Research Cente	GT1	100	5.7	5.7	5.7	9/30/04	GT	NG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Sempra Energy	Sempra Energy	Sempra Energy	Federal Research Cente	GT2	100	2	2	2	9/30/04	GT	NG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Sempra Energy	Sempra Energy	Sempra Energy	Federal Research Cente	GT3	100	4.3	4.3	4.6	12/31/07	GT	NG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Sempra Energy	Sempra Energy	Sempra Energy	Federal Research Cente	GT4	100	4.3	4.3	4.6	12/31/07	GT	NG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Sempra Energy	Sempra Energy	Sempra Energy	Federal Research Cente	GT5	100	4.3	4.3	4.6	12/31/07	GT	NG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Sempra Energy	Sempra Energy	Sempra Energy	Federal Research Cente	GT6	100	4.3	4.3	4.6	6/30/10	GT	NG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Montgomery County Maryla	Montgomery County Mary	Ogden Power Pacific Inc	Gude	IC1	100	0.848	0.797	0.797	7/1/09	IC	LFG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Northeast Maryland Waste D	Northeast Maryland Waste	Northeast Maryland Waste Dis	Montgomery County (M	GEN1	100	67.8	54	56	5/1/95	ST	MSW	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		GenOn Mid Atlantic LLC	NRG Energy Inc	GenOn Mid Atlantic LLC	Morgantown Generatin	3	100	65	48	59	6/1/73	GT	DFO	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		GenOn Mid Atlantic LLC	NRG Energy Inc	GenOn Mid Atlantic LLC	Morgantown Generatin	4	100	65	48	59	6/1/73	GT	DFO	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		GenOn Mid Atlantic LLC	NRG Energy Inc	GenOn Mid Atlantic LLC	Morgantown Generatin	5	100	65	48	59	5/1/73	GT	DFO	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		GenOn Mid Atlantic LLC	NRG Energy Inc	GenOn Mid Atlantic LLC	Morgantown Generatin	6	100	65	48	59	5/1/73	GT	DFO	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		GenOn Mid Atlantic LLC	NRG Energy Inc	GenOn Mid Atlantic LLC	Morgantown Generatin	GT1	100	18	13	17	12/1/70	GT	DFO	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		GenOn Mid Atlantic LLC	NRG Energy Inc	GenOn Mid Atlantic LLC	Morgantown Generatin	GT2	100	18	13	17	2/1/71	GT	DFO	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		GenOn Mid Atlantic LLC	NRG Energy Inc	GenOn Mid Atlantic LLC	Morgantown Generatin	ST1	100	626	596	596	6/1/70	ST	BIT	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		GenOn Mid Atlantic LLC	NRG Energy Inc	GenOn Mid Atlantic LLC	Morgantown Generatin	ST2	100	626	609	609	6/1/71	ST	BIT	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Pepco Energy Services Inc	Pepco Holdings Inc	Pepco Energy Services Inc	National Institutes of H	CGTG	100	22	21.2	21.2	10/1/05	GT	NG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Northeast Maryland Waste D	Northeast Maryland Waste	Bentech Group of Delaware In	Oaks Landfill	IC1	100	1.6	1.5	1.5	7/1/09	IC	LFG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Northeast Maryland Waste D	Northeast Maryland Waste	Bentech Group of Delaware In	Oaks Landfill	IC2	100	0.8	0.8	0.8	7/1/09	IC	LFG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Panda Brandywine LP	Northland Power Income F	Panda Brandywine LP	Panda Brandywine LP	CC	100	288.8	230	230	9/1/96	CC	NG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Prince Georges County	Prince Georges County	Prince Georges County	PG County Brown Static	1	100	1	0.8	0.8	1/1/03	IC	LFG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Prince Georges County	Prince Georges County	Prince Georges County	PG County Brown Static	2	100	1	0.8	0.8	1/1/03	IC	LFG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Prince Georges County	Prince Georges County	Prince Georges County	PG County Brown Static	3	100	1	0.8	0.8	1/1/03	IC	LFG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Prince Georges County	Prince Georges County	Prince Georges County	PG County Brown Static	4	100	1	0.8	0.8	1/1/03	IC	LFG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Prince Georges County	Prince Georges County	Prince Georges County	PR Georges County Bro	3972	100	0.9	0.8	0.8	10/1/87	IC	LFG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Prince Georges County	Prince Georges County	Prince Georges County	PR Georges County Bro	9314	100	0.9	0.8	0.8	10/1/87	IC	LFG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Prince Georges County	Prince Georges County	Prince Georges County	PR Georges County Bro	9340	100	0.9	0.8	0.8	10/1/87	IC	LFG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		NRG Solar Arrowhead LLC	NRG Energy Inc	NRG Solar Arrowhead LLC	Redskins FedEx Field So	PV1	100	1.973	1.583	1.583	9/18/11	PV	SUN	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		SunE MCPS Lakelands LLC	SunEdison	SunE MCPS Lakelands LLC	SunE MCPS Lakelands	PV	100	0.11	0.085	0.085	12/26/08	PV	SUN	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Trigen Cinergy Solutions Coll	Trigen Energy Corp	Trigen Cinergy Solutions Colle	UMCP CHP Plant	1	100	11	9.4	10.8	6/1/03	GT	NG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Trigen Cinergy Solutions Coll	Trigen Energy Corp	Trigen Cinergy Solutions Colle	UMCP CHP Plant	2	100	11	9.4	10.8	6/1/03	GT	NG	Operating	Y	1
PJM ISO	PEPCO	Potomac Electric Power Compan	5004/5005	AP South		Trigen Cinergy Solutions Coll	Trigen Energy Corp	Trigen Cinergy Solutions Colle	UMCP CHP Plant	3	100	5.4	5.4	5.4	7/1/03	ST	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Trexlertown Solar Array	Air Products & Chemicals I	Trexlertown Solar Array	Air Products Solar	PV1	100	1.5	1.5	1.5	6/1/11	PV	SUN	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PEI Power Corp	Energy Transfer Partners LI	PEI Power Corp	Archbald	GEN1	100	23.2	20	20	9/1/88	ST	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Cayuga Energy Inc	Iberdrola SA	PEI Power Corp	Archbald	GEN2	50	30.25	21.85	25	5/10/01	GT	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PEI Power Corp	Energy Transfer Partners LI	PEI Power Corp	Archbald	GEN2	50	30.25	21.85	25	5/10/01	GT	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PEI Power Corp	Energy Transfer Partners LI	PEI Power Corp	Archbald	GEN3	100	4.6	4	4.6	1/15/10	GT	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PEI Power Corp	Energy Transfer Partners LI	PEI Power Corp	Archbald	GEN4	100	4.6	4	4.6	1/15/10	GT	LFG	Operating	Y	1
PJM ISO	PPL	PECO Energy Company		AP South		Bethlehem Renewable Energ	Pepco Holdings Inc	Bethlehem Renewable Energy	Bethlehem Landfill	IC1	100	5.5	4.7	5.4	3/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Powe	PJM East	5004/5005	AP South	Calpine Bethlehem LLC	Calpine Corp	Calpine Bethlehem LLC	Bethlehem Power Plant	CC1	100				5/2/03	CC	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Powe	PJM East	5004/5005	AP South	Calpine Bethlehem LLC	Calpine Corp	Calpine Bethlehem LLC	Bethlehem Power Plant	CC2	100				11/15/03	CC	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Powe	PJM East	5004/5005	AP South	Calpine Bethlehem LLC	Calpine Corp	Calpine Bethlehem LLC	Bethlehem Power Plant	CTG1	100	140	126	121				Operating		
PJM ISO	PPL	Pennsylvania Powe	PJM East	5004/5005	AP South	Calpine Bethlehem LLC	Calpine Corp	Calpine Bethlehem LLC	Bethlehem Power Plant	CTG2	100	140	126	121				Operating		

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	PPL	Pennsylvania Powe	PJM East	5004/5005	AP South	Calpine Bethlehem LLC	Calpine Corp	Calpine Bethlehem LLC	Bethlehem Power Plant	CTG3	100	140	126	121				Operating		
PJM ISO	PPL	Pennsylvania Powe	PJM East	5004/5005	AP South	Calpine Bethlehem LLC	Calpine Corp	Calpine Bethlehem LLC	Bethlehem Power Plant	CTG5	100	140	126	121				Operating		
PJM ISO	PPL	Pennsylvania Powe	PJM East	5004/5005	AP South	Calpine Bethlehem LLC	Calpine Corp	Calpine Bethlehem LLC	Bethlehem Power Plant	CTG6	100	140	126	121				Operating		
PJM ISO	PPL	Pennsylvania Powe	PJM East	5004/5005	AP South	Calpine Bethlehem LLC	Calpine Corp	Calpine Bethlehem LLC	Bethlehem Power Plant	CTG7	100	140	126	121				Operating		
PJM ISO	PPL	Pennsylvania Powe	PJM East	5004/5005	AP South	Calpine Bethlehem LLC	Calpine Corp	Calpine Bethlehem LLC	Bethlehem Power Plant	STG4	100	230	187	177				Operating		
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	Calpine Bethlehem LLC	Calpine Corp	Calpine Bethlehem LLC	Bethlehem Power Plant	STG8	100	230	187	177				Operating		
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	UGI Development Co	UGI Corp	UGI Development Co	Broad Mountain Landfil	GT1	100	5.5	4.3	5.5	1/1/09	GT	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	UGI Development Co	UGI Corp	UGI Development Co	Broad Mountain Landfil	GT2	100	5.5	4.4	5.5	1/1/09	GT	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	Bucknell University	Bucknell University	Bucknell University	Bucknell Univ	CC	100	5.9	4.8	6.7	6/1/98	CC	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	Carlisle Area School District	Carlisle Area School Distric	Carlisle Area School District	CASD Power	PV1	100	0.9	0.9	0.9	10/1/10	PV	SUN	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	Carlisle Area School District	Carlisle Area School Distric	Carlisle Area School District	CASD Power	PV2	100	0.4	0.4	0.4	10/1/10	PV	SUN	Operating	Y	1
PJM ISO	PPL	Pennsylvania Electric Company				PPL Renewable Energy	PPL Corp	PPL Renewable Energy	Community Refuse Serv	IC1	100	1.6	1.6	1.6	1/1/09	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Electric Company				PPL Renewable Energy	PPL Corp	PPL Renewable Energy	Community Refuse Serv	IC2	100	1.6	1.6	1.6	1/1/09	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Electric Company				PPL Renewable Energy	PPL Corp	PPL Renewable Energy	Community Refuse Serv	IC3	100	1.6	1.6	1.6	1/1/09	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Electric Company				PPL Renewable Energy	PPL Corp	PPL Renewable Energy	Community Refuse Serv	IC4	100	1.6	1.6	1.6	1/1/09	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	Fishback	UNT1	100	18.5	14	14	8/1/69	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	Fishback	UNT2	100	18.5	14	14	8/1/69	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	El Paso Marketing LP	Kinder Morgan Inc	El Paso Marketing LP	Foster Wheeler Mt Carr	TG1	100	47.3	43	40	1/1/90	AB	WC	Operating	Y	1
PJM ISO	PPL	Metropolitan Edison Company		5004/5005	AP South	PPL Renewable Energy	PPL Corp	PPL Generation LLC	Frey Farm Landfill	WT1 2	100	3	3	3	2/1/11	WT	WND	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	PPL Generation LLC	PPL Corp	PPL Generation LLC	Frey Farm Landfill	IC1	100	1.6	1.6	1.6	1/16/06	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	PPL Generation LLC	PPL Corp	PPL Generation LLC	Frey Farm Landfill	IC2	100	1.6	1.6	1.6	1/16/06	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	Harrisburg Authority	Harrisburg Authority	Harrisburg Authority	Harrisburg Facility	ST 1	100	24.1	20.8	21.8	4/18/06	ST	MSW	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	Hazleton Generation LLC	Lakeside Energy LLC	Hazleton Generation LLC	Hazleton	GEN2	100	33	27.8	27.8	6/1/02	GT	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	Hazleton Generation LLC	Lakeside Energy LLC	Hazleton Generation LLC	Hazleton	GEN3	100	33	28.4	28.4	6/1/02	GT	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	Hazleton Generation LLC	Lakeside Energy LLC	Hazleton Generation LLC	Hazleton	GEN4	100	33	29	29	6/1/02	GT	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	Hazleton Generation LLC	Lakeside Energy LLC	Hazleton Generation LLC	Hazleton	GEN1	100	72.5	62	67	1/1/89	GT	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	PPL Holtwood LLC	PPL Corp	PPL Holtwood LLC	Holtwood	HY 1	100	10.4	10	10	1/1/49	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	PPL Holtwood LLC	PPL Corp	PPL Holtwood LLC	Holtwood	HY11	100	1.4	1.3	1.3	6/1/11	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	PPL Holtwood LLC	PPL Corp	PPL Holtwood LLC	Holtwood	HY13	100	1.4	1.3	1.3	6/1/11	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	PPL Holtwood LLC	PPL Corp	PPL Holtwood LLC	Holtwood	HY 10	100	12	13.5	13.5	3/1/24	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	PPL Holtwood LLC	PPL Corp	PPL Holtwood LLC	Holtwood	HY 2	100	10.4	11	11	2/1/11	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	PPL Holtwood LLC	PPL Corp	PPL Holtwood LLC	Holtwood	HY 3	100	13.5	12.9	12.9	2/1/11	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	PPL Holtwood LLC	PPL Corp	PPL Holtwood LLC	Holtwood	HY 4	100	10.4	11.8	11.8	5/1/11	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	PPL Holtwood LLC	PPL Corp	PPL Holtwood LLC	Holtwood	HY 5	100	10.4	12.3	12.3	7/1/11	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	PPL Holtwood LLC	PPL Corp	PPL Holtwood LLC	Holtwood	HY 6	100	10.4	12.9	12.9	12/1/11	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	PPL Holtwood LLC	PPL Corp	PPL Holtwood LLC	Holtwood	HY 7	100	10.4	10.8	10.8	10/1/13	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	PPL Holtwood LLC	PPL Corp	PPL Holtwood LLC	Holtwood	HY 8	100	11.4	11	11	12/1/14	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	PPL Holtwood LLC	PPL Corp	PPL Holtwood LLC	Holtwood	HY 9	100	13.2	13.5	13.5	2/1/14	HY	WAT	Operating	Y	1
PJM ISO	PPL	Metropolitan Edison Company		5004/5005	AP South	Granger Energy of Honey Br	Granger Electric Co	Granger Energy of Honey Broo	Honey Brook LFG	IC2	100	1.6	1.6	1.6	3/10/11	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com		5004/5005	AP South	Granger Energy of Honey Br	Granger Electric Co	Granger Energy of Honey Broo	Honey Brook LFG	IC1	100	1.6	1.6	1.6	12/31/06	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	Jenkins	CTG2	100	16	13.8	13.8	7/1/69	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	Jenkins	CTG1	100	16	13.8	13.8	8/1/69	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Gilberton Power Co	Gilberton Power Co	Gilberton Power Co	John B Rich Memorial	GEN1	100	88.4	80	80	2/1/88	AB	WC	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Keystone Recovery Inc	Keystone Recovery Inc	Keystone Recovery Inc	Keystone Landfill (PA)	NO 1	100	0.8	0.7	0.7	1/1/95	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Keystone Recovery Inc	Keystone Recovery Inc	Keystone Recovery Inc	Keystone Landfill (PA)	NO 2	100	0.8	0.7	0.7	1/1/95	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Keystone Recovery Inc	Keystone Recovery Inc	Keystone Recovery Inc	Keystone Landfill (PA)	NO 3	100	0.8	0.7	0.7	1/1/95	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Keystone Recovery Inc	Keystone Recovery Inc	Keystone Recovery Inc	Keystone Landfill (PA)	NO 4	100	0.8	0.7	0.7	1/1/95	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Keystone Recovery Inc	Keystone Recovery Inc	Keystone Recovery Inc	Keystone Landfill (PA)	NO 5	100	0.8	0.7	0.7	3/1/96	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Keystone Recovery Inc	Keystone Recovery Inc	Keystone Recovery Inc	Keystone Landfill (PA)	NO 6	100	0.8	0.7	0.7	3/1/96	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Keystone Recovery Inc	Keystone Recovery Inc	Keystone Recovery Inc	Keystone Landfill (PA)	NO 7	100	0.8	0.7	0.7	3/1/96	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		GDF SUEZ Energy North Ame	International Power	Northeastern Power Co	Kline Township Cogene	GEN1	100	59	52	52	7/1/89	AB	WC	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Koppers Inc (Susquehanna)	Koppers Inc	Koppers Inc (Susquehanna)	Koppers Susquehanna F	GEN1	100	12.5	12	12	6/1/88	ST	WDS	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	Lock Haven (PENNPOW	CTG	100	18.5	14	14	11/1/69	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Locust Ridge Wind Farm LLC	Iberdrola SA	Locust Ridge Wind Farm LLC	Locust Ridge Wind Farn	WT1 13	100	26	26	26	12/31/06	WT	WND	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Locust Ridge Wind Farm II LL	Iberdrola SA	Locust Ridge Wind Farm LLC	Locust Ridge Wind Farn	WT14 64	100	102	102	102	7/15/09	WT	WND	Operating	Y	1
PJM ISO	PPL	Pennsylvania Powe	PJM East	5004/5005	AP South	Lower Mount Bethel Energy	PPL Corp	Lower Mount Bethel Energy LL	Lower Mount Bethel En	CC1	100	651.6	558.5	560.5	5/20/04	CC	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	Martins Creek	CTG1	100	22.3	18	18	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	Martins Creek	CTG2	100	22.3	18	18	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Powe	PJM East	5004/5005	AP South	PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	Martins Creek	MC3	100	850.5	850	850	10/1/75	ST	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Powe	PJM East	5004/5005	AP South	PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	Martins Creek	MC4	100	850.5	850	850	3/1/77	ST	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Powe	PJM East	5004/5005	AP South	PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	Martins Creek	CTG3	100	22.3	18	18	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Powe	PJM East	5004/5005	AP South	PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	Martins Creek	CTG4	100	22.3	18	18	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Masser Farms Realty Ltd	Masser Farms Realty Ltd	Masser Farms Realty Ltd	Masser Farms Realty So	MFRS	100	1	1	0.7	5/1/11	PV	SUN	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Montour LLC	PPL Corp	PPL Montour LLC	Montour	MT1	100	820	755	755	3/1/72	ST	BIT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Montour LLC	PPL Corp	PPL Montour LLC	Montour	MT11	100	17.2	10	10	4/1/73	ST	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Montour LLC	PPL Corp	PPL Montour LLC	Montour	MT2	100	833	750	750	4/1/73	ST	BIT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Hankin Group	Hankin Group	Hankin Group	Morgantown Solar Park	PV1	100	2	1.6	1.4	11/1/11	PV	SUN	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Northampton Generating Co	Energy Investors Funds Gr	Northampton Generating Co L	Northampton Generati	GEN1	100	114.1	112	112	6/1/95	AB	WC	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		NRG Energy Center Paxton Ir	NRG Energy Inc	NRG Energy Center Paxton Inc	Paxton Creek	GEN1	100	6.3	6	6	8/1/86	IC	NG	Standby	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		NRG Energy Center Paxton Ir	NRG Energy Inc	NRG Energy Center Paxton Inc	Paxton Creek	GEN2	100	6.3	6	6	8/1/86	IC	NG	Standby	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Pocono Intl Raceway Inc	Pocono Intl Raceway Inc	Pocono Intl Raceway Inc	Pocono Solar Project	PV1	100	3	3	3	8/1/10	PV	SUN	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Brunner Island LLC	PPL Corp	PPL Brunner Island LLC	PPL Brunner Island	BI1	100	363.3	313	313	6/1/61	ST	BIT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Brunner Island LLC	PPL Corp	PPL Brunner Island LLC	PPL Brunner Island	BI2	100	405	375	375	10/1/65	ST	BIT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Brunner Island LLC	PPL Corp	PPL Brunner Island LLC	PPL Brunner Island	BID2	100	2.7	2.8	2.8	6/1/67	IC	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Brunner Island LLC	PPL Corp	PPL Brunner Island LLC	PPL Brunner Island	BID1	100	2.7	2.8	2.8	6/1/67	IC	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Brunner Island LLC	PPL Corp	PPL Brunner Island LLC	PPL Brunner Island	BI3	100	790.4	749	749	6/1/69	ST	BIT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Brunner Island LLC	PPL Corp	PPL Brunner Island LLC	PPL Brunner Island	BID3	100	2.7	2.2	2.2	6/1/67	IC	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	PPL Martin Creek LLC A	CT1	100	16	14	14	7/1/67	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	PPL Martin Creek LLC A	CT2	100	16	14	14	7/1/67	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	PPL Martin Creek LLC A	CT3	100	16	14	14	7/1/67	GT	DFO	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	PPL Martin Creek LLC Al	CT4	100	16	14	14	7/1/67	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	PPL Martins Creek Harri	CTG1	100	16	14	14	3/1/67	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	PPL Martins Creek Harri	CTG2	100	16	14	14	3/1/67	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	PPL Martins Creek Harri	CTG3	100	16	14	14	3/1/67	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	PPL Martins Creek Harri	CTG4	100	16	14	14	3/1/67	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	PPL Martins Creek LLC H	CTG1	100	16	13.5	14	7/1/67	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	PPL Martins Creek LLC H	CTG2	100	16	13.5	14	7/1/67	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Romark Logistics	Romark Logistics	Romark Logistics	Romark Solar	PV1	100	1.8	1.8	1.8	11/30/11	PV	SUN	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Safe Harbor Water Power Cc	Exelon Corp	Safe Harbor Water Power Corp	Safe Harbor	1	100	33	33	33	10/1/40	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Safe Harbor Water Power Cc	Exelon Corp	Safe Harbor Water Power Corp	Safe Harbor	10	100	37.5	37.5	37.5	6/1/85	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Safe Harbor Water Power Cc	Exelon Corp	Safe Harbor Water Power Corp	Safe Harbor	11	100	37.5	37.5	37.5	4/1/86	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Safe Harbor Water Power Cc	Exelon Corp	Safe Harbor Water Power Corp	Safe Harbor	12	100	37.5	37.5	37.5	9/1/85	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Safe Harbor Water Power Cc	Exelon Corp	Safe Harbor Water Power Corp	Safe Harbor	2	100	33	33	33	11/1/34	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Safe Harbor Water Power Cc	Exelon Corp	Safe Harbor Water Power Corp	Safe Harbor	3	100	32	32	32	12/1/31	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Safe Harbor Water Power Cc	Exelon Corp	Safe Harbor Water Power Corp	Safe Harbor	4	100	32	32	32	12/1/31	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Safe Harbor Water Power Cc	Exelon Corp	Safe Harbor Water Power Corp	Safe Harbor	41	100	2	2	2	12/1/31	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Safe Harbor Water Power Cc	Exelon Corp	Safe Harbor Water Power Corp	Safe Harbor	5	100	32	32	32	1/1/32	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Safe Harbor Water Power Cc	Exelon Corp	Safe Harbor Water Power Corp	Safe Harbor	42	100	2	2	2	12/1/31	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Safe Harbor Water Power Cc	Exelon Corp	Safe Harbor Water Power Corp	Safe Harbor	6	100	32	32	32	1/1/32	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Safe Harbor Water Power Cc	Exelon Corp	Safe Harbor Water Power Corp	Safe Harbor	7	100	32	32	32	10/1/33	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Safe Harbor Water Power Cc	Exelon Corp	Safe Harbor Water Power Corp	Safe Harbor	8	100	37.5	37.5	37.5	4/1/85	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Safe Harbor Water Power Cc	Exelon Corp	Safe Harbor Water Power Corp	Safe Harbor	9	100	37.5	37.5	37.5	2/1/86	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Sight & Sound Ministries Inc	Sight & Sound Ministries Ir	Sight & Sound Ministries Inc	Sight & Sound Theatre	GT1	100	0.6	0.6	0.6	6/30/00	GT	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Sight & Sound Ministries Inc	Sight & Sound Ministries Ir	Sight & Sound Ministries Inc	Sight & Sound Theatre	GT2	100	0.6	0.6	0.6	6/30/00	GT	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Sight & Sound Ministries Inc	Sight & Sound Ministries Ir	Sight & Sound Ministries Inc	Sight & Sound Theatre	GT3	100	1.2	1.2	1.2	6/30/00	GT	NG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Schuylkill Energy Resource Ir	Schuylkill Energy Resource	Schuylkill Energy Resource Inc	St Nicholas Cogeneratic	SNCP	100	99.2	86.5	86.5	9/1/90	AB	WC	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Sunbury Generation LLC	American Metals & Coal In	Sunbury Generation LLC	Sunbury Generation LL(	CTG1	100	23.6	18	23.6	11/1/71	GT	DFO	Standby	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Sunbury Generation LLC	American Metals & Coal In	Sunbury Generation LLC	Sunbury Generation LL(	CTG2	100	23.6	18	23.6	11/1/71	GT	DFO	Standby	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Sunbury Generation LLC	American Metals & Coal In	Sunbury Generation LLC	Sunbury Generation LL(	U1	100	89.1	80	80	11/1/49	ST	BIT	Standby	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Sunbury Generation LLC	American Metals & Coal In	Sunbury Generation LLC	Sunbury Generation LL(	U2	100	89.1	80	80	9/1/49	ST	BIT	Standby	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Sunbury Generation LLC	American Metals & Coal In	Sunbury Generation LLC	Sunbury Generation LL(	U3	100	103.5	94	94	4/1/51	ST	BIT	Standby	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Sunbury Generation LLC	American Metals & Coal In	Sunbury Generation LLC	Sunbury Generation LL(	U4	100	156.2	128	134	8/1/53	ST	BIT	Standby	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Sunbury Generation LLC	American Metals & Coal In	Sunbury Generation LLC	Sunbury Generation LL(	D1	100	5.5	5	5	4/1/67	IC	DFO	Standby	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Allegheny Electric Coop Inc	Allegheny Electric Coop Inc	PPL Susquehanna LLC	Susquehanna	1	10	134.405	126	131	6/1/83	NB	URA	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Susquehanna LLC	PPL Corp	PPL Susquehanna LLC	Susquehanna	1	90	1209.647	1134	1179	6/1/83	NB	URA	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Allegheny Electric Coop Inc	Allegheny Electric Coop Inc	PPL Susquehanna LLC	Susquehanna	2	10	134.4	126	131	2/1/85	NB	URA	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Susquehanna LLC	PPL Corp	PPL Susquehanna LLC	Susquehanna	2	90	1209.6	1134	1179	2/1/85	NB	URA	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Holtwood LLC	PPL Corp	PPL Holtwood LLC	Wallenpaupack	WP1	100	20	22	22	6/1/26	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Holtwood LLC	PPL Corp	PPL Holtwood LLC	Wallenpaupack	WP2	100	20	22	22	6/1/26	HY	WAT	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Waymart Wind Farm LLC	NextEra Energy Inc	Waymart Wind Farm LLC	Waymart Wind Farm	WT1 43	100	64.5	64.5	64.5	10/31/03	WT	WND	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	West Shore	CTG1	100	18.5	14	14	8/1/69	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	West Shore	CTG2	100	18.5	14	14	8/1/69	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Wheelabrator Frackville Ene	Waste Management Inc	Wheelabrator Frackville Energ	Wheelabrator Frackville	GEN1	100	48	42.5	42.5	9/1/88	AB	WC	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	Williamsport	CTG1	100	16	13.6	13.6	8/1/67	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		PPL Martins Creek LLC	PPL Corp	PPL Martins Creek LLC	Williamsport	CTG2	100	16	13.6	13.6	8/1/67	GT	DFO	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South		Wind Park Bear Creek LLC	JPMorgan Chase & Co	Wind Park Bear Creek LLC	Wind Park Bear Creek	WT1 12	100	24	24	24	3/1/06	WT	WND	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	NJR Clean Energy Ventures	New Jersey Resources Corp	NJR Clean Energy Ventures	Adler Development Sola	PV1 4	100	3.9	3.9	3.9	10/1/10	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Public Service Electric & Gas	Public Service Enterprise G	Public Service Electric & Gas Co	Amboy Avenue Solar	PV1	100	2.5	2.5	2.5	12/31/10	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Orion Energy Systems Inc	Orion Energy Group LLC	Orion Energy Systems Inc	Anheuser Busch Newar	PV1	100	0.53	0.53	0.53	5/17/10	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Orion Energy Systems Inc	Orion Energy Group LLC	Orion Energy Systems Inc	Anheuser Busch Newar	PV2	100	0.53	0.53	0.53	1/31/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Public Service Electric & Gas	Public Service Enterprise G	Public Service Electric & Gas Co	Barringer High Solar (PS	PV	100	0.64	0.64	0.64	10/25/10	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Bayonne Plant Holding LLC	Morris Energy Group	Bayonne Plant Holding LLC	Bayonne Cogeneration	CC	100	191.6	158	174	7/1/88	CC	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	ConocoPhillips	ConocoPhillips	ConocoPhillips	Bayway Refinery	ST	100	11.2	11.2	11.2	12/1/67	ST	WH	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Bergen	3	100	18.6	21.3	25.5	7/1/67	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Bergen	CC2	100	606.2	556.9	586.8	6/6/02	CC	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Bergen	CC1	100	737.2	628.5	683.3	6/1/95	CC	NG	Operating	Y	1
PJM ISO	PSEG	Jersey Central Pow	PJM East	5004/5005	AP South	SunE WGJN1 LLC	SunEdison	SunE WGJN1 LLC	Bound Brook Solar	PV	100	0.053	0.053	0.053	2/4/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Bristol Myers Squibb Co	Bristol Myers Squibb Co	Bristol Myers Squibb Co	Bristol Myers Squibb	GEN1	100	9.5	8.8	10.5	7/1/92	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Bristol Myers Squibb Co	Bristol Myers Squibb Co	Bristol Myers Squibb Co	Bristol Myers Squibb	GEN2	100	1	0.6	1	8/1/99	ST	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	BC Landfill Energy LLC	DCO Energy LLC	BC Landfill Energy LLC	Burlington County Reso	IC1	100	1.5	1.435	1.435	10/31/07	IC	LFG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	BC Landfill Energy LLC	DCO Energy LLC	BC Landfill Energy LLC	Burlington County Reso	IC2	100	1.5	1.435	1.435	10/31/07	IC	LFG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	BC Landfill Energy LLC	DCO Energy LLC	BC Landfill Energy LLC	Burlington County Reso	IC3	100	1.5	1.435	1.435	10/31/07	IC	LFG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	BC Landfill Energy LLC	DCO Energy LLC	BC Landfill Energy LLC	Burlington County Reso	IC4	100	1.5	1.435	1.435	10/31/07	IC	LFG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	BC Landfill Energy LLC	DCO Energy LLC	BC Landfill Energy LLC	Burlington County Reso	IC5	100	1.5	1.435	1.435	10/31/07	IC	LFG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Camden Plant Holding LLC	Morris Energy Group	Camden Plant Holding LLC	Camden Cogeneration	CC	100	157	145	144.7	2/1/93	CC	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Public Service Electric & Gas	Public Service Enterprise G	Public Service Electric & Gas Co	Camden School Solar (P	PV	100	0.5	0.5	0.5	3/16/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	EDF Renewable Energy	EDF Group	EDF Renewable Energy	Carrier Clinic Solar	PV1	100	1.9	1.9	1.9	12/31/09	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Public Service Electric & Gas	Public Service Enterprise G	Public Service Electric & Gas Co	Central High Solar (PSE(	PV	100	0.91	0.91	0.91	3/16/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	OBrien Biogas IV LLC	FORTISTAR	OBrien Biogas IV LLC	Cinnamon Bay Facility	UNT2	100	9.6	9.1	9.1	10/1/11	ST	LFG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Constellation Solar Federal L	Exelon Corp	Constellation NewEnergy Inc	Constellation Dept of St	PV1	100	3.9	3.9	3.9	10/3/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Public Service Electric & Gas	Public Service Enterprise G	Public Service Electric & Gas Co	Coxs Corner Solar	PV1	100	1.5	1.5	1.5	6/30/10	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Re Cranbury Solar 1 LLC	Sharp Corp	Re Cranbury Solar 1 LLC	Cranbury Solar	PV1 4	100	5.739	5	5	9/30/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Dynamic Energy Resources L	Dynamic Energy Resources	Dynamic Energy Resources LLC	DER Harrison Solar 1	PV1	100	1.425	1.198	1.198	12/31/10	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Dow Jones & Co	Dow Jones & Co	Dow Jones & Co	Dow Jones Solar	PV1	100	2.5	2.5	2	12/1/10	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Dow Jones & Co	Dow Jones & Co	Dow Jones & Co	Dow Jones Solar	PV2	100	1.6	1.6	1.6	3/1/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Eagle Point Cogeneration Pa	Thunderbird Power Holdin	Eagle Point Cogeneration Partı	Eagle Point Cogeneratic	CC	100	225	195	217	4/1/91	CC	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Essex Partnership LLC	Essex Partnership LLC	Essex Partnership LLC	Edgeboro Landfill Solar	PV1	100	2	2	2	11/9/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Essex Partnership LLC	Essex Partnership LLC	Essex Partnership LLC	Edgeboro Landfill Solar	PV2	100	2	2	2	11/9/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Edison	11	100	41.8	43.7	52.1	5/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Edison	12	100	41.8	43.4	50.8	5/1/71	GT	NG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Edison	13	100	41.8	43	51.7	5/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Edison	14	100	41.8	42.1	51.1	5/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Edison	21	100	41.8	43.1	51	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Edison	22	100	41.8	42.1	52	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Edison	23	100	41.8	43	50.9	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Edison	24	100	41.8	43	51.9	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Edison	31	100	41.8	43.4	50.6	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Edison	32	100	41.8	43.4	51.7	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Edison	33	100	41.8	43.8	51.1	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Edison	34	100	41.8	43.7	51.2	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Public Service Electric & Gas	Public Service Enterprise G	Public Service Electric & Gas Co	Edison Training Center	PV1	100	0.71	0.71	0.71	3/16/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Elmwood Park Power LLC	Morris Energy Group	Morris Energy Operations Co L	Elmwood Park	CC	100	83	64.9	72	5/1/89	CC	NG	Restarted	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Covanta Essex Co	Covanta Holding Corp	Covanta Essex Co	Essex (NJ ARFCESX)	GEN1	100	34.9	30	30	11/1/90	ST	MSW	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Covanta Essex Co	Covanta Holding Corp	Covanta Essex Co	Essex (NJ ARFCESX)	GEN2	100	34.9	30	30	11/1/90	ST	MSW	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Essex (NJ PSEG)	101	100	41.8	42.4	52	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Essex (NJ PSEG)	102	100	41.8	42.9	51.7	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Essex (NJ PSEG)	103	100	41.8	42.5	51.7	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Essex (NJ PSEG)	104	100	41.8	44.5	52.7	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Essex (NJ PSEG)	111	100	41.8	46.9	54.1	12/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Essex (NJ PSEG)	112	100	41.8	47.7	55.6	12/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Essex (NJ PSEG)	113	100	41.8	46.7	54.2	12/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Essex (NJ PSEG)	114	100	41.8	46.8	54.2	12/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Essex (NJ PSEG)	121	100	41.8	46.1	55.8	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Essex (NJ PSEG)	122	100	41.8	48.2	56	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Essex (NJ PSEG)	123	100	41.8	46.2	56.8	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Essex (NJ PSEG)	124	100	41.8	46.6	55.8	6/1/71	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Essex (NJ PSEG)	9	100	93.6	81	91.1	7/1/90	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	BP Solar	BP plc	BP Solar	Fedex Woodbridge	1	100	2.4	2.4	2.4	12/1/09	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Great Falls Hydroelectric Co	Algonquin Power Income F	Great Falls Hydroelectric Co	Great Falls Hydro	GEN1	100	3.6	0.3	0.6	12/1/85	HY	WAT	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Great Falls Hydroelectric Co	Algonquin Power Income F	Great Falls Hydroelectric Co	Great Falls Hydro	GEN2	100	3.6	0.3	0.6	12/1/85	HY	WAT	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Great Falls Hydroelectric Co	Algonquin Power Income F	Great Falls Hydroelectric Co	Great Falls Hydro	GEN3	100	3.6	0.3	0.6	12/1/85	HY	WAT	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	enXco Service Corp	EDF Group	enXco Service Corp	Halls Warehouse Solar	PV1	100	1.7	1.7	1.7	2/1/09	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Hoffmann La Roche Inc	Roche Group	Hoffmann La Roche Inc	Hoffmann Laroche Inc	TG01	100	5.3	4.1	5.3	1/1/04	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Hoffmann La Roche Inc	Roche Group	Hoffmann La Roche Inc	Hoffmann Laroche Inc	TG03	100	5.3	4.1	5.3	1/1/04	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Nuclear LLC	Public Service Enterprise G	PSEG Nuclear LLC	Hope Creek	1	100	1290.7	1174	1239.9	12/1/86	NB	URA	Restarted	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Hudson Generating Sta	2	100	659.7	617.6	652	12/1/68	ST	BIT	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Janssen Pharmaceuticals Inc	Johnson & Johnson	Janssen Pharmaceuticals Inc	Janssen Pharmaceutica	PV1	100	4.1	4.1	4.1	9/23/10	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Constellation Solar New Jers	Exelon Corp	Constellation NewEnergy Inc	Johnson Matthey Solar	PV1	100	4	4	4	3/31/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Solar Rainbow Services LLC	Solar Rainbow Services LLC	Solar Rainbow Services LLC	Jordache Enterprises Sc	PV1	100	1.3	1.3	1.3	4/13/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Solar Rainbow Services LLC	Solar Rainbow Services LLC	Solar Rainbow Services LLC	Jordache Enterprises Sc	PV2	100	1	1	1	4/13/11	PV	SUN	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	KDC Solar Master Tenant 20:	KDC Solar LLC	Advanced Energy Industries In	KDC Solar USS	PV1	100	2	2	2	11/21/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	KDC Solar Master Tenant 20:	KDC Solar LLC	Advanced Energy Industries In	KDC Solar USS	PV2	100	0.8	0.8	0.8	11/21/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Kearny Generating Stati	N121	100	60.5	44.5	50	8/1/01	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Kearny Generating Stati	N122	100	60.5	43.9	49.8	8/1/01	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Kearny Generating Stati	N123	100	60.5	46.1	48.5	8/1/01	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Kearny Generating Stati	N124	100	60.5	44.5	49.4	8/1/01	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Kearny Generating Stati	9	100	18.5	21.9	26.1	5/1/67	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Kinsleys Landfill Inc	New Jersey Board of Public	Kinsleys Landfill Inc	Kinsleys Landfill Inc	11	100	0.5	0.5	0.5	7/1/85	IC	LFG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Kinsleys Landfill Inc	New Jersey Board of Public	Kinsleys Landfill Inc	Kinsleys Landfill Inc	12	100	0.5	0.5	0.5	7/1/85	IC	LFG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Kinsleys Landfill Inc	New Jersey Board of Public	Kinsleys Landfill Inc	Kinsleys Landfill Inc	13	100	0.5	0.5	0.5	7/1/85	IC	LFG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Kinsleys Landfill Inc	New Jersey Board of Public	Kinsleys Landfill Inc	Kinsleys Landfill Inc	14	100	0.5	0.5	0.5	7/1/85	IC	LFG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Public Service Electric & Gas	Public Service Enterprise G	Public Service Electric & Gas C	Linden Solar Farm	PV1	100	2.7	2.7	2.7	3/2/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	SunE WGJN1 LLC	SunEdison	SunE WGJN1 LLC	Magnolia Solar	PV	100	0.053	0.053	0.053	2/4/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	SPP Fund III Management LL	NRG Energy Inc	SPP Fund III Master Tenant LLC	Masonic Charity Founda	PV1	50	0.58	0.508	0.508	5/13/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	SPP Fund III Master Tenant L	NRG Energy Inc	SPP Fund III Master Tenant LLC	Masonic Charity Founda	PV1	50	0.58	0.508	0.508	5/13/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Public Service Electric & Gas	Public Service Enterprise G	Public Service Electric & Gas C	Matrix Stults Road Solar	PV1	100	2.6	2.6	2.6	6/1/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	New Jersey Meadowlands C	New Jersey Meadowlands	New Jersey Meadowlands Con	Meadowlands Solar	PV1	100	0.412	0.412	0.412	2/23/09	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Nautilus Solar Medford BOE	Nautilus Energy LLC	Nautilus Solar Medford BOE LL	Medford BOE Solar	PV1	100	2.482	2.4	2.4	6/15/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Atlantic Electric	PJM East	5004/5005	AP South	Medford NJ (Township Of)	Medfor NJ (Township Of)	Medford NJ (Township Of)	Medford Township Sew	PV1	100	1.5	1.5	1.5	12/31/10	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Mercer Generating Stat	3	100	115.2	115.7	143.2	11/1/67	GT	DFO	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Mercer Generating Stat	1	100	326.4	319.7	334.1	12/1/60	ST	BIT	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Mercer Generating Stat	2	100	326.4	320.3	330.4	6/1/61	ST	BIT	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Merck & Co Inc	Merck & Co Inc	Merck & Co Inc	Merck Rahway Power P	GEN8	100	5	4.8	4.8	1/1/77	ST	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Merck & Co Inc	Merck & Co Inc	Merck & Co Inc	Merck Rahway Power P	GEN9	100	10.8	10	10.2	1/1/04	ST	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Public Service Electric & Gas	Public Service Enterprise G	Public Service Electric & Gas C	Mill Creek Solar	PV1	100	3.5	3.5	3.5	11/1/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Montclair State University C	Montclair State University	Montclair State University Cog	Montclair Cogeneration	1	100	4.1	3.7	4.3	7/1/93	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	National Park	1	100	18.5	21.1	25	6/1/69	GT	KER	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Nautilus Solar Energy LLC	Nautilus Energy LLC	Nautilus Solar Energy LLC	Nautilus Solar Energy	PV	100	0.105	0.105	0.105	11/17/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Nautilus Solar St Josephs LLC	Nautilus Energy LLC	Worldwater & Solar Technolog	Nautilus Solar I	PV	100	0.121	0.121	0.121	9/4/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Newark Bay Cogeneration Pa	Morris Energy Group	Newark Bay Cogeneration Part	Newark Bay Cogenerati	CC	100	156	120.2	136.2	6/1/93	CC	NG	Operating	Y	1
PJM ISO	PSEG	PECO Energy Comp	PJM East	5004/5005	AP South	NFI Solar Inc	Nfi	NFI Solar Inc	NFI Solar	PV1	100	1.1	1.1	1.1	4/20/10	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Paradise Solar Urban Renew	NextEra Energy Inc	Paradise Solar Urban Renewal	Paradise Solar Energy C	PV1	100	5.1	5.1	5.1	6/3/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Public Service Electric & Gas	Public Service Enterprise G	Public Service Electric & Gas C	Park Elementary Solar (	PV	100	0.51	0.51	0.51	10/25/10	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Passaic Valley Water Commi	Passaic Valley Water Comr	Passaic Valley Water Commiss	Passaic Valley Water Cc	GEN1	100	0.6	0.6	0.6	1/1/35	HY	WAT	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Passaic Valley Water Commi	Passaic Valley Water Comr	Passaic Valley Water Commiss	Passaic Valley Water Cc	GEN2	100	0.6	0.6	0.6	1/1/35	HY	WAT	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Passaic Valley Water Commi	Passaic Valley Water Comr	Passaic Valley Water Commiss	Passaic Valley Water Cc	GEN3	100	0.6	0.6	0.6	1/1/35	HY	WAT	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Passaic Valley Water Commi	Passaic Valley Water Comr	Passaic Valley Water Commiss	Passaic Valley Water Cc	GEN4	100	0.6	0.6	0.6	1/1/35	HY	WAT	Operating	Y	1
PJM ISO	PSEG	Jersey Central Pow	PJM East	5004/5005	AP South	PPL New Jersey Biogas LLC	PPL Corp	PPL New Jersey Biogas LLC	Pennsauken Sanitary La	GEN 1	100	0.2	0.2	0.2	6/1/06	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Jersey Central Pow	PJM East	5004/5005	AP South	PPL New Jersey Biogas LLC	PPL Corp	PPL New Jersey Biogas LLC	Pennsauken Sanitary La	GEN 2	100	0.2	0.2	0.2	6/1/06	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Jersey Central Pow	PJM East	5004/5005	AP South	PPL New Jersey Biogas LLC	PPL Corp	PPL New Jersey Biogas LLC	Pennsauken Sanitary La	GEN 3	100	0.1	0.1	0.1	12/1/07	PV	SUN	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	PSEG	Jersey Central Pow	PJM East	5004/5005	AP South	PPL New Jersey Biogas LLC	PPL Corp	PPL New Jersey Biogas LLC	Pennsauken Sanitary La	GEN 4	100	0.2	0.2	0.2	12/1/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Jersey Central Pow	PJM East	5004/5005	AP South	PPL New Jersey Biogas LLC	PPL Corp	PPL New Jersey Biogas LLC	Pennsauken Sanitary La	GEN 5	100	0.1	0.1	0.1	12/1/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Jersey Central Pow	PJM East	5004/5005	AP South	PPL New Jersey Biogas LLC	PPL Corp	PPL New Jersey Biogas LLC	Pennsauken Sanitary La	GEN 6	100	0.2	0.2	0.2	12/1/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Jersey Central Pow	PJM East	5004/5005	AP South	PPL New Jersey Biogas LLC	PPL Corp	PPL New Jersey Biogas LLC	Pennsauken Sanitary La	GEN 7	100	0.2	0.2	0.2	12/1/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Jersey Central Pow	PJM East	5004/5005	AP South	PPL New Jersey Biogas LLC	PPL Corp	PPL New Jersey Biogas LLC	Pennsauken Sanitary La	GEN 8	100	0.2	0.2	0.2	12/1/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Jersey Central Pow	PJM East	5004/5005	AP South	PPL New Jersey Biogas LLC	PPL Corp	PPL New Jersey Biogas LLC	Pennsauken Sanitary La	GEN 9	100	0.1	0.1	0.1	12/1/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Jersey Central Pow	PJM East	5004/5005	AP South	PPL New Jersey Biogas LLC	PPL Corp	PPL New Jersey Biogas LLC	Pennsauken Sanitary La	IC 1	100	0.9	0.9	0.9	11/1/04	IC	LFG	Operating	Y	1
PJM ISO	PSEG	Jersey Central Pow	PJM East	5004/5005	AP South	PPL New Jersey Biogas LLC	PPL Corp	PPL New Jersey Biogas LLC	Pennsauken Sanitary La	IC 2	100	0.9	0.9	0.9	11/1/04	IC	LFG	Operating	Y	1
PJM ISO	PSEG	Jersey Central Pow	PJM East	5004/5005	AP South	PPL New Jersey Biogas LLC	PPL Corp	PPL New Jersey Biogas LLC	Pennsauken Sanitary La	IC 3	100	0.9	0.9	0.9	11/1/04	IC	LFG	Operating	Y	1
PJM ISO	PSEG	Jersey Central Pow	PJM East	5004/5005	AP South	SunE WGJN1 LLC	SunEdison	SunE WGJN1 LLC	Plainfield Solar	PV	100	0.053	0.053	0.053	2/4/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PPL New Jersey Solar LLC	PPL Corp	PPL New Jersey Solar LLC	Princeton ReCAP Solar	PV1	100	0.377	0.377	0.377	12/31/08	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Solar Star New Jersey IV LLC	Integrys Energy Group Inc	Princeton University	Princeton University W	PV2	100	1.3	1.3	1.3	6/1/10	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Public Service Electric & Gas	Public Service Enterprise G	Public Service Electric & Gas C	PSE&G Central Headqua	PV1	100	0.92	0.92	0.92	3/2/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Burlington Genera	111	100	41.8	47.8	55	6/1/72	GT	DFO	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Burlington Genera	112	100	41.8	46.4	54.8	6/1/72	GT	DFO	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Burlington Genera	113	100	41.8	46.1	54.9	6/1/72	GT	DFO	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Burlington Genera	114	100	41.8	42.2	54.8	6/1/72	GT	DFO	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Burlington Genera	8	100	18.5	22.7	25.5	6/1/67	GT	DFO	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Burlington Genera	121	100	60.5	42	54.5	6/1/00	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Burlington Genera	122	100	60.5	42.1	52.9	6/1/00	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Burlington Genera	123	100	60.5	43.6	52.5	6/1/00	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Burlington Genera	124	100	60.5	42.5	53.8	6/1/00	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Burlington Genera	91	100	41.8	46.6	57.5	5/1/72	GT	DFO	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Burlington Genera	92	100	41.8	47.3	55.8	5/1/72	GT	DFO	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Burlington Genera	93	100	41.8	46.8	56.8	5/1/72	GT	DFO	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Burlington Genera	94	100	41.8	46	55.8	5/1/72	GT	DFO	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Linden Generating	5	100	96.1	89.7	90	6/1/00	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Linden Generating	6	100	96.1	90.7	90	6/1/00	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Linden Generating	7	100	96.1	85.9	91.3	6/1/95	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Linden Generating	8	100	96.1	83.8	89.6	6/1/95	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Linden Generating	3	100	18.5	21	24	7/1/67	GT	NG	Standby	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Linden Generating	CC1	100	593	620	643.3	5/1/06	CC	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	PSEG Linden Generating	CC2	100	593	625.9	656.2	5/1/06	CC	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	PSEG Nuclear LLC	PSEG Salem Generating	3	42.59	17.803	16.908	21.934	6/1/71	GT	DFO	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Nuclear LLC	Public Service Enterprise G	PSEG Nuclear LLC	PSEG Salem Generating	3	57.41	23.997	22.792	29.566	6/1/71	GT	DFO	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	PSEG Nuclear LLC	PSEG Salem Generating	1	42.59	532.971	497.409	508.61	6/1/77	NP	URA	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Nuclear LLC	Public Service Enterprise G	PSEG Nuclear LLC	PSEG Salem Generating	1	57.41	718.429	670.491	685.59	6/1/77	NP	URA	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	PSEG Nuclear LLC	PSEG Salem Generating	2	42.59	518.065	493.235	508.354	10/1/81	NP	URA	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Nuclear LLC	Public Service Enterprise G	PSEG Nuclear LLC	PSEG Salem Generating	2	57.41	698.335	664.865	685.246	10/1/81	NP	URA	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Renewvia Energy Corp	Renewvia Energy Corp	Renewvia Energy Corp	Renewvia Northpoint I	PV1	100	1.26	1.26	1.26	10/5/11	PV	SUN	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Public Service Electric & Gas	Public Service Enterprise G	Public Service Electric & Gas Co	Rider Solar (PSEG)	PV	100	0.74	0.74	0.74	10/18/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Rowan University	Rowan University	Rowan University	Rowan University	GT1	100	4.7	4.7	4.7	9/25/08	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Schering Plough Corp	Merck & Co Inc	Schering Plough Corp	Schering Cogen Facility	GEN1	100	4.6	4.2	4.6	2/1/94	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Schering Plough Corp	Merck & Co Inc	Schering Plough Corp	Schering Cogen Facility	GEN2	100	5.7	4.2	4.6	12/1/99	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Sewaren	1	100	103.2	105	109.8	12/1/48	ST	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Sewaren	2	100	100	108.3	114.3	11/1/48	ST	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Sewaren	3	100	108.8	107.9	113.9	10/1/49	ST	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Sewaren	6	100	115.2	107.6	150.9	11/1/65	GT	KER	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	PSEG Fossil LLC	Public Service Enterprise G	PSEG Fossil LLC	Sewaren	4	100	126.5	123.6	127.8	7/1/51	ST	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Public Service Electric & Gas	Public Service Enterprise G	Public Service Electric & Gas Co	Silver Lake Solar Farm (I	PV1	100	1.7	1.7	1.7	10/1/10	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Joan A Turnure Irrevocable T	Joan A Turnure Irrevocable	Syncarpha Solar LLC	Sparta Solar	PV1	100	3.01	2.803	2.803	8/29/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	SunE KHL285 Cherry Hill LLC	SunEdison	SunE KHL285 Cherry Hill LLC	SunE KHL285 Cherry Hil	PV	100	0.285	0.219	0.219	6/6/08	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	SunE KHL478 Hillsborough LL	SunEdison	SunE KHL478 Hillsborough LLC	SunE KHL478 Hillsboro	PV	100	0.3	0.3	0.3	8/18/08	PV	SUN	Operating	Y	1
PJM ISO	PSEG	PECO Energy Comp	PJM East	5004/5005	AP South	SunE KHL722 Mantua LLC	SunEdison	SunE KHL722 Mantua LLC	SunE KHL722 Mantua	PV	100	0.3	0.2	0.2	6/20/08	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	SunE SIT1 Hoboken LLC	SunEdison	SunE SIT1 Hoboken LLC	SunE SIT1 Hoboken	PV	100	0.124	0.124	0.124	8/8/06	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	SunE WG10 Piscataway LLC	SunEdison	SunE WG10 Piscataway LLC	SunE WG10 Piscataway	PV	100	0.038	0.038	0.038	10/25/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	SunE WG3 Bergenfield LLC	SunEdison	SunE WG3 Bergenfield LLC	SunE WG3 Bergenfield	PV	100	0.03	0.03	0.03	10/18/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	SunE WG6 Clifton LLC	SunEdison	SunE WG6 Clifton LLC	SunE WG6 Clifton	PV	100	0.05	0.05	0.05	10/18/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	SunE WG7 Clifton 2 LLC	SunEdison	SunE WG7 Clifton 2 LLC	SunE WG7 Clifton 2	PV	100	0.049	0.041	0.041	11/5/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	SunE WG7825 Westampton	SunEdison	SunE WG7825 Westampton LL	SunE WG7825 Westamp	PV	100	0.037	0.028	0.028	3/24/09	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	SunE WGNJ2 LLC	SunEdison	SunE WGNJ2 LLC	SunE WGNJ2 1	PV	100	0.063	0.063	0.063	6/20/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	SunE WGNJ2 LLC	SunEdison	SunE WGNJ2 LLC	SunE WGNJ2 2	PV	100	0.063	0.063	0.063	6/20/07	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Avidan Energy Solutions	Avidan Management LLC	Avidan Energy Solutions	Talmadge Solar	PV1	100	3.8	3.8	3.8	4/30/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Avidan Energy Solutions	Avidan Management LLC	Avidan Energy Solutions	Talmadge Solar	PV2	100	2	1.869	1.869	4/30/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Public Service Electric & Gas	Public Service Enterprise G	Public Service Electric & Gas Co	Trenton Solar Farm	PV1	100	1.3	1.3	1.3	3/2/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Trigen Trenton Energy Co	Veolia Environnement SA	Trigen Trenton Energy Co	Trigen Trenton	7214	100	6	0.1	3	12/1/83	IC	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Union County Utilities Autho	Union County Utilities Auth	Covanta Union Operations LLC	Union County Resource	GEN1	100	45	37.5	38.5	2/1/94	ST	MSW	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	University of M & D New Jer	University of M & D New Je	University of M & D New Jerse	Univ Medicine Dentistr	GEN1	100	3.5	3.4	3.7	7/1/89	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	University of M & D New Jer	University of M & D New Je	University of M & D New Jerse	Univ Medicine Dentistr	GEN2	100	3.5	3.4	3.7	7/1/89	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	University of M & D New Jer	University of M & D New Je	University of M & D New Jerse	Univ Medicine Dentistr	GEN3	100	3.5	3.4	3.7	7/1/89	GT	NG	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Public Service Electric & Gas	Public Service Enterprise G	Public Service Electric & Gas Co	WEA Texas Bayonne So	PV1	100	1.5	1.5	1.5	3/31/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Waste Management Inc	Waste Management Inc	Wheelabrator Falls Inc	Wheelabrator Falls	WFI1	100	53.3	48.1	48.1	5/1/94	ST	MSW	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	WR Project LLC	KDC Solar LLC	Solar Power Inc	White Rose Solar	PV1	100	4.2	4.2	4.2	11/17/11	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Nautilus Solar Energy LLC	Nautilus Energy LLC	Nautilus Solar Energy LLC	William Paterson Univ S	PV1	100	1.4	1.4	1.4	6/1/10	PV	SUN	Operating	Y	1
PJM ISO	PSEG	Public Service Elect	PJM East	5004/5005	AP South	Public Service Electric & Gas	Public Service Enterprise G	Public Service Electric & Gas Co	Yardville Solar Farm	PV1	100	3.6	3.6	3.6	3/2/11	PV	SUN	Operating	Y	1
PJM ISO	UGI ZOI	UGI Corporation		5004/5005	AP South	Allegheny Energy Supply Co	FirstEnergy Corp	UGI Utilities Inc	Hunlock Power Station	4	100	44	45	45	1/4/01	GT	NG	Operating	Y	1
PJM ISO	UGI ZOI	UGI Corporation		5004/5005	AP South	UGI Utilities Inc	UGI Corp	UGI Utilities Inc	Hunlock Power Station	CC1	100	145.9	126.4	126.5	7/1/11	CC	NG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	1	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	10	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	11	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	12	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	13	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	14	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	15	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	16	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	17	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	18	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	19	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	2	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	20	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	21	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	22	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	23	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	24	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	25	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	26	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	27	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	28	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	29	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	3	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	30	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	31	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	32	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	33	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	34	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	35	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	36	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	37	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	38	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	39	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	4	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	40	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	41	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	42	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	43	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	44	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	45	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	46	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	47	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	48	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	5	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	6	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	7	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	8	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Amelia (Maplewood) La	9	100	0.3	0.3	0.3	8/15/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	1	100	0.3	0.3	0.3	10/8/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	10	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	11	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	12	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	13	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	14	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	15	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	16	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	17	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	18	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	19	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	2	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	20	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	21	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	22	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	23	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	24	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	25	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	26	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	27	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	28	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	29	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	3	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	30	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	31	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	32	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	33	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	34	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	35	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	36	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	4	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	5	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	6	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	7	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	8	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Brunswick Facility	9	100	0.3	0.3	0.3	10/1/07	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	1	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	10	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	11	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	12	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	13	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	14	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	15	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	16	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	17	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	18	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	19	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	2	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	20	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	21	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	22	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	23	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	24	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	25	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	26	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	27	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	28	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	29	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	3	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	30	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	31	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	32	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	33	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	34	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	35	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	36	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	37	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	38	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	39	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	4	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	40	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	41	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	42	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	43	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	44	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	45	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	46	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	47	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	48	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	5	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	6	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	7	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	8	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Charles City Landfill	9	100	0.3	0.3	0.3	11/15/03	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Henrico County Landfill	1	100	0.3	0.3	0.3	9/30/10	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Henrico County Landfill	10	100	0.3	0.3	0.3	9/30/10	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Henrico County Landfill	11	100	0.3	0.3	0.3	9/30/10	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Henrico County Landfill	12	100	0.3	0.3	0.3	9/30/10	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Henrico County Landfill	2	100	0.3	0.3	0.3	9/30/10	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Henrico County Landfill	3	100	0.3	0.3	0.3	9/30/10	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Henrico County Landfill	4	100	0.3	0.3	0.3	9/30/10	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Henrico County Landfill	5	100	0.3	0.3	0.3	9/30/10	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Henrico County Landfill	6	100	0.3	0.3	0.3	9/30/10	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Henrico County Landfill	7	100	0.3	0.3	0.3	9/30/10	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Henrico County Landfill	8	100	0.3	0.3	0.3	9/30/10	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Henrico County Landfill	9	100	0.3	0.3	0.3	9/30/10	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC1	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC10	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC11	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC12	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC13	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC14	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC15	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC16	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC17	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC18	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC19	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC2	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC20	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC21	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC22	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC23	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC24	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC25	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC26	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC27	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC28	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC29	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC3	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC30	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC31	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC32	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC33	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC34	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC35	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC36	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC37	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC38	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC39	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC4	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC40	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC41	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC42	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC43	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC44	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC45	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC46	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC47	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC48	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC5	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC6	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC7	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC8	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Ingenco Shoosmith Faci	IC9	100	0.3	0.3	0.3	6/30/04	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO Wholesale Power LL	King & Queen County L	IC37	100	0.23	0.23	0.23	5/16/12	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO Wholesale Power LL	King & Queen County L	IC38	100	0.229	0.229	0.229	5/16/12	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO Wholesale Power LL	King & Queen County L	IC39	100	0.229	0.229	0.229	5/16/12	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO Wholesale Power LL	King & Queen County L	IC40	100	0.229	0.229	0.229	5/16/12	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO Wholesale Power LL	King & Queen County L	IC41	100	0.229	0.229	0.229	5/16/12	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO Wholesale Power LL	King & Queen County L	IC42	100	0.229	0.229	0.229	5/16/12	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO Wholesale Power LL	King & Queen County L	IC43	100	0.229	0.229	0.229	5/16/12	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO Wholesale Power LL	King & Queen County L	IC44	100	0.229	0.229	0.229	5/16/12	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO Wholesale Power LL	King & Queen County L	IC45	100	0.229	0.229	0.229	5/16/12	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO Wholesale Power LL	King & Queen County L	IC46	100	0.229	0.229	0.229	5/16/12	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO Wholesale Power LL	King & Queen County L	IC47	100	0.229	0.229	0.229	5/16/12	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC48	100	0.229	0.229	0.229	5/16/12	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC1	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC10	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC11	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC12	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC13	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC14	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC15	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC16	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC17	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC18	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC19	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC2	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC20	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC21	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC22	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC23	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC24	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC25	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC26	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC27	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC28	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC29	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC3	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC30	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC31	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC32	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC33	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC34	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC35	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC36	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC4	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC5	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC6	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC7	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC8	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	King & Queen County La	IC9	100	0.3	0.3	0.3	1/15/08	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2A	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2B	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2C	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2D	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2E	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2F	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2G	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2H	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2I	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2J	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2K	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2L	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2M	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2N	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2O	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2P	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2Q	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2R	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2S	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2T	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	2U	100	0.3	0.3	0.3	6/1/00	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	1A	100	0.3	0.3	0.3	10/1/95	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	1B	100	0.3	0.3	0.3	10/1/95	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	1C	100	0.3	0.3	0.3	10/1/95	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	1D	100	0.3	0.3	0.3	10/1/95	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	1E	100	0.3	0.3	0.3	10/1/95	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	1F	100	0.3	0.3	0.3	10/1/95	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	1G	100	0.3	0.3	0.3	10/1/95	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	1H	100	0.3	0.3	0.3	10/1/95	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	1I	100	0.3	0.3	0.3	10/1/95	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	1J	100	0.3	0.3	0.3	10/1/95	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	1K	100	0.3	0.3	0.3	10/1/95	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	1L	100	0.3	0.3	0.3	10/1/95	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	1M	100	0.3	0.3	0.3	10/1/95	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	1N	100	0.3	0.3	0.3	10/1/95	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Rockville 1 & 2	1O	100	0.3	0.3	0.3	10/1/95	IC	DFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	1	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	10	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	11	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	12	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	13	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	14	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	15	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	16	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	17	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	18	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	19	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	2	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	20	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	21	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	22	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	23	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	24	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	25	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	26	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	27	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	28	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	29	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	3	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	30	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	31	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	32	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	33	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	34	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	35	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	36	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	4	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	5	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	6	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	7	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	8	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	INGENCO	INGENCO	INGENCO	Virginia Beach Landfill	9	100	0.3	0.3	0.3	11/1/01	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	1	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	10	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	11	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	12	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	13	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	14	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	15	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	16	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	17	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	18	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	19	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	2	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	20	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	21	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	22	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	23	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	24	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	25	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	26	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	27	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	28	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	29	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	3	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	30	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	31	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	32	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	33	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	34	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	35	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	36	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	37	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	38	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	39	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	4	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	40	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	41	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	42	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	43	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	44	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	45	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	46	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	47	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	48	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	5	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	6	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	7	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	8	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	APS	Allegheny Power				INGENCO	INGENCO	INGENCO	Mountain View (Greenc	9	100	0.3	0.3	0.3	3/15/03	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC1	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC10	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC11	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC12	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC13	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC14	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC15	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC16	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC17	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC18	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC2	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC3	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC4	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC5	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC6	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC7	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC8	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Newland Park Landfill	IC9	100	0.3	0.3	0.3	5/15/07	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC1	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC10	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC11	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC12	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC13	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC14	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC15	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC16	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC17	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC18	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC2	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC3	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC4	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC5	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC6	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC7	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC8	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	PPL	Pennsylvania Power & Light Com	5004/5005	AP South	INGENCO Wholesale Power I	INGENCO	INGENCO Wholesale Power LL	Pine Grove Landfill	IC9	100	0.3	0.3	0.3	2/1/08	IC	LFG	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	NRG Energy Center Dover	NRG Energy Inc	NRG Energy Center Dover	Dover Energy (NRG)	ST1	100	18	16	16	5/1/85	ST	BIT	Operating	Y	1
PJM ISO	DPL	Delmarva Power &	PJM East	5004/5005	AP South	NRG Energy Center Dover	NRG Energy Inc	NRG Energy Center Dover	Dover Energy (NRG)	GT2	100	50	44	50	6/1/01	GT	NG	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Schuylkill Generating St	IC1	100	2.7	2.7	2.7	7/1/67	IC	DFO	Operating	Y	1
PJM ISO	PECO	PECO Energy Comp	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Corp	Exelon Generation Co LLC	Schuylkill Generating St	1	100	190.4	166	175	7/1/58	ST	RFO	Operating	Y	1
PJM ISO	DOM	Virginia Power Company			AP South	Wythe Park Power Inc	INGENCO	Wythe Park Power Inc	WPP 1 Petersburg	1	100	3	3	3	11/1/89	IC	WO	Operating	Y	1
PJM ISO	AEP	American Electric Power				Ohio Power Co	American Electric Power C	Ohio Power Co	Conesville	3	100	161.5	165	165	10/1/62	ST	BIT	Operating	Y	1

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status	Grid Connected (Y/N)	Record Count
PJM ISO	COMED	Commonwealth Edison Co.				Illinois Electrical Generating	U S Energy Systems Inc	Illinois Electrical Generating Pa	Riverside Resource Rec	RO1	100	1.1	0.9	0.9	2/1/97	IC	LFG	Operating	Y	1
PJM ISO	COMED	Commonwealth Edison Co.				Klein Tools Inc	Klein Tools Inc	Klein Tools Inc	Klein Tools Inc Chicago	17	100	1.5	1.5	1.5	12/1/86	IC	DFO	Operating	Y	1
PJM ISO	DAY	Dayton Power & Light Co.				Dayton Power & Light Co (Th	AES Corp (The)	Dayton Power & Light Co (The	O H Hutchings	4	100	69	63	64	2/1/51	ST	BIT	Operating	Y	1

All Capacity

	Summer	Winter
PJM	190,181	198,482
PJM East	33,990	36,121
5004/5005	59,415	62,325
AP South	83,283	87,585

Mothballed

	Summer	Winter
PJM	172	176
PJM East	0	0
5004/5005	0	0
AP South	0	0

Standby

	Summer	Winter
PJM	3,471	3,988
PJM East	1,286	1,465
5004/5005	1,896	2,127
AP South	2,268	2,516

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Backup - PJM Additions

Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	OCI Solar P	OCI Compa	Cornerston	Cornerstone Power Vinela	PV1	100	3.714	3	3	3/12/12	PV	SUN	Operating
PJM ISO	AECO	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Heller Indu	Heller Indu	Heller Indu	Heller Industrial Parks	UNIT1	100	2.7	2.7	2.7	12/1/11	PV	SUN	Operating
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Vineland N	Vineland N	Vineland N	Howard M Down	11	100	68.2	56.2	64	6/1/12	GT	NG	Operating
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	KDC Solar A	KDC Solar L	Advanced E	KDC Solar ACF	PV1	100	2.2	2.2	2.2	5/1/12	PV	SUN	Operating
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	KDC Solar (	KDC Solar L	KDC Solar (	KDC Solar G Glass	PV1	100	2.3	2.3	2.3	9/17/12	PV	SUN	Operating
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	McKee City	McKee City	Marina Ene	McKee City Solar	PV2	100	2.6	2.6	2.6	12/1/11	PV	SUN	Operating
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Pepco Ener	Pepco Holc	Pepco Ener	Midtown Thermal Control	GT1	100	5.5	5.5	5.5	12/31/11	GT	NG	Operating
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	NJ Oak Sola	Lincoln Rer	NJ Oak Sola	NJ Oak Solar	PV1	100	10	10	10	12/29/11	PV	SUN	Operating
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Nautilus Sc	Nautilus En	Nautilus Sc	Raymour Solar Project	PV1	100	1.115	1.078	1.078	6/30/12	PV	SUN	Operating
PJM ISO	DPL	Delmarva Power & Light Company	PJM East	5004/5005	AP South	Diamond S	Bloom Ene	Diamond S	Brookside Fuel Cell	FC1	100	1.5	1.5	1.5	6/18/12	FC	NG	Operating
PJM ISO	DPL	Delmarva Power & Light Company	PJM East	5004/5005	AP South	Diamond S	Bloom Ene	Diamond S	Brookside Fuel Cell	FC2	100	1.5	1.5	1.5	6/18/12	FC	NG	Operating
PJM ISO	DPL	Delmarva Power & Light Company	PJM East	5004/5005	AP South	Washingto	WGL Holdi	Washingto	Kent County Kennedyville	PVKV	100	1	1	1	1/1/12	PV	SUN	Operating
PJM ISO	DPL	Delmarva Power & Light Company	PJM East	5004/5005	AP South	Washingto	WGL Holdi	Washingto	Kent County Solar	PV1	100	1.579	1.579	1.579	7/10/12	PV	SUN	Operating
PJM ISO	DPL	Delmarva Power & Light Company	PJM East	5004/5005	AP South	Washingto	WGL Holdi	Washingto	Kent County Worton Com	WRTN	100	1	1	1	1/1/12	PV	SUN	Operating
PJM ISO	DPL	Delmarva Power & Light Company	PJM East	5004/5005	AP South	Delaware N	Delaware N	Delaware N	Warren F Sam Beasley Ge	GT2	100	51	50	50	6/7/12	GT	NG	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	12 Applega	Sunray Pov	Sunray Pov	12 Applegate Solar	PV1	100	1.913	1.56	1.56	4/12/12	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	24 Applega	Sunray Pov	Sunray Pov	24 Applegate Solar	PV1	100	4.939	3.842	3.842	3/1/12	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	4 Applegat	Sunray Pov	Sunray Pov	4 Applegate Solar	PV1	100	1.781	1.4	1.4	4/12/12	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	Flemingtor	Consolidat	Consolidat	Daisy Solar Farm	PV1	100	8	7.9	7.9	12/31/11	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	Maurice Sc	Maurice Sc	Maurice Sc	Denville Solar Energy Farr	PV1	100	2	2	2	12/1/11	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	Flemingtor	Consolidat	Consolidat	DeSapio No 1 Solar Farm	PV1	100	3	3	3	12/31/11	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	Frenchtow	Consolidat	Consolidat	Frenchtown I Solar	PV1	100	3	3	3	1/1/12	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	ISH Solar C	Duke Energ	ISH Solar C	ISH Solar Central	PV1	100	1.4	1.4	1.4	1/18/12	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	Jacobtown	Jacobtown	Jacobtown	Jacobstown Solar Farm	PV1	100	7	7	7	12/31/11	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	Lakewood	Sunray Pov	Sunray Pov	Lakewood Seven Solar	PV1	100	1.007	0.815	0.815	3/30/12	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	Lebanon Sc	Consolidat	Consolidat	Lebanon Solar	PV1	100	2	2	2	12/31/11	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	NJR Clean E	New Jersey	NJR Clean E	McGraw Hill Solar	1 PV	100	12.6	16.6	8.3	12/1/11	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	Parlin Sola	Tangent En	Tangent En	Parlin Solar	PV1	100	1.3	1.25	1.25	10/24/12	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	PPL Renew	PPL Corp	PPL Renew	PPL Solar	GEN 1	100	0.5	0.5	0.5	6/1/12	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	PPL Renew	PPL Corp	PPL Renew	PPL Solar	GEN 2	100	0.5	0.5	0.5	6/1/12	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	PPL Renew	PPL Corp	PPL Renew	PPL Solar	GEN 3	100	0.5	0.5	0.5	6/1/12	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	PPL Renew	PPL Corp	PPL Renew	PPL Solar	GEN 4	100	0.5	0.5	0.5	6/1/12	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	Zongyi Sola	Zongyi Sola	Zongyi Sola	Tinton Falls Solar Farm	PV1	100	20	20	20	9/10/12	PV	SUN	Operating
PJM ISO	JCPL	Jersey Central Power & Light Compa	PJM East	5004/5005	AP South	United Par	United Par	United Par	UPS Parsippany Solar	PV1	100	1.2	1.2	1.2	10/1/12	PV	SUN	Operating
PJM ISO	PECO	PECO Energy Company	PJM East	5004/5005	AP South	Aqua Penn	Aqua Amer	Aqua Penn	Aqua Pennsylvania Pickeri	PV1	100	1.8	1.8	1.8	4/13/12	PV	SUN	Operating
PJM ISO	PECO	PECO Energy Company	PJM East	5004/5005	AP South	IKEA Group	Ikea Systen	IKEA Group	IKEA Solar Conshohocken	PV1	100	1.201	1.201	1.201	12/13/11	PV	SUN	Operating

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Backup - PJM Additions

Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status
PJM ISO	PECO	PECO Energy Company	PJM East	5004/5005	AP South	IKEA Group	Ikea Systen	IKEA Group	IKEA Solar Philadelphia	PV1	100	1.002	1.002	1.002	12/13/11	PV	SUN	Operating
PJM ISO	PECO	PECO Energy Company	PJM East	5004/5005	AP South	Visteon Sys	Visteon Co	Visteon Sys	Morris Road	IC1	100	2	2	2	5/1/12	IC	DSL	Operating
PJM ISO	PECO	PECO Energy Company	PJM East	5004/5005	AP South	Visteon Sys	Visteon Co	Visteon Sys	Morris Road	IC2	100	2	2	2	5/1/12	IC	DSL	Operating
PJM ISO	PECO	PECO Energy Company	PJM East	5004/5005	AP South	Visteon Sys	Visteon Co	Visteon Sys	Morris Road	IC3	100	2	2	2	5/1/12	IC	DSL	Operating
PJM ISO	PECO	PECO Energy Company	PJM East	5004/5005	AP South	Visteon Sys	Visteon Co	Visteon Sys	Morris Road	IC4	100	2	2	2	5/1/12	IC	DSL	Operating
PJM ISO	PECO	PECO Energy Company	PJM East	5004/5005	AP South	Visteon Sys	Visteon Co	Visteon Sys	Morris Road	IC5	100	2	2	2	5/1/12	IC	DSL	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	180 Energy	180 Energy	180 Raritar	180 Raritan Center Solar	PV1	100	2.3	2.3	2.3	6/7/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Bayonne M	Bayonne M	Bayonne M	Bayonne Wind Energy Prc	WT1	100	1.5	1.5	1.5	8/2/12	WT	WND	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Public Serv	Public Serv	Public Serv	BlackRock Matrix Roof So	PV1	100	2.5	2.5	2.5	4/2/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	SunPower (	TOTAL SA	SunPower (	Bloomberg Solar Farm	PV1	100	1.8	1.8	1.8	6/18/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Camden Sc	Integrys En	Camden Sc	Camden Solar Center	PV1	100	1.5	1.399	1.399	6/15/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	E J Energy	E J Electric	E J Energy	E J Energy Solar	PV1	100	2.9	2.9	2.9	12/31/11	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Public Serv	Public Serv	Public Serv	Food Bank Solar Project	PV1	100	1.02	1.02	1.02	9/30/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Global Pha	Global Pha	Global Pha	Global Pharma Co Solar Fa	PV1	100	1.7	1.7	1.7	3/26/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Hartz Solar	Hartz Mou	Hartz Solar	Hamilton Solar Project	PV1	100	8.454	7.674	7.674	3/31/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Hartz Solar	Hartz Mou	Hartz Solar	Hartz Solar Westside Ave	PV1	100	1.051	1.051	1.051	10/31/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	CGN Solar	CGN Solar	Sedc Jersey	Jersey Gardens Mall Roofl	PV1	50	0.998	0.864	0.864	12/21/11	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	CGN Solar	CGN Solar	Sedc Jersey	Jersey Gardens Mall Roofl	PV2	50	1.405	1.405	1.405	2/3/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Sedc Jersey	Sedc Jersey	Sedc Jersey	Jersey Gardens Mall Roofl	PV1	50	0.998	0.864	0.864	12/21/11	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Sedc Jersey	Sedc Jersey	Sedc Jersey	Jersey Gardens Mall Roofl	PV2	50	1.405	1.405	1.405	2/3/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	KDC Solar I	KDC Solar L	Ray Angelir	KDC Solar WS	PV1	100	4.2	3.6	3.6	12/20/11	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	PSEG Fossi	Public Serv	PSEG Fossi	Kearny Generating Statior	GT12	100	44.5	44.5	44.5	6/1/12	GT	NG	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	PSEG Fossi	Public Serv	PSEG Fossi	Kearny Generating Statior	GT13	100	44.5	44.5	44.5	6/1/12	GT	NG	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	PSEG Fossi	Public Serv	PSEG Fossi	Kearny Generating Statior	GT14	100	44.5	44.5	44.5	6/1/12	GT	NG	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	PSEG Fossi	Public Serv	PSEG Fossi	Kearny Generating Statior	GT15	100	44.5	44.5	44.5	6/1/12	GT	NG	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	PSEG Fossi	Public Serv	PSEG Fossi	Kearny Generating Statior	GT16	100	44.5	44.5	44.5	6/1/12	GT	NG	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	PSEG Fossi	Public Serv	PSEG Fossi	Kearny Generating Statior	GT17	100	44.5	44.5	44.5	6/1/12	GT	NG	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	KDC Solar I	KDC Solar L	Advanced I	Lawrenceville School Sola	PV1	100	5.2	5.2	5.2	5/4/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Loreal USA	Loréal SA	Loreal USA	Loreal Piscataway	UNIT 1	100	1	1	1	12/1/11	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Enfinity Am	Enfinity Am	Enfinity Am	Macys Distribution Center	PV1	100	1.1	1.1	1.1	6/6/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	New Jersey	New Jersey	New Jersey	Meadowlands Solar	PV2	100	3	3	3	5/8/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Frit Solar L	Federal Rea	Frit Solar L	Mercer Mall	1	100	1.1	1.1	1.1	1/1/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	CleanLight	Cleanlight I	CleanLight	Mt Laurel Solar Facility	PV1	100	2.5	2.474	2.474	12/31/11	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Red Burling	Recycled E	Red Burling	National Gypsum CHP	GT1	100	3.4	3.4	3.4	11/14/12	GT	NG	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Public Serv	Public Serv	Public Serv	NJMC Landfill 1A	PV1	100	2.5	2.5	2.5	12/1/11	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	NRG Energ	NRG Energ	NRG Energ	NRG Energy Center Prince	GT1	100	4.6	4.286	4.286	5/16/12	GT	NG	Operating

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Backup - PJM Additions

Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Key Goverr	Keycorp	Princeton U	Princeton University West	PV1	100	4	4	4	10/15/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Earl F Stahl	Earl F Stahl	Earl F Stahl	Reeves Station Road Sola	PV1	100	5.5	5.5	5.5	9/30/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Rutgers Un	Rutgers Un	Rutgers Un	Rutgers University Solar F	PV1	100	1.4	1.4	1.4	3/26/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Public Serv	Public Serv	Public Serv	Summit Associates Solar	PV1	100	1.9	1.9	1.9	12/1/11	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Public Serv	Public Serv	Public Serv	Thorofare Solar Farm	PV1	100	1.5	1.5	1.5	12/28/11	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Nautilus Sc	Nautilus En	Nautilus Sc	Wayne BOE Solar	PV1	100	3.159	3.159	3.159	12/1/11	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Wayne Sol	Wanye Sol	Wayne Sol	Wayne Solar Center	PV1	100	1	0.94	0.94	4/6/12	PV	SUN	Operating
PJM ISO	PSEG	Public Service Electric & Gas Compa	PJM East	5004/5005	AP South	Nautilus Sc	Nautilus En	Nautilus Sc	William Paterson Univ Sol	PV2	100	0.8	0.8	0.8	6/21/12	PV	SUN	Operating
PJM ISO	BGE	Baltimore Gas & Electric Company		5004/5005	AP South	Pepco Ener	Pepco Holc	Pepco Ener	Alpha Ridge Landfill	IC1	100	1	1	1	6/29/12	IC	LFG	Operating
PJM ISO	BGE	Baltimore Gas & Electric Company		5004/5005	AP South	Baltimore (	Baltimore (	Baltimore (	Back River Wastewater Sc	PV1	100	1	1	1	4/24/12	PV	SUN	Operating
PJM ISO	BGE	Baltimore Gas & Electric Company		5004/5005	AP South	les Operati	Energy Inve	les Operati	Millersville LFG	CAT1	100	1.6	1.5	1.5	1/1/12	IC	LFG	Operating
PJM ISO	BGE	Baltimore Gas & Electric Company		5004/5005	AP South	les Operati	Energy Inve	les Operati	Millersville LFG	CAT2	100	1.6	1.5	1.5	1/1/12	IC	LFG	Operating
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	SMECO Sol	Southern N	NVT Licens	Herbert Farm Solar	PV1	100	5.5	5.5	5.5	11/18/12	PV	SUN	Operating
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	IKEA Group	Ikea Systen	IKEA Group	IKEA Solar College Park	PV1	100	1.185	1.185	1.185	2/15/12	PV	SUN	Operating
PJM ISO	PPL	Pennsylvania Power & Light Company		5004/5005	AP South	Dart Conta	Dart Conta	Dart Conta	Dart Container LFG	GT1	100	7	7	7	12/13/11	GT	LFG	Operating
PJM ISO	PPL	Pennsylvania Power & Light Company		5004/5005	AP South	Dart Conta	Dart Conta	Dart Conta	Dart Container LFG	GT2	100	7	7	7	12/13/11	GT	LFG	Operating
PJM ISO	PPL	Pennsylvania Power & Light Company		5004/5005	AP South	Keystone S	Iberdrola S	Keystone S	Keystone Solar	PV1	100	5	4.9	4.9	9/17/12	PV	SUN	Operating
PJM ISO	PPL	Pennsylvania Power & Light Company		5004/5005	AP South	Hudson En	Just Energy	Hudson En	Moravian Acadamey Sola	PV1	100	1.083	1.045	1.045	11/9/12	PV	SUN	Operating
PJM ISO	PPL	Pennsylvania Power & Light Company		5004/5005	AP South	PA Solar Pa	PA Solar Pa	PA Solar Pa	PA Solar Park	PV1	100	10.1	10	10	10/1/12	PV	SUN	Operating
PJM ISO	DOM	Virginia Power Company			AP South	DuPont Fal	E I DuPont	DuPont Fal	Ashburn Corporate Cente	ACC6II	100	13	13	13	6/21/12	IC	DSL	Operating
PJM ISO	DOM	Virginia Power Company			AP South	Elizabeth C	Elizabeth C	Elizabeth C	ECSU Generators	GT1	100	1.36	1.25	1.25	1/31/12	GT	FO2	Operating
PJM ISO	DOM	Virginia Power Company			AP South	Elizabeth C	Elizabeth C	Elizabeth C	ECSU Generators	GT2	100	1.36	1.25	1.25	1/31/12	GT	FO2	Operating
PJM ISO	DOM	Virginia Power Company			AP South	Solar Star N	Duke Energ	Solar Star N	North Carolina Solar Star I	PV1	100	1.3	1	1	12/31/11	PV	SUN	Operating
PJM ISO	DOM	Virginia Power Company			AP South	Solar Star N	Duke Energ	Solar Star N	North Carolina Solar Star I	PV2	100	1.3	1	1	12/31/11	PV	SUN	Operating
PJM ISO	DOM	Virginia Power Company			AP South	Solar Star N	Duke Energ	Solar Star N	North Carolina Solar Star I	PV3	100	1.3	1	1	12/31/11	PV	SUN	Operating
PJM ISO	DOM	Virginia Power Company			AP South	Solar Star N	Duke Energ	Solar Star N	North Carolina Solar Star I	PV4	100	1.3	1	1	12/31/11	PV	SUN	Operating
PJM ISO	DOM	Virginia Power Company			AP South	Solar Star N	Duke Energ	Solar Star N	North Carolina Solar Star I	PV5	100	1.3	1	1	12/31/11	PV	SUN	Operating
PJM ISO	DOM	Virginia Power Company			AP South	Richmond	FORTISTAR	Richmond	Old Dominion Landfill Pro	IC1	100	1.6	1.6	1.6	1/4/12	IC	LFG	Operating
PJM ISO	DOM	Virginia Power Company			AP South	Richmond	FORTISTAR	Richmond	Old Dominion Landfill Pro	IC2	100	1.6	1.6	1.6	1/4/12	IC	LFG	Operating
PJM ISO	DOM	Virginia Power Company			AP South	Richmond	FORTISTAR	Richmond	Old Dominion Landfill Pro	IC3	100	1.6	1.6	1.6	1/4/12	IC	LFG	Operating
PJM ISO	DOM	Virginia Power Company			AP South	Richmond	FORTISTAR	Richmond	Old Dominion Landfill Pro	IC4	100	1.6	1.6	1.6	1/4/12	IC	LFG	Operating
PJM ISO	DOM	Virginia Power Company			AP South	Plymouth S	Plymouth S	Plymouth S	Plymouth Solar	PV1	100	2.4	1.992	1.992	12/31/11	PV	SUN	Operating
PJM ISO	AEP	American Electric Power				Blue Creek	Iberdrola S	Blue Creek	Blue Creek Wind Farm (OI	WT1 64	100	128	128	128	12/21/11	WT	WND	Operating
PJM ISO	AEP	American Electric Power				Blue Creek	Iberdrola S	Blue Creek	Blue Creek Wind Farm (OI	WT65 152	100	176	176	176	3/5/12	WT	WND	Operating
PJM ISO	AEP	American Electric Power				Charleston	Sindicatum	Charleston	Charleston Landfill	IC 3	100	1.06	1	1	4/28/12	IC	LFG	Operating
PJM ISO	AEP	American Electric Power				Third Sun S	Third Sun S	Third Sun S	Columbus Zoo Solar	PV1	100	3.9	3.9	3.9	8/6/12	PV	SUN	Operating

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Backup - PJM Additions

Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status
PJM ISO	AEP	American Electric Power				Cooper Far	Cooper Far	Cooper Far	Cooper Farms Wind	WT1	100	1.5	1.5	1.5	3/1/12	WT	WND	Operating
PJM ISO	AEP	American Electric Power				Cooper Far	Cooper Far	Cooper Far	Cooper Farms Wind	WT2	100	1.5	1.5	1.5	3/1/12	WT	WND	Operating
PJM ISO	AEP	American Electric Power				Appalachia	American E	AEP Gener	Dresden Energy Facility	CC	100	678.3	540	625	2/1/12	CC	NG	Operating
PJM ISO	AEP	American Electric Power				Haviland Pl	Haviland Pl	Haviland Pl	Haviland Plastic Products	GT1	100	1	1	1	4/1/12	GT	OBG	Operating
PJM ISO	AEP	American Electric Power				Haviland Pl	Haviland Pl	Haviland Pl	Haviland Plastic Products	WT1	100	1.5	1.5	1.5	9/1/12	WT	WND	Operating
PJM ISO	AEP	American Electric Power				Haviland Pl	Haviland Pl	Haviland Pl	Haviland Plastic Products	WT2	100	1.5	1.5	1.5	9/1/12	WT	WND	Operating
PJM ISO	AEP	American Electric Power				Haviland Pl	Haviland Pl	Haviland Pl	Haviland Plastic Products	WT3	100	1.5	1.5	1.5	9/1/12	WT	WND	Operating
PJM ISO	AEP	American Electric Power				Martinsvill	Martinsvill	Martinsvill	Martinsville Landfill	IC1	100	1.06	1.06	1.06	2/29/12	IC	LFG	Operating
PJM ISO	AEP	American Electric Power				Quasar Ene	Quasar Ene	Quasar Ene	Quasar Energy	GT1	100	0.91	0.91	0.91	4/20/12	GT	MTE	Operating
PJM ISO	AEP	American Electric Power				Waste Mar	Waste Mar	Waste Mar	Suburban Landfill	IC8	100	0.8	0.8	0.8	2/12/12	IC	LFG	Operating
PJM ISO	AEP	American Electric Power				Virginia Ele	Dominion I	Virginia Ele	Virginia City Hybrid Energ	CFB	100	668	600	614	7/11/12	AB	BIT	Operating
PJM ISO	APS	Allegheny Power				Longview F	Genpower	Longview F	Longview Power	AB1	100	807.5	700	700	1/3/12	ST	BIT	Operating
PJM ISO	APS	Allegheny Power				Constellati	Exelon Cor	Constellati	Mount St Marys Universit	PV1	100	0.3	0.3	0.3	4/25/12	PV	SUN	Operating
PJM ISO	APS	Allegheny Power				Constellati	Exelon Cor	Constellati	Mount St Marys Universit	PV3	100	13.7	13.7	13.7	8/30/12	PV	SUN	Operating
PJM ISO	APS	Allegheny Power				Constellati	Exelon Cor	Constellati	Mount St Marys Universit	PV2	100	1.675	1.675	1.675	4/25/12	PV	SUN	Operating
PJM ISO	APS	Allegheny Power				Pinnacle W	Edison Inte	Pinnacle W	Pinnacle Wind	WT1 23	100	55.2	55.2	55.2	1/23/12	WT	WND	Operating
PJM ISO	APS	Allegheny Power				South Ches	Iberdrola S	South Ches	South Chestnut Ridge Wir	WT1 22	100	46.2	46.2	46.2	12/1/11	WT	WND	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Enfinity BN	BNB Renev	Enfinity BN	BNB Napoleon Solar	PV1	100	8	8	8	12/1/11	PV	SUN	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Bryan Mun	Bryan OH (	Rudolph/Li	Bryan Solar Array	PV1	100	2.1	1.7	1.7	1/17/12	PV	SUN	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Oregon OH	Oregon OH	Oregon OH	Clay High School Wind	WT1	100	0.75	0.75	0.75	10/5/12	WT	WND	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Oregon OH	Oregon OH	Oregon OH	Clay High School Wind	WT2	100	0.75	0.75	0.75	10/5/12	WT	WND	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Solscient E	Solscient E	Solscient E	General Motors Toledo Tr	PV1	100	0.6	0.6	0.6	3/11/12	PV	SUN	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Solscient E	Solscient E	Solscient E	General Motors Toledo Tr	PV2	100	0.6	0.6	0.6	11/15/12	PV	SUN	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Solscient E	Solscient E	Solscient E	General Motors Toledo Tr	PV3	100	0.6	0.6	0.6	11/30/12	PV	SUN	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Akron (City	Akron (City	Akron (City	Hardy Road Landfill	IC1	100	1	1	1	11/21/12	IC	LFG	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Energy Dev	Energy Dev	Energy Dev	Lowellville	IC17	100	1.6	1.6	1.6	1/1/12	IC	LFG	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Energy Dev	Energy Dev	Energy Dev	Lowellville	IC18	100	1.6	1.6	1.6	1/1/12	IC	LFG	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Energy Dev	Energy Dev	Energy Dev	Oberlin Landfill	10	100	1.6	1.6	1.6	11/1/12	IC	LFG	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Energy Dev	Energy Dev	Energy Dev	Oberlin Landfill	11	100	1.6	1.6	1.6	11/1/12	IC	LFG	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Energy Dev	Energy Dev	Energy Dev	Oberlin Landfill	12	100	1.6	1.6	1.6	11/1/12	IC	LFG	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Energy Dev	Energy Dev	Energy Dev	Oberlin Landfill	13	100	1.6	1.6	1.6	11/1/12	IC	LFG	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Energy Dev	Energy Dev	Energy Dev	Oberlin Landfill	14	100	1.6	1.6	1.6	11/1/12	IC	LFG	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Energy Dev	Energy Dev	Energy Dev	Oberlin Landfill	15	100	1.6	1.6	1.6	11/1/12	IC	LFG	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Energy Dev	Energy Dev	Energy Dev	Oberlin Landfill	16	100	1.6	1.6	1.6	11/1/12	IC	LFG	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Energy Dev	Energy Dev	Energy Dev	Oberlin Landfill	17	100	1.6	1.6	1.6	11/1/12	IC	LFG	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Energy Dev	Energy Dev	Energy Dev	Oberlin Landfill	18	100	1.6	1.6	1.6	11/1/12	IC	LFG	Operating

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Backup - PJM Additions

Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status
PJM ISO	ATSI	FirstEnergy ATSI				Energy Dev	Energy Dev	Energy Dev	Oberlin Landfill	9	100	1.6	1.6	1.6	11/1/12	IC	LFG	Operating
PJM ISO	ATSI	FirstEnergy ATSI				Oberlin Spe	Oberlin Spe	Oberlin Spe	Oberlin Spear Point Solar	OSSO	100	2	2	2	11/1/12	PV	SUN	Operating
PJM ISO	ATSI	FirstEnergy ATSI				William So	William So	William So	Sopko Wind	WT1	100	0.225	0.225	0.225	3/1/12	WT	WND	Operating
PJM ISO	COMED	Commonwealth Edison Co.				Bishop Hill	Invenergy I	Invenergy I	Bishop Hill Wind Energy C	WT1 99	100	200	200	200	7/9/12	WT	WND	Operating
PJM ISO	COMED	Commonwealth Edison Co.				Bishop Hill	Invenergy I	Invenergy I	Bishop Hill Wind Energy C	WT100 133	100	51	51	51	7/9/12	WT	WND	Operating
PJM ISO	COMED	Commonwealth Edison Co.				Invenergy I	Invenergy I	Invenergy I	Grand Ridge Solar Farm	PV	100	20	20	20	7/1/12	PV	SUN	Operating
PJM ISO	COMED	Commonwealth Edison Co.				GSG 6 LLC	GSG Wind	GSG 6 LLC	GSG 6 Wind	WT1	100	2.5	2.5	2.5	5/31/12	WT	WND	Operating
PJM ISO	COMED	Commonwealth Edison Co.				Illinois Elec	U S Energy	Illinois Elec	Morris	MO4	100	1.1	1	1	2/1/12	IC	LFG	Operating
PJM ISO	COMED	Commonwealth Edison Co.				Illinois Elec	U S Energy	Illinois Elec	Morris	MO5	100	1.1	1	1	2/1/12	IC	LFG	Operating
PJM ISO	COMED	Commonwealth Edison Co.				Will County	Will County	Waste Mar	Prairie View Landfill	IC1	100	1.6	1.6	1.6	12/22/11	IC	LFG	Operating
PJM ISO	COMED	Commonwealth Edison Co.				Will County	Will County	Waste Mar	Prairie View Landfill	IC2	100	1.6	1.6	1.6	12/22/11	IC	LFG	Operating
PJM ISO	COMED	Commonwealth Edison Co.				Will County	Will County	Waste Mar	Prairie View Landfill	IC3	100	1.6	1.6	1.6	12/22/11	IC	LFG	Operating
PJM ISO	COMED	Commonwealth Edison Co.				Rochelle En	Charles J H	Rochelle En	Rochelle Energy Center	REC1	100	1.6	1.6	1.6	12/1/11	IC	LFG	Operating
PJM ISO	COMED	Commonwealth Edison Co.				Rochelle En	Charles J H	Rochelle En	Rochelle Energy Center	REC2	100	1.6	1.6	1.6	12/1/11	IC	LFG	Operating
PJM ISO	COMED	Commonwealth Edison Co.				Rochelle En	Charles J H	Rochelle En	Rochelle Energy Center	REC3	100	1.6	1.6	1.6	12/1/11	IC	LFG	Operating
PJM ISO	COMED	Commonwealth Edison Co.				Rockford S	New Gener	Rockford So	Rockford Solar Project	PV1	100	3.06	2.922	2.922	10/31/12	PV	SUN	Operating
PJM ISO	COMED	Commonwealth Edison Co.				Algonquin	Algonquin	GSG LLC	Shady Oaks Wind Farm	WT109 111	100	7.5	7.5	7.5	6/1/12	WT	WND	Operating
PJM ISO	COMED	Commonwealth Edison Co.				Algonquin	Algonquin	GSG LLC	Shady Oaks Wind Farm	WT41 108	100	102	102	102	6/1/12	WT	WND	Operating
PJM ISO	DEOK	Duke Energy Ohio				IKEA Group	Ikea Syster	IKEA Group	IKEA Solar West Chester	PV1	100	1.024	1.024	1.024	1/24/12	PV	SUN	Operating
PJM ISO	DEOK	Duke Energy Ohio				Middletow	SunCoke En	Middletow	SunCoke Energy Project	ST	100	67	47	47	12/14/11	ST	WH	Operating
PJM ISO	METED	Jersey Central Power & Light Company				PPL Corp	PPL Corp	PPL Corp	Crayola Solar Park	PV2	50	0.4	0.4	0.4	2/1/12	PV	SUN	Operating
PJM ISO	METED	Jersey Central Power & Light Company				PPL Corp	PPL Corp	PPL Corp	Crayola Solar Park	PV3	50	0.4	0.4	0.4	2/1/12	PV	SUN	Operating
PJM ISO	METED	Jersey Central Power & Light Company				UGI Energy	UGI Corp	PPL Corp	Crayola Solar Park	PV2	50	0.4	0.4	0.4	2/1/12	PV	SUN	Operating
PJM ISO	METED	Jersey Central Power & Light Company				UGI Energy	UGI Corp	PPL Corp	Crayola Solar Park	PV3	50	0.4	0.4	0.4	2/1/12	PV	SUN	Operating
PJM ISO	PENELEC	Pennsylvania Power & Light Company				PPL Renew	PPL Corp	Lycoming C	Allentown LFG Project	IC3	100	1.6	1.6	1.6	10/1/12	IC	LFG	Operating
PJM ISO	PENELEC	Pennsylvania Power & Light Company				PPL Renew	PPL Corp	Lycoming C	Allentown LFG Project	IC4	100	1.6	1.6	1.6	10/1/12	IC	LFG	Operating
PJM ISO	PENELEC	Pennsylvania Electric Company				Chestnut F	EDF Group	Chestnut F	Chestnut Flats Wind Farm	WT1 18	100	36	36	36	12/29/11	WT	WND	Operating
PJM ISO	PENELEC	Pennsylvania Electric Company				Chestnut F	EDF Group	Chestnut F	Chestnut Flats Wind Farm	WT19	100	2	2	2	12/29/11	WT	WND	Operating
PJM ISO	PENELEC	Pennsylvania Electric Company				Highland N	Terra Firma	Highland N	Highland North Wind	WT1 30	100	75	75	75	4/6/12	WT	WND	Operating
PJM ISO	PENELEC	Pennsylvania Electric Company				Laurel Hill	Duke Energ	Laurel Hill	Laurel Hill Wind Farm	WT1 30	100	69	69	69	9/1/12	WT	WND	Operating
PJM ISO	PENELEC	Pennsylvania Power & Light Company				PPL Renew	PPL Corp	PPL Renew	Lycoming County LFG	IC1	100	1.5	1.5	1.5	10/1/12	IC	LFG	Operating
PJM ISO	PENELEC	Pennsylvania Power & Light Company				PPL Renew	PPL Corp	PPL Renew	Lycoming County LFG	IC2	100	1.5	1.5	1.5	10/1/12	IC	LFG	Operating
PJM ISO	PENELEC	Pennsylvania Electric Company				Sandy Ridg	Algonquin	Sandy Ridg	Sandy Ridge Wind Farm	WT1 25	100	50	50	50	2/29/12	WT	WND	Operating
PJM ISO	PENELEC	Pennsylvania Electric Company				Pennsylvar	Pennsylvar	Pennsylvar	SCI Laurel Highlands	CC1	100	3.757	3.757	3.757	7/20/12	CC	LFG	Operating
PJM ISO	PENELEC	Pennsylvania Electric Company				Pennsylvar	Pennsylvar	Pennsylvar	SCI Laurel Highlands	IC1	100	1.6	1.6	1.6	7/20/12	IC	LFG	Operating
PJM ISO	PENELEC	Pennsylvania Electric Company				Pennsylvar	Pennsylvar	Pennsylvar	SCI Laurel Highlands	IC2	100	1.6	1.6	1.6	7/20/12	IC	LFG	Operating

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Backup - PJM Additions

Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Holding Company Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Commercial Online Date	Prime Mover Code	Primary Fuel Code	Unit Status

	Winter	Spring	Summer
PJM	1,030	2,095	3,097
PJM East	64	111	530
5004/5005	78	129	550
AP South	88	145	577

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PJM ISO	PECO	PECO Energy Company	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Generation Co LLC	Eddystone Generating Statio	2	100	353.6	309	311	ST	BIT	Retired	10/1/60	5/31/12
PJM ISO	PPL	Pennsylvania Power & Light	PJM East	5004/5005	AP South	Viking Energy of Northumbe	Viking Energy of Northumberl	Viking Energy Northumberla	GEN1	100	18	16	16	ST	WDS	Retired	11/1/88	3/31/12
PJM ISO	PSEG	Public Service Electric & Gas	PJM East	5004/5005	AP South	PSEG Fossil LLC	PSEG Fossil LLC	Kearny Generating Station	10	100	146.2	122	122	GT	NG	Retired	5/1/70	6/1/12
PJM ISO	PSEG	Public Service Electric & Gas	PJM East	5004/5005	AP South	PSEG Fossil LLC	PSEG Fossil LLC	Kearny Generating Station	11	100	146.2	128	128	GT	NG	Retired	12/1/69	6/1/12
PJM ISO	AECO	Atlantic Electric	PJM East	5004/5005	AP South	Vineland NJ (City of)	Vineland NJ (City of)	Howard M Down	10	100	25	23	23	ST	RFO	Retired	5/1/70	9/1/12
PJM ISO	APS	Allegheny Power		5004/5005	AP South	Allegheny Energy Supply Co	Allegheny Energy Supply Co LL	R Paul Smith Power Station	11	100	75	87	88	ST	BIT	Retired	11/1/58	9/1/12
PJM ISO	APS	Allegheny Power		5004/5005	AP South	Allegheny Energy Supply Co	Allegheny Energy Supply Co LL	R Paul Smith Power Station	9	100	34.5	28	28	ST	BIT	Retired	10/1/47	9/1/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Benning	15	100	290	275	275	ST	DFO	Retired	6/1/68	7/17/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Benning	16	100	290	275	275	ST	DFO	Retired	5/1/72	7/17/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Buzzard Point	E1	100	18	16	16	GT	DFO	Retired	5/1/68	5/31/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Buzzard Point	E2	100	18	16	16	GT	DFO	Retired	5/1/68	5/31/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Buzzard Point	E4	100	18	16	16	GT	DFO	Retired	5/1/68	5/31/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Buzzard Point	E5	100	18	16	16	GT	DFO	Retired	5/1/68	5/31/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Buzzard Point	E6	100	18	16	16	GT	DFO	Retired	5/1/68	5/31/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Buzzard Point	E7	100	18	16	16	GT	DFO	Retired	5/1/68	5/31/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Buzzard Point	E8	100	18	16	16	GT	DFO	Retired	5/1/68	5/31/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Buzzard Point	W10	100	18	16	16	GT	DFO	Retired	6/1/68	5/31/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Buzzard Point	W11	100	18	16	16	GT	DFO	Retired	6/1/68	5/31/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Buzzard Point	W12	100	18	16	16	GT	DFO	Retired	6/1/68	5/31/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Buzzard Point	W13	100	18	16	16	GT	DFO	Retired	6/1/68	5/31/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Buzzard Point	W14	100	18	16	16	GT	DFO	Retired	6/1/68	5/31/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Buzzard Point	W15	100	18	16	16	GT	DFO	Retired	6/1/68	5/31/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Buzzard Point	W16	100	18	16	16	GT	DFO	Retired	6/1/68	5/31/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	Potomac Power Resources	Potomac Power Resources	Buzzard Point	W9	100	18	16	16	GT	DFO	Retired	6/1/68	5/31/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	NRG Potomac River LLC	NRG Potomac River LLC	Potomac River	1	100	92	88	88	ST	BIT	Retired	9/1/49	10/1/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	NRG Potomac River LLC	NRG Potomac River LLC	Potomac River	2	100	92	88	88	ST	BIT	Retired	6/1/50	10/1/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	NRG Potomac River LLC	NRG Potomac River LLC	Potomac River	3	100	110	102	102	ST	BIT	Retired	6/1/54	10/1/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	NRG Potomac River LLC	NRG Potomac River LLC	Potomac River	4	100	110	102	102	ST	BIT	Retired	2/1/56	10/1/12
PJM ISO	PEPCO	Potomac Electric Power Company		5004/5005	AP South	NRG Potomac River LLC	NRG Potomac River LLC	Potomac River	5	100	110	102	102	ST	BIT	Retired	5/1/57	10/1/12
PJM ISO	BGE	Baltimore Gas & Electric Company		5004/5005	AP South	ISG Sparrows Point Inc	ISG Sparrows Point Inc	Sparrows Point	GEN1	100	30	38	38	ST	BFG	Retired	1/1/49	6/30/12
PJM ISO	BGE	Baltimore Gas & Electric Company		5004/5005	AP South	ISG Sparrows Point Inc	ISG Sparrows Point Inc	Sparrows Point	GEN2	100	30	38	38	ST	BFG	Retired	1/1/49	6/30/12
PJM ISO	BGE	Baltimore Gas & Electric Company		5004/5005	AP South	ISG Sparrows Point Inc	ISG Sparrows Point Inc	Sparrows Point	GEN3	100	30	38	38	ST	BFG	Retired	1/1/49	6/30/12
PJM ISO	BGE	Baltimore Gas & Electric Company		5004/5005	AP South	ISG Sparrows Point Inc	ISG Sparrows Point Inc	Sparrows Point	GEN4	100	30	38	38	ST	BFG	Retired	1/1/49	6/30/12
PJM ISO	AEP	American Electric Power				Ohio Power Co	Appalachian Power Co	Phil Sporn	5	100	495.5	440	450	ST	BIT	Retired	12/1/60	2/12/12
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	Monongahela Power Co	Albright	1	100	69	73	76	ST	BIT	Retired	12/1/52	9/1/12
PJM ISO	APS	Allegheny Power				Monongahela Power Co	Monongahela Power Co	Albright	2	100	69	73	76	ST	BIT	Retired	10/1/52	9/1/12
PJM ISO	APS	Allegheny Power				Monongahela Power Co	Monongahela Power Co	Albright	3	100	140.2	137	140	ST	BIT	Retired	10/1/54	9/1/12
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	Allegheny Energy Supply Co LL	Armstrong Power Station	ARM1	100	163.2	172	180	ST	BIT	Retired	4/1/58	9/1/12
PJM ISO	APS	Allegheny Power				Allegheny Energy Supply Co	Allegheny Energy Supply Co LL	Armstrong Power Station	ARM2	100	163.2	171	176	ST	BIT	Retired	6/1/59	9/1/12
PJM ISO	APS	Allegheny Power				Monongahela Power Co	Monongahela Power Co	Rivesville	5	100	35	46	48	ST	BIT	Retired	6/1/43	9/1/12

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PJM ISO	APS	Allegheny Power				Monongahela Power Co	Monongahela Power Co	Rivesville	6	100	74.7	91	94	ST	BIT	Retired	9/1/51	9/1/12
PJM ISO	APS	Allegheny Power				Monongahela Power Co	Monongahela Power Co	Willow Island	1	100	50	54	55	ST	BIT	Retired	2/1/49	9/1/12
PJM ISO	APS	Allegheny Power				Monongahela Power Co	Monongahela Power Co	Willow Island	2	100	163.2	181	186	ST	BIT	Retired	10/1/60	9/1/12
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Generation, LLC	Bay Shore	2	100	140.6	138	138	ST	SUB	Retired	2/1/59	9/1/12
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Generation, LLC	Bay Shore	3	100	140.6	142	142	ST	SUB	Retired	5/1/63	9/1/12
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Generation, LLC	Bay Shore	4	100	217.6	215	215	ST	SUB	Retired	6/1/68	9/1/12
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Generation, LLC	Eastlake (OH)	4	100	208	240	240	ST	SUB	Retired	3/1/56	9/1/12
PJM ISO	ATSI	FirstEnergy ATSI				FirstEnergy Generation, LLC	FirstEnergy Generation, LLC	Eastlake (OH)	5	100	680	597	597	ST	BIT	Retired	9/1/72	9/1/12
PJM ISO	ATSI	FirstEnergy ATSI				NRG Power Midwest LP	NRG Power Midwest LP	Niles (OH ORION)	UNT1	100	132.8	108	108	ST	BIT	Retired	1/1/54	10/1/12
PJM ISO	ATSI	FirstEnergy ATSI				NRG Power Midwest LP	NRG Power Midwest LP	Niles (OH ORION)	UNT2	100	132.8	108	108	ST	BIT	Retired	1/1/54	5/31/12
PJM ISO	COMED	Commonwealth Edison Co.				Little Co of Mary Hospital	Little Co of Mary Hospital	Little Co of Mary Hospital	GEN1	100	3.8	3.2	3.8	GT	NG	Retired	7/1/89	7/31/12
PJM ISO	COMED	Commonwealth Edison Co.				Sherman Hospital	Sherman Hospital	Sherman Hospital	1	100	0.8	0.8	0.8	IC	NG	Retired	11/1/89	4/30/12
PJM ISO	COMED	Commonwealth Edison Co.				Sherman Hospital	Sherman Hospital	Sherman Hospital	2	100	0.8	0.8	0.8	IC	NG	Retired	11/1/89	4/30/12
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Midwest Generations EME LLC	Fisk Street	19	100	374	326	326	ST	SUB	Retired	7/1/59	8/30/12
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Midwest Generations EME LLC	Crawford (IL)	7	100	239.3	213	216	ST	SUB	Retired	5/1/58	8/29/12
PJM ISO	COMED	Commonwealth Edison Co.				Midwest Generations EME L	Midwest Generations EME LLC	Crawford (IL)	8	100	358.1	319	326	ST	SUB	Retired	4/1/61	8/29/12
PJM ISO	COMED	Commonwealth Edison Co.				Countryside Genco LLC	Countryside Genco LLC	Countryside Genco LLC	CS 1	100	1.4	1.3	1.3	IC	LFG	Retired	1/1/00	1/31/12
PJM ISO	COMED	Commonwealth Edison Co.				Countryside Genco LLC	Countryside Genco LLC	Countryside Genco LLC	CS 2	100	1.4	1.3	1.3	IC	LFG	Retired	1/1/00	1/31/12
PJM ISO	COMED	Commonwealth Edison Co.				Countryside Genco LLC	Countryside Genco LLC	Countryside Genco LLC	CS 3	100	1.4	1.3	1.3	IC	LFG	Retired	1/1/00	1/31/12
PJM ISO	COMED	Commonwealth Edison Co.				Countryside Genco LLC	Countryside Genco LLC	Countryside Genco LLC	CS 4	100	1.4	1.3	1.3	IC	LFG	Retired	1/1/00	1/31/12
PJM ISO	COMED	Commonwealth Edison Co.				Countryside Genco LLC	Countryside Genco LLC	Countryside Genco LLC	CS 5	100	1.4	1.3	1.3	IC	LFG	Retired	1/1/00	1/31/12
PJM ISO	COMED	Commonwealth Edison Co.				Countryside Genco LLC	Countryside Genco LLC	Countryside Genco LLC	CS 6	100	1.4	1.3	1.3	IC	LFG	Retired	1/1/00	1/31/12
PJM ISO	COMED	Commonwealth Edison Co.				Gas Recovery Services IL Inc	Gas Recovery Services IL Inc	South Barrington Electric	1	100	0.8	0.8	0.8	IC	LFG	Retired	6/1/97	1/31/12
PJM ISO	COMED	Commonwealth Edison Co.				Gas Recovery Services IL Inc	Gas Recovery Services IL Inc	South Barrington Electric	2	100	0.8	0.8	0.8	IC	LFG	Retired	6/1/97	1/31/12
PJM ISO	COMED	Commonwealth Edison Co.				State Line Energy LLC	BTU Solutions LLC	State Line Energy	ST4	100	388.9	318	318	ST	SUB	Retired	5/1/62	3/25/12
PJM ISO	COMED	Commonwealth Edison Co.				State Line Energy LLC	BTU Solutions LLC	State Line Energy	ST3	100	224.9	197	197	ST	SUB	Retired	12/1/55	3/25/12
PJM ISO	DEOK	Duke Energy Ohio				Duke Energy Ohio	Duke Energy Ohio	Walter C Beckjord	1	100	115	94	94	ST	BIT	Retired	6/1/52	5/1/12
PJM ISO	DEOK	Duke Energy Ohio				Sun Premium Paper Advisors	Sun Premium Paper Advisors L	Smart Papers LLC	1	100	1	1	1	ST	BIT	Retired	6/1/09	8/10/12
PJM ISO	DEOK	Duke Energy Ohio				Sun Premium Paper Advisors	Sun Premium Paper Advisors L	Smart Papers LLC	2	100	1.5	1.5	1.5	ST	BIT	Retired	6/1/09	8/10/12
PJM ISO	DEOK	Duke Energy Ohio				Sun Premium Paper Advisors	Sun Premium Paper Advisors L	Smart Papers LLC	7	100	9.4	9.4	9.4	ST	BIT	Retired	6/1/09	8/10/12
PJM ISO	DEOK	Duke Energy Ohio				Sun Premium Paper Advisors	Sun Premium Paper Advisors L	Smart Papers LLC	8	100	9.4	9.4	9.4	ST	BIT	Retired	6/1/09	8/10/12
PJM ISO	DEOK	Duke Energy Ohio				Sun Premium Paper Advisors	Sun Premium Paper Advisors L	Smart Papers LLC	GEN3	100	6	6	6	ST	BIT	Retired	1/1/24	8/10/12
PJM ISO	DEOK	Duke Energy Ohio				Sun Premium Paper Advisors	Sun Premium Paper Advisors L	Smart Papers LLC	GEN5	100	7.5	7.5	7.5	ST	BIT	Retired	1/1/30	8/10/12
PJM ISO	DEOK	Duke Energy Ohio				Sun Premium Paper Advisors	Sun Premium Paper Advisors L	Smart Papers LLC	GEN6	100	10.5	10.5	10.5	ST	BIT	Retired	1/1/30	8/10/12
PJM ISO	DUQ	Duquesne Light Company				NRG Power Midwest LP	NRG Power Midwest LP	Elrama Power Plant	UNT1	100	100	93	93	ST	BIT	Retired	4/1/52	6/1/12
PJM ISO	DUQ	Duquesne Light Company				NRG Power Midwest LP	NRG Power Midwest LP	Elrama Power Plant	UNT2	100	100	93	93	ST	BIT	Retired	1/1/53	6/1/12
PJM ISO	DUQ	Duquesne Light Company				NRG Power Midwest LP	NRG Power Midwest LP	Elrama Power Plant	UNT3	100	125	103	103	ST	BIT	Retired	9/1/54	6/1/12
PJM ISO	PECO	PECO Energy Company	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Generation Co LLC	Cromby Generating Station	2	100	230	201	211	ST	RFO	Retired	9/1/55	12/31/11
PJM ISO	PECO	PECO Energy Company	PJM East	5004/5005	AP South	Exelon Generation Co LLC	Exelon Generation Co LLC	Cromby Generating Station	ICI	100	2.7	2.7	2.7	IC	DFO	Retired	5/1/67	12/31/11
PJM ISO	PSEG	Public Service Electric & Gas	PJM East	5004/5005	AP South	Generation II Locomotives Ir	Algonquin Cambrian Pacific Ge	Balefill	UNT1	50	0.95	0.05	0.1	IC	LFG	Retired	10/1/98	12/31/11

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Plant ISO Name	Plant ISO Zone Name	Transmission Zone Name	Submarket	Submarket	Submarket	Owner Name	Plant Operator Name	Plant Name	Unit	Percent Owned %	Nameplate Capacity MW	Net Summer Capacity MW	Net Winter Capacity MW	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Retirement Date
PJM ISO	PSEG	Public Service Electric & Gas	PJM East	5004/5005	AP South	Generation II Locomotives Ir	Algonquin Cambrian Pacific Ge	Balefill	UNT2	50	0.95	0.05	0.1	IC	LFG	Retired	10/1/98	12/31/11
PJM ISO	PSEG	Public Service Electric & Gas	PJM East	5004/5005	AP South	Neo Corp	Algonquin Cambrian Pacific Ge	Balefill	UNT1	50	0.95	0.05	0.1	IC	LFG	Retired	10/1/98	12/31/11
PJM ISO	PSEG	Public Service Electric & Gas	PJM East	5004/5005	AP South	Neo Corp	Algonquin Cambrian Pacific Ge	Balefill	UNT2	50	0.95	0.05	0.1	IC	LFG	Retired	10/1/98	12/31/11
PJM ISO	PSEG	Public Service Electric & Gas	PJM East	5004/5005	AP South	PSEG Fossil LLC	PSEG Fossil LLC	Hudson Generating Station	1	100	454.7	355	355	ST	NG	Retired	12/1/64	12/7/11
PJM ISO	AEP	American Electric Power				Shelby Dept of Utilities	Shelby Dept of Utilities	Shelby Munic Light Plant	1A	100	12.5	12	12	ST	BIT	Retired	6/1/68	12/31/11
PJM ISO	AEP	American Electric Power				Shelby Dept of Utilities	Shelby Dept of Utilities	Shelby Munic Light Plant	2	100	12.5	12	12	ST	BIT	Retired	5/1/73	12/31/11
PJM ISO	AEP	American Electric Power				Shelby Dept of Utilities	Shelby Dept of Utilities	Shelby Munic Light Plant	3	100	5	5	5	ST	BIT	Retired	4/1/48	12/31/11
PJM ISO	AEP	American Electric Power				Shelby Dept of Utilities	Shelby Dept of Utilities	Shelby Munic Light Plant	4	100	7	7	7	ST	BIT	Retired	6/1/54	12/31/11
PJM ISO	COMED	Commonwealth Edison Co.				Geneva Energy LLC	Geneva Energy LLC	New Heights	LM2	100	22	19.9	19.9	ST	TDF	Retired	1/1/08	12/31/11

	Winter	Spring	Summer	Fall
PJM	7,037	6,150	4,282	197
PJM East	701	589	23	0
5004/500	2,241	2,129	946	161
AP South	2,241	2,129	946	161

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	Winter	Spring	Summer	Fall
ISO-NE	34,408	34,408	31,969	34,408
CT	8,263	8,263	7,979	8,263
SWCT	3,088	3,088	2,798	3,088

Detailed generation data provided in other workpapers.

http://www.iso-ne.com/trans/celt/report/2012/index.html (2012 CELT Report)

2.1 Generator List with Existing and Expected Seasonal Claimed Capability (SCC)

- Generator Information as of January 1, 2012

- Summer and Winter SCC as of January 1, 2012, and as of the 2011/12 Winter and 2012 Summer Peaks

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ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICIPANT ACRONYM	STATE	COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2012			As of 2011/12 Winter and 2012 Summer Peaks	
																SUMMER SCC (MW)	WINTER SCC (MW)	Change in Summer SCC from 1/1/11	WINTER PEAK SCC JAN 4, 2012	EXPECTED SUMMER PEAK SCC AUG 1, 2012
194	FOUR HILLS LOAD REDUCER	194	FOUR HILLS LOAD REDUCER	IC	LFG		BIO/REFUSE	01-Apr-96	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	55006	1.185	1.084	-0.429	1.084	1.185
253	TURNKEY LANDFILL	253	TURNKEY LANDFILL	IC	LFG		BIO/REFUSE	01-Mar-92	Public Service Company of New Hampshire	PSNH	33	017	NH	NH	54663	0.591	1.286	-0.726	1.286	0.591
321	MANCHESTER 10/10A CC	321	MANCHESTER 10/10A CC	CC	NG		GAS COMBINED CYCLE	15-Nov-95	Dominion Energy Marketing, Inc.	DEM	44	007	RI	RI	3236	149.000	170.000	0.000	170.000	149.000
322	MANCHESTER 11/11A CC	322	MANCHESTER 11/11A CC	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Oct-95	Dominion Energy Marketing, Inc.	DEM	44	007	RI	RI	3236	149.000	170.000	0.000	170.000	149.000
323	MANCHESTER 9/9A CC	323	MANCHESTER 9/9A CC	CC	NG	DFO	GAS/OIL COMBINED CYCLE	14-Nov-95	Dominion Energy Marketing, Inc.	DEM	44	007	RI	RI	3236	149.000	170.000	0.000	170.000	149.000
324	CDECCA	324	CDECCA	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Nov-88	Pawtucket Power Holding Company LLC	PPH	09	003	CT	CT	50498	55.254	61.334	0.000	61.334	55.254
326	ALTRESCO	326	ALTRESCO	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Sep-90	Pawtucket Power Holding Company LLC	PPH	25	003	WMA	WCMA	50002	150.972	165.000	-0.469	165.000	150.972
327	AMOSKEAG	327	AMOSKEAG	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-22	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	2354	16.781	17.500	0.000	17.500	16.781
328	GULF ISLAND COMPOSITE	328	GULF ISLAND COMPOSITE Incremental	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-26	FPL Energy Maine Hydro LLC	FPLEMH	23	001	ME	ME	1480	32.970	32.970	0.000	32.970	32.970
329	ASCUTNEY GT	329	ASCUTNEY GT	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Nov-61	Central Vermont Public Service	CVPS	50	027	VT	VT	3708	0.000	0.000	-8.940	0.000	0.000
330	AYERS ISLAND	330	AYERS ISLAND	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-25	Public Service Company of New Hampshire	PSNH	33	001	NH	NH	2355	8.474	9.080	0.000	9.080	8.474
331	AZISCOHOS HYDRO	331	AZISCOHOS HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-88	NextEra Energy Power Marketing, LLC	FPLP	23	019	ME	ME	50999	6.810	6.810	0.000	6.810	6.810
332	BAR HARBOR DIESELS 1-4	332	BAR HARBOR DIESELS 1-4	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-60	New Brunswick Power Generation Corporation	NBPGC	23	009	BHE	ME	1466	0.000	6.100	-5.950	6.100	0.000
335	BELLOWS FALLS	335	BELLOWS FALLS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-28	TransCanada Power Marketing, Ltd.	TCPM	50	025	VT	NH	3745	48.540	48.540	0.000	48.540	48.540
336	BERLIN 1 GT	336	BERLIN 1 GT	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-72	Green Mountain Power Corporation	GMP	50	023	VT	VT	3734	34.830	45.777	0.000	45.777	34.830
337	BETHLEHEM	337	BETHLEHEM	ST	WDS		BIO/REFUSE	01-Dec-86	GDF SUEZ Energy Marketing NA, Inc.	SUEZ	33	007	NH	NH	50208	15.045	15.201	-0.435	15.201	15.045
339	BRIDGEPORT HARBOR 2	339	BRIDGEPORT HARBOR 2	ST	RFO		OIL STEAM	01-Aug-61	PSEG Energy Resources & Trade LLC	PSEG	09	001	SWCT	CT	568	0.000	0.000	-130.495	0.000	0.000
340	BRIDGEPORT HARBOR 3	340	BRIDGEPORT HARBOR 3	ST	SUB	RFO	COAL STEAM	01-Aug-68	PSEG Energy Resources & Trade LLC	PSEG	09	001	SWCT	CT	568	383.426	384.984	0.000	384.984	383.426
341	BRIDGEPORT HARBOR 4	341	BRIDGEPORT HARBOR 4	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Oct-67	PSEG Energy Resources & Trade LLC	PSEG	09	001	SWCT	CT	568	17.100	22.000	-0.012	22.000	17.100
345	MEAD	345	MEAD	ST	BIT	OBS	COAL STEAM	01-Feb-90	American PowerNet Management, LP	APNM	23	017	ME	ME	10491	4.200	0.000	2.580	0.000	4.200
346	BOLTON FALLS	346	BOLTON FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Green Mountain Power Corporation	GMP	50	023	VT	VT	7056	3.333	6.018	0.000	6.018	3.333
348	BOOT MILLS	348	BOOT MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-85	NSTAR Electric Company	NSTAR	25	017	CMA/NEMA	WCMA	10556	6.731	16.002	0.000	16.002	6.731
349	WHEELABRATOR BRIDGEPORT, L.P.	349	WHEELABRATOR BRIDGEPORT, L.P.	ST	WDS		BIO/REFUSE	01-Apr-88	Wheelabrator Bridgeport, L.P.	WB	09	001	SWCT	CT	50883	58.982	59.270	-0.269	59.270	58.982
350	BRAYTON PT 1	350	BRAYTON PT 1	ST	BIT	NG	COAL STEAM	01-Aug-63	Dominion Energy Marketing, Inc.	DEM	25	005	RI	SEMA	1619	243.455	246.703	0.000	246.703	243.455
351	BRAYTON PT 2	351	BRAYTON PT 2	ST	BIT	NG	COAL STEAM	01-Jul-64	Dominion Energy Marketing, Inc.	DEM	25	005	RI	SEMA	1619	244.000	249.331	0.000	249.331	244.000
352	BRAYTON PT 3	352	BRAYTON PT 3	ST	BIT	NG	COAL STEAM	01-Jul-69	Dominion Energy Marketing, Inc.	DEM	25	005	RI	SEMA	1619	612.000	638.000	0.000	638.000	612.000
353	BRAYTON PT 4	353	BRAYTON PT 4	ST	RFO	NG	GAS/OIL STEAM	01-Dec-74	Dominion Energy Marketing, Inc.	DEM	25	005	RI	SEMA	1619	435.000	445.520	0.000	445.520	435.000
354	BRAYTON DIESELS 1-4	354	Brayton Diesels 1-4 Incremental	IC	DFO		OIL INTERNAL COMBUSTION	01-Mar-67	Dominion Energy Marketing, Inc.	DEM	25	005	RI	SEMA	1619	9.912	9.988	0.000	9.988	9.912
355	BRANFORD 10	355	BRANFORD 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	NRG Power Marketing LLC	NRGPM	09	009	SWCT	CT	540	15.840	20.950	0.000	20.950	15.840
356	BRISTOL REFUSE	356	BRISTOL REFUSE	ST	MSW	NG	BIO/REFUSE	01-May-88	Connecticut Light and Power Company, The	CLP	09	003	CT	CT	50648	11.892	12.693	-0.971	12.693	11.892
357	BRIDGEWATER	357	BRIDGEWATER	ST	WDS		BIO/REFUSE	01-Sep-87	Bridgewater Power Company L.P.	BPCLP	33	009	NH	NH	10290	14.376	14.146	-0.403	14.146	14.376
358	BRUNSWICK	358	BRUNSWICK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-82	FPL Energy Maine Hydro LLC	FPLEMH	23	005	ME	ME	1483	7.062	15.507	1.144	15.507	7.062
359	J. COCKWELL 1	359	J. COCKWELL 1	PS	WAT		HYDRO (PUMPED STORAGE)	01-Sep-74	Bear Swamp Power Company LLC	BSP	25	011	WMA	WCMA	8005	284.100	292.275	-0.206	292.275	284.100
360	J. COCKWELL 2	360	J. COCKWELL 2	PS	WAT		HYDRO (PUMPED STORAGE)	01-Oct-74	Bear Swamp Power Company LLC	BSP	25	011	WMA	WCMA	8005	282.600	292.763	-2.038	292.763	282.600
361	POTTER DIESEL 1	361	POTTER DIESEL 1	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-78	Braintree Electric Light Department, Town of	BELD	25	021	SEMA	SEMA	1660	2.250	2.250	0.000	2.250	2.250
362	BULLS BRIDGE	362	BULLS BRIDGE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-03	FirstLight Power Resources Management, LLC	FPRM	09	005	SWCT	CT	541	4.884	6.538	4.884	6.538	4.884
363	BURLINGTON GT	363	BURLINGTON GT	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jul-71	Burlington Electric Department	BED	50	007	VT	VT	3754	20.000	24.250	1.552	24.250	20.000
365	CANAL 1	365	CANAL 1	ST	RFO		OIL STEAM	01-Jul-68	Genon Energy Management, LLC	MET	25	001	SEMA	SEMA	1599	547.059	564.828	0.000	564.828	547.059
366	CANAL 2	366	CANAL 2	ST	RFO	NG	GAS/OIL STEAM	01-Feb-76	Genon Energy Management, LLC	MET	25	001	SEMA	SEMA	1599	545.125	561.000	0.000	561.000	545.125
367	CAPE GT 4	367	CAPE GT 4	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jan-70	NextEra Energy Power Marketing, LLC	FPLP	23	005	SME	ME	1484	15.931	20.011	0.000	20.011	15.931
368	CAPE GT 5	368	CAPE GT 5	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jan-70	NextEra Energy Power Marketing, LLC	FPLP	23	005	SME	ME	1484	15.822	20.272	0.000	20.272	15.822
369	CATARACT EAST	369	CATARACT EAST	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-37	FPL Energy Maine Hydro LLC	FPLEMH	23	031	SME	ME	695	7.775	8.000	0.000	8.000	7.775
370	COS COB 10	370	COS COB 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	NRG Power Marketing LLC	NRGPM	09	001	NOR	CT	542	19.028	23.000	0.000	23.000	19.028
371	COS COB 11	371	COS COB 11	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	NRG Power Marketing LLC	NRGPM	09	001	NOR	CT	542	18.724	23.000	0.000	23.000	18.724
372	COS COB 12	372	COS COB 12	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	NRG Power Marketing LLC	NRGPM	09	001	NOR	CT	542	19.082	23.000	0.000	23.000	19.082
375	CLEARY 9/9A CC	375	CLEARY 9/9A CC	CC	NG	RFO	GAS/OIL COMBINED CYCLE	01-Dec-75	Taunton Municipal Lighting Plant	TMLP	25	005	SEMA	SEMA	1682	104.931	109.931	0.000	109.931	104.931

Wkp-ISO NE Capacity (CELT Report)

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICIPANT ACRONYM	STATE	COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2012		Change in Summer SCC from 1/1/11	As of 2011/12 Winter and 2012 Summer Peaks	
																SUMMER SCC (MW)	WINTER SCC (MW)		WINTER PEAK SCC JAN 4, 2012	EXPECTED SUMMER PEAK SCC AUG 1, 2012
376	CLEARY 8	376	CLEARY 8	ST	RFO		OIL STEAM	01-Jan-66	Taunton Municipal Lighting Plant	TMLP	25	005	SEMA	SEMA	1682	24.825	26.000	-1.028	26.000	24.825
379	COBBLE MOUNTAIN	379	COBBLE MOUNTAIN	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-23	Holyoke Gas & Electric Department	HGE	25	013	WMA	WCMA	1630	31.126	32.942	31.126	32.942	31.126
380	COMERFORD	380	COMERFORD	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-30	TransCanada Power Marketing, Ltd.	TCPM	33	009	NH	NH	2349	152.270	143.630	9.434	143.630	152.270
382	MERRIMACK CT1	382	MERRIMACK CT1	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Jul-69	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	2364	16.826	21.676	0.000	21.676	16.826
383	MERRIMACK CT2	383	MERRIMACK CT2	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-68	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	2364	16.804	21.304	0.000	21.304	16.804
388	DARTMOUTH POWER	388	DARTMOUTH POWER	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-May-92	Consolidated Edison Energy, Inc	CEEI	25	005	SEMA	SEMA	52026	62.156	67.656	0.000	67.656	62.156
389	DERBY DAM	389	DERBY DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-89	Connecticut Light and Power Company, The	CLP	09	001	SWCT	CT	10063	7.050	7.050	0.000	7.050	7.050
392	DEXTER	392	DEXTER	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-May-90	Algonquin Energy Services Inc.	AESR	09	003	CT	CT	-	31.308	32.899	10.666	32.899	31.308
393	DEERFIELD 5	393	DEERFIELD 5	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Oct-74	TransCanada Power Marketing, Ltd.	TCPM	25	011	WMA	WCMA	1620	13.703	13.990	0.000	13.990	13.703
395	DOREEN	395	DOREEN	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	Hess Corporation	HESS	25	003	WMA	WCMA	1631	15.959	20.809	0.000	20.809	15.959
396	DEVON 10	396	DEVON 10	GT	JF	DFO	OIL COMBUSTION (GAS) TURBINE	01-Apr-88	NRG Power Marketing LLC	NRGPM	09	009	SWCT	CT	544	14.407	19.186	0.000	19.186	14.407
397	DEVON 11	397	DEVON 11	GT	JF	NG	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	09	009	SWCT	CT	544	29.299	38.819	0.000	38.819	29.299
398	DEVON 12	398	DEVON 12	GT	JF	NG	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	09	009	SWCT	CT	544	29.227	38.437	0.000	38.437	29.227
399	DEVON 13	399	DEVON 13	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	09	009	SWCT	CT	544	29.967	38.967	0.000	38.967	29.967
400	DEVON 14	400	DEVON 14	GT	JF	NG	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	09	009	SWCT	CT	544	29.704	40.274	0.000	40.274	29.704
401	EASTMAN FALLS	401	EASTMAN FALLS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-12	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	2356	5.582	6.470	0.000	6.470	5.582
405	ELLSWORTH HYDRO	405	ELLSWORTH HYDRO	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-19	Black Bear Hydro Partners, LLC	BBHP	23	009	BHE	ME	1469	9.070	8.624	-0.027	8.624	9.070
407	EASTPORT DIESELS 1-3	407	EASTPORT DIESELS 1-3	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-48	New Brunswick Power Generation Corporation	NBPGC	23	029	BHE	ME	1468	2.200	2.200	0.000	2.200	2.200
410	ESSEX 19 HYDRO	410	ESSEX 19 HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-17	Green Mountain Power Corporation	GMP	50	007	VT	VT	3737	2.597	7.281	0.499	7.281	2.597
411	EXETER	411	EXETER	ST	TDF	PG	BIO/REFUSE	01-Dec-91	ReEnergy Sterling CT Limited Partnership	REENERGY	09	013	CT	CT	50736	20.062	20.831	-3.947	20.831	20.062
412	FALLS VILLAGE	412	FALLS VILLAGE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-14	FirstLight Power Resources Management, LLC	FPRM	09	005	CT	CT	560	4.963	6.404	4.963	6.404	4.963
413	FIFE BROOK	413	FIFE BROOK	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Oct-74	Bear Swamp Power Company LLC	BSP	25	003	WMA	WCMA	8004	6.089	9.900	0.000	9.900	6.089
415	FLORENCE 1 CG	415	FLORENCE 1 CG	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-92	Vermont Marble Company	VMC	50	021	VT	VT	7337	0.000	0.000	0.000	0.000	0.000
416	FLORENCE 2 CG	416	FLORENCE 2 CG	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-92	Vermont Marble Company	VMC	50	021	VT	VT	7337	0.000	0.000	0.000	0.000	0.000
417	FRAMINGHAM JET 1	417	FRAMINGHAM JET 1	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	Exelon New England Holdings, LLC	EXNEH	25	017	BOSTON	NEMA	1586	10.145	14.175	-0.748	14.175	10.145
418	FRAMINGHAM JET 2	418	FRAMINGHAM JET 2	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	Exelon New England Holdings, LLC	EXNEH	25	017	BOSTON	NEMA	1586	9.914	13.914	0.000	13.914	9.914
419	FRAMINGHAM JET 3	419	FRAMINGHAM JET 3	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	Exelon New England Holdings, LLC	EXNEH	25	017	BOSTON	NEMA	1586	11.250	15.250	-0.168	15.250	11.250
420	FRANKLIN DRIVE 10	420	FRANKLIN DRIVE 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Nov-68	NRG Power Marketing LLC	NRGPM	09	005	CT	CT	561	15.417	20.527	0.000	20.527	15.417
421	FRONT STREET DIESELS 1-3	421	FRONT STREET DIESELS 1-3	IC	DFO		OIL INTERNAL COMBUSTION	01-Dec-80	Chicopee Municipal Lighting Plant	CMLP	25	013	WMA	WCMA	7396	0.000	8.250	-8.286	8.250	0.000
424	GREAT LAKES - MILLINOCKET	424	GREAT LAKES - MILLINOCKET	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Mar-87	Brookfield Energy Marketing, LP	BEMLP	23	019	BHE	ME	55830	75.546	32.304	43.869	32.304	75.546
426	GORGE 1 DIESEL	426	GORGE 1 DIESEL	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jan-65	Green Mountain Power Corporation	GMP	50	007	VT	VT	3735	0.000	0.000	-7.090	0.000	0.000
427	GORHAM	427	GORHAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-09	Public Service Company of New Hampshire	PSNH	33	007	NH	NH	2358	1.959	2.050	0.000	2.050	1.959
429	GALLOP POWER GREENVILLE	429	GREENVILLE	ST	WDS		BIO/REFUSE	01-Mar-87	Gallop Power Greenville,LLC	GALLOP	23	021	ME	ME	54852	0.000	13.805	-14.079	13.805	0.000
432	HARRIS 1	432	HARRIS 1	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-54	FPL Energy Maine Hydro LLC	FPLEMH	23	025	ME	ME	1492	16.790	16.776	0.000	16.776	16.790
433	HARRIS 2	433	HARRIS 2	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-54	FPL Energy Maine Hydro LLC	FPLEMH	23	025	ME	ME	1492	34.865	34.500	0.000	34.500	34.865
434	HARRIS 3	434	HARRIS 3	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-53	FPL Energy Maine Hydro LLC	FPLEMH	23	025	ME	ME	1492	34.210	33.905	0.000	33.905	34.210
435	HARRIMAN	435	HARRIMAN	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-24	TransCanada Power Marketing, Ltd.	TCPM	50	025	WMA	WCMA	3746	41.028	38.663	-0.011	38.663	41.028
436	HEMPHILL 1	436	HEMPHILL 1	ST	WDS		BIO/REFUSE	01-Dec-87	PPL EnergyPlus, LLC	PPLEP	33	019	NH	NH	10838	16.608	16.860	2.471	16.860	16.608
437	HOLYOKE 6/CABOT 6	437	HOLYOKE 6/CABOT 6	ST	NG	DFO	GAS/OIL STEAM	01-Jan-49	Holyoke Gas & Electric Department	HGE	25	013	WMA	WCMA	9864	0.000	0.000	-9.212	0.000	0.000
438	HOLYOKE 8/CABOT 8	438	HOLYOKE 8/CABOT 8	ST	NG	DFO	GAS/OIL STEAM	01-Jan-49	Holyoke Gas & Electric Department	HGE	25	013	WMA	WCMA	9864	0.000	0.000	-9.220	0.000	0.000
440	HIRAM	440	HIRAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-17	FPL Energy Maine Hydro LLC	FPLEMH	23	005	SME	ME	1493	11.189	11.600	0.000	11.600	11.189
445	COVANTA WEST ENFIELD	445	COVANTA WEST ENFIELD	ST	WDS		BIO/REFUSE	01-Nov-87	Covanta Maine, LLC	CM	23	019	BHE	ME	10766	20.461	21.446	0.000	21.446	20.461
446	COVANTA JONESBORO	446	COVANTA JONESBORO	ST	WDS		BIO/REFUSE	01-Nov-87	Covanta Maine, LLC	CM	23	029	BHE	ME	10765	20.226	20.226	0.000	20.226	20.226
448	IPSWICH DIESELS	448	IPSWICH DIESELS	IC	DFO	NG	GAS/OIL INTERNAL COMBUSTION	01-Jan-51	Ipswich Municipal Light Department	IMLD	25	009	BOSTON	NEMA	1670	10.240	9.495	0.000	9.495	10.240
449	JACKMAN	449	JACKMAN	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Feb-26	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	2360	3.550	3.611	0.000	3.611	3.550
451	JOHNSTON LANDFILL	451	JOHNSTON LANDFILL	IC	LFG		BIO/REFUSE	01-Feb-90	Rhode Island Engine Genco, LLC	RRIG	44	007	RI	RI	50365	11.962	12.000	0.000	12.000	11.962
452	KENDALL JET 1	452	KENDALL JET 1	GT	DFO		OIL COMBUSTION (GAS) TURBINE	24-Sep-70	Genon Energy Management, LLC	MET	25	017	BOSTON	NEMA	1595	18.000	23.000	0.000	23.000	18.000
457	LAWRENCE HYDRO	457	LAWRENCE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-81	CHI Power Marketing, Inc. (CHIPM)	CHIPM	25	009	BOSTON	WCMA	50545	7.014	13.360	0.000	13.360	7.014
460	LOCKWOOD	460	LOCKWOOD	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	NextEra Energy Power Marketing, LLC	FPLP	23	011	ME	ME	10066	4.025	4.657	1.529	4.657	4.025
461	LENERGIA ENERGY CENTER	12521	LOWELL POWER REACTIVATION	CC	NG	DFO	GAS/OIL COMBINED CYCLE	11-Mar-93	EDF Trading North America, LLC	EDFT	25	017	CMA/NEMA	WCMA	54586	74.638	78.446	0.000	78.446	74.638
462	LISBON RESOURCE RECOVERY	462	LISBON RESOURCE RECOVERY	ST	MSW		BIO/REFUSE	01-Jan-96	Connecticut Light and Power Company, The	CLP	09	011	CT	CT	54758	13.700	13.649	-0.032	13.649	13.700
463	REENERGY LIVERMORE FALLS	463	AEI LIVERMORE	ST	WDS		BIO/REFUSE	01-Oct-92	ReEnergy Stratton Energy LP	BSEI	23	001	ME	ME	10354	34.695	34.430	0.000	34.430	34.695

Wkp-ISO NE Capacity (CELT Report)

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICIPANT ACRONYM	STATE	COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2012		Change in Summer SCC from 1/1/11	As of 2011/12 Winter and 2012 Summer Peaks	
																SUMMER SCC (MW)	WINTER SCC (MW)		WINTER PEAK SCC JAN 4, 2012	EXPECTED SUMMER PEAK SCC AUG 1, 2012
464	LOST NATION	464	LOST NATION	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	Public Service Company of New Hampshire	PSNH	33	007	NH	NH	2362	13.979	17.992	-0.090	17.992	13.925
465	DEERFIELD 2/LWR DRFIELD	465	DEERFIELD 2/LWR DRFIELD	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-12	TransCanada Power Marketing, Ltd.	TCPM	25	011	WMA	WCMA	6047	19.275	19.500	0.000	19.500	19.275
466	L STREET JET	466	L STREET JET	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-66	Exelon New England Holdings, LLC	EXNEH	25	025	BOSTON	NEMA	1587	16.030	21.770	0.000	21.770	16.030
467	MARBLEHEAD DIESELS	467	MARBLEHEAD DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	25-Sep-98	Marblehead Municipal Light Department	MMLD	25	009	BOSTON	NEMA	-	5.000	5.000	0.000	5.000	5.000
468	MARSHFIELD 6 HYDRO	468	MARSHFIELD 6 HYDRO	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-27	Green Mountain Power Corporation	GMP	50	023	NH	VT	3739	0.000	4.708	-4.657	4.708	0.000
472	M STREET JET	472	M STREET JET	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-78	MA Bay Transp Auth (MBTA)	MBTA	25	025	BOSTON	NEMA	10176	0.000	0.000	-41.886	0.000	0.000
473	MCINDOES	473	MCINDOES	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-31	TransCanada Power Marketing, Ltd.	TCPM	33	009	NH	NH	6483	10.066	10.571	0.000	10.571	10.066
474	J C MCNEIL	474	J C MCNEIL	ST	WDS	NG	BIO/REFUSE	01-Feb-84	Burlington Electric Department	BED	50	007	VT	VT	589	52.000	54.000	0.000	54.000	52.000
475	MEDWAY DIESELS 1-4	475	MEDWAY DIESELS 1-4	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-60	New Brunswick Power Generation Corporation	NBPGC	23	019	BHE	ME	1474	7.950	8.250	3.650	8.250	7.950
476	MERC	476	MERC	ST	MSW	NG	BIO/REFUSE	01-May-87	NextEra Energy Power Marketing, LLC	FPLP	23	031	SME	ME	10338	16.339	16.097	0.299	16.097	16.339
478	MIDDLETOWN 10	478	MIDDLETOWN 10	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Jan-66	NRG Power Marketing LLC	NRGPM	09	007	CT	CT	562	14.260	18.760	-2.863	18.760	14.260
479	MIDDLETOWN 1	479	MIDDLETOWN 1	ST	RFO		OIL STEAM	01-Oct-96	NRG Power Marketing LLC	NRGPM	09	007	CT	CT	562	0.000	0.000	0.000	0.000	0.000
480	MIDDLETOWN 2	480	MIDDLETOWN 2	ST	RFO	NG	GAS/OIL STEAM	01-Jan-58	NRG Power Marketing LLC	NRGPM	09	007	CT	CT	562	117.000	120.000	0.000	120.000	117.000
481	MIDDLETOWN 3	481	MIDDLETOWN 3	ST	RFO	NG	GAS/OIL STEAM	01-Jan-64	NRG Power Marketing LLC	NRGPM	09	007	CT	CT	562	236.000	245.000	0.000	245.000	236.000
482	MIDDLETOWN 4	482	MIDDLETOWN 4	ST	RFO		OIL STEAM	01-Jun-73	NRG Power Marketing LLC	NRGPM	09	007	CT	CT	562	400.000	402.000	0.000	402.000	400.000
484	MILLSTONE POINT 2	484	MILLSTONE POINT 2	ST	NUC		NUCLEAR STEAM	01-Dec-75	Dominion Energy Marketing, Inc.	DEM	09	011	CT	CT	566	875.260	879.305	-0.563	879.305	875.260
485	MILLSTONE POINT 3	485	MILLSTONE POINT 3	ST	NUC		NUCLEAR STEAM	01-Apr-86	Dominion Energy Marketing, Inc.	DEM	09	011	CT	CT	566	1,225.000	1,235.001	0.000	1,235.001	1,225.000
486	MILFORD POWER	486	MILFORD POWER	CC	NG		GAS COMBINED CYCLE	01-Jan-94	ANP Funding I, LLC	ANP	25	027	RI	SEMA	54805	149.000	170.730	0.000	170.730	149.000
487	MILLER HYDRO	487	MILLER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-84	Energy New England LLC	ENE	23	001	ME	ME	50278	7.093	14.060	2.358	14.060	7.093
489	MERRIMACK 1	489	MERRIMACK 1	ST	SUB		COAL STEAM	01-Dec-60	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	2364	112.500	114.000	0.000	114.000	112.500
490	MERRIMACK 2	490	MERRIMACK 2	ST	SUB		COAL STEAM	30-Apr-68	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	2364	338.375	343.025	0.000	343.025	338.375
492	MONTVILLE 10 and 11	492	MONTVILLE 10 and 11	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-67	NRG Power Marketing LLC	NRGPM	09	011	CT	CT	546	5.296	5.354	0.000	5.354	5.296
493	MONTVILLE 5	493	MONTVILLE 5	ST	RFO	NG	GAS/OIL STEAM	01-Jan-54	NRG Power Marketing LLC	NRGPM	09	011	CT	CT	546	81.000	81.590	0.000	81.590	81.000
494	MONTVILLE 6	494	MONTVILLE 6	ST	RFO		OIL STEAM	01-Jul-71	NRG Power Marketing LLC	NRGPM	09	011	CT	CT	546	406.183	409.913	-1.218	409.913	406.183
495	MONTY	495	MONTY	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	FPL Energy Maine Hydro LLC	FPLEMH	23	025	ME	ME	805	28.000	28.000	0.000	28.000	28.000
496	MOORE	496	MOORE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-56	TransCanada Power Marketing, Ltd.	TCPM	33	009	NH	NH	2351	189.032	191.175	-0.944	191.175	189.032
497	MASS POWER	497	MASS POWER	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Jul-93	EquiPower Resources Management, LLC	EPRM	25	013	WMA	WCMA	10726	238.259	276.000	0.000	276.000	238.259
498	MT TOM	498	MT TOM	ST	BIT		COAL STEAM	01-Jun-60	FirstLight Power Resources Management, LLC	FPRM	25	013	WMA	WCMA	1606	142.881	144.594	0.000	144.594	142.881
502	MYSTIC 7	502	MYSTIC 7	ST	NG	RFO	GAS/OIL STEAM	01-Jun-75	Constellation Energy Commodities	CEC	25	017	BOSTON	NEMA	1588	560.469	559.775	-17.124	559.775	560.469
503	MYSTIC JET	503	MYSTIC JET	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jun-69	Constellation Energy Commodities	CEC	25	017	BOSTON	NEMA	1588	8.589	12.739	0.000	12.739	8.589
507	NEA BELLINGHAM	507	NEA BELLINGHAM	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Oct-91	NextEra Energy Power Marketing, LLC	FPLP	25	021	RI	SEMA	10307	277.621	336.503	0.000	336.503	277.621
508	NEWINGTON 1	508	NEWINGTON 1	ST	RFO	NG	GAS/OIL STEAM	01-Jun-74	Public Service Company of New Hampshire	PSNH	33	015	NH	NH	8002	400.200	400.200	0.000	400.200	400.200
513	NEW HAVEN HARBOR	513	NEW HAVEN HARBOR	ST	RFO	NG	GAS/OIL STEAM	01-Aug-75	PSEG Energy Resources & Trade LLC	PSEG	09	009	CT	CT	6156	447.894	453.384	0.000	453.384	447.894
515	NORWICH JET	515	NORWICH JET	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-72	Connecticut Municipal Electric Energy Cooperative	CMEEC	09	011	CT	CT	581	15.255	18.800	0.000	18.800	15.255
519	NORWALK HARBOR 1	519	NORWALK HARBOR 1	ST	RFO		OIL STEAM	01-Jan-60	NRG Power Marketing LLC	NRGPM	09	001	NOR	CT	548	162.000	163.995	0.000	163.995	162.000
520	NORWALK HARBOR 2	520	NORWALK HARBOR 2	ST	RFO		OIL STEAM	01-Jan-63	NRG Power Marketing LLC	NRGPM	09	001	NOR	CT	548	168.000	172.000	0.000	172.000	168.000
521	NORWALK HARBOR 10 (3)	521	NORWALK HARBOR 10 (3)	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	09	001	NOR	CT	548	11.925	17.062	0.000	17.062	11.925
527	OGDEN-MARTIN 1	527	OGDEN-MARTIN 1	ST	MSW	DFO	BIO/REFUSE	01-Jun-89	Dominion Energy Marketing, Inc.	DEM	25	009	BOSTON	NEMA	50661	39.130	42.106	-0.499	42.106	39.130
528	OCEAN ST PWR GT1/GT2/ST1	528	OCEAN ST PWR GT1/GT2/ST1	CC	NG		GAS COMBINED CYCLE	31-Dec-90	TransCanada Power Marketing, Ltd.	TCPM	44	007	RI	RI	51030	270.901	316.901	0.000	316.901	270.901
529	OCEAN ST PWR GT3/GT4/ST2	529	OCEAN ST PWR GT3/GT4/ST2	CC	NG		GAS COMBINED CYCLE	01-Oct-91	TransCanada Power Marketing, Ltd.	TCPM	44	007	RI	RI	54324	270.180	318.180	0.000	318.180	270.180
531	PAWTUCKET POWER	531	PAWTUCKET POWER	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Feb-91	Pawtucket Power Holding Company LLC	PPH	44	007	RI	RI	54056	57.557	60.869	-4.443	60.869	57.557
532	PEJEPSCOT	532	PEJEPSCOT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-87	Topsham Hydro Partners LP	TOPS	23	023	ME	ME	50758	6.491	10.806	2.193	10.806	6.491
536	PERC-ORRINGTON 1	536	PERC-ORRINGTON 1	ST	MSW	NG	BIO/REFUSE	01-Jan-88	Integrys Energy Services, Inc.	IES	23	019	BHE	ME	50051	20.852	20.847	-0.142	20.847	20.852
537	PILGRIM NUCLEAR POWER STATION	537	PILGRIM NUCLEAR POWER STATION	ST	NUC		NUCLEAR STEAM	01-Dec-72	Entergy Nuclear Power Marketing LLC	ENPM	25	023	SEMA	SEMA	1590	677.284	684.746	0.000	684.746	677.284
538	PINETREE POWER	538	PINETREE POWER	ST	WDS		BIO/REFUSE	01-Nov-92	Fitchburg Gas & Electric Light Company	FGE	25	027	NH	WCMA	54620	15.783	16.787	-0.368	16.787	15.783
539	PONTOOK HYDRO	539	PONTOOK HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-86	Brookfield Energy Marketing, LP	BEMLP	33	007	NH	NH	50741	4.266	10.159	0.446	10.159	4.266
540	POTTER 2 CC	540	POTTER 2 CC	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Mar-77	Braintree Electric Light Department, Town of	BELD	25	021	SEMA	SEMA	1660	73.927	91.927	-0.263	91.927	73.927
541	PROCTOR	541	PROCTOR	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Central Vermont Public Service	CVPS	50	021	VT	VT	6450	2.600	2.700	0.700	2.700	2.600
542	ECO MAINE	542	ECO MAINE	ST	MSW	NG	BIO/REFUSE	01-Aug-88	Macquarie Energy LLC	MCPI	23	005	SME	ME	50225	10.752	10.233	-0.277	10.233	10.752
546	RESCO SAUGUS	546	RESCO SAUGUS	ST	MSW		BIO/REFUSE	01-Nov-85	New England Power Company	NEP	25	009	BOSTON	NEMA	50880	32.282	30.114	0.000	30.114	32.282
547	WHEELABRATOR NORTH ANDOVER	547	WHEELABRATOR NORTH ANDOVER	ST	MSW		BIO/REFUSE	01-Aug-85	Wheelabrator North Andover Inc.	WNE	25	009	BOSTON	NEMA	50877	29.633	29.837	0.084	29.837	29.633
549	RUTLAND 5 GT	549	RUTLAND 5 GT	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jan-62	Central Vermont Public Service	CVPS	50	021	VT	VT	3723	8.406	12.816	0.000	12.816	8.406

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ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICIPANT ACRONYM	STATE	COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2012		Change in Summer SCC from 1/1/11	As of 2011/12 Winter and 2012 Summer Peaks	
																SUMMER SCC (MW)	WINTER SCC (MW)		WINTER PEAK SCC JAN 4, 2012	EXPECTED SUMMER PEAK SCC AUG 1, 2012
551	SALEM HARBOR 1	551	SALEM HARBOR 1	ST	BIT	RFO	COAL STEAM	01-Jan-52	Dominion Energy Marketing, Inc.	DEM	25	009	BOSTON	NEMA	1626	79.724	81.419	-0.030	81.419	79.724
552	SALEM HARBOR 2	552	SALEM HARBOR 2	ST	BIT	RFO	COAL STEAM	01-Jan-52	Dominion Energy Marketing, Inc.	DEM	25	009	BOSTON	NEMA	1626	77.955	78.763	0.000	78.763	77.955
553	SALEM HARBOR 3	553	SALEM HARBOR 3	ST	BIT	RFO	COAL STEAM	01-Aug-58	Dominion Energy Marketing, Inc.	DEM	25	009	BOSTON	NEMA	1626	149.805	149.910	0.000	149.910	149.805
554	SALEM HARBOR 4	554	SALEM HARBOR 4	ST	RFO		OIL STEAM	01-Aug-72	Dominion Energy Marketing, Inc.	DEM	25	009	BOSTON	NEMA	1626	436.754	437.353	0.000	437.353	436.754
555	SEABROOK	555	SEABROOK	ST	NUC		NUCLEAR STEAM	01-Apr-90	NextEra Energy Power Marketing, LLC	FPLP	33	015	NH	NH	6115	1,246.225	1,246.650	-0.650	1,246.650	1,246.225
556	SCHILLER 4	556	SCHILLER 4	ST	BIT	RFO	COAL STEAM	01-Apr-52	Public Service Company of New Hampshire	PSNH	33	015	NH	NH	2367	47.500	48.000	0.000	48.000	47.500
557	SCHILLER 5	557	SCHILLER 5	ST	WDS	RFO	BIO/REFUSE	01-May-55	Public Service Company of New Hampshire	PSNH	33	015	NH	NH	2367	43.082	42.594	0.000	42.594	43.082
558	SCHILLER 6	558	SCHILLER 6	ST	BIT	RFO	COAL STEAM	01-Jul-57	Public Service Company of New Hampshire	PSNH	33	015	NH	NH	2367	47.938	48.580	0.000	48.580	47.938
559	SCHILLER CT 1	559	SCHILLER CT 1	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Nov-70	Public Service Company of New Hampshire	PSNH	33	015	NH	NH	2367	17.621	18.500	0.000	18.500	17.621
561	SEARSBURG	561	SEARSBURG	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Mar-22	TransCanada Power Marketing, Ltd.	TCPM	50	003	WMA	WCMA	6529	4.755	4.960	0.000	4.960	4.755
562	SECREC-PRESTON	562	SECREC-PRESTON	ST	MSW	DFO	BIO/REFUSE	01-Jan-92	Connecticut Light and Power Company, The	CLP	09	011	CT	CT	1176	16.169	16.651	-0.280	16.651	16.169
563	SEMASS 1	563	SEMASS 1	ST	MSW	DFO	BIO/REFUSE	01-Oct-88	NSTAR Electric Company	NSTAR	25	023	SEMA	SEMA	50290	50.017	50.118	3.062	50.118	50.017
564	SEMASS 2	564	SEMASS 2	ST	MSW	DFO	BIO/REFUSE	01-May-93	NSTAR Electric Company	NSTAR	25	023	SEMA	SEMA	50290	22.557	25.236	0.686	25.236	22.557
565	SHELDON SPRINGS	565	SHELDON SPRINGS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-88	Vermont Electric Power Company, Inc.	VELCO	50	011	VT	VT	10494	3.946	13.400	0.676	13.400	3.946
566	SHEPAUG	566	SHEPAUG	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-55	FirstLight Power Resources Management, LLC	FPRM	09	009	SWCT	CT	552	41.511	42.559	0.000	42.559	41.511
567	SHERMAN	567	SHERMAN	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Dec-26	TransCanada Power Marketing, Ltd.	TCPM	25	011	WMA	WCMA	6012	6.154	6.220	0.000	6.220	6.154
568	SHREWSBURY DIESELS	35657	Shrewsbury Diesels	IC	DFO		OIL INTERNAL COMBUSTION	01-May-78	Shrewsbury Electric Light Plant	SELP	25	27	CMA/NEMA	WCMA	6125	13.750	13.750	0.000	13.750	13.750
569	SKELTON	569	SKELTON	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-48	FPL Energy Maine Hydro LLC	FPLEMH	23	031	SME	ME	1505	19.704	19.704	0.000	19.704	19.704
570	SMITH	570	SMITH	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-48	Public Service Company of New Hampshire	PSNH	33	007	NH	NH	2368	11.676	15.244	0.000	15.244	11.676
572	SO. MEADOW 11	572	SO. MEADOW 11	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-70	Select Energy Inc.	SEI	09	003	CT	CT	563	35.781	46.921	0.000	46.921	35.781
573	SO. MEADOW 12	573	SO. MEADOW 12	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-70	Select Energy Inc.	SEI	09	003	CT	CT	563	37.701	47.867	0.000	47.867	37.701
574	SO. MEADOW 13	574	SO. MEADOW 13	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-70	Select Energy Inc.	SEI	09	003	CT	CT	563	38.317	47.917	0.000	47.917	38.317
575	SO. MEADOW 14	575	SO. MEADOW 14	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-70	Select Energy Inc.	SEI	09	003	CT	CT	563	36.746	46.346	0.000	46.346	36.746
579	SOMERSET JET 2	579	SOMERSET JET 2	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-May-71	NRG Power Marketing LLC	NRGPM	25	005	SEMA	SEMA	1613	0.000	0.000	0.000	0.000	0.000
580	SO. MEADOW 5	580	SO. MEADOW 5	ST	MSW		BIO/REFUSE	01-Nov-87	Connecticut Light and Power Company, The	CLP	09	003	CT	CT	563	25.677	28.476	1.413	28.476	25.677
581	SO. MEADOW 6	581	SO. MEADOW 6	ST	MSW		BIO/REFUSE	01-Nov-87	Connecticut Light and Power Company, The	CLP	09	003	CT	CT	563	23.742	20.367	-0.684	20.367	23.742
583	STONY BROOK 2A	583	STONY BROOK 2A	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Nov-82	Massachusetts Municipal Wholesale Electric Company	MMWEC	25	013	WMA	WCMA	6081	67.400	87.400	0.000	87.400	67.400
584	STONY BROOK 2B	584	STONY BROOK 2B	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Nov-82	Massachusetts Municipal Wholesale Electric Company	MMWEC	25	013	WMA	WCMA	6081	65.300	85.300	0.000	85.300	65.300
587	STEVENSON	587	STEVENSON	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-19	FirstLight Power Resources Management, LLC	FPRM	09	001	SWCT	CT	553	28.311	28.900	0.000	28.900	28.311
590	REENERGY STRATTON	590	BORALEX STRATTON ENERGY	ST	WDS		BIO/REFUSE	01-Sep-89	ReEnergy Stratton Energy LP	BSEI	23	007	ME	ME	50650	45.024	44.363	0.000	44.363	45.024
591	S.D. WARREN-WESTBROOK	591	S.D. WARREN-WESTBROOK	ST	WDS	RFO	BIO/REFUSE	01-Nov-97	NextEra Energy Power Marketing, LLC	FPLP	23	005	SME	ME	50447	42.590	49.103	0.000	49.103	42.590
592	TAMWORTH	592	TAMWORTH	ST	WDS		BIO/REFUSE	01-Jan-88	GDF SUEZ Energy Marketing NA, Inc.	SUEZ	33	003	NH	NH	50739	19.080	18.302	-0.893	18.302	19.080
594	AES THAMES	594	AES THAMES	ST	BIT		COAL STEAM	01-Dec-89	Connecticut Light and Power Company, The	CLP	09	011	CT	CT	10675	0.000	0.000	-182.653	0.000	0.000
595	TORRINGTON TERMINAL 10	595	TORRINGTON TERMINAL 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Aug-67	NRG Power Marketing LLC	NRGPM	09	005	CT	CT	565	15.638	20.748	0.000	20.748	15.638
596	TUNNEL 10	596	TUNNEL 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	FirstLight Power Resources Management, LLC	FPRM	09	011	CT	CT	557	16.706	21.806	-0.294	21.806	16.706
598	VERGENNES 5 and 6 DIESELS	598	VERGENNES 5 and 6 DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-64	Green Mountain Power Corporation	GMP	50	001	VT	VT	6519	3.940	4.240	0.000	4.240	3.940
599	VERNON	599	VERNON	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-09	TransCanada Power Marketing, Ltd.	TCPM	50	025	WMA	WCMA	2352	32.000	32.000	0.000	32.000	32.000
611	VT YANKEE NUCLEAR PWR STATION	611	VT YANKEE NUCLEAR PWR STATION	ST	NUC		NUCLEAR STEAM	01-Nov-72	Entergy Nuclear Power Marketing LLC	ENPM	50	025	VT	VT	3751	604.250	628.000	0.000	628.000	604.250
612	WATERS RIVER JET 1	612	WATERS RIVER JET 1	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	01-Dec-71	Massachusetts Municipal Wholesale Electric Company	MMWEC	25	009	BOSTON	NEMA	1678	16.050	22.050	0.000	22.050	16.050
613	WATERS RIVER JET 2	613	WATERS RIVER JET 2	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	01-Apr-91	Massachusetts Municipal Wholesale Electric Company	MMWEC	25	009	BOSTON	NEMA	1678	30.506	45.806	0.000	45.806	30.506
614	WATERBURY 22	614	WATERBURY 22	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-53	Green Mountain Power Corporation	GMP	50	005	VT	VT	6520	5.000	5.000	0.000	5.000	5.000
616	WEST ENFIELD	616	WEST ENFIELD	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-88	New Brunswick Power Generation Corporation	NBPGC	23	019	BHE	ME	10255	6.631	11.612	0.000	11.612	6.631
617	WESTON	617	WESTON	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-20	FPL Energy Maine Hydro LLC	FPLEMH	23	025	ME	ME	1509	13.200	13.200	0.000	13.200	13.200
618	DG WHITEFIELD, LLC	618	DG WHITEFIELD, LLC	ST	WDS		BIO/REFUSE	01-Apr-88	Constellation Energy Commodities	CEC	33	007	NH	NH	10839	16.395	17.034	-0.585	17.034	16.395
619	WHITE LAKE JET	619	WHITE LAKE JET	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-68	Public Service Company of New Hampshire	PSNH	33	003	NH	NH	2369	17.447	22.397	0.000	22.397	17.447
620	WILDER	620	WILDER	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-50	TransCanada Power Marketing, Ltd.	TCPM	50	027	VT	NH	2353	41.073	41.337	-0.087	41.337	41.073
621	WILLIAMS	621	WILLIAMS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-39	FPL Energy Maine Hydro LLC	FPLEMH	23	025	ME	ME	1510	14.900	14.900	0.000	14.900	14.900
622	WINOOSKI 1	622	WINOOSKI 1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-93	Vermont Electric Power Company, Inc.	VELCO	50	007	VT	VT	54355	2.183	5.237	0.819	5.237	2.183
623	COVANTA PROJECTS WALLINGFORD	623	WALLINGFORD REFUSE	ST	MSW	DFO	BIO/REFUSE	01-Mar-89	Covanta Projects of Wallingford, L.P.	CPW	09	009	SWCT	CT	50664	4.654	4.221	0.257	4.221	4.654
624	WMI MILLBURY 1	624	WMI MILLBURY 1	ST	MSW		BIO/REFUSE	01-Sep-87	New England Power Company	NEP	25	027	CMA/NEMA	WCMA	50878	39.811	39.891	0.000	39.891	39.811
625	WEST MEDWAY JET 1	625	WEST MEDWAY JET 1	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jul-70	Exelon New England Holdings, LLC	EXNEH	25	021	BOSTON	NEMA	1592	30.762	55.012	0.000	55.012	30.762
626	WEST MEDWAY JET 2	626	WEST MEDWAY JET 2	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Mar-71	Exelon New England Holdings, LLC	EXNEH	25	021	BOSTON	NEMA	1592	34.732	52.932	0.000	52.932	34.732

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ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICIPANT ACRONYM	STATE	COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2012		Change in Summer SCC from 1/1/11	As of 2011/12 Winter and 2012 Summer Peaks	
																SUMMER SCC (MW)	WINTER SCC (MW)		WINTER PEAK SCC JAN 4, 2012	EXPECTED SUMMER PEAK SCC AUG 1, 2012
627	WEST MEDWAY JET 3	627	WEST MEDWAY JET 3	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jul-70	Exelon New England Holdings, LLC	EXNEH	25	021	RI	SEMA	1592	35.441	55.841	0.000	55.841	35.441
628	WOODLAND ROAD	628	WOODLAND ROAD	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jul-69	Hess Corporation	HESS	25	003	WMA	WCMA	1643	15.808	20.658	0.000	20.658	15.808
629	DOWNEAST POWER	629	DOWNEAST POWER	ST	WDS		BIO/REFUSE	01-Nov-97	DownEast Power Company, LLC	DOWN	23	029	BHE	ME	10165	0.000	0.000	0.000	0.000	0.000
630	WEST SPRINGFIELD 10	630	WEST SPRINGFIELD 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-68	Hess Corporation	HESS	25	013	WMA	WCMA	1642	17.143	21.928	-0.072	21.928	17.143
633	WEST SPRINGFIELD 3	633	WEST SPRINGFIELD 3	ST	NG	RFO	GAS/OIL STEAM	01-Jan-57	Hess Corporation	HESS	25	013	WMA	WCMA	1642	94.276	100.087	0.000	100.087	94.276
636	WYMAN HYDRO 1	636	WYMAN HYDRO 1	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-30	FPL Energy Maine Hydro LLC	FPLEMH	23	025	ME	ME	1511	27.362	27.362	0.000	27.362	27.362
637	WYMAN HYDRO 2	637	WYMAN HYDRO 2	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-31	FPL Energy Maine Hydro LLC	FPLEMH	23	025	ME	ME	1511	29.866	29.866	0.000	29.866	29.866
638	WYMAN HYDRO 3	638	WYMAN HYDRO 3	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-40	FPL Energy Maine Hydro LLC	FPLEMH	23	025	ME	ME	1511	0.000	0.000	-25.728	0.000	0.000
639	YARMOUTH 1	639	YARMOUTH 1	ST	RFO		OIL STEAM	01-Jan-57	NextEra Energy Power Marketing, LLC	FPLP	23	005	SME	ME	1507	50.328	52.085	-0.335	52.085	50.328
640	YARMOUTH 2	640	YARMOUTH 2	ST	RFO		OIL STEAM	01-Jan-58	NextEra Energy Power Marketing, LLC	FPLP	23	005	SME	ME	1507	51.131	52.823	0.000	52.823	51.131
641	YARMOUTH 3	641	YARMOUTH 3	ST	RFO		OIL STEAM	01-Jul-65	NextEra Energy Power Marketing, LLC	FPLP	23	005	SME	ME	1507	115.173	116.065	0.000	116.065	115.173
642	YARMOUTH 4	642	YARMOUTH 4	ST	RFO		OIL STEAM	01-Dec-78	NextEra Energy Power Marketing, LLC	FPLP	23	005	SME	ME	1507	603.225	610.375	0.000	610.375	603.225
715	ROCHESTER LANDFILL	715	ROCHESTER LANDFILL	GT	LFG		BIO/REFUSE	01-May-98	New Hampshire Electric Cooperative, Inc.	NHEC	33	017	NH	NH	2007	2.404	2.261	0.531	2.261	2.404
737	SIMPSON G LOAD REDUCER	737	SIMPSON G LOAD REDUCER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Central Vermont Public Service	CVPS	50	009	NH	VT	10608	1.382	3.384	0.000	3.384	1.382
739	ROCKY RIVER	739	ROCKY RIVER	PS	WAT		HYDRO (PUMPED STORAGE)	01-Jan-28	FirstLight Power Resources Management, LLC	FPRM	09	009	SWCT	CT	539	29.350	29.001	0.000	29.001	29.350
754	BAR MILLS	754	BAR MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-56	FPL Energy Maine Hydro LLC	FPLEMH	23	031	SME	ME	1481	1.496	2.897	1.496	2.897	1.496
755	BONNY EAGLE/W. BUXTON	755	BONNY EAGLE/W. BUXTON	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-10	FPL Energy Maine Hydro LLC	FPLEMH	23	031	SME	ME	1482	16.151	17.500	0.000	17.500	16.151
757	HARRIS 4	757	HARRIS 4	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-54	FPL Energy Maine Hydro LLC	FPLEMH	23	025	ME	ME	1492	1.436	1.249	0.000	1.249	1.436
759	MESSALONSKEE COMPOSITE	759	MESSALONSKEE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-18	Messalonskee Stream Hydro, LLC	MESSA	23	011	ME	ME	1497, 1498	3.036	4.400	0.000	4.400	3.036
760	NORTH GORHAM	760	NORTH GORHAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-25	FPL Energy Maine Hydro LLC	FPLEMH	23	005	SME	ME	1501	1.595	2.000	0.000	2.000	1.595
761	SHAWMUT	761	SHAWMUT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-13	FPL Energy Maine Hydro LLC	FPLEMH	23	025	ME	ME	1504	9.500	9.500	0.000	9.500	9.500
767	SES CONCORD	767	SES CONCORD	ST	MSW	RFO	BIO/REFUSE	01-May-89	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	50873	12.159	12.492	-0.028	12.492	12.159
768	GARVINS/HOOKSETT	768	GARVINS/HOOKSETT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-02	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	2357	12.480	14.000	0.000	14.000	12.480
769	HADLEY FALLS 1&2	769	HADLEY FALLS 1&2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-83	Holyoke Gas & Electric Department	HGE	25	013	WMA	WCMA	1605	15.549	29.797	6.850	29.797	15.549
772	NEWPORT HYDRO	772	NEWPORT HYDRO	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-80	Great Bay Power Marketing, Inc	GBPM	50	015	NH	VT	3731	1.610	2.947	0.942	2.947	1.610
774	LOWER LAMOILLE COMPOSITE	774	LOWER LAMOILLE COMPOSITE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-48	Central Vermont Public Service	CVPS	50	015	VT	VT	3711	15.800	16.000	0.000	16.000	15.800
775	MIDDLEBURY COMPOSITE	775	MIDDLEBURY COMPOSITE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-17	Central Vermont Public Service	CVPS	50	001	VT	VT	3716	6.600	6.000	0.000	6.000	6.600
776	N. RUTLAND COMPOSITE	776	N. RUTLAND COMPOSITE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-80	Central Vermont Public Service	CVPS	50	021	VT	VT	3714	5.200	4.360	0.000	4.360	5.200
779	MIDDLESEX 2	779	MIDDLESEX 2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-28	Green Mountain Power Corporation	GMP	50	023	VT	VT	3740	1.553	2.956	0.000	2.956	1.553
781	WEST DANVILLE 1	781	WEST DANVILLE 1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-86	Green Mountain Power Corporation	GMP	50	005	NH	VT	3743	0.000	0.000	0.000	0.000	0.000
783	HIGHGATE FALLS	783	HIGHGATE FALLS	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	50	011	VT	VT	6618	3.587	9.058	0.343	9.058	3.587
786	KEZAR LEDGEMERE COMPOSITE	786	KEZAR LEDGEMERE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-96	NextEra Energy Power Marketing, LLC	FPLP	23	031	SME	ME	7668	0.369	1.079	0.244	0.000	0.000
787	LEWISTON CANAL COMPOSITE	787	LEWISTON CANAL COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-20	FPL Energy Maine Hydro LLC	FPLEMH	23	001	ME	ME	1487	0.000	0.000	0.000	0.000	0.000
789	CEC 002 PAWTUCKET U5	789	CEC 002 PAWTUCKET U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-85	Narragansett Electric Company	NEC	44	007	RI	RI	3233	0.452	0.570	0.452	0.570	0.452
792	CENTENNIAL HYDRO	792	CENTENNIAL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-90	Sterling Municipal Electric Light Department	SMED	25	017	BOSTON	WCMA	7112	0.328	0.507	0.328	0.507	0.328
793	METHUEN HYDRO	793	METHUEN HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Aug-88	Sterling Municipal Electric Light Department	SMED	25	009	BOSTON	NEMA	-	0.018	0.120	0.018	0.120	0.018
794	MINIWAWA	794	MINIWAWA	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-92	Littleton Electric Light & Water Department	LELWD	33	005	VT	NH	-	0.116	0.444	0.116	0.444	0.116
795	RIVER MILL HYDRO	795	RIVER MILL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-89	Middleton Municipal Light Department	MMELD	33	009	NH	NH	3049	0.000	0.086	0.000	0.086	0.000
796	GOODWIN DAM	796	GOODWIN DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-86	Connecticut Light and Power Company, The	CLP	09	005	CT	CT	54302	3.000	3.000	0.000	3.000	3.000
797	WYRE WYND HYDRO	797	CEC 003 WYRE WYND U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-97	Summit Hydropower, Inc.	SUMMIT	09	011	CT	CT	-	1.280	1.307	1.257	1.307	1.280
798	COLEBROOK	798	COLEBROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-88	Connecticut Light and Power Company, The	CLP	09	005	CT	CT	54301	0.860	0.432	0.860	0.432	0.860
799	KINNEYTOWN A	799	KINNEYTOWN A	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-88	Connecticut Light and Power Company, The	CLP	09	009	SWCT	CT	54385	0.000	0.000	0.000	0.000	0.000
800	KINNEYTOWN B	800	KINNEYTOWN B	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-86	Connecticut Light and Power Company, The	CLP	09	009	SWCT	CT	54385	0.330	0.513	0.330	0.513	0.330
801	WILLIMANTIC 1	801	WILLIMANTIC 1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-90	Connecticut Light and Power Company, The	CLP	09	015	CT	CT	-	0.231	0.000	0.231	0.000	0.231
802	WILLIMANTIC 2	802	WILLIMANTIC 2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-90	Connecticut Light and Power Company, The	CLP	09	015	CT	CT	-	0.064	0.323	0.064	0.323	0.064
803	TOUTANT	803	TOUTANT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-94	Connecticut Light and Power Company, The	CLP	09	015	CT	CT	-	0.251	0.396	0.000	0.396	0.251
804	PUTNAM	804	PUTNAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-87	Putnam Hydropower, Inc.	PUTNAM	09	015	CT	CT	-	0.444	0.302	0.444	0.302	0.444
805	GLEN FALLS	805	GLEN FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-98	Connecticut Light and Power Company, The	CLP	09	015	CT	CT	3714	0.000	0.000	0.000	0.000	0.000
806	MECHANICSVILLE	806	MECHANICSVILLE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-95	Sterling Municipal Electric Light Department	SMED	09	015	CT	CT	-	0.107	0.103	0.107	0.103	0.107
807	CEC 004 DAYVILLE POND U5	807	CEC 004 DAYVILLE POND U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-95	Connecticut Light and Power Company, The	CLP	09	015	CT	CT	-	0.024	0.050	0.024	0.050	0.024
808	SANDY HOOK HYDRO	808	SANDY HOOK HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-89	Connecticut Light and Power Company, The	CLP	09	015	CT	CT	-	0.105	0.105	0.028	0.105	0.105
809	PINCHBECK	809	PINCHBECK	ST	WDS		BIO/REFUSE	01-Jul-87	Connecticut Light and Power Company, The	CLP	09	013	CT	CT	-	0.000	0.000	0.000	0.000	0.000

Wkp-ISO NE Capacity (CELT Report)

ASSET ID	ASSET NAME	RESOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICIPANT ACRONYM	STATE	COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2012		Change in Summer SCC from 1/1/11	As of 2011/12 Winter and 2012 Summer Peaks	
																SUMMER SCC (MW)	WINTER SCC (MW)		WINTER PEAK SCC JAN 4, 2012	EXPECTED SUMMER PEAK SCC AUG 1, 2012
810	QUINEBAUG	810	QUINEBAUG	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-90	Connecticut Light and Power Company, The	CLP	09	015	CT	CT	543	0.873	0.839	0.831	0.839	0.873
811	BANTAM	811	BANTAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-05	FirstLight Power Resources Management, LLC	FPRM	09	005	CT	CT	6457	0.060	0.130	0.060	0.130	0.060
812	BEEBE HOLBROOK	812	BEEBE HOLBROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-48	Holyoke Gas & Electric Department	HGE	25	013	WMA	WCMA	1602	0.205	0.205	0.000	0.205	0.205
813	TUNNEL	813	TUNNEL	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-19	FirstLight Power Resources Management, LLC	FPRM	09	011	CT	CT	557	1.056	1.064	1.056	1.064	1.056
814	PATCH	814	PATCH	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Central Vermont Public Service	CVPS	50	021	VT	VT	3719	0.000	0.174	0.000	0.174	0.000
815	CARVER FALLS	815	CARVER FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	25-Sep-98	Central Vermont Public Service	CVPS	50	021	VT	VT	6456	0.325	0.862	0.325	0.862	0.325
816	CAVENDISH	816	CAVENDISH	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	25-Sep-98	Central Vermont Public Service	CVPS	50	027	VT	VT	3710	0.583	0.899	0.460	0.899	0.583
817	TAFTSVILLE VT	817	TAFTSVILLE VT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Central Vermont Public Service	CVPS	50	027	VT	VT	3727	0.000	0.168	0.000	0.168	0.000
818	PIERCE MILLS	818	PIERCE MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Central Vermont Public Service	CVPS	50	005	NH	VT	3721	0.000	0.187	-0.072	0.187	0.000
819	ARNOLD FALLS	819	ARNOLD FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	25-Sep-98	Central Vermont Public Service	CVPS	50	005	VT	VT	3707	0.162	0.244	0.162	0.244	0.162
820	PASSUMPSIC	820	PASSUMPSIC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Central Vermont Public Service	CVPS	50	005	NH	VT	3718	0.290	0.267	0.129	0.267	0.290
821	GAGE	821	GAGE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Central Vermont Public Service	CVPS	50	005	VT	VT	3713	0.182	0.414	0.095	0.414	0.182
822	SMITH (CVPS)	822	SMITH (CVPS)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Central Vermont Public Service	CVPS	50	017	VT	VT	3709	0.469	0.750	0.161	0.750	0.469
823	EAST BARNET	823	EAST BARNET	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Central Vermont Public Service	CVPS	50	005	VT	VT	788	0.895	1.334	0.388	1.334	0.895
824	BATH ELECTRIC HYDRO	824	BATH ELECTRIC HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-85	Public Service Company of New Hampshire	PSNH	33	009	NH	NH	-	0.146	0.159	-0.050	0.159	0.146
825	WEST CHARLESTON	825	WEST CHARLESTON	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-44	Great Bay Power Marketing, Inc	GBPM	50	019	NH	VT	3729	0.000	0.000	0.000	0.000	0.000
826	TROY	826	TROY	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-25	Great Bay Power Marketing, Inc	GBPM	50	019	NH	VT	3733	0.000	0.000	0.000	0.000	0.000
827	SEARSBURG WIND	827	SEARSBURG WIND	WT	WND		WIND TURBINE	01-Jul-97	Green Mountain Power Corporation	GMP	50	003	WMA	WCMA	7381	0.202	0.900	-0.208	0.900	0.202
828	BARTON HYDRO	828	BARTON HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-31	Vermont Public Power Supply Authority	VPPSA	50	019	NH	VT	3753	0.404	0.712	0.194	0.712	0.404
829	ENOSBURG 2 DIESEL	829	ENOSBURG 2 DIESEL	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-35	Vermont Public Power Supply Authority	VPPSA	50	011	VT	VT	4247	0.000	0.416	-0.776	0.416	0.000
830	ENOSBURG HYDRO	830	ENOSBURG HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	50	011	VT	VT	3757	0.000	0.341	-0.501	0.341	0.000
831	VAIL & GREAT FALLS	831	VAIL & GREAT FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	50	005	NH	VT	3726	0.357	0.428	0.319	0.428	0.357
832	CENTER RUTLAND	832	CENTER RUTLAND	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Aug-01	Central Vermont Public Service	CVPS	50	021	VT	VT	6453	0.000	0.000	0.000	0.000	0.000
833	BARNET	833	BARNET	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-01	Central Vermont Public Service	CVPS	50	005	NH	VT	-	0.000	0.162	0.000	0.162	0.000
834	COMPTU FALLS	834	COMPTU FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-82	Central Vermont Public Service	CVPS	50	027	VT	VT	-	0.343	0.402	0.343	0.402	0.343
835	DEWEY MILLS	835	DEWEY MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-01	Central Vermont Public Service	CVPS	50	027	VT	VT	10137	0.419	1.296	0.250	1.296	0.419
836	EMERSON FALLS	836	EMERSON FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-85	Central Vermont Public Service	CVPS	50	005	NH	VT	-	0.000	0.061	0.000	0.061	0.000
837	KILLINGTON	837	KILLINGTON	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-95	Central Vermont Public Service	CVPS	50	021	VT	VT	-	0.000	0.025	0.000	0.025	0.000
838	KINGSBURY	838	KINGSBURY	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-84	Green Mountain Power Corporation	GMP	50	023	VT	VT	-	0.093	0.100	0.001	0.100	0.093
839	LADD'S MILL	839	LADD'S MILL	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-86	Central Vermont Public Service	CVPS	50	023	VT	VT	-	0.034	0.072	0.023	0.072	0.034
840	MARTINSVILLE	840	MARTINSVILLE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-86	Central Vermont Public Service	CVPS	50	027	VT	VT	-	0.000	0.116	0.000	0.116	0.000
841	MORETOWN 8	841	MORETOWN 8	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-89	Central Vermont Public Service	CVPS	50	023	VT	VT	52033	0.000	0.440	0.000	0.440	0.000
842	NANTANA MILL	842	NANTANA MILL	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-86	Central Vermont Public Service	CVPS	50	023	VT	VT	-	0.021	0.106	-0.010	0.106	0.021
843	NEWBURY	843	NEWBURY	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-88	Central Vermont Public Service	CVPS	50	017	VT	VT	-	0.043	0.180	-0.006	0.180	0.043
844	OTTAUQUECHEE	844	OTTAUQUECHEE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-87	Central Vermont Public Service	CVPS	50	027	VT	VT	50126	1.304	1.368	0.698	1.368	1.304
845	SLACK DAM	845	SLACK DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-88	Central Vermont Public Service	CVPS	50	027	VT	VT	-	0.217	0.350	0.187	0.350	0.217
846	WINOOSKI 8	846	WINOOSKI 8	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-85	Central Vermont Public Service	CVPS	50	023	VT	VT	-	0.410	0.626	0.236	0.626	0.410
847	WOODSIDE	847	WOODSIDE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-87	Central Vermont Public Service	CVPS	50	015	VT	VT	-	0.040	0.028	-0.032	0.028	0.040
848	WRIGHTSVILLE	848	WRIGHTSVILLE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-85	Vermont Public Power Supply Authority	VPPSA	50	023	VT	VT	7051	0.068	0.224	0.068	0.224	0.068
849	CRESCENT DAM	849	CRESCENT DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-93	CHI Power Marketing, Inc. (CHIPM)	CHIPM	25	013	WMA	WCMA	-	0.439	0.819	0.439	0.819	0.439
850	GLENDALE HYDRO	850	GLENDALE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-89	CHI Power Marketing, Inc. (CHIPM)	CHIPM	25	003	WMA	WCMA	-	0.575	0.606	0.575	0.606	0.575
851	GARDNER FALLS	851	GARDNER FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-24	EP Energy Massachusetts, LLC	NAEA-EM	25	011	WMA	WCMA	1634	0.000	0.746	0.000	0.746	0.000
852	SOUTH BARRE HYDRO	852	SOUTH BARRE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-89	Massachusetts Municipal Wholesale Electric Company	MMWEC	25	027	CMA/NEMA	WCMA	-	0.091	0.143	0.091	0.143	0.091
853	WEBSTER HYDRO	853	WEBSTER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-83	Massachusetts Municipal Wholesale Electric Company	MMWEC	25	027	CMA/NEMA	WCMA	10404	0.000	0.000	0.000	0.000	0.000
854	ORANGE HYDRO 1	854	ORANGE HYDRO 1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Aug-87	Templeton Municipal Lighting Plant	TTMLP	25	011	WMA	WCMA	-	0.086	0.117	0.086	0.117	0.086
855	ORANGE HYDRO 2	855	ORANGE HYDRO 2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-93	Templeton Municipal Lighting Plant	TTMLP	25	011	WMA	WCMA	-	0.098	0.128	0.098	0.128	0.098
856	HUNT'S POND	856	HUNT'S POND	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Aug-96	Templeton Municipal Lighting Plant	TTMLP	25	027	CMA/NEMA	WCMA	-	0.004	0.017	0.004	0.017	0.004
857	OAKDALE HYDRO	857	OAKDALE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-94	West Boylston Municipal Light	WBMLP	25	027	CMA/NEMA	WCMA	10824	2.312	0.000	-0.616	0.000	2.312
858	STERLING DIESELS	858	STERLING DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	01-Aug-87	Sterling Municipal Electric Light Department	SMED	25	027	CMA/NEMA	WCMA	-	0.329	0.330	-0.001	0.330	0.329
859	BOATLOCK	859	BOATLOCK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-24	Holyoke Gas & Electric Department	HGE	25	013	WMA	WCMA	1603	0.975	2.363	-0.049	2.363	0.975
860	BRIAR HYDRO	860	BRIAR HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-88	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	50351	0.508	3.207	0.508	3.207	0.508
861	CANAAN	861	CANAAN	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-27	Public Service Company of New Hampshire	PSNH	50	009	NH	NH	3750	0.570	1.039	0.072	1.039	0.570

Wkp-ISO NE Capacity (CELT Report)

ASSET ID	ASSET NAME	RESOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICIPANT ACRONYM	STATE	COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2012 SUMMER SCC (MW)	As of Jan. 1, 2012 WINTER SCC (MW)	Change in Summer SCC from 1/1/11	As of 2011/12 Winter and 2012 Summer Peaks WINTER PEAK SCC JAN 4, 2012	As of 2011/12 Winter and 2012 Summer Peaks EXPECTED SUMMER PEAK SCC AUG 1, 2012
862	CHEMICAL	862	CHEMICAL	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-35	Holyoke Gas & Electric Department	HGE	25	013	WMA	WCMA	1604	1.480	1.480	0.000	1.480	1.480
863	CLEMENT DAM	863	CLEMENT DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-85	Public Service Company of New Hampshire	PSNH	33	001	NH	NH	10276	0.633	1.759	0.208	1.759	0.633
864	DWIGHT	864	DWIGHT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-20	EP Energy Massachusetts, LLC	NAEA-EM	25	013	WMA	WCMA	6378	0.401	0.520	0.401	0.520	0.401
865	ERROL	865	ERROL	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-86	Public Service Company of New Hampshire	PSNH	33	007	NH	NH	10570	1.746	2.438	0.143	2.438	1.746
866	GREGGS	866	GREGGS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-86	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	50384	0.549	1.098	0.549	1.098	0.549
867	INDIAN ORCHARD	867	INDIAN ORCHARD	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-28	EP Energy Massachusetts, LLC	NAEA-EM	25	013	WMA	WCMA	6379	0.961	0.672	0.961	0.672	0.961
868	MILTON MILLS HYDRO	868	MILTON MILLS HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-29	Public Service Company of New Hampshire	PSNH	33	017	NH	NH	10519	0.000	0.000	0.000	0.000	0.000
869	MINE FALLS	869	MINE FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-85	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	10183	1.181	1.365	0.957	1.365	1.181
870	PEMBROKE	870	PEMBROKE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-86	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	50312	0.408	1.043	0.408	1.043	0.408
871	PENNACOOK FALLS LOWER	871	PENNACOOK FALLS LOWER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-84	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	50351	1.896	3.206	1.896	3.206	1.896
872	PENNACOOK FALLS UPPER	872	PENNACOOK FALLS UPPER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-86	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	50414	1.270	2.293	1.270	2.293	1.270
873	PUTTS BRIDGE	873	PUTTS BRIDGE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-18	EP Energy Massachusetts, LLC	NAEA-EM	25	013	WMA	WCMA	1637	2.065	1.978	2.065	1.978	2.065
874	RED BRIDGE	874	RED BRIDGE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-26	EP Energy Massachusetts, LLC	NAEA-EM	25	013	WMA	WCMA	1638	1.985	1.943	1.985	1.943	1.985
875	RIVER BEND	875	RIVER BEND	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-86	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	-	0.000	0.985	0.000	0.985	0.000
876	ROBERTSVILLE	876	ROBERTSVILLE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-24	FirstLight Power Resources Management, LLC	FPRM	09	005	CT	CT	549	0.000	0.024	0.000	0.024	0.000
877	SCOTLAND	877	SCOTLAND	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-37	FirstLight Power Resources Management, LLC	FPRM	09	015	CT	CT	551	0.000	1.852	0.000	1.852	0.000
878	SKINNER	878	SKINNER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-24	Holyoke Gas & Electric Department	HGE	25	013	WMA	WCMA	1608	0.000	0.248	0.000	0.248	0.000
879	TAFTVILLE CT	879	TAFTVILLE CT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-06	FirstLight Power Resources Management, LLC	FPRM	09	011	CT	CT	554	0.909	1.044	0.909	1.044	0.909
880	MCCALLUM ENTERPRISES	880	MCCALLUM ENTERPRISES	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-88	United Illuminating Company, The	UI	09	009	SWCT	CT	10063	0.000	0.000	0.000	0.000	0.000
881	SHELTON LANDFILL	881	SHELTON LANDFILL	ST	LFG		BIO/REFUSE	01-Jun-95	United Illuminating Company, The	UI	09	009	SWCT	CT	54336	0.000	0.000	0.000	0.000	0.000
882	FRANKLIN FALLS	882	FRANKLIN FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-78	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	10109	0.352	0.595	0.006	0.595	0.352
883	SALMON FALLS HYDRO	883	SALMON FALLS HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-83	CHI Power Marketing, Inc. (CHIPM)	CHIPM	33	017	NH	ME	50702	0.000	0.480	0.000	0.480	0.000
884	SWANS FALLS	884	SWANS FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-98	Public Service Company of New Hampshire	PSNH	23	017	ME	NH	1518	0.338	0.380	0.149	0.380	0.338
885	STEVENS MILL	885	STEVENS MILL	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-80	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	55861	0.000	0.000	-0.214	0.000	0.000
886	COCHECO FALLS	886	COCHECO FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-83	Public Service Company of New Hampshire	PSNH	33	017	NH	NH	-	0.116	0.428	0.116	0.428	0.116
887	CHINA MILLS DAM	887	CHINA MILLS DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-81	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	-	0.000	0.417	0.000	0.417	0.000
888	NEWFOUND HYDRO	888	NEWFOUND HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-83	Public Service Company of New Hampshire	PSNH	33	009	NH	NH	-	0.341	1.218	0.140	1.218	0.341
889	SUNAPEE HYDRO	889	SUNAPEE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-85	Public Service Company of New Hampshire	PSNH	33	019	NH	NH	-	0.188	0.391	0.188	0.391	0.188
890	NASHUA HYDRO	890	NASHUA HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	-	0.575	0.661	0.445	0.661	0.575
891	HILLSBORO MILLS	891	HILLSBORO MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-88	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	10036	0.032	0.161	0.032	0.161	0.032
892	LAKEPORT DAM	892	LAKEPORT DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-83	Public Service Company of New Hampshire	PSNH	33	001	NH	NH	-	0.147	0.352	0.004	0.352	0.147
893	WEST HOPKINTON HYDRO	893	WEST HOPKINTON HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-82	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	54384	0.382	0.478	0.382	0.478	0.382
894	LISBON HYDRO	894	LISBON HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-86	Public Service Company of New Hampshire	PSNH	33	009	NH	NH	-	0.159	0.398	-0.066	0.398	0.159
895	LOWER ROBERTSON DAM	895	LOWER ROBERTSON DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-87	Harvard Dedicated Energy Limited	HDEL	33	005	VT	NH	-	0.366	0.587	0.315	0.587	0.366
897	OLD NASH DAM	897	OLD NASH DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	33	005	VT	NH	-	0.000	0.077	0.000	0.077	0.000
898	SUGAR RIVER HYDRO	898	SUGAR RIVER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-86	Public Service Company of New Hampshire	PSNH	33	019	NH	NH	-	0.000	0.142	0.000	0.142	0.000
899	GREAT FALLS UPPER	899	GREAT FALLS UPPER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	33	017	NH	NH	-	0.000	0.000	0.000	0.000	0.000
900	GREAT FALLS LOWER	900	GREAT FALLS LOWER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-84	Public Service Company of New Hampshire	PSNH	33	017	NH	NH	50704	0.078	0.550	0.078	0.550	0.078
901	WATERLOOM FALLS	901	WATERLOOM FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-81	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	-	0.019	0.032	0.019	0.032	0.019
902	HOSIERY MILL DAM	902	HOSIERY MILL DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-84	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	-	0.000	0.000	0.000	0.000	0.000
903	WYANDOTTE HYDRO	903	WYANDOTTE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-83	Public Service Company of New Hampshire	PSNH	33	017	NH	NH	-	0.000	0.057	0.000	0.057	0.000
904	LOCHMERE DAM	904	LOCHMERE DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	33	001	NH	NH	54572	0.202	0.647	0.009	0.647	0.202
905	ASHUELOT HYDRO	905	ASHUELOT HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-87	Harvard Dedicated Energy Limited	HDEL	33	005	VT	NH	-	0.386	0.648	0.337	0.648	0.386
906	ROLLINSFORD HYDRO	906	ROLLINSFORD HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-80	Public Service Company of New Hampshire	PSNH	33	017	NH	NH	54418	0.132	0.820	0.132	0.820	0.132
907	BELL MILL/ELM ST. HYDRO	907	BELL MILL/ELM ST. HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-83	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	-	0.000	0.000	0.000	0.000	0.000
908	OTIS MILL HYDRO	908	OTIS MILL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-82	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	50080	0.000	0.013	0.000	0.013	0.000
909	STEELS POND HYDRO	909	STEELS POND HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	-	0.000	0.101	0.000	0.101	0.000
910	CAMPTON DAM	910	CAMPTON DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-85	Public Service Company of New Hampshire	PSNH	33	009	NH	NH	-	0.111	0.178	0.047	0.178	0.111
911	KELLEYS FALLS	911	KELLEYS FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-89	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	-	0.000	0.109	0.000	0.109	0.000
913	GOODRICH FALLS	913	GOODRICH FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-81	Public Service Company of New Hampshire	PSNH	33	003	NH	NH	-	0.180	0.288	0.109	0.288	0.180
914	CHAMBERLAIN FALLS	914	CHAMBERLAIN FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-83	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	-	0.000	0.000	0.000	0.000	0.000
915	MONADNOCK PAPER MILLS	915	MONADNOCK PAPER MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-75	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	-	0.000	0.000	0.000	0.000	0.000

Wkp-ISO NE Capacity (CELT Report)

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICIPANT ACRONYM	STATE	COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2012		Change in Summer SCC from 1/1/11	As of 2011/12 Winter and 2012 Summer Peaks	
																SUMMER SCC (MW)	WINTER SCC (MW)		WINTER PEAK SCC JAN 4, 2012	EXPECTED SUMMER PEAK SCC AUG 1, 2012
919	HOPKINTON HYDRO	919	HOPKINTON HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Sterling Municipal Electric Light Department	SMED	33	013	NH	NH	-	0.117	0.160	0.117	0.160	0.117
921	HADLEY FALLS	921	HADLEY FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-81	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	-	0.000	0.000	0.000	0.000	0.000
922	NOONE FALLS	922	NOONE FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-85	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	-	0.000	0.072	0.000	0.072	0.000
925	OTTER LANE HYDRO	925	OTTER LANE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-84	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	-	0.000	0.064	0.000	0.064	0.000
926	PETERBOROUGH LOWER HYDRO	926	PETERBOROUGH LOWER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-89	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	-	0.000	0.000	0.000	0.000	0.000
928	SALMON BROOK STATION 3	928	SALMON BROOK STATION 3	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-85	Public Service Company of New Hampshire	PSNH	33	013	NH	NH	-	0.000	0.116	0.000	0.116	0.000
931	AVERY DAM	931	AVERY DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-85	Public Service Company of New Hampshire	PSNH	33	001	NH	NH	-	0.158	0.230	-0.007	0.230	0.158
932	WATSON DAM	932	WATSON DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-85	Public Service Company of New Hampshire	PSNH	33	017	NH	NH	-	0.000	0.117	0.000	0.117	0.000
933	WESTON DAM	933	WESTON DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-87	Public Service Company of New Hampshire	PSNH	33	007	NH	NH	1509	0.212	0.340	0.060	0.340	0.212
935	SUNNYBROOK HYDRO 2	935	SUNNYBROOK HYDRO 2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-82	Public Service Company of New Hampshire	PSNH	33	017	NH	NH	-	0.010	0.005	0.001	0.005	0.010
941	PETERBOROUGH UPPER HYDRO	941	PETERBOROUGH UPPER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-90	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	-	0.000	0.114	0.000	0.114	0.000
942	DUNBARTON ROAD LANDFILL	942	DUNBARTON ROAD LANDFILL	IC	LFG		BIO/REFUSE	01-Aug-89	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	55779	0.244	0.290	-0.080	0.290	0.244
943	FOUR HILLS LANDFILL	943	FOUR HILLS LANDFILL	IC	LFG		BIO/REFUSE	01-Apr-96	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	-	0.000	0.000	-0.354	0.000	0.000
946	MERRIMAC PAPER - QF	946	MERRIMAC PAPER - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-71	Massachusetts Electric Company	MEC	25	009	BOSTON	WCMA	10179	0.000	0.000	0.000	0.000	0.000
947	RIVERDALE MILLS - QF	947	RIVERDALE MILLS - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-85	Massachusetts Electric Company	MEC	25	027	CMA/NEMA	SEMA	50601	0.000	0.000	0.000	0.000	0.000
948	PEPPERELL HYDRO COMPANY LLC	948	PEPPERELL HYDRO COMPANY LLC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-20	Swift River Trading Company LLC	SRTC	25	017	BOSTON	WCMA	10694	0.560	0.562	0.366	0.562	0.560
949	VALLEY HYDRO - QF	949	VALLEY HYDRO - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-84	Narragansett Electric Company	NEC	44	003	RI	RI	-	0.079	0.000	0.079	0.000	0.079
950	LP ATHOL - QF	950	LP ATHOL - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-31	Massachusetts Electric Company	MEC	25	027	CMA/NEMA	WCMA	-	0.147	0.046	0.147	0.046	0.147
951	BALTIC MILLS - QF	951	BALTIC MILLS - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-81	Sterling Municipal Electric Light Department	SMED	33	009	NH	NH	-	0.045	0.063	0.037	0.063	0.045
952	PONTIAC ENERGY - QF	952	PONTIAC ENERGY - QF	IC	OBG		BIO/REFUSE	01-Oct-98	Narragansett Electric Company	NEC	44	007	RI	RI	-	0.000	0.104	-0.104	0.104	0.000
953	ATTLEBORO LANDFILL - QF	953	ATTLEBORO LANDFILL - QF	IC	OBG		BIO/REFUSE	01-Nov-97	Massachusetts Electric Company	MEC	25	023	SEMA	SEMA	-	0.117	0.216	0.117	0.216	0.117
954	MM LOWELL LANDFILL - QF	954	MM LOWELL LANDFILL - QF	IC	LFG		BIO/REFUSE	01-Aug-97	Massachusetts Electric Company	MEC	25	017	BOSTON	WCMA	55095	0.072	0.122	-0.035	0.122	0.072
956	WARE COGEN - QF	956	WARE COGEN - QF	ST	MSW		BIO/REFUSE	01-Jan-97	Massachusetts Electric Company	MEC	25	015	WMA	WCMA	-	0.000	0.000	0.000	0.000	0.000
957	HG&E HYDRO/CABOT 1-4	957	HG&E HYDRO/CABOT 1-4	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Holyoke Gas & Electric Department	HGE	25	013	WMA	WCMA	9864	2.590	2.590	0.000	2.590	2.590
959	BARTON 1-4 DIESELS	959	BARTON 1-4 DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	01-Jul-56	Vermont Public Power Supply Authority	VPPSA	50	019	NH	VT	3753	0.586	0.653	-0.038	0.653	0.586
969	POWDER MILL HYDRO	969	POWDER MILL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-90	Massachusetts Municipal Wholesale Electric Company	MMWEC	25	027	CMA/NEMA	WCMA	-	0.000	0.061	0.000	0.061	0.000
970	DUDLEY HYDRO	970	DUDLEY HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-87	Massachusetts Electric Company	MEC	25	027	CMA/NEMA	WCMA	-	0.066	0.100	0.066	0.100	0.066
973	CONCORD STEAM	973	CONCORD STEAM	ST	WDS		BIO/REFUSE	01-Oct-86	Unitil Energy Systems, Inc.	UNITIL-ES	33	013	NH	NH	-	0.000	0.224	0.000	0.224	0.000
978	NEW MILFORD	978	NEW MILFORD	IC	OBG	DFO	BIO/REFUSE	01-Aug-91	Connecticut Light and Power Company, The	CLP	09	005	CT	CT	50564	1.499	1.544	-0.020	1.544	1.499
1005	DIGHTON POWER LLC	1005	BG DIGHTON POWER LLC	CC	NG		GAS COMBINED CYCLE	01-May-99	EquiPower Resources Management, LLC	EPRM	25	005	SEMA	SEMA	55026	150.000	177.388	0.000	177.388	150.000
1028	BUNKER RD #12 GAS TURB	1028	BUNKER RD #12 GAS TURB	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Apr-00	New England Power Company	NEP	25	019	SEMA	SEMA	1615	2.351	3.012	0.000	3.012	2.351
1029	BUNKER RD #13 GAS TURB	1029	BUNKER RD #13 GAS TURB	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Apr-00	New England Power Company	NEP	25	019	SEMA	SEMA	1615	2.840	3.281	0.000	3.281	2.840
1030	OAK BLUFFS	1030	OAK BLUFFS	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-70	Genon Energy Management, LLC	MET	25	007	SEMA	SEMA	1597	8.120	8.120	0.000	8.120	8.120
1031	WEST TISBURY	1031	WEST TISBURY	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-75	Genon Energy Management, LLC	MET	25	007	SEMA	SEMA	6049	5.568	5.524	0.000	5.524	5.568
1032	BRIDGEPORT ENERGY 1	1032	BRIDGEPORT ENERGY 1	CC	NG		GAS COMBINED CYCLE	01-Aug-98	CP Energy Marketing (US) Inc.	CPEM	09	001	SWCT	CT	55042	454.434	533.678	-6.512	533.678	454.434
1034	RIVERSIDE 4-7	1034	RIVERSIDE 4-7	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-21	Holyoke Gas & Electric Department	HGE	25	013	WMA	WCMA	1607	1.552	1.768	0.551	1.768	1.552
1035	RIVERSIDE 8	1035	RIVERSIDE 8	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-31	Holyoke Gas & Electric Department	HGE	25	013	WMA	WCMA	1607	3.024	2.200	3.024	2.200	3.024
1047	FAIRFAX	1047	FAIRFAX	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	25-Sep-98	Central Vermont Public Service	CVPS	50	011	VT	VT	3712	2.211	3.779	1.079	3.779	2.211
1048	WARE HYDRO	1048	WARE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-84	NSTAR Electric Company	NSTAR	25	015	WMA	WCMA	50419	0.420	0.603	0.420	0.603	0.420
1049	COLLINS HYDRO	1049	COLLINS HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	NSTAR Electric Company	NSTAR	25	013	WMA	WCMA	52166	0.568	0.679	0.381	0.679	0.568
1050	CHICOPEE HYDRO	1050	CHICOPEE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-85	NSTAR Electric Company	NSTAR	25	013	WMA	WCMA	50832	1.442	1.263	1.075	1.263	1.442
1051	HAL-BFI	1051	HAL-BFI	IC	LFG		BIO/REFUSE	01-Mar-97	Massachusetts Electric Company	MEC	25	023	SEMA	SEMA	55586	0.000	0.000	0.000	0.000	0.000
1052	EB1-BFI	1052	EB1-BFI	IC	LFG		BIO/REFUSE	01-Mar-97	Taunton Municipal Lighting Plant	TMLP	25	023	SEMA	SEMA	55584	0.000	0.000	-1.081	0.000	0.000
1054	BLACKSTONE HYDRO ASSOC	1054	BLACKSTONE HYDRO ASSOC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-89	Narragansett Electric Company	NEC	44	007	RI	RI	3245	0.000	0.225	0.000	0.225	0.000
1057	BLACKSTONE HYDRO LOAD REDUCER	1057	BLACKSTONE HYDRO LOAD REDUCER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-89	Macquarie Energy LLC	MCPI	44	007	RI	RI	50177	0.655	0.554	0.655	0.554	0.655
1059	BARRE LANDFILL	1059	BARRE LANDFILL	IC	LFG		BIO/REFUSE	01-Jul-96	Dominion Energy Marketing, Inc.	DEM	25	027	WMA	WCMA	55776	0.586	0.743	-0.118	0.743	0.586
1061	MASCOMA HYDRO	1061	MASCOMA HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-89	TransCanada Power Marketing, Ltd.	TCPM	33	009	VT	NH	54471	0.000	0.974	-0.001	0.974	0.000
1062	MWRA COSGROVE	1062	MWRA COSGROVE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Oct-95	Massachusetts Electric Company	MEC	25	027	CMA/NEMA	WCMA	10825	0.893	0.590	-0.046	0.590	0.893
1086	BERKSHIRE POWER	1086	BERKSHIRE POWER	CC	NG		GAS COMBINED CYCLE	19-Jun-00	Shell Energy North America (US), L.P.	SENA	25	013	WMA	WCMA	55041	229.279	246.279	0.000	246.279	229.279
1107	SOMERSET	1107	SOMERSET	ST	BLQ	WDS	BIO/REFUSE	01-Jan-76	Constellation Energy Commodities	CEC	23	011	ME	ME	50406	0.000	0.000	0.000	0.000	0.000
1109	MMWAC	1109	MMWAC	ST	MSW		BIO/REFUSE	01-Jun-92	NextEra Energy Power Marketing, LLC	FPLP	23	001	ME	ME	50035	1.733	2.073	-0.086	2.073	1.733
1113	BRASSUA HYDRO	1113	BRASSUA HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Aug-89	Brookfield Energy Marketing, LP	BEMLP	23	025	ME	ME	10555	2.103	3.288	0.779	3.288	2.103

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ASSET ID	ASSET NAME	RESOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICIPANT ACRONYM	STATE	COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2012		Change in Summer SCC from 1/1/11	As of 2011/12 Winter and 2012 Summer Peaks	
																SUMMER SCC (MW)	WINTER SCC (MW)		WINTER PEAK SCC JAN 4, 2012	EXPECTED SUMMER PEAK SCC AUG 1, 2012
1114	MADISON COMPOSITE	1114	MADISON COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-84	Competitive Energy Services, LLC	CESLLC	23	025	ME	ME	7469	0.000	0.000	0.000	0.000	0.000
1117	GREAT WORKS COMPOSITE	1117	GREAT WORKS COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-84	Macquarie Energy LLC	MCPI	23	031	SME	ME	-	0.012	0.151	0.012	0.151	0.012
1119	KENNEBAGO HYDRO	1119	KENNEBAGO HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-88	NextEra Energy Power Marketing, LLC	FPLP	23	029	BHE	ME	-	0.131	0.538	0.029	0.538	0.131
1122	CASCADE-DIAMOND-QF	1122	CASCADE-DIAMOND-QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	31-Dec-19	Massachusetts Electric Company	MEC	25	013	WMA	WCMA	-	0.105	0.049	0.105	0.049	0.105
1165	CADYS FALLS	1165	CADYS FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	50	017	VT	VT	3765	0.000	0.306	-0.274	0.306	0.000
1166	MORRISVILLE PLANT #2	1166	MORRISVILLE PLANT #2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	50	015	VT	VT	3764	0.363	0.758	0.103	0.758	0.363
1167	WOLCOTT HYDRO #1	1167	WOLCOTT HYDRO #1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-37	Vermont Public Power Supply Authority	VPPSA	50	015	VT	VT	6477	0.301	0.481	0.301	0.481	0.301
1168	H.K. SANDERS	1168	H.K. SANDERS	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-83	Vermont Public Power Supply Authority	VPPSA	50	015	VT	VT	678	1.740	1.686	0.000	1.686	1.740
1185	STONY BROOK GT1A	1185	STONY BROOK GT1A	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Nov-81	Massachusetts Municipal Wholesale Electric Company	MMWEC	25	013	WMA	WCMA	6081	104.000	119.000	0.000	119.000	104.000
1186	STONY BROOK GT1B	1186	STONY BROOK GT1B	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Nov-81	Massachusetts Municipal Wholesale Electric Company	MMWEC	25	013	WMA	WCMA	6081	100.000	116.000	0.000	116.000	100.000
1187	STONY BROOK GT1C	1187	STONY BROOK GT1C	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Nov-81	Massachusetts Municipal Wholesale Electric Company	MMWEC	25	013	WMA	WCMA	6081	104.000	119.000	0.000	119.000	104.000
1188	LOWELL COGENERATION PLANT	1188	LOWELL COGENERATION PLANT	CC	NG	DFO	GAS/OIL COMBINED CYCLE	21-Oct-88	Consolidated Edison Energy, Inc	CEEI	25	017	CMA/NEMA	WCMA	10802	27.175	30.150	-0.575	30.150	27.175
1209	CRRA HARTFORD LANDFILL	1209	CRRA HARTFORD LANDFILL	IC	LFG		BIO/REFUSE	01-Aug-98	Connecticut Light and Power Company, The	CLP	09	003	CT	CT	55163	1.777	1.705	0.035	1.705	1.777
1210	MILLENNIUM	1210	MILLENNIUM	CC	NG		GAS COMBINED CYCLE	06-Apr-01	Merrill Lynch Commodities, Inc.	MLC	25	027	WMA	WCMA	55079	325.786	374.786	0.000	374.786	325.786
1216	MAINE INDEPENDENCE STATION	1216	MAINE INDEPENDENCE STATION	CC	NG		GAS COMBINED CYCLE	01-May-00	Dynegy Marketing and Trade, LLC	DMT1	23	019	BHE	ME	55068	488.275	538.275	0.000	538.275	488.275
1221	ESSEX DIESELS	1221	ESSEX DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-47	Green Mountain Power Corporation	GMP	50	007	VT	VT	3737	7.215	7.854	0.000	7.854	7.215
1224	RANDOLPH/BFG ELECTRIC FACILITY	1224	RANDOLPH/BFG ELECTRIC FACILITY	IC	LFG		BIO/REFUSE	01-Apr-00	Hingham Municipal Lighting Plant	HMLP	25	021	SEMA	SEMA	55585	0.000	0.000	0.000	0.000	0.000
1225	TANNERY DAM	1225	TANNERY DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Massachusetts Electric Company	MEC	25	027	CMA/NEMA	WCMA	55924	0.000	0.000	0.000	0.000	0.000
1226	TIVERTON POWER	1226	TIVERTON POWER	CC	NG		GAS COMBINED CYCLE	18-Aug-00	CP Energy Marketing (US) Inc.	CPEM	44	005	SEMA	RI	55048	244.086	278.756	-0.550	278.756	244.086
1255	RUMFORD POWER	1255	RUMFORD POWER	CC	NG		GAS COMBINED CYCLE	16-Oct-00	CP Energy Marketing (US) Inc.	CPEM	23	017	ME	ME	55100	244.281	269.091	-0.659	269.091	244.281
1258	BHE SMALL HYDRO COMPOSITE	1258	BHE SMALL HYDRO COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-82	New Brunswick Power Generation Corporation	NBPGC	23	021	ME	ME	1469	0.892	2.042	0.742	2.042	0.892
1259	J & L ELECTRIC - BIOMASS I		No Resource [1]	ST	WDS		BIO/REFUSE	01-Nov-84	NextEra Energy Power Marketing, LLC	FPLP	23	007	ME	ME	55034	0.000	0.000	0.000	0.000	0.000
1266	MARSH POWER	1266	MARSH POWER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-86	Christopher M. Anthony	CMA	23	027	ME	ME	1469	0.000	0.000	0.000	0.000	0.000
1267	SPARHAWK	1267	SPARHAWK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-85	Competitive Energy Services, LLC	CESLLC	23	005	SME	ME	-	0.000	0.037	0.000	0.037	0.000
1270	SYSKO STONY BROOK	1270	SYSKO STONY BROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Competitive Energy Services, LLC	CESLLC	23	017	ME	ME	-	0.016	0.015	0.001	0.015	0.016
1271	SYSKO WIGHT BROOK	1271	SYSKO WIGHT BROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-84	Competitive Energy Services, LLC	CESLLC	23	017	ME	ME	-	0.000	0.024	0.000	0.024	0.000
1273	KENNEBEC WATER U5	1273	KENNEBEC WATER U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-95	Messalonskee Stream Hydro, LLC	MESSA	23	025	ME	ME	54148	0.000	0.540	0.000	0.540	0.000
1283	LEWISTON U5	1283	LEWISTON U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-90	Competitive Energy Services, LLC	CESLLC	23	001	ME	ME	1542	0.377	0.383	0.008	0.383	0.377
1286	ANP-BLACKSTONE ENERGY 1	1286	ANP-BLACKSTONE ENERGY CO. #1	CC	NG		GAS COMBINED CYCLE	07-Jun-01	ANP Funding I, LLC	ANP	25	027	RI	SEMA	55212	223.634	253.634	2.278	253.634	223.634
1287	ANP-BLACKSTONE ENERGY 2	1287	ANP-BLACKSTONE ENERGY 2	CC	NG		GAS COMBINED CYCLE	13-Jul-01	ANP Funding I, LLC	ANP	25	027	RI	SEMA	55212	215.874	245.974	-6.440	245.974	215.874
1288	BUCKSPORT ENERGY 4	1288	BUCKSPORT ENERGY 4	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	01-Jan-01	H.Q. Energy Services (US) Inc.	HQE	23	009	BHE	ME	50243	132.600	139.125	2.205	139.125	132.600
1302	TCPMCMPAGF GEN1 U5	1302	TCPMCMPAGF GEN1 U5	IC	OBG		BIO/REFUSE	01-Jun-83	Verso Maine Energy LLC	VERSO	23	007	ME	ME	50081	0.000	0.000	0.000	0.000	0.000
1342	LAKE ROAD 1	1342	LAKE ROAD 1	CC	NG		GAS COMBINED CYCLE	15-Mar-02	EquiPower Resources Management, LLC	EPRM	09	015	RI	RI	55149	245.792	281.416	0.000	281.416	245.792
1343	LAKE ROAD 2	1343	LAKE ROAD 2	CC	NG		GAS COMBINED CYCLE	15-Mar-02	EquiPower Resources Management, LLC	EPRM	09	015	RI	RI	55149	251.213	286.837	0.000	286.837	251.213
1344	LAKE ROAD 3	1344	LAKE ROAD 3	CC	NG		GAS COMBINED CYCLE	22-May-02	EquiPower Resources Management, LLC	EPRM	09	015	RI	RI	55149	248.014	276.784	0.000	276.784	248.014
1368	ROCKY GORGE CORPORATION	1368	ROCKY GORGE CORPORATION	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-84	Rocky Gorge Corporation	RGC	23	031	SME	ME	-	0.087	0.293	0.000	0.293	0.087
1376	WALLINGFORD UNIT 1	1376	PPL WALLINGFORD UNIT 1	GT	NG		GAS COMBUSTION (GAS) TURBINE	31-Dec-01	NextEra Energy Power Marketing, LLC	FPLP	09	009	SWCT	CT	55517	42.300	48.410	0.000	48.410	42.300
1377	WALLINGFORD UNIT 2	1377	PPL WALLINGFORD UNIT 2	GT	NG		GAS COMBUSTION (GAS) TURBINE	07-Feb-02	NextEra Energy Power Marketing, LLC	FPLP	09	009	SWCT	CT	55517	40.609	48.242	-0.758	48.242	40.609
1378	WALLINGFORD UNIT 3	1378	PPL WALLINGFORD UNIT 3	GT	NG		GAS COMBUSTION (GAS) TURBINE	31-Dec-01	NextEra Energy Power Marketing, LLC	FPLP	09	009	SWCT	CT	55517	42.300	47.837	0.000	47.837	42.300
1379	WALLINGFORD UNIT 4	1379	PPL WALLINGFORD UNIT 4	GT	NG		GAS COMBUSTION (GAS) TURBINE	23-Jan-02	NextEra Energy Power Marketing, LLC	FPLP	09	009	SWCT	CT	55517	42.300	47.192	0.393	47.192	42.300
1380	WALLINGFORD UNIT 5	1380	PPL WALLINGFORD UNIT 5	GT	NG		GAS COMBUSTION (GAS) TURBINE	07-Feb-02	NextEra Energy Power Marketing, LLC	FPLP	09	009	SWCT	CT	55517	42.300	49.000	1.579	49.000	42.300
1385	MILFORD POWER 1	1385	MILFORD POWER 1 INCREMENTAL	CC	NG		GAS COMBINED CYCLE	12-Feb-04	Milford Power Company, LLC	MPC	09	009	SWCT	CT	55126	253.610	281.847	0.000	281.847	253.610
1386	MILFORD POWER 2	1386	MILFORD POWER 2	CC	NG		GAS COMBINED CYCLE	03-May-04	Milford Power Company, LLC	MPC	09	009	SWCT	CT	55126	253.093	287.632	0.000	287.632	253.093
1412	ANP-BELLINGHAM 1	1412	ANP-BELLINGHAM 1	CC	NG		GAS COMBINED CYCLE	24-Oct-02	ANP Funding I, LLC	ANP	25	021	RI	SEMA	55211	232.102	262.302	-4.265	262.302	249.178
1415	ANP-BELLINGHAM 2	1415	ANP-BELLINGHAM 2	CC	NG		GAS COMBINED CYCLE	28-Dec-02	ANP Funding I, LLC	ANP	25	021	RI	SEMA	55211	230.316	260.516	-6.704	260.516	230.316
1432	GRS-FALL RIVER	1432	GRS-FALL RIVER	GT	LFG		BIO/REFUSE	01-Aug-00	Taunton Municipal Lighting Plant	TMLP	25	005	SEMA	SEMA	55589	3.113	3.824	0.000	3.824	3.113
1478	MYSTIC 8	1478	MYSTIC 8	CC	NG		GAS COMBINED CYCLE	13-Apr-03	Constellation Energy Commodities	CEC	25	017	BOSTON	NEMA	1588	703.324	841.564	12.409	841.564	703.324
1495	SOUTHBRIDGE P&T QF U5	1495	SOUTHBRIDGE P&T QF U5	IC	NG		GAS INTERNAL COMBUSTION	18-Jun-01	Massachusetts Electric Company	MEC	25	027	CMA/NEMA	WCMA	-	0.000	0.227	0.000	0.227	0.000
1572	GRANBY SANITARY LANDFILL QF	1572	GRANBY SANITARY LANDFILL QF U5	IC	MSW		BIO/REFUSE	12-Jul-02	Industrial Power Services Corp	IPSC	25	015	WMA	WCMA	-	2.609	3.092	-0.191	3.092	2.609
1616	MYSTIC 9	1616	MYSTIC 9	CC	NG		GAS COMBINED CYCLE	11-Jun-03	Constellation Energy Commodities	CEC	25	017	BOSTON	NEMA	1588	695.190	843.950	4.275	843.950	695.190
1625	GRANITE RIDGE ENERGY	1625	GRANITE RIDGE ENERGY	CC	NG		GAS COMBINED CYCLE	01-Apr-03	Merrill Lynch Commodities, Inc.	MLC	33	011	NH	NH	55170	661.322	799.322	0.000	799.322	661.322
1630	RISEP	1630	RISEP	CC	NG		GAS COMBINED CYCLE	05-Nov-02	NextEra Energy Power Marketing, LLC	FPLP	44	007	RI	RI	55107	536.419	575.000	7.841	575.000	536.419

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ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICIPANT ACRONYM	STATE	COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2012		Change in Summer SCC from 1/1/11	As of 2011/12 Winter and 2012 Summer Peaks	
																SUMMER SCC (MW)	WINTER SCC (MW)		WINTER PEAK SCC JAN 4, 2012	EXPECTED SUMMER PEAK SCC AUG 1, 2012
1641	WAUSAU COGEN U5	1641	WAUSAU COGEN U5	GT	NG		GAS COMBUSTION (GAS) TURBINE	01-Dec-01	Public Service Company of New Hampshire	PSNH	33	007	NH	NH	-	0.000	0.000	0.000	0.000	0.000
1649	NAEA NEWINGTON ENERGY, LLC	1649	NAEA NEWINGTON ENERGY, LLC	CC	NG	DFO	GAS/OIL COMBINED CYCLE	18-Sep-02	Shell Energy North America (US), L.P.	SENA	33	015	NH	NH	55661	506.244	559.523	0.000	559.523	506.244
1656	HULL WIND TURBINE U5	1656	HULL WIND TURBINE U5	WT	WND		WIND TURBINE	01-Jul-01	Hull Municipal Lighting Plant	HULL	25	009	BOSTON	SEMA	-	0.046	0.180	-0.052	0.180	0.046
1672	KENDALL CT	1672	KENDALL CT	CC	NG	DFO	GAS/OIL COMBINED CYCLE	18-Dec-02	Genon Energy Management, LLC	MET	25	017	BOSTON	NEMA	1595	153.533	181.505	0.000	181.505	153.533
1678	SYSKO GARDNER BROOK U5	1678	SYSKO GARDNER BROOK U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-02	Competitive Energy Services, LLC	CESLLC	23	017	ME	ME	-	0.000	0.000	0.000	0.000	0.000
1691	FORE RIVER-1	1691	FORE RIVER-1	CC	NG		GAS COMBINED CYCLE	04-Aug-03	Constellation Energy Commodities	CEC	25	021	SEMA	SEMA	55317	688.297	836.632	0.000	836.632	688.297
1693	WEST SPRINGFIELD GT-1	1693	WEST SPRINGFIELD GT-1	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	07-Jun-02	Hess Corporation	HESS	25	013	WMA	WCMA	1642	36.908	46.908	0.000	46.908	36.908
1694	WEST SPRINGFIELD GT-2	1694	WEST SPRINGFIELD GT-2	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	07-Jun-02	Hess Corporation	HESS	25	013	WMA	WCMA	1642	37.441	47.441	0.000	47.441	37.441
1720	MIDDLEBURY LOWER	1720	MIDDLEBURY LOWER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-02	Central Vermont Public Service	CVPS	50	001	VT	VT	3716	1.144	1.277	0.690	1.277	1.144
2278	BARKER LOWER HYDRO	2278	BARKER LOWER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-80	Macquarie Energy LLC	MCPI	23	001	ME	ME	10728	0.000	0.725	0.000	0.725	0.000
2279	BARKER UPPER HYDRO	2279	BARKER UPPER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-87	Macquarie Energy LLC	MCPI	23	001	ME	ME	52171	0.233	1.025	0.233	1.025	0.233
2280	BENTON FALLS HYDRO	2280	BENTON FALLS HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-87	Littleton Electric Light & Water Department	LELWD	23	011	ME	ME	10523	0.658	2.807	0.605	2.807	0.658
2281	BROWNS MILL HYDRO	2281	BROWNS MILL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-83	Macquarie Energy LLC	MCPI	23	021	ME	ME	50688	0.157	0.597	0.157	0.597	0.157
2282	DAMARISCOTTA HYDRO	2282	DAMARISCOTTA HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-84	Macquarie Energy LLC	MCPI	23	015	ME	ME	2282	0.000	0.287	0.000	0.287	0.000
2283	EUSTIS HYDRO	2283	EUSTIS HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-84	Macquarie Energy LLC	MCPI	23	007	ME	ME	50688	0.071	0.151	0.023	0.151	0.071
2284	GARDINER HYDRO	2284	GARDINER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-83	Macquarie Energy LLC	MCPI	23	011	ME	ME	50688	0.000	0.978	0.000	0.978	0.000
2285	GREENVILLE HYDRO	2285	GREENVILLE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-84	Macquarie Energy LLC	MCPI	23	021	ME	ME	50688	0.000	0.510	0.000	0.510	0.000
2286	HACKETT MILLS HYDRO	2286	HACKETT MILLS HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-85	NextEra Energy Power Marketing, LLC	FPLP	23	001	ME	ME	2286	0.097	0.453	0.097	0.453	0.097
2287	MECHANIC FALLS HYDRO	2287	MECHANIC FALLS HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-84	Macquarie Energy LLC	MCPI	23	001	ME	ME	2287	0.151	0.768	0.151	0.768	0.151
2288	NORWAY HYDRO	2288	NORWAY HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-85	Macquarie Energy LLC	MCPI	23	017	ME	ME	50688	0.000	0.000	0.000	0.000	0.000
2289	PIONEER DAM HYDRO	2289	PIONEER DAM HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-85	Christopher M. Anthony	CMA	23	025	ME	ME	2289	0.075	0.081	0.075	0.081	0.075
2290	PITTSFIELD HYDRO	2290	PITTSFIELD HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-84	Macquarie Energy LLC	MCPI	23	025	ME	ME	2290	0.000	0.551	0.000	0.551	0.000
2291	WAVERLY AVENUE HYDRO	2291	WAVERLY AVENUE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-84	Christopher M. Anthony	CMA	23	025	ME	ME	2291	0.159	0.246	0.159	0.246	0.159
2292	YORK HYDRO	2292	YORK HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-84	Macquarie Energy LLC	MCPI	23	031	SME	ME	50688	0.053	0.633	0.053	0.633	0.053
2425	SPRINGFIELD REFUSE-NEW	2425	SPRINGFIELD REFUSE-NEW	ST	MSW	DFO	BIO/REFUSE	01-Sep-88	Covanta Energy Marketing, LLC	CEM	25	013	WMA	WCMA	8100	5.408	5.777	-0.279	5.777	5.408
2426	HYDRO KENNEBEC	2426	HYDRO KENNEBEC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-89	Brookfield Energy Marketing, LP	BEMLP	23	011	ME	ME	54148	7.428	7.478	3.692	7.478	7.428
2430	BELDENS-NEW	2430	BELDENS-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Central Vermont Public Service	CVPS	50	001	VT	VT	6451	1.500	4.100	0.550	4.100	1.500
2431	DODGE FALLS-NEW	2431	DODGE FALLS-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-90	Vermont Electric Power Company, Inc.	VELCO	50	023	VT	VT	10526	3.959	4.560	2.350	4.560	3.959
2432	HUNTINGTON FALLS-NEW	2432	HUNTINGTON FALLS-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-88	Central Vermont Public Service	CVPS	50	001	VT	VT	50713	1.700	2.400	0.200	2.400	1.700
2433	RYEGATE 1-NEW	2433	RYEGATE 1-NEW	ST	WDS		BIO/REFUSE	01-Nov-92	Vermont Electric Power Company, Inc.	VELCO	50	005	NH	VT	51026	20.640	20.720	-0.100	20.720	20.640
2434	GORGE 18 HYDRO-NEW	2434	GORGE 18 HYDRO-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-28	Green Mountain Power Corporation	GMP	50	007	VT	VT	6475	2.157	3.300	0.000	3.300	2.157
2435	VERGENNES HYDRO-NEW	2435	VERGENNES HYDRO-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-12	Green Mountain Power Corporation	GMP	50	001	VT	VT	6519	1.020	2.064	0.000	2.064	1.020
2439	BROCKWAY MILLS U5	2439	BROCKWAY MILLS U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-03	Green Mountain Power Corporation	GMP	50	025	VT	VT	-	0.008	0.340	0.008	0.340	0.008
2462	PLAINVILLE GEN QF U5	2462	PLAINVILLE GEN QF U5	IC	OBG		BIO/REFUSE	24-Mar-03	Massachusetts Electric Company	MEC	25	021	SEMA	SEMA	-	2.732	2.944	-0.266	2.944	2.732
2466	CHERRY 7	2466	CHERRY 7	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	25	017	CMA/NEMA	WCMA	9038	2.800	2.800	0.000	2.800	2.800
2467	CHERRY 8	2467	CHERRY 8	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	25	017	CMA/NEMA	WCMA	9038	3.400	3.400	0.000	3.400	3.400
2468	CHERRY 10	2468	CHERRY 10	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	25	017	CMA/NEMA	WCMA	9038	2.100	2.100	0.000	2.100	2.100
2469	CHERRY 11	2469	CHERRY 11	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	25	017	CMA/NEMA	WCMA	9038	2.100	2.100	0.000	2.100	2.100
2470	CHERRY 12	2470	CHERRY 12	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	25	017	CMA/NEMA	WCMA	9038	4.999	5.000	0.000	5.000	4.999
10308	NECCO COGENERATION FACILITY	10308	NECCO COGENERATION FACILITY	IC	DFO		OIL INTERNAL COMBUSTION	01-Oct-03	New England Confectionery Company, Inc (AKA NECCO, Inc	NECCO	25	025	BOSTON	NEMA	-	4.871	4.948	0.000	4.948	4.871
10347	KENDALL STEAM 1	37040	KENDALL STEAM	ST	NG		GAS STEAM	01-Jan-50	Genon Energy Management, LLC	MET	25	017	BOSTON	NEMA	1595	13.565	17.668	0.000	17.668	13.565
10348	KENDALL STEAM 2	37040	KENDALL STEAM	ST	NG		GAS STEAM	01-Jan-50	Genon Energy Management, LLC	MET	25	017	BOSTON	NEMA	1595	20.738	20.690	0.000	20.690	20.738
10349	KENDALL STEAM 3	37040	KENDALL STEAM	ST	NG		GAS STEAM	01-Jan-50	Genon Energy Management, LLC	MET	25	017	BOSTON	NEMA	1595	19.116	24.442	0.000	24.442	19.116
10362	ACTON HYDRO INC.	10362	ACTON HYDRO INC.	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-94	Concord Municipal Light Plant	Concord	25	017	BOSTON	NEMA	-	0.000	0.000	0.000	0.000	0.000
10366	RRIG EXPANSION PHASE 1	10366	RRIG EXPANSION PHASE 1	IC	LFG		BIO/REFUSE	18-Feb-04	Rhode Island Engine Genco, LLC	RRIG	44	007	RI	RI	50365	0.000	0.000	0.000	0.000	0.000
10401	CELLEY MILL U5	10401	CELLEY MILL U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	33	009	NH	NH	-	0.000	0.112	0.000	0.112	0.000
10402	PETTYBORO HYDRO U5	10402	PETTYBORO HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	09-May-99	Public Service Company of New Hampshire	PSNH	33	009	NH	NH	-	0.000	0.007	-0.001	0.007	0.000
10403	EASTMAN BROOK U5	10403	EASTMAN BROOK U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-85	Public Service Company of New Hampshire	PSNH	33	009	NH	NH	-	0.000	0.068	0.000	0.068	0.000
10404	WHEELABRATOR CLAREMONT U5	10404	WHEELABRATOR CLAREMONT U5	ST	MSW		BIO/REFUSE	01-Mar-04	Public Service Company of New Hampshire	PSNH	33	019	NH	NH	50872	3.799	3.444	0.314	3.444	3.799
10406	LOWER VALLEY HYDRO U5	10406	LOWER VALLEY HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-04	Central Vermont Public Service	CVPS	33	019	NH	NH	-	0.262	0.388	0.262	0.388	0.262
10407	WOODSVILLE HYDRO U5	10407	WOODSVILLE HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-87	Central Vermont Public Service	CVPS	33	019	NH	NH	-	0.000	0.054	0.000	0.054	0.000
10408	LOWER VILLAGE HYDRO U5	10408	LOWER VILLAGE HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-95	Central Vermont Public Service	CVPS	33	019	NH	NH	-	0.000	0.566	0.000	0.566	0.000

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ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICIPANT ACRONYM	STATE	COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2012		Change in Summer SCC from 1/1/11	As of 2011/12 Winter and 2012 Summer Peaks	
																SUMMER SCC (MW)	WINTER SCC (MW)		WINTER PEAK SCC JAN 4, 2012	EXPECTED SUMMER PEAK SCC AUG 1, 2012
10409	SWEETWATER HYDRO U5	10409	SWEETWATER HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-04	Central Vermont Public Service	CVPS	33	019	NH	NH	-	0.246	0.334	0.246	0.334	0.246
10424	GREAT LAKES - BERLIN	10424	GREAT LAKES - BERLIN INCREMENTAL	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	22-Jun-04	Brookfield Energy Marketing, LP	BEMLP	33	007	NH	NH	54639	11.125	21.846	6.123	21.846	11.125
10451	WESTFIELD #1 U5	10451	WESTFIELD #1 U5	IC	OBG		BIO/REFUSE	01-Mar-04	Westfield Gas and Electric Light Department	WGED	25	003	WMA	WCMA	-	0.000	0.000	0.000	0.000	0.000
10615	BLUE SPRUCE FARM	10615	BLUE SPRUCE FARM U5	IC	OBG		BIO/REFUSE	01-Nov-04	Central Vermont Public Service	CVPS	50	021	VT	VT	-	0.166	0.144	-0.034	0.144	0.166
10770	WEST SPRINGFIELD HYDRO U5	10770	WEST SPRINGFIELD HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	10-Jan-05	Littleton Electric Light & Water Department	LELWD	25	003	WMA	WCMA	-	0.307	0.906	0.307	0.906	0.307
10801	COVENTRY CLEAN ENERGY	10801	COVENTRY CLEAN ENERGY	IC	LFG		BIO/REFUSE	01-Feb-05	Vermont Public Power Supply Authority	VPPSA	50	019	VT	VT	-	3.420	3.600	0.180	3.600	3.420
10880	GE LYNN EXCESS REPLACEMENT	10880	GE LYNN EXCESS REPLACEMENT	CC	DFO	NG	GAS/OIL COMBINED CYCLE	11-Oct-05	Constellation NewEnergy, Inc.	CNE	25	025	BOSTON	NEMA	10029	0.000	0.000	0.000	0.000	0.000
10959	RRIG EXPANSION PHASE 2	10959	RRIG EXPANSION PHASE 2	IC	LFG		BIO/REFUSE	01-Jun-05	Rhode Island Engine Genco, LLC	RRIG	44	007	RI	RI	50365	4.649	4.999	-0.215	4.999	4.649
10998	MASSINNOVATION FITCHBURG	10998	MASSINNOVATION FITCHBURG	PV	SUN		MISC. OTHER	01-Aug-05	Fitchburg Gas & Electric Light Company	FGE	25	027	CMA/NEMA	WCMA	-	0.001	0.000	0.001	0.000	0.001
11052	GRTR NEW BEDFORD LFG UTIL PROJ	11052	GRTR NEW BEDFORD LFG UTIL PROJ	IC	LFG		BIO/REFUSE	15-Aug-05	Constellation Energy Commodities	CEC	25	005	SEMA	SEMA	-	2.408	2.431	-0.004	2.431	2.408
11126	NORTH HARTLAND HYDRO	11126	NORTH HARTLAND HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	27-Sep-06	Central Vermont Public Service	CVPS	50	027	VT	VT	-	3.887	4.112	0.664	4.112	3.887
11154	BRATTLEBORO LANDFILL	11154	BRATTLEBORO LANDFILL	IC	LFG		BIO/REFUSE	04-Nov-05	Central Vermont Public Service	CVPS	50	025	VT	VT	-	0.000	0.000	0.000	0.000	0.000
11408	HULL WIND TURBINE II	11408	HULL WIND TURBINE II	WT	WND		WIND TURBINE	27-Sep-05	Hull Municipal Lighting Plant	HULL	25	009	BOSTON	SEMA	-	0.052	0.458	-0.108	0.458	0.052
11424	RUMFORD FALLS	11424	RUMFORD FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	06-Jul-06	Brookfield Energy Marketing, LP	BEMLP	23	017	ME	ME	10493	26.481	36.810	3.669	36.810	26.481
11827	PORTSMOUTH ABBEY WIND QF	11827	PORTSMOUTH ABBEY WIND QF	WT	WND		WIND TURBINE	25-Jul-06	Narragansett Electric Company	NEC	44	005	RI	RI	-	0.000	0.000	0.000	0.000	0.000
11842	WATERSIDE POWER	11842	WATERSIDE POWER	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-May-04	Waterside Power, LLC	WATERSIDE	09	001	NOR	CT	56189	70.937	72.477	-0.767	72.477	70.937
11889	IBEW LOCAL 99 SOLAR QF	11889	IBEW LOCAL 99 SOLAR QF	PV	SUN		MISC. OTHER	01-Sep-06	Narragansett Electric Company	NEC	44	007	RI	RI	-	0.000	0.000	0.000	0.000	0.000
11925	BROCKTON BRIGHTFIELDS	11925	BROCKTON BRIGHTFIELDS	PV	SUN		MISC. OTHER	18-Sep-06	Constellation Energy Commodities	CEC	25	023	SEMA	SEMA	-	0.151	0.000	-0.003	0.000	0.151
12108	FIEC DIESEL	12108	FIEC DIESEL	IC	DFO		OIL INTERNAL COMBUSTION	01-Dec-06	Vermont Public Power Supply Authority	VPPSA	23	011	ME	ME	-	1.640	1.640	0.000	1.640	1.640
12163	PPL GREAT WORKS - RED SHIELD	12163	PPL GREAT WORKS - RED SHIELD	ST	WDS		BIO/REFUSE	24-Jan-07	Competitive Energy Services, LLC	CESLLC	23	019	BHE	ME	-	0.000	0.000	0.000	0.000	0.000
12168	HARRIS ENERGY	12168	HARRIS ENERGY	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-06	Holyoke Gas & Electric Department	HGE	25	013	WMA	WCMA	-	0.000	0.255	0.000	0.255	0.000
12180	BERKSHIRE COW POWER	12180	BERKSHIRE COW POWER	IC	OBG		BIO/REFUSE	06-Dec-06	Vermont Electric Cooperative	VEC	50	011	VT	VT	-	0.258	0.332	-0.025	0.332	0.258
12274	GREEN MOUNTAIN DAIRY	12274	GREEN MOUNTAIN DAIRY	IC	OBG		BIO/REFUSE	01-Feb-07	Central Vermont Public Service	CVPS	50	011	VT	VT	-	0.154	0.235	-0.038	0.235	0.154
12323	COVENTRY CLEAN ENERGY #4	12323	COVENTRY CLEAN ENERGY #4	IC	LFG		BIO/REFUSE	20-Jan-07	Vermont Public Power Supply Authority	VPPSA	50	019	VT	VT	-	2.280	2.400	0.120	2.400	2.280
12504	DEVON 15	12504	DEVON 15-18	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	12-Jul-10	GenConn Energy LLC	GCE	09	9	SWCT	CT	57070	46.852	49.152	0.000	49.152	46.852
12505	MIDDLETOWN 12	12505	MIDDLETOWN 12-15	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	24-Jun-11	GenConn Energy LLC	GCE	09	007	CT	CT	57068	46.900	49.200	46.900	49.200	46.900
12509	UNH POWER PLANT	12509	UNH POWER PLANT	GT	LFG		BIO/REFUSE	20-Oct-09	Public Service Company of New Hampshire	PSNH	33	017	NH	NH	-	3.108	4.478	0.000	4.478	3.108
12510	SWANTON GT-1	12510	SWANTON GAS TURBINE 1	GT	DFO	OBL	OIL COMBUSTION (GAS) TURBINE	12-Feb-10	Vermont Public Power Supply Authority	VPPSA	50	011	VT	VT	-	18.169	20.767	-0.098	20.767	18.169
12511	SWANTON GT-2	12511	SWANTON GAS TURBINE 2	GT	DFO	OBL	OIL COMBUSTION (GAS) TURBINE	24-May-10	Vermont Public Power Supply Authority	VPPSA	50	11	VT	VT	-	18.110	21.055	0.000	21.055	18.110
12530	SHEFFIELD WIND PLANT	12530	SHEFFIELD WIND FARM	WT	WND		WIND TURBINE	19-Oct-11	Vermont Wind, LLC	VTWIND	50	05	VT	VT	57080	10.000	17.000	10.000	17.000	10.000
12551	KIBBY WIND POWER	12551	KIBBY WIND POWER	WT	WND		WIND TURBINE	16-Sep-09	TransCanada Power Marketing, Ltd.	TCPM	23	007	ME	ME	56829	13.375	34.590	-7.025	34.590	13.375
12564	WATERBURY GENERATION FACILITY	12564	WATERBURY GENERATION FACILITY	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	21-May-09	Waterbury Generation LLC	WATERBURY	09	009	SWCT	CT	-	96.349	98.749	-1.171	98.749	96.349
13515	PIERCE STATION	12526	PIERCE	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-07	Connecticut Municipal Electric Energy Cooperative	CMEEC	09	009	SWCT	CT	6635	75.829	96.334	-0.298	96.334	75.829
13664	JOHN STREET #3	13664	JOHN STREET #3	IC	DFO		OIL INTERNAL COMBUSTION	26-Sep-07	Connecticut Municipal Electric Energy Cooperative	CMEEC	09	009	SWCT	CT	56256	2.000	2.000	0.000	2.000	2.000
13665	JOHN STREET #4	13665	JOHN STREET #4	IC	DFO		OIL INTERNAL COMBUSTION	26-Sep-07	Connecticut Municipal Electric Energy Cooperative	CMEEC	09	009	SWCT	CT	46256	2.000	2.000	0.000	2.000	2.000
13666	JOHN STREET 5	12528	JOHN STREET #5	IC	DFO		OIL INTERNAL COMBUSTION	01-Nov-07	Connecticut Municipal Electric Energy Cooperative	CMEEC	09	009	SWCT	CT	56256	2.011	2.003	0.000	2.003	2.011
13669	EAST WINDSOR NORCAP LFG PLANT	13669	MANCHESTER METHANE LLC East Windsor	IC	LFG		BIO/REFUSE	07-May-07	Manchester Methane, LLC	MMLLC	09	003	CT	CT	-	0.877	0.927	-0.098	0.927	0.877
13673	MATEP (DIESEL)	13673	MATEP (DIESEL)	IC	DFO		OIL INTERNAL COMBUSTION	28-Jun-07	MATEP, LLC	MATEP	25	025	BOSTON	NEMA	10883	17.783	18.298	0.000	18.298	17.783
13675	MATEP (COMBINED CYCLE)	13675	MATEP (COMBINED CYCLE)	CC	NG	DFO	GAS/OIL COMBINED CYCLE	28-Jun-07	MATEP, LLC	MATEP	25	025	BOSTON	NEMA	10883	45.285	48.285	3.476	48.285	45.285
13703	VERSO COGEN 1	13703	Verso VCG1	GT	NG	KER	GAS COMBUSTION (GAS) TURBINE	28-Dec-00	Verso Maine Energy LLC	VERSO	23	007	ME	ME	55031	40.300	52.500	0.000	52.500	40.300
13704	VERSO COGEN 2	13704	Verso VCG2	GT	NG	KER	GAS COMBUSTION (GAS) TURBINE	28-Dec-00	Verso Maine Energy LLC	VERSO	23	007	ME	ME	55031	40.300	52.500	0.000	52.500	40.300
13705	VERSO COGEN 3	13705	Verso VCG3	GT	NG	KER	GAS COMBUSTION (GAS) TURBINE	28-Dec-00	Verso Maine Energy LLC	VERSO	23	007	ME	ME	55031	40.300	52.500	0.000	52.500	40.300
13933	JIMINY PEAK WIND QF		No Resource [1]	WT	WND		WIND TURBINE	01-Jul-07	Massachusetts Electric Company	MEC	25	003	WMA	WCMA	-	0.000	0.000	-0.019	0.000	0.000
13975	CORRIVEAU HYDROELECTRIC LLC	13975	CORRIVEAU HYDROELECTRIC LLC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	10-Aug-07	Competitive Energy Services, LLC	CESLLC	23	017	ME	ME	-	0.052	0.215	0.052	0.215	0.052
14087	MAT3	14087	MAT3	IC	DFO		OIL INTERNAL COMBUSTION	11-Dec-07	MATEP, LLC	MATEP	25	025	BOSTON	NEMA	10883	11.573	11.743	-5.860	11.743	11.573
14098	FITCHBURG LANDFILL	35485	FITCHBURG-FCA-5	IC	LFG		BIO/REFUSE	16-Aug-07	Vermont Public Power Supply Authority	VPPSA	25	027	CMA/NEMA	WCMA	-	4.234	4.207	0.469	4.207	4.234
14134	MONTAGNE FARM	14134	MONTAGNE FARM	IC	LFG		BIO/REFUSE	17-Sep-07	Central Vermont Public Service	CVPS	50	011	VT	VT	-	0.121	0.064	-0.069	0.064	0.121
14157	COS COB 13	12524	COS COB 13&14	GT	KER		OIL COMBUSTION (GAS) TURBINE	29-May-08	NRG Power Marketing LLC	NRGPM	09	001	NOR	CT	-	19.053	22.852	-0.148	22.852	19.053
14158	COS COB 14	12524	COS COB 13&14	GT	KER		OIL COMBUSTION (GAS) TURBINE	29-May-08	NRG Power Marketing LLC	NRGPM	09	001	NOR	CT	-	19.607	23.000	0.000	23.000	19.607
14177	WESTBROOK ENERGY CENTER G1	1345	WESTBROOK	CC	NG		GAS COMBINED CYCLE	13-Apr-01	Calpine Energy Services, LP	CALP	23	005	SME	ME	55294	260.938	277.094	5.906	277.094	260.938
14178	WESTBROOK ENERGY CENTER G2	1345	WESTBROOK	CC	NG		GAS COMBINED CYCLE	13-Apr-01	Calpine Energy Services, LP	CALP	23	005	SME	ME	55294	254.380	270.536	0.000	270.536	254.380
14211	INDECK ALEXANDRIA	1631	INDECK-ENERGY ALEXANDRIA, LLC	ST	WDS		BIO/REFUSE	06-Nov-08	Indeck Energy-Alexandria, L.L.C.	IEA	33	009	NH	NH	-	11.364	15.200	-2.518	15.200	11.364

Wkp-ISO NE Capacity (CELT Report)

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICIPANT ACRONYM	STATE	COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2012		Change in Summer SCC from 1/1/11	As of 2011/12 Winter and 2012 Summer Peaks	
																SUMMER SCC (MW)	WINTER SCC (MW)		WINTER PEAK SCC JAN 4, 2012	EXPECTED SUMMER PEAK SCC AUG 1, 2012
14217	NORTHFIELD MOUNTAIN 1	14217	NORTHFIELD MOUNTAIN 1	PS	WAT		HYDRO (PUMPED STORAGE)	30-Nov-72	FirstLight Power Resources Management, LLC	FPRM	25	011	WMA	WCMA	547	270.000	270.000	270.000	270.000	270.000
14218	NORTHFIELD MOUNTAIN 2	14218	NORTHFIELD MOUNTAIN 2	PS	WAT		HYDRO (PUMPED STORAGE)	30-Nov-72	FirstLight Power Resources Management, LLC	FPRM	25	011	WMA	WCMA	547	270.000	270.000	270.000	270.000	270.000
14219	NORTHFIELD MOUNTAIN 3	14219	NORTHFIELD MOUNTAIN 3	PS	WAT		HYDRO (PUMPED STORAGE)	30-Nov-72	FirstLight Power Resources Management, LLC	FPRM	25	011	WMA	WCMA	547	292.000	270.000	292.000	270.000	292.000
14220	NORTHFIELD MOUNTAIN 4	14220	NORTHFIELD MOUNTAIN 4	PS	WAT		HYDRO (PUMPED STORAGE)	30-Nov-72	FirstLight Power Resources Management, LLC	FPRM	25	011	WMA	WCMA	547	270.000	270.000	270.000	270.000	270.000
14271	AMERESCO NORTHAMPTON	14271	AMERESCO NORTHAMPTON	IC	LFG		BIO/REFUSE	01-Nov-07	Constellation Energy Commodities	CEC	25	015	WMA	WCMA	-	0.000	0.000	0.000	0.000	0.000
14382	ETHAN ALLEN CO-GEN 1		No Resource [1]	ST	LFG		BIO/REFUSE	07-Nov-07	Vermont Electric Cooperative	VEC	50	019	NH	VT	-	0.000	0.000	0.000	0.000	0.000
14383	SBER ROYAL MILLS LLC		No Resource [1]	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-07	Narragansett Electric Company	NEC	44	003	RI	RI	-	0.000	0.000	0.000	0.000	0.000
14595	GRANITE RELIABLE POWER LLC	14595	GRANITE RELIABLE POWER	WT	WND		WIND TURBINE	15-Feb-12	Granite Reliable Power, LLC	GRP	33	007	NH	NH	-	0.000	0.000	0.000	0.000	29.900
14610	PRINCETON WIND FARM PROJECT	14610	PRINCETON WIND FARM PROJECT	WT	WND		WIND TURBINE	01-Sep-09	Princeton Municipal Light Department	PMLD	25	027	CMA/NEMA	WCMA	-	0.157	0.582	-0.166	0.582	0.157
14614	KLEEN ENERGY	14614	KLEEN ENERGY	CC	NG	DFO	GAS/OIL COMBINED CYCLE	12-Jul-11	Constellation Energy Commodities	CEC	09	007	CT	CT	56798	620.000	620.000	620.000	620.000	620.000
14623	VALLEY HYDRO (STATION NO. 5)	14623	VALLEY HYDRO (STATION NO. 5)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-08	Holyoke Gas & Electric Department	HGE	25	013	WMA	WCMA	-	0.000	0.520	0.000	0.520	0.000
14652	TEMPLETON WIND TURBINE	14652	TEMPLETON WIND TURBINE	WT	WND		WIND TURBINE	18-May-11	Massachusetts Municipal Wholesale Electric Company	MMWEC	25	027	WMA	WCMA	-	0.074	0.401	0.074	0.401	0.074
14665	RECORD HILL WIND	14665	RECORD HILL WIND	WT	WND		WIND TURBINE	31-Jan-12	Record Hill Wind, LLC	RHW	23	017	ME	ME	57568	0.000	0.000	0.000	0.000	13.600
14695	ORONO	14695	ORONO HYDRO STATION	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	29-Dec-08	Black Bear Hydro Partners, LLC	BBHP	23	019	BHE	ME	57184	1.896	2.135	-0.294	2.135	1.896
14707	COVANTA HAVERHILL - LF GAS	12553	COVANTA HAVERHILL LANDFILL GAS ENG	IC	LFG		BIO/REFUSE	05-Dec-07	Covanta Haverhill Associates	CHA	25	009	BOSTON	NEMA	-	1.242	1.340	-0.271	1.340	1.242
14767	PINE TREE LFGTE		No Resource [1]	IC	LFG		BIO/REFUSE	01-Jan-08	NextEra Energy Power Marketing, LLC	FPLP	23	019	BHE	ME	-	0.000	2.397	-2.825	2.397	0.000
14801	CABOT	766	CABOT/TURNERS FALLS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-05	FirstLight Power Resources Management, LLC	FPRM	25	011	WMA	WCMA	1629	61.481	61.800	0.000	61.800	61.481
14808	TURNERSFALLS	766	CABOT/TURNERS FALLS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-05	FirstLight Power Resources Management, LLC	FPRM	25	011	WMA	WCMA	6388	6.400	6.400	0.000	6.400	6.400
14816	NORDEN 1	16688	NOR1	IC	DFO		OIL INTERNAL COMBUSTION	26-Feb-09	Connecticut Municipal Electric Energy Cooperative	CMEEC	09	001	NOR	CT	-	1.950	1.958	-0.008	1.958	1.950
14817	NORDEN 2	16750	NORDEN #2	IC	DFO		OIL INTERNAL COMBUSTION	26-Feb-09	Connecticut Municipal Electric Energy Cooperative	CMEEC	09	001	NOR	CT	-	1.948	1.947	0.000	1.947	1.948
14818	NORDEN 3	16752	NORDEN #3	IC	DFO		OIL INTERNAL COMBUSTION	26-Feb-09	Connecticut Municipal Electric Energy Cooperative	CMEEC	09	001	NOR	CT	-	1.942	1.942	0.000	1.942	1.942
14823	NORWICH WWTP		No Resource [1]	IC	DFO		OIL INTERNAL COMBUSTION	29-May-08	Connecticut Municipal Electric Energy Cooperative	CMEEC	09	011	SWCT	CT	-	2.000	2.000	0.000	2.000	2.000
14919	ZBE-001		No Resource [1]	GT	WDS	DFO	BIO/REFUSE	01-Mar-08	Public Service Company of New Hampshire	PSNH	33	005	VT	NH	-	0.000	0.000	0.000	0.000	0.000
14925	ICE HOUSE PARTNERS INC.		No Resource [1]	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-08	Massachusetts Electric Company	MEC	25	017	CMA/NEMA	WCMA	-	0.065	0.260	0.000	0.260	0.065
14937	UNION GAS STATION	759	MESSALONSKEE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	19-Mar-35	Messalonskee Stream Hydro, LLC	MESSA	23	011	ME	ME	1500	1.091	1.500	0.000	1.500	1.091
15097	KIMB ROCKY RIVER PH2	14706	KIMBERLY-CLARK CORP ENERGY INDEPE	CC	NG		GAS COMBINED CYCLE	15-Jul-08	Kimberly-Clark Corporation	KCC	09	005	SWCT	CT	-	13.375	16.291	-0.111	16.291	13.375
15115	LEMPSTER WIND	14660	LEMPSTER WIND	WT	WND		WIND TURBINE	24-Sep-08	Public Service Company of New Hampshire	PSNH	33	011	NH	NH	-	2.457	8.518	-1.968	8.518	2.457
15201	FISKE HYDRO	35593	FISKE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-08	Public Service Company of New Hampshire	PSNH	33	005	VT	NH	-	0.135	0.147	0.135	0.147	0.135
15462	HOLY NAME CC JR SR HIGH SCHOOL		No Resource [1]	WT	WND		WIND TURBINE	01-Sep-08	Massachusetts Electric Company	MEC	25	027	CMA/NEMA	WCMA	-	0.000	0.000	0.000	0.000	0.000
15464	STETSON WIND FARM		No Resource [1]	WT	WND		WIND TURBINE	09-Dec-08	Evergreen Wind Power V, LLC	EWP5	23	029	BHE	ME	-	7.056	15.725	0.151	15.725	7.056
15465	NEIGHBORHOOD ENERGY, LLC	15491	NEIGHBORHOOD ENERGY, LLC	IC	OBG		BIO/REFUSE	01-Oct-08	Vermont Electric Cooperative	VEC	50	002	VT	VT	-	0.000	0.000	0.000	0.000	0.000
15484	THOMAS A. WATSON UNIT #1	12500	THOMAS A. WATSON	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	22-Apr-09	Braintree Electric Light Department, Town of	BELD	25	021	SEMA	SEMA	-	52.600	57.400	0.000	57.400	52.600
15485	THOMAS A. WATSON UNIT #2	12500	THOMAS A. WATSON	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	14-Apr-09	Braintree Electric Light Department, Town of	BELD	25	021	SEMA	SEMA	-	52.600	57.400	0.000	57.400	52.600
15488	MIDDLETON BUILDING SUPPLY		No Resource [1]	ST	WDS		BIO/REFUSE	01-Oct-08	Public Service Company of New Hampshire	PSNH	33	017	NH	NH	-	0.000	0.000	0.000	0.000	0.000
15617	MORETOWN LFGTE	35728	MORETOWN LFG	IC	LFG		BIO/REFUSE	01-Dec-08	Green Mountain Power Corporation	GMP	50	009	VT	VT	-	3.017	3.008	0.000	3.008	3.017
15706	BEAVER RIDGE WIND	37072	BEAVER_RIDGE_WIND	WT	WND		WIND TURBINE	15-Oct-08	New Hampshire Electric Cooperative, Inc.	NHEC	23	027	ME	ME	-	0.466	1.240	-0.102	1.240	0.466
15787	WORONOCO HYDRO LLC	37077	WORONOCO HYDRO LLC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-13	Swift River Trading Company LLC	SRTC	25	013	WMA	WCMA	50166	1.288	1.510	1.288	1.510	1.288
15940	DARTMOUTH CT GENERATOR 3	15415	DARTMOUTH POWER EXPANSION	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	12-Aug-09	Consolidated Edison Energy, Inc	CEEI	25	005	SEMA	SEMA	-	20.916	23.116	-0.384	23.116	20.916
15998	CROSSROADS LANDFILL	14663	WMRE CROSSROADS	IC	LFG		BIO/REFUSE	31-Dec-08	Energy America LLC	NRGA	23	025	ME	ME	-	2.294	2.976	0.000	2.976	2.294
16089	TURNERS FALLS HYDRO LLC		No Resource [1]	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-09	Swift River Trading Company LLC	SRTC	25	011	WMA	WCMA	-	0.000	0.000	0.000	0.000	0.000
16183	RICHEY WOODWORKING WIND QF		No Resource [1]	WT	WND		WIND TURBINE	18-Feb-09	Massachusetts Electric Company	MEC	25	009	BOSTON	NEMA	-	0.000	0.000	0.000	0.000	0.000
16188	WILSON HOLDINGS LLC - PV QF		No Resource [1]	PV	SUN		MISC. OTHER	24-Feb-09	Massachusetts Electric Company	MEC	25	027	CMA/NEMA	WCMA	-	0.000	0.000	0.000	0.000	0.000
16233	CITY OF MEDFORD WIND QF		No Resource [1]	WT	WND		WIND TURBINE	27-Feb-09	Massachusetts Electric Company	MEC	25	017	BOSTON	NEMA	-	0.000	0.000	0.000	0.000	0.000
16234	CONSTELLATION-MAJILITE PV QF		No Resource [1]	PV	SUN		MISC. OTHER	27-Feb-09	Massachusetts Electric Company	MEC	25	017	BOSTON	WCMA	-	0.000	0.000	0.000	0.000	0.000
16294	TOWN OF PORTSMOUTH RI WIND QF		No Resource [1]	WT	WND		WIND TURBINE	21-Mar-09	Narragansett Electric Company	NEC	44	005	RI	RI	-	0.178	0.159	0.000	0.159	0.178
16295	PPL VEAZIE	16295	PPL VEAZIE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-11	Black Bear HVGW, LLC	BBHVGW	23	019	BHE	ME	1479	7.389	7.181	2.327	7.181	7.389
16296	MILFORD HYDRO	16296	MILFORD HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-11	Black Bear Hydro Partners, LLC	BBHP	23	019	BHE	ME	1475	5.300	6.132	0.952	6.132	5.300
16331	QUARRY ENERGY PROJECT		No Resource [1]	IC	LFG		BIO/REFUSE	03-Apr-09	Harvard Dedicated Energy Limited	HDEL	25	021	SEMA	SEMA	-	0.379	0.382	0.001	0.382	0.379
16332	BARTLETTS OCEAN VIEW FARM WIND		No Resource [1]	WT	WND		WIND TURBINE	03-Apr-09	Massachusetts Electric Company	MEC	44	005	SEMA	SEMA	-	0.000	0.000	0.000	0.000	0.000
16386	NATURE'S CLASSROOM WIND QF		No Resource [1]	WT	WND		WIND TURBINE	24-Apr-09	Massachusetts Electric Company	MEC	25	027	CMA/NEMA	WCMA	-	0.000	0.000	0.000	0.000	0.000
16441	FACTORY FALLS HYDRO		No Resource [1]	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	15-May-09	Central Vermont Public Service	CVPS	50	027	VT	VT	-	0.029	0.151	0.029	0.151	0.029
16523	STILLWATER	16523	STILLWATER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-11	Black Bear Hydro Partners, LLC	BBHP	23	019	BHE	ME	1478	1.463	1.273	-0.259	1.273	1.463

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Wkp-ISO NE Capacity (CELT Report)

ASSET ID	ASSET NAME	RESOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICIPANT ACRONYM	STATE	COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2012		Change in Summer SCC from 1/1/11	As of 2011/12 Winter and 2012 Summer Peaks	
																SUMMER SCC (MW)	WINTER SCC (MW)		WINTER PEAK SCC JAN 4, 2012	EXPECTED SUMMER PEAK SCC AUG 1, 2012
16524	HOWLAND	16524	HOWLAND	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-11	Black Bear HVGW, LLC	BBHVGW	23	019	BHE	ME	1472	0.615	0.417	0.333	0.417	0.615
16525	MEDWAY	16525	MEDWAY	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-11	Black Bear Hydro Partners, LLC	BBHP	23	019	BHE	ME	55288	3.136	3.115	-0.088	3.115	3.136
16612	STETSON II WIND FARM		No Resource [1]	WT	WND		WIND TURBINE	12-Mar-10	Stetson Wind II, LLC.	STET2	23	029	BHE	ME	56991	2.602	6.740	0.151	6.740	2.602
16614	BERKSHIRE WIND POWER PROJECT	14661	BERKSHIRE WIND POWER PROJECT	WT	WND		WIND TURBINE	28-May-11	Massachusetts Municipal Wholesale Electric Company	MMWEC	25	003	WMA	WCMA	-	1.704	6.988	1.704	6.988	1.704
16631	VICTORY ROAD DORCHESTER PV	16631	VICTORY ROAD DORCHESTER PV	PV	SUN		MISC. OTHER	22-Dec-11	Massachusetts Electric Company	MEC	25	025	BOSTON	NEMA	-	0.316	0.000	0.316	0.000	0.316
16640	HILLDALE AVE HAVERHILL PV	16640	HILLDALE AVE HAVERHILL PV	PV	SUN		MISC. OTHER	15-Feb-11	Massachusetts Electric Company	MEC	25	009	BOSTON	NEMA	-	0.317	0.024	0.317	0.024	0.317
16642	RAILROAD AVENUE REVERE PV	16642	RAILROAD STREET REVERE PV	PV	SUN		MISC. OTHER	16-Feb-11	Massachusetts Electric Company	MEC	25	025	BOSTON	NEMA	-	0.223	0.021	0.223	0.021	0.223
16643	ROVER STREET EVERETT PV	16643	ROVER STREET EVERETT PV	PV	SUN		MISC. OTHER	18-Feb-11	Massachusetts Electric Company	MEC	25	017	BOSTON	NEMA	-	0.171	0.009	0.171	0.009	0.171
16644	MAIN STREET WHITINSVILLE PV	16644	MAIN STREET WHITINSVILLE PV	PV	SUN		MISC. OTHER	01-Jul-10	Massachusetts Electric Company	MEC	25	027	RI	SEMA	-	0.376	0.000	0.003	0.000	0.376
16659	IPSWICH WIND FARM 1	16659	IPSWICH WIND FARM 1	WT	WND		WIND TURBINE	26-Jul-11	Ipswich Municipal Light Department	IMLD	25	009	BOSTON	NEMA	-	0.125	0.342	0.125	0.342	0.125
16675	FOX ISLAND WIND	16675	FOX ISLAND WIND	WT	WND		WIND TURBINE	01-Sep-09	Vermont Public Power Supply Authority	VPPSA	23	013	ME	ME	-	0.000	0.159	0.000	0.159	0.000
16926	THUNDERMIST HYDRO QF	37120	THUNDERMIST HYDROPOWER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	19-Sep-09	Narragansett Electric Company	NEC	44	007	RI	RI	-	0.554	0.717	0.554	0.717	0.554
17023	NE ENGRS MIDDLETOWN RI WIND QF		No Resource [1]	WT	WND		WIND TURBINE	29-Oct-09	Narragansett Electric Company	NEC	44	005	SEMA	RI	-	0.000	0.000	0.000	0.000	0.000
17044	DEVON 16	12504	DEVON 15-18	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	28-Jun-10	GenConn Energy LLC	GCE	09	009	SWCT	CT	57070	46.900	49.200	0.000	49.200	46.900
17045	DEVON 17	12504	DEVON 15-18	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	15-Jun-10	GenConn Energy LLC	GCE	09	009	SWCT	CT	57070	46.900	49.200	0.000	49.200	46.900
17046	DEVON 18	12504	DEVON 15-18	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	09-Jun-10	GenConn Energy LLC	GCE	09	009	SWCT	CT	57070	46.900	49.200	0.000	49.200	46.900
17085	AMERESCO-NEWBURYPORT DPW PV QF		No Resource [1]	PV	SUN		MISC. OTHER	25-Nov-09	Massachusetts Electric Company	MEC	25	009	BOSTON	NEMA	-	0.032	0.000	0.001	0.000	0.032
17086	AMERESCO-NEWBRYPT NOCK MS PVQF		No Resource [1]	PV	SUN		MISC. OTHER	25-Nov-09	Massachusetts Electric Company	MEC	25	009	BOSTON	NEMA	-	0.080	0.000	0.000	0.000	0.080
17128	OTIS_AF_WIND_TURBINE		No Resource [1]	WT	WND		WIND TURBINE	28-Dec-09	NSTAR Electric Company	NSTAR	25	001	SEMA	SEMA	-	0.125	0.199	0.125	0.199	0.125
17194	TOWN_OF_FALMOUTH_WIND_TURBINE		No Resource [1]	WT	WND		WIND TURBINE	10-Feb-10	NSTAR Electric Company	NSTAR	25	001	SEMA	SEMA	57654	0.006	0.133	-0.126	0.133	0.006
17223	SUGAR RIVER 2	17359	SUGAR RIVER 2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	08-Mar-10	Public Service Company of New Hampshire	PSNH	33	019	NH	NH	-	0.000	0.165	0.000	0.165	0.000
17229	MOUNT ST MARY-WRENTHAM MA WIND		No Resource [1]	WT	WND		WIND TURBINE	15-Mar-10	Massachusetts Electric Company	MEC	25	021	RI	SEMA	-	0.002	0.004	0.002	0.004	0.002
17233	RAINBOW UNIT 1	35658	RAINBOW_1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Connecticut Light and Power Company, The	CLP	09	003	CT	CT	559	4.100	4.100	0.000	4.100	4.100
17234	RAINBOW UNIT 2	35656	RAINBOW_2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Connecticut Light and Power Company, The	CLP	09	003	CT	CT	559	4.100	4.100	0.000	4.100	4.100
17259	SEAMAN ENERGY LLC	35442	SEAMAN ENERGY	IC	LFG		BIO/REFUSE	31-Mar-10	Templeton Municipal Lighting Plant	TTMLP	25	027	WMA	WCMA	-	0.398	0.475	-0.087	0.475	0.398
35379	SPAULDING POND HYDRO	35594	SPAULDING POND HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-10	Public Service Company of New Hampshire	PSNH	33	017	NH	NH	-	0.020	0.164	0.020	0.164	0.020
35693	SPRUCE MOUNTAIN WIND	35693	SPRUCE MOUNTAIN WIND	WT	WND		WIND TURBINE	21-Dec-11	Spruce Mountain Wind, LLC	SPRUCE	23	017	ME	ME	-	4.500	9.000	4.500	9.000	4.500
36882	NOTUS WIND I		No Resource [1]	WT	WND		WIND TURBINE	23-Jun-10	NSTAR Electric Company	NSTAR	25	001	SEMA	SEMA	-	0.187	0.500	0.178	0.500	0.187
37073	SOUTHBRIDGE LANDFILL	37073	SOUTHBRIDGE LANDFILL GAS TO ENERGY	IC	LFG		BIO/REFUSE	15-Feb-12	NextEra Energy Power Marketing, LLC	FPLP	25	027	CMA/NEMA	WCMA	-	0.000	0.000	0.000	0.000	1.400
37175	ROLLINS WIND PLANT		No Resource [1]	WT	WND		WIND TURBINE	26-Jul-11	Evergreen Wind Power III, LLC	EWP3	23	019	BHE	ME	56990	6.207	20.860	6.207	20.860	6.207
37224	PATRIOT PL. D FOXBORO MA PV		No Resource [1]	PV	SUN		MISC. OTHER	01-Oct-10	Massachusetts Electric Company	MEC	25	021	RI	SEMA	-	0.028	0.000	-0.072	0.000	0.028
37225	PATRIOT PL. E FOXBORO MA PV		No Resource [1]	PV	SUN		MISC. OTHER	01-Oct-10	Massachusetts Electric Company	MEC	25	021	RI	SEMA	-	0.000	0.000	-0.075	0.000	0.000
37226	PATRIOT PL. F FOXBORO MA PV		No Resource [1]	PV	SUN		MISC. OTHER	01-Oct-10	Massachusetts Electric Company	MEC	25	021	RI	SEMA	-	0.032	0.000	-0.068	0.000	0.032
37227	PATRIOT PL. H FOXBORO MA PV		No Resource [1]	PV	SUN		MISC. OTHER	01-Oct-10	Massachusetts Electric Company	MEC	25	021	RI	SEMA	-	0.022	0.000	-0.053	0.000	0.022
37228	PATRIOT PL. J FOXBORO MA PV		No Resource [1]	PV	SUN		MISC. OTHER	01-Oct-10	Massachusetts Electric Company	MEC	25	021	RI	SEMA	-	0.032	0.000	-0.068	0.000	0.032
37229	PATRIOT PL. K FOXBORO MA PV		No Resource [1]	PV	SUN		MISC. OTHER	01-Oct-10	Massachusetts Electric Company	MEC	25	021	RI	SEMA	-	0.032	0.000	-0.068	0.000	0.032
37230	UNITED NAT. FOODS PROV. RI PV		No Resource [1]	PV	SUN		MISC. OTHER	01-Oct-10	Narragansett Electric Company	NEC	44	007	RI	RI	-	0.001	0.000	-0.074	0.000	0.001
37266	CARLSON ORCH HARVARD MA PV		No Resource [1]	PV	SUN		MISC. OTHER	01-Nov-10	Massachusetts Electric Company	MEC	25	027	CMA/NEMA	WCMA	-	0.066	0.000	-0.134	0.000	0.066
37267	SPRUCE ENV HAVERHILL MA PV		No Resource [1]	PV	SUN		MISC. OTHER	01-Nov-10	Massachusetts Electric Company	MEC	25	009	BOSTON	NEMA	-	0.000	0.000	-0.082	0.000	0.000
37366	MIDDLETOWN 13	12505	MIDDLETOWN 12-15	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	23-Jun-11	GenConn Energy LLC	GCE	09	007	CT	CT	57068	46.900	49.200	46.900	49.200	46.900
37367	MIDDLETOWN 14	12505	MIDDLETOWN 12-15	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	01-Jun-11	GenConn Energy LLC	GCE	09	007	CT	CT	57068	46.900	49.200	46.900	49.200	46.900
37368	MIDDLETOWN 15	12505	MIDDLETOWN 12-15	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	01-Jun-11	GenConn Energy LLC	GCE	09	007	CT	CT	57068	46.900	49.200	46.900	49.200	46.900
37721	ROYAL MILLS WARWICK RI HYDRO		No Resource [1]	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-10	Narragansett Electric Company	NEC	44	003	RI	RI	-	0.000	0.000	-0.225	0.000	0.000
37722	SILVER LAKE SOLAR PV FACILITY	37051	SILVER LAKE PV	PV	SUN		MISC. OTHER	06-Dec-10	Western Massachusetts Electric Company	WMECO	25	003	WMA	WCMA	-	0.661	0.000	0.203	0.000	0.661
37751	NM-UNISTRESS		No Resource [1]	PV	SUN		MISC. OTHER	01-Jan-11	Western Massachusetts Electric Company	WMECO	25	003	WMA	WCMA	-	0.000	0.000	-0.039	0.000	0.000
37752	NM-COUNTRY		No Resource [1]	PV	SUN		MISC. OTHER	01-Jan-11	Western Massachusetts Electric Company	WMECO	25	003	WMA	WCMA	-	0.000	0.000	-0.051	0.000	0.000
37753	NM-HANCOCK		No Resource [1]	PV	SUN		MISC. OTHER	01-Jan-11	Western Massachusetts Electric Company	WMECO	25	003	WMA	WCMA	-	0.000	0.000	-0.033	0.000	0.000
37754	NM-QUALITY		No Resource [1]	PV	SUN		MISC. OTHER	01-Jan-11	Western Massachusetts Electric Company	WMECO	25	003	WMA	WCMA	-	0.000	0.000	-0.052	0.000	0.000
37755	NM-WOOD		No Resource [1]	PV	SUN		MISC. OTHER	01-Jan-11	Western Massachusetts Electric Company	WMECO	25	011	WMA	WCMA	-	0.015	0.000	-0.024	0.000	0.015
37756	NM-FOURSTAR		No Resource [1]	PV	SUN		MISC. OTHER	01-Jan-11	Western Massachusetts Electric Company	WMECO	25	011	WMA	WCMA	-	0.019	0.000	-0.008	0.000	0.019
37757	NM-ASTRO		No Resource [1]	PV	SUN		MISC. OTHER	01-Jan-11	Western Massachusetts Electric Company	WMECO	25	013	WMA	WCMA	-	0.000	0.000	-0.039	0.000	0.000
37758	NM-MARLEY		No Resource [1]	PV	SUN		MISC. OTHER	01-Jan-11	Western Massachusetts Electric Company	WMECO	25	015	WMA	WCMA	-	0.000	0.000	-0.034	0.000	0.000

Wkp-ISO NE Capacity (CELT Report)

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICIPANT ACRONYM	STATE	COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2012		Change in Summer SCC from 1/1/11	As of 2011/12 Winter and 2012 Summer Peaks	
																SUMMER SCC (MW)	WINTER SCC (MW)		WINTER PEAK SCC JAN 4, 2012	EXPECTED SUMMER PEAK SCC AUG 1, 2012
37759	NM-STONE		No Resource [1]	WT	WND		WIND TURBINE	01-Jan-11	Western Massachusetts Electric Company	WMECO	25	003	WMA	WCMA	-	0.000	0.006	-0.247	0.006	0.000
37760	NM-RIVERVIEW		No Resource [1]	PV	SUN		MISC. OTHER	01-Jan-11	Western Massachusetts Electric Company	WMECO	25	003	WMA	WCMA	-	0.000	0.000	-0.069	0.000	0.000
37761	NM-PETRICCA		No Resource [1]	PV	SUN		MISC. OTHER	01-Jan-11	Western Massachusetts Electric Company	WMECO	25	003	WMA	WCMA	-	0.000	0.000	-0.035	0.000	0.000
37823	INDIAN RIVER POWER SUPPLY LLC	37079	INDIAN RIVER POWER SUPPLY LLC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-11	Swift River Trading Company LLC	SRTC	25	013	WMA	WCMA	-	0.236	0.000	0.236	0.000	0.236
37954	BLOUNT SEA FALL RIVER MA PV		No Resource [1]	PV	SUN		MISC. OTHER	16-Mar-11	Massachusetts Electric Company	MEC	25	005	SEMA	SEMA	-	0.000	0.000	0.000	0.000	0.000
37955	TRANS MED TYNGSBORO MA PV		No Resource [1]	PV	SUN		MISC. OTHER	16-Mar-11	Massachusetts Electric Company	MEC	25	017	CMA/NEMA	WCMA	-	0.017	0.001	0.017	0.001	0.017
37956	PH HENBIL BILLERICA MA PV		No Resource [1]	PV	SUN		MISC. OTHER	16-Mar-11	Massachusetts Electric Company	MEC	25	017	CMA/NEMA	WCMA	-	0.007	0.000	0.007	0.000	0.007
37957	CHELM WTR N CHELMSFORD MA PV		No Resource [1]	PV	SUN		MISC. OTHER	16-Mar-11	Massachusetts Electric Company	MEC	25	017	CMA/NEMA	WCMA	-	0.000	0.000	0.000	0.000	0.000
37958	PETER W ELEM LOWELL MA PV		No Resource [1]	PV	SUN		MISC. OTHER	16-Mar-11	Massachusetts Electric Company	MEC	25	017	CMA/NEMA	WCMA	-	0.015	0.000	0.015	0.000	0.015
37959	CIRCLE FIN NEWBURYPORT MA PV		No Resource [1]	PV	SUN		MISC. OTHER	16-Mar-11	Massachusetts Electric Company	MEC	25	009	BOSTON	NEMA	-	0.020	0.000	0.020	0.000	0.020
37965	BIO-DETEK PAWTUCKET RI PV		No Resource [1]	PV	SUN		MISC. OTHER	21-Mar-11	Narragansett Electric Company	NEC	44	007	RI	RI	-	0.000	0.000	0.000	0.000	0.000
37966	LTI HARVARD AP HARVARD MA PV		No Resource [1]	PV	SUN		MISC. OTHER	21-Mar-11	Massachusetts Electric Company	MEC	25	027	CMA/NEMA	WCMA	-	0.021	0.000	0.021	0.000	0.021
37967	HILLSIDE MARLBOROUGH MA PV		No Resource [1]	PV	SUN		MISC. OTHER	21-Mar-11	Massachusetts Electric Company	MEC	25	017	CMA/NEMA	WCMA	-	0.000	0.000	0.000	0.000	0.000
37968	LOW MEM AUD LOWELL MA PV		No Resource [1]	PV	SUN		MISC. OTHER	21-Mar-11	Massachusetts Electric Company	MEC	25	017	CMA/NEMA	WCMA	-	0.024	0.004	0.024	0.004	0.024
37972	DARTMOUTHBUSPARK_PV_ID1592		No Resource [1]	PV	SUN		MISC. OTHER	23-Mar-11	NSTAR Electric Company	NSTAR	25	005	SEMA	SEMA	-	0.671	0.116	0.671	0.116	0.671
37973	GENERAL MILLS METHUEN MA PV		No Resource [1]	PV	SUN		MISC. OTHER	24-Mar-11	Massachusetts Electric Company	MEC	25	009	BOSTON	NEMA	-	0.012	0.000	0.012	0.000	0.012
39663	BARNSTABLE_DPW_ID1545		No Resource [1]	WT	WND		WIND TURBINE	01-Aug-11	NSTAR Electric Company	NSTAR	25	001	SEMA	SEMA	-	0.014	0.080	0.014	0.080	0.014
39664	DART_BLDG_SUPPLY_ID1470		No Resource [1]	PV	SUN		MISC. OTHER	01-Aug-11	NSTAR Electric Company	NSTAR	25	005	SEMA	SEMA	-	0.019	0.080	0.019	0.080	0.019
39665	YARMOUTH_DPW_ID1740		No Resource [1]	PV	SUN		MISC. OTHER	01-Aug-11	NSTAR Electric Company	NSTAR	25	001	SEMA	SEMA	-	0.079	0.107	0.079	0.107	0.079
39675	TURKEY HILL		No Resource [1]	PV	SUN		MISC. OTHER	01-Aug-11	Fitchburg Gas & Electric Light Company	FGE	25	027	CMA/NEMA	WCMA	-	0.005	0.039	0.005	0.039	0.005
39717	HI-GEAR		No Resource [1]	PV	SUN		MISC. OTHER	01-Oct-11	Fitchburg Gas & Electric Light Company	FGE	25	027	CMA/NEMA	WCMA	-	0.117	0.117	0.117	0.117	0.117
39722	GTR_BOSTON_FOODBANKS_ID1628		No Resource [1]	PV	SUN		MISC. OTHER	17-Oct-11	NSTAR Electric Company	NSTAR	25	025	BOSTON	NEMA	-	0.071	0.071	0.071	0.071	0.071
39724	EASTERN_AVE_HOLDINGS_PV_ID1652		No Resource [1]	PV	SUN		MISC. OTHER	17-Oct-11	NSTAR Electric Company	NSTAR	25	025	BOSTON	NEMA	-	0.064	0.064	0.064	0.064	0.064
39738	MWRA_LORING_RD_ID1400		No Resource [1]	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-11	NSTAR Electric Company	NSTAR	25	017	BOSTON	NEMA	-	0.078	0.078	0.078	0.078	0.078
39992	OTIS_WT_AFCEE_ID1692		No Resource [1]	WT	WND		WIND TURBINE	28-Nov-11	NSTAR Electric Company	NSTAR	25	001	SEMA	SEMA	-	1.200	1.200	1.200	1.200	1.200
40015	INDIAN ORCHARD SOLAR FACILITY		No Resource [1]	PV	SUN		MISC. OTHER	01-Dec-11	Western Massachusetts Electric Company	WMECO	25	013	WMA	WCMA	57674	0.595	0.000	0.595	0.000	0.595
40050	EXETER AGRI ENERGY		No Resource [1]	IC	OBG		BIO/REFUSE	19-Dec-11	Vermont Public Power Supply Authority	VPPSA	23	019	BHE	ME	-	0.980	0.980	0.980	0.980	0.980
40066	OLDBARNST_RD_MASHPEE_PV_ID1798		No Resource [1]	PV	SUN		MISC. OTHER	16-Jan-12	NSTAR Electric Company	NSTAR	25	001	SEMA	SEMA	-	0.000	0.000	0.000	0.000	0.120
40067	MARION_DR_KINGSTON_WT_ID1656		No Resource [1]	WT	WND		WIND TURBINE	16-Jan-12	NSTAR Electric Company	NSTAR	25	023	SEMA	SEMA	-	0.000	0.000	0.000	0.000	2.400
40085	QUABBIN 1_ORANGE MA PV NET		No Resource [1]	PV	SUN		MISC. OTHER	25-Jan-12	Massachusetts Electric Company	MEC	25	011	WMA	WCMA	-	0.000	0.000	0.000	0.000	0.037
40086	QUABBIN 2_ORANGE MA PV NET		No Resource [1]	PV	SUN		MISC. OTHER	25-Jan-12	Massachusetts Electric Company	MEC	25	011	WMA	WCMA	-	0.000	0.000	0.000	0.000	0.037
40116	DELAWARE VALLEY CORP PV		No Resource [1]	PV	SUN		MISC. OTHER	31-Jan-12	Massachusetts Electric Company	MEC	25	017	CMA/NEMA	WCMA	-	0.000	0.000	0.000	0.000	0.040
40119	WORCESTER STATE COLLEGE PV		No Resource [1]	PV	SUN		MISC. OTHER	31-Jan-12	Massachusetts Electric Company	MEC	25	027	CMA/NEMA	WCMA	-	0.000	0.000	0.000	0.000	0.040
40137	BERKSHIRE EAST WIND		No Resource [1]	WT	WND		WIND TURBINE	03-Feb-12	Massachusetts Electric Company	MEC	25	011	WMA	WCMA	-	0.000	0.000	0.000	0.000	0.350
40176	NFM SOLAR POWER, LLC		No Resource [1]	PV	SUN		MISC. OTHER	18-Feb-12	FirstLight Power Resources Man	FPRM	25	011	WMA	WCMA	-	0.000	0.000	0.000	0.000	0.650
40194	MICRON		No Resource [1]	PV	SUN		MISC. OTHER	01-Mar-12	Fitchburg Gas and Electric Lig	FGE	25	027	WMA	WCMA	-	0.000	0.000	0.000	0.000	0.039
40207	KEZAR UPPER FALLS	786	KEZAR LEDGEMERE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-96	NextEra Energy Power Marketing	FPLP	23	031	SME	ME	-	0.000	0.000	0.000	0.260	0.089
40208	KEZAR LOWER FALLS	786	KEZAR LEDGEMERE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-96	NextEra Energy Power Marketing	FPLP	23	031	SME	ME	-	0.000	0.000	0.000	0.484	0.165
40209	LEDGEMERE	786	KEZAR LEDGEMERE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-96	NextEra Energy Power Marketing	FPLP	23	031	SME	ME	-	0.000	0.000	0.000	0.335	0.115
	NEW HAVEN HARBOR UNITS 2, 3, & 4	15477	NEW HAVEN HARBOR UNITS 2, 3, & 4	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	01-Jun-12	PSEG New Haven, LLC	PSEG-NH	09	009	CT	CT	6156	0.000	0.000	0.000	0.000	129.600
12549	DFC-ERG Milford Project	12549	DFC-ERG Milford	FC	NG		MISC. OTHER	15-Jun-12			09	009	SWCT	CT		0.000	0.000	0.000	0.000	7.800
															Total	31,766.431	34,407.889	1,632.400	**34,407.889**	**31,969.466**

NOTES:

Appendix A - defines the codes used.

Generator details, including Lead Market Participant, as of January 1, 2012.

CT	**5,174.690**	**5,181.038**
SWCT	**2,541.636**	**2,283.904**
NOR	**546.233**	**514.196**

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	Winter	Spring	Summer	Fall
NYISO	41,347	41,347	38,902	41,347
NYC	10,405	10,405	9,466	10,405
LI	6,072	6,072	5,614	6,072

Detailed generation data provided in other workpapers.

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REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2012 Capability (B) (MW) SUM	WIN	Co-Gen Y/N	Unit Type	F T	C S	Fuel Type 1	Type 2	Type 3	2011 Net Energy GWh	Notes
a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1001	AES Eastern Energy, LP	Cayuga 1		C	23584	Lansing	109	36	1955-09-01	155.3	154.1	149.7	151.4	N	ST	T	A	BIT			515.2	
1002	AES Eastern Energy, LP	Cayuga 2		C	23585	Lansing	109	36	1958-10-01	167.2	154.7	152.7	154.3	N	ST	T	A	BIT			607.1	
1003	AES Eastern Energy, LP	Cayuga IC 1		C	23629	Lansing	109	36	1967-08-01	2.8	2.8	0.0	0.0	N	IC		C	FO2				
1004	AES Eastern Energy, LP	Cayuga IC 2		C	23629	Lansing	109	36	1967-08-01	2.8	2.8	0.0	0.0	N	IC		C	FO2				
1005	AES Eastern Energy, LP	Greenidge 4	(Ret. - 3/18/11)	C	23583	Torrey	123	36	1953-12-01	112.5	106.1	0.0	0.0	N	ST	T	A	BIT	WD	NG	97.2	(P) (1)
1006	AES Eastern Energy, LP	Somerset		A	23543	Somerset	063	36	1984-08-01	655.1	686.5	679.4	684.8	N	ST	W	A	BIT			3,679.6	
1007	AES Eastern Energy, LP	Westover 8	(Ret. - 3/18/11)	C	23580	Union	007	36	1951-12-01	75.0	83.8	0.0	0.0	N	ST	T	A	BIT			10.3	(P) (2)
1008	AES ES Westover LLC	Westover LESR		C	323668	Johnson City	007	36	2010-12-13	8.0	0.0	0.0	0.0		ES			BAT				
1009	Astoria Energy II, LLC	Astoria Energy 2 - CC3		J	323677	Queens	081	36	2011-07-01	330.0	288.0	274.6	312.4	N	CC		A	NG	FO2		1,469.7	(G) (N) (3)
1010	Astoria Energy II, LLC	Astoria Energy 2 - CC4		J	323678	Queens	081	36	2011-07-01	330.0	288.0	274.6	312.4	N	CC		A	NG	FO2			(N)
1011	Astoria Energy, LLC	Astoria East Energy - CC1		J	323581	Queens	081	36	2006-04-01	320.0	278.7	274.1	303.9	N	CC		A	NG	FO2		3,507.6	(G)
1012	Astoria Energy, LLC	Astoria East Energy - CC2		J	323582	Queens	081	36	2006-04-01	320.0	278.7	274.1	303.9	N	CC		A	NG	FO2			
1013	Astoria Generating Company L.P.	Astoria 2	(Ret. - 4/11/12)	J	24149	Queens	081	36	2001-05-01	180.0	177.0	0.0	0.0	N	ST		A	NG			7.9	
1014	Astoria Generating Company L.P.	Astoria 3		J	23516	Queens	081	36	1958-09-01	376.0	369.9	374.3	375.1	N	ST		A	FO6	NG		623.9	
1015	Astoria Generating Company L.P.	Astoria 4		J	23517	Queens	081	36	1961-03-01	387.0	375.6	381.2	386.8	N	ST		A	FO6	NG		297.7	(M)
1016	Astoria Generating Company L.P.	Astoria 5		J	23518	Queens	081	36	1962-05-01	387.0	376.3	380.5	381.8	N	ST		A	FO6	NG		354.6	
1017	Astoria Generating Company L.P.	Astoria GT 01		J	23523	Queens	081	36	1967-07-01	16.0	15.7	15.1	18.1	N	GT		C	NG			0.7	
1018	Astoria Generating Company L.P.	Gowanus 1-1		J	24077	Brooklyn	047	36	1971-06-01	20.0	19.1	18.9	24.5	N	GT		C	FO2			0.4	
1019	Astoria Generating Company L.P.	Gowanus 1-2		J	24078	Brooklyn	047	36	1971-06-01	20.0	17.1	18.5	20.8	N	GT		C	FO2			0.4	
1020	Astoria Generating Company L.P.	Gowanus 1-3		J	24079	Brooklyn	047	36	1971-06-01	20.0	17.2	15.2	22.0	N	GT		C	FO2			0.3	
1021	Astoria Generating Company L.P.	Gowanus 1-4		J	24080	Brooklyn	047	36	1971-06-01	20.0	17.1	16.0	20.9	N	GT		C	FO2			0.3	
1022	Astoria Generating Company L.P.	Gowanus 1-5		J	24084	Brooklyn	047	36	1971-06-01	20.0	16.5	16.0	20.9	N	GT		C	FO2			0.5	
1023	Astoria Generating Company L.P.	Gowanus 1-6		J	24111	Brooklyn	047	36	1971-06-01	20.0	18.0	16.9	22.4	N	GT		C	FO2			0.3	
1024	Astoria Generating Company L.P.	Gowanus 1-7		J	24112	Brooklyn	047	36	1971-06-01	20.0	17.6	16.8	21.5	N	GT		C	FO2			0.3	
1025	Astoria Generating Company L.P.	Gowanus 1-8		J	24113	Brooklyn	047	36	1971-06-01	20.0	16.1	15.5	19.9	N	GT		C	FO2			0.3	
1026	Astoria Generating Company L.P.	Gowanus 2-1		J	24114	Brooklyn	047	36	1971-06-01	20.0	17.9	17.0	22.0	N	GT		C	FO2	NG		2.1	
1027	Astoria Generating Company L.P.	Gowanus 2-2		J	24115	Brooklyn	047	36	1971-06-01	20.0	18.8	18.1	23.9	N	GT		C	FO2	NG		2.0	
1028	Astoria Generating Company L.P.	Gowanus 2-3		J	24116	Brooklyn	047	36	1971-06-01	20.0	20.6	19.2	24.2	N	GT		C	FO2	NG		1.8	
1029	Astoria Generating Company L.P.	Gowanus 2-4		J	24117	Brooklyn	047	36	1971-06-01	20.0	19.3	17.1	22.8	N	GT		C	FO2	NG		1.7	
1030	Astoria Generating Company L.P.	Gowanus 2-5		J	24118	Brooklyn	047	36	1971-06-01	20.0	18.6	17.4	22.2	N	GT		C	FO2	NG		1.7	
1031	Astoria Generating Company L.P.	Gowanus 2-6		J	24119	Brooklyn	047	36	1971-06-01	20.0	20.3	18.9	24.4	N	GT		C	FO2	NG		1.8	

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REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2012 Capability (B) (MW) SUM	WIN	Co-Gen Y/N	Unit Type	F T	C S	Fuel Type 1	Type 2	Type 3	2011 Net Energy GWh	Notes
a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1032	Astoria Generating Company L.P.	Gowanus 2-7		J	24120	Brooklyn	047	36	1971-06-01	20.0	19.6	18.7	23.7	N	GT		C	FO2	NG		1.6	
1033	Astoria Generating Company L.P.	Gowanus 2-8		J	24121	Brooklyn	047	36	1971-06-01	20.0	17.7	17.0	21.6	N	GT		C	FO2	NG		1.5	
1034	Astoria Generating Company L.P.	Gowanus 3-1		J	24122	Brooklyn	047	36	1971-07-01	20.0	17.7	16.6	21.7	N	GT		C	FO2	NG		1.6	
1035	Astoria Generating Company L.P.	Gowanus 3-2		J	24123	Brooklyn	047	36	1971-07-01	20.0	17.7	16.6	21.7	N	GT		C	FO2	NG		2.0	
1036	Astoria Generating Company L.P.	Gowanus 3-3		J	24124	Brooklyn	047	36	1971-07-01	20.0	19.8	18.2	23.6	N	GT		C	FO2	NG		1.9	
1037	Astoria Generating Company L.P.	Gowanus 3-4		J	24125	Brooklyn	047	36	1971-07-01	20.0	17.9	16.3	21.0	N	GT		C	FO2	NG		1.1	
1038	Astoria Generating Company L.P.	Gowanus 3-5		J	24126	Brooklyn	047	36	1971-07-01	20.0	19.0	18.5	22.9	N	GT		C	FO2	NG		1.9	
1039	Astoria Generating Company L.P.	Gowanus 3-6		J	24127	Brooklyn	047	36	1971-07-01	20.0	17.6	16.2	20.0	N	GT		C	FO2	NG		1.3	
1040	Astoria Generating Company L.P.	Gowanus 3-7		J	24128	Brooklyn	047	36	1971-07-01	20.0	18.1	16.9	21.7	N	GT		C	FO2	NG		2.0	
1041	Astoria Generating Company L.P.	Gowanus 3-8		J	24129	Brooklyn	047	36	1971-07-01	20.0	19.0	17.4	23.4	N	GT		C	FO2	NG		1.7	
1042	Astoria Generating Company L.P.	Gowanus 4-1		J	24130	Brooklyn	047	36	1971-07-01	20.0	16.8	14.6	20.6	N	GT		C	FO2			0.3	
1043	Astoria Generating Company L.P.	Gowanus 4-2		J	24131	Brooklyn	047	36	1971-07-01	20.0	17.3	17.4	23.0	N	GT		C	FO2			0.4	
1044	Astoria Generating Company L.P.	Gowanus 4-3		J	24132	Brooklyn	047	36	1971-07-01	20.0	17.6	17.5	23.4	N	GT		C	FO2			0.2	
1045	Astoria Generating Company L.P.	Gowanus 4-4		J	24133	Brooklyn	047	36	1971-07-01	20.0	17.1	15.9	21.7	N	GT		C	FO2			0.2	
1046	Astoria Generating Company L.P.	Gowanus 4-5		J	24134	Brooklyn	047	36	1971-07-01	20.0	17.1	16.1	20.7	N	GT		C	FO2			0.3	
1047	Astoria Generating Company L.P.	Gowanus 4-6		J	24135	Brooklyn	047	36	1971-07-01	20.0	18.6	17.9	22.6	N	GT		C	FO2			0.3	
1048	Astoria Generating Company L.P.	Gowanus 4-7		J	24136	Brooklyn	047	36	1971-07-01	20.0	16.6	16.6	21.6	N	GT		C	FO2			0.3	
1049	Astoria Generating Company L.P.	Gowanus 4-8		J	24137	Brooklyn	047	36	1971-07-01	20.0	19.0	17.5	23.3	N	GT		C	FO2			0.4	
1050	Astoria Generating Company L.P.	Narrows 1-1		J	24228	Brooklyn	047	36	1972-05-01	22.0	21.0	18.7	24.7	N	GT		C	KER	NG		5.1	
1051	Astoria Generating Company L.P.	Narrows 1-2		J	24229	Brooklyn	047	36	1972-05-01	22.0	19.5	16.9	23.4	N	GT		C	KER	NG		4.4	
1052	Astoria Generating Company L.P.	Narrows 1-3		J	24230	Brooklyn	047	36	1972-05-01	22.0	20.4	18.4	24.3	N	GT		C	KER	NG		5.8	
1053	Astoria Generating Company L.P.	Narrows 1-4		J	24231	Brooklyn	047	36	1972-05-01	22.0	20.1	18.8	24.9	N	GT		C	KER	NG		5.5	
1054	Astoria Generating Company L.P.	Narrows 1-5		J	24232	Brooklyn	047	36	1972-05-01	22.0	19.8	18.7	24.4	N	GT		C	KER	NG		7.2	
1055	Astoria Generating Company L.P.	Narrows 1-6		J	24233	Brooklyn	047	36	1972-05-01	22.0	18.9	17.1	23.7	N	GT		C	KER	NG		7.4	
1056	Astoria Generating Company L.P.	Narrows 1-7		J	24234	Brooklyn	047	36	1972-05-01	22.0	18.4	17.4	23.0	N	GT		C	KER	NG		6.6	
1057	Astoria Generating Company L.P.	Narrows 1-8		J	24235	Brooklyn	047	36	1972-05-01	22.0	19.9	17.3	22.2	N	GT		C	KER	NG		6.2	
1058	Astoria Generating Company L.P.	Narrows 2-1		J	24236	Brooklyn	047	36	1972-06-01	22.0	19.4	18.5	23.8	N	GT		C	KER	NG		8.7	
1059	Astoria Generating Company L.P.	Narrows 2-2		J	24237	Brooklyn	047	36	1972-06-01	22.0	18.7	17.8	22.2	N	GT		C	KER	NG		9.9	
1060	Astoria Generating Company L.P.	Narrows 2-3		J	24238	Brooklyn	047	36	1972-06-01	22.0	18.4	17.0	22.4	N	GT		C	KER	NG		7.5	
1061	Astoria Generating Company L.P.	Narrows 2-4		J	24239	Brooklyn	047	36	1972-06-01	22.0	18.4	18.3	23.6	N	GT		C	KER	NG		9.0	
1062	Astoria Generating Company L.P.	Narrows 2-5		J	24240	Brooklyn	047	36	1972-06-01	22.0	19.9	18.2	23.7	N	GT		C	KER	NG		9.8	
1063	Astoria Generating Company L.P.	Narrows 2-6		J	24241	Brooklyn	047	36	1972-06-01	22.0	18.1	16.5	21.2	N	GT		C	KER	NG		7.8	

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REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2012 Capability (B) (MW) SUM	WIN	Co-Gen Y/N	Unit Type	F T	C S	Fuel Type 1	Type 2	Type 3	2011 Net Energy GWh	Notes
a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1064	Astoria Generating Company L.P.	Narrows 2-7		J	24242	Brooklyn	047	36	1972-06-01	22.0	20.7	19.0	23.9	N	GT		C	KER	NG		6.8	
1065	Astoria Generating Company L.P.	Narrows 2-8		J	24243	Brooklyn	047	36	1972-06-01	22.0	17.5	17.4	21.4	N	GT		C	KER	NG		7.9	
1066	Athens Generating Company, LP	Athens 1		F	23668	Athens	039	36	2004-05-01	441.0	316.6	302.9	401.2		CC			NG			451.4	
1067	Athens Generating Company, LP	Athens 2		F	23670	Athens	039	36	2004-05-01	441.0	315.6	305.1	397.9		CC			NG			1,920.5	
1068	Athens Generating Company, LP	Athens 3		F	23677	Athens	039	36	2004-05-01	441.0	312.8	308.6	400.5		CC			NG			1,753.8	
1069	Boralex Hydro Operations Inc	Fourth Branch		F	23824	Waterford	091	36	1987-12-01	3.3	3.5	3.3	3.3		HY			WAT			16.7	
1070	Boralex Hydro Operations Inc	NYS Dam		F	23527	Waterford	091	36	1990-12-01	11.4	11.3	11.4	11.4		HY			WAT			65.7	
1071	Boralex Hydro Operations Inc	Sissonville		E	23735	Potsdam	089	36	1990-08-01	3.1	3.0	3.1	3.1		HY			WAT			13.6	
1072	Boralex Hydro Operations Inc	Warrensburg		F	23737	Warrensburg	113	36	1988-12-01	2.9	3.0	2.9	2.9		HY			WAT			16.2	
1073	Boralex New York LP	Chateaugay Power		D	23792	Chateaugay	033	36	1993-02-01	19.7	18.6	18.5	18.4	N	ST			WD			88.4	
1074	Calpine Energy Service LP	Bethpage		K	23823	Hicksville	059	36	1989-09-01	83.6	54.9	50.5	59.0	Y	CC			NG	FO2		104.5	
1075	Calpine Energy Service LP	Bethpage GT4		K	323586	Hicksville	059	36	2002-07-01	60.0	48.2	44.9	46.2	N	GT			NG			70.2	
1076	Calpine Energy Service LP	KIAC GT 01 (JFK)		J	23816	Jamaica	081	36	1995-01-01	47.1	45.5	45.3	45.8	Y	CT			NG			547.4	(G)
1077	Calpine Energy Service LP	KIAC GT 02 (JFK)		J	23817	Jamaica	081	36	1995-01-01	47.1	45.5	45.3	45.8	Y	CT			NG				
1078	Calpine Energy Service LP	KIAC ST 01 (JFK)		J	23817	Jamaica	081	36	1995-01-01	27.0	26.1	26.0	26.3	Y	CW			NG				
1079	Canandaigua Power Partners, LLC	Canandaigua Wind Power		C	323617	Avoca	101	36	2008-12-05	125.0	125.0	125.0	125.0		WT			WND			242.4	
1080	Carr Street Generating Station LP	Carr St.-E. Syr		C	24060	Dewitt	067	36	1993-08-01	122.6	89.0	86.1	104.7	Y	CC			NG			19.6	
1081	Castleton Power, LLC	Fort Orange		F	23900	Castleton	083	36	1992-01-01	72.0	67.0	61.5	72.0	Y	CC			NG			86.3	
1082	Central Hudson Gas & Elec. Corp.	Coxsackie GT		G	23611	Coxsackie	039	36	1969-12-01	21.6	19.9	0.0	0.0	N	GT		C	KER	NG		0.9	
1083	Central Hudson Gas & Elec. Corp.	Dashville 1		G	23610	Rifton	111	36	1920-01-01	2.4	2.7	0.0	0.0		HY			WAT				
1084	Central Hudson Gas & Elec. Corp.	Dashville 2		G	23610	Rifton	111	36	1920-01-01	2.4	2.7	0.0	0.0		HY			WAT				
1085	Central Hudson Gas & Elec. Corp.	DCRRA		G	23765	Poughkeepsie	027	36	1987-09-01	9.2	8.7	7.6	7.7	N	ST			REF			44.7	
1086	Central Hudson Gas & Elec. Corp.	High Falls		G	23754	Marbletown	111	36	1986-12-01	3.2	3.0	0.0	0.0		HY			WAT				
1087	Central Hudson Gas & Elec. Corp.	Millpond		G	5004	Catskill	039	36	1993-12-01	0.9		0.0	0.0		HY			WAT				
1088	Central Hudson Gas & Elec. Corp.	Montgomery West		G	5005	Montgomery	071	36	1985-11-01	0.2		0.0	0.0		HY			WAT				
1089	Central Hudson Gas & Elec. Corp.	Salisbury Mills		G	5006	Salisbury Mills	071	36	1986-12-01	0.5		0.0	0.0		HY			WAT				
1090	Central Hudson Gas & Elec. Corp.	South Cairo		G	23612	Cairo	039	36	1970-06-01	21.6	17.8	0.0	0.0	N	GT		C	KER			0.8	
1091	Central Hudson Gas & Elec. Corp.	Sturgeon 1		G	23609	Rifton	111	36	1924-01-01	4.8	5.3	0.0	0.0		HY			WAT				
1092	Central Hudson Gas & Elec. Corp.	Sturgeon 2		G	23609	Rifton	111	36	1924-01-01	4.8	5.3	0.0	0.0		HY			WAT				
1093	Central Hudson Gas & Elec. Corp.	Sturgeon 3		G	23609	Rifton	111	36	1924-01-01	4.8	5.3	0.0	0.0		HY			WAT				
1094	Central Hudson Gas & Elec. Corp.	Wallkill		G	5007	Shwangunk	111	36	1986-12-01	0.5		0.0	0.0		HY			WAT				
1095	Central Hudson Gas & Elec. Corp.	Wappingers Falls		G	23765	Wappingers	027	36	1988-12-01	2.0	2.0	2.0	2.1		HY			WAT			12.0	

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REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2012 Capability (B) (MW) SUM	WIN	Co-Gen Y/N	Unit Type	F T	C S	Fuel Type 1	Type 2	Type 3	2011 Net Energy GWh	Notes
a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1096	CHI Energy Inc	Goodyear Lake		E	323669	Milford	077	36	1980-07-01	2.0		0.0	0.0		HY			WAT			0.6	(4)
1097	Commerce Energy, Inc.	Steel Wind		A	323596	Lackawanna	029	36	2007-01-23	20.0	20.0	20.0	20.0		WT			WND			38.4	
1098	Consolidated Edison Co. of NY, In	59 St.	GT 1	J	24138	Manhattan	061	36	1969-06-01	17.1	15.4	14.9	20.3	N	GT		C	KER			0.7	
1099	Consolidated Edison Co. of NY, In	74 St.	GT 1	J	24260	Manhattan	061	36	1968-10-01	18.5	19.0	19.8	19.1	N	GT		C	KER			0.1	
1100	Consolidated Edison Co. of NY, In	74 St.	GT 2	J	24261	Manhattan	061	36	1968-10-01	18.5	20.1	20.1	21.0	N	GT		C	KER			0.2	
1101	Consolidated Edison Co. of NY, In	Brooklyn Navy Yard		J	23515	Brooklyn	047	36	1996-11-01	322.0	266.9	254.2	284.9	Y	CC			NG	FO2		1,911.6	
1102	Consolidated Edison Co. of NY, In	East River	1	J	323558	Manhattan	061	36	2005-04-01	185.0	148.5	147.0	178.1		CC			NG	KER		962.7	
1103	Consolidated Edison Co. of NY, In	East River	2	J	323559	Manhattan	061	36	2005-04-05	189.0	150.4	147.6	177.1		CC			NG	KER		1,033.8	
1104	Consolidated Edison Co. of NY, In	East River	6	J	23660	Manhattan	061	36	1951-11-01	156.2	134.3	134.5	138.0	Y	ST		A	FO6	NG		567.6	
1105	Consolidated Edison Co. of NY, In	East River	7	J	23524	Manhattan	061	36	1955-06-01	200.0	184.7	182.6	183.3	Y	ST		A	FO6	NG		183.3	
1106	Consolidated Edison Co. of NY, In	Hudson Ave	3	J	23810	Brooklyn	047	36	1970-07-01	16.3	16.0	14.5	18.1	Y	GT		C	KER			0.3	
1107	Consolidated Edison Co. of NY, In	Hudson Ave	4	J	23540	Brooklyn	047	36	1970-07-01	16.3	13.9	13.2	17.6	Y	GT		C	KER			0.2	
1108	Consolidated Edison Co. of NY, In	Hudson Ave	5	J	23657	Brooklyn	047	36	1970-07-01	16.3	15.1	14.6	17.9	Y	GT		C	KER			0.4	
1109	Consolidated Edison Energy, Inc.	Massena		D	23902	Massena	089	36	1992-07-01	102.1	82.2	80.7	92.0	Y	CC			NG	FO2		3.6	
1110	Consolidated Edison Energy, Inc.	Rensselaer Cogen		F	23796	Rensselaer	083	36	1993-12-01	103.7	79.0	77.4	82.7	Y	CC			NG			8.7	
1111	Consolidated Hydro New York, Inc	Groveville Hydro		G	323602	Beacon	027	36	1983-12-01	2.0		0.0	0.0		HY			WAT			2.3	
1112	Consolidated Hydro New York, Inc	Walden Hydro		G	24148	Walden	071	36	1983-12-01	2.4	1.5	0.0	0.0		HY			WAT			7.4	
1113	Constellation Energy Commodities	Chaffee		A	323603	Chaffee	029	36	2007-08-09	6.4	6.4	6.4	6.4		IC			MTE			53.5	
1114	Constellation Energy Commodities	High Acres	1	C	23767	Fairport	117	36	1991-06-01	3.2	3.2	3.2	3.2	N	IC			MTE			26.8	
1115	Constellation Energy Commodities	High Acres	2	C	23767	Fairport	117	36	2008-02-28	6.4	6.4	6.4	6.4	N	IC			MTE			51.9	
1116	Constellation Energy Commodities	Madison County LF		E	323628	Wampsville	053	36	2010-03-01	1.6		1.6	1.6	N	IC			MTE			7.2	
1117	Constellation Energy Commodities	Mill Seat		B	323607	Riga	055	36	2007-07-20	6.4	6.4	6.4	6.4		IC			MTE			53.7	
1118	Constellation Energy Commodities	Monroe Livingston		B	24207	Scottsville	055	36	1988-11-01	2.4	2.4	2.4	2.4		IC			MTE			11.0	
1119	Covanta Niagara, LP	American Ref-Fuel	1	A	24010	Niagara	063	36	1993-05-01	25.0	19.6	16.9	15.7	Y	ST			REF			132.3	
1120	Covanta Niagara, LP	American Ref-Fuel	2	A	24010	Niagara	063	36	1993-05-01	25.0	19.6	16.9	15.7	Y	ST			REF			101.1	
1121	Delaware County	Delaware LFGE		E	323621	Walton	025	36	2009-02-11	2.0		0.0	0.0	N	IC			MTE				
1122	Dynegy Power Marketing, Inc.	Danskammer	1	G	23586	Newburgh	071	36	1951-12-01	72.0	67.0	61.0	63.5	N	ST	T	A	FO6	NG	FO2	6.4	
1123	Dynegy Power Marketing, Inc.	Danskammer	2	G	23589	Newburgh	071	36	1954-09-01	73.5	62.7	59.2	61.7	N	ST	T	A	FO6	NG	FO2	6.9	
1124	Dynegy Power Marketing, Inc.	Danskammer	3	G	23590	Newburgh	071	36	1959-10-01	147.1	137.2	137.7	137.2	N	ST	T	A	BIT	NG	FO2	327.3	
1125	Dynegy Power Marketing, Inc.	Danskammer	4	G	23591	Newburgh	071	36	1967-09-01	239.4	236.2	237.0	236.5	N	ST	T	A	BIT	NG	FO2	576.7	
1126	Dynegy Power Marketing, Inc.	Danskammer	5	G	23592	Newburgh	071	36	1967-01-01	2.7	2.5	0.0	0.0	N	IC		C	FO2				
1127	Dynegy Power Marketing, Inc.	Danskammer	6	G	23592	Newburgh	071	36	1967-01-01	2.7	2.5	0.0	0.0	N	IC		C	FO2				

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a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1128	Dynegy Power Marketing, Inc.	Independence		C	23800	Scriba	075	36	1994-11-01	1,254.0	954.4	914.0	1,061.6	Y	CC			NG			3,121.7	
1129	Dynegy Power Marketing, Inc.	Roseton 1		G	23587	Newburgh	071	36	1974-12-01	621.0	614.8	600.0	614.0	N	ST	T	A	FO6	NG	FO2	98.2	
1130	Dynegy Power Marketing, Inc.	Roseton 2		G	23588	Newburgh	071	36	1974-09-01	621.0	605.7	560.0	585.5	N	ST	T	A	FO6	NG	FO2	186.8	
1131	Eagle Creek Hydro Power, LLC	Mongaup 1		G	23641	Forestburg	105	36	1923-07-01	1.0	1.0	1.0	1.0		HY			WAT			21.3	(G)
1132	Eagle Creek Hydro Power, LLC	Mongaup 2		G	23641	Forestburg	105	36	1923-07-01	1.0	1.0	1.0	1.0		HY			WAT				
1133	Eagle Creek Hydro Power, LLC	Mongaup 3		G	23641	Forestburg	105	36	1923-07-01	1.0	1.0	1.0	1.0		HY			WAT				
1134	Eagle Creek Hydro Power, LLC	Mongaup 4		G	23641	Forestburg	105	36	1926-01-01	1.0	1.0	1.0	1.0		HY			WAT				
1135	Eagle Creek Hydro Power, LLC	Rio		G	23641	Glen Spey	105	36	1927-12-01	10.0	10.3	9.9	9.8		HY			WAT			42.8	
1136	Eagle Creek Hydro Power, LLC	Swinging Bridge 2		G	23641	Forestburg	105	36	1930-02-01	7.0	7.2	6.9	6.8		HY			WAT			24.3	
1137	East Coast Power, LLC	Linden Cogen		J	23786	Linden NJ	039	34	1992-05-01	1,034.9	753.3	754.5	800.0	Y	CC			NG			3,126.9	
1138	EDF Trading North America, LLC	Saranac Energy 1		D	23793	Plattsburgh	019	36	1994-06-01	95.2	84.6	82.5	93.1	Y	CT			NG			178.4	
1139	EDF Trading North America, LLC	Saranac Energy 2		D	23793	Plattsburgh	019	36	1994-06-01	95.2	84.6	82.5	93.1	Y	CT			NG			69.7	
1140	EDF Trading North America, LLC	Saranac Energy 3		D	23793	Plattsburgh	019	36	1994-06-01	95.2	84.6	82.5	93.1	Y	CW			NG			126.5	
1141	Empire Generating Co, LLC	EMPIRE_CC_1		F	323656	Rensselaer	083	36	2010-09-02	335.0	294.0	294.0	345.7	Y	CC			NG	FO2		1,908.4	
1142	Empire Generating Co, LLC	EMPIRE_CC_2		F	323658	Rensselaer	083	36	2010-09-02	335.0	298.2	298.2	346.2	Y	CC			NG	FO2		1,928.9	
1143	Entergy Nuclear Power Marketing I	Fitzpatrick 1		C	23598	Scriba	075	36	1975-07-01	882.0	858.9	848.4	849.1		NB		A	UR			7,244.0	
1144	Entergy Nuclear Power Marketing I	Indian Pt 2		H	23530	Buchanan	119	36	1973-08-01	1,299.0	1,026.5	1,020.4	1,028.8		NP		A	UR			8,788.1	
1145	Entergy Nuclear Power Marketing I	Indian Pt 3		H	23531	Buchanan	119	36	1976-04-01	1,012.0	1,040.4	1,040.5	1,046.8		NP		A	UR			8,228.8	
1146	Erie Blvd. Hydro - Beaver River	Belfort 1		E	24048		049	36	1903-01-01	0.4	0.4	0.4	0.4		HY			WAT			3.0	
1147	Erie Blvd. Hydro - Beaver River	Belfort 2		E	24048		049	36	1915-01-01	0.6	0.7	0.6	0.6		HY			WAT			3.5	
1148	Erie Blvd. Hydro - Beaver River	Belfort 3		E	24048		049	36	1918-01-01	1.0	1.0	1.0	1.0		HY			WAT			6.3	
1149	Erie Blvd. Hydro - Beaver River	Eagle 1		E	24048		049	36	1914-01-01	1.3	1.3	1.3	1.3		HY			WAT			9.2	
1150	Erie Blvd. Hydro - Beaver River	Eagle 2		E	24048		049	36	1915-01-01	1.4	1.4	1.4	1.4		HY			WAT			7.3	
1151	Erie Blvd. Hydro - Beaver River	Eagle 3		E	24048		049	36	1919-01-01	1.4	1.4	1.4	1.4		HY			WAT			5.1	
1152	Erie Blvd. Hydro - Beaver River	Eagle 4		E	24048		049	36	1925-01-01	2.1	2.1	2.1	2.1		HY			WAT			14.2	
1153	Erie Blvd. Hydro - Beaver River	Effley 1		E	24048		049	36	1902-01-01	0.4	0.4	0.4	0.4		HY			WAT			2.6	
1154	Erie Blvd. Hydro - Beaver River	Effley 2		E	24048		049	36	1907-01-01	0.4	0.4	0.4	0.4		HY			WAT			2.2	
1155	Erie Blvd. Hydro - Beaver River	Effley 3		E	24048		049	36	1910-01-01	0.6	0.6	0.6	0.6		HY			WAT			4.7	
1156	Erie Blvd. Hydro - Beaver River	Effley 4		E	24048		049	36	1923-01-01	1.6	1.6	1.6	1.6		HY			WAT			7.5	
1157	Erie Blvd. Hydro - Beaver River	Elmer 1		E	24048		049	36	1916-01-01	0.8	0.8	0.8	0.8		HY			WAT			5.3	
1158	Erie Blvd. Hydro - Beaver River	Elmer 2		E	24048		049	36	1916-01-01	0.8	0.8	0.8	0.8		HY			WAT			7.0	
1159	Erie Blvd. Hydro - Beaver River	High Falls 1		E	24048		049	36	1925-01-01	1.6	1.6	1.6	1.6		HY			WAT			11.0	

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REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2012 Capability (B) (MW) SUM	WIN	Co-Gen Y/N	Unit Type	F T	C S	Fuel Type 1	Type 2	Type 3	2011 Net Energy GWh	Notes
a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1160	Erie Blvd. Hydro - Beaver River	High Falls 2		E	24048		049	36	1925-01-01	1.6	1.6	1.6	1.6		HY			WAT			6.0	
1161	Erie Blvd. Hydro - Beaver River	High Falls 3		E	24048		049	36	1925-01-01	1.6	1.6	1.6	1.6		HY			WAT			15.9	
1162	Erie Blvd. Hydro - Beaver River	Moshier 1		E	24048		043	36	1929-01-01	4.0	4.1	4.0	4.0		HY			WAT			28.5	
1163	Erie Blvd. Hydro - Beaver River	Moshier 2		E	24048		043	36	1929-01-01	4.0	4.1	4.0	4.0		HY			WAT			12.8	
1164	Erie Blvd. Hydro - Beaver River	Soft Maple 1		E	24048		049	36	1925-01-01	7.5	7.7	7.5	7.5		HY			WAT			34.8	
1165	Erie Blvd. Hydro - Beaver River	Soft Maple 2		E	24048		049	36	1925-01-01	7.5	7.7	7.5	7.5		HY			WAT			11.6	
1166	Erie Blvd. Hydro - Beaver River	Taylorville 1		E	24048		049	36	1913-01-01	1.1	1.1	1.1	1.1		HY			WAT			8.8	
1167	Erie Blvd. Hydro - Beaver River	Taylorville 2		E	24048		049	36	1913-01-01	1.1	1.1	1.1	1.1		HY			WAT			5.2	
1168	Erie Blvd. Hydro - Beaver River	Taylorville 3		E	24048		049	36	1913-01-01	1.1	1.1	1.1	1.1		HY			WAT			6.1	
1169	Erie Blvd. Hydro - Beaver River	Taylorville 4		E	24048		049	36	1927-01-01	1.2	1.2	1.2	1.2		HY			WAT			6.8	
1170	Erie Blvd. Hydro - Black River	Beebee Island 1		E	24047		045	36	1963-01-01	4.0	4.2	4.0	4.0		HY			WAT			16.3	
1171	Erie Blvd. Hydro - Black River	Beebee Island 2		E	24047		045	36	1968-01-01	4.0	4.2	4.0	4.0		HY			WAT			31.3	
1172	Erie Blvd. Hydro - Black River	Black River 1		E	24047		045	36	1920-01-01	2.0	2.1	2.0	2.0		HY			WAT			11.9	
1173	Erie Blvd. Hydro - Black River	Black River 2		E	24047		045	36	1920-01-01	2.0	2.1	2.0	2.0		HY			WAT			17.3	
1174	Erie Blvd. Hydro - Black River	Black River 3		E	24047		045	36	1920-01-01	2.0	2.1	2.0	2.0		HY			WAT			9.7	
1175	Erie Blvd. Hydro - Black River	Deferiet 1		E	24047		045	36	1925-01-01	3.6	3.8	3.6	3.6		HY			WAT			16.0	
1176	Erie Blvd. Hydro - Black River	Deferiet 2		E	24047		045	36	1925-01-01	3.6	3.8	3.6	3.6		HY			WAT			29.8	
1177	Erie Blvd. Hydro - Black River	Deferiet 3		E	24047		045	36	1925-01-01	3.6	3.8	3.6	3.6		HY			WAT			16.0	
1178	Erie Blvd. Hydro - Black River	Herrings 1		E	24047		045	36	1924-01-01	1.8	1.9	1.8	1.8		HY			WAT			2.7	
1179	Erie Blvd. Hydro - Black River	Herrings 2		E	24047		045	36	1924-01-01	1.8	1.9	1.8	1.8		HY			WAT			10.8	
1180	Erie Blvd. Hydro - Black River	Herrings 3		E	24047		045	36	1924-01-01	1.8	1.9	1.8	1.8		HY			WAT			6.5	
1181	Erie Blvd. Hydro - Black River	Kamargo 1		E	24047		045	36	1921-01-01	1.8	1.9	1.8	1.8		HY			WAT			7.7	
1182	Erie Blvd. Hydro - Black River	Kamargo 2		E	24047		045	36	1921-01-01	1.8	1.9	1.8	1.8		HY			WAT			11.6	
1183	Erie Blvd. Hydro - Black River	Kamargo 3		E	24047		045	36	1921-01-01	1.8	1.9	1.8	1.8		HY			WAT			4.6	
1184	Erie Blvd. Hydro - Black River	Sewalls 1		E	24047		045	36	1925-01-01	1.0	1.1	1.0	1.0		HY			WAT			6.6	
1185	Erie Blvd. Hydro - Black River	Sewalls 2		E	24047		045	36	1925-01-01	1.0	1.1	1.0	1.0		HY			WAT			7.1	
1186	Erie Blvd. Hydro - East Canada Ca	Beardslee 1		F	24051		043	36	1924-01-01	10.0	8.6	10.6	10.6		HY			WAT			35.7	
1187	Erie Blvd. Hydro - East Canada Ca	Beardslee 2		F	24051		043	36	1924-01-01	10.0	8.6	10.6	10.6		HY			WAT			24.8	
1188	Erie Blvd. Hydro - East Canada Ca	Ephratah 1		F	24051		035	36	1920-01-01	1.4	1.2	1.4	1.4		HY			WAT			0.4	
1189	Erie Blvd. Hydro - East Canada Ca	Ephratah 2		F	24051		035	36	1911-01-01	1.2	1.0	1.3	1.3		HY			WAT			7.0	
1190	Erie Blvd. Hydro - East Canada Ca	Ephratah 4		F	24051		035	36	1911-01-01	1.3	1.1	1.4	1.4		HY			WAT			6.0	
1191	Erie Blvd. Hydro - East Canada Mc	Inghams 1		E	24050		043	36	1912-01-01	3.2	3.5	3.2	3.2		HY			WAT			14.7	

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a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1192	Erie Blvd. Hydro - East Canada Mc	Inghams 2		E	24050		043	36	1912-01-01	3.2	3.5	3.2	3.2		HY			WAT			18.0	
1193	Erie Blvd. Hydro - Lower Hudson	Johnsonville 1		F	24059		083	36	1909-01-01	2.4	2.4	2.4	2.4		HY			WAT			4.5	
1194	Erie Blvd. Hydro - Lower Hudson	Schaghticoke 1		F	24059		083	36	1908-01-01	3.3	3.3	3.3	3.3		HY			WAT			22.3	
1195	Erie Blvd. Hydro - Lower Hudson	Schaghticoke 2		F	24059		083	36	1908-01-01	3.3	3.3	3.3	3.3		HY			WAT			17.9	
1196	Erie Blvd. Hydro - Lower Hudson	Schaghticoke 3		F	24059		083	36	1908-01-01	3.3	3.3	3.3	3.3		HY			WAT			15.6	
1197	Erie Blvd. Hydro - Lower Hudson	Schaghticoke 4		F	24059		083	36	1908-01-01	3.3	3.3	3.3	3.3		HY			WAT			21.4	
1198	Erie Blvd. Hydro - Lower Hudson	School Street 1		F	24059	Cohoes	001	36	1974-01-01	7.2	7.2	7.2	7.2		HY			WAT			36.5	
1199	Erie Blvd. Hydro - Lower Hudson	School Street 2		F	24059	Cohoes	001	36	1915-01-01	7.2	7.2	7.2	7.2		HY			WAT			44.5	
1200	Erie Blvd. Hydro - Lower Hudson	School Street 3		F	24059	Cohoes	001	36	1915-01-01	7.2	7.2	7.2	7.2		HY			WAT			24.2	
1201	Erie Blvd. Hydro - Lower Hudson	School Street 4		F	24059	Cohoes	001	36	1922-01-01	7.2	7.2	7.2	7.2		HY			WAT			32.8	
1202	Erie Blvd. Hydro - Lower Hudson	School Street 5		F	24059	Cohoes	001	36	1924-01-01	10.0	10.0	10.0	10.0		HY			WAT			53.3	
1203	Erie Blvd. Hydro - Lower Hudson	Schuylerville		F	24059		091	36	1919-01-01	1.2	1.2	1.2	1.2		HY			WAT			9.3	
1204	Erie Blvd. Hydro - Lower Raquette	Colton 1		E	24057		089	36	1962-01-01	10.0	10.0	10.0	10.0		HY			WAT			70.4	
1205	Erie Blvd. Hydro - Lower Raquette	Colton 2		E	24057		089	36	1918-01-01	10.0	10.0	10.0	10.0		HY			WAT			75.3	
1206	Erie Blvd. Hydro - Lower Raquette	Colton 3		E	24057		089	36	1928-01-01	10.0	10.0	10.0	10.0		HY			WAT			77.0	
1207	Erie Blvd. Hydro - Lower Raquette	East Norfolk		E	24057		089	36	1928-01-01	3.0	3.0	3.0	3.0		HY			WAT			24.2	
1208	Erie Blvd. Hydro - Lower Raquette	Hannawa Falls 1		E	24057		089	36	1914-01-01	3.6	3.6	3.6	3.6		HY			WAT			8.6	
1209	Erie Blvd. Hydro - Lower Raquette	Hannawa Falls 2		E	24057		089	36	1920-01-01	3.6	3.6	3.6	3.6		HY			WAT			9.8	
1210	Erie Blvd. Hydro - Lower Raquette	Higley 1		E	24057		089	36	1913-01-01	1.2	1.2	1.2	1.2		HY			WAT			10.8	
1211	Erie Blvd. Hydro - Lower Raquette	Higley 2		E	24057		089	36	1913-01-01	1.2	1.2	1.2	1.2		HY			WAT			10.0	
1212	Erie Blvd. Hydro - Lower Raquette	Higley 3		E	24057		089	36	1943-01-01	2.1	2.1	2.1	2.1		HY			WAT			11.0	
1213	Erie Blvd. Hydro - Lower Raquette	Higley 4		E	24057		089	36	1943-01-01	2.1	2.1	2.1	2.1		HY			WAT			7.8	
1214	Erie Blvd. Hydro - Lower Raquette	Norfolk		E	24057		089	36	1928-01-01	4.5	4.5	4.5	4.5		HY			WAT			31.5	
1215	Erie Blvd. Hydro - Lower Raquette	Norwood		E	24057		089	36	1928-01-01	2.0	2.0	2.0	2.0		HY			WAT			15.1	
1216	Erie Blvd. Hydro - Lower Raquette	Raymondville		E	24057		089	36	1928-01-01	2.0	2.0	2.0	2.0		HY			WAT			15.0	
1217	Erie Blvd. Hydro - Lower Raquette	Sugar Island 1		E	24057		089	36	1924-01-01	2.6	2.6	2.6	2.6		HY			WAT			11.2	
1218	Erie Blvd. Hydro - Lower Raquette	Sugar Island 2		E	24057		089	36	1924-01-01	2.4	2.4	2.4	2.4		HY			WAT			12.1	
1219	Erie Blvd. Hydro - Lower Raquette	Yaleville 1		E	24057		089	36	1940-01-01	0.5	0.5	0.5	0.5		HY			WAT			2.1	
1220	Erie Blvd. Hydro - Lower Raquette	Yaleville 2		E	24057		089	36	1940-01-01	0.7	0.7	0.7	0.7		HY			WAT			1.1	
1221	Erie Blvd. Hydro - North Salmon	Allens Falls		D	24042		089	36	1927-01-01	4.4	4.5	4.4	4.4		HY			WAT			28.1	
1222	Erie Blvd. Hydro - North Salmon	Chasm 1		D	24042		033	36	1913-01-01	1.0	1.0	1.0	1.0		HY			WAT			5.9	
1223	Erie Blvd. Hydro - North Salmon	Chasm 2		D	24042		033	36	1913-01-01	1.0	1.0	1.0	1.0		HY			WAT			4.4	

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a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1224	Erie Blvd. Hydro - North Salmon	Chasm 3		D	24042		033	36	1926-01-01	1.4	1.4	1.3	1.3		HY			WAT			8.8	
1225	Erie Blvd. Hydro - North Salmon	Franklin 1		D	24042		033	36	1911-01-01	1.1	1.2	1.1	1.1		HY			WAT			5.9	
1226	Erie Blvd. Hydro - North Salmon	Franklin 2		D	24042		033	36	1926-01-01	1.1	1.2	1.1	1.1		HY			WAT			5.3	
1227	Erie Blvd. Hydro - North Salmon	Hogansburg		D	24042		033	36	1930-01-01	0.7	0.7	0.7	0.7		HY			WAT			0.7	
1228	Erie Blvd. Hydro - North Salmon	Macomb		D	24042		033	36	1940-01-01	1.0	1.0	1.0	1.0		HY			WAT			6.5	
1229	Erie Blvd. Hydro - North Salmon	Parishville		D	24042		089	36	1925-01-01	2.4	2.5	2.4	2.4		HY			WAT			14.2	
1230	Erie Blvd. Hydro - North Salmon	Piercefield 1		D	24042		089	36	1957-01-01	1.5	1.5	1.5	1.5		HY			WAT			11.0	
1231	Erie Blvd. Hydro - North Salmon	Piercefield 2		D	24042		089	36	1924-01-01	0.6	0.6	0.6	0.6		HY			WAT			3.9	
1232	Erie Blvd. Hydro - North Salmon	Piercefield 3		D	24042		089	36	1924-01-01	0.6	0.6	0.6	0.6		HY			WAT			4.1	
1233	Erie Blvd. Hydro - NYS Barge	Hydraulic Race		A	23848		063	36	1942-01-01	4.7	3.1	4.6	4.6		HY			WAT			10.6	
1234	Erie Blvd. Hydro - Oak Orchard	Glenwood 1		B	24046		073	36	1950-01-01	0.5	0.4	0.5	0.5		HY			WAT			3.2	
1235	Erie Blvd. Hydro - Oak Orchard	Glenwood 2		B	24046		073	36	1950-01-01	0.5	0.4	0.5	0.5		HY			WAT			2.2	
1236	Erie Blvd. Hydro - Oak Orchard	Glenwood 3		B	24046		073	36	1950-01-01	0.5	0.4	0.5	0.5		HY			WAT			2.3	
1237	Erie Blvd. Hydro - Oak Orchard	Oak Orchard		B	24046		073	36	1941-01-01	0.4	0.3	0.3	0.3		HY			WAT			1.2	
1238	Erie Blvd. Hydro - Oak Orchard	Waterport 1		B	24046		073	36	1941-01-01	2.3	1.8	2.2	2.2		HY			WAT			0.8	
1239	Erie Blvd. Hydro - Oak Orchard	Waterport 2		B	24046		073	36	1968-01-01	2.5	1.9	2.4	2.4		HY			WAT			9.0	
1240	Erie Blvd. Hydro - Oswegatchie	Browns Falls 1		E	24044		089	36	1923-01-01	7.5	7.6	7.5	7.5		HY			WAT			44.8	
1241	Erie Blvd. Hydro - Oswegatchie	Browns Falls 2		E	24044		089	36	1923-01-01	7.5	7.6	7.5	7.5		HY			WAT			12.9	
1242	Erie Blvd. Hydro - Oswegatchie	Eel Weir 1		E	24044		089	36	1928-01-01	0.5	0.5	0.5	0.5		HY			WAT			1.8	
1243	Erie Blvd. Hydro - Oswegatchie	Eel Weir 2		E	24044		089	36	1938-01-01	1.1	1.1	1.1	1.1		HY			WAT			1.7	
1244	Erie Blvd. Hydro - Oswegatchie	Eel Weir 3		E	24044		089	36	1938-01-01	1.1	1.1	1.1	1.1		HY			WAT			2.7	
1245	Erie Blvd. Hydro - Oswegatchie	Flat Rock 1		E	24044		089	36	1924-01-01	3.0	3.0	3.0	3.0		HY			WAT			15.2	
1246	Erie Blvd. Hydro - Oswegatchie	Flat Rock 2		E	24044		089	36	1924-01-01	3.0	3.0	3.0	3.0		HY			WAT			6.5	
1247	Erie Blvd. Hydro - Oswegatchie	Heuvelton 1		E	24044		089	36	1924-01-01	0.5	0.5	0.5	0.5		HY			WAT			2.5	
1248	Erie Blvd. Hydro - Oswegatchie	Heuvelton 2		E	24044		089	36	1924-01-01	0.5	0.5	0.5	0.5		HY			WAT			2.3	
1249	Erie Blvd. Hydro - Oswegatchie	Lower Newton Falls 1		E	24044		089	36	2002-07-01	0.5	0.5	0.5	0.5		HY			WAT			3.2	
1250	Erie Blvd. Hydro - Oswegatchie	Oswegatchie 1		E	24044		089	36	1937-01-01	0.6	0.6	0.6	0.6		HY			WAT			6.2	
1251	Erie Blvd. Hydro - Oswegatchie	Oswegatchie 2		E	24044		089	36	1937-01-01	0.2	0.2	0.2	0.2		HY			WAT			3.0	
1252	Erie Blvd. Hydro - Oswegatchie	South Edwards 1		E	24044		089	36	1937-01-01	1.0	1.0	1.0	1.0		HY			WAT			7.6	
1253	Erie Blvd. Hydro - Oswegatchie	South Edwards 2		E	24044		089	36	1937-01-01	1.0	1.0	1.0	1.0		HY			WAT			5.8	
1254	Erie Blvd. Hydro - Oswegatchie	South Edwards 3		E	24044		089	36	1921-01-01	0.7	0.7	0.7	0.7		HY			WAT			6.5	
1255	Erie Blvd. Hydro - Oswegatchie	South Edwards 4		E	24044		089	36	1937-01-01	0.2	0.2	0.2	0.2		HY			WAT			1.5	

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a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1256	Erie Blvd. Hydro - Oswegatchie	Talcville 1		E	24044		089	36	1986-12-01	0.5	0.5	0.5	0.5		HY			WAT			3.2	
1257	Erie Blvd. Hydro - Oswegatchie	Talcville 2		E	24044		089	36	1986-12-01	0.5	0.5	0.5	0.5		HY			WAT			0.2	
1258	Erie Blvd. Hydro - Oswegatchie	Upper Newton Falls 2		E	24044		089	36	2002-07-01	0.5	0.5	0.5	0.5		HY			WAT			2.7	
1259	Erie Blvd. Hydro - Oswegatchie	Upper Newton Falls 3		E	24044		089	36	2002-07-01	0.5	0.5	0.5	0.5		HY			WAT			3.0	
1260	Erie Blvd. Hydro - Oswegatchie	Upper Newton Falls 4		E	24044		089	36	2002-07-01	0.5	0.5	0.5	0.5		HY			WAT			1.7	
1261	Erie Blvd. Hydro - Seneca Oswego	Baldwinsville 1		C	24041		067	36	1927-01-01	0.3	0.3	0.3	0.3		HY			WAT			1.3	
1262	Erie Blvd. Hydro - Seneca Oswego	Baldwinsville 2		C	24041		067	36	1927-01-01	0.3	0.3	0.3	0.3		HY			WAT			0.0	
1263	Erie Blvd. Hydro - Seneca Oswego	Fulton 1		C	24041		075	36	1924-01-01	0.8	0.7	0.8	0.8		HY			WAT			4.4	
1264	Erie Blvd. Hydro - Seneca Oswego	Fulton 2		C	24041		075	36	1928-01-01	0.5	0.4	0.5	0.5		HY			WAT			0.0	
1265	Erie Blvd. Hydro - Seneca Oswego	Granby 1		C	24041		075	36	1983-05-01	5.0	4.5	5.1	5.1		HY			WAT			24.1	
1266	Erie Blvd. Hydro - Seneca Oswego	Granby 2		C	24041		075	36	1983-05-01	5.0	4.5	5.1	5.1		HY			WAT			29.5	
1267	Erie Blvd. Hydro - Seneca Oswego	Minetto 2		C	24041		075	36	1915-01-01	1.6	1.4	1.6	1.6		HY			WAT			8.7	
1268	Erie Blvd. Hydro - Seneca Oswego	Minetto 3		C	24041		075	36	1915-01-01	1.6	1.4	1.6	1.6		HY			WAT			9.6	
1269	Erie Blvd. Hydro - Seneca Oswego	Minetto 4		C	24041		075	36	1915-01-01	1.6	1.4	1.6	1.6		HY			WAT			7.8	
1270	Erie Blvd. Hydro - Seneca Oswego	Minetto 5		C	24041		075	36	1975-01-01	1.6	1.4	1.6	1.6		HY			WAT			7.3	
1271	Erie Blvd. Hydro - Seneca Oswego	Minetto 6		C	24041		075	36	1975-01-01	1.6	1.4	1.6	1.6		HY			WAT			6.1	
1272	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls E 1		C	24041		075	36	1914-01-01	1.5	1.3	1.6	1.6		HY			WAT			4.7	
1273	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls E 2		C	24041		075	36	1914-01-01	1.5	1.3	1.6	1.6		HY			WAT			7.9	
1274	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls E 3		C	24041		075	36	1914-01-01	1.5	1.3	1.6	1.6		HY			WAT			9.1	
1275	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls W 4		C	24041		075	36	1914-01-01	0.9	0.8	0.9	0.9		HY			WAT			4.9	
1276	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls W 5		C	24041		075	36	1914-01-01	0.9	0.8	0.9	0.9		HY			WAT			5.2	
1277	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls W 6		C	24041		075	36	2007-01-01	0.5	0.8	0.5	0.5		HY			WAT			0.4	
1278	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls W 7		C	24041		075	36	2007-01-01	0.5	0.8	0.5	0.5		HY			WAT			0.2	
1279	Erie Blvd. Hydro - Seneca Oswego	Varick 2		C	24041		075	36	1926-01-01	2.2	2.0	2.2	2.2		HY			WAT			5.6	
1280	Erie Blvd. Hydro - Seneca Oswego	Varick 3		C	24041		075	36	1926-01-01	2.2	2.2	2.2	2.2		HY			WAT			3.7	
1281	Erie Blvd. Hydro - Seneca Oswego	Varick 4		C	24041		075	36	1926-01-01	2.2	2.0	2.2	2.2		HY			WAT			3.8	
1282	Erie Blvd. Hydro - Seneca Oswego	Varick 5		C	24041		075	36	1926-01-01	2.2	2.0	2.2	2.2		HY			WAT			6.0	
1283	Erie Blvd. Hydro - South Salmon	Bennetts Bridge 1		C	24043		075	36	1964-01-01	6.4	7.0	6.4	6.4		HY			WAT			6.7	
1284	Erie Blvd. Hydro - South Salmon	Bennetts Bridge 2		C	24043		075	36	1966-01-01	6.4	7.0	6.4	6.4		HY			WAT			15.0	
1285	Erie Blvd. Hydro - South Salmon	Bennetts Bridge 3		C	24043		075	36	1970-01-01	7.0	7.7	7.0	7.0		HY			WAT			34.8	
1286	Erie Blvd. Hydro - South Salmon	Bennetts Bridge 4		C	24043		075	36	1970-01-01	7.0	7.7	7.0	7.0		HY			WAT			36.4	
1287	Erie Blvd. Hydro - South Salmon	Lighthouse Hill 1		C	24043		075	36	1930-01-01	3.8	4.1	3.7	3.7		HY			WAT			12.7	

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a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1288	Erie Blvd. Hydro - South Salmon	Lighthouse Hill 2		C	24043		075	36	1930-01-01	3.8	4.1	3.7	3.7		HY			WAT			9.9	
1289	Erie Blvd. Hydro - Upper Hudson	E J West 1		F	24058		091	36	1930-01-01	10.0	11.6	10.0	10.0		HY			WAT			41.5	
1290	Erie Blvd. Hydro - Upper Hudson	E J West 2		F	24058		091	36	1930-01-01	10.0	11.6	10.0	10.0		HY			WAT			41.0	
1291	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 1		F	24058		091	36	1924-01-01	1.2	1.4	1.2	1.2		HY			WAT			6.6	
1292	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 2		F	24058		091	36	1924-01-01	1.2	1.4	1.2	1.2		HY			WAT			5.7	
1293	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 3		F	24058		091	36	1924-01-01	1.2	1.4	1.2	1.2		HY			WAT			5.3	
1294	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 4		F	24058		091	36	1924-01-01	1.2	1.4	1.2	1.2		HY			WAT			3.6	
1295	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 5		F	24058		091	36	1924-01-01	1.2	1.4	1.2	1.2		HY			WAT			5.5	
1296	Erie Blvd. Hydro - Upper Hudson	Sherman Island 1		F	24058		113	36	2009-03-01	8.0	0.0	0.0	0.0		HY			WAT			48.2	
1297	Erie Blvd. Hydro - Upper Hudson	Sherman Island 2		F	24058		113	36	1923-01-01	7.2	8.3	7.2	7.2		HY			WAT			54.5	
1298	Erie Blvd. Hydro - Upper Hudson	Sherman Island 3		F	24058		113	36	1923-01-01	8.7	10.1	8.7	8.7		HY			WAT			44.6	
1299	Erie Blvd. Hydro - Upper Hudson	Sherman Island 4		F	24058		113	36	1923-01-01	7.2	8.3	7.2	7.2		HY			WAT			41.2	
1300	Erie Blvd. Hydro - Upper Hudson	Sherman Island 5		F	24058		113	36	1923-01-01	7.2	8.3	7.2	7.2		HY			WAT			31.7	
1301	Erie Blvd. Hydro - Upper Hudson	Sherman Island 6		F	24058		113	36	2009-02-02	1.0	0.0	0.0	0.0		HY			WAT			9.8	
1302	Erie Blvd. Hydro - Upper Hudson	Spier Falls 1		F	24058		091	36	1924-01-01	6.8	7.9	6.8	6.8		HY			WAT			43.8	
1303	Erie Blvd. Hydro - Upper Hudson	Spier Falls 2		F	24058		091	36	1930-01-01	37.6	43.6	37.6	37.6		HY			WAT			228.3	
1304	Erie Blvd. Hydro - Upper Hudson	Stewarts Bridge		F	24058		091	36	1952-01-01	30.0	34.8	30.0	30.0		HY			WAT			176.0	
1305	Erie Blvd. Hydro - Upper Raquette	Blake		E	24056		089	36	1957-01-01	14.4	15.6	14.4	14.4		HY			WAT			67.9	
1306	Erie Blvd. Hydro - Upper Raquette	Five Falls		E	24056		089	36	1955-01-01	22.5	24.4	22.5	22.5		HY			WAT			114.4	
1307	Erie Blvd. Hydro - Upper Raquette	Rainbow Falls		E	24056		089	36	1956-01-01	22.5	24.4	22.5	22.5		HY			WAT			115.8	
1308	Erie Blvd. Hydro - Upper Raquette	South Colton		E	24056		089	36	1954-01-01	19.4	21.0	19.3	19.3		HY			WAT			95.2	
1309	Erie Blvd. Hydro - Upper Raquette	Stark		E	24056		089	36	1957-01-01	22.5	24.4	22.5	22.5		HY			WAT			105.7	
1310	Erie Blvd. Hydro - West Canada	Prospect		E	24049		043	36	1959-01-01	17.3	23.2	17.3	17.3		HY			WAT			78.3	
1311	Erie Blvd. Hydro - West Canada	Trenton Falls 5		E	24049		065	36	1919-01-01	6.8	9.1	6.8	6.8		HY			WAT			49.3	
1312	Erie Blvd. Hydro - West Canada	Trenton Falls 6		E	24049		065	36	1919-01-01	6.4	8.6	6.4	6.4		HY			WAT			48.4	
1313	Erie Blvd. Hydro - West Canada	Trenton Falls 7		E	24049		065	36	1922-01-01	6.4	8.6	6.4	6.4		HY			WAT			48.0	
1314	Erie Blvd. Hydropower LP	West Delaware Hydro		G	323627	Grahamsville	105	36	1988-12-01	7.5	7.3	7.5	7.5		HY			WAT			19.4	
1315	Fenner Wind Power	Fenner Wind Power		C	24204	Fenner	053	36	2001-12-01	30.0	30.0	0.0	0.0		WT			WND			66.0	
1316	First Wind Energy, LLC	Erie Wind		A	323693	Lackawanna	029	36	2012-02-01	15.0	0.0	0.0	0.0		WT			WND			0.0	(N)
1317	Flat Rock Windpower II, LLC	Maple Ridge Wind 2		E	323611	Lowville	049	36	2007-12-01	90.8	90.7	90.8	90.8		WT			WND			202.1	
1318	Flat Rock Windpower, LLC	Maple Ridge Wind 1		E	323574	Lowville	049	36	2006-01-01	231.0	231.0	231.0	231.0		WT			WND			530.2	
1319	Freeport Electric	Freeport 1-1		K	1660	Freeport	059	36	1941-08-01	2.1		1.5	1.9	N	IC			FO2			0.0	

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a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1320	Freeport Electric	Freeport 1-2		K	1660	Freeport	059	36	1949-08-01	2.9		2.2	2.6	N	IC			FO2			0.0	
1321	Freeport Electric	Freeport 1-3		K	1660	Freeport	059	36	1954-08-01	3.1		2.1	2.8	N	IC			FO2			0.0	
1322	Freeport Electric	Freeport 1-4		K	1660	Freeport	059	36	1964-10-01	5.1		4.5	4.6	N	IC			FO2			0.1	
1323	Freeport Electric	Freeport 2-3		K	1660	Freeport	059	36	1973-05-01	18.1		16.2	16.3	N	GT			FO2			0.3	
1324	Freeport Electric	Freeport CT 2		K	23818	Freeport	059	36	2004-03-01	60.5	50.3	45.5	49.0	N	GT			NG			52.4	
1325	GenOn Energy Management, LLC	Bowline 1		G	23526	West Haverstraw	087	36	1972-09-01	621.0	577.7	579.8	600.1	N	ST	T	A	NG	FO6		200.9	
1326	GenOn Energy Management, LLC	Bowline 2		G	23595	West Haverstraw	087	36	1974-05-01	621.0	557.4	157.7	159.5	N	ST	W	A	NG	FO6		3.7	
1327	Hampshire Paper Co., Inc.	Hampshire Paper		E	323593	Gouverneur	089	36	1987-03-01	3.4	3.5	3.4	3.4		HY			WAT			21.7	
1328	Hardscrabble Wind Power LLC	Hardscrabble Wind		E	323673	Fairfield	043	36	2011-02-01	74.0	74.0	74.0	74.0		WT			WND			147.7	(4)
1329	Howard Wind LLC	Howard Wind		C	323690	Howard	101	36	2011-12-01	51.3	57.4	51.3	51.3		WT			WND			6.5	(N) (5)
1330	Indeck Energy Services of Silver S	Indeck-Silver Springs		C	23768	Silver Springs	121	36	1991-04-01	56.6	51.5	49.4	62.5	Y	CC			NG	FO2		13.2	
1331	Indeck-Corinth LP	Indeck-Corinth		F	23802	Corinth	091	36	1995-07-01	147.0	131.2	130.3	132.3	Y	CC		Y	NG	FO2		900.2	
1332	Indeck-Olean LP	Indeck-Olean		A	23982	Olean	009	36	1993-12-01	90.6	79.4	75.7	82.9	Y	CC			NG			138.5	
1333	Indeck-Oswego LP	Indeck-Oswego		C	23783	Oswego	075	36	1990-05-01	57.4	51.6	47.2	57.1	Y	CC			NG			11.5	
1334	Indeck-Yerkes LP	Indeck-Yerkes		A	23781	Tonawanda	029	36	1990-02-01	59.9	49.7	47.9	58.4	Y	CC			NG			11.2	
1335	Innovative Energy Systems, Inc.	Chautauqua LFGE		A	323629	Jamestown	013	36	2010-02-12	9.6	6.4	6.4	6.4	N	IC			MTE			52.0	
1336	Innovative Energy Systems, Inc.	Clinton LFGE		D	323618	Morrisonville	019	36	2008-10-01	6.4	4.8	4.8	4.8	N	IC			MTE			44.3	
1337	Innovative Energy Systems, Inc.	Colonie LFGTE		F	323577	Colonie	001	36	2006-03-01	4.8	4.8	4.8	4.8	N	IC			MTE			30.7	
1338	Innovative Energy Systems, Inc.	DANC LFGE		E	323619	Watertown	045	36	2008-09-08	4.8	4.8	4.8	4.8	N	IC			MTE			37.7	
1339	Innovative Energy Systems, Inc.	Fulton LFGE		F	323630	Johnstown	035	36	2010-06-04	3.2	0.0	0.0	0.0	N	IC			MTE			12.6	
1340	Innovative Energy Systems, Inc.	Hyland LFGE		B	323620	Angelica	003	36	2008-09-08	4.8	4.8	4.8	4.8	N	IC			MTE			35.8	
1341	Integrys Energy Services, Inc.	Beaver Falls		E	23983	Beaver Falls	049	36	1995-03-01	107.8	80.2	80.6	91.3	Y	CC			NG			1.8	
1342	Integrys Energy Services, Inc.	Syracuse		C	23985	Syracuse	067	36	1993-09-01	102.7	86.8	82.8	96.4	Y	CC			NG			8.1	
1343	International Paper Company	Ticonderoga		F	23804	Ticonderoga	031	36	1970-01-01	42.1	7.6	9.9	9.9	Y	ST			FO6			0.1	
1344	Jamestown Board of Public Utilities	Jamestown 5		A	1658	Jamestown	013	36	1951-08-01	28.7		23.5	22.1	Y	ST			BIT			40.0	(G)
1345	Jamestown Board of Public Utilities	Jamestown 6		A	1658	Jamestown	013	36	1968-08-01	25.0		20.5	19.3	Y	ST			BIT				
1346	Jamestown Board of Public Utilities	Jamestown 7		A	1659	Jamestown	013	36	2002-01-01	47.3		38.2	46.2	Y	GT			NG			94.1	
1347	Long Island Power Authority	Babylon (RR)		K	23656	Babylon	103	36	1989-04-01	17.0	15.2	14.6	14.5	N	ST			REF			114.0	
1348	Long Island Power Authority	Barrett 03		K	23706	Island Park	059	36	1970-06-01	18.0	17.9	17.9	20.1	N	GT		C	NG	FO2		1.1	
1349	Long Island Power Authority	Barrett 04		K	23707	Island Park	059	36	1970-07-01	18.0	17.7	17.1	20.4	N	GT		C	NG	FO2		4.8	
1350	Long Island Power Authority	Barrett 05		K	23708	Island Park	059	36	1970-07-01	18.0	17.8	16.9	19.9	N	GT		C	NG	FO2		1.7	
1351	Long Island Power Authority	Barrett 06		K	23709	Island Park	059	36	1970-07-01	18.0	17.8	17.2	20.7	N	GT		C	NG	FO2		3.3	

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a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1352	Long Island Power Authority	Barrett 07 (Ret. - 10/13/11)		K	23710	Island Park	059	36	1970-07-01	18.0	17.3	0.0	0.0	N	GT		C	NG	FO2		-0.1	(R)
1353	Long Island Power Authority	Barrett 08		K	23711	Island Park	059	36	1970-07-01	18.0	17.3	16.7	20.2	N	GT		C	NG	FO2		4.6	
1354	Long Island Power Authority	Barrett 09		K	23700	Island Park	059	36	1971-06-01	41.8	43.4	40.7	50.7	N	JE		C	NG	FO2		24.1	
1355	Long Island Power Authority	Barrett 10		K	23701	Island Park	059	36	1971-06-01	41.8	42.7	41.6	52.5	N	JE		C	NG	FO2		16.2	
1356	Long Island Power Authority	Barrett 11		K	23702	Island Park	059	36	1971-06-01	41.8	43.3	39.8	49.4	N	JE		C	NG	FO2		18.9	
1357	Long Island Power Authority	Barrett 12		K	23703	Island Park	059	36	1971-06-01	41.8	44.0	40.8	48.9	N	JE		C	NG	FO2		16.1	
1358	Long Island Power Authority	Barrett GT 01		K	23704	Island Park	059	36	1970-06-01	18.0	18.1	17.0	19.9	N	GT		C	NG	FO2		0.9	
1359	Long Island Power Authority	Barrett GT 02		K	23705	Island Park	059	36	1970-06-01	18.0	17.4	14.7	18.5	N	GT		C	NG	FO2		1.7	
1360	Long Island Power Authority	Barrett ST 01		K	23545	Island Park	059	36	1956-11-01	188.0	200.2	200.5	191.0	N	ST	T	A	NG	FO6		603.4	
1361	Long Island Power Authority	Barrett ST 02		K	23546	Island Park	059	36	1963-10-01	188.0	197.5	196.2	196.5	N	ST	T	A	NG	FO6		367.3	
1362	Long Island Power Authority	Bethpage 3		K	323564	Hicksville	059	36	2005-05-01	96.0	79.9	76.6	76.7		CC			NG			218.7	
1363	Long Island Power Authority	Caithness_CC_1		K	323624	Brookhaven	103	36	2009-08-01	375.0	309.6	309.6	360.1	N	CC			NG	FO2		2,247.2	
1364	Long Island Power Authority	East Hampton 2		K	23722	E Hampton	103	36	1962-12-01	2.0	2.0	2.0	2.0	N	IC		C	FO2			0.4	
1365	Long Island Power Authority	East Hampton 3		K	23722	E Hampton	103	36	1962-12-01	2.0	2.0	2.0	2.0	N	IC		C	FO2			0.5	
1366	Long Island Power Authority	East Hampton 4		K	23722	E Hampton	103	36	1962-12-01	2.0	2.0	2.0	2.0	N	IC		C	FO2			0.4	
1367	Long Island Power Authority	East Hampton GT 01		K	23717	E Hampton	103	36	1970-12-01	21.3	19.2	18.6	24.6	N	GT		C	FO2			7.9	
1368	Long Island Power Authority	Far Rockaway GT1		K	24212	Far Rockaway	081	36	2002-07-01	60.0	53.5	53.7	54.2	N	GT			NG			94.2	
1369	Long Island Power Authority	Far Rockaway GT2		K	23815	Jamaica Bay	081	36	2003-07-02	60.0	55.4	54.3	55.4	N	GT			FO2			9.2	
1370	Long Island Power Authority	Far Rockaway ST 04		K	23548	Far Rockaway	081	36	1953-12-01	100.0	110.6	106.7	106.2	N	ST	T	A	NG	FO6		343.6	
1371	Long Island Power Authority	Freeport CT 1		K	23764	Freeport	059	36	2004-06-01	60.0	48.3	47.7	49.4	N	GT			NG			94.2	
1372	Long Island Power Authority	Glenwood GT 01		K	23712	Glenwood	059	36	1967-04-01	16.0	14.6	11.7	15.5	N	GT		C	FO2			0.0	
1373	Long Island Power Authority	Glenwood GT 02		K	23688	Glenwood	059	36	1972-06-01	55.0	52.7	48.1	63.5	N	GT		C	FO2			0.8	
1374	Long Island Power Authority	Glenwood GT 03		K	23689	Glenwood	059	36	1972-06-01	55.0	52.7	40.1	66.1	N	GT		C	FO2			0.5	
1375	Long Island Power Authority	Glenwood GT 04		K	24219	Glenwood	059	36	2002-06-01	53.0	40.3	39.4	46.5	N	GT			NG			55.5	
1376	Long Island Power Authority	Glenwood GT 05		K	24220	Glenwood	059	36	2002-06-01	53.0	40.0	40.5	45.3	N	GT			NG			27.5	
1377	Long Island Power Authority	Glenwood ST 04		K	23550	Glenwood	059	36	1952-12-01	114.0	118.7	115.0	111.0	N	ST	T	A	NG			123.0	
1378	Long Island Power Authority	Glenwood ST 05		K	23614	Glenwood	059	36	1954-11-01	114.0	122.0	108.7	105.5	N	ST	T	A	NG			147.5	
1379	Long Island Power Authority	Greenport GT1		K	23814	Greenport	103	36	2003-07-02	54.0	51.9	52.0	54.5	N	GT			FO2			23.6	
1380	Long Island Power Authority	Hempstead (RR)		K	23647	Hempstead	059	36	1989-10-01	78.6	73.7	72.4	73.5	N	ST			REF			555.7	
1381	Long Island Power Authority	Holtsville 01		K	23690	Holtsville	103	36	1974-07-01	56.7	55.1	50.1	63.4	N	JE		C	FO2			4.3	
1382	Long Island Power Authority	Holtsville 02		K	23691	Holtsville	103	36	1974-07-01	56.7	55.3	48.6	61.1	N	JE		C	FO2			2.9	
1383	Long Island Power Authority	Holtsville 03		K	23692	Holtsville	103	36	1974-07-01	56.7	52.1	47.1	61.2	N	JE		C	FO2			3.2	

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a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1384	Long Island Power Authority	Holtsville 04		K	23693	Holtsville	103	36	1974-07-01	56.7	52.7	49.9	62.9	N	JE		C	FO2			2.8	
1385	Long Island Power Authority	Holtsville 05		K	23694	Holtsville	103	36	1974-07-01	56.7	53.3	52.8	64.5	N	JE		C	FO2			3.5	
1386	Long Island Power Authority	Holtsville 06		K	23695	Holtsville	103	36	1975-07-01	56.7	53.0	51.6	62.9	N	JE		C	FO2			5.0	
1387	Long Island Power Authority	Holtsville 07		K	23696	Holtsville	103	36	1975-07-01	56.7	55.1	52.2	63.2	N	JE		C	FO2			4.0	
1388	Long Island Power Authority	Holtsville 08		K	23697	Holtsville	103	36	1975-07-01	56.7	57.4	56.8	66.5	N	JE		C	FO2			4.2	
1389	Long Island Power Authority	Holtsville 09		K	23698	Holtsville	103	36	1975-07-01	56.7	57.5	52.9	65.5	N	JE		C	FO2			4.2	
1390	Long Island Power Authority	Holtsville 10		K	23699	Holtsville	103	36	1975-07-01	56.7	55.1	53.0	65.9	N	JE		C	FO2			7.7	
1391	Long Island Power Authority	Huntington		K	23656	Huntington	103	36	1991-12-01	28.0	25.0	24.4	24.6	N	ST			REF			178.9	
1392	Long Island Power Authority	Islip (RR)		K	23656	Ronkonkoma	103	36	1990-03-01	12.5	11.2	9.2	8.4	N	ST			REF			53.8	
1393	Long Island Power Authority	Long Island Solar Farm		K	323691	Upton	103	36	2011-11-01	31.5	31.5	31.5	31.5		PV			SUN			6.5	(N)(7)
1394	Long Island Power Authority	Montauk 02		K	23721	Montauk	103	36	1971-05-01	2.0	2.0	1.9	1.9	N	IC		C	FO2			0.2	
1395	Long Island Power Authority	Montauk 03		K	23721	Montauk	103	36	1965-11-01	2.0	2.0	1.9	1.9	N	IC		C	FO2			0.3	
1396	Long Island Power Authority	Montauk 04		K	23721	Montauk	103	36	1965-11-01	2.0	2.0	1.9	1.9	N	IC		C	FO2			0.3	
1397	Long Island Power Authority	Northport 1		K	23551	Northport	103	36	1967-07-01	387.0	395.0	394.5	391.5	N	ST	T	A	NG	FO6		310.1	
1398	Long Island Power Authority	Northport 2		K	23552	Northport	103	36	1968-06-01	387.0	396.0	393.7	390.5	N	ST	T	A	NG	FO6		710.9	
1399	Long Island Power Authority	Northport 3		K	23553	Northport	103	36	1972-07-01	387.0	399.2	399.7	393.5	N	ST	T	A	NG	FO6		1,082.6	
1400	Long Island Power Authority	Northport 4		K	23650	Northport	103	36	1977-12-01	387.0	399.2	393.0	393.5	N	ST	T	A	NG	FO6		1,366.0	
1401	Long Island Power Authority	Northport GT		K	23718	Northport	103	36	1967-03-01	16.0	13.8	12.6	14.1	N	GT		C	FO2			0.4	
1402	Long Island Power Authority	Oceanside (LF)		K	5008	Oceanside	059	36	1991-02-01	2.1		0.0	0.0	N	IC			MTE			2.9	
1403	Long Island Power Authority	Oyster Bay (LF)		K	5009	Bethpage	059	36	1986-07-01	1.3		0.0	0.0	N	IC			MTE			0.0	
1404	Long Island Power Authority	Pilgrim GT1		K	24216	Brentwood	103	36	2002-08-01	50.0	43.6	43.5	46.7	N	GT			NG			77.1	
1405	Long Island Power Authority	Pilgrim GT2		K	24217	Brentwood	103	36	2002-08-01	50.0	44.2	42.6	45.6	N	GT			NG			68.5	
1406	Long Island Power Authority	Pinelawn Power 1		K	323563	Babylon	103	36	2005-06-01	82.0	78.0	74.6	77.5		CC			NG	KER		104.1	
1407	Long Island Power Authority	Port Jefferson 3		K	23555	Port Jefferson	103	36	1958-11-01	188.0	194.5	196.7	191.5	N	ST	T	A	FO6	NG		160.9	
1408	Long Island Power Authority	Port Jefferson 4		K	23616	Port Jefferson	103	36	1960-11-01	188.0	198.7	197.2	192.4	N	ST	T	A	FO6	NG		257.4	
1409	Long Island Power Authority	Port Jefferson GT 01		K	23713	Port Jefferson	103	36	1966-12-01	16.0	14.1	12.4	14.8	N	GT		C	FO2			0.1	
1410	Long Island Power Authority	Port Jefferson GT 02		K	24210	P Jefferson	103	36	2002-07-01	53.0	42.0	42.4	46.0	N	GT			NG			55.8	
1411	Long Island Power Authority	Port Jefferson GT 03		K	24211	P Jefferson	103	36	2002-07-01	53.0	41.1	39.9	48.7	N	GT			NG			72.0	
1412	Long Island Power Authority	S Hampton 1		K	23720	South Hampton	103	36	1963-03-01	11.5	10.3	8.6	11.9	N	GT		C	FO2			1.8	
1413	Long Island Power Authority	Shoreham 1		K	23715	Shoreham	103	36	1971-07-01	52.9	48.9	41.6	56.0	N	GT		C	FO2			0.6	
1414	Long Island Power Authority	Shoreham 2		K	23716	Shoreham	103	36	1984-04-01	18.6	18.5	16.6	22.0	N	GT		C	FO2			0.2	
1415	Long Island Power Authority	Shoreham GT3		K	24213	Shoreham	103	36	2002-08-01	50.0	45.1	43.9	46.2	N	GT			NG			11.0	

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a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1416	Long Island Power Authority	Shoreham GT4		K	24214	Shoreham	103	36	2002-08-01	50.0	41.9	42.7	45.9	N	GT			NG			9.8	
1417	Long Island Power Authority	Smithtown (LF)		K	5010	Smithtown	103	36	1985-12-01	1.1		0.0	0.0	N	IC			MTE			0.0	
1418	Long Island Power Authority	South Oaks Hosp		K	5011	Amityville	103	36	1990-06-01	1.0		0.0	0.0	Y	IC			NG			0.0	
1419	Long Island Power Authority	Southold 1		K	23719	Southold	103	36	1964-08-01	14.0	12.3	8.9	15.1	N	GT		C	FO2			1.2	
1420	Long Island Power Authority	Stony Brook		K	24151	Stony Brook	103	36	1995-04-01	47.0	9.6	16.2	19.2	Y	GT			NG			275.8	
1421	Long Island Power Authority	Trigen-NDEC		K	23656	Garden City	059	36	1991-03-01	55.0	51.6	43.2	55.2	Y	CC			NG	FO2		344.8	
1422	Long Island Power Authority	Wading River 1		K	23522	Shoreham	103	36	1989-08-01	79.5	81.2	81.2	98.8	N	GT		C	FO2			12.6	
1423	Long Island Power Authority	Wading River 2		K	23547	Shoreham	103	36	1989-08-01	79.5	81.3	78.3	99.1	N	GT		C	FO2			11.1	
1424	Long Island Power Authority	Wading River 3		K	23601	Shoreham	103	36	1989-08-01	79.5	81.3	76.3	97.6	N	GT		C	FO2			11.3	
1425	Long Island Power Authority	West Babylon 4		K	23714	West Babylon	103	36	1971-08-01	52.4	49.0	48.5	62.5	N	GT		C	FO2			3.8	
1426	Long Island Power Authority	Yaphank (LF)		K	5012	Yaphank	103	36	1983-09-01	1.6		0.0	0.0	N	IC			MTE			4.4	
1427	Lyonsdale BioMass, LLC	Lyonsdale Power		E	23803	Lyonsdale	049	36	1992-08-01	21.1	20.2	20.6	19.7	Y	ST			WD			121.2	
1428	Madison Windpower, LLC	Madison Wind Power		E	24146	Madison	053	36	2000-09-01	11.6	11.5	11.6	11.6		WT			WND			21.7	
1429	MM Albany Energy LLC	Albany LFGE		F	323615	Albany	001	36	1998-05-01	3.8	2.5	2.8	2.8	N	IC			MTE			19.5	
1430	Model City Energy LLC	Model City Energy		A	24167	Lewiston	063	36	2001-06-01	5.6	5.6	5.6	5.6	N	IC			MTE			42.8	
1431	Modern Innovative Energy, LLC	Modern LF		A	323580	Lewiston	063	36	2006-02-01	6.4	6.4	6.4	6.4	N	IC			MTE			37.3	
1432	New York Power Authority	Ashokan 1		G	23654	Ashokan	111	36	1982-11-01	2.3	1.8	2.3	2.4		HY			WAT			6.1	
1433	New York Power Authority	Ashokan 2		G	23654	Ashokan	111	36	1982-11-01	2.3	1.8	2.3	2.4		HY			WAT			2.9	
1434	New York Power Authority	Astoria CC 1		J	323568	Queens	081	36	2006-01-01	288.0	246.2	234.1	260.0		CC			NG	JF	KER	3,035.8	(G)
1435	New York Power Authority	Astoria CC 2		J	323569	Queens	081	36	2006-01-01	288.0	246.2	234.1	260.0		CC			NG	JF	KER		
1436	New York Power Authority	Blenheim - Gilboa 1		F	23756	Gilboa NY	095	36	1973-07-01	290.0	290.7	291.7	291.2		PS			WAT			16.6	
1437	New York Power Authority	Blenheim - Gilboa 2		F	23757	Gilboa NY	095	36	1973-07-01	290.0	291.2	292.3	291.5		PS			WAT			122.0	
1438	New York Power Authority	Blenheim - Gilboa 3		F	23758	Gilboa NY	095	36	1973-07-01	290.0	291.7	290.7	291.7		PS			WAT			32.6	
1439	New York Power Authority	Blenheim - Gilboa 4		F	23759	Gilboa NY	095	36	1973-07-01	290.0	291.5	292.2	291.7		PS			WAT			8.5	
1440	New York Power Authority	Brentwood		K	24164	Brentwood	103	36	2001-08-01	50.0	47.1	46.9	47.0	N	GT			NG			68.1	
1441	New York Power Authority	Crescent 1		F	24018	Crescent	001	36	1991-07-01	2.8	3.1	2.8	2.8		HY			WAT			15.9	
1442	New York Power Authority	Crescent 2		F	24018	Crescent	001	36	1991-07-01	2.8	3.1	2.8	2.8		HY			WAT			14.6	
1443	New York Power Authority	Crescent 3		F	24018	Crescent	001	36	1991-07-01	3.0	3.3	3.0	3.1		HY			WAT			21.2	
1444	New York Power Authority	Crescent 4		F	24018	Crescent	001	36	1991-07-01	3.0	3.3	3.0	3.1		HY			WAT			20.8	
1445	New York Power Authority	Flynn		K	23794	Holtsville	103	36	1994-05-01	170.0	135.5	134.9	164.6	N	CC			NG	FO2		1,061.4	
1446	New York Power Authority	Gowanus 5		J	24156	Brooklyn	047	36	2001-08-01	50.0	45.4	44.3	44.4	N	GT			NG			80.4	
1447	New York Power Authority	Gowanus 6		J	24157	Brooklyn	047	36	2001-08-01	50.0	46.1	45.1	45.3	N	GT			NG			99.4	

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a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1448	New York Power Authority	Grahamsville		G	23607	Grahamsville	105	36	1956-12-01	18.0	16.3	18.0	18.0		HY			WAT			77.6	
1449	New York Power Authority	Greenport IC 4		K	1652	Greenport	103	36	1957-06-06	1.2		1.0	1.0	N	IC			FO2			0.0	
1450	New York Power Authority	Greenport IC 5		K	1652	Greenport	103	36	1965-07-08	1.8		1.5	1.5	N	IC			FO2			0.0	
1451	New York Power Authority	Greenport IC 6		K	1652	Greenport	103	36	1971-09-17	3.8		2.5	2.5	N	IC			FO2			0.0	
1452	New York Power Authority	Harlem River 1		J	24160	Bronx	005	36	2001-08-01	50.0	46.0	42.8	39.5	N	GT			NG			11.0	
1453	New York Power Authority	Harlem River 2		J	24161	Bronx	005	36	2001-08-01	50.0	45.2	45.3	46.0	N	GT			NG			19.9	
1454	New York Power Authority	Hellgate 1		J	24158	Bronx	005	36	2001-08-01	50.0	45.0	46.0	46.0	N	GT			NG			11.5	
1455	New York Power Authority	Hellgate 2		J	24159	Bronx	005	36	2001-08-01	50.0	45.0	44.7	45.5	N	GT			NG			18.7	
1456	New York Power Authority	Jarvis 1		E	23743	Hinckley	065	36	1991-07-01	4.5	4.5	4.5	4.5		HY			WAT			13.9	
1457	New York Power Authority	Jarvis 2		E	23743	Hinckley	065	36	1991-07-01	4.5	4.5	4.5	4.5		HY			WAT			17.5	
1458	New York Power Authority	Kensico 1		I	23655	Kensico	119	36	1983-07-01	1.0	0.6	1.0	1.0		HY			WAT			0.6	
1459	New York Power Authority	Kensico 2		I	23655	Kensico	119	36	1983-07-01	1.0	0.6	1.0	1.0		HY			WAT			0.6	
1460	New York Power Authority	Kensico 3		I	23655	Kensico	119	36	1983-07-01	1.0	0.6	1.0	1.0		HY			WAT			0.0	
1461	New York Power Authority	Kent		J	24152	Brooklyn	047	36	2001-08-01	50.0	46.9	43.8	46.0	N	GT			NG			83.9	
1462	New York Power Authority	Lewiston PS (Fleet)		A	23760	Niagara Falls	063	36	1961-01-01	240.0	240.0	240.0	240.0		PS			WAT			531.0	
1463	New York Power Authority	Moses Niagara (Fleet)		A	23760	Niagara Falls	063	36	1961-01-01	2,860.0	2,460.0	2,441.0	2,443.5		HY			WAT			14,134.2	
1464	New York Power Authority	Neversink		G	23608	Grahamsville	105	36	1953-12-01	25.0	22.0	25.0	25.0		HY			WAT			41.5	
1465	New York Power Authority	Pouch		J	24155	Staten Island	085	36	2001-08-01	50.0	47.1	45.5	45.9	N	GT			NG			110.7	
1466	New York Power Authority	St Lawrence - FDR (Fleet)		D	23600	Massena	089	36	1958-07-01	1,088.0	856.0	831.3	833.3		HY			WAT			7,312.8	
1467	New York Power Authority	Vernon Blvd 2		J	24162	Queens	081	36	2001-08-01	50.0	46.2	44.7	46.4	N	GT			NG			43.4	
1468	New York Power Authority	Vernon Blvd 3		J	24163	Queens	081	36	2001-08-01	50.0	43.8	43.7	45.3	N	GT			NG			39.2	
1469	New York Power Authority	Vischer Ferry 1		F	24020	Vischer Ferry	091	36	1991-07-01	2.8	3.1	2.8	3.0		HY			WAT			11.7	
1470	New York Power Authority	Vischer Ferry 2		F	24020	Vischer Ferry	091	36	1991-07-01	2.8	3.1	2.8	3.0		HY			WAT			16.2	
1471	New York Power Authority	Vischer Ferry 3		F	24020	Vischer Ferry	091	36	1991-07-01	3.0	3.3	3.0	3.0		HY			WAT			17.3	
1472	New York Power Authority	Vischer Ferry 4		F	24020	Vischer Ferry	091	36	1991-07-01	3.0	3.3	3.0	3.0		HY			WAT			20.2	
1473	New York State Elec. & Gas Corp.	AA Dairy		C	5013	Ithaca	109	36	1998-06-01	0.1		0.0	0.0	N	IC			MTE			0.0	
1474	New York State Elec. & Gas Corp.	Alice Falls 1		D	23915	Ausable	019	36	1991-11-01	1.5	2.2	0.0	0.0		HY			WAT				
1475	New York State Elec. & Gas Corp.	Alice Falls 2		D	23915	Ausable	019	36	1991-11-01	0.6	2.2	0.0	0.0		HY			WAT				
1476	New York State Elec. & Gas Corp.	Allegheny 8		C	23528	Kittanning	005	42	1990-10-01	16.0	14.7	16.0	16.0		HY			WAT			84.2	
1477	New York State Elec. & Gas Corp.	Allegheny 9		C	23528	Kittanning	005	42	1990-10-01	22.0	20.2	22.0	22.0		HY			WAT			95.1	
1478	New York State Elec. & Gas Corp.	Auburn - Mill St.		C	5014	Auburn	011	36	1981-10-01	0.4		0.0	0.0		HY			WAT				
1479	New York State Elec. & Gas Corp.	Auburn - No. Div.St		C	5015	Auburn	011	36	1992-12-01	0.8		0.0	0.0		HY			WAT				

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a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1480	New York State Elec. & Gas Corp.	Auburn - State St.		C	24147	Auburn	011	36	1995-01-01	7.4	5.8	5.4	6.9		GT			NG			0.3	
1481	New York State Elec. & Gas Corp.	Broome LFGE		C	323600	Binghamton	007	36	2007-09-01	2.1	2.1	2.1	2.1		IC			MTE			19.6	
1482	New York State Elec. & Gas Corp.	Cadyville 1		D	23628	Schuyler Falls	019	36	1921-08-01	1.2	1.2	1.2	1.2		HY			WAT			6.7	
1483	New York State Elec. & Gas Corp.	Cadyville 2		D	23628	Schuyler Falls	019	36	1921-08-01	1.2	1.2	1.2	1.2		HY			WAT			0.0	
1484	New York State Elec. & Gas Corp.	Cadyville 3		D	23628	Schuyler Falls	019	36	1986-09-01	3.1	3.2	3.1	3.1		HY			WAT			20.5	
1485	New York State Elec. & Gas Corp.	Chasm Hydro		D	5016	Chateaugay	033	36	1982-03-01	1.6		0.0	0.0		HY			WAT				
1486	New York State Elec. & Gas Corp.	Croton Fall Hydro		I	5017	North Salem	119	36	1987-01-01	0.2		0.0	0.0		HY			WAT				
1487	New York State Elec. & Gas Corp.	Harris Lake		D	5018	Newcomb	031	36	1967-08-01	1.7		0.0	0.0		IC		C	FO2				
1488	New York State Elec. & Gas Corp.	High Falls 1		D	23628	Saranac	019	36	1948-08-01	4.0	4.1	4.0	4.0		HY			WAT			6.8	
1489	New York State Elec. & Gas Corp.	High Falls 2		D	23628	Saranac	019	36	1949-08-01	4.0	4.1	4.0	4.0		HY			WAT			25.6	
1490	New York State Elec. & Gas Corp.	High Falls 3		D	23628	Saranac	019	36	1956-08-01	7.0	7.1	7.0	7.0		HY			WAT			39.0	
1491	New York State Elec. & Gas Corp.	Kent Falls 1		D	23628	Schuyler Falls	019	36	1928-08-01	3.6	3.3	3.6	3.6		HY			WAT			15.7	
1492	New York State Elec. & Gas Corp.	Kent Falls 2		D	23628	Schuyler Falls	019	36	1928-08-01	3.6	3.3	3.6	3.6		HY			WAT			17.8	
1493	New York State Elec. & Gas Corp.	Kent Falls 3		D	23628	Schuyler Falls	019	36	1985-07-01	6.4	6.1	6.4	6.4		HY			WAT			39.1	
1494	New York State Elec. & Gas Corp.	Lower Saranac 1		D	23913	Schuyler Falls	019	36	1990-10-01	3.2	9.9	0.0	0.0		HY			WAT				
1495	New York State Elec. & Gas Corp.	Lower Saranac 2		D	23913	Schuyler Falls	019	36	1990-10-01	3.2	9.9	0.0	0.0		HY			WAT				
1496	New York State Elec. & Gas Corp.	Lower Saranac 3		D	23913	Schuyler Falls	019	36	1990-10-01	2.9	9.9	0.0	0.0		HY			WAT				
1497	New York State Elec. & Gas Corp.	Mechanicville 1		F	23645	Stillwater	091	36	1983-09-01	9.2	10.0	9.2	9.3		HY			WAT			50.0	
1498	New York State Elec. & Gas Corp.	Mechanicville 2		F	23645	Stillwater	091	36	1983-09-01	9.3	10.0	9.3	9.3		HY			WAT			40.3	
1499	New York State Elec. & Gas Corp.	Mill C 1		D	23628	Plattsburgh	019	36	1944-08-01	1.0	1.0	1.0	1.0		HY			WAT			3.8	
1500	New York State Elec. & Gas Corp.	Mill C 2		D	23628	Plattsburgh	019	36	1943-08-01	1.2	1.2	1.2	1.2		HY			WAT			3.7	
1501	New York State Elec. & Gas Corp.	Mill C 3		D	23628	Plattsburgh	019	36	1984-11-01	3.8	3.9	3.8	3.8		HY			WAT			20.6	
1502	New York State Elec. & Gas Corp.	Montville Falls		C	5019	Moravia	011	36	1992-08-01	0.2		0.0	0.0		HY			WAT				
1503	New York State Elec. & Gas Corp.	Rainbow Falls 1		D	23628	Ausable	019	36	1926-08-01	1.3	1.3	1.3	1.3		HY			WAT			5.5	
1504	New York State Elec. & Gas Corp.	Rainbow Falls 2		D	23628	Ausable	019	36	1927-08-01	1.3	1.3	1.3	1.3		HY			WAT			5.7	
1505	New York State Elec. & Gas Corp.	Waterloo 2		C	5020	Waterloo	099	36	1998-06-01	0.5		0.0	0.0		HY			WAT				
1506	New York State Elec. & Gas Corp.	Waterloo 3		C	5021	Waterloo	099	36	1998-06-01	0.5		0.0	0.0		HY			WAT				
1507	New York State Elec. & Gas Corp.	Waterloo 4		C	5022	Waterloo	099	36	1998-06-01	0.5		0.0	0.0		HY			WAT				
1508	Niagara Generation, LLC	Niagara Bio-Gen		A	23895	Niagara Falls	063	36	1991-08-01	56.0	50.5	0.0	0.0	Y	ST			WD			0.0	
1509	Niagara Mohawk Power Corp.	Boralex - Hudson Falls		F	24011	Hudson Falls	115	36	1995-10-01	44.0	43.7	44.0	44.0		HY			WAT			279.2	
1510	Niagara Mohawk Power Corp.	Boralex - South Glens Falls		F	24028	Moreau	091	36	1994-12-01	13.8	14.8	0.0	0.0		HY			WAT			106.5	
1511	Niagara Mohawk Power Corp.	CHI-Lachute		F	1654		031	36	1987-12-01	9.0		0.0	0.0		HY			WAT			44.9	

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a	b	c	d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1512	Niagara Mohawk Power Corp.	Fortis - Dolgeville	E	23807	Dolgeville	043	36	1985-07-01	5.0	6.3	0.0	0.0		HY			WAT			25.9	
1513	Niagara Mohawk Power Corp.	Fortis Energy - Philadelphia	E	1656		045	36	1986-08-01	3.6		0.0	0.0		HY			WAT			11.4	
1514	Niagara Mohawk Power Corp.	Fortis Energy - Moose River	E	24016		049	36	1987-09-01	12.6	12.0	0.0	0.0		HY			WAT			28.5	
1515	Niagara Mohawk Power Corp.	Fortistar - N.Tonawanda	A	24026	N Tonawanda	029	36	1993-06-01	55.3	57.0	52.2	60.5	Y	CC			NG			15.9	
1516	Niagara Mohawk Power Corp.	General Mills Inc	A	23808		029	36	1988-12-01	3.8	3.8	0.0	0.0	Y	GT			NG			1.3	
1517	Niagara Mohawk Power Corp.	International Paper - Curtis	F	1655	Corinth	091	36	1986-01-01	29.5		0.0	0.0		HY			WAT			462.0	(G)
1518	Niagara Mohawk Power Corp.	International Paper - Palmer	F	1655	Corinth	091	36	1986-01-01	29.5		0.0	0.0		HY			WAT				
1519	Niagara Mohawk Power Corp.	Little Falls Hydro	E	24013	Little Falls	043	36	1987-01-01	13.0	12.6	0.0	0.0		HY			WAT			64.9	
1520	Niagara Mohawk Power Corp.	Onondaga County	C	23987		067	36	1994-12-01	39.5	32.6	32.4	32.4	Y	ST			REF			206.5	
1521	Niagara Mohawk Power Corp.	Pyrites Assoc.	E	24023	Canton	089	36	1985-12-01	8.2	7.5	0.0	0.0		HY			WAT			34.8	
1522	Niagara Mohawk Power Corp.	Adams Hydro	E	23633		045	36	1987-11-01	0.2		0.0	0.0		HY			WAT			0.0	
1523	Niagara Mohawk Power Corp.	Algon.-Burt Dam Assoc.	A	23774		063	36	1987-12-01	0.4		0.0	0.0		HY			WAT			1.1	
1524	Niagara Mohawk Power Corp.	Algon.-Christine.Falls	F	23643		041	36	1987-12-01	0.8		0.0	0.0		HY			WAT			4.0	
1525	Niagara Mohawk Power Corp.	Algon.-Cranberry. Lake	E	23633		049	36	1987-12-01	0.5		0.0	0.0		HY			WAT			2.1	
1526	Niagara Mohawk Power Corp.	Algon.-Forresport	E	23633		065	36	1987-12-01	3.4		0.0	0.0		HY			WAT			12.6	
1527	Niagara Mohawk Power Corp.	Algon.-Herkimer	E	23633		043	36	1987-12-01	1.6		0.0	0.0		HY			WAT			0.0	
1528	Niagara Mohawk Power Corp.	Algon.-Hollow Dam Power	E	23633		089	36	1987-12-01	1.0		0.0	0.0		HY			WAT			4.6	
1529	Niagara Mohawk Power Corp.	Algon.-Kayuta	E	23633		065	36	1988-05-01	0.4		0.0	0.0		HY			WAT			2.0	
1530	Niagara Mohawk Power Corp.	Algon.-Ogdensburg	E	23633		089	36	1987-12-01	3.5		0.0	0.0		HY			WAT			13.7	
1531	Niagara Mohawk Power Corp.	Algon.-Otter Creek	E	23633		049	36	1986-11-01	0.5		0.0	0.0		HY			WAT			1.9	
1532	Niagara Mohawk Power Corp.	Allied Frozen Storage	A	23774		029	36	2008-05-01	0.1		0.0	0.0		IC			NG			0.0	
1533	Niagara Mohawk Power Corp.	Azure Mnt. Pwr Co	E	23633		033	36	1993-08-01	0.6		0.0	0.0		HY			WAT			2.6	
1534	Niagara Mohawk Power Corp.	Beaver Falls #1	E	23633		049	36	1986-01-01	1.5		0.0	0.0		HY			WAT			9.7	
1535	Niagara Mohawk Power Corp.	Beaver Falls #2	E	23633		049	36	1986-01-01	1.0		0.0	0.0		HY			WAT			5.5	
1536	Niagara Mohawk Power Corp.	Bellows Towers	E	23633		033	36	1987-06-01	0.2		0.0	0.0		HY			WAT			0.0	
1537	Niagara Mohawk Power Corp.	Black River Hyd#1	E	23633	Port Leyden	049	36	1984-07-01	1.9		0.0	0.0		HY			WAT			4.4	
1538	Niagara Mohawk Power Corp.	Black River Hyd#2	E	23633	Port Leyden	049	36	1985-12-01	1.6		0.0	0.0		HY			WAT			2.4	
1539	Niagara Mohawk Power Corp.	Black River Hyd#3	E	23633	Port Leyden	049	36	1984-07-01	2.2		0.0	0.0		HY			WAT			16.8	
1540	Niagara Mohawk Power Corp.	Boralex - Middle Falls	F	23643	Easton	115	36	1989-12-01	2.2		0.0	0.0		HY			WAT			10.3	
1541	Niagara Mohawk Power Corp.	Burrstone Energy Center, LLC	E	23633		065	36	2009-11-01	1.1		0.0	0.0	Y	CG			NG			1.4	
1542	Niagara Mohawk Power Corp.	Burrstone Energy Center, LLC	E	23633		065	36	2009-11-01	2.2		0.0	0.0	Y	CG			NG			0.2	
1543	Niagara Mohawk Power Corp.	Cal Ban Power	A	23774		003	36	1995-06-01	0.1		0.0	0.0	Y	IC			NG			0.0	

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a	b	c	d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1544	Niagara Mohawk Power Corp.	Cellu-Tissue Corp - Natural Dar	E	23633	Natural Dam	089	36	1986-01-01	1.0		0.0	0.0		HY			WAT			0.0	
1545	Niagara Mohawk Power Corp.	Champlain Spinner	F	23643		031	36	1992-07-01	0.4		0.0	0.0		HY			WAT			1.8	
1546	Niagara Mohawk Power Corp.	CHI Dexter Hydro	E	23633	Dexter	045	36	1988-01-01	4.2		0.0	0.0		HY			WAT			21.3	
1547	Niagara Mohawk Power Corp.	CHI Diamond Is HY	E	23633	Watertown	045	36	1986-01-01	1.2		0.0	0.0		HY			WAT			6.2	
1548	Niagara Mohawk Power Corp.	CHI Fowler	E	23633	Fowler	049	36	1986-01-01	0.6		0.0	0.0		HY			WAT			4.3	
1549	Niagara Mohawk Power Corp.	CHI Hailsboro #3	E	23633	Hailsboro	089	36	1986-01-01	0.8		0.0	0.0		HY			WAT			4.4	
1550	Niagara Mohawk Power Corp.	CHI Hailsboro #4	E	23633	Hailsboro	089	36	1986-01-01	1.4		0.0	0.0		HY			WAT			7.8	
1551	Niagara Mohawk Power Corp.	CHI Hailsboro #6	E	23633	Hailsboro	089	36	1986-01-01	0.8		0.0	0.0		HY			WAT			5.8	
1552	Niagara Mohawk Power Corp.	CHI Theresa Hydro	E	23633	Theresa	089	36	1986-01-01	1.3		0.0	0.0		HY			WAT			6.8	
1553	Niagara Mohawk Power Corp.	Chittenden Falls	E	23633		089	36	1995-12-01	0.6		0.0	0.0		HY			WAT			2.8	
1554	Niagara Mohawk Power Corp.	City of Oswego (H.D.)	C	23634		075	36	1994-02-01	11.9		0.0	0.0		HY			WAT			50.1	
1555	Niagara Mohawk Power Corp.	City of Utica - Sand Road	E	23633		065	36	1993-05-01	0.2		0.0	0.0		HY			WAT			1.5	
1556	Niagara Mohawk Power Corp.	City of Utica -Trenton Falls	E	23633		065	36	1993-02-01	0.2		0.0	0.0		HY			WAT			0.8	
1557	Niagara Mohawk Power Corp.	City of Watertown	E	23633		045	36	1986-01-01	8.1		0.0	0.0		HY			WAT			12.9	
1558	Niagara Mohawk Power Corp.	City of Watervliet	F	23643		001	36	1986-01-01	1.2		0.0	0.0		HY			WAT			4.4	
1559	Niagara Mohawk Power Corp.	Cons. HY-Victory	F	23643		091	36	1986-12-01	1.7		0.0	0.0		HY			WAT			8.1	
1560	Niagara Mohawk Power Corp.	Copenhagen Assoc.	E	23633	Copenhagen	049	36	1986-01-01	3.3		0.0	0.0		HY			WAT			10.6	
1561	Niagara Mohawk Power Corp.	Cottrell Paper	F	23643		091	36	1987-01-01	0.3		0.0	0.0		HY			WAT			0.2	
1562	Niagara Mohawk Power Corp.	Edison Hydro Electric	F	23643		021	36	2009-11-01	0.0		0.0	0.0		HY			WAT			2.2	
1563	Niagara Mohawk Power Corp.	Empire HY Partner	E	23633		049	36	1984-11-01	1.0		0.0	0.0		HY			WAT			4.9	
1564	Niagara Mohawk Power Corp.	Finch Paper LLC - Glens Falls	F	23643		113	36	2009-11-01	0.0		0.0	0.0		HY			WAT			3.9	
1565	Niagara Mohawk Power Corp.	Finch Pruyn	F	23643		113	36	1989-12-01	29.0		0.0	0.0		HY			WAT			0.0	
1566	Niagara Mohawk Power Corp.	Fort Miller Assoc	F	23643		091	36	1985-10-01	5.0		0.0	0.0		HY			WAT			28.7	
1567	Niagara Mohawk Power Corp.	Fortis Energy - Diana	E	23633		049	36	1985-07-01	1.8		0.0	0.0		HY			WAT			6.0	
1568	Niagara Mohawk Power Corp.	Franklin Hydro	D	24055		033	36	1995-03-01	0.3		0.0	0.0		HY			WAT			0.0	
1569	Niagara Mohawk Power Corp.	Green Island Power Authority	F	23643	Green Island	001	36	1971-01-01	6.0		0.0	0.0		HY			WAT			43.8	
1570	Niagara Mohawk Power Corp.	Hewittville Hydro	E	23633		089	36	1984-07-01	3.0		0.0	0.0		HY			WAT			16.8	
1571	Niagara Mohawk Power Corp.	Hollings&Vose-Center	F	23643		115	36	1986-01-01	0.4		0.0	0.0		HY			WAT			0.0	
1572	Niagara Mohawk Power Corp.	Hollings&Vose-Lower	F	23643		115	36	1986-01-01	0.4		0.0	0.0		HY			WAT			0.0	
1573	Niagara Mohawk Power Corp.	Hollings&Vose-Upper	F	23643		115	36	1986-01-01	0.4		0.0	0.0		HY			WAT			5.0	
1574	Niagara Mohawk Power Corp.	Hoosick Falls	F	23643		083	36	1988-08-01	0.6		0.0	0.0		HY			WAT			1.7	
1575	Niagara Mohawk Power Corp.	Hydrocarbon-Algny	A	23774		003	36	1992-12-01	0.2		0.0	0.0	Y	IC			NG			0.0	

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a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1576	Niagara Mohawk Power Corp.	Indian Falls HY		E	23633		045	36	1986-01-01	0.3		0.0	0.0		HY			WAT			1.2	
1577	Niagara Mohawk Power Corp.	Kings Falls		E	23633		049	36	1988-05-01	1.6		0.0	0.0		HY			WAT			1.0	
1578	Niagara Mohawk Power Corp.	Laidlaw Energy		A	23774	Ellicottville	009	36	1991-07-01	3.4		0.0	0.0	Y	GT			NG			0.0	
1579	Niagara Mohawk Power Corp.	Laidlaw Energy		A	23774	Ellicottville	009	36	1991-07-01	2.4		0.0	0.0	Y	ST			NG			0.0	
1580	Niagara Mohawk Power Corp.	Laquidara-Long Falls		E	23633		045	36	1991-06-01	3.3		0.0	0.0		HY			WAT			11.1	
1581	Niagara Mohawk Power Corp.	Lyonsdale Assoc. (Burrows)		E	23633	Lyons Falls	049	36	1984-07-01	3.0		0.0	0.0		HY			WAT			13.9	
1582	Niagara Mohawk Power Corp.	Mechanicville		F	23643		091	36	2005-03-01	2.0		0.0	0.0		HY			WAT			18.8	
1583	Niagara Mohawk Power Corp.	Moutainaire Massage Spa		F	23643		113	36	2009-11-01	0.0		0.0	0.0		HY			WAT			0.0	
1584	Niagara Mohawk Power Corp.	Mt. Ida Assoc.		F	23643		083	36	1986-01-01	3.0		0.0	0.0		HY			WAT			12.2	
1585	Niagara Mohawk Power Corp.	Newport HY Assoc		E	23633		043	36	1987-12-01	1.7		0.0	0.0		HY			WAT			8.3	
1586	Niagara Mohawk Power Corp.	Nottingham High School		C	23634		067	36	1988-06-01	0.2		0.0	0.0	Y	CC			NG			0.0	
1587	Niagara Mohawk Power Corp.	Oakvale Construction		D	24055		031	36	2009-11-01	0.0		0.0	0.0		HY			WAT			2.6	
1588	Niagara Mohawk Power Corp.	Onondaga Energy Partners		C	23634		067	36	1987-12-01	1.4		0.0	0.0	Y	IC			MTE			0.0	
1589	Niagara Mohawk Power Corp.	Oswego County		C	23634		075	36	1986-03-01	3.6		0.0	0.0	Y	ST			REF			4.7	
1590	Niagara Mohawk Power Corp.	Oswego HY Partners (Phoenix)		C	23634		067	36	1990-12-01	3.4		0.0	0.0		HY			WAT			9.2	
1591	Niagara Mohawk Power Corp.	Riverrat Glass&Electric		F	23643		031	36	1986-01-01	0.6		0.0	0.0		HY			WAT			2.5	
1592	Niagara Mohawk Power Corp.	Sandy Hollow HY		E	23633		045	36	1986-09-01	0.6		0.0	0.0		HY			WAT			1.9	
1593	Niagara Mohawk Power Corp.	Seneca Limited		C	23634		067	36	1985-12-01	0.2		0.0	0.0		HY			WAT			0.0	
1594	Niagara Mohawk Power Corp.	Stevens&Thompson Paper Co.		F	23643		115	36	1987-12-01	10.5		0.0	0.0		HY			WAT			46.1	
1595	Niagara Mohawk Power Corp.	Stillwater Assoc.		E	23633		043	36	1987-01-01	1.8		0.0	0.0		HY			WAT			5.9	
1596	Niagara Mohawk Power Corp.	Stillwater HY Partners		F	23643		091	36	1993-04-01	3.4		0.0	0.0		HY			WAT			13.9	
1597	Niagara Mohawk Power Corp.	Synergics - Middle Greenwich		F	23643		115	36	1987-12-01	0.2		0.0	0.0		HY			WAT			0.0	
1598	Niagara Mohawk Power Corp.	Synergics - Union Falls		D	24055		019	36	1987-12-01	3.0		0.0	0.0		HY			WAT			14.9	
1599	Niagara Mohawk Power Corp.	Synergics - Upper Greenwich		F	23643		115	36	1987-12-01	0.4		0.0	0.0		HY			WAT			1.9	
1600	Niagara Mohawk Power Corp.	Tannery Island		E	23633		045	36	1986-01-01	1.5		0.0	0.0		HY			WAT			8.7	
1601	Niagara Mohawk Power Corp.	Town of Wells		F	23643	Wells	041	36	1987-12-01	0.5		0.0	0.0		HY			WAT			2.1	
1602	Niagara Mohawk Power Corp.	Tri-City JATC		F	23643		001	36	2009-11-01	0.0		0.0	0.0		IC			NG			0.0	
1603	Niagara Mohawk Power Corp.	Unionville Hydro		E	23633		089	36	1984-07-01	3.0		0.0	0.0		HY			WAT			15.1	
1604	Niagara Mohawk Power Corp.	United States Gypsum		A	23774		037	36	2009-11-01	0.0		0.0	0.0	Y	CG			NG			1.2	
1605	Niagara Mohawk Power Corp.	Valatie Falls		F	23643		021	36	1992-12-01	0.1		0.0	0.0		HY			WAT			0.7	
1606	Niagara Mohawk Power Corp.	Valley Falls Assoc.		F	23643		083	36	1985-08-01	2.5		0.0	0.0		HY			WAT			8.8	
1607	Niagara Mohawk Power Corp.	Village of Gouverneur		E	23633		089	36	1986-01-01	0.1		0.0	0.0		HY			WAT			0.1	

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a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1608	Niagara Mohawk Power Corp.	Village of Potsdam		E	23633		089	36	1986-01-01	0.8		0.0	0.0		HY			WAT			4.8	
1609	Niagara Mohawk Power Corp.	Village of Saranac Lake		E	23633		033	36	1996-12-01	0.2		0.0	0.0		HY			WAT			0.6	
1610	Niagara Mohawk Power Corp.	Wave Hydro LLC		C	23634	Baldwinsville	067	36	2010-02-07	0.8	0.0	0.0	0.0		HY			WAT			0.2	
1611	Niagara Mohawk Power Corp.	West End Dam Assoc.		E	23633		045	36	1986-01-01	4.4		0.0	0.0		HY			WAT			23.5	
1612	Nine Mile Point Nuclear Station, LL	Nine Mile Pt 1		C	23575	Scriba	075	36	1969-11-01	641.8	630.5	629.7	630.0		NB		A	UR			4,618.1	
1613	Nine Mile Point Nuclear Station, LL	Nine Mile Pt 2		C	23744	Scriba	075	36	1988-08-01	1,259.3	1,148.3	1,143.5	1,155.0		NB		B	UR			9,537.5	
1614	Noble Altona Windpark, LLC	Altona Wind Power		D	323606	Altona	019	36	2008-09-23	97.5	97.5	97.5	97.5		WT			WND			178.7	
1615	Noble Bliss Windpark, LLC	Bliss Wind Power		A	323608	Bliss	121	36	2008-03-20	100.5	100.5	100.5	100.5		WT			WND			190.8	
1616	Noble Chateaugay Windpark, LLC	Chateaugay Wind Power		D	323614	Chateaugay	033	36	2008-10-07	106.5	106.5	106.5	106.5		WT			WND			201.8	
1617	Noble Clinton Windpark 1, LLC	Clinton Wind Power		D	323605	Clinton	019	36	2008-04-09	100.5	100.5	100.5	100.5		WT			WND			174.4	
1618	Noble Ellenburg Windpark, LLC	Ellenburg Wind Power		D	323604	Ellenburg	019	36	2008-03-31	81.0	81.0	81.0	81.0		WT			WND			167.9	
1619	Noble Wethersfield Windpark, LLC	Wethersfield Wind Power		C	323626	Wethersfield	121	36	2008-12-11	126.0	126.0	126.0	126.0		WT			WND			256.6	
1620	Northbrook Lyons Falls, LLC	Lyons Falls Hydro		E	23570	Lyons Falls	049	36	1986-01-01	8.0	7.3	6.9	8.0		HY			WAT			46.1	
1621	NRG Power Marketing LLC	Arthur Kill GT 1		J	23520	Staten Island	085	36	1970-06-01	20.0	16.5	10.6	15.5	N	GT		C	KER			0.9	
1622	NRG Power Marketing LLC	Arthur Kill ST 2		J	23512	Staten Island	085	36	1959-08-01	376.2	357.7	338.6	339.6	N	ST		A	NG			986.8	
1623	NRG Power Marketing LLC	Arthur Kill ST 3		J	23513	Staten Island	085	36	1969-06-01	535.5	518.0	513.3	518.4	N	ST		A	NG			604.8	
1624	NRG Power Marketing LLC	Astoria GT 05		J	24106	Queens	081	36	1970-06-01	19.2	16.0	5.1	15.6	N	GT		C	FO2			0.0	
1625	NRG Power Marketing LLC	Astoria GT 07		J	24107	Queens	081	36	1970-06-01	19.2	15.5	12.3	14.0	N	GT		C	FO2			0.1	
1626	NRG Power Marketing LLC	Astoria GT 08		J	24108	Queens	081	36	1970-06-01	19.2	15.3	12.8	15.7	N	GT		C	FO2			0.1	
1627	NRG Power Marketing LLC	Astoria GT 10		J	24110	Queens	081	36	1971-01-01	31.8	24.9	17.5	24.2	N	GT		C	FO2			0.1	
1628	NRG Power Marketing LLC	Astoria GT 11		J	24225	Queens	081	36	1971-02-01	31.8	23.6	16.4	26.5	N	GT		C	FO2			0.2	
1629	NRG Power Marketing LLC	Astoria GT 12		J	24226	Queens	081	36	1971-05-01	31.8	22.7	15.4	24.2	N	GT		C	FO2			0.4	
1630	NRG Power Marketing LLC	Astoria GT 13		J	24227	Queens	081	36	1971-05-01	31.8	24.0	15.3	24.8	N	GT		C	FO2			0.5	
1631	NRG Power Marketing LLC	Astoria GT 2-1		J	24094	Queens	081	36	1970-06-01	46.5	41.2	36.2	46.2	N	GT		C	KER	NG		3.2	
1632	NRG Power Marketing LLC	Astoria GT 2-2		J	24095	Queens	081	36	1970-06-01	46.5	42.4	33.2	44.3	N	GT		C	KER	NG		5.5	
1633	NRG Power Marketing LLC	Astoria GT 2-3		J	24096	Queens	081	36	1970-06-01	46.5	41.2	32.8	44.3	N	GT		C	KER	NG		2.9	
1634	NRG Power Marketing LLC	Astoria GT 2-4		J	24097	Queens	081	36	1970-06-01	46.5	41.0	32.5	42.3	N	GT		C	KER	NG		4.4	
1635	NRG Power Marketing LLC	Astoria GT 3-1		J	24098	Queens	081	36	1970-06-01	46.5	41.2	34.6	43.0	N	GT		C	KER	NG		3.6	
1636	NRG Power Marketing LLC	Astoria GT 3-2		J	24099	Queens	081	36	1970-06-01	46.5	43.5	34.5	44.8	N	GT		C	KER	NG		5.7	
1637	NRG Power Marketing LLC	Astoria GT 3-3		J	24100	Queens	081	36	1970-06-01	46.5	43.0	33.6	44.3	N	GT		C	KER	NG		2.9	
1638	NRG Power Marketing LLC	Astoria GT 3-4		J	24101	Queens	081	36	1970-06-01	46.5	43.0	34.3	44.7	N	GT		C	KER	NG		6.0	
1639	NRG Power Marketing LLC	Astoria GT 4-1		J	24102	Queens	081	36	1970-07-01	46.5	42.6	32.7	45.2	N	GT		C	KER	NG		2.6	

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1640	NRG Power Marketing LLC	Astoria GT 4-2	J	24103	Queens	081	36	1970-07-01	46.5	41.4	32.9	43.8	N	GT		C	KER	NG		2.3	
1641	NRG Power Marketing LLC	Astoria GT 4-3	J	24104	Queens	081	36	1970-07-01	46.5	41.1	34.6	43.7	N	GT		C	KER	NG		3.0	
1642	NRG Power Marketing LLC	Astoria GT 4-4	J	24105	Queens	081	36	1970-07-01	46.5	42.8	33.8	44.4	N	GT		C	KER	NG		6.7	
1643	NRG Power Marketing LLC	Dunkirk 1	A	23563	Dunkirk	013	36	1950-11-01	100.0	96.2	75.0	75.0	N	ST	T	A	BIT			210.5	
1644	NRG Power Marketing LLC	Dunkirk 2	A	23564	Dunkirk	013	36	1950-12-01	100.0	97.2	75.0	75.0	N	ST	T	A	BIT			264.4	
1645	NRG Power Marketing LLC	Dunkirk 3	A	23565	Dunkirk	013	36	1959-09-01	217.6	201.4	185.0	185.0	N	ST	T	A	BIT			782.3	
1646	NRG Power Marketing LLC	Dunkirk 4	A	23566	Dunkirk	013	36	1960-08-01	217.6	199.1	185.0	185.0	N	ST	T	A	BIT			726.1	
1647	NRG Power Marketing LLC	Dunkirk IC 2	A	5050	Dunkirk	013	36	1990-01-01	0.5		0.0	0.0	N	IC			FO2			0.0	
1648	NRG Power Marketing LLC	Huntley 67	A	23561	Tonawanda	029	36	1957-12-01	218.0	196.5	189.0	189.5	N	ST	T	A	BIT			759.4	
1649	NRG Power Marketing LLC	Huntley 68	A	23562	Tonawanda	029	36	1958-12-01	218.0	198.0	189.0	190.0	N	ST	T	A	BIT			646.0	
1650	NRG Power Marketing LLC	Huntley IC 1	A	5051	Tonawanda	029	36	1967-08-01	0.7		0.0	0.0	N	IC			FO2			0.0	
1651	NRG Power Marketing LLC	Oswego 5	C	23606	Oswego	075	36	1976-02-01	901.8	850.3	823.5	823.2	N	ST	W	A	FO6			40.2	
1652	NRG Power Marketing LLC	Oswego 6	C	23613	Oswego	075	36	1980-07-01	901.8	835.2	820.7	824.7	N	ST	W	A	FO6			28.0	
1653	NRG Power Marketing LLC	Oswego IC 1	C	5052	Oswego	075	36	1967-08-01	0.7		0.0	0.0	N	IC			FO2			0.0	
1654	NRG Power Marketing LLC	Oswego IC 2	C	5053	Oswego	075	36	1976-02-01	0.8		0.0	0.0	N	IC			FO2			0.0	
1655	NRG Power Marketing LLC	Oswego IC 3	C	5054	Oswego	075	36	1980-07-01	0.8		0.0	0.0	N	IC			FO2			0.0	
1656	NYSEG Solutions, Inc.	Carthage Energy	E	23857	Carthage	045	36	1991-08-01	62.9	59.0	55.0	63.6	Y	CC			NG			6.5	
1657	Orange and Rockland Utilities	Buttermilk Falls	G	5055	Highland Falls	071	36	1986-12-01	0.1		0.0	0.0		HY			WAT			0.0	
1658	Orange and Rockland Utilities	Intl. Crossroads	G	5056	Mahwah NJ	003	34	1987-12-01	3.0		0.0	0.0	Y	IC			NG	FO2		0.0	
1659	Orange and Rockland Utilities	Landfill G.Part19	G	5057	Goshen	071	36	1988-12-01	2.5		0.0	0.0	N	IC			MTE			0.0	
1660	Orange and Rockland Utilities	Middletown LFG	G	5058	Goshen	071	36	1988-12-01	3.0		0.0	0.0	N	IC			MTE			0.0	
1661	PSEG Energy Resource & Trade, I	Bethlehem Energy Center 1	F	23843	Bethlehem	001	36	2005-07-01	893.1	756.9	757.2	844.8		CC			NG	FO2		4,239.6	
1662	R.E. Ginna Nuclear Power Plant, L	Ginna	B	23603	Ontario	117	36	1970-07-01	614.0	582.0	580.8	582.2		NP		A	UR			4,311.1	
1663	Rochester Gas and Electric Corp.	Allegany GT	B	23514	Hume	003	36	1995-03-01	42.0	39.4	38.2	38.4	Y	CT			NG			73.4	(G)
1664	Rochester Gas and Electric Corp.	Allegany ST	B	23514	Hume	003	36	1995-03-01	25.0	23.5	22.8	22.8	Y	CW			NG				
1665	Rochester Gas and Electric Corp.	Beebee GT (Ret. - 2/18/12)	B	23619	Rochester	055	36	1969-06-01	19.0	15.0	0.0	0.0	N	GT		C	FO2			0.4	(R)
1666	Rochester Gas and Electric Corp.	Mills Mills	B	5059	Fillmore	003	36	1906-07-01	0.2		0.0	0.0		HY			WAT			0.0	
1667	Rochester Gas and Electric Corp.	Mt Morris	B	5060	Mt Morris	051	36	1916-07-01	0.3		0.0	0.0		HY			WAT			0.0	
1668	Rochester Gas and Electric Corp.	Station 2 1	B	23604	Rochester	055	36	1913-07-01	8.5	6.0	8.5	8.5		HY			WAT			26.2	
1669	Rochester Gas and Electric Corp.	Station 26 1	B	23604	Rochester	055	36	1952-08-01	3.0	2.8	3.0	3.0		HY			WAT			5.2	
1670	Rochester Gas and Electric Corp.	Station 5 1	B	23604	Rochester	055	36	1918-07-01	12.9	12.0	12.9	12.9		HY			WAT			0.0	
1671	Rochester Gas and Electric Corp.	Station 5 2	B	23604	Rochester	055	36	1918-07-01	12.9	12.0	12.9	12.9		HY			WAT			0.0	

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a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1672	Rochester Gas and Electric Corp.	Station 5	3	B	23604	Rochester	055	36	1918-07-01	18.0	16.8	18.0	18.0		HY			WAT			0.0	
1673	Rochester Gas and Electric Corp.	Station 9		B	23652	Rochester	055	36	1969-11-01	19.0	15.8	14.1	17.4		GT		C	NG			3.6	
1674	Rochester Gas and Electric Corp.	Wiscoy 1		B	5061	Fillmore	003	36	1922-07-01	0.6		0.0	0.0		HY			WAT			0.0	
1675	Rochester Gas and Electric Corp.	Wiscoy 2		B	5062	Fillmore	003	36	1922-07-01	0.5		0.0	0.0		HY			WAT			0.0	
1676	Rockville Centre, Village of	Charles P Keller	07	K	1661	Rockville Centre	059	36	1942-09-01	2.0		1.9	1.9	N	IC			FO2			0.0	
1677	Rockville Centre, Village of	Charles P Keller	08	K	1661	Rockville Centre	059	36	1950-09-01	2.7		2.6	2.6	N	IC			FO2			0.0	
1678	Rockville Centre, Village of	Charles P Keller	09	K	1661	Rockville Centre	059	36	1954-09-01	3.5		3.4	3.4	N	IC			FO2	NG		0.1	
1679	Rockville Centre, Village of	Charles P Keller	10	K	1661	Rockville Centre	059	36	1954-09-01	3.5		3.4	3.4	N	IC			FO2	NG		0.3	
1680	Rockville Centre, Village of	Charles P Keller	11	K	1661	Rockville Centre	059	36	1962-09-01	5.2		5.0	5.0	N	IC			FO2	NG		0.3	
1681	Rockville Centre, Village of	Charles P Keller	12	K	1661	Rockville Centre	059	36	1967-09-01	5.5		5.3	5.3	N	IC			FO2	NG		1.5	
1682	Rockville Centre, Village of	Charles P Keller	13	K	1661	Rockville Centre	059	36	1974-09-01	5.5		5.3	5.3	N	IC			FO2	NG		1.4	
1683	Rockville Centre, Village of	Charles P Keller	14	K	1661	Rockville Centre	059	36	1994-09-01	6.3		6.0	6.0	N	IC			FO2	NG		0.0	
1684	Selkirk Cogen Partners, L.P.	Selkirk-I		F	23801	Selkirk	001	36	1992-03-01	107.2	82.1	77.1	103.8	Y	CC			NG			562.8	
1685	Selkirk Cogen Partners, L.P.	Selkirk-II		F	23799	Selkirk	001	36	1994-09-01	338.8	291.3	288.1	341.5	Y	CC			NG	FO2		1,441.2	
1686	Seneca Energy II, LLC	Ontario LFGE		C	23819	Canandaigua	069	36	2003-12-01	6.4	5.6	6.4	6.4	N	IC			MTE			51.2	
1687	Seneca Energy II, LLC	Seneca Energy 1		C	23797	Seneca Falls	099	36	1996-03-01	8.8	8.8	8.8	8.8	N	IC			MTE			140.2	(G)
1688	Seneca Energy II, LLC	Seneca Energy 2		C	23797	Seneca Falls	099	36	1997-08-01	8.8	8.8	8.8	8.8	N	IC			MTE				
1689	Seneca Power Partners, L.P.	Batavia		B	24024	Batavia	037	36	1992-06-01	67.3	57.1	48.8	60.5	Y	CC			NG			77.1	
1690	Seneca Power Partners, L.P.	Hillburn GT		G	23639	Hillburn	087	36	1971-04-01	46.5	37.9	35.0	44.0	N	GT		C	NG	KER		0.1	
1691	Seneca Power Partners, L.P.	Shoemaker GT		G	23640	Middletown	071	36	1971-05-01	41.9	33.1	31.4	36.2	N	GT		C	NG	KER		1.4	
1692	Sheldon Energy LLC	High Sheldon Wind Farm		C	323625	Sheldon	121	36	2009-02-01	112.5	112.5	112.5	112.5		WT			WND			261.1	
1693	Shell Energy North America (US), I	Fort Drum		E	23780	Watertown	045	36	1989-07-01	58.0	55.6	0.0	0.0	Y	ST			BIT			0.0	
1694	Shell Energy North America (US), I	Glen Park Hydro		E	23778	Glen Park	045	36	1986-01-01	32.6	40.4	33.4	32.6		HY			WAT			163.0	
1695	Shell Energy North America (US), I	Lockport Cogen GT1		A	23791	Lockport	063	36	1992-07-01	48.7	49.6	42.4	48.9	Y	CT			NG	FO2		60.4	(G)
1696	Shell Energy North America (US), I	Lockport Cogen GT2		A	23791	Lockport	063	36	1992-07-01	48.7	49.6	42.4	48.9	Y	CT			NG	FO2			
1697	Shell Energy North America (US), I	Lockport Cogen GT3		A	23791	Lockport	063	36	1992-07-01	48.7	49.6	42.4	48.9	Y	CT			NG	FO2			
1698	Shell Energy North America (US), I	Lockport Cogen ST1		A	23791	Lockport	063	36	1992-07-01	75.2	76.5	65.5	75.5	Y	CW			NG	FO2			
1699	Shell Energy North America (US), I	Munnsville Wind Power		E	323609	Bouckville	053	36	2007-08-20	34.5	34.5	34.5	34.5		WT			WND			87.5	
1700	Standard Binghamton LLC	Binghamton Cogen (Ret. - 2/15		C	23790	Binghamton	007	36	2001-03-01	47.7	43.8	0.0	0.0	Y	GT			NG	FO2		0.8	(R)
1701	Stephentown Regulation Services	Beacon LESR		F	323632	Stephentown	083	36	2010-11-29	20.0	0.0	0.0	0.0		ES			FW			0.0	
1702	Sterling Power Partners, L.P.	Sterling		E	23777	Sherrill	065	36	1991-06-01	65.3	57.4	51.3	63.1	Y	CC			NG			4.5	
1703	TC Ravenswood, LLC	Ravenswood 01		J	23729	Queens	081	36	1967-07-01	18.6	8.8	9.3	10.3	N	GT		C	NG			0.3	

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a	b	c		d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t	u	v
1704	TC Ravenswood, LLC	Ravenswood 04		J	24252	Queens	081	36	1970-09-01	21.1	15.2	11.1	15.6	N	GT		C	KER	NG		0.5	
1705	TC Ravenswood, LLC	Ravenswood 05		J	24254	Queens	081	36	1970-08-01	21.1	15.7	12.5	16.5	N	GT		C	KER			0.6	
1706	TC Ravenswood, LLC	Ravenswood 06		J	24253	Queens	081	36	1970-08-01	22.0	16.7	12.7	14.3	N	GT		C	KER	NG		0.7	
1707	TC Ravenswood, LLC	Ravenswood 07		J	24255	Queens	081	36	1970-08-01	22.0	16.5	12.7	15.5	N	GT		C	KER	NG		0.4	
1708	TC Ravenswood, LLC	Ravenswood 09		J	24257	Queens	081	36	1970-07-01	25.0	21.7	19.6	22.5	N	GT		C	KER	NG		2.7	
1709	TC Ravenswood, LLC	Ravenswood 10		J	24258	Queens	081	36	1970-08-01	25.0	21.2	20.3	23.5	N	GT		C	KER	NG		2.1	
1710	TC Ravenswood, LLC	Ravenswood 11		J	24259	Queens	081	36	1970-08-01	25.0	20.2	19.2	23.0	N	GT		C	KER	NG		2.4	
1711	TC Ravenswood, LLC	Ravenswood 2-1		J	24244	Queens	081	36	1970-12-01	42.9	40.4	37.8	46.1	N	GT		C	KER	NG		3.3	
1712	TC Ravenswood, LLC	Ravenswood 2-2		J	24245	Queens	081	36	1970-12-01	42.9	37.6	36.9	44.1	N	GT		C	KER	NG		3.6	
1713	TC Ravenswood, LLC	Ravenswood 2-3		J	24246	Queens	081	36	1970-12-01	42.9	39.2	37.4	44.0	N	GT		C	KER	NG		3.8	
1714	TC Ravenswood, LLC	Ravenswood 2-4		J	24247	Queens	081	36	1970-12-01	42.9	39.8	30.9	40.0	N	GT		C	KER	NG		2.3	
1715	TC Ravenswood, LLC	Ravenswood 3-1		J	24248	Queens	081	36	1970-08-01	42.9	40.5	36.9	43.3	N	GT		C	KER	NG		3.4	
1716	TC Ravenswood, LLC	Ravenswood 3-2		J	24249	Queens	081	36	1970-08-01	42.9	38.1	36.3	43.5	N	GT		C	KER	NG		3.0	
1717	TC Ravenswood, LLC	Ravenswood 3-3		J	24250	Queens	081	36	1970-08-01	42.9	37.7	39.1	44.0	N	GT		C	KER	NG		3.1	
1718	TC Ravenswood, LLC	Ravenswood 3-4	(Ret.- 9/1/11)	J	24251	Queens	081	36	1970-08-01	42.9	35.8	0.0	0.0	N	GT		C	KER	NG		0.5	(M) (8)
1719	TC Ravenswood, LLC	Ravenswood CC 04		J	23820	Queens	081	36	2004-05-01	250.0	231.2	212.2	252.5	N	CC			NG	FO2		1,583.5	
1720	TC Ravenswood, LLC	Ravenswood ST 01		J	23533	Queens	081	36	1963-02-01	400.0	365.1	364.7	377.0	N	ST		A	FO6	NG		602.3	
1721	TC Ravenswood, LLC	Ravenswood ST 02		J	23534	Queens	081	36	1963-05-01	400.0	391.6	362.7	366.9	N	ST		A	FO6	NG		392.7	
1722	TC Ravenswood, LLC	Ravenswood ST 03		J	23535	Queens	081	36	1965-06-01	1,027.0	986.8	961.0	971.5	N	ST		A	FO6	NG		760.9	
1723	Trigen-Syracuse Energy Corp.	Syracuse Energy ST1		C	323597	Syracuse	067	36	1991-08-01	11.0	11.0	11.0	11.0	Y	ST			BIT	FO2		86.0	(G)
1724	Trigen-Syracuse Energy Corp.	Syracuse Energy ST2		C	323598	Syracuse	067	36	1991-08-01	90.6	58.9	60.8	63.6	N	ST			BIT	FO2			
1725	Triton Power Company	Chateaugay High Falls		D	323578	Chateaugay	033	36	1987-12-01	3.0		0.0	0.0		HY			WAT			7.5	
1726	Western New York Wind Corp.	Western NY Wind Power		B	24143	Wethersfield	121	36	2000-10-01	6.6	6.6	0.0	0.0		WT			WND			13.4	
1727	Wheelabrator Hudson Falls, LLC	Wheelabrator Hudson Falls		F	23798	Hudson Falls	115	36	1991-10-01	14.4	12.7	11.6	11.8	Y	ST		A	REF			81.9	
1728	Wheelabrator Westchester, LP	Wheelabrator Westchester		H	23653	Peekskill	119	36	1984-04-01	59.7	53.5	52.7	53.0	N	ST		A	REF			404.7	
1729												**38,902**	**41,347**								**139,964.6**	
1730				J								9,466	10,405									
				K								5,614	6,072									

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Load

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	PJM	East	5004/5005	AP South	DOM
Max	154,339	32,542	56,158	75,068	20,588
PST	133,467	26,061	46,144	62,751	16,794
Winter	101,272	18,066	34,193	46,542	12,631
Spring	91,726	16,335	30,414	41,447	11,102
Summer	122,914	23,672	42,263	57,545	15,385
Fall	94,588	17,055	31,762	43,419	11,796

Detailed hourly load data provided in other workpapers.

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Peak Load	154339
Peak Month	133467
Winter	101272
Spring	91726
Summer	122914
Fall	94588

Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
12/1/2011	79114	76912	76117	76395	78332	83855	92863	97616	96410	94578	92764	90843	89156	87905	86645	86256	89354	97583	100098	100079	99093	96193	90742	84721
12/2/2011	80422	78396	77728	77994	79934	85599	94697	99282	98042	95567	93168	90887	88946	87678	86606	86291	88926	95938	97106	96020	94648	92162	88131	82570
12/4/2011	74413	72015	70638	70507	71004	72503	75153	77569	79874	79841	78723	77635	76925	76334	75888	76394	80186	88239	89888	89571	88702	85438	80423	74899
12/5/2011	70993	68851	68118	68260	70198	75406	84622	90110	90498	90457	90078	89422	88595	88253	87731	87820	91073	97600	98196	97093	94991	90738	84185	77113
12/6/2011	71783	68937	67317	67001	68217	73162	82054	87670	88573	89242	89797	89836	89754	89465	89228	89528	92595	97770	98389	97079	95040	91151	84600	77249
12/7/2011	72281	69429	67843	67441	68838	73487	82380	88598	89695	90102	90546	90808	90806	90783	90809	91331	94714	100160	101500	100312	98738	95488	89789	83442
12/8/2011	79052	76503	75588	75855	78037	83514	93170	98761	98652	97310	95905	94250	92711	91627	90589	90577	94172	102767	105107	104685	103504	100318	94725	88000
12/9/2011	83183	80883	79870	80048	82116	87287	96127	101402	100388	97990	95914	93666	91765	90598	89498	89324	92648	99949	100782	99508	98086	95372	90996	84868
12/10/2011	80108	77330	75856	75381	75913	78132	81789	85794	88652	89490	89025	88016	86400	84469	83041	83310	87147	95817	98122	97719	97272	95415	92092	87216
12/11/2011	83388	81062	79868	79723	80603	82211	85568	88605	90317	89914	87929	85993	84277	82879	81669	82012	86308	96397	100059	100918	100587	98028	93117	87649
12/12/2011	83815	82174	81742	82508	84679	90676	100557	106160	105504	103267	100611	97559	95023	93363	92081	92235	95903	104886	107088	106666	105275	101828	95540	88500
12/13/2011	83887	81792	80915	81285	83349	88836	98457	103390	102306	99588	97257	94948	92960	91741	90897	90664	94282	102518	104137	103348	102188	98624	92101	84822
12/14/2011	79582	76810	75524	75367	77096	82176	91302	96618	96249	94774	94048	92737	91700	90952	90396	90457	94036	100723	101296	99862	98032	94250	87732	80449
12/15/2011	75177	72171	70795	70565	71751	76740	85906	91593	91793	91307	90487	89605	88866	88476	88044	88392	91494	97720	98436	97171	95501	92048	85920	78902
12/16/2011	73454	70304	68740	68755	70208	75225	84610	90558	91252	91284	91295	91177	90552	90277	89961	90265	93993	99967	100499	98792	97041	94273	89661	83511
12/17/2011	78439	75333	73790	73288	74058	76326	80237	84500	87909	90135	90883	90466	89758	88642	87816	87880	90997	97639	98842	98078	97173	95339	91791	86661
12/18/2011	82205	79127	77128	76521	76671	78130	80949	84327	87126	88231	87391	85951	85135	84358	83544	83864	87514	96670	99970	100548	100510	97900	93244	87722
12/19/2011	83300	81301	80630	81159	83408	88804	97798	103000	102285	99901	98074	95882	93781	92580	91582	91786	95223	102190	103232	102021	100012	96044	89749	82423
12/20/2011	77052	73646	72073	71783	73232	78107	86666	93005	93851	93745	93684	92978	92240	91635	90832	90745	94161	100851	101829	100672	98964	95277	88895	81530
12/21/2011	75899	72535	70810	70213	71385	75784	83870	89813	91184	91325	91577	91125	90212	89766	89048	89212	91895	97297	97662	96107	94075	90614	84818	78013
12/22/2011	72260	69145	67287	66822	68184	72610	80727	86786	88356	88600	88560	87741	86780	86277	85800	85761	88761	95463	96148	94755	93043	89939	84867	78030
12/23/2011	72454	68892	67170	66488	67360	70632	76695	82014	84546	85887	86582	86403	85427	84461	83893	84075	87344	94381	95103	93774	92289	89816	85938	80271
12/24/2011	75154	71668	69912	69221	69415	70986	73925	77738	81039	82915	83198	82407	81018	79295	78131	77903	80364	87410	88631	87726	87419	86803	85026	81735
12/25/2011	77962	75145	73527	72967	73200	74593	77355	80484	81975	81546	79538	77514	75603	73285	71486	70800	72507	78609	80688	81127	81378	80812	78485	74781
12/26/2011	70998	68573	67252	67074	68173	70550	73698	76513	78249	79837	80725	80522	79291	77589	76342	76421	79829	89092	92010	92070	91462	89308	85132	79960
12/27/2011	75597	73011	71543	71287	72566	76413	82079	87221	90049	92308	93929	94492	94322	93789	92996	92611	94407	98931	99180	97224	95014	91483	86260	80557

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12/28/2011	76035	73198	71912	71896	73641	77621	83836	88865	90780	91957	93010	92938	92130	91235	90440	90579	93625	101874	103891	102814	101461	98467	93484	87637
12/29/2011	83151	80648	79649	79696	81349	85437	91691	96316	97519	97567	96955	95622	94019	92605	91262	90576	93081	99818	101273	99825	97915	94705	89419	83637
12/30/2011	78718	75864	74622	74253	75552	79027	84358	88493	90076	90400	89689	87928	85800	84212	82821	82255	84545	91499	92273	90772	88914	86135	81741	76535
12/31/2011	71651	68393	66487	65485	65604	66898	69342	72301	74791	76867	78449	78863	78757	78123	77459	77663	80435	87129	88243	86195	83660	80771	78043	75152
1/1/2012	74833	72482	70731	69886	69931	70970	72904	74682	76169	76612	76781	76994	77425	77581	77479	78041	81364	87417	89271	88651	87739	85328	82000	77930
1/2/2012	74322	72193	71336	71798	73609	76969	81635	85202	87499	90185	92586	93619	93809	93627	93440	94045	97716	105683	107861	107495	105775	102565	97385	91965
1/3/2012	88272	86358	85821	86357	88632	94402	104058	109954	110139	109653	109836	109692	109232	109086	108645	108839	112012	120009	122565	121821	120250	116301	110521	104368
1/5/2012	90305	87719	86316	86117	87780	92848	101937	107869	107372	105485	103485	101206	99192	97725	96310	95446	97823	105142	108323	108016	106438	102693	96948	90446
1/6/2012	85954	83616	82389	82146	83816	88669	97464	102771	101684	99168	96884	94453	92155	90562	88910	87626	88524	94641	96813	95523	93830	91139	86864	81698
1/7/2012	77535	74693	73187	72746	73322	75497	79000	82809	85149	85962	85576	84407	82589	80842	79369	78664	80168	86756	89664	88754	87623	85279	82122	78068
1/8/2012	74415	72328	71266	71111	71679	73542	76427	79740	82611	83931	83515	82574	82100	81490	80575	80882	84001	91772	95331	95185	94763	92153	87582	83004
1/9/2012	79730	78167	77684	77964	80348	86288	96320	102660	102876	101963	101342	100273	98953	97951	97101	97145	99437	105587	107621	106579	104453	100210	93952	87585
1/10/2012	83057	80875	79724	79995	82053	87839	97805	103922	103173	100721	98349	96151	93975	92719	91270	90714	92708	99456	102966	102807	101532	98425	92690	87055
1/11/2012	83175	81349	80579	80977	83048	88601	98207	103900	102807	101153	99873	98645	97459	96952	96341	96427	98842	103648	104575	102976	100738	96322	89810	83332
1/12/2012	78611	75708	74170	73835	75295	80320	89874	96039	96276	95736	95976	95694	95042	94319	93511	93341	95174	100581	102805	101971	100577	97171	91870	86174
1/13/2012	82237	80205	79689	80361	82753	88704	98363	105607	106745	107517	108312	108290	107611	106675	105664	105327	106954	112696	114115	112121	110210	106850	102054	96472
1/14/2012	92285	89782	88535	87960	88469	90540	93976	97795	100433	101705	101583	100290	98363	96492	95021	94759	97069	102884	105650	104852	103596	101415	97554	93075
1/15/2012	89233	87110	85853	85669	86385	88361	91489	94989	97424	98242	97450	96083	94851	93199	91868	91729	94614	102155	106697	106562	106078	103689	100173	96284
1/16/2012	93361	91791	91514	92155	94142	98644	105320	110194	111078	109779	108243	106267	103816	102162	101147	100956	102954	108515	109464	107839	104965	100162	93902	87408
1/17/2012	82393	79666	78208	77909	79406	84576	93565	99334	99765	99535	99471	99083	98088	97176	95850	94552	96043	101545	103419	102139	100094	96057	90151	84046
1/18/2012	79514	77423	76757	77313	79465	85416	95529	101978	102132	101877	101762	101134	100369	99607	98757	98811	101520	108360	112237	112129	110576	107140	101768	96050
1/19/2012	92107	90465	89765	90382	92912	98981	109075	114823	113601	110786	108905	106665	104763	103484	102488	102579	105025	110532	113415	112656	110909	107054	100548	94485
1/20/2012	90267	88047	87217	87499	89736	95353	104675	110732	110686	109877	109016	107457	105906	104760	103760	103614	105216	110354	111844	110122	107977	104619	99698	94218
1/21/2012	89959	87375	85941	85319	85745	87465	90397	94292	97440	100924	103027	103426	102582	101072	99550	98835	100011	104506	106931	105425	103472	100724	96951	92481
1/22/2012	88570	86447	85350	84975	85347	86760	89211	92394	95307	97717	98397	98208	97722	96866	96106	96055	97646	102558	105100	104028	102084	98459	93454	88336
1/23/2012	83907	81591	80539	80467	82225	87338	96230	102491	103135	103069	103159	102516	101744	100977	100073	99562	101185	105412	106790	105086	102520	98013	91279	85186
1/24/2012	79987	77581	76268	76189	78029	83448	93122	99275	98986	97662	96665	95831	94838	94093	93061	92726	94078	99208	103069	102722	101291	97712	92101	86431
1/25/2012	82214	80276	79355	79759	81886	87816	97552	103507	102909	100992	99507	97726	96096	94785	93787	93505	95539	101433	104558	103732	102240	98475	92537	86077
1/26/2012	81546	79171	78042	77900	79649	84960	94245	100191	100249	99785	99616	98800	97874	97161	96249	96029	97494	101653	102922	101619	99217	94938	88845	82208
1/27/2012	77432	74737	73147	72689	73868	78507	87437	93720	94535	94968	95452	95225	94347	93452	92012	90980	91685	95560	98623	97357	95559	92942	88626	83581
1/28/2012	79681	77280	76143	75979	76932	79197	83096	87310	90181	91092	90630	89402	87967	86137	84258	83468	84588	89619	94400	94206	93088	91168	87641	83700
1/29/2012	80340	78321	77336	77279	78044	80027	82884	85933	88123	88391	87859	86977	86267	85095	83887	84116	86161	92234	98000	98675	97587	94599	90192	85580
1/30/2012	82217	80696	80569	81232	83949	90188	100344	106298	105614	103847	102437	100572	98471	96564	94700	93579	94642	100000	104647	104310	102540	98530	92312	85945

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2/1/2012	73989	71698	70474	70221	71683	76748	86077	91698	91561	90801	90454	89434	88086	87184	86328	85517	86164	90426	94946	94416	92828	89303	83638	77776
2/2/2012	73420	71097	69996	70004	70951	77015	86959	93086	93262	93302	93341	91456	91587	90739	89809	89381	91088	95450	99484	99532	98125	94770	89292	83864
2/4/2012	80536	78076	77087	76793	77358	79249	82530	86286	89028	90903	91517	90798	89444	87896	86719	86703	88060	91889	94696	93819	92123	89650	85717	81221
2/5/2012	77448	74958	73641	73151	73617	75198	77787	80817	83964	86455	86949	86369	85513	84388	83303	82898	84286	88953	93335	92791	92603	91238	89464	85411
2/6/2012	82057	80837	80766	81694	84345	90632	100788	106044	104828	101796	99318	96807	94590	92955	91368	90341	91245	95960	101728	102197	100827	97162	91474	85585
2/7/2012	81495	79372	78501	78740	80902	86624	96574	101913	100661	98705	97470	95850	94518	93372	92112	91388	94026	97409	102390	102542	101213	97778	92221	86624
2/8/2012	82887	80799	80121	80633	82666	88206	98098	103367	102957	102360	101959	101346	100611	100377	99963	99786	101111	104892	108446	108181	106447	102587	96393	90214
2/9/2012	86220	83963	83335	83560	85789	91738	101753	106918	105453	103507	101862	99769	97718	96213	94481	93630	94646	99266	105526	106315	105420	102046	96416	90264
2/10/2012	86095	84012	83350	83517	85622	91317	101002	106063	104975	102904	101303	99777	98181	97263	96622	96532	98168	101649	104231	103002	101058	97906	93377	87912
2/11/2012	83669	81402	80343	80135	80880	83443	87136	91199	94960	98114	99099	98691	97755	96536	95560	95719	97544	101676	107101	107790	106869	104809	101475	97717
2/12/2012	94840	93026	92177	92046	92604	94069	96620	99116	100848	102026	101557	100583	99360	97463	95728	95030	96310	100929	107435	108756	107519	104044	99477	95112
2/13/2012	91735	90027	89829	91330	93294	99415	109306	113998	111965	108814	106275	103579	101343	99314	97441	96328	97379	101685	107334	107597	106069	102397	96289	90206
2/14/2012	85505	83093	81815	81557	83457	89036	98425	103414	103125	102366	101678	99532	97595	96281	95081	94846	96098	99500	103096	102350	100594	96776	90732	84756
2/15/2012	80677	78471	77467	77489	79127	84663	94246	99461	99066	97996	96817	95655	94205	92728	91377	90333	91497	95096	100419	100611	99449	96058	90562	84543
2/16/2012	80213	77812	76784	76639	78220	83571	92870	98365	98460	98434	98492	97999	97277	96672	95830	95465	96281	98861	101659	101389	99552	95411	89825	83843
2/17/2012	79321	76907	75491	75406	77194	82537	91468	96510	96607	95560	94207	92654	90875	89737	88002	86709	86859	89342	94675	95393	94387	92302	88381	83599
2/18/2012	79867	77717	76684	76520	77414	79447	83299	86550	88480	88395	87503	85665	83501	81312	79806	78986	80199	83365	88753	89635	88678	86669	83427	79591
2/19/2012	76030	74156	73332	73179	73658	75417	78194	80740	83996	86073	86501	86215	85659	84737	84023	84376	86203	90400	95594	96260	95007	92491	88679	85005
2/20/2012	81931	80422	79866	80534	82450	87020	93728	98287	100132	100036	99278	97349	95430	93471	91462	90011	90466	94079	101197	103053	102366	99231	94307	88969
2/21/2012	85222	83552	83145	83683	85997	91888	101452	105539	103954	101538	100083	98607	97553	96559	94878	94117	94832	97417	101878	101869	99892	95827	89733	83172
2/22/2012	78801	76442	75195	75348	77217	82909	92209	96827	95827	94122	92467	90974	89547	88663	87576	86926	87965	91070	96013	95922	94181	90682	84817	78783
2/23/2012	74509	72222	71233	71305	73084	78644	88060	92481	92133	91462	91071	90293	89255	88663	87661	87119	87735	90182	95124	95494	93655	89856	84157	78254
2/24/2012	73949	71466	70367	70269	71700	76738	85909	91177	92485	92941	93455	93367	92842	92729	92265	91860	92769	94892	96996	96287	94603	91942	87615	82827
2/25/2012	78991	76643	75586	75623	76453	78918	82667	86007	89571	91924	93011	92465	91210	89543	88287	87575	88685	91744	97052	98347	97116	94716	91010	87058
2/26/2012	83543	81497	80407	80178	80769	82350	85104	86888	88010	87775	86388	84718	83260	81186	79321	78439	79056	82435	89620	93178	92955	90479	86657	82526
2/27/2012	79438	78164	78003	78655	81375	87472	97340	101105	99492	97077	95549	93372	91529	90083	88611	87536	87552	89544	95361	97496	95906	92349	86772	81167
2/28/2012	77494	75657	75185	75731	78267	84271	94401	98665	97478	95625	94158	92367	90545	89206	87765	86541	87053	89538	95542	97492	96373	92777	86956	81360
2/29/2012	77236	75257	74542	74439	76156	81237	90310	95300	95726	95967	96580	96133	94867	93572	92285	91481	91798	94108	96974	97041	94819	90750	84606	78162
3/1/2012	73834	71254	70152	69715	71556	76842	86062	91137	91783	91828	92168	91687	90865	90262	89257	88531	88760	90376	94825	96047	94704	91308	85904	80104
3/2/2012	76331	74359	73735	74093	76215	81951	91323	95698	95052	94189	93739	92862	92007	91490	90905	90745	91816	93666	95577	94886	92577	89412	84398	79100
3/3/2012	74772	71944	70408	69904	70160	71857	75338	78632	82566	85678	86832	86215	84694	82749	80744	79588	80243	82437	87365	88821	87721	85610	82031	77837
3/4/2012	74328	72040	70994	70520	71078	72715	75408	78040	81620	83837	84432	84162	83963	83250	82902	83118	84547	87812	94128	96712	95829	93032	88573	84123

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3/7/2012	79649	77519	76636	76879	78869	84469	93453	96479	94665	92370	90630	89071	87625	86646	85403	84340	84315	85907	90467	92505	90756	86908	80871	74998
3/8/2012	70716	68376	67174	67039	68518	73275	81882	86573	87406	87650	87948	87659	87141	86880	86351	85769	86297	87771	91697	93101	91494	87860	81635	76123
3/9/2012	71956	69597	68489	68428	70170	75506	84532	89478	91095	91609	91448	90708	89750	88822	87546	86290	86109	87330	91565	94531	93954	91668	87427	82703
3/10/2012	79041	77158	76367	76340	77389	80041	83486	86007	88002	88497	87960	86305	83881	81310	78932	77450	77515	79225	84694	88347	88080	86294	83097	79193
3/11/2012	76142	74077	0	73763	73974	75262	77894	80467	81792	81316	79873	78308	77059	75240	73535	72205	72059	72894	74509	79981	83594	81517	77288	72560
3/12/2012	68727	66935	66250	66560	68738	74193	84119	91069	91343	90057	89436	88671	87920	87345	86356	85177	84883	84968	85528	88758	90159	86413	80171	74065
3/13/2012	69161	66145	64636	63903	64961	69452	78453	85023	85505	85533	85922	86004	85947	85928	85658	85028	84678	84238	83714	86668	89538	85910	79683	72875
3/14/2012	67957	65060	63447	63135	64224	68646	78055	84195	84882	85150	85958	86239	86425	86710	86515	86183	86042	85812	85303	87591	90010	86686	80241	73345
3/15/2012	68162	65133	63425	62997	63988	68478	78397	83920	84870	85862	87085	87562	87589	88000	87923	87464	87312	87042	86730	89199	90396	86953	80634	73914
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3/17/2012	67589	64184	62199	61180	61156	62397	65463	68830	71920	75055	76904	77308	77153	76281	75785	75546	75711	75791	75509	77305	79543	77402	73292	68426
3/18/2012	64037	61094	59196	58152	57750	58492	60347	63003	66129	69844	71995	73093	73566	73508	73107	73225	73790	74948	75754	79157	82484	79505	74768	69367
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3/20/2012	68775	65555	63814	62772	63569	67878	76961	82952	84161	85409	87297	88614	89691	91032	91338	91672	91862	91470	90272	91404	93707	89677	82848	75589
3/21/2012	70344	66682	64725	63762	64588	68661	77558	83338	84407	86139	88037	89527	90562	91691	92300	92492	92534	92343	91342	92128	93897	90050	83006	75741
3/22/2012	70096	66530	64444	63689	64348	68769	77470	83125	84445	86348	88435	90065	91316	92986	93843	94218	93944	93533	91977	92919	95089	90886	83759	76314
3/23/2012	70775	66929	64680	63440	64010	68037	76500	81935	83713	85680	87903	89538	90489	91397	91570	91102	90360	88974	86648	86921	88062	84540	79208	73014
3/24/2012	67887	64177	61986	60524	60247	61300	63911	67068	70859	74478	77147	77946	77600	76674	75339	74675	74590	74815	75143	76956	78368	76064	72126	67633
3/25/2012	63460	60454	58699	57776	57448	58199	60219	63019	66470	70324	72346	73343	73793	73378	72731	72237	72242	73119	73875	76965	80295	77847	73221	68351
3/26/2012	64240	61845	61022	60797	62461	67564	76937	82747	84137	84976	85592	85444	84981	84435	83676	82710	82445	82611	83205	86896	91376	88963	83468	77667
3/27/2012	73530	71256	70490	70646	72684	78552	88975	94230	93840	92563	91332	89743	88286	86853	85282	83909	83332	83081	83342	86448	90505	88152	82689	76573
3/28/2012	72265	69672	68475	68189	69519	74410	83250	87732	87187	86707	86463	86525	86423	86430	85735	84875	84387	83967	82993	84367	87692	84773	78407	71957
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3/30/2012	69927	67400	66448	66157	67917	72795	82122	87114	87574	87407	87150	86187	85393	84489	83396	82212	81849	81191	80552	82508	85023	82721	78390	73047
3/31/2012	68430	65221	63720	62899	62970	64290	67510	70789	74873	78079	79838	79773	79029	77933	76737	75761	75756	76130	76439	78300	80515	78722	75341	70762
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4/2/2012	65364	63069	62193	62222	63991	69030	77890	83046	84943	85849	86006	85787	85022	84559	83589	82680	82153	81942	81702	83246	87400	85239	79841	73862
4/3/2012	69259	67214	66160	66218	68039	73066	81642	86295	86504	85894	85633	85354	84825	84891	84505	83930	83668	83051	82319	83687	87574	84730	78988	72507
4/4/2012	68060	65367	63816	63340	64337	68878	77035	81568	83216	84101	85186	85671	85689	85897	85556	84837	84311	83568	82585	83384	86955	84496	79017	72738
4/5/2012	68059	65347	63919	63496	64952	69387	77473	82292	84086	84903	85284	84932	83995	83509	82599	81708	81021	80772	80179	81945	85870	84343	79648	73830
4/7/2012	67917	65715	64589	64595	65212	67175	70416	72977	75616	76838	76724	75597	74242	72524	71016	70259	70174	70553	70931	72821	77032	76134	72925	68589
4/8/2012	64733	62243	61183	60855	61222	62937	65146	67381	70023	71252	70779	70284	69712	68470	67069	66091	65733	65722	66220	67671	73956	73715	70332	66284

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4/12/2012	74708	72428	71479	71642	73250	78454	86891	90889	90880	89814	89001	87731	86767	86154	85040	83748	82938	82669	82101	83517	88207	86740	81335	75621
4/13/2012	71613	69361	68595	68529	70267	75176	83621	87847	88173	87382	86470	85781	84697	83757	82903	81770	81062	80233	79109	79494	82926	81864	77376	72021
4/14/2012	67617	65007	63845	63290	63690	65697	68587	71365	74352	76178	76950	76906	76296	75392	74660	74271	74439	74827	74962	76092	78903	77225	73287	68551
4/15/2012	64299	61454	59624	58561	58393	59080	60579	62402	66206	69609	71866	73289	74149	74836	75425	76178	77534	78926	79483	80827	85105	83416	78197	72344
4/16/2012	67526	64411	62745	62166	63192	67497	75439	80921	84839	87698	90549	92717	94428	95983	97025	97445	97822	97500	95848	94730	97171	94651	86847	78999
4/17/2012	72889	69034	66643	65400	66094	70022	77792	82657	85405	86740	88151	88751	89247	89830	90070	89777	89467	88569	86917	86611	89351	86906	80104	73125
4/18/2012	68256	65364	63796	63242	64379	68612	76887	81698	83509	84413	84760	85282	85111	85094	84602	83991	83818	83868	83679	84532	87061	85097	79031	72330
4/19/2012	67593	64760	63410	62958	64220	68847	77136	81846	83836	84413	85171	85440	85381	85881	85639	85248	84944	84589	83592	83751	87552	85563	79113	72230
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4/21/2012	66507	62960	61215	60233	60300	61734	63805	66899	71482	75035	77358	78485	78862	78559	78272	78357	78684	78784	78316	78535	80588	79023	74773	69690
4/22/2012	65370	62595	60910	59793	59648	60434	62027	64032	68012	71600	73741	75009	75674	75851	75626	75628	76649	78044	79071	80869	82994	81467	76853	72288
4/23/2012	68649	66846	65950	66161	67953	73372	82572	87762	89822	90407	90779	90558	89906	89170	88145	87378	87483	88071	88194	88930	91530	89996	84230	77780
4/24/2012	72915	70661	69716	69645	71494	76870	85292	89214	89368	88400	87988	87233	86666	85992	85138	84115	83427	83279	82724	83687	87752	86551	80905	74953
4/25/2012	70603	68482	67421	67439	69240	74619	83297	87189	87531	86880	86515	86185	85602	85250	84699	83816	83538	83182	82481	83253	86912	85103	79047	72677
4/26/2012	68140	65497	64448	64151	65268	69920	78214	83335	85374	86797	87390	87467	87102	86892	86017	85082	84881	84477	84009	84175	86669	85358	79650	73296
4/27/2012	68742	66013	64752	64486	65916	70758	78708	83546	85405	86040	86349	85708	84736	84136	83096	81870	81106	80326	79435	79451	82940	82984	78849	73685
4/28/2012	69406	66946	65625	65137	65604	67534	69979	73187	76879	79630	80756	80425	79749	78553	76939	75995	75862	76622	76970	78005	80295	79553	76431	71773
4/29/2012	67421	65074	63575	62967	63270	64444	65685	67534	70471	72199	72632	72646	72371	71877	71104	70948	71580	72625	73575	74983	79181	78734	73879	68791
4/30/2012	64712	62727	61710	62082	63892	69079	77350	82411	84314	85168	86215	86683	87071	87192	87263	86590	86516	86447	86148	86695	89333	86798	80331	73461
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5/2/2012	70313	66807	64903	64064	64784	69213	77082	82467	85881	88209	90897	92566	94193	95312	96052	96539	97071	96836	95779	94749	95903	94169	87057	79300
5/3/2012	73220	69250	66969	65794	66500	70536	78501	83957	87630	90320	93236	95696	97899	99986	101597	102908	103896	104114	102521	101077	102057	99791	92233	83681
5/4/2012	76595	72431	69601	68108	68191	71838	78838	84562	88246	90788	93699	95730	96936	98553	99471	99852	100352	99141	96206	93759	94161	92321	86034	78702
5/5/2012	72380	68080	65529	63746	63223	63953	65301	69105	74394	78920	81966	83376	84139	84007	83781	83756	83718	83522	82327	81413	82320	81650	77102	71449
5/6/2012	66190	62697	60530	59115	58574	59025	59333	61425	65691	69891	72536	74712	76390	77528	78164	78913	80121	81250	81404	81341	83501	82900	77438	71016
5/7/2012	66110	63395	61625	61324	62322	66787	74460	80495	83752	86235	88572	90022	90997	92327	92834	92753	93153	92585	91201	90201	91314	88947	82334	75097
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5/10/2012	68068	65092	63340	62653	63410	67503	74376	79591	82427	83791	85112	85635	85484	85685	85385	84745	84492	84067	82932	82348	84557	84697	79158	72573
5/11/2012	67539	64836	63331	62987	64102	68546	75368	80569	82704	83938	84967	85376	85557	85665	85480	85001	84973	84470	82932	81341	82402	82853	77897	71735
5/12/2012	66489	63177	61301	60382	60373	61630	62921	66393	70786	73966	75666	76314	76516	76390	76436	76715	77378	77500	77068	76327	78390	78567	74657	69434

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5/14/2012	66718	64046	62451	62057	63104	67538	74944	81019	84543	86945	89065	90455	91190	91541	91562	91177	91153	91041	90286	89622	90530	89310	82859	75558
5/15/2012	69834	66530	64658	64019	64872	69139	76544	82370	85878	88798	91565	93461	94649	96082	96726	97442	98340	98464	96895	95448	96144	94478	87115	79157
5/16/2012	72860	68709	66140	64715	65181	69378	76266	81884	86134	88830	91568	93661	95325	97242	98197	98630	99031	98518	96353	93773	94161	93047	86116	78138
5/17/2012	71737	68138	65661	64532	65143	68675	75097	80577	83479	85498	87424	88561	89458	90287	90817	91355	91810	91155	89456	87641	88199	87921	81636	74196
5/18/2012	68437	65025	63145	62306	62970	66674	73021	78646	82191	84673	86865	88380	89402	90402	90944	91654	92335	91830	89909	87076	86648	86342	80862	74091
5/19/2012	68324	64487	61974	60594	60280	61190	62279	65886	71133	75628	79026	81595	83465	84937	86571	88347	90493	91654	91033	89043	88077	87358	82364	75751
5/20/2012	70001	65828	63039	61263	60384	60462	60057	63224	68701	74379	78842	82705	85976	88339	90473	92387	94000	95216	94389	92821	93100	92539	86496	79169
5/21/2012	72998	68928	66367	65416	66211	70277	77231	83644	87476	90485	93199	95437	96872	98236	98881	99220	99361	98609	96695	94719	94399	92960	86145	78343
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5/23/2012	72551	68763	66501	65333	66198	69903	76474	82799	87125	90670	94084	96698	98750	100773	101946	102885	103692	103364	101329	99102	98487	97154	90271	82090
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6/15/2012	77969	72948	69688	68011	68085	70658	75185	82317	88658	93722	98495	102346	105403	109027	111497	113447	114781	114964	112232	108003	103746	101883	95778	87226

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6/19/2012	83579	79060	75865	73995	74220	77463	82739	90079	96592	102889	109101	114681	119272	123587	127173	129900	132293	132964	131729	128446	124850	122329	114724	104004
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8/18/2012	81577	76569	73272	70736	69560	69950	71023	72987	78408	83983	88674	92121	94606	96262	97480	98697	99930	100081	98213	94568	93324	91057	85445	78895
8/19/2012	73143	69029	66057	64197	63381	63572	64180	65448	69728	74535	78542	81855	84405	85617	86635	87592	88769	89499	89085	88477	90114	88996	84078	78043
8/20/2012	72935	69460	67485	66508	67419	71544	77943	82638	87460	91873	95872	98958	101182	103409	105005	105951	106811	106053	103316	100609	100523	97504	90258	82331
8/21/2012	76074	72094	69706	68237	68610	72224	78249	82592	87254	91886	96256	99990	103259	106477	108765	109898	110528	109727	107054	103689	103852	100602	92652	84230
8/22/2012	77334	72883	70195	68680	69058	72631	78857	83523	88602	93449	98668	103244	107169	110626	113502	115467	116833	116457	113595	109714	108782	104906	96697	87742

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8/24/2012	84858	79551	76064	73976	73933	77096	83104	87834	93435	99362	105614	111495	116608	121147	124535	126439	127180	125469	121505	116613	114663	110484	102603	94059
8/25/2012	86300	80593	76818	74168	72837	73274	74945	77191	83011	90197	97097	103202	107177	109631	110586	110973	111540	111193	109094	106202	105380	102156	95657	88516
8/26/2012	81850	77024	73505	71188	69853	69674	70325	71694	77498	84606	91303	96763	100964	104197	106430	107790	109141	109254	107674	105474	106391	102869	95621	88187
8/27/2012	81901	77773	75338	74070	75011	79329	87165	92885	98391	103848	109563	114292	118161	121942	124671	126131	127273	127372	124833	121601	120418	114925	105813	96243
8/28/2012	88728	83515	80341	78727	79053	82972	90664	95530	100165	105432	110966	116276	121090	124936	127588	129412	130418	129352	125023	119371	117250	111580	101718	91978
8/29/2012	84050	78742	75226	73220	73148	76724	83660	88176	92970	98062	102968	107408	110971	114504	117457	119795	121373	121142	117829	112852	111739	106540	97297	88151
8/30/2012	81001	75905	72633	71135	71119	74475	81436	86380	91130	96139	101486	106638	111065	115946	119890	123440	125896	126054	122966	118436	116992	111627	102268	92777
8/31/2012	84667	79327	76252	74057	74092	77533	84097	89156	95110	102407	110506	117798	123734	129139	133077	135761	136948	135710	131027	125145	122795	117177	108914	99693
9/1/2012	91936	85899	81864	78977	77546	77605	79171	81437	87560	94797	101489	106758	110838	113802	115864	116534	116194	114261	111043	108547	108083	104131	98068	91254
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9/5/2012	91555	85948	82545	80787	81152	85217	94183	99456	103235	107501	111748	115905	120002	124012	127000	129030	129959	129144	125945	122829	122183	115818	106211	96780
9/6/2012	88921	83577	80026	78053	78255	82350	90779	95754	99558	103725	108172	111813	114961	118576	120919	123160	125056	125020	122040	118887	118002	112176	102632	93289
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9/8/2012	84954	79667	76227	74001	73416	73972	76144	78781	84157	89782	94807	98643	100986	102535	102816	101644	98570	95832	92789	91049	90590	87063	81975	75996
9/9/2012	70570	66738	64290	62515	61724	61738	62801	64101	68155	72957	76838	80059	82415	83884	84808	85956	87047	87776	86754	86629	88199	84592	78511	72457
9/10/2012	67805	64625	62939	62393	63335	67547	75314	79730	82901	86384	89370	91355	92602	93791	94498	94987	95457	95045	93224	92277	93138	88640	81224	74013
9/12/2012	70432	66874	64977	63832	64614	68549	76312	80628	83598	86902	90463	93410	96259	99000	101164	103335	105405	105542	103222	101309	101789	96447	88313	80070
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9/14/2012	73172	69466	66998	65867	66254	70075	77722	82351	85592	89484	93086	95827	97558	99205	100291	100463	100298	98702	95551	93777	93418	89499	83523	76938
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9/16/2012	65069	61824	59910	58733	58085	58708	60009	61339	65194	69519	72309	74637	76285	77484	78329	79210	80420	81593	81387	83077	84755	81023	75308	69731
9/17/2012	65708	63010	61574	61143	62132	66537	74410	79201	82308	85347	88392	90289	92021	93523	94352	94526	94709	94335	93476	95489	95493	91082	84456	77761
9/18/2012	72678	69678	67565	66931	67938	72485	81520	87801	90530	92957	95174	96340	96853	97013	96518	95382	94936	94564	93555	94368	94367	89788	83003	75997
9/19/2012	70661	67180	65080	63980	64448	68257	76329	80632	82343	84121	85598	86576	87166	87819	88057	88190	88353	88106	86461	87900	89022	84863	78436	71842
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9/24/2012	63266	60957	59996	59926	61297	65936	74910	80116	81980	83176	84311	85201	85228	85261	85091	84838	84920	84738	84328	86844	87757	83538	77178	70815
9/25/2012	66380	63557	62199	61947	62873	67290	76206	80853	82202	83710	85211	85878	86542	87347	87700	87478	87815	87710	87546	90293	89857	85719	79280	73022

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10/1/2012	62929	60743	59677	59644	60763	65309	74136	79602	81178	82493	83982	84933	85378	85756	85579	85136	84935	85218	86226	89473	88482	84133	77790	71564
10/2/2012	66913	64061	62624	62281	63250	67515	76581	82522	84400	86322	88351	89894	90175	90985	90941	90970	91317	91565	91838	94234	93600	89246	82713	75982
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10/5/2012	69935	66318	64324	63332	64112	67832	76046	81152	83221	85556	88030	89928	91343	92569	93483	93494	93200	91674	90052	91073	88771	84898	79727	73520
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10/7/2012	64128	61166	59440	58397	58234	59033	60998	63330	66957	70597	72126	73773	74248	74027	73703	73562	74158	75641	77937	81201	80861	77907	73975	69873
10/8/2012	66735	64501	63742	63700	65230	69189	77318	83641	85805	87580	88674	88756	88384	87817	86885	86126	86390	87219	89297	92398	91398	87286	81421	75382
10/9/2012	70658	68129	66800	66477	67898	72425	81390	87048	87611	87750	87857	87256	86648	86211	85320	84525	84533	84930	86695	90241	89313	85369	79236	73187
10/10/2012	68787	66321	64966	64600	65905	70405	79359	85115	85768	86135	86543	86500	86152	85896	85182	84589	84552	84885	86673	90297	89580	85923	80015	74124
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10/17/2012	69915	66832	65602	65304	66782	71797	80861	86678	87003	86472	86138	85648	85439	85280	84893	84364	84446	84882	87435	90082	88850	84823	78529	72624
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10/19/2012	68524	66368	64650	64045	65156	69049	77318	84089	86537	87282	87948	88041	87541	87321	86663	85688	85295	84919	86109	87258	85525	82208	77417	72119
10/20/2012	67349	64318	62464	61461	61526	62872	66026	69620	72894	75561	76707	76723	75915	75098	73987	73359	73426	73793	76215	79298	78372	76023	72621	68497
10/21/2012	64940	62479	61042	60423	60668	61949	64373	67266	70014	71877	72114	71945	71664	71059	70571	70558	71281	72739	76494	80654	80150	77066	72937	68341
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10/23/2012	67659	65132	63236	62786	63949	68074	77415	83820	84770	85508	86366	86654	86849	87476	87317	86970	86778	87203	89217	91475	89239	84458	78711	72635
10/24/2012	67646	64451	63037	62679	63531	67564	76147	82880	83677	84891	85792	86827	87677	88684	89422	89414	89715	89457	91096	93144	90997	86868	80251	73904
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10/26/2012	68305	65368	63428	62651	62923	66826	75795	82574	84313	85241	86088	86122	85955	85779	84974	84269	84094	84169	86470	86597	84596	81693	77048	71603
10/27/2012	66980	63770	62119	60834	60949	62237	65049	69074	72754	75652	77488	77670	77274	76318	75438	74673	74980	75956	79302	80833	79637	77351	73828	69469
10/28/2012	66070	62690	61115	59993	59680	60608	61820	65594	68720	72079	74252	75849	76839	77000	76924	76846	77934	80108	83333	84780	83861	80649	77282	72363
10/29/2012	68674	66771	64927	64443	65572	69560	76537	82965	86478	88678	90600	91535	91152	91301	89548	88443	88250	88448	89801	88031	84469	79753	74698	70031

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10/31/2012	69362	67173	65939	66041	67262	71468	78886	84807	86159	86012	86154	85465	84992	85243	83738	83403	84150	85379	87080	87280	87174	84762	80387	74974
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11/2/2012	71800	69450	68126	68085	69585	74327	82603	88631	89205	88713	88117	86738	85651	85071	84045	83130	83395	84589	88123	89267	87834	85531	81503	76679
11/3/2012	72732	69943	68670	68332	68899	70725	74035	78144	80998	82786	83114	82317	81065	79807	78533	78053	78392	80121	84091	85412	84668	82370	79083	74990
11/4/2012	68534	135343	66553	66582	67292	69012	71610	74488	77211	78345	77858	77248	77043	76379	76066	76776	79426	85557	88110	87814	86478	83102	79026	74180
11/5/2012	72290	70914	70610	71382	73841	79518	88825	93338	94120	93513	92759	91601	90205	89181	88120	87904	90051	96535	99178	98596	96931	93434	88141	83091
11/6/2012	79466	77828	77269	77948	80224	85941	94109	97290	96779	95220	93929	92439	90974	89856	88936	88708	90919	97266	99663	98861	96983	93227	87691	82387
11/7/2012	78480	76306	75140	74978	76744	82570	90934	95142	95690	95660	95312	94305	93460	92842	92476	92561	94929	100146	101654	100518	98072	93615	88350	82746
11/8/2012	78819	76745	75822	75896	77870	83339	92156	96230	96434	95327	94124	92448	90703	89302	88000	87637	89513	95866	98734	98276	96807	93315	87983	82399
11/9/2012	78757	76844	75947	76012	78085	83478	92142	95590	94908	92868	91204	89370	87597	86454	85147	84418	85458	90947	92454	91247	89598	86757	82632	77682
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11/11/2012	67873	65539	64523	64111	64641	66187	68796	71083	73373	73959	73502	72973	72609	72051	71567	71774	74200	80826	82669	81815	80196	76759	72927	68832
11/12/2012	65599	63711	63087	63214	65054	70013	78135	83422	84888	85944	86978	86858	86786	86827	86287	86249	88355	94002	94880	93546	91278	87314	81785	76129
11/14/2012	80214	78265	77553	77737	79938	85750	95161	99162	98142	96275	94882	93231	91618	90694	89774	90047	92817	100006	102175	101598	100143	96599	91291	85564
11/15/2012	81920	79789	78730	78868	80641	85938	95243	99103	98678	96938	95676	93751	92054	91006	89726	89718	92304	98682	100561	100125	98674	95139	89522	83882
11/16/2012	79837	77888	76901	77007	78941	84353	93518	97914	97394	95672	93781	91730	89662	88261	86821	86125	87866	94303	95921	95013	93781	91440	87430	82658
11/17/2012	79041	76984	76086	75776	76748	79243	82987	85908	87375	86933	85391	83330	80949	78852	77339	77048	79522	86142	88139	87761	86740	84913	81542	77827
11/18/2012	74455	72550	71435	71184	71660	73276	76073	78582	80819	81134	80074	78844	77916	76896	76292	76455	79593	86943	89465	89086	87942	84815	80674	76573
11/19/2012	73539	71776	71224	71663	73848	79476	88950	93844	94223	93494	92560	91027	89610	88523	87524	87152	89645	96319	97911	96920	95081	91285	85664	79871
11/20/2012	75555	73191	72113	71895	74381	79334	88250	92924	93228	92206	91305	89633	88420	87881	87153	87026	89319	95261	96502	95615	93941	90661	85256	79629
11/21/2012	75719	73645	72772	72859	75036	80175	88495	93415	93971	92565	91109	89394	87714	86477	85287	84322	85643	91734	93456	92350	91050	88345	83893	78452
11/22/2012	74120	71653	70364	70111	70892	73178	76081	78516	80344	80946	80922	79976	77404	74018	71197	69416	69300	73469	74446	74569	74905	74484	72958	70503
11/23/2012	68400	67152	66819	67267	68730	71976	76118	79085	80186	80329	79836	79072	78195	77455	77031	77785	80923	86754	87526	86324	85004	82637	79190	75096
11/24/2012	71494	69511	68679	68632	69703	71936	75360	79201	82692	85597	87380	87544	86709	85408	84657	84904	87826	94169	95586	94840	93849	91528	87738	83590
11/25/2012	79742	77153	76130	75666	76230	77710	80245	82944	85168	86474	86585	85849	84921	83380	82033	81816	85323	93844	96561	96511	95553	92245	87580	82605
11/26/2012	79189	77473	76825	77276	79314	84973	93717	98763	98383	96243	94425	92714	91082	89774	88854	88924	92212	100115	102113	101582	99923	96093	89990	83871
11/27/2012	79103	76557	75427	75215	77144	82642	91905	97656	98345	98382	99049	98823	98526	98008	97230	97214	100015	106314	107455	106386	104300	100167	94029	87378
11/28/2012	82977	80542	79447	79470	81381	87028	96757	101718	100965	99562	97603	95776	94114	93325	92322	92377	95955	104294	106815	106654	105488	102306	96440	90435
11/29/2012	86214	84170	83489	83917	86204	91897	101359	105981	104586	101489	98809	95382	93784	92245	90869	90783	94116	102707	105047	104814	103516	100081	94157	87916
11/30/2012	83648	81518	80505	80879	82993	88630	97925	102558	101459	98767	96345	93897	91698	90426	89176	88501	91129	97806	98856	97591	96018	93470	88848	83233

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Max	32,542
PST	26,061
Winter	18,066
Spring	16,335
Summer	23,672
Fall	17,055

Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
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12/2/2011	13165	12729	12547	12595	12963	14029	15856	16682	16526	16164	15870	15628	15404	15220	15138	15279	16210	17679	17607	17229	16822	16211	15233	14083
12/3/2011	13137	12559	12332	12286	12463	12917	13709	14252	14819	14918	14820	14490	14236	14002	13925	14041	15135	16718	16837	16629	16415	15902	15119	14105
12/4/2011	13197	12651	12405	12307	12393	12629	13114	13476	13914	13972	13845	13700	13572	13457	13414	13627	14666	16519	16717	16534	16292	15517	14380	13104
12/5/2011	12204	11694	11485	11463	11805	12760	14514	15475	15734	15797	15714	15610	15427	15356	15309	15470	16492	17942	17917	17589	17144	16145	14703	13205
12/6/2011	12086	11561	11250	11196	11456	12364	13994	15140	15475	15635	15799	15878	15786	15822	15837	16150	17306	18211	18025	17589	17043	16123	14651	13111
12/7/2011	12147	11590	11224	11143	11389	12199	13948	15249	15662	15833	15979	16059	16042	16032	16058	16290	17290	18132	17965	17625	17193	16423	15081	13842
12/8/2011	13126	12380	12263	12346	12632	13681	15581	16489	16697	16652	16402	16139	15864	15743	15734	15951	16991	18621	18808	18583	18278	17435	16292	14835
12/9/2011	13810	13381	13186	13171	13540	14549	16359	17345	17206	16755	16386	16082	15749	15636	15571	15679	16752	18156	17958	17675	17179	16496	15492	14215
12/10/2011	13193	12584	12277	12134	12166	12575	13243	13852	14517	14812	14862	14911	14750	14443	14381	14524	15721	17459	17631	17456	17247	16800	16067	14984
12/11/2011	14084	13482	13232	13151	13265	13565	14107	14466	14981	15250	15091	14929	14713	14583	14597	14829	16009	18049	18390	18377	18144	17467	16320	15028
12/12/2011	14117	13651	13515	13594	14010	15168	17044	18010	17960	17677	17367	16967	16602	16381	16263	16504	17744	19561	19722	19464	19101	18212	16704	15129
12/13/2011	14131	13716	13551	13657	14040	15118	17052	17965	17766	17356	16893	16505	16190	16080	16007	16212	17308	19173	19378	19117	18753	17905	16476	14881
12/14/2011	13808	13287	13081	13068	13379	14422	16282	17156	17106	16698	16345	16088	15844	15785	15745	16019	17244	18798	18777	18412	17980	17078	15651	14051
12/15/2011	12901	12324	12047	11995	12217	13152	14958	16026	16129	16115	15938	15679	15600	15602	15640	15852	16931	18293	18209	17795	17391	16507	15078	13533
12/16/2011	12374	11748	11412	11393	11615	12586	14380	15433	15604	15630	15637	15658	15539	15541	15619	15913	17079	18434	18254	17812	17378	16782	15758	14436
12/17/2011	13322	12733	12395	12299	12400	12855	13632	14301	14902	15185	15199	15165	15151	15235	15311	15510	16543	17860	17879	17650	17410	16904	16141	15071
12/18/2011	14116	13495	13197	13103	13155	13476	13993	14536	15155	15494	15433	15295	15250	15181	15200	15456	16666	18645	19025	18999	18812	18134	16979	15625
12/19/2011	14590	14114	13939	14004	14354	15390	17202	18139	18006	17610	17256	16896	16496	16272	16210	16501	17796	19294	19381	18992	18503	17568	16048	14442
12/20/2011	13254	12549	12235	12156	12428	13342	15063	16286	16540	16616	16676	16580	16441	16341	16301	16548	17747	19045	19046	18721	18363	17454	16074	14470
12/21/2011	13293	12660	12337	12229	12469	13377	15024	16196	16469	16603	16604	16512	16330	16197	16179	16431	17484	18525	18408	17954	17466	16583	15174	13647
12/22/2011	12426	11786	11368	11345	11582	12421	14089	15202	15397	15336	15325	15195	15018	14942	14944	15060	16028	17683	17686	17427	17043	16314	15183	13741
12/23/2011	12547	11911	11552	11363	11538	12207	13529	14631	14987	15166	15270	15346	15318	15176	15124	15246	16198	17814	17817	17509	17165	16625	15721	14536
12/24/2011	13490	12794	12463	12346	12373	12694	13311	13935	14637	15030	15133	15175	14999	14759	14680	14793	15668	17342	17251	16944	16774	16576	16135	15391
12/25/2011	14505	13848	13405	13199	13130	13373	13814	14258	14666	14709	14471	14144	13870	13620	13492	13484	14140	15363	15470	15454	15426	15230	14680	13775
12/26/2011	12899	12360	12086	12049	12194	12611	13124	13466	13832	14253	14492	14604	14454	14313	14220	14340	15361	17269	17538	17465	17296	16724	15763	14561
12/27/2011	13614	13033	12740	12668	12930	13592	14696	15584	16128	16544	16799	16850	16813	16779	16777	16950	17852	18533	18224	17635	17044	16079	14917	13711
12/28/2011	12659	12126	11824	11851	12107	12875	14030	14935	15354	15631	15998	16076	16115	16055	16154	16423	17421	19131	19226	18900	18574	17816	16768	15490
12/29/2011	14433	13904	13664	13651	13989	14750	15961	16789	17118	17241	17195	16914	16697	16633	16590	16745	17753	19283	19206	18824	18403	17643	16422	15052
12/30/2011	13992	13304	12982	12949	13185	13881	14998	15675	16057	16205	16031	15717	15317	15023	14872	14952	15795	17565	17578	17227	16772	16204	15298	14146
12/31/2011	13083	12351	11933	11703	11648	11877	12389	12849	13376	13834	13995	14014	13963	13774	13676	13866	14791	16519	16599	16151	15548	14940	14322	13696
1/1/2012	13027	12426	11970	11779	11745	11915	12352	12506	12748	12857	12932	12981	13053	13051	13038	13279	14353	15865	15943	15693	15397	14766	14018	13051

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1/3/2012	13792	13384	13186	13300	13691	14766	16605	17702	17696	17679	17778	17778	17788	17863	17934	18164	19211	21070	21241	21009	20643	19715	18383	17104
1/4/2012	16198	15826	15730	15766	16181	17240	18966	20020	19833	19663	19365	19053	18823	18631	18523	18946	19850	21374	21363	20890	20333	19237	17684	16259
1/5/2012	15215	14660	14438	14374	14632	15557	17257	18482	18505	18412	18215	17745	17427	17332	17259	17291	18160	19687	19783	19567	19178	18314	17032	15666
1/6/2012	14730	14218	13909	13893	14147	15059	16825	17757	17597	17221	16929	16598	16195	16018	15873	15904	16423	17877	17906	17453	17083	16389	15421	14345
1/7/2012	13408	12805	12519	12458	12562	12934	13592	14214	14671	14791	14670	14497	14175	13889	13779	13779	14330	15823	15999	15742	15391	14937	14251	13377
1/8/2012	12599	12085	11824	11746	11829	12125	12637	13011	13487	13888	13998	13950	13994	14008	14031	14205	15044	16771	17115	16960	16764	16092	15138	14091
1/9/2012	13398	13073	12976	13049	13409	14497	16326	17454	17486	17453	17235	16957	16690	16486	16372	16548	17402	18990	19062	18753	18247	17233	15898	14575
1/10/2012	13606	13122	12934	12957	13329	14378	16281	17308	17254	16928	16599	16318	16025	15894	15905	16119	16882	18324	18452	18188	17779	17011	15762	14608
1/11/2012	13775	13412	13275	13352	13794	14837	16742	17729	17449	17035	16632	16310	16081	16076	16111	16229	17094	18444	18431	18032	17536	16628	15359	14054
1/12/2012	13104	12548	12227	12113	12308	13175	14855	16122	16264	16323	16425	16432	16369	16244	16147	16271	16804	17921	17976	17593	17118	16188	14878	13664
1/13/2012	12782	12272	11985	11939	12197	13188	14949	16241	16515	16742	16967	17309	17378	17232	17261	17442	18027	19360	19254	18819	18413	17754	16827	15721
1/14/2012	14823	14353	14071	13943	14036	14412	15034	15669	16235	16568	16603	16523	16347	16174	16008	16049	16770	18174	18337	18070	17733	17250	16495	15591
1/15/2012	14777	14290	14012	13922	14091	14465	15060	15612	16140	16515	16610	16557	16446	16296	16206	16393	17195	18853	19225	18989	18796	18235	17351	16453
1/16/2012	15677	15317	15197	15293	15671	16532	17789	18566	18779	18668	18537	18158	17753	17430	17301	17421	18212	19712	19763	19357	18792	17710	16370	15110
1/17/2012	14147	13656	13419	13366	13596	14525	16246	17323	17221	17379	17496	17641	17432	17305	17173	16859	17176	18484	18507	18103	17524	16512	15183	13840
1/18/2012	12840	12284	12085	12124	12478	13487	15487	16595	16534	16529	16556	16497	16362	16267	16270	16512	17305	19041	19427	19258	18869	18020	16838	15612
1/19/2012	14782	14416	14320	14410	14829	15919	17828	18827	18633	18187	17826	17415	17126	16972	16976	17177	17994	19383	19500	19174	18681	17804	16407	15080
1/20/2012	14141	13647	13385	13357	13705	14766	16652	17798	17774	17634	17592	17379	17105	16979	16955	17184	17767	19241	19358	18944	18478	17762	16760	15666
1/21/2012	14804	14292	14067	14020	14152	14462	15039	15632	16357	17214	17738	17980	17989	17804	17665	17593	17945	19149	19248	18808	18333	17653	16779	15822
1/22/2012	15056	14576	14340	14277	14350	14687	15200	15663	16286	16886	17161	17248	17172	17089	17013	17065	17617	18790	18944	18534	18076	17297	16247	15077
1/23/2012	14093	13546	13342	13315	13610	14541	16253	17355	17487	17636	17662	17646	17475	17324	17256	17388	17922	18836	18702	18247	17592	16541	15176	13793
1/24/2012	12595	12158	11888	11783	12137	13056	14868	15935	15880	15624	15399	15236	15148	15053	14944	15063	15621	16983	17387	17209	16863	16083	14946	13801
1/25/2012	13154	12688	12512	12550	12900	13937	15718	16823	16827	16650	16373	16058	15720	15578	15468	15569	16148	17732	18205	17988	17643	16770	15511	14248
1/26/2012	13380	12866	12662	12626	12966	13897	15671	16727	16769	16847	16913	16879	16817	16805	16749	16868	17451	18458	18457	18093	17559	16623	15327	14031
1/27/2012	13034	12521	12224	12142	12327	13131	14768	15908	16033	16312	16488	16490	16248	16001	15729	15594	15867	16947	17313	17021	16590	15980	15085	14046
1/28/2012	13194	12674	12413	12326	12489	12846	13569	14114	14746	14981	14759	14519	14238	14006	13845	13876	14326	15673	16219	16058	15758	15347	14659	13865
1/29/2012	13170	12712	12470	12431	12535	12879	13413	13737	14205	14397	14391	14325	14313	14281	14165	14210	14808	16345	17125	17087	16761	16104	15078	13988
1/30/2012	13214	12801	12707	12811	13217	14326	16221	17222	17082	16929	16832	16649	16422	16217	16050	16090	16624	18255	18817	18607	18137	17204	15881	14567
1/31/2012	13718	13206	12998	12925	13207	14241	16066	16828	16625	16335	16122	15831	15511	15322	15164	15174	15511	16758	17367	17077	16646	15857	14586	13355
2/1/2012	12415	11997	11749	11618	11920	12835	14598	15614	15640	15696	15602	15457	15150	14992	14724	14698	15027	16344	16870	16594	16179	15312	14075	12938
2/2/2012	12020	11582	11399	11424	11695	12647	14503	15620	15745	15846	15918	15911	15798	15660	15544	15772	16528	17732	17964	17728	17316	16486	15311	14127
2/3/2012	13320	12921	12793	12865	13187	14238	16092	16979	16818	16505	16371	16065	15723	15514	15316	15289	15689	16918	17534	17301	16997	16423	15571	14547
2/4/2012	13739	13277	13067	12969	13060	13422	14117	14646	15104	15388	15386	15267	15121	14932	14779	14854	15306	16371	16711	16432	16105	15610	14891	14015
2/5/2012	13234	12751	12452	12356	12386	12674	13143	13573	14274	14886	15001	14878	14600	14460	14380	14455	14934	16245	16812	16520	16260	15874	15416	14466
2/6/2012	13703	13319	13240	13359	13755	14863	16652	17477	17218	16765	16435	16129	15759	15515	15377	15360	15776	17061	17921	17782	17338	16523	15293	14084
2/7/2012	13251	12793	12645	12673	13055	14107	15939	16692	16389	16054	15849	15626	15397	15211	15100	15147	15590	16931	17748	17581	17269	16433	15249	14049
2/8/2012	13284	12876	12698	12782	13175	14232	16087	17033	17068	16930	16838	16829	16684	16824	16896	17082	17652	18802	19052	18751	18278	17369	16051	14801

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2/10/2012	13944	13547	13355	13387	13722	14815	16670	17481	17172	16772	16461	16181	15880	15697	15639	15862	16354	17410	17776	17369	16916	16305	15402	14351
2/11/2012	13484	13015	12728	12654	12746	13194	13894	14478	15356	16040	16309	16274	16159	15997	15825	15756	16112	17036	17577	17430	17136	16637	16069	15318
2/12/2012	14805	14490	14475	14522	14627	14960	15394	15654	16086	16407	16680	16852	16838	16471	16411	16476	16847	18185	19069	19008	18581	17728	16625	15602
2/13/2012	14739	14293	14184	14285	14621	15739	17546	18330	18122	17809	17482	17116	16743	16428	16213	16186	16530	17771	18747	18631	18265	17326	16026	14809
2/14/2012	13908	13393	13226	13201	13491	14555	16272	17124	17178	17113	17000	16633	16161	15835	15497	15597	16054	17207	17886	17587	17204	16299	15043	13862
2/15/2012	12968	12535	12371	12324	12555	13614	15371	16325	16615	16698	16788	16712	16485	16250	15965	15912	16287	17300	18052	17845	17468	16716	15588	14447
2/16/2012	13543	13134	13018	13029	13380	14307	16018	16990	17027	17020	17038	16989	16875	16795	16820	16967	17298	18033	18370	18036	17544	16615	15328	14098
2/17/2012	13159	12573	12310	12261	12502	13356	14902	15775	15998	15858	15783	15556	15261	15111	14919	14863	15132	16019	16985	16809	16523	16019	15189	14251
2/18/2012	13492	13017	12791	12712	12867	13209	13843	14333	14650	14701	14618	14406	14092	13727	13611	13547	14015	15085	15908	15760	15476	15013	14344	13595
2/19/2012	12883	12461	12240	12207	12283	12578	13013	13344	13895	14274	14324	14249	14130	14001	13839	13798	14256	15414	16416	16306	16071	15503	14752	13907
2/20/2012	13199	12837	12668	12697	13020	13787	14849	15661	16202	16453	16363	16040	15636	15349	15136	15111	15463	16542	17770	17695	17427	16669	15612	14560
2/21/2012	13817	13505	13420	13548	13964	15043	16745	17411	17063	16624	16296	16061	15837	15754	15690	15952	16466	17313	18019	17745	17244	16360	15124	13886
2/22/2012	12935	12482	12228	12210	12558	13561	15241	15943	15907	15745	15555	15370	14977	14929	14801	14825	15094	15987	17026	16857	16372	15530	14323	13081
2/23/2012	12236	11766	11525	11478	11749	12718	14363	15094	15092	15076	15120	15015	14861	14773	14636	14614	14944	15717	16733	16602	16213	15366	14160	13010
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3/17/2012	11375	11031	10887	10842	11144	11824	12306	12991	13440	13493	13352	13209	12956	12746	12695	12752	12830	13088	13955	14151	13737	13057	12163	11367

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3/19/2012	10675	10469	10431	10685	11627	13376	14435	14541	14598	14758	14852	14912	15022	15074	15095	15154	15203	15150	15921	15984	15071	13764	12410	11486
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3/23/2012	11178	10813	10662	10791	11551	13073	14025	14476	14880	15284	15514	15694	15848	15832	15673	15527	15268	14877	15331	15357	14632	13633	12534	11485
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6/3/2012	11258	10819	10595	10514	10339	10455	11110	11978	12790	13454	14007	14382	14734	14863	14799	15094	15463	15356	15257	15316	15049	14013	12794	11844
6/4/2012	11256	10931	10813	11019	11657	12873	14258	15015	15537	15893	16002	15953	15939	15920	15882	15900	15848	15547	15377	15619	15150	13879	12578	11642
6/5/2012	11061	10720	10606	10750	11281	12505	13668	14306	14710	15182	15433	15526	15567	15496	15539	15541	15572	15216	15179	15489	15240	13962	12676	11667
6/6/2012	11105	10774	10655	10827	11303	12556	13845	14556	15102	15572	15874	16087	16201	16235	16352	16508	16565	16254	15998	16180	15921	14606	13234	12159
6/7/2012	11522	11122	10984	11101	11601	12824	14252	15052	15778	16413	16933	17317	17578	17824	17970	17993	17880	17301	16883	16909	16647	15323	13770	12560
6/8/2012	11847	11372	11145	11236	11686	12901	14345	15344	16119	16856	17498	17949	18564	18955	19356	19686	19688	19107	18397	18073	17829	16491	14994	13688
6/9/2012	12730	12130	11782	11598	11477	11784	12800	14069	15080	15825	16534	17272	17773	17915	18044	18382	18474	18309	18013	17889	17852	16903	15598	14400
6/10/2012	13494	12887	12433	12162	11992	12029	12954	14263	15737	17252	18508	19564	20436	21260	21900	22368	22582	22122	21285	20804	20327	18731	16813	15300
6/11/2012	14301	13635	13268	13286	13841	15087	16693	17752	18687	19630	20467	21154	21784	22146	22247	21868	21374	20388	19587	19443	18817	17251	15605	14227
6/12/2012	13459	12927	12747	12864	13489	14837	16341	17224	17807	18358	18593	18623	18577	18368	18239	18123	18072	17801	17657	17840	17283	16087	14711	13578
6/13/2012	12844	12442	12265	12396	13035	14236	15662	16455	16794	17334	17775	18035	18365	18566	18770	18951	18986	18626	18065	17922	17749	16428	14861	13580
6/14/2012	12751	12283	12086	12187	12711	13799	15171	16158	16975	17721	18249	18550	18930	19289	19518	19589	19453	18657	17970	17842	17564	16195	14584	13265
6/15/2012	12405	11907	11674	11728	12076	13146	14615	15691	16558	17250	17766	18158	18617	18964	19293	19480	19382	18753	17813	17218	16888	15719	14275	13073
6/16/2012	12289	11684	11356	11215	11087	11408	12324	13480	14459	15229	15731	16115	16366	16687	17030	17320	17389	17095	16460	16087	16041	15058	13835	12755
6/17/2012	12023	11552	11264	11135	11096	11129	11697	12506	13304	13877	14242	14464	14573	14677	14968	15315	15478	15394	15078	15111	15233	14288	12989	11996
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6/26/2012	12638	12078	11784	11798	12129	13061	14343	15221	15923	16575	16892	17032	17290	17388	17489	17678	17808	17513	17064	16933	16823	15592	14236	12810
6/27/2012	12053	11618	11409	11524	11933	12919	14371	15481	16384	17247	17881	18322	18915	19553	20225	20616	20683	20384	19775	19332	19100	17662	15980	14546
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7/1/2012	16617	15657	14943	14573	14255	14229	15368	17221	19469	21601	23407	24795	25903	26681	27313	27695	27489	26923	26091	25203	24475	22588	20357	18442
7/2/2012	17052	16059	15389	15149	15428	16318	18099	19694	21229	22675	23817	24633	25239	25825	26274	26624	26697	26105	25014	23765	22779	20812	18584	16729
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7/4/2012	17594	16672	16071	15789	15797	15769	16156	17157	18779	20648	22388	23853	24968	25934	26676	27204	27383	26865	25953	25194	24576	23619	22056	20380
7/5/2012	19029	18136	17592	17447	17745	18743	20743	22755	24732	26492	27705	28535	29199	29667	30087	30180	30105	29624	28440	27371	26223	23973	21815	19539
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7/7/2012	18980	17994	17317	16923	16724	16922	18348	20492	22818	25110	26989	28408	29230	29399	29370	29611	29467	28528	26943	25679	25111	23655	21938	20270
7/8/2012	18945	17995	17226	16787	16423	16420	17214	18585	20288	21801	23160	23978	24673	25212	25699	26083	26230	25771	24990	24434	23968	22389	20483	18779
7/9/2012	17503	16658	16059	15939	16277	17098	18332	19416	20561	21531	22413	23215	24110	24751	25226	25665	25739	25170	24094	23261	22516	20681	18584	16886

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7/11/2012	15697	14926	14531	14527	15009	15996	17540	18984	20418	21928	22956	23809	24640	25280	25776	26043	25791	24875	23606	22787	22036	20271	18299	16671
7/12/2012	15548	14773	14373	14280	14708	15665	17231	18682	20060	21323	22576	23673	24870	25761	26439	26712	26495	25486	24035	23127	22412	20589	18711	16941
7/13/2012	15765	14977	14524	14461	14907	15778	17284	18722	20027	21423	22778	23900	24815	25411	25817	25933	25429	24508	23609	23179	22484	21003	19334	17800
7/14/2012	16639	15827	15258	14779	14728	14797	15519	16668	17861	18743	19422	19971	20167	20319	20384	20605	20809	20608	20190	19996	19894	18931	17741	16611
7/15/2012	15625	14948	14530	14365	14323	14438	15276	16594	18373	20373	21922	23424	24290	25151	25228	25262	25300	24981	24273	23999	22744	20701	18807	17310
7/16/2012	16276	15561	15195	15167	15704	16717	18596	20326	21965	23575	25060	26216	27231	27907	28412	28784	28938	28502	27510	26808	25777	23583	21338	19322
7/17/2012	17898	16856	16225	16037	16390	17321	19226	21033	22912	24911	26563	27894	28840	29559	30144	30559	30766	30494	29544	28928	28068	25938	23758	21814
7/18/2012	20466	19492	18865	18703	19087	20107	21957	23774	25858	28023	29817	31235	32259	32542	31740	30310	28681	27298	26300	25795	24968	22968	20916	19174
7/19/2012	17985	17167	16733	16636	17214	18209	19590	20789	21695	22374	22769	22863	22898	22682	22471	22309	22079	21419	20938	20992	20579	19280	17702	16357
7/20/2012	15468	14844	14529	14531	15092	15964	17018	17868	18539	19038	19273	19082	18861	18499	18094	17763	17540	17073	16744	16780	16415	15509	14370	13304
7/21/2012	12676	12174	11935	11849	11944	12126	12808	13865	14839	15573	16169	16595	16906	17165	17368	17715	17784	17531	17065	17149	17061	16208	15109	14025
7/22/2012	13261	12660	12354	12143	12069	12051	12748	13813	15023	16144	17188	18092	18765	19420	19999	20583	20983	20769	20091	19865	19578	18400	16943	15010
7/23/2012	14092	13432	13463	13916	14598	15642	17174	18792	20455	22220	23882	25363	26480	27025	27232	27374	27078	26133	25212	24796	23718	21670	19696	17932
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7/26/2012	15249	14506	14104	14071	14684	15676	17327	18905	20154	21098	22051	23172	24751	26305	27748	28959	29533	29084	27568	25296	23798	21702	19709	18035
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7/28/2012	18191	17200	16560	16192	16116	16179	17171	18923	20702	22290	23449	23885	23821	23692	23282	22825	22347	21822	21206	20963	20095	18647	17231	15929
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7/31/2012	15122	14450	14077	14098	14810	15753	17074	18256	19287	20248	20974	21659	22320	22919	23460	23873	24046	23646	22747	22376	21614	19812	18015	16457
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8/5/2012	17939	17163	16637	16342	16393	16390	17296	19028	21121	23035	24359	25363	26268	26943	27460	27767	27817	26520	24766	23713	22625	21116	19544	18061
8/6/2012	17079	16494	16205	16341	17027	17949	19438	20797	22230	23526	24552	25369	25968	26443	26795	27147	27036	26148	24909	24240	23007	20827	18726	16979
8/7/2012	15642	14784	14355	14269	14751	15555	16962	18290	19492	20832	21885	22708	23394	24016	24441	24682	24742	24289	23345	23202	22433	20716	18890	17297
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8/13/2012	14744	14047	13666	13685	14217	14978	16332	17863	19186	20470	21577	22529	23436	24088	24657	24952	25018	24363	23250	22877	21645	19751	17784	16200
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8/16/2012	14742	14101	13756	13705	14306	15133	16476	17801	19014	20224	21291	22128	23014	23786	24353	24656	24630	23708	22419	22047	20781	18953	17110	15577

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8/25/2012	15085	14344	13834	13624	13752	13988	14578	15761	17097	18343	19449	19971	20219	20186	19961	19726	19393	19075	18939	19142	18507	17403	16124	14944
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9/8/2012	15550	14818	14398	14250	14442	14877	15651	17060	18491	19769	20966	21938	22684	23296	23571	23319	21989	20633	19887	18985	17895	16659	15315	14089
9/9/2012	13189	12582	12203	11949	11929	11983	12313	13120	14183	15050	15738	16285	16772	17104	17378	17675	17805	17432	17524	17457	16471	15144	13802	12716
9/10/2012	12029	11615	11446	11587	12312	13569	14461	15104	15771	16278	16583	16851	17094	17283	17355	17456	17348	16838	16990	16919	15837	14319	12973	11954
9/11/2012	11339	11015	10852	10992	11728	13046	13990	14482	14987	15502	15860	16119	16375	16645	16927	17174	17229	16868	17086	17045	15997	14566	13174	12140
9/12/2012	11548	11202	11043	11161	11865	13253	14199	14805	15505	16201	16524	16962	17434	17895	18261	18651	18688	18115	18174	18034	16898	15281	13811	12715
9/13/2012	12013	11610	11443	11524	12249	13614	14544	15261	16012	16787	17349	17719	18269	18792	19286	19601	19541	18872	18935	18648	17457	15848	14321	13116
9/14/2012	12367	11872	11654	11779	12417	13822	14723	15509	16352	17173	17778	18252	18861	19298	19635	19705	19307	18525	18607	18316	17363	16117	14737	13560
9/15/2012	12741	12247	11924	11791	11820	12117	12464	13343	14063	14538	14755	14929	15021	15136	15259	15411	15422	15123	15455	15389	14742	13805	12789	11855
9/16/2012	11194	10806	10548	10475	10570	10730	11036	11798	12599	13164	13620	13966	14238	14438	14590	14751	14894	14862	15416	15382	14605	13454	12334	11509
9/17/2012	10987	10709	10631	10776	11533	12738	13563	14284	14995	15664	16073	16420	16782	17074	17273	17447	17371	17085	17633	17418	16472	15129	13912	12993
9/18/2012	12429	12130	12061	12299	13242	15025	16312	17136	17877	18419	18805	19055	19262	19275	19301	19434	19625	19545	19582	18915	17770	16237	14789	13685
9/19/2012	12929	12413	11910	11895	12537	14025	14801	15189	15528	15819	16067	16195	16399	16578	16724	16821	16759	16410	16775	16502	15487	14084	12719	11714
9/20/2012	11231	10877	10739	10893	11634	13104	13932	14426	14848	15311	15611	15845	16085	16163	16271	16421	16429	16258	16794	16530	15601	14263	12999	11986
9/21/2012	11448	11109	10998	11143	11840	13345	14269	14829	15434	15983	16322	16500	16787	16969	17170	17230	17071	16520	16802	16393	15544	14447	13252	12234
9/22/2012	11518	11100	10881	10823	11037	11495	12004	12976	13851	14540	15145	15638	15950	16328	16699	16972	17051	17031	17478	17137	16328	15270	14107	12977
9/23/2012	12184	11578	11150	10911	10847	10937	11147	11780	12401	12807	13038	13226	13352	13502	13671	13905	14143	14248	14957	14756	13960	12887	11834	10969

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9/25/2012	10806	10524	10446	10589	11407	12996	13868	14247	14582	14914	15135	15269	15509	15667	15762	15928	15939	15877	16564	16192	15244	13950	12728	11836
9/26/2012	11273	11032	10920	11092	11838	13305	14263	14933	15437	15921	16314	16657	17132	17349	17463	17620	17717	17689	18156	17811	16852	15435	13993	12878
9/27/2012	12225	11844	11716	11850	12675	14378	15487	16027	16586	16827	17123	17250	17481	17703	17838	17958	17802	17824	18284	17837	16861	15501	14034	12935
9/28/2012	12275	11896	11679	11832	12663	14330	15581	16267	16847	17303	17580	17763	18027	18177	18240	18152	17868	17633	17821	17261	16329	15101	13798	12624
9/29/2012	11846	11389	11075	10980	11119	11565	11946	12777	13400	13828	13937	13854	13715	13632	13490	13578	13735	14141	14748	14491	13949	13183	12263	11400
9/30/2012	10816	10382	10197	10139	10250	10536	10777	11454	12057	12522	12807	13088	13262	13284	13289	13477	13766	14188	14931	14691	13904	12938	11960	11068
10/1/2012	10566	10294	10215	10376	11197	12755	13687	14074	14355	14653	14898	15010	15202	15326	15501	15591	15698	16007	16576	16151	15206	13869	12637	11717
10/2/2012	11197	10915	10828	11011	11848	13519	14614	15118	15617	16018	16323	16443	16548	16503	16540	16691	16884	17123	17476	17096	16150	14842	13568	12469
10/3/2012	11971	11598	11469	11681	12538	14259	15442	16096	16613	17178	17424	17800	18114	18308	18429	18597	18636	18896	19284	18879	17654	16245	14810	13588
10/4/2012	12844	12401	12155	12342	13143	14931	15983	16643	17257	17777	18084	18261	18425	18480	18547	18638	18659	18633	18970	18407	17255	15729	14133	12914
10/5/2012	12114	11700	11469	11550	12171	13649	14541	15062	15681	16290	16779	17199	17745	18109	18400	18457	18193	17807	17857	17332	16427	15250	14023	12878
10/6/2012	12133	11633	11310	11215	11403	11856	12296	13148	14015	14707	15214	15500	15633	15542	15263	14993	14691	14828	15220	14792	14119	13248	12300	11425
10/7/2012	10835	10467	10226	10193	10332	10640	10959	11741	12500	12976	13316	13490	13442	13311	13321	13525	13900	14638	14900	14527	13861	12891	12021	11254
10/8/2012	10786	10550	10528	10749	11533	12974	13831	14325	14710	14919	15064	15123	15173	15065	15077	15283	15717	16305	16503	16028	15115	13865	12641	11708
10/9/2012	11272	10891	10821	11065	11865	13624	14754	15038	15169	15322	15398	15338	15363	15258	15267	15447	15782	16360	16594	16148	15204	13873	12572	11725
10/10/2012	11228	10904	10818	11013	11838	13547	14658	14885	15131	15318	15305	15198	15191	15115	15053	15121	15274	15781	16338	15953	15079	13791	12523	11561
10/11/2012	11050	10787	10693	10957	11840	13581	14476	14596	14657	14664	14623	14530	14560	14496	14548	14702	14999	15632	16294	15911	15095	13902	12797	11857
10/12/2012	11337	11074	11004	11251	12105	13771	14742	14862	14874	15064	15111	14864	14802	14576	14480	14585	14835	15346	15772	15449	14845	13995	12993	12174
10/13/2012	11635	11374	11297	11385	11742	12452	12983	13577	13741	13696	13462	13101	12868	12717	12690	12859	13271	14202	14764	14611	14158	13419	12559	11781
10/14/2012	11254	10872	10691	10636	10842	11219	11529	12101	12577	12813	12846	12748	12736	12734	12820	13101	13548	14501	15043	14706	13946	12999	11957	11218
10/15/2012	10750	10505	10459	10668	11560	13225	14365	14765	15142	15550	15716	15808	15788	15725	15853	16005	16257	16689	16677	16115	15170	14010	12587	11589
10/16/2012	10999	10692	10575	10677	11487	13262	14286	14449	14515	14541	14531	14509	14470	14487	14484	14652	15006	15793	16235	15829	14968	13782	12665	11721
10/17/2012	11239	10993	10978	11202	12185	13987	14956	14988	14897	14841	14782	14754	14767	14773	14764	14857	15128	15934	16331	15930	15054	13806	12608	11726
10/18/2012	11231	11024	10960	11164	12108	13838	14811	14880	14853	14969	15003	14950	14973	14988	14994	15175	15517	16333	16516	16084	15174	13945	12721	11793
10/19/2012	11280	11006	10921	11057	11814	13497	14873	15435	15842	16198	16257	16184	16169	16024	15943	15913	15890	16361	16378	15888	15154	14138	12986	11990
10/20/2012	11330	10853	10638	10540	10749	11293	11803	12433	12972	13286	13314	13271	13130	12974	12975	13071	13327	14122	14367	14055	13557	12798	11949	11133
10/21/2012	10588	10275	10099	10079	10255	10729	11045	11631	12089	12276	12340	12367	12387	12425	12531	12835	13279	14350	14728	14461	13678	12727	11702	10936
10/22/2012	10513	10331	10293	10580	11525	13296	14409	14583	14618	14736	14704	14687	14715	14708	14720	14929	15242	16131	16316	15832	14842	13599	12420	11454
10/23/2012	10928	10654	10599	10777	11628	13441	14574	14612	14801	15062	15106	15071	15118	15114	15032	15125	15588	16413	16404	15870	14892	13647	12409	11470
10/24/2012	10934	10700	10561	10762	11591	13316	14515	14730	14922	15044	15202	15077	15201	15290	15338	15489	15709	16511	16500	15978	15125	13766	12508	11556
10/25/2012	11019	10725	10616	10770	11592	13321	14568	14792	15058	15284	15393	15364	15343	15296	15229	15313	15705	16393	16280	15855	15005	13755	12556	11561
10/26/2012	11035	10746	10626	10779	11588	13268	14515	14863	15079	15271	15329	15244	15229	15168	15153	15242	15573	16132	15834	15413	14733	13722	12675	11656
10/27/2012	10974	10618	10400	10355	10588	11169	11876	12584	13190	13500	13582	13518	13359	13207	13152	13269	13694	14696	14714	14386	13847	13084	12201	11382
10/28/2012	10759	10366	10138	10098	10252	10630	11266	11996	12732	13192	13468	13615	13658	13646	13753	13986	14494	15201	14977	14569	13829	13003	12014	11172
10/29/2012	10551	10213	10052	10181	10657	11429	12300	13132	13891	14235	14238	14057	13822	13448	13110	12958	12799	12331	10508	9121	7293	6766	6253	5671
10/30/2012	5507	5383	5371	5413	5616	5994	6337	6709	7225	7662	7937	8120	8188	8252	8436	8726	9214	9731	9776	9651	9270	8694	8104	7599
10/31/2012	7364	7248	7231	7427	7915	8848	9592	9795	10005	10104	10117	10170	10195	10189	10257	10482	10830	11297	11320	11226	10849	10129	9397	8810

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11/3/2012	9852	9603	9522	9558	9856	10417	11019	11530	11987	12156	12150	12085	11954	11947	11982	12210	12662	13530	13577	13369	12951	12328	11614	10831
11/4/2012	10524	9997	9990	10017	10219	10282	10779	11240	11453	11792	11854	11757	11938	11987	12136	12520	13161	14384	14551	14455	13799	12932	12197	11608
11/5/2012	10997	10701	10550	10612	10918	11802	13346	14062	14462	14582	14645	14509	14302	14090	14068	14225	14919	16308	16488	16305	15910	15132	14111	13077
11/6/2012	12391	12049	11898	11961	12313	13230	14569	15206	15280	15300	15300	15137	14915	14790	14661	14829	15526	16832	17053	16826	16451	15645	14487	13621
11/7/2012	12665	12194	11950	11893	12179	13487	14733	15579	15927	16132	16385	16425	16450	16391	16684	16849	17588	18449	18279	17866	17028	15918	14976	13843
11/8/2012	13011	12497	12248	12201	12465	13269	14607	15358	15671	15718	15675	15558	15351	15157	14945	15061	15697	17102	17206	17024	16671	15882	14761	13619
11/9/2012	12839	12476	12268	12285	12572	13512	14916	15593	15559	15448	15263	15038	14822	14730	14669	14778	15311	16533	16508	16149	15779	15184	14320	13418
11/10/2012	12542	12100	11860	11786	11909	12345	12900	13363	13772	13997	14075	13922	13647	13536	13508	13566	14096	15267	15267	15012	14700	14217	13549	12780
11/11/2012	12036	11510	11271	11164	11184	11462	11787	12123	12547	12750	12750	12674	12647	12612	12669	12806	13567	14888	14987	14777	14414	13595	12867	11929
11/12/2012	11212	10863	10720	10767	11053	11959	13465	14328	14540	14656	14691	14703	14735	14779	14684	14749	15434	16739	16591	16242	15699	14758	13557	12359
11/13/2012	11617	10993	10715	10608	10752	11582	13295	14545	14974	15194	15484	15507	15446	15341	15277	15351	16141	17457	17519	17218	16800	15925	14826	13749
11/14/2012	12807	12377	12216	12258	12604	13638	15411	16114	15913	15664	15471	15346	15165	15095	15121	15352	16228	17682	17788	17601	17224	16253	15144	13981
11/15/2012	13192	12700	12491	12519	12788	13797	15506	16164	16143	15996	15856	15614	15561	15500	15433	15641	16584	17896	17913	17670	17257	16384	15146	14008
11/16/2012	13141	12617	12329	12342	12664	13624	15301	16149	16260	16225	16142	16041	15728	15500	15286	15372	16038	17437	17451	17164	16769	16194	15256	14317
11/17/2012	13442	12953	12699	12593	12731	13135	13741	14215	14577	14661	14498	14243	13881	13579	13404	13560	14469	15865	15977	15767	15508	15040	14344	13548
11/18/2012	12764	12338	12085	11973	11996	12199	12626	13025	13534	13742	13715	13675	13654	13636	13641	13835	14731	16186	16234	16057	15667	14951	13982	12996
11/19/2012	12298	11950	11749	11817	12200	13268	15045	16068	16214	16099	16007	15807	15606	15582	15553	15673	16523	17771	17799	17475	16886	15992	14775	13527
11/20/2012	12655	12186	11970	11787	12652	13277	14962	15766	15851	15718	15499	15281	15214	15280	15302	15511	16385	17582	17547	17272	16845	16044	14825	13589
11/21/2012	12718	12267	12099	12074	12363	13384	14955	15856	15874	15693	15497	15321	15092	15063	15029	15087	15709	17081	17037	16678	16362	15814	14918	13869
11/22/2012	13005	12488	12191	12070	12205	12599	13103	13470	13829	14023	14084	14047	13903	13552	13221	12977	13144	13857	13785	13741	13757	13654	13284	12705
11/23/2012	12144	11829	11686	11738	11989	12634	13425	13827	14126	14194	13973	13810	13590	13463	13450	13760	14654	15927	15778	15417	15041	14473	13653	12732
11/24/2012	11923	11478	11328	11316	11459	11886	12556	13084	13717	14157	14543	14765	14815	14813	14780	14904	15732	16886	16940	16680	16408	15879	15113	14157
11/25/2012	13335	12782	12488	12383	12448	12714	13087	13466	13913	14281	14574	14648	14665	14731	14679	14866	15882	17500	17662	17512	17192	16400	15385	14291
11/26/2012	13541	13172	13023	13070	13399	14382	16088	16967	16854	16483	16172	15856	15650	15493	15461	15631	16631	18334	18438	18286	17937	17075	15805	14507
11/27/2012	13479	12961	12662	12572	12841	13787	15581	16712	17015	17152	17506	17547	17575	17576	17533	17673	18495	19406	19239	18823	18304	17307	15960	14626
11/28/2012	13614	13142	12902	12892	13199	14225	16160	16945	16946	16824	16408	16286	16079	16181	16179	16409	17511	19136	19165	19011	18643	17783	16436	15195
11/29/2012	14256	13778	13592	13609	13925	15069	16863	17509	17364	17203	16792	16314	16145	16035	15968	16228	17361	19004	18975	18731	18400	17508	16238	14928
11/30/2012	14025	13554	13372	13426	13788	14799	16585	17375	17297	17049	16743	16315	16060	16116	16047	16103	16952	18188	18019	17630	17259	16638	15639	14452

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Peak	56,158
PST	46,144
Winter	34,193
Spring	30,414
Summer	42,263
Fall	31,762

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12/2/2011	25573	24870	24650	24841	25723	28057	31699	33049	32495	31474	30622	29981	29397	29009	28765	28894	30427	33076	32966	32271	31546	30366	28645	26628
12/3/2011	25056	24169	23866	23885	24341	25313	26895	28039	28985	28905	28509	27825	27228	26650	26369	26558	28424	31285	31510	31153	30779	29854	28421	26653
12/4/2011	25084	24206	23799	23692	23890	24461	25560	26309	27122	27056	26686	26312	25988	25652	25496	25765	27498	30824	31195	30947	30574	29196	27143	24961
12/5/2011	23431	22574	22282	22321	23090	25193	28724	30357	30543	30347	30085	29865	29500	29326	29134	29298	30988	33600	33531	32874	31976	30129	27509	24774
12/6/2011	22841	21891	21367	21252	21789	23654	27031	28986	29330	29554	29786	29921	29878	29847	29854	30275	32032	33619	33261	32570	31559	29829	27223	24533
12/7/2011	22735	21717	21158	21014	21575	23410	26895	29107	29628	29883	30107	30195	30122	30153	30238	30550	32311	33902	33718	33297	32603	31227	28945	26666
12/8/2011	25259	24150	23977	24119	24990	27186	30927	32533	32566	32175	31636	31089	30556	30254	30126	30429	32305	35412	35774	35423	34888	33424	31225	28671
12/9/2011	26924	26163	25873	25910	26738	28910	32487	34114	33614	32566	31686	30927	30192	29796	29539	29642	31441	34191	34005	33462	32663	31476	29652	27461
12/10/2011	25712	24698	24171	23962	24061	24837	26154	27379	28684	29006	28941	28817	28343	27723	27470	27765	29780	32898	33203	32975	32660	31920	30579	28711
12/11/2011	27229	26312	25949	25867	26186	26912	28120	29024	29866	29959	29457	28937	28466	28055	27910	28269	30381	34094	34771	34855	34591	33366	31291	29129
12/12/2011	27621	26962	26809	27133	28143	30578	34421	36080	35738	34982	34105	33048	32206	31698	31370	31754	33810	37195	37462	37141	36440	34948	32236	29597
12/13/2011	27973	27299	27129	27349	28272	30595	34384	35848	35134	33975	32879	31962	31331	30972	30697	30982	32815	36205	36562	36177	35542	34032	31469	28716
12/14/2011	26869	25940	25514	25557	26350	28462	32047	33520	33214	32347	31672	31164	30696	30522	30503	30834	32819	35412	35238	34574	33719	32103	29487	26688
12/15/2011	24741	23757	23300	23300	23863	25914	29437	31300	31258	30997	30534	30209	29972	29963	29922	30219	31936	34238	33995	33309	32400	30825	28238	25502
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12/17/2011	25547	24533	24034	23882	24163	25105	26542	27877	29182	29918	29999	29855	29795	29625	29507	29745	31416	33764	33839	33491	32982	32201	30781	28921
12/18/2011	27306	26271	25717	25548	25687	26389	27549	28726	29858	30320	30109	29791	29539	29275	29147	29497	31518	35013	35750	35780	35548	34376	32266	29925
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12/27/2011	25919	24949	24398	24372	24922	26368	28581	30166	31051	31805	32267	32467	32432	32375	32280	32409	33526	34789	34172	33147	32070	30446	28307	26139

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12/30/2011	26877	25822	25373	25371	25996	27555	29768	31035	31602	31642	31173	30458	29526	28890	28499	28497	29857	32912	32878	32170	31358	30188	28467	26389
12/31/2011	24516	23257	22535	22113	22122	22675	23635	24623	25654	26442	26687	26613	26432	26157	25980	26273	27735	30627	30720	29841	28693	27560	26328	25252
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1/5/2012	29623	28718	28401	28335	28946	30893	34269	36207	36024	35495	34832	34013	33417	33046	32771	32760	34148	37048	37336	37006	36276	34748	32367	29956
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1/7/2012	25174	24180	23767	23706	24000	24828	26178	27456	28357	28473	28138	27623	26958	26339	25976	25892	26778	29332	29669	29162	28630	27759	26533	25029
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1/10/2012	26544	25733	25451	25591	26479	28771	32555	34328	33899	32961	32131	31430	30855	30527	30338	30497	31773	34460	34808	34459	33739	32347	30144	28093
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1/25/2012	25504	24766	24505	24685	25527	27751	31394	33251	33011	32470	31812	31164	30459	30058	29793	29855	30924	33766	34623	34264	33534	31924	29629	27329
1/26/2012	25770	24914	24554	24586	25305	27368	30877	32766	32688	32672	32713	32508	32275	32131	31989	32220	33207	35022	34960	34244	33237	31493	29080	26703
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3/4/2012	23280	22479	22066	21928	22126	22745	23696	24662	26110	26915	27042	26905	26709	26497	26464	26690	27295	28616	31207	31662	31151	30055	28321	26548

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7/8/2012	36440	34230	32614	31366	30585	30087	29981	31537	34197	37210	39879	42203	43725	44980	45871	46562	46824	46677	45652	44258	43344	42615	39791	36577
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7/18/2012	38313	35979	34294	33310	33153	34127	36147	39423	42605	46010	49543	52492	54530	55955	56158	54274	51527	48990	47362	45972	45135	43850	40429	36979

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7/22/2012	25118	23804	22849	22329	22044	22053	22039	23288	25220	27223	29116	30758	32079	33102	34056	35023	36110	36871	36656	35652	35357	35002	32899	30353
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8/5/2012	33760	31873	30478	29581	29130	29175	29175	30854	33802	37285	40478	42888	44642	46127	47220	47916	47779	46648	44474	42160	41102	39544	36994	34373
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10/3/2012	22839	21892	21340	21119	21611	23436	26893	28972	29935	30702	31519	32077	32720	33300	33453	33586	33835	33827	34184	34961	34133	31948	29395	26852
10/4/2012	24686	23393	22652	22264	22690	24468	27990	29952	30891	31793	32567	33169	33479	33723	33685	33681	33883	33739	33468	34134	33032	30982	28159	25303
10/5/2012	23212	21868	21123	20798	21036	22513	25497	27075	27948	28956	29987	30821	31573	32365	32876	33239	33275	32662	31967	32073	30943	29375	27202	24946
10/6/2012	23026	21719	20876	20305	20243	20657	21603	22423	24102	25674	26832	27580	28043	28007	27524	26968	26590	26222	26321	27196	26497	25344	23799	22147
10/7/2012	20613	19619	18989	18629	18575	18880	19565	20342	21760	23162	24028	24563	24776	24677	24454	24464	24899	25600	26783	27235	26592	25356	23698	22179
10/8/2012	20879	20082	19696	19737	20259	21818	24681	26302	27159	27844	28215	28379	28351	28294	28037	27987	28384	29007	30104	30652	29719	28051	25773	23606
10/9/2012	21990	21067	20589	20520	21023	22725	26145	28016	28293	28403	28672	28638	28533	28438	28230	28106	28377	28942	29877	30472	29566	27881	25445	23227
10/10/2012	21705	20798	20292	20160	20625	22399	25712	27612	27881	28108	28378	28376	28239	28146	27930	27851	27987	28269	29188	30051	29195	27543	25219	23064
10/11/2012	21390	20546	20140	20084	20644	22585	26017	27617	27744	27736	27698	27509	27387	27307	27103	27085	27242	27664	28661	29942	29259	27766	25625	23720
10/12/2012	22077	21209	20825	20762	21289	23152	26518	28103	28226	28162	28348	28273	27912	27681	27206	26995	27069	27363	28155	28978	28371	27326	25791	24010
10/13/2012	22624	21773	21390	21284	21527	22308	23718	24874	25950	26176	25948	25427	24853	24239	23832	23688	23946	24475	26021	27047	26733	25934	24582	23038
10/14/2012	21706	20750	20145	19828	19777	20128	20944	21634	22750	23650	24103	24172	24040	23854	23761	23833	24215	24953	26494	27597	27030	25611	23815	22025
10/15/2012	20666	19902	19495	19448	19987	21763	25129	27082	27768	28345	29002	29253	29416	29404	29187	29226	29317	29600	30407	30507	29436	27701	25406	23015
10/16/2012	21287	20353	19827	19643	20070	21848	25338	27105	27373	27398	27470	27534	27440	27340	27226	27173	27374	27816	29093	30000	29270	27620	25436	23512
10/17/2012	21847	21031	20691	20685	21265	23338	26891	28572	28555	28315	28213	27852	27785	27723	27594	27525	27652	27972	29255	30014	29215	27648	25362	23247
10/18/2012	21658	20865	20493	20397	20904	22836	26268	27943	28006	28001	28173	28132	28068	28030	27941	27858	28031	28502	29796	30143	29290	27690	25473	23300
10/19/2012	21685	20773	20275	20101	20488	22091	25261	27677	28554	29226	29765	29884	29775	29676	29462	29265	29163	29079	29694	29668	28681	27298	25383	23340
10/20/2012	21598	20441	19716	19342	19253	19725	20787	21854	23149	24247	24771	24816	24641	24356	24036	23899	24039	24376	25706	26238	25692	24803	23474	21938
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10/22/2012	20490	19760	19474	19521	20171	22206	25753	27719	27896	27817	27926	27783	27690	27682	27507	27566	27735	28193	29588	30019	29054	27278	24989	22932
10/23/2012	21295	20358	19933	19868	20348	22179	25683	27668	27711	28004	28329	28433	28387	28519	28382	28295	28473	29050	30264	30375	29279	27615	25195	22889
10/24/2012	21272	20370	19896	19721	20215	21989	25363	27441	27654	27974	28213	28490	28497	28719	28875	28905	29079	29302	30499	30609	29593	27942	25480	23221
10/25/2012	21549	20579	19985	19827	20234	22011	25389	27587	27876	28246	28642	28740	28638	28594	28458	28362	28518	29008	30097	30069	29214	27614	25317	23137
10/26/2012	21582	20504	19967	19804	20162	21914	25214	27462	27956	28293	28593	28641	28457	28373	28196	28038	28124	28498	29434	28970	28071	26850	25011	23064
10/27/2012	21324	20128	19531	19148	19116	19587	20663	22061	23392	24503	25085	25210	25103	24803	24534	24372	24583	25168	26779	26872	26248	25249	23853	22234
10/28/2012	20766	19686	19045	18662	18609	18904	19676	20922	22258	23642	24496	24940	25252	25308	25316	25490	25905	27089	28148	27850	27109	25792	24205	22460

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Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
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10/30/2012	13817	13426	13112	13080	13321	13959	14978	15890	16796	17873	18861	19433	19803	19948	20049	20293	20821	21684	22710	22662	22206	21245	19856	18520
10/31/2012	17472	16980	16724	16742	17264	18623	21007	22651	22948	23106	23263	23258	23222	23127	22982	23078	23513	24200	24949	24779	24483	23662	22081	20534
11/1/2012	19363	18713	18465	18471	18960	20490	23125	24685	24741	24799	25045	24755	24769	24658	24618	24756	25116	25846	27078	27143	26501	25365	23494	21711
11/2/2012	20353	19608	19216	19155	19766	21397	24208	25929	26027	26166	25989	25597	25360	25336	25208	25211	25564	26372	27569	27406	26711	25839	24392	22777
11/3/2012	21402	20504	20062	19924	20076	20705	21891	23150	24223	25087	25344	25282	25097	24802	24629	24561	24893	25694	27189	27150	26761	25882	24666	23262
11/4/2012	42854	20385	20414	20478	20809	21493	22346	23314	23945	24458	24453	24285	24334	24204	24264	24819	26035	28249	28433	28284	27587	26181	24583	23009
11/5/2012	22055	21451	21282	21444	22257	24275	27433	28831	29389	29380	29304	28953	28506	28090	27892	28083	29263	31842	32182	31826	31069	29571	27629	25792
11/6/2012	24599	24079	23830	24115	24958	27038	29932	30870	30614	30184	29928	29474	29027	28624	28374	28601	29821	32426	32767	32413	31664	30145	27984	26264
11/7/2012	24753	23943	23562	23529	24234	26742	29550	30964	31276	31435	31631	31490	31405	31326	31538	31865	33047	34809	34559	33892	32501	30430	28572	26509
11/8/2012	25013	24215	23831	23820	24469	26366	29387	30622	30865	30788	30493	30060	29561	29049	28617	28751	29914	32508	32821	32449	31737	30217	28097	26033
11/9/2012	24716	24029	23661	23759	24496	26541	29516	30643	30297	29855	29415	28885	28339	28023	27779	27832	28649	30889	30868	30246	29589	28455	26908	25223
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11/11/2012	22480	21635	21237	21104	21237	21834	22630	23362	24156	24404	24308	24089	23930	23757	23701	23897	25131	27567	27791	27429	26784	25312	23891	22291
11/12/2012	21061	20365	20203	20350	21063	22923	25900	27385	27739	27845	27965	27980	27874	27862	27622	27654	28663	30984	30787	30153	29148	27408	25204	23113
11/13/2012	21634	20632	20177	20139	20648	22579	26119	28291	28894	29188	29526	29441	29139	28923	28643	28810	30166	32716	32919	32435	31688	30186	28090	26130
11/14/2012	24571	23888	23630	23780	24599	26826	30353	31489	30963	30290	29848	29366	28886	28730	28612	28958	30463	33198	33421	33108	32464	30903	28838	26836
11/15/2012	25441	24625	24288	24349	25010	27114	30517	31553	31472	30975	30667	30084	29757	29549	29342	29611	31104	33551	33619	33205	32467	30916	28648	26600
11/16/2012	25137	24263	23839	23924	24638	26677	30072	31451	31441	31161	30799	30274	29564	29044	28638	28686	29866	32369	32349	31860	31134	30120	28465	26781
11/17/2012	25345	24541	24177	24048	24401	25314	26602	27568	28186	28116	27718	27128	26395	25753	25359	25462	26853	29413	29640	29327	28926	28096	26860	25454
11/18/2012	24151	23450	23055	22963	23082	23670	24672	25481	26439	26676	26479	26220	26006	25790	25669	25957	27546	30224	30447	30132	29497	28194	26524	24811
11/19/2012	23560	22922	22608	22745	23649	25797	29310	30969	31051	30722	30384	29905	29500	29196	28967	29114	30516	32910	32976	32499	31512	29940	27727	25593
11/20/2012	24117	23326	22966	22834	24109	25839	29218	30660	30627	30182	29642	29131	28834	28812	28776	29030	30478	32664	32543	32078	31292	29903	27742	25662
11/21/2012	24226	23456	23223	23294	24061	26173	29328	30919	30873	30319	29731	29294	28767	28450	28188	28127	29205	31644	31764	31064	30539	29442	27808	25943
11/22/2012	24442	23617	23178	23132	23494	24368	25489	26221	26953	27112	27144	26978	26320	25377	24540	23957	24135	25441	25386	25337	25419	25268	24613	23671
11/23/2012	22806	22319	22198	22419	23087	24457	26051	26847	27276	27093	26557	26078	25582	25256	25146	25545	27051	29148	28828	28168	27467	26458	25087	23565
11/24/2012	22341	21694	21490	21557	21920	22762	24049	25185	26588	27515	28161	28390	28402	28137	27978	28229	29624	31714	31753	31341	30863	29908	28433	26748
11/25/2012	25295	24394	23930	23798	23946	24494	25283	26067	27068	27818	28363	28512	28504	28345	28012	28091	29768	32675	33035	32747	32380	30989	29114	27258
11/26/2012	26004	25343	25134	25283	25998	27955	31086	32589	32328	31457	30708	30042	29548	29103	28866	29116	30829	33955	34279	34023	33336	31830	29426	27123
11/27/2012	25413	24492	24037	23927	24589	26700	30136	32098	32511	32678	33195	33218	33238	33175	32996	33169	34574	36467	36154	35485	34431	32719	30220	27853
11/28/2012	26202	25362	24929	25003	25740	28000	31665	33117	32829	32326	31643	31195	30783	30659	30506	30826	32635	35675	35853	35576	34926	33469	31103	28850
11/29/2012	27286	26504	26270	26397	27255	29574	33148	34313	33811	33193	32335	31483	30758	30345	30100	30419	32255	35275	35467	35127	34492	33021	30679	28389
11/30/2012	26868	26172	25903	26125	26966	29171	32842	34178	33777	32965	32108	31310	30673	30391	30065	30157	31688	33911	33791	33103	32383	31237	29395	27276

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Max	75,068
PST	62,751
Winter	46,542
Spring	41,447
Summer	57,545
Fall	43,419

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12/2/2011	35826	35076	34921	35294	36705	40023	45044	46694	45434	43459	41789	40541	39515	38850	38392	38565	40409	44270	44336	43528	42700	41289	39116	36509
12/3/2011	34524	33394	33070	33202	33899	35377	37574	39284	40385	39928	39104	37965	36962	36039	35611	35798	38266	42316	42720	42359	41844	40634	38796	36471
12/4/2011	34543	33517	33110	33140	33569	34514	36142	37297	38358	37839	36916	36076	35420	34865	34465	34850	37054	41649	42282	41954	41441	39593	36807	33942
12/5/2011	31966	30972	30641	30833	31940	34898	39630	41703	41507	41120	40638	40228	39647	39333	38991	39126	41236	44869	44879	44064	42858	40242	36714	33053
12/6/2011	30499	29268	28615	28463	29158	31790	36456	38933	39167	39404	39650	39755	39639	39615	39607	40048	42208	44585	44273	43393	42035	39689	36227	32642
12/7/2011	30171	28878	28213	28069	28852	31408	36186	39050	39472	39695	39914	40096	40028	40076	40148	40539	42727	45194	45084	44270	43361	41504	38544	35553
12/8/2011	33735	32500	32327	32714	34155	37357	42750	44917	44596	43793	42941	42010	41192	40684	40390	40762	43276	47744	48457	48151	47530	45678	42775	39466
12/9/2011	37353	36480	36245	36477	37721	40789	45659	47767	46651	44750	43352	42111	40989	40306	39833	39934	42234	45999	45817	45048	44151	42654	40255	37400
12/10/2011	35196	33882	33220	32998	33238	34387	36239	38099	39848	40118	39759	39381	38645	37661	37253	37579	40244	44526	45131	44946	44631	43705	41932	39575
12/11/2011	37772	36716	36373	36431	36934	38034	39869	41325	42338	42064	40988	39957	39122	38466	38110	38586	41428	46591	47723	47990	47700	46073	43352	40523
12/12/2011	38662	37867	37711	38187	39596	43022	48183	50225	49493	48092	46538	44936	43714	42972	42456	42930	45587	50232	50579	50261	49397	47375	43941	40550
12/13/2011	38530	37779	37581	38108	39484	42799	47953	49868	48543	46546	44656	43142	42116	41493	41039	41273	43676	48478	49148	48838	48153	46154	42733	39138
12/14/2011	36693	35527	35102	35250	36387	39384	44241	46143	45365	43937	42938	42113	41463	41094	41005	41307	43943	47606	47469	46636	45509	43355	39911	36258
12/15/2011	33810	32538	32052	32067	32911	35810	40701	42996	42566	41871	41013	40299	39806	39666	39566	39869	41956	45297	45123	44264	43117	40993	37523	33977
12/16/2011	31336	29820	29155	29199	30108	32924	37874	40358	40408	40272	40224	40240	39978	39969	40167	40812	43434	46592	46212	45109	44026	42420	40030	37076
12/17/2011	34769	33500	32873	32799	33254	34646	36747	38717	40594	41511	41591	41250	40976	40530	40257	40527	42762	46124	46351	45898	45421	44513	42801	40439
12/18/2011	38387	37030	36238	35990	36211	37205	38895	40576	42107	42335	41626	40761	40424	40012	39749	40122	42749	47511	48643	48794	48623	47171	44479	41576
12/19/2011	39456	38622	38534	39042	40397	43576	48412	50411	49338	47381	45852	44311	42952	42131	41736	42221	44721	48540	48768	47950	46787	44406	40854	37067
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12/22/2011	31402	29911	29072	28939	29774	32248	36662	39146	39592	39510	39239	38779	38255	37917	37763	37883	39831	43666	43674	42970	41956	40241	37557	34088
12/23/2011	31434	29904	29038	28775	29325	31204	34582	37036	38007	38537	38782	38833	38459	37946	37732	37904	39999	43958	43928	43180	42357	41094	39050	36327
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12/25/2011	37378	36083	35378	35191	35440	36367	37875	39331	40133	39487	38214	36953	35984	34992	34309	34065	35252	38318	38761	38805	38885	38493	37231	35213
12/26/2011	33369	32190	31581	31622	32244	33558	35165	36146	37022	37738	38214	38111	37524	36782	36190	36286	38379	43294	44233	44301	44007	42699	40437	37744

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12/28/2011	33348	31942	31459	31635	32703	34968	38365	40504	41148	41452	41891	41944	41640	41380	41294	41679	44038	48737	49097	48436	47665	45834	43237	40331
12/29/2011	38298	37300	37007	37366	38640	41145	44712	46680	47077	46595	45923	45063	44241	43727	43214	43223	45312	49029	48971	48100	46989	45155	42304	39286
12/30/2011	36998	35766	35285	35366	36343	38522	41579	43266	43792	43486	42636	41400	39823	38804	38122	37976	39739	43922	44003	43169	42106	40519	38262	35551
12/31/2011	33063	31454	30467	29970	30047	30818	32165	33534	34912	35933	36151	35985	35698	35233	34959	35287	37113	40985	41266	40122	38743	37293	35815	34477
1/1/2012	33107	32100	31270	31083	31317	32116	33435	34290	34976	34776	34395	34168	34033	33754	33706	34025	36271	39465	39584	38971	38268	36823	35057	32945
1/2/2012	31179	30199	29878	30376	31495	33574	36073	37536	38569	39562	40434	40625	40585	40446	40463	41029	43357	47717	48260	47985	47115	45230	42269	39519
1/3/2012	37733	36955	36821	37392	38843	42248	47467	49899	49352	48621	48662	48542	48446	48508	48564	49241	51833	56410	57023	56564	55693	53421	50383	47480
1/4/2012	45804	45205	45360	45818	47190	50393	55191	57057	55774	54309	53061	51788	50443	49627	49198	49674	51696	55408	55483	54387	52962	50319	46486	43074
1/5/2012	40753	39668	39303	39312	40219	42961	47731	50179	49494	48184	46849	45553	44592	43944	43541	43484	45278	49419	50166	49917	49114	47046	43906	40836
1/6/2012	38749	37813	37373	37484	38500	41297	46008	47926	46852	45171	43712	42310	41097	40309	39672	39355	40265	43785	44066	43148	42205	40576	38394	35876
1/7/2012	33902	32679	32248	32307	32823	34116	36022	37841	39071	39148	38417	37605	36554	35641	35055	34898	35911	39362	39950	39231	38544	37339	35743	33749
1/8/2012	31961	30934	30435	30410	30809	31782	33413	34879	36452	37179	37088	36724	36551	36245	35978	36281	38113	42318	43538	43370	43144	41696	39242	36893
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1/18/2012	32400	31294	31011	31338	32629	35864	41306	43952	43597	43306	43135	42831	42474	42187	42059	42507	44455	48933	50412	50245	49333	47325	44490	41719
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1/21/2012	39690	38693	38210	38056	38374	39289	40810	42562	44407	46289	47328	47580	47307	46557	45936	45725	46620	49395	49795	48872	47829	46344	44204	41989
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1/23/2012	38633	37445	37127	37216	38264	41090	45620	48174	48153	48229	48076	47681	47144	46748	46351	46333	47269	49588	49328	48098	46287	43585	39966	36806
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1/28/2012	33803	32834	32492	32651	33316	34724	36929	38753	40234	40076	39204	38272	37363	36358	35605	35458	36463	39568	41127	40793	40220	39300	37711	35894

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2/1/2012	31805	30836	30287	30235	31218	33953	38855	41014	40574	39956	39537	38928	38169	37804	37435	37262	37752	40575	42169	41546	40487	38419	35372	32562
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3/1/2012	32220	30980	30386	30179	31130	33841	38371	40229	40131	39994	40027	39677	39237	38861	38488	38335	38634	39796	42254	42381	41392	39327	36489	33797

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3/5/2012	35301	34701	34758	35325	36905	40201	44846	46316	45809	45219	44790	44147	43695	43012	42257	42273	42979	44865	48166	48630	47792	45859	42659	39992
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3/10/2012	34049	33264	33024	33147	33771	35279	36948	38407	39552	39856	39535	38715	37551	36370	35313	34854	35237	36540	40029	41067	40810	39934	38324	36463
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3/25/2012	28203	26803	25996	25578	25519	25924	27074	28352	30440	32463	33463	33880	33903	33542	33101	32789	32743	33196	33769	35979	36929	35258	32681	30089
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4/18/2012	29214	27793	26972	26692	27207	29389	33387	35683	36408	36932	36904	37319	37211	37187	36906	36799	36962	37256	37373	38304	39002	37061	33971	30783
4/19/2012	28677	27476	26867	26709	27483	30025	34200	36357	36890	37059	37276	37406	37385	37606	37580	37603	37672	37745	37255	37558	39279	37475	34196	30865
4/20/2012	28667	27195	26585	26393	27030	29393	33265	35540	36335	37073	37605	37879	37950	38195	38120	38150	38187	37964	36977	36759	38053	36505	33953	31082
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4/26/2012	29098	27974	27515	27442	28164	30740	34935	37553	38213	38526	38838	38795	38568	38535	38209	37903	38004	38047	37825	38224	39395	37730	34602	31535
4/27/2012	29234	27987	27384	27186	27953	30380	34147	36457	37164	37386	37613	37363	37037	36744	36335	35944	35842	35754	35374	35625	37322	36498	34363	31968
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5/6/2012	29516	27965	26984	26337	26069	26324	26662	27914	29942	31782	32929	33651	33981	34070	34072	34275	34778	35299	35492	35873	37442	36452	33609	30544

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7/24/2012	42777	40172	38509	37622	37785	39702	42365	46721	51202	55763	59891	62963	65234	66988	67574	67615	67363	66180	64044	61449	59540	57344	52642	47392
7/25/2012	42987	39775	37447	35926	35557	36720	38826	42211	45260	47771	50109	52071	53641	55551	57217	58899	60371	60864	59580	56835	54738	52552	48066	43360
7/26/2012	39504	36873	35447	34716	34975	36825	39664	43444	46842	49753	52516	55842	59136	62840	66220	69128	70956	71485	69920	66793	63645	60472	55025	49808
7/27/2012	45672	42716	40743	39552	39549	41014	43382	46807	50612	54458	58142	61405	63666	65159	66102	66929	67391	67082	64789	61733	59741	57705	53475	48827
7/28/2012	45214	42083	39978	38559	37810	37835	38050	40641	44897	49163	53099	56185	57803	58648	59203	59405	59326	58596	56915	54798	53369	51139	47408	43633
7/29/2012	40289	37565	35650	34434	33708	33581	33402	35357	38923	42345	45404	47724	49632	51154	52646	53955	55051	55599	54984	53296	52172	50837	47203	43176
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7/31/2012	40375	37758	36232	35343	35558	37386	39969	43009	45965	48774	51470	53810	55689	57325	58556	59521	59716	59328	57777	55691	54552	52327	48143	43706
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8/3/2012	43826	40859	38773	37603	37542	39234	41461	44987	48956	53093	57367	61267	64097	66167	67429	67653	67398	66314	63643	60911	59610	57437	53381	49066
8/4/2012	45175	42240	40168	38751	38020	38063	38391	40864	45335	50100	54731	58423	60952	62048	62502	62814	62578	61962	60770	58708	57870	56225	52806	48999
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8/11/2012	41883	39254	37582	36386	35790	36077	36579	38537	41984	45494	48942	51714	53929	55072	55864	56262	56168	55213	53499	51626	51104	49246	46029	42549
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8/13/2012	37605	35261	33795	33068	33365	35055	37424	40489	43927	47134	50377	53154	55376	57418	58803	59885	60649	60631	58902	56330	55506	52527	47941	43308

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8/17/2012	38087	35652	34073	33192	33340	34869	37406	40302	43794	47389	51000	54484	57433	59845	61517	62328	62368	61023	58298	55941	54586	51519	47536	43499
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10/29/2012	28446	27876	26442	26189	26734	28318	30793	33358	35369	37181	38406	38851	38514	38812	37217	36469	36399	36474	36005	33264	30605	27180	25287	23479
10/30/2012	22608	21570	21255	21279	21373	22508	24707	26280	27357	29451	30052	30767	30953	31109	31354	31042	31749	32871	34378	34400	33567	31994	29790	27789
10/31/2012	26329	25681	25355	25406	26204	28401	32011	34276	34287	34092	33981	33702	33417	33011	32797	32913	33545	34517	35591	35300	35050	33912	31758	29528
11/1/2012	27940	27088	26772	26876	27587	29949	33755	35916	35761	35572	35304	35112	34912	34611	34483	34552	35049	36196	38053	38351	37418	35801	33231	30832
11/2/2012	29053	28074	27694	27762	28794	31304	35347	37720	37505	37254	36770	36074	35600	35408	35155	35060	35433	36490	38441	38362	37451	36340	34440	32278
11/3/2012	30495	29404	28846	28796	29100	30112	31836	33660	35103	35975	35978	35581	35103	34493	34053	33847	34237	35368	37668	37833	37400	36264	34633	32663
11/4/2012	60419	28879	28810	28885	29329	30326	31573	33019	34137	34728	34505	34059	33906	33585	33498	34065	35722	38952	39360	39224	38320	36440	34287	31461
11/5/2012	30889	30158	30027	30369	31684	34710	39077	40806	41070	40672	40225	39632	38876	38294	37956	38109	39731	43423	44111	43802	42898	40992	38397	36039
11/6/2012	34516	33883	33721	34252	35591	38653	42465	43543	42995	42080	41367	40600	39924	39357	39150	39494	41213	44683	45116	44575	43463	41264	38397	35975
11/7/2012	34063	33096	32614	32671	33743	37128	41154	42919	43068	43151	43154	42868	42495	42445	42669	43050	44651	47280	47087	46217	44508	41812	39171	36367
11/8/2012	34456	33494	33066	33170	34219	37057	41297	42840	42756	42362	41681	40799	39962	39252	38631	38743	40262	43930	44631	44277	43367	41384	38515	35797
11/9/2012	34129	33322	32979	33230	34427	37404	41613	42987	42065	40978	40143	39263	38415	37876	37463	37421	38689	41782	41760	41110	40295	38888	36903	34685
11/10/2012	32909	32072	31707	31744	32312	33645	35349	36699	37480	37409	36931	36022	35157	34477	34026	33977	35017	38250	38228	37683	37188	35734	34571	32738
11/11/2012	30597	29591	29173	29107	29411	30367	31591	32785	33775	33875	33508	33046	32768	32484	32320	32480	33925	37301	37728	37226	36333	34360	32382	30158
11/12/2012	28500	27627	27403	27634	28660	31193	35173	37107	37479	37540	37703	37675	37534	37478	37180	37189	38415	41614	41456	40606	39247	36873	33852	31030
11/13/2012	29018	27759	27201	27159	27954	30643	35438	38295	39008	39396	39841	39771	39423	39168	38866	39128	41209	44522	45020	44487	43500	41508	38677	36063
11/14/2012	34104	33294	33035	33349	34664	37892	42812	44200	43230	41999	41128	40314	39549	39223	39023	39552	41574	45572	45979	45612	44810	42755	40063	37346
11/15/2012	35565	34548	34124	34135	35080	37932	42457	43738	43378	42642	42079	41298	40654	40277	39909	40292	42265	45557	45575	45146	44183	42068	39010	36285
11/16/2012	34327	33269	32776	32934	34045	36914	41614	43435	43042	42375	41665	40841	39875	39140	38668	38757	40292	43832	43937	43400	42551	41298	39183	37021
11/17/2012	35274	34319	33938	33812	34385	35697	37447	38856	39478	39115	38343	37345	36308	35275	34751	34916	36792	40252	40585	40227	39686	38587	36833	34905
11/18/2012	33189	32242	31699	31615	31871	32719	34157	35387	36595	36921	36453	36006	35608	35272	35089	35463	37551	41149	41516	41019	40192	38413	36056	33703
11/19/2012	31980	31112	30763	30991	32185	35219	40004	42112	42075	41636	41252	40631	40043	39577	39317	39408	41196	44555	44790	44231	42969	40777	37880	34985
11/20/2012	33031	32005	31622	31526	33190	35702	40299	42136	41855	41099	40369	39493	38983	38886	38810	39137	41011	44142	44088	43527	42486	40685	37797	35088

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Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
11/21/2012	33207	32378	32208	32402	33607	36622	40977	43007	42715	41546	40631	39850	39028	38437	38113	38055	39476	42889	43226	42410	41797	40423	38310	35953
11/22/2012	34050	33057	32568	32591	33150	34501	36101	37228	38152	38113	37848	37371	36350	34936	33677	32825	32929	34813	34821	34774	35029	34927	34133	32902
11/23/2012	31902	31408	31399	31837	32888	34941	37178	38247	38443	37660	36672	35747	34931	34327	34073	34469	36334	39247	38955	38110	37262	35951	34155	32237
11/24/2012	30573	29841	29620	29782	30486	31733	33596	35301	37272	38422	39004	39020	38733	38118	37847	38207	40209	43420	43734	43367	42854	41665	39718	37633
11/25/2012	35835	34809	34401	34341	34704	35613	36858	38114	39192	39754	39900	39642	39330	38813	38194	38173	40420	44626	45414	45186	44646	42742	40169	37580
11/26/2012	35995	35231	34952	35195	36284	39230	43589	45452	44754	43076	41821	40679	39882	39220	38831	39063	41284	45528	46146	45912	44997	42981	39813	36810
11/27/2012	34599	33433	32916	32849	33863	36793	41493	43923	44111	44152	44733	44586	44583	44480	44268	44569	46525	49254	48895	48160	46874	44545	41334	38164
11/28/2012	36121	35084	34647	34876	35978	39183	44214	46040	45386	44492	43212	42308	41554	41202	40921	41310	43855	48225	48713	48491	47777	46012	42967	40171
11/29/2012	38320	37475	37374	37744	39158	42383	47272	48908	47666	45884	44220	42798	41690	41005	40518	40872	43272	47667	48209	47964	47288	45354	42290	39369
11/30/2012	37485	36694	36457	36970	38325	41508	46498	48171	47139	45334	43704	42339	41316	40807	40220	40350	42356	45604	45620	44818	43999	42630	40287	37685

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	ISO-NE	CT	SWCT
Max	25,880	6,922	3,489
PST	20,917	5,392	2,717
Winter	17,779	4,292	2,162
Spring	15,490	3,733	1,881
Summer	19,767	5,011	2,526
Fall	16,420	3,970	1,994

Detailed hourly load data provided in other workpapers.

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Dec 2011-Nov 2012 Load

ISONEPe	**Max**	25,880
ISONEA	**Avg Jul**	20,917
ISONEW	**Winter**	17,779
ISONES	**Spring**	15,490
ISONES	**Summer**	19,767
ISONEF	**Fall**	16,420

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
ISONE	12/1/11	11122	10671	10470	10469	10869	12096	14206	15207	15348	15380	15403	15373	15259	15175	15062	15197	16514	17745	17736	17369	16778	15707	14179	12743
ISONE	12/2/11	11815	11366	11160	11161	11534	12696	14831	15855	15963	15896	15790	15651	15428	15311	15194	15288	16576	17379	17089	16576	16000	15147	13941	12633
ISONE	12/3/11	11689	11155	10894	10831	10999	11484	12377	13269	14191	14618	14660	14489	14244	13950	13834	14047	15540	16621	16481	16047	15563	14865	13866	12722
ISONE	12/4/11	11834	11281	11007	10875	10943	11266	11849	12505	13458	14024	14149	14131	14124	13969	13837	14005	15579	16826	16767	16299	15672	14528	13097	11792
ISONE	12/5/11	10947	10495	10313	10310	10680	11849	13950	15037	15252	15419	15532	15527	15411	15331	15175	15273	16656	17821	17676	17161	16407	15171	13562	11999
ISONE	12/6/11	11015	10508	10251	10189	10479	11583	13705	15023	15314	15489	15635	15664	15578	15588	15529	15870	17172	17859	17620	17079	16324	15131	13491	11984
ISONE	12/7/11	10924	10398	10133	10073	10358	11428	13504	14940	15311	15572	15817	15869	15847	15888	15860	16164	17303	17869	17646	17216	16527	15385	13844	12368
ISONE	12/8/11	11424	10956	10765	10756	11134	12290	14456	15582	15792	15899	15972	15933	15807	15779	15692	15850	17183	18352	18269	17975	17402	16313	14735	13200
ISONE	12/9/11	12239	11728	11484	11458	11806	12891	14973	15994	16123	16168	16057	15925	15701	15558	15398	15510	16899	17809	17513	16986	16352	15447	14184	12797
ISONE	12/10/11	11766	11155	10835	10693	10793	11240	12092	13023	14044	14669	14843	14823	14720	14527	14392	14598	16107	17214	17049	16624	16180	15526	14552	13378
ISONE	12/11/11	12445	11884	11597	11496	11595	11928	12559	13227	14136	14718	14882	14882	14835	14692	14579	14843	16564	17940	17961	17646	17078	15948	14522	13183
ISONE	12/12/11	12298	11833	11672	11710	12107	13299	15474	16594	16649	16545	16429	16252	15994	15869	15742	15972	17533	18698	18665	18373	17758	16594	14923	13360
ISONE	12/13/11	12424	11962	11784	11802	12212	13438	15667	16757	16780	16614	16476	16260	16001	15858	15696	15889	17455	18751	18669	18292	17623	16466	14820	13235
ISONE	12/14/11	12230	11718	11480	11450	11770	12860	15052	16231	16346	16329	16282	16176	15997	15952	15894	16124	17570	18610	18464	18047	17393	16255	14614	13037
ISONE	12/15/11	11953	11398	11135	11097	11391	12488	14609	15902	16105	16209	16272	16261	16130	16126	16058	16245	17427	18106	17835	17439	16787	15669	14110	12516
ISONE	12/16/11	11408	10815	10544	10488	10776	11854	13974	15185	15442	15547	15599	15523	15376	15313	15213	15405	16856	17839	17618	17105	16531	15727	14506	13097
ISONE	12/17/11	11995	11421	11142	11054	11174	11681	12575	13522	14583	15176	15327	15239	15061	14973	14994	15286	16726	17621	17402	16991	16585	15922	14925	13752
ISONE	12/18/11	12763	12197	11903	11816	11892	12262	12959	13745	14806	15459	15688	15722	15680	15543	15477	15808	17487	18733	18842	18544	18119	17101	15666	14242
ISONE	12/19/11	13331	12874	12709	12750	13146	14389	16538	17622	17406	17278	17295	17229	16942	16734	16540	16764	18314	19357	19182	18688	17975	16738	15035	13396
ISONE	12/20/11	12238	11616	11311	11251	11621	12738	14877	16131	16373	16417	16422	16346	16164	16113	16031	16259	17875	19052	19028	18713	18113	17026	15390	13800
ISONE	12/21/11	12690	12073	11765	11689	11973	13076	15101	16392	16597	16667	16696	16668	16605	16618	16557	16800	17949	18509	18245	17820	17140	16028	14413	12760
ISONE	12/22/11	11616	10979	10664	10575	10871	11916	13922	15101	15358	15443	15491	15376	15149	15067	14966	15166	16583	17657	17556	17163	16597	15631	14196	12667
ISONE	12/23/11	11519	10913	10596	10537	10826	11733	13396	14749	15375	15680	15750	15685	15497	15328	15175	15301	16621	17724	17494	17073	16594	15861	14712	13390
ISONE	12/24/11	12306	11678	11379	11274	11370	11792	12639	13622	14751	15493	15767	15734	15554	15328	15221	15298	16468	17310	16770	16238	15919	15609	15044	14163
ISONE	12/25/11	13198	12498	12130	11982	11995	12243	12842	13675	14666	15289	15481	15514	15312	14820	14303	14095	14875	15457	15374	15211	14998	14503	13587	12535
ISONE	12/26/11	11637	11119	10866	10786	10962	11448	12182	12790	13578	14315	14738	14852	14728	14487	14314	14485	15969	17390	17322	16991	16486	15622	14407	13128

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
ISONE	12/27/11	12196	11712	11506	11467	11755	12624	14026	15060	15789	16235	16484	16543	16346	16205	16046	16190	17445	18150	17844	17257	16517	15390	13889	12471
ISONE	12/28/11	11425	10820	10458	10386	10621	11410	12797	13936	14683	15203	15570	15774	15763	15740	15634	15759	17095	18384	18308	17917	17357	16379	15080	13778
ISONE	12/29/11	12827	12360	12179	12192	12499	13385	14804	15887	16542	16912	17058	16974	16724	16515	16336	16468	17781	18941	18776	18282	17650	16649	15276	13918
ISONE	12/30/11	12908	12324	12043	11960	12138	12873	14118	15175	15905	16343	16551	16479	16184	15911	15610	15596	16710	17730	17465	16947	16310	15486	14313	13073
ISONE	12/31/11	12072	11456	11073	10911	10931	11240	11880	12665	13633	14548	15152	15343	15264	15080	14915	14944	15986	16929	16557	15804	15066	14362	13617	12882
ISONE	1/1/12	12153	11493	11003	10756	10717	10907	11313	11679	12303	12912	13279	13416	13481	13360	13227	13305	14600	15830	15738	15256	14692	13906	12932	11839
ISONE	1/2/12	10916	10356	10088	10025	10246	10806	11647	12336	13179	14046	14679	14939	14916	14818	14772	14996	16404	17827	17670	17244	16546	15449	14089	12856
ISONE	1/3/12	12039	11631	11434	11457	11869	13089	15246	16455	16659	16773	16925	16951	16884	16859	16795	17029	18357	19809	19849	19515	18880	17766	16278	14977
ISONE	1/4/12	14167	13742	13526	13551	13918	15068	17161	18299	18321	18273	18232	18052	17795	17642	17504	17684	18921	19926	19773	19312	18572	17350	15793	14352
ISONE	1/5/12	13431	12940	12692	12646	12971	14034	16056	17240	17366	17444	17364	17122	16909	16826	16693	16801	17868	19038	18968	18538	17845	16701	15164	13837
ISONE	1/6/12	12967	12496	12255	12194	12491	13546	15531	16720	16858	16876	16802	16552	16278	16136	15912	15988	16922	17815	17529	17024	16350	15473	14280	13054
ISONE	1/7/12	12106	11580	11295	11180	11291	11721	12498	13317	14155	14663	14804	14685	14416	14112	13897	14045	15072	16105	15916	15405	14920	14223	13309	12305
ISONE	1/8/12	11462	10975	10686	10609	10689	11000	11601	12232	13109	13788	14217	14485	14531	14450	14400	14601	15853	17156	17130	16687	16109	15158	13907	12813
ISONE	1/9/12	12096	11750	11622	11667	12089	13301	15487	16748	16871	16889	16881	16735	16452	16276	16048	16103	17186	18646	18601	18102	17378	16183	14661	13314
ISONE	1/10/12	12431	11991	11749	11731	12071	13191	15317	16450	16510	16594	16601	16440	16169	16032	15887	15995	17042	18233	18099	17651	16989	15869	14393	13109
ISONE	1/11/12	12296	11888	11701	11753	12123	13334	15469	16599	16600	16501	16443	16311	16082	15989	15838	15944	16977	18239	18170	17723	17044	15877	14360	13023
ISONE	1/12/12	12142	11656	11427	11422	11776	12883	14875	16251	16633	16905	17144	17203	17136	17060	16832	16792	17594	18502	18314	17771	17025	15828	14322	13012
ISONE	1/13/12	12094	11631	11411	11370	11676	12722	14709	16008	16260	16330	16352	16280	16132	16066	16006	16238	17248	18260	18094	17632	17046	16171	14997	13827
ISONE	1/14/12	12913	12379	12080	11987	12112	12536	13330	14132	15036	15750	16050	15949	15696	15401	15262	15386	16388	17758	17753	17355	16808	16143	15353	14431
ISONE	1/15/12	13565	13045	12835	12809	12953	13313	13937	14609	15558	16271	16660	16790	16777	16607	16505	16638	17715	19124	19148	18615	18082	17182	16106	15028
ISONE	1/16/12	14271	13876	13717	13724	14041	14868	16237	17246	17939	18325	18474	18327	18033	17827	17603	17637	18536	19731	19513	18924	18064	16825	15345	13978
ISONE	1/17/12	13038	12510	12271	12208	12516	13579	15509	16639	16806	16814	16801	16737	16649	16629	16572	16732	17662	18562	18303	17752	16932	15706	14178	12803
ISONE	1/18/12	11879	11406	11163	11134	11499	12688	14863	16004	16122	16220	16345	16353	16277	16259	16182	16318	17288	18922	19060	18728	18083	16992	15599	14319
ISONE	1/19/12	13522	13140	12983	13012	13425	14623	16813	17960	18009	17918	17821	17600	17325	17151	16947	17063	17923	19123	19089	18760	18007	16820	15327	13972
ISONE	1/20/12	13057	12541	12303	12251	12621	13726	15773	16860	16984	17034	17082	17012	16820	16698	16496	16525	17260	18618	18546	18091	17502	16659	15512	14310
ISONE	1/21/12	13453	12973	12680	12565	12672	13082	13892	14855	15931	16867	17443	17690	17687	17464	17179	17058	17709	18827	18632	17988	17324	16463	15407	14371
ISONE	1/22/12	13564	13119	12905	12811	12896	13247	13871	14551	15454	16009	16229	16226	16128	16007	15958	15987	16732	17845	17851	17525	16882	15826	14643	13442
ISONE	1/23/12	12581	12141	11964	11973	12344	13475	15535	16690	16941	17081	17215	17189	17024	16907	16724	16732	17496	18606	18452	17867	17025	15787	14234	12827
ISONE	1/24/12	11932	11365	11088	11017	11331	12376	14455	15603	15719	15654	15673	15607	15428	15310	15145	15158	15917	17312	17328	16916	16245	15134	13749	12451
ISONE	1/25/12	11615	11196	11009	11019	11373	12521	14692	15905	16005	16094	16167	16125	15964	15878	15696	15671	16376	17917	18021	17611	16965	15809	14310	12981
ISONE	1/26/12	12115	11671	11463	11453	11817	12917	15074	16228	16305	16256	16215	16109	15980	15968	15923	16045	16825	18051	18005	17588	16891	15778	14312	12998
ISONE	1/27/12	12110	11602	11368	11285	11583	12605	14534	15842	16246	16510	16689	16746	16632	16499	16280	16206	16701	17423	17167	16588	15965	15120	13997	12857
ISONE	1/28/12	11942	11388	11107	11001	11101	11565	12369	13225	14134	14714	14971	14828	14548	14169	13937	13942	14607	16009	16125	15655	15175	14446	13514	12522
ISONE	1/29/12	11715	11230	10973	10890	10993	11320	11920	12525	13427	14041	14375	14492	14448	14300	14146	14208	15026	16691	16952	16551	15928	14921	13700	12563
ISONE	1/30/12	11797	11416	11268	11312	11720	12877	15057	16226	16379	16519	16504	16433	16305	16185	16013	16069	16746	18338	18539	18100	17421	16233	14721	13365

Backup - ISO-NE Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
ISONE	1/31/12	12515	12052	11829	11805	12147	13247	15343	16502	16615	16597	16519	16328	16049	15822	15556	15467	15998	17484	17684	17260	16556	15438	13958	12640
ISONE	2/1/12	11792	11324	11100	11101	11415	12532	14625	15835	15954	15964	15953	15920	15756	15604	15291	15159	15598	16984	17172	16750	16076	14982	13529	12237
ISONE	2/2/12	11402	10972	10775	10793	11151	12313	14483	15633	15847	15991	16146	16181	16117	16089	16037	16183	16883	17927	17979	17566	16929	15832	14404	13124
ISONE	2/3/12	12285	11838	11678	11701	12062	13231	15390	16450	16581	16542	16503	16343	16046	15845	15600	15518	15980	17259	17433	17003	16430	15576	14412	13157
ISONE	2/4/12	12232	11719	11436	11327	11412	11824	12638	13473	14355	14891	15075	14959	14712	14402	14209	14227	14786	16213	16525	16142	15688	14994	14069	13096
ISONE	2/5/12	12318	11877	11669	11613	11702	12044	12612	13306	14227	14815	15061	15144	15082	14868	14716	14799	15444	16828	16606	15798	15389	14724	14218	13052
ISONE	2/6/12	12178	11764	11614	11655	12027	13155	15213	16238	16383	16296	16253	16109	15822	15602	15324	15210	15683	17176	17606	17170	16414	15238	13822	12532
ISONE	2/7/12	11719	11295	11127	11148	11519	12690	14776	15819	15929	15941	15956	15904	15743	15623	15428	15440	15973	17381	17733	17375	16741	15656	14228	13000
ISONE	2/8/12	12227	11855	11735	11808	12206	13436	15606	16658	16787	16703	16599	16412	16156	16021	15879	16031	16693	17985	18189	17735	17036	15881	14343	13041
ISONE	2/9/12	12188	11757	11557	11570	11960	13172	15317	16304	16307	16175	16084	15905	15648	15482	15237	15194	15645	17054	17583	17263	16685	15657	14223	12978
ISONE	2/10/12	12203	11800	11627	11661	12037	13169	15226	16262	16263	16086	15961	15756	15436	15254	15046	14976	15418	16650	16852	16373	15758	14904	13771	12637
ISONE	2/11/12	11785	11310	11026	10923	11041	11480	12295	13190	14241	15052	15436	15492	15349	15126	14905	14799	15254	16388	16613	16135	15608	14907	14025	13110
ISONE	2/12/12	12437	12066	11939	11949	12111	12482	13084	13752	14690	15368	15702	15775	15708	15538	15367	15453	16107	17601	18203	17890	17265	16230	15050	13931
ISONE	2/13/12	13167	12796	12645	12678	13048	14162	16192	17184	17260	17155	17054	16901	16580	16331	16037	15930	16311	17653	18212	17871	17236	16134	14683	13366
ISONE	2/14/12	12525	12094	11935	11933	12298	13438	15518	16502	16566	16515	16485	16342	16153	16009	15830	15743	16074	17315	17785	17335	16660	15568	14141	12877
ISONE	2/15/12	12019	11559	11336	11313	11626	12776	14833	15932	16149	16201	16247	16177	15984	15893	15712	15652	16038	17183	17580	17167	16466	15369	13923	12605
ISONE	2/16/12	11804	11382	11220	11297	11661	12871	14926	15926	16055	16078	16046	15961	15864	15859	15742	15798	16367	17431	17658	17218	16533	15429	13973	12675
ISONE	2/17/12	11783	11276	11008	10965	11249	12295	14228	15381	15706	15790	15812	15691	15426	15238	14981	14844	15105	16136	16614	16202	15655	14875	13782	12647
ISONE	2/18/12	11805	11331	11108	11015	11129	11600	12341	13139	14018	14519	14668	14548	14263	13914	13696	13709	14175	15326	15796	15382	14900	14212	13285	12341
ISONE	2/19/12	11595	11163	10928	10855	10945	11290	11780	12404	13218	13780	13987	14017	13862	13594	13352	13330	13806	15133	15938	15599	15103	14322	13344	12392
ISONE	2/20/12	11752	11377	11163	11198	11499	12326	13538	14471	15215	15682	15889	15835	15578	15300	15076	15010	15466	16815	17522	17093	16433	15424	14132	12961
ISONE	2/21/12	12213	11828	11681	11743	12124	13223	14941	15932	16241	16226	16186	16025	15777	15653	15543	15547	16005	17220	17677	17180	16411	15304	13885	12622
ISONE	2/22/12	11764	11277	11065	11031	11353	12372	14006	15066	15405	15439	15488	15405	15183	15031	14800	14659	14949	16071	16749	16352	15716	14719	13372	12147
ISONE	2/23/12	11306	10836	10587	10559	10839	11846	13537	14631	15110	15365	15453	15442	15291	15128	14943	14769	14972	16031	16775	16441	15818	14843	13534	12350
ISONE	2/24/12	11544	11081	10867	10880	11195	12170	13797	15022	15771	16165	16431	16517	16416	16356	16240	16168	16471	17142	17179	16635	15929	15001	13825	12661
ISONE	2/25/12	11799	11281	11007	10906	11040	11472	12119	12874	13784	14487	14834	14842	14684	14426	14236	14204	14586	15631	16348	15987	15474	14789	13814	12877
ISONE	2/26/12	12170	11712	11476	11425	11519	11868	12303	12900	13756	14303	14570	14648	14570	14297	14011	13984	14436	15634	16743	16443	15832	14890	13722	12682
ISONE	2/27/12	12006	11668	11553	11622	12053	13254	15132	16134	16241	16186	16116	15980	15801	15667	15464	15454	15916	16965	17537	17088	16296	15155	13737	12453
ISONE	2/28/12	11641	11194	11003	11001	11356	12530	14383	15375	15577	15640	15623	15510	15288	15152	14953	14866	15177	16284	17287	17040	16410	15339	13942	12679
ISONE	2/29/12	11875	11465	11276	11266	11623	12798	14670	15744	15995	16080	16209	16294	16322	16463	16478	16533	16976	17927	18333	17840	17027	15815	14338	13046
ISONE	3/1/12	12193	11773	11560	11563	11880	12925	14697	15829	16328	16646	16921	17014	16965	16875	16744	16697	17016	17842	18371	17966	17257	16126	14671	13377
ISONE	3/2/12	12572	12129	11895	11911	12237	13370	15183	16269	16596	16683	16742	16644	16463	16367	16175	16096	16399	17154	17511	17056	16415	15537	14370	13185
ISONE	3/3/12	12358	11851	11532	11365	11411	11788	12473	13311	14336	15092	15438	15508	15280	14836	14385	14092	14149	14883	15825	15475	14989	14246	13317	12350
ISONE	3/4/12	11575	11103	10841	10733	10815	11110	11583	12263	13250	14027	14372	14503	14473	14253	14113	14117	14464	15441	16507	16250	15631	14640	13434	12375
ISONE	3/5/12	11691	11381	11274	11356	11797	13027	14911	15960	16171	16211	16232	16129	15887	15711	15446	15382	15730	16789	17981	17740	17106	16033	14617	13402

Backup - ISO-NE Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
ISONE	3/6/12	12638	12300	12173	12228	12641	13847	15684	16656	16744	16567	16489	16359	16063	15878	15614	15414	15702	16591	17744	17569	16968	15864	14379	13061
ISONE	3/7/12	12246	11832	11613	11619	11946	13110	14863	15739	15768	15662	15571	15386	15157	15027	14754	14619	14821	15650	16727	16473	15838	14733	13298	11984
ISONE	3/8/12	11189	10755	10534	10487	10803	11912	13582	14617	14846	14926	14980	14965	14823	14756	14589	14487	14667	15444	16284	15984	15312	14226	12785	11529
ISONE	3/9/12	10712	10290	10073	10031	10357	11461	13354	14619	15023	15166	15236	15154	14938	14801	14592	14515	14694	15315	16229	15954	15427	14636	13528	12395
ISONE	3/10/12	11608	11207	11009	10966	11123	11588	12241	13205	14123	14692	14814	14703	14441	14121	13841	13735	13949	14632	15710	15503	15074	14378	13418	12474
ISONE	3/11/12	11752	11536	11320	11099	11051	11223	11630	12090	12783	13413	13741	13824	13728	13451	13117	12908	12965	13343	13997	15160	14926	14019	12852	11631
ISONE	3/12/12	10866	10420	10253	10276	10580	11680	13754	14955	15117	15058	15110	15075	14920	14824	14596	14385	14329	14517	15002	15791	15320	14211	12784	11462
ISONE	3/13/12	10565	10049	9805	9745	10004	10983	12988	14335	14702	14842	14943	14961	14878	14851	14700	14553	14564	14724	14954	15680	15248	14162	12693	11340
ISONE	3/14/12	10435	9946	9698	9687	9915	10920	12943	14190	14481	14650	14785	14809	14676	14645	14488	14377	14485	14827	15186	15743	15340	14322	12898	11593
ISONE	3/15/12	10754	10290	10063	10045	10327	11381	13462	14783	15087	15224	15347	15280	15089	14958	14683	14537	14639	15007	15504	16144	15733	14788	13380	12058
ISONE	3/16/12	11168	10672	10459	10403	10667	11676	13658	14884	15263	15458	15631	15658	15545	15483	15294	15141	15100	15148	15284	15662	15238	14448	13319	12102
ISONE	3/17/12	11163	10588	10290	10149	10217	10575	11299	12129	13155	13846	14166	14124	13871	13545	13211	12933	12873	12926	13171	14027	13919	13327	12468	11503
ISONE	3/18/12	10721	10244	9995	9868	9898	10149	10647	11221	12091	12799	13099	13154	13016	12768	12555	12436	12599	12918	13336	14428	14233	13251	11995	10851
ISONE	3/19/12	10044	9629	9440	9436	9761	10852	12882	14068	14403	14593	14832	14954	14961	15018	14900	14727	14615	14612	14722	15535	15176	14016	12515	11181
ISONE	3/20/12	10307	9853	9644	9580	9881	10896	12874	14023	14305	14452	14657	14787	14846	14964	14924	14853	14843	14881	14899	15688	15429	14306	12757	11415
ISONE	3/21/12	10495	10008	9727	9656	9907	10869	12831	13989	14444	14726	15032	15223	15273	15360	15315	15238	15198	15196	15138	15861	15591	14491	12976	11572
ISONE	3/22/12	10720	10158	9875	9776	9995	10932	12875	14037	14505	14863	15230	15431	15483	15659	15655	15630	15605	15543	15380	16044	15821	14743	13179	11797
ISONE	3/23/12	10903	10348	10002	9893	10104	10986	12822	13995	14454	14754	15015	15088	14969	15004	14867	14689	14591	14431	14146	14737	14465	13630	12498	11303
ISONE	3/24/12	10399	9832	9511	9341	9356	9669	10311	11080	12135	12888	13219	13282	13132	12870	12657	12555	12643	12962	13288	13818	13565	12870	11936	10972
ISONE	3/25/12	10174	9646	9381	9250	9273	9484	9981	10654	11716	12633	13206	13543	13658	13521	13369	13266	13453	13831	14143	14731	14432	13427	12215	11091
ISONE	3/26/12	10306	9885	9711	9726	10072	11184	13250	14458	14873	15045	15130	15062	14905	14815	14598	14486	14596	14989	15387	16344	16213	15243	13830	12571
ISONE	3/27/12	11769	11378	11214	11233	11595	12717	14739	15852	15978	15939	15893	15788	15561	15338	15012	14794	14771	14978	15205	16125	16052	15069	13627	12308
ISONE	3/28/12	11486	11027	10814	10745	11037	12098	14091	15249	15468	15496	15592	15606	15532	15490	15194	14945	14981	15153	15321	15903	15625	14576	13067	11737
ISONE	3/29/12	10865	10416	10189	10150	10456	11499	13502	14672	15004	15230	15407	15433	15329	15251	15011	14920	15039	15312	15584	16117	15814	14800	13333	12053
ISONE	3/30/12	11223	10780	10584	10546	10872	11930	13812	14890	15087	15120	15153	15036	14779	14621	14328	14061	13954	13944	14030	14807	14803	14131	13060	11892
ISONE	3/31/12	10972	10470	10212	10133	10218	10599	11298	12276	13388	14066	14450	14517	14392	14063	13755	13561	13582	13758	13904	14497	14432	13857	12988	11985
ISONE	4/1/12	11184	10687	10449	10357	10401	10692	11123	11759	12563	13082	13278	13312	13305	13221	13134	13211	13596	14171	14587	15072	14690	13736	12512	11386
ISONE	4/2/12	10645	10240	10089	10112	10475	11647	13649	14845	15202	15353	15428	15315	15096	14935	14663	14448	14436	14642	14795	15613	15681	14740	13312	11977
ISONE	4/3/12	11152	10732	10557	10578	10956	12123	14064	15122	15218	15194	15169	15038	14838	14675	14455	14305	14295	14433	14575	15384	15473	14449	12988	11653
ISONE	4/4/12	10776	10341	10116	10083	10379	11473	13356	14420	14602	14646	14741	14743	14614	14581	14456	14302	14304	14437	14568	15270	15237	14243	12829	11494
ISONE	4/5/12	10691	10265	10075	10076	10428	11531	13463	14575	14800	14915	14994	14944	14791	14691	14434	14227	14181	14277	14368	15056	15213	14422	13110	11847
ISONE	4/6/12	11001	10560	10358	10347	10621	11513	12893	13953	14434	14667	14727	14588	14357	14150	13850	13600	13559	13646	13699	14307	14464	13807	12771	11685
ISONE	4/7/12	10875	10404	10166	10086	10213	10628	11227	12156	13072	13553	13662	13575	13367	13098	12853	12807	13043	13388	13651	14197	14183	13530	12552	11478
ISONE	4/8/12	10598	10088	9783	9672	9721	9997	10475	11352	12352	12974	13190	13315	13201	12727	12249	11983	11923	12060	12387	13336	13811	13064	11932	10885
ISONE	4/9/12	10187	9844	9717	9725	10080	11205	13044	14282	14720	14906	15071	15072	14950	14838	14598	14432	14434	14602	14747	15371	15396	14328	12869	11511

Backup - ISO-NE Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
ISONE	4/10/12	10696	10286	10098	10083	10431	11513	13301	14423	14646	14739	14836	14802	14712	14676	14478	14308	14332	14446	14545	15188	15247	14204	12742	11421
ISONE	4/11/12	10606	10185	9997	9998	10332	11414	13223	14434	14737	14789	14859	14819	14671	14604	14432	14282	14318	14471	14618	15272	15271	14256	12830	11527
ISONE	4/12/12	10680	10234	10030	10024	10337	11432	13213	14364	14655	14742	14793	14805	14748	14730	14554	14418	14462	14631	14677	15209	15286	14356	12975	11654
ISONE	4/13/12	10824	10410	10212	10213	10529	11581	13293	14407	14625	14703	14771	14676	14509	14412	14190	13936	13825	13747	13632	14095	14367	13620	12505	11302
ISONE	4/14/12	10458	9965	9685	9626	9735	10153	10689	11652	12508	13032	13238	13184	12990	12750	12541	12468	12519	12675	12751	13241	13470	12807	11819	10823
ISONE	4/15/12	10031	9533	9242	9128	9148	9362	9664	10388	11379	12138	12537	12762	12809	12715	12636	12662	12867	13167	13284	13768	13982	13185	12073	11009
ISONE	4/16/12	10231	9782	9553	9506	9759	10627	11874	13239	14255	14983	15565	15955	16199	16365	16412	16402	16376	16245	15941	16042	16217	15081	13526	12071
ISONE	4/17/12	11063	10483	10128	9979	10198	11045	12367	13832	14690	15212	15595	15789	15871	16031	16049	16015	15977	15836	15438	15492	15635	14502	12965	11596
ISONE	4/18/12	10608	10042	9736	9611	9823	10655	11895	13174	13815	14169	14443	14569	14530	14535	14398	14186	14145	14206	14212	14596	14692	13748	12424	11162
ISONE	4/19/12	10329	9864	9605	9557	9834	10710	12082	13344	13930	14291	14573	14699	14673	14678	14573	14451	14429	14377	14205	14475	14814	13907	12553	11250
ISONE	4/20/12	10401	9936	9701	9602	9842	10629	11875	13122	13862	14386	14772	14955	14946	14961	14833	14653	14525	14322	13973	14126	14352	13537	12390	11204
ISONE	4/21/12	10330	9817	9522	9390	9463	9780	10253	11174	12204	12942	13337	13470	13464	13375	13288	13268	13360	13494	13437	13684	13954	13254	12240	11199
ISONE	4/22/12	10346	9828	9495	9324	9316	9483	9714	10413	11377	12214	12730	13076	13252	13259	13205	13266	13547	13867	14115	14309	14089	13142	12009	10949
ISONE	4/23/12	10259	9895	9731	9698	9977	11034	12858	14238	14813	15102	15313	15400	15302	15234	15024	14857	14921	15097	15066	15231	15188	14118	12669	11346
ISONE	4/24/12	10497	10092	9873	9831	10128	11118	12761	14003	14402	14630	14791	14779	14666	14613	14452	14297	14321	14410	14436	14845	15224	14279	12797	11461
ISONE	4/25/12	10599	10160	9960	9902	10229	11237	12882	14019	14317	14498	14622	14670	14600	14569	14373	14243	14270	14360	14419	14752	15023	14143	12757	11463
ISONE	4/26/12	10591	10135	9950	9950	10269	11310	12964	14110	14418	14547	14661	14724	14668	14678	14522	14399	14534	14841	14935	15150	15147	14159	12729	11416
ISONE	4/27/12	10540	10063	9811	9751	9995	10937	12569	13848	14332	14564	14711	14681	14529	14437	14208	13980	13921	13892	13847	14230	14691	14054	12933	11756
ISONE	4/28/12	10880	10384	10154	10067	10204	10563	11079	12098	12943	13386	13461	13355	13122	12846	12599	12450	12521	12699	12816	13155	13661	13118	12172	11172
ISONE	4/29/12	10340	9875	9647	9573	9639	9843	10166	10926	11782	12399	12658	12769	12711	12542	12359	12330	12514	12863	13084	13503	14113	13299	12054	10918
ISONE	4/30/12	10192	9824	9690	9740	10118	11193	12994	14201	14440	14573	14675	14664	14560	14531	14374	14225	14214	14312	14428	14828	15123	14053	12568	11237
ISONE	5/1/12	10388	9987	9773	9723	9970	10996	12788	14212	14775	15129	15339	15546	15511	15388	15215	15084	15187	15402	15402	15499	15488	14449	12917	11568
ISONE	5/2/12	10684	10213	9974	9919	10184	11180	12958	14292	14682	14908	15092	15100	14993	14943	14768	14619	14670	14847	14976	15246	15354	14376	12866	11517
ISONE	5/3/12	10623	10163	9915	9856	10132	11116	12917	14290	14727	14958	15134	15185	15067	15033	14815	14667	14739	14902	14961	15194	15303	14339	12842	11478
ISONE	5/4/12	10587	10094	9838	9771	10016	10960	12720	14087	14648	14927	15196	15231	15142	15089	14863	14664	14649	14607	14473	14490	14662	13931	12757	11526
ISONE	5/5/12	10544	10000	9666	9515	9565	9873	10449	11460	12523	13212	13516	13575	13441	13219	13005	12858	12846	12926	12898	13044	13536	13036	12083	11062
ISONE	5/6/12	10243	9730	9428	9281	9283	9415	9699	10486	11444	12171	12553	12704	12708	12581	12409	12374	12559	12892	13096	13378	14037	13261	12014	10840
ISONE	5/7/12	10006	9588	9407	9377	9704	10616	12376	13735	14195	14490	14777	14905	14897	14931	14804	14634	14566	14506	14399	14631	15053	14081	12551	11164
ISONE	5/8/12	10285	9823	9576	9508	9780	10704	12467	13903	14419	14719	14990	15075	14987	15011	14870	14793	14958	15208	15196	15275	15223	14174	12707	11366
ISONE	5/9/12	10464	9999	9754	9682	9944	10921	12737	14238	14789	15120	15391	15503	15446	15437	15264	15163	15272	15404	15320	15381	15355	14365	12862	11507
ISONE	5/10/12	10609	10114	9860	9802	10024	10919	12665	14096	14611	14865	15077	15150	15087	15045	14857	14679	14629	14600	14459	14526	14948	14191	12799	11404
ISONE	5/11/12	10493	10000	9734	9672	9951	10758	12491	13788	14218	14473	14660	14733	14637	14569	14380	14189	14089	13971	13773	13742	14211	13714	12594	11345
ISONE	5/12/12	10411	9868	9566	9457	9503	9710	10323	11353	12361	12968	13178	13207	13099	12959	12844	12868	13000	13159	13186	13233	13743	13300	12299	11175
ISONE	5/13/12	10291	9690	9348	9161	9135	9150	9507	10409	11521	12354	12802	13040	13151	13126	13100	13158	13313	13505	13554	13778	14410	13813	12550	11300
ISONE	5/14/12	10408	9942	9681	9610	9904	10782	12515	13992	14634	15082	15476	15710	15787	15781	15655	15512	15504	15547	15434	15433	15529	14546	13036	11620

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
ISONE	5/15/12	10703	10195	9916	9847	10095	10972	12705	14165	14816	15233	15613	15777	15790	15779	15583	15436	15493	15616	15559	15573	15554	14554	13060	11680
ISONE	5/16/12	10785	10279	10015	9934	10182	11121	12915	14408	15072	15468	15774	15916	15905	15944	15931	15931	15978	15953	15739	15642	15991	15124	13551	12019
ISONE	5/17/12	11003	10421	10091	9942	10109	10823	12511	13857	14411	14743	15033	15177	15176	15260	15195	15136	15115	15025	14776	14693	15146	14469	12963	11526
ISONE	5/18/12	10563	9998	9712	9614	9855	10589	12289	13711	14334	14725	15030	15169	15153	15186	15070	14953	14834	14612	14267	14066	14428	13941	12745	11437
ISONE	5/19/12	10464	9902	9567	9391	9450	9574	10222	11312	12440	13144	13494	13663	13657	13572	13532	13600	13751	13884	13807	13631	13979	13602	12541	11378
ISONE	5/20/12	10451	9851	9474	9313	9298	9274	9658	10598	11746	12654	13209	13577	13766	13792	13818	13910	14098	14285	14275	14203	14655	14022	12623	11306
ISONE	5/21/12	10364	9907	9660	9599	9855	10640	12387	13936	14663	15159	15574	15813	15865	15970	15877	15747	15778	15803	15699	15643	15694	14718	13174	11789
ISONE	5/22/12	10874	10371	10129	10033	10297	11164	12946	14413	15023	15434	15829	16010	15999	16011	15889	15786	15791	15834	15665	15553	15634	14785	13325	11922
ISONE	5/23/12	10917	10421	10160	10072	10338	11132	12948	14484	15201	15675	16103	16381	16517	16696	16676	16560	16584	16551	16306	16118	16396	15710	14083	12500
ISONE	5/24/12	11413	10759	10393	10243	10465	11255	13119	14699	15483	16066	16548	16830	16916	16987	16942	16789	16712	16474	16125	15945	16223	15546	13933	12345
ISONE	5/25/12	11307	10739	10398	10292	10510	11284	12965	14427	15142	15584	15914	16137	16172	16234	16150	16072	16066	15937	15649	15407	15610	15162	13952	12583
ISONE	5/26/12	11542	10913	10530	10336	10359	10515	11116	12253	13590	14684	15437	15922	16211	16303	16365	16366	16481	16481	16251	15947	16101	15646	14363	12979
ISONE	5/27/12	11829	11088	10591	10292	10153	9996	10349	11249	12378	13378	14023	14460	14719	14762	14792	14870	15010	15074	14831	14549	14825	14521	13519	12339
ISONE	5/28/12	11392	10770	10419	10247	10268	10366	10841	11813	13123	14213	15041	15660	16103	16263	16373	16496	16723	16888	16697	16491	16715	15969	14345	12789
ISONE	5/29/12	11765	11143	10800	10709	10930	11772	13624	15313	16305	17104	17865	18511	18976	19383	19538	19729	19869	19720	19188	18788	18540	17209	15395	13768
ISONE	5/30/12	12627	11946	11554	11397	11618	12422	14266	15854	16590	17081	17486	17732	17809	17944	17892	17848	17896	17792	17418	17144	17348	16618	14937	13300
ISONE	5/31/12	12102	11414	11007	10832	11012	11735	13526	15176	15978	16642	17223	17613	17830	18115	18208	18275	18278	18021	17484	16937	16976	16352	14630	12926
ISONE	6/1/12	11751	11039	10641	10488	10614	11207	12918	14446	15191	15684	16092	16289	16319	16405	16341	16164	15924	15500	15001	14759	14971	14489	13269	11962
ISONE	6/2/12	10943	10340	9995	9852	9892	10109	10636	11611	12790	13718	14326	14570	14551	14385	14211	14120	14213	14347	14295	14187	14240	13766	12788	11689
ISONE	6/3/12	10802	10188	9822	9619	9582	9564	9919	10764	11899	12789	13347	13709	13851	13792	13726	13698	13815	13984	14100	14137	14304	13706	12514	11311
ISONE	6/4/12	10444	9940	9684	9640	9901	10724	12461	13945	14596	15006	15344	15451	15418	15367	15203	15102	15189	15344	15213	15034	15065	14312	12854	11484
ISONE	6/5/12	10596	10115	9874	9805	10044	10817	12561	14010	14589	14909	15172	15311	15280	15281	15118	15025	15067	15099	14936	14886	15045	14483	13037	11663
ISONE	6/6/12	10666	10138	9884	9782	10042	10782	12517	13970	14564	14910	15243	15407	15443	15499	15387	15291	15287	15231	14964	14844	15134	14610	13095	11663
ISONE	6/7/12	10730	10185	9910	9836	10078	10821	12535	13930	14578	15115	15574	15872	15907	16013	15906	15831	15788	15659	15336	15167	15420	14904	13430	11956
ISONE	6/8/12	10929	10393	10073	9931	10160	10841	12528	14053	14836	15441	15989	16330	16463	16670	16665	16538	16429	16140	15663	15358	15492	15054	13781	12409
ISONE	6/9/12	11355	10675	10298	10044	9998	10047	10735	11903	13126	13917	14357	14540	14552	14450	14357	14378	14531	14641	14537	14373	14580	14454	13449	12248
ISONE	6/10/12	11202	10549	10142	9907	9798	9699	10141	11168	12440	13506	14229	14707	14996	15075	15128	15233	15439	15582	15483	15266	15386	15035	13599	12157
ISONE	6/11/12	11144	10559	10268	10179	10406	11152	12924	14520	15380	15980	16445	16734	16891	17045	17048	17058	17077	16926	16461	16082	16159	15557	13934	12371
ISONE	6/12/12	11360	10741	10453	10336	10590	11301	13088	14660	15491	16009	16451	16689	16796	16994	16953	16861	16825	16669	16333	16122	16221	15510	13979	12520
ISONE	6/13/12	11546	10994	10695	10600	10810	11640	13350	14948	15703	16133	16466	16615	16593	16626	16501	16376	16408	16397	16148	15899	15931	15442	13964	12475
ISONE	6/14/12	11444	10843	10469	10354	10550	11287	12979	14544	15355	15826	16206	16370	16429	16556	16597	16614	16638	16514	16127	15760	15800	15469	13962	12418
ISONE	6/15/12	11331	10651	10292	10161	10330	10921	12565	14155	15120	15754	16230	16458	16526	16660	16661	16621	16581	16340	15835	15354	15270	14986	13709	12298
ISONE	6/16/12	11195	10530	10158	9949	9900	9913	10598	11787	13058	13925	14389	14557	14554	14423	14303	14272	14317	14351	14177	13911	14012	13859	12874	11673
ISONE	6/17/12	10733	10140	9788	9580	9538	9462	9824	10709	11833	12694	13219	13522	13650	13580	13537	13580	13739	13906	13871	13761	14039	13865	12666	11384
ISONE	6/18/12	10498	9981	9767	9724	9998	10739	12290	13848	14761	15355	15833	16083	16131	16354	16283	16246	16272	16178	15848	15530	15578	15129	13598	12115

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
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ISONE	6/20/12	12147	11499	11158	11013	11226	11939	13743	15856	17540	19078	20546	21701	22573	23366	23914	24316	24629	24656	24306	23779	23489	22861	20799	18712
ISONE	6/21/12	17089	16075	15381	14922	14849	15300	17059	19170	20880	22305	23482	24320	24834	25249	25479	25602	25678	25468	24977	24253	23789	23009	20885	18740
ISONE	6/22/12	17101	16022	15291	14821	14801	15234	16883	18949	20659	22093	23268	24206	24823	25178	25109	24777	23999	22967	21713	20696	20226	19465	17899	16205
ISONE	6/23/12	14836	13984	13386	13018	12903	12964	13431	14350	15585	16712	17691	18415	18861	19066	19196	19246	19084	18491	17617	16842	16433	16045	14892	13553
ISONE	6/24/12	12506	11737	11243	10943	10812	10657	11121	12176	13479	14620	15442	16009	16372	16609	16869	17137	17375	17382	17205	16910	17033	16795	15486	14034
ISONE	6/25/12	12930	12260	11880	11745	11950	12614	14132	15817	16786	17319	17704	17777	17710	17653	17583	17544	17435	17320	16957	16532	16461	15899	14389	12894
ISONE	6/26/12	11836	11197	10846	10673	10830	11407	12810	14298	15229	15829	16400	16708	16855	16944	16891	16724	16638	16499	16129	15767	15770	15284	13895	12431
ISONE	6/27/12	11439	10833	10471	10373	10556	11196	12614	14160	15154	15848	16453	16830	17030	17278	17361	17340	17317	17186	16816	16458	16420	16036	14602	13103
ISONE	6/28/12	12002	11336	10947	10745	10909	11521	12995	14751	15985	16880	17677	18249	18658	19005	19345	19572	19845	19873	19502	18914	18722	18265	16622	14852
ISONE	6/29/12	13509	12681	12192	11969	12111	12763	14158	15857	16966	17733	18551	19455	20359	21333	22094	22535	22893	22902	22387	21530	20911	20085	18240	16230
ISONE	6/30/12	14629	13522	12775	12314	12120	12035	12772	14232	15921	17392	18547	19298	19746	20091	20346	20604	20802	20738	20278	19627	19231	18858	17496	15927
ISONE	7/1/12	14591	13650	12981	12571	12338	12134	12585	13818	15469	17077	18374	19400	20112	20591	20793	20509	20188	20100	19955	19471	19162	18656	17054	15299
ISONE	7/2/12	14011	13173	12631	12368	12491	12963	14431	16263	17677	18821	19718	20285	20593	20874	21033	20964	20896	20757	20283	19562	19073	18451	16723	14895
ISONE	7/3/12	13551	12750	12205	11931	11980	12413	13838	15643	17020	18117	18961	19518	19891	20259	20506	20669	20778	20569	19761	18821	18440	17752	16454	15032
ISONE	7/4/12	13838	13016	12488	12244	12261	12408	12811	13543	14552	15815	17109	18151	18894	19261	19482	19705	19954	20078	19727	19123	18841	18340	17354	15977
ISONE	7/5/12	14765	13921	13384	13077	13135	13565	15013	16916	18457	19626	20511	21056	21388	21668	21838	21853	21800	21632	21065	20295	19828	19194	17442	15583
ISONE	7/6/12	14195	13296	12713	12383	12385	12777	14168	16023	17587	18903	20005	20764	21257	21777	22104	22363	22500	22424	21675	20825	20536	19907	18333	16628
ISONE	7/7/12	15300	14404	13792	13407	13251	13229	13782	15098	16771	18194	19174	19856	20321	20317	19883	19472	19466	19584	19362	18838	18548	18214	16996	15542
ISONE	7/8/12	14248	13357	12738	12342	12120	11905	12327	13488	15028	16468	17668	18631	19259	19598	19847	20083	20376	20539	20245	19629	19423	18961	17329	15502
ISONE	7/9/12	14081	13125	12521	12182	12217	12657	14089	15817	17018	17974	18736	19245	19614	20007	20242	20386	20517	20441	19878	19117	18704	18038	16271	14470
ISONE	7/10/12	13161	12339	11813	11571	11642	12080	13519	15236	16454	17398	18219	18768	19160	19627	19991	20260	20434	20341	19841	19114	18803	18282	16567	14822
ISONE	7/11/12	13537	12723	12228	12001	12097	12605	14055	15822	17162	18215	19153	19905	20418	20838	21056	21210	21392	21345	20821	20029	19643	19089	17336	15495
ISONE	7/12/12	14152	13276	12692	12388	12450	12959	14493	16313	17729	18912	20078	20991	21476	22006	22368	22599	22763	22575	21939	20976	20518	19798	17954	16059
ISONE	7/13/12	14594	13658	13082	12767	12829	13347	14785	16677	18207	19540	20730	21670	22356	22910	23108	23072	22922	22408	21490	20599	20261	19619	17987	16270
ISONE	7/14/12	14927	14076	13516	13184	13090	13245	13792	14874	16335	17644	18618	19413	20026	20531	21017	21404	21661	21687	21274	20522	20174	19685	18206	16551
ISONE	7/15/12	15176	14207	13543	13106	12861	12670	13031	14244	15921	17556	19003	20169	20838	20966	20977	21009	21049	21036	20696	20399	20467	19728	18184	16584
ISONE	7/16/12	15430	14688	14215	13966	14063	14702	16241	18280	19864	21137	22257	23156	23852	24450	24577	24626	24579	24397	23830	23081	22788	21882	19793	17725
ISONE	7/17/12	16260	15311	14696	14313	14349	14929	16540	18634	20312	21797	23083	23962	24569	25118	25465	25726	25880	25667	25077	24307	23867	22996	21025	19069
ISONE	7/18/12	17692	16837	16298	15971	15954	16512	17974	20122	21630	22845	24096	25048	25649	25667	25065	23894	23008	22628	22053	21501	21337	20643	18891	17061
ISONE	7/19/12	15657	14646	14003	13610	13587	14067	15234	16653	17479	18053	18614	19001	19236	19574	19695	19847	20003	19947	19373	18684	18568	17924	16362	14717
ISONE	7/20/12	13484	12766	12311	12105	12228	12846	14081	15541	16500	17001	17330	17387	17302	17284	17115	16867	16732	16555	16154	15821	15956	15560	14352	12997
ISONE	7/21/12	11935	11244	10822	10589	10555	10633	11172	12291	13630	14647	15293	15670	15859	15954	16041	16175	16383	16483	16275	15772	15718	15376	14264	13033
ISONE	7/22/12	11986	11313	10888	10626	10521	10417	10736	11695	13009	14201	15182	15975	16538	16862	17163	17466	17869	18120	17926	17447	17458	17019	15693	14250
ISONE	7/23/12	13164	12461	12059	11918	12161	12935	14324	15972	17180	18080	18927	19601	20071	20748	21276	21664	21900	21811	21301	20762	20801	20025	18286	16501

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
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ISONE	7/25/12	13907	12941	12344	11995	12040	12567	13837	15468	16618	17404	18021	18421	18693	19080	19406	19704	19964	19953	19420	18726	18753	18037	16401	14723
ISONE	7/26/12	13561	12794	12334	12152	12315	13090	14515	16066	17103	17813	18344	18648	18910	19465	19953	20405	20858	21105	20880	20569	20360	19350	17676	16006
ISONE	7/27/12	14781	13954	13408	13136	13254	14000	15309	16823	17904	18791	19566	20125	20476	20710	20708	20603	20479	20301	19806	19204	18985	18395	16988	15447
ISONE	7/28/12	14178	13282	12693	12336	12256	12364	12837	13974	15409	16692	17607	18091	18277	18290	18146	17728	17366	17195	16930	16705	16710	16116	15060	13879
ISONE	7/29/12	12849	12180	11741	11487	11426	11517	11716	12478	13564	14537	15211	15715	16020	16058	16007	15931	16086	16308	16216	15985	16159	15683	14496	13207
ISONE	7/30/12	12189	11555	11196	11051	11280	11961	13285	14989	16297	17271	18122	18744	19211	19724	20058	20245	20402	20287	19745	19009	18834	17973	16206	14468
ISONE	7/31/12	13204	12419	11955	11722	11863	12518	13816	15433	16586	17411	18124	18562	18816	19101	19105	18903	18707	18499	18161	17908	18023	17217	15713	14245
ISONE	8/1/12	13137	12441	12017	11842	12025	12775	14125	15794	17032	18058	18964	19628	20129	20570	20721	20526	20356	20110	19651	19221	19251	18492	16832	15186
ISONE	8/2/12	14005	13247	12767	12607	12767	13519	14889	16633	18049	19314	20510	21442	22083	22706	23086	23321	23433	23323	22800	22077	21899	20965	19040	17172
ISONE	8/3/12	15679	14726	14068	13732	13798	14461	15795	17541	19118	20529	21893	22906	23602	24206	24608	24751	24739	24411	23622	22825	22638	21778	20031	18195
ISONE	8/4/12	16578	15560	14810	14332	14121	14182	14670	15999	17738	19340	20743	21778	22423	22803	23018	23039	22841	22413	21656	20919	20828	20057	18657	17145
ISONE	8/5/12	15908	15020	14447	14081	13951	13999	14294	15345	16858	18469	19801	20890	21699	22078	22189	22198	22053	21599	21154	20824	20708	19868	18421	16883
ISONE	8/6/12	15632	14856	14392	14164	14343	15075	16370	18164	19591	20597	21178	21627	21908	22178	22285	22329	22232	21857	21022	20138	19908	18807	16858	15061
ISONE	8/7/12	13688	12835	12293	12046	12142	12762	14011	15668	16852	17824	18706	19382	19852	20355	20636	20820	20909	20691	20090	19477	19550	18640	16902	15195
ISONE	8/8/12	13914	13065	12512	12237	12368	13053	14347	16076	17541	18777	19966	20861	21496	22085	22402	22549	22490	22173	21559	21038	21107	20087	18262	16403
ISONE	8/9/12	14974	14162	13615	13362	13489	14265	15582	17303	18793	20146	21448	22442	23107	23656	23860	23886	23741	23314	22516	21963	21934	20837	19009	17197
ISONE	8/10/12	15853	15026	14485	14243	14370	15145	16480	18189	19599	20739	21642	22248	22385	22262	21802	21173	20794	20366	19799	19387	19384	18659	17355	15905
ISONE	8/11/12	14722	13936	13413	13120	13031	13185	13625	14755	16154	17441	18521	19170	19547	19776	19901	19999	20079	20043	19725	19399	19514	18797	17559	16175
ISONE	8/12/12	14996	14195	13630	13317	13202	13307	13531	14222	15406	16628	17688	18513	19141	19535	19906	20237	20480	20529	20213	19764	19850	18915	17307	15663
ISONE	8/13/12	14399	13568	13040	12767	12875	13560	14731	16408	17816	18996	20022	20746	21212	21638	21923	22047	22153	21997	21315	20667	20599	19350	17453	15634
ISONE	8/14/12	14287	13396	12819	12537	12628	13357	14571	16247	17563	18691	19631	20264	20628	20887	20957	20880	20838	20607	20099	19777	19929	18881	17178	15509
ISONE	8/15/12	14342	13577	13103	12906	13057	13873	15261	16636	17504	18138	18963	19783	20400	20970	21253	21368	21273	20938	20387	20159	20100	18985	17244	15529
ISONE	8/16/12	14197	13347	12834	12609	12713	13484	14793	16221	17388	18446	19417	20136	20601	21008	21237	21331	21367	21145	20442	19806	19751	18606	16853	15082
ISONE	8/17/12	13787	12922	12382	12111	12196	12847	13984	15517	16920	18110	19220	20067	20763	21413	21817	21954	21938	21557	20745	20271	20166	19079	17440	15808
ISONE	8/18/12	14461	13553	12944	12549	12402	12550	12863	13638	14655	15459	15973	16283	16333	16287	16224	16167	16215	16210	16000	15785	15973	15234	14098	12861
ISONE	8/19/12	11859	11156	10674	10424	10316	10386	10496	11263	12420	13446	14154	14580	14821	14843	14855	14941	15189	15371	15336	15410	15750	14989	13764	12573
ISONE	8/20/12	11690	11140	10817	10706	10923	11661	12890	14302	15432	16385	17187	17749	18089	18337	18388	18355	18382	18322	17838	17589	17745	16650	15059	13547
ISONE	8/21/12	12465	11858	11466	11310	11525	12368	13720	15133	16208	17109	17907	18439	18802	19164	19359	19422	19424	19108	18467	18106	18189	17064	15384	13793
ISONE	8/22/12	12653	11952	11504	11271	11402	12149	13310	14848	16022	17027	17906	18534	18915	19325	19575	19643	19686	19446	18846	18423	18520	17416	15720	14126
ISONE	8/23/12	12961	12236	11748	11559	11685	12488	13706	15306	16624	17687	18598	19329	19897	20466	20735	20863	20899	20659	20030	19576	19611	18458	16712	15028
ISONE	8/24/12	13816	12991	12458	12174	12272	12987	14137	15644	16944	18046	19043	19777	20257	20725	20922	20871	20778	20364	19594	19187	19083	18015	16504	14937
ISONE	8/25/12	13673	12879	12341	12032	11983	12236	12688	13703	15033	16219	17092	17652	18002	18216	18323	18286	18185	17925	17396	17157	17113	16252	15021	13706
ISONE	8/26/12	12663	11921	11453	11151	11057	11168	11303	12143	13427	14625	15546	16258	16820	17130	17410	17692	17975	18119	17789	17582	17632	16542	15021	13656
ISONE	8/27/12	12572	11917	11528	11354	11551	12397	13695	15239	16531	17598	18524	19297	19878	20486	20782	20823	20770	20501	19988	20004	19980	18846	17191	15649

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
ISONE	8/28/12	14565	13876	13464	13306	13543	14551	16279	17737	18577	19107	19631	20235	20752	21338	21711	21837	21878	21572	20729	20367	20102	18625	16655	14853
ISONE	8/29/12	13451	12594	12000	11685	11717	12504	13823	15116	15922	16501	16985	17282	17484	17744	17901	18002	18119	18030	17524	17354	17250	16013	14339	12790
ISONE	8/30/12	11749	11111	10730	10580	10758	11621	13062	14411	15378	16168	16865	17311	17604	17988	18202	18346	18454	18258	17721	17747	17719	16560	14949	13497
ISONE	8/31/12	12417	11701	11295	11117	11279	12122	13450	14845	16020	17008	17889	18623	19143	19759	20107	20296	20334	20151	19521	19279	19124	18094	16699	15172
ISONE	9/1/12	13779	13113	12654	12334	12184	12370	12692	13666	15110	16348	17192	17763	18053	18089	18030	17878	17767	17469	16890	16766	16605	15744	14562	13305
ISONE	9/2/12	12283	11614	11172	10935	10837	10947	11098	11820	12981	13975	14655	15123	15505	15662	15748	15777	15807	15830	15603	15679	15594	14834	13760	12605
ISONE	9/3/12	11683	11070	10691	10503	10519	10819	11160	11856	12978	14074	14849	15353	15627	15797	15911	16018	16216	16358	16219	16557	16488	15318	13809	12489
ISONE	9/4/12	11630	11126	10893	10852	11126	12204	14158	15577	16351	16978	17486	17745	17852	17974	17944	18015	18177	18379	18438	18768	18499	17392	15832	14422
ISONE	9/5/12	13466	12924	12662	12606	12925	14065	16168	17682	18512	19168	19498	19588	19568	19712	19861	19930	20105	20080	19720	19804	19415	18018	16155	14480
ISONE	9/6/12	13239	12474	12035	11846	12027	12988	14733	16037	16799	17436	18029	18383	18551	18952	19261	19412	19425	19175	18809	19165	18903	17632	15895	14306
ISONE	9/7/12	13206	12527	12116	11916	12126	13115	14889	16254	17206	18106	18987	19811	20390	20905	21275	21439	21432	20970	20265	20274	19844	18647	17061	15452
ISONE	9/8/12	14236	13422	12935	12664	12620	12987	13554	14507	15912	17086	17946	18418	18659	18704	18666	18612	18600	18588	18616	18722	18160	17077	15539	13951
ISONE	9/9/12	12779	11993	11430	11102	10958	11063	11329	11878	12845	13691	14212	14556	14819	14836	14920	15062	15340	15565	15509	15907	15621	14497	13118	11863
ISONE	9/10/12	11000	10487	10205	10132	10392	11381	13047	14208	14879	15404	15840	16044	16029	16027	15878	15719	15694	15669	15533	15935	15524	14313	12787	11433
ISONE	9/11/12	10579	10071	9794	9730	9980	10972	12632	13758	14310	14764	15152	15407	15525	15718	15742	15752	15816	15816	15656	16111	15724	14488	12931	11570
ISONE	9/12/12	10658	10146	9886	9812	10044	11017	12751	13901	14453	14980	15538	15931	16140	16418	16497	16553	16619	16555	16308	16778	16352	15114	13552	12117
ISONE	9/13/12	11170	10623	10338	10230	10452	11408	13146	14331	15105	15766	16410	16900	17209	17580	17742	17859	17930	17738	17364	17751	17289	15991	14335	12828
ISONE	9/14/12	11775	11155	10789	10655	10841	11773	13475	14672	15495	16232	16917	17432	17766	18136	18272	18250	18108	17609	17069	17289	16780	15765	14404	13033
ISONE	9/15/12	11987	11344	10970	10767	10770	11106	11639	12452	13502	14211	14547	14649	14639	14536	14413	14353	14386	14388	14312	14710	14352	13524	12475	11373
ISONE	9/16/12	10533	9995	9657	9468	9455	9654	9961	10656	11736	12558	13046	13321	13511	13505	13503	13578	13807	14153	14297	14893	14432	13340	12065	10930
ISONE	9/17/12	10188	9770	9548	9530	9810	10822	12515	13660	14309	14828	15322	15619	15770	15984	16044	16060	16103	16130	16096	16624	16000	14734	13175	11809
ISONE	9/18/12	10931	10396	10110	10056	10335	11383	13251	14517	15224	15757	16243	16503	16598	16753	16702	16674	16870	17150	17357	17529	16887	15669	14144	12834
ISONE	9/19/12	11924	11378	11048	10911	11063	11961	13715	14807	15199	15469	15748	15930	15976	16085	16016	15928	15905	15776	15659	16194	15634	14435	12867	11528
ISONE	9/20/12	10608	10106	9833	9754	10007	10997	12807	13874	14351	14703	15055	15216	15215	15323	15250	15132	15108	15101	15203	15817	15326	14206	12724	11384
ISONE	9/21/12	10503	10019	9763	9696	9940	10904	12757	13875	14384	14737	15025	15116	15140	15166	15099	15005	14961	14853	14884	15328	14837	13895	12684	11449
ISONE	9/22/12	10554	10020	9715	9607	9635	9979	10635	11485	12570	13322	13711	13823	13820	13719	13675	13673	13805	14005	14338	14792	14367	13650	12648	11569
ISONE	9/23/12	10815	10243	9912	9745	9699	9893	10241	10839	11853	12646	13107	13346	13438	13384	13350	13398	13596	13943	14267	14861	14294	13200	12007	10865
ISONE	9/24/12	10034	9557	9331	9304	9590	10636	12532	13698	14221	14601	14921	15102	15129	15187	15067	14952	14962	15112	15402	15930	15234	14012	12508	11201
ISONE	9/25/12	10354	9904	9658	9618	9883	10921	12859	13969	14373	14665	14993	15130	15158	15248	15209	15150	15226	15292	15576	16075	15388	14239	12737	11454
ISONE	9/26/12	10592	10125	9892	9839	10140	11159	13049	14245	14881	15370	15800	15985	16019	16070	15971	15820	15915	16172	16519	16680	15989	14831	13330	11991
ISONE	9/27/12	11081	10571	10254	10165	10398	11462	13398	14496	14979	15305	15585	15732	15744	15780	15683	15568	15524	15450	15703	16140	15494	14350	12885	11544
ISONE	9/28/12	10637	10111	9828	9760	10000	10949	12876	14105	14681	15019	15278	15394	15364	15366	15212	15128	15190	15337	15574	15504	14831	13933	12771	11567
ISONE	9/29/12	10642	10097	9783	9631	9661	10039	10752	11654	12728	13482	13866	13938	13848	13625	13447	13343	13469	13774	14229	14352	13872	13149	12183	11122
ISONE	9/30/12	10296	9769	9469	9313	9316	9543	10038	10712	11783	12722	13311	13635	13781	13640	13542	13458	13649	13941	14506	14844	14253	13181	11971	10844
ISONE	10/1/12	10037	9599	9414	9381	9694	10783	12755	13883	14340	14681	14989	15126	15139	15147	15051	14956	15002	15252	15824	16130	15431	14219	12713	11361

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ISONE	10/3/12	10704	10227	10006	9965	10234	11258	13283	14572	15030	15396	15718	15865	15832	15860	15757	15693	15794	16115	16625	16602	15979	14768	13365	12018
ISONE	10/4/12	11021	10481	10213	10142	10384	11402	13453	14760	15263	15622	15922	16057	16017	15988	15823	15703	15793	16094	16578	16519	15861	14766	13335	11950
ISONE	10/5/12	11011	10471	10163	10084	10320	11237	13121	14281	14825	15315	15761	15998	16040	16108	16041	15937	15813	15613	15949	16081	15436	14515	13316	12065
ISONE	10/6/12	11092	10467	10109	9950	9955	10270	10959	11752	12863	13677	14128	14352	14370	14262	14165	14111	14232	14505	14791	14641	14031	13273	12231	11161
ISONE	10/7/12	10305	9771	9467	9331	9333	9533	9985	10614	11630	12354	12749	12947	13087	13078	13081	13140	13382	13722	14431	14392	13845	12969	11923	10888
ISONE	10/8/12	10106	9645	9428	9400	9637	10356	11603	12683	13557	14146	14487	14598	14506	14435	14337	14246	14434	14957	15820	15878	15174	14008	12568	11284
ISONE	10/9/12	10401	9926	9709	9677	9971	11037	13120	14353	14729	14961	15144	15220	15163	15147	15009	14916	15049	15492	16257	16228	15500	14293	12774	11427
ISONE	10/10/12	10563	10089	9857	9801	10072	11098	13160	14454	14820	15057	15279	15382	15358	15360	15272	15217	15385	15734	16324	16276	15551	14372	12866	11503
ISONE	10/11/12	10603	10121	9858	9834	10125	11168	13226	14316	14615	14754	14830	14816	14721	14686	14504	14393	14447	14773	15717	15982	15413	14307	12961	11661
ISONE	10/12/12	10712	10220	9969	9922	10179	11215	13235	14365	14699	14994	15241	15291	15148	15022	14714	14484	14506	14823	15644	15738	15204	14394	13223	12039
ISONE	10/13/12	11133	10651	10410	10321	10447	10906	11720	12604	13521	13936	13995	13805	13512	13195	12944	12874	13088	13640	14663	14688	14251	13535	12564	11537
ISONE	10/14/12	10705	10138	9858	9709	9710	9957	10493	11231	12273	13133	13623	13893	13953	13786	13567	13462	13639	14072	14967	15031	14448	13335	12111	11004
ISONE	10/15/12	10232	9846	9677	9671	9980	11067	13126	14323	14709	15157	15465	15595	15573	15592	15449	15341	15438	15902	16681	16446	15648	14426	12929	11625
ISONE	10/16/12	10734	10221	9930	9815	10006	10952	12943	14173	14406	14575	14780	14829	14724	14681	14493	14373	14507	14958	15994	16018	15382	14204	12892	11650
ISONE	10/17/12	10697	10244	10046	10029	10353	11446	13586	14702	14900	14908	14948	14888	14782	14746	14597	14487	14547	14977	16017	16007	15379	14264	12737	11475
ISONE	10/18/12	10619	10170	9974	9927	10239	11311	13453	14610	14807	14886	14988	14296	14574	14563	14942	14033	14662	15007	15961	15954	15308	14215	12784	11465
ISONE	10/19/12	10569	10079	9849	9796	10060	11050	13058	14412	14886	15226	15504	15578	15494	15477	15346	15260	15379	15760	16127	15734	15107	14220	13032	11787
ISONE	10/20/12	10852	10314	9999	9862	9902	10232	10996	11895	12922	13719	14114	14219	14108	13876	13598	13424	13462	13751	14583	14396	13873	13119	12131	11097
ISONE	10/21/12	10248	9697	9404	9246	9257	9481	10012	10628	11596	12353	12720	12914	12985	12900	12836	12871	13187	13802	14870	14612	14103	13049	11814	10703
ISONE	10/22/12	9928	9536	9377	9387	9698	10789	12905	14058	14346	14617	14855	14943	14874	14855	14705	14591	14686	15150	16178	16004	15207	14028	12625	11339
ISONE	10/23/12	10397	9903	9659	9632	9883	10986	13103	14225	14449	14596	14762	14833	14786	14807	14666	14570	14708	15296	16264	15992	15242	14103	12614	11317
ISONE	10/24/12	10476	10018	9781	9724	10000	11044	13196	14414	14657	14825	14944	14956	14904	14872	14712	14601	14766	15394	16243	15994	15295	14202	12688	11407
ISONE	10/25/12	10537	10079	9861	9834	10106	11186	13314	14442	14600	14753	14889	14903	14807	14769	14599	14476	14570	15097	16077	15909	15277	14211	12770	11457
ISONE	10/26/12	10583	10085	9848	9812	10067	11097	13129	14307	14575	14810	14979	14993	14873	14789	14619	14466	14450	14808	15527	15188	14589	13724	12558	11357
ISONE	10/27/12	10464	9935	9644	9504	9563	9957	10778	11658	12638	13305	13605	13609	13513	13326	13120	13024	13162	13806	14675	14353	13819	13074	12135	11123
ISONE	10/28/12	10318	9785	9465	9312	9309	9548	10110	10892	11916	12828	13354	13673	13864	13837	13788	13813	14188	15001	15682	15332	14607	13614	12473	11368
ISONE	10/29/12	10451	9924	9648	9583	9814	10691	12188	13399	14266	15002	15417	15524	15328	15007	14351	13669	13324	13359	12980	12060	11262	10506	9665	8895
ISONE	10/30/12	8353	8061	7904	7892	8122	8813	10107	11215	11909	12457	12902	13126	13249	13287	13183	13193	13480	14222	14686	14298	13678	12625	11466	10416
ISONE	10/31/12	9713	9315	9098	9056	9293	10207	12021	13208	13502	13779	14012	14096	14051	14023	13908	13855	14019	14412	14689	14386	14032	13225	12007	10866
ISONE	11/1/12	10119	9724	9507	9460	9734	10715	12631	13806	14009	14181	14309	14302	14215	14169	14036	13991	14240	15044	15738	15476	14855	13842	12495	11291
ISONE	11/2/12	10452	9988	9735	9684	9944	10934	12868	14126	14365	14527	14644	14529	14406	14384	14243	14161	14394	15053	15579	15209	14639	13832	12733	11597
ISONE	11/3/12	10734	10202	9945	9825	9905	10291	11097	11968	12819	13416	13613	13542	13367	13129	12945	12874	13185	14040	14812	14499	14054	13401	12523	11602
ISONE	11/4/12	10758	10074	9775	9760	9930	10353	10954	11827	12698	13123	13175	13130	13047	12952	12915	13147	14374	15477	15513	15037	14532	13244	12007	10965
ISONE	11/5/12	10501	10189	10070	10140	10570	11833	13922	15041	15314	15441	15475	15418	15287	15179	14923	15043	16148	17483	17399	16922	16192	15057	13685	12444

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
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ISONE	11/7/12	12302	11803	11474	11388	11831	12923	14902	15836	16199	16409	16565	16694	16691	16759	16819	17162	17973	18792	18733	18006	17336	15960	14400	13120
ISONE	11/8/12	12217	11791	11570	11573	11916	13031	14825	15914	16389	16534	16679	16707	16562	16515	16371	16479	17355	18103	17862	17391	16652	15418	13951	12619
ISONE	11/9/12	11822	11376	11138	11121	11474	12604	14444	15347	15507	15490	15463	15324	15052	14911	14744	14739	15566	16648	16429	15906	15304	14437	13313	12190
ISONE	11/10/12	11319	10860	10596	10502	10640	11098	11816	12665	13508	13900	13928	13762	13511	13250	13096	13202	14242	15384	15181	14735	14232	13529	12616	11642
ISONE	11/11/12	10904	10418	10147	10027	10090	10363	10852	11573	12508	13049	13251	13303	13276	13101	12948	13001	14075	15321	15126	14622	13991	13086	12025	11038
ISONE	11/12/12	10347	9955	9769	9777	10080	11008	12400	13498	14219	14626	14866	14921	14853	14784	14673	14687	15735	16840	16568	15980	15179	13990	12581	11395
ISONE	11/13/12	10567	10102	9855	9835	10131	11226	13184	14348	14671	14909	15141	15222	15194	15204	15129	15281	16177	17153	17001	16533	15837	14752	13328	12091
ISONE	11/14/12	11300	10874	10699	10718	11104	12317	14368	15351	15465	15413	15377	15248	15074	14954	14874	15034	16112	17423	17365	16967	16349	15273	13881	12610
ISONE	11/15/12	11772	11354	11160	11209	11576	12722	14750	15771	15933	15943	15903	15750	15537	15460	15335	15520	16655	17664	17564	17152	16493	15389	13983	12691
ISONE	11/16/12	11873	11439	11213	11231	11567	12693	14630	15632	15823	15775	15711	15516	15314	15233	15109	15171	16166	17050	16818	16333	15788	14957	13883	12736
ISONE	11/17/12	11850	11358	11132	11072	11196	11681	12459	13295	14053	14416	14397	14214	13934	13641	13455	13616	14753	15898	15734	15308	14848	14174	13327	12382
ISONE	11/18/12	11623	11186	10973	10899	10994	11354	11929	12629	13423	13840	13941	13927	13813	13664	13595	13913	15262	16458	16385	15953	15385	14381	13204	12155
ISONE	11/19/12	11466	11124	11010	11079	11498	12702	14780	15836	16004	15930	15855	15699	15450	15313	15149	15266	16417	17613	17541	17142	16499	15373	13975	12669
ISONE	11/20/12	11832	11401	11254	11288	11672	12887	14863	15803	15921	15822	15702	15531	15348	15232	15081	15201	16392	17405	17322	16914	16273	15265	13851	12531
ISONE	11/21/12	11643	11169	10939	10913	11246	12307	14102	15196	15580	15733	15749	15637	15387	15272	15118	15073	16087	17095	16866	16385	15735	14797	13578	12316
ISONE	11/22/12	11364	10813	10500	10390	10501	11000	11747	12662	13678	14347	14634	14631	14128	13311	12586	12217	12682	13225	13234	13208	13146	12790	12236	11472
ISONE	11/23/12	10789	10419	10281	10265	10508	11127	11939	12628	13300	13703	13830	13767	13562	13337	13216	13358	14583	15507	15258	14780	14232	13498	12531	11460
ISONE	11/24/12	10640	10132	9873	9769	9865	10271	10993	11820	12887	13619	13869	13913	13845	13680	13631	13870	15131	16086	15956	15579	15147	14489	13552	12547
ISONE	11/25/12	11735	11234	10981	10894	10993	11316	11825	12451	13451	14195	14643	14865	14884	14731	14720	15013	16363	17386	17253	16790	16223	15018	13712	12535
ISONE	11/26/12	11751	11343	11174	11183	11595	12772	14847	15896	15986	16014	15993	15899	15771	15657	15496	15662	16952	18227	18205	17816	17116	15958	14438	13074
ISONE	11/27/12	12230	11786	11575	11564	11920	13048	15111	16211	16477	16594	16722	16774	16751	16736	16642	16856	18013	18778	18634	18135	17350	16095	14527	13122
ISONE	11/28/12	12208	11721	11522	11520	11883	13029	15125	16232	16354	16383	16430	16302	16103	16054	16013	16247	17519	18536	18431	18025	17379	16269	14758	13376
ISONE	11/29/12	12484	12041	11854	11854	12194	13372	15482	16470	16467	16351	16293	16170	15928	15847	15706	15892	17115	18218	18290	17931	17230	16093	14557	13145
ISONE	11/30/12	12233	11770	11545	11559	11931	13114	15183	16235	16494	16568	16509	16381	16223	16177	16124	16373	17635	18301	18016	17555	16975	16089	14844	13553

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Loads	
MAX	6922
PST	5392
Winter	4292
Spring	3733
Summer	5011
Fall	3970

Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
12/1/2011	2665	2564	2513	2512	2620	2947	3460	3725	3745	3736	3732	3697	3649	3632	3611	3634	3924	4274	4287	4200	4064	3803	3435	3074
12/2/2011	2833	2725	2674	2671	2763	3050	3580	3851	3868	3817	3782	3734	3664	3633	3605	3610	3911	4166	4112	3984	3855	3653	3369	3035
12/3/2011	2787	2651	2590	2573	2616	2740	2959	3189	3421	3527	3527	3470	3386	3308	3269	3303	3638	3963	3942	3843	3740	3589	3351	3072
12/4/2011	2839	2696	2624	2591	2602	2673	2807	2965	3212	3362	3388	3369	3344	3302	3261	3312	3667	4024	4022	3917	3793	3525	3168	2829
12/5/2011	2606	2496	2445	2436	2509	2790	3317	3606	3669	3702	3727	3719	3667	3650	3616	3631	3959	4285	4273	4148	3970	3663	3256	2867
12/6/2011	2606	2481	2412	2388	2458	2722	3250	3591	3664	3697	3734	3736	3713	3724	3714	3784	4084	4272	4226	4091	3914	3626	3221	2828
12/7/2011	2554	2432	2361	2345	2402	2662	3185	3552	3653	3709	3754	3761	3744	3747	3745	3829	4098	4266	4224	4107	3946	3679	3298	2930
12/8/2011	2683	2575	2543	2540	2630	2930	3473	3768	3799	3816	3834	3811	3768	3765	3752	3771	4084	4439	4448	4367	4235	3977	3591	3192
12/9/2011	2935	2815	2763	2762	2846	3128	3651	3937	3963	3939	3897	3838	3750	3716	3685	3697	4017	4290	4225	4082	3927	3706	3401	3048
12/10/2011	2786	2627	2549	2514	2542	2652	2870	3107	3384	3522	3562	3550	3505	3446	3397	3446	3808	4137	4105	4003	3903	3760	3533	3252
12/11/2011	3010	2869	2799	2783	2809	2895	3048	3215	3449	3583	3607	3590	3557	3506	3476	3539	3936	4323	4344	4289	4172	3920	3566	3228
12/12/2011	3004	2885	2842	2860	2956	3262	3814	4104	4097	4050	4020	3970	3903	3892	3866	3907	4217	4506	4524	4515	4410	4130	3718	3316
12/13/2011	3061	2959	2914	2916	3021	3332	3887	4161	4149	4090	4033	3961	3881	3854	3808	3840	4198	4575	4581	4494	4336	4056	3651	3240
12/14/2011	2977	2849	2795	2797	2877	3164	3708	3994	4001	3945	3909	3858	3788	3770	3743	3772	4129	4488	4473	4379	4223	3947	3544	3129
12/15/2011	2839	2704	2630	2617	2678	2950	3474	3793	3846	3856	3870	3861	3807	3805	3783	3803	4142	4362	4322	4204	4048	3777	3383	2980
12/16/2011	2685	2540	2468	2454	2523	2802	3329	3647	3710	3718	3740	3715	3651	3648	3642	3679	4019	4300	4249	4123	3988	3792	3505	3146
12/17/2011	2865	2721	2648	2624	2659	2783	3006	3253	3528	3658	3670	3630	3576	3540	3529	3590	3940	4220	4180	4078	3980	3837	3603	3315
12/18/2011	3066	2910	2839	2821	2842	2934	3112	3311	3566	3730	3775	3773	3762	3718	3703	3771	4156	4534	4569	4523	4427	4193	3847	3484
12/19/2011	3249	3137	3101	3114	3213	3505	4037	4328	4275	4204	4210	4161	4054	3994	3952	4041	4409	4646	4617	4527	4364	4067	3651	3220
12/20/2011	2922	2757	2684	2657	2726	3001	3521	3856	3923	3946	3968	3966	3922	3910	3884	3931	4274	4541	4560	4483	4334	4069	3660	3240
12/21/2011	2939	2792	2714	2686	2755	3018	3524	3865	3926	3965	4000	3999	3964	3951	3930	3987	4222	4349	4315	4255	4113	3851	3462	3023
12/22/2011	2721	2566	2476	2453	2524	2783	3293	3613	3667	3692	3716	3682	3613	3603	3597	3646	3949	4231	4222	4135	4002	3775	3419	3024
12/23/2011	2712	2557	2475	2446	2507	2735	3172	3506	3623	3673	3676	3652	3624	3580	3566	3598	3905	4245	4213	4103	3990	3816	3549	3220

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Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
12/24/2011	2941	2786	2705	2670	2695	2797	2992	3232	3507	3703	3774	3767	3726	3664	3636	3657	3912	4187	4063	3928	3845	3778	3656	3448
12/25/2011	3215	3035	2940	2895	2887	2933	3050	3246	3511	3705	3760	3735	3664	3497	3347	3287	3471	3661	3632	3598	3558	3459	3263	2997
12/26/2011	2772	2630	2559	2547	2590	2705	2870	3003	3207	3389	3506	3549	3517	3441	3390	3418	3737	4137	4126	4050	3952	3762	3478	3167
12/27/2011	2923	2800	2740	2734	2795	2998	3330	3593	3796	3954	4029	4020	3943	3904	3881	3943	4194	4368	4293	4140	3945	3649	3267	2910
12/28/2011	2661	2521	2455	2440	2503	2692	3033	3314	3508	3639	3733	3768	3772	3770	3759	3789	4072	4415	4409	4307	4183	3958	3649	3314
12/29/2011	3080	2958	2903	2907	2977	3183	3524	3798	3965	4070	4098	4059	3990	3922	3883	3922	4218	4497	4499	4382	4222	3980	3663	3322
12/30/2011	3067	2908	2821	2799	2832	2998	3286	3528	3703	3812	3867	3830	3728	3638	3564	3576	3828	4165	4119	3989	3857	3666	3412	3114
12/31/2011	2861	2707	2613	2566	2567	2636	2778	2956	3192	3405	3546	3584	3570	3518	3468	3477	3734	4060	3993	3811	3621	3445	3268	3092
1/1/2012	2904	2737	2617	2553	2549	2599	2693	2759	2907	3047	3137	3174	3188	3155	3128	3149	3438	3791	3773	3662	3534	3354	3124	2853
1/2/2012	2590	2447	2385	2383	2443	2578	2781	2938	3153	3359	3515	3577	3572	3554	3550	3612	3928	4325	4304	4209	4041	3773	3427	3101
1/3/2012	2906	2800	2761	2765	2860	3161	3712	4029	4075	4097	4121	4125	4118	4127	4126	4180	4490	4888	4928	4873	4717	4439	4056	3719
1/4/2012	3518	3416	3368	3368	3450	3727	4247	4536	4530	4504	4486	4428	4340	4313	4295	4338	4612	4893	4878	4791	4624	4326	3919	3547
1/5/2012	3310	3182	3112	3089	3159	3420	3918	4231	4269	4273	4218	4128	4049	4024	4009	4037	4279	4630	4629	4518	4363	4078	3684	3330
1/6/2012	3096	2971	2907	2885	2955	3212	3700	3982	3995	3962	3939	3906	3856	3830	3773	3766	3982	4278	4228	4097	3934	3713	3424	3111
1/7/2012	2872	2742	2677	2656	2689	2793	2985	3194	3411	3536	3553	3503	3419	3324	3253	3264	3483	3819	3794	3672	3553	3391	3181	2930
1/8/2012	2716	2587	2521	2502	2520	2604	2752	2910	3134	3320	3412	3455	3482	3455	3435	3485	3774	4138	4146	4049	3924	3693	3384	3095
1/9/2012	2907	2819	2792	2806	2897	3201	3752	4068	4092	4062	4032	3981	3912	3868	3822	3838	4090	4512	4528	4416	4234	3944	3561	3213
1/10/2012	2971	2847	2790	2787	2880	3176	3723	4016	4018	4011	3973	3909	3843	3829	3850	3876	4102	4424	4412	4291	4123	3860	3491	3150
1/11/2012	2930	2831	2788	2801	2895	3191	3740	4032	4010	3959	3925	3874	3800	3766	3730	3769	4000	4371	4388	4264	4094	3815	3427	3078
1/12/2012	2855	2747	2688	2680	2759	3029	3549	3914	3989	4035	4088	4074	4028	4013	3986	3996	4181	4433	4404	4280	4107	3829	3455	3108
1/13/2012	2871	2746	2688	2674	2746	2997	3493	3797	3828	3828	3869	3870	3861	3917	3959	4023	4251	4529	4501	4370	4209	3987	3700	3394
1/14/2012	3151	3015	2945	2914	2941	3041	3235	3424	3644	3840	3894	3865	3797	3711	3661	3685	3892	4248	4258	4143	4035	3876	3664	3424
1/15/2012	3222	3109	3064	3060	3098	3189	3351	3513	3765	3956	4042	4078	4066	4021	3985	4015	4249	4624	4646	4523	4414	4206	3947	3672
1/16/2012	3478	3379	3341	3347	3426	3634	3970	4221	4394	4487	4518	4487	4419	4368	4291	4264	4448	4801	4780	4644	4431	4128	3749	3395
1/17/2012	3149	3026	2963	2943	3027	3261	3712	4030	4102	4092	4082	4082	4075	4073	4049	4101	4304	4533	4479	4336	4130	3833	3447	3100
1/18/2012	2851	2731	2664	2658	2755	3058	3613	3907	3919	3917	3947	3944	3922	3913	3886	3915	4146	4593	4666	4591	4446	4178	3813	3466
1/19/2012	3248	3169	3145	3156	3260	3565	4121	4422	4432	4385	4352	4276	4192	4148	4104	4137	4333	4623	4656	4569	4378	4074	3683	3327
1/20/2012	3086	2964	2908	2900	2996	3276	3807	4103	4146	4146	4154	4128	4068	4036	3979	3986	4181	4552	4547	4417	4274	4062	3781	3491
1/21/2012	3258	3125	3053	3034	3067	3180	3365	3580	3858	4127	4312	4408	4416	4344	4232	4187	4332	4649	4607	4416	4226	4008	3756	3496
1/22/2012	3301	3184	3135	3124	3145	3229	3378	3533	3758	3890	3945	3948	3923	3886	3860	3883	4076	4425	4438	4304	4153	3892	3601	3296

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Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1/23/2012	3057	2949	2902	2905	2985	3254	3762	4064	4125	4147	4188	4189	4161	4139	4090	4077	4263	4549	4526	4382	4164	3847	3456	3088
1/24/2012	2845	2709	2636	2621	2690	2957	3481	3784	3780	3741	3737	3714	3658	3633	3596	3604	3767	4141	4198	4099	3949	3684	3324	3007
1/25/2012	2783	2676	2631	2625	2707	2987	3531	3841	3878	3890	3920	3878	3800	3776	3725	3714	3869	4286	4359	4261	4104	3831	3458	3115
1/26/2012	2891	2784	2730	2729	2806	3085	3616	3922	3937	3924	3932	3930	3920	3961	3951	3981	4158	4426	4420	4297	4118	3839	3456	3103
1/27/2012	2867	2749	2680	2660	2731	2982	3487	3830	3920	3963	4024	4041	3995	3956	3899	3864	3976	4167	4134	3995	3848	3648	3374	3080
1/28/2012	2846	2704	2630	2604	2637	2748	2962	3196	3439	3604	3662	3586	3488	3395	3345	3355	3481	3820	3880	3784	3683	3519	3294	3058
1/29/2012	2851	2728	2661	2639	2656	2735	2877	3023	3247	3402	3473	3489	3473	3441	3415	3423	3607	4026	4120	4032	3891	3651	3341	3048
1/30/2012	2846	2748	2703	2716	2815	3117	3673	3965	3979	3966	3974	3949	3919	3895	3845	3837	3992	4403	4498	4401	4243	3958	3564	3207
1/31/2012	2978	2863	2808	2800	2868	3142	3669	3947	3945	3889	3840	3778	3707	3665	3621	3588	3694	4076	4182	4088	3921	3657	3291	2956
2/1/2012	2729	2625	2567	2564	2629	2895	3417	3727	3747	3739	3741	3737	3681	3640	3577	3545	3628	3976	4063	3960	3802	3544	3187	2865
2/2/2012	2654	2552	2508	2517	2611	2909	3467	3764	3836	3845	3861	3843	3800	3761	3731	3777	3957	4254	4300	4204	4053	3801	3436	3103
2/3/2012	2892	2795	2757	2771	2869	3159	3700	3974	3994	3969	3950	3898	3824	3765	3704	3677	3777	4112	4194	4086	3951	3752	3462	3137
2/4/2012	2900	2763	2688	2657	2679	2787	2987	3195	3428	3556	3580	3528	3464	3396	3338	3351	3479	3814	3898	3801	3695	3542	3326	3089
2/5/2012	2893	2777	2721	2701	2718	2796	2942	3109	3368	3523	3571	3585	3565	3516	3479	3499	3650	4008	4010	3826	3730	3584	3451	3166
2/6/2012	2953	2864	2835	2844	2936	3226	3745	4004	4018	3977	3949	3887	3795	3733	3661	3630	3729	4103	4259	4164	3990	3701	3341	3006
2/7/2012	2796	2697	2659	2673	2763	3066	3597	3853	3856	3812	3811	3791	3724	3673	3624	3610	3734	4104	4246	4158	4011	3752	3389	3062
2/8/2012	2850	2765	2731	2757	2849	3152	3697	3986	4034	4039	4018	3942	3850	3835	3850	3881	4037	4344	4410	4306	4137	3856	3480	3128
2/9/2012	2908	2811	2764	2777	2879	3179	3720	3975	3966	3929	3916	3858	3774	3731	3665	3639	3736	4084	4278	4216	4084	3841	3486	3160
2/10/2012	2958	2862	2825	2835	2925	3198	3720	3985	3978	3922	3881	3805	3733	3711	3663	3639	3737	4044	4131	4019	3864	3661	3388	3097
2/11/2012	2875	2745	2671	2642	2669	2779	2972	3190	3467	3673	3780	3779	3736	3669	3621	3614	3706	3952	4031	3911	3785	3619	3414	3194
2/12/2012	3030	2935	2908	2910	2950	3036	3185	3343	3585	3775	3854	3855	3844	3795	3750	3768	3908	4241	4419	4357	4214	3966	3671	3371
2/13/2012	3160	3061	3010	3011	3093	3364	3871	4122	4147	4116	4095	4039	3950	3884	3819	3781	3859	4166	4364	4326	4182	3920	3564	3224
2/14/2012	3004	2899	2848	2843	2914	3192	3719	3987	3997	3989	3984	3971	3924	3882	3821	3775	3852	4180	4322	4209	4047	3789	3441	3113
2/15/2012	2885	2767	2705	2702	2774	3052	3557	3832	3873	3854	3846	3830	3788	3765	3728	3714	3792	4076	4246	4153	3987	3731	3377	3046
2/16/2012	2830	2747	2714	2729	2821	3116	3638	3907	3955	3957	3964	3960	3929	3936	3923	3942	4057	4296	4371	4253	4080	3806	3443	3090
2/17/2012	2855	2722	2647	2630	2690	2939	3417	3707	3770	3770	3770	3743	3676	3643	3584	3544	3603	3851	4021	3928	3805	3626	3374	3085
2/18/2012	2866	2741	2679	2658	2691	2804	2985	3181	3396	3512	3530	3482	3420	3346	3297	3302	3392	3661	3804	3710	3597	3434	3226	2998
2/19/2012	2807	2697	2631	2605	2623	2697	2820	2957	3155	3299	3351	3346	3308	3232	3165	3150	3252	3565	3814	3756	3649	3466	3232	2991
2/20/2012	2807	2711	2669	2677	2765	2986	3299	3544	3755	3875	3910	3886	3806	3732	3660	3636	3739	4063	4285	4197	4050	3810	3497	3199
2/21/2012	3001	2911	2874	2887	2983	3261	3709	3961	4003	3975	3957	3902	3823	3813	3781	3776	3874	4184	4306	4188	3995	3712	3355	3024

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2/23/2012	2671	2564	2503	2491	2555	2815	3275	3544	3610	3603	3625	3614	3568	3549	3501	3457	3510	3782	4017	3954	3810	3573	3243	2940
2/24/2012	2740	2622	2570	2580	2680	2938	3341	3659	3865	3951	4014	4028	4000	3985	3946	3918	3983	4169	4206	4058	3892	3663	3371	3072
2/25/2012	2854	2732	2661	2640	2668	2775	2935	3125	3353	3519	3592	3579	3523	3457	3396	3395	3505	3748	3942	3860	3754	3596	3376	3140
2/26/2012	2944	2821	2759	2739	2761	2841	2940	3082	3285	3426	3477	3491	3463	3382	3309	3288	3391	3678	3994	3955	3832	3610	3335	3072
2/27/2012	2891	2819	2811	2835	2933	3237	3735	3982	3969	3909	3875	3812	3756	3688	3622	3645	3767	4032	4214	4115	3933	3653	3296	2952
2/28/2012	2735	2634	2596	2599	2681	2968	3453	3712	3739	3721	3717	3685	3628	3595	3542	3507	3579	3837	4139	4089	3944	3690	3340	3014
2/29/2012	2793	2692	2642	2644	2723	3017	3513	3791	3851	3858	3899	3947	3985	4042	4048	4059	4171	4365	4459	4339	4120	3808	3436	3091
3/1/2012	2879	2778	2725	2719	2792	3057	3544	3860	3959	3990	4026	4031	4005	3993	3971	3966	4049	4213	4359	4306	4163	3902	3544	3200
3/2/2012	2980	2876	2822	2821	2895	3171	3649	3919	3967	3988	4010	4000	3949	3937	3907	3911	3989	4175	4260	4146	3990	3774	3494	3183
3/3/2012	2950	2798	2712	2668	2678	2761	2920	3144	3414	3621	3716	3707	3618	3501	3383	3278	3286	3447	3724	3662	3554	3396	3185	2951
3/4/2012	2742	2611	2538	2515	2532	2598	2710	2885	3153	3355	3432	3461	3428	3342	3311	3324	3456	3703	3962	3914	3789	3559	3269	2992
3/5/2012	2808	2727	2697	2709	2819	3122	3598	3860	3904	3887	3882	3847	3788	3740	3675	3651	3739	3999	4339	4320	4183	3926	3588	3278
3/6/2012	3076	2985	2949	2954	3051	3349	3815	4062	4062	4012	3985	3939	3859	3801	3725	3688	3757	3952	4274	4271	4136	3867	3491	3152
3/7/2012	2933	2832	2772	2772	2858	3142	3591	3824	3822	3787	3753	3698	3629	3581	3501	3479	3513	3685	3994	3951	3810	3551	3202	2863
3/8/2012	2649	2536	2478	2471	2542	2815	3234	3506	3557	3568	3579	3565	3516	3499	3458	3423	3446	3614	3878	3823	3663	3405	3050	2721
3/9/2012	2504	2388	2337	2329	2406	2687	3166	3499	3603	3637	3652	3631	3566	3539	3494	3453	3505	3685	3929	3868	3751	3568	3299	3012
3/10/2012	2809	2709	2665	2658	2694	2809	2970	3207	3435	3560	3582	3529	3438	3340	3245	3207	3254	3419	3732	3710	3626	3479	3262	3031
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3/12/2012	2595	2487	2443	2446	2524	2789	3308	3619	3645	3607	3613	3587	3546	3529	3473	3419	3400	3431	3519	3761	3670	3411	3045	2711
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3/15/2012	2463	2341	2279	2273	2338	2595	3112	3469	3559	3589	3629	3611	3546	3526	3473	3423	3438	3540	3648	3836	3752	3517	3168	2831
3/16/2012	2602	2471	2405	2387	2445	2695	3204	3534	3640	3669	3709	3709	3696	3681	3616	3553	3534	3543	3583	3707	3628	3442	3168	2863
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3/20/2012	2432	2313	2242	2223	2280	2517	3019	3327	3423	3468	3521	3560	3575	3614	3606	3583	3571	3566	3551	3737	3706	3427	3036	2694
3/21/2012	2446	2321	2252	2233	2287	2517	3018	3346	3462	3524	3590	3606	3598	3613	3594	3574	3563	3572	3577	3740	3692	3427	3059	2714
3/22/2012	2479	2343	2274	2246	2300	2535	3030	3342	3457	3522	3607	3648	3651	3691	3690	3677	3669	3662	3618	3772	3756	3485	3101	2757

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3/24/2012	2439	2291	2202	2159	2157	2235	2379	2561	2829	3025	3113	3114	3079	3027	2971	2937	2962	3049	3122	3246	3206	3054	2825	2593
3/25/2012	2379	2243	2175	2142	2144	2188	2315	2468	2737	2987	3132	3215	3233	3196	3173	3150	3172	3227	3295	3471	3459	3234	2925	2636
3/26/2012	2436	2321	2264	2264	2344	2615	3142	3434	3516	3548	3571	3555	3515	3499	3421	3412	3433	3521	3625	3892	3905	3678	3326	2997
3/27/2012	2794	2694	2646	2649	2735	3024	3557	3840	3864	3851	3832	3794	3724	3674	3591	3511	3506	3560	3599	3830	3871	3643	3285	2946
3/28/2012	2734	2614	2565	2545	2608	2874	3368	3645	3669	3639	3669	3695	3728	3760	3614	3510	3478	3496	3507	3703	3710	3473	3103	2759
3/29/2012	2527	2406	2338	2322	2387	2640	3135	3424	3507	3553	3586	3600	3566	3543	3496	3490	3510	3568	3650	3802	3748	3510	3154	2833
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3/31/2012	2551	2413	2353	2330	2352	2444	2630	2871	3173	3410	3542	3567	3514	3438	3376	3351	3375	3405	3416	3523	3497	3343	3120	2880
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4/8/2012	2443	2294	2216	2189	2199	2269	2381	2596	2834	2990	3043	3063	3021	2899	2775	2702	2672	2696	2758	2992	3186	3040	2779	2512
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4/10/2012	2491	2383	2331	2317	2401	2665	3103	3392	3459	3496	3534	3532	3502	3495	3436	3390	3384	3413	3435	3584	3630	3388	3036	2700
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4/20/2012	2418	2283	2211	2189	2243	2449	2773	3103	3295	3418	3513	3554	3551	3566	3534	3481	3436	3378	3309	3363	3415	3227	2951	2652
4/21/2012	2418	2273	2197	2158	2166	2240	2359	2578	2846	3034	3138	3179	3191	3171	3143	3128	3146	3162	3137	3194	3309	3157	2919	2657

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4/24/2012	2496	2387	2332	2323	2397	2657	3104	3426	3515	3549	3576	3557	3525	3515	3477	3435	3446	3468	3485	3600	3714	3484	3111	2756
4/25/2012	2529	2417	2364	2357	2429	2685	3122	3409	3461	3476	3510	3515	3490	3492	3451	3421	3440	3466	3471	3523	3641	3443	3096	2750
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4/30/2012	2389	2302	2266	2279	2374	2639	3103	3405	3468	3483	3514	3498	3464	3459	3423	3385	3371	3387	3416	3519	3630	3398	3029	2680
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5/7/2012	2384	2272	2218	2214	2284	2504	2939	3300	3441	3510	3593	3628	3630	3647	3637	3588	3568	3545	3511	3548	3666	3434	3054	2695
5/8/2012	2455	2329	2263	2242	2302	2527	2975	3340	3475	3540	3607	3626	3594	3601	3579	3554	3585	3640	3641	3673	3684	3434	3063	2715
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5/18/2012	2490	2344	2265	2234	2281	2468	2893	3264	3433	3544	3640	3687	3681	3699	3681	3649	3625	3567	3463	3387	3468	3361	3068	2717
5/19/2012	2470	2321	2221	2178	2189	2213	2361	2632	2933	3125	3225	3274	3279	3266	3277	3303	3352	3384	3352	3286	3353	3272	3014	2721
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5/24/2012	2687	2516	2422	2384	2428	2630	3089	3482	3689	3835	3974	4044	4061	4038	4019	3999	3990	3939	3856	3821	3886	3712	3316	2923
5/25/2012	2642	2503	2415	2382	2423	2615	3037	3422	3617	3742	3850	3898	3894	3915	3900	3887	3857	3825	3758	3691	3757	3661	3357	3014
5/26/2012	2738	2575	2472	2417	2413	2450	2579	2843	3181	3467	3683	3865	4027	4128	4173	4165	4143	4094	3996	3935	3974	3860	3560	3209
5/27/2012	2911	2706	2568	2476	2429	2374	2441	2643	2929	3214	3435	3603	3707	3741	3775	3815	3860	3867	3782	3677	3737	3690	3449	3127
5/28/2012	2846	2671	2560	2499	2496	2512	2627	2886	3261	3629	3931	4196	4410	4531	4593	4644	4718	4767	4683	4580	4610	4425	3941	3473
5/29/2012	3135	2937	2815	2748	2770	2960	3419	3886	4232	4555	4907	5226	5459	5632	5741	5815	5787	5695	5496	5315	5243	4808	4255	3737
5/30/2012	3375	3155	3016	2941	2968	3165	3620	4009	4212	4335	4450	4541	4568	4619	4613	4618	4664	4630	4473	4343	4373	4201	3743	3293
5/31/2012	2975	2781	2664	2603	2630	2789	3236	3657	3887	4066	4222	4329	4394	4491	4542	4580	4596	4530	4361	4186	4163	4017	3587	3136
6/1/2012	2816	2635	2526	2472	2493	2630	3055	3462	3684	3837	3976	4051	4074	4110	4097	4030	3951	3830	3688	3609	3650	3532	3233	2895
6/2/2012	2618	2457	2368	2332	2330	2382	2510	2759	3067	3335	3498	3552	3550	3507	3464	3437	3456	3468	3433	3390	3431	3373	3135	2846
6/3/2012	2594	2427	2314	2254	2227	2191	2278	2504	2806	3044	3200	3309	3374	3389	3409	3405	3404	3421	3412	3422	3486	3384	3070	2740
6/4/2012	2501	2369	2300	2282	2328	2514	2938	3308	3463	3565	3656	3690	3684	3681	3649	3615	3620	3636	3605	3573	3596	3418	3060	2708
6/5/2012	2465	2358	2293	2269	2313	2495	2922	3289	3444	3535	3623	3668	3659	3668	3637	3612	3617	3624	3585	3550	3601	3482	3119	2758
6/6/2012	2500	2371	2300	2278	2320	2499	2936	3314	3481	3600	3708	3777	3781	3800	3780	3778	3764	3745	3663	3614	3676	3557	3185	2808
6/7/2012	2548	2409	2333	2302	2348	2522	2956	3347	3539	3685	3820	3893	3923	3973	3982	3998	4000	3961	3854	3787	3824	3699	3328	2919
6/8/2012	2637	2482	2390	2349	2398	2548	2978	3400	3636	3830	3995	4092	4143	4214	4254	4231	4194	4123	3960	3839	3868	3780	3451	3082
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6/10/2012	2714	2540	2433	2365	2339	2303	2404	2658	2997	3312	3541	3715	3834	3879	3916	3951	3998	4018	3965	3902	3926	3833	3472	3076
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6/14/2012	2768	2603	2507	2469	2507	2658	3085	3511	3743	3893	4016	4069	4077	4129	4163	4186	4199	4166	4069	3956	3943	3868	3486	3066
6/15/2012	2767	2577	2482	2442	2478	2631	3044	3469	3738	3909	4044	4111	4159	4224	4263	4271	4263	4192	4030	3865	3807	3736	3404	3025
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6/17/2012	2669	2495	2384	2321	2295	2271	2325	2519	2804	3047	3204	3307	3351	3355	3369	3392	3424	3457	3419	3359	3416	3397	3103	2765
6/18/2012	2517	2389	2323	2307	2367	2543	2936	3350	3579	3732	3856	3931	3973	4037	4055	4055	4071	4041	3928	3809	3806	3701	3319	2929
6/19/2012	2663	2505	2422	2394	2443	2607	3018	3421	3636	3768	3887	3967	3991	4051	4074	4053	4066	4038	3961	3914	3959	3902	3565	3179
6/20/2012	2883	2699	2599	2566	2625	2798	3243	3807	4259	4677	5102	5455	5743	5996	6189	6316	6410	6411	6305	6135	6034	5848	5303	4730

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6/22/2012	4314	3998	3801	3671	3642	3742	4155	4666	5062	5448	5788	6094	6346	6462	6332	6089	5617	5313	5005	4799	4680	4514	4172	3766
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6/26/2012	2727	2566	2465	2415	2445	2556	2901	3301	3535	3684	3829	3910	3944	3977	3973	3949	3953	3919	3829	3742	3751	3668	3335	2973
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6/28/2012	2879	2689	2575	2520	2548	2671	3038	3489	3824	4087	4350	4546	4683	4847	4983	5084	5185	5205	5093	4913	4823	4711	4286	3804
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7/1/2012	3651	3383	3191	3063	2978	2902	2980	3292	3735	4199	4611	4955	5218	5389	5468	5271	5237	5192	5143	5028	4901	4774	4361	3870
7/2/2012	3481	3222	3040	2945	2954	3052	3407	3912	4317	4650	4935	5102	5200	5326	5426	5474	5482	5408	5272	5039	4846	4664	4200	3692
7/3/2012	3304	3063	2912	2821	2828	2928	3285	3773	4154	4460	4734	4954	5106	5259	5368	5446	5493	5416	5163	4912	4776	4591	4243	3853
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7/5/2012	3743	3500	3350	3258	3268	3380	3757	4304	4741	5107	5427	5638	5766	5887	5931	5964	5947	5896	5698	5433	5225	5009	4531	4006
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7/7/2012	3833	3571	3398	3279	3201	3172	3312	3682	4118	4539	4891	5198	5475	5546	5297	5064	4988	5002	4929	4773	4686	4601	4338	3990
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7/9/2012	3639	3374	3190	3072	3061	3130	3461	3896	4204	4480	4733	4930	5076	5219	5301	5345	5372	5336	5168	4944	4820	4660	4208	3715
7/10/2012	3345	3116	2958	2875	2876	2975	3311	3749	4064	4310	4549	4727	4855	5020	5153	5247	5305	5274	5103	4872	4783	4669	4246	3785
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7/18/2012	4425	4167	4010	3923	3882	3987	4353	4908	5330	5694	6140	6554	6825	6922	6664	6087	5855	5823	5687	5513	5418	5236	4814	4350
7/19/2012	3986	3739	3560	3454	3420	3513	3792	4117	4289	4399	4520	4586	4618	4685	4741	4800	4880	4892	4744	4555	4522	4391	4016	3596
7/20/2012	3269	3090	2970	2914	2927	3096	3398	3753	3958	4047	4109	4124	4082	4055	3988	3904	3859	3825	3738	3674	3717	3627	3356	3042

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7/23/2012	3135	2958	2859	2829	2866	3047	3383	3820	4131	4292	4441	4639	4820	5084	5242	5339	5393	5366	5243	5120	5111	4928	4517	4029
7/24/2012	3649	3415	3269	3197	3211	3375	3730	4239	4668	5035	5399	5650	5828	6005	6119	6173	6142	5932	5608	5367	5248	4990	4473	3945
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7/31/2012	3173	2972	2841	2775	2801	2973	3284	3669	3948	4136	4308	4403	4459	4521	4491	4445	4432	4412	4333	4250	4299	4144	3776	3384
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8/4/2012	4040	3750	3550	3406	3344	3357	3463	3768	4211	4693	5149	5478	5709	5851	5949	5974	5926	5838	5634	5378	5298	5102	4754	4362
8/5/2012	4025	3776	3602	3509	3456	3453	3494	3728	4131	4588	4973	5307	5560	5650	5656	5609	5554	5440	5315	5253	5176	4893	4477	4066
8/6/2012	3737	3542	3441	3387	3426	3599	3926	4366	4709	4970	5059	5228	5351	5456	5538	5616	5637	5543	5307	5031	4931	4646	4144	3660
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8/8/2012	3348	3120	2983	2911	2936	3091	3393	3822	4242	4596	4935	5202	5388	5554	5666	5699	5662	5559	5370	5221	5228	4982	4538	4078
8/9/2012	3728	3509	3373	3302	3315	3488	3803	4255	4628	5002	5387	5706	5910	6055	6146	6217	6198	6029	5745	5551	5495	5210	4750	4276
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8/17/2012	3311	3081	2930	2851	2850	3000	3262	3651	4013	4328	4638	4898	5131	5374	5530	5557	5541	5414	5177	5053	4999	4655	4250	3820
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8/19/2012	2772	2589	2467	2392	2360	2368	2378	2548	2832	3099	3266	3377	3452	3443	3459	3467	3526	3582	3567	3579	3691	3533	3258	2968

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8/25/2012	3332	3101	2949	2851	2836	2888	2991	3230	3576	3916	4206	4400	4527	4611	4671	4698	4636	4486	4288	4201	4192	3993	3689	3349
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9/1/2012	3410	3178	3024	2922	2875	2918	3013	3221	3601	4026	4403	4680	4848	4917	4930	4935	4940	4860	4649	4540	4472	4214	3879	3512
9/2/2012	3204	2999	2858	2763	2710	2714	2719	2885	3203	3488	3705	3851	3987	4090	4173	4212	4220	4204	4102	4073	4066	3888	3604	3292
9/3/2012	3010	2828	2708	2629	2606	2650	2687	2827	3110	3413	3638	3797	3890	3959	3993	3980	4000	4018	3971	4063	4074	3812	3447	3116
9/4/2012	2884	2756	2686	2673	2730	2994	3496	3866	4068	4237	4406	4503	4551	4634	4682	4717	4751	4788	4765	4838	4826	4539	4128	3745
9/5/2012	3464	3311	3219	3190	3247	3522	4068	4449	4661	4833	4965	4949	4910	4975	5013	5051	5152	5217	5076	5049	4975	4591	4109	3645
9/6/2012	3285	3066	2933	2872	2897	3123	3574	3912	4095	4263	4374	4450	4524	4702	4843	4900	4903	4819	4699	4753	4716	4397	3948	3530
9/7/2012	3225	3046	2924	2862	2894	3123	3570	3936	4225	4519	4808	5060	5237	5408	5548	5613	5605	5471	5262	5208	5084	4764	4332	3895
9/8/2012	3550	3314	3179	3097	3076	3140	3276	3529	3908	4233	4452	4532	4564	4618	4649	4664	4659	4642	4631	4545	4285	3976	3623	3257
9/9/2012	2974	2788	2655	2573	2531	2546	2598	2724	2977	3227	3389	3516	3619	3661	3726	3771	3828	3871	3818	3896	3865	3599	3246	2918
9/10/2012	2673	2520	2434	2407	2456	2678	3086	3398	3586	3728	3845	3904	3918	3949	3924	3886	3879	3846	3759	3822	3740	3450	3072	2717
9/11/2012	2482	2350	2277	2257	2305	2531	2952	3253	3391	3518	3627	3684	3719	3786	3795	3770	3790	3798	3729	3825	3752	3453	3074	2719
9/12/2012	2477	2355	2290	2271	2316	2545	2983	3270	3422	3576	3741	3851	3911	3989	4021	4040	4058	4034	3928	4024	3944	3644	3250	2867
9/13/2012	2611	2465	2387	2361	2409	2631	3061	3362	3568	3770	3957	4079	4154	4257	4310	4341	4363	4302	4171	4253	4176	3865	3451	3052
9/14/2012	2769	2609	2512	2471	2503	2720	3136	3428	3654	3868	4065	4199	4276	4370	4414	4419	4379	4225	4055	4119	4011	3776	3457	3114
9/15/2012	2832	2661	2541	2486	2482	2546	2672	2842	3094	3315	3431	3473	3477	3463	3434	3420	3429	3425	3376	3462	3394	3205	2948	2676
9/16/2012	2448	2307	2218	2169	2158	2191	2255	2412	2694	2935	3079	3156	3204	3195	3208	3228	3283	3361	3373	3514	3441	3191	2889	2593
9/17/2012	2392	2274	2218	2208	2264	2479	2865	3159	3367	3529	3678	3774	3827	3911	3935	3933	3938	3917	3866	3999	3870	3553	3167	2813
9/18/2012	2570	2432	2362	2347	2411	2676	3169	3545	3744	3891	4023	4083	4087	4124	4113	4104	4145	4202	4235	4265	4119	3783	3365	3022

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9/19/2012	2773	2634	2558	2517	2522	2705	3132	3401	3504	3593	3716	3783	3789	3830	3828	3807	3797	3750	3708	3835	3728	3440	3064	2713
9/20/2012	2475	2352	2282	2252	2296	2524	2968	3250	3384	3482	3589	3654	3668	3710	3700	3666	3650	3647	3664	3813	3701	3432	3061	2726
9/21/2012	2491	2356	2280	2248	2298	2518	2967	3254	3392	3499	3599	3647	3678	3726	3724	3705	3692	3640	3588	3682	3569	3348	3051	2726
9/22/2012	2482	2336	2252	2217	2210	2280	2428	2626	2911	3121	3229	3261	3279	3273	3257	3247	3277	3343	3452	3547	3468	3315	3080	2778
9/23/2012	2543	2388	2298	2245	2221	2250	2318	2448	2715	2928	3057	3120	3153	3130	3135	3148	3187	3268	3329	3487	3373	3113	2807	2522
9/24/2012	2319	2203	2152	2143	2201	2443	2918	3233	3358	3445	3533	3580	3586	3613	3595	3557	3562	3588	3621	3766	3617	3324	2956	2617
9/25/2012	2404	2288	2224	2208	2270	2510	2985	3275	3393	3486	3581	3617	3625	3658	3660	3641	3645	3642	3681	3835	3691	3424	3060	2723
9/26/2012	2495	2377	2312	2307	2365	2596	3029	3338	3541	3681	3781	3818	3815	3825	3809	3778	3798	3875	3973	4005	3842	3561	3188	2834
9/27/2012	2593	2451	2372	2348	2403	2655	3151	3464	3615	3719	3808	3859	3882	3913	3910	3876	3851	3807	3826	3940	3781	3491	3121	2761
9/28/2012	2519	2384	2307	2281	2328	2546	3015	3358	3511	3602	3685	3712	3704	3710	3662	3616	3620	3649	3688	3684	3535	3318	3033	2724
9/29/2012	2483	2337	2254	2215	2215	2292	2457	2670	2942	3153	3252	3265	3247	3205	3149	3121	3136	3166	3280	3384	3282	3116	2890	2630
9/30/2012	2412	2271	2187	2144	2136	2177	2283	2436	2686	2907	3036	3108	3144	3121	3110	3113	3179	3255	3368	3513	3390	3139	2839	2549
10/1/2012	2342	2226	2172	2162	2228	2479	2962	3259	3388	3475	3563	3604	3611	3637	3624	3608	3610	3650	3749	3863	3695	3391	3018	2675
10/2/2012	2441	2315	2255	2241	2297	2536	3034	3340	3462	3562	3657	3714	3722	3743	3706	3672	3703	3807	3922	3915	3741	3453	3083	2744
10/3/2012	2510	2385	2314	2297	2356	2602	3113	3452	3575	3658	3757	3803	3809	3838	3814	3811	3845	3914	4010	4031	3922	3626	3278	2929
10/4/2012	2657	2511	2434	2410	2463	2716	3235	3568	3720	3835	3931	3970	3962	3965	3936	3894	3911	3982	4085	4077	3928	3656	3283	2922
10/5/2012	2659	2503	2411	2381	2422	2649	3118	3415	3561	3710	3867	3958	3983	3994	3989	3990	3951	3865	3882	3921	3759	3538	3223	2890
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10/8/2012	2378	2258	2205	2194	2250	2442	2790	3086	3308	3448	3529	3544	3526	3522	3490	3453	3507	3638	3833	3853	3684	3398	3048	2713
10/9/2012	2479	2354	2288	2274	2333	2581	3086	3398	3500	3565	3617	3629	3615	3620	3581	3553	3575	3674	3879	3900	3729	3440	3059	2714
10/10/2012	2482	2352	2285	2276	2331	2577	3086	3413	3510	3566	3643	3667	3655	3664	3626	3594	3600	3648	3800	3864	3700	3421	3055	2711
10/11/2012	2465	2340	2275	2265	2325	2583	3102	3384	3467	3505	3537	3534	3501	3491	3451	3423	3434	3504	3721	3820	3689	3423	3095	2769
10/12/2012	2519	2387	2319	2309	2375	2625	3140	3425	3506	3569	3655	3673	3636	3598	3524	3464	3457	3521	3721	3771	3651	3464	3191	2881
10/13/2012	2651	2520	2457	2440	2466	2577	2786	3010	3253	3365	3370	3309	3226	3146	3067	3039	3084	3200	3448	3498	3393	3236	3007	2743
10/14/2012	2533	2384	2302	2260	2252	2300	2421	2593	2837	3062	3171	3211	3220	3163	3108	3082	3132	3248	3506	3569	3442	3184	2884	2596
10/15/2012	2386	2280	2225	2219	2286	2543	3063	3394	3508	3597	3684	3724	3711	3719	3687	3655	3686	3836	4000	3934	3732	3428	3060	2712
10/16/2012	2473	2341	2260	2231	2277	2515	3017	3303	3388	3439	3488	3497	3471	3476	3444	3413	3438	3529	3774	3824	3686	3402	3062	2746
10/17/2012	2500	2377	2331	2330	2400	2668	3212	3515	3572	3574	3574	3561	3531	3520	3484	3451	3464	3557	3831	3860	3722	3447	3073	2732
10/18/2012	2505	2386	2328	2317	2387	2656	3187	3484	3541	3553	3593	3599	3563	3561	3541	3501	3502	3577	3815	3834	3685	3423	3064	2721

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10/20/2012	2550	2403	2309	2265	2269	2349	2535	2744	2996	3195	3302	3322	3301	3258	3194	3154	3151	3205	3410	3387	3260	3087	2861	2602
10/21/2012	2382	2240	2164	2135	2133	2188	2312	2463	2706	2899	2987	3034	3055	3025	3006	3008	3076	3212	3489	3487	3363	3119	2822	2536
10/22/2012	2339	2232	2187	2183	2253	2517	3040	3351	3432	3490	3545	3563	3546	3552	3528	3500	3519	3604	3867	3854	3673	3382	3026	2694
10/23/2012	2446	2320	2250	2240	2300	2553	3085	3368	3431	3473	3530	3556	3557	3578	3550	3534	3569	3720	3924	3857	3675	3402	3031	2691
10/24/2012	2466	2338	2273	2263	2321	2570	3104	3448	3538	3577	3628	3636	3602	3598	3563	3542	3586	3719	3910	3859	3693	3422	3051	2712
10/25/2012	2478	2350	2286	2270	2328	2583	3103	3423	3485	3543	3593	3598	3575	3574	3529	3488	3497	3620	3858	3823	3675	3415	3062	2720
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10/27/2012	2450	2301	2221	2177	2179	2264	2472	2711	2981	3175	3263	3267	3239	3198	3136	3112	3134	3262	3496	3437	3316	3150	2927	2662
10/28/2012	2435	2275	2192	2146	2139	2188	2324	2515	2812	3070	3215	3290	3342	3335	3344	3360	3453	3629	3791	3707	3539	3302	3015	2726
10/29/2012	2476	2316	2233	2209	2248	2426	2741	3044	3301	3508	3606	3566	3439	3319	3132	2981	2891	2802	2515	2175	1980	1834	1685	1565
10/30/2012	1473	1412	1376	1367	1393	1493	1661	1812	1955	2099	2222	2302	2355	2370	2374	2378	2444	2561	2702	2642	2564	2402	2197	2009
10/31/2012	1875	1796	1759	1755	1799	1964	2290	2546	2645	2732	2811	2847	2850	2869	2855	2832	2859	2959	3051	2997	2937	2784	2541	2306
11/1/2012	2146	2060	2012	2002	2064	2269	2648	2902	2986	3041	3095	3113	3089	3100	3069	3067	3111	3260	3438	3404	3280	3069	2776	2510
11/2/2012	2313	2202	2139	2125	2177	2395	2813	3115	3216	3281	3325	3315	3285	3284	3265	3241	3284	3413	3566	3504	3380	3205	2960	2693
11/3/2012	2477	2343	2279	2248	2266	2352	2536	2740	2946	3093	3148	3134	3096	3051	3026	2990	3062	3240	3462	3409	3318	3169	2970	2744
11/4/2012	4954	2335	2300	2293	2330	2423	2565	2776	2988	3091	3098	3091	3067	3030	3017	3082	3326	3675	3669	3561	3414	3170	2889	2643
11/5/2012	2491	2405	2373	2384	2493	2792	3279	3547	3615	3637	3651	3637	3594	3577	3553	3567	3785	4196	4206	4108	3950	3676	3349	3029
11/6/2012	2826	2733	2703	2719	2816	3111	3537	3775	3821	3818	3818	3781	3713	3682	3642	3643	3842	4239	4279	4206	4040	3779	3440	3118
11/7/2012	2901	2782	2717	2708	2779	3062	3582	3854	3940	3988	4049	4088	4107	4139	4162	4208	4423	4656	4571	4441	4214	3893	3521	3194
11/8/2012	2986	2882	2827	2820	2899	3142	3349	3623	3843	3898	3915	3904	3871	3901	3902	3912	4108	4367	4310	4225	4058	3767	3406	3060
11/9/2012	2858	2745	2687	2684	2768	3042	3501	3745	3775	3762	3757	3719	3637	3601	3560	3548	3716	4024	3975	3857	3713	3503	3226	2927
11/10/2012	2701	2573	2512	2490	2516	2625	2807	3025	3275	3407	3394	3331	3256	3188	3138	3140	3355	3662	3606	3487	3366	3197	2980	2742
11/11/2012	2541	2417	2350	2322	2335	2407	2526	2695	2919	3057	3105	3110	3094	3056	3019	3040	3287	3646	3615	3492	3349	3124	2864	2601
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11/13/2012	2482	2365	2304	2289	2352	2616	3105	3412	3516	3547	3604	3628	3628	3644	3630	3637	3840	4160	4138	4040	3886	3621	3251	2931
11/14/2012	2725	2616	2571	2583	2674	2972	3488	3746	3778	3744	3722	3673	3617	3602	3568	3588	3835	4211	4214	4132	3989	3730	3386	3057
11/15/2012	2838	2730	2689	2699	2779	3068	3574	3822	3854	3826	3812	3764	3701	3681	3674	3714	3977	4272	4268	4179	4027	3771	3418	3083
11/16/2012	2856	2752	2697	2697	2775	3034	3526	3771	3804	3803	3789	3750	3712	3694	3652	3617	3838	4133	4099	3988	3863	3668	3401	3111
11/17/2012	2883	2750	2686	2671	2701	2824	3029	3247	3446	3529	3515	3446	3350	3271	3224	3243	3496	3822	3788	3677	3580	3424	3217	2981

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11/19/2012	2727	2642	2611	2624	2730	3035	3567	3846	3886	3868	3865	3829	3753	3713	3672	3677	3923	4274	4280	4184	4043	3767	3414	3073
11/20/2012	2855	2751	2711	2716	2807	3105	3618	3873	3886	3841	3814	3770	3724	3698	3656	3687	3956	4252	4241	4151	4008	3774	3413	3069
11/21/2012	2826	2700	2631	2620	2702	2972	3456	3726	3792	3787	3784	3750	3679	3656	3625	3622	3846	4145	4110	4001	3864	3648	3347	3024
11/22/2012	2777	2633	2552	2526	2561	2682	2867	3087	3347	3507	3577	3590	3491	3292	3086	2957	3026	3172	3161	3158	3154	3089	2954	2769
11/23/2012	2610	2522	2485	2492	2547	2697	2895	3071	3257	3355	3372	3342	3275	3209	3165	3190	3464	3735	3677	3565	3429	3255	3024	2757
11/24/2012	2539	2403	2338	2316	2342	2442	2617	2823	3075	3246	3320	3335	3323	3289	3282	3334	3620	3897	3864	3772	3667	3509	3282	3032
11/25/2012	2820	2684	2611	2583	2596	2674	2797	2955	3206	3433	3539	3552	3554	3532	3519	3542	3836	4156	4148	4053	3906	3637	3312	3002
11/26/2012	2793	2678	2621	2618	2703	2992	3509	3783	3806	3796	3795	3773	3735	3707	3665	3691	3990	4368	4388	4307	4153	3882	3509	3154
11/27/2012	2921	2806	2757	2745	2817	3087	3605	3908	3987	4024	4081	4099	4091	4085	4075	4139	4401	4573	4537	4427	4232	3914	3496	3144
11/28/2012	2896	2776	2717	2713	2793	3085	3612	3869	3883	3872	3861	3808	3759	3774	3789	3845	4143	4459	4455	4362	4218	3959	3590	3227
11/29/2012	2993	2876	2829	2830	2912	3203	3727	3989	3994	3948	3950	3922	3823	3787	3753	3782	4082	4424	4435	4346	4192	3918	3531	3163
11/30/2012	2921	2802	2751	2757	2845	3135	3652	3907	3924	3922	3913	3875	3846	3874	3885	3936	4199	4388	4328	4218	4080	3863	3568	3234

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Loads	
MAX	3489
PST	2717
Winter	2162
Spring	1881
Summer	2526
Fall	1994

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12/2/2011	1425	1371	1345	1343	1390	1534	1801	1937	1946	1920	1902	1878	1843	1827	1813	1816	1967	2096	2068	2004	1939	1838	1695	1526
12/3/2011	1402	1333	1303	1294	1316	1378	1488	1604	1721	1774	1774	1746	1703	1664	1644	1661	1830	1993	1983	1933	1881	1805	1685	1545
12/4/2011	1428	1356	1320	1303	1309	1344	1412	1492	1615	1691	1704	1694	1682	1661	1640	1666	1844	2024	2023	1970	1908	1773	1594	1423
12/5/2011	1311	1256	1230	1225	1262	1404	1669	1814	1846	1862	1875	1870	1844	1836	1819	1826	1991	2155	2149	2087	1997	1842	1638	1442
12/6/2011	1311	1248	1213	1201	1237	1369	1635	1806	1843	1860	1878	1879	1867	1873	1868	1904	2054	2149	2126	2058	1969	1824	1620	1423
12/7/2011	1285	1223	1188	1179	1208	1339	1602	1787	1837	1866	1888	1892	1883	1885	1884	1926	2061	2146	2125	2066	1985	1850	1659	1474
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10/7/2012	1132	1090	1068	1065	1085	1138	1214	1344	1447	1506	1541	1564	1564	1572	1568	1589	1646	1729	1739	1669	1563	1431	1302	1198
10/8/2012	1138	1111	1105	1133	1231	1406	1555	1667	1738	1779	1786	1777	1775	1759	1741	1767	1834	1932	1942	1857	1713	1537	1368	1249
10/9/2012	1186	1153	1146	1176	1300	1555	1713	1764	1797	1823	1829	1821	1824	1804	1791	1801	1852	1954	1966	1880	1734	1542	1368	1251
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10/11/2012	1179	1147	1142	1172	1302	1563	1705	1747	1766	1783	1781	1764	1759	1739	1725	1730	1766	1875	1925	1860	1725	1560	1396	1269
10/12/2012	1203	1169	1164	1197	1323	1583	1727	1767	1798	1842	1851	1832	1813	1776	1746	1742	1775	1875	1900	1840	1746	1608	1452	1336
10/13/2012	1270	1238	1229	1243	1299	1404	1517	1639	1696	1699	1668	1626	1586	1546	1532	1554	1613	1738	1763	1710	1631	1515	1382	1277
10/14/2012	1201	1160	1139	1135	1159	1220	1307	1430	1543	1598	1619	1623	1594	1566	1554	1578	1637	1767	1799	1735	1605	1453	1308	1203
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10/16/2012	1180	1139	1124	1147	1268	1520	1665	1708	1733	1758	1762	1750	1752	1736	1720	1733	1779	1902	1927	1858	1714	1543	1384	1260
10/17/2012	1198	1175	1174	1209	1345	1619	1772	1800	1801	1801	1795	1780	1774	1756	1739	1746	1792	1931	1945	1876	1738	1549	1377	1263
10/18/2012	1203	1173	1167	1203	1339	1606	1756	1784	1790	1811	1814	1796	1795	1784	1764	1765	1803	1923	1932	1857	1725	1544	1371	1252
10/19/2012	1187	1153	1146	1175	1296	1551	1735	1806	1855	1898	1915	1906	1905	1881	1868	1883	1905	1948	1908	1829	1718	1571	1408	1285

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10/21/2012	1129	1090	1076	1075	1102	1166	1241	1364	1461	1506	1529	1540	1524	1515	1516	1550	1619	1758	1758	1695	1572	1422	1278	1178
10/22/2012	1125	1102	1101	1135	1268	1532	1690	1730	1759	1787	1795	1787	1790	1778	1764	1773	1817	1949	1942	1851	1705	1526	1357	1232
10/23/2012	1169	1133	1129	1159	1286	1555	1698	1729	1750	1779	1792	1792	1803	1789	1781	1798	1875	1977	1943	1852	1715	1527	1356	1243
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10/28/2012	1147	1105	1082	1078	1102	1172	1268	1418	1547	1620	1658	1685	1681	1685	1693	1741	1829	1911	1868	1784	1664	1520	1374	1248
10/29/2012	1167	1125	1113	1133	1223	1381	1534	1664	1768	1818	1797	1733	1673	1579	1503	1457	1412	1268	1096	997	925	849	788	742
10/30/2012	711	694	689	702	753	838	914	985	1058	1119	1161	1187	1195	1197	1198	1232	1291	1362	1331	1292	1211	1107	1013	945
10/31/2012	905	886	884	906	990	1154	1283	1333	1377	1417	1435	1436	1446	1439	1427	1441	1492	1538	1511	1481	1402	1280	1162	1082
11/1/2012	1039	1014	1009	1040	1144	1334	1462	1504	1532	1560	1569	1557	1563	1546	1546	1568	1643	1733	1716	1653	1547	1399	1265	1166
11/2/2012	1110	1078	1071	1097	1207	1418	1569	1620	1654	1676	1671	1656	1656	1645	1633	1656	1720	1797	1766	1704	1615	1492	1357	1248
11/3/2012	1181	1149	1133	1142	1186	1278	1381	1485	1558	1586	1580	1560	1538	1526	1507	1543	1633	1745	1718	1673	1597	1497	1382	1283
11/4/2012	1214	1177	1159	1156	1175	1221	1293	1399	1506	1558	1561	1558	1546	1527	1521	1554	1676	1852	1849	1795	1721	1597	1456	1332
11/5/2012	1255	1212	1196	1201	1257	1407	1653	1787	1823	1833	1840	1833	1812	1803	1790	1798	1908	2115	2120	2070	1991	1852	1688	1526
11/6/2012	1424	1378	1362	1370	1419	1568	1783	1903	1926	1925	1925	1906	1871	1855	1835	1835	1937	2136	2157	2120	2036	1905	1733	1571
11/7/2012	1462	1402	1370	1365	1401	1543	1806	1942	1985	2010	2041	2061	2070	2086	2098	2121	2229	2347	2304	2239	2124	1962	1775	1610
11/8/2012	1506	1452	1425	1421	1461	1583	1688	1826	1937	1965	1973	1968	1951	1966	1967	1971	2070	2200	2172	2129	2045	1898	1716	1543
11/9/2012	1441	1384	1354	1353	1395	1534	1764	1888	1903	1896	1894	1874	1833	1815	1795	1789	1872	2028	2004	1944	1872	1766	1626	1475
11/10/2012	1362	1297	1266	1255	1268	1323	1415	1524	1651	1717	1711	1679	1642	1606	1582	1583	1691	1846	1817	1758	1696	1611	1502	1382
11/11/2012	1280	1218	1184	1170	1177	1213	1273	1359	1470	1541	1565	1568	1560	1540	1521	1532	1657	1837	1821	1760	1688	1574	1444	1311
11/12/2012	1218	1172	1149	1149	1187	1308	1509	1664	1750	1793	1820	1826	1812	1801	1781	1784	1916	2055	2022	1946	1849	1702	1523	1359
11/13/2012	1251	1192	1161	1154	1186	1319	1565	1719	1772	1787	1817	1829	1829	1837	1829	1833	1936	2097	2086	2036	1959	1824	1639	1478
11/14/2012	1373	1319	1296	1302	1348	1498	1758	1888	1905	1887	1875	1851	1823	1815	1798	1809	1933	2123	2124	2083	2011	1880	1707	1540
11/15/2012	1430	1376	1356	1360	1401	1546	1801	1926	1943	1928	1922	1897	1865	1855	1852	1872	2005	2153	2151	2106	2030	1900	1722	1554
11/16/2012	1439	1387	1359	1359	1399	1529	1778	1900	1917	1917	1909	1891	1871	1862	1841	1823	1934	2083	2066	2010	1947	1849	1714	1568
11/17/2012	1453	1385	1354	1347	1361	1424	1527	1636	1736	1778	1772	1736	1688	1648	1625	1634	1762	1926	1909	1854	1804	1725	1622	1503
11/18/2012	1407	1346	1316	1306	1317	1359	1433	1518	1622	1676	1686	1678	1654	1636	1630	1660	1812	1988	1987	1940	1872	1751	1609	1470
11/19/2012	1374	1331	1316	1322	1376	1529	1798	1939	1959	1950	1948	1930	1891	1871	1851	1854	1977	2154	2157	2109	2038	1899	1721	1549
11/20/2012	1439	1387	1367	1368	1415	1565	1823	1952	1959	1936	1922	1900	1877	1863	1843	1858	1994	2143	2137	2092	2020	1902	1721	1546
11/21/2012	1424	1361	1326	1320	1362	1498	1742	1878	1911	1908	1908	1891	1854	1843	1827	1826	1939	2089	2072	2016	1948	1838	1687	1524

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11/24/2012	1280	1211	1178	1167	1181	1231	1319	1422	1549	1636	1673	1681	1675	1657	1654	1680	1824	1964	1948	1901	1848	1769	1654	1528
11/25/2012	1421	1353	1316	1302	1308	1348	1410	1489	1616	1730	1784	1790	1792	1780	1773	1785	1933	2095	2090	2042	1968	1833	1669	1513
11/26/2012	1408	1350	1322	1320	1362	1508	1769	1906	1918	1913	1912	1902	1882	1868	1847	1860	2011	2202	2211	2171	2093	1957	1769	1589
11/27/2012	1472	1414	1390	1384	1419	1555	1817	1970	2010	2028	2056	2066	2062	2059	2054	2086	2218	2305	2287	2231	2133	1973	1762	1585
11/28/2012	1459	1399	1370	1367	1407	1555	1820	1950	1957	1951	1946	1920	1894	1902	1909	1937	2089	2248	2245	2198	2126	1996	1809	1626
11/29/2012	1509	1450	1426	1427	1467	1614	1878	2010	2013	1990	1991	1977	1926	1909	1891	1906	2058	2229	2236	2191	2113	1974	1780	1594
11/30/2012	1472	1412	1387	1390	1434	1580	1841	1969	1977	1977	1973	1953	1939	1953	1957	1984	2116	2211	2181	2126	2056	1947	1798	1630

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	NYISO	NYC	LI
Max	32,439		
PST	27,324		
Winter	21,340		
Spring	19,352		
Summer	25,513		
Fall	20,367		

Detailed hourly load data provided in other workpape

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Max	32,439
Peak Month	27,324
Winter	21,340
Spring	19,352
Summer	25,513
Fall	20,367

Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
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12/3/2011	15222	14523	14148	13980	14027	14380	15191	15931	16850	17466	17707	17654	17451	17226	17097	17199	18391	19865	19874	19498	19060	18407	17424	16222
12/4/2011	15171	14427	13988	13735	13702	13950	14438	14905	15726	16402	16768	16869	16859	16769	16731	16962	18236	19916	19901	19556	19089	18108	16699	15260
12/5/2011	14275	13688	13318	13202	13463	14486	16542	18117	18744	19032	19252	19229	19116	19025	18957	19129	20385	21653	21501	20976	20235	19113	17469	15742
12/6/2011	14485	13788	13419	13297	13513	14421	16472	18131	18722	19070	19322	19424	19413	19465	19503	19838	20973	21811	21511	20960	20253	19120	17547	15826
12/7/2011	14602	13911	13537	13387	13589	14560	16651	18382	19036	19461	19728	19855	19824	19860	19867	20197	21289	22045	21768	21258	20620	19550	17994	16294
12/8/2011	15077	14459	14112	14017	14258	15273	17327	18783	19303	19575	19688	19640	19480	19380	19273	19416	20549	22129	21996	21555	20989	20033	18474	16776
12/9/2011	15527	14836	14462	14300	14509	15505	17562	19047	19582	19824	19863	19708	19507	19411	19287	19415	20501	21672	21369	20805	20190	19322	18081	16625
12/10/2011	15426	14655	14191	13970	13982	14371	15169	15937	16860	17533	17861	17983	17911	17736	17637	17797	18956	20595	20644	20253	19833	19211	18240	16997
12/11/2011	15931	15181	14738	14508	14464	14710	15262	15827	16659	17343	17664	17773	17780	17677	17598	17799	19124	20979	21158	20927	20518	19626	18287	16774
12/12/2011	15614	14953	14634	14559	14815	15927	18060	19551	19921	20158	20219	20089	19862	19734	19585	19729	21044	22697	22670	22274	21673	20594	18935	17123
12/13/2011	15892	15245	14917	14838	15106	16159	18325	19688	20020	20153	20129	19989	19794	19658	19547	19679	20929	22495	22368	21925	21247	20146	18554	16790
12/14/2011	15475	14760	14385	14234	14447	15497	17540	19017	19390	19522	19549	19463	19301	19216	19143	19395	20753	22134	22008	21476	20874	19787	18198	16407
12/15/2011	15091	14386	14005	13877	14043	15012	17048	18635	19260	19606	19775	19760	19624	19558	19459	19716	20859	21933	21679	21182	20523	19471	17955	16226
12/16/2011	14924	14200	13809	13708	13937	14898	16915	18450	18994	19384	19528	19469	19301	19247	19205	19505	20662	21823	21478	20886	20295	19473	18309	16811
12/17/2011	15514	14736	14272	14071	14111	14496	15305	16157	17193	17949	18361	18474	18462	18436	18428	18573	19635	21013	21025	20675	20237	19596	18693	17476
12/18/2011	16333	15536	15059	14857	14829	15096	15691	16382	17291	17979	18351	18471	18513	18419	18405	18644	19959	21688	21857	21639	21166	20302	18946	17364
12/19/2011	16120	15465	15128	15008	15269	16313	18412	19893	20299	20500	20550	20443	20243	20117	20030	20388	21710	22880	22668	22094	21430	20271	18687	16794
12/20/2011	15448	14644	14250	14115	14337	15350	17505	19110	19614	19878	19998	19961	19772	19722	19611	19840	21139	22549	22425	21979	21373	20331	18778	16937
12/21/2011	15515	14811	14366	14239	14391	15321	17332	18911	19514	19958	20159	20221	20087	20050	20034	20163	21234	22207	21883	21463	20755	19681	18146	16311
12/22/2011	14978	14260	13883	13590	13778	14649	16560	18097	18612	18890	19037	19044	18894	18819	18761	18930	20095	21399	21232	20818	20263	19312	17965	16282
12/23/2011	14947	14152	13736	13554	13687	14469	16101	17602	18351	18816	18994	19035	18922	18766	18610	18707	19750	21241	21075	20700	20161	19462	18380	16995
12/24/2011	15740	14905	14406	14181	14153	14451	15133	15969	16923	17721	18159	18271	18137	17935	17747	17751	18670	20130	19870	19387	19015	18680	18024	17080
12/25/2011	16051	15293	14700	14366	14226	14381	14840	15415	16168	16808	16996	16972	16862	16611	16344	16304	17012	18015	17909	17805	17733	17419	16697	15639
12/26/2011	14629	13937	13508	13353	13472	13926	14595	15191	15860	16698	17281	17548	17541	17395	17285	17372	18415	20257	20332	20110	19644	18859	17707	16372
12/27/2011	15240	14567	14152	13995	14196	14917	16245	17544	18395	19146	19501	19641	19660	19697	19706	19935	21022	21890	21593	20978	20188	19104	17735	16209
12/28/2011	14979	14244	13811	13667	13834	14626	16022	17352	18270	18987	19534	19833	19912	20011	19945	20046	20965	22443	22315	21813	21238	20288	18969	17535

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12/30/2011	16042	15237	14741	14529	14605	15267	16458	17645	18482	19068	19347	19319	19056	18788	18649	18644	19510	20855	20669	20208	19648	18823	17770	16454
12/31/2011	15245	14444	13907	13608	13551	13757	14308	14930	15646	16537	17149	17399	17422	17389	17276	17378	18357	19752	19674	19090	18363	17618	16845	16072
1/1/2012	15303	14607	13937	13506	13355	13482	13852	14065	14479	15051	15570	15934	16177	16307	16299	16425	17433	18776	18796	18453	18078	17469	16586	15491
1/2/2012	14488	13849	13454	13327	13444	13930	14797	15479	16205	17061	17753	18088	18207	18175	18158	18360	19436	21203	21272	20958	20323	19377	17977	16595
1/4/2012	17737	17173	16819	16651	16849	17774	19854	21272	21490	21874	22014	21902	21712	21623	21471	21599	22571	23812	23708	23179	22444	21241	19638	17944
1/5/2012	16737	16044	15657	15497	15683	16577	18517	20132	20569	20788	20829	20729	20557	20524	20408	20472	21339	22754	22553	22064	21361	20249	18780	17245
1/6/2012	16114	15436	15058	14901	15077	15979	17916	19303	19571	19753	19808	19734	19533	19356	19185	19247	19926	21183	20967	20382	19716	18878	17683	16384
1/7/2012	15292	14575	14119	13897	13899	14235	14883	15548	16370	17072	17472	17545	17400	17183	17027	17073	17775	19223	19276	18873	18369	17726	16854	15829
1/8/2012	14901	14238	13828	13621	13602	13850	14362	14908	15662	16491	17001	17208	17357	17408	17410	17531	18429	20060	20237	19935	19453	18631	17443	16231
1/9/2012	15362	14847	14557	14509	14746	15762	17860	19409	19804	20058	20154	20024	19808	19645	19456	19551	20405	22005	21916	21379	20659	19509	18009	16489
1/10/2012	15449	14856	14529	14433	14675	15682	17790	19267	19698	19941	19936	19896	19732	19662	19604	19835	20624	21823	21644	21118	20402	19335	17851	16381
1/11/2012	15319	14766	14470	14404	14660	15691	17862	19304	19662	19800	19793	19622	19409	19320	19291	19395	20224	21597	21491	21009	20323	19200	17702	16251
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11/10/2012	14630	13987	13598	13378	13406	13749	14410	15187	16131	16852	17150	17128	17000	16788	16736	16833	17549	18636	18579	18185	17659	17001	16102	15086
11/11/2012	14131	13527	13062	12839	12823	13002	13446	13936	14832	15553	15887	15985	15977	15909	15829	15914	16735	18159	18128	17800	17299	16575	15593	14507
11/13/2012	14038	13415	13064	13005	13137	14081	16040	17588	18383	18842	19080	19123	19096	19135	19074	19200	19923	21052	20809	20442	19628	18556	17036	15651
11/14/2012	14788	14219	13863	13726	13993	14984	16955	18106	18605	18875	18986	18917	18856	18897	18734	18932	19792	21107	20994	20562	19984	18902	17569	16134
11/15/2012	15102	14569	14289	14225	14361	15425	17457	18460	18929	19191	19366	19279	19120	19058	18944	18970	19784	21080	20980	20582	19992	18951	17618	16216
11/16/2012	15142	14513	14160	14076	14302	15189	17174	18442	19037	19270	19287	19185	19024	18868	18699	18737	19438	20622	20378	19907	19345	18564	17381	16204
11/17/2012	15153	14507	14125	13945	14030	14435	15098	15807	16700	17297	17523	17435	17146	16869	16665	16695	17533	18979	19022	18645	18208	17547	16726	15761
11/18/2012	14896	14320	13943	13765	13802	14089	14553	15059	15892	16458	16749	16792	16748	16648	16571	16745	17778	19346	19367	19112	18616	17784	16687	15540
11/19/2012	14623	14145	13895	13827	14109	15189	17147	18427	18938	19211	19337	19295	19139	19035	18921	18969	19819	21150	21027	20607	19988	18991	17578	16113
11/20/2012	15035	14435	14130	14042	14287	15340	17255	18438	18989	19237	19301	19236	19036	18932	18873	19015	19918	21024	20857	20432	19804	18918	17560	16088
11/21/2012	14969	14356	14057	13913	14079	15061	16833	18076	18743	19028	19155	19063	18839	18702	18508	18382	19087	20428	20242	19830	19303	18554	17366	16048
11/22/2012	14970	14290	13852	13640	13667	14007	14570	15195	16091	16725	17172	17351	17102	16635	16114	15732	15958	16640	16505	16374	16287	16080	15562	14843
11/23/2012	14110	13627	13358	13267	13409	13958	14838	15539	16365	16909	17134	17267	17243	17142	17043	17146	18108	19181	19004	18584	18088	17397	16481	15455
11/24/2012	14556	13903	13553	13393	13451	13774	14360	15072	16102	16897	17389	17614	17673	17585	17557	17650	18494	19630	19637	19335	18927	18322	17435	16375
11/25/2012	15376	14647	14209	14022	14031	14287	14735	15220	16120	16934	17479	17746	17895	17966	17971	18084	19135	20344	20349	20006	19505	18516	17327	16042
11/26/2012	15048	14513	14212	14121	14389	15413	17330	18695	19213	19470	19643	19611	19511	19461	19420	19548	20596	21894	21827	21495	20942	19874	18306	16702
11/27/2012	15563	14759	14325	14259	14482	15442	17465	18806	19466	19886	20192	20294	20288	20263	20250	20483	21406	22282	22081	21602	20923	19813	18286	16726
11/28/2012	15551	14930	14580	14461	14758	15778	17726	19008	19450	19759	19856	19836	19787	19761	19671	19836	20818	22097	21972	21527	20872	19809	18354	16800
11/29/2012	15659	15037	14670	14609	14987	15883	17839	19050	19429	19662	19789	19694	19506	19418	19299	19445	20479	21797	21671	21259	20641	19594	18179	16644
11/30/2012	15497	14867	14531	14493	14668	15612	17651	18927	19462	19805	20008	20033	19900	19930	19899	20012	20842	21714	21416	20903	20351	19557	18371	16967

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Operating Reserves

http://www.pjm.com/documents/~/media/documents/manuals/m13.ashx
Effective January 1, 2013 the Day-ahead Scheduling Reserve for RFC areas of PJM is 6.91% times Peak Load Forecast for RFC.
Effective January 1, 2012 the Day-ahead Scheduling Reserve for RFC areas of PJM is 7.03% times Peak Load Forecast for RFC.
http://www.pjm.com/sitecore%20modules/web/~/media/committees-groups/task-forces/rpstf/20121016/20121016-draft-manual-13-v51.ashx

	PJM Operating Reserves		
	PJM Other	**DOM**	**Total**
Operating Reserve Percentage	**7.03%**	**see below**	
PST	8,202	349	**8,551**
Winter	6,231	360	**6,591**
Spring	5,668	360	**6,028**
Summer	7,559	349	**7,909**
Fall	5,820	360	**6,180**

PJM East	**5004/5005**	**AP South**
1,832	3,244	3,580
1,270	2,404	2,744
1,148	2,138	2,493
1,664	2,971	3,313
1,199	2,233	2,583

http://www.serc1.org/Documents/SERC%20Standing%20Committee%20Documents/Regional%20Criteria/SERC%20Reg%20Criteria_Contingency%20Reserve%20Policy_Rev%205%20(10-07-11).pdf

UTILITY_NAME	PLANT_CODE	PLANT_NAME	STATE	COUNTY	GENERATOR_ID	PRIME_MOVER	STATUS	NAMEPLATE	SUMMER_CAPABILITY	WINTER_CAPABILITY
Duke Energy Carolinas, LLC	6036	Catawba	SC	York	1	ST	OP	1205.1	1129	1163
Duke Energy Carolinas, LLC	6036	Catawba	SC	York	2	ST	OP	1205.1	1129	1163
Duke Energy Carolinas, LLC	6038	McGuire	NC	Mecklenburg	1	ST	OP	1220.3	1129	1156
Duke Energy Carolinas, LLC	6038	McGuire	NC	Mecklenburg	2	ST	OP	1220.3	1129	1156

				Summer	Winter
July 26, Hour 16		**VACAR**	61,518	1,129	1,163
	31.7%	DUK	19,473	357	368
	21.3%	CPL	13,126	241	248
	7.7%	SCEG	4,761	87	90
	8.3%	SCPSA	5,124	94	97
	30.9%	DOM	19,034	349	360

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http://www.iso-ne.com/rules_proceds/operating/isone/op8/op8_rto_final.pdf

http://www.iso-ne.com/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2012_emm_rprt_final.pdf

Sufficient reserves must be held in the ISO-NE reserve zones to protect the system in case contingencies (e.g., generator outages) occur. The ISO used to hold an amount of 10-minute reserves (i.e., TMSR plus TMNSR) at the system level equal to the size of the largest generation contingency on the system. However, the ISO increased this requirement by 25 percent effective July 23, 2012, (i.e., now 125 percent of the largest generation contingency of the system) due to generator performance issues during past reserve activation events.37 Based on system conditions, the operator determines how much of the 10-minute reserve requirement to hold as spinning reserves.

The ISO holds an amount of 30-minute reserves that includes the system's 10-minute reserve (TMSR and TMNSR) requirements plus an incremental quantity of 30-minute reserves (TMOR). This total used to equal to the size of the largest generation contingency on the system plus half of the size of the second-largest contingency on the system. However, the increase in the 10-minute reserve requirement on July 23, 2012 resulted in a corresponding increase in the 30-minute reserve requirement by 25 percent of the size of the largest contingency. Since higher quality reserves may always be used to satisfy requirements for lower quality products, the entire 30-minute reserve requirement can be satisfied with TMSR or TMNSR.

In 2012, the system-wide reserve requirements averaged:
- 10-Minute Reserves: 1,370 MW prior to July 23 and 1,735 MW afterwards; and
- 30-Minute Reserves: 2,060 MW prior to July 23 and 2,430 MW afterwards.

Winter	Spring	Summer	Fall
2,060	2,060	2,430	2,430

CT

Winter	Spring	Summer	Fall
837	837	765	837

SWCT

Winter	Spring	Summer	Fall
50	50	-	50

http://www.iso-ne.com/trans/rsp/2012/rsp_final_110212.docx

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Table 4-9
Representative Future Operating-Reserve Requirements in Major New England Import Areas (MW)

Area/Improvement	Market Period[a]	Range of Fast-Start Resources Offered into the Past Forward Reserve Auctions (MW)[b]	Representative Future Locational Forward Reserve Market Requirements (MW)	
			Summer[c] (Jun to Sep)	Winter[c] (Oct to May)
Greater Southwest Connecticut[d]	2012	199–515	0[e]	50[e]
	2013		0	0
	2014		0	0
	2015		0	0
	2016		0	0
Greater Connecticut[f, g]	2012	614–1,563[h]	765[e]	837[e]
	2013		400–1,100	0–200
	2014		400–1,100	0–200
Greater Springfield Reliability Project (GSRP), and Interstate Reliability Project (IRP) of the New England East–West Solution (NEEWS)[f]	2015		400–1,100	0–200
	2016		400–1,100 0–300 with IRP of NEEWS	0–200 0 with IRP of NEEWS
BOSTON[g, i]	2012	0–441	0[e]	0[e]
	2013		0–200	0
	2014		0–200	0
	2015		0–200	0
	2016		0–200	0

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NYISO
Locational Reserve Requirements

The NYISO shall define requirements for Spinning Reserve, which may be met only by Suppliers that are eligible to provide Spinning Reserve; 10-Minute Reserve, which may be met by Suppliers that are eligible to provide either Spinning Reserve or 10-Minute Non-Synchronized Reserve; and 30-Minute Reserve, which may be met by Suppliers that are eligible to provide any Operating Reserve product. The NYISO shall also define locational requirements for Spinning Reserve, 10-Minute Reserve, and 30-Minute Reserve located East of Central East and on Long Island as shown in the following table:

	NYCA	Eastern NY	Long Island
A=most severe NYCA Operating Capability Loss (1310 MWs)	Zone A-K	Zone F-K	Zone K
10 Minute Spinning Reserve	½ A = 655 MWs (I)	¼ A = 330 MWs (IV)	0 MWs (VII)
10 Minute Total Reserve	A = 1310 MWs (II)	1200 MWs (V)	1/10 V = 120 MWs (VIII)
30 Minute Reserve	1½ A = 1965 MWs (III)	1200 MWs (VI)	270-540 MWs (I)

I NYCA 10-minute spinning reserve is equal to at least one-half of the 10-minute total reserve. [NYS RC D-R3]

II NYCA 10-minute total reserve is equal to the operating capability loss caused by the most severe contingency under normal transfer conditions. [NYS RC D-R2]

III NYCA 30-minute total reserve is equal to one and one-half the 10-minute reserve necessary to replace the operating capability loss caused by the most severe contingency under normal transfer conditions. [NYS RC D-R2]

IV ENY 10-minute spinning reserve is based on the NERC requirement to plan to meet energy reserve requirements, including the deliverability/capability for any single Contingency and the NPCC requirement that reserves be distributed to ensure that they can be used without exceeding individual element ratings or transfer limitations. [NERC TOP-002, NPCC A-06]

V ENY 10-minute total reserve is based on Reliability Rules that require immediate measures (activation of ENY 10-minute reserves) be applied to bring loadings on an internal NY transfer interface to within limits in 15 minutes. [NYS RC F-R6]

VI ENY 30-minute total reserve is based on the NERC requirement to plan to meet energy reserve requirements, including the deliverability/capability for any single Contingency and the NPCC requirement that reserves be distributed to ensure that they can be used without exceeding individual element ratings or transfer limitations. [NERC TOP-002, NPCC A-06]

VII LI 10-minute spinning reserve is based on the NERC requirement to plan to meet energy reserve requirements, including the deliverability/capability for any single Contingency and the NPCC requirement that reserves be distributed to ensure that they can be used without exceeding individual element ratings or transfer limitations. [NERC TOP-002, NPCC A-06]

VIII LI 10-minute total reserve is based on the NERC requirement to plan to meet energy reserve requirements, including the deliverability/capability for any single Contingency and the NPCC requirement that reserves be distributed to ensure that they can be used without exceeding individual element ratings or transfer limitations. [NERC TOP-002, NPCC A-06]

IX LI 30-minute total reserve is based on Reliability Rules that require the ability to restore a transmission circuit loading to Normal Operating Criteria within 30 minutes of the contingency. The LI 30-minute reserve requirement will vary from 270MW for off-peak hours to 540MW for on-peak hours. [NYS RC F-R1]

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Planned Outages

Wkp-Outages

	Winter	Spring	Summer	Fall
PJM	(10,540)	(28,168)	(1,679)	(18,573)
ISO-NE	(1,271)	(3,000)	(154)	(3,851)
NYISO	(4,010)	(5,948)	(886)	(4,384)

	Share of Generation			
	Winter	Spring	Summer	Fall
PJM East	18%	18%	17%	18%
5004/5005	31%	31%	31%	31%
AP South	44%	43%	43%	44%
CT	24%	24%	25%	24%
SWCT	9%	9%	9%	9%
NYC	25%	25%	24%	25%
LI	15%	15%	14%	15%

	Share of Outages			
	Winter	Spring	Summer	Fall
PJM East	(1,882)	(5,017)	(294)	(3,367)
5004/5005	(3,299)	(8,800)	(518)	(5,789)
AP South	(4,588)	(12,244)	(721)	(8,110)
CT	(305)	(720)	(38)	(925)
SWCT	(114)	(269)	(13)	(346)
NYC	(1,009)	(1,497)	(216)	(1,103)
LI	(589)	(873)	(128)	(644)

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Wkp-Outages

resp_name	respondent_id	report_yr	report_prd	spplmnt_num	row_num	avail_cap	plan_outage	unplan_outage	other_outage	tot_net	ex_avail_cap	ex_not_avail	tot_capability	avail_cap_f	plan_outage_f	unplan_outage_f	other_outage_f
ISO New England Inc.	185	2011	12	0	1200	33665	-1963	-1854	-9100	20748	1251	0	21999	0	0	0	0
ISO New England Inc.	185	2012	12	0	100	32910	896	602	0	34408	895	0	35303	0	0	0	0
ISO New England Inc.	185	2012	12	0	200	32271	953	1260	0	34484	1099	0	35583	0	0	0	0
ISO New England Inc.	185	2012	12	0	300	31986	1239	1260	0	34485	641	0	35126	0	0	0	0
ISO New England Inc.	185	2012	12	0	400	25121	7377	1955	0	34453	821	0	35274	0	0	0	0
ISO New England Inc.	185	2012	12	0	500	31426	384	2501	0	34311	430	0	34741	0	0	0	0
ISO New England Inc.	185	2012	12	0	600	29436	325	2095	0	31856	1266	0	33122	0	0	0	0
ISO New England Inc.	185	2012	12	0	700	31183	45	657	0	31885	1741	0	33626	0	0	0	0
ISO New England Inc.	185	2012	12	0	800	31137	91	684	0	31912	1870	0	33782	0	0	0	0
ISO New England Inc.	185	2012	12	0	900	30665	136	788	0	31589	617	0	32206	0	0	0	0
ISO New England Inc.	185	2012	12	0	1000	25942	8343	111	0	34396	1653	0	36049	0	0	0	0
ISO New England Inc.	185	2012	12	0	1100	30050	3075	1343	0	34468	1954	0	36422	0	0	0	0

resp_name	respondent_id	report_yr	report_prd	spplmnt_num	row_num	avail_cap	plan_outage	unplan_outage	other_outage	tot_net	ex_avail_cap	ex_not_avail	tot_capability	avail_cap_f	plan_outage_f	unplan_outage_f	other_outage_f
New York Independen	211	2011	12	0	1200	41347	-5187	-2301	0	33859	0	0	33859	0	0	0	0
New York Independen	211	2012	12	0	100	37792	-2868	-1325	0	33599	0	0	33599	0	1	2	0
New York Independen	211	2012	12	0	200	37792	-3976	-1146	0	32670	0	0	32670	0	0	0	0
New York Independen	211	2012	12	0	300	37792	-6531	-1329	0	29932	0	0	29932	0	0	0	0
New York Independen	211	2012	12	0	400	37792	-9145	-1329	0	27318	0	0	27318	0	0	0	0
New York Independen	211	2012	12	0	500	38622	-2168	-1454	0	35000	0	0	35000	0	0	0	0
New York Independen	211	2012	12	0	600	38622	-1475	-1360	0	35787	0	0	35787	0	0	0	0
New York Independen	211	2012	12	0	700	38622	-393	-1072	0	37157	0	0	37157	7	0	0	0
New York Independen	211	2012	12	0	800	38622	-789	-494	0	37339	0	0	37339	0	0	0	0
New York Independen	211	2012	12	0	900	38622	-3086	-1456	0	34080	0	0	34080	0	0	0	0
New York Independen	211	2012	12	0	1000	38622	-5931	-1593	0	31098	0	0	31098	0	0	0	0
New York Independen	211	2012	12	0	1100	38622	-4135	-2112	0	32375	0	0	32375	0	0	0	0

Wkp-Outages

resp_name	respondent_id	report_yr	report_prd	spplmnt_num	row_num	avail_cap	plan_outage	unplan_outage	other_outage	tot_net	ex_avail_cap	ex_not_avail	tot_capability	avail_cap_f	plan_outage_f	unplan_outage_f	other_outage_f
PJM Interconnection L	230	2011	12	0	1200	152891	14067	9447	0	176405	2404	62	178871	0	0	0	0
PJM Interconnection L	230	2012	12	0	100	166145	5781	9485	0	181411	2622	0	184033	0	0	0	0
PJM Interconnection L	230	2012	12	0	200	161824	11771	7786	0	181381	2622	0	184003	0	0	0	0
PJM Interconnection L	230	2012	12	0	300	148664	23386	9493	0	181543	2622	0	184165	0	0	0	0
PJM Interconnection L	230	2012	12	0	400	132473	42243	6388	0	181104	2531	91	183726	0	0	0	0
PJM Interconnection L	230	2012	12	0	500	150655	18875	11713	0	181243	2531	91	183865	0	0	0	0
PJM Interconnection L	230	2012	12	0	600	168331	1861	11555	0	181747	2930	5	184682	0	0	0	0
PJM Interconnection L	230	2012	12	0	700	162255	1158	18398	0	181811	3121	0	184932	0	0	0	0
PJM Interconnection L	230	2012	12	0	800	166623	2017	13171	0	181811	3061	60	184932	0	0	0	0
PJM Interconnection L	230	2012	12	0	900	160734	8554	10209	0	179497	3121	0	182618	0	0	0	0
PJM Interconnection L	230	2012	12	0	1000	144042	25815	8020	0	177877	3121	0	180998	0	0	0	0
PJM Interconnection L	230	2012	12	0	1100	141326	21350	15208	0	177884	2970	151	181005	0	0	0	0

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SIL

value progressed as PJM implemented operational procedures to mitigate associated constraints on limiting transmission equipment. While PJM would normally implement operating procedures in its AFC process only as requested and necessary to grant the next transmission service request, PJM implemented operational adjustments as part of the SIL study in order to reflect the real-time import capability of the system.

Table 2 – PJM RTO SIL Results

2012	Month	PJM SIL (MW)	LOAD (MW)
WINTER	January	10194	139759
SPRING	April	5642	116000
SUMMER	July	8434	154805
FALL	November	7029	113772

Table 3 – PJM RTO SIL Results Showing Impact of Generation Redispatch

2012 Season	PJM RTO SIL with no redispatch (MW)	PJM RTO SIL with redispatch (MW)	LOAD (MW)
WINTER	10194	****	139759
SPRING	3738	5642	116000
SUMMER	8434	****	154805
FALL	7029	****	113772

PJM uses these data to manage the OASIS-ATC when assessing transmission availability, and is consistent with PJM practices and procedures.

- The granularity of the first tier areas were represented by their respective BAs.
  - PJM calculated these SIL values based on its ability to import from each BA while simultaneously respecting the limiting elements of other BAs.
  - PJM calculated the transfer distribution factors of each BA on the network. The impact that each BA has on the other BAs was used to calculate the SIL. The SIL is a single calculation at concurrent interface limits rather than the sum of the non-simultaneous import capabilities from each BA. This process is consistent with PJM practices and procedures.

- Rudimentary operational adjustments were applied to relieve a limiting constraint if, in doing so, the overall PJM SIL could be increased. The internal constraints that were mitigated are flowgates that would not limit the ability of PJM to import from external resources. This process is consistent with PJM practices and procedures.

Table 8 below shows the results of all PJM Submarket SIL Analyses.

Table 8 –PJM Submarket SIL Results

2012 Season	Eastern		AP South		5004/5005	
	SIL (MW)	LOAD (MW)	SIL (MW)	LOAD (MW)	SIL (MW)	LOAD (MW)
WINTER	7267	24088	4888	65152	8869	46751
SPRING	4570	20459	4346	55319	5517	39606
SUMMER	6993	31056	7489	74002	7956	54843
FALL	8368	22740	7968	53545	8071	39664

The Tables 9-11 below provide the limiting element for each PJM Submarket SIL categorized by season.

III. SIL TRANSMISSION CAPABILITY

A. The ISO New England-Wide Market

To determine the SILs for the New England-wide geographic market, the ISO used the Attachment C-determined TTC values for all of the external interfaces, except for the NE/HQTE-Phase II external interface, in which case the ISO used 1400 MW to account for the transfer limit that may be imposed based on New York and PJM transmission system conditions. As explained above, the TTCs for the New England Area external interfaces are not adjusted to account for firm transmission reservations, TRM or CBM, and are as posted on the OASIS. Accordingly, the SILs for the New England-wide market for the 2012 power year, which are shown in Table 1, below, are the sum of the 1400 MW limit of the NE/HQTE-Phase II and the TTCs for the remainder external interfaces in the New England Area, and are consistent for all seasons. The SILs are indicative of what could feasibly be simultaneously imported into the New England Area in the Real-Time Energy Market. While these limits can be utilized simultaneously in the Real-Time Energy Market, the ISO does not consider this magnitude of total imports for use in other evaluations due to the historical use of the interfaces by market participants.

Table 1
SILs For New England-Wide Market*

Season/Year	Winter 2012	Spring 2012	Summer 2012	Fall 2012
SIL (MW)	4548	4548	4548	4548
Peak Load (MW)	19600	19500	25500	21100

* The peak load values reflected in this table have been rounded down

B. CT and SWCT Import Interfaces Submarkets

As discussed above, the SILs for the CT Import Interface and SWCT Import Interface for the 2012 power year are based on the limits reported in the RSP 2012.[34] The limits reported in RSP 2012 and utilized here are the all-lines-in conditions, first contingency limits at the peak load.

[34] *See* RSP 2012 at 56, notes (d) and (f). The Commission has previously found reliance on limits reported in the ISO's RSP to be acceptable. *See Northeast Utilities Service Company, et al.*, 123 FERC ¶ 61,172 at P 12 (2008) (finding use of RSP satisfies the requirements in the April 14 Order that "an applicant is required to provide a reasonable approximation of simultaneous import capability that would have been available to suppliers in surrounding first-tier markets during each seasonable peak.").

Table 2**
SILs For CT and SWCT Import Interfaces

Season/Year	Winter 2012	Spring 2012	Summer 2012	Fall 2012
CT Import SIL (MW)	2500	2500	2500	2500
CT Peak Load (MW)	4950	5860	6950	5650
SWCT Import SIL (MW)	2450***	2900***	3200	2820***
SWCT Peak Load (MW)	2450	2900	3410	2820

** The peak load values reflected in this table have been rounded down.

*** The import transfer limit for these seasons was determined to be 3200 MW. However, in accordance with Order No. 697, for purposes of determining the SILs, those limits were adjusted to be no greater than the SWCT peak load for the respective season.

IV. DOCUMENTS INCLUDED IN THIS FILING

The Supplemental Filing includes the following documents:

- This transmittal letter; and
- excel spreadsheets files:
  - ISO-NE SIL 2012 Historical Data

2012 NYISO Simultaneous Import limits

Seasonal Simultaneous Import Limit (SIL)		
2011-12 Season	NYISO Simultaneous Import Limits	NYISO System Peak Loads
Winter	8099 MW	24137 MW
Spring	7360 MW	28470 MW
Summer	7820 MW	32587 MW
Fall	8130 MW	28296 MW

Simultaneous import limits (SIL) values provided are consistent with the TTCs employed in operating the transmission system and posting availability on OASIS during the seasonal peak loads periods of 2011-12

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Uncommitted Capacity

Total Uncommitted Capacity in First Tier Markets

Dec 2011-Nov 2012

MISO	Pivotal Supplier	Market Share Analysis				Reference
		Winter	Spring	Summer	Fall	
Installed Capacity	116,686	115,363	117,097	116,686	119,085	NewPage MBR Companies CIS
Average Daily Peak Native Load in Peak Month	(86,359)					FERC Form 714
Average Peak Native Load in the Season		(65,629)	(58,964)	(78,107)	(60,603)	FERC Form 714
Operating Reserves	(3,354)	(3,354)	(3,354)	(3,354)	(3,354)	MISO Report
Planned Outages		(9,962)	(15,473)	(3,613)	(11,490)	FERC Form 714
Total Uncommitted Capacity in MISO	26,973	36,418	39,306	31,611	43,638	

DUK	Pivotal Supplier	Market Share Analysis				Reference
		Winter	Spring	Summer	Fall	
Installed Capacity	23,098	23,098	23,098	23,098	23,098	FERC Form 714
Average Daily Peak Native Load in Peak Month	(17,273)					FERC Form 714
Average Peak Native Load in the Season		(12,862)	(12,064)	(16,044)	(12,293)	FERC Form 714
Operating Reserves	(357)	(368)	(368)	(357)	(368)	Wkp-1st Tier Oper Reserves
Planned Outages		(993)	(1,662)	(58)	(2,409)	FERC Form 714
Total Uncommitted Capacity in DUK	5,468	8,875	9,003	6,639	8,028	

CPL	Pivotal Supplier	Market Share Analysis				Reference
		Winter	Spring	Summer	Fall	
Installed Capacity	13,734	13,734	13,734	13,734	13,734	FERC Form 714
Average Daily Peak Native Load in Peak Month	(11,822)					FERC Form 714
Average Peak Native Load in the Season		(8,835)	(7,948)	(10,777)	(8,500)	FERC Form 714
Operating Reserves	(241)	(248)	(248)	(241)	(248)	Wkp-1st Tier Oper Reserves
Planned Outages		(549)	(1,728)	0	(997)	FERC Form 714
Total Uncommitted Capacity in CPL	1,671	4,102	3,810	2,716	3,989	

TVA	Pivotal Supplier	Market Share Analysis				Reference
		Winter	Spring	Summer	Fall	
Installed Capacity	42,073	42,073	42,073	42,073	42,073	FERC Form 714
Average Daily Peak Native Load in Peak Month	(25,349)					FERC Form 714
Average Peak Native Load in the Season		(21,983)	(20,815)	(26,262)	(20,415)	FERC Form 714
Operating Reserves	(866)	(892)	(892)	(866)	(892)	Wkp-1st Tier Oper Reserves
Planned Outages		(2,194)	(3,755)	(1,163)	(4,531)	FERC Form 714
Total Uncommitted Capacity in TVA	15,858	17,004	16,611	13,782	16,235	

LGEE	Pivotal Supplier	Market Share Analysis				Reference
		Winter	Spring	Summer	Fall	
Installed Capacity	7,696	7,696	7,696	7,696	7,696	FERC Form 714
Average Daily Peak Native Load in Peak Month	(5,576)					FERC Form 714
Average Peak Native Load in the Season		(4,652)	(4,424)	(5,920)	(4,375)	FERC Form 714
Operating Reserves	(200)	(206)	(206)	(200)	(206)	Wkp-1st Tier Oper Reserves
Planned Outages		(151)	(1,559)	0	(856)	FERC Form 714
Total Uncommitted Capacity in LGEE	1,920	2,687	1,507	1,576	2,259	

EKPC		Winter	Spring	Summer	Fall	
Installed Capacity	2,999	2,999	2,999	2,999	2,999	FERC Form 714
Average Daily Peak Native Load in Peak Month	(1,969)					FERC Form 714
Average Peak Native Load in the Season		(1,896)	(1,481)	(1,904)	(1,552)	FERC Form 714
Operating Reserves	(63)	(65)	(65)	(63)	(65)	Wkp-1st Tier Oper Reserves
Planned Outages		(198)	(374)	(25)	(505)	FERC Form 714
Total Uncommitted Capacity in LGEE	967	840	1,079	1,007	877	

IESO		Winter	Spring	Summer	Fall	
Installed Capacity	35,858	35,858	35,858	35,858	35,858	IESO 2012 18 month outlook
Average Daily Peak Native Load in Peak Month	(21,148)					IESO
Average Peak Native Load in the Season		(19,282)	(16,950)	(19,899)	(17,778)	IESO
Operating Reserves	(1,580)	(1,580)	(1,580)	(1,580)	(1,580)	IESO
Planned Outages		0	0	0	0	NA
Total Uncommitted Capacity in IESO	13,130	14,996	17,328	14,379	16,500	

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HQT		Winter	Spring	Summer	Fall	
Installed Capacity	35,829	35,829	35,829	35,829	35,829	HQ 2012 Annual Report
Average Daily Peak Native Load in Peak Month	(33,296)					Peak hour from HQ 2012 Annual Report, shaped based on IESO hourly load profile
Average Peak Native Load in the Season		(30,358)	(26,686)	(31,329)	(27,990)	
Operating Reserves	(1,580)	(1,580)	(1,580)	(1,580)	(1,580)	estimated based on IESO
Planned Outages		0	0	0	0	
Total Uncommitted Capacity in HQT	953	3,891	7,563	2,920	6,259	

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Import Allocation

Import Allocation						
Row		PST	Winter	Spring	Summer	Fall
	Allocation of Imports into PJM					
A	Seller's Uncommitted Capacity in MISO	1,484	1,497	1,497	1,484	1,497
B	Seller's Uncommitted Capacity in NYISO	1,926	1,741	1,650	1,882	1,723
C	Seller's Uncommitted Capacity in CPLE	-	-	-	-	-
D	Seller's Uncommitted Capacity in DUK	-	-	-	-	-
E	Seller's Uncommitted Capacity in EKPC	-	-	-	-	-
F	Seller's Uncommitted Capacity in LGEE	-	-	-	-	-
G	Seller's Uncommitted Capacity in TVA	-	-	-	-	-
H	**Seller's Uncommitted Capacity (SUM A-G)**	**3,410**	**3,238**	**3,147**	**3,367**	**3,220**
I	Total Uncommitted Capacity in MISO	26,973	36,418	39,306	31,611	43,638
J	Total Uncommitted Capacity in NYISO	9,613	14,032	14,082	10,538	14,631
K	Total Uncommitted Capacity in CPLE	1,671	4,102	3,810	2,716	3,989
L	Total Uncommitted Capacity in DUK	5,468	8,875	9,003	6,639	8,028
M	Total Uncommitted Capacity in EKPC	967	840	1,079	1,007	877
N	Total Uncommitted Capacity in LGEE	1,920	2,687	1,507	1,576	2,259
O	Total Uncommitted Capacity in TVA	15,858	17,004	16,611	13,782	16,235
P	**Total Uncommitted Capacity (SUM I-O)**	**62,470**	**83,957**	**85,400**	**67,871**	**89,656**
Q	**Seller's Share of Uncommitted Capacity into PJM (H/P)**	5.5%	3.9%	3.7%	5.0%	3.6%
R	**Imports into PJM**	8,434	10,194	5,642	8,434	7,029
S	**Seller's Share of Imports into PJM (Q*R)**	382	280	168	347	301

Row		PST	Winter	Spring	Summer	Fall
	Allocation of Imports into PJM East					
A	Seller's Uncommitted Capacity in PJM	7,963	10,599	9,168	8,752	10,759
B	Less Seller's Uncommitted Capacity in PJM East	(814)	(2,697)	(2,367)	(1,236)	(2,471)
C	Plus Seller's Uncommitted Capacity in NYISO	1,926	1,741	1,650	1,882	1,723
D	**Seller's Uncommitted Capacity (SUM A-C)**	**9,075**	**9,642**	**8,451**	**9,399**	**10,012**
E	Total Uncommitted Capacity in PJM	55,541	88,144	80,804	65,059	83,047
F	Less Total Uncommitted Capacity in PJM East	(6,651)	(15,668)	(14,321)	(8,913)	(15,064)
G	Plus Total Uncommitted Capacity in NYISO	9,613	14,032	14,082	10,538	14,631
H	**Total Uncommitted Capacity (SUM E-G)**	**58,504**	**86,509**	**80,566**	**66,684**	**82,614**
I	**Seller's Share of Uncommitted Capacity into PJM East (D/H)**	15.5%	11.1%	10.5%	14.1%	12.1%
J	**Imports into PJM East**	6,993	7,267	4,570	6,993	8,368
K	**Seller's Share of Imports into PJM East (I*J)**	1,085	810	479	986	1,014

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Row		PST	Winter	Spring	Summer	Fall
	Allocation of Imports into 5004/5005					
A	Seller's Uncommitted Capacity in PJM	7,963	10,599	9,168	8,752	10,759
B	Less Seller's Uncommitted Capacity in 5004/5005	(1,007)	(3,625)	(3,310)	(1,707)	(3,423)
C	Plus Seller's Uncommitted Capacity in NYISO	1,926	1,741	1,650	1,882	1,723
D	**Seller's Uncommitted Capacity (SUM A-C)**	**8,882**	**8,715**	**7,509**	**8,927**	**9,059**
E	Total Uncommitted Capacity in PJM	55,541	88,144	80,804	65,059	83,047
F	Less Total Uncommitted Capacity in 5004/5005	(11,523)	(24,749)	(23,231)	(15,159)	(23,298)
G	Plus Total Uncommitted Capacity in NYISO	9,613	14,032	14,082	10,538	14,631
H	**Total Uncommitted Capacity (SUM E-G)**	**53,632**	**77,428**	**71,656**	**60,438**	**74,381**
I	**Seller's Share of Uncommitted Capacity into 5004/5005 (D/H)**	16.6%	11.3%	10.5%	14.8%	12.2%
J	**Imports into 5004/5005**	7,956	8,869	5,517	7,956	8,071
K	**Seller's Share of Imports into 5004/5005 (I*J)**	1,318	998	578	1,175	983

Row		PST	Winter	Spring	Summer	Fall
	Allocation of Imports into AP South					
A	Seller's Uncommitted Capacity in PJM	7,963	10,599	9,168	8,752	10,759
B	Less Seller's Uncommitted Capacity in AP South	(1,170)	(3,799)	(3,249)	(1,623)	(3,358)
C	Plus Seller's Uncommitted Capacity in NYISO	1,926	1,741	1,650	1,882	1,723
D	Plus Seller's Uncommitted Capacity in CPLE	-	-	-	-	-
E	**Seller's Uncommitted Capacity (SUM A-D)**	**8,719**	**8,541**	**7,570**	**9,011**	**9,124**
F	Total Uncommitted Capacity in PJM	55,541	88,144	80,804	65,059	83,047
G	Less Total Uncommitted Capacity in AP South	(18,475)	(36,040)	(33,675)	(23,228)	(34,259)
H	Plus Total Uncommitted Capacity in NYISO	9,613	14,032	14,082	10,538	14,631
I	Plus Total Uncommitted Capacity in CPLE	1,671	4,102	3,810	2,716	3,989
J	**Total Uncommitted Capacity (SUM F-I)**	**48,350**	**70,239**	**65,022**	**55,086**	**67,409**
K	**Seller's Share of Uncommitted Capacity into 5004/5005 (E/J)**	18.0%	12.2%	11.6%	16.4%	13.5%
L	**Imports into AP South**	7,489	4,888	4,346	7,489	7,968
M	**Seller's Share of Imports into AP South (K*L)**	1,351	594	506	1,225	1,078

	Allocation of Imports into NYISO					
A	Seller's Uncommitted Capacity in PJM	7,963	10,599	9,168	8,752	10,759
B	Seller's Uncommitted Capacity ISO-NE	3,463	510	556	-	774
C	Seller's Uncommitted Capacity in HQT	-	-	-	-	-
D	Seller's Uncommitted Capacity in IESO	-	-	-	-	-
E	**Seller's Uncommitted Capacity (SUM A-D)**	**11,427**	**11,109**	**9,724**	**8,752**	**11,533**
F	Total Uncommitted Capacity in PJM	55,541	88,144	80,804	65,059	83,047
G	Total Uncommitted Capacity in ISO-NE	8,623	13,299	13,858	9,619	11,706
H	Total Uncommitted Capacity in HQT	953	3,891	7,563	2,920	6,259
I	Total Uncommitted Capacity in IESO	13,130	14,996	17,328	14,379	16,500
J	**Total Uncommitted Capacity (SUM F-I)**	**78,248**	**120,330**	**119,553**	**91,977**	**117,513**
K	**Seller's Share of Uncommitted Capacity into NYISO (E/J)**	14.6%	9.2%	8.1%	9.5%	9.8%
L	**Imports into NYISO**	7,820	8,099	7,360	7,820	8,130
M	**Seller's Share of Imports into NYISO (K*L)**	1,142	748	599	744	798

	Allocation of Imports into ISO-NE					
A	Seller's Uncommitted Capacity in NYISO	1,926	1,741	1,650	1,882	1,723
B	Seller's Uncommitted Capacity in HQT	-	-	-	-	-
C	Seller's Uncommitted Capacity in NBSO	-	-	-	-	-
D	**Seller's Uncommitted Capacity (SUM A-C)**	**1,926**	**1,741**	**1,650**	**1,882**	**1,723**
E	Total Uncommitted Capacity in NYISO	9,613	14,032	14,082	10,538	14,631
F	Total Uncommitted Capacity in HQT	953	3,891	7,563	2,920	6,259
G	Total Uncommitted Capacity in NBSO	-	-	-	-	-
H	**Total Uncommitted Capacity (SUM E-G)**	**10,567**	**17,923**	**21,645**	**13,459**	**20,890**
I	**Seller's Share of Uncommitted Capacity into ISO-NE (D/H)**	18.2%	9.7%	7.6%	14.0%	8.2%
J	**Imports into ISO-NE**	4,548	4,548	4,548	4,548	4,548
K	**Seller's Share of Imports into ISO-NE (I*J)**	829	442	347	636	375

	Allocation of Imports into CT					
A	Seller's Uncommitted Capacity in ISO-NE	3,463	510	556	-	774
B	Less Seller's Uncommitted Capacity in CT	-	-	-	-	-
C	Seller's Uncommitted Capacity in NYISO	1,926	1,741	1,650	1,882	1,723
D	**Seller's Uncommitted Capacity (SUM A-C)**	**5,390**	**2,251**	**2,206**	**1,882**	**2,497**
E	Total Uncommitted Capacity in ISO-NE	8,623	13,299	13,858	9,619	11,706
F	Less Total Uncommitted Capacity in CT	(1,823)	(2,828)	(2,972)	(2,165)	(2,531)
G	Total Uncommitted Capacity in NYISO	9,613	14,032	14,082	10,538	14,631
H	**Total Uncommitted Capacity (SUM E-G)**	**16,414**	**24,503**	**24,968**	**17,992**	**23,807**
I	**Seller's Share of Uncommitted Capacity into CT (D/H)**	32.8%	9.2%	8.8%	10.5%	10.5%
J	**Imports into CT**	2,500	2,500	2,500	2,500	2,500
K	**Seller's Share of Imports into CT (I*J)**	821	230	221	262	262

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ADDITIONAL DATA ON FIRST-TIER MARKETS (For Import Allocation)

http://www.serc1.org/Documents/SERC%20Standing%20Committee%20Documents/Regional%20Criteria/SERC%20Reg%20Criteria_Contingency%20Reserve%20Policy_Rev%205%20(10-07-11).pdf

UTILITY_NAME	PLANT_CODE	PLANT_NAME	STATE	COUNTY	GENERATOR_ID	PRIME_MOVER	STATUS	NAMEPLATE	SUMMER_CAPABILITY	WINTER_CAPABILITY
Duke Energy Carolinas, LLC	6036	Catawba	SC	York	1	ST	OP	1205.1	1129	1163
Duke Energy Carolinas, LLC	6036	Catawba	SC	York	2	ST	OP	1205.1	1129	1163
Duke Energy Carolinas, LLC	6038	McGuire	NC	Mecklenburg	1	ST	OP	1220.3	1129	1156
Duke Energy Carolinas, LLC	6038	McGuire	NC	Mecklenburg	2	ST	OP	1220.3	1129	1156

			Summer	Winter
July 26, Hour 16	**VACAR**	61,518	1,129	1,163
31.7%	DUK	19,473	357	368
21.3%	CPL	13,126	241	248
7.7%	SCEG	4,761	87	90
8.3%	SCPSA	5,124	94	97
30.9%	DOM	19,034	349	360

UTILITY_NAME	PLANT_CODE	PLANT_NAME	STATE	COUNTY	GENERATOR_ID	PRIME_MOVER	STATUS	NAMEPLATE	SUMMER_CAPABILITY	WINTER_CAPABILITY
Tennessee Valley Authority	6152	Sequoyah	TN	Hamilton	1	ST	OP	1220.5	1152	1177.4

			Summer	Winter
July 26, Hour 16	**TEE**	40,536	1,152	1,177
76.7%	TVA	31,098	866	892
17.7%	LGEE	7,173	200	206
5.6%	EKPC	2,265	63	65

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VACAR Reserve Sharing Group>>>

Dec 2011-Nov 2012 Load

VACARP	**Max**	61,518
VACARA	**Avg Jul**	54,605
VACARW	**Winter**	40,812
VACARS	**Spring**	37,097
VACARS	**Summer**	50,231
VACARF	**Fall**	38,853

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
VACAR	12/1/11	33957	33608	33814	34463	35907	39152	43862	44899	42930	40167	37925	35835	34313	33446	32639	32472	33685	37591	39878	40660	40898	40075	38363	36583
VACAR	12/2/11	35546	35490	35886	36595	38175	41318	45889	46926	44577	40870	37582	35160	33547	32406	31631	31514	32096	35584	37077	37055	37178	36817	35789	34107
VACAR	12/3/11	32977	32540	32570	32913	33646	35020	36826	38246	38611	36992	35139	33274	31703	30554	29830	29783	31027	34501	35727	35889	35798	35114	33834	32264
VACAR	12/4/11	31130	30621	30553	30936	31565	32634	34166	35524	36336	35141	33132	31409	30482	29894	29225	29125	30145	33702	34963	34934	34581	33132	30956	28799
VACAR	12/5/11	27297	26581	26369	26629	27661	30266	34453	35801	34892	34445	33876	33491	32987	32721	32352	32278	33175	36183	36996	36673	35730	33583	30791	27900
VACAR	12/6/11	26005	24987	24482	24372	24933	27136	31228	32749	32381	32408	32551	32556	32341	32328	32244	32189	32851	35454	36156	35679	34787	32967	30147	27337
VACAR	12/7/11	25323	24353	23897	23766	24342	26389	30414	32258	32105	32259	32478	32759	32734	32832	32698	32797	33719	36313	37133	36862	36489	35111	33001	30837
VACAR	12/8/11	29623	29339	29492	30124	31830	35096	40394	42161	40968	39178	37701	36288	34966	34090	33384	33438	34838	39153	41155	41809	41942	41063	38973	36676
VACAR	12/9/11	35328	34908	34918	35325	36508	39203	43484	44600	42922	40532	38337	36269	34669	33655	32813	32641	33938	37385	38145	37720	37366	36498	34787	32647
VACAR	12/10/11	31085	30194	29854	29894	30378	31643	33515	35348	36851	36780	35720	34604	33368	32199	31544	31554	33041	36732	38197	38582	38790	38503	37463	35964
VACAR	12/11/11	34892	34525	34671	35041	35734	36919	38723	40482	41497	40160	37748	35665	34322	33306	32620	32738	34650	39096	40877	41587	41523	40279	38189	36026
VACAR	12/12/11	34764	34215	34137	34565	35836	38726	43200	44616	43667	42770	41628	40295	39037	37949	36881	36573	37659	41497	42937	42912	42496	40888	38443	35979
VACAR	12/13/11	34427	34068	34035	34509	35705	38620	43331	44547	42725	40068	37635	35648	34249	33427	32818	32546	33488	37084	38824	39101	38980	37718	35317	32797
VACAR	12/14/11	31206	30555	30496	30776	31816	34406	38707	40104	38620	37064	35720	34497	33659	33099	32629	32507	33585	36937	38316	38112	37653	36275	33805	31233
VACAR	12/15/11	29623	28963	28836	29097	30119	32849	37445	38777	37392	35686	34362	33210	32321	31993	31655	31544	32172	35005	36124	35859	35317	33808	31205	28431
VACAR	12/16/11	26461	25295	24842	24873	25659	27825	31958	33468	33008	32752	32632	32438	32153	32063	32037	32258	33420	35798	36099	35370	34725	33621	31982	29781
VACAR	12/17/11	28143	27268	26843	26980	27433	28682	30440	32384	34245	35105	34942	34180	33362	32466	31880	31896	33171	36449	38005	38046	38314	38172	37305	35843
VACAR	12/18/11	34516	33867	33564	33662	34214	35403	37224	39300	40645	39208	36599	34431	33474	32609	31948	31802	33276	37265	39569	40420	41036	40429	39080	37406
VACAR	12/19/11	36339	35982	36376	37161	38732	41729	45835	47549	46368	43067	40084	37763	35920	34782	33803	33577	34451	38269	40022	40022	39626	38143	35832	33151
VACAR	12/20/11	31372	30430	30066	30204	31082	33401	36985	38737	38111	36898	35725	34778	33866	33344	33063	32886	33873	36852	37552	37150	36326	34790	32207	29507
VACAR	12/21/11	27488	26481	25957	25944	26558	28522	31673	33495	33739	33955	34212	33924	33629	33546	33103	33201	33759	35912	36303	35627	34621	33184	30828	28095
VACAR	12/22/11	25986	24786	24191	23932	24458	26133	28984	30852	31606	32104	32410	32223	31865	31649	31479	31238	31910	34524	35161	34441	33643	32244	30289	27640
VACAR	12/23/11	25497	24270	23510	23222	23449	24726	26719	28427	29620	30521	30817	30567	30010	29544	29219	29047	29745	32542	33439	32983	32622	31977	30665	28816
VACAR	12/24/11	27114	26146	25687	25749	26317	27422	29174	31109	33006	33304	32634	31497	30541	29564	29074	29129	30051	32830	33626	33540	33690	33671	33102	31950
VACAR	12/25/11	30794	30181	30080	30322	30824	31849	33473	34915	35724	34611	32689	31326	30623	29719	28791	28305	28565	30762	31627	31836	31974	31646	30688	29283
VACAR	12/26/11	28213	27602	27550	27999	28940	30429	32227	33558	34293	33945	33237	32226	30923	29729	28893	28716	29799	33972	36168	36693	36754	35914	34271	32236
VACAR	12/27/11	30637	29685	29126	29007	29569	31101	33354	35160	35856	36591	36931	36493	35655	34591	33621	32947	33220	35796	37010	36598	36069	34770	33109	31221

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VACAR Reserve Sharing Group>>>

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
VACAR	12/28/11	29874	29379	29343	29751	30874	32905	35748	37647	37973	37083	36234	35173	33886	32970	32285	32119	33325	37286	39320	39544	39469	38524	37065	35261
VACAR	12/29/11	34375	34267	34733	35689	37280	39753	42985	44892	44605	42332	39762	37607	35791	34554	33469	32934	33907	37339	39196	39272	39081	38228	36497	34572
VACAR	12/30/11	33276	32564	32445	32704	33835	35847	38675	40368	40250	38294	36227	34340	32530	31423	30499	30135	31016	33984	34982	34485	33843	32684	31045	29062
VACAR	12/31/11	27308	26284	25596	25288	25438	26047	27225	28409	29606	30226	30166	29753	29240	28492	28019	27932	28718	31557	32997	32434	31921	31201	30371	29703
VACAR	1/1/12	29085	29043	28961	29312	29950	31116	32591	33856	34599	33291	31289	29856	29188	28425	27784	27501	28328	30748	31811	31454	30869	29827	28578	26959
VACAR	1/2/12	25856	25416	25557	26303	27635	29858	32905	34862	35877	36173	36090	35393	34550	33822	33323	33592	35294	39590	42026	42659	42595	41600	39815	38241
VACAR	1/3/12	37531	37599	38181	39253	40912	44306	49032	50832	49895	48372	47274	45971	44682	43862	43251	43604	45445	49553	52123	52438	52078	50558	48308	46381
VACAR	1/4/12	45534	45378	45989	46780	48313	51474	55725	56834	54675	51142	47943	45202	42824	41221	39830	39613	41010	44821	47143	47201	46687	44982	42300	39849
VACAR	1/5/12	38250	37682	37371	37633	38534	41214	45747	47182	45575	42750	40129	37993	36265	35153	34350	33965	34740	38029	40619	41136	41284	40133	38114	36251
VACAR	1/6/12	35078	34850	34957	35426	36751	39519	44027	45406	43574	40472	37614	35436	33785	32715	31783	31256	31530	34039	35744	35451	35028	34257	32990	31224
VACAR	1/7/12	29917	29286	29196	29465	30050	31262	32909	34391	35380	35033	33662	32308	31025	29996	29218	29013	29356	31643	33020	32453	31854	30835	29472	27769
VACAR	1/8/12	26216	25558	25292	25300	25724	26622	28100	29811	31743	32078	31351	30477	30243	29841	29432	29356	30294	33222	34698	34521	34208	32935	30949	28993
VACAR	1/9/12	27750	27203	27129	27430	28643	31423	36057	38028	37395	37176	37181	37240	37104	36812	36666	36896	37892	40024	41045	40336	39203	37218	34563	32131
VACAR	1/10/12	30488	29734	29372	29518	30499	33057	37364	39089	38135	37114	36118	34965	33942	33355	32859	32699	33592	36558	38322	38402	37866	36343	33868	31590
VACAR	1/11/12	30200	29595	29303	29506	30315	32827	37048	38702	37643	37162	36969	36843	36555	36231	35779	35747	36564	38207	38881	38092	37094	35232	32685	30260
VACAR	1/12/12	28700	28044	27824	28130	29265	31996	36661	38267	37190	36027	35271	34478	33537	32807	32170	31952	32558	35285	37005	36958	36514	35008	32900	30974
VACAR	1/13/12	29927	29758	30244	31255	33179	36805	42155	44769	44241	43329	42369	40912	39432	38221	37201	36911	38073	41525	43773	43703	43287	42136	40570	38845
VACAR	1/14/12	37751	37454	37594	38048	38982	40583	42783	44774	45554	44001	41935	39911	37799	36125	35050	34708	35836	38899	41319	41534	41553	40891	39613	37857
VACAR	1/15/12	36656	36014	35630	35770	36142	37245	38868	40660	41901	40969	38813	36931	35865	34925	33955	33500	34629	37875	40881	41526	42039	41517	40582	39466
VACAR	1/16/12	38891	39071	39479	40272	41709	44113	46917	48687	48613	46925	44660	42390	40369	38862	38141	37859	38530	41127	42640	42202	41215	39124	36722	34345
VACAR	1/17/12	32612	31845	31475	31642	32441	34869	39062	40401	39173	37779	36838	35826	34988	34277	33470	32980	33359	35586	37229	36844	35799	33841	31317	28790
VACAR	1/18/12	27005	26310	25983	26132	27193	30005	34744	36838	36424	36047	35651	35153	34537	34034	33580	33564	34709	37941	41174	41618	41491	40345	38527	36484
VACAR	1/19/12	35483	35374	35782	36596	38322	41796	47013	49044	47290	44442	42059	39777	37737	36582	35770	35847	36890	39768	42192	42420	41928	40467	38219	35968
VACAR	1/20/12	34713	34349	34300	34879	36105	38733	42998	44539	43035	41188	39692	38153	37157	36562	36000	36117	36949	39134	39879	39285	38432	37168	35360	33315
VACAR	1/21/12	31699	30793	30261	29955	30104	30780	31936	33393	34743	35873	36474	36295	35862	35103	34498	34288	34897	36470	37398	36902	36178	35217	33786	32258
VACAR	1/22/12	30985	30482	30402	30630	31252	32388	33885	35989	38358	39629	39715	39435	39537	39327	39006	38990	39463	41472	42574	42143	41439	39796	37731	35575
VACAR	1/23/12	33967	33288	33087	33453	34523	37112	41217	43049	42471	42212	41796	41086	40300	39497	38718	38234	38408	40230	41416	40624	39327	37128	34193	31413
VACAR	1/24/12	29593	28596	28182	28166	28813	31146	35493	37144	36217	35496	34837	34016	32991	32380	31720	31354	31641	33398	36297	36459	36181	34912	32905	31066
VACAR	1/25/12	30029	29886	30072	30689	32181	35480	40834	42535	41096	38226	36230	34691	33400	32650	31992	31640	32188	34382	37211	37493	37018	35659	33396	31294
VACAR	1/26/12	29870	29145	28971	29136	30122	32543	37015	38277	36951	35995	35224	34201	33264	32686	32215	31985	32346	34175	36010	35696	34871	33091	30489	28030
VACAR	1/27/12	26176	25081	24598	24395	24856	26771	30681	32499	32336	32363	32439	32204	31731	31247	30770	30346	30444	31707	33827	33613	33145	32417	31311	29833
VACAR	1/28/12	28885	28597	28877	29610	30706	32565	34844	36918	37948	36458	34688	33075	31537	30277	29204	28898	29273	31112	33681	33788	33662	33131	32098	30859
VACAR	1/29/12	29911	29710	29851	30415	31504	32863	35081	37268	38598	37312	35060	33270	32290	31230	30362	29948	30694	33332	36971	38031	38318	37531	35980	34414
VACAR	1/30/12	33542	33349	33658	34400	36126	39562	44684	46623	44630	41256	38501	36553	34985	33839	32948	32464	32835	35037	38474	39068	38920	37830	35858	33826
VACAR	1/31/12	32754	32418	32561	33159	34544	37609	42506	43831	41650	38650	36362	34492	33200	32465	31612	31216	31554	33045	36177	36508	36008	34527	32310	30208

VACAR Reserve Sharing Group>>>

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
VACAR	2/1/12	28859	28263	28053	28277	29187	31700	36226	37467	36258	34887	33808	32812	31893	31453	31209	31170	31469	33167	35193	34958	34127	32549	30098	27410
VACAR	2/2/12	25930	25122	24777	24809	24830	27990	32652	34299	33366	32997	32648	31091	31763	31551	31159	30944	31101	32286	34750	35044	34547	33163	30992	29084
VACAR	2/3/12	27913	27518	27810	28555	29929	33188	38362	40301	39011	37058	35541	34109	32851	32018	31209	30767	31094	32741	35710	36039	35970	35506	34293	32721
VACAR	2/4/12	31493	30705	30428	30430	30724	31682	33082	34326	35438	35740	35205	34333	33341	32573	31937	31781	32262	33632	35091	34688	34034	32875	31234	29307
VACAR	2/5/12	27854	26903	26520	26276	26479	27239	28470	30133	32137	33340	33329	33063	33178	33039	32920	33017	33627	35251	36520	35919	35837	35023	34440	32645
VACAR	2/6/12	31439	31167	31386	32044	33501	36594	41209	42876	41889	40489	39129	37761	36648	35794	35051	34687	35339	37363	40237	40397	39777	38072	35712	33453
VACAR	2/7/12	32164	31727	31805	32218	33683	36960	42010	43314	41346	38727	36771	35031	33604	32788	32092	31748	33323	34027	37550	38402	38491	37478	35779	34023
VACAR	2/8/12	33260	33266	33614	34410	35789	38955	43578	44587	42835	40795	39389	38169	37115	36446	35776	35531	36004	37747	40563	40872	40703	39255	37156	35267
VACAR	2/9/12	34229	34047	34370	35091	36663	39893	45019	46493	44390	41662	39490	37479	35934	34793	33973	33577	34139	36348	40130	41263	41394	40431	38438	36645
VACAR	2/10/12	35745	35633	35987	36648	38108	41148	45795	46933	44963	42367	40497	38860	37330	36459	35849	35630	36190	37494	38980	38487	37682	36441	34782	32876
VACAR	2/11/12	31386	30433	30228	30156	30681	31933	33607	35369	37000	37542	37132	36549	35934	35271	34990	35463	36790	39704	43981	45705	46602	46801	46114	45295
VACAR	2/12/12	44648	44607	44803	45212	45932	47153	48704	50008	50186	48725	46159	43544	41690	39842	38234	37262	37533	39955	43901	45481	45639	44752	43154	41632
VACAR	2/13/12	40978	40969	41648	43310	44541	48010	52851	53918	50968	46585	43144	40481	38253	36661	35479	34903	35478	37534	41120	42046	42087	40870	38684	36400
VACAR	2/14/12	34877	34193	33956	34148	35008	37666	42074	43228	42038	40968	39685	37976	36418	35434	34832	34400	34908	36473	38742	38822	38162	36558	34246	31925
VACAR	2/15/12	30526	30118	30087	30657	31970	35175	40091	41375	39426	36985	35312	33947	32973	32300	31738	31265	31538	32775	35869	36650	36443	35275	33186	30987
VACAR	2/16/12	29801	29224	29094	29277	30253	32809	37244	38507	37631	37118	36833	36181	35564	35200	34892	34702	35088	36018	37726	37892	36940	35268	32892	30552
VACAR	2/17/12	28843	27985	27653	27839	28865	31446	35734	37160	36396	35189	34104	33093	32277	31738	31134	30619	30621	31439	33949	34576	34341	33667	32474	30873
VACAR	2/18/12	29670	29091	28972	29296	29893	31168	33134	34860	35663	34583	33225	31769	30444	29321	28636	28339	28795	29728	32514	32556	31923	30995	29508	27981
VACAR	2/19/12	26607	25977	25659	25709	26050	26880	28310	29911	32290	33874	34241	34475	34959	35317	35622	36074	37079	38835	40768	40879	40317	39102	37472	36015
VACAR	2/20/12	34928	34571	34645	35180	36444	38778	42246	44033	43760	42286	40578	38935	37303	35887	34659	33966	34049	35594	39623	41304	41608	40689	39196	37419
VACAR	2/21/12	36712	36714	37226	38055	39689	42766	47542	48214	45729	42562	40286	38456	36970	35560	34288	33489	33609	34706	37686	38597	38110	36545	34267	31631
VACAR	2/22/12	30454	29823	29741	30039	31199	33979	38612	39486	37475	35586	34144	33043	32190	31709	31266	30967	31314	32291	34934	35231	34634	33013	30535	28029
VACAR	2/23/12	26406	25683	25383	25540	26575	29105	33440	34699	33781	33111	32681	32164	31726	31729	31427	31291	31209	31643	34075	34666	33921	32109	29643	27096
VACAR	2/24/12	25397	24347	23980	23849	24384	26371	30292	31653	31750	32102	32431	32370	32111	31996	31711	31362	31272	31833	33195	32998	32151	31113	29652	27781
VACAR	2/25/12	26689	26252	26335	26831	27677	29226	31289	33499	35299	35728	35333	34403	33359	32277	31387	30980	31480	33153	36147	37350	37379	36759	35796	34638
VACAR	2/26/12	33719	33407	33646	34139	35039	36520	38412	39999	40159	38541	36267	34209	32813	31358	30225	29453	29691	31307	34835	36757	37045	36254	34645	33189
VACAR	2/27/12	32131	31809	31804	31993	32989	35640	40072	41072	39588	38454	37585	36531	35603	34846	34048	33475	33406	34336	36957	37482	36587	34576	32175	29918
VACAR	2/28/12	28477	27767	27713	28052	29252	32247	36963	38036	36612	35009	33834	32922	32026	31553	31099	30813	30849	31511	34482	35632	35188	33570	31305	29159
VACAR	2/29/12	27702	27190	27051	27138	27899	30360	34489	35846	35351	34960	34977	34419	33827	33385	32926	32580	32671	33407	35297	35501	34437	32587	30004	27294
VACAR	3/1/12	25723	24664	24173	23991	24612	26781	30767	31978	31743	31633	31839	31805	31755	31772	31732	31673	31582	31786	33764	34627	33738	31990	29504	27154
VACAR	3/2/12	25474	24762	24528	24620	25588	28046	32426	33878	33594	33347	33128	32856	32510	32366	32188	32176	32524	33169	34443	34416	33363	32043	30171	28121
VACAR	3/3/12	26476	25315	24674	24421	24385	24911	26084	27271	29078	30543	31199	31139	30590	29729	28994	28624	28990	29924	31925	32091	31485	30595	29128	27423
VACAR	3/4/12	26081	25288	25066	25106	25641	26581	28131	29913	32089	32783	32275	31505	31091	30695	30437	30423	31153	32901	36103	37954	37933	36985	35460	34021
VACAR	3/5/12	33054	32930	33189	33799	34894	37732	41782	42481	41419	39999	38880	37828	36971	36135	35250	34743	35004	36357	39764	41608	41379	40150	38177	36330
VACAR	3/6/12	35560	35573	36102	37063	38729	42160	46604	46807	43741	40599	38350	36568	35023	34049	33166	32594	32699	33892	37256	39221	39276	38084	35971	34018

VACAR Reserve Sharing Group>>>

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
VACAR	3/7/12	32895	32608	32668	33054	34347	37201	41312	41501	38948	36669	34951	33642	32617	32154	31673	31345	31333	31908	34173	35260	34585	33001	30540	28085
VACAR	3/8/12	26606	25924	25625	25742	26654	29221	33177	34222	33259	32599	32352	32042	31739	31473	31246	31056	31013	31313	33431	34449	33711	31947	29326	26776
VACAR	3/9/12	24987	24105	23537	23549	24142	26262	30004	31491	31926	32243	32326	32223	31875	31418	31164	30693	30623	31029	32722	34104	34052	33470	32020	30487
VACAR	3/10/12	29301	28914	29055	29378	30212	31730	33377	34789	35218	34714	33655	32362	31094	29924	28954	28503	28613	29402	31923	33660	33738	33391	32366	31124
VACAR	3/11/12	30296	30050	13938	30480	31571	32902	34775	36453	36277	34279	32297	30926	29957	29123	28080	27678	27689	28019	29374	31719	32140	30937	29118	27276
VACAR	3/12/12	26253	25934	26102	26841	28657	32342	36186	36914	35696	34174	33073	32353	31825	31469	31176	31012	30965	31205	32315	33991	33588	31294	28738	26349
VACAR	3/13/12	24817	24004	23723	23870	24979	28003	31344	32105	31943	31970	32039	31998	31982	31992	32124	32196	32163	32258	32751	34468	34259	31917	29030	26324
VACAR	3/14/12	24692	23817	23332	23536	24598	27529	30781	31582	31414	31754	32236	32696	33231	33740	34125	34463	34696	34704	34725	35782	35112	32697	29577	26842
VACAR	3/15/12	24910	23911	23393	23436	24472	27458	31611	31434	31487	31998	32720	33254	34072	34840	35280	35230	35117	34988	35143	35856	35335	32957	29851	27167
VACAR	3/16/12	25196	24163	23544	23652	24486	27131	30201	31177	31333	31851	32351	32614	33021	33503	33901	34168	33981	33587	33323	33827	33224	31477	29185	26633
VACAR	3/17/12	24870	23669	23016	22673	22859	23687	24794	26141	27774	29213	30142	30709	31182	31502	31928	32187	32304	32034	31723	32364	31991	30166	28006	25821
VACAR	3/18/12	24069	22880	22246	21934	22108	22531	23576	24984	26697	27727	28248	28657	28974	29063	29138	29526	30030	30269	30766	32269	32277	30197	27682	25271
VACAR	3/19/12	23693	22922	22536	22698	23958	26913	30161	31130	31246	31723	32367	32982	33709	34275	34801	35122	35330	35376	35306	36293	35573	32914	29570	26846
VACAR	3/20/12	25076	24061	23529	23516	24482	27337	30497	31304	31575	32226	32891	33843	34740	35745	36449	36954	36965	36611	36378	37049	36207	33417	30133	27191
VACAR	3/21/12	25421	24331	23800	23704	24734	27487	30474	31319	31497	32224	33015	33620	34293	34798	35242	35566	35478	35237	35052	36058	35439	32882	29825	27157
VACAR	3/22/12	25322	24250	23680	23658	24713	27604	30624	31468	31858	32473	33203	33993	34763	35512	36076	36569	36545	36226	36098	36962	36525	33921	30523	27619
VACAR	3/23/12	25693	24487	23991	23839	24651	27269	30106	30969	31678	32551	33642	34799	35966	37029	37730	38014	37774	37115	36242	36095	35199	33193	30631	28003
VACAR	3/24/12	25966	24648	23898	23477	23577	24356	25502	26846	28739	30366	31413	31774	32002	32026	31919	31761	31563	31217	30948	31667	31084	29554	27470	25329
VACAR	3/25/12	23656	22706	22179	21814	21909	22438	23435	24947	26741	27934	28299	28573	28825	28737	28606	28620	28682	29019	29644	31210	31100	29239	26883	24907
VACAR	3/26/12	23501	22742	22425	22724	23912	27008	30041	30952	31117	31429	31743	32010	32375	32493	32928	33360	33548	33453	33229	34296	34251	31650	28739	26284
VACAR	3/27/12	24673	23992	23733	24012	25508	28964	32494	33452	33107	32744	32304	31917	31572	31268	31061	30927	31008	31018	31586	33398	33713	31803	29103	27042
VACAR	3/28/12	25756	25141	24980	25447	26858	30287	33327	33570	32878	32323	31819	31501	31591	31762	32079	32225	32614	32712	32778	34184	34231	31944	28998	26378
VACAR	3/29/12	24745	23769	23355	23310	24350	27104	29929	30646	31159	31908	32816	33650	34465	35143	35702	35988	35993	35615	35108	35630	35197	32540	29442	26548
VACAR	3/30/12	24626	23817	23385	23535	24556	27371	30222	31149	31388	31618	31951	32219	32780	33406	33764	33997	33887	33319	32994	33333	33155	31336	28903	26656
VACAR	3/31/12	24816	23799	23162	22963	23176	23905	25061	26361	27997	29170	29997	30253	30246	30363	30390	30506	30612	30627	30499	31235	31124	29377	27463	25191
VACAR	4/1/12	23513	22514	21980	21793	21970	22646	23523	25122	26754	27501	27643	27804	28161	28489	28691	29076	29590	29670	29768	30979	31062	29415	26957	24853
VACAR	4/2/12	23573	22645	22333	22596	23748	26352	29051	30185	30936	31895	32608	33402	34131	34701	35179	35481	35358	34957	34413	35124	34889	32588	29484	26983
VACAR	4/3/12	25227	24381	23928	24092	25105	28087	30995	32048	32038	32020	32146	32226	32595	33036	33546	33908	34118	33957	34019	34803	34499	32157	29270	26730
VACAR	4/4/12	25023	24032	23561	23441	24325	26991	29353	30383	31168	32071	33276	34387	35674	36793	37589	37932	37794	37317	36496	36642	36083	33579	30459	27591
VACAR	4/5/12	25688	24536	23762	23672	24573	27016	29476	30592	31393	32243	32730	33246	33595	33609	33426	32990	32461	32115	31992	32530	32425	30653	28290	26062
VACAR	4/6/12	24533	23791	23421	23535	24322	26224	28375	29930	31027	31667	31625	31029	29562	29737	29216	28860	28816	28729	28603	29822	30608	29655	28133	26581
VACAR	4/7/12	25380	24964	24838	24987	25668	26941	28518	29998	30686	30448	29788	29014	28160	27621	27248	27276	27441	27605	27799	29028	29749	28701	27046	25282
VACAR	4/8/12	23877	23342	23113	23333	23977	25227	26439	28010	28999	28670	27846	27260	27172	26988	27023	27228	27426	27500	27561	27794	29618	28189	26086	24067
VACAR	4/9/12	22697	22057	21763	22042	23307	25749	28522	29592	30284	30917	31254	31485	31618	31511	31915	32010	32204	32065	31813	32854	32886	30564	27799	25445
VACAR	4/10/12	23980	23280	22916	23230	24548	27255	29936	31127	31412	31463	31735	31752	31850	31879	31991	32014	32028	31803	31836	32871	32993	30882	28300	25998

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
VACAR	4/11/12	24665	23844	23706	24017	25258	28080	30788	31999	32093	32265	32185	31930	31532	31351	31141	31139	31375	31667	32051	33630	34246	32725	30438	28600
VACAR	4/12/12	27645	27330	27390	28145	29800	33156	36008	36595	35654	34532	33608	32626	32061	31482	31063	30814	30683	30696	31035	32407	33266	31760	29574	27917
VACAR	4/13/12	26904	26669	26757	27299	28828	31926	34482	35011	34200	33245	32433	31642	31064	30795	30429	30306	30302	29988	29734	30669	31222	29874	28016	26218
VACAR	4/14/12	25010	24400	24244	24554	25220	26539	27874	29264	29930	29872	29599	29305	28975	28772	28745	29011	29354	29457	29257	30003	30505	29199	27204	25144
VACAR	4/15/12	23626	22711	22136	21908	22077	22580	23344	24941	26753	27888	28638	29346	29992	30693	31404	32244	32998	33379	33294	34108	34597	32664	29787	27026
VACAR	4/16/12	25165	23978	23346	23316	24477	27183	29723	31149	32225	33573	34990	36316	37555	38763	39633	40404	40720	40654	39963	39957	39367	36542	32848	29543
VACAR	4/17/12	27351	25966	25178	24900	25732	28186	30685	31859	33041	34364	35730	36996	38327	39271	39824	40257	40301	39704	38818	38493	37800	34789	31016	27916
VACAR	4/18/12	25891	24675	24028	23975	24928	27498	30203	31123	31584	32266	32370	32775	32975	33035	33024	32980	32985	32966	33066	33798	33585	31349	28661	26186
VACAR	4/19/12	24767	23936	23603	23701	24860	27741	30377	31114	31271	31438	31544	31607	31558	31558	31507	31442	31340	31572	31744	32669	33178	31237	28527	26114
VACAR	4/20/12	24557	23663	23315	23455	24657	27408	29980	30790	31101	31534	31690	31831	31998	32214	32312	32692	32800	32681	32072	32403	32686	31078	28676	26309
VACAR	4/21/12	24609	23546	22818	22629	22916	23536	24521	26092	28016	29434	30548	31432	32387	32907	33308	33823	34014	33590	32987	33094	32849	31037	28707	26448
VACAR	4/22/12	24489	23334	22671	22302	22257	22403	23410	24896	26748	27956	28517	28965	29153	29080	28955	29048	29357	29771	30336	31387	31474	29698	27553	25726
VACAR	4/23/12	24546	24033	23920	24391	25977	29378	32556	33430	33442	33430	33486	33233	33147	32793	32394	32394	32751	33375	34073	35445	35751	33923	31408	29334
VACAR	4/24/12	28287	27871	27857	28450	30251	33876	36604	36457	35214	33951	33117	32259	31767	31255	30981	30836	30715	30877	31180	32626	33479	32061	29295	27297
VACAR	4/25/12	26101	25672	25635	26087	27685	31056	33815	34234	33627	33093	32611	32241	31765	31602	31614	31723	31746	32021	31947	32897	33491	31477	28694	26262
VACAR	4/26/12	24675	23846	23558	23743	24745	27586	30264	31347	31758	32348	32742	32981	33296	33584	33767	33771	33863	33751	33665	34244	34484	32473	29584	27056
VACAR	4/27/12	25278	24249	23810	23720	24724	27261	29767	30907	31734	32560	33433	34042	34851	35463	35907	35967	35920	35309	34284	34068	34091	32272	29765	27344
VACAR	4/28/12	25472	24351	23731	23463	23723	24498	25453	27046	28795	30067	30608	30792	30863	30884	30823	30917	30953	30983	30812	31195	31548	30124	28151	26133
VACAR	4/29/12	24619	23586	22971	22735	22881	23308	24063	25737	27483	28476	29187	30001	30820	31540	32203	32912	33536	33616	33365	33612	33927	32061	29048	26442
VACAR	4/30/12	24629	23622	23158	23302	24461	27374	30063	31329	32107	32936	34201	35230	36263	37099	37883	38218	38263	38056	37471	37708	37556	34934	31508	28611
VACAR	5/1/12	26626	25445	24734	24613	25682	28329	31051	32530	33675	35124	36774	38356	39996	41437	42585	43354	43539	43029	42128	41677	41133	38333	34191	30792
VACAR	5/2/12	28274	26866	25942	25677	26524	29148	31767	33377	34895	36864	38940	40909	43071	44682	45984	46830	47040	46579	45192	43983	42691	39434	35285	31567
VACAR	5/3/12	28918	27298	26268	25811	26499	28853	31536	33080	34545	36098	37976	39820	42001	43875	45176	46017	46164	45618	44463	43457	42564	39552	35085	31513
VACAR	5/4/12	28969	27270	26302	25961	26717	29028	31407	33147	34641	36396	38409	40193	41919	43523	44541	45182	45298	44255	42490	41213	40514	38128	34712	31373
VACAR	5/5/12	28828	27050	25993	25289	25285	25622	26376	28735	31945	34843	37280	39098	40640	41696	42244	42273	41877	40885	39298	38196	37444	35345	32372	29548
VACAR	5/6/12	27452	25972	25009	24303	24255	24494	25158	26986	29202	30769	31713	32562	33600	34197	34864	35550	36066	36196	35648	35560	35601	33542	30477	27572
VACAR	5/7/12	25639	24509	23857	23863	24978	27598	30079	31493	32279	33402	34496	35475	36504	37538	38330	39018	39159	38834	37867	37501	37254	34739	31265	28341
VACAR	5/8/12	26355	25189	24656	24613	25620	28063	30616	32036	33035	34156	35165	36114	37053	37909	38665	39408	39721	39435	38828	38512	38166	35773	32292	29369
VACAR	5/9/12	27304	26042	25408	25320	26177	28778	31412	32782	33735	34698	35574	36263	36634	36843	36697	36351	35788	35552	34909	34899	34556	32367	29446	26844
VACAR	5/10/12	25216	24170	23651	23651	24643	27032	29454	30651	31301	31964	32520	32884	33277	33704	34053	34512	34693	34496	33828	33642	33791	31947	28820	26234
VACAR	5/11/12	24648	23690	23228	23176	24249	26710	29042	30427	30956	31465	31918	32211	32659	33143	33610	34136	34429	34211	33144	32454	32309	30814	28434	25969
VACAR	5/12/12	24332	23294	22731	22589	22921	23464	24308	26092	27866	29099	29970	30474	30879	31254	31644	32064	32311	32181	31567	31495	31853	30622	28459	26177
VACAR	5/13/12	24379	23231	22502	22251	22315	22491	23135	25171	27335	28769	29479	29958	30438	30621	30683	30771	30762	30871	30857	31613	32109	30918	28656	26255
VACAR	5/14/12	24674	23810	23347	23560	24570	27343	30058	31596	32431	33572	34600	35232	35932	36152	36346	36548	36613	36528	36257	36202	35959	33792	30704	28046
VACAR	5/15/12	26273	25158	24693	24678	25722	28249	30945	32480	33543	34911	36452	37833	38961	40120	41099	41798	41749	41454	40332	39835	39100	36355	32666	29673

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
VACAR	5/16/12	27533	26190	25435	25262	26115	28715	31156	32871	34061	35510	37126	38652	39998	41128	41999	42539	42627	42057	40794	39975	39370	36695	33029	29857
VACAR	5/17/12	27596	26265	25549	25206	26128	28360	30838	32332	33578	34926	36495	37793	38808	39240	39172	38812	38124	37344	36585	36349	36299	34262	30847	28158
VACAR	5/18/12	26193	25005	24360	24203	25079	27286	29621	30999	31853	32582	33294	33802	34263	34860	35210	35487	35736	35139	33950	33143	33282	31862	29238	26757
VACAR	5/19/12	24836	23627	22961	22648	22850	23288	24059	25816	27812	29127	29999	30659	31226	31694	32410	33096	33505	33454	32683	32169	32152	30800	28447	26066
VACAR	5/20/12	24215	23084	22327	22002	22121	22213	22841	24886	27116	28554	29711	30832	32023	33120	34257	35075	35569	35677	35149	35013	35136	33385	30344	27670
VACAR	5/21/12	25672	24672	24061	24172	25348	27809	30425	32101	33548	35093	36651	37975	39246	40308	41290	42047	42314	41921	40795	39895	39092	36484	32814	29628
VACAR	5/22/12	27535	26185	25385	25201	26014	28297	30842	32719	33958	35641	37376	38955	40504	41780	42672	43096	42731	41911	40648	39600	38772	36360	32701	29623
VACAR	5/23/12	27557	26305	25509	25299	26167	28495	31078	32681	33911	35560	37222	38696	40082	41495	42388	43037	42934	42272	40861	39737	39216	36818	33292	30040
VACAR	5/24/12	27791	26522	25721	25447	26361	28722	31441	33322	34850	36833	38931	41079	43007	44452	45376	46021	46207	45591	44040	42728	41947	39399	35674	32023
VACAR	5/25/12	29470	27886	26903	26558	27270	29288	31919	34163	36195	38649	41085	43302	45399	46974	47838	48394	48493	47849	45964	43842	42303	39935	36356	32771
VACAR	5/26/12	30053	28206	27013	26216	26012	26006	26857	29471	32728	36109	38957	41404	43301	44566	45528	46356	46444	45809	44348	42505	41137	39070	35745	32524
VACAR	5/27/12	29819	28027	26776	25994	25709	25514	26312	28920	32207	35206	37523	39567	41246	42576	43673	44593	45073	44556	43045	41164	40262	38348	35247	32203
VACAR	5/28/12	29781	28136	27087	26651	26828	27138	27937	30182	33298	36745	39832	42288	44063	45644	46592	47245	47398	46920	45562	44285	43437	41058	37119	33539
VACAR	5/29/12	30981	29449	28502	28177	29158	31389	34180	36793	38962	41436	43561	45529	47066	48083	48517	48425	48040	47158	45797	44637	43519	40721	36886	33341
VACAR	5/30/12	31039	29267	28470	28140	28866	31172	33666	35368	36551	38012	39448	40825	41949	43232	44238	45185	45727	45668	44533	42748	41508	38859	34969	31446
VACAR	5/31/12	28916	27399	26450	26010	26848	28840	31355	33855	36272	39050	41745	44179	46350	48061	48729	49484	49827	49207	47678	45647	44183	41590	37448	33715
VACAR	6/1/12	30987	29103	28043	27556	28405	30428	32945	35255	37209	39302	41412	43314	44664	45239	45517	45364	44483	42621	40865	39499	38784	36923	33795	30795
VACAR	6/2/12	28427	26776	25677	24986	24794	24918	25585	27536	29803	31715	33253	34177	34941	35639	36240	36847	37046	36738	35605	34295	33754	32357	29851	27302
VACAR	6/3/12	25114	23724	22914	22569	22535	22405	23088	25082	27569	29509	31021	32417	33621	34962	36140	37291	38276	38585	37929	36885	36433	34848	31625	28638
VACAR	6/4/12	26538	25273	24681	24636	25640	27684	30206	32074	33740	35350	36837	38030	39122	40169	41165	41773	41902	41659	40672	39325	38696	36646	33092	29930
VACAR	6/5/12	27611	26286	25445	25235	26081	27957	30218	31825	32761	33665	34411	34959	35298	35651	36115	36507	36503	36190	35474	34921	35027	33619	30643	27816
VACAR	6/6/12	25823	24627	24134	24040	25018	27043	29338	30860	31698	32341	32840	33422	33892	34480	34902	35345	35794	35865	35293	34902	34901	33623	30633	27781
VACAR	6/7/12	25780	24655	24065	24067	24948	26757	29026	30975	32360	33755	35248	36584	37735	38878	39979	40668	40949	40727	39651	38357	37798	36043	32543	29341
VACAR	6/8/12	26971	25525	24802	24649	25324	26816	29056	31394	33382	35339	37399	38824	40343	41683	42771	43641	44082	43590	41999	39850	38440	36618	33279	30058
VACAR	6/9/12	27683	26025	24925	24342	24389	24461	25306	27784	30858	33804	36617	39013	40958	42280	43555	44479	44858	44331	42702	40978	39548	37601	34495	31309
VACAR	6/10/12	28758	26926	25905	25216	24910	24717	25451	27928	31235	34210	36525	38705	40372	41311	42091	42460	42682	42445	41599	40670	39903	38330	35106	32025
VACAR	6/11/12	29513	28107	27229	27042	27952	29839	32147	34609	36731	38807	40792	42050	43308	44327	44946	44774	44116	43365	42187	41320	40876	39246	35949	32775
VACAR	6/12/12	30526	29108	28350	28211	28977	30942	33391	35300	36707	38224	39778	41000	42095	43154	44108	44970	45232	45049	43975	42854	42132	40017	36451	32998
VACAR	6/13/12	30437	28926	27965	27605	28234	29805	32095	34672	36922	39147	41764	43826	45477	46690	47519	47816	47663	47016	45182	43201	41859	39565	35657	32055
VACAR	6/14/12	29248	27672	26690	26372	26944	28362	30573	32668	34528	36428	38031	39326	40578	41857	42923	43698	43836	43333	41920	40113	39492	37841	34395	30914
VACAR	6/15/12	28673	26941	25838	25551	26171	27369	29427	31778	33934	35820	37390	38835	40003	41073	42141	42825	43033	42431	40628	38599	37500	35912	32803	29771
VACAR	6/16/12	27148	25601	24598	24070	24013	23998	24810	26877	29366	31590	33304	34661	35858	37098	38230	39272	39904	39587	38205	36467	35574	34192	31363	28382
VACAR	6/17/12	26008	24408	23634	23127	23046	22781	23431	25667	28237	30345	31924	33472	34933	36338	37582	38730	39365	39254	38299	36885	36286	34929	31972	29131
VACAR	6/18/12	26897	25521	24832	24655	25499	27091	29185	31534	33564	35716	37805	39709	41342	42985	44052	44792	45000	44555	43411	41852	41006	38967	35360	31863
VACAR	6/19/12	29354	27888	26905	26576	27134	28685	30969	33438	35780	38556	41544	44362	47003	49257	50988	52081	52519	51959	50478	48418	46907	44265	40022	35983

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
VACAR	6/20/12	32940	30866	29501	29000	29473	30887	33223	36304	39543	43094	46605	49711	51988	53759	54840	55407	55590	54828	53601	51331	49769	47092	42738	38445
VACAR	6/21/12	35321	33074	31649	30906	31218	32460	34915	37987	41282	45129	48821	51973	54297	55638	56156	56276	55993	55068	53445	51474	50065	47473	43320	39470
VACAR	6/22/12	36326	34180	32697	32023	32161	33152	35110	37969	41052	44663	47948	50918	53187	54390	54162	52967	50998	48993	46734	44420	43214	40907	37802	34432
VACAR	6/23/12	31781	29892	28713	28016	27699	27619	28512	31345	35012	38790	42100	44871	46972	48383	49301	50011	50110	49512	47824	45619	44067	41815	38303	34797
VACAR	6/24/12	31950	30081	28558	27624	27293	27092	27644	30671	34537	38348	41738	44475	46546	47741	48525	48772	48580	47664	46078	44511	43415	41559	38359	34848
VACAR	6/25/12	32198	30506	29452	28989	29717	31342	33745	36498	39339	42480	45569	48397	50206	51885	52775	52737	52440	51392	49718	47585	46029	43332	39106	35036
VACAR	6/26/12	32146	30051	28673	27927	28184	29366	31088	33160	34846	36465	37920	38967	40054	41047	41809	42732	43157	42911	41540	39696	38609	36635	33073	29559
VACAR	6/27/12	27208	25722	24964	24686	25289	26807	28703	30989	33136	35199	37208	39111	40655	42503	44342	46177	47320	47314	45942	43627	41982	39493	35512	31766
VACAR	6/28/12	29047	27311	26323	25885	26488	27894	30003	32600	35299	38469	41728	45055	47887	50439	52604	54076	54707	54312	52947	50556	48638	46028	41673	37332
VACAR	6/29/12	34301	32166	30715	30013	30313	31530	33542	36755	40705	45244	49743	53742	56778	58765	60064	60959	61336	60948	59572	57455	55795	52637	46760	40087
VACAR	6/30/12	36531	33858	31934	30554	29945	29565	30047	32729	36582	40723	44706	48107	50824	52685	54099	55208	55811	55540	54480	52741	51258	48641	45169	41303
VACAR	7/1/12	38134	35699	34007	32735	31986	31435	31891	34691	38786	43496	47779	51437	53815	55137	55673	55420	53996	52057	49777	47748	46111	43800	40360	36858
VACAR	7/2/12	34048	32070	30749	30007	30423	31674	33082	35256	37996	41150	44269	47092	49475	51551	53152	54330	54725	54322	53067	51092	49337	46632	42319	38196
VACAR	7/3/12	35075	32965	31531	30906	31229	32227	34223	37328	41218	45394	49350	52747	55175	56596	57138	57108	56536	55265	53425	51207	49512	46383	42443	39118
VACAR	7/4/12	35727	33439	31883	30903	30557	30355	30620	32683	36216	40555	44687	48074	50721	52750	54135	54708	54518	53290	51164	48779	46934	44801	42168	38793
VACAR	7/5/12	35848	33576	32122	31425	31587	32655	34584	38070	42371	47011	51345	54726	57421	58723	59289	59137	58126	56706	54669	52542	50883	48088	44013	40013
VACAR	7/6/12	36985	34774	33238	32430	32543	33497	35031	37774	41384	45228	49080	52345	54730	56689	57912	58396	58195	57123	55270	52990	51163	48658	44789	41072
VACAR	7/7/12	37971	35677	33952	32784	32272	32074	32791	35781	40423	45204	49564	53137	55705	56668	57731	58235	58239	57594	56392	54666	53364	54881	47679	44101
VACAR	7/8/12	40956	38675	36943	35547	34828	34287	34587	37669	42160	46616	50509	54013	56633	58169	58893	58973	58619	57453	55929	54157	52974	50383	46624	43045
VACAR	7/9/12	40070	38021	36515	35672	35956	37119	39023	41878	45179	48756	52043	54624	56525	57575	57403	56200	55303	54032	52110	49947	48431	45729	41941	38407
VACAR	7/10/12	35622	33826	32687	32160	32664	34364	36183	38659	41114	43781	46268	48328	49856	50781	50762	49864	48606	47234	45620	44341	43392	41492	38065	34877
VACAR	7/11/12	32548	31033	30119	29779	30314	32084	34233	36251	38210	40329	42293	43990	45459	46551	47035	47212	46814	45621	43854	42328	41426	39622	36468	33392
VACAR	7/12/12	31143	29710	28756	28440	29180	30956	32887	34855	36857	38988	41134	42916	44498	45760	46559	46870	46866	46106	44833	43518	42707	40954	37465	34046
VACAR	7/13/12	31635	29957	29040	28747	29304	30851	32709	35045	37364	39881	42287	44317	46042	47297	48152	48112	47667	46326	44698	43340	42508	40880	37927	34949
VACAR	7/14/12	32367	30830	29735	29156	29280	29704	30374	32488	35802	39432	42801	45360	47181	48331	49206	49642	49711	48852	47292	45468	44311	42265	39103	35827
VACAR	7/15/12	33198	31392	30087	29199	28877	28730	29457	32425	36435	40131	43553	46411	48463	50467	51571	52010	51783	50958	49345	47593	46430	44337	40752	37263
VACAR	7/16/12	34601	32613	31489	31074	31630	33177	35209	38149	41105	44529	48139	51543	53644	55584	56677	56545	55344	53776	51798	49809	48223	45760	42216	38446
VACAR	7/17/12	35276	33381	32044	31518	31863	33347	35385	38293	41686	45493	49400	52686	55314	57226	58119	58306	57808	56785	55168	53367	52255	49511	45068	41074
VACAR	7/18/12	38034	35825	34199	33504	33869	35204	37183	40179	43458	47399	51416	54675	57338	58892	59439	58911	57776	56102	54214	52210	50855	48181	44097	40385
VACAR	7/19/12	37487	35463	34133	33391	33964	35332	37312	40061	43028	46413	50102	53044	55465	57215	58151	58387	57865	56261	54430	52410	50983	48263	44026	40166
VACAR	7/20/12	37257	35219	33882	33275	33690	35040	36718	39101	41612	44461	47291	49561	51368	52173	52427	52030	50936	49154	47018	45271	44291	42138	39086	35908
VACAR	7/21/12	33470	31742	30671	30017	29976	30240	30955	32716	35251	38130	40772	43197	44811	45885	46590	46885	46466	45367	43728	42321	41728	39800	36979	34177
VACAR	7/22/12	32050	30453	29354	28691	28510	28539	29158	31569	34914	38028	40488	42720	44823	46320	47536	48385	49054	49074	47980	46529	45513	43482	40113	36644
VACAR	7/23/12	34025	32272	31182	30913	31621	33288	35409	38526	42047	45908	49828	52969	55198	56608	57314	57165	56512	55692	53868	51500	49874	46835	42762	38863
VACAR	7/24/12	36122	34143	32951	32396	32812	34473	36613	39719	43579	47608	51477	54551	56746	58139	58220	57215	55518	52965	50557	48634	47310	44637	40852	37144

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
VACAR	7/25/12	34412	32616	31426	30948	31530	33284	35142	37173	39283	41689	44375	46997	49571	51723	53290	54415	54721	54239	52763	50678	49146	46434	42314	38603
VACAR	7/26/12	35715	33569	32597	32335	32913	34461	36781	39869	43406	47644	51489	55008	57595	59565	60744	61518	61507	61039	59882	58012	56502	53494	49021	44758
VACAR	7/27/12	41519	39006	37390	36330	36499	37571	39055	41855	45548	49522	53252	56314	58157	59486	59900	59393	58251	56313	53764	51147	49070	46363	42819	39096
VACAR	7/28/12	36438	34312	32759	31769	31444	31536	31992	34440	38254	42059	45686	48804	51010	52795	54305	55179	55320	54427	52489	50245	48416	45326	41508	37896
VACAR	7/29/12	35082	32814	31139	30036	29362	29197	29482	32050	35944	39520	42894	45727	48093	49868	50930	51399	51714	51183	49635	47744	46167	43704	40070	36363
VACAR	7/30/12	33621	31713	30642	30279	30946	32661	34493	37110	40199	43474	46616	49311	51319	52700	53249	53104	52166	50808	49020	47310	46230	43447	39712	36221
VACAR	7/31/12	33469	31587	30543	30024	30697	32341	34305	36373	38675	41289	43823	46067	47864	49167	49839	50155	49625	48663	47329	46139	45124	42656	39181	35905
VACAR	8/1/12	33470	31693	30588	30225	30845	32660	34480	36576	38686	41046	44012	46689	48702	50651	52329	53638	54193	53470	51619	49515	47960	45183	41288	37414
VACAR	8/2/12	34684	32672	31247	30784	31303	32787	34685	37311	40785	44736	48538	51751	54190	56064	56826	56397	55487	54016	51470	49321	47805	44864	40855	37345
VACAR	8/3/12	34295	32330	30972	30296	30700	32267	34050	36383	39389	42784	46065	49153	51602	53576	54793	55349	55204	54089	51880	49856	48462	45944	42299	38776
VACAR	8/4/12	35780	33690	32149	31261	30984	31119	31667	33964	37713	41379	44763	47662	49783	51057	52089	52716	52774	52055	50476	48665	47391	45075	41761	38358
VACAR	8/5/12	35544	33554	32190	31169	30887	30717	31138	33811	37834	41378	44336	46797	48733	50083	50774	51052	50885	50133	48425	47128	46091	43820	40507	37108
VACAR	8/6/12	34738	33102	32061	31688	32361	34221	36371	38601	41052	44123	47089	49559	51630	53231	53960	53950	53278	51743	49609	47995	46607	43812	40174	36723
VACAR	8/7/12	34270	32572	31624	31296	32088	33895	35911	37588	39141	40760	42741	44651	46634	48256	49200	49473	49111	48262	46836	45933	44966	42468	39027	35737
VACAR	8/8/12	33400	31771	30795	30542	31351	33334	35251	37022	38899	41128	43745	46124	48245	49972	50978	51245	50911	49915	48317	46599	45387	42609	38820	35300
VACAR	8/9/12	32687	30916	29831	29467	30108	31876	33758	36006	38501	41696	45134	48071	50460	52388	53818	53936	53261	52222	50581	48843	47513	44356	40465	36909
VACAR	8/10/12	34441	32590	31572	31075	31786	33525	35317	36970	38649	40645	42663	44125	45597	46840	47859	48511	48637	47612	45905	44722	44012	41850	38845	35725
VACAR	8/11/12	33289	31457	30335	29684	29579	29918	30506	32268	35298	38108	40227	41836	43344	44004	44369	44201	43589	42560	41396	40545	39925	37975	35230	32440
VACAR	8/12/12	30161	28521	27609	27028	26849	27040	27479	29372	32193	34924	37359	39610	41985	43789	45223	46372	47193	47035	45692	44071	42902	40246	36693	33470
VACAR	8/13/12	30956	29200	28220	27960	28642	30498	32457	34632	37508	40851	44253	46984	49182	50947	52148	52837	52863	52134	49990	48048	46521	43092	39055	35393
VACAR	8/14/12	32861	31104	29944	29601	30187	32118	33866	35832	38387	41444	44603	47505	49851	51864	53404	54092	53963	52961	51265	49674	48302	45107	40808	37062
VACAR	8/15/12	34335	32398	31187	30654	31265	33123	35041	37082	39618	42335	44995	47236	49257	50822	51829	51815	51069	49637	47630	45996	44964	42008	38003	34484
VACAR	8/16/12	31801	30120	29062	28590	29091	30949	32648	34622	37110	40042	42954	45616	48009	50109	51532	52245	52338	51538	49408	47356	45781	42568	38434	34607
VACAR	8/17/12	31871	29998	28882	28354	28878	30478	32212	34482	37520	40916	44468	47512	49842	51471	52550	52488	51171	49488	47324	45614	44348	41651	38411	34856
VACAR	8/18/12	32477	30624	29444	28552	28364	28618	29021	30652	33510	36523	39011	41184	42897	44207	45286	46128	46429	45812	44271	43008	41839	39432	36287	33204
VACAR	8/19/12	30825	29202	28042	27318	27199	27444	28021	29530	31933	34140	35459	36346	36737	36942	37155	37449	37798	37721	37395	37618	37422	35655	33016	30652
VACAR	8/20/12	28718	27514	26794	26860	27871	30389	32541	33980	35395	36834	38455	39966	41561	43026	43988	44473	44384	43705	42517	41814	41168	38454	34963	31815
VACAR	8/21/12	29724	28364	27591	27373	28195	30503	32416	33823	35492	37314	39460	41484	43324	44781	45933	46341	46101	45196	43790	43009	42154	39143	35480	32213
VACAR	8/22/12	29977	28402	27570	27288	28188	30484	32555	33878	35579	37585	39586	41942	43920	45341	46393	46921	46595	45342	43817	42859	41958	39111	35510	32100
VACAR	8/23/12	29939	28470	27691	27408	28316	30673	32809	34255	36049	38447	40906	43208	45030	46412	47342	47690	47182	45901	44109	43252	42341	39471	35830	32456
VACAR	8/24/12	30064	28758	27710	27368	28283	30450	32412	33870	35714	37788	39696	41122	42235	43195	43821	43861	43421	42295	40354	39555	38925	36721	33850	31033
VACAR	8/25/12	28896	27346	26467	25948	26033	26542	27155	28795	30984	33500	35341	37036	38129	38906	39396	39786	39968	39555	38368	37770	37227	35172	32508	29911
VACAR	8/26/12	27790	26415	25469	25016	24889	25167	25715	27419	30330	33038	35556	38096	40406	42278	43762	44848	45479	45000	43542	42591	41619	38579	35032	31911
VACAR	8/27/12	29521	28151	27352	27273	28201	31087	33439	34886	37153	40085	43194	45759	48069	49918	51203	51718	51766	51193	49727	48525	46988	43248	39087	35405
VACAR	8/28/12	32934	31304	30322	29974	30978	33829	36222	37472	38981	41090	43431	45475	47633	48920	49432	49756	49374	48430	47168	46210	44760	41468	37752	34502

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
VACAR	8/29/12	32225	30590	29768	29540	30380	33116	35492	36745	38314	40318	42869	45123	47053	48532	49475	49879	49748	48838	47298	46045	44621	41246	37276	33844
VACAR	8/30/12	31450	29942	29062	28712	29661	32263	34613	35860	37537	39644	42056	44424	46482	47921	49470	50087	50292	49574	48130	47205	45971	42580	38586	34995
VACAR	8/31/12	32451	30701	29714	29352	30271	32762	35036	36532	38720	41775	45120	48251	50499	52988	54477	55117	55286	54170	51960	50073	48229	45176	41536	37974
VACAR	9/1/12	35270	33104	31625	30688	30242	30485	30944	32809	36552	40578	44355	47273	49507	50810	51272	51372	50801	49683	48180	47105	45628	42848	39632	36476
VACAR	9/2/12	33867	31846	30647	29767	29369	29638	29984	31850	35394	39116	42387	45345	47199	48179	48365	48121	47448	46249	44863	43953	42386	39863	36989	34110
VACAR	9/3/12	31848	30125	29169	28756	28770	29399	30005	31461	34536	38073	41247	43675	45152	46148	46572	46575	46360	45514	44582	44169	42924	39892	36593	33562
VACAR	9/4/12	31384	30047	29283	29218	30235	33240	36080	37522	38889	40878	43168	45388	47533	49172	50058	50374	50206	49506	48278	47730	46350	42874	38972	35694
VACAR	9/5/12	33323	31705	30756	30433	31408	34251	36936	38170	39593	41721	43787	46237	48271	50107	51668	52463	52462	51719	50298	49468	47726	43994	39840	36448
VACAR	9/6/12	34037	32439	31353	31040	31858	34735	37434	38762	40173	42133	44169	45959	47895	49548	50168	50317	50211	49043	47326	46552	44783	41301	37506	34290
VACAR	9/7/12	31824	30222	29375	29026	29818	32374	34832	36158	37799	40249	42974	45576	47931	49813	51182	51657	51672	50469	48204	46658	44651	41782	38250	35017
VACAR	9/8/12	32464	30651	29459	28843	28775	29343	30164	31789	35053	38428	41924	45010	47233	48725	48987	48042	45973	43979	42250	41132	39572	36989	34012	31293
VACAR	9/9/12	29088	27468	26394	25703	25354	25576	26013	27393	29549	31331	32969	34565	36220	37407	38307	39076	39529	39061	37901	37385	36235	33455	30206	27472
VACAR	9/10/12	25678	24542	23990	24066	25021	27842	30000	31052	32445	33887	35427	36614	37828	38779	39828	40245	40583	39990	38861	38628	37368	34267	30888	28083
VACAR	9/11/12	26250	24914	24531	24470	25421	28024	30406	31130	32153	33149	34353	35413	36558	37826	38988	39885	40205	39702	38543	38588	37230	33985	30629	27764
VACAR	9/12/12	25974	24854	24321	24314	25272	27925	30035	30949	32002	33401	34709	36077	37266	38644	39945	40987	41369	40747	39287	38900	37454	34454	30943	28126
VACAR	9/13/12	26264	25074	24561	24485	25468	28196	30471	31408	32137	33747	35267	36588	37855	39102	40133	41133	41388	40728	39674	39658	38391	35343	31811	29008
VACAR	9/14/12	27082	25874	25177	25063	25959	28455	30746	31820	33129	34859	36703	38312	39816	41148	42061	42545	42437	41375	39872	39159	37856	35311	32423	29478
VACAR	9/15/12	27248	25828	24953	24582	24656	25320	26025	27301	29948	32429	34536	36124	37487	38677	39721	40265	40225	39339	37845	37388	36061	33678	31019	28504
VACAR	9/16/12	26566	25227	24401	23972	23819	24298	24997	26401	28540	30305	31468	32460	33251	33796	34135	34306	34682	34707	34903	35559	34721	32381	29649	27364
VACAR	9/17/12	25745	24727	24367	24549	25701	28570	31292	32279	33559	34812	36176	37299	38477	39341	39935	40178	40039	39775	39931	40294	38987	36239	33124	30514
VACAR	9/18/12	28843	27825	27403	27518	28697	31857	34918	36305	37304	38614	39695	40226	40487	40313	40114	39685	39257	39191	39404	39870	38602	35729	32425	29635
VACAR	9/19/12	27669	26447	25698	25548	26332	28978	31447	32128	32575	33181	33915	34530	35150	35808	36294	36654	36597	36098	35564	36141	35171	32660	29617	26985
VACAR	9/20/12	25305	24327	23875	23866	24923	27694	30150	30875	31614	32520	33518	34416	35467	36222	37053	37656	37753	37205	36660	37348	35968	33337	30110	27510
VACAR	9/21/12	25660	24643	24028	23967	24900	27392	29782	30598	31672	33243	34589	35963	37368	38522	39548	40465	40553	39530	38066	37473	36061	33607	30863	28416
VACAR	9/22/12	26423	25104	24331	24034	23872	24764	25691	27095	29487	31711	33799	35907	37594	39278	40652	41615	41572	40455	39340	38976	37320	34876	32105	29432
VACAR	9/23/12	26998	25602	24549	23943	23703	23932	24353	25751	27901	29533	30783	31833	32880	33667	34389	34773	35028	34516	33846	34072	32704	30090	27422	25258
VACAR	9/24/12	23738	22878	22531	22642	23750	26673	29208	30093	30729	31442	32039	32654	33136	33665	34118	34676	34810	34444	34395	34908	33554	30961	28029	25686
VACAR	9/25/12	24300	23448	23072	23262	24410	27226	29561	30211	30764	31398	32017	32572	33331	34033	34822	35420	35631	35215	35303	35948	34512	31770	28680	26309
VACAR	9/26/12	24744	23915	23413	23406	24598	27426	29897	30621	31485	32742	33782	35101	36596	38098	39471	40645	41021	40362	39591	39575	37789	34718	31174	28285
VACAR	9/27/12	26268	25063	24396	24315	25304	28114	30830	31667	32678	34136	35896	37596	39414	41424	42770	43877	43691	42420	41519	41185	38972	35721	32244	29086
VACAR	9/28/12	27135	25792	25045	24892	25838	28377	30894	31776	33032	34676	36420	38229	39851	41159	41692	41665	41061	39709	38843	38341	36672	34329	31675	28939
VACAR	9/29/12	26943	25672	24865	24347	24328	25009	26055	27387	29119	30597	31568	32124	32171	32218	32086	32117	32043	31865	32377	32880	31863	30300	28234	26186
VACAR	9/30/12	24562	23503	22852	22485	22596	23031	23821	25232	26959	28302	28992	29564	30270	30921	31270	31350	31663	31848	32864	33554	32415	30263	27937	25860
VACAR	10/1/12	24338	23503	23187	23572	24623	27432	30468	31546	31955	32619	33290	33660	34045	34355	34375	34360	34371	34835	35763	36461	34956	32659	30052	27728
VACAR	10/2/12	26341	25534	25188	25406	26507	29577	32642	33792	34906	36120	37301	38634	39687	40478	41008	41123	41218	40829	41193	41466	39899	37114	33778	31034

VACAR Reserve Sharing Group>>>

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
VACAR	10/3/12	29095	28040	27367	27325	28262	31106	34027	34898	35698	37206	38009	39269	40623	41388	42239	41987	41860	41625	42160	42028	40191	37327	34225	31283
VACAR	10/4/12	29107	27752	26932	26768	27664	30488	33337	34214	34758	35803	36914	37978	39091	39828	40703	41004	40891	39931	39608	39658	37774	34955	31526	28673
VACAR	10/5/12	26634	25360	24696	24616	25511	27970	30593	31436	32101	33429	34747	36027	37269	38501	39484	40011	39733	38307	37121	36651	34962	32681	30124	27657
VACAR	10/6/12	25706	24519	23801	23335	23452	24269	25223	26447	28439	30475	32325	33877	35300	36270	36792	37259	37065	36165	35804	35478	33969	31720	29407	27029
VACAR	10/7/12	25070	23857	23189	22722	22760	23234	24134	24971	27026	28532	28981	30124	30552	30816	31098	31244	31242	31694	32598	32713	31353	29413	27149	25315
VACAR	10/8/12	23942	23189	22933	23141	24311	26596	29136	30881	31657	31985	32470	32592	32611	32369	32297	32567	33141	33996	35249	35294	33888	31678	29140	26990
VACAR	10/9/12	25861	25243	24987	25217	26474	29489	32427	33033	33062	33117	33004	32710	32478	32127	31874	31717	31998	32702	34265	34834	33441	31243	28622	26484
VACAR	10/10/12	25116	24583	24291	24484	25762	28827	31732	32145	31908	31728	31668	31598	31676	31817	31894	31889	31905	32105	33366	34063	32813	30540	28093	25914
VACAR	10/11/12	24553	23844	23735	24107	25545	28873	31936	32546	32352	32253	31979	31683	31496	31482	31507	31545	31539	31644	33065	33967	32887	30849	28578	26688
VACAR	10/12/12	25366	24698	24469	24862	26181	29206	32176	32831	32670	32416	32136	31744	31693	31584	31567	31367	31331	31234	31989	32251	31234	29727	27840	26043
VACAR	10/13/12	24808	24015	23832	23722	24267	25462	26926	28444	29910	30253	29857	29429	28951	28583	28396	28531	28629	28806	30117	30731	29899	28800	27123	25523
VACAR	10/14/12	24288	23557	23276	23265	23654	24420	25623	27082	28535	28889	28766	28700	29156	29355	29439	29740	30184	30757	32294	32871	31635	29558	27289	25321
VACAR	10/15/12	23862	23182	22803	22983	24171	27154	30217	31420	31860	32601	33255	33718	34329	34335	34427	34562	34241	34234	35708	35668	33872	31397	28599	26310
VACAR	10/16/12	24728	23838	23467	23671	24986	28134	31246	32021	31979	31913	31956	31799	31953	31898	31868	31981	32071	32290	33594	34124	32800	30428	28298	26338
VACAR	10/17/12	24881	24361	24203	24526	25915	29211	32286	32967	32695	32321	31866	31802	31554	31552	31621	31755	31806	32013	33390	33916	32783	30660	28203	26117
VACAR	10/18/12	24778	24152	23939	24287	25587	28704	31822	32437	32361	32382	32664	32857	32718	33014	32984	33003	33105	33565	34836	35178	33875	31611	29064	26714
VACAR	10/19/12	25229	24396	24015	24012	25047	27832	30533	31627	32073	32606	32877	33093	33285	33472	33438	33390	32961	32629	32931	32696	31575	29900	27775	25789
VACAR	10/20/12	24423	23491	23062	23057	23528	24639	26016	27565	28832	29369	29418	29169	29005	28834	28862	28827	29029	29226	30407	30685	29706	28272	26580	25029
VACAR	10/21/12	23794	23200	22870	22889	23331	24345	25706	27234	28736	28760	28538	28304	28203	28142	28130	28242	28650	29186	30967	31626	30542	28800	26897	25198
VACAR	10/22/12	24123	23734	23745	24338	25978	29394	32962	33795	33438	32893	32408	32245	32072	32074	32195	32288	32344	32571	34091	34307	32771	30481	28004	25941
VACAR	10/23/12	24530	23840	23701	24012	25531	28806	32052	32742	32495	32220	32304	32271	32562	32940	33344	33565	33561	33571	34674	34614	32992	30548	27994	25811
VACAR	10/24/12	24376	23586	23306	23562	24840	28055	31049	31939	31800	32059	32396	32905	33480	34193	34786	35347	35267	35070	35859	35654	33955	31475	28799	26440
VACAR	10/25/12	24727	23924	23488	23573	24806	27852	30796	31576	31863	32397	33037	33540	34137	34646	35057	35377	35066	34941	35839	35794	34208	31873	29128	26698
VACAR	10/26/12	25087	24115	23747	23669	24722	27434	30393	31480	31838	32464	32760	32939	33158	33175	32962	32660	32380	32357	33383	33053	31855	30339	28322	26230
VACAR	10/27/12	24669	23638	23102	22896	23209	24078	25426	26778	28096	29321	29803	29943	29813	29562	29280	29195	29326	29999	31375	31189	30131	28737	26768	25062
VACAR	10/28/12	24330	22827	22245	22014	22070	22805	23248	25179	26443	27698	28334	28733	28969	28944	28782	28885	29320	30333	31820	31946	30896	29343	27919	25670
VACAR	10/29/12	24399	24688	23855	24235	25748	28721	31583	32734	33352	33919	34270	34413	34324	34740	33845	34047	34847	36302	37698	37405	36019	33861	31666	29805
VACAR	10/30/12	29332	28437	28342	28768	29853	32800	35859	36555	36557	37425	36664	36354	35715	35425	35252	34891	35581	36962	38600	38572	37192	35133	32588	30747
VACAR	10/31/12	29696	29346	29342	29743	31404	34849	37932	38482	37561	36369	35270	34226	33264	32541	32120	32220	32282	33134	34402	34650	34779	33524	31495	29808
VACAR	11/1/12	28815	28494	28588	29309	31012	34552	37703	38301	37279	35890	34483	33681	32847	32100	31886	31637	31974	33497	35869	36499	35681	34180	32068	30466
VACAR	11/2/12	29635	29394	29590	30329	32197	35654	38655	39189	38116	36534	34952	33580	32706	31918	31315	31003	30963	31891	33688	33859	33222	32315	30788	29242
VACAR	11/3/12	28333	27973	28054	28547	29556	31229	33132	34803	35390	34414	33021	31652	30472	29595	29044	28859	29021	30125	32098	32452	32052	31104	29687	28096
VACAR	11/4/12	27052	40740	25938	25957	26362	27240	28533	30130	31646	31619	30645	29788	29468	29157	28914	28924	29828	32477	33640	33444	32701	31089	29280	26825
VACAR	11/5/12	26543	26160	26294	26729	28175	31242	35567	36794	36147	35179	34320	33547	32726	32305	31913	31911	32658	35607	37600	37803	37178	35781	33813	32016
VACAR	11/6/12	30997	30642	30757	31201	32408	35032	38326	39242	39256	38921	38299	37752	36929	36350	35986	35996	37120	39690	40843	40421	39544	37692	35562	33404

VACAR Reserve Sharing Group>>>

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
VACAR	11/7/12	32315	31798	31546	31907	33090	35815	39773	40570	39860	38892	37828	36762	35630	35202	34827	34838	35976	38916	40413	40221	39503	37842	35561	33451
VACAR	11/8/12	32412	32101	32127	32637	33983	37009	41207	41873	40201	37996	36258	34688	33589	32940	32391	32201	32955	35920	38104	38485	38161	36968	35004	33021
VACAR	11/9/12	32065	31819	32042	32720	34134	37065	41416	41962	39963	37175	35294	33856	32672	31936	31345	31030	31677	33985	35093	34934	34690	34010	32804	31337
VACAR	11/10/12	30285	30017	30137	30566	31516	33045	34894	36191	35959	34228	32494	31006	29876	29096	28572	28321	28839	31220	32148	31845	31653	30590	29834	28493
VACAR	11/11/12	27051	26665	26722	27072	27734	28862	30317	31900	32594	31568	30100	28989	28624	28327	28112	27912	28376	30913	31964	31607	30771	29337	27539	25727
VACAR	11/12/12	24411	23772	23511	23706	24552	26593	29658	31218	31734	31938	32308	32316	32112	32046	31947	31760	32287	34784	35506	34914	33749	31770	29334	26881
VACAR	11/13/12	25270	24328	23907	23839	24644	26851	31023	32833	32950	33212	33448	33355	33139	33126	32862	33016	34358	36940	38450	38444	37789	36316	34117	32027
VACAR	11/14/12	30878	30524	30434	31017	32396	35452	40231	41134	40024	38619	37383	36186	35063	34533	34143	34416	35876	39375	40577	40335	39602	37893	35648	33372
VACAR	11/15/12	32069	31463	31197	31474	32473	35058	39313	40464	39896	39461	39068	38398	37528	36913	36296	36215	37171	39781	40741	40643	39954	38288	35855	33726
VACAR	11/16/12	32211	31540	31418	31607	32730	35413	39771	40739	39473	37878	36317	34890	33687	32908	32328	32232	32992	35968	37237	37220	36968	36345	35121	33504
VACAR	11/17/12	32517	32139	32195	32353	33107	34424	36261	37621	38066	37052	35601	34010	32606	31477	30884	30922	32016	34832	35774	35607	35131	34211	32635	30945
VACAR	11/18/12	29651	28905	28506	28376	28649	29446	30665	32082	33673	34091	33314	32417	31862	31506	31007	31052	32013	34799	35771	35479	34818	33175	31149	29240
VACAR	11/19/12	27823	27163	26961	27118	28059	30701	34881	36272	35895	35568	35251	34578	33894	33477	33044	32716	33575	36382	37689	37512	36771	35105	32987	30706
VACAR	11/20/12	29225	28504	28384	28620	29694	32227	36395	37540	36826	35899	35144	34004	33108	32610	32246	32211	32967	35790	36932	36912	36353	35274	33398	31408
VACAR	11/21/12	30300	29914	30051	30546	31857	34364	37815	39338	38757	37059	35740	34411	33275	32478	32006	31719	32293	34989	36329	36288	36162	35454	33976	32108
VACAR	11/22/12	30768	30248	30170	30511	31312	32793	34509	35939	36762	36092	34983	33661	31606	29631	28113	27105	26816	28570	29551	29899	30514	30819	30579	29959
VACAR	11/23/12	29693	29843	30295	31160	32472	34388	36445	37450	36845	34605	32619	30859	29432	28462	27885	27732	28487	31247	32078	31738	31351	30499	29215	27814
VACAR	11/24/12	26584	26141	26113	26481	27459	28902	30825	32569	33958	34220	33746	32809	31714	30637	30134	30157	31569	35241	36977	37472	37783	37473	36513	35423
VACAR	11/25/12	34723	34622	34938	35504	36481	37974	39775	41262	41370	39715	37250	35071	33699	32435	31459	31190	32592	36580	38725	39323	39252	38088	36354	34580
VACAR	11/26/12	33640	33481	33630	34243	35739	38910	43520	44658	42907	39702	37190	35223	33904	33038	32436	32132	33184	36376	38229	38493	38034	36613	34425	32234
VACAR	11/27/12	30886	30267	30068	30159	31126	33515	37624	38732	37780	37110	36785	36099	35814	35596	35521	35806	37113	39676	40231	39917	39048	37156	34783	32314
VACAR	11/28/12	30839	30155	30090	30662	32000	34849	39679	41022	39907	38374	36886	35587	34455	33766	33157	33272	34767	38680	40883	41470	41609	40863	38989	37313
VACAR	11/29/12	36481	36469	36982	37895	39708	42745	47249	48308	46178	42329	39149	37034	35374	34368	33555	33450	34748	38650	40678	41324	41465	40382	38472	36576
VACAR	11/30/12	35638	35516	35794	36573	38072	41099	45615	46618	44408	40820	37827	35558	34040	33045	32217	31911	32883	36045	37230	37075	36895	36300	34949	33128

Backup - DOM Hourly Load

DOMP	**Max**	20,588
DOMA	**Avg Jul**	16,794
DOMW	**Winter**	12,631
DOMS	**Spring**	11,102
DOMS	**Summer**	15,385
DOMF	**Fall**	11,796

Dec 2011-Nov 2012 Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DOM	12/1/11	9610	9420	9494	9773	10170	11166	12434	12864	12277	11624	11125	10652	10327	10125	9911	9922	10409	11738	12147	12255	12210	11863	11194	10592
DOM	12/2/11	10253	10206	10271	10453	10982	11966	13345	13645	12939	11985	11167	10560	10118	9841	9627	9671	9982	11194	11370	11257	11154	10923	10471	9881
DOM	12/3/11	9468	9225	9204	9317	9558	10064	10679	11245	11400	11023	10595	10140	9734	9389	9242	9240	9842	11031	11210	11206	11065	10780	10375	9818
DOM	12/4/11	9459	9311	9311	9448	9679	10053	10582	10988	11236	10783	10230	9764	9432	9213	8969	9085	9556	10825	11087	11007	10867	10397	9664	8981
DOM	12/5/11	8535	8398	8359	8512	8850	9705	10906	11346	10964	10773	10553	10363	10147	10007	9857	9828	10248	11269	11348	11190	10882	10113	9205	8279
DOM	12/6/11	7658	7377	7248	7211	7369	8136	9425	9947	9837	9850	9864	9834	9761	9768	9753	9773	10176	10966	11012	10823	10476	9860	9004	8109
DOM	12/7/11	7436	7161	7055	7055	7277	7998	9291	9943	9844	9812	9807	9901	9906	9923	9910	9989	10416	11292	11366	10973	10758	10277	9599	8887
DOM	12/8/11	8476	8350	8350	8595	9165	10171	11823	12384	12030	11618	11305	10921	10636	10430	10264	10333	10971	12332	12683	12728	12642	12254	11550	10795
DOM	12/9/11	10429	10317	10372	10567	10983	11879	13172	13653	13037	12184	11666	11184	10797	10510	10294	10292	10793	11808	11812	11586	11488	11178	10603	9939
DOM	12/10/11	9484	9184	9049	9036	9177	9550	10085	10720	11164	11112	10818	10564	10302	9938	9783	9814	10464	11628	11928	11971	11971	11785	11353	10864
DOM	12/11/11	10543	10404	10424	10564	10748	11122	11749	12301	12472	12105	11531	11020	10656	10411	10200	10317	11047	12497	12952	13135	13109	12707	12061	11394
DOM	12/12/11	11041	10905	10902	11054	11453	12444	13762	14145	13755	13110	12433	11888	11508	11274	11086	11176	11777	13037	13117	13120	12957	12427	11705	10953
DOM	12/13/11	10557	10480	10452	10759	11212	12204	13569	14020	13409	12571	11777	11180	10785	10521	10342	10291	10861	12273	12586	12661	12611	12122	11264	10422
DOM	12/14/11	9824	9587	9588	9693	10037	10922	12194	12623	12151	11590	11266	10949	10767	10572	10502	10473	11124	12194	12231	12062	11790	11252	10424	9570
DOM	12/15/11	9069	8781	8752	8767	9048	9896	11264	11696	11308	10874	10479	10090	9834	9703	9644	9650	10020	11059	11128	10955	10717	10168	9285	8475
DOM	12/16/11	7874	7443	7303	7351	7654	8377	9718	10261	10136	10127	10119	10106	10046	10065	10165	10359	11015	11869	11777	11531	11296	10848	10312	9676
DOM	12/17/11	9222	8967	8839	8917	9091	9541	10205	10840	11412	11593	11592	11395	11181	10905	10750	10782	11346	12360	12512	12407	12439	12312	12020	11518
DOM	12/18/11	11081	10759	10521	10442	10524	10816	11346	11850	12249	12015	11517	10970	10885	10737	10602	10625	11231	12498	12893	13014	13075	12795	12213	11651
DOM	12/19/11	11243	11093	11252	11485	11979	12879	14071	14461	13946	13064	12404	11756	11254	10883	10651	10621	11109	12299	12486	12378	12154	11556	10730	9807
DOM	12/20/11	9212	8854	8724	8745	9024	9784	11021	11551	11367	11088	10855	10609	10380	10192	10072	10055	10581	11759	11907	11754	11453	10927	10067	9160
DOM	12/21/11	8580	8233	8004	8026	8234	8925	9999	10631	10620	10519	10541	10461	10396	10340	10277	10330	10681	11330	11272	11116	10721	10147	9327	8516
DOM	12/22/11	7837	7468	7322	7231	7514	8184	9213	9834	10007	10031	9962	9815	9649	9506	9463	9427	9816	10840	10834	10688	10427	10022	9394	8563
DOM	12/23/11	7927	7530	7317	7305	7413	7892	8664	9218	9557	9754	9822	9755	9597	9411	9354	9361	9850	10886	10930	10752	10557	10259	9792	9112
DOM	12/24/11	8572	8243	8058	8029	8169	8496	9046	9652	10255	10425	10323	10082	9847	9591	9479	9544	10030	11059	11172	11142	11172	11146	10952	10577
DOM	12/25/11	10234	10037	9987	10065	10244	10601	11131	11610	11701	11171	10529	9976	9649	9311	9044	8946	9166	10004	10166	10216	10278	10185	9880	9432

Backup - DOM Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DOM	12/26/11	9082	8820	8747	8832	9109	9551	10061	10398	10542	10456	10396	10189	9896	9576	9325	9341	9784	11181	11657	11767	11751	11430	10860	10230
DOM	12/27/11	9749	9465	9317	9328	9524	10080	10816	11324	11496	11752	11847	11852	11722	11493	11317	11068	11031	11707	11758	11499	11193	10685	10098	9401
DOM	12/28/11	8972	8754	8767	8861	9260	9915	10781	11284	11352	11131	11033	10866	10585	10381	10236	10254	10843	12238	12470	12456	12344	11931	11411	10817
DOM	12/29/11	10427	10289	10367	10644	11147	11936	13012	13453	13355	12802	12308	11937	11578	11330	11061	10955	11456	12536	12614	12455	12190	11846	11172	10576
DOM	12/30/11	10121	9944	9912	9995	10347	10967	11811	12231	12190	11844	11463	10942	10297	9914	9623	9479	9882	11010	11125	10999	10748	10331	9795	9162
DOM	12/31/11	8547	8197	7932	7857	7925	8143	8530	8911	9258	9491	9464	9372	9266	9076	8979	9014	9378	10358	10546	10281	10050	9733	9487	9225
DOM	1/1/12	9010	8930	8849	8950	9111	9487	9970	10299	10461	10098	9608	9302	9131	8975	8880	8837	9325	10193	10274	10087	9867	9484	9053	8530
DOM	1/2/12	8178	7980	7996	8256	8636	9298	10095	10567	10842	11018	11124	11013	10890	10727	10649	10878	11471	12717	12985	13038	12896	12490	11822	11168
DOM	1/3/12	10844	10757	10857	11131	11648	12728	14218	14746	14355	13828	13712	13578	13485	13484	13522	13768	14506	15767	16092	16056	15913	15286	14584	13888
DOM	1/4/12	13604	13469	13667	13896	14365	15323	16538	16881	16216	15375	14732	14171	13601	13242	12942	12948	13453	14570	14764	14522	14182	13508	12507	11635
DOM	1/5/12	11130	10950	10902	10977	11273	12068	13462	13972	13470	12689	12017	11540	11175	10898	10770	10724	11130	12371	12830	12911	12838	12298	11539	10880
DOM	1/6/12	10422	10304	10272	10298	10659	11464	12734	13062	12505	11771	11119	10644	10318	10020	9759	9632	9780	10737	10937	10754	10591	10207	9758	9153
DOM	1/7/12	8728	8499	8481	8601	8823	9288	9844	10385	10714	10675	10279	9982	9596	9302	9079	9006	9133	10030	10281	10069	9914	9580	9210	8720
DOM	1/8/12	8256	8083	8029	8088	8262	8603	9152	9682	10254	10257	10030	9728	9569	9377	9198	9273	9691	10880	11373	11426	11395	11052	10386	9807
DOM	1/9/12	9481	9280	9239	9386	9844	10723	12109	12661	12393	12197	12090	12114	12054	12030	12095	12285	12753	13492	13541	13252	12855	12200	11268	10536
DOM	1/10/12	10001	9840	9785	9922	10324	11235	12585	13217	12797	12177	11610	11054	10599	10314	10100	10037	10459	11667	12139	12189	12063	11693	10987	10396
DOM	1/11/12	10111	10038	10108	10307	10742	11707	13014	13514	12906	12518	12203	12056	11875	11698	11591	11688	12106	12711	12595	12250	11834	11041	10128	9218
DOM	1/12/12	8634	8326	8207	8284	8641	9520	10931	11451	11054	10586	10453	10184	9938	9750	9604	9584	9790	10734	11012	10945	10763	10175	9450	8739
DOM	1/13/12	8323	8087	8102	8309	8852	9978	11630	12522	12381	12269	12255	12005	11723	11481	11229	11239	11718	12923	13214	13095	12913	12478	12019	11430
DOM	1/14/12	11124	10986	11015	11121	11315	11731	12344	12932	13181	12898	12498	12092	11556	11172	10975	10961	11478	12493	12843	12811	12736	12571	12212	11623
DOM	1/15/12	11272	11105	10965	11006	11120	11480	12031	12540	12896	12861	12458	12000	11735	11488	11265	11219	11748	12911	13603	13590	13640	13334	12980	12526
DOM	1/16/12	12301	12326	12438	12709	13221	13926	14747	15237	15075	14380	13751	13142	12574	12083	11851	11743	12104	13127	13337	13166	12791	12116	11334	10547
DOM	1/17/12	9907	9621	9422	9473	9743	10477	11708	12212	11910	11480	11149	10794	10606	10386	10142	10029	10199	11083	11385	11189	10868	10117	9347	8561
DOM	1/18/12	8004	7771	7730	7823	8228	9206	10698	11368	11249	11085	10906	10817	10710	10586	10532	10668	11239	12511	13202	13278	13132	12635	11999	11323
DOM	1/19/12	11021	10999	11139	11419	11999	13053	14643	15214	14528	13533	12936	12288	11777	11414	11146	11267	11716	12804	13272	13203	12958	12405	11483	10678
DOM	1/20/12	10265	10021	10024	10226	10699	11566	13006	13495	13155	12855	12658	12370	12181	11938	11690	11824	12212	13116	13194	12986	12759	12348	11789	11275
DOM	1/21/12	10830	10617	10457	10373	10451	10676	11084	11628	12084	12497	12677	12626	12457	12197	12015	11970	12285	12970	13213	13056	12879	12610	12077	11599
DOM	1/22/12	11152	10946	10866	10908	11005	11246	11602	12213	12767	13119	13218	13112	13099	13005	12908	12937	13142	13758	13868	13617	13338	12774	12005	11296
DOM	1/23/12	10787	10514	10424	10560	10908	11766	12990	13573	13373	13263	13085	12863	12655	12476	12273	12151	12338	12964	13008	12655	12162	11427	10427	9534
DOM	1/24/12	8962	8634	8502	8521	8829	9600	10998	11480	11151	10776	10452	10253	9972	9815	9627	9511	9732	10556	11204	11205	11084	10604	9928	9306
DOM	1/25/12	9026	9027	9028	9252	9755	10841	12460	12978	12485	11690	11249	10856	10495	10302	10098	9981	10292	11272	11927	11892	11687	11180	10403	9722
DOM	1/26/12	9264	9062	9029	9074	9501	10344	11685	12132	11642	11162	10817	10430	10134	9973	9867	9862	10090	10790	11139	10966	10730	10101	9295	8563
DOM	1/27/12	8002	7633	7478	7411	7558	8216	9428	10045	10036	10017	10028	9959	9787	9625	9449	9311	9409	10064	10544	10395	10203	9898	9447	9009
DOM	1/28/12	8660	8556	8580	8772	9089	9644	10363	11016	11330	10955	10576	10167	9792	9378	9052	8977	9165	9945	10559	10500	10374	10184	9826	9429
DOM	1/29/12	9143	9076	9024	9224	9560	9966	10625	11214	11509	11188	10728	10420	10208	9882	9570	9488	9811	10792	11637	11792	11719	11280	10695	10121

Backup - DOM Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DOM	1/30/12	9716	9578	9597	9834	10434	11519	12957	13559	13101	12336	11758	11357	10970	10649	10390	10225	10449	11437	12171	12200	12061	11607	10858	10120
DOM	1/31/12	9670	9416	9391	9465	9798	10665	12028	12396	11765	11084	10632	10231	9943	9763	9481	9436	9590	10226	10941	10908	10603	10056	9274	8572
DOM	2/1/12	8143	7970	7839	7921	8255	9020	10420	10801	10548	10226	9995	9741	9476	9355	9315	9265	9285	9977	10532	10402	10084	9571	8808	8037
DOM	2/2/12	7554	7284	7182	7242	6789	8355	10054	10582	10166	10168	10054	8691	9716	9575	9400	9389	9551	10425	10886	10977	10757	10304	9630	9138
DOM	2/3/12	8754	8603	8732	8990	9450	10500	12027	12663	12207	11519	11102	10680	10320	9985	9764	9646	9862	10585	11349	11402	11383	11178	10781	10324
DOM	2/4/12	9986	9809	9804	9889	10077	10408	10888	11323	11586	11464	11153	10735	10357	10159	10066	10158	10547	11201	11486	11345	11140	10809	10270	9716
DOM	2/5/12	9312	9059	8989	8960	9123	9406	9840	10429	10990	11378	11513	11446	11335	11138	11000	10951	11144	11836	12205	11996	12050	11875	11649	11125
DOM	2/6/12	10781	10773	11001	11320	11846	12928	14252	14630	13928	12870	11999	11351	10843	10506	10252	10125	10391	11250	12058	12069	11942	11362	10662	9910
DOM	2/7/12	9445	9218	9177	9280	9774	10829	12419	12906	12202	11390	10877	10463	10194	9955	9765	9617	10949	10540	11518	11587	11549	11111	10529	9950
DOM	2/8/12	9672	9653	9714	9972	10446	11384	12760	13183	12696	12256	12027	11832	11723	11725	11722	11801	12081	12731	13123	12956	12725	12075	11269	10567
DOM	2/9/12	10191	10067	10143	10335	10795	11824	13415	13848	13191	12499	12027	11512	11093	10716	10440	10344	10529	11387	12490	12665	12588	12161	11441	10774
DOM	2/10/12	10349	10273	10355	10502	11102	12111	13576	13965	13281	12373	11779	11272	10875	10757	10764	10798	11169	11730	11940	11686	11423	10943	10487	9893
DOM	2/11/12	9489	9241	9141	9073	9157	9595	10073	10745	11331	11702	11675	11591	11421	11077	11003	11293	11724	12597	13545	13823	13929	13901	13547	13332
DOM	2/12/12	13115	13029	13102	13247	13438	13793	14237	14588	14631	14398	13958	13411	13078	12667	12295	12081	12269	13162	14216	14397	14220	13848	13242	12734
DOM	2/13/12	12426	12415	12602	13558	13497	14602	15904	16137	15067	13811	12958	12343	11741	11199	10898	10714	10983	11722	12650	12739	12655	12170	11394	10669
DOM	2/14/12	10193	9974	9883	9921	10274	11242	12666	13086	12754	12359	11954	11359	10840	10532	10390	10216	10511	11171	11749	11687	11431	10866	10097	9384
DOM	2/15/12	8904	8797	8754	8954	9353	10361	11880	12243	11608	11003	10606	10303	10135	9895	9761	9604	9774	10363	11296	11488	11429	11022	10344	9633
DOM	2/16/12	9242	9018	8982	8988	9339	10219	11566	12075	11752	11590	11523	11295	11183	11078	11016	11066	11279	11698	12063	12000	11683	11109	10353	9614
DOM	2/17/12	9076	8847	8749	8791	9129	10049	11383	11837	11581	11204	10823	10450	10108	9971	9726	9660	9740	10191	10893	11114	11058	10829	10434	9937
DOM	2/18/12	9587	9471	9443	9581	9766	10160	10745	11317	11447	11002	10563	10084	9650	9230	8935	8814	8998	9246	10287	10265	10128	9843	9412	9006
DOM	2/19/12	8560	8436	8426	8475	8668	9013	9513	10010	10693	11089	11150	11081	11079	11083	11214	11388	11790	12469	12972	12894	12664	12237	11616	11107
DOM	2/20/12	10702	10533	10507	10640	10891	11506	12438	12863	12920	12575	12337	11976	11600	11222	10879	10680	10809	11467	12631	12938	12962	12549	12043	11483
DOM	2/21/12	11226	11192	11420	11693	12258	13223	14697	14876	14006	12755	12079	11764	11540	11249	10814	10581	10672	11255	12111	12154	11938	11339	10501	9432
DOM	2/22/12	9191	8962	8907	9014	9444	10321	11710	12013	11463	10981	10478	10168	9931	9765	9626	9490	9701	10147	10915	10808	10600	10019	9181	8425
DOM	2/23/12	7982	7754	7710	7804	8202	9040	10391	10817	10438	10125	9904	9699	9587	9512	9396	9397	9373	9604	10384	10463	10200	9614	8842	8066
DOM	2/24/12	7577	7298	7186	7216	7410	8151	9451	10054	10018	9944	9849	9795	9659	9670	9640	9609	9636	10040	10321	10104	9786	9469	8947	8409
DOM	2/25/12	8062	7895	7861	8032	8282	8774	9422	10129	10805	11005	10955	10746	10504	10204	9946	9921	10182	10953	11827	11994	11918	11564	11140	10740
DOM	2/26/12	10391	10210	10184	10253	10452	10860	11428	11779	11687	11356	10876	10409	10074	9671	9362	9240	9300	9972	11132	11490	11506	11141	10587	10115
DOM	2/27/12	9770	9741	9858	10102	10632	11682	13118	13357	12437	11589	10992	10566	10222	10013	9950	9822	9850	10203	11100	11205	10848	10198	9511	8750
DOM	2/28/12	8413	8176	8210	8366	8829	9924	11349	11729	11250	10782	10433	10144	9850	9632	9497	9456	9519	9876	10949	11200	11130	10633	9946	9356
DOM	2/29/12	9000	8928	8978	9026	9340	10138	11362	11794	11622	11528	11670	11419	11055	10759	10537	10404	10489	10903	11340	11149	10732	10064	9143	8353
DOM	3/1/12	7860	7523	7384	7359	7598	8364	9658	10002	9828	9676	9662	9571	9475	9422	9354	9282	9289	9483	10221	10381	10103	9551	8801	8157
DOM	3/2/12	7716	7604	7592	7685	8190	9216	10741	11168	10807	10389	10202	10013	9813	9783	9884	10107	10408	10810	11091	10837	10487	10079	9414	8800
DOM	3/3/12	8321	7970	7767	7692	7720	7890	8327	8786	9332	9738	9820	9658	9456	9121	8904	8711	8870	9194	9906	9946	9788	9473	8998	8474
DOM	3/4/12	8134	7862	7824	7822	8009	8290	8775	9306	9933	10247	10184	10022	9951	9850	9769	9743	10022	10675	11618	11910	11787	11370	10793	10289

Backup - DOM Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DOM	3/5/12	9971	9901	10024	10328	10867	11792	13029	13362	13297	13146	12860	12591	12395	12056	11808	11738	11868	12392	13324	13547	13303	12787	12056	11369
DOM	3/6/12	11134	11043	11206	11457	11915	12936	14220	14202	13207	12259	11737	11280	10883	10575	10341	10210	10317	10827	11943	12275	12203	11717	10944	10319
DOM	3/7/12	9954	9849	9850	10015	10492	11483	12829	12785	11876	11055	10598	10198	9885	9731	9601	9480	9478	9743	10458	10701	10441	9830	9043	8326
DOM	3/8/12	7843	7672	7544	7615	7888	8678	9877	10274	10014	9784	9712	9597	9519	9407	9345	9311	9371	9557	10282	10409	10126	9524	8651	7939
DOM	3/9/12	7411	7149	6925	6961	7176	7918	9127	9605	9964	10069	10046	9961	9963	9778	9790	9605	9568	9759	10152	10673	10716	10510	9971	9573
DOM	3/10/12	9147	9062	9073	9175	9400	9894	10446	10873	11043	10979	10761	10415	10024	9659	9268	9141	9165	9512	10571	10959	10964	10853	10483	10079
DOM	3/11/12	9796	9652		9673	9977	10208	10750	11238	11393	10913	10406	9911	9570	9326	8882	8646	8603	8697	8952	9767	10129	9830	9290	8555
DOM	3/12/12	8105	7931	7963	8106	8504	9472	11001	11664	11209	10593	10210	9927	9652	9574	9475	9378	9321	9333	9496	10233	10325	9661	8833	8038
DOM	3/13/12	7440	7092	6964	6928	7051	7808	9112	9773	9634	9619	9665	9718	9708	9674	9748	9845	9821	9858	9856	10396	10634	9896	9022	8111
DOM	3/14/12	7468	7114	6840	6873	7005	7638	8960	9624	9531	9601	9776	9929	10010	10164	10216	10315	10413	10445	10329	10677	10715	10106	9199	8191
DOM	3/15/12	7489	7097	6878	6824	6968	7626	9867	9501	9448	9559	9796	9876	10095	10390	10559	10687	10695	10678	10514	10865	10821	10197	9292	8281
DOM	3/16/12	7570	7195	6930	6876	6992	7580	8830	9505	9404	9536	9728	9773	9763	9799	9823	9831	9736	9669	9555	9830	9811	9421	8810	8038
DOM	3/17/12	7446	7066	6858	6729	6681	6874	7273	7735	8277	8709	8958	9072	9103	9003	8995	9066	9140	9214	9088	9383	9447	9041	8466	7835
DOM	3/18/12	7228	6878	6643	6542	6546	6610	6923	7366	7882	8346	8571	8590	8638	8620	8513	8538	8703	8805	8995	9532	9842	9260	8504	7645
DOM	3/19/12	7106	6810	6684	6633	6896	7563	8887	9450	9384	9463	9589	9733	9842	9959	10003	9981	10062	10176	10085	10535	10612	9955	8927	8051
DOM	3/20/12	7469	7081	6903	6827	6968	7661	8941	9527	9540	9566	9651	9852	9994	10169	10330	10430	10524	10489	10375	10729	10727	10030	9094	8140
DOM	3/21/12	7539	7105	6966	6863	7051	7685	8932	9500	9453	9582	9711	9772	9895	9977	10073	10091	10132	10155	10084	10387	10509	9871	8979	8115
DOM	3/22/12	7495	7071	6830	6785	6946	7618	8921	9510	9480	9640	9775	9981	10189	10438	10620	10801	10848	10859	10671	10948	11110	10457	9427	8433
DOM	3/23/12	7787	7321	7105	6995	7058	7689	8912	9367	9522	9756	10159	10574	10943	11279	11601	11793	11859	11791	11259	11162	11118	10474	9685	8833
DOM	3/24/12	8062	7566	7242	7037	6982	7167	7492	7928	8578	9194	9576	9665	9620	9518	9242	9196	9213	9252	9292	9574	9579	9143	8590	7946
DOM	3/25/12	7352	6977	6755	6594	6578	6653	6962	7305	7944	8526	8742	8817	8878	8819	8729	8702	8650	8867	9025	9570	9734	9212	8462	7750
DOM	3/26/12	7153	6864	6757	6721	6934	7669	8926	9434	9411	9360	9435	9497	9451	9425	9371	9340	9303	9277	9290	9771	10264	9698	8925	8203
DOM	3/27/12	7731	7531	7528	7594	8011	9016	10735	11334	11096	10743	10402	10129	9901	9688	9468	9244	9270	9288	9445	10121	10629	10219	9480	8718
DOM	3/28/12	8240	8002	8029	8106	8369	9235	10568	10813	10422	10095	9746	9613	9528	9496	9582	9555	9644	9698	9686	10036	10314	9668	8806	7873
DOM	3/29/12	7395	7034	6880	6779	6949	7541	8777	9350	9377	9479	9611	9637	9646	9690	9683	9733	9758	9729	9603	9839	10119	9582	8729	7857
DOM	3/30/12	7168	7097	7031	7092	7298	8108	9579	10079	9969	9767	9648	9426	9412	9379	9362	9264	9269	9309	9226	9445	9793	9342	8696	8077
DOM	3/31/12	7313	7052	6883	6887	6914	7095	7563	7945	8399	8609	8881	8811	8642	8615	8544	8487	8460	8505	8591	8860	8951	8417	8066	7457
DOM	4/1/12	6999	6725	6602	6613	6672	7016	7348	7794	8325	8525	8494	8314	8253	8132	8016	7953	8085	8225	8325	8789	9116	8724	7975	7322
DOM	4/2/12	7009	6717	6585	6592	6829	7486	8576	9050	9123	9191	9236	9233	9150	9072	8986	8994	8990	9067	9087	9434	9852	9449	8676	7980
DOM	4/3/12	7499	7293	7252	7338	7719	8565	9867	10346	10083	9757	9550	9409	9281	9267	9226	9236	9259	9301	9247	9529	9833	9346	8497	7713
DOM	4/4/12	7174	6831	6752	6572	6802	7475	8599	9036	9196	9272	9536	9633	9795	9963	10034	10096	10096	10146	10001	10109	10322	9747	8878	8000
DOM	4/5/12	7358	6971	6710	6621	6803	7391	8484	8998	9169	9274	9303	9319	9280	9226	9184	9170	9231	9302	9342	9636	10020	9620	8950	8238
DOM	4/6/12	7646	7398	7353	7375	7614	8301	9332	9872	10027	10037	10004	9805	8693	9353	9176	9006	8959	8988	8915	9161	9639	9414	8971	8454
DOM	4/7/12	8052	7882	7743	7734	7875	8149	8692	9152	9466	9507	9400	9194	8915	8599	8375	8320	8299	8376	8497	8752	9217	9017	8658	8080
DOM	4/8/12	7581	7394	7330	7379	7527	7913	8337	8744	9082	9103	8840	8543	8490	8355	8218	8169	8175	8196	8214	7390	9079	8766	8192	7499

Backup - DOM Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DOM	4/9/12	6966	6729	6557	6667	6913	7566	8790	8995	9218	9367	9434	9479	9398	9089	9322	9233	9263	9287	9231	9584	9856	9300	8459	7738
DOM	4/10/12	7236	6949	6819	6879	7163	7871	9005	9531	9560	9505	9535	9519	9410	9375	9337	9269	9352	9316	9321	9576	9924	9445	8692	7926
DOM	4/11/12	7452	7143	7143	7244	7529	8271	9490	10112	10120	10118	10034	9940	9739	9683	9604	9638	9731	9887	10007	10408	10834	10417	9657	8937
DOM	4/12/12	8564	8373	8334	8446	8706	9467	10564	10965	10748	10389	10208	9965	9738	9561	9383	9336	9290	9319	9305	9558	10166	9786	9157	8543
DOM	4/13/12	8104	7952	7901	7952	8236	8982	10020	10394	10279	10021	9856	9645	9451	9321	9178	9069	9159	9094	8901	9059	9465	9155	8598	8020
DOM	4/14/12	7565	7297	7259	7274	7412	7732	8179	8630	8952	8981	8933	8886	8820	8694	8525	8506	8570	8661	8659	8853	9286	8996	8422	7761
DOM	4/15/12	7209	6871	6643	6527	6536	6620	6800	7140	7842	8411	8798	9054	9203	9456	9753	10081	10341	10557	10622	10718	11155	10648	9717	8696
DOM	4/16/12	7982	7512	7252	7120	7267	7845	8918	9568	9962	10391	10884	11348	11725	12128	12492	12776	13017	13055	12852	12544	12641	11992	10870	9629
DOM	4/17/12	8740	8150	7828	7582	7658	8122	9154	9624	9950	10158	10412	10650	10862	11075	11200	11301	11283	11173	10852	10689	10869	10168	9090	8137
DOM	4/18/12	7483	7063	6859	6816	6958	7571	8727	9236	9331	9470	9324	9566	9509	9499	9428	9407	9501	9598	9690	9899	10033	9443	8682	7800
DOM	4/19/12	7321	7017	6884	6832	7074	7829	8994	9430	9470	9440	9458	9514	9480	9500	9469	9435	9470	9608	9560	9631	10123	9647	8811	7901
DOM	4/20/12	7304	6973	6827	6810	7029	7734	8870	9364	9479	9532	9625	9652	9627	9686	9674	9785	9849	9868	9588	9488	9864	9407	8743	8005
DOM	4/21/12	7417	7036	6787	6669	6707	6827	7126	7564	8251	8741	9090	9370	9663	9769	9891	10088	10247	10279	10053	9969	10012	9535	8839	8093
DOM	4/22/12	7418	6995	6790	6633	6577	6615	6912	7270	7917	8422	8758	8950	9058	9048	9077	9068	9231	9446	9590	9788	9990	9460	8751	8063
DOM	4/23/12	7584	7343	7265	7332	7612	8429	9719	10288	10331	10194	10311	10225	10199	10060	9935	9926	10144	10400	10553	10787	11144	10585	9757	8928
DOM	4/24/12	8457	8240	8127	8206	8597	9451	10725	11008	10617	10135	9829	9594	9410	9226	9243	9120	9072	9212	9213	9481	10111	9772	9032	8325
DOM	4/25/12	7836	7723	7700	7870	8238	9218	10470	10764	10371	9882	9665	9634	9434	9451	9438	9369	9393	9428	9338	9536	10021	9510	8702	7851
DOM	4/26/12	7260	6955	6868	6845	6988	7690	8887	9518	9520	9558	9649	9725	9704	9759	9685	9521	9571	9548	9496	9580	10031	9606	8758	7945
DOM	4/27/12	7323	7052	6894	6828	7011	7681	8759	9228	9372	9369	9442	9321	9350	9372	9365	9268	9302	9297	9121	9040	9439	9144	8599	7939
DOM	4/28/12	7417	7133	6993	6913	7041	7324	7720	8211	8826	9182	9226	9175	9127	8964	8866	8772	8827	9086	9198	9312	9621	9259	8794	8250
DOM	4/29/12	7736	7462	7259	7178	7168	7339	7558	7931	8401	8731	8757	8724	8702	8598	8469	8462	8531	8639	8774	8908	9496	9226	8412	7651
DOM	4/30/12	7100	6807	6678	6761	6984	7730	8871	9343	9473	9337	9583	9629	9598	9494	9526	9451	9454	9548	9487	9649	10069	9551	8696	7828
DOM	5/1/12	7303	7033	6888	6827	7044	7702	8851	9470	9694	9871	10175	10493	10799	11081	11370	11623	11865	12001	11977	11905	12049	11475	10258	9144
DOM	5/2/12	8250	7738	7515	7399	7461	8153	9212	9886	10231	10569	11046	11410	11891	12184	12576	12869	13042	13028	12717	12232	12124	11383	10185	9081
DOM	5/3/12	8207	7709	7342	7143	7239	7792	8945	9478	9656	9735	9886	10161	10555	11060	11586	12110	12515	12761	12546	12180	12265	11605	10448	9284
DOM	5/4/12	8436	7876	7576	7446	7572	8153	9060	9897	10372	10836	11471	11929	12138	12529	12816	12979	13263	12938	12435	12110	12152	11617	10649	9575
DOM	5/5/12	8671	8087	7761	7497	7433	7511	7679	8364	9372	10213	10993	11525	11882	12002	11964	11833	11573	11351	10962	10740	10768	10375	9585	8806
DOM	5/6/12	8065	7604	7326	7098	7034	7111	7241	7597	8179	8759	9091	9313	9498	9579	9665	9768	9952	10088	10047	10107	10410	10030	9139	8189
DOM	5/7/12	7529	7101	6838	6802	6957	7623	8645	9262	9433	9622	9835	9986	10109	10320	10419	10543	10577	10508	10283	10194	10428	9987	9066	8130
DOM	5/8/12	7506	7111	6912	6848	7020	7589	8640	9277	9513	9831	10070	10305	10432	10512	10683	10858	11049	11095	11066	10947	11210	10714	9654	8705
DOM	5/9/12	8003	7530	7348	7287	7404	8038	9104	9746	10000	10110	10392	10547	10608	10818	10823	10876	10805	10856	10598	10578	10545	9929	9044	8138
DOM	5/10/12	7541	7145	6956	6893	7008	7618	8576	9170	9336	9426	9619	9621	9626	9672	9689	9769	9844	9876	9747	9643	9942	9649	8752	7845
DOM	5/11/12	7265	6952	6792	6729	6857	7538	8523	9224	9317	9420	9504	9565	9652	9687	9667	9758	9900	9938	9754	9460	9554	9394	8745	7911
DOM	5/12/12	7379	6993	6726	6692	6760	6896	7131	7659	8337	8808	9106	9235	9342	9390	9499	9720	9858	9892	9716	9501	9717	9507	8911	8183
DOM	5/13/12	7580	7086	6773	6665	6625	6690	6747	7286	8082	8799	9266	9607	9914	10104	10262	10352	10264	10220	10042	10040	10344	10122	9318	8396

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Backup - DOM Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DOM	5/14/12	7751	7311	7088	7067	7222	7835	8866	9501	9775	9958	10249	10416	10593	10721	10787	10820	10807	10828	10772	10751	10975	10513	9524	8582
DOM	5/15/12	7943	7421	7291	7215	7391	8024	9123	9825	10093	10444	10881	11294	11590	11996	12172	12330	12354	12427	12049	11917	11860	11171	10053	9041
DOM	5/16/12	8228	7701	7387	7227	7374	8042	9020	9751	10048	10331	10623	11016	11401	11964	12341	12547	12699	12705	12380	11992	12027	11422	10377	9269
DOM	5/17/12	8371	7878	7572	7406	7533	8033	8984	9683	10000	10296	10650	10832	10950	10946	11023	11091	11102	11101	10873	10569	10719	10324	9314	8355
DOM	5/18/12	7634	7197	6949	6816	6976	7463	8430	9093	9406	9709	9914	10093	10147	10250	10368	10434	10656	10533	10157	9750	9823	9650	8879	8096
DOM	5/19/12	7440	7026	6736	6584	6608	6751	6920	7486	8223	8728	9025	9249	9431	9529	9774	10072	10349	10494	10314	9975	9985	9715	9037	8247
DOM	5/20/12	7590	7128	6815	6655	6654	6716	6761	7251	8035	8666	9058	9332	9598	9801	10034	10136	10185	10383	10425	10372	10565	10314	9419	8586
DOM	5/21/12	7910	7496	7217	7211	7443	8051	9069	9646	9974	10250	10556	10784	10911	11030	11159	11281	11448	11555	11372	11127	11208	10798	9781	8785
DOM	5/22/12	8041	7599	7357	7250	7410	8010	9054	9791	10050	10332	10715	11166	11542	11931	12038	12173	12348	12343	12106	11721	11736	11278	10137	9036
DOM	5/23/12	8307	7807	7538	7360	7497	8086	9074	9883	10347	10861	11414	11836	12062	12374	12570	12796	12905	12847	12464	12074	12064	11469	10344	9192
DOM	5/24/12	8353	7871	7541	7412	7535	8115	9144	9987	10396	10861	11376	11976	12431	12811	12946	13022	13171	13100	12734	12358	12277	11833	10844	9673
DOM	5/25/12	8806	8261	7955	7850	7969	8485	9466	10295	10815	11324	11977	12601	13187	13721	14012	14310	14460	14523	14073	13302	12813	12391	11406	10299
DOM	5/26/12	9369	8672	8202	7961	7824	7832	7989	8725	9792	10823	11756	12551	13125	13516	13815	14108	14155	14059	13705	13097	12708	12380	11423	10409
DOM	5/27/12	9436	8785	8276	7980	7822	7742	7827	8477	9584	10771	11706	12452	13006	13383	13700	13972	14165	14140	13821	13152	12820	12329	11403	10438
DOM	5/28/12	9559	8864	8480	8214	8204	8327	8456	9097	10071	11174	12214	13135	13919	14444	14841	15268	15577	15719	15481	15001	14704	14120	12779	11442
DOM	5/29/12	10371	9739	9296	9012	9070	9549	10470	11557	12295	13172	13839	14529	15128	15598	16039	16227	16319	16188	15671	14991	14515	13620	12179	10870
DOM	5/30/12	10007	9245	8992	8718	8763	9297	10271	10906	11168	11264	11505	11803	11982	12199	12371	12645	12983	13223	13034	12646	12401	12009	10869	9678
DOM	5/31/12	8836	8280	7978	7794	7886	8420	9275	10192	10843	11490	12159	12735	13240	13724	14127	14523	14791	14776	14416	13761	13270	12764	11505	10172
DOM	6/1/12	9139	8460	8086	7913	8030	8664	9595	10451	10997	11591	12237	12838	13189	13501	13612	13360	13214	12897	12408	11901	11724	11292	10423	9437
DOM	6/2/12	8639	8090	7738	7400	7289	7342	7469	8113	8967	9606	10070	10329	10416	10524	10577	10695	10754	10724	10583	10233	10081	9948	9285	8523
DOM	6/3/12	7802	7290	6974	6843	6756	6731	6799	7305	8170	8847	9374	9714	10051	10349	10581	10833	11167	11388	11299	10963	10820	10655	9669	8668
DOM	6/4/12	7884	7423	7163	7061	7272	7801	8653	9371	9909	10311	10816	11196	11474	11742	11997	12113	12194	12109	11722	11253	11091	10785	9758	8693
DOM	6/5/12	7871	7445	7200	7064	7228	7682	8561	9244	9584	9748	9906	9998	10006	10038	10066	10132	10146	10134	9968	9829	10038	9920	9052	8153
DOM	6/6/12	7467	7104	6914	6815	6995	7510	8405	9152	9526	9661	9915	10111	10343	10479	10482	10541	10705	10782	10635	10429	10428	10291	9391	8352
DOM	6/7/12	7662	7257	7006	6998	7150	7650	8495	9244	9692	10118	10513	10837	11055	11378	11744	11949	12187	12288	11965	11558	11356	11072	10020	8943
DOM	6/8/12	8063	7558	7325	7230	7322	7775	8509	9467	10000	10522	11071	11419	11826	12199	12622	13034	13292	13272	12975	12302	11803	11494	10509	9447
DOM	6/9/12	8623	8010	7558	7282	7271	7313	7470	8287	9394	10428	11334	12195	12759	13149	13580	13976	14203	14229	13912	13276	12638	12247	11269	10168
DOM	6/10/12	9214	8477	8095	7799	7585	7559	7635	8405	9593	10843	11954	12903	13680	14216	14634	14862	15083	15200	14960	14302	13797	13376	12164	10765
DOM	6/11/12	9660	9015	8558	8356	8421	8811	9577	10541	11399	12238	13110	13707	14143	14477	14685	14791	14770	14605	14013	13540	13341	12915	11834	10571
DOM	6/12/12	9658	9017	8800	8655	8742	9247	10192	10922	11249	11547	11867	12126	12310	12540	12721	12961	13209	13433	13345	13134	13008	12665	11620	10360
DOM	6/13/12	9427	8912	8503	8339	8350	8824	9572	10417	10986	11444	11896	12425	12730	12970	13278	13553	13773	13770	13241	12512	12022	11704	10626	9494
DOM	6/14/12	8575	8056	7731	7620	7754	8241	9069	9736	10239	10696	11085	11324	11610	11916	12126	12469	12635	12719	12450	11884	11631	11462	10499	9412
DOM	6/15/12	8716	8128	7618	7459	7543	7958	8718	9606	10341	10838	11336	11725	11945	12217	12486	12647	12831	12790	12254	11621	11058	10879	9992	9091
DOM	6/16/12	8238	7669	7361	7136	7100	7132	7300	7933	8782	9537	10055	10421	10701	10967	11213	11462	11651	11651	11357	10811	10502	10406	9681	8777
DOM	6/17/12	7988	7448	7148	6936	6892	6806	6899	7470	8296	8956	9392	9770	10119	10359	10647	10935	11156	11209	10985	10568	10387	10345	9621	8702

Backup - DOM Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DOM	6/18/12	7903	7434	7200	7082	7232	7670	8338	9012	9535	9917	10270	10572	10749	10966	11042	11108	11206	11227	11159	10991	11030	10883	10072	8997
DOM	6/19/12	8270	7867	7649	7582	7706	8209	8903	9654	10203	10941	11771	12658	13458	14289	15035	15614	16002	16026	15794	15282	14738	14170	12958	11555
DOM	6/20/12	10433	9658	9169	8950	9034	9391	10083	11153	12248	13344	14519	15533	16278	16843	17264	17522	17691	17665	17439	16771	16137	15582	14275	12780
DOM	6/21/12	11670	10782	10243	9895	9857	10200	10904	11958	13056	14314	15502	16508	17202	17659	17841	17862	17858	17669	17262	16620	16151	15690	14462	13230
DOM	6/22/12	12067	11265	10775	10459	10418	10718	11265	12196	13032	14117	15099	16067	16892	17266	17380	17161	16270	15363	14649	13762	13196	12602	11841	10824
DOM	6/23/12	9906	9242	8805	8522	8379	8387	8502	9311	10494	11645	12684	13463	14029	14338	14612	14870	15013	14926	14537	13856	13157	12724	11709	10624
DOM	6/24/12	9680	9029	8576	8231	8054	8025	8011	8739	10008	11274	12394	13279	13914	14339	14646	14771	14861	14876	14655	14156	13709	13444	12384	11148
DOM	6/25/12	10157	9487	9032	8842	8914	9357	10034	10985	11905	12898	13941	14756	15065	15448	15609	15042	14842	14345	13782	13069	12489	11976	10905	9698
DOM	6/26/12	8783	8144	7715	7472	7490	7895	8441	9204	9764	10279	10703	11012	11314	11620	11842	12272	12620	12812	12554	12043	11636	11351	10326	9155
DOM	6/27/12	8269	7718	7464	7301	7407	7827	8372	9195	9941	10601	11275	11868	12188	12561	13150	13880	14427	14552	14258	13663	13113	12644	11494	10231
DOM	6/28/12	9191	8521	8150	7913	7973	8361	9001	9820	10672	11621	12695	13675	14498	15254	15850	16326	16693	16790	16532	15839	15170	14678	13402	11933
DOM	6/29/12	10932	10195	9681	9422	9403	9806	10363	11368	12598	13922	15233	16584	17535	18251	18721	19076	19249	19210	19002	18384	17893	16916	14076	10448
DOM	6/30/12	9312	8506	8049	7705	7510	7499	7497	8152	9098	10098	11068	11846	12549	13096	13584	14069	14531	14771	14748	14453	13952	13278	12452	11292
DOM	7/1/12	10309	9588	9150	8756	8592	8522	8477	9083	10198	11591	12854	13990	14796	15477	15840	16116	16118	16137	15927	15426	14956	14477	13368	12171
DOM	7/2/12	11134	10376	9903	9540	9492	9775	10197	11056	12011	12921	13837	14643	15321	15909	16324	16630	16792	16795	16452	15825	15140	14568	13277	11927
DOM	7/3/12	10861	10057	9595	9323	9333	9633	10235	11271	12380	13573	14696	15724	16511	16954	17272	17545	17588	17384	16971	16242	15694	14829	13658	12461
DOM	7/4/12	11433	10685	10134	9842	9730	9741	9740	10173	11051	12308	13614	14719	15611	16373	17002	17440	17678	17627	17120	16433	15764	15168	14322	13177
DOM	7/5/12	12031	11086	10531	10176	10106	10357	10909	11996	13267	14672	15957	16984	17858	18353	18737	18935	18948	18880	18595	17905	17418	16780	15446	14047
DOM	7/6/12	12869	11992	11342	11004	10934	11234	11642	12471	13544	14585	15737	16666	17312	17781	18113	18359	18527	18481	18281	17518	16840	16268	15133	13940
DOM	7/7/12	12852	11959	11338	10884	10613	10505	10570	11418	12922	14511	16015	17219	18011	17828	18045	18157	18241	18193	18033	17552	17266	20588	16040	14895
DOM	7/8/12	13870	13003	12428	11888	11539	11373	11268	12008	13348	14870	16185	17335	18120	18606	18896	18922	18434	17807	17265	16643	16231	15616	14540	13342
DOM	7/9/12	12359	11666	11197	10849	10847	11166	11717	12336	12965	13613	14300	14781	15408	15860	16045	15880	16040	15985	15502	14822	14429	13853	12723	11562
DOM	7/10/12	10660	10020	9699	9487	9539	10084	10685	11525	12289	13149	13852	14393	14743	14881	14917	14896	14716	14499	14225	13751	13412	13130	12037	10978
DOM	7/11/12	10061	9453	9141	8949	8965	9514	10228	10946	11612	12294	12875	13554	14153	14613	14850	15096	15126	14983	14494	13794	13434	12996	12064	10806
DOM	7/12/12	9867	9255	8835	8609	8712	9154	9843	10602	11353	12095	12878	13571	14177	14701	15033	15226	15367	15256	14797	14086	13554	13133	12014	10722
DOM	7/13/12	9699	9012	8668	8490	8528	9017	9583	10383	11112	11949	12716	13353	13878	14351	14828	14937	15037	14826	14364	13751	13344	13016	12131	11116
DOM	7/14/12	10183	9592	9122	8933	8840	8960	9098	9591	10436	11632	12747	13532	13983	14197	14437	14508	14488	14204	13853	13393	13167	12828	12043	11100
DOM	7/15/12	10278	9662	9292	9013	8904	8964	9041	9691	10882	12084	13474	14501	15141	16057	16470	16460	16286	15938	15337	14789	14394	14028	12983	11872
DOM	7/16/12	10991	10200	9845	9616	9644	10035	10642	11586	12539	13349	14530	15637	16063	16856	17513	17754	17869	17765	17507	16973	16333	15697	14713	13290
DOM	7/17/12	11847	11032	10434	10139	10098	10437	10967	11909	12967	14206	15485	16532	17276	17918	18185	18129	18131	18052	17818	17324	17223	16657	15213	13844
DOM	7/18/12	12730	11909	11272	10883	10831	11164	11740	12738	13775	15017	16402	17415	18297	18735	18910	18738	18519	18060	17572	16914	16537	15873	14641	13317
DOM	7/19/12	12240	11507	11005	10659	10676	11056	11660	12519	13350	14101	15328	16249	17038	17596	18030	18340	18418	18169	17805	17118	16613	16013	14569	13175
DOM	7/20/12	12134	11381	10834	10556	10535	10889	11320	12027	12680	13360	14010	14553	14925	15091	15246	15379	15433	15175	14520	13902	13584	13025	12053	11075
DOM	7/21/12	10215	9607	9229	8978	8890	8932	9061	9481	10217	10963	11566	12012	12118	12148	12125	12029	11798	11674	11479	11358	11361	11131	10460	9775
DOM	7/22/12	9095	8552	8249	8087	8006	8083	8173	8625	9410	10218	10859	11403	11925	12366	12765	13206	13737	14091	13992	13616	13340	13019	11999	10914

Backup - DOM Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DOM	7/23/12	9983	9429	9114	8994	9105	9636	10227	11126	12148	13116	14254	15212	15743	16082	16494	16776	16934	16742	16246	15558	14994	14307	13096	11780
DOM	7/24/12	10786	10113	9670	9461	9493	10053	10701	11713	12895	14112	15192	16072	16641	17221	17332	16957	16511	15642	14982	14460	14146	13663	12580	11427
DOM	7/25/12	10428	9768	9334	9093	9138	9526	10124	10921	11711	12500	13170	13732	14277	14791	15226	15668	16035	16068	15710	14928	14318	13666	12479	11214
DOM	7/26/12	10242	9450	9177	9074	9172	9636	10414	11313	12240	13327	14472	15798	16802	17774	18479	19034	19183	19187	19029	18349	17948	17202	15732	14193
DOM	7/27/12	13014	12144	11523	11139	11143	11446	11891	12637	13663	14718	15770	16699	17232	17727	18021	18085	17963	17538	16664	15648	14983	14451	13359	12133
DOM	7/28/12	11254	10420	9897	9570	9397	9457	9549	10247	11395	12519	13650	14643	15248	15775	16314	16687	16920	16885	16449	15765	15123	14432	13334	12182
DOM	7/29/12	11192	10332	9717	9288	9004	8924	8773	9377	10642	11827	12907	13731	14350	14843	15245	15482	15776	15908	15668	15113	14572	14018	12859	11604
DOM	7/30/12	10564	9809	9428	9237	9307	9750	10246	11128	12238	13234	14189	14973	15561	15990	16252	16307	16186	15941	15485	14963	14691	13966	12881	11655
DOM	7/31/12	10694	9886	9531	9265	9311	9729	10394	11082	11974	12902	13830	14701	15328	15756	16016	16155	15909	15452	14966	14511	14190	13498	12440	11304
DOM	8/1/12	10346	9634	9247	8975	9008	9530	10102	10749	11338	11943	12834	13719	14146	14579	15144	15720	16038	16052	15612	14910	14557	13886	12721	11465
DOM	8/2/12	10478	9754	9248	9032	9126	9566	10205	11032	12054	13199	14332	15445	16221	16988	17373	17275	17147	16774	16067	15339	14930	14273	13016	11825
DOM	8/3/12	10766	10030	9482	9196	9167	9687	10240	11032	12038	13101	14202	15254	15979	16660	17089	17284	17323	17144	16481	15736	15288	14712	13668	12554
DOM	8/4/12	11545	10754	10189	9859	9692	9656	9685	10340	11645	12994	14196	15223	15926	16264	16559	16790	16923	16858	16490	15784	15368	14810	13848	12719
DOM	8/5/12	11762	11033	10541	10162	10010	9964	9923	10581	11814	13109	14191	15103	15815	16330	16723	16985	16825	16538	15858	15284	15013	14511	13476	12307
DOM	8/6/12	11429	10767	10339	10136	10199	10682	11360	11953	12582	13288	13991	14707	15358	16039	16279	16385	16258	15881	15264	14671	14390	13812	12607	11441
DOM	8/7/12	10527	9895	9562	9322	9496	9959	10695	11292	11809	12352	13202	13887	14568	15110	15394	15604	15818	15804	15344	14904	14661	14045	12897	11733
DOM	8/8/12	10697	10074	9641	9480	9615	10092	10763	11366	11976	12509	13259	13908	14437	14897	15473	15807	15952	15774	15485	14913	14683	13986	12786	11575
DOM	8/9/12	10622	9923	9501	9298	9366	9775	10410	11100	11998	12976	14093	15048	15791	16504	17006	17218	17289	17146	16717	15857	15552	14699	13467	12189
DOM	8/10/12	11306	10568	10132	9880	9973	10423	11056	11513	12018	12592	13328	13798	14167	14560	15054	15476	15620	15543	14999	14387	14148	13529	12617	11533
DOM	8/11/12	10667	9981	9572	9261	9108	9176	9312	9745	10667	11638	12521	13201	13837	14069	14206	14327	14084	13823	13490	13001	12788	12269	11355	10456
DOM	8/12/12	9595	8920	8581	8340	8198	8211	8290	8690	9534	10552	11351	12034	12703	13215	13499	13819	14194	14387	14158	13525	13250	12673	11589	10553
DOM	8/13/12	9668	8996	8659	8504	8592	9054	9694	10393	11274	12183	13223	14096	14749	15337	15747	16038	16249	16193	15674	14985	14756	13892	12669	11402
DOM	8/14/12	10435	9799	9414	9286	9384	9874	10561	11045	11743	12549	13556	14572	15372	16012	16414	16659	16681	16564	16026	15395	15106	14239	12880	11655
DOM	8/15/12	10649	9936	9446	9183	9270	9715	10381	11059	11876	12606	13484	14046	14608	14975	15231	15179	15000	14669	14138	13642	13507	12795	11687	10528
DOM	8/16/12	9613	8986	8635	8467	8496	8952	9490	10171	10990	11932	12820	13580	14267	14849	15380	15744	15967	15982	15416	14584	14154	13359	12099	10875
DOM	8/17/12	9836	9183	8778	8504	8547	8877	9522	10256	11138	12138	13185	14216	15041	15710	16221	16490	16461	16139	15438	14683	14336	13503	12446	11416
DOM	8/18/12	10467	9844	9372	8940	8785	8808	8971	9309	10176	11100	11786	12423	12833	13126	13457	13640	13784	13669	13316	12707	12475	11909	11024	10009
DOM	8/19/12	9220	8647	8276	7972	7887	7910	8038	8370	9120	10011	10538	10803	10884	10760	10669	10622	10634	10720	10731	10759	11041	10675	9974	9224
DOM	8/20/12	8531	8083	7866	7802	7981	8547	9383	9908	10337	10714	11059	11365	11694	12045	12396	12743	12979	12928	12540	12177	12249	11575	10529	9551
DOM	8/21/12	8779	8319	8025	7923	7995	8538	9259	9722	10272	10829	11452	12127	12725	13185	13628	13764	13825	13615	13140	12797	12809	12114	10969	9825
DOM	8/22/12	9058	8439	8095	7922	8014	8603	9378	9923	10531	11112	11629	12400	13117	13704	14156	14526	14642	14368	13801	13214	13117	12367	11217	10088
DOM	8/23/12	9247	8694	8368	8229	8352	8840	9753	10256	10877	11712	12604	13419	13958	14382	14819	14999	15122	14919	14294	13599	13559	12807	11632	10370
DOM	8/24/12	9439	8875	8484	8321	8430	8950	9668	10250	10849	11564	12311	12790	13174	13504	13760	13667	13488	13205	12731	12408	12475	11929	11095	10214
DOM	8/25/12	9415	8828	8589	8366	8362	8488	8714	9139	9737	10559	11169	11567	11743	11619	11420	11337	11560	11715	11606	11433	11579	11153	10466	9696
DOM	8/26/12	8995	8499	8214	8022	7924	7952	8164	8402	9380	10338	11212	11863	12321	12656	12943	13039	13190	13100	12786	12432	12463	11853	10851	9890

Backup - DOM Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DOM	8/27/12	9093	8613	8315	8250	8328	8954	9885	10388	11065	11930	12887	13715	14492	15187	15825	16008	16070	16117	15658	15020	14808	13815	12487	11229
DOM	8/28/12	10302	9746	9380	9180	9221	9780	10719	11295	11875	12664	13517	14466	15385	15999	16367	16601	16603	16401	15761	14932	14474	13479	12115	10908
DOM	8/29/12	9889	9177	8830	8603	8586	9167	10021	10546	11167	11870	12894	13599	14250	14810	15246	15551	15691	15518	14896	14165	13860	12937	11640	10386
DOM	8/30/12	9471	8906	8557	8312	8476	8882	9754	10299	11035	11768	12551	13361	14109	14800	15326	15663	15930	15858	15364	14749	14526	13649	12358	11068
DOM	8/31/12	10131	9541	9194	8939	9010	9468	10290	10837	11630	12645	13739	14733	15037	15993	16659	16969	17139	17109	16525	15664	15333	14437	13350	12200
DOM	9/1/12	11285	10462	9942	9554	9323	9372	9544	9901	10920	11923	12806	13489	14049	14492	14880	15188	15264	15106	14717	14476	14346	13634	12630	11638
DOM	9/2/12	10735	9993	9582	9225	9030	9050	9177	9479	10396	11423	12200	12852	13309	13610	13884	14081	14021	13856	13446	13199	12926	12255	11415	10547
DOM	9/3/12	9767	9209	8857	8710	8676	8853	9174	9436	10279	11326	12195	12766	13148	13463	13754	14065	14266	14401	14284	14171	14075	13226	12077	10983
DOM	9/4/12	10105	9511	9123	9012	9135	9813	10997	11508	11920	12505	13207	14087	14822	15427	15840	16170	16229	16146	15684	15487	15324	14303	12986	11772
DOM	9/5/12	10834	10188	9788	9569	9685	10328	11442	11987	12439	13055	13709	14583	15187	15696	16121	16382	16423	16306	15876	15581	15308	14193	12857	11613
DOM	9/6/12	10703	10080	9695	9516	9649	10338	11494	12061	12424	12857	13234	13380	13666	14015	14236	14273	14368	14254	13771	13447	13246	12382	11193	10107
DOM	9/7/12	9246	8639	8389	8217	8331	8871	9931	10572	11145	11940	12836	13739	14469	15211	15740	16015	16222	16105	15406	14650	14234	13350	12337	11244
DOM	9/8/12	10307	9597	9183	8923	8868	8960	9270	9698	10828	11853	12964	13851	14515	15098	15282	14867	13804	13260	12689	12322	11964	11309	10389	9510
DOM	9/9/12	8769	8227	7874	7593	7458	7440	7590	7880	8562	9296	9962	10447	10924	11181	11419	11636	11841	11885	11608	11341	11319	10529	9474	8487
DOM	9/10/12	7855	7371	7172	7132	7259	7873	8842	9234	9630	10052	10483	10778	10976	11182	11291	11554	11649	11606	11354	11146	11111	10274	9236	8279
DOM	9/11/12	7684	7190	7069	7023	7171	7735	8787	9154	9473	9790	10130	10312	10480	10730	11024	11306	11555	11635	11292	11252	11172	10279	9255	8260
DOM	9/12/12	7618	7206	7028	6936	7060	7717	8694	9063	9370	9778	10072	10468	10815	11195	11582	11914	12215	12211	11762	11613	11380	10579	9514	8531
DOM	9/13/12	7823	7367	7188	7076	7222	7898	8941	9290	9601	10058	10522	10937	11206	11560	11857	12276	12579	12576	12126	12036	11872	10983	9865	8901
DOM	9/14/12	8178	7727	7490	7340	7460	8009	9039	9575	10033	10550	11109	11610	11985	12383	12708	12948	13058	12939	12300	12063	11824	11089	10192	9227
DOM	9/15/12	8418	7909	7649	7493	7414	7507	7754	8062	8905	9617	10065	10234	10259	10379	10578	10843	10837	10716	10345	10338	10262	9700	8994	8249
DOM	9/16/12	7654	7212	6970	6845	6739	6875	7110	7367	8025	8661	9025	9302	9453	9543	9583	9611	9763	9977	10023	10405	10417	9750	8869	8103
DOM	9/17/12	7518	7168	7025	7020	7145	7740	8900	9228	9660	9983	10317	10530	10721	10816	10969	11062	11182	11264	11397	11689	11542	10813	9917	8990
DOM	9/18/12	8390	7985	7786	7768	7960	8690	9969	10742	11143	11486	11970	12266	12412	12332	12209	11858	11664	11818	11806	11982	11715	10956	9971	8982
DOM	9/19/12	8240	7836	7544	7417	7459	7971	9048	9435	9529	9676	9874	10022	10088	10222	10346	10469	10553	10596	10304	10597	10538	9882	8927	8037
DOM	9/20/12	7419	7041	6944	6882	7068	7687	8786	9155	9371	9564	9885	10087	10259	10453	10653	10831	10988	10931	10633	11106	10780	10104	9113	8343
DOM	9/21/12	7619	7261	7034	6978	7090	7658	8824	9163	9481	9912	10278	10677	10951	11202	11617	11907	12086	11988	11469	11382	11103	10361	9542	8790
DOM	9/22/12	8075	7571	7356	7197	7063	7296	7632	8022	8830	9503	10148	10823	11272	11709	12060	12400	12409	12304	11922	11969	11625	10933	10110	9165
DOM	9/23/12	8393	7886	7450	7213	7122	7113	7278	7502	8146	8635	8963	9159	9386	9570	9637	9709	9821	9868	9751	10068	9928	9240	8461	7676
DOM	9/24/12	7124	6836	6709	6680	6871	7521	8600	9038	9153	9285	9557	9755	9778	9844	9900	9996	10112	10142	10008	10358	10209	9483	8556	7779
DOM	9/25/12	7240	6955	6797	6786	6964	7618	8729	9148	9176	9387	9628	9774	9925	10076	10219	10290	10427	10431	10290	10754	10543	9805	8854	8034
DOM	9/26/12	7537	7229	7012	6917	7173	7829	8929	9372	9581	9886	10216	10591	10985	11449	11819	12208	12468	12474	12106	12450	12079	11240	10065	8988
DOM	9/27/12	8222	7778	7455	7365	7502	8134	9368	9770	10015	10455	11002	11543	12078	12741	13223	13476	13528	13259	12878	12982	12454	11463	10419	9251
DOM	9/28/12	8535	8053	7742	7575	7716	8309	9451	9860	10153	10645	11232	11699	12043	12286	12335	12275	12207	11918	11592	11618	11231	10617	9812	8897
DOM	9/29/12	8202	7651	7395	7192	7112	7234	7561	7956	8468	8962	9241	9305	9323	9211	9152	9131	9132	9041	9187	9574	9393	9013	8471	7873
DOM	9/30/12	7297	6982	6733	6570	6615	6679	6900	7238	7822	8402	8669	8949	9140	9357	9435	9478	9588	9630	9718	10190	10004	9263	8532	7771

Backup - DOM Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DOM	10/1/12	7205	6869	6724	6969	6924	7548	8660	9178	9292	9398	9675	9739	9819	9845	9867	9857	9861	10079	10264	10651	10355	9694	8825	8055
DOM	10/2/12	7500	7163	7053	7074	7235	7878	9195	9781	10008	10256	10556	11142	11010	11170	11296	11390	11568	11713	11741	12193	11971	11204	10257	9293
DOM	10/3/12	8618	8215	7987	7936	8014	8693	10043	10680	10866	11625	11557	11972	12323	12662	13426	13181	13309	13214	13185	13462	13008	12164	11127	10026
DOM	10/4/12	9253	8694	8395	8281	8360	8913	10220	10780	10851	11117	11477	11841	12112	12146	12514	12579	12727	12526	12134	12356	11930	11047	9950	8910
DOM	10/5/12	8092	7608	7402	7280	7359	7866	9061	9499	9719	10172	10611	11002	11330	11586	11982	12150	12230	11907	11377	11373	10833	10121	9481	8611
DOM	10/6/12	7883	7446	7182	6999	6897	7101	7495	7804	8515	9174	9716	10163	10551	10613	10528	10558	10549	10327	10150	10306	10009	9387	8737	8009
DOM	10/7/12	7349	6936	6758	6581	6594	6703	6968	7000	7756	8416	8235	8854	8850	8778	8810	8799	8731	9171	9549	9761	9464	8954	8358	7788
DOM	10/8/12	7317	7042	6984	6959	7178	7303	8043	9319	9750	9696	9868	9876	9827	9689	9652	9693	9789	10085	10487	10622	10274	9633	8855	8107
DOM	10/9/12	7785	7506	7377	7399	7604	8330	9582	10076	10017	9985	9929	9839	9790	9682	9592	9522	9609	9783	10169	10527	10178	9550	8656	7889
DOM	10/10/12	7301	7098	6910	6903	7102	7794	9078	9539	9472	9437	9513	9500	9493	9562	9550	9540	9651	9649	9963	10340	10019	9369	8605	7792
DOM	10/11/12	7280	7016	6876	6960	7223	7978	9309	9814	9700	9680	9634	9527	9384	9387	9303	9315	9336	9350	9713	10239	10054	9476	8757	8137
DOM	10/12/12	7643	7406	7271	7347	7655	8348	9682	10217	10067	9848	9803	9679	9562	9434	9329	9165	9259	9270	9516	9819	9584	9227	8649	8162
DOM	10/13/12	7744	7494	7502	7432	7610	7959	8576	9116	9615	9612	9436	9199	8899	8676	8509	8489	8476	8565	8966	9425	9224	9030	8519	7992
DOM	10/14/12	7604	7332	7192	7156	7251	7437	7793	8168	8652	8889	8888	8813	8845	8861	8832	8927	9052	9239	9669	10103	9865	9260	8550	7771
DOM	10/15/12	7194	6927	6778	6827	6997	7676	8841	9554	9530	9704	9948	10057	10247	10044	9991	10084	9941	10087	10720	10729	10307	9645	8795	7982
DOM	10/16/12	7382	7040	6894	6865	7085	7813	9133	9681	9625	9600	9657	9560	9634	9530	9479	9506	9563	9618	9961	10351	10133	9451	8713	8083
DOM	10/17/12	7525	7283	7219	7237	7490	8320	9575	10163	10089	9862	9404	9553	9415	9411	9468	9455	9511	9628	9967	10361	10120	9543	8772	8024
DOM	10/18/12	7469	7151	7063	7113	7374	8140	9404	9984	9842	9791	9840	9796	9770	9827	9772	9750	9770	9987	10378	10622	10350	9706	8887	8139
DOM	10/19/12	7536	7226	7075	7013	7184	7836	8946	9733	9849	10017	10144	10217	10278	10352	10349	10339	10294	10228	10240	10273	9935	9414	8704	8039
DOM	10/20/12	7504	7056	6804	6746	6798	7008	7428	7940	8435	8851	8952	8943	8881	8777	8759	8689	8743	8771	9171	9426	9154	8758	8304	7773
DOM	10/21/12	7318	7049	6903	6881	6944	7193	7562	7992	8522	8731	8770	8701	8644	8611	8562	8516	8653	8802	9363	9773	9526	9052	8428	7754
DOM	10/22/12	7338	7178	7103	7219	7548	8300	9765	10344	10298	10033	9874	9784	9662	9644	9631	9632	9626	9723	10079	10332	10108	9429	8662	7942
DOM	10/23/12	7373	7061	6983	7001	7319	8028	9376	9894	9743	9614	9697	9664	9749	9891	10040	10090	10106	10093	10330	10549	10157	9525	8688	7916
DOM	10/24/12	7321	6988	6820	6822	6950	7664	8902	9554	9489	9582	9678	9909	10037	10299	10456	10691	10723	10701	10889	11036	10577	9944	9020	8181
DOM	10/25/12	7536	7191	7040	6935	7140	7744	8939	9549	9639	9706	9887	9959	10123	10226	10373	10485	10458	10391	10633	10834	10460	9893	9045	8218
DOM	10/26/12	7660	7290	7120	7031	7186	7833	9045	9764	9844	9950	10021	10071	10049	9954	9895	9786	9789	9824	10129	10142	9769	9429	8774	8074
DOM	10/27/12	7430	7056	6835	6720	6790	6979	7416	7920	8421	8888	9060	9185	9148	9030	8966	8878	8919	9082	9634	9678	9411	9006	8442	7842
DOM	10/28/12	7998	6975	6760	6651	6565	6692	6287	7163	7441	8197	8789	9048	9147	9158	9147	9176	9314	9584	9943	9965	9688	9371	9181	7991
DOM	10/29/12	7402	7940	7046	7023	7179	7572	8305	9005	9500	9976	10366	10618	10670	11332	10508	10418	10551	10787	10905	10632	10271	9605	9082	8496
DOM	10/30/12	8791	8144	8143	8199	8052	8549	9729	10390	10561	11578	11191	11334	11150	11161	11305	10749	10928	11187	11668	11738	11361	10749	9934	9269
DOM	10/31/12	8857	8701	8631	8664	8940	9778	11004	11625	11339	10986	10718	10444	10195	9884	9815	9835	10032	10317	10642	10521	10567	10250	9677	8994
DOM	11/1/12	8577	8375	8307	8405	8627	9459	10630	11231	11020	10773	10259	10357	10143	9953	9865	9796	9933	10350	10975	11208	10917	10436	9737	9121
DOM	11/2/12	8700	8466	8478	8607	9028	9907	11139	11791	11478	11088	10781	10477	10240	10072	9947	9849	9869	10118	10872	10956	10740	10501	10048	9501
DOM	11/3/12	9093	8900	8784	8872	9024	9407	9945	10510	10880	10888	10634	10299	10006	9691	9424	9286	9344	9674	10479	10683	10639	10382	9967	9401
DOM	11/4/12	8967	17092	8396	8407	8520	8833	9227	9705	10192	10270	10052	9774	9572	9381	9234	9246	9687	10703	10927	10940	10733	10259	9704	8452

Backup - DOM Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DOM	11/5/12	8834	8707	8745	8925	9427	10435	11644	11975	11681	11292	10921	10679	10370	10204	10064	10026	10468	11581	11929	11976	11829	11421	10768	10247
DOM	11/6/12	9917	9804	9891	10137	10633	11615	12533	12673	12381	11896	11439	11126	10897	10733	10776	10893	11392	12257	12349	12162	11799	11119	10413	9711
DOM	11/7/12	9310	9153	9052	9142	9509	10386	11604	11955	11792	11716	11523	11378	11090	11119	11131	11185	11604	12471	12528	12325	12007	11382	10599	9858
DOM	11/8/12	9443	9279	9235	9350	9750	10691	11910	12218	11891	11574	11188	10739	10401	10203	10014	9992	10348	11422	11810	11828	11630	11167	10418	9764
DOM	11/9/12	9413	9293	9318	9471	9931	10863	12097	12344	11768	11123	10728	10378	10076	9853	9684	9589	10040	10893	10892	10864	10706	10433	9995	9462
DOM	11/10/12	9102	8994	8984	9094	9343	9803	10341	10750	10715	10293	9877	9447	9132	8885	8675	8617	8840	9942	9891	9807	9887	9320	9405	8968
DOM	11/11/12	8117	7956	7936	8003	8174	8533	8961	9423	9619	9471	9200	8957	8838	8727	8619	8583	8794	9734	9937	9797	9549	9048	8491	7867
DOM	11/12/12	7439	7262	7200	7284	7597	8270	9273	9722	9740	9695	9738	9695	9660	9616	9558	9535	9752	10630	10669	10453	10099	9465	8648	7917
DOM	11/13/12	7384	7127	7024	7020	7306	8064	9319	10004	10114	10208	10315	10330	10284	10245	10223	10318	11043	11806	12101	12052	11812	11322	10587	9933
DOM	11/14/12	9533	9406	9405	9569	10065	11066	12459	12711	12267	11709	11280	10948	10663	10493	10411	10594	11111	12374	12558	12504	12346	11852	11225	10510
DOM	11/15/12	10124	9923	9836	9786	10070	10818	11940	12185	11906	11667	11412	11214	10897	10728	10567	10681	11161	12006	11956	11941	11716	11152	10362	9685
DOM	11/16/12	9190	9006	8937	9010	9407	10237	11542	11984	11601	11214	10866	10567	10311	10096	10030	10071	10426	11463	11588	11540	11417	11178	10718	10240
DOM	11/17/12	9929	9778	9761	9764	9984	10383	10845	11288	11292	10999	10625	10217	9913	9522	9392	9454	9939	10839	10945	10900	10760	10491	9973	9451
DOM	11/18/12	9038	8792	8644	8652	8789	9049	9485	9906	10156	10245	9974	9786	9602	9482	9420	9506	10005	10925	11069	10887	10695	10219	9532	8892
DOM	11/19/12	8420	8190	8155	8246	8536	9422	10694	11143	11024	10914	10868	10726	10543	10381	10350	10294	10680	11645	11814	11732	11457	10837	10153	9392
DOM	11/20/12	8914	8679	8656	8692	9081	9863	11081	11476	11228	10917	10727	10362	10149	10074	10034	10107	10533	11478	11545	11449	11194	10782	10055	9426
DOM	11/21/12	8981	8922	8985	9108	9546	10449	11649	12088	11842	11227	10900	10556	10261	9987	9925	9928	10271	11245	11462	11346	11258	10981	10502	10010
DOM	11/22/12	9608	9440	9390	9459	9656	10133	10612	11007	11199	11001	10704	10393	10030	9559	9137	8868	8794	9372	9435	9437	9610	9659	9520	9231
DOM	11/23/12	9096	9089	9201	9418	9801	10484	11127	11400	11167	10567	10115	9669	9349	9071	8927	8924	9283	10099	10127	9942	9795	9493	9068	8672
DOM	11/24/12	8232	8147	8130	8225	8566	8971	9547	10116	10684	10907	10843	10630	10331	9981	9869	9978	10585	11706	11981	12026	11991	11757	11285	10885
DOM	11/25/12	10540	10415	10471	10543	10758	11119	11575	12047	12124	11936	11537	11130	10826	10468	10182	10082	10652	11951	12379	12439	12266	11753	11055	10322
DOM	11/26/12	9991	9888	9818	9912	10286	11275	12503	12863	12426	11619	11113	10637	10334	10117	9965	9947	10455	11573	11867	11889	11661	11151	10387	9687
DOM	11/27/12	9186	8941	8879	8922	9274	10093	11357	11825	11600	11474	11538	11368	11345	11305	11272	11400	11951	12787	12741	12675	12443	11826	11114	10311
DOM	11/28/12	9919	9722	9718	9873	10238	11183	12549	12923	12557	12166	11569	11113	10771	10543	10415	10484	11220	12550	12860	12915	12851	12543	11864	11321
DOM	11/29/12	11034	10971	11104	11347	11903	12809	14124	14595	13855	12691	11885	11315	10932	10660	10418	10453	11017	12392	12742	12837	12796	12333	11611	10980
DOM	11/30/12	10617	10522	10554	10845	11359	12337	13656	13993	13362	12369	11596	11029	10643	10416	10155	10193	10668	11693	11829	11715	11616	11393	10892	10409

Backup - DUK Hourly Load

DUKPe	**Max**	19,473
DUKAv	**Avg Jul**	17,273
DUKW	**Winter**	12,862
DUKSp	**Spring**	12,064
DUKSu	**Summer**	16,044
DUKFa	**Fall**	12,293

Dec 2011-Nov 2012 Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DUK	12/1/11	11,006	10,913	10,970	11,234	11,676	12,682	14,238	14,585	14,056	13,243	12,473	11,761	11,226	10,917	10,666	10,568	10,793	11,787	12,526	12,729	12,810	12,559	12,037	11,429
DUK	12/2/11	11,087	11,013	11,089	11,308	11,729	12,679	14,123	14,615	14,085	13,134	12,200	11,500	10,934	10,602	10,340	10,219	10,311	11,133	11,640	11,626	11,595	11,486	11,154	10,598
DUK	12/3/11	10,200	10,038	10,019	10,088	10,289	10,636	11,138	11,567	11,811	11,548	11,102	10,562	10,095	9,713	9,506	9,456	9,754	10,720	11,165	11,253	11,254	11,065	10,714	10,281
DUK	12/4/11	9,932	9,723	9,744	9,846	10,039	10,376	10,852	11,297	11,643	11,274	10,601	10,071	9,809	9,611	9,415	9,308	9,570	10,613	11,072	11,053	10,963	10,546	9,910	9,249
DUK	12/5/11	8,829	8,536	8,471	8,506	8,832	9,644	11,092	11,713	11,543	11,451	11,356	11,198	11,029	10,896	10,804	10,803	10,973	11,794	12,024	11,906	11,627	10,979	10,098	9,213
DUK	12/6/11	8,597	8,271	8,116	8,054	8,258	8,877	10,146	10,792	10,711	10,770	10,819	10,844	10,751	10,728	10,680	10,642	10,811	11,499	11,678	11,516	11,280	10,763	9,880	9,018
DUK	12/7/11	8,404	8,051	7,873	7,828	8,018	8,644	9,912	10,649	10,619	10,696	10,846	10,896	10,850	10,912	10,887	10,907	11,076	11,799	12,024	12,191	12,160	11,790	11,133	10,451
DUK	12/8/11	10,109	10,008	10,048	10,234	10,700	11,629	13,212	13,805	13,452	12,854	12,333	11,883	11,395	11,133	10,865	10,778	11,050	12,258	12,914	13,102	13,169	12,928	12,308	11,620
DUK	12/9/11	11,174	11,005	10,967	11,109	11,481	12,343	13,725	14,224	13,908	13,315	12,531	11,802	11,228	10,902	10,612	10,526	10,860	11,937	12,301	12,218	12,135	11,883	11,387	10,752
DUK	12/10/11	10,255	9,967	9,883	9,923	10,173	10,609	11,268	11,821	12,233	12,036	11,521	11,043	10,565	10,167	9,893	9,841	10,199	11,338	11,899	11,965	12,051	11,994	11,700	11,246
DUK	12/11/11	10,938	10,824	10,868	10,988	11,200	11,540	12,066	12,596	12,930	12,541	11,803	11,128	10,744	10,414	10,162	10,130	10,615	12,003	12,690	12,843	12,884	12,485	11,795	11,159
DUK	12/12/11	10,767	10,566	10,535	10,642	10,983	11,782	13,257	13,884	13,712	13,647	13,520	13,196	12,752	12,330	11,930	11,727	11,894	12,979	13,618	13,625	13,540	13,086	12,300	11,474
DUK	12/13/11	10,949	10,759	10,684	10,669	10,939	11,775	13,272	13,766	13,315	12,608	11,983	11,454	11,038	10,825	10,623	10,510	10,570	11,430	12,017	12,020	11,936	11,543	10,815	9,970
DUK	12/14/11	9,443	9,151	9,048	9,084	9,306	10,045	11,425	12,011	11,748	11,522	11,283	11,025	10,749	10,601	10,476	10,383	10,484	11,400	11,909	11,806	11,679	11,272	10,496	9,672
DUK	12/15/11	9,135	8,916	8,866	8,941	9,268	10,084	11,523	12,089	11,797	11,462	11,240	10,957	10,676	10,614	10,454	10,397	10,455	11,157	11,627	11,540	11,373	10,940	10,135	9,229
DUK	12/16/11	8,587	8,259	8,084	8,053	8,267	8,926	10,158	10,713	10,604	10,569	10,572	10,519	10,394	10,388	10,319	10,354	10,624	11,256	11,375	11,189	10,964	10,647	10,129	9,407
DUK	12/17/11	8,812	8,511	8,409	8,424	8,554	8,916	9,461	10,013	10,567	10,849	10,778	10,554	10,263	9,967	9,677	9,600	9,859	10,894	11,516	11,559	11,651	11,621	11,362	10,901
DUK	12/18/11	10,493	10,321	10,267	10,397	10,637	11,032	11,613	12,211	12,663	12,132	11,221	10,475	10,114	9,812	9,576	9,496	9,833	11,022	11,810	12,078	12,241	12,148	11,684	11,167
DUK	12/19/11	10,783	10,661	10,740	10,984	11,461	12,409	13,844	14,541	14,311	13,528	12,716	12,095	11,543	11,247	10,925	10,795	10,968	12,072	12,676	12,646	12,547	12,108	11,475	10,676
DUK	12/20/11	10,101	9,813	9,695	9,728	10,021	10,704	11,882	12,558	12,431	12,201	11,925	11,619	11,282	11,230	11,122	11,095	11,199	11,942	12,102	11,912	11,620	11,122	10,315	9,449
DUK	12/21/11	8,767	8,470	8,320	8,284	8,457	9,006	9,975	10,699	10,842	11,029	11,172	11,156	11,064	11,042	10,910	10,824	10,919	11,463	11,548	11,299	10,998	10,620	9,907	9,048
DUK	12/22/11	8,387	7,980	7,782	7,729	7,849	8,329	9,160	9,871	10,167	10,373	10,520	10,471	10,362	10,315	10,281	10,224	10,330	10,961	11,108	10,879	10,623	10,195	9,507	8,681
DUK	12/23/11	7,958	7,574	7,339	7,230	7,293	7,684	8,343	8,875	9,242	9,516	9,561	9,456	9,200	9,054	8,944	8,840	8,934	9,725	10,191	10,046	10,035	9,911	9,567	9,047
DUK	12/24/11	8,583	8,312	8,256	8,327	8,505	8,866	9,382	9,997	10,507	10,499	10,197	9,826	9,471	9,124	8,955	8,960	9,133	9,886	10,171	10,123	10,137	10,120	9,944	9,597
DUK	12/25/11	9,249	9,032	8,991	9,050	9,141	9,372	9,795	10,248	10,624	10,520	10,058	9,794	9,705	9,426	9,103	8,881	8,819	9,418	9,812	9,933	9,994	9,902	9,616	9,221
DUK	12/26/11	8,896	8,747	8,739	8,877	9,158	9,585	10,117	10,510	10,724	10,603	10,329	9,966	9,558	9,165	8,855	8,784	9,052	10,199	10,864	10,952	10,900	10,633	10,107	9,526

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Backup - DUK Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DUK	12/27/11	9,078	8,786	8,625	8,610	8,854	9,368	10,183	10,970	11,305	11,584	11,714	11,542	11,132	10,716	10,434	10,314	10,438	11,272	11,728	11,651	11,488	11,094	10,564	9,934
DUK	12/28/11	9,527	9,372	9,307	9,387	9,651	10,243	11,102	11,786	11,908	11,653	11,381	11,018	10,609	10,297	10,060	9,935	10,150	11,217	11,961	11,982	11,921	11,643	11,202	10,668
DUK	12/29/11	10,401	10,356	10,477	10,744	11,227	11,967	13,006	13,712	13,746	13,115	12,494	11,825	11,159	10,675	10,302	10,091	10,227	11,204	11,930	11,974	11,980	11,733	11,228	10,578
DUK	12/30/11	10,108	9,848	9,734	9,763	10,031	10,600	11,472	12,109	12,222	11,741	11,108	10,598	10,183	9,908	9,695	9,640	9,826	10,536	10,788	10,544	10,315	9,902	9,361	8,737
DUK	12/31/11	8,268	7,946	7,784	7,722	7,820	8,024	8,397	8,737	9,120	9,292	9,278	9,103	8,929	8,666	8,490	8,438	8,617	9,436	10,049	9,924	9,728	9,546	9,241	9,007
DUK	1/1/12	8,819	8,770	8,763	8,842	9,015	9,337	9,752	10,134	10,419	10,186	9,641	9,286	9,147	8,806	8,537	8,469	8,652	9,286	9,703	9,642	9,517	9,270	8,938	8,546
DUK	1/2/12	8,313	8,219	8,309	8,506	8,888	9,583	10,564	11,288	11,527	11,568	11,468	11,236	10,956	10,743	10,570	10,591	11,113	12,437	13,358	13,608	13,671	13,456	12,958	12,495
DUK	1/3/12	12,310	12,291	12,432	12,654	13,106	14,036	15,491	16,215	15,936	15,510	15,189	14,748	14,275	13,969	13,667	13,638	14,020	15,182	16,052	16,190	16,043	15,587	14,848	14,224
DUK	1/4/12	13,960	13,902	14,012	14,175	14,602	15,526	16,980	17,506	16,879	15,921	15,005	14,127	13,412	12,918	12,441	12,297	12,572	13,575	14,415	14,469	14,404	13,897	13,170	12,489
DUK	1/5/12	12,005	11,770	11,636	11,689	11,983	12,856	14,367	15,025	14,624	13,795	12,928	12,277	11,821	11,452	11,135	10,930	10,984	11,756	12,620	12,751	12,739	12,379	11,754	11,146
DUK	1/6/12	10,798	10,669	10,702	10,841	11,263	12,132	13,626	14,290	13,896	13,083	12,235	11,564	10,996	10,663	10,376	10,161	10,151	10,712	11,385	11,313	11,201	10,966	10,545	10,005
DUK	1/7/12	9,623	9,414	9,350	9,412	9,589	9,916	10,400	10,817	11,105	11,035	10,693	10,274	9,875	9,540	9,276	9,215	9,345	9,989	10,403	10,230	10,019	9,702	9,189	8,648
DUK	1/8/12	8,164	7,893	7,789	7,786	7,893	8,158	8,619	9,139	9,739	10,000	9,856	9,679	9,702	9,608	9,482	9,489	9,744	10,481	10,849	10,733	10,551	10,144	9,533	8,970
DUK	1/9/12	8,564	8,359	8,305	8,399	8,696	9,542	11,017	11,826	11,737	11,791	11,919	11,939	11,890	11,842	11,718	11,743	11,918	12,527	12,859	12,704	12,369	11,727	10,870	10,074
DUK	1/10/12	9,535	9,209	9,065	9,060	9,319	10,054	11,448	12,091	11,896	11,724	11,541	11,297	11,012	10,953	10,773	10,735	10,886	11,619	12,152	12,122	11,891	11,345	10,526	9,754
DUK	1/11/12	9,234	8,944	8,791	8,785	8,960	9,704	11,035	11,781	11,643	11,624	11,774	11,818	11,767	11,708	11,557	11,550	11,603	12,004	12,326	12,087	11,910	11,421	10,643	9,971
DUK	1/12/12	9,520	9,305	9,227	9,271	9,569	10,386	11,843	12,479	12,205	11,906	11,632	11,403	11,139	10,958	10,784	10,697	10,886	11,563	12,112	12,076	11,984	11,595	11,060	10,594
DUK	1/13/12	10,392	10,451	10,676	10,982	11,545	12,568	14,118	14,924	14,690	14,294	13,893	13,402	12,914	12,522	12,160	11,998	12,272	13,136	13,895	13,861	13,741	13,427	13,025	12,471
DUK	1/14/12	12,148	12,055	12,075	12,176	12,479	12,947	13,584	14,188	14,478	13,972	13,274	12,552	11,913	11,392	11,028	10,893	11,059	11,848	12,669	12,626	12,544	12,259	11,740	11,232
DUK	1/15/12	10,828	10,657	10,618	10,677	10,882	11,213	11,693	12,260	12,668	12,350	11,686	11,145	10,837	10,534	10,165	9,988	10,195	11,048	12,057	12,255	12,397	12,244	11,982	11,697
DUK	1/16/12	11,502	11,524	11,642	11,846	12,277	13,026	14,021	14,688	14,825	14,615	14,129	13,574	13,046	12,712	12,533	12,430	12,542	13,106	13,559	13,401	13,099	12,488	11,774	11,066
DUK	1/17/12	10,537	10,380	10,295	10,382	10,607	11,424	12,839	13,327	12,929	12,516	12,386	12,188	11,844	11,552	11,281	11,086	11,150	11,725	12,076	11,939	11,585	11,009	10,224	9,439
DUK	1/18/12	8,881	8,663	8,523	8,543	8,925	9,871	11,455	12,363	12,264	12,023	11,823	11,591	11,297	11,123	10,920	10,848	11,033	11,872	12,957	13,085	13,067	12,698	12,082	11,420
DUK	1/19/12	11,085	10,995	11,078	11,281	11,762	12,811	14,420	15,241	14,862	14,113	13,452	12,808	12,265	11,956	11,799	11,811	12,058	12,683	13,410	13,410	13,277	12,877	12,277	11,550
DUK	1/20/12	11,165	11,058	11,031	11,109	11,377	12,109	13,471	14,123	13,748	13,164	12,672	12,179	11,860	11,717	11,625	11,609	11,794	12,264	12,475	12,247	11,947	11,574	10,962	10,254
DUK	1/21/12	9,700	9,383	9,207	9,139	9,195	9,418	9,807	10,302	10,699	11,102	11,388	11,403	11,271	11,033	10,803	10,610	10,609	10,953	11,281	11,079	10,818	10,490	10,056	9,544
DUK	1/22/12	9,161	8,998	8,951	9,037	9,275	9,642	10,102	10,747	11,499	11,850	11,856	11,766	11,832	11,813	11,714	11,668	11,824	12,415	12,904	12,803	12,613	12,169	11,661	11,014
DUK	1/23/12	10,586	10,346	10,322	10,425	10,765	11,535	12,842	13,676	13,613	13,612	13,660	13,641	13,511	13,324	13,105	12,925	12,923	13,311	13,658	13,413	13,049	12,352	11,512	10,730
DUK	1/24/12	10,099	9,762	9,622	9,610	9,824	10,605	11,882	12,595	12,359	12,197	12,023	11,654	11,186	10,908	10,630	10,463	10,444	10,852	11,842	11,952	11,923	11,560	10,986	10,448
DUK	1/25/12	10,090	9,975	10,079	10,268	10,700	11,696	13,233	13,974	13,699	12,701	12,050	11,524	11,092	10,828	10,606	10,476	10,494	10,911	11,860	12,030	11,844	11,411	10,704	9,952
DUK	1/26/12	9,447	9,154	9,037	9,045	9,304	10,039	11,392	11,991	11,709	11,578	11,477	11,249	11,026	10,885	10,705	10,612	10,610	11,062	11,640	11,576	11,317	10,776	9,957	9,121
DUK	1/27/12	8,496	8,199	8,001	7,956	8,111	8,734	9,932	10,633	10,561	10,541	10,594	10,488	10,340	10,198	10,084	9,898	9,866	10,135	10,908	10,885	10,797	10,602	10,237	9,844
DUK	1/28/12	9,524	9,470	9,548	9,728	10,082	10,653	11,326	11,925	12,233	11,775	11,196	10,618	10,134	9,732	9,461	9,293	9,391	9,835	10,697	10,751	10,704	10,522	10,193	9,846
DUK	1/29/12	9,569	9,526	9,632	9,832	10,192	10,674	11,356	12,064	12,521	12,002	11,141	10,491	10,139	9,838	9,586	9,453	9,609	10,338	11,481	11,803	11,878	11,655	11,178	10,705
DUK	1/30/12	10,401	10,308	10,395	10,579	11,051	12,105	13,747	14,484	14,024	13,177	12,399	11,797	11,321	11,017	10,731	10,521	10,498	10,919	12,063	12,265	12,186	11,821	11,205	10,557

Backup - DUK Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DUK	1/31/12	10,255	10,170	10,218	10,359	10,789	11,730	13,294	13,928	13,381	12,569	11,932	11,430	10,978	10,747	10,491	10,311	10,306	10,649	11,669	11,748	11,623	11,167	10,502	9,759
DUK	2/1/12	9,345	9,136	9,089	9,162	9,456	10,262	11,667	12,188	11,883	11,635	11,388	11,050	10,737	10,612	10,501	10,511	10,689	11,195	11,689	11,559	11,328	10,785	10,032	9,192
DUK	2/2/12	8,691	8,454	8,362	8,379	8,633	9,366	10,744	11,386	11,150	10,920	10,785	10,648	10,492	10,451	10,292	10,182	10,120	10,292	11,165	11,255	11,133	10,700	10,031	9,399
DUK	2/3/12	9,063	8,949	9,011	9,196	9,622	10,580	12,190	12,928	12,537	11,904	11,435	11,031	10,579	10,375	10,095	9,914	9,908	10,226	11,104	11,170	11,141	10,983	10,606	10,042
DUK	2/4/12	9,569	9,284	9,120	9,054	9,118	9,355	9,767	10,200	10,679	11,050	11,178	11,152	10,986	10,770	10,526	10,366	10,365	10,596	11,104	10,988	10,731	10,344	9,787	9,175
DUK	2/5/12	8,683	8,344	8,209	8,094	8,125	8,333	8,665	9,208	9,768	10,089	10,007	9,959	10,017	10,040	10,023	10,021	10,218	10,651	11,067	10,873	10,808	10,578	10,428	9,878
DUK	2/6/12	9,497	9,369	9,393	9,506	9,882	10,735	12,241	12,987	12,872	12,749	12,504	12,242	11,950	11,796	11,569	11,447	11,510	11,855	12,815	13,006	12,932	12,455	11,813	11,190
DUK	2/7/12	10,875	10,836	10,923	11,077	11,499	12,498	14,035	14,562	13,986	13,108	12,362	11,752	11,212	10,946	10,679	10,543	10,511	10,843	11,963	12,278	12,330	12,013	11,467	10,954
DUK	2/8/12	10,653	10,606	10,670	10,822	11,155	12,098	13,480	13,909	13,504	13,137	12,954	12,643	12,233	11,862	11,489	11,312	11,298	11,697	12,749	12,916	12,830	12,392	11,751	11,163
DUK	2/9/12	10,822	10,709	10,806	10,976	11,416	12,440	13,930	14,598	14,068	13,241	12,622	12,063	11,620	11,341	11,075	10,928	10,975	11,451	12,549	12,937	13,007	12,704	12,082	11,549
DUK	2/10/12	11,249	11,196	11,284	11,510	11,895	12,795	14,278	14,810	14,337	13,823	13,381	12,923	12,479	12,182	11,923	11,739	11,715	11,913	12,443	12,339	12,109	11,772	11,169	10,497
DUK	2/11/12	9,983	9,675	9,594	9,631	9,868	10,313	10,920	11,399	11,814	11,909	11,767	11,575	11,457	11,232	11,151	11,230	11,723	12,690	14,201	14,771	14,926	14,783	14,450	14,077
DUK	2/12/12	13,760	13,652	13,637	13,714	13,908	14,243	14,664	15,095	15,157	14,673	13,900	13,089	12,473	11,939	11,475	11,181	11,239	11,815	13,048	13,568	13,616	13,329	12,879	12,392
DUK	2/13/12	12,190	12,161	12,316	12,605	13,196	14,236	15,892	16,413	15,793	14,599	13,701	12,930	12,274	11,836	11,451	11,315	11,442	11,824	12,859	13,164	13,118	12,708	12,024	11,270
DUK	2/14/12	10,797	10,521	10,376	10,405	10,675	11,471	12,895	13,401	13,156	13,007	12,723	12,367	11,976	11,797	11,644	11,560	11,637	11,875	12,555	12,600	12,396	11,961	11,235	10,572
DUK	2/15/12	10,230	10,179	10,260	10,540	10,989	12,038	13,684	14,232	13,656	12,679	11,967	11,452	11,017	10,775	10,575	10,388	10,327	10,536	11,424	11,623	11,510	11,115	10,475	9,736
DUK	2/16/12	9,337	9,115	9,032	9,072	9,374	10,099	11,478	12,083	11,890	11,775	11,643	11,560	11,371	11,352	11,210	11,120	11,115	11,274	11,927	12,025	11,846	11,336	10,610	9,860
DUK	2/17/12	9,312	9,022	8,907	9,002	9,319	10,132	11,486	12,069	11,858	11,480	11,142	10,833	10,554	10,369	10,134	9,899	9,789	9,856	10,613	10,785	10,691	10,478	10,027	9,485
DUK	2/18/12	9,025	8,794	8,728	8,784	8,921	9,341	9,942	10,456	10,826	10,642	10,313	9,929	9,562	9,218	9,025	8,973	9,111	9,422	10,141	10,197	10,015	9,747	9,235	8,703
DUK	2/19/12	8,255	8,020	7,911	7,897	7,969	8,214	8,611	9,153	9,878	10,408	10,606	10,788	11,103	11,337	11,484	11,630	11,993	12,505	13,140	13,229	13,031	12,554	11,992	11,482
DUK	2/20/12	11,065	10,946	10,955	11,142	11,598	12,392	13,534	14,208	14,134	13,606	13,005	12,452	11,977	11,546	11,169	10,915	10,860	11,167	12,318	12,875	12,917	12,669	12,172	11,633
DUK	2/21/12	11,379	11,393	11,475	11,687	12,193	13,184	14,634	15,067	14,605	14,048	13,377	12,697	12,094	11,630	11,238	10,992	10,968	11,191	12,095	12,404	12,263	11,837	11,133	10,424
DUK	2/22/12	10,013	9,837	9,817	9,923	10,282	11,205	12,723	13,150	12,550	11,901	11,491	11,076	10,778	10,598	10,442	10,392	10,426	10,551	11,252	11,463	11,243	10,781	10,025	9,197
DUK	2/23/12	8,715	8,476	8,434	8,475	8,781	9,577	10,967	11,467	11,247	11,134	10,976	10,721	10,473	10,447	10,355	10,277	10,205	10,220	10,905	11,172	10,973	10,437	9,670	8,873
DUK	2/24/12	8,327	7,979	7,823	7,791	7,936	8,518	9,698	10,141	10,223	10,376	10,538	10,566	10,523	10,481	10,366	10,200	10,054	10,014	10,440	10,519	10,363	10,123	9,747	9,239
DUK	2/25/12	8,891	8,773	8,831	8,957	9,231	9,669	10,344	10,895	11,348	11,369	11,197	10,882	10,568	10,235	9,927	9,738	9,805	10,099	11,066	11,511	11,496	11,391	11,066	10,678
DUK	2/26/12	10,394	10,336	10,417	10,604	10,879	11,305	11,863	12,390	12,501	11,828	11,080	10,419	10,057	9,688	9,336	9,117	9,151	9,510	10,486	11,178	11,305	11,134	10,741	10,357
DUK	2/27/12	10,105	10,040	10,034	10,075	10,338	11,076	12,424	12,943	12,800	12,695	12,551	12,230	11,907	11,660	11,279	10,961	10,804	10,990	11,767	12,027	11,835	11,262	10,588	9,878
DUK	2/28/12	9,400	9,231	9,193	9,312	9,691	10,575	12,143	12,595	12,110	11,545	11,173	10,842	10,587	10,486	10,337	10,192	10,100	10,158	10,942	11,304	11,095	10,567	9,828	9,065
DUK	2/29/12	8,525	8,295	8,167	8,150	8,350	9,097	10,444	11,079	11,058	11,080	11,126	11,066	10,931	10,857	10,687	10,553	10,544	10,661	11,217	11,357	11,053	10,531	9,702	8,929
DUK	3/1/12	8,352	8,002	7,852	7,809	7,968	8,663	9,905	10,406	10,343	10,359	10,486	10,491	10,480	10,525	10,543	10,515	10,438	10,337	10,763	11,139	10,881	10,320	9,537	8,741
DUK	3/2/12	8,203	7,986	7,919	7,965	8,221	8,959	10,293	10,900	10,882	10,933	10,883	10,753	10,680	10,657	10,541	10,403	10,350	10,449	10,922	10,960	10,691	10,281	9,708	8,976
DUK	3/3/12	8,488	8,164	7,971	7,886	7,905	8,099	8,460	8,771	9,324	9,747	9,980	9,983	9,791	9,465	9,162	9,021	9,119	9,371	9,970	10,121	9,958	9,706	9,287	8,779
DUK	3/4/12	8,357	8,089	8,011	7,997	8,109	8,446	8,913	9,442	9,992	10,034	9,778	9,577	9,541	9,497	9,437	9,478	9,626	10,071	11,041	11,773	11,825	11,592	11,130	10,731
DUK	3/5/12	10,481	10,406	10,425	10,499	10,702	11,555	12,854	13,193	12,809	12,382	12,130	11,884	11,626	11,427	11,156	10,906	10,880	11,167	12,199	12,924	12,904	12,529	11,921	11,360

Backup - DUK Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DUK	3/6/12	11,117	11,106	11,222	11,509	12,006	13,053	14,555	14,801	13,981	13,051	12,362	11,802	11,347	11,057	10,758	10,540	10,455	10,591	11,474	12,179	12,201	11,862	11,264	10,663
DUK	3/7/12	10,302	10,159	10,158	10,278	10,645	11,499	12,861	13,127	12,589	12,048	11,559	11,165	10,832	10,665	10,489	10,372	10,313	10,361	10,957	11,365	11,176	10,671	9,932	9,098
DUK	3/8/12	8,656	8,406	8,313	8,298	8,552	9,326	10,612	11,033	10,921	10,795	10,759	10,641	10,516	10,444	10,353	10,242	10,158	10,132	10,680	11,053	10,854	10,304	9,504	8,744
DUK	3/9/12	8,198	7,908	7,704	7,676	7,830	8,466	9,657	10,191	10,297	10,394	10,456	10,393	10,234	10,183	10,022	9,857	9,744	9,769	10,310	10,751	10,735	10,531	10,098	9,581
DUK	3/10/12	9,166	8,994	8,990	9,088	9,323	9,774	10,278	10,676	10,816	10,681	10,367	10,036	9,645	9,283	9,022	8,876	8,889	9,021	9,642	10,192	10,181	10,022	9,721	9,352
DUK	3/11/12	9,114	9,068	9,157	9,352	9,683	10,229	10,814	11,270	10,902	10,231	9,656	9,424	9,162	8,906	8,677	8,651	8,725	8,831	9,484	10,133	9,903	9,385	8,819	8,371
DUK	3/12/12	8,144	8,110	8,190	8,468	9,239	10,631	11,522	11,349	11,146	10,966	10,783	10,601	10,500	10,334	10,264	10,182	10,118	10,245	10,782	11,072	10,558	9,738	8,946	8,307
DUK	3/13/12	7,948	7,797	7,745	7,904	8,550	9,831	10,602	10,457	10,455	10,513	10,520	10,480	10,548	10,584	10,580	10,568	10,501	10,475	10,788	11,346	10,861	9,962	9,073	8,331
DUK	3/14/12	7,929	7,731	7,663	7,783	8,355	9,618	10,373	10,241	10,278	10,505	10,694	10,852	11,088	11,219	11,317	11,399	11,380	11,319	11,419	11,749	11,100	10,198	9,152	8,452
DUK	3/15/12	7,997	7,733	7,665	7,762	8,358	9,612	10,404	10,248	10,407	10,654	10,840	11,057	11,357	11,495	11,524	11,382	11,157	11,085	11,432	11,449	10,984	10,056	9,079	8,468
DUK	3/16/12	7,965	7,736	7,663	7,814	8,246	9,474	10,202	10,196	10,339	10,530	10,602	10,680	10,879	11,083	11,244	11,315	11,203	10,924	10,925	11,020	10,548	9,852	9,013	8,263
DUK	3/17/12	7,807	7,535	7,346	7,312	7,461	7,819	8,171	8,601	9,157	9,519	9,739	9,877	9,992	10,153	10,322	10,399	10,354	10,200	10,229	10,445	10,043	9,356	8,606	7,953
DUK	3/18/12	7,490	7,224	7,058	7,011	7,093	7,338	7,722	8,226	8,682	8,827	8,890	9,063	9,154	9,165	9,302	9,548	9,724	9,772	9,977	10,517	10,078	9,322	8,542	7,890
DUK	3/19/12	7,522	7,367	7,308	7,469	8,135	9,423	10,233	10,231	10,387	10,590	10,841	11,043	11,388	11,649	11,825	12,007	12,029	11,919	11,900	12,177	11,468	10,428	9,335	8,571
DUK	3/20/12	8,131	7,855	7,733	7,824	8,386	9,638	10,336	10,301	10,497	10,824	11,178	11,552	12,023	12,351	12,609	12,686	12,466	12,196	12,180	12,270	11,597	10,488	9,452	8,640
DUK	3/21/12	8,242	7,944	7,830	7,903	8,459	9,738	10,373	10,327	10,501	10,817	11,096	11,325	11,680	11,884	12,072	12,149	12,088	11,900	11,829	12,140	11,491	10,430	9,371	8,625
DUK	3/22/12	8,175	7,909	7,793	7,878	8,440	9,707	10,444	10,408	10,652	10,914	11,118	11,285	11,564	11,724	11,865	12,039	11,982	11,809	11,786	12,140	11,565	10,532	9,464	8,679
DUK	3/23/12	8,190	7,894	7,779	7,833	8,353	9,512	10,117	10,189	10,506	10,878	11,167	11,414	11,716	11,928	12,021	11,910	11,623	11,271	11,196	11,232	10,712	10,011	9,175	8,460
DUK	3/24/12	7,997	7,714	7,572	7,543	7,692	7,988	8,390	8,836	9,375	9,765	9,976	10,063	10,175	10,278	10,439	10,425	10,301	10,046	9,875	10,057	9,608	8,970	8,279	7,644
DUK	3/25/12	7,241	7,046	6,911	6,858	6,969	7,237	7,596	8,196	8,657	8,754	8,815	8,907	8,959	8,898	8,848	8,941	9,067	9,111	9,432	9,910	9,561	8,892	8,225	7,746
DUK	3/26/12	7,432	7,291	7,221	7,391	8,009	9,327	9,970	10,026	10,171	10,349	10,472	10,591	10,804	10,868	11,088	11,232	11,164	11,018	10,912	11,357	10,783	9,771	8,805	8,128
DUK	3/27/12	7,729	7,527	7,450	7,617	8,290	9,661	10,290	10,240	10,205	10,249	10,193	10,132	10,161	10,105	10,116	10,152	10,112	10,081	10,246	10,878	10,433	9,583	8,694	8,103
DUK	3/28/12	7,799	7,670	7,643	7,881	8,560	9,991	10,558	10,432	10,415	10,414	10,387	10,326	10,422	10,496	10,603	10,660	10,662	10,633	10,683	11,255	10,820	9,913	8,934	8,267
DUK	3/29/12	7,841	7,625	7,518	7,610	8,189	9,433	10,006	10,049	10,292	10,643	10,967	11,258	11,616	11,857	12,068	12,135	11,979	11,699	11,498	11,785	11,162	10,132	9,086	8,269
DUK	3/30/12	7,811	7,540	7,412	7,537	8,039	9,150	9,680	9,788	9,930	10,156	10,275	10,393	10,647	10,887	11,059	11,112	10,998	10,726	10,644	10,770	10,313	9,619	8,813	8,091
DUK	3/31/12	7,626	7,370	7,207	7,179	7,372	7,724	8,036	8,510	9,035	9,395	9,627	9,741	9,863	9,950	10,019	10,099	10,092	9,934	9,863	10,128	9,720	9,079	8,345	7,672
DUK	4/1/12	7,240	6,963	6,825	6,790	6,854	7,131	7,394	8,021	8,404	8,490	8,546	8,699	8,874	9,042	9,197	9,384	9,554	9,555	9,626	10,034	9,706	9,064	8,336	7,801
DUK	4/2/12	7,437	7,125	7,105	7,306	7,894	8,961	9,602	9,944	10,247	10,595	10,876	11,157	11,531	11,874	12,149	12,326	12,182	11,998	11,686	11,938	11,323	10,346	9,250	8,540
DUK	4/3/12	8,038	7,709	7,575	7,692	8,210	9,302	9,862	10,011	10,191	10,451	10,595	10,763	11,074	11,273	11,586	11,711	11,650	11,458	11,548	11,750	11,173	10,201	9,217	8,536
DUK	4/4/12	8,096	7,820	7,694	7,763	8,299	9,371	9,819	10,059	10,454	10,905	11,329	11,806	12,355	12,698	12,907	12,781	12,514	12,247	11,964	12,184	11,567	10,586	9,518	8,733
DUK	4/5/12	8,272	7,965	7,763	7,857	8,354	9,406	9,925	10,126	10,396	10,722	10,814	10,898	11,057	11,111	11,070	10,836	10,491	10,290	10,241	10,342	9,967	9,224	8,418	7,839
DUK	4/6/12	7,495	7,313	7,234	7,312	7,634	8,224	8,646	9,064	9,423	9,536	9,434	9,224	9,052	8,941	8,832	8,865	8,917	8,851	8,781	9,278	9,101	8,623	8,083	7,605
DUK	4/7/12	7,315	7,205	7,235	7,328	7,572	8,042	8,420	8,918	9,071	9,007	8,839	8,685	8,510	8,433	8,438	8,534	8,627	8,618	8,632	9,188	9,013	8,484	7,846	7,327
DUK	4/8/12	7,010	6,866	6,833	6,933	7,207	7,606	7,883	8,446	8,607	8,395	8,258	8,257	8,225	8,201	8,284	8,409	8,527	8,550	8,578	9,229	9,034	8,447	7,761	7,270
DUK	4/9/12	6,962	6,839	6,844	7,029	7,612	8,627	9,286	9,680	9,872	10,088	10,221	10,295	10,405	10,434	10,501	10,550	10,540	10,461	10,384	10,834	10,417	9,509	8,644	7,997

Backup - DUK Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DUK	4/10/12	7,639	7,506	7,438	7,627	8,215	9,344	9,939	10,112	10,260	10,366	10,446	10,492	10,544	10,534	10,511	10,505	10,389	10,301	10,323	10,849	10,480	9,663	8,808	8,239
DUK	4/11/12	7,908	7,772	7,744	7,963	8,643	9,796	10,423	10,583	10,543	10,654	10,607	10,483	10,402	10,300	10,193	10,185	10,153	10,170	10,341	10,986	10,786	10,156	9,445	9,032
DUK	4/12/12	8,844	8,834	8,912	9,253	10,047	11,350	11,958	11,769	11,404	11,170	10,868	10,616	10,504	10,360	10,217	10,157	10,047	9,983	10,210	10,731	10,554	9,859	9,091	8,705
DUK	4/13/12	8,511	8,516	8,588	8,904	9,515	10,733	11,255	11,191	10,876	10,653	10,411	10,170	10,075	10,026	9,904	9,851	9,772	9,647	9,641	10,114	9,883	9,315	8,644	8,112
DUK	4/14/12	7,814	7,712	7,689	7,851	8,143	8,629	8,934	9,331	9,474	9,490	9,392	9,283	9,183	9,164	9,205	9,348	9,459	9,429	9,334	9,760	9,535	8,941	8,240	7,658
DUK	4/15/12	7,313	7,109	7,002	7,024	7,123	7,376	7,714	8,319	8,679	8,762	8,865	9,096	9,319	9,505	9,707	9,989	10,168	10,213	10,184	10,706	10,502	9,736	8,880	8,225
DUK	4/16/12	7,821	7,568	7,450	7,550	8,178	9,386	9,960	10,285	10,644	11,125	11,566	11,945	12,339	12,649	12,790	12,979	13,042	12,895	12,590	12,835	12,290	11,104	9,963	9,082
DUK	4/17/12	8,578	8,216	8,047	8,130	8,650	9,777	10,298	10,608	11,030	11,577	12,051	12,489	13,009	13,204	13,292	13,384	13,355	13,072	12,682	12,670	11,889	10,639	9,507	8,699
DUK	4/18/12	8,205	7,911	7,768	7,845	8,401	9,575	10,137	10,252	10,375	10,552	10,559	10,507	10,533	10,406	10,359	10,375	10,378	10,391	10,446	10,769	10,422	9,621	8,757	8,220
DUK	4/19/12	7,888	7,709	7,683	7,827	8,453	9,685	10,258	10,328	10,385	10,458	10,431	10,416	10,425	10,408	10,369	10,309	10,224	10,194	10,273	10,796	10,507	9,697	8,818	8,216
DUK	4/20/12	7,849	7,684	7,616	7,775	8,359	9,507	10,019	10,129	10,229	10,355	10,364	10,311	10,397	10,422	10,414	10,437	10,390	10,258	10,087	10,446	10,265	9,609	8,798	8,099
DUK	4/21/12	7,686	7,435	7,304	7,300	7,457	7,781	8,071	8,652	9,139	9,466	9,735	9,925	10,124	10,276	10,390	10,539	10,560	10,368	10,199	10,474	10,140	9,421	8,662	7,998
DUK	4/22/12	7,501	7,224	7,062	6,997	7,074	7,311	7,585	8,193	8,658	8,804	8,860	8,986	9,027	8,999	8,962	9,060	9,176	9,272	9,509	9,947	9,698	9,087	8,498	8,060
DUK	4/23/12	7,884	7,817	7,898	8,186	9,007	10,441	11,121	11,116	11,100	11,160	11,135	11,080	11,015	10,843	10,668	10,611	10,606	10,710	10,905	11,557	11,324	10,625	9,828	9,340
DUK	4/24/12	9,142	9,092	9,183	9,503	10,327	11,774	12,206	11,803	11,409	11,137	11,005	10,766	10,677	10,527	10,370	10,313	10,259	10,224	10,357	11,050	10,751	10,096	9,203	8,665
DUK	4/25/12	8,423	8,314	8,304	8,517	9,178	10,467	10,993	10,969	10,983	11,001	10,896	10,683	10,617	10,503	10,523	10,556	10,551	10,584	10,578	11,108	10,844	9,950	9,031	8,423
DUK	4/26/12	8,049	7,839	7,790	7,941	8,534	9,710	10,245	10,408	10,571	10,783	10,819	10,728	10,844	10,891	10,915	10,941	10,912	10,851	10,886	11,238	10,921	10,076	9,131	8,429
DUK	4/27/12	8,035	7,800	7,688	7,783	8,314	9,336	9,905	10,165	10,451	10,792	11,069	11,305	11,570	11,791	11,894	11,986	11,880	11,532	11,155	11,312	11,023	10,221	9,295	8,522
DUK	4/28/12	7,968	7,670	7,500	7,480	7,625	7,899	8,171	8,699	9,110	9,349	9,392	9,410	9,362	9,333	9,296	9,349	9,357	9,340	9,308	9,680	9,547	8,988	8,348	7,756
DUK	4/29/12	7,410	7,207	7,080	7,038	7,178	7,315	7,605	8,233	8,625	8,767	9,000	9,388	9,776	10,197	10,615	11,045	11,332	11,305	11,135	11,376	11,042	10,163	9,198	8,447
DUK	4/30/12	7,970	7,702	7,580	7,671	8,254	9,495	10,121	10,424	10,780	11,249	11,717	12,196	12,705	13,163	13,511	13,660	13,632	13,449	13,175	13,349	12,838	11,728	10,574	9,722
DUK	5/1/12	9,127	8,716	8,494	8,521	9,029	10,107	10,711	11,103	11,636	12,261	12,883	13,451	14,126	14,596	14,933	15,000	14,739	14,314	13,878	13,856	13,379	12,107	10,808	9,819
DUK	5/2/12	9,223	8,838	8,576	8,584	9,096	10,186	10,832	11,290	11,905	12,691	13,424	14,170	14,943	15,480	15,866	16,092	15,952	15,612	14,956	14,673	14,034	12,637	11,235	10,173
DUK	5/3/12	9,470	8,995	8,775	8,744	9,166	10,152	10,852	11,327	11,912	12,712	13,469	14,157	15,024	15,588	15,908	15,995	15,616	15,117	14,547	14,401	13,790	12,488	11,059	10,009
DUK	5/4/12	9,348	8,875	8,672	8,628	9,104	10,076	10,739	11,084	11,586	12,154	12,760	13,322	14,000	14,456	14,725	14,883	14,729	14,297	13,602	13,304	12,904	11,843	10,660	9,662
DUK	5/5/12	8,982	8,510	8,241	8,109	8,173	8,281	8,685	9,491	10,330	11,099	11,634	12,062	12,543	12,968	13,205	13,223	13,146	12,785	12,241	12,123	11,775	10,982	9,992	9,120
DUK	5/6/12	8,545	8,103	7,860	7,749	7,763	7,828	8,164	8,912	9,556	9,868	10,130	10,466	10,827	11,209	11,546	11,894	12,101	12,017	11,683	11,683	11,418	10,466	9,465	8,674
DUK	5/7/12	8,159	7,892	7,741	7,862	8,464	9,583	10,233	10,525	10,836	11,271	11,656	12,027	12,437	12,774	13,088	13,333	13,303	13,083	12,660	12,665	12,254	11,125	9,955	9,203
DUK	5/8/12	8,671	8,339	8,201	8,289	8,889	9,966	10,595	10,866	11,192	11,506	11,785	11,987	12,320	12,579	12,864	13,112	13,045	12,844	12,603	12,667	12,185	11,124	10,058	9,276
DUK	5/9/12	8,786	8,491	8,337	8,379	8,883	9,952	10,589	10,860	11,094	11,433	11,617	11,701	11,734	11,590	11,445	11,292	11,115	11,010	10,868	10,987	10,809	9,932	8,986	8,334
DUK	5/10/12	7,937	7,725	7,630	7,740	8,325	9,285	9,933	10,160	10,349	10,582	10,682	10,768	10,891	10,993	11,104	11,212	11,169	11,026	10,805	10,973	10,830	9,938	8,968	8,298
DUK	5/11/12	7,910	7,676	7,587	7,698	8,239	9,201	9,786	9,985	10,168	10,363	10,438	10,468	10,611	10,766	10,913	11,102	11,104	10,879	10,429	10,398	10,245	9,522	8,689	8,008
DUK	5/12/12	7,590	7,400	7,284	7,299	7,502	7,674	8,064	8,626	9,028	9,278	9,419	9,497	9,588	9,659	9,750	9,894	9,926	9,838	9,709	9,959	9,929	9,298	8,567	7,899
DUK	5/13/12	7,482	7,230	7,090	7,028	7,088	7,155	7,543	8,248	8,721	8,858	8,925	9,040	9,049	9,037	8,984	9,028	9,103	9,207	9,393	9,806	9,673	9,106	8,492	7,976
DUK	5/14/12	7,620	7,482	7,455	7,621	8,246	9,405	10,149	10,418	10,735	11,070	11,213	11,315	11,486	11,612	11,701	11,839	11,915	11,866	11,745	11,788	11,284	10,298	9,401	8,696

Backup - DUK Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DUK	5/15/12	8,256	8,022	7,905	8,021	8,584	9,657	10,288	10,531	10,905	11,326	11,675	12,017	12,388	12,729	13,028	13,242	13,288	13,103	12,777	12,701	12,271	11,143	9,914	9,095
DUK	5/16/12	8,626	8,305	8,105	8,187	8,713	9,748	10,399	10,764	11,250	11,827	12,400	12,890	13,351	13,672	13,945	14,091	13,976	13,673	13,212	13,048	12,604	11,391	10,083	9,254
DUK	5/17/12	8,711	8,344	8,211	8,232	8,717	9,664	10,348	10,712	11,196	11,795	12,333	12,814	13,276	13,552	13,552	13,377	12,970	12,515	12,179	12,264	12,008	11,062	9,837	9,066
DUK	5/18/12	8,567	8,233	8,073	8,106	8,612	9,537	10,163	10,434	10,740	11,041	11,321	11,509	11,760	12,050	12,264	12,476	12,372	11,953	11,413	11,223	11,082	10,286	9,292	8,466
DUK	5/19/12	7,939	7,625	7,448	7,404	7,542	7,639	8,026	8,618	9,142	9,502	9,768	10,004	10,219	10,430	10,667	10,862	10,943	10,733	10,360	10,312	10,229	9,457	8,689	7,945
DUK	5/20/12	7,472	7,204	7,056	6,997	7,049	7,035	7,465	8,230	8,832	9,191	9,574	9,970	10,410	10,853	11,306	11,678	11,913	11,819	11,470	11,404	11,285	10,319	9,305	8,506
DUK	5/21/12	8,011	7,783	7,715	7,866	8,429	9,435	10,172	10,666	11,223	11,894	12,495	12,967	13,564	14,009	14,402	14,623	14,494	14,058	13,446	13,190	12,669	11,430	10,227	9,335
DUK	5/22/12	8,815	8,469	8,267	8,325	8,837	9,767	10,470	10,947	11,479	12,095	12,589	12,963	13,422	13,850	14,244	14,370	14,164	13,733	13,177	12,889	12,388	11,179	10,047	9,202
DUK	5/23/12	8,679	8,396	8,232	8,271	8,796	9,803	10,441	10,721	10,999	11,457	11,842	12,229	12,677	13,087	13,439	13,693	13,614	13,329	12,775	12,552	12,253	11,245	10,129	9,256
DUK	5/24/12	8,706	8,391	8,246	8,288	8,831	9,789	10,518	10,842	11,263	11,843	12,485	13,046	13,694	14,204	14,637	14,930	14,870	14,562	13,920	13,638	13,299	12,112	10,823	9,834
DUK	5/25/12	9,191	8,779	8,526	8,478	8,911	9,706	10,470	11,113	11,928	12,774	13,658	14,355	15,013	15,466	15,683	15,776	15,747	15,264	14,461	13,876	13,401	12,257	10,959	9,883
DUK	5/26/12	9,170	8,709	8,429	8,218	8,225	8,208	8,650	9,572	10,618	11,672	12,570	13,331	13,940	14,340	14,664	14,848	14,800	14,445	13,829	13,295	12,884	11,838	10,732	9,763
DUK	5/27/12	9,006	8,510	8,193	8,008	7,965	7,855	8,361	9,371	10,369	11,141	11,739	12,320	12,767	13,093	13,395	13,713	13,886	13,710	13,218	12,677	12,426	11,564	10,439	9,485
DUK	5/28/12	8,866	8,441	8,203	8,179	8,329	8,434	8,807	9,494	10,406	11,471	12,374	13,086	13,677	14,161	14,451	14,606	14,556	14,208	13,652	13,290	12,975	11,891	10,676	9,800
DUK	5/29/12	9,210	8,826	8,664	8,752	9,347	10,302	11,228	11,839	12,458	13,228	13,841	14,466	14,878	15,035	14,990	14,783	14,515	14,037	13,601	13,470	13,099	11,973	10,891	10,016
DUK	5/30/12	9,458	9,070	8,866	8,927	9,484	10,396	11,114	11,550	12,114	12,919	13,635	14,238	14,773	15,375	15,777	16,064	16,003	15,678	14,923	14,197	13,695	12,241	10,945	9,892
DUK	5/31/12	9,198	8,735	8,524	8,509	8,968	9,768	10,580	11,279	12,033	12,988	13,848	14,637	15,376	15,894	16,160	16,312	16,168	15,766	15,089	14,508	14,096	12,795	11,534	10,518
DUK	6/1/12	9,855	9,417	9,173	9,140	9,579	10,385	11,079	11,602	12,230	12,833	13,396	13,805	14,133	14,169	14,041	13,996	13,604	13,036	12,466	12,081	11,875	11,012	9,934	9,106
DUK	6/2/12	8,470	8,029	7,754	7,656	7,720	7,731	8,115	8,785	9,367	9,812	10,118	10,330	10,505	10,718	10,954	11,204	11,301	11,105	10,668	10,355	10,313	9,612	8,776	8,030
DUK	6/3/12	7,553	7,237	7,059	7,020	7,077	7,038	7,483	8,207	8,826	9,221	9,605	10,045	10,428	10,837	11,263	11,657	12,010	12,056	11,739	11,480	11,420	10,530	9,555	8,762
DUK	6/4/12	8,236	7,934	7,836	7,953	8,506	9,378	10,175	10,662	11,122	11,701	12,185	12,609	13,073	13,419	13,728	13,942	13,830	13,542	13,123	12,822	12,626	11,583	10,344	9,532
DUK	6/5/12	8,952	8,590	8,355	8,371	8,895	9,714	10,310	10,639	10,958	11,316	11,676	11,958	12,212	12,403	12,652	12,798	12,644	12,318	11,923	11,804	11,724	10,808	9,735	8,926
DUK	6/6/12	8,426	8,137	7,987	8,066	8,612	9,516	10,110	10,362	10,512	10,743	10,883	10,985	11,098	11,194	11,354	11,486	11,489	11,358	11,107	11,073	11,122	10,352	9,398	8,684
DUK	6/7/12	8,218	7,965	7,853	7,915	8,434	9,205	9,912	10,390	10,831	11,371	11,814	12,146	12,564	12,899	13,146	13,305	13,201	12,970	12,545	12,135	12,061	11,160	10,004	9,069
DUK	6/8/12	8,520	8,173	8,009	8,078	8,490	9,103	9,877	10,502	11,075	11,775	12,336	12,751	13,155	13,548	13,840	14,050	14,057	13,740	13,019	12,365	12,084	11,166	9,996	9,043
DUK	6/9/12	8,456	8,089	7,835	7,731	7,819	7,829	8,300	9,127	9,947	10,744	11,547	12,237	12,768	13,138	13,457	13,629	13,631	13,327	12,667	12,287	12,022	11,137	10,109	9,137
DUK	6/10/12	8,510	8,113	7,853	7,732	7,746	7,634	8,124	8,969	9,830	10,506	10,950	11,408	11,667	11,742	11,798	11,840	11,847	11,665	11,456	11,459	11,406	10,779	9,924	9,255
DUK	6/11/12	8,802	8,546	8,422	8,546	9,104	9,953	10,732	11,311	11,766	12,256	12,603	12,847	13,265	13,532	13,697	13,651	13,434	13,230	12,947	12,803	12,677	11,895	10,871	10,031
DUK	6/12/12	9,515	9,200	9,020	9,106	9,597	10,408	11,114	11,643	12,093	12,688	13,232	13,707	14,255	14,755	15,241	15,546	15,391	14,930	14,230	13,776	13,406	12,271	10,960	10,013
DUK	6/13/12	9,351	8,941	8,729	8,716	9,155	9,749	10,610	11,469	12,305	13,184	14,114	14,727	15,271	15,699	15,905	15,899	15,777	15,414	14,778	14,141	13,843	12,715	11,307	10,256
DUK	6/14/12	9,526	9,088	8,782	8,767	9,103	9,628	10,385	11,010	11,584	12,213	12,720	13,178	13,633	14,080	14,417	14,573	14,477	14,155	13,523	13,044	12,871	11,858	10,678	9,699
DUK	6/15/12	9,050	8,655	8,435	8,423	8,802	9,303	10,068	10,718	11,301	11,932	12,454	12,836	13,233	13,605	13,891	14,064	13,990	13,591	12,894	12,269	12,114	11,233	10,145	9,210
DUK	6/16/12	8,534	8,116	7,837	7,733	7,785	7,752	8,194	8,923	9,655	10,271	10,753	11,154	11,565	11,977	12,409	12,769	12,850	12,609	12,025	11,515	11,364	10,602	9,599	8,697
DUK	6/17/12	8,079	7,677	7,469	7,362	7,375	7,278	7,709	8,514	9,244	9,761	10,278	10,847	11,367	11,897	12,337	12,699	12,840	12,671	12,246	11,957	11,918	11,167	10,166	9,349
DUK	6/18/12	8,791	8,447	8,276	8,316	8,780	9,423	10,223	10,951	11,656	12,498	13,387	14,154	14,856	15,461	15,864	16,059	15,898	15,539	14,870	14,281	13,941	12,796	11,509	10,424

Backup - DUK Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DUK	6/19/12	9,734	9,320	8,986	8,947	9,329	9,931	10,739	11,532	12,388	13,401	14,378	15,225	15,997	16,592	16,946	17,092	16,908	16,530	15,870	15,145	14,815	13,587	12,126	11,020
DUK	6/20/12	10,239	9,686	9,357	9,313	9,674	10,274	11,210	12,160	13,210	14,449	15,487	16,414	17,102	17,566	17,810	17,841	17,771	17,339	16,694	16,011	15,588	14,464	12,936	11,751
DUK	6/21/12	10,943	10,336	9,956	9,840	10,168	10,722	11,668	12,624	13,699	15,002	16,125	17,004	17,641	17,883	17,994	17,963	17,808	17,481	16,799	16,220	15,846	14,613	13,165	12,001
DUK	6/22/12	11,174	10,583	10,174	10,062	10,291	10,690	11,504	12,460	13,585	14,838	15,892	16,695	17,247	17,353	16,746	15,747	14,775	14,137	13,613	13,186	13,100	12,221	11,180	10,212
DUK	6/23/12	9,565	9,088	8,816	8,696	8,706	8,696	9,237	10,192	11,203	12,267	13,312	14,214	14,886	15,298	15,558	15,738	15,702	15,399	14,756	14,127	13,816	12,786	11,604	10,557
DUK	6/24/12	9,811	9,292	8,933	8,713	8,630	8,556	9,022	10,186	11,366	12,390	13,393	14,213	14,872	15,252	15,459	15,430	15,254	14,752	14,039	13,600	13,375	12,449	11,404	10,447
DUK	6/25/12	9,819	9,418	9,232	9,243	9,703	10,363	11,306	12,217	13,103	14,194	15,283	16,211	16,941	17,479	17,852	18,047	17,874	17,508	16,834	16,118	15,684	14,364	12,838	11,592
DUK	6/26/12	10,737	10,073	9,631	9,438	9,699	10,157	10,843	11,458	12,001	12,579	13,100	13,486	13,917	14,303	14,608	14,837	14,796	14,494	13,781	13,021	12,719	11,622	10,343	9,357
DUK	6/27/12	8,736	8,364	8,152	8,171	8,562	9,114	9,855	10,515	11,149	11,894	12,488	13,058	13,636	14,271	14,821	15,244	15,362	15,172	14,535	13,737	13,369	12,211	10,874	9,803
DUK	6/28/12	9,124	8,707	8,471	8,462	8,825	9,392	10,214	11,046	11,909	12,961	13,998	14,962	15,941	16,718	17,390	17,763	17,765	17,453	16,787	15,966	15,528	14,216	12,752	11,515
DUK	6/29/12	10,639	10,027	9,610	9,482	9,733	10,196	11,050	12,148	13,494	15,077	16,536	17,636	18,487	18,882	19,083	19,327	19,400	19,146	18,471	17,719	17,239	15,922	14,406	13,076
DUK	6/30/12	11,995	11,119	10,518	10,106	9,987	9,867	10,272	11,314	12,598	14,000	15,274	16,411	17,301	17,946	18,356	18,657	18,687	18,370	17,809	17,147	16,721	15,630	14,244	12,993
DUK	7/1/12	12,074	11,334	10,818	10,449	10,237	9,984	10,419	11,571	13,014	14,479	15,873	17,014	17,593	17,643	17,668	17,810	17,601	16,885	15,999	15,445	14,920	13,799	12,575	11,509
DUK	7/2/12	10,676	10,101	9,639	9,481	9,770	10,301	10,786	11,311	12,020	13,079	14,058	15,032	15,771	16,372	16,863	17,175	17,161	16,839	16,316	15,756	15,413	14,164	12,748	11,537
DUK	7/3/12	10,764	10,218	9,887	9,803	10,097	10,549	11,308	12,276	13,522	14,920	16,125	17,096	17,759	18,056	18,038	17,693	17,370	16,798	16,051	15,407	14,932	13,768	12,552	11,438
DUK	7/4/12	10,605	9,979	9,609	9,369	9,356	9,216	9,438	10,319	11,560	12,942	14,185	15,163	15,891	16,434	16,608	16,557	16,257	15,647	14,970	14,242	13,794	13,010	12,123	11,109
DUK	7/5/12	10,353	9,811	9,461	9,354	9,603	10,071	10,928	12,082	13,471	15,030	16,457	17,483	18,158	18,300	18,138	17,860	17,311	16,586	15,636	14,989	14,468	13,319	12,047	10,977
DUK	7/6/12	10,200	9,666	9,348	9,252	9,505	9,892	10,560	11,517	12,691	14,042	15,257	16,288	17,054	17,667	18,036	18,144	17,826	17,168	16,439	15,771	15,340	14,286	12,934	11,764
DUK	7/7/12	10,955	10,347	9,927	9,677	9,631	9,531	10,059	11,155	12,588	14,099	15,408	16,383	17,093	17,573	17,915	18,113	18,021	17,693	17,075	16,420	16,012	14,957	13,672	12,566
DUK	7/8/12	11,691	11,126	10,676	10,341	10,207	10,010	10,423	11,673	13,102	14,417	15,596	16,715	17,534	17,920	18,029	17,937	17,956	17,648	17,082	16,589	16,275	15,182	13,928	12,906
DUK	7/9/12	12,077	11,511	11,091	10,967	11,248	11,791	12,657	13,791	14,999	16,374	17,493	18,369	18,939	19,116	18,707	18,023	17,571	17,082	16,459	15,773	15,285	14,171	12,941	11,985
DUK	7/10/12	11,259	10,777	10,425	10,388	10,804	11,444	12,125	12,781	13,340	14,050	14,697	15,261	15,774	16,168	16,183	15,740	15,166	14,539	13,993	13,786	13,544	12,679	11,595	10,773
DUK	7/11/12	10,195	9,783	9,554	9,558	9,991	10,694	11,320	11,811	12,300	12,833	13,264	13,596	14,003	14,204	14,276	14,386	14,236	13,758	13,112	12,738	12,575	11,725	10,674	9,866
DUK	7/12/12	9,360	9,019	8,848	8,887	9,311	10,083	10,708	11,188	11,630	12,138	12,593	12,893	13,176	13,344	13,459	13,553	13,492	13,263	12,985	12,893	12,856	12,129	11,024	10,151
DUK	7/13/12	9,603	9,227	8,993	9,035	9,426	10,062	10,761	11,348	11,912	12,605	13,297	13,935	14,534	14,999	15,271	15,289	14,845	14,182	13,430	13,129	12,955	12,204	11,184	10,350
DUK	7/14/12	9,693	9,345	9,164	9,107	9,262	9,479	9,830	10,597	11,563	12,568	13,535	14,229	14,757	15,083	15,310	15,484	15,443	15,180	14,614	14,040	13,652	12,697	11,599	10,672
DUK	7/15/12	9,997	9,522	9,142	8,932	8,884	8,800	9,261	10,430	11,619	12,607	13,531	14,376	15,041	15,507	15,803	15,968	15,826	15,436	14,919	14,461	14,218	13,291	12,142	11,169
DUK	7/16/12	10,531	10,109	9,821	9,864	10,266	10,955	11,724	12,515	13,331	14,459	15,670	16,690	17,445	17,926	18,091	17,849	16,851	16,032	15,246	14,662	14,210	13,172	11,970	11,061
DUK	7/17/12	10,388	9,968	9,683	9,677	10,071	10,747	11,545	12,462	13,539	14,841	16,086	17,046	17,796	18,284	18,483	18,579	18,382	17,874	17,146	16,586	16,164	14,821	13,395	12,243
DUK	7/18/12	11,447	10,857	10,463	10,411	10,732	11,352	12,131	13,100	14,219	15,581	16,800	17,766	18,480	18,899	18,923	18,659	17,890	16,880	16,078	15,546	15,211	14,043	12,719	11,709
DUK	7/19/12	10,982	10,472	10,167	10,113	10,477	11,076	11,858	12,709	13,725	14,908	15,987	16,929	17,704	18,199	18,416	18,299	17,773	16,909	16,042	15,613	15,278	14,080	12,770	11,827
DUK	7/20/12	11,087	10,605	10,266	10,209	10,579	11,167	11,854	12,579	13,312	14,282	15,264	16,068	16,633	16,801	16,679	16,170	15,402	14,724	14,099	13,764	13,517	12,630	11,587	10,664
DUK	7/21/12	10,015	9,596	9,312	9,218	9,352	9,491	9,869	10,612	11,406	12,268	13,137	13,968	14,689	15,278	15,724	15,995	15,926	15,511	14,729	14,082	13,741	12,824	11,781	10,816
DUK	7/22/12	10,232	9,744	9,416	9,231	9,203	9,153	9,525	10,494	11,527	12,423	13,209	13,958	14,645	15,115	15,355	15,466	15,547	15,430	15,051	14,691	14,439	13,481	12,356	11,409
DUK	7/23/12	10,717	10,193	9,929	9,963	10,394	11,063	11,908	12,989	14,158	15,549	16,768	17,679	18,310	18,676	18,636	18,321	17,830	17,416	16,825	16,259	15,834	14,598	13,312	12,254

Backup - DUK Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DUK	7/24/12	11,505	10,914	10,589	10,524	10,845	11,458	12,272	13,351	14,583	15,955	17,146	18,008	18,645	18,680	18,279	17,820	17,288	16,456	15,674	15,203	14,847	13,696	12,401	11,441
DUK	7/25/12	10,686	10,233	9,964	9,964	10,404	11,223	11,890	12,315	12,740	13,492	14,535	15,580	16,590	17,323	17,784	17,999	17,766	17,372	16,788	16,273	15,925	14,750	13,347	12,277
DUK	7/26/12	11,458	10,960	10,603	10,593	11,005	11,611	12,403	13,497	14,705	16,176	17,360	18,186	18,835	19,227	19,363	19,473	19,339	19,114	18,534	17,907	17,378	16,058	14,562	13,394
DUK	7/27/12	12,522	11,882	11,416	11,241	11,401	11,867	12,486	13,569	14,827	16,231	17,421	18,264	18,798	19,072	19,114	18,783	18,065	17,030	16,086	15,427	14,994	13,913	12,673	11,650
DUK	7/28/12	10,916	10,384	9,964	9,759	9,779	9,798	10,104	11,093	12,468	13,859	15,016	15,935	16,589	17,071	17,445	17,678	17,532	17,098	16,286	15,506	14,894	13,739	12,506	11,426
DUK	7/29/12	10,600	9,989	9,542	9,257	9,149	9,037	9,357	10,424	11,502	12,477	13,455	14,286	15,086	15,591	15,947	16,234	16,369	16,056	15,443	14,868	14,420	13,313	12,124	11,065
DUK	7/30/12	10,341	9,874	9,606	9,629	10,053	10,760	11,471	12,338	13,333	14,551	15,683	16,586	17,301	17,725	17,983	17,986	17,608	16,971	16,234	15,585	15,084	13,781	12,432	11,390
DUK	7/31/12	10,588	10,076	9,831	9,796	10,215	10,841	11,490	12,123	12,752	13,432	13,969	14,404	14,740	14,884	14,910	14,878	14,760	14,608	14,302	14,053	13,757	12,788	11,672	10,820
DUK	8/1/12	10,198	9,773	9,585	9,623	10,039	10,728	11,358	12,176	13,076	14,117	15,072	15,930	16,729	17,424	17,899	18,140	18,015	17,469	16,617	16,059	15,511	14,247	12,946	11,902
DUK	8/2/12	11,087	10,526	10,185	10,072	10,420	11,015	11,679	12,522	13,586	14,870	16,075	17,034	17,819	18,318	18,560	18,563	18,288	17,870	16,956	16,197	15,687	14,331	12,913	11,824
DUK	8/3/12	10,974	10,404	10,051	9,950	10,277	10,885	11,491	12,162	12,989	13,984	14,832	15,679	16,492	17,100	17,563	17,715	17,425	16,758	15,904	15,451	14,984	13,931	12,660	11,605
DUK	8/4/12	10,785	10,293	9,916	9,724	9,738	9,850	10,143	10,970	11,955	12,847	13,713	14,460	15,116	15,493	15,814	15,965	15,933	15,487	14,878	14,520	14,125	13,141	12,077	11,120
DUK	8/5/12	10,414	9,896	9,558	9,321	9,281	9,175	9,480	10,535	11,696	12,557	13,366	14,226	15,037	15,554	15,784	15,845	15,750	15,345	14,753	14,518	14,131	13,144	12,077	11,184
DUK	8/6/12	10,592	10,198	9,948	9,954	10,387	11,178	11,884	12,616	13,462	14,548	15,522	16,230	16,813	17,194	17,436	17,464	17,088	16,336	15,433	15,114	14,503	13,317	12,172	11,196
DUK	8/7/12	10,589	10,165	9,972	10,012	10,479	11,315	11,904	12,394	12,757	13,241	13,656	14,102	14,778	15,353	15,761	15,904	15,725	15,271	14,699	14,481	13,990	12,873	11,737	10,783
DUK	8/8/12	10,241	9,834	9,629	9,655	10,123	10,968	11,540	12,141	12,888	13,963	15,088	16,015	16,807	17,110	16,748	16,235	15,629	15,062	14,444	14,158	13,833	12,693	11,497	10,525
DUK	8/9/12	9,873	9,455	9,255	9,250	9,679	10,468	11,101	11,797	12,421	13,407	14,341	15,113	15,880	16,446	16,686	16,466	15,849	15,257	14,698	14,501	13,904	12,730	11,519	10,626
DUK	8/10/12	9,999	9,590	9,399	9,381	9,872	10,615	11,145	11,691	12,202	12,784	13,351	13,832	14,294	14,736	15,026	15,160	15,096	14,700	14,093	13,903	13,508	12,625	11,565	10,600
DUK	8/11/12	9,896	9,430	9,129	9,021	9,108	9,338	9,594	10,193	11,054	11,742	12,136	12,507	12,897	13,129	13,292	13,369	13,333	13,071	12,686	12,558	12,259	11,371	10,435	9,593
DUK	8/12/12	9,021	8,636	8,358	8,218	8,236	8,324	8,451	9,345	10,280	11,025	11,779	12,529	13,225	13,774	14,244	14,579	14,736	14,465	13,823	13,461	12,963	11,893	10,788	9,860
DUK	8/13/12	9,259	8,846	8,642	8,674	9,131	9,927	10,561	11,279	12,198	13,254	14,296	15,032	15,681	16,140	16,479	16,620	16,407	15,957	15,079	14,621	13,917	12,646	11,382	10,467
DUK	8/14/12	9,866	9,440	9,187	9,165	9,590	10,479	10,991	11,706	12,499	13,465	14,282	14,999	15,704	16,253	16,782	16,998	16,793	16,201	15,510	15,246	14,657	13,473	12,106	11,077
DUK	8/15/12	10,366	9,880	9,602	9,582	10,027	10,868	11,463	12,040	12,715	13,491	14,096	14,672	15,317	15,945	16,378	16,375	16,010	15,335	14,630	14,241	13,734	12,599	11,251	10,264
DUK	8/16/12	9,582	9,161	8,915	8,878	9,292	10,091	10,662	11,281	12,044	12,942	13,759	14,543	15,279	15,842	16,277	16,434	16,309	15,829	15,037	14,586	13,920	12,701	11,342	10,242
DUK	8/17/12	9,560	9,115	8,880	8,847	9,199	9,939	10,449	11,220	12,132	13,213	14,234	14,985	15,643	16,022	16,142	15,678	14,930	14,266	13,689	13,487	12,995	12,073	10,989	10,064
DUK	8/18/12	9,430	9,013	8,711	8,586	8,704	8,888	9,027	9,767	10,644	11,448	12,003	12,387	12,771	13,141	13,496	13,823	13,949	13,655	13,114	12,976	12,501	11,605	10,582	9,803
DUK	8/19/12	9,202	8,795	8,522	8,390	8,437	8,585	8,874	9,392	9,896	10,229	10,550	10,926	11,237	11,547	11,793	11,987	12,069	11,897	11,682	11,832	11,468	10,772	9,924	9,241
DUK	8/20/12	8,788	8,499	8,391	8,473	9,045	10,124	10,681	11,062	11,512	12,098	12,661	13,202	13,778	14,208	14,382	14,305	14,025	13,667	13,323	13,344	12,840	11,766	10,647	9,691
DUK	8/21/12	9,178	8,842	8,678	8,708	9,199	10,166	10,643	11,109	11,778	12,487	13,314	13,957	14,500	14,887	15,101	15,203	14,986	14,543	13,951	13,810	13,179	11,967	10,764	9,871
DUK	8/22/12	9,319	8,915	8,775	8,821	9,357	10,387	10,892	11,237	11,675	12,313	13,000	13,658	14,190	14,534	14,753	14,834	14,554	14,026	13,532	13,515	12,952	11,825	10,671	9,814
DUK	8/23/12	9,237	8,882	8,714	8,745	9,285	10,255	10,738	11,214	11,853	12,565	13,296	13,934	14,529	15,005	15,284	15,410	15,088	14,487	13,902	13,927	13,290	12,144	10,896	9,915
DUK	8/24/12	9,271	8,890	8,677	8,679	9,133	10,038	10,517	11,058	11,734	12,530	13,167	13,587	14,143	14,491	14,707	14,787	14,536	14,010	13,123	12,862	12,258	11,309	10,218	9,326
DUK	8/25/12	8,710	8,309	8,059	7,952	8,065	8,263	8,452	9,168	9,902	10,681	11,277	11,809	12,251	12,678	13,040	13,280	13,198	12,757	12,135	12,062	11,578	10,661	9,775	8,906
DUK	8/26/12	8,398	8,029	7,793	7,688	7,699	7,845	8,005	8,833	9,682	10,373	11,086	11,915	12,750	13,391	13,914	14,319	14,505	14,236	13,656	13,525	12,833	11,606	10,491	9,636
DUK	8/27/12	9,030	8,680	8,504	8,552	9,170	10,352	10,887	11,411	12,131	13,027	13,968	14,726	15,496	16,125	16,545	16,777	16,770	16,365	15,732	15,519	14,610	13,158	11,794	10,787

Backup - DUK Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DUK	8/28/12	10,138	9,662	9,480	9,479	10,110	11,390	11,930	12,248	12,697	13,458	14,366	15,103	15,841	16,203	16,327	16,354	16,032	15,509	15,092	14,997	14,149	12,863	11,658	10,761
DUK	8/29/12	10,215	9,827	9,618	9,708	10,280	11,538	12,072	12,433	12,903	13,546	14,286	14,846	15,364	15,658	15,795	15,945	15,768	15,387	14,967	14,884	14,035	12,799	11,554	10,607
DUK	8/30/12	9,987	9,590	9,414	9,437	9,971	11,233	11,784	12,131	12,646	13,435	14,230	14,898	15,468	15,851	16,171	16,271	16,028	15,538	15,039	15,058	14,372	13,092	11,857	10,879
DUK	8/31/12	10,209	9,798	9,585	9,648	10,193	11,404	11,992	12,378	12,978	13,950	14,994	15,924	16,785	17,401	17,735	17,882	17,662	16,998	16,124	15,792	14,928	13,810	12,584	11,415
DUK	9/1/12	10,671	10,095	9,699	9,488	9,453	9,583	9,724	10,623	11,928	13,283	14,452	15,374	16,042	16,217	16,103	15,736	15,273	14,682	14,175	13,953	13,276	12,323	11,352	10,480
DUK	9/2/12	9,816	9,374	9,058	8,906	8,912	9,064	9,174	10,030	11,198	12,314	13,391	14,423	15,019	15,295	15,339	15,276	14,905	14,231	13,641	13,384	12,722	11,776	10,863	10,035
DUK	9/3/12	9,468	9,053	8,823	8,790	8,922	9,170	9,264	9,977	10,943	11,990	12,982	13,758	14,173	14,300	14,221	13,987	13,657	13,161	12,885	12,868	12,326	11,363	10,501	9,752
DUK	9/4/12	9,292	9,078	8,980	9,149	9,788	11,146	11,880	12,198	12,554	13,032	13,493	13,959	14,447	14,810	15,008	14,932	14,630	14,220	14,001	14,035	13,319	12,218	11,198	10,435
DUK	9/5/12	9,902	9,569	9,340	9,471	10,056	11,413	12,047	12,296	12,663	13,168	13,665	14,164	14,767	15,378	15,828	16,157	16,126	15,745	15,230	15,156	14,210	12,971	11,746	10,910
DUK	9/6/12	10,296	9,919	9,660	9,686	10,191	11,474	12,037	12,380	12,837	13,495	14,183	14,846	15,492	15,969	16,095	16,054	15,970	15,482	14,955	14,917	14,012	12,700	11,495	10,596
DUK	9/7/12	9,936	9,504	9,305	9,295	9,786	10,905	11,437	11,789	12,360	13,233	14,148	14,990	15,749	16,273	16,608	16,641	16,449	15,839	14,952	14,617	13,724	12,698	11,476	10,454
DUK	9/8/12	9,740	9,262	8,937	8,805	8,906	9,190	9,413	10,092	10,989	12,056	13,165	14,200	14,889	15,138	14,910	14,277	13,521	12,728	12,318	12,160	11,555	10,730	9,881	9,089
DUK	9/9/12	8,543	8,112	7,828	7,677	7,654	7,807	7,950	8,605	9,221	9,673	10,099	10,630	11,086	11,529	11,887	12,171	12,290	12,005	11,575	11,622	10,933	9,986	9,047	8,360
DUK	9/10/12	7,916	7,683	7,593	7,708	8,297	9,455	9,906	10,232	10,714	11,225	11,664	12,053	12,496	12,747	13,038	13,291	13,186	12,827	12,485	12,561	11,821	10,725	9,667	8,918
DUK	9/11/12	8,452	8,161	8,062	8,110	8,653	9,820	10,317	10,484	10,736	11,063	11,330	11,675	12,159	12,595	12,960	13,180	13,053	12,692	12,374	12,603	11,733	10,548	9,509	8,777
DUK	9/12/12	8,340	8,069	7,954	8,042	8,599	9,738	10,139	10,359	10,794	11,317	11,812	12,192	12,696	13,067	13,319	13,581	13,498	13,059	12,591	12,575	11,743	10,595	9,527	8,733
DUK	9/13/12	8,286	8,004	7,900	8,017	8,515	9,663	10,085	10,326	10,636	11,096	11,523	11,822	12,241	12,619	12,885	13,056	12,882	12,404	12,206	12,308	11,611	10,556	9,503	8,765
DUK	9/14/12	8,270	8,023	7,889	7,983	8,497	9,629	10,065	10,249	10,622	11,071	11,520	11,921	12,393	12,792	13,110	13,294	13,191	12,660	12,246	12,096	11,459	10,567	9,649	8,822
DUK	9/15/12	8,315	7,976	7,723	7,672	7,821	8,148	8,313	8,968	9,705	10,412	11,049	11,647	12,180	12,592	12,955	13,094	12,986	12,562	12,194	12,100	11,405	10,538	9,633	8,884
DUK	9/16/12	8,365	8,034	7,844	7,719	7,768	7,966	8,218	8,776	9,282	9,519	9,694	9,895	10,042	10,146	10,228	10,398	10,571	10,588	10,874	10,990	10,499	9,783	9,021	8,425
DUK	9/17/12	8,058	7,883	7,826	7,982	8,641	9,933	10,624	10,783	11,057	11,351	11,538	11,699	11,960	12,151	12,283	12,358	12,272	12,226	12,516	12,490	11,882	10,928	10,028	9,374
DUK	9/18/12	8,969	8,772	8,744	8,906	9,576	10,901	11,611	11,778	12,070	12,412	12,554	12,573	12,517	12,418	12,321	12,335	12,284	12,221	12,406	12,512	11,879	10,858	9,849	9,035
DUK	9/19/12	8,578	8,222	8,036	8,097	8,582	9,790	10,262	10,370	10,575	10,821	11,083	11,305	11,637	11,920	12,180	12,328	12,208	11,912	11,798	11,877	11,206	10,269	9,297	8,552
DUK	9/20/12	8,139	7,893	7,779	7,872	8,439	9,634	10,090	10,216	10,510	10,838	11,124	11,361	11,731	12,060	12,328	12,455	12,349	12,017	11,961	12,001	11,333	10,349	9,310	8,563
DUK	9/21/12	8,114	7,852	7,735	7,802	8,317	9,421	9,870	10,060	10,497	11,010	11,391	11,791	12,192	12,569	12,804	13,007	12,820	12,327	11,967	11,814	11,179	10,386	9,444	8,709
DUK	9/22/12	8,187	7,862	7,697	7,665	7,775	8,107	8,327	8,933	9,666	10,354	10,979	11,541	12,006	12,474	12,857	13,051	12,956	12,427	12,169	11,984	11,306	10,446	9,575	8,730
DUK	9/23/12	8,099	7,677	7,414	7,266	7,277	7,468	7,577	8,236	8,862	9,204	9,550	9,902	10,175	10,434	10,709	10,940	10,994	10,703	10,600	10,578	9,946	9,088	8,337	7,807
DUK	9/24/12	7,472	7,325	7,260	7,419	8,045	9,287	9,811	9,976	10,214	10,445	10,567	10,675	10,836	10,960	11,066	11,175	11,126	10,936	11,109	11,134	10,435	9,545	8,679	8,104
DUK	9/25/12	7,761	7,547	7,505	7,663	8,291	9,489	9,936	10,003	10,178	10,430	10,545	10,686	10,934	11,086	11,276	11,402	11,325	11,175	11,474	11,469	10,830	9,817	8,908	8,269
DUK	9/26/12	7,898	7,693	7,611	7,751	8,348	9,606	10,057	10,200	10,506	10,934	11,182	11,578	12,058	12,498	12,894	13,092	13,025	12,603	12,602	12,426	11,607	10,529	9,485	8,723
DUK	9/27/12	8,285	7,966	7,852	7,921	8,461	9,705	10,236	10,366	10,755	11,235	11,734	12,209	12,737	13,225	13,625	13,829	13,638	13,081	12,984	12,698	11,845	10,749	9,658	8,858
DUK	9/28/12	8,330	8,035	7,906	7,996	8,492	9,624	10,084	10,292	10,688	11,185	11,566	12,128	12,747	13,215	13,327	13,192	12,754	12,205	12,052	11,690	11,100	10,276	9,424	8,665
DUK	9/29/12	8,196	7,908	7,735	7,709	7,796	8,167	8,522	8,964	9,478	9,807	9,937	9,931	9,878	9,849	9,890	9,970	9,988	9,912	10,200	10,155	9,788	9,188	8,520	7,942
DUK	9/30/12	7,545	7,266	7,140	7,058	7,139	7,378	7,612	8,179	8,642	8,833	9,049	9,306	9,571	9,737	9,845	9,864	9,914	9,957	10,497	10,412	9,894	9,217	8,478	7,959
DUK	10/1/12	7,625	7,463	7,423	7,586	8,259	9,491	10,240	10,377	10,517	10,673	10,744	10,747	10,736	10,641	10,598	10,615	10,615	10,775	11,187	11,025	10,411	9,644	8,894	8,373

Backup - DUK Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DUK	10/2/12	8,046	7,893	7,880	8,090	8,748	10,054	10,754	10,908	11,237	11,705	11,981	12,283	12,776	13,024	13,158	13,193	13,128	12,914	13,145	12,975	12,175	11,152	10,054	9,341
DUK	10/3/12	8,829	8,493	8,354	8,436	9,045	10,286	10,859	10,955	11,261	11,710	12,139	12,455	12,876	12,983	12,815	12,660	12,494	12,426	12,761	12,507	11,757	10,793	9,851	9,096
DUK	10/4/12	8,581	8,285	8,147	8,229	8,790	10,092	10,754	10,788	10,937	11,299	11,617	11,975	12,451	12,789	13,039	13,126	12,934	12,424	12,476	12,252	11,430	10,421	9,412	8,685
DUK	10/5/12	8,222	7,942	7,804	7,882	8,392	9,509	10,028	10,122	10,485	10,927	11,221	11,561	12,008	12,376	12,627	12,729	12,488	11,912	11,714	11,397	10,803	10,011	9,154	8,422
DUK	10/6/12	7,907	7,639	7,466	7,438	7,601	7,948	8,191	8,672	9,236	9,744	10,161	10,585	10,984	11,310	11,531	11,597	11,456	11,186	11,357	11,054	10,470	9,694	8,899	8,159
DUK	10/7/12	7,684	7,358	7,188	7,122	7,171	7,420	7,775	8,206	8,620	8,768	8,901	9,010	9,042	9,014	9,030	9,130	9,271	9,422	9,944	9,815	9,387	8,787	8,172	7,703
DUK	10/8/12	7,419	7,302	7,303	7,480	8,124	9,359	10,169	10,276	10,468	10,676	10,754	10,779	10,832	10,758	10,749	10,847	11,037	11,329	11,802	11,575	10,965	10,132	9,344	8,793
DUK	10/9/12	8,494	8,375	8,345	8,531	9,172	10,397	11,037	10,915	10,951	11,007	10,940	10,789	10,708	10,551	10,455	10,421	10,455	10,754	11,317	11,187	10,636	9,790	8,967	8,460
DUK	10/10/12	8,198	8,060	8,045	8,246	8,921	10,209	10,811	10,655	10,599	10,587	10,533	10,500	10,559	10,540	10,502	10,491	10,386	10,462	11,007	10,917	10,382	9,558	8,765	8,221
DUK	10/11/12	7,946	7,847	7,863	8,090	8,800	10,257	10,915	10,830	10,757	10,693	10,559	10,440	10,438	10,370	10,341	10,374	10,285	10,356	11,029	10,976	10,417	9,695	8,957	8,392
DUK	10/12/12	8,099	7,991	8,007	8,190	8,835	10,119	10,708	10,623	10,628	10,604	10,471	10,307	10,290	10,281	10,249	10,177	10,054	10,051	10,466	10,240	9,861	9,293	8,553	7,979
DUK	10/13/12	7,637	7,466	7,377	7,455	7,708	8,171	8,602	9,059	9,332	9,368	9,253	9,086	8,957	8,871	8,870	8,933	8,988	9,042	9,628	9,504	9,216	8,772	8,201	7,752
DUK	10/14/12	7,479	7,327	7,294	7,317	7,512	7,854	8,281	8,794	9,056	8,993	8,889	8,934	8,949	8,919	8,903	8,987	9,177	9,455	10,157	10,046	9,550	8,904	8,266	7,805
DUK	10/15/12	7,523	7,399	7,376	7,545	8,188	9,482	10,341	10,431	10,634	10,851	10,923	10,954	11,054	11,053	11,118	11,065	10,919	10,858	11,304	11,054	10,396	9,542	8,708	8,157
DUK	10/16/12	7,837	7,693	7,686	7,890	8,598	9,957	10,650	10,574	10,543	10,541	10,508	10,445	10,501	10,496	10,479	10,483	10,388	10,514	11,049	10,915	10,255	9,463	8,792	8,218
DUK	10/17/12	7,909	7,822	7,832	8,043	8,769	10,135	10,823	10,665	10,618	10,578	10,491	10,454	10,496	10,487	10,498	10,511	10,425	10,462	10,978	10,809	10,254	9,441	8,630	8,095
DUK	10/18/12	7,844	7,734	7,748	7,944	8,621	9,928	10,596	10,508	10,553	10,641	10,601	10,795	10,663	10,707	10,712	10,638	10,589	10,826	11,307	11,118	10,529	9,721	8,918	8,312
DUK	10/19/12	7,957	7,784	7,714	7,880	8,429	9,623	10,223	10,222	10,360	10,483	10,508	10,450	10,488	10,426	10,347	10,218	10,027	9,959	10,303	10,108	9,732	9,186	8,498	7,964
DUK	10/20/12	7,681	7,537	7,517	7,585	7,872	8,394	8,891	9,319	9,527	9,515	9,408	9,262	9,132	9,075	9,064	9,074	9,120	9,293	9,751	9,604	9,275	8,746	8,185	7,756
DUK	10/21/12	7,481	7,393	7,385	7,473	7,712	8,134	8,659	9,216	9,389	9,160	8,977	8,916	8,882	8,829	8,827	8,907	9,048	9,332	9,971	9,889	9,432	8,831	8,256	7,872
DUK	10/22/12	7,680	7,619	7,697	7,980	8,779	10,199	11,030	10,956	10,836	10,750	10,628	10,579	10,627	10,618	10,669	10,710	10,634	10,736	11,263	10,980	10,283	9,443	8,688	8,089
DUK	10/23/12	7,801	7,665	7,658	7,842	8,548	9,920	10,642	10,550	10,567	10,599	10,635	10,702	10,834	10,907	10,992	11,025	10,890	10,896	11,333	11,003	10,369	9,430	8,609	8,057
DUK	10/24/12	7,735	7,597	7,570	7,766	8,466	9,833	10,574	10,478	10,515	10,621	10,701	10,800	11,058	11,215	11,320	11,388	11,263	11,161	11,483	11,152	10,543	9,616	8,785	8,235
DUK	10/25/12	7,814	7,636	7,562	7,752	8,416	9,726	10,445	10,340	10,480	10,675	10,821	10,937	11,132	11,248	11,306	11,269	11,063	11,122	11,504	11,232	10,615	9,748	8,881	8,230
DUK	10/26/12	7,874	7,678	7,622	7,711	8,299	9,471	10,181	10,203	10,397	10,603	10,717	10,754	10,853	10,858	10,778	10,660	10,428	10,432	10,691	10,419	10,015	9,367	8,659	7,991
DUK	10/27/12	7,642	7,398	7,295	7,305	7,490	7,880	8,358	8,709	9,104	9,324	9,381	9,364	9,321	9,281	9,243	9,241	9,271	9,538	9,847	9,658	9,272	8,743	8,098	7,613
DUK	10/28/12	7,265	7,106	6,967	6,976	7,114	7,413	7,894	8,345	8,730	8,763	8,749	8,857	8,888	8,839	8,812	8,902	9,058	9,541	9,963	9,873	9,430	8,897	8,391	8,004
DUK	10/29/12	7,833	7,790	7,872	8,149	8,937	10,320	11,232	11,231	11,284	11,342	11,342	11,252	11,208	11,083	11,061	11,229	11,515	12,214	12,596	12,334	11,719	10,930	10,181	9,679
DUK	10/30/12	9,447	9,367	9,345	9,591	10,334	11,575	12,332	12,104	12,062	12,051	11,868	11,735	11,600	11,468	11,425	11,525	11,745	12,286	12,627	12,359	11,854	11,069	10,298	9,797
DUK	10/31/12	9,573	9,475	9,524	9,796	10,557	11,888	12,594	12,323	12,054	11,800	11,521	11,251	11,004	10,821	10,689	10,661	10,582	10,886	11,212	11,284	11,205	10,609	9,927	9,507
DUK	11/1/12	9,264	9,204	9,238	9,535	10,305	11,712	12,458	12,226	11,904	11,565	11,245	10,956	10,768	10,547	10,428	10,339	10,397	11,004	11,706	11,671	11,309	10,707	10,053	9,632
DUK	11/2/12	9,497	9,500	9,581	9,878	10,640	11,957	12,601	12,324	11,997	11,632	11,151	10,818	10,607	10,301	10,050	9,967	9,935	10,311	10,734	10,616	10,383	9,945	9,388	8,950
DUK	11/3/12	8,762	8,757	8,818	9,021	9,417	9,995	10,587	10,979	10,967	10,508	10,060	9,604	9,246	9,031	8,918	8,947	8,998	9,447	9,890	9,765	9,518	9,090	8,578	8,142
DUK	11/4/12	7,849	7,849	7,671	7,686	7,805	8,101	8,528	9,040	9,563	9,556	9,244	9,018	8,955	8,866	8,844	8,846	9,112	9,794	10,243	10,168	9,946	9,472	8,944	8,443
DUK	11/5/12	8,171	8,082	8,148	8,301	8,750	9,685	11,144	11,718	11,569	11,278	11,064	10,825	10,612	10,504	10,385	10,325	10,431	11,135	11,829	11,844	11,622	11,145	10,526	9,954

Backup - DUK Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
DUK	11/6/12	9,636	9,498	9,474	9,540	9,860	10,651	11,841	12,341	12,499	12,600	12,553	12,555	12,235	12,057	11,813	11,744	11,937	12,671	13,138	13,011	12,725	12,174	11,529	10,873
DUK	11/7/12	10,551	10,379	10,327	10,461	10,803	11,642	12,947	13,309	12,990	12,609	12,242	11,795	11,431	11,245	11,069	11,008	11,238	12,027	12,622	12,598	12,393	11,911	11,224	10,567
DUK	11/8/12	10,225	10,087	10,053	10,170	10,553	11,457	12,919	13,262	12,732	12,017	11,576	11,157	10,838	10,667	10,513	10,427	10,527	11,219	11,913	11,987	11,878	11,514	10,937	10,291
DUK	11/9/12	10,011	9,938	9,986	10,178	10,547	11,440	12,877	13,160	12,656	11,887	11,338	10,881	10,524	10,345	10,122	10,007	9,999	10,561	10,950	10,840	10,737	10,525	10,108	9,651
DUK	11/10/12	9,327	9,229	9,278	9,437	9,713	10,133	10,750	11,195	11,236	10,776	10,285	9,864	9,520	9,260	9,125	9,041	9,145	9,693	10,105	9,989	9,855	9,609	9,207	8,800
DUK	11/11/12	8,490	8,376	8,393	8,516	8,733	9,094	9,566	10,067	10,330	10,012	9,464	9,095	8,987	8,905	8,778	8,738	8,873	9,567	9,955	9,860	9,645	9,213	8,702	8,188
DUK	11/12/12	7,808	7,563	7,473	7,545	7,750	8,380	9,391	9,981	10,289	10,521	10,655	10,715	10,625	10,604	10,534	10,468	10,541	11,238	11,508	11,317	10,941	10,329	9,595	8,825
DUK	11/13/12	8,315	8,018	7,867	7,878	8,116	8,850	10,291	10,925	10,976	11,041	11,055	10,914	10,720	10,647	10,479	10,423	10,574	11,370	12,076	12,095	11,984	11,629	10,986	10,376
DUK	11/14/12	10,045	9,955	9,981	10,147	10,518	11,485	13,073	13,515	13,200	12,686	12,309	11,871	11,466	11,261	11,072	11,087	11,443	12,371	12,837	12,745	12,477	11,928	11,155	10,458
DUK	11/15/12	10,080	9,862	9,864	9,968	10,299	11,129	12,609	13,071	12,935	12,800	12,743	12,509	12,166	11,952	11,669	11,554	11,631	12,465	13,001	13,016	12,895	12,480	11,779	11,220
DUK	11/16/12	10,853	10,668	10,684	10,804	11,194	12,101	13,581	13,938	13,428	12,689	11,987	11,418	10,929	10,650	10,390	10,261	10,379	11,179	11,676	11,665	11,625	11,452	11,114	10,577
DUK	11/17/12	10,265	10,182	10,183	10,269	10,498	10,899	11,488	11,848	11,990	11,662	11,222	10,740	10,281	9,900	9,618	9,536	9,768	10,629	11,097	11,057	10,959	10,695	10,262	9,760
DUK	11/18/12	9,373	9,124	9,008	8,941	8,986	9,198	9,557	9,979	10,516	10,620	10,309	9,945	9,758	9,579	9,408	9,384	9,596	10,472	10,930	10,909	10,758	10,312	9,757	9,204
DUK	11/19/12	8,797	8,582	8,538	8,563	8,830	9,634	10,965	11,490	11,389	11,294	11,163	10,964	10,705	10,603	10,455	10,352	10,462	11,238	11,781	11,770	11,565	11,116	10,450	9,729
DUK	11/20/12	9,316	9,104	9,057	9,181	9,501	10,328	11,713	12,163	11,928	11,656	11,404	10,994	10,669	10,503	10,335	10,243	10,329	11,081	11,593	11,581	11,447	11,139	10,610	10,044
DUK	11/21/12	9,696	9,560	9,597	9,747	10,096	10,858	11,910	12,480	12,464	11,965	11,504	11,099	10,718	10,503	10,271	10,060	10,066	10,757	11,203	11,157	11,090	10,853	10,386	9,772
DUK	11/22/12	9,343	9,155	9,160	9,282	9,559	9,955	10,467	10,888	11,194	10,979	10,672	10,283	9,595	8,980	8,520	8,220	8,096	8,548	8,895	8,975	9,103	9,185	9,110	8,954
DUK	11/23/12	8,863	8,912	9,029	9,263	9,638	10,161	10,786	11,082	11,049	10,536	10,025	9,574	9,138	8,817	8,642	8,579	8,746	9,557	9,845	9,719	9,582	9,339	8,932	8,538
DUK	11/24/12	8,189	8,053	8,093	8,227	8,496	8,941	9,497	9,953	10,355	10,393	10,247	9,983	9,640	9,304	9,122	9,124	9,484	10,569	11,199	11,313	11,414	11,345	11,067	10,751
DUK	11/25/12	10,545	10,484	10,570	10,751	11,044	11,464	12,046	12,503	12,637	12,049	11,246	10,594	10,206	9,842	9,560	9,451	9,770	10,915	11,655	11,847	11,863	11,523	11,058	10,571
DUK	11/26/12	10,325	10,233	10,346	10,578	11,041	12,017	13,556	14,153	13,687	12,807	12,078	11,510	11,111	10,844	10,610	10,484	10,602	11,499	12,075	12,065	11,910	11,429	10,758	10,025
DUK	11/27/12	9,568	9,283	9,120	9,118	9,347	10,086	11,415	11,959	11,781	11,676	11,612	11,511	11,454	11,327	11,300	11,369	11,642	12,315	12,530	12,401	12,141	11,576	10,813	10,016
DUK	11/28/12	9,518	9,259	9,211	9,372	9,762	10,635	12,210	12,795	12,537	12,040	11,663	11,302	11,024	10,812	10,599	10,530	10,758	11,812	12,526	12,660	12,721	12,476	11,936	11,344
DUK	11/29/12	11,108	11,050	11,158	11,421	11,913	12,848	14,439	14,853	14,342	13,390	12,540	11,909	11,406	11,080	10,819	10,757	10,923	11,934	12,615	12,746	12,743	12,395	11,774	11,181
DUK	11/30/12	10,871	10,768	10,836	11,033	11,464	12,383	13,901	14,420	13,913	12,985	12,056	11,375	10,886	10,577	10,320	10,193	10,314	11,136	11,574	11,522	11,467	11,258	10,787	10,232

Backup - CPL Hourly Load

Dec 2011-Nov 2012 Load

CPLPea	**Max**	13,193
CPLAv	**Avg Jul**	11,822
CPLW	**Winter**	8,835
CPLSp	**Spring**	7,948
CPLSu	**Summer**	10,777
CPLFa	**Fall**	8,500

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
CPL	12/1/11	7389	7307	7324	7434	7779	8510	9629	9823	9308	8640	8131	7654	7280	7048	6861	6819	7128	8133	8725	8945	9070	8934	8597	8248
CPL	12/2/11	7987	8042	8146	8332	8705	9417	10459	10615	9921	8860	8013	7429	7069	6743	6556	6572	6640	7530	7929	8028	8114	8104	7901	7571
CPL	12/3/11	7369	7320	7338	7398	7531	7803	8175	8394	8411	7966	7483	7029	6639	6396	6222	6194	6447	7296	7592	7608	7643	7533	7270	6906
CPL	12/4/11	6619	6529	6528	6611	6758	6992	7362	7710	7869	7530	6948	6486	6276	6142	6024	5950	6168	7006	7281	7301	7250	6934	6464	5917
CPL	12/5/11	5551	5382	5329	5339	5530	6105	7023	7230	7069	6961	6885	6792	6683	6679	6580	6556	6766	7505	7731	7648	7447	7019	6407	5725
CPL	12/6/11	5305	5075	4957	4931	5065	5579	6558	6826	6717	6682	6766	6759	6677	6700	6722	6650	6737	7455	7665	7600	7408	6997	6335	5696
CPL	12/7/11	5241	5023	4915	4880	5008	5510	6422	6704	6659	6709	6770	6844	6832	6841	6813	6834	6979	7650	7811	7697	7526	7146	6661	6187
CPL	12/8/11	5875	5819	5856	5985	6351	7156	8400	8796	8578	8211	7915	7577	7270	7092	6918	6930	7259	8351	8894	9102	9164	8976	8525	7990
CPL	12/9/11	7675	7637	7572	7610	7842	8419	9413	9507	9098	8575	8103	7666	7269	7047	6838	6772	7057	7889	8055	7950	7821	7617	7193	6693
CPL	12/10/11	6281	6115	6060	6081	6196	6514	6915	7308	7725	7780	7632	7340	7037	6773	6640	6670	6989	7889	8224	8356	8450	8416	8203	7847
CPL	12/11/11	7559	7525	7551	7604	7791	8047	8443	8848	9081	8705	8084	7544	7238	7001	6831	6866	7369	8423	8858	9012	9024	8730	8246	7718
CPL	12/12/11	7384	7242	7243	7338	7657	8338	9375	9617	9336	9109	8892	8562	8312	8097	7791	7671	7888	8828	9247	9283	9158	8824	8233	7678
CPL	12/13/11	7323	7249	7278	7394	7696	8376	9478	9703	9249	8594	7977	7466	7104	6899	6730	6670	6898	7750	8213	8308	8285	8053	7576	7055
CPL	12/14/11	6744	6697	6710	6790	7035	7617	8647	8860	8449	8036	7654	7262	7013	6861	6672	6663	6896	7796	8168	8230	8211	7935	7399	6867
CPL	12/15/11	6503	6400	6383	6468	6726	7371	8448	8660	8186	7605	7189	6895	6683	6609	6516	6454	6607	7298	7581	7568	7472	7144	6568	5917
CPL	12/16/11	5489	5215	5139	5145	5301	5794	6713	6971	6850	6735	6664	6639	6562	6517	6487	6512	6718	7276	7378	7213	7099	6889	6546	6053
CPL	12/17/11	5677	5504	5398	5433	5568	5818	6215	6703	7134	7371	7345	7181	6927	6685	6596	6637	6934	7799	8190	8292	8416	8443	8310	8008
CPL	12/18/11	7725	7576	7542	7546	7663	7983	8464	8992	9225	8723	7980	7441	7130	6886	6686	6672	7030	8047	8659	8930	9172	9055	8779	8380
CPL	12/19/11	8210	8165	8318	8502	8856	9516	10427	10739	10438	9542	8652	8000	7517	7259	7024	7013	7249	8202	8705	8741	8698	8403	7847	7210
CPL	12/20/11	6870	6649	6569	6601	6832	7379	8228	8542	8272	7903	7552	7243	7017	6858	6738	6689	6889	7606	7777	7656	7539	7221	6613	6037
CPL	12/21/11	5568	5339	5252	5242	5387	5849	6547	6846	6937	7040	7068	6991	6877	6857	6769	6780	6903	7530	7613	7452	7266	6993	6481	5851
CPL	12/22/11	5393	5095	4916	4867	4936	5286	5914	6286	6508	6624	6706	6695	6631	6625	6560	6498	6623	7237	7503	7271	7090	6734	6355	5724
CPL	12/23/11	5204	4960	4778	4705	4756	5013	5425	5771	6058	6314	6455	6384	6281	6166	6076	6032	6120	6738	6957	6863	6777	6642	6375	5981
CPL	12/24/11	5619	5412	5322	5371	5530	5807	6250	6708	7149	7181	6996	6745	6518	6300	6173	6191	6404	7067	7232	7212	7264	7260	7149	6878
CPL	12/25/11	6595	6506	6528	6609	6774	7068	7435	7773	7931	7528	6943	6558	6372	6175	5966	5856	5924	6423	6622	6666	6676	6613	6410	6089
CPL	12/26/11	5843	5746	5777	5911	6162	6547	6999	7345	7510	7418	7169	6905	6503	6235	6072	6001	6249	7289	7840	8021	8092	7970	7665	7186
CPL	12/27/11	6796	6621	6464	6397	6480	6773	7209	7559	7712	7826	7852	7700	7482	7215	6810	6570	6643	7299	7615	7537	7444	7176	6827	6474

Backup - CPL Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
CPL	12/28/11	6163	6070	6082	6210	6501	6983	7615	8048	8120	7920	7662	7385	7121	6878	6697	6653	6905	7892	8431	8523	8544	8321	7995	7613
CPL	12/29/11	7391	7426	7584	7834	8242	8830	9580	10025	9882	9124	8289	7692	7288	7005	6751	6621	6847	7752	8262	8347	8378	8249	7906	7501
CPL	12/30/11	7244	7069	7016	7078	7334	7821	8486	8885	8779	8151	7587	7089	6702	6411	6194	6099	6254	6947	7270	7217	7099	6883	6542	6103
CPL	12/31/11	5684	5466	5316	5269	5298	5442	5668	5885	6135	6274	6286	6178	6035	5884	5783	5745	5884	6543	6911	6804	6714	6585	6413	6282
CPL	1/1/12	6126	6180	6169	6280	6461	6718	7090	7415	7556	7135	6560	6121	5969	5821	5658	5556	5656	6287	6611	6553	6410	6139	5804	5405
CPL	1/2/12	5084	5038	5080	5228	5536	6051	6830	7265	7492	7529	7502	7331	7084	6888	6749	6793	7169	8251	8902	9081	9057	8803	8446	8080
CPL	1/3/12	7919	8002	8177	8463	8907	9733	10816	11145	10991	10703	10350	10007	9632	9410	9216	9302	9801	10813	11488	11554	11479	11160	10626	10200
CPL	1/4/12	10020	10069	10204	10426	10820	11567	12524	12692	12171	11213	10375	9654	9016	8621	8309	8223	8639	9677	10341	10456	10375	10036	9453	8873
CPL	1/5/12	8552	8417	8354	8390	8537	9122	10080	10300	9905	9230	8598	8041	7599	7342	7103	7016	7260	8072	8739	8923	9007	8817	8408	8047
CPL	1/6/12	7807	7783	7817	8000	8309	8947	9992	10265	9703	8792	8048	7471	7070	6794	6615	6493	6578	7183	7596	7530	7473	7339	7061	6686
CPL	1/7/12	6382	6273	6262	6306	6433	6687	7056	7386	7624	7515	7165	6790	6501	6255	6065	6015	6086	6599	6948	6832	6704	6466	6178	5753
CPL	1/8/12	5355	5207	5148	5107	5185	5336	5630	5992	6433	6520	6359	6128	6065	6043	5961	5934	6158	6794	7115	7034	6968	6649	6228	5758
CPL	1/9/12	5417	5358	5384	5444	5752	6387	7487	7915	7795	7789	7835	7821	7846	7804	7762	7784	8015	8537	8744	8604	8311	7888	7286	6732
CPL	1/10/12	6335	6147	6066	6078	6261	6852	7804	8116	7896	7752	7536	7261	7016	6858	6755	6744	6948	7654	8128	8115	8043	7681	7108	6589
CPL	1/11/12	6201	6071	5985	5981	6135	6677	7681	7976	7782	7718	7640	7631	7580	7561	7453	7391	7623	8032	8148	7914	7644	7190	6601	6082
CPL	1/12/12	5736	5635	5636	5734	6035	6685	7794	8065	7810	7553	7363	7155	6974	6804	6648	6565	6693	7373	7917	7930	7830	7496	6940	6423
CPL	1/13/12	6092	5984	6063	6357	6864	7725	9073	9639	9526	9285	9035	8698	8358	8088	7807	7719	8000	8831	9411	9440	9340	9083	8723	8293
CPL	1/14/12	7991	7946	7998	8133	8399	8823	9354	9874	9999	9620	9058	8506	8002	7565	7282	7171	7458	8262	8950	9109	9197	9066	8807	8423
CPL	1/15/12	8124	8002	7888	7850	7913	8124	8499	8920	9233	8954	8378	7856	7566	7355	7169	7057	7297	8133	8841	9098	9248	9188	8998	8735
CPL	1/16/12	8660	8713	8826	9025	9331	9869	10511	10914	10920	10393	9753	9112	8538	8153	7951	7913	8128	8776	9139	9027	8826	8414	7791	7191
CPL	1/17/12	6848	6619	6571	6565	6754	7323	8293	8516	8243	7935	7601	7340	7162	7069	6881	6731	6803	7262	7813	7761	7584	7164	6572	6009
CPL	1/18/12	5611	5459	5354	5401	5582	6124	7114	7530	7467	7510	7538	7461	7344	7220	7069	7023	7267	8048	8869	9040	9003	8794	8389	7892
CPL	1/19/12	7620	7569	7656	7880	8256	9093	10286	10671	10303	9665	8983	8368	7857	7575	7347	7320	7595	8356	8976	9040	8924	8551	8010	7567
CPL	1/20/12	7274	7260	7275	7452	7835	8598	9513	9810	9369	8696	8132	7663	7436	7282	7200	7229	7429	7977	8150	8035	7840	7559	7183	6682
CPL	1/21/12	6301	6128	5972	5893	5918	6050	6229	6474	6752	6957	6980	6876	6798	6666	6535	6545	6749	7152	7297	7179	7025	6834	6573	6309
CPL	1/22/12	6099	6093	6204	6335	6541	6901	7320	7869	8496	8816	8811	8702	8669	8544	8491	8434	8525	8969	9200	9128	8935	8514	8042	7569
CPL	1/23/12	7115	7046	6960	7031	7257	7829	8732	9016	8924	8807	8712	8490	8232	7962	7730	7570	7582	8016	8401	8265	7991	7536	6851	6272
CPL	1/24/12	5858	5632	5492	5478	5639	6114	7090	7406	7234	7128	7074	6909	6709	6609	6492	6436	6480	6856	7578	7611	7532	7247	6813	6392
CPL	1/25/12	6110	6113	6182	6359	6729	7472	8774	9018	8641	8029	7522	7169	6899	6728	6559	6478	6565	7031	7686	7786	7757	7561	7130	6698
CPL	1/26/12	6431	6360	6358	6417	6645	7234	8219	8367	8036	7814	7578	7261	6954	6747	6600	6521	6577	6999	7513	7452	7254	6892	6284	5721
CPL	1/27/12	5307	5059	4959	4931	5052	5464	6359	6692	6606	6628	6696	6650	6541	6473	6371	6271	6285	6508	7022	6937	6802	6685	6510	6068
CPL	1/28/12	5852	5780	5915	6101	6377	6844	7419	7927	8085	7700	7219	6853	6466	6230	6010	5942	6009	6426	7072	7094	7080	6969	6748	6439
CPL	1/29/12	6189	6108	6141	6215	6420	6752	7256	7783	8123	7887	7380	6931	6686	6424	6187	6138	6292	6908	7884	8199	8362	8246	7955	7629
CPL	1/30/12	7432	7451	7538	7680	8063	8856	10082	10421	9883	8921	8171	7640	7299	6988	6768	6672	6775	7290	8207	8400	8440	8203	7792	7337
CPL	1/31/12	7089	7043	7094	7279	7603	8372	9506	9704	9097	8326	7708	7237	6912	6740	6553	6495	6553	6942	7721	7838	7774	7467	6992	6523

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
CPL	2/1/12	6214	6076	6019	6033	6193	6778	7801	7958	7598	7191	6943	6755	6576	6470	6390	6344	6413	6768	7349	7311	7176	6829	6300	5695
CPL	2/2/12	5356	5172	5083	5087	5206	5755	6721	7019	6864	6775	6700	6632	6501	6478	6401	6349	6359	6547	7255	7284	7178	6898	6380	5905
CPL	2/3/12	5679	5598	5635	5818	6173	6954	8211	8561	8258	7828	7453	7076	6782	6570	6379	6291	6358	6768	7573	7709	7731	7728	7478	7190
CPL	2/4/12	6943	6831	6758	6776	6827	7079	7404	7696	7844	7672	7419	7128	6862	6624	6470	6421	6488	6816	7149	7079	6922	6646	6283	5840
CPL	2/5/12	5450	5221	5142	5129	5159	5335	5616	6012	6542	6856	6863	6744	6893	6943	6980	7071	7255	7626	7879	7773	7725	7560	7461	7062
CPL	2/6/12	6801	6740	6803	6961	7274	7993	9038	9285	9143	8924	8624	8203	7882	7619	7438	7355	7501	8029	8672	8667	8468	8018	7391	6834
CPL	2/7/12	6503	6389	6408	6516	6873	7655	8863	9130	8755	8187	7784	7368	7007	6805	6652	6572	6738	7213	8045	8233	8279	8118	7753	7380
CPL	2/8/12	7242	7298	7409	7646	8040	8804	9904	10037	9449	8699	8122	7771	7521	7408	7257	7198	7319	7811	8595	8739	8788	8576	8167	7788
CPL	2/9/12	7574	7572	7673	7857	8227	8962	10173	10430	9823	9062	8466	7941	7549	7235	7031	6933	7108	7657	8615	8928	9045	8903	8526	8168
CPL	2/10/12	8033	8048	8194	8412	8749	9518	10592	10782	10169	9285	8731	8355	8028	7825	7644	7562	7694	8015	8414	8282	8143	7849	7449	7031
CPL	2/11/12	6685	6503	6430	6399	6473	6680	7014	7384	7762	7967	7846	7662	7466	7460	7446	7484	7698	8349	9391	9888	10230	10448	10386	10231
CPL	2/12/12	10131	10171	10236	10368	10534	10829	11227	11501	11542	11179	10424	9716	9176	8644	8226	7973	8049	8606	9606	10025	10119	9922	9567	9254
CPL	2/13/12	9063	9069	9231	9463	9847	10643	11700	11876	11188	10173	9299	8611	8062	7688	7393	7277	7391	7980	8931	9144	9214	9040	8581	8090
CPL	2/14/12	7715	7572	7567	7647	7824	8427	9413	9624	9289	8945	8581	8144	7702	7385	7189	7075	7170	7574	8212	8245	8115	7753	7284	6705
CPL	2/15/12	6350	6200	6167	6227	6562	7259	8407	8696	8196	7639	7265	6938	6691	6562	6434	6359	6403	6642	7477	7665	7641	7434	7010	6559
CPL	2/16/12	6340	6254	6253	6346	6584	7239	8308	8437	8235	8073	7979	7817	7583	7450	7364	7322	7438	7690	8075	8003	7770	7357	6843	6265
CPL	2/17/12	5901	5714	5650	5658	5892	6461	7496	7767	7502	7159	6919	6673	6478	6369	6247	6167	6178	6358	7017	7151	7130	7035	6810	6467
CPL	2/18/12	6176	6052	6016	6035	6166	6443	6879	7256	7430	7196	6843	6501	6179	5968	5819	5747	5819	6054	6676	6680	6550	6361	6040	5661
CPL	2/19/12	5328	5142	5043	5045	5108	5257	5596	5994	6611	7058	7176	7294	7468	7619	7676	7778	7958	8287	8702	8712	8629	8432	8123	7849
CPL	2/20/12	7665	7603	7611	7698	8003	8562	9420	9772	9534	9149	8632	8223	7738	7427	7162	6991	7033	7438	8468	8916	9045	8907	8600	8218
CPL	2/21/12	8114	8148	8290	8463	8829	9522	10596	10669	9992	9202	8589	8068	7655	7253	6987	6795	6805	7084	7858	8108	7992	7623	7112	6549
CPL	2/22/12	6228	6103	6089	6153	6389	7063	8093	8238	7724	7283	6991	6803	6612	6518	6406	6331	6364	6581	7266	7357	7237	6852	6331	5788
CPL	2/23/12	5345	5198	5123	5136	5357	5954	6980	7187	6964	6837	6722	6677	6568	6560	6499	6463	6477	6564	7166	7256	7133	6699	6163	5557
CPL	2/24/12	5155	4892	4815	4783	4885	5334	6192	6401	6483	6618	6736	6731	6662	6596	6481	6405	6404	6571	6994	6920	6724	6427	6047	5481
CPL	2/25/12	5336	5234	5269	5364	5583	5992	6486	7021	7402	7565	7492	7276	6976	6730	6527	6404	6495	6900	7640	7933	7994	7877	7687	7428
CPL	2/26/12	7219	7163	7328	7537	7837	8226	8726	9135	9071	8572	7884	7361	7016	6682	6380	6184	6214	6574	7500	8045	8192	8074	7744	7443
CPL	2/27/12	7210	7124	7059	6997	7087	7624	8561	8696	8438	8209	8110	7913	7698	7500	7365	7307	7398	7631	8194	8196	7961	7490	6900	6346
CPL	2/28/12	5975	5813	5735	5793	6027	6670	7739	7900	7599	7196	6953	6740	6500	6441	6338	6269	6283	6437	7110	7440	7349	7025	6550	6095
CPL	2/29/12	5758	5649	5616	5691	5857	6443	7390	7563	7402	7217	7009	6841	6684	6622	6521	6465	6467	6615	7185	7302	7088	6718	6168	5591
CPL	3/1/12	5172	4952	4823	4741	4882	5367	6248	6478	6499	6543	6639	6677	6724	6728	6740	6721	6724	6730	7179	7366	7173	6738	6184	5583
CPL	3/2/12	5147	4924	4833	4832	4992	5492	6377	6699	6783	6829	6824	6768	6649	6553	6475	6413	6482	6580	6997	7005	6798	6498	6109	5597
CPL	3/3/12	5191	4935	4799	4734	4727	4859	5088	5317	5773	6140	6373	6381	6259	6153	6006	5957	6043	6271	6711	6660	6506	6306	5964	5557
CPL	3/4/12	5235	5093	5043	5077	5229	5442	5785	6200	6786	7068	6943	6665	6468	6297	6231	6223	6446	6840	7629	8051	8073	7931	7620	7308
CPL	3/5/12	7186	7213	7308	7483	7716	8335	9217	9250	8900	8436	8064	7768	7503	7354	7154	7027	7119	7499	8453	8903	8911	8676	8264	7868
CPL	3/6/12	7695	7780	7933	8161	8597	9424	10395	10334	9578	8832	8221	7774	7385	7070	6856	6687	6711	7065	7927	8443	8546	8324	7882	7464

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
CPL	3/7/12	7282	7302	7364	7493	7810	8422	9352	9277	8488	7849	7388	6999	6744	6611	6478	6412	6434	6605	7221	7430	7291	7002	6412	5865
CPL	3/8/12	5535	5376	5342	5418	5653	6288	7159	7295	6968	6774	6689	6629	6526	6473	6419	6364	6359	6418	6953	7238	7088	6729	6136	5544
CPL	3/9/12	5147	4932	4828	4823	4953	5370	6256	6562	6599	6654	6693	6640	6497	6427	6305	6228	6269	6423	6946	7230	7208	7122	6909	6583
CPL	3/10/12	6346	6294	6347	6446	6671	7001	7356	7594	7633	7460	7074	6735	6447	6106	5892	5797	5833	6018	6649	7056	7160	7153	6962	6704
CPL	3/11/12	6555	6533	0	6535	6857	7247	7665	8148	8254	7708	7108	6629	6349	6095	5851	5682	5606	5682	5847	6458	6905	6762	6406	5974
CPL	3/12/12	5704	5634	5678	5835	6127	6818	7946	8389	8075	7499	7035	6768	6569	6509	6404	6355	6370	6385	6506	6997	7225	6821	6257	5629
CPL	3/13/12	5195	4927	4858	4821	4937	5416	6390	6811	6664	6635	6649	6606	6538	6573	6593	6580	6573	6549	6600	6975	7285	6941	6276	5610
CPL	3/14/12	5146	4868	4698	4669	4768	5240	6193	6611	6465	6468	6543	6627	6723	6889	7002	7090	7175	7208	7188	7369	7579	7098	6471	5745
CPL	3/15/12	5194	4900	4721	4664	4739	5174	6125	6528	6434	6545	6697	6839	6996	7228	7333	7371	7382	7351	7235	7454	7671	7247	6550	5850
CPL	3/16/12	5299	4995	4788	4756	4844	5216	6072	6452	6406	6505	6632	6711	6802	6947	7107	7225	7318	7308	7162	7155	7256	6904	6455	5812
CPL	3/17/12	5293	4932	4740	4589	4608	4699	4949	5146	5543	5934	6237	6413	6601	6752	6847	6957	7031	6992	6792	6869	6994	6624	6142	5630
CPL	3/18/12	5103	4782	4610	4475	4453	4499	4653	4900	5323	5683	5795	5873	5955	5992	6007	6039	6167	6262	6279	6574	6909	6523	5960	5381
CPL	3/19/12	4944	4667	4559	4519	4618	5081	5995	6398	6337	6410	6557	6699	6742	6850	6932	7011	7167	7259	7256	7371	7642	7182	6394	5700
CPL	3/20/12	5192	4926	4767	4712	4766	5185	6131	6432	6441	6544	6664	6801	6945	7195	7366	7584	7731	7777	7697	7763	7936	7419	6657	5915
CPL	3/21/12	5349	5066	4894	4806	4868	5285	6183	6525	6489	6600	6801	7001	7119	7218	7334	7398	7399	7372	7288	7457	7648	7202	6559	5842
CPL	3/22/12	5309	5029	4868	4791	4856	5277	6164	6463	6458	6598	6824	6984	7163	7374	7526	7598	7687	7610	7630	7701	7922	7484	6718	5940
CPL	3/23/12	5384	5090	4903	4804	4861	5196	6026	6361	6406	6561	6852	7133	7419	7698	7928	8045	8135	8077	7910	7757	7699	7311	6752	6123
CPL	3/24/12	5572	5182	4957	4830	4781	4848	5084	5310	5700	6126	6407	6496	6548	6505	6591	6658	6671	6602	6596	6638	6689	6444	5935	5421
CPL	3/25/12	4978	4691	4537	4447	4412	4479	4652	4867	5368	5761	5872	5915	6048	6073	6103	6019	6034	6079	6103	6354	6658	6344	5829	5302
CPL	3/26/12	4890	4669	4568	4558	4659	5112	6048	6406	6397	6480	6557	6631	6726	6841	6944	7057	7199	7224	7152	7174	7486	7007	6291	5577
CPL	3/27/12	5027	4817	4697	4700	4826	5378	6446	6813	6754	6693	6644	6564	6463	6406	6308	6291	6354	6379	6474	6743	7197	6933	6383	5836
CPL	3/28/12	5460	5301	5216	5219	5436	6019	7082	7345	7052	6810	6664	6502	6484	6557	6574	6562	6759	6806	6813	6988	7410	7069	6433	5738
CPL	3/29/12	5217	4954	4815	4737	4817	5209	6121	6355	6392	6546	6819	7110	7249	7392	7599	7667	7816	7840	7691	7585	7751	7230	6541	5755
CPL	3/30/12	5219	4909	4730	4672	4754	5096	5903	6204	6261	6327	6473	6607	6708	6940	7084	7274	7375	7306	7141	7071	7214	6916	6353	5832
CPL	3/31/12	5308	5002	4762	4687	4657	4728	4985	5173	5603	5987	6196	6255	6242	6226	6237	6329	6455	6553	6498	6563	6801	6529	6045	5575
CPL	4/1/12	5027	4711	4526	4399	4390	4423	4582	4751	5262	5625	5651	5639	5686	5788	5832	5951	6045	6083	6093	6310	6640	6410	5905	5335
CPL	4/2/12	4881	4663	4568	4578	4657	5092	5868	6141	6291	6470	6664	6814	6962	7028	7103	7128	7224	7219	7115	7147	7374	6971	6308	5649
CPL	4/3/12	5103	4921	4743	4694	4793	5346	6235	6561	6511	6453	6544	6507	6508	6586	6707	6793	6932	7013	6985	7127	7350	6991	6436	5754
CPL	4/4/12	5236	4975	4815	4768	4821	5249	5983	6278	6381	6524	6771	7057	7316	7666	7987	8231	8362	8282	8046	7829	7932	7507	6804	6043
CPL	4/5/12	5520	5190	4982	4891	4928	5283	5988	6231	6386	6510	6592	6684	6655	6652	6501	6398	6351	6348	6383	6609	6762	6497	6035	5477
CPL	4/6/12	5091	4875	4758	4731	4828	5131	5634	6040	6420	6775	6913	6845	6696	6456	6272	6079	5997	5972	5951	6102	6599	6525	6297	5948
CPL	4/7/12	5665	5530	5499	5539	5666	5951	6301	6605	6808	6726	6489	6194	5905	5733	5604	5555	5587	5650	5685	5833	6266	6202	5919	5502
CPL	4/8/12	5163	5015	4926	4936	5027	5283	5576	5908	6252	6258	5930	5667	5616	5571	5521	5523	5585	5658	5673	5788	6257	6042	5594	5054
CPL	4/9/12	4692	4507	4403	4397	4554	4985	5677	6058	6190	6317	6434	6473	6474	6521	6536	6562	6654	6618	6595	6662	7023	6637	6053	5372
CPL	4/10/12	4976	4777	4669	4659	4794	5242	6022	6429	6505	6499	6514	6478	6532	6568	6602	6613	6637	6628	6609	6715	7094	6717	6169	5527

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
CPL	4/11/12	5120	4889	4772	4723	4834	5299	6075	6418	6516	6532	6548	6504	6467	6409	6334	6274	6295	6355	6446	6689	7190	7036	6587	6119
CPL	4/12/12	5833	5734	5730	5868	6156	6769	7717	8090	7880	7490	7194	6898	6674	6523	6390	6297	6263	6288	6314	6536	7054	6895	6454	5989
CPL	4/13/12	5706	5607	5632	5735	6020	6576	7413	7705	7490	7177	6924	6644	6435	6352	6263	6230	6228	6187	6153	6188	6582	6385	6026	5593
CPL	4/14/12	5260	5099	5051	5080	5214	5515	5888	6185	6345	6306	6185	6063	5959	5923	5913	5979	6073	6133	6093	6082	6466	6294	5887	5362
CPL	4/15/12	4950	4674	4507	4406	4404	4522	4621	4854	5388	5720	5884	6008	6202	6375	6516	6653	6824	6968	6951	6916	7310	7015	6401	5727
CPL	4/16/12	5195	4893	4727	4645	4743	5164	5934	6271	6480	6699	7036	7312	7565	7887	8100	8264	8294	8366	8270	8133	8261	7868	7066	6208
CPL	4/17/12	5593	5280	5066	4934	4995	5379	6169	6463	6686	7001	7384	7764	8114	8388	8627	8776	8876	8794	8774	8588	8686	8170	7224	6322
CPL	4/18/12	5703	5346	5135	5003	5039	5412	6203	6474	6566	6708	6908	7071	7175	7368	7432	7394	7372	7288	7233	7274	7460	7070	6403	5700
CPL	4/19/12	5259	4995	4853	4806	4884	5303	6157	6407	6439	6528	6588	6615	6574	6551	6522	6476	6507	6515	6570	6783	7113	6844	6214	5608
CPL	4/20/12	5170	4939	4800	4763	4865	5301	6098	6346	6383	6474	6572	6617	6678	6797	6893	6972	7036	7055	6955	6818	7031	6849	6327	5717
CPL	4/21/12	5228	4935	4711	4659	4657	4763	4900	5140	5626	6008	6355	6630	6879	7063	7201	7316	7380	7305	7159	6962	7139	6831	6373	5815
CPL	4/22/12	5278	4995	4778	4665	4550	4409	4775	4944	5420	5801	5925	5970	6005	6018	5943	5921	5930	6034	6143	6360	6657	6362	5894	5404
CPL	4/23/12	5049	4888	4814	4818	4996	5568	6565	6911	6898	6890	6861	6843	6842	6840	6752	6762	6882	7080	7262	7474	7861	7529	6973	6422
CPL	4/24/12	6092	5943	5911	5977	6213	6875	7788	7959	7702	7405	7150	6853	6694	6620	6487	6390	6414	6418	6480	6640	7235	7150	6397	5940
CPL	4/25/12	5564	5465	5429	5456	5649	6182	7100	7286	7161	7072	6984	6867	6641	6529	6432	6433	6464	6508	6526	6601	7051	6855	6215	5608
CPL	4/26/12	5135	4913	4812	4792	4900	5358	6191	6440	6500	6642	6819	6942	6971	7013	7080	7101	7092	7134	7146	7145	7522	7262	6614	5969
CPL	4/27/12	5457	5138	4962	4875	4924	5318	6020	6347	6540	6772	7020	7226	7421	7584	7784	7849	7892	7816	7586	7287	7404	7174	6575	5933
CPL	4/28/12	5418	5077	4848	4721	4705	4833	4968	5223	5658	5957	6132	6180	6169	6189	6170	6212	6246	6255	6213	6223	6510	6335	5931	5455
CPL	4/29/12	5044	4740	4585	4522	4531	4601	4704	4982	5480	5794	5919	5993	6110	6237	6421	6586	6803	6934	6938	6850	7180	6971	6286	5636
CPL	4/30/12	5131	4815	4702	4664	4778	5226	6005	6347	6438	6637	6866	7068	7332	7605	7847	8032	8130	8109	8015	7907	8183	7794	7082	6270
CPL	5/1/12	5668	5342	5123	5041	5143	5583	6392	6692	6850	7199	7622	8030	8376	8765	9080	9367	9558	9508	9300	9009	9091	8721	7776	6908
CPL	5/2/12	6137	5805	5462	5366	5385	5767	6511	6874	7170	7633	8132	8641	9153	9683	9961	10184	10359	10404	10303	9992	9834	9295	8403	7314
CPL	5/3/12	6565	6103	5799	5588	5546	5910	6601	7020	7424	7786	8410	8951	9494	10014	10287	10457	10695	10625	10477	10044	9909	9371	8241	7271
CPL	5/4/12	6493	6035	5649	5489	5448	5756	6368	6815	7133	7595	8124	8628	9047	9529	9887	10009	10109	9978	9577	9062	8917	8528	7808	6976
CPL	5/5/12	6319	5832	5518	5335	5238	5330	5344	5748	6499	7244	7916	8431	8828	9134	9263	9301	9255	9092	8729	8260	8098	7706	7102	6426
CPL	5/6/12	5858	5492	5227	5089	5024	5062	5102	5344	5897	6358	6490	6620	6919	6931	7066	7202	7344	7447	7434	7298	7460	7153	6598	5842
CPL	5/7/12	5331	5026	4863	4772	4880	5313	6001	6354	6544	6805	7130	7411	7672	7962	8188	8418	8589	8540	8377	8071	8180	7833	7013	6204
CPL	5/8/12	5615	5302	5106	5006	5056	5447	6124	6483	6715	6979	7281	7529	7744	8029	8236	8462	8642	8634	8486	8214	8304	8009	7198	6379
CPL	5/9/12	5787	5476	5265	5180	5234	5653	6347	6724	6955	7214	7464	7766	7957	8174	8264	8211	8038	7798	7657	7473	7496	7207	6571	5861
CPL	5/10/12	5401	5128	4947	4870	4941	5322	5967	6305	6442	6619	6800	6916	6982	7126	7219	7329	7439	7424	7302	7112	7228	7034	6353	5668
CPL	5/11/12	5194	4890	4733	4706	4812	5214	5870	6195	6291	6425	6523	6640	6706	6804	6986	7131	7267	7296	7137	6840	6834	6688	6178	5527
CPL	5/12/12	5076	4767	4642	4550	4547	4689	4753	5117	5532	5862	6103	6229	6303	6458	6611	6714	6815	6795	6640	6486	6659	6564	6121	5587
CPL	5/13/12	5021	4747	4562	4494	4475	4514	4496	4900	5513	5946	6115	6181	6310	6360	6258	6278	6232	6233	6202	6323	6677	6570	6098	5489
CPL	5/14/12	5057	4859	4702	4676	4782	5202	5942	6320	6502	6828	7207	7458	7657	7671	7632	7530	7483	7450	7460	7362	7559	7341	6653	5988
CPL	5/15/12	5505	5259	5125	5041	5124	5550	6292	6705	6905	7211	7590	7889	8234	8652	8852	8954	8997	8972	8754	8448	8443	8064	7281	6519

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CPL	5/16/12	5892	5558	5387	5311	5323	5735	6407	6822	7036	7383	7816	8219	8556	8793	8892	8873	8856	8662	8408	8203	8238	7940	7153	6404
CPL	5/17/12	5813	5508	5297	5155	5216	5614	6272	6631	6867	7220	7632	7952	8211	8322	8246	8163	7995	7788	7669	7585	7674	7369	6694	6025
CPL	5/18/12	5473	5221	5011	4917	4945	5284	5880	6205	6332	6482	6668	6770	6871	6941	7007	7058	7115	7056	6872	6637	6833	6724	6267	5671
CPL	5/19/12	5172	4833	4674	4558	4526	4665	4724	5072	5539	5888	6107	6255	6353	6442	6597	6709	6821	6855	6699	6493	6590	6528	6007	5462
CPL	5/20/12	4968	4696	4507	4403	4382	4460	4426	4844	5368	5730	5940	6124	6379	6599	6853	6978	7123	7190	7131	7110	7284	7168	6581	5915
CPL	5/21/12	5336	5056	4917	4846	4949	5391	6055	6437	6697	7007	7352	7685	7935	8265	8535	8777	8982	9048	8954	8683	8551	8217	7381	6482
CPL	5/22/12	5869	5508	5252	5132	5166	5567	6210	6680	6978	7375	7907	8412	8817	9084	9221	9218	9032	8807	8520	8267	8222	7946	7140	6401
CPL	5/23/12	5829	5538	5291	5180	5229	5630	6305	6668	6923	7200	7602	7957	8330	8855	9156	9175	8994	8734	8519	8173	8127	7873	7131	6347
CPL	5/24/12	5786	5476	5276	5149	5222	5625	6357	6836	7184	7606	8119	8631	9130	9535	9784	9953	10091	10025	9731	9286	9089	8811	7959	6991
CPL	5/25/12	6267	5855	5581	5430	5437	5775	6405	6934	7332	7881	8415	8967	9413	9786	9995	10097	10162	10088	9820	9314	9010	8724	8015	7147
CPL	5/26/12	6408	5938	5627	5404	5323	5351	5345	5772	6412	7125	7692	8191	8587	8894	9164	9396	9547	9541	9303	8835	8542	8328	7648	6888
CPL	5/27/12	6278	5819	5503	5287	5208	5257	5173	5600	6257	6897	7385	7812	8233	8670	8952	9185	9312	9197	8875	8439	8224	8030	7465	6753
CPL	5/28/12	6161	5803	5516	5415	5386	5503	5562	5927	6596	7417	8212	8820	9277	9627	9767	9847	9784	9649	9381	9052	8926	8673	7905	6974
CPL	5/29/12	6336	5977	5738	5580	5674	6071	6742	7333	7823	8371	8947	9444	9833	10154	10266	10338	10238	10054	9734	9358	9250	8884	8088	7206
CPL	5/30/12	6611	6244	5978	5843	5872	6282	6958	7384	7507	7715	7867	7974	8064	8222	8429	8674	8965	9170	9148	8789	8527	8288	7428	6597
CPL	5/31/12	5927	5600	5342	5221	5287	5639	6167	6750	7230	7850	8491	9110	9696	10231	10483	10644	10752	10664	10444	9914	9592	9223	8326	7325
CPL	6/1/12	6577	6106	5809	5645	5681	5999	6601	7156	7556	7985	8549	9112	9592	9884	10148	10221	10043	9581	9200	8810	8641	8468	7785	6953
CPL	6/2/12	6324	5884	5603	5378	5268	5261	5235	5585	6067	6499	6910	7223	7456	7656	7863	7947	8057	8067	7854	7481	7218	7082	6561	5920
CPL	6/3/12	5301	4915	4757	4631	4558	4571	4540	4925	5504	6021	6344	6601	6866	7153	7416	7743	7963	8097	8099	7846	7694	7568	6898	6139
CPL	6/4/12	5575	5241	5034	4985	5056	5412	5984	6510	6893	7313	7701	7986	8287	8586	8786	8908	9038	9039	8965	8634	8431	8176	7370	6542
CPL	6/5/12	5885	5546	5288	5190	5225	5571	6145	6541	6658	6889	7057	7223	7352	7563	7717	7815	7881	7884	7809	7523	7490	7420	6783	5992
CPL	6/6/12	5453	5101	4956	4865	4929	5252	5833	6212	6351	6515	6611	6772	6886	7062	7237	7429	7634	7708	7646	7455	7434	7398	6749	6032
CPL	6/7/12	5442	5140	4971	4858	4914	5235	5742	6191	6443	6685	7018	7430	7717	8030	8284	8492	8648	8685	8547	8225	8043	7918	7178	6316
CPL	6/8/12	5749	5340	5097	4997	4974	5283	5707	6188	6698	7102	7624	8045	8409	8768	9029	9242	9363	9334	9053	8553	8118	7917	7294	6509
CPL	6/9/12	5822	5394	5141	4951	4908	4935	4942	5353	5993	6670	7319	7938	8478	8821	9202	9445	9594	9542	9199	8703	8423	8206	7571	6815
CPL	6/10/12	6175	5678	5366	5142	5026	4974	4896	5326	6155	6942	7531	8041	8526	8933	9113	9213	9214	9118	8824	8509	8376	8207	7536	6829
CPL	6/11/12	6184	5802	5615	5479	5565	5917	6386	6946	7396	7844	8278	8599	8899	9275	9468	9341	9145	8883	8674	8467	8415	8293	7719	6978
CPL	6/12/12	6377	6043	5776	5707	5753	6077	6573	7005	7380	7754	8167	8472	8747	9014	9135	9254	9329	9312	9218	8930	8859	8698	8049	7267
CPL	6/13/12	6589	6171	5908	5771	5772	6039	6434	6990	7470	8041	8695	9212	9802	10107	10369	10481	10388	10353	9944	9568	9137	8774	7940	6945
CPL	6/14/12	6218	5761	5444	5244	5223	5459	5773	6296	6754	7209	7603	7938	8185	8429	8701	8829	8932	8879	8725	8365	8168	8117	7423	6557
CPL	6/15/12	5932	5456	5196	5049	5069	5282	5579	6083	6535	6938	7324	7654	7956	8202	8525	8689	8812	8764	8558	8143	7811	7689	7082	6331
CPL	6/16/12	5626	5239	4964	4796	4728	4781	4764	5126	5666	6149	6577	6936	7203	7541	7744	8023	8281	8312	8094	7664	7360	7265	6692	6014
CPL	6/17/12	5366	4992	4761	4624	4549	4540	4468	4862	5466	6043	6387	6680	7009	7386	7709	8003	8265	8392	8287	7890	7607	7511	6854	6174
CPL	6/18/12	5553	5183	4991	4856	4950	5240	5552	6130	6571	7056	7548	8000	8405	8918	9330	9681	9891	9903	9765	9349	9004	8778	7928	7076
CPL	6/19/12	6360	5915	5594	5424	5403	5675	6114	6685	7184	7787	8501	9246	9865	10434	10845	11128	11263	11218	10932	10392	9969	9673	8774	7806

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
CPL	6/20/12	7054	6522	6159	5911	5871	6122	6475	7144	7796	8500	9301	10055	10688	11203	11490	11637	11705	11583	11481	10964	10512	10185	9250	8237
CPL	6/21/12	7403	6898	6506	6268	6202	6429	6752	7391	8085	8816	9652	10483	11169	11616	11722	11782	11747	11535	11254	10844	10472	10209	9344	8411
CPL	6/22/12	7629	7122	6745	6545	6399	6524	6812	7372	8011	8773	9577	10376	11015	11524	11582	11572	11503	11221	10565	9904	9487	9103	8403	7619
CPL	6/23/12	6930	6384	6105	5873	5796	5800	5802	6214	7005	7870	8617	9207	9769	10219	10530	10711	10799	10699	10331	9768	9387	9123	8420	7568
CPL	6/24/12	6878	6401	6001	5769	5610	5576	5489	5914	6785	7719	8516	9143	9728	10135	10327	10420	10411	10245	9859	9451	9127	8952	8325	7523
CPL	6/25/12	6862	6445	6166	5986	5997	6313	6744	7362	7984	8661	9294	9976	10526	11040	11387	11558	11600	11528	11340	10860	10443	10065	9087	8049
CPL	6/26/12	7239	6697	6294	6032	5916	6021	6289	6723	7052	7356	7717	7975	8239	8526	8749	8914	8969	8848	8666	8339	7998	7868	7191	6350
CPL	6/27/12	5727	5330	5097	4991	5002	5228	5568	6098	6526	6921	7428	7871	8252	8745	9147	9559	9912	10041	9912	9394	8855	8534	7675	6794
CPL	6/28/12	6099	5660	5380	5219	5248	5489	5814	6389	6973	7625	8335	9122	9753	10370	10913	11344	11590	11550	11407	10958	10399	10061	9148	8125
CPL	6/29/12	7346	6812	6447	6202	6140	6349	6621	7253	8033	8938	9933	10893	11729	12311	12741	12949	13075	13106	12886	12513	12028	11670	10804	9694
CPL	6/30/12	8820	8163	7544	7072	6780	6649	6508	6925	7846	8911	9961	10841	11524	12035	12410	12684	12823	12814	12588	12134	11737	11445	10688	9792
CPL	7/1/12	8966	8324	7860	7487	7189	7071	6891	7347	8272	9340	10310	11172	11910	12360	12468	12013	11282	10466	9895	9418	9092	8821	8210	7508
CPL	7/2/12	6912	6445	6172	6044	6100	6362	6626	7089	7614	8180	8903	9497	10032	10582	11034	11396	11604	11661	11484	11026	10616	10247	9351	8405
CPL	7/3/12	7547	7074	6689	6456	6373	6496	6803	7421	8255	9140	10142	11024	11662	12118	12317	12345	12302	12202	11924	11369	10929	10453	9687	8821
CPL	7/4/12	8009	7405	7028	6722	6559	6563	6477	6748	7482	8454	9450	10307	10975	11418	11808	11842	11700	11332	10788	10185	9753	9362	8952	8255
CPL	7/5/12	7575	7042	6717	6502	6471	6613	6853	7520	8378	9318	10334	11227	11990	12428	12646	12645	12372	11991	11447	10863	10496	10097	9295	8406
CPL	7/6/12	7617	7117	6747	6530	6441	6597	6811	7367	8098	8986	9849	10735	11362	11963	12331	12381	12358	12120	11580	11057	10605	10309	9564	8717
CPL	7/7/12	7937	7395	6961	6693	6567	6618	6567	6997	7954	8950	9935	10821	11531	12024	12317	12403	12474	12391	12251	11896	11432	11174	10431	9583
CPL	7/8/12	8751	8212	7793	7484	7276	7185	7020	7443	8392	9384	10280	11077	11742	12211	12508	12569	12618	12610	12460	12084	11770	11466	10665	9757
CPL	7/9/12	9012	8462	8047	7765	7662	7843	8071	8680	9449	10344	11201	11988	12495	12763	12779	12486	12030	11512	11046	10598	10285	9872	9125	8271
CPL	7/10/12	7575	7162	6833	6610	6615	6887	7240	7777	8342	8847	9416	9945	10352	10763	10899	10778	10611	10377	9973	9528	9324	8969	8249	7494
CPL	7/11/12	6887	6538	6313	6150	6124	6428	6902	7369	7775	8238	8690	9071	9397	9740	9881	9808	9623	9257	8913	8615	8482	8349	7737	7094
CPL	7/12/12	6537	6233	5973	5875	5905	6223	6627	7038	7483	7963	8495	8960	9370	9773	9967	10045	10051	9907	9659	9262	9120	8922	8238	7464
CPL	7/13/12	6885	6468	6205	6041	6071	6305	6653	7185	7752	8336	8908	9452	9842	10119	10178	10093	9987	9786	9561	9217	9040	8916	8320	7617
CPL	7/14/12	6985	6576	6278	6113	6028	6091	6133	6548	7326	8140	8927	9618	10191	10624	10917	11054	11153	11044	10753	10262	9910	9625	8923	8097
CPL	7/15/12	7329	6842	6459	6178	6029	5976	5899	6377	7376	8361	9098	9693	10231	10667	10958	11156	11285	11323	11096	10606	10223	9960	9128	8304
CPL	7/16/12	7498	7004	6678	6460	6446	6704	7084	7734	8481	9233	9928	10761	11410	11841	12022	11957	11823	11399	10895	10321	10022	9732	8947	8045
CPL	7/17/12	7324	6885	6586	6404	6366	6579	7026	7626	8349	9115	10007	10840	11533	12101	12410	12568	12574	12415	12101	11577	11189	10832	9916	8937
CPL	7/18/12	8173	7612	7189	6969	6924	7133	7465	8046	8719	9493	10346	11153	11832	12263	12529	12476	12579	12538	12306	11761	11407	11008	10125	9185
CPL	7/19/12	8388	7855	7516	7266	7219	7441	7737	8337	9001	9802	10639	11360	11850	12364	12606	12678	12712	12587	12326	11691	11260	10831	9939	8964
CPL	7/20/12	8172	7633	7262	7060	7025	7220	7532	8054	8685	9356	10056	10685	11191	11504	11604	11524	11234	10749	10271	9770	9566	9297	8718	7954
CPL	7/21/12	7363	6896	6621	6409	6323	6404	6465	6720	7299	8049	8804	9463	10034	10448	10608	10657	10519	10093	9655	9250	9071	8762	8145	7441
CPL	7/22/12	6925	6566	6286	6074	5992	6028	5998	6304	7105	7934	8500	9010	9574	10025	10384	10634	10737	10684	10424	9962	9692	9475	8776	7952
CPL	7/23/12	7328	6894	6553	6440	6466	6772	7195	7852	8648	9456	10423	11178	11880	12377	12638	12602	12568	12490	12036	11277	10739	10217	9315	8401
CPL	7/24/12	7725	7263	6979	6771	6750	6981	7405	8002	8809	9598	10569	11427	12166	12642	12832	12626	12011	11390	10843	10256	9993	9646	8906	7935

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CPL	7/25/12	7341	6922	6586	6413	6393	6635	7017	7538	7998	8526	9142	9762	10362	10879	11314	11633	11803	11757	11547	11021	10703	10327	9462	8549
CPL	7/26/12	7812	7331	7063	6897	6870	7131	7568	8159	8950	9909	10922	11818	12405	12795	13059	13126	13193	13134	13083	12760	12362	11971	11023	10011
CPL	7/27/12	9171	8562	8133	7864	7775	7952	8202	8685	9502	10388	11329	12157	12699	13016	13157	13151	13153	13019	12698	12000	11302	10702	9885	8991
CPL	7/28/12	8225	7699	7282	6959	6797	6762	6692	6971	7711	8461	9282	10063	10649	11114	11465	11728	11864	11794	11439	10908	10468	9751	8856	8033
CPL	7/29/12	7351	6800	6401	6145	5965	5967	5897	6207	7056	7950	8702	9416	10048	10600	10993	11229	11318	11220	10917	10378	10047	9668	8867	7964
CPL	7/30/12	7257	6764	6476	6259	6258	6559	6943	7479	8090	8788	9550	10183	10544	10792	10667	10428	10084	9886	9665	9354	9259	9055	8308	7538
CPL	7/31/12	6899	6499	6201	6056	6087	6420	6877	7284	7732	8190	8793	9374	9963	10553	10930	11217	11308	11164	10826	10387	10190	9810	8984	8117
CPL	8/1/12	7509	7003	6635	6461	6480	6722	7200	7581	7843	8240	8736	9293	9799	10345	10785	11134	11376	11343	11024	10470	10131	9756	8903	7906
CPL	8/2/12	7322	6835	6515	6329	6296	6505	6905	7397	8144	8960	9796	10450	11027	11460	11581	11371	11071	10693	10282	9838	9608	9287	8499	7710
CPL	8/3/12	6982	6566	6261	6043	6059	6293	6649	7112	7758	8491	9261	10003	10561	10980	11292	11451	11551	11445	11135	10572	10266	9886	9137	8281
CPL	8/4/12	7527	7057	6653	6389	6282	6265	6345	6614	7452	8386	9225	9919	10431	10770	11104	11316	11417	11418	11131	10587	10302	9954	9214	8412
CPL	8/5/12	7634	7146	6831	6543	6409	6354	6296	6659	7676	8583	9259	9744	10099	10417	10478	10489	10619	10649	10478	10033	9840	9523	8800	8012
CPL	8/6/12	7356	6930	6625	6474	6467	6766	7226	7755	8318	8973	9740	10445	11017	11511	11769	11818	11823	11623	11233	10607	10359	9794	8983	8123
CPL	8/7/12	7485	7073	6718	6629	6626	6846	7345	7693	8040	8358	8799	9334	9813	10168	10343	10249	9993	9775	9574	9365	9398	9029	8372	7622
CPL	8/8/12	7087	6651	6442	6325	6356	6673	7182	7569	7846	8131	8547	9020	9490	10141	10702	10982	11058	10835	10476	9851	9480	9017	8262	7416
CPL	8/9/12	6808	6412	6091	5906	5915	6177	6587	7072	7578	8303	9079	9800	10302	10760	11132	11336	11445	11379	11038	10527	10494	10025	9184	8292
CPL	8/10/12	7657	7184	6898	6638	6606	6822	7267	7633	8001	8387	8790	9175	9562	9842	10011	10083	10083	9795	9472	9156	9215	8975	8432	7765
CPL	8/11/12	7189	6735	6492	6319	6256	6335	6427	6661	7328	8021	8594	9035	9396	9568	9667	9501	9426	9098	8770	8494	8495	8264	7736	7096
CPL	8/12/12	6567	6073	5894	5715	5663	5686	5754	5958	6536	7083	7529	7952	8526	9050	9537	9888	10143	10227	10051	9590	9458	9007	8234	7455
CPL	8/13/12	6791	6318	6085	5919	5924	6209	6678	7100	7688	8490	9322	10095	10618	11087	11403	11586	11618	11507	11179	10685	10474	9814	8936	7922
CPL	8/14/12	7207	6720	6386	6190	6126	6397	6818	7230	7815	8534	9323	10095	10631	11177	11607	11714	11740	11679	11541	11014	10828	10249	9334	8378
CPL	8/15/12	7648	7136	6835	6640	6613	6860	7349	7790	8385	9021	9773	10511	11013	11403	11519	11425	11287	11073	10688	10125	9972	9515	8605	7744
CPL	8/16/12	7058	6618	6310	6119	6105	6337	6828	7177	7699	8312	8970	9691	10185	10744	11111	11309	11433	11332	10989	10417	10216	9610	8772	7800
CPL	8/17/12	7098	6585	6252	6054	6005	6253	6687	7089	7716	8499	9369	10081	10661	11098	11417	11563	11523	11303	10838	10274	10033	9461	8784	7939
CPL	8/18/12	7265	6729	6369	6148	6029	6029	6131	6269	6866	7573	8383	9041	9583	10038	10375	10541	10581	10498	10169	9727	9576	9125	8433	7636
CPL	8/19/12	6971	6526	6215	5982	5880	5873	5959	6158	6825	7521	7879	7987	8045	7985	7965	7916	8002	8157	8138	8087	8212	7928	7337	6778
CPL	8/20/12	6261	5941	5720	5656	5736	6097	6757	7111	7371	7627	7939	8233	8572	9051	9443	9688	9808	9717	9458	9155	9205	8732	7971	7174
CPL	8/21/12	6606	6224	5982	5830	5880	6224	6885	7221	7465	7739	8141	8460	8851	9266	9593	9706	9673	9534	9376	9132	9215	8747	7990	7180
CPL	8/22/12	6590	6168	5963	5764	5801	6145	6768	7142	7425	7884	8432	8980	9412	9760	9927	9937	9860	9665	9436	9135	9186	8745	8044	7058
CPL	8/23/12	6559	6169	5949	5801	5812	6197	6839	7151	7482	7999	8500	9076	9475	9860	10057	10116	10026	9691	9288	9069	9041	8581	7891	7093
CPL	8/24/12	6520	6263	5918	5798	5832	6028	6748	6989	7327	7616	7890	8099	8163	8198	8278	8224	8159	8045	7867	7719	7854	7610	7155	6529
CPL	8/25/12	6039	5690	5457	5330	5276	5345	5492	5623	6064	6570	6915	7282	7493	7639	7722	7791	7862	7883	7770	7591	7715	7416	6879	6306
CPL	8/26/12	5728	5425	5196	5040	4982	4994	5077	5251	5843	6537	7042	7629	8229	8809	9292	9626	9861	9897	9703	9342	9356	8800	7960	7100
CPL	8/27/12	6470	6050	5802	5705	5788	6236	7038	7319	7754	8399	9121	9708	10140	10538	10786	10876	10981	10990	10769	10414	10337	9638	8733	7785
CPL	8/28/12	7122	6689	6413	6235	6282	6689	7508	7824	8093	8468	8839	9199	9485	9789	9901	9972	9944	9780	9650	9453	9541	9006	8258	7499

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CPL	8/29/12	6908	6513	6307	6204	6252	6669	7508	7789	7987	8300	8791	9368	9853	10263	10580	10674	10632	10413	10097	9825	9786	9161	8301	7448
CPL	8/30/12	6826	6449	6178	6055	6069	6484	7269	7528	7748	8172	8761	9405	9935	10349	10665	10886	10958	10852	10502	10154	10146	9428	8507	7550
CPL	8/31/12	6844	6374	6069	5922	5942	6295	7010	7354	7692	8249	8929	9695	10381	11011	11418	11683	11658	11605	11339	10790	10561	9939	9195	8407
CPL	9/1/12	7711	7178	6816	6600	6450	6451	6517	6690	7378	8340	9439	10263	10941	11359	11446	11533	11408	11278	10941	10527	10295	9722	9000	8208
CPL	9/2/12	7564	7058	6729	6503	6332	6331	6395	6504	7276	8209	9044	9857	10446	10623	10462	10259	10126	10129	9901	9620	9430	8903	8300	7590
CPL	9/3/12	6999	6564	6252	6117	6033	6135	6267	6316	6840	7604	8398	9052	9617	10104	10465	10666	10676	10523	10131	9888	9700	8990	8216	7436
CPL	9/4/12	6833	6440	6225	6086	6092	6511	7329	7669	8051	8547	9185	9774	10352	10861	11173	11317	11348	11259	10937	10577	10481	9715	8743	7845
CPL	9/5/12	7178	6683	6477	6300	6320	6725	7575	7862	8197	8717	9264	9891	10389	10875	11243	11397	11441	11384	11219	10819	10712	9936	8973	8099
CPL	9/6/12	7453	7012	6748	6579	6594	6976	7804	8058	8410	8906	9563	10163	10725	11223	11368	11428	11281	10939	10455	10095	9957	9274	8413	7656
CPL	9/7/12	6995	6622	6344	6190	6214	6610	7386	7677	7849	8172	8562	9022	9492	9950	10300	10590	10740	10560	10164	9794	9567	9001	8266	7546
CPL	9/8/12	6945	6508	6193	6046	5987	6065	6253	6432	7048	7735	8400	9101	9729	10279	10664	10815	10797	10534	9971	9558	9254	8628	7891	7189
CPL	9/9/12	6560	6079	5795	5574	5455	5457	5542	5647	6145	6575	6919	7226	7575	7885	8095	8305	8429	8403	8182	7889	7942	7368	6692	5957
CPL	9/10/12	5449	5172	5007	4957	5036	5429	6183	6332	6584	6884	7208	7491	7755	8099	8346	8556	8704	8704	8421	8227	8181	7585	6792	6108
CPL	9/11/12	5542	5243	5089	4978	5065	5453	6205	6361	6542	6790	7065	7358	7596	7909	8173	8447	8645	8605	8319	8142	8146	7547	6759	6044
CPL	9/12/12	5538	5278	5068	4988	5080	5435	6183	6397	6544	6772	7055	7383	7584	7923	8253	8548	8713	8715	8397	8207	8180	7615	6814	6107
CPL	9/13/12	5593	5282	5108	5037	5107	5480	6270	6462	6593	6876	7242	7571	7861	8221	8533	8802	8973	8958	8681	8592	8569	7991	7201	6452
CPL	9/14/12	5926	5573	5341	5284	5322	5678	6453	6645	6904	7315	7822	8261	8563	8892	9036	9047	9016	8877	8621	8423	8312	7851	7247	6543
CPL	9/15/12	5916	5554	5275	5147	5125	5210	5400	5505	6077	6690	7265	7729	8211	8546	8863	8963	9070	8979	8508	8288	8148	7634	7074	6393
CPL	9/16/12	5869	5441	5201	5022	4958	5012	5130	5260	5785	6285	6625	6754	7002	7154	7214	7185	7234	7263	7222	7459	7473	7074	6513	5897
CPL	9/17/12	5486	5256	5083	5042	5166	5597	6353	6671	6882	7188	7581	8034	8456	8772	9023	9183	9164	9060	8911	9038	8884	8285	7508	6856
CPL	9/18/12	6329	6027	5857	5789	5921	6382	7297	7641	7845	8226	8531	8661	8759	8753	8808	8654	8542	8451	8438	8614	8610	8030	7336	6640
CPL	9/19/12	6099	5796	5589	5480	5517	5889	6710	6955	6981	7043	7148	7221	7226	7308	7297	7356	7445	7385	7327	7521	7548	7113	6474	5817
CPL	9/20/12	5371	5148	4965	4903	5002	5385	6193	6449	6500	6668	6872	7164	7368	7415	7688	7902	8021	7973	7758	7912	7872	7374	6704	5999
CPL	9/21/12	5521	5233	5036	4965	5015	5346	6103	6324	6448	6710	7041	7367	7758	8066	8340	8569	8716	8564	8197	7942	7796	7318	6732	6146
CPL	9/22/12	5625	5266	5008	4940	4899	4959	5191	5329	5794	6291	6765	7236	7725	8160	8550	8827	8981	8851	8518	8434	8211	7767	7181	6533
CPL	9/23/12	5925	5571	5325	5132	5006	4994	5088	5200	5782	6262	6577	6830	7091	7309	7522	7621	7688	7676	7402	7390	7281	6752	6119	5483
CPL	9/24/12	5044	4787	4692	4623	4746	5138	6000	6188	6336	6507	6684	6810	6948	7074	7231	7401	7511	7511	7335	7511	7417	6900	6203	5594
CPL	9/25/12	5163	4950	4808	4788	4874	5306	6156	6332	6437	6568	6738	6855	7021	7208	7450	7627	7785	7681	7547	7814	7618	7109	6423	5776
CPL	9/26/12	5294	5055	4924	4858	4942	5350	6212	6307	6446	6734	6979	7247	7566	7898	8281	8637	8853	8791	8499	8452	8248	7612	6843	6126
CPL	9/27/12	5549	5228	5069	4969	5050	5454	6290	6442	6601	6874	7289	7670	8101	8596	8981	9283	9380	9240	8874	8868	8528	7847	7072	6255
CPL	9/28/12	5783	5394	5190	5105	5183	5474	6283	6447	6735	7052	7502	7961	8365	8755	9030	9187	9153	8864	8539	8529	8179	7667	7104	6476
CPL	9/29/12	5918	5605	5306	5127	5078	5209	5360	5629	6015	6422	6735	6941	6953	6884	6844	6762	6761	6785	6823	7032	6895	6606	6177	5701
CPL	9/30/12	5285	4995	4803	4700	4673	4716	4853	5060	5472	5863	6032	6075	6253	6352	6499	6488	6601	6636	6771	7120	6979	6642	6147	5610
CPL	10/1/12	5168	4953	4826	4797	4901	5330	6192	6596	6553	6714	6837	6918	7011	7117	7174	7249	7329	7408	7560	7960	7775	7322	6763	6168
CPL	10/2/12	5748	5522	5404	5389	5498	5985	6884	7308	7407	7599	7943	8215	8687	9010	9186	9301	9217	9142	9159	9292	9099	8587	7885	7143

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CPL	10/3/12	6580	6389	6153	6025	6081	6508	7339	7589	7753	7962	8270	8596	8976	9119	9291	9415	9411	9347	9319	9353	9136	8548	7847	7157
CPL	10/4/12	6464	6103	5862	5715	5726	6180	6952	7177	7302	7514	7770	8007	8230	8412	8500	8563	8568	8445	8305	8551	8273	7840	7023	6359
CPL	10/5/12	5788	5425	5183	5117	5168	5548	6276	6584	6576	6807	7089	7402	7642	7971	8187	8425	8440	8205	7851	7812	7522	7094	6563	5939
CPL	10/6/12	5491	5169	4947	4833	4819	4903	5123	5303	5706	6180	6697	7064	7434	7742	7975	8272	8311	8168	7906	7928	7638	7088	6648	6079
CPL	10/7/12	5531	5219	4996	4822	4766	4788	4929	5023	5559	5973	6139	6217	6348	6551	6661	6703	6751	6763	6823	7051	6855	6409	5871	5379
CPL	10/8/12	5001	4807	4683	4635	4736	5192	6020	6406	6477	6592	6735	6811	6887	6847	6887	6901	7049	7225	7483	7711	7445	7035	6477	5850
CPL	10/9/12	5473	5283	5152	5128	5295	5771	6637	6951	6939	6917	6974	6956	6844	6821	6771	6668	6737	6868	7123	7498	7280	6879	6360	5767
CPL	10/10/12	5331	5178	5061	5040	5194	5643	6550	6773	6709	6639	6607	6621	6597	6665	6735	6731	6766	6810	6902	7327	7187	6790	6260	5665
CPL	10/11/12	5260	5030	4944	4925	5067	5613	6550	6818	6811	6745	6652	6610	6559	6572	6584	6586	6632	6645	6728	7192	7116	6702	6244	5745
CPL	10/12/12	5337	5139	5055	5091	5254	5731	6736	6923	6892	6802	6675	6611	6538	6564	6574	6583	6597	6564	6579	6810	6633	6332	6035	5550
CPL	10/13/12	5206	4942	4852	4820	4880	5060	5404	5718	6103	6305	6275	6170	6066	5996	5950	5962	6027	6070	6180	6536	6408	6170	5868	5461
CPL	10/14/12	5107	4891	4817	4789	4841	4950	5217	5502	5960	6120	6022	5999	6084	6201	6276	6360	6445	6538	6704	7056	6848	6410	5883	5399
CPL	10/15/12	4976	4761	4656	4584	4730	5191	6076	6392	6487	6630	6794	6962	7110	7282	7303	7315	7289	7270	7454	7793	7502	7000	6340	5727
CPL	10/16/12	5291	4993	4845	4812	4935	5430	6364	6689	6691	6645	6630	6615	6592	6619	6664	6694	6740	6753	6895	7319	7157	6655	6200	5712
CPL	10/17/12	5255	5127	5031	5035	5200	5743	6716	7040	6954	6868	6866	6681	6581	6610	6578	6567	6602	6603	6823	7239	7113	6721	6207	5692
CPL	10/18/12	5261	5091	5010	5032	5184	5666	6659	6914	6800	6750	6861	6854	6777	6883	6842	6916	7044	7015	7163	7544	7376	6950	6373	5759
CPL	10/19/12	5322	5050	4920	4866	4989	5424	6232	6564	6646	6737	6829	7000	7060	7154	7220	7279	7224	7041	6923	6982	6769	6403	6044	5486
CPL	10/20/12	5093	4839	4698	4649	4684	4887	5209	5526	5919	6094	6132	6077	6064	5993	6031	6045	6120	6117	6231	6466	6281	6064	5699	5287
CPL	10/21/12	4947	4737	4625	4590	4637	4775	5053	5386	5926	6020	5961	5856	5833	5829	5789	5807	5906	5971	6233	6672	6536	6174	5783	5344
CPL	10/22/12	5004	4893	4875	4943	5168	5793	6853	7229	7127	6969	6806	6692	6611	6644	6650	6670	6763	6767	6994	7350	7087	6671	6091	5602
CPL	10/23/12	5194	4987	4925	4933	5129	5697	6724	7085	6919	6804	6771	6695	6703	6806	6881	6951	7028	6994	7153	7408	7130	6717	6102	5504
CPL	10/24/12	5101	4881	4795	4800	4950	5459	6392	6790	6681	6654	6703	6818	6869	7043	7206	7405	7437	7369	7440	7587	7299	6837	6266	5606
CPL	10/25/12	5131	4896	4740	4709	4829	5351	6239	6619	6540	6621	6764	6948	7082	7328	7463	7594	7617	7507	7524	7721	7425	6891	6319	5707
CPL	10/26/12	5188	4962	4807	4754	4850	5260	6093	6465	6467	6605	6644	6718	6732	6786	6752	6693	6678	6624	6928	7010	6823	6527	6149	5673
CPL	10/27/12	5304	5010	4844	4757	4749	4877	5117	5409	5683	6081	6266	6304	6301	6228	6111	6082	6101	6224	6567	6618	6409	6184	5760	5363
CPL	10/28/12	4977	4774	4643	4540	4539	4637	4828	5176	5599	5911	5966	5968	6030	6027	5986	5934	6009	6175	6589	6839	6716	6360	5921	5479
CPL	10/29/12	5130	4952	4905	4928	5147	5695	6668	7172	7221	7258	7319	7315	7252	7208	7183	7224	7409	7659	8268	8560	8386	7955	7401	6874
CPL	10/30/12	6477	6319	6229	6219	6405	7015	7950	8329	8168	8088	8004	7872	7658	7598	7423	7428	7529	7769	8274	8472	8257	7909	7303	6777
CPL	10/31/12	6456	6348	6347	6409	6633	7253	8240	8583	8418	8080	7718	7422	7120	6968	6866	6816	6808	6888	7243	7439	7570	7474	7002	6541
CPL	11/1/12	6231	6147	6202	6323	6618	7262	8311	8663	8450	7963	7654	7230	6952	6795	6662	6619	6667	6854	7492	7908	7870	7690	7225	6800
CPL	11/2/12	6570	6528	6563	6686	6988	7629	8560	8852	8743	8263	7752	7292	6929	6704	6540	6382	6342	6461	6930	7199	7154	7085	6828	6481
CPL	11/3/12	6251	6130	6188	6300	6558	6941	7409	7914	8154	7889	7413	7004	6592	6313	6133	6019	6027	6177	6689	7021	7023	6919	6690	6285
CPL	11/4/12	6147	11765	5842	5829	5955	6131	6424	6788	7067	6971	6597	6299	6204	6152	6061	6083	6271	6908	7217	7156	7003	6608	6183	5779
CPL	11/5/12	5568	5488	5526	5600	5953	6700	7774	7972	7761	7496	7264	7018	6811	6714	6647	6637	6837	7605	8188	8293	8200	7901	7478	7045
CPL	11/6/12	6838	6812	6863	6971	7249	7808	8567	8656	8696	8678	8605	8464	8313	8191	8059	8014	8327	8827	9027	8908	8768	8355	7842	7295

Backup - CPL Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
CPL	11/7/12	7047	6901	6836	6917	7192	7822	8689	8811	8713	8413	8150	7892	7599	7416	7283	7336	7647	8434	8825	8825	8690	8345	7830	7390
CPL	11/8/12	7190	7164	7229	7385	7748	8489	9400	9448	9000	8319	7805	7379	7103	6941	6798	6744	6908	7661	8278	8457	8427	8197	7769	7277
CPL	11/9/12	7038	7000	7082	7270	7626	8348	9271	9373	8845	8092	7534	7144	6844	6671	6525	6452	6575	7172	7524	7516	7543	7416	7191	6877
CPL	11/10/12	6695	6654	6679	6768	7021	7375	7797	8075	7903	7386	6898	6530	6269	6085	5971	5941	6031	6509	6824	6745	6663	6501	6245	5962
CPL	11/11/12	5775	5706	5742	5837	5999	6260	6632	6997	7095	6759	6353	6058	5936	5892	5858	5812	5928	6476	6678	6599	6440	6099	5742	5361
CPL	11/12/12	5086	4941	4888	4957	5140	5610	6191	6552	6686	6728	6828	6814	6798	6757	6733	6705	6808	7359	7574	7466	7189	6760	6199	5633
CPL	11/13/12	5269	5053	4922	4867	5044	5554	6452	6773	6795	6830	6913	6945	6968	7003	7028	7088	7395	8049	8314	8313	8130	7768	7250	6756
CPL	11/14/12	6517	6433	6456	6588	6906	7644	8717	8879	8625	8332	8012	7686	7383	7254	7147	7212	7534	8367	8662	8613	8451	8076	7531	7006
CPL	11/15/12	6697	6566	6537	6607	6839	7490	8505	8750	8675	8585	8485	8314	8178	8125	8067	8070	8268	8777	8928	8852	8634	8176	7602	7022
CPL	11/16/12	6631	6479	6404	6418	6650	7220	8160	8355	8102	7781	7488	7155	6878	6707	6561	6562	6800	7507	7880	7913	7892	7756	7494	7172
CPL	11/17/12	6924	6846	6872	6965	7130	7481	7869	8221	8346	8064	7661	7253	6916	6671	6566	6608	6889	7550	7725	7655	7552	7310	6983	6587
CPL	11/18/12	6271	6089	5993	5919	5958	6148	6385	6731	7196	7292	7151	6930	6818	6763	6606	6668	6867	7484	7661	7622	7458	7102	6634	6189
CPL	11/19/12	5877	5704	5647	5719	5930	6523	7503	7766	7694	7589	7486	7328	7176	7067	6959	6940	7148	7778	8081	8031	7867	7506	6981	6416
CPL	11/20/12	6071	5928	5854	5920	6102	6695	7625	7839	7698	7472	7327	7077	6885	6769	6691	6662	6863	7564	7843	7895	7796	7559	7119	6645
CPL	11/21/12	6371	6294	6308	6382	6710	7292	8071	8430	8265	7931	7596	7294	6960	6804	6663	6616	6779	7475	7792	7870	7870	7723	7425	7023
CPL	11/22/12	6692	6585	6574	6658	6838	7207	7610	7970	8158	8016	7729	7373	6772	6251	5852	5605	5561	6027	6310	6441	6617	6700	6685	6565
CPL	11/23/12	6531	6613	6736	6990	7298	7730	8201	8465	8263	7629	7048	6571	6193	5998	5828	5788	5978	6675	6904	6892	6826	6624	6363	5993
CPL	11/24/12	5718	5595	5565	5646	5857	6175	6638	7040	7270	7292	7139	6874	6616	6353	6231	6232	6593	7515	7986	8199	8348	8314	8124	7926
CPL	11/25/12	7743	7803	7915	8115	8403	8784	9250	9574	9509	8928	8207	7569	7174	6882	6649	6592	6954	7940	8451	8660	8701	8485	8128	7752
CPL	11/26/12	7541	7531	7593	7757	8106	8878	9864	10030	9544	8699	7961	7457	7067	6839	6720	6613	6806	7671	8175	8311	8243	7984	7518	6999
CPL	11/27/12	6758	6674	6696	6753	6973	7510	8414	8558	8276	7990	7748	7470	7315	7300	7324	7387	7740	8394	8569	8489	8307	7870	7292	6751
CPL	11/28/12	6420	6333	6344	6502	6905	7649	8829	9158	8780	8301	7908	7557	7272	7093	6943	6969	7342	8376	9003	9224	9323	9212	8843	8464
CPL	11/29/12	8313	8396	8537	8751	9160	9927	10871	11007	10519	9484	8594	7962	7489	7253	7035	7005	7328	8301	8886	9107	9218	9039	8654	8218
CPL	11/30/12	8080	8118	8225	8423	8777	9498	10578	10746	10027	8962	8154	7487	7054	6812	6613.3	6560.2	6776.2	7596.5	7947.4	7995.4	7937	7861.3	7657	7245

Backup - SCEG Hourly Load

Dec 2011-Nov 2012 Load

SCEGP	Max	4,761
SCEG	Avg Jul	4,265
SCEG	Winter	2,973
SCEG	Spring	2,971
SCEG	Summer	3,903
SCEG	Fall	3,064

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCEG	12/1/11	2610	2621	2633	2653	2762	2978	3336	3409	3330	3080	2923	2735	2626	2577	2496	2464	2497	2706	2944	3038	3036	2990	2866	2748
SCEG	12/2/11	2702	2703	2747	2806	2920	3143	3504	3561	3388	3092	2868	2692	2559	2454	2465	2421	2466	2653	2816	2799	2846	2817	2765	2661
SCEG	12/3/11	2560	2571	2576	2606	2702	2820	2982	3063	3075	2879	2676	2487	2400	2313	2271	2247	2257	2463	2614	2610	2618	2559	2475	2391
SCEG	12/4/11	2301	2231	2164	2213	2225	2284	2350	2408	2490	2493	2435	2305	2291	2264	2216	2193	2212	2400	2543	2537	2518	2423	2237	2121
SCEG	12/5/11	1998	1952	1922	1920	2007	2174	2484	2522	2502	2509	2472	2494	2447	2470	2444	2432	2463	2625	2758	2755	2685	2545	2343	2152
SCEG	12/6/11	2049	1957	1934	1928	1952	2065	2353	2393	2398	2394	2400	2430	2465	2457	2442	2456	2436	2578	2684	2647	2603	2465	2267	2074
SCEG	12/7/11	1928	1853	1812	1790	1821	1951	2218	2310	2343	2373	2383	2416	2426	2431	2416	2415	2467	2612	2760	2773	2770	2680	2556	2394
SCEG	12/8/11	2348	2330	2335	2372	2502	2754	3151	3275	3173	3059	2929	2808	2679	2589	2555	2529	2616	2856	3031	3089	3131	3089	2929	2786
SCEG	12/9/11	2694	2630	2656	2671	2777	2946	3248	3272	3147	2965	2810	2653	2549	2469	2427	2406	2446	2664	2745	2713	2669	2630	2524	2382
SCEG	12/10/11	2259	2193	2150	2146	2140	2184	2321	2414	2536	2603	2591	2564	2502	2445	2396	2373	2436	2653	2792	2812	2822	2808	2748	2652
SCEG	12/11/11	2577	2550	2540	2557	2601	2673	2813	2915	3050	3010	2874	2734	2627	2571	2543	2527	2566	2799	2937	2976	2957	2876	2721	2575
SCEG	12/12/11	2481	2455	2435	2447	2562	2776	3090	3205	3178	3200	3192	3126	3009	2909	2815	2776	2815	3031	3147	3117	3061	2927	2782	2630
SCEG	12/13/11	2509	2476	2491	2538	2608	2764	3116	3178	3053	2891	2720	2577	2476	2436	2385	2362	2386	2583	2736	2782	2772	2697	2538	2400
SCEG	12/14/11	2298	2263	2259	2294	2391	2603	2932	3028	2913	2796	2672	2566	2491	2480	2428	2436	2458	2631	2804	2781	2739	2659	2481	2319
SCEG	12/15/11	2214	2161	2157	2184	2262	2455	2811	2880	2811	2686	2614	2531	2459	2430	2416	2416	2460	2593	2728	2706	2677	2569	2427	2238
SCEG	12/16/11	2094	2020	1988	2001	2071	2203	2525	2592	2569	2529	2527	2490	2478	2459	2439	2417	2422	2552	2621	2567	2540	2443	2320	2199
SCEG	12/17/11	2071	1966	1919	1929	1898	2014	2076	2167	2298	2394	2363	2337	2307	2275	2274	2257	2297	2468	2624	2633	2610	2604	2485	2379
SCEG	12/18/11	2265	2284	2275	2293	2346	2447	2578	2707	2836	2785	2629	2528	2447	2381	2349	2312	2381	2619	2820	2875	2934	2903	2858	2753
SCEG	12/19/11	2682	2649	2642	2700	2812	3039	3315	3478	3435	3199	2929	2767	2632	2547	2452	2460	2445	2666	2843	2845	2816	2748	2600	2446
SCEG	12/20/11	2335	2265	2255	2265	2310	2460	2688	2796	2783	2683	2602	2537	2488	2465	2450	2408	2445	2615	2714	2679	2628	2512	2379	2201
SCEG	12/21/11	2075	2004	1975	1965	2007	2135	2367	2460	2495	2497	2539	2537	2519	2513	2471	2490	2485	2621	2707	2646	2592	2517	2374	2203
SCEG	12/22/11	2043	1962	1910	1877	1900	1958	2143	2246	2331	2384	2435	2462	2450	2437	2424	2379	2381	2521	2616	2573	2500	2416	2312	2133
SCEG	12/23/11	2019	1903	1829	1778	1805	1902	2007	2090	2182	2277	2295	2277	2279	2277	2243	2225	2239	2392	2485	2439	2385	2336	2229	2105
SCEG	12/24/11	1980	1887	1813	1813	1847	1916	2032	2111	2256	2334	2329	2160	2148	2084	2042	2011	2036	2193	2305	2299	2303	2303	2240	2162
SCEG	12/25/11	2072	2015	1991	1994	2029	2092	2294	2289	2377	2357	2272	2214	2184	2154	2110	2075	2093	2213	2254	2241	2246	2215	2144	2035
SCEG	12/26/11	1968	1919	1902	1946	2001	2114	2254	2355	2471	2470	2439	2381	2307	2219	2174	2140	2189	2452	2661	2725	2730	2655	2542	2397
SCEG	12/27/11	2270	2174	2131	2098	2132	2215	2358	2440	2474	2510	2501	2454	2397	2312	2256	2232	2271	2458	2607	2623	2644	2589	2508	2394

Backup - SCEG Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCEG	12/28/11	2310	2275	2307	2322	2412	2552	2781	2906	2946	2909	2825	2726	2572	2515	2470	2439	2502	2707	2942	2994	2986	2957	2856	2753
SCEG	12/29/11	2710	2692	2738	2809	2905	3059	3285	3396	3372	3266	3042	2847	2682	2583	2503	2438	2488	2662	2889	2913	2908	2815	2741	2616
SCEG	12/30/11	2527	2513	2497	2580	2691	2849	3050	3164	3150	2964	2773	2628	2490	2394	2336	2271	2349	2485	2606	2577	2538	2460	2367	2240
SCEG	12/31/11	2124	2054	2010	1985	2005	2052	2123	2165	2240	2257	2276	2277	2251	2196	2163	2148	2182	2332	2486	2413	2419	2389	2301	2284
SCEG	1/1/12	2261	2258	2251	2274	2320	2393	2486	2558	2628	2548	2391	2271	2230	2172	2126	2080	2109	2249	2338	2324	2247	2188	2123	2007
SCEG	1/2/12	1920	1881	1895	1937	2034	2161	2381	2512	2635	2695	2691	2628	2579	2499	2440	2439	2498	2786	3049	3087	3118	3040	2967	2894
SCEG	1/3/12	2838	2897	2945	3052	3169	3408	3778	3914	3840	3726	3614	3468	3335	3234	3169	3141	3227	3518	3791	3850	3828	3759	3613	3513
SCEG	1/4/12	3432	3442	3495	3553	3673	3940	4296	4397	4223	3912	3625	3399	3177	3011	2912	2866	2940	3179	3446	3510	3468	3362	3178	3021
SCEG	1/5/12	2894	2856	2819	2866	2951	3164	3486	3550	3406	3230	3032	2867	2716	2618	2534	2493	2508	2687	2946	2986	3007	2953	2838	2723
SCEG	1/6/12	2638	2661	2681	2731	2826	3051	3423	3506	3347	3094	2874	2681	2530	2447	2379	2340	2349	2482	2674	2678	2647	2597	2511	2383
SCEG	1/7/12	2295	2243	2226	2241	2281	2377	2490	2570	2646	2613	2492	2405	2315	2245	2200	2183	2184	2304	2480	2454	2416	2320	2234	2108
SCEG	1/8/12	1997	1967	1929	1947	1979	2047	2153	2256	2357	2376	2303	2239	2232	2210	2183	2186	2200	2331	2485	2456	2408	2298	2168	2020
SCEG	1/9/12	1938	1892	1888	1907	1959	2155	2494	2604	2557	2525	2532	2511	2506	2482	2451	2423	2431	2543	2714	2687	2633	2497	2348	2177
SCEG	1/10/12	2070	2034	1981	2011	2059	2208	2528	2600	2568	2521	2529	2510	2493	2457	2475	2454	2482	2637	2742	2738	2675	2552	2369	2199
SCEG	1/11/12	2094	2034	1946	1959	1981	2140	2411	2496	2470	2495	2543	2527	2515	2502	2538	2509	2517	2561	2709	2711	2652	2562	2405	2249
SCEG	1/12/12	2164	2139	2115	2161	2240	2422	2746	2843	2807	2764	2737	2671	2569	2510	2436	2410	2422	2574	2751	2724	2707	2589	2441	2329
SCEG	1/13/12	2265	2348	2403	2501	2636	2907	3293	3445	3435	3419	3322	3192	3030	2915	2830	2790	2782	3019	3278	3295	3267	3203	3061	2961
SCEG	1/14/12	2870	2851	2855	2888	2961	3096	3279	3375	3434	3347	3184	3035	2863	2717	2621	2547	2623	2780	3048	3062	3128	3089	3019	2917
SCEG	1/15/12	2831	2794	2748	2741	2718	2817	2900	3018	3066	2946	2779	2655	2558	2513	2407	2386	2443	2630	2879	2957	2993	2982	2894	2832
SCEG	1/16/12	2789	2830	2849	2883	2999	3160	3294	3406	3386	3297	3106	2971	2825	2723	2642	2643	2651	2810	3025	3004	2939	2801	2649	2500
SCEG	1/17/12	2357	2309	2272	2295	2373	2488	2807	2869	2766	2652	2598	2534	2479	2438	2383	2354	2373	2506	2705	2687	2616	2492	2305	2124
SCEG	1/18/12	2001	1946	1921	1913	1978	2133	2490	2590	2538	2554	2546	2519	2477	2432	2408	2377	2390	2517	2771	2810	2822	2750	2657	2548
SCEG	1/19/12	2477	2496	2551	2604	2700	2976	3369	3545	3423	3221	3058	2913	2713	2629	2543	2540	2573	2709	3000	3071	3067	3014	2895	2743
SCEG	1/20/12	2655	2652	2640	2675	2742	2880	3174	3225	3084	2980	2901	2795	2724	2630	2554	2534	2533	2648	2770	2745	2670	2562	2453	2306
SCEG	1/21/12	2145	2048	2054	2037	2039	2091	2177	2231	2325	2399	2461	2472	2434	2382	2348	2371	2420	2489	2602	2564	2492	2427	2313	2194
SCEG	1/22/12	2086	2019	1985	1953	1992	2047	2146	2268	2410	2537	2587	2618	2648	2669	2670	2688	2689	2856	3021	3001	2962	2853	2712	2539
SCEG	1/23/12	2452	2394	2407	2429	2495	2670	3020	3088	2996	2987	2912	2818	2765	2710	2639	2616	2627	2731	2893	2859	2775	2623	2448	2244
SCEG	1/24/12	2142	2082	2031	2036	2058	2202	2515	2592	2511	2483	2457	2435	2396	2387	2354	2331	2328	2376	2599	2603	2567	2470	2327	2181
SCEG	1/25/12	2103	2085	2096	2141	2230	2446	2873	2989	2882	2739	2600	2485	2430	2382	2352	2327	2334	2413	2636	2649	2608	2498	2343	2216
SCEG	1/26/12	2129	2076	2050	2061	2094	2281	2634	2682	2605	2568	2558	2528	2489	2487	2455	2440	2442	2526	2688	2667	2581	2452	2319	2147
SCEG	1/27/12	2025	1948	1919	1872	1874	2006	2295	2410	2432	2464	2458	2463	2444	2415	2379	2359	2325	2373	2542	2525	2493	2433	2333	2252
SCEG	1/28/12	2194	2126	2132	2213	2276	2364	2538	2657	2782	2680	2602	2499	2397	2308	2234	2225	2230	2304	2503	2505	2525	2499	2412	2322
SCEG	1/29/12	2268	2244	2235	2274	2370	2446	2611	2743	2837	2789	2663	2521	2450	2359	2336	2259	2304	2429	2717	2846	2873	2813	2766	2645
SCEG	1/30/12	2643	2631	2688	2756	2902	3122	3542	3668	3504	3176	2899	2737	2606	2521	2449	2423	2452	2547	2836	2889	2873	2827	2735	2631
SCEG	1/31/12	2564	2558	2581	2668	2794	3039	3404	3485	3347	3082	2842	2639	2550	2478	2417	2369	2390	2470	2705	2753	2740	2661	2530	2446

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCEG	2/1/12	2314	2272	2272	2301	2397	2587	2990	3080	2935	2752	2624	2526	2467	2448	2408	2417	2407	2464	2658	2658	2562	2475	2285	2103
SCEG	2/2/12	2014	1935	1894	1884	1935	2069	2379	2472	2419	2406	2425	2461	2449	2419	2419	2409	2408	2364	2553	2574	2543	2412	2253	2089
SCEG	2/3/12	1945	1940	1956	2003	2055	2262	2646	2741	2721	2664	2583	2508	2435	2421	2375	2321	2324	2390	2617	2625	2570	2526	2428	2299
SCEG	2/4/12	2198	2104	2101	2068	2078	2124	2219	2308	2388	2446	2415	2364	2307	2255	2211	2189	2216	2260	2466	2390	2394	2317	2212	2080
SCEG	2/5/12	1983	1902	1868	1843	1812	1850	1920	1984	2132	2224	2220	2233	2260	2290	2304	2319	2303	2346	2439	2403	2357	2219	2149	2011
SCEG	2/6/12	1892	1883	1870	1856	1958	2170	2487	2670	2653	2688	2742	2747	2737	2703	2657	2651	2689	2820	3025	3008	2930	2791	2609	2431
SCEG	2/7/12	2328	2299	2300	2315	2398	2587	2937	3014	2906	2804	2700	2587	2491	2440	2387	2382	2396	2501	2744	2828	2837	2766	2651	2521
SCEG	2/8/12	2458	2466	2479	2546	2643	2894	3308	3357	3274	3084	2918	2793	2665	2570	2468	2445	2448	2504	2745	2816	2819	2734	2624	2509
SCEG	2/9/12	2445	2437	2463	2549	2630	2890	3271	3328	3182	3060	2874	2764	2630	2565	2509	2499	2529	2659	2935	2994	2984	2922	2791	2672
SCEG	2/10/12	2634	2598	2590	2624	2704	2896	3216	3283	3174	3090	3002	2873	2733	2636	2585	2550	2567	2636	2782	2760	2690	2638	2529	2416
SCEG	2/11/12	2295	2240	2220	2219	2247	2333	2458	2561	2686	2658	2622	2574	2518	2459	2424	2413	2476	2639	2980	3147	3267	3345	3333	3298
SCEG	2/12/12	3294	3338	3355	3400	3458	3533	3671	3782	3818	3678	3450	3212	3097	2934	2802	2718	2723	2850	3138	3334	3390	3353	3285	3189
SCEG	2/13/12	3165	3190	3234	3306	3451	3692	4061	4173	3933	3561	3255	3023	2820	2744	2652	2612	2606	2711	3010	3154	3183	3094	2967	2797
SCEG	2/14/12	2709	2664	2677	2696	2725	2853	3164	3201	3089	2997	2905	2775	2679	2607	2546	2525	2511	2594	2779	2794	2717	2603	2435	2269
SCEG	2/15/12	2151	2101	2074	2083	2158	2353	2743	2833	2763	2682	2612	2534	2460	2436	2384	2385	2376	2436	2630	2691	2654	2550	2357	2206
SCEG	2/16/12	2111	2084	2088	2097	2141	2274	2593	2612	2573	2549	2565	2514	2533	2494	2439	2422	2419	2433	2624	2618	2577	2485	2308	2191
SCEG	2/17/12	2054	1978	1951	1955	2009	2109	2365	2458	2466	2464	2458	2435	2404	2345	2358	2299	2301	2330	2505	2523	2493	2418	2337	2236
SCEG	2/18/12	2159	2137	2137	2144	2203	2285	2416	2511	2583	2553	2468	2371	2301	2213	2185	2154	2206	2287	2445	2444	2389	2289	2236	2119
SCEG	2/19/12	2037	1967	1941	1948	1915	1953	2037	2075	2226	2333	2326	2320	2338	2334	2298	2303	2326	2393	2578	2632	2612	2544	2500	2420
SCEG	2/20/12	2372	2377	2403	2433	2571	2765	3046	3196	3194	3096	2958	2869	2754	2628	2526	2490	2482	2539	2838	2965	2988	2892	2803	2670
SCEG	2/21/12	2574	2562	2567	2642	2746	2936	3298	3310	3150	2978	2842	2706	2599	2516	2429	2374	2366	2394	2592	2706	2663	2569	2420	2276
SCEG	2/22/12	2172	2122	2117	2137	2209	2398	2740	2793	2671	2578	2511	2422	2362	2372	2370	2319	2292	2350	2526	2567	2513	2409	2234	2072
SCEG	2/23/12	1941	1886	1839	1834	1878	2010	2287	2355	2360	2366	2391	2415	2424	2483	2476	2455	2450	2464	2605	2682	2600	2474	2333	2171
SCEG	2/24/12	2002	1924	1909	1859	1892	2009	2339	2365	2409	2455	2518	2552	2531	2502	2512	2463	2456	2491	2544	2529	2414	2311	2232	2104
SCEG	2/25/12	2000	1965	1950	1973	2011	2088	2210	2363	2496	2537	2493	2457	2396	2298	2259	2239	2259	2353	2536	2660	2684	2669	2654	2579
SCEG	2/26/12	2522	2463	2452	2463	2518	2631	2737	2851	2950	2958	2850	2687	2557	2428	2337	2162	2269	2352	2565	2707	2695	2617	2462	2292
SCEG	2/27/12	2202	2117	2115	2075	2155	2322	2669	2772	2712	2738	2716	2702	2667	2623	2554	2517	2461	2544	2701	2729	2676	2556	2373	2240
SCEG	2/28/12	2110	2032	2012	2009	2054	2206	2533	2583	2547	2481	2435	2402	2371	2342	2313	2285	2292	2315	2480	2566	2519	2384	2224	2049
SCEG	2/29/12	1934	1868	1843	1834	1875	2024	2330	2405	2380	2409	2384	2388	2426	2445	2432	2421	2419	2411	2557	2629	2554	2344	2250	1894
SCEG	3/1/12	1940	1903	1871	1854	1887	2026	2328	2398	2439	2452	2504	2514	2515	2529	2512	2485	2493	2496	2632	2679	2644	2512	2330	2163
SCEG	3/2/12	2039	1963	1899	1901	1908	2042	2303	2368	2370	2420	2454	2520	2562	2581	2557	2497	2450	2484	2547	2604	2525	2440	2306	2165
SCEG	3/3/12	2038	1937	1882	1894	1865	1892	1958	1996	2132	2250	2325	2354	2308	2261	2248	2248	2253	2285	2406	2416	2357	2313	2182	2058
SCEG	3/4/12	1958	1899	1866	1861	1897	1922	2026	2134	2307	2328	2326	2293	2250	2246	2243	2207	2241	2350	2574	2739	2744	2660	2586	2487
SCEG	3/5/12	2385	2376	2370	2391	2456	2650	2961	2967	2847	2729	2667	2556	2504	2442	2407	2365	2358	2384	2598	2771	2740	2699	2560	2473
SCEG	3/6/12	2395	2422	2432	2506	2612	2852	3176	3224	3050	2864	2700	2573	2494	2432	2376	2341	2337	2401	2624	2824	2796	2702	2556	2411

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCEG	3/7/12	2304	2259	2257	2248	2304	2542	2766	2744	2663	2550	2444	2391	2350	2366	2348	2343	2331	2325	2475	2581	2537	2435	2283	2134
SCEG	3/8/12	2009	1961	1943	1961	2005	2173	2466	2525	2467	2437	2443	2389	2406	2417	2409	2415	2407	2396	2519	2615	2573	2425	2280	2095
SCEG	3/9/12	1968	1891	1867	1855	1887	2027	2270	2345	2369	2397	2397	2433	2420	2384	2349	2349	2348	2364	2440	2493	2443	2374	2247	2131
SCEG	3/10/12	2043	1996	2014	2022	2072	2172	2298	2397	2481	2476	2426	2339	2232	2213	2174	2159	2145	2181	2319	2440	2422	2390	2301	2179
SCEG	3/11/12	2120	2077	2072	2111	2158	2248	2354	2461	2456	2368	2277	2252	2199	2172	2145	2140	2136	2172	2312	2417	2350	2232	2070	1947
SCEG	3/12/12	1882	1873	1878	1948	2129	2455	2590	2534	2476	2421	2395	2401	2398	2380	2359	2365	2349	2380	2474	2542	2450	2286	2111	1953
SCEG	3/13/12	1870	1835	1827	1849	1946	2229	2370	2329	2331	2367	2374	2389	2397	2392	2380	2393	2420	2433	2500	2593	2483	2289	2115	1953
SCEG	3/14/12	1875	1845	1839	1865	2020	2274	2389	2354	2366	2380	2416	2476	2541	2580	2607	2630	2618	2621	2645	2703	2597	2399	2169	2021
SCEG	3/15/12	1922	1877	1853	1882	1996	2276	2393	2390	2414	2493	2543	2620	2669	2755	2769	2807	2749	2730	2726	2807	2664	2466	2257	2075
SCEG	3/16/12	1962	1916	1866	1892	1991	2224	2360	2365	2418	2439	2507	2572	2639	2735	2747	2760	2723	2673	2645	2650	2539	2393	2194	2051
SCEG	3/17/12	1944	1878	1843	1819	1866	1917	2006	2119	2213	2318	2399	2459	2520	2587	2646	2688	2662	2573	2574	2612	2504	2349	2192	2044
SCEG	3/18/12	1930	1863	1819	1794	1816	1858	1895	2010	2124	2213	2292	2358	2418	2436	2438	2466	2504	2498	2530	2619	2481	2309	2101	1966
SCEG	3/19/12	1869	1843	1798	1830	1976	2231	2329	2349	2424	2493	2575	2647	2767	2855	2907	2933	2911	2844	2864	2923	2757	2475	2272	2095
SCEG	3/20/12	1969	1908	1878	1891	1993	2261	2335	2324	2389	2480	2589	2674	2771	2861	2926	2949	2910	2829	2792	2877	2732	2491	2249	2058
SCEG	3/21/12	1960	1910	1859	1890	1979	2248	2390	2381	2445	2533	2620	2676	2727	2764	2769	2813	2784	2737	2732	2824	2700	2490	2280	2094
SCEG	3/22/12	2003	1961	1928	1937	2063	2335	2429	2430	2522	2573	2639	2713	2807	2839	2859	2886	2804	2759	2786	2829	2704	2511	2298	2113
SCEG	3/23/12	2005	1917	1912	1912	2024	2252	2367	2413	2489	2563	2649	2759	2841	2928	2948	2930	2872	2757	2717	2730	2622	2474	2302	2137
SCEG	3/24/12	2022	1945	1878	1862	1899	2004	2081	2162	2323	2423	2499	2555	2610	2642	2586	2540	2498	2464	2400	2479	2399	2297	2131	1982
SCEG	3/25/12	1882	1824	1794	1777	1789	1853	1883	2054	2092	2173	2194	2233	2235	2232	2212	2236	2199	2199	2258	2371	2283	2128	1960	1855
SCEG	3/26/12	1777	1744	1734	1805	1932	2195	2357	2359	2382	2444	2454	2503	2544	2607	2676	2727	2760	2720	2712	2753	2621	2367	2156	2010
SCEG	3/27/12	1906	1870	1834	1873	1994	2233	2308	2296	2321	2343	2349	2341	2335	2390	2445	2449	2439	2401	2467	2578	2484	2274	2089	1989
SCEG	3/28/12	1893	1864	1848	1896	2025	2317	2402	2390	2405	2448	2486	2504	2580	2617	2646	2696	2672	2648	2657	2748	2630	2451	2221	2063
SCEG	3/29/12	1977	1909	1879	1896	2030	2287	2356	2378	2453	2551	2644	2726	2833	2957	3014	3056	3011	2965	2951	2980	2850	2576	2347	2143
SCEG	3/30/12	2045	1961	1916	1947	2037	2306	2373	2390	2453	2525	2690	2807	2895	2980	3010	3034	2945	2832	2777	2812	2718	2526	2347	2167
SCEG	3/31/12	2080	2003	1957	1948	1976	2043	2118	2227	2354	2454	2508	2551	2563	2606	2596	2578	2584	2556	2526	2633	2549	2399	2168	2072
SCEG	4/1/12	1964	1892	1848	1835	1851	1906	1930	2056	2163	2263	2341	2421	2508	2577	2636	2707	2735	2713	2643	2714	2567	2402	2196	2050
SCEG	4/2/12	1949	1897	1870	1888	2001	2223	2318	2388	2510	2687	2847	2992	3159	3272	3364	3435	3384	3238	3150	3143	2979	2708	2450	2259
SCEG	4/3/12	2119	2063	2007	2024	2054	2266	2348	2387	2450	2520	2582	2639	2722	2793	2852	2912	2915	2859	2899	2942	2830	2606	2370	2199
SCEG	4/4/12	2078	2006	1957	1965	2038	2254	2322	2413	2507	2615	2732	2841	3009	3141	3217	3261	3221	3118	3029	3018	2868	2644	2397	2218
SCEG	4/5/12	2092	2046	1997	2011	2109	2303	2393	2484	2571	2714	2865	3027	3167	3213	3241	3242	3154	3009	2895	2847	2677	2477	2277	2112
SCEG	4/6/12	2001	1945	1884	1895	1960	2096	2166	2235	2283	2361	2357	2328	2307	2282	2248	2243	2256	2240	2238	2383	2342	2242	2119	2029
SCEG	4/7/12	1948	1912	1896	1923	1979	2064	2152	2260	2300	2295	2257	2212	2185	2187	2164	2217	2230	2247	2259	2351	2344	2214	2085	1946
SCEG	4/8/12	1866	1812	1793	1818	1857	1932	1982	2121	2168	2166	2143	2168	2178	2232	2242	2300	2299	2266	2274	2418	2363	2195	2029	1903
SCEG	4/9/12	1818	1773	1761	1782	1921	2119	2182	2250	2308	2378	2401	2451	2513	2549	2599	2651	2644	2615	2561	2665	2547	2334	2106	1991
SCEG	4/10/12	1892	1822	1794	1815	1955	2187	2282	2303	2350	2391	2425	2485	2549	2603	2624	2636	2615	2560	2548	2625	2498	2318	2117	1973

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCEG	4/11/12	1894	1841	1814	1846	1940	2168	2244	2302	2327	2355	2369	2374	2394	2403	2401	2413	2449	2434	2435	2538	2445	2294	2151	2010
SCEG	4/12/12	1958	1932	1934	2002	2168	2440	2557	2562	2559	2517	2476	2437	2411	2376	2383	2374	2365	2360	2380	2542	2476	2335	2191	2085
SCEG	4/13/12	2036	2022	2039	2082	2225	2451	2549	2547	2509	2467	2428	2428	2416	2412	2403	2412	2381	2355	2324	2473	2404	2273	2148	2011
SCEG	4/14/12	1955	1929	1886	1904	1969	2043	2126	2239	2297	2312	2309	2302	2300	2299	2342	2371	2395	2392	2381	2474	2438	2281	2148	2002
SCEG	4/15/12	1917	1853	1824	1815	1820	1854	1885	2072	2204	2281	2330	2373	2431	2471	2512	2566	2608	2582	2565	2679	2580	2393	2188	2007
SCEG	4/16/12	1900	1838	1815	1837	1962	2218	2280	2367	2450	2544	2653	2739	2821	2921	2957	3007	2995	2941	2914	3011	2876	2614	2368	2165
SCEG	4/17/12	2058	1991	1941	1969	2042	2285	2367	2440	2500	2692	2809	2946	3075	3166	3222	3229	3203	3125	3029	3072	2938	2689	2414	2194
SCEG	4/18/12	2084	2011	1971	1987	2117	2356	2454	2523	2609	2685	2701	2746	2777	2768	2779	2729	2681	2635	2614	2702	2596	2370	2192	2054
SCEG	4/19/12	1955	1913	1885	1903	2030	2276	2364	2372	2377	2415	2435	2444	2439	2442	2455	2461	2414	2414	2489	2550	2500	2337	2145	2018
SCEG	4/20/12	1917	1859	1860	1875	1995	2245	2314	2300	2367	2452	2496	2510	2520	2525	2559	2596	2570	2520	2485	2586	2497	2372	2182	2042
SCEG	4/21/12	1965	1898	1851	1856	1880	1946	2012	2145	2302	2389	2483	2575	2622	2665	2727	2752	2713	2654	2603	2664	2616	2461	2263	2119
SCEG	4/22/12	1996	1918	1882	1854	1884	1917	1968	2100	2195	2267	2284	2306	2323	2288	2272	2298	2295	2292	2346	2432	2344	2179	2016	1919
SCEG	4/23/12	1837	1823	1795	1862	2013	2273	2363	2344	2357	2414	2436	2408	2389	2358	2357	2354	2331	2340	2391	2494	2447	2313	2147	2051
SCEG	4/24/12	1990	1964	1970	2025	2192	2489	2573	2533	2461	2394	2350	2321	2302	2281	2231	2322	2264	2260	2322	2461	2419	2236	2069	1927
SCEG	4/25/12	1880	1855	1848	1855	2028	2307	2352	2372	2361	2359	2341	2369	2400	2416	2493	2530	2537	2531	2541	2623	2555	2361	2165	2016
SCEG	4/26/12	1921	1872	1830	1906	1949	2228	2315	2345	2471	2578	2617	2714	2835	2918	3001	2998	2999	2963	2897	2962	2839	2607	2379	2205
SCEG	4/27/12	2090	1983	1984	2005	2111	2337	2404	2511	2609	2748	2854	3008	3172	3270	3326	3325	3311	3200	3052	3075	2947	2742	2533	2361
SCEG	4/28/12	2213	2110	2063	2029	2031	2083	2149	2305	2476	2609	2774	2895	3005	3124	3186	3190	3175	3052	2913	2890	2781	2613	2410	2244
SCEG	4/29/12	2120	2049	1988	1969	1988	1999	2062	2213	2387	2544	2708	2903	3071	3224	3311	3347	3384	3334	3206	3184	3049	2785	2539	2348
SCEG	4/30/12	2220	2131	2088	2086	2207	2460	2559	2652	2767	2932	3091	3262	3403	3511	3577	3621	3583	3492	3378	3387	3224	2918	2512	2388
SCEG	5/1/12	2265	2181	2109	2105	2235	2454	2546	2661	2767	2910	3051	3191	3343	3504	3574	3638	3616	3513	3393	3349	3206	2943	2643	2426
SCEG	5/2/12	2287	2213	2177	2166	2282	2513	2599	2661	2796	2962	3175	3313	3523	3660	3745	3787	3763	3669	3518	3434	3251	2987	2703	2477
SCEG	5/3/12	2312	2230	2153	2156	2260	2477	2548	2643	2778	2931	3100	3247	3404	3541	3626	3656	3551	3415	3356	3264	3171	2982	2587	2434
SCEG	5/4/12	2309	2206	2161	2160	2249	2473	2587	2644	2731	2880	2996	3106	3281	3367	3392	3440	3390	3290	3186	3154	3060	2851	2612	2419
SCEG	5/5/12	2268	2191	2128	2096	2107	2178	2235	2466	2721	2973	3209	3360	3509	3612	3717	3787	3762	3640	3498	3433	3283	3035	2779	2571
SCEG	5/6/12	2394	2289	2179	2127	2109	2088	2161	2366	2594	2723	2831	2881	2992	3056	3122	3164	3165	3116	3048	3062	2972	2755	2506	2313
SCEG	5/7/12	2194	2136	2105	2113	2235	2457	2513	2615	2688	2808	2909	3010	3113	3223	3272	3301	3248	3176	3082	3077	2993	2727	2484	2280
SCEG	5/8/12	2149	2099	2057	2073	2134	2339	2448	2555	2657	2795	2886	3008	3137	3254	3299	3287	3260	3189	3101	3098	3001	2752	2534	2351
SCEG	5/9/12	2223	2149	2128	2141	2213	2444	2556	2663	2737	2856	2947	3012	3017	2984	2960	2858	2775	2796	2769	2779	2723	2520	2299	2159
SCEG	5/10/12	2062	1973	1943	1961	2063	2271	2341	2410	2489	2620	2679	2743	2826	2870	2906	2969	2975	2922	2826	2813	2737	2511	2276	2085
SCEG	5/11/12	2005	1949	1907	1909	2030	2203	2295	2399	2498	2528	2640	2681	2748	2835	2905	2946	2944	2877	2735	2744	2687	2499	2300	2136
SCEG	5/12/12	2017	1943	1922	1901	1927	1957	2030	2182	2350	2446	2530	2611	2683	2726	2725	2695	2693	2640	2583	2624	2623	2491	2316	2151
SCEG	5/13/12	2054	1993	1938	1934	1952	1945	2050	2213	2350	2424	2445	2464	2459	2475	2447	2451	2461	2462	2459	2570	2593	2432	2270	2119
SCEG	5/14/12	2030	1970	1952	2005	2117	2359	2498	2606	2700	2832	2869	2964	3044	3069	3049	3058	3074	3019	2969	2976	2899	2642	2415	2243
SCEG	5/15/12	2137	2077	2065	2080	2158	2379	2505	2602	2735	2891	3047	3244	3379	3488	3580	3591	3468	3337	3199	3193	3074	2846	2581	2355

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCEG	5/16/12	2255	2169	2144	2117	2258	2479	2583	2713	2802	2899	3030	3170	3270	3328	3352	3434	3414	3358	3243	3158	3051	2801	2583	2319
SCEG	5/17/12	2181	2119	2073	2067	2175	2417	2513	2574	2680	2778	2823	2919	2998	3087	3045	2937	2834	2783	2702	2759	2719	2538	2324	2179
SCEG	5/18/12	2078	1999	1979	2004	2107	2367	2440	2527	2574	2601	2570	2568	2627	2665	2644	2641	2661	2618	2563	2591	2593	2416	2226	2115
SCEG	5/19/12	2011	1948	1900	1899	1932	1942	2022	2152	2261	2304	2378	2394	2431	2466	2517	2556	2550	2504	2466	2482	2473	2351	2169	2026
SCEG	5/20/12	1922	1878	1819	1829	1849	1843	1908	2060	2197	2262	2349	2455	2564	2674	2781	2883	2927	2867	2844	2850	2766	2578	2346	2170
SCEG	5/21/12	2054	2006	1938	1963	2136	2320	2432	2581	2722	2856	3027	3161	3266	3353	3445	3483	3464	3408	3305	3222	3098	2822	2560	2359
SCEG	5/22/12	2241	2141	2115	2089	2131	2326	2459	2573	2689	2863	3007	3106	3257	3380	3523	3565	3523	3414	3255	3190	3088	2812	2542	2365
SCEG	5/23/12	2256	2167	2124	2119	2175	2379	2494	2623	2746	2938	3122	3278	3384	3502	3529	3634	3612	3540	3412	3319	3241	2956	2680	2456
SCEG	5/24/12	2332	2242	2190	2188	2295	2506	2650	2769	2954	3150	3372	3591	3741	3836	3908	3914	3866	3750	3607	3518	3431	3147	2854	2605
SCEG	5/25/12	2433	2348	2264	2274	2359	2549	2668	2814	2954	3222	3365	3541	3760	3853	3926	3941	3903	3801	3613	3479	3357	3106	2834	2582
SCEG	5/26/12	2419	2325	2263	2222	2223	2204	2319	2557	2812	3085	3285	3446	3594	3671	3723	3774	3769	3678	3527	3418	3303	3067	2822	2596
SCEG	5/27/12	2443	2350	2259	2232	2237	2201	2311	2493	2716	2927	3043	3206	3334	3421	3514	3543	3529	3445	3310	3212	3139	2982	2775	2590
SCEG	5/28/12	2447	2370	2312	2280	2316	2309	2400	2655	2898	3108	3277	3345	3366	3429	3471	3425	3444	3365	3232	3223	3157	2946	2668	2509
SCEG	5/29/12	2386	2309	2277	2286	2395	2579	2744	2889	3019	3160	3279	3357	3460	3529	3445	3305	3205	3175	3145	3153	3094	2872	2621	2447
SCEG	5/30/12	2327	2255	2227	2234	2324	2485	2589	2741	2851	3042	3208	3363	3536	3677	3771	3817	3787	3693	3564	3410	3311	3027	2739	2524
SCEG	5/31/12	2384	2268	2200	2192	2295	2462	2636	2820	3040	3315	3556	3736	3879	3969	3994	3965	3921	3837	3707	3576	3459	3241	2864	2756
SCEG	6/1/12	2602	2455	2369	2349	2435	2572	2725	2914	3134	3366	3565	3707	3774	3712	3695	3706	3624	3476	3304	3188	3113	2923	2704	2525
SCEG	6/2/12	2389	2304	2233	2193	2192	2241	2261	2431	2605	2802	2951	3042	3139	3215	3251	3316	3283	3239	3084	2954	2871	2689	2457	2269
SCEG	6/3/12	2100	2025	1949	1925	1950	1902	1997	2169	2370	2535	2671	2824	2949	3119	3239	3303	3363	3342	3201	3098	3075	2869	2605	2385
SCEG	6/4/12	2294	2205	2214	2222	2321	2475	2607	2726	2868	2949	3021	3035	3067	3130	3190	3248	3258	3283	3221	3172	3114	2853	2673	2424
SCEG	6/5/12	2290	2190	2152	2154	2198	2343	2457	2556	2659	2751	2784	2779	2776	2730	2724	2732	2711	2710	2685	2688	2695	2510	2326	2167
SCEG	6/6/12	2068	1999	1986	1997	2102	2271	2387	2491	2547	2591	2656	2678	2692	2762	2782	2853	2858	2842	2776	2776	2778	2605	2364	2196
SCEG	6/7/12	2088	2023	1989	2014	2070	2194	2329	2492	2640	2767	2917	3009	3106	3195	3269	3291	3237	3179	3070	3004	2948	2738	2485	2295
SCEG	6/8/12	2140	2065	2053	2057	2123	2185	2354	2516	2702	2848	3057	3212	3324	3404	3466	3495	3482	3386	3243	3103	3035	2836	2581	2385
SCEG	6/9/12	2239	2135	2067	2052	2048	2021	2131	2362	2592	2790	3005	3110	3242	3347	3391	3417	3419	3341	3205	3147	3084	2882	2631	2456
SCEG	6/10/12	2322	2251	2195	2167	2179	2177	2260	2420	2600	2742	2860	2955	3026	3041	3071	3062	3056	3016	2972	2999	2955	2820	2613	2436
SCEG	6/11/12	2321	2225	2213	2202	2266	2463	2625	2783	2971	3120	3259	3291	3287	3311	3318	3264	3174	3124	3044	3018	2958	2781	2515	2374
SCEG	6/12/12	2285	2216	2196	2207	2268	2436	2592	2722	2847	2970	3073	3135	3152	3194	3276	3367	3429	3451	3372	3284	3167	2955	2681	2475
SCEG	6/13/12	2371	2271	2223	2203	2295	2444	2590	2745	2931	3137	3354	3543	3696	3802	3816	3728	3603	3478	3372	3295	3227	2951	2664	2472
SCEG	6/14/12	2324	2232	2198	2188	2267	2390	2543	2675	2866	3043	3214	3328	3453	3588	3664	3701	3651	3550	3379	3269	3222	2979	2722	2512
SCEG	6/15/12	2343	2261	2196	2177	2246	2329	2456	2593	2759	2913	3038	3141	3249	3351	3438	3493	3482	3401	3225	3047	3025	2824	2579	2381
SCEG	6/16/12	2229	2123	2077	2046	2070	2020	2135	2296	2455	2607	2738	2849	2958	3062	3159	3217	3276	3231	3113	2998	2926	2711	2503	2295
SCEG	6/17/12	2152	2042	2005	1970	1988	1933	2027	2221	2405	2558	2722	2861	2975	3089	3189	3271	3281	3256	3129	3011	2911	2743	2487	2286
SCEG	6/18/12	2159	2075	2037	2052	2140	2258	2413	2608	2789	2999	3182	3348	3505	3635	3722	3748	3738	3660	3528	3379	3286	3038	2741	2520
SCEG	6/19/12	2337	2239	2185	2184	2205	2301	2482	2674	2877	3090	3287	3461	3629	3753	3839	3899	3879	3789	3655	3542	3431	3161	2884	2625

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SCEG	6/21/12	2497	2387	2297	2278	2349	2481	2682	2885	3075	3317	3577	3786	3959	4045	4100	4123	4064	3950	3771	3628	3553	3252	2959	2737
SCEG	6/22/12	2539	2411	2313	2299	2353	2445	2614	2818	3016	3234	3464	3659	3823	3950	3993	4029	4024	3921	3750	3561	3509	3255	2987	2752
SCEG	6/23/12	2552	2431	2357	2315	2303	2277	2429	2724	3012	3317	3531	3780	3913	3980	4013	4054	4065	3982	3832	3670	3584	3355	3092	2866
SCEG	6/24/12	2670	2525	2439	2373	2356	2314	2423	2683	2958	3226	3462	3671	3746	3731	3724	3754	3714	3656	3521	3440	3366	3152	2921	2690
SCEG	6/25/12	2522	2416	2350	2314	2408	2502	2672	2807	2991	3177	3337	3497	3625	3728	3681	3823	3779	3711	3587	3480	3422	3159	2886	2635
SCEG	6/26/12	2487	2387	2314	2307	2381	2506	2648	2783	2887	2990	3058	3090	3117	3119	3114	3126	3123	3112	3033	2926	2914	2691	2456	2219
SCEG	6/27/12	2055	1995	1961	1966	2025	2154	2293	2454	2588	2726	2898	3024	3178	3336	3456	3569	3589	3537	3397	3237	3136	2879	2573	2345
SCEG	6/28/12	2198	2100	2043	2034	2134	2234	2384	2577	2778	3032	3292	3496	3713	3891	4058	4120	4111	4009	3844	3683	3581	3331	3026	2763
SCEG	6/29/12	2578	2470	2390	2352	2429	2502	2652	2858	3170	3481	3825	4089	4315	4438	4530	4557	4548	4482	4340	4158	4063	3835	3547	3280
SCEG	6/30/12	3076	2909	2781	2700	2709	2662	2733	2988	3289	3583	3879	4157	4367	4462	4512	4515	4479	4405	4252	4116	4073	3862	3583	3392
SCEG	7/1/12	3180	3075	2932	2890	2849	2795	2906	3160	3431	3732	4038	4305	4435	4530	4480	4344	4077	3868	3630	3461	3269	3038	2823	2605
SCEG	7/2/12	2478	2379	2345	2292	2384	2496	2614	2800	3052	3336	3557	3739	3944	4066	4172	4268	4237	4141	4056	3886	3785	3501	3177	2905
SCEG	7/3/12	2711	2599	2528	2485	2520	2617	2778	3004	3302	3621	3894	4144	4316	4405	4462	4424	4308	4106	3880	3748	3634	3385	3094	2840
SCEG	7/4/12	2666	2529	2410	2348	2331	2291	2319	2519	2812	3131	3412	3620	3804	3928	4026	4101	4089	4000	3830	3671	3573	3399	3178	2960
SCEG	7/5/12	2797	2666	2571	2550	2607	2705	2860	3105	3424	3731	4026	4236	4411	4559	4628	4606	4520	4393	4205	4095	3974	3687	3360	3129
SCEG	7/6/12	2944	2818	2720	2661	2664	2706	2843	3043	3302	3536	3825	4041	4204	4325	4396	4398	4358	4280	4100	4050	3879	3626	3339	3088
SCEG	7/7/12	2887	2748	2638	2550	2552	2534	2596	2868	3203	3526	3806	4032	4182	4274	4336	4413	4398	4325	4182	4060	3989	3771	3513	3314
SCEG	7/8/12	3125	2991	2864	2791	2740	2680	2732	2994	3330	3622	3885	4059	4252	4338	4408	4471	4482	4418	4269	4141	4068	3800	3563	3310
SCEG	7/9/12	3126	3025	2928	2911	2955	3042	3185	3421	3707	4006	4309	4491	4574	4653	4686	4661	4588	4471	4302	4159	4035	3733	3432	3189
SCEG	7/10/12	2970	2829	2745	2720	2786	2878	3004	3221	3469	3750	4028	4237	4393	4427	4357	4209	4037	3915	3631	3517	3400	3191	2928	2699
SCEG	7/11/12	2585	2471	2420	2421	2496	2639	2789	2950	3124	3407	3603	3772	3807	3814	3827	3795	3746	3642	3507	3420	3330	3123	2845	2667
SCEG	7/12/12	2547	2441	2404	2382	2488	2607	2748	2928	3079	3272	3432	3584	3713	3792	3883	3872	3762	3619	3463	3438	3388	3167	2906	2707
SCEG	7/13/12	2561	2468	2425	2428	2491	2612	2772	2941	3145	3339	3514	3615	3731	3760	3753	3701	3667	3553	3460	3406	3362	3183	2959	2742
SCEG	7/14/12	2595	2493	2446	2385	2434	2439	2512	2752	3073	3345	3575	3741	3868	3947	4010	3993	4005	3928	3769	3651	3536	3316	3075	2847
SCEG	7/15/12	2682	2558	2473	2414	2419	2379	2461	2749	3023	3270	3423	3620	3716	3809	3841	3893	3915	3861	3721	3614	3543	3307	3051	2805
SCEG	7/16/12	2644	2534	2469	2459	2529	2677	2830	3082	3302	3563	3802	4011	4145	4250	4322	4264	4131	4037	3865	3756	3641	3392	3125	2868
SCEG	7/17/12	2705	2617	2551	2525	2571	2692	2820	3050	3295	3558	3747	3908	4146	4215	4248	4210	3988	3832	3699	3625	3534	3305	3027	2778
SCEG	7/18/12	2646	2534	2449	2449	2539	2699	2846	3036	3257	3539	3752	3997	4169	4284	4352	4321	4218	4097	3917	3813	3617	3425	3150	2937
SCEG	7/19/12	2785	2687	2612	2584	2658	2763	2952	3130	3293	3625	3890	4040	4181	4232	4190	4169	4119	3960	3731	3621	3563	3316	3095	2833
SCEG	7/20/12	2690	2596	2551	2519	2580	2704	2812	2986	3236	3517	3753	3942	4083	4178	4237	4259	4187	3957	3773	3632	3529	3344	3117	2899
SCEG	7/21/12	2747	2649	2580	2545	2564	2552	2612	2759	2968	3189	3408	3620	3701	3645	3704	3744	3770	3739	3615	3513	3488	3260	3058	2863
SCEG	7/22/12	2708	2620	2519	2480	2470	2475	2534	2820	3153	3398	3613	3812	3985	4040	4141	4129	4091	4012	3860	3760	3653	3420	3203	2942
SCEG	7/23/12	2789	2683	2609	2597	2661	2756	2885	3144	3391	3706	3982	4208	4378	4474	4483	4470	4352	4241	4058	3919	3828	3540	3254	3012
SCEG	7/24/12	2857	2744	2665	2643	2720	2837	2964	3185	3444	3756	4031	4251	4413	4545	4629	4650	4581	4473	4250	4113	3964	3594	3250	2992

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCEG	7/25/12	2793	2665	2593	2607	2691	2852	2951	3116	3350	3570	3762	3943	4125	4282	4356	4378	4326	4287	4147	4030	3920	3671	3379	3154
SCEG	7/26/12	2986	2858	2799	2792	2863	2982	3139	3368	3669	4014	4277	4495	4630	4725	4759	4761	4686	4580	4391	4284	4212	3971	3696	3462
SCEG	7/27/12	3263	3130	3044	2968	2948	3020	3117	3322	3604	3890	4142	4369	4549	4659	4619	4457	4272	4104	3918	3795	3645	3416	3225	2946
SCEG	7/28/12	2781	2708	2643	2574	2580	2593	2643	2853	3102	3332	3560	3751	3922	4073	4207	4284	4263	4097	3907	3793	3736	3494	3238	2990
SCEG	7/29/12	2849	2717	2606	2553	2517	2491	2556	2799	3107	3386	3662	3859	4002	4105	4049	3888	3798	3683	3508	3419	3341	3120	2915	2679
SCEG	7/30/12	2542	2434	2390	2410	2480	2626	2750	2898	3068	3238	3389	3573	3734	3917	3972	3980	3892	3714	3515	3427	3290	3050	2790	2581
SCEG	7/31/12	2429	2331	2268	2273	2317	2487	2587	2743	2945	3215	3453	3643	3750	3812	3799	3694	3483	3334	3243	3222	3171	2978	2784	2634
SCEG	8/1/12	2508	2435	2349	2410	2478	2664	2743	2907	3087	3242	3522	3688	3823	3999	4093	4116	4125	4034	3889	3752	3597	3366	3114	2823
SCEG	8/2/12	2684	2581	2483	2500	2568	2732	2867	3066	3354	3689	3963	4196	4365	4398	4418	4370	4185	3972	3704	3618	3467	3231	2962	2754
SCEG	8/3/12	2561	2472	2403	2386	2454	2596	2696	2916	3141	3445	3678	3895	4071	4217	4245	4237	4204	4104	3922	3764	3666	3438	3197	2972
SCEG	8/4/12	2785	2609	2529	2463	2485	2515	2570	2798	3080	3365	3579	3760	3878	3977	4041	4003	3928	3791	3651	3583	3484	3305	3066	2827
SCEG	8/5/12	2665	2560	2478	2450	2451	2449	2515	2750	3025	3274	3468	3623	3619	3646	3599	3582	3488	3473	3340	3337	3285	3048	2841	2655
SCEG	8/6/12	2523	2449	2390	2387	2482	2672	2825	2968	3162	3465	3702	3869	4001	4044	3994	3803	3703	3597	3498	3480	3365	3170	2930	2751
SCEG	8/7/12	2626	2532	2503	2516	2566	2711	2829	2939	3076	3216	3359	3468	3538	3624	3659	3686	3558	3439	3339	3318	3221	3018	2786	2580
SCEG	8/8/12	2476	2400	2367	2362	2447	2635	2699	2782	2919	3048	3192	3303	3505	3686	3847	3938	3947	3894	3747	3654	3521	3266	2960	2722
SCEG	8/9/12	2546	2429	2357	2335	2413	2570	2705	2878	3093	3306	3612	3879	4040	4169	4234	4215	4128	3993	3828	3746	3508	3173	2889	2659
SCEG	8/10/12	2538	2456	2421	2410	2503	2649	2767	2880	3038	3248	3406	3458	3548	3617	3681	3692	3641	3481	3368	3369	3314	3131	2873	2669
SCEG	8/11/12	2540	2442	2366	2372	2388	2416	2448	2626	2852	3077	3187	3216	3233	3251	3236	3151	3029	2932	2883	2920	2886	2751	2584	2434
SCEG	8/12/12	2315	2260	2224	2206	2205	2251	2287	2451	2664	2834	3062	3264	3467	3573	3645	3720	3725	3663	3518	3462	3339	3077	2800	2587
SCEG	8/13/12	2417	2328	2232	2268	2310	2473	2586	2768	3008	3252	3492	3688	3849	3976	4043	4067	4037	3927	3748	3641	3439	3147	2853	2621
SCEG	8/14/12	2482	2378	2308	2282	2369	2500	2595	2744	2979	3243	3537	3694	3829	3941	4010	4040	4057	3959	3782	3692	3544	3283	2983	2754
SCEG	8/15/12	2607	2514	2442	2416	2491	2677	2779	2941	3155	3401	3631	3850	4027	4090	4169	4173	4094	3979	3829	3772	3608	3324	3015	2766
SCEG	8/16/12	2601	2504	2419	2402	2466	2627	2727	2879	3035	3249	3482	3671	3908	4108	4126	4116	4009	3902	3736	3644	3470	3191	2874	2642
SCEG	8/17/12	2504	2395	2318	2315	2389	2560	2652	2853	3111	3378	3690	3938	4075	4138	4204	4135	3977	3649	3416	3382	3260	3023	2797	2596
SCEG	8/18/12	2453	2366	2290	2259	2260	2308	2335	2490	2733	2979	3209	3427	3613	3697	3781	3844	3823	3738	3604	3557	3404	3178	2902	2703
SCEG	8/19/12	2536	2468	2402	2367	2370	2406	2459	2573	2766	2907	2993	3038	2986	3048	3093	3200	3263	3223	3171	3238	3126	2929	2685	2543
SCEG	8/20/12	2416	2337	2307	2327	2438	2664	2743	2841	2960	3100	3246	3404	3583	3675	3697	3607	3539	3445	3364	3385	3226	3017	2718	2552
SCEG	8/21/12	2413	2322	2294	2305	2416	2630	2675	2735	2821	2948	3069	3275	3421	3522	3599	3646	3597	3521	3430	3428	3259	2953	2675	2496
SCEG	8/22/12	2353	2281	2237	2231	2383	2616	2682	2749	2887	3035	3217	3345	3492	3610	3658	3668	3606	3487	3387	3370	3195	2900	2640	2463
SCEG	8/23/12	2353	2289	2210	2229	2349	2644	2713	2762	2911	3029	3145	3284	3427	3501	3508	3462	3320	3204	3125	3139	3033	2820	2575	2415
SCEG	8/24/12	2284	2226	2184	2180	2320	2581	2650	2704	2777	2949	3098	3224	3327	3404	3464	3494	3471	3373	3206	3146	2987	2787	2543	2316
SCEG	8/25/12	2206	2127	2017	2001	2047	2090	2106	2284	2489	2672	2843	2958	3090	3218	3333	3402	3415	3326	3196	3118	2975	2742	2522	2336
SCEG	8/26/12	2165	2119	2050	2020	2037	2039	2080	2272	2486	2646	2871	3078	3260	3399	3523	3586	3609	3544	3411	3365	3188	2914	2640	2471
SCEG	8/27/12	2333	2280	2224	2240	2354	2613	2712	2817	3013	3216	3457	3610	3766	3868	3886	3837	3728	3594	3507	3508	3358	3104	2853	2652
SCEG	8/28/12	2564	2471	2447	2434	2557	2852	2911	2960	3050	3117	3190	3244	3295	3297	3253	3205	3156	3131	3140	3182	3073	2905	2701	2559

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCEG	8/29/12	2444	2379	2341	2354	2477	2717	2834	2900	3042	3192	3413	3586	3727	3853	3874	3819	3719	3604	3529	3457	3224	2996	2718	2549
SCEG	8/30/12	2419	2345	2292	2300	2426	2684	2784	2848	2932	3056	3131	3224	3325	3376	3454	3469	3460	3422	3380	3352	3222	3023	2759	2588
SCEG	8/31/12	2476	2370	2315	2321	2427	2669	2764	2900	3132	3381	3605	3779	3924	4063	4127	4127	4093	3934	3746	3676	3453	3261	2962	2785
SCEG	9/1/12	2609	2496	2415	2360	2373	2397	2428	2614	2930	3279	3544	3765	3897	4029	4112	4135	4117	4011	3852	3764	3592	3350	3078	2867
SCEG	9/2/12	2697	2562	2462	2446	2441	2438	2423	2678	2968	3269	3565	3784	3949	4036	4069	4047	3906	3762	3623	3573	3393	3187	2978	2778
SCEG	9/3/12	2632	2521	2473	2399	2426	2481	2477	2700	3003	3317	3559	3756	3827	3830	3745	3670	3554	3429	3363	3364	3164	2936	2710	2509
SCEG	9/4/12	2415	2338	2293	2325	2453	2734	2795	2918	3077	3283	3489	3653	3837	3930	3976	3915	3820	3740	3626	3583	3403	3121	2859	2676
SCEG	9/5/12	2546	2490	2427	2425	2539	2779	2877	2991	3141	3356	3557	3770	3903	4042	4100	4107	4062	3963	3758	3727	3532	3237	2985	2794
SCEG	9/6/12	2638	2563	2490	2494	2588	2858	2946	3011	3139	3299	3406	3577	3784	3983	4046	4068	4039	3956	3838	3827	3569	3291	3051	2820
SCEG	9/7/12	2676	2582	2534	2526	2630	2852	2920	2972	3109	3342	3604	3811	3981	4099	4073	4007	3858	3708	3566	3538	3350	3150	2899	2665
SCEG	9/8/12	2549	2485	2391	2371	2416	2434	2466	2685	2926	3223	3493	3677	3738	3777	3776	3749	3514	3442	3370	3276	3163	2951	2746	2585
SCEG	9/9/12	2467	2395	2342	2275	2231	2304	2322	2435	2585	2665	2811	2960	3100	3196	3246	3265	3266	3136	3041	3050	2845	2613	2392	2217
SCEG	9/10/12	2091	2025	1977	2006	2126	2378	2400	2518	2655	2761	2908	3034	3150	3255	3353	3383	3342	3258	3125	3134	2911	2627	2388	2201
SCEG	9/11/12	2104	2018	1985	1990	2105	2365	2410	2457	2563	2666	2806	2910	3051	3168	3239	3265	3251	3162	3054	3068	2859	2601	2382	2179
SCEG	9/12/12	2066	2012	1969	2002	2101	2345	2390	2477	2579	2700	2800	2922	3018	3147	3244	3278	3239	3132	3046	3026	2824	2617	2361	2195
SCEG	9/13/12	2106	2028	2006	2021	2158	2428	2474	2548	2590	2760	2876	2998	3119	3193	3260	3302	3271	3175	3136	3149	2961	2726	2469	2290
SCEG	9/14/12	2188	2117	2079	2071	2188	2443	2461	2551	2695	2832	3042	3181	3305	3392	3453	3446	3391	3221	3127	3078	2909	2711	2512	2310
SCEG	9/15/12	2160	2084	2018	1997	2029	2093	2117	2237	2468	2679	2890	3072	3209	3335	3403	3444	3397	3291	3182	3129	2910	2717	2529	2336
SCEG	9/16/12	2228	2123	2071	2078	2042	2091	2119	2303	2515	2722	2888	3046	3175	3295	3396	3412	3390	3308	3222	3200	2981	2755	2483	2333
SCEG	9/17/12	2205	2150	2112	2116	2270	2527	2603	2697	2867	3058	3274	3460	3605	3701	3708	3686	3584	3463	3410	3350	3152	2907	2663	2491
SCEG	9/18/12	2412	2350	2314	2354	2468	2779	2886	2962	3059	3165	3260	3276	3301	3304	3304	3285	3200	3147	3161	3159	2999	2760	2516	2345
SCEG	9/19/12	2231	2165	2126	2132	2247	2501	2611	2626	2704	2786	2894	3004	3123	3218	3270	3254	3161	3040	3007	2952	2785	2544	2303	2126
SCEG	9/20/12	2018	1964	1915	1925	2053	2311	2376	2410	2485	2587	2693	2812	2929	3015	3075	3095	3004	2929	2937	2944	2786	2543	2311	2143
SCEG	9/21/12	2053	1985	1950	1957	2039	2278	2310	2382	2522	2690	2826	2944	3076	3184	3248	3307	3262	3124	3014	2954	2793	2602	2392	2209
SCEG	9/22/12	2096	2023	1978	1969	1971	2063	2106	2238	2413	2626	2805	2970	3131	3261	3358	3415	3384	3237	3146	3081	2886	2723	2443	2398
SCEG	9/23/12	2191	2108	2045	2016	2015	2045	2058	2210	2369	2540	2682	2821	2942	3020	3069	3077	3057	2952	2864	2818	2601	2370	2131	2004
SCEG	9/24/12	1911	1848	1837	1868	1986	2242	2299	2361	2415	2501	2590	2672	2753	2812	2874	2907	2873	2797	2804	2776	2595	2364	2147	1988
SCEG	9/25/12	1911	1861	1838	1859	1978	2230	2284	2321	2406	2500	2582	2629	2730	2828	2911	3010	2992	2897	2913	2865	2686	2460	2218	2057
SCEG	9/26/12	1962	1914	1875	1884	1995	2256	2315	2363	2475	2610	2716	2851	2995	3120	3240	3289	3266	3155	3103	3031	2844	2599	2345	2189
SCEG	9/27/12	2078	2011	1975	1994	2110	2377	2449	2515	2650	2775	2936	3090	3243	3376	3473	3518	3466	3310	3259	3190	2973	2716	2456	2265
SCEG	9/28/12	2156	2077	2036	2045	2150	2414	2477	2555	2711	2872	3044	3182	3273	3370	3412	3387	3321	3189	3155	3066	2905	2702	2512	2322
SCEG	9/29/12	2200	2117	2062	2035	2054	2123	2143	2255	2417	2564	2703	2836	2946	3025	3020	3000	2955	2897	2935	2881	2751	2595	2405	2178
SCEG	9/30/12	2044	1977	1922	1925	1933	1989	2071	2227	2358	2432	2489	2535	2555	2576	2569	2588	2621	2656	2776	2748	2602	2411	2246	2142
SCEG	10/1/12	2051	2024	1987	2036	2159	2448	2577	2638	2722	2854	2961	3080	3200	3281	3324	3327	3279	3224	3306	3272	3074	2873	2661	2443
SCEG	10/2/12	2384	2337	2320	2336	2457	2749	2863	2911	3066	3223	3342	3423	3542	3593	3591	3582	3511	3395	3444	3383	3178	2921	2684	2498

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCEG	10/3/12	2378	2323	2296	2313	2415	2687	2781	2768	2842	2937	3005	3104	3185	3222	3252	3254	3190	3171	3251	3182	3015	2780	2548	2341
SCEG	10/4/12	2216	2165	2075	2119	2219	2515	2616	2648	2732	2845	2895	2946	3003	3077	3166	3209	3141	3066	3111	3059	2892	2653	2434	2254
SCEG	10/5/12	2142	2083	2035	2038	2147	2386	2505	2510	2579	2693	2801	2908	3042	3150	3176	3180	3107	2976	2965	2880	2731	2567	2363	2203
SCEG	10/6/12	2085	1994	1960	1951	1960	2041	2079	2171	2354	2552	2733	2873	2975	3100	3171	3211	3168	3049	2989	2914	2740	2584	2401	2240
SCEG	10/7/12	2116	2038	1986	1950	1949	2012	2049	2166	2337	2462	2629	2843	2995	3138	3169	3176	3102	2998	3048	2924	2735	2515	2301	2137
SCEG	10/8/12	2022	1924	1880	1901	2005	2248	2354	2340	2384	2433	2453	2463	2446	2424	2411	2433	2456	2498	2599	2536	2396	2214	2058	1930
SCEG	10/9/12	1863	1848	1858	1879	2012	2297	2420	2385	2441	2460	2459	2444	2432	2410	2394	2398	2396	2412	2601	2569	2447	2271	2103	1982
SCEG	10/10/12	1925	1905	1895	1911	2092	2392	2474	2444	2425	2414	2407	2422	2438	2446	2473	2489	2460	2469	2615	2577	2432	2239	2057	1941
SCEG	10/11/12	1875	1828	1839	1869	2023	2307	2392	2380	2400	2436	2413	2423	2452	2475	2503	2480	2462	2459	2581	2550	2416	2238	2112	2037
SCEG	10/12/12	1968	1862	1833	1862	1974	2237	2312	2321	2349	2390	2432	2454	2504	2548	2587	2602	2566	2517	2571	2515	2406	2279	2119	2000
SCEG	10/13/12	1919	1876	1843	1830	1877	1952	2006	2099	2210	2274	2291	2325	2336	2348	2359	2388	2391	2362	2473	2405	2295	2190	2060	1962
SCEG	10/14/12	1863	1820	1794	1795	1822	1877	1927	2040	2145	2220	2323	2344	2454	2498	2528	2562	2557	2557	2657	2604	2459	2319	2134	2007
SCEG	10/15/12	1936	1897	1862	1900	2034	2302	2422	2433	2527	2632	2716	2787	2822	2848	2888	2912	2889	2846	2944	2867	2648	2443	2209	2032
SCEG	10/16/12	1922	1863	1848	1855	1984	2269	2358	2367	2399	2421	2438	2451	2480	2485	2495	2510	2509	2504	2626	2567	2431	2249	2085	1975
SCEG	10/17/12	1912	1860	1841	1887	2030	2315	2424	2411	2422	2439	2450	2455	2463	2460	2473	2500	2486	2499	2641	2601	2459	2282	2104	1991
SCEG	10/18/12	1897	1876	1862	1910	2030	2312	2438	2411	2468	2515	2554	2610	2658	2712	2726	2734	2693	2725	2820	2750	2632	2445	2256	2126
SCEG	10/19/12	2046	2003	1986	2000	2115	2355	2450	2434	2492	2563	2591	2603	2653	2690	2697	2695	2621	2551	2575	2483	2396	2272	2086	1983
SCEG	10/20/12	1899	1851	1837	1836	1893	1982	2045	2128	2222	2266	2277	2288	2283	2298	2288	2318	2310	2302	2392	2361	2278	2137	1978	1906
SCEG	10/21/12	1839	1814	1777	1765	1818	1883	1967	2074	2148	2171	2179	2194	2206	2232	2250	2288	2312	2302	2466	2408	2291	2134	1996	1893
SCEG	10/22/12	1832	1812	1823	1873	2016	2325	2461	2459	2466	2471	2473	2479	2486	2500	2513	2534	2529	2574	2620	2599	2437	2247	2080	1959
SCEG	10/23/12	1883	1858	1861	1896	2047	2353	2452	2441	2443	2456	2466	2502	2530	2560	2595	2615	2602	2615	2727	2622	2501	2299	2111	1994
SCEG	10/24/12	1920	1871	1878	1897	2037	2347	2436	2429	2440	2511	2575	2640	2709	2736	2800	2813	2718	2735	2831	2741	2585	2390	2206	2035
SCEG	10/25/12	1948	1900	1886	1915	2035	2327	2452	2430	2503	2588	2681	2750	2804	2838	2863	2865	2824	2806	2918	2815	2671	2485	2280	2104
SCEG	10/26/12	2051	1969	1931	1927	2051	2295	2437	2447	2495	2585	2644	2681	2714	2738	2721	2671	2615	2609	2672	2598	2497	2362	2217	2091
SCEG	10/27/12	1995	1941	1920	1905	1958	2039	2125	2197	2286	2375	2393	2379	2370	2334	2319	2333	2342	2400	2478	2433	2331	2228	2079	1956
SCEG	10/28/12	1866	1820	1797	1779	1810	1871	1963	2029	2146	2183	2213	2249	2270	2301	2322	2341	2349	2400	2523	2471	2336	2181	2041	1909
SCEG	10/29/12	1844	1809	1816	1855	2015	2327	2463	2489	2495	2521	2512	2480	2453	2428	2412	2410	2440	2540	2669	2627	2524	2376	2226	2127
SCEG	10/30/12	2056	2031	2038	2153	2271	2566	2704	2664	2667	2660	2615	2534	2494	2444	2426	2437	2507	2662	2796	2750	2637	2477	2303	2248
SCEG	10/31/12	2206	2191	2214	2228	2414	2747	2856	2800	2727	2632	2567	2484	2421	2373	2340	2329	2328	2390	2524	2569	2554	2441	2282	2195
SCEG	11/1/12	2185	2187	2214	2289	2475	2787	2921	2880	2784	2689	2605	2555	2511	2463	2444	2425	2444	2555	2725	2722	2645	2526	2380	2316
SCEG	11/2/12	2267	2285	2297	2381	2541	2847	2973	2907	2789	2664	2590	2509	2451	2441	2407	2413	2401	2470	2493	2456	2383	2295	2178	2054
SCEG	11/3/12	2009	1964	2006	2030	2124	2277	2388	2464	2499	2397	2343	2294	2251	2222	2250	2271	2277	2332	2436	2388	2326	2257	2124	2040
SCEG	11/4/12	1944	1906	1900	1908	1923	1960	2028	2109	2231	2254	2242	2256	2283	2312	2333	2322	2318	2466	2549	2509	2430	2296	2157	2017
SCEG	11/5/12	1929	1873	1856	1853	1914	2086	2354	2403	2438	2454	2495	2516	2474	2462	2437	2416	2455	2599	2731	2739	2625	2520	2394	2263
SCEG	11/6/12	2175	2119	2118	2125	2194	2327	2493	2570	2645	2689	2665	2610	2551	2511	2549	2551	2586	2776	2950	2966	2926	2839	2709	2596

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCEG	11/7/12	2540	2523	2486	2509	2596	2763	3074	3081	3032	2937	2869	2792	2715	2668	2617	2589	2649	2856	3041	3045	2994	2869	2719	2604
SCEG	11/8/12	2557	2543	2559	2608	2689	2906	3187	3224	3036	2894	2734	2613	2547	2484	2458	2445	2462	2627	2843	2859	2825	2752	2634	2532
SCEG	11/9/12	2487	2478	2503	2558	2655	2835	3207	3220	3073	2861	2717	2635	2528	2465	2441	2407	2411	2559	2675	2659	2641	2585	2492	2418
SCEG	11/10/12	2347	2336	2341	2373	2426	2514	2641	2773	2769	2641	2509	2417	2322	2275	2245	2234	2242	2374	2500	2467	2427	2375	2308	2199
SCEG	11/11/12	2157	2113	2106	2113	2152	2231	2283	2338	2415	2362	2321	2229	2253	2240	2255	2235	2260	2418	2530	2490	2440	2300	2144	2052
SCEG	11/12/12	1919	1878	1865	1847	1909	2038	2288	2349	2425	2435	2454	2483	2496	2492	2512	2473	2507	2663	2738	2710	2633	2485	2324	2132
SCEG	11/13/12	2040	1955	1915	1919	1961	2070	2350	2434	2432	2457	2519	2535	2556	2575	2549	2497	2542	2682	2790	2761	2692	2571	2413	2219
SCEG	11/14/12	2122	2101	2074	2111	2161	2333	2687	2735	2766	2720	2679	2693	2647	2629	2640	2644	2701	2909	2993	2974	2903	2754	2592	2444
SCEG	11/15/12	2332	2288	2272	2294	2368	2528	2846	2952	2940	2953	2944	2931	2896	2870	2834	2807	2855	3008	3154	3127	3054	2971	2774	2608
SCEG	11/16/12	2499	2442	2416	2403	2456	2622	2938	2962	2929	2881	2816	2740	2676	2633	2594	2554	2578	2740	2852	2837	2768	2728	2634	2513
SCEG	11/17/12	2430	2400	2388	2340	2419	2489	2668	2750	2880	2841	2761	2654	2530	2464	2426	2439	2471	2635	2719	2720	2676	2580	2455	2354
SCEG	11/18/12	2266	2201	2187	2188	2199	2250	2348	2411	2555	2636	2659	2631	2574	2579	2538	2538	2559	2763	2839	2809	2740	2619	2464	2325
SCEG	11/19/12	2227	2176	2157	2168	2222	2366	2647	2717	2692	2716	2700	2657	2580	2562	2501	2456	2505	2648	2786	2776	2702	2576	2437	2334
SCEG	11/20/12	2236	2138	2136	2122	2213	2395	2713	2777	2770	2721	2664	2647	2579	2524	2476	2462	2496	2654	2778	2763	2714	2641	2570	2413
SCEG	11/21/12	2356	2305	2258	2359	2425	2592	2765	2866	2839	2747	2702	2571	2493	2473	2432	2402	2402	2560	2706	2716	2705	2687	2600	2439
SCEG	11/22/12	2359	2332	2318	2334	2389	2505	2640	2715	2780	2754	2673	2576	2414	2254	2163	2069	2039	2141	2270	2328	2377	2413	2397	2376
SCEG	11/23/12	2359	2377	2412	2480	2598	2731	2855	2931	2878	2703	2558	2383	2253	2182	2151	2127	2123	2317	2443	2413	2396	2349	2257	2162
SCEG	11/24/12	2081	2028	2010	2003	2077	2166	2291	2389	2497	2486	2458	2384	2309	2251	2211	2164	2195	2400	2539	2583	2602	2620	2619	2565
SCEG	11/25/12	2538	2556	2586	2621	2669	2776	2930	3023	3036	2921	2747	2590	2474	2380	2333	2314	2358	2606	2822	2848	2871	2820	2720	2627
SCEG	11/26/12	2533	2535	2570	2624	2753	3001	3385	3468	3322	3042	2815	2685	2597	2544	2493	2471	2498	2674	2853	2877	2866	2791	2634	2529
SCEG	11/27/12	2458	2419	2425	2419	2476	2636	2956	2951	2872	2828	2802	2753	2739	2742	2709	2672	2780	2952	2990	2936	2846	2719	2573	2410
SCEG	11/28/12	2279	2186	2175	2232	2314	2464	2787	2842	2818	2775	2735	2675	2600	2576	2545	2531	2584	2800	3013	3068	3062	3010	2849	2795
SCEG	11/29/12	2747	2749	2797	2885	3009	3191	3481	3539	3360	3091	2864	2704	2627	2554	2511	2524	2584	2802	2983	3054	3078	3004	2899	2775
SCEG	11/30/12	2700	2686	2696	2742	2822	3030	3321	3346	3206	3030	2863	2720	2634	2584	2532	2471	2497	2690	2793	2787	2743	2655	2571	2441

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Backup - SCPSA Hourly Load

Dec 2011-Nov 2012 Load

SCPSAPe	**Max**	5,387
SCPSAA	**Avg Jan**	3,766
SCPSAV	**Winter**	3,646
SCPSAS	**Spring**	3,388
SCPSAS	**Summer**	4,391
SCPSAF	**Fall**	3,490

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCPSA	12/1/11	3342	3347	3393	3369	3520	3816	4225	4218	3959	3580	3273	3033	2854	2779	2705	2699	2858	3227	3536	3693	3772	3729	3669	3566
SCPSA	12/2/11	3517	3526	3633	3696	3839	4113	4458	4490	4244	3799	3334	2979	2867	2766	2643	2631	2697	3074	3322	3345	3469	3487	3498	3396
SCPSA	12/3/11	3380	3386	3433	3504	3566	3697	3852	3977	3914	3576	3283	3056	2835	2743	2589	2646	2727	2991	3146	3212	3218	3177	3000	2868
SCPSA	12/4/11	2819	2827	2806	2818	2864	2929	3020	3121	3098	3061	2918	2783	2674	2664	2601	2589	2639	2858	2980	3036	2983	2832	2681	2531
SCPSA	12/5/11	2384	2313	2288	2352	2442	2638	2948	2990	2814	2751	2610	2644	2681	2669	2667	2659	2725	2990	3135	3174	3089	2927	2738	2531
SCPSA	12/6/11	2396	2307	2227	2248	2289	2479	2746	2791	2718	2712	2702	2689	2687	2675	2647	2668	2691	2956	3117	3093	3020	2882	2661	2440
SCPSA	12/7/11	2314	2265	2242	2213	2218	2286	2571	2652	2640	2669	2672	2702	2720	2725	2672	2652	2781	2960	3172	3228	3275	3218	3052	2918
SCPSA	12/8/11	2815	2832	2903	2938	3112	3386	3808	3901	3735	3436	3219	3099	2986	2846	2782	2868	2942	3356	3633	3788	3836	3816	3661	3485
SCPSA	12/9/11	3356	3319	3351	3368	3425	3616	3926	3944	3732	3493	3227	2964	2826	2727	2642	2645	2782	3087	3232	3253	3253	3190	3080	2881
SCPSA	12/10/11	2806	2735	2712	2708	2692	2786	2926	3085	3193	3249	3158	3093	2962	2876	2832	2856	2953	3224	3354	3478	3496	3500	3459	3355
SCPSA	12/11/11	3275	3222	3288	3328	3394	3537	3652	3822	3964	3799	3456	3239	3057	2909	2884	2898	3053	3374	3440	3621	3549	3481	3366	3180
SCPSA	12/12/11	3091	3047	3022	3084	3181	3386	3716	3765	3686	3704	3591	3523	3456	3339	3259	3223	3285	3622	3808	3767	3780	3624	3423	3244
SCPSA	12/13/11	3089	3104	3130	3149	3250	3501	3896	3880	3699	3404	3178	2971	2846	2746	2738	2713	2773	3048	3272	3330	3376	3303	3124	2950
SCPSA	12/14/11	2897	2857	2891	2915	3047	3219	3509	3582	3359	3120	2845	2695	2639	2585	2551	2552	2623	2916	3204	3233	3234	3157	3005	2805
SCPSA	12/15/11	2702	2705	2678	2737	2815	3043	3399	3452	3290	3059	2840	2737	2669	2637	2625	2627	2630	2898	3060	3090	3078	2987	2790	2572
SCPSA	12/16/11	2417	2358	2328	2323	2366	2525	2844	2931	2849	2792	2750	2684	2673	2634	2627	2616	2641	2845	2948	2870	2826	2794	2675	2446
SCPSA	12/17/11	2361	2320	2278	2277	2322	2393	2483	2661	2834	2898	2864	2713	2684	2634	2583	2620	2735	2928	3163	3155	3198	3192	3128	3037
SCPSA	12/18/11	2952	2927	2959	2984	3044	3125	3223	3540	3672	3553	3252	3017	2898	2793	2735	2697	2801	3079	3387	3523	3614	3528	3546	3455
SCPSA	12/19/11	3421	3414	3424	3490	3624	3886	4178	4330	4238	3734	3383	3145	2974	2846	2751	2688	2680	3030	3312	3412	3411	3328	3180	3012
SCPSA	12/20/11	2854	2849	2823	2865	2895	3074	3166	3290	3258	3023	2791	2770	2699	2599	2681	2639	2759	2930	3052	3149	3086	3008	2833	2660
SCPSA	12/21/11	2498	2435	2406	2427	2473	2607	2785	2859	2845	2870	2892	2779	2773	2794	2676	2777	2771	2968	3163	3114	3044	2907	2739	2477
SCPSA	12/22/11	2326	2281	2261	2228	2259	2376	2554	2615	2593	2692	2787	2780	2773	2766	2751	2710	2760	2965	3100	3030	3003	2877	2721	2539
SCPSA	12/23/11	2389	2303	2247	2204	2182	2235	2280	2473	2581	2660	2684	2695	2653	2636	2602	2589	2602	2801	2876	2883	2868	2829	2702	2571
SCPSA	12/24/11	2360	2292	2238	2209	2266	2337	2464	2641	2839	2865	2789	2684	2557	2465	2425	2423	2448	2625	2746	2764	2814	2842	2817	2736
SCPSA	12/25/11	2644	2591	2583	2604	2636	2716	2818	2995	3091	3035	2887	2784	2713	2653	2568	2547	2563	2704	2773	2780	2780	2731	2638	2506
SCPSA	12/26/11	2424	2370	2385	2433	2510	2632	2796	2950	3046	2998	2904	2785	2659	2534	2467	2450	2525	2851	3146	3228	3281	3226	3097	2897
SCPSA	12/27/11	2744	2639	2589	2574	2579	2665	2788	2867	2869	2919	3017	2945	2922	2855	2804	2763	2837	3060	3302	3288	3300	3226	3112	3018

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Backup - SCPSA Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCPSA	12/28/11	2902	2908	2880	2971	3050	3212	3469	3623	3647	3470	3333	3178	2999	2899	2822	2838	2925	3232	3516	3589	3674	3672	3601	3410
SCPSA	12/29/11	3446	3504	3567	3658	3759	3961	4102	4306	4250	4025	3629	3306	3084	2961	2852	2829	2889	3185	3501	3583	3625	3585	3450	3301
SCPSA	12/30/11	3276	3190	3286	3288	3432	3610	3856	3979	3909	3594	3296	3083	2858	2796	2651	2646	2705	3006	3193	3148	3143	3108	2980	2820
SCPSA	12/31/11	2685	2621	2554	2455	2390	2386	2507	2711	2853	2912	2862	2823	2759	2670	2604	2587	2657	2888	3005	3012	3010	2948	2929	2905
SCPSA	1/1/12	2869	2905	2929	2966	3043	3181	3293	3450	3535	3324	3089	2876	2711	2651	2583	2559	2586	2733	2885	2848	2828	2746	2660	2471
SCPSA	1/2/12	2361	2298	2277	2376	2541	2765	3035	3230	3381	3363	3305	3185	3041	2965	2915	2891	3043	3399	3732	3845	3853	3811	3622	3604
SCPSA	1/3/12	3620	3652	3770	3953	4082	4401	4729	4812	4773	4605	4409	4170	3955	3765	3677	3755	3891	4273	4700	4788	4815	4766	4637	4556
SCPSA	1/4/12	4518	4496	4611	4730	4853	5118	5387	5358	5186	4721	4206	3851	3618	3429	3226	3279	3406	3820	4177	4244	4258	4179	3992	3831
SCPSA	1/5/12	3669	3689	3660	3711	3790	4004	4352	4335	4170	3806	3554	3268	2954	2843	2808	2802	2858	3143	3484	3565	3693	3686	3575	3455
SCPSA	1/6/12	3413	3433	3485	3556	3694	3925	4252	4283	4123	3732	3338	3076	2871	2791	2654	2630	2672	2925	3152	3176	3116	3148	3115	2997
SCPSA	1/7/12	2889	2857	2877	2905	2924	2994	3119	3233	3291	3195	3033	2857	2738	2654	2598	2594	2608	2721	2908	2868	2801	2767	2661	2540
SCPSA	1/8/12	2444	2408	2397	2372	2405	2478	2546	2742	2960	2925	2803	2703	2675	2603	2608	2474	2501	2736	2876	2872	2886	2792	2634	2438
SCPSA	1/9/12	2350	2314	2313	2294	2392	2616	2950	3022	2913	2874	2805	2855	2808	2654	2640	2661	2775	2925	3187	3089	3035	2906	2791	2612
SCPSA	1/10/12	2547	2504	2475	2447	2536	2708	2999	3065	2978	2940	2902	2843	2822	2773	2756	2729	2817	2981	3161	3238	3194	3072	2878	2652
SCPSA	1/11/12	2560	2508	2473	2474	2497	2599	2907	2935	2842	2807	2809	2811	2818	2762	2640	2609	2715	2899	3103	3130	3054	3018	2908	2740
SCPSA	1/12/12	2646	2639	2639	2680	2780	2983	3347	3429	3314	3218	3086	3065	2917	2785	2698	2696	2767	3041	3213	3283	3230	3153	3009	2889
SCPSA	1/13/12	2855	2888	3000	3106	3282	3627	4041	4239	4209	4062	3864	3615	3407	3215	3175	3165	3301	3616	3975	4012	4026	3945	3742	3690
SCPSA	1/14/12	3618	3616	3651	3730	3828	3986	4222	4405	4462	4164	3921	3726	3465	3279	3144	3136	3218	3516	3809	3926	3948	3906	3835	3662
SCPSA	1/15/12	3601	3456	3411	3496	3509	3611	3745	3922	4038	3858	3512	3275	3169	3035	2949	2850	2946	3153	3501	3626	3761	3769	3728	3676
SCPSA	1/16/12	3639	3678	3724	3809	3881	4132	4344	4442	4407	4240	3921	3591	3386	3191	3164	3130	3105	3308	3580	3604	3560	3305	3174	3041
SCPSA	1/17/12	2963	2916	2915	2927	2964	3157	3415	3477	3325	3196	3104	2970	2897	2832	2783	2780	2834	3010	3250	3268	3146	3059	2869	2657
SCPSA	1/18/12	2508	2471	2455	2452	2480	2671	2987	2987	2906	2875	2838	2765	2709	2673	2651	2648	2780	2993	3375	3405	3467	3468	3400	3301
SCPSA	1/19/12	3280	3315	3358	3412	3605	3863	4295	4373	4174	3910	3630	3400	3125	3008	2935	2909	2948	3216	3534	3696	3702	3620	3554	3430
SCPSA	1/20/12	3354	3358	3330	3417	3452	3580	3834	3886	3679	3493	3329	3146	2956	2995	2931	2921	2981	3129	3290	3272	3216	3125	2973	2798
SCPSA	1/21/12	2723	2617	2571	2513	2501	2545	2639	2758	2883	2918	2968	2918	2902	2825	2797	2792	2834	2906	3005	3024	2964	2856	2767	2612
SCPSA	1/22/12	2487	2426	2396	2397	2439	2552	2715	2892	3186	3307	3243	3237	3289	3296	3223	3263	3283	3474	3581	3594	3591	3486	3311	3157
SCPSA	1/23/12	3027	2988	2974	3008	3098	3312	3633	3696	3565	3543	3427	3274	3137	3025	2971	2972	2938	3208	3456	3432	3350	3190	2955	2633
SCPSA	1/24/12	2532	2486	2535	2521	2463	2625	3008	3071	2962	2912	2831	2765	2728	2661	2617	2613	2657	2758	3074	3088	3075	3031	2851	2739
SCPSA	1/25/12	2700	2686	2687	2669	2767	3025	3494	3576	3389	3067	2809	2657	2484	2410	2377	2378	2503	2755	3102	3136	3122	3009	2816	2706
SCPSA	1/26/12	2599	2493	2497	2539	2578	2645	3085	3105	2959	2873	2794	2733	2661	2594	2588	2550	2627	2798	3030	3035	2989	2870	2634	2478
SCPSA	1/27/12	2346	2242	2241	2225	2261	2351	2667	2719	2701	2713	2663	2644	2619	2536	2487	2507	2559	2627	2811	2871	2850	2799	2784	2660
SCPSA	1/28/12	2655	2665	2702	2796	2882	3060	3198	3393	3518	3348	3095	2938	2748	2629	2447	2461	2478	2602	2850	2938	2979	2957	2919	2823
SCPSA	1/29/12	2742	2756	2819	2870	2962	3025	3233	3464	3608	3446	3148	2907	2807	2727	2683	2610	2678	2865	3252	3391	3486	3537	3386	3314
SCPSA	1/30/12	3350	3381	3440	3551	3676	3960	4356	4491	4118	3646	3274	3022	2789	2664	2610	2623	2661	2844	3197	3314	3360	3372	3268	3181
SCPSA	1/31/12	3176	3231	3277	3388	3560	3803	4274	4318	4060	3589	3248	2955	2817	2737	2670	2605	2715	2758	3141	3261	3268	3176	3012	2908

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Backup - SCPSA Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCPSA	2/1/12	2843	2809	2834	2860	2886	3053	3348	3440	3294	3083	2858	2740	2637	2568	2595	2633	2675	2763	2965	3028	2977	2889	2673	2383
SCPSA	2/2/12	2315	2277	2256	2217	2267	2445	2754	2840	2767	2728	2684	2659	2605	2628	2647	2615	2663	2658	2891	2954	2936	2849	2698	2553
SCPSA	2/3/12	2472	2428	2476	2548	2629	2892	3288	3408	3288	3143	2968	2814	2735	2667	2596	2595	2642	2772	3067	3133	3145	3091	3000	2866
SCPSA	2/4/12	2797	2677	2645	2643	2624	2716	2804	2799	2941	3108	3040	2954	2829	2765	2664	2647	2646	2759	2886	2886	2847	2759	2682	2496
SCPSA	2/5/12	2426	2377	2312	2250	2260	2315	2429	2500	2705	2793	2726	2681	2673	2628	2613	2655	2707	2792	2930	2874	2897	2791	2753	2569
SCPSA	2/6/12	2468	2402	2319	2401	2541	2768	3191	3304	3293	3258	3260	3218	3236	3170	3135	3109	3248	3409	3667	3647	3505	3446	3237	3088
SCPSA	2/7/12	3013	2985	2997	3030	3139	3391	3756	3702	3497	3238	3048	2861	2700	2642	2609	2634	2729	2930	3280	3476	3496	3470	3379	3218
SCPSA	2/8/12	3235	3243	3342	3424	3505	3775	4126	4101	3912	3619	3368	3130	2973	2881	2840	2775	2858	3004	3351	3445	3541	3478	3345	3240
SCPSA	2/9/12	3197	3262	3285	3374	3595	3777	4230	4289	4126	3800	3501	3199	3042	2936	2918	2873	2998	3194	3541	3739	3770	3741	3598	3482
SCPSA	2/10/12	3480	3518	3564	3600	3658	3828	4133	4093	4002	3796	3604	3437	3215	3059	2933	2981	3045	3200	3401	3420	3317	3239	3148	3039
SCPSA	2/11/12	2934	2774	2843	2834	2936	3012	3142	3280	3407	3306	3222	3147	3072	3043	2966	3043	3169	3429	3864	4076	4250	4324	4398	4357
SCPSA	2/12/12	4348	4417	4473	4483	4594	4755	4905	5042	5038	4797	4427	4116	3866	3658	3436	3309	3253	3522	3893	4157	4294	4300	4181	4063
SCPSA	2/13/12	4134	4134	4265	4378	4550	4837	5294	5319	4987	4441	3931	3574	3356	3194	3085	2985	3056	3297	3670	3845	3917	3858	3718	3574
SCPSA	2/14/12	3463	3462	3453	3479	3510	3673	3936	3916	3750	3660	3522	3331	3221	3113	3063	3024	3079	3259	3447	3496	3503	3375	3195	2995
SCPSA	2/15/12	2891	2841	2832	2853	2908	3164	3377	3371	3203	2982	2862	2720	2670	2632	2584	2529	2658	2798	3042	3183	3209	3154	3000	2853
SCPSA	2/16/12	2771	2753	2739	2774	2815	2978	3299	3300	3181	3131	3123	2995	2894	2826	2863	2772	2837	2923	3037	3246	3064	2981	2778	2622
SCPSA	2/17/12	2500	2424	2396	2433	2516	2695	3004	3029	2989	2882	2762	2702	2733	2684	2669	2594	2613	2704	2921	3003	2969	2907	2866	2748
SCPSA	2/18/12	2723	2637	2648	2752	2837	2939	3152	3320	3377	3190	3038	2884	2752	2692	2672	2651	2661	2719	2965	2970	2841	2755	2585	2492
SCPSA	2/19/12	2427	2412	2338	2344	2390	2443	2553	2679	2882	2986	2983	2992	2971	2944	2950	2975	3012	3181	3376	3412	3381	3335	3241	3157
SCPSA	2/20/12	3124	3112	3169	3267	3381	3553	3808	3994	3978	3860	3646	3415	3234	3064	2923	2890	2865	2983	3368	3610	3696	3672	3578	3415
SCPSA	2/21/12	3419	3419	3474	3570	3663	3901	4317	4292	3976	3579	3399	3221	3082	2912	2820	2747	2798	2782	3030	3225	3254	3177	3101	2950
SCPSA	2/22/12	2850	2799	2811	2812	2875	2992	3346	3292	3067	2843	2673	2574	2507	2456	2422	2435	2531	2662	2975	3036	3041	2952	2764	2547
SCPSA	2/23/12	2423	2369	2277	2291	2357	2524	2815	2873	2772	2649	2688	2652	2674	2727	2701	2699	2704	2791	3015	3093	3015	2885	2635	2429
SCPSA	2/24/12	2336	2254	2247	2200	2261	2359	2612	2692	2617	2709	2790	2726	2736	2747	2712	2685	2722	2717	2896	2926	2864	2783	2679	2548
SCPSA	2/25/12	2400	2385	2424	2505	2570	2703	2827	3091	3248	3252	3196	3042	2915	2810	2728	2678	2739	2848	3078	3252	3287	3258	3249	3213
SCPSA	2/26/12	3193	3235	3265	3282	3353	3498	3658	3844	3950	3827	3577	3333	3109	2889	2810	2750	2757	2899	3152	3337	3347	3288	3111	2982
SCPSA	2/27/12	2844	2787	2738	2744	2777	2936	3300	3304	3201	3223	3216	3120	3109	3050	2900	2868	2893	2968	3195	3325	3267	3070	2803	2704
SCPSA	2/28/12	2579	2515	2563	2572	2651	2872	3199	3229	3106	3005	2840	2794	2718	2652	2614	2611	2655	2725	3001	3122	3095	2961	2757	2594
SCPSA	2/29/12	2485	2450	2447	2437	2477	2658	2963	3005	2889	2726	2788	2705	2731	2702	2749	2737	2752	2817	2998	3064	3010	2930	2741	2527
SCPSA	3/1/12	2399	2284	2243	2228	2277	2361	2628	2694	2634	2603	2548	2552	2561	2568	2583	2670	2638	2740	2969	3062	2937	2869	2652	2510
SCPSA	3/2/12	2369	2285	2285	2237	2277	2337	2712	2743	2752	2776	2765	2802	2806	2792	2731	2756	2834	2846	2886	3010	2862	2745	2634	2583
SCPSA	3/3/12	2438	2309	2255	2215	2168	2171	2251	2401	2517	2668	2701	2763	2776	2729	2674	2687	2705	2803	2932	2948	2876	2797	2697	2555
SCPSA	3/4/12	2397	2345	2322	2349	2397	2481	2632	2831	3071	3106	3044	2948	2881	2805	2757	2772	2818	2965	3241	3481	3504	3432	3331	3206
SCPSA	3/5/12	3031	3034	3062	3098	3153	3400	3721	3709	3566	3306	3159	3029	2943	2856	2725	2707	2779	2915	3190	3463	3521	3459	3376	3260
SCPSA	3/6/12	3219	3222	3309	3430	3599	3895	4258	4246	3925	3593	3330	3139	2914	2915	2835	2816	2879	3008	3288	3500	3530	3479	3325	3161

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SCPSA	3/7/12	3053	3039	3039	3020	3096	3255	3504	3568	3332	3167	2962	2889	2806	2781	2757	2738	2777	2874	3062	3183	3140	3063	2870	2662
SCPSA	3/8/12	2563	2509	2483	2450	2556	2756	3063	3095	2889	2809	2749	2786	2772	2732	2720	2724	2718	2810	2997	3134	3070	2965	2755	2454
SCPSA	3/9/12	2263	2225	2213	2234	2296	2481	2694	2788	2697	2729	2734	2796	2761	2646	2698	2654	2694	2714	2874	2957	2950	2933	2795	2619
SCPSA	3/10/12	2599	2568	2631	2647	2746	2889	2999	3249	3245	3118	3027	2837	2746	2663	2598	2530	2581	2670	2742	3013	3011	2973	2899	2810
SCPSA	3/11/12	2711	2720	2709	2809	2896	2970	3192	3336	3272	3059	2850	2710	2677	2624	2525	2559	2619	2637	2779	2944	2853	2728	2533	2429
SCPSA	3/12/12	2418	2386	2393	2484	2658	2966	3127	2978	2790	2695	2650	2656	2706	2672	2674	2732	2807	2862	3057	3147	3030	2788	2591	2422
SCPSA	3/13/12	2364	2353	2329	2368	2495	2719	2870	2735	2859	2836	2831	2805	2791	2769	2823	2810	2848	2943	3007	3158	2996	2829	2544	2319
SCPSA	3/14/12	2274	2259	2292	2346	2450	2759	2866	2752	2774	2800	2807	2812	2869	2888	2983	3029	3110	3111	3144	3284	3121	2896	2586	2433
SCPSA	3/15/12	2308	2304	2276	2304	2411	2770	2822	2767	2784	2747	2844	2862	2955	2972	3095	2983	3134	3144	3236	3281	3195	2991	2673	2493
SCPSA	3/16/12	2400	2321	2297	2314	2413	2637	2737	2659	2766	2841	2882	2878	2938	2939	2980	3037	3001	3013	3036	3172	3070	2907	2713	2469
SCPSA	3/17/12	2380	2258	2229	2224	2243	2378	2395	2540	2584	2733	2809	2888	2966	3007	3118	3077	3117	3055	3040	3055	3003	2796	2600	2359
SCPSA	3/18/12	2318	2133	2116	2112	2200	2226	2383	2482	2686	2658	2700	2773	2809	2850	2878	2935	2932	2932	2985	3027	2967	2783	2575	2389
SCPSA	3/19/12	2252	2235	2187	2247	2333	2615	2717	2702	2714	2767	2805	2860	2970	2962	3134	3190	3161	3178	3201	3287	3094	2874	2642	2429
SCPSA	3/20/12	2315	2291	2248	2262	2369	2592	2754	2720	2708	2812	2809	2964	3007	3169	3218	3305	3334	3320	3334	3410	3215	2989	2681	2438
SCPSA	3/21/12	2331	2306	2251	2242	2377	2531	2596	2586	2609	2692	2787	2846	2872	2955	2994	3115	3075	3073	3119	3250	3091	2889	2636	2481
SCPSA	3/22/12	2340	2280	2261	2267	2408	2667	2666	2657	2746	2748	2847	3030	3040	3137	3206	3245	3224	3189	3225	3344	3224	2937	2616	2454
SCPSA	3/23/12	2327	2265	2292	2295	2355	2620	2684	2639	2755	2793	2815	2919	3047	3196	3232	3336	3285	3219	3160	3214	3048	2923	2717	2450
SCPSA	3/24/12	2313	2241	2249	2205	2223	2349	2455	2610	2763	2858	2955	2995	3049	3083	3061	2942	2880	2853	2785	2919	2809	2700	2535	2336
SCPSA	3/25/12	2203	2168	2182	2138	2161	2216	2342	2525	2680	2720	2676	2701	2705	2715	2714	2722	2732	2763	2826	3005	2864	2663	2407	2254
SCPSA	3/26/12	2249	2174	2145	2249	2378	2705	2740	2727	2756	2796	2825	2788	2850	2752	2849	3004	3122	3214	3163	3241	3097	2807	2562	2366
SCPSA	3/27/12	2280	2247	2224	2228	2387	2676	2715	2769	2731	2716	2716	2751	2712	2679	2724	2791	2833	2869	2954	3078	2970	2794	2457	2396
SCPSA	3/28/12	2364	2304	2244	2345	2468	2725	2717	2590	2584	2556	2536	2556	2577	2596	2674	2752	2877	2927	2939	3157	3057	2843	2604	2437
SCPSA	3/29/12	2315	2247	2263	2288	2365	2634	2669	2514	2645	2689	2775	2919	3121	3247	3338	3397	3429	3382	3365	3441	3315	3020	2739	2524
SCPSA	3/30/12	2383	2310	2296	2287	2428	2711	2687	2688	2775	2843	2865	2986	3118	3220	3249	3313	3300	3146	3206	3235	3117	2933	2694	2489
SCPSA	3/31/12	2489	2372	2353	2262	2257	2315	2359	2506	2606	2725	2785	2895	2936	2966	2994	3013	3021	3079	3021	3051	3103	2953	2839	2415
SCPSA	4/1/12	2283	2223	2179	2156	2203	2170	2269	2500	2600	2598	2611	2731	2840	2950	3010	3081	3171	3094	3081	3132	3033	2815	2545	2345
SCPSA	4/2/12	2297	2243	2205	2232	2367	2590	2687	2662	2765	2952	2985	3206	3329	3455	3577	3598	3578	3435	3375	3462	3361	3114	2800	2555
SCPSA	4/3/12	2468	2395	2351	2344	2329	2608	2683	2743	2803	2839	2875	2908	3010	3117	3175	3256	3362	3326	3340	3455	3313	3013	2750	2528
SCPSA	4/4/12	2439	2400	2343	2373	2365	2642	2630	2597	2630	2755	2908	3050	3199	3325	3444	3563	3601	3524	3456	3502	3394	3095	2862	2597
SCPSA	4/5/12	2446	2364	2310	2292	2379	2633	2686	2753	2871	3023	3156	3318	3436	3407	3430	3344	3234	3166	3131	3096	2999	2835	2610	2396
SCPSA	4/6/12	2300	2260	2192	2222	2286	2472	2597	2719	2874	2958	2917	2827	2814	2705	2688	2667	2687	2678	2718	2898	2927	2851	2663	2545
SCPSA	4/7/12	2400	2435	2465	2463	2576	2735	2953	3063	3041	2913	2803	2729	2645	2669	2667	2650	2698	2714	2726	2904	2909	2784	2538	2427
SCPSA	4/8/12	2257	2255	2231	2267	2359	2493	2661	2791	2890	2748	2675	2625	2663	2629	2758	2827	2840	2830	2822	2969	2885	2739	2510	2341
SCPSA	4/9/12	2259	2209	2198	2167	2307	2452	2587	2609	2696	2767	2764	2787	2828	2918	2957	3014	3103	3084	3042	3109	3043	2784	2537	2347
SCPSA	4/10/12	2237	2226	2196	2250	2421	2611	2688	2752	2737	2702	2815	2778	2815	2799	2917	2991	3035	2998	3035	3106	2997	2739	2514	2333

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SCPSA	4/12/12	2446	2457	2480	2576	2723	3130	3212	3209	3063	2966	2862	2710	2734	2662	2690	2650	2718	2746	2826	3040	3016	2885	2681	2595
SCPSA	4/13/12	2547	2572	2597	2626	2832	3184	3245	3174	3046	2927	2814	2755	2687	2684	2681	2744	2762	2705	2715	2835	2888	2746	2600	2482
SCPSA	4/14/12	2416	2363	2359	2445	2482	2620	2747	2879	2862	2783	2780	2771	2713	2692	2760	2807	2857	2842	2790	2834	2780	2687	2507	2361
SCPSA	4/15/12	2237	2204	2160	2136	2194	2208	2324	2556	2640	2714	2761	2815	2837	2886	2916	2955	3057	3059	2972	3089	3050	2872	2601	2371
SCPSA	4/16/12	2267	2167	2102	2164	2327	2570	2631	2658	2689	2814	2851	2972	3105	3178	3294	3378	3372	3397	3337	3434	3299	2964	2581	2459
SCPSA	4/17/12	2382	2329	2296	2285	2387	2623	2697	2724	2875	2936	3074	3147	3267	3438	3483	3567	3584	3540	3481	3474	3418	3123	2781	2564
SCPSA	4/18/12	2416	2344	2295	2324	2413	2584	2682	2638	2703	2851	2878	2885	2981	2994	3026	3075	3053	3054	3083	3154	3074	2845	2627	2412
SCPSA	4/19/12	2344	2302	2298	2333	2419	2648	2604	2577	2600	2597	2632	2618	2640	2657	2692	2761	2725	2841	2852	2909	2935	2712	2539	2371
SCPSA	4/20/12	2317	2208	2212	2232	2409	2621	2679	2651	2643	2721	2633	2741	2776	2784	2772	2902	2955	2980	2957	3065	3029	2841	2626	2446
SCPSA	4/21/12	2313	2242	2165	2145	2215	2219	2412	2591	2698	2830	2885	2932	3099	3134	3099	3128	3114	2984	2973	3025	2942	2789	2570	2423
SCPSA	4/22/12	2296	2202	2159	2153	2172	2151	2170	2389	2558	2662	2690	2753	2740	2727	2701	2701	2725	2727	2748	2860	2785	2610	2394	2280
SCPSA	4/23/12	2192	2162	2148	2193	2349	2667	2788	2771	2756	2772	2743	2677	2702	2692	2682	2741	2788	2845	2962	3133	2975	2871	2703	2593
SCPSA	4/24/12	2606	2632	2666	2739	2922	3287	3312	3154	3025	2880	2783	2725	2684	2601	2650	2691	2706	2763	2808	2994	2963	2807	2594	2440
SCPSA	4/25/12	2398	2315	2354	2389	2592	2882	2900	2843	2751	2779	2725	2688	2673	2703	2728	2835	2801	2970	2964	3029	3020	2801	2581	2364
SCPSA	4/26/12	2310	2267	2258	2259	2374	2600	2626	2636	2696	2787	2838	2872	2942	3003	3086	3210	3289	3255	3240	3319	3171	2922	2702	2508
SCPSA	4/27/12	2373	2276	2282	2229	2364	2589	2679	2656	2762	2879	3048	3182	3338	3446	3538	3539	3535	3464	3370	3354	3278	2991	2763	2589
SCPSA	4/28/12	2456	2361	2327	2320	2321	2359	2445	2608	2725	2970	3084	3132	3200	3274	3305	3394	3348	3250	3180	3090	3089	2929	2668	2428
SCPSA	4/29/12	2309	2128	2059	2028	2016	2054	2134	2378	2590	2640	2803	2993	3161	3284	3387	3472	3486	3404	3312	3294	3160	2916	2613	2360
SCPSA	4/30/12	2208	2167	2110	2120	2238	2463	2507	2563	2649	2781	2944	3075	3225	3326	3422	3454	3464	3458	3416	3416	3242	2943	2644	2403
SCPSA	5/1/12	2263	2173	2120	2119	2231	2483	2551	2604	2728	2883	3043	3191	3352	3491	3628	3726	3761	3693	3580	3558	3408	3087	2706	2495
SCPSA	5/2/12	2377	2272	2212	2162	2300	2529	2613	2666	2793	3009	3163	3375	3561	3675	3836	3898	3924	3866	3698	3652	3448	3132	2759	2522
SCPSA	5/3/12	2364	2261	2199	2180	2288	2522	2590	2612	2775	2934	3111	3304	3524	3672	3769	3799	3787	3700	3537	3568	3429	3106	2750	2515
SCPSA	5/4/12	2383	2278	2244	2238	2344	2570	2653	2707	2819	2931	3058	3208	3453	3642	3721	3871	3807	3752	3690	3583	3481	3289	2983	2741
SCPSA	5/5/12	2588	2430	2345	2252	2334	2322	2433	2666	3023	3314	3528	3720	3878	3980	4095	4129	4141	4017	3868	3640	3520	3247	2914	2625
SCPSA	5/6/12	2590	2484	2417	2240	2325	2405	2490	2767	2976	3061	3171	3282	3364	3422	3465	3522	3504	3528	3436	3410	3341	3138	2769	2554
SCPSA	5/7/12	2426	2354	2310	2314	2442	2622	2687	2737	2778	2896	2966	3041	3173	3259	3363	3423	3442	3527	3465	3494	3399	3067	2747	2524
SCPSA	5/8/12	2414	2338	2380	2397	2521	2722	2809	2855	2958	3045	3143	3285	3420	3535	3583	3689	3725	3673	3572	3586	3466	3174	2848	2658
SCPSA	5/9/12	2505	2396	2330	2333	2443	2691	2816	2789	2949	3085	3154	3237	3318	3277	3205	3114	3055	3092	3017	3082	2983	2779	2546	2352
SCPSA	5/10/12	2275	2199	2175	2187	2306	2536	2637	2606	2685	2717	2740	2836	2952	3043	3135	3233	3266	3248	3148	3101	3054	2815	2471	2338
SCPSA	5/11/12	2274	2223	2209	2134	2311	2554	2568	2624	2682	2729	2813	2857	2942	3051	3139	3199	3214	3221	3089	3012	2989	2711	2522	2387
SCPSA	5/12/12	2270	2191	2157	2147	2185	2248	2330	2508	2619	2705	2812	2902	2963	3021	3059	3041	3019	3016	2919	2925	2925	2762	2544	2357
SCPSA	5/13/12	2242	2175	2139	2130	2175	2187	2299	2524	2669	2742	2728	2666	2706	2645	2732	2662	2702	2749	2761	2874	2822	2688	2478	2275
SCPSA	5/14/12	2216	2188	2150	2191	2203	2542	2603	2751	2719	2884	3062	3079	3152	3079	3177	3301	3334	3365	3311	3325	3242	2998	2711	2537
SCPSA	5/15/12	2432	2379	2307	2321	2465	2639	2737	2817	2905	3039	3259	3389	3370	3255	3467	3681	3642	3615	3553	3576	3452	3131	2837	2663

Backup - SCPSA Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCPSA	5/16/12	2532	2457	2412	2420	2447	2711	2747	2821	2925	3070	3257	3357	3420	3371	3469	3594	3682	3659	3551	3574	3450	3141	2833	2611
SCPSA	5/17/12	2520	2416	2396	2346	2487	2632	2721	2732	2835	2837	3057	3276	3373	3333	3306	3244	3223	3157	3162	3172	3179	2969	2678	2533
SCPSA	5/18/12	2441	2355	2348	2360	2439	2635	2708	2740	2801	2749	2821	2862	2858	2954	2927	2878	2932	2979	2945	2942	2951	2786	2574	2409
SCPSA	5/19/12	2274	2195	2203	2203	2242	2291	2367	2488	2647	2705	2721	2757	2792	2827	2855	2897	2842	2868	2844	2907	2875	2749	2545	2386
SCPSA	5/20/12	2263	2178	2130	2118	2187	2159	2281	2501	2684	2705	2790	2951	3072	3193	3283	3400	3421	3418	3279	3277	3236	3006	2693	2493
SCPSA	5/21/12	2361	2331	2274	2286	2391	2612	2697	2771	2932	3086	3221	3378	3570	3651	3749	3883	3926	3852	3718	3673	3566	3217	2865	2667
SCPSA	5/22/12	2569	2468	2394	2405	2470	2627	2649	2728	2762	2976	3158	3308	3466	3535	3646	3770	3664	3614	3590	3533	3338	3145	2835	2619
SCPSA	5/23/12	2486	2397	2324	2369	2470	2597	2764	2786	2896	3104	3242	3396	3629	3677	3694	3739	3809	3822	3691	3619	3531	3275	3008	2789
SCPSA	5/24/12	2614	2542	2468	2410	2478	2687	2772	2888	3053	3373	3579	3835	4011	4066	4101	4202	4209	4154	4048	3928	3851	3496	3194	2920
SCPSA	5/25/12	2773	2643	2577	2526	2594	2773	2910	3007	3166	3448	3670	3838	4026	4148	4222	4270	4221	4173	3997	3871	3722	3457	3142	2860
SCPSA	5/26/12	2687	2562	2492	2411	2417	2411	2554	2845	3094	3404	3654	3885	4055	4145	4162	4230	4173	4086	3984	3860	3700	3457	3120	2868
SCPSA	5/27/12	2656	2563	2545	2487	2477	2459	2640	2979	3281	3470	3650	3777	3906	4009	4112	4180	4181	4064	3821	3684	3653	3443	3165	2937
SCPSA	5/28/12	2748	2658	2576	2563	2593	2565	2712	3009	3327	3575	3755	3902	3824	3983	4062	4099	4037	3979	3816	3719	3675	3428	3091	2814
SCPSA	5/29/12	2678	2598	2527	2547	2672	2888	2996	3175	3367	3505	3655	3733	3767	3767	3777	3772	3763	3704	3646	3665	3561	3372	3107	2802
SCPSA	5/30/12	2636	2453	2407	2418	2423	2712	2734	2787	2911	3072	3233	3447	3594	3759	3890	3985	3989	3904	3864	3706	3574	3294	2988	2755
SCPSA	5/31/12	2571	2516	2406	2294	2412	2551	2697	2814	3126	3407	3691	3961	4159	4243	3965	4040	4195	4164	4022	3888	3766	3567	3219	2944
SCPSA	6/1/12	2814	2665	2606	2509	2680	2808	2945	3132	3292	3527	3665	3852	3976	3973	4021	4081	3998	3631	3487	3519	3431	3228	2949	2774
SCPSA	6/2/12	2605	2469	2349	2359	2325	2343	2505	2622	2797	2996	3204	3253	3425	3526	3595	3685	3651	3603	3416	3272	3271	3026	2772	2560
SCPSA	6/3/12	2358	2257	2175	2150	2194	2163	2269	2476	2699	2885	3027	3233	3327	3504	3641	3755	3773	3702	3591	3498	3424	3226	2898	2684
SCPSA	6/4/12	2549	2470	2434	2415	2485	2618	2787	2805	2948	3076	3114	3204	3221	3292	3464	3562	3582	3686	3641	3444	3434	3249	2947	2739
SCPSA	6/5/12	2613	2515	2450	2456	2535	2647	2745	2845	2902	2961	2988	3001	2952	2917	2956	3030	3121	3144	3089	3077	3080	2961	2747	2578
SCPSA	6/6/12	2409	2286	2291	2297	2380	2494	2603	2643	2762	2831	2775	2876	2873	2983	3047	3036	3108	3175	3129	3169	3139	2977	2731	2517
SCPSA	6/7/12	2370	2270	2246	2282	2380	2473	2548	2658	2754	2814	2986	3162	3293	3376	3536	3631	3676	3605	3524	3435	3390	3155	2856	2718
SCPSA	6/8/12	2499	2389	2318	2287	2415	2470	2609	2721	2907	3092	3311	3397	3629	3764	3814	3820	3888	3858	3709	3527	3400	3205	2899	2674
SCPSA	6/9/12	2543	2397	2324	2326	2343	2363	2463	2655	2932	3172	3412	3533	3711	3825	3925	4012	4011	3892	3719	3565	3381	3129	2915	2733
SCPSA	6/10/12	2537	2407	2396	2376	2374	2373	2536	2808	3057	3177	3230	3398	3473	3379	3475	3483	3482	3446	3387	3401	3369	3148	2869	2740
SCPSA	6/11/12	2546	2519	2421	2459	2596	2695	2827	3028	3199	3349	3542	3606	3714	3732	3778	3727	3593	3523	3509	3492	3485	3362	3010	2821
SCPSA	6/12/12	2691	2632	2558	2536	2617	2774	2920	3008	3138	3265	3439	3560	3631	3651	3735	3842	3874	3923	3810	3730	3692	3428	3141	2883
SCPSA	6/13/12	2699	2631	2602	2576	2662	2749	2889	3051	3230	3341	3705	3919	3978	4112	4151	4155	4122	4001	3847	3685	3630	3421	3120	2888
SCPSA	6/14/12	2605	2535	2535	2553	2597	2644	2803	2951	3085	3267	3409	3558	3697	3844	4015	4126	4141	4030	3843	3551	3600	3425	3073	2734
SCPSA	6/15/12	2632	2441	2393	2443	2511	2497	2606	2778	2998	3199	3238	3479	3620	3698	3801	3932	3918	3885	3697	3519	3492	3287	3005	2758
SCPSA	6/16/12	2521	2454	2359	2359	2330	2313	2417	2599	2808	3026	3181	3301	3431	3551	3705	3801	3846	3784	3616	3479	3422	3208	2888	2599
SCPSA	6/17/12	2423	2249	2251	2235	2242	2224	2328	2600	2826	3027	3145	3314	3463	3607	3700	3822	3823	3726	3652	3459	3463	3163	2844	2620
SCPSA	6/18/12	2491	2382	2328	2349	2397	2500	2659	2833	3013	3246	3418	3635	3827	4005	4094	4196	4267	4226	4089	3852	3745	3472	3110	2846
SCPSA	6/19/12	2653	2547	2491	2439	2491	2569	2731	2893	3128	3337	3607	3772	4054	4189	4323	4348	4467	4396	4227	4057	3954	3674	3280	2977

Backup - SCPSA Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCPSA	6/20/12	2759	2664	2546	2552	2586	2664	2838	3031	3266	3553	3824	4029	4080	4179	4255	4352	4396	4352	4237	3996	4026	3703	3358	3004
SCPSA	6/21/12	2808	2671	2647	2625	2642	2628	2909	3129	3367	3680	3965	4192	4326	4435	4499	4546	4516	4433	4359	4162	4043	3709	3390	3091
SCPSA	6/22/12	2917	2799	2690	2658	2700	2775	2915	3123	3408	3701	3916	4121	4210	4297	4461	4458	4426	4351	4157	4007	3922	3726	3391	3025
SCPSA	6/23/12	2828	2747	2630	2610	2515	2459	2542	2904	3298	3691	3956	4207	4375	4548	4588	4638	4531	4506	4368	4198	4123	3827	3478	3182
SCPSA	6/24/12	2911	2834	2609	2538	2643	2621	2699	3149	3420	3739	3973	4169	4286	4284	4369	4397	4340	4135	4004	3864	3838	3562	3325	3040
SCPSA	6/25/12	2838	2740	2672	2604	2695	2807	2989	3127	3356	3550	3714	3957	4049	4190	4246	4267	4345	4300	4175	4058	3991	3768	3390	3062
SCPSA	6/26/12	2900	2750	2719	2678	2698	2787	2867	2992	3142	3261	3342	3404	3467	3479	3496	3583	3649	3645	3506	3367	3342	3103	2757	2478
SCPSA	6/27/12	2421	2315	2290	2257	2293	2484	2615	2727	2932	3057	3119	3290	3401	3590	3768	3925	4030	4012	3840	3596	3509	3225	2896	2593
SCPSA	6/28/12	2435	2323	2279	2257	2308	2418	2590	2768	2967	3230	3408	3800	3982	4206	4393	4523	4548	4510	4377	4110	3960	3742	3345	2996
SCPSA	6/29/12	2806	2662	2587	2555	2608	2677	2856	3128	3410	3826	4216	4540	4712	4883	4989	5050	5064	5004	4873	4681	4572	4294	3927	3589
SCPSA	6/30/12	3328	3161	3042	2971	2959	2888	3037	3350	3751	4131	4524	4852	5083	5146	5237	5283	5291	5180	5083	4891	4775	4426	4202	3834
SCPSA	7/1/12	3605	3378	3247	3153	3119	3063	3198	3530	3871	4354	4704	4956	5081	5127	5217	5137	4918	4701	4326	3998	3874	3665	3384	3065
SCPSA	7/2/12	2848	2769	2690	2650	2677	2740	2859	3000	3299	3634	3914	4181	4407	4622	4759	4861	4931	4886	4759	4599	4383	4152	3766	3422
SCPSA	7/3/12	3192	3017	2832	2839	2906	2932	3099	3356	3759	4140	4493	4759	4927	5063	5049	5101	4968	4775	4599	4441	4323	3948	3452	3558
SCPSA	7/4/12	3014	2841	2702	2622	2581	2544	2646	2924	3311	3720	4026	4265	4440	4597	4691	4768	4794	4684	4456	4248	4050	3862	3593	3292
SCPSA	7/5/12	3092	2971	2842	2843	2800	2909	3034	3367	3831	4260	4571	4796	5004	5083	5140	5091	4975	4856	4786	4690	4527	4205	3865	3454
SCPSA	7/6/12	3355	3181	3081	2983	2999	3068	3175	3376	3749	4079	4412	4615	4798	4953	5036	5114	5126	5074	4870	4594	4499	4169	3819	3563
SCPSA	7/7/12	3340	3228	3088	2980	2909	2886	2999	3343	3756	4118	4400	4682	4888	4969	5118	5149	5105	4992	4851	4738	4665	4391	4023	3743
SCPSA	7/8/12	3519	3343	3182	3043	3066	3039	3144	3551	3988	4323	4563	4827	4985	5094	5052	5074	5129	4970	4853	4700	4630	4319	3928	3730
SCPSA	7/9/12	3496	3357	3252	3180	3244	3277	3393	3650	4059	4419	4740	4995	5109	5183	5186	5150	5074	4982	4801	4595	4397	4100	3720	3400
SCPSA	7/10/12	3158	3038	2985	2955	2920	3071	3129	3355	3674	3985	4275	4492	4594	4542	4406	4241	4076	3904	3798	3759	3712	3523	3256	2933
SCPSA	7/11/12	2820	2788	2691	2701	2738	2809	2994	3175	3399	3557	3861	3997	4099	4180	4201	4127	4083	3981	3828	3761	3605	3429	3148	2959
SCPSA	7/12/12	2832	2762	2696	2687	2764	2889	2961	3099	3312	3520	3736	3908	4062	4150	4217	4174	4194	4061	3929	3839	3789	3603	3283	3002
SCPSA	7/13/12	2887	2782	2749	2753	2788	2855	2940	3188	3443	3652	3852	3962	4057	4068	4122	4092	4131	3979	3883	3837	3807	3561	3333	3124
SCPSA	7/14/12	2911	2824	2725	2618	2716	2735	2801	3000	3404	3747	4017	4240	4382	4480	4532	4603	4622	4496	4303	4122	4046	3799	3463	3111
SCPSA	7/15/12	2912	2808	2721	2662	2641	2611	2795	3178	3535	3809	4027	4221	4334	4427	4499	4533	4471	4400	4272	4123	4052	3751	3448	3113
SCPSA	7/16/12	2937	2766	2676	2675	2745	2806	2929	3232	3452	3925	4209	4444	4581	4711	4729	4721	4670	4543	4285	4097	4017	3767	3461	3182
SCPSA	7/17/12	3012	2879	2790	2773	2757	2892	3027	3246	3536	3773	4075	4360	4563	4708	4793	4820	4733	4612	4404	4255	4145	3896	3517	3272
SCPSA	7/18/12	3038	2913	2826	2792	2843	2856	3001	3259	3488	3769	4116	4344	4560	4711	4725	4717	4570	4527	4341	4176	4083	3832	3462	3237
SCPSA	7/19/12	3092	2942	2833	2769	2934	2996	3105	3366	3659	3977	4258	4466	4692	4824	4909	4901	4843	4636	4526	4367	4269	4023	3653	3367
SCPSA	7/20/12	3174	3004	2969	2931	2971	3060	3200	3455	3699	3946	4208	4313	4536	4599	4661	4698	4680	4549	4355	4203	4095	3842	3611	3316
SCPSA	7/21/12	3130	2994	2929	2867	2847	2861	2948	3144	3361	3661	3857	4134	4269	4366	4429	4460	4453	4350	4250	4118	4067	3823	3535	3282
SCPSA	7/22/12	3090	2971	2884	2819	2839	2800	2928	3326	3719	4055	4307	4537	4694	4774	4891	4950	4942	4857	4653	4500	4389	4087	3779	3427
SCPSA	7/23/12	3208	3073	2977	2919	2995	3061	3194	3415	3702	4081	4401	4692	4887	4999	5063	4996	4828	4803	4703	4487	4479	4173	3785	3416
SCPSA	7/24/12	3249	3109	3048	2997	3004	3144	3271	3468	3848	4187	4539	4793	4881	5051	5148	5162	5127	5004	4808	4602	4360	4038	3715	3349

Backup - SCPSA Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCPSA	7/25/12	3164	3028	2949	2871	2904	3048	3160	3283	3484	3601	3766	3980	4217	4448	4610	4737	4791	4755	4571	4426	4280	4020	3647	3409
SCPSA	7/26/12	3217	2970	2955	2979	3003	3101	3257	3532	3842	4218	4458	4711	4923	5044	5084	5124	5106	5024	4845	4712	4602	4292	4008	3698
SCPSA	7/27/12	3549	3288	3274	3118	3232	3286	3359	3642	3952	4295	4590	4825	4879	5012	4989	4917	4798	4622	4398	4277	4146	3881	3677	3376
SCPSA	7/28/12	3262	3101	2973	2907	2891	2926	3004	3276	3578	3888	4178	4412	4602	4762	4874	4802	4741	4553	4408	4273	4195	3910	3574	3265
SCPSA	7/29/12	3090	2976	2873	2793	2727	2778	2899	3243	3637	3880	4168	4435	4607	4729	4696	4566	4453	4316	4099	3966	3787	3585	3305	3051
SCPSA	7/30/12	2917	2832	2742	2744	2848	2966	3083	3267	3470	3663	3805	3996	4179	4276	4375	4403	4396	4296	4121	3981	3906	3595	3301	3057
SCPSA	7/31/12	2859	2795	2712	2634	2767	2864	2957	3141	3272	3550	3778	3945	4083	4162	4184	4211	4165	4105	3992	3966	3816	3582	3301	3030
SCPSA	8/1/12	2909	2848	2772	2756	2840	3016	3077	3163	3342	3504	3848	4059	4205	4304	4408	4528	4639	4572	4477	4324	4164	3928	3604	3318
SCPSA	8/2/12	3113	2976	2816	2851	2893	2969	3029	3294	3647	4018	4372	4626	4758	4900	4894	4818	4796	4707	4461	4329	4113	3742	3465	3232
SCPSA	8/3/12	3012	2858	2775	2721	2743	2806	2974	3161	3463	3763	4092	4322	4499	4619	4604	4662	4701	4638	4438	4333	4258	3977	3637	3364
SCPSA	8/4/12	3138	2977	2862	2826	2787	2833	2924	3242	3581	3787	4050	4300	4432	4553	4571	4642	4573	4501	4326	4191	4112	3865	3556	3280
SCPSA	8/5/12	3069	2919	2782	2693	2736	2775	2924	3286	3623	3855	4052	4101	4163	4136	4190	4151	4203	4128	3996	3956	3822	3594	3313	2950
SCPSA	8/6/12	2838	2758	2759	2737	2826	2923	3076	3309	3528	3849	4134	4308	4441	4443	4482	4480	4406	4306	4181	4123	3990	3719	3482	3212
SCPSA	8/7/12	3043	2907	2869	2817	2921	3064	3138	3270	3459	3593	3725	3860	3937	4001	4043	4030	4017	3973	3880	3865	3696	3503	3235	3019
SCPSA	8/8/12	2899	2812	2716	2720	2810	2966	3067	3164	3270	3477	3659	3878	4006	4138	4208	4283	4325	4350	4165	4023	3870	3647	3315	3062
SCPSA	8/9/12	2838	2697	2627	2678	2735	2886	2955	3159	3411	3704	4009	4231	4447	4509	4760	4701	4550	4447	4300	4212	4055	3729	3406	3143
SCPSA	8/10/12	2941	2792	2722	2766	2832	3016	3082	3253	3390	3634	3788	3862	4026	4085	4087	4100	4197	4093	3973	3907	3827	3590	3358	3158
SCPSA	8/11/12	2997	2869	2776	2711	2719	2653	2725	3043	3397	3630	3789	3877	3981	3987	3968	3853	3717	3636	3567	3572	3497	3320	3120	2861
SCPSA	8/12/12	2663	2632	2552	2549	2547	2568	2697	2928	3179	3430	3638	3831	4064	4177	4298	4366	4395	4293	4142	4033	3892	3596	3282	3015
SCPSA	8/13/12	2821	2712	2602	2595	2685	2835	2938	3092	3340	3672	3920	4073	4285	4407	4476	4526	4552	4550	4310	4116	3935	3593	3215	2981
SCPSA	8/14/12	2871	2767	2649	2678	2718	2868	2901	3107	3351	3653	3905	4145	4315	4481	4591	4681	4692	4558	4406	4327	4167	3863	3505	3198
SCPSA	8/15/12	3065	2932	2862	2833	2864	3003	3069	3252	3487	3816	4011	4157	4292	4409	4532	4663	4678	4581	4345	4216	4143	3775	3445	3182
SCPSA	8/16/12	2947	2851	2783	2724	2732	2942	2941	3114	3342	3607	3923	4131	4370	4566	4638	4642	4620	4493	4230	4125	4021	3707	3347	3048
SCPSA	8/17/12	2873	2720	2654	2634	2738	2849	2902	3064	3423	3688	3990	4292	4422	4503	4566	4622	4280	4131	3943	3788	3724	3591	3395	2841
SCPSA	8/18/12	2862	2672	2702	2619	2586	2585	2557	2817	3091	3423	3630	3906	4097	4205	4177	4280	4292	4252	4068	4041	3883	3615	3346	3053
SCPSA	8/19/12	2896	2766	2627	2607	2625	2670	2691	3037	3326	3472	3499	3592	3585	3602	3635	3724	3830	3724	3673	3702	3575	3351	3096	2866
SCPSA	8/20/12	2722	2654	2510	2602	2671	2957	2977	3058	3215	3295	3550	3762	3934	4047	4070	4130	4033	3948	3832	3753	3648	3364	3098	2847
SCPSA	8/21/12	2748	2657	2612	2607	2705	2945	2954	3036	3156	3311	3484	3665	3827	3921	4012	4022	4020	3983	3893	3842	3692	3362	3082	2841
SCPSA	8/22/12	2657	2599	2500	2550	2633	2733	2835	2827	3061	3241	3308	3559	3709	3733	3899	3956	3933	3796	3661	3625	3508	3274	2938	2677
SCPSA	8/23/12	2543	2436	2450	2404	2518	2737	2766	2872	2926	3142	3361	3495	3641	3664	3674	3703	3626	3600	3500	3518	3418	3119	2836	2663
SCPSA	8/24/12	2550	2504	2447	2390	2568	2853	2829	2869	3027	3129	3230	3422	3428	3598	3612	3689	3767	3662	3427	3420	3351	3086	2839	2648
SCPSA	8/25/12	2526	2392	2345	2299	2283	2356	2391	2581	2792	3018	3137	3420	3552	3752	3881	3976	3933	3874	3661	3566	3380	3200	2866	2667
SCPSA	8/26/12	2504	2343	2216	2246	2247	2337	2389	2661	2939	3144	3345	3611	3846	4023	4090	4278	4314	4223	3986	3927	3779	3406	3090	2814
SCPSA	8/27/12	2595	2528	2507	2526	2561	2932	2917	2951	3190	3513	3761	4000	4175	4200	4161	4220	4217	4127	4061	4064	3875	3533	3220	2952
SCPSA	8/28/12	2808	2736	2602	2646	2808	3118	3154	3145	3266	3383	3519	3463	3627	3632	3584	3624	3639	3609	3525	3646	3523	3215	3020	2775

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Backup - SCPSA Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCPSA	8/29/12	2769	2694	2672	2671	2785	3025	3057	3077	3215	3410	3485	3724	3859	3948	3980	3890	3938	3916	3809	3714	3716	3353	3063	2854
SCPSA	8/30/12	2747	2652	2621	2608	2719	2980	3022	3054	3176	3213	3383	3536	3645	3545	3854	3798	3916	3904	3845	3892	3705	3388	3105	2910
SCPSA	8/31/12	2791	2618	2551	2522	2699	2926	2980	3063	3288	3550	3853	4120	4372	4520	4538	4456	4734	4524	4226	4151	3954	3729	3445	3167
SCPSA	9/1/12	2994	2873	2753	2686	2643	2682	2731	2981	3396	3753	4114	4382	4578	4713	4731	4780	4739	4606	4495	4385	4119	3819	3572	3283
SCPSA	9/2/12	3055	2859	2816	2687	2654	2755	2815	3159	3556	3901	4187	4429	4476	4615	4611	4458	4490	4271	4252	4177	3915	3742	3433	3160
SCPSA	9/3/12	2982	2778	2764	2740	2713	2760	2823	3032	3471	3836	4113	4343	4387	4451	4387	4187	4207	4000	3919	3878	3659	3377	3089	2882
SCPSA	9/4/12	2739	2680	2662	2646	2767	3036	3079	3229	3287	3511	3794	3915	4075	4144	4061	4040	4179	4141	4030	4048	3823	3517	3186	2966
SCPSA	9/5/12	2863	2775	2724	2668	2808	3006	2995	3034	3153	3425	3592	3829	4025	4116	4376	4420	4410	4321	4215	4185	3964	3657	3279	3032
SCPSA	9/6/12	2947	2865	2760	2765	2836	3089	3153	3252	3363	3576	3783	3993	4228	4358	4423	4494	4553	4412	4307	4266	3999	3654	3354	3111
SCPSA	9/7/12	2971	2875	2803	2798	2857	3136	3158	3148	3336	3562	3824	4014	4240	4280	4461	4404	4403	4257	4116	4059	3776	3583	3272	3108
SCPSA	9/8/12	2923	2799	2755	2698	2598	2694	2762	2882	3262	3561	3902	4181	4362	4433	4355	4334	4337	4015	3902	3816	3636	3371	3105	2920
SCPSA	9/9/12	2749	2655	2555	2584	2556	2568	2609	2826	3036	3122	3178	3302	3535	3616	3660	3699	3703	3632	3495	3483	3196	2959	2601	2451
SCPSA	9/10/12	2367	2291	2241	2263	2303	2707	2669	2736	2862	2965	3164	3258	3451	3496	3800	3461	3702	3595	3476	3560	3344	3056	2805	2577
SCPSA	9/11/12	2468	2302	2326	2369	2427	2651	2687	2674	2839	2840	3022	3158	3272	3424	3592	3687	3701	3608	3504	3523	3320	3010	2724	2504
SCPSA	9/12/12	2412	2289	2302	2346	2432	2690	2629	2653	2715	2834	2970	3112	3153	3312	3547	3666	3704	3630	3491	3479	3327	3048	2727	2560
SCPSA	9/13/12	2456	2393	2359	2334	2466	2727	2701	2782	2717	2957	3104	3260	3428	3509	3598	3697	3683	3615	3525	3573	3378	3087	2773	2600
SCPSA	9/14/12	2520	2434	2378	2385	2492	2696	2728	2800	2875	3091	3210	3339	3570	3689	3754	3810	3781	3678	3578	3499	3352	3093	2823	2576
SCPSA	9/15/12	2439	2305	2288	2273	2267	2362	2441	2529	2793	3031	3267	3442	3628	3825	3922	3921	3935	3791	3616	3533	3336	3089	2789	2642
SCPSA	9/16/12	2450	2417	2315	2308	2312	2354	2420	2695	2933	3118	3236	3463	3579	3658	3714	3700	3724	3571	3562	3505	3351	3019	2763	2606
SCPSA	9/17/12	2478	2270	2321	2389	2479	2773	2812	2900	3093	3232	3466	3576	3735	3901	3952	3889	3837	3762	3697	3727	3527	3306	3008	2803
SCPSA	9/18/12	2743	2691	2702	2701	2772	3105	3155	3182	3187	3325	3380	3450	3498	3506	3472	3553	3567	3554	3593	3603	3399	3125	2753	2633
SCPSA	9/19/12	2521	2428	2403	2422	2527	2827	2816	2742	2786	2855	2916	2978	3076	3140	3201	3247	3230	3165	3128	3194	3094	2852	2616	2453
SCPSA	9/20/12	2358	2281	2272	2284	2361	2677	2705	2645	2748	2863	2944	2992	3180	3279	3309	3373	3391	3355	3371	3385	3197	2967	2672	2462
SCPSA	9/21/12	2353	2312	2273	2265	2439	2689	2675	2669	2724	2921	3053	3184	3391	3501	3539	3675	3669	3527	3419	3381	3190	2940	2753	2562
SCPSA	9/22/12	2440	2382	2292	2263	2164	2339	2435	2573	2784	2937	3102	3337	3460	3674	3827	3922	3842	3636	3585	3508	3292	3007	2796	2606
SCPSA	9/23/12	2390	2360	2315	2316	2283	2312	2352	2603	2742	2892	3011	3121	3286	3334	3452	3426	3468	3317	3229	3218	2948	2640	2374	2288
SCPSA	9/24/12	2187	2082	2033	2052	2102	2485	2498	2530	2611	2704	2641	2742	2821	2975	3047	3197	3188	3058	3139	3129	2898	2669	2444	2221
SCPSA	9/25/12	2225	2135	2124	2166	2303	2583	2456	2407	2567	2513	2524	2628	2721	2835	2966	3091	3102	3031	3079	3046	2835	2579	2277	2173
SCPSA	9/26/12	2053	2024	1991	1996	2140	2385	2384	2379	2477	2578	2689	2834	2992	3133	3237	3419	3409	3339	3281	3216	3011	2738	2436	2259
SCPSA	9/27/12	2134	2080	2045	2066	2181	2444	2487	2574	2657	2797	2935	3084	3255	3486	3468	3771	3679	3530	3524	3447	3172	2946	2639	2457
SCPSA	9/28/12	2331	2233	2171	2171	2297	2556	2599	2622	2745	2922	3076	3259	3423	3533	3588	3624	3626	3533	3505	3438	3257	3067	2823	2579
SCPSA	9/29/12	2427	2391	2367	2284	2288	2276	2469	2583	2741	2842	2952	3111	3071	3249	3180	3254	3207	3230	3232	3238	3036	2898	2661	2492
SCPSA	9/30/12	2391	2283	2254	2232	2236	2269	2385	2528	2665	2772	2753	2699	2751	2899	2922	2932	2939	2969	3102	3084	2936	2730	2534	2378
SCPSA	10/1/12	2289	2194	2227	2184	2380	2615	2799	2757	2871	2980	3073	3176	3279	3471	3412	3312	3287	3349	3446	3553	3341	3126	2909	2689
SCPSA	10/2/12	2663	2619	2531	2517	2569	2911	2946	2884	3188	3337	3479	3571	3672	3681	3777	3657	3794	3665	3704	3623	3476	3250	2898	2759

Backup - SCPSA Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCPSA	10/3/12	2690	2620	2577	2615	2707	2932	3005	2906	2976	2972	3038	3142	3263	3402	3455	3477	3456	3467	3644	3524	3275	3042	2852	2663
SCPSA	10/4/12	2593	2505	2453	2424	2569	2788	2795	2821	2936	3028	3155	3209	3295	3404	3484	3527	3521	3470	3582	3440	3249	2994	2707	2465
SCPSA	10/5/12	2390	2302	2272	2299	2445	2661	2723	2721	2742	2830	3025	3154	3247	3418	3512	3527	3468	3307	3214	3189	3073	2888	2563	2482
SCPSA	10/6/12	2340	2271	2246	2114	2175	2276	2335	2497	2628	2825	3018	3192	3356	3505	3587	3621	3581	3435	3402	3276	3112	2967	2722	2542
SCPSA	10/7/12	2390	2306	2261	2247	2280	2311	2413	2576	2754	2913	3077	3200	3317	3335	3428	3436	3387	3340	3234	3162	2912	2748	2447	2308
SCPSA	10/8/12	2183	2114	2083	2166	2268	2494	2550	2540	2578	2588	2660	2663	2619	2651	2598	2693	2810	2859	2878	2850	2808	2664	2406	2310
SCPSA	10/9/12	2246	2231	2255	2280	2391	2694	2751	2706	2714	2748	2702	2682	2704	2663	2662	2708	2801	2885	3055	3053	2900	2753	2536	2386
SCPSA	10/10/12	2361	2342	2380	2384	2453	2789	2819	2734	2703	2651	2608	2555	2589	2604	2634	2638	2642	2715	2879	2902	2793	2584	2406	2295
SCPSA	10/11/12	2192	2123	2213	2263	2432	2718	2770	2704	2684	2699	2721	2683	2663	2678	2776	2790	2824	2834	3014	3010	2884	2738	2508	2377
SCPSA	10/12/12	2319	2300	2303	2372	2463	2771	2738	2747	2734	2772	2755	2693	2799	2757	2828	2840	2855	2832	2857	2867	2750	2596	2484	2352
SCPSA	10/13/12	2302	2237	2258	2185	2192	2320	2338	2452	2650	2694	2602	2649	2693	2692	2708	2759	2747	2767	2870	2861	2756	2638	2475	2356
SCPSA	10/14/12	2235	2187	2179	2208	2228	2302	2405	2578	2722	2667	2644	2610	2824	2876	2900	2904	2953	2968	3107	3062	2913	2665	2456	2339
SCPSA	10/15/12	2233	2198	2131	2127	2222	2503	2537	2610	2682	2784	2874	2958	3096	3108	3127	3186	3203	3173	3286	3225	3019	2767	2547	2412
SCPSA	10/16/12	2296	2249	2194	2249	2384	2665	2741	2710	2721	2706	2723	2728	2746	2768	2751	2788	2871	2901	3063	2972	2824	2610	2508	2350
SCPSA	10/17/12	2280	2269	2280	2324	2426	2698	2748	2688	2612	2574	2655	2659	2599	2584	2604	2722	2782	2821	2981	2906	2837	2673	2490	2315
SCPSA	10/18/12	2307	2300	2256	2288	2378	2658	2725	2620	2698	2685	2808	2802	2850	2885	2932	2965	3009	3012	3168	3144	2988	2789	2630	2378
SCPSA	10/19/12	2368	2333	2320	2253	2330	2594	2682	2674	2726	2806	2805	2823	2806	2850	2825	2859	2795	2850	2890	2850	2743	2625	2443	2317
SCPSA	10/20/12	2246	2208	2206	2241	2281	2368	2443	2652	2729	2643	2649	2599	2645	2691	2720	2701	2736	2743	2862	2828	2718	2567	2414	2307
SCPSA	10/21/12	2209	2207	2180	2180	2220	2360	2465	2566	2751	2678	2651	2637	2638	2641	2702	2724	2731	2779	2934	2884	2757	2609	2434	2335
SCPSA	10/22/12	2269	2232	2247	2323	2467	2777	2853	2807	2711	2670	2627	2711	2686	2668	2732	2742	2792	2771	3135	3046	2856	2691	2483	2349
SCPSA	10/23/12	2279	2269	2274	2340	2488	2808	2858	2772	2823	2747	2735	2708	2746	2776	2836	2884	2935	2973	3131	3032	2835	2577	2484	2340
SCPSA	10/24/12	2299	2249	2243	2277	2437	2752	2745	2688	2675	2691	2739	2738	2807	2900	3004	3050	3126	3104	3216	3138	2951	2688	2522	2383
SCPSA	10/25/12	2298	2301	2260	2262	2386	2704	2721	2638	2701	2807	2884	2946	2996	3006	3052	3164	3104	3115	3260	3192	3037	2856	2603	2439
SCPSA	10/26/12	2314	2216	2267	2246	2336	2575	2637	2601	2635	2721	2734	2715	2810	2839	2816	2850	2870	2868	2963	2884	2751	2654	2523	2401
SCPSA	10/27/12	2298	2233	2208	2209	2222	2303	2410	2543	2602	2653	2703	2711	2673	2689	2641	2661	2693	2755	2849	2802	2708	2576	2389	2288
SCPSA	10/28/12	2224	2152	2078	2068	2042	2192	2276	2466	2527	2644	2617	2611	2634	2619	2515	2532	2590	2633	2802	2798	2726	2534	2385	2287
SCPSA	10/29/12	2190	2197	2216	2280	2470	2807	2915	2837	2852	2822	2731	2748	2741	2689	2681	2766	2932	3102	3260	3252	3119	2995	2776	2629
SCPSA	10/30/12	2561	2576	2587	2606	2791	3095	3144	3068	3099	3048	2986	2879	2813	2754	2673	2752	2872	3058	3235	3253	3083	2929	2750	2656
SCPSA	10/31/12	2604	2631	2626	2646	2860	3183	3238	3151	3023	2871	2746	2625	2524	2495	2410	2579	2532	2653	2781	2837	2883	2750	2607	2571
SCPSA	11/1/12	2558	2581	2627	2757	2987	3332	3383	3301	3121	2900	2720	2583	2473	2342	2487	2458	2533	2734	2971	2990	2940	2821	2673	2597
SCPSA	11/2/12	2601	2615	2671	2777	3000	3314	3382	3315	3109	2887	2678	2484	2479	2400	2371	2392	2416	2531	2659	2632	2562	2489	2346	2256
SCPSA	11/3/12	2218	2222	2258	2324	2433	2609	2803	2936	2890	2732	2571	2451	2377	2338	2319	2336	2375	2495	2604	2595	2546	2456	2328	2228
SCPSA	11/4/12	2145	2128	2129	2127	2159	2215	2326	2488	2593	2568	2510	2441	2454	2446	2442	2427	2440	2606	2704	2671	2589	2454	2292	2134
SCPSA	11/5/12	2041	2010	2019	2050	2131	2336	2651	2726	2698	2659	2576	2509	2459	2421	2380	2507	2467	2687	2923	2951	2902	2794	2647	2507
SCPSA	11/6/12	2431	2409	2411	2428	2472	2631	2892	3002	3035	3058	3037	2997	2933	2858	2789	2794	2878	3159	3379	3374	3326	3205	3069	2929

Backup - SCPSA Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
SCPSA	11/7/12	2867	2842	2845	2878	2990	3202	3459	3414	3333	3217	3044	2905	2795	2754	2727	2720	2838	3128	3397	3428	3419	3335	3189	3032
SCPSA	11/8/12	2997	3028	3051	3124	3243	3466	3791	3721	3542	3192	2955	2800	2700	2645	2608	2593	2710	2991	3260	3354	3401	3338	3246	3157
SCPSA	11/9/12	3116	3110	3153	3243	3375	3579	3964	3865	3621	3212	2977	2818	2700	2602	2573	2575	2652	2800	3052	3055	3063	3051	3018	2929
SCPSA	11/10/12	2814	2804	2855	2894	3013	3220	3365	3398	3336	3132	2925	2748	2633	2591	2556	2488	2581	2702	2828	2837	2821	2785	2669	2564
SCPSA	11/11/12	2512	2514	2545	2603	2676	2744	2875	3075	3135	2964	2762	2650	2610	2563	2602	2544	2521	2718	2864	2861	2697	2677	2460	2259
SCPSA	11/12/12	2159	2128	2085	2073	2156	2295	2515	2614	2594	2559	2633	2609	2533	2577	2610	2579	2679	2894	3017	2968	2887	2731	2568	2374
SCPSA	11/13/12	2262	2175	2179	2155	2217	2313	2611	2697	2633	2676	2646	2631	2611	2656	2583	2690	2804	3033	3169	3223	3171	3026	2881	2743
SCPSA	11/14/12	2661	2629	2518	2602	2746	2924	3295	3294	3166	3172	3103	2988	2904	2896	2873	2879	3087	3354	3527	3499	3425	3283	3145	2954
SCPSA	11/15/12	2836	2824	2688	2819	2897	3093	3413	3506	3440	3456	3484	3430	3391	3238	3159	3103	3256	3525	3702	3707	3655	3509	3338	3191
SCPSA	11/16/12	3038	2945	2977	2972	3023	3233	3550	3500	3413	3313	3160	3010	2893	2822	2753	2784	2809	3079	3241	3265	3266	3231	3161	3002
SCPSA	11/17/12	2969	2933	2991	3015	3076	3172	3391	3514	3558	3486	3332	3146	2966	2920	2882	2885	2949	3179	3288	3275	3184	3135	2962	2793
SCPSA	11/18/12	2703	2699	2674	2676	2717	2801	2890	3055	3250	3298	3221	3125	3110	3103	3035	2956	2986	3155	3272	3252	3167	2923	2762	2630
SCPSA	11/19/12	2502	2511	2464	2422	2541	2756	3072	3156	3096	3055	3034	2903	2890	2864	2779	2674	2780	3073	3227	3203	3180	3070	2966	2835
SCPSA	11/20/12	2688	2655	2681	2705	2797	2946	3263	3285	3202	3133	3022	2924	2826	2740	2710	2737	2746	3013	3173	3224	3202	3153	3044	2880
SCPSA	11/21/12	2896	2833	2903	2950	3080	3173	3420	3474	3347	3189	3038	2891	2843	2711	2715	2713	2775	2952	3166	3199	3239	3210	3063	2864
SCPSA	11/22/12	2766	2736	2728	2778	2870	2993	3180	3359	3431	3342	3205	3036	2795	2587	2441	2343	2326	2482	2641	2718	2807	2862	2867	2833
SCPSA	11/23/12	2844	2852	2917	3009	3137	3282	3476	3572	3488	3170	2873	2662	2499	2394	2337	2314	2357	2599	2759	2772	2752	2694	2595	2449
SCPSA	11/24/12	2364	2318	2315	2380	2463	2649	2852	3071	3152	3142	3059	2938	2818	2748	2701	2659	2712	3051	3272	3351	3428	3437	3418	3296
SCPSA	11/25/12	3357	3364	3396	3474	3607	3831	3974	4115	4064	3881	3513	3188	3019	2863	2735	2751	2858	3168	3418	3529	3551	3507	3393	3308
SCPSA	11/26/12	3250	3294	3303	3372	3553	3739	4212	4144	3928	3535	3223	2934	2795	2694	2648	2617	2823	2959	3259	3351	3354	3258	3128	2994
SCPSA	11/27/12	2916	2950	2948	2947	3056	3190	3482	3439	3251	3142	3085	2997	2961	2922	2916	2978	3000	3228	3401	3416	3311	3165	2991	2826
SCPSA	11/28/12	2703	2655	2642	2683	2781	2918	3304	3304	3215	3092	3011	2940	2788	2742	2655	2758	2863	3142	3481	3603	3652	3622	3497	3389
SCPSA	11/29/12	3279	3303	3386	3491	3723	3970	4334	4314	4102	3673	3266	3144	2920	2821	2772	2711	2896	3221	3452	3580	3630	3611	3534	3422
SCPSA	11/30/12	3370	3422	3483	3530	3650	3851	4159	4113	3900	3474	3158	2947	2823	2656	2597	2494	2628	2929	3087	3056	3132	3133	3042	2801

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TEE Reserve Sharing Group>>>

Dec 2011-Nov 2012 Load

TEEPeak	**Max**	40,536
TEEAvg	**Avg Jun**	32,653
TEEWint	**Winter**	28,384
TEESpri	**Spring**	26,630
TEESum	**Summer**	34,031
TEEFall	**Fall**	26,235

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TEE	12/1/11	27446	27327	27469	27868	28593	30523	32689	32496	30805	29066	27373	26098	25089	24355	23774	23867	25057	27146	28092	28691	28639	28297	27462	26587
TEE	12/2/11	25988	25995	26018	26502	27243	29084	31219	30917	29389	27524	26015	25086	24192	23458	23114	23043	24022	25610	26039	26304	26264	25960	25213	24185
TEE	12/3/11	23533	23224	23104	23150	23741	24347	25278	25935	25849	25038	24075	23086	22262	21706	21508	21475	22400	24044	24453	24403	24170	23521	22414	21523
TEE	12/4/11	20749	20312	20122	20168	20388	20918	21439	22154	22609	22485	21929	21518	21419	21270	21109	21269	22595	23973	24005	23862	23277	22363	20930	19807
TEE	12/5/11	19109	18735	18634	18745	19570	21281	23558	24223	24270	24294	24357	24295	24457	24373	24451	24709	25727	26848	26997	26590	25900	24901	23307	21680
TEE	12/6/11	20801	20542	20490	20402	21163	23007	25306	25949	25776	25853	25914	25872	25898	25923	25628	26022	27242	28335	28482	28098	27690	26564	24784	23490
TEE	12/7/11	22505	22176	22072	22199	22972	24670	27120	27749	27915	28205	28536	28606	28733	28717	28676	29133	30350	31699	31864	31701	31230	30429	29016	27841
TEE	12/8/11	27370	27301	27267	27615	28482	30396	32540	32604	31076	29669	28213	27283	26516	25967	25548	25608	27129	29402	30438	30823	30921	30311	28743	27824
TEE	12/9/11	27395	27240	27364	27738	28537	30439	32686	32680	31245	29399	27637	26296	25521	25012	24769	24985	26285	28214	28640	28548	28470	27888	27011	25959
TEE	12/10/11	25240	25069	25054	25430	25793	26716	27866	28819	29263	28776	27835	26699	25792	25072	24572	24748	26279	28531	29267	29540	29605	29311	28599	27881
TEE	12/11/11	27454	27146	27346	27495	27981	28740	29754	30634	30190	28518	26515	25144	24349	23707	23128	23376	24778	27069	28132	28762	28713	28126	26465	26541
TEE	12/12/11	25543	25455	25558	25788	26544	28348	30579	30792	29918	28770	27787	26836	26132	25716	25337	25424	26529	28082	28503	28212	27726	26391	24703	23210
TEE	12/13/11	22298	21942	21594	21594	22309	23954	26026	26379	25986	25765	25635	25265	24895	24565	24242	24391	25353	27009	27287	27061	26599	25527	23968	22462
TEE	12/14/11	21610	21212	20912	21068	21811	23496	25679	25905	25206	24595	24031	23691	23352	23077	22835	22650	23657	25465	25650	25356	25039	23966	22624	21147
TEE	12/15/11	20004	19563	19249	19386	19947	21478	23683	24064	23807	23706	23723	23741	23641	23522	23294	23297	24161	25311	25389	25346	24877	23948	22568	21210
TEE	12/16/11	20487	20100	20037	20372	20978	22848	25451	26165	26361	26530	26845	26812	26705	26450	26275	26486	27237	28461	28384	28132	27790	27182	26227	25064
TEE	12/17/11	24282	23946	23700	23881	24408	25199	26289	27512	28083	27679	26697	25792	24819	23776	23366	23370	24770	26996	27572	27809	27896	27509	26854	26000
TEE	12/18/11	25378	25151	25201	25408	25950	26694	27821	28566	28313	26960	25073	23852	22972	22430	22038	22085	23602	25681	26386	26713	26773	26262	25374	24549
TEE	12/19/11	23978	23878	24019	24516	25296	26951	28816	29246	28450	27675	26828	26153	25558	25026	24720	24823	25748	27456	27743	27761	27369	26415	25095	23785
TEE	12/20/11	22628	21939	21853	22016	22505	23742	25485	26131	26092	26045	25844	25392	24991	24756	24490	24462	25324	26287	26245	25798	25218	24083	22686	21219
TEE	12/21/11	20190	19586	19192	19126	19596	20892	22586	23341	23711	24002	24104	24057	24027	23816	23641	23646	24359	25707	25952	25726	25436	24686	23492	22184
TEE	12/22/11	21324	20817	20689	20740	21055	22245	23889	24692	25074	25401	25591	25634	25475	25407	25281	25357	25967	26795	26707	26376	25879	25025	23730	22419
TEE	12/23/11	21460	20664	20488	20529	20809	21588	22808	23852	24835	25276	25363	25239	24978	24645	24596	24714	25559	26447	26426	26048	25855	25263	24310	23124
TEE	12/24/11	22209	21662	21440	21337	21549	22324	23234	24292	25008	24903	24193	23305	22314	21632	21137	21153	21909	23366	23838	23965	24171	24079	23627	22836
TEE	12/25/11	22297	21792	21494	21431	21614	22081	22870	23711	24425	24266	23348	22548	21619	20566	19744	19425	20156	21724	22487	22941	23188	23170	22758	22247
TEE	12/26/11	21901	21814	21984	22430	23049	24047	25091	25748	26241	25996	25575	25144	24499	24082	23860	24024	24773	26225	26364	26241	25606	24700	23680	22502
TEE	12/27/11	21551	21103	20794	20987	21466	22408	23743	24747	25485	26102	26546	26807	26738	26613	26469	26643	27383	28699	28633	28283	27718	26665	25541	24403

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TEE Reserve Sharing Group>>>

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TEE	12/28/11	23788	23566	23592	23787	24419	25816	27374	28124	27817	26928	26044	25325	24629	24092	23777	23780	24964	27125	27923	28082	27951	27328	26538	25633
TEE	12/29/11	25162	24936	24947	25183	25801	26994	28452	29008	28403	27281	26176	25283	24321	23659	23017	22834	23657	25598	26260	26200	25916	25136	23971	22852
TEE	12/30/11	22118	21590	21426	21398	21707	22602	23722	24083	24125	23955	23632	23226	22580	22133	21861	21730	22170	23721	23941	23653	23328	22750	21844	20877
TEE	12/31/11	20123	19690	19636	19821	20292	21054	21936	22753	22994	22706	22281	21906	21308	20673	20273	20194	21095	22905	23426	23043	22619	22114	21595	20993
TEE	1/1/12	20461	20106	19610	19248	19082	19170	19438	19948	20557	20700	20695	20641	20692	20465	20264	20387	21162	23127	23893	23899	23889	23817	23175	22494
TEE	1/2/12	22122	22097	22319	22784	23532	24872	26262	26905	27310	27792	28054	28008	27896	27798	27848	28381	29995	31986	32594	32676	32364	31599	30634	29783
TEE	1/3/12	29303	29109	29279	29689	30482	32326	34519	34886	34018	33340	32566	31735	30756	30061	29355	29045	30406	32996	34037	34220	33957	33151	32020	31020
TEE	1/4/12	30664	30375	30387	30622	31395	33004	34876	34808	33297	31768	30355	29101	28025	27350	26561	26439	27339	29318	30189	30074	29834	28922	27434	26269
TEE	1/5/12	25766	25692	25828	26392	27162	29117	31478	31853	30486	28716	27264	26015	25397	24658	24027	23811	24608	26728	27778	27963	27925	27200	25868	24977
TEE	1/6/12	24447	24186	24257	24593	25350	27424	29743	29898	28389	26984	25663	24815	24134	23581	22906	22571	23092	24595	24988	24857	24632	24009	22686	21491
TEE	1/7/12	20805	20173	19738	19484	19586	20080	20635	21449	22309	22806	22935	22729	22493	22110	21889	21838	22360	23689	23992	23844	23574	22928	22068	21216
TEE	1/8/12	20651	20418	20267	20444	20712	21331	22212	23215	24209	24180	23547	23090	22972	22792	22474	22723	23483	24917	25355	25245	24740	23841	22583	21401
TEE	1/9/12	20754	20477	20329	20526	21283	23144	25569	26038	25873	25825	25780	25395	25102	24739	24511	24543	25307	26650	27115	26658	26012	25115	23858	22734
TEE	1/10/12	22002	21665	21599	21827	22520	24331	26569	27180	26793	26329	25921	25426	25088	24854	24608	24662	25459	26641	27227	26869	26203	25007	23605	22311
TEE	1/11/12	21446	20886	20595	20409	20923	22533	24661	25120	24879	24734	24815	24782	24830	24783	24646	24923	25660	26692	27014	26657	26401	25225	23728	22392
TEE	1/12/12	21662	21287	21107	21215	21808	23501	25959	26505	26416	26600	26850	27247	27640	28238	28624	29461	30664	32594	33625	33837	33612	32491	31186	30205
TEE	1/13/12	29995	29860	29862	30117	30761	32355	34148	34734	34615	34331	33938	33338	32741	31913	31426	31331	31873	33221	33438	33052	32669	31731	30918	30069
TEE	1/14/12	29647	29476	29295	29718	30194	31108	32073	32605	32301	31427	30179	29045	27789	26709	25811	25714	26246	28092	28581	28448	27942	27417	26506	25687
TEE	1/15/12	25374	25164	25258	25504	25957	26843	27953	29153	29253	28264	26910	25850	25047	24154	23589	23528	24432	26688	27728	28102	27956	27425	26611	25954
TEE	1/16/12	25412	25004	24849	24887	25110	26086	27272	27942	27806	27991	27899	27767	27437	26967	26632	26331	26693	27835	27738	27181	26252	24999	23503	22146
TEE	1/17/12	21333	20749	20567	20590	20948	22486	24625	25090	24803	24638	24644	24574	24495	24299	24089	24321	25086	26362	27212	27211	26981	26388	25477	24622
TEE	1/18/12	24309	24403	24574	25063	25969	27988	30420	30906	30666	30274	29763	29067	28340	27753	27221	27317	28379	30585	31641	31687	31462	30741	29618	28642
TEE	1/19/12	28233	28088	28212	28525	29344	31332	33578	33439	32169	31004	29903	28955	28206	27314	26576	26335	26941	28684	29378	29191	28803	27747	26359	25053
TEE	1/20/12	24216	23839	23626	23743	24293	26002	28100	28333	28027	27843	27580	27032	26635	26345	26005	25903	26171	26945	27110	26439	25700	24753	23586	22194
TEE	1/21/12	21278	20671	20492	20589	20990	21611	22590	23827	24757	25952	26530	26662	26483	26275	26131	26244	26677	27727	27964	27706	27165	26418	25359	24382
TEE	1/22/12	23456	22950	22725	22628	22861	23174	23973	24763	25339	25393	24645	24167	23765	23411	23043	23048	23471	24472	24885	24544	23895	22847	21660	20437
TEE	1/23/12	19621	19239	18998	19253	19918	21628	23861	24319	24265	24193	24069	23865	23737	23387	23089	23186	23716	25224	26169	26121	25734	24953	23690	22548
TEE	1/24/12	22087	22152	22330	22638	23765	25857	28404	28707	27739	26403	25460	24789	24205	23796	23441	23225	23678	25438	26812	27166	26987	26382	25265	24416
TEE	1/25/12	23859	23650	23678	23944	24731	26505	28755	28837	28058	27286	26564	26017	25683	25257	24840	24823	25321	26690	27352	27001	26420	25274	23800	22369
TEE	1/26/12	21565	21040	20638	20501	20955	22484	24471	24766	24358	24502	24558	24539	24294	24031	23779	24154	24623	25667	26091	25752	25219	24113	22725	21487
TEE	1/27/12	20870	20743	20658	21058	21723	23662	26214	26632	26472	26340	26246	25950	25477	25105	24666	24468	24796	26301	26968	26831	26761	26239	25445	24529
TEE	1/28/12	23986	23665	23639	23630	23933	24516	25194	25936	26251	26048	25578	24908	24261	23499	22926	22785	23414	25147	26407	26685	26684	26666	26224	25751
TEE	1/29/12	25488	25474	25786	26054	26595	27306	28279	28984	28621	27118	25558	24426	23727	23130	22575	22402	23178	24941	26408	26784	26832	26342	25386	24614
TEE	1/30/12	24416	24400	24803	25281	26312	28404	30652	30841	29261	27769	26492	25586	24800	24165	23611	23376	23570	25297	26556	26584	26463	25507	24295	23141
TEE	1/31/12	22619	22384	22322	22464	23158	25002	27198	27234	26340	25516	24902	24345	23907	23542	23103	22973	23323	24802	25794	25731	25132	24005	22522	21321

TEE Reserve Sharing Group>>>

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TEE	2/1/12	20611	20137	19737	19688	20182	21833	23917	24066	23774	23697	23703	23599	23520	23350	23168	23141	23587	24688	25121	24886	24360	23346	21840	20565
TEE	2/2/12	19881	19378	19274	19501	20095	22030	24576	24885	24561	24169	23770	23407	23134	22877	22677	22492	22620	23978	25202	25360	25380	24570	23458	22449
TEE	2/3/12	22034	21972	22011	22466	23254	25223	27604	27766	26782	25721	24964	24278	23954	23488	23113	22911	23176	24232	24823	24731	24323	23625	22627	21443
TEE	2/4/12	20549	19919	19663	19688	19870	20305	21134	22097	23162	23807	24026	23852	23471	23068	22839	22753	23086	23836	23977	23747	23033	22297	21240	20148
TEE	2/5/12	19400	18973	18816	18656	18876	19356	20140	21213	22356	22729	22470	22325	22367	22426	22280	22405	22827	23728	24153	24214	23998	23903	23150	22168
TEE	2/6/12	21589	21445	21449	21739	22672	24696	27170	27647	27182	26496	26045	25434	24941	24495	24126	24162	24560	25776	27290	27672	27624	27006	25959	24927
TEE	2/7/12	24566	24573	24855	25240	26252	28515	30847	30829	29252	27490	26065	25095	24462	23966	23391	23367	23963	25621	26913	27093	27026	26250	24816	23477
TEE	2/8/12	22885	22554	22296	22475	23339	25324	27556	27844	27520	27201	26958	26751	26753	26723	26676	27038	27854	29188	29882	29743	29217	28270	26776	25582
TEE	2/9/12	24893	24692	24525	24800	25332	27339	29598	29789	29348	28857	28302	27744	27110	26594	26028	25912	26520	28279	29821	30047	29985	29218	28095	27133
TEE	2/10/12	26658	26539	26566	26787	27413	29123	31235	31497	30829	30082	29177	28447	27897	27562	27266	27501	28133	29261	29663	29218	28777	27927	26862	26017
TEE	2/11/12	25507	25238	25391	25763	26458	27611	28909	30379	31693	32296	32369	31920	31302	30663	30144	30021	30755	32369	33619	33772	33603	33002	32243	31514
TEE	2/12/12	30966	30876	30995	31123	31559	32233	32885	33487	33234	31932	30245	28828	27788	26691	25970	25655	26130	28046	29981	30843	30774	30430	29685	29015
TEE	2/13/12	28997	29202	29557	30265	31181	33560	35725	35483	33837	32286	31092	30123	29386	28882	28536	28582	29089	30233	31046	31026	30494	29563	27953	26567
TEE	2/14/12	25792	25316	25161	25260	25736	27416	29537	29776	29446	29251	29089	28702	28573	28211	27917	27758	28088	28987	29521	29200	28775	27533	26133	24808
TEE	2/15/12	24161	23786	23707	23810	24579	26495	28562	28654	27785	26905	25996	25191	24662	24263	24030	24075	24455	25698	26499	26516	26094	25115	23621	22215
TEE	2/16/12	21372	20926	20813	20817	21157	22843	25010	25330	25111	25157	25023	24914	24641	24249	23979	24031	24281	25367	26356	26427	26005	25166	23952	22668
TEE	2/17/12	22105	21928	22091	22363	23095	25041	27330	27649	26998	26066	25352	24713	24069	23481	22990	22815	23106	24076	25111	25181	24832	24285	23536	22636
TEE	2/18/12	21919	21596	21520	21658	22191	22988	24054	24819	25030	24860	24246	23641	23106	22845	22566	22699	23081	24022	24711	24582	24272	23651	22842	21784
TEE	2/19/12	21197	20903	20787	20888	21224	21889	23025	24195	25448	25990	26089	26163	26240	25929	25686	25555	25841	26945	27937	28139	28034	27555	26723	26075
TEE	2/20/12	25784	25833	26210	26713	27621	29484	31330	31790	30872	29651	28575	27404	26565	25753	24925	24488	24545	25689	27626	28165	28053	27441	26040	24881
TEE	2/21/12	24229	23908	23642	23601	24076	25713	27572	27569	26925	26302	25932	25417	24976	24508	23998	23742	23870	24735	26263	26521	26204	25276	24209	23176
TEE	2/22/12	22712	22698	22753	22934	23635	25352	27272	27126	26419	25790	25416	24952	24639	24368	23953	23766	24241	25157	26005	25864	25412	24360	22933	21525
TEE	2/23/12	20557	20232	19973	20106	20651	22465	24587	24746	24252	23821	23680	23379	23335	23221	22912	22919	22997	23770	24975	24951	24383	23244	21656	20159
TEE	2/24/12	19180	18721	18352	18268	18783	20351	22355	23148	23283	23648	23995	24002	24003	23947	24055	24263	24812	25616	26738	26925	26738	26171	25447	24606
TEE	2/25/12	24201	23958	24000	24221	24825	25726	26626	27053	26874	26569	25954	25395	24522	23866	23178	23008	23160	24299	25978	26632	26699	26535	25928	25300
TEE	2/26/12	24948	24804	24915	25142	25683	26603	27431	27756	27075	25689	24090	23162	22408	21743	21194	20956	21218	22238	23905	24747	24570	24029	23005	22297
TEE	2/27/12	21725	21416	21427	21672	22373	24153	26297	26392	25627	25009	24520	23965	23696	23340	22829	22744	22854	23560	25008	25301	24688	23804	22513	21396
TEE	2/28/12	20996	21131	21001	21303	22212	24360	26810	26683	25556	24662	23953	23388	23155	22901	22743	22674	22953	23586	24671	24863	24364	23074	21586	20086
TEE	2/29/12	19000	18648	18491	18506	18854	20160	22167	22631	22707	22778	22878	22967	22911	22837	22687	22783	23005	23560	24293	24178	23689	22613	21050	19519
TEE	3/1/12	18711	18276	18142	18338	18996	20818	23092	23426	23035	22734	22641	22532	22428	22342	22175	22270	22248	22479	23903	24284	23889	23029	21767	20574
TEE	3/2/12	19791	19417	19197	19277	19800	21366	23164	23256	23377	23532	23551	23572	23534	23357	22977	22244	21633	21790	22223	22128	21882	20961	20061	19208
TEE	3/3/12	18511	18385	18400	18634	19276	20359	21577	22877	23566	23518	23229	22540	22028	21493	21060	20927	21260	22082	23566	23895	23793	23345	22688	22053
TEE	3/4/12	21601	21568	21667	21906	22473	23456	24282	24943	25117	24506	23787	23575	23317	22930	22499	22367	22635	23604	25240	25702	25490	24660	23493	22498
TEE	3/5/12	21855	21747	21704	22074	23003	25124	27275	27610	27375	26991	26551	26040	25666	25213	24619	24387	24527	25549	27589	28466	28328	27748	26488	25564
TEE	3/6/12	25312	25196	25233	25618	26319	28104	29920	29239	27659	26366	25422	24592	23972	23386	22918	22691	22623	23310	24907	25503	25127	23948	22714	21509

TEE Reserve Sharing Group>>>

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TEE	3/7/12	20955	20716	20592	20742	21410	23145	24881	24710	23775	23336	23039	22771	22722	22552	22405	22426	22422	22893	24175	24437	23970	22913	21457	20056
TEE	3/8/12	19176	18727	18632	18706	19097	20761	22647	23099	23141	23272	23229	23343	23646	23586	23422	23488	23966	24731	25510	25478	25005	23868	22433	21299
TEE	3/9/12	20745	20481	20322	20681	21616	23668	25880	26500	26175	25596	25097	24519	24028	23300	22747	22361	22313	22912	24363	24801	24863	24524	23699	22868
TEE	3/10/12	22494	22356	22447	22687	23131	24084	24915	25281	24967	24332	23443	22644	21789	21063	20603	20297	20417	20835	22218	22759	22491	22112	21393	20706
TEE	3/11/12	20319	20140	4494	20334	20702	21526	22410	23030	23081	22368	21675	21252	20952	20459	20039	20023	20170	20421	21317	22710	22292	21274	20213	19014
TEE	3/12/12	18187	17820	17748	17874	18528	20399	22268	22653	22665	23018	23195	23243	23281	23158	22863	22795	22921	23071	23319	24337	23865	22649	21015	19518
TEE	3/13/12	18618	18149	17776	17899	18432	20192	21943	22113	22141	22398	22640	22834	23080	23243	23367	23580	23680	23697	23687	25066	24636	23259	21357	19798
TEE	3/14/12	18626	18042	17709	17662	18228	20012	21965	22065	22155	22452	22836	23389	23935	24268	24460	24703	24868	24846	24721	25518	25021	23590	21672	19945
TEE	3/15/12	18968	18229	17882	17819	18554	20220	22103	22203	22464	23046	23646	24377	25245	25593	25715	25491	25210	24940	24994	25157	24776	23328	21583	20043
TEE	3/16/12	19067	18362	17979	17953	18348	19942	21710	22107	22398	22785	23178	23449	23631	23607	23563	23464	23438	23257	23126	23777	23353	22346	21013	19504
TEE	3/17/12	18394	17778	17269	17186	17396	17904	18673	19256	20441	21380	21890	22379	22647	22701	22785	22781	22921	22830	22796	23316	22827	21852	20519	19159
TEE	3/18/12	18037	17339	16915	16675	16820	17097	17738	18396	19754	20459	20832	21374	22136	22680	23134	23647	24111	24097	23844	24846	24348	22992	21130	19595
TEE	3/19/12	18494	17969	17662	17585	18241	20015	22101	22409	22673	23237	23911	24504	25346	25887	26432	26877	27004	26751	26497	27217	26511	24747	22592	20661
TEE	3/20/12	19513	18739	18299	18044	18544	20211	22151	22214	22522	23326	24139	25043	26003	26769	27399	27841	27870	27415	26855	27608	26918	25184	22833	20880
TEE	3/21/12	19635	18860	18309	18037	18526	20298	22082	22169	22592	23410	24318	25259	26020	26499	26657	26690	26606	26229	26003	26549	25986	24453	22267	20478
TEE	3/22/12	19515	18801	18292	18198	18586	20283	22110	22472	22787	23399	23871	24405	24596	24932	24867	24933	24830	24613	24571	25241	24920	23544	21604	20001
TEE	3/23/12	18973	18375	18105	18006	18438	20163	22061	22292	22470	23000	23414	23750	24039	24159	24185	24210	24211	23860	23440	23910	23519	22455	21034	19605
TEE	3/24/12	18388	17701	17235	17097	17200	17565	18254	19118	20123	20975	21259	21257	21172	20949	20838	20616	20780	20780	20670	21501	21506	20765	19558	18448
TEE	3/25/12	17569	17068	16824	16648	16804	17286	18033	19033	19881	20271	20104	20126	20304	20425	20475	20692	21003	21249	21619	22671	22620	21613	20052	18691
TEE	3/26/12	17705	17268	17118	17105	18055	20073	21922	22072	22402	22609	23034	23333	23699	23676	24006	24365	24616	24618	24428	25340	24978	23372	21474	19867
TEE	3/27/12	18820	18207	18070	18060	18610	20729	22562	22605	22597	22599	22605	22887	23227	23690	24065	24535	24859	24835	24632	25406	24987	23404	21249	19696
TEE	3/28/12	18645	18153	17815	17840	18374	20216	21669	21786	22062	22561	23207	23958	24702	25404	25844	26217	26284	26209	25626	26133	25651	24061	21972	20268
TEE	3/29/12	19058	18470	18053	17912	18405	20143	21831	21938	22276	22920	23554	24293	24927	25490	25767	26043	26319	25916	25533	26175	25831	24116	22124	20273
TEE	3/30/12	19013	18515	18026	17930	18351	19983	21680	21969	22402	22792	23234	23670	23945	23931	23992	23976	24032	23695	23357	23957	23720	22635	21162	19665
TEE	3/31/12	18589	17936	17489	17165	17356	17821	18452	19226	20450	21348	21962	22430	22783	23115	23518	23810	23860	23554	22858	23229	22852	21660	20298	18875
TEE	4/1/12	17825	17228	16830	16634	16865	17318	17712	18719	20118	20599	21023	21751	22455	23109	23576	24149	24820	25001	24656	25169	24943	23483	21716	20243
TEE	4/2/12	19045	18323	18028	18023	18793	20531	22168	22656	23326	24304	25233	25992	26800	27518	28278	28773	28893	28699	28201	28392	27573	25771	23382	21510
TEE	4/3/12	20152	19180	18709	18544	19085	20683	22311	22586	23124	23880	24889	25907	26805	27828	28273	28571	28382	28018	27382	27622	27000	25095	23022	21085
TEE	4/4/12	19956	19241	18757	18690	19278	20820	22245	22632	23374	24186	25031	25714	26547	27283	27845	27924	27920	27449	26667	26635	26344	24868	22752	20833
TEE	4/5/12	19796	19027	18466	18250	18896	20543	21983	22365	22879	23434	23709	23915	23920	23982	23769	23590	23517	23279	23136	23494	23316	22128	20728	19260
TEE	4/6/12	18402	17859	17468	17434	17872	19231	20300	21009	21461	21667	21671	21455	21163	21108	21021	20895	21181	20998	20732	21381	21646	20847	19811	18663
TEE	4/7/12	17908	17444	17282	17298	17829	18507	19130	20071	20657	20724	20604	20405	20264	20079	20026	20293	20747	20830	20714	21407	21511	20602	19453	18132
TEE	4/8/12	17259	16630	16546	16415	16652	17225	17801	18786	19819	19844	19428	19510	19416	19410	19400	19515	19699	19657	19680	20958	21108	20120	18887	17712
TEE	4/9/12	17127	16862	16864	17267	18261	20296	22188	22776	22843	22964	23080	23103	23021	23039	23086	23115	23262	23282	23286	24026	23955	22533	20824	19352
TEE	4/10/12	18467	17949	17877	18122	18876	21003	22623	22970	22999	22989	23072	23037	22945	22817	22707	22715	22754	22679	22753	23824	24092	22875	21130	19873

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TEE	4/11/12	19392	19064	19060	19356	20535	22765	24572	24547	24032	23833	23627	23387	23039	22909	22592	22684	22818	22915	23036	24179	24684	23731	22437	21392
TEE	4/12/12	20803	20769	20887	21288	22439	24612	26270	26042	25107	24192	23679	23158	22699	22664	22361	22205	22215	22283	22434	23593	23908	23013	21366	20232
TEE	4/13/12	19671	19499	19533	19821	21022	23109	24651	24536	23852	23367	23025	22743	22588	22583	22523	22471	22566	22444	22208	23030	23041	22160	20796	19515
TEE	4/14/12	18663	18180	17884	17760	18021	18656	19262	19935	20926	21431	21594	21590	21713	21931	22150	22457	22757	22780	22660	22971	23164	22106	20647	19260
TEE	4/15/12	18196	17394	16987	16869	16873	17181	17513	18785	20001	20759	21132	21567	22204	22818	23320	24017	24538	24701	24412	24826	24921	23880	22151	20444
TEE	4/16/12	19508	18759	18158	18156	18928	20855	22375	23015	23425	23853	24282	24561	24806	25026	25200	25100	25021	24778	24408	25045	25016	23461	21485	19860
TEE	4/17/12	18750	18135	17751	17670	18500	20394	21935	22212	22541	22865	23149	23185	23208	23012	22683	22808	22906	22809	22931	23660	23629	22298	20613	19202
TEE	4/18/12	18509	18067	17890	17956	18723	20765	22206	22696	22644	22784	22879	22959	22989	23060	23148	23346	23476	23552	23405	23842	24160	22924	21055	19573
TEE	4/19/12	18723	18282	18028	18140	19055	20873	22415	22601	22470	22357	22824	23020	23269	23640	23919	24353	24756	24878	24406	24639	24874	23579	21675	20034
TEE	4/20/12	18863	18221	17879	17843	18648	20578	22013	22434	22684	23080	23467	23780	23896	23984	24226	24364	24276	23961	23448	23766	23656	22335	20760	19455
TEE	4/21/12	18426	17714	17196	17228	17389	17946	18480	19411	20569	21419	21818	21686	21641	21405	21210	21147	21136	21121	21314	21910	21917	21047	19961	18904
TEE	4/22/12	18225	17816	17563	17591	17840	18227	18743	19930	20822	21048	20761	20609	20582	20342	20376	20562	20879	21118	21568	22420	22914	22039	20829	19788
TEE	4/23/12	19335	18987	18985	19394	20622	23046	24722	24810	24585	24472	24387	24025	23565	23251	22829	22559	22748	22837	23154	23976	24658	23566	22152	20916
TEE	4/24/12	20299	20196	20183	20539	21488	23887	25364	25076	24432	23984	23547	23326	23071	22889	22760	22905	22907	23039	23180	23902	24124	22835	21121	19762
TEE	4/25/12	18958	18541	18350	18388	19158	21131	22456	22582	22648	22792	22999	23278	23517	23931	24247	24533	24729	24857	24695	25129	25560	24178	22221	20554
TEE	4/26/12	19366	18784	18387	18392	19114	20675	22235	22695	23122	23691	24375	24979	25392	25751	25955	26115	26505	26370	26028	26221	26196	24716	22600	20694
TEE	4/27/12	19517	18767	18348	18276	18893	20542	22134	22004	23476	23218	23712	23761	23830	23972	24018	24080	24263	23946	23485	23652	23765	22815	21261	19788
TEE	4/28/12	18843	17947	17525	17491	17704	18257	18533	19621	20903	21710	22299	22898	23449	24122	24793	25404	26033	26034	25485	24915	24784	23375	21717	19993
TEE	4/29/12	18787	17917	17431	17264	17227	17222	17482	18874	20464	21504	22432	23475	24627	25505	26208	26818	27337	27270	26878	26657	26522	24649	22486	20581
TEE	4/30/12	19388	18601	18075	18091	18673	20595	22034	22820	23777	25009	26500	27718	28815	29756	30030	30185	30295	29856	29037	29021	28654	26801	24477	22351
TEE	5/1/12	20994	20107	19520	19278	19776	21483	22818	23692	24574	25830	27227	28409	29383	30434	30973	31396	31647	31334	30456	29952	29917	28014	25331	23108
TEE	5/2/12	21721	20837	20096	19796	20372	22059	23550	24445	25681	27389	28853	30309	31426	32376	33146	33640	33918	33548	32474	31654	31248	29157	26235	23895
TEE	5/3/12	22510	21393	20559	20138	20607	22262	23668	24613	25263	26164	26924	27381	27926	28446	29165	29165	29237	28848	28454	28298	28390	26808	24668	22676
TEE	5/4/12	21178	20413	19704	19498	20253	21858	23318	24004	25051	26095	27038	28430	29357	30499	31381	32052	32080	31594	30296	29393	29078	27491	25378	23176
TEE	5/5/12	21795	20606	19970	19553	19468	19669	20033	21077	22379	23770	25068	26283	27580	28658	29581	30228	30557	30183	29424	28596	28122	26632	24458	22354
TEE	5/6/12	20783	19952	19324	18909	18687	18815	18963	20301	22323	23882	25353	26841	28496	29871	30891	31485	31617	31285	30191	29303	28989	27070	24387	22129
TEE	5/7/12	20894	19751	19310	19203	19738	21416	22877	23997	25048	25990	26938	27706	28244	28837	29264	29650	29709	29414	28612	28323	28006	26355	24104	22100
TEE	5/8/12	20960	20154	19630	19308	19902	21524	23065	23751	24462	25244	26133	26672	27129	27774	28076	28352	28599	28331	27498	27127	27103	25545	23328	21418
TEE	5/9/12	20233	19440	19060	18762	19327	20949	22307	22779	23075	23622	24259	24422	24802	25055	25297	25691	26061	25825	25285	24743	25065	23759	21654	19965
TEE	5/10/12	18915	18394	17981	17876	18508	20127	21443	21914	22405	22815	23178	23421	23746	24074	24397	24673	25046	24931	24471	24131	24665	23300	21444	19732
TEE	5/11/12	18739	18229	17790	17943	18546	20202	21565	22169	22420	22881	23163	23449	23714	24052	24493	24884	24983	24629	23831	23600	23871	22908	21325	19859
TEE	5/12/12	18611	17926	17639	17464	17637	17938	18491	19389	20448	21145	21531	21743	21907	22005	22042	22198	22091	22052	22176	22316	22487	21754	20624	19208
TEE	5/13/12	16437	15941	15526	15295	15306	15578	16065	17190	18254	18712	18781	18860	18799	18846	18799	18875	19155	19455	19627	20108	20510	19741	18554	17401
TEE	5/14/12	18229	17861	17619	17630	18408	20092	21616	22340	22924	23603	24125	24273	24629	25080	25363	25680	25957	25882	25579	25363	25800	24339	22275	20539
TEE	5/15/12	19415	18772	18329	18327	18865	20457	21773	22556	23210	24095	24928	25684	26230	26849	27338	27723	27906	27562	26961	26537	26719	25129	22910	20888

TEE Reserve Sharing Group>>>

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TEE	5/16/12	19689	18893	18405	18208	18733	20234	21479	22376	23355	24413	25383	26189	27288	28129	29006	29978	30243	29958	29039	28128	27955	26051	23504	21403
TEE	5/17/12	20020	19204	18609	18479	18940	20408	21723	22533	23331	24344	25394	26477	27485	28674	29502	30082	30229	29905	29056	28040	28008	26461	24001	21732
TEE	5/18/12	20409	19594	18827	18808	19317	20505	21761	22909	23937	25149	26518	27800	29001	29986	30804	31276	31193	30483	29112	27820	27594	26129	24037	22011
TEE	5/19/12	20458	19385	18718	18236	18195	18462	18926	20341	22154	23650	25284	26549	27876	28910	29542	30014	30075	29680	28582	27397	26908	25348	23290	21386
TEE	5/20/12	19839	18786	18056	17813	17728	17566	17943	19480	21486	23092	24418	25916	27557	28482	29216	29623	29969	29720	28808	27825	27442	25588	23453	21365
TEE	5/21/12	20066	19180	18655	18647	19225	20531	21953	23205	24165	25558	26843	27813	28806	29394	29612	29525	29130	28251	27349	26612	26538	25177	23048	21045
TEE	5/22/12	19739	18980	18425	18340	18817	19987	21303	22138	22997	23741	24373	25102	25871	26633	26858	27080	27261	27034	26406	25766	25792	24507	22320	20313
TEE	5/23/12	19205	18475	17947	17740	18219	19369	20782	21743	22627	23682	24644	25474	26440	27377	28133	28844	29229	29167	28577	27282	27021	25515	23174	21063
TEE	5/24/12	19793	18850	18289	18250	18636	19801	21193	22373	23669	25059	26664	28049	29315	30628	31638	32333	32492	32077	31127	29898	29527	28050	25551	23317
TEE	5/25/12	21560	20451	19647	19404	19663	20586	21838	23474	25336	27328	29262	30916	32115	33195	33931	34177	34264	33609	32425	30819	30274	28550	25949	23439
TEE	5/26/12	21672	20180	19258	18752	18620	18461	18860	20501	22849	25256	27580	29322	30599	31658	32375	33174	33382	33068	32089	30605	29913	28035	25601	23409
TEE	5/27/12	21674	20225	19230	18746	18448	18148	18532	20428	22947	25361	27434	29289	30780	31682	32500	32998	33199	32939	31824	30607	29827	28166	25598	23528
TEE	5/28/12	21817	20634	19778	19110	19056	18945	19271	20919	23464	26052	28388	30101	31476	32377	33000	33460	33603	33324	32381	31289	30918	29225	26847	24348
TEE	5/29/12	22708	21600	20821	20495	20979	22131	23482	25155	26743	28231	29456	30559	31728	32657	33253	33542	33345	32598	31407	30164	29331	27579	25318	23146
TEE	5/30/12	21506	20371	19667	19244	19568	20420	21522	22963	24621	26458	28266	29771	31006	31862	32105	32044	31909	31231	30221	28782	28110	26547	24151	21861
TEE	5/31/12	20323	19355	18729	18494	18849	19791	20979	22417	23818	25118	26435	27615	28880	30238	30969	30896	30595	29756	28513	27659	27241	25703	23716	21767
TEE	6/1/12	20431	19577	19155	18837	19088	20095	21132	21901	22355	22843	23266	23315	23353	23392	23417	23314	23269	22822	22232	21889	22295	21664	20257	18746
TEE	6/2/12	17799	17136	16636	16404	16431	16631	17039	18003	19034	19830	20443	20807	21053	21336	21742	22318	22722	22784	22327	21971	22411	21684	20129	18628
TEE	6/3/12	17506	16653	16234	16000	16023	16159	16517	17757	19177	20457	21575	22904	24114	25265	26288	27202	27959	27999	27527	26757	26667	25284	23247	21362
TEE	6/4/12	19962	19125	18687	18626	19034	20062	21420	22612	23581	24628	25710	26681	27459	28132	28875	29217	29316	29117	28445	27620	27487	26280	24166	22079
TEE	6/5/12	20634	19766	19068	18911	19338	20322	21408	22682	23723	24752	25746	26513	27132	27899	28470	28772	28927	28509	27635	26542	26303	25051	23032	20994
TEE	6/6/12	19409	18629	18001	17741	18264	19052	20263	21536	22608	23676	24531	25194	25710	26531	27119	27653	28128	27927	27218	26032	25841	24740	22641	20720
TEE	6/7/12	19399	18552	18104	17733	18325	19186	20396	21735	22805	23841	25104	26107	26959	27844	28603	29266	29517	29260	28356	27083	26915	25725	23400	21316
TEE	6/8/12	19888	18945	18472	18093	18548	19293	20606	22079	23433	24815	26361	27586	28546	29637	30432	31029	31282	31022	29824	28431	27842	26334	24106	21868
TEE	6/9/12	20303	19213	18392	18019	17986	17899	18409	19865	21564	23503	25238	26760	27832	28723	29296	29921	30056	29640	28731	27692	27355	26134	24116	22042
TEE	6/10/12	20424	19443	18613	18291	18081	18023	18294	19407	21024	22152	23000	23687	24533	25037	25411	25836	25964	26110	25789	25457	25638	24843	23271	21601
TEE	6/11/12	20383	19634	19290	19336	20002	21325	22586	24022	24913	25979	26977	27946	29135	30351	31213	31372	30844	30231	29190	28097	27745	26571	24471	22620
TEE	6/12/12	21176	20212	19646	19425	19815	20818	22044	23336	24446	25621	26805	27827	28813	29788	30616	31151	31369	30864	29936	28783	28412	27054	24657	22360
TEE	6/13/12	20861	19789	19194	18889	19098	19971	21237	22530	23848	25497	26927	28240	29563	30538	31424	32091	32416	32195	31163	29697	28820	27297	24664	22332
TEE	6/14/12	20685	19668	18700	18377	18896	19704	20992	22553	23955	25770	27565	29296	30741	31844	32773	33406	33877	33598	32579	31170	30437	28913	26137	23708
TEE	6/15/12	21872	20702	19771	19535	19848	20692	22002	23582	25391	27428	29285	30853	32081	33290	34128	34650	34752	34045	32793	31197	30662	29147	26790	24471
TEE	6/16/12	22668	21376	20532	19972	19639	19489	19793	21373	23350	25315	27116	28446	29432	30485	30976	31272	31634	31394	30552	29279	28615	27392	25199	22991
TEE	6/17/12	21291	20160	19258	18840	18601	18462	18596	20415	22554	24364	25604	26855	27901	28829	29307	29780	29876	29762	29077	28135	27847	26682	24615	22419
TEE	6/18/12	20797	19816	19360	19207	19544	20557	21989	23939	25958	27990	29997	31458	32731	33682	34421	35004	35143	34704	33819	32457	31654	30082	27361	24601
TEE	6/19/12	22824	21588	20692	20425	20656	21388	22687	24663	26684	28841	30776	32396	33449	34624	35307	35841	35949	35625	34597	33149	32289	30541	27800	25188

TEE Reserve Sharing Group>>>

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TEE	6/20/12	23310	21952	20992	20346	20613	21475	22783	24694	26679	28851	30980	32532	33935	35064	35849	36314	36339	35995	35030	33577	32754	31112	28336	25576
TEE	6/21/12	23782	22357	21516	21049	21318	21857	23281	25248	27230	29501	31671	33282	34492	35524	36325	36712	36815	36259	35274	34024	33194	31553	28777	26097
TEE	6/22/12	24243	22947	21952	21390	21562	22260	23459	25177	27163	29271	31336	32935	34142	35122	35694	35996	35935	35312	34278	32735	31644	30129	27640	25143
TEE	6/23/12	23188	21837	20603	20086	19854	19683	20014	21760	24177	26595	29031	30747	32045	33100	33895	34475	34793	34585	33782	32017	30794	29063	26578	24160
TEE	6/24/12	22300	21013	20017	19302	18911	18510	18955	20923	23519	26111	28554	30672	32449	33659	34627	35326	35760	35558	34837	33388	32361	30607	27848	25349
TEE	6/25/12	23426	22133	21213	20825	21063	21775	23090	25255	27447	29957	32400	34500	35973	37063	37631	37969	38006	37528	36442	34892	34053	32215	29351	26594
TEE	6/26/12	24431	23066	21897	21135	21092	21541	22543	23945	25294	26579	27982	29049	30140	31114	31924	32582	32818	32524	31586	29999	28967	27347	24673	22191
TEE	6/27/12	20569	19359	18632	18315	18617	19343	20407	21885	23406	25144	26885	28557	30267	31937	33379	34646	35387	35407	34603	32757	31371	29691	26803	23911
TEE	6/28/12	22089	20744	19920	19432	19828	20372	21454	23231	25276	27648	30361	32845	35044	36847	38249	39146	39445	39293	38390	36791	35750	33791	30867	27918
TEE	6/29/12	25785	24252	23013	22353	22346	23061	23945	25954	28320	31197	34141	36298	38311	39578	40155	40486	40536	39961	38570	37321	36309	34848	32394	29640
TEE	6/30/12	27418	25581	24138	23255	22691	22273	22767	24745	27517	30526	33374	35665	37290	38432	39232	39677	39756	39549	38796	37354	36464	34750	32230	29814
TEE	7/1/12	27545	25774	24552	23748	23190	22778	22775	24543	27718	30541	32985	35086	36755	38005	38542	38843	39155	38896	38041	36365	35275	33707	30965	28355
TEE	7/2/12	26364	24973	23904	23267	23330	23792	24783	26446	28352	30762	32817	34598	36022	37276	37855	37843	37582	36842	35876	34508	33443	31759	29357	26937
TEE	7/3/12	25151	23644	22679	22126	22173	22611	23519	25282	27498	29709	31971	33910	35431	36679	37354	37526	37377	36715	35599	33996	33286	31689	29397	27039
TEE	7/4/12	25120	23600	22513	21684	21486	21180	21291	22889	25670	28546	31372	33488	35117	35968	36423	36572	36521	35946	34578	33002	32033	30524	28783	26816
TEE	7/5/12	25029	23672	22750	22230	22345	22909	24029	26170	28743	31611	34233	36217	37853	38363	38594	38306	37603	36221	34610	33219	32658	31322	28964	26720
TEE	7/6/12	24913	23586	22517	21801	21876	22243	23185	24901	27139	29513	32248	34566	36554	37841	38601	38933	38570	37594	36113	34627	34070	32447	30137	27802
TEE	7/7/12	25760	24353	23130	22433	22090	21976	22261	24090	26830	29782	32628	34860	36357	37272	37940	38323	38127	37966	37033	35816	35105	33504	31110	28823
TEE	7/8/12	26867	25426	24399	23563	23251	22868	23011	24799	27371	29369	31309	33071	34731	35870	36302	36115	35733	34742	33644	32342	31906	30353	28029	25929
TEE	7/9/12	24319	23240	22588	22134	22535	23439	24509	26130	27349	28854	30446	31837	32891	33802	34491	34855	34914	34591	33611	32428	31902	30314	28001	25845
TEE	7/10/12	24138	22847	22041	21718	21849	22692	23814	25330	26738	28329	30092	31353	32370	32978	33104	32759	32111	31407	30593	29812	29614	28446	26333	24187
TEE	7/11/12	22765	21814	21130	20858	21317	22256	23406	24808	26057	27198	28425	29244	30036	30710	31033	31405	31621	31391	30585	29701	29526	28513	26403	24185
TEE	7/12/12	22632	21674	20801	20714	20952	22243	23295	24421	25419	26471	27351	28008	28273	28570	28559	28268	27908	27620	27132	26781	26981	26326	24652	22980
TEE	7/13/12	21583	20801	20243	20180	20567	21624	22615	23983	24996	26137	27226	28126	28866	29824	30446	30922	30974	30674	29862	28973	28813	27781	25933	23954
TEE	7/14/12	22424	21479	20736	20154	20246	20371	20618	21915	23724	25647	27299	28651	29238	29502	29394	29266	28928	28385	27719	26973	26787	26015	24297	22632
TEE	7/15/12	21204	20179	19571	19118	18963	18869	19220	20761	22838	24604	26230	27685	29407	30786	31858	32798	33138	33008	32238	31239	30591	29157	27101	24868
TEE	7/16/12	23053	22066	21312	20997	21330	22290	23622	25597	27945	30601	32835	34503	35584	36200	36586	36830	36738	36221	35353	34060	33608	31928	29280	26849
TEE	7/17/12	25090	24001	22981	22364	22791	23666	24726	26700	28890	31176	33607	35108	36224	37028	37397	37734	37536	37093	36159	34857	34507	32705	30121	27412
TEE	7/18/12	25615	24374	23472	23052	23374	24159	25295	26930	28975	31118	33386	35217	36412	37218	37219	36819	35653	34392	33171	32019	31668	30156	27810	25696
TEE	7/19/12	23984	22990	22178	21901	22412	23260	24446	26096	27777	29820	31859	33723	35461	36970	37681	38255	38165	37421	36183	35133	34376	32589	29744	27151
TEE	7/20/12	25482	24300	23278	22856	23020	23536	24451	25649	26946	28465	30039	31392	32649	33642	34701	35304	35437	34834	33834	32601	32081	30644	28356	26199
TEE	7/21/12	24448	23066	22087	21708	21176	21203	21445	22638	24472	26246	28072	29430	30570	31781	32711	33448	33689	33475	32570	31062	30367	28930	26774	24542
TEE	7/22/12	23017	21760	20983	20415	20107	20008	20086	21870	24422	26629	28412	30087	31637	32630	33167	33832	34273	34182	33452	32122	31503	30011	27899	25791
TEE	7/23/12	24144	23034	22393	22139	22379	23282	24621	26662	28846	31219	33430	35256	36699	37702	38257	38719	38927	38642	37810	36380	35661	33805	31094	28492
TEE	7/24/12	26729	25315	24238	23735	23865	24826	25928	27789	29978	32250	34300	35848	37195	38122	38801	39200	39115	38509	37628	36269	35503	33712	31133	28724

TEE Reserve Sharing Group>>>

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TEE	7/25/12	26795	25372	24344	23769	23929	24656	25623	27416	29653	32147	34515	36346	37704	38902	39630	39915	40031	39787	38733	37250	36633	34895	32175	29666
TEE	7/26/12	27658	26329	25394	24781	24928	25728	26656	28650	30967	33405	35615	37084	38441	39333	39889	40082	39887	39184	37946	36464	35951	33943	31164	28344
TEE	7/27/12	26524	25177	24207	23641	23743	24468	25394	27091	28808	30641	32561	34121	35050	35806	36142	36528	36486	36059	34878	33126	32277	30695	28478	26330
TEE	7/28/12	24401	23026	21992	21391	21059	21002	21161	22943	25426	27814	30110	31900	33358	34374	35038	35573	35661	35087	33969	32135	31220	29327	27047	24592
TEE	7/29/12	22797	21390	20396	19725	19317	19232	19244	20977	23428	25727	27699	29355	30709	31504	32191	32475	32572	32315	31596	30343	29864	28426	26281	24168
TEE	7/30/12	22544	21409	20746	20617	21062	22136	23324	24898	26765	28604	30575	32290	33926	35329	36547	37361	37559	37246	36327	35045	34661	32622	29977	27714
TEE	7/31/12	26088	24760	23981	23531	23573	24573	25415	26756	28408	30321	32321	33665	34927	36165	36908	37683	37999	37595	36585	35112	34486	32444	29732	27277
TEE	8/1/12	25500	24053	23066	22659	22677	23848	24783	26311	28475	30772	33435	35429	37261	38458	38891	38713	38110	37151	35754	34200	33551	31436	28915	26408
TEE	8/2/12	24626	23346	22434	22056	22241	23248	24078	25697	27662	29894	32285	34383	36194	37680	38269	38526	38429	37757	36517	35087	34764	32843	30296	27855
TEE	8/3/12	26096	24783	23809	23347	23620	24617	25545	26475	27496	28848	30136	30980	31758	32514	33183	33610	33698	33414	32554	31679	31619	30386	28539	26505
TEE	8/4/12	24921	23850	22963	22349	22214	22366	22640	23904	26037	28301	30386	32069	33401	34366	34367	33949	33284	32483	31337	30463	30353	28940	27277	25459
TEE	8/5/12	24057	22973	22299	21733	21477	21572	21617	22979	24927	26401	27588	29099	30556	31361	31927	32018	31496	30686	29872	29285	29200	27707	25851	24036
TEE	8/6/12	22715	21938	21445	21198	21605	22972	24175	25529	27116	28831	30501	31882	33131	34155	34774	35378	35703	35464	34558	33462	33165	31228	28532	26090
TEE	8/7/12	24235	23115	22151	21745	22060	23321	24337	25754	27531	29556	31941	33519	34783	35939	36816	37275	37348	36936	35804	34580	33956	31658	28945	26415
TEE	8/8/12	24525	23271	22424	21916	22262	23324	24389	25856	27767	30163	32538	34573	36024	37284	38083	38518	38635	38287	37158	35791	35176	32789	30031	27517
TEE	8/9/12	25755	24445	23606	23055	23376	24816	25765	26725	27895	29224	30513	31610	32423	33111	33224	33199	33037	32621	31728	31138	30976	29252	26765	24597
TEE	8/10/12	23239	22639	22009	21604	21870	23283	24462	25331	26273	27609	28708	29772	30554	31182	31790	32258	32055	31011	29461	28435	28156	26629	24429	22683
TEE	8/11/12	21103	20096	19269	18780	18542	18839	18682	19803	21563	23254	24701	25935	26934	27627	28537	29213	29597	29388	28345	26869	26126	24543	22472	20693
TEE	8/12/12	19203	18269	17577	17254	17131	17116	17217	18425	20172	21674	23006	24478	25957	27244	28443	29249	29922	29828	28831	27766	27592	25806	23542	21521
TEE	8/13/12	20321	19547	19128	19039	19628	21187	22493	23487	24507	25479	26415	26968	27485	27943	28368	28571	28757	28667	28091	27756	27955	26569	24401	22422
TEE	8/14/12	21092	20493	19967	19717	20348	21977	23495	24143	24884	25865	26920	27973	29061	30290	31191	31749	32053	31641	30691	29834	29662	27568	25165	23037
TEE	8/15/12	21583	20740	19879	19722	20299	21937	23119	23790	24813	26180	27700	29069	30198	31421	32499	33248	33670	33320	32384	31017	30725	28329	25572	23122
TEE	8/16/12	21875	20769	20195	19756	20092	21821	22874	24055	25648	27477	29660	31295	32801	34285	35102	35738	35974	35392	34087	33442	32611	30239	27384	24764
TEE	8/17/12	22996	21954	20987	20587	21035	22521	23816	24456	25093	26015	26853	27433	27589	28187	28661	29000	29109	28776	27784	27263	27185	25734	23961	22189
TEE	8/18/12	20779	19857	19267	18912	18760	19106	19350	20332	21885	23675	25005	26210	26863	27469	28072	28551	28668	28186	27116	26454	26100	24564	22760	21003
TEE	8/19/12	19772	18944	18358	18101	17945	18101	18295	19201	20759	22165	23478	24739	26006	27092	27946	28472	28872	28615	27817	27047	26636	24761	22484	20479
TEE	8/20/12	19308	18514	17964	17862	18509	20190	21475	22356	23350	24800	26139	27377	28428	29426	30092	30697	30977	30667	29691	28657	28245	26039	23554	21337
TEE	8/21/12	19950	19133	18561	18410	18903	20459	21729	22531	23452	24768	26262	27577	28427	29319	29905	30523	30643	30143	29244	28503	28152	25950	23454	21074
TEE	8/22/12	19921	18920	18521	18292	18616	20285	21452	22192	23338	24744	26394	27786	28764	30677	31462	32498	32943	32697	31492	30215	29489	27187	24365	22266
TEE	8/23/12	20740	19790	19116	18978	19406	20969	22017	22551	23924	25612	27518	29004	30480	31912	32994	33827	34214	33826	32606	31573	30765	28390	25527	23227
TEE	8/24/12	21727	20570	19705	19518	19808	21307	22525	23365	24872	26681	28531	30417	31938	32954	33881	34464	34495	33701	32045	30728	29731	27831	25548	23430
TEE	8/25/12	21844	20713	19977	19463	19456	19569	19755	20980	22846	24957	26872	28410	29645	30492	30892	31044	30835	30271	29266	28502	27867	26071	24077	22173
TEE	8/26/12	20727	19599	18931	18611	18557	18445	18790	20090	22254	24266	26297	28310	29981	31318	32280	32952	33289	33120	32039	31213	30160	27856	25449	23389
TEE	8/27/12	21836	20887	20305	19942	20412	22157	23738	24837	26425	28436	30761	32667	34071	35116	35882	36364	36542	36013	34717	33880	32837	30264	27291	25214
TEE	8/28/12	23742	22487	21760	21493	21854	23457	24985	25632	26782	28333	29977	31639	32966	34069	34832	35091	35059	34557	33407	32765	31943	29664	26994	24661

TEE Reserve Sharing Group>>>

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TEE	8/29/12	23101	21942	21241	20908	21364	23071	24328	25100	26536	28185	30252	31942	33492	34726	35480	36023	36038	35367	33948	33320	32368	29957	27300	24954
TEE	8/30/12	23357	22182	21427	21185	21496	23074	24541	25212	26317	27724	29349	30789	32030	32851	33427	33647	33572	33069	32144	32063	31534	29532	27227	25290
TEE	8/31/12	23828	22897	22150	21965	22489	24076	25661	26364	27573	28915	30461	31340	32105	32825	33489	33986	33865	33173	31935	31412	30642	28979	26869	24913
TEE	9/1/12	23405	22338	21629	21050	20963	21252	21476	22382	24231	26227	27897	29219	30354	31277	31973	32265	32397	32136	31126	30569	29482	27778	25879	24070
TEE	9/2/12	22532	21515	20925	20443	20320	20484	20712	21715	23392	24769	25792	26893	27784	28445	28969	29093	28956	28415	27555	27138	26379	25031	23413	21984
TEE	9/3/12	20733	19868	19461	19096	19229	19616	19895	20438	21957	23702	25019	26084	26694	27215	27824	28300	28711	28600	28287	28536	27922	26360	24309	22587
TEE	9/4/12	21478	20651	20204	20214	20891	22802	24651	25304	26334	27527	28888	30229	31385	32537	33431	34158	34441	34122	33274	33092	32157	29918	27323	25160
TEE	9/5/12	23550	22464	21808	21536	22020	23881	25391	26030	27271	28779	30560	32169	33719	35137	35974	36128	35831	34722	33217	32168	30771	28680	26205	23889
TEE	9/6/12	22496	21538	20925	20665	21060	22876	24357	24847	25683	27096	28700	30452	32148	33725	34911	35662	35814	35295	34128	33601	32241	29544	26858	24470
TEE	9/7/12	22851	21677	20899	20571	20956	22520	23936	24681	26116	28083	30401	32403	33981	35289	36236	36789	36720	35901	34298	33340	32058	30254	27731	25328
TEE	9/8/12	23613	22341	21031	20906	20764	21022	21388	21875	23010	23879	24372	24656	24711	24652	24628	24813	24952	24622	23881	23703	23230	21896	20444	18883
TEE	9/9/12	17721	17098	16639	16391	16343	16571	16692	17724	18982	19833	20587	21516	22433	23406	24216	25117	25749	25626	24912	25008	24362	22675	20787	19136
TEE	9/10/12	18101	17379	17195	17148	17886	19599	20920	21483	22295	23330	24296	24968	25683	26528	27303	27972	28320	27872	26914	26759	25966	24193	21972	20038
TEE	9/11/12	18974	18294	17856	17727	18314	20112	21386	21738	22473	23490	24554	25482	26541	27588	28405	29123	29469	29142	28100	28002	27140	25199	22785	21037
TEE	9/12/12	19679	18992	18516	18410	18988	20703	22255	22554	23169	23973	25038	26128	27224	28065	28682	29211	29294	28847	27847	27941	27073	25241	23113	21185
TEE	9/13/12	20005	19250	18791	18669	19221	20864	22414	22751	23381	24577	25904	26793	27706	28767	29311	29882	29886	29282	28336	28437	27589	25743	23392	21439
TEE	9/14/12	20135	19225	18756	18514	19020	20607	22026	22450	23287	24514	25850	26925	27614	28318	28714	28643	28382	27566	26489	26337	25521	24206	22677	20799
TEE	9/15/12	19595	18626	18055	17772	17812	18176	18597	19393	20642	21926	23001	24065	25112	26086	26681	26951	26845	26141	25223	25433	24538	23301	21697	20038
TEE	9/16/12	18898	18125	17755	17504	17446	17556	18086	18888	20333	21369	22409	23588	24793	25704	26232	26719	26951	26730	26321	26839	25852	24289	22372	20814
TEE	9/17/12	19848	19176	18791	18725	19415	21203	23166	23679	24161	24643	24938	25024	25017	24960	24753	24696	24812	24925	25244	25627	24930	23728	22201	20654
TEE	9/18/12	19667	19080	18696	18607	19200	21090	22769	23043	23233	23419	23683	23694	23629	23844	23861	23891	23868	23591	23220	23920	23312	21845	19998	18646
TEE	9/19/12	17795	17291	16935	16990	17695	19416	20958	21253	21521	21858	22171	22278	22280	22485	22745	23193	23473	23406	23057	23635	23045	21771	20049	18587
TEE	9/20/12	17714	17241	17067	17061	17729	19664	21248	21361	21697	21985	22384	22683	22971	23583	24144	24677	25073	24780	24290	24911	24322	22980	21104	19428
TEE	9/21/12	18456	17856	17443	17425	17998	19750	21213	21274	21865	22426	22989	23532	23866	24371	24774	25296	25390	24856	24187	24293	23635	22701	21251	19760
TEE	9/22/12	18570	17811	17405	17108	17226	17679	18272	18925	20303	21566	22718	23392	24062	24464	24794	25203	25135	24461	23452	23328	22306	21051	19462	18101
TEE	9/23/12	17136	16406	16137	15969	16083	16396	16772	17776	18883	19220	19362	19744	20197	20306	20671	21001	21421	21501	21555	22302	21604	20374	18821	17740
TEE	9/24/12	17054	16769	16699	16991	17850	19924	21653	22023	22215	22332	22451	22392	22276	22354	22506	22786	22987	22843	23003	23840	23229	21977	20329	18977
TEE	9/25/12	18231	17750	17582	17669	18498	20409	22126	22145	22498	22914	23136	23276	23574	24056	24425	24845	25188	25101	25282	25823	25164	23852	22071	20405
TEE	9/26/12	19340	18725	18391	18361	18870	20516	22267	22334	22874	23708	24563	25305	25981	26877	27629	28129	28357	27932	27379	27459	26374	24662	22530	20778
TEE	9/27/12	19568	18890	18372	18246	18850	20664	22381	22681	23243	23956	25041	25956	26719	27580	28285	28740	28817	28216	27811	27920	26973	25318	23194	21302
TEE	9/28/12	20176	19442	18987	18791	19454	21085	22879	23108	23597	24313	25058	25682	26106	26449	26513	26480	26249	25624	25246	25269	24502	23513	22092	20610
TEE	9/29/12	19461	18745	18217	17914	17906	18243	18945	19578	20770	21624	22283	22842	23386	23834	24241	24455	24373	23762	23470	23593	22736	21509	20009	18689
TEE	9/30/12	17742	16920	16592	16465	16356	16695	17205	17884	19128	19712	19971	20425	20907	20965	21180	20955	21521	21720	22534	22965	22249	21034	19604	18510
TEE	10/1/12	17687	17261	16980	17041	17952	19557	21518	22009	22464	22921	23124	23140	23125	22873	22832	22877	23008	23089	23766	23933	23469	22411	20802	19392
TEE	10/2/12	18457	17882	17590	17620	18235	20119	21959	21374	23200	22898	23247	23489	23413	23582	23417	23387	23372	23236	23703	24040	23476	22118	20596	19290

TEE Reserve Sharing Group>>>

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TEE	10/3/12	18409	17889	17617	17607	18252	20042	21584	21674	21928	22369	22839	22965	23190	23648	23894	24152	24059	23736	24115	24466	23766	22448	20861	19345
TEE	10/4/12	18410	17855	17412	17431	18099	19936	21603	21790	22190	22800	23372	23957	24485	25004	25491	25826	25915	25421	25343	25514	24570	22909	21208	19749
TEE	10/5/12	18631	18008	17726	17726	18203	19843	21561	21688	22245	22967	23717	24343	24628	25269	25544	25694	25488	24931	24623	24272	23302	22110	20698	19162
TEE	10/6/12	18056	17414	16888	16712	16949	17460	18172	18749	19689	20421	20657	20503	20327	20144	20018	19953	20127	20371	21199	21503	20913	20063	19079	18091
TEE	10/7/12	17339	16956	16701	16674	16826	17183	17907	18775	19931	20319	20244	20207	20060	19875	19748	19652	19832	20136	21386	22191	21704	20801	19777	18867
TEE	10/8/12	18245	17993	17922	18076	18955	20812	22676	23191	23604	23850	23883	23543	23129	22778	22456	22294	22379	22630	23695	24205	23517	22634	21386	20251
TEE	10/9/12	19635	19314	19219	19401	20156	22068	23989	24003	23943	23654	23324	22862	22496	22221	21893	21714	21785	21795	22806	23551	23046	21893	20617	19556
TEE	10/10/12	18910	18432	18382	18464	19188	20843	22649	22731	22830	22864	22775	22421	22161	22143	21965	21724	21882	21924	22799	23381	23131	22196	20961	19798
TEE	10/11/12	19302	19078	19094	19418	20364	22512	24296	24505	24078	23626	23233	22714	22344	22191	22022	21976	21791	22023	23006	23507	22902	21783	20593	19390
TEE	10/12/12	18675	18258	18103	18097	18652	20422	22234	22522	22668	23012	23076	22881	22399	22390	22283	22096	22039	22052	22575	22545	22211	21400	20364	19228
TEE	10/13/12	18543	17967	17749	17702	17894	18478	19336	19892	20600	21045	21167	21228	21216	21349	21511	21689	21743	21775	22454	22584	22036	21198	20006	18835
TEE	10/14/12	17894	17193	16825	16624	16751	17203	17772	18426	19486	19993	20153	20498	20611	20723	20827	20936	21343	21675	22727	23024	22241	21277	19793	18607
TEE	10/15/12	17705	17232	17023	17057	17656	19483	21363	21626	21976	22468	22824	22788	23031	23164	23168	23066	23093	22917	23706	23904	23170	22024	20411	19136
TEE	10/16/12	18353	18037	17918	18075	19032	21104	23067	23222	22957	22824	22725	22528	22372	22401	22377	22331	22422	22378	23610	23855	23064	21859	20484	19116
TEE	10/17/12	18307	17811	17667	17778	18634	20513	22337	22436	22346	22493	22550	22582	22574	22744	22886	23016	23115	23052	23922	23992	23270	21895	20434	19081
TEE	10/18/12	18332	17774	17496	17556	18267	19970	21924	22125	22367	22452	22522	22545	22622	22471	22325	22181	22111	22176	23175	23494	22951	21875	20435	19169
TEE	10/19/12	18515	18144	17990	18177	19045	21007	22885	22888	22765	22777	22563	22318	21913	21903	21694	21530	21609	21891	22611	22478	22047	21365	20272	19101
TEE	10/20/12	18346	17899	17680	17644	18012	18686	19636	20328	20947	21269	21128	20870	20615	20383	20132	20212	20367	20502	21403	21537	21136	20369	19382	18584
TEE	10/21/12	18033	17624	17556	17604	17967	18544	19453	20294	20873	20504	19935	19880	19840	19980	20095	20473	20694	21055	22163	22370	21571	20517	19241	18147
TEE	10/22/12	17527	17219	17108	17313	18189	20236	22252	22381	22585	22771	22913	22995	23176	23530	23799	23974	23994	23857	24703	24602	23584	22192	20630	19116
TEE	10/23/12	18089	17492	17358	17444	18260	20253	22240	22278	22482	22738	22969	23193	23380	23742	23990	24182	24196	24039	24784	24628	23714	22384	20574	19125
TEE	10/24/12	18178	17630	17410	17507	18135	20131	22159	22259	22282	22499	22811	23118	23450	23995	24306	24628	24730	24356	24846	24575	23739	22148	20395	19003
TEE	10/25/12	18069	17531	17307	17312	18071	19994	21844	21937	22067	22346	22753	23055	23488	23893	24162	24334	24364	24003	24607	24709	23992	22509	20643	18865
TEE	10/26/12	17984	17482	17226	17196	17909	19685	21555	21733	21960	22309	22533	22492	22580	22528	22472	22526	22569	22771	23285	22908	22441	21746	20557	19429
TEE	10/27/12	18432	17962	17713	17795	18098	18701	19664	20717	21570	22227	22329	22046	21850	21458	21272	21335	21411	21825	22812	22688	22076	21365	20397	19576
TEE	10/28/12	18882	18474	18159	18146	18367	18976	19917	20901	21773	22003	21793	21470	21399	21344	21157	21115	21537	22141	23658	23909	23395	22592	21408	20493
TEE	10/29/12	20097	19901	20062	20527	21566	23866	26281	26562	26292	26042	25481	25196	24630	24352	23957	23980	24322	25215	26695	26656	26253	25183	23662	22863
TEE	10/30/12	21900	21644	21568	21866	22914	25041	27089	27152	26920	26798	26544	26003	25461	25036	24694	24697	24849	25488	26792	26696	26284	25012	23721	22679
TEE	10/31/12	21963	21680	21795	21994	22996	25131	27070	27344	26744	25933	25171	24530	23968	23419	23040	22863	22769	23020	24050	24382	24567	24178	23095	22121
TEE	11/1/12	21662	21628	21823	22124	23275	25575	27756	27849	27051	25863	24904	24159	23726	23159	22707	22628	22814	23326	25110	25326	24999	23842	22414	21360
TEE	11/2/12	20706	20357	20172	20247	21104	23137	25024	24966	24444	23730	23167	22696	22446	21991	21675	21672	21689	21878	23084	23069	22688	22155	21197	20386
TEE	11/3/12	19732	19680	19672	19853	20522	21398	22544	23299	23588	23242	22672	22185	21757	21474	21247	21387	21625	22202	22895	22773	22196	21345	20284	19192
TEE	11/4/12	18342	31275	17441	17553	17957	18757	19740	21042	21938	21805	21130	20699	20494	20263	20210	20306	20945	22681	23495	23557	23160	22500	21599	20930
TEE	11/5/12	20787	20908	21206	21575	22640	24837	26941	26936	26381	25410	24804	24162	23735	23427	23229	23341	24280	25706	26267	25984	25350	24324	22882	21916
TEE	11/6/12	21274	20968	20890	20974	21549	23522	25107	25351	25368	25106	24860	24388	24264	24172	24009	24110	24901	26110	26576	26207	25513	24410	23035	21917

TEE Reserve Sharing Group>>>

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TEE	11/7/12	21049	20708	20488	20451	21060	22942	24820	24920	24704	24529	24522	24399	24257	24124	24014	24216	25059	26516	26953	26662	25934	24957	23677	22687
TEE	11/8/12	22355	22323	22500	22890	23750	25950	27967	27822	26733	25582	24867	24099	23674	23253	22770	22817	23561	25335	26126	26231	26199	25276	24196	23433
TEE	11/9/12	23019	23040	23113	23428	24259	26383	28215	27961	26548	25175	24310	23549	23041	22565	22183	21908	22377	23663	24055	23832	23433	22984	22115	21180
TEE	11/10/12	20477	20125	20077	20270	20703	21551	22269	22802	22791	22346	21680	21213	20706	20498	20364	20314	20828	21978	22162	21953	21473	20732	19837	18962
TEE	11/11/12	18443	18184	18152	18353	18696	19311	19869	20695	21178	20860	20222	20044	20090	19897	19712	19697	20527	22008	22292	22004	21575	20570	19469	18378
TEE	11/12/12	17715	17423	17224	17255	17617	19274	21315	22174	22621	23104	23409	23649	23644	23583	23434	23594	24436	26144	26837	26834	26477	25690	24726	23850
TEE	11/13/12	23365	23377	23510	23737	24850	27204	29341	29082	27918	26776	25837	25030	24413	23924	23663	23793	24780	26829	27900	28094	27984	27162	25885	24898
TEE	11/14/12	24512	24418	24543	24663	25415	27361	29149	28872	27866	26800	25947	25139	24634	24197	23995	24193	25259	27142	27671	27602	27227	26365	25091	24130
TEE	11/15/12	23751	23588	23796	24157	25014	27133	29249	29117	27653	26149	25115	24021	23578	23222	22860	22866	23704	25757	26400	26641	26546	25828	24710	23788
TEE	11/16/12	23449	23278	23527	23889	24761	26930	28937	28762	27363	26119	24936	24045	23430	22960	22561	22336	23321	24859	25381	25378	25230	24726	24145	23316
TEE	11/17/12	22908	22828	22777	23127	23754	24773	25695	26263	25865	24803	23750	22754	22045	21392	20909	20908	21567	23083	23710	23849	23793	23384	22762	22182
TEE	11/18/12	21861	21796	21946	22255	22704	23437	24458	25210	24829	23644	22301	21445	20901	20577	20348	20360	21239	23064	23659	23850	23676	23074	22237	21611
TEE	11/19/12	21185	21418	21676	22102	23082	25302	27392	27464	26327	25163	24369	23585	23052	22810	22495	22432	23062	24745	25351	25246	24850	24024	22834	21552
TEE	11/20/12	21010	20628	20343	20445	21048	22776	24660	25021	24484	23869	23390	22899	22833	22564	22342	22280	22821	24123	24419	24170	23764	22849	21543	20281
TEE	11/21/12	19575	19114	19005	19121	19814	21349	22936	23732	23746	23365	23111	22653	22527	22311	21958	21752	22094	23378	23672	23414	23062	22451	21321	20254
TEE	11/22/12	19429	19003	19067	19339	19898	20795	21669	22541	22846	22907	22503	21575	20193	19144	18494	18078	18293	19229	19552	19583	19460	19263	18689	18200
TEE	11/23/12	17862	17794	17773	17895	18244	18941	19666	20196	20545	20747	20871	20784	20514	20220	19957	19965	20698	22282	22720	22919	22828	22541	21974	21407
TEE	11/24/12	21101	21065	21140	21565	22229	23169	24185	24927	25304	25157	24512	23703	22966	22336	22025	22216	23588	25618	26417	26772	26845	26650	25918	25495
TEE	11/25/12	25083	24910	25059	25198	25583	26223	26869	27375	26718	25476	23963	22735	22081	21560	20992	21039	22234	24261	25128	25291	25031	24452	23310	22644
TEE	11/26/12	22281	22188	22238	22510	23214	25016	27124	27195	26367	25786	25073	24446	24158	23790	23638	23861	24860	26214	26533	26175	25690	24623	23008	21812
TEE	11/27/12	20973	20650	20690	20780	21344	23405	25595	26127	26143	26314	26500	26478	26313	26108	25945	26125	27113	28771	29030	29123	28729	27678	26212	25178
TEE	11/28/12	24611	24528	24530	24689	25577	27686	29868	29928	28989	27809	26595	25608	25066	24492	24123	24203	25547	27886	28832	29209	29307	28664	27561	26579
TEE	11/29/12	26125	26094	26367	26628	27540	29534	31593	31458	29904	27982	26434	25227	24474	23883	23430	23479	24609	26657	27422	27717	27620	26976	25582	24524
TEE	11/30/12	24065	23702	23846	24025	24679	26597	28444	28393	27225	25881	24893	23923	23229	22798	22294	22133	23164	24663	25107	24924	24801	24235	23206	22241

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Dec 2011-Nov 2012 Load

TVAPe	**Max**	31,098
TVAAv	**Avg Jun**	25,349
TVAW	**Winter**	21,983
TVASp	**Spring**	20,815
TVASu	**Summer**	26,262
TVAFa	**Fall**	20,415

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TVA	12/1/11	21283	21324	21471	21851	22446	23998	25541	25071	23572	22191	20921	19953	19166	18629	18280	18480	19649	21323	21828	22263	22191	21876	21183	20552
TVA	12/2/11	20147	20183	20291	20766	21430	22866	24400	23846	22495	20977	19780	19161	18575	18020	17707	17818	18735	19905	20063	20220	20248	19983	19383	18581
TVA	12/3/11	18199	17972	17936	18086	18576	19100	19791	20252	20069	19316	18551	17755	17201	16828	16711	16823	17704	18942	19023	18966	18753	18184	17266	16608
TVA	12/4/11	16064	15815	15726	15791	15991	16429	16798	17356	17679	17424	16978	16653	16590	16491	16455	16646	17718	18742	18573	18459	17940	17226	16076	15280
TVA	12/5/11	14808	14563	14499	14644	15327	16743	18389	18646	18669	18624	18651	18635	18760	18714	18769	19035	19953	20835	20880	20484	19934	19134	17875	16635
TVA	12/6/11	16062	15939	15907	15920	16532	18010	19710	19969	19809	19868	19858	19853	19798	19790	19628	19966	21147	21879	21865	21616	21253	20242	18913	17919
TVA	12/7/11	17199	17011	17002	17171	17816	19205	20993	21280	21427	21639	21897	22011	22142	22073	22092	22563	23597	24666	24667	24550	24134	23420	22277	21448
TVA	12/8/11	21223	21175	21188	21556	22257	23856	25505	25113	23792	22706	21588	20907	20327	19931	19586	19796	21198	22945	23582	23878	23892	23394	22136	21497
TVA	12/9/11	21300	21261	21381	21746	22470	24053	25618	25301	24022	22481	21108	20111	19614	19262	19136	19485	20549	21940	22185	22153	22084	21587	20812	20042
TVA	12/10/11	19562	19526	19549	19891	20177	20906	21763	22381	22662	22220	21509	20613	19900	19385	19009	19259	20636	22375	22724	22953	22965	22688	22038	21448
TVA	12/11/11	21188	20942	21160	21337	21703	22359	23158	23732	23225	21754	20314	19363	18706	18219	17876	18193	19515	21240	21795	22203	22069	21568	20151	20512
TVA	12/12/11	19615	19630	19694	19849	20414	21820	23381	23199	22476	21631	21007	20478	19987	19692	19486	19697	20766	21895	21973	21709	21183	20126	18748	17663
TVA	12/13/11	17065	16836	16651	16757	17299	18648	20148	20086	19815	19650	19596	19380	19101	18873	18629	18717	19647	20958	21069	20916	20482	19582	18355	17259
TVA	12/14/11	16681	16484	16346	16522	17165	18652	20228	20038	19475	18985	18558	18309	18047	17829	17669	17570	18505	19874	19819	19559	19297	18366	17336	16252
TVA	12/15/11	15466	15208	15002	15141	15607	16917	18505	18541	18274	18179	18140	18213	18089	18014	17819	17967	18806	19643	19568	19437	18963	18147	17040	16091
TVA	12/16/11	15614	15360	15287	15529	16063	17523	19493	19780	19926	20073	20390	20389	20335	20157	20028	20278	21023	21925	21678	21521	21196	20726	19960	19069
TVA	12/17/11	18589	18406	18311	18527	18935	19711	20542	21461	21804	21309	20469	19697	18957	18217	17957	18123	19378	21078	21409	21527	21554	21269	20810	20268
TVA	12/18/11	19886	19778	19843	20028	20463	21058	21904	22418	21987	20790	19261	18388	17703	17303	17079	17196	18547	20173	20542	20716	20769	20282	19647	19089
TVA	12/19/11	18729	18705	18906	19315	19996	21333	22733	22871	22064	21271	20550	20007	19507	19084	18861	19049	19881	21290	21438	21514	21186	20431	19401	18470
TVA	12/20/11	17579	17043	17107	17188	17587	18568	19763	20028	19995	19930	19802	19442	19100	19021	18826	18906	19729	20411	20237	19941	19407	18448	17312	16289
TVA	12/21/11	15574	15161	14955	14941	15346	16436	17693	18074	18339	18550	18657	18643	18592	18418	18277	18328	19005	20066	20048	19853	19571	18979	18045	17046
TVA	12/22/11	16465	16115	16008	16085	16384	17319	18509	18999	19153	19380	19570	19625	19524	19436	19368	19436	19999	20612	20494	20203	19850	19148	18145	17161
TVA	12/23/11	16453	15975	15922	15981	16183	16870	17780	18522	19292	19575	19594	19447	19265	19037	18982	19107	19881	20534	20399	20166	19993	19483	18752	17849
TVA	12/24/11	17218	16820	16655	16574	16745	17386	18137	18908	19427	19277	18700	18038	17349	16846	16533	16637	17362	18491	18648	18763	18872	18731	18279	17660
TVA	12/25/11	17223	16845	16595	16565	16724	17088	17719	18348	18854	18707	18087	17607	16950	16143	15558	15399	16098	17354	17735	18102	18268	18228	17893	17492
TVA	12/26/11	17277	17263	17385	17741	18225	18970	19685	20060	20449	20254	19999	19669	19197	18907	18802	18979	19714	20631	20658	20494	20011	19307	18536	17607
TVA	12/27/11	16899	16575	16341	16494	16892	17624	18637	19317	19902	20386	20673	20850	20730	20577	20393	20486	21148	22155	22066	21833	21348	20543	19702	18895

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TVA	12/28/11	18536	18447	18529	18798	19340	20530	21755	22149	21703	20810	19997	19439	18903	18511	18280	18369	19440	21227	21638	21776	21731	21219	20612	19974
TVA	12/29/11	19657	19522	19586	19818	20310	21324	22536	22770	22132	21046	20015	19309	18628	18185	17734	17693	18513	20154	20385	20329	20063	19471	18522	17734
TVA	12/30/11	17223	16863	16787	16793	17123	17895	18715	18768	18774	18553	18277	17952	17411	17006	16891	16850	17322	18581	18586	18381	18111	17684	16954	16255
TVA	12/31/11	15726	15480	15571	15785	16166	16771	17555	18122	18206	17756	17326	16995	16511	16066	15788	15829	16659	18122	18188	17902	17499	17089	16708	16218
TVA	1/1/12	15878	15584	15263	14958	14859	14989	15262	15658	16202	16202	16155	16062	16010	15726	15532	15635	16376	17963	18296	18269	18162	18160	17719	17254
TVA	1/2/12	17029	17078	17293	17662	18335	19436	20378	20792	21086	21317	21336	21151	20912	20785	20852	21396	22909	24523	24901	24900	24759	24144	23433	22816
TVA	1/3/12	22465	22409	22604	22948	23656	25101	26744	26753	26074	25505	24963	24284	23500	22888	22335	22283	23545	25657	26300	26431	26187	25549	24688	23982
TVA	1/4/12	23778	23636	23711	23992	24624	25881	27240	26894	25534	24257	23050	22133	21241	20775	20265	20300	21219	22890	23257	23133	22899	22193	21068	20230
TVA	1/5/12	20048	20027	20203	20689	21377	22965	24679	24620	23396	21854	20778	19908	19377	18890	18426	18372	19081	20871	21400	21565	21519	21033	20032	19334
TVA	1/6/12	19076	19006	19059	19434	20151	21855	23574	23387	22073	20882	19805	19130	18606	18196	17713	17509	18066	19385	19406	19299	19090	18516	17453	16573
TVA	1/7/12	16072	15660	15394	15311	15466	15860	16350	16890	17552	17880	18022	17799	17584	17343	17229	17236	17764	18774	18666	18434	18163	17579	16801	16087
TVA	1/8/12	15689	15543	15417	15461	15674	16121	16817	17547	18313	18326	17934	17790	17794	17732	17573	17884	18591	19637	19624	19502	19039	18229	17225	16303
TVA	1/9/12	15882	15678	15566	15741	16373	17874	19650	19694	19592	19531	19497	19266	19155	18989	18874	19069	19846	20810	20852	20347	19694	18932	17937	17094
TVA	1/10/12	16558	16282	16217	16436	17012	18398	20001	20251	20026	19747	19531	19334	19201	19165	19005	19225	20012	20926	20998	20582	20011	18882	17828	16870
TVA	1/11/12	16256	15915	15673	15513	15953	17350	18891	18975	18770	18709	18813	18810	18937	19000	19013	19363	20035	20911	20922	20630	20458	19504	18300	17303
TVA	1/12/12	16770	16469	16397	16507	17063	18493	20296	20471	20382	20548	20777	21144	21422	21931	22243	22899	23850	25355	26023	26156	25921	25024	23937	23121
TVA	1/13/12	22986	22911	22856	23118	23653	24853	26194	26461	26265	25967	25570	25061	24512	23800	23374	23395	24026	25277	25399	25217	24869	24228	23695	23140
TVA	1/14/12	22898	22843	22676	23102	23482	24285	25006	25284	24884	24081	23020	22103	21137	20383	19619	19470	19972	21543	21777	21642	21250	20866	20173	19597
TVA	1/15/12	19414	19309	19464	19688	20111	20896	21847	22750	22674	21640	20446	19618	18995	18354	18041	18115	18935	20832	21322	21577	21450	20972	20342	19864
TVA	1/16/12	19494	19206	19128	19158	19317	20103	21002	21344	21202	21379	21302	21211	20886	20501	20212	20028	20480	21447	21280	20822	20033	19086	17984	17008
TVA	1/17/12	16526	16090	16014	16011	16391	17739	19333	19377	19137	19049	19047	19022	18903	18770	18685	18883	19472	20423	20892	20775	20563	20063	19393	18803
TVA	1/18/12	18689	18837	19087	19542	20305	22021	23837	23915	23734	23355	22879	22355	21739	21298	20849	21043	22071	23963	24470	24431	24173	23630	22722	22043
TVA	1/19/12	21851	21761	21867	22142	22816	24441	26085	25712	24650	23695	22829	21989	21395	20707	20104	20047	20662	22125	22562	22365	21950	20997	19859	18837
TVA	1/20/12	18207	17969	17776	17920	18364	19750	21279	21185	20925	20747	20516	20149	19905	19698	19485	19440	19682	20374	20424	19901	19249	18548	17674	16595
TVA	1/21/12	15940	15519	15432	15509	15837	16331	17090	17963	18673	19580	19937	20078	19977	19791	19686	19793	20273	21085	21094	20898	20480	19873	19062	18316
TVA	1/22/12	17662	17344	17191	17179	17343	17605	18276	18964	19390	19258	18661	18372	18094	17887	17704	17799	18265	19120	19292	18980	18438	17624	16719	15811
TVA	1/23/12	15286	15023	14873	15060	15669	17050	18699	18779	18771	18729	18568	18378	18267	18004	17741	17853	18402	19758	20221	20141	19813	19136	18255	17359
TVA	1/24/12	17095	17185	17347	17706	18615	20350	22245	22117	21228	20145	19418	18951	18459	18197	17985	17880	18277	19891	20656	20841	20624	20046	19206	18494
TVA	1/25/12	18169	18006	18079	18283	18924	20423	22036	21777	21081	20434	19860	19552	19242	18939	18636	18658	19085	20334	20676	20378	19906	18989	17874	16854
TVA	1/26/12	16284	15904	15636	15580	16038	17325	18775	18782	18552	18707	18832	18840	18628	18454	18281	18682	19144	19954	20175	19878	19391	18504	17453	16564
TVA	1/27/12	16155	16027	15981	16318	16875	18483	20365	20445	20257	20003	19872	19583	19154	18770	18413	18252	18581	19921	20466	20435	20416	20014	19491	18802
TVA	1/28/12	18469	18297	18314	18365	18623	19143	19748	20189	20416	20032	19549	19063	18590	18067	17675	17587	18281	19819	20514	20628	20652	20655	20286	19968
TVA	1/29/12	19830	19885	20194	20517	20966	21610	22400	22907	22377	20993	19687	18838	18314	17887	17468	17393	18018	19619	20522	20793	20793	20377	19609	19016
TVA	1/30/12	18956	18954	19278	19708	20579	22230	23835	23669	22241	20994	20073	19516	19022	18580	18185	18152	18394	19995	20768	20681	20525	19777	18842	18007
TVA	1/31/12	17709	17580	17584	17773	18376	19932	21489	21160	20414	19703	19233	18852	18507	18224	17880	17882	18183	19459	20057	19963	19457	18495	17308	16442

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TVA	2/1/12	15981	15699	15417	15378	15861	17244	18758	18564	18389	18328	18338	18307	18254	18149	18004	18071	18528	19416	19560	19269	18818	17959	16822	15902
TVA	2/2/12	15431	15102	15030	15265	15790	17369	19198	19106	18818	18496	18240	18018	17838	17679	17562	17486	17663	18898	19652	19653	19564	18879	17944	17222
TVA	2/3/12	17017	17015	17046	17405	18122	19700	21431	21205	20347	19508	18980	18589	18416	18183	17907	17929	18169	19108	19359	19238	18827	18262	17438	16545
TVA	2/4/12	15913	15446	15336	15404	15558	15863	16498	17266	18057	18469	18558	18380	18015	17739	17551	17554	17887	18560	18518	18255	17670	17074	16285	15451
TVA	2/5/12	14880	14599	14509	14390	14596	15039	15665	16454	17345	17463	17216	17086	17119	17159	17113	17300	17675	18511	18657	18597	18348	18271	17604	16824
TVA	2/6/12	16418	16302	16311	16515	17259	18897	20692	20758	20418	20001	19752	19420	19106	18825	18626	18730	19133	20202	21213	21349	21270	20731	19909	19164
TVA	2/7/12	19003	19034	19274	19622	20515	22362	24072	23732	22378	20857	19782	19087	18681	18339	17961	18024	18638	20097	20867	20887	20748	20071	18919	17904
TVA	2/8/12	17438	17271	17089	17357	18036	19642	21279	21168	20868	20611	20325	20202	20172	20231	20226	20561	21271	22481	22933	22780	22410	21654	20476	19592
TVA	2/9/12	19181	19096	19040	19274	19812	21435	23084	22966	22580	22102	21600	21112	20583	20165	19662	19652	20215	21804	23017	23160	23128	22539	21701	21055
TVA	2/10/12	20765	20717	20781	21028	21562	22954	24473	24368	23838	23128	22364	21746	21293	21112	20875	21084	21694	22663	22848	22435	22074	21394	20604	19948
TVA	2/11/12	19598	19493	19656	19974	20529	21455	22452	23620	24676	25155	25166	24771	24219	23612	23221	23162	23812	25262	26151	26213	26070	25601	25018	24490
TVA	2/12/12	24224	24130	24230	24330	24668	25259	25795	26187	25885	24726	23280	22219	21444	20605	20075	19966	20466	22173	23611	24162	23978	23688	23165	22665
TVA	2/13/12	22752	22924	23348	23883	24611	26507	28012	27421	25968	24780	23882	23193	22637	22306	22040	22128	22589	23638	24216	24073	23579	22843	21564	20527
TVA	2/14/12	19941	19668	19581	19717	20153	21506	23054	22973	22678	22434	22295	21994	21876	21567	21399	21337	21644	22509	22764	22400	22012	20988	19905	18948
TVA	2/15/12	18460	18166	18125	18265	18886	20540	21963	21758	21075	20416	19812	19257	18925	18639	18465	18568	18954	20004	20554	20436	20044	19241	18040	17003
TVA	2/16/12	16441	16182	16074	16143	16404	17847	19476	19416	19312	19316	19197	19107	18818	18506	18312	18378	18683	19589	20331	20311	19940	19257	18311	17405
TVA	2/17/12	17048	17003	17107	17300	17916	19521	21119	21131	20667	20000	19490	18993	18520	18082	17706	17701	18027	18935	19659	19519	19119	18685	18035	17284
TVA	2/18/12	16816	16570	16513	16744	17191	17871	18727	19228	19301	19160	18752	18339	17967	17863	17725	17888	18174	18974	19351	19138	18830	18314	17651	16830
TVA	2/19/12	16362	16200	16101	16180	16492	17051	17947	18934	19931	20250	20285	20374	20331	20051	19866	19783	20031	21007	21814	21860	21802	21461	20819	20340
TVA	2/20/12	20173	20202	20558	20911	21719	23164	24425	24523	23675	22698	21859	20988	20319	19731	19170	18882	19056	20051	21517	21688	21533	21019	19902	18995
TVA	2/21/12	18533	18331	18196	18224	18657	20094	21438	21223	20651	20100	19785	19467	19007	18673	18245	18141	18326	19189	20416	20441	20172	19445	18620	17853
TVA	2/22/12	17573	17627	17684	17905	18452	19860	21183	20762	20203	19787	19536	19283	19097	18904	18640	18550	18991	19693	20278	20034	19673	18787	17647	16601
TVA	2/23/12	15893	15658	15491	15587	16099	17570	19027	18855	18460	18195	18085	17999	18053	18012	17841	18051	18091	18723	19694	19506	18983	18066	16767	15614
TVA	2/24/12	14980	14612	14372	14302	14761	16063	17461	17840	17954	18226	18468	18430	18331	18236	18242	18485	18919	19629	20540	20620	20527	20022	19503	18906
TVA	2/25/12	18676	18572	18661	18939	19439	20179	20949	21138	20845	20457	19935	19317	18633	18086	17567	17574	17862	18897	20284	20532	20581	20445	19935	19483
TVA	2/26/12	19246	19119	19225	19422	19907	20702	21292	21489	20819	19721	18536	17875	17373	16906	16539	16448	16684	17606	18964	19352	19104	18649	17816	17300
TVA	2/27/12	16883	16727	16651	16848	17470	18951	20427	20275	19653	19175	18953	18561	18383	18141	17752	17777	17936	18558	19755	19697	19110	18390	17344	16500
TVA	2/28/12	16228	16413	16268	16450	17196	18957	20691	20263	19328	18725	18278	17971	17864	17764	17759	17774	18072	18668	19554	19418	18938	17863	16724	15631
TVA	2/29/12	14797	14630	14539	14600	14920	16028	17499	17628	17708	17769	17903	17958	17915	17867	17697	17883	18131	18623	19171	18806	18301	17482	16185	15089
TVA	3/1/12	14528	14183	14114	14250	14783	16264	17838	17856	17573	17356	17316	17324	17246	17258	17206	17348	17378	17626	18787	18850	18400	17693	16623	15720
TVA	3/2/12	15149	14848	14695	14757	15206	16525	17808	17675	17843	18027	18115	18240	18160	18085	17857	17473	17141	17302	17643	17306	17002	16209	15434	14730
TVA	3/3/12	14198	14111	14149	14346	14857	15712	16634	17646	18152	18110	17864	17363	16967	16567	16305	16299	16601	17345	18485	18506	18365	17911	17415	16952
TVA	3/4/12	16653	16710	16760	17044	17500	18284	18944	19476	19423	18762	18219	18033	17823	17593	17278	17279	17553	18407	19653	19794	19576	18900	18002	17218
TVA	3/5/12	16720	16692	16681	16928	17686	19421	20989	20987	20663	20328	19922	19531	19190	18862	18499	18433	18579	19544	21217	21625	21443	20964	20012	19296
TVA	3/6/12	19209	19213	19355	19648	20264	21736	22977	22160	20874	19928	19276	18736	18328	17887	17567	17495	17544	18233	19645	19822	19448	18475	17510	16582

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TVA	3/7/12	16248	16159	16078	16287	16823	18223	19332	18957	18221	17946	17711	17581	17520	17441	17364	17476	17475	17934	19035	19021	18566	17676	16512	15517
TVA	3/8/12	14880	14583	14565	14719	15106	16422	17714	17907	17936	17989	17885	17985	18225	18169	18068	18157	18570	19215	19802	19623	19165	18206	17110	16268
TVA	3/9/12	15863	15685	15548	15882	16709	18361	19833	20188	19971	19639	19290	18914	18488	17939	17583	17304	17343	17890	19107	19230	19122	18816	18135	17529
TVA	3/10/12	17280	17219	17376	17545	17989	18708	19324	19549	19259	18737	18054	17442	16828	16347	16051	15875	16030	16441	17624	17746	17481	17106	16502	15962
TVA	3/11/12	15732	15688	0	15710	16028	16601	17274	17794	17913	17431	17017	16684	16507	16122	15813	15792	15925	16132	16740	17830	17533	16823	16008	15050
TVA	3/12/12	14355	14085	13983	13999	14379	15647	17057	17470	17468	17742	17979	18013	18024	17994	17755	17732	17795	17912	18080	18888	18647	17739	16514	15335
TVA	3/13/12	14587	14159	13902	13949	14246	15492	16842	17066	17088	17308	17541	17734	17936	18116	18239	18447	18568	18618	18539	19507	19246	18273	16808	15584
TVA	3/14/12	14665	14185	13938	13913	14263	15472	16957	17109	17179	17432	17787	18271	18754	19076	19195	19457	19600	19574	19408	19888	19544	18530	17023	15647
TVA	3/15/12	14839	14266	14037	13959	14409	15543	16989	17136	17376	17830	18393	19017	19734	20058	20106	20015	19800	19526	19624	19819	19507	18428	17040	15777
TVA	3/16/12	15035	14462	14220	14151	14337	15452	16824	17158	17359	17656	18001	18301	18469	18507	18516	18503	18475	18337	18180	18611	18361	17618	16549	15383
TVA	3/17/12	14474	13955	13559	13522	13697	14052	14594	15053	15984	16728	17216	17591	17888	17965	18006	17964	18085	17985	17932	18364	18034	17309	16262	15196
TVA	3/18/12	14324	13809	13410	13237	13349	13585	13981	14492	15545	16098	16318	16758	17429	17886	18245	18676	19052	19003	18767	19437	19109	18097	16688	15500
TVA	3/19/12	14666	14210	13927	13805	14186	15366	17029	17382	17536	17967	18499	18967	19650	20068	20536	20900	21009	20801	20640	21178	20651	19362	17702	16202
TVA	3/20/12	15333	14761	14431	14187	14451	15560	17106	17206	17426	18070	18713	19432	20175	20800	21290	21640	21598	21231	20757	21316	20854	19684	17884	16370
TVA	3/21/12	15402	14802	14391	14145	14404	15601	17038	17139	17402	18006	18716	19433	19973	20337	20375	20347	20239	19968	19899	20282	19957	18939	17336	15951
TVA	3/22/12	15290	14766	14372	14290	14495	15625	17100	17453	17606	18016	18350	18690	18755	18987	18929	19001	18926	18846	18840	19298	19190	18249	16773	15557
TVA	3/23/12	14803	14378	14228	14129	14312	15509	17011	17260	17319	17755	18113	18402	18647	18846	18893	18918	18852	18531	18250	18556	18344	17649	16513	15355
TVA	3/24/12	14480	13958	13616	13528	13576	13806	14310	14978	15744	16463	16672	16687	16613	16509	16459	16299	16421	16427	16318	16934	16981	16481	15506	14660
TVA	3/25/12	13994	13573	13374	13221	13291	13662	14255	15049	15708	16028	15883	15864	16069	16209	16195	16381	16611	16825	17073	17889	17903	17137	15927	14845
TVA	3/26/12	14016	13716	13546	13457	14098	15540	16991	17163	17404	17574	17957	18248	18621	18629	18968	19316	19583	19583	19399	19958	19723	18461	16992	15597
TVA	3/27/12	14722	14224	14058	13914	14192	15593	17037	17169	17247	17340	17460	17821	18217	18694	19120	19596	19948	19897	19667	20088	19792	18578	16887	15597
TVA	3/28/12	14820	14330	14096	14042	14421	15612	16767	16933	17132	17554	18160	18759	19372	19925	20348	20698	20755	20718	20266	20574	20202	19067	17447	16057
TVA	3/29/12	15107	14641	14262	14137	14449	15551	16950	17059	17313	17897	18499	19200	19764	20281	20572	20842	20977	20732	20368	20707	20439	19200	17634	16172
TVA	3/30/12	15053	14721	14286	14180	14321	15523	16826	17147	17454	17805	18220	18508	18619	18663	18580	18561	18605	18375	18176	18631	18456	17714	16608	15430
TVA	3/31/12	14684	14171	13815	13592	13737	14053	14560	15147	16125	16866	17392	17885	18262	18631	18957	19184	19246	19079	18469	18721	18300	17361	16289	15122
TVA	4/1/12	14289	13795	13429	13253	13354	13643	13928	14610	15771	16212	16578	17321	18040	18717	19247	19770	20296	20473	19989	20221	20025	18903	17461	16251
TVA	4/2/12	15262	14605	14371	14353	14865	16112	17451	17794	18312	19139	19991	20683	21419	22081	22804	23288	23467	23198	22782	22745	22177	20731	18829	17202
TVA	4/3/12	16084	15267	14873	14707	15048	16233	17583	17745	18145	18757	19608	20421	21067	21846	22213	22434	22233	21946	21375	21491	21062	19697	18066	16526
TVA	4/4/12	15660	15109	14747	14709	15071	16203	17344	17676	18206	18820	19535	20020	20669	21368	21849	22057	22154	21829	21138	21034	20871	19823	18155	16553
TVA	4/5/12	15716	15132	14661	14466	14897	16071	17239	17524	17895	18374	18704	18887	18893	18956	18818	18741	18635	18456	18342	18384	18255	17368	16281	15107
TVA	4/6/12	14426	13936	13557	13489	13727	14595	15412	16000	16496	16752	16856	16727	16491	16487	16482	16529	16743	16626	16369	16754	16963	16356	15504	14575
TVA	4/7/12	13927	13566	13398	13350	13741	14232	14684	15466	15989	16188	16178	16135	16001	15915	15853	16126	16498	16580	16489	16931	17021	16349	15428	14349
TVA	4/8/12	13656	13166	13074	12919	13085	13489	13975	14772	15560	15650	15269	15400	15365	15464	15486	15609	15749	15648	15617	16548	16639	15882	14961	13971
TVA	4/9/12	13479	13244	13199	13410	14086	15498	17028	17591	17688	17841	17977	18013	17926	17989	18122	18238	18375	18407	18349	18829	18770	17700	16362	15204
TVA	4/10/12	14391	13981	13936	14084	14597	16122	17493	17791	17828	17788	17935	17952	17809	17795	17747	17858	17854	17778	17798	18528	18735	17832	16454	15401

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TVA	4/11/12	14959	14691	14666	14880	15690	17327	18884	18936	18489	18392	18230	18086	17808	17694	17516	17551	17666	17704	17837	18616	19125	18422	17340	16469
TVA	4/12/12	15985	15916	16054	16337	17148	18768	20105	20037	19333	18698	18339	17904	17647	17590	17400	17296	17335	17388	17490	18355	18727	18086	16749	15856
TVA	4/13/12	15363	15166	15171	15435	16245	17736	19005	18947	18471	18110	17875	17679	17567	17607	17654	17694	17806	17720	17544	18000	18138	17512	16371	15409
TVA	4/14/12	14691	14372	14210	14094	14226	14707	15166	15638	16437	16816	17003	17037	17221	17459	17698	18013	18294	18271	18139	18348	18478	17644	16480	15375
TVA	4/15/12	14543	13853	13533	13443	13486	13608	13856	14846	15915	16509	16699	17046	17518	18055	18486	19032	19452	19608	19342	19516	19632	18908	17603	16385
TVA	4/16/12	15512	14853	14358	14294	14794	16176	17391	17912	18207	18506	18882	19101	19271	19470	19616	19615	19512	19346	19197	19568	19566	18459	16964	15695
TVA	4/17/12	14813	14356	14020	13980	14499	15799	17074	17289	17528	17779	18081	18063	18060	17950	17649	17813	17865	17853	17960	18457	18429	17437	16219	15127
TVA	4/18/12	14516	14167	14048	14067	14559	16001	17236	17663	17586	17642	17775	17813	17837	17888	17950	18068	18267	18352	18233	18540	18831	17965	16568	15376
TVA	4/19/12	14706	14368	14198	14259	14822	16075	17347	17520	17409	17242	17678	17861	18070	18320	18612	18970	19313	19465	19088	19241	19391	18511	17086	15778
TVA	4/20/12	14842	14405	14125	14061	14586	15953	17173	17498	17661	17971	18277	18520	18528	18640	18831	18986	18982	18791	18369	18582	18507	17502	16336	15352
TVA	4/21/12	14540	14030	13617	13588	13718	14093	14498	15165	16088	16762	17100	17072	17058	16821	16696	16751	16694	16577	16680	17133	17192	16526	15715	14880
TVA	4/22/12	14304	14006	13751	13814	13937	14298	14612	15459	16198	16403	16104	15960	15993	15903	15934	16076	16318	16511	16775	17449	17927	17280	16349	15471
TVA	4/23/12	15040	14807	14744	14981	15845	17636	18978	19110	18923	18888	18910	18660	18226	18025	17740	17557	17693	17795	18049	18643	19264	18552	17399	16326
TVA	4/24/12	15838	15727	15742	15982	16614	18344	19618	19452	18996	18667	18345	18199	17982	17836	17770	17884	18001	18028	18093	18619	18937	17940	16547	15509
TVA	4/25/12	14871	14539	14407	14385	14919	16329	17406	17564	17629	17774	18008	18240	18418	18818	19150	19333	19498	19622	19498	19707	20142	19162	17590	16258
TVA	4/26/12	15274	14821	14514	14493	14937	16111	17334	17700	17943	18344	18921	19435	19689	20007	20149	20245	20616	20590	20398	20542	20562	19599	18011	16516
TVA	4/27/12	15562	14964	14626	14503	14880	15931	17240	17092	18461	18173	18724	18790	18896	19053	19139	19231	19417	19218	18773	18798	18856	18189	16984	15758
TVA	4/28/12	15000	14260	13895	13868	13953	14393	14576	15444	16474	17193	17764	18402	18934	19500	20024	20573	21130	21117	20582	20065	19988	18885	17579	16188
TVA	4/29/12	15174	14467	14053	13871	13834	13773	13900	15005	16332	17290	18094	18997	19986	20735	21318	21827	22164	22159	21765	21393	21225	19756	18028	16548
TVA	4/30/12	15562	14895	14437	14424	14722	16115	17311	17913	18641	19583	20781	21737	22651	23468	23664	23779	23870	23586	22881	22844	22646	21280	19416	17764
TVA	5/1/12	16630	15937	15497	15242	15523	16770	17837	18514	19272	20371	21521	22495	23245	24062	24503	24889	25135	24907	24200	23697	23615	22186	20095	18286
TVA	5/2/12	17167	16512	15888	15623	15985	17143	18347	18948	19858	21187	22369	23538	24427	25192	25783	26158	26330	26090	25241	24481	24139	22718	20466	18624
TVA	5/3/12	17597	16749	16110	15749	16031	17197	18372	19060	19440	20076	20567	20868	21223	21582	22161	22227	22407	22198	21899	21743	21861	20748	19185	17664
TVA	5/4/12	16506	15956	15525	15322	15800	17005	18114	18652	19359	20120	20874	21890	22585	23584	24306	24923	25156	24936	23928	23126	22900	21702	20088	18312
TVA	5/5/12	17280	16388	15864	15609	15484	15647	15914	16685	17630	18750	19808	20851	22037	22870	23634	24118	24387	24093	23479	22723	22281	21149	19432	17765
TVA	5/6/12	16538	15955	15461	15158	14902	14991	15066	16040	17610	18801	19876	20999	22324	23515	24324	24808	24805	24516	23631	22901	22639	21208	19169	17421
TVA	5/7/12	16419	15520	15161	15094	15450	16545	17691	18565	19332	19985	20635	21119	21419	21770	22024	22353	22442	22260	21726	21495	21555	20464	18746	17185
TVA	5/8/12	16331	15744	15293	15003	15379	16549	17821	18397	18973	19603	20391	20783	21177	21668	21961	22110	22298	22142	21468	21187	21211	20102	18429	16933
TVA	5/9/12	15979	15371	15093	14861	15244	16357	17483	17819	18036	18415	18896	19011	19234	19528	19746	20059	20400	20238	19841	19321	19578	18656	17041	15655
TVA	5/10/12	14859	14506	14206	14041	14428	15586	16640	17014	17322	17698	17972	18172	18466	18756	19044	19366	19704	19594	19245	18892	19283	18331	16877	15561
TVA	5/11/12	14756	14345	14029	14098	14501	15625	16740	17250	17439	17814	18064	18325	18505	18774	19158	19457	19509	19192	18641	18457	18647	17962	16775	15635
TVA	5/12/12	14650	14143	13981	13838	13907	14123	14531	15211	16049	16616	16993	17160	17279	17371	17364	17481	17387	17411	17408	17543	17753	17207	16416	15314
TVA	5/13/12	12719	12376	12005	11833	11772	11927	12358	13153	13956	14315	14356	14412	14457	14507	14420	14516	14727	14972	15108	15435	15813	15282	14362	13540
TVA	5/14/12	14498	14169	13929	13927	14397	15565	16736	17307	17799	18323	18824	18908	19232	19646	19924	20189	20356	20306	20023	19857	20181	19097	17513	16143
TVA	5/15/12	15264	14771	14412	14405	14703	15891	16912	17540	18077	18736	19442	19975	20360	20941	21339	21660	21810	21473	20964	20616	20750	19622	17957	16340

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TVA	5/16/12	15430	14838	14474	14265	14576	15593	16611	17334	18085	18799	19611	20254	21112	21753	22461	23278	23546	23396	22669	21887	21728	20312	18442	16677
TVA	5/17/12	15640	15005	14571	14490	14739	15777	16834	17483	18119	18947	19947	20824	21720	22747	23437	23900	24007	23737	23001	22173	22124	20976	19115	17303
TVA	5/18/12	16214	15525	14971	14878	15184	16018	17016	17974	18768	19768	20935	21979	22876	23681	24260	24557	24438	23790	22664	21595	21498	20434	18830	17281
TVA	5/19/12	16080	15295	14779	14382	14348	14511	14794	15862	17267	18411	19687	20715	21727	22531	22984	23322	23334	22989	22041	21149	20709	19591	18113	16672
TVA	5/20/12	15523	14684	14169	13990	13912	13819	14047	15242	16758	17936	18898	20052	21329	22201	22742	23055	23303	23111	22349	21546	21225	19878	18299	16722
TVA	5/21/12	15739	15048	14652	14602	14954	15890	17019	17941	18584	19616	20694	21437	22238	22778	22971	22919	22605	21926	21230	20660	20647	19668	18027	16460
TVA	5/22/12	15411	14897	14462	14402	14723	15624	16677	17290	17988	18541	19036	19566	20053	20659	20875	21102	21235	21043	20538	19952	19994	19070	17365	15779
TVA	5/23/12	14965	14430	14040	13834	14120	14948	16024	16733	17377	18149	18872	19481	20166	20998	21577	22249	22497	22503	22052	21006	20780	19642	17925	16283
TVA	5/24/12	15350	14666	14242	14172	14420	15252	16258	17163	18105	19128	20378	21446	22485	23663	24451	25030	25171	24844	24101	23084	22912	21798	19949	18178
TVA	5/25/12	16819	15971	15296	15118	15189	15796	16709	17977	19379	20860	22348	23654	24548	25419	26058	26269	26332	25829	24901	23593	23216	21886	19904	18035
TVA	5/26/12	16703	15522	14871	14482	14319	14193	14416	15622	17366	19252	21086	22535	23516	24370	25021	25567	25736	25514	24739	23514	23010	21554	19749	18086
TVA	5/27/12	16780	15610	14834	14471	14211	14068	14259	15644	17559	19401	20998	22429	23653	24461	25046	25366	25510	25339	24476	23463	22876	21604	19652	18097
TVA	5/28/12	16825	15940	15292	14749	14691	14589	14740	15932	17893	19916	21704	23060	24158	24899	25404	25747	25842	25636	24862	23956	23719	22418	20692	18772
TVA	5/29/12	17516	16635	16001	15757	16054	16815	17842	19215	20632	21862	23099	24149	25241	26160	26719	26880	26529	25820	24800	23736	22883	21542	19817	18156
TVA	5/30/12	16896	15984	15469	15132	15318	15888	16648	17756	19030	20464	21929	23105	24185	25021	25333	25327	25205	24603	23782	22646	22063	20907	19081	17288
TVA	5/31/12	16089	15324	14864	14667	14850	15517	16386	17527	18604	19613	20601	21490	22511	23633	24124	23894	23557	22881	21962	21343	21059	19965	18477	16946
TVA	6/1/12	15932	15225	14885	14593	14759	15435	16214	16790	17168	17538	17906	18003	18098	18227	18306	18305	18308	17973	17466	17065	17369	16934	15820	14628
TVA	6/2/12	13887	13363	12990	12770	12799	12911	13192	13925	14820	15424	15940	16285	16504	16822	17178	17710	18105	18220	17872	17459	17775	17190	15878	14707
TVA	6/3/12	13779	13195	12792	12558	12528	12644	12919	13880	15011	15998	16905	17927	18980	19971	20818	21536	22132	22222	21826	21197	21061	20028	18451	16943
TVA	6/4/12	15760	15095	14734	14627	14838	15602	16621	17493	18166	18915	19724	20623	21340	22111	22930	23410	23559	23464	22907	22097	21928	21031	19362	17744
TVA	6/5/12	16513	15759	15186	15006	15193	15920	16707	17679	18485	19324	20155	20760	21235	21866	22368	22655	22857	22528	21842	20823	20625	19680	18153	16467
TVA	6/6/12	15210	14533	14072	13909	14241	14823	15699	16739	17598	18487	19227	19761	20113	20866	21377	21863	22246	22090	21485	20431	20286	19428	17849	16325
TVA	6/7/12	15282	14611	14181	13888	14256	14790	15742	16781	17642	18402	19451	20125	20835	21579	22181	22720	22892	22682	21920	20898	20818	19967	18244	16688
TVA	6/8/12	15561	14835	14432	14149	14334	15001	15924	17062	18106	19144	20390	21344	22027	22942	23562	24070	24307	24062	23041	21970	21510	20435	18806	17049
TVA	6/9/12	15873	15100	14489	14213	14154	14075	14417	15456	16786	18231	19601	20786	21549	22254	22630	23019	23099	22694	21961	21232	21067	20214	18796	17266
TVA	6/10/12	16047	15302	14611	14316	14183	14181	14303	15143	16239	16984	17532	17913	18448	18847	19145	19523	19673	19890	19757	19570	19735	19202	18093	16857
TVA	6/11/12	15929	15342	15067	15076	15480	16479	17408	18533	19184	19974	20793	21562	22531	23512	24132	24213	23610	23148	22248	21330	21023	20175	18672	17313
TVA	6/12/12	16211	15528	15105	14986	15207	15928	16870	17818	18568	19459	20244	20910	21578	22342	23051	23567	23751	23443	22803	21948	21718	20790	19005	17312
TVA	6/13/12	16165	15358	14954	14721	14815	15474	16395	17509	18580	19818	20887	21899	22943	23719	24383	24906	25131	24986	24143	22985	22320	21181	19134	17395
TVA	6/14/12	16127	15353	14614	14366	14731	15288	16258	17500	18586	19996	21470	22808	23986	24885	25646	26060	26434	26210	25418	24323	23809	22703	20575	18702
TVA	6/15/12	17236	16295	15616	15364	15552	16225	17152	18356	19766	21345	22775	23929	24798	25747	26341	26709	26761	26197	25135	23810	23476	22370	20569	18825
TVA	6/16/12	17474	16503	15918	15483	15221	15091	15252	16478	18055	19660	21076	22157	22957	23741	24037	24193	24559	24473	23782	22740	22171	21236	19515	17896
TVA	6/17/12	16509	15644	14982	14608	14399	14275	14330	15647	17385	18838	19915	20879	21829	22662	23129	23549	23647	23571	22988	22122	21765	20874	19235	17541
TVA	6/18/12	16215	15381	15018	14888	14958	15731	16754	18255	19763	21339	22952	23990	24996	25734	26323	26813	26932	26585	25889	24815	24200	23047	20976	18843
TVA	6/19/12	17493	16505	15902	15723	15824	16359	17282	18777	20286	21881	23449	24651	25389	26380	26910	27352	27455	27222	26425	25266	24660	23340	21268	19333

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TVA	6/20/12	17889	16863	16117	15606	15754	16386	17309	18730	20190	21859	23496	24639	25781	26719	27375	27666	27670	27413	26631	25493	24885	23731	21627	19506
TVA	6/21/12	18135	17110	16462	16125	16250	16622	17636	19109	20558	22268	24019	25167	26179	27018	27663	28054	28081	27720	26994	25989	25435	24244	22087	20089
TVA	6/22/12	18657	17663	16931	16465	16529	17047	17859	19239	20754	22379	24081	25318	26289	27064	27534	27801	27747	27319	26491	25354	24529	23437	21518	19591
TVA	6/23/12	18090	17045	16120	15694	15559	15464	15566	16905	18799	20700	22633	24019	25062	25871	26466	26923	27189	27008	26385	25068	24091	22709	20757	18882
TVA	6/24/12	17360	16308	15545	14924	14620	14370	14649	16134	18121	20118	22109	23768	25217	26176	26947	27477	27841	27717	27094	26027	25180	23803	21717	19788
TVA	6/25/12	18318	17275	16533	16155	16282	16757	17740	19392	21114	23036	25027	26655	27842	28784	29325	29605	29681	29357	28613	27492	26946	25638	23452	21299
TVA	6/26/12	19616	18484	17552	16880	16733	17040	17676	18856	19902	20949	22131	22995	23872	24632	25276	25760	25855	25607	24834	23576	22714	21500	19411	17415
TVA	6/27/12	16133	15164	14587	14302	14466	14979	15711	16856	18058	19398	20816	22098	23504	24882	25984	26952	27529	27529	26918	25452	24394	23151	20914	18632
TVA	6/28/12	17168	16152	15507	15152	15463	15796	16575	17900	19474	21295	23460	25356	27017	28426	29541	30251	30467	30331	29670	28398	27597	26091	23845	21519
TVA	6/29/12	19860	18686	17723	17215	17149	17721	18293	19799	21594	23783	26125	27728	29313	30296	30765	31020	31098	30676	29877	28935	28187	27132	25232	23118
TVA	6/30/12	21321	19904	18764	18099	17613	17334	17662	19110	21245	23586	25858	27683	28967	29785	30354	30728	30777	30651	30054	28947	28278	26985	25019	23205
TVA	7/1/12	21388	20095	19128	18553	18105	17760	17736	19121	21778	24001	25839	27411	28665	29531	29844	30029	30253	30060	29472	28280	27626	26696	24567	22446
TVA	7/2/12	20876	19815	18923	18328	18340	18678	19383	20651	22046	23795	25315	26601	27628	28582	28936	28838	28530	27914	27254	26162	25363	24171	22422	20591
TVA	7/3/12	19256	18149	17421	17009	17026	17334	18069	19432	21211	22939	24689	26203	27358	28348	28894	29002	28877	28439	27570	26307	25726	24574	22851	21005
TVA	7/4/12	19530	18351	17478	16804	16684	16471	16516	17670	19760	21939	24119	25771	27085	27724	28024	28099	28010	27551	26445	25204	24481	23295	21951	20510
TVA	7/5/12	19098	18132	17449	17061	17066	17458	18243	19827	21843	23994	26036	27514	28827	29470	29808	29885	29422	28318	26919	25705	25278	24345	22592	20844
TVA	7/6/12	19449	18373	17557	16928	16928	17248	17848	19077	20741	22449	24537	26281	27823	28941	29585	29742	29358	28587	27379	26141	25701	24449	22709	20997
TVA	7/7/12	19420	18349	17420	16940	16709	16684	16845	18187	20167	22398	24561	26372	27572	28336	28903	29230	29118	28912	28223	27358	26795	25596	23677	21910
TVA	7/8/12	20396	19290	18548	17944	17687	17458	17476	18838	20739	22148	23592	24925	26322	27354	27747	27808	27771	27120	26344	25408	25028	23854	21985	20349
TVA	7/9/12	19043	18190	17581	17226	17416	18069	18796	20046	21027	22238	23568	24741	25597	26422	27054	27385	27406	27120	26374	25373	24960	23734	22015	20320
TVA	7/10/12	18996	17949	17334	17016	17050	17577	18383	19499	20562	21707	23031	23860	24573	24923	24905	24549	23872	23248	22628	22097	22065	21363	19875	18334
TVA	7/11/12	17258	16633	16198	16032	16413	17146	18005	18934	19672	20304	21088	21432	21871	22295	22538	22881	23127	23017	22528	21940	21924	21317	19840	18249
TVA	7/12/12	17110	16434	15824	15781	15966	16969	17745	18607	19159	19689	20291	20553	20592	20825	20840	20747	20643	20567	20331	20088	20366	19986	18789	17525
TVA	7/13/12	16471	15954	15549	15517	15686	16553	17308	18295	19087	19984	20912	21641	22254	23057	23603	24018	24143	23936	23280	22465	22325	21561	20120	18532
TVA	7/14/12	17328	16649	16077	15641	15709	15847	15929	16747	18008	19425	20653	21714	22346	22786	22907	22863	22551	22070	21517	20955	20810	20191	18878	17534
TVA	7/15/12	16471	15724	15258	14886	14730	14666	14894	16137	17798	19184	20450	21664	22987	24040	24854	25487	25798	25692	24977	24189	23587	22487	20911	19175
TVA	7/16/12	17812	17052	16442	16215	16374	17040	18016	19521	21307	23357	25179	26507	27279	27730	28016	28192	28161	27816	27127	26061	25637	24467	22453	20510
TVA	7/17/12	19253	18423	17643	17146	17455	18082	18851	20282	21972	23670	25555	26727	27551	28208	28480	28763	28555	28192	27477	26413	26140	24880	22909	20788
TVA	7/18/12	19438	18519	17814	17557	17725	18322	19168	20380	21877	23506	25359	26769	27739	28310	28249	27960	27214	26337	25519	24645	24406	23406	21615	19949
TVA	7/19/12	18658	17871	17252	17056	17374	17935	18815	20025	21303	22851	24344	25744	27050	28337	28946	29534	29548	29242	28566	27753	27333	25940	23678	21553
TVA	7/20/12	20148	19238	18343	17971	18074	18372	19028	19980	20909	22088	23363	24497	25463	26226	27075	27612	27838	27491	26711	25712	25326	24218	22506	20785
TVA	7/21/12	19371	18328	17577	17266	16866	16835	16985	17857	19255	20580	22044	23145	24030	25037	25763	26307	26421	26238	25522	24397	23856	22793	21192	19442
TVA	7/22/12	18280	17346	16712	16247	16004	15987	15963	17278	19241	20918	22216	23415	24587	25332	25653	26041	26345	26276	25717	24671	24214	23162	21601	19999
TVA	7/23/12	18746	17894	17359	17058	17181	17805	18779	20339	21987	23793	25626	26974	27980	28778	29227	29565	29706	29560	28914	27744	27126	25838	23758	21717
TVA	7/24/12	20374	19278	18420	18071	18106	18742	19599	21174	23006	24830	26535	27723	28715	29404	29924	30255	30180	29714	29144	28036	27518	26242	24229	22334

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TVA	7/25/12	20783	19668	18906	18402	18472	18985	19640	20992	22733	24627	26493	27830	28774	29681	30265	30518	30648	30370	29539	28390	27952	26622	24544	22562
TVA	7/26/12	20998	20015	19305	18862	18979	19507	20220	21714	23469	25402	27112	28188	29220	29974	30442	30659	30657	30271	29464	28374	28034	26604	24398	22115
TVA	7/27/12	20725	19658	18906	18433	18433	18911	19632	20983	22330	23740	25205	26318	26894	27367	27563	27847	27785	27491	26785	25627	25209	24086	22420	20777
TVA	7/28/12	19246	18197	17392	16935	16675	16620	16690	17980	19943	21923	23793	25236	26448	27262	27782	28178	28212	27757	26906	25496	24733	23265	21420	19467
TVA	7/29/12	18061	16971	16122	15570	15225	15162	15108	16438	18334	20178	21733	23052	24093	24698	25227	25385	25358	25168	24630	23639	23230	22226	20592	18977
TVA	7/30/12	17777	16885	16357	16227	16506	17300	18116	19266	20667	21900	23415	24705	25964	27147	28203	28924	29040	28846	28250	27220	27006	25532	23485	21753
TVA	7/31/12	20485	19524	18954	18561	18500	19224	19883	20833	21920	23289	24728	25651	26552	27564	28180	28826	29153	28860	28111	26954	26464	24971	22842	20987
TVA	8/1/12	19627	18547	17797	17479	17451	18292	19026	20204	21773	23524	25609	27130	28562	29563	29956	29751	29179	28334	27179	26030	25598	24138	22256	20360
TVA	8/2/12	19042	18074	17485	17225	17261	18022	18635	19820	21253	22915	24717	26336	27723	28951	29418	29528	29425	28833	27890	26837	26695	25352	23497	21595
TVA	8/3/12	20235	19304	18509	18158	18287	19011	19719	20459	21295	22310	23418	24010	24550	25251	25865	26274	26361	26087	25418	24657	24728	23782	22295	20725
TVA	8/4/12	19447	18612	17913	17477	17329	17393	17562	18553	20175	21934	23568	24879	25917	26702	26540	26228	25692	25069	24208	23466	23446	22410	21184	19774
TVA	8/5/12	18652	17822	17284	16772	16552	16575	16627	17733	19379	20609	21543	22819	24024	24727	25198	25191	24701	24018	23322	22872	22750	21625	20151	18724
TVA	8/6/12	17712	17106	16743	16538	16697	17728	18659	19678	20873	22153	23456	24486	25368	26165	26606	27119	27369	27222	26529	25699	25551	24188	22129	20257
TVA	8/7/12	18812	17979	17301	16947	17132	18073	18831	19806	21103	22611	24418	25633	26608	27558	28291	28588	28643	28309	27379	26406	26027	24420	22358	20411
TVA	8/8/12	18948	18035	17397	17037	17263	17998	18832	19901	21315	23085	24927	26516	27583	28537	29165	29474	29558	29269	28410	27316	26897	25135	23053	21119
TVA	8/9/12	19783	18822	18196	17781	18026	19024	19777	20462	21268	22200	23011	23637	24212	24686	24890	25114	25326	25158	24536	24034	24034	22756	20866	19107
TVA	8/10/12	18053	17476	16986	16797	16960	17913	18893	19567	20301	21416	22218	22961	23577	24152	24674	25115	24866	24015	22823	22045	21893	20804	19103	17795
TVA	8/11/12	16556	15788	15169	14751	14590	14775	14594	15460	16796	18258	19393	20395	21254	21884	22534	23047	23380	23173	22266	21079	20460	19255	17665	16278
TVA	8/12/12	15114	14373	13811	13543	13423	13454	13471	14363	15766	16892	17926	19059	20260	21301	22225	22830	23356	23319	22538	21647	21482	20171	18372	16789
TVA	8/13/12	15824	15243	14925	14834	15232	16428	17460	18176	18856	19587	20312	20724	21139	21619	21945	22076	22203	22203	21711	21402	21587	20671	18962	17373
TVA	8/14/12	16323	15915	15513	15247	15694	16874	18087	18592	19063	19836	20661	21474	22318	23318	24039	24534	24835	24576	23836	23121	23010	21485	19619	17923
TVA	8/15/12	16804	16144	15427	15276	15694	16802	17755	18241	18927	19953	21218	22273	23080	24050	24923	25560	25882	25634	24928	23854	23692	21951	19833	17846
TVA	8/16/12	16966	16145	15735	15358	15520	16777	17620	18566	19767	21160	22929	24135	25238	26376	27074	27554	27770	27363	26355	25839	25416	23666	21500	19361
TVA	8/17/12	17943	17114	16331	15964	16283	17310	18310	18817	19305	20092	20853	21311	21275	21741	22065	22253	22298	22053	21299	21033	21081	20041	18765	17426
TVA	8/18/12	16327	15672	15225	14971	14817	15095	15282	15958	17191	18530	19609	20571	21049	21408	21816	22135	22224	21858	21067	20613	20376	19266	17929	16538
TVA	8/19/12	15590	14975	14521	14315	14166	14298	14442	15098	16232	17249	18219	19196	20183	21090	21715	22078	22384	22200	21587	20978	20688	19351	17613	15990
TVA	8/20/12	15120	14469	14004	13931	14313	15535	16579	17226	17913	19084	20166	21114	21958	22687	23247	23737	23928	23719	22931	22089	21881	20225	18332	16556
TVA	8/21/12	15511	14877	14433	14311	14595	15630	16731	17300	18009	19071	20304	21269	21938	22700	23270	23768	23870	23481	22772	22138	21933	20321	18342	16426
TVA	8/22/12	15579	14746	14488	14324	14494	15632	16585	17174	18057	19149	20482	21548	22216	23833	24390	25146	25516	25314	24299	23284	22808	21148	18961	17346
TVA	8/23/12	16166	15426	14919	14819	15054	16118	16968	17369	18349	19719	21180	22318	23375	24463	25307	25903	26234	26051	25016	24178	23693	21978	19805	18040
TVA	8/24/12	16884	16010	15420	15313	15413	16426	17376	18066	19219	20514	21918	23304	24407	25207	25875	26280	26283	25610	24343	23357	22714	21368	19653	18071
TVA	8/25/12	16891	16008	15497	15153	15140	15197	15343	16184	17530	19089	20468	21536	22408	23007	23269	23320	23184	22755	22013	21538	21129	19910	18420	17038
TVA	8/26/12	15962	15176	14646	14436	14371	14259	14596	15487	17075	18605	20069	21628	22940	23978	24746	25283	25551	25482	24642	23902	23079	21410	19590	18016
TVA	8/27/12	16770	16051	15611	15237	15512	16735	18074	18835	20020	21537	23397	24848	25932	26875	27628	28121	28381	27994	26952	26232	25454	23517	21142	19549
TVA	8/28/12	18371	17377	16862	16573	16736	17862	19153	19709	20564	21805	23110	24375	25353	26213	26801	26956	26920	26515	25659	25200	24745	23114	21093	19293

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TVA	8/29/12	18090	17212	16697	16477	16707	17904	19005	19519	20608	21885	23478	24760	25915	26881	27409	27792	27829	27302	26256	25827	25221	23517	21532	19763
TVA	8/30/12	18488	17580	17018	16829	16966	18074	19311	19824	20576	21561	22732	23687	24417	24896	25184	25214	25078	24638	23987	23995	23741	22376	20742	19328
TVA	8/31/12	18279	17632	17104	16980	17343	18494	19778	20302	21057	22045	23218	23901	24478	25082	25677	26026	25842	25298	24354	23863	23336	22122	20544	19062
TVA	9/1/12	17938	17188	16646	16205	16129	16369	16546	17187	18624	20047	21425	22475	23394	24124	24731	25091	25241	25068	24298	23778	22937	21620	20212	18759
TVA	9/2/12	17532	16746	16300	15915	15824	15898	16044	16765	18082	19119	19996	20930	21729	22440	22926	23093	22959	22585	21760	21272	20620	19607	18318	17208
TVA	9/3/12	16160	15478	15153	14827	14891	15162	15378	15737	16870	18263	19299	20192	20697	21034	21477	21873	22221	22167	21924	22075	21628	20501	18978	17566
TVA	9/4/12	16705	16074	15747	15697	16111	17428	18881	19476	20213	21176	22324	23349	24148	24967	25607	26110	26253	26030	25406	25209	24572	23016	21043	19409
TVA	9/5/12	18208	17444	16904	16645	16949	18327	19631	20053	20867	21874	23146	24323	25540	26788	27637	28149	28227	27503	26258	25293	24208	22645	20685	18814
TVA	9/6/12	17689	16940	16414	16194	16407	17612	18823	19195	19905	20989	22304	23678	24971	26231	27127	27718	27802	27406	26501	26035	25052	22963	20902	19027
TVA	9/7/12	17755	16884	16279	16024	16223	17313	18446	19014	20123	21588	23342	24889	26111	27159	27922	28344	28299	27686	26496	25608	24705	23351	21357	19645
TVA	9/8/12	18334	17414	16336	16330	16196	16364	16623	17061	18004	18715	19198	19384	19396	19239	19161	19268	19347	19120	18523	18389	18035	17088	15958	14758
TVA	9/9/12	13850	13368	13062	12869	12808	13004	13091	13810	14739	15400	15982	16677	17444	18193	18899	19586	20135	20168	19523	19506	19085	17812	16383	15104
TVA	9/10/12	14230	13659	13499	13445	13883	15155	16221	16608	17239	17982	18832	19369	19907	20596	21204	21722	21988	21661	20921	20715	20213	18998	17283	15774
TVA	9/11/12	14927	14397	14075	13950	14273	15534	16617	16857	17448	18272	19102	19834	20677	21465	22082	22636	22874	22619	21806	21704	21191	19804	17952	16517
TVA	9/12/12	15422	14911	14540	14448	14812	16007	17344	17572	17951	18462	19284	20038	20843	21471	21973	22394	22438	22087	21342	21387	20882	19583	18030	16468
TVA	9/13/12	15567	14977	14656	14555	14864	15998	17283	17503	17935	18812	19847	20473	21123	21940	22392	22885	22906	22456	21728	21774	21259	20013	18204	16673
TVA	9/14/12	15648	15017	14673	14519	14790	15824	17036	17424	17966	18813	19758	20548	21085	21734	22127	22273	22193	21595	20712	20521	19952	19072	17887	16389
TVA	9/15/12	15478	14759	14301	14047	14066	14355	14671	15225	16219	17271	18234	19188	20125	20974	21458	21592	21565	20981	20176	20225	19576	18647	17318	16026
TVA	9/16/12	15096	14507	14166	13924	13931	14037	14367	15006	16139	16982	17812	18786	19765	20504	20923	21197	21318	21147	20816	21086	20378	19241	17690	16478
TVA	9/17/12	15719	15157	14778	14721	15115	16384	17961	18387	18759	19125	19372	19394	19360	19312	19177	19138	19273	19332	19571	19825	19420	18594	17473	16247
TVA	9/18/12	15425	15010	14712	14574	14978	16274	17584	17849	17975	18096	18344	18367	18330	18562	18631	18693	18677	18424	18149	18587	18193	17101	15698	14651
TVA	9/19/12	13952	13600	13322	13325	13796	15002	16280	16491	16636	16889	17186	17258	17258	17459	17694	18097	18341	18291	17978	18340	17966	17047	15744	14574
TVA	9/20/12	13847	13509	13355	13362	13778	15065	16420	16510	16752	17009	17356	17556	17741	18289	18784	19266	19616	19351	18864	19245	18904	17937	16515	15207
TVA	9/21/12	14431	13932	13588	13574	13937	15154	16358	16434	16802	17234	17691	18067	18325	18787	19172	19644	19764	19391	18764	18776	18257	17566	16468	15331
TVA	9/22/12	14463	13925	13592	13357	13440	13701	14199	14629	15756	16770	17766	18360	18962	19359	19688	20034	20013	19524	18718	18504	17677	16679	15505	14354
TVA	9/23/12	13562	13011	12707	12580	12623	12810	13071	13747	14714	15013	15180	15492	15954	16125	16383	16695	16994	17080	16992	17538	17020	16014	14835	13920
TVA	9/24/12	13323	13106	12977	13192	13710	15166	16608	16899	17021	17141	17276	17248	17134	17287	17431	17689	17865	17744	17830	18458	18103	17188	15936	14845
TVA	9/25/12	14242	13890	13766	13787	14366	15682	17076	17085	17301	17598	17861	17953	18237	18761	19198	19642	19917	19909	19886	20279	19822	18896	17471	16138
TVA	9/26/12	15258	14727	14457	14381	14720	15789	17236	17278	17651	18365	19146	19738	20301	21056	21694	22195	22337	21944	21407	21316	20572	19301	17621	16237
TVA	9/27/12	15274	14764	14327	14200	14588	15869	17250	17525	17940	18513	19482	20290	20972	21739	22395	22786	22837	22320	21889	21851	21166	19912	18340	16772
TVA	9/28/12	15840	15217	14863	14741	15137	16278	17707	17933	18324	18910	19649	20204	20629	21000	21006	20945	20792	20278	19880	19850	19266	18536	17468	16306
TVA	9/29/12	15439	14886	14492	14241	14201	14452	15023	15437	16341	17044	17645	18190	18604	19019	19318	19460	19381	18889	18581	18673	18010	17009	15847	14816
TVA	9/30/12	14077	13395	13188	12999	12906	13120	13513	14020	15015	15469	15671	15988	16314	16345	16540	16234	16764	16956	17559	17870	17384	16468	15403	14550
TVA	10/1/12	13876	13579	13347	13311	13975	15105	16685	17100	17456	17796	17962	17972	17902	17742	17683	17774	17866	17893	18387	18654	18391	17636	16424	15271
TVA	10/2/12	14544	14106	13875	13875	14277	15623	17101	16488	18199	17744	18069	18192	18063	18164	18044	18033	18076	17982	18261	18598	18233	17288	16111	15097

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TVA	10/3/12	14438	14078	13903	13840	14291	15582	16781	16901	17093	17368	17751	17792	17921	18306	18490	18745	18693	18430	18719	18961	18549	17586	16394	15194
TVA	10/4/12	14451	14046	13681	13712	14141	15482	16779	16942	17237	17705	18178	18607	18966	19379	19793	20127	20192	19839	19745	19874	19167	17934	16644	15485
TVA	10/5/12	14615	14146	13917	13948	14205	15376	16693	16783	17183	17726	18349	18835	19008	19578	19924	20022	19961	19484	19147	18845	18141	17285	16190	15035
TVA	10/6/12	14162	13708	13277	13120	13267	13659	14210	14633	15291	15902	16099	16017	15902	15773	15704	15648	15777	15963	16587	16793	16382	15722	14961	14239
TVA	10/7/12	13649	13351	13153	13068	13147	13472	13944	14639	15507	15826	15783	15721	15671	15568	15516	15368	15536	15734	16652	17258	16907	16278	15435	14736
TVA	10/8/12	14288	14010	13946	14069	14587	15889	17385	17807	18104	18286	18353	18084	17741	17481	17299	17174	17264	17467	18253	18634	18154	17523	16551	15669
TVA	10/9/12	15157	14920	14856	14929	15467	16766	18359	18424	18412	18264	18051	17687	17352	17220	16979	16849	16878	16841	17609	18207	17916	17108	16153	15247
TVA	10/10/12	14746	14413	14367	14412	14849	16017	17455	17565	17625	17689	17673	17333	17086	17133	17043	16843	16992	17060	17655	18026	17898	17249	16310	15348
TVA	10/11/12	14890	14741	14738	14865	15528	16999	18478	18695	18433	18151	17978	17568	17238	17214	17137	17113	17015	17144	17842	18218	17855	17044	16107	15133
TVA	10/12/12	14502	14171	14024	14012	14323	15537	17015	17287	17438	17747	17892	17758	17375	17380	17336	17228	17205	17202	17525	17532	17298	16674	15881	14987
TVA	10/13/12	14436	13985	13840	13739	13858	14268	14905	15320	15991	16441	16636	16744	16767	16940	17128	17253	17270	17292	17723	17814	17405	16787	15863	14970
TVA	10/14/12	14212	13652	13312	13153	13256	13599	14007	14490	15323	15725	15827	16098	16184	16265	16379	16448	16781	17046	17823	18083	17494	16815	15635	14733
TVA	10/15/12	14000	13590	13389	13391	13710	14997	16484	16726	16969	17354	17690	17663	17858	17987	18076	18029	18049	17869	18362	18500	17976	17190	15919	14851
TVA	10/16/12	14276	13986	13863	13945	14523	16007	17558	17755	17554	17505	17523	17379	17188	17261	17282	17262	17337	17337	18260	18419	17899	17034	15923	14795
TVA	10/17/12	14152	13784	13663	13774	14281	15567	17092	17216	17176	17348	17396	17375	17368	17551	17677	17810	17961	17892	18524	18582	18068	17033	15914	14832
TVA	10/18/12	14281	13834	13635	13670	14091	15314	16904	17163	17304	17318	17379	17380	17445	17344	17262	17179	17117	17110	17821	18102	17727	16982	15877	14868
TVA	10/19/12	14397	14103	13982	14092	14691	16063	17597	17619	17526	17520	17369	17165	16769	16768	16582	16420	16429	16645	17262	17173	16921	16464	15653	14715
TVA	10/20/12	14104	13795	13661	13673	13946	14411	15165	15705	16117	16400	16324	16141	15933	15753	15604	15656	15860	15953	16644	16743	16441	15877	15096	14490
TVA	10/21/12	14028	13697	13653	13701	13963	14402	15112	15758	16275	16043	15593	15595	15581	15774	15903	16215	16381	16649	17393	17583	16937	16207	15217	14337
TVA	10/22/12	13824	13572	13474	13560	14147	15614	17212	17298	17483	17596	17752	17869	17965	18264	18534	18710	18751	18607	19175	19107	18369	17344	16140	14955
TVA	10/23/12	14131	13661	13606	13679	14205	15643	17209	17268	17431	17634	17835	17922	18019	18322	18538	18768	18786	18652	19134	19054	18386	17428	16068	14906
TVA	10/24/12	14180	13774	13644	13726	14144	15617	17267	17414	17372	17480	17713	17880	18077	18529	18860	19245	18974	18903	19225	19042	18522	17414	16072	14978
TVA	10/25/12	14256	13831	13604	13567	14069	15410	16916	16992	17055	17245	17571	17767	18058	18412	18618	18756	18813	18540	18975	19119	18634	17564	16109	14663
TVA	10/26/12	14012	13641	13464	13405	13898	15181	16643	16774	16976	17257	17459	17461	17445	17446	17440	17478	17554	17705	18080	17798	17455	16968	16052	15210
TVA	10/27/12	14372	14071	13852	13895	14137	14552	15278	16097	16764	17264	17382	17178	17027	16713	16505	16590	16702	17019	17784	17716	17262	16765	15948	15362
TVA	10/28/12	14797	14498	14252	14201	14411	14858	15534	16316	17073	17255	17022	16761	16658	16530	16360	16308	16589	17074	18308	18550	18242	17628	16752	16013
TVA	10/29/12	15677	15549	15650	15989	16644	18345	20251	20565	20276	20027	19571	19337	18933	18642	18265	18267	18511	19171	20461	20504	20230	19505	18299	17761
TVA	10/30/12	16950	16759	16774	16900	17643	19228	20911	21027	20733	20584	20283	19814	19261	18872	18600	18536	18710	19150	20271	20288	20065	19237	18212	17422
TVA	10/31/12	16950	16777	16843	17041	17746	19322	20993	21207	20696	19913	19298	18730	18283	17862	17569	17426	17380	17526	18305	18471	18790	18648	17849	17142
TVA	11/1/12	16796	16873	17060	17307	18051	19806	21692	21793	21117	20055	19259	18606	18237	17837	17506	17480	17657	17916	19293	19548	19314	18504	17392	16579
TVA	11/2/12	16118	15830	15761	15768	16264	17781	19321	19292	18842	18252	17835	17454	17279	16965	16768	16840	16860	16906	17827	17762	17461	16969	16175	15539
TVA	11/3/12	14996	14937	14966	15119	15543	16234	17041	17653	17960	17658	17198	16843	16617	16513	16396	16542	16723	17068	17631	17516	17033	16387	15547	14703
TVA	11/4/12	14017	27007	13216	13330	13566	14208	15007	16079	16798	16653	16146	15887	15806	15672	15674	15795	16428	17813	18230	18202	17839	17250	16533	16092
TVA	11/5/12	16006	16077	16275	16531	17407	19218	20738	20460	19920	19193	18817	18396	18118	17882	17850	18025	18896	20095	20286	19981	19442	18539	17363	16629
TVA	11/6/12	16163	15989	15950	15982	16457	18108	19293	19292	19318	19168	19128	18889	18821	18791	18734	18880	19616	20550	20684	20376	19746	18836	17751	16921

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
TVA	11/7/12	16293	16082	15966	15924	16402	17984	19278	19114	18929	18742	18782	18717	18549	18473	18410	18706	19507	20673	20849	20563	19927	19127	18114	17351
TVA	11/8/12	17177	17227	17427	17741	18472	20242	21693	21259	20283	19431	18950	18424	18135	17852	17490	17681	18404	19844	20164	20216	20185	19373	18517	17970
TVA	11/9/12	17755	17805	17937	18235	18902	20676	21912	21440	20200	19185	18603	18111	17709	17437	17137	16959	17483	18545	18615	18412	18069	17750	17097	16397
TVA	11/10/12	15959	15721	15718	15952	16354	17043	17568	17915	17845	17456	16883	16543	16132	16016	15955	15966	16390	17425	17311	17131	16771	16154	15466	14875
TVA	11/11/12	14543	14404	14371	14527	14852	15313	15702	16382	16667	16319	15750	15651	15749	15550	15481	15474	16261	17446	17455	17114	16748	16031	15178	14377
TVA	11/12/12	13893	13724	13547	13537	13834	15230	16698	17178	17561	17883	18128	18310	18237	18139	18025	18220	18967	20404	20678	20615	20325	19626	18876	18240
TVA	11/13/12	17922	17955	18064	18264	19203	21246	22679	22192	21158	20347	19709	19264	18813	18445	18201	18441	19392	21075	21601	21701	21588	20793	19838	19133
TVA	11/14/12	18864	18856	18973	19123	19710	21274	22527	22053	21182	20369	19790	19260	18852	18492	18381	18573	19539	21008	21227	21176	20835	20070	19083	18399
TVA	11/15/12	18206	18060	18253	18558	19342	21047	22555	22129	20896	19789	19011	18250	17969	17764	17482	17623	18410	20025	20273	20439	20349	19678	18832	18110
TVA	11/16/12	17926	17834	18084	18465	19167	20938	22362	21884	20765	19750	18903	18298	17830	17563	17310	17179	18115	19390	19613	19595	19396	18963	18456	17888
TVA	11/17/12	17630	17582	17617	17889	18479	19296	19963	20321	19856	18999	18187	17467	16968	16522	16205	16265	16970	18203	18486	18531	18459	18139	17657	17191
TVA	11/18/12	17006	17011	17166	17419	17835	18374	19166	19753	19272	18289	17220	16618	16298	16035	15862	15975	16758	18223	18443	18530	18342	17883	17207	16738
TVA	11/19/12	16456	16733	16933	17268	18021	19824	21211	20945	20017	19121	18479	17980	17681	17456	17202	17264	17863	19190	19498	19406	19049	18402	17485	16503
TVA	11/20/12	16198	15945	15757	15840	16388	17819	19134	19166	18771	18286	17945	17625	17562	17397	17233	17233	17782	18818	18882	18668	18305	17581	16577	15709
TVA	11/21/12	15178	14859	14805	14880	15487	16701	17866	18295	18214	17852	17687	17346	17303	17172	16912	16805	17152	18246	18241	18055	17761	17225	16349	15560
TVA	11/22/12	15020	14743	14839	15117	15612	16342	17024	17718	17858	17857	17526	16780	15724	14979	14555	14289	14551	15318	15416	15443	15347	15136	14633	14255
TVA	11/23/12	14051	14058	14069	14198	14491	15073	15629	16003	16238	16250	16261	16142	15944	15758	15594	15614	16310	17582	17723	17829	17711	17420	16978	16543
TVA	11/24/12	16368	16399	16465	16872	17445	18190	18992	19493	19699	19462	18867	18219	17618	17190	16975	17245	18494	20084	20475	20750	20774	20571	19952	19668
TVA	11/25/12	19425	19392	19577	19727	20087	20656	21124	21527	20747	19528	18246	17319	16887	16563	16180	16297	17413	19028	19545	19646	19373	18988	18076	17593
TVA	11/26/12	17432	17352	17392	17596	18088	19461	21007	20786	20040	19684	19094	18645	18419	18084	18015	18243	19132	20093	20247	19871	19477	18715	17453	16545
TVA	11/27/12	15947	15710	15784	15867	16381	18033	19659	19837	19824	19920	20183	20220	20133	20023	19973	20113	21053	22315	22377	22451	22009	21158	19996	19209
TVA	11/28/12	18867	18806	18763	18907	19702	21469	23078	22882	22098	21147	20251	19563	19184	18792	18558	18693	19937	21754	22270	22477	22527	21939	21086	20398
TVA	11/29/12	20074	20117	20365	20615	21364	23070	24470	24016	22636	21085	19973	19121	18586	18184	17886	17998	19107	20715	21124	21326	21207	20623	19567	18836
TVA	11/30/12	18638	18509	18602	18833	19353	20922	22229	21851	20836	19838	19058	18373	17773	17491	17172	17129	18052	19202	19369	19226	19048	18621	17801	17050

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Backup - LGEE Hourly Load

Dec 2011-Nov 2012 Load

LGEEP	**Max**	7,223
LGEEA	**Avg Jun**	5,576
LGEEV	**Winter**	4,652
LGEES	**Spring**	4,424
LGEES	**Summer**	5,920
LGEEF	**Fall**	4,375

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
LGEE	12/1/11	4379	4266	4245	4241	4287	4539	4942	5218	5132	4993	4766	4539	4412	4292	4132	4060	4033	4364	4613	4704	4639	4566	4480	4329
LGEE	12/2/11	4176	4118	4069	4068	4100	4367	4777	4994	4916	4735	4549	4390	4198	4067	4076	3950	3969	4214	4368	4441	4352	4308	4168	4078
LGEE	12/3/11	3847	3786	3689	3587	3642	3689	3859	4001	4062	4069	3981	3876	3693	3579	3533	3388	3419	3716	3937	3925	3890	3834	3683	3521
LGEE	12/4/11	3326	3192	3104	3088	3069	3162	3278	3401	3450	3557	3535	3498	3492	3484	3380	3388	3548	3813	3924	3882	3857	3712	3505	3323
LGEE	12/5/11	3162	3089	3060	3033	3116	3318	3772	4128	4192	4265	4305	4266	4303	4310	4328	4313	4356	4501	4554	4520	4416	4293	4060	3788
LGEE	12/6/11	3564	3465	3423	3370	3414	3661	4061	4393	4452	4483	4526	4516	4564	4612	4557	4513	4528	4720	4840	4756	4655	4565	4316	4074
LGEE	12/7/11	3877	3775	3698	3649	3729	3913	4363	4684	4743	4815	4854	4807	4837	4874	4843	4826	4847	5050	5126	5069	5035	4983	4783	4578
LGEE	12/8/11	4372	4347	4294	4264	4348	4587	4982	5304	5251	5094	4933	4734	4607	4529	4446	4334	4370	4695	4924	4970	5013	4909	4703	4501
LGEE	12/9/11	4319	4239	4206	4200	4217	4441	4894	5194	5146	5001	4806	4539	4389	4270	4210	4166	4258	4551	4678	4659	4613	4487	4419	4191
LGEE	12/10/11	4046	3939	3896	3898	3945	4098	4306	4511	4597	4607	4510	4348	4244	4088	4019	3951	4021	4354	4598	4631	4716	4665	4567	4460
LGEE	12/11/11	4338	4281	4241	4198	4273	4345	4498	4680	4717	4625	4324	4129	4021	3924	3750	3720	3740	4103	4471	4564	4633	4562	4383	4218
LGEE	12/12/11	4121	4044	4029	4106	4222	4500	4958	5324	5292	5122	4928	4714	4558	4454	4344	4249	4242	4518	4718	4735	4711	4514	4302	4031
LGEE	12/13/11	3804	3693	3590	3554	3619	3779	4189	4552	4506	4490	4442	4392	4315	4280	4251	4273	4238	4445	4526	4529	4495	4313	4083	3798
LGEE	12/14/11	3632	3469	3323	3307	3380	3537	3958	4330	4295	4248	4210	4132	4121	4095	4038	3966	3909	4186	4273	4272	4216	4084	3898	3645
LGEE	12/15/11	3379	3236	3162	3154	3196	3334	3752	4071	4106	4165	4198	4174	4212	4195	4147	4022	4006	4211	4275	4341	4342	4255	4051	3780
LGEE	12/16/11	3588	3483	3493	3505	3552	3804	4242	4588	4668	4743	4748	4678	4690	4605	4572	4528	4484	4700	4810	4740	4739	4634	4464	4283
LGEE	12/17/11	4074	3942	3798	3783	3853	3917	4093	4257	4378	4455	4385	4336	4177	3976	3887	3773	3878	4221	4430	4451	4435	4390	4246	4022
LGEE	12/18/11	3844	3759	3732	3731	3824	3899	4083	4238	4315	4241	4090	3873	3740	3669	3590	3506	3638	3926	4127	4207	4212	4210	4022	3844
LGEE	12/19/11	3687	3612	3584	3662	3731	3941	4263	4528	4629	4632	4566	4494	4443	4407	4345	4270	4340	4501	4599	4508	4475	4333	4141	3873
LGEE	12/20/11	3672	3566	3431	3470	3527	3671	4067	4380	4455	4493	4475	4433	4388	4314	4224	4151	4160	4349	4378	4265	4233	4118	3947	3648
LGEE	12/21/11	3414	3293	3146	3076	3127	3289	3590	3904	4014	4079	4110	4077	4111	4095	4079	4020	3998	4186	4316	4320	4284	4174	3956	3759
LGEE	12/22/11	3513	3434	3381	3347	3345	3500	3850	4150	4288	4364	4398	4387	4407	4393	4379	4332	4348	4469	4513	4467	4359	4238	4020	3795
LGEE	12/23/11	3576	3380	3302	3270	3304	3380	3590	3834	3950	4090	4162	4162	4134	4085	4068	4010	4034	4209	4273	4228	4166	4085	3919	3703
LGEE	12/24/11	3524	3396	3343	3317	3328	3419	3532	3701	3814	3846	3779	3668	3525	3382	3293	3241	3240	3482	3665	3660	3705	3720	3699	3597
LGEE	12/25/11	3528	3448	3403	3368	3380	3447	3561	3696	3766	3781	3581	3425	3285	3142	2979	2907	2910	3124	3362	3413	3472	3473	3435	3337
LGEE	12/26/11	3254	3208	3218	3266	3359	3515	3722	3897	3964	3944	3864	3782	3671	3617	3549	3520	3583	3894	4018	4007	3949	3827	3655	3473

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LGEE	12/27/11	3315	3242	3191	3194	3218	3383	3618	3871	3995	4095	4192	4228	4266	4291	4296	4332	4404	4579	4603	4518	4449	4284	4079	3860
LGEE	12/28/11	3702	3591	3555	3533	3597	3738	3989	4269	4335	4342	4354	4207	4149	4058	4042	4009	4053	4302	4436	4439	4364	4296	4142	3974
LGEE	12/29/11	3860	3791	3742	3729	3816	3927	4147	4375	4431	4455	4394	4276	4091	3965	3860	3749	3743	3971	4179	4205	4153	4026	3860	3642
LGEE	12/30/11	3504	3355	3299	3293	3241	3337	3563	3767	3848	3885	3868	3828	3768	3763	3646	3580	3527	3737	3886	3813	3783	3632	3525	3315
LGEE	12/31/11	3175	3013	2982	2959	3008	3042	3129	3281	3382	3498	3557	3557	3453	3359	3238	3156	3177	3398	3716	3627	3616	3538	3449	3351
LGEE	1/1/12	3219	3168	3016	3017	2957	2979	2930	3057	3063	3174	3251	3285	3364	3394	3350	3389	3398	3664	3957	3996	4015	3975	3849	3692
LGEE	1/2/12	3561	3539	3493	3603	3670	3849	4120	4341	4429	4583	4762	4821	4893	4914	4907	4910	4983	5215	5367	5426	5296	5176	4997	4822
LGEE	1/3/12	4762	4627	4631	4639	4693	4984	5382	5677	5687	5625	5495	5365	5212	5162	5051	4865	4932	5229	5451	5458	5437	5298	5093	4867
LGEE	1/4/12	4772	4688	4624	4579	4652	4886	5287	5560	5511	5379	5276	5043	4950	4825	4588	4506	4472	4673	4985	4963	4962	4798	4552	4323
LGEE	1/5/12	4118	4076	4035	4077	4110	4310	4815	5201	5168	5045	4837	4605	4553	4417	4295	4173	4194	4311	4649	4614	4641	4464	4204	4080
LGEE	1/6/12	3882	3768	3771	3679	3682	3949	4337	4675	4654	4528	4408	4262	4182	4039	3952	3847	3781	3893	4108	4080	4057	4013	3813	3658
LGEE	1/7/12	3467	3364	3225	3135	3086	3163	3225	3414	3518	3580	3583	3607	3586	3499	3439	3358	3379	3610	3867	3890	3877	3862	3733	3653
LGEE	1/8/12	3515	3430	3416	3492	3501	3636	3732	3919	4027	4054	3939	3746	3700	3628	3553	3517	3516	3757	4044	4073	4032	3931	3784	3624
LGEE	1/9/12	3489	3450	3389	3425	3484	3736	4211	4562	4605	4618	4608	4537	4390	4251	4231	4087	4010	4273	4548	4533	4530	4440	4257	4042
LGEE	1/10/12	3927	3867	3847	3816	3926	4170	4626	4943	4933	4817	4700	4535	4403	4299	4228	4090	4082	4179	4546	4532	4460	4398	4179	3948
LGEE	1/11/12	3761	3618	3563	3563	3607	3725	4141	4477	4501	4473	4448	4439	4451	4373	4284	4222	4212	4330	4483	4421	4366	4197	3983	3761
LGEE	1/12/12	3621	3581	3462	3446	3466	3608	4099	4428	4475	4508	4539	4578	4658	4717	4738	4824	4960	5199	5404	5432	5428	5254	5093	4971
LGEE	1/13/12	4893	4864	4890	4885	4990	5178	5515	5826	5877	5926	5917	5879	5859	5789	5693	5636	5545	5628	5683	5536	5471	5309	5128	4874
LGEE	1/14/12	4735	4655	4629	4596	4645	4719	4880	5049	5107	5110	4968	4872	4674	4518	4417	4407	4415	4631	4796	4790	4718	4614	4437	4254
LGEE	1/15/12	4162	4085	4056	4016	4056	4160	4275	4422	4540	4568	4500	4363	4251	4131	3987	3847	3912	4159	4510	4576	4570	4533	4399	4225
LGEE	1/16/12	4139	4040	3974	4031	4040	4177	4413	4668	4725	4770	4786	4750	4770	4724	4680	4596	4523	4617	4664	4604	4493	4290	4029	3765
LGEE	1/17/12	3573	3434	3350	3378	3297	3447	3795	4188	4204	4166	4196	4172	4251	4186	4089	4137	4208	4409	4662	4696	4672	4598	4407	4242
LGEE	1/18/12	4075	4000	3951	3955	4075	4281	4721	5083	5123	5111	5090	4968	4910	4824	4721	4638	4603	4811	5137	5175	5187	5057	4881	4689
LGEE	1/19/12	4505	4455	4452	4460	4549	4764	5189	5410	5336	5247	5112	5078	4978	4863	4774	4612	4576	4767	4904	4892	4904	4834	4649	4464
LGEE	1/20/12	4334	4201	4182	4186	4230	4453	4821	5128	5149	5234	5179	5081	4980	4905	4825	4770	4743	4781	4843	4737	4660	4510	4251	4065
LGEE	1/21/12	3883	3755	3689	3693	3746	3823	3980	4228	4384	4568	4675	4702	4635	4589	4575	4561	4538	4701	4871	4832	4730	4611	4463	4274
LGEE	1/22/12	4086	3929	3887	3797	3883	3903	4003	4046	4142	4290	4248	4132	4060	3974	3877	3799	3776	3880	4029	3993	3914	3753	3573	3373
LGEE	1/23/12	3155	3070	3023	3073	3112	3338	3756	4048	4100	4104	4137	4171	4150	4162	4125	4046	4005	4053	4395	4386	4329	4234	3960	3764
LGEE	1/24/12	3646	3618	3618	3528	3688	3905	4360	4748	4748	4641	4507	4380	4318	4229	4133	4073	4046	4188	4525	4597	4598	4594	4349	4299
LGEE	1/25/12	4119	4082	3977	4043	4133	4308	4725	5056	5056	5020	4925	4784	4780	4694	4622	4567	4617	4688	4873	4808	4736	4582	4317	4038
LGEE	1/26/12	3889	3759	3677	3598	3584	3717	4124	4390	4388	4357	4362	4311	4316	4224	4134	4133	4130	4258	4399	4354	4325	4153	3930	3704
LGEE	1/27/12	3530	3514	3451	3478	3501	3722	4165	4549	4576	4645	4692	4672	4686	4639	4609	4547	4540	4629	4696	4633	4581	4489	4291	4133
LGEE	1/28/12	3975	3841	3820	3759	3776	3825	3895	4085	4184	4292	4284	4191	4081	3925	3794	3766	3702	3791	4199	4310	4281	4246	4155	4048
LGEE	1/29/12	3959	3912	3880	3831	3859	3976	4080	4173	4280	4211	4078	3936	3852	3711	3652	3580	3656	3794	4169	4226	4257	4206	4065	3950
LGEE	1/30/12	3841	3820	3855	3895	3977	4312	4748	5069	5027	4909	4698	4507	4345	4219	4113	3947	3881	3954	4221	4285	4302	4159	3943	3731
LGEE	1/31/12	3588	3468	3413	3366	3426	3617	4077	4376	4337	4311	4229	4150	4099	4030	3955	3872	3846	4009	4226	4209	4154	4030	3829	3630

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LGEE	2/2/12	3328	3188	3161	3160	3155	3411	3893	4241	4253	4223	4165	4058	4043	3972	3959	3822	3804	3844	4116	4196	4228	4146	3988	3788
LGEE	2/3/12	3622	3544	3566	3596	3648	3877	4310	4647	4626	4532	4410	4255	4171	4044	3958	3810	3809	3862	4067	4044	4043	3957	3797	3605
LGEE	2/4/12	3413	3287	3164	3117	3116	3206	3379	3510	3662	3837	3954	3924	3944	3847	3816	3764	3736	3815	3942	3982	3892	3751	3595	3405
LGEE	2/5/12	3288	3192	3130	3075	3076	3093	3255	3413	3532	3693	3712	3742	3751	3776	3714	3647	3662	3717	3910	3970	4012	3960	3920	3790
LGEE	2/6/12	3663	3644	3659	3699	3818	4077	4540	4910	4888	4734	4581	4423	4274	4182	4074	4023	4025	4080	4405	4536	4558	4490	4310	4088
LGEE	2/7/12	4027	3946	3947	3956	4006	4288	4742	5047	4990	4820	4617	4468	4319	4255	4109	4019	4007	4078	4400	4494	4528	4451	4245	4026
LGEE	2/8/12	3941	3809	3770	3725	3774	4054	4455	4789	4834	4816	4841	4825	4812	4789	4758	4733	4760	4828	4981	4972	4863	4711	4514	4307
LGEE	2/9/12	4132	4021	3920	3930	3928	4169	4606	4879	4874	4925	4880	4853	4826	4756	4692	4627	4617	4684	4902	4939	4892	4766	4551	4341
LGEE	2/10/12	4217	4153	4113	4063	4113	4350	4742	5036	5028	5015	4979	4882	4845	4717	4688	4701	4688	4775	4897	4869	4811	4677	4463	4361
LGEE	2/11/12	4228	4111	4093	4088	4143	4291	4507	4709	4849	4934	5019	5002	4895	4903	4818	4733	4774	4884	5161	5217	5169	5124	4969	4812
LGEE	2/12/12	4618	4610	4630	4641	4677	4736	4797	4980	4953	4917	4774	4597	4388	4287	4122	4017	4011	4112	4484	4665	4736	4646	4526	4418
LGEE	2/13/12	4318	4341	4357	4441	4605	4860	5268	5602	5544	5354	5198	5054	4954	4843	4793	4745	4725	4811	4933	4995	4977	4826	4579	4350
LGEE	2/14/12	4204	4057	4014	3963	3995	4190	4606	4924	4920	4968	4977	4913	4919	4862	4783	4707	4672	4710	4902	4879	4843	4705	4452	4261
LGEE	2/15/12	4127	4036	4013	3957	4044	4279	4712	4988	4935	4817	4658	4520	4392	4339	4261	4187	4192	4252	4434	4465	4441	4298	4077	3862
LGEE	2/16/12	3642	3507	3478	3442	3468	3620	4036	4318	4308	4356	4372	4351	4391	4341	4243	4226	4171	4254	4417	4466	4426	4321	4128	3843
LGEE	2/17/12	3710	3635	3644	3655	3741	3974	4396	4723	4690	4554	4399	4272	4205	4111	4017	3918	3852	3859	4054	4181	4158	4093	3975	3851
LGEE	2/18/12	3671	3596	3598	3496	3534	3615	3769	3942	4049	4058	3953	3865	3756	3642	3577	3554	3581	3661	3869	3938	3935	3847	3715	3562
LGEE	2/19/12	3473	3372	3361	3375	3376	3441	3604	3716	3833	4010	4065	4085	4138	4112	4086	4049	4077	4168	4283	4422	4386	4306	4166	4029
LGEE	2/20/12	3941	3932	3974	4035	4106	4402	4835	5132	5130	5003	4860	4681	4569	4430	4268	4122	4085	4133	4420	4647	4671	4571	4393	4196
LGEE	2/21/12	4072	3976	3884	3800	3782	3936	4328	4557	4577	4538	4517	4398	4443	4344	4339	4271	4154	4109	4324	4433	4396	4250	4063	3886
LGEE	2/22/12	3737	3677	3628	3633	3685	3884	4321	4579	4515	4436	4341	4224	4152	4117	4056	3963	3983	4068	4227	4286	4223	4099	3859	3639
LGEE	2/23/12	3488	3387	3313	3327	3327	3515	3994	4268	4271	4240	4224	4087	4024	3991	3870	3787	3796	3840	3972	4053	3993	3842	3659	3422
LGEE	2/24/12	3184	3109	3018	2984	3006	3193	3590	3921	4010	4110	4190	4242	4331	4337	4366	4305	4331	4367	4494	4551	4502	4420	4262	4093
LGEE	2/25/12	3960	3836	3789	3738	3782	3895	3962	4116	4220	4305	4251	4314	4181	4117	4020	3871	3781	3855	4037	4330	4355	4294	4226	4054
LGEE	2/26/12	3998	3947	3929	3940	4027	4116	4204	4290	4288	4127	3902	3793	3608	3513	3395	3327	3324	3369	3564	3844	3873	3804	3668	3544
LGEE	2/27/12	3434	3312	3383	3434	3455	3702	4130	4375	4366	4299	4163	4078	4022	3949	3879	3800	3750	3774	3912	4127	4107	3984	3799	3604
LGEE	2/28/12	3498	3489	3434	3488	3569	3805	4342	4581	4528	4403	4260	4115	4037	3934	3827	3801	3749	3722	3844	4043	4000	3832	3586	3315
LGEE	2/29/12	3135	3002	2950	2911	2943	3106	3497	3809	3871	3921	3876	3949	3930	3902	3857	3781	3726	3735	3886	4033	4012	3804	3612	3339
LGEE	3/1/12	3141	3088	3020	3063	3119	3323	3791	4056	4061	4029	4022	3954	3930	3913	3878	3803	3736	3702	3817	4009	4034	3911	3776	3561
LGEE	3/2/12	3422	3349	3299	3275	3318	3462	3827	4021	4063	4073	4056	4056	4074	4013	3916	3630	3437	3414	3462	3614	3661	3556	3448	3348
LGEE	3/3/12	3198	3140	3117	3131	3174	3318	3521	3684	3856	3876	3882	3791	3701	3616	3507	3401	3410	3456	3674	3860	3892	3856	3785	3617
LGEE	3/4/12	3543	3469	3483	3420	3506	3646	3699	3809	3935	3991	3922	3894	3890	3782	3693	3598	3599	3689	3982	4169	4170	4093	3890	3771
LGEE	3/5/12	3670	3618	3586	3677	3774	4043	4454	4718	4855	4832	4831	4785	4783	4699	4533	4406	4385	4414	4633	4928	4936	4853	4613	4467
LGEE	3/6/12	4324	4250	4230	4237	4233	4450	4875	5031	4922	4729	4554	4391	4303	4211	4098	3966	3896	3830	3940	4204	4185	4067	3855	3649
LGEE	3/7/12	3493	3362	3309	3247	3309	3544	3979	4169	4160	4109	4067	4000	3996	3923	3916	3826	3783	3773	3873	4101	4010	3925	3687	3420

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LGEE	3/9/12	3581	3519	3488	3470	3510	3785	4294	4536	4513	4413	4315	4208	4173	4060	3912	3847	3734	3753	3919	4143	4189	4118	4023	3853
LGEE	3/10/12	3759	3664	3621	3643	3621	3755	3908	3990	4005	3976	3873	3770	3612	3444	3364	3245	3245	3226	3374	3625	3610	3624	3513	3392
LGEE	3/11/12	3249	3148	3156	3250	3276	3439	3585	3605	3600	3488	3347	3308	3235	3200	3116	3140	3121	3149	3339	3520	3421	3222	3093	2931
LGEE	3/12/12	2873	2767	2803	2868	3065	3464	3848	3923	3949	3988	3985	4016	4013	3976	3904	3847	3883	3884	3913	4050	3858	3652	3367	3158
LGEE	3/13/12	3047	3032	2921	2985	3114	3477	3831	3836	3848	3908	3931	3952	3975	3990	3992	3976	3949	3900	3922	4148	4023	3743	3462	3226
LGEE	3/14/12	3052	2963	2886	2894	3030	3418	3805	3832	3869	3947	3987	4065	4106	4135	4182	4155	4157	4083	4053	4248	4092	3815	3556	3287
LGEE	3/15/12	3192	3039	2947	2961	3134	3546	3857	3868	3930	4033	4086	4169	4277	4342	4380	4244	4130	4112	4010	4019	3957	3710	3447	3273
LGEE	3/16/12	3087	3004	2880	2877	3034	3362	3683	3764	3872	3935	3980	3985	3987	3971	3909	3837	3811	3736	3745	3902	3804	3598	3398	3140
LGEE	3/17/12	2993	2907	2802	2784	2776	2878	3043	3115	3300	3459	3490	3588	3608	3597	3595	3645	3644	3607	3636	3694	3583	3400	3211	2991
LGEE	3/18/12	2837	2666	2645	2599	2606	2648	2796	2865	3077	3213	3351	3456	3516	3606	3688	3749	3790	3817	3787	3988	3872	3655	3361	3105
LGEE	3/19/12	2901	2861	2858	2884	3074	3483	3792	3850	3948	4072	4182	4313	4445	4579	4614	4635	4619	4561	4476	4548	4388	4090	3756	3428
LGEE	3/20/12	3224	3042	2967	2934	3106	3500	3822	3869	3969	4103	4241	4403	4543	4669	4757	4817	4813	4738	4642	4740	4542	4176	3781	3492
LGEE	3/21/12	3287	3118	3013	2998	3123	3515	3841	3884	4027	4217	4386	4556	4717	4831	4913	4923	4905	4797	4654	4731	4535	4179	3789	3469
LGEE	3/22/12	3261	3095	3015	2972	3089	3486	3787	3843	3994	4142	4281	4428	4540	4620	4591	4548	4507	4375	4339	4425	4286	4008	3668	3405
LGEE	3/23/12	3208	3070	2996	2974	3151	3486	3858	3895	4005	4115	4136	4174	4220	4166	4131	4112	4138	4098	3989	4077	3922	3652	3457	3224
LGEE	3/24/12	3006	2905	2780	2756	2752	2852	3001	3099	3283	3385	3450	3417	3430	3315	3308	3306	3328	3315	3296	3475	3377	3157	3005	2834
LGEE	3/25/12	2672	2587	2574	2518	2600	2655	2758	2822	2984	3059	3100	3126	3139	3123	3190	3209	3252	3281	3356	3521	3463	3335	3079	2904
LGEE	3/26/12	2821	2687	2692	2748	2972	3367	3703	3734	3813	3888	3900	3908	3916	3892	3889	3907	3858	3841	3791	4012	3910	3658	3373	3213
LGEE	3/27/12	3059	2971	2974	3054	3197	3705	4050	4031	4019	3978	3943	3924	3889	3897	3845	3824	3786	3784	3779	3983	3900	3650	3355	3128
LGEE	3/28/12	2965	2925	2839	2882	3033	3514	3752	3805	3897	3981	4006	4155	4280	4381	4317	4340	4273	4234	4104	4212	4109	3805	3466	3255
LGEE	3/29/12	3035	2959	2920	2833	3034	3427	3678	3737	3822	3897	3922	3972	4057	4074	4055	4058	4134	3975	3923	4110	4051	3703	3440	3155
LGEE	3/30/12	3046	2891	2858	2833	3032	3360	3680	3676	3801	3867	3919	4038	4186	4188	4247	4245	4243	4178	3994	4081	4003	3770	3512	3271
LGEE	3/31/12	3008	2910	2825	2742	2790	2880	2920	3053	3209	3349	3417	3405	3417	3382	3428	3450	3436	3320	3245	3337	3340	3169	2982	2808
LGEE	4/1/12	2632	2538	2539	2499	2612	2715	2778	2959	3112	3212	3261	3263	3250	3267	3234	3273	3405	3399	3483	3645	3625	3418	3200	3001
LGEE	4/2/12	2893	2843	2788	2800	2957	3332	3609	3722	3856	3993	4031	4105	4155	4216	4249	4228	4222	4188	4167	4248	4057	3831	3530	3357
LGEE	4/3/12	3135	3032	2944	2907	3073	3354	3607	3703	3851	3982	4109	4294	4478	4687	4732	4787	4728	4657	4592	4672	4506	4107	3821	3528
LGEE	4/4/12	3343	3219	3098	3051	3226	3502	3759	3830	3995	4199	4311	4441	4569	4613	4667	4542	4405	4291	4171	4259	4118	3807	3553	3317
LGEE	4/5/12	3153	2997	2897	2875	3014	3369	3590	3699	3787	3846	3844	3849	3888	3881	3825	3729	3726	3651	3585	3837	3768	3529	3341	3132
LGEE	4/6/12	2976	2932	2889	2908	3025	3350	3526	3658	3656	3662	3579	3569	3555	3508	3468	3330	3366	3297	3283	3421	3456	3289	3166	3010
LGEE	4/7/12	2915	2817	2823	2842	2908	3036	3136	3218	3318	3264	3194	3136	3173	3113	3125	3106	3163	3163	3111	3279	3274	3100	2953	2795
LGEE	4/8/12	2661	2548	2547	2570	2619	2696	2765	2920	3021	2997	3011	2999	2979	2933	2899	2893	2946	3002	2986	3223	3252	3103	2908	2804
LGEE	4/9/12	2721	2666	2684	2838	3019	3465	3736	3830	3872	3917	3892	3917	3948	3913	3853	3765	3723	3689	3735	3900	3874	3633	3372	3162
LGEE	4/10/12	3098	2974	2955	2972	3141	3572	3782	3878	3900	3944	3943	3920	3972	3883	3826	3704	3723	3716	3702	3935	3950	3722	3450	3294
LGEE	4/11/12	3246	3233	3201	3280	3547	3937	4152	4184	4165	4165	4161	4102	4066	4004	3876	3901	3882	3882	3838	4094	4076	3889	3747	3591
LGEE	4/12/12	3486	3491	3447	3490	3727	4126	4404	4356	4259	4121	4049	3999	3945	3911	3836	3780	3719	3716	3725	3890	3850	3654	3441	3258

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Backup - LGEE Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
LGEE	4/13/12	3185	3212	3230	3247	3421	3877	4084	4105	4042	4020	3943	3919	3896	3866	3782	3678	3657	3595	3550	3775	3692	3512	3335	3130
LGEE	4/14/12	2984	2851	2792	2740	2834	2943	3007	3165	3343	3418	3420	3407	3357	3349	3346	3344	3342	3371	3373	3463	3491	3327	3121	2934
LGEE	4/15/12	2758	2667	2607	2564	2592	2709	2715	2906	3005	3190	3358	3448	3516	3603	3658	3766	3830	3809	3782	3944	3908	3703	3444	3177
LGEE	4/16/12	3066	2991	2920	2988	3173	3575	3837	3962	4059	4166	4208	4267	4321	4361	4334	4238	4249	4146	4081	4151	4101	3772	3461	3231
LGEE	4/17/12	3040	2942	2889	2853	3041	3455	3687	3766	3852	3940	3960	3981	4029	3978	3930	3862	3847	3787	3824	3896	3891	3661	3420	3190
LGEE	4/18/12	3089	2994	2939	2951	3134	3530	3709	3828	3868	3908	3936	3992	4005	4041	4066	4054	4014	3988	3967	4049	4034	3717	3451	3238
LGEE	4/19/12	3089	3005	2921	2931	3155	3541	3777	3842	3923	3962	3983	4051	4091	4164	4176	4206	4201	4191	4145	4144	4149	3847	3504	3266
LGEE	4/20/12	3102	2926	2866	2862	3056	3430	3625	3759	3866	3949	4051	4101	4192	4209	4203	4199	4094	3996	3917	3952	3912	3639	3384	3113
LGEE	4/21/12	2966	2899	2776	2755	2772	2910	2964	3153	3327	3445	3472	3470	3413	3388	3345	3273	3278	3329	3388	3479	3433	3305	3112	2948
LGEE	4/22/12	2901	2789	2785	2780	2841	2824	2961	3204	3273	3317	3359	3376	3351	3295	3297	3337	3318	3353	3456	3618	3664	3488	3286	3132
LGEE	4/23/12	3126	3093	3112	3185	3444	3906	4183	4245	4240	4195	4142	4089	4093	4038	3930	3833	3829	3789	3822	3968	3992	3761	3555	3413
LGEE	4/24/12	3323	3306	3263	3313	3521	3979	4187	4183	4117	4043	3984	3969	3929	3888	3889	3889	3737	3813	3812	3950	3940	3697	3451	3258
LGEE	4/25/12	3103	3060	2990	3035	3206	3611	3829	3883	3925	3957	3941	4002	4037	4062	4054	4059	4015	4005	3970	4088	4053	3824	3560	3328
LGEE	4/26/12	3132	3079	2999	2997	3194	3481	3714	3865	4027	4197	4341	4342	4480	4526	4566	4585	4566	4474	4330	4307	4224	3868	3523	3203
LGEE	4/27/12	3040	2917	2825	2829	2992	3398	3618	3708	3796	3853	3835	3843	3799	3793	3775	3739	3676	3623	3541	3654	3680	3461	3222	3026
LGEE	4/28/12	2889	2778	2722	2695	2782	2879	2946	3113	3229	3331	3345	3349	3415	3480	3554	3630	3657	3652	3665	3596	3521	3296	3051	2848
LGEE	4/29/12	2692	2572	2528	2515	2529	2580	2616	2809	2983	3094	3197	3317	3433	3551	3649	3764	3840	3863	3793	3865	3900	3644	3325	3084
LGEE	4/30/12	2909	2832	2765	2818	2996	3369	3599	3794	3978	4225	4474	4684	4827	4911	4993	4971	4952	4814	4678	4669	4499	4190	3885	3571
LGEE	5/1/12	3382	3235	3132	3085	3276	3601	3861	4041	4170	4300	4492	4672	4861	5011	5105	5073	5017	4939	4823	4762	4785	4455	4073	3794
LGEE	5/2/12	3570	3418	3272	3251	3371	3755	4017	4311	4550	4872	5099	5339	5500	5640	5718	5793	5817	5706	5542	5477	5383	4931	4529	4101
LGEE	5/3/12	3839	3633	3487	3419	3534	3861	4052	4328	4552	4752	4969	5128	5302	5392	5448	5442	5313	5159	5009	4994	4924	4598	4211	3876
LGEE	5/4/12	3622	3481	3313	3321	3422	3695	3967	4174	4438	4673	4846	5074	5252	5384	5505	5510	5330	5085	4818	4755	4669	4386	4083	3773
LGEE	5/5/12	3499	3266	3193	3058	3052	3135	3169	3353	3615	3791	3996	4135	4217	4387	4515	4624	4660	4628	4473	4426	4389	4149	3813	3510
LGEE	5/6/12	3257	3072	2961	2886	2899	2927	2957	3174	3522	3791	4140	4426	4661	4809	4955	5008	5109	5055	4891	4755	4744	4406	3964	3618
LGEE	5/7/12	3429	3273	3193	3172	3326	3691	3938	4215	4410	4663	4899	5138	5336	5462	5600	5631	5586	5465	5250	5186	4921	4554	4187	3798
LGEE	5/8/12	3573	3381	3363	3307	3463	3791	4006	4138	4260	4379	4498	4598	4658	4753	4841	4862	4861	4734	4607	4523	4453	4157	3774	3470
LGEE	5/9/12	3308	3149	3056	3021	3198	3542	3756	3927	3964	4146	4268	4318	4441	4412	4414	4369	4369	4295	4153	4140	4146	3868	3537	3308
LGEE	5/10/12	3115	2962	2903	2905	3083	3371	3613	3737	3914	3970	4064	4108	4127	4155	4147	4120	4094	4099	3996	3950	4038	3716	3478	3188
LGEE	5/11/12	3056	2965	2853	2908	3026	3374	3610	3754	3827	3902	3941	3997	4044	4158	4191	4195	4227	4156	3999	3942	3958	3763	3465	3218
LGEE	5/12/12	3045	2899	2797	2754	2827	2877	2981	3113	3309	3418	3424	3481	3516	3490	3538	3573	3508	3490	3574	3562	3538	3400	3166	2948
LGEE	5/13/12	2813	2712	2645	2648	2677	2767	2776	3012	3180	3273	3290	3314	3242	3253	3291	3260	3304	3337	3356	3457	3449	3302	3118	2936
LGEE	5/14/12	2838	2799	2785	2854	3033	3434	3699	3884	3946	4055	4095	4142	4180	4212	4224	4232	4283	4286	4243	4261	4261	4008	3645	3412
LGEE	5/15/12	3226	3106	3003	3014	3171	3437	3713	3886	4028	4127	4328	4464	4609	4619	4676	4682	4723	4669	4578	4528	4523	4198	3825	3525
LGEE	5/16/12	3319	3159	3024	3022	3174	3491	3740	3944	4119	4378	4521	4632	4810	4962	5094	5147	5127	5023	4850	4768	4736	4370	3968	3681
LGEE	5/17/12	3405	3252	3118	3060	3199	3518	3731	3867	4041	4176	4225	4376	4447	4580	4671	4727	4761	4681	4599	4496	4443	4153	3765	3495
LGEE	5/18/12	3289	3116	2996	2985	3133	3400	3631	3794	3991	4172	4332	4483	4772	4883	5043	5151	5163	5102	4917	4753	4671	4368	3986	3653

Backup - LGEE Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
LGEE	5/19/12	3373	3136	3022	2945	2942	2991	3142	3387	3695	3997	4236	4442	4662	4834	4950	5035	5102	5096	4921	4707	4670	4342	3926	3620
LGEE	5/20/12	3321	3160	2993	2938	2936	2873	2944	3177	3539	3889	4123	4417	4632	4771	4872	4945	4995	4935	4813	4693	4621	4285	3885	3555
LGEE	5/21/12	3338	3187	3085	3133	3270	3558	3817	4083	4335	4589	4745	4950	5031	5083	5091	5050	4985	4826	4655	4538	4478	4208	3860	3566
LGEE	5/22/12	3343	3187	3094	3024	3161	3419	3634	3825	3981	4128	4246	4403	4641	4712	4747	4746	4766	4728	4603	4564	4535	4273	3930	3627
LGEE	5/23/12	3405	3235	3140	3121	3252	3504	3767	3986	4186	4419	4598	4789	4995	5072	5188	5214	5296	5182	5088	4903	4830	4556	4122	3803
LGEE	5/24/12	3546	3337	3237	3234	3331	3599	3886	4130	4409	4708	4987	5203	5366	5485	5627	5703	5683	5620	5459	5282	5104	4841	4395	4075
LGEE	5/25/12	3778	3569	3409	3342	3502	3731	3987	4292	4645	5050	5357	5648	5864	5997	6041	6077	6060	5905	5724	5523	5375	5071	4634	4151
LGEE	5/26/12	3830	3591	3376	3305	3299	3285	3392	3710	4120	4533	4887	5107	5296	5478	5597	5691	5691	5656	5492	5300	5163	4852	4405	4057
LGEE	5/27/12	3750	3567	3364	3294	3255	3132	3253	3614	4004	4462	4812	5053	5296	5386	5543	5676	5702	5654	5449	5310	5166	4877	4467	4103
LGEE	5/28/12	3817	3577	3412	3319	3350	3324	3412	3763	4177	4563	4944	5247	5447	5556	5660	5725	5763	5686	5583	5437	5382	5091	4654	4334
LGEE	5/29/12	3996	3827	3720	3710	3849	4125	4350	4595	4728	4907	4887	4934	5001	4997	5048	5145	5215	5180	5091	4956	4880	4602	4210	3855
LGEE	5/30/12	3560	3399	3252	3222	3320	3530	3811	4125	4417	4766	4984	5223	5301	5293	5217	5161	5136	5069	4935	4721	4630	4329	3949	3618
LGEE	5/31/12	3342	3197	3072	3021	3128	3352	3597	3876	4128	4348	4626	4840	5012	5180	5342	5442	5425	5296	5036	4861	4718	4420	4066	3790
LGEE	6/1/12	3535	3420	3300	3294	3360	3618	3789	3933	4015	4100	4142	4095	4076	3979	3930	3844	3785	3692	3605	3645	3731	3571	3387	3149
LGEE	6/2/12	2983	2886	2778	2752	2765	2787	2876	3049	3204	3321	3417	3405	3421	3397	3427	3469	3480	3433	3384	3403	3494	3357	3190	2960
LGEE	6/3/12	2817	2655	2659	2613	2662	2627	2721	2883	3102	3375	3543	3772	3876	4031	4162	4294	4376	4366	4327	4184	4176	3961	3650	3380
LGEE	6/4/12	3248	3099	3048	3075	3219	3407	3677	3955	4183	4408	4609	4658	4680	4642	4570	4480	4378	4296	4214	4192	4191	3947	3672	3427
LGEE	6/5/12	3238	3145	3052	3005	3152	3366	3620	3880	4068	4216	4338	4468	4584	4684	4725	4708	4646	4555	4402	4345	4303	4091	3742	3506
LGEE	6/6/12	3281	3153	3045	3004	3129	3290	3560	3763	3969	4103	4192	4301	4432	4468	4525	4541	4571	4543	4449	4350	4304	4111	3763	3463
LGEE	6/7/12	3273	3120	3051	2982	3160	3359	3577	3827	3996	4230	4371	4659	4763	4864	4985	5062	5091	5025	4929	4737	4637	4378	4003	3659
LGEE	6/8/12	3376	3175	3133	3034	3233	3345	3601	3912	4138	4441	4664	4865	5074	5188	5326	5399	5411	5368	5198	4953	4846	4494	4072	3740
LGEE	6/9/12	3438	3188	3074	2988	3026	3029	3143	3410	3724	4051	4318	4592	4780	4943	5083	5233	5242	5244	5133	4898	4758	4501	4078	3702
LGEE	6/10/12	3423	3212	3091	3074	3038	2952	3058	3208	3603	3942	4151	4378	4621	4706	4828	4857	4785	4704	4564	4467	4482	4288	3933	3633
LGEE	6/11/12	3421	3295	3242	3315	3479	3761	4021	4275	4495	4677	4827	4993	5210	5349	5500	5539	5541	5481	5310	5204	5117	4874	4474	4125
LGEE	6/12/12	3880	3662	3526	3464	3585	3789	4028	4327	4585	4830	5138	5403	5663	5778	5866	5860	5811	5643	5428	5199	5066	4749	4337	3889
LGEE	6/13/12	3620	3442	3289	3208	3272	3447	3734	3950	4143	4493	4728	4928	5143	5273	5417	5499	5563	5493	5345	5108	4953	4668	4264	3838
LGEE	6/14/12	3619	3334	3131	3084	3180	3356	3616	3904	4159	4500	4730	5030	5209	5376	5510	5628	5641	5593	5426	5222	5033	4712	4262	3871
LGEE	6/15/12	3573	3421	3216	3199	3293	3421	3732	4069	4390	4727	5044	5346	5628	5799	5956	6060	6079	5977	5818	5634	5454	5170	4758	4348
LGEE	6/16/12	3995	3802	3571	3479	3396	3378	3474	3728	3975	4260	4520	4750	4893	5118	5244	5354	5318	5211	5110	4935	4877	4614	4299	3877
LGEE	6/17/12	3657	3465	3287	3272	3207	3238	3245	3610	3930	4163	4268	4432	4535	4574	4597	4605	4630	4614	4546	4473	4557	4343	4074	3707
LGEE	6/18/12	3497	3399	3344	3313	3517	3716	4053	4407	4804	5163	5421	5751	5934	6102	6183	6246	6243	6148	5992	5814	5654	5351	4909	4464
LGEE	6/19/12	4159	3948	3710	3648	3744	3893	4215	4617	4998	5388	5652	5960	6210	6307	6437	6484	6449	6380	6138	5991	5771	5458	5018	4549
LGEE	6/20/12	4214	3977	3792	3683	3747	3938	4236	4649	5088	5485	5852	6132	6392	6517	6623	6645	6616	6481	6364	6118	5961	5577	5118	4648
LGEE	6/21/12	4354	4069	3913	3784	3906	4026	4342	4770	5151	5572	5852	6208	6348	6480	6587	6595	6593	6445	6228	6069	5839	5508	5095	4614
LGEE	6/22/12	4302	4088	3873	3804	3885	4038	4318	4589	4909	5291	5516	5816	5982	6121	6201	6213	6142	6022	5841	5579	5362	5086	4684	4248
LGEE	6/23/12	3949	3691	3448	3367	3283	3255	3375	3656	4063	4433	4783	5038	5206	5384	5538	5625	5653	5619	5526	5188	5007	4749	4377	4019

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
LGEE	6/24/12	3761	3584	3415	3366	3288	3165	3251	3588	4019	4481	4833	5145	5392	5546	5729	5891	5887	5810	5745	5493	5371	5115	4614	4240
LGEE	6/25/12	3916	3732	3590	3598	3665	3884	4144	4543	4899	5326	5674	6009	6210	6316	6341	6345	6311	6143	5892	5615	5369	4996	4538	4064
LGEE	6/26/12	3728	3521	3339	3264	3334	3452	3733	3928	4168	4358	4514	4698	4837	5000	5125	5202	5296	5218	5097	4840	4713	4429	4023	3664
LGEE	6/27/12	3413	3228	3111	3064	3160	3348	3593	3874	4144	4451	4708	5002	5226	5480	5696	5857	5952	5955	5794	5553	5294	4962	4506	4107
LGEE	6/28/12	3807	3580	3416	3321	3431	3577	3826	4178	4574	4983	5392	5809	6211	6515	6686	6831	6848	6828	6645	6418	6240	5894	5409	4978
LGEE	6/29/12	4650	4369	4162	4051	4096	4211	4435	4830	5256	5778	6223	6636	6966	7118	7186	7223	7173	7102	6683	6388	6152	5842	5417	4992
LGEE	6/30/12	4646	4377	4111	3927	3890	3828	3904	4269	4712	5192	5604	5965	6176	6413	6590	6622	6627	6620	6466	6251	6095	5805	5389	4996
LGEE	7/1/12	4690	4345	4129	3955	3873	3871	3854	4114	4446	4889	5352	5709	6033	6286	6437	6536	6571	6512	6321	5953	5635	5211	4793	4444
LGEE	7/2/12	4175	3945	3798	3787	3835	3996	4179	4503	4902	5370	5732	6102	6412	6583	6757	6814	6801	6703	6463	6268	6103	5726	5279	4870
LGEE	7/3/12	4530	4246	4060	3951	3961	4136	4254	4603	4945	5301	5641	5957	6207	6414	6496	6559	6500	6326	6101	5896	5790	5454	5056	4729
LGEE	7/4/12	4366	4134	3975	3857	3788	3728	3740	4027	4505	5023	5472	5807	6052	6188	6298	6339	6345	6264	6074	5868	5676	5491	5210	4859
LGEE	7/5/12	4604	4332	4136	4021	4126	4279	4560	4992	5396	5916	6332	6682	6931	6812	6782	6509	6354	6127	5962	5884	5772	5441	4987	4670
LGEE	7/6/12	4335	4174	3975	3853	3931	3969	4194	4611	5021	5505	5961	6351	6671	6813	6870	6994	6992	6790	6645	6452	6323	5991	5624	5202
LGEE	7/7/12	4855	4640	4423	4247	4134	4060	4140	4495	5049	5549	5993	6315	6494	6633	6694	6756	6750	6726	6542	6313	6187	5913	5569	5217
LGEE	7/8/12	4925	4665	4486	4326	4252	4155	4200	4496	4957	5359	5736	6058	6238	6281	6279	6106	5826	5565	5366	5095	5082	4833	4532	4183
LGEE	7/9/12	3988	3838	3826	3731	3930	4120	4406	4681	4865	5093	5250	5410	5538	5563	5613	5582	5593	5576	5453	5314	5204	4937	4525	4205
LGEE	7/10/12	3922	3751	3588	3587	3684	3910	4171	4506	4768	5117	5455	5794	6034	6214	6315	6328	6305	6213	6067	5890	5738	5380	4917	4561
LGEE	7/11/12	4277	4001	3811	3716	3777	3914	4179	4568	4966	5346	5674	6028	6267	6448	6502	6478	6457	6326	6113	5905	5787	5485	5040	4615
LGEE	7/12/12	4304	4059	3873	3802	3856	4079	4307	4504	4886	5292	5477	5808	5945	5992	5961	5817	5581	5397	5173	5109	5017	4812	4479	4215
LGEE	7/13/12	3949	3776	3631	3577	3751	3951	4173	4417	4602	4792	4920	5084	5190	5288	5277	5296	5222	5124	5010	4943	4947	4722	4434	4152
LGEE	7/14/12	3915	3710	3590	3476	3499	3464	3576	3908	4334	4687	5005	5196	5143	5004	4791	4757	4734	4736	4661	4598	4521	4348	4073	3877
LGEE	7/15/12	3613	3411	3291	3246	3246	3240	3293	3513	3794	4065	4319	4527	4767	5021	5210	5433	5483	5429	5393	5260	5233	4983	4677	4311
LGEE	7/16/12	4005	3825	3741	3649	3783	4034	4285	4694	5081	5523	5845	6033	6292	6441	6511	6539	6506	6418	6286	6126	6017	5658	5197	4853
LGEE	7/17/12	4520	4313	4150	4011	4100	4291	4541	4972	5343	5775	6172	6460	6635	6734	6771	6780	6759	6687	6541	6387	6294	5911	5500	5076
LGEE	7/18/12	4749	4523	4400	4304	4382	4534	4753	5138	5525	5907	6211	6510	6681	6870	6923	6803	6418	6112	5824	5607	5540	5167	4769	4428
LGEE	7/19/12	4117	3957	3794	3742	3853	4111	4342	4696	5025	5402	5806	6155	6474	6615	6669	6650	6517	6183	5690	5530	5311	5046	4623	4313
LGEE	7/20/12	4098	3885	3810	3758	3836	4025	4266	4430	4706	4967	5133	5293	5491	5679	5844	5835	5769	5568	5365	5219	5103	4852	4467	4147
LGEE	7/21/12	3863	3632	3423	3358	3303	3321	3371	3600	3939	4257	4550	4754	4901	5081	5204	5319	5394	5389	5243	4993	4861	4575	4184	3844
LGEE	7/22/12	3579	3340	3243	3162	3113	3033	3103	3440	3850	4259	4603	4990	5248	5415	5562	5796	5879	5837	5734	5547	5419	5097	4729	4399
LGEE	7/23/12	4094	3919	3868	3873	3982	4206	4491	4869	5292	5729	6033	6369	6683	6825	6891	6927	6928	6829	6696	6501	6430	6042	5585	5175
LGEE	7/24/12	4881	4645	4465	4409	4469	4692	4873	5070	5376	5707	5970	6276	6559	6725	6832	6861	6847	6707	6470	6276	6080	5690	5286	4889
LGEE	7/25/12	4607	4388	4196	4130	4194	4397	4650	5001	5445	5882	6252	6614	6930	7117	7197	7185	7151	7136	6974	6738	6649	6274	5822	5435
LGEE	7/26/12	5132	4875	4674	4570	4591	4792	5000	5385	5790	6177	6513	6803	7051	7139	7199	7118	6948	6699	6365	6100	5954	5576	5138	4769
LGEE	7/27/12	4476	4239	4056	4003	4072	4260	4437	4698	4998	5341	5679	6025	6293	6481	6549	6606	6614	6496	6131	5637	5229	4973	4604	4244
LGEE	7/28/12	3950	3702	3524	3398	3361	3342	3402	3759	4149	4465	4746	4999	5188	5335	5436	5526	5558	5480	5308	5063	4931	4621	4263	3900
LGEE	7/29/12	3622	3428	3289	3187	3137	3125	3132	3435	3812	4161	4453	4751	4963	5099	5203	5296	5383	5341	5222	5013	4937	4646	4306	3956

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BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
LGEE	7/30/12	3702	3526	3421	3410	3534	3772	4017	4399	4770	5190	5525	5833	6077	6240	6364	6407	6403	6318	6111	5912	5780	5413	4986	4604
LGEE	7/31/12	4317	4076	3886	3824	3891	4107	4257	4616	5043	5462	5852	6158	6402	6565	6674	6722	6673	6573	6371	6141	6031	5663	5247	4857
LGEE	8/1/12	4548	4274	4091	3986	4051	4281	4459	4787	5188	5580	5990	6340	6628	6755	6781	6786	6687	6615	6452	6176	5972	5561	5088	4630
LGEE	8/2/12	4311	4033	3822	3725	3816	3998	4218	4539	4953	5370	5790	6162	6471	6628	6713	6803	6751	6715	6513	6265	6103	5656	5197	4789
LGEE	8/3/12	4521	4282	4076	4020	4090	4328	4518	4648	4822	5061	5196	5341	5554	5581	5598	5587	5575	5545	5398	5300	5175	5002	4752	4436
LGEE	8/4/12	4214	4031	3885	3759	3778	3841	3863	4094	4452	4807	5193	5441	5647	5779	5866	5758	5630	5502	5298	5178	5131	4897	4556	4289
LGEE	8/5/12	4061	3913	3805	3741	3733	3782	3789	3952	4151	4338	4535	4726	4906	5004	5084	5163	5104	5010	4900	4810	4813	4569	4311	4055
LGEE	8/6/12	3831	3671	3596	3569	3738	4021	4231	4507	4818	5169	5448	5717	5948	6142	6261	6326	6316	6224	6076	5847	5748	5349	4887	4487
LGEE	8/7/12	4190	3940	3745	3691	3785	4023	4219	4588	4972	5383	5761	6055	6275	6417	6504	6589	6588	6511	6352	6147	5986	5519	5062	4662
LGEE	8/8/12	4319	4081	3893	3806	3870	4129	4348	4670	5069	5526	5914	6267	6550	6757	6893	6964	6947	6852	6630	6415	6265	5809	5350	4955
LGEE	8/9/12	4630	4375	4213	4137	4196	4457	4646	4849	5144	5461	5778	6114	6373	6528	6476	6222	5918	5682	5474	5403	5285	4948	4565	4270
LGEE	8/10/12	4054	4130	3976	3734	3813	4102	4277	4490	4639	4807	5045	5248	5377	5392	5449	5460	5449	5318	5036	4834	4726	4434	4092	3750
LGEE	8/11/12	3484	3291	3161	3044	3035	3080	3082	3300	3586	3788	4002	4144	4269	4360	4503	4644	4734	4706	4591	4349	4265	3967	3651	3324
LGEE	8/12/12	3108	2950	2855	2803	2786	2785	2820	2995	3289	3555	3804	4057	4252	4415	4651	4821	4880	4846	4677	4564	4539	4226	3906	3616
LGEE	8/13/12	3430	3309	3209	3216	3355	3616	3845	4117	4386	4615	4740	4838	4848	4854	4927	4969	4967	4904	4824	4804	4767	4497	4153	3899
LGEE	8/14/12	3703	3538	3434	3420	3572	3888	4138	4304	4517	4721	4869	5062	5203	5398	5484	5522	5501	5343	5132	5065	4970	4620	4241	3941
LGEE	8/15/12	3703	3556	3439	3397	3550	3896	4127	4299	4563	4859	5040	5285	5496	5692	5814	5878	5895	5814	5636	5425	5300	4883	4436	4081
LGEE	8/16/12	3826	3613	3441	3396	3509	3830	4048	4270	4608	4939	5211	5550	5848	6079	6190	6261	6241	6069	5866	5746	5404	4964	4519	4148
LGEE	8/17/12	3897	3713	3588	3531	3640	3986	4223	4357	4496	4596	4674	4759	4915	5040	5157	5224	5254	5157	4963	4762	4635	4342	3981	3647
LGEE	8/18/12	3416	3213	3083	2995	3009	3070	3074	3287	3551	3859	4079	4244	4394	4543	4698	4796	4803	4703	4533	4374	4264	3963	3653	3382
LGEE	8/19/12	3179	3019	2938	2875	2873	2893	2883	3089	3384	3659	3927	4161	4358	4501	4641	4759	4849	4772	4634	4503	4391	4060	3703	3413
LGEE	8/20/12	3200	3072	3022	3021	3200	3541	3749	3977	4224	4448	4669	4881	5043	5210	5288	5371	5374	5307	5130	4963	4812	4439	4006	3682
LGEE	8/21/12	3444	3279	3197	3145	3295	3646	3844	4011	4238	4454	4666	4905	5023	5129	5111	5165	5167	5075	4909	4807	4699	4305	3937	3590
LGEE	8/22/12	3383	3242	3110	3096	3205	3588	3803	3991	4211	4480	4682	4952	5183	5399	5527	5688	5667	5690	5473	5263	5069	4617	4164	3804
LGEE	8/23/12	3556	3379	3248	3196	3342	3702	3883	4044	4355	4649	4940	5233	5526	5773	5931	6077	6125	5933	5776	5631	5370	4915	4420	4039
LGEE	8/24/12	3770	3571	3413	3346	3457	3776	3961	4186	4476	4825	5116	5522	5832	6049	6195	6269	6253	6127	5851	5621	5368	4947	4523	4141
LGEE	8/25/12	3871	3631	3455	3336	3323	3362	3381	3626	4019	4431	4840	5177	5447	5607	5711	5749	5718	5632	5430	5247	5061	4675	4281	3937
LGEE	8/26/12	3681	3468	3334	3220	3199	3213	3167	3465	3871	4265	4674	5015	5247	5471	5608	5695	5753	5672	5522	5434	5276	4856	4463	4126
LGEE	8/27/12	3914	3734	3639	3625	3764	4144	4391	4678	5003	5374	5700	6058	6272	6331	6293	6295	6179	6041	5837	5763	5549	5128	4719	4384
LGEE	8/28/12	4154	3973	3853	3788	3933	4263	4477	4600	4831	5078	5343	5607	5889	6054	6177	6253	6218	6113	5873	5719	5441	4990	4524	4112
LGEE	8/29/12	3895	3668	3516	3428	3576	3929	4123	4306	4612	4900	5268	5577	5827	6037	6171	6276	6219	6091	5825	5649	5378	4899	4432	4027
LGEE	8/30/12	3773	3548	3383	3347	3457	3798	4009	4192	4468	4791	5131	5480	5811	6089	6305	6454	6466	6367	6180	6111	5917	5481	5002	4606
LGEE	8/31/12	4311	4097	3918	3850	3951	4299	4559	4816	5078	5368	5624	5753	5894	5971	5983	6101	6108	5966	5766	5725	5549	5225	4844	4494
LGEE	9/1/12	4225	3984	3823	3698	3712	3732	3784	3949	4281	4620	4847	5029	5205	5336	5365	5284	5283	5209	5076	5055	4851	4599	4269	4000
LGEE	9/2/12	3759	3592	3500	3401	3411	3457	3545	3683	3950	4181	4270	4386	4453	4382	4435	4387	4382	4304	4274	4323	4247	4051	3803	3586
LGEE	9/3/12	3450	3317	3264	3230	3286	3389	3438	3536	3801	4049	4237	4396	4443	4628	4742	4778	4832	4795	4722	4803	4676	4415	4031	3839

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LGEE	9/4/12	3676	3518	3425	3440	3661	4069	4423	4563	4764	4943	5111	5343	5611	5853	6050	6160	6228	6148	5960	5951	5719	5265	4808	4465
LGEE	9/5/12	4117	3909	3802	3793	3956	4316	4504	4718	5062	5437	5859	6169	6369	6472	6459	6094	5750	5471	5285	5251	5015	4664	4317	3976
LGEE	9/6/12	3776	3648	3567	3515	3641	4075	4317	4473	4569	4847	5087	5363	5683	5904	6095	6171	6201	6080	5860	5818	5534	5116	4668	4314
LGEE	9/7/12	4060	3803	3677	3608	3711	4077	4314	4496	4773	5138	5505	5814	6080	6239	6388	6442	6383	6232	5925	5845	5601	5266	4869	4329
LGEE	9/8/12	4025	3758	3587	3497	3488	3543	3633	3628	3780	3878	3909	3976	4020	4112	4153	4196	4220	4171	4044	3999	3898	3628	3387	3141
LGEE	9/9/12	2970	2852	2726	2684	2691	2740	2756	2927	3161	3308	3446	3644	3753	3925	3989	4138	4213	4105	4032	4106	3978	3710	3409	3141
LGEE	9/10/12	3044	2921	2903	2918	3129	3408	3675	3855	4030	4267	4361	4444	4573	4691	4819	4923	4934	4841	4670	4686	4465	4059	3704	3390
LGEE	9/11/12	3213	3114	3006	2967	3173	3575	3705	3879	3992	4162	4359	4514	4673	4859	5013	5106	5149	5068	4881	4881	4598	4224	3811	3607
LGEE	9/12/12	3404	3272	3168	3139	3295	3681	3871	3974	4186	4416	4602	4872	5096	5238	5299	5369	5364	5242	5043	5062	4784	4410	3992	3749
LGEE	9/13/12	3515	3427	3294	3250	3436	3788	4039	4176	4339	4610	4824	5045	5225	5412	5458	5487	5447	5318	5138	5154	4907	4474	4085	3787
LGEE	9/14/12	3593	3334	3231	3166	3327	3709	3887	3959	4203	4541	4762	4963	5051	5087	5070	4908	4726	4518	4361	4400	4198	3900	3637	3353
LGEE	9/15/12	3122	2944	2839	2824	2818	2874	2951	3120	3325	3484	3608	3693	3777	3858	3948	4025	3959	3862	3802	3892	3698	3502	3346	3056
LGEE	9/16/12	2850	2752	2727	2703	2669	2728	2836	2919	3085	3276	3465	3609	3796	3936	4034	4165	4222	4186	4141	4290	4091	3802	3584	3307
LGEE	9/17/12	3174	3094	3076	3084	3284	3665	3973	4112	4203	4310	4328	4373	4411	4396	4340	4286	4258	4236	4299	4417	4264	3990	3702	3509
LGEE	9/18/12	3357	3232	3167	3179	3312	3747	4069	4114	4172	4242	4232	4229	4223	4186	4155	4088	4056	3987	3928	4092	3952	3670	3354	3152
LGEE	9/19/12	3029	2900	2849	2860	3021	3369	3605	3726	3840	3915	3950	3985	3967	3984	3998	4020	4010	3981	3925	4066	3910	3660	3373	3153
LGEE	9/20/12	3049	2937	2910	2884	3054	3508	3709	3768	3881	3936	3984	4082	4159	4221	4260	4254	4275	4241	4206	4376	4182	3918	3612	3331
LGEE	9/21/12	3196	3063	2976	2970	3093	3475	3708	3716	3929	4066	4171	4277	4328	4359	4360	4376	4333	4229	4147	4193	4100	3929	3678	3421
LGEE	9/22/12	3205	3039	2937	2865	2903	3033	3085	3244	3421	3612	3737	3792	3857	3878	3866	3905	3881	3730	3570	3590	3448	3283	2951	2833
LGEE	9/23/12	2680	2529	2598	2515	2561	2666	2692	2914	3011	3071	3067	3170	3149	3111	3181	3199	3278	3280	3365	3455	3334	3231	2960	2855
LGEE	9/24/12	2761	2760	2762	2828	3055	3459	3735	3822	3939	3964	3989	3972	3967	3937	3974	3946	3919	3880	3910	4044	3828	3632	3359	3167
LGEE	9/25/12	3048	2917	2890	2901	3090	3504	3771	3885	4004	4132	4059	4106	4093	4096	4028	4005	4022	3947	4081	4170	4038	3743	3510	3288
LGEE	9/26/12	3120	3071	3004	3044	3173	3585	3837	3913	4052	4166	4206	4339	4419	4543	4602	4589	4602	4570	4594	4660	4363	4057	3767	3476
LGEE	9/27/12	3291	3157	3113	3125	3239	3632	3919	3978	4105	4224	4335	4420	4472	4551	4591	4626	4600	4517	4507	4589	4422	4149	3780	3582
LGEE	9/28/12	3360	3255	3163	3112	3329	3689	3977	4044	4151	4230	4246	4293	4308	4268	4363	4334	4265	4137	4150	4134	3987	3823	3539	3296
LGEE	9/29/12	3081	2941	2840	2815	2798	2876	2966	3067	3319	3435	3482	3494	3585	3630	3714	3755	3768	3641	3676	3675	3512	3363	3120	2933
LGEE	9/30/12	2775	2653	2554	2612	2600	2697	2731	2827	2997	3140	3196	3325	3456	3462	3478	3543	3555	3557	3677	3754	3600	3421	3173	3010
LGEE	10/1/12	2911	2798	2760	2828	2991	3337	3642	3745	3839	3937	3972	3983	4040	3966	3967	3902	3909	3948	4055	4011	3884	3689	3408	3261
LGEE	10/2/12	3074	2972	2923	2921	3076	3445	3766	3845	3936	4077	4085	4177	4232	4278	4232	4178	4111	4045	4188	4174	4026	3725	3522	3302
LGEE	10/3/12	3148	3011	2942	2970	3077	3428	3722	3727	3783	3950	4018	4092	4164	4219	4263	4250	4188	4126	4183	4222	4020	3783	3511	3284
LGEE	10/4/12	3135	3016	2953	2917	3069	3424	3732	3789	3906	4041	4121	4256	4385	4460	4519	4493	4482	4368	4343	4353	4171	3857	3591	3377
LGEE	10/5/12	3183	3073	3017	2971	3122	3408	3711	3779	3921	4082	4193	4301	4388	4427	4348	4370	4227	4189	4184	4120	3910	3649	3422	3165
LGEE	10/6/12	2984	2816	2755	2749	2766	2858	2942	3050	3255	3342	3369	3336	3300	3282	3239	3220	3253	3286	3410	3483	3353	3212	3046	2838
LGEE	10/7/12	2725	2656	2631	2686	2722	2759	2934	3017	3196	3254	3266	3287	3230	3191	3141	3168	3148	3256	3445	3571	3474	3293	3168	3017
LGEE	10/8/12	2894	2915	2895	2950	3195	3574	3874	3999	4102	4147	4133	4099	4049	4019	3900	3880	3835	3841	4002	4085	3957	3751	3562	3386
LGEE	10/9/12	3290	3204	3173	3262	3406	3850	4168	4183	4186	4117	4068	4026	4033	3927	3864	3825	3822	3806	3953	4071	3900	3624	3413	3299

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Backup - LGEE Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
LGEE	10/10/12	3183	3050	3024	3051	3228	3597	3905	3934	3994	3978	3928	3935	3948	3918	3850	3788	3787	3711	3890	4034	3953	3729	3520	3342
LGEE	10/11/12	3327	3227	3225	3367	3537	4023	4277	4317	4240	4172	4075	4012	4003	3902	3839	3798	3716	3776	3933	4037	3814	3609	3414	3258
LGEE	10/12/12	3190	3112	3094	3079	3174	3586	3852	3894	3906	3970	3933	3901	3853	3845	3815	3758	3698	3678	3788	3750	3674	3512	3346	3155
LGEE	10/13/12	3066	2940	2844	2920	2918	3060	3198	3288	3338	3391	3347	3349	3337	3321	3309	3333	3360	3341	3537	3543	3440	3284	3102	2920
LGEE	10/14/12	2784	2657	2645	2617	2649	2712	2810	2909	3046	3186	3244	3298	3320	3330	3337	3335	3388	3434	3622	3641	3502	3313	3134	2928
LGEE	10/15/12	2788	2763	2761	2786	2968	3346	3662	3715	3829	3894	3926	3929	3975	3994	3940	3905	3841	3823	4002	4008	3881	3605	3367	3213
LGEE	10/16/12	3080	3046	3012	3058	3317	3695	4009	4046	4044	4022	3983	3951	3996	4004	3959	3923	3884	3810	3999	4076	3868	3635	3439	3292
LGEE	10/17/12	3157	3041	3007	2994	3240	3652	3941	3948	3945	3987	4019	4061	4051	4053	4067	4015	3955	3933	4080	4094	3916	3705	3459	3262
LGEE	10/18/12	3098	3031	2963	2975	3146	3547	3808	3827	3903	3960	3988	4019	4018	3985	3918	3827	3813	3860	4020	4014	3891	3666	3433	3221
LGEE	10/19/12	3090	3003	2979	3017	3195	3589	3889	3919	3948	3991	3960	3938	3949	3923	3869	3857	3879	3905	3959	3910	3779	3626	3419	3248
LGEE	10/20/12	3154	3048	2981	2901	2978	3120	3246	3363	3517	3553	3521	3469	3435	3414	3324	3362	3308	3327	3461	3468	3415	3258	3089	2968
LGEE	10/21/12	2885	2828	2799	2800	2852	2939	3073	3171	3236	3196	3159	3126	3132	3115	3094	3140	3196	3240	3489	3492	3370	3171	2984	2847
LGEE	10/22/12	2743	2698	2696	2778	2959	3377	3741	3810	3861	3950	3949	3920	4011	4083	4058	4038	3995	3972	4137	4111	3912	3644	3395	3182
LGEE	10/23/12	3018	2910	2839	2835	2996	3397	3754	3774	3854	3937	3998	4100	4184	4228	4237	4201	4139	4095	4265	4188	4012	3723	3463	3247
LGEE	10/24/12	3081	2967	2869	2880	3047	3436	3755	3762	3864	3959	4053	4161	4272	4345	4395	4370	4324	4227	4346	4249	4026	3701	3404	3179
LGEE	10/25/12	3017	2905	2833	2842	2996	3404	3735	3750	3841	3934	4012	4114	4233	4274	4310	4297	4259	4144	4278	4190	4012	3742	3439	3203
LGEE	10/26/12	3041	2925	2871	2857	3013	3376	3689	3770	3840	3887	3940	3910	3980	3942	3875	3870	3803	3855	3880	3856	3734	3583	3388	3161
LGEE	10/27/12	3050	2932	2908	2920	2941	3096	3236	3429	3532	3612	3649	3621	3548	3465	3461	3429	3390	3474	3634	3585	3496	3303	3228	3061
LGEE	10/28/12	2971	2871	2822	2841	2835	2974	3149	3245	3354	3444	3442	3430	3438	3486	3429	3450	3517	3611	3804	3817	3676	3554	3353	3251
LGEE	10/29/12	3202	3148	3171	3247	3536	3953	4381	4375	4453	4446	4385	4339	4305	4275	4205	4180	4216	4352	4500	4451	4360	4095	3872	3714
LGEE	10/30/12	3578	3544	3461	3536	3743	4122	4433	4465	4531	4550	4588	4563	4521	4513	4444	4465	4417	4556	4687	4610	4477	4179	3999	3815
LGEE	10/31/12	3645	3547	3590	3592	3774	4201	4486	4512	4479	4461	4367	4328	4278	4202	4090	4052	4010	4049	4202	4323	4234	4027	3817	3660
LGEE	11/1/12	3556	3487	3473	3483	3767	4158	4466	4489	4424	4370	4265	4192	4163	4041	3967	3908	3887	4024	4268	4209	4153	3912	3680	3524
LGEE	11/2/12	3371	3348	3250	3272	3482	3881	4155	4190	4155	4098	4052	3994	3957	3866	3781	3727	3715	3821	3983	4013	3919	3796	3699	3519
LGEE	11/3/12	3394	3417	3353	3385	3515	3648	3879	3982	3973	4009	3959	3872	3751	3626	3537	3549	3623	3754	3835	3800	3754	3581	3446	3261
LGEE	11/4/12	3130	3090	3040	3018	3144	3273	3379	3489	3607	3625	3587	3486	3425	3348	3333	3304	3306	3562	3814	3852	3805	3782	3627	3467
LGEE	11/5/12	3421	3447	3507	3588	3699	3970	4360	4615	4652	4532	4442	4291	4227	4193	4101	4040	4051	4174	4419	4411	4321	4231	4025	3828
LGEE	11/6/12	3738	3618	3569	3614	3653	3841	4161	4343	4409	4349	4274	4114	4131	4087	4038	3986	4004	4129	4344	4292	4234	4089	3906	3677
LGEE	11/7/12	3531	3435	3334	3316	3395	3611	3996	4230	4270	4325	4326	4305	4311	4273	4247	4134	4139	4316	4507	4443	4383	4249	4076	3919
LGEE	11/8/12	3760	3691	3695	3700	3783	4044	4449	4687	4658	4515	4399	4249	4204	4119	4037	3934	3915	4120	4389	4389	4390	4303	4119	3964
LGEE	11/9/12	3818	3770	3764	3754	3824	4039	4440	4617	4581	4401	4250	4099	4050	3921	3868	3798	3683	3845	4035	3999	3940	3839	3673	3500
LGEE	11/10/12	3297	3207	3149	3099	3119	3243	3354	3474	3525	3539	3511	3464	3400	3331	3300	3248	3305	3370	3563	3528	3463	3355	3223	3007
LGEE	11/11/12	2871	2765	2746	2766	2790	2865	3004	3058	3162	3216	3241	3211	3212	3191	3134	3120	3150	3324	3499	3543	3501	3329	3187	2995
LGEE	11/12/12	2849	2760	2747	2751	2809	3011	3398	3712	3788	3899	3999	3997	4071	4080	4020	4007	4019	4204	4453	4505	4442	4371	4191	4039
LGEE	11/13/12	3892	3854	3827	3863	3952	4183	4640	4870	4842	4667	4523	4340	4263	4223	4150	4042	4034	4238	4561	4593	4590	4552	4341	4171
LGEE	11/14/12	4057	3956	3950	3903	4011	4247	4690	4874	4881	4729	4599	4442	4354	4296	4251	4191	4221	4485	4656	4650	4581	4510	4323	4119

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Backup - LGEE Hourly Load

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
LGEE	11/15/12	3979	3935	3942	3941	4020	4267	4728	4923	4809	4636	4450	4308	4207	4140	4084	3965	3959	4240	4465	4491	4437	4417	4233	4064
LGEE	11/16/12	3977	3900	3880	3879	3947	4177	4609	4837	4776	4626	4469	4283	4185	4075	3983	3901	3917	4050	4209	4211	4227	4185	4088	3897
LGEE	11/17/12	3802	3738	3680	3724	3734	3864	4017	4134	4232	4096	3990	3860	3729	3577	3475	3424	3408	3541	3822	3845	3843	3781	3643	3561
LGEE	11/18/12	3469	3396	3372	3373	3396	3528	3665	3781	3839	3723	3627	3494	3330	3327	3309	3218	3308	3528	3782	3817	3846	3735	3611	3491
LGEE	11/19/12	3407	3354	3371	3419	3584	3864	4331	4633	4587	4484	4362	4195	4124	4112	4056	3959	3951	4130	4329	4285	4257	4114	3916	3715
LGEE	11/20/12	3528	3443	3347	3350	3409	3566	3958	4243	4209	4152	4074	4046	4035	3966	3925	3862	3810	3966	4110	4068	4051	3890	3689	3487
LGEE	11/21/12	3265	3179	3130	3095	3178	3368	3650	3918	4016	4047	4040	3955	3927	3860	3805	3737	3700	3814	3983	3927	3887	3781	3603	3380
LGEE	11/22/12	3196	3045	2997	2990	3009	3095	3203	3314	3416	3419	3391	3320	3175	2981	2869	2761	2696	2804	2932	2932	2933	2943	2867	2793
LGEE	11/23/12	2707	2634	2623	2618	2646	2722	2864	3002	3088	3192	3261	3283	3235	3181	3139	3117	3137	3382	3598	3617	3612	3582	3499	3380
LGEE	11/24/12	3302	3246	3238	3248	3295	3404	3563	3730	3848	3911	3899	3825	3732	3613	3537	3487	3579	3873	4138	4189	4205	4194	4095	3971
LGEE	11/25/12	3865	3768	3690	3719	3722	3766	3891	3974	4051	4050	3935	3781	3659	3511	3396	3388	3450	3699	3935	3963	3960	3834	3675	3529
LGEE	11/26/12	3427	3386	3402	3447	3582	3854	4273	4554	4565	4466	4363	4265	4240	4229	4194	4163	4218	4456	4570	4570	4499	4300	4038	3868
LGEE	11/27/12	3683	3614	3614	3593	3636	3884	4272	4597	4642	4667	4636	4622	4566	4542	4477	4426	4393	4636	4834	4856	4871	4751	4493	4313
LGEE	11/28/12	4173	4136	4124	4128	4164	4435	4839	5095	5099	4921	4746	4539	4467	4378	4239	4151	4200	4502	4767	4848	4914	4806	4650	4402
LGEE	11/29/12	4289	4235	4242	4200	4335	4562	4948	5202	5158	4965	4735	4543	4414	4307	4167	4114	4093	4364	4583	4636	4631	4560	4320	4113
LGEE	11/30/12	3929	3799	3731	3696	3787	3972	4370	4659	4615	4440	4337	4213	4169	4031	3990	3864	3881	4082	4219	4176	4219	4108	3950	3779

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Backup - EKPC Load

Dec 2011-Nov 2012 Load

EKPCP	**Max**	2,473
EKPCA	**Avg Jan**	1,969
EKPCV	**Winter**	1,896
EKPCS	**Spring**	1,481
EKPCS	**Summer**	1,904
EKPCF	**Fall**	1,552

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
EKPC	12/1/11	1784	1737	1753	1776	1860	1986	2206	2207	2101	1882	1686	1606	1511	1434	1362	1327	1375	1459	1651	1724	1809	1855	1799	1706
EKPC	12/2/11	1665	1694	1658	1668	1713	1851	2042	2077	1978	1812	1686	1535	1419	1371	1331	1275	1318	1491	1608	1643	1664	1669	1662	1526
EKPC	12/3/11	1487	1466	1479	1477	1523	1558	1628	1682	1718	1653	1543	1455	1368	1299	1264	1264	1277	1386	1493	1512	1527	1503	1465	1394
EKPC	12/4/11	1359	1305	1292	1289	1328	1327	1363	1397	1480	1504	1416	1367	1337	1295	1274	1235	1329	1418	1508	1521	1480	1425	1349	1204
EKPC	12/5/11	1139	1083	1075	1068	1127	1220	1397	1449	1409	1405	1401	1394	1394	1349	1354	1361	1418	1512	1563	1586	1550	1474	1372	1257
EKPC	12/6/11	1175	1138	1160	1112	1217	1336	1535	1587	1515	1502	1530	1503	1536	1521	1443	1543	1567	1736	1777	1726	1782	1757	1555	1497
EKPC	12/7/11	1429	1390	1372	1379	1427	1552	1764	1785	1745	1751	1785	1788	1754	1770	1741	1744	1906	1983	2071	2082	2061	2026	1956	1815
EKPC	12/8/11	1775	1779	1785	1795	1877	1953	2053	2187	2033	1869	1692	1642	1582	1507	1516	1478	1561	1762	1932	1975	2016	2008	1904	1826
EKPC	12/9/11	1776	1740	1777	1792	1850	1945	2174	2185	2077	1917	1723	1646	1518	1480	1423	1334	1478	1723	1777	1736	1773	1814	1780	1726
EKPC	12/10/11	1632	1604	1609	1641	1671	1712	1797	1927	2004	1949	1816	1738	1648	1599	1544	1538	1622	1802	1945	1956	1924	1958	1994	1973
EKPC	12/11/11	1928	1923	1945	1960	2005	2036	2098	2222	2248	2139	1877	1652	1622	1564	1502	1463	1523	1726	1866	1995	2011	1996	1931	1811
EKPC	12/12/11	1807	1781	1835	1833	1908	2028	2240	2269	2150	2017	1852	1644	1587	1570	1507	1478	1521	1669	1812	1768	1832	1751	1653	1516
EKPC	12/13/11	1429	1413	1353	1283	1391	1527	1689	1741	1665	1625	1597	1493	1479	1412	1362	1401	1468	1606	1692	1616	1622	1632	1530	1405
EKPC	12/14/11	1297	1259	1243	1239	1266	1307	1493	1537	1436	1362	1263	1250	1184	1153	1128	1114	1243	1405	1558	1525	1526	1516	1390	1250
EKPC	12/15/11	1159	1119	1085	1091	1144	1227	1426	1452	1427	1362	1385	1354	1340	1313	1328	1308	1349	1457	1546	1568	1572	1546	1477	1339
EKPC	12/16/11	1285	1257	1257	1338	1363	1521	1716	1797	1767	1714	1707	1745	1680	1688	1675	1680	1730	1836	1896	1871	1855	1822	1803	1712
EKPC	12/17/11	1619	1598	1591	1571	1620	1571	1654	1794	1901	1915	1843	1759	1685	1583	1522	1474	1514	1697	1733	1831	1907	1850	1798	1710
EKPC	12/18/11	1648	1614	1626	1649	1663	1737	1834	1910	2011	1929	1722	1591	1529	1458	1369	1383	1417	1582	1717	1790	1792	1770	1705	1616
EKPC	12/19/11	1562	1561	1529	1539	1569	1677	1820	1847	1757	1772	1712	1652	1608	1535	1514	1504	1527	1665	1706	1739	1708	1651	1553	1442
EKPC	12/20/11	1377	1330	1315	1358	1391	1503	1655	1723	1642	1622	1567	1517	1503	1421	1440	1405	1435	1527	1630	1592	1578	1517	1427	1282
EKPC	12/21/11	1202	1132	1091	1109	1123	1167	1303	1363	1358	1373	1337	1337	1324	1303	1285	1298	1356	1455	1588	1553	1581	1533	1491	1379
EKPC	12/22/11	1346	1268	1300	1308	1326	1426	1530	1543	1633	1657	1623	1622	1544	1578	1534	1589	1620	1714	1700	1706	1670	1639	1565	1463
EKPC	12/23/11	1431	1309	1264	1278	1322	1338	1438	1496	1593	1611	1607	1630	1579	1523	1546	1597	1644	1704	1754	1654	1696	1695	1639	1572
EKPC	12/24/11	1467	1446	1442	1446	1476	1519	1565	1683	1767	1780	1714	1599	1440	1404	1311	1275	1307	1393	1525	1542	1594	1628	1649	1579
EKPC	12/25/11	1546	1499	1496	1498	1510	1546	1590	1667	1805	1778	1680	1516	1384	1281	1207	1119	1148	1246	1390	1426	1448	1469	1430	1418
EKPC	12/26/11	1370	1343	1381	1423	1465	1562	1684	1791	1828	1798	1712	1693	1631	1558	1509	1525	1476	1700	1688	1740	1646	1566	1489	1422
EKPC	12/27/11	1337	1286	1262	1299	1356	1401	1488	1559	1588	1621	1681	1729	1742	1745	1780	1825	1831	1965	1964	1932	1921	1838	1760	1648

Backup - EKPC Load

Dec 2011-Nov 2012 Load

EKPCP	**Max**	2,473
EKPCA	**Avg Jan**	1,969
EKPCV	**Winter**	1,896
EKPCS	**Spring**	1,481
EKPCS	**Summer**	1,904
EKPCF	**Fall**	1,552

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
EKPC	12/28/11	1550	1528	1508	1456	1482	1548	1630	1706	1779	1776	1693	1679	1577	1523	1455	1402	1471	1596	1849	1867	1856	1813	1784	1685
EKPC	12/29/11	1645	1623	1619	1636	1675	1743	1769	1863	1840	1780	1767	1698	1602	1509	1423	1392	1401	1473	1696	1666	1700	1639	1589	1476
EKPC	12/30/11	1391	1372	1340	1312	1343	1370	1444	1548	1503	1517	1487	1446	1401	1364	1324	1300	1321	1403	1469	1459	1434	1434	1365	1307
EKPC	12/31/11	1222	1197	1083	1077	1118	1241	1252	1350	1406	1452	1398	1354	1344	1248	1247	1209	1259	1385	1522	1514	1504	1487	1438	1424
EKPC	1/1/12	1364	1354	1331	1273	1266	1202	1246	1233	1292	1324	1289	1294	1318	1345	1382	1363	1388	1500	1640	1634	1712	1682	1607	1548
EKPC	1/2/12	1532	1480	1533	1519	1527	1587	1764	1772	1795	1892	1956	2036	2091	2099	2089	2075	2103	2248	2326	2350	2309	2279	2204	2145
EKPC	1/3/12	2076	2073	2044	2102	2133	2241	2393	2456	2257	2210	2108	2086	2044	2011	1969	1897	1929	2110	2286	2331	2333	2304	2239	2171
EKPC	1/4/12	2114	2051	2052	2051	2119	2237	2349	2354	2252	2132	2029	1925	1834	1750	1708	1633	1648	1755	1947	1978	1973	1931	1814	1716
EKPC	1/5/12	1600	1589	1590	1626	1675	1842	1984	2032	1922	1817	1649	1502	1467	1351	1306	1266	1333	1546	1729	1784	1765	1703	1632	1563
EKPC	1/6/12	1489	1412	1427	1480	1517	1620	1832	1836	1662	1574	1450	1423	1346	1346	1241	1215	1245	1317	1474	1478	1485	1480	1420	1260
EKPC	1/7/12	1266	1149	1119	1038	1034	1057	1060	1145	1239	1346	1330	1323	1323	1268	1221	1244	1217	1305	1459	1520	1534	1487	1534	1476
EKPC	1/8/12	1447	1445	1434	1491	1537	1574	1663	1749	1869	1800	1674	1554	1478	1432	1348	1322	1376	1523	1687	1670	1669	1681	1574	1474
EKPC	1/9/12	1383	1349	1374	1360	1426	1534	1708	1782	1676	1676	1675	1592	1557	1499	1406	1387	1451	1567	1715	1778	1788	1743	1664	1598
EKPC	1/10/12	1517	1516	1535	1575	1582	1763	1942	1986	1834	1765	1690	1557	1484	1390	1375	1347	1365	1536	1683	1755	1732	1727	1598	1493
EKPC	1/11/12	1429	1353	1359	1333	1363	1458	1629	1668	1608	1552	1554	1533	1442	1410	1349	1338	1413	1451	1609	1606	1577	1524	1445	1328
EKPC	1/12/12	1271	1237	1248	1262	1279	1400	1564	1606	1559	1544	1534	1525	1560	1590	1643	1738	1854	2040	2198	2249	2263	2213	2156	2113
EKPC	1/13/12	2116	2085	2116	2114	2118	2324	2439	2447	2473	2438	2451	2398	2370	2324	2359	2300	2302	2316	2356	2299	2329	2194	2095	2055
EKPC	1/14/12	2014	1978	1990	2020	2067	2104	2187	2272	2310	2236	2191	2070	1978	1808	1775	1837	1859	1918	2008	2016	1974	1937	1896	1836
EKPC	1/15/12	1798	1770	1738	1800	1790	1787	1831	1981	2039	2056	1964	1869	1801	1669	1561	1566	1585	1697	1896	1949	1936	1920	1870	1865
EKPC	1/16/12	1779	1758	1747	1698	1753	1806	1857	1930	1879	1842	1811	1806	1781	1742	1740	1707	1690	1771	1794	1755	1726	1623	1490	1373
EKPC	1/17/12	1234	1225	1203	1201	1260	1300	1497	1525	1462	1423	1401	1380	1341	1343	1315	1301	1406	1530	1658	1740	1746	1727	1677	1577
EKPC	1/18/12	1545	1566	1536	1566	1589	1686	1862	1908	1809	1808	1794	1744	1691	1631	1651	1636	1705	1811	2034	2081	2102	2054	2015	1910
EKPC	1/19/12	1877	1872	1893	1923	1979	2127	2304	2317	2183	2062	1962	1888	1833	1744	1698	1676	1703	1792	1912	1934	1949	1916	1851	1752
EKPC	1/20/12	1675	1669	1668	1637	1699	1799	2000	2020	1953	1862	1885	1802	1750	1742	1695	1693	1746	1790	1843	1801	1791	1695	1661	1534
EKPC	1/21/12	1455	1397	1371	1387	1407	1457	1520	1636	1700	1804	1918	1882	1871	1895	1870	1890	1866	1941	1999	1976	1955	1934	1834	1792
EKPC	1/22/12	1708	1677	1647	1652	1635	1666	1694	1753	1807	1845	1736	1663	1611	1550	1462	1450	1430	1472	1564	1571	1543	1470	1368	1253
EKPC	1/23/12	1180	1146	1102	1120	1137	1240	1406	1492	1394	1360	1364	1316	1320	1221	1223	1287	1309	1413	1553	1594	1592	1583	1475	1425

Backup - EKPC Load

Dec 2011-Nov 2012 Load

EKPCP	Max	2,473
EKPCA	Avg Jan	1,969
EKPCV	Winter	1,896
EKPCS	Spring	1,481
EKPCS	Summer	1,904
EKPCF	Fall	1,552

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
EKPC	1/24/12	1346	1349	1365	1404	1462	1602	1799	1842	1763	1617	1535	1458	1428	1370	1323	1272	1355	1359	1631	1728	1765	1742	1710	1623
EKPC	1/25/12	1571	1562	1622	1618	1674	1774	1994	2004	1921	1832	1779	1681	1661	1624	1582	1598	1619	1668	1803	1815	1778	1703	1609	1477
EKPC	1/26/12	1392	1377	1325	1323	1333	1442	1572	1594	1418	1438	1364	1388	1350	1353	1364	1339	1349	1455	1517	1520	1503	1456	1342	1219
EKPC	1/27/12	1185	1202	1226	1262	1347	1457	1684	1638	1639	1692	1682	1695	1637	1696	1644	1669	1675	1751	1806	1763	1764	1736	1663	1594
EKPC	1/28/12	1542	1527	1505	1506	1534	1548	1551	1662	1651	1724	1745	1654	1590	1507	1457	1432	1431	1537	1694	1747	1751	1765	1783	1735
EKPC	1/29/12	1699	1677	1712	1706	1770	1720	1799	1904	1964	1914	1793	1652	1561	1532	1455	1429	1504	1528	1717	1765	1782	1759	1712	1648
EKPC	1/30/12	1619	1626	1670	1678	1756	1862	2069	2103	1993	1866	1721	1563	1433	1366	1313	1277	1295	1348	1567	1618	1636	1571	1510	1403
EKPC	1/31/12	1322	1336	1325	1325	1356	1453	1632	1698	1589	1502	1440	1343	1301	1288	1268	1219	1294	1334	1511	1559	1521	1480	1385	1249
EKPC	2/1/12	1182	1137	1102	1142	1116	1197	1345	1372	1251	1241	1228	1183	1165	1149	1116	1167	1211	1299	1423	1465	1432	1429	1287	1188
EKPC	2/2/12	1122	1088	1083	1076	1150	1250	1485	1538	1490	1450	1365	1331	1253	1226	1156	1184	1153	1236	1434	1511	1588	1545	1526	1439
EKPC	2/3/12	1395	1413	1399	1465	1484	1646	1863	1914	1809	1681	1574	1434	1367	1261	1248	1172	1198	1262	1397	1449	1453	1406	1392	1293
EKPC	2/4/12	1223	1186	1163	1167	1196	1236	1257	1321	1443	1501	1514	1548	1512	1482	1472	1435	1463	1461	1517	1510	1471	1472	1360	1292
EKPC	2/5/12	1232	1182	1177	1191	1204	1224	1220	1346	1479	1573	1542	1497	1497	1491	1453	1458	1490	1500	1586	1647	1638	1672	1626	1554
EKPC	2/6/12	1508	1499	1479	1525	1595	1722	1938	1979	1876	1761	1712	1591	1561	1488	1426	1409	1402	1494	1672	1787	1796	1785	1740	1675
EKPC	2/7/12	1536	1593	1634	1662	1731	1865	2033	2050	1884	1813	1666	1540	1462	1372	1321	1324	1318	1446	1646	1712	1750	1728	1652	1547
EKPC	2/8/12	1506	1474	1437	1393	1529	1628	1822	1887	1818	1774	1792	1724	1769	1703	1692	1744	1823	1879	1968	1991	1944	1905	1786	1683
EKPC	2/9/12	1580	1575	1565	1596	1592	1735	1908	1944	1894	1830	1822	1779	1701	1673	1674	1633	1688	1791	1902	1948	1965	1913	1843	1737
EKPC	2/10/12	1676	1669	1672	1696	1738	1819	2020	2093	1963	1939	1834	1819	1759	1733	1703	1716	1751	1823	1918	1914	1892	1856	1795	1708
EKPC	2/11/12	1681	1634	1642	1701	1786	1865	1950	2050	2168	2207	2184	2147	2188	2148	2105	2126	2169	2223	2307	2342	2364	2277	2256	2212
EKPC	2/12/12	2124	2136	2135	2152	2214	2238	2293	2320	2396	2289	2191	2012	1956	1799	1773	1672	1653	1761	1886	2016	2060	2096	1994	1932
EKPC	2/13/12	1927	1937	1852	1941	1965	2193	2445	2460	2325	2152	2012	1876	1795	1733	1703	1709	1775	1784	1897	1958	1938	1894	1810	1690
EKPC	2/14/12	1647	1591	1566	1580	1588	1720	1877	1879	1848	1849	1817	1795	1778	1782	1735	1714	1772	1768	1855	1921	1920	1840	1776	1599
EKPC	2/15/12	1574	1584	1569	1588	1649	1676	1887	1908	1775	1672	1526	1414	1345	1285	1304	1320	1309	1442	1511	1615	1609	1576	1504	1350
EKPC	2/16/12	1289	1237	1261	1232	1285	1376	1498	1596	1491	1485	1454	1456	1432	1402	1424	1427	1427	1524	1608	1650	1639	1588	1513	1420
EKPC	2/17/12	1347	1290	1340	1408	1438	1546	1815	1795	1641	1512	1463	1448	1344	1288	1267	1196	1227	1282	1398	1481	1555	1507	1526	1501
EKPC	2/18/12	1432	1430	1409	1418	1466	1502	1558	1649	1680	1642	1541	1437	1383	1340	1264	1257	1326	1387	1491	1506	1507	1490	1476	1392
EKPC	2/19/12	1362	1331	1325	1333	1356	1397	1474	1545	1684	1730	1739	1704	1771	1766	1734	1723	1733	1770	1840	1857	1846	1788	1738	1706

Backup - EKPC Load

Dec 2011-Nov 2012 Load

EKPCP	**Max**	2,473
EKPCA	**Avg Jan**	1,969
EKPCV	**Winter**	1,896
EKPCS	**Spring**	1,481
EKPCS	**Summer**	1,904
EKPCF	**Fall**	1,552

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
EKPC	2/20/12	1670	1699	1678	1767	1796	1918	2070	2135	2067	1950	1856	1735	1677	1592	1487	1484	1404	1505	1689	1830	1849	1851	1745	1690
EKPC	2/21/12	1624	1601	1562	1577	1637	1683	1806	1789	1697	1664	1630	1552	1526	1491	1414	1330	1390	1437	1523	1647	1636	1581	1526	1437
EKPC	2/22/12	1402	1394	1441	1396	1498	1608	1768	1785	1701	1567	1539	1445	1390	1347	1257	1253	1267	1396	1500	1544	1516	1474	1427	1285
EKPC	2/23/12	1176	1187	1169	1192	1225	1380	1566	1623	1521	1386	1371	1293	1258	1218	1201	1081	1110	1207	1309	1392	1407	1336	1230	1123
EKPC	2/24/12	1016	1000	962	982	1016	1095	1304	1387	1319	1312	1337	1330	1341	1374	1447	1473	1562	1620	1704	1754	1709	1729	1682	1607
EKPC	2/25/12	1565	1550	1550	1544	1604	1652	1715	1799	1809	1807	1768	1764	1708	1663	1591	1563	1517	1547	1657	1770	1763	1796	1767	1763
EKPC	2/26/12	1704	1738	1761	1780	1749	1785	1935	1977	1968	1841	1652	1494	1427	1324	1260	1181	1210	1263	1377	1551	1593	1576	1521	1453
EKPC	2/27/12	1408	1377	1393	1390	1448	1500	1740	1742	1608	1535	1404	1326	1291	1250	1198	1167	1168	1228	1341	1477	1471	1430	1370	1292
EKPC	2/28/12	1270	1229	1299	1365	1447	1598	1777	1839	1700	1534	1415	1302	1254	1203	1157	1099	1132	1196	1273	1402	1426	1379	1276	1140
EKPC	2/29/12	1068	1016	1002	995	991	1026	1171	1194	1128	1088	1099	1060	1066	1068	1133	1119	1148	1202	1236	1339	1376	1327	1253	1091
EKPC	3/1/12	1042	1005	1008	1025	1094	1231	1463	1514	1401	1349	1303	1254	1252	1171	1091	1119	1134	1151	1299	1425	1455	1425	1368	1293
EKPC	3/2/12	1220	1220	1203	1245	1276	1379	1529	1560	1471	1432	1380	1276	1300	1259	1204	1141	1055	1074	1118	1208	1219	1196	1179	1130
EKPC	3/3/12	1115	1134	1134	1157	1245	1329	1422	1547	1558	1532	1483	1386	1360	1310	1248	1227	1249	1281	1407	1529	1536	1578	1488	1484
EKPC	3/4/12	1405	1389	1424	1442	1467	1526	1639	1658	1759	1753	1646	1648	1604	1555	1528	1490	1483	1508	1605	1739	1744	1667	1601	1509
EKPC	3/5/12	1465	1437	1437	1469	1543	1660	1832	1905	1857	1831	1798	1724	1693	1652	1587	1548	1563	1591	1739	1913	1949	1931	1863	1801
EKPC	3/6/12	1779	1733	1648	1733	1822	1918	2068	2048	1863	1709	1592	1465	1341	1288	1253	1230	1183	1247	1322	1477	1494	1406	1349	1278
EKPC	3/7/12	1214	1195	1205	1208	1278	1378	1570	1584	1394	1281	1261	1190	1206	1188	1125	1124	1164	1186	1267	1315	1394	1312	1258	1119
EKPC	3/8/12	1043	983	982	991	957	1135	1324	1342	1270	1286	1290	1289	1289	1269	1240	1267	1344	1399	1499	1538	1536	1504	1359	1246
EKPC	3/9/12	1301	1277	1286	1329	1397	1522	1753	1776	1691	1544	1492	1397	1367	1301	1252	1210	1236	1269	1337	1428	1552	1590	1541	1486
EKPC	3/10/12	1455	1473	1450	1499	1521	1621	1683	1742	1703	1619	1516	1432	1349	1272	1188	1177	1142	1168	1220	1388	1400	1382	1378	1352
EKPC	3/11/12	1338	1304	1338	1374	1398	1486	1551	1631	1568	1449	1311	1260	1210	1137	1110	1091	1124	1140	1238	1360	1338	1229	1112	1033
EKPC	3/12/12	959	968	962	1007	1084	1288	1363	1260	1248	1288	1231	1214	1244	1188	1204	1216	1243	1275	1326	1399	1360	1258	1134	1025
EKPC	3/13/12	984	958	953	965	1072	1223	1270	1211	1205	1182	1168	1148	1169	1137	1136	1157	1163	1179	1226	1411	1367	1243	1087	988
EKPC	3/14/12	909	894	885	855	935	1122	1203	1124	1107	1073	1062	1053	1075	1057	1083	1091	1111	1189	1260	1382	1385	1245	1093	1011
EKPC	3/15/12	937	924	898	899	1011	1131	1257	1199	1158	1183	1167	1191	1234	1193	1229	1232	1280	1302	1360	1319	1312	1190	1096	993
EKPC	3/16/12	945	896	879	925	977	1128	1203	1185	1167	1194	1197	1163	1175	1129	1138	1124	1152	1184	1201	1264	1188	1130	1066	981
EKPC	3/17/12	927	916	908	880	923	974	1036	1088	1157	1193	1184	1200	1151	1139	1184	1172	1192	1238	1228	1258	1210	1143	1046	972

Backup - EKPC Load

Dec 2011-Nov 2012 Load

EKPCP	Max	2,473
EKPCA	Avg Jan	1,969
EKPCV	Winter	1,896
EKPCS	Spring	1,481
EKPCS	Summer	1,904
EKPCF	Fall	1,552

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
EKPC	3/18/12	876	864	860	839	865	864	961	1039	1132	1148	1163	1160	1191	1188	1201	1222	1269	1277	1290	1421	1367	1240	1081	990
EKPC	3/19/12	927	898	877	896	981	1166	1280	1177	1189	1198	1230	1224	1251	1240	1282	1342	1376	1389	1381	1491	1472	1295	1134	1031
EKPC	3/20/12	956	936	901	923	987	1151	1223	1139	1127	1153	1185	1208	1285	1300	1352	1384	1459	1446	1456	1552	1522	1324	1168	1018
EKPC	3/21/12	946	940	905	894	999	1182	1203	1146	1163	1187	1216	1270	1330	1331	1369	1420	1462	1464	1450	1536	1494	1335	1142	1058
EKPC	3/22/12	964	940	905	936	1002	1172	1223	1176	1187	1241	1240	1287	1301	1325	1347	1384	1397	1392	1392	1518	1444	1287	1163	1039
EKPC	3/23/12	962	927	881	903	975	1168	1192	1137	1146	1130	1165	1174	1172	1147	1161	1180	1221	1231	1201	1277	1253	1154	1064	1026
EKPC	3/24/12	902	838	839	813	872	907	943	1041	1096	1127	1137	1153	1129	1125	1071	1011	1031	1038	1056	1092	1148	1127	1047	954
EKPC	3/25/12	903	908	876	909	913	969	1020	1162	1189	1184	1121	1136	1096	1093	1090	1102	1140	1143	1190	1261	1254	1141	1046	942
EKPC	3/26/12	868	865	880	900	985	1166	1228	1175	1185	1147	1177	1177	1162	1155	1149	1142	1175	1194	1238	1370	1345	1253	1109	1057
EKPC	3/27/12	1039	1012	1038	1092	1221	1431	1475	1405	1331	1281	1202	1142	1121	1099	1100	1115	1125	1154	1186	1335	1295	1176	1007	971
EKPC	3/28/12	860	898	880	916	920	1090	1150	1048	1033	1026	1041	1044	1050	1098	1179	1179	1256	1257	1256	1347	1340	1189	1059	956
EKPC	3/29/12	916	870	871	942	922	1165	1203	1142	1141	1126	1133	1121	1106	1135	1140	1143	1208	1209	1242	1358	1341	1213	1050	946
EKPC	3/30/12	914	903	882	917	998	1100	1174	1146	1147	1120	1095	1124	1140	1080	1165	1170	1184	1142	1187	1245	1261	1151	1042	964
EKPC	3/31/12	897	855	849	831	829	888	972	1026	1116	1133	1153	1140	1104	1102	1133	1176	1178	1155	1144	1171	1212	1130	1027	945
EKPC	4/1/12	904	895	862	882	899	960	1006	1150	1235	1175	1184	1167	1165	1125	1095	1106	1119	1129	1184	1303	1293	1162	1055	991
EKPC	4/2/12	890	875	869	870	971	1087	1108	1140	1158	1172	1211	1204	1226	1221	1225	1257	1204	1313	1252	1399	1339	1209	1023	951
EKPC	4/3/12	933	881	892	930	964	1096	1121	1138	1128	1141	1172	1192	1260	1295	1328	1350	1421	1415	1415	1459	1432	1291	1135	1031
EKPC	4/4/12	953	913	912	930	981	1115	1142	1126	1173	1167	1185	1253	1309	1302	1329	1325	1361	1329	1358	1342	1355	1238	1044	963
EKPC	4/5/12	927	898	908	909	985	1103	1154	1142	1197	1214	1161	1179	1139	1145	1126	1120	1156	1172	1209	1273	1293	1231	1106	1021
EKPC	4/6/12	1000	991	1022	1037	1120	1286	1362	1351	1309	1253	1236	1159	1117	1113	1071	1036	1072	1075	1080	1206	1227	1202	1141	1078
EKPC	4/7/12	1066	1061	1061	1106	1180	1239	1310	1387	1350	1272	1232	1134	1090	1051	1048	1061	1086	1087	1114	1197	1216	1153	1072	988
EKPC	4/8/12	942	916	925	926	948	1040	1061	1094	1238	1197	1148	1111	1072	1013	1015	1013	1004	1007	1077	1187	1217	1135	1018	937
EKPC	4/9/12	927	952	981	1019	1156	1333	1424	1355	1283	1206	1211	1173	1147	1137	1111	1112	1164	1186	1202	1297	1311	1200	1090	986
EKPC	4/10/12	978	994	986	1066	1138	1309	1348	1301	1271	1257	1194	1165	1164	1139	1134	1153	1177	1185	1253	1361	1407	1321	1226	1178
EKPC	4/11/12	1187	1140	1193	1196	1298	1501	1536	1427	1378	1276	1236	1199	1165	1211	1200	1232	1270	1329	1361	1469	1483	1420	1350	1332
EKPC	4/12/12	1332	1362	1386	1461	1564	1718	1761	1649	1515	1373	1291	1255	1107	1163	1125	1129	1161	1179	1219	1348	1331	1273	1176	1118
EKPC	4/13/12	1123	1121	1132	1139	1356	1496	1562	1484	1339	1237	1207	1145	1125	1110	1087	1099	1103	1129	1114	1255	1211	1136	1090	976

Backup - EKPC Load

Dec 2011-Nov 2012 Load

EKPCP	**Max**	2,473
EKPCA	**Avg Jan**	1,969
EKPCV	**Winter**	1,896
EKPCS	**Spring**	1,481
EKPCS	**Summer**	1,904
EKPCF	**Fall**	1,552

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
EKPC	4/14/12	988	957	882	926	961	1006	1089	1132	1146	1197	1171	1146	1135	1123	1106	1100	1121	1138	1148	1160	1195	1135	1046	951
EKPC	4/15/12	895	874	847	862	795	864	942	1033	1081	1060	1075	1073	1170	1160	1176	1219	1256	1284	1288	1366	1381	1269	1104	882
EKPC	4/16/12	930	915	880	874	961	1104	1147	1141	1159	1181	1192	1193	1214	1195	1250	1247	1260	1286	1130	1326	1349	1230	1060	934
EKPC	4/17/12	897	837	842	837	960	1140	1174	1157	1161	1146	1108	1141	1119	1084	1104	1133	1194	1169	1147	1307	1309	1200	974	885
EKPC	4/18/12	904	906	903	938	1030	1234	1261	1205	1190	1234	1168	1154	1147	1131	1132	1224	1195	1212	1205	1253	1295	1242	1036	959
EKPC	4/19/12	928	909	909	950	1078	1257	1291	1239	1138	1153	1163	1108	1108	1156	1131	1177	1242	1222	1173	1254	1334	1221	1085	990
EKPC	4/20/12	919	890	888	920	1006	1195	1215	1177	1157	1160	1139	1159	1176	1135	1192	1179	1200	1174	1162	1232	1237	1194	1040	990
EKPC	4/21/12	920	785	803	885	899	943	1018	1093	1154	1212	1246	1144	1170	1196	1169	1123	1164	1215	1246	1298	1292	1216	1134	1076
EKPC	4/22/12	1020	1021	1027	997	1062	1105	1170	1267	1351	1328	1298	1273	1238	1144	1145	1149	1243	1254	1337	1353	1323	1271	1194	1185
EKPC	4/23/12	1169	1087	1129	1228	1333	1504	1561	1455	1422	1389	1335	1276	1246	1188	1159	1169	1226	1253	1283	1365	1402	1253	1198	1177
EKPC	4/24/12	1138	1163	1178	1244	1353	1564	1559	1441	1319	1274	1218	1158	1160	1165	1101	1132	1169	1198	1275	1333	1247	1198	1123	995
EKPC	4/25/12	984	942	953	968	1033	1191	1221	1135	1094	1061	1050	1036	1062	1051	1043	1141	1216	1230	1227	1334	1365	1192	1071	968
EKPC	4/26/12	960	884	874	902	983	1083	1187	1130	1152	1150	1113	1202	1223	1218	1240	1285	1323	1306	1300	1372	1410	1249	1066	975
EKPC	4/27/12	915	886	897	944	1021	1213	1276	1204	1219	1192	1153	1128	1135	1126	1104	1110	1170	1105	1171	1200	1229	1165	1055	1004
EKPC	4/28/12	954	909	908	928	969	985	1011	1064	1200	1186	1190	1147	1100	1142	1215	1201	1246	1265	1238	1254	1275	1194	1087	957
EKPC	4/29/12	921	878	850	878	864	869	966	1060	1149	1120	1141	1161	1208	1219	1241	1227	1333	1248	1320	1399	1397	1249	1133	949
EKPC	4/30/12	917	874	873	849	955	1111	1124	1113	1158	1201	1245	1297	1337	1377	1373	1435	1473	1456	1478	1508	1509	1331	1176	1016
EKPC	5/1/12	982	935	891	951	977	1112	1120	1137	1132	1159	1214	1242	1277	1361	1365	1434	1495	1488	1433	1493	1517	1373	1163	1028
EKPC	5/2/12	984	907	936	922	1016	1161	1186	1186	1273	1330	1385	1432	1499	1544	1645	1689	1771	1752	1691	1696	1726	1508	1240	1170
EKPC	5/3/12	1074	1011	962	970	1042	1204	1244	1225	1271	1336	1388	1385	1401	1472	1556	1496	1517	1491	1546	1561	1605	1462	1272	1136
EKPC	5/4/12	1050	976	866	855	1031	1158	1237	1178	1254	1302	1318	1466	1520	1531	1570	1619	1594	1573	1550	1512	1509	1403	1207	1091
EKPC	5/5/12	1016	952	913	886	932	887	950	1039	1134	1229	1264	1297	1326	1401	1432	1486	1510	1462	1472	1447	1452	1334	1213	1079
EKPC	5/6/12	988	925	902	865	886	897	940	1087	1191	1290	1337	1416	1511	1547	1612	1669	1703	1714	1669	1647	1606	1456	1254	1090
EKPC	5/7/12	1046	958	956	937	962	1180	1248	1217	1306	1342	1404	1449	1489	1605	1640	1666	1681	1689	1636	1642	1530	1337	1171	1117
EKPC	5/8/12	1056	1029	974	998	1060	1184	1238	1216	1229	1262	1244	1291	1294	1353	1274	1380	1440	1455	1423	1417	1439	1286	1125	1015
EKPC	5/9/12	946	920	911	880	885	1050	1068	1033	1075	1061	1095	1093	1127	1115	1137	1263	1292	1292	1291	1282	1341	1235	1076	1002
EKPC	5/10/12	941	926	872	930	997	1170	1190	1163	1169	1147	1142	1141	1153	1163	1206	1187	1248	1238	1230	1289	1344	1253	1089	983

Backup - EKPC Load

Dec 2011-Nov 2012 Load

EKPCP	Max	2,473
EKPCA	Avg Jan	1,969
EKPCV	Winter	1,896
EKPCS	Spring	1,481
EKPCS	Summer	1,904
EKPCF	Fall	1,552

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
EKPC	5/11/12	927	919	908	937	1019	1203	1215	1165	1154	1165	1158	1127	1165	1120	1144	1232	1247	1281	1191	1201	1266	1183	1085	1006
EKPC	5/12/12	916	884	861	872	903	938	979	1065	1090	1111	1114	1102	1112	1144	1140	1144	1196	1151	1194	1211	1196	1147	1042	946
EKPC	5/13/12	905	853	876	814	857	884	931	1025	1118	1124	1135	1134	1100	1086	1088	1099	1124	1146	1163	1216	1248	1157	1074	925
EKPC	5/14/12	893	893	905	849	978	1093	1181	1149	1179	1225	1206	1223	1217	1222	1215	1259	1318	1290	1313	1245	1358	1234	1117	984
EKPC	5/15/12	925	895	914	908	991	1129	1148	1130	1105	1232	1158	1245	1261	1289	1323	1381	1373	1420	1419	1393	1446	1309	1128	1023
EKPC	5/16/12	940	896	907	921	983	1150	1128	1098	1151	1236	1251	1303	1366	1414	1451	1553	1570	1539	1520	1473	1491	1369	1094	1045
EKPC	5/17/12	975	947	920	929	1002	1113	1158	1183	1171	1221	1222	1277	1318	1347	1394	1455	1461	1487	1456	1371	1441	1332	1121	934
EKPC	5/18/12	906	953	860	945	1000	1087	1114	1141	1178	1209	1251	1338	1353	1422	1501	1568	1592	1591	1531	1472	1425	1327	1221	1077
EKPC	5/19/12	1005	954	917	909	905	960	990	1092	1192	1242	1361	1392	1487	1545	1608	1657	1639	1595	1620	1541	1529	1415	1251	1094
EKPC	5/20/12	995	942	894	885	880	874	952	1061	1189	1267	1397	1447	1596	1510	1602	1623	1671	1674	1646	1586	1596	1425	1269	1088
EKPC	5/21/12	989	945	918	912	1001	1083	1117	1181	1246	1353	1404	1426	1537	1533	1550	1556	1540	1499	1464	1414	1413	1301	1161	1019
EKPC	5/22/12	985	896	869	914	933	944	992	1023	1028	1072	1091	1133	1177	1262	1236	1232	1260	1263	1265	1250	1263	1164	1025	907
EKPC	5/23/12	835	810	767	785	847	917	991	1024	1064	1114	1174	1204	1279	1307	1368	1381	1436	1482	1437	1373	1411	1317	1127	977
EKPC	5/24/12	897	847	810	844	885	950	1049	1080	1155	1223	1299	1400	1464	1480	1560	1600	1638	1613	1567	1532	1511	1411	1207	1064
EKPC	5/25/12	963	911	942	944	972	1059	1142	1205	1312	1418	1557	1614	1703	1779	1832	1831	1872	1875	1800	1703	1683	1593	1411	1253
EKPC	5/26/12	1139	1067	1011	965	1002	983	1052	1169	1363	1471	1607	1680	1787	1810	1757	1916	1955	1898	1858	1791	1740	1629	1447	1266
EKPC	5/27/12	1144	1048	1032	981	982	948	1020	1170	1384	1498	1624	1807	1831	1835	1911	1956	1987	1946	1899	1834	1785	1685	1479	1328
EKPC	5/28/12	1175	1117	1074	1042	1015	1032	1119	1224	1394	1573	1740	1794	1871	1922	1936	1988	1998	2002	1936	1896	1817	1716	1501	1242
EKPC	5/29/12	1196	1138	1100	1028	1076	1191	1290	1345	1383	1462	1470	1476	1486	1500	1486	1517	1601	1598	1516	1472	1568	1435	1291	1135
EKPC	5/30/12	1050	988	946	890	930	1002	1063	1082	1174	1228	1353	1443	1520	1548	1555	1556	1568	1559	1504	1415	1417	1311	1121	955
EKPC	5/31/12	892	834	793	806	871	922	996	1014	1086	1157	1208	1285	1357	1425	1503	1560	1613	1579	1515	1455	1464	1318	1173	1031
EKPC	6/1/12	964	932	970	950	969	1042	1129	1178	1172	1205	1218	1217	1179	1186	1181	1165	1176	1157	1161	1179	1195	1159	1050	969
EKPC	6/2/12	929	887	868	882	867	933	971	1029	1010	1085	1086	1117	1128	1117	1137	1139	1137	1131	1071	1109	1142	1137	1061	961
EKPC	6/3/12	910	803	783	829	833	888	877	994	1064	1084	1127	1205	1258	1263	1308	1372	1451	1411	1374	1376	1430	1295	1146	1039
EKPC	6/4/12	954	931	905	924	977	1053	1122	1164	1232	1305	1377	1400	1439	1379	1375	1327	1379	1357	1324	1331	1368	1302	1132	908
EKPC	6/5/12	883	862	830	900	993	1036	1081	1123	1170	1212	1253	1285	1313	1349	1377	1409	1424	1426	1391	1374	1375	1280	1137	1021
EKPC	6/6/12	918	943	884	828	894	939	1004	1034	1041	1086	1112	1132	1165	1197	1217	1249	1311	1294	1284	1251	1251	1201	1029	932

Backup - EKPC Load

Dec 2011-Nov 2012 Load

EKPCP	**Max**	2,473
EKPCA	**Avg Jan**	1,969
EKPCV	**Winter**	1,896
EKPCS	**Spring**	1,481
EKPCS	**Summer**	1,904
EKPCF	**Fall**	1,552

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
EKPC	6/7/12	844	821	872	863	909	1037	1077	1127	1167	1209	1282	1323	1361	1401	1437	1484	1534	1553	1507	1448	1460	1380	1153	969
EKPC	6/8/12	951	935	907	910	981	947	1081	1105	1189	1230	1307	1377	1445	1507	1544	1560	1564	1592	1585	1508	1486	1405	1228	1079
EKPC	6/9/12	992	925	829	818	806	795	849	999	1054	1221	1319	1382	1503	1526	1583	1669	1715	1702	1637	1562	1530	1419	1242	1074
EKPC	6/10/12	954	929	911	901	860	890	933	1056	1182	1226	1317	1396	1464	1484	1438	1456	1506	1516	1468	1420	1421	1353	1245	1111
EKPC	6/11/12	1033	997	981	945	1043	1085	1157	1214	1234	1328	1357	1391	1394	1490	1581	1620	1693	1602	1632	1563	1605	1522	1325	1182
EKPC	6/12/12	1085	1022	1015	975	1023	1101	1146	1191	1293	1332	1423	1514	1572	1668	1699	1724	1807	1778	1705	1636	1628	1515	1315	1159
EKPC	6/13/12	1076	989	951	960	1011	1050	1108	1071	1125	1186	1312	1413	1477	1546	1624	1686	1722	1716	1675	1604	1547	1448	1266	1099
EKPC	6/14/12	939	981	955	927	985	1060	1118	1149	1210	1274	1365	1458	1546	1583	1617	1718	1802	1795	1735	1625	1595	1498	1300	1135
EKPC	6/15/12	1063	986	939	972	1003	1046	1118	1157	1235	1356	1466	1578	1655	1744	1831	1881	1912	1871	1840	1753	1732	1607	1463	1298
EKPC	6/16/12	1199	1071	1043	1010	1022	1020	1067	1167	1320	1395	1520	1539	1582	1626	1695	1725	1757	1710	1660	1604	1567	1542	1385	1218
EKPC	6/17/12	1125	1051	989	960	995	949	1021	1158	1239	1363	1421	1544	1537	1593	1581	1626	1599	1577	1543	1540	1525	1465	1306	1171
EKPC	6/18/12	1085	1036	998	1006	1069	1110	1182	1277	1391	1488	1624	1717	1801	1846	1915	1945	1968	1971	1938	1828	1800	1684	1476	1294
EKPC	6/19/12	1172	1135	1080	1054	1088	1136	1190	1269	1400	1572	1675	1785	1850	1937	1960	2005	2045	2023	2034	1892	1858	1743	1514	1306
EKPC	6/20/12	1207	1112	1083	1057	1112	1151	1238	1315	1401	1507	1632	1761	1762	1828	1851	2003	2053	2101	2035	1966	1908	1804	1591	1422
EKPC	6/21/12	1293	1178	1141	1140	1162	1209	1303	1369	1521	1661	1800	1907	1965	2026	2075	2063	2141	2094	2052	1966	1920	1801	1595	1394
EKPC	6/22/12	1284	1196	1148	1121	1148	1175	1282	1349	1500	1601	1739	1801	1871	1937	1959	1982	2046	1971	1946	1802	1753	1606	1438	1304
EKPC	6/23/12	1149	1101	1035	1025	1012	964	1073	1199	1315	1462	1615	1690	1777	1845	1891	1927	1951	1958	1871	1761	1696	1605	1444	1259
EKPC	6/24/12	1179	1121	1057	1012	1003	975	1055	1201	1379	1512	1612	1759	1840	1937	1951	1958	2032	2031	1998	1868	1810	1689	1517	1321
EKPC	6/25/12	1192	1126	1090	1072	1116	1134	1206	1320	1434	1595	1699	1836	1921	1963	1965	2019	2014	2028	1937	1785	1738	1581	1361	1231
EKPC	6/26/12	1087	1061	1006	991	1025	1049	1134	1161	1224	1272	1337	1356	1431	1482	1523	1620	1667	1699	1655	1583	1540	1418	1239	1112
EKPC	6/27/12	1023	967	934	949	991	1016	1103	1155	1204	1295	1361	1457	1537	1575	1699	1837	1906	1923	1891	1752	1683	1578	1383	1172
EKPC	6/28/12	1114	1012	997	959	934	999	1053	1153	1228	1370	1509	1680	1816	1906	2022	2064	2130	2134	2075	1975	1913	1806	1613	1421
EKPC	6/29/12	1275	1197	1128	1087	1101	1129	1217	1325	1470	1636	1793	1934	2032	2164	2204	2243	2265	2183	2010	1998	1970	1874	1745	1530
EKPC	6/30/12	1451	1300	1263	1229	1188	1111	1201	1366	1560	1748	1912	2017	2147	2234	2288	2327	2352	2278	2276	2156	2091	1960	1822	1613
EKPC	7/1/12	1467	1334	1295	1240	1212	1147	1185	1308	1494	1651	1794	1966	2057	2188	2261	2278	2331	2324	2248	2132	2014	1800	1605	1465
EKPC	7/2/12	1313	1213	1183	1152	1155	1118	1221	1292	1404	1597	1770	1895	1982	2111	2162	2191	2251	2225	2159	2078	1977	1862	1656	1476
EKPC	7/3/12	1365	1249	1198	1166	1186	1141	1196	1247	1342	1469	1641	1750	1866	1917	1964	1965	2000	1950	1928	1793	1770	1661	1490	1305

Backup - EKPC Load

Dec 2011-Nov 2012 Load

EKPCP	**Max**	2,473
EKPCA	**Avg Jan**	1,969
EKPCV	**Winter**	1,896
EKPCS	**Spring**	1,481
EKPCS	**Summer**	1,904
EKPCF	**Fall**	1,552

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
EKPC	7/4/12	1224	1115	1060	1023	1014	981	1035	1192	1405	1584	1781	1910	1980	2056	2101	2134	2166	2131	2059	1930	1876	1738	1622	1447
EKPC	7/5/12	1327	1208	1165	1148	1153	1172	1226	1351	1504	1701	1865	2021	2095	2081	2004	1912	1827	1776	1729	1630	1608	1536	1385	1206
EKPC	7/6/12	1129	1039	985	1020	1017	1026	1143	1213	1377	1559	1750	1934	2060	2087	2146	2197	2220	2217	2089	2034	2046	2007	1804	1603
EKPC	7/7/12	1485	1364	1287	1246	1247	1232	1276	1408	1614	1835	2074	2173	2291	2303	2343	2337	2259	2328	2268	2145	2123	1995	1864	1696
EKPC	7/8/12	1546	1471	1365	1293	1312	1255	1335	1465	1675	1862	1981	2088	2171	2235	2276	2201	2136	2057	1934	1839	1796	1666	1512	1397
EKPC	7/9/12	1288	1212	1181	1177	1189	1250	1307	1403	1457	1523	1628	1686	1756	1817	1824	1888	1915	1895	1784	1741	1738	1643	1461	1320
EKPC	7/10/12	1220	1147	1119	1115	1115	1205	1260	1325	1408	1505	1606	1699	1763	1841	1884	1882	1934	1946	1898	1825	1811	1703	1541	1292
EKPC	7/11/12	1230	1180	1121	1110	1127	1196	1222	1306	1419	1548	1663	1784	1898	1967	1993	2046	2037	2048	1944	1856	1815	1711	1523	1321
EKPC	7/12/12	1218	1181	1104	1131	1130	1195	1243	1310	1374	1490	1583	1647	1736	1753	1758	1704	1684	1656	1628	1584	1598	1528	1384	1240
EKPC	7/13/12	1163	1071	1063	1086	1130	1120	1134	1271	1307	1361	1394	1401	1422	1479	1566	1608	1609	1614	1572	1565	1541	1498	1379	1270
EKPC	7/14/12	1181	1120	1069	1037	1038	1060	1113	1260	1382	1535	1641	1741	1749	1712	1696	1646	1643	1579	1541	1420	1456	1476	1346	1221
EKPC	7/15/12	1120	1044	1022	986	987	963	1033	1111	1246	1355	1461	1494	1653	1725	1794	1878	1857	1887	1868	1790	1771	1687	1513	1382
EKPC	7/16/12	1236	1189	1129	1133	1173	1216	1321	1382	1557	1721	1811	1963	2013	2029	2059	2099	2071	1987	1940	1873	1954	1803	1630	1486
EKPC	7/17/12	1317	1265	1188	1207	1236	1293	1334	1446	1575	1731	1880	1921	2038	2086	2146	2191	2222	2214	2141	2057	2073	1914	1712	1548
EKPC	7/18/12	1428	1332	1258	1191	1267	1303	1374	1412	1573	1705	1816	1938	1992	2038	2047	2056	2021	1943	1828	1767	1722	1583	1426	1319
EKPC	7/19/12	1209	1162	1132	1103	1185	1214	1289	1375	1449	1567	1709	1824	1937	2018	2066	2071	2100	1996	1927	1850	1732	1603	1443	1285
EKPC	7/20/12	1236	1177	1125	1127	1110	1139	1157	1239	1331	1410	1543	1602	1695	1737	1782	1857	1830	1775	1758	1670	1652	1574	1383	1267
EKPC	7/21/12	1214	1106	1087	1084	1007	1047	1089	1181	1278	1409	1478	1531	1639	1663	1744	1822	1874	1848	1805	1672	1650	1562	1398	1256
EKPC	7/22/12	1158	1074	1028	1006	990	988	1020	1152	1331	1452	1593	1682	1802	1883	1952	1995	2049	2069	2001	1904	1870	1752	1569	1393
EKPC	7/23/12	1304	1221	1166	1208	1216	1271	1351	1454	1567	1697	1771	1913	2036	2099	2139	2227	2293	2253	2200	2135	2105	1925	1751	1600
EKPC	7/24/12	1474	1392	1353	1255	1290	1392	1456	1545	1596	1713	1795	1849	1921	1993	2045	2084	2088	2088	2014	1957	1905	1780	1618	1501
EKPC	7/25/12	1405	1316	1242	1237	1263	1274	1333	1423	1475	1638	1770	1902	2000	2104	2168	2212	2232	2281	2220	2122	2032	1999	1809	1669
EKPC	7/26/12	1528	1439	1415	1349	1358	1429	1436	1551	1708	1826	1990	2093	2170	2220	2248	2305	2282	2214	2117	1990	1963	1763	1628	1460
EKPC	7/27/12	1323	1280	1245	1205	1238	1297	1325	1410	1480	1560	1677	1778	1863	1958	2030	2075	2087	2072	1962	1862	1839	1636	1454	1309
EKPC	7/28/12	1205	1127	1076	1058	1023	1040	1069	1204	1334	1426	1571	1665	1722	1777	1820	1869	1891	1850	1755	1576	1556	1441	1364	1225
EKPC	7/29/12	1114	991	985	968	955	945	1004	1104	1282	1388	1513	1552	1653	1707	1761	1794	1831	1806	1744	1691	1697	1554	1383	1235
EKPC	7/30/12	1065	998	968	980	1022	1064	1191	1233	1328	1514	1635	1752	1885	1942	1980	2030	2116	2082	1966	1913	1875	1677	1506	1357

Backup - EKPC Load

Dec 2011-Nov 2012 Load

EKPCP	Max	2,473
EKPCA	Avg Jan	1,969
EKPCV	Winter	1,896
EKPCS	Spring	1,481
EKPCS	Summer	1,904
EKPCF	Fall	1,552

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
EKPC	7/31/12	1286	1160	1141	1146	1182	1242	1275	1307	1445	1570	1741	1856	1973	2036	2054	2135	2173	2162	2103	2017	1991	1810	1643	1433
EKPC	8/1/12	1325	1232	1178	1194	1175	1275	1298	1320	1514	1668	1836	1959	2071	2140	2154	2176	2244	2202	2123	1994	1981	1737	1571	1418
EKPC	8/2/12	1273	1239	1127	1106	1164	1228	1225	1338	1456	1609	1778	1885	2000	2101	2138	2195	2253	2209	2114	1985	1966	1835	1602	1471
EKPC	8/3/12	1340	1197	1224	1169	1243	1278	1308	1368	1379	1477	1522	1629	1654	1682	1720	1749	1762	1782	1738	1722	1716	1602	1492	1344
EKPC	8/4/12	1260	1207	1165	1113	1107	1132	1215	1257	1410	1560	1625	1749	1837	1885	1961	1963	1962	1912	1831	1819	1776	1633	1537	1396
EKPC	8/5/12	1344	1238	1210	1220	1192	1215	1201	1294	1397	1454	1510	1554	1626	1630	1645	1664	1691	1658	1650	1603	1637	1513	1389	1257
EKPC	8/6/12	1172	1161	1106	1091	1170	1223	1285	1344	1425	1509	1597	1679	1815	1848	1907	1933	2018	2018	1953	1916	1866	1691	1516	1346
EKPC	8/7/12	1233	1196	1105	1107	1143	1225	1287	1360	1456	1562	1762	1831	1900	1964	2021	2098	2117	2116	2073	2027	1943	1719	1525	1342
EKPC	8/8/12	1258	1155	1134	1073	1129	1197	1209	1285	1383	1552	1697	1790	1891	1990	2025	2080	2130	2166	2118	2060	2014	1845	1628	1443
EKPC	8/9/12	1342	1248	1197	1137	1154	1335	1342	1414	1483	1563	1724	1859	1838	1897	1858	1863	1793	1781	1718	1701	1657	1548	1334	1220
EKPC	8/10/12	1132	1033	1047	1073	1097	1268	1292	1274	1333	1386	1445	1563	1600	1638	1667	1683	1740	1678	1602	1556	1537	1391	1234	1138
EKPC	8/11/12	1063	1017	939	985	917	984	1006	1043	1181	1208	1306	1396	1411	1383	1500	1522	1483	1509	1488	1441	1401	1321	1156	1091
EKPC	8/12/12	981	946	911	908	922	877	926	1067	1117	1227	1276	1362	1445	1528	1567	1598	1686	1663	1616	1555	1571	1409	1264	1116
EKPC	8/13/12	1067	995	994	989	1041	1143	1188	1194	1265	1277	1363	1406	1498	1470	1496	1526	1587	1560	1556	1550	1601	1401	1286	1150
EKPC	8/14/12	1066	1040	1020	1050	1082	1215	1270	1247	1304	1308	1390	1437	1540	1574	1668	1693	1717	1722	1723	1648	1682	1463	1305	1173
EKPC	8/15/12	1076	1040	1013	1049	1055	1239	1237	1250	1323	1368	1442	1511	1622	1679	1762	1810	1893	1872	1820	1738	1733	1495	1303	1195
EKPC	8/16/12	1083	1011	1019	1002	1063	1214	1206	1219	1273	1378	1520	1610	1715	1830	1838	1923	1963	1960	1866	1857	1791	1609	1365	1255
EKPC	8/17/12	1156	1127	1068	1092	1112	1225	1283	1282	1292	1327	1326	1363	1399	1406	1439	1523	1557	1566	1522	1468	1469	1351	1215	1116
EKPC	8/18/12	1036	972	959	946	934	941	994	1087	1143	1286	1317	1395	1420	1518	1558	1620	1641	1625	1516	1467	1460	1335	1178	1083
EKPC	8/19/12	1003	950	899	911	906	910	970	1014	1143	1257	1332	1382	1465	1501	1590	1635	1639	1643	1596	1566	1557	1350	1168	1076
EKPC	8/20/12	988	973	938	910	996	1114	1147	1153	1213	1268	1304	1382	1427	1529	1557	1589	1675	1641	1630	1605	1552	1375	1216	1099
EKPC	8/21/12	995	977	931	954	1013	1183	1154	1220	1205	1243	1292	1403	1466	1490	1524	1590	1606	1587	1563	1558	1520	1324	1175	1058
EKPC	8/22/12	959	932	923	872	917	1065	1064	1027	1070	1115	1230	1286	1365	1445	1545	1664	1760	1693	1720	1668	1612	1422	1240	1116
EKPC	8/23/12	1018	985	949	963	1010	1149	1166	1138	1220	1244	1398	1453	1579	1676	1756	1847	1855	1842	1814	1764	1702	1497	1302	1148
EKPC	8/24/12	1073	989	872	859	938	1105	1188	1113	1177	1342	1497	1591	1699	1698	1811	1915	1959	1964	1851	1750	1649	1516	1372	1218
EKPC	8/25/12	1082	1074	1025	974	993	1010	1031	1170	1297	1437	1564	1697	1790	1878	1912	1975	1933	1884	1823	1717	1677	1486	1376	1198
EKPC	8/26/12	1084	955	951	955	987	973	1027	1138	1308	1396	1554	1667	1794	1869	1926	1974	1985	1966	1875	1877	1805	1590	1396	1247

Backup - EKPC Load

Dec 2011-Nov 2012 Load

EKPCP	Max	2,473
EKPCA	Avg Jan	1,969
EKPCV	Winter	1,896
EKPCS	Spring	1,481
EKPCS	Summer	1,904
EKPCF	Fall	1,552

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
EKPC	8/27/12	1152	1102	1055	1080	1136	1278	1273	1324	1402	1525	1664	1761	1867	1910	1961	1948	1982	1978	1928	1885	1834	1619	1430	1281
EKPC	8/28/12	1217	1137	1045	1132	1185	1332	1355	1323	1387	1450	1524	1657	1724	1802	1854	1882	1921	1929	1875	1846	1757	1560	1377	1256
EKPC	8/29/12	1116	1062	1028	1003	1081	1238	1200	1275	1316	1400	1506	1605	1750	1808	1900	1955	1990	1974	1867	1844	1769	1541	1336	1164
EKPC	8/30/12	1096	1054	1026	1009	1073	1202	1221	1196	1273	1372	1486	1622	1802	1866	1938	1979	2028	2064	1977	1957	1876	1675	1483	1356
EKPC	8/31/12	1238	1168	1128	1135	1195	1283	1324	1246	1438	1502	1619	1686	1733	1772	1829	1859	1915	1909	1815	1824	1757	1632	1481	1357
EKPC	9/1/12	1242	1166	1160	1147	1122	1151	1146	1246	1326	1560	1625	1715	1755	1817	1877	1890	1873	1859	1752	1736	1694	1559	1398	1311
EKPC	9/2/12	1241	1177	1125	1127	1085	1129	1123	1267	1360	1469	1526	1577	1602	1623	1608	1613	1615	1526	1521	1543	1512	1373	1292	1190
EKPC	9/3/12	1123	1073	1044	1039	1052	1065	1079	1165	1286	1390	1483	1496	1554	1553	1605	1649	1658	1638	1641	1658	1618	1444	1300	1182
EKPC	9/4/12	1097	1059	1032	1077	1119	1305	1347	1265	1357	1408	1453	1537	1626	1717	1774	1888	1960	1944	1908	1932	1866	1637	1472	1286
EKPC	9/5/12	1225	1111	1102	1098	1115	1238	1256	1259	1342	1468	1555	1677	1810	1877	1878	1885	1854	1748	1674	1624	1548	1371	1203	1099
EKPC	9/6/12	1031	950	944	956	1012	1189	1217	1179	1209	1260	1309	1411	1494	1590	1689	1773	1811	1809	1767	1748	1655	1465	1288	1129
EKPC	9/7/12	1036	990	943	939	1022	1130	1176	1171	1220	1357	1554	1700	1790	1891	1926	2003	2038	1983	1877	1887	1752	1637	1505	1354
EKPC	9/8/12	1254	1169	1108	1079	1080	1115	1132	1186	1226	1286	1265	1296	1295	1301	1314	1349	1385	1331	1314	1315	1297	1180	1099	984
EKPC	9/9/12	901	878	851	838	844	827	845	987	1082	1125	1159	1195	1236	1288	1328	1393	1401	1353	1357	1396	1299	1153	995	891
EKPC	9/10/12	827	799	793	785	874	1036	1024	1020	1026	1081	1103	1155	1203	1241	1280	1327	1398	1370	1323	1358	1288	1136	985	874
EKPC	9/11/12	834	783	775	810	868	1003	1064	1002	1033	1056	1093	1134	1191	1264	1310	1381	1446	1455	1413	1417	1351	1171	1022	913
EKPC	9/12/12	853	809	808	823	881	1015	1040	1008	1032	1095	1152	1218	1285	1356	1410	1448	1492	1518	1462	1492	1407	1248	1091	968
EKPC	9/13/12	923	846	841	864	921	1078	1092	1072	1107	1155	1233	1275	1358	1415	1461	1510	1533	1508	1470	1509	1423	1256	1103	979
EKPC	9/14/12	894	874	852	829	903	1074	1103	1067	1118	1160	1330	1414	1478	1497	1517	1462	1463	1453	1416	1416	1371	1234	1153	1057
EKPC	9/15/12	995	923	915	901	928	947	975	1048	1098	1171	1159	1184	1210	1254	1275	1334	1321	1298	1245	1316	1264	1152	1033	956
EKPC	9/16/12	952	866	862	877	846	791	883	963	1109	1111	1132	1193	1232	1264	1275	1357	1411	1397	1364	1463	1383	1246	1098	1029
EKPC	9/17/12	955	925	937	920	1016	1154	1232	1180	1199	1208	1238	1257	1246	1252	1236	1272	1281	1357	1374	1385	1246	1144	1026	898
EKPC	9/18/12	885	838	817	854	910	1069	1116	1080	1086	1081	1107	1098	1076	1096	1075	1110	1135	1180	1143	1241	1167	1074	946	843
EKPC	9/19/12	814	791	764	805	878	1045	1073	1036	1045	1054	1035	1035	1055	1042	1053	1076	1122	1134	1154	1229	1169	1064	932	860
EKPC	9/20/12	818	795	802	815	897	1091	1119	1083	1064	1040	1044	1045	1071	1073	1100	1157	1182	1188	1220	1290	1236	1125	977	890
EKPC	9/21/12	829	861	879	881	968	1121	1147	1124	1134	1126	1127	1188	1213	1225	1242	1276	1293	1236	1276	1324	1278	1206	1105	1008
EKPC	9/22/12	902	847	876	886	883	945	988	1052	1126	1184	1215	1240	1243	1227	1240	1264	1241	1207	1164	1234	1181	1089	1006	914

Backup - EKPC Load

Dec 2011-Nov 2012 Load

EKPCP	Max	2,473
EKPCA	Avg Jan	1,969
EKPCV	Winter	1,896
EKPCS	Spring	1,481
EKPCS	Summer	1,904
EKPCF	Fall	1,552

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
EKPC	9/23/12	894	866	832	874	899	920	1009	1115	1158	1136	1115	1082	1094	1070	1107	1107	1149	1141	1198	1309	1250	1129	1026	965
EKPC	9/24/12	970	903	960	971	1085	1299	1310	1302	1255	1227	1186	1172	1175	1130	1101	1151	1203	1219	1263	1338	1298	1157	1034	965
EKPC	9/25/12	941	943	926	981	1042	1223	1279	1175	1193	1184	1216	1217	1244	1199	1199	1198	1249	1245	1315	1374	1304	1213	1090	979
EKPC	9/26/12	962	927	930	936	977	1142	1194	1143	1171	1177	1211	1228	1261	1278	1333	1345	1418	1418	1378	1483	1439	1304	1142	1065
EKPC	9/27/12	1003	969	932	921	1023	1163	1212	1178	1198	1219	1224	1246	1275	1290	1299	1328	1380	1379	1415	1480	1385	1257	1074	948
EKPC	9/28/12	976	970	961	938	988	1118	1195	1131	1122	1173	1163	1185	1169	1181	1144	1201	1192	1209	1216	1285	1249	1154	1085	1008
EKPC	9/29/12	941	918	885	858	907	915	956	1074	1110	1145	1156	1158	1197	1185	1209	1240	1224	1232	1213	1245	1214	1137	1042	940
EKPC	9/30/12	890	872	850	854	850	878	961	1037	1116	1103	1104	1112	1137	1158	1162	1178	1202	1207	1298	1341	1265	1145	1028	950
EKPC	10/1/12	900	884	873	902	986	1115	1191	1164	1169	1188	1190	1185	1183	1165	1182	1201	1233	1248	1324	1268	1194	1086	970	860
EKPC	10/2/12	839	804	792	824	882	1051	1092	1041	1065	1077	1093	1120	1118	1140	1141	1176	1185	1209	1254	1268	1217	1105	963	891
EKPC	10/3/12	823	800	772	797	884	1032	1081	1046	1052	1051	1070	1081	1105	1123	1141	1157	1178	1180	1213	1283	1197	1079	956	867
EKPC	10/4/12	824	793	778	802	889	1030	1092	1059	1047	1054	1073	1094	1134	1165	1179	1206	1241	1214	1255	1287	1232	1118	973	887
EKPC	10/5/12	833	789	792	807	876	1059	1157	1126	1141	1159	1175	1207	1232	1264	1272	1302	1300	1258	1292	1307	1251	1176	1086	962
EKPC	10/6/12	910	890	856	843	916	943	1020	1066	1143	1177	1189	1150	1125	1089	1075	1085	1097	1122	1202	1227	1178	1129	1072	1014
EKPC	10/7/12	965	949	917	920	957	952	1029	1119	1228	1239	1195	1199	1159	1116	1091	1116	1148	1146	1289	1362	1323	1230	1174	1114
EKPC	10/8/12	1063	1068	1081	1057	1173	1349	1417	1385	1398	1417	1397	1360	1339	1278	1257	1240	1280	1322	1440	1486	1406	1360	1273	1196
EKPC	10/9/12	1188	1190	1190	1210	1283	1452	1462	1396	1345	1273	1205	1149	1111	1074	1050	1040	1085	1148	1244	1273	1230	1161	1051	1010
EKPC	10/10/12	981	969	991	1001	1111	1229	1289	1232	1211	1197	1174	1153	1127	1092	1072	1093	1103	1153	1254	1321	1280	1218	1131	1108
EKPC	10/11/12	1085	1110	1131	1186	1299	1490	1541	1493	1405	1303	1180	1134	1103	1075	1046	1065	1060	1103	1231	1252	1233	1130	1072	999
EKPC	10/12/12	983	975	985	1006	1155	1299	1367	1341	1324	1295	1251	1222	1171	1165	1132	1110	1136	1172	1262	1263	1239	1214	1137	1086
EKPC	10/13/12	1041	1042	1065	1043	1118	1150	1233	1284	1271	1213	1184	1135	1112	1088	1074	1103	1113	1142	1194	1227	1191	1127	1041	945
EKPC	10/14/12	898	884	868	854	846	892	955	1027	1117	1082	1082	1102	1107	1128	1111	1153	1174	1195	1282	1300	1245	1149	1024	946
EKPC	10/15/12	917	879	873	880	978	1140	1217	1185	1178	1220	1208	1196	1198	1183	1152	1132	1203	1225	1342	1396	1313	1229	1125	1072
EKPC	10/16/12	997	1005	1043	1072	1192	1402	1500	1421	1359	1297	1219	1198	1188	1136	1136	1146	1201	1231	1351	1360	1297	1190	1122	1029
EKPC	10/17/12	998	986	997	1010	1113	1294	1304	1272	1225	1158	1135	1146	1155	1140	1142	1191	1199	1227	1318	1316	1286	1157	1061	987
EKPC	10/18/12	953	909	898	911	1030	1109	1212	1135	1160	1174	1155	1146	1159	1142	1145	1175	1181	1206	1334	1378	1333	1227	1125	1080
EKPC	10/19/12	1028	1038	1029	1068	1159	1355	1399	1350	1291	1266	1234	1215	1195	1212	1243	1253	1301	1341	1390	1395	1347	1275	1200	1138

Backup - EKPC Load

Dec 2011-Nov 2012 Load

EKPCP	**Max**	2,473
EKPCA	**Avg Jan**	1,969
EKPCV	**Winter**	1,896
EKPCS	**Spring**	1,481
EKPCS	**Summer**	1,904
EKPCF	**Fall**	1,552

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
EKPC	10/20/12	1088	1056	1038	1070	1088	1155	1225	1260	1313	1316	1283	1260	1247	1216	1204	1194	1199	1222	1298	1326	1280	1234	1197	1126
EKPC	10/21/12	1120	1099	1104	1103	1152	1203	1268	1365	1362	1265	1183	1159	1127	1091	1098	1118	1117	1166	1281	1295	1264	1139	1040	963
EKPC	10/22/12	960	949	938	975	1083	1245	1299	1273	1241	1225	1212	1206	1200	1183	1207	1226	1248	1278	1391	1384	1303	1204	1095	979
EKPC	10/23/12	940	921	913	930	1059	1213	1277	1236	1197	1167	1136	1171	1177	1192	1215	1213	1271	1292	1385	1386	1316	1233	1043	972
EKPC	10/24/12	917	889	897	901	944	1078	1137	1083	1046	1060	1045	1077	1101	1121	1051	1013	1432	1226	1275	1284	1191	1033	919	846
EKPC	10/25/12	796	795	870	903	1006	1180	1193	1195	1171	1167	1170	1174	1197	1207	1234	1281	1292	1319	1354	1400	1346	1203	1095	999
EKPC	10/26/12	931	916	891	934	998	1128	1223	1189	1144	1165	1134	1121	1155	1140	1157	1178	1212	1211	1325	1254	1252	1195	1117	1058
EKPC	10/27/12	1010	959	953	980	1020	1053	1150	1191	1274	1351	1298	1247	1275	1280	1306	1316	1319	1332	1394	1387	1318	1297	1221	1153
EKPC	10/28/12	1114	1105	1085	1104	1121	1144	1234	1340	1346	1304	1329	1279	1303	1328	1368	1357	1431	1456	1546	1542	1477	1410	1303	1229
EKPC	10/29/12	1218	1204	1241	1291	1386	1568	1649	1622	1563	1569	1525	1520	1392	1435	1487	1533	1595	1692	1734	1701	1663	1583	1491	1388
EKPC	10/30/12	1372	1341	1333	1430	1528	1691	1745	1660	1656	1664	1673	1626	1679	1651	1650	1696	1722	1782	1834	1798	1742	1596	1510	1442
EKPC	10/31/12	1368	1356	1362	1361	1476	1608	1591	1625	1569	1559	1506	1472	1407	1355	1381	1385	1379	1445	1543	1588	1543	1503	1429	1319
EKPC	11/1/12	1310	1268	1290	1334	1457	1611	1598	1567	1510	1438	1380	1361	1326	1281	1234	1240	1270	1386	1549	1569	1532	1426	1342	1257
EKPC	11/2/12	1217	1179	1161	1207	1358	1475	1548	1484	1447	1380	1280	1248	1210	1160	1126	1105	1114	1151	1274	1294	1308	1390	1323	1328
EKPC	11/3/12	1342	1326	1353	1349	1464	1516	1624	1664	1655	1575	1515	1470	1389	1335	1314	1296	1279	1380	1429	1457	1409	1377	1291	1228
EKPC	11/4/12	1195	1178	1185	1205	1247	1276	1354	1474	1533	1527	1397	1326	1263	1243	1203	1207	1211	1306	1451	1503	1516	1468	1439	1371
EKPC	11/5/12	1360	1384	1424	1456	1534	1649	1843	1861	1809	1685	1545	1475	1390	1352	1278	1276	1333	1437	1562	1592	1587	1554	1494	1459
EKPC	11/6/12	1373	1361	1371	1378	1439	1573	1653	1716	1641	1589	1458	1385	1312	1294	1237	1244	1281	1431	1548	1539	1533	1485	1378	1319
EKPC	11/7/12	1225	1191	1188	1211	1263	1347	1546	1576	1505	1462	1414	1377	1397	1378	1357	1376	1413	1527	1597	1656	1624	1581	1487	1417
EKPC	11/8/12	1418	1405	1378	1449	1495	1664	1825	1876	1792	1636	1518	1426	1335	1282	1243	1202	1242	1371	1573	1626	1624	1600	1560	1499
EKPC	11/9/12	1446	1465	1412	1439	1533	1668	1863	1904	1767	1589	1457	1339	1282	1207	1178	1151	1211	1273	1405	1421	1424	1395	1345	1283
EKPC	11/10/12	1221	1197	1210	1219	1230	1265	1347	1413	1421	1351	1286	1206	1174	1151	1109	1100	1133	1183	1288	1294	1239	1223	1148	1080
EKPC	11/11/12	1029	1015	1035	1060	1054	1133	1163	1255	1349	1325	1231	1182	1129	1156	1097	1103	1116	1238	1338	1347	1326	1210	1104	1006
EKPC	11/12/12	973	939	930	967	974	1033	1219	1284	1272	1322	1282	1342	1336	1364	1389	1367	1450	1536	1706	1714	1710	1693	1659	1571
EKPC	11/13/12	1551	1568	1619	1610	1695	1775	2022	2020	1918	1762	1605	1426	1337	1256	1312	1310	1354	1516	1738	1800	1806	1817	1706	1594
EKPC	11/14/12	1591	1606	1620	1637	1694	1840	1932	1945	1803	1702	1558	1437	1428	1409	1363	1429	1499	1649	1788	1776	1811	1785	1685	1612
EKPC	11/15/12	1566	1593	1601	1658	1652	1819	1966	2065	1948	1724	1654	1463	1402	1318	1294	1278	1335	1492	1662	1711	1760	1733	1645	1614

Backup - EKPC Load

Dec 2011-Nov 2012 Load

EKPCP	Max	2,473
EKPCA	Avg Jan	1,969
EKPCV	Winter	1,896
EKPCS	Spring	1,481
EKPCS	Summer	1,904
EKPCF	Fall	1,552

BAA	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
EKPC	11/16/12	1546	1544	1563	1545	1647	1815	1966	2041	1822	1743	1564	1464	1415	1322	1268	1256	1289	1419	1559	1572	1607	1578	1601	1531
EKPC	11/17/12	1476	1508	1480	1514	1541	1613	1715	1808	1777	1708	1573	1427	1348	1293	1229	1219	1189	1339	1402	1473	1491	1464	1462	1430
EKPC	11/18/12	1386	1389	1408	1463	1473	1535	1627	1676	1718	1632	1454	1333	1273	1215	1177	1167	1173	1313	1434	1503	1488	1456	1419	1382
EKPC	11/19/12	1322	1331	1372	1415	1477	1614	1850	1886	1723	1558	1528	1410	1247	1242	1237	1209	1248	1425	1524	1555	1544	1508	1433	1334
EKPC	11/20/12	1284	1240	1239	1255	1251	1391	1568	1612	1504	1431	1371	1228	1236	1201	1184	1185	1229	1339	1427	1434	1408	1378	1277	1085
EKPC	11/21/12	1132	1076	1070	1146	1149	1280	1420	1519	1516	1466	1384	1352	1297	1279	1241	1210	1242	1318	1448	1432	1414	1445	1369	1314
EKPC	11/22/12	1213	1215	1231	1232	1277	1358	1442	1509	1572	1631	1586	1475	1294	1184	1070	1028	1046	1107	1204	1208	1180	1184	1189	1152
EKPC	11/23/12	1104	1102	1081	1079	1107	1146	1173	1191	1219	1305	1349	1359	1335	1281	1224	1234	1251	1318	1399	1473	1505	1539	1497	1484
EKPC	11/24/12	1431	1420	1437	1445	1489	1575	1630	1704	1757	1784	1746	1659	1616	1533	1513	1484	1515	1661	1804	1833	1866	1885	1871	1856
EKPC	11/25/12	1793	1750	1792	1752	1774	1801	1854	1874	1920	1898	1782	1635	1535	1486	1416	1354	1371	1534	1648	1682	1698	1630	1559	1522
EKPC	11/26/12	1422	1450	1444	1467	1544	1701	1844	1855	1762	1636	1616	1536	1499	1477	1429	1455	1510	1665	1716	1734	1714	1608	1517	1399
EKPC	11/27/12	1343	1326	1292	1320	1327	1488	1664	1693	1677	1727	1681	1636	1614	1543	1495	1586	1667	1820	1819	1816	1849	1769	1723	1656
EKPC	11/28/12	1571	1586	1643	1654	1711	1782	1951	1951	1792	1741	1598	1506	1415	1322	1326	1359	1410	1630	1795	1884	1866	1919	1825	1779
EKPC	11/29/12	1762	1742	1760	1813	1841	1902	2175	2240	2110	1932	1726	1563	1474	1392	1377	1367	1409	1578	1715	1755	1782	1793	1695	1575
EKPC	11/30/12	1498	1394	1513	1496	1539	1703	1845	1883	1774	1603	1498	1337	1287	1276	1132	1140	1231	1379	1519	1522	1534	1506	1455	1412

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Peak	24636
PST	21148
Winter	19282
Spring	16950
Summer	19899
Fall	17778

Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
12/1/2011	14508	13993	13690	13707	13852	14564	16039	17428	17344	17166	17088	17005	16717	16744	16835	17228	18203	19422	19198	19010	18823	17972	16754	15467
12/2/2011	14507	13970	13717	13563	13668	14406	15789	17160	17730	17705	17722	17536	17155	17106	17000	17096	18064	19296	19057	18665	18391	17736	16739	15577
12/3/2011	14575	13954	13659	13495	13464	13743	14271	14926	15627	16012	16162	16251	16228	16070	15892	15943	16993	18220	17646	17029	16656	16141	15288	14368
12/4/2011	13463	12843	12516	12285	12177	12385	12741	13335	14002	14965	15337	15457	15707	15675	15684	15983	17130	18074	17748	17350	16902	16205	15169	13976
12/5/2011	13110	12711	12462	12519	12733	13433	14843	16513	17172	17182	17376	17469	17489	17582	17550	17693	18851	19670	19412	19183	18903	18222	16947	15485
12/6/2011	14438	13933	13731	13613	13739	14365	15901	17252	17699	17729	17878	17952	17887	17849	17789	18110	18996	20004	19704	19380	19214	18395	17039	15660
12/7/2011	14702	14048	13765	13567	13821	14533	15839	17441	17776	17851	17868	17883	17765	17922	17941	18169	19109	20085	19782	19618	19199	18495	17144	15671
12/8/2011	14500	14089	13847	13770	13860	14542	15764	17650	17665	17448	17285	17265	17106	17071	17045	17393	18373	19812	19822	19527	19307	18478	17286	15918
12/9/2011	14716	14240	13978	13871	13951	14642	16228	17666	18179	18126	18164	18162	17944	17834	17769	17908	18650	19732	19526	19191	18754	18198	17215	15916
12/10/2011	14868	14239	13890	13799	13860	14256	14910	15789	16579	17032	17252	17206	16974	16781	16736	16961	17823	19100	19094	18529	18071	17421	16567	15453
12/11/2011	14520	13958	13667	13440	13342	13580	13999	14680	15293	15673	15874	16076	15944	15741	15655	15924	17043	18893	18866	18545	18026	17357	16282	14957
12/12/2011	14222	13652	13511	13433	13601	14293	16095	17621	17842	17738	17667	17570	17337	17415	17298	17503	18398	19960	19931	19655	19366	18535	17234	15658
12/13/2011	14688	14103	13882	13842	13979	14634	16019	17602	17907	17866	17881	17626	17399	17461	17492	17733	18762	19817	19625	19258	18959	18188	16927	15317
12/14/2011	14303	13786	13468	13375	13545	14165	15704	17204	17473	17428	17537	17615	17629	17642	17701	18009	18947	19891	19481	19185	18898	18172	16835	15181
12/15/2011	14080	13576	13230	12961	13125	13738	15185	16672	17282	17259	17362	17399	17271	17187	17114	17270	17864	18821	18642	18447	17968	17476	16372	15007
12/16/2011	14015	13591	13297	13205	13320	14079	15588	17121	17649	17573	17649	17594	17452	17421	17488	17738	18496	19434	19270	18867	18532	17956	17027	15637
12/17/2011	14583	14018	13644	13558	13585	13935	14666	15721	16489	17146	17301	17383	17192	16838	16761	16977	17912	19168	19018	18544	18073	17547	16701	15738
12/18/2011	14812	14185	13845	13682	13656	13986	14365	15072	15709	16279	16694	16906	16911	16725	16731	16974	17973	19252	18907	18537	18202	17472	16419	15230
12/19/2011	14243	13754	13558	13462	13622	14325	15706	17297	17562	17655	17828	17910	17944	17936	18103	18250	19302	20183	19833	19556	19170	18410	17365	15837
12/20/2011	14812	14294	14040	14031	14279	15008	16461	17992	18125	18086	17965	17855	17706	17801	17604	17914	18941	20204	20131	19873	19582	18914	17633	16092
12/21/2011	14957	14318	13953	13809	13925	14675	16085	17592	18107	18147	18243	18281	18187	17950	17880	17988	19013	19708	19476	19297	18932	18097	16975	15446
12/22/2011	14387	13980	13654	13520	13575	14258	15646	17138	17432	17335	17171	17021	16992	16890	16965	17253	18153	19267	19122	18834	18621	18035	17022	15659
12/23/2011	14594	13980	13699	13561	13642	14260	15516	16904	17396	17530	17465	17383	17171	16947	16737	16813	17692	19399	19295	19225	18855	18312	17351	15871
12/24/2011	14897	14363	14026	13848	13792	14006	14466	15156	15775	16308	16556	16562	16412	16118	16086	16136	16879	17901	17383	16799	16382	16054	15562	14803
12/25/2011	13815	13154	12688	12464	12366	12556	12929	13596	14166	14575	14940	15007	15008	14868	14897	14959	15498	16092	15551	15309	15274	15068	14546	13764
12/26/2011	12966	12495	12235	12103	12144	12378	12836	13382	13914	14481	14853	15057	14819	14463	14210	14213	15253	16582	16496	16260	15885	15456	14676	13739
12/27/2011	12918	12415	12095	11974	12026	12394	13058	13876	14501	15122	15696	16061	16228	16176	16264	16648	17476	18543	18162	17779	17393	16600	15545	14549
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4/5/2012	13227	12954	12941	13099	13870	15159	16475	16794	16720	16697	16533	16383	16099	15730	15519	15548	15500	15475	15957	16973	16647	15527	14254	13377
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5/20/2012	11769	11384	11114	11125	11136	11131	11664	12600	13601	14117	14624	14911	14921	15007	15143	15525	15804	15591	15279	14927	15279	14506	13646	12681

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6/30/2012	14816	14164	13668	13335	13287	13316	14225	15375	16677	17791	18710	19269	19545	19806	20111	20324	20454	20116	19616	18978	18702	17860	16592	15364
7/1/2012	14379	13875	13356	13048	12791	12667	13206	14430	15695	16695	17436	17801	18001	18237	18427	18619	18873	18686	18198	17546	17177	16292	15448	14460
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10/21/2012	12002	11734	11676	11580	11657	12016	12533	13221	13787	14153	14271	14287	14225	14096	14095	14541	14950	15598	16152	15727	15131	14295	13298	12546
10/22/2012	12175	11968	11931	12044	12714	14308	15997	16184	16234	16262	16304	16269	16230	16112	16160	16505	16774	17373	17809	17370	16653	15440	14206	13112
10/23/2012	12631	12492	12339	12414	12947	14403	16027	16528	16649	16781	16855	16773	16885	16715	16770	17070	17440	17782	17865	17446	16714	15601	14318	13325
10/24/2012	12795	12653	12436	12590	13194	14707	16354	16744	16682	16823	16750	16688	16729	16702	16665	16971	17315	17833	18081	17606	16847	15519	14324	13342
10/25/2012	12714	12474	12238	12277	12855	14358	15958	16346	16274	16290	16271	16067	16192	16189	16126	16377	16441	16863	17558	17072	16304	15242	13907	13139
10/26/2012	12526	12208	12066	12054	12467	14165	15804	16133	16205	16344	16359	16380	16429	16162	16128	16304	16670	17148	16968	16703	16021	15093	13937	12853
10/27/2012	12357	12045	11868	11877	12100	12668	13563	14497	15292	15765	16049	16005	15825	15609	15488	15658	15894	16168	16157	15682	15093	14362	13486	12717
10/28/2012	12205	11954	11782	11820	11913	12328	13024	13724	14458	14868	15231	15444	15485	15441	15490	15979	16544	16933	16720	16193	15650	14767	13856	13072
10/29/2012	12629	12506	12491	12671	13219	14776	16528	17087	17331	17383	17494	17321	17282	17325	17507	17954	18360	18829	18740	18182	17204	15983	14714	13779
10/30/2012	13227	13030	12955	12966	13366	14788	16240	16450	16555	16913	16924	16768	16788	16681	16765	17049	17568	18030	17995	17460	16747	15628	14452	13610
10/31/2012	13137	12845	12831	12829	13295	14825	16465	16998	16906	17006	17029	17003	16919	16845	17023	17379	17576	17827	17652	17368	16764	15703	14474	13618
11/1/2012	13219	13017	12881	12937	13450	14801	16496	16988	17008	16953	17012	16927	16895	16703	16761	17199	17700	18349	18540	18032	17318	16188	14944	13927
11/2/2012	13364	13105	12992	13160	13524	15185	16697	17082	16879	16908	16897	16664	16734	16586	16603	16876	17303	17887	17929	17552	16974	15915	14664	13806
11/3/2012	13210	12909	12806	12849	12940	13584	14528	15189	15684	15904	16018	15917	15781	15572	15582	15845	16352	16980	16904	16371	15988	15176	14377	13482
11/4/2012	13053	12767	12512	12446	12452	12704	13126	13796	14615	15318	15586	15693	15753	15612	15536	15763	16553	17726	17791	17360	16818	16070	15090	14161
11/5/2012	13540	13204	13141	13226	13393	14198	15705	17170	17413	17450	17617	17536	17383	17330	17306	17479	18281	19051	19254	19027	18602	17847	16648	15380
11/6/2012	14518	14061	13786	13786	13928	14643	16204	17318	17483	17547	17588	17615	17628	17648	17537	17582	18248	19409	19419	19096	18687	17902	16689	15423
11/7/2012	14506	14029	13886	13770	13943	14691	16048	17245	17418	17261	17143	17026	16891	16760	16776	16884	17918	19058	19189	18892	18548	17863	16562	15305
11/8/2012	14488	14060	13832	13802	13967	14816	16271	17550	17485	17161	17144	17008	16860	16798	16607	16662	17487	18848	18903	18633	18262	17446	16261	15030
11/9/2012	14026	13615	13289	13183	13331	14132	15497	16885	17370	17350	17283	17103	16900	16973	16933	17010	17411	18203	18043	17661	17253	16651	15682	14480
11/10/2012	13469	12909	12600	12513	12573	12910	13551	14134	14890	15526	15867	15993	15881	15814	15703	15845	16391	17341	16973	16346	15897	15417	14563	13782
11/11/2012	12943	12496	12162	11972	11824	12004	12526	12892	13471	13997	14262	14230	14335	14293	14271	14501	15296	16560	16570	16216	15876	15201	14275	13333
11/12/2012	12658	12280	12066	11937	12107	12905	14337	15688	16057	16212	16500	16730	16830	16724	16878	16928	17634	18459	18092	17764	17445	16567	15608	14521
11/13/2012	13686	13245	13101	13061	13186	13945	15433	16999	17129	17150	17161	17133	17131	17128	17055	17398	18143	19359	19083	18789	18326	17576	16306	15055
11/14/2012	14188	13789	13475	13418	13593	14350	15733	17030	17162	17022	16923	16850	16802	16835	16740	16939	17942	18922	18987	18686	18357	17680	16439	15034
11/15/2012	14083	13697	13527	13381	13630	14238	15638	16972	17100	16802	16703	16631	16503	16452	16383	16570	17510	18557	18577	18400	18072	17507	16300	15123
11/16/2012	14157	13809	13512	13488	13625	14320	15588	16899	17048	16719	16604	16522	16385	16327	16284	16296	17089	18029	17914	17634	17298	16584	15610	14612

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11/17/2012	13766	13216	12907	12747	12818	13164	13870	14523	15191	15617	15635	15545	15362	15104	14944	15031	15733	17028	17174	16652	16212	15619	14897	14002
11/18/2012	13327	12830	12601	12403	12311	12613	12989	13383	14123	14632	14711	14679	14736	14578	14528	14840	15891	17357	17280	16934	16532	15866	14950	14021
11/19/2012	13473	13043	12850	12945	13173	13995	15337	16717	16927	16786	16845	16678	16577	16500	16444	16678	17660	18859	18710	18530	18136	17349	16008	14747
11/20/2012	13950	13506	13292	13235	13401	14029	15381	16908	17001	16800	16819	16779	16633	16504	16448	16633	17564	18801	18550	18257	17886	17233	15964	14785
11/21/2012	13912	13452	13213	13133	13315	13971	15363	16779	16958	16896	16897	16647	16471	16307	16254	16458	17436	18735	18640	18387	17996	17228	15912	14638
11/22/2012	13735	13236	12997	13006	13233	13832	15058	16456	16470	16330	16122	16027	15876	15874	15886	16082	16794	17964	17737	17521	17340	16718	15538	14251
11/23/2012	13315	13005	12504	12481	12524	13170	14370	15846	16392	16535	16526	16561	16485	16444	16463	16600	17342	18082	17814	17615	17273	16776	15900	14688
11/24/2012	13794	13244	12877	12658	12717	12975	13526	14415	15086	15780	15992	16130	16138	15955	15821	15982	16759	18061	17864	17352	16911	16325	15611	14577
11/25/2012	13847	13355	13083	12917	12917	13182	13597	14268	14800	15510	15998	16032	16040	15946	15949	16140	17233	18593	18255	17794	17402	16782	15812	14742
11/26/2012	13961	13621	13471	13413	13606	14461	15911	17618	17805	17858	17705	17716	17582	17650	17681	18073	19040	20125	19899	19675	19322	18473	17209	15801
11/27/2012	14804	14303	14082	13977	14108	14949	16497	17862	17872	17798	17645	17533	17489	17441	17589	17843	18857	19830	19776	19462	19101	18322	17046	15688
11/28/2012	14779	14321	14010	13986	14034	14805	16298	17660	17976	17835	17962	17946	17664	17761	17736	18003	19066	19965	19722	19528	19212	18392	17137	15767
11/29/2012	14819	14343	14137	14019	14160	14810	16228	17667	17783	17569	17498	17444	17264	17336	17346	17646	18581	19591	19404	19304	19020	18286	17131	15737
11/30/2012	14759	14267	13975	13935	14227	14867	16443	18031	18509	18480	18606	18574	18464	18469	18445	18609	19474	20144	19669	19581	19158	18542	17406	16096

	Winter	Spring	Summer	Fall
MISO	(9,962)	(15,473)	(3,613)	(11,490)
DUK	(993)	(1,662)	(58)	(2,409)
CPL	(549)	(1,728)	-	(997)
TVA	(2,194)	(3,755)	(1,163)	(4,531)
LGEE	(151)	(1,559)	-	(856)
EKPC	(198)	(374)	(25)	(505)

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resp_name	respondent_id	report_yr	report_prd	spplmnt_num	row_num	avail_cap	plan_outage	unplan_outage	other_outage	tot_net	ex_avail_cap	ex_not_avail	tot_capability
MISO	321	2011	12	0	1200	94197	12922	15376	0	122495	2448	0	124943
MISO	321	2012	12	0	100	100585	7811	11601	0	119997	1833	0	121830
MISO	321	2012	12	0	200	95381	9153	13315	0	117849	2172	0	120021
MISO	321	2012	12	0	300	94678	11979	9499	0	116156	1917	0	118073
MISO	321	2012	12	0	400	85802	18918	10656	0	115376	2310	0	117686
MISO	321	2012	12	0	500	87807	15521	13563	0	116891	2071	0	118962
MISO	321	2012	12	0	600	96572	4282	14076	0	114930	2972	0	117902
MISO	321	2012	12	0	700	95989	2983	14358	0	113330	2649	0	115979
MISO	321	2012	12	0	800	97394	3575	12967	0	113936	2584	0	116520
MISO	321	2012	12	0	900	94642	7159	12493	0	114294	2665	0	116959
MISO	321	2012	12	0	1000	86360	18024	14009	0	118393	2111	0	120504
MISO	321	2012	12	0	1100	87327	9287	18795	0	115409	1760	0	117169

resp_name	respondent_id	report_yr	report_prd	spplmnt_num	row_num	avail_cap	plan_outage	unplan_outage	other_outage	tot_net	ex_avail_cap	ex_not_avail	tot_capability
Duke Energy Carolinas	157	2011	12	0	1200	23417	2080	1165	1224	27886	189	0	28075
Duke Energy Carolinas	157	2012	12	0	100	23322	691	856	1648	26517	173	0	26690
Duke Energy Carolinas	157	2012	12	0	200	23322	208	197	2526	26253	173	0	26426
Duke Energy Carolinas	157	2012	12	0	300	23322	1280	215	4238	29055	173	0	29228
Duke Energy Carolinas	157	2012	12	0	400	23098	2593	430	2863	28984	143	0	29127
Duke Energy Carolinas	157	2012	12	0	500	23098	1114	829	1276	26317	143	0	26460
Duke Energy Carolinas	157	2012	12	0	600	23098	40	552	0	23690	143	0	23833
Duke Energy Carolinas	157	2012	12	0	700	23098	71	132	100	23401	143	0	23544
Duke Energy Carolinas	157	2012	12	0	800	23098	63	232	1537	24930	143	0	25073
Duke Energy Carolinas	157	2012	12	0	900	23098	300	1580	1206	26184	143	0	26327
Duke Energy Carolinas	157	2012	12	0	1000	22713	2174	699	3317	28903	143	0	29046
Duke Energy Carolinas	157	2012	12	0	1100	22713	4754	598	0	28065	143	0	28208

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resp_name	respondent_id	report_yr	report_prd	spplmnt_num	row_num	avail_cap	plan_outage	unplan_outage	other_outage	tot_net	ex_avail_cap	ex_not_avail	tot_capability
Progress Energy (Carc	233	2011	12	0	100	14677	506	217	0	15400	1653	0	17053
Progress Energy (Carc	233	2012	12	0	100	14636	378	435	0	15449	1240	0	16689
Progress Energy (Carc	233	2012	12	0	200	13990	762	697	0	15449	1600	0	17049
Progress Energy (Carc	233	2012	12	0	300	12976	1954	519	0	15449	1254	0	16703
Progress Energy (Carc	233	2012	12	0	400	12469	2150	830	0	15449	1074	0	16523
Progress Energy (Carc	233	2012	12	0	500	12622	1080	458	0	14160	916	0	15076
Progress Energy (Carc	233	2012	12	0	600	13676	0	484	0	14160	1217	0	15377
Progress Energy (Carc	233	2012	12	0	700	13734	0	421	0	14155	1376	0	15531
Progress Energy (Carc	233	2012	12	0	800	14649	0	426	0	15075	969	0	16044
Progress Energy (Carc	233	2012	12	0	900	14616	52	407	0	15075	1188	0	16263
Progress Energy (Carc	233	2012	12	0	1000	13269	1289	632	0	15190	1076	0	16266
Progress Energy (Carc	233	2012	12	0	1100	13527	1649	14	0	15190	927	0	16117

resp_name	respondent_id	report_yr	report_prd	spplmnt_num	row_num	avail_cap	plan_outage	unplan_outage	other_outage	tot_net	ex_avail_cap	ex_not_avail	tot_capability
Tennessee Valley Autl	263	2011	12	0	1200	39066	3910	808	0	43784	0	0	43784
Tennessee Valley Autl	263	2012	12	0	100	43926	1296	694	0	45916	1060	0	46976
Tennessee Valley Autl	263	2012	12	0	200	43159	1376	1381	0	45916	1386	0	47302
Tennessee Valley Autl	263	2012	12	0	300	41795	3785	336	0	45916	881	0	46797
Tennessee Valley Autl	263	2012	12	0	400	38326	5743	1847	0	45916	1420	0	47336
Tennessee Valley Autl	263	2012	12	0	500	41242	1736	2938	0	45916	2312	0	48228
Tennessee Valley Autl	263	2012	12	0	600	42073	1326	1859	0	45258	1232	0	46490
Tennessee Valley Autl	263	2012	12	0	700	42171	901	2186	0	45258	1463	0	46721
Tennessee Valley Autl	263	2012	12	0	800	41986	1262	2010	0	45258	803	0	46061
Tennessee Valley Autl	263	2012	12	0	900	40273	2919	2066	0	45258	2126	0	47384
Tennessee Valley Autl	263	2012	12	0	1000	37086	5465	3365	0	45916	99	0	46015
Tennessee Valley Autl	263	2012	12	0	1100	37695	5209	3012	0	45916	652	0	46568

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resp_name	respondent_id	report_yr	report_prd	spplmnt_num	row_num	avail_cap	plan_outage	unplan_outage	other_outage	tot_net	ex_avail_cap	ex_not_avail	tot_capability
Louisville Gas & Electr	197	2011	12	0	1200	8166	0	706	0	8872	0	0	8872
Louisville Gas & Electr	197	2012	12	0	100	8181	0	753	0	8934	0	0	8934
Louisville Gas & Electr	197	2012	12	0	200	8054	454	427	0	8935	0	0	8935
Louisville Gas & Electr	197	2012	12	0	300	7338	1175	422	0	8935	0	0	8935
Louisville Gas & Electr	197	2012	12	0	400	6198	2135	208	0	8541	0	0	8541
Louisville Gas & Electr	197	2012	12	0	500	5491	1366	1684	0	8541	0	0	8541
Louisville Gas & Electr	197	2012	12	0	600	7696	0	645	0	8341	0	0	8341
Louisville Gas & Electr	197	2012	12	0	700	7731	0	807	0	8538	0	0	8538
Louisville Gas & Electr	197	2012	12	0	800	7905	0	634	0	8539	0	0	8539
Louisville Gas & Electr	197	2012	12	0	900	7582	0	956	0	8538	0	0	8538
Louisville Gas & Electr	197	2012	12	0	1000	6623	2118	193	0	8934	0	0	8934
Louisville Gas & Electr	197	2012	12	0	1100	7477	450	1007	0	8934	0	0	8934

resp_name	respondent_id	report_yr	report_prd	spplmnt_num	row_num	avail_cap	plan_outage	unplan_outage	other_outage	tot_net	ex_avail_cap	ex_not_avail	tot_capability
East Kentucky Power	159	2011	12	0	1200	2753	369	0	0	3122	451	0	3573
East Kentucky Power	159	2012	12	0	100	2999	0	0	45	3044	456	0	3500
East Kentucky Power	159	2012	12	0	200	2810	225	0	0	3035	273	0	3308
East Kentucky Power	159	2012	12	0	300	2605	416	0	0	3021	104	0	3125
East Kentucky Power	159	2012	12	0	400	2208	630	137	35	3010	173	0	3183
East Kentucky Power	159	2012	12	0	500	2786	75	0	0	2861	58	0	2919
East Kentucky Power	159	2012	12	0	600	2807	0	0	0	2807	356	0	3163
East Kentucky Power	159	2012	12	0	700	2807	0	0	0	2807	72	0	2879
East Kentucky Power	159	2012	12	0	800	2765	75	0	0	2840	70	0	2910
East Kentucky Power	159	2012	12	0	900	2221	510	109	0	2840	415	0	3255
East Kentucky Power	159	2012	12	0	1000	1915	865	207	0	2987	314	0	3301
East Kentucky Power	159	2012	12	0	1100	2550	140	331	0	3021	327	0	3348

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PUBLIC VERSION
Pursuant to the Commission's Regulations Regarding Requests for Privileged Treatment of Documents, 18 C.F.R. § 388.112, Information Contained in Attachment A of This Submission Constitutes Privileged, Protected, and Confidential Information and Has Been Redacted from This Public Version

December 29, 2016

BY ELECTRONIC FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Atlantic City Electric Company, Docket No. ER10-2997-___
Baltimore Gas and Electric Company, Docket No. ER10-2172-___
Bethlehem Renewable Energy, LLC, Docket No. ER10-3003-___
Commonwealth Edison Company, Docket No. ER10-1048-___
Constellation Energy Commodities Group Maine, LLC, Docket No. ER10-2192-__
Constellation Energy Services, Inc., Docket No. ER15-1537-___
Constellation Energy Services of New York, Inc., Docket No. ER15-1539-___
Constellation Mystic Power, LLC, Docket No. ER11-2056-___
Constellation NewEnergy, Inc., Docket No. ER10-2178-___
Constellation Power Source Generation, LLC, Docket No. ER14-1524-___
Clinton Battery Utility, LLC, Docket No. ER16-2194-___
Criterion Power Partners, LLC, Docket No. ER10-3308-___
Delmarva Power & Light Company, Docket No. ER10-3018-___
Eastern Landfill Gas, LLC, Docket No. ER10-3015-___
Exelon Framingham, LLC, Docket No. ER10-1020-___
Exelon Generation Company, LLC, Docket No. ER13-1536-___
Exelon New Boston, LLC, Docket No. ER10-1078-___
Exelon West Medway, LLC, Docket No. ER10-1080-___
Exelon West Medway II, LLC, Docket No. ER16-2708-___
Exelon Wyman, LLC, Docket No. ER10-1081-___
Fair Wind Power Partners, LLC, Docket No. ER15-2293-___
Fourmile Wind Energy, LLC, Docket No. ER14-2145-___
Handsome Lake Energy, LLC, Docket No. ER10-2180-___
PECO Energy Company, Docket No. ER10-1143-___

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Kimberly D. Bose
December 29, 2016

Pepco Energy Services, Inc., Docket No. ER10-2992-___
Potomac Electric Power Company, Docket No. ER10-3030-___

Updated Market Power Analysis for the Northeast Region

Dear Secretary Bose:

Pursuant to Section 35.37 of the Federal Energy Regulatory Commission's (the Commission) regulations[1] and Orders Nos. 697, 697-A, 816, and 816-A[2], the above-captioned subsidiaries of Exelon Corporation (Exelon) (collectively, the Exelon NE Entities) hereby submit for filing an updated market power analysis for the Northeast (NE) Region for the study period of December 1, 2014 through November 30, 2015. The NE Region consists of the balancing authority areas (BAAs) operated by ISO New England, Inc. (ISO-NE), New York Independent System Operator, Inc. (NYISO), and PJM Interconnection, L.L.C. (PJM).

As discussed below and as described in the attached affidavit of Julie R. Solomon and Julie M. Carey (collectively Navigant) of Navigant Consulting, Inc. (the Navigant Affidavit), the Exelon NE Entities pass the indicative screens in all relevant markets and submarkets, and continue to lack market power in the NE Region. Therefore, the Exelon NE Entities ask the Commission to accept this updated market power analysis and find that they continue to be granted market-based rate (MBR) authority to make wholesale sales of electric energy, capacity, and ancillary services. In support thereof, the Exelon NE Entities state as follows:

I. REQUEST FOR PRIVILEGED TREATMENT

The Exelon NE Entities request privileged treatment pursuant to Section 388.112 of the Commission's regulations for hourly load data, which is accessible via links to the work papers of Navigant contained in the market screens submitted as part of Attachment A. The work papers contain information about confidential, commercially sensitive load data that could harm the Exelon NE Entities if publicly released. Pursuant to Section 35.37(f) of the Commission's regulations, a proposed protective order is included herewith as Attachment B. Communications

[1] 18 C.F.R. § 35.37 (2016).

[2] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified,* 121 FERC ¶ 61,260 (2007), *order on reh'g,* Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 (2008), *clarified,* 124 FERC ¶ 61,055 (2008), *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g,* Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g,* Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Montana Consumer Counsel v. FERC,* 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom. Public Citizen, Inc. v. FERC,* 133 S. Ct. 26 (2012); *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 816, 153 FERC ¶ 61,065 (2015) (Order No. 816), *order on reh'g and clarification*, Order No. 816-A, 155 FERC ¶ 61,188 (2016) (Order No. 816-A).

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concerning this request for privileged treatment should be directed to Jane Rueger at 202-626-6534 or Harold Bulger, III at 202-637-6182.

II. DOCUMENTS SUBMITTED

The Exelon NE Entities include the following attachments with this filing:

- This transmittal letter;
- Attachment A: Affidavit of Julie R. Solomon, Managing Director of Navigant Consulting, Inc. and Julie M. Carey, Director of Navigant Consulting, Inc., including exhibits and work papers;
- Attachment B: Proposed protective order; and
- Attachment C: Appendices in the format set forth in Appendix B to 18 C.F.R. Part 35, Subpart H listing by balancing authority area and geographic region: (1) all affiliates that have MBR authority and all reportable generation assets owned by Exelon or its affiliates; (2) all reportable long-term power purchase agreements of Exelon or its affiliates; and (3) all electric transmission facilities and natural gas intrastate pipelines and/or gas storage facilities owned or controlled by Exelon or its affiliates.[3]

III. COMMUNICATIONS

Communications concerning this notice should be directed to the following persons:

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Jane E. Rueger*
Harold W. Bulger, III
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Christopher A. Wilson
Director, Federal Regulatory Affairs
Exelon Corporation

[3] The Exelon NE Entities include in the long-term purchase agreement tab of the asset appendix power purchase agreements from generation facilities that may be qualifying facilities (QFs) and that may not have MBR authority. These power purchase agreements are included out of an abundance of caution, because the Exelon NE Entities do not own such generation facilities and may not be able to make definitive representations regarding their regulatory status.

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December 29, 2016

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* Persons denoted with an asterisk are those designated for service pursuant to 18 C.F.R. § 385.2010. The Exelon NE Entities respectfully request waiver of 18 C.F.R. § 385.2010(k) so that they may designate three persons to receive service on their behalf.

IV. EXELON NE ENTITIES

Exelon is a publicly traded holding company, headquartered in Chicago, Illinois, with operations and business activities in 48 states, the District of Columbia, Canada, and the United Kingdom.[4] The Exelon NE Entities consist of the indirect, wholly owned subsidiaries of Exelon that have MBR authorization and own electric generation or transmission facilities in the NE Region or operate as power marketers with MBR authorization.

The Exelon NE Entities include the following entities that own electric generation facilities in the NE Region:

- Exelon Generation Company, LLC (Exelon Generation) is owned directly by Exelon. Exelon Generation is one of the largest competitive power generators in the United States. Exelon Generation and its subsidiaries operate one of the nation's cleanest and lowest-cost power generation fleets, with generation facilities located in a number of organized markets across the country. In addition, Constellation, an Exelon Generation business unit consisting of subsidiaries and divisions of Exelon Generation, is one of the nation's leading marketers of electricity, natural gas, and related products in wholesale and retail markets. Exelon Generation serves as a supplier of energy to, among others, utilities and municipalities to meet their native load obligations. Through various subsidiaries, Exelon Generation is also a retail competitive energy provider. In the NE Region, Exelon Generation directly owns and operates nuclear, fossil, and hydroelectric generation facilities with a total generation capacity of approximately 22,581 MW (summer).[5] Exelon Generation also purchases

[4] No individual shareholder of Exelon owns a 10% or greater interest in Exelon's outstanding voting securities.

[5] In some instances, however, Exelon Generation owns only a share of certain generation facilities, as noted in the End Notes tab of the asset appendix provide in Attachment C. On December 7, 2016, the Commission authorized the acquisition by Exelon Generation of the James A. FitzPatrick Nuclear Power Plant, which is located in New York. *See Entergy Nuclear FitzPatrick, LLC*, 157 FERC ¶ 61,183 (2016). The transaction is expected to close in 2017. Pursuant to the requirements of 18 C.F.R. § 35.42, the relevant Exelon NE Entities will file a notice of change in status no later than 30 days after consummation of the transaction.

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approximately 2,572 MW from several generation facilities located in the NE Region under long-term contracts that are included in the asset appendix and the market power analysis pursuant to the criteria set forth in Order No. 816.[6] The Commission has granted Exelon Generation MBR authority.[7]

- Bethlehem Renewable Energy, LLC (Bethlehem Renewable) is a wholly owned subsidiary of Exelon Generation, whose upstream ownership is described above. Bethlehem Renewable owns an approximately 3.7 MW landfill gas-fired facility located in the PJM balancing authority area (BAA). The Commission has granted Bethlehem Renewable MBR authority.[8]

- Constellation Mystic Power, LLC (Mystic) is a wholly owned subsidiary of Constellation Holdings, LLC, (Constellation Holdings), which is a wholly owned subsidiary of Exelon Generation, whose upstream ownership is described above. Mystic owns the following generating facilities and related interconnection facilities, all of which are located in the ISO-NE BAA: (a) Mystic Unit 7, an approximately 571 MW (summer) oil and natural gas-fired facility in Everett, Massachusetts; (b) Mystic Jet, an approximately 9 MW (summer) oil facility in Everett, Massachusetts; and (c) Mystic Units 8 (at approximately 704 MW (summer)) and 9 (at approximately 714 MW (summer)), natural gas-fired facilities located in Everett, Massachusetts, with a total capacity of approximately 1,418 MW. The Commission has granted Mystic market-based rate authority.[9]

- Constellation Power Source Generation, LLC (CPSG) is a wholly owned subsidiary of Constellation Nuclear, LLC (Constellation Nuclear), which is owned by Exelon Generation (95%) and Constellation Holdings (5%). CPSG owns multiple generation facilities in the PJM BAA with a total capacity of approximately 842 MW (summer). The Commission has granted CPSG MBR authority.[10]

- Clinton Battery Utility, LLC (Clinton Battery) is a wholly owned subsidiary of Exelon Generation, whose upstream ownership is described above. Clinton

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6 *See* Order No. 816 at P 145.

7 *Exelon Generating Co.*, 93 FERC ¶ 61,140 (2000), *reh'g denied*, 95 FERC ¶ 61,309 (2001).

8 *Bethlehem Renewable Energy, LLC*, Docket No. ER07-903-000 (unpublished delegated letter order issued July 11, 2007).

9 *Constellation Mystic Power, LLC*, Docket Nos. ER10-2281-000, *et al.* (unpublished delegated letter order issued Oct. 27, 2010).

10 *AmerGen Vt., LLC*, 90 FERC ¶ 61,307, *reh'g denied sub nom. Baltimore Gas & Elec. Co.*, 91 FERC ¶ 61,270 (2000); *Constellation Power Source Generation, LLC*, Letter Order, Docket Nos. ER14-1523-000, *et al.* (Apr. 23, 2014) (accepting for filing new tariffs reflecting the name change of Constellation Power Source Generation, Inc. to Constellation Power Source Generation, LLC).

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Battery owns an approximately 10 MW (summer) energy storage facility located in the PJM BAA. The Commission has granted Clinton Battery MBR authority.[11]

- Criterion Power Partners, LLC (Criterion) is a wholly owned subsidiary of Constellation Holdings, whose upstream ownership is described above. Criterion owns an approximately 70 MW (summer) wind farm located in the PJM BAA. The Commission has granted Criterion MBR authority.[12]

- Eastern Landfill Gas, LLC (Eastern Landfill) is a wholly owned subsidiary of Exelon Generation, whose upstream ownership is described above. Eastern Landfill owns a 3 MW landfill gas-fired facility located in the PJM BAA. The Commission has granted Eastern Landfill MBR authority.[13]

- Exelon Framingham, LLC (Exelon Framingham) is a wholly owned subsidiary of Exelon New England Holdings, LLC (Exelon New England Holdings), which is owned by Exelon Generation, whose upstream ownership is described above. Exelon Framingham owns three fossil fueled plants with a combined capacity of approximately 31 MW (summer) in the ISO-NE BAA. The Commission has granted Exelon Framingham MBR authority.[14]

- Exelon New Boston, LLC (Exelon New Boston) is a wholly owned subsidiary of Exelon New England Holdings, whose upstream ownership is described above. Exelon New Boston owned an approximately 16 MW (summer) fossil fueled plant in the ISO-NE BAA that was decommissioned in October 2016. The Commission has granted Exelon New Boston MBR authority.[15]

- Exelon West Medway, LLC (Exelon West Medway) is a wholly owned subsidiary of Exelon New England Holdings, whose upstream ownership is described above. Exelon West Medway owns the following three fossil fueled plants located in the ISO-NE BAA: Jet 1 and Jet 2, with a combined capacity of approximately 82 MW (summer); and Jet 3, with a capacity of approximately 42 MW (summer), for

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11 *Clinton Battery Utility, LLC*, Docket No. ER16-2194-000 (unpublished delegated letter order issued Aug. 12, 2016).

12 *Criterion Power Partners, LLC*, Letter Order, Docket Nos. ER10-1443-000, *et al.* (Aug. 9, 2010).

13 *Eastern Landfill Gas, LLC*, Letter Order, Docket No. ER05-1054-000, *et al.* (Sept. 14, 2005).

14 *Sithe New England Holdings LLC*, 83 FERC ¶ 61,035 (1998) (accepting for filing the market-based rate tariff of Sithe Framingham LLC); *Sithe Energies, Inc. and Exelon Generation Company, LLC*, Letter Order, Docket No. ER01-513-004 (June 12, 2013) (accepting for filing tariff revisions reflecting the name change from Sithe Framingham LLC to Exelon Framingham, LLC).

15 *Sithe New England Holdings LLC*, 83 FERC ¶ 61,035 (1998) (accepting for filing the market-based rate tariff of Sithe New Boston LLC); *Sithe Energies, Inc. and Exelon Generation Company, LLC*, Letter Order, Docket No. ER01-513-004 (June 12, 2013) (accepting for filing tariff revisions reflecting the name change from Sithe New Boston LLC to Exelon New Boston, LLC).

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a combined total across Jet 1, 2, and 3 of approximately 124 MW (summer). The Commission has granted Exelon West Medway MBR authority.[16]

- Exelon West Medway II, LLC (Exelon West Medway II) is a wholly owned subsidiary of Exelon New England Holdings, whose upstream ownership is described above. Exelon West Medway II is developing an approximately 195 MW (summer rating) electric generation facility that will be located in the ISO-NE BAA and is expected to achieve commercial operations in April 2018. The Commission has granted Exelon West Medway II MBR authority.[17]

- Exelon Wyman, LLC (Exelon Wyman) is a wholly owned subsidiary of Exelon New England Holdings, whose upstream ownership is described above. Exelon Wyman owns a 5.9% interest in a fossil fueled plant with a total capacity of approximately 602 MW (summer) in the ISO-NE BAA. The facility is operated by FPL Energy Wyman IV LLC, which is a subsidiary of NextEra Energy Resources, LLC and is not an affiliate of Exelon. The Commission has granted Exelon Wyman MBR authority.[18]

- Fair Wind Power Partners, LLC (Fair Wind) is a wholly owned subsidiary of Exelon Wind, LLC (Exelon Wind). Exelon Wind is owned by Exelon Generation Acquisitions, LLC, which is owned by Exelon Generation, whose upstream ownership is described above. Fair Wind owns an approximately 30 MW (summer) wind-powered electric generation facility located in the PJM BAA. The Commission has granted Fair Wind MBR authority.[19]

- Fourmile Wind Energy, LLC (Fourmile) is a wholly owned subsidiary of Exelon Wind, whose upstream ownership is described above. Fourmile owns and operates an approximately 40 MW (summer) wind-powered electric generation facility located in the PJM BAA. The Commission has granted Fourmile MBR authority.[20]

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[16] *Sithe New England Holdings LLC*, 83 FERC ¶ 61,035 (1998) (accepting for filing the market-based rate tariff of Sithe West Medway LLC); *Sithe Energies, Inc. and Exelon Generation Company, LLC*, Letter Order, Docket No. ER01-513-004 (June 12, 2013) (accepting for filing tariff revisions reflecting the name change from Sithe West Medway LLC to Exelon West Medway, LLC).

[17] *Exelon West Medway II, LLC*, Docket No. ER16-2708-000 (unpublished delegated letter order issued Oct. 27, 2016).

[18] *Sithe New England Holdings LLC*, 83 FERC ¶ 61,035 (1998) (accepting for filing the market-based rate tariff of Sithe Wyman LLC); *Sithe Energies, Inc. and Exelon Generation Company, LLC*, Letter Order, Docket No. ER01-513-004 (June 12, 2013) (accepting for filing tariff revisions reflecting the name change from Sithe Wyman LLC to Exelon Wyman, LLC).

[19] *Fair Wind Power Partners, LLC*, Letter Order, Docket No. ER15-2293-000 (Sept. 8, 2015).

[20] *Fourmile Wind Energy, LLC*, 148 FERC ¶ 61,104 (2014).

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- Handsome Lake Energy, LLC (Handsome Lake) is a wholly owned subsidiary of Constellation Power, Inc. (CPI). CPI is a wholly owned subsidiary of Constellation Holdings, whose upstream ownership is described above. Handsome Lake owns an approximately 267.5 MW (summer) natural gas-fired generating facility located in the PJM BAA. The Commission has granted Handsome Lake MBR authority.[21]

The Exelon NE Entities are affiliated with Constellation Energy Nuclear Group, Inc. (CENG), which is a joint venture between Exelon and EDF Inc. (EDF).[22] In the NE Region, CENG owns the following three subsidiaries that own generation facilities and have market-based rate authority:[23]

- Calvert Cliffs Nuclear Power Plant, LLC (CCNPP) is an indirect, wholly owned subsidiary of CENG. Specifically, CCNPP is a wholly owned subsidiary of Constellation Nuclear Power Plants, LLC (Constellation Nuclear Power Plants), which is a wholly owned subsidiary of CENG. Constellation Nuclear, whose upstream ownership is described above, and its subsidiary CE Nuclear, LLC own approximately 50.01% of the interests in CENG. The remaining 49.99% interest in CENG is owned indirectly by EDF. CCNPP owns and operates the Calvert Cliffs Nuclear Power Plant in the PJM BAA, which has a generating capacity of approximately 1,708 MW (summer). CCNPP sells all of the energy produced by its facility to Exelon Generation and EDF Trading North America, LLC (EDF Trading NA) under long-term firm agreements executed in 2009 that remain in effect, as amended, through the complete and permanent cessation of power generation by the facility. Each of Exelon Generation and EDF Trading NA receives approximately 50% of the energy output of CCNPP's facility under its respective agreement. The Commission has granted CCNPP MBR authority.[24]

- Nine Mile Point Nuclear Station, LLC (Nine Mile Point) is a wholly owned subsidiary of Constellation Nuclear Power Plants, whose upstream ownership is described above. Nine Mile Point owns 100% of an approximately 630 MW unit (Unit 1) and an 82% share of an approximately 1,287 MW unit (Unit 2) of a nuclear generation facility located in the NYISO BAA. Nine Mile Point sells all of the energy produced by its facility to Exelon Generation and EDF Trading NA under long-term firm agreements executed in 2009 that remain in effect, as amended, through the complete and permanent cessation of power generation by the facility. Each of Exelon Generation and EDF Trading NA receives

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21 *Constellation Power Source*, *Inc.*, Letter Order, Docket Nos. ER01-556-000, *et al.* (Jan. 19, 2001).

22 EDF is not an affiliate of Exelon.

23 CENG's subsidiaries are contemporaneously filing an updated market power analysis under separate cover.

24 *Calvert Cliffs Nuclear Power Plant, Inc.*, 92 FERC ¶ 62,161 (2000).

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approximately 50% of the energy output of Nine Mile's facility under its respective agreement. The Commission has granted Nine Mile Point market-based rate authority.[25]

- R.E. Ginna Nuclear Power Plant, LLC (Ginna) is a wholly owned subsidiary of Constellation Nuclear Power Plants, whose upstream ownership is described above. Ginna owns an approximately 582 MW nuclear generation facility located in the NYISO BAA. The Commission has granted Ginna MBR authority.[26]

The Exelon NE Entities are also affiliated with generation in several markets that are first-tier to the NE Region, as described in the Navigant Affidavit, attached as Attachment A.

The Exelon NE Entities also include the following four power marketers:

- Constellation Energy Commodities Group Maine, LLC, which is owned by Constellation Energy Upstream Holdings, Inc. Constellation Energy Upstream Holdings, Inc. is owned by Exelon Generation, whose upstream ownership is described above.
- Constellation NewEnergy, Inc. (CNE), which is owned by Constellation Energy Resources, LLC (Constellation Energy Resources). Constellation Energy Resources is owned by Exelon Generation, whose upstream ownership is described above.
- Constellation Energy Services, Inc. (CES), which is owned by Constellation Energy Resources, whose upstream ownership is described above. CES was formerly known as Integrys Energy Services, Inc. and changed its name effective April 1, 2015.
- Constellation Energy Services of New York, Inc. (CES of NY), which is owned by CES, whose upstream ownership is described above. CES of NY was formerly known as Integrys Energy Services of New York, Inc. and changed its name effective April 1, 2015.

Each of these four marketers operates primarily as a competitive retail supplier and has been granted MBR authority by the Commission.[27] None of the four marketers owns or controls

[25] *Nine Mile Point Nuclear Station, LLC*, 95 FERC ¶ 61,202 (2001).

[26] *R.E. Ginna Nuclear Power Plant, LLC*, Docket No. ER04-485-000 (unpublished delegated letter order issued Mar. 24, 2004).

[27] See *Constellation Power Source Maine, LLC*, Letter Order, Docket No. ER02-699-000 (Feb. 26, 2002); *NEV, L.L.C.*, 81 FERC ¶ 61,186 (1997) (granting Constellation NewEnergy, Inc. market-based rate authority); *Wisconsin Public Service Corp., et al.*, 75 FERC ¶ 61,057 (1996) (granting Constellation Energy Services, Inc. market-based rate authority); *Advantage Energy, Inc.*, Letter Order, Docket No. ER97-2758-000 (July 14, 1997)

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any generation facilities, except for limited behind-the-meter facilities, or any transmission facilities in the United States. CNE owns Pepco Energy Services, Inc. (PES), which is primarily engaged in providing energy services, including investment-grade energy audits and installation of energy conservation measures for federal, state and local governments, specialized construction work for electric utilities, and the delivery of thermal energy under long-term contracts. PES does not own any electrical generation facilities, except for certain limited behind-the-meter generation facilities, and has been granted MBR authority.[28]

The Exelon NE Entities also include the following franchised public utilities within the meaning of 18 C.F.R. § 35.36(a)(5): Commonwealth Edison Company (ComEd), PECO Energy Company (PECO), Baltimore Gas and Electric Company (BGE), Potomac Electric Power Company (Pepco), Delmarva Power & Light Company (DPL), and Atlantic City Electric Company (ACE) (collectively, the Franchised Public Utilities).

ComEd and PECO are owned by Exelon Energy Delivery Company, LLC (EEDC), which in turn is owned by Exelon. BGE is owned by RF HoldCo LLC, which in turn is owned by EEDC. Pepco, DPL, and ACE are owned by Pepco Holdings LLC, which is owned by PH Holdco LLC. PH Holdco LLC is owned by EEDC. Together, the Franchised Public Utilities own electric distribution systems through which they deliver electricity to customers in Illinois, Pennsylvania, Maryland, the District of Columbia, Delaware, and New Jersey. All of the Franchised Public Utilities' retail customers have access to competitively priced retail power and, as a result, are not considered captive for purposes of the Commission's MBR regulations.[29]

The Commission granted each of the Franchised Public Utilities MBR authority.[30] The Franchised Public Utilities do not own any electric generation facilities, except for limited behind-the-meter facilities located at substation sites,[31] and serve as default service providers for

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(granting Constellation Energy Services of New York, Inc. market-based rate authority). In a letter order issued on June 23, 2015 in Docket Nos. ER15-1537-000, *et al.*, the Commission accepted for filing the notice of succession reflecting the names changes from Integrys Energy Services, Inc. to Constellation Energy Services, Inc. and from Integrys Energy Services of New York, Inc. to Constellation Energy Services of New York, Inc.

[28] *Pepco Energy Services, Inc.*, 84 FERC ¶ 61,024 (1998).

[29] *See Exelon Generation Co.*¸126 FERC ¶ 61,031 at PP 43-48 (2009); *Baltimore Gas & Elec. Co.*, Letter Order, Docket Nos. ER99-2948-012, *et al.* (Sept. 16, 2008); *Exelon Generation Co.*, 93 FERC ¶ 61,140 at 61,425 (2000), *on reh'g*, 95 FERC ¶ 61,309 (2001); *AmerGen VT, LLC*, 90 FERC ¶ 61,307 at 61,995, *on reh'g*, *Baltimore Gas & Elec. Co*., 91 FERC ¶ 61,270 (2000); *Potomac Elec. Power Co., et al.*, 93 FERC ¶ 61,240 at 61,781-82 (2000); *Pepco Holdings, Inc.*, 141 FERC ¶ 61,034 (2012).

[30] *Commonwealth Edison Co.*, 82 FERC ¶ 61,317 (1998); *PECO Energy Company*, 74 FERC ¶ 61,336 (1996); *Green Power Partners I, LLC*, 88 FERC ¶ 61,005 (1999); *Potomac Electric Power Company*, 85 FERC ¶ 61,019 (1998); *Delmarva Power & Light Company*, 76 FERC ¶ 61,331 (1996); *Atlantic City Electric Company*, 75 FERC ¶ 61,167 (1996).

[31] These behind-the-meter facilities have not been included in the indicative screens or asset appendix submitted with this application. *See Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 816, 153 FERC ¶ 61,065 at P

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those electric customers that do not choose competitive suppliers or whose competitive supplier failed to deliver electric supply. ACE and DPL have long-term power purchase agreements that, as a result of the refinements to the Commission's market-based rate program adopted in Order No. 816,[32] are included in the asset appendix and in the market power analysis. ACE's long-term power purchase agreements obligate ACE to pay the generators for specified amounts of energy at a specified price, and the costs are recovered from ACE's retail customers. ACE bids the energy into the PJM market and credits retail customers for all energy revenues received by ACE from PJM. ACE does not control those generating units and cannot withhold the output of the units from the market. DPL's long-term power purchase agreements are fixed-price, must-run contracts, and DPL has no ability to withhold this generation.

The Franchised Public Utilities own transmission facilities, but have transferred operational control over such facilities to PJM, which provides transmission service pursuant to an Open Access Transmission Tariff (OATT) on file with the Commission.[33] In addition, PECO and BGE own certain intrastate natural gas transportation and distribution facilities used to distribute natural gas to customers in Philadelphia and central Maryland and operate liquefied natural gas facilities and propane-air facilities associated with their respective distribution activities that do not offer services to third parties. Furthermore, DPL supplies and delivers natural gas to retail customers and provides transportation-only services to retail customers that purchase natural gas from another supplier. DPL owns intrastate natural gas transportation and distribution facilities pipelines, and a liquefied natural gas storage facility.

V. UPDATED MARKET POWER ANALYSIS

As required by the Commission's regulations and the Exelon NE Entities' MBR authorizations, the Exelon NE Entities provide below their updated market power analysis demonstrating that they lack horizontal and vertical market power in the relevant wholesale electricity markets in the NE Region.

A. Horizontal Market Power Analysis

In Order No. 697, the Commission retained two indicative screens for assessing generation market power in the relevant geographic markets: a pivotal supplier screen (PSS) and a market share screen (MSS).[34] If the seller passes both indicative screens, there is a rebuttable

255 (2015), *reh'g*, Order No. 816-A, 155 FERC ¶ 61,188 (2016) ("[W]e clarify that qualifying facilities that are exempt from [Federal Power Act] section 205 and facilities that are behind-the-meter facilities do not need to be reported in the asset appendix or indicative screens.").

32 *See* Order No. 816 at P 145.

33 Commonwealth Edison Company of Indiana, Inc. (ComEd of Indiana), a wholly owned subsidiary of ComEd, also owns a small amount of electric transmission property in Indiana. As with ComEd, the transmission facilities owned by ComEd of Indiana, Inc. are under the operational control of PJM.

34 Order No. 697 at P 62.

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presumption that the seller does not possess market power in generation and no further analysis is required.

As demonstrated below and in the Navigant Affidavit attached hereto as Attachment A, the Exelon NE Entities pass both screens in PJM (as well as the following submarkets within PJM: PJM East, AP South, and 5004/5005), ISO-NE (as well as the CT submarket),[35] and NYISO which are the only relevant markets for this analysis.[36] Accordingly, the Exelon NE Entities lack horizontal market power in the relevant markets and submarkets in the NE Region. In any event, the Exelon NE Entities commit to comply with all applicable PJM, ISO-NE, and NYISO rules regarding market monitoring and mitigation.[37]

Navigant conducted its analyses consistent with Order No. 697, Order No. 816 and related orders, performing the two indicative horizontal market power screens required by the Commission. Navigant's analysis is based on the study period of December 2014-November 2015, the most recent available actual historical data. Consistent with Order No. 816, Navigant attributes to the Exelon NE Entities the generation owned by the Exelon NE Entities and their affiliates in each of the relevant markets and submarkets, adjusted for long-term firm purchases and sales, as well as a pro rata share of imports from affiliated uncommitted capacity in relevant first-tier markets.[38] As permitted by the Commission in Order No. 816, however, Navigant has not included qualifying facilities that are exempt from Section 205 of the Federal Power Act or behind-the-meter facilities in the generation attributed to the Exelon NE Entities.[39]

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[35] The Exelon NE Entities note the Commission recently concluded in a FPA section 203 proceeding that, based on evidence presented in that proceeding, "Connecticut and Southwest Connecticut are not separate geographic markets at this time because the constraints have not been frequently binding and therefore do not prevent competing supply from reaching customers within the Connecticut and Southwest Connecticut areas." *Atlas Power Finance, LLC*, 157 FERC ¶ 61,237, at P48 (2016) ("*Atlas*"). Nonetheless, given that the required study period for this updated market power analysis differs from the period studied in *Atlas*, the Exelon NE Entities conservatively provide an analysis of the Connecticut submarket in this updated market power analysis. The Exelon NE Entities do not own or purchase power from, and are not affiliated with, any generating facilities in Southwest Connecticut.

[36] Consistent with the Commission's approach for evaluating independent generators, the relevant geographic market is the BAA with which relevant generation is interconnected, i.e., the ISO-NE, NYISO, and PJM BAAs and their submarkets. *See* Order No. 697 at P 232 n. 217 ("Where a generator is interconnecting to a non-affiliate owned or controlled transmission system, there is only one relevant market (i.e., the balancing authority area in which the generator is located)."); *id.* at P 865 n. 1009 (same).

[37] The Commission has adopted a rebuttable presumption that existing Commission-approved RTO/ISO market monitoring and mitigation is sufficient to address any market power concerns. *See* Order No. 697-A at P 111; *see also NextEra Energy Power Mktg., LLC*, Docket Nos. ER09-832-004, *et al.* (letter order issued Mar. 25, 2010).

[38] Attachment A, Navigant Aff. at 7.

[39] *See* Order No. 816 at P 255.

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With respect to load, Navigant attributes to the Exelon NE Entities load they served in PJM, NYISO and ISO-NE during the study period. This load includes wholesale load directly supplied by Exelon Generation such as net physical sales to parties that primarily serve load[40] as well as sales under certain long-term inter-company agreements by which Exelon Generation sells energy, capacity and other electric products to several retail electric supplier affiliates that are necessary to meet those affiliates' retail load obligations in the relevant markets.[41] Under Exelon Generation's long-term contracts with its retail electric supplier affiliates, Exelon Generation is obligated to supply sufficient quantities to satisfy the physical retail supply obligations of each retail electric supplier affiliate. Therefore, the deduction of these sales in the load calculation is consistent with the Commission's permitted deductions in Order No. 697 as well as the load calculations used in Exelon's 2010 and 2013 updated market power analyses that were accepted by the Commission.[42]

1. Pivotal Supplier Screen

The PSS "measures the ability of a firm to dominate the market at peak periods."[43] If demand in a specific market can be met without at least some power from a supplier, that supplier passes the PSS.[44] The Commission's required analysis under the PSS measures the uncommitted capacity of the supplier seeking MBR authorization, determined by adding the total nameplate or seasonal capacity of generation owned or controlled through contract and firm purchases, less the supplier's long-term firm sales, operating reserves and native load commitments.[45] The supplier's uncommitted capacity is deemed available for wholesale transactions.[46] The same methodology used in the PSS to calculate an applicant's uncommitted capacity is applied to measure competing suppliers' uncommitted capacity.[47]

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40 Attachment A, Navigant Aff. at 11.

41 As noted in Attachment A, Navigant Aff. at FN 28, the Commission permits sellers to deduct "long-term load following contracts to the extent that the seller has included in its total capacity a corresponding generating unit or long-term firm purchase contract that will be used to meet the obligation."

42 *Commonwealth Edison Co.*, Docket Nos. ER10-1048-002, *et al.*, Updated Market Power Analysis, Solomon Affidavit at 10 (filed Dec. 30, 2010, as supplemented Mar. 21, 2011) (accepted by unpublished delegated letter order issued June 22, 2011); *AV Solar Ranch 1, LLC*, Docket No. ER12-2178-008 (filed Dec. 30, 2013, as supplemented May 16, 2014) (accepted by unpublished delegated letter order issued Aug. 5, 2014).

43 Order No. 697 at P 65; *see also AEP Power Mktg., Inc.*, 107 FERC ¶ 61,018 at P 71 (2004) (*AEP Power Marketing*).

44 *AEP Power Marketing* at P 72.

45 Order No. 697 at P 38.

46 *Id.* at P 42; *AEP Power Marketing* at P 99.

47 In Order No. 697, the Commission adopted the same native load proxy for the market share screen as is employed in the pivotal supplier screen. Order No. 697 at P 135.

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As demonstrated in the Navigant Affidavit, the Exelon NE Entities pass the PSS in all relevant markets and submarkets because the Exelon NE Entities' net uncommitted capacity is less than each market's net uncommitted supply. The following table summarizes the results of the PSS.

Relevant Market	Exhibit No.	Exelon NE Entities Uncommitted Capacity	Net Uncommitted Supply	Result
PJM	NCI-5	5,092 MW	37,930 MW	Pass
AP South	NCI-11	1,868 MW	9,827 MW	Pass
5004/5005	NCI-9	1,936 MW	7,431 MW	Pass
PJM East	NCI-7	2,780 MW	9,498 MW	Pass
ISO-NE	NCI-13	0 MW	12,225 MW	Pass
CT	NCI-15	0 MW	3,706 MW	Pass
NYISO	NCI-17	97 MW	12,602 MW	Pass

2. Market Share Screen

The market share screen addresses on a seasonal basis "whether a seller has a dominant position in the market based on the number of megawatts of uncommitted capacity owned or controlled by the seller as compared to the uncommitted capacity of the entire relevant market."[48] If the applicant has less than a 20 percent market share in all four seasons, it passes the market share screen.[49]

The Exelon NE Entities pass the MSS in all the relevant markets and submarkets because their market share is below the 20% threshold in each season. The following table summarizes the results of the MSS.

Relevant Market	Exhibit No.	Winter	Spring	Summer	Fall	Result
PJM	NCI-6	10.6%	10.4%	9.0%	9.9%	Pass
AP South	NCI-12	12.1%	12.3%	8.7%	9.4%	Pass
5004/5005	NCI-10	16.1%	16.4%	11.6%	12.7%	Pass
PJM East	NCI-8	18.8%	17.7%	18.0%	15.9%	Pass
ISO-NE	NCI-14	0%	0%	0%	0%	Pass
CT	NCI-16	0%	0%	0%	0%	Pass
NYISO	NCI-18	4.1%	1.7%	0.4%	0.6%	Pass

In addition, as stated in the Navigant Affidavit, the Exelon NE Entities are subject to RTO/ISO market monitoring and mitigation in all relevant markets in the NE region. The

[48] *See* Order No. 697 at P 43.

[49] *Id.* at PP 44, 89.

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Commission previously has found that such market monitoring and mitigation generally results in transparent pricing and mitigates any attempts to exercise market power.[50] Also, Navigant notes the Exelon NE Entities are subject to certain additional behavioral commitments in PJM, entered into via a Settlement Agreement with the PJM Market Monitor at the time of the merger between Exelon and Constellation Energy Group, Inc. that mitigates any horizontal market power.[51] Finally, Navigant's market share analysis is extremely conservative, which means the Exelon NE Entities' market share is overstated in PJM and the relevant submarkets.[52]

In sum, Navigant concludes that the Exelon NE Entities do not have market power in any of the relevant markets or submarkets in the NE Region.

B. Vertical Market Power Analysis

In evaluating vertical market power, the Commission considers both transmission market power and the ability of the seller and its affiliates to erect barriers to entry in the relevant markets.[53] As explained below, the Exelon NE Entities continue to lack vertical market power.

i. Transmission Market Power

In order to receive market-based rate authorization, the seller and its affiliates must also lack, or have adequately mitigated, transmission market power. The Exelon NE Entities are affiliated with the Franchised Public Utilities, which distribute electricity to millions of customers in the District of Columbia, Illinois, Maryland, New Jersey, Delaware, and Pennsylvania. The Franchised Public Utilities have each transferred operational control over their transmission systems to PJM, and transmission service over those facilities is provided by PJM under its OATT. The Commission has frequently held that membership in a Commission-approved regional transmission organization (RTO) sufficiently addresses vertical market power concerns in an RTO market such as PJM.[54] None of the other Exelon NE Entities nor their affiliates own or control any transmission facilities in the NE Region other than certain limited

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50 Attachment A, Navigant Aff. at 16 (citing Order No. 697 at PP 241-242).

51 Attachment A, Navigant Aff. at 17.

52 Attachment A, Navigant Aff. at 11. Navigant explains that their Total Uncommitted Capacity determination in each RTO market and submarket is "extremely conservative" because, except for the Exelon NE Entities, no attempt was made to match load commitments and generation commitments. Navigant's analysis of the amount of load attributable to "others" "assumes that every MW of generation is 'committed' to the extent there is load, even though in reality every MW of generation is not necessarily committed by ownership or contractual commitment to serving a specific load." *Id.* As Navigant notes, some parties rely on short-term purchases from the RTO markets to meet load obligations. As a result, the competing uncommitted capacity deemed to compete with the Exelon NE Entities' uncommitted capacity is conservatively low in the Navigant analysis.

53 *See* Order No. 697 at P 399.

54 *See*, *e.g.*, *Exelon Corp.*, 138 FERC ¶ 61,167 at P 113 (2012); *Duke Energy*, 136 FERC ¶ 61,245 at P 161 (2011); *FirstEnergy Corp.*, 133 FERC ¶ 61,222 at PP 56-57 (2010); *PPL Corp.*, 133 FERC ¶ 61,083 at P 18 (2010); *Exelon Corp.*, 127 FERC ¶ 61,161 at PP 90, 93 (2009).

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and discrete interconnection facilities necessary to interconnect their generating facilities to the electric grid. The Commission has previously ruled that such limited interconnection facilities do not convey transmission market power.[55] The Exelon NE Entities (other than the Franchised Public Utilities) affirm that they qualify for the blanket OATT waiver pursuant to section 35.28(d)(2) of the Commission's regulations.[56] Accordingly, the Exelon NE Entities and their affiliates lack transmission market power.[57]

ii. Barriers to Entry

The Commission also considers whether a company that is authorized to sell at market-based rates can erect barriers to entry by competing wholesale power suppliers in the relevant geographic markets by exercising control over the following inputs to electric power production: intrastate natural gas transportation; intrastate natural gas storage or distribution facilities; physical coal supplies sources and ownership of or control over who may access transportation of coal supplies.[58] In Order No. 697, the Commission adopted a rebuttable presumption that sellers cannot erect barriers to entry with regard to the ownership or control of, or affiliation with any entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities and sources of coal supplies and the transportation of coal supplies such as barges and rail cars.[59]

Except for the natural gas distribution facilities owned by PECO, BGE, and DPL described in Section IV above, none of the Exelon NE Entities or any of their affiliates owns or controls any inputs to electric power production in the United States. The ownership of certain natural gas distribution facilities by PECO, BGE, and DPL does not raise any vertical market power concerns, because the Commission has adopted a rebuttable presumption that sellers cannot erect barriers to entry based on ownership or control of, or affiliation with an entity that owns or controls such natural gas facilities.[60] The Exelon NE Entities and their affiliates affirmatively state that they have not erected barriers to entry into the relevant markets and will

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55 *See, e.g.*, *AES Huntington Beach, LLC*, 111 FERC ¶ 61,079, at P 43 (2005); *Zond Dev. Corp.*, 80 FERC ¶ 61,051, at 61,153 (1997).

56 18 C.F.R. § 35.28(d)(2) (as amended by *Open Access and Priority Rights on Interconnection Customer's Interconnection Facilities*, Order No. 807, 80 Fed. Reg. 17,654 (Apr. 1, 2014), FERC Stats. & Regs. ¶ 31,367 at PP 55, 57 (2015), *order denying reh'g*, Order No. 807-A, 153 FERC ¶ 61,047 (2015)). The Commission explained in Order No. 807 that the blanket waiver supersedes specific OATT waivers that an entity previously received pursuant to the Commission's "limited and discrete" standard. *See* Order No. 807 at P 89.

57 *See* Order No. 697 at P 21.

58 18 C.F.R. § 35.36(a)(4). The Commission does not consider ownership or control of natural gas supply, interstate natural gas transportation (including interstate natural gas storage), oil supply or oil transportation in its barriers to entry analysis. *See* Order No. 697 at P 442.

59 Order No. 697 at P 446.

60 *Id*.

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not erect barriers to entry into the relevant markets.[61] Thus, the Exelon NE Entities satisfy the Commission's requirements for showing a lack of ability to erect barriers to entry.

C. The Exelon NE Entities and Their Affiliates Continue to Qualify for Waiver of the Affiliate Restrictions

The affiliate restrictions govern the relationship between franchised public utilities with captive customers and their market-regulated power sales affiliates, which include wholesale power sales by a market-based rate seller to its franchised public utility affiliate, as well as transactions involving non-power goods and services between the franchised public utility and its market-regulated power sales affiliate.[62] The only franchised public utilities affiliated with the Exelon NE Entities are the Franchised Public Utilities, and the Commission has previously found that the establishment of a code of conduct governing the relationship between the Franchised Public Utilities and their market-regulated power sales affiliates was not necessary because the Franchised Public Utilities do not have any captive wholesale or retail customers.[63] Consistent with Commission precedent, waiver of the affiliate restrictions with respect to the Exelon NE Entities remains appropriate because, as explained below, the Franchised Public Utilities continue to have no captive wholesale or retail customers.

The Commission's regulations define "franchised public utility" to mean "a public utility with a franchised service obligation under state law"[64] and "captive customers" to mean "any wholesale or retail electric energy customers served by a franchised public utility under cost-based regulation."[65] None of the Franchised Public Utilities have any wholesale electric energy customers served under cost-based rates. While the Franchised Public Utilities serve retail electric energy customers under cost-based rates in their respective service territories, all of their retail customers have the option to choose a competitive retail electric supplier. The Commission clarified in Order No. 697 that

> the definition of "captive customers" does not include those customers who have retail choice, *i.e.* the ability to select a retail supplier based on the rates, terms and conditions of service offered.

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61 *See* Order No. 697 at P 448.

62 18 C.F.R. § 35.39 (2016).

63 *Exelon Generation Co*., 126 FERC ¶ 61,031, at PP 43-48 (2009); *Baltimore Gas & Elec. Co.*, Docket Nos. ER99-2948-012, *et al.* (unpublished delegated letter order issued Sept. 16, 2008). Waiver of the code of conduct was originally granted in *Exelon Generation Co.*, 93 FERC ¶ 61,140, at 61,425-26 (2000), *reh'g denied*, 95 FERC ¶ 61,309 (2001); *AmerGen Vt., LLC*, 90 FERC ¶ 61,307, at 61,995, *reh'g denied sub nom.*, *Baltimore Gas & Elec. Co*., 91 FERC ¶ 61,270 (2000); *Potomac Elec. Power Co.*, *et al.*, 93 FERC ¶ 61,240 at 61,781-82 (2000); and *Pepco Holdings, Inc*., 141 FERC ¶ 61,034 (2012).

64 18 C.F.R. § 35.36(a)(5) (2016).

65 *Id.* § 35.36(a)(6) (2016).

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> Retail customers who choose to be served under cost-based rates but have the ability, by virtue of state law, to choose one retail supplier over another, are not considered to be under "cost-based regulation" and therefore are not "captive."[66]

Thus, the Franchised Public Utilities do not have any retail captive customers. Because the Franchised Public Utilities do not have any wholesale or retail captive customers, continuation of the waiver of the affiliate restrictions is appropriate.

VI. CONCLUSION

Based on the foregoing, the Exelon NE Entities respectfully request that the Commission issue an order finding that each of them continues to lack market power and continues to be authorized to engage in the wholesale sale of electricity at market-based rates in the NE Region.

Respectfully submitted,

Jane E. Rueger
Jane E. Rueger
Harold W. Bulger, III

Counsel for the Exelon NE Entities

[66] Order No. 697 at P 479.

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in these proceedings.

Dated at Washington, D.C., this 29th day of December, 2016.

/s/ Harold W. Bulger, III

Harold W. Bulger, III
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Attachment A:

Affidavit and Exhibits of Julie R. Solomon and Julie M. Carey of Navigant Consulting, Inc.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Atlantic City Electric Company	**)**	**Docket No. ER10-2997-___**
Baltimore Gas and Electric Company	**)**	**Docket No. ER10-2175-___**
Bethlehem Renewable Energy, LLC	**)**	**Docket No. ER10-3003-___**
Commonwealth Edison Company	**)**	**Docket No. ER10-1048-___**
Constellation Energy Commodities Group Maine, LLC	**)**	**Docket No. ER10-2192-__**
Constellation Energy Services, Inc.	**)**	**Docket No. ER15-1537-__**
Constellation Energy Services of New York, Inc.	**)**	**Docket No. ER15-1539-__**
Constellation Mystic Power, LLC	**)**	**Docket No. ER11-2056-__**
Constellation NewEnergy, Inc.	**)**	**Docket No. ER10-2178-__**
Constellation Power Source Generation, LLC	**)**	**Docket No. ER14-1524-__**
Clinton Battery Utility, LLC	**)**	**Docket No. ER16-2194-__**
Criterion Power Partners, LLC	**)**	**Docket No. ER10-3308-__**
Delmarva Power & Light Company	**)**	**Docket No. ER10-3018-__**
Eastern Landfill Gas, LLC	**)**	**Docket No. ER10-3015-__**
Exelon Framingham, LLC	**)**	**Docket No. ER10-1020-__**
Exelon Generation Company, LLC	**)**	**Docket No. ER13-1536-__**
Exelon New Boston, LLC	**)**	**Docket No. ER10-1078-__**
Exelon West Medway, LLC	**)**	**Docket No. ER10-1080-__**
Exelon West Medway II, LLC	**)**	**Docket No. ER16-2708-__**
Exelon Wyman, LLC	**)**	**Docket No. ER10-1081-__**
Fair Wind Power Partners, LLC	**)**	**Docket No. ER15-2293-__**
Fourmile Wind Energy, LLC	**)**	**Docket No. ER14-2145-__**
Handsome Lake Energy, LLC	**)**	**Docket No. ER10-2180-__**
PECO Energy Company	**)**	**Docket No. ER14-767-__**
Pepco Energy Services, Inc.	**)**	**Docket No. ER10-2992-__**
Potomac Electric Power Company	**)**	**Docket No. ER10-3030-__**

AFFIDAVIT OF
JULIE R. SOLOMON
AND
JULIE M. CAREY

INTRODUCTION

My name is Julie R. Solomon. I am a Managing Director of Navigant Consulting, Inc. My business address is 1200 19th Street, N.W., Suite 700, Washington, DC 20036. A large portion of my consulting activities involves electric utility industry restructuring and the transition from

regulation to competition. I have been involved extensively in consulting on market power issues concerning mergers, other asset transactions and market-based rate applications. I have filed a number of affidavits before the Federal Energy Regulatory Commission (the "Commission") in connection with electric utility mergers, the purchase and sale of jurisdictional assets, applications for market-based rates, and triennial updates. Included among these, I have filed a number of affidavits with the Commission on behalf of relevant affiliates of Exelon Corporation ("Exelon") with market-based rate authority in connection with past triennial updates. My resume is attached as Exhibit NCI-1.

My name is Julie M. Carey. I am a Director of Navigant Consulting, Inc., with the same business address. I have worked in the electric utility industry for approximately 20 years, primarily as an economic consultant. I routinely conduct competition analyses and analyze market power issues within the electric utility industry for a variety of purposes, including for approval of mergers and acquisitions, for approval of market based rates, and to evaluate wholesale market rules on competition. I have experience analyzing market power issues in the context of legal and regulatory proceedings involving claims of anticompetitive behavior or market manipulation. I previously have submitted affidavits before the Commission addressing applications for market-based authority and triennial updates as well as generation asset acquisitions for electric utilities. I also frequently provide testimony on a wide variety of economic issues across the energy industry before numerous regulatory agencies, courts and within arbitrations. I am an adjunct professor at Georgetown University teaching in the graduate economics program. My resume is attached as Exhibit NCI-2.

We have been asked by counsel for the above-captioned subsidiaries of Exelon with market-based rate authority (the "Exelon NE Entities" or "Sellers") to perform an analysis of market power

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in compliance with the Commission's guidelines contained in *Order No. 697*[1], and *Order No. 816*.[2] Here we provide an evaluation of horizontal and vertical market power issues for the relevant markets in the Northeast Region[3] in which the Exelon NE Entities are transmission owners and/or own generation facilities.

SUMMARY OF CONCLUSIONS

Based on the analyses discussed herein, we find that, under the Commission's guidelines, the Exelon NE Entities satisfy the Commission's horizontal market power screens. The Exelon NE Entities also do not have vertical market power in the relevant markets.

The analysis we have conducted is consistent with *Order No. 697, Order No. 816* and related orders. We have performed the two indicative horizontal market power screens required by the Commission, namely a pivotal supplier analysis based on the annual peak demand of the relevant market ("Pivotal Supplier Analysis") and a market share analysis ("Market Share Analysis") applied on a seasonal basis for the relevant study period of December 2014-November 2015. Here we provide an evaluation of market power for the default relevant geographic markets in which the Exelon NE Entities own generation in the Northeast Region, namely PJM and relevant submarkets

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1 *Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity and Ancillary Servs. by Pub. Utils.*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g and clarification*, Order No. 697-A, FERC Stats. & Regs ¶ 31,268, *order on reh'g and clarification*, 124 FERC ¶ 61,055, *order on reh'g and clarification*, Order No. 697-B, FERC Stats. & Regs ¶ 31,285 (2008), *order on reh'g and clarification*, Order No. 697-C, FERC Stats. & Regs ¶ 31,291 (2009), *order on reh'g and clarification*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305, *order on clarification*, 131 FERC ¶ 61,021, *reh'g denied*, 134 FERC ¶ 61,046 (2010), *appeal docketed sub nom. Mont. Consumer Counsel v. FERC,* Nos. 08-71827, *et al.* (9th Cir. filed May 1, 2008) (collectively, "Order No. 697") (codified at 18 C.F.R. pt. 35).

2 *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 816, 153 FERC ¶ 61,065 (2015), 153 FERC ¶ 61,065 (2015), *order on reh'g*, Order No. 816-A, 155 FERC ¶ 61,188 (2016).

3 The Northeast Region includes PJM Interconnection, LLC ("PJM"), New York Independent System Operator, Inc. ("NYISO"), and ISO New England Inc. ("ISO-NE"). *Order No. 697*, Appendix D.

(PJM East, AP South, and 5004/5005),[4] ISO-NE and a relevant submarket (Connecticut ("CT")), and NYISO (collectively, the "Northeast Region RTOs").[5]

The Exelon NE Entities pass the Pivotal Supplier Analysis and Market Share Analysis in all relevant markets and submarkets, and hence are presumed not to have horizontal market power in the Northeast Region.[6] Additionally, there are other protections in place that further prevent market power concerns. First, *Order No. 697* contemplates that Commission-approved market monitoring and mitigation in RTO markets or submarkets be considered as part of market power analysis.[7] Each of the relevant Northeast Region markets and submarkets is subject to extensive Commission-approved market monitoring and mitigation that generally results in transparent pricing and mitigates attempts to exercise market power.[8] Second, the Exelon NE Entities are subject to additional behavioral commitments in PJM, entered into as part of the merger between Exelon Corporation and Constellation Energy Group, Inc. (*see* Docket No. EC11-83-000) (the "Exelon-Constellation Merger") that mitigate any horizontal market power.[9]

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4 Although not described in Order No. 697, the Commission has adopted the convention that AP South and 5004/5005 submarkets are relevant submarkets in PJM. *See, e.g.*, *Exelon Corp.*, 138 FERC ¶ 61,167 (2012).

5 While the Commission has identified submarkets in NYISO, none of the Exelon NE Entities own or purchase generation under long-term firm agreements in those submarkets so none of them are relevant to our analysis.

6 These results differ from the indicative screens analysis results for PJM and submarkets submitted by the Exelon MBR Entities earlier in 2016. *See* Notice of Change in Status, of the Exelon MBR Entities, filed in Docket Nos. ER10-2997, *et al*., on April 22, 2016; and accepted in *Atlantic City Elec. Co*., *et al*., Docket Nos. ER10-2997, *et al*. (Oct. 26, 2016) (unpublished letter order). The differences primarily result from (i) a correction in load assigned to the Exelon MBR Entities for the PJM East submarket (and hence, the other submarkets as well), which had been under-reported in the prior filing; (ii) updated Simultaneous Import Limits ("SIL"); (iii) using planned outages reported in the FERC Form 714 (not previously available) rather than day-ahead planned outage forecasts published by PJM); (iv) using operating reserves reported in the PJM SIL study (not previously available) rather than a calculated reserve number; and (v) inclusion of load served by the Exelon NE Entities in NYISO (first-tier to PJM). Thus, whereas the Notice of Change in Status had reported some market share screen failures in submarkets, there are no such screen failures here.

7 *See* Order No. 697 at PP 241-242.

8 Order No. 697 at P 241.

9 *See* Answer of Exelon Corporation and Constellation Energy Group, Inc., Docket No. EC11-83-000 (filed Oct. 11, 2011) ("Section 203 Amendment") (describing the behavioral commitments). *See also Exelon Corporation, et al.*, 138 FERC ¶ 61,167 at PP 82-85 and 94 (2012) (describing the commitments and relying in part on the commitments to find that the merger would not adversely affect competition).

The Exelon NE Entities also lack vertical market power. Commonwealth Edison Company ("ComEd"), PECO Energy Company ("PECO"), Baltimore Gas and Electric ("BGE"), Atlantic City Electric Company ("ACE"), Delmarva Power & Light Company ("DPL"), and Potomac Electric Power Company ("Pepco") each own transmission facilities in PJM, but such facilities are under the functional control of PJM and are subject to the terms and conditions of the PJM Open Access Transmission Tariff ("OATT"). Outside of PJM, the only transmission facilities owned or controlled by the Exelon NE Entities or their affiliates consist of those necessary to connect their generating facilities to the grid and thus do not raise any vertical market power concerns.

The Exelon NE Entities cannot erect barriers to entry in relevant markets. Except for PECO, BGE, and DPL, the Exelon NE Entities have no ownership or control of intrastate natural gas transportation or intrastate natural gas storage or distribution facilities. PECO and BGE own intrastate natural gas distribution facilities in PJM and have liquefied natural gas ("LNG") facilities that are used to provide peak gas to their customers. DPL owns intrastate natural gas transportation and distribution facilities pipelines and a liquefied natural gas storage facility. DPL supplies and delivers natural gas to retail customers and provides transportation-only services to retail customers that purchase natural gas from another supplier. The ownership by PECO, BGE and DPL of these assets is subject to the Commission's rebuttable presumption that such ownership does not allow a seller to raise entry barriers.[10] Hence, no vertical concerns are present with respect to the Exelon NE Entities' owned natural gas distribution and LNG facilities.

The Exelon NE Entities do not own or control sources of coal supplies or transportation of coal supplies. In any event, these assets would be subject to the rebuttable presumption that such ownership or control does not allow a seller to raise entry barriers. There are no other issues that raise any relevant competitive concerns.

We understand that an affirmative statement on behalf of the Exelon NE Entities is included in their submission to the effect that they have not erected barriers to entry and will not erect barriers to entry.

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[10] *Order No. 697* at P 22.

DESCRIPTION OF EXELON NE ENTITIES

For purposes of our analysis, Exhibit NCI-3 details the generation owned or purchased under long-term firm contract by the Exelon NE Entities in the Northeast Region, and also reflects generation owned and purchased under long-term firm contract in relevant first-tier markets. A detailed description of the Exelon NE Entities is provided in the submittal letter.

HORIZONTAL MARKET POWER

In *Order No. 697* and *Order No. 816*, the Commission codified a methodology for assessing market power to be used by applicants requesting market-based rate authority under Section 205 of the Federal Power Act or making their required triennial market power update filings. The Commission applies two screens – the Pivotal Supplier Analysis and the Market Share Analysis – intended to demonstrate a lack of horizontal market power. If an entity fails to pass either of the screens, there is a presumption of horizontal market power and further analysis is required.[11]

In *Order No. 697*, the Commission defines the default relevant market as the balancing authority area ("BAA") in which the applicant is physically located and the BAAs directly interconnected to the seller's BAA (first-tier BAAs). Where a generator is interconnected to a non-affiliate owned transmission system, the only relevant market is the BAA in which the generator is located.[12] Sellers located in, and members of, RTOs may use the geographic region under the control of the RTO as the default relevant geographic market.[13] Sellers located in, and members of, an RTO/ISO are not required to analyze first-tier markets to the RTO/ISO. If the Commission has made specific findings of submarkets within an RTO/ISO, the default relevant market becomes the submarket(s) of the RTO/ISO.[14]

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[11] *See Order No. 697-A* at Appendix A to Subpart H, and the current version of the horizontal market power wholesale market share and pivotal supplier indicative screens from *Order No. 816*. While the Commission in *Order No. 816* changed the screen formats and adjusted some input definitions, the main elements of the indicative screens described here have remained consistent since the *Order No. 697* series of orders. http://www.ferc.gov/industries/electric/gen-info/mbr/important-orders/OrderNo816/appendix-A.xlsx.

[12] *Order No.697* at P 232 n.217.

[13] *Id.* at P 235.

[14] *Id.* at PP 236, 246; *Order No. 697-A* at P 90. The relevant submarket in PJM that was identified in *Order No. 697* and related orders was PJM East. The AP South and 5004/5005 submarkets also have been reviewed by the

Pivotal Supplier Analysis

The Pivotal Supplier Analysis seeks to determine if load can be served without an applicant's generation. *Order No. 697-A* specifies a number of calculations for the Pivotal Supplier Analysis.

First, Total Uncommitted Supply is calculated based on installed capacity (adjusted for long-term firm purchases and sales) plus imports less the reserve requirement (*i.e.*, operating reserves) less the average daily peak native load for the peak month.

Second, Wholesale Load is calculated based on the difference between the annual peak load (needle peak) for the balancing authority and the average daily peak native load for the peak month.

Third, Net Uncommitted Supply is calculated based on the difference between Total Uncommitted Supply and Wholesale Load. Seller's Uncommitted Capacity is based on Seller's Total Uncommitted Capacity less its average daily peak native load.

If Seller's Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Analysis is passed.

Market Share Analysis

The Market Share Analysis evaluates, for each of the four seasons, whether the seller has a dominant position in the market, with dominance defined as a market share in excess of 20 percent.

Order No. 697 and *Order No. 816* specify a number of calculations for the market share screen.

First, Seller and Affiliate Capacity is calculated based on installed capacity (adjusted for long-term firm purchases and sales) plus imports less planned outages. Non-Affiliate Capacity is calculated in a similar manner.

Commission as relevant submarkets in PJM. *Exelon Corp.*, 138 FERC ¶ 61,167 (2012). Submarkets in ISO-NE identified in *Order No. 697* include CT (where the Exelon NE Entities have a long-term firm power purchase agreement) and SWCT (where the Exelon NE Entities do not own or purchase generation under long-term firm agreements). There are two submarkets in NYISO (New York City and Long Island), but the Exelon NE Entities do not own or purchase generation under long-term firm agreements in either of these submarkets.

Second, Capacity Deductions are calculated based on average peak native load in the season (averaged over all days) plus operating reserves.

Third, Seller's Uncommitted Capacity is calculated by subtracting the Capacity Deductions attributed to Seller from Seller and Affiliate Capacity, and Total Competing Supply is calculated by subtracting the Capacity Deductions attributed to others from Non-Affiliate Capacity. Total Seasonal Uncommitted Capacity is the sum of Seller's Uncommitted Capacity and Total Competing Supply.

Finally, Seller's Market Share is calculated as Seller's Uncommitted Capacity as a percentage of Total Seasonal Uncommitted Capacity.

If Seller's Market Share is less than 20 percent in all seasons, the Market Share Analysis is passed.

Assumptions

Relevant Geographic Markets. Our analysis is focused on PJM (including the PJM East, AP South, and 5004/5005 submarkets), ISO-NE (including the CT submarket) and NYISO as the relevant default geographic markets because those are the markets and submarkets in which the Exelon NE Entities own or purchase generation under long-term firm agreements.

Study Period. Our analysis is based on a December 2014-November 2015 study period, as required.[15] The following seasons are used in the analysis: Winter (December-February), Spring (March-May), Summer (June-August) and Fall (September-November).

Generating Capacity. For seasonal ratings relevant to the Exelon NE Entities' generation, we rely on summer and winter ratings reported in the Energy Information Administration's "Annual Electric Generator Report," Form EIA-860[16] or in the Exelon NE Entities' asset appendix to the extent it reports more updated information.

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15 http://www.ferc.gov/industries/electric/gen-info/mbr/triennial/sw.asp.

16 http://www.eia.gov/cneaf/electricity/page/eia860.html.

For PJM installed capacity, we rely on data reported by ABB Velocity Suite (a proprietary third-party database) based on net dependable capacity ratings. For the PJM submarkets, we relied on the same installed capacity data, identifying generating units in the submarkets based on location and aided by information in PJM's 2012 Simultaneous Import Limit ("SIL") Study.[17]

For ISO-NE, we base the analysis on the generating units reported by ISO-NE in its 2015 "CELT" Report.[18] Where available, we used the EIA-860 seasonal (summer/winter) ratings for ISO-NE generating units;[19] if a unit was reported in the CELT Report and not the EIA-860, we used the CELT Report ratings.

For NYISO installed capacity, we rely on seasonal capacity ratings reported by NYISO in its 2015 "Gold Book").[20]

For the Pivotal Supplier Analysis, we use summer ratings, consistent with the time of annual peak. For the Market Share Analysis, we use summer ratings for the Summer season, and winter ratings for all other seasons.

Operating Reserves. For PJM, operating reserves are based on data PJM reported in its SIL analysis for the December 2016 Northeast triennial filings.[21] For the PJM East and 5004/5005 submarkets, we estimated operating reserves based on the 5.93 percent Day-ahead Scheduling Reserve requirement applicable in the NERC *RelabilityFirst* Corporation for the study period.[22] For the AP

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17 *See 2012 Simultaneous Import Limit Study*, PJM, Docket No. AD10-002, October 2, 2013.

18 *2015-2024 Forecast Report of Capacity, Energy, Loads and Transmission*, System Planning, ISO New England, May 1, 2015, https://www.iso-ne.com/static-assets/documents/2015/05/2015_celt_report.xls.

19 The use of EIA-860 data, where available, is necessary because the ISO-NE CELT report reflects derated capacity for energy-limited facilities, and the analysis we conducted requires that the analysis be based on installed seasonal capacity ratings.

20 *2015 Load and Capacity Data Report* 2015 ("Gold Book"), NYISO, April 2016, http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2015%20Load%20%20Capacity%20Data%20Report_Revised.pdf.

21 *See PJM Interconnection, L.L.C.*, Informational Filing of 2015 Simultaneous Import Limit Study Report for PJM Region, Docket No. AD10-2-007 (filed Sept. 2, 2016), Attachment 11.

22 *See Manual 13 (*http://www.pjm.com/documents/~/media/documents/manuals/m13.ashx),http://www.pjm.com/~/media/committe

South submarket, the operating reserve requirement is based on Dominion's share of the Virginia-Carolinas ("VACAR") reserve sharing requirement,[23] plus the 5.93 percent applicable in the NERC *ReliabilityFirst* Corporation for the rest of the AP South submarket.

For ISO-NE, operating reserves are based on its reserve requirements for Winter 2014/15 and Summer 2015.[24] For the spring and fall seasons, we used the average of winter and summer reserve requirements.

For NYISO, operating reserves for NYISO are based on its reported locational reserve requirements for the "NYCA" control area, based on 30-minute reserves.[25]

We conservatively did not assign any operating reserves to the Exelon NE Entities.

Load Data. We used hourly load data from PJM, ISO-NE and NYISO reported for the RTOs and data from ABB Velocity Suite for PJM and the 2015 Simultaneous Import Limit Study Report for the ISO-NE submarkets.[26] The PJM submarkets are defined based on the following transmission zones:

Transmission Zones		PJM East	5004/5005	AP South
AE	Atlantic City Electric Company	x	x	x
DP&L	Delmarva Power & Light	x	x	x
JCP&L	Jersey Central Power & Light Company	x	x	x
PE	PECO Energy Company	x	x	x
PSE&G	Public Service Electric & Gas Company	x	x	x
RECO	Rockland Electric Company	x	x	x

es-groups/subcommittees/sos/20141125/20141125-item-06a-manual-13-version-57-2015-day-ahead-scheduling-reserve-update.ashx.

23 *See SERC Regional Criteria, Contingency Reserve Policy, NERC Reliability Standard BAL-00*2, October 28, 2014, http://www.serc1.org/docs/default-source/program-areas/standards-regional-criteria/regional-criteria/serc-reg-criteria_contingency-reserve-policy-rev-6-(10-28-14).pdf.

24 *See,* for example, *Assumptions and Other Information for the Summer 2015 Forward Reserve Auction*, https://www.iso-ne.com/static-assets/documents/2015/03/forward_reserve_auction_assumptions_summer_2015.docx.

25 NYISO, *Locational Reserve Requirements*, http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf.

26 *2015 Simultaneous Import Limit Study*, ISO New England Inc., Docket No. AD10-2-009, (filed Dec. 20, 2016).

Transmission Zones		PJM East	5004/5005	AP South
ME	Metropolitan Edison Company		x	x
PPL	PPL Electric Utilities		x	x
BGE	Baltimore Gas & Electric		x	x
PEPCO	Potomac Electric Power Company		x	x
UGI	UGI Utilities, Inc.		x	x
VAP	Virginia Electric & Power (Dominion)			x

The Exelon NE Entities provided us with data on the load they served in the relevant markets during the study period. This includes load directly supplied by Exelon Generation, including net physical sales to parties that primarily serve load,[27] as well as sales by Exelon Generation to retail affiliates of the Exelon NE Entities in support of their load obligations.[28]

Other Load and Generation Commitments. The Total Uncommitted Capacity determined in each of the RTO markets and submarkets is extremely conservative, because no attempt has been made to match load commitments (and, correspondingly, generation commitments) attributable to individual parties, other than the Exelon NE Entities, in the RTOs. Under the Market Share Analysis, for example, the amount of load attributable to "others" is simply the difference between the total average peak native load in the season and the amount attributable to the seller (in this case, the Exelon NE Entities). The result is very conservative in that it assumes all load in the market is met with specific generation committed to serving it via ownership or contractual commitment, which is not an accurate reflection of the facts in a market where some parties rely on short-term market purchases from the RTO to meet load obligations. In other words, our analysis assumes that every MW of generation is "committed" to the extent there is load, even though in reality every MW of generation is not necessarily committed by ownership or contractual commitment to serving a

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[27] The Commission allows market-based rate sellers to consider their sales to load-serving entities on a short-term basis when computing their uncommitted capacity ("We will allow IPPs to deduct short term native load obligations if they can show that the power sold to the utility was used to meet native load." *Order No. 697* at P 155). For purposes of our screen calculations, we considered only sales by the Exelon NE Entities to load-serving entities that are subject to contracts for the sale of physical energy while simultaneously netting out purchases from the same load-serving entities.

[28] Sellers may deduct "long-term load following contracts to the extent that the seller has included in its total capacity a corresponding generating unit or long-term firm purchase contract that will be used to meet the obligation." *Order No. 697* at P 154.

specific load. Thus, the Total Competing (Uncommitted) Supply that is assumed to compete with Exelon NE Entities' Uncommitted Capacity in our analysis is conservatively low.

Planned Outages. We calculated average planned outages for each of the seasons based on outages at time of monthly peaks reported in the PJM, ISO-NE and NYISO FERC Form No. 714s.[29] For the submarkets, we estimated outages based on the submarket's share of generation relative to total RTO generation. For the Exelon NE Entities, we estimated outages based on their share of generation relative to total generation in the relevant market or submarket.

Simultaneous Import Limits. For PJM, we relied on the SIL data recently submitted to the Commission by PJM in connection with the Northeast Region triennial market-based rate filings.[30] For ISO-NE, we relied on its 2015 Simultaneous Import Limit Study Report.[31] For NYISO, we relied on its 2015 Simultaneous Import Limit Study.[32]

Allocating Imports. We allocated imports to the Exelon NE Entities in a manner consistent with the *Order No. 697-A Clarification Order*, which states that "market-based rate sellers, after accounting for the firm transmission rights held by the sellers and their affiliates, may allocate simultaneous transmission import capability on a *pro rata* basis (*i.e.*, based on the relative shares of the market-based rate seller's (and its affiliates') and competing suppliers' uncommitted generation capacity in first-tier markets when performing the indicative screens."[33] Based on the Exelon NE Entities' share of uncommitted capacity in markets first-tier to the relevant markets (or submarkets) being analyzed,

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29 *Order No. 697* indicates that planned outages should be consistent with those reported in FERC Form No. 714, and that "[t]o determine the amount of planned outages for a given season, the total number of MW-days of outages is divided by the total number of days in the season." *Order No. 697* at P 43. However, the FERC Form No. 714 reports planned outages only at time of peak for the month, and hence it is not possible to determine the total number of MW-days of outages from these data.

30 *See PJM Interconnection, L.L.C.*, Informational Filing of 2015 Simultaneous Import Limit Study Report for PJM Region, Docket No. AD10-2-007 (filed Sept. 2, 2016).

31 See note 26.

32 *2015 Simultaneous Transmission Import Limit Study*, New York Independent System Operator, Inc., Docket No. AD10-2-008, (filed Dec. 19, 2016).

33 *Order No. 697-A Clarification Order* at Ordering Paragraph (A).

we allocated a pro rata share of the SIL to them. The remainder of the SIL was assumed to be Non-Affiliate Capacity.

Results of Analysis

Exhibit NCI-4 summarizes the results, as excerpted below. As shown, the Exelon NE Entities pass the Pivotal Supplier Analysis and the Market Share Analysis in each of the relevant markets. These analyses are conducted in a manner consistent with Order Nos. 697 and 816, and, as required, an electronic version of the screens is being submitted.[34]

Market/ Submarket	Exhibit	Pivotal Supplier Analysis	Exhibit	Market Share Analysis			
				Winter	Spring	Summer	Fall
PJM	NCI-5	Pass	NCI-6	10.6%	10.4%	9.0%	9.9%
PJM East	NCI-7	Pass	NCI-8	18.8%	17.7%	18.0%	15.9%
5004/5005	NCI-9	Pass	NCI-10	16.1%	16.4%	11.6%	12.7%
AP South	NCI-11	Pass	NCI-12	12.1%	12.3%	8.7%	9.4%
ISO-NE	NCI-13	Pass	NCI-14	0.0%	0.0%	0.0%	0.0%
CT	NCI-15	Pass	NCI-16	0.0%	0.0%	0.0%	0.0%
NYISO	NCI-17	Pass	NCI-18	4.1%	1.7%	0.4%	0.6%

Exhibits NCI-5 through NCI-12 contain the detailed results of the Pivotal Supplier Analysis and the Market Share Analysis in PJM and the PJM submarkets. Exhibits NCI-13 through NCI-16 contain the detailed results in ISO-NE and the CT submarket. Exhibits NCI-17 through NCI-18 contain the detailed results in NYISO. (Odd number exhibits contain the Pivotal Supplier Analysis and even number exhibits contain the Market Share Analysis.)

[34] We are submitting both a confidential and public version of the indicative screens and workpapers. To the extent the detailed data supporting the indicative screens includes proprietary data from ABB Velocity Suite, such detailed data is included in the confidential version. The public version contains a top-level summary of the inputs that rely on ABB Velocity Suite data. The confidential version also includes the Exelon NE Entities' confidential information.

PJM

In PJM, the Exelon NE Entities own 22,567 MW (summer rating) of capacity, have 2,723 MW of long-term purchases and 854 MW of long-term sales commitments (see Exhibit NCI-3).[35]

Pivotal Supplier Analysis. The Exelon NE Entities' Installed Capacity in PJM is 22,567 MW. They have 2,723 MW of long-term purchases and 854 MW of long-term sales. After taking into account their load commitments and imports attributed to them, Sellers' Uncommitted Capacity is 5,092 MW. Net Uncommitted Supply is 37,930 MW. Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Analysis is passed in PJM. See Exhibit NCI-5.

Market Share Analysis. The Exelon NE Entities' Installed Capacity in PJM ranges from 22,567 MW to 23,368 MW. The Exelon NE Entities have 2,723 MW to 2,971 MW of long-term purchases, and 854 MW to 884 MW of long-term sales. After taking into account their load commitments and planned outages and imports attributed to them, Sellers' Uncommitted Capacity ranges from 5,370 MW to 8,755 MW. Total Seasonal Uncommitted Capacity ranges from 59,488 MW to 82,781 MW. Sellers' Market Share ranges from 9.0 to 10.6 percent. Because Sellers' Market Share is less than 20 percent in all seasons, the Market Share Analysis is passed in PJM. See Exhibit NCI-6.

Thus, on the basis of the Commission's screens, the Exelon NE Entities do not have horizontal market power in PJM.

PJM East

In PJM East, the Exelon NE Entities own 7,154 MW (summer rating) of capacity and have 398 MW of long-term purchases (see Exhibit NCI-3).

Pivotal Supplier Analysis. The Exelon NE Entities' Installed Capacity in PJM East is 7,154 MW. They have 398 MW of long-term purchases. After taking into account their load commitments

[35] The sale commitments reflect the sale of 50 percent of the output of the Calvert Cliffs nuclear facility to EDF Trading North America, LLC ("EDF Trading NA") under a long-term agreement executed in 2009 that remains in effect, as amended, through the complete and permanent cessation of power generation by the facility.

and imports attributed to them, Sellers' Uncommitted Capacity is 2,780 MW. Net Uncommitted Supply is 9,498 MW. Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Analysis is passed in PJM East. *See* Exhibit NCI-7.

Market Share Analysis. The Exelon NE Entities' Installed Capacity in PJM East ranges from 7,154 MW to 7,576 MW. The Exelon NE Entities have 398 MW of long-term purchases. After taking into account their load commitments and planned outages and imports attributed to them, Sellers' Uncommitted Capacity ranges from 2,884 MW to 4,422 MW. Total Seasonal Uncommitted Capacity ranges from 16,068 MW to 23,574 MW. Sellers' Market Share ranges from 15.9 to 18.8 percent. Because Sellers' Market Share is less than 20 percent in all seasons, the Market Share Analysis is passed in PJM East. See Exhibit NCI-8.

Thus, on the basis of the Commission's screens, the Exelon NE Entities do not have horizontal market power in PJM East.

5004/5005

In 5004/5005, the Exelon NE Entities own 11,739 MW (summer rating) of capacity, have 1,020 MW of long-term purchases and 854 MW of long-term sales commitments (see Exhibit NCI-3).[36]

Pivotal Supplier Analysis. The Exelon NE Entities' Installed Capacity in 5004/5005 is 11,739 MW. They have 1,020 MW of long-term purchases and 854 MW of long-term sales. After taking into account their load commitments and imports attributed to them, Sellers' Uncommitted Capacity is 1,936 MW. Net Uncommitted Supply is 7,431 MW. Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Analysis is passed in 5004/5005. See Exhibit NCI-9.

Market Share Analysis. The Exelon NE Entities' Installed Capacity in 5004/5005 ranges from 11,739 MW to 12,367 MW. The Exelon NE Entities have 1,020 MW of long-term purchases and 854 MW to 884 MW of long-term sales. After taking into account their load commitments and

[36] As noted above, the sale commitments reflect the sale of 50 percent of the output of the Calvert Cliffs nuclear facility to EDF Trading NA.

planned outages and imports attributed to them, Sellers' Uncommitted Capacity ranges from 2,050 MW to 4,308 MW. Total Seasonal Uncommitted Capacity ranges from 17,672 MW to 26,558 MW. Sellers' Market Share ranges from 11.6 to 16.4 percent. Because Sellers' Market Share is less than 20 percent in all seasons, the Market Share Analysis is passed in 5004/5005. See Exhibit NCI-10.

AP South

In AP South, the Exelon NE Entities own 11,741 MW (summer rating) of capacity, have 1,026 MW of long-term purchases and 854 MW of long-term sales commitments (see Exhibit NCI-3).

Pivotal Supplier Analysis. The Exelon NE Entities' Installed Capacity in AP South is 11,741 MW. They have 1,026 MW of long-term purchases and 854 MW of long-term sales. After taking into account their load commitments and imports attributed to them, Sellers' Uncommitted Capacity is 1,868 MW. Net Uncommitted Supply is 9,827 MW. Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Analysis is passed in AP South. See Exhibit NCI-11.

Market Share Analysis. The Exelon NE Entities' Installed Capacity in AP South ranges from 11,741 MW to 12,368 MW. The Exelon NE Entities have 1,026 MW of long-term purchases and 854 MW to 884 MW of long-term sales. After taking into account their load commitments and planned outages and imports attributed to them, Sellers' Uncommitted Capacity ranges from 1,976 MW to 4,397 MW. Total Seasonal Uncommitted Capacity ranges from 22,720 MW to 35,884 MW. Sellers' Market Share ranges from 8.7 to 12.3 percent. Because Sellers' Market Share is less than 20 percent in all seasons, the Market Share Analysis is passed in AP South. See Exhibit NCI-12.

Thus, on the basis of the Commission's screens, the Exelon NE Entities do not have horizontal market power in AP South.

Market Mitigation. As we noted earlier, there are other protections in place that further prevent market power concerns. *Order No. 697* specifically considers that Commission-approved market monitoring and mitigation in RTO/ISO markets or submarkets are relevant to the market power analysis. In *Order No. 697*, the Commission stated that it "believe[s] the added protections provided in structured markets with market monitoring and mitigation generally result in a market

where prices are transparent and attempts to exercise of market power will be sufficiently mitigated."[37] PJM – as well as the other Northeast Region RTOs – is subject to extensive Commission-approved market monitoring and mitigation, and the Commission previously has found that such market monitoring and mitigation is sufficient to address any potential market power concerns in PJM and submarkets.[38]

Further, the Exelon NE Entities also are subject to additional behavioral commitments in PJM entered into as part of the Exelon-Constellation merger that further mitigate any horizontal market power that the Exelon NE Entities might be deemed to possess in PJM and relevant submarkets. These behavioral commitments include (i) notification procedures for planned retirements; (ii) prescribed rules on energy market offers specific to nuclear generation, peaking generation and other types of generation; and (iii) agreement with respect to bidding ancillary services.[39] In connection with these commitments, the PJM Independent Market Monitor ("IMM") concluded that "[t]he commitments made by the Applicants in the Settlement…would alleviate the Market Monitor's concerns about the effects of the merger on PJM markets. Based on the information that the Applicants will provide to the Market Monitor…and the information available to the Market Monitor under the PJM market rules, the Market Monitor will have the information needed to monitor compliance…" Thus, the existing market monitoring and mitigation in place generally in PJM is further strengthened by the behavioral commitments agreed upon to the Exelon NE Entities.

ISO-NE

In ISO-NE, the Exelon NE Entities own 2,204 MW (summer rating) of capacity, and have 623 MW of long-term firm purchases (see Exhibit NCI-3).

Pivotal Supplier Analysis. The Exelon NE Entities' Installed Capacity is 2,204 MW, and their Long-Term Firm Purchases are 623 MW. The Exelon NE Entities' load exceeds their

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37 *See Order No. 697* at PP 241-242.

38 *See*, *Baltimore Gas and Electric et al.*, Docket Nos. ER10-2172-007 *et al*., (Nov 1, 2012) (unpublished letter order), also citing to *PSEG Energy Resources & Trade*, 125 FERC ¶ 61,073 (2008).

39 *See* note 9.

generation and purchases in ISO-NE. Thus, after taking into account their load commitments and imports attributed to them, Sellers' Uncommitted Capacity zero. Net Uncommitted Supply is 12,225 MW. Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Screen is passed. See Exhibit NCI-13.

Market Share Analysis. The Exelon NE Entities' Installed Capacity ranges from 2,204 MW to 2,565 MW, and their Long-Term Firm Purchases range from 623 MW to 624 MW. The Exelon NE Entities' load exceeds their generation and purchases in ISO-NE. Thus, after taking into account their load commitments and planned outages and imports attributed to them, Sellers' Uncommitted Capacity is zero. Total Seasonal Uncommitted Capacity ranges from 18,976 MW to 20,166 MW. Sellers' Market Share is zero in all seasons. Because Sellers' Market Share is less than 20 percent in all seasons, the Market Share Screen is passed. See Exhibit NCI-14.

Thus, on the basis of the Commission's screens, the Exelon NE Entities do not have horizontal market power in ISO-NE.

CT

In CT, the Exelon NE Entities purchase 622 MW of capacity under a long-term firm contract (see Exhibit NCI-3). We note that the Commission recently concluded that CT and SWCT are no longer separate relevant geographic markets, but we nevertheless include an analysis of the CT submarket.[40]

Pivotal Supplier Analysis. The Exelon NE Entities' Installed Capacity is zero, and their Long-Term Firm Purchases are 622 MW. The Exelon NE Entities' load exceeds their generation and purchases in CT. Thus, after taking into account their load commitments and imports attributed to them, Sellers' Uncommitted Capacity is zero. Net Uncommitted Supply is 3,706 MW. Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Screen is passed. See Exhibit NCI-15.

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[40] *Atlas Power Finance, LLC*, 157 FERC ¶ 61,237 at P 48 (2016) ("We conclude that Connecticut and Southwest Connecticut are not separate geographic markets at this time because the constraints have not been frequently binding and therefore do not prevent competing supply from reaching customers within the Connecticut and Southwest Connecticut areas.").

Market Share Analysis. The Exelon NE Entities' Installed Capacity is zero, and their Long-Term Firm Purchases range from 622 MW to 623 MW. The Exelon NE Entities' load exceeds their generation and purchases in CT. Thus, after taking into account their load commitments and planned outages and imports attributed to them, Sellers' Uncommitted Capacity is zero. Total Seasonal Uncommitted Capacity ranges from 5,925 MW to 6,610 MW. Sellers' Market Share is zero in all seasons. Because Sellers' Market Share is less than 20 percent in all seasons, the Market Share Screen is passed. See Exhibit NCI-16.

Thus, on the basis of the Commission's screens, the Exelon NE Entities do not have horizontal market power in CT.

Market Mitigation in ISO-NE. ISO-NE also is subject to extensive Commission-approved market monitoring and mitigation, and the Commission previously has found that such market monitoring and mitigation is sufficient to provide protection against market power concerns in ISO-NE and submarkets.[41]

Because the Exelon NE Entities pass the indicative screens in ISO-NE and the relevant submarkets, the Exelon NE Entities are presumed not to have horizontal market power in these markets.

NYISO

In NYISO, the Exelon NE Entities own 2,274 MW (summer rating) of capacity, have 29 MW of long-term firm purchases and 846 MW of long-term sales commitments (see Exhibit NCI-3). [42]

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41 "As the Commission has previously found, the ISO-NE market monitoring and mitigation rules are sufficient to address market power concerns in the ISO-NE market and Connecticut submarket." (citing to *Dominion Energy Marketing, Inc.*, 125 FERC ¶ 61,070 at P 27 (2008); *NRG Power Marketing LLC*, Docket No. ER97-4281-018 (April 27, 2009) (delegated letter order)). *Dominion Energy Marketing, Inc.*, Docket No. ER01-468-012 (July 28, 2011) (unpublished letter order).

42 The sale commitments reflect the sale of 50 percent of the output of the Nine Mile nuclear facility to EDF Trading NA under a long-term agreement executed in 2009 that remains in effect, as amended, through the complete and permanent cessation of power generation by the facility.

Pivotal Supplier Analysis. The Exelon NE Entities' Installed Capacity is 2,274 MW, and purchases are 29 MW. Their long-term firm sales are 846 MW. After taking into account their load commitments and planned outages and imports attributed to them, Sellers' Uncommitted Capacity is 97 MW. Net Uncommitted Supply is 12,602 MW. Because Sellers' Uncommitted Capacity is less than the Net Uncommitted Supply, the Pivotal Supplier Screen is passed. See Exhibit NCI-17.

Market Share Analysis. The Exelon NE Entities' Installed Capacity is 2,274 MW to 2,287 MW. Their Long-Term Firm purchases are 29 MW and long term sales range from 846 MW to 852 MW. After taking into account their load commitments and planned outages and imports attributed to them, Sellers' Uncommitted Capacity ranges from 84 MW to 850 MW. Total Seasonal Uncommitted Capacity ranges from 18,857 MW to 20,911 MW. Sellers' Market Share ranges from 0.4 to 4.1 percent. Because Sellers' Market Share is less than 20 percent in all seasons, the Market Share Screen is passed. See Exhibit NCI-18.

Market Mitigation in NYISO. NYISO also is subject to extensive Commission-approved market monitoring and mitigation, and the Commission previously has found that such market monitoring and mitigation is sufficient to provide protection against market power concerns in NYISO and submarkets.[43]

Thus, on the basis of the Commission's screens, the Exelon NE Entities do not have horizontal market power in NYISO.

Transmission

ComEd, PECO BGE, ACE, DPL, and Pepco each own transmission facilities located in PJM, but those facilities are under the functional control of PJM and subject to the terms and conditions of the PJM OATT, which the Commission has deemed to mitigate a seller's transmission market power.[44] The Exelon NE Entities own no transmission in other relevant markets other than the

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[43] The Commission "will consider any existing Commission-approved market monitoring and mitigation regime already in place within the RTO/ISO that provides for mitigation of the submarket…We find that the NYISO market monitoring and mitigation rules are sufficient to address market power concerns in the New York City submarket." *Canandaigua Power Partners, LLC*, 141 FERC ¶ 61,210, P 17 (2012), also citing to *Niagara Mohawk Power Corp.*, 123 FERC ¶ 61,175, at P 35 (2008).

[44] *Order No. 697* at P 21.

equipment necessary to connect their generation to the grid and thus there are no vertical concerns in relation to these facilities.

Barriers to Entry

The Exelon NE Entities have no ownership or control of intrastate natural gas transportation or intrastate natural gas storage, but as described above some of them do operate natural gas distribution facilities in PJM, and have LNG facilities that are used to provide peak gas to their customers. As the Commission has determined, there is rebuttable presumption that such ownership does not allow a seller to raise entry barriers.[45] Hence, no vertical concerns are present with respect to the Exelon NE Entities' owned natural gas distribution facilities.

The Exelon NE Entities do not own or control sources of coal supplies or the transportation of coal supplies. The Commission has determined that there is a rebuttable presumption that such ownership or control does not allow a seller to raise entry barriers. There are no other issues that raise any relevant competitive concerns.

We understand that an affirmative statement on behalf of the Exelon NE Entities is included in their submission that they have not erected barriers to entry and will not erect barriers to entry.

Based on these facts, the Exelon NE Entities have demonstrated a lack of vertical market power.

Since the Exelon NE Entities lack both horizontal and vertical market power, we conclude that they satisfy the Commission's tests for market-based rate authority.

CONCLUSION

On the basis of the foregoing analysis, the Exelon NE Entities satisfy the Commission's horizontal and vertical market power tests for market-based rate authority in the relevant markets.

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[45] *Id.* at P 22.

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NAVIGANT

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Professional History

- Managing Director, Navigant Consulting - 2010-Present
- Vice President, Charles River Associates - 2001-2010
- Senior Vice President, Putnam, Hayes and Bartlett, Inc. and PHB Hagler Bailly, Inc., Washington, DC - 1986-2000
- Economist, Economic Consulting Services, Inc., Washington, DC - 1979-1986
- Economist, U.S. Department of Labor, Washington, DC - 1976-1979

Education

- M.B.A. Finance, The Wharton School University of Pennsylvania
- B.A. Economics, Connecticut College

Testimony

- Written testimony provided in more than 150 regulatory proceedings

Julie Solomon is a Managing Director at Navigant Consulting, Inc. in the Energy Practice's Power Systems, Markets & Pricing group. She has more than 20 years of consulting experience, specializing in the areas of regulatory and utility economics, financial analysis and business valuation. Ms. Solomon has participated in analysis of proposed regulatory reforms, supply options and utility industry restructuring in the gas and electric industries. She also has advised utility clients in corporate strategy and corporate restructuring, and consulted to legal counsel on a variety of litigation and regulatory matters, including antitrust litigation and contract disputes. She has filed testimony in numerous proceedings before the Federal Energy Regulatory Commission. Much of her current practice focuses on regulatory and market power issues concerning mergers and acquisitions and compliance filings in the electricity market.

» Advised clients in the electric and gas utility industry on competition issues, including the impact of mergers on competition. Directed a large number of analytic studies relating to obtaining merger approval from regulatory authorities.

» Advised clients in the electric utility industry on restructuring strategies, including potential mergers and acquisitions, functional unbundling and cost savings.

» Consulted in the electric and gas utility industries in a variety of regulatory and competition matters, including rate proceedings, prudence reviews, proposed regulatory reforms, analysis of supply options, privatization and restructuring.

» Advised utility and non-utility clients on many aspects of the competitive independent power industry, including strategic and financial consulting assignments.

» Consulted legal counsel on a variety of litigation matters, including the development of expert testimony on liability issues and the calculation of damages in a variety of industries.

» Provided strategic and economic analyses for clients in trade regulatory proceedings such as dumping and subsidies.

» Provided financial and business valuation analyses in a number of transactions, including fair market value for taxation purposes and valuation of family-owned businesses.

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Professional Experience

Electric and Gas Utilities

Mergers and Acquisitions (Market Power and Competition Issues)

» Advised clients and conducted analytic studies in connection with a large number of major electric and electric-gas mergers and asset transactions of regulated companies. Provided testimony to FERC for a number of these types of transactions.

» Advised clients and provided confidential pre-screening analyses for potential mergers and acquisitions.

» Conducted numerous analytic studies in connection with FERC market-based rate applications and compliance filings for electricity sellers. Provided testimony to FERC for a number of these types of transactions.

» Conducted numerous analytic studies in connection with FERC market-based rate applications and compliance filings for gas storage facilities. Provided testimony to FERC for a number of these types of transactions.

Utility Restructuring and Stranded Cost

» Conducted analytic studies and provided litigation support in connection with state stranded cost proceedings in Ohio (Cincinnati Gas & Electric and Dayton Power & Light); West Virginia (Monongahela Power and Potomac Edison); Maryland (Potomac Edison) and Pennsylvania (West Penn Power).

» Provided analytic support evaluating the benefits of Public Service of Colorado's proposed DC transmission line between Colorado and Kansas in support of a regulatory proceeding.

» Assisted in studies relating to privatization of the electricity industry in the United Kingdom, including development of a computer model to simulate electricity dispatch and project future prices, capacity needs and utility revenues under various scenarios. During temporary assignment to London office.

» Participated in antitrust litigation involving a utility and a cogenerator, including preparation of an expert report on liability and damage issues, preparation of expert witnesses for deposition, and assistance in preparation for depositions of opposing expert and in-house witnesses.

» Assisted in the valuation of the interests of several firms in various cogeneration projects for the purpose of combining these interests into a new entity or selling interests to third parties.

» Analyzed the financial feasibility and viability of a large number of cogeneration projects, assisted in the preparation of presentations and filings and presented testimony to the relevant public utility commission. Ms. Solomon also assisted in the development of a PC-based financial model to analyze various cogeneration projects.

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» Participated in a study to analyze the financial effects of a variety of restructuring options for a utility, including transfer and/or sale of assets and subsequent sale-leasebacks, and debt restructuring alternatives. In addition, she developed a PC-based financial model with applications to utility restructuring plans.

» Provided litigation support in major utility rate proceedings, including assisting in the preparation of responses to interrogatories and data requests, preparation of company and outside expert witnesses for deposition and hearings, and assistance in the deposition and cross-examination of intervenor witnesses.

» Participated in proceedings involving regulation of an oil pipeline, which included evaluating the business risks faced by the company.

Business Valuation

» Participated in a valuation study involving the fair market value of a privately held company for purposes of an IRS proceeding.

» Participated in a valuation study in a divorce proceeding, where the assets being valued included a privately held business.

» Participated in two strategic engagements that developed business plans and identified potential acquisition candidates for the client.

» Provided advice to a client concerning the benefits and potential risks of developing a partnership with a competitor.

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Testimony or Expert Report Experience (2013-July 2016)

- Supplemental Affidavit on behalf of Dynegy Inc. et al., Docket Nos. EC16-93 and -94, July 8, 2016.
- Affidavit on behalf of Arlington Valley, LLC et al., Docket No. ER10-2756 et al., market-based rate triennial filing, June 30, 2016.
- Affidavit on behalf of Sundevil Holdings et al., Docket No. ER16-2107 et al., market-based rate triennial filing, June 30, 2016.
- Affidavit (with Matthew E. Arenchild) on behalf of BHE Northwest Companies, Docket No. ER10-3246 et al., market-based rate triennial filing, June 30, 2016.
- Affidavit on behalf of BHE Renewables, LLC, Docket No. ER13-520 et al., market-based rate triennial filing, June 30, 2016.
- Affidavit on behalf of Atlantic Renewable Projects II LLC et al., Docket No. ER10-2822 et al., market-based rate triennial filing, June 30, 2016.
- Affidavit on behalf of the Calpine MBR Sellers, Docket No. ER10-2042 et al., market-based rate triennial filing, June 30, 2016.
- Affidavit on behalf of the NorthWestern Corporation, Docket No. ER11-1858, market-based rate triennial filing, June 29, 2016.
- Affidavit on behalf of the ArcLight Energy Marketing et al., LLC, Docket No. ER16-2014 et al., market-based rate triennial filing, June 24, 2016.
- Affidavit on behalf of River Bend Solar, LLC Docket No. ER16-1913, application for market-based rates, June 10, 2016.
- Affidavit (with Matthew E. Arenchild) on behalf of Nevada Power Company et al., Docket No. EC16-130, application for authorization of disposition of jurisdictional facilities, June 7, 2016.
- Affidavit on behalf of Apple Energy, LLC, Docket No. ER16-1887, application for market-based rates, June 6, 2016.
- Affidavit on behalf of Marshall Solar, LLC, Docket No. ER16-1872, application for market-based rates, June 3, 2016.
- Affidavit on behalf of the Dominion Companies, Docket No. ER13-2109 et al., notice of change in status filing, May 25, 2016.
- Affidavit on behalf of Eastern Shore Solar LLC, Docket No. ER16-1750, application for market-based rates, May 20, 2016.
- Affidavit on behalf of Roswell Solar LLC and Chaves County Solar, LLC, Docket No. ER16-1440 and ER16-1672, applications for market-based rates, May 20, 2016 and May 17, 2016.
- Affidavit on behalf of Exelon MBR Entities, Docket No. ER10-2997 et al., notice of change in status filing, April 22, 2016.

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- Affidavit on behalf of Live Oak Solar LLC, White Oak Solar, LLC, and White Pine Solar, LLC, Docket No. ER16-1354, ER16-1293 and ER16-1277, applications for market-based rates, April 6, 2016, March 30, 2016 and March 25, 2016.
- Affidavit on behalf of Atlas Power Finance, LLC, Dynegy Inc., Energy Capital Partners III, LLC, and GDF SUEZ Energy North America, Inc., Docket No. EC16-93, application for authorization of disposition of jurisdictional facilities, March 25, 2016.
- Affidavit on behalf of Dynegy Inc. and Energy Capital Partners III, LLC, Docket No. EC16-94, application for authorization of disposition of jurisdictional facilities, March 25, 2016.
- Affidavit on behalf of Grande Prairie Wind, LLC, Docket No. ER16-1258, application for market-based rates, March 22, 2016.
- Affidavit on behalf of Florida Power & Light Company, Docket No. ER16-628-001, application for market-based rates, March 21, 2016.
- Affidavit on behalf of Essential Power, LLC, Docket No. EC16-82, application for authorization of disposition of jurisdictional facilities, February 29, 2016.
- Affidavit on behalf of Duke Energy Florida, LLC, Docket No. EC16-69, application for authorization of disposition of jurisdictional facilities, February 10, 2016.
- Affidavit on behalf of Nassau Energy, LLC, Docket No. ER16-806, application for market-based rates, January 21, 2016.
- Affidavit on behalf of ECP MBR Sellers, Docket No. ER16-72, market-based rate triennial filing, December 31, 2015.
- Affidavit on behalf of SDG&E Sellers, Docket No. ER14-474, market-based rate triennial filing, December 30, 2015.
- Affidavit on behalf of New Harquahala Generating Company, Docket No. ER15-2013, market-based rate triennial filing, December 30, 2015.
- Affidavit on behalf of Exelon SPP Entities, Docket No. ER14-474, market-based rate triennial filing, December 29, 2015.
- Affidavit on behalf of Florida Power & Light Company, Docket No. ER16-628-000, application for market-based rates, December 23, 2015.
- Affidavit on behalf of ENGIE Portfolio Management, LLC et al, Docket No. ER16-581 et al., application for market-based rates, December 18, 2015.
- Affidavit on behalf of Marshall Wind Energy, LLC, Docket No. ER16-438, market-based rate triennial filing, December 18, 2015.
- Affidavit on behalf of Marshall Wind Energy, LLC, Docket No. ER16-438, application for market-based rates, December 1, 2015.
- Affidavit on behalf of Calpine Granite Holdings, LLC, Docket No. EC16-19, application for authorization of disposition of jurisdictional facilities, October 27, 2015.

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- Affidavit on behalf of Berkshire Hathaway, Inc., Docket No. EC16-10, application for authorization of disposition of jurisdictional facilities, October 8, 2015.
- Affidavit on behalf of Panda Patriot, LLC, Docket No. ER15-2472, application for market-based rates, September 29, 2015.
- Affidavit on behalf of Talen Energy Corporation, Docket No. EC14-112, Motion to Amend Mitigation Plan, September 25, 2015.
- Affidavit on behalf of BHE MBR Sellers, Docket No. ER12-162, notification of change in status, September 25, 2015.
- Affidavit on behalf of Talen Energy Corporation, Docket No. EC14-112, Motion to Amend Mitigation Plan, September 8, 2015.
- Affidavit on behalf of BHE MBR Sellers, Docket No. ER13-521, response to Commission Staff Deficiency Letter and Request for Additional Information, September 24, 2015.
- Affidavit on behalf of BHE MBR Sellers, Docket No. ER13-521, supplemental filing, September 8, 2015.
- Affidavit on behalf of GDF SUEZ MBR Sellers, Docket No. ER14-1699, notice of change, August 31, 2015.
- Affidavits on behalf of PacifiCorp and NV Energy, Docket No. ER15-2283, EIM analysis, July 27, 2015.
- Affidavit on behalf of NorthWestern Corporation and Beethoven Wind, LLC, Docket No. EC15-176, application for authorization of disposition of jurisdictional facilities, July 24 2015.
- Affidavit on behalf of MidAmerican Energy Services, LLC, Docket No. ER15-2211, application for market-based rates, July 24, 2015.
- Affidavit on behalf of The Empire District Electric Company, Docket No. ER10-2738, market-based rate triennial filing, June 30, 2015.
- Affidavit on behalf of Exelon MBR Sellers, Docket No. ER10-2172 *et al*., market-based rate triennial filing, June 30, 2015.
- Affidavit on behalf of Oklahoma Gas & Electric, Docket No. ER11-2105, market-based rate triennial filing, June 30, 2015.
- Affidavit on behalf of LG&E Energy Marketing, Inc., Docket No. ER10-1714, market-based rate triennial filing, June 30, 2015.
- Affidavit on behalf of Westar Energy, Inc., Docket No. ER10-2507, market-based rate triennial filing, June 29, 2015.
- Affidavit on behalf of the Alabama Power Company, *et al*., Docket No. EL15-39, *et al*., response to show cause order, June 26, 2015.
- Affidavit on behalf of Wisconsin Electric Power Company, Docket No. ER15-2019 market-based rate triennial filing, June 26, 2015.

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- Affidavit on behalf of Panda Liberty LLC, Docket No. ER15-1841, market-based rate application, June 2, 2015.
- Affidavit on behalf of CCI U.S. Asset Holdings LLC, Docket No. EC15-108, application for authorization of disposition of jurisdictional facilities, March 31, 2015.
- Affidavit on behalf of Florida Power & Light Company, Docket No. EC15-102, application for authorization of disposition of jurisdictional facilities, March 23, 2015.
- Affidavit on behalf of Osprey Energy Center, LLC, Docket No. EC15-96, application for authorization of disposition of jurisdictional facilities, March 13, 2015.
- Affidavit on behalf of the Berkshire Hathaway Energy MBR Sellers, Docket No. EL15-22, *et al*., response to show cause order, February 9, 2015.
- Affidavit on behalf of ECP MBR Sellers, Docket No. ER13-2477, notice of change in status, January 20, 2015.
- Affidavit on behalf of NorthWestern Corporation, Docket No. ER11-1859, market-based rate triennial filing, December 30, 2014.
- Affidavit on behalf of Exelon, Docket No. ER12-2178, market-based rate triennial filing, December 23, 2014.
- Affidavit on behalf of Dynegy Inc., Docket No. ER14-1569, market-based rate triennial filing, December 23, 2014.
- Affidavit on behalf of Northern Indiana Public Service, Docket No. ER10-1781, market-based rate triennial filing, December 23, 2014.
- Affidavit on behalf of AES Corp, Docket No. ER10-3415, market-based rate triennial filing, December 22, 2014.
- Affidavit on behalf of Ameren Illinois Company, Union Electric Company, and AmerenEnergy Medina Valley Cogen, L.L.C. Docket No. ER10-1119, ER10-1123, and ER10-1103, market-based rate triennial filing, December 19, 2014.
- Affidavit on behalf of Duke Energy MBR Sellers, Docket No. ER10-1325, market-based rate triennial filing, December 19, 2014.
- Affidavit on behalf of Duke Energy Progress, Inc., Docket No. EC15-9, application for authorization of disposition of jurisdictional facilities, October 10, 2014.
- Comments of Julie R. Solomon and Matthew E. Arenchild regarding NOPR on market-based rate authority, Docket No. RM14-14, September 23, 2014.
- Affidavit on behalf of Dynegy Resource I, LLC, Docket No. EC14-141, application for authorization of disposition of jurisdictional facilities, September 11, 2014.
- Affidavit on behalf of Dynegy Inc., Docket No. EC14-140, application for authorization of disposition of jurisdictional facilities, September 11, 2014.
- Affidavit on behalf of Calpine Fore River Energy Center, LLC, Docket No. EC14-135, application for authorization of disposition of jurisdictional facilities, September 5, 2014.

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- Affidavit on behalf of Seiling Wind, LLC; Seiling Wind II, LLC; Mammoth Plains Wind Project, LLC; and Palo Duro Wind Energy, LLC, Docket No. ER14-2707-10, market-based rate applications, August 26, 2014.
- Affidavit on behalf of ECP MBR Sellers, Docket No. ER10-2302, notification of change in status, August 18, 2014.
- Affidavit on behalf of Millennium Power Partners, L.P., Docket No. ER10-3286, notification of change in status, August 4, 2014.
- Affidavit on behalf of Granite Acquisition, Inc., Docket No. EC14-125, application for authorization of disposition of jurisdictional facilities, August 15, 2014.
- Testimony (Direct and Rebuttal), on behalf of Duke Energy Florida, Inc., Docket No. 140111-EI before the Florida Public Service Commission, Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018, May 27, 2014 and August 5, 2014.
- Affidavit on behalf of LS Power Development, LLC, Docket No. ER13-2318, notification of change in status, August 4, 2014.
- Supplemental Affidavit on behalf of Powerex Corp., Docket No. ER11-2664, market-based rate triennial filing, July 25, 2014.
- Supplemental Affidavit on behalf of Berkshire Hathaway Energy, Docket No. ER13-1266, notification of change in status, August 17, 2014.
- Affidavit on behalf of RJS Power Holdings LLC and PPL Corporation, Docket No. EC14-112, application for authorization of disposition of jurisdictional facilities, July 15, 2014.
- Affidavit on behalf of South Carolina Electric & Gas Company, Docket No. ER10-2498, market-based rate triennial filing, July 14, 2014.
- Affidavit on behalf of Consumers Energy Company, Docket No. EC14-110, application for authorization of disposition of jurisdictional facilities, July 1, 2014.
- Affidavit on behalf of J.P. Morgan Sellers, Docket No. ER10-2331, market-based rate triennial filing, June 30, 2014.
- Affidavit on behalf of Duke Energy MBR Sellers, Docket No. ER10-1325, market-based rate triennial filing, June 30, 2014.
- Affidavit on behalf of PPL Southeast Companies, Docket No. ER10-1511, market-based rate triennial filing, June 30, 2014.
- Affidavit on behalf of NextEra Companies, Docket No. ER10-1852, market-based rate triennial filing, June 30, 2014.
- Affidavit on behalf of NextEra Companies, Docket No. ER10-1838, market-based rate triennial filing, June 30, 2014.
- Affidavit on behalf of Brookfield Companies, Docket No. ER11-2292, market-based rate triennial filing, June 30, 2014.

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- Affidavit on behalf of Calpine Corp, Docket No. ER10-1944, market-based rate triennial filing, June 30, 2014.
- Affidavit on behalf of LS Northeast MBR Sellers, Docket No. ER13-2318, market-based rate triennial filing, June 30, 2014.
- Affidavit on behalf of GDF SUEZ Northeast MBR Sellers, Docket No. ER10-2670, market-based rate triennial filing, June 30, 2014.
- Affidavit on behalf of Safe Harbor Water Power Corp., Docket No. ER13-395, market-based rate triennial filing, June 27, 2014.
- Affidavit on behalf of ECP MBR Sellers, Docket No. ER13-2477, market-based rate triennial filing, June 23, 2014.
- Affidavit on behalf of Rockland Sellers, Docket No. ER12-1436, market-based rate triennial filing and notification of change in status, June 19, 2014.
- Affidavit on behalf of Exelon Corp and Pepco Holdings, Inc., Docket No. EC14-96, application for authorization of disposition of jurisdictional facilities, May 30, 2014.
- Affidavit on behalf of Nevada Power Co and Nevada Sun-Peak Limited Partnership, Docket No. EC14-83, application for authorization of disposition of jurisdictional facilities, May 2, 2014.
- Affidavit on behalf of Nevada Power Co and Las Vegas Cogeneration Limited Partnership, Docket No. EC14-84, application for authorization of disposition of jurisdictional facilities, May 2, 2014.
- Affidavit on behalf of NatGen Southeast Power LLC, Docket No. EC14-81, application for authorization of disposition of jurisdictional facilities, April 28, 2014.
- Surrebuttal Testimony on Behalf of Commonwealth Edison Company, Illinois Commerce Commission, Application for a Certificate of Public Convenience and Necessity, No. 13-0657, April 9, 2014.
- Affidavit on behalf of KMC Thermo, LLC, Docket No. ER14-1468, market-based rate application, March 12, 2014.
- Affidavit on behalf of Trailstone Power, LLC, Docket No. ER14-1439, market-based rate application, March 6, 2014.
- Affidavit on behalf of MACH Gen, LLC et al., Docket No. EC14-61, application for authorization of disposition of jurisdictional facilities, March 4, 2014.
- Affidavit on behalf of MidAmerican Geothermal, LLC, et al., Docket No. EC14-59, application for authorization of disposition of jurisdictional facilities, February 20, 2014.
- Affidavit on behalf of Green Mountain Power Corporation, Docket No. ER11-1933, market-based rate triennial filing, February 7, 2014.
- Affidavit on behalf of NorthWestern Corporation, et al., Docket No. EC14-41, application for authorization of disposition of jurisdictional facilities, January 10, 2014.

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- Affidavit on behalf of NorthWestern Corporation, Docket No. ER11-1858, notification of change in status, January 10, 2014.
- Affidavit on behalf of MidAmerican Energy, Docket No. ER10-2475, notification of change in status, January 2, 2014.
- Affidavit on behalf of Powerex Corp., Docket No. ER11-2664, market-based rate triennial filing, December 31, 2013.
- Affidavit on behalf of TransAlta, Docket No. ER10-2847, market-based rate triennial filing, December 31, 2013.
- Affidavit on behalf of Duquesne Light Company, Docket No. ER10-1910, market-based rate triennial filing, December 31, 2013.
- Affidavit on behalf of Constellation Energy Nuclear Group, Docket No. ER10-2179, market-based rate triennial filing, December 30, 2013.
- Affidavit on behalf of Exelon, Docket No. ER12-2178, market-based rate triennial filing, December 30, 2013.
- Affidavit on behalf of Dominion, Docket No. ER13-434, market-based rate triennial filing, December 30, 2013.
- Affidavit on behalf of Brookfield Companies, Docket No. ER10-2895, market-based rate triennial filing, December 30, 2013.
- Affidavit on behalf of Oklahoma Gas & Electric, Docket No. ER14-882, notification of change in status/tariff filing, December 30, 2013.
- Affidavit on behalf of AES Corp, Docket No. ER10-3415, market-based rate triennial filing, December 26, 2013.
- Affidavit on behalf of JPMorgan, Docket No. ER10-2331, market-based rate triennial filing, December 23, 2013.
- Affidavit on behalf of Northeast Utilities, Docket No. ER10-1801, market-based rate triennial filing, December 20, 2013.
- Affidavit on behalf of Iberdrola, Docket No. ER10-2822, market-based rate triennial filing, December 20, 2013.
- Affidavit on behalf of PHI, Docket No. ER10-2997, market-based rate triennial filing, December 20, 2013.
- Affidavit on behalf of Essential Power, Docket No. ER12-952, market-based rate triennial filing, December 20, 2013.
- Affidavit on behalf of Empire District, Docket No. ER14-793, notification of change in status/tariff filing, December 20, 2013.
- Affidavit on behalf of Westar Energy, Inc., Docket No. ER14-724, notification of change in status/tariff filing, December 19, 2013.

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- Affidavit on behalf of Alpha Gen Power, LLC, Docket No. ER14-630, market-based rate application, December 16, 2013.
- Affidavit on behalf of Black Bear Hydro Partners, LLC, Docket No. EC14-28, application for authorization of disposition of jurisdictional facilities, November 14, 2013.
- Affidavit on behalf of Sierra Pacific Power Company, Docket No. ER10-2474, notification of change in status, November 4, 2013.
- Affidavit on behalf of ECP, Docket No. ER11-3859, notification of change in status, September 30, 2013.
- Affidavit on behalf of Steele Flats Wind Project, LLC, Docket No. ER13-2474, market-based rate application, September 27, 2013.
- Affidavit on behalf of Tuscola Wind II, LLC, Docket No. ER13-2458, market-based rate application, September 26, 2013.
- Affidavit on behalf of Pheasant Run Wind, LLC and Pheasant Run Wind II, LLC, Docket Nos. ER13-2461-2, market-based rate applications, September 26, 2013.
- Affidavit on behalf of TPF II and USPG Holdings, LLC, Docket No. EC13-154, application for authorization of disposition of jurisdictional facilities, September 25, 2013.
- Affidavit on behalf of Seneca Generation, LLC et al., Docket Nos. ER13-2316-9, market-based rate applications, September 4, 2013.
- Affidavit on behalf of Seneca Generation, LLC et al., Docket No. EC13-143, application for authorization of disposition of jurisdictional facilities, September 4, 2013.
- Supplemental Affidavit on behalf of MidAmerican Energy (Silver Merger Sub, Inc.), Docket No. EC13-128, application for authorization of disposition of jurisdictional facilities, August 17, 2013.
- Affidavit on behalf of Desert Sunlight 250, LLC and Desert Sunlight 300, LLC, Docket Nos. ER13-1991-2, market-based rate applications, July 17, 2013.
- Affidavit on behalf of MidAmerican Energy (Silver Merger Sub, Inc.), Docket No. EC13-128, application for authorization of disposition of jurisdictional facilities, July 12, 2013.
- Affidavit on behalf of Calpine Southwest MBR Sellers, Docket No. ER10-1942, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of NextEra Companies, Docket No. ER10-1847, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of Wayzata Entities, Docket No. ER10-1777, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of AES MBR Affiliates, Docket No. ER10-3415, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of Sierra Pacific Power Company, *et al.* under ER10-2474, Docket No. ER10-24744, market-based rate triennial filing, July 1, 2013.

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- Affidavit on behalf of NorthWestern Corporation, Docket No. ER11-1858, market-based rate triennial filing, July 1, 2013.
- Affidavit on behalf of SGOC Southwest MBR Sellers, Docket No. ER10-2864, market-based rate triennial filing, June 28, 2013.
- Affidavit on behalf of GWF Energy LLC, et al. Docket No. ER10-3301, market-based rate triennial filing, June 28, 2013.
- Affidavit on behalf of NV Energy, Inc., application for approval of internal reorganization, Docket No. EC13-113, May 31, 2013.
- Affidavit on behalf of Midwest Generation, LLC, Docket No. EC13-103, application for authorization of disposition of jurisdictional facilities, May 6, 2013.
- Affidavit of behalf of Nevada Power Company (with Matthew E. Arenchild), Docket No. EC13-96, application for authorization of disposition of jurisdictional facilities, April 17, 2013.
- Affidavit of behalf of Dynegy Inc., Docket No. EC13-93, application for authorization of disposition of jurisdictional facilities, April 16, 2013.
- Application on behalf of Florida Power & Light Company, Docket No. EC13-91, application for authorization of disposition of jurisdictional facilities, April 12, 2013.
- Affidavit on behalf of Blythe Energy LLC, et al., Docket No. EC13-89, application for authorization of disposition of jurisdictional facilities, April 2, 2013.
- Affidavit on behalf of New Harquahala Generating Company, LLC, Docket No. ER10-3310, market-based rate triennial filing, March 29, 2013.
- Affidavit on behalf of Dominion Energy Brayton Point, et al., Docket No. EC13-82, application for authorization of disposition of jurisdictional facilities, March 21, 2013.
- Affidavit on behalf of Duke Energy Carolinas, LLC et al., Docket No. ER10-2566, et al., notice of change in status, January 29, 2013.
- Affidavit on behalf of CCI Roseton LLC, Docket No. ER13-773, market-based rate application, January 17, 2013.
- Affidavit on behalf of CCI Roseton LLC, Docket No. EC13-63, application for authorization of disposition of jurisdictional facilities, January 16, 2013.

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NAVIGANT

Julie M. Carey

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Professional Summary

Julie Carey is an energy economist and a Director with Navigant Consulting, Inc. She is also an adjunct professor at Georgetown University where she teaches a graduate level course in energy economics.

Julie has more than 20 years of experience addressing economic issues across the energy sector including: power, crude oil, natural gas, natural gas liquids, renewables, coal, pipelines and railroad industries as well as energy intensive industries such as manufacturing and chemicals. She frequently provides expert reports and testimony in regulatory proceedings and in commercial disputes, including courts and international arbitrations.

Julie's expertise includes economic analyses of market dynamics (supply, demand and pricing) as well as competition, claims of market manipulation and regulatory economics.

She frequently analyzes economic damages (historical and future lost profit analyses) and conducts asset valuation analyses. She has assessed and quantified economic damages and valuations in dozens of cases. She has completed this work in breach of contract, antitrust, class action and other types of disputes.

Julie also has substantial experience conducting environmental analysis (e.g. greenhouse gases and other types of emissions) and frequently completes macroeconomic modeling (i.e. jobs, GDP, taxes) to study the impact of energy infrastructure construction and operations on the economy.

For her assignments, she frequently employs statistical and econometric analyses.

Areas of Expertise

Electricity Industry Experience

Ms. Carey provides expert consulting and testifying services in commercial disputes and regulatory proceedings addressing electricity industry issues. Within commercial disputes she has been involved in claims of breach of contracts, partnership disputes, delayed plant operations, diminished value claims, replacement power, antitrust and manipulation claims, EPA clean air act, among others. Within regulatory proceedings she has been involved in matters evaluating potential impact on competition for regulatory approval of mergers and acquisitions, market-based rate authority, proposed energy infrastructure projects and evaluations of energy manipulation claims and market rules and market design features of wholesale power markets. Her work often includes economic analysis of energy, capacity and ancillary services within wholesale power markets, competition, damages, valuation, energy contracts, macroeconomic and other issues. A few examples include:

- Expert testimony in matters related to competition within wholesale electricity markets, such as market power screens and delivered price test analyses for regulatory approval of mergers and acquisitions and market-based rate authority. Within this work, she analyzes product and geographic markets, including assessments of transmission constraints. The economic analysis includes evaluation of delivered fuel costs and operational characteristics of power plants (seasonal capabilities, short run marginal costs, efficiency rates, etc.).

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Julie M. Carey

- Expert report analyzing economic and environmental analysis of the GHG impact from the construction and operation of a new coal terminal export facility and downstream power markets for regulatory approval. This work included long-term market and economic analysis of the elasticity of demand of coal, forecast of GHG emission and other energy market impacts within downstream energy markets (U.S. and Pacific Basin). This work also included analysis of power generation economics (short run marginal costs, power plant efficiencies), fuel price forecasts, and an evaluation of the range of potential outcomes of the GHG forecasts.
- Expert testimony regarding the economics of a power purchase agreement and evaluation of the claim of economic damages (past and future) associated with the alleged breach of a contract. This work included analysis of the appropriate economic theory of damages.
- Expert testimony regarding the impact of a proposed market rule regarding the transmission allocation among market participants, incentives for new entry and an evaluation of economic efficiency and potential market power within the wholesale electricity market.
- Retained testifying expert in an investigation involving claims of market manipulation of wholesale power markets to evaluate of the energy companies' economic behavior, including economic purpose of the transactions and the reasonableness of the prices reflective of market outcomes.
- Expert consulting to evaluate the asset valuations of numerous natural gas-fired power plants, including long term forecasts of market prices, revenues and costs, cost of capital, and the development of a discounted cash flow analysis. This work included a probabilistic analysis using monte carlo simulations to forecast cash flows under different financial and operational conditions.
- Expert report analyzing the economic impact (GDP, jobs etc.) from constructing and operating a proposed power plant and evaluating the potential impact on competition.
- Expert consulting to quantify the asset valuations of a substantial portfolio of electricity generation plants, including coal, nuclear, natural gas and renewable assets in the Northeastern U.S. This assignment was used to aid the client in business decision making during an evolving market and regulatory climate. This work included the development of long term forecasts of market prices, revenues and costs, cost of capital, and the development of a discounted cash flow analysis.
- Consulting expert analysis in a Clean Air Act dispute between a utility and the EPA involving a coal-fired power plant's numerous power plant modifications. The work included the impact of increasing market demand on power plant emissions as a consideration to whether the utility violated the EPA rules.
- Provided expert reports in a coal contract dispute involving replacement coal purchases, and evaluation of economic damages and impact of market prices, and coal quality attributes.
- Expert consulting regarding proposed market rules for capacity markets, including an evaluation of economic incentives and implications for market power.
- Numerous expert reports regarding power plant performance, forecasts of new electric generating capacity and fuel supply projections.

Renewable Industry Experience

Ms. Carey frequently provides expert consulting and testifying services in commercial disputes and regulatory proceedings involving the renewable energy industry. Within commercial disputes she has been involved in claims of breach of contracts, antitrust and bankruptcy claims. Before regulators Ms. Carey has evaluated the potential impact on competition for approval of market-based rate authority. Her work often includes analysis of energy markets (supply, demand, and pricing), competition, damages, valuation, energy contracts, macroeconomic and other issues. A few examples include:

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- Expert testimony on economic damages in a dispute involving a power purchase agreement for geothermal power with an aluminum manufacturer in an international arbitration.
- Expert report in an international arbitration providing an analysis of the solar panel market, reasonableness of market prices and the market value of solar power products.
- Expert consulting regarding antitrust claims and valuation analysis of the solar panel industry.
- Expert report in a bankruptcy court proceeding regarding the outlook for silane gas and the thin film solar market and past and future economic damages associated with the failure to fulfill a take or pay contract obligation.
- Expert consulting regarding the reasonableness of contract prices in wind power purchase agreement for regulatory approval.
- Expert consulting regarding economic damages with respect to delayed operations of a polysilicon and silane gas manufacturing plants and effect on solar module sales.
- Expert consulting regarding antitrust claims regarding the solar panel manufacturing industry. This work included economic analysis of the potential anticompetitive behavior and a valuation analysis of a solar panel company, including the development of a discounted cash flow analysis analyzing the future cash flows and net present value of the enterprise.
- Expert consulting and economic analysis regarding the capital and operating costs of different types of renewable power facilities and environmental and economic impact analyses of investments.
- Expert consulting regarding economics of power purchase agreements for renewable power and ancillary services.
- Expert reports in numerous cases regarding the unique economics and operational aspects of wind, solar, geothermal, and hydro power supply within competition analysis for wholesale power markets.
- Expert consulting regarding the economic impact (GDP, jobs, taxes etc.) and environmental analyses from constructing and operating renewable energy facilities.

Oil and Gas Industry Experience

Ms. Carey provides expert consulting and testifying services in commercial disputes and regulatory proceedings involving oil and gas industry issues. Within commercial disputes she has been involved in claims of breach of breach of product and transportation contract, other commercial disputes involving antitrust and manipulation operational, environmental, and bankruptcy claims. Before U.S. and Canadian regulators Ms. Carey has evaluated the potential impact on competition for approval of market-based rate authority, negotiated rates, proposed energy infrastructure projects and evaluations of energy manipulation claims. Her work often includes analysis of energy markets (supply, demand, and pricing), competition, damages, valuation, energy contracts, macroeconomic and other issues. A few examples include:

- Expert report regarding past and future economic damages and economics of the product market, supply, demand and pricing in a chemical product contract dispute before a bankruptcy court.
- Retained testifying expert to conduct economic analysis of crude oil markets, pricing and alternative transportation economics (rail, truck, waterborne and pipeline) in a crude oil contract dispute.
- Expert consulting in numerous disputes/investigations involving claims of market manipulation and anticompetitive behavior within natural gas, natural gas liquids and other energy product markets. This work includes market and econometric analysis as to whether the actual market prices reflect competitive market prices (i.e. consistent with supply, demand, prices and constraints etc.).

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- Expert analysis for numerous regulatory filings conducting economic impact assessments of constructing and operating proposed oil and gas pipeline project.
- Evaluation and economic analysis of the potential effects of EPA gasoline sulfur content regulations (Tier 3) on U.S. retail gasoline prices, macro-economic impacts, sulfur reduction and other benefits.
- Expert consulting providing economic analysis of the competitiveness of crude oil transportation market in Western Canada to evaluate competition within pipeline markets. This work also included economic analysis of the negotiations process and negotiated rates for new transportation contract sales to determine if the process was competitive and the rates were consistent with fair market value prices.
- Expert testimony in numerous cases regarding delivered fuel cost and economics of natural gas, crude oil and refined products to downstream energy markets and evaluation of competition.
- Expert consulting in numerous cases to evaluate competition for transportation of crude oil and refined products and the reasonableness of negotiated and market-based rates.
- Expert consulting in a refined product contract dispute involving economic analysis of crude oil and refined product markets and rail, truck, and pipeline transportation economics and economic damages.
- Expert consulting economic analyses of price formation/separation of crude oil price indices for energy contract dispute.
- Expert consulting in a natural gas tolling contract dispute conducting an economic analysis of natural gas markets and an analysis of past and the future economic damages.
- Consulting expert on the reasonableness of business decisions and damages related to an area of mutual interest purchase agreement and acquisitions of oil and gas assets in a shale basin.

Railroad Transportation Industry Experience

Ms. Carey frequently provides expert consulting and testifying services in commercial disputes and regulatory proceedings involving the railroad transportation industry. A few examples include:

- Expert report before the U.S. federal transportation regulatory, Surface Transportation Board ("STB") regarding the potential introduction of indirect competition analyses within market dominance determinations for coal transportation to utility generation facilities for purpose of in coal transportation rate disputes.
- Expert consulting conducting numerous competition analyses of rail and pipeline transportation (and other modes of transportation) for crude oil and refined products in the U.S. and Western Canada in a commercial dispute.
- Expert consulting analyzing economics of containerized freight transportation, including intermodal rail and competition with alternative transportation modes in a transportation contract dispute.
- Expert consulting analyzing the economics of competition in railroad transportation services including evaluating the impact of fuel surcharges in a commercial dispute.
- Expert reports in numerous regulatory proceedings involving rail transportation rate disputes for coal, including evaluation of appropriate regulatory construct long term forecasts of coal deliveries, transportation rates (all modes), and revenue attribution methodologies for shared facilities.

Coal Industry Experience

Ms. Carey has experience analyzing coal markets and has proffered testimony on long term fuel supply

Julie M. Carey

assessments and analyzed economic damages from claims of breach of coal contracts. Ms. Carey routinely analyzes the economics of the delivered cost of coal, natural gas and other fuels to electric utilities in the U.S., Canada and elsewhere to evaluate the impact on competition for regulatory proceedings or commercial disputes. She has provided expert evidence regarding the long term elasticity of demand of coal and greenhouse gas and other energy market impacts within downstream energy markets U.S. and Pacific Basin. Ms. Carey has provided expert reports to the regulators on issues such as long term forecasts of coal volumes from U.S. coal basins and import from foreign sources to U.S. coal fired power plants, industrial facilities and to export terminals in disputes regarding the reasonableness of rail transportation rates. Ms. Carey has provided expert reports in coal contract disputes and served as a consulting expert in a lawsuit alleging violations against the EPA clean air act. She has analyzed the impact of regulations of SO2, NOx and carbon emissions on coal generation facilities and evaluated the substitutability of different types of coal in terms of quality attributes and economics.

Selected Publications and Presentations

- **Comments to the FERC Notice of Inquiry:** Modifications to Commission Requirements for Review of Transactions under Section 203 of the Federal Power Act and Market-Based Rate Applications under Section 205 of the Federal Power Act RM16-21-000, Market Power Experts (including Julie Carey), November 28, 2016.
- **Crude Oil and Transportation Market and Regulatory Developments**, Julie Carey, Association of Oil Pipeline Business Conference, Sept 16, 2016.
- **Will Trudeau and Obama Fulfill Their Energy Promises?** Julie Carey, The Energy Advisors, March 25, 2016.
- **NGL Market Development Panel**, Infocast Midstream Summit, February 17, 2016.
- **Energy Market Trends, Economic Implications, and the Outlook for Infrastructure**, Construction Superconference, December 8, 2015.
- **Effects of Rising Demand for Energy Infrastructure Development on Labor, Other Resources, and the Economy**, Julie Carey (with Chris Ring and Rebekah Hannif-Ali), Navigant Construction Forum, Dec. 2015.
- **Trials, Tribulations and Turmoil in Crude Oil Markets**, Association of Corporate Counsel, November 24, 2015.
- **Near Term Energy Market Dynamics and the Clean Power Plan**, Western Coal Traffic League Fall Meetings, Julie Carey (with Maggie Shober), November, 19, 2015.
- **The Impact of Crude Oil and Natural Gas Market Trends on Litigation**, Energy Litigation Journal (ABA Section), Julie M. Carey (with Bob Broxson and Sonya Kwon), November 2015.
- **Today's Energy Market and the Cost of Artificially Suppressing Demand with the Crude Oil Export Ban**, Kelley, Drye, and Warren, Energy Regulatory Conference, October 22, 2015.
- **Regulation and Competition in Oil Pipelines and Related Industries**, Association of Oil Pipelines Business Conference, Julie Carey (with Julie Solomon), September 17, 2015.
- **Low Crude Oil Price Impacts: Market Dynamics, Economic Implications and Disputes**, Texas Lawyers Houston, Julie Carey (with Robert Lang), May 21, 2015.
- **Rising Tide: Litigation Wave from Low Oil Prices & Economic Implications**, Texas Lawyers- Dallas, Julie Carey (with Robert Lang), May 8, 2015.

NAVIGANT

Julie M. Carey

- **What Is the Future of the Long-Delayed Keystone XL Pipeline?** Inter-American Dialogue's Latin America Advisor – Energy, May 5, 2014.
- **Enforcement Shifts Energy-Trading Strategies**, Energy Litigation Journal (ABA Section), Julie M. Carey (with Cliff Hamal and Ben Ullman), March 2014.
- **Energy Commodity Trading's Evolving Regulatory Frontier**, Natural Gas Notes, January 2014.
- **Trading Firms in the Bullseye Amid Stepped Up Oversight Of Energy Markets**, Forbes October 11, 2013.
- **Rail Emerging as Long-Term North American Crude Option, Oil and Gas Journal,** August 5, 2013.
- **How Unconventional Oil and Gas Is Supercharging the U.S. Economy**, Forbes (online), December 13, 2012.
- **Unconventional Resources, Economic Growth and Power Generation Implications**, Julie M. Carey, PowerGen Conference, Orlando, Florida, December 13, 2012.
- S**urprise Side Effect Of Shale Gas Boom: A Plunge in U.S. Greenhouse Gas Emissions, Forbes,** December 7, 2012.
- **The Economics of Unconventional Oil and Gas,** North American Gas Summit, Julie M. Carey, November 15, 2012.
- **The Unconventional Path for Domestic Crude Oil and Natural Gas Resources,** U.S. Association for Energy Economists Dialog, Julie M. Carey and Christopher L. Ring, September, 2012.
- **Shale Gas and Oil: Economy-Wide Game Changers,** Natural Gas Notes, August 1, 2012.
- **The Renewable Transformation and Nine Trends to Watch For**, Julie Carey (with Cliff W. Hamal), US Association for Energy Economists Dialog, November 2010.
- **Capacity Market Design Fundamentals**, EUCI conference workshop, Julie Carey (with Cliff Hamal and Cleve Tyler), Baltimore, MD, October 27, 2010.
- **Market Forum Participant for the Future Outlook for Fuel Cell Generating Technology**, April 13, 2005.

Client Reports

- Economic Analysis of Electric Vehicle Market from Illinois' Proposed Legislation May 17, 2016. Julie M. Carey (with Celia David and John Gartner). (Updated August 10, 2016)
- Economic Analysis of Clean Energy Jobs from Illinois' Proposed Legislation May 11, 2016 and September 16, 2015. Julie M. Carey (with Celia David and Bruce Hamilton).
- Evaluation of the Economic Contributions of Littoral Combat Ship (LCS) Program, Lockheed Martin Corporation, Julie M. Carey (with Kate Rodenrys), January 7, 2015. (Supplemented December 2015)
- An Analysis of a Refined Product Pipeline Competitive Tariff Rates and of the Current Competitiveness of the Refined Product Pipelines Market-Based Rate Markets, Confidential Report, June 9, 2014, Julie M. Carey (with Kate Rodenrys and George Schink).
- Oil Pipeline Regulation and Competition, Confidential White Paper for the Association of Oil Pipe Lines, Julie Carey (with George Schink, Rick Smead, and Julie Solomon), August 2013.
- Report on the Preliminary Analysis of the Potential Competition Faced by a Reversed Crude Oil Pipeline and Competition Faced by an Existing System, Confidential Report, June 24, 2013, Julie Carey (with Kate Rodenrys and George Schink).

NAVIGANT

Julie M. Carey

- Report on the Preliminary Analysis of the Competition Faced by a Crude Oil Pipeline System, Confidential Report, June 7, 2013, Julie Carey (with Kate Rodenrys and George Schink).
- Spent Nuclear Fuel Management: How centralized interim storage might expand options and reduce costs, A study conducted for the Blue Ribbon Commission on America's Nuclear Future, Julie Carey (with Cliff W. Hamal and Christopher L. Ring), May 2011.
- Meeting the Challenge of Spent Fuel in Decommissioned Storage, Presentation to Blue Ribbon Commission on America's Nuclear Future, Julie Carey (with Cliff Hamal and Chris Ring), January 3, 2011.
- Clean Energy Policy Initiative Impacts on the Environment and the Economy, Confidential Client Report, May, 2009.
- Strategic Recommendations for Expiring Power Contracts, Confidential Report, Julie Carey (with Cliff W. Hamal), Prepared On Behalf of Ontario Power Authority, January 22, 2009.
- Force Majeure Risks and Ontario Power Authority's Power Contracts, Julie Carey (with Cliff W. Hamal), Prepared On Behalf of Ontario Power Authority, March 31, 2008.
- Financial Accommodation for Force Majeure Events, Julie Carey (with Cliff W. Hamal), Prepared On Behalf of Ontario Power Authority, January 21, 2008.
- Power Generation Investments in a Capacity Demand-Curve Market, Cliff W. Hamal and Julie A. Murphy, The Energy and Utility Project, May 2005.

Expert Affidavits & Testimony Experience

December 22, 2016	FERC Docket No. ER11-47 et al., Triennial Update for Market Based Rate Authority for American Electric Power Company, et al. in the Northeast region, Affidavit of Julie M. Carey.
December 22, 2016	FERC Docket No. ER11-1933 et al., Triennial Update for Market Based Rate Authority for Green Mountain Power, et al. in the Northeast region, Affidavit of Julie M. Carey.
November 29, 2016	U.S. Army Corps of Engineers, Seattle District, Response to Draft Environmental Impact Statement for the National Environmental Policy Act Regarding the Proposed Millennium Bulk Terminals Longview Project, Expert Evidence.
June 13, 2016	Cowlitz County and the Washington State Department of Ecology, Response to Draft Environmental Impact Statement for the State Environmental Policy Act Regarding the Proposed Millennium Bulk Terminals Longview Project, Expert Evidence.
January 17, 2016	FERC Docket No. Docket No. EC16-__, Supplemental Affidavit of Julie M. Carey to Support Ohio Valley Electric Corporation's Application for Market Based Rate Authority in PJM, MISO and other market areas. (Initial Report November 6, 2015)
December 28, 2015	FERC Docket No. ER10-2302__, Triennial Update for Market Based Rate Authority for Public Service Company of New Mexico, Affidavit of Julie M. Carey.
December 16, 2015	Wisconsin Public Service Commission, Docket No. 6800-CE-176, Surrebuttal Testimony of Julie M. Carey.
December 4, 2015	Wisconsin Public Service Commission, Docket No. 6800-CE-176, Application for a CPCN To Build an Natural Gas-Fueled Power Plant at its Riverside Energy Center Facility, Rebuttal Testimony of Julie M. Carey.

Julie M. Carey

November 6, 2015	FERC Docket No. Docket No. EC15-__, Supplemental Affidavit of Julie M. Carey to Support PNM's Application for Authorization of Disposition of Jurisdictional Facilities. (Initial Report September 25, 2015)
June 30, 2015	FERC Docket No. ER11-47 et al., Triennial Update for Market Based Rate Authority for American Electric Power Company, et al. in the Southwestern Power Pool region, Affidavit of Julie M. Carey.
April 25, 2015	Minnesota Public Utilities Commission Docket No. PL-9/PPL-15-137, In the Matter of the Application of Enbridge Energy, Limited Partnership for a Routing Permit for the Line 3 Replacement Project in Minnesota from the North Dakota Border to the Wisconsin Border. Economic Impact Assessment Study.
November 5, 2014	National Energy Board Application of Enbridge Energy, Line 3 Replacement Program; Economic Impact Assessment Study.
August 15, 2014	FERC Docket No. ER10-2302-__ Change in Status Filing for Public Service Company of New Mexico, et al., Affidavit of Julie M. Carey.
December 27, 2013	FERC Docket No. ER14-__, Change in Status Filing for American Electric Power Company, et al., Southwest Power Pool, Affidavit of Julie M. Carey (with Ben Ullman).
December 20, 2013	FERC Docket No. ER11-47 et al., Triennial Update for Market Based Rate Authority for American Electric Power Company, et al. in the PJM RTO region, Affidavit of Julie M. Carey.
July 5, 2013	FERC Docket No. ER13-1896-000, Application of American Generation Resources Inc. for Market Based Rate Authority, Affidavit of Julie Carey.
June 11, 2013	ULVAC, INC vs. China Solar Power (Holdings) Ltd., In the Matter of a Commercial Arbitration, Hong Kong International Arbitration Centre, HKIAC /A11013, Expert Report of Julie Carey.
April 17, 2013	Energy Conversion Devices, Inc., et al., Chapter 11, Case No. 12-43166, U.S. Bankruptcy Court Eastern District of Michigan Southern Division, Expert Report for Praxair by Julie Carey (with Graham Stevens).
February 5, 2013	HS Orka hf. vs. Nordural Grundartangi, ehf and Orkauveita Reykjavikur, In the Matter of a Commercial Arbitration, Stockholm Chamber of Commerce Arbitration V (191/2011), Expert Testimony of Julie M. Carey.
January 14, 2013	Surface Transportation Board ("STB"), Ex. Parte No. 717, Reply Verified Statement of Julie M. Carey (with James M. Speyer) to Petition of Association of American Railroads to Institute a Rulemaking Proceeding to Reintroduce Indirect Competition As A Factor Considered in Market Dominance Determinations For Coal Transported to Utility Generation Facilities.
December 21, 2012	FERC Docket No. ER96-1551-__ and ER01-615-__ and ER09-74-__, Triennial Update for Market Based Rate Authority for Public Service Company of New Mexico, Affidavit of Julie M. Carey.
October 24, 2012	HS Orka hf. vs. Nordural Grundartangi, ehf and Orkauveita Reykjavikur, In the Matter of a Commercial Arbitration, Stockholm Chamber of Commerce Arbitration V (191/2011), Expert Rebuttal Report of Julie M. Carey.

Julie M. Carey

September 18-19, 2012	On behalf of Montana Alberta Tie Ltd ("Enbridge – MATL"), Alberta Utilities Commission, Proceeding 1633, Expert Testimony of Julie M. Carey (with Cliff Hamal).
August 29, 2012	HS Orka hf. vs. Nordural Grundartangi, ehf and Orkauveita Reykjavikur, In the Matter of a Commercial Arbitration, Stockholm Chamber of Commerce Arbitration V (191/2011), Expert Report of Julie M. Carey.
June 29, 2012	FERC Docket No. ER11-47, Triennial Update for Market Based Rate Authority for American Electric Power Company, et al. in the Southwestern Power Pool region, Affidavit of Julie M. Carey.
June 15, 2012	On behalf of Montana Alberta Tie Ltd ("Enbridge – MATL"), Alberta Utilities Commission, Proceeding 1633, Testimony of Julie M. Carey (with Cliff Hamal).
March 1, 2012	FERC Docket No. ER97-4143, Change in Status Filing for Market Based Rates for the American Electric Power Company, et al, Affidavit of Julie M. Carey.
March 23, 2010	FERC Docket No. ER10-727-001, Request for Market Based Rate Authority for AEP Retail Energy Partners LLC, Affidavit of Julie M. Carey.
March 8, 2010	FERC Docket No. ER96-1551-__ and ER01-615-__ and ER09-74-__, Triennial Update for Market Based Rate Authority for Public Service Company of New Mexico, Affidavit of Julie M. Carey.
December 11, 2008	On behalf of COALSALES II, L.L.C., in the matter of Gulf Power Company v. COALSALES II, L.L.C. Docket no. 3:06 CV 270/MCR/MD, before the US District Court for the Northern District of Florida, Pensacola Division, Expert Report of Julie M. Carey (with Cliff Hamal).
August 19, 2008	On behalf of COALSALES II, L.L.C., in the matter of Gulf Power Company v. COALSALES II, L.L.C. Docket no. 3:06 CV 270/MCR/MD, before the US District Court for the Northern District of Florida, Pensacola Division, Expert Report of Julie M. Carey (with Cliff Hamal)
May 25, 2007	FERC Docket Nos. ER96-2495-_ ER97-4143-__, ER97-1238-__, ER98-2075-__ and ER98-542-__, Change in Status Filing for American Electric Power for Market-Based Rate Authority, Affidavit of Julie M. Carey.
April 17, 2006	FERC Docket No. Docket EC06-113-000, Application for Asset Transfer of Contra Costa #8 for Pacific Gas and Electric Company, Mirant Delta, LLC and Mirant Special Procurement, Inc., Affidavit of Julie A. Murphy.
January 12, 2006	FERC Docket No. ER96-1551-__ and ER01-615-__, Change in Status Filing for Public Service Company of New Mexico for Market-Based Rate Authority, Affidavit of Julie A. Murphy.
July 21, 2005	FERC Docket No. ER05-1244-000 and ER05-1244-001, Application by Societe Generale Energie (USA) Corp. for Market-Based Rate Authority, Affidavit of Julie A. Murphy.
July 15, 2005	FERC Docket No. ER96-1551-006 and ER01-615-003, Compliance Filing for Public Service Company of New Mexico for Market-Based Rate Authority, Affidavit of Julie Murphy.
April 21, 2005	Testimony of Julie Murphy on behalf of Onvoy, Inc., Onvoy, Inc. v. Allete, Inc. f/k/a Minnesota Power, Inc. d/b/a Minnesota Power and Light Company and, Enventis

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	Telecom, Inc., Sixth Judicial District Court File No. 69-C9-03-601595, St. Louis County, Minnesota.
April 4, 2005	STB Docket No. 42071, Otter Tail Power Company v. BNSF Railway Company, Sponsored Testimony within Section III-A Stand-Alone Traffic Group of the Response Testimony of Burlington Northern Santa Fe Railway Company.
March 1, 2005	STB Docket No. 42071, Otter Tail Power Company v. BNSF Railway Company, Sponsored Testimony within Section III-A Stand-Alone Traffic Group of Supplemental Evidence of Burlington Northern Santa Fe Railway Company.
December 5, 2004	Expert Report Julie A. Murphy (with John Klick) on behalf of Onvoy, Inc., Onvoy, Inc. v. Allete, Inc. f/k/a Minnesota Power, Inc. d/b/a Minnesota Power and Light Company and, Enventis Telecom, Inc., Sixth Judicial District Court File No. 69-C9-03-601595, St. Louis County, Minnesota.
September 9, 2004	STB Docket No. 41191 (Sub-No. 1), AEP Texas North Company v. Burlington Northern and Santa Fe Railway Company, Verified Statement of Julie A. Murphy.
May 24, 2004	STB Docket No. 41191 (Sub-No. 1), AEP Texas North Company v. Burlington Northern and Santa Fe Railway Company, Sponsored Testimony within Section III-A Stand-Alone Traffic Group of Reply Evidence and Argument of Burlington Northern Santa Fe Railway Company.
May 10, 2004	MI PSC Case No. U-13531, In the Matter of the Commission's Own Motion to Review the Costs of Telecommunication Services Provided by SBC Michigan, Final Reply Declaration of Julie A. Murphy (with Michael Baranowski).
April 18, 2004	STB Docket No. 41185, Arizona Public Service and PacifiCorp v. Burlington Northern Santa Fe Railway Company, Verified Statement of Julie Murphy.
March 22, 2004	STB Docket No. 42071, Otter Tail Power Company v. Burlington Northern and Santa Fe Railway Company, Sponsored Testimony within Section III-A Stand-Alone Traffic Group of Supplemental Reply Evidence and Argument of Burlington Northern Santa Fe Railway Company.
February 19, 2004	Texas PUC SOAH Docket. No.473-04-0001, PUC Project No. 27957, Application of CenturyTel of San Marcos, Inc. for Approval of a Plan for Disaggregation of State and Federal Universal Service Support, Testimony of Julie Murphy on Behalf of Grande Communications Networks, Inc.
January 26, 2004	STB Docket No. 42058. Arizona Electric Power Cooperative Inc. v. the Burlington Northern and Santa Fe Railway Company and Union Pacific Railroad Company, Sponsored Testimony within Section III-A Stand-Alone Traffic Group of Reply Evidence and Argument of Burlington Northern Santa Fe Railway Co..
January 20, 2004	MI PSC Case No. U-13531, In the Matter of the Commission's Own Motion to Review the Costs of Telecommunication Services Provided by SBC Michigan, Reply Declaration of Julie A. Murphy (with Michael Baranowski).
January 12, 2004	STB Docket No. 42070, Duke Energy v. CSX Transportation, Inc., Sponsored Testimony within Section III-A Stand-Alone Traffic Group of Response to Supplemental Testimony of CSX Transportation, Inc.

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January 5, 2004	STB Docket No. 42070, Duke Energy v. CSX Transportation, Inc., Sponsored Testimony within Section III-A Stand-Alone Traffic Group of Supplemental Testimony of CSX Transportation, Inc.
December 29, 2003	Texas PUC SOAH Docket. No.473-04-0001, PUC Project No. 27957, Application of CenturyTel of San Marcos, Inc. for Approval of a Plan for Disaggregation of State and Federal Universal Service Support, Direct Testimony of Julie Murphy on Behalf of Grande Communications Networks, Inc.
October 8, 2003	STB Docket No. 42071, Otter Tail Power Co. v. Burlington Northern Santa Fe Railway Company, Sponsored Testimony within Section III-A Stand-Alone Traffic Group A of Reply Evidence and Argument of Burlington Northern Santa Fe Railway Co.
April 18, 2003	STB Docket No. 42058, Arizona Electric Power Coop, Inc. v. Burlington Northern Santa Fe Railway Co. and Union Pacific Railroad, In Support of UP's Petition to Require Submission of New Opening Evidence, Or, Alternatively, To Dismiss, Verified Statement of Julie Murphy (with John Klick).
April 4, 2003	FCC WCB Docket No.03-18. In the Matter of Alascom, Inc. Request for Waiver of Commission Rule and Orders Requiring Annual Tariff Revision, Alascom, Inc. Petition for Waiver, Declaration of John Klick and Julie Murphy, Supplement to Waiver Request and Response to FOIA Request.
April 4, 2003	STB Docket No. 42057, Xcel v. Burlington Northern Santa Fe Railway Co., Sponsored Testimony within Section III-A Stand-Alone Traffic Group of Reply Evidence and Argument of Burlington Northern Santa Fe Railway Co.
March 13, 2003	FCC WCB Docket No.03-18. In the Matter of Alascom, Inc. Request for Waiver of Commission Rule and Orders Requiring Annual Tariff Revision, Alascom, Inc. Petition for Waiver, Declaration of Julie Murphy (with John Klick), Alascom's Opposition to General Communication, Inc. FOIA, Control No. 2003-208.
March 5, 2003	FCC WCB Docket No.03-18. In the Matter of Alascom, Inc. Request for Waiver of Commission Rule and Orders Requiring Annual Tariff Revision, Alascom, Inc. Petition for Waiver, Reply Declaration of Julie Murphy (with John Klick).
February 7, 2003	CA PUC Application No. 01-02-024. Joint Application of AT&T Communications of California, Inc. (U 5002 C) and WorldCom, Inc. for the Commission to Reexamine the Recurring Costs and Prices of Unbundled Switching, Loop, Transport and Other Network Elements in Its First Annual Review of Unbundled Network Element Cost Pursuant to Ordering Parag. 11 of D.99-11-050. Reply Declaration of Julie Murphy (with Robert A. Mercer).
January 7, 2003	FCC WCB Docket No. 03-18. In the Matter of Alascom, Inc. Request for Waiver of Commission Rule and Orders Requiring Annual Tariff Revision, Alascom, Inc. Petition for Waiver, Declaration of Julie Murphy (with John Klick).
October 11, 2002	STB Docket No. 42072, Carolina Power & Light Co. v. Norfolk Southern Railway Co., Sponsored Testimony within Section III-A Stand-Alone Traffic Group of Reply Evidence and Argument of Norfolk Southern Railway Co.
September 27, 2002	STB Docket No. 42069, Duke Energy Corporation v. Norfolk Southern Railway Company, Sponsored Testimony within Section III-A Stand-Alone Traffic Group of Reply Evidence and Argument of Norfolk Southern Railway Co.

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September 20, 2002	STB Docket No. 42070, Duke Energy Corporation v. CSX Transportation, Inc., Sponsored Testimony within Section III-A Stand-Alone Traffic Group of Reply Evidence and Argument of CSX Transportation, Inc.

Work History

Georgetown University (Adjunct Professor)	2016 - Present
Navigant Consulting, Inc. (Director)	2011 - Present
LECG, Inc. (Principal)	2004 - 2010
FTI Consulting, Inc. (Manager, Director)	2000 - 2004
LECG, Inc. (Associate, Senior Associate, Economist)	1996 - 2000
American Public Power Association (Research Analyst)	1994 - 1996

Certifications, Memberships and Awards

International Association for Energy Economists
U.S. Association for Energy Economists

Education

Doctoral Studies Program Coursework/M.A., Economics	Pennsylvania State University
Bachelor of Science, Economics	Allegheny College

Exhibit NCI-3

Generation Affiliated with Exelon NE Entities in the Northeast Region and Relevant First-Tier Markets

Balancing Authority Area		Plant Name	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share	Owned and Purchased (MW) Summer	Owned and Purchased (MW) Winter
ISO-NE							
ISO-NE		Wyman (Yarmouth) 4	602.1	605.8	5.90%	35.5	35.7
ISO-NE		Framingham Jet	31.4	43.4	100.00%	31.4	43.4
ISO-NE		West Medway 1-2	81.8	125.6	100.00%	81.8	125.6
ISO-NE		West Medway 3	42.0	64.0	100.00%	42.0	64.0
ISO-NE		New Boston (L Street Jet)	16.0	21.8	100.00%	16.0	21.8
ISO-NE		Mystic 7	570.8	559.8	100.00%	570.8	559.8
ISO-NE		Mystic 8	703.4	841.5	100.00%	703.4	841.5
ISO-NE		Mystic 9	713.9	858.5	100.00%	713.9	858.5
ISO-NE		Mystic Jet	9.1	14.5	100.00%	9.1	14.5
ISO-NE	CT	Kleen Energy (purchase)				622.0	623.0
ISO-NE		Ameresco Northampton (purchase)				0.8	0.8
Subtotal, ISO-NE			**2,770.5**	**3,134.9**		**2,826.7**	**3,188.6**
Subtotal, CT						**622.0**	**623.0**
NYISO							
NYISO		Nine Mile Point [1/]	1,692.3	1,703.8	50.01%	1,692.3	1,703.8
NYISO		Ginna	582.0	583.0	50.01%	582.0	583.0
NYISO		Sale of Nine Mile Point to EDF [2/]				(846.0)	(851.7)
NYISO		Purchase (WM Renewable Energy, LLC)				28.8	28.8
Subtotal, NYISO			**2,274.3**	**2,286.8**		**1,457.1**	**1,463.9**
PJM							
PJM		Braidwood	2,361.0	2,416.0	100.0%	2,361.0	2,416.0
PJM		Byron	2,318.0	2,364.0	100.0%	2,318.0	2,364.0
PJM	5004/5005	Calvert Cliffs [4/]	1,707.8	1,768.0	50.0%	1,707.8	1,768.0
PJM	East	Chester	39.0	54.0	100.0%	39.0	54.0
PJM	East	Conowingo	572.0	572.0	100.0%	572.0	572.0
PJM		Criterion Power	70.0	70.0	100.0%	70.0	70.0
PJM	East	Croydon	392.0	512.0	100.0%	392.0	512.0
PJM	East	Delaware	56.0	74.0	100.0%	56.0	74.0
PJM		Dresden	1,797.0	1,805.0	100.0%	1,797.0	1,805.0
PJM	East	Eddystone	820.0	836.0	100.0%	820.0	836.0
PJM	East	Fairless Hills	60.0	60.0	100.0%	60.0	60.0
PJM	East	Falls	51.0	60.0	100.0%	51.0	60.0
PJM		Fair Wind Facility	30.0	30.0	100.0%	30.0	30.0
PJM		Fourmile Wind	40.0	40.0	100.0%	40.0	40.0
PJM	5004/5005	Gould Street	97.0	97.0	100.0%	97.0	97.0
PJM		Handsome Lake	267.5	267.5	100.0%	267.5	267.5

Exhibit NCI-3

Balancing Authority Area		Plant Name	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share	Owned and Purchased (MW) Summer	Owned and Purchased (MW) Winter
PJM		La Salle	2,271.6	2,313.0	100.0%	2,271.6	2,313.0
PJM	East	Limerick	2,241.8	2,386.0	100.0%	2,241.8	2,386.0
PJM	East	Moser	51.0	60.0	100.0%	51.0	60.0
PJM	East	Muddy Run	1,070.0	1,070.0	100.0%	1,070.0	1,070.0
PJM	5004/5005	Notch Cliff	116.7	116.7	100.0%	116.7	116.7
PJM	East	Oyster Creek	607.7	637.0	100.0%	607.7	637.0
PJM	5004/5005	Peach Bottom (inc. upgrade)	2,450.40	2,658.0	50.0%	1,225.2	1,329.0
PJM	East	Pennsbury	5.4	5.4	100.0%	5.4	5.4
PJM	5004/5005	Perryman	302.6	302.6	100.0%	302.6	302.6
PJM	5004/5005	Perryman 6	110.0	130.0	100.0%	110.0	130.0
PJM	5004/5005	Philadelphia Road	60.9	60.9	100.0%	60.9	60.9
PJM		Quad Cities	1,819.0	1,819.0	75.0%	1,364.3	1,364.3
PJM	East	Richmond	98.0	132.0	100.0%	98.0	132.0
PJM	5004/5005	Riverside	39.0	39.0	100.0%	39.0	39.0
PJM	East	Salem	2,366.6	2,366.6	42.6%	1,007.9	1,007.9
PJM	East	Schuylkill	30.0	38.0	100.0%	30.0	38.0
PJM		Southeast Chicago	296.0	320.0	100.0%	296.0	320.0
PJM	East	Southwark	52.0	72.0	100.0%	52.0	72.0
PJM	5004/5005	Three Mile Island 1	802.8	829.0	100.0%	802.8	829.0
PJM	5004/5005	Westport	115.8	115.8	100.0%	115.8	115.8
PJM	5004/5005	Bethlehem Renewable Plant	4.7	1.2	100.0%	4.7	1.2
PJM	5004/5005	Eastern LFG	3.0	1.5	100.0%	3.0	1.5
PJM	AP South	Fauquier LFG (retired Jan 2016)	2.0	1.0	100.0%	2.0	1.0
PJM		Clinton Battery (2016)	10.0	10.0	100.0%	10.0	10.0
Subtotal, PJM						22,566.7	23,367.8
Long-Term Purchases							
PJM		Elwood Energy, LLC [3/]				600.0	768.0
PJM	5004/5005	Calpine Mid Merit LLC				545.0	545.0
PJM		Cordova Energy Company, LLC				521.2	601.2
PJM		Backbone Mountain Windpower LLC				66.0	66.0
PJM		Bellefontaine Gas Producers, LLC				4.5	4.5
PJM		Forward Wind Power LLC				29.4	29.4
PJM		High Trail Wind Farm, LLC				99.0	99.0
PJM		Mill Run Windpower, LLC				15.6	15.6
PJM		Old Trail Wind Farm, LLC				198.0	198.0
PJM		Patton Wind Farm, LLC				16.0	16.0
PJM		Somerset Windpower, LLC				9.0	9.0
PJM		WM Renewable Energy, LLC				10.1	10.1
PJM	AP South	WM Renewable Energy, LLC				3.8	3.8
PJM	5004/5005	Green Gas Pioneer Crossing Energy, LLC				5.0	5.0
PJM	5004/5005	Green Knight Economic Development Corporation				3.3	3.3

Exhibit NCI-3

Balancing Authority Area		Plant Name	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share	Owned and Purchased (MW) Summer	Owned and Purchased (MW) Winter
PJM	5004/5005	Keystone Solar, L.L.C.				4.9	4.9
PJM	5004/5005	Waymart Wind Farm, L.P.				64.5	64.5
PJM	AP South	Ameresco Stafford, LLC				2.0	2.0
PJM	East	Ameresco Delaware Energy, LLC				7.0	7.0
PJM	East	MF Mesa Lane LLC				3.0	3.0
PJM	East	Chambers Cogeneration				187.6	187.6
PJM	East	Logan Generating				200.0	200.0
PJM		AES Armenia Mountain				50.0	50.0
PJM		Roth Rock				40.0	40.0
PJM		Chestnut Flats				38.0	38.0
Subtotal, PJM						2,722.9	2,970.9
Long-Term Sales							
PJM	5004/5005	CENG sale (Calvert Cliffs) to EDF [4/]				(853.7)	(883.8)
Subtotal, PJM						24,435.9	25,454.9
Subtotal, PJM East						7,551.4	7,973.9
Subtotal, 5004/5005						11,905.9	12,503.5
Subtotal, AP South						11,913.7	12,510.3
First-Tier Markets							
MISO		Beebe Renewable Energy	81.6	81.6	100%	81.6	81.6
MISO		Beebe 1B Renewable Energy, LLC (2014)	50.4	50.4	100%	50.4	50.4
MISO		Clinton	1,065.0	1,078.0	100%	1,065.0	1,078.0
MISO		Harvest Windfarm	52.8	52.8	100%	52.8	52.8
MISO		Harvest II Windfarm	59.4	59.4	100%	59.4	59.4
MISO		Michigan Wind 1	69.0	69.0	100%	69.0	69.0
MISO		Michigan Wind 2	90.0	90.0	100%	90.0	90.0
Long-Term Purchases							
MISO		Tenaska Frontier				870.0	936.0
MISO		Pioneer Trail Wind Farm, LLC				110.4	110.4
Subtotal, MISO			1,468.2	1,481.2		2,448.6	2,527.6

Plant ratings based on 2015 EIA-860 data
https://www.eia.gov/electricity/data/eia860/

1/ Total capacity reflects 100% of unit 1 and 82% of unit 2. The remaining 18% of unit 2 is owned by Long Island Power Authority.

2/ A subsidiary of Electricite de France SA ("EDF"), which owns the other 49.99% of Constellation Energy Nuclear Group, Inc. ("CENG") (owner of the nuclear plants), purchases on a unit-contingent basis 49.99 percent of the nuclear plant output owned by CENG not sold to third parties. The sale represents 49.99% of CENG's share of Nine Mile Point.

3/ The current PPA is only 300 MW PPA. Another PPA was terminated August 16, 2016.

4/ A subsidiary of Electricite de France SA ("EDF"), which owns the other 49.99% of Constellation Energy Nuclear Group, Inc. ("CENG") (owner of the nuclear plants), purchases on a unit-contingent basis 49.99 percent of the nuclear plant output owned by CENG not sold to third parties. The sale represents 49.99% of CENG's share of Calvert Cliff.

Market/ Submarket	Exhibit	Pivotal Supplier Analysis	Exhibit	Market Share Analysis			
				Winter	Spring	Summer	Fall
PJM	NCI-5	Pass	NCI-6	10.6%	10.4%	9.0%	9.9%
PJM East	NCI-7	Pass	NCI-8	18.8%	17.7%	18.0%	15.9%
5004/5005	NCI-9	Pass	NCI-10	16.1%	16.4%	11.6%	12.7%
AP South	NCI-11	Pass	NCI-12	12.1%	12.3%	8.7%	9.4%
ISO-NE	NCI-13	Pass	NCI-14	0.0%	0.0%	0.0%	0.0%
CT	NCI-15	Pass	NCI-16	0.0%	0.0%	0.0%	0.0%
NYISO	NCI-17	Pass	NCI-18	4.1%	1.7%	0.4%	0.6%

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Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **PJM**
Data Year -> **Dec 2014-Nov 2015**

Row				Reference
	Generation			
	Seller and Affiliate Capacity (owned or controlled)			
A	Installed Capacity (from inside the study area)		22,567	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)		0	
B	Long-Term Firm Purchases (from inside the study area)		2,723	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)		0	
C	Long-Term Firm Sales (in and outside the study area)		854	Exhibit NCI-3
D	Uncommitted Capacity Imports		194	Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)			
E	Installed Capacity (from inside the study area)		160,493	Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)		0	
F	Long-Term Firm Purchases (from inside the study area)		854	Offset Row C
F1	Long-Term Firm Purchases (from outside the study area)		0	
G	Long-Term Firm Sales (in and outside the study area)		2,723	Offset Row B
H	Uncommitted Capacity Imports		7,406	Wkp - SILs, less Row D
I	Study Area Reserve Requirement		9,097	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any		0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)		59,963	
	Load			
L	Balancing Authority Area Annual Peak Load		143,633	Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month		121,600	Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any		19,538	Wkp - Exelon Load Summary
O	Wholesale Load (L-M)		22,033	
P	Net Uncommitted Supply (K-O)		37,930	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)		5,092	
Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)			**Pass**	
		Total Imports (Sum D,H), as filed by Seller ->	7,600	
		% of SIL for Seller's imported capacity ->	0.03	
		% of SIL for Other's imported capacity ->	0.97	
		SIL value ->	7,600	PJM Interconnection 2015 SIL Study
		Do Total Imports exceed the SIL value? ->	No	

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Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **PJM**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled or under LT contract)					
A	Installed Capacity (inside the study area)	23,368	23,368	22,567	23,368	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0	0	0	0	
B	Long-Term Firm Purchases (inside the study area)	2,971	2,971	2,723	2,971	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
C	Long-Term Firm Sales (in and outside the study area)	884	884	854	884	Exhibit NCI-3
D	Seasonal Average Planned Outages	979	3,106	524	2,981	Pro Rata Share of Outages
E	Uncommitted Capacity Imports	290	278	199	154	Wkp - Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	112,390	94,917	117,821	95,173	Wkp - Summary of Inputs Data
G	Amount of Line F Attributable to Seller, if any	16,011	14,104	18,740	15,366	Wkp - Exelon Load Summary
H	Amount of Line F Attributable to Non-Affiliates, if any	96,379	80,813	99,081	79,807	
I	Study Area Reserve Requirement	8,067	6,367	9,097	6,391	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	
K	Amount of Line I Attributable to Non-Affiliates, if any	8,067	6,367	9,097	6,391	
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	176,232	173,322	160,493	169,417	Wkp - Summary of Inputs Data, less Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	
M	Long-Term Firm Purchases (inside the study area)	884	884	854	884	Offset Row C
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
N	Long-Term Firm Sales (in and outside the study area)	2,971	2,971	2,723	2,971	Offset Row B
O	Seasonal Average Planned Outages	7,380	23,036	3,730	21,608	Wkp - Summary of Inputs Data, less Row D
P	Uncommitted Capacity Imports	11,707	12,445	7,401	6,913	Wkp - SILs, less Row E
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	74,026	73,464	54,118	66,437	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	8,755	8,523	5,370	7,262	
S	Total Seasonal Uncommitted Capacity (Q+R)	82,781	81,987	59,488	73,699	
T	**Seller's Market Share** (R÷S)	10.6%	10.4%	9.0%	9.9%	
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass	
U	Total Imports, as filed by Seller (E+P)	11,997	12,723	7,600	7,067	
V	SIL value*	11,997	12,723	7,600	7,067	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No	

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Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **PJM East**
Data Year -> **Dec 2014-Nov 2015**

Row				Reference
	Generation			
	Seller and Affiliate Capacity (owned or controlled)			
A	Installed Capacity (from inside the study area)	7,154		Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0		
B	Long-Term Firm Purchases (from inside the study area)	398		Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0		
C	Long-Term Firm Sales (in and outside the study area)	0		
D	Uncommitted Capacity Imports	291		Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)			
E	Installed Capacity (from inside the study area)	27,476		Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)	0		
F	Long-Term Firm Purchases (from inside the study area)	0		
F1	Long-Term Firm Purchases (from outside the study area)	0		
G	Long-Term Firm Sales (in and outside the study area)	398		Offset Row B
H	Uncommitted Capacity Imports	6,246		Wkp - SILs, less Row D
I	Study Area Reserve Requirement	1,429		Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0		
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)		15,645	
	Load			
L	Balancing Authority Area Annual Peak Load	30,240		Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month	24,093		Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any	5,063		Wkp - Exelon Load Summary
O	Wholesale Load (L-M)		6,147	
P	Net Uncommitted Supply (K-O)		9,498	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)		2,780	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)		**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->		6,537	
	% of SIL for Seller's imported capacity ->		0.04	
	% of SIL for Other's imported capacity ->		0.96	
	SIL value ->	6,537		PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->		No	

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Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **PJM East**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled or under LT contract)					
A	Installed Capacity (inside the study area)	7,576	7,576	7,154	7,576	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0	0	0	0	
B	Long-Term Firm Purchases (inside the study area)	398	398	398	398	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	
D	Seasonal Average Planned Outages	317	1,007	166	966	Pro Rata Share of Outages
E	Uncommitted Capacity Imports	532	612	318	484	Wkp - Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	19,303	16,803	22,934	17,326	Wkp - Summary of Inputs Data
G	Amount of Line F Attributable to Seller, if any	3,767	3,417	4,819	3,923	Wkp - Exelon Load Summary
H	Amount of Line F Attributable to Non-Affiliates, if any	15,536	13,386	18,115	13,403	
I	Study Area Reserve Requirement	1,145	996	1,360	1,027	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	
K	Amount of Line I Attributable to Non-Affiliates, if any	1,145	996	1,360	1,027	
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	30,540	29,831	27,476	30,159	Wkp - Summary of Inputs Data, less Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
N	Long-Term Firm Sales (in and outside the study area)	398	398	398	398	Offset Row B
O	Seasonal Average Planned Outages	1,279	3,965	639	3,847	Wkp - Summary of Inputs Data, less Row D
P	Uncommitted Capacity Imports	6,970	8,218	6,219	7,375	Wkp - SILs, less Row E
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	19,152	19,304	13,184	18,860	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	4,422	4,162	2,884	3,568	
S	Total Seasonal Uncommitted Capacity (Q+R)	23,574	23,466	16,068	22,428	
T	**Seller's Market Share** (R÷S)	18.8%	17.7%	18.0%	15.9%	
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass	
U	Total Imports, as filed by Seller (E+P)	7,502	8,830	6,537	7,859	
V	SIL value*	7,502	8,830	6,537	7,859	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No	

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Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **5004/5005**
Data Year -> **Dec 2014-Nov 2015**

Row			
	Generation		**Reference**
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	11,739	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0	
B	Long-Term Firm Purchases (from inside the study area)	1,020	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	
C	Long-Term Firm Sales (in and outside the study area)	854	Exhibit NCI-3
D	Uncommitted Capacity Imports	407	Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	44,075	Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)	0	
F	Long-Term Firm Purchases (from inside the study area)	854	Offset Row C
F1	Long-Term Firm Purchases (from outside the study area)	0	
G	Long-Term Firm Sales (in and outside the study area)	1,020	Offset Row B
H	Uncommitted Capacity Imports	5,912	Wkp - SILs, less Row D
I	Study Area Reserve Requirement	2,512	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	17,253	
	Load		
L	Balancing Authority Area Annual Peak Load	52,190	Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month	42,368	Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any	10,376	Wkp - Exelon Load Summary
O	Wholesale Load (L-M)	9,822	
P	Net Uncommitted Supply (K-O)	7,431	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,936	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->	6,319	
	% of SIL for Seller's imported capacity ->	0.06	
	% of SIL for Other's imported capacity ->	0.94	
	SIL value ->	6,319	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->	No	

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Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **5004/5005**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled or under LT contract)					
A	Installed Capacity (inside the study area)	12,367	12,367	11,739	12,367	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0	0	0	0	
B	Long-Term Firm Purchases (inside the study area)	1,020	1,020	1,020	1,020	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
C	Long-Term Firm Sales (in and outside the study area)	884	884	854	884	Exhibit NCI-3
D	Seasonal Average Planned Outages	518	1,644	273	1,577	Pro Rata Share of Outages
E	Uncommitted Capacity Imports	627	583	435	440	Wkp - Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	36,840	31,515	40,748	31,648	Wkp - Summary of Inputs Data
G	Amount of Line F Attributable to Seller, if any	8,348	7,135	10,017	8,235	Wkp - Exelon Load Summary
H	Amount of Line F Attributable to Non-Affiliates, if any	28,492	24,380	30,731	23,413	
I	Study Area Reserve Requirement	2,185	1,869	2,416	1,877	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	
K	Amount of Line I Attributable to Non-Affiliates, if any	2,185	1,869	2,416	1,877	
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	47,624	46,915	44,075	47,374	Wkp - Summary of Inputs Data, less Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	
M	Long-Term Firm Purchases (inside the study area)	884	884	854	884	Offset Row C
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
N	Long-Term Firm Sales (in and outside the study area)	1,020	1,020	1,020	1,020	Offset Row B
O	Seasonal Average Planned Outages	1,994	6,235	1,024	6,043	Wkp - Summary of Inputs Data, less Row D
P	Uncommitted Capacity Imports	7,477	7,710	5,884	5,663	Wkp - SILs, less Row E
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	22,294	22,005	15,622	21,568	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	4,264	4,308	2,050	3,131	
S	Total Seasonal Uncommitted Capacity (Q+R)	26,558	26,312	17,672	24,699	
T	**Seller's Market Share** (R÷S)	16.1%	16.4%	11.6%	12.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass	
U	Total Imports, as filed by Seller (E+P)	8,104	8,293	6,319	6,103	
V	SIL value*	8,104	8,293	6,319	6,103	
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No	PJM Interconnection 2015 SIL Study

Exhibit NCI-11

Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **AP South**
Data Year -> **Dec 2014-Nov 2015**

Row			
	Generation		**Reference**
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	11,741	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0	
B	Long-Term Firm Purchases (from inside the study area)	1,026	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	
C	Long-Term Firm Sales (in and outside the study area)	854	Exhibit NCI-3
D	Uncommitted Capacity Imports	331	Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	67,228	Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)	0	
F	Long-Term Firm Purchases (from inside the study area)	854	Offset Row C
F1	Long-Term Firm Purchases (from outside the study area)	0	
G	Long-Term Firm Sales (in and outside the study area)	1,026	Offset Row B
H	Uncommitted Capacity Imports	4,124	Wkp - SILs, less Row D
I	Study Area Reserve Requirement	2,868	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	22,448	
	Load		
L	Balancing Authority Area Annual Peak Load	70,729	Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month	58,108	Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any	10,376	Wkp - Exelon Load Summary
O	Wholesale Load (L-M)	12,621	
P	Net Uncommitted Supply (K-O)	9,827	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,868	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->	4,455	
	% of SIL for Seller's imported capacity ->	0.07	
	% of SIL for Other's imported capacity ->	0.93	
	SIL value ->	4,455	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->	No	

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Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **AP South**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled or under LT contract)					
A	Installed Capacity (inside the study area)	12,368	12,368	11,741	12,368	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0	0	0	0	
B	Long-Term Firm Purchases (inside the study area)	1,026	1,026	1,026	1,026	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
C	Long-Term Firm Sales (in and outside the study area)	884	884	854	884	Exhibit NCI-3
D	Seasonal Average Planned Outages	518	1,644	273	1,577	Pro Rata Share of Outages
E	Uncommitted Capacity Imports	720	733	353	515	Wkp - Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	51,170	43,394	56,097	43,262	Wkp - Summary of Inputs Data
G	Amount of Line F Attributable to Seller, if any	8,453	7,202	10,017	8,235	Wkp - Exelon Load Summary
H	Amount of Line F Attributable to Non-Affiliates, if any	42,717	36,192	46,080	35,027	
I	Study Area Reserve Requirement	2,552	2,266	2,772	2,230	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	
K	Amount of Line I Attributable to Non-Affiliates, if any	2,552	2,266	2,772	2,230	
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	72,170	71,461	67,228	71,825	Wkp - Summary of Inputs Data, less Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	
M	Long-Term Firm Purchases (inside the study area)	884	884	854	884	Offset Row C
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
N	Long-Term Firm Sales (in and outside the study area)	1,026	1,026	1,026	1,026	Offset Row B
O	Seasonal Average Planned Outages	3,022	9,497	1,562	9,161	Wkp - Summary of Inputs Data, less Row D
P	Uncommitted Capacity Imports	7,177	8,123	4,102	5,553	Wkp - SILs, less Row E
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	30,914	31,487	20,744	30,818	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	4,259	4,397	1,976	3,213	
S	Total Seasonal Uncommitted Capacity (Q+R)	35,173	35,884	22,720	34,031	
T	**Seller's Market Share** (R÷S)	12.1%	12.3%	8.7%	9.4%	
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass	
U	Total Imports, as filed by Seller (E+P)	7,897	8,856	4,455	6,068	
V	SIL value*	7,897	8,856	4,455	6,068	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No	

Exhibit NCI-13

Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **ISO-NE**
Data Year -> **Dec 2014-Nov 2015**

Row				Reference
	Generation			
	Seller and Affiliate Capacity (owned or controlled)			
A	Installed Capacity (from inside the study area)	2,204		Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0		
B	Long-Term Firm Purchases (from inside the study area)	623		Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0		
C	Long-Term Firm Sales (in and outside the study area)	0		
D	Uncommitted Capacity Imports	0		Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)			
E	Installed Capacity (from inside the study area)	31,220		Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)	0		
F	Long-Term Firm Purchases (from inside the study area)	0		
F1	Long-Term Firm Purchases (from outside the study area)	0		
G	Long-Term Firm Sales (in and outside the study area)	623		Offset Row B
H	Uncommitted Capacity Imports	4,548		Wkp - SILs, less Row D
I	Study Area Reserve Requirement	1,310		Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0		
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)		17,041	
	Load			
L	Balancing Authority Area Annual Peak Load	24,437		Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month	19,621		Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any	4,000		Wkp - Exelon Load Summary
O	Wholesale Load (L-M)		4,816	
P	Net Uncommitted Supply (K-O)		12,225	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)		0	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)		**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->		4,548	
	% of SIL for Seller's imported capacity ->		0.00	
	% of SIL for Other's imported capacity ->		1.00	
	SIL value ->	4,548		PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->		No	

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Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **ISO-NE**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled or under LT contract)					
A	Installed Capacity (inside the study area)	2,565	2,565	2,204	2,565	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0	0	0	0	
B	Long-Term Firm Purchases (inside the study area)	624	624	623	624	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	
D	Seasonal Average Planned Outages	81	233	16	213	Pro Rata Share of Outages
E	Uncommitted Capacity Imports	47	0	0	0	Wkp - Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	18,391	15,604	18,719	16,307	Wkp - Summary of Inputs Data
G	Amount of Line F Attributable to Seller, if any	3,627	3,224	4,080	3,720	Wkp - Exelon Load Summary
H	Amount of Line F Attributable to Non-Affiliates, if any	14,764	12,380	14,639	12,587	
I	Study Area Reserve Requirement	1,562	1,436	1,310	1,436	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	
K	Amount of Line I Attributable to Non-Affiliates, if any	1,562	1,436	1,310	1,436	
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	33,011	33,011	31,220	33,011	Wkp - Summary of Inputs Data, less Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
N	Long-Term Firm Sales (in and outside the study area)	624	624	623	624	Offset Row B
O	Seasonal Average Planned Outages	1,046	3,001	220	2,747	Wkp - Summary of Inputs Data, less Row D
P	Uncommitted Capacity Imports	4,501	4,548	4,548	4,548	Wkp - SILs, less Row E
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	19,517	20,119	18,976	20,166	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	0	0	0	0	
S	Total Seasonal Uncommitted Capacity (Q+R)	19,517	20,119	18,976	20,166	
T	**Seller's Market Share** (R÷S)	0.0%	0.0%	0.0%	0.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass	
U	Total Imports, as filed by Seller (E+P)	4,548	4,548	4,548	4,548	
V	SIL value*	4,548	4,548	4,548	4,548	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No	

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Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **CT**
Data Year -> **Dec 2014-Nov 2015**

Row				Reference
	Generation			
	Seller and Affiliate Capacity (owned or controlled)			
A	Installed Capacity (from inside the study area)		0	
A1	Remote Capacity (from outside the study area)		0	
B	Long-Term Firm Purchases (from inside the study area)		622	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)		0	
C	Long-Term Firm Sales (in and outside the study area)		0	
D	Uncommitted Capacity Imports		0	Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)			
E	Installed Capacity (from inside the study area)		7,789	Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)		0	
F	Long-Term Firm Purchases (from inside the study area)		0	
F1	Long-Term Firm Purchases (from outside the study area)		0	
G	Long-Term Firm Sales (in and outside the study area)		622	Offset Row B
H	Uncommitted Capacity Imports		3,050	Wkp - SILs, less Row D
I	Study Area Reserve Requirement		714	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any		0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	5,071		
	Load			
L	Balancing Authority Area Annual Peak Load		6,419	Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month		5,054	Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any		1,470	Wkp - Exelon Load Summary
O	Wholesale Load (L-M)	1,365		
P	Net Uncommitted Supply (K-O)	3,706		
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	0		
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**		
	Total Imports (Sum D,H), as filed by Seller ->	3,050		
	% of SIL for Seller's imported capacity ->	0.00		
	% of SIL for Other's imported capacity ->	1.00		
	SIL value ->		3,050	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->	No		

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Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **CT**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled or under LT contract)					
A	Installed Capacity (inside the study area)	0	0	0	0	
A1	Remote Capacity (from outside the study area)	0	0	0	0	
B	Long-Term Firm Purchases (inside the study area)	623	623	622	623	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	
D	Seasonal Average Planned Outages	0	0	0	0	
E	Uncommitted Capacity Imports	28	0	0	0	Wkp - Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	4,497	3,789	4,827	4,005	Wkp - Summary of Inputs Data
G	Amount of Line F Attributable to Seller, if any	1,012	868	1,304	1,197	Wkp - Exelon Load Summary
H	Amount of Line F Attributable to Non-Affiliates, if any	3,485	2,921	3,523	2,808	
I	Study Area Reserve Requirement	363	539	714	539	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	
K	Amount of Line I Attributable to Non-Affiliates, if any	363	539	714	539	
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	8,213	8,213	7,789	8,213	Wkp - Summary of Inputs Data, less Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
N	Long-Term Firm Sales (in and outside the study area)	623	623	622	623	Offset Row B
O	Seasonal Average Planned Outages	260	747	55	683	Wkp - Summary of Inputs Data, less Row D
P	Uncommitted Capacity Imports	3,022	3,050	3,050	3,050	Wkp - SILs, less Row E
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	6,504	6,433	5,925	6,610	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	0	0	0	0	
S	Total Seasonal Uncommitted Capacity (Q+R)	6,504	6,433	5,925	6,610	
T	**Seller's Market Share** (R÷S)	0.0%	0.0%	0.0%	0.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass	
U	Total Imports, as filed by Seller (E+P)	3,050	3,050	3,050	3,050	
V	SIL value*	3,050	3,050	3,050	3,050	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No	

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Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **NYISO**
Data Year -> **Dec 2014-Nov 2015**

Row				Reference
	Generation			
	Seller and Affiliate Capacity (owned or controlled)			
A	Installed Capacity (from inside the study area)		2,274	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)		0	
B	Long-Term Firm Purchases (from inside the study area)		29	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)		0	
C	Long-Term Firm Sales (in and outside the study area)		846	Exhibit NCI-3
D	Uncommitted Capacity Imports		414	Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)			
E	Installed Capacity (from inside the study area)		36,391	Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)		0	
F	Long-Term Firm Purchases (from inside the study area)		846	Offset Row C
F1	Long-Term Firm Purchases (from outside the study area)		0	
G	Long-Term Firm Sales (in and outside the study area)		29	Offset Row B
H	Uncommitted Capacity Imports		7,281	Wkp - SILs, less Row D
I	Study Area Reserve Requirement		2,620	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any		0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)		18,496	
	Load			
L	Balancing Authority Area Annual Peak Load		31,138	Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month		25,244	Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any		1,774	Wkp - Exelon Load Summary
O	Wholesale Load (L-M)		5,894	
P	Net Uncommitted Supply (K-O)		12,602	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)		97	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)		**Pass**	
		Total Imports (Sum D,H), as filed by Seller ->	7,695	
		% of SIL for Seller's imported capacity ->	0.05	
		% of SIL for Other's imported capacity ->	0.95	
		SIL value ->	7,695	PJM Interconnection 2015 SIL Study
		Do Total Imports exceed the SIL value? ->	No	

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Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **NYISO**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled or under LT contract)					
A	Installed Capacity (inside the study area)	2,287	2,287	2,274	2,287	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0	0	0	0	
B	Long-Term Firm Purchases (inside the study area)	29	29	29	29	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
C	Long-Term Firm Sales (in and outside the study area)	852	852	846	852	Exhibit NCI-3
D	Seasonal Average Planned Outages	187	331	43	265	Pro Rata Share of Outages
E	Uncommitted Capacity Imports	625	542	456	526	Wkp - Import Allocation
	Capacity Deductions					
F	Average Peak Native Load in the Season	22,045	19,393	24,144	20,374	Wkp - Summary of Inputs Data
G	Amount of Line F Attributable to Seller, if any	1,053	1,345	1,785	1,610	Wkp - Exelon Load Summary
H	Amount of Line F Attributable to Non-Affiliates, if any	20,992	18,048	22,359	18,764	
I	Study Area Reserve Requirement	2,620	2,620	2,620	2,620	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	
K	Amount of Line I Attributable to Non-Affiliates, if any	2,620	2,620	2,620	2,620	
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	38,726	38,726	36,391	38,726	Wkp - Summary of Inputs Data, less Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	
M	Long-Term Firm Purchases (inside the study area)	852	852	846	852	Offset Row C
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	
N	Long-Term Firm Sales (in and outside the study area)	29	29	29	29	Offset Row B
O	Seasonal Average Planned Outages	3,161	5,604	696	4,478	Wkp - Summary of Inputs Data, less Row D
P	Uncommitted Capacity Imports	6,899	6,308	7,239	7,109	Wkp - SILs, less Row E
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	19,674	19,585	18,773	20,795	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	850	330	84	116	
S	Total Seasonal Uncommitted Capacity (Q+R)	20,524	19,915	18,857	20,911	
T	**Seller's Market Share** (R÷S)	4.1%	1.7%	0.4%	0.6%	
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass	
U	Total Imports, as filed by Seller (E+P)	7,524	6,850	7,695	7,635	
V	SIL value*	7,524	6,850	7,695	7,635	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No	

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Atlantic City Electric Company	)	**Docket No. ER10-2997-___**
Baltimore Gas and Electric Company	)	**Docket No. ER10-2175-___**
Bethlehem Renewable Energy, LLC	)	**Docket No. ER10-3003-___**
Commonwealth Edison Company	)	**Docket No. ER10-1048-___**
Constellation Energy Commodities Group Maine, LLC	)	**Docket No. ER10-2192-__**
Constellation Energy Services, Inc.	)	**Docket No. ER15-1537-__**
Constellation Energy Services of New York, Inc.	)	**Docket No. ER15-1539-__**
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Constellation NewEnergy, Inc.	)	**Docket No. ER10-2178-__**
Constellation Power Source Generation, LLC	)	**Docket No. ER14-1524-__**
Clinton Battery Utility, LLC	)	**Docket No. ER16-2194-__**
Criterion Power Partners, LLC	)	**Docket No. ER10-3308-__**
Delmarva Power & Light Company	)	**Docket No. ER10-3018-__**
Eastern Landfill Gas, LLC	)	**Docket No. ER10-3015-__**
Exelon Framingham, LLC	)	**Docket No. ER10-1020-__**
Exelon Generation Company, LLC	)	**Docket No. ER13-1536-__**
Exelon New Boston, LLC	)	**Docket No. ER10-1078-__**
Exelon West Medway, LLC	)	**Docket No. ER10-1080-__**
Exelon West Medway II, LLC	)	**Docket No. ER16-2708-__**
Exelon Wyman, LLC	)	**Docket No. ER10-1081-__**
Fair Wind Power Partners, LLC	)	**Docket No. ER15-2293-__**
Fourmile Wind Energy, LLC	)	**Docket No. ER14-2145-__**
Handsome Lake Energy, LLC	)	**Docket No. ER10-2180-__**
PECO Energy Company	)	**Docket No. ER14-767-__**
Pepco Energy Services, Inc.	)	**Docket No. ER10-2992-__**
Potomac Electric Power Company	)	**Docket No. ER10-3030-__**

AFFIDAVIT

District of Columbia §
§
§

JULIE R. SOLOMON being duly sworn, deposes and states: that she prepared the Affidavit and Exhibits of Julie R. Solomon and Julie M Carey and that the statements contained therein and the Exhibits attached hereto are true and correct to the best of her knowledge and belief.

Julie R. Solomon

SUBSCRIBED AND SWORN TO BEFORE ME, this the 21st day of December 2016.

JANET P. CASHION NOTARY PUBLIC MY COMMISSION EXPIRES 7/14/2017 DISTRICT OF COLUMBIA

Notary Public, District of Columbia

Printed Name: Janet P. Cashion

My Commission Expires: July 14, 2017

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UNITED STATES OF AMERICA
BEFORE THE
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Delmarva Power & Light Company	)	**Docket No. ER10-3018-__**
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Pepco Energy Services, Inc.	)	**Docket No. ER10-2992-__**
Potomac Electric Power Company	)	**Docket No. ER10-3030-__**

AFFIDAVIT

District of Columbia §
§
§

JULIE M. CAREY being duly sworn, deposes and states: that she prepared the Affidavit and Exhibits of Julie R. Solomon and Julie M Carey and that the statements contained therein and the Exhibits attached hereto are true and correct to the best of her knowledge and belief.

Julie M Carey

Julie M. Carey

SUBSCRIBED AND SWORN TO BEFORE ME, this the 22 day of December 2016.

AVIS M. DICKENS NOTARY PUBLIC MY COMMISSION EXPIRES 3/31/2019 DISTRICT OF COLUMBIA

Avis M Dickens

Notary Public, District of Columbia

Printed Name: Avis M Dickens

My Commission Expires: 3/31/2019

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Attachment B:
Proposed Protective Order

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UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

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Fourmile Wind Energy, LLC	**)**	**Docket No. ER14-2145-___**
Handsome Lake Energy, LLC	**)**	**Docket No. ER10-2180-___**
PECO Energy Company	**)**	**Docket No. ER10-1143-___**
Pepco Energy Services, Inc.	**)**	**Docket No. ER10-2992-___**
Potomac Electric Power Company	**)**	**Docket No. ER10-3030-___**

PROTECTIVE ORDER

(Issued ___)

1. This Protective Order shall govern the use of all Privileged Materials produced by, or on behalf of, any Participant. Notwithstanding any order terminating this proceeding, this Protective Order shall remain in effect until specifically modified or terminated by the Presiding Administrative Law Judge (Presiding Judge) or the Chief Administrative Law Judge (Chief Judge) or the Federal Energy Regulatory Commission (Commission).

2. This Protective Order applies to the following two categories of materials: (A) A Participant may designate as privileged those materials which customarily are treated by that Participant as sensitive or proprietary, which are not available to the public, and which, if disclosed freely, would subject that Participant or its customers to risk of competitive disadvantage or other business injury; and (B) A Participant shall designate as privileged those materials which contain critical energy infrastructure information, as defined in 18 CFR § 388.113(c)(1) (Critical Energy Infrastructure Information).

3. Definitions -- For purposes of this Order:

(a) The term "Participant" shall mean a Participant as defined in 18 CFR § 385.102(b).

(b) (1) The term "Privileged Materials" means (A) materials (including depositions) provided by a Participant in response to discovery requests and designated by such Participant as privileged; (B) any information contained in or obtained from such designated materials; (C) any other materials which are made subject to this Protective Order by the Presiding Judge or the Chief Judge, by the Commission, by any court or other body having appropriate authority, or by agreement of the Participants; (D) notes of Privileged Materials; and (E) copies of Privileged Materials. The Participant producing the Privileged Materials shall physically mark them on each page as "PRIVILEGED MATERIALS" or with words of similar import as long as the term "Privileged Materials" is included in that designation to indicate that they are Privileged Materials. If the Privileged Materials contain Critical Energy Infrastructure Information, the Participant producing such information shall additionally mark on each page containing such information the words "Contains Critical Energy Infrastructure Information – Do Not Release."

(2) The term "Notes of Privileged Materials" means memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses materials described in Paragraph 3(b)(1). Notes of Privileged Materials are subject to the same restrictions provided in this order for Privileged Materials except as specifically provided in this order.

(3) Privileged Materials shall not include (A) any information or document that has been filed with and accepted into the public files of the Commission, or contained in the public files of any other federal or state agency, or any federal or state court, unless the information or document has been determined to be privileged by such agency or court, or (B) information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Protective Order, or (C) any information or document labeled as "Non-Internet Public" by a Participant, in accordance with Paragraph 30 of FERC Order No. 630, FERC Stat. & Reg. ¶ 31,140. Privileged Materials do include any information or document contained in the files of the Commission that has been designated as Critical Energy Infrastructure Information.

(c) The term "Non-Disclosure Certificate" shall mean the certificate annexed hereto by which Participants who have been granted access to Privileged Materials shall

certify their understanding that such access to Privileged Materials is provided pursuant to the terms and restrictions of this Protective Order, and that such Participants have read the Protective Order and agree to be bound by it. All Non-Disclosure Certificates shall be served on all parties on the official service list maintained by the Secretary in this proceeding.

(d) The term "Reviewing Representative" shall mean a person who has signed a Non-Disclosure Certificate and who is:

(1) Commission Trial Staff designated as such in this proceeding;

(2) an attorney who has made an appearance in this proceeding for a Participant;

(3) attorneys, paralegals, and other employees associated for purposes of this case with an attorney described in Subparagraph (2);

(4) an expert or an employee of an expert retained by a Participant for the purpose of advising, preparing for or testifying in this proceeding;

(5) a person designated as a Reviewing Representative by order of the Presiding Judge or the Chief Judge or the Commission; or

(6) employees or other representatives of Participants appearing in this proceeding with significant responsibility for this docket.

4. Privileged Materials shall be made available under the terms of this Protective Order only to Participants and only to their Reviewing Representatives as provided in Paragraphs 7-9.

5. Privileged Materials shall remain available to Participants until the later of the date that an order terminating this proceeding becomes no longer subject to judicial review, or the date that any other Commission proceeding relating to the Privileged Material is concluded and no longer subject to judicial review. If requested to do so in writing after that date, the Participants shall, within fifteen days of such request, return the Privileged Materials (excluding Notes of Privileged Materials) to the Participant that produced them, or shall destroy the materials, except that copies of filings, official transcripts and exhibits in this proceeding that contain Privileged Materials, and Notes of Privileged Material may be retained, if they are maintained in accordance with Paragraph 6, below. Within such time period each Participant, if requested to do so, shall also submit to the producing Participant an affidavit stating that, to the best of its knowledge, all Privileged Materials and all Notes of Privileged Materials have been returned or have been destroyed or will be maintained in accordance with Paragraph 6. To the extent Privileged Materials are not returned or destroyed, they shall remain subject to the Protective Order.

6. All Privileged Materials shall be maintained by the Participant in a secure place. Access to those materials shall be limited to those Reviewing Representatives specifically authorized pursuant to Paragraphs 8-9. The Secretary shall place any Privileged Materials filed with the Commission in a non-public file. By placing such documents in a non-public file, the Commission is not making a determination of any claim of privilege. The Commission retains the right to make determinations regarding any claim of privilege and the discretion to release information necessary to carry out its jurisdictional responsibilities. For documents submitted to Commission Trial Staff (Staff), Staff shall follow the notification procedures of 18 CFR § 388.112 before making public any Privileged Materials.

7. Privileged Materials shall be treated as privileged by each Participant and by the Reviewing Representative in accordance with the certificate executed pursuant to Paragraph 9. Privileged Materials shall not be used except as necessary for the conduct of this proceeding, nor shall they be disclosed in any manner to any person except a Reviewing Representative who is engaged in the conduct of this proceeding and who needs to know the information in order to carry out that person's responsibilities in this proceeding. Reviewing Representatives may make copies of Privileged Materials, but such copies become Privileged Materials. Reviewing Representatives may make notes of Privileged Materials, which shall be treated as Notes of Privileged Materials if they disclose the contents of Privileged Materials.

8. (a) If a Reviewing Representative's scope of employment includes the marketing of energy, the direct supervision of any employee or employees whose duties include the marketing of energy, the provision of consulting services to any person whose duties include the marketing of energy, or the direct supervision of any employee or employees whose duties include the marketing of energy, such Reviewing Representative may not use information contained in any Privileged Materials obtained through this proceeding to give any Participant or any competitor of any Participant a commercial advantage.

(b) In the event that a Participant wishes to designate as a Reviewing Representative a person not described in Paragraph 3 (d) above, the Participant shall seek agreement from the Participant providing the Privileged Materials. If an agreement is reached that person shall be a Reviewing Representative pursuant to Paragraphs 3(d) above with respect to those materials. If no agreement is reached, the Participant shall submit the disputed designation to the Presiding Judge for resolution.

9. (a) A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Privileged Materials pursuant to this Protective Order unless that Reviewing Representative has first executed a Non-Disclosure Certificate; provided, that if an attorney qualified as a Reviewing Representative has executed such a certificate, the paralegals, secretarial and clerical personnel under the attorney’s instruction, supervision or control need not do so. A copy of each Non-Disclosure Certificate shall be provided to counsel for the Participant

asserting privilege prior to disclosure of any Privileged Material to that Reviewing Representative.

(b) Attorneys qualified as Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this order.

10. Any Reviewing Representative may disclose Privileged Materials to any other Reviewing Representative as long as the disclosing Reviewing Representative and the receiving Reviewing Representative both have executed a Non-Disclosure Certificate. In the event that any Reviewing Representative to whom the Privileged Materials are disclosed ceases to be engaged in these proceedings, or is employed or retained for a position whose occupant is not qualified to be a Reviewing Representative under Paragraph 3(d), access to Privileged Materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Non-Disclosure Certificate shall continue to be bound by the provisions of this Protective Order and the certification.

11. Subject to Paragraph 18, the Presiding Judge or the Chief Judge or the Commission shall resolve any disputes arising under this Protective Order. Prior to presenting any dispute under this Protective Order to the Presiding Judge or the Chief Judge or the Commission, the parties to the dispute shall use their best efforts to resolve it. Any Participant that contests the designation of materials as privileged shall notify the Participant that provided the privileged materials by specifying in writing the materials the designation of which is contested. This Protective Order shall automatically cease to apply to such materials five (5) business days after the notification is made unless the designator, within said 5-day period, files a motion with the Presiding Judge or the Chief Judge or the Commission, with supporting affidavits, demonstrating that the materials should continue to be privileged. In any challenge to the designation of materials as privileged, the burden of proof shall be on the Participant seeking protection. If the Presiding Judge or the Chief Judge or the Commission finds that the materials at issue are not entitled to privilege, the procedures of Paragraph 18 shall apply. The procedures described above shall not apply to privileged materials designated by a Participant as Critical Energy Infrastructure Information. Materials so designated shall remain privileged and subject to the provisions of this Protective Order, unless a Participant requests and obtains a determination from the Commission's Critical Energy Infrastructure Information Coordinator that such materials need not remain privileged.

12. All copies of all documents reflecting Privileged Materials, including the portion of the hearing testimony, exhibits, transcripts, briefs and other documents, which refer to Privileged Materials, shall be filed and served in sealed envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Protective Order. Such documents shall be marked "PRIVILEGED MATERIALS" and shall be filed under seal and served under seal upon the Presiding Judge and all Reviewing Representatives who are on the service list. Such documents containing Critical Energy Infrastructure Information shall be additionally marked "Contains Critical Energy Infrastructure Information – Do Not Release." For anything filed under seal, redacted versions or,

where an entire document is privileged, a letter indicating such, will also be filed with the Commission and served on all Participants on the service list and the Presiding Judge. Counsel for the producing Participant shall provide to all Participants who request the same, a list of Reviewing Representatives who are entitled to receive such material. Counsel shall take all reasonable precautions necessary to assure that Privileged Materials are not distributed to unauthorized persons.

13. If any Participant desires to include, utilize or refer to any Privileged Materials or information derived therefrom in testimony or exhibits during the hearing in these proceedings in such a manner that might require disclosure of such material to persons other than reviewing representatives, such Participant shall first notify both counsel for the disclosing Participant and the Presiding Judge of such desire, identifying with particularity each of the Privileged Materials. Thereafter, use of such Privileged Material will be governed by procedures determined by the Presiding Judge.

14. Nothing in this Protective Order shall be construed as precluding any Participant from objecting to the use of Privileged Materials on any legal grounds.

15. Nothing in this Protective Order shall preclude any Participant from requesting the Presiding Judge, the Chief Judge, the Commission, or any other body having appropriate authority, to find that this Protective Order should not apply to all or any materials previously designated as Privileged Materials pursuant to this Protective Order. The Presiding Judge or the Chief Judge or the Commission may alter or amend this Protective Order as circumstances warrant at any time during the course of this proceeding.

16. Each Participant governed by this Protective Order has the right to seek changes in it as appropriate from the Presiding Judge or the Chief Judge or the Commission.

17. All Privileged Materials filed with the Commission, the Presiding Judge, or any other judicial or administrative body, in support of, or as a part of, a motion, other pleading, brief, or other document, shall be filed and served in sealed envelopes or other appropriate containers bearing prominent markings indicating that the contents include Privileged Materials subject to this Protective Order. Such documents containing Critical Energy Infrastructure Information shall be additionally marked “Contains Critical Energy Infrastructure Information – Do Not Release."

18. If the Presiding Judge or the Chief Judge finds at any time in the course of this proceeding that all or part of the Privileged Materials need not be privileged, those materials shall, nevertheless, be subject to the privilege afforded by this Protective Order for three (3) business days from the date of issuance of the Presiding Judge's or the Chief Judge’s determination, and if the Participant seeking privilege files an interlocutory appeal or requests that the issue be certified to the Commission, for an additional seven (7) business days. None of the Participants waives its rights to seek additional administrative or judicial remedies after the Presiding Judge's or the Chief Judge’s decision respecting Privileged Materials or Reviewing Representatives, or the

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Commission's denial of any appeal thereof. The provisions of 18 CFR §§ 388.112 and 388.113 shall apply to any requests under the Freedom of Information Act (5 U.S.C. § 552) for Privileged Materials in the files of the Commission.

19. Nothing in this Protective Order shall be deemed to preclude any Participant from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced in this proceeding under this Protective Order.

20. None of the Participants waives the right to pursue any other legal or equitable remedies that may be available in the event of actual or anticipated disclosure of Privileged Materials.

21. The contents of Privileged Materials or any other form of information that copies or discloses Privileged Materials shall not be disclosed to anyone other than in accordance with this Protective Order and shall be used only in connection with this (these) proceeding(s). Any violation of this Protective Order and of any Non-Disclosure Certificate executed hereunder shall constitute a violation of an order of the Commission.

Presiding Administrative Law Judge

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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Pepco Energy Services, Inc.	**)**	**Docket No. ER10-2992-___**
Potomac Electric Power Company	**)**	**Docket No. ER10-3030-___**

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Privileged Materials is provided to me pursuant to the terms and restrictions of the Protective Order in this proceeding, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by it. I understand that the contents of the Privileged Materials, any notes or other memoranda, or any other form of information that copies or discloses Privileged Materials shall not be disclosed to anyone other than in accordance with that Protective Order. I acknowledge that a violation of this certificate constitutes a violation of an order of the Federal Energy Regulatory Commission.

By: _____
Printed Name: _____

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Title: _____
Representing: _____
Date: _____

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Attachment C:
Asset Appendices of Exelon Corporation and Subsidiaries

Exhibit NCI-3

Generation Affiliated with Exelon NE Entities in the Northeast Region and Relevant First-Tier Markets

Balancing Authority Area		Plant Name	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share	Owned and Purchased (MW) Summer	Owned and Purchased (MW) Winter
ISO-NE							
ISO-NE		Wyman (Yarmouth) 4	602.1	605.8	5.90%	35.5	35.7
ISO-NE		Framingham Jet	31.4	43.4	100.00%	31.4	43.4
ISO-NE		West Medway 1-2	81.8	125.6	100.00%	81.8	125.6
ISO-NE		West Medway 3	42.0	64.0	100.00%	42.0	64.0
ISO-NE		New Boston (L Street Jet)	16.0	21.8	100.00%	16.0	21.8
ISO-NE		Mystic 7	570.8	559.8	100.00%	570.8	559.8
ISO-NE		Mystic 8	703.4	841.5	100.00%	703.4	841.5
ISO-NE		Mystic 9	713.9	858.5	100.00%	713.9	858.5
ISO-NE		Mystic Jet	9.1	14.5	100.00%	9.1	14.5
ISO-NE	CT	Kleen Energy (purchase)				622.0	623.0
ISO-NE		Ameresco Northampton (purchase)				0.8	0.8
Subtotal, ISO-NE			**2,770.5**	**3,134.9**		**2,826.7**	**3,188.6**
Subtotal, CT						**622.0**	**623.0**
NYISO							
NYISO		Nine Mile Point [1/]	1,692.3	1,703.8	50.01%	1,692.3	1,703.8
NYISO		Ginna	582.0	583.0	50.01%	582.0	583.0
NYISO		Sale of Nine Mile Point to EDF [2/]				(846.0)	(851.7)
NYISO		Purchase (WM Renewable Energy, LLC)				28.8	28.8
Subtotal, NYISO			**2,274.3**	**2,286.8**		**1,457.1**	**1,463.9**
PJM							
PJM		Braidwood	2,361.0	2,416.0	100.0%	2,361.0	2,416.0
PJM		Byron	2,318.0	2,364.0	100.0%	2,318.0	2,364.0
PJM	5004/5005	Calvert Cliffs [4/]	1,707.8	1,768.0	50.0%	1,707.8	1,768.0
PJM	East	Chester	39.0	54.0	100.0%	39.0	54.0
PJM	East	Conowingo	572.0	572.0	100.0%	572.0	572.0
PJM		Criterion Power	70.0	70.0	100.0%	70.0	70.0
PJM	East	Croydon	392.0	512.0	100.0%	392.0	512.0
PJM	East	Delaware	56.0	74.0	100.0%	56.0	74.0
PJM		Dresden	1,797.0	1,805.0	100.0%	1,797.0	1,805.0
PJM	East	Eddystone	820.0	836.0	100.0%	820.0	836.0
PJM	East	Fairless Hills	60.0	60.0	100.0%	60.0	60.0
PJM	East	Falls	51.0	60.0	100.0%	51.0	60.0
PJM		Fair Wind Facility	30.0	30.0	100.0%	30.0	30.0
PJM		Fourmile Wind	40.0	40.0	100.0%	40.0	40.0
PJM	5004/5005	Gould Street	97.0	97.0	100.0%	97.0	97.0
PJM		Handsome Lake	267.5	267.5	100.0%	267.5	267.5

Exhibit NCI-3

Balancing Authority Area		Plant Name	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share	Owned and Purchased (MW) Summer	Owned and Purchased (MW) Winter
PJM		La Salle	2,271.6	2,313.0	100.0%	2,271.6	2,313.0
PJM	East	Limerick	2,241.8	2,386.0	100.0%	2,241.8	2,386.0
PJM	East	Moser	51.0	60.0	100.0%	51.0	60.0
PJM	East	Muddy Run	1,070.0	1,070.0	100.0%	1,070.0	1,070.0
PJM	5004/5005	Notch Cliff	116.7	116.7	100.0%	116.7	116.7
PJM	East	Oyster Creek	607.7	637.0	100.0%	607.7	637.0
PJM	5004/5005	Peach Bottom (inc. upgrade)	2,450.40	2,658.0	50.0%	1,225.2	1,329.0
PJM	East	Pennsbury	5.4	5.4	100.0%	5.4	5.4
PJM	5004/5005	Perryman	302.6	302.6	100.0%	302.6	302.6
PJM	5004/5005	Perryman 6	110.0	130.0	100.0%	110.0	130.0
PJM	5004/5005	Philadelphia Road	60.9	60.9	100.0%	60.9	60.9
PJM		Quad Cities	1,819.0	1,819.0	75.0%	1,364.3	1,364.3
PJM	East	Richmond	98.0	132.0	100.0%	98.0	132.0
PJM	5004/5005	Riverside	39.0	39.0	100.0%	39.0	39.0
PJM	East	Salem	2,366.6	2,366.6	42.6%	1,007.9	1,007.9
PJM	East	Schuylkill	30.0	38.0	100.0%	30.0	38.0
PJM		Southeast Chicago	296.0	320.0	100.0%	296.0	320.0
PJM	East	Southwark	52.0	72.0	100.0%	52.0	72.0
PJM	5004/5005	Three Mile Island 1	802.8	829.0	100.0%	802.8	829.0
PJM	5004/5005	Westport	115.8	115.8	100.0%	115.8	115.8
PJM	5004/5005	Bethlehem Renewable Plant	4.7	1.2	100.0%	4.7	1.2
PJM	5004/5005	Eastern LFG	3.0	1.5	100.0%	3.0	1.5
PJM	AP South	Fauquier LFG (retired Jan 2016)	2.0	1.0	100.0%	2.0	1.0
PJM		Clinton Battery (2016)	10.0	10.0	100.0%	10.0	10.0
Subtotal, PJM						22,566.7	23,367.8
Long-Term Purchases							
PJM		Elwood Energy, LLC [3/]				600.0	768.0
PJM	5004/5005	Calpine Mid Merit LLC				545.0	545.0
PJM		Cordova Energy Company, LLC				521.2	601.2
PJM		Backbone Mountain Windpower LLC				66.0	66.0
PJM		Bellefontaine Gas Producers, LLC				4.5	4.5
PJM		Forward Wind Power LLC				29.4	29.4
PJM		High Trail Wind Farm, LLC				99.0	99.0
PJM		Mill Run Windpower, LLC				15.6	15.6
PJM		Old Trail Wind Farm, LLC				198.0	198.0
PJM		Patton Wind Farm, LLC				16.0	16.0
PJM		Somerset Windpower, LLC				9.0	9.0
PJM		WM Renewable Energy, LLC				10.1	10.1
PJM	AP South	WM Renewable Energy, LLC				3.8	3.8
PJM	5004/5005	Green Gas Pioneer Crossing Energy, LLC				5.0	5.0
PJM	5004/5005	Green Knight Economic Development Corporation				3.3	3.3

Exhibit NCI-3

Balancing Authority Area		Plant Name	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share	Owned and Purchased (MW) Summer	Owned and Purchased (MW) Winter
PJM	5004/5005	Keystone Solar, L.L.C.				4.9	4.9
PJM	5004/5005	Waymart Wind Farm, L.P.				64.5	64.5
PJM	AP South	Ameresco Stafford, LLC				2.0	2.0
PJM	East	Ameresco Delaware Energy, LLC				7.0	7.0
PJM	East	MF Mesa Lane LLC				3.0	3.0
PJM	East	Chambers Cogeneration				187.6	187.6
PJM	East	Logan Generating				200.0	200.0
PJM		AES Armenia Mountain				50.0	50.0
PJM		Roth Rock				40.0	40.0
PJM		Chestnut Flats				38.0	38.0
Subtotal, PJM						2,722.9	2,970.9
Long-Term Sales							
PJM	5004/5005	CENG sale (Calvert Cliffs) to EDF [4/]				(853.7)	(883.8)
Subtotal, PJM						24,435.9	25,454.9
Subtotal, PJM East						7,551.4	7,973.9
Subtotal, 5004/5005						11,905.9	12,503.5
Subtotal, AP South						11,913.7	12,510.3
First-Tier Markets							
MISO		Beebe Renewable Energy	81.6	81.6	100%	81.6	81.6
MISO		Beebe 1B Renewable Energy, LLC (2014)	50.4	50.4	100%	50.4	50.4
MISO		Clinton	1,065.0	1,078.0	100%	1,065.0	1,078.0
MISO		Harvest Windfarm	52.8	52.8	100%	52.8	52.8
MISO		Harvest II Windfarm	59.4	59.4	100%	59.4	59.4
MISO		Michigan Wind 1	69.0	69.0	100%	69.0	69.0
MISO		Michigan Wind 2	90.0	90.0	100%	90.0	90.0
Long-Term Purchases							
MISO		Tenaska Frontier				870.0	936.0
MISO		Pioneer Trail Wind Farm, LLC				110.4	110.4
Subtotal, MISO			1,468.2	1,481.2		2,448.6	2,527.6

Plant ratings based on 2015 EIA-860 data
https://www.eia.gov/electricity/data/eia860/

1/ Total capacity reflects 100% of unit 1 and 82% of unit 2. The remaining 18% of unit 2 is owned by Long Island Power Authority.

2/ A subsidiary of Electricite de France SA ("EDF"), which owns the other 49.99% of Constellation Energy Nuclear Group, Inc. ("CENG") (owner of the nuclear plants), purchases on a unit-contingent basis 49.99 percent of the nuclear plant output owned by CENG not sold to third parties. The sale represents 49.99% of CENG's share of Nine Mile Point.

3/ The current PPA is only 300 MW PPA. Another PPA was terminated August 16, 2016.

4/ A subsidiary of Electricite de France SA ("EDF"), which owns the other 49.99% of Constellation Energy Nuclear Group, Inc. ("CENG") (owner of the nuclear plants), purchases on a unit-contingent basis 49.99 percent of the nuclear plant output owned by CENG not sold to third parties. The sale represents 49.99% of CENG's share of Calvert Cliff.

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Market/ Submarket	Exhibit	Pivotal Supplier Analysis	Exhibit	Market Share Analysis			
				Winter	Spring	Summer	Fall
PJM	NCI-5	Pass	NCI-6	10.6%	10.4%	9.0%	9.9%
PJM East	NCI-7	Pass	NCI-8	18.8%	17.7%	18.0%	15.9%
5004/5005	NCI-9	Pass	NCI-10	16.1%	16.4%	11.6%	12.7%
AP South	NCI-11	Pass	NCI-12	12.1%	12.3%	8.7%	9.4%
ISO-NE	NCI-13	Pass	NCI-14	0.0%	0.0%	0.0%	0.0%
CT	NCI-15	Pass	NCI-16	0.0%	0.0%	0.0%	0.0%
NYISO	NCI-17	Pass	NCI-18	4.1%	1.7%	0.4%	0.6%

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Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **PJM**
Data Year -> **Dec 2014-Nov 2015**

Row			Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	22,567	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0	
B	Long-Term Firm Purchases (from inside the study area)	2,723	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	
C	Long-Term Firm Sales (in and outside the study area)	854	Exhibit NCI-3
D	Uncommitted Capacity Imports	194	Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	160,493	Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)	0	
F	Long-Term Firm Purchases (from inside the study area)	854	Offset Row C
F1	Long-Term Firm Purchases (from outside the study area)	0	
G	Long-Term Firm Sales (in and outside the study area)	2,723	Offset Row B
H	Uncommitted Capacity Imports	7,406	Wkp - SILs, less Row D
I	Study Area Reserve Requirement	9,097	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	59,963	
	Load		
L	Balancing Authority Area Annual Peak Load	143,633	Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month	121,600	Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any	19,538	Wkp - Exelon Load Summary
O	Wholesale Load (L-M)	22,033	
P	Net Uncommitted Supply (K-O)	37,930	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,092	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->	7,600	
	% of SIL for Seller's imported capacity ->	0.03	
	% of SIL for Other's imported capacity ->	0.97	
	SIL value ->	7,600	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->	No	

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Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **PJM**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled or under LT contract)				
A	Installed Capacity (inside the study area)	23,368	23,368	22,567	23,368
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	2,971	2,971	2,723	2,971
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	884	884	854	884
D	Seasonal Average Planned Outages	979	3,106	524	2,981
E	Uncommitted Capacity Imports	290	278	199	154
	Capacity Deductions				
F	Average Peak Native Load in the Season	112,390	94,917	117,821	95,173
G	Amount of Line F Attributable to Seller, if any	16,011	14,104	18,740	15,366
H	Amount of Line F Attributable to Non-Affiliates, if any	96,379	80,813	99,081	79,807
I	Study Area Reserve Requirement	8,067	6,367	9,097	6,391
J	Amount of Line I Attributable to Seller, if any	0	0	0	0
K	Amount of Line I Attributable to Non-Affiliates, if any	8,067	6,367	9,097	6,391
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	176,232	173,322	160,493	169,417
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	884	884	854	884
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	2,971	2,971	2,723	2,971
O	Seasonal Average Planned Outages	7,380	23,036	3,730	21,608
P	Uncommitted Capacity Imports	11,707	12,445	7,401	6,913
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	74,026	73,464	54,118	66,437
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	8,755	8,523	5,370	7,262
S	Total Seasonal Uncommitted Capacity (Q+R)	82,781	81,987	59,488	73,699
T	**Seller's Market Share** (R÷S)	10.6%	10.4%	9.0%	9.9%
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass
U	Total Imports, as filed by Seller (E+P)	11,997	12,723	7,600	7,067
V	SIL value*	11,997	12,723	7,600	7,067
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No

P.

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Reference

Exhibit NCI-3

Exhibit NCI-3

Exhibit NCI-3
Pro Rata Share of Outages
Wkp - Import Allocation

Wkp - Summary of Inputs Data
Wkp - Exelon Load Summary

Wkp - Summary of Inputs Data

Wkp - Summary of Inputs Data, less Row A

Offset Row C

Offset Row B
Wkp - Summary of Inputs Data, less Row D
Wkp - SILs, less Row E

JM Interconnection 2015 SIL Study

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Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **PJM East**
Data Year -> **Dec 2014-Nov 2015**

Row			
	Generation		**Reference**
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,154	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0	
B	Long-Term Firm Purchases (from inside the study area)	398	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	
C	Long-Term Firm Sales (in and outside the study area)	0	
D	Uncommitted Capacity Imports	291	Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	27,476	Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)	0	
F	Long-Term Firm Purchases (from inside the study area)	0	
F1	Long-Term Firm Purchases (from outside the study area)	0	
G	Long-Term Firm Sales (in and outside the study area)	398	Offset Row B
H	Uncommitted Capacity Imports	6,246	Wkp - SILs, less Row D
I	Study Area Reserve Requirement	1,429	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	15,645	
	Load		
L	Balancing Authority Area Annual Peak Load	30,240	Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month	24,093	Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any	5,063	Wkp - Exelon Load Summary
O	Wholesale Load (L-M)	6,147	
P	Net Uncommitted Supply (K-O)	9,498	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	2,780	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->	6,537	
	% of SIL for Seller's imported capacity ->	0.04	
	% of SIL for Other's imported capacity ->	0.96	
	SIL value ->	6,537	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->	No	

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Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **PJM East**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled or under LT contract)				
A	Installed Capacity (inside the study area)	7,576	7,576	7,154	7,576
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	398	398	398	398
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
D	Seasonal Average Planned Outages	317	1,007	166	966
E	Uncommitted Capacity Imports	532	612	318	484
	Capacity Deductions				
F	Average Peak Native Load in the Season	19,303	16,803	22,934	17,326
G	Amount of Line F Attributable to Seller, if any	3,767	3,417	4,819	3,923
H	Amount of Line F Attributable to Non-Affiliates, if any	15,536	13,386	18,115	13,403
I	Study Area Reserve Requirement	1,145	996	1,360	1,027
J	Amount of Line I Attributable to Seller, if any	0	0	0	0
K	Amount of Line I Attributable to Non-Affiliates, if any	1,145	996	1,360	1,027
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	30,540	29,831	27,476	30,159
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	398	398	398	398
O	Seasonal Average Planned Outages	1,279	3,965	639	3,847
P	Uncommitted Capacity Imports	6,970	8,218	6,219	7,375
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	19,152	19,304	13,184	18,860
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	4,422	4,162	2,884	3,568
S	Total Seasonal Uncommitted Capacity (Q+R)	23,574	23,466	16,068	22,428
T	**Seller's Market Share** (R÷S)	18.8%	17.7%	18.0%	15.9%
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass
U	Total Imports, as filed by Seller (E+P)	7,502	8,830	6,537	7,859
V	SIL value*	7,502	8,830	6,537	7,859
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No

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Reference

Exhibit NCI-3

Exhibit NCI-3

Pro Rata Share of Outages
Wkp - Import Allocation

Wkp - Summary of Inputs Data
Wkp - Exelon Load Summary

Wkp - Summary of Inputs Data

Wkp - Summary of Inputs Data, less Row A

Offset Row B
Wkp - Summary of Inputs Data, less Row D
Wkp - SILs, less Row E

PJM Interconnection 2015 SIL Study

Exhibit NCI-9

Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **5004/5005**
Data Year -> **Dec 2014-Nov 2015**

Row				
	Generation			**Reference**
	Seller and Affiliate Capacity (owned or controlled)			
A	Installed Capacity (from inside the study area)	11,739		Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0		
B	Long-Term Firm Purchases (from inside the study area)	1,020		Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0		
C	Long-Term Firm Sales (in and outside the study area)	854		Exhibit NCI-3
D	Uncommitted Capacity Imports	407		Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)			
E	Installed Capacity (from inside the study area)	44,075		Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)	0		
F	Long-Term Firm Purchases (from inside the study area)	854		Offset Row C
F1	Long-Term Firm Purchases (from outside the study area)	0		
G	Long-Term Firm Sales (in and outside the study area)	1,020		Offset Row B
H	Uncommitted Capacity Imports	5,912		Wkp - SILs, less Row D
I	Study Area Reserve Requirement	2,512		Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0		
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)		17,253	
	Load			
L	Balancing Authority Area Annual Peak Load	52,190		Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month	42,368		Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any	10,376		Wkp - Exelon Load Summary
O	Wholesale Load (L-M)		9,822	
P	Net Uncommitted Supply (K-O)		7,431	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)		1,936	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)		**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->		6,319	
	% of SIL for Seller's imported capacity ->		0.06	
	% of SIL for Other's imported capacity ->		0.94	
	SIL value ->	6,319		PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->		No	

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Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **5004/5005**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled or under LT contract)				
A	Installed Capacity (inside the study area)	12,367	12,367	11,739	12,367
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	1,020	1,020	1,020	1,020
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	884	884	854	884
D	Seasonal Average Planned Outages	518	1,644	273	1,577
E	Uncommitted Capacity Imports	627	583	435	440
	Capacity Deductions				
F	Average Peak Native Load in the Season	36,840	31,515	40,748	31,648
G	Amount of Line F Attributable to Seller, if any	8,348	7,135	10,017	8,235
H	Amount of Line F Attributable to Non-Affiliates, if any	28,492	24,380	30,731	23,413
I	Study Area Reserve Requirement	2,185	1,869	2,416	1,877
J	Amount of Line I Attributable to Seller, if any	0	0	0	0
K	Amount of Line I Attributable to Non-Affiliates, if any	2,185	1,869	2,416	1,877
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	47,624	46,915	44,075	47,374
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	884	884	854	884
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	1,020	1,020	1,020	1,020
O	Seasonal Average Planned Outages	1,994	6,235	1,024	6,043
P	Uncommitted Capacity Imports	7,477	7,710	5,884	5,663
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	22,294	22,005	15,622	21,568
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	4,264	4,308	2,050	3,131
S	Total Seasonal Uncommitted Capacity (Q+R)	26,558	26,312	17,672	24,699
T	**Seller's Market Share** (R÷S)	16.1%	16.4%	11.6%	12.7%
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass
U	Total Imports, as filed by Seller (E+P)	8,104	8,293	6,319	6,103
V	SIL value*	8,104	8,293	6,319	6,103
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No

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Reference

Exhibit NCI-3

Exhibit NCI-3

Exhibit NCI-3
Pro Rata Share of Outages
Wkp - Import Allocation

Wkp - Summary of Inputs Data
Wkp - Exelon Load Summary

Wkp - Summary of Inputs Data

Wkp - Summary of Inputs Data, less Row A

Offset Row C

Offset Row B
Wkp - Summary of Inputs Data, less Row D
Wkp - SILs, less Row E

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Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **AP South**
Data Year -> **Dec 2014-Nov 2015**

Row			
	Generation		**Reference**
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	11,741	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0	
B	Long-Term Firm Purchases (from inside the study area)	1,026	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	
C	Long-Term Firm Sales (in and outside the study area)	854	Exhibit NCI-3
D	Uncommitted Capacity Imports	331	Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	67,228	Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)	0	
F	Long-Term Firm Purchases (from inside the study area)	854	Offset Row C
F1	Long-Term Firm Purchases (from outside the study area)	0	
G	Long-Term Firm Sales (in and outside the study area)	1,026	Offset Row B
H	Uncommitted Capacity Imports	4,124	Wkp - SILs, less Row D
I	Study Area Reserve Requirement	2,868	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	22,448	
	Load		
L	Balancing Authority Area Annual Peak Load	70,729	Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month	58,108	Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any	10,376	Wkp - Exelon Load Summary
O	Wholesale Load (L-M)	12,621	
P	Net Uncommitted Supply (K-O)	9,827	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,868	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->	4,455	
	% of SIL for Seller's imported capacity ->	0.07	
	% of SIL for Other's imported capacity ->	0.93	
	SIL value ->	4,455	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->	No	

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Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **AP South**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled or under LT contract)				
A	Installed Capacity (inside the study area)	12,368	12,368	11,741	12,368
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	1,026	1,026	1,026	1,026
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	884	884	854	884
D	Seasonal Average Planned Outages	518	1,644	273	1,577
E	Uncommitted Capacity Imports	720	733	353	515
	Capacity Deductions				
F	Average Peak Native Load in the Season	51,170	43,394	56,097	43,262
G	Amount of Line F Attributable to Seller, if any	8,453	7,202	10,017	8,235
H	Amount of Line F Attributable to Non-Affiliates, if any	42,717	36,192	46,080	35,027
I	Study Area Reserve Requirement	2,552	2,266	2,772	2,230
J	Amount of Line I Attributable to Seller, if any	0	0	0	0
K	Amount of Line I Attributable to Non-Affiliates, if any	2,552	2,266	2,772	2,230
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	72,170	71,461	67,228	71,825
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	884	884	854	884
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	1,026	1,026	1,026	1,026
O	Seasonal Average Planned Outages	3,022	9,497	1,562	9,161
P	Uncommitted Capacity Imports	7,177	8,123	4,102	5,553
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	30,914	31,487	20,744	30,818
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	4,259	4,397	1,976	3,213
S	Total Seasonal Uncommitted Capacity (Q+R)	35,173	35,884	22,720	34,031
T	**Seller's Market Share** (R÷S)	12.1%	12.3%	8.7%	9.4%
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass
U	Total Imports, as filed by Seller (E+P)	7,897	8,856	4,455	6,068
V	SIL value*	7,897	8,856	4,455	6,068
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No

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Reference

Exhibit NCI-3

Exhibit NCI-3

Exhibit NCI-3
Pro Rata Share of Outages
Wkp - Import Allocation

Wkp - Summary of Inputs Data
Wkp - Exelon Load Summary

Wkp - Summary of Inputs Data

Wkp - Summary of Inputs Data, less Row A

Offset Row C

Offset Row B
Wkp - Summary of Inputs Data, less Row D
Wkp - SILs, less Row E

PJM Interconnection 2015 SIL Study

Exhibit NCI-13

Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **ISO-NE**
Data Year -> **Dec 2014-Nov 2015**

Row				Reference
	Generation			
	Seller and Affiliate Capacity (owned or controlled)			
A	Installed Capacity (from inside the study area)	2,204		Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0		
B	Long-Term Firm Purchases (from inside the study area)	623		Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0		
C	Long-Term Firm Sales (in and outside the study area)	0		
D	Uncommitted Capacity Imports	0		Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)			
E	Installed Capacity (from inside the study area)	31,220		Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)	0		
F	Long-Term Firm Purchases (from inside the study area)	0		
F1	Long-Term Firm Purchases (from outside the study area)	0		
G	Long-Term Firm Sales (in and outside the study area)	623		Offset Row B
H	Uncommitted Capacity Imports	4,548		Wkp - SILs, less Row D
I	Study Area Reserve Requirement	1,310		Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0		
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)		17,041	
	Load			
L	Balancing Authority Area Annual Peak Load	24,437		Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month	19,621		Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any	4,000		Wkp - Exelon Load Summary
O	Wholesale Load (L-M)		4,816	
P	Net Uncommitted Supply (K-O)		12,225	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)		0	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)		**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->		4,548	
	% of SIL for Seller's imported capacity ->		0.00	
	% of SIL for Other's imported capacity ->		1.00	
	SIL value ->	4,548		PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->		No	

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Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **ISO-NE**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled or under LT contract)				
A	Installed Capacity (inside the study area)	2,565	2,565	2,204	2,565
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	624	624	623	624
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
D	Seasonal Average Planned Outages	81	233	16	213
E	Uncommitted Capacity Imports	47	0	0	0
	Capacity Deductions				
F	Average Peak Native Load in the Season	18,391	15,604	18,719	16,307
G	Amount of Line F Attributable to Seller, if any	3,627	3,224	4,080	3,720
H	Amount of Line F Attributable to Non-Affiliates, if any	14,764	12,380	14,639	12,587
I	Study Area Reserve Requirement	1,562	1,436	1,310	1,436
J	Amount of Line I Attributable to Seller, if any	0	0	0	0
K	Amount of Line I Attributable to Non-Affiliates, if any	1,562	1,436	1,310	1,436
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	33,011	33,011	31,220	33,011
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	624	624	623	624
O	Seasonal Average Planned Outages	1,046	3,001	220	2,747
P	Uncommitted Capacity Imports	4,501	4,548	4,548	4,548
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	19,517	20,119	18,976	20,166
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	0	0	0	0
S	Total Seasonal Uncommitted Capacity (Q+R)	19,517	20,119	18,976	20,166
T	**Seller's Market Share** (R÷S)	0.0%	0.0%	0.0%	0.0%
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass
U	Total Imports, as filed by Seller (E+P)	4,548	4,548	4,548	4,548
V	SIL value*	4,548	4,548	4,548	4,548
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No

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Reference

Exhibit NCI-3

Exhibit NCI-3

Pro Rata Share of Outages
Wkp - Import Allocation

Wkp - Summary of Inputs Data
Wkp - Exelon Load Summary

Wkp - Summary of Inputs Data

Wkp - Summary of Inputs Data, less Row A

Offset Row B
Wkp - Summary of Inputs Data, less Row D
Wkp - SILs, less Row E

PJM Interconnection 2015 SIL Study

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Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **CT**
Data Year -> **Dec 2014-Nov 2015**

Row				Reference
	Generation			
	Seller and Affiliate Capacity (owned or controlled)			
A	Installed Capacity (from inside the study area)		0	
A1	Remote Capacity (from outside the study area)		0	
B	Long-Term Firm Purchases (from inside the study area)		622	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)		0	
C	Long-Term Firm Sales (in and outside the study area)		0	
D	Uncommitted Capacity Imports		0	Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)			
E	Installed Capacity (from inside the study area)		7,789	Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)		0	
F	Long-Term Firm Purchases (from inside the study area)		0	
F1	Long-Term Firm Purchases (from outside the study area)		0	
G	Long-Term Firm Sales (in and outside the study area)		622	Offset Row B
H	Uncommitted Capacity Imports		3,050	Wkp - SILs, less Row D
I	Study Area Reserve Requirement		714	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any		0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	5,071		
	Load			
L	Balancing Authority Area Annual Peak Load		6,419	Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month		5,054	Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any		1,470	Wkp - Exelon Load Summary
O	Wholesale Load (L-M)	1,365		
P	Net Uncommitted Supply (K-O)	3,706		
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	0		
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**		
	Total Imports (Sum D,H), as filed by Seller ->	3,050		
	% of SIL for Seller's imported capacity ->	0.00		
	% of SIL for Other's imported capacity ->	1.00		
	SIL value ->		3,050	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->	No		

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Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **CT**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled or under LT contract)				
A	Installed Capacity (inside the study area)	0	0	0	0
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	623	623	622	623
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
D	Seasonal Average Planned Outages	0	0	0	0
E	Uncommitted Capacity Imports	28	0	0	0
	Capacity Deductions				
F	Average Peak Native Load in the Season	4,497	3,789	4,827	4,005
G	Amount of Line F Attributable to Seller, if any	1,012	868	1,304	1,197
H	Amount of Line F Attributable to Non-Affiliates, if any	3,485	2,921	3,523	2,808
I	Study Area Reserve Requirement	363	539	714	539
J	Amount of Line I Attributable to Seller, if any	0	0	0	0
K	Amount of Line I Attributable to Non-Affiliates, if any	363	539	714	539
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	8,213	8,213	7,789	8,213
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	623	623	622	623
O	Seasonal Average Planned Outages	260	747	55	683
P	Uncommitted Capacity Imports	3,022	3,050	3,050	3,050
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	6,504	6,433	5,925	6,610
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	0	0	0	0
S	Total Seasonal Uncommitted Capacity (Q+R)	6,504	6,433	5,925	6,610
T	**Seller's Market Share** (R÷S)	0.0%	0.0%	0.0%	0.0%
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass
U	Total Imports, as filed by Seller (E+P)	3,050	3,050	3,050	3,050
V	SIL value*	3,050	3,050	3,050	3,050
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No

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Reference

Exhibit NCI-3

Wkp - Import Allocation

Wkp - Summary of Inputs Data
Wkp - Exelon Load Summary

Wkp - Summary of Inputs Data

Wkp - Summary of Inputs Data, less Row A

Offset Row B
Wkp - Summary of Inputs Data, less Row D
Wkp - SILs, less Row E

PJM Interconnection 2015 SIL Study

Exhibit NCI-17

Part I – Pivotal Supplier Analysis

Applicant-> **Exelon NE Entities**
Market -> **NYISO**
Data Year -> **Dec 2014-Nov 2015**

Row			
	Generation		**Reference**
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	2,274	Exhibit NCI-3
A1	Remote Capacity (from outside the study area)	0	
B	Long-Term Firm Purchases (from inside the study area)	29	Exhibit NCI-3
B1	Long-Term Firm Purchases (from outside the study area)	0	
C	Long-Term Firm Sales (in and outside the study area)	846	Exhibit NCI-3
D	Uncommitted Capacity Imports	414	Wkp - Import Allocation
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	36,391	Wkp - Summary of Inputs Data, less Row A
E1	Remote Capacity (from outside the study area)	0	
F	Long-Term Firm Purchases (from inside the study area)	846	Offset Row C
F1	Long-Term Firm Purchases (from outside the study area)	0	
G	Long-Term Firm Sales (in and outside the study area)	29	Offset Row B
H	Uncommitted Capacity Imports	7,281	Wkp - SILs, less Row D
I	Study Area Reserve Requirement	2,620	Wkp - Summary of Inputs Data
J	Amount of Line I Attributable to Seller, if any	0	
K	Total Uncommitted Supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	18,496	
	Load		
L	Balancing Authority Area Annual Peak Load	31,138	Wkp - Summary of Inputs Data
M	Average Daily Peak Native Load in Peak Month	25,244	Wkp - Summary of Inputs Data
N	Amount of Line M Attributable to Seller, if any	1,774	Wkp - Exelon Load Summary
O	Wholesale Load (L-M)	5,894	
P	Net Uncommitted Supply (K-O)	12,602	
Q	Seller's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	97	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D,H), as filed by Seller ->	7,695	
	% of SIL for Seller's imported capacity ->	0.05	
	% of SIL for Other's imported capacity ->	0.95	
	SIL value ->	7,695	PJM Interconnection 2015 SIL Study
	Do Total Imports exceed the SIL value? ->	No	

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Part II – Market Share Analysis

Applicant-> **Exelon NE Entities**
Study Area -> **NYISO**
Data Year -> **Dec 2014-Nov 2015**
As filed by the Applicant/Seller

Row		Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled or under LT contract)				
A	Installed Capacity (inside the study area)	2,287	2,287	2,274	2,287
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	29	29	29	29
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	852	852	846	852
D	Seasonal Average Planned Outages	187	331	43	265
E	Uncommitted Capacity Imports	625	542	456	526
	Capacity Deductions				
F	Average Peak Native Load in the Season	22,045	19,393	24,144	20,374
G	Amount of Line F Attributable to Seller, if any	1,053	1,345	1,785	1,610
H	Amount of Line F Attributable to Non-Affiliates, if any	20,992	18,048	22,359	18,764
I	Study Area Reserve Requirement	2,620	2,620	2,620	2,620
J	Amount of Line I Attributable to Seller, if any	0	0	0	0
K	Amount of Line I Attributable to Non-Affiliates, if any	2,620	2,620	2,620	2,620
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	38,726	38,726	36,391	38,726
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	852	852	846	852
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	29	29	29	29
O	Seasonal Average Planned Outages	3,161	5,604	696	4,478
P	Uncommitted Capacity Imports	6,899	6,308	7,239	7,109
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	19,674	19,585	18,773	20,795
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	850	330	84	116
S	Total Seasonal Uncommitted Capacity (Q+R)	20,524	19,915	18,857	20,911
T	**Seller's Market Share** (R÷S)	4.1%	1.7%	0.4%	0.6%
	Results (Pass if < 20% and Fail if ≥ 20%)	Pass	Pass	Pass	Pass
U	Total Imports, as filed by Seller (E+P)	7,524	6,850	7,695	7,635
V	SIL value*	7,524	6,850	7,695	7,635
	Do Total Imports exceed SIL value? (is U<=V)	No	No	No	No

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Reference

Exhibit NCI-3

Exhibit NCI-3

Exhibit NCI-3
Pro Rata Share of Outages
Wkp - Import Allocation

Wkp - Summary of Inputs Data
Wkp - Exelon Load Summary

Wkp - Summary of Inputs Data

Wkp - Summary of Inputs Data, less Row A

Offset Row C

Offset Row B
Wkp - Summary of Inputs Data, less Row D
Wkp - SILs, less Row E

PJM Interconnection 2015 SIL Study

2015 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Technology
58962	Fair Wind Power Partners	59147	Fair Wind Power	MD	Garrett	1	Wind
55951	Exelon Nuclear	6022	Braidwood Generation Station	IL	Will	1	Nuclear
55951	Exelon Nuclear	6022	Braidwood Generation Station	IL	Will	1	Nuclear
55951	Exelon Nuclear	6022	Braidwood Generation Station	IL	Will	2	Nuclear
55951	Exelon Nuclear	6023	Byron Generating Station	IL	Ogle	1	Nuclear
55951	Exelon Nuclear	6023	Byron Generating Station	IL	Ogle	2	Nuclear
55951	Exelon Nuclear	6011	Calvert Cliffs Nuclear Power Plant	MD	Calvert	1	Nuclear
55951	Exelon Nuclear	6011	Calvert Cliffs Nuclear Power Plant	MD	Calvert	2	Nuclear
6035	Exelon Power	3157	Chester Generating Station	PA	Chester	7	Liquids
6035	Exelon Power	3157	Chester Generating Station	PA	Chester	8	Liquids
6035	Exelon Power	3157	Chester Generating Station	PA	Chester	9	Liquids
6035	Exelon Power	1574	Conowingo	MD	Harford	1	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	10	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	11	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	2	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	3	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	4	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	5	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	6	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	7	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	8	Conventio
6035	Exelon Power	1574	Conowingo	MD	Harford	9	Conventio
56661	Criterion Power Partners LLC	57300	Criterion Wind Project	MD	GARRET	1	Onshore
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	11	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	12	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	21	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	22	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	31	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	32	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	41	Petroleum
6035	Exelon Power	8012	Croydon CT Generating Station	PA	Bucks	42	Petroleum
6035	Exelon Power	3160	Delaware Generating Station	PA	Philadelph	10	Petroleum
6035	Exelon Power	3160	Delaware Generating Station	PA	Philadelph	11	Petroleum
6035	Exelon Power	3160	Delaware Generating Station	PA	Philadelph	12	Petroleum
6035	Exelon Power	3160	Delaware Generating Station	PA	Philadelph	9	Petroleum
55951	Exelon Nuclear	869	Dresden Generating Station	IL	Grundy	2	Nuclear
55951	Exelon Nuclear	869	Dresden Generating Station	IL	Grundy	3	Nuclear
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	10	Petroleum
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	20	Petroleum
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	3	Petroleum
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	30	Petroleum
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	4	Petroleum
6035	Exelon Power	3161	Eddystone Generating Station	PA	Delaware	40	Petroleum
6035	Exelon Power	57191	Exelon Solar Chicago	IL	Cook	ECS1	PV
6035	Exelon Power	7701	Fairless Hills	PA	Bucks	A	Landfill
6035	Exelon Power	7701	Fairless Hills	PA	Bucks	B	Landfill
6035	Exelon Power	3162	Falls	PA	Bucks	1	Petroleum
6035	Exelon Power	3162	Falls	PA	Bucks	2	Petroleum
6035	Exelon Power	3162	Falls	PA	Bucks	3	Petroleum
4161	Constellation Power Source Gen	1553	Gould Street	MD	Baltimore	3	Natural
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT01	Natural
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT02	Natural
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT03	Natural
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT04	Natural
8027	Handsome Lake Energy LLC	55233	Handsome Lake Energy LLC	PA	Venango	GT05	Natural
55951	Exelon Nuclear	6026	LaSalle Generating Station	IL	LaSalle	1	Nuclear
55951	Exelon Nuclear	6026	LaSalle Generating Station	IL	LaSalle	2	Nuclear
55951	Exelon Nuclear	6105	Limerick	PA	Montgom	1	Nuclear
55951	Exelon Nuclear	6105	Limerick	PA	Montgom	2	Nuclear
6035	Exelon Power	3163	Moser Generating Station	PA	Montgom	1	Petroleum
6035	Exelon Power	3163	Moser Generating Station	PA	Montgom	2	Petroleum
6035	Exelon Power	3163	Moser Generating Station	PA	Montgom	3	Petroleum
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	1	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	2	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	3	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	4	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	5	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	6	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	7	Hydroelec
6035	Exelon Power	3164	Muddy Run	PA	Lancaster	8	Hydroelec
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT1	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT2	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT3	Natural

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Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Technology
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT4	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT5	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT6	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT7	Natural
4161	Constellation Power Source Gen	1555	Notch Cliff	MD	Baltimore	GT8	Natural
55951	Exelon Nuclear	2388	Oyster Creek	NJ	Ocean	1	Nuclear
14432	Panther Creek Power Operating, LLC	50776	Panther Creek Energy Facility	PA	Carbon	GEN1	Conventio
55951	Exelon Nuclear	3166	Peach Bottom	PA	York	2	Nuclear
55951	Exelon Nuclear	3166	Peach Bottom	PA	York	3	Nuclear
6035	Exelon Power	7690	Pennsbury	PA	Bucks	1	Landfill
6035	Exelon Power	7690	Pennsbury	PA	Bucks	2	Landfill
4161	Constellation Power Source Gen	1556	Perryman	MD	Harford	GT1	Petroleum
4161	Constellation Power Source Gen	1556	Perryman	MD	Harford	GT2	Petroleum
4161	Constellation Power Source Gen	1556	Perryman	MD	Harford	GT3	Petroleum
4161	Constellation Power Source Gen	1556	Perryman	MD	Harford	GT4	Petroleum
4161	Constellation Power Source Gen	1556	Perryman	MD	Harford	GT5	Natural
4161	Constellation Power Source Gen	1557	Philadelphia	MD	Baltimore	GT1	Petroleum
4161	Constellation Power Source Gen	1557	Philadelphia	MD	Baltimore	GT2	Petroleum
4161	Constellation Power Source Gen	1557	Philadelphia	MD	Baltimore	GT3	Petroleum
4161	Constellation Power Source Gen	1557	Philadelphia	MD	Baltimore	GT4	Petroleum
55951	Exelon Nuclear	880	Quad Cities Generating Station	IL	Rock	1	Nuclear
55951	Exelon Nuclear	880	Quad Cities Generating Station	IL	Rock	2	Nuclear
6035	Exelon Power	3168	Richmond Generating Station	PA	Philadelph	91	Petroleum
6035	Exelon Power	3168	Richmond Generating Station	PA	Philadelph	92	Petroleum
4161	Constellation Power Source Gen	1559	Riverside (MD)	MD	Baltimore	4	Natural
4161	Constellation Power Source Gen	1559	Riverside (MD)	MD	Baltimore	GT7	Petroleum
4161	Constellation Power Source Gen	1559	Riverside (MD)	MD	Baltimore	GT8	Petroleum
15478	PSEG Nuclear LLC	2410	PSEG Salem Generating Station	NJ	Salem	1	Nuclear
15478	PSEG Nuclear LLC	2410	PSEG Salem Generating Station	NJ	Salem	2	Nuclear
15478	PSEG Nuclear LLC	2410	PSEG Salem Generating Station	NJ	Salem	3	Petroleum
6035	Exelon Power	3169	Schuylkill Generating Station	PA	Philadelph	10	Petroleum
6035	Exelon Power	3169	Schuylkill Generating Station	PA	Philadelph	11	Petroleum
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT05	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT06	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT07	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT08	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT09	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT10	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT11	Natural
6035	Exelon Power	55281	Southeast Chicago Energy Project	IL	Cook	GT12	Natural
6035	Exelon Power	3170	Southwark	PA	Philadelph	3	Petroleum
6035	Exelon Power	3170	Southwark	PA	Philadelph	4	Petroleum
6035	Exelon Power	3170	Southwark	PA	Philadelph	5	Petroleum
6035	Exelon Power	3170	Southwark	PA	Philadelph	6	Petroleum
55951	Exelon Nuclear	8011	Three Mile Island	PA	Dauphin	1	Nuclear
4161	Constellation Power Source Gen	1560	Westport	MD	Baltimore	GT5	Natural
57311	Constellation Solar Federal LLC	58029	Constellation New Energy Inc	NJ	Burlington	PV1	Solar
57044	Constellation Solar New Jersey, LLC	57733	Benjamin Moore & Co. Solar	NJ	Morris	PV1	Solar
56976	Constellation Solar New Jersey II, LLC	57723	Johnson Matthey, Inc. Solar	NJ	Glouceste	PV1	Solar
56975	Constellation Solar Maryland, LLC	57646	McCormick & Co. Inc. at Belcamp	MD	Harford	PV1	Solar
57065	Constellation Solar Horizons LLC	57758	Mount Saint Mary's	MD	Frederick	PV1	Solar
56976	Constellation Solar New Jersey II, LLC	57647	Toys R Us- DE, Inc. at Mt. Olive, NJ	NJ	Morris	PV1	Solar
57044	Constellation Solar New Jersey, LLC	57745	The City of Vineland at West Vineland	NJ	Cumberla	PV1	Solar
57044	Constellation Solar New Jersey, LLC	57746	The City of Vineland at North Vineland	NJ	Cumberla	PV1	Solar
56975	Constellation Solar Maryland, LLC	59841	General Motors Corp at White Marsh	MD	Baltimore	PV1	Solar
58304	Constellation Solar Maryland II LLC	58329	UMMS at Pocomoke	MD	Somerset	PV1	Solar
56608	Calpine Mid-Merit LLC	55524	York Energy Center	PA	York	CTG1	Gas Fired
56608	Calpine Mid-Merit LLC	55524	York Energy Center	PA	York	CTG2	Gas Fired
56608	Calpine Mid-Merit LLC	55524	York Energy Center	PA	York	CTG3	Gas Fired
56608	Calpine Mid-Merit LLC	55524	York Energy Center	PA	York	STG1	Gas Fired
4210	Cordova Energy Co LLC	55188	Cordova Energy	IL	Island	PT11	Gas Fired
4210	Cordova Energy Co LLC	55188	Cordova Energy	IL	Island	PT21	Gas Fired
4210	Cordova Energy Co LLC	55188	Cordova Energy	IL	Island	PT31	Gas Fired
5259	Elwood Energy LLC	55199	Elwood Energy LLC	IL	Will	GT5	Gas Fired
5259	Elwood Energy LLC	55199	Elwood Energy LLC	IL	Will	GT6	Gas Fired
5259	Elwood Energy LLC	55199	Elwood Energy LLC	IL	Will	GT7	Gas Fired
5259	Elwood Energy LLC	55199	Elwood Energy LLC	IL	Will	GT8	Gas Fired
55951	Exelon Nuclear	6122	R E Ginna Nuclear Power Plant	NY	Wayne	1	Nuclear

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Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Technology
55951	Exelon Nuclear	2589	Nine Mile Point Nuclear Station	NY	Oswego	1	Nuclear
55951	Exelon Nuclear	2589	Nine Mile Point Nuclear Station	NY	Oswego	2	Nuclear
58784	Fourmile Wind Energy, LLC	58904	Fourmile Ridge	MD	Garrett	1	Wind

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Prime Mover	Unit Code	Ownership	Duct Burners	Can Bypass Heat Recovery Steam Generator?	RTO/ISO LMP Node Designation	RTO/ISO Location Designation for Reporting Wholesale Sales Data to FERC	Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Status	Operating Month	Operating Year
WT		S	X	X			30.0		30.0	30.0	OP	11	2015
ST		S	X	X	86031201	86031201	1,224.9	0.900	1,178.0	1,208.0	OP	7	1988
ST		S	X	X	86031201	86031201	1,224.9	0.900	1,183.0	1,208.0	OP	7	1988
ST		S	X	X	86031202	86031202	1,224.9	0.900	1,154.0	1,176.0	OP	10	1988
ST		S	X	X	86041201	86041201	1,224.9	0.900	1,164.0	1,188.0	OP	9	1985
ST		S	X	X	86041202	86041202	1,224.9	0.900	1,136.0	1,158.0	OP	8	1987
ST		J	X	X			918.0	0.900	866.0	890.0	OP	5	1975
ST		J	X	X			910.7	0.900	841.8	878.0	OP	4	1977
GT		S	X	X			18.6	0.850	13.0	18.0	OP	2	1969
GT		S	X	X			18.6	0.850	13.0	18.0	OP	5	1969
GT		S	X	X			18.6	0.850	13.0	18.0	OP	3	1969
HY		S	X	X			45.0	0.900	48.0	48.0	OP	3	1928
HY		S	X	X			55.6	0.900	65.0	65.0	OP	5	1964
HY		S	X	X			55.6	0.900	65.0	65.0	OP	5	1964
HY		S	X	X			36.0	0.900	36.0	36.0	OP	3	1928
HY		S	X	X			48.0	0.900	48.0	48.0	OP	3	1928
HY		S	X	X			47.7	0.900	48.0	48.0	OP	4	1928
HY		S	X	X			36.0	0.900	36.0	36.0	OP	6	1928
HY		S	X	X			47.7	0.900	48.0	48.0	OP	7	1928
HY		S	X	X			48.0	0.900	48.0	48.0	OP	6	1928
HY		S	X	X			55.6	0.900	65.0	65.0	OP	3	1964
HY		S	X	X			55.6	0.900	65.0	65.0	OP	3	1964
WT		S	X	X			70.0		70.0	70.0	OP	12	2010
GT		S	X	X			68.3	0.900	49.0	64.0	OP	6	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	6	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	6	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	6	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	8	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	8	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	7	1974
GT		S	X	X			68.3	0.900	49.0	64.0	OP	7	1974
GT		S	X	X			18.6	0.850	13.0	18.0	OP	5	1969
GT		S	X	X			18.6	0.850	13.0	18.0	OP	4	1969
GT		S	X	X			18.6	0.850	13.0	18.0	OP	5	1969
GT		S	X	X			21.2	0.850	17.0	20.0	OP	7	1970
ST		S	X	X	86101102	86101102	1,009.3	0.945	902.0	902.0	OP	8	1970
ST		S	X	X	86101103	86101103	1,009.3	0.945	895.0	903.0	OP	10	1971
GT		S	X	X			18.6	0.850	13.0	18.0	OP	5	1967
GT		S	X	X			18.6	0.850	13.0	18.0	OP	10	1967
ST		S	X	X			391.0	0.850	380.0	380.0	OP	9	1974
GT		S	X	X			21.2	0.850	17.0	20.0	OP	3	1970
ST		S	X	X		20060104	391.0	0.850	380.0	380.0	OP	6	1976
GT		S	X	X			21.2	0.850	17.0	20.0	OP	6	1970
	S	N	N			9.0			9.0	9.0	OP	12	2009
ST		S	X	X			30.0	0.850	30.0	30.0	OP	12	1996
ST		S	X	X			30.0	0.800	30.0	30.0	OP	12	1996
GT		S	X	X			21.2	0.850	17.0	20.0	OP	5	1970
GT		S	X	X			21.2	0.850	17.0	20.0	OP	5	1970
GT		S	X	X			21.2	0.850	17.0	20.0	OP	6	1970
ST		S	X	X			103.5	0.850	97.0	97.0	OP	12	1952
GT		S	X	X	1104241	1104241	58.9	0.850	53.5	53.5	OP	8	2001
GT		S	X	X	1104241	1104241	58.9	0.850	53.5	53.5	OP	8	2001
GT		S	X	X	1104241	1104241	58.9	0.850	53.5	53.5	OP	7	2001
GT		S	X	X	1104241	1104241	58.9	0.850	53.5	53.5	OP	7	2001
GT		S	X	X	1104241	1104241	58.9	0.850	53.5	53.5	OP	7	2001
ST		S	X	X	86191101	86191101	1,170.0	0.900	1,135.4	1,152.0	OP	1	1984
ST		S	X	X	86191102	86191102	1,170.0	0.900	1,136.2	1,161.0	OP	10	1984
ST		S	X	X	20021101	20021101	1,138.5	0.900	1,119.7	1,191.0	OP	2	1986
ST		S	X	X	20021102	20021102	1,138.5	0.900	1,122.1	1,195.0	OP	1	1990
GT		S	X	X			21.2	0.850	17.0	20.0	OP	6	1970
GT		S	X	X			21.2	0.850	17.0	20.0	OP	5	1970
GT		S	X	X			21.2	0.850	17.0	20.0	OP	6	1970
PS		S	X	X			134.0	0.900	134.0	134.0	OP	4	1967
PS		S	X	X			134.0	0.900	133.0	133.0	OP	4	1967
PS		S	X	X			134.0	0.900	134.0	134.0	OP	4	1967
PS		S	X	X			134.0	0.900	134.0	134.0	OP	6	1967
PS		S	X	X			134.0	0.900	134.0	134.0	OP	10	1967
PS		S	X	X			134.0	0.900	133.0	133.0	OP	10	1967
PS		S	X	X			134.0	0.900	134.0	134.0	OP	2	1968
PS		S	X	X			134.0	0.900	134.0	134.0	OP	2	1968
GT		S	X	X			18.0	0.850	14.0	14.0	OP	6	1969
GT		S	X	X			18.0	0.850	14.0	14.0	OP	6	1969
GT		S	X	X			18.0	0.850	14.0	14.0	OP	6	1969

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Prime Mover	Unit Code	Ownership	Duct Burners	Can Bypass Heat Recovery Steam Generator?	RTO/ISO LMP Node Designation	RTO/ISO Location Designation for Reporting Wholesale Sales Data to FERC	Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Status	Operating Month	Operating Year
GT		S	X	X			18.0	0.850	14.0	14.0	OP	6	1969
GT		S	X	X			18.0	0.850	14.6	14.6	OP	6	1969
GT		S	X	X			18.0	0.850	15.6	15.6	OP	6	1969
GT		S	X	X			18.0	0.850	14.5	14.5	OP	6	1969
GT		S	X	X			18.0	0.850	16.0	16.0	OP	6	1969
ST		S	X	X	51101101	51101101	550.0	0.800	607.7	637.0	OP	12	1969
ST		S	X	X			94.0	0.850	83.0	83.0	OP	7	1992
ST		J	X	X	20141102	20141102	1,244.8	0.920	1,223.7	1,296.0	OP	7	1974
ST		J	X	X	20141103	20141103	1,377.0	0.900	1,122.7	1,284.0	OP	12	1974
GT		S	X	X			3.0	0.800	2.7	2.7	OP	9	1996
GT		S	X	X			3.0	0.800	2.7	2.7	OP	9	1996
GT		S	X	X			53.1	0.850	52.0	52.0	OP	1	1972
GT		S	X	X			53.1	0.850	51.0	51.0	OP	4	1972
GT		S	X	X			53.1	0.850	51.0	51.0	OP	4	1972
GT		S	X	X			53.1	0.850	52.0	52.0	OP	4	1972
GT		S	X	X			192.0	0.900	147.6	147.6	OP	6	1995
GT		S	X	X			20.7	0.850	15.3	15.3	OP	8	1970
GT		S	X	X			20.7	0.850	16.0	16.0	OP	8	1970
GT		S	X	X			20.7	0.850	14.8	14.8	OP	9	1970
GT		S	X	X			20.7	0.850	14.8	14.8	OP	9	1970
ST		J	X	X	86251101	86251101	1,009.3	0.945	908.0	908.0	OP	12	1972
ST		J	X	X	86251102	86251102	1,009.3	0.945	911.0	911.0	OP	12	1972
GT		S	X	X			65.8	0.900	49.0	66.0	OP	6	1973
GT		S	X	X			65.8	0.900	49.0	66.0	OP	6	1973
ST		S	X	X			72.2	0.850	74.0	74.0	OP	9	1951
GT		S	X	X			25.0	0.850	19.0	19.0	OP	9	1970
GT		S	X	X			25.0	0.850	20.0	20.0	OP	9	1970
ST		J	X	X	50489	SALEM	1,170.0	0.900	1,170.2	1,170.2	OP	6	1977
ST		J	X	X	50490	SALEM	1,170.0	0.900	1,158.0	1,158.0	OP	10	1981
GT		J	X	X	50488	SALEM	41.8	0.900	38.4	38.4	SB	6	1971
GT		S	X	X			18.6	0.850	13.0	18.0	OP	5	1969
GT		S	X	X			21.2	0.850	17.0	20.0	OP	6	1971
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			50.9	0.850	37.0	40.0	OP	6	2002
GT		S	X	X			18.6	0.850	13.0	18.0	OP	6	1967
GT		S	X	X			18.6	0.850	13.0	18.0	OP	10	1967
GT		S	X	X			18.6	0.850	13.0	18.0	OP	7	1967
GT		S	X	X			18.6	0.850	13.0	18.0	OP	11	1968
ST		S	X	X	20111201	20111201	980.8	0.945	802.8	829.0	OP	8	1974
GT		S	X	X			121.5	0.900	115.8	115.8	OP	2	1969
PV		S	X	X			3.9		3.9	3.9	OP	12	2011
PV		S	X	X			1.4		1.4	1.4	OP	12	2010
PV		S	X	X			4.0		4.0	4.0	OP	3	2011
PV		S	X	X			1.4		1.4	1.4	OP	12	2010
PV		S	X	X			13.7		13.7	13.7	OP	7	2012
PV		S	X	X			4.1		4.1	4.1	OP	12	2011
PV		S	X	X			3.7		3.7	3.7	OP	10	2011
PV		S	X	X			2.3		2.3	2.3	OP	10	2011
PV		S	X	X			1.0		1.0	1.0	OP	5	2011
PV		S	X	X			2.8		2.8	2.8	OP	2	2013
CT	CCB1	S	X	N	T	T	120.0	0.850	113.0	113.0	OP	3	2011
CT	CCB1	S	X	N	T	T	120.0	0.850	122.0	122.0	OP	3	2011
CT	CCB1	S	X	N	T	T	120.0	0.850	122.0	122.0	OP	3	2011
CA	CCB1	S	N	X			200.0	0.850	188.0	188.0	OP	3	2011
CT	CC1	S	X	N	32417721	32417721	210.0	0.850	165.0	205.0	OP	6	2001
CT	CC1	S	X	N	32417723	32417723	210.0	0.850	165.0	205.0	OP	6	2001
CA	CC1	S	N	X	32417725	32417725	191.2	0.850	191.2	191.2	OP	6	2001
GT		J	X	X			192.0	0.850	150.0	192.0	OP	7	2001
GT		J	X	X			192.0	0.850	150.0	192.0	OP	7	2001
GT		J	X	X			192.0	0.850	150.0	192.0	OP	8	2001
GT		J	X	X			192.0	0.850	150.0	192.0	OP	8	2001
ST		J	X	X			614.0	0.920	582.0	583.0	OP	7	1970

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Prime Mover	Unit Code	Ownership	Duct Burners	Can Bypass Heat Recovery Steam Generator?	RTO/ISO LMP Node Designation	RTO/ISO Location Designation for Reporting Wholesale Sales Data to FERC	Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Status	Operating Month	Operating Year
ST		J	X	X			641.8	0.850	637.0	637.0	OP	12	1969
ST		J	X	X			1,259.3	0.900	1,287.0	1,301.0	OP	7	1987
WT		S	X	X			40.0		40.0	40.0	OP	12	2014

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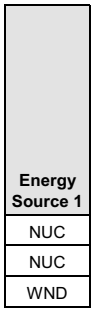

Energy Source 1
NUC
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WND

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2015 Form EIA-860 Data - Schedule 3, 'Generator Data' (Prelim)

Utility ID	Utility Name	Plant Code	Plant Name	State
6035	Exelon Power	59882	Exelon West Medway II LLC	MA
6035	Exelon Power	59882	Exelon West Medway II LLC	MA
55951	Exelon Nuclear	2589	Nine Mile Point Nuclear Station	NY
55951	Exelon Nuclear	2589	Nine Mile Point Nuclear Station	NY
55951	Exelon Nuclear	6122	R E Ginna Nuclear Power Plant	NY
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
49965	Constellation Mystic Power LLC	1588	Mystic Generating Station	MA
6035	Exelon Power	1586	Exelon Framingham LLC	MA
6035	Exelon Power	1586	Exelon Framingham LLC	MA
6035	Exelon Power	1586	Exelon Framingham LLC	MA
6035	Exelon Power	1587	Exelon L Street	MA
6035	Exelon Power	1592	Exelon Medway LLC	MA
6035	Exelon Power	1592	Exelon Medway LLC	MA
6035	Exelon Power	1592	Exelon Medway LLC	MA
31719	FPL Energy Wyman LLC	1507	William F Wyman	ME
55993	Kleen Energy Systems, LLC	56798	Kleen Energy Systems Project	CT
55993	Kleen Energy Systems, LLC	56798	Kleen Energy Systems Project	CT
55993	Kleen Energy Systems, LLC	56798	Kleen Energy Systems Project	CT

County	Generator ID	Technology	Prime Mover	Unit Code	Ownership	Duct Burners	Can Bypass Heat Recovery Steam Generator?	RTO/ISO LMP Node Designation	RTO/ISO Location Designation for Reporting Wholesale Sales Data to FERC
Norfolk	4	Gas Fired	GT		S	X	X		
Norfolk	5	Gas Fired	GT		S	X	X		
Oswego	1	Nuclear	ST		J	X	X		
Oswego	2	Nuclear	ST		J	X	X		
Wayne	1	Nuclear	ST		J	X	X		
Middlesex	7	m Liquids	ST		S	X	X	MYSTIC	MYSTIC
Middlesex	GT1	m Liquids	GT		S	X	X	MYSTIC	MYSTIC
Middlesex	GT81	Gas Fired	CT	G941	S	X	Y	MYSTIC	MYSTIC
Middlesex	GT82	Gas Fired	CT	G941	S	X	Y	MYSTIC	MYSTIC
Middlesex	GT93	Gas Fired	CT	G942	S	X	Y	MYSTIC	MYSTIC
Middlesex	GT94	Gas Fired	CT	G942	S	X	Y	MYSTIC	MYSTIC
Middlesex	ST85	Gas Fired	CA	G941	S	Y	X	MYSTIC	MYSTIC
Middlesex	ST96	Gas Fired	CA	G942	S	Y	X	MYSTIC	MYSTIC
Norfolk	GT1	m Liquids	GT		S	X	X		
Norfolk	GT2	m Liquids	GT		S	X	X		
Norfolk	GT3	m Liquids	GT		S	X	X		
Suffolk	GT1	m Liquids	GT		S	X	X		
Norfolk	GT1	m Liquids	GT		S	X	X		
Norfolk	GT2	m Liquids	GT		S	X	X		
Norfolk	GT3	m Liquids	GT		S	X	X		
Cumberland	4	Petroleum Liquids	ST		J	X	X		
Middlesex	ST	Gas Fired	CA	CC01	S	Y	X	14614	14614
Middlesex	U1	Gas Fired	CT	CC01	S	X	N	14614	14614
Middlesex	U2	Gas Fired	CT	CC01	S	X	N	14614	14614

637.0
1055.34

Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Status	Effective Month	Effective Year	Current Month	Current Year	Associated with Combined Heat and Power System
100.0	0.900	97.4	103.5	L	6	2018	6	2018	N
100.0	0.900	97.4	103.5	L	6	2018	6	2018	N
641.8	0.850	637.0	637.0						
1,259.3	0.900	1,287.0	1,301.0						
614.0	0.920	582.0	583.0						
617.0	0.900	570.8	559.8	90.0	N			OP	X
14.2	0.850	9.1	14.5	5.0	N			SB	Y
278.6	0.850	224.6	268.7	140.0	N			OP	X
278.6	0.850	226.7	271.2	140.0	N			OP	X
278.6	0.850	227.9	274.1	140.0	N			OP	X
278.6	0.850	230.1	276.7	140.0	N			OP	X
315.0	0.850	252.1	301.6	75.0	N			OP	X
315.0	0.850	255.9	307.7	75.0	N			OP	X
14.2	0.850	10.2	14.2	5.0	N			OP	X
14.2	0.850	9.9	13.9	5.0	N			OP	X
14.2	0.850	11.3	15.3	5.0	N			OP	X
18.6	0.850	16.0	21.8	6.0	N			OP	X
45.0	0.850	42.0	64.0	20.0	N			OP	X
45.0	0.850	39.8	61.6	20.0	N			OP	X
45.0	0.850	42.0	64.0	20.0	N			OP	X
632.4	0.930	602.1	605.8	60.0	N			OP	X
295.0	1.000	268.0	233.0	177.0	N			OP	X
199.0	1.000	177.0	195.0	120.0	N			OP	X
199.0	1.000	177.0	195.0	120.0	N			OP	X

Sector Name	Sector	Previously Canceled	Energy Source 1	Energy Source 2	Energy Source 3	Energy Source 4	Energy Source 5	Energy Source 6	Turbines, Inverters, or Hydrokinetic Buoys
CHP	2	N	NG	DFO					1
CHP	2	N	NG	DFO					1

6	1975			N	CHP	2	X	RFO	NG
6	1969			N	CHP	2	X	DFO	
4	2003			N	CHP	2	X	NG	
4	2003			N	CHP	2	X	NG	
6	2003			N	CHP	2	X	NG	
6	2003			N	CHP	2	X	NG	
4	2003			N	CHP	2	X	NG	
6	2003			N	CHP	2	X	NG	
3	1970			N	CHP	2	X	DFO	
9	1969			N	CHP	2	X	DFO	
9	1969			N	CHP	2	X	DFO	
9	1966	10	2016	N	CHP	2	X	DFO	
7	1970			N	CHP	2	X	DFO	
3	1971			N	CHP	2	X	DFO	
7	1970			N	CHP	2	X	DFO	
1	1978			N	IPP Non-CHP	2	X	RFO	
7	2011			N	CHP	2	X	NG	DFO
7	2011			N	CHP	2	X	NG	DFO
7	2011			N	CHP	2	X	NG	DFO

Fluidized Bed Technology?	Pulverized Coal Technology?	Stoker Technology?	Other Combustion Technology?	Subcritical Technology?	Supercritical Technology?	Ultrasupercritical Technology?	Solid Fuel Gasification System?	Carbon Capture Technology?	Switch Between Oil and Natural Gas?
									Y
							N	N	Y

				NG		NG		N	N
				DFO		DFO		N	N
				NG		NG		N	N
				NG				N	N
				NG				N	N
				NG				N	N
				NG				N	N
				NG				N	N
								N	
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								N	
				DFO				N	N
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Cofire Fuels?
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					N	N
					N	N
					N	Y
					N	Y

2015 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Utility ID	Utility Name	Plant Code	Plant Name	State	County	Generator ID	Technology
57397	Beebe Renewable Energy LLC	58020	Beebe Renewable Energy LLC	MI	Gratiot	1	Wind

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Prime Mover	Unit Code	Ownership	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Status	Operating Month	Operating Year	Energy Source 1	Energy Source 2
WT		S		81.6	81.6	OP	12	2012	WND	

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SIL Values used for the Northeast Region Triennials

Study Period of December 2014 to November 2015

	Study Area	Area Abbr	Winter 2014	Spring 2015	Summer 2015	Fall 2015	SIL Values Source
1	ISO-NE	ISO-NE	4,548	4,548	4,548	4,548	*Simultaneous Import Limit for 2015*, ISO New England Inc., Docket No. AD10-2-00_, (filed Dec. 20, 2016).
2	Connecticut	CT	3,050	3,050	3,050	3,050	
3	Southwest Connecticut	SWCT	2,540	2,370	3,200	3,190	
4	New Brunswick	NBPC	1,768	1,742	1,337	1,305	FERC Accepted Notheast SILs Dec11 to Nov12
5	NYISO	NYISO	7,524	6,850	7,695	7,635	NYISO's Informational Filing Regarding the
6	New York City	NYC	6,575	6,325	6,325	6,325	Simultaneous Import Limitation Study, Docket
7	Long Island	Long Island	1,760	2,090	2,090	2,090	No. AD10-2. (Filed Dec 19, 2016)
8	PJM	PJM	11,997	12,723	7,600	7,067	PJM Interconnection, L.L.C., Docket No. AD10-2
9	PJM East	PJM East	7,502	8,830	6,537	7,859	PJM Interconnection, L.L.C., Docket No. AD10-2
10	AP South	AP South	7,897	8,856	4,455	6,068	PJM Interconnection, L.L.C., Docket No. AD10-2
11	5004/5005	5004/5005	8,104	8,293	6,319	6,103	PJM Interconnection, L.L.C., Docket No. AD10-2

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		PST Summer	Winter	Spring	Summer	Fall
	Allocation of Imports into ISO-NE					
A	Seller's Uncommitted Capacity in NYISO	0	225	0	0	0
B	Seller's Uncommitted Capacity in HQT	0	0	0	0	0
C	Seller's Uncommitted Capacity in NBPC	0	0	0	0	0
D	**Seller's Uncommitted Capacity (SUM A-C)**	**0**	**225**	**0**	**0**	**0**
E	Total Uncommitted Capacity in NYISO	10,800	12,999	13,065	11,161	13,276
F	Total Uncommitted Capacity in HQT	11,132	7,914	10,905	13,475	15,221
G	Total Uncommitted Capacity in NBPC	1,203	825	994	1,228	1,339
H	**Total Uncommitted Capacity (SUM E-G)**	**23,135**	**21,738**	**24,964**	**25,864**	**29,836**
I	**Seller's Share of Uncommitted Capacity into ISO-NE (D/H)**	0.0%	1.0%	0.0%	0.0%	0.0%
J	**Imports into ISO-NE**	4,548	4,548	4,548	4,548	4,548
L	**Seller's Share of Imports into ISO-NE**	0	47	0	0	0

		PST Summer	Winter	Spring	Summer	Fall
	Allocation of Imports into CT					
A	Seller's Uncommitted Capacity in NYISO	0	225	0	0	0
B	Plus Seller's Ucommitted Capacity in ISO-NE	0	0	0	0	0
C	Less Seller's Uncommitted Capacity in CT	0	0	0	0	0
D	**Seller's Uncommitted Capacity (SUM A-B Less C)**	**0**	**225**	**0**	**0**	**0**
E	Total Uncommitted Capacity in NYISO	10,800	12,999	13,065	11,161	13,276
F	Plus Total Uncommitted Capacity in ISO-NE	12,493	14,497	15,302	13,159	14,873
G	Less Total Uncommitted Capacity in CT	2,020	3,092	3,139	2,192	2,986
H	**Total Uncommitted Capacity (SUM E-F Less G)**	**21,272**	**24,404**	**25,228**	**22,128**	**25,163**
I	**Seller's Share of Uncommitted Capacity into CT (D/H)**	0.0%	0.9%	0.0%	0.0%	0.0%
J	**Imports into CT**	3,050	3,050	3,050	3,050	3,050
K	**Seller's Share of Imports into CT (I*J)**	0	28	0	0	0

		PST Summer	Winter	Spring	Summer	Fall
	Allocation of Imports into NYISO					
A	Seller's Uncommitted Capacity in PJM	4,897	8,465	8,245	5,171	7,108
B	Seller's Uncommitted Capacity in ISO-NE	0	0	0	0	0
C	Seller's Uncommitted Capacity in HQT	0	0	0	0	0
D	Seller's Uncommitted Capacity in IESO	0	0	0	0	0
E	**Seller's Uncommitted Capacity (SUM A-F)**	**4,897**	**8,465**	**8,245**	**5,171**	**7,108**
F	Total Uncommitted Capacity in PJM	52,364	70,785	69,265	51,889	66,633
G	Total Uncommitted Capacity in ISO-NE	12,493	14,497	15,302	13,159	14,873
H	Total Uncommitted Capacity in HQT	11,132	7,914	10,905	13,475	15,221
I	Total Uncommitted Capacity in IESO	14,987	8,702	8,820	8,649	6,486

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J	**Total Uncommitted Capacity (SUM G-K)**	**90,975**	**101,897**	**104,292**	**87,172**	**103,213**
K	**Seller's Share of Uncommitted Capacity into NYISO (F/K)**	5.4%	8.3%	7.9%	5.9%	6.9%
L	**Imports into NYISO**	7,695	7,524	6,850	7,695	7,635
M	**Seller's Share of Imports into NYISO (L*M)**	414	625	542	456	526

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Seller Uncommitted Capacity in all BAAs, Markets or Sub-Markets

Dec 2014-Nov 2015

	Pivotal Supplier Analysis	Market Share Analysis			
ISONE Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	2,827	3,189	3,189	2,827	3,189
Average Daily Peak Native Load in Peak Month	(4,000)				
Average Peak Native Load in the Season		(3,627)	(3,224)	(4,080)	(3,720)
Operating Reserves	0	0	0	0	0
Planned Outages		(81)	(233)	(16)	(213)
Total Uncommitted Capacity in ISONE	0	0	0	0	0

	Pivotal Supplier Analysis	Market Share Analysis			
CT Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	622	623	623	622	623
Average Daily Peak Native Load in Peak Month	(1,470)				
Average Peak Native Load in the Season		(1,012)	(868)	(1,304)	(1,197)
Operating Reserves	0	0	0	0	0
Planned Outages		0	0	0	0
Total Uncommitted Capacity in CT	0	0	0	0	0

	Pivotal Supplier Analysis	Market Share Analysis			
PJM Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	24,436	25,455	25,455	24,436	25,455
Average Daily Peak Native Load in Peak Month	(19,538)				
Average Peak Native Load in the Season		(16,011)	(14,104)	(18,740)	(15,366)
Operating Reserves	0	0	0	0	0
Planned Outages		(979)	(3,106)	(524)	(2,981)
Total Uncommitted Capacity in PJM	4,897	8,465	8,245	5,171	7,108

	Pivotal Supplier Analysis	Market Share Analysis			
AP South Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	11,914	12,510	12,510	11,914	12,510
Average Daily Peak Native Load in Peak Month	(10,376)				
Average Peak Native Load in the Season		(8,453)	(7,202)	(10,017)	(8,235)

Operating Reserves	0	0	0	0	0
Planned Outages		(518)	(1,644)	(273)	(1,577)
Total Uncommitted Capacity in AP South	1,538	3,539	3,665	1,623	2,698

	Pivotal Supplier Analysis	Market Share Analysis			
5004/5005 Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	11,906	12,504	12,504	11,906	12,504
Average Daily Peak Native Load in Peak Month	(10,376)				
Average Peak Native Load in the Season		(8,348)	(7,135)	(10,017)	(8,235)
Operating Reserves	0	0	0	0	0
Planned Outages		(518)	(1,644)	(273)	(1,577)
Total Uncommitted Capacity in 5004/5005	1,530	3,637	3,725	1,616	2,691

	Pivotal Supplier Analysis	Market Share Analysis			
PJM East Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	7,551	7,974	7,974	7,551	7,974
Average Daily Peak Native Load in Peak Month	(5,063)				
Average Peak Native Load in the Season		(3,767)	(3,417)	(4,819)	(3,923)
Operating Reserves	0	0	0	0	0
Planned Outages		(317)	(1,007)	(166)	(966)
Total Uncommitted Capacity in PJM East	2,488	3,890	3,550	2,566	3,084

	Pivotal Supplier Analysis	Market Share Analysis			
NYISO Market	**PST Summer**	Winter	Spring	Summer	Fall
Installed Capacity	1,457	1,464	1,464	1,457	1,464
Average Daily Peak Native Load in Peak Month	(1,774)				
Average Peak Native Load in the Season		(1,053)	(1,345)	(1,785)	(1,610)
Operating Reserves	0	0	0	0	0
Planned Outages		(187)	(331)	(43)	(265)
Total Uncommitted Capacity in NYISO	0	225	0	0	0

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Total Uncommitted Capacity in all BAAs, Markets or Sub-Markets

Dec 2014-Nov 2015

	Pivotal Supplier		Market Share Analysis				
NBPC Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	4,361	4,427	4,427	4,427	4,361	4,427	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(2,741)	(2,741)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(2,654)	(2,062)	(1,595)	(1,764)	Wkp - Summary of Inputs Data
Operating Reserves	(417)	(417)	(417)	(430)	(441)	(429)	Wkp - Summary of Inputs Data
Planned Outages			(531)	(942)	(1,096)	(895)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in NBPC	1,203	1,269	825	994	1,228	1,339	

	Pivotal Supplier		Market Share Analysis				
NSPI Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	2,659	2,648	2,648	2,648	2,659	2,748	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(2,041)	(2,041)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(1,759)	(1,366)	(1,057)	(1,169)	Wkp - Summary of Inputs Data
Operating Reserves	(276)	(276)	(276)	(285)	(293)	(285)	Wkp - Summary of Inputs Data
Planned Outages			(318)	(563)	(669)	(555)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in NSPI	342		295	433	641	739	

	Pivotal Supplier		Market Share Analysis				
IESO Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	36,740	36,058	36,058	36,428	36,740	36,995	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(20,089)	(20,089)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(19,875)	(16,965)	(17,949)	(17,489)	Wkp - Summary of Inputs Data
Operating Reserves	(1,664)	(1,664)	(1,392)	(1,540)	(1,664)	(1,656)	Wkp - Summary of Inputs Data
Planned Outages			(6,089)	(9,103)	(8,478)	(11,364)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in IESO	14,987	14,305	8,702	8,820	8,649	6,486	

	Pivotal Supplier		Market Share Analysis				
HQT Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	45,936	45,885	45,885	46,280	45,936	46,269	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(33,304)	(33,304)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(32,242)	(25,046)	(19,377)	(21,430)	Wkp - Summary of Inputs Data
Operating Reserves	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	Wkp - Summary of Inputs Data
Planned Outages			(4,230)	(8,830)	(11,584)	(8,117)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in HQT	11,132	11,082	7,914	10,905	13,475	15,221	

	Pivotal Supplier		Market Share Analysis				
NYISO Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	38,665	41,013	41,013	41,013	38,665	41,013	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(25,244)	(25,244)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(22,045)	(19,393)	(24,144)	(20,374)	Wkp - Summary of Inputs Data
Operating Reserves	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	(2,620)	Wkp - Summary of Inputs Data
Planned Outages			(3,348)	(5,935)	(739)	(4,743)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in NYISO	10,800	13,148	12,999	13,065	11,161	13,276	

	Pivotal Supplier		Market Share Analysis				
NYC Sub-Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data

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Average Daily Peak Native Load in Peak Month	#N/A	#N/A					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Operating Reserves	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Planned Outages			#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in NYC	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	

	Pivotal Supplier		Market Share Analysis				
Long Island Sub-Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	#N/A	#N/A					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Operating Reserves	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Planned Outages			#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in Long Island	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	

	Pivotal Supplier		Market Share Analysis				
ISO-NE Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	33,424	35,576	35,576	35,576	33,424	35,576	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(19,621)	(19,621)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(18,391)	(15,604)	(18,719)	(16,307)	Wkp - Summary of Inputs Data
Operating Reserves	(1,310)	(1,310)	(1,562)	(1,436)	(1,310)	(1,436)	Wkp - Summary of Inputs Data
Planned Outages			(1,127)	(3,234)	(236)	(2,960)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in ISO-NE	12,493	14,645	14,497	15,302	13,159	14,873	

	Pivotal Supplier		Market Share Analysis				
CT Sub-Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	7,789	8,213	8,213	8,213	7,789	8,213	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(5,054)	(5,054)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(4,497)	(3,789)	(4,827)	(4,005)	Wkp - Summary of Inputs Data
Operating Reserves	(714)	(714)	(363)	(539)	(714)	(539)	Wkp - Summary of Inputs Data
Planned Outages			(260)	(747)	(55)	(683)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in CT	2,020	2,444	3,092	3,139	2,192	2,986	

	Pivotal Supplier		Market Share Analysis				
SWCT Sub-Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	#N/A	#N/A					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Operating Reserves	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Planned Outages			#N/A	#N/A	#N/A	#N/A	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in SWCT	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	

	Pivotal Supplier		Market Share Analysis				
PJM Market	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	183,060	199,600	199,600	196,690	183,060	192,785	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(121,600)	(121,600)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(112,390)	(94,917)	(117,821)	(95,173)	Wkp - Summary of Inputs Data
Operating Reserves	(9,097)	(9,097)	(8,067)	(6,367)	(9,097)	(6,391)	Wkp - Summary of Inputs Data
Planned Outages			(8,359)	(26,142)	(4,254)	(24,589)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in PJM	52,364	68,903	70,785	69,265	51,889	66,633	

	Pivotal Supplier		Market Share Analysis

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AP South Sub-Market	PST Summer	PST Winter	Winter	Spring	Summer	Fall	Reference
Installed Capacity	78,969	84,538	84,538	83,829	78,969	84,193	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(58,108)	(58,108)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(51,170)	(43,394)	(56,097)	(43,262)	Wkp - Summary of Inputs Data
Operating Reserves	(2,868)	(2,868)	(2,552)	(2,266)	(2,772)	(2,230)	Wkp - Summary of Inputs Data
Planned Outages			(3,540)	(11,141)	(1,835)	(10,738)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in AP South	17,993	23,562	27,276	27,027	18,265	27,963	

	Pivotal Supplier		Market Share Analysis				
5004/5005 Sub-Market	PST Summer	PST Winter	Winter	Spring	Summer	Fall	Reference
Installed Capacity	55,814	59,991	59,991	59,282	55,814	59,741	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(42,368)	(42,368)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(36,840)	(31,515)	(40,748)	(31,648)	Wkp - Summary of Inputs Data
Operating Reserves	(2,512)	(2,512)	(2,185)	(1,869)	(2,416)	(1,877)	Wkp - Summary of Inputs Data
Planned Outages			(2,512)	(7,879)	(1,297)	(7,620)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in 5004/5005	10,934	15,111	18,454	18,018	11,353	18,595	

	Pivotal Supplier		Market Share Analysis				
PJM East Sub-Market	PST Summer	PST Winter	Winter	Spring	Summer	Fall	Reference
Installed Capacity	34,630	38,116	38,116	37,407	34,630	37,735	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(24,093)	(24,093)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(19,303)	(16,803)	(22,934)	(17,326)	Wkp - Summary of Inputs Data
Operating Reserves	(1,429)	(1,429)	(1,145)	(996)	(1,360)	(1,027)	Wkp - Summary of Inputs Data
Planned Outages			(1,596)	(4,972)	(805)	(4,813)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in PJM East	9,109	12,594	16,072	14,636	9,532	14,569	

	Pivotal Supplier		Market Share Analysis				
MISO Balancing Authority Area	PST Summer	PST Winter	Winter	Spring	Summer	Fall	Reference
Installed Capacity	168,505	175,367	175,367	175,695	168,505	175,039	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(102,563)	(102,563)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(86,929)	(76,192)	(97,947)	(80,875)	Wkp - Summary of Inputs Data
Operating Reserves	(2,438)	(2,438)	(2,440)	(2,439)	(2,438)	(2,440)	Wkp - Summary of Inputs Data
Planned Outages			(13,735)	(24,153)	(7,363)	(19,757)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in MISO	63,504	70,366	72,264	72,912	60,757	71,967	

	Pivotal Supplier		Market Share Analysis				
CPLE Balancing Authority Area	PST Summer	PST Winter	Winter	Spring	Summer	Fall	Reference
Installed Capacity	13,525	14,696	14,696	14,696	13,525	14,720	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(10,538)	(10,538)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(9,332)	(7,425)	(10,231)	(7,487)	Wkp - Summary of Inputs Data
Operating Reserves	(244)	(244)	(244)	(233)	(221)	(230)	Wkp - Summary of Inputs Data
Planned Outages			(655)	(1,525)	(16)	(1,175)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in CPLE	2,743	3,914	4,465	5,514	3,057	5,827	

	Pivotal Supplier		Market Share Analysis				
CPLW Balancing Authority Area	PST Summer	PST Winter	Winter	Spring	Summer	Fall	Reference
Installed Capacity	826	878	878	878	826	878	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(869)	(869)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(770)	(612)	(844)	(618)	Wkp - Summary of Inputs Data
Operating Reserves	(20)	(20)	(20)	(19)	(18)	(19)	Wkp - Summary of Inputs Data
Planned Outages			(39)	(91)	(1)	(70)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in CPLW	0	0	49	155	0	171	

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	Pivotal Supplier		Market Share Analysis				
LGEE Balancing Authority Area	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	8,838	9,033	9,033	8,793	8,838	9,108	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(5,754)	(5,754)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(5,124)	(4,348)	(5,616)	(4,421)	Wkp - Summary of Inputs Data
Operating Reserves	(222)	(222)	(222)	(223)	(231)	(242)	Wkp - Summary of Inputs Data
Planned Outages			0	(1,187)	0	(892)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in LGEE	2,862	3,057	3,687	3,034	2,991	3,553	

	Pivotal Supplier		Market Share Analysis				
DUKE Balancing Authority Area	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	24,632	25,619	25,619	25,619	24,632	25,619	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(16,433)	(16,433)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(14,053)	(11,801)	(15,919)	(11,970)	Wkp - Summary of Inputs Data
Operating Reserves	(358)	(358)	(358)	(365)	(372)	(393)	Wkp - Summary of Inputs Data
Planned Outages			(1,002)	(3,838)	(254)	(2,127)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in DUKE	7,840	8,828	10,207	9,616	8,087	11,129	

	Pivotal Supplier		Market Share Analysis				
TVA Balancing Authority Area	**PST Summer**	**PST Winter**	Winter	Spring	Summer	Fall	**Reference**
Installed Capacity	35,065	37,014	37,014	37,014	35,065	36,069	Wkp - Summary of Inputs Data
Average Daily Peak Native Load in Peak Month	(25,981)	(25,981)					Wkp - Summary of Inputs Data
Average Peak Native Load in the Season			(22,486)	(18,523)	(24,974)	(18,959)	Wkp - Summary of Inputs Data
Operating Reserves	(1,043)	(1,043)	(1,043)	(1,042)	(1,008)	(1,023)	Wkp - Summary of Inputs Data
Planned Outages			(3,257)	(6,237)	(1,810)	(6,067)	Wkp - Summary of Inputs Data
Total Uncommitted Capacity in TVA	8,040	9,990	10,228	11,213	7,272	10,021	

	Generation (MW)						
	PST	MST					
Markets or Sub-Markets	PSA	Winter	Spring	Summer	Fall	Reference	Markets or Sub-Markets
NBPC	4,427	4,427	4,427	4,361	4,427	Wkp - Canadian BAAs Generation	NBPC
NSPI	2,648	2,648	2,648	2,659	2,748	Wkp - Canadian BAAs Generation	NSPI
IESO	36,058	36,058	36,428	36,740	36,995	Wkp - Canadian BAAs Generation	IESO
HQT	45,885	45,885	46,280	45,936	46,269	Wkp - Canadian BAAs Generation	HQT
NYISO	38,665	41,013	41,013	38,665	41,013	Wkp - NYCA_2015	NYISO
ISO-NE	33,424	35,576	35,576	33,424	35,576	Wkp - ISO-NE CELT	ISO-NE
CT	7,789	8,213	8,213	7,789	8,213	Wkp - ISO-NE CELT	CT
PJM	183,060	199,600	196,690	183,060	192,785	Wkp - PJM Generation Summary	PJM
AP South	78,969	84,538	83,829	78,969	84,193	Wkp - PJM Generation Summary	AP South
5004/5005	55,814	59,991	59,282	55,814	59,741	Wkp - PJM Generation Summary	5004/5005
PJM East	34,630	38,116	37,407	34,630	37,735	Wkp - PJM Generation Summary	PJM East

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CPLE	13,525	14,696	14,696	13,525	14,720	Wkp - SE-MISO Gen Summary	CPLE
CPLW	826	878	878	826	878	Wkp - SE-MISO Gen Summary	CPLW
DUKE	24,632	25,619	25,619	24,632	25,619	Wkp - SE-MISO Gen Summary	DUKE
LGEE	8,838	9,033	8,793	8,838	9,108	Wkp - SE-MISO Gen Summary	LGEE
MISO	168,505	175,367	175,695	168,505	175,039	Wkp - SE-MISO Gen Summary	MISO
TVA	35,065	37,014	37,014	35,065	36,069	Wkp - SE-MISO Gen Summary	TVA

Load (MW)								
PST		MST						PST
Peak	Avg	Winter	Spring	Summer	Fall	Reference	Markets or Sub-Markets	PSA
3,206	2,741	2,654	2,062	1,595	1,764	Wkp - Canadian BAAs Loads	NBPC	417
2,604	2,041	1,759	1,366	1,057	1,169	Wkp - Canadian BAAs Loads	NSPI	276
21,814	20,089	19,875	16,965	17,949	17,489	Wkp - Canadian BAAs Loads	IESO	1,664
38,950	33,304	32,242	25,046	19,377	21,430	Wkp - Canadian BAAs Loads	HQT	1,500
31,138	25,244	22,045	19,393	24,144	20,374	Wkp - NYISO Load	NYISO	2,620
24,437	19,621	18,391	15,604	18,719	16,307	Wkp - ISO-NE Load	ISO-NE	1,310
6,419	5,054	4,497	3,789	4,827	4,005	Wkp - CT Load	CT	714
143,633	121,600	112,390	94,917	117,821	95,173	Wkp - PJM Load	PJM	9,097
70,729	58,108	51,170	43,394	56,097	43,262	Wkp - AP South Load	AP South	2,868
52,190	42,368	36,840	31,515	40,748	31,648	Wkp - 5004 5005 Load	5004/5005	2,512
30,240	24,093	19,303	16,803	22,934	17,326	Wkp - PJM East Load	PJM East	1,429
14,383	10,538	9,332	7,425	10,231	7,487	Wkp - Southeast & MISO Load	CPLE	244
1,186	869	770	612	844	618	Wkp - Southeast & MISO Load	CPLW	20
21,101	16,433	14,053	11,801	15,919	11,970	Wkp - Southeast & MISO Load	DUKE	358
7,236	5,754	5,124	4,348	5,616	4,421	Wkp - Southeast & MISO Load	LGEE	222
118,332	102,563	86,929	76,192	97,947	80,875	Wkp - Southeast & MISO Load	MISO	2,438
32,751	25,981	22,486	18,523	24,974	18,959	Wkp - Southeast & MISO Load	TVA	1,043

Reserves (MW) MST					Markets or Sub-Markets	Outages (MW) MST		
Winter	Spring	Summer	Fall	Reference		Winter	Spring	Summer
417	430	441	429	Wkp - NPCC Outages & Reserves	NBPC	531	942	1,096
276	285	293	285	Wkp - NPCC Outages & Reserves	NSPI	318	563	669
1,392	1,540	1,664	1,656	Wkp - NPCC Outages & Reserves	IESO	6,089	9,103	8,478
1,500	1,500	1,500	1,500	Wkp - NPCC Outages & Reserves	HQT	4,230	8,830	11,584
2,620	2,620	2,620	2,620	Wkp - NYISO Reserves	NYISO	3,348	5,935	739
1,562	1,436	1,310	1,436	Wkp - ISO-NE Reserves	ISO-NE	1,127	3,234	236
363	539	714	539	Wkp - ISO-NE Reserves	CT	260	747	55
8,067	6,367	9,097	6,391	Wkp - PJM Operating Reserves	PJM	8,359	26,142	4,254
2,552	2,266	2,772	2,230	Wkp - PJM Operating Reserves	AP South	3,540	11,141	1,835
2,185	1,869	2,416	1,877	Wkp - PJM Operating Reserves	5004/5005	2,512	7,879	1,297
1,145	996	1,360	1,027	Wkp - PJM Operating Reserves	PJM East	1,596	4,972	805
244	233	221	230	Wkp - SERC Operating Reserves	CPLE	655	1,525	16
20	19	18	19	Wkp - SERC Operating Reserves	CPLW	39	91	1
358	365	372	393	Wkp - SERC Operating Reserves	DUKE	1,002	3,838	254
222	223	231	242	Wkp - SERC Operating Reserves	LGEE	0	1,187	0
2,440	2,439	2,438	2,440	MISO Triennials Data (Dec12 to Nov13)	MISO	13,735	24,153	7,363
1,043	1,042	1,008	1,023	Wkp - SERC Operating Reserves	TVA	3,257	6,237	1,810

Fall	Reference
895	Wkp - NPCC Outages & Reserves
555	Wkp - NPCC Outages & Reserves
11,364	Wkp - NPCC Outages & Reserves
8,117	Wkp - NPCC Outages & Reserves
4,743	Wkp - NYISO Outages
2,960	Wkp - ISO-NE Outages
683	Wkp - ISO-NE Outages
24,589	Wkp - PJM Outages
10,738	Wkp - PJM Outages
7,620	Wkp - PJM Outages
4,813	Wkp - PJM Outages

1,175	Wkp -Southeast and MISO Outages
70	Wkp -Southeast and MISO Outages
2,127	Wkp -Southeast and MISO Outages
892	Wkp -Southeast and MISO Outages
19,757	Wkp -Southeast and MISO Outages
6,067	Wkp -Southeast and MISO Outages

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Ventyx IESO Load Summary	
Peak	22,516
Peak Month	July
January Peak	21,814
January Avg	20,089
February Peak	21,494
February Avg	20,556
PST	18,815
Winter	19,875
Spring	16,965
Summer	17,949
Fall	17,489

Modeled Loads	
IESO	
January Peak	21,814
Peak Month	Jan
IESO July Peak	22,516
IESO July Avg	18,815
Summer Peak	22,516
PST	20,089
Winter	19,875
Spring	16,965
Summer	17,949
Fall	17,489

Modeled Loads	
Maritimes	
Peak	5,314
Peak Month	Feb
Summer Peak	3,688
PST	4,782
Winter	4,413
Spring	3,428
Summer	2,652
Fall	2,933

Modeled Loads	
NBPC	
Peak	3,206
Peak Month	Jan
NBPC Feb Peak	3,196
NBPC Feb Avg	2,876
PST	2,741
Winter	2,654
Spring	2,062
Summer	1,595
Fall	1,764

Modeled Loads	
NSPI	
Peak	2,604
Peak Month	Feb
PST	2,041
Winter	1,759
Spring	1,366
Summer	1,057
Fall	1,169

Modeled Loads	
HQT BAA	
Peak	38,950
Peak Month	Jan
NBPC Jan Peak	3,206
NBPC Jan Avg	2,741
Summer Peak	20,766
PST	33,304
Winter	32,242
Spring	25,046
Summer	19,377
Fall	21,430

IESO load from ABB, The Velocity Suite
NBPC Load from New Bruswick Power archive website
Maritimes and Hydro Quebec Peak demand from NPCC seasonnal assessment.
NSPI load is assumed to be the difference between the Maritimes and NBPC Loads
https://www.npcc.org/Library/Seasonal%20Assessment/2015-16W_NPCC%20Seasonal%20Assessment%20-%20Final%20Report%20-%20Posted%20NPCC%20Web%20Site%2020151204.pdf
https://www.npcc.org/Library/Seasonal%20Assessment/NPCC_Reliability_Assessment_for_2016_Summer-Final_Report.pdf

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Ontario Balancing Authority Areas Load Data - Source: Ventyx, The Velocity Suite
Dec 2014-Nov 2015 Load

Needle Peak	**IESO**	22,516
Avg July (P Month)	**IESO**	18,815
Winter	**IESO**	19,875
Spring	**IESO**	16,965
Summer	**IESO**	17,949
Fall	**IESO**	17,489

Source: ABB, The Velocity Suite
CONFIDENTIAL DATA REDACTED

Date	BAA	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
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Table AP-6 – Québec

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat. (MW)	Req. Reserves (MW)
7-Dec-14	44,681	4,290	1,500
14-Dec-14	44,681	4,394	1,500
21-Dec-14	44,681	4,549	1,500
28-Dec-14	44,681	4,386	1,500
4-Jan-15	44,681	3,924	1,500
11-Jan-15	44,681	3,985	1,500
18-Jan-15	44,681	4,125	1,500
25-Jan-15	44,681	4,142	1,500
1-Feb-15	44,681	4,137	1,500
8-Feb-15	44,681	4,214	1,500
15-Feb-15	44,681	4,284	1,500
22-Feb-15	44,681	4,324	1,500
1-Mar-15	44,681	4,592	1,500
8-Mar-15	44,681	4,756	1,500
15-Mar-15	44,681	4,761	1,500
22-Mar-15	44,681	4,686	1,500
29-Mar-15	44,681	5,301	1,500

Season	Outages Factors (%)
Winter	10%
Winter	10%
Winter	10%
Winter	10%
Winter	9%
Winter	9%
Winter	9%
Winter	9%
Winter	9%
Winter	9%
Winter	10%
Winter	10%
Spring	10%
Spring	11%
Spring	11%
Spring	10%
Spring	12%

Tables AP-5 – Ontario

Installed Capacity (MW)	Known Maint./Derat. (MW)	Req. Reserves (MW)
34,382	5,888	1,392
34,382	5,853	1,392
34,382	5,063	1,392
34,382	4,565	1,392
34,628	5,379	1,392
34,628	6,148	1,392
34,628	6,120	1,392
38,628	6,142	1,392
35,065	6,585	1,392
35,165	7,119	1,392
35,065	7,156	1,392
35,065	7,050	1,392
35,232	7,288	1,392
35,232	7,436	1,392
35,232	7,456	1,392
35,232	7,513	1,392
35,232	11,368	1,392

Season	Outages Factors (%)
Winter	17%
Winter	17%
Winter	15%
Winter	13%
Winter	16%
Winter	18%
Winter	18%
Winter	18%
Winter	19%
Winter	20%
Winter	20%
Winter	20%
Spring	21%
Spring	21%
Spring	21%
Spring	21%
Spring	32%

Tables AP-2 – Maritimes

Installed Capacity (MW)	Known Maint./Derat. (MW)	Req. Reserves (MW)
7,557	847	693
7,557	847	693
7,557	847	693
7,557	798	693
7,586	820	693
7,586	820	693
7,586	820	693
7,586	836	693
7,618	893	693
7,618	893	693
7,618	877	693
7,639	1,046	693
7,639	1,046	693
7,639	1,046	693
7,639	970	693
7,647	1,187	693

Season	Outages Factors (%)
Winter	11%
Winter	11%
Winter	11%
Winter	11%
Winter	11%
Winter	11%
Winter	11%
Winter	11%
Winter	12%
Winter	12%
Winter	12%
Winter	12%
Spring	14%
Spring	14%
Spring	14%
Spring	13%
Spring	18%

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat (MW)	Req. Reserves (MW)
26-Mar-15	44,813	12,693	1,500
2-Apr-15	44,813	12,162	1,500
10-Apr-15	44,813	12,393	1,500
17-Apr-15	44,813	12,637	1,500
24-Apr-15	44,813	13,052	1,500
31-May-15	44,813	11,604	1,500
7-Jun-15	44,813	12,488	1,500
14-Jun-15	44,813	11,837	1,500
21-Jun-15	44,813	10,650	1,500
28-Jun-15	44,813	11,198	1,500
5-Jul-15	44,813	12,299	1,500
12-Jul-15	44,813	11,708	1,500
19-Jul-15	44,813	11,430	1,500
26-Jul-15	44,813	10,731	1,500
2-Aug-15	44,813	10,892	1,500
9-Aug-15	44,813	11,795	1,500
16-Aug-15	44,813	11,605	1,500
23-Aug-15	44,813	11,665	1,500
30-Aug-15	44,813	12,299	1,500
6-Sep-15	44,813	12,287	1,500
13-Sep-15	44,813	11,287	1,500

Season	Outages Factors (%)
Spring	28%
Spring	27%
Spring	28%
Spring	28%
Spring	27%
Spring	26%
Summer	28%
Summer	28%
Summer	24%
Summer	25%
Summer	27%
Summer	28%
Summer	24%
Summer	26%
Summer	27%
Fall	27%
Fall	25%

Installed Capacity (MW)	Known Maint./Derat. (MW)	Req. Reserves (MW)
35,126	10,754	1,664
35,251	10,936	1,664
35,251	10,709	1,664
35,251	8,738	1,664
35,251	8,660	1,664
35,251	9,091	1,664
35,251	9,329	1,664
35,251	9,273	1,664
35,251	8,724	1,664
35,253	8,768	1,664
35,547	7,851	1,664
35,547	7,820	1,664
35,547	7,794	1,664
35,547	7,848	1,664
35,547	8,863	1,664
35,547	8,357	1,664
35,547	7,637	1,664
35,547	8,358	1,664
35,845	9,606	1,664
35,845	13,618	1,664
35,845	13,030	1,632

Season	Outages Factors (%)
Spring	31%
Spring	31%
Spring	30%
Spring	35%
Spring	35%
Spring	36%
Summer	36%
Summer	38%
Summer	25%
Summer	25%
Summer	25%
Summer	22%
Summer	22%
Summer	22%
Summer	22%
Summer	22%
Summer	25%
Summer	24%
Summer	27%
Fall	28%
Fall	39%

Installed Capacity (MW)	Known Maint./Derat. (MW)	Req. Reserves (MW)
7,693	2,048	734
7,722	2,131	734
7,722	1,978	734
7,722	1,605	734
7,722	1,714	734
7,722	1,784	734
7,723	1,906	734
7,723	1,859	734
7,723	1,644	734
7,723	1,616	734
7,726	1,674	734
7,726	1,671	734
7,726	1,667	734
7,726	1,850	734
7,726	1,815	734
7,726	1,720	734
7,726	2,044	734
7,726	2,065	734
7,726	1,809	734
7,741	1,788	734
7,741	2,115	734

Season	Outages Factors (%)
Spring	27%
Spring	28%
Spring	28%
Spring	27%
Spring	22%
Spring	23%
Summer	29%
Summer	24%
Summer	27%
Summer	27%
Summer	22%
Summer	22%
Summer	22%
Summer	27%
Summer	21%
Summer	22%
Summer	28%
Summer	27%
Summer	23%
Fall	23%
Fall	27%

Week Beginning Sundays	Installed Capacity (MW)	Known Maint./Derat (MW)	Req. Reserves (MW)
21-Nov-15	45,380	8,487	1,500
28-Nov-15	45,380	8,406	1,500

Season	Outages Factors (%)
Fall	10%
Fall	10%

Installed Capacity (MW)	Known Maint./Derat. (MW)	Req. Reserves (MW)
35,748	9,051	1,664
35,748	8,875	1,664

Season	Outages Factors (%)
Fall	25%
Fall	29%

Installed Capacity (MW)	Known Maint./Derat. (MW)	Req. Reserves (MW)
7,743	931	693
7,744	960	693

Season	Outages Factors (%)
Fall	12%
Fall	12%

	Québec				Ontario				Maritimes			
	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Average Outage Factors	9%	26%	26%	18%	18%	26%	24%	32%	11%	20%	23%	19%
Average Outages	4,130	8,830	11,584	8,117	6,089	9,103	8,478	11,364	849	1,565	1,765	1,450
Operating Reserves	1,500	1,500	1,500	1,500	1,392	1,540	1,664	1,656	693	715	734	714

	NBPC Generation				NSPI Generation			
	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall
Total Generation	4,427	4,427	4,361	4,427	2,648	2,648	2,659	2,748
Share of Maritimes Outages	521	942	1,096	895	328	623	669	555
Share of Operating Reserves	417	430	441	429	276	285	293	285
Total Load	2,654	2,062	1,595	1,764	1,759	1,266	1,057	1,369

Source Links
2015: https://www.npcc.org/Library/Seasonal%20Assessment/NPCC%20Seasonal%20Assessment%20Report-Final_20141202.pdf

https://www.npcc.org/Library/Seasonal%20Assessment/20145_NPCC%20Seasonal%20Assessment%20Final%20Report.pdf

https://www.npcc.org/Library/Seasonal%20Assessment/2014-2015_Winter_NPCC%20Seasonal%20Assessment%20Report-Final_20141202.pdf

https://www.npcc.org/Library/Seasonal%20Assessment/2015-16W_NPCC%20Seasonal%20Assessment%20-%20Final%20Report%20-%20Posted%20NPCC%20Web%20Site%2020151204.pdf

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Max	3,206
Max Month	1
PST	2,741
Winter	2,654
Spring	2,062
Summer	1,595
Fall	1,764

Source: New Brunswick Power Website Archive data
http://tso.nbpower.com/Public/en/system_information_archive.aspx

NB Power load assumed to be "NB_DEMAND" +/- "NMISA" +/- "PEI"

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	2,087	12/1/2014	1,586	1,500	1,485	1,469	1,462	1,472	1,528	1,734	1,949	1,936	1,869	1,848	1,825	1,781	1,771	1,782	1,807	1,966	2,087	2,067	2,040	2,005	1,936	1,817
Winter	12	2,586	12/2/2014	1,699	1,616	1,647	1,672	1,697	1,756	1,873	2,087	2,348	2,375	2,295	2,243	2,206	2,154	2,152	2,161	2,234	2,436	2,586	2,543	2,568	2,550	2,461	2,330
Winter	12	2,357	12/3/2014	2,178	2,058	2,009	2,007	1,976	1,991	2,019	2,205	2,357	2,297	2,229	2,181	2,144	2,071	2,022	1,954	1,927	2,013	2,067	2,003	1,972	1,911	1,787	1,635
Winter	12	2,296	12/4/2014	1,555	1,469	1,475	1,495	1,507	1,541	1,617	1,828	2,078	2,074	2,008	1,933	1,903	1,860	1,858	1,876	1,879	2,032	2,250	2,269	2,296	2,284	2,228	2,154
Winter	12	2,729	12/5/2014	2,052	2,001	2,008	2,028	2,037	2,100	2,210	2,451	2,729	2,723	2,642	2,552	2,491	2,400	2,352	2,302	2,318	2,436	2,565	2,546	2,530	2,483	2,429	2,366
Winter	12	2,403	12/6/2014	2,270	2,159	2,094	2,057	2,026	2,019	2,028	2,100	2,209	2,320	2,395	2,403	2,352	2,305	2,259	2,221	2,242	2,332	2,335	2,230	2,121	2,034	1,947	1,877
Winter	12	2,567	12/7/2014	1,763	1,719	1,666	1,663	1,667	1,695	1,751	1,838	1,943	2,077	2,162	2,178	2,180	2,174	2,134	2,107	2,159	2,357	2,520	2,541	2,563	2,567	2,479	2,365
Winter	12	3,009	12/8/2014	2,255	2,207	2,196	2,248	2,300	2,358	2,480	2,701	2,995	3,009	2,922	2,811	2,721	2,579	2,480	2,452	2,494	2,647	2,739	2,696	2,654	2,618	2,528	2,409
Winter	12	2,668	12/9/2014	2,260	2,175	2,123	2,131	2,173	2,186	2,272	2,412	2,642	2,668	2,608	2,531	2,417	2,389	2,367	2,364	2,377	2,481	2,530	2,462	2,430	2,348	2,228	2,052
Winter	12	2,285	#########	1,941	1,742	1,707	1,693	1,698	1,717	1,795	1,972	2,197	2,285	2,186	2,124	2,177	2,192	2,184	2,153	2,143	2,228	2,285	2,211	2,277	2,191	2,120	1,967
Winter	12	2,206	#########	1,767	1,670	1,653	1,636	1,617	1,621	1,681	1,886	2,100	2,064	2,039	2,022	2,013	1,989	1,959	1,939	1,984	2,111	2,206	2,172	2,111	2,052	1,952	1,836
Winter	12	2,199	#########	1,700	1,595	1,594	1,585	1,575	1,644	1,722	1,928	2,167	2,167	2,127	2,118	2,109	2,059	2,064	2,057	2,073	2,164	2,199	2,146	2,079	2,024	1,953	1,862
Winter	12	2,146	#########	1,746	1,704	1,652	1,638	1,649	1,659	1,710	1,823	1,935	2,036	2,049	2,037	1,965	1,963	1,915	1,912	1,979	2,112	2,135	2,146	2,133	2,124	2,064	1,969
Winter	12	2,273	#########	1,873	1,791	1,752	1,723	1,705	1,717	1,768	1,850	1,953	2,064	2,145	2,156	2,153	2,115	2,085	2,073	2,088	2,193	2,273	2,223	2,168	2,128	2,063	1,914
Winter	12	2,352	#########	1,780	1,679	1,656	1,640	1,657	1,696	1,760	1,979	2,198	2,193	2,166	2,107	2,129	2,099	2,085	2,070	2,104	2,245	2,350	2,352	2,286	2,263	2,187	2,044
Winter	12	2,395	#########	1,906	1,797	1,776	1,782	1,798	1,839	1,935	2,157	2,383	2,395	2,332	2,259	2,237	2,194	2,164	2,147	2,184	2,285	2,361	2,372	2,343	2,313	2,224	2,079
Winter	12	2,395	#########	1,929	1,837	1,802	1,795	1,793	1,820	1,908	2,144	2,391	2,395	2,303	2,254	2,228	2,172	2,132	2,139	2,176	2,265	2,355	2,352	2,328	2,324	2,223	2,055
Winter	12	2,455	#########	1,871	1,734	1,679	1,657	1,645	1,664	1,729	1,929	2,178	2,201	2,195	2,195	2,220	2,181	2,174	2,189	2,219	2,337	2,455	2,435	2,418	2,361	2,271	2,123
Winter	12	2,318	#########	1,976	1,823	1,815	1,766	1,771	1,789	1,859	2,039	2,286	2,301	2,253	2,188	2,135	2,074	2,135	2,119	2,165	2,229	2,318	2,278	2,238	2,205	2,149	2,030
Winter	12	2,396	#########	1,913	1,813	1,808	1,809	1,808	1,833	1,875	1,992	2,109	2,233	2,309	2,316	2,289	2,244	2,186	2,164	2,215	2,330	2,396	2,329	2,278	2,236	2,185	2,094
Winter	12	2,399	#########	1,999	1,933	1,891	1,864	1,869	1,874	1,908	1,972	2,092	2,227	2,313	2,331	2,315	2,297	2,259	2,230	2,244	2,322	2,399	2,370	2,342	2,288	2,236	2,124
Winter	12	2,442	#########	2,000	1,926	1,893	1,881	1,898	1,934	2,019	2,192	2,364	2,409	2,420	2,395	2,355	2,280	2,253	2,198	2,241	2,364	2,442	2,416	2,395	2,359	2,293	2,165
Winter	12	2,387	#########	2,036	1,919	1,894	1,895	1,870	1,893	1,974	2,137	2,318	2,374	2,373	2,356	2,332	2,277	2,243	2,217	2,218	2,317	2,387	2,368	2,332	2,286	2,229	2,095
Winter	12	2,239	#########	1,948	1,837	1,774	1,753	1,752	1,775	1,827	1,960	2,106	2,188	2,239	2,228	2,211	2,144	2,087	2,091	2,077	2,096	2,063	1,956	1,881	1,859	1,799	1,728
Winter	12	1,762	#########	1,641	1,588	1,543	1,491	1,476	1,472	1,489	1,542	1,586	1,651	1,706	1,747	1,762	1,741	1,712	1,678	1,655	1,658	1,694	1,671	1,682	1,677	1,657	1,598
Winter	12	1,897	#########	1,568	1,489	1,483	1,467	1,476	1,495	1,552	1,618	1,679	1,750	1,821	1,835	1,802	1,761	1,716	1,670	1,645	1,755	1,897	1,889	1,873	1,833	1,805	1,747
Winter	12	1,999	#########	1,678	1,620	1,559	1,571	1,556	1,564	1,592	1,653	1,738	1,831	1,851	1,865	1,824	1,746	1,679	1,657	1,678	1,802	1,957	1,998	1,999	1,980	1,954	1,889
Winter	12	2,093	#########	1,796	1,756	1,723	1,717	1,731	1,737	1,715	1,802	1,847	1,926	1,968	1,959	1,944	1,921	1,912	1,904	1,916	1,987	2,093	2,053	1,992	1,954	1,889	1,783
Winter	12	2,319	#########	1,696	1,639	1,619	1,612	1,644	1,677	1,752	1,880	1,992	2,051	2,035	2,002	2,009	1,990	1,969	1,928	1,986	2,154	2,292	2,319	2,317	2,284	2,230	2,158
Winter	12	2,788	#########	2,067	1,997	2,027	2,051	2,095	2,147	2,252	2,414	2,603	2,672	2,667	2,583	2,572	2,536	2,499	2,469	2,492	2,653	2,788	2,768	2,760	2,745	2,688	2,551
Winter	12	2,887	#########	2,457	2,399	2,387	2,385	2,418	2,442	2,522	2,670	2,817	2,887	2,885	2,834	2,749	2,611	2,568	2,536	2,557	2,691	2,790	2,736	2,673	2,638	2,579	2,516
Winter	1	2,521	1/1/2015	2,461	2,386	2,371	2,344	2,339	2,349	2,400	2,457	2,475	2,493	2,521	2,481	2,389	2,305	2,247	2,203	2,231	2,356	2,426	2,354	2,356	2,319	2,258	2,146
Winter	1	2,445	1/2/2015	2,033	1,952	1,908	1,889	1,912	1,952	2,058	2,187	2,306	2,308	2,333	2,347	2,282	2,220	2,177	2,139	2,164	2,286	2,445	2,429	2,405	2,386	2,355	2,276
Winter	1	2,804	1/3/2015	2,217	2,169	2,187	2,208	2,246	2,288	2,344	2,435	2,559	2,666	2,691	2,662	2,617	2,599	2,556	2,528	2,533	2,682	2,804	2,797	2,780	2,743	2,693	2,585
Winter	1	2,520	1/4/2015	2,504	2,418	2,378	2,362	2,344	2,333	2,315	2,350	2,400	2,435	2,507	2,517	2,520	2,495	2,429	2,408	2,404	2,469	2,481	2,438	2,413	2,329	2,207	2,037
Winter	1	2,634	1/5/2015	1,913	1,849	1,799	1,750	1,764	1,819	1,906	2,076	2,234	2,254	2,209	2,217	2,211	2,192	2,185	2,185	2,251	2,417	2,578	2,601	2,629	2,634	2,573	2,461
Winter	1	3,067	1/6/2015	2,375	2,319	2,338	2,378	2,415	2,465	2,586	2,819	3,064	3,067	2,955	2,871	2,822	2,747	2,681	2,640	2,728	2,921	3,025	3,010	2,994	2,953	2,863	2,715
Winter	1	3,041	1/7/2015	2,584	2,526	2,535	2,523	2,536	2,580	2,670	2,837	3,041	3,020	2,960	2,845	2,751	2,637	2,549	2,539	2,559	2,664	2,770	2,755	2,746	2,699	2,636	2,513
Winter	1	3,099	1/8/2015	2,414	2,349	2,377	2,430	2,495	2,530	2,616	2,841	3,092	3,099	2,968	2,884	2,806	2,701	2,669	2,641	2,712	2,918	3,091	3,088	3,084	3,046	2,965	2,819
Winter	1	3,023	1/9/2015	2,689	2,573	2,586	2,580	2,591	2,646	2,716	2,879	3,023	2,966	2,915	2,856	2,791	2,653	2,589	2,574	2,552	2,541	2,594	2,578	2,573	2,546	2,488	2,375
Winter	1	2,629	1/10/2015	2,284	2,216	2,219	2,256	2,277	2,319	2,365	2,444	2,549	2,629	2,626	2,540	2,452	2,355	2,279	2,247	2,308	2,434	2,603	2,614	2,611	2,576	2,512	2,412
Winter	1	2,752	1/11/2015	2,312	2,240	2,245	2,272	2,301	2,357	2,390	2,528	2,646	2,752	2,732	2,624	2,480	2,391	2,317	2,306	2,339	2,505	2,634	2,630	2,602	2,545	2,504	2,354
Winter	1	2,688	1/12/2015	2,196	2,125	2,123	2,123	2,110	2,158	2,249	2,471	2,688	2,678	2,628	2,610	2,552	2,504	2,505	2,475	2,491	2,560	2,610	2,572	2,529	2,488	2,398	2,215
Winter	1	2,873	1/13/2015	2,080	1,950	1,924	1,916	1,967	2,049	2,184	2,437	2,701	2,724	2,641	2,541	2,498	2,437	2,384	2,373	2,437	2,606	2,805	2,855	2,873	2,858	2,792	2,622
Winter	1	3,206	1/14/2015	2,575	2,503	2,504	2,508	2,548	2,622	2,732	2,953	3,206	3,191	3,074	2,916	2,788	2,640	2,568	2,522	2,527	2,663	2,801	2,812	2,808	2,758	2,669	2,539
Winter	1	2,956	1/15/2015	2,433	2,330	2,335	2,338	2,346	2,397	2,491	2,739	2,956	2,922	2,827	2,717	2,627	2,520	2,476	2,441	2,469	2,558	2,645	2,647	2,637	2,597	2,509	2,353
Winter	1	2,510	1/16/2015	2,212	2,131	2,076	2,058	2,027	2,098	2,118	2,304	2,510	2,501	2,435	2,372	2,307	2,257	2,234	2,246	2,233	2,329	2,427	2,464	2,465	2,396	2,383	2,313
Winter	1	2,812	1/17/2015	2,236	2,210	2,218	2,273	2,324	2,378	2,447	2,567	2,703	2,811	2,812	2,756	2,669	2,598	2,492	2,429	2,424	2,578	2,768	2,775	2,747	2,681	2,660	2,590
Winter	1	2,632	1/18/2015	2,513	2,505	2,483	2,497	2,507	2,482	2,501	2,548	2,623	2,632	2,610	2,577	2,519	2,442	2,362	2,240	2,236	2,309	2,372	2,318	2,247	2,170	2,065	1,952
Winter	1	2,167	1/19/2015	1,815	1,713	1,644	1,638	1,653	1,672	1,762	1,992	2,154	2,110	2,078	2,074	2,056	2,050	2,023	2,005	2,017	2,087	2,167	2,125	2,087	2,031	1,963	1,865
Winter	1	2,489	1/20/2015	1,772	1,658	1,630	1,640	1,676	1,715	1,819	2,059	2,296	2,336	2,304	2,245	2,233	2,183	2,162	2,123	2,158	2,282	2,424	2,470	2,489	2,480	2,440	2,349
Winter	1	2,852	1/21/2015	2,256	2,185	2,204	2,228	2,253	2,300	2,412	2,626	2,852	2,806	2,666	2,561	2,500	2,411	2,332	2,294	2,302	2,366	2,522	2,571	2,617	2,607	2,562	2,453
Winter	1	2,982	1/22/2015	2,356	2,280	2,279	2,300	2,332	2,394	2,507	2,745	2,982	2,965	2,876	2,776	2,679	2,568	2,519	2,483	2,498	2,575	2,626	2,622	2,622	2,533	2,455	2,309
Winter	1	2,794	1/23/2015	2,196	2,141	2,163	2,205	2,242	2,300	2,363	2,563	2,794	2,781	2,691	2,583	2,454	2,366	2,288	2,235	2,251	2,358	2,485	2,498	2,453	2,406	2,340	2,201
Winter	1	2,374	1/24/2015	2,090	2,018	2,006	2,013	2,024	2,022	2,014	2,095	2,237	2,333	2,371	2,356	2,326	2,268	2,222	2,191	2,164	2,267	2,374	2,345	2,241	2,203	2,137	2,047
Winter	1	2,545	1/25/2015	1,946	1,862	1,850	1,844	1,819	1,845	1,889	1,957	2,067	2,196	2,233	2,162	2,187	2,164	2,112	2,093	2,124	2,251	2,400	2,472	2,540	2,545	2,445	2,339
Winter	1	2,834	1/26/2015	2,242	2,182	2,187	2,211	2,196	2,274	2,391	2,633	2,834	2,824	2,700	2,595	2,510	2,424	2,321	2,295	2,342	2,470	2,650	2,693	2,681	2,670	2,627	2,529
Winter	1	2,817	1/27/2015	2,405	2,357	2,349	2,404	2,398	2,435	2,475	2,585	2,763	2,792	2,816	2,806	2,817	2,801	2,732	2,677	2,649	2,713	2,720	2,665	2,599	2,522	2,411	2,274
Winter	1	2,614	1/28/2015	2,177	2,150	2,119	2,117	2,109	2,132	2,187	2,420	2,588	2,576	2,566	2,558	2,576	2,540	2,502	2,479	2,498	2,577	2,604	2,614	2,587	2,533	2,468	2,335
Winter	1	2,908	1/29/2015	2,245	2,196	2,213	2,241	2,279	2,325	2,435	2,659	2,908	2,850	2,692	2,553	2,452	2,352	2,266	2,230	2,242	2,331	2,457	2,571	2,589	2,581	2,528	2,447
Winter	1	2,915	1/30/2015	2,353	2,280	2,288	2,331	2,361	2,418	2,506	2,719	2,915	2,887	2,809	2,743	2,669	2,590	2,519	2,481	2,486	2,552	2,575	2,572	2,524	2,470	2,401	2,294
Winter	1	2,476	1/31/2015	2,168	2,082	2,050	2,037	2,038	2,053	2,079	2,139	2,202	2,267	2,360	2,396	2,451	2,476	2,404	2,343	2,337	2,409	2,466	2,462	2,431	2,384	2,363	2,242
Winter	2	2,753	2/1/2015	2,194	2,158	2,169	2,185	2,150	2,185	2,237	2,330	2,434	2,539	2,537	2,482	2,447	2,384	2,333	2,298	2,315	2,435	2,628	2,731	2,753	2,739	2,693	2,609
Winter	2	3,169	2/2/2015	2,509	2,403	2,373	2,379	2,447	2,502	2,619	2,900	3,169	3,160	3,120	3,074	3,049	3,014	2,999	3,010	2,990	3,091	3,152	3,125	3,066	2,984	2,861	2,705
Winter	2	2,983	2/3/2015	2,555	2,434	2,438	2,456	2,493	2,529	2,581	2,692	2,846	2,983	2,867	2,798	2,752	2,622	2,547	2,501	2,509	2,645	2,795	2,838	2,837	2,802	2,741	2,631
Winter	2	3,196	2/4/2015	2,550	2,505	2,513	2,539	2,564	2,610	2,733	2,974	3,196	3,132	3,007	2,856	2,726	2,673	2,599	2,575	2,562	2,632	2,691	2,704	2,650	2,542	2,424	2,274
Winter	2	2,562	2/5/2015	2,140	2,060	2,064	2,027	1,986	1,986	2,067	2,217	2,406	2,397	2,404	2,375	2,363	2,342	2,308	2,317	2,374	2,479	2,545	2,562	2,543	2,503	2,442	2,374
Winter	2	2,966	2/6/2015	2,333	2,239	2,237	2,283	2,315	2,381	2,492	2,752	2,966	2,900	2,766	2,658	2,576	2,491	2,430	2,387	2,397	2,492	2,635	2,727	2,733	2,707	2,638	2,573
Winter	2	2,915	2/7/2015	2,494	2,369	2,419	2,438	2,457	2,514	2,564	2,686	2,838	2,915	2,850	2,738	2,622	2,550	2,482	2,462	2,469	2,551	2,682	2,734	2,707	2,667	2,603	2,537
Winter	2	2,859	2/8/2015	2,470	2,411	2,415	2,419	2,426	2,480	2,566	2,660	2,769	2,859	2,836	2,733	2,581	2,500	2,422	2,386	2,415	2,560	2,671	2,755	2,741	2,726	2,650	2,538
Winter	2	3,132	2/9/2015	2,449	2,402	2,406	2,428	2,473	2,521	2,627	2,880	3,132	3,130	3,020	2,937	2,853	2,740	2,681	2,633	2,661	2,779	2,874	2,948	2,952	2,910	2,847	2,701
Winter	2	3,090	2/10/2015	2,590	2,516	2,518	2,537	2,577	2,611	2,710	2,919	3,090	3,075	2,998	2,886	2,797	2,701	2,618	2,569	2,573	2,636	2,694	2,763	2,750	2,756	2,674	2,518
Winter	2	3,044	2/11/2015	2,378	2,355	2,350	2,358	2,391	2,447	2,590	2,791	3,044	2,993	2,844	2,717	2,595	2,495	2,397	2,361	2,422	2,547	2,679	2,799	2,812	2,781	2,692	2,551
Winter	2	2,898	2/12/2015	2,432	2,362	2,352	2,367	2,385	2,417	2,484	2,692	2,898	2,876	2,873	2,718	2,654	2,593	2,628	2,557	2,553	2,643	2,683	2,728	2,702	2,645	2,547	2,462
Winter	2	2,902	2/13/2015	2,331	2,252	2,239	2,256	2,290	2,327	2,425	2,615	2,855	2,902	2,770	2,665	2,559	2,431	2,306	2,279	2,332	2,406	2,541	2,684	2,697	2,648	2,598	2,539
Winter	2	2,952	2/14/2015	2,455	2,424	2,443	2,483	2,532	2,586	2,639	2,779	2,899	2,952	2,931	2,886	2,831	2,732	2,652	2,584	2,577	2,649	2,732	2,789	2,786	2,744	2,677	2,590
Winter	2	2,949	2/15/2015	2,521	2,453	2,420	2,418	2,388	2,390	2,416	2,464	2,565	2,630	2,709	2,771	2,804	2,815	2,816	2,776	2,818	2,895	2,948	2,949	2,917	2,854	2,766	2,647
Winter	2	2,936	2/16/2015	2,556	2,481	2,486	2,483	2,506	2,536	2,620	2,799	2,910	2,936	2,935	2,911	2,900	2,794	2,713	2,673	2,674	2,736	2,789	2,863	2,868	2,798	2,709	2,590
Winter	2	2,937	2/17/2015	2,477	2,430	2,416	2,412	2,417	2,452	2,540	2,744	2,937	2,911	2,783	2,697	2,629	2,519	2,448	2,392	2,407	2,510	2,600	2,709	2,727	2,693	2,634	2,539
Winter	2	3,010	2/18/2015	2,436	2,354	2,365	2,382	2,408	2,456	2,563	2,808	3,010	2,971	2,809	2,615	2,565	2,442	2,388	2,346	2,366	2,437	2,525	2,633	2,656	2,637	2,565	2,443
Winter	2	2,787	2/19/2015	2,345	2,284	2,271	2,277	2,295	2,317	2,400	2,614	2,787	2,759	2,696	2,618	2,550	2,533	2,481	2,462	2,489	2,548	2,518	2,554	2,580	2,518	2,424	2,258
Winter	2	2,626	2/20/2015	2,133	1,987	1,967	1,962	1,961	2,001	2,125	2,308	2,539	2,534	2,449	2,391	2,360	2,325	2,292	2,287	2,321	2,406	2,492	2,591	2,626	2,585	2,516	2,408
Winter	2	2,626	2/21/2015	2,269	2,282	2,199	2,234	2,266	2,314	2,377	2,485	2,600	2,626	2,586	2,520	2,446	2,356	2,273	2,218	2,191	2,278	2,416	2,512	2,498	2,426	2,337	2,208
Winter	2	2,397	2/22/2015	2,120	2,041	1,987	1,962	1,923	1,910	1,940	2,001	2,091	2,189	2,282	2,267	2,232	2,215	2,181	2,150	2,159	2,218	2,278	2,372	2,397	2,358	2,298	2,204
Winter	2	2,671	2/23/2015	2,120	2,067	2,067	2,089	2,096	2,147	2,234	2,467	2,652	2,605	2,504	2,404	2,336	2,288	2,232	2,197	2,214	2,327	2,466	2,612	2,671	2,646	2,641	2,566
Winter	2	3,160	2/24/2015	2,511	2,472	2,509	2,563	2,618	2,669	2,750	2,962	3,160	3,048	2,904	2,823	2,742	2,635	2,572	2,536	2,547	2,624	2,722	2,829	2,852	2,814	2,735	2,591
Winter	2	2,636	2/25/2015	2,489	2,365	2,365	2,348	2,322	2,344	2,340	2,501	2,636	2,627	2,544	2,498	2,519	2,442	2,416	2,368	2,352	2,325	2,330	2,389	2,415	2,364	2,298	2,277
Winter	2	2,711	2/26/2015	2,198	2,064	2,134	2,160	2,194	2,230	2,299	2,529	2,711	2,651	2,547	2,474	2,415	2,394	2,382	2,374	2,431	2,539	2,607	2,686	2,687	2,653	2,588	2,510
Winter	2	2,900	2/27/2015	2,342	2,251	2,243	2,246	2,267	2,329	2,438	2,700	2,900	2,803	2,674	2,590	2,486	2,377	2,308	2,265	2,281	2,348	2,417	2,563	2,592	2,552	2,466	2,447
Winter	2	2,766	2/28/2015	2,384	2,322	2,306	2,321	2,367	2,415	2,495	2,635	2,758	2,766	2,697	2,585	2,462	2,344	2,238	2,139	2,057	2,114	2,205	2,332	2,386	2,350	2,298	2,224
Spring	3	2,553	3/1/2015	2,168	2,123	2,108	2,132	2,190	2,242	2,295	2,395	2,475	2,553	2,534	2,478	2,395	2,340	2,284	2,211	2,193	2,249	2,333	2,412	2,407	2,344	2,260	2,153
Spring	3	2,454	3/2/2015	2,059	1,994	1,948	1,937	1,950	1,967	2,048	2,229	2,387	2,454	2,423	2,395	2,344	2,239	2,205	2,193	2,172	2,272	2,260	2,352	2,372	2,293	2,219	2,117
Spring	3	2,678	3/3/2015	2,120	1,999	2,048	2,094	2,137	2,227	2,334	2,536	2,678	2,609	2,507	2,451	2,394

Contains Proprietary Material
Do Not Distribute

Spring	3	2,495	3/7/2015	2,264	2,176	2,159	2,172	2,195	2,223	2,284	2,380	2,465	2,495	2,429	2,345	2,252	2,159	2,056	1,978	1,960	2,011	2,125	2,271	2,326	2,279	2,213	2,131
Spring	3	2,360	3/8/2015	2,068	2,010		1,995	2,040	2,074	2,085	2,154	2,264	2,360	2,341	2,292	2,226	2,166	2,107	2,065	2,065	2,114	2,180	2,217	2,309	2,354	2,288	2,169
Spring	3	2,701	3/9/2015	2,038	1,938	1,905	1,939	2,015	2,070	2,144	2,401	2,678	2,701	2,586	2,467	2,370	2,258	2,231	2,161	2,195	2,236	2,251	2,239	2,329	2,361	2,312	2,216
Spring	3	2,639	3/10/2015	2,106	2,021	1,993	2,004	2,013	2,062	2,159	2,362	2,634	2,639	2,487	2,335	2,256	2,129	2,042	1,965	1,929	1,971	1,978	2,027	2,111	2,152	2,103	1,954
Spring	3	2,068	3/11/2015	1,815	1,729	1,692	1,668	1,674	1,685	1,738	1,861	2,068	2,060	1,982	1,902	1,827	1,805	1,728	1,642	1,592	1,706	1,702	1,697	1,801	1,880	1,852	1,771
Spring	3	2,375	3/12/2015	1,662	1,605	1,590	1,617	1,633	1,685	1,767	1,989	2,241	2,258	2,183	2,109	2,051	2,015	2,051	2,026	2,029	2,121	2,145	2,177	2,294	2,375	2,325	2,216
Spring	3	2,760	3/13/2015	2,104	2,096	2,090	2,118	2,162	2,213	2,303	2,512	2,755	2,760	2,629	2,508	2,439	2,340	2,270	2,192	2,152	2,151	2,148	2,155	2,274	2,361	2,348	2,276
Spring	3	2,578	3/14/2015	2,168	2,122	2,129	2,155	2,180	2,235	2,300	2,420	2,532	2,578	2,523	2,439	2,343	2,250	2,145	2,072	2,025	2,045	2,081	2,108	2,178	2,192	2,151	2,076
Spring	3	2,435	3/15/2015	1,965	1,832	1,798	1,798	1,805	1,809	1,845	1,953	2,057	2,175	2,303	2,364	2,397	2,391	2,361	2,321	2,329	2,366	2,393	2,372	2,420	2,435	2,354	2,239
Spring	3	2,526	3/16/2015	2,146	2,065	2,037	2,080	2,114	2,149	2,210	2,344	2,500	2,526	2,450	2,391	2,328	2,240	2,171	2,099	2,043	2,051	2,079	2,088	2,179	2,241	2,224	2,137
Spring	3	2,739	3/17/2015	2,040	1,963	1,988	2,020	2,061	2,134	2,229	2,500	2,739	2,710	2,544	2,482	2,423	2,306	2,246	2,194	2,169	2,231	2,252	2,259	2,291	2,323	2,225	2,107
Spring	3	2,445	3/18/2015	2,050	1,920	1,912	1,916	1,942	1,979	2,055	2,234	2,420	2,445	2,426	2,395	2,360	2,284	2,227	2,182	2,203	2,240	2,264	2,294	2,377	2,416	2,320	2,215
Spring	3	2,700	3/19/2015	2,113	2,054	2,080	2,092	2,119	2,159	2,301	2,492	2,700	2,676	2,582	2,488	2,392	2,263	2,189	2,121	2,084	2,100	2,062	2,078	2,187	2,284	2,228	2,129
Spring	3	2,638	3/20/2015	2,032	2,015	1,975	1,992	2,016	2,062	2,147	2,395	2,638	2,570	2,417	2,317	2,237	2,130	2,066	1,994	1,947	1,962	1,946	1,967	2,054	2,131	2,102	2,021
Spring	3	2,246	3/21/2015	1,944	1,888	1,876	1,876	1,895	1,934	1,977	2,070	2,170	2,246	2,245	2,221	2,156	2,075	1,997	1,917	1,877	1,893	1,916	1,933	1,999	2,032	2,003	1,940
Spring	3	2,466	3/22/2015	1,851	1,809	1,786	1,775	1,768	1,774	1,776	1,801	1,870	1,947	2,027	2,068	2,087	2,054	1,993	1,994	2,035	2,128	2,185	2,242	2,361	2,466	2,440	2,336
Spring	3	2,798	3/23/2015	2,257	2,222	2,238	2,259	2,298	2,333	2,412	2,607	2,798	2,795	2,695	2,575	2,456	2,294	2,249	2,175	2,140	2,141	2,127	2,117	2,215	2,317	2,247	2,126
Spring	3	2,611	3/24/2015	2,022	1,969	1,985	2,008	2,030	2,072	2,169	2,391	2,611	2,581	2,446	2,327	2,234	2,098	2,024	1,958	1,938	1,968	1,956	1,955	2,040	2,156	2,117	2,014
Spring	3	2,531	3/25/2015	1,886	1,837	1,884	1,918	1,945	1,992	2,074	2,297	2,531	2,444	2,283	2,160	2,050	1,938	1,868	1,829	1,825	1,854	1,841	1,838	1,913	2,015	1,988	1,887
Spring	3	2,213	3/26/2015	1,820	1,762	1,631	1,620	1,630	1,674	1,772	1,973	2,213	2,201	2,101	2,047	2,013	1,947	1,910	1,867	1,868	1,903	1,920	1,889	1,931	1,970	1,974	1,882
Spring	3	2,212	3/27/2015	1,775	1,697	1,678	1,680	1,686	1,715	1,791	1,986	2,182	2,212	2,180	2,154	2,099	2,006	1,946	1,900	1,871	1,875	1,885	1,875	1,914	1,952	1,924	1,853
Spring	3	2,200	3/28/2015	1,771	1,703	1,687	1,687	1,705	1,739	1,789	1,883	1,997	2,096	2,200	2,194	2,083	2,004	1,928	1,863	1,837	1,853	1,921	1,931	1,977	2,021	1,997	1,937
Spring	3	2,120	3/29/2015	1,864	1,816	1,839	1,791	1,801	1,823	1,867	1,942	2,046	2,120	2,101	2,036	1,979	1,914	1,859	1,800	1,766	1,794	1,811	1,811	1,880	1,986	1,956	1,876
Spring	3	2,368	3/30/2015	1,778	1,703	1,694	1,733	1,769	1,830	1,937	2,164	2,368	2,351	2,256	2,166	2,130	2,063	2,015	1,975	1,965	2,021	2,009	2,019	2,070	2,105	2,006	1,879
Spring	3	2,188	3/31/2015	1,757	1,676	1,662	1,665	1,668	1,702	1,794	2,003	2,188	2,187	2,122	2,083	2,006	1,948	1,916	1,880	1,885	1,934	1,931	1,910	1,950	2,023	1,976	1,868
Spring	4	2,343	4/1/2015	1,752	1,679	1,659	1,669	1,687	1,726	1,819	2,078	2,343	2,286	2,182	2,114	2,047	1,981	1,936	1,889	1,878	1,905	1,873	1,879	1,962	2,077	2,050	1,949
Spring	4	2,433	4/2/2015	1,849	1,775	1,792	1,821	1,848	1,879	1,989	2,237	2,433	2,371	2,248	2,117	2,048	1,954	1,903	1,845	1,848	1,854	1,856	1,876	1,936	2,002	1,963	1,874
Spring	4	1,960	4/3/2015	1,761	1,684	1,646	1,593	1,611	1,623	1,667	1,756	1,841	1,929	1,960	1,957	1,949	1,898	1,828	1,776	1,717	1,706	1,658	1,627	1,652	1,740	1,740	1,693
Spring	4	2,062	4/4/2015	1,630	1,583	1,556	1,550	1,536	1,543	1,592	1,690	1,807	1,926	1,971	1,990	1,984	1,936	1,916	1,901	1,917	1,981	2,037	2,048	2,023	2,062	2,044	1,979
Spring	4	2,122	4/5/2015	1,899	1,868	1,866	1,845	1,865	1,897	1,944	2,021	2,109	2,122	2,108	2,044	2,062	2,026	1,970	1,937	1,924	1,909	1,867	1,870	1,909	2,043	2,063	1,994
Spring	4	2,523	4/6/2015	1,920	1,882	1,906	1,914	1,985	2,084	2,213	2,398	2,523	2,493	2,414	2,338	2,250	2,167	2,090	2,009	1,972	2,009	2,058	2,073	2,099	2,176	2,150	2,044
Spring	4	2,440	4/7/2015	1,946	1,861	1,845	1,843	1,844	1,902	2,005	2,231	2,440	2,428	2,329	2,228	2,132	2,009	1,963	1,932	1,922	1,951	1,939	1,915	1,948	2,042	2,028	1,949
Spring	4	2,397	4/8/2015	1,829	1,778	1,790	1,810	1,850	1,899	1,985	2,221	2,397	2,323	2,210	2,134	2,093	2,019	1,960	1,902	1,886	1,916	1,933	1,918	1,987	2,059	2,038	1,959
Spring	4	2,402	4/9/2015	1,854	1,796	1,783	1,776	1,797	1,850	1,941	2,171	2,402	2,368	2,239	2,119	2,047	1,965	1,913	1,862	1,846	1,868	1,855	1,844	1,887	2,010	1,980	1,900
Spring	4	2,308	4/10/2015	1,812	1,768	1,749	1,744	1,748	1,784	1,865	2,053	2,262	2,308	2,267	2,220	2,189	2,128	2,097	2,050	2,052	2,090	2,041	2,007	1,978	1,987	1,911	1,795
Spring	4	1,802	4/11/2015	1,678	1,579	1,540	1,505	1,510	1,506	1,539	1,618	1,710	1,762	1,794	1,790	1,778	1,759	1,680	1,643	1,627	1,673	1,706	1,691	1,731	1,802	1,776	1,698
Spring	4	1,817	4/12/2015	1,623	1,573	1,551	1,536	1,549	1,582	1,617	1,694	1,755	1,778	1,816	1,781	1,766	1,760	1,712	1,668	1,650	1,693	1,702	1,674	1,713	1,815	1,817	1,721
Spring	4	2,225	4/13/2015	1,634	1,546	1,532	1,560	1,607	1,673	1,784	2,020	2,225	2,170	2,036	1,938	1,855	1,775	1,721	1,669	1,654	1,676	1,648	1,594	1,590	1,644	1,601	1,475
Spring	4	1,865	4/14/2015	1,392	1,366	1,388	1,406	1,426	1,457	1,506	1,660	1,845	1,865	1,842	1,816	1,808	1,740	1,699	1,631	1,625	1,678	1,657	1,623	1,603	1,675	1,658	1,588
Spring	4	1,930	4/15/2015	1,489	1,422	1,438	1,445	1,460	1,481	1,542	1,741	1,930	1,825	1,749	1,769	1,756	1,709	1,710	1,678	1,691	1,729	1,746	1,742	1,773	1,883	1,886	1,771
Spring	4	2,130	4/16/2015	1,658	1,596	1,615	1,650	1,672	1,695	1,727	1,917	2,130	2,047	1,938	1,881	1,821	1,767	1,759	1,703	1,694	1,711	1,700	1,688	1,696	1,846	1,840	1,670
Spring	4	1,975	4/17/2015	1,563	1,519	1,545	1,561	1,571	1,601	1,641	1,799	1,971	1,975	1,944	1,892	1,844	1,780	1,760	1,732	1,682	1,626	1,622	1,579	1,583	1,652	1,650	1,552
Spring	4	1,777	4/18/2015	1,481	1,449	1,372	1,392	1,376	1,407	1,470	1,576	1,675	1,736	1,772	1,777	1,762	1,717	1,668	1,628	1,604	1,630	1,647	1,615	1,643	1,747	1,746	1,672
Spring	4	1,947	4/19/2015	1,608	1,569	1,567	1,574	1,591	1,618	1,635	1,694	1,772	1,907	1,947	1,928	1,879	1,816	1,748	1,680	1,632	1,662	1,668	1,660	1,667	1,760	1,767	1,692
Spring	4	2,124	4/20/2015	1,570	1,492	1,477	1,495	1,535	1,605	1,714	1,960	2,124	2,065	1,988	1,937	1,877	1,800	1,761	1,703	1,697	1,778	1,796	1,786	1,797	1,843	1,782	1,609
Spring	4	1,980	4/21/2015	1,481	1,380	1,390	1,390	1,399	1,428	1,509	1,687	1,946	1,980	1,952	1,911	1,907	1,873	1,849	1,849	1,854	1,916	1,915	1,885	1,876	1,881	1,816	1,685
Spring	4	1,904	4/22/2015	1,573	1,497	1,466	1,467	1,446	1,464	1,490	1,669	1,881	1,904	1,882	1,810	1,766	1,689	1,638	1,619	1,619	1,662	1,660	1,655	1,680	1,798	1,775	1,651
Spring	4	2,034	4/23/2015	1,546	1,490	1,479	1,490	1,505	1,540	1,613	1,816	2,027	2,034	2,022	2,003	1,970	1,921	1,908	1,902	1,901	1,944	1,945	1,911	1,891	1,921	1,849	1,750
Spring	4	2,113	4/24/2015	1,616	1,555	1,547	1,553	1,557	1,594	1,677	1,897	2,110	2,113	2,084	2,051	2,016	1,941	1,923	1,886	1,698	1,709	1,677	1,816	1,847	1,863	1,846	1,760
Spring	4	1,947	4/25/2015	1,664	1,607	1,558	1,553	1,571	1,587	1,619	1,693	1,799	1,905	1,915	1,947	1,931	1,878	1,809	1,734	1,695	1,713	1,718	1,706	1,712	1,770	1,783	1,722
Spring	4	1,828	4/26/2015	1,632	1,569	1,509	1,498	1,515	1,562	1,609	1,660	1,727	1,776	1,819	1,828	1,803	1,785	1,753	1,700	1,704	1,744	1,766	1,761	1,759	1,787	1,731	1,637
Spring	4	1,974	4/27/2015	1,526	1,458	1,445	1,456	1,460	1,467	1,544	1,750	1,974	1,974	1,909	1,854	1,801	1,782	1,763	1,706	1,720	1,824	1,924	1,852	1,890	1,974	1,923	1,786
Spring	4	2,023	4/28/2015	1,657	1,578	1,568	1,566	1,565	1,581	1,649	1,816	2,023	2,005	1,924	1,901	1,903	1,857	1,856	1,809	1,831	1,888	1,903	1,884	1,882	1,894	1,859	1,737
Spring	4	2,099	4/29/2015	1,649	1,586	1,579	1,585	1,588	1,606	1,682	1,880	2,092	2,099	2,059	2,010	1,941	1,858	1,831	1,784	1,844	1,823	1,827	1,826	1,816	1,839	1,769	1,653
Spring	4	2,036	4/30/2015	1,545	1,475	1,454	1,446	1,457	1,504	1,593	1,785	1,999	2,036	2,013	1,999	1,977	1,925	1,900	1,858	1,856	1,880	1,885	1,863	1,874	1,924	1,897	1,782
Spring	5	2,101	5/1/2015	1,675	1,607	1,595	1,592	1,602	1,629	1,713	1,888	2,077	2,101	1,980	1,951	1,906	1,849	1,812	1,736	1,697	1,681	1,654	1,625	1,645	1,743	1,787	1,714
Spring	5	1,848	5/2/2015	1,628	1,583	1,561	1,569	1,587	1,617	1,647	1,723	1,798	1,840	1,848	1,813	1,764	1,694	1,623	1,557	1,517	1,524	1,526	1,508	1,485	1,524	1,550	1,455
Spring	5	1,699	5/3/2015	1,368	1,316	1,314	1,318	1,307	1,344	1,395	1,485	1,557	1,644	1,699	1,693	1,653	1,607	1,548	1,494	1,469	1,450	1,454	1,440	1,464	1,530	1,561	1,444
Spring	5	1,844	5/4/2015	1,363	1,294	1,273	1,280	1,293	1,331	1,432	1,641	1,844	1,826	1,759	1,718	1,676	1,633	1,574	1,531	1,490	1,498	1,470	1,426	1,382	1,417	1,402	1,304
Spring	5	1,415	5/5/2015	1,215	1,164	1,178	1,160	1,156	1,167	1,195	1,206	1,282	1,279	1,406	1,407	1,361	1,307	1,279	1,260	1,257	1,295	1,298	1,283	1,295	1,360	1,415	1,310
Spring	5	1,582	5/6/2015	1,209	1,126	1,128	1,139	1,158	1,179	1,228	1,401	1,582	1,554	1,507	1,436	1,471	1,466	1,447	1,429	1,445	1,507	1,506	1,483	1,520	1,551	1,565	1,465
Spring	5	1,629	5/7/2015	1,346	1,241	1,232	1,199	1,211	1,230	1,284	1,434	1,629	1,611	1,556	1,505	1,495	1,468	1,469	1,445	1,443	1,483	1,471	1,435	1,444	1,506	1,540	1,460
Spring	5	1,812	5/8/2015	1,335	1,261	1,246	1,245	1,224	1,279	1,321	1,508	1,757	1,812	1,808	1,796	1,785	1,740	1,707	1,654	1,614	1,618	1,609	1,592	1,588	1,631	1,661	1,592
Spring	5	1,588	5/9/2015	1,489	1,404	1,381	1,370	1,365	1,370	1,396	1,400	1,466	1,556	1,588	1,568	1,541	1,477	1,411	1,356	1,342	1,369	1,378	1,392	1,374	1,389	1,384	1,308
Spring	5	1,563	5/10/2015	1,240	1,179	1,149	1,111	1,133	1,119	1,167	1,242	1,339	1,452	1,527	1,558	1,563	1,538	1,500	1,465	1,419	1,458	1,467	1,458	1,487	1,525	1,548	1,451
Spring	5	1,619	5/11/2015	1,332	1,242	1,178	1,125	1,148	1,130	1,180	1,352	1,552	1,574	1,546	1,569	1,569	1,563	1,543	1,527	1,529	1,581	1,585	1,567	1,573	1,619	1,597	1,452
Spring	5	1,653	5/12/2015	1,316	1,240	1,207	1,208	1,204	1,215	1,276	1,429	1,648	1,653	1,628	1,620	1,606	1,568	1,557	1,532	1,543	1,596	1,616	1,592	1,556	1,573	1,549	1,422
Spring	5	1,641	5/13/2015	1,316	1,240	1,224	1,206	1,218	1,228	1,258	1,389	1,603	1,598	1,630	1,630	1,641	1,601	1,564	1,524	1,558	1,577	1,554	1,518	1,492	1,550	1,609	1,505
Spring	5	1,744	5/14/2015	1,389	1,334	1,327	1,324	1,340	1,367	1,428	1,586	1,744	1,685	1,645	1,645	1,622	1,591	1,549	1,509	1,502	1,527	1,524	1,495	1,489	1,509	1,566	1,492
Spring	5	1,654	5/15/2015	1,311	1,226	1,225	1,243	1,258	1,298	1,338	1,483	1,627	1,654	1,642	1,610	1,597	1,570	1,546	1,512	1,497	1,491	1,495	1,456	1,427	1,433	1,450	1,371
Spring	5	1,494	5/16/2015	1,247	1,171	1,132	1,121	1,141	1,166	1,194	1,240	1,337	1,427	1,486	1,494	1,480	1,457	1,409	1,362	1,358	1,366	1,376	1,369	1,352	1,357	1,331	1,246
Spring	5	1,542	5/17/2015	1,146	1,099	1,067	1,064	1,045	1,046	1,053	1,087	1,189	1,324	1,430	1,505	1,532	1,542	1,523	1,487	1,494	1,515	1,539	1,521	1,523	1,525	1,517	1,445
Spring	5	1,618	5/18/2015	1,334	1,246	1,240	1,226	1,232	1,255	1,298	1,375	1,463	1,544	1,590	1,618	1,611	1,571	1,516	1,467	1,449	1,474	1,479	1,461	1,457	1,481	1,492	1,356
Spring	5	1,627	5/19/2015	1,192	1,107	1,031	1,024	1,020	1,052	1,095	1,296	1,525	1,566	1,622	1,577	1,583	1,548	1,554	1,540	1,550	1,599	1,627	1,596	1,590	1,609	1,569	1,413
Spring	5	1,546	5/20/2015	1,271	1,154	1,125	1,122	1,147	1,151	1,208	1,378	1,539	1,546	1,501	1,464	1,434	1,401	1,410	1,370	1,370	1,397	1,411	1,402	1,411	1,430	1,463	1,372
Spring	5	1,545	5/21/2015	1,290	1,237	1,219	1,209	1,225	1,234	1,266	1,397	1,545	1,526	1,480	1,454	1,441	1,387	1,401	1,417	1,427	1,473	1,473	1,436	1,415	1,425	1,457	1,370
Spring	5	1,635	5/22/2015	1,226	1,126	1,117	1,114	1,133	1,162	1,214	1,380	1,595	1,635	1,632	1,604	1,599	1,552	1,553	1,455	1,454	1,471	1,515	1,485	1,474	1,491	1,517	1,456
Spring	5	1,629	5/23/2015	1,350	1,267	1,157	1,183	1,216	1,202	1,216	1,289	1,394	1,515	1,604	1,629	1,594	1,570	1,512	1,447	1,447	1,472	1,459	1,382	1,370	1,365	1,462	1,403
Spring	5	1,514	5/24/2015	1,345	1,244	1,242	1,258	1,276	1,280	1,286	1,306	1,381	1,468	1,514	1,480	1,449	1,405	1,344	1,308	1,302	1,337	1,337	1,383	1,408	1,408	1,435	1,376
Spring	5	1,515	5/25/2015	1,237	1,157	1,150	1,142	1,133	1,144	1,200	1,352	1,503	1,515	1,506	1,501	1,470	1,452	1,438	1,419	1,398	1,419	1,439	1,452	1,419	1,403	1,410	1,305
Spring	5	1,450	5/26/2015	1,192	1,056	1,023	1,015	1,010	1,024	1,069	1,221	1,401	1,442	1,447	1,450	1,441	1,395	1,387	1,380	1,404	1,424	1,431	1,442	1,410	1,387	1,385	1,313
Spring	5	1,553	5/27/2015	1,187	1,102	1,060	1,056	1,051	1,058	1,086	1,199	1,398	1,462	1,507	1,549	1,553	1,528	1,512	1,490	1,480	1,501	1,486	1,454	1,433	1,431	1,415	1,312
Spring	5	1,561	5/28/2015	1,206	1,136	1,100	1,067	1,055	1,058	1,044	1,179	1,373	1,448	1,445	1,482	1,527	1,502	1,516	1,483	1,443	1,457	1,488	1,487	1,494	1,530	1,561	1,486
Spring	5	1,590	5/29/2015	1,350	1,218	1,189	1,176	1,177	1,179	1,206	1,350	1,531	1,572	1,589	1,581	1,563	1,548	1,571	1,579	1,579	1,590	1,559	1,541	1,502	1,485	1,480	1,371
Spring	5	1,475	5/30/2015	1,268	1,156	1,142	1,110	1,110	1,112	1,136	1,163	1,271	1,396	1,437	1,458	1,475	1,470	1,442	1,396	1,384	1,398	1,407	1,399	1,392	1,377	1,415	1,382
Spring	5	1,564	5/31/2015	1,303	1,241	1,190	1,144	1,132	1,137	1,138	1,129	1,174	1,256	1,331	1,359	1,329	1,357	1,397	1,454	1,470	1,528	1,564	1,553	1,553	1,554	1,562	1,471
Summer	6	1,715	6/1/2015	1,341	1,253	1,217	1,201	1,204	1,211	1,272	1,446	1,671	1,699	1,709	1,712	1,715	1,692	1,677	1,639	1,618	1,635	1,626	1,595	1,583	1,595	1,596	1,509
Summer	6	1,825	6/2/2015	1,400	1,321	1,284	1,279	1,273	1,290	1,353	1,517	1,717	1,754	1,753	1,758	1,729	1,728	1,725	1,706	1,734	1,800	1,817	1,825	1,815	1,814	1,777	1,637
Summer	6	1,799	6/3/2015	1,503	1,389	1,373	1,347	1,347	1,349	1,394	1,588	1,790	1,799	1,759	1,722	1,702	1,634	1,587	1,570	1,587	1,627	1,628	1,660	1,679	1,684	1,674	1,571
Summer	6	1,766	6/4/2015	1,436	1,351	1,344	1,347	1,322	1,373	1,427	1,607	1,766	1,734	1,681	1,657	1,657	1,618	1,599	1,571	1,559	1,585	1,563	1,534	1,514	1,516	1,535	1,432
Summer	6	1,634	6/5/2015	1,328	1,220	1,171	1,170	1,168	1,203	1,234	1,402	1,603	1,634	1,624	1,590	1,548	1,501	1,493	1,463	1,441	1,439	1,425	1,334	1,301	1,286	1,329	1,276
Summer	6	1,524	6/6/2015	1,217	1,182	1,118	1,075	1,081	1,094	1,087	1,157	1,278	1,406	1,495	1,515	1,524	1,523	1,474	1,420	1,398	1,412	1,415	1,396	1,370	1,378	1,399	1,379
Summer	6	1,462	6/7/2015	1,307	1,236	1,186	1,149	1,124	1,135	1,121	1,173	1,215	1,268	1,354	1,385	1,421	1,412	1,376	1,351	1,362	1,405	1,443	1,423	1,425	1,436	1,462	1,366
Summer	6	1,578	6/8/2015	1,250	1,178	1,152	1,134	1,157	1,187	1,228	1,382	1,524	1,567

Contains Proprietary Material
Do Not Distribute

Summer	6	1,524	6/20/2015	1,310	1,216	1,186	1,167	1,176	1,173	1,178	1,206	1,266	1,371	1,457	1,510	1,524	1,502	1,464	1,429	1,416	1,432	1,429	1,407	1,381	1,355	1,361	1,309
Summer	6	1,528	6/21/2015	1,207	1,122	1,084	1,067	1,071	1,084	1,088	1,121	1,203	1,316	1,423	1,483	1,511	1,516	1,504	1,491	1,480	1,528	1,522	1,503	1,492	1,520	1,503	1,384
Summer	6	1,626	6/22/2015	1,267	1,184	1,160	1,137	1,127	1,132	1,112	1,241	1,424	1,481	1,520	1,589	1,626	1,569	1,541	1,524	1,523	1,541	1,555	1,535	1,502	1,495	1,498	1,416
Summer	6	1,598	6/23/2015	1,279	1,179	1,179	1,188	1,188	1,197	1,234	1,378	1,529	1,527	1,538	1,555	1,573	1,582	1,588	1,574	1,555	1,592	1,598	1,588	1,547	1,515	1,493	1,355
Summer	6	1,514	6/24/2015	1,235	1,161	1,149	1,118	1,106	1,109	1,106	1,226	1,367	1,444	1,484	1,494	1,478	1,491	1,514	1,500	1,492	1,503	1,478	1,467	1,455	1,453	1,494	1,432
Summer	6	1,513	6/25/2015	1,283	1,192	1,199	1,151	1,102	1,118	1,129	1,273	1,419	1,480	1,474	1,513	1,503	1,503	1,482	1,472	1,456	1,497	1,512	1,493	1,447	1,472	1,474	1,423
Summer	6	1,537	6/26/2015	1,291	1,211	1,169	1,148	1,145	1,170	1,196	1,304	1,456	1,517	1,530	1,532	1,537	1,521	1,508	1,476	1,484	1,487	1,476	1,442	1,407	1,416	1,429	1,391
Summer	6	1,484	6/27/2015	1,292	1,213	1,151	1,137	1,124	1,125	1,129	1,173	1,258	1,364	1,445	1,477	1,484	1,472	1,441	1,412	1,404	1,417	1,427	1,401	1,376	1,347	1,326	1,292
Summer	6	1,450	6/28/2015	1,196	1,105	1,120	1,052	1,051	1,019	1,024	1,060	1,155	1,257	1,353	1,415	1,430	1,450	1,438	1,407	1,401	1,441	1,429	1,394	1,384	1,408	1,411	1,285
Summer	6	1,570	6/29/2015	1,191	1,122	1,081	1,045	1,044	1,007	1,019	1,155	1,267	1,439	1,490	1,540	1,557	1,546	1,558	1,537	1,535	1,570	1,547	1,510	1,481	1,452	1,439	1,365
Summer	6	1,568	6/30/2015	1,256	1,137	1,121	1,094	1,082	1,081	1,101	1,214	1,412	1,502	1,526	1,548	1,558	1,533	1,529	1,530	1,531	1,568	1,558	1,516	1,480	1,468	1,469	1,406
Summer	7	1,530	7/1/2015	1,281	1,188	1,138	1,105	1,094	1,102	1,099	1,139	1,262	1,373	1,460	1,517	1,530	1,506	1,466	1,429	1,421	1,443	1,437	1,402	1,386	1,382	1,362	1,268
Summer	7	1,526	7/2/2015	1,180	1,104	1,084	1,057	1,051	1,048	1,074	1,171	1,334	1,409	1,437	1,481	1,518	1,501	1,526	1,495	1,478	1,476	1,457	1,444	1,395	1,404	1,416	1,385
Summer	7	1,514	7/3/2015	1,261	1,154	1,085	1,062	1,042	1,058	1,063	1,153	1,303	1,434	1,463	1,503	1,491	1,506	1,514	1,513	1,474	1,471	1,458	1,429	1,396	1,409	1,399	1,349
Summer	7	1,501	7/4/2015	1,269	1,178	1,122	1,080	1,067	1,024	1,013	1,063	1,170	1,292	1,415	1,462	1,486	1,501	1,483	1,461	1,458	1,470	1,455	1,441	1,421	1,380	1,373	1,319
Summer	7	1,518	7/5/2015	1,222	1,138	1,074	1,061	1,057	1,072	1,070	1,075	1,195	1,329	1,430	1,452	1,495	1,505	1,482	1,475	1,465	1,498	1,518	1,484	1,466	1,465	1,471	1,391
Summer	7	1,656	7/6/2015	1,276	1,191	1,157	1,116	1,095	1,091	1,143	1,287	1,452	1,560	1,590	1,617	1,624	1,614	1,614	1,602	1,618	1,656	1,647	1,608	1,565	1,548	1,548	1,463
Summer	7	1,600	7/7/2015	1,301	1,207	1,153	1,118	1,093	1,109	1,133	1,229	1,326	1,398	1,441	1,494	1,525	1,556	1,600	1,584	1,569	1,565	1,544	1,476	1,414	1,395	1,373	1,303
Summer	7	1,556	7/8/2015	1,174	1,074	1,039	1,022	1,008	1,020	1,051	1,123	1,262	1,343	1,370	1,407	1,473	1,523	1,519	1,484	1,488	1,512	1,556	1,531	1,493	1,473	1,426	1,365
Summer	7	1,632	7/9/2015	1,228	1,158	1,097	1,083	1,098	1,104	1,139	1,259	1,439	1,553	1,592	1,615	1,617	1,625	1,626	1,604	1,596	1,632	1,617	1,577	1,530	1,530	1,560	1,503
Summer	7	1,684	7/10/2015	1,328	1,221	1,183	1,160	1,134	1,133	1,172	1,294	1,462	1,571	1,619	1,669	1,675	1,665	1,684	1,674	1,654	1,666	1,644	1,621	1,545	1,496	1,494	1,426
Summer	7	1,573	7/11/2015	1,326	1,269	1,212	1,191	1,171	1,173	1,179	1,209	1,316	1,428	1,521	1,562	1,573	1,563	1,542	1,536	1,525	1,542	1,545	1,527	1,501	1,464	1,443	1,381
Summer	7	1,566	7/12/2015	1,259	1,178	1,098	1,071	1,041	1,032	1,075	1,043	1,130	1,269	1,389	1,480	1,526	1,550	1,535	1,497	1,513	1,547	1,554	1,540	1,548	1,550	1,566	1,503
Summer	7	1,719	7/13/2015	1,348	1,231	1,156	1,144	1,118	1,125	1,151	1,307	1,459	1,563	1,650	1,698	1,719	1,718	1,688	1,655	1,650	1,671	1,661	1,607	1,556	1,574	1,574	1,485
Summer	7	1,641	7/14/2015	1,306	1,187	1,106	1,093	1,063	1,074	1,100	1,215	1,384	1,509	1,571	1,609	1,641	1,609	1,630	1,608	1,596	1,620	1,613	1,582	1,539	1,490	1,487	1,384
Summer	7	1,680	7/15/2015	1,223	1,123	1,094	1,101	1,099	1,091	1,143	1,261	1,442	1,540	1,609	1,628	1,680	1,655	1,644	1,636	1,612	1,613	1,594	1,589	1,570	1,524	1,489	1,445
Summer	7	1,587	7/16/2015	1,307	1,163	1,132	1,048	1,044	1,058	1,118	1,218	1,387	1,468	1,493	1,519	1,532	1,499	1,503	1,502	1,515	1,574	1,587	1,556	1,544	1,517	1,519	1,438
Summer	7	1,642	7/17/2015	1,272	1,103	1,069	1,058	1,091	1,103	1,137	1,259	1,417	1,526	1,590	1,612	1,642	1,636	1,618	1,566	1,551	1,561	1,565	1,516	1,463	1,429	1,449	1,399
Summer	7	1,494	7/18/2015	1,279	1,164	1,087	1,071	1,048	1,040	1,042	1,079	1,165	1,273	1,400	1,461	1,492	1,494	1,464	1,440	1,438	1,473	1,479	1,460	1,450	1,439	1,426	1,353
Summer	7	1,500	7/19/2015	1,229	1,142	1,093	1,091	1,088	1,076	1,082	1,085	1,154	1,230	1,156	1,156	1,156	1,356	1,500	1,442	1,417	1,442	1,463	1,445	1,437	1,448	1,445	1,371
Summer	7	1,640	7/20/2015	1,243	1,151	1,123	1,093	1,110	1,123	1,149	1,248	1,435	1,522	1,592	1,631	1,640	1,633	1,617	1,579	1,578	1,611	1,582	1,546	1,527	1,499	1,529	1,405
Summer	7	1,592	7/21/2015	1,276	1,175	1,231	1,195	1,203	1,206	1,233	1,292	1,411	1,480	1,527	1,569	1,592	1,578	1,568	1,541	1,530	1,542	1,508	1,485	1,478	1,458	1,442	1,383
Summer	7	1,604	7/22/2015	1,222	1,111	1,066	1,044	1,028	1,048	1,061	1,159	1,325	1,476	1,505	1,567	1,573	1,586	1,567	1,517	1,477	1,564	1,604	1,550	1,504	1,505	1,483	1,420
Summer	7	1,566	7/23/2015	1,301	1,199	1,151	1,154	1,124	1,126	1,172	1,277	1,423	1,495	1,530	1,557	1,552	1,537	1,520	1,492	1,538	1,566	1,549	1,523	1,500	1,477	1,510	1,424
Summer	7	1,552	7/24/2015	1,295	1,186	1,147	1,116	1,105	1,119	1,129	1,252	1,381	1,458	1,531	1,552	1,550	1,507	1,500	1,474	1,456	1,462	1,451	1,407	1,379	1,370	1,396	1,343
Summer	7	1,466	7/25/2015	1,245	1,174	1,130	1,115	1,109	1,107	1,130	1,140	1,220	1,328	1,401	1,451	1,466	1,450	1,413	1,399	1,384	1,415	1,417	1,412	1,377	1,334	1,399	1,319
Summer	7	1,415	7/26/2015	1,220	1,143	1,114	1,078	1,071	1,065	1,082	1,056	1,151	1,258	1,315	1,385	1,411	1,415	1,385	1,354	1,338	1,370	1,387	1,367	1,370	1,359	1,368	1,271
Summer	7	1,591	7/27/2015	1,120	1,041	1,016	1,006	1,006	1,036	1,078	1,174	1,330	1,413	1,482	1,509	1,497	1,496	1,524	1,550	1,533	1,586	1,591	1,535	1,492	1,501	1,511	1,408
Summer	7	1,567	7/28/2015	1,267	1,166	1,135	1,105	1,097	1,088	1,123	1,186	1,316	1,414	1,460	1,536	1,567	1,538	1,519	1,498	1,488	1,514	1,508	1,476	1,483	1,488	1,491	1,418
Summer	7	1,644	7/29/2015	1,289	1,148	1,112	1,079	1,057	1,081	1,138	1,246	1,396	1,526	1,575	1,588	1,593	1,588	1,624	1,623	1,618	1,644	1,628	1,586	1,545	1,522	1,560	1,485
Summer	7	1,644	7/30/2015	1,338	1,211	1,174	1,157	1,131	1,134	1,157	1,251	1,448	1,527	1,597	1,630	1,644	1,629	1,610	1,606	1,613	1,634	1,616	1,582	1,538	1,527	1,540	1,448
Summer	7	1,599	7/31/2015	1,286	1,173	1,093	1,075	1,054	1,055	1,087	1,183	1,337	1,409	1,470	1,540	1,549	1,557	1,585	1,572	1,582	1,599	1,588	1,562	1,491	1,461	1,434	1,358
Summer	8	1,576	8/1/2015	1,255	1,173	1,100	1,090	1,091	1,085	1,093	1,135	1,243	1,395	1,496	1,551	1,574	1,576	1,551	1,514	1,484	1,484	1,494	1,458	1,393	1,376	1,381	1,373
Summer	8	1,510	8/2/2015	1,265	1,201	1,152	1,114	1,096	1,076	1,087	1,097	1,168	1,277	1,427	1,484	1,510	1,499	1,429	1,400	1,390	1,429	1,457	1,443	1,410	1,371	1,398	1,318
Summer	8	1,563	8/3/2015	1,247	1,108	1,072	1,084	1,079	1,079	1,097	1,141	1,215	1,321	1,442	1,504	1,563	1,542	1,520	1,494	1,482	1,515	1,544	1,506	1,454	1,461	1,466	1,387
Summer	8	1,643	8/4/2015	1,268	1,153	1,116	1,087	1,072	1,066	1,089	1,198	1,375	1,459	1,518	1,566	1,626	1,615	1,606	1,617	1,605	1,643	1,622	1,549	1,508	1,469	1,481	1,323
Summer	8	1,634	8/5/2015	1,182	1,106	1,131	1,077	1,067	1,086	1,140	1,257	1,441	1,530	1,577	1,573	1,626	1,634	1,616	1,604	1,561	1,580	1,603	1,552	1,515	1,485	1,493	1,401
Summer	8	1,621	8/6/2015	1,268	1,196	1,135	1,117	1,117	1,140	1,181	1,254	1,418	1,525	1,608	1,609	1,621	1,574	1,582	1,556	1,526	1,541	1,537	1,500	1,481	1,487	1,513	1,391
Summer	8	1,609	8/7/2015	1,236	1,155	1,114	1,086	1,081	1,087	1,130	1,231	1,398	1,498	1,571	1,602	1,609	1,582	1,573	1,563	1,555	1,578	1,567	1,529	1,484	1,451	1,460	1,386
Summer	8	1,531	8/8/2015	1,287	1,201	1,149	1,119	1,158	1,158	1,155	1,154	1,230	1,353	1,445	1,503	1,531	1,509	1,486	1,470	1,439	1,460	1,461	1,437	1,414	1,411	1,405	1,349
Summer	8	1,511	8/9/2015	1,266	1,183	1,118	1,099	1,104	1,104	1,108	1,110	1,164	1,280	1,388	1,451	1,495	1,511	1,479	1,387	1,350	1,380	1,415	1,436	1,459	1,483	1,503	1,410
Summer	8	1,636	8/10/2015	1,283	1,187	1,120	1,098	1,069	1,080	1,134	1,250	1,400	1,467	1,520	1,558	1,569	1,556	1,565	1,581	1,593	1,632	1,636	1,601	1,564	1,559	1,581	1,477
Summer	8	1,622	8/11/2015	1,343	1,230	1,147	1,122	1,121	1,134	1,158	1,276	1,437	1,509	1,570	1,611	1,563	1,593	1,622	1,601	1,620	1,612	1,580	1,564	1,510	1,528	1,512	1,408
Summer	8	1,505	8/12/2015	1,243	1,166	1,157	1,138	1,143	1,125	1,134	1,221	1,347	1,408	1,453	1,477	1,472	1,445	1,461	1,428	1,440	1,490	1,505	1,470	1,470	1,484	1,478	1,363
Summer	8	1,683	8/13/2015	1,235	1,131	1,087	1,077	1,077	1,071	1,132	1,239	1,380	1,504	1,551	1,580	1,610	1,591	1,612	1,573	1,600	1,672	1,683	1,644	1,596	1,594	1,622	1,489
Summer	8	1,699	8/14/2015	1,370	1,261	1,213	1,185	1,181	1,186	1,219	1,310	1,452	1,557	1,627	1,670	1,699	1,680	1,664	1,610	1,603	1,607	1,599	1,560	1,518	1,504	1,520	1,414
Summer	8	1,602	8/15/2015	1,285	1,179	1,137	1,117	1,091	1,080	1,098	1,140	1,246	1,352	1,471	1,531	1,575	1,584	1,576	1,559	1,557	1,588	1,602	1,576	1,545	1,525	1,536	1,447
Summer	8	1,592	8/16/2015	1,345	1,260	1,200	1,157	1,129	1,119	1,143	1,163	1,221	1,351	1,462	1,539	1,585	1,592	1,566	1,535	1,513	1,553	1,578	1,574	1,548	1,561	1,571	1,419
Summer	8	1,766	8/17/2015	1,294	1,189	1,135	1,135	1,130	1,139	1,182	1,304	1,481	1,600	1,697	1,736	1,766	1,757	1,755	1,749	1,755	1,761	1,733	1,694	1,667	1,669	1,669	1,517
Summer	8	1,825	8/18/2015	1,382	1,259	1,213	1,186	1,172	1,189	1,225	1,340	1,513	1,625	1,698	1,776	1,819	1,816	1,825	1,811	1,809	1,811	1,800	1,750	1,728	1,746	1,743	1,590
Summer	8	1,803	8/19/2015	1,457	1,320	1,293	1,243	1,219	1,238	1,272	1,387	1,556	1,652	1,704	1,741	1,786	1,778	1,777	1,769	1,771	1,803	1,789	1,736	1,696	1,697	1,702	1,542
Summer	8	1,765	8/20/2015	1,385	1,269	1,246	1,217	1,197	1,214	1,240	1,355	1,536	1,632	1,684	1,735	1,765	1,734	1,738	1,738	1,739	1,756	1,709	1,668	1,640	1,627	1,620	1,490
Summer	8	1,715	8/21/2015	1,352	1,252	1,229	1,200	1,211	1,188	1,207	1,319	1,486	1,603	1,662	1,676	1,706	1,715	1,676	1,672	1,657	1,657	1,614	1,569	1,567	1,533	1,527	1,430
Summer	8	1,634	8/22/2015	1,310	1,237	1,204	1,176	1,165	1,163	1,189	1,219	1,304	1,429	1,536	1,611	1,634	1,620	1,600	1,595	1,594	1,606	1,616	1,589	1,542	1,576	1,563	1,479
Summer	8	1,618	8/23/2015	1,382	1,302	1,230	1,207	1,199	1,203	1,211	1,222	1,274	1,400	1,506	1,566	1,606	1,618	1,606	1,536	1,536	1,588	1,600	1,591	1,583	1,609	1,605	1,482
Summer	8	1,763	8/24/2015	1,359	1,234	1,201	1,183	1,177	1,188	1,236	1,347	1,522	1,621	1,687	1,738	1,754	1,730	1,729	1,721	1,728	1,763	1,745	1,700	1,640	1,666	1,611	1,468
Summer	8	1,724	8/25/2015	1,340	1,255	1,264	1,245	1,240	1,233	1,264	1,374	1,518	1,610	1,625	1,663	1,690	1,686	1,695	1,685	1,699	1,724	1,706	1,672	1,665	1,668	1,633	1,523
Summer	8	1,660	8/26/2015	1,363	1,253	1,217	1,198	1,191	1,200	1,220	1,305	1,446	1,516	1,553	1,604	1,653	1,625	1,578	1,554	1,588	1,619	1,660	1,654	1,628	1,627	1,574	1,429
Summer	8	1,644	8/27/2015	1,299	1,196	1,165	1,138	1,136	1,145	1,185	1,304	1,469	1,575	1,611	1,626	1,597	1,601	1,586	1,591	1,607	1,644	1,624	1,581	1,553	1,601	1,576	1,466
Summer	8	1,645	8/28/2015	1,358	1,269	1,226	1,202	1,181	1,157	1,218	1,340	1,465	1,529	1,578	1,629	1,645	1,628	1,616	1,600	1,605	1,614	1,603	1,579	1,542	1,565	1,548	1,465
Summer	8	1,558	8/29/2015	1,352	1,240	1,208	1,179	1,155	1,146	1,160	1,218	1,284	1,394	1,490	1,547	1,558	1,542	1,526	1,504	1,467	1,483	1,468	1,441	1,414	1,464	1,448	1,372
Summer	8	1,589	8/30/2015	1,270	1,237	1,169	1,146	1,130	1,136	1,158	1,157	1,217	1,322	1,424	1,487	1,527	1,536	1,515	1,496	1,496	1,538	1,547	1,545	1,532	1,589	1,571	1,443
Summer	8	1,596	8/31/2015	1,307	1,218	1,179	1,127	1,125	1,131	1,177	1,274	1,422	1,487	1,533	1,580	1,596	1,580	1,538	1,521	1,531	1,550	1,529	1,478	1,459	1,492	1,461	1,327
Fall	9	1,559	9/1/2015	1,210	1,142	1,143	1,100	1,060	1,061	1,087	1,198	1,351	1,435	1,465	1,495	1,466	1,450	1,456	1,438	1,437	1,505	1,517	1,499	1,494	1,559	1,515	1,397
Fall	9	1,650	9/2/2015	1,263	1,176	1,158	1,138	1,140	1,137	1,160	1,293	1,420	1,468	1,504	1,547	1,574	1,587	1,611	1,616	1,627	1,650	1,619	1,600	1,593	1,623	1,567	1,452
Fall	9	1,589	9/3/2015	1,295	1,215	1,185	1,144	1,148	1,145	1,170	1,288	1,451	1,532	1,571	1,589	1,588	1,546	1,551	1,536	1,537	1,562	1,547	1,506	1,478	1,489	1,445	1,343
Fall	9	1,571	9/4/2015	1,256	1,154	1,131	1,126	1,102	1,120	1,164	1,285	1,418	1,484	1,517	1,569	1,571	1,543	1,534	1,533	1,519	1,534	1,513	1,483	1,448	1,479	1,464	1,382
Fall	9	1,463	9/5/2015	1,287	1,240	1,183	1,161	1,142	1,129	1,120	1,162	1,247	1,308	1,388	1,463	1,463	1,439	1,406	1,389	1,376	1,401	1,403	1,383	1,360	1,354	1,303	1,226
Fall	9	1,518	9/6/2015	1,178	1,124	1,052	1,049	1,038	1,055	1,096	1,131	1,206	1,311	1,396	1,456	1,507	1,514	1,494	1,473	1,472	1,499	1,518	1,496	1,477	1,508	1,426	1,309
Fall	9	1,548	9/7/2015	1,206	1,119	1,075	1,053	1,035	1,041	1,058	1,054	1,118	1,204	1,292	1,383	1,443	1,462	1,448	1,457	1,472	1,520	1,524	1,503	1,524	1,548	1,469	1,375
Fall	9	1,606	9/8/2015	1,241	1,155	1,146	1,128	1,104	1,177	1,191	1,353	1,502	1,470	1,486	1,560	1,605	1,574	1,588	1,567	1,579	1,605	1,595	1,571	1,570	1,606	1,530	1,391
Fall	9	1,524	9/9/2015	1,285	1,214	1,192	1,162	1,144	1,149	1,199	1,353	1,494	1,501	1,521	1,524	1,491	1,451	1,451	1,450	1,477	1,501	1,470	1,448	1,487	1,509	1,435	1,325
Fall	9	1,571	9/10/2015	1,214	1,166	1,135	1,131	1,111	1,098	1,133	1,295	1,465	1,537	1,571	1,566	1,555	1,541	1,513	1,439	1,452	1,493	1,476	1,443	1,444	1,493	1,425	1,283
Fall	9	1,557	9/11/2015	1,147	1,084	1,058	1,047	1,027	1,043	1,089	1,288	1,465	1,495	1,494	1,546	1,557	1,547	1,542	1,514	1,462	1,453	1,463	1,446	1,384	1,373	1,344	1,286
Fall	9	1,394	9/12/2015	1,198	1,136	1,072	1,018	994	1,002	1,029	1,056	1,119	1,217	1,303	1,376	1,394	1,370	1,334	1,312	1,300	1,351	1,372	1,348	1,344	1,382	1,345	1,312
Fall	9	1,531	9/13/2015	1,205	1,161	1,096	1,063	1,059	1,054	1,067	1,102	1,169	1,283	1,381	1,452	1,488	1,499	1,463	1,432	1,428	1,466	1,481	1,472	1,492	1,531	1,473	1,340
Fall	9	1,566	9/14/2015	1,218	1,144	1,091	1,070	1,069	1,077	1,095	1,228	1,447	1,444	1,487	1,499	1,516	1,527	1,506	1,492	1,527	1,566	1,542	1,506	1,486	1,515	1,437	1,287
Fall	9	1,569	9/15/2015	1,164	1,107	1,058	1,064	1,067	1,076	1,120	1,286	1,482	1,500	1,489	1,447	1,455	1,450	1,475	1,463	1,473	1,541	1,528	1,502	1,522	1,569	1,512	1,356
Fall	9	1,587	9/16/2015	1,227	1,140	1,113	1,101	1,089	1,081	1,121	1,273	1,445	1,457	1,463	1,490	1,520	1,500	1,514	1,514	1,529	1,587	1,567	1,533	1,549	1,577	1,509	1,406
Fall	9	1,588	9/17/2015	1,274	1,183	1,149	1,120	1,136	1,110	1,168	1,301	1,473	1,462	1,488	1,522	1,536	1,535	1,559	1,555	1,529	1,569	1,581	1,537	1,550	1,588	1,509	1,384
Fall	9	1,654	9/18/2015	1,257	1,163	1,135	1,115	1,105	1,117	1,154	1,300	1,490	1,516	1,559	1,591	1,618	1,613	1,629	1,634	1,638	1,654	1,607	1,551	1,545	1,516	1,454	1,364
Fall	9	1,510	9/19/2015	1,264	1,137	1,119	1,083	1,068	1,029	1,034	1,073	1,181	1,309	1,413	1,467	1,497	1,510	1,495	1,436	1,406	1,422	1,426	1,388	1,404	1,383	1,320	1,253
Fall	9	1,395	9/20/2015	1,151	1,061	1,105	1,067	1,032	1,010	1,020	1,068	1,077	1,184	1,278	1,365	1,395	1,383	1,344	1,313	1,316	1,367	1,380	1,383	1,321	1,335	1,285	1,203
Fall	9	1,541	9/21/2015	1,117	1,032	1,021	1,016	1,023	1,045	1,098	1,275	1,477

Contains Proprietary Material
Do Not Distribute

Fall	10	1,555	10/3/2015	1,313	1,238	1,224	1,221	1,246	1,243	1,232	1,301	1,394	1,501	1,551	1,555	1,523	1,496	1,432	1,404	1,376	1,403	1,407	1,415	1,477	1,483	1,492	1,428
Fall	10	1,644	10/4/2015	1,361	1,313	1,309	1,333	1,316	1,341	1,367	1,431	1,518	1,611	1,644	1,631	1,607	1,566	1,501	1,466	1,453	1,481	1,515	1,527	1,616	1,627	1,563	1,456
Fall	10	1,809	10/5/2015	1,361	1,297	1,282	1,270	1,276	1,302	1,378	1,587	1,809	1,799	1,752	1,725	1,686	1,621	1,584	1,543	1,557	1,571	1,587	1,599	1,655	1,635	1,531	1,394
Fall	10	1,727	10/6/2015	1,296	1,219	1,219	1,221	1,229	1,251	1,317	1,518	1,705	1,727	1,665	1,622	1,565	1,514	1,491	1,488	1,497	1,535	1,536	1,536	1,602	1,594	1,499	1,399
Fall	10	1,627	10/7/2015	1,281	1,204	1,188	1,161	1,167	1,209	1,264	1,427	1,627	1,592	1,545	1,509	1,484	1,450	1,432	1,405	1,406	1,445	1,449	1,412	1,436	1,485	1,415	1,265
Fall	10	1,585	10/8/2015	1,153	1,003	1,004	978	989	1,018	1,098	1,245	1,447	1,493	1,489	1,472	1,504	1,458	1,458	1,450	1,446	1,483	1,488	1,517	1,580	1,585	1,512	1,411
Fall	10	1,701	10/9/2015	1,300	1,208	1,216	1,221	1,242	1,273	1,343	1,528	1,663	1,701	1,680	1,654	1,639	1,627	1,669	1,653	1,643	1,678	1,686	1,692	1,687	1,638	1,565	1,463
Fall	10	1,515	#########	1,289	1,213	1,200	1,192	1,198	1,204	1,259	1,344	1,395	1,486	1,515	1,514	1,483	1,438	1,411	1,371	1,358	1,342	1,364	1,391	1,506	1,494	1,438	1,382
Fall	10	1,704	#########	1,332	1,285	1,283	1,287	1,305	1,328	1,305	1,342	1,438	1,593	1,650	1,667	1,658	1,704	1,660	1,592	1,528	1,559	1,531	1,545	1,573	1,522	1,510	1,395
Fall	10	1,684	#########	1,325	1,250	1,199	1,176	1,190	1,211	1,244	1,344	1,427	1,535	1,622	1,673	1,684	1,647	1,608	1,564	1,548	1,539	1,506	1,508	1,595	1,571	1,464	1,299
Fall	10	1,657	#########	1,181	1,112	1,102	1,084	1,057	1,089	1,167	1,353	1,599	1,582	1,574	1,598	1,613	1,568	1,522	1,494	1,530	1,589	1,622	1,628	1,657	1,574	1,469	1,370
Fall	10	1,564	#########	1,261	1,153	1,128	1,112	1,097	1,098	1,137	1,310	1,504	1,499	1,490	1,472	1,466	1,433	1,440	1,428	1,425	1,475	1,472	1,500	1,564	1,528	1,463	1,359
Fall	10	1,742	#########	1,217	1,143	1,110	1,102	1,120	1,163	1,245	1,450	1,728	1,742	1,691	1,705	1,665	1,610	1,604	1,578	1,536	1,568	1,590	1,628	1,709	1,675	1,577	1,458
Fall	10	1,733	#########	1,349	1,278	1,249	1,253	1,272	1,354	1,384	1,550	1,733	1,720	1,675	1,654	1,613	1,559	1,537	1,527	1,562	1,612	1,605	1,619	1,641	1,601	1,549	1,485
Fall	10	1,805	#########	1,396	1,347	1,318	1,322	1,325	1,371	1,449	1,549	1,694	1,805	1,785	1,787	1,771	1,724	1,675	1,641	1,660	1,725	1,767	1,788	1,804	1,778	1,680	1,609
Fall	10	1,777	#########	1,458	1,392	1,406	1,318	1,307	1,347	1,392	1,436	1,532	1,642	1,658	1,659	1,660	1,627	1,590	1,588	1,588	1,623	1,649	1,697	1,763	1,777	1,696	1,612
Fall	10	2,017	#########	1,519	1,466	1,448	1,476	1,487	1,457	1,554	1,797	1,985	2,017	1,950	1,912	1,842	1,780	1,754	1,708	1,708	1,745	1,757	1,843	1,946	1,942	1,854	1,713
Fall	10	1,858	#########	1,584	1,496	1,446	1,425	1,413	1,420	1,493	1,665	1,858	1,837	1,783	1,737	1,720	1,644	1,600	1,560	1,555	1,514	1,524	1,621	1,687	1,684	1,616	1,509
Fall	10	1,805	#########	1,353	1,301	1,310	1,321	1,348	1,388	1,464	1,620	1,805	1,789	1,691	1,622	1,556	1,504	1,473	1,441	1,434	1,479	1,506	1,555	1,661	1,666	1,669	1,575
Fall	10	2,033	#########	1,500	1,456	1,468	1,484	1,494	1,538	1,621	1,837	2,033	2,022	2,008	1,976	1,940	1,903	1,871	1,814	1,800	1,850	1,777	1,750	1,722	1,683	1,592	1,479
Fall	10	1,749	#########	1,372	1,291	1,254	1,218	1,215	1,248	1,311	1,526	1,749	1,747	1,693	1,665	1,630	1,578	1,594	1,592	1,603	1,660	1,642	1,668	1,679	1,657	1,590	1,488
Fall	10	1,786	#########	1,395	1,356	1,335	1,312	1,312	1,339	1,384	1,450	1,580	1,751	1,786	1,751	1,729	1,661	1,612	1,563	1,539	1,571	1,606	1,657	1,713	1,675	1,622	1,534
Fall	10	1,633	#########	1,437	1,359	1,289	1,276	1,278	1,305	1,322	1,377	1,415	1,535	1,563	1,584	1,582	1,588	1,565	1,529	1,530	1,591	1,611	1,630	1,633	1,583	1,520	1,409
Fall	10	1,882	#########	1,302	1,250	1,253	1,269	1,264	1,314	1,391	1,599	1,882	1,853	1,790	1,746	1,732	1,688	1,679	1,634	1,644	1,703	1,688	1,749	1,842	1,849	1,781	1,653
Fall	10	2,126	#########	1,566	1,506	1,508	1,546	1,576	1,583	1,646	1,880	2,126	2,111	2,009	1,930	1,844	1,747	1,684	1,638	1,645	1,686	1,731	1,826	1,862	1,812	1,776	1,636
Fall	10	2,072	#########	1,499	1,443	1,451	1,447	1,449	1,475	1,536	1,801	2,062	2,072	1,989	1,873	1,797	1,732	1,689	1,646	1,655	1,737	1,792	1,851	1,867	1,818	1,750	1,627
Fall	10	1,806	#########	1,512	1,416	1,384	1,374	1,381	1,384	1,439	1,622	1,806	1,725	1,697	1,680	1,685	1,616	1,589	1,528	1,510	1,543	1,558	1,562	1,589	1,556	1,471	1,415
Fall	10	1,673	#########	1,334	1,296	1,279	1,265	1,250	1,276	1,323	1,492	1,673	1,671	1,620	1,599	1,584	1,541	1,523	1,487	1,528	1,548	1,510	1,536	1,626	1,642	1,577	1,539
Fall	10	1,789	#########	1,484	1,387	1,394	1,459	1,475	1,506	1,536	1,612	1,674	1,781	1,789	1,756	1,706	1,664	1,606	1,547	1,534	1,580	1,622	1,668	1,683	1,670	1,633	1,581
Fall	11	1,883	11/1/2015	1,530	1,435	1,412	1,423	1,443	1,479	1,517	1,582	1,704	1,806	1,858	1,836	1,822	1,803	1,790	1,755	1,789	1,841	1,883	1,821	1,714	1,630	1,512	1,428
Fall	11	1,845	11/2/2015	1,338	1,295	1,241	1,228	1,230	1,265	1,347	1,579	1,787	1,742	1,717	1,674	1,647	1,598	1,629	1,621	1,657	1,758	1,841	1,845	1,827	1,819	1,691	1,622
Fall	11	2,060	11/3/2015	1,522	1,429	1,470	1,471	1,490	1,521	1,611	1,820	1,998	1,998	1,981	1,956	1,932	1,904	1,903	1,884	1,907	2,003	2,060	2,027	1,984	1,946	1,852	1,731
Fall	11	1,867	11/4/2015	1,594	1,496	1,495	1,467	1,460	1,496	1,568	1,700	1,867	1,843	1,790	1,749	1,704	1,658	1,623	1,567	1,589	1,645	1,746	1,770	1,738	1,713	1,631	1,537
Fall	11	1,958	11/5/2015	1,453	1,349	1,363	1,380	1,374	1,402	1,478	1,680	1,883	1,886	1,871	1,835	1,860	1,813	1,800	1,777	1,803	1,888	1,948	1,958	1,939	1,890	1,796	1,660
Fall	11	1,841	11/6/2015	1,547	1,429	1,391	1,357	1,354	1,371	1,458	1,579	1,841	1,826	1,795	1,753	1,715	1,661	1,659	1,609	1,622	1,662	1,666	1,612	1,580	1,509	1,435	1,376
Fall	11	1,633	11/7/2015	1,332	1,252	1,242	1,228	1,224	1,230	1,226	1,264	1,278	1,350	1,380	1,386	1,389	1,376	1,366	1,385	1,424	1,544	1,627	1,633	1,599	1,562	1,525	1,475
Fall	11	1,825	11/8/2015	1,399	1,378	1,345	1,365	1,392	1,388	1,435	1,497	1,574	1,687	1,736	1,743	1,739	1,722	1,662	1,622	1,622	1,695	1,819	1,825	1,810	1,787	1,748	1,660
Fall	11	2,018	11/9/2015	1,573	1,542	1,502	1,493	1,502	1,523	1,598	1,820	2,018	1,996	1,918	1,788	1,757	1,697	1,609	1,562	1,561	1,661	1,805	1,817	1,792	1,752	1,677	1,556
Fall	11	1,883	#########	1,438	1,370	1,353	1,391	1,401	1,422	1,516	1,715	1,883	1,838	1,756	1,700	1,655	1,584	1,549	1,543	1,551	1,658	1,798	1,777	1,739	1,692	1,626	1,527
Fall	11	1,873	#########	1,481	1,417	1,405	1,396	1,399	1,418	1,443	1,519	1,628	1,734	1,800	1,807	1,738	1,710	1,704	1,703	1,726	1,808	1,870	1,862	1,873	1,823	1,746	1,623
Fall	11	2,029	#########	1,553	1,493	1,480	1,476	1,502	1,537	1,590	1,842	2,029	2,027	1,958	1,894	1,845	1,773	1,741	1,705	1,746	1,798	1,878	1,893	1,860	1,803	1,711	1,589
Fall	11	1,750	#########	1,480	1,395	1,328	1,337	1,363	1,353	1,407	1,550	1,750	1,739	1,707	1,712	1,675	1,609	1,599	1,562	1,595	1,666	1,735	1,722	1,695	1,661	1,616	1,538
Fall	11	1,800	#########	1,407	1,320	1,277	1,282	1,277	1,306	1,357	1,446	1,565	1,679	1,749	1,697	1,691	1,685	1,662	1,631	1,640	1,720	1,800	1,762	1,730	1,701	1,644	1,575
Fall	11	1,867	#########	1,496	1,446	1,431	1,439	1,450	1,475	1,509	1,562	1,652	1,732	1,774	1,753	1,702	1,663	1,610	1,621	1,662	1,778	1,867	1,854	1,811	1,794	1,743	1,643
Fall	11	2,038	#########	1,496	1,426	1,443	1,443	1,479	1,514	1,586	1,800	1,998	1,973	1,921	1,888	1,867	1,825	1,820	1,822	1,871	1,956	2,038	2,011	1,950	1,883	1,818	1,697
Fall	11	2,014	#########	1,579	1,482	1,504	1,493	1,491	1,521	1,585	1,822	1,999	1,978	1,876	1,829	1,803	1,765	1,744	1,731	1,762	1,890	1,993	2,014	2,008	1,970	1,863	1,730
Fall	11	2,182	#########	1,624	1,548	1,524	1,530	1,529	1,564	1,667	1,920	2,130	2,161	2,103	2,077	2,061	2,023	1,985	1,939	1,921	2,057	2,182	2,162	2,119	2,072	1,970	1,857
Fall	11	2,195	#########	1,725	1,626	1,639	1,611	1,612	1,644	1,734	1,962	2,195	2,160	2,112	2,078	2,050	1,992	1,969	1,912	1,921	2,007	2,094	2,058	2,018	1,962	1,882	1,717
Fall	11	1,877	#########	1,591	1,498	1,477	1,444	1,442	1,443	1,521	1,688	1,877	1,853	1,840	1,843	1,831	1,783	1,756	1,742	1,742	1,799	1,830	1,777	1,732	1,684	1,628	1,551
Fall	11	1,907	#########	1,475	1,424	1,387	1,370	1,367	1,334	1,367	1,447	1,604	1,737	1,778	1,756	1,721	1,724	1,691	1,673	1,700	1,805	1,907	1,881	1,850	1,802	1,740	1,652
Fall	11	1,795	#########	1,560	1,512	1,401	1,391	1,398	1,408	1,392	1,451	1,510	1,594	1,643	1,636	1,630	1,620	1,608	1,612	1,590	1,708	1,782	1,795	1,786	1,772	1,723	1,573
Fall	11	2,014	#########	1,451	1,356	1,346	1,319	1,341	1,395	1,492	1,714	1,824	1,811	1,783	1,783	1,777	1,764	1,766	1,758	1,777	1,921	1,965	2,004	2,014	1,971	1,898	1,792
Fall	11	2,326	#########	1,694	1,611	1,645	1,647	1,652	1,693	1,768	1,982	2,218	2,210	2,169	2,143	2,129	2,093	2,078	2,057	2,101	2,227	2,326	2,289	2,276	2,239	2,148	2,006
Fall	11	2,444	#########	1,885	1,809	1,797	1,817	1,831	1,875	1,994	2,217	2,444	2,383	2,255	2,153	2,076	2,004	1,987	1,963	1,977	2,144	2,285	2,288	2,277	2,247	2,182	2,047
Fall	11	2,443	#########	1,931	1,863	1,876	1,888	1,901	1,926	2,008	2,237	2,443	2,376	2,242	2,133	2,083	2,023	1,964	1,910	1,939	1,997	2,050	2,017	1,971	1,921	1,851	1,716
Fall	11	1,821	#########	1,560	1,455	1,459	1,454	1,458	1,466	1,506	1,673	1,821	1,797	1,751	1,706	1,666	1,623	1,616	1,592	1,619	1,671	1,715	1,698	1,654	1,600	1,556	1,491
Fall	11	2,063	#########	1,422	1,367	1,328	1,310	1,323	1,358	1,417	1,476	1,581	1,727	1,834	1,894	1,926	1,916	1,914	1,900	1,900	2,006	2,063	2,035	2,018	2,006	1,941	1,863
Fall	11	2,173	#########	1,776	1,683	1,674	1,649	1,651	1,675	1,713	1,792	1,895	1,992	2,012	1,993	1,982	1,974	1,929	1,890	1,933	2,055	2,173	2,156	2,147	2,102	2,001	1,904
Fall	11	2,474	#########	1,850	1,794	1,790	1,813	1,827	1,864	1,951	2,222	2,471	2,474	2,384	2,338	2,320	2,259	2,253	2,240	2,286	2,411	2,474	2,428	2,359	2,289	2,178	2,041

Contains Proprietary Material
Do Not Distribute

Max	2,974
Max Month	2
PST	2,643
Winter	2,431
Spring	1,898
Summer	1,402
Fall	1,603

Source: ABB, The Velocity Suite
CONFIDENTIAL DATA REDACTED

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	1																										

Contains Proprietary Material
Do Not Distribute

Spring	1
Spring	1
Spring	1

Contains Proprietary Material
Do Not Distribute

Summer	1
Summer	1
Summer	1

Contains Proprietary Material
Do Not Distribute

Fall	1																										

Contains Proprietary Material
Do Not Distribute

2.1 Generator List with Existing and Expected Seasonal Claimed Capability (SCC)

- **Generator Information as of January 1, 2015**
- **Summer and Winter SCC as of January 1, 2015, and as of the 2014/15 Winter and 2015 Summer Peaks**

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTICI-PANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	Change in Summer SCC from 8/1/14
194	FOUR HILLS LOAD REDUCER	194	FOUR HILLS LOAD REDUCER	IC	LFG		BIO/REFUSE	01-Apr-96	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	55006	0.000	0.000	0.000	0.000	0.000
253	TURNKEY LANDFILL	253	TURNKEY LANDFILL	IC	LFG		BIO/REFUSE	01-Mar-92	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH	54663	0.730	0.732	0.730	0.732	-0.003
321	MANCHESTER 10/10A CC	321	MANCHESTER 10 10A CC	CC	NG	DFO	GAS/OIL COMBINED CYCLE	15-Nov-95	Dominion Energy Marketing, Inc.	DEM	RI	07	RI	RI	3236	170.000	149.000	170.000	159.000	10.000
322	MANCHESTER 11 11A CC	322	MANCHESTER 11 11A CC	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Oct-95	Dominion Energy Marketing, Inc.	DEM	RI	07	RI	RI	3236	170.000	153.594	170.000	159.000	5.406
323	MANCHESTER 9/9A CC	323	MANCHESTER 9 9A CC	CC	NG	DFO	GAS/OIL COMBINED CYCLE	14-Nov-95	Dominion Energy Marketing, Inc.	DEM	RI	07	RI	RI	3236	169.785	148.785	169.785	159.000	10.215
324	CDECCA	324	CDECCA	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Nov-88	Pawtucket Power Holding Company LLC	PPH	CT	03	CT	CT	50498	61.334	49.522	61.334	49.522	-5.732
326	ALTRESCO	326	ALTRESCO	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-Sep-90	Pawtucket Power Holding Company LLC	PPH	MA	03	WMA	WCMA	50002	178.879	144.612	178.879	144.612	-6.370
327	AMOSKEAG	327	AMOSKEAG	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-22	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	2354	17.500	16.781	17.500	16.781	0.000
328	GULF ISLAND COMPOSITE	328	GULF ISLAND COMPOSITE Incremental	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-26	Brookfield White Pine Hydro LLC	FPLEMH	ME	01	ME	ME	8005	32.970	32.970	32.970	32.970	0.000
329	ASCUTNEY GT	329	ASCUTNEY GT	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Nov-61	Green Mountain Power Corporation	GMP	VT	27	VT	VT	3708	12.581	8.503	12.581	8.503	-0.143
330	AYERS ISLAND	330	AYERS ISLAND	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-25	Public Service Company of New Hampshire	PSNH	NH	01	NH	NH	2355	9.080	8.474	9.080	8.474	0.000
331	AZISCOHOS HYDRO	331	AZISCOHOS HYDRO	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jul-88	Brookfield Energy Marketing, LP	BEMLP	ME	19	ME	ME	50999	6.800	6.800	6.800	6.800	-0.010
332	BAR HARBOR DIESELS 1-4	332	BAR HARBOR DIESELS 1-4	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-69	Energy New England LLC	ENE	ME	09	BHE	ME	1486	4.000	0.000	4.000	0.000	-3.800
335	BELLOWS FALLS	335	BELLOWS FALLS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-28	TransCanada Power Marketing, Ltd.	TCPM	VT	25	VT	NH	3745	48.540	48.540	48.540	48.540	0.000
336	BERLIN 1 GT	336	BERLIN 1 GT	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-72	Green Mountain Power Corporation	GMP	VT	23	VT	VT	3734	50.409	40.260	50.409	40.260	0.000
337	BETHLEHEM	337	BETHLEHEM	ST	WDS		BIO/REFUSE	01-Dec-86	GDF Suez Energy Marketing NA, Inc.	SUEZ	NH	07	NH	NH	50208	15.321	15.303	15.321	15.303	0.129
340	BRIDGEPORT HARBOR 3	340	BRIDGEPORT HARBOR 3	ST	SUB		COAL STEAM	01-Aug-68	PSEG Energy Resources & Trade LLC	PSEG	CT	01	SWCT	CT	568	384.984	383.426	384.984	383.426	0.000
341	BRIDGEPORT HARBOR 4	341	BRIDGEPORT HARBOR 4	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Oct-67	PSEG Energy Resources & Trade LLC	PSEG	CT	01	SWCT	CT	568	21.924	16.907	21.924	16.907	0.000
345	MEAD	345	MEAD	ST	BIT	OBS	COAL STEAM	01-Feb-90	American PowerNet Management, LP	APNM	ME	17	ME	ME	10495	0.000	0.000	0.000	0.000	-0.485
346	BOLTON FALLS	346	BOLTON FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Green Mountain Power Corporation	GMP	VT	23	VT	VT	7056	3.397	0.000	3.397	0.000	-2.149
348	BOOT MILLS	348	BOOT MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-85	NSTAR Electric Company	NSTAR	MA	17	CMA/NEMA	WCMA	10556	11.400	6.010	11.400	6.010	-6.355
349	WHEELABRATOR BRIDGEPORT, L.P.	349	WHEELABRATOR BRIDGEPORT, L.P.	ST	MSW		BIO/REFUSE	01-Apr-88	Wheelabrator Bridgeport, L.P.	WB	CT	01	SWCT	CT	50883	59.267	59.069	59.267	59.069	0.195
350	BRAYTON PT 1	350	BRAYTON PT 1	ST	BIT	NG	COAL STEAM	01-Aug-63	Brayton Point Energy, LLC	BPE	MA	05	RI	SEMA	1619	241.366	225.230	241.366	225.230	0.000
351	BRAYTON PT 2	351	BRAYTON PT 2	ST	BIT	NG	COAL STEAM	01-Jul-64	Brayton Point Energy, LLC	BPE	MA	05	RI	SEMA	1619	242.455	237.842	242.455	237.842	0.000
352	BRAYTON PT 3	352	BRAYTON PT 3	ST	BIT	NG	COAL STEAM	01-Jul-69	Brayton Point Energy, LLC	BPE	MA	05	RI	SEMA	1619	598.606	596.289	598.606	596.289	-15.195
353	BRAYTON PT 4	353	BRAYTON PT 4	ST	RFO	NG	GAS/OIL STEAM	01-Dec-74	Brayton Point Energy, LLC	BPE	MA	05	RI	SEMA	1619	445.520	434.025	445.520	434.025	0.000
354	BRAYTON DIESELS 1-4	354	Brayton Diesels 1-4 Incremental	IC	DFO		OIL INTERNAL COMBUSTION	01-Mar-67	Brayton Point Energy, LLC	BPE	MA	05	RI	SEMA	1619	0.000	0.000	0.000	0.000	0.000
355	BRANFORD 10	355	BRANFORD 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	540	20.950	15.940	20.950	15.940	0.000
356	BRISTOL REFUSE	356	BRISTOL REFUSE	ST	MSW		BIO/REFUSE	01-May-88	Covanta Energy Marketing, LLC	CEM	CT	03	CT	CT	50648	12.440	12.941	12.440	12.941	0.571
357	BRIDGEWATER	357	BRIDGEWATER	ST	WDS		BIO/REFUSE	01-Sep-87	Bridgewater Power Company L.P.	BPCLP	NH	09	NH	NH	10290	14.395	14.170	14.395	14.170	-0.622
358	BRUNSWICK	358	BRUNSWICK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-82	Brookfield White Pine Hydro LLC	FPLEMH	ME	05	ME	ME	1483	11.107	10.585	11.107	10.585	-3.237
359	J. COCKWELL 1	359	J. COCKWELL 1	PS	WAT		HYDRO (PUMPED STORAGE)	01-Sep-74	Bear Swamp Power Company LLC	BSP	MA	03	WMA	WCMA	8005	292.275	292.275	292.275	292.275	0.000
360	J. COCKWELL 2	360	J. COCKWELL 2	PS	WAT		HYDRO (PUMPED STORAGE)	01-Oct-74	Bear Swamp Power Company LLC	BSP	MA	03	WMA	WCMA	8005	292.113	293.238	292.113	293.238	0.000
362	BULLS BRIDGE	362	BULLS BRIDGE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-03	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	05	SWCT	CT	541	5.470	5.388	5.470	5.388	2.159
363	BURLINGTON GT	363	BURLINGTON GT	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jul-71	Burlington Electric Department	BED	VT	07	VT	VT	3754	23.354	19.104	23.354	19.104	0.000
365	CANAL 1	365	CANAL 1	ST	RFO		OIL STEAM	01-Jul-68	Genon Energy Management, LLC	MET	MA	01	SEMA	SEMA	1599	562.305	565.240	562.305	565.240	565.240
366	CANAL 2	366	CANAL 2	ST	RFO	NG	GAS/OIL STEAM	01-Feb-76	Genon Energy Management, LLC	MET	MA	01	SEMA	SEMA	1599	303.000	558.750	303.000	558.750	0.000
367	CAPE GT 4	367	CAPE GT 4	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jan-70	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1484	20.011	15.487	20.011	15.487	-0.209
368	CAPE GT 5	368	CAPE GT 5	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jan-70	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1484	20.272	15.822	20.272	15.822	0.000
369	CATARACT EAST	369	CATARACT EAST	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-37	Brookfield White Pine Hydro LLC	FPLEMH	ME	31	SME	ME	1486	8.000	7.775	8.000	7.775	0.000
370	COS COB 10	370	COS COB 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	NRG Power Marketing LLC	NRGPM	CT	01	NOR	CT	542	23.000	18.932	23.000	18.932	0.000
371	COS COB 11	371	COS COB 11	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	NRG Power Marketing LLC	NRGPM	CT	01	NOR	CT	542	23.000	18.724	23.000	18.724	0.000
372	COS COB 12	372	COS COB 12	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	NRG Power Marketing LLC	NRGPM	CT	01	NOR	CT	542	23.000	19.082	23.000	19.082	0.000
375	CLEARY 9 9A CC	375	CLEARY 9 9A CC	CC	NG	DFO	GAS COMBINED CYCLE	01-Dec-75	Taunton Municipal Lighting Plant	TMLP	MA	05	SEMA	SEMA	1682	109.931	104.931	109.931	104.931	0.000
376	CLEARY 8	376	CLEARY 8	ST	RFO		OIL STEAM	01-Jan-66	Taunton Municipal Lighting Plant	TMLP	MA	05	SEMA	SEMA	1682	22.253	24.825	22.253	24.825	0.000
379	COBBLE MOUNTAIN	379	COBBLE MOUNTAIN	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-23	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	1630	32.480	31.126	32.480	31.126	0.000
380	COMERFORD	380	COMERFORD	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-30	TransCanada Power Marketing, Ltd.	TCPM	NH	09	NH	NH	2349	168.111	166.135	168.111	166.135	0.000
382	MERRIMACK CT1	382	MERRIMACK CT1	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Jul-69	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2364	21.676	16.826	21.676	16.826	0.000
383	MERRIMACK CT2	383	MERRIMACK CT2	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-68	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2364	21.304	16.804	21.304	16.804	0.000
388	DARTMOUTH POWER	388	DARTMOUTH POWER	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-May-92	Consolidated Edison Energy, Inc	CEEI	MA	05	SEMA	SEMA	52026	67.656	60.457	67.656	60.457	-1.692
389	DERBY DAM	389	DERBY DAM	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Mar-89	Connecticut Light and Power Company, The	CLP	CT	01	SWCT	CT	10063	7.050	7.050	7.050	7.050	0.000
393	DEERFIELD 5	393	DEERFIELD 5	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Oct-74	TransCanada Power Marketing, Ltd.	TCPM	MA	11	WMA	WCMA	1620	13.990	13.703	13.990	13.703	0.000
395	DOREEN	395	DOREEN	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	Essential Power Massachusetts, LLC	NAEA-EM	MA	03	WMA	WCMA	1631	20.670	15.820	20.670	15.820	0.000
396	DEVON 10	396	DEVON 10	GT	JF	DFO	OIL COMBUSTION (GAS) TURBINE	01-Apr-88	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	544	18.852	14.407	18.852	14.407	0.000
397	DEVON 11	397	DEVON 11	GT	JF	NG	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	544	38.819	29.299	38.819	29.299	0.000
398	DEVON 12	398	DEVON 12	GT	JF	NG	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	544	38.437	29.227	38.437	29.227	0.000
399	DEVON 13	399	DEVON 13	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	544	38.967	29.967	38.967	29.967	0.000
400	DEVON 14	400	DEVON 14	GT	JF	NG	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-96	NRG Power Marketing LLC	NRGPM	CT	09	SWCT	CT	544	40.274	29.704	40.274	29.704	0.000
401	EASTMAN FALLS	401	EASTMAN FALLS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-12	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2356	6.470	5.582	6.470	5.582	0.000
405	ELLSWORTH HYDRO	405	ELLSWORTH HYDRO	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-19	Black Bear Hydro Partners, LLC	BBHP	ME	09	BHE	ME	1469	9.050	9.044	9.050	9.044	0.000
407	EASTPORT DIESELS 1-3	407	EASTPORT DIESELS 1-3	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-48	Energy New England LLC	ENE	ME	29	BHE	ME	1468	2.100	1.800	2.100	1.800	-0.200
410	ESSEX 19 HYDRO	410	ESSEX 19 HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-17	Green Mountain Power Corporation	GMP	VT	07	VT	VT	3737	4.258	2.266	4.258	2.266	-2.918
411	EXETER	411	EXETER	ST	TDF	OBS	BIO/REFUSE	01-Dec-91	ReEnergy Sterling CT Limited Partnership	REENERGY	CT	13	CT	CT	50736	0.000	0.000	0.000	0.000	-20.981
412	FALLS VILLAGE	412	FALLS VILLAGE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-14	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	05	CT	CT	560	4.349	3.939	4.349	3.939	1.561
413	FIFE BROOK	413	FIFE BROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-74	Bear Swamp Power Company LLC	BSP	MA	03	WMA	WCMA	8004	9.900	6.089	9.900	6.089	0.000
417	FRAMINGHAM JET 1	417	FRAMINGHAM JET 1	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	Exelon Generation Company, LLC	EXGC	MA	17	BOSTON	NEMA	1586	14.175	10.145	14.175	10.145	0.000
418	FRAMINGHAM JET 2	418	FRAMINGHAM JET 2	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	Exelon Generation Company, LLC	EXGC	MA	17	BOSTON	NEMA	1586	15.686	9.743	15.686	9.743	0.000
419	FRAMINGHAM JET 3	419	FRAMINGHAM JET 3	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	Exelon Generation Company, LLC	EXGC	MA	17	BOSTON	NEMA	1586	15.250	10.790	15.250	10.790	0.000
420	FRANKLIN DRIVE 10	420	FRANKLIN DRIVE 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Nov-68	NRG Power Marketing LLC	NRGPM	CT	05	CT	CT	561	20.527	15.417	20.527	15.417	0.000
421	FRONT STREET DIESELS 1-3	421	FRONT STREET DIESELS 1-3	IC	DFO		OIL INTERNAL COMBUSTION	01-Dec-80	Chicopee Municipal Lighting Plant	CMLP	MA	13	WMA	WCMA	7396	8.250	7.713	8.250	7.713	0.000
424	GREAT LAKES - MILLINOCKET	424	GREAT LAKES - MILLINOCKET	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Mar-87	Brookfield Energy Marketing, LP	BEMLP	ME	19	BHE	ME	55830	55.317	74.958	55.317	74.958	44.575
426	GORGE 1 DIESEL	426	GORGE 1 DIESEL	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jan-85	Green Mountain Power Corporation	GMP	VT	07	VT	VT	3735	11.000	0.000	11.000	0.000	-7.099
427	GORHAM	427	GORHAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-54	Public Service Company of New Hampshire	PSNH	NH	07	NH	NH	2358	1.518	1.434	1.518	1.434	0.001
432	HARRIS 1	432	HARRIS 1	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-54	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1492	16.776	16.790	16.776	16.790	0.000
433	HARRIS 2	433	HARRIS 2	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-54	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1492	34.500	34.865	34.500	34.865	0.000
434	HARRIS 3	434	HARRIS 3	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-53	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1492	33.905	34.210	33.905	34.210	0.000
435	HARRIMAN	435	HARRIMAN	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-24	TransCanada Power Marketing, Ltd.	TCPM	VT	25	WMA	WCMA	3746	38.663	40.943	38.663	40.943	0.000
436	HEMPHILL 1	436	HEMPHILL 1	ST	WDS		BIO/REFUSE	01-Dec-87	Springfield Power, LLC	SPRING	NH	19	NH	NH	10838	16.764	16.968	16.764	16.968	0.270
440	HIRAM	440	HIRAM	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-17	Brookfield White Pine Hydro LLC	FPLEMH	ME	05	SME	ME	1493	11.600	11.189	11.600	11.189	0.000
445	COVANTA WEST ENFIELD	445	COVANTA WEST ENFIELD	ST	WDS		BIO/REFUSE	01-Nov-87	Covanta Maine, LLC	CM	ME	19	BHE	ME	10766	21.446	20.461	21.446	20.461	0.000
446	COVANTA JONESBORO	446	COVANTA JONESBORO	ST	WDS		BIO/REFUSE	01-Nov-87	Covanta Maine, LLC	CM	ME	29	BHE	ME	10765	20.226	20.226	20.226	20.226	0.000
448	IPSWICH DIESELS	448	IPSWICH DIESELS	IC	DFO	NG	GAS/OIL INTERNAL COMBUSTION	01-Jan-51	Ipswich Municipal Light Department	IMLD	MA	09	BOSTON	NEMA	1670	9.495	9.729	9.495	9.729	-0.511
449	JACKMAN	449	JACKMAN	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Feb-26	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	2360	3.541	3.600	3.541	3.600	0.000
452	KENDALL JET 1	452	KENDALL JET 1	GT	DFO		OIL COMBUSTION (GAS) TURBINE	24-Sep-70	Kendall Green Energy, LLC	KENDALL	MA	17	BOSTON	NEMA	1595	23.000	18.000	23.000	18.000	0.000
457	LAWRENCE HYDRO	457	LAWRENCE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-81	CHI Power Marketing, Inc.	CHIPM	MA	09	CMA/NEMA	WCMA	50545	8.576	6.160	8.576	6.160	-3.318
460	LOCKWOOD	460	LOCKWOOD	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Brookfield Energy Marketing, LP	BEMLP	ME	11	ME	ME	10066	4.113	4.046	4.113	4.046	0.162
461	LENERGIA ENERGY CENTER	12521	Lowell Power Reactivation	CC	NG	DFO	GAS/OIL COMBINED CYCLE	11-Mar-93	EDF Trading North America, LLC	EDFT	MA	17	CMA/NEMA	WCMA	54586	78.446	74.638	78.446	74.638	0.000
462	LISBON RESOURCE RECOVERY	462	LISBON RESOURCE RECOVERY	ST	MSW		BIO/REFUSE	01-Jan-96	Connecticut Light and Power Company, The	CLP	CT	11	CT	CT	54758	13.530	13.325	13.530	13.325	-0.197
463	REENERGY LIVERMORE FALLS	463	AEI LIVERMORE	ST	WDS		BIO/REFUSE	01-Oct-92	ReEnergy Stratton LLC	REH	ME	01	ME	ME	10354	34.430	34.695	34.430	34.695	0.000
464	LOST NATION	464	LOST NATION	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-69	Public Service Company of New Hampshire	PSNH	NH	07	NH	NH	2362	17.992	13.926	17.992	13.926	0.000
465	DEERFIELD 2/LWR DRFIELD	465	DEERFIELD 2 LWR DRFIELD	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-12	TransCanada Power Marketing, Ltd.	TCPM	MA	11	WMA	WCMA	7, 6083, 6	19.500	19.275	19.500	19.275	0.000
466	L STREET JET	466	L STREET JET	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Sep-66	Exelon Generation Company, LLC	EXGC	MA	25	BOSTON	NEMA	1587	21.770	16.030	21.770	16.030	0.000
467	MARBLEHEAD DIESELS	467	MARBLEHEAD DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	25-Sep-68	Marblehead Municipal Light Department	MMLD	MA	09	BOSTON	NEMA	6586	5.000	5.000	5.000	5.000	0.000
468	MARSHFIELD 6 HYDRO	468	MARSHFIELD 6 HYDRO	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-27	Green Mountain Power Corporation	GMP	VT	23	NH	VT	3739	4.380	4.412	4.380	4.412	0.000
472	M STREET JET	472	M STREET JET	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-78	Massachusetts Bay Transportation Authority	MBTA	MA	25	BOSTON	NEMA	10176	67.200	47.000	67.200	47.000	0.000
473	MCINDOES	473	MCINDOES	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-31	TransCanada Power Marketing, Ltd.	TCPM	NH	09	NH	NH	6483	10.571	10.066	10.571	10.066	0.000
474	J C MCNEIL	474	J C MCNEIL	ST	WDS	NG	BIO/REFUSE	01-Feb-84	Burlington Electric Department	BED	VT	07	VT	VT	589	54.000	52.000	54.000	52.000	0.000
475	MEDWAY DIESELS 1-4	475	MEDWAY DIESELS 1-4	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-68	Energy New England LLC	ENE	ME	19	BHE	ME	1474	6.412	4.029	6.412	4.029	-3.921
478	MIDDLETOWN 10	478	MIDDLETOWN 10	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Jan-66	NRG Power Marketing LLC	NRGPM	CT	07	CT	CT	562	20.015	15.515	20.015	15.515	0.000
480	MIDDLETOWN 2	480	MIDDLETOWN 2	ST	RFO	NG	GAS/OIL STEAM	01-Jan-58	NRG Power Marketing LLC	NRGPM	CT	07	CT	CT	562	120.000	117.000	120.000	117.000	0.000
481	MIDDLETOWN 3	481	MIDDLETOWN 3	ST	RFO	NG	GAS/OIL STEAM	01-Jan-64	NRG Power Marketing LLC	NRGPM	CT	07	CT	CT	562	244.398	233.679	244.398	233.679	0.000
482	MIDDLETOWN 4	482	MIDDLETOWN 4	ST	RFO		OIL STEAM	01-Jun-73	NRG Power Marketing LLC	NRGPM	CT	07	CT	CT	562	402.000	399.923	402.000	399.923	0.000
484	MILLSTONE POINT 2	484	MILLSTONE POINT 2	ST	NUC		NUCLEAR STEAM	01-Dec-75	Dominion Energy Marketing, Inc.	DEM	CT	11	CT	CT	566	875.912	870.855	875.912	870.855	0.000
485	MILLSTONE POINT 3	485	MILLSTONE POINT 3	ST	NUC		NUCLEAR STEAM	01-Apr-86	Dominion Energy Marketing, Inc.	DEM	CT	11	CT	CT	566	1,235.001	1,225.000	1,235.001	1,225.000	0.000
486	MILFORD POWER	486	MILFORD POWER	CC	NG		GAS COMBINED CYCLE	01-Jan-94	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	27	RI	SEMA	54805	170.730	149.000	170.730	149.000	0.000
487	MILLER HYDRO	487	MILLER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-84	Energy New England LLC	ENE	ME	01	ME	ME	50278	9.769	9.428	9.769	9.428	0.002
489	MERRIMACK 1	489	MERRIMACK 1	ST	BIT		COAL STEAM	01-Dec-60	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2364	108.000	108.000	108.000	108.000	0.000
490	MERRIMACK 2	490	MERRIMACK 2	ST	BIT		COAL STEAM	30-Apr-68	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2364	330.513	330.000	330.513	330.000	0.000
492	MONTVILLE 10 and 11	492	MONTVILLE 10 and 11	IC	KER		OIL INTERNAL COMBUSTION	01-Jan-67	NRG Power Marketing LLC	NRGPM	CT	11	CT	CT	546	5.354	5.296	5.354	5.296	0.000
493	MONTVILLE 5	493	MONTVILLE 5	ST	RFO	NG	GAS/OIL STEAM	01-Jan-54	NRG Power Marketing LLC	NRGPM	CT	11	CT	CT	546	81.590	81.000	81.590	81.000	0.000
494	MONTVILLE 6	494	MONTVILLE 6	ST	RFO		OIL STEAM	01-Jul-71	NRG Power Marketing LLC	NRGPM	CT	11	CT	CT	546	406.659

Contains Proprietary Material
Do Not Distribute

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 81/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 9, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
561	SEARSBURG	561	SEARSBURG	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Mar-22	TransCanada Power Marketing, Ltd.	TCPM	VT	03	WMA	WCMA	6529	4.960	4.755	4.960	4.755	0.000
562	SECREC-PRESTON	562	SECREC-PRESTON	ST	MSW	DFO	BIO/REFUSE	01-Jan-92	Connecticut Light and Power Company, The	CLP	CT	11	CT	CT	10646	16.232	15.857	16.232	15.857	0.044
563	SEMASS 1	563	SEMASS 1	ST	MSW	DFO	BIO/REFUSE	01-Oct-88	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA	50290	50.314	49.185	50.314	49.185	1.171
564	SEMASS 2	564	SEMASS 2	ST	MSW	DFO	BIO/REFUSE	01-May-93	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA	50290	24.878	22.640	24.878	22.640	0.585
565	SHELDON SPRINGS	565	SHELDON SPRINGS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-88	Vermont Electric Power Company, Inc.	VELCO	VT	11	VT	VT	10494	9.370	2.286	9.370	2.286	-6.381
566	SHEPAUG	566	SHEPAUG	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-55	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	09	SWCT	CT	552	42.523	41.511	42.523	41.511	0.000
567	SHERMAN	567	SHERMAN	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Dec-26	TransCanada Power Marketing, Ltd.	TCPM	MA	11	WMA	WCMA	6012	6.220	6.154	6.220	6.154	0.000
568	SHREWSBURY DIESELS	35657	Shrewsbury Diesels	IC	DFO		OIL INTERNAL COMBUSTION	01-May-78	Shrewsbury Electric & Cable Operations	SELP	MA	27	CMA/NEMA	WCMA	6125	13.650	13.750	13.650	13.750	0.000
569	SKELTON	569	SKELTON	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-48	Brookfield White Pine Hydro LLC	FPLEMH	ME	31	SME	ME	1505	19.704	19.704	19.704	21.600	1.896
570	SMITH	570	SMITH	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-48	Public Service Company of New Hampshire	PSNH	NH	07	NH	NH	2368	13.214	8.353	13.214	8.353	-4.787
572	SO. MEADOW 11	572	SO. MEADOW 11	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-70	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	46.921	35.781	46.921	35.781	0.000
573	SO. MEADOW 12	573	SO. MEADOW 12	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-70	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	47.815	37.649	47.815	37.649	0.000
574	SO. MEADOW 13	574	SO. MEADOW 13	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-70	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	47.917	38.317	47.917	38.317	0.000
575	SO. MEADOW 14	575	SO. MEADOW 14	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-70	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	46.346	36.746	46.346	36.746	0.000
580	SO. MEADOW 5	580	SO. MEADOW 5	ST	MSW	NG	BIO/REFUSE	01-Nov-87	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	24.327	26.136	24.327	26.136	4.140
581	SO. MEADOW 6	581	SO. MEADOW 6	ST	MSW	NG	BIO/REFUSE	01-Nov-87	NextEra Energy Power Marketing, LLC	FPLP	CT	03	CT	CT	563	22.050	16.623	22.050	16.623	-1.836
583	STONY BROOK 2A	583	STONY BROOK 2A	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Nov-82	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	13	WMA	WCMA	6081	87.400	67.400	87.400	67.400	0.000
584	STONY BROOK 2B	584	STONY BROOK 2B	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Nov-82	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	13	WMA	WCMA	6081	85.300	65.300	85.300	65.300	0.000
587	STEVENSON	587	STEVENSON	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-19	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	01	SWCT	CT	553	28.844	28.311	28.844	28.311	0.000
590	REENERGY STRATTON	590	BORALEX STRATTON ENERGY	ST	WDS		BIO/REFUSE	01-Sep-89	ReEnergy Stratton LLC	REH	ME	07	ME	ME	50650	44.363	45.024	44.363	45.024	0.000
591	S.D. WARREN-WESTBROOK	591	S.D. WARREN-WESTBROOK	ST	WDS	RFO	BIO/REFUSE	01-Nov-97	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	50447	49.103	42.590	49.103	42.590	0.000
592	TAMWORTH	592	TAMWORTH	ST	WDS		BIO/REFUSE	01-Jan-88	GDF Suez Energy Marketing NA, Inc.	SUEZ	NH	03	NH	NH	50739	19.973	20.074	19.973	20.074	0.720
595	TORRINGTON TERMINAL 10	595	TORRINGTON TERMINAL 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Aug-67	NRG Power Marketing LLC	NRGPM	CT	05	CT	CT	565	20.748	15.638	20.748	15.638	0.000
596	TUNNEL 10	596	TUNNEL 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-69	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	11	CT	CT	557	21.691	16.257	21.691	16.257	-0.334
598	VERGENNES 5 AND 6 DIESELS	598	VERGENNES 5 and 6 DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-64	Green Mountain Power Corporation	GMP	VT	01	VT	VT	6519	4.240	3.940	4.240	3.940	0.000
599	VERNON	599	VERNON	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-09	TransCanada Power Marketing, Ltd.	TCPM	VT	25	WMA	WCMA	2352	32.000	32.000	32.000	32.000	0.000
612	WATERS RIVER JET 1	612	WATERS RIVER JET 1	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	01-Dec-71	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	09	BOSTON	NEMA	1678	21.974	15.974	21.974	15.974	0.000
613	WATERS RIVER JET 2	613	WATERS RIVER JET 2	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	01-Apr-91	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	09	BOSTON	NEMA	1678	40.000	28.500	40.000	28.500	0.000
614	WATERBURY 22	614	WATERBURY 22	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-53	Green Mountain Power Corporation	GMP	VT	23	VT	VT	6520	5.000	5.000	5.000	5.000	0.000
616	WEST ENFIELD	616	WEST ENFIELD	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-88	New Brunswick Energy Marketing Corporation	NBPGC	ME	19	BHE	ME	10255	10.646	8.818	10.646	8.818	-7.577
617	WESTON	617	WESTON	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-20	Brookfield White Pine Hydro LLC	FPLEMH	ME	17	ME	ME	1509	8.315	10.831	8.315	10.831	1.644
618	DG WHITEFIELD, LLC	618	DG WHITEFIELD, LLC	ST	WDS		BIO/REFUSE	01-Apr-88	Exelon Generation Company, LLC	EXGC	NH	07	NH	NH	10839	15.726	15.603	15.726	15.603	-0.567
619	WHITE LAKE JET	619	WHITE LAKE JET	GT	JF		OIL COMBUSTION (GAS) TURBINE	01-Aug-68	Public Service Company of New Hampshire	PSNH	NH	03	NH	NH	2369	22.397	17.447	22.397	17.447	0.000
620	WILDER	620	WILDER	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-50	TransCanada Power Marketing, Ltd.	TCPM	VT	27	VT	NH	2353	40.698	39.083	40.698	39.083	0.000
621	WILLIAMS	621	WILLIAMS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-39	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1510	14.900	14.900	14.900	14.900	0.000
622	WINOOSKI 1	622	WINOOSKI 1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-93	Burlington Electric Department	BED	VT	07	VT	VT	54355	2.614	1.363	2.614	1.363	-1.828
623	COVANTA PROJECTS WALLINGFORD	623	WALLINGFORD REFUSE	ST	MSW	DFO	BIO/REFUSE	01-Mar-89	Covanta Projects of Wallingford, L.P.	CPW	CT	09	SWCT	CT	50664	5.275	5.027	5.275	5.027	-1.542
624	WMI MILLBURY 1	624	WMI MILLBURY 1	ST	MSW		BIO/REFUSE	01-Sep-87	New England Power Company	NEP	MA	27	CMA/NEMA	WCMA	50878	39.891	39.811	39.891	39.811	0.000
625	WEST MEDWAY JET 1	625	WEST MEDWAY JET 1	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jul-70	Exelon Generation Company, LLC	EXGC	MA	21	BOSTON	NEMA	1592	62.915	42.000	62.915	42.000	0.000
626	WEST MEDWAY JET 2	626	WEST MEDWAY JET 2	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Mar-71	Exelon Generation Company, LLC	EXGC	MA	21	BOSTON	NEMA	1592	61.598	39.848	61.598	39.848	0.000
627	WEST MEDWAY JET 3	627	WEST MEDWAY JET 3	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Jul-70	Exelon Generation Company, LLC	EXGC	MA	21	RI	SEMA	1592	62.401	42.001	62.401	42.001	6.580
628	WOODLAND ROAD	628	WOODLAND ROAD	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jul-69	Essential Power Massachusetts, LLC	NAEA-EM	MA	03	WMA	WCMA	1643	20.658	15.808	20.658	15.808	0.000
630	WEST SPRINGFIELD 10	630	WEST SPRINGFIELD 10	GT	KER		OIL COMBUSTION (GAS) TURBINE	01-Jan-68	Essential Power Massachusetts, LLC	NAEA-EM	MA	13	WMA	WCMA	1642	21.928	17.143	21.928	17.143	0.000
633	WEST SPRINGFIELD 3	633	WEST SPRINGFIELD 3	ST	NG	RFO	GAS/OIL STEAM	01-Jan-57	Essential Power Massachusetts, LLC	NAEA-EM	MA	13	WMA	WCMA	1642	100.087	94.276	100.087	94.276	0.000
636	WYMAN HYDRO 1	636	WYMAN HYDRO 1	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-30	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1511	27.400	27.362	27.400	27.362	0.000
637	WYMAN HYDRO 2	637	WYMAN HYDRO 2	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-31	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1511	29.900	29.866	29.900	29.866	0.000
638	WYMAN HYDRO 3	638	WYMAN HYDRO 3	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-40	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1511	25.700	25.548	25.700	25.548	0.000
639	YARMOUTH 1	639	YARMOUTH 1	ST	RFO		OIL STEAM	01-Jan-57	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1507	50.065	0.000	50.065	0.000	0.000
640	YARMOUTH 2	640	YARMOUTH 2	ST	RFO		OIL STEAM	01-Jan-58	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1507	52.823	50.045	52.823	50.045	-0.760
641	YARMOUTH 3	641	YARMOUTH 3	ST	RFO		OIL STEAM	01-Jul-65	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1507	114.720	109.040	114.720	109.040	-1.830
642	YARMOUTH 4	642	YARMOUTH 4	ST	RFO		OIL STEAM	01-Dec-78	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	1507	605.875	602.050	605.875	602.050	0.000
715	ROCHESTER LANDFILL	715	ROCHESTER LANDFILL	GT	LFG		BIO/REFUSE	01-May-98	New Hampshire Electric Cooperative, Inc.	NHEC	NH	17	NH	NH	2007	2.257	2.192	2.257	2.192	0.048
737	SIMPSON G LOAD REDUCER	737	SIMPSON G LOAD REDUCER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Green Mountain Power Corporation	GMP	VT	09	NH	VT	10608	2.656	2.388	2.656	2.388	-0.620
739	ROCKY RIVER	739	ROCKY RIVER	PS	WAT		HYDRO (PUMPED STORAGE)	01-Jan-28	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	09	SWCT	CT	539	28.127	28.853	28.127	28.853	0.000
754	BAR MILLS	754	BAR MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-56	Brookfield White Pine Hydro LLC	FPLEMH	ME	31	SME	ME	1481	1.586	0.000	1.586	0.000	-2.067
755	BONNY EAGLE/W. BUXTON	755	BONNY EAGLE W. BUXTON	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-10	Brookfield White Pine Hydro LLC	FPLEMH	ME	31	SME	ME	1482, 1508	17.500	16.151	17.500	16.151	0.000
757	HARRIS 4	757	HARRIS 4	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-54	Brookfield White Pine Hydro LLC	FPLEMH	ME	25	ME	ME	1492	1.249	1.436	1.249	1.436	0.000
759	MESSALONSKEE COMPOSITE	759	MESSALONSKEE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-17	Messalonskee Stream Hydro, LLC	MESSA	ME	11	ME	ME	1497	4.016	3.948	4.016	3.948	-0.099
760	NORTH GORHAM	760	NORTH GORHAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-25	Brookfield White Pine Hydro LLC	FPLEMH	ME	05	SME	ME	1501	1.121	1.475	1.121	1.475	-0.283
761	SHAWMUT	761	SHAWMUT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-13	Brookfield White Pine Hydro LLC	FPLEMH	ME	11	ME	ME	1504	6.066	7.239	6.066	7.239	0.738
767	SES CONCORD	767	SES CONCORD	ST	MSW		BIO/REFUSE	01-May-89	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	50873	12.397	12.096	12.397	12.096	-0.020
768	GARVINS/HOOKSETT	768	GARVINS HOOKSETT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-02	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	2357, 2358	5.844	3.853	5.844	3.853	-3.423
769	HADLEY FALLS 1&2	769	HADLEY FALLS 1&2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-83	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	1605	23.436	20.229	23.436	20.229	2.509
772	NEWPORT HYDRO	772	NEWPORT HYDRO	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-80	Great Bay Power Marketing, Inc	GBPM	VT	19	NH	VT	3731	1.722	1.215	1.722	1.215	-0.912
774	LOWER LAMOILLE COMPOSITE	774	LOWER LAMOILLE COMPOSITE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-48	Green Mountain Power Corporation	GMP	VT	07	VT	VT	3711	16.000	10.106	16.000	10.106	-5.694
775	MIDDLEBURY COMPOSITE	775	MIDDLEBURY COMPOSITE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-17	Green Mountain Power Corporation	GMP	VT	01	VT	VT	3716	5.724	5.678	5.724	5.678	0.078
776	N. RUTLAND COMPOSITE	776	N. RUTLAND COMPOSITE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-80	Green Mountain Power Corporation	GMP	VT	21	VT	VT	3714	4.155	4.503	4.155	4.503	0.000
779	MIDDLESEX 2	779	MIDDLESEX 2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-28	Green Mountain Power Corporation	GMP	VT	23	VT	VT	3740	1.504	0.000	1.504	0.000	-1.368
781	WEST DANVILLE 1	781	WEST DANVILLE 1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-86	Green Mountain Power Corporation	GMP	VT	05	VT	VT	3743	0.000	0.000	0.000	0.000	0.000
783	HIGHGATE FALLS	783	HIGHGATE FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	VT	11	VT	VT	6618	7.895	1.663	7.895	1.663	-2.653
789	CEC 002 PAWTUCKET U5	789	CEC 002 PAWTUCKET U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-85	The Narragansett Electric Company	NEC	RI	07	RI	SEMA	3233	0.556	0.000	0.556	0.000	-0.219
792	CENTENNIAL HYDRO	792	CENTENNIAL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-90	Sterling Municipal Electric Light Department	SMED	MA	17	CMA/NEMA	WCMA	7112	0.554	0.108	0.554	0.108	-0.181
793	METHUEN HYDRO	793	METHUEN HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Aug-88	Sterling Municipal Electric Light Department	SMED	MA	09	BOSTON	NEMA		0.118	0.000	0.118	0.000	0.000
794	MINNEWAWA	794	MINNEWAWA	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-92	Littleton Electric Light & Water Department	LELWD	NH	05	VT	NH		0.605	0.190	0.605	0.190	-0.007
795	RIVER MILL HYDRO	795	RIVER MILL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-89	Middleton Municipal Light Department	MMELD	NH	09	VT	NH	3049	0.000	0.000	0.000	0.000	0.000
796	GOODWIN DAM	796	GOODWIN DAM	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Feb-86	Connecticut Light and Power Company, The	CLP	CT	05	CT	CT	54302	3.000	3.000	3.000	3.000	0.000
797	WYRE WYND HYDRO	797	CEC 003 WYRE WYND U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-97	Summit Hydropower, Inc.	SUMMIT	CT	11	CT	CT		0.000	0.079	0.000	0.079	-0.853
798	COLEBROOK	798	COLEBROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-88	Connecticut Light and Power Company, The	CLP	CT	05	CT	CT	54301	0.388	0.948	0.388	0.948	0.190
800	KINNEYTOWN B	800	KINNEYTOWN B	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-86	Connecticut Light and Power Company, The	CLP	CT	09	SWCT	CT	54385	0.523	0.000	0.523	0.000	0.000
801	WILLIMANTIC 1	801	WILLIMANTIC 1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-90	Connecticut Light and Power Company, The	CLP	CT	15	CT	CT		0.343	0.000	0.343	0.000	0.000
802	WILLIMANTIC 2	802	WILLIMANTIC 2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-90	Connecticut Light and Power Company, The	CLP	CT	15	CT	CT		0.191	0.000	0.191	0.000	0.000
803	TOUTANT	803	TOUTANT	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Feb-94	Connecticut Light and Power Company, The	CLP	CT	15	CT	CT		0.396	0.251	0.396	0.251	0.000
804	PUTNAM	804	PUTNAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-87	Putnam Hydropower, Inc.	PUTNAM	CT	15	CT	CT		0.384	0.000	0.384	0.000	-0.185
806	MECHANICSVILLE	806	MECHANICSVILLE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-95	Sterling Municipal Electric Light Department	SMED	CT	15	CT	CT		0.098	0.000	0.098	0.000	-0.033
807	CEC 004 DAYVILLE POND U5	807	CEC 004 DAYVILLE POND U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-95	Connecticut Light and Power Company, The	CLP	CT	15	CT	CT		0.049	0.000	0.049	0.000	0.000
808	SANDY HOOK HYDRO	808	SANDY HOOK HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-89	Connecticut Light and Power Company, The	CLP	CT	15	SWCT	CT		0.070	0.000	0.070	0.000	0.000
809	PINCHBECK	809	PINCHBECK	ST	WDS		BIO/REFUSE	01-Jul-87	Connecticut Light and Power Company, The	CLP	CT	13	CT	CT		0.000	0.000	0.000	0.000	0.000
810	QUINEBAUG	810	QUINEBAUG	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-90	Connecticut Light and Power Company, The	CLP	CT	15	CT	CT	543	0.892	0.040	0.892	0.040	-0.290
811	BANTAM	811	BANTAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-05	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	05	CT	CT	6457	0.085	0.000	0.085	0.000	-0.068
812	BEEBE HOLBROOK	812	BEEBE HOLBROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-48	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	1602	0.000	0.000	0.000	0.000	-0.170
813	TUNNEL	813	TUNNEL	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-19	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	11	CT	CT	557	1.048	0.000	1.048	0.000	-0.746
814	PATCH	814	PATCH	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	21	VT	VT	3719	0.087	0.031	0.087	0.031	0.031
815	CARVER FALLS	815	CARVER FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	25-Sep-98	Green Mountain Power Corporation	GMP	VT	21	VT	VT	6456	0.770	0.000	0.770	0.000	-0.083
816	CAVENDISH	816	CAVENDISH	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	25-Sep-98	Green Mountain Power Corporation	GMP	VT	27	VT	VT	3710	0.457	0.337	0.457	0.337	-0.029
817	TAFTSVILLE VT	817	TAFTSVILLE VT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	27	VT	VT	3727	0.000	0.000	0.000	0.000	0.000
818	PIERCE MILLS	818	PIERCE MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	05	NH	VT	3721	0.135	0.056	0.135	0.056	0.180
819	ARNOLD FALLS	819	ARNOLD FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	25-Sep-98	Green Mountain Power Corporation	GMP	VT	05	NH	VT	3707	0.123	0.000	0.123	0.000	-0.320
820	PASSUMPSIC	820	PASSUMPSIC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	05	NH	VT	3718	0.232	0.077	0.232	0.077	-0.170
821	GAGE	821	GAGE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	05	NH	VT	3713	0.252	0.000	0.252	0.000	-0.401
822	SMITH (CVPS)	822	SMITH (CVPS)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	17	VT	VT	3709	0.460	0.264	0.460	0.264	-0.643
823	EAST BARNET	823	EAST BARNET	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Green Mountain Power Corporation	GMP	VT	05	NH	VT	788	0.907	0.399	0.907	0.399	-0.195
824	BATH ELECTRIC HYDRO	824	BATH ELECTRIC HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-85	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.154	0.270	0.154	0.270	-0.036
827	SEARSBURG WIND	827	SEARSBURG WIND	WT	WND		WIND TURBINE	01-Jul-97	Green Mountain Power Corporation	GMP	VT	03	WMA	WCMA	7381	1.123	0.113	1.123	0.113	-0.222
828	BARTON HYDRO	828	BARTON HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-31	Vermont Public Power Supply Authority	VPPSA	VT	19	NH	VT	3753	0.384	0.073	0.384	0.073	-0.371
830	ENOSBURG HYDRO	830	ENOSBURG HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	VT	11	VT	VT	3757	0.315	0.457	0.315	0.457	-0.078
831	VAIL & GREAT FALLS	831	VAIL & GREAT FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	VT	05	NH	VT	3726	0.992	0.196	0.992	0.196	0.067
832	CENTER RUTLAND	832	CENTER RUTLAND	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Aug-01	Green Mountain Power Corporation	GMP	VT	21	VT	VT	6453	0.000	0.096	0.000	0.096	0.096
833	BARNET	833	BARNET	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-01	Green Mountain Power Corporation	GMP	VT	05	VT	VT		0.139	0.000	0.139	0.000	-0.167
834	COMTU FALLS	834	COMPTU FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-82	Green Mountain Power Corporation	GMP	VT	27	VT	VT		0.251	0.214	0.251	0.214	-0.002
835	DEW

Contains Proprietary Material
Do Not Distribute

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PAINT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 9, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
875	RIVER BEND	875	RIVER BEND	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-86	Massachusetts Municipal Wholesale Electric Company	MMWEC	NH	13	NH	NH		1.218	0.705	1.218	0.705	-0.712
876	ROBERTSVILLE	876	ROBERTSVILLE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-24	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	03	CT	CT	549	0.065	0.000	0.065	0.000	0.000
877	SCOTLAND	877	SCOTLAND	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-37	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	15	CT	CT	551	1.340	0.000	1.340	0.000	0.000
878	SKINNER	878	SKINNER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-24	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	1608	0.000	0.000	0.000	0.000	-0.248
879	TAFTVILLE CT	879	TAFTVILLE CT	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-06	GDF Suez Energy Marketing NA, Inc.	SUEZ	CT	11	CT	CT	554	0.993	0.000	0.993	0.000	0.000
882	FRANKLIN FALLS	882	FRANKLIN FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-78	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	10109	0.436	0.444	0.436	0.444	-0.198
883	SALMON FALLS HYDRO		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-83	CHI Power Marketing, Inc.	CHIPM	NH	17	SME	ME	50702	0.392	0.000	0.392	0.000	-0.145
884	SWANS FALLS	884	SWANS FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-98	Public Service Company of New Hampshire	PSNH	ME	17	NH	NH	1518	0.280	0.259	0.280	0.259	-0.184
886	COCHECO FALLS	886	COCHECO FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-83	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.223	0.175	0.223	0.175	0.175
887	CHINA MILLS DAM	887	CHINA MILLS DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-81	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH	50103	0.344	0.000	0.344	0.000	-0.025
888	NEWFOUND HYDRO	888	NEWFOUND HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-83	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH	50324	0.687	0.237	0.687	0.237	-0.435
889	SUNAPEE HYDRO	889	SUNAPEE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-85	Public Service Company of New Hampshire	PSNH	NH	19	NH	NH		0.328	0.180	0.328	0.180	0.005
890	NASHUA HYDRO	890	NASHUA HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.492	0.287	0.492	0.287	0.287
891	HILLSBORO MILLS	891	HILLSBORO MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-88	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	10036	0.136	0.000	0.136	0.000	0.000
892	LAKEPORT DAM	892	LAKEPORT DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-83	Power Supply Services, LLC	PSS	NH	01	NH	NH		0.136	0.212	0.136	0.212	-0.240
893	WEST HOPKINTON HYDRO	893	WEST HOPKINTON HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-82	CHI Power Marketing, Inc.	CHIPM	NH	13	NH	NH	54384	0.384	0.270	0.384	0.270	-0.139
894	LISBON HYDRO	894	LISBON HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-86	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.203	0.241	0.203	0.241	-0.109
895	LOWER ROBERTSON DAM	895	LOWER ROBERTSON DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-87	Massachusetts Municipal Wholesale Electric Company	MMWEC	NH	05	VT	NH		0.538	0.374	0.538	0.374	-0.130
897	OLD NASH DAM	897	OLD NASH DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	NH	05	VT	NH		0.081	0.041	0.081	0.041	0.007
898	SUGAR RIVER HYDRO	898	SUGAR RIVER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-86	Public Service Company of New Hampshire	PSNH	NH	19	NH	NH		0.119	0.058	0.119	0.058	0.058
900	GREAT FALLS 1 LOWER	900	GREAT FALLS 1 LOWER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-84	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH	50704	0.478	0.168	0.478	0.168	0.100
901	WATERLOOM FALLS	901	WATERLOOM FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-81	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.031	0.000	0.031	0.000	0.000
902	HOSIERY MILL DAM	902	HOSIERY MILL DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-84	Swift River Trading Company LLC	SRTC	NH	11	NH	NH		0.000	0.001	0.000	0.001	0.001
903	WYANDOTTE HYDRO	903	WYANDOTTE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-83	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.034	0.000	0.034	0.000	0.000
904	LOCHMERE DAM	904	LOCHMERE DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Massachusetts Municipal Wholesale Electric Company	MMWEC	NH	01	NH	NH	54572	0.482	0.231	0.482	0.231	-0.220
905	ASHUELOT HYDRO	905	ASHUELOT HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-87	Massachusetts Municipal Wholesale Electric Company	MMWEC	NH	05	VT	NH		0.452	0.392	0.452	0.392	-0.172
906	ROLLINSFORD HYDRO	906	ROLLINSFORD HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-80	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH	54418	0.734	0.178	0.734	0.178	-0.104
908	OTIS MILL HYDRO	908	OTIS MILL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-82	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	50080	0.007	0.000	0.007	0.000	0.000
909	STEELS POND HYDRO	909	STEELS POND HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.000	0.000	0.000	0.000	0.000
910	CAMPTON DAM	910	CAMPTON DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-85	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.091	0.106	0.091	0.106	-0.007
911	KELLEYS FALLS	911	KELLEYS FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-89	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.000	0.000	0.000	0.000	-0.105
913	GOODRICH FALLS	913	GOODRICH FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-81	Public Service Company of New Hampshire	PSNH	NH	03	NH	NH		0.237	0.189	0.237	0.189	-0.099
914	CHAMBERLAIN FALLS	914	CHAMBERLAIN FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-83	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.000	0.000	0.000	0.000	0.000
915	MONADNOCK PAPER MILLS	915	MONADNOCK PAPER MILLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-75	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.000	0.000	0.000	0.000	0.000
919	HOPKINTON HYDRO	919	HOPKINTON HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Sterling Municipal Electric Light Department	SMED	NH	13	NH	NH		0.151	0.119	0.151	0.119	-0.004
922	NOONE FALLS	922	NOONE FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-85	Public Service Company of New Hampshire	PSNH	NH	11	VT	NH		0.067	0.000	0.067	0.000	-0.027
925	OTTER LANE HYDRO	925	OTTER LANE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-84	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH		0.033	0.015	0.033	0.015	-0.004
926	PETERBOROUGH LOWER HYDRO	926	PETERBOROUGH LOWER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-89	Public Service Company of New Hampshire	PSNH	NH	11	VT	NH		0.130	0.037	0.130	0.037	0.001
928	SALMON BROOK STATION 3	928	SALMON BROOK STATION 3	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-85	Public Service Company of New Hampshire	PSNH	NH	13	NH	NH		0.000	0.000	0.000	0.000	-0.117
931	AVERY DAM	931	AVERY DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-85	Public Service Company of New Hampshire	PSNH	NH	01	NH	NH		0.163	0.175	0.163	0.175	-0.073
932	WATSON DAM	932	WATSON DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-85	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.122	0.066	0.122	0.066	-0.004
933	WESTON DAM	933	WESTON DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-87	Public Service Company of New Hampshire	PSNH	NH	07	NH	NH	1509	0.236	0.254	0.236	0.254	-0.060
935	SUNNYBROOK HYDRO 2	935	SUNNYBROOK HYDRO 2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-82	Public Service Company of New Hampshire	PSNH	NH	07	NH	NH		0.004	0.009	0.004	0.009	-0.007
941	PETERBOROUGH UPPER HYDRO	941	PETERBOROUGH UPPER HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-90	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.147	0.000	0.147	0.000	-0.051
942	DUNBARTON ROAD LANDFILL	942	DUNBARTON ROAD LANDFILL	IC	LFG		BIO/REFUSE	01-Aug-89	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	55779	0.000	0.000	0.000	0.000	0.000
943	FOUR HILLS LANDFILL	943	FOUR HILLS LANDFILL	IC	LFG		BIO/REFUSE	01-Apr-96	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.723	0.694	0.723	0.694	-0.027
947	RIVERDALE MILLS - QF	947	RIVERDALE MILLS - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jul-85	Massachusetts Electric Company	MEC	MA	27	RI	SEMA	50601	0.000	0.000	0.000	0.000	0.000
948	PEPPERELL HYDRO COMPANY LLC	948	PEPPERELL HYDRO COMPANY LLC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-20	Swift River Trading Company LLC	SRTC	MA	17	CMA/NEMA	WCMA	10694	0.484	0.446	0.484	0.446	-0.275
949	VALLEY HYDRO - QF	949	VALLEY HYDRO - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-84	The Narragansett Electric Company	NEC	RI	03	RI	RI		0.106	0.000	0.106	0.000	-0.004
950	LP ATHOL - QF	950	LP ATHOL - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-31	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.049	0.055	0.049	0.055	-0.058
951	BALTIC MILLS - QF	951	BALTIC MILLS - QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-81	Sterling Municipal Electric Light Department	SMED	NH	09	VT	NH		0.061	0.061	0.061	0.061	-0.002
952	PONTIAC ENERGY - QF	952	PONTIAC ENERGY - QF	IC	OBG		BIO/REFUSE	01-Oct-98	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
953	ATTLEBORO LANDFILL - QF	953	ATTLEBORO LANDFILL - QF	IC	OBG		BIO/REFUSE	01-Nov-97	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.105	0.119	0.105	0.119	0.119
954	MM LOWELL LANDFILL - QF	954	MM LOWELL LANDFILL - QF	IC	LFG		BIO/REFUSE	01-Aug-97	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA	55095	0.099	0.077	0.099	0.077	-0.020
957	HG&E HYDRO/CABOT 1-4	957	HG&E HYDRO/CABOT 1-4	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	9864	0.607	0.922	0.607	0.922	-0.863
959	BARTON 1-4 DIESELS	959	BARTON 1-4 DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	01-Jul-56	Vermont Public Power Supply Authority	VPPSA	VT	19	NH	VT	3753	0.000	0.000	0.000	0.000	0.000
969	POWDER MILL HYDRO	969	POWDER MILL HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-90	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
970	DUDLEY HYDRO	970	DUDLEY HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-87	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.106	0.000	0.106	0.000	-0.040
973	CONCORD STEAM		No Resource (1)	ST	WDS		BIO/REFUSE	01-Oct-86	Unitil Energy Systems, Inc.	UNITIL-ES	NH	13	NH	NH		0.208	0.000	0.208	0.000	0.000
978	NEW MILFORD	978	NEW MILFORD	IC	OBG	DFO	BIO/REFUSE	01-Aug-91	Connecticut Light and Power Company, The	CLP	CT	05	SWCT	CT	50564	1.282	1.177	1.282	1.177	-0.127
1005	BRIGHTON POWER LLC	1005	BRIGHTON POWER LLC	CC	NG		GAS COMBINED CYCLE	01-May-99	EquiPower Resources Management, LLC	EPRM	MA	05	SEMA	SEMA	55026	185.000	160.539	185.000	160.539	-0.000
1028	BUNKER RD #12 GAS TURB	1028	BUNKER RD #12 GAS TURB	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Apr-00	New England Power Company	NEP	MA	19	SEMA	SEMA	1615	3.012	2.351	3.012	2.351	0.000
1029	BUNKER RD #13 GAS TURB	1029	BUNKER RD #13 GAS TURB	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-Apr-00	New England Power Company	NEP	MA	19	SEMA	SEMA	1615	3.281	2.806	3.281	2.806	0.000
1030	OAK BLUFFS	1030	OAK BLUFFS	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-70	Genon Energy Management, LLC	MET	MA	07	SEMA	SEMA	1597	8.120	7.471	8.120	7.471	0.000
1031	WEST TISBURY	1031	WEST TISBURY	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-75	Genon Energy Management, LLC	MET	MA	07	SEMA	SEMA	6049	5.142	5.005	5.142	5.005	0.000
1032	BRIDGEPORT ENERGY 1	1032	BRIDGEPORT ENERGY 1	CC	NG		GAS COMBINED CYCLE	01-Aug-98	Emera Energy Services Subsidiary No. 5 LLC	EES5	CT	01	SWCT	CT	55042	519.937	487.000	519.937	487.000	36.736
1034	RIVERSIDE 4-7	1034	RIVERSIDE 4-7	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-21	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	1607	1.477	1.139	1.477	1.139	-0.826
1035	RIVERSIDE 8	1035	RIVERSIDE 8	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-31	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	1607	3.190	3.083	3.190	3.083	-0.211
1047	FAIRFAX	1047	FAIRFAX	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	25-Sep-98	Green Mountain Power Corporation	GMP	VT	11	VT	VT	3712	3.775	1.122	3.775	1.122	-2.629
1048	WARE HYDRO	1048	WARE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-84	Pioneer Hydro Electric Co., Inc.	PHE	MA	15	WMA	WCMA	50419	0.450	0.000	0.450	0.000	-0.273
1049	COLLINS HYDRO	1049	COLLINS HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-82	Swift River Trading Company LLC	SRTC	MA	13	WMA	WCMA	52166	0.660	0.234	0.660	0.234	-0.258
1050	CHICOPEE HYDRO	1050	CHICOPEE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-85	Chicopee Municipal Lighting Plant	CMLP	MA	13	WMA	WCMA	50832	0.989	0.411	0.989	0.411	-0.410
1054	BLACKSTONE HYDRO ASSOC	1054	BLACKSTONE HYDRO ASSOC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-89	The Narragansett Electric Company	NEC	RI	07	RI	RI	3245	0.000	0.000	0.000	0.000	0.000
1057	BLACKSTONE HYDRO LOAD REDUCER	1057	BLACKSTONE HYDRO LOAD REDUCER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-89	Blackstone Hydro, Inc.	BHI	RI	07	RI	RI	50177	0.494	0.104	0.494	0.104	-0.198
1059	BARRE LANDFILL	1059	BARRE LANDFILL	IC	LFG		BIO/REFUSE	01-Jul-96	Dominion Energy Marketing, Inc.	DEM	MA	27	WMA	WCMA	55776	0.592	0.658	0.592	0.658	0.230
1061	MASCOMA HYDRO	1061	MASCOMA HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-88	TransCanada Power Marketing, Ltd.	TCPM	NH	09	VT	NH	54471	0.558	0.000	0.558	0.000	0.380
1062	MWRA COSGROVE	1062	MWRA COSGROVE	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Oct-95	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA	10825	0.148	0.834	0.148	0.834	-0.064
1086	BERKSHIRE POWER	1086	BERKSHIRE POWER	CC	NG		GAS COMBINED CYCLE	19-Jun-00	Direct Energy Business Marketing, LLC	DEBM	MA	13	WMA	WCMA	55041	246.279	229.279	246.279	229.279	0.000
1107	SOMERSET	1107	SOMERSET	ST	BLQ	WDS	BIO/REFUSE	01-Jan-76	NextEra Energy Power Marketing, LLC	FPLP	ME	11	ME	ME	50406	0.000	0.000	0.000	0.000	0.000
1109	MMWAC	1109	MMWAC	ST	MSW		BIO/REFUSE	01-Jun-92	Mid-Maine Waste Action Corporation	MMWAC	ME	01	ME	ME	50035	2.039	1.986	2.039	1.986	0.052
1113	BRASSUA HYDRO	1113	BRASSUA HYDRO	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Aug-89	Brookfield Energy Marketing, LP	BEMLP	ME	25	ME	ME	10555	1.071	2.696	1.071	2.696	0.002
1114	MADISON COMPOSITE	1114	MADISON COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Sep-84	Competitive Energy Services, LLC	CESLLC	ME	25	ME	ME	7469	0.000	0.000	0.000	0.000	0.000
1117	GREAT WORKS COMPOSITE	1117	GREAT WORKS COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-84	Blackstone Hydro, Inc.	BHI	ME	31	SME	ME		0.111	0.009	0.111	0.009	-0.039
1119	KENNEBAGO HYDRO	1119	KENNEBAGO HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-88	Exelon Generation Company, LLC	EXGC	ME	29	ME	ME		0.252	0.285	0.252	0.285	0.081
1122	CASCADE-DIAMOND-QF	1122	CASCADE-DIAMOND-QF	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-19	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.216	0.038	0.216	0.038	-0.182
1165	CADYS FALLS	1165	CADYS FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	VT	15	VT	VT	3765	0.454	0.226	0.454	0.226	0.162
1166	MORRISVILLE PLANT #2	1166	MORRISVILLE PLANT #2	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Vermont Public Power Supply Authority	VPPSA	VT	15	VT	VT	3764	0.579	0.135	0.579	0.135	-0.208
1167	WOLCOTT HYDRO #1	1167	WOLCOTT HYDRO #1	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-37	Vermont Public Power Supply Authority	VPPSA	VT	15	VT	VT	6477	0.275	0.136	0.275	0.136	-0.266
1168	H.K. SANDERS	1168	H.K. SANDERS	HW	WAT		HYDRO (WEEKLY CYCLE)	01-Jan-83	Vermont Public Power Supply Authority	VPPSA	VT	15	VT	VT	678	1.715	1.800	1.715	1.800	0.000
1185	STONY BROOK GT1A	1185	STONY BROOK GT1A	CC	DFO	NG	GAS/OIL COMBINED CYCLE	01-Nov-81	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	13	WMA	WCMA	6081	119.000	103.858	119.000	103.858	-0.142
1186	STONY BROOK GT1B	1186	STONY BROOK GT1B	CC	DFO	NG	GAS/OIL COMBINED CYCLE	01-Nov-81	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	13	WMA	WCMA	6081	115.932	99.932	115.932	99.932	0.000
1187	STONY BROOK GT1C	1187	STONY BROOK GT1C	CC	DFO	NG	GAS/OIL COMBINED CYCLE	01-Nov-81	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	13	WMA	WCMA	6081	119.000	100.143	119.000	100.143	-3.857
1209	CRRA HARTFORD LANDFILL	1209	CRRA HARTFORD LANDFILL	IC	LFG		BIO/REFUSE	01-Aug-98	Connecticut Light and Power Company, The	CLP	CT	03	CT	CT	55163	1.285	1.212	1.285	1.212	-0.036
1210	MILLENNIUM	1210	MILLENNIUM	CC	NG		GAS COMBINED CYCLE	06-Apr-01	Consolidated Edison Energy, Inc	CEEI	MA	27	WMA	WCMA	55079	383.904	334.904	383.904	334.904	0.000
1221	ESSEX DIESELS	1221	ESSEX DIESELS	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-47	Green Mountain Power Corporation	GMP	VT	07	VT	VT	3737	7.246	7.215	7.246	7.215	0.000
1225	TANNERY DAM	1225	TANNERY DAM	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-00	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA	55924	0.000	0.000	0.000	0.000	0.000
1226	TIVERTON POWER	1226	TIVERTON POWER	CC	NG		GAS COMBINED CYCLE	18-Aug-00	Emera Energy Services Subsidiary No. 6 LLC	EES6	RI	05	SEMA	RI	55048	278.756	243.208	278.756	243.208	0.000
1255	RUMFORD POWER	1255	RUMFORD POWER	CC	NG		GAS COMBINED CYCLE	16-Oct-00	Emera Energy Services Subsidiary No. 7 LLC	EES7	ME	17	ME	ME	55100	269.091	244.281	269.091	244.281	0.000
1258	BHE SMALL HYDRO COMPOSITE	1258	BHE SMALL HYDRO COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-82	New Brunswick Energy Marketing Corporation	NBPGC	ME	21	BHE	ME		0.813	0.496	0.813	0.496	-0.473
1266	MARSH POWER	1266	MARSH POWER	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-86	Christopher M. Anthony	CMA	ME	27	ME	ME	1469	0.000	0.000	0.000	0.000	0.000
1267	SPARHAWK	1267	SPARHAWK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-85	Union Atlantic Electricity	UNION	ME	05	SME	ME		0.013	0.000	0.013	0.000	0.003
1270	SYSKO STONY BROOK	1270	SYSKO STONY BROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-00	Union Atlantic Electricity	UNION	ME	17	ME	ME		0.016	0.015	0.016	0.015	-0.002
1271	SYSKO WIGHT BROOK	1271	SYSKO WIGHT BROOK	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-84	Union Atlantic Electricity	UNION	ME	17	ME	ME		0.021	0.000	0.021	0.000	0.000
1273	KENNEBEC WATER US	1273	KENNEBEC WATER US	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-95	Messalonskee Stream Hydro, LLC	MESSA	ME	11	ME	ME	54148	0.518	0.512	0.518	0.512	0.512
1286	ANP-BLACKSTONE ENERGY 1	1286	ANP-BLACKSTONE ENERGY CO. #1	CC	NG		GAS COMBINED CYCLE	07-Jun-01	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	27	RI	SEMA	55212	246.947	239.174	246.947	239.174	0.000
1287	ANP-BLACKSTONE ENERGY 2	1287	ANP-BLACKSTONE ENERGY 2	CC	NG		GAS COMBINED CYCLE	13-Jul-01	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	27	RI	SEMA	55212	249.338	234.134	249.338	234.134	-0.258

Contains Proprietary Material
Do Not Distribute

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
2425	SPRINGFIELD REFUSE-NEW	2425	SPRINGFIELD REFUSE-NEW	ST	MSW	DFO	BIO/REFUSE	01-Sep-88	Covanta Energy Marketing, LLC	CEM	MA	13	WMA	WCMA	50273	5.700	6.124	5.700	6.124	0.201
2426	HYDRO KENNEBEC	2426	Hydro Kennebec	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-89	Brookfield Energy Marketing, LP	BEMLP	ME	11	ME	ME	54148	9.520	11.524	9.520	11.524	3.463
2430	BELDENS-NEW	2430	BELDENS-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-80	Green Mountain Power Corporation	GMP	VT	01	VT	VT	6451	1.616	0.906	1.616	0.906	-1.440
2431	DODGE FALLS-NEW	2431	DODGE FALLS-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-90	Vermont Electric Power Company, Inc.	VELCO	NH	09	VT	VT	10526	3.371	3.629	3.371	3.629	-0.672
2432	HUNTINGTON FALLS-NEW	2432	HUNTINGTON FALLS-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-88	Green Mountain Power Corporation	GMP	VT	01	VT	VT	50713	2.008	1.728	2.008	1.728	-1.493
2433	RYEGATE 1-NEW	2433	RYEGATE 1-NEW	ST	WDS		BIO/REFUSE	01-Nov-92	Vermont Electric Power Company, Inc.	VELCO	VT	05	NH	VT	51026	19.920	19.560	19.920	19.560	-0.700
2434	GORGE 18 HYDRO-NEW	2434	GORGE 18 HYDRO-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-28	Green Mountain Power Corporation	GMP	VT	07	VT	VT	6475	1.542	0.000	1.542	0.000	-0.670
2435	VERGENNES HYDRO-NEW	2435	VERGENNES HYDRO-NEW	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-12	Green Mountain Power Corporation	GMP	VT	01	VT	VT	6519	1.476	0.923	1.476	0.923	-0.817
2439	BROCKWAY MILLS U5	2439	BROCKWAY MILLS U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-03	Green Mountain Power Corporation	GMP	VT	25	VT	VT		0.196	0.000	0.196	0.000	-0.139
2462	PLAINVILLE GEN GF U5	2462	PLAINVILLE GEN GF U5	IC	OBG		BIO/REFUSE	24-Mar-03	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		2.287	2.106	2.287	2.106	0.001
2466	CHERRY 7	2466	CHERRY 7	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	MA	17	CMA/NEMA	WCMA	9038	2.800	2.800	2.800	2.800	0.000
2467	CHERRY 8	2467	CHERRY 8	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	MA	17	CMA/NEMA	WCMA	9038	3.400	3.400	3.400	3.400	0.000
2468	CHERRY 10	2468	CHERRY 10	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	MA	17	CMA/NEMA	WCMA	9038	2.100	2.100	2.100	2.100	0.000
2469	CHERRY 11	2469	CHERRY 11	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	MA	17	CMA/NEMA	WCMA	9038	2.100	2.100	2.100	2.100	0.000
2470	CHERRY 12	2470	CHERRY 12	IC	DFO		OIL INTERNAL COMBUSTION	01-Jan-51	Hudson Light & Power Department	HLPD	MA	17	CMA/NEMA	WCMA	9038	4.999	4.999	4.999	4.999	0.000
10308	NECCO COGENERATION FACILITY	10308	NECCO COGENERATION FACILITY	IC	NG		GAS INTERNAL COMBUSTION	01-Oct-03	New England Confectionery Company, Inc	NECCO	MA	25	BOSTON	NEMA	55999	4.939	0.017	4.939	0.017	-4.726
10347	KENDALL STEAM 1	37040	KENDALL STEAM	CC	NG		GAS COMBINED CYCLE	01-Jan-50	Kendall Green Energy, LLC	KENDALL	MA	17	BOSTON	NEMA	1595	14.752	14.505	14.752	14.505	0.000
10348	KENDALL STEAM 2	37040	KENDALL STEAM	CC	NG		GAS COMBINED CYCLE	01-Jan-50	Kendall Green Energy, LLC	KENDALL	MA	17	BOSTON	NEMA	1595	19.669	19.340	19.669	19.340	0.000
10349	KENDALL STEAM 3	37040	KENDALL STEAM	CC	NG		GAS COMBINED CYCLE	01-Jan-50	Kendall Green Energy, LLC	KENDALL	MA	17	BOSTON	NEMA	1595	20.141	19.805	20.141	19.805	0.000
10401	CELLEY MILL U5	10401	CELLEY MILL U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-84	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.064	0.031	0.064	0.031	-0.040
10402	PETTYBORO HYDRO U5	10402	PETTYBORO HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	09-May-99	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.000	0.000	0.000	0.000	0.000
10403	EASTMAN BROOK U5	10403	EASTMAN BROOK U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jun-85	Public Service Company of New Hampshire	PSNH	NH	09	NH	NH		0.030	0.008	0.030	0.008	-0.021
10404	WHEELABRATOR CLAREMONT U5	10404	WHEELABRATOR CLAREMONT U5	ST	MSW		BIO/REFUSE	01-Mar-04	Wheelabrator North Andover Inc	WNE	NH	19	NH	NH	50872	0.000	0.000	0.000	0.000	-3.648
10406	LOWER VALLEY HYDRO U5	10406	LOWER VALLEY HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-04	Green Mountain Power Corporation	GMP	NH	19	NH	NH		0.083	0.000	0.083	0.000	-0.177
10407	WOODSVILLE HYDRO U5	10407	WOODSVILLE HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-87	Green Mountain Power Corporation	GMP	NH	19	NH	NH		0.069	0.166	0.069	0.166	-0.071
10408	LOWER VILLAGE HYDRO U5	10408	LOWER VILLAGE HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-95	Green Mountain Power Corporation	GMP	NH	19	NH	NH	50285	0.000	0.000	0.000	0.000	0.000
10409	SWEETWATER HYDRO U5	10409	SWEETWATER HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-04	Green Mountain Power Corporation	GMP	NH	19	NH	NH		0.257	0.221	0.257	0.221	0.015
10424	GREAT LAKES - BERLIN	10424	Great Lakes - Berlin Incremental	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	22-Jun-04	Brookfield Energy Marketing, LP	BEMLP	NH	07	NH	NH	54639	10.854	9.230	10.854	9.230	-0.364
10451	WESTFIELD #1 U5	10451	WESTFIELD #1 U5	IC	OBG		BIO/REFUSE	01-Mar-04	Westfield Gas and Electric Light Department	WGED	MA	13	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
10615	BLUE SPRUCE FARM	10615	BLUE SPRUCE FARM U5	IC	OBG		BIO/REFUSE	01-Nov-04	Green Mountain Power Corporation	GMP	VT	21	VT	VT		0.296	0.305	0.296	0.305	0.018
10770	WEST SPRINGFIELD HYDRO U5	10770	WEST SPRINGFIELD HYDRO U5	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	10-Jan-05	Littleton Electric Light & Water Department	LELWD	MA	13	WMA	WCMA		0.774	0.515	0.774	0.515	-0.074
10801	COVENTRY CLEAN ENERGY	10801	COVENTRY CLEAN ENERGY	IC	LFG		BIO/REFUSE	01-Feb-05	Vermont Public Power Supply Authority	VPPSA	VT	19	NH	VT		3.300	3.268	3.300	3.268	-0.152
10880	GE LYNN EXCESS REPLACEMENT	10880	GE LYNN EXCESS REPLACEMENT	GT	DFO	NG	GAS/OIL COMBUSTION (GAS) TURBINE	11-Oct-05	Constellation NewEnergy, Inc.	CNE	MA	25	BOSTON	NEMA	10029	0.000	0.000	0.000	0.000	0.000
10959	RRIG EXPANSION PHASE 2	10959	RRIG EXPANSION PHASE 2	IC	LFG		BIO/REFUSE	01-Jun-05	Rhode Island Engine Genco, LLC	RRIG	RI	07	RI	RI	50365	0.000	0.000	0.000	0.000	0.000
10998	MASSINNOVATION FITCHBURG	10998	MASSINNOVATION FITCHBURG	PV	SUN		PHOTOVOLTAIC	01-Aug-05	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
11052	GRTR NEW BEDFORD LFG UTIL PROJ	11052	GRTR NEW BEDFORD LFG UTIL PROJ	IC	LFG		BIO/REFUSE	15-Aug-05	Exelon Generation Company, LLC	EXGC	MA	05	SEMA	SEMA		2.458	2.449	2.458	2.449	0.021
11126	NORTH HARTLAND HYDRO	11126	NORTH HARTLAND HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	27-Sep-06	Green Mountain Power Corporation	GMP	VT	27	VT	VT		0.983	1.207	0.983	1.207	0.122
11408	HULL WIND TURBINE II	11408	HULL WIND TURBINE II	WT	WND		WIND TURBINE	27-Sep-05	Hull Municipal Lighting Plant	HULL	MA	23	SEMA	SEMA	56800	0.248	0.075	0.248	0.075	0.038
11424	RUMFORD FALLS	11424	RUMFORD FALLS	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	06-Jul-06	Brookfield Energy Marketing, LP	BEMLP	ME	17	ME	ME	10493	30.830	32.470	30.830	32.470	-1.690
11827	PORTSMOUTH ABBEY WIND QF		No Resource (1)	WT	WND		WIND TURBINE	25-Jul-06	The Narragansett Electric Company	NEC	RI	05	SEMA	RI		0.000	0.000	0.000	0.000	0.000
11842	WATERSIDE POWER	11842	WATERSIDE POWER	GT	DFO		OIL COMBUSTION (GAS) TURBINE	01-May-04	Waterside Power, LLC	WATERSIDE	CT	01	NOR	CT	56189	71.557	70.017	71.557	70.017	0.000
11889	BEW LOCAL 99 SOLAR QF		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-06	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
11925	BROCKTON BRIGHTFIELDS	11925	BROCKTON BRIGHTFIELDS	PV	SUN		PHOTOVOLTAIC	18-Sep-06	Exelon Generation Company, LLC	EXGC	MA	23	SEMA	SEMA		0.000	0.152	0.000	0.152	0.006
12108	FIEC DIESEL	12108	FIEC DIESEL	IC	DFO		OIL INTERNAL COMBUSTION	01-Dec-06	Vermont Public Power Supply Authority	VPPSA	ME	13	ME	ME		1.596	1.540	1.596	1.540	0.000
12163	PPL GREAT WORKS - RED SHIELD	12163	PPL GREAT WORKS - RED SHIELD	ST	WDS		BIO/REFUSE	24-Jan-07	Competitive Energy Services, LLC	CESLLC	ME	19	BHE	ME	10700	0.000	0.000	0.000	0.000	0.000
12168	HARRIS ENERGY	12168	HARRIS ENERGY	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-06	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA	54981	0.000	0.000	0.000	0.000	0.000
12180	BERKSHIRE COW POWER	12180	BERKSHIRE COW POWER	IC	OBG		BIO/REFUSE	06-Dec-06	Vermont Electric Cooperative, Inc.	VEC	VT	11	VT	VT		0.262	0.207	0.262	0.207	-0.004
12274	GREEN MOUNTAIN DAIRY	12274	GREEN MOUNTAIN DAIRY	IC	OBG		BIO/REFUSE	01-Feb-07	Green Mountain Power Corporation	GMP	VT	11	VT	VT		0.220	0.218	0.220	0.218	-0.031
12323	COVENTRY CLEAN ENERGY #4	12323	COVENTRY CLEAN ENERGY #4	IC	LFG		BIO/REFUSE	20-Jan-07	Vermont Public Power Supply Authority	VPPSA	VT	19	NH	VT		2.200	2.179	2.200	2.179	-0.101
12504	DEVON 15	12504	Devon 15-18	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	12-Jul-10	GenConn Energy LLC	GCE	CT	09	SWCT	CT	57070	49.200	46.889	49.200	46.889	0.000
12505	MIDDLETOWN 12-15	12505	Middletown 12-15	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	24-Jun-11	GenConn Energy LLC	GCE	CT	07	CT	CT	57068	49.200	46.900	49.200	46.900	0.000
12509	UNH POWER PLANT	12509	UNH Power Plant	GT	LFG		BIO/REFUSE	20-Oct-09	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH	58180	4.378	3.008	4.378	3.008	0.000
12510	SWANTON GT-1	12510	Swanton Gas Turbine 1	GT	DFO	OBL	OIL COMBUSTION (GAS) TURBINE	12-Feb-10	Vermont Public Power Supply Authority	VPPSA	VT	11	VT	VT		23.954	19.304	23.954	19.304	0.000
12511	SWANTON GT-2	12511	Swanton Gas Turbine 2	GT	DFO	OBL	OIL COMBUSTION (GAS) TURBINE	24-May-10	Vermont Public Power Supply Authority	VPPSA	VT	11	VT	VT		23.839	19.349	23.839	19.349	0.000
12529	HOOSAC WIND		No Resource (1)	WT	WND		WIND TURBINE	27-Dec-12	Iberdrola Renewables, LLC	IR	MA	03	WMA	WCMA	57380	13.627	3.942	13.627	3.942	-1.332
12530	SHEFFIELD WIND PLANT	12530	Sheffield Wind Farm	WT	WND		WIND TURBINE	19-Oct-11	Vermont Wind LLC	VTWIND	VT	05	VT	VT	57080	9.685	3.295	9.685	3.295	0.995
12551	KIBBY WIND POWER	12551	Kibby Wind Power	WT	WND		WIND TURBINE	16-Sep-09	TransCanada Power Marketing, Ltd.	TCPM	ME	07	ME	ME	56829	35.060	18.275	35.060	18.275	0.480
12564	WATERBURY GENERATION FACILITY	12564	Waterbury Generation Facility	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	21-May-09	Waterbury Generation LLC	WATERBURY	CT	09	SWCT	CT	56629	98.128	95.821	98.128	95.821	1.088
13515	PIERCE STATION	12526	Pierce	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	01-Oct-07	Connecticut Municipal Electric Energy Cooperative	CMEEC	CT	09	SWCT	CT	6635	94.590	74.085	94.590	74.085	0.000
13669	EAST WINDSOR NORCAP LFG PLANT	13669	Manchester Methane LLC East Windsor Facility	IC	LFG		BIO/REFUSE	07-May-07	Manchester Methane, LLC	MMLLC	CT	03	CT	CT		0.698	0.783	0.698	0.783	0.000
13673	MATEP (DIESEL)	13673	MATEP (DIESEL)	IC	DFO		OIL INTERNAL COMBUSTION	28-Jun-07	MATEP, LLC	MATEP	MA	25	BOSTON	NEMA	10883	17.460	17.120	17.460	17.120	0.000
13675	MATEP (COMBINED CYCLE)	13675	MATEP (COMBINED CYCLE)	CC	NG	DFO	GAS/OIL COMBINED CYCLE	28-Jun-07	MATEP, LLC	MATEP	MA	25	BOSTON	NEMA	10883	48.275	42.515	48.275	42.515	0.000
13703	VERSO COGEN 1	13703	Verso VCG1	GT	NG	KER	GAS COMBUSTION (GAS) TURBINE	28-Dec-00	Verso Maine Energy LLC	VERSO	ME	07	ME	ME	55031	53.760	42.483	53.760	42.483	0.000
13704	VERSO COGEN 2	13704	Verso VCG2	GT	NG	KER	GAS COMBUSTION (GAS) TURBINE	28-Dec-00	Verso Maine Energy LLC	VERSO	ME	07	ME	ME	55031	56.333	44.314	56.333	44.314	0.000
13705	VERSO COGEN 3	13705	Verso VCG3	GT	NG	KER	GAS COMBUSTION (GAS) TURBINE	28-Dec-00	Verso Maine Energy LLC	VERSO	ME	07	ME	ME	55031	55.123	41.962	55.123	41.962	0.000
13933	UMINY PEAK WIND QF		No Resource (1)	WT	WND		WIND TURBINE	01-Jul-07	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.020	0.000	0.020	0.000	0.000
13975	CORRIVEAU HYDROELECTRIC LLC	13975	Corriveau Hydroelectric LLC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	10-Aug-07	Union Atlantic Electricity	UNION	ME	17	ME	ME		0.053	0.063	0.053	0.063	-0.040
14087	MAT3	14087	MAT3	IC	DFO		OIL INTERNAL COMBUSTION	11-Dec-07	MATEP, LLC	MATEP	MA	25	BOSTON	NEMA	10883	18.630	17.970	18.630	17.970	0.000
14098	FITCHBURG LANDFILL	35485	Fitchburg-FCA-5	IC	LFG		BIO/REFUSE	16-Aug-07	Vermont Public Power Supply Authority	VPPSA	MA	27	WMA	WCMA	56527	3.316	3.093	3.316	3.093	-1.093
14134	MONTAGNE FARM	14134	MONTAGNE FARM	IC	LFG		BIO/REFUSE	17-Sep-07	Green Mountain Power Corporation	GMP	VT	11	VT	VT		0.000	0.000	0.000	0.000	-0.080
14152	COS COB 13	12524	Cos Cob 13&14	GT	KER		OIL COMBUSTION (GAS) TURBINE	29-May-08	NRG Power Marketing LLC	NRGPM	CT	542	NOR	CT	542	22.852	19.053	22.852	19.053	0.000
14158	COS COB 14	12524	Cos Cob 13&14	GT	KER		OIL COMBUSTION (GAS) TURBINE	29-May-08	NRG Power Marketing LLC	NRGPM	CT	01	NOR	CT	542	22.602	19.209	22.602	19.209	0.000
14177	WESTBROOK ENERGY CENTER G1	1345	WESTBROOK	CC	NG		GAS COMBINED CYCLE	13-Apr-01	Calpine Energy Services, LP	CALP	ME	05	SME	ME	55294	281.835	261.204	281.835	261.204	0.268
14178	WESTBROOK ENERGY CENTER G2	1345	WESTBROOK	CC	NG		GAS COMBINED CYCLE	13-Apr-01	Calpine Energy Services, LP	CALP	ME	05	SME	ME	55294	285.063	261.204	285.063	261.204	6.824
14211	INDECK ALEXANDRIA	1631	Indeck-Energy Alexandria, LLC	ST	WDS		BIO/REFUSE	06-Nov-08	Indeck Energy-Alexandria, L.L.C.	IEA	NH	09	NH	NH		15.200	15.031	15.200	15.031	0.000
14217	NORTHFIELD MOUNTAIN 1	14217	NORTHFIELD MOUNTAIN 1	PS	WAT		HYDRO (PUMPED STORAGE)	30-Nov-72	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	547	270.000	270.000	270.000	270.000	0.000
14218	NORTHFIELD MOUNTAIN 2	14218	NORTHFIELD MOUNTAIN 2	PS	WAT		HYDRO (PUMPED STORAGE)	30-Nov-72	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	547	293.500	293.500	293.500	293.500	0.000
14219	NORTHFIELD MOUNTAIN 3	14219	NORTHFIELD MOUNTAIN 3	PS	WAT		HYDRO (PUMPED STORAGE)	30-Nov-72	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	547	292.000	292.000	292.000	292.000	0.000
14220	NORTHFIELD MOUNTAIN 4	14220	NORTHFIELD MOUNTAIN 4	PS	WAT		HYDRO (PUMPED STORAGE)	30-Nov-72	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	547	274.638	293.500	274.638	293.500	0.000
14271	AMERESCO NORTHAMPTON	14271	Ameresco Northampton	IC	LFG		BIO/REFUSE	01-Nov-07	Exelon Generation Company, LLC	EXGC	MA	15	WMA	WCMA		0.752	0.748	0.752	0.748	0.000
14595	GRANITE RELIABLE POWER, LLC	14595	Granite Reliable Power	WT	WND		WIND TURBINE	15-Feb-12	Granite Reliable Power, LLC	GRP	NH	07	NH	NH	58004	26.748	14.034	26.748	14.034	0.102
14610	PRINCETON WIND FARM PROJECT	14610	Princeton Wind Farm Project	WT	WND		WIND TURBINE	01-Sep-09	Princeton Municipal Light Department	PMLD	MA	27	WMA	WCMA	7501	0.297	0.154	0.297	0.154	0.124
14614	KLEEN ENERGY	14614	Kleen Energy	CC	NG	DFO	GAS/OIL COMBINED CYCLE	12-Jul-11	Exelon Generation Company, LLC	EXGC	CT	07	CT	CT	56798	620.000	620.000	620.000	620.000	0.000
14623	VALLEY HYDRO (STATION NO. 5)	14623	Valley Hydro (Station No. 5)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-08	Holyoke Gas & Electric Department	HGE	MA	13	WMA	WCMA		0.604	0.000	0.604	0.000	-0.552
14652	TEMPLETON WIND TURBINE	14652	Templeton Wind Turbine	WT	WND		WIND TURBINE	18-May-11	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	27	WMA	WCMA		0.157	0.058	0.157	0.058	-0.041
14665	RECORD HILL WIND	14665	Record Hill Wind	WT	WND		WIND TURBINE	31-Jan-12	Record Hill Wind, LLC	RHW	ME	17	ME	ME	57568	12.305	5.168	12.305	5.168	-1.780
14695	ORONO	14695	Orono Hydro Station	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	29-Dec-08	Black Bear Hydro Partners, LLC	BBHP	ME	19	BHE	ME	57184	1.681	1.790	1.681	1.790	1.790
14707	COVANTA HAVERHILL - LF GAS	12553	Covanta Haverhill Landfill Gas Engine	IC	LFG		BIO/REFUSE	05-Dec-07	Covanta Haverhill Associates	CHA	MA	09	BOSTON	NEMA	50661	1.091	1.089	1.091	1.089	-0.099
14767	PINE TREE LFGTE		No Resource (1)	IC	LFG		BIO/REFUSE	01-Jan-08	NextEra Energy Power Marketing, LLC	FPLP	ME	19	BHE	ME		0.000	0.000	0.000	0.000	0.000
14801	CABOT	766	CABOT TURNERS FALLS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-05	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	1629	61.800	61.481	61.800	61.481	0.000
14808	TURNERSFALLS	766	CABOT TURNERS FALLS	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-05	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	6388	6.400	6.400	6.400	6.400	0.000
14816	NORDEN 1	16688	Nor1	IC	DFO		OIL INTERNAL COMBUSTION	26-Feb-09	Connecticut Municipal Electric Energy Cooperative	CMEEC	CT	01	NOR	CT	57689	1.958	1.789	1.958	1.789	0.000
14817	NORDEN 2	16750	Norden #2	IC	DFO		OIL INTERNAL COMBUSTION	26-Feb-09	Connecticut Municipal Electric Energy Cooperative	CMEEC	CT	01	NOR	CT	57689	1.947	1.789	1.947	1.789	-0.159
14818	NORDEN 3	16752	Norden #3	IC	DFO		OIL INTERNAL COMBUSTION	26-Feb-09	Connecticut Municipal Electric Energy Cooperative	CMEEC	CT	01	NOR	CT	57689	1.942	1.775	1.942	1.775	-0.167
14823	NORWICH WWTP		No Resource (1)	IC	DFO		OIL INTERNAL COMBUSTION	29-May-08	Connecticut Municipal Electric Energy Cooperative	CMEEC	CT	11	CT	CT	57624	2.000	2.000	2.000	2.000	0.000
14919	DBE-001		No Resource (1)	GT	WDS	DFO	BIO/REFUSE	01-Mar-08	Public Service Company of New Hampshire	PSNH	NH	05	VT	NH		0.000	0.000	0.000	0.000	0.000
14925	ICE HOUSE PARTNERS INC.		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Apr-08	Littleton Electric Light & Water Department	LELWD	MA	17	CMA/NEMA	WCMA		0.093	0.101	0.093	0.101	0.008
14937	UNION GAS STATION	759	MESSALONSKEE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	19-Mar-08	Messalonskee Stream Hydro, LLC	MESSA	ME	11	ME	ME		1.303	1.218	1.303	1.218	-0.113
15097	KIMB ROCKY RIVER PH2	14706	Kimberly-Clark Corp Energy Independence Project	CC	NG		GAS COMBINED CYCLE	15-Jul-08	Kimberly-Clark Corporation	KCC	CT	05	SWCT	CT	58084	14.451	13.853	14.451	13.853	0.837
15115	LEMPSTER WIND	14660	Lempster Wind	WT	WND		WIND TURBINE	24-Sep-08	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH	56399	8.224	2.430	8.224	2.430	-0.815
15201	PSNH 3MILE HYDRO	35593	PSNH 3MILE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Jan-08	Public Service Company of New Hampshire	PSNH	NH	05	VT	NH		0.000	0.000	0.000	0.000	-1.139
15462	HOLY NAME CC JR SR HGH SCHOOL		No Resource (1)	WT	WND		WIND TURBINE	01-Sep-08	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
15464	STETSON WIND FARM		No Resource (1)	WT	WND		WIND TURBINE	09-Dec-08	Stetson Holdings, LLC	STETSON	ME	29	BHE	ME	56989	15.189	6.490	15.189	6.490	-1.103
15477	NEW HAVEN HARBOR UNIT 2	15477	New Haven Harbor Units 2, 3, & 4	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	30-May-12	PSEG New Haven, LLC	PSEG-NH	CT	09	CT	CT	6156	48.600	43.200	48.600	43.200	0.000
15484	THOMAS A. WATSON UNIT #1	12500	Thomas A. Watson	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	22-Apr-09	Braintree Electric Light Department, Town of	BELD	MA	21	SEMA	SEMA	1660	57.400	52.600	57.400	52.600	0.000
15485	THOMAS A. WATSON UNIT #2	12500	Thomas A. Watson	GT	NG	DFO	GAS/OIL COMBUSTION (GAS) TURBINE	14-Apr-09	Braintree Electric Light Department, Town of	BELD	MA	21	SEMA	SEMA	1660	57.400	52.600	57.400	52.600	0.000
15488	MIDDLETON BUILDING SUPPLY		No Resource (1)	ST	WDS		BIO/REFUSE	01-Oct-08	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.000	0.000	0.000	0.000	0.000
15509	PLAINFIELD RENEWABLE ENERGY	15509	Plainfield Renewable Energy	ST	WDS	OBS	BIO/REFUSE	12-Dec-13	Plainfield Renewable Energy, LLC	PRE	CT	15	CT	CT	56847	36.464	35.534	36.464	35.534	0.333
15617	MORETOWN LFGTE	35728	Moretown LG	IC	LFG		BIO/REFUSE	01-Dec-08	Green Mountain Power Corporation	GMP	V

Contains Proprietary Material
Do Not Distribute

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PAINT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 9, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
17233	RAINBOW UNIT 1	35658	Rainbow_1	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-80	Connecticut Light and Power Company, The	CLP	CT	03	CT	CT	559	4.100	4.100	4.100	4.100	0.000
17234	RAINBOW UNIT 2	35658	Rainbow_2	HDP	WAT		HYDRO (DAILY CYCLE - PONDAGE)	01-Jan-80	Connecticut Light and Power Company, The	CLP	CT	03	CT	CT	559	4.100	4.100	4.100	4.100	0.000
17259	SEAMAN ENERGY LLC	35442	Seaman Energy	IC	LFG		BIO/REFUSE	31-Mar-10	Templeton Municipal Lighting Plant	TTMLP	MA	27	CMA/NEMA	WCMA		0.249	0.170	0.249	0.170	-0.146
35379	SPAULDING POND HYDRO	35594	Spaulding Pond Hydro	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-May-10	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.201	0.035	0.201	0.035	-0.028
35555	GMCW	35555	GMCW	WT	WND		WIND TURBINE	31-Dec-12	Burlington Electric Department	BED	VT	07	VT	VT	58238	3.289	0.888	3.289	0.888	0.038
35693	SPRUCE MOUNTAIN WIND	35693	Spruce Mountain Wind	WT	WND		WIND TURBINE	21-Dec-11	Spruce Mountain Wind, LLC	SPRUCE	ME	17	ME	ME	58026	6.873	2.410	6.873	2.410	0.077
35979	KINGDOM COMMUNITY WIND	35979	Kingdom Community Wind	WT	WND		WIND TURBINE	16-Nov-12	Green Mountain Power Corporation	GMP	VT	19	VT	VT	57979	21.720	8.400	21.720	8.400	-1.360
36882	NOTUS WIND I		No Resource (1)	WT	WND		WIND TURBINE	23-Jun-10	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA	57414	0.483	0.280	0.483	0.280	-0.092
37050	GROTON WIND	37050	Groton Wind Project	WT	WND		WIND TURBINE	28-Dec-12	Iberdrola Renewables, LLC	IR	NH	09	NH	NH	58141	8.244	5.019	8.244	5.019	-1.395
37073	SOUTHBRIDGE LANDFILL	38178	Southbridge Landfill Gas to Energy 17-18	IC	LFG		BIO/REFUSE	15-Feb-12	NextEra Energy Power Marketing, LLC	FPLP	MA	27	CMA/NEMA	WCMA	59011	1.506	1.402	1.506	1.402	0.095
37175	ROLLINS WIND PLANT		No Resource (1)	WT	WND		WIND TURBINE	26-Jul-11	Evergreen Wind (II, LLC	EWP3	ME	19	BHE	ME	56990	14.915	6.391	14.915	6.391	-1.383
37224	PATRIOT PL_D FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.038	0.000	0.038	0.002
37225	PATRIOT PL_E FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.000	0.000	0.000	0.000
37226	PATRIOT PL_F FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.042	0.000	0.042	0.003
37227	PATRIOT PL_H FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.023	0.000	0.023	0.003
37228	PATRIOT PL_J FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.038	0.000	0.038	0.005
37229	PATRIOT PL_K FOXBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.033	0.000	0.033	0.001
37230	UNITED NAT. FOODS PROV. RI PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-10	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.003	0.000	0.003	0.003
37266	CARLSON ORCH HARVARD MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Nov-10	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.065	0.000	0.065	-0.023
37267	SPRUCE ENV HAVERHILL MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Nov-10	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
37366	MIDDLETOWN 13	12505	Middletown 12-15	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	23-Jun-11	GenConn Energy LLC	GCE	CT	07	CT	CT	57068	49.200	46.900	49.200	46.900	0.000
37367	MIDDLETOWN 14	12505	Middletown 12-15	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	01-Jun-11	GenConn Energy LLC	GCE	CT	07	CT	CT	57068	49.200	46.900	49.200	46.900	0.000
37368	MIDDLETOWN 15	12505	Middletown 12-15	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	01-Jun-11	GenConn Energy LLC	GCE	CT	07	CT	CT	57068	49.200	46.900	49.200	46.900	0.000
37721	ROYAL MILLS WARWICK RI HYDRO		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-10	The Narragansett Electric Company	NEC	RI	03	RI	RI		0.000	0.000	0.000	0.000	0.000
37722	SILVER LAKE SOLAR PV FACILITY	37051	Silver lake PV	PV	SUN		PHOTOVOLTAIC	06-Dec-10	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA	57676	0.000	0.696	0.000	0.696	0.014
37751	NM-UNISTRESS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37752	NM-COUNTRY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37753	NM-HANCOCK		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.017	0.000	0.017	0.010
37754	NM-QUALITY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37755	NM-WOOD		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.014	0.000	0.014	0.002
37756	NM-FOURSTAR		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.020	0.000	0.020	-0.001
37757	NM-ASTRO		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	13	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37758	NM-MARLEY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	15	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37759	NM-STONE		No Resource (1)	WT	WND		WIND TURBINE	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.022	0.000	0.022	0.000	0.000
37760	NM-RIVERVIEW		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.006	0.000	0.006	0.006
37761	NM-PETRICCA		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jan-11	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
37823	INDIAN RIVER POWER SUPPLY LLC	37079	Indian River Power Supply LLC	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-11	Swift River Trading Company LLC	SRTC	MA	13	WMA	WCMA		0.309	0.280	0.309	0.280	0.096
37955	TRANS MED TYNGSBORO MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.028	0.000	0.028	0.003
37956	PH HENBIL BILLERICA MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.010	0.000	0.010	0.002
37957	CHELM WTR N CHELMSFORD MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.044	0.000	0.044	-0.002
37958	PETER W ELEM LOWELL MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.016	0.000	0.016	0.002
37959	CIRCLE FIN NEWBURYPORT MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Mar-11	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
37965	BIO-DETEK PAWTUCKET RI PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Mar-11	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
37966	LTI HARVARD AP HARVARD MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Mar-11	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
37967	HILLSIDE MARLBOROUGH MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.002	0.000	0.002	0.002
37969	LOW MEM AUD LOWELL MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Mar-11	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.026	0.000	0.026	0.000
37972	DARTMOUTHBUSPARK_PV_ID1592		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Mar-11	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA	57473	0.000	0.708	0.000	0.708	0.057
37973	GENERAL MILLS METHUEN MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Mar-11	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.017	0.000	0.017	0.004
38083	ORONO B HYDRO	38083	Orono "B" Hydro	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-13	Black Bear Hydro Partners, LLC	BBHP	ME	19	BHE	ME		3.030	3.290	3.030	3.290	3.290
38084	STILLWATER B HYDRO	38084	Stillwater "B" Hydro	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	20-Sep-13	Black Bear Hydro Partners, LLC	BBHP	ME	19	BHE	ME		1.638	1.487	1.638	1.487	1.487
38172	SADDLEBACK RIDGE WIND		No Resource (1)	WT	WND		WIND TURBINE	19-Dec-14	Spruce Mountain Wind, LLC	SPRUCE	ME	07	ME	ME	58608	0.000	0.000	0.000	0.000	0.000
38287	WMA CHESTER SOLAR 1	38287	WMA Chester Solar 1	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Vermont Public Power Supply Authority	VPPSA	MA	13	WMA	WCMA		0.000	2.078	0.000	2.078	2.078
38302	TOWN_OF_CARVER_PV_1763		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-14	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
39663	BARNSTABLE_DPW_ID1545		No Resource (1)	WT	WND		WIND TURBINE	01-Aug-11	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.020	0.320	0.020	0.320	0.022
39664	DART_BLDG_SUPPLY_ID1476		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-11	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.048	0.000	0.048	0.007
39665	YARMOUTH_ DPW_ID1740		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-11	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.117	0.000	0.117	0.016
39675	TURKEY HILL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-11	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.016	0.000	0.016	0.003
39717	HI GEAR		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-11	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.103	0.000	0.103	0.003
39722	GTR_BOSTON_FOODBANKS_ID1628		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Oct-11	NSTAR Electric Company	NSTAR	MA	25	BOSTON	NEMA		0.000	0.089	0.000	0.089	0.006
39724	EASTERN_AVE_HOLDINGS_PV_ID1652		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Oct-11	NSTAR Electric Company	NSTAR	MA	25	BOSTON	NEMA		0.000	0.089	0.000	0.089	0.007
39738	MWRA_LORING_RD_ID1400		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Nov-11	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.091	0.155	0.091	0.155	-0.021
40015	INDIAN ORCHARD SOLAR FACILITY	38081	Indian Orchard Solar PV	PV	SUN		PHOTOVOLTAIC	01-Dec-11	Western Massachusetts Electric Company	WMECO	MA	13	WMA	WCMA	57674	0.000	0.803	0.000	0.803	-0.078
40050	EXETER AGRI ENERGY		No Resource (1)	IC	OBG		BIO/REFUSE	19-Dec-11	Vermont Public Power Supply Authority	VPPSA	ME	19	BHE	ME		0.935	0.895	0.935	0.895	-0.002
40052	NEW HAVEN HARBOR UNIT 3	15477	New Haven Harbor Units 2, 3, & 4	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	30-May-12	PSEG New Haven, LLC	PSEG-NH	CT	09	CT	CT	6156	48.600	43.200	48.600	43.200	0.000
40053	NEW HAVEN HARBOR UNIT 4	15477	New Haven Harbor Units 2, 3, & 4	GT	KER	NG	OIL COMBUSTION (GAS) TURBINE	30-May-12	PSEG New Haven, LLC	PSEG-NH	CT	09	CT	CT	6156	48.600	43.200	48.600	43.200	0.000
40054	JOHNSTON LFG TURBINE PLANT	14599	Rhode Island LFG Genco, LLC - ST	CC	LFG		BIO/REFUSE	25-May-13	Rhode Island Engine Genco, LLC	RRIG	RI	07	RI	RI	59254	27.891	26.430	27.891	26.430	0.067
40060	OLDBARNET_RD_MASHPEE_PV_ID1798		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-12	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.133	0.000	0.133	0.015
40067	MARION_DR_KINGSTON_WT_ID1656		No Resource (1)	WT	WND		WIND TURBINE	16-Jan-12	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.819	0.473	0.819	0.473	-0.409
40085	QUABBIN 1_ORANGE MA PV NET		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Jan-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40086	QUABBIN 2_ORANGE MA PV NET		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Jan-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40116	DELAWARE VALLEY CORP PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	31-Jan-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
40119	WORCESTER STATE COLLEGE PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	31-Jan-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40137	BERKSHIRE EAST WIND		No Resource (1)	WT	WND		WIND TURBINE	03-Feb-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.263	0.000	0.263	-0.038
40176	NFM SOLAR POWER, LLC	38078	NFM Solar Power, LLC	SU	SUN		PHOTOVOLTAIC	18-Feb-12	GDF Suez Energy Marketing NA, Inc.	SUEZ	MA	11	WMA	WCMA	58210	0.000	0.649	0.000	0.649	0.042
40194	MICRON		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Mar-12	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40207	KEZAR UPPER FALLS	786	KEZAR LEDGEMERE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-12	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	7668	0.280	0.118	0.280	0.118	-0.136
40208	KEZAR LOWER FALLS	786	KEZAR LEDGEMERE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-12	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	7668	0.453	0.248	0.453	0.248	-0.188
40209	LEDGEMERE	786	KEZAR LEDGEMERE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Mar-12	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME	7668	0.235	0.057	0.235	0.057	-0.095
40225	MILLIPORE PV - BILLERICA		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Mar-12	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.000	0.000	0.000	0.000
40242	TANTASQUA JR HIGH_PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Mar-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	-0.008
40243	SOLAR SHOP LLC BLDG 14_PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Mar-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.038	0.000	0.038	0.000
40244	SOLAR SHOP LLC BLDG 10_PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Mar-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.049	0.000	0.049	0.001
40246	HODGES BADGE CO_WIND		No Resource (1)	WT	WND		WIND TURBINE	30-Mar-12	The Narragansett Electric Company	NEC	RI	05	SEMA	RI		0.000	0.000	0.000	0.000	0.000
40247	QUABBIN BARRE - WIND		No Resource (1)	WT	WND		WIND TURBINE	29-Mar-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.408	0.000	0.406	-0.004
40248	JJ CARROLL WW PLANT_PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Mar-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.205	0.000	0.205	-0.009
40249	WESTBORO SUITES		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Mar-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.006	0.000	0.006	0.000
40250	SHAWS SUPER MARKET		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Mar-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40251	VETERAN HOMESTEAD PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Mar-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.003	0.000	0.003	-0.010
40259	COMMERCE_PK_RD_PV_ID1871		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Apr-12	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.131	0.000	0.131	0.018
40263	MATOUK TEXTILE WORKS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Apr-12	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
40270	TECTA AMERICA		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Apr-12	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.007	0.000	0.007	-0.017
40327	FORE RIVER 11	1691	FORE RIVER-1	CC	NG		GAS COMBINED CYCLE	04-Aug-03	Calpine Energy Services, LP	CALP	MA	21	SEMA	SEMA	55317	416.611	362.997	416.611	362.997	0.000
40328	FORE RIVER 12	1691	FORE RIVER-1	CC	NG		GAS COMBINED CYCLE	04-Aug-03	Calpine Energy Services, LP	CALP	MA	21	SEMA	SEMA	55317	421.500	362.712	421.500	362.712	0.000
40338	MAINE INDEPENDENCE STATION 1	1216	MAINE INDEPENDENCE STATION	CC	NG		GAS COMBINED CYCLE	01-May-00	Dynegy Marketing and Trade, LLC	DMT1	ME	19	BHE	ME	55068	269.138	244.138	269.138	244.138	0.000
40339	MAINE INDEPENDENCE STATION 2	1216	MAINE INDEPENDENCE STATION	CC	NG		GAS COMBINED CYCLE	01-May-00	Dynegy Marketing and Trade, LLC	DMT1	ME	19	BHE	ME	55068	269.138	244.138	269.138	244.138	0.000
40340	NEXAMP CAP-WORCESTER ACADEMY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Apr-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
40342	VERSO BUCKSPORT G5		No Resource (1)	ST	OBS	NG	BIO/REFUSE	15-Nov-12	Verso Maine Energy LLC	VERSO	ME	09	BHE	ME	50243	22.265	0.000	22.265	0.000	-22.494
40343	BULL HILL WIND		No Resource (1)	WT	WND		WIND TURBINE	27-Oct-12	Blue Sky East, LLC	BSE	ME	09	BHE	ME	57083	13.458	6.457	13.458	6.457	1.483
40365	EAST ISLAND COMMUNITY - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Apr-12	Massachusetts Electric Company	MEC	MA	09	CMA/NEMA	WCMA		0.000	0.037	0.000	0.037	0.001
40482	DURFEE UNION MILLS BLDG 9 - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-May-12	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
40483	TYNGSBOROUGH SPORTS PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-May-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
40484	BANCROFT SCHOOL PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-May-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40485	LITCHFIELD LECOMINSTER PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-May-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
40520	MANCHESTER-BOSTON REGIONAL PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-May-12	Public Service Company of New Hampshire	PSNH	NH	11	NH	NH		0.000	0.000	0.000	0.000	-0.008
40524	MOUNT WACHUSSETT CC WIND		No Resource (1)	WT	WND		WIND TURBINE	11-May-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA	58025	0.000	0.000	0.000	0.000	0.000
40555	BLACKCOMB WORC MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-May-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.063	0.000	0.063	0.007
41782	PAWTUCKET MEMORIAL ELEM SCH		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-May-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
41783	PHOENIX FINANCE LLC		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-May-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.017	0.000	0.017	-0.005
41784	NANTUCKET HIGH SCHOOL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-May-12	Massachusetts Electric Company	MEC	MA	19	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
41806	NM-PROPEL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.000	0.000	0.000	-0.014
41807	NM-PITTSFIELD WWTP		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA	59060	0.000	0.550	0.000	0.550	-0.103
41808	NM-MASS DEP		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	13	WMA	WCMA		0.000	0.006	0.000	0.006	0.005
41809	NM-GREENFIELD CC		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
41810	NM-FULL BLOOM MARKET		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.033	0.000	0.033	0.033
41811	NM-BERKSHIRE CC		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jun-12	Western Massachusetts Electric Company	WMECO	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
41815	TIFFANY AND CO - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Jun-12	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
41816	QUABOAG REGIONAL ELEM - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Jun-12	Massachusetts Electric Company	MEC	MA	27	WMA	WC

Contains Proprietary Material
Do Not Distribute

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC-PANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
41881	TOWN OF SWAMPSCOTT HS - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jul-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.156	0.000	0.156	-0.069
41882	NEXAMP CAP-NASHOBA VALLEY THS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Jul-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
41921	MSI REALTY JAMES ST - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Jul-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
41922	LIGHTOLIER - WIND		No Resource (1)	WT	WND		WIND TURBINE	23-Jul-12	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.194	0.127	0.194	0.127	0.127
41923	BLACKCOMB SOLAR III-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Jul-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.379	0.000	0.379	0.002
41924	COREMARK-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Jul-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.173	0.000	0.173	0.007
42041	D.D. BEAN		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	02-Aug-12	Constellation NewEnergy, Inc.	CNE	NH	05	VT	NH		0.000	0.000	0.000	0.000	0.000
42043	SWANSEA WATER DISTRICT		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Aug-12	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.000	0.000	0.000	0.000	0.000
42045	NM-GREENFIELD MA LANDFILL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-12	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.000	0.635	0.000	0.635	-0.186
42046	ST. MARYS HIGH SCHOOL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Aug-12	Massachusetts Electric Company	MEC	MA	25	BOSTON	NEMA		0.000	0.011	0.000	0.011	0.006
42048	TANTASQUA HIGH- PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Aug-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.012	0.000	0.012	0.012
42050	PETE'S TIRE BARN		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Aug-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.065	0.000	0.065	0.018
42083	CANTON_LANDFILL_PV_ID1726		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Aug-12	NSTAR Electric Company	NSTAR	MA	21	SEMA	SEMA		0.000	2.559	0.000	2.559	0.177
42091	QUABOAG REGIONAL HS - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Aug-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.048	0.000	0.048	0.002
42092	TOWN OF SUTTON MA PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Aug-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42104	HYDEPARKSTORPV_ID919		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	25	BOSTON	NEMA		0.000	0.059	0.000	0.059	-0.016
42105	MILLST_NATICKPV_ID1818		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.070	0.000	0.070	-0.015
42106	SUBURBANATHLETIC2_ID1637		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.036	0.000	0.036	0.000
42107	4M_ALDRINRDPV_ID1856		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.000	0.049	0.000	0.049	0.001
42108	BROADWAY_RENEWABLE_ID1772		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.000	0.382	0.000	0.382	-0.013
42109	COCHITUATERD_FRAMPV_ID1873		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.079	0.000	0.079	0.006
42110	DOUGLAS_SCHOOLPV_ID1464		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.034	0.000	0.034	0.006
42111	HYANNIS_SELF_STOR_ID1946		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.198	0.000	0.198	0.030
42112	POND_ST_ASHLAND_ID1736		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.185	0.000	0.185	0.009
42113	COBSCOOK BAY TEP TGU 1		No Resource (1)	OT	WAT		MISC. OTHER	04-Sep-12	New Brunswick Energy Marketing Corporation	NBPGC	ME	29	BHE	ME		0.000	0.000	0.000	0.000	0.000
42114	PUMPKIN HILL	1258	BHE SMALL HYDRO COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Dec-82	New Brunswick Energy Marketing Corporation	NBPGC	ME	19	BHE	ME	50699	0.000	0.572	0.000	0.572	-0.638
42115	GLC_ACUSHNETLLC_ID1821_1824		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.000	1.861	0.000	1.861	0.025
42116	DSD_REALTY_TRUST_ID1672		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.500	0.000	0.500	-0.003
42117	CONST_SOLAR_NORFOLK_ID1846		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	21	RI	SEMA	57942	0.000	0.649	0.000	0.649	0.003
42118	CONED_HXVILLERD_ID1862		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Sep-12	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	1.123	0.000	1.123	0.071
42123	KEZAR LEDGEMERE COMPOSITE	786	KEZAR LEDGEMERE COMPOSITE	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Oct-12	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME		0.057	0.076	0.057	0.076	0.010
42135	18 PHOENIX PARK BLDG DEAST & F		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Sep-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42136	18 PHOENIX PARK BLDG DEAST & J		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Sep-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42137	18 PHOENIX PARK BLDG DWEST		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Sep-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.017	0.000	0.017	0.000
42149	FAVORITE FOODS PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Oct-12	Public Service Company of New Hampshire	PSNH	NH	17	NH	NH		0.000	0.000	0.000	0.000	0.000
42155	LEICESTER HS - BWSC RENEWABLE		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Oct-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
42158	UMASS LOWELL LEITCH HALL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Oct-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42157	MILLBROOK RIVERSIDE LLC		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Oct-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42158	MOHAWK DRIVE CORPORATION		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Oct-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.036	0.000	0.036	0.004
42193	TRUE NORTH ENERGY A		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59390	0.000	0.601	0.000	0.601	0.073
42194	TRUE NORTH ENERGY B		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59390	0.000	0.458	0.000	0.458	-0.045
42195	TRUE NORTH ENERGY C		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59390	0.000	0.423	0.000	0.423	0.027
42196	TRUE NORTH ENERGY D		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59390	0.000	0.541	0.000	0.541	0.019
42197	TRUE NORTH ENERGY E		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59390	0.000	0.562	0.000	0.562	0.059
42201	MATTHEW KUSS MS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Nov-12	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
42202	DR AMP 100 AMES POND - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Nov-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.025	0.000	0.025	0.016
42203	WESTFORD SOLAR 3 - PV	38181	Westford Solar	PV	SUN		PHOTOVOLTAIC	08-Nov-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA	58534	0.000	0.463	0.000	0.463	0.007
42204	BPV LOWELL		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Nov-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.033	0.000	0.033	0.003
42205	SALEM STATE UNIVERSITY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
42212	DR AMP 200 AMES POND - PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Nov-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.028	0.000	0.028	-0.004
42213	CUMMINGS PROPERTY E GMR		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.040	0.000	0.040	0.040
42214	ORCHARD MADE PRODUCTS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Nov-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.012	0.000	0.012	-0.007
42215	WESTBOROUGH TREATMENT PL BD		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Nov-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
42344	CAMELOT_WIND_ID1240		No Resource (1)	WT	WND		WIND TURBINE	01-Dec-12	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA	58958	0.198	0.159	0.198	0.159	-0.004
42346	3 RIVERS PALMER-SPRINGFLD-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Dec-12	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
42347	CONSTELLATION SOLAR-UXBRG-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Dec-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA	57941	0.000	0.830	0.000	0.830	0.059
42349	15 UNION SOLAR LLC-LAWRENCE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Dec-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.075	0.000	0.075	0.037
42350	BARRETT-FRANKLIN-SOLAR		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Dec-12	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.257	0.000	0.257	0.019
42351	OMA GROUP-CHARLTON-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Dec-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.419	0.000	0.419	-0.016
42352	OSG SOLAR 1-ORANGE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Dec-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.439	0.000	0.439	0.006
42353	OSG SOLAR 2-ORANGE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Dec-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.439	0.000	0.439	0.003
42354	OSG SOLAR 3-ORANGE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Dec-12	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.217	0.000	0.217	0.001
42355	CIL CEDAR-MARLBORO-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Dec-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.047	0.000	0.047	0.047
42356	LEEWOOD SWIX-HAVERHILL-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Dec-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.125	0.000	0.125	-0.004
42357	UP BLACKSTONE WWTP-MILLBURY-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Dec-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.126	0.000	0.126	-0.003
42359	FOREKICKS-MARLBORO-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Dec-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.088	0.000	0.088	0.008
42360	35 LYMAN LLC-NORTHBORO-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Dec-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.092	0.000	0.092	0.007
42364	CAPITAL GROUP-SOUTHBORO-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Dec-12	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.376	0.000	0.376	-0.013
42365	LOFT 27-LOWELL-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Dec-12	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.107	0.000	0.107	-0.007
42366	SOLTAS SPECTOR-LAWRENCE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Dec-12	Massachusetts Electric Company	MEC	MA	09	CMA/NEMA	WCMA		0.000	0.149	0.000	0.149	0.000
42375	DEXTER 1	392	DEXTER	CC	NG	DFO	GAS/OIL COMBINED CYCLE	01-May-90	Algonquin Energy Services Inc.	AESR	CT	03	CT	CT	10567	38.363	37.839	38.363	37.839	0.205
42376	DEXTER 2	392	DEXTER	CC	NG		GAS COMBINED CYCLE	01-May-90	Algonquin Energy Services Inc.	AESR	CT	03	CT	CT	10567	4.833	4.432	4.833	4.432	0.205
42383	SALEM STATE-SALEM-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Dec-12	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
42384	BJS WHOLESALE CLUB LEOMINSTER		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Dec-12	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
42385	CORNER BROOK-MILFORD-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Dec-12	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.056	0.000	0.056	0.001
42394	WINDENERGYDEV-MKINGSTN-WIND		No Resource (1)	WT	WND		WIND TURBINE	02-Jan-13	The Narragansett Electric Company	NEC	RI	09	RI	RI		0.187	0.134	0.187	0.134	0.056
42411	EXTRA SPACE-PLAINVILLE-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Jan-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.040	0.000	0.040	0.040
42412	EXTRA SPACE-SAUGUS-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.039	0.000	0.039	0.007
42413	35 LYMAN LLC - ACTIVE		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Jan-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.023	0.000	0.023	0.023
42414	NE ELECTRO-FALL RIVER-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Jan-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.016	0.000	0.016	-0.010
42424	IPSWICH WIND II		No Resource (1)	WT	WND		WIND TURBINE	09-Jan-13	Ipswich Municipal Light Department	IMLD	MA	09	BOSTON	NEMA	59023	0.313	0.152	0.313	0.152	0.007
42431	SOLECT PLUMBING-NORWELL-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Jan-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.049	0.000	0.049	-0.003
42432	VAUGHN CORP-SALISBURY-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Jan-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.031	0.000	0.031	0.003
42433	BETHANY CHURCH-MENDON-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Jan-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.029	0.000	0.029	-0.001
42438	EXTRA SPACE-NORTHBORO-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jan-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.038	0.000	0.038	0.005
42439	CITY OF BROCKTON-SWANSEA-PV1		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jan-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.520	0.000	0.520	0.034
42440	CITY OF BROCKTON-SWANSEA-PV2		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jan-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.770	0.000	0.770	0.051
42443	WAL-MART LUN (PV)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Jan-13	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
42444	MRTA (PV)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-Jan-13	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.019	0.000	0.019	0.012
42448	CITY OF GLOUCESTER 1 - WIND		No Resource (1)	WT	WND		WIND TURBINE	06-Feb-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.395	0.127	0.395	0.127	0.009
42449	CITY OF GLOUCESTER 2 - WIND		No Resource (1)	WT	WND		WIND TURBINE	06-Feb-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.274	0.106	0.274	0.106	-0.053
42482	CITY_OF_WALTHAM_PV_ID1805		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.072	0.000	0.072	0.016
42483	FIRST_HIGHLAND_PV_ID2021		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	25	BOSTON	NEMA		0.000	0.346	0.000	0.346	-0.043
42484	UNITEDSALVAGE_PV_ID1966		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.213	0.000	0.213	0.082
42485	SOLCHEMY_PV_ID1969		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	07	SEMA	SEMA		0.000	0.118	0.000	0.118	0.030
42486	AIRPORT_WAY_PV_ID1875		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.633	0.000	0.633	0.096
42487	BILL_BENNETT_PV_ID1967		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Feb-13	NSTAR Electric Company	NSTAR	MA	07	SEMA	SEMA		0.000	0.387	0.000	0.387	0.141
42495	VARIANSEMICON-GLOUCESTER-WT		No Resource (1)	WT	WND		WIND TURBINE	21-Feb-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
42496	HANOVER SOLAR-LEICESTER-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Feb-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.363	0.000	0.363	-0.077
42497	WESTFORD SOLAR 4- PV	38181	Westford Solar	PV	SUN		PHOTOVOLTAIC	21-Feb-13	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA	58534	0.000	0.444	0.000	0.444	-0.008
42504	BERKSHIRE SRECS-GT BARRGTN-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Feb-13	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
42505	CUMMINGS 1000-BEVERLY-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Feb-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.083	0.000	0.083	-0.002
42597	GPT JACLEN-BEVERLY-CHP		No Resource (1)	IC	NG		GAS INTERNAL COMBUSTION	26-Mar-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
42598	NEW BARRE HYDRO	852	SOUTH BARRE HYDRO	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	02-Apr-13	Massachusetts Municipal Wholesale Electric Company	MMWEC	MA	27	WMA	WCMA		0.047	0.000	0.047	0.000	0.000
42599	MAPREMCT-97GREEN-02035-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Apr-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.052	0.000	0.052	0.002
42600	HOSEACWALREG-ORCHARD-01225-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Apr-13	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.000	0.081	0.000	0.081	0.014
42601	CARLSTROMPM-65FISHER-0158-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Apr-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.200	0.000	0.200	0.007
42602	KEYPOLYMER-1 JACOB-01843-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Apr-13	Massachusetts Electric Company	MEC	MA	09	CMA/NEMA	WCMA		0.000	0.112	0.000	0.112	0.049
42603	BARRE1-750BARRE-01005-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Apr-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.343	0.000	0.343	0.016
42611	AUBUCHON-95AUBUCHON-01473-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Apr-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.116	0.000	0.116	0.022
42612	NPPDEVELOP-370PATRIOT-02035-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Apr-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.229	0.000	0.229	0.013
42613	AMERICOLD-0PEW-01930-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Apr-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
42631	CABRAL-247BAKER-02777-PV		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Apr-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.231	0.000	0.231	0.029
42632	ALPHA GRAINGER-02038PV250NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Apr-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.000	0.000	0.000	0.000
42633	NORTHBORSPORTS-0153ZPV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Apr-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.061	0.000	0.061	0.033
42641	NATICKMEMORIAL SCHOOL_PV_ID1892		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Apr-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.043	0.000	0.043	0.002
42812	PEGASUS_PV_ID1809		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-May-13	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.441	0.000	0.441	0.007

Contains Proprietary Material
Do Not Distribute

ASSET ID	ASSET NAME	RE-SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
43492	NARR BAY - 02903WT4500NM		No Resource (1)	WT	WND		WIND TURBINE	09-Jul-13	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
43509	DOUGLAS SOLAR-01516PV200NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Jul-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA	57934	0.000	1.048	0.000	1.048	0.068
43510	SANDF MGMNT-02725PV623NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Jul-13	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.000	0.239	0.000	0.239	-0.002
43512	WEST GREENWICH - 02817PV2000DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jul-13	The Narragansett Electric Company	NEC	RI	03	RI	RI		0.000	0.934	0.000	0.934	0.067
43527	STUART THOMAS - 02842PV500DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Jul-13	The Narragansett Electric Company	NEC	RI	05	SEMA	RI		0.000	0.213	0.000	0.213	0.038
43528	EXTRA SPC MGMT-02035PV102NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Jul-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.026	0.000	0.026	0.000
43529	CREEDON AND CO-01604PV110NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Jul-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.012	0.000	0.012	-0.002
43531	28 HASTINGS - 01756PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Jul-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.038	0.000	0.038	0.022
43556	CALLAHAN - 02324PV110NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.010	0.000	0.010	0.004
43557	BRDGWTR RECYCLE-02324PV96NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.045	0.000	0.045	0.004
43558	COMMERCE GRN-02339PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.032	0.000	0.032	0.000
43572	JDH_SOLAR_SYSTEMS_PV_2221		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-13	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.000	0.242	0.000	0.242	0.035
43573	NEW_ENGLAND_RESINS_PV_2309		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Aug-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.188	0.000	0.188	0.016
43574	TOWN_OF_FAIRHAVEN_LF_PV_1714		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.189	0.000	0.189	0.053
43575	NE_ELEMENTARY_WALTHAM_PV_1872		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.114	0.000	0.114	0.012
43576	GLC_ACUSHNET_PV_1888		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.507	0.000	0.507	0.028
43577	GLC_ACUSHNET_PV_1889		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.383	0.000	0.383	0.027
43578	GLC_ACUSHNET_PV_1890		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	0.508	0.000	0.508	0.038
43579	GOIS_SOLAR_ONE_PV_2040		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-13	NSTAR Electric Company	NSTAR	MA	17	BOSTON	NEMA		0.000	0.386	0.000	0.386	0.011
43586	COMTRAN CABLE-02864PV400DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Aug-13	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.217	0.000	0.217	0.006
43587	TRAVIS_HOSPITALITY_PV_2239		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Aug-13	NSTAR Electric Company	NSTAR	MA	01	SEMA	SEMA		0.000	0.066	0.000	0.066	0.020
43603	WORC GEAR AND RACK-01537PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Aug-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
43604	METRO WST PROVIS-01747PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Aug-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.033	0.000	0.033	0.011
43605	PRECISE PACK-02720PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
43606	CITY NORTHAMPTON-02721PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-13	Massachusetts Electric Company	MEC	MA	15	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
43607	COX PRTSMTH-02871PV500DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-13	The Narragansett Electric Company	NEC	RI	05	RI	RI		0.000	0.235	0.000	0.235	0.235
43608	35 LYMAN LLC-01532PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Aug-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.016	0.000	0.016	0.000
43609	MA CORRECTIONAL-01440WT3300NM		No Resource (1)	WT	WND		WIND TURBINE	05-Sep-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
43623	E BRIDGEWATER-02333PV2000NM	38114	East Bridgewater Solar Energy Project	PV	SUN		PHOTOVOLTAIC	12-Sep-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	1.062	0.000	1.062	1.062
43624	TJ MAXX - 02061PV260NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Sep-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
43643	SUNGEN UXBRIDGE1-01569PV560NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Sep-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.501	0.000	0.501	0.501
43644	SUNGEN UXBRIDGE2-01569PV560NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Sep-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.494	0.000	0.494	0.494
43645	SUNGEN UXBRIDGE3-01569PV560NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Sep-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.479	0.000	0.479	0.479
43652	TWN W BRDGEWTR-02379PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Sep-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.768	0.000	0.768	0.768
43653	40 WASHINGTON LTD-01581PV750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Sep-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.165	0.000	0.165	0.165
43654	3 COUNTY FAIR ASN-01060PV250NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Sep-13	Massachusetts Electric Company	MEC	MA	15	WMA	WCMA		0.000	0.108	0.000	0.108	0.108
43655	SPRING HILL FARM-01835PV229NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Oct-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.073	0.000	0.073	0.073
43656	SVC TIRE TRUCK - 01527PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Oct-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
43657	RIPTA - 02907PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Sep-13	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.000	0.000
43658	TWN LANCASTER-01523PV500DF		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Oct-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.195	0.000	0.195	0.195
43659	TWN OF SCITUATE2-02066PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Oct-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA	59013	0.000	0.810	0.000	0.810	0.810
43678	DISCOVER MARBLE - 01527PV142NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Oct-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
43682	NEXTSUN ENERGY-01516PV3000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Oct-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	1.590	0.000	1.590	1.590
43683	TWN OF SCITUATE1-02066PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	22-Oct-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA	59013	0.000	0.544	0.000	0.544	0.544
43684	KEY BOSTON-02039PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Oct-13	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.776	0.000	0.776	0.776
43685	CONNNCUT MARINE-02859PV120DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Oct-13	The Narragansett Electric Company	NEC	RI	05	SEMA	RI		0.000	0.049	0.000	0.049	0.049
43688	SHEA CONCRETE-01913PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Oct-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.088	0.000	0.088	0.088
43687	SUNGEN ORANGE1-01364PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Oct-13	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA	58411	0.000	0.654	0.000	0.654	0.654
43688	SUNGEN ORANGE2-01364PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Oct-13	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA	58411	0.000	0.208	0.000	0.208	0.208
43689	BOSTON NORTH TECH-01913PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Oct-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
43690	OXFORD REALTY-01604PV149NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Oct-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.030	0.000	0.030	0.030
43691	CRAFT INC-02703PV285NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	30-Oct-13	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.000	0.037	0.000	0.037	0.037
43695	KOHLS-01906PV252NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Oct-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
43696	STOP AND SHOP-02155PV200NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Oct-13	Massachusetts Electric Company	MEC	MA	17	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
43698	NTHBRDGE SOLAR-01560PV1910NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Oct-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA	58385	0.000	1.125	0.000	1.125	1.125
43706	CITY OF LOWELL1-01364PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Nov-13	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.421	0.000	0.421	0.421
43707	CITY OF LOWELL2-01364PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Nov-13	Massachusetts Electric Company	MEC	MA	11	WMA	WCMA		0.000	0.859	0.000	0.859	0.859
43708	HANNAFORD-02061PV135NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Nov-13	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
43709	CITY OF LOWELL 1-01331PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Nov-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.430	0.000	0.430	0.430
43710	CITY OF LOWELL 2-01331PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Nov-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.487	0.000	0.487	0.487
43711	CITY OF LOWELL 3-01331PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Nov-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.492	0.000	0.492	0.492
43712	PHOENIX FINS-01464PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Nov-13	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
43713	CUMMINGS PROP-01915PV110NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Nov-13	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.040	0.000	0.040	0.040
43714	EXTRA SPC STOR-02189PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Nov-13	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.031	0.000	0.031	0.031
43715	MILFORD IND-01757PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Nov-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.038	0.000	0.038	0.038
43716	NEXAMP-02852PV2000DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	06-Nov-13	The Narragansett Electric Company	NEC	RI	09	RI	RI		0.000	0.940	0.000	0.940	0.940
43717	ASSUMPTION-01562PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-Nov-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	1.034	0.000	1.034	1.034
43729	GRAFTON WATER-01519PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Nov-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA	59394	0.000	0.715	0.000	0.715	0.715
43731	JEFFERSON-02720PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Nov-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.011	0.000	0.011	0.011
43734	TOWN EASTON-02375PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Nov-13	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA	59134	0.000	0.812	0.000	0.812	0.812
43735	28 HASTINGS-01756PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Nov-13	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.030	0.000	0.030	0.030
43736	SMITH COLLEGE-01060NG3500QF		No Resource (1)	IC	NG		GAS INTERNAL COMBUSTION	22-Nov-13	Massachusetts Electric Company	MEC	MA	15	WMA	WCMA	58166	0.134	0.000	0.134	0.000	0.000
43747	PARSONS GRP-01581PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Dec-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.027	0.000	0.027	0.027
43748	ACUMEN-01752PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Dec-13	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.033	0.000	0.033	0.033
43749	WILVECO-01821PV62NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Dec-13	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.002	0.000	0.002	0.002
43750	CANTON HIGH SCHOOL 2009		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Dec-13	NSTAR Electric Company	NSTAR	MA	21	SEMA	SEMA		0.000	0.200	0.000	0.200	0.200
43751	EAGLE LEASE-01540PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Dec-13	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.016	0.000	0.016	0.016
43752	EXTRA SPACE-01607PV91.2NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Dec-13	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.029	0.000	0.029	0.029
43762	FORBES STREET 1-02914PV3000DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Dec-13	The Narragansett Electric Company	NEC	RI	07	RI	RI	58583	0.012	1.449	0.012	1.449	1.449
43766	EXTRA SPACE-02149PV237NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Dec-13	Massachusetts Electric Company	MEC	MA	17	BOSTON	NEMA		0.000	0.029	0.000	0.029	0.029
43840	SOLVENTERRA-01089PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jan-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.019	0.479	0.019	0.479	0.479
43841	FLAIR ONE-01507PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jan-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.010	0.366	0.010	0.366	0.366
43842	FORRESTALL-01507PV950NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jan-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.009	0.342	0.009	0.342	0.342
43869	FRPV WEST-02720PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Jan-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.025	0.508	0.025	0.508	0.508
43870	FRPV EAST-02720PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Jan-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.030	0.506	0.030	0.506	0.506
43871	SYNAGRO-02886CHP2000QF		No Resource (1)	ST	NG		GAS STEAM	07-Jan-14	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.094	0.000	0.094	0.000	0.000
43874	MASS MOCA1-01247PV225NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Jan-14	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.000	0.000	0.000	0.000	0.000
43875	CUMMINGS PROP-01915PV230NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	09-Jan-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.073	0.000	0.073	0.073
43876	KENNEDY CARPET-02189PV95NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Jan-14	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.025	0.000	0.025	0.025
43878	MCI WORLD COMM-01821PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Jan-14	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.000	0.000	0.000	0.000
43884	MASS MOCA3 01247PV177NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-14	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.049	0.000	0.049	0.000	0.049
43885	NM-HP HOOD AND SONS		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Feb-14	Western Massachusetts Electric Company	WMECO	MA	13	WMA	WCMA		0.038	0.702	0.038	0.702	0.702
43886	NM-FRANKLIN COUNTY SHERIFF		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Feb-14	Western Massachusetts Electric Company	WMECO	MA	11	WMA	WCMA		0.037	0.617	0.037	0.617	0.617
43887	NM-TOWN OF AGAWAM SOLAR		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Feb-14	Western Massachusetts Electric Company	WMECO	MA	13	WMA	WCMA		0.062	0.739	0.062	0.739	0.739
43892	SYNCARPHA SOLAR-01740PV495NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Jan-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.201	2.516	0.201	2.516	2.516
43893	HUBBARDSTON-01432PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Jan-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.087	1.015	0.087	1.015	1.015
43903	SUNGEN-02720PV2850NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.160	1.748	0.160	1.748	1.748
43904	CITY OF METHUEN-01523PV3000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.176	1.550	0.176	1.550	1.550
43907	PALMER SOLAR-01069PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Feb-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.092	0.917	0.092	0.917	0.917
43908	NEXTSUN ENERGY-02370PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Feb-14	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.076	0.844	0.076	0.844	0.844
43915	CITIZENS-02769PV200NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Feb-14	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.127	1.093	0.127	1.093	1.093
43916	TOWN OF ADAMS-01220PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Feb-14	Massachusetts Electric Company	MEC	MA	03	WMA	WCMA		0.055	0.434	0.055	0.434	0.434
43917	CHEER PACK-02397PV1750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-14	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.195	0.000	0.195	0.195
43918	CITY OF LOWELL-01851PV1333NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-14	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.050	0.615	0.050	0.615	0.615
43919	SOLVENTERRA 1-01535PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.034	0.515	0.034	0.515	0.515
43920	SOLVENTERRA 2-01535PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	14-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.039	0.519	0.039	0.519	0.519
43921	COXCOM-02893PV135DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Feb-14	The Narragansett Electric Company	NEC	RI	03	RI	RI		0.009	0.072	0.009	0.072	0.072
43922	SOLVENTERRA 4-01083PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.062	0.552	0.062	0.552	0.552
43923	PLYMOUTH PUBLIC SCHOOLS-#2062		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.278	2.284	0.278	2.284	2.284
43924	TOWN OF DARTMOUTH #1777		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.059	0.575	0.059	0.575	0.575
43927	SOUTHERN SKY-CARVER #1 (1997)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.067	0.509	0.067	0.509	0.509
43928	SOUTHERN SKY-CARVER #2 (1998)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.075	0.502	0.075	0.502	0.502
43929	SOUTHERN SKY-CARVER #4 (2000)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.069	0.478	0.069	0.478	0.478
43930	SOUTHERN SKY-CARVER #5 (2001)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.079	0.504	0.079	0.504	0.504
43932	SOUTHERN SKY-CARVER #3 (1999)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	13-Feb-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA		0.071	0.464	0.071	0.464	0.464
43936	SOLVENTERRA 1-01083PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.039	0.536	0.039	0.536	0.536
43937	SOLVENTERRA 2-01083PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.060	0.537	0.060	0.537	0.537
43938	SOLVENTERRA 3-01083PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.062	0.552	0.062	0.552	0.552
43948	SUNGEN 1-01810PV950NM		No

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Contains Proprietary Material
Do Not Distribute

ASSET ID	ASSET NAME	RE SOURCE ID	RESOURCE NAME	GEN TYPE ID	PRIM FUEL TYPE	ALT FUEL TYPE	FUEL GEN TYPE DESC	IN-SERVICE DATE (ACTUAL OR EXPECTED)	LEAD PARTICIPANT NAME	LEAD PARTIC. PANT ACRONYM	STATE	FIPS COUNTY	RSP AREA	LOAD ZONE NAME	EIA PLANT NUMBER	As of Jan. 1, 2015		As of 2014/15 Winter and 2015 Summer Peaks		Change in Summer SCC from 8/1/14
																WINTER SCC (MW)	SUMMER SCC (MW)	WINTER PEAK SCC JAN 5, 2015	EXPECTED SUMMER PEAK SCC AUG 1, 2015	
46210	NEXAMP-01475PV1900NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Apr-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.246	0.887	0.246	0.887	0.887
46211	GIGUERE-01524PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Apr-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.006	0.000	0.006	0.006
46212	BODWELL REALTY-02322PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Apr-14	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
46213	PINGREE SCHOOL-01982PV85NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	21-Apr-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.026	0.000	0.026	0.026
46220	BERKELEY-01844PV200NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Apr-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.263	0.921	0.263	0.921	0.921
46221	JP SULLIVAN-01432PV90NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Apr-14	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.025	0.000	0.025	0.025
46267	COTTAGE STREET SOLAR FACILITY		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-May-14	Western Massachusetts Electric Company	WMECO	MA	19	WMA	WCMA	58568	0.000	1.635	0.000	1.635	1.635
46268	OLD TIME SPORTS-01952PV150NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	08-May-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.031	0.000	0.031	0.031
46294	LAWRENCE 1-01840PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-May-14	Massachusetts Electric Company	MEC	MA	09	CMA/NEMA	WCMA		0.000	0.032	0.000	0.032	0.032
46295	LAWRENCE 2-01840PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-May-14	Massachusetts Electric Company	MEC	MA	09	CMA/NEMA	WCMA		0.000	0.034	0.000	0.034	0.034
46479	CANTON_MIDDLE_SCHOOL_2013		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-May-14	NSTAR Electric Company	NSTAR	MA	21	SEMA	SEMA		0.000	0.138	0.000	0.138	0.138
46480	CEDAR_SOLAR1_2411		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-May-14	NSTAR Electric Company	NSTAR	MA	25	BOSTON	NEMA		0.000	0.039	0.000	0.039	0.039
46481	TOWN_OF_MARSHFIELD_1865		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-May-14	NSTAR Electric Company	NSTAR	MA	23	SEMA	SEMA	58410	0.000	1.716	0.000	1.716	1.716
46482	NEWBEDFORD_DPI_1843_1844		No Resource (1)	PV	SUN		PHOTOVOLTAIC	23-May-14	NSTAR Electric Company	NSTAR	MA	05	SEMA	SEMA		0.000	1.676	0.000	1.676	1.676
46483	MILFORD INDUSTRIAL-0175PV82NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-May-14	Massachusetts Electric Company	MEC	MA	09	RI	SEMA		0.000	0.030	0.000	0.030	0.030
46484	WORCESTER SCHL-01602PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-May-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.000	0.000
46485	NPP DEVELOPMENT-02035PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-May-14	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.030	0.000	0.030	0.030
46486	WB HUNT-02176PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jun-14	Massachusetts Electric Company	MEC	MA	17	BOSTON	NEMA		0.000	0.000	0.000	0.000	0.000
46487	CIDER HILL-01913PV78NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jun-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.030	0.000	0.030	0.030
46537	CUMMINGS-01911PV82NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Jun-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.023	0.000	0.023	0.023
46538	SILVIA-02720PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Jun-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.000	0.000
46539	BCC SEA QALIBC-01854PV66NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Jun-14	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.026	0.000	0.026	0.026
46540	NPP DEVELOPMENT-02035PV62NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Jun-14	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.018	0.000	0.018	0.018
46541	TEKNOR APEX-02703PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	11-Jun-14	Massachusetts Electric Company	MEC	MA	23	RI	SEMA		0.000	0.000	0.000	0.000	0.000
46564	EPG SOLAR-01009PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Jun-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.832	0.000	0.832	0.832
46565	CABOT BEVERLY-01915PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	25-Jun-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA	59242	0.000	1.205	0.000	1.205	1.205
46566	PRECISE PACKAGING-02720PV250NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.082	0.000	0.082	0.082
46567	NORTH BROOKFIELD-01535PV3000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	1.402	0.000	1.402	1.402
46568	GLC-MA SOLAR-01440PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.392	0.000	0.392	0.392
46569	NUGEN NCMC (PV)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.223	0.000	0.223	0.223
46570	NUGEN LUN (PV)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	01-Jul-14	Fitchburg Gas & Electric Light Company	FGE	MA	27	WMA	WCMA		0.000	0.860	0.000	0.860	0.860
46607	HARVARD SOLAR-01451PV260NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Jul-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.115	0.000	0.115	0.115
46636	GOOSE RIVER HYDRO, INC.		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Aug-14	Goose River Hydro, Inc.	GOOSE	ME	27	ME	ME		0.000	0.037	0.000	0.037	0.037
46641	205 STURBRIDGE-01010PV3000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.000	0.943	0.000	0.943	0.943
46643	EPG SOLAR-01005PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.678	0.000	0.678	0.678
46644	UGT RENEW ENERGY-01540PV2750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Aug-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	1.348	0.000	1.348	1.348
46645	NEXAMP CAPITAL-01007PV1300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Aug-14	Massachusetts Electric Company	MEC	MA	15	WMA	WCMA		0.000	0.595	0.000	0.595	0.595
46646	SOLTAS ENERGY-01010PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Aug-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.000	1.642	0.000	1.642	1.642
46647	BLUEWAVE CAPITAL-02769PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	07-Aug-14	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.000	0.368	0.000	0.368	0.368
46653	WESTBORO SOLAR-01581PV1820NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Aug-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA	59368	0.000	0.054	0.000	0.054	0.054
46657	INDIAN HILL-01069PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Aug-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA	59362	0.000	0.477	0.000	0.477	0.477
46659	BROWN SOLAR-01069PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Aug-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA	59361	0.000	0.325	0.000	0.325	0.325
46660	STATE SOLAR-01069PV1000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Aug-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.000	0.462	0.000	0.462	0.462
46662	DISTRIBUTOR CORP-02148PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-14	Massachusetts Electric Company	MEC	MA	17	BOSTON	NEMA		0.000	0.000	0.000	0.120	0.120
46663	CITY OF LAWRENCE-01841PV300NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-14	Massachusetts Electric Company	MEC	MA	09	CMA/NEMA	WCMA		0.000	0.000	0.000	0.120	0.120
46664	NEXAMP CAPITAL-01543PV4099NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	03-Sep-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	2.000	2.000
46665	SX INDUSTRIES-02072PV170NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Sep-14	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.000	0.000	0.068	0.068
46666	CUMMINGS-01915PV224NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Sep-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.090	0.090
46667	E NAZARENE-02170PV85NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	05-Sep-14	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.000	0.000	0.034	0.034
46691	CORNERSTONE-01057PV3000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Sep-14	Massachusetts Electric Company	MEC	MA	13	WMA	WCMA		0.000	0.000	0.000	1.200	1.200
46717	EAST BAY-02915PV70NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Sep-14	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.028	0.028
46718	EXTRA SPACE-02151PV144.3NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Sep-14	Massachusetts Electric Company	MEC	MA	25	BOSTON	NEMA		0.000	0.000	0.000	0.058	0.058
46719	STONEHILL COLL-02356PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Sep-14	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.800	0.800
46721	ALL AMERICAN-02852PV250DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	24-Sep-14	The Narragansett Electric Company	NEC	RI	09	RI	RI		0.000	0.000	0.000	0.100	0.100
46733	BILLERICA-01821PV4999NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Sep-14	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.000	0.000	2.000	2.000
46732	PIONEER SOLAR-01453PV495NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Sep-14	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.198	0.198
46733	TKS SOLAR-02301PV180NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	26-Sep-14	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.000	0.000	0.072	0.072
46911	NEXTSUN ENERGY-02896PV850DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	04-Dec-14	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.340	0.340
46913	WOONSOCKET-02895PV190DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Dec-14	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.076	0.076
46914	BILLERICA-01523PV2499NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Dec-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	1.000	1.000
46915	NEXAMP-01844PV2000NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Dec-14	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.800	0.800
46916	PHILLIPS-01810PV495NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Dec-14	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.198	0.198
46917	NEWPORT VINEYARDS-02882PV50DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Dec-14	The Narragansett Electric Company	NEC	RI	05	SEMA	RI		0.000	0.000	0.000	0.029	0.029
46918	TOWN OF WESTFORD-01452PV2800NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Dec-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	1.120	1.120
46924	BILLERICA-01523PV2500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	15-Dec-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	1.000	1.000
46925	GLC-MA SOLAR-01440PV1980NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Dec-14	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.792	0.792
46926	STILLWATER-02917PV56DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	17-Dec-14	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.022	0.022
46947	AMERIPRIDE-01607PV225NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.090	0.090
46948	MILFORD IND-01757PV170NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Jan-15	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.000	0.000	0.068	0.068
46949	NEW SALEM-01452PV675NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Jan-15	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.270	0.270
46952	TOWN OF WENDELL-01876PV260NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-15	Massachusetts Electric Company	MEC	MA	17	BOSTON	WCMA		0.000	0.000	0.000	0.104	0.104
46953	MACHINE INC-02072PV75NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-15	Massachusetts Electric Company	MEC	MA	21	SEMA	SEMA		0.000	0.000	0.000	0.030	0.030
46954	PROTECTOWIRE-02359PV70NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	16-Jan-15	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.000	0.000	0.028	0.028
46955	MASS FISHERIES-01581PV251NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.100	0.100
46982	GLOBAL LIQUORS-02720PV85NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	28-Jan-15	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.034	0.034
46984	FIVEMILE RIVER1-01503PV750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.300	0.300
46985	FIVEMILE RIVER2-01503PV750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.300	0.300
46986	FIVEMILE RIVER3-01503PV750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.300	0.300
46987	FIVEMILE RIVER4-01503PV750NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	29-Jan-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.300	0.300
46992	RIN LOGISTICS-02720PV1500NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Feb-15	Massachusetts Electric Company	MEC	MA	05	SEMA	SEMA		0.000	0.000	0.000	0.600	0.600
46993	PARAGON HOLDINGS-01740PV995NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Feb-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.398	0.398
46997	BOLTONVILLE HYDRO		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	01-Feb-15	Green Mountain Power Corporation	GMP	VT	17	VT	VT	50539	0.000	0.000	0.000	0.527	0.527
46998	STEERE ELECTRIC-02814PV72DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Feb-15	The Narragansett Electric Company	NEC	RI	07	RI	RI		0.000	0.000	0.000	0.029	0.029
47002	ONE KENWOOD-02038PV266NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-15	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.000	0.000	0.106	0.106
47003	S SHORE MILLWORK-02766PV648NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-15	Massachusetts Electric Company	MEC	MA	05	RI	SEMA		0.000	0.000	0.000	0.259	0.259
47004	IRON MOUNTAIN-01532PV760NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	10-Feb-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.304	0.304
47007	FRANKLIN FORD-02038PV140NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-15	Massachusetts Electric Company	MEC	MA	21	RI	SEMA		0.000	0.000	0.000	0.056	0.056
47008	MCGEE TOYOTA-02339PV85NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	12-Feb-15	Massachusetts Electric Company	MEC	MA	23	RI	SEMA		0.000	0.000	0.000	0.034	0.034
47020	NEXAMP-02898PV499DG		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Feb-15	The Narragansett Electric Company	NEC	RI	09	RI	RI		0.000	0.000	0.000	0.200	0.200
47032	ABINGTON TARGET-02351PV418NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Feb-15	Massachusetts Electric Company	MEC	MA	23	SEMA	SEMA		0.000	0.000	0.000	0.167	0.167
47033	HANOVER TARGET-02338PV441NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Feb-15	Massachusetts Electric Company	MEC	MA	23	RI	SEMA		0.000	0.000	0.000	0.176	0.176
47034	MARLBORO TARGET-01752PV441NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	27-Feb-15	Massachusetts Electric Company	MEC	MA	17	CMA/NEMA	WCMA		0.000	0.000	0.000	0.176	0.176
47035	MILFORD TARGET-01757PV302NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Mar-15	Massachusetts Electric Company	MEC	MA	27	RI	SEMA		0.000	0.000	0.000	0.121	0.121
47036	NORTHBORO WALMART-01532PV368NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Mar-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.147	0.147
47037	LYNN WALMART-01905PV232NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	02-Mar-15	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.093	0.093
47040	BOOTHBAY ENERGY STORAGE		No Resource (1)	OT	OTR		MISC. OTHER	09-Mar-15	Convergent Energy and Power LLC	CONV	ME	15	ME	ME		0.000	0.000	0.000	0.483	0.483
47060	HANNAFORD FOOD-01535PV120NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Mar-15	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.048	0.048
47061	WHITTIER FARMS-01590PV114NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Mar-15	Massachusetts Electric Company	MEC	MA	27	CMA/NEMA	WCMA		0.000	0.000	0.000	0.046	0.046
47062	EASTERN BANK-01901PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	18-Mar-15	Massachusetts Electric Company	MEC	MA	09	BOSTON	NEMA		0.000	0.000	0.000	0.040	0.040
47063	SWISS TURN-01540PV100NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Mar-15	Massachusetts Electric Company	MEC	MA	27	WMA	WCMA		0.000	0.000	0.000	0.040	0.040
47064	1ST CONGREGATION-02176PV90NM		No Resource (1)	PV	SUN		PHOTOVOLTAIC	20-Mar-15	Massachusetts Electric Company	MEC	MA	17	BOSTON	NEMA		0.000	0.000	0.000	0.036	0.036
47065	210 UPHAM (PV)		No Resource (1)	PV	SUN		PHOTOVOLTAIC	19-Mar-15	Fitchburg Gas and Electric Lig	FGE	MA	27	WMA	WCMA		0.000	0.000	0.000	0.029	0.029
47066	S.D. WARREN SACCARAPPA HYDRO		No Resource (1)	HDR	WAT		HYDRO (DAILY CYCLE - RUN OF RIVER)	20-Mar-15	NextEra Energy Power Marketing, LLC	FPLP	ME	05	SME	ME		0.000	0.000	0.000	0.540	0.540
46976	BUCKSPORT G3		No Resource (1)	ST	WDS		BIO/REFUSE	16-Apr-15	. Tenaska Power Services Company	TPS	ME	09	BHE	ME	50243	0.000	0.000	0.000	73.000	73.000
	Forecasted Photovoltaic Capacity			PV	SUN		PHOTOVOLTAIC	01-Jul-15								0.000	0.000	0.000	8.248	8.248
															Total	32.647	30.494	32.647	30.749	677
															CT			5,333	5,163	(43)
															NOR			192	170	2
															SWCT			2,536	2,320	561

NOTES:

Appendix A - defines the codes used.

Generator details, including Lead Market Participant, as of January 1, 2015.

Additional information and changes to generating asset Lead Participant since January 1, 2015 may be found in the Endnotes following Section 2.1.

The Expected Summer Peak SCC is based on the April 2015 SCC Report and capacity that is expected to be added by August 1st based on the interconnection queue and information provided to ISO-NE by the lead participants. In this table, new capacity consists of one new 73 MW generator and uprates to Manchester Station, Bridgeport Energy, Granite Ridge Energy, and EP Newington Energy totaling approximately 147 MW.

New PV resources that do not yet have an SCC value due to a lack of historical generation data have an assumed SCC of 40 percent of nameplate.

Based on the PV forecast, approximately 8 MW of additional capacity is expected to go commercial by July 1, 2015. See Sec. 3.1.2, "PV in Markets" category for more details on the forecast.

When an alternate fuel is listed, the unit may not necessarily be fully operable on both fuels.

FOOTNOTES:

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Table 3-5
Local Operating Reserve Requirements
Summer 2014 and Winter 2014/2015 Forward Reserve Auctions (MW)

Location Name	Product	Summer 2013	Winter 2013/2014	Summer 2014	Winter 2014/2015
CT	TMOR[a]	747	578	900	363
NEMA/Boston	TMOR[a]	0	0	0	0
SWCT	TMOR[a]	0	155	94	87
Systemwide	TMNSR	1,349	1,532	1,573	1,562
Systemwide	TMOR[a]	723	915	891	831

(a) TMNSR also can be used to satisfy this requirement.

http://www.iso-ne.com/static-assets/documents/2015/05/2014-amr.pdf
http://www.iso-ne.com/static-assets/documents/2016/05/2015_imm_amr_final_5_25_2016.pdf
ISO-NE 2014 Annual Markets Report
ISO-NE 2015 Annual Markets Report

	Winter	Spring	Summer	Fall
ISO-NE	1562	1436	1310	1436
CT	363	538.5	714	538.5
SWCT	87	112.5	138	112.5

Spring, Fall = average of Winter, Summer

Operating Reserves: The bulk power system needs reserve capacity to be able to respond to contingencies, such as those caused by unexpected outages. Operating reserves are provided by the unloaded capacity of generating resources, either online or offline, which can deliver energy within 10 or 30 minutes. The ISO procures both system-wide reserve, and local reserve for import-constrained areas. The system reserve requirement has been relatively constant over the past three years, with a total ten-minute reserve requirement of about 1,700MW and total thirty-minute reserve requirement of about 2,500MW in 2015.

Per ISO-NE ISO New England's Internal Market Monitor 2015 Annual Markets Report Note above, the 2014-2015 reserves are assumed to be the same as the 2013-2014 Reserves.

The TMNSR and TMOR requirements are based on first- and second-contingency losses (refer to Sections 2.1.4 and 2.2.1). The methodology to calculate these requirements is described in OP 8 (Section 2.2.1) and the ISO New England Manual for Forward Reserve (Manual M-36) (December 3, 2013), http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

The Forward Reserve requirements for the New England Control Area are based on expected system operating conditions. The TMNSR purchase amount represents the expected single contingency of the HQ Phase II Interconnection, including a TMNSR bias of 63%. The TMNSR purchase amount is increased to reflect a 20% average fleet-wide historical non-performance of resources called upon after a contingency.[1] The TMOR purchase amount represents the expected single contingency of Seabrook. The Replacement Reserve will be equal to 160 MW.

Forward Reserve Requirements

Reserve Zone	Reserve Category	Local 2nd Contingency MW	External Reserve Support MW	Reserve Requirement MW
New England Control Area	TMNSR	N/A	N/A	1310
New England Control Area	TMOR	N/A	N/A	785
SWCT	TMOR	503	365	138
CT	TMOR	1213	499	714
NEMA/Boston	TMOR	880	549	331

The New England Control Area Forward Reserve Requirements are based on a 1st contingency of 1,664 MW and a 2nd contingency of 1,249 MW.

https://www.iso-ne.com/static-assets/documents/2015/03/forward_reserve_auction_assumptions_summer_2015.docx

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FERC Form 714 Outages

Month	Planned Outage and Derating (MW)
Dec-14	2,033
Jan15	160
Feb15	1,187
Mar15	2,362
Apr15	4,595
May15	2,746
Jun15	627
Jul15	80
Aug15	0
Sep15	482
Oct15	6,598
Nov15	1,801

	Planned Outage and Derating (MW)				
	Winter	Spring	Summer	Fall	Notes
ISO-NE	1,127	3,234	236	2,960	NYISO outages
CT	260	747	55	683	Estimated based on generation ratios

	Generation (MW)			
	Winter	Spring	Summer	Fall
ISO-NE	35,576	35,576	33,424	35,576
CT	8,213	8,213	7,789	8,213

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Needle Peak	24,437
Peak Month	7
PST	19,621
Winter	18,391
Spring	15,604
Summer	18,719
Fall	16,307

Source: ISO-NE

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	17,146	12/1/2014	10,753	10,347	10,184	10,211	10,595	11,749	13,695	14,747	14,901	14,876	14,968	14,940	14,880	14,917	14,890	15,129	16,299	17,146	17,055	16,653	16,038	14,961	13,562	12,334
Winter	12	18,415	12/2/2014	11,554	11,158	11,002	11,048	11,468	12,683	14,792	15,870	16,092	16,135	16,194	16,156	16,133	16,233	16,254	16,551	17,736	18,415	18,275	17,865	17,174	15,998	14,422	13,024
Winter	12	17,801	12/3/2014	12,145	11,634	11,401	11,366	11,702	12,775	14,690	15,788	16,039	16,127	16,214	16,229	16,100	16,041	15,967	16,233	17,236	17,801	17,579	17,106	16,462	15,373	13,948	12,668
Winter	12	18,125	12/4/2014	11,869	11,434	11,271	11,311	11,703	12,905	15,005	15,959	15,966	15,847	15,736	15,586	15,404	15,401	15,440	15,752	17,062	18,114	18,125	17,776	17,277	16,131	14,708	13,434
Winter	12	17,857	12/5/2014	12,626	12,189	11,996	12,034	12,438	13,615	15,658	16,657	16,667	16,481	16,328	16,084	15,910	15,930	15,962	16,215	17,364	17,857	17,501	16,969	16,410	15,595	14,406	13,143
Winter	12	16,745	12/6/2014	12,198	11,647	11,305	11,147	11,190	11,592	12,392	13,274	14,339	15,108	15,486	15,575	15,504	15,286	15,172	15,318	16,291	16,745	16,436	15,905	15,375	14,652	13,678	12,620
Winter	12	18,005	12/7/2014	11,795	11,311	11,036	10,952	11,048	11,387	12,054	12,830	13,838	14,534	14,789	14,782	14,712	14,625	14,627	15,043	16,641	17,925	18,005	17,743	17,262	16,268	15,051	13,882
Winter	12	19,843	12/8/2014	12,989	12,586	12,469	12,522	12,986	14,175	16,312	17,492	17,745	17,844	17,984	17,949	17,849	17,801	17,734	17,992	19,134	19,843	19,640	19,189	18,476	17,231	15,564	14,085
Winter	12	19,049	12/9/2014	13,146	12,609	12,312	12,237	12,546	13,615	15,416	16,646	17,066	17,309	17,500	17,597	17,536	17,566	17,493	17,643	18,501	19,049	18,712	18,081	17,196	15,912	14,309	12,952
Winter	12	18,372	12/10/2014	12,049	11,557	11,334	11,312	11,648	12,760	14,719	15,930	16,176	16,330	16,253	16,536	16,537	16,528	16,310	16,561	17,627	18,372	18,217	17,763	17,083	15,941	14,420	12,995
Winter	12	18,636	12/11/2014	12,114	11,611	11,410	11,429	11,776	12,907	14,915	16,078	16,313	16,421	16,519	16,547	16,485	16,465	16,440	16,630	17,789	18,636	18,488	18,094	17,502	16,439	14,903	13,479
Winter	12	18,208	12/12/2014	12,576	12,097	11,875	11,859	12,229	13,362	15,330	16,421	16,594	16,517	16,441	16,328	16,149	16,093	16,091	16,362	17,500	18,208	17,919	17,442	16,861	16,021	14,857	13,600
Winter	12	17,064	12/13/2014	12,601	12,035	11,759	11,680	11,802	12,271	13,105	13,975	14,895	15,361	15,436	15,299	15,026	14,729	14,620	14,901	16,197	17,064	16,849	16,403	15,944	15,280	14,328	13,214
Winter	12	17,219	12/14/2014	12,304	11,741	11,444	11,334	11,390	11,714	12,322	13,006	13,873	14,417	14,556	14,513	14,465	14,339	14,317	14,616	16,076	17,219	17,178	16,861	16,325	15,311	13,968	12,719
Winter	12	18,367	12/15/2014	11,906	11,504	11,355	11,405	11,864	13,101	15,196	16,278	16,300	16,147	16,009	15,830	15,609	15,526	15,447	15,701	17,093	18,362	18,367	17,998	17,383	16,238	14,684	13,283
Winter	12	18,485	12/16/2014	12,358	11,882	11,667	11,660	12,032	13,183	15,241	16,373	16,554	16,604	16,656	16,629	16,478	16,465	16,384	16,634	17,773	18,485	18,303	17,836	17,172	16,013	14,447	12,957
Winter	12	17,878	12/17/2014	11,949	11,436	11,177	11,157	11,486	12,598	14,570	15,783	15,971	15,978	15,976	15,891	15,703	15,653	15,561	15,779	17,025	17,878	17,735	17,340	16,773	15,725	14,231	12,792
Winter	12	18,215	12/18/2014	11,828	11,322	11,102	11,115	11,491	12,684	14,765	15,931	16,092	16,033	15,955	15,924	15,805	15,798	15,737	16,008	17,289	18,215	18,128	17,740	17,208	16,194	14,732	13,275
Winter	12	18,279	12/19/2014	12,343	11,835	11,589	11,569	11,926	13,038	15,030	16,198	16,436	16,531	16,574	16,474	16,258	16,172	16,068	16,287	17,435	18,279	18,065	17,617	17,097	16,293	15,148	13,854
Winter	12	17,569	12/20/2014	12,873	12,324	12,049	11,940	12,060	12,518	13,366	14,320	15,277	15,819	15,985	15,936	15,785	15,603	15,558	15,825	16,932	17,569	17,317	16,837	16,386	15,701	14,695	13,535
Winter	12	17,728	12/21/2014	12,599	11,983	11,676	11,553	11,604	11,922	12,537	13,345	14,371	15,130	15,504	15,650	15,678	15,579	15,534	15,665	16,930	17,728	17,616	17,262	16,711	15,763	14,411	13,109
Winter	12	18,112	12/22/2014	12,199	11,709	11,504	11,503	11,887	12,971	14,837	16,013	16,338	16,364	16,298	16,201	16,035	15,934	15,859	16,080	17,266	18,112	17,994	17,581	16,988	15,964	14,538	13,054
Winter	12	17,711	12/23/2014	12,016	11,426	11,119	11,071	11,400	12,420	14,219	15,510	15,915	16,108	16,218	16,211	16,071	16,010	15,939	16,104	17,106	17,711	17,492	17,048	16,485	15,572	14,232	12,854
Winter	12	16,368	12/24/2014	11,739	11,087	10,746	10,620	10,830	11,575	12,863	14,090	14,956	15,597	15,962	16,011	15,808	15,703	15,667	15,738	16,355	16,368	15,510	14,727	14,238	13,736	13,027	12,105
Winter	12	14,122	12/25/2014	11,160	10,508	10,090	9,896	9,919	10,227	10,811	11,641	12,613	13,374	13,657	13,648	13,374	13,103	12,832	12,755	13,465	14,122	14,047	13,912	13,754	13,324	12,520	11,584
Winter	12	16,379	12/26/2014	10,857	10,411	10,209	10,195	10,453	11,121	12,135	12,929	13,608	14,085	14,327	14,348	14,166	13,954	13,870	14,057	15,221	16,379	16,203	15,790	15,325	14,577	13,535	12,453
Winter	12	15,621	12/27/2014	11,599	11,117	10,840	10,741	10,854	11,222	11,884	12,537	13,296	13,786	13,954	13,875	13,642	13,333	13,168	13,340	14,530	15,621	15,524	15,140	14,737	14,073	13,084	12,052
Winter	12	16,107	12/28/2014	11,188	10,641	10,320	10,166	10,208	10,497	10,977	11,615	12,464	13,284	13,774	13,997	14,073	13,980	13,834	13,974	15,207	16,107	15,994	15,552	15,010	14,229	13,108	12,076
Winter	12	17,910	12/29/2014	11,316	10,879	10,753	10,821	11,226	12,173	13,628	14,689	15,295	15,522	15,550	15,565	15,479	15,418	15,396	15,605	16,763	17,910	17,796	17,338	16,776	15,830	14,543	13,328
Winter	12	18,734	12/30/2014	12,533	12,093	11,928	11,934	12,275	13,216	14,644	15,731	16,298	16,607	16,721	16,585	16,362	16,253	16,187	16,396	17,531	18,734	18,622	18,209	17,662	16,734	15,445	14,229
Winter	12	18,443	12/31/2014	13,381	12,892	12,677	12,660	12,955	13,800	15,097	16,101	16,713	16,902	16,889	16,747	16,540	16,347	16,208	16,291	17,356	18,443	18,037	17,255	16,548	15,844	15,062	14,362
Winter	1	17,326	1/1/2015	13,662	13,069	12,645	12,425	12,454	12,774	13,247	13,537	13,966	14,429	14,771	14,887	14,869	14,796	14,714	14,949	16,151	17,326	17,155	16,688	16,134	15,328	14,227	13,154
Winter	1	17,673	1/2/2015	12,361	11,854	11,618	11,615	11,881	12,616	13,763	14,673	15,267	15,608	15,761	15,808	15,699	15,541	15,407	15,522	16,575	17,673	17,421	16,934	16,394	15,599	14,537	13,486
Winter	1	17,710	1/3/2015	12,648	12,187	11,933	11,864	11,987	12,386	13,125	13,857	14,644	15,217	15,538	15,728	15,731	15,680	15,729	15,958	16,976	17,710	17,486	16,958	16,342	15,468	14,387	13,283
Winter	1	17,000	1/4/2015	12,363	11,763	11,404	11,245	11,217	11,431	11,916	12,527	13,337	14,193	14,805	15,202	15,425	15,448	15,358	15,475	16,379	17,000	16,695	16,058	15,372	14,210	12,960	11,863
Winter	1	19,224	1/5/2015	11,133	10,791	10,672	10,747	11,208	12,419	14,504	15,627	15,772	15,875	16,000	16,031	16,015	16,092	16,146	16,518	17,717	19,163	19,224	18,867	18,277	17,163	15,747	14,529
Winter	1	20,011	1/6/2015	13,743	13,368	13,240	13,287	13,664	14,793	16,749	17,910	18,047	18,216	18,382	18,401	18,273	18,167	18,017	18,100	18,994	20,011	19,956	19,554	18,877	17,745	16,270	15,010
Winter	1	20,439	1/7/2015	14,233	13,824	13,645	13,639	13,951	14,981	16,931	18,016	18,072	17,921	17,812	17,718	17,661	17,670	17,688	17,977	19,062	20,293	20,439	20,159	19,706	18,690	17,348	16,129
Winter	1	20,583	1/8/2015	15,415	15,090	14,955	15,016	15,420	16,446	18,253	19,413	19,647	19,556	19,397	19,188	18,833	18,625	18,406	18,503	19,468	20,583	20,543	20,143	19,473	18,317	16,786	15,442
Winter	1	19,111	1/9/2015	14,646	14,193	13,965	13,884	14,130	15,059	16,816	17,946	18,121	18,341	18,505	18,371	17,933	17,611	17,337	17,315	18,075	19,111	18,928	18,454	17,883	17,046	15,974	14,835
Winter	1	18,376	1/10/2015	14,041	13,582	13,357	13,329	13,486	13,961	14,795	15,640	16,418	16,866	16,959	16,804	16,510	16,330	16,223	16,435	17,363	18,376	18,367	17,899	17,615	16,966	15,998	15,000
Winter	1	18,668	1/11/2015	14,251	13,793	13,576	13,503	13,566	13,862	14,417	15,005	15,779	16,335	16,531	16,660	16,709	16,648	16,626	16,758	17,631	18,668	18,479	17,874	17,154	16,019	14,714	13,568
Winter	1	18,797	1/12/2015	12,794	12,367	12,182	12,231	12,581	13,691	15,497	16,608	16,879	17,130	17,379	17,497	17,486	17,382	17,203	17,233	18,006	18,797	18,577	17,993	17,218	16,036	14,658	13,466
Winter	1	19,614	1/13/2015	12,713	12,310	12,193	12,271	12,718	13,961	16,079	17,241	17,367	17,344	17,323	17,202	17,024	16,993	16,918	17,116	18,103	19,521	19,614	19,307	18,749	17,693	16,314	15,118
Winter	1	19,803	1/14/2015	14,387	14,054	13,938	13,980	14,346	15,423	17,404	18,536	18,656	18,717	18,783	18,699	18,513	18,364	18,171	18,212	18,930	19,803	19,682	19,213	18,524	17,344	15,887	14,612
Winter	1	19,000	1/15/2015	13,803	13,386	13,202	13,205	13,536	14,640	16,591	17,632	17,701	17,707	17,714	17,615	17,413	17,286	17,137	17,174	17,909	19,000	18,942	18,513	17,895	16,845	15,468	14,276
Winter	1	18,650	1/16/2015	13,506	13,164	12,967	12,969	13,316	14,361	16,251	17,227	17,363	17,201	16,969	16,725	16,603	16,636	16,574	16,676	17,469	18,650	18,606	18,219	17,740	16,981	15,968	14,915
Winter	1	18,122	1/17/2015	14,177	13,768	13,600	13,563	13,722	14,237	15,068	15,914	16,726	17,093	17,123	16,893	16,538	16,140	15,898	16,025	16,857	18,122	18,049	17,574	17,054	16,282	15,290	14,289
Winter	1	17,072	1/18/2015	13,515	13,023	12,703	12,554	12,565	12,806	13,277	13,843	14,658	15,353	15,769	15,977	15,990	15,921	15,863	15,904	16,479	17,072	16,675	15,929	15,308	14,502	13,585	12,511
Winter	1	18,025	1/19/2015	11,740	11,321	11,140	11,194	11,509	12,388	13,680	14,651	15,294	15,720	16,054	16,174	16,112	16,028	15,943	16,071	16,794	18,025	17,933	17,443	16,746	15,639	14,306	13,149
Winter	1	18,339	1/20/2015	12,454	12,065	11,892	11,918	12,313	13,466	15,457	16,477	16,467	16,363	16,255	16,088	15,915	15,836	15,813	15,999	16,864	18,261	18,339	17,917	17,294	16,174	14,833	13,644
Winter	1	18,521	1/21/2015	12,944	12,590	12,449	12,513	12,954	14,161	16,230	17,295	17,197	16,967	16,836	16,731	16,569	16,436	16,259	16,379	17,216	18,521	18,520	18,084	17,404	16,239	14,788	13,566
Winter	1	18,058	1/22/2015	12,781	12,371	12,195	12,216	12,601	13,722	15,730	16,787	16,887	16,757	16,582	16,380	16,173	16,070	15,902	15,973	16,664	18,011	18,058	17,687	17,100	16,058	14,695	13,550
Winter	1	17,523	1/23/2015	12,853	12,484	12,360	12,429	12,840	13,965	15,983	17,021	16,997	16,766	16,544	16,290	15,994	15,799	15,616	15,664	16,322	17,523	17,482	17,028	16,461	15,634	14,549	13,454
Winter	1	17,403	1/24/2015	12,625	12,145	11,877	11,755	11,863	12,286	13,079	13,876	14,749	15,523	16,014	16,200	16,191	16,034	15,827	15,805	16,355	17,403	17,183	16,533	15,844	14,990	13,988	13,041
Winter	1	17,425	1/25/2015	12,281	11,829	11,556	11,458	11,521	11,850	12,468	13,101	13,949	14,446	14,622	14,623	14,515	14,341	14,298	14,593	15,570	17,210	17,425	17,125	16,590	15,677	14,562	13,584
Winter	1	19,531	1/26/2015	12,944	12,629	12,541	12,642	13,128	14,408	16,588	17,722	17,899	17,932	17,953	17,896	17,826	17,815	17,737	17,766	18,395	19,531	19,425	18,697	17,769	16,628	15,416	14,359
Winter	1	18,727	1/27/2015	13,622	13,219	13,044	13,053	13,256	13,727	14,443	15,060	15,785	16,399	16,696	16,822	16,870	16,743	16,605	16,628	17,318	18,727	18,632	18,035	17,290	16,299	15,153	14,165
Winter	1	19,361	1/28/2015	13,545	13,239	13,111	13,133	13,457	14,313	15,707	16,734	17,410	17,689	17,831	17,816	17,666	17,477	17,181	17,127	17,711	19,186	19,361	18,896	18,214	17,099	15,764	14,630
Winter	1	18,661	1/29/2015	13,975	13,660	13,544	13,652	14,075	15,201	17,142	18,092	18,089	17,838	17,587	17,272	16,915	16,667	16,451	16,516	17,151	18,521	18,661	18,268	17,611	16,515	15,106	13,840
Winter	1	18,114	1/30/2015	13,077	12,658	12,464	12,435	12,747	13,738	15,519	16,610	16,915	17,105	17,190	17,100	16,917	16,834	16,669	16,626	17,054	18,040	18,114	17,711	17,248	16,531	15,538	14,570
Winter	1	18,686	1/31/2015	13,905	13,544	13,412	13,436	13,639	14,191	15,072	15,951	16,886	17,423	17,505	17,379	17,080	16,700	16,444	16,483	17,075	18,452	18,686	18,292	17,790	17,032	16,051	15,037
Winter	2	17,999	2/1/2015	14,296	13,847	13,621	13,522	13,606	13,894	14,452	15,041	15,750	16,132	16,132	16,037	15,931	15,743	15,713	15,923	16,643	17,999	17,647	16,743	16,265	15,631	15,013	14,306
Winter	2	19,916	2/2/2015	13,458	13,029	12,888	12,959	13,314	14,155	15,354	16,231	17,027	17,719	18,242	18,537	18,613	18,528	18,399	18,379	18,844	19,916	19,911	19,321	18,477	17,310	16,017	14,882
Winter	2	19,599	2/3/2015	14,276	13,964	13,889	13,992	14,372	15,392	16,969	17,957	18,367	18,360	18,282	18,191	17,869	17,638	17,371	17,293	17,754	19,174	19,599	19,320	18,725	17,690	16,286	15,088
Winter	2	18,581	2/4/2015	14,383	14,045	13,886	13,885	14,212	15,246	17,103	18,007	18,021	17,917	17,846	17,648	17,344	17,172	16,971	16,868	17,223	18,401	18,581	18,164	17,487	16,371	14,927	13,711
Winter	2	19,642	2/5/2015	12,892	12,428	12,215	12,201	12,537	13,618	15,452	16,500	16,815	17,092	17,341	17,437	17,383	17,355	17,180	17,149	17,636	19,097	19,642	19,397	18,916	17,944	16,572	15,423
Winter	2	19,112	2/6/2015	14,726	14,403	14,280	14,342	14,710	15,815	17,689	18,577	18,594	18,530	18,484	18,374	18,115	17,848	17,512	17,339	17,695	18,829	19,112	18,773	18,266	17,449	16,368	15,251
Winter	2	17,680	2/7/2015	14,412	13,923	13,637	13,498	13,528	13,897	14,640	15,476	16,271	16,632	16,825	16,721	16,552	16,440	16,320	16,315	16,664	17,643	17,680	17,174	16,607	15,811	14,832	13,861
Winter	2	18,491	2/8/2015	13,125	12,679	12,430	12,317	12,400	12,650	13,160	13,758	14,767	15,558	16,056	16,340	16,466	16,438	16,404	16,607	17,243	18,401	18,491	17,986	17,293	16,326	15,293	14,366
Winter	2	19,658	2/9/2015	13,691	13,324	13,175	13,192	13,529	14,391	15,619	16,507	17,287	17,920	18,386	18,662	18,686	18,537	18,252	18,062	18,413	19,585	19,658	19,057	18,211	17,045	15,698	14,563
Winter	2	18,822	2/10/2015	13,846	13,470	13,294	13,286	13,604	14,543	16,034	17,042	17,546	17,683	17,646	17,506	17,290	17,082	16,843	16,690	17,026	18,296	18,822	18,442	17,802	16,732	15,350	14,196
Winter	2	18,964	2/11/2015	13,476	13,121	12,959	13,046	13,510	14,623	16,527	17,449	17,607	17,560	17,443	17,285	17,083	16,922	16,713	16,721	17,205	18,463	18,964	18,662	18,122	17,116	15,757	14,573
Winter	2	18,792	2/12/2015	13,874	13,477	13,306	13,350	13,674	14,737	16,561	17,499	17,692	17,785	17,782	17,613	17,381	17,264	17,054	17,042	17,454	18,424	18,792	18,492	17,948	16,990	15,671	14,537
Winter	2	19,343	2/13/2015	13,808	13,519	13,480	13,633	14,080	15,292	17,174	18,188	18,390	18,444	18,428	18,256	17,956	17,736	17,480	17,429	17,772	18,826	19,343	19,038	18,623	17,879	16,832	15,792
Winter	2	18,532	2/14/2015	15,034	14,607	14,413	14,354	14,495	14,942	15,698	16,516	17,286	17,685	17,724	17,524	17,269	17,022	16,855	16,895	17,287	18,300	18,532	17,952	17,247	16,326	15,333	14,409
Winter	2	19,590	2/15/2015	13,712	13,338	13,157	13,096	13,169	13,434	13,929	14,514	15,496	16,330	16,886	17,163	17,204	17,074	16,887	16,950	17,471	18,929	19,590	19,179	18,609	17,806	16,889	15,993
Winter	2	20,108	2/16/2015	15,404	15,093	14,989	15,036	15,319	16,029	17,083	17,955	18,664	19,043	19,153	19,037	18,746	18,405	18,131	18,093	18,554	19,713	20,108	19,659	18,989	17,947	16,673	15,508
Winter	2	19,514	2/17/2015	14,780	14,388	14,208	14,215	14,560	15,494	17,047	18,070	18,609	18,839	18,908	18,751	18,433	18,137	17,769	17,643	17,962	19,018	19,514	19,123	18,477	17,421	16,094	14,935
Winter	2	18,763	2/18/2015	14,214	13,876	13,728	13,777	14,171	15,199	16,839	17,786	18,010	17,968	17,830	17,551	17,191	17,006	16,808	16,782	17,174	18,304	18,763	18,380	17,739	16,725	15,414	14,279
Winter	2	19,705	2/19/2015	13,549	13,150	12,999	13,046	13,397	14,407	15,982	16,951	17,283	17,333	17,367	17,451	17,356	17,290	17,192	17,293	17,763	19,007	19,705	19,475	18,954	18,008	16,737	15,669
Winter	2	19,540	2/20/2015	14,988	14,666	14,546	14,610	14,992	16,017	17,575	18,601	18,944	19,022	18,959	18,769	18,478	18,234	17,951	17,789	18,060	18,952	19,540	19,229	18,714	17,903	16,878	15,834
Winter	2	18,223	2/21/2015	15,076	14,746	14,603	14,575	14,748	15,216	15,905	16,679	17,340	17,576	17,499	17,265	17,008	16,864	16,776	16,833	17,156	18,013	18,223	17,679	16,991	16,077	14,980	13,954
Winter	2	17,270	2/22/2015	13,180	12,690	12,392	12,260	12,291	12,553	12,997	13,593	14,450	15,111	15,449	15,499	15,285	14,931	14,668	14,678	15,135	16,476	17,270	16,942	16,306	15,309	14,244	13,274
Winter	2	19,862	2/23/2015	12,653	12,315	12,175	12,224	12,650	13,803	15,699	16,819	17,273	17,466	17,502	17,501	17,305	17,190	17,059	17,185	17,714	18,940	19,862	19,670	19,172	18,190	16,893	15,773
Winter	2	19,983	2/24/2015	15,118	14,851	14,768	14,851	15,246	16,370	18,127	18,962	18,920	18,870	18,674	18,416	18,102	17,876	17,680	17,647	18,106	19,254	19,983	19,649	18,960	17,818	16,325	15,045
Winter	2	18,605	2/25/2015	14,276	13,903	13,730	13,747	14,079	15,163	16,878	17,706	17,669	17,458	17,290	17,026	16,729	16,523	16,292	16,286	16,707	17,763	18,605	18,408	17,835	16,840	15,518	14,393
Winter	2	19,206	2/26/2015	13,691	13,356	13,217	13,278	13,634	14,728	16,525	17,527	17,856	18,044	18,124	18,062	17,834	17,510	17,272	17,360	17,759	18,605	19,206	18,894	18,276	17,198	15,818	14,627
Winter	2	18,313	2/27/2015	13,939	13,626	13,520	13,584	13,975	15,073	16,812	17,653	17,697	17,554	17,382	17,144	16,808	16,587	16,335	16,262	16,587	17,461	18,313	18,029	17,623	16,900	15,897	14,889
Winter	2	17,337	2/28/2015	14,220	13,868	13,724	13,697	13,867	14,367	15,110	15,883	16,454	16,691	16,593	16,298	15,870	15,443	15,150	15,100	15,483	16,452	17,337	17,091	16,703	16,096	15,264	14,418
Spring	3	18,198	3/1/2015	13,805	13,493	13,354	13,314	13,406	13,740	14,163	14,861	15,605	16,039	16,241	16,293	16,151	16,050	16,038	16,233	16,708	17,664	18,198	17,749	17,009	15,882	14,667	13,629
Spring	3	18,586	3/2/2015	12,963	12,621	12,492	12,524	12,901	13,943	15,501	16,491	16,823	16,835	16,823	16,718	16,576	16,454	16,310	16,279	16,664	17,682	18,586	18,308	17,710	16,594	15,221	14,092

Contains Proprietary Material
Do Not Distribute

Spring	3	18,800	3/3/2015	13,422	13,097	12,982	13,053	13,521	14,694	16,484	17,227	17,140	16,987	16,878	16,714	16,543	16,545	16,515	16,629	17,111	18,201	18,800	18,451	17,783	16,568	15,109	13,866
Spring	3	17,706	3/4/2015	13,021	12,549	12,294	12,272	12,601	13,619	15,248	16,169	16,449	16,473	16,400	16,273	16,097	15,963	15,746	15,796	16,223	17,129	17,706	17,345	16,672	15,568	14,195	13,040
Spring	3	18,848	3/5/2015	12,294	11,923	11,769	11,790	12,183	13,320	15,134	16,201	16,620	16,923	17,203	17,293	17,294	17,293	17,136	17,142	17,503	18,306	18,848	18,512	17,948	16,884	15,579	14,474
Spring	3	18,082	3/6/2015	13,870	13,586	13,504	13,596	14,038	15,209	16,904	17,742	17,746	17,559	17,400	17,125	16,752	16,494	16,219	16,123	16,416	17,192	18,082	17,835	17,357	16,577	15,510	14,478
Spring	3	16,572	3/7/2015	13,703	13,283	13,103	13,076	13,268	13,758	14,408	15,177	15,752	15,971	15,884	15,597	15,176	14,762	14,553	14,611	14,983	15,761	16,572	16,265	15,783	15,030	14,107	13,218
Spring	3	16,400	3/8/2015	12,539		12,361	12,183	11,975	11,980	12,198	12,680	13,189	13,928	14,575	14,840	14,870	14,859	14,724	14,432	14,244	14,370	14,806	15,505	16,400	16,129	15,235	14,074
Spring	3	16,717	3/9/2015	12,989	12,301	11,979	11,852	11,923	12,298	13,380	15,325	16,461	16,566	16,083	16,085	15,816	15,508	15,286	14,984	14,782	14,839	15,227	15,830	16,717	16,372	15,394	14,080
Spring	3	16,610	3/10/2015	12,905	12,162	11,778	11,632	11,681	12,028	13,118	15,120	16,188	16,235	15,968	15,715	15,431	15,174	15,003	14,825	14,804	15,063	15,553	16,147	16,610	16,125	15,095	13,700
Spring	3	15,840	3/11/2015	12,498	11,711	11,331	11,105	11,087	11,395	12,406	14,302	15,381	15,334	15,094	15,021	14,884	14,684	14,516	14,267	14,149	14,231	14,577	15,026	15,840	15,583	14,634	13,362
Spring	3	16,839	3/12/2015	12,196	11,446	11,089	10,939	10,988	11,347	12,477	14,529	15,625	15,714	15,617	15,553	15,392	15,170	15,047	14,847	14,741	14,889	15,330	15,941	16,839	16,623	15,735	14,446
Spring	3	16,560	3/13/2015	13,295	12,545	12,203	12,073	12,126	12,472	13,547	15,514	16,541	16,560	16,357	16,122	15,865	15,535	15,247	14,916	14,672	14,725	14,990	15,433	16,101	15,815	15,111	14,042
Spring	3	15,563	3/14/2015	12,969	12,176	11,713	11,468	11,349	11,424	11,784	12,542	13,411	14,364	15,075	15,467	15,563	15,436	15,200	14,978	14,858	14,952	15,191	15,372	15,487	15,092	14,409	13,499
Spring	3	16,279	3/15/2015	12,524	11,761	11,318	11,026	10,899	10,924	11,164	11,706	12,355	13,309	14,049	14,382	14,568	14,597	14,388	14,240	14,334	14,745	15,258	15,699	16,279	15,912	14,977	13,816
Spring	3	16,474	3/16/2015	12,777	12,092	11,773	11,633	11,697	12,116	13,268	15,280	16,247	16,251	16,033	15,850	15,598	15,303	15,141	14,868	14,673	14,723	15,108	15,684	16,474	16,137	15,111	13,751
Spring	3	16,826	3/17/2015	12,569	11,824	11,381	11,177	11,154	11,488	12,558	14,535	15,694	16,000	16,136	16,218	16,079	15,653	15,388	15,158	14,961	15,193	15,575	15,978	16,826	16,612	15,723	14,443
Spring	3	17,853	3/18/2015	13,310	12,588	12,243	12,130	12,199	12,606	13,733	15,743	16,765	16,797	16,615	16,501	16,354	16,163	16,038	15,831	15,773	15,982	16,464	17,005	17,853	17,573	16,564	15,169
Spring	3	17,212	3/19/2015	13,970	13,229	12,886	12,746	12,770	13,161	14,291	16,265	17,198	17,079	16,836	16,692	16,463	16,146	15,904	15,570	15,398	15,511	15,872	16,356	17,212	17,005	16,092	14,793
Spring	3	16,984	3/20/2015	13,602	12,863	12,495	12,362	12,398	12,759	13,849	15,764	16,755	16,984	16,920	16,818	16,599	16,335	16,273	16,151	16,067	16,181	16,389	16,575	16,937	16,548	15,725	14,595
Spring	3	15,695	3/21/2015	13,476	12,662	12,215	11,967	11,823	11,918	12,298	13,068	13,898	14,862	15,504	15,695	15,470	14,961	14,442	14,048	13,828	13,930	14,248	14,576	15,104	14,877	14,260	13,418
Spring	3	16,441	3/22/2015	12,517	11,822	11,416	11,223	11,186	11,340	11,704	12,308	12,982	13,750	14,226	14,465	14,542	14,454	14,234	14,000	13,968	14,217	14,796	15,434	16,441	16,335	15,482	14,346
Spring	3	17,333	3/23/2015	13,326	12,669	12,406	12,343	12,431	12,907	14,122	16,126	17,115	17,076	16,890	16,765	16,549	16,284	16,020	15,696	15,468	15,573	16,008	16,494	17,333	17,118	16,087	14,727
Spring	3	16,945	3/24/2015	13,523	12,812	12,479	12,394	12,428	12,823	13,973	15,963	16,945	16,854	16,456	16,103	15,818	15,509	15,276	14,990	14,847	14,965	15,332	15,730	16,574	16,447	15,465	14,107
Spring	3	16,448	3/25/2015	12,929	12,277	11,961	11,833	11,914	12,335	13,509	15,497	16,363	16,172	15,756	15,441	15,136	14,843	14,648	14,430	14,443	14,767	15,326	15,889	16,448	16,055	15,034	13,646
Spring	3	16,030	3/26/2015	12,455	11,690	11,293	11,084	11,039	11,321	12,378	14,292	15,255	15,420	15,399	15,301	15,192	15,064	15,142	15,112	15,082	15,323	15,645	15,802	16,030	15,598	14,585	13,216
Spring	3	15,683	3/27/2015	12,036	11,288	10,847	10,648	10,643	10,951	11,990	13,947	15,113	15,440	15,621	15,683	15,556	15,322	15,228	15,006	14,879	14,970	15,071	15,112	15,447	15,223	14,485	13,430
Spring	3	15,402	3/28/2015	12,376	11,588	11,140	10,908	10,818	10,923	11,330	12,133	13,068	14,115	14,847	15,208	15,201	15,027	14,762	14,474	14,353	14,431	14,683	14,936	15,402	15,220	14,601	13,738
Spring	3	15,238	3/29/2015	12,817	12,120	11,729	11,510	11,437	11,535	11,857	12,387	13,044	13,743	14,066	14,072	13,929	13,702	13,401	13,117	12,999	13,189	13,708	14,240	15,166	15,238	14,372	13,242
Spring	3	16,512	3/30/2015	12,229	11,589	11,285	11,167	11,230	11,606	12,733	14,708	15,847	16,210	16,353	16,512	16,477	16,302	16,066	15,736	15,396	15,479	15,811	16,008	16,389	16,112	15,086	13,689
Spring	3	15,964	3/31/2015	12,473	11,712	11,317	11,152	11,162	11,545	12,673	14,551	15,447	15,390	15,228	15,089	14,857	14,563	14,458	14,331	14,358	14,620	15,075	15,379	15,964	15,759	14,762	13,374
Spring	4	15,783	4/1/2015	12,231	11,537	11,190	11,066	11,095	11,520	12,694	14,653	15,537	15,467	15,195	15,041	14,876	14,625	14,468	14,205	14,073	14,187	14,537	14,913	15,693	15,783	14,897	13,605
Spring	4	15,818	4/2/2015	12,476	11,765	11,443	11,342	11,381	11,770	12,903	14,787	15,755	15,818	15,717	15,611	15,264	14,847	14,517	14,182	13,952	13,967	14,220	14,528	15,199	15,113	14,239	12,958
Spring	4	14,652	4/3/2015	11,748	10,921	10,474	10,227	10,173	10,415	11,219	12,607	13,565	14,190	14,531	14,652	14,561	14,322	14,197	14,054	13,939	14,017	14,138	14,139	14,404	14,185	13,455	12,432
Spring	4	14,370	4/4/2015	11,397	10,609	10,155	9,888	9,761	9,851	10,217	10,911	11,773	12,811	13,356	13,581	13,608	13,413	13,137	12,887	12,773	12,900	13,224	13,538	14,202	14,370	13,843	13,032
Spring	4	14,278	4/5/2015	12,082	11,261	10,808	10,593	10,510	10,582	10,900	11,414	12,181	12,911	13,337	13,379	13,359	13,223	12,843	12,492	12,336	12,479	12,808	13,234	14,075	14,278	13,562	12,506
Spring	4	15,410	4/6/2015	11,502	10,819	10,521	10,451	10,538	10,959	12,117	14,003	15,067	15,274	15,187	15,106	14,940	14,676	14,517	14,276	14,106	14,165	14,444	14,740	15,410	15,373	14,356	13,014
Spring	4	16,021	4/7/2015	11,814	10,982	10,587	10,407	10,401	10,738	11,830	13,730	14,832	15,091	15,217	15,383	15,379	15,287	15,260	15,096	15,061	15,259	15,601	15,745	16,021	15,744	14,733	13,350
Spring	4	16,441	4/8/2015	12,128	11,363	10,983	10,825	10,841	11,197	12,326	14,156	15,164	15,250	15,134	15,108	15,103	15,077	15,204	15,182	15,257	15,542	15,959	16,159	16,441	16,095	15,138	13,743
Spring	4	16,455	4/9/2015	12,563	11,810	11,396	11,227	11,240	11,576	12,673	14,572	15,699	15,990	16,120	16,223	16,173	16,013	15,890	15,724	15,640	15,747	16,023	16,171	16,455	16,180	15,215	13,830
Spring	4	15,697	4/10/2015	12,592	11,782	11,328	11,103	11,090	11,385	12,398	14,221	15,338	15,599	15,667	15,697	15,581	15,371	15,237	15,045	14,891	14,918	14,959	14,911	15,066	14,871	14,071	12,979
Spring	4	13,799	4/11/2015	11,854	10,993	10,515	10,260	10,173	10,270	10,677	11,317	12,142	12,873	13,312	13,428	13,313	13,057	12,776	12,518	12,359	12,446	12,711	12,967	13,543	13,799	13,241	12,390
Spring	4	13,853	4/12/2015	11,439	10,761	10,361	10,175	10,111	10,203	10,509	10,913	11,545	12,141	12,486	12,558	12,499	12,335	12,092	11,908	11,899	12,143	12,572	12,886	13,573	13,853	12,952	11,813
Spring	4	14,644	4/13/2015	10,732	10,128	9,783	9,647	9,692	10,110	11,255	12,941	13,952	14,129	14,172	14,219	14,161	14,024	13,944	13,783	13,669	13,736	13,949	14,057	14,587	14,644	13,602	12,235
Spring	4	14,745	4/14/2015	11,017	10,290	9,861	9,663	9,645	9,940	10,948	12,646	13,855	14,207	14,314	14,410	14,305	14,161	14,121	13,943	13,833	13,935	14,145	14,298	14,745	14,624	13,617	12,236
Spring	4	14,493	4/15/2015	11,053	10,283	9,881	9,678	9,674	10,015	11,085	12,700	13,683	13,826	13,858	13,867	13,826	13,717	13,713	13,571	13,495	13,535	13,725	13,811	14,272	14,493	13,540	12,205
Spring	4	14,485	4/16/2015	10,989	10,229	9,834	9,650	9,699	10,079	11,184	12,823	13,806	13,908	13,917	13,918	13,835	13,687	13,624	13,442	13,368	13,417	13,620	13,767	14,291	14,485	13,555	12,242
Spring	4	14,781	4/17/2015	11,058	10,265	9,860	9,645	9,619	9,907	10,869	12,532	13,742	14,296	14,629	14,781	14,726	14,533	14,378	14,103	13,865	13,763	13,733	13,649	13,800	13,963	13,225	12,155
Spring	4	13,032	4/18/2015	11,022	10,220	9,747	9,489	9,395	9,477	9,859	10,384	11,234	11,983	12,451	12,541	12,479	12,304	12,117	11,985	11,955	12,131	12,410	12,516	12,752	13,032	12,426	11,501
Spring	4	13,353	4/19/2015	10,579	9,864	9,442	9,194	9,097	9,160	9,417	9,753	10,408	11,153	11,627	11,834	11,853	11,778	11,611	11,476	11,474	11,716	12,147	12,508	13,074	13,353	12,532	11,483
Spring	4	15,288	4/20/2015	10,490	9,858	9,520	9,378	9,394	9,733	10,698	12,116	13,360	14,101	14,589	14,917	15,076	15,124	15,128	14,985	14,897	15,024	15,272	15,276	15,288	14,909	13,846	12,542
Spring	4	14,565	4/21/2015	11,359	10,589	10,172	9,945	9,903	10,191	11,077	12,591	13,742	14,247	14,412	14,545	14,565	14,392	14,277	14,013	13,824	13,820	13,894	13,904	14,220	14,471	13,599	12,290
Spring	4	14,448	4/22/2015	11,116	10,326	9,908	9,730	9,685	10,040	11,005	12,420	13,467	13,759	13,857	13,937	13,934	13,881	13,902	13,796	13,710	13,854	14,123	14,241	14,448	14,431	13,476	12,182
Spring	4	14,939	4/23/2015	11,039	10,281	9,878	9,669	9,674	10,001	11,003	12,431	13,523	13,899	14,074	14,236	14,277	14,250	14,241	14,025	13,910	14,029	14,276	14,436	14,759	14,939	14,107	12,859
Spring	4	14,577	4/24/2015	11,709	10,981	10,560	10,373	10,369	10,665	11,607	12,987	14,052	14,430	14,502	14,529	14,429	14,253	14,118	13,927	13,752	13,769	13,926	14,058	14,381	14,577	13,898	12,883
Spring	4	13,287	4/25/2015	11,826	11,042	10,621	10,385	10,328	10,452	10,835	11,389	12,143	12,748	12,996	12,984	12,795	12,548	12,329	12,101	12,038	12,164	12,467	12,688	12,986	13,287	12,730	11,870
Spring	4	13,679	4/26/2015	10,956	10,283	9,876	9,663	9,580	9,643	9,882	10,227	10,864	11,575	12,029	12,207	12,366	12,417	12,371	12,286	12,317	12,559	12,975	13,231	13,561	13,679	12,788	11,641
Spring	4	14,635	4/27/2015	10,594	9,940	9,567	9,420	9,454	9,801	10,881	12,565	13,727	14,005	14,064	14,123	14,154	14,117	14,090	13,903	13,845	13,970	14,271	14,357	14,536	14,635	13,667	12,281
Spring	4	14,470	4/28/2015	11,079	10,317	9,897	9,715	9,711	10,029	11,068	12,738	13,801	14,022	14,057	14,037	13,797	13,683	13,723	13,566	13,463	13,552	13,725	13,782	14,072	14,470	13,555	12,176
Spring	4	14,357	4/29/2015	10,946	10,157	9,746	9,532	9,520	9,837	10,827	12,474	13,489	13,717	13,756	13,855	13,879	13,792	13,817	13,700	13,565	13,588	13,691	13,737	14,075	14,357	13,442	12,076
Spring	4	14,359	4/30/2015	10,858	10,081	9,657	9,451	9,456	9,767	10,780	12,441	13,573	13,844	13,929	13,967	13,889	13,789	13,773	13,658	13,577	13,617	13,759	13,832	14,129	14,359	13,466	12,163
Spring	5	13,960	5/1/2015	10,940	10,175	9,755	9,551	9,529	9,820	10,754	12,369	13,502	13,853	13,931	13,960	13,884	13,743	13,665	13,491	13,323	13,301	13,298	13,239	13,429	13,807	13,190	12,142
Spring	5	12,974	5/2/2015	11,057	10,249	9,785	9,561	9,484	9,592	9,942	10,566	11,469	12,139	12,369	12,375	12,277	12,130	11,959	11,794	11,759	11,891	12,118	12,217	12,478	12,974	12,443	11,517
Spring	5	13,460	5/3/2015	10,577	9,849	9,467	9,200	9,081	9,132	9,304	9,628	10,343	11,100	11,596	11,835	11,929	11,978	11,920	11,863	11,927	12,146	12,517	12,745	13,043	13,460	12,665	11,433
Spring	5	15,035	5/4/2015	10,330	9,615	9,248	9,084	9,083	9,426	10,389	12,037	13,160	13,566	13,873	14,196	14,425	14,552	14,696	14,677	14,629	14,688	14,751	14,614	14,673	15,035	14,067	12,577
Spring	5	15,037	5/5/2015	11,223	10,355	9,880	9,625	9,540	9,813	10,733	12,386	13,696	14,173	14,441	14,615	14,823	14,863	14,957	14,984	14,981	14,983	14,926	14,716	14,745	15,037	14,070	12,558
Spring	5	14,769	5/6/2015	11,216	10,346	9,869	9,595	9,506	9,732	10,638	12,239	13,446	13,862	14,150	14,352	14,423	14,400	14,463	14,416	14,404	14,480	14,536	14,407	14,391	14,769	13,845	12,382
Spring	5	15,335	5/7/2015	11,030	10,160	9,677	9,430	9,363	9,652	10,491	12,116	13,323	13,806	14,197	14,596	14,838	14,957	15,152	15,214	15,241	15,335	15,277	15,022	14,893	15,202	14,334	12,776
Spring	5	14,887	5/8/2015	11,406	10,490	9,951	9,628	9,527	9,764	10,575	12,139	13,411	13,983	14,385	14,650	14,816	14,833	14,887	14,797	14,715	14,680	14,536	14,232	14,104	14,354	13,661	12,444
Spring	5	13,831	5/9/2015	11,198	10,274	9,758	9,436	9,292	9,357	9,647	10,179	11,127	12,023	12,537	12,685	12,717	12,722	12,681	12,722	12,835	13,000	13,236	13,307	13,408	13,831	13,333	12,341
Spring	5	15,908	5/10/2015	11,239	10,422	9,883	9,567	9,427	9,443	9,557	9,900	10,796	11,868	12,699	13,222	13,559	13,787	14,007	14,246	14,523	14,909	15,256	15,348	15,439	15,908	15,220	13,838
Spring	5	16,955	5/11/2015	12,477	11,528	10,994	10,646	10,520	10,792	11,664	13,347	14,900	15,705	16,313	16,778	16,955	16,934	16,952	16,840	16,764	16,738	16,585	16,289	16,112	16,175	15,094	13,452
Spring	5	17,077	5/12/2015	11,984	11,073	10,572	10,294	10,196	10,460	11,351	12,980	14,278	14,806	15,192	15,688	16,184	16,606	16,955	17,073	17,012	17,077	16,968	16,613	16,344	16,359	15,263	13,486
Spring	5	14,543	5/13/2015	11,858	10,829	10,235	9,905	9,789	10,002	10,757	12,348	13,562	13,991	14,235	14,463	14,543	14,474	14,484	14,358	14,257	14,303	14,302	14,166	14,137	14,464	13,684	12,255
Spring	5	14,510	5/14/2015	10,965	10,127	9,672	9,449	9,433	9,719	10,546	12,179	13,282	13,632	13,860	14,058	14,157	14,127	14,209	14,187	14,195	14,309	14,362	14,245	14,177	14,510	13,781	12,347
Spring	5	14,394	5/15/2015	11,013	10,165	9,693	9,472	9,424	9,705	10,468	12,047	13,202	13,682	13,995	14,245	14,355	14,341	14,394	14,277	14,108	14,123	14,020	13,778	13,674	13,971	13,388	12,244
Spring	5	13,564	5/16/2015	11,070	10,196	9,673	9,389	9,277	9,352	9,618	10,219	11,258	12,230	12,839	13,146	13,215	13,141	13,056	12,980	12,949	13,009	13,164	13,187	13,265	13,564	13,079	12,134
Spring	5	15,349	5/17/2015	11,088	10,278	9,792	9,503	9,361	9,364	9,409	9,798	10,705	11,749	12,577	13,148	13,590	13,869	13,992	14,148	14,388	14,789	15,160	15,262	15,140	15,349	14,591	13,117
Spring	5	15,068	5/18/2015	11,704	10,783	10,263	9,961	9,857	10,103	10,950	12,545	13,770	14,214	14,470	14,678	14,832	14,859	15,006	15,032	15,022	15,066	15,068	14,869	14,757	14,965	14,097	12,632
Spring	5	15,353	5/19/2015	11,264	10,416	9,955	9,710	9,639	9,919	10,775	12,405	13,720	14,223	14,565	14,901	15,050	15,033	15,014	14,978	14,974	15,160	15,346	15,265	15,153	15,353	14,544	13,096
Spring	5	14,297	5/20/2015	11,763	10,823	10,256	9,878	9,730	9,949	10,672	12,309	13,495	13,909	14,098	14,253	14,297	14,246	14,278	14,151	14,007	14,026	14,092	13,982	13,956	14,285	13,651	12,304
Spring	5	14,381	5/21/2015	11,013	10,167	9,747	9,486	9,458	9,752	10,563	12,192	13,326	13,758	13,949	14,161	14,203	14,188	14,212	14,108	14,077	14,106	14,142	14,028	14,027	14,381	13,735	12,359
Spring	5	14,514	5/22/2015	11,069	10,202	9,736	9,489	9,445	9,688	10,494	12,029	13,278	13,787	14,116	14,348	14,472	14,507	14,514	14,368	14,233	14,177	14,128	13,903	13,667	13,824	13,351	12,227
Spring	5	12,796	5/23/2015	11,044	10,137	9,639	9,349	9,220	9,264	9,400	9,979	10,815	11,630	12,101	12,268	12,241	12,129	11,943	11,799	11,799	11,993	12,303	12,455	12,459	12,796	12,516	11,605
Spring	5	13,198	5/24/2015	10,609	9,856	9,411	9,162	9,046	9,083	9,120	9,502	10,241	11,073	11,741	12,091	12,293	12,357	12,350	12,356	12,483	12,713	12,969	12,971	12,872	13,198	12,873	11,942
Spring	5	14,992	5/25/2015	10,910	10,099	9,608	9,317	9,183	9,245	9,380	9,874	10,691	11,761	12,647	13,206	13,623	13,873	13,909	13,923	14,056	14,377	14,720	14,714	14,671	14,992	14,336	12,908
Spring	5	18,470	5/26/2015	11,607	10,745	10,271	10,013	9,967	10,219	11,030	12,769	14,295	15,089	15,794	16,453	16,830	17,088	17,544	17,913	18,229	18,470	18,462	18,130	17,785	17,785	16,890	15,097
Spring	5	19,544	5/27/2015	13,446	12,303	11,643	11,241	11,069	11,277	12,042	13,727	15,168	15,992	16,733	17,514	18,155	18,623	19,109	19,354	19,524	19,544	19,254	18,700	18,211	17,996	16,973	15,225
Spring	5	19,363	5/28/2015	13,615	12,503	11,837	11,405	11,248	11,453	12,241	14,030	15,466	16,175	16,763	17,361	17,900	18,324	18,831	19,143	19,363	19,296	18,925	18,280	17,766	17,654	16,780	14,948
Spring	5	17,854	5/29/2015	13,222	12,028	11,309	10,879	10,673	10,830	11,510	13,169	14,587	15,435	16,055	16,548	16,890	17,071	17,348	17,534	17,738	17,854	17,602	16,928	16,303	16,202	15,546	14,171
Spring	5	17,405	5/30/2015	12,756	11,677	10,986	10,547	10,331	10,334	10,443	11,058	12,103	13,300	14,296	15,076	15,726	16,177	16,484	16,790	17,076	17,324	17,405	17,084	16,494	16,383	15,883	14,655
Spring	5	15,409	5/31/2015	13,343	12,284	11,625	11,201	10,928	10,865	10,855	11,166	11,963	13,000	13,999	14,688	15,162	15,409	15,401	15,141	14,837	14,709	14,768	14,550	14,218	13,963	13,089	11,848
Summer	6	14,984	6/1/2015	10,734	10,030	9,636	9,430	9,422	9,731	10,652	12,270	13,583	14,164	14,504	14,783	14,880	14,801	14,745	14,586	14,532	14,702	14,984	14,953	14,804	14,623	13,697	12,329
Summer	6	14,864	6/2/2015	11,137	10,349	9,923	9,724	9,664	9,940	10,836	12,495	13,773	14,275	14,607	14,820	14,864	14,778	14,721	14,545	14,499	14,637	14,850	14,828	14,684	14,649	13,898	12,508
Summer	6	14,352	6/3/2015	11,246	10,409	9,968	9,755	9,708	10,017	10,798	12,451	13,570	13,890	14,029	14,242	14,302	14,246	14,247	14,157	14,128	14,186	14,261	14,169	14,062	14,352	13,876	12,476
Summer	6	14,460	6/4/2015	11,163	10,272	9,819	9,589	9,563	9,847	10,635	12,273	13,470	13,886

Contains Proprietary Material
Do Not Distribute

Summer	6	19,755	6/12/2015	14,488	13,201	12,351	11,815	11,550	11,661	12,296	13,911	15,309	16,154	16,900	17,631	18,275	18,664	19,224	19,552	19,720	19,755	19,420	18,700	17,983	17,856	17,343	16,049
Summer	6	17,740	6/13/2015	14,618	13,490	12,771	12,323	12,034	11,964	12,008	12,645	13,752	14,842	15,593	16,125	16,497	16,715	16,839	17,033	17,296	17,605	17,740	17,496	16,908	16,562	16,119	14,850
Summer	6	16,648	6/14/2015	13,451	12,304	11,564	11,071	10,766	10,646	10,530	10,946	11,812	12,928	13,962	14,696	15,210	15,570	15,754	15,933	16,182	16,447	16,648	16,502	16,052	16,045	15,440	13,979
Summer	6	15,928	6/15/2015	12,588	11,633	11,037	10,707	10,612	10,875	11,727	13,246	14,542	15,190	15,545	15,844	15,928	15,854	15,806	15,615	15,469	15,496	15,550	15,397	15,192	15,036	14,257	12,919
Summer	6	16,707	6/16/2015	11,679	10,828	10,343	10,137	10,081	10,351	11,098	12,691	14,049	14,725	15,158	15,565	15,835	16,048	16,361	16,426	16,427	16,594	16,707	16,593	16,436	16,412	15,934	14,436
Summer	6	16,423	6/17/2015	12,958	11,898	11,254	10,862	10,668	10,797	11,420	13,078	14,475	15,145	15,493	15,769	15,963	15,997	16,195	16,272	16,385	16,423	16,257	15,862	15,516	15,525	14,977	13,481
Summer	6	16,482	6/18/2015	12,054	11,053	10,471	10,159	10,043	10,249	10,924	12,465	13,776	14,498	15,004	15,426	15,743	15,913	16,156	16,335	16,447	16,482	16,374	15,998	15,684	15,689	15,184	13,819
Summer	6	18,328	6/19/2015	12,439	11,434	10,864	10,568	10,471	10,720	11,463	13,023	14,455	15,355	16,100	16,807	17,393	17,734	18,034	18,230	18,328	18,275	18,034	17,494	16,842	16,445	15,934	14,558
Summer	6	14,307	6/20/2015	13,028	11,841	11,049	10,542	10,258	10,150	10,175	10,762	11,767	12,806	13,572	14,006	14,235	14,307	14,279	14,190	14,129	14,130	14,134	13,995	13,876	13,987	13,694	12,838
Summer	6	16,718	6/21/2015	11,835	11,038	10,531	10,238	10,122	10,148	10,280	10,667	11,511	12,612	13,610	14,338	14,833	15,072	15,164	15,295	15,628	16,107	16,613	16,718	16,506	16,459	16,144	14,793
Summer	6	20,012	6/22/2015	13,354	12,302	11,657	11,239	11,122	11,342	12,066	13,665	15,269	16,405	17,259	17,959	18,511	18,863	19,275	19,518	19,779	20,012	19,999	19,687	19,092	18,653	17,893	16,044
Summer	6	20,923	6/23/2015	14,276	13,008	12,217	11,684	11,518	11,683	12,356	13,932	15,564	16,681	17,601	18,594	19,322	19,543	19,981	20,512	20,923	20,867	20,511	20,008	19,458	19,049	18,272	16,563
Summer	6	19,392	6/24/2015	14,777	13,353	12,500	11,935	11,598	11,630	12,166	13,764	15,317	16,242	16,891	17,511	17,937	18,234	18,565	18,869	19,168	19,392	19,338	18,866	18,199	17,743	17,133	15,471
Summer	6	18,472	6/25/2015	13,778	12,520	11,756	11,267	11,038	11,136	11,661	13,138	14,662	15,634	16,348	17,002	17,513	17,859	18,256	18,452	18,472	18,402	18,178	17,704	17,293	17,190	16,663	15,195
Summer	6	16,993	6/26/2015	13,692	12,599	11,919	11,505	11,321	11,447	11,995	13,259	14,521	15,268	15,763	16,126	16,363	16,516	16,766	16,878	16,921	16,993	16,865	16,427	15,831	15,467	15,050	13,849
Summer	6	14,227	6/27/2015	12,493	11,435	10,775	10,363	10,141	10,107	10,158	10,744	11,748	12,729	13,481	13,935	14,170	14,227	14,115	13,986	13,862	13,846	13,876	13,798	13,701	13,798	13,388	12,492
Summer	6	13,700	6/28/2015	11,470	10,661	10,149	9,871	9,703	9,691	9,798	10,096	10,795	11,740	12,635	13,254	13,587	13,677	13,576	13,405	13,341	13,496	13,700	13,684	13,548	13,502	13,046	11,992
Summer	6	15,859	6/29/2015	10,914	10,196	9,761	9,534	9,514	9,755	10,471	11,801	13,172	13,994	14,565	15,060	15,400	15,558	15,727	15,750	15,693	15,750	15,859	15,676	15,480	15,388	14,957	13,600
Summer	6	17,912	6/30/2015	12,221	11,244	10,667	10,341	10,204	10,390	10,993	12,365	13,870	14,854	15,608	16,300	16,840	17,207	17,645	17,842	17,897	17,912	17,771	17,369	16,881	16,705	16,181	14,775
Summer	7	18,681	7/1/2015	13,268	12,232	11,606	11,258	11,126	11,338	12,061	13,488	14,879	15,792	16,422	16,960	17,323	17,545	17,921	18,202	18,436	18,650	18,681	18,304	17,762	17,403	16,766	15,248
Summer	7	17,682	7/2/2015	13,652	12,460	11,653	11,187	10,962	11,022	11,537	12,861	14,381	15,390	16,103	16,697	17,090	17,345	17,598	17,682	17,585	17,486	17,311	16,845	16,404	16,290	15,833	14,576
Summer	7	16,376	7/3/2015	13,194	12,083	11,330	10,835	10,540	10,487	10,603	11,262	12,309	13,328	14,127	14,677	15,007	15,191	15,379	15,596	15,882	16,230	16,376	15,971	15,323	15,056	14,613	13,632
Summer	7	13,992	7/4/2015	12,529	11,472	10,772	10,342	10,123	10,065	10,057	10,403	11,198	12,143	12,974	13,519	13,817	13,992	13,876	13,631	13,444	13,409	13,510	13,455	13,245	13,173	12,952	12,441
Summer	7	16,692	7/5/2015	11,646	10,807	10,220	9,867	9,693	9,629	9,575	9,866	10,690	11,775	12,797	13,642	14,302	14,824	15,188	15,505	15,895	16,322	16,688	16,692	16,438	16,382	16,068	14,818
Summer	7	20,106	7/6/2015	13,336	12,277	11,592	11,212	11,023	11,195	11,729	13,061	14,642	15,836	16,897	17,863	18,640	19,099	19,494	19,717	19,877	20,058	20,106	19,696	19,126	18,786	18,036	16,273
Summer	7	20,988	7/7/2015	14,563	13,329	12,540	12,091	11,906	12,088	12,777	14,272	15,880	16,967	17,890	18,818	19,588	20,107	20,604	20,868	20,977	20,988	20,903	20,481	20,016	19,803	18,980	17,320
Summer	7	21,638	7/8/2015	15,656	14,457	13,659	13,155	12,898	13,049	13,683	15,233	16,899	17,992	18,721	19,515	20,261	20,808	21,319	21,603	21,638	21,621	21,397	20,866	20,114	19,668	18,748	16,888
Summer	7	17,917	7/9/2015	15,030	13,717	12,783	12,229	11,926	11,998	12,543	13,769	15,080	15,866	16,385	16,859	17,166	17,370	17,729	17,857	17,889	17,917	17,761	17,362	17,059	17,020	16,371	14,926
Summer	7	18,844	7/10/2015	13,530	12,501	11,891	11,551	11,395	11,525	12,107	13,382	14,760	15,737	16,462	17,042	17,575	17,895	18,227	18,461	18,663	18,844	18,800	18,320	17,667	17,272	16,795	15,442
Summer	7	18,602	7/11/2015	13,924	12,678	11,874	11,337	11,026	10,909	10,958	11,483	12,644	13,974	15,117	15,974	16,635	17,054	17,371	17,651	18,025	18,374	18,602	18,434	17,884	17,534	17,058	15,819
Summer	7	20,162	7/12/2015	14,414	13,232	12,428	11,881	11,509	11,331	11,181	11,518	12,494	13,780	15,092	16,279	17,331	18,109	18,650	19,080	19,532	19,915	20,162	19,983	19,574	19,469	18,942	17,334
Summer	7	21,122	7/13/2015	15,595	14,329	13,513	13,016	12,749	12,871	13,508	14,909	16,537	17,709	18,664	19,526	20,171	20,681	21,042	21,122	21,098	21,111	20,992	20,454	19,713	19,239	18,384	16,532
Summer	7	20,048	7/14/2015	14,778	13,526	12,786	12,370	12,177	12,368	13,045	14,483	16,108	17,211	18,090	18,738	19,090	19,338	19,791	20,048	20,048	19,822	19,676	19,516	19,180	19,108	18,436	16,922
Summer	7	21,117	7/15/2015	15,374	14,214	13,513	13,075	12,883	13,057	13,765	15,260	16,913	18,010	18,917	19,752	20,351	20,726	21,094	21,117	20,958	20,755	20,327	19,622	18,826	18,339	17,356	15,643
Summer	7	17,211	7/16/2015	13,947	12,712	11,936	11,410	11,147	11,212	11,729	12,888	14,251	15,015	15,504	15,905	16,171	16,328	16,593	16,752	16,921	17,154	17,211	16,884	16,366	16,170	15,647	14,253
Summer	7	17,773	7/17/2015	12,789	11,705	11,050	10,670	10,523	10,680	11,207	12,434	13,883	14,877	15,586	16,217	16,702	17,002	17,376	17,583	17,686	17,773	17,717	17,170	16,630	16,559	16,082	14,861
Summer	7	16,838	7/18/2015	13,563	12,524	11,904	11,487	11,283	11,268	11,476	11,969	12,878	13,957	14,819	15,359	15,609	15,747	15,885	15,967	16,210	16,549	16,838	16,830	16,646	16,707	16,406	15,422
Summer	7	21,368	7/19/2015	14,223	13,241	12,611	12,222	11,959	11,879	11,915	12,277	13,353	14,896	16,437	17,772	18,898	19,758	20,273	20,478	20,655	21,045	21,368	21,132	20,777	20,677	19,835	18,255
Summer	7	24,437	7/20/2015	16,655	15,498	14,738	14,201	13,972	14,153	14,894	16,293	18,284	19,917	21,243	22,383	23,213	23,689	24,143	24,291	24,357	24,437	24,365	23,813	22,971	22,463	21,343	19,206
Summer	7	22,683	7/21/2015	17,170	15,746	14,727	14,061	13,655	13,685	14,265	15,581	17,027	17,946	18,611	19,325	19,963	20,504	21,207	21,741	22,268	22,683	22,622	22,024	21,236	20,760	19,759	17,865
Summer	7	19,755	7/22/2015	15,969	14,581	13,642	12,967	12,570	12,569	13,082	14,369	15,893	16,886	17,578	18,193	18,657	19,001	19,402	19,631	19,739	19,755	19,595	19,004	18,344	18,037	17,359	15,776
Summer	7	18,942	7/23/2015	14,195	12,975	12,226	11,737	11,466	11,549	12,123	13,420	14,967	16,012	16,757	17,399	17,855	18,206	18,587	18,782	18,834	18,942	18,843	18,432	17,863	17,692	17,050	15,527
Summer	7	18,199	7/24/2015	13,987	12,778	12,010	11,541	11,305	11,413	11,923	13,111	14,634	15,743	16,509	17,155	17,631	17,903	18,127	18,199	18,195	18,152	17,923	17,376	16,759	16,584	16,045	14,764
Summer	7	15,778	7/25/2015	13,402	12,307	11,590	11,132	10,873	10,797	10,910	11,397	12,397	13,456	14,323	14,896	15,240	15,397	15,439	15,483	15,571	15,705	15,778	15,538	15,181	15,280	14,895	13,929
Summer	7	17,080	7/26/2015	12,855	11,965	11,367	10,980	10,796	10,769	10,899	11,189	11,931	12,930	13,869	14,589	15,112	15,568	15,945	16,179	16,414	16,797	17,080	17,044	16,889	16,952	16,456	15,232
Summer	7	20,877	7/27/2015	13,884	12,947	12,356	12,006	11,868	12,104	12,842	14,169	15,720	16,834	17,695	18,456	19,052	19,522	20,056	20,467	20,750	20,877	20,790	20,346	19,740	19,549	18,652	16,939
Summer	7	23,171	7/28/2015	15,298	14,062	13,313	12,856	12,652	12,776	13,473	14,828	16,469	17,725	18,901	20,088	21,071	21,895	22,597	22,989	23,162	23,171	23,032	22,430	21,683	21,364	20,333	18,359
Summer	7	24,437	7/29/2015	16,400	15,009	14,102	13,546	13,245	13,308	13,901	15,262	17,099	18,597	19,966	21,301	22,374	23,094	23,720	24,029	24,216	24,437	24,399	23,946	23,277	22,875	21,801	19,746
Summer	7	23,865	7/30/2015	17,763	16,286	15,333	14,662	14,328	14,404	15,017	16,442	18,181	19,627	20,937	22,041	22,736	23,181	23,626	23,865	23,702	23,297	22,747	21,989	21,326	20,989	20,053	18,334
Summer	7	21,880	7/31/2015	16,633	15,317	14,469	13,857	13,525	13,524	14,019	15,205	16,867	18,186	19,191	20,103	20,707	21,046	21,431	21,690	21,830	21,880	21,649	20,930	19,952	19,330	18,401	16,781
Summer	8	18,939	8/1/2015	15,085	13,769	12,895	12,302	11,982	11,910	12,037	12,529	13,713	15,148	16,445	17,340	18,038	18,588	18,837	18,939	18,932	18,826	18,781	18,530	17,971	17,756	17,123	15,816
Summer	8	19,003	8/2/2015	14,383	13,226	12,404	11,829	11,456	11,243	11,172	11,370	12,288	13,522	14,671	15,598	16,388	16,969	17,412	17,772	18,199	18,670	19,003	18,880	18,380	18,299	17,589	16,122
Summer	8	22,919	8/3/2015	14,660	13,625	12,969	12,530	12,369	12,589	13,323	14,679	16,469	17,852	18,960	19,982	20,820	21,443	22,077	22,476	22,743	22,919	22,715	21,997	21,208	20,936	19,969	18,184
Summer	8	21,920	8/4/2015	16,449	15,205	14,413	13,960	13,743	13,897	14,620	15,695	16,827	17,595	18,531	19,541	20,477	21,137	21,759	21,920	21,549	21,060	20,887	20,374	19,770	19,531	18,490	16,768
Summer	8	20,212	8/5/2015	15,053	13,786	12,953	12,413	12,125	12,184	12,756	13,874	15,374	16,506	17,395	18,103	18,701	19,263	19,774	20,099	20,170	20,212	20,006	19,357	18,604	18,435	17,508	15,795
Summer	8	18,322	8/6/2015	14,126	12,894	12,126	11,627	11,372	11,481	12,105	13,245	14,673	15,705	16,447	17,056	17,501	17,795	18,085	18,263	18,300	18,322	18,163	17,682	17,264	17,314	16,482	15,073
Summer	8	18,025	8/7/2015	13,666	12,543	11,814	11,379	11,161	11,272	11,830	12,926	14,356	15,453	16,231	16,845	17,271	17,572	17,858	17,999	18,025	18,008	17,842	17,290	16,650	16,550	15,852	14,577
Summer	8	15,982	8/8/2015	13,189	12,137	11,451	11,004	10,736	10,679	10,799	11,180	12,205	13,311	14,208	14,816	15,208	15,450	15,535	15,591	15,728	15,916	15,982	15,674	15,362	15,510	14,955	13,928
Summer	8	15,622	8/9/2015	12,761	11,814	11,206	10,775	10,542	10,457	10,517	10,703	11,469	12,519	13,388	13,989	14,376	14,662	14,786	14,854	14,987	15,311	15,622	15,597	15,364	15,527	14,877	13,654
Summer	8	18,988	8/10/2015	12,401	11,529	10,988	10,663	10,560	10,801	11,524	12,691	14,159	15,284	16,142	16,858	17,467	17,914	18,405	18,733	18,901	18,988	18,882	18,386	17,833	17,792	16,793	15,280
Summer	8	17,745	8/11/2015	13,864	12,794	12,192	11,844	11,710	11,950	12,794	14,095	15,452	16,351	16,939	17,391	17,586	17,620	17,676	17,596	17,538	17,616	17,745	17,598	17,494	17,429	16,534	15,148
Summer	8	19,898	8/12/2015	13,834	12,849	12,267	11,895	11,729	11,893	12,631	13,806	15,260	16,407	17,247	18,004	18,585	18,953	19,352	19,573	19,733	19,898	19,834	19,306	18,681	18,510	17,482	15,837
Summer	8	19,250	8/13/2015	14,208	13,065	12,307	11,830	11,601	11,698	12,366	13,450	14,884	15,944	16,730	17,423	17,952	18,293	18,708	18,951	19,111	19,250	19,154	18,647	18,026	17,907	16,950	15,375
Summer	8	20,051	8/14/2015	13,814	12,651	11,912	11,430	11,170	11,287	11,923	12,963	14,413	15,618	16,590	17,388	17,990	18,423	18,980	19,455	19,796	20,051	19,981	19,386	18,652	18,475	17,506	16,035
Summer	8	20,198	8/15/2015	14,556	13,352	12,556	12,045	11,748	11,671	11,861	12,263	13,334	14,680	15,980	17,157	18,157	18,935	19,501	19,851	20,115	20,198	20,056	19,522	18,951	18,761	17,822	16,417
Summer	8	20,923	8/16/2015	15,012	13,908	13,117	12,599	12,255	12,072	12,115	12,270	13,187	14,550	15,864	17,101	18,149	18,958	19,546	19,991	20,367	20,694	20,923	20,673	20,199	20,170	19,103	17,427
Summer	8	24,047	8/17/2015	15,815	14,648	13,885	13,397	13,164	13,279	13,995	15,191	16,835	18,357	19,745	21,068	22,105	22,849	23,502	23,790	23,934	24,047	23,991	23,470	22,857	22,553	21,117	19,100
Summer	8	24,216	8/18/2015	17,163	15,746	14,878	14,281	13,937	13,998	14,698	15,901	17,520	18,898	20,219	21,536	22,642	23,484	24,113	24,216	23,939	23,700	23,295	22,530	21,995	21,731	20,407	18,503
Summer	8	23,624	8/19/2015	16,695	15,481	14,695	14,185	13,958	14,072	14,814	16,056	17,627	18,918	20,002	21,026	21,874	22,510	23,098	23,456	23,598	23,624	23,406	22,664	21,911	21,645	20,362	18,480
Summer	8	22,513	8/20/2015	16,677	15,403	14,591	14,143	13,920	14,084	14,870	16,183	17,662	18,815	19,744	20,628	21,314	21,770	22,252	22,484	22,513	22,468	22,146	21,410	20,828	20,667	19,521	17,879
Summer	8	21,166	8/21/2015	16,296	15,116	14,373	13,931	13,743	13,969	14,794	16,058	17,432	18,414	19,046	19,496	19,811	20,217	20,671	20,940	21,061	21,166	20,935	20,253	19,738	19,494	18,439	16,989
Summer	8	17,706	8/22/2015	15,472	14,291	13,477	12,938	12,582	12,427	12,565	12,870	13,716	14,781	15,748	16,473	16,923	17,179	17,332	17,413	17,541	17,697	17,706	17,423	17,100	17,107	16,326	15,189
Summer	8	17,474	8/23/2015	13,982	13,015	12,367	11,930	11,654	11,567	11,678	11,887	12,548	13,581	14,503	15,262	15,855	16,279	16,507	16,664	16,793	17,061	17,355	17,385	17,374	17,474	16,628	15,358
Summer	8	20,880	8/24/2015	14,100	13,188	12,645	12,364	12,280	12,558	13,462	14,829	16,197	17,212	18,018	18,797	19,404	19,902	20,441	20,707	20,833	20,880	20,856	20,370	19,964	19,793	18,536	16,877
Summer	8	21,733	8/25/2015	15,268	14,110	13,392	12,917	12,721	12,944	13,778	15,155	16,572	17,584	18,447	19,317	19,997	20,542	21,045	21,454	21,660	21,733	21,562	21,003	20,633	20,311	18,965	17,201
Summer	8	20,376	8/26/2015	15,538	14,315	13,515	12,996	12,725	12,819	13,617	14,933	16,144	17,058	17,879	18,655	19,262	19,670	20,085	20,301	20,376	20,334	20,076	19,365	18,848	18,563	17,267	15,567
Summer	8	18,281	8/27/2015	13,936	12,787	12,098	11,656	11,454	11,582	12,280	13,463	14,744	15,703	16,394	17,004	17,459	17,769	18,120	18,274	18,281	18,272	18,185	17,709	17,416	17,311	16,193	14,647
Summer	8	17,691	8/28/2015	13,195	12,156	11,496	11,112	10,924	11,042	11,776	12,939	14,186	15,152	15,866	16,444	16,878	17,147	17,445	17,562	17,595	17,691	17,556	17,054	16,768	16,576	15,614	14,309
Summer	8	16,517	8/29/2015	12,985	11,945	11,288	10,840	10,576	10,530	10,738	11,088	11,962	13,134	14,120	14,773	15,200	15,491	15,704	15,905	16,140	16,410	16,517	16,250	16,139	16,078	15,298	14,227
Summer	8	18,767	8/30/2015	13,096	12,221	11,600	11,210	10,992	10,921	11,019	11,233	11,984	13,162	14,354	15,424	16,391	17,056	17,503	17,840	18,171	18,550	18,767	18,612	18,758	18,710	17,596	16,110
Summer	8	22,568	8/31/2015	14,697	13,634	12,987	12,564	12,400	12,603	13,538	14,981	16,409	17,562	18,637	19,701	20,624	21,298	21,887	22,221	22,419	22,568	22,484	21,898	21,655	21,199	19,624	17,609
Fall	9	21,458	9/1/2015	15,766	14,522	13,684	13,115	12,796	12,885	13,679	15,033	16,250	17,251	18,173	19,040	19,641	20,126	20,702	21,038	21,301	21,458	21,245	20,552	20,231	19,788	18,249	16,370
Fall	9	22,766	9/2/2015	14,655	13,526	12,776	12,326	12,111	12,281	13,186	14,690	15,919	16,851	17,851	18,915	19,911	20,727	21,533	22,072	22,520	22,766	22,595	21,906	21,567	21,011	19,392	17,398
Fall	9	22,759	9/3/2015	15,599	14,359	13,553	13,062	12,785	12,908	13,772	15,264	16,484	17,503	18,541	19,596	20,547	21,351	22,097	22,460	22,707	22,759	22,350	21,714	21,608	21,121	19,658	17,756
Fall	9	18,396	9/4/2015	16,014	14,814	14,019	13,522	13,225	13,301	13,951	15,151	16,106	16,728	17,174	17,595	17,949	18,143	18,333	18,396	18,355	18,343	18,090	17,381	17,115	16,742	15,692	14,314
Fall	9	15,974	9/5/2015	12,956	11,915	11,246	10,809	10,528	10,476	10,674	10,987	11,748	12,815	13,651	14,193	14,537	14,815	15,051	15,291	15,571	15,851	15,974	15,690	15,587	15,359	14,527	13,411
Fall	9	17,102	9/6/2015	12,262	11,364	10,797	10,441	10,233	10,186	10,301	10,480	11,163	12,243	13,166	13,947	14,648	15,228	15,721	16,136	16,584	16,978	17,102	16,719	16,556	16,251	15,359	14,237
Fall	9	20,921	9/7/2015	13,071	12,127	11,500	11,102	10,883	10,868	11,134	11,449	12,176	13,389	14,679	15,884	16,996	17,963	18,800	19,535	20,158	20,699	20,921	20,570	20,664	20,301	18,862	17,000
Fall	9	24,368	9/8/2015	15,383	14,269	13,601	13,194	12,999	13,209	14,192	15,904	17,322	18,527	19,766	21,045	22,186	23,167	23,963	24,291	24,368	24,338	24,032	23,444	23,380	22,570	20,841	18,725
Fall	9	24,275	9/9/2015	16,886	15,577	14,750	14,237	13,974	14,081	14,983	16,547	17,786	18,830	19,918	21,031	21,920	22,706	23,492	23,961	24,199	24,275	23,917	23,267	23,202	22,483	20,960	18,908
Fall	9	19,108	9/10/2015	17,067	15,790	15,021	14,508	14,240	14,291	15,170	16,775	17,806	18,335	18,768	19,048	19,108	19,067	18,947	18,593	18,313	18,198	18,131	17,970	18,003	17,369	16,174	14,838
Fall	9	16,866	9/11/2015	13,504	12,490	11,876	11,490	11,363	11,555	12,429	14,049	15,093	15,632	16,012	16,294	16,418	16,444	16,633	16,729	16,799	16,866	16,764	16,424	16,519	16,094	15,097	13,844
Fall	9	15,638	9/12/2015	12,606	11,652	11,057	10,676	10,498	10,490	10,767	11,244	12,077	13,099	13,878	14,446	14,808	15,056	15,218	15,303	15,397	15,395	15,342	15,364	15,638	15,255	14,471	13,468
Fall	9	15,810	9/13/2015	12,396	11,563	11,028	10,667	10,484	10,437	10,588	10,929	11,535	12,523

Contains Proprietary Material
Do Not Distribute

Fall	9	15,610	9/21/2015	11,104	10,329	9,905	9,681	9,666	9,936	10,890	12,480	13,425	13,852	14,177	14,466	14,653	14,719	14,900	14,913	14,906	14,984	15,068	15,216	15,610	14,930	13,764	12,343
Fall	9	15,611	9/22/2015	11,162	10,384	9,959	9,756	9,717	10,010	10,950	12,692	13,725	14,111	14,454	14,790	14,948	14,984	15,090	15,051	15,047	15,086	15,129	15,219	15,611	14,991	13,844	12,431
Fall	9	15,879	9/23/2015	11,185	10,415	9,986	9,774	9,706	9,958	10,867	12,427	13,389	13,862	14,192	14,534	14,762	14,891	15,103	15,225	15,352	15,526	15,607	15,564	15,879	15,220	14,026	12,574
Fall	9	16,032	9/24/2015	11,332	10,506	10,076	9,833	9,743	10,027	10,965	12,628	13,619	14,108	14,503	14,891	15,165	15,316	15,550	15,621	15,682	15,764	15,715	15,663	16,032	15,399	14,217	12,781
Fall	9	14,817	9/25/2015	11,493	10,658	10,175	9,884	9,797	10,014	10,907	12,496	13,458	13,953	14,264	14,541	14,668	14,653	14,726	14,701	14,613	14,608	14,545	14,595	14,817	14,237	13,369	12,251
Fall	9	13,602	9/26/2015	11,150	10,319	9,826	9,567	9,453	9,501	9,818	10,430	11,206	12,076	12,571	12,746	12,770	12,678	12,534	12,433	12,458	12,635	12,899	13,256	13,602	13,174	12,453	11,523
Fall	9	14,456	9/27/2015	10,577	9,876	9,434	9,192	9,086	9,119	9,355	9,769	10,424	11,259	11,808	12,078	12,253	12,392	12,437	12,489	12,628	13,035	13,511	13,987	14,456	13,827	12,810	11,641
Fall	9	16,780	9/28/2015	10,672	9,966	9,583	9,411	9,392	9,698	10,712	12,487	13,529	14,034	14,478	14,907	15,233	15,486	15,792	15,891	15,938	16,060	16,199	16,475	16,780	16,030	14,790	13,359
Fall	9	18,219	9/29/2015	12,089	11,227	10,738	10,486	10,423	10,725	11,795	13,727	14,882	15,495	16,035	16,558	17,012	17,359	17,670	17,758	17,759	17,791	17,860	18,151	18,219	17,473	16,266	14,757
Fall	9	18,044	9/30/2015	13,422	12,514	12,020	11,760	11,671	11,969	13,031	15,035	16,349	16,991	17,450	17,872	18,044	18,027	17,920	17,589	17,114	16,785	16,685	16,695	16,660	15,895	14,637	13,133
Fall	10	15,367	10/1/2015	11,765	10,835	10,321	10,016	9,930	10,154	11,048	12,813	13,801	14,154	14,346	14,525	14,522	14,481	14,490	14,397	14,369	14,470	14,779	15,260	15,367	14,713	13,675	12,292
Fall	10	14,927	10/2/2015	11,098	10,324	9,874	9,648	9,590	9,828	10,759	12,538	13,599	14,059	14,291	14,447	14,452	14,404	14,364	14,231	14,186	14,293	14,550	14,927	14,844	14,256	13,424	12,332
Fall	10	14,032	10/3/2015	11,226	10,430	9,977	9,695	9,566	9,657	9,995	10,716	11,611	12,569	13,229	13,509	13,519	13,409	13,178	12,990	12,938	13,068	13,418	13,962	14,032	13,583	12,903	11,983
Fall	10	14,440	10/4/2015	11,022	10,263	9,811	9,531	9,400	9,417	9,662	10,126	10,746	11,604	12,145	12,355	12,442	12,413	12,289	12,194	12,295	12,658	13,255	14,047	14,440	13,835	12,833	11,657
Fall	10	15,416	10/5/2015	10,603	9,937	9,595	9,436	9,466	9,825	10,898	12,792	13,803	14,063	14,144	14,253	14,283	14,261	14,280	14,181	14,107	14,250	14,584	15,191	15,416	14,720	13,580	12,193
Fall	10	15,427	10/6/2015	11,039	10,295	9,894	9,692	9,680	9,979	11,005	12,882	13,825	13,989	14,053	14,144	14,190	14,176	14,257	14,203	14,199	14,402	14,704	15,267	15,427	14,740	13,612	12,198
Fall	10	15,509	10/7/2015	10,974	10,200	9,818	9,624	9,590	9,879	10,866	12,744	13,766	13,969	14,091	14,221	14,308	14,297	14,389	14,417	14,456	14,635	14,868	15,343	15,509	14,825	13,693	12,280
Fall	10	15,192	10/8/2015	11,050	10,289	9,855	9,671	9,613	9,884	10,856	12,687	13,643	13,844	13,920	14,024	14,031	14,037	14,104	14,055	14,039	14,178	14,404	14,998	15,192	14,585	13,581	12,233
Fall	10	15,478	10/9/2015	11,009	10,223	9,826	9,633	9,592	9,858	10,784	12,568	13,690	14,206	14,577	14,916	15,056	15,065	15,101	15,010	14,911	15,014	15,237	15,478	15,146	14,487	13,609	12,485
Fall	10	13,613	10/10/2015	11,320	10,460	9,921	9,596	9,445	9,491	9,843	10,540	11,298	12,121	12,540	12,645	12,534	12,346	12,139	11,995	12,031	12,318	12,794	13,495	13,613	13,192	12,547	11,667
Fall	10	13,768	10/11/2015	10,752	10,052	9,645	9,403	9,311	9,351	9,610	10,100	10,696	11,494	12,013	12,192	12,190	12,118	12,031	12,005	12,160	12,553	13,015	13,678	13,768	13,280	12,393	11,452
Fall	10	15,334	10/12/2015	10,525	9,826	9,464	9,265	9,230	9,479	10,175	11,374	12,296	13,006	13,493	13,783	13,908	13,931	13,979	13,989	14,072	14,335	14,727	15,334	15,310	14,545	13,418	12,099
Fall	10	15,855	10/13/2015	10,920	10,158	9,729	9,514	9,485	9,782	10,811	12,691	13,822	14,258	14,596	14,776	14,841	14,904	15,003	14,957	14,881	14,993	15,246	15,855	15,741	14,992	13,858	12,496
Fall	10	15,285	10/14/2015	11,266	10,417	9,945	9,672	9,609	9,863	10,848	12,642	13,595	13,871	14,074	14,293	14,405	14,406	14,416	14,320	14,240	14,311	14,602	15,285	15,273	14,578	13,446	12,086
Fall	10	15,204	10/15/2015	10,909	10,151	9,740	9,513	9,510	9,803	10,852	12,766	13,764	13,924	13,912	13,898	13,850	13,761	13,787	13,731	13,748	13,992	14,380	15,152	15,204	14,605	13,586	12,247
Fall	10	14,673	10/16/2015	11,052	10,273	9,845	9,598	9,571	9,856	10,870	12,730	13,802	14,125	14,259	14,294	14,180	14,021	13,941	13,820	13,718	13,795	14,055	14,673	14,570	14,041	13,277	12,227
Fall	10	14,091	10/17/2015	11,160	10,366	9,917	9,684	9,597	9,694	10,085	10,870	11,737	12,543	12,897	12,973	12,878	12,724	12,527	12,409	12,438	12,740	13,304	14,091	14,035	13,595	12,988	12,135
Fall	10	15,285	10/18/2015	11,212	10,512	10,117	9,888	9,802	9,889	10,210	10,809	11,492	12,326	12,745	12,867	12,945	13,012	13,061	13,055	13,174	13,601	14,328	15,284	15,285	14,776	13,811	12,762
Fall	10	16,227	10/19/2015	11,775	11,025	10,616	10,486	10,523	10,940	12,114	14,174	15,287	15,404	15,260	15,129	14,906	14,635	14,446	14,247	14,198	14,524	15,242	16,227	16,168	15,486	14,375	12,946
Fall	10	15,710	10/20/2015	11,701	10,891	10,472	10,263	10,222	10,515	11,588	13,526	14,514	14,626	14,594	14,622	14,563	14,420	14,349	14,208	14,181	14,397	14,856	15,710	15,579	14,854	13,738	12,352
Fall	10	15,580	10/21/2015	11,147	10,386	9,976	9,754	9,714	10,004	11,011	12,949	14,054	14,331	14,477	14,586	14,569	14,439	14,406	14,292	14,259	14,421	14,847	15,580	15,400	14,715	13,624	12,291
Fall	10	15,656	10/22/2015	11,102	10,342	9,914	9,676	9,645	9,937	10,990	12,925	13,990	14,210	14,359	14,524	14,598	14,568	14,598	14,555	14,509	14,640	15,050	15,656	15,409	14,737	13,675	12,323
Fall	10	14,975	10/23/2015	11,081	10,289	9,795	9,536	9,460	9,763	10,768	12,659	13,740	14,002	14,089	14,112	14,058	13,939	13,865	13,737	13,625	13,810	14,263	14,975	14,778	14,335	13,601	12,589
Fall	10	14,399	10/24/2015	11,518	10,767	10,341	10,104	10,056	10,178	10,603	11,442	12,288	13,182	13,598	13,632	13,534	13,368	13,176	13,044	13,092	13,359	13,934	14,399	14,126	13,624	12,969	12,062
Fall	10	14,578	10/25/2015	11,109	10,367	9,911	9,632	9,507	9,540	9,782	10,304	11,042	11,931	12,739	13,163	13,383	13,455	13,230	13,003	12,905	13,111	13,687	14,578	14,399	13,756	12,768	11,631
Fall	10	15,792	10/26/2015	10,624	9,997	9,670	9,508	9,542	9,933	11,137	13,213	14,342	14,412	14,303	14,251	14,124	13,954	13,864	13,730	13,731	14,034	14,787	15,792	15,638	15,004	14,004	12,653
Fall	10	15,868	10/27/2015	11,496	10,786	10,427	10,280	10,308	10,663	11,822	13,883	14,921	14,956	14,722	14,446	14,330	14,108	14,002	13,862	13,878	14,180	14,916	15,868	15,663	15,021	13,978	12,622
Fall	10	16,247	10/28/2015	11,482	10,755	10,355	10,149	10,140	10,456	11,554	13,562	14,612	14,722	14,797	14,878	14,830	14,817	14,931	14,884	14,943	15,328	16,023	16,247	15,836	15,187	14,111	12,795
Fall	10	15,494	10/29/2015	11,587	10,804	10,352	10,135	10,075	10,312	11,333	13,240	14,525	14,795	14,933	15,008	14,933	14,880	14,898	14,670	14,453	14,396	14,767	15,494	15,244	14,616	13,545	12,273
Fall	10	14,820	10/30/2015	11,151	10,292	9,816	9,552	9,508	9,778	10,783	12,726	13,834	13,985	14,002	14,076	14,028	13,829	13,700	13,503	13,475	13,675	14,158	14,820	14,538	14,049	13,327	12,353
Fall	10	13,708	10/31/2015	11,287	10,569	10,140	9,920	9,838	9,987	10,445	11,267	12,133	12,912	13,234	13,199	12,993	12,784	12,610	12,484	12,515	12,841	13,372	13,708	13,370	13,051	12,540	11,755
Fall	11	14,993	11/1/2015	10,562	9,651	9,384	9,367	9,485	9,836	10,439	11,259	12,189	12,839	13,163	13,278	13,205	13,074	12,956	13,023	13,825	14,993	14,773	14,244	13,542	12,490	11,373	10,491
Fall	11	15,931	11/2/2015	9,937	9,603	9,503	9,557	9,979	11,198	13,009	13,902	14,061	14,076	14,162	14,134	14,093	14,053	14,009	14,088	14,810	15,931	15,723	15,166	14,384	13,310	12,064	11,000
Fall	11	15,937	11/3/2015	10,348	9,989	9,828	9,844	10,229	11,377	13,089	13,924	13,992	14,026	14,110	14,143	14,118	14,218	14,238	14,321	14,866	15,937	15,780	15,220	14,421	13,292	11,976	10,875
Fall	11	15,825	11/4/2015	10,215	9,859	9,677	9,702	10,061	11,186	12,948	13,843	13,926	13,927	14,009	14,038	13,997	14,059	14,054	14,165	14,731	15,825	15,693	15,178	14,432	13,311	12,035	10,929
Fall	11	16,157	11/5/2015	10,242	9,874	9,689	9,694	10,041	11,135	12,906	13,824	14,085	14,254	14,424	14,541	14,576	14,619	14,608	14,610	15,203	16,157	15,917	15,409	14,707	13,614	12,279	11,124
Fall	11	16,006	11/6/2015	10,412	9,981	9,768	9,719	10,024	11,026	12,785	13,840	14,355	14,714	14,943	14,986	14,889	15,006	14,878	14,803	15,313	16,006	15,621	15,011	14,348	13,450	12,357	11,232
Fall	11	14,357	11/7/2015	10,341	9,811	9,528	9,396	9,452	9,853	10,455	11,262	12,127	12,648	12,842	12,851	12,760	12,625	12,596	12,761	13,584	14,357	14,021	13,589	13,044	12,344	11,527	10,686
Fall	11	14,918	11/8/2015	10,024	9,619	9,376	9,318	9,415	9,723	10,214	10,899	11,615	12,036	12,185	12,275	12,336	12,300	12,351	12,609	13,645	14,918	14,783	14,372	13,766	12,796	11,728	10,837
Fall	11	16,203	11/9/2015	10,264	9,972	9,838	9,904	10,344	11,564	13,412	14,297	14,288	14,187	14,159	14,065	13,980	13,980	13,986	14,128	15,073	16,203	16,061	15,550	14,819	13,720	12,395	11,272
Fall	11	16,326	11/10/2015	10,571	10,210	10,031	10,051	10,431	11,567	13,452	14,367	14,562	14,607	14,651	14,618	14,591	14,653	14,612	14,773	15,561	16,326	16,075	15,527	14,826	13,762	12,527	11,403
Fall	11	16,431	11/11/2015	10,648	10,237	10,018	9,998	10,263	11,137	12,514	13,615	14,311	14,726	14,962	15,017	14,939	14,907	14,823	14,912	15,716	16,431	16,092	15,529	14,825	13,721	12,411	11,316
Fall	11	16,415	11/12/2015	10,601	10,210	9,985	10,006	10,332	11,424	13,291	14,303	14,686	14,897	15,049	15,166	15,130	15,122	15,053	15,161	15,848	16,415	16,150	15,620	14,928	13,832	12,485	11,347
Fall	11	15,665	11/13/2015	10,539	10,092	9,863	9,851	10,168	11,205	12,947	13,820	13,992	14,068	14,195	14,164	14,032	14,091	14,058	14,123	14,875	15,665	15,391	14,882	14,293	13,462	12,426	11,381
Fall	11	15,304	11/14/2015	10,625	10,214	9,985	9,881	10,020	10,488	11,207	12,010	12,819	13,265	13,526	13,542	13,354	13,104	13,072	13,326	14,330	15,304	15,058	14,622	14,169	13,469	12,575	11,707
Fall	11	15,262	11/15/2015	11,029	10,589	10,343	10,280	10,353	10,684	11,178	11,758	12,389	12,811	12,940	13,001	12,961	12,830	12,865	13,234	14,364	15,262	15,081	14,448	14,043	13,041	11,884	11,010
Fall	11	16,287	11/16/2015	10,266	9,930	9,813	9,884	10,343	11,519	13,427	14,369	14,444	14,330	14,254	14,231	14,137	14,150	14,114	14,275	15,224	16,287	16,161	15,716	15,009	13,880	12,603	11,464
Fall	11	16,616	11/17/2015	10,819	10,506	10,359	10,422	10,845	12,070	13,987	14,824	14,777	14,586	14,440	14,254	14,114	14,104	14,117	14,422	15,519	16,616	16,570	16,237	15,651	14,553	13,234	12,112
Fall	11	16,647	11/18/2015	11,426	11,100	10,939	10,992	11,415	12,605	14,481	15,317	15,228	15,064	14,855	14,642	14,425	14,391	14,412	14,659	15,780	16,647	16,474	16,075	15,395	14,290	12,878	11,682
Fall	11	16,355	11/19/2015	10,909	10,461	10,254	10,233	10,568	11,672	13,581	14,532	14,759	14,855	14,929	14,939	14,852	14,832	14,804	14,982	15,834	16,355	16,113	15,649	14,952	13,849	12,517	11,378
Fall	11	15,576	11/20/2015	10,617	10,198	9,971	9,912	10,194	11,192	13,011	13,961	14,161	14,207	14,195	14,107	13,936	13,899	13,861	13,982	14,765	15,576	15,279	14,813	14,283	13,504	12,530	11,542
Fall	11	15,124	11/21/2015	10,828	10,433	10,230	10,167	10,341	10,842	11,607	12,418	13,183	13,467	13,391	13,227	13,000	12,842	12,840	13,103	14,191	15,124	14,909	14,487	14,038	13,355	12,497	11,576
Fall	11	15,744	11/22/2015	10,798	10,398	10,093	10,002	10,065	10,375	10,896	11,567	12,489	13,117	13,410	13,660	13,815	13,881	13,905	14,194	15,199	15,744	15,518	15,040	14,425	13,475	12,432	11,467
Fall	11	17,439	11/23/2015	10,832	10,504	10,368	10,469	10,906	12,099	14,108	15,062	15,162	15,033	14,985	14,886	14,745	14,790	14,867	15,191	16,378	17,439	17,362	17,000	16,450	15,408	14,176	13,018
Fall	11	17,211	11/24/2015	12,217	11,728	11,541	11,561	12,008	13,168	15,058	15,941	15,918	15,679	15,504	15,283	15,077	15,016	14,995	15,235	16,289	17,211	17,147	16,861	16,275	15,284	13,986	12,792
Fall	11	16,828	11/25/2015	12,035	11,599	11,421	11,456	11,857	12,911	14,577	15,562	15,764	15,626	15,426	15,184	14,898	14,831	14,786	14,935	15,946	16,828	16,577	16,131	15,563	14,667	13,510	12,301
Fall	11	14,394	11/26/2015	11,412	10,880	10,579	10,460	10,569	10,996	11,667	12,499	13,435	14,013	14,287	14,394	13,997	13,274	12,611	12,235	12,630	12,919	12,812	12,703	12,552	12,120	11,507	10,761
Fall	11	14,683	11/27/2015	10,163	9,832	9,633	9,619	9,796	10,344	11,103	11,684	12,310	12,737	12,847	12,828	12,760	12,688	12,673	12,874	13,961	14,683	14,388	13,912	13,400	12,681	11,786	10,831
Fall	11	14,954	11/28/2015	10,070	9,614	9,331	9,236	9,327	9,685	10,333	11,114	12,150	12,939	13,435	13,654	13,706	13,630	13,497	13,681	14,534	14,954	14,692	14,306	13,880	13,254	12,390	11,486
Fall	11	16,211	11/29/2015	10,735	10,358	10,154	10,103	10,226	10,567	11,167	11,827	12,617	13,069	13,177	13,202	13,183	13,159	13,257	13,673	15,132	16,211	16,201	15,839	15,305	14,351	13,292	12,273
Fall	11	17,692	11/30/2015	11,514	11,108	10,961	11,031	11,486	12,698	14,513	15,600	15,732	15,665	15,599	15,528	15,418	15,481	15,470	15,707	16,831	17,692	17,605	17,189	16,538	15,417	13,969	12,695

Contains Proprietary Material
Do Not Distribute

Max	6,419
Max Month	7
PST	5,054
Winter	4,497
Spring	3,789
Summer	4,827
Fall	4,005

Source: ISONE 2015 SIL Filing

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	4,108	12/1/2014	2,619	2,462	2,403	2,390	2,407	2,552	2,964	3,424	3,536	3,505	3,522	3,526	3,546	3,531	3,534	3,522	3,626	3,992	4,108	4,052	3,927	3,775	3,461	3,112
Winter	12	4,392	12/2/2014	2,813	2,665	2,604	2,578	2,602	2,788	3,204	3,695	3,852	3,860	3,831	3,839	3,811	3,837	3,838	3,868	3,997	4,329	4,392	4,323	4,233	4,009	3,666	3,255
Winter	12	4,285	12/3/2014	2,959	2,808	2,723	2,676	2,700	2,850	3,202	3,669	3,809	3,857	3,885	3,872	3,845	3,839	3,812	3,842	3,970	4,231	4,285	4,196	4,085	3,885	3,576	3,183
Winter	12	4,322	12/4/2014	2,926	2,772	2,694	2,678	2,727	2,891	3,324	3,789	3,887	3,813	3,773	3,729	3,639	3,646	3,656	3,672	3,809	4,237	4,322	4,265	4,171	4,019	3,735	3,370
Winter	12	4,313	12/5/2014	3,089	2,926	2,825	2,843	2,881	3,025	3,458	3,888	4,012	3,958	3,975	3,931	3,868	3,891	3,902	3,895	4,024	4,313	4,312	4,233	4,051	3,867	3,628	3,322
Winter	12	4,023	12/6/2014	3,010	2,827	2,711	2,650	2,618	2,662	2,826	3,058	3,299	3,539	3,680	3,739	3,721	3,711	3,667	3,648	3,729	4,023	3,996	3,892	3,757	3,646	3,440	3,199
Winter	12	4,273	12/7/2014	2,934	2,753	2,638	2,594	2,599	2,649	2,763	2,937	3,150	3,382	3,459	3,479	3,467	3,435	3,418	3,455	3,613	4,166	4,273	4,260	4,181	4,032	3,745	3,431
Winter	12	4,830	12/8/2014	3,183	3,029	2,976	2,970	3,026	3,201	3,618	4,086	4,282	4,314	4,341	4,363	4,313	4,306	4,310	4,299	4,429	4,737	4,830	4,709	4,590	4,390	4,033	3,613
Winter	12	4,627	12/9/2014	3,284	3,076	2,984	2,938	2,932	3,098	3,426	3,837	4,121	4,202	4,256	4,308	4,300	4,325	4,292	4,270	4,320	4,593	4,627	4,525	4,371	4,074	3,796	3,352
Winter	12	4,514	12/10/2014	3,044	2,884	2,783	2,744	2,763	2,915	3,290	3,809	3,916	3,945	3,963	3,947	3,949	3,969	3,923	3,855	4,075	4,443	4,514	4,478	4,367	4,155	3,819	3,422
Winter	12	4,578	12/11/2014	3,118	2,957	2,852	2,826	2,871	3,011	3,425	3,855	4,017	4,043	4,043	4,053	4,027	4,007	4,012	3,987	4,089	4,469	4,578	4,490	4,382	4,203	3,873	3,478
Winter	12	4,427	12/12/2014	3,167	2,992	2,928	2,908	2,944	3,078	3,470	3,967	4,065	4,057	4,059	4,027	3,943	3,950	3,888	3,875	3,969	4,393	4,427	4,331	4,172	4,043	3,813	3,500
Winter	12	4,102	12/13/2014	3,174	2,959	2,870	2,825	2,815	2,872	3,015	3,258	3,476	3,644	3,694	3,649	3,578	3,487	3,452	3,426	3,567	4,021	4,102	4,014	3,905	3,767	3,617	3,353
Winter	12	4,170	12/14/2014	3,062	2,884	2,781	2,717	2,709	2,746	2,834	2,978	3,123	3,383	3,454	3,499	3,498	3,525	3,427	3,461	3,577	4,094	4,170	4,110	4,046	3,853	3,602	3,238
Winter	12	4,443	12/15/2014	2,929	2,794	2,720	2,704	2,742	2,943	3,341	3,833	3,950	3,931	3,856	3,798	3,734	3,721	3,675	3,654	3,781	4,307	4,443	4,385	4,292	4,122	3,803	3,416
Winter	12	4,518	12/16/2014	3,069	2,919	2,841	2,824	2,850	3,030	3,414	3,909	4,054	4,036	4,068	4,062	4,008	4,012	3,979	3,962	4,076	4,438	4,518	4,421	4,289	4,087	3,749	3,332
Winter	12	4,302	12/17/2014	2,970	2,792	2,687	2,635	2,655	2,798	3,164	3,678	3,806	3,789	3,736	3,695	3,660	3,642	3,650	3,679	3,830	4,221	4,302	4,239	4,127	3,926	3,640	3,253
Winter	12	4,439	12/18/2014	2,925	2,746	2,646	2,630	2,660	2,806	3,240	3,728	3,879	3,838	3,862	3,890	3,824	3,764	3,760	3,783	3,897	4,335	4,439	4,365	4,272	4,116	3,821	3,429
Winter	12	4,481	12/19/2014	3,059	2,867	2,796	2,746	2,778	2,929	3,319	3,795	3,979	3,966	3,999	3,940	3,851	3,851	3,808	3,861	3,981	4,369	4,481	4,362	4,225	4,080	3,870	3,565
Winter	12	4,280	12/20/2014	3,223	3,022	2,892	2,859	2,854	2,917	3,054	3,295	3,554	3,772	3,869	3,918	3,947	3,880	3,851	3,847	3,944	4,253	4,280	4,147	4,043	3,917	3,719	3,452
Winter	12	4,295	12/21/2014	3,141	2,958	2,827	2,783	2,660	2,787	2,904	3,067	3,282	3,554	3,657	3,741	3,770	3,769	3,735	3,752	3,844	4,249	4,295	4,258	4,154	3,995	3,710	3,352
Winter	12	4,411	12/22/2014	3,048	2,868	2,784	2,737	2,777	2,916	3,282	3,763	3,927	3,950	3,957	3,928	3,874	3,828	3,795	3,814	3,955	4,338	4,411	4,342	4,207	4,019	3,713	3,333
Winter	12	4,279	12/23/2014	2,998	2,783	2,669	2,634	2,654	2,777	3,140	3,588	3,800	3,839	3,890	3,879	3,871	3,836	3,847	3,817	3,873	4,224	4,279	4,186	4,072	3,919	3,655	3,300
Winter	12	4,005	12/24/2014	2,967	2,725	2,578	2,524	2,543	2,640	2,853	3,197	3,440	3,642	3,792	3,888	3,849	3,853	3,820	3,793	3,841	4,005	3,944	3,677	3,526	3,377	3,249	3,077
Winter	12	3,364	12/25/2014	2,825	2,570	2,435	2,353	2,297	2,341	2,428	2,569	2,815	3,063	3,211	3,209	3,200	3,206	3,135	3,076	3,049	3,338	3,363	3,364	3,347	3,292	3,163	2,935
Winter	12	3,919	12/26/2014	2,729	2,547	2,488	2,466	2,501	2,581	2,776	3,022	3,184	3,345	3,425	3,428	3,400	3,361	3,288	3,270	3,340	3,813	3,919	3,875	3,752	3,644	3,442	3,174
Winter	12	3,726	12/27/2014	2,938	2,767	2,655	2,602	2,608	2,667	2,769	2,932	3,104	3,281	3,356	3,357	3,279	3,219	3,118	3,087	3,188	3,635	3,726	3,680	3,574	3,447	3,301	3,062
Winter	12	3,821	12/28/2014	2,838	2,616	2,497	2,438	2,409	2,432	2,504	2,662	2,794	3,049	3,202	3,321	3,301	3,335	3,272	3,266	3,372	3,770	3,821	3,756	3,645	3,488	3,289	3,006
Winter	12	4,271	12/29/2014	2,793	2,632	2,558	2,538	2,575	2,746	3,014	3,367	3,586	3,711	3,701	3,693	3,701	3,642	3,632	3,625	3,685	4,167	4,271	4,172	4,063	3,884	3,656	3,339
Winter	12	4,547	12/30/2014	3,072	2,885	2,816	2,799	2,838	2,994	3,263	3,606	3,805	3,926	4,028	4,035	3,961	3,933	3,866	3,863	3,959	4,403	4,547	4,452	4,353	4,176	3,931	3,619
Winter	12	4,440	12/31/2014	3,308	3,145	3,067	3,021	3,020	3,146	3,381	3,704	3,893	3,965	4,008	3,988	3,907	3,885	3,837	3,812	3,927	4,364	4,440	4,301	4,104	3,910	3,716	3,551
Winter	1	4,144	1/1/2015	3,394	3,243	3,112	3,032	3,002	3,036	3,127	3,232	3,254	3,371	3,481	3,565	3,569	3,538	3,503	3,501	3,609	4,051	4,144	4,077	3,946	3,796	3,536	3,279
Winter	1	4,208	1/2/2015	3,031	2,889	2,777	2,750	2,767	2,885	3,103	3,367	3,555	3,701	3,762	3,761	3,719	3,724	3,668	3,621	3,692	4,112	4,208	4,089	3,968	3,850	3,650	3,373
Winter	1	4,303	1/3/2015	3,112	2,968	2,866	2,824	2,831	2,899	3,021	3,181	3,358	3,507	3,648	3,698	3,740	3,736	3,772	3,815	3,907	4,266	4,303	4,192	4,021	3,811	3,595	3,317
Winter	1	4,044	1/4/2015	3,018	2,860	2,744	2,678	2,650	2,687	2,746	2,894	3,036	3,289	3,459	3,598	3,685	3,713	3,679	3,660	3,709	4,018	4,044	3,939	3,794	3,543	3,271	2,948
Winter	1	4,690	1/5/2015	2,695	2,560	2,505	2,498	2,531	2,720	3,119	3,644	3,770	3,766	3,817	3,857	3,825	3,838	3,822	3,869	3,998	4,469	4,690	4,650	4,554	4,352	4,037	3,679
Winter	1	4,897	1/6/2015	3,411	3,262	3,218	3,201	3,233	3,375	3,749	4,246	4,361	4,385	4,424	4,435	4,411	4,389	4,375	4,329	4,416	4,751	4,897	4,841	4,767	4,543	4,212	3,835
Winter	1	5,123	1/7/2015	3,568	3,441	3,354	3,318	3,336	3,471	3,837	4,336	4,431	4,374	4,378	4,371	4,344	4,356	4,341	4,417	4,520	4,902	5,123	5,027	5,018	4,869	4,546	4,170
Winter	1	5,110	1/8/2015	3,930	3,831	3,735	3,730	3,782	3,940	4,280	4,735	4,900	4,855	4,765	4,741	4,642	4,564	4,491	4,479	4,555	4,940	5,110	5,039	4,937	4,738	4,402	4,006
Winter	1	4,718	1/9/2015	3,726	3,560	3,466	3,405	3,401	3,533	3,837	4,281	4,437	4,502	4,572	4,591	4,455	4,355	4,301	4,206	4,265	4,575	4,718	4,629	4,476	4,314	4,091	3,792
Winter	1	4,594	1/10/2015	3,525	3,375	3,279	3,264	3,275	3,356	3,498	3,710	3,946	4,114	4,212	4,160	4,126	4,034	3,979	3,937	4,031	4,406	4,594	4,527	4,425	4,307	4,123	3,882
Winter	1	4,549	1/11/2015	3,636	3,468	3,376	3,317	3,330	3,382	3,476	3,608	3,761	3,939	4,003	4,049	4,076	4,082	4,064	4,074	4,081	4,437	4,549	4,430	4,304	4,091	3,770	3,429
Winter	1	4,599	1/12/2015	3,183	3,017	2,970	2,920	2,962	3,110	3,448	3,850	4,009	4,128	4,239	4,299	4,310	4,308	4,261	4,207	4,253	4,542	4,599	4,502	4,333	4,083	3,756	3,412
Winter	1	4,877	1/13/2015	3,134	2,980	2,914	2,885	2,925	3,127	3,547	4,049	4,190	4,170	4,157	4,169	4,129	4,110	4,076	4,064	4,208	4,628	4,877	4,807	4,716	4,562	4,255	3,894
Winter	1	4,863	1/14/2015	3,621	3,584	3,450	3,445	3,468	3,650	4,001	4,512	4,586	4,608	4,638	4,633	4,569	4,527	4,464	4,417	4,477	4,717	4,863	4,813	4,705	4,471	4,144	3,783
Winter	1	4,697	1/15/2015	3,518	3,347	3,286	3,268	3,316	3,473	3,854	4,328	4,417	4,357	4,311	4,276	4,180	4,114	4,091	4,038	4,102	4,444	4,697	4,611	4,523	4,339	4,046	3,665
Winter	1	4,585	1/16/2015	3,406	3,285	3,187	3,153	3,188	3,326	3,691	4,142	4,260	4,199	4,155	4,068	4,007	4,005	3,990	3,994	4,027	4,361	4,585	4,535	4,419	4,273	4,078	3,804
Winter	1	4,429	1/17/2015	3,576	3,425	3,347	3,299	3,335	3,415	3,566	3,772	3,976	4,147	4,198	4,138	4,056	3,951	3,856	3,810	3,883	4,199	4,429	4,327	4,232	4,081	3,880	3,623
Winter	1	4,177	1/18/2015	3,403	3,238	3,145	3,080	3,082	3,103	3,189	3,310	3,473	3,699	3,877	4,005	4,049	4,053	3,994	3,951	3,951	4,174	4,177	4,039	3,852	3,724	3,492	3,211
Winter	1	4,445	1/19/2015	2,969	2,836	2,747	2,733	2,776	2,886	3,152	3,437	3,679	3,805	3,929	3,968	3,941	3,921	3,919	3,907	3,925	4,250	4,445	4,356	4,225	4,021	3,713	3,350
Winter	1	4,437	1/20/2015	3,093	2,951	2,784	2,846	2,874	3,034	3,442	3,923	4,009	3,964	3,930	3,900	3,843	3,854	3,858	3,871	3,873	4,206	4,437	4,386	4,257	4,061	3,760	3,452
Winter	1	4,536	1/21/2015	3,207	3,110	3,020	3,012	3,067	3,247	3,660	4,136	4,226	4,185	4,142	4,120	4,083	4,035	3,938	3,903	3,993	4,322	4,536	4,443	4,346	4,117	3,791	3,438
Winter	1	4,392	1/22/2015	3,174	3,025	2,979	2,936	2,960	3,127	3,485	3,935	4,076	4,084	4,052	3,997	3,918	3,885	3,797	3,769	3,785	4,113	4,392	4,335	4,261	4,081	3,777	3,435
Winter	1	4,261	1/23/2015	3,183	3,073	2,998	2,996	3,029	3,217	3,612	4,071	4,186	4,091	4,053	3,984	3,875	3,798	3,740	3,740	3,779	4,073	4,261	4,182	4,037	3,921	3,657	3,388
Winter	1	4,195	1/24/2015	3,109	2,953	2,846	2,838	2,841	2,902	3,023	3,199	3,349	3,565	3,750	3,867	3,919	3,891	3,822	3,777	3,831	4,079	4,195	4,043	3,899	3,731	3,545	3,279
Winter	1	4,179	1/25/2015	3,045	2,886	2,819	2,764	2,750	2,805	2,891	3,050	3,210	3,398	3,473	3,493	3,478	3,434	3,403	3,426	3,542	3,877	4,173	4,179	4,086	3,944	3,712	3,448
Winter	1	4,859	1/26/2015	3,208	3,093	2,989	2,988	3,057	3,240	3,687	4,173	4,327	4,330	4,363	4,441	4,433	4,475	4,464	4,419	4,409	4,685	4,859	4,674	4,421	4,154	3,896	3,631
Winter	1	4,639	1/27/2015	3,384	3,275	3,206	3,179	3,211	3,269	3,389	3,537	3,647	3,841	3,939	3,964	3,964	3,975	3,950	3,959	4,050	4,387	4,639	4,526	4,364	4,169	3,894	3,628
Winter	1	4,759	1/28/2015	3,415	3,322	3,273	3,237	3,279	3,440	3,745	4,103	4,351	4,441	4,438	4,452	4,366	4,268	4,187	4,117	4,142	4,410	4,759	4,704	4,588	4,390	4,081	3,752
Winter	1	4,606	1/29/2015	3,500	3,393	3,355	3,359	3,381	3,525	3,987	4,422	4,511	4,420	4,358	4,232	4,147	4,081	4,020	4,030	4,106	4,342	4,606	4,521	4,416	4,184	3,882	3,506
Winter	1	4,463	1/30/2015	3,251	3,115	3,031	2,992	3,029	3,159	3,488	3,876	4,065	4,101	4,167	4,106	4,087	4,053	4,029	3,954	3,998	4,213	4,463	4,438	4,357	4,243	4,014	3,789
Winter	1	4,573	1/31/2015	3,542	3,443	3,369	3,395	3,421	3,497	3,681	3,887	4,097	4,285	4,342	4,314	4,248	4,186	4,049	4,018	4,036	4,254	4,573	4,526	4,428	4,331	4,108	3,846
Winter	2	4,341	2/1/2015	3,623	3,470	3,381	3,360	3,346	3,396	3,473	3,600	3,768	3,944	3,960	3,913	3,868	3,788	3,771	3,748	3,827	4,070	4,341	4,125	3,926	3,808	3,648	3,509
Winter	2	4,885	2/2/2015	3,268	3,111	3,018	3,037	3,087	3,220	3,431	3,704	3,891	4,109	4,259	4,387	4,450	4,437	4,465	4,418	4,413	4,590	4,885	4,735	4,623	4,369	4,069	3,777
Winter	2	4,775	2/3/2015	3,562	3,468	3,426	3,429	3,472	3,624	3,941	4,283	4,507	4,567	4,518	4,480	4,372	4,298	4,196	4,158	4,191	4,410	4,775	4,764	4,680	4,506	4,233	3,902
Winter	2	4,536	2/4/2015	3,684	3,471	3,429	3,426	3,438	3,563	3,905	4,355	4,358	4,366	4,368	4,311	4,243	4,173	4,101	4,078	4,060	4,227	4,536	4,513	4,345	4,207	3,857	3,507
Winter	2	4,796	2/5/2015	3,219	3,126	2,968	2,847	2,881	3,091	3,408	3,816	4,086	4,148	4,238	4,256	4,245	4,208	4,137	4,079	4,111	4,374	4,791	4,796	4,705	4,546	4,245	3,920
Winter	2	4,714	2/6/2015	3,720	3,583	3,473	3,484	3,518	3,719	3,985	4,517	4,600	4,520	4,541	4,536	4,493	4,370	4,275	4,217	4,317	4,318	4,714	4,665	4,551	4,401	4,196	3,999
Winter	2	4,314	2/7/2015	3,655	3,497	3,379	3,336	3,307	3,354	3,444	3,682	3,838	4,033	4,090	4,117	4,053	4,107	4,022	3,888	3,948	4,110	4,314	4,243	4,099	3,954	3,732	3,478
Winter	2	4,373	2/8/2015	3,251	3,094	3,028	2,998	2,969	2,963	3,037	3,180	3,344	3,590	3,748	3,823	3,826	3,842	3,810	3,834	3,841	4,131	4,373	4,323	4,218	4,003	3,792	3,549
Winter	2	4,859	2/9/2015	3,339	3,210	3,169	3,156	3,192	3,358	3,589	3,887	4,108	4,198	4,408	4,614	4,562	4,562	4,510	4,423	4,442	4,565	4,859	4,729	4,627	4,382	4,116	3,671
Winter	2	4,567	2/10/2015	3,577	3,350	3,260	3,235	3,249	3,398	3,689	4,021	4,291	4,313	4,258	4,206	4,150	4,093	4,039	3,976	3,964	4,109	4,567	4,497	4,316	4,190	3,949	3,586
Winter	2	4,549	2/11/2015	3,372	3,193	3,133	3,158	3,183	3,358	3,759	4,159	4,314	4,250	4,205	4,121	4,030	3,988	3,920	3,903	3,924	4,127	4,538	4,549	4,419	4,280	3,956	3,755
Winter	2	4,522	2/12/2015	3,432	3,323	3,225	3,228	3,275	3,400	3,680	4,149	4,290	4,257	4,276	4,238	4,138	4,108	4,087	3,900	4,074	4,246	4,522	4,506	4,432	4,277	4,047	3,687
Winter	2	4,763	2/13/2015	3,504	3,412	3,381	3,386	3,468	3,651	4,044	4,421	4,517	4,571	4,575	4,572	4,555	4,447	4,337	4,265	4,277	4,411	4,763	4,746	4,636	4,534	4,327	4,070
Winter	2	4,534	2/14/2015	3,831	3,711	3,673	3,624	3,646	3,696	3,860	4,016	4,218	4,422	4,415	4,257	4,325	4,235	4,121	4,122	4,147	4,276	4,534	4,461	4,310	4,147	3,900	3,719
Winter	2	4,791	2/15/2015	3,450	3,296	3,291	3,241	3,252	3,254	3,385	3,540	3,729	3,966	4,219	4,330	4,319	4,289	4,198	4,130	4,168	4,405	4,791	4,767	4,689	4,661	4,380	4,199
Winter	2	5,029	2/16/2015	3,978	3,860	3,827	3,821	3,860	3,971	4,158	4,438	4,681	4,811	4,882	4,811	4,796	4,703	4,577	4,555	4,572	4,661	5,029	4,971	4,861	4,715	4,401	4,019
Winter	2	4,934	2/17/2015	3,704	3,612	3,565	3,516	3,549	3,701	4,016	4,403	4,580	4,744	4,769	4,675	4,568	4,496	4,355	4,257	4,271	4,521	4,915	4,934	4,792	4,651	4,259	3,935

Contains Proprietary Material
Do Not Distribute

Winter	2	4,716	2/18/2015	3,764	3,616	3,521	3,525	3,634	3,649	4,176	4,566	4,703	4,716	4,544	4,480	4,324	4,253	4,136	4,108	4,084	4,276	4,690	4,662	4,477	4,489	4,059	3,651
Winter	2	5,186	2/19/2015	3,430	3,320	3,271	3,290	3,314	3,434	3,830	4,271	4,463	4,458	4,475	4,379	4,372	4,316	4,292	4,295	4,407	4,655	5,076	5,180	5,186	4,790	4,497	4,196
Winter	2	4,990	2/20/2015	3,946	3,900	3,860	3,840	3,911	4,085	4,441	4,853	4,964	4,966	4,971	4,852	4,804	4,745	4,578	4,540	4,522	4,657	4,976	4,990	4,934	4,792	4,572	4,303
Winter	2	4,671	2/21/2015	3,977	3,805	3,778	3,738	3,748	3,813	3,969	4,099	4,325	4,435	4,476	4,358	4,302	4,313	4,196	4,189	4,240	4,398	4,671	4,569	4,397	4,227	3,947	3,607
Winter	2	4,212	2/22/2015	3,379	3,231	3,106	3,043	3,035	3,066	3,093	3,242	3,393	3,627	3,671	3,780	3,668	3,625	3,562	3,528	3,560	3,729	4,186	4,212	3,978	3,917	3,679	3,360
Winter	2	4,963	2/23/2015	3,167	3,062	2,987	2,961	3,027	3,207	3,568	4,063	4,253	4,364	4,334	4,375	4,305	4,276	4,222	4,209	4,260	4,449	4,903	4,963	4,950	4,794	4,541	4,145
Winter	2	5,107	2/24/2015	3,884	3,786	3,738	3,738	3,829	3,963	4,381	4,735	4,786	4,783	4,754	4,718	4,579	4,488	4,406	4,391	4,490	4,658	5,081	5,107	4,999	4,637	4,295	3,897
Winter	2	4,551	2/25/2015	3,708	3,506	3,483	3,428	3,474	3,642	4,002	4,407	4,521	4,399	4,314	4,295	4,137	4,109	3,928	3,956	4,022	4,158	4,505	4,551	4,496	4,336	4,042	3,618
Winter	2	4,770	2/26/2015	3,420	3,316	3,285	3,228	3,214	3,387	3,778	4,197	4,457	4,423	4,450	4,453	4,419	4,299	4,206	4,183	4,203	4,437	4,769	4,770	4,636	4,417	4,134	3,781
Winter	2	4,529	2/27/2015	3,484	3,404	3,335	3,334	3,399	3,539	3,931	4,341	4,396	4,357	4,343	4,226	4,202	4,095	4,059	4,005	3,992	4,127	4,443	4,529	4,423	4,297	4,131	3,901
Winter	2	4,326	2/28/2015	3,608	3,497	3,435	3,403	3,431	3,516	3,707	3,816	4,070	4,157	4,147	4,121	4,019	3,875	3,810	3,725	3,708	3,860	4,121	4,326	4,200	4,180	4,052	3,773
Spring	3	4,553	3/1/2015	3,600	3,440	3,401	3,340	3,350	3,401	3,399	3,574	3,744	3,909	4,019	4,077	4,071	4,047	4,021	4,060	4,122	4,254	4,553	4,550	4,352	4,156	3,845	3,525
Spring	3	4,538	3/2/2015	3,295	3,180	3,112	3,095	3,126	3,258	3,509	3,848	4,090	4,111	4,061	4,105	4,070	4,018	3,958	3,929	4,010	4,111	4,400	4,538	4,392	4,292	3,956	3,750
Spring	3	4,720	3/3/2015	3,372	3,251	3,187	3,209	3,331	3,425	3,818	4,236	4,266	4,202	4,152	4,129	4,066	4,088	4,073	4,069	4,152	4,367	4,720	4,718	4,544	4,315	3,932	3,559
Spring	3	4,310	3/4/2015	3,217	3,112	3,031	2,989	3,007	3,150	3,460	3,805	3,968	4,052	4,017	3,995	3,955	3,954	3,869	3,868	3,902	4,022	4,310	4,299	4,236	3,970	3,642	3,301
Spring	3	4,645	3/5/2015	3,041	3,002	2,851	2,831	2,896	3,098	3,408	3,687	3,990	4,100	4,238	4,330	4,322	4,350	4,324	4,267	4,287	4,431	4,632	4,645	4,570	4,367	4,003	3,777
Spring	3	4,484	3/6/2015	3,529	3,381	3,361	3,343	3,383	3,543	3,927	4,352	4,423	4,366	4,313	4,271	4,176	4,097	4,019	3,963	3,932	4,069	4,361	4,484	4,376	4,260	4,088	3,754
Spring	3	4,068	3/7/2015	3,480	3,351	3,242	3,261	3,248	3,362	3,531	3,589	3,850	3,962	3,974	3,865	3,848	3,648	3,517	3,602	3,622	3,767	3,984	4,068	3,979	3,815	3,678	3,397
Spring	3	3,918	3/8/2015	3,153	3,043	2,981	2,994	2,919	2,921	2,982	3,123	3,179	3,444	3,543	3,550	3,511	3,503	3,444	3,344	3,383	3,426	3,552	3,785	3,918	3,802	3,597	3,299
Spring	3	4,060	3/9/2015	3,010	2,946	2,906	2,879	2,919	3,076	3,388	3,899	4,060	3,976	3,879	3,794	3,751	3,665	3,590	3,517	3,481	3,547	3,624	3,807	3,969	3,841	3,572	3,254
Spring	3	4,047	3/10/2015	3,054	2,880	2,818	2,812	2,846	3,011	3,362	3,878	4,004	3,922	3,840	3,789	3,731	3,677	3,610	3,592	3,637	3,731	3,860	3,930	4,047	3,884	3,561	3,234
Spring	3	3,779	3/11/2015	2,914	2,784	2,707	2,653	2,674	2,819	3,136	3,644	3,752	3,779	3,740	3,692	3,660	3,622	3,559	3,545	3,483	3,535	3,649	3,689	3,772	3,728	3,373	3,082
Spring	3	3,992	3/12/2015	2,756	2,681	2,626	2,593	2,616	2,732	3,172	3,663	3,809	3,753	3,669	3,707	3,719	3,574	3,537	3,474	3,486	3,551	3,627	3,821	3,992	3,885	3,623	3,304
Spring	3	4,015	3/13/2015	3,073	2,926	2,889	2,848	2,919	3,025	3,401	3,816	4,015	3,952	3,892	3,811	3,749	3,669	3,573	3,530	3,460	3,534	3,613	3,709	3,856	3,746	3,541	3,274
Spring	3	3,765	3/14/2015	3,060	2,895	2,767	2,700	2,696	2,702	2,799	3,076	3,283	3,521	3,689	3,753	3,765	3,690	3,564	3,560	3,472	3,511	3,574	3,653	3,616	3,490	3,294	3,119
Spring	3	3,850	3/15/2015	2,859	2,700	2,617	2,634	2,567	2,569	2,666	2,844	2,974	3,234	3,323	3,339	3,444	3,396	3,341	3,328	3,338	3,499	3,637	3,672	3,850	3,691	3,456	3,190
Spring	3	3,896	3/16/2015	2,909	2,801	2,742	2,731	2,781	2,872	3,302	3,770	3,854	3,746	3,766	3,723	3,615	3,575	3,485	3,492	3,440	3,471	3,602	3,764	3,896	3,752	3,429	3,103
Spring	3	3,991	3/17/2015	2,842	2,663	2,616	2,604	2,611	2,737	3,147	3,617	3,778	3,800	3,787	3,857	3,716	3,573	3,603	3,500	3,523	3,564	3,683	3,756	3,991	3,849	3,620	3,317
Spring	3	4,326	3/18/2015	3,079	2,949	2,858	2,864	2,894	2,953	3,443	3,874	4,025	3,956	3,935	3,925	3,887	3,900	3,807	3,804	3,735	3,786	3,989	4,083	4,326	4,118	3,832	3,471
Spring	3	4,152	3/19/2015	3,403	3,085	3,046	3,034	3,061	3,209	3,638	4,060	4,152	4,086	4,015	3,974	3,884	3,837	3,737	3,649	3,636	3,671	3,741	3,911	4,097	3,991	3,701	3,373
Spring	3	4,199	3/20/2015	3,153	3,013	2,938	2,900	2,973	3,081	3,479	3,915	4,057	4,054	4,047	4,064	4,033	4,041	4,036	3,980	3,999	4,070	4,141	4,146	4,199	4,012	3,793	3,510
Spring	3	3,818	3/21/2015	3,196	3,091	3,000	2,944	2,877	2,937	3,114	3,284	3,520	3,735	3,818	3,805	3,678	3,504	3,410	3,305	3,254	3,303	3,340	3,481	3,587	3,487	3,291	3,183
Spring	3	3,897	3/22/2015	2,834	2,755	2,758	2,667	2,673	2,705	2,819	2,952	3,113	3,327	3,413	3,445	3,415	3,386	3,259	3,264	3,278	3,376	3,502	3,650	3,897	3,806	3,567	3,337
Spring	3	4,184	3/23/2015	3,109	2,977	2,936	2,921	3,023	3,191	3,551	4,001	4,173	4,109	4,041	4,001	3,927	3,860	3,789	3,701	3,669	3,736	3,872	3,963	4,184	4,040	3,764	3,418
Spring	3	4,095	3/24/2015	3,174	3,152	3,010	2,942	2,951	3,110	3,547	4,001	4,095	4,055	3,967	3,892	3,796	3,739	3,680	3,586	3,553	3,581	3,738	3,841	4,055	3,906	3,632	3,260
Spring	3	4,055	3/25/2015	3,060	2,952	2,877	2,898	2,936	3,103	3,430	3,842	4,055	3,933	3,759	3,728	3,643	3,508	3,565	3,492	3,551	3,750	3,895	3,938	3,990	3,813	3,513	3,139
Spring	3	3,813	3/26/2015	2,859	2,738	2,659	2,627	2,635	2,779	3,147	3,582	3,720	3,740	3,730	3,747	3,706	3,688	3,726	3,669	3,687	3,672	3,741	3,813	3,806	3,647	3,327	3,032
Spring	3	3,759	3/27/2015	2,753	2,615	2,524	2,507	2,520	2,676	3,014	3,518	3,627	3,710	3,759	3,747	3,675	3,672	3,619	3,570	3,607	3,569	3,563	3,529	3,713	3,615	3,407	3,101
Spring	3	3,778	3/28/2015	2,926	2,730	2,643	2,597	2,609	2,658	2,797	3,002	3,276	3,529	3,669	3,678	3,693	3,622	3,560	3,500	3,464	3,469	3,549	3,698	3,778	3,657	3,519	3,274
Spring	3	3,497	3/29/2015	3,048	2,929	2,867	2,777	2,776	2,862	2,935	3,066	3,291	3,430	3,462	3,408	3,360	3,260	3,212	3,119	2,984	3,033	3,095	3,240	3,497	3,438	3,210	3,070
Spring	3	3,524	3/30/2015	2,877	2,763	2,717	2,739	2,706	2,640	2,900	3,248	3,430	3,517	3,495	3,524	3,468	3,373	3,249	3,189	3,199	3,187	3,283	3,364	3,372	3,382	3,196	3,126
Spring	3	3,735	3/31/2015	2,820	2,769	2,626	2,636	2,654	2,828	3,096	3,372	3,476	3,473	3,420	3,448	3,364	3,339	3,305	3,366	3,387	3,444	3,574	3,622	3,707	3,735	3,481	3,053
Spring	4	3,387	4/1/2015	2,862	2,742	2,668	2,662	2,684	2,606	2,964	3,247	3,387	3,367	3,280	3,220	3,136	3,107	3,110	3,091	2,999	3,043	3,130	3,230	3,386	3,282	3,203	2,986
Spring	4	3,450	4/2/2015	2,776	2,772	2,756	2,695	2,725	2,908	3,139	3,297	3,450	3,336	3,236	3,211	3,113	3,142	3,037	2,976	2,904	2,966	3,043	3,149	3,198	3,101	3,023	2,709
Spring	4	2,834	4/3/2015	2,614	2,459	2,390	2,358	2,348	2,408	2,447	2,608	2,596	2,629	2,713	2,834	2,726	2,744	2,611	2,618	2,644	2,635	2,691	2,718	2,744	2,572	2,465	2,447
Spring	4	3,371	4/4/2015	2,269	2,418	2,298	2,229	2,216	2,275	2,354	2,557	2,799	3,005	3,080	3,157	3,136	3,029	2,977	2,954	2,934	3,004	3,084	3,136	3,371	3,322	3,245	2,988
Spring	4	3,347	4/5/2015	2,700	2,547	2,503	2,497	2,445	2,473	2,536	2,753	2,921	3,107	3,146	3,156	3,175	3,103	3,042	2,957	2,995	2,991	3,027	3,130	3,347	3,312	3,187	2,855
Spring	4	3,665	4/6/2015	2,629	2,529	2,491	2,499	2,511	2,679	3,099	3,461	3,665	3,644	3,609	3,557	3,491	3,439	3,379	3,309	3,291	3,287	3,386	3,442	3,654	3,559	3,235	2,909
Spring	4	3,763	4/7/2015	2,607	2,473	2,394	2,360	2,364	2,543	2,892	3,299	3,485	3,546	3,627	3,635	3,662	3,642	3,573	3,590	3,614	3,686	3,763	3,737	3,759	3,732	3,384	3,018
Spring	4	3,903	4/8/2015	2,793	2,650	2,582	2,500	2,510	2,658	3,033	3,404	3,668	3,683	3,665	3,711	3,708	3,692	3,653	3,685	3,640	3,726	3,749	3,812	3,903	3,756	3,517	3,146
Spring	4	3,862	4/9/2015	2,839	2,724	2,658	2,623	2,647	2,783	3,153	3,601	3,759	3,788	3,823	3,862	3,821	3,759	3,764	3,707	3,684	3,798	3,828	3,812	3,822	3,747	3,515	3,175
Spring	4	3,741	4/10/2015	2,846	2,676	2,629	2,593	2,604	2,726	3,035	3,472	3,616	3,680	3,703	3,741	3,694	3,660	3,616	3,550	3,431	3,522	3,572	3,532	3,510	3,535	3,230	2,961
Spring	4	3,205	4/11/2015	2,692	2,573	2,437	2,364	2,353	2,381	2,545	2,685	2,884	3,043	3,123	3,084	3,023	2,978	2,905	2,804	2,791	2,824	2,874	2,922	3,205	3,159	2,999	2,752
Spring	4	3,199	4/12/2015	2,562	2,532	2,362	2,343	2,337	2,359	2,497	2,602	2,755	2,858	2,908	2,907	2,851	2,824	2,776	2,728	2,750	2,826	2,871	2,901	3,199	3,084	2,928	2,664
Spring	4	3,587	4/13/2015	2,435	2,355	2,351	2,343	2,392	2,523	2,873	3,219	3,402	3,445	3,485	3,510	3,429	3,401	3,362	3,333	3,281	3,325	3,368	3,362	3,587	3,471	3,191	2,877
Spring	4	3,582	4/14/2015	2,637	2,442	2,370	2,312	2,325	2,443	2,761	3,105	3,343	3,408	3,435	3,582	3,476	3,413	3,400	3,414	3,375	3,385	3,417	3,434	3,564	3,429	3,218	2,829
Spring	4	3,523	4/15/2015	2,598	2,443	2,430	2,316	2,333	2,461	2,813	3,097	3,266	3,360	3,328	3,373	3,349	3,387	3,334	3,300	3,266	3,293	3,313	3,161	3,523	3,438	3,124	2,821
Spring	4	3,509	4/16/2015	2,532	2,522	2,295	2,313	2,328	2,445	2,695	3,183	3,328	3,354	3,384	3,374	3,341	3,301	3,363	3,274	3,243	3,259	3,239	3,302	3,509	3,395	3,134	2,845
Spring	4	3,599	4/17/2015	2,620	2,443	2,366	2,282	2,332	2,458	2,740	3,106	3,321	3,471	3,582	3,599	3,562	3,539	3,484	3,467	3,398	3,330	3,381	3,327	3,351	3,376	3,161	2,916
Spring	4	3,189	4/18/2015	2,578	2,446	2,300	2,294	2,287	2,317	2,461	2,588	2,812	2,985	3,099	3,074	3,056	3,016	2,960	2,971	2,955	3,022	3,048	3,000	3,189	3,164	2,965	2,676
Spring	4	3,314	4/19/2015	2,426	2,400	2,218	2,162	2,142	2,138	2,176	2,337	2,516	2,715	2,813	2,868	2,872	2,844	2,872	2,820	2,826	2,923	2,990	3,107	3,314	3,209	2,978	2,680
Spring	4	3,786	4/20/2015	2,453	2,305	2,265	2,238	2,269	2,444	2,808	3,252	3,470	3,585	3,651	3,721	3,724	3,750	3,672	3,662	3,675	3,705	3,770	3,756	3,786	3,587	3,261	2,912
Spring	4	3,546	4/21/2015	2,600	2,479	2,386	2,358	2,352	2,486	2,780	3,213	3,396	3,454	3,497	3,489	3,445	3,434	3,377	3,323	3,323	3,319	3,321	3,353	3,546	3,473	3,201	2,844
Spring	4	3,580	4/22/2015	2,519	2,385	2,318	2,299	2,303	2,461	2,779	3,227	3,387	3,388	3,398	3,423	3,387	3,376	3,381	3,366	3,369	3,449	3,472	3,528	3,580	3,477	3,161	2,888
Spring	4	3,719	4/23/2015	2,601	2,413	2,327	2,317	2,351	2,492	2,727	3,158	3,431	3,470	3,483	3,494	3,488	3,496	3,448	3,411	3,390	3,486	3,504	3,537	3,719	3,690	3,385	3,053
Spring	4	3,663	4/24/2015	2,729	2,617	2,552	2,508	2,517	2,684	3,037	3,409	3,540	3,576	3,580	3,577	3,556	3,521	3,486	3,452	3,459	3,469	3,478	3,532	3,663	3,611	3,434	3,151
Spring	4	3,239	4/25/2015	2,912	2,715	2,629	2,557	2,595	2,664	2,757	2,943	3,115	3,220	3,239	3,155	3,115	3,053	2,916	2,889	2,860	2,912	2,974	3,014	3,183	3,183	3,034	2,798
Spring	4	3,346	4/26/2015	2,598	2,468	2,385	2,364	2,337	2,412	2,445	2,592	2,767	2,941	3,021	3,013	3,016	3,017	2,977	2,972	2,945	3,041	3,162	3,221	3,346	3,294	3,026	2,748
Spring	4	3,623	4/27/2015	2,565	2,273	2,194	2,191	2,188	2,326	2,677	3,201	3,382	3,386	3,468	3,445	3,395	3,424	3,406	3,375	3,342	3,425	3,477	3,503	3,623	3,496	3,208	2,795
Spring	4	3,429	4/28/2015	2,581	2,443	2,345	2,307	2,339	2,483	2,770	3,288	3,389	3,429	3,373	3,356	3,286	3,361	3,307	3,217	3,217	3,229	3,278	3,243	3,411	3,374	3,118	2,701
Spring	4	3,369	4/29/2015	2,448	2,304	2,231	2,179	2,195	2,341	2,656	3,064	3,240	3,223	3,287	3,299	3,268	3,314	3,353	3,319	3,276	3,295	3,282	3,187	3,369	3,364	3,057	2,725
Spring	4	3,383	4/30/2015	2,421	2,280	2,186	2,169	2,189	2,348	2,578	3,058	3,241	3,249	3,284	3,279	3,290	3,277	3,308	3,240	3,211	3,239	3,229	3,255	3,383	3,346	3,066	2,696
Spring	5	3,364	5/1/2015	2,587	2,267	2,228	2,175	2,200	2,294	2,591	3,041	3,221	3,254	3,265	3,354	3,364	3,266	3,264	3,230	3,163	3,163	3,136	3,154	3,249	3,267	3,029	2,773
Spring	5	3,051	5/2/2015	2,478	2,306	2,222	2,199	2,179	2,226	2,327	2,570	2,748	2,918	2,987	2,937	2,913	2,922	2,838	2,828	2,849	2,859	2,902	2,846	3,011	3,051	2,829	2,639
Spring	5	3,176	5/3/2015	2,421	2,283	2,196	2,146	2,115	2,165	2,176	2,292	2,551	2,689	2,792	2,850	2,860	2,876	2,886	2,875	2,869	2,960	3,022	3,059	3,176	3,143	2,922	2,623
Spring	5	3,585	5/4/2015	2,289	2,243	2,146	2,112	2,129	2,237	2,491	3,051	3,184	3,264	3,359	3,456	3,523	3,558	3,580	3,585	3,539	3,520	3,526	3,472	3,559	3,544	3,214	2,866
Spring	5	3,742	5/5/2015	2,537	2,368	2,267	2,166	2,209	2,328	2,566	3,113	3,302	3,404	3,506	3,589	3,593	3,669	3,697	3,730	3,727	3,724	3,742	3,694	3,737	3,664	3,343	2,924
Spring	5	3,594	5/6/2015	2,642	2,509	2,345	2,306	2,296	2,404	2,668	3,062	3,312	3,369	3,568	3,583	3,569	3,594	3,583	3,553	3,541	3,538	3,555	3,497	3,514	3,572	3,252	2,904
Spring	5	3,810	5/7/2015	2,600	2,514	2,328	2,274	2,276	2,380	2,693	3,109	3,314	3,412	3,498	3,625	3,687	3,721	3,779	3,782	3,810	3,774	3,739	3,666	3,695	3,736	3,344	2,994
Spring	5	4,058	5/8/2015	2,678	2,486	2,418	2,303	2,335	2,420	2,675	3,141	3,327	3,520	3,627	3,757	3,824	3,954	4,016	4,043	4,050	4,058	3,983	3,793	3,764	3,757	3,465	3,087
Spring	5	3,440	5/9/2015	2,775	2,577	2,472	2,321	2,322	2,382	2,439	2,553	2,841	3,116	3,197	3,238	3,252	3,241	3,254	3,255	3,286	3,326	3,341	3,342	3,400	3,440	3,260	2,962
Spring	5	3,961	5/10/2015	2,740	2,538	2,377	2,329	2,343	2,314	2,344	2,495	2,742	3,014	3,191	3,343	3,476	3,521	3,571	3,622	3,713	3,814	3,824	3,799	3,844	3,961	3,568	3,344
Spring	5	4,685	5/11/2015	2,957	2,758	2,629	2,591	2,553	2,673	2,955	3,443	3,771	3,941	4,099	4,264	4,392	4,507	4,575	4,659	4,685	4,684	4,611	4,516	4,466	4,417	4,027	3,559
Spring	5	4,691	5/12/2015	3,158	2,960	2,839	2,756	2,746	2,870	3,176	3,621	3,917	4,064	4,245	4,479	4,626	4,691	4,602	4,577	4,517	4,557	4,484	4,380	4,319	4,220	3,768	3,152
Spring	5	3,578	5/13/2015	2,788	2,549	2,427	2,361	2,333	2,428	2,571	3,118	3,294	3,404	3,481	3,503	3,491	3,523	3,578	3,460	3,415	3,416	3,440	3,384	3,424	3,422	3,139	2,774
Spring	5	3,508	5/14/2015	2,518	2,322	2,190	2,175	2,204	2,327	2,606	3,053	3,227	3,321	3,381	3,428	3,444	3,464	3,485	3,503	3,487	3,507	3,508	3,419	3,461	3,427	3,209	2,801
Spring	5	3,502	5/15/2015	2,488	2,333	2,233	2,213	2,181	2,335	2,500	3,000	3,218	3,309	3,398	3,438	3,443	3,466	3,502	3,470	3,433	3,433	3,367	3,325	3,308	3,338	3,115	2,839
Spring	5	3,249	5/16/2015	2,529	2,347	2,242	2,177	2,164	2,192	2,255	2,429	2,702	2,994	3,123	3,165	3,193	3,213	3,157	3,108	3,137	3,167	3,184	3,164	3,214	3,249	3,086	2,833

Contains Proprietary Material
Do Not Distribute

Spring	5	4,011	5/17/2015	2,557	2,426	2,258	2,234	2,213	2,185	2,181	2,372	2,632	2,945	3,143	3,333	3,499	3,581	3,626	3,717	3,806	3,938	3,947	4,011	3,934	3,974	3,682	3,245
Spring	5	3,886	5/18/2015	2,930	2,681	2,569	2,483	2,482	2,617	2,875	3,294	3,496	3,598	3,683	3,755	3,782	3,847	3,867	3,886	3,842	3,779	3,716	3,655	3,764	3,698	3,401	3,039
Spring	5	3,896	5/19/2015	2,692	2,535	2,412	2,368	2,385	2,526	2,763	3,238	3,490	3,575	3,626	3,644	3,718	3,728	3,742	3,749	3,816	3,896	3,864	3,856	3,886	3,873	3,531	3,166
Spring	5	3,540	5/20/2015	2,866	2,499	2,465	2,398	2,412	2,504	2,725	3,170	3,387	3,492	3,498	3,540	3,395	3,426	3,502	3,463	3,452	3,463	3,464	3,414	3,467	3,519	3,249	2,904
Spring	5	3,525	5/21/2015	2,603	2,436	2,374	2,320	2,332	2,440	2,680	3,115	3,368	3,429	3,499	3,505	3,503	3,525	3,477	3,479	3,473	3,474	3,468	3,439	3,487	3,512	3,250	2,917
Spring	5	3,626	5/22/2015	2,570	2,453	2,335	2,302	2,279	2,403	2,588	3,082	3,307	3,364	3,517	3,539	3,579	3,626	3,584	3,552	3,523	3,491	3,466	3,383	3,336	3,389	3,144	2,872
Spring	5	3,128	5/23/2015	2,699	2,396	2,254	2,267	2,232	2,220	2,270	2,368	2,718	2,839	2,990	3,028	3,011	2,953	2,956	2,946	2,933	2,991	3,048	3,027	3,028	3,128	2,983	2,780
Spring	5	3,260	5/24/2015	2,496	2,370	2,288	2,192	2,181	2,192	2,185	2,293	2,546	2,805	2,878	3,010	3,045	3,069	3,045	3,030	3,104	3,140	3,121	3,058	3,081	3,260	3,100	2,801
Spring	5	3,783	5/25/2015	2,564	2,392	2,305	2,253	2,232	2,272	2,309	2,324	2,676	2,928	3,102	3,252	3,389	3,489	3,536	3,592	3,651	3,721	3,770	3,696	3,669	3,783	3,461	3,116
Spring	5	4,621	5/26/2015	2,759	2,616	2,498	2,340	2,419	2,454	2,784	3,283	3,573	3,806	3,950	4,186	4,353	4,373	4,517	4,621	4,609	4,604	4,503	4,357	4,264	4,259	3,873	3,403
Spring	5	4,673	5/27/2015	3,015	2,791	2,620	2,553	2,533	2,643	2,842	3,362	3,599	3,891	4,095	4,289	4,414	4,521	4,609	4,673	4,669	4,633	4,459	4,364	4,300	4,145	3,746	3,371
Spring	5	4,556	5/28/2015	3,027	2,761	2,624	2,537	2,548	2,678	2,845	3,393	3,666	3,769	3,938	4,051	4,102	4,207	4,498	4,554	4,556	4,511	4,475	4,321	4,247	4,188	3,845	3,344
Spring	5	4,585	5/29/2015	2,983	2,725	2,588	2,432	2,410	2,465	2,644	3,200	3,497	3,677	3,865	4,007	4,109	4,273	4,354	4,435	4,585	4,520	4,437	4,208	4,112	3,966	3,770	3,414
Spring	5	4,358	5/30/2015	2,998	2,816	2,629	2,526	2,483	2,494	2,525	2,759	3,060	3,349	3,605	3,795	3,986	4,093	4,176	4,267	4,312	4,358	4,260	4,106	3,914	3,904	3,762	3,467
Spring	5	3,941	5/31/2015	3,127	2,892	2,765	2,669	2,596	2,609	2,566	2,692	2,962	3,252	3,496	3,666	3,752	3,847	3,926	3,906	3,941	3,876	3,908	3,763	3,691	3,513	3,142	2,884
Summer	6	3,678	6/1/2015	2,616	2,465	2,289	2,331	2,333	2,444	2,709	3,129	3,351	3,506	3,572	3,615	3,644	3,663	3,615	3,567	3,571	3,652	3,678	3,577	3,602	3,531	3,214	2,822
Summer	6	3,628	6/2/2015	2,610	2,492	2,342	2,392	2,344	2,406	2,729	3,149	3,399	3,482	3,582	3,545	3,555	3,628	3,611	3,532	3,548	3,588	3,622	3,580	3,560	3,565	3,253	2,890
Summer	6	3,575	6/3/2015	2,614	2,506	2,372	2,348	2,347	2,477	2,724	3,173	3,335	3,353	3,433	3,385	3,508	3,539	3,480	3,544	3,548	3,565	3,558	3,496	3,482	3,575	3,316	2,914
Summer	6	3,625	6/4/2015	2,603	2,439	2,341	2,299	2,357	2,394	2,696	3,060	3,308	3,423	3,506	3,550	3,594	3,625	3,623	3,617	3,597	3,586	3,604	3,500	3,507	3,569	3,292	2,930
Summer	6	3,287	6/5/2015	2,692	2,459	2,349	2,374	2,317	2,364	2,697	2,814	2,903	2,948	3,045	3,114	3,180	3,234	3,276	3,287	3,236	3,238	3,225	3,053	3,059	2,985	2,911	2,671
Summer	6	3,111	6/6/2015	2,466	2,157	2,023	1,983	1,969	1,939	2,050	2,176	2,425	2,741	2,867	3,026	3,111	3,028	3,067	2,926	2,924	2,992	2,943	2,842	2,778	2,864	2,669	2,534
Summer	6	3,399	6/7/2015	2,278	2,144	2,029	1,889	1,782	1,755	1,871	1,933	1,991	2,364	2,555	2,723	2,635	2,674	2,682	2,721	2,743	2,851	2,884	3,000	3,359	3,399	3,189	2,898
Summer	6	4,011	6/8/2015	2,649	2,403	2,338	2,309	2,323	2,480	2,821	3,154	3,413	3,558	3,710	3,775	3,801	3,779	3,904	3,926	3,947	4,011	3,947	3,846	3,785	3,918	3,560	3,167
Summer	6	4,318	6/9/2015	2,870	2,651	2,566	2,492	2,520	2,632	2,944	3,362	3,658	3,809	3,961	4,020	4,067	4,147	4,160	4,211	4,305	4,318	4,303	4,207	4,147	4,093	3,772	3,353
Summer	6	4,576	6/10/2015	2,929	2,731	2,616	2,514	2,493	2,512	2,857	3,301	3,613	3,773	3,966	4,139	4,148	4,304	4,462	4,469	4,560	4,576	4,499	4,361	4,284	4,298	3,954	3,491
Summer	6	5,262	6/11/2015	3,129	2,942	2,782	2,678	2,703	2,797	3,024	3,497	3,819	3,976	4,201	4,480	4,713	4,813	5,005	5,123	5,262	5,260	5,260	5,155	5,067	5,038	4,651	4,072
Summer	6	5,301	6/12/2015	3,638	3,362	3,149	2,994	2,925	3,018	3,219	3,722	4,038	4,260	4,497	4,682	4,900	5,012	5,198	5,301	5,272	5,224	5,131	4,976	4,763	4,763	4,465	4,069
Summer	6	4,716	6/13/2015	3,656	3,386	3,221	3,097	3,070	3,032	3,029	3,326	3,711	3,880	4,141	4,272	4,340	4,413	4,516	4,552	4,630	4,716	4,622	4,519	4,311	4,282	4,049	3,683
Summer	6	4,686	6/14/2015	3,289	3,019	2,858	2,726	2,631	2,607	2,582	2,757	3,005	3,422	3,651	3,959	4,142	4,264	4,379	4,496	4,589	4,675	4,686	4,513	4,327	4,397	4,053	3,564
Summer	6	4,176	6/15/2015	3,284	2,997	2,847	2,769	2,774	2,867	3,098	3,570	3,820	3,939	4,037	4,145	4,176	4,129	4,066	4,047	3,991	3,991	3,983	3,891	3,851	3,811	3,537	3,169
Summer	6	4,385	6/16/2015	2,871	2,682	2,592	2,529	2,527	2,651	2,839	3,295	3,626	3,786	3,870	3,990	4,043	4,152	4,219	4,179	4,243	4,385	4,381	4,311	4,269	4,309	4,031	3,610
Summer	6	4,450	6/17/2015	3,194	2,975	2,824	2,703	2,660	2,739	2,982	3,395	3,766	3,966	4,093	4,182	4,250	4,338	4,391	4,444	4,450	4,368	4,228	4,063	3,969	4,022	3,690	3,307
Summer	6	4,210	6/18/2015	3,006	2,615	2,477	2,418	2,407	2,515	2,703	3,146	3,414	3,645	3,871	3,960	3,916	4,060	4,078	4,210	4,147	4,066	3,885	3,833	3,852	3,815	3,555	3,212
Summer	6	4,828	6/19/2015	2,958	2,760	2,622	2,571	2,605	2,713	2,955	3,432	3,698	3,958	4,199	4,404	4,585	4,716	4,800	4,828	4,821	4,803	4,772	4,566	4,322	4,341	4,092	3,688
Summer	6	3,627	6/20/2015	3,272	3,019	2,792	2,670	2,589	2,559	2,632	2,686	3,034	3,194	3,475	3,580	3,596	3,627	3,596	3,506	3,339	3,427	3,421	3,424	3,423	3,478	3,299	3,102
Summer	6	4,625	6/21/2015	2,856	2,687	2,661	2,521	2,502	2,517	2,547	2,656	2,921	3,236	3,433	3,635	3,800	3,944	4,083	4,221	4,365	4,537	4,625	4,466	4,318	4,330	4,133	3,715
Summer	6	5,324	6/22/2015	3,344	3,126	2,938	2,861	2,833	2,912	3,219	3,573	3,987	4,290	4,555	4,769	4,883	5,059	5,098	5,221	5,264	5,324	5,264	5,215	4,942	4,888	4,498	3,976
Summer	6	5,776	6/23/2015	3,469	3,239	3,028	2,903	2,922	2,946	3,173	3,610	4,132	4,469	4,830	5,039	5,198	5,425	5,561	5,776	5,684	5,235	5,113	4,981	4,824	4,727	4,457	3,953
Summer	6	4,996	6/24/2015	3,566	3,198	2,994	2,872	2,840	2,843	3,002	3,381	3,867	4,106	4,331	4,493	4,596	4,695	4,796	4,887	4,976	4,996	4,968	4,748	4,563	4,508	4,181	3,730
Summer	6	4,737	6/25/2015	3,283	3,076	2,818	2,696	2,669	2,683	2,895	3,336	3,678	3,884	4,105	4,336	4,463	4,568	4,690	4,737	4,733	4,674	4,602	4,414	4,369	4,325	4,064	3,692
Summer	6	4,575	6/26/2015	3,314	3,074	2,955	2,848	2,818	2,868	3,090	3,484	3,784	3,926	4,127	4,243	4,266	4,378	4,466	4,551	4,575	4,550	4,459	4,272	4,109	4,068	3,831	3,511
Summer	6	3,614	6/27/2015	3,116	2,911	2,736	2,653	2,565	2,578	2,594	2,769	3,063	3,298	3,493	3,555	3,614	3,531	3,495	3,415	3,374	3,398	3,386	3,370	3,354	3,353	3,176	2,909
Summer	6	3,375	6/28/2015	2,640	2,547	2,489	2,398	2,352	2,358	2,383	2,507	2,701	2,965	3,135	3,244	3,293	3,323	3,342	3,264	3,289	3,351	3,375	3,299	3,340	3,365	3,219	2,887
Summer	6	4,095	6/29/2015	2,676	2,542	2,433	2,425	2,397	2,509	2,740	3,076	3,445	3,648	3,756	3,903	3,986	4,032	4,080	4,075	4,067	4,095	4,095	4,057	3,926	3,947	3,687	3,322
Summer	6	4,678	6/30/2015	2,976	2,738	2,678	2,578	2,560	2,661	2,866	3,267	3,583	3,839	4,117	4,322	4,428	4,467	4,598	4,678	4,643	4,609	4,529	4,358	4,259	4,248	3,984	3,632
Summer	7	4,973	7/1/2015	3,291	3,148	2,961	2,900	2,900	3,007	3,276	3,613	3,906	4,003	4,300	4,505	4,623	4,767	4,862	4,931	4,967	4,973	4,922	4,739	4,540	4,503	4,250	3,771
Summer	7	4,596	7/2/2015	3,420	3,121	2,882	2,779	2,714	2,695	2,917	3,312	3,715	3,997	4,169	4,374	4,482	4,569	4,596	4,580	4,492	4,466	4,405	4,215	4,089	4,083	3,872	3,554
Summer	7	4,240	7/3/2015	3,182	2,956	2,751	2,620	2,577	2,573	2,617	2,809	3,071	3,391	3,585	3,686	3,838	3,923	3,974	4,144	4,172	4,240	4,202	4,010	3,823	3,818	3,584	3,379
Summer	7	3,567	7/4/2015	3,064	2,849	2,683	2,573	2,516	2,518	2,552	2,556	2,849	3,104	3,313	3,490	3,532	3,567	3,509	3,466	3,430	3,462	3,498	3,402	3,343	3,405	3,263	3,155
Summer	7	4,399	7/5/2015	2,866	2,705	2,535	2,456	2,441	2,419	2,357	2,525	2,776	3,042	3,350	3,581	3,761	3,868	3,962	4,082	4,216	4,326	4,399	4,289	4,202	4,203	3,997	3,673
Summer	7	5,099	7/6/2015	3,293	3,060	2,876	2,853	2,732	2,819	3,001	3,382	3,742	4,037	4,336	4,631	4,817	4,984	5,046	5,058	5,099	5,083	5,038	4,869	4,677	4,649	4,258	3,874
Summer	7	5,397	7/7/2015	3,493	3,270	3,087	3,021	3,005	3,112	3,363	3,725	4,163	4,381	4,635	4,823	5,028	5,144	5,185	5,349	5,397	5,339	5,263	5,142	5,005	4,909	4,529	4,071
Summer	7	5,504	7/8/2015	3,732	3,409	3,249	3,121	3,084	3,190	3,415	3,893	4,163	4,440	4,561	4,815	5,114	5,323	5,439	5,504	5,496	5,411	5,411	5,307	5,072	5,040	4,701	4,166
Summer	7	4,488	7/9/2015	3,800	3,440	3,219	3,097	3,049	3,099	3,257	3,624	3,925	4,128	4,168	4,316	4,367	4,393	4,480	4,488	4,419	4,433	4,398	4,295	4,256	4,246	3,943	3,599
Summer	7	4,952	7/10/2015	3,258	3,044	2,965	2,877	2,857	2,927	3,132	3,544	3,912	4,077	4,326	4,470	4,576	4,732	4,774	4,867	4,893	4,952	4,880	4,633	4,427	4,391	4,120	3,741
Summer	7	4,802	7/11/2015	3,334	3,075	2,954	2,787	2,698	2,698	2,655	2,905	3,220	3,574	3,950	4,171	4,311	4,527	4,553	4,657	4,714	4,757	4,802	4,610	4,395	4,361	4,103	3,764
Summer	7	5,044	7/12/2015	3,395	3,156	2,967	2,831	2,763	2,689	2,620	2,851	3,089	3,438	3,792	4,113	4,400	4,559	4,720	4,802	4,909	4,930	5,044	4,806	4,740	4,701	4,437	4,013
Summer	7	5,530	7/13/2015	3,605	3,346	3,228	3,046	3,001	3,092	3,300	3,695	4,089	4,338	4,651	4,909	5,158	5,350	5,467	5,530	5,526	5,529	5,492	5,229	4,957	4,808	4,423	3,937
Summer	7	5,175	7/14/2015	3,505	3,365	3,152	3,107	3,068	3,170	3,287	3,786	4,187	4,412	4,692	4,847	4,988	4,990	5,175	5,125	5,008	4,872	4,886	4,824	4,737	4,634	4,397	4,012
Summer	7	5,283	7/15/2015	3,649	3,429	3,289	3,190	3,168	3,233	3,532	3,975	4,303	4,508	4,769	4,940	5,157	5,283	5,269	5,200	5,098	5,094	5,037	4,794	4,605	4,433	4,128	3,688
Summer	7	4,474	7/16/2015	3,293	3,030	2,831	2,723	2,662	2,766	2,887	3,285	3,588	3,752	3,863	4,041	4,125	4,211	4,238	4,412	4,423	4,474	4,455	4,286	4,098	4,101	3,814	3,472
Summer	7	4,613	7/17/2015	3,061	2,840	2,652	2,570	2,549	2,628	2,845	3,226	3,552	3,720	3,916	4,129	4,302	4,403	4,498	4,570	4,599	4,613	4,520	4,256	4,120	4,092	3,867	3,553
Summer	7	4,615	7/18/2015	3,265	2,988	2,904	2,803	2,784	2,794	2,823	2,989	3,285	3,587	3,758	3,946	3,994	4,036	4,120	4,264	4,444	4,567	4,615	4,518	4,388	4,432	4,224	3,927
Summer	7	5,754	7/19/2015	3,625	3,390	3,243	3,124	3,065	3,038	3,003	3,167	3,595	3,955	4,385	4,775	5,101	5,341	5,422	5,560	5,610	5,754	5,683	5,517	5,383	5,412	5,086	4,605
Summer	7	6,419	7/20/2015	4,219	3,992	3,825	3,701	3,651	3,721	3,958	4,385	4,969	5,315	5,651	5,962	6,184	6,220	6,332	6,397	6,419	6,394	6,306	6,122	5,955	5,844	5,389	4,809
Summer	7	5,975	7/21/2015	4,307	3,930	3,693	3,543	3,467	3,499	3,645	4,109	4,346	4,538	4,768	4,990	5,189	5,380	5,648	5,865	5,975	5,971	5,852	5,636	5,293	5,085	4,782	4,241
Summer	7	5,042	7/22/2015	3,745	3,445	3,233	3,055	2,965	2,998	3,156	3,568	3,988	4,138	4,379	4,595	4,613	4,827	4,901	4,990	5,027	5,042	4,983	4,807	4,511	4,465	4,098	3,697
Summer	7	4,918	7/23/2015	3,271	3,021	2,892	2,710	2,694	2,787	2,958	3,316	3,676	3,978	4,178	4,382	4,462	4,597	4,707	4,782	4,886	4,918	4,857	4,707	4,476	4,458	4,082	3,685
Summer	7	4,827	7/24/2015	3,331	3,039	2,864	2,751	2,757	2,780	2,916	3,283	3,682	3,901	4,153	4,346	4,448	4,606	4,602	4,783	4,794	4,827	4,754	4,510	4,258	4,283	4,149	3,677
Summer	7	4,479	7/25/2015	3,324	3,048	2,878	2,769	2,681	2,701	2,669	2,905	3,211	3,546	3,804	4,021	4,149	4,266	4,354	4,414	4,466	4,479	4,429	4,229	4,096	4,115	3,954	3,667
Summer	7	4,563	7/26/2015	3,414	3,135	3,008	2,878	2,834	2,824	2,870	2,847	3,140	3,418	3,691	3,891	4,078	4,278	4,370	4,519	4,546	4,563	4,543	4,440	4,309	4,375	4,131	3,821
Summer	7	5,500	7/27/2015	3,479	3,318	3,155	3,059	3,039	3,172	3,342	3,732	4,005	4,300	4,444	4,609	4,775	4,914	5,071	5,319	5,439	5,500	5,498	5,257	5,074	5,035	4,620	4,187
Summer	7	4,630	7/28/2015	3,827	3,519	3,308	3,224	3,157	3,227	3,429	3,847	4,317	4,630	3,767	3,779	3,729	3,871	3,980	4,059	4,014	4,150	4,057	3,900	3,911	3,883	3,740	3,734
Summer	7	6,266	7/29/2015	3,612	3,458	3,627	3,599	3,608	3,418	3,381	3,366	3,772	4,060	4,174	4,834	5,057	5,982	6,153	6,239	6,266	6,198	6,188	5,988	5,746	5,668	5,239	4,655
Summer	7	5,829	7/30/2015	4,109	3,868	3,666	3,551	3,497	3,569	3,734	4,165	4,598	4,872	5,159	5,341	5,489	5,656	5,829	5,761	5,649	5,447	5,251	5,074	4,820	4,857	4,654	4,193
Summer	7	5,726	7/31/2015	3,703	3,568	3,388	3,244	3,172	3,181	3,363	3,747	4,139	4,564	4,728	4,974	5,168	5,409	5,543	5,640	5,690	5,726	5,584	5,334	4,995	4,802	4,385	4,075
Summer	8	4,984	8/1/2015	3,575	3,334	3,173	3,034	2,970	2,970	2,982	3,150	3,527	3,883	4,265	4,509	4,715	4,857	4,908	4,943	4,984	4,926	4,862	4,712	4,494	4,499	4,213	3,861
Summer	8	4,947	8/2/2015	3,477	3,187	3,031	2,876	2,789	2,734	2,705	2,801	3,165	3,467	3,766	4,049	4,274	4,430	4,557	4,696	4,820	4,947	4,916	4,739	4,633	4,615	4,354	3,898
Summer	8	5,844	8/3/2015	3,582	3,349	3,212	3,091	3,014	3,142	3,331	3,774	4,204	4,569	4,788	5,024	5,280	5,486	5,661	5,750	5,841	5,844	5,741	5,524	5,345	5,361	4,964	4,446
Summer	8	5,925	8/4/2015	4,013	3,729	3,550	3,451	3,410	3,472	3,669	4,007	4,281	4,545	4,873	5,217	5,429	5,642	5,776	5,860	5,925	5,898	5,791	5,590	5,297	5,183	4,712	4,211
Summer	8	5,243	8/5/2015	3,729	3,450	3,236	3,079	3,057	3,004	3,204	3,580	3,975	4,232	4,475	4,600	4,845	5,051	5,165	5,243	5,184	5,165	5,072	4,833	4,555	4,601	4,235	3,762
Summer	8	4,616	8/6/2015	3,372	3,079	2,919	2,821	2,763	2,850	2,951	3,338	3,681	3,930	4,205	4,326	4,369	4,509	4,577	4,616	4,578	4,581	4,524	4,351	4,311	4,268	3,960	3,614
Summer	8	4,748	8/7/2015	3,241	3,026	2,883	2,781	2,727	2,795	2,937	3,307	3,646	3,899	4,119	4,305	4,420	4,528	4,635	4,705	4,748	4,729	4,673	4,455	4,316	4,216	3,947	3,571
Summer	8	4,134	8/8/2015	3,186	3,036	2,848	2,728	2,679	2,664	2,672	2,826	3,084	3,405	3,658	3,815	3,952	3,995	4,044	4,064	4,112	4,134	4,071	3,949	3,917	3,948	3,701	3,422
Summer	8	4,192	8/9/2015	3,144	2,911	2,775	2,654	2,599	2,593	2,563	2,651	2,921	3,233	3,463	3,634	3,776	3,910	4,019	4,065	4,121	4,147	4,192	4,074	3,984	4,074	3,750	3,458
Summer	8	4,898	8/10/2015	3,148	2,933	2,810	2,691	2,703	2,813	3,026	3,369	3,749	3,942	4,138	4,445	4,649	4,725	4,830	4,898	4,898	4,834	4,742	4,525	4,443	4,416	4,134	3,770
Summer	8	4,518	8/11/2015	3,396	3,203	3,079	3,010	2,989	3,101	3,398	3,750	4,008	4,204	4,338	4,433	4,448	4,504	4,487	4,407	4,426	4,470	4,518	4,400	4,403	4,348	4,052	3,655
Summer	8	4,997	8/12/2015	3,355	3,159	3,050	2,898	2,868	2,931	3,150	3,474	3,837	4,077	4,323	4,530	4,633	4,782	4,891	4,958	4,997	4,994	4,960	4,735	4,587	4,523	4,203	3,726

Contains Proprietary Material
Do Not Distribute

Summer	8	4,880	8/13/2015	3,395	3,100	2,996	2,841	2,798	2,853	3,031	3,340	3,717	3,959	4,190	4,315	4,474	4,631	4,726	4,806	4,850	4,880	4,755	4,619	4,435	4,335	4,026	3,669
Summer	8	5,210	8/14/2015	3,147	3,073	2,879	2,779	2,683	2,727	2,957	3,247	3,598	3,894	4,187	4,367	4,561	4,705	4,859	5,033	5,110	5,210	5,003	4,789	4,634	4,564	4,214	3,841
Summer	8	5,319	8/15/2015	3,505	3,225	3,054	2,924	2,859	2,857	2,825	2,999	3,338	3,725	4,092	4,415	4,692	4,846	5,034	5,178	5,262	5,319	5,217	5,012	4,875	4,770	4,477	4,056
Summer	8	5,402	8/16/2015	3,715	3,447	3,260	3,137	3,058	3,025	3,030	2,997	3,376	3,703	4,121	4,501	4,789	5,007	5,162	5,236	5,325	5,390	5,402	5,217	5,112	5,055	4,726	4,245
Summer	8	6,237	8/17/2015	3,856	3,650	3,369	3,283	3,217	3,278	3,497	3,824	4,263	4,712	5,023	5,449	5,661	5,995	6,064	6,160	6,169	6,237	6,155	5,947	5,776	5,617	5,034	4,596
Summer	8	6,200	8/18/2015	4,118	3,814	3,631	3,477	3,367	3,467	3,695	4,012	4,479	4,771	5,150	5,514	5,765	6,030	6,089	6,200	6,097	6,046	5,932	5,643	5,545	5,358	4,879	4,398
Summer	8	6,027	8/19/2015	3,973	3,749	3,656	3,504	3,439	3,506	3,770	4,040	4,481	4,778	5,119	5,428	5,603	5,777	5,933	5,962	6,009	6,027	5,845	5,541	5,389	5,294	4,858	4,407
Summer	8	5,849	8/20/2015	4,002	3,748	3,567	3,473	3,441	3,512	3,791	4,089	4,525	4,896	5,125	5,383	5,396	5,684	5,823	5,849	5,788	5,763	5,570	5,368	5,363	5,115	4,726	4,313
Summer	8	4,996	8/21/2015	3,952	3,710	3,533	3,455	3,430	3,550	3,799	4,075	4,386	4,565	4,624	4,717	4,799	4,812	4,867	4,929	4,983	4,996	4,978	4,753	4,701	4,488	4,284	3,925
Summer	8	4,614	8/22/2015	3,570	3,311	3,084	2,955	2,847	2,771	2,869	2,931	3,223	3,490	3,785	3,972	4,145	4,287	4,420	4,514	4,573	4,614	4,544	4,404	4,337	4,248	3,968	3,652
Summer	8	4,658	8/23/2015	3,345	3,104	3,034	2,867	2,828	2,780	2,791	2,874	3,068	3,272	3,591	3,877	4,062	4,225	4,336	4,439	4,531	4,618	4,658	4,523	4,580	4,500	4,222	3,879
Summer	8	5,635	8/24/2015	3,507	3,328	3,182	3,136	3,113	3,187	3,483	3,850	4,206	4,508	4,718	5,000	5,186	5,391	5,520	5,594	5,635	5,626	5,564	5,288	5,241	5,014	4,557	4,154
Summer	8	5,800	8/25/2015	3,786	3,565	3,256	3,210	3,202	3,312	3,591	3,980	4,290	4,554	4,827	5,111	5,248	5,462	5,617	5,789	5,776	5,800	5,642	5,432	5,338	5,148	4,660	4,142
Summer	8	4,916	8/26/2015	3,770	3,530	3,291	3,108	2,956	2,994	3,331	3,586	3,886	4,088	4,269	4,470	4,653	4,787	4,807	4,878	4,883	4,916	4,840	4,581	4,530	4,236	3,978	3,618
Summer	8	4,482	8/27/2015	3,180	2,921	2,800	2,726	2,696	2,769	2,948	3,341	3,586	3,854	3,996	4,222	4,318	4,385	4,429	4,469	4,469	4,465	4,482	4,274	4,294	4,184	3,760	3,460
Summer	8	4,474	8/28/2015	3,136	2,844	2,702	2,637	2,612	2,679	2,942	3,274	3,549	3,806	3,946	4,110	4,202	4,269	4,339	4,474	4,429	4,459	4,363	4,145	4,141	3,978	3,713	3,405
Summer	8	4,211	8/29/2015	3,033	2,790	2,688	2,579	2,538	2,485	2,589	2,690	2,954	3,278	3,498	3,785	3,834	3,899	4,026	4,077	4,145	4,211	4,175	4,076	4,114	3,991	3,745	3,477
Summer	8	4,956	8/30/2015	3,187	3,012	2,832	2,758	2,692	2,667	2,695	2,645	2,994	3,361	3,726	4,041	4,278	4,516	4,567	4,718	4,825	4,888	4,883	4,853	4,956	4,784	4,376	3,984
Summer	8	5,874	8/31/2015	3,673	3,371	3,232	3,144	3,124	3,209	3,549	3,888	4,276	4,468	4,756	5,036	5,275	5,501	5,632	5,762	5,753	5,874	5,868	5,686	5,628	5,327	4,849	4,283
Fall	9	5,728	9/1/2015	3,855	3,655	3,407	3,268	3,209	3,280	3,586	3,832	4,203	4,470	4,736	5,055	5,191	5,286	5,552	5,666	5,622	5,728	5,616	5,393	5,340	5,058	4,528	4,020
Fall	9	5,966	9/2/2015	3,627	3,360	3,159	3,077	3,038	3,062	3,408	3,703	4,113	4,352	4,676	4,906	5,255	5,480	5,667	5,798	5,920	5,966	5,864	5,571	5,516	5,236	4,689	4,195
Fall	9	5,969	9/3/2015	3,710	3,446	3,298	3,182	3,097	3,181	3,447	3,816	4,162	4,415	4,700	5,068	5,265	5,601	5,809	5,904	5,968	5,969	5,779	5,605	5,637	5,360	4,820	4,342
Fall	9	5,232	9/4/2015	4,003	3,636	3,468	3,357	3,307	3,385	3,730	4,060	4,341	4,515	4,651	4,780	4,921	5,021	5,157	5,208	5,232	5,188	5,024	4,707	4,731	4,499	4,137	3,718
Fall	9	4,194	9/5/2015	3,358	3,093	2,929	2,808	2,696	2,656	2,732	2,781	2,974	3,357	3,494	3,698	3,755	3,894	3,957	4,032	4,148	4,194	4,111	3,978	4,000	3,824	3,528	3,313
Fall	9	4,308	9/6/2015	3,005	2,781	2,629	2,577	2,491	2,480	2,497	2,557	2,763	3,070	3,272	3,535	3,736	3,878	4,015	4,150	4,263	4,308	4,279	4,042	4,059	3,915	3,626	3,395
Fall	9	5,221	9/7/2015	3,137	2,937	2,720	2,595	2,589	2,637	2,711	2,736	2,989	3,310	3,670	3,999	4,302	4,550	4,741	4,954	5,110	5,221	5,174	4,984	5,097	4,866	4,468	4,042
Fall	9	6,332	9/8/2015	3,652	3,387	3,281	3,183	3,162	3,262	3,597	3,997	4,299	4,648	4,997	5,394	5,717	5,999	6,292	6,203	6,328	6,332	6,229	5,997	6,048	5,571	5,076	4,526
Fall	9	6,195	9/9/2015	4,120	3,789	3,603	3,483	3,414	3,511	3,799	4,144	4,478	4,719	5,064	5,399	5,587	5,840	6,040	6,156	6,195	6,174	5,973	5,695	5,730	5,440	4,973	4,475
Fall	9	4,735	9/10/2015	4,052	3,750	3,633	3,494	3,417	3,448	3,828	4,202	4,442	4,515	4,553	4,735	4,677	4,723	4,710	4,631	4,621	4,625	4,610	4,565	4,529	4,300	3,892	3,551
Fall	9	4,409	9/11/2015	3,240	2,977	2,880	2,782	2,767	2,850	3,155	3,467	3,726	3,855	3,981	4,048	4,060	4,121	4,205	4,283	4,320	4,409	4,310	4,200	4,191	4,002	3,774	3,359
Fall	9	3,916	9/12/2015	2,929	2,823	2,749	2,636	2,600	2,568	2,662	2,743	3,084	3,298	3,538	3,739	3,814	3,913	3,912	3,916	3,832	3,798	3,838	3,879	3,892	3,751	3,540	3,276
Fall	9	4,032	9/13/2015	3,116	2,815	2,690	2,604	2,548	2,570	2,591	2,686	2,898	3,189	3,369	3,549	3,668	3,779	3,852	3,908	3,973	4,002	4,008	4,032	3,934	3,780	3,399	3,065
Fall	9	3,909	9/14/2015	2,804	2,600	2,491	2,432	2,442	2,511	2,820	3,127	3,279	3,513	3,577	3,733	3,746	3,822	3,816	3,825	3,805	3,857	3,829	3,776	3,909	3,663	3,274	3,027
Fall	9	4,319	9/15/2015	2,690	2,574	2,470	2,417	2,406	2,534	2,855	3,088	3,456	3,533	3,680	3,841	3,921	4,002	4,174	4,188	4,279	4,319	4,316	4,234	4,260	3,979	3,579	3,312
Fall	9	4,696	9/16/2015	2,854	2,744	2,588	2,533	2,520	2,584	3,027	3,283	3,512	3,709	3,913	4,074	4,174	4,356	4,525	4,601	4,696	4,687	4,694	4,465	4,533	4,181	3,869	3,441
Fall	9	4,955	9/17/2015	3,067	2,919	2,800	2,657	2,601	2,732	3,019	3,362	3,630	3,796	3,996	4,259	4,401	4,604	4,731	4,880	4,955	4,942	4,874	4,656	4,645	4,375	3,956	3,505
Fall	9	4,799	9/18/2015	3,193	2,980	2,813	2,634	2,651	2,775	3,061	3,336	3,575	3,771	4,023	4,243	4,386	4,557	4,686	4,766	4,799	4,792	4,657	4,392	4,425	4,066	3,844	3,506
Fall	9	4,151	9/19/2015	3,132	2,874	2,705	2,603	2,561	2,605	2,706	2,809	3,041	3,417	3,588	3,720	3,886	4,017	4,086	4,150	4,151	4,129	4,024	4,016	4,044	3,923	3,715	3,462
Fall	9	3,756	9/20/2015	3,207	2,991	2,891	2,813	2,731	2,751	2,785	2,757	2,909	3,120	3,200	3,365	3,519	3,547	3,581	3,648	3,654	3,735	3,724	3,705	3,756	3,506	3,145	2,972
Fall	9	3,790	9/21/2015	2,515	2,452	2,411	2,313	2,320	2,470	2,768	3,132	3,318	3,417	3,520	3,579	3,620	3,689	3,719	3,787	3,726	3,772	3,725	3,790	3,779	3,562	3,217	2,851
Fall	9	3,787	9/22/2015	2,530	2,475	2,397	2,318	2,351	2,487	2,778	3,209	3,339	3,435	3,561	3,639	3,642	3,711	3,730	3,711	3,705	3,733	3,727	3,786	3,787	3,551	3,254	2,956
Fall	9	3,943	9/23/2015	2,633	2,500	2,411	2,362	2,342	2,464	2,768	3,031	3,302	3,405	3,507	3,657	3,651	3,807	3,818	3,834	3,880	3,943	3,907	3,912	3,876	3,643	3,372	2,983
Fall	9	4,058	9/24/2015	2,656	2,491	2,409	2,356	2,348	2,459	2,757	3,152	3,316	3,475	3,611	3,727	3,806	3,895	3,959	4,058	4,049	4,052	4,043	4,019	4,053	3,802	3,472	3,110
Fall	9	3,747	9/25/2015	2,771	2,583	2,493	2,435	2,412	2,498	2,830	3,152	3,359	3,494	3,575	3,653	3,651	3,733	3,747	3,708	3,714	3,712	3,626	3,703	3,656	3,463	3,264	2,959
Fall	9	3,290	9/26/2015	2,602	2,415	2,339	2,298	2,339	2,278	2,519	2,511	2,692	3,023	3,071	3,107	3,174	3,181	3,150	3,131	3,116	3,143	3,189	3,290	3,283	3,182	2,955	2,746
Fall	9	3,473	9/27/2015	2,433	2,361	2,320	2,186	2,182	2,182	2,250	2,337	2,548	2,757	2,884	2,986	3,020	3,041	3,068	3,100	3,131	3,277	3,327	3,473	3,473	3,301	3,016	2,764
Fall	9	4,178	9/28/2015	2,476	2,349	2,356	2,233	2,251	2,427	2,781	3,095	3,340	3,436	3,561	3,734	3,790	3,878	3,923	3,946	3,987	4,023	4,010	4,178	4,075	3,877	3,493	3,163
Fall	9	4,604	9/29/2015	2,852	2,661	2,571	2,532	2,510	2,643	3,051	3,473	3,775	3,865	4,036	4,189	4,304	4,445	4,518	4,535	4,542	4,539	4,505	4,604	4,481	4,239	3,911	3,539
Fall	9	4,553	9/30/2015	3,218	3,003	2,964	2,899	2,919	3,037	3,419	3,837	4,159	4,301	4,475	4,553	4,491	4,415	4,276	4,192	4,068	4,109	4,048	4,174	4,044	3,803	3,414	3,072
Fall	10	3,767	10/1/2015	2,681	2,531	2,452	2,377	2,377	2,474	2,808	3,212	3,383	3,386	3,445	3,524	3,516	3,532	3,522	3,500	3,452	3,544	3,595	3,767	3,680	3,506	3,184	2,825
Fall	10	3,638	10/2/2015	2,518	2,408	2,338	2,286	2,303	2,375	2,711	3,083	3,345	3,392	3,475	3,508	3,506	3,512	3,475	3,452	3,444	3,499	3,618	3,638	3,549	3,409	3,197	2,885
Fall	10	3,509	10/3/2015	2,605	2,470	2,376	2,328	2,357	2,424	2,527	2,667	2,960	3,172	3,349	3,402	3,396	3,384	3,328	3,283	3,263	3,267	3,389	3,509	3,414	3,291	3,084	2,844
Fall	10	3,565	10/4/2015	2,723	2,339	2,261	2,246	2,193	2,148	2,262	2,379	2,653	2,896	3,014	2,988	3,117	3,022	2,975	2,944	3,028	3,130	3,259	3,565	3,461	3,283	3,000	2,721
Fall	10	3,672	10/5/2015	2,561	2,266	2,162	2,175	2,215	2,324	2,682	3,121	3,281	3,352	3,413	3,372	3,354	3,338	3,380	3,355	3,310	3,382	3,468	3,672	3,657	3,392	3,143	2,744
Fall	10	3,689	10/6/2015	2,532	2,306	2,274	2,226	2,270	2,358	2,724	3,109	3,268	3,307	3,332	3,387	3,359	3,375	3,409	3,401	3,399	3,471	3,544	3,689	3,574	3,366	3,126	2,751
Fall	10	3,691	10/7/2015	2,402	2,312	2,239	2,192	2,197	2,296	2,671	3,149	3,225	3,307	3,326	3,372	3,380	3,421	3,474	3,452	3,460	3,514	3,520	3,691	3,574	3,374	3,056	2,683
Fall	10	3,596	10/8/2015	2,508	2,304	2,206	2,178	2,202	2,303	2,673	3,131	3,246	3,293	3,332	3,382	3,355	3,398	3,424	3,373	3,410	3,421	3,436	3,596	3,584	3,399	3,050	2,699
Fall	10	3,642	10/9/2015	2,434	2,296	2,242	2,190	2,209	2,317	2,683	3,064	3,251	3,360	3,472	3,520	3,495	3,525	3,552	3,502	3,468	3,570	3,633	3,642	3,504	3,325	3,057	2,812
Fall	10	3,186	10/10/2015	2,527	2,382	2,236	2,156	2,137	2,148	2,293	2,465	2,652	2,899	2,963	2,939	2,907	2,862	2,833	2,890	2,905	2,958	3,010	3,186	3,114	3,003	2,834	2,628
Fall	10	3,260	10/11/2015	2,420	2,293	2,238	2,133	2,073	2,155	2,226	2,342	2,522	2,757	2,840	2,876	2,858	2,849	2,804	2,837	2,890	3,037	3,084	3,260	3,207	3,055	2,835	2,602
Fall	10	3,745	10/12/2015	2,407	2,346	2,272	2,226	2,236	2,249	2,532	2,821	3,076	3,207	3,249	3,378	3,336	3,381	3,399	3,419	3,496	3,404	3,504	3,737	3,745	3,492	3,160	2,910
Fall	10	3,852	10/13/2015	2,521	2,392	2,329	2,293	2,285	2,415	2,817	3,226	3,374	3,443	3,556	3,602	3,615	3,677	3,669	3,683	3,642	3,681	3,730	3,852	3,753	3,567	3,206	2,894
Fall	10	3,670	10/14/2015	2,639	2,452	2,347	2,348	2,305	2,432	2,715	3,148	3,143	3,228	3,456	3,481	3,459	3,493	3,483	3,512	3,371	3,482	3,512	3,670	3,642	3,453	3,068	2,807
Fall	10	3,707	10/15/2015	2,541	2,376	2,263	2,284	2,357	2,403	2,819	3,273	3,363	3,390	3,406	3,420	3,383	3,406	3,371	3,353	3,381	3,430	3,507	3,707	3,628	3,499	3,161	2,827
Fall	10	3,560	10/16/2015	2,557	2,430	2,348	2,303	2,296	2,437	2,782	3,220	3,388	3,392	3,416	3,425	3,439	3,415	3,374	3,367	3,340	3,379	3,439	3,560	3,487	3,311	3,010	2,855
Fall	10	3,409	10/17/2015	2,587	2,431	2,365	2,316	2,246	2,363	2,492	2,651	2,868	3,047	3,133	3,124	3,106	3,076	3,000	2,974	3,002	3,102	3,179	3,409	3,365	3,264	3,105	2,901
Fall	10	3,765	10/18/2015	2,691	2,502	2,412	2,410	2,386	2,438	2,552	2,655	2,850	3,086	3,156	3,129	3,202	3,204	3,165	3,142	3,166	3,369	3,507	3,765	3,689	3,565	3,257	2,945
Fall	10	3,990	10/19/2015	2,767	2,642	2,593	2,531	2,609	2,807	3,174	3,691	3,845	3,814	3,779	3,746	3,642	3,612	3,542	3,513	3,530	3,628	3,750	3,990	3,934	3,750	3,350	3,020
Fall	10	3,794	10/20/2015	2,686	2,646	2,494	2,445	2,524	2,533	2,998	3,396	3,527	3,511	3,516	3,524	3,476	3,451	3,447	3,436	3,436	3,480	3,643	3,794	3,672	3,558	3,160	2,858
Fall	10	3,790	10/21/2015	2,635	2,349	2,244	2,214	2,193	2,325	2,717	3,127	3,283	3,433	3,371	3,432	3,428	3,474	3,541	3,466	3,400	3,478	3,593	3,790	3,714	3,487	3,035	2,898
Fall	10	3,776	10/22/2015	2,544	2,440	2,278	2,295	2,298	2,414	2,878	3,183	3,375	3,413	3,472	3,548	3,493	3,536	3,590	3,489	3,591	3,481	3,719	3,776	3,669	3,499	3,189	2,815
Fall	10	3,582	10/23/2015	2,565	2,409	2,253	2,261	2,244	2,430	2,720	3,213	3,326	3,403	3,415	3,385	3,352	3,361	3,295	3,299	3,272	3,321	3,476	3,582	3,572	3,396	3,210	2,970
Fall	10	3,457	10/24/2015	2,700	2,547	2,454	2,431	2,446	2,507	2,650	2,847	3,085	3,271	3,276	3,250	3,213	3,163	3,133	3,078	3,103	3,200	3,311	3,457	3,337	3,219	3,052	2,736
Fall	10	3,500	10/25/2015	2,571	2,344	2,263	2,195	2,160	2,179	2,261	2,340	2,614	2,829	3,018	3,019	3,113	3,098	2,990	2,967	3,015	3,091	3,305	3,500	3,424	3,214	2,793	2,573
Fall	10	3,808	10/26/2015	2,342	2,259	2,228	2,186	2,221	2,353	2,796	3,283	3,453	3,448	3,484	3,415	3,326	3,309	3,267	3,267	3,368	3,460	3,663	3,808	3,721	3,578	3,246	2,850
Fall	10	3,798	10/27/2015	2,587	2,410	2,459	2,389	2,397	2,554	3,013	3,455	3,484	3,546	3,497	3,434	3,376	3,338	3,294	3,296	3,328	3,429	3,656	3,798	3,713	3,515	3,096	2,792
Fall	10	3,849	10/28/2015	2,648	2,474	2,358	2,310	2,314	2,452	2,830	3,333	3,398	3,465	3,511	3,525	3,531	3,555	3,555	3,541	3,555	3,653	3,849	3,824	3,702	3,495	3,212	2,785
Fall	10	3,596	10/29/2015	2,546	2,427	2,358	2,289	2,312	2,390	2,688	3,201	3,361	3,403	3,467	3,470	3,461	3,445	3,431	3,343	3,300	3,284	3,416	3,596	3,565	3,286	3,024	2,653
Fall	10	3,464	10/30/2015	2,501	2,262	2,168	2,220	2,143	2,268	2,656	3,147	3,275	3,246	3,251	3,296	3,243	3,228	3,172	3,127	3,127	3,206	3,387	3,464	3,371	3,267	3,051	2,840
Fall	10	3,204	10/31/2015	2,544	2,383	2,308	2,300	2,282	2,339	2,481	2,703	2,920	3,083	3,137	3,096	3,052	3,011	2,931	2,905	2,953	3,049	3,204	3,160	3,095	3,028	2,906	2,677
Fall	11	3,513	11/1/2015	2,487	2,323	2,187	2,147	2,101	2,222	2,298	2,395	2,710	2,973	3,007	3,091	3,061	3,054	2,994	2,973	3,028	3,316	3,513	3,405	3,279	3,074	2,831	2,513
Fall	11	3,838	11/2/2015	2,402	2,255	2,199	2,197	2,242	2,413	2,807	3,177	3,300	3,371	3,381	3,368	3,374	3,351	3,322	3,331	3,313	3,636	3,838	3,733	3,547	3,289	3,062	2,746
Fall	11	3,805	11/3/2015	2,511	2,397	2,336	2,303	2,351	2,507	2,847	3,172	3,295	3,338	3,328	3,400	3,360	3,385	3,389	3,377	3,390	3,610	3,805	3,692	3,583	3,319	3,016	2,757
Fall	11	3,844	11/4/2015	2,461	2,332	2,262	2,241	2,314	2,407	2,800	3,176	3,306	3,291	3,325	3,360	3,348	3,378	3,386	3,363	3,355	3,557	3,844	3,701	3,554	3,357	3,030	2,747
Fall	11	3,856	11/5/2015	2,463	2,295	2,260	2,233	2,274	2,404	2,746	3,173	3,365	3,370	3,413	3,481	3,382	3,473	3,478	3,460	3,481	3,735	3,856	3,741	3,630	3,375	3,068	2,748
Fall	11	3,852	11/6/2015	2,501	2,372	2,291	2,231	2,231	2,397	2,768	3,155	3,371	3,439	3,535	3,542	3,541	3,521	3,528	3,495	3,488	3,728	3,852	3,745	3,552	3,301	3,049	2,832
Fall	11	3,474	11/7/2015	2,800	2,706	2,723	2,709	2,682	2,729	2,919	3,059	3,228	3,365	2,969	3,037	3,021	2,997	2,997	2,952	3,063	3,369	3,474	3,316	3,165	2,994	2,752	2,531
Fall	11	3,542	11/8/2015	2,313	2,251	2,152	2,081	2,069	2,130	2,263	2,300	2,517	2,657	2,784	2,696	2,858	2,892	2,784	2,876	2,903	3,385	3,542	3,453	3,319	3,216	2,919	2,633

Contains Proprietary Material
Do Not Distribute

Fall	11	3,947	11/9/2015	2,574	2,514	2,451	2,433	2,439	2,523	2,663	3,130	3,194	3,183	3,394	3,379	3,431	3,408	3,351	3,291	3,303	3,741	3,947	3,779	3,578	3,471	3,135	2,777
Fall	11	3,963	11/10/2015	2,537	2,350	2,358	2,339	2,327	2,601	2,816	3,185	3,428	3,513	3,482	3,432	3,351	3,244	3,540	3,533	3,544	3,888	3,963	3,780	3,689	3,592	3,112	2,935
Fall	11	3,936	11/11/2015	2,595	2,447	2,392	2,340	2,372	2,500	2,747	3,118	3,331	3,472	3,527	3,588	3,515	3,471	3,561	3,488	3,517	3,936	3,920	3,794	3,768	3,532	3,298	3,022
Fall	11	4,046	11/12/2015	2,666	2,609	2,430	2,470	2,379	2,578	2,893	3,317	3,536	3,636	3,681	3,665	3,689	3,709	3,688	3,653	3,770	3,887	4,046	3,914	3,772	3,518	3,206	2,979
Fall	11	3,846	11/13/2015	2,654	2,497	2,452	2,375	2,412	2,508	2,870	3,179	3,369	3,471	3,417	3,412	3,510	3,412	3,435	3,395	3,383	3,715	3,846	3,747	3,576	3,426	3,237	2,949
Fall	11	3,734	11/14/2015	2,713	2,572	2,476	2,447	2,425	2,492	2,622	2,807	3,011	3,197	3,268	3,278	3,203	3,181	3,147	3,175	3,272	3,658	3,734	3,616	3,561	3,463	3,214	2,995
Fall	11	3,742	11/15/2015	2,817	2,661	2,585	2,557	2,514	2,582	2,725	2,802	2,928	3,150	3,173	3,181	3,122	3,102	3,076	3,147	3,215	3,654	3,742	3,647	3,529	3,368	3,088	2,840
Fall	11	3,972	11/16/2015	2,609	2,444	2,410	2,412	2,451	2,631	2,999	3,398	3,510	3,482	3,487	3,505	3,490	3,483	3,464	3,381	3,434	3,880	3,972	3,869	3,715	3,526	3,224	2,893
Fall	11	4,006	11/17/2015	2,677	2,561	2,596	2,508	2,577	2,749	3,044	3,590	3,530	3,555	3,541	3,512	3,465	3,447	3,438	3,456	3,438	3,886	4,006	3,970	3,918	3,690	3,435	3,189
Fall	11	4,038	11/18/2015	2,905	2,766	2,663	2,686	2,706	2,852	3,248	3,619	3,748	3,787	3,728	3,659	3,589	3,623	3,570	3,596	3,636	3,911	4,038	3,927	3,821	3,637	3,352	2,919
Fall	11	3,936	11/19/2015	2,702	2,561	2,473	2,416	2,430	2,560	2,879	3,323	3,491	3,532	3,591	3,639	3,611	3,651	3,552	3,593	3,652	3,876	3,936	3,891	3,737	3,565	3,330	2,984
Fall	11	3,748	11/20/2015	2,675	2,517	2,448	2,368	2,322	2,525	2,853	3,091	3,394	3,369	3,397	3,427	3,368	3,331	3,364	3,346	3,376	3,664	3,748	3,689	3,567	3,440	3,217	2,938
Fall	11	3,643	11/21/2015	2,745	2,599	2,507	2,421	2,499	2,555	2,704	2,843	3,056	3,306	3,311	3,116	3,074	2,997	3,013	3,038	3,136	3,495	3,643	3,607	3,471	3,355	3,105	2,942
Fall	11	3,797	11/22/2015	2,578	2,430	2,340	2,280	2,271	2,284	2,405	2,610	2,775	3,012	3,053	3,138	3,237	3,312	3,297	3,367	3,456	3,699	3,797	3,729	3,582	3,444	3,213	2,947
Fall	11	4,237	11/23/2015	2,761	2,591	2,554	2,545	2,592	2,756	3,149	3,529	3,716	3,705	3,687	3,644	3,584	3,576	3,645	3,625	3,699	4,102	4,237	4,209	4,101	3,959	3,641	3,314
Fall	11	4,213	11/24/2015	3,032	2,894	2,848	2,810	2,827	3,035	3,386	3,838	3,947	3,925	3,861	3,759	3,657	3,657	3,641	3,656	3,784	3,975	4,213	4,160	4,104	3,966	3,648	3,358
Fall	11	4,166	11/25/2015	3,062	2,820	2,887	2,756	2,793	3,101	3,378	3,789	3,878	3,893	3,784	3,846	3,720	3,781	3,711	3,647	3,669	4,084	4,166	4,054	3,940	3,722	3,492	3,263
Fall	11	3,573	11/26/2015	3,084	2,767	2,676	2,587	2,606	2,681	2,783	2,954	3,328	3,406	3,516	3,565	3,573	3,464	3,235	3,127	3,013	3,168	3,160	3,109	3,127	3,092	2,958	2,737
Fall	11	3,551	11/27/2015	2,602	2,439	2,326	2,347	2,362	2,455	2,557	2,749	2,892	3,089	3,172	3,080	3,136	3,076	3,069	3,045	3,115	3,438	3,551	3,452	3,310	3,207	3,018	2,775
Fall	11	3,637	11/28/2015	2,535	2,323	2,302	2,247	2,261	2,259	2,396	2,564	2,780	2,996	3,102	3,252	3,338	3,244	3,280	3,221	3,351	3,567	3,637	3,511	3,433	3,316	3,180	2,934
Fall	11	3,930	11/29/2015	2,690	2,559	2,474	2,505	2,342	2,467	2,549	2,726	2,903	3,103	3,143	3,276	3,185	3,092	3,131	3,197	3,314	3,853	3,930	3,862	3,787	3,581	3,406	3,130
Fall	11	4,287	11/30/2015	2,845	2,600	2,585	2,579	2,627	2,732	3,176	3,646	3,851	3,853	3,793	3,846	3,805	3,749	3,687	3,719	3,813	4,188	4,287	4,240	4,155	3,932	3,630	3,204

Contains Proprietary Material
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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
a	b	c	d	e	f	g	h	i	j	k	l	m	n	o	p	q	r	s	t
1001	Albany Energy LLC	Albany LFGE	F	323615	Albany	001	36	1998-05-01	5.6	4.5	5.6	5.6		IC	MTE			24.3	
1002	Astoria Energy II, LLC	Astoria Energy 2 - CC3	J	323677	Queens	081	36	2011-07-01	330.0	288.0	269.4	312.9		CC	NG	FO2		3,082.5	**(G)**
1003	Astoria Energy II, LLC	Astoria Energy 2 - CC4	J	323678	Queens	081	36	2011-07-01	330.0	288.0	269.4	312.9		CC	NG	FO2			
1004	Astoria Energy, LLC	Astoria East Energy - CC1	J	323581	Queens	081	36	2006-04-01	320.0	278.7	276.9	311.6		CC	NG	FO2		3,496.2	**(G)**
1005	Astoria Energy, LLC	Astoria East Energy - CC2	J	323582	Queens	081	36	2006-04-01	320.0	278.7	276.9	311.6		CC	NG	FO2			
1006	Astoria Generating Company L.P.	Astoria 2 (ReAct. - 12/31/14)	J	24149	Queens	081	36	1954-03-01	180.0	177.0	167.9	166.6		ST	NG			2.4	**(D) (1)**
1007	Astoria Generating Company L.P.	Astoria 3	J	23516	Queens	081	36	1958-09-01	376.0	369.9	376.0	376.4		ST	FO6	NG		188.8	
1008	Astoria Generating Company L.P.	Astoria 5	J	23518	Queens	081	36	1962-05-01	387.0	376.3	381.0	380.6		ST	FO6	NG		993.9	
1009	Astoria Generating Company L.P.	Astoria GT 01	J	23523	Queens	081	36	1967-07-01	16.0	15.7	14.7	18.0		GT	NG			0.7	
1010	Astoria Generating Company L.P.	Gowanus 1-1	J	24077	Brooklyn	047	36	1971-06-01	20.0	19.1	18.2	24.1		GT	FO2			0.1	
1011	Astoria Generating Company L.P.	Gowanus 1-2	J	24078	Brooklyn	047	36	1971-06-01	20.0	17.1	18.5	21.3		GT	FO2			0.2	
1012	Astoria Generating Company L.P.	Gowanus 1-3	J	24079	Brooklyn	047	36	1971-06-01	20.0	17.2	16.3	21.9		GT	FO2			0.2	
1013	Astoria Generating Company L.P.	Gowanus 1-4	J	24080	Brooklyn	047	36	1971-06-01	20.0	17.1	16.0	21.3		GT	FO2			0.1	
1014	Astoria Generating Company L.P.	Gowanus 1-5	J	24084	Brooklyn	047	36	1971-06-01	20.0	16.5	16.1	22.4		GT	FO2			0.2	
1015	Astoria Generating Company L.P.	Gowanus 1-6	J	24111	Brooklyn	047	36	1971-06-01	20.0	18.0	15.6	21.8		GT	FO2			0.2	
1016	Astoria Generating Company L.P.	Gowanus 1-7	J	24112	Brooklyn	047	36	1971-06-01	20.0	17.6	16.7	22.3		GT	FO2			0.2	
1017	Astoria Generating Company L.P.	Gowanus 1-8	J	24113	Brooklyn	047	36	1971-06-01	20.0	16.1	14.6	19.9		GT	FO2			0.2	
1018	Astoria Generating Company L.P.	Gowanus 2-1	J	24114	Brooklyn	047	36	1971-06-01	20.0	17.9	17.3	21.4		GT	FO2	NG		0.7	
1019	Astoria Generating Company L.P.	Gowanus 2-2	J	24115	Brooklyn	047	36	1971-06-01	20.0	18.8	18.3	22.0		GT	FO2	NG		0.6	
1020	Astoria Generating Company L.P.	Gowanus 2-3	J	24116	Brooklyn	047	36	1971-06-01	20.0	20.6	19.1	24.2		GT	FO2	NG		0.5	
1021	Astoria Generating Company L.P.	Gowanus 2-4	J	24117	Brooklyn	047	36	1971-06-01	20.0	19.3	17.4	22.2		GT	FO2	NG		0.5	
1022	Astoria Generating Company L.P.	Gowanus 2-5	J	24118	Brooklyn	047	36	1971-06-01	20.0	18.6	17.0	21.4		GT	FO2	NG		0.6	
1023	Astoria Generating Company L.P.	Gowanus 2-6	J	24119	Brooklyn	047	36	1971-06-01	20.0	20.3	19.1	23.6		GT	FO2	NG		0.7	
1024	Astoria Generating Company L.P.	Gowanus 2-7	J	24120	Brooklyn	047	36	1971-06-01	20.0	19.6	18.5	23.0		GT	FO2	NG		0.6	
1025	Astoria Generating Company L.P.	Gowanus 2-8	J	24121	Brooklyn	047	36	1971-06-01	20.0	17.7	17.0	21.5		GT	FO2	NG		0.3	
1026	Astoria Generating Company L.P.	Gowanus 3-1	J	24122	Brooklyn	047	36	1971-07-01	20.0	17.7	16.9	22.0		GT	FO2	NG		0.4	
1027	Astoria Generating Company L.P.	Gowanus 3-2	J	24123	Brooklyn	047	36	1971-07-01	20.0	17.7	16.9	21.9		GT	FO2	NG		0.4	
1028	Astoria Generating Company L.P.	Gowanus 3-3	J	24124	Brooklyn	047	36	1971-07-01	20.0	19.8	18.0	23.9		GT	FO2	NG		0.5	
1029	Astoria Generating Company L.P.	Gowanus 3-4	J	24125	Brooklyn	047	36	1971-07-01	20.0	17.9	16.3	21.7		GT	FO2	NG		0.4	
1030	Astoria Generating Company L.P.	Gowanus 3-5	J	24126	Brooklyn	047	36	1971-07-01	20.0	19.0	17.3	24.0		GT	FO2	NG		0.5	
1031	Astoria Generating Company L.P.	Gowanus 3-6	J	24127	Brooklyn	047	36	1971-07-01	20.0	17.6	15.4	20.0		GT	FO2	NG		0.8	
1032	Astoria Generating Company L.P.	Gowanus 3-7	J	24128	Brooklyn	047	36	1971-07-01	20.0	18.1	18.0	24.2		GT	FO2	NG		0.4	
1033	Astoria Generating Company L.P.	Gowanus 3-8	J	24129	Brooklyn	047	36	1971-07-01	20.0	19.0	17.6	23.8		GT	FO2	NG		0.3	
1034	Astoria Generating Company L.P.	Gowanus 4-1	J	24130	Brooklyn	047	36	1971-07-01	20.0	16.8	18.6	23.0		GT	FO2			0.2	
1035	Astoria Generating Company L.P.	Gowanus 4-2	J	24131	Brooklyn	047	36	1971-07-01	20.0	17.3	17.4	20.9		GT	FO2			0.2	
1036	Astoria Generating Company L.P.	Gowanus 4-3	J	24132	Brooklyn	047	36	1971-07-01	20.0	17.6	17.1	22.0		GT	FO2			0.2	
1037	Astoria Generating Company L.P.	Gowanus 4-4	J	24133	Brooklyn	047	36	1971-07-01	20.0	17.1	16.5	21.5		GT	FO2			0.1	
1038	Astoria Generating Company L.P.	Gowanus 4-5	J	24134	Brooklyn	047	36	1971-07-01	20.0	17.1	16.2	21.2		GT	FO2			0.2	
1039	Astoria Generating Company L.P.	Gowanus 4-6	J	24135	Brooklyn	047	36	1971-07-01	20.0	18.6	18.0	22.9		GT	FO2			0.2	
1040	Astoria Generating Company L.P.	Gowanus 4-7	J	24136	Brooklyn	047	36	1971-07-01	20.0	16.6	16.4	21.3		GT	FO2			0.1	
1041	Astoria Generating Company L.P.	Gowanus 4-8	J	24137	Brooklyn	047	36	1971-07-01	20.0	19.0	17.0	22.1		GT	FO2			0.2	
1042	Astoria Generating Company L.P.	Narrows 1-1	J	24228	Brooklyn	047	36	1972-05-01	22.0	21.0	19.2	23.6		GT	KER	NG		2.4	
1043	Astoria Generating Company L.P.	Narrows 1-2	J	24229	Brooklyn	047	36	1972-05-01	22.0	19.5	17.2	22.2		GT	KER	NG		2.0	
1044	Astoria Generating Company L.P.	Narrows 1-3	J	24230	Brooklyn	047	36	1972-05-01	22.0	20.4	18.2	23.3		GT	KER	NG		2.1	
1045	Astoria Generating Company L.P.	Narrows 1-4	J	24231	Brooklyn	047	36	1972-05-01	22.0	20.1	19.2	24.2		GT	KER	NG		1.7	
1046	Astoria Generating Company L.P.	Narrows 1-5	J	24232	Brooklyn	047	36	1972-05-01	22.0	19.8	18.5	24.5		GT	KER	NG		1.4	
1047	Astoria Generating Company L.P.	Narrows 1-6	J	24233	Brooklyn	047	36	1972-05-01	22.0	18.9	16.1	21.7		GT	KER	NG		1.4	
1048	Astoria Generating Company L.P.	Narrows 1-7	J	24234	Brooklyn	047	36	1972-05-01	22.0	18.4	16.2	21.7		GT	KER	NG		1.8	
1049	Astoria Generating Company L.P.	Narrows 1-8	J	24235	Brooklyn	047	36	1972-05-01	22.0	19.9	17.2	22.6		GT	KER	NG		1.3	
1050	Astoria Generating Company L.P.	Narrows 2-1	J	24236	Brooklyn	047	36	1972-06-01	22.0	19.4	19.0	24.0		GT	KER	NG		2.1	
1051	Astoria Generating Company L.P.	Narrows 2-2	J	24237	Brooklyn	047	36	1972-06-01	22.0	18.7	17.2	21.0		GT	KER	NG		1.4	
1052	Astoria Generating Company L.P.	Narrows 2-3	J	24238	Brooklyn	047	36	1972-06-01	22.0	18.4	18.1	22.0		GT	KER	NG		1.4	
1053	Astoria Generating Company L.P.	Narrows 2-4	J	24239	Brooklyn	047	36	1972-06-01	22.0	18.4	18.4	21.9		GT	KER	NG		1.7	
1054	Astoria Generating Company L.P.	Narrows 2-5	J	24240	Brooklyn	047	36	1972-06-01	22.0	19.9	17.9	22.8		GT	KER	NG		1.4	
1055	Astoria Generating Company L.P.	Narrows 2-6	J	24241	Brooklyn	047	36	1972-06-01	22.0	18.1	15.8	20.7		GT	KER	NG		1.3	
1056	Astoria Generating Company L.P.	Narrows 2-7	J	24242	Brooklyn	047	36	1972-06-01	22.0	20.7	18.7	23.8		GT	KER	NG		1.4	
1057	Astoria Generating Company L.P.	Narrows 2-8	J	24243	Brooklyn	047	36	1972-06-01	22.0	17.5	16.5	20.8		GT	KER	NG		1.3	
1058	Athens Generating Company, LP	Athens 1	F	23668	Athens	039	36	2004-05-01	441.0	316.6	321.2	398.2		CC	NG	FO2		1,056.8	
1059	Athens Generating Company, LP	Athens 2	F	23670	Athens	039	36	2004-05-01	441.0	315.6	315.5	398.7		CC	NG	FO2		757.8	
1060	Athens Generating Company, LP	Athens 3	F	23677	Athens	039	36	2004-05-01	441.0	312.8	313.2	389.3		CC	NG	FO2		844.7	
1061	Bayonne Energy Center, LLC	Bayonne EC CTG1	J	323682	Bayonne	NJ	017	34	2012-06-01	64.0	64.0	58.9	62.9		JE	NG	KER		152.1	
1062	Bayonne Energy Center, LLC	Bayonne EC CTG2	J	323683	Bayonne	NJ	017	34	2012-06-01	64.0	64.0	59.0	62.8		JE	NG	KER		182.2	
1063	Bayonne Energy Center, LLC	Bayonne EC CTG3	J	323684	Bayonne	NJ	017	34	2012-06-01	64.0	64.0	56.4	62.9		JE	NG	KER		154.7	
1064	Bayonne Energy Center, LLC	Bayonne EC CTG4	J	323685	Bayonne	NJ	017	34	2012-06-01	64.0	64.0	56.3	62.8		JE	NG	KER		152.2	
1065	Bayonne Energy Center, LLC	Bayonne EC CTG5	J	323686	Bayonne	NJ	017	34	2012-06-01	64.0	64.0	57.0	62.8		JE	NG	KER		149.2	
1066	Bayonne Energy Center, LLC	Bayonne EC CTG6	J	323687	Bayonne	NJ	017	34	2012-06-01	64.0	64.0	55.5	62.8		JE	NG	KER		180.6	
1067	Bayonne Energy Center, LLC	Bayonne EC CTG7	J	323688	Bayonne	NJ	017	34	2012-06-01	64.0	64.0	57.6	62.9		JE	NG	KER		160.1	
1068	Bayonne Energy Center, LLC	Bayonne EC CTG8	J	323689	Bayonne	NJ	017	34	2012-06-01	64.0	64.0	58.9	62.7		JE	NG	KER		169.3	
1069	Binghamton BOP, LLC	Binghamton (ReAct. - 12/16/	C	23790	Binghamton	007	36	2001-03-01	47.7	43.8	45.1	46.9	Yes	CC	NG	KER		0.5	**(D) (2)**
1070	Boralex Hydro Operations Inc	Fourth Branch	F	23824	Waterford	091	36	1987-12-01	3.3	3.5	3.3	3.3		HY	WAT			16.6	
1071	Boralex Hydro Operations Inc	NYS Dam	F	23527	Waterford	091	36	1990-12-01	11.4	11.3	11.4	11.4		HY	WAT			53.1	

Contains Proprietary Material
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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1072	Boralex Hydro Operations Inc	Sissonville		E	23735	Potsdam	089	36	1990-08-01	3.1	3.0	3.1	3.1		HY	WAT			14.6	
1073	Boralex Hydro Operations Inc	Warrensburg		F	23737	Warrensburg	113	36	1988-12-01	2.9	3.0	2.9	2.9		HY	WAT			11.8	
1074	Calpine Energy Services LP	Bethpage		K	23823	Hicksville	059	36	1989-09-01	83.6	54.9	50.0	56.7		CC	NG			295.2	
1075	Calpine Energy Services LP	Bethpage GT4		K	323586	Hicksville	059	36	2002-07-01	60.0	48.2	44.3	46.6		GT	NG			123.6	
1076	Calpine Energy Services LP	KIAC_JFK_GT1		J	23816	Jamaica	081	36	1995-02-01	60.6	58.7	59.9	60.4	YES	CC	NG	FO2		734.3	(G)
1077	Calpine Energy Services LP	KIAC_JFK_GT2		J	23817	Jamaica	081	36	1995-02-01	60.6	58.3	59.7	61.2	YES	CC	NG	FO2			
1078	Canandaigua Power Partners, LLC	Canandaigua Wind Power		C	323617	Avoca	101	36	2008-12-05	125.0	125.0	125.0	125.0		WT	WND			259.5	
1079	Canastota Windpower LLC	Fenner Wind Power		C	24204	Fenner	053	36	2001-12-01	30.0	0.0	0.0	0.0		WT	WND			66.8	
1080	Carr Street Generating Station LP	Carr St.-E. Syr		C	24060	Dewitt	067	36	1993-08-01	122.6	89.0	83.2	105.1		CC	NG	FO2		97.7	
1081	Castleton Power, LLC	Castleton Energy Center		F	23900	Castleton	083	36	1992-01-01	72.0	67.0	60.0	72.0		CC	NG	FO2		229.4	
1082	Cayuga Operating Company, LLC	Cayuga 1		C	23584	Lansing	109	36	1955-09-01	155.3	154.1	153.3	153.7		ST	BIT			408.8	(S)
1083	Cayuga Operating Company, LLC	Cayuga 2		C	23585	Lansing	109	36	1958-10-01	167.2	154.7	151.0	153.6		ST	BIT			507.4	(S)
1084	Cayuga Operating Company, LLC	Cayuga IC 1		C	23629	Lansing	109	36	1967-08-01	2.8	0.0	0.0	0.0		IC	FO2				
1085	Cayuga Operating Company, LLC	Cayuga IC 2		C	23629	Lansing	109	36	1967-08-01	2.8	0.0	0.0	0.0		IC	FO2				
1086	Central Hudson Gas & Elec. Corp.	Coxsackie GT		G	23611	Coxsackie	039	36	1969-12-01	21.6	19.9	19.0	23.3		GT	KER	NG		0.3	
1087	Central Hudson Gas & Elec. Corp.	Dashville 1		G	23610	Rifton	111	36	1920-01-01	2.4	2.7	0.0	0.0		HY	WAT				
1088	Central Hudson Gas & Elec. Corp.	Dashville 2		G	23610	Rifton	111	36	1920-01-01	2.4	2.7	0.0	0.0		HY	WAT				
1089	Central Hudson Gas & Elec. Corp.	DCRRA		G	23765	Poughkeepsie	027	36	1987-09-01	9.2	8.8	7.7	7.4		ST	REF			43.2	
1090	Central Hudson Gas & Elec. Corp.	High Falls		G	23754	Marbletown	111	36	1986-12-01	3.2	3.0	0.0	0.0		HY	WAT				
1091	Central Hudson Gas & Elec. Corp.	Millpond		G	5004	Catskill	039	36	1993-12-01	0.9		0.0	0.0		HY	WAT				
1092	Central Hudson Gas & Elec. Corp.	Montgomery West		G	5005	Montgomery	071	36	1985-11-01	0.2		0.0	0.0		HY	WAT				
1093	Central Hudson Gas & Elec. Corp.	Salisbury Mills		G	5006	Salisbury Mills	071	36	1986-12-01	0.5		0.0	0.0		HY	WAT				
1094	Central Hudson Gas & Elec. Corp.	South Cairo		G	23612	Cairo	039	36	1970-06-01	21.6	17.8	18.2	23.3		GT	KER			0.1	
1095	Central Hudson Gas & Elec. Corp.	Sturgeon 1		G	23609	Rifton	111	36	1924-01-01	4.8	5.0	0.0	0.0		HY	WAT				
1096	Central Hudson Gas & Elec. Corp.	Sturgeon 2		G	23609	Rifton	111	36	1924-01-01	4.8	5.8	0.0	0.0		HY	WAT				
1097	Central Hudson Gas & Elec. Corp.	Sturgeon 3		G	23609	Rifton	111	36	1924-01-01	4.8	5.0	0.0	0.0		HY	WAT				
1098	Central Hudson Gas & Elec. Corp.	Wallkill		G	5007	Shwangunk	111	36	1986-12-01	0.5		0.0	0.0		HY	WAT				
1099	Central Hudson Gas & Elec. Corp.	Wappingers Falls		G	23765	Wappingers	027	36	1988-12-01	2.0	2.0	2.0	2.0		HY	WAT			8.8	
1100	CHI Energy Inc	Goodyear Lake		E	323669	Milford	077	36	1980-07-01	1.4	1.4	0.0	0.0		HY	WAT			4.3	
1101	Consolidated Edison Co. of NY, Inc.	59 St. GT 1		J	24138	Manhattan	061	36	1969-06-01	17.1	15.4	15.1	20.7		GT	KER	NG		0.3	
1102	Consolidated Edison Co. of NY, Inc.	74 St. GT 1		J	24260	Manhattan	061	36	1968-10-01	18.5	19.0	17.7	17.9		GT	KER			0.2	
1103	Consolidated Edison Co. of NY, Inc.	74 St. GT 2		J	24261	Manhattan	061	36	1968-10-01	18.5	20.1	17.4	20.1		GT	KER			0.5	
1104	Consolidated Edison Co. of NY, Inc.	Brooklyn Navy Yard		J	23515	Brooklyn	047	36	1996-11-01	322.0	266.9	261.5	296.1	YES	CC	NG	FO2		1,953.5	
1105	Consolidated Edison Co. of NY, Inc.	East River 1		J	323558	Manhattan	061	36	2005-04-01	185.0	150.5	144.6	180.4		CC	NG	KER		1,058.1	
1106	Consolidated Edison Co. of NY, Inc.	East River 2		J	323559	Manhattan	061	36	2005-04-05	185.0	152.4	144.8	181.8		CC	NG	KER		1,156.7	
1107	Consolidated Edison Co. of NY, Inc.	East River 6		J	23660	Manhattan	061	36	1951-11-01	156.2	134.3	138.3	137.9	YES	ST	FO6	NG		431.5	
1108	Consolidated Edison Co. of NY, Inc.	East River 7		J	23524	Manhattan	061	36	1955-06-01	200.0	184.7	183.6	185.0	YES	ST	FO6	NG		105.9	
1109	Consolidated Edison Co. of NY, Inc.	Hudson Ave 3		J	23810	Brooklyn	047	36	1970-07-01	16.3	16.0	14.8	18.7		GT	KER			0.2	
1110	Consolidated Edison Co. of NY, Inc.	Hudson Ave 4		J	23540	Brooklyn	047	36	1970-07-01	16.3	13.9	13.7	17.5		GT	KER			0.4	
1111	Consolidated Edison Co. of NY, Inc.	Hudson Ave 5		J	23657	Brooklyn	047	36	1970-07-01	16.3	15.1	15.0	18.6		GT	KER			0.5	
1112	Consolidated Edison Energy, Inc.	Broome 2 LFGE		C	323671	Binghamton	007	36	2013-01-31	1.6	1.6	1.6	1.6		IC	MTE			13.1	
1113	Consolidated Edison Energy, Inc.	Massena		D	23902	Massena	089	36	1992-07-01	102.1	82.2	80.3	90.7		CC	NG	FO2		1.7	
1114	Consolidated Edison Energy, Inc.	Rensselaer		F	23796	Rensselaer	083	36	1993-12-01	96.9	79.0	77.0	82.7		CC	NG	FO2		48.0	
1115	Consolidated Edison Energy, Inc.	Roseton 1		G	23587	Newburgh	071	36	1974-12-01	621.0	614.8	610.5	618.7		ST	FO6	NG	FO2	176.4	
1116	Consolidated Edison Energy, Inc.	Roseton 2		G	23588	Newburgh	071	36	1974-09-01	621.0	605.7	597.0	587.2		ST	FO6	NG	FO2	202.0	
1117	Consolidated Hydro New York, Inc.	Groveville Hydro		G	323602	Beacon	027	36	1983-12-01	0.9	0.9	0.0	0.0		HY	WAT			1.6	
1118	Consolidated Hydro New York, Inc.	Walden Hydro		G	24148	Walden	071	36	1983-12-01	2.4	0.0	0.0	0.0		HY	WAT			3.0	
1119	Covanta Niagara, LP	American Ref-Fuel 1		A	24010	Niagara	063	36	1993-05-01	25.0	19.6	18.4	17.5	YES	ST	REF			241.1	(G)
1120	Covanta Niagara, LP	American Ref-Fuel 2		A	24010	Niagara	063	36	1993-05-01	25.0	19.6	18.4	17.5	YES	ST	REF				
1121	Danskammer Energy, LLC	Danskammer 1	(ReAct. - 10/	G	23586	Newburgh	071	36	1951-12-01	72.0	67.0	60.7	60.7		ST	NG	FO6			(D)
1122	Danskammer Energy, LLC	Danskammer 2	(ReAct. - 10/	G	23589	Newburgh	071	36	1954-09-01	73.5	62.7	59.5	59.5		ST	NG	FO6			(D)
1123	Danskammer Energy, LLC	Danskammer 3	(ReAct. - 12/	G	23590	Newburgh	071	36	1959-10-01	147.1	137.2	137.5	137.5		ST	NG			1.2	(D) (3)
1124	Danskammer Energy, LLC	Danskammer 4	(ReAct. - 11/	G	23591	Newburgh	071	36	1967-09-01	239.4	236.2	232.0	178.7		ST	NG			3.1	(D) (4)
1125	Dynegy Danskammer, LLC	Danskammer 5		G	23592	Newburgh	071	36	1967-01-01	2.7	0.0	0.0	0.0		IC	FO2				
1126	Dynegy Danskammer, LLC	Danskammer 6		G	23592	Newburgh	071	36	1967-01-01	2.7	0.0	0.0	0.0		IC	FO2				
1127	Dynegy Marketing and Trade, LLC	Independence		C	23800	Scriba	075	36	1994-11-01	1,254.0	954.4	910.8	1,112.0		CC	NG			6,026.3	
1128	Eagle Creek Hydro Power, LLC	Mongaup 1		G	23641	Forestburg	105	36	1923-07-01	1.0	0.9	1.0	1.0		HY	WAT			10.3	(G)
1129	Eagle Creek Hydro Power, LLC	Mongaup 2		G	23641	Forestburg	105	36	1923-07-01	1.0	1.0	1.0	1.0		HY	WAT				
1130	Eagle Creek Hydro Power, LLC	Mongaup 3		G	23641	Forestburg	105	36	1923-07-01	1.0	1.0	1.0	1.0		HY	WAT				
1131	Eagle Creek Hydro Power, LLC	Mongaup 4		G	23641	Forestburg	105	36	1926-01-01	1.0	1.0	1.0	1.0		HY	WAT				
1132	Eagle Creek Hydro Power, LLC	Rio		G	23641	Glen Spey	105	36	1927-12-01	10.8	10.8	10.4	10.1		HY	WAT			23.0	
1133	Eagle Creek Hydro Power, LLC	Swinging Bridge 2		G	23641	Forestburg	105	36	1930-02-01	7.0	7.9	6.6	6.5		HY	WAT			9.1	
1134	East Coast Power, LLC	Linden Cogen		J	23786	Linden NJ	039	34	1992-05-01	1,034.9	755.3	757.8	800.0	YES	CC	NG	BUT		3,308.3	
1135	Empire Generating Co, LLC	EMPIRE_CC_1		F	323656	Rensselaer	083	36	2010-09-02	335.0	294.2	287.3	335.9		CC	NG	FO2		1,357.3	
1136	Empire Generating Co, LLC	EMPIRE_CC_2		F	323658	Rensselaer	083	36	2010-09-02	335.0	298.2	288.3	335.8		CC	NG	FO2		1,339.2	
1137	Entergy Nuclear Power Marketing LLC	Fitzpatrick 1		C	23598	Scriba	075	36	1975-07-01	882.0	858.9	836.8	842.9		NB	UR			5,828.7	
1138	Entergy Nuclear Power Marketing LLC	Indian Point 2		H	23530	Buchanan	119	36	1973-08-01	1,299.0	1,026.5	1,020.0	1,031.0		NP	UR			8,331.3	
1139	Entergy Nuclear Power Marketing LLC	Indian Point 3		H	23531	Buchanan	119	36	1976-04-01	1,012.0	1,040.4	1,034.8	1,047.0		NP	UR			8,979.0	
1140	Erie Blvd. Hydro - Beaver River	Belfort 1		E	24048	Belfort	049	36	1903-01-01	0.4	0.4	0.4	0.4		HY	WAT			1.8	
1141	Erie Blvd. Hydro - Beaver River	Belfort 2		E	24048	Belfort	049	36	1915-01-01	0.6	0.6	0.6	0.6		HY	WAT			5.1	
1142	Erie Blvd. Hydro - Beaver River	Belfort 3		E	24048	Belfort	049	36	1918-01-01	1.0	1.0	1.0	1.0		HY	WAT			5.2	
1143	Erie Blvd. Hydro - Beaver River	Eagle 1		E	24048	Watson	049	36	1914-01-01	1.3	1.2	1.3	1.3		HY	WAT			10.2	

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1144	Erie Blvd. Hydro - Beaver River	Eagle 2		E	24048	Watson	049	36	1915-01-01	1.4	1.3	1.4	1.4		HY	WAT			9.0	
1145	Erie Blvd. Hydro - Beaver River	Eagle 3		E	24048	Watson	049	36	1919-01-01	1.4	1.3	1.4	1.4		HY	WAT			7.0	
1146	Erie Blvd. Hydro - Beaver River	Eagle 4		E	24048	Watson	049	36	1925-01-01	2.1	2.0	2.1	2.1		HY	WAT			12.2	
1147	Erie Blvd. Hydro - Beaver River	Effley 1		E	24048	Belfort	049	36	1902-01-01	0.4	0.3	0.4	0.4		HY	WAT			2.6	
1148	Erie Blvd. Hydro - Beaver River	Effley 2		E	24048	Belfort	049	36	1907-01-01	0.4	0.3	0.4	0.4		HY	WAT			2.2	
1149	Erie Blvd. Hydro - Beaver River	Effley 3		E	24048	Belfort	049	36	1910-01-01	0.6	0.5	0.6	0.6		HY	WAT			4.3	
1150	Erie Blvd. Hydro - Beaver River	Effley 4		E	24048	Belfort	049	36	1923-01-01	1.6	1.5	1.6	1.6		HY	WAT			9.2	
1151	Erie Blvd. Hydro - Beaver River	Elmer 1		E	24048	Belfort	049	36	1916-01-01	0.8	0.9	0.8	0.8		HY	WAT			5.9	
1152	Erie Blvd. Hydro - Beaver River	Elmer 2		E	24048	Belfort	049	36	1916-01-01	0.8	0.9	0.8	0.8		HY	WAT			7.4	
1153	Erie Blvd. Hydro - Beaver River	High Falls 1		E	24048	Indian River	049	36	1925-01-01	1.6	1.9	1.6	1.6		HY	WAT			12.1	
1154	Erie Blvd. Hydro - Beaver River	High Falls 2		E	24048	Indian River	049	36	1925-01-01	1.6	1.9	1.6	1.6		HY	WAT			9.4	
1155	Erie Blvd. Hydro - Beaver River	High Falls 3		E	24048	Indian River	049	36	1925-01-01	1.6	1.9	1.6	1.6		HY	WAT			13.5	
1156	Erie Blvd. Hydro - Beaver River	Moshier 1		E	24048	Belfort	043	36	1929-01-01	4.0	4.0	4.0	4.0		HY	WAT			28.5	
1157	Erie Blvd. Hydro - Beaver River	Moshier 2		E	24048	Belfort	043	36	1929-01-01	4.0	4.0	4.0	4.0		HY	WAT			18.8	
1158	Erie Blvd. Hydro - Beaver River	Soft Maple 1		E	24048	Croghan	049	36	1925-01-01	7.5	8.0	7.5	7.5		HY	WAT			37.6	
1159	Erie Blvd. Hydro - Beaver River	Soft Maple 2		E	24048	Croghan	049	36	1925-01-01	7.5	8.0	7.5	7.5		HY	WAT			8.0	
1160	Erie Blvd. Hydro - Beaver River	Taylorville 1		E	24048	Belfort	049	36	1913-01-01	1.1	1.0	1.1	1.1		HY	WAT			8.4	
1161	Erie Blvd. Hydro - Beaver River	Taylorville 2		E	24048	Belfort	049	36	1913-01-01	1.1	1.0	1.1	1.1		HY	WAT			5.1	
1162	Erie Blvd. Hydro - Beaver River	Taylorville 3		E	24048	Belfort	049	36	1913-01-01	1.1	1.0	1.1	1.1		HY	WAT			6.8	
1163	Erie Blvd. Hydro - Beaver River	Taylorville 4		E	24048	Belfort	049	36	1927-01-01	1.2	1.1	1.2	1.2		HY	WAT			8.4	
1164	Erie Blvd. Hydro - Black River	Beebee Island 1		E	24047	Watertown	045	36	1963-01-01	4.0	4.4	4.0	4.0		HY	WAT			13.0	
1165	Erie Blvd. Hydro - Black River	Beebee Island 2		E	24047	Watertown	045	36	1968-01-01	4.0	4.4	4.0	4.0		HY	WAT			31.0	
1166	Erie Blvd. Hydro - Black River	Black River 1		E	24047	Black River	045	36	1920-01-01	2.0	2.3	2.0	2.0		HY	WAT			10.8	
1167	Erie Blvd. Hydro - Black River	Black River 2		E	24047	Black River	045	36	1920-01-01	2.0	2.3	2.0	2.0		HY	WAT			15.4	
1168	Erie Blvd. Hydro - Black River	Black River 3		E	24047	Black River	045	36	1920-01-01	2.0	2.3	2.0	2.0		HY	WAT			7.7	
1169	Erie Blvd. Hydro - Black River	Deferiet 1		E	24047	Deferiet	045	36	1925-01-01	3.6	3.7	3.6	3.6		HY	WAT			15.7	
1170	Erie Blvd. Hydro - Black River	Deferiet 2		E	24047	Deferiet	045	36	1925-01-01	3.6	3.7	3.6	3.6		HY	WAT			29.9	
1171	Erie Blvd. Hydro - Black River	Deferiet 3		E	24047	Deferiet	045	36	1925-01-01	3.6	3.7	3.6	3.6		HY	WAT			13.5	
1172	Erie Blvd. Hydro - Black River	Herrings 1		E	24047	Herrings	045	36	1924-01-01	1.8	1.8	1.8	1.8		HY	WAT			4.5	
1173	Erie Blvd. Hydro - Black River	Herrings 2		E	24047	Herrings	045	36	1924-01-01	1.8	1.8	1.8	1.8		HY	WAT			9.6	
1174	Erie Blvd. Hydro - Black River	Herrings 3		E	24047	Herrings	045	36	1924-01-01	1.8	1.8	1.8	1.8		HY	WAT			4.0	
1175	Erie Blvd. Hydro - Black River	Kamargo 1		E	24047	Black River	045	36	1921-01-01	1.8	1.8	1.8	1.8		HY	WAT			7.8	
1176	Erie Blvd. Hydro - Black River	Kamargo 2		E	24047	Black River	045	36	1921-01-01	1.8	1.8	1.8	1.8		HY	WAT			12.8	
1177	Erie Blvd. Hydro - Black River	Kamargo 3		E	24047	Black River	045	36	1921-01-01	1.8	1.8	1.8	1.8		HY	WAT			2.3	
1178	Erie Blvd. Hydro - Black River	Sewalls 1		E	24047	Watertown	045	36	1925-01-01	1.0	1.1	1.0	1.0		HY	WAT			6.2	
1179	Erie Blvd. Hydro - Black River	Sewalls 2		E	24047	Watertown	045	36	1925-01-01	1.0	1.1	1.0	1.0		HY	WAT			4.2	
1180	Erie Blvd. Hydro - East Canada Capita	Beardslee 1		F	24051	Little Falls	043	36	1924-01-01	10.0	9.5	10.0	10.0		HY	WAT			22.6	
1181	Erie Blvd. Hydro - East Canada Capita	Beardslee 2		F	24051	Little Falls	043	36	1924-01-01	10.0	9.5	10.0	10.0		HY	WAT			28.8	
1182	Erie Blvd. Hydro - East Canada Capita	Ephratah 1		F	24051	Caroga Lake	035	36	1920-01-01	1.4	0.7	1.4	1.4		HY	WAT			1.0	
1183	Erie Blvd. Hydro - East Canada Capita	Ephratah 2		F	24051	Caroga Lake	035	36	1911-01-01	1.2	0.6	1.2	1.2		HY	WAT			0.5	
1184	Erie Blvd. Hydro - East Canada Capita	Ephratah 3		F	24051	Caroga Lake	035	36	1911-01-01	1.3	0.0	0.0	0.0		HY	WAT			4.2	
1185	Erie Blvd. Hydro - East Canada Capita	Ephratah 4		F	24051	Caroga Lake	035	36	1911-01-01	1.3	0.7	1.3	1.3		HY	WAT			7.6	
1186	Erie Blvd. Hydro - East Canada Moha	Inghams 1		E	24050	Little Falls	043	36	1912-01-01	3.2	3.5	3.2	3.2		HY	WAT			11.9	
1187	Erie Blvd. Hydro - East Canada Moha	Inghams 2		E	24050	Little Falls	043	36	1912-01-01	3.2	3.5	3.2	3.2		HY	WAT			16.5	
1188	Erie Blvd. Hydro - Lower Hudson	Johnsonville 1		F	24059	Johnsonville	083	36	1909-01-01	1.2	1.3	1.2	1.2		HY	WAT			3.3	
1189	Erie Blvd. Hydro - Lower Hudson	Johnsonville 2		F	24059	Johnsonville	083	36	1909-01-01	1.2	1.3	1.2	1.2		HY	WAT			6.8	
1190	Erie Blvd. Hydro - Lower Hudson	Schaghticoke 1		F	24059	Schaghticoke	083	36	1908-01-01	3.3	4.1	3.3	3.3		HY	WAT			19.9	
1191	Erie Blvd. Hydro - Lower Hudson	Schaghticoke 2		F	24059	Schaghticoke	083	36	1908-01-01	3.3	4.1	3.3	3.3		HY	WAT			8.5	
1192	Erie Blvd. Hydro - Lower Hudson	Schaghticoke 3		F	24059	Schaghticoke	083	36	1908-01-01	3.3	4.1	3.3	3.3		HY	WAT			12.6	
1193	Erie Blvd. Hydro - Lower Hudson	Schaghticoke 4		F	24059	Schaghticoke	083	36	1908-01-01	3.3	4.1	3.3	3.3		HY	WAT			16.4	
1194	Erie Blvd. Hydro - Lower Hudson	School Street 1		F	24059	Cohoes	001	36	1974-01-01	7.2	6.9	7.2	7.2		HY	WAT			39.7	
1195	Erie Blvd. Hydro - Lower Hudson	School Street 2		F	24059	Cohoes	001	36	1915-01-01	7.2	6.9	7.2	7.2		HY	WAT			40.2	
1196	Erie Blvd. Hydro - Lower Hudson	School Street 3		F	24059	Cohoes	001	36	1915-01-01	7.2	6.9	7.2	7.2		HY	WAT			35.2	
1197	Erie Blvd. Hydro - Lower Hudson	School Street 4		F	24059	Cohoes	001	36	1922-01-01	7.2	6.9	7.2	7.2		HY	WAT			31.8	
1198	Erie Blvd. Hydro - Lower Hudson	School Street 5		F	24059	Cohoes	001	36	1924-01-01	10.0	9.6	10.0	10.0		HY	WAT			21.2	
1199	Erie Blvd. Hydro - Lower Hudson	Schuylerville		F	24059	Schuylerville	091	36	1919-01-01	1.2	1.5	1.2	1.2		HY	WAT			7.3	
1200	Erie Blvd. Hydro - Lower Raquette	Colton 1		E	24057	Colton	089	36	1962-01-01	10.0	10.0	10.0	10.0		HY	WAT			64.8	
1201	Erie Blvd. Hydro - Lower Raquette	Colton 2		E	24057	Colton	089	36	1918-01-01	10.0	10.0	10.0	10.0		HY	WAT			56.5	
1202	Erie Blvd. Hydro - Lower Raquette	Colton 3		E	24057	Colton	089	36	1928-01-01	10.0	10.0	10.0	10.0		HY	WAT			68.6	
1203	Erie Blvd. Hydro - Lower Raquette	East Norfolk		E	24057	East Norfolk	089	36	1928-01-01	3.0	4.0	3.0	3.0		HY	WAT			24.9	
1204	Erie Blvd. Hydro - Lower Raquette	Hannawa Falls 1		E	24057	Hannawa Falls	089	36	1914-01-01	3.6	3.7	3.6	3.6		HY	WAT			20.6	
1205	Erie Blvd. Hydro - Lower Raquette	Hannawa Falls 2		E	24057	Hannawa Falls	089	36	1920-01-01	3.6	3.7	3.6	3.6		HY	WAT			26.4	
1206	Erie Blvd. Hydro - Lower Raquette	Higley 1		E	24057	Colton	089	36	1913-01-01	1.2	1.1	1.2	1.2		HY	WAT			8.0	
1207	Erie Blvd. Hydro - Lower Raquette	Higley 2		E	24057	Colton	089	36	1913-01-01	1.2	1.1	1.2	1.2		HY	WAT			7.9	
1208	Erie Blvd. Hydro - Lower Raquette	Higley 3		E	24057	Colton	089	36	1943-01-01	2.1	2.0	2.1	2.1		HY	WAT			10.0	
1209	Erie Blvd. Hydro - Lower Raquette	Higley 4		E	24057	Colton	089	36	1943-01-01	2.1	2.0	2.1	2.1		HY	WAT			7.5	
1210	Erie Blvd. Hydro - Lower Raquette	Norfolk		E	24057	Norfolk	089	36	1928-01-01	4.5	4.8	4.5	4.5		HY	WAT			28.2	
1211	Erie Blvd. Hydro - Lower Raquette	Norwood		E	24057	Norwood	089	36	1928-01-01	2.0	2.2	2.0	2.0		HY	WAT			13.6	
1212	Erie Blvd. Hydro - Lower Raquette	Raymondville		E	24057	Raymondville	089	36	1928-01-01	2.0	2.1	2.0	2.0		HY	WAT			13.1	
1213	Erie Blvd. Hydro - Lower Raquette	Sugar Island 1		E	24057	Potsdam	089	36	1924-01-01	2.6	2.1	2.6	2.6		HY	WAT			9.9	
1214	Erie Blvd. Hydro - Lower Raquette	Sugar Island 2		E	24057	Potsdam	089	36	1924-01-01	2.4	2.0	2.4	2.4		HY	WAT			17.1	
1215	Erie Blvd. Hydro - Lower Raquette	Yaleville 1		E	24057	Norwood	089	36	1940-01-01	0.5	0.2	0.5	0.5		HY	WAT			2.3	

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1216	Erie Blvd. Hydro - Lower Raquette	Yaleville 2		E	24057	Norwood	089	36	1940-01-01	0.2	0.3	0.2	0.2		HY	WAT			0.8	
1217	Erie Blvd. Hydro - North Salmon	Allens Falls		D	24042	Allens Falls	089	36	1927-01-01	4.4	5.0	4.4	4.4		HY	WAT			24.8	
1218	Erie Blvd. Hydro - North Salmon	Chasm 1		D	24042	Chateaugay	033	36	1913-01-01	1.0	1.1	1.0	1.0		HY	WAT			5.2	
1219	Erie Blvd. Hydro - North Salmon	Chasm 2		D	24042	Chateaugay	033	36	1913-01-01	1.0	1.1	1.0	1.0		HY	WAT			2.8	
1220	Erie Blvd. Hydro - North Salmon	Chasm 3		D	24042	Chateaugay	033	36	1926-01-01	1.4	1.6	1.4	1.4		HY	WAT			0.0	
1221	Erie Blvd. Hydro - North Salmon	Franklin 1		D	24042	Franklin	033	36	1911-01-01	1.1	1.1	1.1	1.1		HY	WAT			5.5	
1222	Erie Blvd. Hydro - North Salmon	Franklin 2		D	24042	Franklin	033	36	1926-01-01	1.1	1.1	1.1	1.1		HY	WAT			3.6	
1223	Erie Blvd. Hydro - North Salmon	Hogansburg		D	24042	Hogansburg	033	36	1930-01-01	0.7	0.3	0.7	0.7		HY	WAT			0.7	
1224	Erie Blvd. Hydro - North Salmon	Macomb		D	24042	Malone	033	36	1940-01-01	1.0	0.9	1.0	1.0		HY	WAT			4.4	
1225	Erie Blvd. Hydro - North Salmon	Parishville		D	24042	Parishville	089	36	1925-01-01	2.4	2.3	2.4	2.4		HY	WAT			14.1	
1226	Erie Blvd. Hydro - North Salmon	Piercefield 1		D	24042	Piercefield	089	36	1957-01-01	1.5	1.6	1.5	1.5		HY	WAT			9.5	
1227	Erie Blvd. Hydro - North Salmon	Piercefield 2		D	24042	Piercefield	089	36	1924-01-01	0.6	0.6	0.6	0.6		HY	WAT			3.6	
1228	Erie Blvd. Hydro - North Salmon	Piercefield 3		D	24042	Piercefield	089	36	1924-01-01	0.6	0.6	0.6	0.6		HY	WAT			2.7	
1229	Erie Blvd. Hydro - NYS Barge	Hydraulic Race		A	23848	Lockport	063	36	1942-01-01	4.7	3.1	4.7	4.7		HY	WAT			9.3	
1230	Erie Blvd. Hydro - Oak Orchard	Glenwood 1		B	24046	Medina	073	36	1950-01-01	0.5	0.5	0.5	0.5		HY	WAT			2.7	
1231	Erie Blvd. Hydro - Oak Orchard	Glenwood 2		B	24046	Medina	073	36	1950-01-01	0.5	0.5	0.5	0.5		HY	WAT			3.6	
1232	Erie Blvd. Hydro - Oak Orchard	Glenwood 3		B	24046	Medina	073	36	1950-01-01	0.5	0.5	0.5	0.5		HY	WAT			0.0	
1233	Erie Blvd. Hydro - Oak Orchard	Oak Orchard		B	24046	Waterport	073	36	1941-01-01	0.4	0.3	0.4	0.4		HY	WAT			1.1	
1234	Erie Blvd. Hydro - Oak Orchard	Waterport 1		B	24046	Waterport	073	36	1941-01-01	2.3	1.6	2.3	2.3		HY	WAT			6.6	
1235	Erie Blvd. Hydro - Oak Orchard	Waterport 2		B	24046	Waterport	073	36	1968-01-01	2.5	1.8	2.5	2.5		HY	WAT			7.8	
1236	Erie Blvd. Hydro - Oswegatchie	Browns Falls 1		E	24044	Oswegatchie	089	36	1923-01-01	7.5	8.0	7.5	7.5		HY	WAT			37.9	
1237	Erie Blvd. Hydro - Oswegatchie	Browns Falls 2		E	24044	Oswegatchie	089	36	1923-01-01	7.5	8.0	7.5	7.5		HY	WAT			23.6	
1238	Erie Blvd. Hydro - Oswegatchie	Eel Weir 1		E	24044	Heuvelton	089	36	1928-01-01	0.5	0.3	0.5	0.5		HY	WAT			2.1	
1239	Erie Blvd. Hydro - Oswegatchie	Eel Weir 2		E	24044	Heuvelton	089	36	1938-01-01	1.1	0.8	1.1	1.1		HY	WAT			2.7	
1240	Erie Blvd. Hydro - Oswegatchie	Eel Weir 3		E	24044	Heuvelton	089	36	1938-01-01	1.1	0.8	1.1	1.1		HY	WAT			4.8	
1241	Erie Blvd. Hydro - Oswegatchie	Flat Rock 1		E	24044	Flat Rock	089	36	1924-01-01	3.0	2.6	3.0	3.0		HY	WAT			12.9	
1242	Erie Blvd. Hydro - Oswegatchie	Flat Rock 2		E	24044	Flat Rock	089	36	1924-01-01	3.0	2.6	3.0	3.0		HY	WAT			5.8	
1243	Erie Blvd. Hydro - Oswegatchie	Heuvelton 1		E	24044	Heuvelton	089	36	1924-01-01	0.5	0.4	0.5	0.5		HY	WAT			2.5	
1244	Erie Blvd. Hydro - Oswegatchie	Heuvelton 2		E	24044	Heuvelton	089	36	1924-01-01	0.5	0.4	0.5	0.5		HY	WAT			2.2	
1245	Erie Blvd. Hydro - Oswegatchie	Lower Newton Falls 1		E	24044	Newton Falls	089	36	2002-07-01	0.5	0.6	0.5	0.5		HY	WAT			2.9	
1246	Erie Blvd. Hydro - Oswegatchie	Oswegatchie 1		E	24044	Oswegatchie	089	36	1937-01-01	0.6	1.3	0.6	0.6		HY	WAT			5.3	
1247	Erie Blvd. Hydro - Oswegatchie	Oswegatchie 2		E	24044	Oswegatchie	089	36	1937-01-01	0.2	0.5	0.2	0.2		HY	WAT			2.8	
1248	Erie Blvd. Hydro - Oswegatchie	South Edwards 1		E	24044	South Edwards	089	36	1937-01-01	1.0	1.2	1.0	1.0		HY	WAT			9.3	
1249	Erie Blvd. Hydro - Oswegatchie	South Edwards 2		E	24044	South Edwards	089	36	1937-01-01	1.0	1.2	1.0	1.0		HY	WAT			5.1	
1250	Erie Blvd. Hydro - Oswegatchie	South Edwards 3		E	24044	South Edwards	089	36	1921-01-01	0.7	0.8	0.7	0.7		HY	WAT			4.5	
1251	Erie Blvd. Hydro - Oswegatchie	South Edwards 4		E	24044	South Edwards	089	36	1937-01-01	0.2	0.2	0.2	0.2		HY	WAT			0.0	
1252	Erie Blvd. Hydro - Oswegatchie	Talcville 1		E	24044	Edwards	089	36	1986-12-01	0.5	0.4	0.5	0.5		HY	WAT			3.1	
1253	Erie Blvd. Hydro - Oswegatchie	Talcville 2		E	24044	Edwards	089	36	1986-12-01	0.5	0.4	0.5	0.5		HY	WAT			0.3	
1254	Erie Blvd. Hydro - Oswegatchie	Upper Newton Falls 2		E	24044	Newton Falls	089	36	2002-07-01	0.5	0.4	0.5	0.5		HY	WAT			2.2	
1255	Erie Blvd. Hydro - Oswegatchie	Upper Newton Falls 3		E	24044	Newton Falls	089	36	2002-07-01	0.5	0.4	0.5	0.5		HY	WAT			1.4	
1256	Erie Blvd. Hydro - Oswegatchie	Upper Newton Falls 4		E	24044	Newton Falls	089	36	2002-07-01	0.5	0.4	0.5	0.5		HY	WAT			1.8	
1257	Erie Blvd. Hydro - Seneca Oswego	Baldwinsville 1		C	24041	Baldwinsville	067	36	1927-01-01	0.3	0.2	0.3	0.3		HY	WAT			1.6	
1258	Erie Blvd. Hydro - Seneca Oswego	Baldwinsville 2		C	24041	Baldwinsville	067	36	1927-01-01	0.3	0.2	0.3	0.3		HY	WAT			1.4	
1259	Erie Blvd. Hydro - Seneca Oswego	Granby 1		C	24041	Granby	075	36	1983-05-01	5.0	5.1	5.2	5.2		HY	WAT			22.0	
1260	Erie Blvd. Hydro - Seneca Oswego	Granby 2		C	24041	Granby	075	36	1983-05-01	5.0	5.1	5.2	5.2		HY	WAT			25.8	
1261	Erie Blvd. Hydro - Seneca Oswego	Minetto 2		C	24041	Minetto	075	36	1915-01-01	1.6	1.5	1.7	1.7		HY	WAT			9.3	
1262	Erie Blvd. Hydro - Seneca Oswego	Minetto 3		C	24041	Minetto	075	36	1915-01-01	1.6	1.5	1.7	1.7		HY	WAT			9.2	
1263	Erie Blvd. Hydro - Seneca Oswego	Minetto 4		C	24041	Minetto	075	36	1915-01-01	1.6	1.5	1.7	1.7		HY	WAT			7.8	
1264	Erie Blvd. Hydro - Seneca Oswego	Minetto 5		C	24041	Minetto	075	36	1975-01-01	1.6	1.5	1.7	1.7		HY	WAT			6.9	
1265	Erie Blvd. Hydro - Seneca Oswego	Minetto 6		C	24041	Minetto	075	36	1975-01-01	1.6	1.5	1.7	1.7		HY	WAT			5.5	
1266	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls E 1		C	24041	Oswego	075	36	1914-01-01	1.5	1.5	1.6	1.6		HY	WAT			10.1	
1267	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls E 2		C	24041	Oswego	075	36	1914-01-01	1.5	1.5	1.6	1.6		HY	WAT			6.9	
1268	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls E 3		C	24041	Oswego	075	36	1914-01-01	1.5	1.5	1.6	1.6		HY	WAT			6.4	
1269	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls W 4		C	24041	Oswego	075	36	1914-01-01	0.9	1.0	0.9	0.9		HY	WAT			4.6	
1270	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls W 5		C	24041	Oswego	075	36	1914-01-01	0.9	1.0	0.9	0.9		HY	WAT			5.1	
1271	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls W 6		C	24041	Oswego	075	36	2007-01-01	0.5	0.5	0.5	0.5		HY	WAT			0.1	
1272	Erie Blvd. Hydro - Seneca Oswego	Oswego Falls W 7		C	24041	Oswego	075	36	2007-01-01	0.5	0.5	0.5	0.5		HY	WAT			0.3	
1273	Erie Blvd. Hydro - Seneca Oswego	Varick 2		C	24041	Oswego	075	36	1926-01-01	2.2	1.9	2.3	2.3		HY	WAT			9.9	
1274	Erie Blvd. Hydro - Seneca Oswego	Varick 3		C	24041	Oswego	075	36	1926-01-01	2.2	2.1	2.3	2.3		HY	WAT			5.3	
1275	Erie Blvd. Hydro - Seneca Oswego	Varick 4		C	24041	Oswego	075	36	1926-01-01	2.2	1.9	2.3	2.3		HY	WAT			6.5	
1276	Erie Blvd. Hydro - Seneca Oswego	Varick 5		C	24041	Oswego	075	36	1926-01-01	2.2	1.9	2.3	2.3		HY	WAT			7.1	
1277	Erie Blvd. Hydro - South Salmon	Bennetts Bridge 1		C	24043	Altmar	075	36	1964-01-01	6.4	7.0	6.4	6.4		HY	WAT			7.7	
1278	Erie Blvd. Hydro - South Salmon	Bennetts Bridge 2		C	24043	Altmar	075	36	1966-01-01	6.4	7.0	6.4	6.4		HY	WAT			20.2	
1279	Erie Blvd. Hydro - South Salmon	Bennetts Bridge 3		C	24043	Altmar	075	36	1970-01-01	7.0	7.7	7.0	7.0		HY	WAT			38.1	
1280	Erie Blvd. Hydro - South Salmon	Bennetts Bridge 4		C	24043	Altmar	075	36	1970-01-01	7.0	7.7	7.0	7.0		HY	WAT			38.0	
1281	Erie Blvd. Hydro - South Salmon	Lighthouse Hill 1		C	24043	Altmar	075	36	1930-01-01	3.8	4.1	3.8	3.8		HY	WAT			17.4	
1282	Erie Blvd. Hydro - South Salmon	Lighthouse Hill 2		C	24043	Altmar	075	36	1930-01-01	3.8	4.1	3.8	3.8		HY	WAT			8.0	
1283	Erie Blvd. Hydro - Upper Hudson	E J West 1		F	24058	Hadley	091	36	1930-01-01	10.0	11.9	10.0	10.0		HY	WAT			31.4	
1284	Erie Blvd. Hydro - Upper Hudson	E J West 2		F	24058	Hadley	091	36	1930-01-01	10.0	11.9	10.0	10.0		HY	WAT			35.9	
1285	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 1		F	24058	S Glens Falls	091	36	1924-01-01	1.2	0.9	1.2	1.2		HY	WAT			5.1	
1286	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 2		F	24058	S Glens Falls	091	36	1924-01-01	1.2	0.9	1.2	1.2		HY	WAT			4.3	
1287	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 3		F	24058	S Glens Falls	091	36	1924-01-01	1.2	0.9	1.2	1.2		HY	WAT			4.5	

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LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1288	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 4		F	24058	S Glens Falls	091	36	1924-01-01	1.2	0.9	1.2	1.2		HY	WAT			6.2	
1289	Erie Blvd. Hydro - Upper Hudson	Feeder Dam 5		F	24058	S Glens Falls	091	36	1924-01-01	1.2	0.9	1.2	1.2		HY	WAT			6.3	
1290	Erie Blvd. Hydro - Upper Hudson	Sherman Island 1		F	24058	Queensbury	113	36	2009-03-01	8.0	0.0	0.0	0.0		HY	WAT			36.2	
1291	Erie Blvd. Hydro - Upper Hudson	Sherman Island 2		F	24058	Queensbury	113	36	1923-01-01	7.2	8.1	7.2	7.2		HY	WAT			39.0	
1292	Erie Blvd. Hydro - Upper Hudson	Sherman Island 3		F	24058	Queensbury	113	36	1923-01-01	8.7	9.7	8.7	8.7		HY	WAT			34.9	
1293	Erie Blvd. Hydro - Upper Hudson	Sherman Island 4		F	24058	Queensbury	113	36	1923-01-01	7.2	8.1	7.2	7.2		HY	WAT			34.0	
1294	Erie Blvd. Hydro - Upper Hudson	Sherman Island 5		F	24058	Queensbury	113	36	1923-01-01	7.2	8.1	7.2	7.2		HY	WAT			19.9	
1295	Erie Blvd. Hydro - Upper Hudson	Sherman Island 6		F	24058	Queensbury	113	36	2009-02-02	1.0	0.0	0.0	0.0		HY	WAT			10.1	
1296	Erie Blvd. Hydro - Upper Hudson	Spier Falls 1		F	24058	Moreau	091	36	1924-01-01	6.8	8.4	6.8	6.8		HY	WAT			56.2	
1297	Erie Blvd. Hydro - Upper Hudson	Spier Falls 2		F	24058	Moreau	091	36	1930-01-01	37.6	46.9	37.6	37.6		HY	WAT			172.6	
1298	Erie Blvd. Hydro - Upper Hudson	Stewarts Bridge		F	24058	Hadley	091	36	1952-01-01	30.0	35.8	30.0	30.0		HY	WAT			113.3	
1299	Erie Blvd. Hydro - Upper Raquette	Blake		E	24056	Stark	089	36	1957-01-01	14.4	15.6	14.4	14.4		HY	WAT			58.1	
1300	Erie Blvd. Hydro - Upper Raquette	Five Falls		E	24056	Colton	089	36	1955-01-01	22.5	24.4	22.5	22.5		HY	WAT			97.7	
1301	Erie Blvd. Hydro - Upper Raquette	Rainbow Falls		E	24056	Colton	089	36	1956-01-01	22.5	24.4	22.5	22.5		HY	WAT			99.4	
1302	Erie Blvd. Hydro - Upper Raquette	South Colton		E	24056	South Colton	089	36	1954-01-01	19.4	20.9	19.4	19.4		HY	WAT			82.3	
1303	Erie Blvd. Hydro - Upper Raquette	Stark		E	24056	Stark	089	36	1957-01-01	22.5	24.6	22.5	22.5		HY	WAT			91.6	
1304	Erie Blvd. Hydro - West Canada	Prospect		E	24049	Prospect	043	36	1959-01-01	17.3	21.7	17.3	17.3		HY	WAT			77.9	
1305	Erie Blvd. Hydro - West Canada	Trenton Falls 5		E	24049	Trenton	065	36	1919-01-01	6.8	9.6	6.8	6.8		HY	WAT			59.5	
1306	Erie Blvd. Hydro - West Canada	Trenton Falls 6		E	24049	Trenton	065	36	1919-01-01	6.4	9.1	6.4	6.4		HY	WAT			54.1	
1307	Erie Blvd. Hydro - West Canada	Trenton Falls 7		E	24049	Trenton	065	36	1922-01-01	6.4	9.1	6.4	6.4		HY	WAT			39.7	
1308	Erie Blvd. Hydropower LP	West Delaware Hydro		G	323627	Grahamsville	105	36	1988-12-01	7.5	7.5	7.5	7.5		HY	WAT			23.0	
1309	Erie Wind, LLC	Erie Wind		A	323693	Lackawanna	029	36	2012-02-01	15.0	0.0	0.0	0.0		WT	WND			39.3	
1310	Exelon Generation Company, LLC	Chaffee		A	323603	Chaffee	029	36	2007-08-09	6.4	6.4	6.4	6.4		IC	MTE			49.4	
1311	Exelon Generation Company, LLC	High Acres 1		C	23767	Fairport	117	36	1991-06-01	3.2	3.2	3.2	3.2		IC	MTE			26.6	
1312	Exelon Generation Company, LLC	High Acres 2		C	23767	Fairport	117	36	2008-02-28	6.4	6.4	6.4	6.4		IC	MTE			51.7	
1313	Exelon Generation Company, LLC	Madison County LF		E	323628	Wampsville	053	36	2010-03-01	1.6	1.6	1.6	1.6		IC	MTE			6.2	
1314	Exelon Generation Company, LLC	Mill Seat		B	323607	Riga	055	36	2007-07-20	6.4	6.4	6.4	6.4		IC	MTE			48.6	
1315	Exelon Generation Company, LLC	Monroe Livingston		B	24207	Scottsville	055	36	1988-11-01	2.4	2.4	2.4	2.4		IC	MTE			8.6	
1316	Exelon Generation Company, LLC	Oneida-Herkimer LFGE		E	323681	Boonville	065	36	2012-04-01	3.2	3.2	3.2	3.2		IC	MTE			24.7	
1317	Exelon Generation Company, LLC	Synergy Biogas		B	323694	Wyoming	121	36	2012-09-01	2.0	2.0	0.0	0.0		IC	MTE			6.2	
1318	Flat Rock Windpower II, LLC	Maple Ridge Wind 2		E	323611	Lowville	049	36	2007-12-01	90.7	90.7	90.8	90.8		WT	WND			225.8	
1319	Flat Rock Windpower, LLC	Maple Ridge Wind 1		E	323574	Lowville	049	36	2006-01-01	231.0	231.0	231.0	231.0		WT	WND			587.4	
1320	Freeport Electric	Freeport 1-2		K	1660	Freeport	059	36	1949-08-01	2.9	2.0	2.5	2.9		IC	FO2			0.0	
1321	Freeport Electric	Freeport 1-3		K	1660	Freeport	059	36	1954-08-01	3.1	2.1	2.7	3.0		IC	FO2			0.0	
1322	Freeport Electric	Freeport 1-4		K	1660	Freeport	059	36	1964-10-01	5.1	4.4	4.5	5.0		IC	FO2			0.2	
1323	Freeport Electric	Freeport 2-3		K	1660	Freeport	059	36	1973-05-01	18.1	18.1	15.8	17.9		GT	KER			0.2	
1324	Freeport Electric	Freeport CT 2		K	23818	Freeport	059	36	2004-03-01	60.5	50.3	48.5	49.9		GT	NG			52.5	
1325	GenOn Energy Management, LLC	Bowline 1		G	23526	West Haverstraw	087	36	1972-09-01	621.0	577.7	579.3	576.7		ST	NG	FO6		1,387.8	
1326	GenOn Energy Management, LLC	Bowline 2		G	23595	West Haverstraw	087	36	1974-05-01	621.0	557.4	183.0	183.0		ST	NG	FO6		99.6	
1327	Hampshire Paper Co., Inc.	Hampshire Paper		E	323593	Gouverneur	089	36	1987-03-01	3.4	3.5	3.4	3.4		HY	WAT			18.8	
1328	Hardscrabble Wind Power LLC	Hardscrabble Wind		E	323673	Fairfield	043	36	2011-02-01	74.0	74.0	74.0	74.0		WT	WND			184.3	
1329	Howard Wind LLC	Howard Wind		C	323690	Howard	101	36	2011-12-01	57.4	57.4	55.4	55.4		WT	WND			133.0	
1330	Indeck Energy Services of Silver Sprir	Indeck-Silver Springs		C	23768	Silver Springs	121	36	1991-04-01	56.6	51.5	50.3	61.3	YES	CC	NG	FO2		36.4	
1331	Indeck-Corinth LP	Indeck-Corinth		F	23802	Corinth	091	36	1995-07-01	147.0	131.2	129.5	132.2	YES	CC	NG	FO2		876.7	
1332	Indeck-Olean LP	Indeck-Olean		A	23982	Olean	009	36	1993-12-01	90.6	79.4	76.0	84.4	YES	CC	NG	FO2		330.0	
1333	Indeck-Oswego LP	Indeck-Oswego		C	23783	Oswego	075	36	1990-05-01	57.4	51.6	48.8	61.5		CC	NG	FO2		65.6	
1334	Indeck-Yerkes LP	Indeck-Yerkes		A	23781	Tonawanda	029	36	1990-02-01	59.9	49.7	47.9	56.2	YES	CC	NG	FO2		68.1	
1335	Innovative Energy Systems, Inc.	Chautauqua LFGE		A	323629	Jamestown	013	36	2010-02-12	9.6	0.0	0.0	0.0		IC	MTE			42.4	
1336	Innovative Energy Systems, Inc.	Clinton LFGE		D	323618	Morrisonville	019	36	2008-10-01	6.4	6.4	6.4	6.4		IC	MTE			39.6	
1337	Innovative Energy Systems, Inc.	Colonie LFGTE		F	323577	Colonie	001	36	2006-03-01	4.8	4.8	4.8	4.8		IC	MTE			37.0	
1338	Innovative Energy Systems, Inc.	DANC LFGE		E	323619	Watertown	045	36	2008-09-08	6.4	6.4	6.4	6.4		IC	MTE			39.4	
1339	Innovative Energy Systems, Inc.	Fulton LFGE		F	323630	Johnstown	035	36	2010-06-04	3.2	0.0	0.0	0.0		IC	MTE			12.4	
1340	Innovative Energy Systems, Inc.	Hyland LFGE		B	323620	Angelica	003	36	2008-09-08	4.8	4.8	4.8	4.8		IC	MTE			31.6	
1341	Innovative Energy Systems, Inc.	Steuben County LF		C	323667	Bath	101	36	2012-08-01	3.2	3.2	3.2	3.2		IC	MTE			22.3	
1342	International Paper Company	Ticonderoga		F	23804	Ticonderoga	031	36	1970-01-01	42.1	7.6	9.5	9.8	YES	ST	FO6			0.0	
1343	Jamestown Board of Public Utilities	Jamestown 5		A	1658	Jamestown	013	36	1951-08-01	28.7	23.0	16.2	16.6	YES	ST	BIT	NG		4.7	
1344	Jamestown Board of Public Utilities	Jamestown 6		A	1658	Jamestown	013	36	1968-08-01	25.0	22.4	14.2	14.7	YES	ST	BIT	NG		45.5	
1345	Jamestown Board of Public Utilities	Jamestown 7		A	1659	Jamestown	013	36	2002-01-01	47.3	40.0	38.6	45.6	YES	GT	NG			174.0	
1346	Lakeside New York, LLC	Beaver Falls		E	23983	Beaver Falls	049	36	1995-03-01	107.8	80.2	81.1	89.3		CC	NG	FO2		1.3	
1347	Lakeside New York, LLC	Syracuse		C	23985	Syracuse	067	36	1993-09-01	102.7	86.8	85.6	97.8		CC	NG	FO2		41.0	
1348	Long Island Power Authority	Babylon (RR)		K	323704	Babylon	103	36	1989-04-01	17.0	15.5	14.3	15.0		ST	REF			109.5	
1349	Long Island Power Authority	Barrett 03		K	23706	Island Park	059	36	1970-06-01	18.0	17.9	17.0	19.2		GT	NG	FO2		2.4	
1350	Long Island Power Authority	Barrett 04		K	23707	Island Park	059	36	1970-07-01	18.0	17.7	17.5	20.4		GT	NG	FO2		6.6	
1351	Long Island Power Authority	Barrett 05		K	23708	Island Park	059	36	1970-07-01	18.0	17.8	17.3	19.9		GT	NG	FO2		2.0	
1352	Long Island Power Authority	Barrett 06		K	23709	Island Park	059	36	1970-07-01	18.0	17.8	17.1	20.1		GT	NG	FO2		3.0	
1353	Long Island Power Authority	Barrett 08		K	23711	Island Park	059	36	1970-07-01	18.0	17.3	17.2	20.4		GT	NG	FO2		2.2	
1354	Long Island Power Authority	Barrett 09		K	23700	Island Park	059	36	1971-06-01	41.8	43.4	39.4	48.2		JE	NG	FO2		9.1	
1355	Long Island Power Authority	Barrett 10		K	23701	Island Park	059	36	1971-06-01	41.8	42.7	39.9	49.4		JE	NG	FO2		24.3	
1356	Long Island Power Authority	Barrett 11		K	23702	Island Park	059	36	1971-06-01	41.8	43.3	39.8	49.5		JE	NG	FO2		14.5	
1357	Long Island Power Authority	Barrett 12		K	23703	Island Park	059	36	1971-06-01	41.8	44.0	40.3	49.5		JE	NG	FO2		23.2	
1358	Long Island Power Authority	Barrett GT 01		K	23704	Island Park	059	36	1970-06-01	18.0	18.1	11.4	0.0		GT	NG	FO2		0.1	
1359	Long Island Power Authority	Barrett GT 02		K	23705	Island Park	059	36	1970-06-01	18.0	17.4	14.7	17.1		GT	NG	FO2		4.7	

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1360	Long Island Power Authority	Barrett ST 01		K	23545	Island Park	059	36	1956-11-01	188.0	200.2	195.2	192.5		ST	NG	FO6		623.4	
1361	Long Island Power Authority	Barrett ST 02		K	23546	Island Park	059	36	1963-10-01	188.0	197.5	196.0	194.8		ST	NG	FO6		804.8	
1362	Long Island Power Authority	Bethpage 3		K	323564	Hicksville	059	36	2005-05-01	96.0	79.9	77.1	77.3		CC	NG			140.6	
1363	Long Island Power Authority	Caithness_CC_1		K	323624	Brookhaven	103	36	2009-08-01	375.0	315.6	306.7	358.6		CC	NG	FO2		2,393.7	
1364	Long Island Power Authority	East Hampton 2		K	23722	E Hampton	103	36	1962-12-01	2.0	2.0	2.0	2.0		IC	FO2			0.4	
1365	Long Island Power Authority	East Hampton 3		K	23722	E Hampton	103	36	1962-12-01	2.0	2.0	2.0	2.0		IC	FO2			0.5	
1366	Long Island Power Authority	East Hampton 4		K	23722	E Hampton	103	36	1962-12-01	2.0	2.0	2.0	2.0		IC	FO2			0.5	
1367	Long Island Power Authority	East Hampton GT 01		K	23717	E Hampton	103	36	1970-12-01	21.3	19.2	19.0	24.4		JE	FO2			5.0	
1368	Long Island Power Authority	Far Rockaway GT1		K	24212	Far Rockaway	081	36	2002-07-01	60.5	53.5	53.9	57.1		JE	NG			225.6	
1369	Long Island Power Authority	Far Rockaway GT2		K	23815	Jamaica Bay	081	36	2003-07-02	60.5	55.4	54.3	53.8		JE	FO2			16.9	
1370	Long Island Power Authority	Freeport CT 1		K	23764	Freeport	059	36	2004-06-01	60.0	48.3	48.3	49.7		GT	NG	FO2		105.5	
1371	Long Island Power Authority	Glenwood GT 01		K	23712	Glenwood	059	36	1967-04-01	16.0	14.6	12.6	17.6		GT	FO2			0.1	
1372	Long Island Power Authority	Glenwood GT 02		K	23688	Glenwood	059	36	1972-06-01	55.0	52.7	50.0	62.0		GT	FO2			2.5	
1373	Long Island Power Authority	Glenwood GT 03		K	23689	Glenwood	059	36	1972-06-01	55.0	52.7	51.2	67.3		GT	FO2			3.1	
1374	Long Island Power Authority	Glenwood GT 04		K	24219	Glenwood	059	36	2002-06-01	53.0	40.3	39.7	46.4		GT	NG	FO2		99.6	
1375	Long Island Power Authority	Glenwood GT 05		K	24220	Glenwood	059	36	2002-06-01	53.0	40.0	38.3	47.2		GT	NG	FO2		97.2	
1376	Long Island Power Authority	Greenport GT1		K	23814	Greenport	103	36	2003-07-02	54.0	51.9	51.3	56.8		JE	FO2			13.9	
1377	Long Island Power Authority	Hempstead (RR)		K	23647	Hempstead	059	36	1989-10-01	78.6	73.7	72.1	73.4		ST	REF			574.6	
1378	Long Island Power Authority	Holtsville 01		K	23690	Holtsville	103	36	1974-07-01	56.7	55.1	53.2	62.6		JE	FO2			3.4	
1379	Long Island Power Authority	Holtsville 02		K	23691	Holtsville	103	36	1974-07-01	56.7	55.3	47.6	59.3		JE	FO2			3.2	
1380	Long Island Power Authority	Holtsville 03		K	23692	Holtsville	103	36	1974-07-01	56.7	52.1	47.4	60.1		JE	FO2			2.4	
1381	Long Island Power Authority	Holtsville 04		K	23693	Holtsville	103	36	1974-07-01	56.7	52.7	51.9	59.0		JE	FO2			2.8	
1382	Long Island Power Authority	Holtsville 05		K	23694	Holtsville	103	36	1974-07-01	56.7	53.3	53.8	66.3		JE	FO2			3.8	
1383	Long Island Power Authority	Holtsville 06		K	23695	Holtsville	103	36	1975-07-01	56.7	53.0	51.2	63.9		JE	FO2			10.6	
1384	Long Island Power Authority	Holtsville 07		K	23696	Holtsville	103	36	1975-07-01	56.7	55.1	52.2	60.1		JE	FO2			1.1	
1385	Long Island Power Authority	Holtsville 08		K	23697	Holtsville	103	36	1975-07-01	56.7	57.4	52.3	68.3		JE	FO2			2.4	
1386	Long Island Power Authority	Holtsville 09		K	23698	Holtsville	103	36	1975-07-01	56.7	57.5	53.2	66.5		JE	FO2			6.9	
1387	Long Island Power Authority	Holtsville 10		K	23699	Holtsville	103	36	1975-07-01	56.7	55.1	52.9	66.1		JE	FO2			2.1	
1388	Long Island Power Authority	Huntington (RR)		K	323705	Huntington	103	36	1991-12-01	28.0	24.7	24.2	24.3		ST	REF			190.1	
1389	Long Island Power Authority	Islip (RR)		K	323679	Ronkonkoma	103	36	1990-03-01	12.5	11.2	8.6	8.7		ST	REF			51.2	
1390	Long Island Power Authority	Long Island Solar Farm		K	323691	Upton	103	36	2011-11-01	31.5	31.5	31.5	31.5		PV	SUN			51.0	
1391	Long Island Power Authority	Northport 1		K	23551	Northport	103	36	1967-07-01	387.0	395.0	399.7	391.3		ST	NG	FO6		356.5	
1392	Long Island Power Authority	Northport 2		K	23552	Northport	103	36	1968-06-01	387.0	396.0	396.5	398.7		ST	NG	FO6		609.8	
1393	Long Island Power Authority	Northport 3		K	23553	Northport	103	36	1972-07-01	387.0	399.2	391.2	382.2		ST	NG	FO6		685.1	
1394	Long Island Power Authority	Northport 4		K	23650	Northport	103	36	1977-12-01	387.0	399.2	391.2	393.2		ST	NG	FO6		1,060.3	
1395	Long Island Power Authority	Northport GT		K	23718	Northport	103	36	1967-03-01	16.0	13.8	11.9	15.4		GT	FO2			0.1	
1396	Long Island Power Authority	Oceanside (LF)		K	5008	Oceanside	059	36	1991-02-01	2.1	1.1	0.0	0.0		IC	MTE				
1397	Long Island Power Authority	Oyster Bay (LF)		K	5009	Bethpage	059	36	1986-07-01	1.3	0.0	0.0	0.0		IC	MTE				
1398	Long Island Power Authority	Pilgrim GT1		K	24216	Brentwood	103	36	2002-08-01	50.0	45.6	45.3	46.5		GT	NG			86.9	
1399	Long Island Power Authority	Pilgrim GT2		K	24217	Brentwood	103	36	2002-08-01	50.0	46.2	45.3	46.3		GT	NG			94.3	
1400	Long Island Power Authority	Pinelawn Power 1		K	323563	Babylon	103	36	2005-06-01	82.0	78.0	76.1	77.8		CC	NG	KER		136.4	
1401	Long Island Power Authority	Port Jefferson 3		K	23555	Port Jefferson	103	36	1958-11-01	188.0	194.5	196.7	195.3		ST	FO6	NG		93.6	
1402	Long Island Power Authority	Port Jefferson 4		K	23616	Port Jefferson	103	36	1960-11-01	188.0	198.7	196.7	198.0		ST	FO6	NG		191.2	
1403	Long Island Power Authority	Port Jefferson GT 01		K	23713	Port Jefferson	103	36	1966-12-01	16.0	14.1	12.9	18.0		GT	FO2			0.1	
1404	Long Island Power Authority	Port Jefferson GT 02		K	24210	Port Jefferson	103	36	2002-07-01	53.0	42.0	41.0	45.9		GT	NG	FO2		93.3	
1405	Long Island Power Authority	Port Jefferson GT 03		K	24211	Port Jefferson	103	36	2002-07-01	53.0	41.1	40.5	46.1		GT	NG	FO2		88.2	
1406	Long Island Power Authority	S Hampton 1		K	23720	South Hampton	103	36	1963-03-01	11.5	10.3	8.3	12.0		GT	FO2			0.1	
1407	Long Island Power Authority	Shoreham 1		K	23715	Shoreham	103	36	1971-07-01	52.9	48.9	48.9	65.6		GT	FO2			0.9	
1408	Long Island Power Authority	Shoreham 2		K	23716	Shoreham	103	36	1984-04-01	18.6	18.5	15.8	20.9		JE	FO2			0.2	
1409	Long Island Power Authority	Shoreham GT3		K	24213	Shoreham	103	36	2002-08-01	50.0	45.1	45.0	45.9		GT	FO2			6.4	
1410	Long Island Power Authority	Shoreham GT4		K	24214	Shoreham	103	36	2002-08-01	50.0	41.9	44.2	45.9		GT	FO2			6.0	
1411	Long Island Power Authority	Smithtown (LF)		K	5010	Smithtown	103	36	1985-12-01	1.1	0.0	0.0	0.0		IC	MTE				
1412	Long Island Power Authority	South Oaks Hosp		K	5011	Amityville	103	36	1990-06-01	1.0	0.0	0.0	0.0		IC	NG				
1413	Long Island Power Authority	Southold 1		K	23719	Southold	103	36	1964-08-01	14.0	12.3	13.0	15.3		GT	FO2			0.2	
1414	Long Island Power Authority	Stony Brook		K	24151	Stony Brook	103	36	1995-04-01	47.0	9.6	17.2	19.0	YES	GT	NG	FO2		283.3	
1415	Long Island Power Authority	Trigen-NDEC		K	323695	Garden City	059	36	1991-03-01	55.0	51.6	43.0	56.4	YES	CC	NG	FO2		343.0	
1416	Long Island Power Authority	Wading River 1		K	23522	Shoreham	103	36	1989-08-01	79.5	81.2	78.8	98.3		GT	FO2			9.7	
1417	Long Island Power Authority	Wading River 2		K	23547	Shoreham	103	36	1989-08-01	79.5	81.3	76.6	96.2		GT	FO2			13.4	
1418	Long Island Power Authority	Wading River 3		K	23601	Shoreham	103	36	1989-08-01	79.5	81.3	73.3	95.5		GT	FO2			8.2	
1419	Long Island Power Authority	West Babylon 4		K	23714	West Babylon	103	36	1971-08-01	52.4	49.0	47.8	66.1		GT	FO2			2.4	
1420	Long Island Power Authority	Yaphank (LF)		K	5012	Yaphank	103	36	1983-09-01	1.6	1.5	0.0	0.0		IC	MTE				
1421	Madison Windpower, LLC	Madison Wind Power		E	24146	Madison	053	36	2000-09-01	11.6	11.5	11.6	11.6		WT	WND			21.0	
1422	Marble River LLC	Marble River Wind		D	323696	Ellenburg	019	36	2012-07-01	215.5	0.0	0.0	0.0		WT	WND			539.2	
1423	Marsh Hill Energy LLC	Marsh Hill Wind Farm		C	323713	Jasper	101	36	2014-12-01	16.2	0.0	0.0	0.0		WT	WND			8.8	**(N) (5)**
1424	Model City Energy LLC	Model City Energy		A	24167	Lewiston	063	36	2001-06-01	5.6	5.6	5.6	5.6		IC	MTE			39.5	
1425	Modern Innovative Energy, LLC	Modern LF		A	323580	Lewiston	063	36	2006-02-01	6.4	6.4	6.4	6.4		IC	MTE			31.5	
1426	New York Power Authority	Ashokan 1		G	23654	Ashokan	111	36	1982-11-01	2.3	1.8	2.3	2.3		HY	WAT			4.7	
1427	New York Power Authority	Ashokan 2		G	23654	Ashokan	111	36	1982-11-01	2.3	1.8	2.3	2.3		HY	WAT			3.0	
1428	New York Power Authority	Astoria CC 1		J	323568	Queens	081	36	2006-01-01	288.0	246.2	229.5	260.0		CC	NG	JF	KER	3,246.7	**(G)**
1429	New York Power Authority	Astoria CC 2		J	323569	Queens	081	36	2006-01-01	288.0	246.2	229.4	260.0		CC	NG	JF	KER		
1430	New York Power Authority	Blenheim - Gilboa 1		F	23756	Gilboa NY	095	36	1973-07-01	290.0	290.7	290.9	292.2		PS	WAT			83.1	
1431	New York Power Authority	Blenheim - Gilboa 2		F	23757	Gilboa NY	095	36	1973-07-01	290.0	291.2	291.6	292.1		PS	WAT			217.1	

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1432	New York Power Authority	Blenheim - Gilboa 3		F	23758	Gilboa NY	095	36	1973-07-01	290.0	291.7	292.0	291.2		PS	WAT			35.0	
1433	New York Power Authority	Blenheim - Gilboa 4		F	23759	Gilboa NY	095	36	1973-07-01	290.0	291.5	292.7	293.7		PS	WAT			30.9	
1434	New York Power Authority	Brentwood		K	24164	Brentwood	103	36	2001-08-01	50.0	47.1	45.5	46.4		GT	NG			43.2	
1435	New York Power Authority	Crescent 1		F	24018	Crescent	001	36	1991-07-01	2.8	3.2	2.8	2.8		HY	WAT			15.4	
1436	New York Power Authority	Crescent 2		F	24018	Crescent	001	36	1991-07-01	2.8	3.2	2.8	2.8		HY	WAT			15.3	
1437	New York Power Authority	Crescent 3		F	24018	Crescent	001	36	1991-07-01	3.0	3.2	3.0	3.0		HY	WAT			21.0	
1438	New York Power Authority	Crescent 4		F	24018	Crescent	001	36	1991-07-01	3.0	3.2	3.0	3.0		HY	WAT			0.0	
1439	New York Power Authority	Flynn		K	23794	Holtsville	103	36	1994-05-01	170.0	135.5	133.8	162.7		CC	NG	FO2		1,208.0	
1440	New York Power Authority	Gowanus 5		J	24156	Brooklyn	047	36	2001-08-01	50.0	45.4	40.0	40.0		GT	NG			31.3	
1441	New York Power Authority	Gowanus 6		J	24157	Brooklyn	047	36	2001-08-01	50.0	46.1	39.9	39.9		GT	NG			40.1	
1442	New York Power Authority	Grahamsville		G	23607	Grahamsville	105	36	1956-12-01	18.0	16.3	18.0	18.0		HY	WAT			98.8	
1443	New York Power Authority	Greenport IC 4		K	1652	Greenport	103	36	1957-06-06	1.2	1.7	1.0	1.0		IC	FO2			0.0	
1444	New York Power Authority	Greenport IC 5		K	1652	Greenport	103	36	1965-07-08	1.8	1.7	1.5	1.5		IC	FO2			0.0	
1445	New York Power Authority	Greenport IC 6		K	1652	Greenport	103	36	1971-09-17	3.8	2.7	2.5	2.5		IC	FO2			0.0	
1446	New York Power Authority	Harlem River 1		J	24160	Bronx	005	36	2001-08-01	50.0	46.0	39.9	39.9		GT	NG			31.0	
1447	New York Power Authority	Harlem River 2		J	24161	Bronx	005	36	2001-08-01	50.0	45.2	40.0	40.0		GT	NG			23.3	
1448	New York Power Authority	Hellgate 1		J	24158	Bronx	005	36	2001-08-01	50.0	45.0	39.9	39.9		GT	NG			24.7	
1449	New York Power Authority	Hellgate 2		J	24159	Bronx	005	36	2001-08-01	50.0	45.0	40.0	40.0		GT	NG			20.9	
1450	New York Power Authority	Jarvis 1		E	23743	Hinckley	065	36	1991-07-01	4.5	4.5	4.5	4.5		HY	WAT			26.2	
1451	New York Power Authority	Jarvis 2		E	23743	Hinckley	065	36	1991-07-01	4.5	4.5	4.5	4.5		HY	WAT			0.0	
1452	New York Power Authority	Kent		J	24152	Brooklyn	047	36	2001-08-01	50.0	46.9	46.0	46.6		GT	NG			39.8	
1453	New York Power Authority	Lewiston PS (Fleet)		A	23760	Niagara Falls	063	36	1961-01-01	240.0	240.0	240.0	240.0		PS	WAT			483.2	
1454	New York Power Authority	Moses Niagara (Fleet)		A	23760	Niagara Falls	063	36	1961-01-01	2,860.0	2,460.0	2,444.7	2,442.0		HY	WAT			13,211.9	
1455	New York Power Authority	Neversink		G	23608	Grahamsville	105	36	1953-12-01	25.0	22.0	25.0	25.0		HY	WAT			41.4	
1456	New York Power Authority	Pouch		J	24155	Staten Island	085	36	2001-08-01	50.0	47.1	46.0	46.8		GT	NG			40.7	
1457	New York Power Authority	St Lawrence - FDR (Fleet)		D	23600	Massena	089	36	1958-07-01	1,088.0	856.0	843.2	820.8		HY	WAT			7,077.5	
1458	New York Power Authority	Vernon Blvd 2		J	24162	Queens	081	36	2001-08-01	50.0	46.2	40.0	40.0		GT	NG			20.9	
1459	New York Power Authority	Vernon Blvd 3		J	24163	Queens	081	36	2001-08-01	50.0	43.8	39.9	39.9		GT	NG			28.3	
1460	New York Power Authority	Vischer Ferry 1		F	24020	Vischer Ferry	091	36	1991-07-01	2.8	3.2	2.8	2.9		HY	WAT			15.0	
1461	New York Power Authority	Vischer Ferry 2		F	24020	Vischer Ferry	091	36	1991-07-01	2.8	3.2	2.8	2.9		HY	WAT			14.4	
1462	New York Power Authority	Vischer Ferry 3		F	24020	Vischer Ferry	091	36	1991-07-01	3.0	3.2	3.0	2.9		HY	WAT			0.0	
1463	New York Power Authority	Vischer Ferry 4		F	24020	Vischer Ferry	091	36	1991-07-01	3.0	3.2	3.0	2.9		HY	WAT			21.0	
1464	New York State Elec. & Gas Corp.	AA Dairy		C	5013	Ithaca	109	36	1998-06-01	0.1		0.0	0.0		IC	MTE			0.0	
1465	New York State Elec. & Gas Corp.	Alice Falls 1		D	23915	Ausable	019	36	1991-11-01	1.5	1.6	0.0	0.0		HY	WAT			0.0	
1466	New York State Elec. & Gas Corp.	Alice Falls 2		D	23915	Ausable	019	36	1991-11-01	0.6	0.6	0.0	0.0		HY	WAT			0.0	
1467	New York State Elec. & Gas Corp.	Allegheny 8		C	23528	Kittanning PA	005	42	1990-10-01	16.0	14.7	16.0	16.0		HY	WAT			105.8	
1468	New York State Elec. & Gas Corp.	Allegheny 9		C	23528	Kittanning PA	005	42	1990-10-01	22.0	20.2	22.0	22.0		HY	WAT			129.3	
1469	New York State Elec. & Gas Corp.	Auburn - Mill St.		C	5014	Auburn	011	36	1981-10-01	0.4		0.0	0.0		HY	WAT				
1470	New York State Elec. & Gas Corp.	Auburn - No. Div.St		C	5015	Auburn	011	36	1992-12-01	0.8		0.0	0.0		HY	WAT				
1471	New York State Elec. & Gas Corp.	Auburn - State St.		C	24147	Auburn	011	36	1995-01-01	7.4	5.8	5.0	6.9		GT	NG			0.9	
1472	New York State Elec. & Gas Corp.	Broome LFGE		C	323600	Binghamton	007	36	2007-09-01	2.1	2.1	2.1	2.1		IC	MTE			16.9	
1473	New York State Elec. & Gas Corp.	Cadyville 1		D	23628	Schuyler Falls	019	36	1921-08-01	1.2	1.0	1.2	1.2		HY	WAT			5.1	
1474	New York State Elec. & Gas Corp.	Cadyville 2		D	23628	Schuyler Falls	019	36	1921-08-01	1.2	1.0	1.2	1.2		HY	WAT			5.4	
1475	New York State Elec. & Gas Corp.	Cadyville 3		D	23628	Schuyler Falls	019	36	1986-09-01	3.1	2.7	3.1	3.1		HY	WAT			13.2	
1476	New York State Elec. & Gas Corp.	Chasm Hydro		D	5016	Chateaugay	033	36	1982-03-01	1.6		0.0	0.0		HY	WAT				
1477	New York State Elec. & Gas Corp.	Croton Fall Hydro		I	5017	North Salem	119	36	1987-01-01	0.2		0.0	0.0		HY	WAT				
1478	New York State Elec. & Gas Corp.	Harris Lake		D	5018	Newcomb	031	36	1967-08-01	1.7		0.0	0.0		IC	FO2				
1479	New York State Elec. & Gas Corp.	High Falls 1		D	23628	Saranac	019	36	1948-08-01	4.0	4.3	4.0	4.0		HY	WAT			13.1	
1480	New York State Elec. & Gas Corp.	High Falls 2		D	23628	Saranac	019	36	1949-08-01	4.0	4.3	4.0	4.0		HY	WAT			21.7	
1481	New York State Elec. & Gas Corp.	High Falls 3		D	23628	Saranac	019	36	1956-08-01	7.0	8.2	7.0	7.0		HY	WAT			41.0	
1482	New York State Elec. & Gas Corp.	Kent Falls 1		D	23628	Schuyler Falls	019	36	1928-08-01	3.6	3.0	3.6	3.6		HY	WAT			17.5	
1483	New York State Elec. & Gas Corp.	Kent Falls 2		D	23628	Schuyler Falls	019	36	1928-08-01	3.6	3.0	3.6	3.6		HY	WAT			0.0	
1484	New York State Elec. & Gas Corp.	Kent Falls 3		D	23628	Schuyler Falls	019	36	1985-07-01	6.4	6.0	6.4	6.4		HY	WAT			37.5	
1485	New York State Elec. & Gas Corp.	Lower Saranac 1		D	23913	Schuyler Falls	019	36	1990-10-01	3.2	3.5	0.0	0.0		HY	WAT			0.0	
1486	New York State Elec. & Gas Corp.	Lower Saranac 2		D	23913	Schuyler Falls	019	36	1990-10-01	3.2	3.5	0.0	0.0		HY	WAT			0.0	
1487	New York State Elec. & Gas Corp.	Lower Saranac 3		D	23913	Schuyler Falls	019	36	1990-10-01	0.3	2.9	0.0	0.0		HY	WAT			0.0	
1488	New York State Elec. & Gas Corp.	Mechanicville 1		F	23645	Stillwater	091	36	1983-09-01	9.2	10.0	9.2	9.3		HY	WAT			45.7	
1489	New York State Elec. & Gas Corp.	Mechanicville 2		F	23645	Stillwater	091	36	1983-09-01	9.3	10.0	9.3	9.3		HY	WAT			40.0	
1490	New York State Elec. & Gas Corp.	Mill C 1		D	23628	Plattsburgh	019	36	1944-08-01	1.0	0.9	1.0	1.0		HY	WAT			4.9	
1491	New York State Elec. & Gas Corp.	Mill C 2		D	23628	Plattsburgh	019	36	1943-08-01	1.2	1.2	1.2	1.2		HY	WAT			4.8	
1492	New York State Elec. & Gas Corp.	Mill C 3		D	23628	Plattsburgh	019	36	1984-11-01	3.8	3.7	3.8	3.8		HY	WAT			15.8	
1493	New York State Elec. & Gas Corp.	Montville Falls		C	5019	Moravia	011	36	1992-08-01	0.2		0.0	0.0		HY	WAT				
1494	New York State Elec. & Gas Corp.	Rainbow Falls 1		D	23628	Ausable	019	36	1926-08-01	1.3	1.5	1.3	1.3		HY	WAT			0.0	
1495	New York State Elec. & Gas Corp.	Rainbow Falls 2		D	23628	Ausable	019	36	1927-08-01	1.3	1.5	1.3	1.3		HY	WAT			0.0	
1496	New York State Elec. & Gas Corp.	Waterloo 2		C	5020	Waterloo	099	36	1998-06-01	0.5		0.0	0.0		HY	WAT				
1497	New York State Elec. & Gas Corp.	Waterloo 3		C	5021	Waterloo	099	36	1998-06-01	0.5		0.0	0.0		HY	WAT				
1498	New York State Elec. & Gas Corp.	Waterloo 4		C	5022	Waterloo	099	36	1998-06-01	0.5		0.0	0.0		HY	WAT				
1499	Niagara Generation, LLC	Niagara Bio-Gen		A	23895	Niagara Falls	063	36	1991-08-01	56.0	50.5	43.2	37.2		ST	WD			89.3	
1500	Niagara Mohawk Power Corp.	Boralex - Hudson Falls		F	24011	Hudson Falls	115	36	1995-10-01	44.0	43.7	44.0	44.0		HY	WAT			228.5	
1501	Niagara Mohawk Power Corp.	Boralex - South Glens Falls		F	24028	Moreau	091	36	1994-12-01	13.8	14.8	0.0	0.0		HY	WAT			89.9	
1502	Niagara Mohawk Power Corp.	CHI-LaChute		F	1654	Ticonderoga	031	36	1987-12-01	9.0	8.9	0.0	0.0		HY	WAT			33.5	
1503	Niagara Mohawk Power Corp.	Fortis - Dolgeville		E	23807	Dolgeville	043	36	1985-07-01	5.0	6.3	0.0	0.0		HY	WAT			17.4	

Contains Proprietary Material
Do Not Distribute

TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1504	Niagara Mohawk Power Corp.	Fortis Energy - Philadelphia	E	1656	Philadelphia	045	36	1986-08-01	3.6	3.2	0.0	0.0		HY	WAT			8.8	
1505	Niagara Mohawk Power Corp.	Fortis Energy - Moose River	E	24016	Moose River	049	36	1987-09-01	12.6	12.0	0.0	0.0		HY	WAT			45.9	
1506	Niagara Mohawk Power Corp.	Fortistar - N.Tonawanda	A	24026	N Tonawanda	029	36	1993-06-01	55.3	57.0	54.9	63.9		CC	NG	FO2		39.8	
1507	Niagara Mohawk Power Corp.	General Mills Inc	A	23808	Buffalo	029	36	1988-12-01	3.8	3.8	0.0	0.0		GT	NG			0.5	
1508	Niagara Mohawk Power Corp.	International Paper - Curtis	F	1655	Corinth	091	36	1986-01-01	9.8	30.8	0.0	0.0		HY	WAT			415.8	(G)
1509	Niagara Mohawk Power Corp.	International Paper - Palmer	F	1655	Corinth	091	36	1986-01-01	49.2	30.8	0.0	0.0		HY	WAT				
1510	Niagara Mohawk Power Corp.	Little Falls Hydro	E	24013	Little Falls	043	36	1987-01-01	13.0	12.6	0.0	0.0		HY	WAT			61.1	
1511	Niagara Mohawk Power Corp.	Onondaga County	C	23987	North Syracuse	067	36	1994-12-01	39.5	32.6	32.1	30.8		ST	REF			187.6	
1512	Niagara Mohawk Power Corp.	Pyrites Assoc.	E	24023	Canton	089	36	1985-12-01	8.2	7.5	0.0	0.0		HY	WAT			29.7	
1513	Niagara Mohawk Power Corp.	Adams Hydro	E	23633	Adams	045	36	1987-11-01	0.2		0.0	0.0		HY	WAT			0.0	
1514	Niagara Mohawk Power Corp.	Algon.-Burt Dam Assoc.	A	23774	Burt	063	36	1987-12-01	0.4		0.0	0.0		HY	WAT			2.2	
1515	Niagara Mohawk Power Corp.	Algon.-Christine.Falls	F	23643	Wells	041	36	1987-12-01	0.8		0.0	0.0		HY	WAT			2.5	
1516	Niagara Mohawk Power Corp.	Algon.-Cranberry. Lake	E	23633	Cranberry Lake	049	36	1987-12-01	0.5		0.0	0.0		HY	WAT			0.0	
1517	Niagara Mohawk Power Corp.	Algon.-Forrestport	E	23633	Forrestport	065	36	1987-12-01	3.4		0.0	0.0		HY	WAT			8.1	
1518	Niagara Mohawk Power Corp.	Algon.-Herkimer	E	23633	Herkimer	043	36	1987-12-01	1.6		0.0	0.0		HY	WAT			0.0	
1519	Niagara Mohawk Power Corp.	Algon.-Hollow Dam Power	E	23633	Saint Lawrence	089	36	1987-12-01	1.0		0.0	0.0		HY	WAT			3.1	
1520	Niagara Mohawk Power Corp.	Algon.-Kayuta	E	23633	Kayuta	065	36	1988-05-01	0.4		0.0	0.0		HY	WAT			0.0	
1521	Niagara Mohawk Power Corp.	Algon.-Ogdensburg	E	23633	Ogdensberg	089	36	1987-12-01	3.5		0.0	0.0		HY	WAT			10.0	
1522	Niagara Mohawk Power Corp.	Algon.-Otter Creek	E	23633	Greig	049	36	1986-11-01	0.5		0.0	0.0		HY	WAT			1.2	
1523	Niagara Mohawk Power Corp.	Allied Frozen Storage	A	23774	Cheektowaga	029	36	2008-05-01	0.1		0.0	0.0		IC	NG			0.1	
1524	Niagara Mohawk Power Corp.	Azure Mnt. Pwr Co	E	23633	St. Regis Falls	033	36	1993-08-01	0.6		0.0	0.0		HY	WAT			1.8	
1525	Niagara Mohawk Power Corp.	Beaver Falls #1	E	23633	Beaver Falls	049	36	1986-01-01	1.5		0.0	0.0		HY	WAT			10.4	
1526	Niagara Mohawk Power Corp.	Beaver Falls #2	E	23633	Beaver Falls	049	36	1986-01-01	1.0		0.0	0.0		HY	WAT			5.7	
1527	Niagara Mohawk Power Corp.	Bellows Towers	E	23633	Malone	033	36	1987-06-01	0.2		0.0	0.0		HY	WAT			0.0	
1528	Niagara Mohawk Power Corp.	Black River Hyd#1	E	23633	Port Leyden	049	36	1984-07-01	1.9		0.0	0.0		HY	WAT			4.9	
1529	Niagara Mohawk Power Corp.	Black River Hyd#2	E	23633	Port Leyden	049	36	1985-12-01	1.6		0.0	0.0		HY	WAT			2.1	
1530	Niagara Mohawk Power Corp.	Black River Hyd#3	E	23633	Port Leyden	049	36	1984-07-01	2.2		0.0	0.0		HY	WAT			14.9	
1531	Niagara Mohawk Power Corp.	Boralex - Middle Falls	F	23643	Easton	115	36	1989-12-01	2.2		0.0	0.0		HY	WAT			13.2	
1532	Niagara Mohawk Power Corp.	Burrstone Energy Center, LLC	E	23633	Utica	065	36	2009-11-01	1.1		0.0	0.0		IC	NG			2.7	
1533	Niagara Mohawk Power Corp.	Burrstone Energy Center, LLC	E	23633	Utica	065	36	2009-11-01	2.2		0.0	0.0		IC	NG			0.1	
1534	Niagara Mohawk Power Corp.	Cal Ban Power	A	23774	Allegany	003	36	1995-06-01	0.1		0.0	0.0		IC	NG			0.1	
1535	Niagara Mohawk Power Corp.	Cellu-Tissue Corp - Natural Da	E	23633	Natural Dam	089	36	1986-01-01	1.0		0.0	0.0		HY	WAT			0.0	
1536	Niagara Mohawk Power Corp.	Champlain Spinner	F	23643	Whitehall	031	36	1992-07-01	0.4		0.0	0.0		HY	WAT			1.2	
1537	Niagara Mohawk Power Corp.	CHI Dexter Hydro	E	23633	Dexter	045	36	1988-01-01	4.2		0.0	0.0		HY	WAT			11.7	
1538	Niagara Mohawk Power Corp.	CHI Diamond Is HY	E	23633	Watertown	045	36	1986-01-01	1.2		0.0	0.0		HY	WAT			6.3	
1539	Niagara Mohawk Power Corp.	CHI Fowler	E	23633	Fowler	049	36	1986-01-01	0.6		0.0	0.0		HY	WAT			1.7	
1540	Niagara Mohawk Power Corp.	CHI Hailsboro #3	E	23633	Hailsboro	089	36	1986-01-01	0.8		0.0	0.0		HY	WAT			4.3	
1541	Niagara Mohawk Power Corp.	CHI Hailsboro #4	E	23633	Hailsboro	089	36	1986-01-01	1.4		0.0	0.0		HY	WAT			11.6	
1542	Niagara Mohawk Power Corp.	CHI Hailsboro #6	E	23633	Hailsboro	089	36	1986-01-01	0.8		0.0	0.0		HY	WAT			5.2	
1543	Niagara Mohawk Power Corp.	CHI Theresa Hydro	E	23633	Theresa	089	36	1986-01-01	1.3		0.0	0.0		HY	WAT			7.5	
1544	Niagara Mohawk Power Corp.	Chittenden Falls	F	23643	Stuyvesant	021	36	1995-12-01	0.6		0.0	0.0		HY	WAT			0.6	
1545	Niagara Mohawk Power Corp.	City of Oswego (H.D.)	C	23634	Oswego	075	36	1994-02-01	11.9		0.0	0.0		HY	WAT			50.0	
1546	Niagara Mohawk Power Corp.	City of Utica - Sand Road	E	23633	Utica	065	36	1993-05-01	0.2		0.0	0.0		HY	WAT			1.6	
1547	Niagara Mohawk Power Corp.	City of Utica -Trenton Falls	E	23633	Utica	065	36	1993-02-01	0.2		0.0	0.0		HY	WAT			0.4	
1548	Niagara Mohawk Power Corp.	City of Watertown	E	23633	Watertown	045	36	1986-01-01	8.1		0.0	0.0		HY	WAT			13.6	
1549	Niagara Mohawk Power Corp.	City of Watervliet	F	23643	Guilderland	001	36	1986-01-01	1.2		0.0	0.0		HY	WAT			3.3	
1550	Niagara Mohawk Power Corp.	Cons. HY-Victory	F	23643	Victory Falls	091	36	1986-12-01	1.7		0.0	0.0		HY	WAT			5.7	
1551	Niagara Mohawk Power Corp.	Copenhagen Assoc.	E	23633	Copenhagen	049	36	1986-01-01	3.3		0.0	0.0		HY	WAT			10.4	
1552	Niagara Mohawk Power Corp.	Cottrell Paper	F	23643	Rock City Falls	091	36	1987-01-01	0.3		0.0	0.0		HY	WAT			0.1	
1553	Niagara Mohawk Power Corp.	Edison Hydro Electric	F	23643	Stottville	021	36	2009-11-01	0.4		0.0	0.0		HY	WAT			1.9	
1554	Niagara Mohawk Power Corp.	Empire HY Partner	E	23633	Port Leyden	049	36	1984-11-01	1.0		0.0	0.0		HY	WAT			5.0	
1555	Niagara Mohawk Power Corp.	Finch Paper LLC - Glens Falls	F	23643	Glens Falls	113	36	2009-11-01	11.8		0.0	0.0		HY	WAT			2.0	
1556	Niagara Mohawk Power Corp.	Finch Pruyn	F	23643	Glens Falls	113	36	1989-12-01	29.0		0.0	0.0		HY	WAT			0.0	
1557	Niagara Mohawk Power Corp.	Fort Miller Assoc	F	23643	Schuylerville	091	36	1985-10-01	5.0		0.0	0.0		HY	WAT			24.3	
1558	Niagara Mohawk Power Corp.	Fortis Energy - Diana	E	23633	Diana	049	36	1985-07-01	1.8		0.0	0.0		HY	WAT			7.1	
1559	Niagara Mohawk Power Corp.	Franklin Hydro	D	24055	Franklin Falls	033	36	1995-03-01	0.3		0.0	0.0		HY	WAT			0.0	
1560	Niagara Mohawk Power Corp.	Green Island Power Authority	F	23643	Green Island	001	36	1971-01-01	6.0		0.0	0.0		HY	WAT			35.7	
1561	Niagara Mohawk Power Corp.	Hewittville Hydro	E	23633	Potsdam	089	36	1984-07-01	3.0		0.0	0.0		HY	WAT			13.5	
1562	Niagara Mohawk Power Corp.	Hollings&Vose-Center	F	23643	Easton	115	36	1986-01-01	0.4		0.0	0.0		HY	WAT			0.2	
1563	Niagara Mohawk Power Corp.	Hollings&Vose-Lower	F	23643	Easton	115	36	1986-01-01	0.4		0.0	0.0		HY	WAT			0.0	
1564	Niagara Mohawk Power Corp.	Hollings&Vose-Upper	F	23643	Easton	115	36	1986-01-01	0.4		0.0	0.0		HY	WAT			4.6	
1565	Niagara Mohawk Power Corp.	Hoosick Falls	F	23643	Hoosick Falls	083	36	1988-08-01	0.6		0.0	0.0		HY	WAT			0.0	
1566	Niagara Mohawk Power Corp.	Hydrocarbon-Algny	A	23774	Allegany	003	36	1992-12-01	0.2		0.0	0.0		IC	NG			0.0	
1567	Niagara Mohawk Power Corp.	Indian Falls HY	E	23633	Theresa	045	36	1986-01-01	0.3		0.0	0.0		HY	WAT			0.6	
1568	Niagara Mohawk Power Corp.	Kings Falls	E	23633	Copenhagen	049	36	1988-05-01	1.6		0.0	0.0		HY	WAT			0.0	
1569	Niagara Mohawk Power Corp.	Laidlaw Energy	A	23774	Ellicottville	009	36	1991-07-01	3.4		0.0	0.0		GT	NG			0.0	
1570	Niagara Mohawk Power Corp.	Laidlaw Energy	A	23774	Ellicottville	009	36	1991-07-01	2.4		0.0	0.0		ST	NG			0.0	
1571	Niagara Mohawk Power Corp.	Laquidara-Long Falls	E	23633	Carthage	045	36	1991-06-01	3.3		0.0	0.0		HY	WAT			5.2	
1572	Niagara Mohawk Power Corp.	Lyonsdale Assoc. (Burrows)	E	23633	Lyons Falls	049	36	1984-07-01	3.0		0.0	0.0		HY	WAT			11.1	
1573	Niagara Mohawk Power Corp.	Mechanicville	F	23643	Mechanicville	091	36	2005-03-01	2.0		0.0	0.0		HY	WAT			17.2	
1574	Niagara Mohawk Power Corp.	Mountainaire Massage Spa	F	23643	Wevertown	113	36	2009-11-01	0.0		0.0	0.0		HY	WAT			0.0	
1575	Niagara Mohawk Power Corp.	Mt. Ida Assoc.	F	23643	Troy	083	36	1986-01-01	6.0		0.0	0.0		HY	WAT			9.1	

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TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1576	Niagara Mohawk Power Corp.	Newport HY Assoc		E	23633	Newport	043	36	1987-12-01	1.7		0.0	0.0		HY	WAT			7.3	
1577	Niagara Mohawk Power Corp.	Nottingham High School		C	23634	Syracuse	067	36	1988-06-01	0.2		0.0	0.0		CC	NG			0.0	
1578	Niagara Mohawk Power Corp.	Oakvale Construction		D	24055	Wilmington	031	36	2009-11-01	0.4		0.0	0.0		HY	WAT			1.6	
1579	Niagara Mohawk Power Corp.	Onondaga Energy Partners		C	23634	Onondaga	067	36	1987-12-01	1.4		0.0	0.0		IC	MTE			0.0	
1580	Niagara Mohawk Power Corp.	Oswego County		C	23634	Oswego	075	36	1986-03-01	3.6		0.0	0.0		ST	REF			5.0	
1581	Niagara Mohawk Power Corp.	Oswego HY Partners (Phoeni		C	23634	Phoenix	067	36	1990-12-01	3.4		0.0	0.0		HY	WAT			11.6	
1582	Niagara Mohawk Power Corp.	Riverrat Glass&Electric		F	23643	Wadhams	031	36	1986-01-01	0.6		0.0	0.0		HY	WAT			2.2	
1583	Niagara Mohawk Power Corp.	Sandy Hollow HY		E	23633	Sandy Hollow	045	36	1986-09-01	0.6		0.0	0.0		HY	WAT			1.5	
1584	Niagara Mohawk Power Corp.	Seneca Limited		C	23634	Syracuse	067	36	1985-12-01	0.2		0.0	0.0		HY	WAT			0.0	
1585	Niagara Mohawk Power Corp.	St. Elizabeth Medical Center		E	23633	Utica	065	36	2012-02-01	0.6		0.0	0.0		IC	NG			0.6	
1586	Niagara Mohawk Power Corp.	Stevens&Thompson Paper Cc		F	23643	Middle Falls	115	36	1987-12-01	10.5		0.0	0.0		HY	WAT			14.3	
1587	Niagara Mohawk Power Corp.	Stillwater Assoc.		E	23633	Webb	043	36	1987-01-01	1.8		0.0	0.0		HY	WAT			7.5	
1588	Niagara Mohawk Power Corp.	Stillwater HY Partners		F	23643	Stillwater	091	36	1993-04-01	3.4		0.0	0.0		HY	WAT			13.6	
1589	Niagara Mohawk Power Corp.	Stuyvesant Falls		F	23643	Stuyvesant	021	36	2013-02-01	7.0		0.0	0.0		HY	WAT			12.7	
1590	Niagara Mohawk Power Corp.	Sustainable Bioelectric LLC		A	23774	Wheeatfield	063	36	2014-03-01	0.6		0.0	0.0		IC	MTE				
1591	Niagara Mohawk Power Corp.	Synergics - Middle Greenwich		F	23643	Greenwich	115	36	1987-12-01	0.2		0.0	0.0		HY	WAT			0.0	
1592	Niagara Mohawk Power Corp.	Synergics - Union Falls		D	24055	Union Falls	019	36	1987-12-01	3.0		0.0	0.0		HY	WAT			13.4	
1593	Niagara Mohawk Power Corp.	Synergics - Upper Greenwich		F	23643	Greenwich	115	36	1987-12-01	0.4		0.0	0.0		HY	WAT			0.0	
1594	Niagara Mohawk Power Corp.	Tannery Island		E	23633	Carthage	045	36	1986-01-01	1.5		0.0	0.0		HY	WAT			9.2	
1595	Niagara Mohawk Power Corp.	Town of Wells		F	23643	Wells	041	36	1987-12-01	0.5		0.0	0.0		HY	WAT			1.6	
1596	Niagara Mohawk Power Corp.	Tri-City JATC		F	23643	Latham	001	36	2009-11-01	0.0		0.0	0.0		IC	NG			0.0	
1597	Niagara Mohawk Power Corp.	Unionville Hydro		E	23633	Potsdam	089	36	1984-07-01	3.0		0.0	0.0		HY	WAT			13.6	
1598	Niagara Mohawk Power Corp.	United States Gypsum		A	23774	Batavia	037	36	2009-11-01	5.8		0.0	0.0		CC	NG			0.9	
1599	Niagara Mohawk Power Corp.	Valatie Falls		F	23643	Valatie	021	36	1992-12-01	0.1		0.0	0.0		HY	WAT			0.5	
1600	Niagara Mohawk Power Corp.	Valley Falls Assoc.		F	23643	Valley Falls	083	36	1985-08-01	2.5		0.0	0.0		HY	WAT			8.2	
1601	Niagara Mohawk Power Corp.	Village of Gouverneur		E	23633	Gouverneur	089	36	1986-01-01	0.1		0.0	0.0		HY	WAT			0.5	
1602	Niagara Mohawk Power Corp.	Village of Potsdam		E	23633	Potsdam	089	36	1986-01-01	0.8		0.0	0.0		HY	WAT			3.1	
1603	Niagara Mohawk Power Corp.	Village of Potsdam 2		E	23633	Potsdam	089	36	2014-04-01	0.5		0.0	0.0		HY	WAT			1.2	
1604	Niagara Mohawk Power Corp.	Village of Saranac Lake		E	23633	Saranac Lake	033	36	1996-12-01	0.2		0.0	0.0		HY	WAT			0.5	
1605	Niagara Mohawk Power Corp.	Wave Hydro LLC		C	23634	Baldwinsville	067	36	2010-02-07	0.8		0.0	0.0		HY	WAT			0.0	
1606	Niagara Mohawk Power Corp.	West End Dam Assoc.		E	23633	Carthage	045	36	1986-01-01	4.4		0.0	0.0		HY	WAT			24.3	
1607	Niagara Wind Power, LLC	Steel Wind		A	323596	Lackawanna	029	36	2007-01-23	20.0	20.0	20.0	20.0		WT	WND			46.6	
1608	Nine Mile Point Nuclear Station, LLC	Nine Mile Point 1		C	23575	Scriba	075	36	1969-11-01	641.8	630.5	636.6	639.7		NB	UR			5,442.1	
1609	Nine Mile Point Nuclear Station, LLC	Nine Mile Point 2		C	23744	Scriba	075	36	1988-08-01	1,259.3	1,246.6	1,290.4	1,296.5		NB	UR			9,797.1	
1610	Noble Altona Windpark, LLC	Altona Wind Power		D	323606	Altona	019	36	2008-09-23	97.5	97.5	97.5	97.5		WT	WND			186.4	
1611	Noble Bliss Windpark, LLC	Bliss Wind Power		A	323608	Bliss	121	36	2008-03-20	100.5	100.5	100.5	100.5		WT	WND			206.6	
1612	Noble Chateaugay Windpark, LLC	Chateaugay Wind Power		D	323614	Chateaugay	033	36	2008-10-07	106.5	106.5	106.5	106.5		WT	WND			200.5	
1613	Noble Clinton Windpark 1, LLC	Clinton Wind Power		D	323605	Clinton	019	36	2008-04-09	100.5	100.5	100.5	100.5		WT	WND			186.2	
1614	Noble Ellenburg Windpark, LLC	Ellenburg Wind Power		D	323604	Ellenburg	019	36	2008-03-31	81.0	81.0	81.0	81.0		WT	WND			176.6	
1615	Noble Wethersfield Windpark, LLC	Wethersfield Wind Power		C	323626	Wethersfield	121	36	2008-12-11	126.0	126.0	126.0	126.0		WT	WND			267.8	
1616	Northbrook Lyons Falls, LLC	Lyons Falls Hydro		E	23570	Lyons Falls	049	36	1986-01-01	8.0	7.3	8.0	8.0		HY	WAT			41.1	
1617	NRG Power Marketing LLC	Arthur Kill GT 1		J	23520	Staten Island	085	36	1970-06-01	20.0	16.5	10.9	11.8		GT	NG			0.3	
1618	NRG Power Marketing LLC	Arthur Kill ST 2		J	23512	Staten Island	085	36	1959-08-01	376.2	357.7	338.3	340.9		ST	NG			788.8	
1619	NRG Power Marketing LLC	Arthur Kill ST 3		J	23513	Staten Island	085	36	1969-06-01	535.5	518.0	503.0	527.1		ST	NG			331.4	
1620	NRG Power Marketing LLC	Astoria GT 05		J	24106	Queens	081	36	1970-06-01	19.2	16.0	12.3	15.8		GT	FO2			0.1	
1621	NRG Power Marketing LLC	Astoria GT 07		J	24107	Queens	081	36	1970-06-01	19.2	15.5	11.5	14.0		GT	FO2			0.1	
1622	NRG Power Marketing LLC	Astoria GT 08		J	24108	Queens	081	36	1970-06-01	19.2	15.3	11.4	14.8		GT	FO2			0.1	
1623	NRG Power Marketing LLC	Astoria GT 10		J	24110	Queens	081	36	1971-01-01	31.8	24.9	18.4	22.6		GT	FO2			0.5	
1624	NRG Power Marketing LLC	Astoria GT 11		J	24225	Queens	081	36	1971-02-01	31.8	23.6	16.5	25.0		GT	FO2			1.0	
1625	NRG Power Marketing LLC	Astoria GT 12		J	24226	Queens	081	36	1971-05-01	31.8	22.7	17.7	22.4		GT	FO2			0.6	
1626	NRG Power Marketing LLC	Astoria GT 13		J	24227	Queens	081	36	1971-05-01	31.8	24.0	16.9	22.1		GT	FO2			0.4	
1627	NRG Power Marketing LLC	Astoria GT 2-1		J	24094	Queens	081	36	1970-06-01	46.5	41.2	35.7	43.9		JE	KER	NG		6.2	
1628	NRG Power Marketing LLC	Astoria GT 2-2		J	24095	Queens	081	36	1970-06-01	46.5	42.4	32.2	42.7		JE	KER	NG		6.8	
1629	NRG Power Marketing LLC	Astoria GT 2-3		J	24096	Queens	081	36	1970-06-01	46.5	41.2	31.8	42.2		JE	KER	NG		3.6	
1630	NRG Power Marketing LLC	Astoria GT 2-4		J	24097	Queens	081	36	1970-06-01	46.5	41.0	32.6	43.4		JE	KER	NG		3.1	
1631	NRG Power Marketing LLC	Astoria GT 3-1		J	24098	Queens	081	36	1970-06-01	46.5	41.2	31.7	41.8		JE	KER	NG		4.1	
1632	NRG Power Marketing LLC	Astoria GT 3-2		J	24099	Queens	081	36	1970-06-01	46.5	43.5	33.7	42.5		JE	KER	NG		3.1	
1633	NRG Power Marketing LLC	Astoria GT 3-3		J	24100	Queens	081	36	1970-06-01	46.5	43.0	32.2	42.3		JE	KER	NG		4.5	
1634	NRG Power Marketing LLC	Astoria GT 3-4		J	24101	Queens	081	36	1970-06-01	46.5	43.0	34.3	42.5		JE	KER	NG		3.1	
1635	NRG Power Marketing LLC	Astoria GT 4-1		J	24102	Queens	081	36	1970-07-01	46.5	42.6	34.3	42.7		JE	KER	NG		6.9	
1636	NRG Power Marketing LLC	Astoria GT 4-2		J	24103	Queens	081	36	1970-07-01	46.5	41.4	33.6	43.6		JE	KER	NG		3.8	
1637	NRG Power Marketing LLC	Astoria GT 4-3		J	24104	Queens	081	36	1970-07-01	46.5	41.1	32.8	42.8		JE	KER	NG		2.6	
1638	NRG Power Marketing LLC	Astoria GT 4-4		J	24105	Queens	081	36	1970-07-01	46.5	42.8	31.6	42.5		JE	KER	NG		3.8	
1639	NRG Power Marketing LLC	Dunkirk 2		A	23564	Dunkirk	013	36	1950-12-01	100.0	97.2	75.0	75.0		ST	BIT			368.5	(S)
1640	NRG Power Marketing LLC	Dunkirk IC 2		A	5050	Dunkirk	013	36	1990-01-01	0.5		0.0	0.0		IC	FO2				
1641	NRG Power Marketing LLC	Huntley 67		A	23561	Tonawanda	029	36	1957-12-01	218.0	196.5	187.9	187.0		ST	BIT			500.0	
1642	NRG Power Marketing LLC	Huntley 68		A	23562	Tonawanda	029	36	1958-12-01	218.0	198.0	189.5	187.2		ST	BIT			703.9	
1643	NRG Power Marketing LLC	Huntley IC 1		A	5051	Tonawanda	029	36	1967-08-01	0.7		0.0	0.0		IC	FO2				
1644	NRG Power Marketing LLC	Oswego 5		C	23606	Oswego	075	36	1976-02-01	901.8	850.3	828.5	825.5		ST	FO6			43.3	
1645	NRG Power Marketing LLC	Oswego 6		C	23613	Oswego	075	36	1980-07-01	901.8	835.2	826.5	832.0		ST	FO6	NG		40.6	
1646	NRG Power Marketing LLC	Oswego IC 1		C	5052	Oswego	075	36	1967-08-01	0.7		0.0	0.0		IC	FO2				
1647	NRG Power Marketing LLC	Oswego IC 2		C	5053	Oswego	075	36	1976-02-01	0.8		0.0	0.0		IC	FO2				

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EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1648	NRG Power Marketing LLC	Oswego IC	3	C	5054	Oswego	075	36	1980-07-01	0.8		0.0	0.0		IC	FO2				
1649	Orange and Rockland Utilities	Buttermilk Falls		G	5055	Highland Falls	071	36	1986-12-01	0.1		0.0	0.0		HY	WAT				
1650	Orange and Rockland Utilities	Intl. Crossroads		G	5056	Mahwah NJ	003	34	1987-12-01	3.0		0.0	0.0		IC	NG	FO2			
1651	Orange and Rockland Utilities	Landfill G.Part19		G	5057	Goshen	071	36	1988-12-01	2.5		0.0	0.0		IC	MTE				
1652	Orange and Rockland Utilities	Middletown LFG		G	5058	Goshen	071	36	1988-12-01	3.0		0.0	0.0		IC	MTE				
1653	PSEG Energy Resource & Trade, LLC	Bethlehem Energy Center		F	23843	Bethlehem	001	36	2005-07-01	893.1	756.9	762.0	870.3		CC	NG	FO2		4,526.7	
1654	R.E. Ginna Nuclear Power Plant, LLC	Ginna		B	23603	Ontario	117	36	1970-07-01	614.0	582.0	581.4	582.8		NP	UR			4,662.5	
1655	ReEnergy Holdings LLC	Black River		E	23780	Watertown	045	36	2013-05-30	55.5	55.6	50.8	52.4		ST	WD			302.6	
1656	ReEnergy Holdings LLC	Lyonsdale		E	23803	Lyonsdale	049	36	1992-08-01	21.1	20.2	20.3	20.6	YES	ST	WD			146.7	
1657	Rochester Gas and Electric Corp.	Mills Mills		B	5059	Fillmore	003	36	1906-07-01	0.2		0.0	0.0		HY	WAT				
1658	Rochester Gas and Electric Corp.	Mt Morris		B	5060	Mt Morris	051	36	1916-07-01	0.3		0.0	0.0		HY	WAT				
1659	Rochester Gas and Electric Corp.	Station 2	1	B	23604	Rochester	055	36	1913-07-01	8.5	6.5	8.5	8.5		HY	WAT			36.5	
1660	Rochester Gas and Electric Corp.	Station 26	1	B	23604	Rochester	055	36	1952-08-01	3.0	3.0	3.0	3.0		HY	WAT			0.8	
1661	Rochester Gas and Electric Corp.	Station 5	1	B	23604	Rochester	055	36	1918-07-01	14.0	11.8	14.0	14.0		HY	WAT			4.3	
1662	Rochester Gas and Electric Corp.	Station 5	2	B	23604	Rochester	055	36	1918-07-01	13.6	11.8	13.6	13.6		HY	WAT			0.0	
1663	Rochester Gas and Electric Corp.	Station 5	3	B	23604	Rochester	055	36	1918-07-01	18.0	16.5	18.0	18.0		HY	WAT			86.9	
1664	Rochester Gas and Electric Corp.	Wiscoy	1	B	5061	Fillmore	003	36	1922-07-01	0.6		0.0	0.0		HY	WAT				
1665	Rochester Gas and Electric Corp.	Wiscoy	2	B	5062	Fillmore	003	36	1922-07-01	0.5		0.0	0.0		HY	WAT				
1666	Rockville Centre, Village of	Charles P Keller	07	K	1661	Rockville Centre	059	36	1942-09-01	2.0	2.0	2.0	2.0		IC	FO2			0.0	
1667	Rockville Centre, Village of	Charles P Keller	08	K	1661	Rockville Centre	059	36	1950-09-01	2.4	2.8	2.4	2.4		IC	FO2			0.0	
1668	Rockville Centre, Village of	Charles P Keller	09	K	1661	Rockville Centre	059	36	1954-09-01	3.5	3.3	3.5	3.5		IC	FO2	NG		0.0	
1669	Rockville Centre, Village of	Charles P Keller	10	K	1661	Rockville Centre	059	36	1954-09-01	3.5	3.2	3.5	3.5		IC	FO2	NG		0.0	
1670	Rockville Centre, Village of	Charles P Keller	11	K	1661	Rockville Centre	059	36	1962-09-01	5.2	5.2	5.2	5.2		IC	FO2	NG		0.1	
1671	Rockville Centre, Village of	Charles P Keller	12	K	1661	Rockville Centre	059	36	1967-09-01	5.5	5.5	5.5	5.5		IC	FO2	NG		0.0	
1672	Rockville Centre, Village of	Charles P Keller	13	K	1661	Rockville Centre	059	36	1974-09-01	5.5	5.6	5.5	5.5		IC	FO2	NG		0.1	
1673	Rockville Centre, Village of	Charles P Keller	14	K	1661	Rockville Centre	059	36	1994-09-01	6.2	6.3	6.2	6.2		IC	FO2	NG		0.5	
1674	Selkirk Cogen Partners, L.P.	Selkirk-I		F	23801	Selkirk	001	36	1992-03-01	107.2	82.1	76.2	107.6	YES	CC	NG	FO2		287.0	
1675	Selkirk Cogen Partners, L.P.	Selkirk-II		F	23799	Selkirk	001	36	1994-09-01	338.8	291.3	270.4	334.2	YES	CC	NG	FO2		928.6	
1676	Seneca Energy II, LLC	Ontario LFGE		C	23819	Canandaigua	069	36	2003-12-01	11.2	5.6	11.2	11.2		IC	MTE			75.7	
1677	Seneca Energy II, LLC	Seneca Energy 1		C	23797	Seneca Falls	099	36	1996-03-01	8.8	8.8	8.8	8.8		IC	MTE			141.8	**(G)**
1678	Seneca Energy II, LLC	Seneca Energy 2		C	23797	Seneca Falls	099	36	1997-08-01	8.8	8.8	8.8	8.8		IC	MTE				
1679	Seneca Falls Power Corp.	Seneca Falls 1		C	23627	Seneca Falls	099	36	1998-06-01	1.8	1.6	0.0	0.0		HY	WAT			0.0	
1680	Seneca Falls Power Corp.	Seneca Falls 2		C	23627	Seneca Falls	099	36	1998-06-01	1.8	1.6	0.0	0.0		HY	WAT			0.0	
1681	Seneca Falls Power Corp.	Seneca Falls 4		C	23627	Seneca Falls	099	36	1998-06-01	2.0	1.8	0.0	0.0		HY	WAT			0.0	
1682	Seneca Power Partners, L.P.	Allegany		B	23514	Hume	003	36	1995-03-01	67.0	62.9	60.0	61.7	YES	CC	NG			96.5	
1683	Seneca Power Partners, L.P.	Batavia		B	24024	Batavia	037	36	1992-06-01	67.3	57.1	48.8	60.1		CC	NG			10.8	
1684	Seneca Power Partners, L.P.	Carthage Energy		E	23857	Carthage	045	36	1991-08-01	62.9	59.0	55.5	63.6		CC	NG	FO2		11.4	
1685	Seneca Power Partners, L.P.	Hillburn GT		G	23639	Hillburn	087	36	1971-04-01	46.5	37.9	34.8	43.3		JE	KER			0.3	
1686	Seneca Power Partners, L.P.	Shoemaker GT		G	23640	Middletown	071	36	1971-05-01	41.9	33.1	31.6	41.0		JE	KER			0.4	
1687	Seneca Power Partners, L.P.	Sterling		E	23777	Sherrill	065	36	1991-06-01	65.3	57.4	50.1	63.0		CC	NG			22.4	
1688	Sheldon Energy LLC	High Sheldon Wind Farm		C	323625	Sheldon	121	36	2009-02-01	112.5	112.5	112.5	112.5		WT	WND			270.7	
1689	Shell Energy North America (US), L.P.	Glen Park Hydro		E	23778	Glen Park	045	36	1986-01-01	32.6	40.4	32.6	32.6		HY	WAT			168.3	
1690	Shell Energy North America (US), L.P.	Lockport		A	23791	Lockport	063	36	1992-07-01	221.3	225.2	202.7	220.3		CC	NG	FO2		388.8	
1691	Shell Energy North America (US), L.P.	Munnsville Wind Power		E	323609	Bouckville	053	36	2007-08-20	34.5	34.5	34.5	34.5		WT	WND			96.0	
1692	Somerset Operating Company, LLC	Somerset		A	23543	Somerset	063	36	1984-08-01	655.1	686.5	681.5	681.2		ST	BIT			1,786.6	
1693	Stephentown Spindle LLC	Beacon LESR		F	323632	Stephentown	083	36	2010-11-29	20.0	0.0	0.0	0.0		ES	FW			0.0	
1694	Stony Creek Energy LLC	Orangeville Wind Farm		C	323706	Orangeville	121	36	2013-12-01	93.9	88.5	93.9	93.9		WT	WND			274.1	
1695	TC Ravenswood, LLC	Ravenswood 01		J	23729	Queens	081	36	1967-07-01	18.6	8.8	9.3	9.6		GT	NG			0.1	
1696	TC Ravenswood, LLC	Ravenswood 04		J	24252	Queens	081	36	1970-09-01	21.1	15.2	12.9	15.4		GT	KER	NG		0.2	
1697	TC Ravenswood, LLC	Ravenswood 05		J	24254	Queens	081	36	1970-08-01	21.1	15.7	13.6	15.6		GT	KER			0.1	
1698	TC Ravenswood, LLC	Ravenswood 06		J	24253	Queens	081	36	1970-08-01	22.0	16.7	13.4	15.8		GT	KER	NG		0.2	
1699	TC Ravenswood, LLC	Ravenswood 09		J	24257	Queens	081	36	1970-07-01	25.0	21.7	16.9	21.7		JE	KER	NG		1.6	
1700	TC Ravenswood, LLC	Ravenswood 10		J	24258	Queens	081	36	1970-08-01	25.0	21.2	18.0	22.8		JE	KER	NG		0.3	
1701	TC Ravenswood, LLC	Ravenswood 11		J	24259	Queens	081	36	1970-08-01	25.0	20.2	17.2	22.8		JE	KER	NG		1.4	
1702	TC Ravenswood, LLC	Ravenswood 2-1		J	24244	Queens	081	36	1970-12-01	42.9	40.4	32.7	37.4		JE	NG			1.6	
1703	TC Ravenswood, LLC	Ravenswood 2-2		J	24245	Queens	081	36	1970-12-01	42.9	37.6	31.4	43.0		JE	NG			1.5	
1704	TC Ravenswood, LLC	Ravenswood 2-3		J	24246	Queens	081	36	1970-12-01	42.9	39.2	0.0	0.0		JE	NG			0.0	
1705	TC Ravenswood, LLC	Ravenswood 2-4		J	24247	Queens	081	36	1970-12-01	42.9	39.8	32.0	37.5		JE	NG			1.8	
1706	TC Ravenswood, LLC	Ravenswood 3-1		J	24248	Queens	081	36	1970-08-01	42.9	40.5	30.3	40.9		JE	NG			1.4	
1707	TC Ravenswood, LLC	Ravenswood 3-2		J	24249	Queens	081	36	1970-08-01	42.9	38.1	30.6	35.8		JE	NG			1.3	
1708	TC Ravenswood, LLC	Ravenswood 3-3	(MB - 10/3	J	24250	Queens	081	36	1970-08-01	42.9	37.7	0.0	0.0		JE	NG			0.9	**(M) (6)**
1709	TC Ravenswood, LLC	Ravenswood 3-4	(ReAct. - 8	J	24251	Queens	081	36	1970-08-01	42.9	35.8	30.9	38.6		JE	NG			1.5	**(D) (7)**
1710	TC Ravenswood, LLC	Ravenswood CC	04	J	23820	Queens	081	36	2004-05-01	250.0	231.2	216.6	262.9		CC	NG	FO2		1,527.2	
1711	TC Ravenswood, LLC	Ravenswood ST	01	J	23533	Queens	081	36	1963-02-01	400.0	365.1	366.2	363.6		ST	FO6	NG		696.3	
1712	TC Ravenswood, LLC	Ravenswood ST	02	J	23534	Queens	081	36	1963-05-01	400.0	391.6	363.5	373.7		ST	FO6	NG		1,006.0	
1713	TC Ravenswood, LLC	Ravenswood ST	03	J	23535	Queens	081	36	1965-06-01	1,027.0	986.8	969.2	960.1		ST	FO6	NG		1,540.3	
1714	TransAlta Energy Marketing (U.S.) Inc	Saranac Energy		D	23793	Plattsburgh	019	36	1994-06-01	285.6	253.7	244.9	273.4		CC	NG			224.3	
1715	Triton Power Company	Chateaugay High Falls		D	323578	Chateaugay	033	36	1987-12-01	1.7	1.7	0.0	0.0		HY	WAT			4.3	
1716	Western New York Wind Corp.	Western NY Wind Power		B	24143	Wethersfield	121	36	2000-10-01	6.6	0.0	0.0	0.0		WT	WND			9.3	
1717	Wheelabrator Hudson Falls, LLC	Wheelabrator Hudson Falls		F	23798	Hudson Falls	115	36	1991-10-01	14.4	12.7	11.4	11.7		ST	REF			74.9	
1718	Wheelabrator Westchester, LP	Wheelabrator Westchester		H	23653	Peekskill	119	36	1984-04-01	59.7	53.5	52.7	53.6		ST	REF			388.7	
1719																				

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Contains Proprietary Material
Do Not Distribute

TABLE III - 2

EXISTING GENERATING FACILITIES

LINE REF. NO.	Owner, Operator, and / or Billing Organization	Station	Unit	Zone	PTID	Location Town	Cnty	St	In-Service Date YY-MM-DD	Name Plate Rating (MW)	CRIS Sum Cap (A) (MW)	2015 Capability (B) (MW) SUM	WIN	Co-Gen	Unit Type	Fuel (U) Type 1	Type 2	Type 3	2014 Net Energy (GWh)	Notes
1720										44,866.1	40,333.7	38,664.5	41,012.8						141,186.6	
1721				J						11,398.8	10,223.4	9,597.0	10,560.6							

Contains Proprietary Material
Do Not Distribute

Max	31,138
Peak Month	7
PST	25,244
Winter	22,045
Spring	19,393
Summer	24,144
Fall	20,374

Source: NYISO

SIL Study
24,893
24,418
31,266
31,179

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	21,185	12/1/2014	14,220	13,616	13,287	13,224	13,497	14,498	16,506	17,769	18,270	18,637	18,888	18,940	18,882	18,884	18,880	19,092	20,181	21,185	21,029	20,601	20,071	19,094	17,738	16,283
Winter	12	21,996	12/2/2014	15,242	14,655	14,333	14,246	14,541	15,635	17,671	18,946	19,413	19,603	19,837	19,833	19,845	19,937	20,024	20,287	21,327	21,996	21,835	21,369	20,649	19,560	17,986	16,471
Winter	12	21,652	12/3/2014	15,318	14,675	14,270	14,138	14,334	15,250	17,166	18,527	19,044	19,407	19,666	19,733	19,721	19,811	19,863	19,865	20,847	21,652	21,389	21,004	20,464	19,490	18,020	16,551
Winter	12	21,613	12/4/2014	15,512	14,928	14,575	14,494	14,762	15,747	17,679	18,896	19,323	19,560	19,572	19,387	19,325	19,267	19,209	19,467	20,446	21,613	21,466	21,085	20,583	19,689	18,278	16,864
Winter	12	21,460	12/5/2014	15,822	15,229	14,954	14,850	15,006	16,053	17,942	19,131	19,557	19,848	19,958	19,960	19,914	19,882	19,901	20,132	20,997	21,460	21,073	20,573	19,992	19,212	18,031	16,660
Winter	12	20,018	12/6/2014	15,536	14,773	14,307	14,084	14,094	14,433	15,170	16,023	16,988	17,791	18,293	18,494	18,523	18,408	18,348	18,490	19,303	20,018	19,855	19,424	19,000	18,380	17,434	16,389
Winter	12	20,968	12/7/2014	15,426	14,738	14,348	14,178	14,207	14,511	15,102	15,697	16,556	17,170	17,486	17,593	17,648	17,629	17,665	17,984	19,296	20,864	20,968	20,770	20,358	19,525	18,319	17,050
Winter	12	23,095	12/8/2014	16,111	15,590	15,329	15,267	15,562	16,598	18,519	19,872	20,452	20,837	21,037	21,023	20,899	20,901	20,864	21,078	22,091	23,095	22,917	22,422	21,725	20,649	19,086	17,449
Winter	12	22,518	12/9/2014	16,176	15,502	15,093	14,964	15,179	16,098	18,003	19,567	20,081	20,496	20,838	20,931	20,877	20,834	20,702	20,817	21,686	22,518	22,242	21,698	20,924	19,879	18,327	16,737
Winter	12	22,828	12/10/2014	15,639	14,986	14,637	14,544	14,775	15,739	17,646	19,107	19,682	20,144	20,359	20,438	20,450	20,467	20,456	20,687	21,765	22,828	22,655	22,190	21,509	20,441	18,901	17,276
Winter	12	22,609	12/11/2014	16,148	15,501	15,141	15,061	15,281	16,239	18,052	19,426	19,965	20,268	20,413	20,417	20,335	20,318	20,306	20,495	21,515	22,609	22,385	21,936	21,334	20,326	18,859	17,292
Winter	12	22,122	12/12/2014	16,167	15,528	15,169	15,041	15,199	16,161	18,080	19,451	19,978	20,349	20,396	20,292	20,106	20,067	19,977	20,100	21,048	22,122	21,854	21,315	20,699	19,923	18,755	17,390
Winter	12	20,486	12/13/2014	16,205	15,449	14,975	14,771	14,767	15,142	15,912	16,689	17,578	18,163	18,441	18,444	18,303	18,141	18,077	18,329	19,410	20,486	20,410	20,025	19,565	18,924	17,974	16,772
Winter	12	20,471	12/14/2014	15,744	14,964	14,502	14,280	14,265	14,498	15,028	15,631	16,480	17,241	17,676	17,854	17,912	17,889	17,850	18,012	19,138	20,471	20,407	20,298	19,829	18,984	17,640	16,327
Winter	12	21,987	12/15/2014	15,278	14,688	14,407	14,317	14,574	15,580	17,568	18,949	19,367	19,631	19,725	19,662	19,475	19,451	19,374	19,543	20,656	21,987	21,889	21,453	20,848	19,872	18,377	16,778
Winter	12	21,968	12/16/2014	15,564	14,900	14,551	14,442	14,687	15,668	17,694	19,133	19,610	19,932	20,075	20,042	19,924	19,834	19,719	19,925	20,985	21,968	21,749	21,330	20,713	19,683	18,172	16,514
Winter	12	21,926	12/17/2014	15,256	14,556	14,201	14,063	14,274	15,187	17,214	18,618	19,068	19,344	19,514	19,476	19,418	19,508	19,587	19,886	20,933	21,926	21,675	21,245	20,671	19,779	18,335	16,819
Winter	12	22,187	12/18/2014	15,628	14,959	14,600	14,512	14,779	15,810	17,781	19,129	19,549	19,847	19,947	19,942	19,840	19,789	19,745	19,999	21,119	22,187	22,014	21,611	21,048	20,109	18,694	17,137
Winter	12	22,134	12/19/2014	16,050	15,391	14,980	14,867	15,132	16,103	17,932	19,353	19,927	20,272	20,419	20,363	20,111	19,962	19,843	20,038	21,027	22,134	21,852	21,436	20,852	20,105	19,004	17,659
Winter	12	21,028	12/20/2014	16,467	15,746	15,308	15,060	15,072	15,429	16,187	17,022	17,966	18,789	19,172	19,272	19,191	19,014	18,948	19,060	20,001	21,028	20,927	20,544	20,110	19,469	18,569	17,390
Winter	12	20,957	12/21/2014	16,310	15,534	15,072	14,780	14,750	14,989	15,540	16,178	17,060	17,907	18,414	18,585	18,640	18,539	18,528	18,769	19,891	20,957	20,943	20,681	20,237	19,458	18,208	16,903
Winter	12	22,074	12/22/2014	15,844	15,128	14,779	14,674	14,896	15,806	17,589	18,981	19,639	20,075	20,265	20,242	20,031	19,964	19,936	20,163	21,078	22,074	21,848	21,353	20,763	19,861	18,478	16,991
Winter	12	21,324	12/23/2014	15,742	14,944	14,520	14,362	14,519	15,356	17,007	18,464	19,175	19,660	19,905	19,917	19,756	19,700	19,595	19,658	20,477	21,324	21,144	20,666	20,071	19,265	17,973	16,495
Winter	12	19,625	12/24/2014	15,187	14,350	13,872	13,647	13,749	14,354	15,564	16,812	17,763	18,590	19,069	19,265	19,135	19,006	18,834	18,731	19,296	19,625	18,899	18,160	17,560	17,058	16,315	15,428
Winter	12	17,507	12/25/2014	14,450	13,720	13,238	12,909	12,866	13,075	13,573	14,232	14,957	15,682	16,015	16,128	16,225	16,184	16,030	16,025	16,620	17,507	17,497	17,358	17,165	16,832	16,125	15,108
Winter	12	19,843	12/26/2014	14,254	13,650	13,287	13,159	13,315	13,962	15,048	16,003	16,797	17,468	17,801	17,892	17,738	17,513	17,326	17,421	18,349	19,843	19,775	19,424	18,976	18,284	17,253	16,101
Winter	12	18,786	12/27/2014	15,021	14,315	13,858	13,648	13,662	13,932	14,598	15,162	15,844	16,467	16,851	16,935	16,801	16,533	16,354	16,399	17,316	18,745	18,786	18,488	18,076	17,447	16,542	15,453
Winter	12	19,288	12/28/2014	14,459	13,733	13,298	13,087	13,070	13,287	13,758	14,326	15,024	15,846	16,471	16,820	17,037	17,039	16,998	17,165	18,228	19,288	19,267	18,939	18,467	17,806	16,795	15,648
Winter	12	21,428	12/29/2014	14,687	14,136	13,815	13,726	13,962	14,858	16,276	17,509	18,349	18,877	19,210	19,343	19,256	19,185	19,140	19,233	20,129	21,428	21,311	20,887	20,289	19,452	18,229	16,832
Winter	12	22,203	12/30/2014	15,741	15,119	14,776	14,683	14,869	15,668	17,076	18,328	19,129	19,669	19,944	20,015	19,949	19,857	19,834	19,956	20,853	22,203	22,084	21,665	21,148	20,310	19,067	17,612
Winter	12	21,953	12/31/2014	16,482	15,744	15,338	15,167	15,314	16,021	17,320	18,408	19,146	19,649	19,904	20,023	19,888	19,775	19,682	19,719	20,473	21,953	21,656	20,900	20,098	19,310	18,552	17,809
Winter	1	20,225	1/1/2015	17,052	16,304	15,759	15,425	15,341	15,530	15,879	16,081	16,454	17,001	17,527	17,843	17,944	17,887	17,784	17,932	18,822	20,225	20,108	19,810	19,410	18,746	17,667	16,518
Winter	1	21,193	1/2/2015	15,636	15,043	14,684	14,495	14,635	15,377	16,494	17,468	18,225	18,904	19,265	19,394	19,322	19,191	19,063	19,148	19,955	21,193	21,023	20,519	19,987	19,206	18,173	17,013
Winter	1	20,642	1/3/2015	15,981	15,332	14,982	14,760	14,784	15,105	15,727	16,396	17,089	17,828	18,435	18,807	18,973	18,966	19,026	19,143	19,878	20,642	20,520	20,081	19,474	18,618	17,601	16,436
Winter	1	19,736	1/4/2015	15,452	14,695	14,170	13,853	13,736	13,924	14,332	14,846	15,516	16,317	16,980	17,419	17,607	17,673	17,692	17,816	18,690	19,736	19,680	19,278	18,711	17,779	16,642	15,526
Winter	1	23,003	1/5/2015	14,657	14,234	14,028	14,020	14,391	15,567	17,647	19,085	19,552	19,957	20,226	20,332	20,377	20,400	20,408	20,624	21,482	22,957	23,003	22,683	22,052	21,005	19,539	18,099
Winter	1	23,632	1/6/2015	17,175	16,600	16,274	16,185	16,441	17,302	19,168	20,670	21,174	21,563	21,844	21,884	21,764	21,715	21,610	21,750	22,433	23,623	23,632	23,256	22,605	21,545	19,957	18,488
Winter	1	24,648	1/7/2015	17,480	16,888	16,544	16,431	16,653	17,553	19,489	20,930	21,418	21,715	21,916	21,974	21,986	22,014	22,054	22,288	23,094	24,514	24,648	24,289	23,709	22,711	21,316	19,864
Winter	1	24,327	1/8/2015	18,913	18,314	17,947	17,835	18,114	19,022	20,738	22,137	22,510	22,895	22,974	22,816	22,572	22,408	22,223	22,292	23,036	24,327	24,322	23,954	23,321	22,234	20,662	19,176
Winter	1	23,069	1/9/2015	18,138	17,564	17,185	17,034	17,194	17,959	19,717	21,187	21,626	22,020	22,190	22,085	21,773	21,575	21,363	21,357	21,901	23,069	22,930	22,414	21,827	21,044	19,927	18,731
Winter	1	22,334	1/10/2015	17,763	17,177	16,819	16,653	16,721	17,096	17,826	18,592	19,469	20,142	20,447	20,478	20,400	20,170	20,007	20,068	20,756	22,142	22,334	21,945	21,514	20,867	19,905	18,871
Winter	1	21,443	1/11/2015	17,924	17,200	16,773	16,525	16,477	16,646	17,125	17,627	18,354	19,016	19,504	19,723	19,700	19,609	19,413	19,402	20,114	21,443	21,431	21,029	20,427	19,475	18,241	17,012
Winter	1	22,559	1/12/2015	16,094	15,607	15,309	15,204	15,466	16,408	18,217	19,685	20,291	20,784	21,107	21,270	21,227	21,159	21,048	21,095	21,704	22,559	22,396	21,874	21,168	20,133	18,796	17,448
Winter	1	23,668	1/13/2015	16,454	15,930	15,665	15,646	15,938	17,080	19,100	20,567	21,021	21,390	21,568	21,456	21,311	21,236	21,149	21,361	22,045	23,465	23,668	23,355	22,720	21,756	20,407	19,062
Winter	1	23,222	1/14/2015	18,120	17,572	17,249	17,160	17,404	18,368	20,286	21,735	22,165	22,383	22,363	22,115	21,799	21,655	21,488	21,500	22,048	23,222	23,207	22,748	22,078	21,087	19,673	18,250
Winter	1	22,679	1/15/2015	17,274	16,739	16,405	16,326	16,567	17,518	19,461	20,838	21,228	21,421	21,397	21,211	20,894	20,736	20,557	20,631	21,300	22,635	22,679	22,314	21,693	20,692	19,168	17,822
Winter	1	22,452	1/16/2015	16,850	16,282	15,933	15,814	16,004	16,879	18,776	20,120	20,542	20,780	20,831	20,758	20,621	20,449	20,425	20,566	21,128	22,309	22,452	22,023	21,523	20,788	19,706	18,524
Winter	1	21,099	1/17/2015	17,608	17,031	16,722	16,579	16,650	17,002	17,782	18,552	19,390	20,007	20,237	20,170	19,835	19,443	19,182	19,143	19,713	20,968	21,099	20,727	20,193	19,510	18,597	17,528
Winter	1	20,222	1/18/2015	16,685	16,041	15,596	15,318	15,264	15,399	15,814	16,338	17,092	17,902	18,513	18,854	18,999	19,019	18,948	19,027	19,515	20,222	20,121	19,690	19,096	18,306	17,328	16,263
Winter	1	21,623	1/19/2015	15,459	14,964	14,658	14,574	14,778	15,473	16,677	17,732	18,604	19,312	19,731	19,899	19,850	19,872	19,886	19,970	20,506	21,623	21,579	21,149	20,477	19,523	18,161	16,881
Winter	1	22,144	1/20/2015	15,940	15,425	15,130	15,052	15,345	16,419	18,424	19,709	20,192	20,437	20,411	20,335	20,183	20,217	20,172	20,247	20,944	22,140	22,144	21,771	21,172	20,282	18,920	17,526
Winter	1	22,439	1/21/2015	16,584	16,119	15,893	15,880	16,220	17,235	19,224	20,552	20,930	21,242	21,367	21,257	20,945	20,701	20,595	20,730	21,260	22,385	22,439	22,013	21,353	20,329	18,943	17,526
Winter	1	22,118	1/22/2015	16,500	15,910	15,612	15,515	15,778	16,748	18,631	20,019	20,454	20,729	20,843	20,691	20,453	20,257	20,081	20,100	20,622	21,923	22,118	21,755	21,192	20,248	18,912	17,528
Winter	1	21,425	1/23/2015	16,523	16,044	15,753	15,664	15,895	16,882	18,800	20,141	20,508	20,756	20,704	20,523	20,208	20,008	19,788	19,778	20,249	21,349	21,425	20,954	20,373	19,561	18,445	17,247
Winter	1	20,458	1/24/2015	16,307	15,650	15,318	15,163	15,212	15,515	16,196	16,942	17,808	18,603	19,122	19,365	19,308	19,068	18,919	18,969	19,455	20,428	20,458	20,060	19,498	18,761	17,830	16,787
Winter	1	20,754	1/25/2015	15,900	15,258	14,849	14,679	14,681	14,957	15,505	16,099	16,960	17,606	17,975	18,107	18,087	17,948	17,891	18,035	18,697	20,263	20,754	20,582	20,165	19,368	18,326	17,309
Winter	1	23,112	1/26/2015	16,491	16,034	15,804	15,788	16,101	17,157	19,074	20,598	21,154	21,635	21,932	22,092	22,092	22,046	21,858	21,705	22,021	23,112	23,105	22,509	21,712	20,671	19,454	18,169
Winter	1	22,964	1/27/2015	17,249	16,686	16,398	16,319	16,505	17,128	18,210	18,983	19,553	20,196	20,607	20,784	20,805	20,697	20,600	20,635	21,175	22,642	22,964	22,575	21,891	20,876	19,535	18,245
Winter	1	23,166	1/28/2015	17,391	16,951	16,719	16,677	16,962	17,922	19,752	21,041	21,561	21,881	21,979	21,781	21,487	21,289	21,039	20,993	21,394	22,749	23,166	22,815	22,225	21,204	19,779	18,429
Winter	1	22,758	1/29/2015	17,516	17,002	16,778	16,713	17,029	17,961	19,879	21,127	21,530	21,736	21,692	21,534	21,312	21,268	21,174	21,246	21,713	22,690	22,758	22,290	21,546	20,429	18,980	17,642
Winter	1	22,613	1/30/2015	16,704	16,122	15,760	15,608	15,792	16,665	18,455	19,844	20,462	20,972	21,207	21,157	21,013	20,879	20,733	20,745	21,109	22,229	22,613	22,243	21,754	21,006	19,925	18,825
Winter	1	22,020	1/31/2015	17,917	17,354	17,055	16,927	17,014	17,363	18,121	18,931	19,835	20,509	20,828	20,763	20,513	20,160	19,916	19,858	20,243	21,483	22,020	21,744	21,233	20,527	19,534	18,476
Winter	2	21,227	2/1/2015	17,551	16,910	16,464	16,233	16,190	16,423	16,849	17,356	18,148	18,688	19,033	19,190	19,206	19,199	19,234	19,448	20,067	21,154	21,227	20,641	20,143	19,547	18,787	17,731
Winter	2	23,654	2/2/2015	16,782	16,287	16,030	15,981	16,203	16,988	18,447	19,665	20,644	21,492	22,008	22,218	22,225	22,262	22,212	22,172	22,393	23,423	23,654	23,242	22,508	21,461	20,200	18,886
Winter	2	23,494	2/3/2015	17,976	17,460	17,215	17,152	17,428	18,352	20,111	21,317	21,924	22,162	22,207	22,091	21,812	21,635	21,410	21,338	21,713	22,921	23,494	23,181	22,519	21,543	20,021	18,595
Winter	2	22,432	2/4/2015	17,576	16,992	16,662	16,520	16,731	17,616	19,431	20,588	21,031	21,325	21,423	21,323	21,150	21,026	20,870	20,745	21,041	22,088	22,432	22,069	21,381	20,294	18,881	17,483
Winter	2	23,633	2/5/2015	16,508	15,903	15,615	15,525	15,792	16,776	18,741	20,153	20,747	21,260	21,495	21,523	21,381	21,294	21,167	21,180	21,650	22,952	23,633	23,459	22,887	21,905	20,549	19,201
Winter	2	22,829	2/6/2015	18,232	17,702	17,427	17,383	17,626	18,598	20,459	21,730	22,129	22,386	22,461	22,421	22,174	21,845	21,481	21,353	21,581	22,463	22,829	22,426	21,847	21,044	19,918	18,628
Winter	2	20,783	2/7/2015	17,605	16,952	16,507	16,273	16,256	16,548	17,224	17,967	18,848	19,553	19,979	20,124	19,944	19,698	19,486	19,315	19,450	20,362	20,783	20,391	19,860	19,169	18,292	17,295
Winter	2	21,114	2/8/2015	16,373	15,772	15,402	15,149	15,156	15,400	15,873	16,373	17,263	18,074	18,602	18,858	19,009	19,025	19,092	19,209	19,726	20,782	21,114	20,787	20,259	19,448	18,374	17,300
Winter	2	23,242	2/9/2015	16,513	16,065	15,804	15,741	16,068	17,006	18,665	19,971	20,767	21,422	21,887	22,041	22,074	22,051	21,885	21,855	22,165	23,050	23,242	22,831	22,050	20,961	19,480	18,081
Winter	2	22,506	2/10/2015	17,090	16,514	16,199	16,101	16,339	17,300	19,123	20,455	21,008	21,200	21,300	21,223	20,947	20,791	20,598	20,635	20,914	21,919	22,506	22,273	21,696	20,732	19,311	17,960
Winter	2	22,529	2/11/2015	16,978	16,513	16,227	16,228	16,492	17,540	19,516	20,798	21,101	21,313	21,284	21,102	20,818	20,589	20,353	20,371	20,764	21,798	22,529	22,222	21,675	20,622	19,264	17,851
Winter	2	22,826	2/12/2015	16,777	16,257	15,910	15,821	16,054	16,953	18,848	20,074	20,602	20,921	21,045	20,972	20,789	20,742	20,584	20,802	21,201	22,164	22,826	22,635	22,188	21,343	20,062	18,903
Winter	2	23,321	2/13/2015	18,061	17,584	17,367	17,387	17,716	18,673	20,514	21,761	22,306	22,680	22,816	22,560	22,209	21,969	21,732	21,586	21,829	22,693	23,321	23,029	22,513	21,744	20,550	19,326
Winter	2	21,698	2/14/2015	18,393	17,756	17,408	17,198	17,158	17,444	18,041	18,657	19,642	20,402	20,731	20,759	20,555	20,354	20,230	20,182	20,362	21,165	21,698	21,398	20,868	20,169	19,192	18,222
Winter	2	23,163	2/15/2015	17,342	16,840	16,655	16,589	16,678	16,969	17,478	18,007	19,121	20,077	20,640	20,812	20,761	20,592	20,363	20,418	20,951	22,151	23,163	22,887	22,341	21,772	20,926	19,919
Winter	2	23,754	2/16/2015	19,081	18,560	18,260	18,131	18,285	18,911	19,955	20,880	21,755	22,353	22,616	22,667	22,402	22,139	21,973	21,941	22,221	23,110	23,754	23,412	22,805	21,888	20,656	19,403
Winter	2	23,397	2/17/2015	18,429	17,857	17,569	17,506	17,785	18,603	19,976	21,174	21,979	22,479	22,688	22,566	22,286	22,014	21,720	21,557	21,785	22,549	23,397	23,091	22,505	21,600	20,319	19,090
Winter	2	22,839	2/18/2015	18,152	17,642	17,351	17,273	17,539	18,413	19,885	21,024	21,710	22,001	21,971	21,690	21,364	21,180	20,994	20,961	21,247	22,175	22,839	22,467	21,848	21,004	19,713	18,452
Winter	2	24,024	2/19/2015	17,496	16,970	16,711	16,679	16,953	17,844	19,384	20,545	21,321	21,760	21,950	22,090	22,083	22,044	21,918	21,938	22,208	23,102	24,024	23,853	23,360	22,541	21,374	20,171
Winter	2	23,746	2/20/2015	19,187	18,608	18,352	18,307	18,542	19,424	20,895	21,981	22,834	23,331	23,471	23,408	23,105	22,828	22,491	22,287	22,438	23,013	23,746	23,483	22,979	22,323	21,246	20,077
Winter	2	22,108	2/21/2015	19,020	18,448	18,050	17,824	17,805	18,126	18,773	19,416	20,252	20,756	21,008	21,025	20,966	20,819	20,802	20,762	21,016	21,679	22,108	21,766	21,142	20,212	19,191	18,142
Winter	2	20,911	2/22/2015	17,285	16,683	16,230	15,977	15,942	16,121	16,567	16,975	17,823	18,509	18,878	18,867	18,695	18,493	18,278	18,359	18,790	19,909	20,911	20,753	20,260	19,422	18,397	17,362
Winter	2	24,144	2/23/2015	16,584	16,109	15,928	15,925	16,109	17,319	19,264	20,572	21,274	21,871	22,168	22,133	22,009	21,810	21,772	21,805	22,282	23,158	24,144	24,071	23,571	22,628	21,339	19,973
Winter	2	23,955	2/24/2015	18,917	18,365	18,096	18,050	18,375	19,365	21,150	22,275	22,665	22,855	22,894	22,636	22,362	22,209	22,028	21,993	22,207	23,062	23,955	23,584	22,936	21,919	20,417	18,905
Winter	2	22,679	2/25/2015	17,939	17,341	17,027	16,915	17,196	18,136	19,894	21,003	21,344	21,484	21,436	21,221	20,951	20,765	20,597	20,600	20,942	21,642	22,679	22,565	21,949	21,062	19,638	18,323
Winter	2	23,331	2/26/2015	17,454	17,003	16,744	16,726	16,969	17,963	19,823	21,058	21,625	22,026	22,187	22,094	21,754	21,495	21,487	21,590	21,929	22,590	23,331	23,050	22,492	21,530	20,175	18,808
Winter	2	22,501	2/27/2015	17,893	17,365	17,079	17,030	17,292	18,321	20,041	21,171	21,564	21,770	21,750	21,578	21,278	21,095	20,865	20,800	21,014	21,573	22,501	22,349	21,903	21,206	20,183	19,041
Winter	2	21,244	2/28/2015	18,150	17,626	17,329	17,215	17,282	17,659	18,314	19,034	19,808	20,275	20,439	20,259	19,933	19,591	19,290	19,133	19,352	20,046	21,244	21,231	20,838	20,277	19,451	18,581
Spring	3	21,805	3/1/2015	17,761	17,217	16,876	16,682	16,663	16,865	17,216	17,662	18,492	19,000	19,388	19,613	19,743	19,826	19,891	19,967	20,339	21,061	21,805	21,547	20,885	19,879	18,698	17,514
Spring	3	22,544	3/2/2015	16,668	16,214	15,959	15,911	16,160	17,139	18,732	19,914	20,686	21,041	21,183	21,135	20,996	20,894	20,665	20,568	20,786	21,449	22,544	22,397	21,833	20,848	19,488	18,126

SI-SSA-0010

Contains Proprietary Material
Do Not Distribute

Spring	3	22,697	3/3/2015	17,203	16,720	16,485	16,451	16,744	17,829	19,550	20,570	21,035	21,285	21,366	21,328	21,248	21,267	21,254	21,293	21,494	22,106	22,697	22,494	21,857	20,737	19,243	17,791
Spring	3	21,683	3/4/2015	16,731	16,124	15,751	15,599	15,815	16,781	18,472	19,651	20,171	20,434	20,544	20,494	20,293	20,126	20,015	20,137	20,426	21,019	21,683	21,421	20,799	19,855	18,521	17,243
Spring	3	23,122	3/5/2015	16,315	15,803	15,505	15,476	15,776	16,775	18,510	19,828	20,655	21,213	21,635	21,769	21,785	21,722	21,536	21,474	21,720	22,313	23,122	22,963	22,318	21,335	20,013	18,716
Spring	3	22,378	3/6/2015	17,960	17,487	17,240	17,257	17,587	18,603	20,060	21,071	21,438	21,720	21,848	21,730	21,420	21,184	20,920	20,806	20,965	21,472	22,378	22,156	21,626	20,882	19,861	18,671
Spring	3	20,390	3/7/2015	17,693	17,156	16,758	16,614	16,654	17,028	17,596	18,317	19,130	19,543	19,647	19,529	19,325	19,106	18,980	18,913	19,123	19,576	20,390	20,266	19,817	19,076	18,118	17,127
Spring	3	19,580	3/8/2015	16,235	0	15,630	15,303	15,120	15,215	15,604	16,039	16,658	17,314	17,692	17,884	17,938	17,860	17,686	17,491	17,548	17,818	18,330	19,505	19,580	18,956	17,918	16,707
Spring	3	20,238	3/9/2015	15,830	15,364	15,113	15,046	15,268	16,133	18,029	19,485	19,833	19,882	19,816	19,657	19,390	19,133	18,874	18,670	18,722	18,956	19,244	20,238	20,091	19,306	18,017	16,664
Spring	3	20,286	3/10/2015	15,673	15,099	14,801	14,746	14,939	15,934	17,892	19,283	19,579	19,615	19,580	19,457	19,259	19,150	19,011	19,065	19,251	19,536	19,815	20,286	19,884	18,970	17,667	16,306
Spring	3	19,534	3/11/2015	15,342	14,733	14,326	14,170	14,300	15,202	17,175	18,559	18,908	19,045	19,072	18,951	18,781	18,628	18,329	18,201	18,318	18,438	18,637	19,534	19,492	18,665	17,400	16,051
Spring	3	20,127	3/12/2015	15,120	14,600	14,304	14,262	14,439	15,444	17,443	18,833	19,246	19,446	19,557	19,460	19,146	19,012	18,832	18,734	18,787	18,990	19,248	20,127	20,074	19,340	18,028	16,723
Spring	3	19,789	3/13/2015	15,800	15,241	14,959	14,924	15,172	16,087	18,045	19,367	19,700	19,789	19,685	19,434	19,068	18,854	18,528	18,363	18,423	18,515	18,770	19,455	19,273	18,612	17,557	16,418
Spring	3	18,772	3/14/2015	15,363	14,735	14,373	14,194	14,179	14,475	15,233	16,119	17,097	17,978	18,525	18,688	18,574	18,334	18,054	17,920	17,992	18,212	18,433	18,772	18,411	17,616	16,924	15,949
Spring	3	19,419	3/15/2015	15,029	14,381	13,961	13,759	13,767	14,028	14,541	15,200	16,151	17,074	17,598	17,840	17,899	17,809	17,791	17,886	18,053	18,449	18,688	19,419	19,266	18,524	17,387	16,167
Spring	3	19,909	3/16/2015	15,325	14,816	14,519	14,456	14,723	15,688	17,697	18,963	19,287	19,509	19,565	19,436	19,209	19,033	18,753	18,522	18,569	18,791	19,097	19,909	19,713	18,792	17,457	15,981
Spring	3	20,268	3/17/2015	14,887	14,262	13,905	13,796	14,046	15,023	17,030	18,510	19,063	19,431	19,584	19,542	19,408	19,263	19,013	18,901	18,985	19,087	19,266	20,169	20,268	19,531	18,221	16,873
Spring	3	20,950	3/18/2015	15,975	15,491	15,220	15,163	15,417	16,407	18,362	19,554	20,037	20,271	20,352	20,279	20,071	19,942	19,737	19,729	19,835	20,040	20,171	20,950	20,883	20,007	18,696	17,344
Spring	3	20,295	3/19/2015	16,338	15,729	15,453	15,437	15,742	16,759	18,728	19,888	20,208	20,295	20,224	20,047	19,791	19,623	19,357	19,161	19,185	19,329	19,451	20,246	20,269	19,533	18,352	17,056
Spring	3	20,490	3/20/2015	15,982	15,423	15,105	14,997	15,209	16,121	17,957	19,291	19,935	20,285	20,490	20,475	20,322	20,280	20,185	20,133	20,086	20,069	20,020	20,385	20,197	19,403	18,376	17,217
Spring	3	18,639	3/21/2015	16,176	15,512	15,090	14,894	14,884	15,171	15,919	16,722	17,701	18,381	18,616	18,577	18,421	18,173	17,896	17,737	17,691	17,712	17,840	18,493	18,639	18,153	17,372	16,408
Spring	3	19,649	3/22/2015	15,537	14,949	14,599	14,463	14,503	14,783	15,369	15,916	16,738	17,336	17,720	17,814	17,815	17,651	17,472	17,401	17,580	17,953	18,382	19,444	19,649	18,968	17,896	16,798
Spring	3	20,914	3/23/2015	16,006	15,604	15,380	15,382	15,667	16,659	18,539	19,757	20,274	20,511	20,622	20,484	20,258	20,121	19,881	19,661	19,709	19,889	20,073	20,883	20,914	20,083	18,827	17,390
Spring	3	20,382	3/24/2015	16,381	15,876	15,626	15,564	15,839	16,819	18,739	19,977	20,332	20,382	20,333	20,194	19,942	19,712	19,359	19,136	19,104	19,189	19,296	20,043	20,238	19,442	18,072	16,766
Spring	3	20,365	3/25/2015	15,846	15,348	15,091	15,048	15,310	16,284	18,217	19,441	19,755	19,746	19,654	19,473	19,207	19,146	19,204	19,453	19,803	20,113	20,189	20,365	19,994	19,095	17,733	16,341
Spring	3	19,864	3/26/2015	15,327	14,758	14,421	14,284	14,499	15,337	17,308	18,530	19,027	19,341	19,546	19,625	19,617	19,536	19,412	19,351	19,487	19,618	19,594	19,864	19,589	18,675	17,318	16,015
Spring	3	19,680	3/27/2015	15,048	14,450	14,120	13,996	14,224	15,183	17,078	18,415	19,058	19,526	19,680	19,633	19,456	19,369	19,215	19,135	19,097	19,011	18,914	19,310	19,233	18,580	17,573	16,409
Spring	3	19,173	3/28/2015	15,500	14,961	14,628	14,460	14,482	14,806	15,590	16,429	17,453	18,204	18,695	18,762	18,620	18,369	18,121	17,944	17,921	18,084	18,316	18,914	19,173	18,758	17,951	17,008
Spring	3	18,596	3/29/2015	16,152	15,583	15,234	15,082	15,082	15,309	15,795	16,255	16,906	17,339	17,568	17,599	17,477	17,239	16,982	16,817	16,852	17,070	17,352	18,187	18,596	17,996	17,043	15,967
Spring	3	20,279	3/30/2015	15,116	14,640	14,382	14,310	14,555	15,491	17,272	18,672	19,461	19,966	20,279	20,234	19,918	19,606	19,345	19,275	19,308	19,351	19,304	19,697	19,826	18,961	17,682	16,314
Spring	3	19,820	3/31/2015	15,268	14,759	14,385	14,264	14,512	15,473	17,184	18,332	18,854	19,126	19,154	19,138	19,064	19,175	19,086	19,063	19,129	19,243	19,412	19,820	19,769	18,978	17,631	16,354
Spring	4	19,178	4/1/2015	15,345	14,818	14,550	14,501	14,752	15,689	17,337	18,513	18,975	19,139	19,113	18,951	18,709	18,522	18,307	18,151	18,145	18,191	18,220	18,823	19,178	18,570	17,374	16,060
Spring	4	18,842	4/2/2015	15,132	14,534	14,275	14,192	14,419	15,367	16,993	18,058	18,633	18,842	18,815	18,606	18,334	18,125	17,895	17,696	17,749	17,860	17,954	18,486	18,449	17,674	16,493	15,255
Spring	4	17,839	4/3/2015	14,187	13,525	13,124	12,950	13,048	13,697	14,859	15,930	16,885	17,489	17,783	17,839	17,687	17,566	17,382	17,288	17,252	17,297	17,228	17,476	17,395	16,792	15,870	14,829
Spring	4	17,567	4/4/2015	13,877	13,300	12,928	12,737	12,777	13,085	13,721	14,416	15,374	16,158	16,576	16,649	16,538	16,297	16,070	15,957	15,996	16,214	16,440	17,070	17,567	17,167	16,391	15,424
Spring	4	17,062	4/5/2015	14,568	13,890	13,507	13,293	13,310	13,610	14,037	14,533	15,216	15,783	16,092	16,152	16,065	15,881	15,758	15,652	15,640	15,678	15,896	16,644	17,062	16,656	15,763	14,771
Spring	4	18,482	4/6/2015	13,995	13,533	13,295	13,219	13,481	14,401	15,916	17,111	17,832	18,226	18,294	18,201	18,010	17,896	17,703	17,574	17,579	17,772	17,868	18,388	18,482	17,604	16,429	15,123
Spring	4	19,026	4/7/2015	14,130	13,529	13,198	13,086	13,304	14,248	15,799	17,022	17,858	18,349	18,596	18,617	18,545	18,487	18,365	18,270	18,397	18,669	18,744	19,026	18,894	18,067	16,815	15,484
Spring	4	19,521	4/8/2015	14,558	13,994	13,671	13,586	13,806	14,691	16,330	17,597	18,374	18,860	19,181	19,267	19,217	19,183	19,071	19,032	19,187	19,318	19,329	19,521	19,316	18,528	17,248	15,903
Spring	4	19,406	4/9/2015	14,941	14,372	14,025	13,877	14,078	14,939	16,512	17,771	18,594	19,038	19,281	19,277	19,173	19,092	18,920	18,775	18,827	18,992	19,124	19,406	19,282	18,448	17,138	15,829
Spring	4	19,020	4/10/2015	14,853	14,260	13,889	13,728	13,926	14,756	16,307	17,465	18,192	18,675	18,978	19,020	18,820	18,706	18,509	18,359	18,292	18,284	18,090	18,123	18,265	17,623	16,514	15,378
Spring	4	17,148	4/11/2015	14,441	13,763	13,332	13,134	13,137	13,473	14,021	14,729	15,583	16,207	16,538	16,605	16,494	16,266	16,022	15,862	15,866	15,928	16,039	16,515	17,148	16,795	16,069	15,156
Spring	4	16,966	4/12/2015	14,281	13,686	13,364	13,175	13,168	13,403	13,727	14,202	14,841	15,269	15,533	15,578	15,468	15,282	15,109	15,023	15,182	15,474	15,693	16,274	16,966	16,338	15,344	14,250
Spring	4	18,208	4/13/2015	13,369	12,886	12,656	12,604	12,859	13,910	15,686	16,930	17,525	17,766	17,809	17,766	17,673	17,679	17,605	17,560	17,566	17,567	17,432	17,864	18,208	17,343	15,972	14,528
Spring	4	18,116	4/14/2015	13,445	12,862	12,524	12,384	12,563	13,494	15,323	16,646	17,406	17,691	17,902	17,861	17,737	17,734	17,650	17,573	17,639	17,715	17,716	17,965	18,116	17,254	15,945	14,541
Spring	4	17,965	4/15/2015	13,464	12,912	12,633	12,561	12,797	13,797	15,436	16,688	17,197	17,422	17,552	17,522	17,411	17,410	17,330	17,302	17,357	17,386	17,247	17,524	17,965	17,194	15,884	14,499
Spring	4	17,892	4/16/2015	13,495	12,944	12,632	12,579	12,831	13,832	15,492	16,719	17,252	17,497	17,602	17,583	17,438	17,379	17,273	17,189	17,249	17,295	17,213	17,540	17,892	17,102	15,763	14,414
Spring	4	18,136	4/17/2015	13,438	12,854	12,557	12,404	12,552	13,443	15,229	16,591	17,341	17,831	18,114	18,136	18,036	17,925	17,692	17,540	17,526	17,371	17,100	17,184	17,504	16,889	15,824	14,552
Spring	4	16,471	4/18/2015	13,547	12,876	12,476	12,273	12,273	12,550	13,007	13,852	14,805	15,400	15,758	15,861	15,889	15,760	15,619	15,533	15,582	15,680	15,681	15,861	16,471	15,993	15,080	14,091
Spring	4	16,663	4/19/2015	13,227	12,597	12,200	12,000	11,981	12,171	12,381	13,015	13,814	14,471	14,853	14,984	15,010	14,924	14,801	14,784	14,961	15,245	15,522	16,142	16,663	16,023	14,958	13,819
Spring	4	18,858	4/20/2015	12,998	12,534	12,288	12,228	12,456	13,449	15,313	16,878	17,688	18,304	18,694	18,858	18,764	18,651	18,480	18,360	18,391	18,486	18,392	18,480	18,434	17,450	16,040	14,597
Spring	4	18,010	4/21/2015	13,624	13,087	12,712	12,589	12,815	13,702	15,354	16,754	17,513	17,912	18,001	17,953	17,824	17,772	17,624	17,562	17,596	17,636	17,432	17,605	18,010	17,239	15,953	14,540
Spring	4	18,397	4/22/2015	13,568	13,009	12,678	12,581	12,816	13,770	15,379	16,652	17,285	17,641	17,862	17,895	17,896	17,947	17,887	18,021	18,254	18,353	18,270	18,234	18,397	17,572	16,245	14,855
Spring	4	18,962	4/23/2015	13,900	13,358	13,060	12,979	13,242	14,212	15,838	17,126	17,759	18,142	18,336	18,417	18,348	18,283	18,187	18,106	18,274	18,490	18,482	18,667	18,962	18,151	16,761	15,417
Spring	4	18,675	4/24/2015	14,435	13,921	13,603	13,520	13,745	14,661	16,292	17,604	18,249	18,532	18,675	18,650	18,522	18,412	18,220	18,081	18,052	18,010	17,844	17,973	18,431	17,932	16,950	15,702
Spring	4	16,668	4/25/2015	14,669	14,043	13,718	13,553	13,584	13,884	14,329	15,094	15,857	16,273	16,389	16,287	16,081	15,808	15,534	15,368	15,375	15,535	15,649	15,939	16,668	16,393	15,605	14,648
Spring	4	17,014	4/26/2015	13,783	13,224	12,906	12,725	12,743	12,928	13,185	13,836	14,558	15,072	15,340	15,477	15,516	15,464	15,403	15,384	15,616	15,930	16,155	16,475	17,014	16,431	15,386	14,261
Spring	4	18,327	4/27/2015	13,392	12,906	12,581	12,517	12,859	13,838	15,458	16,807	17,548	17,870	17,912	17,987	17,977	17,943	17,877	17,783	17,826	17,939	17,899	18,089	18,327	17,534	16,150	14,771
Spring	4	17,910	4/28/2015	13,732	13,185	12,901	12,777	13,031	13,980	15,548	16,762	17,334	17,617	17,730	17,747	17,682	17,658	17,551	17,498	17,558	17,550	17,355	17,380	17,910	17,279	15,893	14,483
Spring	4	17,948	4/29/2015	13,500	12,935	12,614	12,526	12,744	13,617	15,132	16,513	17,123	17,521	17,728	17,873	17,877	17,911	17,879	17,891	17,948	17,875	17,546	17,432	17,916	17,166	15,767	14,317
Spring	4	17,831	4/30/2015	13,373	12,801	12,448	12,318	12,596	13,455	15,014	16,400	17,071	17,420	17,690	17,756	17,668	17,718	17,660	17,615	17,601	17,496	17,267	17,301	17,831	17,166	15,855	14,432
Spring	5	17,580	5/1/2015	13,449	12,836	12,538	12,430	12,626	13,461	15,012	16,397	17,033	17,349	17,580	17,575	17,449	17,416	17,309	17,169	17,090	16,961	16,745	16,771	17,193	16,731	15,667	14,442
Spring	5	16,216	5/2/2015	13,439	12,867	12,516	12,310	12,341	12,624	13,062	13,963	14,843	15,426	15,704	15,782	15,714	15,598	15,420	15,297	15,355	15,511	15,464	15,612	16,216	15,897	15,055	14,028
Spring	5	16,847	5/3/2015	13,209	12,675	12,291	12,059	12,040	12,154	12,345	13,041	13,882	14,498	14,978	15,246	15,429	15,447	15,455	15,533	15,706	15,932	16,023	16,171	16,847	16,319	15,199	13,986
Spring	5	19,209	5/4/2015	13,106	12,593	12,313	12,236	12,411	13,219	14,804	16,298	17,224	17,819	18,355	18,690	18,931	19,081	19,060	19,132	19,209	19,139	18,759	18,671	18,952	18,181	16,704	15,173
Spring	5	19,846	5/5/2015	14,092	13,371	12,952	12,812	12,958	13,733	15,248	16,846	17,761	18,389	18,934	19,192	19,320	19,515	19,695	19,811	19,846	19,609	19,116	18,900	19,085	18,310	16,850	15,328
Spring	5	18,612	5/6/2015	14,226	13,575	13,171	12,998	13,115	13,921	15,526	17,050	17,777	18,228	18,533	18,612	18,591	18,612	18,527	18,499	18,554	18,491	18,152	17,911	18,260	17,686	16,277	14,768
Spring	5	19,603	5/7/2015	13,688	13,022	12,688	12,548	12,714	13,501	14,978	16,490	17,368	18,051	18,551	18,890	19,052	19,250	19,362	19,472	19,603	19,473	18,961	18,579	18,810	18,208	16,722	15,177
Spring	5	20,708	5/8/2015	14,018	13,347	12,944	12,757	12,899	13,637	15,172	16,699	17,809	18,601	19,272	19,765	20,038	20,333	20,516	20,674	20,708	20,522	19,918	19,373	19,359	18,753	17,470	15,990
Spring	5	18,130	5/9/2015	14,750	13,930	13,426	13,150	13,055	13,198	13,539	14,516	15,695	16,533	17,043	17,328	17,478	17,572	17,705	17,839	17,945	17,959	17,922	17,850	18,130	17,802	16,827	15,674
Spring	5	19,286	5/10/2015	14,650	13,820	13,264	12,987	12,937	12,966	13,110	13,910	15,059	16,118	17,009	17,611	18,001	18,290	18,513	18,777	18,938	18,995	18,895	18,803	19,286	18,901	17,707	16,303
Spring	5	23,036	5/11/2015	15,125	14,477	14,075	13,892	14,057	14,899	16,580	18,363	19,491	20,417	21,252	21,854	22,214	22,667	22,862	23,029	23,036	22,872	22,250	21,612	21,564	20,817	19,138	17,396
Spring	5	22,379	5/12/2015	16,095	15,245	14,730	14,501	14,639	15,412	17,084	18,841	19,927	20,657	21,460	21,953	22,239	22,374	22,379	22,239	22,219	21,972	21,289	20,693	20,741	19,942	18,156	16,232
Spring	5	18,671	5/13/2015	14,869	14,041	13,529	13,283	13,336	14,020	15,478	16,924	17,758	18,217	18,495	18,592	18,667	18,671	18,643	18,604	18,585	18,435	18,009	17,773	17,981	17,493	16,156	14,704
Spring	5	18,354	5/14/2015	13,679	13,054	12,682	12,581	12,760	13,520	15,034	16,429	17,166	17,592	17,722	17,880	17,938	18,079	18,191	18,238	18,354	18,317	17,949	17,604	17,882	17,438	16,035	14,600
Spring	5	18,448	5/15/2015	13,557	12,956	12,600	12,457	12,641	13,400	14,922	16,353	17,151	17,652	18,052	18,239	18,276	18,437	18,442	18,448	18,437	18,190	17,734	17,495	17,704	17,235	16,157	14,924
Spring	5	17,576	5/16/2015	13,929	13,264	12,864	12,651	12,592	12,758	13,177	14,119	15,245	16,087	16,682	16,917	17,100	17,140	17,107	17,155	17,311	17,364	17,313	17,308	17,576	17,312	16,391	15,339
Spring	5	20,000	5/17/2015	14,372	13,650	13,194	12,916	12,828	12,826	13,024	13,878	15,116	16,216	17,075	17,815	18,360	18,726	19,001	19,334	19,753	20,000	19,888	19,568	19,788	19,465	18,080	16,675
Spring	5	20,418	5/18/2015	15,541	14,733	14,257	14,047	14,199	15,002	16,440	17,904	18,860	19,491	19,950	20,167	20,268	20,330	20,370	20,360	20,418	20,314	19,833	19,604	19,574	18,793	17,280	15,698
Spring	5	20,718	5/19/2015	14,613	13,896	13,489	13,306	13,437	14,237	15,823	17,402	18,338	18,850	19,324	19,612	19,700	19,844	20,145	20,511	20,713	20,718	20,182	19,570	19,522	18,926	17,535	16,004
Spring	5	18,351	5/20/2015	14,701	13,855	13,314	13,055	13,160	13,820	15,310	16,825	17,683	18,105	18,280	18,351	18,247	18,196	18,091	18,031	18,023	17,950	17,630	17,483	17,797	17,445	16,153	14,733
Spring	5	18,029	5/21/2015	13,717	13,076	12,722	12,604	12,787	13,530	15,040	16,490	17,180	17,684	17,921	18,029	17,964	17,970	17,921	17,851	17,849	17,801	17,588	17,498	17,742	17,270	16,019	14,625
Spring	5	18,182	5/22/2015	13,615	13,022	12,664	12,513	12,673	13,269	14,580	16,023	16,936	17,509	17,877	18,076	18,156	18,182	18,086	17,950	17,830	17,711	17,433	17,160	17,328	17,127	16,080	14,801
Spring	5	16,151	5/23/2015	13,777	13,109	12,724	12,537	12,500	12,535	12,936	13,740	14,649	15,270	15,614	15,707	15,618	15,498	15,364	15,395	15,529	15,750	15,818	15,760	16,088	16,151	15,362	14,361
Spring	5	16,537	5/24/2015	13,528	12,894	12,519	12,332	12,265	12,224	12,426	13,092	14,013	14,800	15,409	15,780	15,988	16,073	16,117	16,190	16,345	16,430	16,341	16,180	16,534	16,537	15,782	14,790
Spring	5	19,529	5/25/2015	13,885	13,242	12,860	12,594	12,585	12,684	12,993	13,753	14,795	15,891	16,775	17,580	18,126	18,456	18,709	19,043	19,314	19,529	19,434	19,254	19,483	19,224	17,915	16,483
Spring	5	24,285	5/26/2015	15,404	14,636	14,193	13,936	14,037	14,713	16,366	18,260	19,641	20,730	21,640	22,340	22,892	23,433	23,790	24,108	24,285	24,070	23,362	22,635	22,373	21,826	20,121	18,277
Spring	5	24,190	5/27/2015	16,892	15,994	15,415	15,113	15,200	15,873	17,587	19,434	20,637	21,477	22,264	22,800	23,046	23,537	23,871	24,094	24,190	23,881	22,968	22,178	21,922	21,226	19,552	17,794
Spring	5	23,754	5/28/2015	16,455	15,649	15,163	14,912	14,979	15,706	17,280	19,023	20,003	20,726	21,209	21,940	22,440	22,988	23,350	23,606	23,754	23,462	22,700	21,997	21,705	21,187	19,467	17,597
Spring	5	23,435	5/29/2015	16,133	15,193	14,611	14,280	14,341	14,862	16,362	18,086	19,347	20,264	21,016	21,608	22,084	22,538	22,908	23,293	23,435	23,017	22,025	21,182	20,837	20,473	19,278	17,777
Spring	5	22,447	5/30/2015	16,476	15,548	14,969	14,625	14,537	14,586	15,113	16,377	17,912	19,248	20,406	21,244	21,755	22,072	22,338	22,423	22,447	22,210	21,646	20,976	20,650	20,324	19,219	17,879
Spring	5	19,841	5/31/2015	16,671	15,724	15,088	14,639	14,376	14,260	14,423	15,138	16,332	17,499	18,444	19,200	19,667	19,841	19,813	19,754	19,508	19,515	19,361	19,215	19,193	18,484	17,165	15,634
Summer	6	19,071	6/1/2015	14,495	13,863	13,486	13,320	13,459	14,195	15,746	17,305	18,070	18,602	18,984	19,071	19,014	18,898	18,732	18,602	18,553	18,582	18,297	18,073	17,979	17,305	15,968	14,586
Summer	6	18,382	6/2/2015	13,606	13,014	12,639	12,490	12,660	13,394	14,911	16,460	17,354	17,896	18,241	18,382	18,339	18,307	18,173	18,093	18,128	18,142	17,942	17,697	17,711	17,314	15,970	14,552
Summer	6	18,600	6/3/2015	13,533	12,954	12,575	12,428	12,620	13,315	14,861	16,296	17,082	17,526	17,794	17,969	18,068	18,292	18,385	18,490	18,600	18,530	18,099	17,721	17,803	17,644	16,278	14,760
Summer	6	18,696	6/4/2015	13,677	13,015	12,629	12,452	12,603	13,210	14,729	16,246	17,151	17,729

Contains Proprietary Material
Do Not Distribute

Summer	6	26,231	6/12/2015	18,513	17,465	16,776	16,284	16,156	16,622	18,113	19,864	21,172	22,220	23,165	23,925	24,387	25,028	25,645	26,231	26,179	25,676	24,883	24,147	23,769	23,265	21,851	20,201
Summer	6	22,589	6/13/2015	18,742	17,831	17,156	16,628	16,366	16,245	16,665	17,793	19,053	20,018	20,631	21,100	21,390	21,600	21,838	22,143	22,467	22,589	22,236	21,515	20,938	20,776	19,707	18,314
Summer	6	22,719	6/14/2015	17,051	16,069	15,425	15,018	14,812	14,626	14,847	15,857	17,263	18,676	19,860	20,823	21,505	21,947	22,247	22,484	22,658	22,719	22,246	21,702	21,732	21,321	19,973	18,329
Summer	6	24,111	6/15/2015	17,116	16,284	15,778	15,547	15,698	16,517	18,107	19,895	21,079	21,897	22,508	23,006	23,531	23,930	24,111	24,017	23,734	23,298	22,558	21,865	21,463	20,961	19,465	17,750
Summer	6	23,396	6/16/2015	16,450	15,626	15,111	14,907	15,061	15,871	17,442	19,254	20,426	21,126	21,702	22,127	22,420	22,691	22,733	22,987	23,396	23,394	22,958	22,554	22,153	21,707	20,048	18,174
Summer	6	22,746	6/17/2015	16,702	15,733	15,099	14,739	14,766	15,230	16,822	18,682	19,974	20,856	21,520	22,035	22,328	22,630	22,746	22,625	22,365	21,849	21,086	20,515	20,322	20,048	18,671	17,096
Summer	6	21,701	6/18/2015	15,837	15,106	14,596	14,346	14,423	15,053	16,551	18,246	19,404	20,145	20,694	21,059	21,339	21,627	21,701	21,664	21,628	21,425	20,897	20,505	20,346	20,021	18,682	17,124
Summer	6	23,993	6/19/2015	15,854	15,143	14,676	14,477	14,573	15,257	16,831	18,607	19,842	20,868	21,688	22,494	23,012	23,396	23,608	23,821	23,993	23,681	22,858	22,001	21,408	21,106	19,937	18,371
Summer	6	18,735	6/20/2015	16,913	15,837	15,114	14,637	14,419	14,270	14,588	15,484	16,641	17,576	18,292	18,604	18,735	18,696	18,633	18,562	18,586	18,685	18,672	18,592	18,711	18,636	17,891	16,901
Summer	6	23,277	6/21/2015	15,922	15,246	14,800	14,550	14,426	14,394	14,616	15,453	16,682	17,954	19,186	20,261	21,172	21,791	22,180	22,594	23,126	23,277	22,728	22,196	21,912	21,962	20,839	19,274
Summer	6	26,544	6/22/2015	17,864	16,876	16,288	15,897	15,885	16,370	17,876	19,782	21,275	22,342	23,247	23,969	24,511	25,132	25,716	26,232	26,544	26,452	25,875	25,136	24,672	24,195	22,491	20,513
Summer	6	28,100	6/23/2015	18,963	17,916	17,334	17,017	17,023	17,650	19,391	21,418	23,251	24,529	25,470	26,474	27,213	27,623	27,987	28,100	27,890	27,726	26,793	25,863	24,981	24,234	22,542	20,639
Summer	6	24,895	6/24/2015	18,896	17,672	16,658	16,033	15,886	16,238	17,684	19,466	20,762	21,729	22,508	23,106	23,521	23,973	24,332	24,684	24,832	24,895	24,254	23,382	22,547	22,157	20,634	18,734
Summer	6	24,007	6/25/2015	17,231	16,211	15,500	15,097	15,051	15,440	16,889	18,720	20,156	21,252	22,115	22,789	23,279	23,731	23,934	24,007	23,856	23,319	22,483	21,901	21,673	21,363	20,124	18,548
Summer	6	23,412	6/26/2015	17,221	16,260	15,652	15,334	15,362	15,874	17,224	18,893	20,224	21,193	21,963	22,339	22,669	22,970	23,226	23,360	23,412	23,170	22,349	21,391	20,735	20,462	19,310	17,800
Summer	6	18,483	6/27/2015	16,514	15,605	15,004	14,612	14,451	14,402	14,771	15,668	16,856	17,658	18,191	18,475	18,483	18,310	18,097	17,872	17,707	17,655	17,549	17,461	17,480	17,152	16,269	15,296
Summer	6	17,787	6/28/2015	14,461	13,844	13,437	13,204	13,127	13,145	13,284	13,850	14,822	15,795	16,534	16,975	17,118	17,105	17,119	17,180	17,349	17,569	17,613	17,583	17,787	17,762	16,852	15,760
Summer	6	20,932	6/29/2015	14,824	14,090	13,606	13,390	13,499	14,049	15,409	17,048	18,367	19,284	19,926	20,319	20,543	20,795	20,904	20,856	20,865	20,932	20,571	20,104	19,780	19,643	18,389	16,839
Summer	6	22,663	6/30/2015	15,596	14,853	14,426	14,202	14,197	14,789	16,151	17,916	19,310	20,340	21,177	21,770	22,002	22,186	22,377	22,660	22,663	22,379	21,772	21,177	20,938	20,721	19,589	18,160
Summer	7	23,804	7/1/2015	16,891	16,027	15,541	15,283	15,304	15,874	17,161	18,690	19,956	20,971	21,849	22,471	22,809	23,260	23,606	23,778	23,804	23,664	22,984	22,262	21,746	21,525	20,149	18,493
Summer	7	22,337	7/2/2015	17,090	16,052	15,356	14,936	14,884	15,314	16,591	18,271	19,470	20,364	21,181	21,714	22,057	22,313	22,337	22,136	21,972	21,717	21,071	20,473	20,195	19,896	18,717	17,352
Summer	7	20,675	7/3/2015	16,108	15,179	14,519	14,107	13,947	13,996	14,541	15,620	16,746	17,752	18,535	19,062	19,430	19,745	20,061	20,435	20,675	20,585	20,138	19,525	19,172	19,034	18,112	16,956
Summer	7	18,211	7/4/2015	15,872	15,036	14,479	14,118	13,930	13,891	14,069	14,758	15,804	16,822	17,572	17,963	18,211	18,192	18,058	17,974	18,087	18,168	17,927	17,503	17,246	17,159	16,777	16,141
Summer	7	21,343	7/5/2015	15,281	14,584	14,057	13,744	13,582	13,440	13,566	14,354	15,567	16,691	17,785	18,706	19,403	19,949	20,348	20,764	21,148	21,343	21,123	20,670	20,539	20,580	19,517	18,130
Summer	7	25,621	7/6/2015	16,923	16,095	15,537	15,261	15,325	15,803	17,065	18,915	20,549	22,019	23,238	24,085	24,614	25,089	25,381	25,580	25,621	25,415	24,683	23,922	23,446	23,139	21,698	19,969
Summer	7	28,172	7/7/2015	18,563	17,683	17,136	16,843	16,974	17,651	19,086	21,006	22,626	23,979	25,154	26,127	26,871	27,642	28,023	28,043	28,172	27,882	27,070	26,232	25,652	25,164	23,422	21,433
Summer	7	26,609	7/8/2015	19,820	18,682	17,953	17,588	17,523	18,064	19,436	21,111	22,320	23,232	24,050	24,785	25,462	26,092	26,609	26,567	26,146	25,603	24,933	24,309	24,012	23,595	22,139	20,337
Summer	7	22,900	7/9/2015	18,834	17,785	17,114	16,565	16,456	16,926	18,037	19,574	20,610	21,271	21,701	22,044	22,253	22,481	22,513	22,624	22,900	22,857	22,253	21,692	21,529	21,057	19,883	18,562
Summer	7	24,406	7/10/2015	17,437	16,648	16,174	15,896	15,858	16,283	17,452	19,155	20,465	21,391	22,189	22,674	23,087	23,491	23,829	24,157	24,406	24,314	23,604	22,764	22,069	21,683	20,442	18,890
Summer	7	23,172	7/11/2015	17,542	16,522	15,829	15,339	15,120	15,003	15,330	16,405	17,807	19,188	20,355	21,167	21,757	22,119	22,434	22,793	23,092	23,172	22,879	22,183	21,652	21,465	20,481	19,160
Summer	7	23,904	7/12/2015	17,903	16,963	16,143	15,664	15,322	15,109	15,214	16,110	17,531	19,027	20,405	21,492	22,278	22,872	23,310	23,713	23,904	23,869	23,592	23,129	22,878	22,811	21,618	20,031
Summer	7	27,754	7/13/2015	18,648	17,678	17,059	16,744	16,749	17,299	18,562	20,485	22,146	23,643	24,805	25,711	26,447	27,045	27,430	27,638	27,754	27,462	26,490	25,448	24,677	24,171	22,533	20,667
Summer	7	25,453	7/14/2015	19,115	18,074	17,407	17,038	17,023	17,647	19,033	20,947	22,425	23,562	24,223	24,749	25,029	25,107	25,085	25,120	25,380	25,453	24,857	24,310	24,079	23,792	22,418	20,657
Summer	7	23,901	7/15/2015	19,250	18,248	17,552	17,163	17,112	17,671	19,059	20,712	21,839	22,736	23,301	23,508	23,527	23,596	23,625	23,729	23,901	23,707	22,940	22,142	21,618	21,151	19,685	17,980
Summer	7	22,715	7/16/2015	16,630	15,663	15,002	14,592	14,540	15,035	16,164	17,749	18,956	19,867	20,492	20,919	21,250	21,705	22,037	22,412	22,689	22,715	22,149	21,361	20,816	20,507	19,174	17,638
Summer	7	23,069	7/17/2015	16,378	15,565	14,909	14,627	14,690	15,234	16,421	18,124	19,464	20,593	21,453	22,002	22,390	22,748	22,915	23,010	23,069	22,853	22,089	21,277	20,997	20,766	19,771	18,450
Summer	7	24,465	7/18/2015	17,358	16,506	15,986	15,683	15,602	15,754	16,144	17,101	18,411	19,591	20,587	21,495	22,173	22,605	23,108	23,766	24,361	24,465	24,179	23,633	23,364	23,158	22,109	20,827
Summer	7	27,776	7/19/2015	19,556	18,598	17,872	17,371	17,088	16,891	16,973	18,035	19,809	21,644	23,480	24,852	25,865	26,574	27,160	27,606	27,776	27,687	27,249	26,653	26,495	26,295	24,962	23,353
Summer	7	30,575	7/20/2015	21,942	20,979	20,325	19,920	19,880	20,439	21,566	23,560	25,433	26,899	28,117	29,064	29,652	30,212	30,449	30,575	30,573	30,329	29,625	28,794	28,220	27,474	25,559	23,448
Summer	7	27,893	7/21/2015	21,655	20,427	19,609	19,135	19,093	19,705	20,945	22,502	23,829	24,820	25,761	26,304	26,704	26,983	27,281	27,668	27,893	27,588	26,718	25,749	24,893	24,331	22,717	20,735
Summer	7	24,949	7/22/2015	19,104	17,869	16,958	16,499	16,382	16,762	17,858	19,575	20,913	21,899	22,666	23,237	23,643	24,129	24,480	24,793	24,949	24,823	23,991	23,010	22,454	22,034	20,643	18,910
Summer	7	24,622	7/23/2015	17,525	16,569	15,857	15,496	15,465	15,978	17,195	18,966	20,338	21,380	22,168	22,759	23,137	23,565	23,998	24,380	24,622	24,525	23,809	22,920	22,272	21,853	20,432	18,680
Summer	7	24,579	7/24/2015	17,289	16,345	15,733	15,399	15,369	15,859	16,947	18,715	20,126	21,213	22,151	22,787	23,230	23,685	24,069	24,370	24,579	24,437	23,687	22,822	22,282	21,885	20,623	19,110
Summer	7	22,978	7/25/2015	17,746	16,742	16,029	15,550	15,331	15,333	15,614	16,676	18,073	19,366	20,448	21,214	21,750	22,110	22,440	22,749	22,978	22,967	22,568	21,933	21,774	21,619	20,700	19,497
Summer	7	24,389	7/26/2015	18,314	17,368	16,694	16,244	16,001	15,951	16,007	16,711	17,934	19,368	20,708	21,810	22,705	23,434	23,936	24,206	24,360	24,389	23,862	23,424	23,420	23,103	21,752	20,232
Summer	7	28,345	7/27/2015	18,901	18,017	17,423	17,098	17,160	17,887	19,037	20,720	22,241	23,602	24,698	25,622	26,406	27,154	27,711	28,106	28,345	28,276	27,555	26,649	26,042	25,460	23,726	21,760
Summer	7	30,434	7/28/2015	20,143	19,034	18,285	17,813	17,765	18,380	19,645	21,638	23,515	25,164	26,621	27,746	28,524	29,215	29,742	30,148	30,434	30,278	29,510	28,442	27,741	27,077	25,258	23,174
Summer	7	31,138	7/29/2015	21,427	20,162	19,264	18,721	18,622	19,144	20,312	22,279	24,149	25,870	27,446	28,617	29,451	30,211	30,687	30,938	31,138	30,975	30,354	29,427	28,851	28,245	26,387	24,267
Summer	7	28,775	7/30/2015	22,465	21,222	20,389	19,934	19,906	20,510	21,763	23,507	24,969	26,030	26,908	27,686	28,307	28,722	28,775	28,435	28,035	27,532	26,886	26,131	25,682	25,224	23,679	21,879
Summer	7	27,615	7/31/2015	20,324	19,228	18,417	17,863	17,689	18,033	19,022	20,802	22,411	23,711	24,823	25,626	26,210	26,774	27,175	27,497	27,615	27,371	26,468	25,350	24,549	23,935	22,526	20,894
Summer	8	24,132	8/1/2015	19,452	18,358	17,554	17,033	16,778	16,771	16,946	18,018	19,623	21,130	22,305	22,994	23,543	23,730	23,880	24,044	24,132	24,034	23,565	22,843	22,465	22,106	20,959	19,550
Summer	8	24,325	8/2/2015	18,278	17,302	16,564	16,039	15,703	15,535	15,494	16,421	17,877	19,320	20,658	21,605	22,316	22,840	23,228	23,678	24,107	24,325	24,028	23,448	23,438	23,242	22,185	20,654
Summer	8	28,275	8/3/2015	19,395	18,419	17,758	17,432	17,440	18,039	19,231	21,058	22,714	24,032	25,138	25,968	26,658	27,369	27,851	28,119	28,275	27,957	27,046	26,177	25,789	25,188	23,519	21,703
Summer	8	27,615	8/4/2015	20,199	19,198	18,545	18,219	17,811	18,155	19,231	20,714	22,064	23,436	24,716	25,664	26,354	26,994	27,356	27,533	27,615	27,289	26,398	25,371	24,885	24,127	22,388	20,524
Summer	8	25,757	8/5/2015	19,066	17,966	17,202	16,832	16,736	17,255	18,364	19,965	21,273	22,411	23,415	24,147	24,663	25,109	25,419	25,656	25,757	25,405	24,504	23,639	23,211	22,673	21,134	19,395
Summer	8	24,049	8/6/2015	17,921	16,881	16,190	15,755	15,730	16,244	17,298	18,926	20,237	21,291	22,071	22,622	22,952	23,376	23,748	24,013	24,049	23,738	22,971	22,308	22,222	21,708	20,394	18,875
Summer	8	24,098	8/7/2015	17,592	16,677	16,056	15,636	15,611	16,151	17,135	18,750	20,155	21,306	22,178	22,793	23,160	23,519	23,734	23,957	24,098	23,931	23,152	22,244	21,809	21,207	19,937	18,465
Summer	8	20,977	8/8/2015	17,221	16,240	15,589	15,162	14,995	15,079	15,321	16,261	17,522	18,674	19,580	20,141	20,412	20,591	20,806	20,945	20,977	20,761	20,330	19,942	20,071	19,843	18,932	17,859
Summer	8	21,862	8/9/2015	16,921	16,114	15,454	15,023	14,804	14,789	14,813	15,612	16,873	17,929	18,919	19,693	20,263	20,675	21,019	21,275	21,640	21,862	21,637	21,055	21,102	20,825	19,653	18,273
Summer	8	25,010	8/10/2015	17,148	16,354	15,865	15,638	15,759	16,469	17,612	19,337	20,818	22,053	23,015	23,753	24,268	24,751	24,992	25,010	24,793	24,351	23,578	23,003	22,913	22,192	20,843	19,391
Summer	8	24,598	8/11/2015	18,180	17,332	16,821	16,582	16,710	17,473	18,858	20,263	21,337	22,141	22,734	23,085	23,339	23,695	23,927	24,301	24,598	24,494	23,972	23,335	23,100	22,453	21,034	19,433
Summer	8	24,960	8/12/2015	18,019	17,012	16,347	16,014	15,978	16,575	17,740	19,383	20,740	21,766	22,630	23,279	23,675	24,119	24,496	24,767	24,960	24,761	23,909	23,054	22,841	22,151	20,659	18,958
Summer	8	24,374	8/13/2015	17,524	16,522	15,850	15,455	15,436	16,027	17,119	18,768	20,149	21,224	22,063	22,671	23,126	23,553	23,872	24,178	24,374	24,262	23,550	22,631	22,455	21,784	20,359	18,706
Summer	8	25,722	8/14/2015	17,390	16,500	15,859	15,495	15,455	16,028	17,146	18,756	20,340	21,588	22,525	23,311	24,014	24,699	25,214	25,560	25,722	25,386	24,506	23,570	23,355	22,668	21,361	19,928
Summer	8	25,348	8/15/2015	18,584	17,565	16,873	16,390	16,152	16,186	16,380	17,416	18,943	20,483	21,908	23,026	23,865	24,472	24,864	25,216	25,348	25,157	24,573	23,791	23,689	23,127	22,013	20,633
Summer	8	25,910	8/16/2015	19,344	18,325	17,562	17,056	16,702	16,633	16,602	17,343	18,874	20,395	21,893	23,256	24,356	25,058	25,434	25,568	25,797	25,910	25,579	24,943	25,040	24,422	23,024	21,380
Summer	8	30,543	8/17/2015	20,047	19,083	18,392	18,006	18,001	18,640	19,771	21,550	23,263	24,967	26,555	27,874	28,941	29,758	30,171	30,382	30,543	30,408	29,558	28,526	28,192	27,047	25,090	23,013
Summer	8	29,569	8/18/2015	21,303	20,146	19,320	18,827	18,775	19,397	20,535	22,236	23,886	25,333	26,807	28,084	28,830	29,381	29,569	29,536	29,354	29,075	28,174	27,298	27,066	26,082	24,277	22,419
Summer	8	29,550	8/19/2015	20,864	19,829	19,112	18,763	18,747	19,433	20,758	22,443	24,142	25,572	26,831	27,784	28,467	29,038	29,371	29,550	29,417	29,038	28,259	27,482	27,382	26,473	24,816	22,911
Summer	8	28,651	8/20/2015	21,428	20,367	19,664	19,289	19,294	20,026	21,273	22,931	24,559	26,003	27,092	27,878	28,276	28,581	28,651	28,557	28,382	27,780	26,823	26,281	26,053	25,248	23,722	21,992
Summer	8	25,483	8/21/2015	20,554	19,449	18,694	18,251	18,164	18,694	19,721	20,866	21,935	22,662	23,389	23,995	24,348	24,739	25,071	25,316	25,483	25,315	24,507	23,683	23,461	22,589	21,160	19,594
Summer	8	22,004	8/22/2015	18,204	17,186	16,476	15,927	15,617	15,631	15,762	16,471	17,834	18,983	19,856	20,498	20,976	21,279	21,591	21,832	21,990	22,004	21,586	20,930	20,932	20,274	19,213	18,020
Summer	8	22,867	8/23/2015	16,962	16,168	15,594	15,254	15,117	15,187	15,240	15,944	17,070	18,284	19,368	20,268	20,996	21,610	21,955	22,239	22,613	22,867	22,644	22,290	22,605	21,972	20,782	19,465
Summer	8	26,483	8/24/2015	18,290	17,491	16,939	16,693	16,794	17,514	18,783	20,318	21,796	22,980	23,957	24,825	25,366	25,903	26,222	26,451	26,483	26,230	25,313	24,584	24,564	23,598	22,024	20,228
Summer	8	27,036	8/25/2015	18,850	17,985	17,363	17,111	17,179	17,941	19,245	20,704	22,159	23,338	24,435	25,206	25,865	26,460	26,848	27,026	27,036	26,747	25,789	25,062	24,754	23,558	21,700	19,726
Summer	8	23,823	8/26/2015	18,162	17,092	16,360	15,918	15,873	16,475	17,576	18,993	20,261	21,261	22,023	22,553	22,990	23,450	23,758	23,823	23,794	23,475	22,702	22,181	22,146	21,222	19,767	18,235
Summer	8	22,374	8/27/2015	17,003	16,169	15,592	15,295	15,309	15,938	17,050	18,453	19,780	20,732	21,426	21,890	22,103	22,160	22,299	22,374	22,368	22,291	21,647	21,136	21,159	20,288	18,880	17,449
Summer	8	22,692	8/28/2015	16,203	15,383	14,847	14,587	14,613	15,231	16,361	17,741	19,012	20,069	20,848	21,360	21,652	22,008	22,279	22,520	22,692	22,480	21,761	21,141	21,035	20,190	18,976	17,625
Summer	8	21,578	8/29/2015	16,348	15,469	14,901	14,560	14,412	14,553	14,861	15,661	17,006	18,248	19,242	19,975	20,416	20,700	20,998	21,313	21,578	21,556	21,088	20,739	20,902	20,240	19,268	18,190
Summer	8	23,452	8/30/2015	17,103	16,246	15,689	15,282	15,077	15,119	15,224	15,814	17,117	18,446	19,736	20,912	21,855	22,552	23,100	23,385	23,452	23,441	23,156	23,129	23,430	22,707	21,525	20,059
Summer	8	28,661	8/31/2015	18,811	17,918	17,400	17,097	17,167	17,995	19,299	20,823	22,397	23,702	24,878	25,842	26,597	27,384	28,060	28,433	28,661	28,426	27,582	27,035	26,879	25,681	23,847	21,904
Fall	9	28,425	9/1/2015	20,324	19,189	18,396	17,925	17,879	18,497	19,828	21,282	22,711	23,975	25,153	26,070	26,776	27,398	27,853	28,205	28,425	28,136	27,104	26,349	26,067	24,727	22,898	20,971
Fall	9	28,978	9/2/2015	19,455	18,383	17,706	17,301	17,318	18,071	19,472	20,917	22,329	23,724	25,027	26,215	27,176	27,968	28,630	28,978	28,961	28,479	27,439	26,854	26,646	25,384	23,567	21,697
Fall	9	29,420	9/3/2015	20,134	19,098	18,377	17,947	17,904	18,593	20,048	21,509	22,921	24,212	25,471	26,582	27,564	28,516	29,176	29,401	29,420	29,082	28,065	27,559	27,255	25,961	24,041	22,080
Fall	9	26,616	9/4/2015	20,508	19,398	18,662	18,151	18,106	18,742	20,024	21,379	22,867	24,133	24,999	25,517	25,772	26,085	26,373	26,590	26,616	26,276	25,217	24,445	23,969	22,818	21,337	19,693
Fall	9	22,888	9/5/2015	18,333	17,335	16,575	16,067	15,828	15,882	16,104	16,822	18,095	19,334	20,320	21,021	21,595	22,015	22,395	22,701	22,888	22,826	22,198	21,681	21,537	20,695	19,525	18,205
Fall	9	22,713	9/6/2015	17,042	16,139	15,525	15,108	14,886	14,888	14,966	15,523	16,834	18,168	19,354	20,378	21,236	21,848	22,256	22,533	22,713	22,589	21,979	21,621	21,539	20,830	19,768	18,559
Fall	9	26,257	9/7/2015	17,476	16,641	16,088	15,740	15,622	15,786	16,036	16,762	18,246	19,843	21,345	22,627	23,655	24,485	25,173	25,778	26,209	26,257	25,765	25,685	25,777	24,675	22,948	21,163
Fall	9	31,058	9/8/2015	19,807	18,847	18,170	17,814	17,819	18,603	20,283	21,801	23,459	25,039	26,526	27,987	29,214	30,173	30,734	31,010	31,058	30,744	29,753	29,370	28,902	27,396	25,141	22,926
Fall	9	29,426	9/9/2015	21,264	20,061	19,326	18,900	18,902	19,794	21,606	23,095	24,421	25,807	26,926	27,880	28,554	29,119	29,325	29,426	29,139	28,604	27,647	27,388	27,166	25,911	23,974	22,051
Fall	9	23,969	9/10/2015	20,459	19,341	18,527	18,134	18,082	18,748	20,374	21,553	22,386	23,056	23,506	23,734	23,795	23,923	23,874	23,928	23,969	23,830	23,362	23,330	23,044	21,980	20,452	18,785
Fall	9	23,351	9/11/2015	17,489	16,567	15,938	15,586	15,613	16,372	18,010	19,205	20,111	20,836	21,386	21,746	22,024	22,464	22,815	23,108	23,351	23,169	22,392	22,137	21,724	20,781	19,509	18,141
Fall	9	20,384	9/12/2015	16,927	16,013	15,417	15,075	14,944	15,131	15,575	16,353	17,666	18,860	19,608	20,024	20,237	20,314	20,265	20,115	20,019	20,114	20,191	20,384	20,115	19,505	18,551	17,433
Fall	9	19,850	9/13/2015	16,419	15,666	15,166	14,823	14,685	14,737	14,972	15,420	16,406	17,498

Contains Proprietary Material
Do Not Distribute

Fall	9	19,855	9/21/2015	14,418	13,804	13,428	13,269	13,438	14,333	16,059	17,190	17,998	18,593	19,036	19,263	19,442	19,626	19,609	19,558	19,622	19,614	19,491	19,855	19,348	18,263	16,893	15,480
Fall	9	19,802	9/22/2015	14,399	13,691	13,360	13,195	13,384	14,246	16,119	17,357	18,097	18,666	19,086	19,351	19,496	19,636	19,703	19,766	19,802	19,704	19,372	19,725	19,244	18,182	16,852	15,498
Fall	9	20,482	9/23/2015	14,540	13,852	13,446	13,280	13,426	14,199	15,633	16,752	17,627	18,285	18,799	19,115	19,419	19,809	20,045	20,249	20,482	20,362	19,899	20,111	19,610	18,489	17,015	15,641
Fall	9	21,303	9/24/2015	14,649	14,004	13,587	13,349	13,489	14,292	15,933	17,110	18,054	18,777	19,394	19,856	20,197	20,586	20,844	21,102	21,303	21,132	20,580	20,872	20,324	19,208	17,744	16,285
Fall	9	20,140	9/25/2015	15,158	14,417	13,944	13,732	13,839	14,618	16,297	17,473	18,313	18,924	19,405	19,706	19,871	20,078	20,140	20,128	20,002	19,661	19,312	19,508	18,967	18,080	16,880	15,632
Fall	9	17,717	9/26/2015	14,588	13,902	13,454	13,217	13,147	13,388	13,948	14,577	15,593	16,366	16,790	16,966	17,027	17,025	17,018	17,013	17,064	17,105	17,192	17,717	17,405	16,728	15,815	14,845
Fall	9	18,255	9/27/2015	14,021	13,396	12,970	12,758	12,703	12,851	13,164	13,475	14,421	15,184	15,711	16,053	16,271	16,442	16,602	16,773	17,058	17,391	17,643	18,255	17,927	17,043	15,973	14,959
Fall	9	21,354	9/28/2015	14,112	13,585	13,345	13,266	13,481	14,418	16,311	17,667	18,503	19,174	19,646	20,020	20,221	20,430	20,627	20,894	21,072	21,038	20,931	21,354	20,678	19,577	18,185	16,824
Fall	9	22,937	9/29/2015	15,742	15,091	14,736	14,546	14,724	15,626	17,709	19,138	20,158	20,998	21,701	22,236	22,641	22,937	22,843	22,772	22,767	22,758	22,707	22,811	22,125	21,024	19,462	17,882
Fall	9	22,116	9/30/2015	16,700	16,039	15,604	15,292	15,418	16,385	18,377	19,925	20,804	21,490	21,967	22,116	22,065	21,908	21,213	20,724	20,613	20,400	20,191	20,332	19,545	18,357	16,897	15,424
Fall	10	18,899	10/1/2015	14,355	13,711	13,238	12,969	13,088	13,917	15,715	16,925	17,529	17,927	18,177	18,218	18,167	18,151	18,091	18,069	18,132	18,296	18,576	18,899	18,371	17,346	16,042	14,761
Fall	10	18,581	10/2/2015	13,791	13,147	12,791	12,618	12,775	13,633	15,428	16,702	17,380	17,818	18,071	18,130	18,060	18,106	18,033	17,998	18,109	18,236	18,451	18,581	18,041	17,224	16,147	14,964
Fall	10	17,538	10/3/2015	13,905	13,255	12,899	12,703	12,717	13,035	13,684	14,404	15,461	16,268	16,752	16,905	16,909	16,763	16,653	16,589	16,676	16,899	17,302	17,538	17,164	16,594	15,735	14,730
Fall	10	17,444	10/4/2015	13,852	13,198	12,786	12,542	12,493	12,700	13,115	13,553	14,453	15,190	15,576	15,676	15,610	15,526	15,462	15,563	15,766	16,116	16,683	17,444	17,072	16,294	15,220	14,182
Fall	10	18,959	10/5/2015	13,350	12,849	12,591	12,529	12,754	13,684	15,528	16,810	17,392	17,733	17,907	17,966	17,947	17,971	17,904	17,854	17,932	18,090	18,419	18,959	18,431	17,404	16,040	14,702
Fall	10	19,179	10/6/2015	13,696	13,147	12,789	12,645	12,861	13,719	15,556	16,769	17,313	17,671	17,889	17,951	18,023	18,125	18,176	18,273	18,478	18,607	18,873	19,179	18,578	17,538	16,170	14,813
Fall	10	19,323	10/7/2015	13,822	13,197	12,835	12,677	12,830	13,679	15,536	16,760	17,404	17,816	18,043	18,233	18,327	18,474	18,545	18,667	18,790	18,858	19,043	19,323	18,663	17,625	16,251	14,899
Fall	10	19,113	10/8/2015	13,869	13,270	12,885	12,744	12,909	13,817	15,717	16,962	17,543	17,939	18,171	18,256	18,310	18,402	18,382	18,359	18,464	18,470	18,759	19,113	18,524	17,538	16,225	14,853
Fall	10	19,457	10/9/2015	13,866	13,308	12,972	12,854	13,030	13,894	15,725	17,134	18,008	18,603	18,989	19,211	19,256	19,326	19,386	19,364	19,407	19,439	19,457	19,206	18,527	17,667	16,562	15,273
Fall	10	17,043	10/10/2015	14,125	13,404	12,923	12,612	12,563	12,835	13,464	14,127	14,998	15,592	15,858	15,889	15,779	15,634	15,515	15,463	15,642	15,913	16,544	17,043	16,728	16,136	15,335	14,458
Fall	10	17,217	10/11/2015	13,607	12,979	12,551	12,338	12,299	12,494	12,967	13,459	14,235	14,867	15,217	15,357	15,409	15,396	15,403	15,487	15,767	16,106	16,699	17,217	16,830	16,144	15,260	14,280
Fall	10	19,162	10/12/2015	13,420	12,857	12,530	12,406	12,567	13,300	14,585	15,710	16,744	17,439	17,828	18,057	18,206	18,296	18,381	18,448	18,600	18,637	18,923	19,162	18,447	17,435	16,097	14,773
Fall	10	19,571	10/13/2015	13,715	13,102	12,784	12,658	12,838	13,784	15,716	17,105	17,754	18,281	18,698	18,921	19,022	19,054	18,877	18,922	18,936	19,027	19,422	19,571	18,830	17,792	16,393	14,968
Fall	10	18,987	10/14/2015	13,835	13,250	12,873	12,695	12,834	13,662	15,553	16,897	17,482	17,897	18,096	18,177	18,203	18,272	18,255	18,232	18,300	18,390	18,821	18,987	18,350	17,323	15,999	14,614
Fall	10	18,796	10/15/2015	13,607	13,053	12,722	12,603	12,781	13,726	15,644	16,910	17,454	17,766	17,935	17,922	17,847	17,862	17,805	17,817	17,946	18,100	18,627	18,796	18,242	17,256	15,985	14,707
Fall	10	18,206	10/16/2015	13,666	13,059	12,704	12,587	12,782	13,642	15,541	16,843	17,390	17,687	17,889	17,925	17,821	17,764	17,654	17,600	17,675	17,788	18,206	18,201	17,701	16,949	15,880	14,713
Fall	10	17,592	10/17/2015	13,783	13,199	12,835	12,634	12,641	12,975	13,689	14,432	15,361	15,987	16,266	16,281	16,192	16,026	15,902	15,895	16,088	16,468	17,300	17,592	17,212	16,655	15,863	14,895
Fall	10	18,340	10/18/2015	14,043	13,513	13,130	12,925	12,920	13,174	13,684	14,258	15,078	15,723	16,030	16,244	16,345	16,331	16,229	16,264	16,515	16,994	17,983	18,340	17,986	17,211	16,174	15,082
Fall	10	19,695	10/19/2015	14,229	13,757	13,523	13,473	13,763	14,797	16,767	18,047	18,484	18,697	18,770	18,599	18,345	18,261	18,094	18,058	18,238	18,635	19,505	19,695	19,093	18,098	16,709	15,330
Fall	10	19,191	10/20/2015	14,314	13,728	13,366	13,231	13,404	14,312	16,209	17,527	17,985	18,174	18,317	18,241	18,142	18,111	18,060	18,088	18,278	18,556	19,191	19,163	18,477	17,464	16,174	14,828
Fall	10	19,145	10/21/2015	13,733	13,192	12,831	12,721	12,916	13,757	15,662	17,068	17,520	17,882	18,123	18,274	18,323	18,383	18,336	18,338	18,384	18,535	19,145	19,112	18,482	17,477	16,181	14,882
Fall	10	19,278	10/22/2015	13,812	13,207	12,856	12,754	12,911	13,756	15,665	17,036	17,606	17,987	18,224	18,343	18,448	18,533	18,505	18,474	18,584	18,714	19,278	19,213	18,580	17,595	16,297	14,955
Fall	10	18,361	10/23/2015	13,959	13,302	12,929	12,775	12,931	13,749	15,635	16,945	17,488	17,803	17,916	17,867	17,744	17,650	17,549	17,426	17,499	17,701	18,356	18,361	17,859	17,171	16,193	15,064
Fall	10	17,579	10/24/2015	14,134	13,532	13,149	12,990	13,016	13,377	14,082	14,891	15,717	16,312	16,602	16,658	16,592	16,476	16,367	16,315	16,440	16,898	17,579	17,477	17,034	16,481	15,697	14,747
Fall	10	17,587	10/25/2015	13,914	13,328	12,902	12,623	12,538	12,720	13,172	13,781	14,635	15,500	15,999	16,265	16,311	16,208	16,043	16,010	16,168	16,530	17,454	17,587	17,136	16,345	15,326	14,237
Fall	10	19,273	10/26/2015	13,413	12,966	12,700	12,660	12,934	13,979	15,977	17,412	17,858	18,096	18,148	18,056	17,918	17,858	17,769	17,736	17,883	18,288	19,218	19,273	18,679	17,744	16,418	15,102
Fall	10	19,298	10/27/2015	14,148	13,651	13,332	13,255	13,526	14,516	16,505	17,896	18,207	18,343	18,349	18,237	18,086	17,997	17,851	17,809	17,989	18,399	19,298	19,247	18,638	17,697	16,432	15,146
Fall	10	20,088	10/28/2015	14,185	13,596	13,229	13,098	13,282	14,208	16,139	17,646	18,205	18,618	18,878	19,018	19,028	19,030	18,942	19,020	19,372	19,803	20,088	19,706	19,018	18,022	16,698	15,331
Fall	10	19,185	10/29/2015	14,315	13,687	13,306	13,145	13,255	14,093	16,039	17,475	17,973	18,327	18,528	18,668	18,535	18,492	18,316	18,189	18,270	18,592	19,185	18,979	18,394	17,509	16,231	14,907
Fall	10	18,425	10/30/2015	13,912	13,333	12,950	12,799	12,955	13,861	15,733	17,216	17,601	17,834	17,927	17,978	17,786	17,706	17,555	17,460	17,489	17,772	18,425	18,336	17,839	17,174	16,181	15,050
Fall	10	17,137	10/31/2015	14,106	13,511	13,156	12,972	13,002	13,342	14,122	14,938	15,720	16,286	16,512	16,486	16,280	16,085	15,930	15,880	16,077	16,424	17,137	17,005	16,711	16,235	15,481	14,611
Fall	11	17,969	11/1/2015	13,498	12,837	12,617	12,516	12,534	12,816	13,352	14,016	14,984	15,626	15,953	16,093	16,088	16,011	16,001	16,126	16,638	17,944	17,969	17,570	16,992	16,023	15,072	14,110
Fall	11	19,568	11/2/2015	13,421	12,891	12,623	12,591	12,901	13,972	15,888	16,957	17,503	17,835	18,038	18,084	17,981	17,933	17,877	17,902	18,420	19,568	19,491	18,975	18,224	17,211	15,904	14,653
Fall	11	19,615	11/3/2015	13,765	13,259	12,981	12,902	13,195	14,195	15,841	16,872	17,406	17,705	17,932	18,021	18,036	18,124	18,151	18,202	18,534	19,615	19,507	18,911	18,162	17,096	15,816	14,571
Fall	11	19,579	11/4/2015	13,611	13,077	12,794	12,705	12,962	13,934	15,769	16,876	17,444	17,746	18,009	18,123	18,120	18,202	18,200	18,212	18,535	19,579	19,486	18,923	18,216	17,165	15,844	14,578
Fall	11	20,065	11/5/2015	13,663	13,128	12,822	12,720	12,945	13,884	15,709	16,996	17,677	18,160	18,490	18,544	18,580	18,651	18,689	18,741	19,197	20,065	19,842	19,319	18,605	17,629	16,279	15,010
Fall	11	20,071	11/6/2015	14,006	13,403	13,084	12,965	13,167	14,122	15,949	17,368	18,277	18,819	19,087	19,254	19,258	19,209	19,091	19,043	19,337	20,071	19,662	19,026	18,303	17,472	16,394	15,191
Fall	11	17,872	11/7/2015	14,190	13,523	13,109	12,861	12,817	13,098	13,678	14,502	15,516	16,140	16,519	16,638	16,593	16,487	16,382	16,443	17,008	17,872	17,766	17,354	16,907	16,323	15,528	14,621
Fall	11	18,094	11/8/2015	13,785	13,215	12,851	12,647	12,645	12,906	13,326	13,843	14,646	15,190	15,499	15,706	15,754	15,734	15,730	15,902	16,586	17,963	18,094	17,810	17,358	16,536	15,539	14,523
Fall	11	19,805	11/9/2015	13,803	13,362	13,118	13,075	13,413	14,458	16,322	17,425	17,859	18,077	18,102	17,987	17,852	17,844	17,796	17,895	18,594	19,805	19,718	19,300	18,616	17,649	16,340	14,968
Fall	11	20,106	11/10/2015	13,937	13,433	13,100	13,023	13,278	14,232	16,097	17,337	17,983	18,431	18,661	18,750	18,674	18,637	18,583	18,777	19,394	20,106	19,772	19,222	18,464	17,486	16,254	15,030
Fall	11	19,783	11/11/2015	14,072	13,471	13,119	12,995	13,190	13,979	15,235	16,469	17,445	17,987	18,273	18,344	18,279	18,241	18,183	18,240	18,868	19,783	19,617	19,116	18,419	17,482	16,220	14,948
Fall	11	20,173	11/12/2015	13,913	13,358	13,001	12,906	13,160	14,156	15,999	17,352	17,981	18,407	18,681	18,733	18,684	18,743	18,691	18,786	19,390	20,173	19,933	19,348	18,626	17,603	16,346	15,032
Fall	11	19,553	11/13/2015	13,993	13,409	13,019	12,916	13,123	14,031	15,821	17,026	17,602	17,925	18,155	18,192	18,110	18,068	17,970	18,027	18,646	19,553	19,374	18,837	18,204	17,395	16,366	15,180
Fall	11	18,449	11/14/2015	14,265	13,695	13,321	13,139	13,182	13,567	14,224	14,930	15,819	16,474	16,795	16,849	16,779	16,671	16,618	16,700	17,340	18,449	18,373	18,000	17,552	16,862	16,033	15,100
Fall	11	18,177	11/15/2015	14,281	13,736	13,371	13,174	13,177	13,418	13,827	14,280	14,948	15,428	15,677	15,804	15,804	15,767	15,804	15,932	16,711	18,094	18,177	17,807	17,325	16,531	15,458	14,312
Fall	11	19,730	11/16/2015	13,542	13,082	12,854	12,846	13,141	14,139	16,026	17,100	17,557	17,786	17,868	17,854	17,873	17,876	17,859	17,909	18,544	19,730	19,594	19,158	18,517	17,570	16,301	14,962
Fall	11	20,221	11/17/2015	14,052	13,520	13,270	13,242	13,542	14,629	16,598	17,668	18,078	18,186	18,181	18,111	17,981	17,955	17,940	18,085	18,941	20,221	20,112	19,687	19,050	18,076	16,731	15,347
Fall	11	20,098	11/18/2015	14,397	13,852	13,538	13,433	13,681	14,638	16,561	17,721	18,148	18,291	18,283	18,235	18,143	18,187	18,184	18,376	19,244	20,098	19,844	19,317	18,635	17,632	16,310	14,938
Fall	11	20,061	11/19/2015	13,940	13,383	13,066	12,957	13,152	14,060	15,935	17,202	17,800	18,202	18,444	18,531	18,565	18,564	18,535	18,653	19,319	20,061	19,801	19,299	18,611	17,559	16,341	15,018
Fall	11	19,423	11/20/2015	14,034	13,431	13,058	12,922	13,109	13,988	15,825	16,932	17,475	17,775	17,836	17,792	17,701	17,667	17,645	17,705	18,345	19,423	19,171	18,640	18,104	17,353	16,320	15,217
Fall	11	18,314	11/21/2015	14,305	13,713	13,385	13,211	13,285	13,693	14,379	15,101	15,934	16,430	16,641	16,609	16,491	16,334	16,290	16,407	17,232	18,314	18,222	17,810	17,325	16,653	15,796	14,823
Fall	11	18,819	11/22/2015	14,010	13,443	13,041	12,813	12,814	13,029	13,517	14,040	14,876	15,550	16,010	16,303	16,475	16,576	16,659	16,931	17,847	18,819	18,769	18,467	17,974	17,172	16,063	14,983
Fall	11	20,993	11/23/2015	14,194	13,755	13,547	13,528	13,852	14,916	16,854	18,041	18,532	18,758	18,828	18,828	18,731	18,706	18,715	18,900	19,807	20,993	20,913	20,538	19,908	18,885	17,583	16,205
Fall	11	20,739	11/24/2015	15,191	14,605	14,290	14,218	14,473	15,544	17,397	18,622	19,079	19,194	19,154	19,020	18,875	18,823	18,763	18,879	19,692	20,739	20,562	20,177	19,560	18,646	17,373	16,027
Fall	11	20,080	11/25/2015	15,038	14,486	14,143	14,056	14,340	15,264	16,991	18,123	18,657	18,900	18,875	18,742	18,512	18,355	18,249	18,285	19,006	20,080	19,923	19,490	18,903	18,097	16,961	15,731
Fall	11	16,936	11/26/2015	14,679	14,019	13,586	13,370	13,444	13,796	14,372	14,922	15,694	16,373	16,776	16,936	16,811	16,399	15,919	15,576	15,814	16,274	16,119	15,924	15,721	15,452	14,865	14,103
Fall	11	18,286	11/27/2015	13,370	12,911	12,626	12,510	12,676	13,176	14,045	14,785	15,464	16,007	16,358	16,476	16,460	16,361	16,406	16,567	17,419	18,286	18,038	17,588	17,063	16,368	15,465	14,464
Fall	11	18,336	11/28/2015	13,594	13,015	12,662	12,456	12,491	12,850	13,486	14,196	15,146	15,944	16,448	16,754	16,827	16,796	16,763	16,944	17,723	18,336	18,270	17,943	17,529	16,945	16,072	15,049
Fall	11	19,199	11/29/2015	14,196	13,614	13,264	13,054	13,102	13,381	13,915	14,447	15,242	15,920	16,359	16,410	16,414	16,416	16,457	16,760	17,843	19,135	19,199	18,951	18,460	17,621	16,474	15,360
Fall	11	21,086	11/30/2015	14,541	14,076	13,837	13,764	14,099	15,186	17,182	18,457	18,824	19,078	19,162	19,028	18,859	18,759	18,666	18,832	19,869	21,086	21,009	20,549	19,871	18,822	17,369	15,916

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FERC Form 714 Outages

Month	Planned Outage and Derating (MW)
Dec-14	3,297
Jan15	3,180
Feb15	3,568
Mar15	6,026
Apr15	7,520
May15	4,259
Jun15	1,496
Jul15	440
Aug15	281
Sep15	1,327
Oct15	7,477
Nov15	5,426

	Planned Outage and Derating (MW)				
	Winter	Spring	Summer	Fall	Notes
NYISO	3,348	5,935	739	4,743	NYISO outages
NY-City	862	1,528	183	1,221	Estimated based on generation ratios
Long Island	468	829	101	663	Estimated based on generation ratios

	Generation (MW)			
	Winter	Spring	Summer	Fall
NYISO	41,013	41,013	38,665	41,013
NY-City	10,561	10,561	9,597	10,561
Long Island	5,732	5,732	5,281	5,732

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	PSA	Winter	Spring	Summer	Fall	Notes
NYISO Reserves	2,620	2,620	2,620	2,620	2,620	NYISO Locational Reserve Requirements (30-minute reserves)
NY-City	#REF!	#REF!	#REF!	#REF!	#REF!	Estimated based on load ratios
Long Island	540	540	540	540	540	Maximum LI Locational Reserve Requirements (30-minute reserves)

	Loads				
	PSA	Winter	Spring	Summer	Fall
NYISO	25,244	22,045	19,393	24,144	20,374
NY-City	#REF!	#REF!	#REF!	#REF!	#REF!
Long Island	#REF!	#REF!	#REF!	#REF!	#REF!

http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf

NYISO
Locational Reserve Requirements

The NYISO shall define requirements for Spinning Reserve, which may be met only by Suppliers that are eligible to provide Spinning Reserve; 10-Minute Reserve, which may be met by Suppliers that are eligible to provide either Spinning Reserve or 10-Minute Non-Synchronized Reserve; and 30-Minute Reserve, which may be met by Suppliers that are eligible to provide any Operating Reserve product. The NYISO shall also define locational requirements for Spinning Reserve, 10-Minute Reserve, and 30-Minute Reserve located in East of Central–East (EAST), in Southeastern New York (SENY) and on Long Island (LI) as shown in the following table:

	NYCA	EAST	SENY	LI
A=most severe NYCA Operating Capability Loss (1310 MWs)	Zone A-K	Zone F-K	Zone G-K	Zone K
10 Minute Spinning Reserve	½ A = 655 MWs (I)	¼ A = 330 MWs (IV)	0 MWs	0 MWs
10 Minute Total Reserve	A = 1310 MWs (II)	1200 MWs (V)	0 MWs	$^{1}/_{10}$ V = 120 MWs (VIII)
30 Minute Reserve	2 A = 2620 MWs (III)	1200 MWs (VI)	1300 MWs (VII)	270-540 MWs (IX)

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Source: RTO

	PJM
Max	143,633
Peak Month	7
PST	121,600
Winter	112,390
Spring	94,917
Summer	117,821
Fall	95,173

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	102,668	12/1/2014	70,381	68,446	67,764	68,161	70,444	76,128	84,884	90,282	91,203	91,189	91,836	91,776	91,829	91,811	91,779	92,445	95,733	101,439	102,668	101,987	100,291	96,470	90,714	84,732
Winter	12	110,873	12/2/2014	80,525	78,286	77,574	77,980	80,090	85,967	95,553	101,320	102,173	102,630	103,122	103,037	102,901	102,911	102,603	103,044	106,193	110,792	110,873	109,348	106,785	101,968	95,298	88,771
Winter	12	106,204	12/3/2014	83,905	81,113	79,602	79,325	81,114	86,183	95,107	100,446	100,367	99,996	99,745	99,041	98,104	97,266	96,052	95,696	98,556	104,849	106,204	105,479	104,054	100,662	94,871	88,963
Winter	12	109,104	12/4/2014	84,723	82,551	81,758	82,124	84,287	90,141	99,955	104,875	104,152	102,630	101,256	99,544	98,606	98,133	97,941	98,533	102,027	108,501	109,104	108,029	106,297	102,316	96,191	89,658
Winter	12	104,351	12/5/2014	84,891	81,949	80,646	80,558	82,192	87,130	96,094	101,346	101,410	101,125	101,214	100,457	99,438	98,682	97,895	97,865	100,427	104,351	103,620	101,486	99,179	95,844	91,032	85,028
Winter	12	96,752	12/6/2014	80,208	76,949	75,150	74,391	74,752	76,530	80,068	83,883	87,393	90,142	91,406	91,509	90,735	89,824	88,960	88,996	91,693	96,170	96,752	95,591	94,358	92,148	88,444	84,077
Winter	12	102,331	12/7/2014	79,958	77,424	76,296	76,130	77,032	79,002	82,258	85,648	88,254	89,170	88,566	87,148	86,119	84,990	84,516	85,364	90,142	99,259	101,864	102,331	101,962	98,965	94,151	88,877
Winter	12	113,955	12/8/2014	85,216	83,506	82,915	83,514	85,975	91,863	101,605	107,058	107,620	107,275	106,802	105,963	104,859	104,117	103,414	103,912	107,321	113,305	113,955	112,514	110,388	106,093	99,412	92,296
Winter	12	110,721	12/9/2014	87,318	84,683	83,420	83,438	85,167	90,647	99,563	105,126	105,422	105,171	104,880	103,946	102,866	102,008	101,037	101,305	104,426	110,215	110,721	109,407	107,222	102,824	96,096	89,371
Winter	12	113,559	12/10/2014	84,508	81,989	80,995	81,151	83,268	88,825	98,226	103,449	103,468	102,684	102,571	102,242	101,639	101,558	101,257	101,841	105,788	112,411	113,559	112,382	110,709	106,921	100,621	93,962
Winter	12	114,045	12/11/2014	89,594	87,225	86,339	86,577	88,735	94,425	104,168	109,511	108,929	107,689	106,446	104,902	103,726	102,882	101,914	102,090	105,641	112,601	114,045	113,234	111,866	108,250	101,952	95,291
Winter	12	109,191	12/12/2014	90,392	87,870	86,702	86,834	88,742	94,114	103,252	108,674	108,384	107,292	105,509	103,484	101,379	100,147	98,801	98,632	101,774	108,575	109,191	107,840	106,268	103,585	98,951	93,203
Winter	12	100,490	12/13/2014	88,294	85,371	84,023	83,775	84,441	86,721	90,223	94,274	96,806	97,313	96,502	94,990	93,191	91,605	90,505	90,632	93,713	99,671	100,490	99,427	98,173	96,027	91,991	87,198
Winter	12	98,486	12/14/2014	82,641	80,025	78,576	77,886	78,015	79,446	82,076	85,015	87,614	88,694	88,521	87,864	87,549	86,491	85,813	86,105	89,557	96,827	98,486	98,159	97,021	93,763	88,793	83,253
Winter	12	105,072	12/15/2014	79,058	76,804	76,020	76,514	78,941	84,785	94,566	100,339	100,184	98,490	96,999	95,206	93,472	92,271	91,027	91,013	94,614	102,884	105,072	104,783	103,565	99,779	93,918	87,114
Winter	12	106,709	12/16/2014	82,294	79,686	78,574	78,654	80,467	85,925	95,301	100,953	100,495	99,400	98,884	98,145	97,445	97,116	97,150	97,648	100,871	106,394	106,709	105,346	103,550	99,760	93,347	86,305
Winter	12	109,307	12/17/2014	81,302	78,612	77,534	77,405	79,395	85,188	94,651	100,406	100,161	98,992	98,337	97,490	96,786	96,686	96,502	96,916	100,687	107,877	109,307	108,659	107,473	104,435	98,828	92,226
Winter	12	113,423	12/18/2014	87,282	85,004	84,127	84,317	86,588	92,352	102,125	107,737	107,287	106,133	105,488	104,426	102,891	102,040	101,581	101,837	105,584	112,361	113,423	112,264	110,939	107,230	100,985	94,134
Winter	12	110,832	12/19/2014	88,924	86,015	84,812	84,921	86,932	92,223	101,340	107,405	107,566	106,809	106,055	104,283	102,547	100,967	99,680	99,657	103,020	109,961	110,832	109,497	108,054	105,391	100,902	95,173
Winter	12	105,010	12/20/2014	90,098	87,297	85,773	85,397	85,878	88,332	91,906	96,297	99,456	101,486	101,848	100,663	98,742	96,702	95,461	95,362	98,267	104,403	105,010	103,880	102,853	100,690	96,674	91,778
Winter	12	104,387	12/21/2014	87,358	84,412	82,846	82,240	82,546	84,158	86,902	90,241	93,210	94,515	93,944	92,596	91,207	89,094	87,922	88,183	92,142	100,729	103,851	104,387	104,095	101,821	97,572	92,569
Winter	12	109,089	12/22/2014	88,412	85,962	85,180	85,311	87,217	91,984	99,540	105,061	106,251	106,052	105,268	104,072	102,539	101,196	100,525	100,327	103,042	108,610	109,089	107,587	105,744	101,813	95,998	89,201
Winter	12	100,145	12/23/2014	83,660	80,274	78,624	77,852	79,136	83,221	90,333	95,691	97,012	97,274	97,163	96,304	94,828	93,806	92,654	92,162	94,428	99,611	100,145	98,523	96,412	92,985	87,818	81,237
Winter	12	88,815	12/24/2014	75,581	71,879	69,800	68,921	69,578	72,287	76,856	81,383	84,298	86,842	88,399	88,352	87,085	85,851	84,852	84,140	85,605	88,815	87,014	84,326	82,595	80,993	78,334	74,445
Winter	12	83,815	12/25/2014	70,175	67,079	65,166	64,390	64,845	66,331	69,161	72,757	75,930	78,240	79,165	79,439	78,810	77,524	76,045	75,231	76,498	81,692	83,346	83,498	83,815	83,249	81,159	77,865
Winter	12	93,069	12/26/2014	74,906	73,058	72,560	73,239	75,198	78,945	84,275	88,555	89,997	89,375	87,724	85,802	83,737	81,728	80,235	79,960	82,713	90,696	93,069	92,554	91,697	89,678	86,012	81,607
Winter	12	88,934	12/27/2014	77,511	75,287	74,125	73,763	74,352	76,209	79,177	82,517	84,509	84,901	84,064	82,770	80,915	79,077	77,752	77,568	80,120	87,269	88,934	88,340	87,299	85,432	81,929	77,593
Winter	12	92,467	12/28/2014	73,533	70,859	69,288	68,585	68,753	70,038	72,252	75,165	77,542	80,060	81,199	81,692	82,016	81,653	81,340	81,673	84,799	90,242	92,467	91,819	90,693	87,979	84,307	79,709
Winter	12	106,148	12/29/2014	76,057	73,839	73,136	73,466	75,375	79,840	86,424	92,427	94,719	96,108	96,824	96,719	95,558	95,083	94,650	94,646	97,087	104,388	106,148	104,906	103,166	99,992	94,934	89,310
Winter	12	110,969	12/30/2014	85,158	82,961	81,918	81,927	83,766	88,076	94,820	100,377	102,214	103,005	102,649	101,217	99,391	98,078	97,027	96,779	99,895	107,912	110,969	110,315	109,205	106,587	102,033	96,808
Winter	12	110,712	12/31/2014	92,824	90,825	90,213	90,391	92,159	96,213	102,039	106,177	106,966	106,284	104,907	103,100	101,041	98,994	97,394	96,911	100,075	108,863	110,712	108,487	105,835	102,991	99,729	96,399
Winter	1	100,418	1/1/2015	94,002	91,930	90,377	89,636	89,869	91,496	93,609	94,661	94,393	93,595	93,037	92,148	90,712	88,937	87,566	87,639	90,579	98,472	100,418	99,622	98,106	95,346	91,232	86,865
Winter	1	102,363	1/2/2015	83,243	81,050	79,966	79,816	81,302	85,142	90,711	95,487	97,348	97,671	97,117	96,171	94,593	93,186	92,091	91,900	94,277	101,121	102,363	101,127	99,669	97,212	93,105	88,464
Winter	1	98,387	1/3/2015	84,415	81,797	80,286	79,699	79,928	81,614	84,139	87,128	89,799	92,616	94,899	95,640	95,306	94,640	93,652	93,100	94,728	98,387	97,974	95,964	93,496	90,264	86,137	81,225
Winter	1	95,931	1/4/2015	76,690	73,582	71,615	70,618	70,505	71,601	73,364	76,032	78,390	80,803	82,444	83,440	84,311	84,568	84,318	84,797	87,843	93,682	95,931	95,028	94,128	90,877	86,854	82,810
Winter	1	119,815	1/5/2015	79,944	78,810	78,898	79,993	82,975	89,652	100,128	106,670	107,140	106,612	106,112	105,633	104,812	104,105	103,709	104,398	108,250	116,660	119,815	119,285	117,705	113,945	108,021	102,163
Winter	1	122,846	1/6/2015	98,195	96,106	95,176	95,196	97,136	102,616	111,077	116,543	116,476	116,026	115,483	114,466	113,053	111,749	110,567	110,015	112,517	120,195	122,846	122,385	120,670	116,843	111,068	105,659
Winter	1	135,639	1/7/2015	101,571	99,579	98,804	99,208	101,335	106,680	114,922	120,461	121,092	120,319	119,993	119,579	119,189	119,289	119,290	120,394	124,240	131,953	135,424	135,639	134,763	131,875	126,616	121,623
Winter	1	134,197	1/8/2015	118,502	117,119	116,828	117,144	119,316	124,060	131,396	136,197	135,305	133,080	130,834	128,427	126,223	124,293	123,179	123,214	125,800	132,509	134,759	133,640	131,229	126,824	120,108	113,728
Winter	1	122,167	1/9/2015	108,949	106,487	105,074	104,539	105,718	109,710	116,898	121,704	121,409	120,176	118,113	115,500	113,330	111,596	110,255	109,958	112,332	119,266	122,167	121,493	120,294	117,981	114,018	109,342
Winter	1	119,065	1/10/2015	106,201	104,570	104,250	104,682	106,176	108,963	113,020	117,234	119,065	118,510	116,514	113,773	110,625	107,315	105,225	104,923	108,084	115,500	119,027	118,968	118,430	116,574	112,914	108,868
Winter	1	109,169	1/11/2015	105,354	103,403	102,366	102,072	102,390	103,729	106,065	108,686	109,169	107,281	104,271	101,458	99,304	97,352	96,045	96,259	99,665	106,626	108,701	107,561	105,704	101,773	96,767	91,716
Winter	1	113,974	1/12/2015	88,199	86,206	85,742	85,963	88,132	93,149	101,131	107,630	109,235	109,643	109,517	109,352	108,528	107,717	106,653	106,492	108,191	112,613	113,974	112,515	110,010	105,613	100,289	94,790
Winter	1	121,214	1/13/2015	90,741	88,452	87,906	88,563	90,994	96,952	106,849	113,166	113,271	112,227	111,242	109,939	108,667	107,583	107,177	107,634	110,467	117,588	121,214	120,989	119,514	115,895	110,058	104,471
Winter	1	121,315	1/14/2015	100,703	98,717	98,152	98,659	100,747	106,284	114,884	120,549	120,956	120,280	119,168	117,851	116,665	114,618	113,150	112,676	114,265	119,266	121,315	120,171	118,253	113,961	107,744	101,669
Winter	1	116,668	1/15/2015	97,651	95,639	94,615	94,862	96,902	102,120	111,013	116,668	115,936	113,989	111,582	109,019	106,641	104,875	103,386	103,077	105,101	111,271	114,737	114,338	113,000	109,335	103,530	97,774
Winter	1	112,992	1/16/2015	94,058	92,038	91,508	91,662	93,894	99,342	107,895	112,992	111,753	108,980	106,918	104,847	102,692	100,980	99,604	99,021	100,724	106,405	109,484	108,652	107,396	104,783	101,042	96,542
Winter	1	104,517	1/17/2015	93,001	91,161	90,606	90,858	92,071	94,552	98,520	102,531	104,517	103,877	101,601	98,712	95,244	92,333	90,257	89,754	92,132	98,326	101,907	101,398	100,108	97,703	93,907	89,613
Winter	1	98,475	1/18/2015	85,813	83,580	81,932	81,296	81,152	82,141	84,235	87,036	89,840	92,376	93,566	93,890	93,746	92,730	91,617	90,892	92,173	96,520	98,475	98,411	96,712	94,174	90,375	86,670
Winter	1	106,188	1/19/2015	83,833	82,395	81,993	82,443	84,445	88,567	95,060	100,413	102,519	102,752	101,668	100,242	98,809	97,682	96,318	95,571	96,982	102,674	106,188	105,974	104,528	101,041	95,610	90,186
Winter	1	108,376	1/20/2015	86,501	84,813	84,408	84,972	87,346	93,404	102,897	108,376	107,518	105,135	101,841	100,571	98,458	97,423	96,288	96,183	98,165	103,602	106,713	106,327	104,953	101,506	96,189	90,689
Winter	1	112,252	1/21/2015	86,648	84,800	84,236	84,413	86,723	92,555	101,982	107,373	106,948	106,060	105,549	104,970	104,012	103,682	103,256	103,142	105,036	109,832	112,252	111,085	109,397	105,245	99,349	93,904
Winter	1	110,280	1/22/2015	89,895	87,720	86,890	87,056	89,116	94,564	103,574	109,259	109,309	108,374	106,946	104,772	102,811	101,250	100,050	99,900	101,676	107,125	110,280	109,759	108,129	104,856	98,994	93,708
Winter	1	110,667	1/23/2015	89,583	87,617	87,243	87,620	89,904	95,666	105,125	110,667	109,670	107,668	105,653	103,553	101,574	100,588	99,815	99,989	101,881	106,038	107,736	106,503	104,633	101,456	96,980	91,868
Winter	1	102,257	1/24/2015	87,741	85,509	83,997	83,517	83,903	85,884	89,002	92,901	95,846	98,614	99,927	99,896	98,513	96,783	95,252	94,231	94,940	99,431	102,257	101,434	99,712	97,115	93,053	88,487
Winter	1	100,769	1/25/2015	84,828	82,421	81,080	80,707	81,178	82,746	85,195	88,046	90,652	91,867	91,642	91,172	90,172	89,171	88,074	88,446	90,950	97,053	100,769	100,557	99,311	96,304	92,046	87,909
Winter	1	118,210	1/26/2015	84,673	83,351	83,095	83,834	86,436	92,550	101,654	108,345	109,803	110,475	111,011	110,530	110,039	109,713	108,977	108,805	110,528	115,330	118,210	116,939	114,359	110,230	104,637	99,354
Winter	1	118,540	1/27/2015	95,260	93,519	92,838	93,228	95,179	100,019	107,895	113,311	114,303	114,021	112,945	111,368	109,458	107,953	106,404	106,023	108,121	114,088	118,540	118,182	116,531	112,922	107,606	102,192
Winter	1	122,273	1/28/2015	99,006	97,919	97,648	98,479	101,236	107,345	116,990	122,273	120,526	116,971	113,732	110,354	107,445	105,272	103,220	102,849	104,827	111,239	116,674	116,963	116,000	112,314	106,679	101,111
Winter	1	118,159	1/29/2015	97,643	96,032	95,629	96,209	98,637	104,453	113,600	118,159	116,433	113,967	111,964	109,936	108,212	107,436	106,541	106,497	108,211	112,391	114,590	113,517	111,117	106,596	100,378	94,385
Winter	1	115,519	1/30/2015	89,969	87,576	86,497	86,566	88,716	94,043	103,096	108,744	108,967	108,411	107,796	106,856	105,577	104,744	103,632	103,241	104,792	110,122	115,228	115,519	114,676	112,601	108,829	104,888
Winter	1	111,797	1/31/2015	101,771	100,336	99,937	100,284	101,437	104,023	107,767	111,409	111,797	111,655	111,868	110,961	109,868	108,435	107,569	107,954	107,567	109,113	107,590	107,465	106,441	104,318	100,742	96,659
Winter	2	103,665	2/1/2015	99,181	91,116	90,027	89,404	89,340	90,417	92,480	94,907	97,059	98,130	97,669	96,915	96,319	95,704	95,189	95,691	98,040	102,508	103,665	101,206	99,217	96,655	93,595	89,116
Winter	2	120,485	2/2/2015	85,143	82,973	82,025	82,271	84,148	89,472	97,673	103,631	104,978	106,049	107,013	107,109	106,628	106,180	105,715	105,671	108,056	113,967	119,733	120,485	119,029	115,425	109,737	104,236
Winter	2	121,191	2/3/2015	101,026	99,518	99,007	99,597	101,976	107,505	116,460	121,191	120,326	118,223	115,519	111,995	108,765	106,495	104,450	103,729	105,380	110,812	116,476	117,036	115,673	111,978	106,275	100,385
Winter	2	114,251	2/4/2015	96,493	94,345	93,552	93,487	95,294	100,693	109,768	114,251	112,409	109,160	106,370	103,676	101,233	99,147	97,636	96,975	98,566	103,397	108,264	108,785	107,499	103,866	98,222	92,661
Winter	2	123,695	2/5/2015	88,862	86,959	86,318	86,913	89,452	95,485	105,344	111,724	112,602	112,617	112,499	111,261	109,696	108,404	107,130	106,823	109,216	115,615	122,417	123,695	123,097	120,228	115,132	110,157
Winter	2	127,381	2/6/2015	106,845	105,644	105,473	105,954	108,312	113,982	122,847	127,381	124,753	121,387	118,524	115,612	112,284	109,722	107,726	106,542	106,712	109,887	113,924	113,325	112,048	108,929	104,658	99,494
Winter	2	102,343	2/7/2015	95,484	93,255	92,148	91,654	91,826	93,432	96,676	100,017	102,023	102,343	100,646	97,412	93,329	89,931	87,475	86,304	86,958	90,717	95,530	95,786	94,665	92,392	88,809	84,969
Winter	2	93,941	2/8/2015	81,514	79,227	78,177	77,599	77,998	79,206	81,612	84,155	86,376	87,349	86,570	85,371	84,201	82,955	82,193	82,323	84,315	88,903	93,684	93,941	92,495	89,170	85,054	80,872
Winter	2	113,055	2/9/2015	77,452	75,751	75,380	76,214	78,904	84,915	94,774	101,065	102,276	103,101	104,038	104,232	104,046	103,830	103,319	103,704	105,606	109,804	113,055	112,567	110,696	106,660	100,806	95,204
Winter	2	114,183	2/10/2015	91,452	89,783	89,329	89,846	91,880	97,629	106,710	112,407	112,838	112,615	112,005	110,371	108,451	106,628	104,777	103,675	104,217	108,378	113,706	114,183	112,810	109,500	103,557	97,862
Winter	2	114,516	2/11/2015	94,031	92,302	91,812	92,309	94,713	100,641	110,188	114,516	112,644	110,164	107,750	104,941	102,105	100,250	98,580	98,164	99,674	104,224	109,821	110,396	109,216	105,705	100,377	94,654
Winter	2	130,851	2/12/2015	96,631	88,703	87,928	88,242	89,575	94,665	106,060	111,368	111,046	110,157	108,294	107,872	107,311	106,596	106,226	106,250	108,128	112,992	119,161	120,851	120,450	118,152	113,639	109,090
Winter	2	128,761	2/13/2015	106,589	105,760	105,817	106,966	109,618	115,318	124,228	128,761	127,115	124,532	121,764	118,647	115,369	112,651	110,147	108,746	109,698	113,889	119,031	119,266	118,181	115,593	111,400	106,437
Winter	2	113,813	2/14/2015	102,598	100,403	99,014	98,250	98,345	99,728	102,497	105,212	107,801	109,548	109,747	108,714	106,818	104,868	103,273	102,426	103,781	107,432	112,534	113,813	113,421	112,731	111,055	109,263
Winter	2	127,475	2/15/2015	108,340	108,384	108,947	109,968	111,591	113,967	117,242	119,757	121,290	121,821	120,710	119,016	116,729	113,986	111,717	110,857	112,599	118,316	125,719	127,475	126,774	124,797	121,472	118,270
Winter	2	134,183	2/16/2015	115,800	114,993	114,643	115,338	116,884	121,072	126,900	130,754	132,213	132,926	132,553	130,548	128,516	127,214	126,349	125,961	127,053	130,389	134,183	133,384	130,682	126,451	120,492	115,177
Winter	2	126,240	2/17/2015	111,777	109,999	109,231	109,579	111,177	115,018	121,233	125,025	126,240	124,877	122,766	119,538	116,639	114,283	112,248	111,380	112,566	117,166	123,265	124,109	122,445	119,115	113,795	109,517
Winter	2	127,107	2/18/2015	106,542	105,692	105,838	106,867	109,221	114,528	123,117	127,107	125,447	121,808	118,853	116,241	114,330	112,921	112,054	112,594	114,785	119,605	125,758	126,798	126,071	123,374	118,885	114,776
Winter	2	140,386	2/19/2015	112,308	111,506	111,882	113,337	116,203	121,808	129,594	133,522	133,056	131,649	129,766	128,346	126,737	125,716	124,944	125,214	127,477	132,392	138,886	140,386	139,399	137,114	132,574	128,428
Winter	2	143,129	2/20/2015	125,665	124,750	124,784	125,840	127,861	132,615	139,530	143,129	141,840	138,982	136,112	132,570	128,896	125,386	122,339	121,024	121,613	125,154	130,983	131,932	130,985	128,469	124,216	119,717
Winter	2	119,441	2/21/2015	115,795	113,625	112,199	111,672	111,824	113,207	115,763	117,517	118,370	119,441	119,436	118,438	116,950	114,880	112,717	111,260	111,438	113,377	116,182	115,007	111,797	107,847	103,335	98,365
Winter	2	106,323	2/22/2015	94,329	91,919	90,713	90,234	90,356	91,571	93,725	95,416	98,060	99,924	99,269	97,105	94,934	92,933	91,393	91,304	93,015	98,054	104,324	106,323	105,586	102,715	98,799	94,819
Winter	2	127,775	2/23/2015	92,310	90,989	90,875	91,421	94,753	100,690	110,049	115,430	117,204	117,039	116,813	115,631	113,822	112,080	110,686	110,451	112,414	117,208	124,876	127,775	127,500	124,785	120,076	115,573
Winter	2	134,132	2/24/2015	113,038	112,293	112,470	113,561	116,332	122,154	130,663	134,132	131,619	127,664	123,917	120,643	117,816	115,732	114,181	113,487	115,094	118,761	123,988	125,187	123,438	119,706	114,019	108,778
Winter	2	122,289	2/25/2015	104,851	103,413	102,938	103,537	105,352	110,699	119,253	122,289	119,043	114,969	111,633	108,481	105,697	103,888	102,247	101,718	103,418	107,515	113,838	115,072	113,933	110,691	105,185	99,941
Winter	2	119,359	2/26/2015	96,185	94,426	93,983	94,535	96,754	102,025	110,488	114,913	116,127	116,135	115,534	113,417	111,170	109,437	108,388	107,999	109,108	112,816	118,000	119,359	118,457	115,205	110,028	104,998
Winter	2	121,067	2/27/2015	101,799	100,213	99,730	100,389	102,570	108,019	116,914	121,067	119,702	116,521	114,083	111,431	109,088	107,330	105,622	104,454	105,326	108,858	115,204	117,755	117,731	115,900	112,363	108,312
Winter	2	114,963	2/28/2015	105,369	104,029	103,695	104,084	105,412	108,302	112,177	114,498	114,963	113,688	110,850	107,153	103,464	99,803	97,302	95,925	96,924	100,770	107,473	109,837	109,554	107,931	104,836	101,028
Spring	3	111,112	3/1/2015	98,093	96,299	95,423	94,705	94,766	95,609	97,359	99,031	101,620	103,803	104,778	104,825	104,833	103,980	103,245	102,798	103,875	106,722	110,320	111,112	108,884	104,867	99,922	95,310
Spring	3	112,134	3/2/2015	91,845	90,213	89,883	90,319	92,327	97,672	105,816	110,085	110,809	108,462	106,375	104,019	101,841	99,943	98,251	97,187	98,253	101,857	109,138	112,134	111,207	108,148	103,227	98,064
Spring	3	114,461	3/3/2015	94,755	93,228	92,644	93,093	95,238	100,687	109,474

Contains Proprietary Material
Do Not Distribute

Spring	4	92,469	4/2/2015	74,038	72,233	71,643	72,056	74,288	79,817	88,359	92,469	91,936	90,200	89,057	87,695	86,282	85,471	84,304	83,194	82,754	82,645	82,498	84,066	86,135	83,363	78,070	71,975
Spring	4	82,162	4/3/2015	67,345	64,351	62,999	62,433	63,259	66,416	72,127	76,252	78,853	81,016	82,109	82,162	81,518	80,704	80,055	79,272	79,231	79,524	79,296	80,288	81,514	79,574	75,811	71,107
Spring	4	79,892	4/4/2015	66,975	64,476	63,114	62,441	63,048	64,829	67,923	71,194	74,994	77,620	78,339	77,701	76,274	74,511	72,934	71,893	71,859	72,333	72,972	75,596	79,892	79,527	77,064	73,348
Spring	4	76,582	4/5/2015	69,823	67,499	66,641	66,447	67,225	69,067	71,972	74,641	76,582	76,565	74,866	73,114	71,601	69,905	68,020	66,736	66,014	66,174	67,314	70,599	75,660	75,327	72,263	68,471
Spring	4	87,056	4/6/2015	65,718	64,045	64,151	64,880	67,218	72,715	81,173	85,879	87,056	86,730	86,391	85,668	84,849	84,070	83,083	82,149	81,800	82,023	82,041	84,289	87,015	84,186	78,721	72,844
Spring	4	89,290	4/7/2015	68,242	65,555	64,075	63,725	64,986	69,331	77,566	82,792	84,778	85,913	87,166	87,212	87,047	86,874	86,379	85,669	85,659	86,039	86,274	87,898	89,290	85,918	80,036	73,905
Spring	4	91,683	4/8/2015	69,529	66,992	65,670	65,303	66,603	71,332	79,596	84,771	86,795	88,033	89,048	89,164	89,000	88,686	87,903	87,214	87,418	88,003	88,667	90,339	91,683	88,704	83,058	77,153
Spring	4	92,720	4/9/2015	72,761	70,126	68,661	68,444	69,923	74,863	83,615	88,232	89,951	90,805	91,487	91,617	91,531	91,031	90,165	89,619	89,636	90,073	90,415	91,566	92,720	89,818	83,999	77,893
Spring	4	89,432	4/10/2015	73,079	70,467	69,055	68,451	69,649	74,005	82,049	86,831	88,612	89,338	89,432	88,826	87,987	87,058	85,943	84,396	83,531	82,820	81,693	81,875	84,381	82,640	78,136	73,040
Spring	4	77,383	4/11/2015	68,479	66,006	64,527	64,084	64,485	66,488	69,495	72,120	74,798	76,427	76,842	76,103	74,985	73,686	72,287	71,602	71,427	71,758	72,089	73,370	77,383	76,894	73,748	69,829
Spring	4	79,870	4/12/2015	66,217	64,326	63,425	63,383	64,006	65,979	68,500	70,441	72,389	73,011	72,580	71,981	71,350	70,547	69,930	70,015	70,647	71,953	72,998	75,470	79,870	78,068	73,336	68,309
Spring	4	88,036	4/13/2015	64,510	62,577	61,672	61,896	63,756	69,084	78,361	83,252	84,277	84,120	84,856	84,750	84,928	85,348	85,071	84,908	84,942	84,934	84,280	85,074	88,036	84,995	78,846	72,131
Spring	4	86,675	4/14/2015	67,171	64,433	62,776	62,158	63,295	67,770	76,508	81,417	83,410	84,603	85,545	85,568	85,318	84,993	84,321	83,418	83,366	83,444	83,674	84,637	86,675	84,278	78,175	72,132
Spring	4	86,396	4/15/2015	67,842	65,650	64,357	64,321	65,913	70,964	79,577	83,887	84,708	84,781	84,528	84,133	83,758	83,491	82,726	81,983	81,819	81,992	81,677	83,062	86,396	83,764	78,485	72,461
Spring	4	86,192	4/16/2015	68,344	65,813	64,633	64,630	66,067	71,146	79,491	83,804	84,385	84,302	84,577	84,103	83,796	83,567	82,978	82,465	82,293	82,318	82,040	83,433	86,192	84,003	78,153	72,090
Spring	4	85,616	4/17/2015	67,646	64,887	63,574	63,032	64,333	68,658	76,934	81,272	83,153	84,432	85,383	85,334	85,477	85,616	85,139	84,511	84,188	83,451	82,066	81,704	84,057	82,565	77,378	71,253
Spring	4	78,849	4/18/2015	66,218	62,905	61,011	59,934	60,136	61,506	63,922	66,672	70,508	73,520	75,233	75,889	75,987	75,878	75,760	75,921	76,724	77,113	76,472	76,271	78,849	77,651	73,401	68,184
Spring	4	79,522	4/19/2015	63,590	60,461	58,554	57,532	57,390	58,131	59,264	61,280	65,111	68,150	69,682	70,564	71,110	71,077	71,014	71,216	72,233	73,901	75,040	77,195	79,522	77,140	72,623	67,863
Spring	4	88,161	4/20/2015	64,223	62,118	61,169	61,076	62,619	67,388	76,234	81,458	84,122	85,521	86,895	87,414	87,495	87,494	87,333	87,009	86,690	86,703	86,239	86,438	88,161	85,535	79,329	72,773
Spring	4	86,403	4/21/2015	68,382	65,605	64,200	63,830	64,911	69,719	78,001	82,343	83,736	83,935	84,320	84,296	83,921	83,890	83,283	82,592	82,702	82,617	82,163	82,812	86,403	84,687	78,760	72,707
Spring	4	88,647	4/22/2015	68,497	66,017	65,031	64,750	66,284	71,372	79,929	84,400	85,474	85,925	86,333	86,161	86,081	86,232	85,827	85,289	85,126	85,269	85,151	85,687	88,647	86,940	81,227	75,252
Spring	4	90,110	4/23/2015	71,171	69,155	68,201	68,214	70,127	75,554	84,123	88,358	88,526	88,024	87,977	87,712	87,252	86,547	85,751	85,108	85,018	85,313	85,464	86,636	90,110	88,885	83,597	77,890
Spring	4	91,229	4/24/2015	73,937	71,953	71,128	71,387	73,437	78,786	87,303	91,229	90,992	89,508	88,387	86,928	85,366	84,070	82,627	81,204	80,336	79,736	79,108	79,975	83,762	83,136	79,271	74,274
Spring	4	81,328	4/25/2015	70,103	67,939	67,020	66,547	67,168	69,006	71,703	74,718	78,388	80,573	81,229	80,585	79,254	77,989	76,524	75,846	75,920	76,367	77,196	78,592	81,328	80,481	76,912	72,711
Spring	4	78,641	4/26/2015	68,998	66,733	65,365	65,018	65,196	66,599	68,379	70,283	72,757	73,947	73,737	73,114	72,654	71,834	71,014	70,449	70,912	71,700	72,568	74,385	78,514	78,641	74,635	70,015
Spring	4	87,426	4/27/2015	66,829	65,306	65,049	65,572	68,020	73,824	82,618	86,943	87,212	86,396	85,861	85,461	85,286	85,059	84,062	83,093	83,113	83,284	83,418	84,578	87,426	86,109	80,499	74,689
Spring	4	86,575	4/28/2015	70,614	68,437	67,537	67,680	69,499	75,073	83,214	86,575	86,272	85,291	84,893	84,175	83,715	83,378	82,464	81,662	81,320	81,211	80,504	80,922	84,282	83,723	77,806	71,860
Spring	4	85,392	4/29/2015	67,391	65,158	64,311	64,383	66,049	71,188	79,342	83,688	84,000	83,748	83,865	84,076	84,127	84,055	83,922	83,386	83,441	83,091	82,316	82,238	85,392	84,133	78,015	71,640
Spring	4	84,996	4/30/2015	66,849	64,152	62,745	62,481	63,915	68,405	76,447	81,270	82,950	83,728	84,452	84,410	84,387	84,425	83,849	83,237	82,821	82,483	82,083	82,577	84,996	83,838	78,562	72,475
Spring	5	84,125	5/1/2015	67,925	65,541	64,293	63,867	65,277	69,823	77,465	81,807	83,276	83,756	84,125	83,824	83,361	82,868	81,969	80,993	80,561	79,930	78,987	78,780	80,847	80,526	76,290	70,964
Spring	5	75,726	5/2/2015	66,378	63,540	62,202	61,522	61,931	63,770	65,855	68,676	71,628	73,254	73,979	74,025	73,668	73,165	72,686	72,711	73,028	73,457	73,291	73,458	75,726	75,578	71,584	66,750
Spring	5	81,125	5/3/2015	62,644	60,271	58,750	57,813	57,821	58,950	59,831	62,016	65,391	68,350	69,849	71,140	71,974	72,735	73,210	73,775	75,106	76,746	77,499	78,239	81,125	80,230	74,983	69,060
Spring	5	92,899	5/4/2015	64,540	61,997	60,606	60,204	61,402	66,028	73,401	78,989	81,969	84,177	86,549	88,602	90,012	91,338	91,922	92,491	92,750	92,899	91,749	90,700	92,405	90,468	83,232	75,716
Spring	5	96,658	5/5/2015	69,968	66,622	64,338	63,429	64,362	68,489	75,777	81,251	84,537	86,733	89,433	91,278	92,747	94,514	95,786	96,407	96,658	95,982	94,420	93,357	94,599	92,563	85,276	77,525
Spring	5	97,579	5/6/2015	71,786	68,155	65,868	64,692	65,481	69,509	76,627	81,758	84,877	86,922	89,278	91,502	93,292	95,344	96,519	97,209	97,579	96,860	95,017	93,358	94,003	92,408	85,170	77,204
Spring	5	101,580	5/7/2015	71,157	67,167	65,023	63,894	64,663	68,648	75,632	80,855	84,032	87,168	90,155	92,665	95,317	97,666	99,481	100,677	101,550	101,580	100,019	97,858	97,951	96,136	88,299	79,838
Spring	5	107,010	5/8/2015	73,689	69,553	66,954	65,780	66,138	69,790	76,532	81,986	86,393	90,181	94,013	97,404	100,264	103,303	105,143	106,233	107,010	105,958	103,049	99,044	97,932	95,633	88,849	80,942
Spring	5	93,140	5/9/2015	74,128	69,589	66,760	64,961	64,300	65,202	66,572	69,842	74,863	79,340	82,604	84,856	86,677	88,319	89,907	91,476	92,712	93,140	91,896	89,770	89,922	89,052	84,034	77,384
Spring	5	94,750	5/10/2015	71,651	67,485	64,788	63,222	62,370	62,772	63,344	66,528	72,046	77,405	81,467	84,784	87,382	89,349	91,115	92,730	93,974	94,750	94,252	93,100	91,500	94,148	87,973	80,815
Spring	5	111,596	5/11/2015	74,641	71,036	68,754	67,913	68,731	73,376	80,666	87,222	91,888	95,470	99,525	102,977	106,540	109,327	111,070	111,405	111,596	110,838	108,609	105,271	104,433	101,272	92,715	84,055
Spring	5	105,026	5/12/2015	77,298	73,207	70,769	69,475	69,957	73,793	80,873	86,960	90,807	94,366	97,389	99,718	101,316	103,281	104,183	104,743	105,026	104,066	101,583	98,494	98,107	96,123	88,124	79,371
Spring	5	87,059	5/13/2015	73,032	69,062	66,671	65,400	65,885	69,585	76,120	81,072	83,534	85,033	86,111	86,455	86,531	86,695	86,895	86,734	87,059	86,840	85,538	84,612	85,811	85,308	79,276	72,892
Spring	5	86,168	5/14/2015	68,064	65,303	63,773	63,485	64,559	68,689	75,475	80,365	82,427	83,286	84,133	84,648	84,930	85,639	85,713	85,778	86,036	86,168	84,947	84,128	86,078	85,425	79,046	72,669
Spring	5	90,857	5/15/2015	67,620	64,450	62,980	62,356	63,462	67,467	74,020	78,971	82,076	83,998	85,846	86,978	87,895	89,084	89,727	90,317	90,857	90,617	89,090	87,277	87,661	87,327	82,299	76,078
Spring	5	92,740	5/16/2015	70,432	66,620	64,359	62,842	62,588	63,557	64,712	68,446	73,678	78,206	81,896	84,620	86,961	88,718	90,385	91,896	92,740	92,467	90,839	89,154	89,260	88,347	83,927	77,834
Spring	5	101,303	5/17/2015	72,388	68,525	65,911	64,348	63,620	63,840	64,349	67,069	72,588	77,860	82,231	86,330	89,986	92,866	95,043	97,377	99,760	101,303	101,284	100,035	99,746	98,657	92,177	84,439
Spring	5	113,132	5/18/2015	78,049	73,888	71,312	70,121	70,948	75,168	82,680	89,501	94,815	99,498	104,135	107,892	110,321	112,242	113,132	113,048	112,673	111,145	107,948	104,788	103,136	100,030	91,969	83,468
Spring	5	105,992	5/19/2015	76,822	72,698	70,157	68,832	69,317	73,121	79,731	85,499	88,721	91,453	94,389	96,771	98,696	100,568	102,464	104,373	105,918	105,992	104,140	100,934	99,824	97,994	90,154	81,562
Spring	5	89,431	5/20/2015	74,848	70,237	67,538	66,169	66,540	69,954	76,043	81,435	84,241	85,830	86,905	87,677	87,765	88,398	88,846	89,114	89,431	89,095	87,702	86,318	87,278	86,707	80,609	74,009
Spring	5	85,456	5/21/2015	68,841	65,848	63,961	63,373	64,344	68,459	75,247	80,381	83,156	84,539	85,313	85,456	85,282	85,294	84,832	84,120	84,050	83,910	83,311	83,021	84,083	83,712	78,819	72,482
Spring	5	84,002	5/22/2015	68,052	65,268	63,000	62,273	64,389	68,172	74,144	78,971	81,339	82,459	83,491	83,863	83,882	84,002	83,916	83,678	83,621	83,070	81,688	79,791	80,263	80,615	76,106	70,077
Spring	5	76,960	5/23/2015	65,132	61,893	60,029	59,156	59,110	59,993	60,917	63,823	67,597	70,542	72,110	72,769	72,963	72,986	73,218	74,095	75,506	76,780	76,960	76,104	76,339	76,651	73,015	67,980
Spring	5	83,360	5/24/2015	63,466	60,225	58,382	57,445	57,108	57,332	57,496	60,220	64,396	68,009	70,674	73,140	74,971	76,524	78,204	80,003	81,984	83,360	83,145	81,713	81,367	81,668	77,809	72,450
Spring	5	97,314	5/25/2015	67,314	63,452	61,364	60,081	59,922	60,579	61,169	64,107	69,300	74,713	79,932	84,039	87,462	89,806	91,786	93,846	95,800	97,314	96,753	95,021	94,697	94,304	87,690	80,164
Spring	5	118,081	5/26/2015	73,936	69,582	67,136	65,681	66,543	70,257	77,558	85,172	90,695	95,312	100,163	104,431	108,261	111,842	114,448	116,641	118,081	117,865	115,666	111,833	109,593	106,905	98,693	89,572
Spring	5	117,558	5/27/2015	82,002	77,113	74,119	72,435	72,885	76,724	83,655	90,760	95,691	99,623	103,737	107,873	111,291	114,351	116,475	117,188	117,558	116,788	113,468	109,640	107,408	105,056	97,112	87,745
Spring	5	120,840	5/28/2015	80,305	75,543	72,663	71,021	71,229	74,922	81,471	88,261	93,316	97,941	102,859	107,411	111,245	115,011	117,906	119,688	120,840	120,150	117,258	113,400	110,387	107,854	99,356	89,542
Spring	5	119,894	5/29/2015	81,639	76,301	72,765	71,189	71,233	74,490	80,527	87,410	92,551	97,610	102,315	106,432	109,930	113,615	116,639	118,730	119,894	118,783	115,083	110,053	106,707	104,809	98,197	89,907
Spring	5	108,167	5/30/2015	82,225	77,003	73,418	71,251	70,288	70,571	71,813	76,449	83,336	90,151	96,019	100,461	103,713	105,528	106,607	107,371	108,167	107,473	104,791	100,941	98,513	96,969	91,292	84,203
Spring	5	101,600	5/31/2015	77,739	73,023	69,793	67,564	66,504	66,289	66,602	70,269	76,598	83,199	88,759	93,467	96,915	99,534	100,878	101,600	101,427	101,173	99,371	96,824	95,848	94,186	88,181	81,121
Summer	6	101,491	6/1/2015	75,017	71,286	69,041	67,823	68,848	72,488	79,096	85,395	89,392	92,477	95,504	97,972	99,799	101,341	101,491	101,286	100,059	98,424	96,106	93,987	92,876	90,489	84,450	77,335
Summer	6	89,379	6/2/2015	71,706	68,637	66,709	65,912	66,631	70,304	76,472	81,764	84,822	86,787	88,318	89,117	89,174	89,379	88,665	87,999	87,592	87,327	86,411	85,481	85,813	85,120	80,113	73,559
Summer	6	88,867	6/3/2015	68,726	65,774	63,885	63,236	64,143	67,990	73,961	79,252	82,488	84,292	85,949	86,991	87,300	88,003	88,246	88,377	88,785	88,867	87,967	86,908	87,130	86,968	81,907	75,285
Summer	6	95,895	6/4/2015	69,938	66,778	64,706	63,853	64,697	68,343	74,420	80,106	83,780	86,338	88,779	90,486	91,796	93,540	94,475	95,236	95,895	95,643	94,579	93,241	93,036	92,269	86,977	79,481
Summer	6	97,569	6/5/2015	73,466	69,356	66,977	65,890	66,297	69,767	75,060	80,848	85,020	88,093	90,774	92,860	94,219	95,530	96,619	97,266	97,569	96,824	94,725	92,277	90,886	89,944	84,967	78,115
Summer	6	90,658	6/6/2015	71,784	67,392	64,954	63,633	63,155	63,881	64,947	68,438	73,196	77,817	81,330	83,590	84,994	85,950	86,747	88,048	89,618	90,658	89,675	87,410	85,258	84,710	80,482	74,186
Summer	6	93,701	6/7/2015	68,390	64,541	62,145	60,544	59,877	59,726	59,736	62,915	68,142	73,264	77,149	80,750	83,747	86,042	87,937	89,860	92,016	93,673	93,701	92,445	92,180	92,181	87,158	80,655
Summer	6	113,883	6/8/2015	74,848	71,097	68,845	67,753	68,531	72,334	78,570	85,106	90,263	94,478	98,771	102,209	105,323	108,742	111,215	112,826	113,883	112,546	109,923	106,678	104,236	100,864	93,724	85,348
Summer	6	114,190	6/9/2015	78,463	73,937	71,257	70,002	70,321	73,842	79,825	86,349	90,982	94,651	98,767	102,355	105,600	108,681	110,854	112,549	114,022	114,190	111,983	108,484	105,820	103,738	96,615	87,555
Summer	6	124,478	6/10/2015	80,198	74,925	71,791	70,258	70,202	73,427	79,085	86,068	91,808	97,018	102,298	106,991	111,164	115,425	118,703	121,948	124,053	124,478	121,894	117,521	113,928	111,533	103,804	94,069
Summer	6	131,922	6/11/2015	86,060	80,281	76,695	74,632	74,503	77,484	83,178	90,544	97,029	103,330	109,801	116,103	121,265	125,843	128,698	130,683	131,922	131,167	128,334	124,263	121,149	118,662	110,399	100,433
Summer	6	131,052	6/12/2015	91,964	85,816	81,708	79,276	79,153	81,835	87,408	95,522	103,235	110,463	117,547	123,114	127,188	129,890	131,052	130,533	129,030	126,626	122,150	117,220	114,044	111,986	105,231	96,633
Summer	6	117,700	6/13/2015	88,899	83,581	79,670	76,996	75,431	75,553	76,849	81,790	89,161	95,947	102,010	106,304	109,929	112,486	114,787	116,570	117,700	117,509	115,026	110,864	107,590	105,580	99,753	92,426
Summer	6	120,955	6/14/2015	85,380	80,393	76,724	74,287	72,922	72,332	72,546	76,853	84,337	91,460	100,853	110,441	118,407	123,914	126,955	128,559	130,955	130,657	128,559	125,341	122,736	120,206	103,736	94,644
Summer	6	134,129	6/15/2015	88,475	83,615	80,667	79,105	79,857	83,509	89,887	97,384	103,820	109,522	115,044	119,815	124,166	127,845	130,499	132,956	134,129	133,301	129,935	125,965	122,191	118,663	110,330	100,715
Summer	6	130,241	6/16/2015	92,559	86,853	83,204	80,948	81,006	84,186	90,148	97,487	103,999	109,987	115,427	119,724	122,973	125,939	127,572	129,058	130,241	129,247	126,543	121,863	116,898	113,690	105,614	95,788
Summer	6	112,899	6/17/2015	87,695	81,983	78,246	76,098	75,960	78,468	83,960	90,829	95,946	99,823	103,384	106,510	108,961	111,350	112,597	112,899	112,340	110,515	107,856	105,054	103,857	102,787	96,691	88,906
Summer	6	121,368	6/18/2015	82,238	77,923	75,107	73,868	74,334	78,092	83,673	90,340	95,970	100,691	105,813	110,111	113,783	117,420	119,697	121,368	121,187	118,607	115,406	111,686	108,940	106,534	99,559	91,163
Summer	6	115,405	6/19/2015	84,058	79,168	76,063	74,280	74,438	77,457	82,345	88,738	94,301	99,368	104,487	108,210	111,060	113,166	114,501	115,111	115,405	114,408	111,185	106,935	104,303	102,812	97,250	89,396
Summer	6	105,366	6/20/2015	82,531	77,768	74,335	72,234	71,280	71,763	72,794	76,153	81,919	87,712	92,641	96,525	99,469	101,652	103,291	104,701	105,366	105,275	103,687	101,664	99,795	98,001	93,540	87,305
Summer	6	120,192	6/21/2015	81,238	76,818	74,042	72,203	71,197	71,281	71,411	74,811	81,865	89,287	95,924	101,808	106,667	110,215	113,545	116,619	119,258	120,192	118,801	115,944	113,088	111,877	106,219	97,786
Summer	6	134,545	6/22/2015	89,809	84,263	80,488	78,391	78,109	80,555	85,993	94,547	102,310	108,989	115,659	120,881	124,948	128,331	131,501	133,635	134,381	134,545	133,126	129,542	125,754	123,177	115,142	104,923
Summer	6	137,287	6/23/2015	96,301	90,564	86,884	84,794	84,965	87,695	93,088	100,613	107,711	114,485	121,117	126,594	130,703	134,243	136,118	136,923	137,287	135,895	129,879	123,716	117,865	113,594	106,257	96,906
Summer	6	121,042	6/24/2015	88,719	82,755	78,635	76,028	75,294	77,317	81,933	88,691	94,352	99,048	103,809	107,796	111,449	114,909	117,485	119,727	121,042	120,884	118,516	114,130	109,480	107,124	99,438	90,585
Summer	6	113,915	6/25/2015	82,698	77,570	74,230	72,260	72,615	75,315	80,420	86,987	92,653	97,588	102,229	106,377	109,471	112,107	113,555	113,875	113,915	112,662	110,230	107,256	105,113	103,203	96,610	88,478
Summer	6	109,122	6/26/2015	81,645	76,988	74,043	72,727	75,393	80,176	85,816	90,875	95,273	99,251	103,307	107,132	109,787	112,347	113,512	109,122	109,106	108,072	105,112	101,475	99,026	97,703	91,282	85,084
Summer	6	87,808	6/27/2015	78,578	74,022	71,202	69,370	68,829	69,428	70,710	73,534	77,965	82,270	85,653	87,315	87,752	87,808	87,580	87,166	87,196	87,019	86,398	85,160	84,527	83,817	80,415	75,411
Summer	6	89,123	6/28/2015	70,775	67,441	64,881	63,137	62,718	62,698	62,725	65,450	70,205	74,732	78,296	80,706	83,012	84,566	85,621	86,924	88,145	89,123	88,708	87,685	86,756	87,094	83,013	76,863
Summer	6	103,222	6/29/2015	71,549	67,889	65,822	64,912	65,581	68,546	73,541	79,368	84,296	88,118	91,783	94,760	96,888	99,107	100,633	101,841	102,749	103,222	101,893	99,463	97,270	95,995	90,163	82,550
Summer	6	113,079	6/30/2015	76,166	72,087	69,649	68,496	68,947	72,095	77,172	83,330	88,861	93,408	97,999	102,253	106,118	109,760	111,847	112,568	113,079	112,269	109,317	105,592	103,129	101,356	94,891	86,705
Summer	7	112,608	7/1/2015	79,795	74,937	71,746	70,140	70,177	73,053	77,468	82,983	88,060	92,505	96,910	100,776	104,142	107,446	109,664	111,345	112,608	112,492	109,802	105,608	102,479	100,999	94,477	86,367
Summer	7	99,415	7/2/2015	79,215	74,513	71,408	69,868	70,067	72,643	77,208	82,581	87,014	90,379	93,758	96,084	97,647	99,030	99,415	99,396	99,255	98,987	97,017	94,168	92,210	91,280	86,224	79,226
Summer	7	96,403	7/3/2015	72,916	68,650	65,792	64,162	63,559	64,313	65,609	69,063	73,987	78,946	83,494	87,090	90,106	92,533	94,316	95,844	96,403	96,217	93,853	90,730	89,154	88,012	84,283	78,875
Summer	7	93,336	7/4/2015	73,366	69,160	66,454	64,583	63,673	63,908	63,725	66,124	70,827

Contains Proprietary Material
Do Not Distribute

Summer	8	127,063	8/14/2015	81,838	77,089	73,811	71,900	71,961	75,018	80,152	85,121	90,743	96,275	101,497	106,389	111,585	116,657	121,239	124,580	126,918	127,063	123,907	117,634	114,105	110,243	102,135	92,759
Summer	8	123,513	8/15/2015	84,704	79,157	75,077	72,649	71,251	71,815	72,932	75,664	82,476	89,911	97,129	103,977	109,787	115,053	119,073	122,007	123,513	123,009	119,954	115,144	111,627	107,898	100,512	92,516
Summer	8	129,803	8/16/2015	85,277	79,683	75,717	72,927	71,338	71,021	71,125	73,390	80,338	89,157	97,914	106,278	113,412	119,027	123,017	126,381	128,776	129,803	128,038	123,469	120,579	116,448	107,753	98,320
Summer	8	139,650	8/17/2015	90,613	85,102	81,652	79,518	79,527	82,905	88,813	94,554	101,653	110,183	119,009	127,178	133,528	137,803	139,650	139,643	139,482	138,100	134,818	130,364	128,109	122,410	112,220	101,998
Summer	8	133,464	8/18/2015	93,824	88,311	84,464	82,218	82,207	85,299	91,561	96,816	102,015	107,555	113,974	120,083	125,076	129,010	131,429	132,550	133,464	132,447	129,073	124,884	123,577	118,596	108,882	99,323
Summer	8	133,354	8/19/2015	91,517	86,621	83,433	81,536	81,891	85,629	92,439	98,092	104,019	110,017	116,353	121,342	126,023	129,856	132,299	133,286	133,354	131,513	127,533	122,725	121,301	116,791	107,867	98,778
Summer	8	121,714	8/20/2015	91,499	86,712	83,609	81,999	82,309	85,808	92,788	97,578	101,805	106,555	110,445	114,120	116,843	119,354	120,721	121,231	121,714	120,806	117,450	113,444	111,354	107,755	99,794	91,599
Summer	8	119,364	8/21/2015	84,669	80,048	76,952	75,043	75,158	78,116	83,710	87,979	92,971	97,638	102,279	105,838	109,070	112,431	115,685	117,557	119,364	118,597	115,041	109,165	105,966	102,033	94,953	86,865
Summer	8	106,985	8/22/2015	79,791	74,846	71,363	69,158	67,964	68,603	69,732	71,922	77,493	83,359	88,327	92,582	95,925	98,739	101,445	104,137	106,428	106,985	104,786	99,895	97,743	94,338	87,991	81,091
Summer	8	109,331	8/23/2015	75,112	70,813	67,935	66,103	64,955	65,178	65,782	67,375	72,521	78,502	83,770	88,826	93,517	97,886	101,652	105,042	107,949	109,331	107,831	104,743	104,263	100,855	93,616	86,336
Summer	8	121,793	8/24/2015	79,945	75,650	72,915	71,496	72,165	75,834	82,307	86,829	91,957	97,321	103,009	108,122	112,778	116,656	119,402	121,094	121,793	120,476	117,070	112,580	111,167	106,605	97,775	89,042
Summer	8	112,073	8/25/2015	82,202	77,933	74,975	73,226	73,427	76,947	83,239	87,567	92,164	96,533	100,830	103,908	106,401	108,725	110,359	111,348	112,073	111,650	108,511	104,557	104,033	99,489	91,425	83,201
Summer	8	102,854	8/26/2015	76,851	73,000	70,181	68,943	69,343	72,949	79,690	84,018	87,672	90,771	93,748	96,229	98,294	100,313	101,341	101,814	102,854	102,435	100,332	97,778	98,138	94,838	87,400	79,886
Summer	8	103,565	8/27/2015	74,215	70,706	68,415	67,340	68,066	71,817	78,634	83,039	86,866	90,405	93,747	96,268	98,455	100,660	101,860	102,551	103,565	103,232	101,037	98,271	98,932	95,491	87,945	80,196
Summer	8	107,563	8/28/2015	74,315	70,349	68,106	66,895	67,350	70,871	77,037	81,943	86,089	90,299	94,363	97,594	100,411	102,956	104,805	106,287	107,563	107,096	103,872	99,640	98,862	95,044	88,688	81,412
Summer	8	106,635	8/29/2015	75,142	70,867	67,931	66,244	65,641	66,389	68,193	70,675	75,890	81,917	87,725	92,662	96,840	100,371	103,032	105,259	106,635	106,373	104,109	100,909	100,812	97,318	91,465	84,599
Summer	8	114,421	8/30/2015	78,551	74,205	70,877	68,786	67,867	68,039	68,724	70,364	75,743	81,957	88,302	94,350	100,289	105,125	109,151	111,741	113,922	114,421	112,298	110,272	110,360	106,059	98,504	90,615
Summer	8	133,453	8/31/2015	84,155	79,596	76,824	75,526	76,197	80,577	88,886	93,754	98,272	103,502	109,716	115,741	120,703	125,016	128,767	131,434	133,380	133,453	130,421	126,187	124,641	118,254	108,015	98,292
Fall	9	138,975	9/1/2015	90,311	84,612	80,837	78,822	78,883	82,719	90,527	95,540	100,839	107,331	115,010	122,123	128,443	133,312	136,369	137,946	138,975	138,619	135,883	131,708	129,729	122,760	112,167	101,938
Fall	9	138,664	9/2/2015	93,316	87,642	83,323	80,874	80,665	84,679	92,515	97,023	101,741	108,078	115,464	122,748	129,233	134,512	137,576	138,664	138,256	136,928	133,723	129,383	127,332	121,240	111,031	100,831
Fall	9	141,210	9/3/2015	92,625	87,254	83,394	81,019	80,862	84,803	92,545	97,414	102,716	109,172	116,962	124,390	131,238	136,556	139,315	140,460	141,210	139,944	136,789	132,566	129,873	122,770	112,688	102,596
Fall	9	133,169	9/4/2015	94,068	88,404	84,514	82,253	81,975	85,068	91,906	96,695	102,006	108,100	114,742	121,345	126,655	130,832	133,022	133,169	132,062	128,910	123,081	118,136	115,484	110,141	102,595	94,320
Fall	9	116,000	9/5/2015	87,003	81,733	77,793	75,297	74,136	74,546	76,119	77,955	83,652	90,209	96,341	101,408	106,039	109,752	112,771	114,757	116,000	115,356	111,861	107,663	106,102	101,364	94,833	87,415
Fall	9	116,818	9/6/2015	80,926	75,752	72,355	70,088	68,781	68,690	69,374	70,523	76,111	83,615	90,800	97,825	103,603	108,479	112,162	114,907	116,604	116,818	113,815	109,278	107,374	102,547	96,018	88,913
Fall	9	128,068	9/7/2015	82,213	77,185	73,453	71,313	70,367	71,055	72,447	73,653	79,187	87,728	96,598	105,116	112,172	117,256	121,382	124,813	127,350	128,068	125,640	122,205	120,970	114,411	105,056	96,069
Fall	9	138,388	9/8/2015	88,600	83,423	80,006	78,077	78,377	82,589	91,042	96,799	102,390	109,208	117,167	124,404	130,507	135,037	136,882	137,554	138,388	137,910	134,995	131,253	129,801	122,120	111,764	101,647
Fall	9	131,701	9/9/2015	93,403	87,823	84,120	82,130	82,431	86,489	95,100	100,338	104,263	109,112	114,910	120,665	125,670	129,663	131,397	131,701	131,320	129,491	126,079	123,711	122,150	115,729	106,244	96,991
Fall	9	111,039	9/10/2015	89,591	84,827	81,550	79,317	79,641	83,626	92,040	96,481	99,198	102,362	105,363	107,599	109,419	110,677	111,017	110,923	111,039	110,341	108,231	106,655	106,095	101,162	93,497	85,550
Fall	9	107,715	9/11/2015	79,064	74,701	72,599	70,914	71,585	75,133	83,096	87,520	90,444	93,660	97,011	99,867	102,196	104,959	106,328	107,369	107,715	106,576	102,658	99,535	98,242	93,818	87,593	81,028
Fall	9	86,446	9/12/2015	75,193	71,049	68,374	66,390	66,000	67,131	69,566	72,239	76,560	80,681	83,896	85,813	86,446	86,344	85,877	85,267	84,940	84,880	84,347	85,279	86,000	83,695	79,054	73,936
Fall	9	83,047	9/13/2015	69,388	66,296	63,908	62,456	61,716	62,273	63,595	64,942	68,423	72,433	75,092	76,837	78,215	79,054	79,182	79,256	79,695	80,399	80,110	81,026	83,047	79,406	74,298	69,315
Fall	9	94,824	9/14/2015	65,519	63,253	61,910	61,549	62,804	66,976	74,594	78,873	81,324	83,719	86,116	87,842	88,967	90,214	91,519	92,802	94,293	94,824	93,710	93,393	93,895	89,197	82,175	75,344
Fall	9	105,341	9/15/2015	70,289	67,020	65,137	64,392	65,397	69,320	76,999	81,406	83,805	86,515	89,530	92,606	94,757	97,497	100,154	102,589	104,792	105,341	102,965	101,010	100,550	94,628	86,386	78,765
Fall	9	112,439	9/16/2015	72,843	69,239	67,138	66,057	66,816	70,705	78,305	82,543	85,335	88,916	92,937	96,644	100,238	103,887	107,312	110,140	112,260	112,439	109,489	107,043	105,609	99,382	90,668	82,525
Fall	9	116,254	9/17/2015	76,037	72,062	69,507	68,149	68,631	72,482	80,199	84,252	87,194	91,093	95,330	99,667	103,636	108,095	111,356	114,327	116,254	115,469	111,414	108,803	107,657	101,733	93,085	84,273
Fall	9	113,052	9/18/2015	77,948	74,130	71,191	69,687	70,102	74,018	81,487	85,310	88,911	92,804	96,969	100,565	104,096	107,559	110,309	112,094	113,052	111,789	107,577	104,994	103,004	98,064	91,388	83,886
Fall	9	100,447	9/19/2015	77,351	72,982	70,145	68,445	67,676	68,332	70,796	73,256	77,880	82,838	87,360	91,389	94,390	96,804	98,646	99,825	100,447	99,929	97,285	95,792	94,660	90,488	84,680	78,250
Fall	9	88,880	9/20/2015	72,917	69,180	66,541	64,825	64,083	64,255	65,421	66,661	70,369	74,366	77,236	79,681	81,658	83,380	84,865	86,522	87,984	88,799	87,503	88,072	88,880	84,006	77,828	72,115
Fall	9	92,517	9/21/2015	67,812	65,047	63,600	62,957	64,142	68,277	76,408	81,177	83,059	85,149	87,514	89,209	90,560	91,618	91,780	91,785	92,300	92,353	91,739	92,517	92,303	87,631	80,880	74,502
Fall	9	95,800	9/22/2015	69,575	66,674	64,906	64,114	65,091	69,185	77,364	81,878	83,730	85,950	88,511	90,052	91,705	93,473	94,287	95,074	95,800	95,704	94,527	94,908	94,845	90,060	82,857	75,985
Fall	9	100,172	9/23/2015	70,732	67,564	65,503	64,578	65,221	69,006	76,806	80,884	83,186	85,844	89,126	91,344	93,107	95,390	97,324	98,814	100,172	100,087	97,772	97,221	96,473	90,737	83,330	76,178
Fall	9	100,534	9/24/2015	70,586	67,369	65,383	64,405	65,243	69,018	77,147	81,553	83,479	85,972	88,725	91,625	94,051	96,320	98,053	99,567	100,534	100,055	97,256	97,424	96,937	91,495	84,372	77,004
Fall	9	93,655	9/25/2015	71,671	68,218	66,201	65,391	66,043	70,247	78,096	82,381	84,629	87,053	89,391	91,027	92,221	93,274	93,655	93,069	92,058	90,554	88,674	89,236	88,373	84,782	79,963	74,260
Fall	9	81,500	9/26/2015	69,184	65,817	63,411	62,110	61,802	62,945	65,593	68,232	71,781	75,274	77,654	78,861	79,412	79,737	79,687	80,064	80,236	80,232	79,774	81,361	81,500	78,778	74,624	69,849
Fall	9	87,012	9/27/2015	65,817	62,805	60,824	59,661	59,296	59,970	61,492	63,473	67,020	70,622	73,164	75,441	77,295	78,636	79,527	80,590	81,609	82,823	83,889	86,833	87,012	83,385	78,158	73,281
Fall	9	104,418	9/28/2015	69,046	66,310	64,776	64,473	65,717	70,263	78,838	84,726	87,118	89,711	92,511	94,966	97,310	99,856	101,620	102,718	103,335	103,336	102,507	104,418	103,342	98,218	90,802	83,254
Fall	9	102,180	9/29/2015	77,282	73,424	71,094	70,108	70,875	75,398	84,200	89,989	92,236	94,662	97,443	99,486	101,000	102,180	101,829	100,927	100,465	100,357	100,653	102,158	100,568	95,643	88,869	81,896
Fall	9	96,535	9/30/2015	76,091	72,649	70,603	69,899	70,628	75,076	83,963	89,436	91,113	93,015	94,632	95,899	96,417	96,535	95,530	94,647	93,785	92,597	91,727	93,321	92,495	87,748	81,082	74,311
Fall	10	86,056	10/1/2015	69,205	65,946	64,021	63,332	64,021	68,012	76,074	80,979	82,251	83,235	84,073	84,295	84,315	84,253	83,761	83,094	82,838	82,914	83,588	86,056	85,629	82,126	76,504	70,931
Fall	10	84,604	10/2/2015	66,564	63,760	62,313	61,661	62,694	66,710	74,480	79,964	81,602	82,878	83,952	84,143	83,995	83,818	83,308	82,474	82,576	82,711	83,336	84,604	83,634	80,564	76,066	71,189
Fall	10	80,819	10/3/2015	67,011	64,314	62,925	62,020	61,948	63,302	66,196	69,762	73,529	77,256	79,438	80,057	79,576	78,658	77,771	77,173	77,326	77,808	79,089	80,819	79,999	77,338	73,564	69,318
Fall	10	80,481	10/4/2015	65,328	62,645	60,838	59,880	59,646	60,476	62,498	64,826	67,822	70,881	72,320	72,969	73,206	72,844	72,535	72,608	73,360	74,823	76,648	80,481	80,446	77,052	72,576	67,748
Fall	10	88,823	10/5/2015	64,415	62,199	61,268	61,103	62,553	66,964	75,600	80,663	81,999	82,673	83,490	83,939	84,394	84,932	84,882	84,600	84,786	84,929	85,569	88,823	87,576	83,347	77,212	71,314
Fall	10	89,818	10/6/2015	66,976	64,225	62,893	62,519	63,636	68,096	76,445	81,353	82,032	82,833	83,987	84,450	85,260	86,012	86,527	86,867	87,058	86,849	86,812	89,818	88,906	84,383	77,914	71,949
Fall	10	90,766	10/7/2015	67,272	64,501	62,974	62,406	63,396	67,646	75,916	80,992	82,052	83,334	84,526	85,696	86,815	87,833	88,569	88,821	89,223	88,773	88,162	90,766	89,366	84,812	78,418	72,185
Fall	10	92,076	10/8/2015	67,290	64,283	62,822	62,131	63,043	67,189	75,324	80,265	81,377	83,043	84,977	86,618	88,152	89,732	90,397	90,457	90,430	89,657	89,453	92,076	90,823	86,530	80,403	73,797
Fall	10	89,459	10/9/2015	68,873	65,936	64,220	63,293	64,027	68,038	75,980	81,248	83,132	85,032	87,002	88,359	88,879	89,305	89,459	89,247	88,467	87,684	86,884	87,483	85,592	82,083	77,095	71,645
Fall	10	76,740	10/10/2015	66,698	63,399	61,412	60,324	59,992	61,175	63,924	67,049	69,839	72,398	73,663	73,839	73,302	72,714	72,295	72,251	72,660	73,057	73,907	76,740	76,155	73,876	70,384	66,540
Fall	10	79,722	10/11/2015	62,916	60,560	59,094	58,397	58,453	59,452	61,672	64,108	66,999	69,249	69,862	70,262	70,604	70,877	71,252	71,876	73,020	74,664	76,129	79,722	79,017	75,501	71,188	66,948
Fall	10	90,150	10/12/2015	63,463	61,276	60,401	60,356	61,881	66,134	73,766	79,024	80,684	82,231	83,814	84,662	85,315	85,959	86,311	86,544	86,997	86,936	87,468	90,150	88,179	83,889	77,610	71,615
Fall	10	89,378	10/13/2015	67,032	64,293	62,826	62,281	63,280	67,501	75,883	81,105	82,063	83,383	84,728	85,526	85,937	86,371	86,140	86,013	85,980	85,987	87,130	89,378	87,760	83,191	77,287	71,266
Fall	10	87,564	10/14/2015	66,914	64,078	62,475	62,127	63,142	67,441	75,746	81,212	82,044	82,592	83,374	83,584	83,924	84,248	84,197	83,717	83,682	83,500	84,710	87,564	86,300	82,368	76,554	71,009
Fall	10	87,090	10/15/2015	66,910	64,239	63,150	64,395	67,113	77,814	82,996	83,704	83,626	83,736	83,642	83,381	83,467	83,214	83,024	83,045	82,989	84,174	87,090	85,909	84,168	76,764	71,090	
Fall	10	83,650	10/16/2015	66,993	64,458	63,224	62,988	64,325	68,707	76,677	81,975	82,759	83,277	83,427	83,179	82,572	82,247	81,507	80,586	80,289	80,212	81,210	83,650	82,613	80,047	76,175	71,595
Fall	10	80,754	10/17/2015	67,558	65,202	63,923	63,612	64,006	66,065	69,479	73,247	75,978	77,356	77,352	76,660	75,854	74,783	73,765	73,278	73,545	74,621	77,277	80,754	80,310	78,554	75,621	72,091
Fall	10	85,294	10/18/2015	69,031	67,140	66,104	65,854	66,458	68,244	70,957	74,033	76,751	77,621	76,723	75,832	75,375	74,957	74,183	73,797	74,653	76,693	80,328	85,238	85,294	82,561	78,857	75,003
Fall	10	94,825	10/19/2015	72,257	71,050	70,644	71,492	73,907	79,396	89,021	94,825	94,732	92,718	90,621	88,779	87,408	86,038	84,696	83,997	83,947	84,954	87,863	91,615	90,571	86,949	81,680	76,228
Fall	10	89,522	10/20/2015	72,284	70,092	69,055	68,978	70,740	75,951	84,352	89,522	88,806	87,631	86,867	85,779	84,895	84,572	84,266	83,890	83,808	83,948	86,059	89,370	87,875	83,639	77,733	72,247
Fall	10	89,211	10/21/2015	68,372	66,304	65,268	65,054	66,690	71,675	80,708	85,925	85,958	85,332	85,227	84,858	84,881	85,276	85,228	85,057	84,937	85,068	86,555	89,211	87,560	83,337	77,580	71,667
Fall	10	89,538	10/22/2015	67,447	65,095	63,872	63,511	64,882	69,475	78,252	83,860	84,291	84,254	84,540	84,739	84,842	85,478	85,713	85,486	85,584	85,372	87,154	89,538	87,563	83,428	77,669	71,711
Fall	10	84,304	10/23/2015	67,253	64,542	63,074	62,525	63,704	67,833	76,173	81,697	82,290	83,068	83,491	83,363	82,914	83,232	82,742	82,240	82,040	81,773	83,058	84,304	82,452	79,668	75,512	70,573
Fall	10	79,462	10/24/2015	66,468	63,858	62,299	61,528	61,937	63,594	66,924	70,645	73,628	75,845	76,903	76,688	75,853	74,820	73,993	73,504	73,958	75,426	78,327	79,462	78,016	75,612	71,977	67,718
Fall	10	80,613	10/25/2015	63,786	61,373	59,776	58,885	58,782	59,564	61,611	64,635	67,563	70,370	71,802	72,245	72,448	72,073	71,597	71,487	72,139	73,429	77,341	80,613	79,589	76,262	72,048	67,958
Fall	10	80,916	10/26/2015	64,792	63,065	62,356	62,644	64,575	69,797	79,074	85,631	86,103	85,885	85,525	84,973	84,129	83,423	82,657	82,042	82,275	83,289	87,040	89,916	88,223	84,671	79,270	74,113
Fall	10	91,828	10/27/2015	70,126	68,135	67,004	67,075	68,602	73,563	82,549	88,393	88,406	88,084	87,538	86,991	86,471	86,006	85,323	84,930	85,224	86,875	90,668	91,828	89,662	85,686	79,917	74,165
Fall	10	90,892	10/28/2015	70,098	67,664	66,231	65,644	66,861	70,987	79,229	85,200	86,498	86,962	87,906	88,042	87,899	87,920	87,342	86,772	87,162	87,952	90,302	90,892	88,814	84,859	79,151	73,422
Fall	10	89,137	10/29/2015	68,913	66,354	64,898	64,099	65,449	69,912	78,427	84,510	85,118	85,615	86,253	86,271	85,825	85,266	84,608	83,860	83,540	84,175	87,166	89,137	87,767	84,278	78,646	73,117
Fall	10	87,132	10/30/2015	69,067	66,605	65,565	65,437	66,836	71,286	80,303	86,632	87,132	86,433	86,140	85,303	84,304	83,313	82,271	81,467	81,518	82,227	84,963	86,132	84,773	82,327	78,534	74,007
Fall	10	79,901	10/31/2015	70,279	68,022	66,901	66,459	66,933	68,916	72,295	75,985	78,878	79,885	79,901	78,930	77,556	76,375	75,300	74,840	75,306	75,910	78,077	78,474	77,720	75,980	73,180	69,375
Fall	11	81,554	11/1/2015	65,834		61,163	60,639	60,853	62,471	64,662	67,216	70,568	72,601	72,910	72,639	72,588	72,011	71,736	71,822	73,615	78,987	81,554	80,614	78,728	74,872	70,765	66,840
Fall	11	91,502	11/2/2015	63,935	62,565	61,918	62,121	64,203	69,403	78,163	82,507	83,952	84,796	85,524	85,668	85,491	85,503	84,920	84,452	85,379	89,198	91,502	90,054	87,217	82,923	77,332	71,800
Fall	11	91,924	11/3/2015	68,314	66,371	65,379	65,483	67,527	72,979	80,891	84,433	84,766	84,705	84,985	85,526	85,698	86,218	86,261	86,161	86,305	89,486	91,924	90,251	87,585	83,109	77,069	71,262
Fall	11	92,479	11/4/2015	67,313	65,309	64,140	64,028	65,837	71,019	79,365	83,229	83,922	84,339	84,973	85,545	86,087	86,805	86,957	86,593	86,815	90,792	92,479	90,649	87,695	83,154	77,223	71,625
Fall	11	94,038	11/5/2015	67,445	65,000	63,664	63,484	64,713	69,368	77,930	82,277	84,373	86,069	87,342	88,023	88,593	89,264	89,167	88,777	89,014	92,609	94,038	92,221	89,373	85,042	78,777	73,160
Fall	11	90,735	11/6/2015	68,794	66,200	64,722	64,177	65,160	69,490	77,543	82,579	84,714	86,439	87,801	88,259	88,281	88,125	87,896	87,037	87,096	90,589	90,735	88,412	85,758	82,237	77,327	71,870
Fall	11	81,638	11/7/2015	67,304	64,306	62,628	61,685	61,770	63,465	66,053	69,326	73,166	76,032	77,065	77,360	76,973	75,921	75,048	74,716	76,099	80,202	81,638	80,393	78,963	76,665	73,412	69,729
Fall	11	84,934	11/8/2015	66,579	64,595	63,362	63,157	63,753	65,314	67,997	70,223	72,710	73,745	73,428	72,931	72,570	72,057	71,600	72,103	74,289	81,346	84,934	84,744	83,721	80,867	77,049	73,534
Fall	11	95,207	11/9/2015	71,126	69,769	69,616	70,288	72,716	78,288	87,746	91,868	91,519	90,562	89,863	88,940	88,325	87,889	87,108	86,695	88,700	93,725	95,207	93,612	90,859	86,483	80,568	75,186
Fall	11	92,824	11/10/2015	70,716	68,461	67,329	67,007	68,474	73,051	81,606	86,293	86,704	87,286	88,013	87,767	87,240	86,930	86,243	85,960	87,519	91,553	92,824	91,173	88,582	84,645	79,564	74,253
Fall	11	91,641	11/11/2015	70,708	68,513	67,503	67,506	69,114	73,628	81,245	85,423	86,169	86,213	86,091	85,392	84,603	84,062	83,330	83,095	84,777	90,254	91,641	90,209	88,138	84,588	79,304	74,041
Fall	11	92,782	11/12/2015	70,065	68,053	67,044	66,957	68,479	73,421	81,851	86,536	87,385	87,931	88,405	87,714	87,090	86,727	85,926	85,712	87,351	91,858	92,782	91,284	89,232	85,228	79,579	74,118
Fall	11	90,995	11/13/2015	70,247	68,091	67,145	67,214	68,928	73,687	82,290	86,664	86,890	86,397	86,120	85,309	84,640	83,973	83,270	82,845	84,559	89,872	90,995	89,850	88,429	85,684	81,731	77,028
Fall	11	85,130	11/14/2015	73,344	70,932	70,001	69,644	70,529	72,575	76,081	78,989	81,017	81,774	81,168	79,782	77,900	76,084	74,792	74,702	76,777	82,848	85,130	84,504	83,601	81,888	78,840	75,486
Fall	11	83,733	11/15/2015	72,640	70,870	70,016	69,870	70,555	72,236	74,665	76,811	77,785	77,013	75,

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	AP South
Max	70,729
Peak Month	7
PST	58,108
Winter	51,170
Spring	43,394
Summer	56,097
Fall	43,262

Source: ABB Velocity Suite
CONFIDENTIAL DATA REDACTED

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	1																										

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Spring	1
Spring	1
Spring	1

Contains Proprietary Material
Do Not Distribute

Summer	1
Summer	1
Summer	1

Contains Proprietary Material
Do Not Distribute

Fall	1																										

Contains Proprietary Material
Do Not Distribute

	5004/5005
Max	52,190
Peak Month	7
PST	42,368
Winter	36,840
Spring	31,515
Summer	40,748
Fall	31,648

Source: ABB Velocity Suite
CONFIDENTIAL DATA REDACTED

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	1																										

Contains Proprietary Material
Do Not Distribute

Spring	1
Spring	1
Spring	1

Contains Proprietary Material
Do Not Distribute

| | | |

Contains Proprietary Material
Do Not Distribute

Fall	1																										

Contains Proprietary Material
Do Not Distribute

	PJM East
Max	30,240
Peak Month	7
PST	24,093
Winter	19,303
Spring	16,803
Summer	22,934
Fall	17,326

Source: ABB Velocity Suite
CONFIDENTIAL DATA REDACTED

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	1																										

Contains Proprietary Material
Do Not Distribute

Spring	1
Spring	1
Spring	1

Contains Proprietary Material
Do Not Distribute

Summer	1
Summer	1
Summer	1

Contains Proprietary Material
Do Not Distribute

Fall	1																										

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FERC Form 714 Outages

Month	Planned Outage and Derating (MW)
Dec-14	13,851
Jan15	3,616
Feb15	7,609
Mar15	19,290
Apr15	34,834
May15	24,301
Jun15	4,660
Jul15	4,535
Aug15	3,566
Sep15	3,993
Oct15	46,567
Nov15	23,207

	Planned Outage and Derating (MW)					Generation (MW)			
	Winter	Spring	Summer	Fall	Note	Winter	Spring	Summer	Fall
PJM	8,359	26,142	4,254	24,589	PJM outages	199,600	196,690	183,060	192,785
AP South	3,540	11,141	1,835	10,738	Estimated based on generation ratios	84,538	83,829	78,969	84,193
5004/5005	2,512	7,879	1,297	7,620	Estimated based on generation ratios	59,991	59,282	55,814	59,741
PJM East	1,596	4,972	805	4,813	Estimated based on generation ratios	38,116	37,407	34,630	37,735

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	Operating Reserves					
	PST	Winter	Spring	Summer	Fall	Note
PJM	9,097	8,067	6,367	9,097	6,391	PJM Interconnection, L.L.C., Docket No. AD10-2 Reserves
AP South	2,868	2,552	2,266	2,772	2,230	5.93% of 5004/5005 Load + Dominion share of VACAR Reserves
5004/5005	2,512	2,185	1,869	2,416	1,877	5.93% of 5004/5005 Load
PJM East	1,429	1,145	996	1,360	1,027	5.93% of PJM East Load

Loads				
PST	Winter	Spring	Summer	Fall
121,600	112,390	94,917	117,821	95,173
58,108	51,170	43,394	56,097	43,262
42,368	36,840	31,515	40,748	31,648
24,093	19,303	16,803	22,934	17,326

Methodology
PJM Operating Reserves are based on the August 2016 PJM SIL filing
Submarket Operating Reserves = PJM Op Res * Submarket Load/PJM Load

Attachment 11: PJM Operating Reserves

PJM's Day-Ahead Scheduling Reserve (DASR) requirement is calculated using a 3 year historical average of both a Load Forecast Error (LFE) component, as well as a Forced Outage Rate (FOR) component. The LFE component is a 3 year historical average of the under forecasted load. The FOR is the 3 year historical average of resource forced outages which impacted next-day operations, and which were reported after the day-ahead commitments had been completed. The sum of the LFE and LOF components determine PJM's DASR for the next calendar year, calculated as a percentage of the forecasted peak load. Shown below is the calculation of the 2015 DASR, as well as the applicable reserve amounts which may be used by PJM members when filing a Market Share Analysis.

DASR = LFE + LOF (calculated as a percentage of forecasted peak load)
2015 DASR = 2.15% + 3.78%
2015 DASR = 5.93%

2015 SIL Operating Reserves		
Season	Peak Load (MW)	DASR (MW)
Winter	136,044	8067
Spring	107,372	6367
Summer	153,402	9097
Fall	107,782	6391

Area	Ancillary Service Market Area	Day-ahead Scheduling (Operating)	Contingency (Primary)	Synchronized Reserve
RTO		Annual %	150% Largest Single Contingency	Largest Single Contingency
	Mid-Atlantic & Dominion	N/A	1700 MW	Largest Single Contingency
SERC	Dominion	VACAR ARS%	VACAR ARS%	VACAR ARS%

Effective January 1, ~~2014~~ 2015 the Day-ahead Scheduling Reserve for RFC and EKPC regions of PJM is ~~6.27~~5.93% times Peak Load Forecast for RFC plus EKPC.

http://www.pjm.com/~/media/committees-groups/subcommittees/sos/20141125/20141125-item-06a-manual-13-version-57-2015-da

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PJM Generation Summary

	Modeled Generation MW			
	Winter	**Spring**	**Summer**	**Fall**
PJM	199,600	196,690	183,060	192,785
AP South	84,538	83,829	78,969	84,193
5004-5005	59,991	59,282	55,814	59,741
PJM East	38,116	37,407	34,630	37,735

Operating generation during the study period

	Winter	**Spring**	**Summer**	**Fall**
PJM	189,859	189,859	182,872	192,785
AP South	82,190	82,190	78,969	84,193
5004-5005	57,758	57,758	55,814	59,741
PJM East	35,883	35,883	34,630	37,735

Currently retired generation but operating during the study period

	Winter	**Spring**	**Summer**	**Fall**
PJM	9,741	6,832	189	0
AP South	2,349	1,639	0	0
5004-5005	2,234	1,524	0	0
PJM East	2,234	1,524	0	0

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Generation Dataset Including Ventyx Data as of 9/29/2016

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Holding Company Name	Plant Name	Unit	Unit ID	Plant EIA ID	Node	Supplier	East Units

							Unit Capacity (MW)		
5004/5005 Units	AP South Units	Prime Mover Type	Primary Fuel Type	Unit Status	Added During Study Period	Percent Owned %	Name Plate	Summer	Winter

Unit Capacity Adjusted for Ownership and Status (MW)		Modeled Capacity (MW)				Unit Onsite Capacity Use (MW)		Onsite Unit Usa Ownership an
Summer	Winter	Winter	Spring	Summer	Fall	Summer	Winter	Summer

	Modeled Capacity (MW)			
	Winter	Spring	Summer	Fall
PJM	189,859	189,859	182,872	192,785
AP South	82,190	82,190	78,969	84,193
5004/5005	57,758	57,758	55,814	59,741
PJM East	35,883	35,883	34,630	37,735

ge Adjusted for d Status (MW)				
Winter	Online Date	Retirement Date	Proposed Retirement Date	ABB Retirement Date

ABB Retirement Date - Source	Grid Connected (Y/N)	Plant County

Plant State	Unit NERC Region Abbrev	Plant NAICS

PJM Retired Units during the study period

CONFIDENTIAL DATA REDACTED

Unit ID	Holding Company Name	Plant Name	Unit	Plant Aliases	Season	East Units	5004/5005 Units	AP South Units

							Modeled Capacity (MW)			Ventyx Data
Retirement Date	ABB Retirement Date	Plant Government ID	Unit NERC Sub Region Abbrev	Unit ISO Name	Unit ISO Zone Name	Percent Owned %	Nameplate	Summer	Winter	Nameplate

		Modeled Capacity (MW)			Capacity t
		Nameplate	Summer	Winter	Winter
PJM	Winter	911	829	905	0
	Spring	2,974	2,751	2,910	2,910
	Summer	6,868	6,509	6,634	6,634
	Fall	196	189	198	198
	Period	10,948	10,278	10,647	9,741
AP South	Winter	698	640	660	0
	Spring	624	570	710	710
	Summer	1,571	1,639	1,639	1,639
	Fall	0	0	0	0
	Period	2,893	2,848	3,008	2,349
5004/5005	Winter	48	45	55	0
	Spring	624	570	710	710
	Summer	1,456	1,524	1,524	1,524
	Fall	0	0	0	0
	Period	2,129	2,138	2,288	2,234
PJM East	Winter	48	45	55	0
	Spring	624	570	710	710
	Summer	1,456	1,524	1,524	1,524
	Fall	0	0	0	0
	Period	2,129	2,138	2,288	2,234

abase Capacity (MW)							
Summer	Winter	Prime Mover Code	Primary Fuel Code	Unit Status	Commercial Online Date	Grid Connected (Y/N)	Plant NAICS Code

o Add Back into Generation (MW)		
Spring	Summer	Fall
0	0	0
0	0	0
6,634	0	0
198	189	0
6,832	189	0
0	0	0
0	0	0
1,639	0	0
0	0	0
1,639	0	0
0	0	0
0	0	0
1,524	0	0
0	0	0
1,524	0	0
0	0	0
0	0	0
1,524	0	0
0	0	0
1,524	0	0

	Ventyx Database EIA Capacity (MW)				
Plant NAICS Description	**Nameplate**	**Summer**	**Winter**	**Plant City**	**Plant County**

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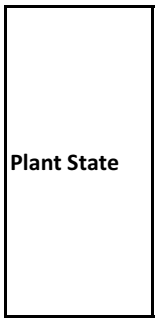

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Contains Proprietary Material
Do Not Distribute

Southeast and MISO Generation Summary

	Modeled Generation MW			
	Winter	**Spring**	**Summer**	**Fall**
CPLE	14,696	14,696	13,525	14,720
CPLW	878	878	826	878
DUKE	25,619	25,619	24,632	25,619
LGEE	9,033	8,793	8,838	9,108
MISO	175,367	175,695	168,505	175,039
TVA	37,014	37,014	35,065	36,069

Operating generation during the study period

	Winter	**Spring**	**Summer**	**Fall**
CPLE	14,696	14,696	13,525	14,720
CPLW	878	878	826	878
DUKE	25,619	25,619	24,632	25,619
LGEE	8,301	8,301	8,677	9,108
MISO	174,022	175,003	168,404	175,039
TVA	36,069	36,069	34,127	36,069

Currently retired generation but operating during the study period

	Winter	**Spring**	**Summer**	**Fall**
CPLE	0	0	0	0
CPLW	0	0	0	0
DUKE	0	0	0	0
LGEE	732	492	161	0
MISO	1,345	692	101	0
TVA	945	945	938	0

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Southeast and MISO Retired Units during the study period

CONFIDENTIAL DATA REDACTED

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		Modelec
		Modelec
		Nameplate
MISO	Winter	0
MISO	Spring	742
MISO	Summer	642
MISO	Fall	126
MISO	Period	1,510
LGEE	Winter	0
LGEE	Spring	272
LGEE	Summer	373
LGEE	Fall	189
LGEE	Period	833
TVA	Winter	0
TVA	Spring	0
TVA	Summer	0
TVA	Fall	1,125
TVA	Period	1,125

ł Capacity (MW)	Ventyx Database Capacity (MW)

ł Capacity (MW)		Capacity to Add Back into Generation (MW)			
Summer	Winter	Winter	Spring	Summer	Fall
0	0	0	0	0	0
632	653	653	0	0	0
575	589	589	589	0	0
101	103	103	103	101	0
1,309	1,345	1,345	692	101	0
0	0	0	0	0	0
240	240	240	0	0	0
323	323	323	323	0	0
161	169	169	169	161	0
724	732	732	492	161	0
0	0	0	0	0	0
0	0	0	0	0	0
0	0	0	0	0	0
938	945	945	945	938	0
938	945	945	945	938	0

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Ventyx Database EIA Capacity (MW)

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Contains Proprietary Material
Do Not Distribute

	MISO	CPLE	CPLW	DUKE	LGEE	TVA
Max	118,332	14,383	1,186	21,101	7,236	32,751
Peak Month	7	2	2	2	2	1
PST	102,563	10,538	869	16,433	5,754	25,981
Winter	86,929	9,332	770	14,053	5,124	22,486
Spring	76,192	7,425	612	11,801	4,348	18,523
Summer	97,947	10,231	844	15,919	5,616	24,974
Fall	80,875	7,487	618	11,970	4,421	18,959

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	91,352	12/1/2014	65,909	64,245	63,482	63,438	64,509	67,485	73,235	80,235	82,680	83,202	83,862	84,202	84,060	84,152	83,896	83,628	84,111	87,614	91,082	91,352	90,226	88,350	84,357	79,529
Winter	12	88,515	12/2/2014	75,587	73,313	71,793	71,051	71,441	73,300	78,278	84,659	86,038	85,836	85,478	85,064	84,245	83,416	83,013	82,205	82,478	85,494	88,419	88,515	87,331	85,357	81,254	76,384
Winter	12	86,783	12/3/2014	72,348	70,047	68,712	68,184	68,790	71,035	76,257	82,751	83,917	83,185	82,266	81,283	80,053	79,320	78,712	78,110	78,714	82,396	86,497	86,783	85,945	84,267	80,626	75,638
Winter	12	86,587	12/4/2014	71,826	69,590	68,297	67,677	68,119	70,352	75,572	81,994	83,755	83,155	82,727	82,354	81,899	81,169	80,992	80,501	80,686	83,744	86,587	86,447	85,347	83,330	79,497	74,490
Winter	12	82,922	12/5/2014	70,181	67,422	65,939	64,837	65,040	67,252	72,299	78,329	80,283	80,481	80,761	80,789	80,431	79,955	79,552	78,755	78,772	81,228	82,922	81,959	80,298	78,718	75,908	71,894
Winter	12	79,699	12/6/2014	68,001	65,246	63,620	62,664	62,694	63,703	65,770	68,993	71,314	73,655	75,179	75,360	74,799	73,858	73,214	72,771	73,236	76,558	79,699	79,246	78,378	76,941	74,640	71,212
Winter	12	82,198	12/7/2014	67,898	65,493	64,203	63,275	63,463	64,105	65,696	68,013	70,208	72,421	73,544	73,321	72,905	72,622	72,219	72,025	73,086	77,840	81,790	82,198	81,417	79,590	76,224	71,919
Winter	12	86,601	12/8/2014	68,360	66,346	65,368	65,138	65,977	68,854	74,726	81,734	83,656	83,241	82,608	81,997	81,064	80,634	79,802	79,467	79,724	82,895	86,297	86,601	85,521	83,870	80,264	75,219
Winter	12	87,447	12/9/2014	71,211	68,881	67,822	67,532	68,119	70,744	76,666	83,657	85,393	84,430	83,725	82,790	81,856	81,083	80,802	80,429	80,884	83,937	87,210	87,447	86,623	85,028	81,180	76,197
Winter	12	88,921	12/10/2014	72,295	70,191	68,932	68,540	69,118	71,656	77,512	84,186	86,000	85,372	84,495	83,724	82,701	81,688	81,234	80,656	81,235	84,854	88,829	88,921	88,027	86,520	82,475	77,468
Winter	12	87,694	12/11/2014	73,472	71,022	69,696	69,318	69,909	72,537	78,180	84,859	85,850	85,191	84,571	83,683	82,340	81,034	80,225	79,357	79,586	83,448	87,399	87,694	87,053	85,488	81,815	76,838
Winter	12	84,572	12/12/2014	72,775	70,436	69,021	68,397	69,011	71,142	76,484	82,884	84,572	83,859	83,201	82,273	81,059	79,970	79,313	78,495	78,655	81,522	83,862	83,036	81,817	80,004	77,117	73,079
Winter	12	76,243	12/13/2014	69,134	66,152	64,478	63,679	63,361	64,226	66,284	69,344	71,859	73,738	74,574	73,907	72,779	71,559	70,545	69,723	70,295	73,266	76,243	75,988	74,717	73,267	70,901	67,494
Winter	12	76,562	12/14/2014	64,072	61,499	60,069	59,264	59,193	59,735	61,248	63,730	66,251	68,213	68,871	68,632	68,374	68,213	67,802	67,719	68,644	72,584	76,245	76,562	75,779	74,029	70,621	66,568
Winter	12	83,910	12/15/2014	63,115	60,943	59,917	59,522	60,224	62,776	68,355	75,393	77,943	78,005	78,452	78,695	78,577	78,253	77,881	77,551	77,868	81,081	83,910	83,909	82,694	80,675	76,801	71,858
Winter	12	87,992	12/16/2014	67,652	65,132	63,654	63,060	63,690	66,002	71,544	78,530	80,993	81,010	81,180	81,098	80,635	80,325	80,165	79,793	80,491	83,578	87,244	87,992	86,932	84,822	82,071	76,530
Winter	12	89,983	12/17/2014	73,704	71,120	70,164	69,764	70,380	73,060	78,957	85,710	87,480	86,632	85,802	84,865	83,590	82,538	82,006	81,664	82,167	85,793	89,601	89,983	89,137	87,570	83,961	78,729
Winter	12	88,469	12/18/2014	74,421	71,913	70,405	69,821	70,224	72,438	77,854	84,271	85,765	85,312	85,022	84,595	83,565	82,937	82,544	82,094	82,624	85,603	88,469	88,186	87,541	85,617	82,131	77,119
Winter	12	87,127	12/19/2014	72,985	70,457	68,928	68,341	68,639	70,762	75,966	82,311	84,561	84,439	84,250	83,758	83,115	82,208	81,900	81,156	81,456	84,715	87,127	86,076	84,723	83,003	80,266	76,256
Winter	12	80,990	12/20/2014	72,176	69,235	67,713	66,754	66,458	67,279	69,540	72,587	75,414	77,644	78,994	78,866	77,808	76,325	75,147	74,368	74,872	77,994	80,990	80,880	79,983	78,735	76,553	73,193
Winter	12	80,003	12/21/2014	70,175	67,566	65,970	65,175	65,044	65,736	67,405	70,266	72,618	74,423	74,868	74,168	73,289	72,432	71,453	70,863	71,866	75,685	79,502	80,003	79,495	78,067	75,420	71,559
Winter	12	83,069	12/22/2014	68,103	65,811	64,447	63,856	64,141	66,307	70,628	76,096	79,142	79,714	80,283	80,458	79,816	79,242	78,660	78,089	78,229	80,697	83,069	82,808	81,656	79,580	76,246	71,534
Winter	12	80,631	12/23/2014	67,324	64,261	62,526	61,487	61,505	63,416	67,420	72,699	75,702	76,777	77,532	77,897	77,299	76,455	76,146	75,401	75,308	77,972	80,631	80,324	79,158	77,391	74,407	69,947
Winter	12	74,745	12/24/2014	65,699	62,666	60,671	59,780	59,762	60,856	63,600	67,592	70,864	72,992	74,318	74,745	73,952	72,738	72,052	71,344	71,384	73,065	74,384	73,319	72,221	71,442	70,239	68,095
Winter	12	70,102	12/25/2014	65,475	63,171	61,496	60,735	60,899	61,725	63,674	66,347	68,834	70,102	70,079	69,119	67,279	64,876	62,839	61,145	61,135	63,634	67,492	68,633	68,911	68,586	67,238	64,783
Winter	12	75,012	12/26/2014	62,058	60,072	59,019	58,720	59,121	60,672	63,732	67,276	69,539	70,812	71,485	71,614	70,706	69,615	68,601	68,089	68,432	71,603	75,012	74,580	73,542	72,064	69,471	66,031
Winter	12	75,252	12/27/2014	62,703	60,131	58,516	57,499	57,351	57,867	59,493	61,871	64,019	66,387	68,828	70,116	70,287	69,872	69,132	68,617	69,517	72,462	75,252	75,068	74,312	73,061	71,006	68,023
Winter	12	80,080	12/28/2014	65,096	62,894	61,689	60,850	61,046	61,713	63,279	65,634	67,610	69,631	71,297	71,889	72,177	71,885	71,384	70,841	71,703	75,197	79,859	80,080	79,686	78,175	75,708	72,282
Winter	12	87,028	12/29/2014	69,260	67,552	66,592	66,301	66,844	68,919	73,112	78,320	80,808	81,885	82,235	82,056	81,176	80,191	79,353	78,551	78,782	82,145	86,760	87,028	86,032	84,138	80,942	76,842
Winter	12	90,469	12/30/2014	73,514	71,394	70,040	69,596	70,045	72,053	76,124	81,024	83,498	84,368	84,835	84,546	83,903	83,068	82,143	81,525	81,699	85,277	89,898	90,469	89,807	88,391	85,600	81,760
Winter	12	87,295	12/31/2014	78,397	76,276	75,084	74,643	74,916	76,608	80,225	84,667	86,756	87,295	87,025	85,912	84,074	82,059	80,547	79,082	78,827	82,019	86,521	85,825	83,749	81,673	79,285	76,651
Winter	1	80,590	1/1/2015	74,302	72,198	70,655	69,594	69,047	69,505	70,688	72,086	72,591	73,799	75,195	75,862	75,617	74,496	73,328	72,634	73,366	76,709	80,590	80,452	79,243	77,643	74,923	71,386
Winter	1	81,261	1/2/2015	68,324	66,213	64,941	64,462	64,877	66,395	69,805	74,000	76,553	77,743	78,710	78,685	77,882	77,066	76,336	75,716	75,650	78,372	81,261	80,693	79,319	77,434	74,774	71,242
Winter	1	78,000	1/3/2015	67,747	65,265	63,545	62,636	62,546	63,060	64,470	66,761	68,893	70,777	72,901	74,102	74,525	74,079	73,399	72,703	72,970	75,211	78,000	77,738	76,632	75,134	72,677	69,718
Winter	1	88,160	1/4/2015	66,815	64,569	63,269	62,669	62,756	63,692	65,269	67,845	70,420	72,812	74,609	75,680	76,385	76,924	76,920	76,852	77,926	81,558	87,218	88,160	87,835	86,160	83,463	80,201
Winter	1	97,062	1/5/2015	77,786	76,794	76,345	76,648	77,844	80,943	86,991	94,113	96,101	95,533	94,776	93,804	92,414	91,114	89,877	88,956	88,955	91,770	95,949	97,062	96,223	94,240	90,584	86,246
Winter	1	94,607	1/6/2015	82,462	80,516	79,482	79,100	79,434	81,993	87,173	93,476	94,607	93,321	91,767	89,979	88,160	86,978	86,046	85,210	85,509	88,393	92,789	94,147	93,489	91,959	88,699	84,845
Winter	1	103,050	1/7/2015	81,808	80,001	79,104	79,045	79,825	82,577	88,014	94,214	96,147	95,821	95,476	95,020	93,982	93,008	92,313	91,688	92,164	95,543	101,268	103,050	102,782	101,355	98,204	94,363
Winter	1	104,733	1/8/2015	91,587	89,965	89,021	88,838	89,549	92,045	96,921	103,269	104,733	103,792	102,669	101,391	100,062	98,460	96,974	95,717	95,635	98,184	102,104	102,707	101,414	99,240	94,998	89,943
Winter	1	98,484	1/9/2015	86,369	83,948	82,888	82,303	83,006	85,109	90,197	96,298	97,923	97,331	96,533	95,815	94,489	93,147	92,205	91,378	91,393	93,851	98,192	98,484	97,424	95,632	92,716	89,166
Winter	1	92,037	1/10/2015	86,101	83,864	82,785	82,410	82,751	83,982	86,075	88,974	90,989	92,037	91,732	90,072	87,668	85,123	83,150	81,626	81,904	84,599	88,922	89,242	88,296	86,686	84,005	80,352
Winter	1	84,899	1/11/2015	77,078	74,723	73,393	72,450	72,131	72,475	73,738	75,947	77,727	79,517	80,161	79,916	79,361	78,775	78,120	77,453	77,853	80,831	84,743	84,899	83,801	81,445	78,260	74,310
Winter	1	93,117	1/12/2015	71,393	69,770	68,736	68,553	69,428	72,078	77,476	84,282	86,621	86,275	86,419	86,475	85,953	85,558	85,017	84,479	84,562	87,357	92,219	93,117	92,436	90,620	87,215	82,936
Winter	1	96,466	1/13/2015	79,616	77,768	76,751	76,570	77,369	80,236	85,850	92,825	94,717	93,706	92,805	91,872	90,383	89,376	88,314	87,440	87,504	90,347	95,340	96,466	95,894	93,830	90,104	85,357
Winter	1	95,412	1/14/2015	81,989	80,251	79,206	78,992	79,599	81,785	87,245	93,841	95,412	94,730	93,678	92,364	90,959	89,446	88,277	87,415	87,502	90,024	94,410	94,848	93,728	91,333	87,180	82,260
Winter	1	91,641	1/15/2015	78,535	76,617	75,452	75,027	75,611	78,008	83,659	89,983	91,641	90,222	88,999	87,713	86,205	84,730	83,493	82,140	81,750	83,499	88,509	90,101	89,692	87,897	84,616	80,135
Winter	1	91,902	1/16/2015	77,038	75,315	74,378	74,371	75,196	77,847	83,400	90,174	91,902	90,292	87,957	85,476	83,050	80,875	79,289	77,748	77,137	78,702	82,884	83,869	83,326	82,173	79,877	76,406
Winter	1	79,190	1/17/2015	73,596	71,663	70,434	69,921	70,000	70,939	73,099	76,072	78,246	79,190	78,448	76,727	74,701	72,680	70,837	69,603	69,628	71,713	75,619	76,388	75,619	74,034	71,944	68,909
Winter	1	75,607	1/18/2015	66,344	64,381	63,340	63,081	63,333	64,080	65,928	68,641	70,904	72,445	72,373	71,107	69,906	68,836	67,756	66,788	66,736	68,786	73,260	75,607	75,217	74,000	72,140	69,439
Winter	1	83,172	1/19/2015	67,323	66,196	65,780	65,958	67,058	69,691	74,798	80,731	83,172	83,113	82,100	80,446	78,647	77,167	75,979	74,939	74,846	76,665	80,374	82,087	81,204	79,346	75,891	71,834
Winter	1	83,665	1/20/2015	68,686	66,927	65,989	65,840	66,388	69,203	75,008	81,896	83,665	82,363	80,985	79,644	78,246	77,176	76,786	76,053	76,096	77,908	81,455	82,536	81,715	79,712	76,444	71,924
Winter	1	84,002	1/21/2015	68,667	66,787	65,823	65,532	66,192	68,784	74,413	81,451	83,300	82,045	80,886	79,995	78,893	78,153	77,792	77,276	77,203	79,063	82,785	84,002	83,032	81,135	77,756	73,368
Winter	1	88,377	1/22/2015	70,050	68,079	66,936	66,631	67,238	69,661	75,204	82,039	83,847	83,226	83,057	82,737	82,004	81,590	81,293	80,895	81,421	83,779	87,711	88,377	87,389	85,374	81,619	76,785
Winter	1	86,266	1/23/2015	73,330	71,253	70,062	69,486	69,981	72,326	77,530	84,236	86,266	85,968	85,926	85,366	84,016	82,694	81,622	80,763	80,526	81,992	85,391	85,849	84,675	83,025	80,133	76,739
Winter	1	79,412	1/24/2015	73,411	71,284	70,052	69,708	69,793	70,803	73,155	76,395	78,592	79,412	78,731	77,029	74,852	72,784	70,751	69,246	68,748	70,329	74,503	76,095	75,604	74,490	72,578	69,661
Winter	1	80,008	1/25/2015	67,091	65,340	64,297	63,766	63,843	64,662	66,398	68,901	71,376	72,970	73,283	72,603	71,953	71,375	70,698	70,135	70,826	73,442	78,088	80,008	79,519	77,948	75,220	71,945
Winter	1	87,302	1/26/2015	69,377	67,901	67,446	67,570	68,736	71,723	77,820	85,325	87,302	86,366	85,468	84,269	82,761	81,575	80,639	79,393	78,982	80,406	84,426	86,456	85,485	83,332	79,728	75,274
Winter	1	85,506	1/27/2015	71,909	70,061	68,932	68,682	69,339	71,778	77,295	84,315	85,506	84,123	82,545	81,249	79,960	79,028	78,338	77,509	77,223	78,532	82,574	84,421	83,788	82,117	78,685	74,574
Winter	1	86,794	1/28/2015	71,441	69,846	69,124	69,112	69,777	72,639	78,667	85,485	86,794	85,010	83,188	81,450	79,767	78,369	77,612	76,787	76,759	78,335	82,357	84,045	82,965	81,192	77,797	73,091
Winter	1	84,553	1/29/2015	69,554	67,422	66,201	65,656	66,003	68,230	73,616	80,383	82,303	81,574	81,311	81,075	80,406	79,996	79,867	79,364	79,397	80,478	83,407	84,553	83,630	81,716	78,340	74,087
Winter	1	85,804	1/30/2015	70,823	68,862	67,873	67,696	68,514	71,202	76,812	83,922	85,804	84,925	83,962	82,631	80,812	79,229	77,649	76,131	75,598	76,686	80,771	82,828	82,353	81,260	79,046	75,809
Winter	1	78,702	1/31/2015	72,826	70,539	69,612	69,138	69,150	70,035	72,127	74,976	77,090	78,690	78,702	77,443	75,558	73,838	72,654	72,085	72,011	73,757	77,066	78,043	76,975	75,622	73,475	70,497
Winter	2	78,886	2/1/2015	67,603	65,501	64,175	63,604	63,357	63,899	65,365	67,467	69,401	71,631	73,262	73,766	74,106	74,235	74,141	73,844	74,302	76,023	78,596	78,886	78,024	77,092	75,838	73,313
Winter	2	92,168	2/2/2015	70,687	69,521	69,230	69,807	71,092	74,085	80,007	87,457	90,063	90,005	89,646	88,456	86,800	85,179	83,837	82,451	82,136	83,921	88,963	92,168	91,676	89,953	86,706	82,153
Winter	2	92,824	2/3/2015	78,999	77,337	76,610	76,339	77,031	79,610	85,145	91,907	92,824	91,519	89,839	88,360	86,404	84,735	83,308	82,285	81,978	83,564	87,769	89,991	89,218	87,232	83,366	78,767
Winter	2	90,369	2/4/2015	75,177	72,966	71,761	71,329	71,860	74,357	79,824	86,481	87,514	86,618	85,816	85,147	84,151	83,596	83,117	82,760	82,958	84,346	88,095	90,369	89,697	88,094	84,790	80,542
Winter	2	92,801	2/5/2015	77,663	75,990	75,477	75,521	76,458	79,062	84,770	91,631	92,801	91,441	89,899	88,350	86,458	84,891	83,615	82,275	81,708	82,882	87,890	91,410	91,457	89,974	86,748	82,619
Winter	2	92,183	2/6/2015	79,608	77,809	76,999	76,535	77,154	79,509	84,836	91,273	92,183	90,723	88,726	86,134	83,629	81,372	79,693	77,961	76,917	77,214	80,362	82,660	82,123	80,991	78,696	75,488
Winter	2	77,785	2/7/2015	72,273	70,441	69,280	68,723	68,760	69,891	72,161	75,245	76,959	77,785	76,649	74,458	72,154	69,903	68,096	66,778	66,517	67,394	70,794	73,139	72,325	71,090	68,925	65,950
Winter	2	75,427	2/8/2015	63,304	61,414	60,354	59,663	59,677	60,263	61,657	63,917	65,753	67,558	68,252	67,748	67,547	67,450	67,149	66,986	67,594	69,463	72,998	75,427	74,867	72,761	70,286	66,782
Winter	2	85,379	2/9/2015	64,249	62,749	62,093	62,009	62,851	65,800	71,678	78,811	80,947	81,230	81,361	81,295	80,858	80,435	80,019	79,358	79,143	80,045	83,209	85,379	84,424	82,396	78,767	74,372
Winter	2	85,866	2/10/2015	71,068	69,223	68,354	68,200	69,032	71,590	77,527	84,377	85,866	85,015	83,918	82,531	81,007	79,479	78,408	77,232	76,661	77,768	81,282	84,452	84,408	82,834	79,400	75,218
Winter	2	85,981	2/11/2015	72,095	70,290	69,301	69,069	69,906	72,454	78,226	85,150	85,981	84,605	83,201	81,820	80,632	79,758	79,136	78,656	78,515	79,680	82,751	85,756	85,375	83,963	80,815	76,710
Winter	2	89,196	2/12/2015	73,681	72,206	71,435	71,462	72,509	75,426	81,456	88,535	89,851	89,088	88,165	86,906	85,476	84,180	83,416	82,460	82,105	83,262	87,086	90,538	90,381	89,196	86,121	82,139
Winter	2	92,340	2/13/2015	78,890	77,144	76,175	76,246	76,963	79,421	84,734	91,110	92,340	91,203	89,747	87,765	85,460	83,263	81,850	80,333	79,610	80,023	82,617	85,300	84,607	83,344	81,029	77,552
Winter	2	83,778	2/14/2015	74,604	72,776	71,596	71,042	71,440	72,524	74,790	77,569	79,686	81,171	81,075	79,991	78,699	77,301	76,185	75,331	75,707	77,016	80,596	83,778	83,234	82,005	80,120	77,411
Winter	2	86,460	2/15/2015	75,144	73,539	72,750	72,441	72,627	73,703	75,288	77,521	79,399	81,094	81,651	80,912	79,981	79,031	77,983	77,099	77,633	79,669	83,763	86,460	85,639	83,970	81,280	78,107
Winter	2	93,857	2/16/2015	75,594	73,982	73,096	73,046	73,663	75,835	80,190	85,097	87,024	88,298	89,216	89,384	88,754	88,077	87,353	86,607	86,527	87,742	91,087	93,857	92,934	90,943	87,706	83,715
Winter	2	94,782	2/17/2015	81,103	79,672	79,002	79,032	79,822	82,379	87,668	93,306	94,667	94,782	93,981	92,700	90,878	89,172	87,516	86,154	85,489	86,550	90,053	93,938	93,792	92,215	88,856	84,738
Winter	2	96,371	2/18/2015	81,861	80,477	79,803	79,946	80,701	83,319	88,880	94,831	96,001	94,745	93,522	92,296	90,812	89,671	88,705	87,714	87,577	88,696	92,401	96,343	96,371	95,287	92,427	88,427
Winter	2	99,150	2/19/2015	85,565	84,135	83,507	83,710	84,608	87,141	92,367	98,171	99,150	98,143	96,569	94,822	92,466	90,626	89,091	87,582	87,272	88,231	91,935	96,220	96,391	95,096	92,162	88,163
Winter	2	95,864	2/20/2015	85,079	83,433	82,504	82,206	82,678	84,639	89,249	94,778	95,864	95,342	94,318	92,893	90,917	89,236	87,990	86,730	86,113	86,432	88,390	89,930	88,390	86,287	82,914	78,789
Winter	2	79,998	2/21/2015	75,319	72,677	70,984	70,110	69,708	69,950	71,760	73,804	75,422	77,591	78,548	78,414	77,447	76,157	74,662	73,379	73,096	74,190	76,918	79,998	79,508	78,239	76,053	73,082
Winter	2	86,490	2/22/2015	70,464	68,720	67,762	67,401	67,392	67,970	69,623	71,655	73,418	75,733	76,947	76,978	76,776	76,714	76,377	76,199	76,832	78,904	82,807	86,490	86,424	84,991	82,641	79,523
Winter	2	98,370	2/23/2015	77,410	76,055	75,708	75,990	77,342	80,356	86,137	92,714	94,542	94,478	94,090	93,577	92,742	91,846	90,648	89,529	89,267	90,703	94,424	98,370	97,812	95,780	91,991	87,424
Winter	2	95,668	2/24/2015	84,151	82,240	81,172	80,802	81,409	83,791	88,793	94,630	95,668	94,948	93,972	92,588	90,900	89,075	87,424	85,627	84,710	85,537	88,492	92,455	92,134	90,084	86,378	81,549
Winter	2	92,598	2/25/2015	78,512	76,813	75,895	75,865	76,677	79,273	84,663	90,596	91,469	90,569	89,907	88,924	87,700	86,476	85,627	84,855	84,689	85,969	88,905	92,598	92,521	90,588	87,184	82,938
Winter	2	95,046	2/26/2015	79,690	77,851	77,162	77,087	77,887	80,625	86,287	92,303	93,453	93,212	92,389	91,173	89,343	87,951	86,995	85,844	85,585	86,778	89,934	94,457	95,046	93,808	90,670	86,743
Winter	2	97,543	2/27/2015	83,852	82,445	81,788	81,933	82,742	85,407	90,958	96,964	97,543	95,926	93,900	91,503	88,977	86,771	85,056	83,415	82,713	83,443	86,150	90,437	90,670	89,674	87,451	84,386
Winter	2	87,028	2/28/2015	81,593	79,796	78,824	78,439	78,632	79,673	81,799	84,116	85,951	87,028	86,323	84,088	81,438	78,946	76,909	75,578	75,545	76,577	79,133	82,341	82,027	80,747	78,349	75,282
Spring	3	81,816	3/1/2015	72,404	70,406	69,130	68,463	68,298	68,682	69,977	71,573	73,090	75,206	75,893	75,744	75,245	74,785	73,957	73,507	73,823	74,978	77,915	81,816	81,652	79,864	76,907	73,553
Spring	3	87,149	3/2

Contains Proprietary Material
Do Not Distribute

Spring	3	70,760	3/29/2015	64,013	62,006	61,052	60,564	60,567	61,138	62,530	64,537	66,107	67,590	68,245	68,115	67,828	67,470	66,807	66,381	66,378	67,455	68,096	68,419	70,102	70,760	68,007	64,300
Spring	3	74,416	3/30/2015	60,934	59,003	57,978	57,620	58,393	60,801	66,133	72,309	73,837	73,772	74,008	73,964	73,806	73,570	73,351	72,887	72,375	72,285	71,917	72,011	74,112	74,416	70,890	65,977
Spring	3	74,274	3/31/2015	61,992	59,301	57,852	57,323	57,647	59,762	64,634	70,682	72,214	72,492	72,836	72,956	72,954	72,912	73,061	72,764	72,353	72,117	71,644	71,351	73,547	74,274	70,698	65,802
Spring	4	73,704	4/1/2015	61,805	59,283	57,906	57,197	57,597	59,600	64,377	70,102	71,504	71,654	72,043	72,302	72,549	72,834	73,161	72,785	72,467	72,052	71,517	71,151	73,211	73,704	70,316	65,582
Spring	4	74,414	4/2/2015	61,224	58,519	56,917	56,025	56,292	58,129	62,475	68,210	70,248	71,475	72,674	73,588	73,977	74,103	74,414	74,095	73,664	73,064	72,395	71,776	72,791	72,941	69,778	65,302
Spring	4	70,792	4/3/2015	61,136	58,207	56,538	55,714	55,538	56,730	59,741	63,763	65,965	68,290	69,915	70,792	70,773	70,691	70,549	70,094	69,527	69,364	68,784	68,189	69,243	70,140	68,017	64,881
Spring	4	65,696	4/4/2015	61,576	59,234	57,569	56,881	56,812	57,455	59,181	61,257	62,818	64,839	65,696	65,215	64,272	63,148	62,016	61,293	61,025	61,305	61,543	61,708	63,993	65,621	64,187	61,402
Spring	4	64,726	4/5/2015	58,506	56,066	54,772	54,043	53,969	54,569	56,039	57,987	59,791	61,749	62,362	61,845	61,130	60,079	58,809	57,867	57,474	57,703	58,394	59,801	63,171	64,726	62,882	59,849
Spring	4	74,499	4/6/2015	57,000	55,351	54,443	54,278	54,910	57,179	61,990	67,611	70,109	71,594	72,881	73,621	74,093	73,963	73,863	73,318	72,862	72,365	72,377	72,631	74,499	74,407	71,087	66,795
Spring	4	76,667	4/7/2015	62,523	59,728	58,156	57,307	57,425	59,098	63,711	69,488	71,903	73,044	74,183	75,291	75,723	75,836	75,932	75,844	75,658	75,951	75,914	75,552	76,667	76,450	72,887	67,932
Spring	4	77,392	4/8/2015	63,854	60,981	59,215	58,222	58,337	60,139	64,570	70,304	72,435	73,606	74,717	75,496	76,200	76,861	77,392	77,175	77,286	77,024	76,771	76,444	77,253	77,300	73,759	68,733
Spring	4	78,300	4/9/2015	64,503	61,702	59,887	58,929	59,065	60,640	65,073	70,808	73,328	74,695	75,954	76,976	77,483	77,833	78,300	78,094	77,946	78,032	77,384	76,691	77,465	77,209	73,631	68,574
Spring	4	74,092	4/10/2015	63,996	61,031	59,230	58,148	58,035	59,646	63,825	69,206	71,547	72,792	73,704	74,092	73,732	73,458	72,830	71,760	70,512	69,520	68,435	67,941	69,066	70,208	68,008	64,350
Spring	4	66,352	4/11/2015	60,640	58,302	56,693	56,127	55,997	56,863	58,811	60,696	62,549	64,549	65,478	65,603	65,225	65,041	64,581	64,236	63,943	63,920	63,830	63,649	64,940	66,352	64,217	60,960
Spring	4	68,400	4/12/2015	57,700	55,393	53,848	53,008	52,796	53,053	54,204	55,473	57,145	59,574	61,122	61,794	62,340	62,711	62,806	62,662	63,057	63,840	64,499	65,275	67,347	68,400	65,569	61,581
Spring	4	73,984	4/13/2015	58,059	55,812	54,348	53,942	54,380	56,607	61,726	67,751	70,214	71,391	72,459	73,389	73,804	73,915	73,956	73,674	73,336	73,143	72,675	72,314	73,312	73,984	70,422	65,594
Spring	4	72,500	4/14/2015	61,296	58,663	57,128	56,223	56,600	58,617	63,847	69,405	71,381	71,944	72,307	72,491	72,191	72,111	71,795	71,204	70,345	70,040	69,797	69,677	71,116	72,500	69,402	64,716
Spring	4	73,732	4/15/2015	60,367	57,730	56,261	55,643	55,737	57,658	62,511	67,866	69,718	70,371	71,143	71,784	71,937	72,504	72,943	72,922	72,607	72,181	71,480	71,134	72,349	73,732	70,601	65,508
Spring	4	74,143	4/16/2015	61,216	58,341	56,730	55,877	56,054	57,805	62,606	68,045	70,257	71,210	72,128	72,538	73,152	73,546	73,819	73,408	73,201	72,942	72,163	71,990	73,296	74,143	70,829	65,845
Spring	4	75,132	4/17/2015	61,403	58,683	56,967	56,053	56,118	57,697	62,113	67,105	69,243	70,524	72,065	73,173	73,720	74,261	74,986	75,132	74,919	74,644	73,550	72,068	71,978	72,801	70,081	65,670
Spring	4	67,219	4/18/2015	61,292	57,899	55,718	54,499	54,000	54,429	55,828	57,307	59,413	62,480	64,617	65,752	66,132	66,097	65,950	65,884	65,671	65,757	65,632	65,253	66,099	67,219	65,021	61,437
Spring	4	69,364	4/19/2015	57,863	55,229	53,413	52,232	51,763	51,970	52,856	53,725	55,925	59,016	61,329	62,836	63,991	64,829	65,424	66,037	66,910	67,905	68,634	68,548	69,322	69,364	66,500	62,386
Spring	4	73,737	4/20/2015	58,673	56,394	55,118	54,547	55,017	56,963	61,954	67,758	70,314	71,617	72,561	73,319	73,609	73,585	73,696	73,039	72,459	72,558	72,439	72,102	72,926	73,737	70,528	65,819
Spring	4	74,218	4/21/2015	61,814	59,102	57,824	57,230	57,315	59,574	64,636	70,007	71,938	72,510	72,630	72,750	72,670	72,694	72,519	72,275	72,046	72,228	71,981	71,784	72,697	74,218	70,997	66,164
Spring	4	75,709	4/22/2015	61,922	59,478	58,312	57,474	57,890	59,745	64,758	69,888	71,849	72,464	72,986	73,667	74,137	74,433	74,748	74,518	74,452	74,097	73,702	73,317	74,200	75,709	72,653	68,164
Spring	4	75,289	4/23/2015	64,171	61,736	60,256	59,589	59,865	62,014	66,954	71,946	73,622	73,927	74,180	74,455	74,416	74,350	74,285	73,778	73,358	73,185	72,491	72,060	73,130	75,289	72,621	67,980
Spring	4	73,650	4/24/2015	63,837	61,360	59,997	59,286	59,544	61,302	65,878	70,610	72,681	73,229	73,566	73,650	73,228	73,018	72,675	71,922	71,324	70,865	70,227	69,770	70,559	71,149	68,909	65,376
Spring	4	68,587	4/25/2015	61,732	59,197	57,436	56,632	56,323	56,871	58,365	60,104	62,734	65,767	67,835	68,587	68,359	67,733	67,032	66,522	66,451	66,598	66,781	66,485	66,734	67,994	66,173	62,638
Spring	4	69,653	4/26/2015	59,211	56,846	55,450	54,648	54,392	54,756	55,714	56,612	58,694	61,179	62,601	63,243	63,799	64,158	64,202	64,476	64,895	65,535	66,101	66,249	67,408	69,653	67,389	63,202
Spring	4	72,204	4/27/2015	59,716	57,528	56,520	56,059	56,597	59,005	64,106	69,225	71,726	72,179	72,204	71,956	71,770	71,719	71,331	70,587	70,156	69,900	69,696	69,755	70,352	72,015	69,423	64,720
Spring	4	71,779	4/28/2015	60,716	58,289	57,053	56,508	56,896	58,892	63,600	68,627	70,622	70,982	71,243	71,504	71,324	71,343	71,358	70,909	70,333	69,994	69,495	69,131	69,928	71,779	68,992	64,136
Spring	4	71,917	4/29/2015	59,911	57,274	56,091	55,509	55,932	58,002	62,897	67,784	69,889	70,246	70,598	70,949	70,958	71,181	71,411	71,183	70,707	70,532	70,191	69,828	70,060	71,917	69,151	64,150
Spring	4	72,715	4/30/2015	59,768	57,253	55,645	54,902	55,232	57,112	61,989	66,933	69,366	70,062	70,679	71,202	71,394	71,568	72,044	72,076	71,988	71,894	71,334	70,842	70,921	72,715	70,296	65,188
Spring	5	72,058	5/1/2015	60,905	57,730	56,073	55,226	55,421	57,428	62,104	66,856	69,056	69,762	70,645	71,083	71,269	71,637	72,058	71,894	71,827	71,075	70,344	69,351	68,735	70,227	67,765	63,459
Spring	5	67,296	5/2/2015	59,068	55,785	53,975	52,841	52,372	52,954	54,596	55,802	58,625	61,575	63,421	64,320	64,903	65,344	65,738	66,104	66,645	67,034	67,113	66,564	65,909	67,296	65,168	61,231
Spring	5	71,682	5/3/2015	57,450	54,723	52,622	51,514	50,698	50,576	51,145	51,768	54,753	58,095	60,973	62,681	64,286	65,738	66,836	67,707	68,693	69,837	70,330	70,000	69,979	71,682	69,111	64,141
Spring	5	79,354	5/4/2015	59,494	56,605	54,872	53,909	54,186	56,029	60,666	66,026	69,476	71,482	73,552	75,398	76,688	78,106	79,059	79,309	79,354	79,134	78,524	77,373	77,140	78,048	74,412	68,502
Spring	5	80,151	5/5/2015	63,067	59,721	57,576	56,437	56,262	57,727	62,252	67,213	70,404	72,414	74,347	76,130	77,644	78,872	79,819	80,151	80,143	79,983	79,228	78,099	77,437	78,274	74,795	69,022
Spring	5	82,568	5/6/2015	63,653	60,633	58,274	56,991	56,915	58,432	62,696	67,486	70,681	72,754	74,726	76,773	78,379	79,869	81,317	82,101	82,519	82,568	81,904	80,785	79,614	80,460	76,970	70,756
Spring	5	85,941	5/7/2015	65,209	61,480	59,051	57,625	57,409	59,027	63,061	67,951	71,707	74,191	76,877	79,536	81,553	83,430	84,851	85,671	85,941	85,731	84,599	82,883	81,857	82,583	78,736	72,624
Spring	5	83,086	5/8/2015	67,087	63,160	60,663	59,055	58,569	59,899	63,660	68,623	72,291	75,027	77,462	79,537	81,055	82,122	83,086	83,025	82,645	82,113	80,472	78,440	77,240	77,509	74,858	70,024
Spring	5	73,826	5/9/2015	65,226	61,526	59,080	57,600	56,730	56,936	57,910	59,348	62,359	65,816	68,379	70,062	71,327	71,974	72,481	72,933	73,483	73,826	73,523	72,361	71,578	72,720	70,914	66,663
Spring	5	74,751	5/10/2015	62,311	59,049	56,779	55,338	54,534	54,545	55,144	55,757	58,912	62,809	65,740	67,889	69,459	70,773	71,665	72,419	73,221	73,754	73,714	73,310	73,582	74,751	72,299	67,616
Spring	5	80,130	5/11/2015	63,226	60,576	58,796	57,904	57,921	59,859	64,525	69,690	73,159	75,060	76,703	78,506	79,562	80,072	80,130	79,804	78,876	78,406	77,588	76,734	75,898	76,695	73,587	68,038
Spring	5	75,704	5/12/2015	63,326	60,329	58,406	57,341	57,331	58,913	63,083	67,972	70,921	72,181	73,314	74,148	74,803	75,267	75,704	75,435	74,945	74,608	73,879	73,140	73,106	74,182	72,017	66,864
Spring	5	75,440	5/13/2015	62,550	59,713	58,051	57,093	57,178	58,935	63,159	67,935	70,647	71,702	72,687	73,528	74,139	74,713	75,362	75,322	75,176	74,953	74,497	73,696	73,477	75,440	72,849	67,599
Spring	5	77,641	5/14/2015	63,055	60,179	58,307	57,224	57,170	58,926	63,099	68,034	70,988	72,213	73,659	74,766	75,661	76,536	77,470	77,641	77,379	77,333	76,828	76,205	76,086	76,978	73,989	68,731
Spring	5	80,591	5/15/2015	64,243	61,140	59,424	58,258	58,094	59,474	63,598	68,499	71,771	74,028	76,160	77,827	79,291	80,256	80,591	80,281	79,513	78,774	77,442	75,733	74,745	75,887	73,711	69,160
Spring	5	75,903	5/16/2015	64,824	61,473	59,358	57,907	57,333	57,549	58,662	60,171	63,436	66,994	70,022	72,043	73,469	74,351	75,070	75,407	75,776	75,903	75,607	74,696	73,636	74,796	73,266	69,216
Spring	5	79,503	5/17/2015	64,981	61,759	59,584	58,043	57,332	57,325	57,539	58,399	61,422	65,531	69,108	71,627	73,724	75,357	76,120	77,250	78,361	79,208	79,503	78,824	77,882	78,821	76,727	71,700
Spring	5	85,504	5/18/2015	66,883	63,514	61,374	60,201	60,068	61,824	66,153	71,455	75,739	78,430	80,619	82,726	84,128	84,881	85,504	85,379	84,774	84,172	83,089	81,580	79,829	79,770	76,615	70,670
Spring	5	77,567	5/19/2015	65,267	61,632	59,935	58,546	58,480	59,809	63,042	67,861	71,031	72,484	73,711	74,870	75,677	76,482	77,189	77,567	77,530	77,550	76,540	75,466	74,990	75,857	73,472	68,584
Spring	5	78,644	5/20/2015	64,196	61,493	59,357	58,487	58,582	59,913	63,764	68,454	71,705	73,454	74,919	76,471	77,297	78,008	78,644	78,252	78,147	78,050	77,633	76,976	76,348	76,979	74,599	69,460
Spring	5	76,160	5/21/2015	64,911	62,209	60,315	59,311	59,003	60,688	64,589	68,720	71,613	73,311	74,622	75,306	75,805	76,160	76,117	75,274	74,203	73,167	72,117	71,334	70,796	72,716	71,463	66,803
Spring	5	74,023	5/22/2015	62,346	59,598	57,728	56,527	56,359	57,861	61,158	65,485	68,614	69,965	71,109	71,983	72,457	72,988	73,456	73,868	74,023	73,787	72,928	71,242	70,098	71,062	69,646	65,155
Spring	5	71,456	5/23/2015	60,592	57,386	55,335	54,061	53,357	53,462	53,995	54,878	58,174	61,815	64,511	66,493	67,974	69,074	69,848	70,414	70,937	71,456	71,305	70,301	68,837	69,610	68,159	64,436
Spring	5	71,318	5/24/2015	60,460	57,160	55,073	53,762	53,046	52,818	52,953	53,598	56,643	60,675	63,849	66,324	68,339	69,623	70,307	70,756	71,098	71,264	71,318	70,460	69,617	70,379	68,738	65,009
Spring	5	76,702	5/25/2015	61,045	57,818	55,929	54,643	54,032	54,290	55,151	55,853	58,449	62,521	66,526	69,816	72,238	73,794	74,642	75,332	76,118	76,702	76,674	75,752	74,962	75,434	73,632	68,788
Spring	5	86,817	5/26/2015	63,918	60,478	58,454	57,262	57,039	58,730	62,702	68,282	72,731	75,505	77,915	80,153	82,066	83,649	84,978	85,681	86,428	86,817	85,955	84,495	82,533	82,048	79,285	73,426
Spring	5	85,857	5/27/2015	68,003	64,172	61,721	60,308	60,028	61,458	64,933	69,746	74,050	76,667	79,077	81,174	82,583	83,450	84,484	85,021	85,554	85,857	85,638	84,623	82,731	82,470	79,862	73,577
Spring	5	92,466	5/28/2015	67,848	63,700	61,015	59,525	58,967	60,217	63,234	68,120	72,726	76,321	79,659	82,901	85,810	88,554	90,865	92,138	92,466	92,350	91,190	89,226	86,876	86,173	83,342	77,038
Spring	5	91,612	5/29/2015	70,933	66,445	63,505	61,874	61,373	62,784	65,871	70,555	75,333	79,054	82,473	85,479	87,800	89,477	90,910	91,422	91,612	90,800	88,863	86,292	83,678	83,132	80,479	75,264
Spring	5	77,808	5/30/2015	69,687	65,466	62,566	60,636	59,618	59,589	60,139	61,351	65,265	69,735	73,476	76,012	77,303	77,808	77,549	77,274	76,664	75,551	73,945	72,304	70,760	70,622	69,244	65,440
Spring	5	67,878	5/31/2015	61,563	58,285	56,038	54,674	53,999	53,809	53,887	54,227	56,981	60,282	62,622	64,449	65,761	66,528	66,718	66,229	66,138	66,541	66,985	67,009	66,866	67,878	66,938	63,263
Summer	6	78,295	6/1/2015	59,293	56,794	55,435	54,746	54,955	56,901	60,747	65,403	68,966	71,486	73,275	74,842	76,016	77,068	77,987	78,205	78,295	78,035	77,491	76,302	75,238	75,468	73,876	68,847
Summer	6	81,231	6/2/2015	63,997	60,620	58,451	57,064	56,958	58,393	61,598	66,039	69,809	72,253	74,742	76,668	78,265	79,581	80,748	81,113	81,231	80,956	80,370	79,072	77,545	77,887	76,005	70,668
Summer	6	84,216	6/3/2015	65,268	61,639	59,322	57,976	57,531	59,020	62,042	66,613	70,573	73,234	75,791	78,002	79,860	81,426	82,866	83,586	84,061	84,216	83,597	82,122	80,466	80,219	78,144	72,558
Summer	6	89,968	6/4/2015	67,114	63,237	60,731	59,291	58,983	60,213	63,514	67,879	72,191	75,438	78,565	81,538	83,751	85,763	87,709	88,860	89,642	89,968	89,308	87,754	85,659	85,196	82,951	76,780
Summer	6	91,874	6/5/2015	70,661	66,266	63,373	61,500	60,769	61,706	64,582	68,877	73,513	77,462	81,191	84,473	87,115	89,039	90,865	91,734	91,874	91,338	89,671	87,277	84,213	82,617	79,938	74,624
Summer	6	82,834	6/6/2015	68,878	64,484	61,193	59,132	57,941	57,867	57,894	59,092	62,635	66,978	70,762	74,041	76,558	78,178	79,642	80,864	82,135	82,834	82,622	81,073	78,888	78,031	76,273	71,607
Summer	6	88,975	6/7/2015	66,647	62,549	59,797	58,052	57,003	56,700	56,556	57,193	60,910	66,221	71,148	75,581	79,073	82,097	84,127	85,494	87,192	88,611	88,975	87,843	85,913	84,716	82,363	77,035
Summer	6	96,644	6/8/2015	71,554	67,473	64,441	62,570	61,984	63,190	66,392	71,080	76,008	80,014	83,823	87,350	90,279	92,800	95,045	95,993	96,558	96,644	95,406	93,158	90,495	88,828	85,605	78,979
Summer	6	98,343	6/9/2015	72,521	68,094	65,076	63,187	62,481	63,552	66,183	70,602	75,548	79,897	83,957	87,993	91,037	93,774	96,195	97,424	98,172	98,343	97,702	95,833	93,255	91,721	88,807	81,934
Summer	6	105,843	6/10/2015	75,330	70,518	66,980	65,023	64,172	65,232	68,091	72,727	77,935	82,828	87,360	91,736	95,890	99,677	102,371	104,318	105,702	105,843	104,473	101,843	98,221	95,680	91,857	84,338
Summer	6	96,995	6/11/2015	77,089	71,924	68,381	66,162	65,154	66,019	68,634	73,109	77,856	81,838	85,979	89,618	92,500	94,536	96,258	96,995	96,872	95,672	93,964	91,974	89,857	88,915	86,330	80,350
Summer	6	93,077	6/12/2015	74,492	70,082	67,144	65,193	64,446	65,633	68,149	72,196	77,108	81,421	85,460	88,450	90,499	91,904	92,771	93,077	92,737	91,821	89,276	86,617	84,219	82,915	80,892	75,801
Summer	6	84,291	6/13/2015	70,561	66,461	63,600	61,870	60,840	60,973	61,708	63,462	67,247	71,862	75,640	79,009	81,245	82,567	83,278	83,511	83,963	84,291	83,559	82,058	80,137	79,884	78,417	74,234
Summer	6	88,888	6/14/2015	69,894	66,049	63,390	61,552	60,522	60,365	60,172	61,021	64,853	69,986	74,455	78,048	81,325	84,159	85,874	86,850	87,568	88,545	88,888	87,927	86,260	85,431	83,723	78,564
Summer	6	99,540	6/15/2015	72,973	68,930	66,101	64,691	64,353	65,786	68,983	74,046	79,556	83,989	88,096	92,010	95,423	97,750	99,308	99,540	99,365	98,805	97,399	95,270	92,831	90,967	88,007	82,126
Summer	6	97,065	6/16/2015	75,777	71,228	68,095	66,117	65,364	66,261	69,181	73,548	78,432	82,479	85,939	89,104	91,664	93,911	95,762	96,957	97,065	96,581	95,035	92,734	89,979	88,568	85,746	79,658
Summer	6	94,520	6/17/2015	73,650	69,271	66,369	64,607	63,882	65,326	68,187	72,365	76,747	80,610	84,277	87,526	90,257	92,269	93,841	94,464	94,520	93,985	92,630	90,939	88,905	88,185	85,998	80,404
Summer	6	95,926	6/18/2015	74,591	70,444	67,652	65,902	65,322	66,494	69,464	73,836	78,603	82,752	86,349	89,628	92,122	94,372	95,618	95,926	95,773	94,947	93,539	91,650	89,333	88,208	86,067	80,497
Summer	6	90,962	6/19/2015	74,385	70,094	67,102	64,989	64,402	65,209	67,870	71,679	75,992	79,467	82,616	85,211	87,175	88,672	90,282	90,907	90,962	90,437	88,890	86,396	84,169	82,897	81,178	76,490
Summer	6	89,737	6/20/2015	74,591	71,319	67,111	64,160	62,326	61,288	61,048	61,515	62,682	66,046	70,680	74,992	78,506	81,421	83,670	85,742	87,355	88,781	89,724	89,737	88,379	86,372	84,886	83,147	78,529
Summer	6	93,125	6/21/2015	73,141	68,621	64,996	62,762	61,362	60,811	60,344	61,204	64,917	70,319	75,335	79,379	83,093	86,052	88,413	90,248	91,775	92,941	93,125	92,110	90,097	88,887	87,013	81,561
Summer	6	106,061	6/22/2015	75,480	71,056	68,052	66,187	65,493	66,834	69,971	75,019	80,808	86,140	91,081	95,658	99,295	102,091	104,385	105,379	105,647	106,061	105,889	104,257	101,353	99,404	96,405	89,531
Summer	6	103,253	6/23/2015	82,765	77,140	73,349	70,681	69,450	70,171	72,609	76,933	81,506	85,797	89,704	93,432	96,316	99,352	101,736	102,924	103,253	102,996	101,289	98,821	95,130	92,795	89,878	82,928
Summer	6	99,475	6/24/2015	76,068	71,259	67,881	65,688	64,821	65,740	68,262	72,288	77,262	81,748	85,537	89,315	92,990	95,583	97,481	98,931	99,475	99,464	98,109	95,941	93,098	91,436	88,784	82,391
Summer	6	99,688	6/25/2015	76,148	71,422	68,430	66,424	65,638	66,656	69,746	73,623	78,081	81,983	85,411	88,991	92,396	95,650	98,187	99,304	99,688	99,120	97,795	95,795	92,822	91,095	88,289	82,009
Summer	6	93,149	6/26/2015	75,670	70,957	67,760	65,685	64,939	65,632	68,060	72,003	76,619	80,835	84,320	87,886	90,507	91,854	92,868	93,149	92,911	92,113	90,013	87,419	84,782	83,418	81,370	76,716
Summer	6	83,041	6/27/2015	71,449	67,131	64,185	62,418	61,214	61,087	61,525	62,323	65,645	69,995	73,980	77,033	79,022	80,381	81,332	81,894	82,651	83,041	82,605	81,003	78,915	77,450	75,773	71,552
Summer	6	82,311	6/28/2015	66,989	62,872	60,100	58,314	57,230	56,977	56,488	57,211	60,366	64,657	68,333	71,798	74,674	77,015	78,836	80,224	81,417	82,092	82,311	81,379	79,847	79,186	77,793	73,296
Summer	6	96,660	6/29/2015	68,356	64,713	62,303	60,907	60,705	62,242	65,289	69,517	74,608	79,070	83,038	86,860	90,169	92,538	94,773	96,133	96,549	96,660	95,616	93,635	90,584	88,963	86,020	79,925
Summer	6	94,097	6/30/2015	73,509	69,021	65,855	63,923	63,089	64,192	67,271	71,064	75,303

Contains Proprietary Material
Do Not Distribute

Summer	8	104,310	8/4/2015	78,853	73,853	70,247	67,944	66,966	67,874	70,802	74,146	78,498	83,093	87,926	92,478	96,416	99,492	102,175	103,701	104,310	103,941	102,433	100,044	96,790	95,393	91,521	84,734
Summer	8	102,044	8/5/2015	78,314	73,895	70,712	68,603	67,829	68,753	71,967	75,408	79,481	83,651	87,953	92,018	95,582	98,887	101,209	101,964	102,044	101,559	100,509	98,183	95,089	94,224	90,463	83,956
Summer	8	101,031	8/6/2015	78,044	73,815	70,646	68,564	67,939	68,996	72,362	75,969	79,264	82,995	86,819	90,309	93,300	95,747	98,383	99,948	100,958	101,031	99,852	97,662	94,759	93,882	90,114	83,970
Summer	8	104,310	8/7/2015	78,079	73,522	70,411	68,260	67,347	68,344	71,568	75,057	79,078	83,468	87,727	91,661	95,151	98,237	101,150	103,047	104,082	104,310	103,027	100,346	96,760	95,311	91,426	85,188
Summer	8	96,706	8/8/2015	79,170	74,309	70,899	68,494	67,004	66,791	67,553	68,136	70,984	76,081	81,104	85,605	89,161	91,875	93,735	94,864	96,038	96,706	96,197	94,112	91,550	91,005	87,788	82,370
Summer	8	98,955	8/9/2015	76,943	72,542	69,520	67,227	65,662	64,825	65,046	65,442	68,127	73,121	77,989	82,294	86,455	90,324	93,219	95,293	97,145	98,658	98,955	97,703	95,673	94,831	91,222	85,302
Summer	8	108,587	8/10/2015	79,304	75,219	72,297	70,438	69,936	71,144	75,122	79,193	83,268	87,819	92,403	96,840	100,743	103,948	106,287	107,189	108,172	108,587	107,475	105,248	101,730	99,780	95,118	87,312
Summer	8	105,165	8/11/2015	80,772	75,848	72,354	70,106	69,167	70,152	73,662	77,368	81,242	85,801	90,379	94,598	98,272	101,056	103,304	104,564	105,165	104,941	103,544	101,056	97,517	95,856	91,104	83,690
Summer	8	105,249	8/12/2015	77,292	72,509	69,267	67,108	66,283	67,149	70,741	74,388	78,209	82,569	86,781	91,353	95,338	98,693	101,633	103,534	104,905	105,249	104,145	101,807	98,204	96,689	91,887	84,564
Summer	8	108,275	8/13/2015	78,100	73,304	70,008	67,912	66,987	67,811	71,544	75,466	79,090	83,559	88,262	93,023	97,328	101,346	104,825	106,925	108,241	108,275	107,204	104,514	101,350	100,255	95,564	88,303
Summer	8	113,010	8/14/2015	81,380	76,404	72,854	70,482	69,300	70,256	74,049	78,203	82,057	86,836	92,026	96,992	101,827	105,899	109,219	111,553	113,010	112,605	110,588	106,746	102,195	99,582	94,690	87,541
Summer	8	106,502	8/15/2015	80,764	75,442	71,526	68,597	66,904	66,417	67,174	67,807	71,634	78,019	84,610	90,808	95,804	99,446	102,186	104,318	105,795	106,502	105,641	102,445	98,288	96,415	92,122	85,570
Summer	8	102,882	8/16/2015	79,201	73,948	70,319	67,546	65,777	65,189	65,335	65,671	69,117	75,519	81,970	87,789	92,730	96,544	99,356	100,987	102,134	102,882	102,334	100,137	97,423	96,195	91,623	85,040
Summer	8	107,374	8/17/2015	78,592	74,211	71,035	69,096	68,265	69,495	74,149	79,003	83,215	87,626	92,439	97,284	101,399	104,806	106,941	107,374	107,062	105,877	103,974	101,183	98,623	97,365	91,908	84,632
Summer	8	102,758	8/18/2015	78,254	73,725	70,798	68,615	68,036	69,333	73,658	78,339	81,708	85,364	89,603	93,975	97,586	100,379	102,328	102,758	102,143	101,063	99,278	96,889	95,098	94,415	89,669	82,918
Summer	8	92,760	8/19/2015	77,236	73,255	70,120	68,439	67,925	69,268	73,299	78,081	81,249	84,320	87,291	89,827	91,350	92,363	92,760	91,949	91,101	90,892	89,876	88,157	87,032	87,125	82,884	76,709
Summer	8	87,614	8/20/2015	71,361	67,687	64,972	63,292	62,774	64,014	67,992	72,182	74,855	77,457	79,826	82,005	83,424	84,782	86,254	87,138	87,332	87,614	86,534	84,973	83,525	83,667	80,177	74,244
Summer	8	91,430	8/21/2015	68,930	65,254	62,990	61,651	61,313	62,550	66,240	70,120	73,392	77,191	80,511	83,582	86,020	88,125	89,859	90,879	91,430	91,293	90,078	87,473	84,922	84,520	80,871	75,396
Summer	8	86,799	8/22/2015	70,272	66,238	63,368	61,558	60,610	60,801	61,693	62,712	65,446	70,176	74,581	78,190	81,235	83,544	85,318	86,114	86,799	86,665	85,891	83,561	81,718	81,410	77,826	72,991
Summer	8	86,515	8/23/2015	68,449	64,759	61,924	60,300	59,278	58,876	59,387	59,925	62,400	67,064	71,496	75,016	77,979	80,460	82,607	84,184	85,471	86,385	86,515	84,890	83,267	82,915	78,713	73,085
Summer	8	89,609	8/24/2015	68,055	64,528	62,229	60,955	60,620	62,035	65,909	70,253	73,382	76,404	79,573	82,467	84,512	86,520	88,197	89,121	89,546	89,609	88,584	86,794	85,551	85,087	80,265	74,431
Summer	8	85,445	8/25/2015	69,147	65,573	63,189	61,614	61,101	62,455	66,436	70,597	72,841	75,400	77,774	80,014	81,598	83,126	84,235	84,847	85,201	85,445	84,813	83,517	82,464	82,139	77,653	71,512
Summer	8	86,983	8/26/2015	66,470	62,993	60,962	59,570	59,341	60,621	64,531	69,081	71,629	74,168	76,633	79,126	81,016	82,669	84,439	85,566	86,575	86,983	86,488	85,006	83,697	83,461	78,865	72,560
Summer	8	88,283	8/27/2015	67,433	63,821	61,500	60,191	59,667	60,899	64,976	69,406	72,107	74,779	77,303	79,844	81,902	84,064	86,102	87,380	88,081	88,283	87,206	85,420	84,373	84,323	79,732	73,682
Summer	8	90,227	8/28/2015	68,403	64,584	62,225	60,667	60,420	61,525	65,461	69,727	72,693	75,622	78,590	81,531	84,048	86,197	88,261	89,525	90,227	89,984	88,357	85,693	84,095	83,049	79,073	73,959
Summer	8	84,600	8/29/2015	68,982	64,983	62,300	60,552	59,697	59,923	61,196	62,558	64,529	68,632	72,883	76,124	78,689	80,729	82,156	83,278	83,984	84,600	84,373	82,978	82,217	81,718	78,601	73,897
Summer	8	92,914	8/30/2015	69,423	65,477	62,828	61,104	60,035	59,605	60,117	60,859	63,040	67,452	71,905	76,261	80,296	84,001	87,095	89,248	91,156	92,575	92,914	91,426	90,355	89,459	84,485	78,014
Summer	8	106,821	8/31/2015	72,336	68,367	65,734	63,900	63,489	65,147	69,837	75,034	78,541	82,464	86,935	91,615	96,152	100,365	103,675	105,713	106,642	106,821	105,392	102,750	100,853	99,152	93,015	85,167
Fall	9	111,632	9/1/2015	78,420	73,827	70,313	68,235	67,365	68,409	72,822	78,415	81,291	85,392	90,310	95,690	100,720	104,757	108,351	110,577	111,488	111,632	110,073	107,298	105,607	103,721	96,819	88,889
Fall	9	110,663	9/2/2015	82,043	76,891	73,395	71,214	70,155	71,091	75,546	81,030	84,395	88,001	92,660	97,880	102,425	105,985	108,893	110,157	110,663	110,315	108,517	105,955	104,011	102,059	95,870	87,878
Fall	9	111,106	9/3/2015	80,737	75,771	72,224	70,067	69,076	70,288	74,795	80,350	83,624	87,848	92,740	97,942	102,825	106,553	108,941	110,206	111,039	111,106	109,440	106,465	104,334	102,403	96,172	88,290
Fall	9	109,524	9/4/2015	81,628	76,316	73,043	70,784	69,690	70,677	74,387	79,340	82,578	86,749	91,788	96,770	100,854	104,451	107,294	108,892	109,524	108,945	106,354	102,530	99,956	97,605	92,303	85,790
Fall	9	102,277	9/5/2015	79,530	74,413	70,758	68,259	66,582	66,075	66,670	67,924	70,353	75,869	81,829	87,581	92,522	96,197	98,968	100,679	101,957	102,277	101,152	97,922	95,713	93,531	88,643	82,953
Fall	9	104,209	9/6/2015	77,376	72,863	69,375	66,927	65,296	64,504	64,734	65,254	67,910	74,037	80,716	86,901	92,516	97,349	100,779	102,996	103,954	104,209	102,938	99,415	96,779	94,050	89,046	82,825
Fall	9	102,318	9/7/2015	76,859	72,320	68,850	66,427	64,992	64,625	65,367	66,041	67,789	73,170	80,081	86,732	92,333	96,381	99,193	100,910	102,029	102,318	101,084	98,690	97,852	95,664	89,599	82,378
Fall	9	106,130	9/8/2015	76,355	72,165	69,271	67,634	67,174	68,608	73,606	79,758	83,147	86,724	91,173	96,159	100,184	103,403	105,838	106,130	105,687	104,504	102,398	99,754	98,539	96,054	89,770	82,402
Fall	9	92,801	9/9/2015	76,249	71,658	68,821	66,964	66,196	67,490	71,983	77,402	79,300	81,331	83,914	86,473	88,606	90,545	91,899	92,489	92,801	92,660	91,413	89,316	88,895	87,351	82,052	75,373
Fall	9	92,195	9/10/2015	69,957	66,339	63,945	62,659	62,396	63,842	68,479	73,979	76,086	78,727	81,865	84,820	87,411	89,526	91,425	92,128	92,195	91,682	90,030	87,674	87,579	85,917	80,719	74,309
Fall	9	80,016	9/11/2015	69,019	65,245	62,948	61,491	60,953	62,362	66,598	71,923	73,952	75,636	77,148	78,348	79,248	79,644	80,016	79,789	78,841	78,022	76,526	74,788	75,139	74,365	71,192	67,099
Fall	9	70,181	9/12/2015	62,829	59,795	57,748	56,347	55,749	56,073	57,320	58,922	60,729	63,777	66,108	67,738	68,771	69,416	69,804	69,853	70,126	70,181	69,781	68,691	69,122	68,674	65,720	61,956
Fall	9	71,867	9/13/2015	58,278	55,511	53,570	52,325	51,603	51,627	52,462	53,378	55,084	58,342	60,598	62,404	63,907	65,096	65,982	67,082	68,693	70,073	70,882	70,578	71,867	71,137	67,437	62,726
Fall	9	85,662	9/14/2015	59,068	56,379	54,984	54,175	54,356	56,268	61,032	66,649	68,905	70,998	73,222	75,594	77,410	79,731	81,896	83,371	84,730	85,662	85,298	83,845	84,707	83,078	78,020	71,982
Fall	9	93,519	9/15/2015	66,924	63,322	61,052	59,761	59,506	61,059	65,570	71,167	73,387	75,567	78,236	81,152	84,093	86,833	89,756	91,841	93,159	93,519	92,250	89,882	89,867	87,533	82,034	75,504
Fall	9	98,663	9/16/2015	69,777	66,032	63,437	61,859	61,393	62,523	66,879	72,525	74,583	77,259	80,889	84,334	87,792	91,420	94,728	96,836	98,043	98,663	97,578	94,933	94,402	91,564	85,740	78,977
Fall	9	99,479	9/17/2015	73,060	68,934	65,929	64,245	63,582	64,849	69,361	75,154	77,804	80,411	83,418	86,931	90,161	93,458	96,254	98,235	99,297	99,479	97,879	95,265	94,582	91,964	86,191	79,196
Fall	9	93,712	9/18/2015	73,131	68,859	65,935	64,212	63,531	64,680	69,136	74,665	76,772	79,274	81,983	84,895	87,591	90,260	92,532	93,319	93,712	93,089	91,210	88,840	88,106	85,570	81,251	75,944
Fall	9	79,364	9/19/2015	70,663	66,533	63,722	61,671	60,500	60,291	61,268	63,229	65,030	68,593	71,669	73,983	75,605	76,810	77,797	78,576	79,135	79,364	78,376	76,400	76,516	74,692	70,951	66,499
Fall	9	77,082	9/20/2015	62,210	59,012	56,909	55,358	54,562	54,473	55,044	56,232	57,644	61,388	64,661	67,167	69,755	71,535	73,123	74,085	75,191	75,937	76,133	75,635	77,082	75,117	71,068	66,233
Fall	9	85,833	9/21/2015	62,395	59,619	57,957	57,023	57,030	58,810	63,518	69,192	71,251	73,261	75,301	77,534	79,177	81,151	82,902	84,205	85,227	85,833	85,281	83,863	84,220	81,609	76,578	70,471
Fall	9	88,788	9/22/2015	65,265	61,720	59,450	58,092	57,883	59,472	63,916	69,632	71,514	73,651	76,243	78,797	81,043	83,518	85,822	87,462	88,645	88,788	87,626	85,669	85,812	82,795	77,465	71,152
Fall	9	90,276	9/23/2015	65,874	62,329	60,044	58,668	58,471	59,871	64,375	70,022	72,139	74,364	77,021	79,911	82,791	85,362	87,737	89,166	90,160	90,276	89,034	86,986	87,012	83,836	78,519	72,201
Fall	9	89,868	9/24/2015	66,940	63,549	61,154	59,805	59,390	60,834	65,378	71,139	73,176	75,259	78,022	80,862	83,330	85,954	88,130	89,414	89,868	89,599	87,893	86,210	86,749	83,918	78,850	72,590
Fall	9	89,764	9/25/2015	67,275	63,738	61,426	59,973	59,549	60,825	65,337	70,795	72,761	74,858	77,545	80,706	83,410	85,925	88,132	89,306	89,764	89,096	86,699	83,687	83,157	80,236	76,103	71,224
Fall	9	78,195	9/26/2015	66,312	62,447	59,814	58,293	57,456	57,447	58,846	60,818	62,310	65,875	69,357	72,043	74,279	76,046	77,206	77,805	78,195	78,053	77,076	76,011	76,793	74,961	71,830	67,634
Fall	9	79,479	9/27/2015	63,528	60,261	58,226	56,748	55,837	55,724	56,511	57,997	59,563	62,743	65,686	68,018	70,329	72,324	73,721	74,737	75,680	76,893	77,385	77,965	79,479	77,332	73,240	68,942
Fall	9	89,185	9/28/2015	64,595	61,793	60,167	59,189	59,219	61,221	66,346	72,839	75,143	77,134	79,470	81,929	84,174	86,457	88,268	89,075	89,185	88,756	87,676	87,388	88,118	85,110	80,627	74,545
Fall	9	82,688	9/29/2015	69,414	65,716	63,233	61,698	61,322	62,936	67,409	73,786	75,820	77,160	78,490	79,662	80,860	81,822	82,688	82,543	82,537	82,222	81,169	80,892	81,760	79,383	74,848	68,941
Fall	9	79,891	9/30/2015	64,315	61,083	59,283	57,996	57,885	59,369	63,969	69,881	71,309	72,592	73,945	75,521	76,925	78,092	79,379	79,817	79,891	79,775	78,618	78,192	79,684	77,232	72,868	67,354
Fall	10	76,578	10/1/2015	62,953	59,937	58,031	56,876	56,731	58,220	62,760	68,576	69,961	70,846	72,032	72,918	73,630	74,584	75,563	75,873	75,914	75,716	74,670	74,728	76,578	74,489	70,399	65,643
Fall	10	72,072	10/2/2015	61,307	58,601	56,828	55,856	55,950	57,368	61,931	67,782	69,366	70,270	70,953	71,497	71,752	71,702	72,072	71,664	71,396	71,147	70,350	70,484	71,756	70,040	67,276	63,287
Fall	10	67,714	10/3/2015	59,443	56,981	55,076	54,166	53,755	54,368	55,962	58,644	60,500	63,147	64,776	65,328	65,380	65,152	64,760	64,440	64,588	65,099	65,268	66,351	67,714	66,291	63,694	60,428
Fall	10	69,642	10/4/2015	57,122	55,022	53,498	52,497	52,042	52,199	53,184	55,257	56,959	59,638	61,408	62,277	62,781	62,965	63,150	62,983	63,383	64,450	65,466	67,257	69,642	67,810	64,783	60,888
Fall	10	78,910	10/5/2015	58,041	55,791	54,623	54,123	54,489	56,700	61,662	67,945	70,321	71,164	72,321	73,365	73,970	74,771	75,608	76,199	76,375	76,496	76,322	77,519	78,910	76,490	72,362	66,934
Fall	10	81,331	10/6/2015	62,466	59,680	57,967	57,028	57,031	58,614	63,350	69,588	71,641	72,815	74,174	75,723	77,184	78,626	79,767	80,439	80,714	80,557	79,823	80,130	81,331	78,527	73,857	68,286
Fall	10	82,337	10/7/2015	63,670	60,811	58,702	57,566	57,435	59,127	63,654	69,769	71,675	72,770	74,409	76,346	78,303	79,953	81,333	82,028	82,337	82,201	81,290	81,414	82,132	79,146	74,617	69,267
Fall	10	83,182	10/8/2015	64,472	61,508	59,307	58,233	58,208	59,806	64,049	70,201	72,212	73,484	75,400	77,567	79,584	81,216	82,836	83,105	83,182	82,996	82,319	82,526	82,929	80,108	75,637	70,158
Fall	10	78,268	10/9/2015	65,504	62,314	60,121	58,782	58,476	60,013	64,201	70,186	72,311	73,394	74,818	76,101	76,918	77,595	78,268	77,883	77,301	76,556	75,433	75,429	75,558	73,429	70,280	66,010
Fall	10	69,535	10/10/2015	62,035	59,123	57,200	55,787	55,336	55,714	57,427	59,833	61,396	63,921	65,766	66,477	66,808	66,901	67,104	67,305	67,771	68,104	67,837	68,616	69,535	67,631	64,749	61,095
Fall	10	74,139	10/11/2015	57,687	55,264	53,481	52,504	51,904	52,163	53,248	55,034	56,559	59,210	61,353	62,744	63,851	65,441	66,786	68,218	69,780	71,223	71,796	72,787	74,139	71,432	67,814	63,535
Fall	10	80,571	10/12/2015	59,822	57,419	55,743	54,982	55,019	56,858	61,354	67,511	69,686	71,448	73,584	75,497	77,097	78,594	79,823	80,122	80,550	80,500	80,138	80,571	80,571	77,607	73,023	67,490
Fall	10	78,617	10/13/2015	62,879	59,694	57,961	56,903	56,783	58,524	63,203	69,403	71,286	72,194	73,413	74,599	75,474	76,424	77,658	78,220	78,383	78,171	77,616	78,121	78,617	75,487	71,073	65,826
Fall	10	78,061	10/14/2015	61,406	58,494	56,896	55,744	55,971	57,872	62,455	68,772	70,532	70,883	71,503	72,439	73,194	74,185	75,481	76,360	76,862	77,095	76,635	77,522	78,061	75,012	70,582	65,498
Fall	10	78,716	10/15/2015	61,104	58,526	56,808	56,007	56,162	57,836	62,516	68,915	70,617	71,270	72,202	73,202	74,316	75,697	77,289	78,240	78,393	78,467	77,772	78,488	78,716	75,965	71,690	66,728
Fall	10	75,109	10/16/2015	62,327	59,598	57,775	56,810	56,848	58,666	63,024	69,261	71,116	71,818	72,708	73,358	73,852	74,209	74,887	75,109	74,893	74,482	73,741	74,413	74,672	72,635	69,677	65,646
Fall	10	68,737	10/17/2015	61,933	59,489	57,630	56,628	56,258	57,022	58,816	61,483	63,486	65,707	67,001	66,981	66,460	65,788	65,489	65,032	64,797	64,925	65,167	67,508	68,737	67,349	64,974	62,141
Fall	10	70,123	10/18/2015	59,163	56,941	55,700	55,053	54,975	55,324	56,617	58,955	60,669	62,712	63,454	63,247	63,034	63,116	62,977	62,897	63,165	64,169	65,339	68,183	70,123	68,173	65,149	61,412
Fall	10	76,516	10/19/2015	58,335	56,662	55,732	55,571	56,097	58,410	63,702	70,595	72,768	72,935	73,190	73,341	73,274	73,171	73,530	73,324	73,402	73,546	73,631	75,841	76,516	74,072	70,058	65,124
Fall	10	77,559	10/20/2015	61,249	58,915	57,327	56,572	56,667	58,646	63,376	69,803	71,765	71,990	72,671	73,436	74,185	74,757	75,434	75,315	75,137	75,134	75,232	77,174	77,559	74,942	71,211	66,428
Fall	10	79,366	10/21/2015	62,139	59,549	57,811	56,994	57,036	58,937	63,516	70,062	72,118	72,579	73,486	74,561	75,669	76,768	77,896	78,145	78,218	78,113	77,710	79,234	79,366	76,616	72,348	67,339
Fall	10	79,133	10/22/2015	62,970	60,223	58,458	57,482	57,279	59,120	63,897	70,163	72,428	72,813	73,702	74,760	75,697	76,695	77,773	78,112	78,047	77,705	77,042	79,050	79,133	76,686	72,772	67,895
Fall	10	75,967	10/23/2015	63,571	60,760	58,798	57,863	57,819	59,551	63,680	69,864	72,291	73,125	74,177	75,080	75,381	75,748	75,967	75,581	75,116	74,607	74,585	75,598	74,831	72,792	69,989	66,241
Fall	10	69,027	10/24/2015	62,228	59,307	57,502	56,229	55,771	56,181	57,864	60,540	63,181	65,434	67,497	68,526	68,823	68,479	67,837	67,132	66,784	66,607	67,216	69,027	68,736	67,111	64,606	61,400
Fall	10	69,414	10/25/2015	58,365	55,775	54,306	53,303	52,670	52,874	54,172	56,302	58,358	60,390	61,977	62,684	63,059	63,162	62,662	62,420	62,520	63,341	65,050	68,821	69,414	67,528	64,747	61,316
Fall	10	75,509	10/26/2015	58,440	56,546	55,548	55,158	55,612	57,844	63,064	69,931	72,608	72,841	73,159	73,261	73,305	73,296	72,903	72,123	71,476	71,428	72,390	75,509	75,245	73,187	69,557	64,910
Fall	10	76,040	10/27/2015	61,063	58,611	57,270	56,470	56,530	58,314	62,975	69,673	72,383	72,360	72,837	73,108	73,183	73,040	72,851	72,407	72,105	72,445	73,794	76,040	75,625	73,431	69,474	64,962
Fall	10	76,930	10/28/2015	61,225	58,790	57,247	56,327	56,284	58,134	62,729	69,099	71,940	72,128	72,946	73,680	73,963	74,339	74,884	74,691	74,787	75,028	75,471	76,930	76,593	74,560	71,079	66,267
Fall	10	76,382	10/29/2015	62,208	59,694	58,036	57,412	57,531	59,518	64,337	71,016	73,338	73,302	73,769	74,235	74,181	74,197	74,391	74,217	74,107	74,162	74,609	76,382	76,223	74,093	70,500	66,054
Fall	10	73,233	10/30/2015	62,253	59,744	58,113	57,474	57,594	59,488	64,382	70,571	73,233	73,203	73,227	73,046	72,530	71,973	71,774	71,000	70,278	69,905	70,279	72,020	71,555	70,173	67,583	64,188
Fall	10	68,826	10/31/2015	60,850	58,349	56,701	55,673	55,570	56,073	57,779	60,349	63,185	65,440	67,545	68,558	68,826	68,146	67,448	66,841	66,431	66,333	66,263	67,059	66,573	65,323	63,190	60,602
Fall	11	69,377	11/1/2015	56,583	53,994	53,051	52,515	52,527	53,165	54,754	56,643	58,713	60,703	61,630	61,891	62,045	62,140	61,979	61,820	62,279	64,388	68,976	69,377	67,950	65,577	62,598	59,365
Fall	11	76,703	11/2/2015	56,632	55,061	54,218	54,056	54,784	57,175	62,538	68,267	70,208	71,212	72,121	72,725	73,007	73,228	73,232	72,804	72,444	73,213	76,344	76,703	74,770	71,855	67,938	63,355
Fall	11	77,048	11/3/2015	59,887	57,605	56,345	55,779	56,252	58,301	63,352	68,846	70,638	71,382	72,384	73,168	73,686	73,890	74,151	73,687	72,920	73,537	76,748	77,048	75,207	72,495	68,313	63,549
Fall	11	78,391	11/4/2015	60,001	57,792	56,451	55,641	55,927	57,876	62,811	68,370	70,262	71,476	72,716	73,855	74,509	74,871	75,611	75,429	75,098	75,638	78,391	78,244	76,110	73,306	69,238	64,696
Fall	11	79,923	11/5/2015	60,639	58,301	56,787	56,063	56,252	58,228	63,171	69,026	71,179	72,554	73

Contains Proprietary Material
Do Not Distribute

Season	Month	Max	Date	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Winter	12	8,089	12/1/2014	5,769	5,669	5,723	5,867	6,150	6,813	7,896	8,089	7,755	7,281	6,967	6,712	6,565	6,448	6,383	6,388	6,509	7,169	7,517	7,507	7,389	7,058	6,624	6,099
Winter	12	8,256	12/2/2014	5,748	5,640	5,611	5,661	5,899	6,480	7,444	7,804	7,630	7,546	7,444	7,293	7,170	7,081	7,037	7,079	7,373	8,028	8,256	8,175	8,047	7,652	7,094	6,571
Winter	12	7,836	12/3/2014	6,143	5,938	5,845	5,869	6,025	6,552	7,501	7,704	7,558	7,447	7,347	7,164	6,974	6,835	6,715	6,664	6,846	7,596	7,836	7,801	7,653	7,342	6,826	6,268
Winter	12	8,173	12/4/2014	5,837	5,649	5,592	5,625	5,820	6,405	7,399	7,711	7,593	7,484	7,310	7,114	6,895	6,808	6,705	6,743	7,073	7,844	8,158	8,173	8,110	7,839	7,345	6,833
Winter	12	8,247	12/5/2014	6,386	6,289	6,266	6,294	6,523	7,078	8,019	8,247	8,007	7,740	7,625	7,230	7,001	6,866	6,829	6,663	7,045	7,705	7,777	7,693	7,601	7,368	6,995	6,540
Winter	12	7,247	12/6/2014	6,135	5,906	5,807	5,751	5,788	5,966	6,290	6,572	6,901	7,065	7,031	6,894	6,760	6,629	6,532	6,492	6,756	7,239	7,247	7,097	6,906	6,689	6,358	5,981
Winter	12	8,707	12/7/2014	5,590	5,404	5,371	5,460	5,612	5,923	6,381	6,878	7,457	7,675	7,487	7,181	7,065	6,838	6,738	6,804	7,192	8,109	8,525	8,707	8,700	8,468	8,099	7,678
Winter	12	9,518	12/8/2014	7,433	7,335	7,313	7,416	7,588	8,327	9,295	9,518	9,267	8,988	8,607	8,286	8,109	8,064	8,069	8,215	8,615	9,336	9,461	9,469	9,277	8,881	8,275	7,732
Winter	12	9,522	12/9/2014	7,355	7,245	7,261	7,347	7,597	8,268	9,249	9,522	9,360	9,197	9,058	8,870	8,651	8,486	8,373	8,430	8,739	9,403	9,513	9,423	9,215	8,788	8,124	7,517
Winter	12	9,624	12/10/2014	7,175	7,070	7,102	7,211	7,567	8,305	9,382	9,624	9,279	8,670	8,171	7,857	7,603	7,574	7,574	7,715	8,092	9,040	9,442	9,521	9,527	9,309	8,865	8,419
Winter	12	11,021	12/11/2014	8,246	8,315	8,469	8,678	9,104	9,812	10,778	11,021	10,672	9,876	9,223	8,675	8,180	7,824	7,640	7,648	8,085	9,162	9,753	10,047	10,241	10,148	9,705	9,256
Winter	12	11,252	12/12/2014	9,019	8,962	9,044	9,178	9,500	10,202	11,092	11,252	10,793	9,836	8,966	8,282	7,782	7,424	7,198	7,143	7,440	8,345	8,773	8,944	9,056	9,031	8,785	8,433
Winter	12	9,860	12/13/2014	8,166	8,126	8,114	8,251	8,509	8,910	9,430	9,860	9,823	9,049	8,234	7,568	7,052	6,724	6,526	6,443	6,674	7,591	7,989	8,121	8,268	8,275	8,130	7,847
Winter	12	9,378	12/14/2014	7,727	7,685	7,710	7,819	7,967	8,333	8,772	9,234	9,378	8,733	7,952	7,260	6,910	6,646	6,397	6,381	6,649	7,687	8,217	8,494	8,616	8,503	8,193	7,896
Winter	12	10,791	12/15/2014	7,722	7,756	7,895	8,134	8,565	9,351	10,517	10,791	10,209	9,167	8,311	7,721	7,268	6,644	6,852	6,784	7,089	8,022	8,514	8,676	8,723	8,561	8,100	7,669
Winter	12	9,546	12/16/2014	7,408	7,390	7,452	7,561	7,825	8,506	9,447	9,546	8,968	8,371	7,968	7,694	7,534	7,465	7,345	7,350	7,539	8,185	8,425	8,344	8,184	7,836	7,315	6,770
Winter	12	8,890	12/17/2014	6,415	6,339	6,373	6,497	6,819	7,528	8,583	8,890	8,531	8,000	7,579	7,223	6,915	6,791	6,674	6,669	6,980	7,897	8,384	8,464	8,477	8,283	7,820	7,331
Winter	12	9,883	12/18/2014	7,062	7,031	7,119	7,331	7,683	8,435	9,595	9,883	9,472	8,868	8,317	7,778	7,363	7,153	7,037	7,122	7,454	8,386	8,888	9,017	9,079	8,869	8,389	7,884
Winter	12	9,762	12/19/2014	7,537	7,455	7,450	7,549	7,792	8,435	9,460	9,762	9,402	8,725	8,126	7,639	7,180	6,974	6,831	6,837	7,175	8,095	8,456	8,507	8,533	8,434	8,118	7,708
Winter	12	9,077	12/20/2014	7,386	7,217	7,131	7,148	7,253	7,485	7,848	8,261	8,669	8,951	8,972	8,865	8,640	8,440	8,251	8,199	8,349	8,977	9,077	9,009	8,915	8,764	8,470	8,078
Winter	12	8,877	12/21/2014	7,672	7,471	7,430	7,448	7,528	7,766	8,093	8,505	8,877	8,806	8,340	7,714	7,370	7,109	6,915	6,965	7,316	8,117	8,347	8,359	8,317	8,098	7,697	7,197
Winter	12	9,458	12/22/2014	6,863	6,739	6,747	6,868	7,120	7,613	8,239	8,759	8,941	9,065	9,094	8,948	8,778	8,726	8,678	8,654	8,838	9,387	9,458	9,350	9,180	8,824	8,293	7,710
Winter	12	8,717	12/23/2014	7,324	7,098	7,006	7,024	7,161	7,587	8,176	8,568	8,675	8,717	8,658	8,471	8,227	8,072	7,950	7,872	8,036	8,583	8,578	8,414	8,227	7,948	7,468	6,864
Winter	12	7,039	12/24/2014	6,368	6,045	5,830	5,705	5,738	5,912	6,255	6,543	6,737	6,967	7,039	6,969	6,793	6,625	6,484	6,345	6,460	6,821	6,739	6,519	6,347	6,185	5,909	5,516
Winter	12	6,848	12/25/2014	5,069	4,778	4,614	4,538	4,556	4,731	5,060	5,480	5,915	6,251	6,304	6,218	5,982	5,697	5,477	5,378	5,459	6,009	6,406	6,575	6,759	6,848	6,797	6,661
Winter	12	8,805	12/26/2014	6,569	6,592	6,733	6,962	7,258	7,820	8,372	8,757	8,805	8,189	7,497	6,965	6,528	6,214	6,006	5,927	6,141	6,985	7,480	7,646	7,783	7,751	7,545	7,303
Winter	12	8,782	12/27/2014	7,120	7,114	7,194	7,396	7,612	7,938	8,426	8,738	8,782	8,131	7,434	6,893	6,473	6,130	5,929	5,888	6,055	6,782	7,164	7,191	7,169	6,982	6,727	6,342
Winter	12	6,873	12/28/2014	5,985	5,769	5,664	5,586	5,612	5,688	5,901	6,089	6,359	6,487	6,366	6,160	6,148	6,045	5,941	5,942	6,116	6,667	6,873	6,754	6,613	6,362	5,964	5,492
Winter	12	8,066	12/29/2014	5,140	4,960	4,878	4,874	5,000	5,382	5,927	6,384	6,604	6,847	7,004	7,097	7,063	7,084	7,060	7,067	7,270	7,900	8,066	7,976	7,819	7,524	7,107	6,686
Winter	12	9,716	12/30/2014	6,404	6,260	6,246	6,325	6,533	7,007	7,639	8,144	8,416	8,616	8,766	8,802	8,788	8,757	8,649	8,655	8,813	9,463	9,716	9,677	9,632	9,452	9,151	8,847
Winter	12	10,681	12/31/2014	8,679	8,699	8,809	8,975	9,280	9,746	10,419	10,681	10,558	10,158	9,499	8,729	8,172	7,805	7,574	7,527	7,913	8,894	9,397	9,395	9,434	9,427	9,275	9,138
Winter	1	10,268	1/1/2015	9,069	9,110	9,142	9,277	9,465	9,770	10,112	10,268	10,107	9,396	8,578	7,952	7,458	7,006	6,763	6,700	6,948	7,824	8,233	8,328	8,284	8,104	7,703	7,243
Winter	1	7,862	1/2/2015	6,892	6,649	6,526	6,491	6,595	6,958	7,477	7,823	7,862	7,787	7,609	7,387	7,216	7,071	6,979	6,932	7,109	7,712	7,819	7,668	7,517	7,272	6,931	6,533
Winter	1	7,572	1/3/2015	6,172	5,941	5,830	5,815	5,908	6,078	6,379	6,626	6,902	7,165	7,274	7,243	7,116	6,982	6,871	6,857	6,983	7,463	7,572	7,392	7,237	6,926	6,542	6,145
Winter	1	7,044	1/4/2015	5,706	5,434	5,229	5,108	5,079	5,092	5,218	5,441	5,700	6,046	6,062	6,058	6,111	6,144	6,075	6,099	6,272	6,826	7,044	6,953	6,816	6,425	5,939	5,485
Winter	1	9,066	1/5/2015	5,160	5,027	5,039	5,149	5,468	6,239	7,435	7,897	7,787	7,653	7,473	7,257	7,068	6,984	6,878	6,917	7,237	8,126	8,838	9,039	9,066	8,920	8,535	8,151
Winter	1	11,150	1/6/2015	8,022	8,092	8,252	8,500	8,912	9,724	10,867	11,150	10,583	9,492	8,707	8,077	7,601	7,296	7,123	7,175	7,454	8,230	8,900	9,052	9,071	8,842	8,456	8,066
Winter	1	12,003	1/7/2015	7,931	7,963	8,111	8,370	8,792	9,588	10,699	10,861	10,519	9,816	9,473	9,323	9,248	9,220	9,258	9,462	9,955	10,936	11,483	11,802	11,978	12,003	11,893	11,806
Winter	1	14,519	1/8/2015	11,941	12,150	12,408	12,765	13,141	13,726	14,219	14,519	14,255	14,012	13,107	12,305	11,569	10,995	10,531	10,478	10,905	11,973	12,889	13,210	13,276	13,002	12,548	12,047
Winter	1	12,288	1/9/2015	11,787	11,625	11,533	11,418	11,361	11,639	12,288	12,160	11,844	11,213	10,547	9,740	9,035	8,505	8,100	8,004	8,327	9,207	9,814	9,886	9,883	9,743	9,434	9,082
Winter	1	11,069	1/10/2015	8,935	8,915	9,027	9,287	9,594	9,999	10,519	10,979	11,069	10,727	10,192	9,557	8,988	8,451	8,117	8,027	8,374	9,441	10,279	10,576	10,787	10,697	10,747	10,477
Winter	1	12,102	1/11/2015	10,356	10,478	10,666	10,881	11,088	11,427	11,778	12,102	11,996	11,027	9,924	9,042	8,431	8,010	7,804	7,718	8,011	8,684	8,975	8,925	8,759	8,358	7,829	7,342
Winter	1	8,935	1/12/2015	6,970	6,843	6,840	6,911	7,176	7,766	8,606	8,935	8,711	8,573	8,473	8,353	8,241	8,160	8,025	7,947	8,055	8,510	8,703	8,560	8,282	7,858	7,276	6,732
Winter	1	10,609	1/13/2015	6,381	6,202	6,165	6,258	6,537	7,192	8,262	8,762	8,693	8,827	8,958	9,024	9,108	9,198	9,207	9,361	9,696	10,329	10,609	10,553	10,429	10,051	9,568	9,145
Winter	1	11,537	1/14/2015	8,932	8,907	8,997	9,119	9,416	9,964	10,684	11,273	11,537	11,424	11,187	10,988	10,746	10,574	10,416	10,408	10,591	11,114	11,349	11,198	10,962	10,508	9,899	9,339
Winter	1	10,948	1/15/2015	9,030	8,896	8,847	8,933	9,161	9,731	10,601	10,948	10,808	10,492	10,049	9,630	9,225	9,115	8,996	9,015	9,268	9,795	10,052	10,011	9,804	9,439	8,852	8,282
Winter	1	10,254	1/16/2015	7,929	7,794	7,770	7,852	8,135	8,833	9,877	10,254	9,949	9,337	8,650	8,130	7,663	7,373	7,123	6,990	7,169	7,863	8,526	8,674	8,815	8,817	8,651	8,444
Winter	1	10,012	1/17/2015	8,301	8,336	8,432	8,578	8,783	9,160	9,637	10,010	10,012	9,423	8,727	8,072	7,477	7,038	6,748	6,658	6,900	7,633	8,183	8,244	8,208	8,013	7,694	7,274
Winter	1	7,620	1/18/2015	6,890	6,645	6,546	6,516	6,529	6,620	6,800	7,083	7,402	7,558	7,334	7,012	6,719	6,489	6,295	6,215	6,347	6,934	7,478	7,608	7,620	7,540	7,376	7,105
Winter	1	9,471	1/19/2015	7,017	7,045	7,202	7,408	7,746	8,300	9,042	9,471	9,397	8,757	8,164	7,623	7,209	6,880	6,700	6,567	6,749	7,374	8,046	8,135	8,100	7,888	7,463	7,078
Winter	1	8,933	1/20/2015	6,823	6,754	6,736	6,776	7,039	7,620	8,540	8,933	8,686	8,170	7,686	7,243	6,901	6,703	6,579	6,523	6,635	7,211	7,849	7,886	7,796	7,464	7,030	6,550
Winter	1	8,815	1/21/2015	6,261	6,168	6,143	6,286	6,603	7,329	8,401	8,815	8,529	8,072	7,646	7,230	6,900	6,703	6,559	6,554	6,717	7,317	8,052	8,168	8,182	7,973	7,621	7,286
Winter	1	10,215	1/22/2015	7,124	7,144	7,334	7,590	7,938	8,772	9,891	10,215	9,833	9,142	8,372	7,723	7,236	6,949	6,733	6,730	6,953	7,556	8,255	8,411	8,421	8,276	7,868	7,476
Winter	1	9,436	1/23/2015	7,227	7,193	7,221	7,310	7,469	8,032	8,949	9,241	9,085	8,931	8,834	8,776	8,710	8,718	8,735	8,805	9,001	9,386	9,436	9,153	8,818	8,410	7,878	7,318
Winter	1	8,756	1/24/2015	6,885	6,638	6,488	6,524	6,665	6,946	7,314	7,747	8,161	8,494	8,602	8,512	8,433	8,247	7,976	7,621	7,631	8,028	8,603	8,655	8,756	8,633	8,411	8,108
Winter	1	9,768	1/25/2015	7,913	7,883	7,992	8,166	8,372	8,708	9,198	9,668	9,768	9,037	8,076	7,337	6,912	6,601	6,338	6,291	6,492	7,180	8,000	8,229	8,282	8,115	7,744	7,416
Winter	1	9,387	1/26/2015	7,145	7,071	7,102	7,210	7,506	8,086	9,090	9,387	9,085	8,761	8,459	8,097	7,761	7,593	7,528	7,635	7,958	8,537	8,968	8,978	8,821	8,470	7,972	7,496
Winter	1	10,578	1/27/2015	7,277	7,219	7,336	7,504	7,899	8,662	9,813	10,200	10,091	9,915	9,687	9,429	9,115	8,784	8,528	8,422	8,663	9,303	10,186	10,466	10,578	10,365	9,897	9,494
Winter	1	11,929	1/28/2015	9,308	9,306	9,406	9,538	9,883	10,647	11,704	11,929	11,271	10,662	9,964	9,303	8,747	8,344	8,018	7,901	8,186	8,969	10,078	10,465	10,646	10,542	10,199	9,875
Winter	1	12,626	1/29/2015	9,824	9,907	10,114	10,347	10,708	11,477	12,485	12,626	11,978	10,996	10,012	9,221	8,688	8,411	8,162	8,046	8,337	8,966	9,539	9,603	9,474	9,071	8,498	7,948
Winter	1	9,504	1/30/2015	7,559	7,416	7,347	7,312	7,471	7,942	8,885	9,216	8,970	8,693	8,401	8,169	7,911	7,705	7,486	7,441	7,695	8,403	9,219	9,406	9,504	9,477	9,302	9,063
Winter	1	10,925	1/31/2015	8,952	9,010	9,154	9,351	9,613	10,042	10,510	10,925	10,844	10,306	9,576	8,918	8,242	7,693	7,287	7,143	7,312	7,975	8,885	9,198	9,376	9,346	9,134	8,845
Winter	2	9,135	2/1/2015	8,609	8,434	8,296	8,252	8,247	8,342	8,552	8,868	9,135	8,837	8,301	7,742	7,322	7,116	6,925	6,919	7,128	7,565	7,846	7,632	7,491	7,234	6,891	6,393
Winter	2	9,513	2/2/2015	5,922	5,658	5,558	5,556	5,695	6,232	7,186	7,522	7,366	7,327	7,396	7,358	7,210	7,152	7,139	7,105	7,344	8,051	9,082	9,384	9,513	9,366	9,033	8,707
Winter	2	11,657	2/3/2015	8,589	8,680	8,863	9,139	9,570	10,410	11,416	11,657	11,322	10,584	9,764	9,050	8,465	8,056	7,752	7,634	7,878	8,673	9,772	10,145	10,281	10,109	9,718	9,327
Winter	2	11,696	2/4/2015	9,159	9,169	9,344	9,565	9,897	10,655	11,588	11,696	11,305	10,126	9,095	8,367	7,797	7,520	7,283	7,260	7,485	8,064	8,770	8,796	8,676	8,279	7,690	7,124
Winter	2	10,221	2/5/2015	6,765	6,598	6,568	6,632	6,828	7,517	8,555	8,861	8,703	8,630	8,453	8,187	7,767	7,494	7,301	7,324	7,665	8,488	9,613	10,035	10,221	10,129	9,810	9,494
Winter	2	12,620	2/6/2015	9,423	9,541	9,763	10,045	10,509	11,415	12,424	12,620	12,191	11,201	10,292	9,459	8,847	8,467	8,277	8,322	8,598	9,100	9,683	9,732	9,669	9,504	9,233	8,998
Winter	2	10,559	2/7/2015	8,882	8,876	9,006	9,141	9,381	9,743	10,268	10,559	10,297	9,486	8,634	7,941	7,296	6,850	6,565	6,413	6,490	6,920	7,691	7,823	7,835	7,728	7,474	7,122
Winter	2	7,712	2/8/2015	6,880	6,729	6,680	6,719	6,805	7,011	7,324	7,627	7,712	7,387	6,865	6,388	6,148	5,903	5,722	5,656	5,773	6,121	6,868	7,026	6,954	6,647	6,252	5,816
Winter	2	7,779	2/9/2015	5,516	5,448	5,430	5,544	5,809	6,443	7,485	7,779	7,538	7,239	7,005	6,791	6,610	6,580	6,536	6,573	6,730	7,127	7,621	7,586	7,382	6,995	6,543	6,072
Winter	2	10,271	2/10/2015	5,825	5,727	5,788	6,009	6,348	7,166	8,417	8,995	9,070	9,213	9,376	9,349	9,317	9,315	9,263	9,286	9,393	9,767	10,266	10,271	10,085	9,696	9,119	8,627
Winter	2	10,891	2/11/2015	8,397	8,369	8,451	8,579	8,916	9,589	10,667	10,891	10,473	9,945	9,357	8,719	8,189	7,748	7,379	7,176	7,256	7,784	8,803	9,167	9,335	9,249	8,960	8,591
Winter	2	10,757	2/12/2015	8,354	8,415	8,482	8,625	8,959	9,683	10,695	10,757	9,941	8,887	8,109	7,575	7,197	7,053	7,058	7,242	7,733	8,389	9,278	9,709	9,915	9,866	9,577	9,328
Winter	2	12,006	2/13/2015	9,208	9,332	9,505	9,788	10,192	10,946	11,863	12,006	11,580	11,202	10,586	10,012	9,526	9,170	8,866	8,663	8,755	9,363	10,317	10,684	10,844	10,875	10,723	10,522
Winter	2	11,849	2/14/2015	10,463	10,546	10,692	10,844	11,032	11,361	11,739	11,849	11,331	10,372	9,541	8,752	8,121	7,578	7,219	7,055	7,181	7,680	8,376	8,432	8,291	8,147	8,014	7,992
Winter	2	12,693	2/15/2015	8,203	8,734	9,422	10,037	10,682	11,324	12,049	12,565	12,693	12,470	11,872	11,199	10,678	10,126	9,687	9,490	9,650	10,344	11,399	11,640	11,674	11,561	11,377	11,089
Winter	2	12,451	2/16/2015	10,976	10,902	10,938	10,960	11,117	11,604	12,248	12,383	12,451	12,352	12,049	11,599	11,114	10,849	10,780	10,857	11,222	11,821	12,164	11,983	11,630	11,134	10,746	10,360
Winter	2	11,788	2/17/2015	10,170	10,119	10,101	10,021	10,165	10,537	11,001	11,369	11,615	11,788	11,663	11,358	11,031	10,588	10,306	10,266	10,473	10,984	11,572	11,502	11,323	10,997	10,602	10,277
Winter	2	12,653	2/18/2015	10,203	10,319	10,560	10,785	11,029	11,519	12,263	12,653	12,383	11,535	10,774	10,160	9,741	9,458	9,221	9,203	9,359	9,976	10,801	10,959	11,100	10,914	10,609	10,413
Winter	2	13,704	2/19/2015	10,533	10,816	11,054	11,454	11,950	12,572	13,373	13,704	13,601	13,402	12,905	12,389	11,919	11,506	11,208	11,131	11,411	12,247	13,459	13,563	13,616	13,671	13,586	13,410
Winter	2	15,569	2/20/2015	13,325	13,606	13,863	14,071	14,454	14,950	15,441	15,569	15,181	14,686	13,806	12,922	12,118	11,459	10,848	10,509	10,533	11,121	12,239	12,550	12,638	12,690	12,501	12,283
Winter	2	12,517	2/21/2015	12,111	12,109	12,060	12,127	12,167	12,330	12,517	12,517	12,261	11,803	11,154	10,483	9,862	9,249	8,843	8,615	8,621	8,753	9,113	9,009	8,767	8,420	7,924	7,430
Winter	2	7,889	2/22/2015	7,038	6,866	6,802	6,786	6,850	7,011	7,320	7,553	7,889	7,802	7,524	7,112	6,865	6,697	6,546	6,488	6,557	6,968	7,543	7,698	7,597	7,240	6,810	6,355
Winter	2	10,525	2/23/2015	6,046	5,927	5,890	5,984	6,265	6,886	7,954	8,374	8,471	8,624	8,827	8,979	9,042	9,073	9,039	9,124	9,334	9,717	10,362	10,525	10,504	10,268	9,901	9,490
Winter	2	12,556	2/24/2015	9,294	9,321	9,393	9,569	9,909	10,642	11,607	12,040	12,292	12,491	12,556	12,549	12,476	12,281	12,134	11,993	11,977	12,229	12,549	12,450	12,150	11,622	11,139	10,763
Winter	2	12,266	2/25/2015	10,564	10,565	10,615	10,707	10,897	11,300	11,900	12,266	12,087	11,409	10,637	10,046	9,525	9,178	8,874	8,876	9,368	9,752	10,367	10,362	10,463	10,277	9,918	9,594
Winter	2	11,078	2/26/2015	9,452	9,390	9,293	9,275	9,280	9,553	10,196	10,626	10,809	10,817	10,741	10,566	10,377	10,230	10,066	10,056	10,183	10,486	11,050	11,078	10,921	10,594	10,062	9,680
Winter	2	11,946	2/27/2015	9,504	9,476	9,549	9,738	10,077	10,729	11,626	11,946	11,435	10,465	9,576	8,909	8,349	7,976	7,675	7,496	7,587	8,031	8,939	9,381	9,575	9,623	9,450	9,173
Winter	2	11,156	2/28/2015	9,058	9,126	9,290	9,519	9,820	10,269	10,784	11,112	11,156	10,842	10,258	9,674	9,057	8,579	8,197	8,012	8,156	8,684	9,513	9,833	9,912	9,808	9,501	9,155
Spring	3	10,149	3/1/2015	8,827	8,636	8,627	8,624	8,761	9,015	9,393	9,781	10,116	10,149	9,995	9,655	9,477	9,317	9,129	9,017	9,074	9,292	9,741	9,829	9,638	9,237	8,710	8,183
Spring	3	9,468	3/2/2015	7,854	7,652	7,621	7,661	7,869	8,433	9,356	9,468	9,186	8,848	8,399	7,853	7,379	6,978	6,772	6,600	6,672	6,926	7,769	8,187	8,204	8,016	7,640	7,260
Spring	3	9,822	3/3/2015	7,011	6,953	7,030	7,172	7,470	8,158	9,214	9,531	9,421	9,351	9,281	9,138	9,000	8,922	8,831	8,859	9,070	9,352	9,810	9,822	9,606	9,126	8,470	7,804

Contains Proprietary Material
Do Not Distribute

Spring	4	7,123	4/6/2015	4,844	4,695	4,636	4,706	4,843	5,372	6,005	6,357	6,415	6,358	6,346	6,363	6,312	6,363	6,412	6,461	6,537	6,617	6,655	6,825	7,123	6,765	6,160	5,594
Spring	4	7,309	4/7/2015	5,131	4,862	4,738	4,683	4,759	5,114	5,834	6,155	6,257	6,394	6,512	6,631	6,668	6,696	6,716	6,733	6,770	6,804	6,863	7,017	7,309	6,967	6,402	5,767
Spring	4	8,063	4/8/2015	5,269	5,049	4,885	4,781	4,855	5,204	5,884	6,181	6,325	6,522	6,680	6,931	7,181	7,442	7,664	7,843	8,003	8,051	8,019	7,990	8,063	7,640	6,898	6,145
Spring	4	7,878	4/9/2015	5,572	5,231	4,985	4,927	4,989	5,309	5,899	6,200	6,374	6,540	6,702	6,827	7,026	7,270	7,526	7,759	7,878	7,849	7,784	7,785	7,829	7,388	6,754	6,090
Spring	4	8,091	4/10/2015	5,576	5,286	5,120	5,011	5,063	5,391	5,995	6,286	6,554	6,805	7,094	7,378	7,616	7,783	7,914	8,091	7,955	7,931	7,849	7,702	7,868	7,520	6,953	6,297
Spring	4	6,945	4/11/2015	5,790	5,437	5,234	5,054	4,995	5,044	5,219	5,357	5,721	6,023	6,168	6,270	6,299	6,381	6,527	6,708	6,885	6,945	6,903	6,563	6,775	6,438	5,967	5,432
Spring	4	6,755	4/12/2015	4,981	4,696	4,547	4,471	4,469	4,569	4,747	4,992	5,437	5,663	5,642	5,622	5,721	5,794	5,860	5,935	6,041	6,148	6,180	6,381	6,755	6,445	5,886	5,299
Spring	4	7,600	4/13/2015	4,871	4,659	4,550	4,550	4,696	5,191	6,010	6,266	6,264	6,294	6,457	6,556	6,659	6,809	6,920	6,991	7,123	7,156	7,176	7,304	7,600	7,219	6,561	5,875
Spring	4	7,966	4/14/2015	5,379	5,092	4,935	4,870	4,955	5,364	6,211	6,505	6,574	6,718	6,896	7,082	7,213	7,386	7,506	7,607	7,700	7,710	7,723	7,740	7,966	7,590	6,864	6,109
Spring	4	7,064	4/15/2015	5,590	5,279	5,121	5,079	5,059	5,333	6,183	6,394	6,415	6,405	6,459	6,451	6,396	6,441	6,376	6,295	6,416	6,534	6,697	6,860	7,064	6,723	6,200	5,618
Spring	4	7,124	4/16/2015	5,229	5,034	4,956	4,955	5,081	5,546	6,459	6,742	6,665	6,687	6,711	6,614	6,562	6,508	6,449	6,414	6,465	6,524	6,642	6,826	7,124	6,810	6,236	5,581
Spring	4	7,099	4/17/2015	5,175	4,984	4,871	4,821	4,903	5,276	6,123	6,398	6,437	6,478	6,515	6,551	6,559	6,606	6,647	6,700	6,836	6,884	6,837	6,850	7,099	6,873	6,410	5,848
Spring	4	7,064	4/18/2015	5,340	4,992	4,840	4,706	4,705	4,826	5,048	5,263	5,656	6,025	6,282	6,481	6,614	6,771	6,904	7,016	7,056	7,064	6,960	6,851	7,053	6,773	6,330	5,755
Spring	4	6,907	4/19/2015	5,291	4,995	4,763	4,650	4,597	4,650	4,770	4,981	5,471	5,872	6,098	6,241	6,338	6,402	6,343	6,294	6,317	6,416	6,559	6,751	6,907	6,616	6,128	5,600
Spring	4	7,757	4/20/2015	5,165	4,919	4,807	4,757	4,832	5,234	6,077	6,414	6,488	6,643	6,917	7,130	7,381	7,648	7,757	7,620	7,613	7,532	7,516	7,579	7,736	7,388	6,720	6,039
Spring	4	7,323	4/21/2015	5,496	5,195	5,022	4,929	4,985	5,370	6,085	6,316	6,373	6,436	6,526	6,586	6,621	6,803	6,856	7,001	7,116	7,146	7,097	6,991	7,323	6,994	6,336	5,638
Spring	4	7,329	4/22/2015	5,192	4,951	4,812	4,776	4,907	5,377	6,240	6,493	6,438	6,400	6,440	6,509	6,453	6,562	6,670	6,850	6,983	7,065	7,062	7,021	7,329	7,065	6,409	5,705
Spring	4	6,997	4/23/2015	5,215	4,954	4,821	4,783	4,877	5,284	6,073	6,321	6,345	6,353	6,352	6,349	6,349	6,412	6,470	6,538	6,655	6,639	6,611	6,618	6,997	6,800	6,207	5,571
Spring	4	6,677	4/24/2015	5,199	4,992	4,902	4,887	5,017	5,542	6,380	6,677	6,567	6,445	6,373	6,271	6,205	6,161	6,099	6,102	6,180	6,224	6,166	6,137	6,474	6,331	5,930	5,510
Spring	4	6,416	4/25/2015	5,112	4,900	4,812	4,757	4,780	4,945	5,189	5,439	5,857	6,098	6,245	6,229	6,201	6,115	6,013	5,994	6,036	6,104	6,148	6,222	6,416	6,222	5,860	5,420
Spring	4	6,685	4/26/2015	5,017	4,849	4,720	4,671	4,641	4,729	4,922	5,224	5,715	6,046	6,129	6,075	6,098	6,070	5,973	5,913	5,943	6,065	6,125	6,314	6,685	6,486	6,014	5,528
Spring	4	6,983	4/27/2015	5,169	5,025	4,969	5,022	5,248	5,821	6,713	6,983	6,755	6,518	6,405	6,316	6,268	6,246	6,223	6,247	6,317	6,365	6,386	6,502	6,906	6,699	6,087	5,529
Spring	4	7,025	4/28/2015	5,122	4,942	4,917	4,975	5,203	5,809	6,735	7,025	6,763	6,554	6,382	6,279	6,188	6,186	6,154	6,167	6,275	6,352	6,430	6,505	6,871	6,677	6,071	5,456
Spring	4	6,854	4/29/2015	5,083	4,904	4,839	4,844	5,007	5,532	6,391	6,644	6,511	6,433	6,374	6,349	6,268	6,295	6,301	6,308	6,376	6,452	6,546	6,591	6,854	6,643	6,084	5,500
Spring	4	6,838	4/30/2015	5,061	4,875	4,789	4,781	4,892	5,376	6,206	6,483	6,392	6,324	6,289	6,201	6,127	6,169	6,139	6,150	6,236	6,316	6,443	6,550	6,838	6,609	6,081	5,480
Spring	5	6,480	5/1/2015	5,099	4,892	4,785	4,773	4,893	5,323	6,120	6,424	6,430	6,458	6,480	6,448	6,359	6,302	6,206	6,116	6,095	6,083	6,059	6,106	6,480	6,448	6,126	5,694
Spring	5	6,190	5/2/2015	5,326	5,108	5,024	4,991	5,070	5,274	5,503	5,771	5,951	5,980	5,892	5,812	5,758	5,741	5,725	5,754	5,839	5,942	5,918	5,906	6,190	6,071	5,666	5,211
Spring	5	6,805	5/3/2015	4,779	4,611	4,490	4,437	4,486	4,623	4,755	5,095	5,494	5,645	5,653	5,675	5,805	5,958	6,055	6,220	6,373	6,570	6,624	6,561	6,805	6,594	6,010	5,353
Spring	5	7,741	5/4/2015	4,867	4,607	4,484	4,456	4,573	5,063	5,808	6,117	6,231	6,330	6,530	6,720	6,901	7,169	7,347	7,513	7,673	7,741	7,728	7,570	7,721	7,460	6,711	5,868
Spring	5	8,154	5/5/2015	5,327	4,992	4,803	4,710	4,753	5,170	5,878	6,188	6,292	6,437	6,659	6,873	7,099	7,424	7,685	7,943	8,131	8,154	8,048	7,779	7,830	7,513	6,728	5,906
Spring	5	8,009	5/6/2015	5,312	4,985	4,806	4,720	4,792	5,184	5,878	6,190	6,265	6,495	6,644	6,850	7,098	7,380	7,643	7,853	7,996	8,009	7,887	7,670	7,748	7,428	6,689	5,937
Spring	5	7,944	5/7/2015	5,380	5,073	4,866	4,774	4,870	5,281	6,015	6,309	6,427	6,613	6,807	6,951	7,177	7,380	7,564	7,751	7,942	7,944	7,861	7,678	7,837	7,620	6,894	6,112
Spring	5	7,856	5/8/2015	5,511	5,142	4,938	4,859	4,904	5,248	5,915	6,290	6,487	6,766	7,054	7,274	7,439	7,616	7,705	7,769	7,856	7,835	7,689	7,455	7,525	7,361	6,871	6,229
Spring	5	7,640	5/9/2015	5,665	5,315	5,085	4,950	4,927	5,027	5,141	5,447	5,982	6,426	6,769	7,077	7,274	7,457	7,548	7,602	7,640	7,590	7,403	7,244	7,321	7,222	6,780	6,115
Spring	5	7,257	5/10/2015	5,700	5,351	5,144	5,004	4,954	4,998	5,059	5,416	6,000	6,417	6,625	6,640	6,734	6,755	6,777	6,805	6,856	6,898	6,934	6,978	7,257	7,140	6,649	6,020
Spring	5	9,573	5/11/2015	5,546	5,254	5,123	5,057	5,148	5,576	6,322	6,671	6,864	7,095	7,470	7,836	8,224	8,660	8,980	9,302	9,518	9,573	9,469	9,101	9,029	8,543	7,668	6,818
Spring	5	10,048	5/12/2015	6,204	5,863	5,616	5,489	5,532	5,943	6,627	7,031	7,340	7,786	8,325	8,856	9,346	9,785	9,881	10,040	10,048	10,007	9,879	9,574	9,516	9,067	8,098	7,168
Spring	5	8,971	5/13/2015	6,452	6,027	5,653	5,530	5,490	5,822	6,387	6,662	6,780	6,994	7,282	7,557	7,817	8,184	8,457	8,739	8,950	8,971	8,814	8,366	8,163	7,773	6,944	6,106
Spring	5	7,556	5/14/2015	5,498	5,182	4,965	4,873	4,942	5,255	5,885	6,160	6,257	6,379	6,497	6,632	6,773	7,009	7,177	7,366	7,556	7,556	7,419	7,224	7,407	7,209	6,545	5,798
Spring	5	7,571	5/15/2015	5,269	4,988	4,850	4,796	4,850	5,170	5,805	6,120	6,230	6,358	6,536	6,695	6,833	7,037	7,198	7,341	7,523	7,571	7,462	7,215	7,207	7,076	6,564	5,936
Spring	5	8,421	5/16/2015	5,384	5,068	4,840	4,700	4,685	4,802	4,849	5,143	5,672	6,146	6,520	6,879	7,287	7,647	7,963	8,244	8,409	8,421	8,196	7,854	7,777	7,502	6,927	6,213
Spring	5	9,132	5/17/2015	5,624	5,202	4,902	4,801	4,687	4,716	4,684	5,007	5,601	6,214	6,686	7,163	7,656	8,107	8,484	8,793	9,039	9,132	9,047	8,706	8,587	8,296	7,476	6,652
Spring	5	10,530	5/18/2015	6,030	5,580	5,404	5,276	5,329	5,717	6,391	6,823	7,176	7,622	8,255	8,912	9,450	9,911	10,112	10,352	10,506	10,530	10,381	10,151	9,982	9,441	8,464	7,491
Spring	5	10,287	5/19/2015	6,742	6,283	5,984	5,766	5,760	6,076	6,744	7,212	7,525	7,956	8,478	9,056	9,284	10,087	10,287	10,247	10,242	10,079	9,840	9,514	9,274	8,922	8,047	7,138
Spring	5	10,216	5/20/2015	6,452	6,037	5,741	5,567	5,549	5,852	6,414	6,934	7,279	7,715	8,250	8,695	9,174	9,614	9,953	10,125	10,216	10,197	10,063	9,672	9,375	8,953	8,010	7,112
Spring	5	8,927	5/21/2015	6,405	5,979	5,750	5,602	5,612	5,904	6,535	6,900	7,114	7,403	7,817	8,197	8,594	8,927	8,923	8,751	8,592	8,429	8,166	7,855	7,794	7,590	6,862	6,103
Spring	5	7,520	5/22/2015	5,550	5,218	5,013	4,897	4,924	5,268	5,793	6,097	6,236	6,397	6,531	6,684	6,784	6,961	7,118	7,283	7,446	7,520	7,362	7,055	6,902	6,757	6,282	5,658
Spring	5	7,531	5/23/2015	5,150	4,799	4,594	4,471	4,496	4,597	4,656	4,972	5,405	5,735	5,942	6,147	6,347	6,557	6,811	7,066	7,373	7,531	7,470	7,135	6,942	6,793	6,281	5,687
Spring	5	7,952	5/24/2015	5,167	4,852	4,630	4,512	4,453	4,488	4,462	4,787	5,322	5,818	6,180	6,498	6,794	7,095	7,362	7,613	7,837	7,952	7,823	7,453	7,220	7,074	6,525	5,862
Spring	5	8,878	5/25/2015	5,355	4,969	4,728	4,564	4,545	4,614	4,655	4,953	5,512	6,161	6,689	7,112	7,467	7,832	8,185	8,480	8,702	8,878	8,760	8,425	8,233	7,978	7,223	6,353
Spring	5	10,180	5/26/2015	5,727	5,343	5,097	4,969	5,016	5,335	5,939	6,557	6,946	7,397	7,908	8,416	8,986	9,491	9,842	10,141	10,180	10,130	10,077	9,717	9,595	9,177	8,281	7,398
Spring	5	10,141	5/27/2015	6,682	6,247	5,915	5,808	5,777	6,135	6,781	7,237	7,614	7,979	8,480	8,999	9,380	9,789	10,060	10,141	10,096	10,050	9,778	9,265	9,037	8,752	7,898	7,017
Spring	5	10,125	5/28/2015	6,323	5,914	5,650	5,474	5,484	5,802	6,427	6,920	7,253	7,636	8,095	8,585	9,042	9,537	9,908	10,125	10,112	10,073	9,955	9,562	9,309	8,926	8,037	7,110
Spring	5	10,139	5/29/2015	6,350	5,871	5,591	5,386	5,413	5,722	6,247	6,719	7,197	7,696	8,249	8,717	9,190	9,584	9,929	10,139	10,119	10,038	9,871	9,339	8,952	8,681	7,946	7,185
Spring	5	9,873	5/30/2015	6,470	5,979	5,619	5,389	5,309	5,356	5,385	5,834	6,549	7,286	7,857	8,402	8,826	9,133	9,401	9,661	9,871	9,873	9,676	9,197	8,811	8,545	7,868	7,070
Spring	5	10,103	5/31/2015	6,340	5,880	5,494	5,287	5,165	5,145	5,079	5,529	6,338	7,139	7,729	8,290	8,766	9,283	9,588	9,821	10,031	10,103	9,984	9,559	9,242	8,931	8,113	7,230
Summer	6	10,940	6/1/2015	6,539	6,067	5,787	5,645	5,676	6,000	6,604	7,233	7,748	8,325	8,988	9,602	10,158	10,657	10,881	10,940	10,877	10,657	10,236	9,671	9,408	8,974	8,137	7,266
Summer	6	9,254	6/2/2015	6,577	6,120	5,837	5,687	5,693	6,006	6,602	7,110	7,419	7,793	8,175	8,445	8,664	8,868	9,070	9,254	9,246	9,046	8,804	8,556	8,484	8,156	7,409	6,601
Summer	6	7,677	6/3/2015	6,085	5,782	5,487	5,400	5,398	5,732	6,400	6,683	6,793	6,947	7,068	7,201	7,260	7,366	7,429	7,481	7,621	7,677	7,632	7,571	7,596	7,457	6,923	6,225
Summer	6	8,045	6/4/2015	5,706	5,407	5,237	5,125	5,199	5,569	6,183	6,527	6,688	6,903	7,107	7,297	7,473	7,668	7,813	7,912	8,045	8,009	7,915	7,746	7,743	7,643	7,044	6,314
Summer	6	8,233	6/5/2015	5,769	5,412	5,208	5,134	5,174	5,510	6,055	6,406	6,595	6,788	6,978	7,252	7,435	7,694	7,888	8,054	8,232	8,233	8,088	7,810	7,687	7,606	7,040	6,373
Summer	6	9,680	6/6/2015	5,788	5,409	5,174	4,996	4,949	5,003	5,044	5,416	6,090	6,772	7,448	8,028	8,548	8,939	9,257	9,494	9,653	9,680	9,444	8,975	8,524	8,353	7,677	6,930
Summer	6	9,377	6/7/2015	6,195	5,723	5,435	5,214	5,087	5,063	5,005	5,405	6,064	6,734	7,128	7,578	8,045	8,467	8,806	9,064	9,279	9,377	9,234	8,853	8,548	8,333	7,581	6,737
Summer	6	10,683	6/8/2015	6,093	5,645	5,353	5,196	5,236	5,538	6,104	6,618	7,092	7,617	8,237	8,820	9,343	9,860	10,202	10,456	10,680	10,683	10,484	10,084	9,797	9,474	8,647	7,733
Summer	6	10,451	6/9/2015	7,021	6,599	6,308	6,115	6,087	6,336	6,795	7,309	7,696	8,151	8,637	9,152	9,570	10,006	10,220	10,408	10,451	10,325	10,004	9,559	9,241	8,866	8,092	7,217
Summer	6	10,941	6/10/2015	6,550	6,092	5,865	5,674	5,673	5,951	6,452	6,949	7,293	7,744	8,308	8,948	9,590	10,161	10,612	10,858	10,941	10,874	10,634	10,214	9,886	9,590	8,747	7,795
Summer	6	11,479	6/11/2015	7,110	6,619	6,304	6,062	6,050	6,341	6,799	7,414	8,073	8,772	9,542	10,197	10,735	11,167	11,438	11,428	11,479	11,419	11,298	10,920	10,511	10,198	9,309	8,386
Summer	6	11,092	6/12/2015	7,596	7,022	6,635	6,382	6,299	6,511	6,874	7,538	8,246	8,940	9,646	10,246	10,706	10,945	11,052	11,092	11,068	11,006	10,845	10,413	10,034	9,812	9,096	8,279
Summer	6	11,380	6/13/2015	7,541	7,047	6,696	6,423	6,273	6,259	6,258	6,812	7,710	8,641	9,491	10,186	10,724	11,104	11,325	11,296	11,380	11,359	11,245	10,891	10,454	10,165	9,384	8,520
Summer	6	11,650	6/14/2015	7,730	7,185	6,766	6,450	6,249	6,181	6,095	6,640	7,651	8,684	9,521	10,245	10,806	11,191	11,364	11,498	11,629	11,650	11,552	11,263	10,819	10,470	9,603	8,693
Summer	6	12,722	6/15/2015	7,867	7,317	6,925	6,650	6,603	6,827	7,175	7,960	8,782	9,787	10,791	11,590	12,063	12,409	12,665	12,722	12,651	12,594	12,616	12,420	11,964	11,486	10,414	9,339
Summer	6	12,849	6/16/2015	8,498	7,813	7,478	7,120	7,015	7,157	7,445	8,155	8,941	9,927	10,942	11,713	12,283	12,658	12,816	12,849	12,823	12,766	12,815	12,639	12,174	11,705	10,710	9,670
Summer	6	12,723	6/17/2015	8,853	8,213	7,710	7,372	7,236	7,370	7,664	8,367	9,116	9,917	10,735	11,475	12,042	12,513	12,635	12,723	12,704	12,683	12,549	12,157	11,699	11,273	10,315	9,197
Summer	6	12,639	6/18/2015	8,386	7,827	7,435	7,180	7,107	7,289	7,563	8,071	8,621	9,401	10,262	11,075	11,849	12,416	12,639	12,416	12,280	12,088	11,715	11,195	10,627	10,039	9,163	8,287
Summer	6	12,367	6/19/2015	7,594	7,118	6,785	6,574	6,538	6,759	7,072	7,583	8,217	8,940	9,692	10,464	11,095	11,711	12,116	12,338	12,367	12,107	11,544	10,785	10,233	9,751	9,001	8,080
Summer	6	11,710	6/20/2015	7,320	6,840	6,445	6,205	6,111	6,091	6,111	6,510	7,326	8,329	9,258	10,068	10,759	11,214	11,535	11,710	11,667	11,657	11,465	11,040	10,622	10,299	9,640	8,887
Summer	6	12,095	6/21/2015	8,184	7,608	7,205	6,939	6,795	6,684	6,582	7,135	8,128	9,036	9,706	10,252	10,762	11,160	11,512	11,789	12,015	12,095	11,932	11,526	11,065	10,734	9,897	8,925
Summer	6	12,672	6/22/2015	8,139	7,534	7,180	6,888	6,794	6,951	7,207	7,932	8,722	9,589	10,490	11,252	11,854	12,327	12,672	12,548	12,671	12,588	12,452	12,101	11,654	11,262	10,314	9,329
Summer	6	12,773	6/23/2015	8,540	8,018	7,686	7,388	7,345	7,516	7,787	8,443	9,187	9,948	10,833	11,576	12,176	12,562	12,733	12,577	12,773	12,752	12,670	12,320	11,952	11,625	10,766	9,797
Summer	6	12,719	6/24/2015	9,002	8,464	8,058	7,823	7,680	7,813	8,117	8,688	9,314	10,058	10,879	11,555	11,909	12,472	12,652	12,617	12,719	12,652	12,474	12,072	11,428	11,006	9,999	8,946
Summer	6	12,349	6/25/2015	8,122	7,537	7,167	6,895	6,775	6,929	7,212	7,671	8,111	8,679	9,350	10,027	10,587	11,318	11,805	12,143	12,349	12,341	12,083	11,669	11,235	10,731	9,870	8,941
Summer	6	12,571	6/26/2015	8,194	7,730	7,417	7,163	7,109	7,302	7,593	8,022	8,696	9,470	10,361	11,069	11,623	12,065	12,411	12,571	12,465	12,101	11,560	10,895	10,460	10,008	9,221	8,337
Summer	6	9,836	6/27/2015	7,622	7,080	6,677	6,406	6,268	6,258	6,223	6,577	7,206	7,988	8,669	9,192	9,637	9,800	9,836	9,620	9,628	9,703	9,521	9,187	8,836	8,581	8,047	7,394
Summer	6	9,747	6/28/2015	6,789	6,380	6,167	6,011	5,957	5,958	5,896	6,170	6,802	7,408	7,743	8,106	8,459	8,767	9,101	9,395	9,641	9,747	9,586	9,194	8,709	8,469	7,800	6,943
Summer	6	10,775	6/29/2015	6,259	5,808	5,509	5,373	5,361	5,628	5,919	6,436	7,006	7,618	8,263	8,928	9,462	9,954	10,309	10,580	10,744	10,775	10,609	10,152	9,713	9,391	8,509	7,579
Summer	6	11,757	6/30/2015	6,865	6,308	5,995	5,822	5,792	5,995	6,312	6,917	7,485	8,166	8,927	9,703	10,382	10,975	11,386	11,649	11,757	11,552	11,032	10,417	9,789	9,295	8,478	7,593
Summer	7	10,784	7/1/2015	6,846	6,365	6,064	5,919	5,887	6,131	6,483	6,915	7,317	7,755	8,284	8,880	9,439	9,974	10,388	10,661	10,784	10,727	10,435	9,978	9,717	9,410	8,658	7,795
Summer	7	10,724	7/2/2015	7,115	6,679	6,427	6,274	6,270	6,492	6,811	7,241	7,664	8,147	8,703	9,271	9,753	10,219	10,538	10,667	10,724	10,593	10,066	9,492	9,159	8,883	8,220	7,435
Summer	7	8,793	7/3/2015	6,744	6,263	5,945	5,758	5,713	5,817	5,915	6,197	6,686	7,123	7,512	7,810	8,137	8,401	8,564	8,688	8,776	8,793	8,587	8,302	8,105	8,028	7,591	7,016
Summer	7	9,707	7/4/2015	6,495	6,095	5,821	5,616	5,550	5,543	5,491	5,849	6,587	7,401	8,092	8,646	8,992	9,209	9,250	9,380	9,622	9,707	9,444	8,959	8,583	8,264	7,952	7,471
Summer	7	10,537	7/5/2015	6,839	6,354	6,027	5,792	5,670	5,651	5,501	5,839	6,631	7,454	8,231	8,878	9,521	10,028	10,317	10,482	10,537	10,461	10,115	9,608	9,266	8,962	8,238	7,490
Summer	7	11,515	7/6/2015	6,822	6,373	6,112	5,945	5,966	6,249	6,571	7,078	7,714	8,406	9,147	9,779	10,292	10,755	11,104	11,390	11,515	11,479	11,169	10,649	10,195	9,812	8,993	8,047
Summer	7	11,897	7/7/2015	7,256	6,739	6,412	6,205	6,194	6,443	6,778	7,357	8,011	8,793	9,598	10,343	10,985	11,450	11,612	11,842	11,897	11,845	11,762	11,288	10,894	10,486	9,595	8,651
Summer	7	11,786	7/8/2015	7,862	7,324	6,970	6,715	6,670	6,862	7,210	7,703	8,257	8,924

Contains Proprietary Material
Do Not Distribute

Summer	8	11,150	8/12/2015	6,754	6,305	6,028	5,902	5,895	6,196	6,644	7,007	7,544	8,140	8,778	9,383	9,917	10,418	10,751	11,025	11,150	11,117	10,845	10,251	9,851	9,251	8,309	7,418
Summer	8	10,985	8/13/2015	6,672	6,163	5,884	5,715	5,689	5,933	6,376	6,730	7,263	7,883	8,622	9,294	9,843	10,307	10,671	10,892	10,985	10,856	10,536	10,028	9,768	9,258	8,366	7,515
Summer	8	10,927	8/14/2015	6,799	6,330	6,029	5,842	5,809	6,044	6,457	6,821	7,356	8,054	8,740	9,419	9,942	10,360	10,733	10,867	10,927	10,826	10,468	9,863	9,512	9,007	8,239	7,416
Summer	8	10,663	8/15/2015	6,704	6,209	5,899	5,657	5,568	5,571	5,667	5,889	6,565	7,349	8,149	8,878	9,469	9,874	10,204	10,444	10,629	10,663	10,370	9,794	9,473	8,919	8,247	7,426
Summer	8	10,830	8/16/2015	6,720	6,234	5,888	5,643	5,532	5,510	5,505	5,763	6,538	7,389	8,125	8,811	9,506	10,029	10,414	10,647	10,825	10,830	10,566	10,082	9,865	9,368	8,527	7,677
Summer	8	11,966	8/17/2015	7,017	6,569	6,258	6,073	6,064	6,365	6,849	7,190	7,727	8,445	9,304	10,130	10,868	11,460	11,806	11,966	11,956	11,780	11,393	10,919	10,707	10,086	9,173	8,220
Summer	8	10,010	8/18/2015	7,512	7,059	6,720	6,534	6,526	6,806	7,386	7,638	8,005	8,383	8,874	9,266	9,553	9,786	9,970	10,010	9,926	9,778	9,570	9,291	9,314	8,887	8,020	7,371
Summer	8	11,148	8/19/2015	6,824	6,446	6,273	6,171	6,245	6,550	7,132	7,476	7,838	8,278	8,830	9,372	9,873	10,359	10,707	10,970	11,148	11,144	10,877	10,460	10,188	9,541	8,672	7,881
Summer	8	11,725	8/20/2015	7,299	6,877	6,614	6,451	6,426	6,730	7,326	7,702	8,101	8,576	9,137	9,673	10,119	10,607	11,099	11,468	11,725	11,657	11,316	10,844	10,606	9,979	9,109	8,208
Summer	8	11,416	8/21/2015	7,525	7,062	6,727	6,536	6,487	6,773	7,299	7,589	8,131	8,779	9,498	10,123	10,616	11,021	11,317	11,416	11,397	11,196	10,795	10,216	9,882	9,369	8,595	7,816
Summer	8	10,346	8/22/2015	7,108	6,587	6,193	5,940	5,830	5,882	5,920	6,126	6,750	7,487	8,206	8,799	9,275	9,669	9,992	10,227	10,346	10,321	9,998	9,424	9,155	8,578	7,829	7,093
Summer	8	10,185	8/23/2015	6,406	5,945	5,640	5,352	5,247	5,274	5,304	5,502	6,177	6,899	7,474	7,988	8,572	9,145	9,577	9,863	10,080	10,185	10,037	9,650	9,561	8,959	8,083	7,289
Summer	8	11,309	8/24/2015	6,675	6,291	6,148	6,188	6,243	6,467	7,156	7,392	7,720	8,399	9,216	9,959	10,596	11,147	11,309	11,140	10,979	10,799	10,644	10,295	10,213	9,593	8,625	7,723
Summer	8	11,411	8/25/2015	7,051	6,635	6,345	6,221	6,252	6,645	7,391	7,629	7,882	8,390	8,951	9,592	10,178	10,727	10,895	11,222	11,411	11,320	11,038	10,598	10,465	9,763	8,815	7,913
Summer	8	10,440	8/26/2015	7,244	6,800	6,521	6,305	6,274	6,605	7,309	7,474	7,633	7,992	8,372	8,690	9,018	9,477	9,868	10,212	10,440	10,369	10,084	9,700	9,606	9,010	8,096	7,276
Summer	8	9,506	8/27/2015	6,676	6,265	6,024	5,896	5,924	6,330	7,107	7,254	7,410	7,636	7,986	8,377	8,761	9,131	9,358	9,423	9,506	9,461	9,239	8,969	8,995	8,506	7,644	6,842
Summer	8	10,035	8/28/2015	6,216	5,853	5,600	5,469	5,501	5,835	6,513	6,708	7,031	7,493	7,970	8,410	8,840	9,287	9,644	9,902	10,035	9,918	9,541	8,961	8,745	8,204	7,528	6,806
Summer	8	9,399	8/29/2015	6,148	5,712	5,457	5,277	5,227	5,284	5,385	5,546	6,127	6,706	7,274	7,853	8,333	8,704	8,995	9,225	9,399	9,382	9,073	8,668	8,533	8,096	7,454	6,768
Summer	8	8,824	8/30/2015	6,174	5,763	5,474	5,322	5,217	5,217	5,255	5,488	6,113	6,687	7,139	7,598	8,119	8,544	8,742	8,824	8,747	8,617	8,459	8,400	8,467	8,037	7,342	6,648
Summer	8	9,161	8/31/2015	6,179	5,848	5,690	5,649	5,736	6,192	7,022	7,286	7,440	7,618	7,775	8,015	8,152	8,371	8,576	8,729	8,993	9,125	9,161	9,059	9,117	8,597	7,814	7,011
Fall	9	11,116	9/1/2015	6,441	6,080	5,875	5,789	5,842	6,248	7,071	7,249	7,523	7,968	8,565	9,267	9,853	10,432	10,840	11,027	11,116	11,106	10,999	10,621	10,455	9,642	8,632	7,700
Fall	9	11,855	9/2/2015	6,980	6,567	6,253	6,078	6,043	6,397	7,115	7,344	7,732	8,368	9,172	10,019	10,594	11,210	11,534	11,738	11,855	11,751	11,643	11,237	10,956	10,162	9,105	8,114
Fall	9	11,539	9/3/2015	7,416	6,924	6,580	6,355	6,339	6,661	7,360	7,557	7,866	8,355	8,985	9,578	10,227	10,811	11,230	11,453	11,539	11,364	11,000	10,617	10,432	9,663	8,681	7,782
Fall	9	11,507	9/4/2015	7,072	6,598	6,289	6,108	6,049	6,398	7,079	7,311	7,736	8,424	9,232	10,074	10,759	11,277	11,507	11,414	11,174	10,743	10,182	9,736	9,469	8,881	8,193	7,423
Fall	9	9,745	9/5/2015	6,781	6,345	6,019	5,779	5,768	5,822	5,964	6,107	6,628	7,254	7,843	8,383	8,860	9,283	9,595	9,745	9,610	9,377	8,973	8,643	8,530	8,079	7,508	6,909
Fall	9	8,505	9/6/2015	6,307	5,903	5,666	5,508	5,450	5,470	5,604	5,746	6,272	6,752	7,121	7,442	7,772	8,078	8,306	8,433	8,505	8,480	8,304	8,160	8,070	7,690	7,206	6,675
Fall	9	9,807	9/7/2015	6,175	5,842	5,648	5,546	5,557	5,690	5,872	5,978	6,427	7,085	7,760	8,360	8,842	9,215	9,469	9,725	9,807	9,777	9,488	9,241	9,223	8,598	7,764	6,955
Fall	9	10,961	9/8/2015	6,384	6,025	5,815	5,729	5,813	6,268	7,096	7,429	7,665	8,059	8,693	9,345	9,897	10,388	10,692	10,890	10,961	10,880	10,624	10,360	10,235	9,490	8,594	7,726
Fall	9	11,337	9/9/2015	7,076	6,670	6,409	6,251	6,275	6,655	7,409	7,666	8,046	8,549	9,130	9,690	10,184	10,682	10,965	11,148	11,337	11,304	11,043	10,762	10,589	9,878	8,930	8,089
Fall	9	11,611	9/10/2015	7,468	7,050	6,808	6,662	6,682	7,079	7,843	8,087	8,349	8,801	9,333	9,876	10,406	10,954	11,372	11,611	11,510	11,438	11,065	10,697	10,401	9,636	8,741	7,822
Fall	9	10,128	9/11/2015	7,159	6,724	6,393	6,212	6,173	6,561	7,274	7,484	7,676	8,032	8,448	8,891	9,331	9,700	9,964	10,070	10,128	10,012	9,723	9,437	9,251	8,709	8,061	7,309
Fall	9	8,127	9/12/2015	6,729	6,305	6,051	5,864	5,821	5,871	6,070	6,256	6,719	7,222	7,660	7,893	8,060	8,105	8,127	8,123	8,037	7,993	7,886	7,924	7,908	7,566	7,070	6,529
Fall	9	7,707	9/13/2015	6,008	5,677	5,443	5,263	5,180	5,183	5,271	5,364	5,811	6,269	6,545	6,777	7,041	7,285	7,498	7,605	7,670	7,707	7,498	7,329	7,371	6,855	6,218	5,572
Fall	9	8,087	9/14/2015	5,127	4,860	4,720	4,706	4,804	5,218	5,960	6,174	6,288	6,463	6,649	6,802	6,959	7,247	7,468	7,720	8,005	8,087	7,962	7,824	7,746	7,188	6,436	5,764
Fall	9	8,453	9/15/2015	5,268	5,033	4,884	4,809	4,896	5,299	6,052	6,219	6,345	6,491	6,753	6,977	7,242	7,538	7,832	8,189	8,387	8,453	8,268	8,096	8,008	7,368	6,652	5,953
Fall	9	8,465	9/16/2015	5,420	5,134	4,970	4,866	4,934	5,323	6,054	6,262	6,367	6,541	6,782	7,049	7,315	7,688	7,991	8,287	8,465	8,372	8,229	8,246	8,194	7,655	6,997	6,293
Fall	9	8,821	9/17/2015	5,767	5,463	5,292	5,226	5,300	5,689	6,467	6,673	6,759	6,994	7,296	7,614	7,930	8,289	8,495	8,681	8,821	8,777	8,568	8,462	8,420	7,839	7,128	6,367
Fall	9	9,460	9/18/2015	5,778	5,470	5,286	5,190	5,206	5,581	6,281	6,527	6,680	7,017	7,428	7,875	8,327	8,744	9,128	9,365	9,460	9,387	9,007	8,705	8,498	7,924	7,294	6,633
Fall	9	9,875	9/19/2015	6,060	5,663	5,433	5,288	5,260	5,290	5,491	5,697	6,226	6,888	7,556	8,153	8,655	9,083	9,457	9,728	9,875	9,846	9,460	9,054	8,666	8,032	7,332	6,633
Fall	9	9,824	9/20/2015	5,992	5,569	5,279	5,079	4,987	4,999	5,116	5,269	5,921	6,561	7,150	7,713	8,349	8,946	9,426	9,691	9,824	9,783	9,386	9,258	8,995	8,335	7,534	6,776
Fall	9	9,280	9/21/2015	6,193	5,826	5,602	5,494	5,575	5,993	6,778	7,063	7,208	7,529	7,952	8,354	8,695	9,054	9,188	9,254	9,280	9,177	9,014	9,069	8,804	8,158	7,436	6,728
Fall	9	8,747	9/22/2015	6,194	5,869	5,673	5,591	5,653	6,026	6,837	7,038	7,151	7,345	7,605	7,860	8,015	8,258	8,486	8,649	8,747	8,635	8,452	8,574	8,494	7,952	7,283	6,607
Fall	9	8,271	9/23/2015	6,057	5,745	5,573	5,474	5,517	5,946	6,696	6,905	7,026	7,193	7,453	7,651	7,876	8,094	8,221	8,263	8,271	8,174	8,089	8,269	8,181	7,692	7,015	6,353
Fall	9	7,833	9/24/2015	5,805	5,494	5,330	5,234	5,282	5,649	6,437	6,666	6,748	6,885	7,029	7,199	7,296	7,396	7,473	7,435	7,472	7,456	7,548	7,833	7,744	7,328	6,739	6,164
Fall	9	7,499	9/25/2015	5,691	5,429	5,274	5,242	5,293	5,682	6,467	6,815	6,937	7,056	7,231	7,323	7,332	7,380	7,394	7,348	7,354	7,349	7,341	7,499	7,406	7,109	6,654	6,148
Fall	9	6,957	9/26/2015	5,690	5,409	5,237	5,128	5,114	5,200	5,404	5,619	6,013	6,391	6,662	6,765	6,773	6,719	6,663	6,633	6,653	6,676	6,706	6,957	6,902	6,658	6,298	5,864
Fall	9	7,758	9/27/2015	5,398	5,140	4,964	4,883	4,868	4,947	5,128	5,381	5,813	6,233	6,439	6,618	6,814	6,955	7,041	7,115	7,231	7,347	7,430	7,758	7,681	7,278	6,747	6,199
Fall	9	8,806	9/28/2015	5,726	5,467	5,334	5,270	5,391	5,860	6,703	7,109	7,206	7,416	7,699	7,948	8,173	8,319	8,520	8,538	8,506	8,490	8,515	8,806	8,682	8,188	7,564	6,948
Fall	9	9,711	9/29/2015	6,419	6,143	5,952	5,899	5,984	6,384	7,235	7,588	7,699	7,965	8,336	8,734	9,055	9,418	9,639	9,711	9,636	9,505	9,452	9,639	9,366	8,744	8,029	7,281
Fall	9	9,820	9/30/2015	6,723	6,420	6,170	6,081	6,123	6,543	7,335	7,664	7,808	8,042	8,322	8,700	9,075	9,551	9,679	9,782	9,820	9,686	9,560	9,541	9,050	8,540	7,727	6,955
Fall	10	7,307	10/1/2015	6,389	6,018	5,782	5,619	5,627	5,973	6,758	7,073	7,045	7,105	7,162	7,119	7,058	7,046	6,968	6,923	6,887	6,930	7,070	7,307	7,176	6,778	6,255	5,701
Fall	10	6,942	10/2/2015	5,307	5,067	4,936	4,858	4,951	5,294	6,077	6,431	6,478	6,605	6,657	6,739	6,686	6,688	6,622	6,569	6,631	6,731	6,857	6,942	6,807	6,528	6,107	5,655
Fall	10	7,149	10/3/2015	5,287	5,024	4,908	4,830	4,818	4,942	5,171	5,364	5,784	6,234	6,546	6,769	6,820	6,851	6,826	6,830	6,888	6,917	6,909	7,149	6,995	6,722	6,354	5,946
Fall	10	6,920	10/4/2015	5,551	5,279	5,117	5,016	4,921	4,952	5,081	5,294	5,698	6,046	6,236	6,338	6,420	6,460	6,427	6,371	6,402	6,468	6,628	6,920	6,764	6,399	5,926	5,425
Fall	10	7,157	10/5/2015	5,016	4,804	4,667	4,617	4,724	5,084	5,826	6,177	6,274	6,421	6,567	6,637	6,632	6,630	6,567	6,556	6,593	6,667	6,858	7,157	6,994	6,607	6,090	5,539
Fall	10	7,235	10/6/2015	5,127	4,925	4,810	4,775	4,905	5,300	6,045	6,379	6,404	6,452	6,511	6,543	6,509	6,579	6,629	6,674	6,785	6,803	6,855	7,235	7,133	6,709	6,151	5,561
Fall	10	7,752	10/7/2015	5,179	4,945	4,843	4,814	4,909	5,339	6,093	6,374	6,361	6,446	6,548	6,631	6,766	6,992	7,195	7,434	7,568	7,648	7,603	7,752	7,622	7,111	6,436	5,802
Fall	10	7,921	10/8/2015	5,340	5,088	4,935	4,873	4,971	5,353	6,155	6,379	6,423	6,612	6,858	7,051	7,352	7,682	7,894	7,877	7,921	7,843	7,742	7,831	7,773	7,307	6,652	5,988
Fall	10	7,881	10/9/2015	5,530	5,246	5,063	4,978	5,038	5,380	6,132	6,353	6,444	6,647	6,922	7,200	7,448	7,769	7,817	7,881	7,867	7,774	7,587	7,671	7,598	7,188	6,811	6,235
Fall	10	6,583	10/10/2015	5,694	5,379	5,183	5,063	5,052	5,128	5,326	5,569	5,874	6,233	6,426	6,507	6,501	6,439	6,385	6,295	6,335	6,354	6,420	6,583	6,468	6,197	5,845	5,418
Fall	10	6,842	10/11/2015	5,022	4,769	4,637	4,506	4,475	4,567	4,749	5,003	5,402	5,668	5,752	5,745	5,854	5,966	6,068	6,170	6,311	6,436	6,461	6,842	6,706	6,282	5,782	5,306
Fall	10	7,747	10/12/2015	4,940	4,718	4,612	4,581	4,689	5,100	5,905	6,221	6,299	6,450	6,580	6,681	6,787	6,929	7,050	7,208	7,334	7,357	7,431	7,747	7,490	6,985	6,387	5,758
Fall	10	7,717	10/13/2015	5,323	5,076	4,948	4,888	4,978	5,360	6,186	6,419	6,471	6,581	6,707	6,852	7,036	7,213	7,355	7,484	7,618	7,586	7,570	7,717	7,679	7,174	6,534	5,905
Fall	10	7,619	10/14/2015	5,424	5,168	5,010	4,927	5,007	5,398	6,198	6,390	6,362	6,506	6,665	6,782	6,932	7,166	7,338	7,474	7,577	7,501	7,407	7,619	7,378	6,869	6,249	5,613
Fall	10	7,230	10/15/2015	5,170	4,951	4,808	4,787	4,880	5,325	6,164	6,418	6,403	6,395	6,488	6,492	6,553	6,659	6,728	6,838	6,921	6,904	6,891	7,230	7,075	6,649	6,125	5,510
Fall	10	6,888	10/16/2015	5,160	4,916	4,840	4,821	4,937	5,363	6,197	6,483	6,461	6,483	6,517	6,567	6,602	6,702	6,735	6,782	6,736	6,617	6,676	6,888	6,716	6,449	6,059	5,627
Fall	10	6,484	10/17/2015	5,221	5,020	4,877	4,858	4,929	5,107	5,475	5,802	6,147	6,220	6,178	6,069	5,964	5,907	5,900	5,918	5,996	6,042	6,175	6,484	6,416	6,203	5,892	5,506
Fall	10	7,108	10/18/2015	5,172	5,022	4,965	4,980	5,088	5,311	5,674	6,140	6,646	6,685	6,428	6,184	6,041	5,917	5,785	5,773	5,826	6,052	6,447	7,042	7,108	6,861	6,566	6,186
Fall	10	8,419	10/19/2015	5,969	5,894	5,935	6,061	6,357	7,054	7,952	8,419	8,389	8,015	7,498	7,121	6,804	6,613	6,471	6,398	6,465	6,655	7,092	7,661	7,599	7,325	6,929	6,503
Fall	10	8,419	10/20/2015	6,211	6,160	6,220	6,131	6,573	7,305	8,132	8,419	8,268	7,791	7,267	6,916	6,639	6,516	6,430	6,422	6,486	6,566	6,865	7,280	7,164	6,842	6,347	5,899
Fall	10	7,842	10/21/2015	5,600	5,529	5,524	5,603	5,862	6,526	7,511	7,842	7,609	7,206	6,865	6,640	6,487	6,503	6,518	6,503	6,694	6,769	6,912	7,236	7,077	6,687	6,162	5,643
Fall	10	7,312	10/22/2015	5,273	5,123	5,084	5,085	5,312	5,872	6,833	7,154	7,001	6,791	6,756	6,624	6,600	6,700	6,733	6,890	6,979	6,979	7,078	7,312	7,096	6,673	6,140	5,581
Fall	10	7,086	10/23/2015	5,152	4,962	4,869	4,873	4,985	5,449	6,274	6,584	6,604	6,558	6,581	6,576	6,621	6,772	6,901	7,010	7,086	7,022	6,980	7,067	6,811	6,507	6,078	5,606
Fall	10	6,559	10/24/2015	5,196	4,908	4,690	4,682	4,687	4,815	5,123	5,401	5,709	5,980	6,058	6,050	6,002	6,064	6,048	6,143	6,204	6,224	6,381	6,559	6,390	6,132	5,729	5,296
Fall	10	6,921	10/25/2015	4,927	4,724	4,588	4,498	4,486	4,555	4,783	5,106	5,505	5,784	5,822	5,779	5,845	5,919	6,009	6,079	6,175	6,322	6,674	6,921	6,702	6,299	5,832	5,321
Fall	10	7,323	10/26/2015	4,958	4,712	4,596	4,546	4,650	5,050	5,834	6,253	6,272	6,400	6,484	6,501	6,478	6,461	6,429	6,410	6,490	6,642	7,127	7,323	7,138	6,741	6,212	5,684
Fall	10	7,484	10/27/2015	5,313	5,139	5,056	5,061	5,199	5,683	6,539	6,925	6,824	6,823	6,881	6,880	6,797	6,842	6,811	6,786	6,889	7,049	7,385	7,484	7,236	6,823	6,264	5,732
Fall	10	7,526	10/28/2015	5,314	5,144	5,006	4,967	5,068	5,513	6,308	6,712	6,671	6,764	6,859	6,947	6,936	6,938	6,816	6,844	6,975	7,034	7,401	7,526	7,379	7,017	6,482	5,873
Fall	10	7,544	10/29/2015	5,473	5,218	5,072	4,991	5,069	5,471	6,278	6,624	6,582	6,637	6,805	6,930	7,015	7,131	7,170	7,218	7,209	7,141	7,371	7,544	7,380	6,978	6,398	5,784
Fall	10	6,677	10/30/2015	5,338	5,117	4,933	4,874	4,929	5,353	6,127	6,466	6,402	6,420	6,420	6,371	6,396	6,415	6,447	6,466	6,479	6,452	6,535	6,677	6,525	6,322	5,983	5,608
Fall	10	6,469	10/31/2015	5,283	5,099	5,024	5,013	5,071	5,273	5,622	5,990	6,320	6,469	6,406	6,174	6,041	5,937	5,905	5,919	5,941	5,967	6,075	6,115	6,086	6,007	5,720	5,342
Fall	11	6,902	11/1/2015	4,814	4,707	4,673	4,567	4,582	4,523	5,038	5,268	5,706	5,936	5,984	5,968	6,096	6,099	6,105	5,977	6,381	6,673	6,902	6,674	6,477	6,151	5,562	5,269
Fall	11	7,416	11/2/2015	4,894	4,735	4,645	4,645	4,778	5,278	6,125	6,430	6,569	6,720	6,838	6,877	6,847	6,813	6,714	6,617	6,811	7,249	7,416	7,286	6,956	6,548	6,029	5,523
Fall	11	7,379	11/3/2015	5,188	4,976	4,858	4,849	4,955	5,391	6,217	6,491	6,595	6,634	6,663	6,665	6,563	6,546	6,556	6,611	6,767	7,185	7,379	7,344	7,100	6,597	6,037	5,552
Fall	11	7,457	11/4/2015	5,170	4,987	4,898	4,866	4,993	5,466	6,245	6,450	6,486	6,473	6,550	6,604	6,602	6,624	6,610	6,621	6,837	7,211	7,457	7,332	7,117	6,627	6,117	5,623
Fall	11	7,646	11/5/2015	5,267	5,077	4,947	4,885	5,022	5,457	6,308	6,551	6,616	6,708	6,815	6,836	6,880	6,862	7,000	6,977	7,042	7,413	7,646	7,508	7,255	6,817	6,268	5,701
Fall	11	7,529	11/6/2015	5,307	5,098	4,949	4,926	5,025	5,474	6,252	6,505	6,641	6,781	6,944	7,094	7,210	7,300	7,285	7,211	7,199	7,466	7,529	7,332	7,106	6,810	6,405	5,946
Fall	11	7,315	11/7/2015	5,480	5,231	5,077	4,976	4,976	5,128	5,326	5,625	6,123	6,546	6,854	7,038	7,068	7,116	7,107	7,091	7,082	7,315	7,300	7,071	6,661	6,327	5,904	5,430
Fall	11	6,966	11/8/2015	4,945	4,672	4,521	4,426	4,431	4,554	4,768	5,064	5,561	5,855	5,880	5,853	5,868	5,879	5,902	5,935	6,117	6,793	6,966	6,888	6,726	6,369	5,939	5,509
Fall	11	7,704	11/9/2015	5,212	5,065	5,028	5,043	5,235	5,783	6,700	6,962	6,997	7,057	7,122	7,125	7,079	7,043	6,993	6,964	7,124	7,588	7,704	7,558	7,269	6,840	6,279	5,764
Fall	11	7,247	11/10/2015	5,402	5,219	5,120	5,097	5,244	5,715	6,551	6,776	6,748	6,755	6,755	6,738	6,669	6,661	6,597	6,552	6,581	6,981	7,247	7,106	6,906	6,548	6,137	5,683
Fall	11	7,229	11/11/2015	5,367	5,218	5,181	5,196	5,394	5,811	6,386	6,707	6,738	6,672	6,603	6,495	6,363	6,372	6,358	6,350	6,496	6,927	7,229	7,105	6,967	6,651	6,208	5,765
Fall	11	7,477	11/12/2015	5,492	5,375	5,329	5,403	5,551	6,128	6,982	7,109	6,844	6,642	6,547	6,479	6,459	6,575	6,602	6,645	6,710	7,122	7,477	7,164	7,011	6,605	6,054	5,520
Fall	11	7,063	11/13/2015	5,159	4,961	4,845	4,877	5,027	5,524	6,410	6,656	6,557	6,494	6

Contains Proprietary Material
Do Not Distribute

Winter	12	12,507	12/7/2014	9,423	9,150	9,047	9,045	9,183	9,516	10,054	10,586	11,094	11,045	10,664	10,324	10,129	9,923	9,757	9,777	10,214	11,505	12,206	12,409	12,507	12,212	11,654	11,096
Winter	12	14,800	12/8/2014	10,755	10,623	10,644	10,761	11,154	12,085	13,596	14,214	14,083	13,950	13,866	13,736	13,555	13,471	13,412	13,481	13,776	14,579	14,800	14,658	14,358	13,731	12,856	11,982
Winter	12	14,176	12/9/2014	11,444	11,143	11,017	11,056	11,339	12,157	13,604	14,176	13,890	13,489	12,900	12,362	11,982	11,922	11,929	12,084	12,417	13,309	13,660	13,635	13,454	13,012	12,241	11,476
Winter	12	14,581	12/10/2014	11,153	11,027	11,083	11,230	11,623	12,544	14,079	14,581	14,081	13,274	12,749	12,401	12,067	11,921	11,783	11,815	12,256	13,539	14,203	14,308	14,263	13,924	13,224	12,576
Winter	12	16,083	12/11/2014	12,265	12,243	12,354	12,586	13,087	14,114	15,716	16,083	15,581	14,803	13,796	13,053	12,410	12,026	11,771	11,709	12,088	13,276	14,013	14,297	14,428	14,185	13,525	12,828
Winter	12	15,977	12/12/2014	12,473	12,424	12,468	12,663	13,037	13,951	15,473	15,977	15,408	14,312	13,284	12,446	11,772	11,415	11,102	10,964	11,193	12,226	12,744	12,698	12,773	12,624	12,192	11,681
Winter	12	13,577	12/13/2014	11,277	11,148	11,202	11,334	11,615	12,087	12,807	13,345	13,577	12,909	12,025	11,281	10,666	10,234	9,939	9,853	10,048	10,983	11,467	11,570	11,588	11,495	11,233	10,806
Winter	12	12,787	12/14/2014	10,495	10,400	10,435	10,570	10,799	11,187	11,789	12,413	12,787	12,168	11,197	10,473	10,078	9,752	9,537	9,459	9,757	10,860	11,542	11,752	11,844	11,645	11,167	10,706
Winter	12	15,029	12/15/2014	10,458	10,492	10,605	10,947	11,514	12,610	14,330	15,029	14,606	13,646	12,758	12,066	11,534	11,236	11,010	10,931	11,183	12,269	12,946	13,037	13,038	12,683	12,013	11,222
Winter	12	13,247	12/16/2014	10,755	10,496	10,438	10,452	10,678	11,392	12,699	13,247	12,962	12,759	12,549	12,293	11,964	11,761	11,503	11,349	11,548	12,423	12,849	12,781	12,655	12,237	11,506	10,742
Winter	12	13,974	12/17/2014	10,304	10,191	10,252	10,413	10,835	11,812	13,378	13,974	13,592	12,787	12,142	11,624	11,184	10,974	10,774	10,718	11,015	12,074	12,712	12,759	12,740	12,432	11,805	11,103
Winter	12	14,383	12/18/2014	10,763	10,716	10,802	10,998	11,411	12,374	13,874	14,383	14,022	13,570	13,046	12,498	11,996	11,687	11,418	11,390	11,638	12,595	13,048	13,030	12,906	12,529	11,841	11,095
Winter	12	14,203	12/19/2014	10,609	10,428	10,424	10,604	11,045	11,961	13,510	14,203	13,969	13,164	12,397	11,738	11,284	11,099	10,916	10,899	11,145	12,166	12,565	12,496	12,385	12,166	11,694	11,039
Winter	12	12,667	12/20/2014	10,491	10,170	10,024	9,985	10,106	10,378	10,895	11,513	12,081	12,554	12,667	12,535	12,201	11,890	11,649	11,561	11,746	12,474	12,659	12,514	12,363	12,053	11,502	10,839
Winter	12	11,946	12/21/2014	10,291	9,966	9,801	9,771	9,848	10,076	10,453	11,017	11,564	11,715	11,371	10,928	10,726	10,526	10,349	10,334	10,647	11,592	11,946	11,922	11,819	11,509	10,945	10,291
Winter	12	14,169	12/22/2014	9,836	9,608	9,584	9,737	10,104	10,803	11,856	12,704	12,984	13,257	13,402	13,387	13,289	13,264	13,165	13,170	13,362	14,034	14,169	14,019	13,687	13,191	12,459	11,640
Winter	12	13,041	12/23/2014	11,049	10,685	10,505	10,482	10,666	11,240	12,105	12,776	12,922	13,041	13,033	12,837	12,576	12,467	12,324	12,204	12,275	12,862	12,877	12,613	12,321	11,866	11,178	10,355
Winter	12	11,161	12/24/2014	9,644	9,281	9,062	8,978	9,082	9,394	9,886	10,342	10,672	11,033	11,161	11,029	10,754	10,550	10,362	10,253	10,319	10,684	10,486	10,153	9,894	9,613	9,213	8,672
Winter	12	10,243	12/25/2014	8,188	7,866	7,719	7,729	7,852	8,168	8,669	9,193	9,654	9,693	9,551	9,343	9,033	8,614	8,329	8,194	8,303	9,062	9,665	9,895	10,141	10,243	10,168	9,979
Winter	12	12,760	12/26/2014	9,872	9,930	10,078	10,310	10,681	11,307	12,064	12,636	12,760	12,140	11,272	10,493	9,939	9,454	9,149	9,008	9,247	10,192	10,864	10,916	10,986	10,920	10,550	10,170
Winter	12	11,687	12/27/2014	9,862	9,692	9,727	9,783	10,051	10,380	10,966	11,437	11,687	11,252	10,640	10,028	9,529	9,123	8,868	8,782	8,973	9,824	10,276	10,237	10,119	9,846	9,360	8,809
Winter	12	10,225	12/28/2014	8,353	8,085	7,947	7,905	7,905	8,097	8,419	8,744	9,159	9,467	9,458	9,349	9,325	9,208	9,110	9,056	9,204	9,925	10,225	10,174	9,994	9,632	9,117	8,532
Winter	12	11,821	12/29/2014	8,085	7,815	7,733	7,725	7,929	8,492	9,390	10,114	10,372	10,599	10,820	10,894	10,839	10,766	10,654	10,578	10,756	11,494	11,821	11,669	11,430	11,025	10,436	9,772
Winter	12	13,650	12/30/2014	9,357	9,177	9,114	9,217	9,545	10,220	11,166	12,048	12,327	12,628	12,808	12,825	12,713	12,582	12,368	12,229	12,371	13,166	13,650	13,635	13,570	13,296	12,798	12,223
Winter	12	13,979	12/31/2014	11,847	11,693	11,674	11,742	12,032	12,684	13,432	13,976	13,979	13,781	13,257	12,591	12,079	11,690	11,340	11,214	11,465	12,520	13,150	13,054	12,890	12,654	12,343	12,169
Winter	1	13,649	1/1/2015	11,982	11,991	12,013	12,168	12,430	12,863	13,323	13,611	13,649	13,141	12,311	11,671	11,015	10,526	10,116	9,986	10,278	11,225	11,637	11,598	11,395	11,062	10,527	9,982
Winter	1	11,883	1/2/2015	9,518	9,260	9,134	9,165	9,427	9,986	10,821	11,466	11,666	11,736	11,633	11,475	11,286	11,118	11,056	10,885	11,033	11,768	11,883	11,669	11,421	11,041	10,485	9,887
Winter	1	11,550	1/3/2015	9,405	9,053	8,924	8,852	8,909	9,119	9,567	9,985	10,369	10,887	11,134	11,176	11,063	10,918	10,815	10,840	10,980	11,442	11,550	11,330	11,190	10,780	10,131	9,690
Winter	1	11,023	1/4/2015	9,166	8,869	8,654	8,544	8,561	8,732	9,037	9,444	9,823	10,131	10,153	10,118	10,185	10,171	9,989	9,864	9,950	10,614	11,023	10,899	10,766	10,355	9,863	9,386
Winter	1	13,778	1/5/2015	9,123	9,075	9,209	9,468	9,975	11,048	12,746	13,542	13,335	12,921	12,599	12,210	11,863	11,600	11,340	11,275	11,520	12,544	13,533	13,778	13,736	13,384	12,845	12,335
Winter	1	16,126	1/6/2015	12,063	12,104	12,190	12,483	12,969	13,974	15,543	16,126	15,662	14,578	13,668	12,861	12,216	11,903	11,595	11,596	11,841	12,728	13,641	13,816	13,779	13,429	12,858	12,317
Winter	1	18,179	1/7/2015	12,040	11,981	12,056	12,237	12,659	13,577	15,035	15,494	15,048	14,733	14,477	14,285	14,180	14,150	13,988	14,140	14,867	16,292	17,438	17,857	18,179	18,160	17,790	17,437
Winter	1	20,376	1/8/2015	17,280	17,330	17,469	17,689	17,961	18,525	19,786	20,376	19,942	19,037	18,338	17,500	16,597	15,852	15,263	15,061	15,437	16,636	17,726	17,976	17,944	17,507	16,812	16,092
Winter	1	17,084	1/9/2015	15,564	15,245	15,035	14,987	14,980	15,414	16,629	17,084	16,682	16,023	15,308	14,508	13,782	13,230	12,771	12,569	12,875	13,914	14,742	14,827	14,930	14,773	14,404	13,952
Winter	1	16,484	1/10/2015	13,633	13,627	13,738	13,946	14,324	14,848	15,529	16,217	16,484	15,872	15,106	14,364	13,399	12,704	12,165	11,929	12,257	13,438	14,513	14,789	14,938	14,857	14,684	14,342
Winter	1	16,428	1/11/2015	14,197	14,214	14,382	14,590	14,903	15,271	15,758	16,255	16,428	15,535	14,171	13,123	12,547	12,187	12,021	12,022	12,350	13,161	13,543	13,505	13,295	12,823	12,161	11,557
Winter	1	14,375	1/12/2015	11,161	10,996	11,004	11,113	11,479	12,328	13,729	14,375	14,148	14,057	14,005	13,847	13,668	13,486	13,285	13,158	13,243	13,718	14,044	13,878	13,533	12,818	11,986	11,187
Winter	1	15,348	1/13/2015	10,652	10,352	10,184	10,174	10,444	11,273	12,671	13,452	13,388	13,441	13,598	13,706	13,683	13,767	13,762	13,853	14,151	14,894	15,348	15,234	15,041	14,478	13,705	12,987
Winter	1	15,887	1/14/2015	12,588	12,510	12,479	12,635	12,965	13,809	15,113	15,873	15,887	15,755	15,585	15,236	14,762	14,379	14,083	13,939	14,041	14,659	15,197	15,015	14,814	14,377	13,714	13,128
Winter	1	16,325	1/15/2015	12,773	12,736	12,781	12,973	13,325	14,196	15,654	16,325	16,022	15,603	15,075	14,404	13,896	13,745	13,570	13,514	13,663	14,198	14,664	14,535	14,274	13,745	12,915	12,240
Winter	1	15,661	1/16/2015	11,843	11,849	11,948	12,175	12,553	13,484	14,910	15,661	15,317	14,516	13,585	12,833	12,155	11,691	11,283	11,099	11,128	11,817	12,746	12,864	12,939	12,864	12,558	12,124
Winter	1	14,514	1/17/2015	11,882	11,877	11,987	12,188	12,523	13,016	13,696	14,233	14,514	13,849	12,837	12,068	11,326	10,760	10,335	10,140	10,376	11,129	11,997	12,058	12,066	11,883	11,532	10,965
Winter	1	11,772	1/18/2015	10,474	10,156	9,999	9,941	10,047	10,284	10,739	11,362	11,772	11,669	11,050	10,431	10,124	9,896	9,745	9,629	9,780	10,506	11,375	11,558	11,546	11,366	11,047	10,699
Winter	1	14,036	1/19/2015	10,550	10,523	10,623	10,878	11,312	12,100	13,185	13,987	14,036	13,399	12,751	12,075	11,559	11,165	10,893	10,733	10,819	11,439	12,377	12,474	12,270	11,909	11,292	10,709
Winter	1	13,673	1/20/2015	10,344	10,198	10,180	10,259	10,608	11,451	12,899	13,673	13,456	12,764	12,112	11,586	11,138	10,910	10,701	10,607	10,663	11,250	12,007	12,016	11,830	11,321	10,707	10,016
Winter	1	13,264	1/21/2015	9,569	9,431	9,421	9,560	9,975	10,937	12,474	13,264	12,958	12,360	11,944	11,481	11,145	10,939	10,754	10,636	10,803	11,349	12,297	12,371	12,353	12,071	11,477	10,961
Winter	1	14,946	1/22/2015	10,701	10,688	10,866	11,155	11,651	12,706	14,292	14,946	14,633	13,966	13,112	12,269	11,632	11,331	11,168	11,111	11,250	11,856	12,733	12,846	12,830	12,501	11,903	11,221
Winter	1	14,548	1/23/2015	10,878	10,647	10,563	10,588	10,847	11,609	12,979	13,665	13,604	13,685	13,865	13,917	13,857	13,905	13,845	13,894	14,032	14,455	14,548	14,237	13,892	13,398	12,713	12,042
Winter	1	13,149	1/24/2015	11,556	11,301	11,161	11,115	11,197	11,437	11,865	12,468	12,838	13,135	13,149	12,771	12,043	11,336	10,880	10,612	10,725	11,432	12,474	12,614	12,645	12,522	12,175	11,827
Winter	1	13,873	1/25/2015	11,492	11,418	11,421	11,564	11,864	12,299	12,879	13,535	13,873	13,090	11,937	11,047	10,578	10,165	9,850	9,727	9,859	10,655	11,716	11,909	11,810	11,385	10,796	10,250
Winter	1	13,848	1/26/2015	9,908	9,814	9,842	10,030	10,478	11,374	12,924	13,662	13,400	13,136	12,753	12,479	12,240	12,157	11,975	11,985	12,185	12,827	13,699	13,848	13,752	13,327	12,671	12,055
Winter	1	15,776	1/27/2015	11,750	11,716	11,858	12,065	12,571	13,546	15,105	15,776	15,384	14,908	14,420	13,866	13,207	12,714	12,309	12,162	12,423	13,148	14,430	14,735	14,722	14,327	13,650	13,069
Winter	1	16,850	1/28/2015	12,779	12,771	12,867	13,093	13,577	14,622	16,235	16,850	16,231	15,227	14,384	13,589	12,897	12,456	12,068	11,887	12,052	12,724	13,963	14,322	14,507	14,229	13,663	13,119
Winter	1	16,849	1/29/2015	12,891	12,886	13,031	13,234	13,732	14,743	16,349	16,849	16,260	15,271	14,448	13,828	13,285	13,006	12,870	12,704	12,671	13,106	14,000	14,098	13,991	13,426	12,557	11,771
Winter	1	14,132	1/30/2015	11,184	10,851	10,672	10,740	11,075	11,987	13,488	14,132	13,871	13,559	13,236	12,760	12,308	11,970	11,728	11,587	11,796	12,463	13,576	13,784	13,817	13,677	13,331	12,966
Winter	1	15,454	1/31/2015	12,688	12,688	12,799	13,012	13,438	13,960	14,692	15,284	15,454	14,654	13,663	12,808	11,992	11,327	10,808	10,623	10,742	11,435	12,389	12,561	12,580	12,375	11,992	11,445
Winter	2	12,253	2/1/2015	10,983	10,753	10,658	10,582	10,678	10,857	11,247	11,702	12,248	12,253	11,756	11,260	10,976	10,835	10,721	10,781	10,992	11,442	11,699	11,422	11,201	10,867	10,504	9,884
Winter	2	14,718	2/2/2015	9,299	8,982	8,854	8,824	9,070	9,799	11,151	11,909	11,727	11,741	11,808	11,741	11,734	11,719	11,620	11,643	11,945	12,864	14,259	14,685	14,718	14,403	13,784	13,218
Winter	2	17,471	2/3/2015	12,989	12,961	13,117	13,411	14,001	15,093	16,893	17,471	16,845	15,593	14,535	13,681	12,968	12,526	12,080	11,836	11,951	12,676	13,988	14,433	14,523	14,188	13,595	12,975
Winter	2	16,707	2/4/2015	12,628	12,569	12,699	12,909	13,398	14,396	16,084	16,707	16,105	14,988	13,943	13,031	12,357	11,970	11,662	11,527	11,813	12,484	13,417	13,499	13,414	12,888	12,168	11,480
Winter	2	14,935	2/5/2015	11,067	10,917	10,879	11,042	11,379	12,304	13,838	14,392	13,936	13,421	13,059	12,820	12,407	12,125	11,924	11,827	12,084	12,864	14,268	14,798	14,935	14,664	14,138	13,689
Winter	2	18,345	2/6/2015	13,523	13,609	13,823	14,224	14,841	16,053	17,793	18,345	17,527	16,235	15,064	14,174	13,432	13,047	12,781	12,649	12,687	12,997	13,850	13,957	13,925	13,814	13,484	13,018
Winter	2	14,561	2/7/2015	12,704	12,627	12,640	12,776	12,999	13,458	14,144	14,494	14,561	13,875	13,070	12,215	11,369	10,728	10,221	9,926	9,936	10,363	11,282	11,502	11,455	11,240	10,842	10,357
Winter	2	11,454	2/8/2015	9,990	9,791	9,744	9,758	9,900	10,210	10,665	11,184	11,454	11,073	10,420	9,879	9,536	9,275	9,045	8,946	9,075	9,518	10,455	10,720	10,550	10,099	9,558	8,977
Winter	2	12,469	2/9/2015	8,598	8,381	8,350	8,399	8,711	9,577	11,044	11,758	11,646	11,569	11,521	11,542	11,507	11,493	11,354	11,372	11,464	11,807	12,469	12,376	12,065	11,430	10,656	9,960
Winter	2	13,178	2/10/2015	9,510	9,341	9,283	9,429	9,812	10,720	12,260	12,994	12,837	12,705	12,566	12,362	12,112	11,955	11,626	11,302	11,358	11,729	12,802	13,164	13,178	12,889	12,277	11,697
Winter	2	15,778	2/11/2015	11,396	11,405	11,534	11,833	12,363	13,486	15,196	15,778	15,134	14,041	13,201	12,441	11,811	11,479	11,112	10,904	10,961	11,361	12,434	12,803	12,857	12,597	12,030	11,450
Winter	2	15,473	2/12/2015	11,132	11,068	11,181	11,429	11,931	12,973	14,613	15,125	14,448	13,391	12,605	12,079	11,776	11,770	11,844	12,017	12,351	13,227	14,736	15,367	15,473	15,300	14,684	14,116
Winter	2	16,972	2/13/2015	13,802	13,750	13,796	13,912	14,246	15,131	16,493	16,972	16,697	16,219	15,680	14,952	14,159	13,471	12,823	12,457	12,571	13,077	14,303	14,749	14,915	14,833	14,538	14,103
Winter	2	15,382	2/14/2015	13,805	13,736	13,776	13,917	14,125	14,545	15,094	15,382	15,314	14,659	13,837	12,958	12,093	11,453	10,968	10,912	11,092	11,547	12,280	12,328	12,260	12,027	12,095	12,174
Winter	2	16,841	2/15/2015	12,444	12,914	13,460	13,976	14,546	15,201	16,027	16,623	16,841	16,416	15,681	14,823	14,121	13,461	12,917	12,594	12,643	13,384	14,792	15,375	15,437	15,228	14,824	14,308
Winter	2	17,256	2/16/2015	13,973	13,782	13,703	13,775	14,035	14,729	15,956	16,568	16,630	16,591	16,442	16,187	15,944	15,912	15,888	15,996	16,286	16,781	17,256	16,951	16,460	15,877	15,217	14,627
Winter	2	15,932	2/17/2015	14,134	13,933	13,861	13,918	14,123	14,534	15,121	15,495	15,819	15,932	15,656	15,005	14,440	14,085	13,799	13,684	13,905	14,498	15,353	15,444	15,187	14,715	14,226	13,720
Winter	2	17,424	2/18/2015	13,511	13,509	13,697	13,936	14,463	15,269	16,415	17,158	17,019	16,162	15,525	15,050	14,599	14,480	14,557	14,628	14,858	15,583	16,910	17,418	17,424	17,238	16,872	16,568
Winter	2	19,764	2/19/2015	16,523	16,647	16,898	17,276	17,773	18,438	19,306	19,764	19,664	19,262	18,709	18,056	17,365	16,858	16,390	16,128	16,312	17,216	18,791	19,554	19,735	19,557	19,068	18,684
Winter	2	21,101	2/20/2015	18,554	18,641	18,915	19,143	19,568	20,086	20,767	21,101	20,491	19,678	18,774	17,794	16,795	15,968	15,265	14,761	14,783	15,501	16,590	16,808	16,716	16,407	15,909	15,331
Winter	2	15,980	2/21/2015	14,754	14,661	14,697	14,642	14,636	14,910	15,144	15,423	15,818	15,980	15,724	15,291	14,764	14,171	13,750	13,475	13,445	13,634	14,172	14,149	13,933	13,518	12,985	12,384
Winter	2	12,942	2/22/2015	12,000	11,796	11,704	11,789	11,819	11,984	12,278	12,549	12,942	12,864	12,276	11,824	11,396	10,981	10,555	10,598	10,430	10,889	11,664	11,956	11,828	11,400	10,852	10,272
Winter	2	14,297	2/23/2015	9,932	9,665	9,636	9,739	10,043	10,964	12,417	13,216	13,190	13,206	13,218	13,014	12,600	12,240	11,936	11,745	12,041	12,695	13,811	14,292	14,297	13,863	13,365	12,692
Winter	2	16,739	2/24/2015	12,278	12,238	12,293	12,495	12,957	14,007	15,512	16,225	16,450	16,629	16,631	16,614	16,477	16,315	16,120	15,913	15,930	16,157	16,697	16,739	16,408	15,839	15,088	14,374
Winter	2	17,150	2/25/2015	13,880	13,702	13,674	13,789	14,175	15,069	16,530	17,150	16,622	15,794	15,021	14,358	13,726	13,316	13,089	13,265	13,558	13,974	14,672	14,767	14,602	14,097	13,597	12,959
Winter	2	15,032	2/26/2015	12,561	12,301	12,193	12,209	12,386	12,793	13,385	13,763	14,129	14,229	14,289	14,160	13,954	13,656	13,458	13,402	13,465	13,728	14,609	15,032	14,931	14,519	13,863	13,215
Winter	2	16,143	2/27/2015	12,895	12,766	12,780	12,968	13,406	14,290	15,494	16,143	16,017	15,227	14,316	13,547	12,864	12,414	12,010	11,682	11,666	11,998	13,004	13,579	13,746	13,680	13,405	12,985
Winter	2	14,973	2/28/2015	12,689	12,678	12,795	12,893	13,192	13,535	14,087	14,477	14,973	14,966	14,536	13,880	13,123	12,520	11,998	11,726	11,828	12,229	13,242	13,750	13,805	13,604	13,190	12,652
Spring	3	14,204	3/1/2015	12,196	11,909	11,801	11,801	11,979	12,305	12,816	13,296	13,941	14,204	14,061	13,737	13,485	13,235	12,900	12,684	12,607	12,829	13,465	13,648	13,447	12,910	12,283	11,623
Spring	3	13,797	3/2/2015	11,187	10,981	10,903	10,928	11,204	11,972	13,396	13,797	13,464	12,941	12,351	11,810	11,350	11,078	10,824	10,659	10,622	10,779	11,591	12,127	12,052	11,653	11,048	10,360
Spring	3	14,042	3/3/2015	9,883	9,660	9,606	9,692	10,019	10,867	12,416	13,088	13,073	13,106	13,187	13,155	13,058	13,052	12,923	12,871	12,972	13,323	13,952	14,042	13,782	13,168	12,408	11,501
Spring	3	12,850	3/4/2015	10,912	10,591	10,413	10,445	10,618	11,308	12,548	12,850	12,478	12,137	11,815	11,371	11,098	10,927	10,723	10,613	10,622	10,710	11,302	11,634	11,502	10,979	10,291	9,395
Spring	3	13,797	3/5/2015	8,814	8,469	8,340	8,225	8,400	9,071	10,393	10,977	11,079	11,186	11,378	11,554	11,625	11,728	11,780	11,916	12,209	12,730	13,473	13,780	13,797	13,470	12,896	12,335
Spring	3	16,260	3/6/2015	12,064	12,099	12,319	12,618	13,198	14,241	15,834	16,260	15,842	15,274	14,602	13,870	13,206	12,646	12,163	11,771	11,693	12,054	13,030	13,789	14,026	13,979	13,691	13,302
Spring	3	15,173	3/7/2015	13,054	13,069	13,208	13,509	13,808	14,287	14,899	15,173	14,619	13,570	12,628	11,816	11,057	10,430	10,021	9,749	9,736	9,961	10,664	11,273	11,337	11,238	10,958	10,577
Spring	3	12,350	3/8/2015	10,307	0	10,208	10,258	10,512	10,860	11,377	11,960	12,350	11,853	10,931	10,220	9,802	9,514	9,192	8,979	9,018	9,146	9,359	10,085	10,621	10,313	9,732	9,073
Spring	3	11,714	3/9/2015	8,565	8,331	8,288	8,260	8,553	9,369	10,820	11,714	11,549	11,510	11,534	11,385	11,151	11,002	10,751	10,540	10,389	10,396	10,543	11,218	11,522	11,046	10,310	9,512
Spring	3	11,574	3/10/2015	8,929	8,612	8,446	8,447	8,643	9,381	10,736	11,574	11,344	11,291

Contains Proprietary Material
Do Not Distribute

Spring	4	12,709	4/14/2015	8,783	8,384	8,195	8,096	8,200	8,810	10,192	10,875	10,997	11,137	11,342	11,485	11,630	11,809	11,928	12,071	12,387	12,496	12,441	12,466	12,709	12,095	11,006	9,953
Spring	4	11,451	4/15/2015	9,114	8,631	8,345	8,193	8,275	8,851	10,101	10,653	10,646	10,678	10,858	10,864	10,862	10,893	10,835	10,824	10,891	10,981	11,091	11,222	11,451	11,008	10,196	9,338
Spring	4	11,554	4/16/2015	8,804	8,484	8,330	8,301	8,503	9,208	10,566	11,190	11,254	11,328	11,453	11,377	11,244	11,142	10,993	10,925	10,957	11,049	11,132	11,303	11,554	11,130	10,282	9,440
Spring	4	10,769	4/17/2015	8,912	8,562	8,367	8,283	8,434	9,003	10,209	10,659	10,708	10,731	10,750	10,689	10,593	10,566	10,554	10,542	10,555	10,478	10,378	10,397	10,769	10,489	9,864	9,102
Spring	4	10,884	4/18/2015	8,449	8,040	7,788	7,665	7,658	7,853	8,220	8,496	9,073	9,552	9,927	10,226	10,428	10,580	10,689	10,767	10,783	10,762	10,666	10,571	10,884	10,615	9,988	9,203
Spring	4	10,557	4/19/2015	8,505	8,031	7,762	7,595	7,550	7,653	7,900	8,181	8,820	9,279	9,506	9,632	9,783	9,823	9,771	9,761	9,845	10,031	10,193	10,377	10,557	10,224	9,553	8,836
Spring	4	11,728	4/20/2015	8,276	7,917	7,757	7,734	7,905	8,589	9,905	10,469	10,631	10,852	11,121	11,325	11,551	11,728	11,719	11,577	11,443	11,318	11,240	11,111	11,406	11,062	10,186	9,175
Spring	4	11,213	4/21/2015	8,487	8,100	7,880	7,772	7,879	8,496	9,740	10,335	10,385	10,402	10,478	10,486	10,481	10,610	10,665	10,695	10,787	10,787	10,775	10,743	11,213	10,915	9,984	9,031
Spring	4	11,398	4/22/2015	8,416	8,115	7,987	7,995	8,242	8,969	10,347	10,839	10,759	10,636	10,632	10,611	10,609	10,767	10,834	10,913	10,994	11,018	10,945	10,930	11,398	11,082	10,150	9,180
Spring	4	11,210	4/23/2015	8,537	8,150	7,943	7,860	8,000	8,655	9,884	10,389	10,426	10,414	10,518	10,522	10,528	10,606	10,660	10,746	10,802	10,841	10,787	10,734	11,210	10,910	10,023	9,104
Spring	4	10,940	4/24/2015	8,496	8,206	8,104	8,101	8,322	9,072	10,410	10,940	10,784	10,615	10,478	10,314	10,152	10,159	10,096	10,046	10,098	10,099	9,973	9,892	10,316	10,105	9,493	8,781
Spring	4	10,157	4/25/2015	8,200	7,883	7,695	7,608	7,671	7,877	8,231	8,587	9,184	9,686	9,996	10,107	10,045	9,940	9,784	9,661	9,675	9,752	9,757	9,851	10,157	9,940	9,434	8,813
Spring	4	10,358	4/26/2015	8,243	7,909	7,704	7,640	7,660	7,809	8,092	8,473	9,177	9,600	9,701	9,698	9,790	9,759	9,621	9,520	9,558	9,617	9,641	9,830	10,358	10,154	9,502	8,791
Spring	4	11,046	4/27/2015	8,361	8,122	8,059	8,129	8,412	9,187	10,515	11,046	10,887	10,708	10,660	10,579	10,499	10,513	10,481	10,434	10,510	10,460	10,455	10,495	11,004	10,770	9,940	9,045
Spring	4	11,277	4/28/2015	8,479	8,245	8,182	8,270	8,574	9,395	10,771	11,277	11,027	10,801	10,688	10,553	10,475	10,465	10,434	10,472	10,549	10,576	10,557	10,596	11,099	10,821	9,921	9,031
Spring	4	10,961	4/29/2015	8,452	8,140	8,008	8,017	8,234	8,955	10,187	10,760	10,730	10,639	10,709	10,734	10,711	10,700	10,594	10,545	10,527	10,496	10,479	10,503	10,961	10,779	9,943	9,094
Spring	4	10,993	4/30/2015	8,557	8,296	8,163	8,155	8,357	9,058	10,249	10,726	10,696	10,634	10,619	10,626	10,684	10,813	10,832	10,822	10,827	10,788	10,654	10,587	10,993	10,741	9,928	9,047
Spring	5	10,556	5/1/2015	8,416	8,065	7,931	7,917	8,119	8,767	9,943	10,484	10,542	10,556	10,534	10,463	10,345	10,318	10,189	10,037	10,015	9,933	9,883	9,826	10,208	10,164	9,596	8,936
Spring	5	9,864	5/2/2015	8,365	8,062	7,926	7,889	7,994	8,280	8,612	9,003	9,355	9,476	9,477	9,433	9,388	9,355	9,398	9,511	9,704	9,754	9,759	9,657	9,864	9,721	9,065	8,366
Spring	5	10,694	5/3/2015	7,783	7,486	7,283	7,209	7,239	7,414	7,595	7,993	8,537	8,803	8,907	9,030	9,272	9,489	9,677	9,898	10,176	10,485	10,536	10,425	10,694	10,490	9,649	8,733
Spring	5	12,799	5/4/2015	8,064	7,695	7,519	7,444	7,612	8,294	9,421	10,076	10,317	10,613	11,014	11,358	11,701	12,140	12,380	12,536	12,777	12,799	12,720	12,438	12,465	12,066	10,985	9,820
Spring	5	13,706	5/5/2015	9,007	8,486	8,157	7,993	8,070	8,647	9,703	10,314	10,571	10,875	11,290	11,657	12,067	12,592	13,051	13,431	13,664	13,706	13,518	13,077	12,992	12,523	11,319	9,998
Spring	5	13,958	5/6/2015	9,111	8,583	8,280	8,128	8,170	8,745	9,763	10,259	10,530	10,868	11,315	11,790	12,271	12,834	13,270	13,630	13,931	13,958	13,715	13,222	13,089	12,634	11,361	10,064
Spring	5	13,337	5/7/2015	9,200	8,661	8,336	8,157	8,226	8,771	9,828	10,363	10,634	11,002	11,428	11,882	12,312	12,859	13,167	13,293	13,337	13,190	12,898	12,672	12,784	12,433	11,323	10,112
Spring	5	14,043	5/8/2015	9,246	8,716	8,384	8,177	8,257	8,778	9,697	10,286	10,615	10,956	11,454	11,903	12,345	12,885	13,375	13,760	14,043	13,973	13,569	12,931	12,652	12,190	11,273	10,177
Spring	5	12,850	5/9/2015	9,241	8,627	8,230	8,015	7,926	8,078	8,244	8,721	9,425	10,111	10,668	11,167	11,580	11,990	12,392	12,745	12,850	12,797	12,557	12,131	12,020	11,745	10,972	10,019
Spring	5	12,259	5/10/2015	9,156	8,600	8,220	7,963	7,881	7,948	8,053	8,475	9,356	10,026	10,422	10,650	10,921	11,256	11,543	11,810	12,066	12,259	12,191	11,923	12,064	11,941	11,062	10,021
Spring	5	16,541	5/11/2015	9,209	8,710	8,438	8,289	8,363	8,922	9,966	10,686	11,223	11,902	12,747	13,575	14,375	15,235	15,846	16,280	16,541	16,495	16,110	15,566	15,364	14,661	13,214	11,772
Spring	5	16,063	5/12/2015	10,667	9,985	9,510	9,250	9,233	9,731	10,765	11,443	11,955	12,601	13,319	14,012	14,573	15,109	15,602	15,931	16,063	15,880	15,462	14,836	14,467	13,780	12,424	11,010
Spring	5	14,620	5/13/2015	9,941	9,331	8,903	8,625	8,647	9,134	10,100	10,579	10,789	11,140	11,659	12,088	12,523	13,084	13,593	14,106	14,505	14,620	14,378	13,658	13,179	12,668	11,358	10,097
Spring	5	12,466	5/14/2015	9,171	8,624	8,285	8,146	8,224	8,744	9,675	10,202	10,419	10,610	10,821	11,062	11,275	11,572	11,858	12,095	12,373	12,466	12,295	11,964	12,105	11,853	10,915	9,795
Spring	5	13,224	5/15/2015	9,046	8,567	8,298	8,200	8,279	8,844	9,829	10,390	10,598	10,831	11,120	11,374	11,644	12,097	12,506	12,840	13,170	13,224	12,926	12,415	12,276	12,043	11,164	10,183
Spring	5	13,886	5/16/2015	9,345	8,789	8,410	8,192	8,108	8,213	8,325	8,760	9,516	10,265	11,007	11,682	12,312	12,873	13,319	13,658	13,834	13,886	13,605	12,962	12,685	12,318	11,351	10,544
Spring	5	14,328	5/17/2015	9,529	8,882	8,472	8,173	8,023	8,048	7,998	8,407	9,215	9,881	10,491	11,217	11,991	12,776	13,344	13,753	14,157	14,328	14,158	13,748	13,488	13,115	11,964	10,792
Spring	5	16,802	5/18/2015	9,869	9,311	8,943	8,757	8,858	9,459	10,501	11,236	11,774	12,473	13,484	14,411	15,248	15,934	16,354	16,628	16,802	16,585	15,952	15,376	15,036	14,261	12,914	11,576
Spring	5	16,066	5/19/2015	10,546	9,902	9,501	9,231	9,229	9,700	10,734	11,413	11,783	12,234	12,919	13,678	14,420	15,188	15,714	15,968	16,066	15,921	15,611	15,147	14,761	14,233	12,804	11,403
Spring	5	16,797	5/20/2015	10,355	9,637	9,223	8,992	8,966	9,439	10,334	11,062	11,532	12,121	12,940	13,766	14,490	15,292	15,924	16,422	16,797	16,728	16,370	15,623	15,062	14,446	13,065	11,652
Spring	5	14,559	5/21/2015	10,640	9,949	9,537	9,292	9,339	9,843	10,804	11,384	11,685	12,003	12,441	12,760	13,047	13,430	13,828	14,273	14,559	14,537	14,220	13,640	13,275	12,831	11,562	10,204
Spring	5	12,130	5/22/2015	9,246	8,656	8,320	8,133	8,188	8,653	9,450	10,024	10,286	10,548	10,790	10,917	11,060	11,293	11,574	11,805	12,097	12,130	11,975	11,488	11,099	10,904	10,078	9,108
Spring	5	11,728	5/23/2015	8,333	7,857	7,595	7,459	7,425	7,571	7,636	7,961	8,535	9,024	9,380	9,654	9,906	10,174	10,552	11,003	11,425	11,728	11,665	11,243	10,818	10,620	9,826	8,932
Spring	5	12,264	5/24/2015	8,204	7,680	7,393	7,213	7,153	7,189	7,184	7,598	8,313	8,935	9,365	9,757	10,231	10,674	11,109	11,616	12,010	12,264	12,169	11,673	11,210	10,988	10,262	9,344
Spring	5	13,673	5/25/2015	8,572	8,048	7,713	7,492	7,482	7,590	7,657	8,020	8,707	9,534	10,282	10,902	11,396	11,895	12,425	12,949	13,428	13,673	13,531	13,193	12,925	12,566	11,445	10,363
Spring	5	16,378	5/26/2015	9,515	8,999	8,726	8,572	8,667	9,202	10,211	11,084	11,702	12,431	13,242	13,968	14,584	15,273	15,705	15,964	16,265	16,378	16,075	15,474	15,080	14,403	13,015	11,630
Spring	5	15,630	5/27/2015	10,592	9,884	9,412	9,172	9,179	9,679	10,569	11,280	11,719	12,112	12,621	13,076	13,521	14,115	14,607	15,093	15,519	15,630	15,431	14,779	14,303	13,902	12,611	11,284
Spring	5	16,432	5/28/2015	10,282	9,665	9,256	9,057	9,080	9,578	10,553	11,282	11,757	12,585	13,428	14,236	15,026	15,697	16,156	16,386	16,432	16,153	15,575	14,816	14,484	13,926	12,768	11,463
Spring	5	15,627	5/29/2015	10,476	9,827	9,384	9,102	9,131	9,538	10,393	11,115	11,577	12,136	12,794	13,421	13,992	14,652	15,105	15,454	15,627	15,525	15,015	14,327	13,731	13,323	12,319	11,063
Spring	5	15,108	5/30/2015	10,019	9,358	8,944	8,640	8,517	8,602	8,658	9,209	10,138	11,050	11,943	12,590	13,195	13,708	14,177	14,650	14,970	15,108	14,869	14,266	13,642	13,271	12,333	11,210
Spring	5	15,133	5/31/2015	10,252	9,559	9,107	8,762	8,576	8,535	8,498	8,984	9,920	10,828	11,566	12,332	13,164	13,867	14,359	14,703	14,997	15,133	14,903	14,288	13,768	13,394	12,279	11,059
Summer	6	16,464	6/1/2015	10,160	9,572	9,196	9,018	9,104	9,677	10,618	11,482	12,094	12,796	13,661	14,485	15,187	15,826	16,114	16,364	16,464	16,005	15,298	14,599	14,193	13,704	12,460	11,200
Summer	6	14,311	6/2/2015	10,224	9,617	9,249	9,000	9,066	9,582	10,551	11,264	11,489	11,899	12,286	12,865	13,453	14,055	14,311	14,282	14,231	13,980	13,658	13,202	12,925	12,547	11,505	10,389
Summer	6	11,891	6/3/2015	9,538	9,047	8,744	8,593	8,683	9,196	10,158	10,787	11,056	11,245	11,434	11,585	11,685	11,815	11,846	11,891	11,879	11,801	11,618	11,477	11,627	11,477	10,626	9,676
Summer	6	12,272	6/4/2015	8,987	8,606	8,418	8,274	8,401	8,958	9,907	10,504	10,729	10,975	11,242	11,414	11,442	11,648	11,816	12,050	12,218	12,272	12,161	11,981	12,026	11,953	11,065	10,094
Summer	6	13,832	6/5/2015	9,252	8,737	8,445	8,314	8,418	8,881	9,740	10,381	10,757	11,116	11,519	11,957	12,367	12,881	13,351	13,678	13,832	13,658	13,372	12,873	12,495	12,373	11,542	10,473
Summer	6	15,074	6/6/2015	9,605	9,000	8,596	8,340	8,294	8,379	8,418	8,971	9,887	10,856	11,849	12,668	13,366	13,981	14,458	14,821	15,074	14,984	14,652	14,029	13,437	13,065	12,111	11,018
Summer	6	14,373	6/7/2015	10,070	9,374	8,931	8,588	8,407	8,391	8,361	8,815	9,759	10,690	11,378	12,029	12,704	13,297	13,676	13,938	14,205	14,373	14,190	13,724	13,359	13,111	12,129	11,039
Summer	6	16,486	6/8/2015	10,170	9,597	9,251	9,104	9,165	9,768	10,685	11,575	12,158	12,745	13,446	14,145	14,704	15,476	16,057	16,424	16,486	16,166	15,710	15,102	14,719	14,238	13,075	11,781
Summer	6	16,919	6/9/2015	10,761	10,035	9,585	9,336	9,316	9,806	10,668	11,406	11,863	12,358	13,133	13,937	14,786	15,678	16,272	16,662	16,919	16,646	16,031	15,299	14,683	14,240	13,128	11,789
Summer	6	17,296	6/10/2015	10,793	10,036	9,599	9,334	9,302	9,765	10,528	11,300	11,890	12,628	13,609	14,584	15,415	16,226	16,779	17,116	17,296	17,169	16,777	16,153	15,583	15,162	13,828	12,436
Summer	6	17,632	6/11/2015	11,273	10,559	10,044	9,708	9,697	10,073	10,903	11,809	12,629	13,629	14,681	15,670	16,410	16,958	17,432	17,532	17,632	17,479	17,013	16,375	15,768	15,331	14,033	12,700
Summer	6	17,191	6/12/2015	11,592	10,831	10,362	10,006	9,944	10,311	11,027	11,839	12,660	13,427	14,268	15,084	15,798	16,417	16,833	17,117	17,191	16,974	16,391	15,711	15,107	14,888	13,957	12,754
Summer	6	17,242	6/13/2015	11,726	10,950	10,451	10,013	9,798	9,828	9,820	10,487	11,616	12,903	14,116	15,114	15,810	16,334	16,659	16,916	17,197	17,242	16,978	16,400	15,649	15,219	14,099	12,805
Summer	6	17,480	6/14/2015	11,716	10,884	10,249	9,798	9,506	9,390	9,226	9,879	11,221	12,649	13,868	14,921	15,774	16,425	16,898	17,225	17,441	17,480	17,231	16,660	16,053	15,698	14,522	13,183
Summer	6	19,597	6/15/2015	12,019	11,118	10,596	10,220	10,221	10,554	11,161	12,301	13,380	14,635	15,989	17,149	18,008	18,699	19,185	19,515	19,597	19,522	19,247	18,660	17,809	17,262	15,768	14,156
Summer	6	19,692	6/16/2015	12,911	12,018	11,323	10,894	10,705	11,041	11,584	12,576	13,691	15,008	16,442	17,578	18,387	19,138	19,475	19,595	19,692	19,592	19,430	18,918	18,241	17,670	16,293	14,744
Summer	6	19,977	6/17/2015	13,507	12,578	11,829	11,308	11,160	11,439	11,979	12,919	13,997	15,166	16,465	17,591	18,504	19,157	19,583	19,844	19,977	19,778	19,363	18,656	18,025	17,509	16,133	14,631
Summer	6	19,840	6/18/2015	13,432	12,461	11,845	11,436	11,305	11,553	12,090	12,910	13,930	15,154	16,574	17,848	18,789	19,466	19,813	19,840	19,765	19,401	18,710	17,918	17,274	16,596	15,235	13,817
Summer	6	18,741	6/19/2015	12,666	11,846	11,293	10,941	10,762	11,102	11,512	12,327	13,326	14,373	15,522	16,640	17,501	18,307	18,737	18,741	18,382	17,866	17,148	16,293	15,543	15,218	14,129	12,872
Summer	6	16,831	6/20/2015	11,795	10,993	10,441	10,090	9,891	9,872	9,885	10,417	11,583	12,827	14,186	15,315	16,096	16,623	16,831	16,653	16,685	16,199	15,666	15,213	14,716	14,495	13,668	12,628
Summer	6	17,935	6/21/2015	11,641	10,894	10,366	9,949	9,711	9,618	9,460	10,085	11,357	12,629	13,675	14,617	15,389	16,120	16,747	17,286	17,734	17,935	17,739	17,219	16,439	15,832	14,640	13,200
Summer	6	19,726	6/22/2015	12,030	11,133	10,564	10,226	10,158	10,496	11,061	12,064	13,129	14,406	15,781	17,011	17,961	18,786	19,369	19,726	19,724	19,444	18,695	17,884	17,250	16,736	15,417	13,893
Summer	6	19,827	6/23/2015	12,774	12,013	11,454	11,085	10,954	11,260	11,798	12,739	13,760	15,005	16,446	17,597	18,502	19,172	19,607	19,741	19,688	19,827	19,503	18,976	18,326	17,874	16,582	15,046
Summer	6	20,003	6/24/2015	13,893	12,999	12,351	11,963	11,783	12,107	12,581	13,376	14,456	15,665	16,992	18,093	18,858	19,349	19,778	19,948	20,003	19,860	19,106	18,094	17,292	16,680	15,391	13,945
Summer	6	19,926	6/25/2015	12,817	11,941	11,355	10,987	10,997	11,337	11,915	12,695	13,563	14,524	15,744	16,878	17,871	18,789	19,390	19,809	19,926	19,820	19,317	18,595	17,815	17,228	15,817	14,331
Summer	6	19,443	6/26/2015	13,136	12,291	11,710	11,291	11,170	11,388	11,778	12,492	13,396	14,474	15,614	16,799	17,807	18,612	19,237	19,443	19,348	18,881	17,986	17,046	16,270	15,542	14,208	12,940
Summer	6	15,555	6/27/2015	11,784	11,044	10,505	10,143	9,959	9,990	10,040	10,311	10,888	11,640	12,554	13,434	14,198	14,837	15,356	15,555	15,123	14,492	13,804	13,236	12,908	12,826	12,149	11,246
Summer	6	14,474	6/28/2015	10,376	9,781	9,336	9,024	8,766	8,655	8,467	8,902	9,710	10,409	10,954	11,473	11,983	12,547	13,052	13,607	14,097	14,474	14,344	13,869	13,026	12,662	11,684	10,503
Summer	6	16,140	6/29/2015	9,567	8,922	8,550	8,321	8,377	8,782	9,298	10,071	10,771	11,489	12,361	13,143	13,913	14,678	15,257	15,767	16,050	16,140	15,899	15,243	14,489	14,134	12,966	11,694
Summer	6	17,124	6/30/2015	10,635	9,996	9,525	9,308	9,280	9,655	10,211	11,023	11,853	12,817	13,964	15,061	16,014	16,758	17,119	17,124	16,828	16,255	15,524	14,762	14,128	13,836	12,813	11,595
Summer	7	16,386	7/1/2015	10,612	9,941	9,515	9,273	9,256	9,632	10,215	10,837	11,429	12,118	13,036	13,948	14,801	15,552	16,045	16,386	16,386	16,077	15,482	14,794	14,315	13,968	12,931	11,751
Summer	7	15,147	7/2/2015	10,785	10,156	9,781	9,492	9,483	9,837	10,410	10,975	11,443	12,069	13,016	13,858	14,546	15,001	15,147	15,099	14,837	14,405	13,951	13,384	13,027	12,881	12,053	10,998
Summer	7	13,208	7/3/2015	10,065	9,457	9,120	8,878	8,836	8,986	9,183	9,527	10,068	10,639	11,107	11,438	11,800	12,027	12,356	12,743	13,069	13,208	12,973	12,540	12,196	12,058	11,410	10,595
Summer	7	14,029	7/4/2015	9,857	9,267	8,857	8,559	8,437	8,537	8,487	8,799	9,578	10,440	11,281	11,867	12,263	12,589	12,930	13,406	13,932	14,029	13,637	12,973	12,350	11,953	11,385	10,844
Summer	7	14,253	7/5/2015	10,076	9,448	8,985	8,727	8,567	8,565	8,527	8,869	9,616	10,450	11,171	11,906	12,822	13,629	14,126	14,253	14,209	14,224	14,033	13,577	13,087	12,871	12,025	11,013
Summer	7	17,474	7/6/2015	10,130	9,499	9,128	8,899	8,972	9,475	10,132	10,958	11,788	12,706	13,707	14,704	15,508	16,246	16,851	17,244	17,474	17,463	17,095	16,312	15,567	15,111	13,843	12,472
Summer	7	18,591	7/7/2015	11,313	10,661	10,057	9,737	9,669	9,986	10,599	11,404	12,259	13,250	14,427	15,636	16,615	17,390	17,950	18,349	18,591	18,539	18,176	17,456	16,801	16,282	14,977	13,562
Summer	7	18,766	7/8/2015	12,434	11,642	11,049	10,625	10,584	10,901	11,523	12,204	12,879	13,813	15,133	16,203	17,138	17,964	18,487	18,766	18,746	18,105	17,250	16,511	15,929	15,517	14,368	13,043
Summer	7	19,666	7/9/2015	11,951	11,223	10,750	10,447	10,361	10,691	11,279	12,061	13,059	14,243	15,686	16,931	17,831	18,612	19,140	19,486	19,654	19,666	19,366	18,666	17,827	17,264	15,885	14,352
Summer	7	19,439	7/10/2015	13,045	12,085	11,379	10,863	10,658	10,855	11,193	11,971	13,031	14,279	15,681	16,847	17,735	18,433	18,913	19,239	19,439	19,279	18,850	18,007	16,980	16,378	15,012	13,604
Summer	7	17,589	7/11/2015	12,349	11,423	10,680	10,157	9,930	9,983	10,037	10,339	11,370	12,732	14,063	15,120	15,925	16,559	17,042	17,400	17,589	17,575	17,145	16,466	15,743	15,298	14,197	12,946
Summer	7	16,105	7/12/2015	11,799	10,939	10,267	9,828	9,550	9,449	9,233	9,682	10,712	11,788	12,774	13,703	14,578	15,266	15,687	15,914	16,105	16,087	15,594	15,096	14,657	14,407	13,496	12,323
Summer	7	19,355	7/13/2015	11,400	10,688	10,261	10,028	10,070	10,521	11,261	12,011	12,685	13,317	14,452	15,757	16,908	17,903	18,659	19,201	19,317	19,355	18,844	17,968	17,034	15,741	14,359	12,897
Summer	7	16,505	7/14/2015	11,883	11,063	10,558	10,218	10,192	10,561	11,172	11,909	12,409	12,807	13,198	13,671	13,960	14,470	15,185	15,979	16,444	16,505	16,214	15,672	15,307	14,841	13,782	12,563
Summer	7	17,241	7/15/2015	11,627	11,002	10,602	10,340	10,348	10,688	11,286	12,050	13,001	13,995	15,067	15,864	16,325	16,793	17,031	16,999	17,177	17,241	17,029	16,454	15,706	15,256	14,014	12,584
Summer	7	17,754	7/16/2015	11,567	10,793	10,270	9,980	9,936	10,317	10,893	11,629	12,491	13,261

Contains Proprietary Material
Do Not Distribute

Summer	8	18,237	8/20/2015	11,484	10,910	10,516	10,307	10,312	10,860	11,912	12,458	12,951	13,516	14,278	15,123	15,954	16,871	17,571	18,045	18,237	18,102	17,570	16,760	16,371	15,614	14,300	12,991
Summer	8	17,132	8/21/2015	11,930	11,221	10,728	10,400	10,332	10,701	11,675	12,079	12,674	13,371	14,196	14,928	15,604	16,222	16,711	16,959	17,132	17,032	16,514	15,645	15,208	14,499	13,343	12,131
Summer	8	15,772	8/22/2015	11,116	10,411	9,884	9,572	9,443	9,489	9,686	9,895	10,592	11,430	12,326	13,095	13,815	14,441	14,941	15,352	15,652	15,772	15,450	14,745	14,378	13,724	12,730	11,677
Summer	8	15,010	8/23/2015	10,735	10,059	9,580	9,305	9,111	9,080	9,200	9,300	10,053	10,846	11,526	12,065	12,626	13,104	13,523	14,067	14,601	15,010	14,881	14,497	14,456	13,830	12,702	11,574
Summer	8	18,499	8/24/2015	10,710	10,182	9,823	9,652	9,793	10,397	11,600	12,067	12,715	13,602	14,765	15,806	16,719	17,445	17,922	18,306	18,499	18,370	17,816	17,060	16,698	15,787	14,300	12,900
Summer	8	17,782	8/25/2015	11,925	11,113	10,612	10,303	10,274	10,734	11,735	12,032	12,424	13,039	13,871	14,651	15,455	16,267	16,933	17,440	17,782	17,746	17,330	16,540	16,158	15,122	13,571	12,189
Summer	8	16,119	8/26/2015	11,135	10,416	9,813	9,474	9,447	9,891	11,004	11,283	11,607	12,186	12,697	13,263	13,799	14,457	15,012	15,614	16,065	16,119	15,775	15,086	14,824	14,007	12,764	11,448
Summer	8	15,938	8/27/2015	10,502	9,909	9,482	9,271	9,323	9,795	10,927	11,364	11,567	12,028	12,653	13,278	14,056	14,695	15,256	15,672	15,938	15,797	15,400	14,746	14,559	13,775	12,441	11,304
Summer	8	15,927	8/28/2015	10,308	9,607	9,245	8,980	8,995	9,453	10,509	10,924	11,242	11,779	12,462	13,170	13,840	14,632	15,230	15,675	15,927	15,763	15,237	14,288	13,906	13,124	12,072	10,982
Summer	8	14,444	8/29/2015	9,930	9,292	8,931	8,557	8,443	8,552	8,748	8,944	9,595	10,343	11,103	11,852	12,588	13,273	13,769	14,164	14,444	14,320	13,791	13,318	13,204	12,600	11,736	10,725
Summer	8	12,948	8/30/2015	9,856	9,326	8,909	8,664	8,533	8,583	8,718	8,942	9,636	10,328	10,854	11,367	11,857	12,338	12,538	12,761	12,934	12,948	12,781	12,698	12,818	12,188	11,250	10,330
Summer	8	16,367	8/31/2015	9,591	9,137	8,844	8,757	8,892	9,487	10,760	11,281	11,593	12,168	12,899	13,548	14,245	14,866	15,435	15,981	16,235	16,367	16,079	15,544	15,285	14,376	12,994	11,637
Fall	9	18,059	9/1/2015	10,722	10,011	9,632	9,379	9,375	9,892	11,057	11,420	11,991	12,799	13,989	15,022	15,953	16,805	17,436	17,865	18,059	17,929	17,541	16,856	16,523	15,408	13,913	12,474
Fall	9	18,681	9/2/2015	11,488	10,707	10,210	9,920	9,832	10,398	11,558	11,959	12,454	13,387	14,500	15,723	16,823	17,681	18,210	18,524	18,681	18,518	18,026	17,305	17,001	15,875	14,396	13,067
Fall	9	18,099	9/3/2015	11,986	11,246	10,716	10,411	10,329	10,769	11,859	12,286	12,658	13,430	14,457	15,384	16,300	17,124	17,712	18,018	18,099	17,947	17,394	16,638	16,354	15,318	13,844	12,466
Fall	9	17,909	9/4/2015	11,412	10,669	10,231	9,890	9,824	10,306	11,369	11,758	12,241	13,118	14,380	15,535	16,595	17,432	17,892	17,909	17,485	16,928	16,102	15,176	14,704	13,822	12,670	11,542
Fall	9	14,420	9/5/2015	10,576	9,943	9,469	9,197	9,068	9,117	9,349	9,492	10,158	10,838	11,558	12,389	12,871	13,345	13,842	14,143	14,420	14,378	14,009	13,409	13,277	12,561	11,732	10,729
Fall	9	14,386	9/6/2015	9,880	9,264	8,915	8,642	8,508	8,522	8,656	8,799	9,513	10,270	11,006	11,738	12,402	13,097	13,666	14,068	14,370	14,386	14,050	13,350	13,210	12,501	11,606	10,682
Fall	9	14,838	9/7/2015	9,856	9,261	8,880	8,690	8,625	8,849	9,122	9,194	9,721	10,492	11,276	11,927	12,468	13,056	13,663	14,289	14,693	14,838	14,545	14,068	14,050	13,201	11,973	10,861
Fall	9	16,789	9/8/2015	9,984	9,407	9,039	8,877	8,980	9,598	10,882	11,431	11,910	12,522	13,327	14,136	14,884	15,650	16,180	16,544	16,789	16,718	16,368	15,866	15,772	14,690	13,390	12,000
Fall	9	16,431	9/9/2015	11,094	10,497	10,109	9,907	9,940	10,550	11,768	12,316	12,655	13,220	14,050	14,806	15,506	16,133	16,357	16,431	16,223	15,808	15,379	15,039	14,957	14,132	12,924	11,785
Fall	9	17,150	9/10/2015	10,979	10,406	10,067	9,892	9,943	10,606	11,890	12,385	12,601	13,083	13,832	14,722	15,616	16,460	16,997	17,150	17,032	16,393	15,485	14,962	14,690	13,778	12,597	11,483
Fall	9	15,699	9/11/2015	10,644	10,013	9,655	9,428	9,515	10,051	11,176	11,629	11,965	12,460	13,126	13,733	14,245	14,789	15,173	15,520	15,699	15,535	15,110	14,485	14,219	13,388	12,367	11,365
Fall	9	12,030	9/12/2015	10,419	9,784	9,393	9,116	8,998	9,125	9,462	9,762	10,277	10,816	11,259	11,548	11,731	11,878	11,975	12,007	12,030	12,001	11,859	11,700	11,766	11,263	10,501	9,676
Fall	9	10,862	9/13/2015	8,900	8,397	8,006	7,805	7,691	7,701	7,892	8,003	8,577	9,071	9,386	9,631	9,936	10,189	10,332	10,517	10,725	10,862	10,789	10,644	10,859	10,261	9,440	8,663
Fall	9	12,301	9/14/2015	8,084	7,758	7,608	7,556	7,706	8,331	9,476	9,924	10,113	10,380	10,659	10,827	11,021	11,289	11,562	11,877	12,174	12,301	12,192	11,966	11,971	11,207	10,128	9,176
Fall	9	13,292	9/15/2015	8,523	8,141	7,941	7,867	7,980	8,549	9,734	10,099	10,259	10,534	10,935	11,251	11,595	12,016	12,395	12,847	13,179	13,292	13,096	12,640	12,619	11,684	10,549	9,523
Fall	9	12,711	9/16/2015	8,822	8,430	8,173	8,031	8,168	8,780	9,951	10,352	10,480	10,699	11,092	11,441	11,678	12,037	12,334	12,534	12,711	12,641	12,449	12,399	12,457	11,740	10,726	9,750
Fall	9	14,110	9/17/2015	9,026	8,595	8,365	8,240	8,328	8,904	10,069	10,470	10,629	11,000	11,492	11,964	12,361	12,910	13,375	13,830	14,088	14,110	13,798	13,377	13,281	12,369	11,208	10,105
Fall	9	14,775	9/18/2015	9,283	8,762	8,483	8,331	8,405	8,917	10,058	10,393	10,677	11,117	11,725	12,266	12,772	13,397	13,998	14,481	14,775	14,666	14,062	13,337	12,953	12,089	11,131	10,111
Fall	9	14,420	9/19/2015	9,290	8,672	8,326	8,104	8,026	8,186	8,477	8,713	9,282	9,907	10,671	11,437	12,084	12,787	13,447	13,966	14,352	14,420	13,807	13,163	12,731	11,898	10,878	10,022
Fall	9	14,700	9/20/2015	9,125	8,554	8,199	7,947	7,850	7,879	8,059	8,219	8,934	9,747	10,560	11,413	12,336	13,244	13,953	14,396	14,700	14,700	14,321	14,108	13,833	12,885	11,779	10,758
Fall	9	12,691	9/21/2015	9,959	9,449	9,155	8,971	9,074	9,647	10,910	11,523	11,602	11,764	12,049	12,228	12,389	12,630	12,673	12,691	12,673	12,438	12,204	12,407	12,291	11,603	10,703	9,747
Fall	9	12,296	9/22/2015	9,069	8,634	8,439	8,375	8,510	9,115	10,394	10,992	11,055	11,158	11,328	11,431	11,496	11,675	11,824	12,002	12,138	12,078	11,983	12,175	12,296	11,614	10,732	9,801
Fall	9	13,151	9/23/2015	9,122	8,680	8,410	8,325	8,446	9,030	10,276	10,774	10,886	11,099	11,465	11,709	11,919	12,295	12,620	12,944	13,151	13,052	12,799	12,732	12,717	11,945	10,953	9,954
Fall	9	11,755	9/24/2015	9,196	8,705	8,460	8,323	8,413	8,984	10,157	10,622	10,636	10,790	10,988	11,148	11,230	11,403	11,430	11,451	11,379	11,315	11,293	11,755	11,666	11,075	10,317	9,451
Fall	9	11,088	9/25/2015	8,837	8,441	8,222	8,128	8,239	8,780	9,925	10,566	10,680	10,849	11,068	11,088	11,021	10,979	10,905	10,823	10,804	10,725	10,683	10,919	10,845	10,458	9,822	9,206
Fall	9	10,314	9/26/2015	8,579	8,198	7,986	7,870	7,841	8,032	8,365	8,714	9,168	9,657	9,989	10,138	10,095	10,059	9,979	9,918	9,929	9,952	10,046	10,314	10,252	9,908	9,389	8,760
Fall	9	10,824	9/27/2015	8,205	7,822	7,635	7,479	7,471	7,574	7,822	8,135	8,656	9,084	9,315	9,427	9,602	9,672	9,669	9,722	9,863	10,056	10,300	10,824	10,790	10,392	9,775	9,121
Fall	9	12,940	9/28/2015	8,640	8,301	8,207	8,169	8,376	9,044	10,352	11,136	11,249	11,510	11,793	12,027	12,128	12,247	12,328	12,407	12,483	12,483	12,551	12,940	12,818	12,234	11,357	10,442
Fall	9	13,992	9/29/2015	9,759	9,326	9,138	9,035	9,127	9,760	11,090	11,792	11,941	12,204	12,549	12,824	12,940	13,149	13,327	13,580	13,711	13,711	13,653	13,992	13,842	13,009	11,978	10,953
Fall	9	15,751	9/30/2015	10,194	9,662	9,352	9,194	9,292	9,865	11,134	11,728	11,919	12,194	12,819	13,473	14,171	14,807	15,278	15,566	15,751	15,537	15,059	15,022	14,552	13,529	12,236	11,046
Fall	10	11,551	10/1/2015	10,075	9,492	9,088	8,877	8,856	9,383	10,607	11,238	11,215	11,322	11,480	11,551	11,528	11,507	11,453	11,348	11,282	11,184	11,186	11,545	11,429	10,866	10,025	9,209
Fall	10	10,782	10/2/2015	8,601	8,237	8,070	7,990	8,069	8,597	9,731	10,365	10,454	10,638	10,782	10,773	10,686	10,640	10,513	10,380	10,336	10,322	10,350	10,642	10,495	10,130	9,549	8,933
Fall	10	10,438	10/3/2015	8,387	8,068	7,880	7,737	7,816	8,006	8,416	8,863	9,391	9,932	10,297	10,438	10,378	10,244	10,078	9,980	9,961	9,984	10,038	10,379	10,161	9,784	9,244	8,665
Fall	10	10,363	10/4/2015	8,201	7,846	7,670	7,524	7,492	7,578	7,878	8,244	8,752	9,219	9,355	9,418	9,509	9,540	9,497	9,452	9,555	9,676	9,862	10,363	10,284	9,814	9,182	8,582
Fall	10	11,501	10/5/2015	8,102	7,823	7,665	7,661	7,866	8,542	9,825	10,540	10,543	10,760	10,905	10,938	10,906	10,980	10,940	10,941	10,924	10,894	10,988	11,501	11,344	10,728	9,896	9,060
Fall	10	11,609	10/6/2015	8,503	8,151	8,002	7,953	8,093	8,788	10,047	10,645	10,589	10,626	10,701	10,758	10,803	10,993	11,113	11,282	11,352	11,269	11,160	11,609	11,522	10,874	9,982	9,118
Fall	10	12,441	10/7/2015	8,506	8,209	8,051	7,969	8,131	8,778	10,034	10,649	10,648	10,746	10,947	11,085	11,318	11,693	11,952	12,239	12,441	12,404	12,189	12,371	12,118	11,371	10,335	9,426
Fall	10	12,755	10/8/2015	8,817	8,370	8,112	8,013	8,138	8,734	9,958	10,469	10,508	10,822	11,279	11,598	11,985	12,376	12,593	12,654	12,755	12,693	12,433	12,712	12,484	11,709	10,743	9,793
Fall	10	12,679	10/9/2015	9,026	8,595	8,278	8,184	8,277	8,830	9,996	10,537	10,610	10,915	11,299	11,653	11,914	12,239	12,516	12,650	12,679	12,517	12,143	12,234	11,923	11,408	10,695	9,869
Fall	10	10,277	10/10/2015	9,074	8,599	8,252	8,079	8,047	8,200	8,549	8,984	9,427	9,903	10,209	10,277	10,235	10,101	9,965	9,839	9,818	9,823	9,908	10,106	9,963	9,567	9,093	8,487
Fall	10	10,602	10/11/2015	7,973	7,625	7,434	7,287	7,328	7,462	7,784	8,192	8,707	9,060	9,088	9,132	9,298	9,405	9,518	9,671	9,861	10,057	10,097	10,602	10,479	9,955	9,224	8,525
Fall	10	12,066	10/12/2015	8,049	7,706	7,595	7,558	7,758	8,404	9,673	10,274	10,388	10,604	10,895	11,042	11,274	11,543	11,642	11,704	11,763	11,737	11,668	12,066	11,810	11,092	10,143	9,237
Fall	10	12,399	10/13/2015	8,620	8,223	8,047	7,988	8,115	8,736	9,987	10,655	10,606	10,782	11,004	11,229	11,455	11,832	12,057	12,270	12,399	12,277	12,045	12,348	12,066	11,272	10,244	9,365
Fall	10	11,750	10/14/2015	8,671	8,228	8,005	7,915	8,070	8,725	9,986	10,593	10,563	10,697	10,836	10,981	11,094	11,336	11,502	11,663	11,737	11,628	11,446	11,750	11,508	10,811	9,918	9,078
Fall	10	11,567	10/15/2015	8,482	8,164	7,969	7,938	8,130	8,829	10,132	10,741	10,738	10,784	10,860	10,915	10,932	11,076	11,172	11,216	11,299	11,236	11,152	11,567	11,351	10,752	9,919	9,145
Fall	10	10,898	10/16/2015	8,514	8,187	8,028	8,002	8,138	8,731	9,917	10,559	10,555	10,706	10,803	10,898	10,862	10,847	10,734	10,683	10,699	10,609	10,474	10,771	10,527	10,138	9,552	8,923
Fall	10	10,154	10/17/2015	8,427	8,096	7,969	7,950	8,076	8,412	8,930	9,537	10,066	10,154	10,001	9,763	9,517	9,362	9,232	9,196	9,300	9,370	9,510	10,024	9,945	9,648	9,244	8,782
Fall	10	10,672	10/18/2015	8,379	8,165	8,101	8,147	8,283	8,603	9,132	9,803	10,433	10,413	10,025	9,701	9,520	9,342	9,196	9,152	9,207	9,465	9,795	10,582	10,672	10,319	9,818	9,302
Fall	10	13,072	10/19/2015	9,083	8,969	9,048	9,220	9,668	10,661	12,298	13,072	12,959	12,533	11,952	11,471	11,116	10,922	10,721	10,635	10,581	10,721	11,138	11,887	11,810	11,369	10,619	9,955
Fall	10	13,126	10/20/2015	9,651	9,520	9,525	9,697	10,093	10,960	12,506	13,126	12,921	12,350	11,735	11,280	10,951	10,810	10,650	10,588	10,591	10,634	10,885	11,504	11,312	10,914	10,135	9,438
Fall	10	12,545	10/21/2015	9,059	8,906	8,977	8,992	9,433	10,353	11,852	12,545	12,312	11,831	11,386	11,109	10,872	10,829	10,806	10,868	10,883	10,870	11,008	11,463	11,259	10,724	9,903	9,190
Fall	10	11,789	10/22/2015	8,712	8,491	8,440	8,506	8,829	9,645	11,072	11,789	11,582	11,336	11,062	10,932	10,840	10,928	10,969	11,090	11,142	11,101	11,081	11,507	11,337	10,753	9,966	9,169
Fall	10	11,335	10/23/2015	8,623	8,301	8,194	8,155	8,313	8,910	10,160	10,839	10,852	10,848	10,847	10,855	10,922	11,117	11,228	11,331	11,335	11,227	11,083	11,245	10,893	10,437	9,796	9,107
Fall	10	10,269	10/24/2015	8,453	8,006	7,767	7,652	7,681	7,940	8,356	8,849	9,278	9,628	9,804	9,774	9,734	9,647	9,637	9,665	9,705	9,822	10,001	10,269	10,042	9,734	9,172	8,506
Fall	10	10,878	10/25/2015	7,995	7,624	7,494	7,385	7,408	7,527	7,824	8,365	8,775	9,186	9,295	9,346	9,479	9,647	9,695	9,759	9,901	10,068	10,429	10,878	10,647	10,101	9,444	8,759
Fall	10	11,826	10/26/2015	8,341	7,928	7,737	7,663	7,814	8,450	9,647	10,503	10,603	10,696	10,882	10,919	10,903	10,920	10,802	10,770	10,816	10,960	11,518	11,826	11,559	10,966	10,239	9,415
Fall	10	12,217	10/27/2015	8,906	8,654	8,517	8,539	8,768	9,491	10,783	11,597	11,576	11,597	11,782	11,747	11,774	11,805	11,666	11,671	11,704	11,773	12,176	12,217	11,908	11,264	10,509	9,652
Fall	10	11,801	10/28/2015	9,148	8,786	8,585	8,517	8,663	9,271	10,498	11,257	11,123	11,228	11,318	11,321	11,288	11,295	11,315	11,236	11,252	11,207	11,461	11,801	11,569	11,064	10,185	9,355
Fall	10	11,521	10/29/2015	8,773	8,426	8,208	8,161	8,304	8,947	10,175	10,852	10,837	10,896	11,030	11,076	11,072	11,084	11,005	10,924	10,885	10,856	11,144	11,521	11,346	10,811	10,041	9,250
Fall	10	11,215	10/30/2015	8,688	8,385	8,234	8,258	8,475	9,170	10,420	11,215	11,168	11,006	10,836	10,695	10,417	10,385	10,268	10,194	10,127	10,122	10,258	10,592	10,397	10,133	9,694	9,127
Fall	10	10,430	10/31/2015	8,666	8,399	8,308	8,328	8,419	8,736	9,260	9,818	10,246	10,430	10,358	10,228	10,014	9,733	9,541	9,442	9,465	9,486	9,607	9,692	9,619	9,440	9,046	8,552
Fall	11	10,600	11/1/2015	7,926	7,737	7,687	7,598	7,658	7,855	8,247	8,678	9,296	9,596	9,572	9,519	9,561	9,558	9,539	9,504	9,692	10,360	10,600	10,420	10,150	9,567	8,988	8,446
Fall	11	11,868	11/2/2015	8,061	7,844	7,744	7,748	7,969	8,694	10,051	10,716	10,944	11,155	11,320	11,309	11,268	11,290	11,182	11,164	11,281	11,702	11,868	11,659	11,241	10,583	9,854	9,130
Fall	11	11,816	11/3/2015	8,682	8,379	8,200	8,174	8,342	9,055	10,296	10,811	10,900	11,018	11,129	11,110	11,066	11,059	10,961	10,914	11,016	11,517	11,816	11,661	11,291	10,633	9,790	9,055
Fall	11	11,776	11/4/2015	8,590	8,288	8,122	8,085	8,276	8,954	10,228	10,715	10,826	10,932	11,015	10,981	10,965	10,981	10,913	10,861	10,957	11,467	11,776	11,564	11,225	10,616	9,843	9,082
Fall	11	11,920	11/5/2015	8,542	8,260	8,117	8,076	8,228	8,913	10,163	10,636	10,720	10,826	10,963	11,017	11,055	11,177	11,218	11,247	11,262	11,610	11,920	11,757	11,415	10,839	10,013	9,235
Fall	11	11,560	11/6/2015	8,672	8,347	8,147	8,091	8,260	8,885	10,105	10,637	10,832	11,023	11,172	11,240	11,199	11,198	11,161	11,057	11,035	11,364	11,560	11,284	10,998	10,580	9,992	9,336
Fall	11	10,641	11/7/2015	8,694	8,311	8,078	7,950	8,002	8,232	8,637	8,995	9,610	10,091	10,405	10,512	10,425	10,318	10,216	10,155	10,194	10,629	10,641	10,380	10,009	9,531	8,993	8,356
Fall	11	10,904	11/8/2015	7,845	7,536	7,347	7,300	7,366	7,578	7,985	8,453	9,185	9,573	9,617	9,565	9,581	9,566	9,534	9,574	9,712	10,597	10,904	10,856	10,683	10,211	9,668	9,114
Fall	11	12,815	11/9/2015	8,760	8,567	8,532	8,598	8,918	9,729	11,184	11,845	11,947	12,063	12,198	12,212	12,160	12,154	12,010	11,973	12,122	12,563	12,815	12,574	12,138	11,452	10,643	9,834
Fall	11	11,535	11/10/2015	9,292	8,951	8,765	8,703	8,916	9,620	10,896	11,308	11,154	11,024	10,917	10,820	10,737	10,771	10,711	10,703	10,763	11,142	11,535	11,369	11,068	10,571	10,004	9,353
Fall	11	11,725	11/11/2015	8,990	8,767	8,738	8,842	9,176	9,971	11,150	11,725	11,626	11,333	11,134	10,904	10,755	10,718	10,724	10,757	10,809	11,210	11,628	11,497	11,302	10,799	10,130	9,480
Fall	11	11,612	11/12/2015	9,110	8,875	8,803	8,947	9,121	9,949	11,244	11,583	11,330	11,142	11,057	10,930	10,803	10,802	10,757	10,799	10,807	11,190	11,612	11,448	11,155	10,542	9,796	9,113
Fall	11	11,330	11/13/2015	8,677	8,434	8,384	8,451	8,751	9,561	10,891	11,330	11,181	10,956	10,812	10,622	10,424	10,302	10,178	10,115	10,272	10,891	11,323	11,206	11,086	10,884	10,525	10,048
Fall	11	11,600	11/14/2015	9,653	9,492	9,473	9,598	9,851	10,354	10,972	11,434	11,600	11,215	10,818	10,403	9,996	9,698	9,499	9,464	9,679	10,475	11,002	11,013	10,983	10,819	10,578	10,271
Fall	11	12,199	11/15/2015	10,097	10,082	10,155	10,332	10,604	11,024	11,595	12,075	12,199	11,494	10,634	10,071	9,796	9,575	9,533	9,535	9,800	10,748	11,097	11,101	11,036	10,664	10,165	9,760
Fall	11	13,704	11/16/2015	9,596	9,648	9,833	10,101	10,627	11,645	13,299	13,704	13,219	12,518	11,908	11,408	10,996	10,836	10,659	10,645	10,805	11,551	12,046	12,004	11,741	11,182	10,478	9,791
Fall	11	11,962	11/17/2015	9,413	9,216	9,090	9,123	9,392	10,214	11,618	11,962	11,736	11,485	11,294	11,102	10,856	10,801	10,730	10,756	10,969	11,716	11,910	11,820	11,557	11,026	10,253	9,512
Fall	11	11,929	11/18/2015	9,014	8,754	8,627	8,621	8,833	9,573	10,853	11,318	11,263	11,180	11,206	11,120	10,996	11,085	11,012	10,983	11,142	11,733	11,929	11,698	11,393	10,797	10,015	9,213
Fall	11	11,748	11/19/2015	8,695	8,391	8,203	8,151	8,328	8,993	10,333	10,939	11,051	11,162	11,278	11,266	11,211	11,254	11,202	11,206	11,121	11,429	11,748	11,531	11,204	10,663	9,874	9,179
Fall	11	11,559	11/20/2015	8,695	8,494	8,396	8,458	8,805	9,599	11,052	11,559	11,415	11,194	10,962	10,730	10,520	10,435	10,292	10,242	10,359	10,997	11,361	11,292	11,215	11,016	10,655	10,182
Fall	11	11,984	11/21/2015	9,810	9,715	9,705	9,816	10,092	10,607	11,292	11,864	11,984	11,552

Contains Proprietary Material
Do Not Distribute

Winter	12	4,685	12/15/2014	3,547	3,520	3,455	3,483	3,540	3,786	4,263	4,603	4,682	4,685	4,612	4,504	4,454	4,252	4,208	4,204	4,304	4,529	4,657	4,609	4,568	4,415	4,135	3,880
Winter	12	4,820	12/16/2014	3,642	3,497	3,368	3,396	3,410	3,566	3,961	4,308	4,362	4,420	4,467	4,443	4,478	4,471	4,470	4,465	4,533	4,701	4,820	4,820	4,792	4,649	4,411	4,162
Winter	12	5,201	12/17/2014	3,993	3,843	3,786	3,780	3,888	4,109	4,559	4,884	5,011	5,004	5,060	4,941	4,863	4,766	4,744	4,652	4,726	4,995	5,165	5,144	5,201	5,118	4,875	4,676
Winter	12	5,253	12/18/2014	4,453	4,355	4,290	4,228	4,355	4,542	4,932	5,253	5,223	5,209	5,226	5,091	5,012	5,035	4,936	4,863	4,924	5,042	5,220	5,167	5,177	5,013	4,809	4,566
Winter	12	5,219	12/19/2014	4,393	4,277	4,204	4,216	4,255	4,463	4,901	5,211	5,219	5,120	4,984	4,904	4,829	4,745	4,676	4,607	4,574	4,818	5,046	5,091	5,082	5,043	4,882	4,707
Winter	12	4,781	12/20/2014	4,484	4,355	4,269	4,219	4,194	4,270	4,406	4,597	4,716	4,781	4,738	4,673	4,562	4,421	4,287	4,228	4,243	4,454	4,659	4,663	4,644	4,621	4,528	4,410
Winter	12	4,781	12/21/2014	4,289	4,231	4,235	4,209	4,290	4,404	4,554	4,716	4,781	4,674	4,429	4,185	4,010	3,921	3,795	3,737	3,811	4,133	4,402	4,450	4,508	4,491	4,354	4,171
Winter	12	4,626	12/22/2014	4,050	3,924	3,900	3,848	3,927	4,056	4,383	4,546	4,618	4,626	4,515	4,404	4,336	4,272	4,199	4,127	4,151	4,379	4,407	4,380	4,386	4,239	4,067	3,807
Winter	12	4,224	12/23/2014	3,597	3,462	3,332	3,279	3,275	3,410	3,696	3,980	4,080	4,175	4,224	4,112	4,117	4,057	4,082	4,034	4,010	4,196	4,176	4,066	3,990	3,867	3,672	3,407
Winter	12	3,625	12/24/2014	3,179	3,025	2,926	2,867	2,870	2,934	3,074	3,240	3,361	3,490	3,532	3,528	3,516	3,473	3,449	3,427	3,470	3,605	3,625	3,584	3,557	3,536	3,440	3,318
Winter	12	3,736	12/25/2014	3,191	3,108	3,066	3,055	3,080	3,153	3,261	3,383	3,491	3,598	3,635	3,621	3,556	3,417	3,288	3,183	3,176	3,339	3,577	3,652	3,719	3,736	3,701	3,620
Winter	12	4,177	12/26/2014	3,514	3,471	3,459	3,467	3,540	3,681	3,898	4,103	4,177	4,144	4,006	3,838	3,694	3,555	3,435	3,383	3,404	3,622	3,771	3,787	3,766	3,698	3,583	3,430
Winter	12	3,656	12/27/2014	3,250	3,130	3,086	3,044	3,030	3,077	3,195	3,307	3,399	3,478	3,570	3,588	3,567	3,489	3,372	3,344	3,359	3,580	3,656	3,642	3,568	3,510	3,365	3,201
Winter	12	4,178	12/28/2014	3,095	2,959	2,934	2,926	2,967	3,034	3,160	3,325	3,449	3,608	3,702	3,754	3,802	3,818	3,797	3,804	3,867	4,085	4,178	4,160	4,118	4,012	3,870	3,722
Winter	12	4,660	12/29/2014	3,588	3,522	3,495	3,530	3,615	3,783	4,074	4,367	4,479	4,547	4,585	4,509	4,449	4,374	4,320	4,286	4,317	4,497	4,660	4,630	4,595	4,503	4,331	4,149
Winter	12	4,862	12/30/2014	4,047	3,944	3,923	3,931	3,985	4,199	4,501	4,788	4,862	4,830	4,732	4,614	4,496	4,390	4,285	4,205	4,202	4,469	4,748	4,741	4,735	4,688	4,563	4,406
Winter	12	5,032	12/31/2014	4,283	4,240	4,218	4,235	4,298	4,462	4,724	4,976	4,977	5,032	4,908	4,761	4,601	4,450	4,329	4,205	4,221	4,493	4,732	4,718	4,659	4,593	4,487	4,397
Winter	1	4,469	1/1/2015	4,325	4,263	4,233	4,243	4,271	4,331	4,418	4,469	4,441	4,458	4,456	4,390	4,318	4,146	4,014	3,946	4,042	4,270	4,438	4,412	4,328	4,275	4,090	3,896
Winter	1	4,507	1/2/2015	3,797	3,699	3,609	3,619	3,616	3,740	3,983	4,182	4,278	4,329	4,469	4,463	4,449	4,389	4,336	4,306	4,279	4,441	4,507	4,387	4,349	4,244	4,100	3,890
Winter	1	3,825	1/3/2015	3,758	3,616	3,553	3,479	3,518	3,522	3,555	3,717	3,751	3,810	3,789	3,825	3,738	3,691	3,680	3,593	3,652	3,752	3,805	3,697	3,646	3,507	3,321	3,173
Winter	1	4,431	1/4/2015	3,070	2,917	2,857	2,835	2,784	2,864	2,960	3,111	3,174	3,441	3,482	3,590	3,708	3,747	3,788	3,855	3,981	4,243	4,431	4,426	4,393	4,375	4,267	4,199
Winter	1	5,660	1/5/2015	4,134	4,137	4,223	4,281	4,477	4,745	5,270	5,643	5,660	5,590	5,554	5,365	5,271	5,125	4,977	5,032	4,987	5,228	5,544	5,532	5,501	5,366	5,130	4,926
Winter	1	5,448	1/6/2015	4,743	4,634	4,518	4,434	4,476	4,699	5,094	5,448	5,396	5,363	5,298	5,252	5,168	4,975	4,887	4,877	4,918	5,024	5,231	5,277	5,292	5,217	5,013	4,873
Winter	1	6,588	1/7/2015	4,719	4,645	4,602	4,636	4,773	4,991	5,401	5,726	5,818	5,889	6,012	5,986	6,000	6,081	5,988	6,043	6,084	6,298	6,581	6,588	6,560	6,434	6,355	6,265
Winter	1	6,964	1/8/2015	6,128	6,145	6,094	6,074	6,127	6,406	6,666	6,964	6,957	6,795	6,657	6,499	6,381	6,241	6,158	6,077	5,980	6,002	6,157	6,018	5,899	5,696	5,531	5,292
Winter	1	5,780	1/9/2015	5,128	5,013	4,951	4,901	4,916	5,045	5,339	5,563	5,650	5,639	5,617	5,573	5,466	5,344	5,271	5,178	5,211	5,387	5,665	5,675	5,706	5,780	5,643	5,499
Winter	1	6,097	1/10/2015	5,432	5,401	5,432	5,452	5,538	5,684	5,812	5,965	6,097	5,883	5,729	5,512	5,301	5,030	4,814	4,633	4,664	4,817	5,146	5,166	5,270	5,289	5,155	5,009
Winter	1	4,926	1/11/2015	4,926	4,843	4,801	4,727	4,675	4,678	4,714	4,788	4,777	4,819	4,690	4,615	4,523	4,415	4,399	4,335	4,386	4,568	4,699	4,655	4,611	4,446	4,275	4,057
Winter	1	5,150	1/12/2015	3,932	3,840	3,789	3,785	3,840	4,081	4,500	4,837	4,870	4,898	4,882	4,850	4,815	4,816	4,807	4,814	4,842	4,992	5,150	5,126	5,048	4,980	4,751	4,601
Winter	1	5,571	1/13/2015	4,508	4,380	4,359	4,352	4,414	4,648	5,048	5,367	5,398	5,442	5,461	5,442	5,433	5,399	5,347	5,327	5,313	5,422	5,571	5,557	5,453	5,296	5,084	4,840
Winter	1	5,489	1/14/2015	4,687	4,569	4,439	4,473	4,497	4,698	5,111	5,388	5,473	5,434	5,489	5,431	5,350	5,187	5,113	4,992	4,940	5,129	5,346	5,408	5,340	5,196	4,996	4,762
Winter	1	5,354	1/15/2015	4,607	4,495	4,457	4,416	4,466	4,690	5,103	5,354	5,307	5,343	5,299	5,224	5,153	5,109	4,966	4,953	4,854	4,977	5,249	5,276	5,262	5,094	4,975	4,765
Winter	1	5,490	1/16/2015	4,576	4,562	4,542	4,493	4,598	4,808	5,155	5,490	5,456	5,365	5,103	4,957	4,700	4,559	4,353	4,231	4,185	4,279	4,613	4,658	4,743	4,657	4,534	4,420
Winter	1	4,596	1/17/2015	4,288	4,208	4,165	4,178	4,168	4,240	4,411	4,568	4,596	4,569	4,381	4,256	4,015	3,836	3,743	3,646	3,579	3,757	4,071	4,108	4,057	3,929	3,819	3,705
Winter	1	4,143	1/18/2015	3,507	3,402	3,323	3,346	3,358	3,452	3,589	3,756	3,876	3,956	3,906	3,799	3,777	3,708	3,633	3,588	3,611	3,783	4,063	4,112	4,143	4,107	3,966	3,899
Winter	1	4,975	1/19/2015	3,791	3,804	3,815	3,882	4,027	4,267	4,622	4,862	4,975	4,897	4,695	4,523	4,360	4,157	4,106	3,983	3,874	3,948	4,275	4,424	4,491	4,363	4,247	4,082
Winter	1	4,945	1/20/2015	4,000	3,926	3,893	3,936	3,979	4,249	4,718	4,945	4,914	4,769	4,620	4,388	4,278	4,201	4,102	4,050	3,943	4,148	4,394	4,419	4,393	4,250	4,047	3,865
Winter	1	4,667	1/21/2015	3,709	3,631	3,605	3,610	3,632	3,845	4,329	4,667	4,648	4,602	4,478	4,360	4,267	4,210	4,116	4,007	4,041	4,155	4,457	4,548	4,521	4,469	4,294	4,124
Winter	1	5,138	1/22/2015	3,991	3,965	3,979	3,993	4,115	4,331	4,807	5,138	5,119	5,060	5,005	4,846	4,796	4,683	4,631	4,589	4,607	4,722	4,913	4,909	4,867	4,731	4,557	4,303
Winter	1	5,022	1/23/2015	4,170	4,084	4,027	4,056	4,087	4,313	4,725	4,969	5,022	5,010	5,003	4,960	4,901	4,850	4,802	4,752	4,761	4,875	5,001	4,963	4,905	4,754	4,583	4,382
Winter	1	4,627	1/24/2015	4,226	4,127	4,087	4,075	4,075	4,144	4,308	4,489	4,627	4,622	4,623	4,536	4,391	4,258	4,145	4,171	4,162	4,216	4,516	4,497	4,459	4,387	4,269	4,073
Winter	1	4,338	1/25/2015	3,957	3,867	3,863	3,781	3,805	3,843	3,946	4,061	4,146	4,224	4,190	4,064	4,065	4,009	3,979	3,942	3,998	4,077	4,338	4,329	4,277	4,126	3,980	3,769
Winter	1	5,402	1/26/2015	3,712	3,685	3,700	3,820	3,982	4,296	4,878	5,177	5,336	5,382	5,402	5,321	5,329	5,248	5,212	5,147	5,177	5,205	5,358	5,303	5,272	5,046	4,809	4,590
Winter	1	5,345	1/27/2015	4,430	4,345	4,302	4,240	4,306	4,553	4,933	5,242	5,303	5,345	5,296	5,159	5,125	4,965	4,875	4,831	4,772	4,886	5,157	5,254	5,199	5,148	4,981	4,824
Winter	1	5,765	1/28/2015	4,690	4,630	4,605	4,728	4,812	5,057	5,515	5,765	5,756	5,533	5,319	5,151	4,959	4,816	4,652	4,544	4,486	4,618	4,954	5,011	5,042	4,904	4,763	4,513
Winter	1	4,938	1/29/2015	4,349	4,258	4,191	4,113	4,085	4,240	4,672	4,938	4,904	4,843	4,741	4,622	4,565	4,530	4,461	4,493	4,542	4,652	4,807	4,833	4,832	4,695	4,539	4,331
Winter	1	5,000	1/30/2015	4,209	4,091	4,008	3,993	4,091	4,271	4,664	4,956	4,965	5,000	4,948	4,823	4,729	4,597	4,497	4,389	4,296	4,433	4,803	4,858	4,828	4,788	4,693	4,577
Winter	1	4,970	1/31/2015	4,487	4,532	4,502	4,533	4,584	4,675	4,813	4,911	4,970	4,863	4,660	4,455	4,246	4,153	4,012	3,972	4,051	4,139	4,351	4,359	4,303	4,231	4,073	3,911
Winter	2	4,222	2/1/2015	3,776	3,667	3,649	3,624	3,625	3,660	3,779	3,933	3,983	4,073	4,190	4,147	4,152	4,188	4,151	4,129	4,155	4,183	4,222	4,106	4,019	3,900	3,825	3,660
Winter	2	5,509	2/2/2015	3,538	3,511	3,567	3,615	3,834	4,159	4,710	5,147	5,319	5,437	5,509	5,495	5,441	5,382	5,228	5,189	5,171	5,262	5,456	5,471	5,460	5,291	5,104	4,833
Winter	2	5,581	2/3/2015	4,676	4,579	4,516	4,523	4,642	4,863	5,331	5,581	5,567	5,424	5,253	5,082	4,935	4,747	4,638	4,518	4,449	4,550	4,933	5,059	5,068	4,952	4,759	4,554
Winter	2	5,188	2/4/2015	4,436	4,340	4,239	4,255	4,290	4,556	4,971	5,188	5,133	4,941	4,826	4,602	4,457	4,344	4,228	4,186	4,091	4,245	4,529	4,578	4,582	4,492	4,340	4,209
Winter	2	5,610	2/5/2015	4,170	4,195	4,191	4,280	4,424	4,722	5,233	5,537	5,610	5,569	5,448	5,328	5,162	5,064	4,927	4,761	4,824	4,884	5,202	5,418	5,410	5,354	5,243	5,142
Winter	2	6,065	2/6/2015	5,099	5,062	5,062	5,096	5,191	5,395	5,848	6,065	5,943	5,799	5,686	5,424	5,206	4,924	4,768	4,636	4,544	4,554	4,738	4,819	4,832	4,705	4,589	4,422
Winter	2	4,403	2/7/2015	4,220	4,192	4,116	4,075	4,107	4,151	4,291	4,403	4,380	4,384	4,288	4,105	3,897	3,748	3,643	3,526	3,472	3,503	3,758	3,838	3,833	3,770	3,647	3,482
Winter	2	3,852	2/8/2015	3,361	3,164	3,210	3,196	3,175	3,177	3,319	3,449	3,502	3,627	3,596	3,480	3,533	3,518	3,518	3,494	3,550	3,645	3,851	3,852	3,825	3,660	3,492	3,296
Winter	2	5,022	2/9/2015	3,100	3,055	3,085	3,070	3,098	3,337	3,889	4,237	4,344	4,388	4,500	4,529	4,594	4,611	4,642	4,645	4,667	4,782	5,003	5,022	4,992	4,860	4,727	4,521
Winter	2	5,334	2/10/2015	4,468	4,338	4,310	4,295	4,372	4,548	5,007	5,334	5,313	5,215	5,245	5,128	5,018	4,892	4,772	4,635	4,641	4,677	4,956	5,043	5,012	4,924	4,743	4,611
Winter	2	5,448	2/11/2015	4,541	4,461	4,443	4,478	4,572	4,777	5,211	5,448	5,410	5,286	5,161	4,898	4,736	4,509	4,324	4,300	4,180	4,341	4,619	4,710	4,683	4,534	4,418	4,193
Winter	2	5,696	2/12/2015	4,119	4,038	4,055	4,075	4,147	4,385	4,858	5,198	5,326	5,451	5,513	5,503	5,429	5,426	5,343	5,303	5,300	5,371	5,591	5,696	5,633	5,570	5,343	5,171
Winter	2	5,931	2/13/2015	5,024	4,959	4,932	4,950	4,997	5,224	5,668	5,907	5,931	5,741	5,576	5,290	5,130	4,922	4,798	4,606	4,534	4,624	4,979	5,028	5,075	5,006	4,859	4,691
Winter	2	5,515	2/14/2015	4,504	4,364	4,293	4,254	4,242	4,312	4,429	4,520	4,577	4,679	4,780	4,778	4,741	4,731	4,723	4,665	4,685	4,856	5,221	5,456	5,515	5,515	5,447	5,373
Winter	2	5,678	2/15/2015	5,297	5,122	5,161	5,185	5,320	5,386	5,541	5,661	5,678	5,591	5,459	5,297	5,141	4,957	4,832	4,773	4,758	4,987	5,237	5,406	5,360	5,281	5,133	5,027
Winter	2	6,025	2/16/2015	4,915	4,867	4,864	4,938	5,074	5,242	5,537	5,796	5,869	6,013	5,975	6,025	5,989	5,874	5,816	5,699	5,639	5,711	5,880	5,868	5,734	5,574	5,359	5,260
Winter	2	6,005	2/17/2015	5,190	5,139	5,233	5,191	5,307	5,531	5,720	5,904	6,005	5,916	5,662	5,460	5,311	5,192	5,094	4,998	5,026	5,130	5,461	5,578	5,578	5,496	5,350	5,285
Winter	2	6,381	2/18/2015	5,186	5,115	5,100	5,053	5,115	5,280	5,554	5,661	5,780	5,778	5,843	5,852	5,791	5,745	5,721	5,769	5,792	5,931	6,193	6,365	6,381	6,362	6,252	6,134
Winter	2	6,897	2/19/2015	6,057	6,083	6,137	6,176	6,234	6,460	6,748	6,897	6,865	6,761	6,737	6,644	6,523	6,362	6,260	6,151	6,097	6,187	6,499	6,742	6,742	6,736	6,573	6,557
Winter	2	7,236	2/20/2015	6,574	6,476	6,560	6,586	6,650	6,840	7,102	7,236	7,179	6,981	6,810	6,575	6,314	6,064	5,881	5,792	5,776	5,816	5,988	5,983	5,889	5,728	5,468	5,233
Winter	2	5,013	2/21/2015	5,008	4,868	4,790	4,737	4,642	4,630	4,744	4,741	4,833	4,907	5,009	5,013	4,954	4,880	4,819	4,762	4,829	4,838	4,868	4,920	4,803	4,695	4,552	4,420
Winter	2	4,972	2/22/2015	4,272	4,234	4,191	4,185	4,233	4,330	4,353	4,523	4,594	4,568	4,581	4,525	4,440	4,320	4,332	4,311	4,406	4,575	4,817	4,912	4,972	4,786	4,636	4,514
Winter	2	6,003	2/23/2015	4,447	4,435	4,480	4,547	4,721	5,003	5,419	5,725	5,857	5,802	5,715	5,686	5,538	5,451	5,385	5,299	5,241	5,380	5,678	5,966	5,989	6,003	5,814	5,744
Winter	2	6,399	2/24/2015	5,589	5,566	5,483	5,534	5,529	5,788	6,124	6,399	6,319	6,051	5,823	5,579	5,457	5,308	5,125	5,049	4,982	5,035	5,301	5,592	5,587	5,524	5,306	5,093
Winter	2	5,655	2/25/2015	5,008	4,887	4,880	4,829	4,890	5,025	5,402	5,655	5,544	5,404	5,246	5,036	4,900	4,813	4,765	4,730	4,753	4,873	5,070	5,206	5,151	5,014	4,820	4,615
Winter	2	5,441	2/26/2015	4,521	4,403	4,424	4,461	4,509	4,748	5,140	5,328	5,323	5,231	5,141	4,997	4,834	4,753	4,685	4,670	4,776	4,979	5,211	5,433	5,441	5,415	5,303	5,157
Winter	2	6,090	2/27/2015	5,048	5,040	5,059	5,038	5,152	5,430	5,861	6,090	6,017	5,798	5,604	5,436	5,326	5,177	5,031	4,918	4,862	4,943	5,234	5,462	5,494	5,467	5,325	5,198
Winter	2	5,380	2/28/2015	5,091	5,058	4,992	5,001	5,005	5,022	5,200	5,358	5,380	5,337	5,147	4,936	4,678	4,492	4,323	4,254	4,263	4,359	4,562	4,682	4,636	4,547	4,390	4,220
Spring	3	4,582	3/1/2015	4,123	3,998	4,013	3,959	3,981	4,002	4,072	4,178	4,271	4,415	4,430	4,359	4,281	4,210	4,143	4,140	4,226	4,309	4,491	4,582	4,572	4,432	4,299	4,150
Spring	3	5,213	3/2/2015	4,056	4,025	4,042	4,088	4,200	4,504	4,994	5,191	5,213	5,061	4,966	4,826	4,698	4,589	4,436	4,360	4,343	4,439	4,735	4,966	4,949	4,879	4,746	4,530
Spring	3	4,987	3/3/2015	4,416	4,319	4,214	4,181	4,218	4,409	4,803	4,987	4,946	4,943	4,921	4,782	4,672	4,609	4,513	4,407	4,315	4,323	4,409	4,427	4,389	4,215	4,013	3,781
Spring	3	5,175	3/4/2015	3,586	3,517	3,480	3,512	3,529	3,797	4,126	4,436	4,510	4,556	4,629	4,711	4,714	4,711	4,753	4,880	4,807	4,978	5,092	5,175	5,100	4,983	4,828	4,691
Spring	3	5,456	3/5/2015	4,625	4,528	4,504	4,568	4,630	4,749	4,921	5,075	5,156	5,260	5,240	5,190	5,247	5,161	5,061	4,969	4,868	4,967	5,124	5,407	5,456	5,362	5,315	5,239
Spring	3	6,170	3/6/2015	5,199	5,237	5,269	5,384	5,489	5,652	5,962	6,170	6,085	5,851	5,702	5,452	5,230	5,077	4,980	4,820	4,776	4,757	5,025	5,275	5,286	5,248	5,117	4,988
Spring	3	5,038	3/7/2015	4,895	4,814	4,825	4,792	4,822	4,877	5,008	5,038	4,978	4,810	4,693	4,519	4,381	4,192	4,051	3,892	3,830	3,903	4,081	4,328	4,345	4,286	4,183	4,033
Spring	3	4,274	3/8/2015	0	3,855	3,846	3,852	3,918	4,067	4,198	4,274	4,257	4,079	3,919	3,798	3,669	3,596	3,520	3,495	3,537	3,638	3,819	4,047	3,965	3,869	3,657
Spring	3	4,639	3/9/2015	3,586	3,490	3,469	3,497	3,569	3,855	4,311	4,613	4,639	4,614	4,551	4,463	4,338	4,215	4,103	4,080	3,961	3,940	3,997	4,115	4,285	4,191	3,934	3,814
Spring	3	4,432	3/10/2015	3,563	3,545	3,381	3,434	3,426	3,654	4,051	4,349	4,385	4,391	4,410	4,416	4,432	4,360	4,339	4,289	4,228	4,181	4,197	4,232	4,282	4,171	3,938	3,672
Spring	3	4,261	3/11/2015	3,476	3,359	3,278	3,252	3,280	3,433	3,892	4,145	4,181	4,226	4,261	4,197	4,119	4,039	4,024	3,937	3,872	3,800	3,820	3,859	4,093	4,036	3,805	3,630
Spring	3	4,342	3/12/2015	3,427	3,371	3,324	3,288	3,356	3,557	4,051	4,342	4,329	4,278	4,301	4,199	4,145	4,040	3,965	3,903	3,750	3,758	3,752	3,852	4,052	3,974	3,814	3,537
Spring	3	4,228	3/13/2015	3,336	3,206	3,161	3,120	3,118	3,302	3,733	4,033	4,082	4,143	4,201	4,210	4,228	4,201	4,114	4,111	4,070	4,030	4,034	4,030	4,078	4,000	3,811	3,661
Spring	3	3,733	3/14/2015	3,420	3,279	3,177	3,142	3,138	3,148	3,310	3,390	3,551	3,641	3,727	3,733	3,725	3,619	3,551	3,503	3,473	3,440	3,406	3,488	3,579	3,566	3,442	3,287
Spring	3	3,638	3/15/2015	3,149	3,053	2,995	2,995	3,061	3,156	3,287	3,453	3,545	3,577	3,500	3,431	3,387	3,318	3,250	3,193	3,209	3,241	3,264	3,359	3,638	3,523	3,428	3,176
Spring	3	4,171	3/16/2015	3,083	3,012	3,007	3,028	3,090	3,295	3,783	4,171	4,108	4,057	4,075	3,994	3,895	3,881	3,928	3,901	3,784	3,725	3,650	3,725	4,001	3,904	3,652	3,423
Spring	3	4,016	3/17/2015	3,193	3,125	3,023	2,933	2,923	3,128	3,561	3,883	3,961	3,971	4,016	3,954	3,991	3,926	3,857	3,788	3,691	3,722	3,689	3,723	3,954	3,899	3,744	3,615
Spring	3	4,636	3/18/2015	3,507	3,388	3,425	3,455	3,514	3,802	4,342	4,636	4,554	4,552	4,532

Contains Proprietary Material
Do Not Distribute

Spring	4	3,966	4/22/2015	3,238	3,064	3,051	3,014	3,005	3,252	3,606	3,828	3,896	3,887	3,955	3,950	3,966	3,937	3,912	3,849	3,780	3,711	3,639	3,701	3,859	3,879	3,721	3,440
Spring	4	4,166	4/23/2015	3,310	3,172	3,211	3,175	3,275	3,466	3,943	4,166	4,163	4,100	4,074	4,002	3,985	3,936	3,941	3,795	3,752	3,636	3,680	3,699	3,862	3,906	3,725	3,494
Spring	4	4,203	4/24/2015	3,355	3,318	3,272	3,280	3,316	3,534	3,928	4,203	4,100	4,137	4,036	3,962	3,900	3,828	3,787	3,719	3,651	3,629	3,585	3,582	3,707	3,690	3,483	3,305
Spring	4	3,576	4/25/2015	3,086	2,982	2,904	2,823	2,830	2,894	2,955	3,114	3,241	3,404	3,516	3,576	3,492	3,453	3,433	3,400	3,404	3,425	3,388	3,441	3,485	3,428	3,323	3,134
Spring	4	3,419	4/26/2015	2,934	2,819	2,738	2,705	2,693	2,714	2,784	2,880	3,060	3,194	3,234	3,197	3,155	3,141	3,084	3,052	3,071	3,097	3,128	3,173	3,313	3,419	3,229	3,038
Spring	4	3,906	4/27/2015	2,889	2,823	2,814	2,857	2,957	3,205	3,619	3,866	3,906	3,889	3,884	3,857	3,839	3,821	3,800	3,730	3,682	3,647	3,633	3,609	3,709	3,745	3,531	3,300
Spring	4	3,886	4/28/2015	3,136	2,999	2,983	2,977	3,012	3,252	3,665	3,885	3,886	3,869	3,873	3,839	3,824	3,806	3,778	3,715	3,672	3,647	3,615	3,608	3,699	3,745	3,525	3,223
Spring	4	3,830	4/29/2015	3,069	2,945	2,892	2,878	2,928	3,128	3,428	3,597	3,623	3,619	3,651	3,786	3,822	3,830	3,822	3,809	3,749	3,717	3,661	3,625	3,721	3,740	3,523	3,271
Spring	4	3,796	4/30/2015	3,061	2,921	2,846	2,808	2,821	3,001	3,355	3,587	3,685	3,682	3,757	3,789	3,796	3,787	3,769	3,690	3,664	3,600	3,593	3,580	3,689	3,711	3,578	3,415
Spring	5	3,855	5/1/2015	3,271	3,118	3,083	3,045	3,069	3,245	3,562	3,806	3,855	3,852	3,837	3,815	3,830	3,767	3,760	3,710	3,717	3,691	3,631	3,621	3,684	3,716	3,516	3,297
Spring	5	3,459	5/2/2015	3,105	2,951	2,880	2,807	2,789	2,874	2,932	3,016	3,156	3,279	3,312	3,382	3,335	3,354	3,364	3,397	3,384	3,390	3,429	3,397	3,386	3,459	3,239	3,065
Spring	5	3,847	5/3/2015	2,820	2,752	2,677	2,571	2,602	2,624	2,691	2,720	2,883	3,122	3,206	3,179	3,383	3,395	3,464	3,519	3,681	3,777	3,811	3,796	3,846	3,847	3,602	3,264
Spring	5	4,724	5/4/2015	3,019	2,947	2,827	2,763	2,779	2,974	3,331	3,585	3,865	3,972	4,155	4,217	4,324	4,457	4,592	4,648	4,724	4,695	4,640	4,539	4,548	4,468	4,205	3,828
Spring	5	5,054	5/5/2015	3,530	3,327	3,195	3,061	3,102	3,171	3,515	3,787	3,953	4,152	4,339	4,531	4,704	4,839	4,936	5,037	5,054	5,046	5,022	4,935	4,840	4,724	4,321	3,956
Spring	5	5,252	5/6/2015	3,614	3,396	3,219	3,064	3,071	3,196	3,461	3,668	3,868	4,079	4,331	4,527	4,809	4,948	5,049	5,126	5,225	5,252	5,231	5,103	5,016	4,870	4,531	4,065
Spring	5	5,478	5/7/2015	3,741	3,495	3,283	3,255	3,201	3,311	3,674	3,878	4,083	4,251	4,493	4,744	4,962	5,201	5,385	5,474	5,469	5,478	5,448	5,290	5,171	5,068	4,670	4,225
Spring	5	5,508	5/8/2015	3,843	3,591	3,404	3,265	3,199	3,310	3,588	3,855	4,093	4,342	4,620	4,867	5,125	5,310	5,486	5,491	5,508	5,434	5,306	5,134	4,899	4,839	4,534	4,186
Spring	5	5,042	5/9/2015	3,814	3,598	3,370	3,249	3,194	3,185	3,239	3,308	3,528	3,857	4,143	4,427	4,546	4,690	4,816	4,945	5,042	5,027	4,861	4,719	4,584	4,581	4,284	3,958
Spring	5	4,839	5/10/2015	3,654	3,386	3,235	3,139	3,013	3,019	2,967	3,014	3,373	3,661	3,959	4,139	4,283	4,345	4,457	4,617	4,727	4,839	4,834	4,722	4,658	4,672	4,365	3,935
Spring	5	5,538	5/11/2015	3,641	3,406	3,317	3,152	3,167	3,308	3,658	3,936	4,201	4,409	4,794	5,014	5,324	5,538	5,531	5,506	5,367	5,276	5,145	4,946	4,804	4,687	4,412	4,026
Spring	5	4,539	5/12/2015	3,726	3,459	3,317	3,258	3,224	3,314	3,624	3,831	3,995	4,151	4,231	4,329	4,339	4,452	4,494	4,539	4,473	4,389	4,297	4,186	4,089	4,135	3,849	3,514
Spring	5	4,261	5/13/2015	3,316	3,104	2,999	2,942	2,906	3,116	3,363	3,608	3,728	3,836	3,939	3,987	4,057	4,091	4,152	4,204	4,218	4,261	4,237	4,138	4,116	4,106	3,830	3,504
Spring	5	4,322	5/14/2015	3,276	3,109	2,995	2,910	2,923	3,076	3,395	3,607	3,739	3,844	3,892	3,979	4,082	4,130	4,198	4,289	4,322	4,276	4,212	4,171	4,234	4,232	3,979	3,698
Spring	5	5,271	5/15/2015	3,448	3,261	3,147	3,078	3,085	3,188	3,511	3,742	3,935	4,166	4,378	4,602	4,780	4,945	5,133	5,249	5,229	5,271	5,240	4,975	4,842	4,776	4,502	4,200
Spring	5	4,051	5/16/2015	3,866	3,614	3,473	3,319	3,225	3,235	3,259	3,382	3,593	3,816	3,954	4,051	4,045	3,976	3,968	3,925	4,014	3,997	3,936	3,904	3,931	3,929	3,759	3,487
Spring	5	4,731	5/17/2015	3,265	3,075	2,987	2,915	2,872	2,869	2,921	2,950	3,279	3,638	3,827	4,010	4,194	4,238	4,414	4,479	4,607	4,716	4,731	4,656	4,595	4,560	4,233	3,857
Spring	5	4,834	5/18/2015	3,580	3,384	3,277	3,241	3,200	3,365	3,709	3,950	4,137	4,328	4,505	4,582	4,669	4,730	4,798	4,783	4,761	4,826	4,834	4,658	4,657	4,652	4,288	4,025
Spring	5	4,858	5/19/2015	3,702	3,506	3,330	3,229	3,197	3,280	3,522	3,756	3,964	4,117	4,277	4,426	4,539	4,646	4,778	4,826	4,858	4,837	4,773	4,593	4,457	4,389	4,055	3,690
Spring	5	4,252	5/20/2015	3,404	3,203	3,055	2,977	2,952	3,088	3,385	3,599	3,782	3,876	3,948	4,004	4,080	4,159	4,220	4,252	4,249	4,226	4,100	4,031	4,045	4,030	3,759	3,537
Spring	5	3,919	5/21/2015	3,286	3,090	3,034	2,944	2,943	3,068	3,386	3,577	3,726	3,827	3,882	3,915	3,919	3,892	3,840	3,831	3,766	3,716	3,672	3,686	3,736	3,850	3,667	3,372
Spring	5	3,984	5/22/2015	3,239	3,072	3,043	2,963	3,008	3,158	3,382	3,684	3,726	3,876	3,878	3,943	3,930	3,968	3,960	3,984	3,946	3,922	3,926	3,781	3,780	3,830	3,627	3,370
Spring	5	3,990	5/23/2015	3,113	2,906	2,813	2,745	2,755	2,699	2,765	2,798	2,985	3,133	3,271	3,337	3,446	3,508	3,639	3,735	3,885	3,957	3,990	3,935	3,780	3,742	3,555	3,291
Spring	5	4,493	5/24/2015	3,032	2,807	2,697	2,668	2,627	2,649	2,588	2,730	2,944	3,153	3,334	3,586	3,718	3,932	4,081	4,259	4,422	4,493	4,454	4,373	4,172	4,165	3,949	3,576
Spring	5	4,010	5/25/2015	3,352	3,128	3,022	2,964	2,916	2,911	2,950	2,956	3,111	3,371	3,575	3,755	3,877	3,896	3,933	3,985	3,924	3,938	3,938	3,983	3,947	4,010	3,819	3,513
Spring	5	5,203	5/26/2015	3,228	3,085	3,015	2,986	2,999	3,168	3,495	3,846	4,082	4,336	4,671	4,948	5,074	5,182	5,203	5,135	5,131	5,038	4,822	4,667	4,544	4,476	4,217	3,908
Spring	5	5,096	5/27/2015	3,647	3,396	3,339	3,212	3,183	3,278	3,576	3,881	4,067	4,288	4,484	4,740	4,911	5,075	5,096	5,026	4,910	4,693	4,555	4,406	4,281	4,295	4,070	3,724
Spring	5	5,135	5/28/2015	3,450	3,240	3,079	3,017	2,990	3,126	3,455	3,719	3,926	4,109	4,291	4,465	4,623	4,779	4,940	5,051	5,117	5,135	5,001	4,896	4,773	4,719	4,476	4,096
Spring	5	5,272	5/29/2015	3,747	3,493	3,339	3,224	3,178	3,286	3,537	3,844	4,086	4,328	4,486	4,728	4,959	5,078	5,179	5,227	5,259	5,272	5,197	5,046	4,855	4,771	4,507	4,172
Spring	5	5,013	5/30/2015	3,835	3,570	3,375	3,266	3,171	3,167	3,161	3,312	3,604	3,974	4,310	4,579	4,787	4,870	4,933	5,013	5,013	4,992	4,952	4,767	4,591	4,508	4,263	3,903
Spring	5	4,085	5/31/2015	3,624	3,356	3,196	3,119	3,024	3,002	2,972	3,039	3,249	3,463	3,696	3,754	3,861	3,915	3,990	4,049	4,067	4,085	4,080	3,959	3,846	3,865	3,739	3,460
Summer	6	4,060	6/1/2015	3,203	3,048	2,964	2,962	2,953	3,139	3,366	3,623	3,782	3,901	4,040	4,037	4,060	4,016	4,014	4,013	3,975	3,881	3,892	3,817	3,766	3,841	3,664	3,422
Summer	6	4,027	6/2/2015	3,240	3,096	3,010	2,962	2,941	3,123	3,331	3,565	3,786	3,871	3,950	3,984	4,010	4,014	4,025	4,027	3,943	3,888	3,896	3,871	3,875	3,914	3,725	3,493
Summer	6	4,202	6/3/2015	3,308	3,144	3,037	3,032	2,993	3,139	3,419	3,665	3,771	3,934	3,998	4,039	4,139	4,191	4,198	4,202	4,154	4,147	4,143	4,083	4,053	4,090	3,923	3,619
Summer	6	5,229	6/4/2015	3,365	3,166	3,055	3,008	3,013	3,136	3,324	3,612	3,871	4,027	4,233	4,384	4,620	4,774	4,915	5,077	5,176	5,229	5,193	5,061	4,902	4,801	4,515	4,111
Summer	6	5,492	6/5/2015	3,723	3,425	3,290	3,183	3,138	3,250	3,481	3,685	3,924	4,256	4,521	4,736	4,982	5,156	5,334	5,440	5,492	5,478	5,423	5,251	5,068	4,888	4,662	4,231
Summer	6	5,087	6/6/2015	3,903	3,624	3,445	3,240	3,190	3,134	3,133	3,245	3,515	3,762	4,072	4,299	4,500	4,745	4,867	4,968	5,087	5,070	5,006	4,846	4,631	4,530	4,290	3,939
Summer	6	5,471	6/7/2015	3,605	3,334	3,165	3,027	3,011	2,932	2,912	3,001	3,244	3,677	4,033	4,361	4,689	4,951	5,109	5,250	5,377	5,471	5,381	5,310	5,198	5,030	4,821	4,446
Summer	6	5,203	6/8/2015	4,075	3,858	3,704	3,644	3,614	3,700	3,977	4,235	4,395	4,558	4,698	4,882	4,960	5,073	5,203	5,186	4,983	4,844	4,874	4,773	4,598	4,609	4,391	3,989
Summer	6	5,790	6/9/2015	3,754	3,518	3,364	3,277	3,204	3,347	3,509	3,789	4,094	4,420	4,619	4,970	5,202	5,539	5,634	5,693	5,784	5,790	5,718	5,505	5,300	5,132	4,780	4,378
Summer	6	6,216	6/10/2015	3,944	3,626	3,470	3,344	3,310	3,381	3,559	3,890	4,210	4,527	4,927	5,283	5,581	5,818	6,035	6,204	6,216	6,204	6,112	5,974	5,722	5,578	5,222	4,733
Summer	6	6,441	6/11/2015	4,295	3,965	3,766	3,578	3,499	3,544	3,773	4,055	4,429	4,803	5,224	5,641	5,984	6,209	6,319	6,395	6,441	6,389	6,304	6,143	5,878	5,736	5,450	5,006
Summer	6	6,330	6/12/2015	4,567	4,230	3,990	3,835	3,801	3,883	4,099	4,369	4,762	5,148	5,493	5,827	6,086	6,238	6,302	6,274	6,298	6,330	6,146	5,986	5,804	5,645	5,362	4,990
Summer	6	5,675	6/13/2015	4,614	4,315	4,096	3,893	3,777	3,738	3,718	3,880	4,225	4,541	4,908	5,151	5,330	5,482	5,585	5,587	5,632	5,675	5,552	5,420	5,249	5,102	4,929	4,556
Summer	6	5,817	6/14/2015	4,229	3,982	3,802	3,664	3,583	3,524	3,432	3,560	3,931	4,300	4,703	5,016	5,184	5,408	5,504	5,613	5,655	5,776	5,817	5,693	5,507	5,431	5,161	4,761
Summer	6	6,576	6/15/2015	4,403	4,170	3,981	3,868	3,818	3,937	4,157	4,456	4,930	5,341	5,626	5,943	6,175	6,334	6,475	6,570	6,576	6,539	6,480	6,314	6,100	5,970	5,618	5,188
Summer	6	6,468	6/16/2015	4,768	4,505	4,288	4,151	4,068	4,173	4,344	4,555	4,971	5,297	5,694	5,958	6,158	6,335	6,433	6,468	6,287	6,123	6,014	5,766	5,587	5,521	5,149	4,772
Summer	6	6,426	6/17/2015	4,430	4,138	3,950	3,844	3,787	3,919	4,153	4,373	4,564	4,855	5,209	5,537	5,800	6,096	6,218	6,426	6,397	6,216	5,944	5,741	5,447	5,382	5,067	4,700
Summer	6	6,470	6/18/2015	4,349	4,026	3,891	3,709	3,628	3,809	3,971	4,230	4,676	5,034	5,489	5,866	6,181	6,383	6,430	6,470	6,348	5,978	5,683	5,413	5,234	5,128	4,848	4,495
Summer	6	5,743	6/19/2015	4,126	3,889	3,737	3,626	3,660	3,739	3,994	4,199	4,441	4,667	4,908	5,202	5,436	5,622	5,743	5,731	5,627	5,413	5,145	4,944	4,758	4,767	4,533	4,269
Summer	6	4,819	6/20/2015	3,992	3,732	3,587	3,454	3,439	3,466	3,488	3,589	3,792	3,985	4,198	4,279	4,357	4,378	4,410	4,541	4,652	4,766	4,817	4,819	4,643	4,547	4,358	4,062
Summer	6	5,493	6/21/2015	3,760	3,546	3,376	3,238	3,221	3,188	3,165	3,285	3,572	3,993	4,338	4,715	4,985	5,113	5,256	5,422	5,477	5,493	5,388	5,224	5,052	5,005	4,747	4,464
Summer	6	6,138	6/22/2015	4,003	3,801	3,607	3,458	3,415	3,572	3,786	4,014	4,270	4,588	4,946	5,304	5,573	5,776	5,965	6,039	6,138	6,080	6,049	5,874	5,702	5,604	5,332	4,926
Summer	6	6,386	6/23/2015	4,556	4,297	4,099	3,981	3,932	4,021	4,226	4,458	4,756	5,136	5,488	5,825	6,112	6,307	6,292	6,386	6,365	6,339	6,340	6,164	5,944	5,743	5,407	4,918
Summer	6	5,963	6/24/2015	4,482	4,131	3,847	3,640	3,556	3,613	3,756	3,981	4,214	4,499	4,785	5,079	5,358	5,558	5,756	5,910	5,949	5,963	5,767	5,627	5,368	5,169	4,835	4,430
Summer	6	6,195	6/25/2015	4,062	3,762	3,544	3,409	3,329	3,440	3,655	3,858	4,127	4,351	4,596	4,845	5,121	5,456	5,790	6,023	6,182	6,195	6,100	5,910	5,750	5,664	5,355	4,951
Summer	6	5,961	6/26/2015	4,524	4,217	3,943	3,734	3,630	3,702	3,859	4,044	4,266	4,577	4,842	5,186	5,501	5,704	5,885	5,961	5,948	5,774	5,303	4,942	4,736	4,671	4,453	4,163
Summer	6	4,247	6/27/2015	3,901	3,676	3,487	3,385	3,306	3,335	3,344	3,440	3,649	3,841	3,966	3,997	4,037	4,108	4,117	4,144	4,221	4,231	4,247	4,101	3,898	3,824	3,669	3,408
Summer	6	4,523	6/28/2015	3,146	3,008	2,922	2,739	2,717	2,720	2,700	2,770	2,968	3,281	3,444	3,605	3,834	3,960	4,046	4,258	4,411	4,490	4,523	4,379	4,242	4,155	3,998	3,635
Summer	6	5,214	6/29/2015	3,425	3,155	3,066	2,971	2,989	3,167	3,396	3,529	3,842	4,034	4,269	4,546	4,748	4,918	5,065	5,175	5,214	5,188	5,149	5,009	4,845	4,718	4,499	4,115
Summer	6	5,432	6/30/2015	3,757	3,546	3,331	3,212	3,209	3,338	3,504	3,672	3,942	4,182	4,401	4,678	4,939	5,151	5,358	5,424	5,432	5,416	5,307	5,054	4,820	4,682	4,424	4,067
Summer	7	4,887	7/1/2015	3,761	3,548	3,325	3,173	3,214	3,286	3,519	3,730	3,989	4,186	4,385	4,557	4,712	4,875	4,887	4,834	4,739	4,780	4,691	4,613	4,539	4,560	4,338	4,017
Summer	7	4,893	7/2/2015	3,760	3,546	3,447	3,312	3,307	3,450	3,654	3,830	3,960	4,148	4,323	4,445	4,587	4,719	4,840	4,843	4,825	4,893	4,804	4,664	4,520	4,471	4,302	3,939
Summer	7	4,383	7/3/2015	3,628	3,449	3,298	3,210	3,155	3,187	3,275	3,307	3,491	3,682	3,875	4,000	4,172	4,309	4,383	4,317	4,303	4,273	4,203	4,077	3,952	3,958	3,774	3,554
Summer	7	4,607	7/4/2015	3,335	3,157	2,983	2,915	2,886	2,886	2,916	2,879	3,044	3,299	3,574	3,858	4,058	4,215	4,330	4,482	4,607	4,587	4,475	4,303	4,083	3,966	3,850	3,689
Summer	7	4,469	7/5/2015	3,470	3,255	3,112	2,986	2,939	2,949	2,915	2,992	3,094	3,271	3,491	3,599	3,830	3,937	4,020	4,101	4,237	4,404	4,469	4,434	4,289	4,255	4,028	3,717
Summer	7	5,947	7/6/2015	3,427	3,273	3,153	3,098	3,095	3,229	3,428	3,701	3,992	4,302	4,619	4,959	5,295	5,532	5,743	5,829	5,892	5,947	5,902	5,755	5,513	5,378	5,041	4,634
Summer	7	5,193	7/7/2015	4,289	3,968	3,790	3,656	3,632	3,735	3,934	4,127	4,417	4,665	4,861	5,047	5,147	5,125	5,193	5,169	5,065	4,912	4,840	4,752	4,691	4,664	4,528	4,201
Summer	7	5,374	7/8/2015	3,984	3,688	3,608	3,495	3,456	3,574	3,827	4,059	4,258	4,471	4,639	4,814	4,885	5,035	5,160	5,252	5,210	5,352	5,374	5,240	5,076	5,058	4,783	4,452
Summer	7	5,606	7/9/2015	4,169	3,900	3,721	3,661	3,642	3,777	3,959	4,181	4,440	4,598	4,762	4,907	5,048	5,168	5,371	5,509	5,578	5,606	5,589	5,456	5,312	5,183	4,943	4,515
Summer	7	5,448	7/10/2015	4,160	3,823	3,638	3,528	3,505	3,584	3,798	4,011	4,262	4,615	4,936	5,146	5,246	5,284	5,448	5,409	5,442	5,294	5,087	4,975	4,748	4,663	4,500	4,145
Summer	7	5,284	7/11/2015	3,797	3,556	3,391	3,264	3,191	3,179	3,192	3,287	3,470	3,765	4,038	4,355	4,547	4,780	4,968	5,093	5,222	5,284	5,226	5,092	4,869	4,773	4,503	4,232
Summer	7	5,520	7/12/2015	3,870	3,646	3,490	3,383	3,332	3,331	3,359	3,392	3,443	3,674	3,901	4,183	4,558	4,896	5,131	5,339	5,489	5,520	5,501	5,370	5,196	5,070	4,900	4,497
Summer	7	6,372	7/13/2015	4,128	3,880	3,705	3,595	3,567	3,676	3,887	4,125	4,488	4,918	5,370	5,822	6,124	6,372	6,177	5,778	5,446	5,345	5,279	5,276	5,101	5,056	4,900	4,408
Summer	7	6,296	7/14/2015	4,142	4,016	3,865	3,718	3,629	3,748	3,950	4,120	4,390	4,669	5,044	5,375	5,603	5,816	6,086	6,262	6,296	6,221	6,154	5,899	5,588	5,394	5,104	4,679
Summer	7	5,532	7/15/2015	4,283	3,999	3,789	3,628	3,586	3,620	3,822	4,004	4,244	4,447	4,602	4,808	4,916	5,047	5,238	5,392	5,532	5,494	5,501	5,344	5,191	5,094	4,791	4,422
Summer	7	6,053	7/16/2015	4,048	3,733	3,532	3,456	3,426	3,499	3,688	3,903	4,185	4,466	4,810	5,096	5,337	5,595	5,812	5,974	6,053	6,012	5,958	5,788	5,594	5,416	5,100	4,684
Summer	7	6,476	7/17/2015	4,294	4,002	3,795	3,678	3,592	3,677	3,833	4,098	4,443	4,858	5,316	5,678	5,968	6,240	6,448	6,476	6,468	6,415	6,248	6,097	5,935	5,759	5,405	4,793
Summer	7	6,150	7/18/2015	4,392	4,088	3,865	3,696	3,575	3,593	3,597	3,656	3,988	4,371	4,845	5,232	5,578	5,858	6,026	6,098	6,150	6,105	6,023	5,892	5,717	5,583	5,357	5,040
Summer	7	6,030	7/19/2015	4,683	4,382	4,163	3,938	3,825	3,730	3,734	3,787	4,143	4,553	4,900	5,263	5,613	5,800	5,973	6,030	5,974	5,965	5,865	5,720	5,515	5,431	5,133	4,815
Summer	7	6,172	7/20/2015	4,456	4,173	3,949	3,872	3,873	3,971	4,173	4,477	4,767	5,130	5,400	5,683	5,838	6,058	6,108	6,141	6,108	6,172	6,157	6,047	5,869	5,744	5,375	5,016
Summer	7	6,352	7/21/2015	4,640	4,330	4,089	3,935	3,954	4,004	4,255	4,465	4,773	4,993	5,236	5,591	5,816	6,025	6,240	6,343	6,352	6,293	6,221	5,941	5,689	5,630	5,216	4,800
Summer	7	5,980	7/22/2015	4,364	4,093	3,821	3,719	3,593	3,695	3,880	4,042	4,300	4,550	4,837	5,090	5,362	5,585	5,796	5,958	5,980	5,979	5,889	5,706	5,444	5,268	4,920	4,495
Summer	7	5,858	7/23/2015	4,079	3,815	3,628	3,526	3,495	3,558	3,780	3,959	4,233	4,501	4,805	5,055	5,260	5,490	5,681	5,768	5,833	5,858	5,799	5,593	5,403	5,266	4,962	4,531
Summer	7	6,060	7/24/2015	4,170	3,867	3,659	3,506	3,435	3,528	3,654	3,880	4,197	4,550

Contains Proprietary Material
Do Not Distribute

Summer	8	5,457	8/28/2015	3,502	3,285	3,194	3,116	3,072	3,173	3,545	3,636	3,757	4,076	4,247	4,469	4,645	4,859	5,071	5,264	5,408	5,457	5,365	5,130	4,984	4,741	4,490	4,121
Summer	8	5,472	8/29/2015	3,794	3,532	3,394	3,220	3,168	3,156	3,254	3,296	3,511	3,844	4,252	4,574	4,856	5,100	5,289	5,462	5,458	5,472	5,353	5,117	5,004	4,811	4,439	4,150
Summer	8	5,123	8/30/2015	3,824	3,581	3,415	3,258	3,227	3,191	3,234	3,208	3,481	3,794	4,093	4,333	4,591	4,836	4,967	5,008	5,030	5,123	5,028	4,941	4,875	4,763	4,405	4,058
Summer	8	6,109	8/31/2015	3,803	3,540	3,381	3,294	3,336	3,459	3,854	4,031	4,286	4,553	4,877	5,186	5,494	5,750	5,921	6,057	6,109	6,092	6,054	5,795	5,655	5,402	4,951	4,500
Fall	9	6,204	9/1/2015	4,135	3,863	3,596	3,549	3,478	3,644	3,934	4,115	4,372	4,651	5,022	5,362	5,687	5,890	6,067	6,143	6,204	6,131	6,041	5,953	5,796	5,532	5,087	4,595
Fall	9	6,378	9/2/2015	4,205	3,930	3,720	3,586	3,558	3,656	4,001	4,225	4,455	4,761	5,156	5,515	5,795	6,084	6,224	6,322	6,378	6,364	6,237	6,108	5,960	5,721	5,248	4,764
Fall	9	6,411	9/3/2015	4,441	4,101	3,890	3,693	3,625	3,801	4,115	4,268	4,469	4,841	5,175	5,609	5,994	6,199	6,267	6,350	6,372	6,411	6,320	6,145	6,038	5,693	5,218	4,795
Fall	9	6,461	9/4/2015	4,453	4,094	3,920	3,744	3,724	3,735	4,091	4,291	4,420	4,761	5,212	5,647	5,964	6,247	6,324	6,424	6,461	6,345	6,175	5,981	5,812	5,523	5,053	4,628
Fall	9	5,885	9/5/2015	4,310	3,983	3,716	3,558	3,433	3,414	3,423	3,418	3,567	3,984	4,440	4,816	5,231	5,547	5,730	5,855	5,885	5,867	5,652	5,373	5,236	4,932	4,650	4,242
Fall	9	5,678	9/6/2015	3,902	3,679	3,426	3,355	3,266	3,214	3,268	3,280	3,442	3,866	4,228	4,593	4,976	5,260	5,520	5,582	5,668	5,678	5,523	5,314	5,185	4,942	4,575	4,195
Fall	9	5,795	9/7/2015	3,927	3,652	3,491	3,385	3,337	3,309	3,356	3,327	3,503	3,939	4,366	4,768	5,141	5,393	5,517	5,696	5,795	5,762	5,686	5,466	5,376	5,122	4,773	4,355
Fall	9	6,388	9/8/2015	4,023	3,786	3,628	3,517	3,486	3,639	3,959	4,248	4,498	4,859	5,223	5,592	5,946	6,219	6,310	6,388	6,377	6,372	6,281	6,100	6,029	5,674	5,239	4,799
Fall	9	5,588	9/9/2015	4,450	4,155	3,955	3,853	3,773	3,872	4,255	4,517	4,643	4,849	5,115	5,294	5,377	5,494	5,554	5,588	5,487	5,323	5,231	5,149	5,103	4,950	4,592	4,258
Fall	9	5,658	9/10/2015	3,991	3,725	3,606	3,569	3,525	3,701	4,047	4,308	4,348	4,445	4,653	4,860	5,012	5,204	5,324	5,547	5,634	5,658	5,535	5,327	5,264	5,037	4,592	4,183
Fall	9	5,279	9/11/2015	3,865	3,633	3,376	3,316	3,289	3,411	3,780	3,973	4,122	4,380	4,625	4,894	5,127	5,279	5,278	5,220	5,072	4,800	4,629	4,426	4,425	4,251	3,943	3,695
Fall	9	3,633	9/12/2015	3,402	3,239	3,118	3,026	2,965	2,989	3,082	3,144	3,226	3,378	3,500	3,617	3,593	3,577	3,607	3,561	3,633	3,631	3,539	3,508	3,534	3,418	3,311	3,130
Fall	9	3,652	9/13/2015	2,889	2,810	2,694	2,621	2,609	2,654	2,745	2,757	2,914	3,087	3,186	3,228	3,323	3,369	3,366	3,377	3,452	3,507	3,546	3,551	3,652	3,553	3,310	3,086
Fall	9	4,438	9/14/2015	2,898	2,803	2,765	2,766	2,830	2,958	3,329	3,551	3,679	3,827	3,883	4,027	4,088	4,203	4,266	4,310	4,416	4,438	4,401	4,298	4,338	4,143	3,830	3,518
Fall	9	4,959	9/15/2015	3,289	3,159	3,039	2,923	2,910	3,094	3,439	3,625	3,717	3,856	4,073	4,187	4,292	4,479	4,620	4,754	4,910	4,959	4,920	4,705	4,672	4,450	4,106	3,692
Fall	9	5,235	9/16/2015	3,399	3,203	3,081	2,950	2,986	3,143	3,503	3,644	3,751	3,959	4,194	4,407	4,591	4,781	5,016	5,085	5,220	5,235	5,153	4,884	4,810	4,552	4,130	3,753
Fall	9	5,265	9/17/2015	3,508	3,266	3,127	3,017	3,046	3,173	3,489	3,734	3,816	4,055	4,215	4,340	4,643	4,788	5,007	5,132	5,235	5,265	5,134	4,949	4,915	4,576	4,230	3,866
Fall	9	5,443	9/18/2015	3,556	3,378	3,228	3,116	3,070	3,185	3,577	3,744	3,846	4,085	4,334	4,580	4,855	5,022	5,214	5,377	5,443	5,423	5,318	5,041	5,005	4,767	4,374	4,042
Fall	9	4,517	9/19/2015	3,762	3,548	3,395	3,230	3,150	3,114	3,244	3,319	3,481	3,801	4,041	4,312	4,476	4,509	4,517	4,438	4,387	4,311	4,169	4,089	4,080	3,910	3,676	3,446
Fall	9	3,918	9/20/2015	3,196	2,989	2,836	2,806	2,738	2,740	2,792	2,828	2,942	3,141	3,362	3,461	3,604	3,658	3,680	3,855	3,918	3,902	3,806	3,820	3,904	3,748	3,505	3,228
Fall	9	4,660	9/21/2015	3,032	2,882	2,758	2,735	2,793	3,045	3,406	3,632	3,709	3,854	4,032	4,142	4,291	4,379	4,465	4,581	4,649	4,660	4,642	4,524	4,528	4,254	3,925	3,579
Fall	9	4,898	9/22/2015	3,357	3,217	3,094	2,968	2,960	3,106	3,431	3,673	3,767	3,950	4,091	4,254	4,374	4,532	4,609	4,796	4,830	4,898	4,848	4,660	4,687	4,411	4,004	3,696
Fall	9	5,216	9/23/2015	3,461	3,281	3,145	3,083	3,081	3,174	3,540	3,781	3,838	4,039	4,200	4,337	4,567	4,748	4,942	5,139	5,216	5,213	5,037	4,894	4,765	4,497	4,122	3,776
Fall	9	5,260	9/24/2015	3,484	3,269	3,139	3,046	3,034	3,157	3,499	3,713	3,806	3,988	4,167	4,376	4,627	4,858	5,070	5,196	5,260	5,225	5,079	4,919	4,892	4,608	4,215	3,830
Fall	9	4,317	9/25/2015	3,534	3,325	3,174	3,070	3,020	3,169	3,491	3,740	3,791	3,917	4,066	4,181	4,250	4,310	4,317	4,310	4,247	4,189	4,092	4,065	4,070	3,936	3,726	3,523
Fall	9	3,784	9/26/2015	3,272	3,108	2,958	2,911	2,845	2,848	2,974	3,134	3,253	3,377	3,542	3,602	3,633	3,670	3,699	3,687	3,721	3,752	3,744	3,676	3,784	3,677	3,528	3,319
Fall	9	4,232	9/27/2015	3,130	2,955	2,888	2,764	2,757	2,806	2,775	2,925	3,017	3,241	3,380	3,533	3,669	3,841	3,971	4,096	4,159	4,204	4,148	4,197	4,232	4,082	3,792	3,582
Fall	9	5,257	9/28/2015	3,329	3,170	3,046	3,046	3,080	3,199	3,612	3,870	3,940	4,126	4,366	4,530	4,794	4,992	5,147	5,257	5,223	5,199	5,120	5,115	5,025	4,851	4,489	4,145
Fall	9	4,595	9/29/2015	3,826	3,657	3,526	3,375	3,343	3,543	3,901	4,193	4,299	4,439	4,546	4,540	4,573	4,595	4,587	4,534	4,474	4,538	4,488	4,484	4,534	4,363	4,055	3,733
Fall	9	4,188	9/30/2015	3,573	3,432	3,302	3,159	3,148	3,262	3,634	3,891	3,938	4,072	4,129	4,123	4,188	4,146	4,096	4,057	4,047	3,990	3,992	4,086	4,136	3,945	3,706	3,437
Fall	10	3,986	10/1/2015	3,248	3,071	3,035	2,943	2,965	3,097	3,404	3,678	3,740	3,841	3,909	3,959	3,961	3,968	3,940	3,909	3,880	3,861	3,783	3,913	3,986	3,769	3,654	3,391
Fall	10	3,945	10/2/2015	3,196	3,081	2,988	2,949	2,907	3,066	3,388	3,675	3,758	3,864	3,928	3,900	3,945	3,919	3,879	3,748	3,707	3,758	3,741	3,822	3,801	3,638	3,511	3,317
Fall	10	3,557	10/3/2015	3,157	3,015	2,947	2,903	2,864	2,912	2,970	3,151	3,259	3,439	3,485	3,557	3,542	3,507	3,476	3,431	3,405	3,432	3,427	3,509	3,516	3,413	3,259	3,093
Fall	10	3,857	10/4/2015	2,926	2,800	2,789	2,742	2,677	2,767	2,740	2,856	3,020	3,140	3,154	3,205	3,301	3,273	3,309	3,348	3,506	3,587	3,609	3,700	3,857	3,649	3,445	3,215
Fall	10	4,761	10/5/2015	3,076	2,960	2,859	2,885	2,918	3,042	3,410	3,664	3,736	3,932	4,039	4,197	4,334	4,485	4,597	4,679	4,746	4,761	4,665	4,597	4,531	4,318	4,067	3,723
Fall	10	4,914	10/6/2015	3,463	3,257	3,168	3,100	3,078	3,150	3,461	3,710	3,780	3,978	4,143	4,287	4,432	4,574	4,762	4,893	4,914	4,837	4,758	4,694	4,673	4,382	4,057	3,748
Fall	10	5,005	10/7/2015	3,479	3,262	3,125	3,030	2,994	3,157	3,531	3,729	3,860	3,992	4,135	4,335	4,497	4,715	4,820	4,977	5,005	4,955	4,895	4,768	4,715	4,430	4,093	3,775
Fall	10	5,030	10/8/2015	3,538	3,335	3,211	3,115	3,077	3,212	3,539	3,828	3,908	4,058	4,265	4,395	4,591	4,792	4,872	4,984	5,030	4,930	4,884	4,762	4,708	4,403	4,117	3,818
Fall	10	4,380	10/9/2015	3,496	3,381	3,233	3,149	3,104	3,290	3,552	3,833	3,903	4,097	4,278	4,348	4,380	4,366	4,356	4,228	4,221	4,088	4,034	4,058	3,985	3,832	3,617	3,382
Fall	10	3,538	10/10/2015	3,217	3,068	2,983	2,830	2,867	2,866	2,919	3,043	3,096	3,215	3,327	3,369	3,416	3,428	3,451	3,453	3,538	3,525	3,446	3,499	3,514	3,415	3,177	3,003
Fall	10	3,652	10/11/2015	2,869	2,734	2,694	2,653	2,673	2,653	2,759	2,872	2,971	3,074	3,122	3,195	3,298	3,287	3,336	3,321	3,434	3,572	3,562	3,577	3,652	3,503	3,253	3,070
Fall	10	4,401	10/12/2015	2,923	2,815	2,739	2,709	2,771	2,961	3,420	3,644	3,671	3,816	3,887	3,928	4,053	4,160	4,236	4,279	4,286	4,331	4,281	4,401	4,329	4,122	3,870	3,563
Fall	10	4,144	10/13/2015	3,319	3,145	3,050	2,966	3,001	3,158	3,529	3,810	3,832	3,926	3,967	4,069	4,108	4,144	4,093	4,120	4,072	4,003	3,969	4,095	4,092	3,898	3,636	3,387
Fall	10	4,078	10/14/2015	3,193	3,080	2,983	2,932	2,931	3,117	3,507	3,821	3,768	3,836	3,904	3,989	3,995	4,064	4,078	4,072	4,027	4,004	3,911	4,024	3,973	3,793	3,551	3,334
Fall	10	4,028	10/15/2015	3,175	3,051	2,986	2,928	2,925	3,067	3,531	3,841	3,867	3,864	3,931	3,901	3,948	3,946	4,028	3,980	3,971	3,893	3,872	3,976	3,974	3,836	3,668	3,441
Fall	10	3,924	10/16/2015	3,233	3,118	3,009	2,889	2,910	3,034	3,416	3,644	3,720	3,832	3,899	3,924	3,883	3,891	3,885	3,838	3,795	3,736	3,704	3,752	3,748	3,613	3,515	3,310
Fall	10	3,594	10/17/2015	3,165	3,077	2,988	2,946	2,962	3,049	3,160	3,348	3,510	3,594	3,517	3,498	3,411	3,381	3,310	3,303	3,238	3,287	3,310	3,476	3,532	3,444	3,324	3,241
Fall	10	3,689	10/18/2015	3,102	3,047	3,003	3,056	3,065	3,165	3,295	3,463	3,581	3,627	3,541	3,435	3,390	3,304	3,295	3,234	3,254	3,299	3,410	3,616	3,689	3,605	3,472	3,328
Fall	10	4,370	10/19/2015	3,229	3,126	3,179	3,196	3,313	3,510	4,006	4,356	4,370	4,368	4,245	4,157	4,043	3,974	3,947	3,867	3,848	3,843	3,864	4,040	4,044	3,849	3,674	3,487
Fall	10	4,153	10/20/2015	3,361	3,258	3,176	3,159	3,185	3,361	3,762	4,054	4,077	4,153	4,091	4,083	4,089	4,053	4,034	3,999	3,942	3,954	3,909	4,042	4,015	3,889	3,651	3,454
Fall	10	4,158	10/21/2015	3,284	3,189	3,099	3,092	3,131	3,299	3,715	4,028	4,058	4,021	4,049	3,995	4,021	4,034	4,079	4,056	4,064	4,049	4,012	4,158	4,092	3,981	3,682	3,470
Fall	10	4,349	10/22/2015	3,285	3,094	3,043	2,990	3,021	3,205	3,588	3,867	3,911	3,961	4,041	4,048	4,183	4,177	4,258	4,349	4,316	4,294	4,210	4,336	4,229	4,029	3,744	3,493
Fall	10	4,243	10/23/2015	3,315	3,148	3,032	2,968	2,901	3,068	3,436	3,722	3,815	3,895	4,006	4,076	4,084	4,243	4,143	4,146	4,126	4,055	4,022	4,057	3,977	3,827	3,634	3,417
Fall	10	3,684	10/24/2015	3,247	3,057	2,980	2,870	2,851	2,876	2,996	3,169	3,253	3,412	3,500	3,545	3,524	3,546	3,518	3,520	3,474	3,539	3,616	3,684	3,622	3,457	3,309	3,132
Fall	10	3,562	10/25/2015	2,965	2,817	2,714	2,674	2,628	2,667	2,731	2,870	2,955	3,128	3,209	3,235	3,258	3,236	3,256	3,238	3,269	3,288	3,403	3,562	3,536	3,407	3,245	3,022
Fall	10	4,018	10/26/2015	2,848	2,779	2,722	2,729	2,810	3,082	3,477	3,797	3,818	3,887	3,918	3,951	3,946	3,883	3,868	3,805	3,749	3,815	3,894	4,018	3,968	3,807	3,592	3,362
Fall	10	4,137	10/27/2015	3,188	3,081	2,996	2,939	3,002	3,153	3,563	3,913	3,968	4,036	4,079	4,054	3,995	3,960	3,942	3,937	3,948	3,937	4,069	4,137	4,054	3,889	3,656	3,439
Fall	10	4,031	10/28/2015	3,275	3,148	3,063	3,049	3,024	3,192	3,533	3,830	3,901	3,926	3,977	3,986	3,991	3,964	3,944	3,918	3,851	3,838	3,850	4,031	3,977	3,842	3,606	3,388
Fall	10	3,900	10/29/2015	3,161	3,032	2,927	2,889	2,917	3,102	3,489	3,816	3,841	3,863	3,900	3,866	3,845	3,828	3,794	3,747	3,688	3,626	3,689	3,900	3,899	3,787	3,600	3,435
Fall	10	4,153	10/30/2015	3,371	3,262	3,216	3,190	3,202	3,385	3,841	4,126	4,153	4,145	4,116	4,060	3,957	3,869	3,794	3,754	3,720	3,673	3,703	3,856	3,849	3,730	3,635	3,523
Fall	10	3,611	10/31/2015	3,408	3,285	3,204	3,165	3,124	3,170	3,258	3,373	3,455	3,554	3,611	3,591	3,512	3,434	3,388	3,346	3,325	3,240	3,284	3,432	3,409	3,334	3,208	3,079
Fall	11	3,554	11/1/2015	2,902	2,768	2,722	2,681	2,660	2,705	2,798	2,896	3,086	3,187	3,194	3,182	3,199	3,190	3,183	3,186	3,253	3,392	3,554	3,486	3,508	3,347	3,203	3,029
Fall	11	3,955	11/2/2015	2,909	2,801	2,830	2,855	2,930	3,088	3,501	3,701	3,789	3,898	3,940	3,867	3,857	3,877	3,837	3,800	3,791	3,789	3,955	3,903	3,788	3,614	3,437	3,311
Fall	11	4,194	11/3/2015	3,156	3,045	3,009	2,989	3,000	3,186	3,507	3,725	3,756	3,858	3,917	3,838	3,994	4,053	4,092	4,057	4,063	4,053	4,194	4,106	3,992	3,807	3,555	3,336
Fall	11	4,307	11/4/2015	3,146	3,030	2,933	2,891	2,901	3,117	3,473	3,630	3,722	3,863	3,972	4,020	4,072	4,150	4,191	4,128	4,041	4,136	4,307	4,239	4,121	3,884	3,673	3,385
Fall	11	4,251	11/5/2015	3,220	3,082	2,999	2,945	2,957	3,130	3,492	3,751	3,815	3,956	4,001	4,094	4,155	4,223	4,251	4,202	4,131	4,209	4,247	4,209	4,137	4,003	3,795	3,541
Fall	11	4,091	11/6/2015	3,382	3,221	3,106	3,035	3,014	3,235	3,511	3,739	3,883	3,998	4,091	4,083	4,013	4,029	3,966	3,957	3,843	3,941	3,964	3,770	3,828	3,568	3,430	3,163
Fall	11	3,551	11/7/2015	3,031	2,933	2,796	2,746	2,694	2,771	2,947	3,050	3,204	3,281	3,424	3,329	3,306	3,265	3,234	3,228	3,207	3,377	3,551	3,487	3,496	3,408	3,297	3,138
Fall	11	3,713	11/8/2015	2,999	2,953	2,894	2,865	2,871	3,005	3,122	3,244	3,337	3,382	3,384	3,275	3,278	3,207	3,145	3,128	3,171	3,414	3,675	3,713	3,698	3,586	3,480	3,297
Fall	11	4,194	11/9/2015	3,204	3,175	3,160	3,193	3,241	3,441	3,837	4,107	4,120	4,179	4,139	4,137	4,107	4,023	3,976	3,963	3,907	4,063	4,194	4,113	4,029	3,872	3,636	3,442
Fall	11	4,097	11/10/2015	3,270	3,183	3,104	3,068	3,149	3,298	3,683	3,890	3,965	4,033	4,001	4,005	3,944	3,891	3,835	3,803	3,770	3,852	4,077	4,097	4,049	3,952	3,758	3,582
Fall	11	4,235	11/11/2015	3,482	3,381	3,363	3,341	3,419	3,592	4,046	4,235	4,214	4,166	4,066	3,987	3,922	3,839	3,832	3,828	3,778	3,922	4,127	4,042	3,973	3,817	3,604	3,421
Fall	11	3,987	11/12/2015	3,229	3,114	3,017	2,967	2,992	3,134	3,556	3,705	3,760	3,828	3,890	3,845	3,845	3,766	3,768	3,756	3,710	3,803	3,987	3,983	3,938	3,862	3,651	3,419
Fall	11	4,073	11/13/2015	3,302	3,234	3,171	3,176	3,204	3,427	3,863	4,073	4,068	4,002	4,008	3,951	3,900	3,850	3,793	3,723	3,684	3,826	4,043	3,985	3,948	3,854	3,750	3,621
Fall	11	3,945	11/14/2015	3,516	3,442	3,413	3,433	3,467	3,543	3,727	3,893	3,945	3,848	3,734	3,620	3,473	3,406	3,296	3,259	3,289	3,448	3,646	3,664	3,701	3,654	3,546	3,363
Fall	11	3,650	11/15/2015	3,273	3,270	3,229	3,190	3,325	3,373	3,523	3,607	3,650	3,555	3,435	3,350	3,314	3,241	3,224	3,213	3,262	3,425	3,648	3,645	3,594	3,539	3,482	3,326
Fall	11	4,320	11/16/2015	3,236	3,143	3,143	3,146	3,284	3,567	4,068	4,302	4,320	4,282	4,215	4,136	4,075	4,045	3,998	3,993	3,972	4,123	4,231	4,133	4,094	3,960	3,728	3,547
Fall	11	4,081	11/17/2015	3,356	3,262	3,160	3,135	3,171	3,361	3,753	4,002	4,026	4,059	4,081	4,037	4,024	3,992	3,909	3,844	3,815	4,021	4,076	4,072	3,937	3,830	3,610	3,369
Fall	11	4,124	11/18/2015	3,174	3,074	2,992	2,947	2,975	3,129	3,534	3,800	3,847	3,926	3,963	3,956	3,991	3,995	3,962	3,868	3,894	4,030	4,124	4,018	3,965	3,771	3,514	3,349
Fall	11	4,002	11/19/2015	3,172	3,043	2,938	2,960	2,995	3,213	3,682	3,889	3,878	3,858	3,868	3,858	3,810	3,786	3,771	3,723	3,755	3,745	4,001	4,002	3,999	3,927	3,733	3,536
Fall	11	4,520	11/20/2015	3,457	3,461	3,431	3,426	3,522	3,825	4,257	4,520	4,499	4,332	4,191	4,078	4,018	3,893	3,833	3,768	3,785	3,962	4,161	4,147	4,121	4,045	3,921	3,772
Fall	11	3,996	11/21/2015	3,628	3,520	3,493	3,399	3,404	3,532	3,717	3,820	3,879	3,825	3,740	3,617	3,597	3,555	3,535	3,630	3,777	3,930	3,995	3,996	3,960	3,909	3,820	3,657
Fall	11	4,483	11/22/2015	3,534	3,464	3,460	3,422	3,475	3,602	3,712	3,843	4,028	4,103	4,085	3,996	3,944	3,895	3,819	3,796	3,806	4,108	4,407	4,463	4,483	4,381	4,259	4,155
Fall	11	5,190	11/23/2015	4,098	4,050	4,040	4,140	4,201	4,486	4,851	5,190	5,080	4,894	4,706	4,546	4,366	4,292	4,170	4,104	4,062	4,356	4,535	4,591	4,575	4,417	4,336	4,118
Fall	11	4,803	11/24/2015	4,003	3,932	3,915	3,918	4,006	4,195	4,616	4,803	4,741	4,574	4,384	4,237	4,141	4,031	3,969	3,913	3,873	4,036	4,211	4,224	4,173	4,101	3,920	3,779
Fall	11	4,412	11/25/2015	3,621	3,539	3,566	3,564	3,563	3,800	4,087	4,281	4,412	4,319	4,219	4,063	4,018	3,896	3,811	3,735	3,717	3,817	3,975	3,971	3,928	3,765	3,649	3,396
Fall	11	3,348	11/26/2015	3,166	3,120	2,979	2,935	2,946	2,975	3,071	3,128	3,303	3,348	3,342	3,337	3,218	2,999	2,908	2,852	2,778	2,821	2,968	2,941	2,976	2,903	2,862	2,803
Fall	11	3,384	11/27/2015	2,661	2,645	2,594	2,640	2,628	2,746	2,857	3,013	3,007	3,163	3,203	3,193	3,157	3,103	3,064	3,055	3,062	3,235	3,384	3,341	3,265	3,189	3,115	2,920
Fall	11	3,557	11/28/2015	2,814	2,706	2,658	2,617	2,600	2,680	2,762	2,903	3,063	3,186	3,320	3,285	3,326	3,290	3,251	3,234	3,329	3,471	3,557	3,466	3,402	3,328	3,188	3,026
Fall	11	3,869	11/29/2015	2,865	2,811	2,770	2,736	2,766	2,848	2,961	3,060	3,224	3,377

Contains Proprietary Material
Do Not Distribute

Winter	12	18,383	12/23/2014	14,663	14,262	14,073	13,933	14,242	15,168	16,313	16,749	17,072	17,330	17,421	17,431	17,381	17,306	17,298	17,266	17,980	18,383	18,196	17,889	17,367	16,563	15,572	14,554
Winter	12	17,105	12/24/2014	13,767	13,279	12,909	12,731	12,935	13,503	14,321	14,942	15,503	16,095	16,336	16,337	16,176	16,063	15,967	16,024	16,596	17,105	16,880	16,776	16,654	16,412	15,820	15,192
Winter	12	16,909	12/25/2014	14,707	14,300	14,122	14,253	14,502	15,035	15,807	16,464	16,800	16,672	16,359	15,681	14,735	14,051	13,573	13,529	14,336	15,814	16,252	16,677	16,909	16,829	16,545	16,197
Winter	12	19,181	12/26/2014	16,024	16,097	16,272	16,481	17,050	17,944	18,879	19,181	18,920	18,120	17,478	16,754	16,177	15,789	15,545	15,661	16,537	17,727	17,833	17,769	17,524	17,012	16,254	15,419
Winter	12	16,966	12/27/2014	14,835	14,473	14,288	14,217	14,450	14,866	15,416	15,754	16,226	16,568	16,587	16,418	16,045	15,628	15,524	15,662	16,384	16,966	16,833	16,692	16,366	15,762	14,986	14,185
Winter	12	18,392	12/28/2014	13,647	13,257	13,136	13,103	13,300	13,647	14,370	15,226	15,959	16,387	16,373	16,355	16,442	16,507	16,401	16,663	17,614	18,369	18,392	18,214	17,786	17,182	16,210	15,535
Winter	12	20,459	12/29/2014	15,091	14,810	14,734	14,810	15,211	16,265	17,478	17,900	18,257	18,602	18,869	18,877	18,799	18,748	18,681	18,797	19,541	20,459	20,363	20,089	19,635	18,886	17,931	17,050
Winter	12	21,550	12/30/2014	16,628	16,502	16,482	16,601	16,987	18,134	19,403	19,884	20,113	20,121	19,789	19,371	18,903	18,579	18,316	18,369	19,376	21,070	21,526	21,550	21,340	20,908	20,212	19,527
Winter	12	21,954	12/31/2014	19,235	19,098	19,052	19,092	19,500	20,400	21,555	21,954	21,903	21,472	20,864	20,331	19,718	19,178	18,692	18,710	19,653	21,335	21,517	21,325	21,043	20,645	20,260	19,813
Winter	1	20,120	1/1/2015	19,644	19,554	19,552	19,529	19,685	19,896	20,120	20,078	19,953	19,839	19,585	19,115	18,708	18,387	18,168	18,314	19,011	19,663	19,518	19,108	18,759	18,092	17,342	16,596
Winter	1	19,476	1/2/2015	16,086	15,748	15,623	15,626	15,932	16,748	17,626	18,258	18,583	18,815	19,112	19,011	18,790	18,605	18,391	18,395	18,780	19,476	19,353	18,945	18,482	17,763	16,853	15,974
Winter	1	16,774	1/3/2015	15,323	14,821	14,537	14,444	14,471	14,763	15,142	15,527	15,925	16,173	16,295	16,122	15,869	15,709	15,593	15,693	16,251	16,774	16,564	16,116	15,711	15,087	14,216	13,488
Winter	1	19,314	1/4/2015	12,886	12,515	12,380	12,348	12,459	12,919	13,521	14,319	15,118	15,389	15,367	15,563	15,797	15,974	16,150	16,545	17,528	18,849	19,097	19,314	19,228	18,881	18,274	17,882
Winter	1	23,995	1/5/2015	17,811	17,896	18,144	18,641	19,633	21,475	23,357	23,769	23,361	22,742	22,075	21,431	20,821	20,307	19,779	19,877	21,075	23,123	23,846	23,995	23,855	23,137	22,191	21,506
Winter	1	24,561	1/6/2015	21,162	21,078	21,022	21,019	21,688	23,201	24,561	24,030	22,788	21,758	20,942	20,178	19,683	19,307	18,945	19,177	20,279	21,920	22,696	22,817	22,676	22,050	21,160	20,555
Winter	1	31,334	1/7/2015	20,293	20,245	20,150	20,340	20,938	22,472	24,078	24,321	24,284	24,425	24,660	24,812	24,952	25,222	25,461	26,193	27,909	30,145	30,983	31,334	31,073	30,498	29,844	29,274
Winter	1	32,751	1/8/2015	29,045	29,098	29,337	29,704	30,248	31,332	32,751	32,747	31,453	29,912	28,453	26,919	25,416	24,926	24,121	24,219	25,246	26,903	27,369	27,254	26,806	25,754	24,527	23,584
Winter	1	26,542	1/9/2015	23,116	22,993	23,029	23,285	23,728	25,150	26,542	26,343	25,534	24,567	23,608	22,560	21,833	21,224	20,947	21,166	22,310	24,225	24,748	24,776	24,917	24,811	24,370	23,946
Winter	1	28,007	1/10/2015	23,904	24,137	24,518	25,027	25,660	26,545	27,544	28,007	27,163	25,727	24,309	22,798	21,363	20,450	19,708	19,700	20,831	22,940	23,506	23,818	23,646	23,435	22,782	22,008
Winter	1	21,909	1/11/2015	21,433	21,091	20,745	20,606	20,617	20,909	21,426	21,895	21,909	21,253	20,499	20,007	19,936	19,587	19,361	19,357	19,979	20,977	20,965	20,640	20,071	19,235	18,132	17,276
Winter	1	21,805	1/12/2015	16,793	16,444	16,410	16,512	16,945	18,433	20,038	20,321	19,993	20,027	20,177	19,954	20,017	19,941	19,794	19,894	20,665	21,753	21,805	21,599	21,093	20,357	19,311	18,458
Winter	1	24,397	1/13/2015	18,132	18,035	18,119	18,464	19,144	20,812	22,476	22,742	22,621	22,794	22,878	22,886	22,687	22,585	22,409	22,747	23,456	24,397	24,379	24,060	23,551	22,665	21,381	20,588
Winter	1	23,859	1/14/2015	20,083	19,954	19,881	19,929	20,459	21,957	23,495	23,557	23,216	23,010	22,753	22,225	21,713	21,051	20,616	20,767	21,582	23,258	23,796	23,859	23,693	23,041	22,019	21,431
Winter	1	24,506	1/15/2015	21,184	21,149	21,171	21,215	21,757	23,111	24,506	24,450	23,913	23,503	23,170	22,769	22,424	21,948	21,660	21,748	22,314	23,357	23,716	23,563	23,343	22,578	21,613	20,905
Winter	1	25,153	1/16/2015	20,710	20,752	20,854	21,130	21,883	23,517	25,153	25,098	23,855	22,223	20,944	19,635	18,596	17,937	17,489	17,306	17,991	19,675	20,307	20,526	20,675	20,505	20,165	19,748
Winter	1	22,167	1/17/2015	19,549	19,405	19,521	19,803	20,366	21,003	21,782	22,167	21,581	20,197	18,951	17,917	16,981	16,193	15,697	15,620	16,164	17,764	18,211	18,245	18,066	17,630	17,040	16,386
Winter	1	18,047	1/18/2015	15,779	15,572	15,453	15,400	15,688	16,294	17,033	17,698	17,952	17,384	16,662	16,112	15,804	15,523	15,140	15,166	15,813	17,259	17,945	18,021	18,047	17,857	17,240	16,869
Winter	1	20,586	1/19/2015	16,736	16,771	17,022	17,322	17,946	19,097	20,227	20,586	19,932	18,962	18,283	17,656	17,142	16,640	16,325	16,272	16,679	18,262	18,794	18,813	18,530	17,815	16,862	16,190
Winter	1	20,528	1/20/2015	15,867	15,879	15,854	16,061	16,902	18,760	20,528	20,432	19,395	18,353	17,580	17,026	16,743	16,448	16,258	16,424	16,986	18,313	18,655	18,605	18,259	17,571	16,534	15,886
Winter	1	20,570	1/21/2015	15,694	15,651	15,639	16,138	16,981	18,684	20,570	20,569	19,566	18,380	17,612	16,982	16,685	16,437	16,242	16,242	17,031	18,675	19,386	19,514	19,581	19,117	18,230	17,646
Winter	1	21,778	1/22/2015	17,480	17,483	17,590	17,755	18,428	20,064	21,778	21,606	21,084	20,413	20,118	19,732	19,450	19,191	19,129	19,249	19,985	21,108	21,462	21,358	20,874	20,037	18,902	18,153
Winter	1	21,721	1/23/2015	17,639	17,394	17,328	17,357	17,947	19,583	21,031	21,315	21,260	21,242	21,237	21,046	20,955	20,771	20,718	20,593	21,067	21,721	21,586	21,158	20,820	20,228	19,365	18,590
Winter	1	21,629	1/24/2015	18,148	18,082	18,101	18,292	18,775	19,602	20,551	21,158	21,629	21,278	20,667	19,650	18,621	17,750	17,182	17,039	17,629	19,145	19,797	19,779	19,648	19,371	18,823	18,263
Winter	1	20,096	1/25/2015	17,965	17,946	17,915	18,100	18,428	18,923	19,625	20,096	19,856	18,902	17,735	17,000	16,529	16,304	16,285	16,546	17,326	18,435	18,764	18,709	18,361	17,759	16,903	16,274
Winter	1	23,222	1/26/2015	15,958	15,831	16,078	16,361	17,354	19,203	21,139	21,548	21,610	21,804	21,982	21,914	21,702	21,581	21,193	21,160	21,594	22,832	23,222	22,965	22,459	21,482	20,286	19,467
Winter	1	22,793	1/27/2015	19,039	18,814	18,806	18,816	19,555	21,211	22,793	22,709	22,123	21,434	20,932	20,638	20,427	20,172	20,001	20,104	20,579	21,804	22,413	22,383	21,955	21,169	20,146	19,429
Winter	1	23,918	1/28/2015	19,023	18,873	19,054	19,542	20,429	22,115	23,918	23,697	22,275	21,087	20,194	19,276	18,492	17,927	17,400	17,543	18,170	19,903	20,743	20,913	20,737	20,058	19,083	18,418
Winter	1	21,130	1/29/2015	18,003	17,794	17,656	17,788	18,340	19,733	21,130	20,909	20,225	19,721	19,112	18,301	17,653	17,241	16,894	17,009	17,589	18,927	19,425	19,524	19,263	18,564	17,675	16,993
Winter	1	21,482	1/30/2015	16,807	16,728	16,843	17,067	17,790	19,472	21,297	21,482	21,201	20,660	19,944	19,297	18,625	18,146	17,658	17,640	18,187	19,869	20,677	20,931	20,995	20,773	20,232	19,752
Winter	1	22,281	1/31/2015	19,804	19,848	20,011	20,297	20,640	21,258	21,843	22,281	22,193	21,598	20,421	19,224	18,379	17,684	17,488	17,430	18,051	19,023	19,255	19,165	18,904	18,369	17,635	16,880
Winter	2	18,412	2/1/2015	16,396	16,117	15,942	15,915	15,877	16,367	17,004	17,665	18,315	18,412	18,202	18,033	17,986	17,792	17,549	17,607	17,904	18,171	17,850	17,517	17,124	16,650	16,039	15,402
Winter	2	24,728	2/2/2015	15,158	15,190	15,444	15,935	17,208	19,415	21,677	22,370	22,769	23,113	23,431	23,308	22,903	22,378	22,021	22,175	22,747	24,105	24,728	24,692	24,354	23,603	22,588	21,948
Winter	2	26,710	2/3/2015	21,619	21,752	22,011	22,415	23,169	24,974	26,710	26,340	24,854	23,203	22,019	20,980	19,925	19,155	18,543	18,452	19,082	20,787	22,108	22,507	22,409	21,769	20,868	20,297
Winter	2	24,390	2/4/2015	20,060	20,058	20,198	20,522	21,091	22,777	24,390	24,019	22,672	21,059	19,938	19,046	18,462	17,954	17,749	17,946	18,636	19,931	20,679	20,657	20,451	19,746	18,884	18,145
Winter	2	24,058	2/5/2015	17,850	17,833	18,088	18,524	19,319	21,187	23,262	23,636	23,262	22,672	21,970	21,204	20,650	20,124	19,668	19,692	20,410	22,387	23,686	24,042	24,058	23,497	22,751	22,405
Winter	2	27,603	2/6/2015	22,415	22,601	22,970	23,489	24,342	26,065	27,603	27,109	25,347	23,467	21,946	20,493	19,306	18,549	17,888	17,670	18,005	19,447	20,485	20,671	20,619	20,153	19,583	19,123
Winter	2	20,969	2/7/2015	18,726	18,671	18,743	18,964	19,375	20,019	20,707	20,969	20,308	19,228	18,109	17,188	16,346	15,633	15,151	14,952	15,187	16,288	17,134	17,100	16,992	16,576	15,989	15,410
Winter	2	16,970	2/8/2015	14,933	14,761	14,693	14,860	14,891	15,368	15,921	16,419	16,773	16,621	16,044	15,609	15,474	15,227	15,127	15,155	15,552	16,510	16,970	16,777	16,190	15,487	14,576	13,702
Winter	2	20,915	2/9/2015	13,257	13,111	13,061	13,138	13,823	15,420	17,132	17,396	17,393	17,456	17,655	17,815	17,855	17,885	17,931	18,194	18,946	20,291	20,889	20,915	20,638	19,870	18,965	18,212
Winter	2	22,472	2/10/2015	17,919	17,917	18,019	18,172	18,919	20,649	22,406	22,472	22,309	21,872	21,429	20,709	20,037	19,264	18,636	18,495	18,945	20,521	21,734	21,900	21,845	21,201	20,300	19,669
Winter	2	24,311	2/11/2015	19,570	19,730	20,036	20,348	21,163	22,758	24,311	23,885	22,536	21,002	19,616	18,501	17,844	17,218	16,732	16,609	17,046	18,483	19,649	19,733	19,881	19,355	18,462	17,704
Winter	2	25,279	2/12/2015	17,400	17,273	17,426	17,731	18,510	20,343	22,134	22,294	22,132	22,041	22,171	22,083	21,857	21,458	20,977	21,041	21,798	23,596	24,987	25,279	25,151	24,557	23,652	22,921
Winter	2	26,488	2/13/2015	22,585	22,584	22,585	22,702	23,299	24,913	26,488	26,254	25,288	24,131	22,946	21,813	20,865	20,237	19,745	19,782	20,205	21,576	22,593	22,782	22,680	22,358	21,860	21,291
Winter	2	22,071	2/14/2015	21,028	20,838	20,725	20,759	21,030	21,513	21,982	22,071	21,686	20,944	20,040	18,962	18,265	17,805	17,523	17,682	18,217	19,154	20,211	20,490	20,870	21,215	21,388	21,578
Winter	2	26,623	2/15/2015	22,044	22,556	23,096	23,692	24,418	25,268	26,074	26,623	26,537	25,684	24,535	23,564	22,835	22,197	21,864	22,035	22,743	24,021	24,740	24,481	24,003	23,375	22,635	21,905
Winter	2	25,507	2/16/2015	21,531	21,316	21,206	21,328	21,801	22,773	23,674	24,024	24,457	24,780	25,017	25,099	25,113	24,774	24,476	24,396	24,568	25,407	25,507	24,987	24,360	23,818	23,235	22,777
Winter	2	26,413	2/17/2015	22,828	22,827	23,001	23,284	23,861	24,949	26,042	26,413	26,396	26,009	25,472	24,869	24,105	23,385	22,907	22,865	23,470	24,842	25,909	25,915	25,716	25,198	24,486	24,030
Winter	2	28,354	2/18/2015	23,849	23,846	23,888	23,991	24,259	25,137	26,132	26,409	26,300	25,804	25,412	25,063	24,614	24,351	24,305	24,587	25,329	26,787	28,095	28,354	28,289	28,052	27,619	27,412
Winter	2	32,164	2/19/2015	27,487	27,882	28,371	28,857	29,763	31,175	32,164	31,921	31,069	30,169	29,301	28,206	27,377	26,661	26,110	25,973	26,494	28,270	29,636	29,968	30,085	29,674	28,933	28,283
Winter	2	30,159	2/20/2015	28,129	28,172	28,157	28,326	28,643	29,582	30,159	30,080	29,591	28,852	27,831	26,989	26,364	26,056	25,915	25,931	26,198	27,069	27,257	26,710	25,980	25,033	23,895	22,881
Winter	2	22,960	2/21/2015	22,313	22,170	21,829	21,715	21,687	21,747	22,004	22,224	22,678	22,960	22,861	22,642	22,094	21,493	21,131	20,999	21,043	21,369	21,652	21,279	20,789	20,182	19,422	18,774
Winter	2	22,140	2/22/2015	18,363	18,059	18,024	18,172	18,459	18,872	19,488	20,160	20,768	20,834	20,515	20,165	19,791	19,523	19,395	19,602	20,281	21,379	22,140	22,097	21,821	21,342	20,675	20,126
Winter	2	26,075	2/23/2015	19,961	20,112	20,328	20,773	21,638	23,184	24,595	25,085	25,140	24,795	24,180	23,536	23,016	22,943	23,038	23,211	23,735	24,999	26,075	26,034	25,730	24,963	23,852	23,044
Winter	2	25,894	2/24/2015	22,588	22,428	22,556	22,919	23,502	24,620	25,838	25,894	25,547	25,108	24,605	23,930	23,303	22,682	22,354	22,017	22,223	23,254	24,755	24,959	24,806	24,422	23,665	23,026
Winter	2	26,595	2/25/2015	22,896	22,957	23,111	23,411	24,117	25,460	26,595	26,391	25,302	24,180	23,437	22,815	22,459	22,411	22,295	22,507	22,983	23,714	24,361	23,812	23,324	22,602	21,670	20,909
Winter	2	23,883	2/26/2015	20,519	20,292	20,283	20,483	21,001	21,955	22,874	23,208	22,755	22,288	21,824	21,463	21,044	20,777	20,504	20,757	21,476	22,612	23,676	23,883	23,702	23,125	22,435	21,750
Winter	2	26,135	2/27/2015	21,530	21,491	21,736	22,116	22,894	24,501	25,974	26,135	25,544	24,706	23,676	22,859	21,991	21,197	20,615	20,476	21,014	22,464	23,874	24,169	24,005	23,878	23,145	22,428
Winter	2	23,540	2/28/2015	22,160	21,900	21,782	21,718	22,025	22,627	23,205	23,540	23,526	22,819	21,770	20,503	19,215	18,133	17,539	17,267	17,519	18,624	19,613	19,650	19,483	18,996	18,349	17,734
Spring	3	18,928	3/1/2015	17,168	16,890	16,784	16,851	16,910	17,237	17,758	18,239	18,789	18,627	18,110	17,691	17,510	17,263	17,171	17,264	17,598	18,266	18,911	18,928	18,526	17,896	17,094	16,354
Spring	3	21,084	3/2/2015	16,070	15,883	16,025	16,411	17,222	18,943	20,739	21,084	20,942	20,641	20,306	19,744	19,226	18,660	18,150	18,022	18,415	19,557	20,673	20,680	20,196	19,438	18,456	17,386
Spring	3	19,561	3/3/2015	16,776	16,471	16,355	16,300	16,864	18,288	19,561	19,515	19,128	18,828	18,668	18,373	17,823	17,713	17,488	17,389	17,746	18,405	18,992	18,735	18,157	17,146	15,782	14,819
Spring	3	20,260	3/4/2015	14,290	13,977	13,735	13,620	14,164	15,559	16,929	17,006	16,935	16,999	17,144	17,140	17,310	17,520	17,606	18,015	18,579	19,640	20,260	20,194	19,949	19,370	18,710	18,264
Spring	3	25,938	3/5/2015	18,162	18,310	18,663	19,122	19,920	21,170	22,202	22,709	23,342	23,694	24,002	24,047	24,003	23,849	23,574	23,487	23,727	24,634	25,909	25,938	25,656	25,244	24,590	24,216
Spring	3	27,804	3/6/2015	24,158	24,301	24,612	25,011	25,739	27,140	27,804	27,519	26,238	25,025	23,903	22,842	21,849	20,920	20,092	19,697	19,695	20,758	22,502	22,948	23,093	22,904	22,524	21,966
Spring	3	23,893	3/7/2015	21,880	21,902	22,029	22,312	22,810	23,526	23,893	23,318	22,134	20,824	19,624	18,478	17,406	16,567	16,060	15,733	15,788	16,564	18,073	18,306	18,434	18,259	17,826	17,419
Spring	3	20,150	3/8/2015	17,352	0	19,275	17,715	18,074	18,663	19,599	20,150	19,810	18,450	17,157	16,256	15,680	15,233	14,829	14,877	15,103	15,509	16,269	17,317	17,144	16,712	15,813	14,989
Spring	3	18,491	3/9/2015	14,516	14,381	14,311	14,504	15,050	16,539	18,202	18,491	18,323	18,140	18,040	17,812	17,270	16,928	16,582	16,577	16,719	16,988	17,741	18,435	18,132	17,365	16,328	15,224
Spring	3	17,908	3/10/2015	14,589	14,230	14,202	14,243	14,617	15,848	17,349	17,626	17,264	17,249	17,317	17,308	17,122	16,888	16,600	16,565	16,631	16,866	17,366	17,908	17,394	16,634	15,466	14,452
Spring	3	17,435	3/11/2015	13,728	13,270	13,106	13,070	13,385	14,644	16,248	16,546	16,440	16,497	16,664	16,693	16,594	16,521	16,263	16,208	16,242	16,408	16,778	17,435	17,246	16,643	15,582	14,603
Spring	3	17,485	3/12/2015	14,066	13,717	13,628	13,702	14,254	15,692	17,314	17,485	17,195	16,956	16,777	16,500	16,273	16,117	15,894	15,915	15,849	16,013	16,402	17,098	16,936	16,173	15,081	14,046
Spring	3	17,364	3/13/2015	13,411	13,043	12,744	12,695	13,062	14,369	15,944	16,319	16,360	16,603	16,878	16,825	16,841	16,771	16,655	16,468	16,482	16,669	17,027	17,364	17,027	16,500	15,538	14,606
Spring	3	16,302	3/14/2015	14,036	13,550	13,364	13,267	13,348	13,895	14,400	14,939	15,679	16,221	16,302	16,132	15,765	15,435	15,124	15,039	14,968	15,043	15,346	15,941	15,582	15,091	14,353	13,518
Spring	3	15,747	3/15/2015	12,957	12,665	12,529	12,492	12,767	13,367	14,021	14,766	15,187	14,983	14,412	14,172	14,066	13,756	13,698	13,849	14,046	14,192	14,545	15,747	15,739	15,120	14,092	13,158
Spring	3	17,792	3/16/2015	12,815	12,627	12,865	13,177	13,965	15,725	17,580	17,792	17,252	16,669	16,312	16,169	16,049	15,981	15,998	16,044	16,096	16,092	16,260	17,156	16,954	15,990	14,651	13,532
Spring	3	16,913	3/17/2015	12,831	12,469	12,257	12,303	12,868	14,222	15,749	15,890	15,721	15,560	15,607	15,802	15,920	15,940	15,974	15,914	15,907	15,899	15,992	16,913	16,773	15,897	14,669	13,614
Spring	3	17,794	3/18/2015	13,054	12,785	12,580	12,743	13,477	14,978	16,736	17,082	17,122	17,153	17,081	16,943	16,707	16,326	15,978	16,048	16,239	16,558	17,046	17,794	17,581	16,900	15,699	14,696
Spring	3	17,956	3/19/2015	14,096	13,902	13,757	13,754	14,371	15,768	17,435	17,676	17,654	17,668	17,859	17,571	17,406	17,273	17,009	16,930	16,918	17,019	17,345	17,956	17,707	17,006	15,871	14,945
Spring	3	17,048	3/20/2015	14,333	13,976	13,763	13,655	14,104	15,331	16,833	16,960	16,914	16,907	17,048	17,041	16,738	16,573	16,367	16,156	16,170	16,225	16,398	16,948	16,692	16,145	15,368	14,534
Spring	3	15,992	3/21/2015	13,995	13,526	13,466	13,422	13,731	14,348	15,119	15,607	15,992	15,915	15,559	15,125	14,686	14,380	14,168	14,076	14,188	14,362	14,745	15,555	15,354	14,850	14,118	13,338
Spring	3	16,165	3/22/2015	12,762	12,513	12,344	12,379	12,548	12,889	13,610	14,201	14,994	15,041	14,635	14,492	14,533	14,391	14,190	14,312	14,535	14,839	15,363	16,165	15,989	15,268	14,355	13,569
Spring	3	17,267	3/23/2015	13,099	12,972	12,901	13,145	13,796	15,512	17,112	17,267	16,820	16,413	16,263	15,984	15,916	15,822	15,689	15,719	15,749	15,867	16,017	16,969	16,749	15,763	14,663	13,538
Spring	3	17,131	3/24/2015	13,037	12,760	12,580	12,755	13,416	14,971	16,620	16,692	16,378	16,119	16,010	15,831	15,776	15,902	15,941	16,095	16,160	16,155	16,304	17,131	17,006	16,059	14,812	13,612
Spring	3	17,428	3/25/2015	13,029	12,624	12,424	12,379	12,680	14,005	15,461	15,533	15,553	15,630	15,887	16,063	16,115	16,377	16,487	16,573	16,795	16,758	16,680	17,428	17,303	16,431	15,075	13,845
Spring	3	17,586	3/26/2015	13,108	12,581	12,366	12,255	12,565	13,781	15,220	15,272	15,446	15,665

Contains Proprietary Material
Do Not Distribute

Spring	4	16,645	4/30/2015	12,830	12,427	12,267	12,479	13,124	14,491	15,745	15,924	15,815	15,916	15,947	15,741	15,808	15,964	15,936	15,975	16,008	15,946	15,860	16,143	16,645	15,929	14,576	13,683
Spring	5	16,216	5/1/2015	13,108	12,797	12,698	12,916	13,476	14,912	16,050	16,216	15,963	15,878	15,855	15,666	15,319	15,266	15,303	15,455	15,575	15,479	15,232	15,300	15,858	15,319	14,500	13,551
Spring	5	15,733	5/2/2015	12,840	12,490	12,342	12,376	12,691	13,131	13,433	14,065	14,470	14,609	14,547	14,565	14,534	14,960	15,143	15,495	15,712	15,733	15,591	15,462	15,548	14,858	13,879	12,808
Spring	5	16,884	5/3/2015	12,141	11,694	11,435	11,397	11,547	11,830	12,057	12,968	13,642	13,853	14,074	14,293	14,801	15,276	15,787	16,248	16,679	16,884	16,588	16,579	16,777	15,963	14,551	13,259
Spring	5	19,683	5/4/2015	12,497	11,930	11,821	11,873	12,392	13,697	14,812	15,427	15,815	16,379	17,102	17,591	18,119	18,609	18,998	19,431	19,683	19,682	19,393	18,854	19,102	17,830	15,962	14,478
Spring	5	20,451	5/5/2015	13,562	12,919	12,607	12,452	12,814	13,964	14,977	15,617	16,079	16,689	17,409	18,108	18,739	19,370	19,828	20,205	20,451	20,446	19,946	19,505	19,548	18,292	16,431	14,851
Spring	5	21,328	5/6/2015	13,773	13,100	12,807	12,694	13,002	14,128	15,224	15,782	16,411	17,042	17,786	18,557	19,289	19,944	20,564	21,009	21,328	21,218	20,631	19,889	19,780	18,523	16,696	15,011
Spring	5	21,940	5/7/2015	14,009	13,243	12,786	12,702	13,056	14,224	15,218	15,887	16,516	17,352	18,362	19,162	19,981	20,669	21,163	21,640	21,940	21,774	21,249	20,605	20,410	19,064	17,145	15,435
Spring	5	21,916	5/8/2015	14,299	13,616	13,209	13,115	13,457	14,513	15,544	16,280	17,119	18,149	19,201	19,995	20,547	21,342	21,589	21,916	21,907	21,445	20,702	19,895	19,821	18,647	17,048	15,633
Spring	5	20,790	5/9/2015	14,422	13,622	13,195	12,886	12,838	13,086	13,352	14,416	15,652	16,713	17,645	18,338	18,991	19,696	20,119	20,544	20,790	20,502	19,888	19,414	19,212	18,099	16,694	15,277
Spring	5	21,859	5/10/2015	14,103	13,242	12,923	12,644	12,419	12,476	12,772	13,951	15,317	16,570	17,696	18,762	19,784	20,567	21,179	21,654	21,859	21,651	21,064	20,731	20,591	19,281	17,527	15,797
Spring	5	22,070	5/11/2015	14,716	14,168	13,756	13,632	14,001	15,087	16,292	17,117	17,986	19,105	20,131	20,958	21,618	22,008	21,991	22,070	22,050	21,609	21,093	20,633	20,849	19,541	17,590	15,805
Spring	5	20,076	5/12/2015	14,704	13,998	13,650	13,528	13,802	14,938	16,023	16,703	17,374	17,973	18,463	18,801	19,128	19,483	19,834	20,076	19,930	19,360	18,663	18,368	18,494	17,407	15,654	14,317
Spring	5	19,600	5/13/2015	13,478	12,978	12,662	12,569	13,020	13,970	14,894	15,453	15,648	16,081	16,482	16,846	17,380	17,914	18,581	19,074	19,560	19,600	19,083	18,417	18,611	17,551	15,916	14,508
Spring	5	19,328	5/14/2015	13,539	12,985	12,717	12,631	12,883	14,135	15,385	15,736	16,093	16,498	16,984	17,560	18,011	18,615	19,047	19,278	19,328	19,038	18,803	18,719	19,071	18,109	16,601	15,098
Spring	5	20,966	5/15/2015	14,278	13,710	13,286	13,067	13,433	14,549	15,631	16,487	17,282	18,159	18,913	19,531	20,291	20,878	20,881	20,966	20,919	20,429	19,540	19,054	19,210	18,351	16,857	15,542
Spring	5	18,860	5/16/2015	14,501	13,811	13,382	13,120	13,145	13,290	13,743	14,718	15,943	16,645	17,307	17,662	17,923	18,233	18,546	18,763	18,860	18,735	18,352	18,170	18,244	17,540	16,342	14,893
Spring	5	19,603	5/17/2015	13,938	13,321	12,927	12,642	12,633	12,820	12,884	13,909	15,326	16,311	16,988	17,495	17,903	18,347	18,917	19,313	19,603	19,461	18,973	18,804	18,857	17,838	16,435	15,054
Spring	5	20,806	5/18/2015	14,199	13,565	13,185	13,178	13,637	14,765	16,046	16,816	17,542	18,216	19,123	19,766	20,207	20,597	20,804	20,741	20,806	20,753	20,439	20,050	20,077	18,983	17,380	15,787
Spring	5	22,348	5/19/2015	14,808	14,167	13,745	13,583	14,028	15,107	16,200	16,892	17,447	18,075	18,855	19,551	20,333	21,096	21,784	22,185	22,348	22,057	21,308	20,527	20,448	19,176	17,357	15,701
Spring	5	20,883	5/20/2015	14,531	13,617	13,151	13,083	13,239	14,089	15,075	15,817	16,433	17,227	17,943	18,610	19,348	20,000	20,508	20,827	20,883	20,654	20,107	19,713	19,705	18,599	16,942	15,516
Spring	5	16,732	5/21/2015	14,497	13,927	13,530	13,417	13,673	14,661	15,606	16,138	16,554	16,603	16,732	16,487	16,232	16,117	16,072	15,874	15,817	15,682	15,657	15,799	16,368	15,841	14,734	13,693
Spring	5	16,694	5/22/2015	12,999	12,586	12,423	12,512	12,982	13,918	14,870	15,364	15,575	15,668	15,647	15,702	15,594	15,842	16,142	16,451	16,662	16,694	16,370	15,833	16,194	15,624	14,541	13,471
Spring	5	18,302	5/23/2015	12,641	12,088	11,855	11,798	11,864	11,978	12,282	12,960	13,662	14,240	14,766	15,273	15,773	16,361	17,050	17,656	18,217	18,302	17,986	17,195	17,192	16,442	15,164	13,925
Spring	5	19,620	5/24/2015	13,003	12,401	11,955	11,654	11,701	11,703	11,757	12,826	14,102	15,199	15,899	16,737	17,581	18,316	18,876	19,353	19,620	19,441	18,796	18,161	18,052	17,164	15,781	14,514
Spring	5	18,152	5/25/2015	13,669	13,008	12,601	12,436	12,480	12,493	12,623	13,343	14,305	15,389	16,267	16,755	17,154	17,458	17,642	17,944	18,151	18,152	17,895	17,671	17,878	17,020	15,642	14,601
Spring	5	20,850	5/26/2015	13,743	13,300	12,981	12,882	13,205	14,099	15,185	16,329	17,205	17,907	18,728	19,365	19,920	20,479	20,722	20,818	20,850	20,646	20,285	19,764	19,856	18,976	17,422	15,865
Spring	5	20,877	5/27/2015	14,806	14,115	13,744	13,590	14,032	14,857	15,580	16,616	17,458	18,204	19,328	19,955	20,567	20,831	20,736	20,877	20,845	20,442	19,833	19,350	19,484	18,662	17,155	15,676
Spring	5	22,117	5/28/2015	14,655	14,015	13,642	13,572	13,958	14,688	15,604	16,432	17,193	18,063	18,973	19,612	20,241	21,000	21,602	21,983	22,117	21,889	21,290	20,723	20,872	19,932	18,276	16,588
Spring	5	21,826	5/29/2015	15,550	14,765	14,264	14,042	14,368	15,002	15,935	16,990	17,762	18,722	19,612	20,242	20,809	21,419	21,701	21,826	21,745	21,085	20,221	19,617	19,793	19,008	17,582	16,122
Spring	5	21,182	5/30/2015	15,109	14,167	13,651	13,445	13,407	13,416	13,770	14,928	16,574	17,959	19,105	19,955	20,378	20,859	21,060	21,148	21,182	20,983	20,246	19,480	19,256	18,406	16,993	15,681
Spring	5	18,772	5/31/2015	14,421	13,538	13,069	12,766	12,709	12,693	12,817	13,806	15,113	16,106	16,882	17,682	18,275	18,639	18,772	18,703	18,572	18,405	17,946	17,572	17,645	16,922	15,653	14,429
Summer	6	19,042	6/1/2015	13,677	13,056	12,863	12,806	13,185	13,985	14,937	15,841	16,460	17,017	17,753	18,059	18,362	18,629	18,770	19,042	19,011	18,768	18,411	17,934	18,080	17,408	15,997	14,763
Summer	6	18,320	6/2/2015	13,723	13,174	12,809	12,681	13,150	13,924	14,740	15,599	16,188	16,711	17,229	17,571	17,806	18,141	18,300	18,264	18,320	18,078	17,844	17,578	17,829	17,036	15,730	14,519
Summer	6	19,421	6/3/2015	13,592	13,000	12,693	12,672	13,017	13,615	14,453	15,198	15,726	16,338	17,080	17,586	17,973	18,447	18,936	19,210	19,421	19,313	18,883	18,267	18,295	17,647	16,117	14,766
Summer	6	22,217	6/4/2015	13,728	13,164	12,687	12,480	12,765	13,488	14,478	15,426	16,241	17,123	18,089	18,793	19,694	20,513	21,168	21,799	22,217	22,152	21,487	20,570	20,450	19,552	17,781	16,201
Summer	6	22,811	6/5/2015	15,054	14,240	13,749	13,548	13,774	14,295	15,217	16,465	17,646	18,903	20,214	21,198	21,820	22,298	22,627	22,811	22,729	22,271	21,603	20,805	20,731	19,713	18,121	16,386
Summer	6	23,587	6/6/2015	15,135	14,208	13,653	13,436	13,253	13,294	13,548	14,621	16,165	17,890	19,407	20,553	21,480	22,311	22,832	23,387	23,587	23,344	22,754	21,743	21,165	20,038	18,400	16,653
Summer	6	24,356	6/7/2015	15,337	14,500	14,019	13,460	13,118	12,904	13,230	14,662	16,472	18,298	19,797	21,032	22,236	23,073	23,286	23,792	24,277	24,356	23,779	22,850	22,392	21,144	19,212	17,524
Summer	6	24,006	6/8/2015	16,311	15,531	14,873	14,755	14,885	15,725	16,772	18,159	19,509	21,007	22,387	23,331	23,932	24,006	23,864	23,247	22,446	21,880	21,215	20,613	20,573	19,631	17,926	16,471
Summer	6	25,219	6/9/2015	15,387	14,802	14,361	14,229	14,392	15,071	16,057	17,337	18,377	19,610	21,014	22,135	23,097	23,994	24,736	25,001	25,219	24,958	24,288	23,097	22,618	21,404	19,295	17,467
Summer	6	26,195	6/10/2015	16,176	15,174	14,638	14,264	14,431	15,048	16,104	17,374	18,787	20,362	22,082	23,323	24,267	25,090	25,524	26,009	26,195	25,936	25,356	24,257	23,730	22,426	20,299	18,396
Summer	6	26,351	6/11/2015	16,978	16,025	15,379	15,075	15,272	15,704	16,623	18,118	19,661	21,498	22,914	24,208	25,166	25,793	26,135	26,351	26,240	25,823	25,178	24,050	23,606	22,601	20,496	18,741
Summer	6	25,093	6/12/2015	17,440	16,480	15,776	15,418	15,565	16,030	16,877	18,221	19,687	20,909	22,282	23,318	24,008	24,512	24,968	25,051	25,093	24,824	24,058	22,941	22,535	21,648	19,915	18,311
Summer	6	24,846	6/13/2015	16,881	16,102	15,395	14,963	14,745	14,784	15,215	16,401	18,011	19,509	20,885	21,975	22,935	23,639	24,227	24,587	24,846	24,579	23,860	22,830	22,245	20,933	19,282	17,724
Summer	6	25,286	6/14/2015	16,428	15,543	14,764	14,306	14,162	13,896	14,161	15,627	17,478	19,153	20,585	21,888	22,941	23,767	24,463	24,901	25,286	25,230	24,669	23,618	22,965	21,915	20,075	18,340
Summer	6	27,989	6/15/2015	16,972	16,013	15,452	15,219	15,330	15,921	17,116	18,780	20,570	22,363	24,124	25,447	26,347	27,072	27,572	27,820	27,989	27,593	27,058	25,984	25,426	24,008	21,854	19,824
Summer	6	28,167	6/16/2015	18,326	17,243	16,433	16,093	16,269	16,688	17,679	19,352	21,178	23,121	24,884	26,084	26,980	27,741	28,028	28,082	28,167	27,939	27,283	26,334	25,881	24,534	22,288	20,418
Summer	6	28,542	6/17/2015	18,845	17,725	16,967	16,330	16,404	16,727	17,629	19,102	20,826	22,779	24,594	25,866	26,839	27,693	28,225	28,469	28,542	28,156	27,297	26,018	25,529	24,095	22,057	20,086
Summer	6	26,732	6/18/2015	18,607	17,625	16,789	16,452	16,511	17,004	17,937	19,272	20,876	22,586	24,251	25,440	26,137	26,706	26,732	26,692	26,431	25,942	25,311	24,351	24,172	23,019	21,198	19,365
Summer	6	25,489	6/19/2015	18,080	17,320	16,681	16,292	16,501	17,175	18,002	19,151	20,395	21,786	23,045	24,033	24,822	25,350	25,462	25,489	25,208	24,471	23,350	22,288	22,013	21,224	19,781	18,238
Summer	6	24,317	6/20/2015	17,117	16,345	15,887	15,549	15,447	15,572	15,786	16,682	18,035	19,311	20,575	21,471	22,243	22,966	23,508	24,098	24,317	24,143	23,602	22,703	22,115	21,158	19,654	18,028
Summer	6	26,005	6/21/2015	16,834	15,982	15,376	14,964	14,878	14,750	15,026	16,602	18,575	20,433	22,027	23,405	24,424	25,206	25,640	25,869	26,005	25,618	24,901	23,843	23,311	22,092	20,422	18,708
Summer	6	27,806	6/22/2015	17,472	16,496	15,897	15,667	16,001	16,404	17,407	19,014	20,615	22,500	24,347	25,723	26,773	27,431	27,773	27,806	27,684	27,094	26,100	25,024	24,675	23,475	21,510	19,674
Summer	6	28,865	6/23/2015	18,431	17,463	16,737	16,386	16,639	17,235	18,048	19,555	21,235	22,964	24,608	25,953	26,975	27,830	28,570	28,852	28,865	28,589	27,859	27,073	26,570	25,207	23,143	21,065
Summer	6	27,774	6/24/2015	19,386	18,181	17,379	16,829	16,863	17,392	18,122	19,353	20,893	22,470	24,030	25,093	26,117	26,874	27,482	27,774	27,405	26,750	25,665	24,630	24,145	22,905	20,921	19,072
Summer	6	28,575	6/25/2015	17,924	16,751	16,228	15,836	16,022	16,558	17,383	18,693	20,235	21,827	23,719	25,213	26,440	27,473	27,977	28,500	28,575	28,289	27,659	26,636	26,079	24,771	22,688	20,686
Summer	6	27,694	6/26/2015	19,297	18,200	17,487	17,030	17,093	17,398	18,035	19,321	21,071	23,001	24,826	26,230	27,047	27,597	27,694	27,346	26,583	25,378	23,903	22,672	22,165	20,896	19,436	18,316
Summer	6	20,763	6/27/2015	16,729	15,864	15,452	15,131	14,932	15,130	15,236	16,043	17,041	18,016	18,783	19,354	19,912	20,293	20,564	20,716	20,763	20,660	20,194	19,081	18,882	18,201	16,773	15,370
Summer	6	21,434	6/28/2015	14,229	13,321	12,920	12,557	12,455	12,257	12,570	13,668	15,090	16,249	17,187	17,901	18,861	19,603	20,376	21,007	21,404	21,434	21,007	20,034	19,490	18,554	16,954	15,565
Summer	6	23,955	6/29/2015	14,509	13,852	13,345	13,204	13,596	14,273	15,132	16,065	17,252	18,342	19,411	20,471	21,465	22,343	22,967	23,705	23,955	23,862	23,314	22,479	22,127	21,094	19,258	17,385
Summer	6	23,191	6/30/2015	16,229	15,514	14,923	14,611	14,754	15,348	16,172	17,076	18,163	19,354	20,598	21,489	22,070	22,704	22,989	23,191	23,162	22,698	22,030	21,324	21,205	20,352	18,768	17,273
Summer	7	20,335	7/1/2015	16,142	15,503	14,897	14,661	14,816	15,348	16,078	16,920	17,682	18,515	19,342	19,851	20,236	20,335	20,301	20,266	20,199	19,908	19,574	19,157	19,355	18,915	17,615	16,270
Summer	7	21,279	7/2/2015	15,329	14,726	14,364	14,313	14,529	15,309	15,976	16,815	17,519	18,131	18,856	19,354	19,791	20,315	20,913	21,129	21,279	20,999	20,562	20,002	20,112	19,412	18,109	16,634
Summer	7	18,333	7/3/2015	15,558	14,804	14,327	14,088	14,038	14,151	14,359	15,022	15,858	16,774	17,341	17,685	17,919	18,179	18,292	18,302	18,333	18,174	17,689	17,375	17,506	17,017	16,229	15,096
Summer	7	18,523	7/4/2015	14,223	13,472	12,977	12,904	12,796	12,841	12,913	13,552	14,544	15,702	16,506	17,211	17,771	18,129	18,375	18,523	18,455	18,099	17,522	16,891	16,594	16,194	15,662	14,702
Summer	7	20,767	7/5/2015	13,744	13,127	12,777	12,406	12,261	12,362	12,566	13,441	14,608	15,637	16,581	17,583	18,569	19,282	19,810	20,341	20,672	20,767	20,420	19,724	19,403	18,695	17,340	15,893
Summer	7	24,648	7/6/2015	14,846	14,143	13,630	13,527	13,804	14,494	15,327	16,438	17,444	18,656	19,887	21,036	22,086	23,109	23,769	24,344	24,648	24,504	23,971	23,034	22,689	21,567	19,765	17,979
Summer	7	26,232	7/7/2015	16,774	15,913	15,377	15,037	15,287	15,868	16,722	17,954	19,453	20,876	22,467	23,693	24,715	25,540	26,113	26,232	26,135	25,605	24,570	23,634	23,224	22,147	20,346	18,565
Summer	7	26,910	7/8/2015	17,248	16,301	15,799	15,364	15,385	15,986	16,826	18,071	19,395	21,137	22,825	24,067	24,945	25,889	26,531	26,867	26,910	26,668	25,920	24,782	24,376	23,221	21,236	19,395
Summer	7	27,653	7/9/2015	18,002	17,074	16,448	16,082	16,255	16,842	17,561	19,013	20,636	22,432	24,160	25,243	26,131	26,825	27,337	27,595	27,653	27,382	26,639	25,473	24,873	23,642	21,616	19,578
Summer	7	27,875	7/10/2015	18,141	17,148	16,294	15,913	15,970	16,446	17,264	18,572	20,381	22,307	24,047	25,354	26,392	27,184	27,607	27,833	27,875	27,336	26,511	25,063	24,519	23,442	21,638	19,724
Summer	7	26,552	7/11/2015	18,298	17,264	16,500	15,968	15,713	15,608	15,737	17,012	18,910	20,908	22,816	24,264	25,297	25,972	26,258	26,552	26,436	26,257	25,643	24,582	23,976	22,705	20,979	19,232
Summer	7	26,089	7/12/2015	17,844	16,724	15,974	15,569	15,329	15,137	15,280	16,629	18,648	20,509	22,106	23,151	23,895	24,682	25,217	25,794	26,089	25,965	25,452	24,662	24,105	22,963	21,237	19,570
Summer	7	29,027	7/13/2015	18,283	17,467	16,704	16,371	16,577	17,132	17,951	19,658	21,382	23,331	25,268	26,412	27,544	28,247	28,829	29,027	28,924	28,491	27,671	26,759	26,209	24,969	22,871	21,064
Summer	7	27,681	7/14/2015	19,696	18,696	18,100	17,682	17,835	18,606	19,236	20,486	21,576	22,995	24,214	25,398	26,556	27,482	27,681	27,129	25,778	24,538	23,320	22,314	21,884	20,960	19,480	17,996
Summer	7	26,826	7/15/2015	16,820	16,118	15,704	15,422	15,427	16,138	16,960	18,150	19,409	20,789	22,377	23,601	24,696	25,644	26,320	26,730	26,826	26,422	25,630	24,355	23,851	22,636	20,729	18,846
Summer	7	27,314	7/16/2015	17,419	16,400	15,681	15,428	15,615	16,170	17,047	18,328	19,803	21,513	23,094	24,236	25,271	26,200	26,842	27,253	27,314	27,095	26,615	25,477	24,930	23,595	21,596	19,608
Summer	7	28,743	7/17/2015	18,221	17,201	16,519	16,115	16,294	16,817	17,606	18,842	20,554	22,533	24,547	25,911	26,978	27,831	28,395	28,710	28,743	28,353	27,638	26,444	25,870	24,613	22,589	20,958
Summer	7	27,264	7/18/2015	19,344	18,176	17,346	16,809	16,509	16,428	16,573	17,914	20,082	22,159	24,146	25,540	26,283	26,786	27,150	27,144	27,264	27,051	26,463	25,331	24,818	23,689	22,021	20,269
Summer	7	27,311	7/19/2015	18,851	17,697	16,851	16,287	16,134	15,945	16,066	17,578	19,828	21,834	23,512	24,820	25,723	26,450	26,695	26,950	27,311	27,194	26,705	25,828	25,343	24,117	22,336	20,674
Summer	7	29,018	7/20/2015	19,305	18,307	17,681	17,431	17,579	18,319	19,098	20,236	21,589	23,407	25,297	26,868	27,921	28,751	29,018	28,828	28,158	27,609	26,720	25,788	25,411	24,252	22,380	20,597
Summer	7	27,603	7/21/2015	19,308	18,382	17,789	17,486	17,603	18,274	18,870	20,122	21,353	22,818	24,372	25,537	26,524	27,181	27,603	27,454	27,060	26,687	25,881	24,930	24,562	23,319	21,310	19,479
Summer	7	25,787	7/22/2015	18,024	17,159	16,573	16,324	16,433	17,124	17,793	18,643	19,767	21,161	22,441	23,548	24,481	25,313	25,617	25,787	25,765	25,573	24,757	23,987	23,704	22,456	20,708	19,128
Summer	7	23,227	7/23/2015	17,907	17,221	16,581	16,343	16,553	17,309	18,117	18,874	19,704	20,588	21,437	21,927	22,436	22,526	22,772	23,109	23,227	23,129	22,801	22,202	22,297	21,446	19,874	18,401
Summer	7	27,005	7/24/2015	17,261	16,459	15,962	15,611	15,924	16,587	17,303	18,518	19,730	21,221	22,768	23,987	25,020	26,005	26,605	27,005	26,987	26,675	25,745	24,465	23,910	22,585	20,734	18,935
Summer	7	26,681	7/25/2015	17,571	16,461	15,804	15,369	15,184	15,167	15,203	16,459	18,244	20,066	21,974	23,455	24,598	25,525	26,213	26,585	26,654	26,681	25,834	24,556	23,800	22,255	20,554	18,743
Summer	7	26,380	7/26/2015	17,424	16,399	15,695	15,173	14,910	14,728	14,811	16,299	18,263	20,260	21,946	23,602	24,809	25,672	26,102	26,350	26,380	26,146	25,473	24,523	24,201	22,875	20,969	19,321
Summer	7	28,828	7/27/2015	18,120	17,175	16,687	16,355	16,511	17,177	18,080	19,368	21,079	23,009	25,066	26,592	27,471	28,101	28,351	28,689	28,828	28,684	27,898	26,993	26,566	25,093	23,016	21,218
Summer	7	28,630	7/28/2015	19,795	18,684	17,999	17,571	17,619	18,273	18,901	20,328	22,249	24,025	26,198	27,465	28,111	28,550	28,630	28,372	27,643	26,920	26,259	25,515	25,257	24,146	22,437	20,646
Summer	7	28,970	7/29/2015	19,545	18,143	17,579	17,189	17,203	17,798	18,523	19,575	20,974	22,638	24,309	25,699	26,903	27,710	28,266	28,714	28,970	28,796	28,021	27,077	26,651	25,188	22,998	21,132
Summer	7	27,672	7/30/2015	19,755	18,749	17,961	17,524	17,586	18,198	18,899	19,913	21,130	22,479	23,856	24,978	25,900	26,730	27,316	27,672	27,519	26,931	25,923	24,504	24,016	22,483	20,462	18,481
Summer	7	26,246	7/31/2015	17,099	16,037	15,456	14,956	15,061	15,706	16,229	17,497	18,967	20,432	21,921	23,024	23,931	24,873	25,654	26,156	26,246	25,801	24,893	23,399	22,582	21,259	19,401	17,640
Summer	8	25,969	8/1/2015	16,286	15,266	14,518	14,142	14,127	14,186	14,291	15,447	17,145	19,134

Contains Proprietary Material
Do Not Distribute

Fall	9	25,492	9/5/2015	16,815	15,736	15,161	14,689	14,395	14,485	14,585	15,377	17,123	19,033	20,937	22,706	24,037	24,953	25,473	25,492	25,338	24,652	23,504	22,841	21,777	20,267	18,646	17,138
Fall	9	24,340	9/6/2015	15,891	15,084	14,501	14,011	13,875	13,843	13,999	14,891	16,592	18,230	19,662	21,154	22,403	23,368	23,939	24,289	24,340	23,746	22,543	21,850	20,890	19,470	18,045	16,637
Fall	9	24,597	9/7/2015	15,492	14,630	14,110	13,679	13,632	13,717	13,668	14,300	15,939	17,835	19,837	21,450	22,657	23,553	24,071	24,475	24,597	24,203	23,307	22,849	21,875	20,105	18,265	16,666
Fall	9	25,812	9/8/2015	15,569	14,812	14,250	14,193	14,439	15,629	16,827	17,519	18,714	20,169	21,788	23,094	24,145	25,084	25,439	25,688	25,812	25,480	24,781	24,436	23,521	21,755	19,693	18,042
Fall	9	23,220	9/9/2015	16,830	16,196	15,759	15,527	15,630	16,715	17,903	18,188	18,930	20,098	21,280	22,168	22,888	23,209	23,220	23,068	22,646	21,985	21,380	21,292	20,684	19,340	17,798	16,409
Fall	9	23,227	9/10/2015	15,603	14,989	14,663	14,537	14,878	16,017	17,300	17,568	18,047	18,573	19,206	19,739	20,563	21,465	22,303	22,952	23,227	22,896	22,164	21,885	21,197	19,722	18,046	16,485
Fall	9	22,190	9/11/2015	15,510	14,748	14,296	14,177	14,453	15,583	16,669	17,034	17,850	19,010	20,174	21,030	21,776	22,190	22,011	21,659	21,202	20,270	19,424	19,066	18,543	17,657	16,476	15,221
Fall	9	17,134	9/12/2015	14,216	13,512	13,184	12,926	12,882	13,130	13,380	13,854	14,754	15,463	15,934	16,206	16,462	16,729	17,044	17,134	17,028	16,631	15,994	16,211	15,731	14,919	13,990	12,995
Fall	9	16,297	9/13/2015	12,246	11,789	11,467	11,397	11,373	11,579	11,860	12,471	13,327	13,637	13,879	14,141	14,541	14,841	15,129	15,544	15,913	16,045	15,793	16,297	15,877	14,828	13,670	12,693
Fall	9	18,553	9/14/2015	12,080	11,881	11,628	11,748	12,280	13,586	14,767	15,008	15,374	15,686	16,145	16,338	16,660	17,083	17,567	18,172	18,553	18,426	18,109	18,141	17,584	16,474	15,007	13,666
Fall	9	20,128	9/15/2015	13,031	12,483	12,304	12,297	12,803	13,984	15,073	15,333	15,680	16,125	16,679	17,120	17,733	18,450	19,060	19,729	20,128	19,918	19,320	19,328	18,717	17,439	15,806	14,392
Fall	9	21,122	9/16/2015	13,507	13,007	12,668	12,614	13,030	14,171	15,381	15,423	15,980	16,692	17,444	17,899	18,650	19,467	20,192	20,915	21,122	20,957	20,251	19,965	19,279	17,858	16,233	14,839
Fall	9	22,201	9/17/2015	13,829	13,277	12,867	12,886	13,202	14,449	15,498	15,822	16,393	16,968	17,897	18,648	19,528	20,510	21,280	21,900	22,201	21,863	20,893	20,749	19,921	18,510	16,805	15,194
Fall	9	23,150	9/18/2015	14,166	13,606	13,215	13,068	13,376	14,439	15,650	15,872	16,623	17,544	18,691	19,582	20,546	21,356	22,315	22,927	23,150	22,601	21,284	20,592	19,609	18,408	16,928	15,459
Fall	9	22,168	9/19/2015	14,257	13,700	13,187	12,883	12,807	13,128	13,453	13,999	15,296	16,539	17,749	18,966	20,108	21,115	21,853	22,168	21,978	21,371	20,506	20,178	19,182	17,980	16,698	15,382
Fall	9	20,000	9/20/2015	14,372	13,688	13,110	12,800	12,539	12,658	12,890	13,534	14,656	15,564	16,430	17,335	18,275	19,058	19,482	19,833	20,000	19,473	18,999	19,120	18,167	16,849	15,377	14,193
Fall	9	19,845	9/21/2015	13,454	12,907	12,666	12,636	13,195	14,391	15,709	15,944	16,232	16,614	17,240	17,736	18,200	18,810	19,238	19,690	19,845	19,547	19,108	19,188	18,504	17,177	15,574	14,309
Fall	9	21,219	9/22/2015	13,421	12,865	12,555	12,561	12,941	14,143	15,335	15,490	15,919	16,587	17,236	17,901	18,549	19,359	20,243	20,868	21,219	20,929	20,211	20,033	19,271	17,698	16,137	14,787
Fall	9	22,319	9/23/2015	13,945	13,279	12,933	12,829	13,184	14,269	15,431	15,637	16,130	16,937	17,876	18,742	19,696	20,719	21,415	22,044	22,319	21,947	21,174	20,769	19,767	18,277	16,564	15,196
Fall	9	22,116	9/24/2015	14,325	13,560	13,254	13,030	13,312	14,538	15,722	15,876	16,471	17,312	18,353	19,281	20,110	21,074	21,722	22,116	22,011	21,442	20,861	20,744	19,797	18,349	16,741	15,301
Fall	9	18,290	9/25/2015	14,322	13,639	13,315	13,189	13,647	14,644	16,009	16,177	16,437	16,948	17,471	17,815	18,046	18,187	18,290	18,218	18,042	17,754	17,618	17,578	17,078	16,393	15,509	14,417
Fall	9	17,321	9/26/2015	13,616	13,022	12,685	12,491	12,522	12,871	13,403	13,911	14,743	15,527	16,059	16,393	16,686	16,913	17,049	17,077	17,065	16,841	17,009	17,321	16,899	16,049	15,128	14,127
Fall	9	19,125	9/27/2015	13,313	12,740	12,316	12,330	12,361	12,465	12,922	13,482	14,562	15,359	15,913	16,618	17,385	17,903	18,280	18,478	18,846	18,733	18,747	19,125	18,398	17,158	15,899	14,784
Fall	9	20,157	9/28/2015	13,984	13,474	13,311	13,233	13,735	14,977	16,444	16,897	17,241	17,873	18,440	18,856	19,213	19,519	19,656	19,600	19,605	19,584	19,952	20,157	19,592	18,506	17,150	15,862
Fall	9	20,079	9/29/2015	15,084	14,548	14,184	14,053	14,537	15,863	17,298	17,558	17,828	18,149	18,538	18,827	19,148	19,355	19,664	19,921	20,079	19,851	19,835	19,921	19,170	18,185	16,804	15,483
Fall	9	18,345	9/30/2015	14,619	14,188	13,769	13,750	14,202	15,345	16,745	16,950	17,142	17,475	17,856	17,934	18,074	18,345	18,283	18,220	18,080	17,837	18,124	18,188	17,564	16,677	15,377	14,106
Fall	10	16,967	10/1/2015	13,470	12,976	12,716	12,734	13,112	14,277	15,597	15,697	15,916	16,094	16,242	16,364	16,303	16,235	16,186	16,191	16,223	16,201	16,495	16,967	16,541	15,659	14,529	13,495
Fall	10	15,711	10/2/2015	12,686	12,318	12,130	12,085	12,551	13,784	15,219	15,348	15,480	15,565	15,693	15,711	15,406	15,245	15,110	14,965	14,881	14,934	15,333	15,618	15,374	14,788	13,890	13,061
Fall	10	15,254	10/3/2015	12,391	11,985	11,790	11,726	11,807	12,195	12,813	13,251	13,903	14,531	14,810	14,735	14,643	14,512	14,479	14,345	14,500	14,642	15,156	15,254	15,005	14,355	13,601	12,771
Fall	10	16,298	10/4/2015	12,212	11,799	11,627	11,507	11,629	11,873	12,345	12,958	13,720	14,042	14,076	14,147	14,254	14,192	14,407	14,621	14,909	15,074	15,639	16,298	15,881	14,908	13,819	12,803
Fall	10	19,398	10/5/2015	12,223	11,849	11,703	11,782	12,260	13,391	14,614	15,003	15,562	16,023	16,492	17,121	17,695	18,194	18,708	19,130	19,393	19,200	19,156	19,398	18,676	17,467	15,948	14,517
Fall	10	20,819	10/6/2015	13,706	13,203	12,842	12,781	13,170	14,355	15,483	15,688	16,201	16,851	17,595	18,361	19,219	19,769	20,327	20,811	20,819	20,370	19,996	19,989	19,024	17,840	16,270	14,788
Fall	10	20,783	10/7/2015	13,836	13,168	12,818	12,733	12,942	14,195	15,144	15,254	15,677	16,343	17,119	17,987	18,927	19,674	20,240	20,659	20,783	20,301	19,854	19,473	18,611	17,413	15,996	14,621
Fall	10	20,630	10/8/2015	13,809	13,310	12,996	12,762	13,174	14,477	15,564	15,701	16,242	16,958	17,848	18,619	19,411	19,973	20,630	20,596	20,566	20,072	20,018	19,947	19,185	18,012	16,525	15,208
Fall	10	19,679	10/9/2015	14,276	13,799	13,353	13,195	13,492	14,535	15,788	16,026	16,637	17,245	18,035	18,790	19,395	19,679	19,606	19,313	18,718	18,077	17,882	17,619	17,043	16,206	15,233	13,969
Fall	10	15,575	10/10/2015	13,257	12,730	12,419	12,265	12,215	12,487	13,088	13,488	14,194	14,733	14,963	15,076	14,997	14,953	15,021	15,171	15,257	15,144	15,420	15,575	15,036	14,469	13,502	12,716
Fall	10	16,159	10/11/2015	12,130	11,741	11,487	11,346	11,496	11,803	12,280	12,801	13,570	13,933	13,992	14,125	14,394	14,680	14,953	15,283	15,674	15,662	16,020	16,159	15,595	14,644	13,694	12,912
Fall	10	18,603	10/12/2015	12,200	11,986	11,785	11,768	12,294	13,471	14,782	15,148	15,473	15,865	16,166	16,429	16,704	17,212	17,602	17,995	18,229	18,003	18,432	18,603	17,861	16,760	15,440	14,287
Fall	10	17,379	10/13/2015	13,389	12,828	12,469	12,484	12,817	13,753	14,982	15,083	15,317	15,808	16,304	16,601	16,900	17,024	17,202	17,379	17,375	16,997	17,137	17,342	16,600	15,574	14,320	13,368
Fall	10	17,409	10/14/2015	12,808	12,386	12,264	12,357	12,796	14,114	15,407	15,547	15,714	15,867	16,055	16,232	16,271	16,415	16,688	17,034	17,314	17,091	17,230	17,409	16,839	15,869	14,565	13,601
Fall	10	17,941	10/15/2015	12,985	12,592	12,426	12,477	12,989	14,164	15,490	15,617	15,636	15,828	16,180	16,324	16,617	16,717	17,277	17,758	17,941	17,692	17,773	17,921	17,298	16,295	15,063	13,903
Fall	10	16,018	10/16/2015	13,238	12,789	12,519	12,454	12,901	13,979	15,214	15,432	15,603	15,842	16,018	16,014	16,001	15,844	15,852	15,834	15,722	15,494	15,682	15,871	15,628	15,051	14,255	13,473
Fall	10	15,370	10/17/2015	12,934	12,603	12,530	12,450	12,718	13,181	14,042	14,752	15,226	15,200	14,974	14,816	14,250	14,124	14,000	13,964	14,116	14,231	15,080	15,370	15,157	14,672	14,069	13,451
Fall	10	16,309	10/18/2015	13,054	12,929	12,871	12,953	13,244	13,805	14,505	15,422	15,867	15,442	14,867	14,534	14,271	14,115	13,972	13,994	14,238	14,675	15,828	16,309	15,988	15,306	14,544	13,884
Fall	10	18,518	10/19/2015	13,698	13,637	13,780	14,134	15,005	16,655	18,426	18,518	18,016	17,314	16,966	16,256	16,002	15,562	15,386	15,342	15,458	15,626	16,503	16,952	16,556	15,841	14,732	13,990
Fall	10	17,593	10/20/2015	13,480	13,398	13,380	13,563	14,331	15,973	17,556	17,593	17,055	16,547	16,184	15,901	15,749	15,474	15,412	15,537	15,701	15,705	16,529	16,861	16,355	15,584	14,341	13,507
Fall	10	17,181	10/21/2015	13,053	12,861	12,749	13,007	13,657	15,141	16,680	16,606	16,309	16,147	15,948	15,915	15,853	15,952	16,085	16,372	16,470	16,474	17,028	17,181	16,694	15,735	14,615	13,606
Fall	10	17,538	10/22/2015	12,914	12,656	12,535	12,651	13,353	14,588	16,051	16,091	15,945	15,821	15,998	16,099	16,244	16,476	16,604	16,897	17,053	16,884	17,402	17,538	17,018	15,934	14,641	13,500
Fall	10	16,821	10/23/2015	12,870	12,480	12,384	12,496	13,060	14,373	15,869	16,096	16,041	16,050	16,132	16,326	16,369	16,527	16,628	16,711	16,690	16,359	16,821	16,729	16,307	15,766	14,749	13,741
Fall	10	16,197	10/24/2015	13,192	12,650	12,367	12,207	12,381	12,731	13,371	13,906	14,627	15,143	15,564	15,549	15,544	15,500	15,407	15,395	15,416	15,474	16,197	15,929	15,564	14,908	14,113	13,048
Fall	10	15,802	10/25/2015	12,393	12,018	11,801	11,603	11,629	11,900	12,379	12,982	13,642	13,969	14,149	14,214	14,326	14,346	14,427	14,465	14,709	14,966	15,802	15,736	15,388	14,565	13,557	12,702
Fall	10	16,964	10/26/2015	12,117	11,923	11,792	11,941	12,525	13,843	15,433	15,822	15,884	16,070	16,165	16,221	16,044	15,827	15,660	15,655	15,813	16,263	16,956	16,964	16,498	15,687	14,535	13,575
Fall	10	17,226	10/27/2015	13,061	12,703	12,519	12,556	13,122	14,493	15,865	16,227	16,282	16,628	16,667	16,571	16,397	15,970	15,753	15,857	16,053	16,536	17,226	17,161	16,568	15,716	14,629	13,653
Fall	10	16,758	10/28/2015	13,129	12,839	12,627	12,680	13,159	14,377	15,868	16,145	16,165	16,215	16,284	16,153	16,029	15,783	15,777	15,841	15,903	15,973	16,635	16,758	16,412	15,662	14,464	13,534
Fall	10	16,568	10/29/2015	12,939	12,528	12,394	12,454	12,905	14,229	15,800	15,938	15,760	15,795	15,945	15,824	15,774	15,591	15,493	15,440	15,476	15,488	16,348	16,568	16,295	15,533	14,499	13,564
Fall	10	16,721	10/30/2015	12,918	12,656	12,673	12,790	13,395	14,919	16,627	16,721	16,431	16,054	15,516	15,301	14,985	14,655	14,541	14,377	14,361	14,505	15,278	15,392	15,201	14,722	14,095	13,242
Fall	10	15,058	10/31/2015	12,921	12,552	12,318	12,220	12,422	12,892	13,355	13,946	14,635	15,001	15,058	14,897	14,727	14,565	14,476	14,404	14,416	14,528	14,874	14,640	14,434	13,906	13,187	12,365
Fall	11	15,833	11/1/2015	11,777	11,494	11,223	11,152	11,367	11,614	12,152	13,135	13,881	13,979	13,783	14,033	14,007	14,029	13,986	14,162	14,923	15,833	15,816	15,456	14,794	14,078	13,185	12,429
Fall	11	17,475	11/2/2015	11,936	11,729	11,652	11,586	12,005	13,387	14,724	15,054	15,264	15,452	15,785	16,006	16,053	16,043	16,009	16,092	16,462	17,429	17,475	16,925	16,342	15,369	14,269	13,253
Fall	11	17,840	11/3/2015	12,711	12,367	12,251	12,027	12,359	13,712	14,821	15,057	15,321	15,450	15,956	16,190	16,451	16,569	16,583	16,533	16,845	17,829	17,840	17,406	16,763	15,689	14,550	13,413
Fall	11	17,951	11/4/2015	12,869	12,478	12,231	12,029	12,374	13,665	14,870	15,101	15,380	15,716	16,165	16,388	16,714	16,815	16,735	16,657	16,941	17,951	17,948	17,500	16,917	15,718	14,615	13,608
Fall	11	18,709	11/5/2015	12,933	12,560	12,332	12,218	12,557	13,857	15,143	15,470	15,779	16,150	16,712	17,110	17,454	17,585	17,739	17,721	17,878	18,709	18,632	18,196	17,531	16,637	15,342	14,280
Fall	11	17,590	11/6/2015	13,625	13,328	12,940	12,810	13,032	14,218	15,406	15,731	16,120	16,302	16,725	16,924	16,985	17,012	16,856	16,704	17,044	17,590	17,257	16,771	16,203	15,478	14,539	13,525
Fall	11	15,969	11/7/2015	12,782	12,356	12,056	11,938	12,066	12,469	12,999	13,588	14,441	14,985	15,144	15,080	14,792	14,666	14,608	14,688	15,246	15,969	15,736	15,518	15,088	14,612	13,907	13,214
Fall	11	16,260	11/8/2015	12,682	12,470	12,383	12,324	12,488	12,932	13,455	14,267	14,759	14,678	14,327	14,175	14,151	14,069	13,999	14,188	14,945	16,080	16,260	16,036	15,548	14,828	13,899	13,296
Fall	11	17,867	11/9/2015	12,829	12,508	12,500	12,709	13,088	14,579	16,027	16,185	16,340	16,405	16,553	16,595	16,568	16,481	16,287	16,416	17,008	17,867	17,779	17,434	16,757	15,867	14,730	13,783
Fall	11	17,391	11/10/2015	13,094	12,932	12,837	12,993	13,399	14,814	16,128	16,151	15,986	15,932	15,977	15,973	15,901	15,939	15,849	15,855	16,175	17,309	17,391	17,199	16,618	16,018	15,129	14,431
Fall	11	17,643	11/11/2015	14,086	13,931	13,954	14,081	14,532	16,006	17,083	16,968	16,375	16,055	16,019	16,031	16,084	16,075	16,183	16,201	16,655	17,643	17,596	17,103	16,676	15,836	14,674	13,822
Fall	11	17,368	11/12/2015	13,273	12,918	12,720	12,578	12,931	14,166	15,392	15,590	15,687	15,680	15,963	16,065	15,999	15,968	15,910	15,833	16,166	17,361	17,368	17,245	16,681	15,972	14,948	14,229
Fall	11	17,722	11/13/2015	13,942	13,679	13,802	13,910	14,489	16,198	17,690	17,578	16,983	16,624	16,458	16,162	15,734	15,666	15,629	15,820	16,438	17,722	17,708	17,632	17,519	17,163	16,539	15,959
Fall	11	18,158	11/14/2015	15,533	15,562	15,694	15,982	16,306	17,120	17,732	18,158	17,725	17,078	16,262	15,508	15,225	14,935	14,745	14,684	15,544	16,605	16,888	16,710	16,505	16,214	15,769	15,377
Fall	11	17,278	11/15/2015	15,198	15,149	15,232	15,376	15,640	16,091	16,623	17,143	17,195	16,501	15,815	15,277	14,945	14,650	14,551	14,630	15,755	17,121	17,262	17,278	17,044	16,493	15,675	15,153
Fall	11	18,390	11/16/2015	14,835	14,748	14,800	14,818	15,483	17,120	18,390	18,279	17,921	17,455	17,255	17,048	16,801	16,533	16,445	16,676	17,464	18,360	18,281	17,946	17,183	16,234	15,000	14,149
Fall	11	17,709	11/17/2015	13,667	13,427	13,328	13,280	13,732	15,161	16,468	16,508	16,429	16,278	16,317	16,289	16,330	16,234	16,146	16,279	16,974	17,709	17,629	17,259	16,644	15,792	14,687	13,661
Fall	11	17,965	11/18/2015	13,137	12,896	12,695	12,597	12,871	14,087	15,597	15,905	16,101	16,247	16,494	16,643	16,597	16,603	16,543	16,636	17,085	17,946	17,965	17,581	17,046	16,135	15,168	14,214
Fall	11	17,613	11/19/2015	13,591	13,321	13,196	13,181	13,770	15,364	16,769	16,797	16,502	16,272	16,110	16,003	15,943	15,957	15,824	15,846	16,265	17,412	17,613	17,445	17,161	16,562	15,691	14,918
Fall	11	18,673	11/20/2015	14,597	14,381	14,465	14,831	15,461	17,233	18,673	18,498	17,789	17,253	17,028	16,555	16,298	16,009	15,798	15,831	16,658	17,803	17,952	17,898	17,737	17,388	16,716	16,214
Fall	11	17,774	11/21/2015	15,735	15,554	15,626	15,710	16,000	16,574	17,082	17,329	17,236	16,797	16,502	16,043	15,746	15,596	15,694	15,941	16,710	17,685	17,774	17,698	17,571	17,087	16,649	16,242
Fall	11	20,511	11/22/2015	15,928	15,910	15,931	16,153	16,683	17,345	18,055	18,840	19,010	18,532	17,909	17,377	16,978	16,680	16,567	16,882	18,141	19,768	20,222	20,511	20,344	19,895	19,425	18,990
Fall	11	23,475	11/23/2015	18,904	19,061	19,304	19,631	20,389	21,998	23,475	23,191	22,104	20,603	19,763	18,959	18,351	17,835	17,559	17,580	18,648	20,190	20,619	20,685	20,575	20,156	19,396	18,698
Fall	11	22,218	11/24/2015	18,484	18,411	18,516	18,794	19,507	21,085	22,218	21,945	20,804	19,474	18,670	17,888	17,441	17,090	16,858	16,906	17,824	19,150	19,428	19,315	19,140	18,551	17,701	17,062
Fall	11	19,045	11/25/2015	16,616	16,486	16,299	16,357	16,698	17,792	18,748	19,045	18,638	18,011	17,573	17,075	16,681	16,299	15,953	15,913	16,523	17,534	17,457	17,179	16,923	16,459	15,455	14,470
Fall	11	15,698	11/26/2015	13,818	13,466	13,220	13,250	13,508	14,034	14,545	15,088	15,536	15,698	15,618	14,980	14,082	13,367	12,929	12,666	12,829	13,518	13,479	13,408	13,276	12,996	12,520	11,977
Fall	11	14,889	11/27/2015	11,622	11,427	11,367	11,431	11,682	12,246	12,775	13,148	13,553	13,751	13,824	13,702	13,554	13,439	13,383	13,462	14,228	14,889	14,784	14,561	14,280	13,750	13,063	12,262
Fall	11	15,272	11/28/2015	11,661	11,368	11,240	11,309	11,440	11,872	12,342	12,914	13,676	14,213	14,419	14,414	14,268	14,172	14,083	14,137	14,759	15,272	15,065	15,058	14,713	14,179	13,436	12,614
Fall	11	16,619	11/29/2015	12,057	11,750	11,554	11,466	11,577	12,080	12,548	13,183	13,968	14,352	14,488	14,610	14,797	14,895	14,886	15,234	16,015	16,619	16,585	16,483	15,847	15,241	14,217	13,395
Fall	11	18,331	11/30/2015	12,908	12,584	12,567	12,481	12,930	14,345	15,857	16,036	16,216	16,346	16,547	16,688	16,711	16,732	16,660	16,869	17,634	18,331	18,185	17,923	17,241	16,387	15,065	14,069

Wkp - SERC Operating Reserves

Southeast Operating Reserves

VACAR Reserve Sharing Group

Coincident Peak Load Date		Winter Peak Load 02/20/15, Hour 8	Spring Peak Load 03/06/15, Hour 8	Summer Peak Load 06/23/15, Hour 18	Fall Peak Load 09/02/15, Hour 16	Winter Max of mos the largest s
Dominion	VAP	21,651	17,719	18,955	16,640	367
Duke	DUKE	21,101	16,260	19,827	18,524	358
Progress Energy Carolinas	CPL	15,569	11,245	12,752	11,738	264
	CPLE					244
	CPLW					20
SCEG	SCEG	4,970	3,200	4,450	4,185	84
SC	SC	5,869	3,895	4,834	4,214	100
	Total	**69,160**	**52,319**	**60,818**	**55,301**	

Largest Single Unit	Summer	Winter
DUK BAA : Catawba 1	1,140	1,174

http://www.serc1.org/docs/default-source/program-areas/standards-regional-criteria/regional-criteria/serc-reg-criteria_contingency-reserve-policy-r

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TEE Reserve Sharing Group

		Winter Peak Load	Spring Peak Load	Summer Peak Load	Fall Peak Load
Coincident Peak Load Date		01/08/15, Hour 8	03/06/15, Hour 7	07/29/15, Hour 17	09/04/15, Hour 16
TVA	TVA	32,747	27,804	28,970	27,142
LGEE	LGEE	6,964	5,962	6,628	6,424
	Total	**39,711**	**33,766**	**35,598**	**33,566**

Winter
1
1,043
222

Largest Single Unit	Summer	Winter
TVA BAA: Cumberland (TN) 1	1,239	1,265

http://www.serc1.org/docs/default-source/program-areas/standards-regional-criteria/regional-criteria/serc-reg-criteria_contingency-reserve-policy-

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Spring	Summer	Fall
t severe single contingency or 1.0 times ingle resource in the combined systems		
397	355	353
365	372	393
252	239	249
233	221	230
19	18	19
72	83	89
87	91	89

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Spring	Summer	Fall
x Largest Single Unit, Shared		
1,042	1,008	1,023
223	231	242

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FERC Form 714 Outages

	Planned Outage and Derating (MW)				
Month	MISO	CPL	DUKE	LGEE	TVA
Dec-14	######	2,077	2,316	0	5,939
Jan15	######	5	209	0	1,658
Feb15	######	0	480	0	2,173
Mar15	######	578	3,148	758	4,098
Apr15	######	2,098	3,901	2,504	8,727
May15	######	2,171	4,464	300	5,885
Jun15	8,163	2	247	0	2,271
Jul15	6,429	0	325	0	1,440
Aug15	7,498	50	189	0	1,718
Sep15	7,327	36	417	0	2,717
Oct15	######	2,035	2,902	1,208	8,241
Nov15	######	1,664	3,062	1,467	7,242

	Planned Outage and Derating (MW)					**Generation (MW)**			
	Winter	Spring	Summer	Fall	Note	Winter	Spring	Summer	Fall
MISO	13,735	24,153	7,363	19,757	MISO outages				
CPL	694	1,616	17	1,245	CPL outages	15,574	15,574	14,351	15,598
CPLE	655	1,525	16	1,175	Estimated based on generation ratios	14,696	14,696	13,525	14,720
CPLW	39	91	1	70	Estimated based on generation ratios	878	878	826	878
DUKE	1,002	3,838	254	2,127	DUKE outages				
LGEE	0	1,187	0	892	LGEE outages				
TVA	3,257	6,237	1,810	6,067	TVA outages				

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Area	PST	Winter	Spring	Summer	Fall
PJM	19,538	16,011	14,104	18,740	15,366
AP South	10,376	8,453	7,202	10,017	8,235
5004-5005	10,376	8,348	7,135	10,017	8,235
PJM East	5,063	3,767	3,417	4,819	3,923
NYISO	1,774	1,053	1,345	1,785	1,610
ISONE	4,000	3,627	3,224	4,080	3,720
CT	1,470	1,012	868	1,304	1,197

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Asset Appendix: Generation Assets - December 2016

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned by**	**Controlled by**	**Date Control Transferred**	**Location**		**In-Service Date**	**Capacity Rating: Nameplate (MW)**	**Capacity Rating: Used in Filing (MW)**	**Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative**	**End Note Number (Enter text in End Note Tab)**
						Market / Balancing Authority Area	**Geographic Region**					
Beebe 1B Renewable Energy, LLC	ER14-2144	Beebe 1b WF	Beebe 1B Renewable Energy, LLC	Beebe 1B Renewable Energy, LLC	N/A	MISO	Central	12/12/2014	50.40	50.40	S	
Beebe Renewable Energy, LLC	ER12-2311	Beebe 1a WF	Beebe Renewable Energy, LLC	Beebe Renewable Energy, LLC	N/A	MISO	Central	1/17/2013	81.60	81.60	S	
Exelon Generation Company, LLC	ER00-3251	Clinton	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	MISO	Central	11/1/1987	1138.30	1065.00	S	
Harvest II Windfarm, LLC	ER12-2201 QF12-522	Harvest 2 WF	Harvest II Windfarm, LLC	Harvest II Windfarm, LLC	N/A	MISO	Central	11/28/2012	59.40	59.40	S	
Harvest Windfarm, LLC	ER07-1246 QF07-29	Harvest 1 WF	Harvest Windfarm, LLC	Harvest Windfarm, LLC	N/A	MISO	Central	2/28/2008	52.80	52.80	S	
Michigan Wind 1, LLC	ER05-1511 QF05-228	Michigan Wind 1 WF	Michigan Wind 1, LLC	Michigan Wind 1, LLC	N/A	MISO	Central	12/16/2008	69.00	69.00	S	
Michigan Wind 2, LLC	ER11-3989	Michigan Wind 2 WF	Michigan Wind 2, LLC	Michigan Wind 2, LLC	N/A	MISO	Central	1/5/2012	90.00	90.00	S	
Atlantic City Electric Company	ER96-1361	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Baltimore Gas and Electric Company	ER99-2948	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Commonwealth Edison Company	ER98-1734	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Energy Commodities Group Maine, LLC	ER02-699	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Energy Services of New York, Inc.	ER07-651	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Energy Services, Inc.	ER07-650	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation NewEnergy, Inc.	ER96-1387	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Delmarva Power & Light Company	ER96-2571	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
PECO Energy Company	ER01-1147	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Pepco Energy Services, Inc.	ER98-3096	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Potomac Electric Power Company	ER98-4138	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
Constellation Mystic Power, LLC	ER10-2281	Mystic 7	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/1975	617.00	575.48	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	278.60	228.77	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	278.60	229.97	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 8 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	4/14/2003	315.00	244.58	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	278.60	231.40	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 GT2	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	278.60	232.50	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic 9 STG1	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/10/2003	315.00	247.24	S	
Constellation Mystic Power, LLC	ER10-2281	Mystic Jet	Constellation Mystic Power, LLC	Constellation Mystic Power, LLC	N/A	ISO-NE	Northeast	6/1/1969	14.20	8.28	S	
Exelon Framingham LLC	ER98-1943	Framingham Jet 1	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	3/1/1970	14.20	10.15	S	
Exelon Framingham LLC	ER98-1943	Framingham Jet 2	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/1969	14.20	10.05	S	
Exelon Framingham LLC	ER98-1943	Framingham Jet 3	Exelon Framingham LLC	Exelon Framingham LLC	N/A	ISO-NE	Northeast	9/1/1969	14.20	11.25	S	
Exelon New Boston, LLC	ER98-1943	New Boston Jet	Exelon New Boston, LLC	Exelon New Boston, LLC	N/A	ISO-NE	Northeast	9/1/1966	18.60	16.00	S	1
Exelon West Medway, LLC	ER98-1943	West Medway Jet 1	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/1970	45.00	42.00	S	
Exelon West Medway, LLC	ER98-1943	West Medway Jet 2	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	3/1/1971	45.00	39.85	S	
Exelon West Medway, LLC	ER98-1943	West Medway Jet 3	Exelon West Medway, LLC	Exelon West Medway, LLC	N/A	ISO-NE	Northeast	7/1/1970	45.00	42.00	S	
Exelon Wyman, LLC	ER98-1943	Wyman 4	Exelon Wyman, LLC (5.9%)	FPL Energy Wyman IV LLC	N/A	ISO-NE	Northeast	1/1/1978	632.40	602.00	S	2
Exelon West Medway II, LLC	ER16-2708	West Medway 4	Exelon West Medway II, LLC	Exelon West Medway II, LLC	N/A	ISO-NE	Northeast	6/1/2018	100.00	97.40	S	
Exelon West Medway II, LLC	ER16-2708	West Medway 5	Exelon West Medway II, LLC	Exelon West Medway II, LLC	N/A	ISO-NE	Northeast	6/1/2018	100.00	97.40	S	
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 1	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	12/1/1969	641.80	626.10	S	
Nine Mile Point Nuclear Station, LLC	ER01-1654	Nine Mile Point 2	Nine Mile Point Nuclear Station, LLC	Nine Mile Point Nuclear Station, LLC	N/A	NYISO	Northeast	8/1/1988	1428.45	1289.60	S	3
R. E. Ginna Nuclear Power Plant, LLC	ER04-485	Ginna	R. E. Ginna Nuclear Power Plant, LLC	R. E. Ginna Nuclear Power Plant, LLC	N/A	NYISO	Northeast	7/1/1970	614.00	582.00	S	
Clinton Battery Utility, LLC	ER16-2194	Clinton Battery Project	Clinton Battery Utility, LLC	Clinton Battery Utility, LLC	N/A	PJM	Northeast	10/14/2016	10.00	10.00	N	
Criterion Power Partners, LLC	ER10-1443	Criterion WF	Criterion Power Partners, LLC	Criterion Power Partners, LLC	N/A	PJM	Northeast	2/4/2011	70.00	70.00	S	
Exelon Generation Company, LLC	ER00-3251	Braidwood 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	7/1/1988	1224.90	1183.00	S	
Exelon Generation Company, LLC	ER00-3251	Braidwood 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1988	1224.90	1154.00	S	
Exelon Generation Company, LLC	ER00-3251	Byron 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	9/1/1985	1224.90	1164.00	S	
Exelon Generation Company, LLC	ER00-3251	Byron 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/1987	1224.90	1136.00	S	
Exelon Generation Company, LLC	ER00-3251	Dresden 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	8/1/1970	1009.00	902.00	S	
Exelon Generation Company, LLC	ER00-3251	Dresden 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1971	1009.00	895.00	S	
Exelon Generation Company, LLC	ER00-3251	LaSalle 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	1/1/1984	1170.00	1130.00	S	
Exelon Generation Company, LLC	ER00-3251	LaSalle 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	10/1/1984	1170.00	1133.90	S	
Exelon Generation Company, LLC	ER00-3251	Quad Cities 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1972	1009.30	908.00	S	4
Exelon Generation Company, LLC	ER00-3251	Quad Cities 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	12/1/1972	1009.30	911.00	S	5
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Exelon Generation Company, LLC	ER00-3251	SeChicagoUnit 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM	Northeast	5/24/2002	50.90	37.00	S	
Fair Wind Power Partners, LLC	ER15-2293	Fair Wind WF	Fair Wind Power Partners, LLC	Fair Wind Power Partners, LLC	N/A	PJM	Northeast	11/24/2015	30.00	30.00	S	
Fourmile Wind Energy, LLC	ER14-2145 QF14-721	Fourmile Ridge WF	Fourmile Wind Energy, LLC	Fourmile Wind Energy, LLC	N/A	PJM	Northeast	1/15/2015	40.00	40.00	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 1	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	

SI-SSA-0010-3861

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned by	Controlled by	Date Control Transferred	Location		In-Service Date	Capacity Rating: Nameplate (MW)	Capacity Rating: Used in Filing (MW)	Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative	End Note Number (Enter text in End Note Tab)
						Market / Balancing Authority Area	Geographic Region					
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 2	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 3	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 4	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Handsome Lake Energy, LLC	ER10-2180	Handsome Lake 5	Handsome Lake Energy, LLC	Handsome Lake Energy, LLC	N/A	PJM	Northeast	7/31/2001	58.90	53.50	S	
Bethlehem Renewable Energy, LLC	ER07-903	Bethlehem Landfill	Bethlehem Renewable Energy, LLC	Bethlehem Renewable Energy, LLC	N/A	PJM 5004/5005	Northeast	3/1/2008	5.50	3.70	S	
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 1	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM 5004/5005	Northeast	5/1/1975	918.00	866.00	S	
Calvert Cliffs Nuclear Power Plant, LLC	ER00-2917	Calvert Cliffs 2	Calvert Cliffs Nuclear Power Plant, LLC	Calvert Cliffs Nuclear Power Plant, LLC	N/A	PJM 5004/5005	Northeast	4/1/1977	910.70	841.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Gould Street 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	12/1/1952	103.50	97.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.60	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	15.60	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	14.50	S	
Constellation Power Source Generation, LLC	ER00-1598	Notch Cliff 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1969	18.00	16.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	1/1/1972	53.10	52.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	4/1/1972	53.10	51.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	4/1/1972	53.10	52.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 51	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/1/1995	192.00	147.60	S	
Constellation Power Source Generation, LLC	ER00-1598	Perryman 6	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	6/28/2015	141.00	109.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 1	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	8/1/1970	20.70	15.30	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 2	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	8/1/1970	20.70	16.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 3	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	20.70	14.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Philadelphia Road 4	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	20.70	14.80	S	
Constellation Power Source Generation, LLC	ER00-1598	Riverside 7	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	25.00	19.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Riverside 8	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	9/1/1970	25.00	20.00	S	
Constellation Power Source Generation, LLC	ER00-1598	Westport 5	Constellation Power Source Generation, LLC	Constellation Power Source Generation, LLC	N/A	PJM 5004/5005	Northeast	2/1/1969	121.50	115.80	S	
Eastern Landfill Gas, LLC	ER05-1054	Eastern Landfill	Eastern Landfill Gas, LLC	Eastern Landfill Gas, LLC	N/A	PJM 5004/5005	Northeast	10/26/2006	3.00	4.00	S	
Exelon Generation Company, LLC	ER00-3251	TMI 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM 5004/5005	Northeast	9/2/1974	980.90	802.80	S	
Exelon Generation Company, LLC	ER00-3251	Chester 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/7/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Chester 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/20/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Chester 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/6/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/1/1928	45.00	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/25/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/4/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/1/1928	36.00	36.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/6/1928	48.00	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/5/1928	47.70	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1928	36.00	36.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/1/1928	47.70	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1928	48.00	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/10/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Conowingo 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/25/1964	55.60	65.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 21	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 22	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/18/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 31	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	8/6/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 32	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	8/8/1974	68.30	48.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 41	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Croydon 42	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1974	68.30	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/7/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/19/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 12	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/12/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Delaware 9	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/24/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/20/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 20	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/24/1974	391.00	380.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 30	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	3/7/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/29/1976	391.00	380.00	S	
Exelon Generation Company, LLC	ER00-3251	Eddystone 40	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/21/1970	21.20	17.00	S	

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned by	Controlled by	Date Control Transferred	Location		In-Service Date	Capacity Rating: Nameplate (MW)	Capacity Rating: Used in Filing (MW)	Capacity Raiting: Methodology Used in [K]: (N)ameplate, (S)easonal, 5-yr (U)nit, 5-yr (E)IA, (A)lternative	End Note Number (Enter text in End Note Tab)
						Market / Balancing Authority Area	Geographic Region					
Exelon Generation Company, LLC	ER00-3251	Fairless Hills A	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1996	30.00	30.00	S	
Exelon Generation Company, LLC	ER00-3251	Fairless Hills B	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1996	30.00	30.00	S	
Exelon Generation Company, LLC	ER00-3251	Falls 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/22/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Falls 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/10/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Falls 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/28/1970	21.10	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Limerick 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/1/1986	1138.50	1119.70	S	
Exelon Generation Company, LLC	ER00-3251	Limerick 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	1/1/1990	1138.50	1122.10	S	
Exelon Generation Company, LLC	ER00-3251	Moser 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/9/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Moser 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/29/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Moser 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/11/1970	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/10/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	4/10/1967	134.00	133.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/1/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/11/1967	134.00	133.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 7	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/10/1968	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Muddy Run 8	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	2/10/1968	134.00	134.00	S	
Exelon Generation Company, LLC	ER00-3251	Oyster Creek 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/1/1969	550.00	607.70	S	
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/5/1974	1244.80	1223.70	S	6
Exelon Generation Company, LLC	ER00-3251	Peach Bottom 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	12/23/1974	1377.00	1226.70	S	7
Exelon Generation Company, LLC	ER00-3251	Pennsbury 1	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/1/1996	3.00	3.00	S	
Exelon Generation Company, LLC	ER00-3251	Pennsbury 2	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	9/1/1996	3.00	3.00	S	
Exelon Generation Company, LLC	ER00-3251	Richmond 91	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/7/1973	65.80	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Richmond 92	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/7/1973	65.80	49.00	S	
Exelon Generation Company, LLC	ER00-3251	Salem 1	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	6/30/1977	1251.40	1173.99	S	8
Exelon Generation Company, LLC	ER00-3251	Salem 2	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	10/13/1981	1216.40	1158.02	S	9
Exelon Generation Company, LLC	ER00-3251	Salem 3	PSEG (ExGen 42.59%)	PSEG	N/A	PJM-East	Northeast	6/17/1971	41.80	37.57	S	10
Exelon Generation Company, LLC	ER00-3251	Schuylkill 10	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	5/30/1969	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Schuylkill 11	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/11/1971	21.20	17.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 3	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	6/14/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 4	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	10/9/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 5	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	7/26/1967	18.60	13.00	S	
Exelon Generation Company, LLC	ER00-3251	Southwark 6	Exelon Generation Company, LLC	Exelon Generation Company, LLC	N/A	PJM-East	Northeast	11/7/1968	18.60	13.00	S	
Cassia Gulch Wind Park LLC	ER10-75 QF05-180	Cassia Gulch WF	Cassia Gulch Wind Park LLC	Cassia Gulch Wind Park LLC	N/A	IPCO	Northwest	3/31/2009	18.90	18.90	S	
High Mesa Energy, LLC	ER12-2528 QF13-77	High Mesa WF	High Mesa Energy, LLC	High Mesa Energy, LLC	N/A	IPCO	Northwest	8/28/2012	39.90	39.90	S	
Tuana Springs Energy, LLC	ER10-87 QF08-742	Tuana Springs WF	Tuana Springs Energy, LLC	Tuana Springs Energy, LLC	N/A	IPCO	Northwest	7/27/2010	16.80	16.80	S	
Cow Branch Wind Power, L.L.C.	ER07-1223 QF07-253	Cow Branch WF	Cow Branch Wind Power, L.L.C.	Cow Branch Wind Power, L.L.C.	N/A	AECI	Southeast	3/3/2008	50.40	50.40	S	
CR Clearing, LLC	ER07-1222 QF07-248	Conception WF	CR Clearing, LLC	CR Clearing, LLC	N/A	AECI	Southeast	5/1/2008	50.40	50.40	S	
Wind Capital Holdings, LLC	ER07-1208 QF07-222	Wind Capital Holdings LLC WF	Wind Capital Holdings, LLC	Wind Capital Holdings, LLC	N/A	AECI	Southeast	5/14/2007	56.70	56.70	S	
CER Generation, LLC	ER10-662	Hillabee GT1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	258.40	234.40	S	
CER Generation, LLC	ER10-662	Hillabee GT2	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	258.40	234.40	S	
CER Generation, LLC	ER10-662	Hillabee STG1	CER Generation, LLC	CER Generation, LLC	N/A	SOCO	Southeast	6/8/2010	306.00	283.90	S	
AV Solar Ranch 1, LLC	ER12-2178	Antelope Valley SF	AV Solar Ranch 1, LLC	AV Solar Ranch 1, LLC	N/A	CAISO	Southwest	12/28/2012	253.00	241.50	S	
Bluestem Wind Energy, LLC	ER16-2363	Bluestem WF	Bluestem Wind Energy, LLC	Bluestem Wind Energy, LLC	N/A	SPP	SPP	12/16/2016	198.00	198.00	N	
Exelon Wind 4, LLC	ER07-1202 QF03-13	Exelon Wind 4 WF	Exelon Wind 4, LLC	Exelon Wind 4, LLC	N/A	SPP	SPP	12/15/2006	79.80	79.80	S	
Shooting Star Wind Project, LLC	ER12-1829	Shooting Star WF	Shooting Star Wind Project, LLC	Shooting Star Wind Project, LLC	N/A	SPP	SPP	9/29/2012	104.00	104.00	S	
Wildcat Wind, LLC	ER12-1223 QF12-412	Wildcat WF	Wildcat Wind, LLC	Wildcat Wind, LLC	N/A	SPP	SPP	7/1/2012	27.30	27.30	S	

Asset Appendix: Transmission Assets/Natural Gas Asset - December 2016

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
						Location			
Filing Entity and its Energy Affiliates	**Cite to order accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO**	**Asset Name and Use**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Market / Balancing Authority Area**	**Geographic Region**	**Size: (length and kV)**	**End Note Number (Enter text in End Note Tab)**
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	703.18 combined miles 115kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	54.82 combined miles 138kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	322.23 combined miles 230kV lines	
Baltimore Gas and Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Baltimore Gas and Electric Company	PJM	1998	PJM	Northeast	217.94 combined miles 500kV lines	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Transportation	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	161.4 combined miles	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Storage (LNG)	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	1,056 mmcf	
Baltimore Gas and Electric Company	N/A	Intrastate Gas Distribution	Baltimore Gas and Electric Company	Baltimore Gas and Electric Company	N/A	PJM	Northeast	13,398 combined miles	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	90 combined miles 765kV lines	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	2,656 combined miles 345kV lines	
Commonwealth Edison Company	107 FERC ¶ 61,087 (2004)	Electric Transmission	Commonwealth Edison Company	PJM	2004	PJM	Northeast	2,904 combined miles 138kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	446 combined miles 500kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	548 combined miles 230kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	156 combined miles 138kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	200 combined miles 69kV lines	
PECO Energy Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	PECO Energy Company	PJM	1998	PJM	Northeast	0.47 combined miles 13.2kV lines	
PECO Energy Company	N/A	Intrastate Gas Transportation	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	30 combined miles	
PECO Energy Company	N/A	Intrastate Gas Storage (LNG)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	1,200 mmcf	
PECO Energy Company	N/A	Intrastate Gas Stogare (LP)	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	125 mmcf	
PECO Energy Company	N/A	Intrastate Gas Distribution	PECO Energy Company	PECO Energy Company	N/A	PJM	Northeast	13,046 combined miles	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	281 combined miles 500kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	223 combined miles 230kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	242 combined miles 138kV lines	
Atlantic City Electric Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Atlantic City Electric Company	PJM	1998	PJM	Northeast	636 combined miles 69kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	297 combined miles 500kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	470 combined miles 230kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	557 combined miles 138kV lines	
Delmarva Power & Light Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Delmarva Power & Light Company	PJM	1998	PJM	Northeast	580 combined miles 69kV lines	
Delmarva Power & Light Company	N/A	Intrastate Gas Transportation	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	111 combined miles	
Delmarva Power & Light Company	N/A	Intrastate Gas Storage (LNG)	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	248 mmcf	
Delmarva Power & Light Company	N/A	Intrastate Gas Distribution	Delmarva Power & Light Company	PJM	N/A	PJM	Northeast	3,279 combined miles	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	142 combined miles 500kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	821 combined miles 230kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	89 combined miles 138kV lines	
Potomac Electric Power Company	81 FERC ¶ 61,257 (1997)	Electric Transmission	Potomac Electric Power Company	PJM	1998	PJM	Northeast	38 combined miles 115kV lines	

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Exelon

March 17, 2016

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Docket Nos. RM05-15-000; RM94-14

Enclosed please find our annual Federal Energy Regulatory Commission (FERC) financial report as produced by our trustee, The Northern Trust Company. The Exelon Generation Company, LLC units are reported as follows:

- those formerly owned by Commonwealth Edison Company (Braidwood 1 & 2, Byron 1 & 2, Dresden 1, 2 & 3, LaSalle 1& 2, Zion 1& 2 and Quad Cities 1 & 2) – the reports are consolidated for the Tax Qualified and Non-Tax Qualified Trusts;

- those formerly owned by PECO Energy Company (Limerick 1 & 2, Salem 1 & 2, and Peach Bottom 1, 2 & 3) - the reports are consolidated for the Tax Qualified and Non-Tax Qualified Trusts; and

- those formerly owned by AmerGen Energy Company, LLC the reports are provided separately for each of the three units (TMI, Oyster Creek and Clinton) and the reports are consolidated for Tax Qualified and Non-Tax Qualified Trusts.

In 2015, there were no decommissioning expenses paid out of any Exelon units and only the legacy PECO units received rate payer contributions.

There has not been an opinion expressed on any of the attached reports by an independent public accountant, therefore none is enclosed.

If you have any questions, please contact me at (312) 394-3956.

Sincerely,

Brian E. Andersen

Brian E. Andersen
Managing Director, Public Markets and NDT Investments

Clinton

SI-SSA-0010-3932

Change in Book and Market Value

	Cost	Market value	For more information
Opening balance	367,687,771.37	500,931,691.94	Beginning Assets
Miscellaneous Cash Receipts	0.10	0.10	See funding & disbursement summary
Interportfolio Transfers In	94,617,807.47	94,617,807.47	See funding & disbursement summary
Security Receipts	6,090,405.11	6,720,886.00	See funding & disbursement summary
Total receipts	100,708,212.68	101,338,693.57	See funding & disbursement summary
Interportfolio Transfers Out	- 94,617,807.47	- 94,617,807.47	See funding & disbursement summary
Security Deliveries	- 6,090,405.11	- 6,720,886.00	See funding & disbursement summary
Total disbursements	- 100,708,212.58	- 101,338,693.47	See funding & disbursement summary
Income received	12,128,427.22	12,128,427.22	See income & expense summary, cash activity detail
Expenses paid Fund expenses/ taxes	- 7,123,227.42	- 7,123,227.42	See income & expense summary
Unrealized gain/loss change	0.00	- 48,149,312.57	See asset summary
Realized gain/loss Gain / Loss	30,711,595.63	30,711,595.63	See realized gain/loss summary
Accrued income change	- 283,006.65	- 283,006.65	See income & expense summary
Total amortization expense	- 3,489,028.07	- 3,489,028.07	See fixed income amortization
Total OID/MKT accretion income	79,075.92	79,075.92	See fixed income amortization
Accrued expense change	253,447.55	253,447.55	See income & expense summary
Closing balance	399,965,055.65	485,059,663.65	Ending Assets

No Rate payer contributions
No Decommissioning expense

SI-SSA-0010-3933

◆ Change in Cash Value

	Market value	Cost	For more information
Opening balance	16,307,815.46	16,308,820.59	
Miscellaneous cash receipts	- 38,825.11	- 38,825.11	See funding & disbursement summary
Interportfolio transfers in	94,617,807.47	94,617,807.47	See funding & disbursement summary
Total receipts	94,578,982.36	94,578,982.36	See funding & disbursement summary
Interportfolio transfers out	- 94,617,807.47	- 94,617,807.47	See funding & disbursement summary
Total disbursements	- 94,617,807.47	- 94,617,807.47	See funding & disbursement summary
Income received	12,136,038.44	12,136,038.44	See income & expense summary, cash activity detail
Expenses paid	- 7,123,227.42	- 7,123,227.42	See income & expense summary
Capital changes	8,030,644.23	8,030,644.23	See capital change detail
Foreign currency bought	36,635,003.59	36,635,003.59	See foreign exchange summary
Foreign currency sold	- 36,635,003.59	- 36,635,003.59	See foreign exchange summary
Realized gain/loss	64,741.79	64,741.79	See realized gain/loss summary
Unrealized gain/loss	829.84	0.00	See asset summary
Securities bought Purchases	- 202,101,213.63	- 202,101,213.63	See investment transaction summary
Securities sold Sales	177,532,428.96	177,532,428.96	See investment transaction summary
Principal paydowns	2,292,879.02	2,292,879.02	See investment transaction summary
Closing balance	7,102,111.58	7,102,286.87	

SI-SSA-0010-3934

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Translation	Total	Market value incl. accruals	%
All Other								
Recoverable taxes								
Recoverable taxes	24,018.99	0.00	0.00	0.00	0.00	0.00	24,018.99	0.005%
Total recoverable taxes	**24,018.99**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**24,018.99**	**0.005%**
Total all other	**24,018.99**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**24,018.99**	**0.005%**
Cash and Cash Equivalents								
Funds - short term investment								
Funds - Short Term Investment	65.52	5,416,384.78	5,416,384.78	0.00	0.00	0.00	5,416,450.30	1.117%
Total funds - short term investment	**65.52**	**5,416,384.78**	**5,416,384.78**	**0.00**	**0.00**	**0.00**	**5,416,450.30**	**1.117%**
Cash								
Cash	- 50.48	129,148.99	129,324.28	0.00	-175.29	- 175.29	129,098.51	0.027%
Total cash	**- 50.48**	**129,148.99**	**129,324.28**	**0.00**	**-175.29**	**- 175.29**	**129,098.51**	**0.027%**
Invested cash								
Invested cash	11.11	1,556,577.81	1,556,577.81	0.00	0.00	0.00	1,556,588.92	0.321%
Total invested cash	**11.11**	**1,556,577.81**	**1,556,577.81**	**0.00**	**0.00**	**0.00**	**1,556,588.92**	**0.321%**
Total cash and cash equivalents	**26.15**	**7,102,111.58**	**7,102,286.87**	**0.00**	**-175.29**	**- 175.29**	**7,102,137.73**	**1.464%**
Adjustments To Cash								
Pending foreign exchange purchases Ending liability								
Pending foreign exchange purchases	0.00	40,128.26	40,126.96	0.00	1.30	1.30	40,128.26	0.008%
Total pending foreign exchange purchases	**0.00**	**40,128.26**	**40,126.96**	**0.00**	**1.30**	**1.30**	**40,128.26**	**0.008%**
Pending foreign exchange sales								
Pending foreign exchange sales	0.00	- 40,126.96	- 40,126.96	0.00	0.00	0.00	-40,126.96	- 0.008%
Total pending foreign exchange sales	**0.00**	**- 40,126.96**	**- 40,126.96**	**0.00**	**0.00**	**0.00**	**-40,126.96**	**- 0.008%**

SI-SSA-0010-3935

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Adjustments To Cash								
Pending trade purchases		Ending liability						
Pending trade purchases	0.00	- 1,597,099.33	- 1,597,100.31	0.00	0.98	0.98	-1,597,099.33	- 0.329%
Total pending trade purchases	**0.00**	**- 1,597,099.33**	**- 1,597,100.31**	**0.00**	**0.98**	**0.98**	**-1,597,099.33**	**- 0.329%**
Pending trade sales								
Pending trade sales	0.00	2,008,993.77	2,008,993.77	0.00	0.00	0.00	2,008,993.77	0.414%
Total pending trade sales	**0.00**	**2,008,993.77**	**2,008,993.77**	**0.00**	**0.00**	**0.00**	**2,008,993.77**	**0.414%**
Total adjustments to cash	**0.00**	**411,895.74**	**411,893.46**	**0.00**	**2.28**	**2.28**	**411,895.74**	**0.085%**
Total Unrealized Gains						**103,871,414.73**		
Total Unrealized Losses						**- 18,776,806.73**		
Total	**1,727,843.69**	**483,331,819.96**	**398,237,211.96**	**89,128,974.44**	**-4,034,366.44**	**85,094,608.00**	**485,059,663.65**	**100.000%**

Total Cost incl. Accruals **399,965,055.65**

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
All Other								
Recoverable taxes								
Recoverable taxes	1,532.97	0.00	0.00	0.00	0.00	0.00	1,532.97	0.000%
Total recoverable taxes	**1,532.97**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**1,532.97**	**0.000%**
Total all other	**1,532.97**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**1,532.97**	**0.000%**
Cash and Cash Equivalents								
Funds - short term investment								
Funds - Short Term Investment	116.27	13,447,595.26	13,447,595.26	0.00	0.00	0.00	13,447,711.53	2.685%
Total funds - short term investment	**116.27**	**13,447,595.26**	**13,447,595.26**	**0.00**	**0.00**	**0.00**	**13,447,711.53**	**2.685%**
Cash								
Cash	3.42	38,939.34	39,944.47	0.00	-1,005.13	- 1,005.13	38,942.76	0.008%
Total cash	**3.42**	**38,939.34**	**39,944.47**	**0.00**	**-1,005.13**	**- 1,005.13**	**38,942.76**	**0.008%**
Invested cash								
Invested cash	26.44	2,821,280.86	2,821,280.86	0.00	0.00	0.00	2,821,307.30	0.563%
Total invested cash	**26.44**	**2,821,280.86**	**2,821,280.86**	**0.00**	**0.00**	**0.00**	**2,821,307.30**	**0.563%**
Total cash and cash equivalents	**146.13**	**16,307,815.46**	**16,308,820.59**	**0.00**	**-1,005.13**	**- 1,005.13**	**16,307,961.59**	**3.256%**
Adjustments To Cash								
Pending trade sales								
Pending trade sales	0.00	428,724.31	428,724.31	0.00	0.00	0.00	428,724.31	0.086%
Total pending trade sales	**0.00**	**428,724.31**	**428,724.31**	**0.00**	**0.00**	**0.00**	**428,724.31**	**0.086%**
Other payables Beginning liability								
Other Payables	0.00	- 38,825.21	- 38,825.21	0.00	0.00	0.00	-38,825.21	- 0.008%
Total other payables	**0.00**	**- 38,825.21**	**- 38,825.21**	**0.00**	**0.00**	**0.00**	**-38,825.21**	**- 0.008%**
Total adjustments to cash	**0.00**	**389,899.10**	**389,899.10**	**0.00**	**0.00**	**0.00**	**389,899.10**	**0.078%**

SI-SSA-0010-3937

Oyster Creek

SI-SSA-0010-3938

Change in Book and Market Value

	Cost	Market value	For more information
Opening balance	663,078,718.20	861,563,852.11	Beginning Assets
Miscellaneous Cash Receipts	0.42	0.42	See funding & disbursement summary
Interportfolio Transfers In	98,373,742.56	98,373,742.56	See funding & disbursement summary
Security Receipts	12,805,852.77	13,213,330.28	See funding & disbursement summary
Total receipts	111,179,595.75	111,587,073.26	See funding & disbursement summary
Interportfolio Transfers Out	- 98,373,742.56	- 98,373,742.56	See funding & disbursement summary
Security Deliveries	- 12,805,852.49	- 13,213,329.00	See funding & disbursement summary
Total disbursements	- 111,179,595.05	- 111,587,071.56	See funding & disbursement summary
Income received	19,096,141.47	19,096,141.47	See income & expense summary, cash activity detail
Expenses paid Fund expenses/taxes	- 11,624,517.28	- 11,624,517.28	See income & expense summary
Unrealized gain/loss change	0.00	- 54,642,672.63	See asset summary
Unrealized gain/loss on security movements	0.00	- 1.00	See funding & disbursement summary
Realized gain/loss Gain/Loss	27,387,327.30	27,387,327.30	See realized gain/loss summary
Accrued income change	- 247,914.91	- 247,914.91	See income & expense summary
Total amortization expense	- 5,225,602.72	- 5,225,602.72	See fixed income amortization
Total OID/MKT accretion income	76,989.66	76,989.66	See fixed income amortization
Accrued expense change	62,170.59	62,170.59	See income & expense summary
Closing balance	692,603,313.01	836,445,774.29	Ending Assets

No rate payer contributions
No decommissioning expense

SI-SSA-0010-3939

◆ Change in Cash Value

	Market value	Cost	For more information
Opening balance	5,998,683.20	6,002,885.02	
Miscellaneous cash receipts	- 34,474.60	- 34,474.60	See funding & disbursement summary
Interportfolio transfers in	98,373,742.56	98,373,742.56	See funding & disbursement summary
Total receipts	98,339,267.96	98,339,267.96	See funding & disbursement summary
Interportfolio transfers out	- 98,373,742.56	- 98,373,742.56	See funding & disbursement summary
Total disbursements	- 98,373,742.56	- 98,373,742.56	See funding & disbursement summary
Income received	19,173,155.33	19,173,155.33	See income & expense summary, cash activity detail
Expenses paid	- 11,624,517.28	- 11,624,517.28	See income & expense summary
Capital changes	5,360,992.72	5,360,992.72	See capital change detail
Foreign currency bought	2,433,012.68	2,433,012.68	See foreign exchange summary
Foreign currency sold	- 2,433,012.68	- 2,433,012.68	See foreign exchange summary
Realized gain/loss	- 19,486.71	- 19,486.71	See realized gain/loss summary
Unrealized gain/loss	2,185.26	0.00	See asset summary
Securities bought Purchases	- 419,864,464.37	- 419,864,464.37	See investment transaction summary
Securities sold Sales	448,085,621.38	448,085,621.38	See investment transaction summary
Principal paydowns	1,533,967.58	1,533,967.58	See investment transaction summary
Closing balance	48,611,662.51	48,613,679.07	

SI-SSA-0010-3940

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Funds - short term investment								
Funds - Short Term Investment	431.03	45,442,822.67	45,442,822.67	0.00	0.00	0.00	45,443,253.70	5.433%
Total funds - short term investment	**431.03**	**45,442,822.67**	**45,442,822.67**	**0.00**	**0.00**	**0.00**	**45,443,253.70**	**5.433%**
Cash								
Cash	- 8.38	125,503.83	127,520.39	0.00	-2,016.56	- 2,016.56	125,495.45	0.015%
Total cash	**- 8.38**	**125,503.83**	**127,520.39**	**0.00**	**-2,016.56**	**- 2,016.56**	**125,495.45**	**0.015%**
Invested cash								
Invested cash	19.24	3,043,336.01	3,043,336.01	0.00	0.00	0.00	3,043,355.25	0.364%
Total invested cash	**19.24**	**3,043,336.01**	**3,043,336.01**	**0.00**	**0.00**	**0.00**	**3,043,355.25**	**0.364%**
Total cash and cash equivalents	**441.89**	**48,611,662.51**	**48,613,679.07**	**0.00**	**-2,016.56**	**- 2,016.56**	**48,612,104.40**	**5.812%**
Adjustments To Cash								
Pending foreign exchange purchases ← Ending liability								
Pending foreign exchange purchases	0.00	23,608.30	23,749.57	0.00	-141.27	- 141.27	23,608.30	0.003%
Total pending foreign exchange purchases	**0.00**	**23,608.30**	**23,749.57**	**0.00**	**-141.27**	**- 141.27**	**23,608.30**	**0.003%**
Pending foreign exchange sales								
Pending foreign exchange sales	0.00	- 23,749.57	- 23,749.57	0.00	0.00	0.00	-23,749.57	- 0.003%
Total pending foreign exchange sales	**0.00**	**- 23,749.57**	**- 23,749.57**	**0.00**	**0.00**	**0.00**	**-23,749.57**	**- 0.003%**
Pending trade purchases ← Ending liability								
Pending trade purchases	0.00	- 14,708,549.64	- 14,708,780.71	0.00	231.07	231.07	-14,708,549.64	- 1.758%
Total pending trade purchases	**0.00**	**- 14,708,549.64**	**- 14,708,780.71**	**0.00**	**231.07**	**231.07**	**-14,708,549.64**	**- 1.758%**
Pending trade sales								
Pending trade sales	0.00	14,621,566.72	14,621,566.72	0.00	0.00	0.00	14,621,566.72	1.748%
Total pending trade sales	**0.00**	**14,621,566.72**	**14,621,566.72**	**0.00**	**0.00**	**0.00**	**14,621,566.72**	**1.748%**
Total adjustments to cash	**0.00**	**- 87,124.19**	**- 87,213.99**	**0.00**	**89.80**	**89.80**	**-87,124.19**	**- 0.010%**

SI-SSA-0010-3941

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Funds - short term investment								
Funds - Short Term Investment	23.06	1,718,029.05	1,718,029.05	0.00	0.00	0.00	1,718,052.11	0.199%
Total funds - short term investment	**23.06**	**1,718,029.05**	**1,718,029.05**	**0.00**	**0.00**	**0.00**	**1,718,052.11**	**0.199%**
Cash								
Cash	55.51	152,927.88	157,129.70	0.00	-4,201.82	- 4,201.82	152,983.39	0.018%
Total cash	**55.51**	**152,927.88**	**157,129.70**	**0.00**	**-4,201.82**	**- 4,201.82**	**152,983.39**	**0.018%**
Invested cash								
Invested cash	28.12	4,127,726.27	4,127,726.27	0.00	0.00	0.00	4,127,754.39	0.479%
Total invested cash	**28.12**	**4,127,726.27**	**4,127,726.27**	**0.00**	**0.00**	**0.00**	**4,127,754.39**	**0.479%**
Total cash and cash equivalents	**106.69**	**5,998,683.20**	**6,002,885.02**	**0.00**	**-4,201.82**	**- 4,201.82**	**5,998,789.89**	**0.696%**
Adjustments To Cash								
Pending trade purchases		Beginning liability						
Pending trade purchases	0.00	- 1,678,131.90	- 1,678,131.90	0.00	0.00	0.00	-1,678,131.90	- 0.195%
Total pending trade purchases	**0.00**	**- 1,678,131.90**	**- 1,678,131.90**	**0.00**	**0.00**	**0.00**	**-1,678,131.90**	**- 0.195%**
Pending trade sales								
Pending trade sales	0.00	798,764.98	798,764.98	0.00	0.00	0.00	798,764.98	0.093%
Total pending trade sales	**0.00**	**798,764.98**	**798,764.98**	**0.00**	**0.00**	**0.00**	**798,764.98**	**0.093%**
Other payables								
Other Payables	0.00	- 34,475.02	- 34,475.02	0.00	0.00	0.00	-34,475.02	- 0.004%
Total other payables	**0.00**	**- 34,475.02**	**- 34,475.02**	**0.00**	**0.00**	**0.00**	**-34,475.02**	**- 0.004%**
Total adjustments to cash	**0.00**	**- 913,841.94**	**- 913,841.94**	**0.00**	**0.00**	**0.00**	**-913,841.94**	**- 0.106%**

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Change in Book and Market Value

	Cost	Market value	For more information
Opening balance	487,985,290.94	604,855,677.18	Beginning Assets
Miscellaneous Cash Receipts	0.07	0.07	See funding & disbursement summary
Interportfolio Transfers In	64,831,704.09	64,831,704.09	See funding & disbursement summary
Security Receipts	7,751,422.98	8,554,306.24	See funding & disbursement summary
Total receipts	72,583,127.14	73,386,010.40	See funding & disbursement summary
Interportfolio Transfers Out	- 64,831,704.09	- 64,831,704.09	See funding & disbursement summary
Security Deliveries	- 7,751,422.74	- 8,554,306.00	See funding & disbursement summary
Total disbursements	- 72,583,126.83	- 73,386,010.09	See funding & disbursement summary
Income received	13,193,948.71	13,193,948.71	See income & expense summary, cash activity detail
Expenses paid Fund expenses/taxes	- 6,298,291.44	- 6,298,291.44	See income & expense summary
Unrealized gain/loss change	0.00	- 26,051,409.64	See asset summary
Realized gain/loss Gain/loss	7,562,079.88	7,562,079.88	See realized gain/loss summary
Accrued income change	- 207,837.19	- 207,837.19	See income & expense summary
Total amortization expense	- 3,278,199.80	- 3,278,199.80	See fixed income amortization
Total OID/MKT accretion income	40,752.23	40,752.23	See fixed income amortization
Accrued expense change	322,569.82	322,569.82	See income & expense summary
Closing balance	499,320,313.46	590,139,290.06	Ending Assets

No rate payer contributions
No decommissioning expens

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Change in Cash Value

	Market value	Cost	For more information
Opening balance	16,313,092.90	16,313,752.94	
Miscellaneous cash receipts	- 49,413.84	- 49,413.84	See funding & disbursement summary
Interportfolio transfers in	64,831,704.09	64,831,704.09	See funding & disbursement summary
Total receipts	64,782,290.25	64,782,290.25	See funding & disbursement summary
Interportfolio transfers out	- 64,831,704.09	- 64,831,704.09	See funding & disbursement summary
Total disbursements	- 64,831,704.09	- 64,831,704.09	See funding & disbursement summary
Income received	13,214,948.22	13,214,948.22	See income & expense summary, cash activity detail
Expenses paid	- 6,298,291.44	- 6,298,291.44	See income & expense summary
Capital changes	2,198,678.94	2,198,678.94	See capital change detail
Foreign currency bought	1,235,789.31	1,235,789.31	See foreign exchange summary
Foreign currency sold	- 1,235,789.31	- 1,235,789.31	See foreign exchange summary
Realized gain/loss	- 12,963.25	- 12,963.25	See realized gain/loss summary
Unrealized gain/loss	- 972.10	0.00	See asset summary
Securities bought (Purchases)	- 300,405,626.68	- 300,405,626.68	See investment transaction summary
Securities sold (Sales)	294,938,537.05	294,938,537.05	See investment transaction summary
Principal paydowns	1,016,826.31	1,016,826.31	See investment transaction summary
Closing balance	20,914,816.11	20,916,448.25	

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Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Funds - short term investment								
Funds - Short Term Investment	192.05	18,704,355.03	18,704,355.03	0.00	0.00	0.00	18,704,547.08	3.170%
Total funds - short term investment	**192.05**	**18,704,355.03**	**18,704,355.03**	**0.00**	**0.00**	**0.00**	**18,704,547.08**	**3.170%**
Cash								
Cash	24.25	65,135.43	66,767.57	0.00	-1,632.14	- 1,632.14	65,159.68	0.011%
Total cash	**24.25**	**65,135.43**	**66,767.57**	**0.00**	**-1,632.14**	**- 1,632.14**	**65,159.68**	**0.011%**
Invested cash								
Invested cash	17.46	2,145,325.65	2,145,325.65	0.00	0.00	0.00	2,145,343.11	0.364%
Total invested cash	**17.46**	**2,145,325.65**	**2,145,325.65**	**0.00**	**0.00**	**0.00**	**2,145,343.11**	**0.364%**
Total cash and cash equivalents	**233.76**	**20,914,816.11**	**20,916,448.25**	**0.00**	**-1,632.14**	**- 1,632.14**	**20,915,049.87**	**3.544%**
Adjustments To Cash								
Pending foreign exchange purchases * Ending liability								
Pending foreign exchange purchases	0.00	45,308.88	45,454.69	0.00	-145.81	- 145.81	45,308.88	0.008%
Total pending foreign exchange purchases	**0.00**	**45,308.88**	**45,454.69**	**0.00**	**-145.81**	**- 145.81**	**45,308.88**	**0.008%**
Pending foreign exchange sales								
Pending foreign exchange sales	0.00	- 45,454.69	- 45,454.69	0.00	0.00	0.00	-45,454.69	- 0.008%
Total pending foreign exchange sales	**0.00**	**- 45,454.69**	**- 45,454.69**	**0.00**	**0.00**	**0.00**	**-45,454.69**	**- 0.008%**
Pending trade purchases * Ending liability								
Pending trade purchases	0.00	- 4,976,857.62	- 4,976,983.99	0.00	126.37	126.37	-4,976,857.62	- 0.843%
Total pending trade purchases	**0.00**	**- 4,976,857.62**	**- 4,976,983.99**	**0.00**	**126.37**	**126.37**	**-4,976,857.62**	**- 0.843%**
Pending trade sales								
Pending trade sales	0.00	5,784,876.27	5,784,876.27	0.00	0.00	0.00	5,784,876.27	0.980%
Total pending trade sales	**0.00**	**5,784,876.27**	**5,784,876.27**	**0.00**	**0.00**	**0.00**	**5,784,876.27**	**0.980%**
Total adjustments to cash	**0.00**	**807,872.84**	**807,892.28**	**0.00**	**-19.44**	**- 19.44**	**807,872.84**	**0.137%**

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Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Funds - short term investment								
Funds - Short Term Investment	119.00	13,766,264.83	13,766,264.83	0.00	0.00	0.00	13,766,383.83	2.276%
Total funds - short term investment	**119.00**	**13,766,264.83**	**13,766,264.83**	**0.00**	**0.00**	**0.00**	**13,766,383.83**	**2.276%**
Cash								
Cash	9.50	28,842.36	29,502.40	0.00	-660.04	- 660.04	28,851.86	0.005%
Total cash	**9.50**	**28,842.36**	**29,502.40**	**0.00**	**-660.04**	**- 660.04**	**28,851.86**	**0.005%**
Invested cash								
Invested cash	17.34	2,517,985.71	2,517,985.71	0.00	0.00	0.00	2,518,003.05	0.416%
Total invested cash	**17.34**	**2,517,985.71**	**2,517,985.71**	**0.00**	**0.00**	**0.00**	**2,518,003.05**	**0.416%**
Total cash and cash equivalents	**145.84**	**16,313,092.90**	**16,313,752.94**	**0.00**	**-660.04**	**- 660.04**	**16,313,238.74**	**2.697%**
Adjustments To Cash								
Pending trade purchases * Beginning liability								
Pending trade purchases	0.00	- 1,564,684.70	- 1,564,684.70	0.00	0.00	0.00	-1,564,684.70	- 0.259%
Total pending trade purchases	**0.00**	**- 1,564,684.70**	**- 1,564,684.70**	**0.00**	**0.00**	**0.00**	**-1,564,684.70**	**- 0.259%**
Pending trade sales								
Pending trade sales	0.00	813,297.04	813,297.04	0.00	0.00	0.00	813,297.04	0.134%
Total pending trade sales	**0.00**	**813,297.04**	**813,297.04**	**0.00**	**0.00**	**0.00**	**813,297.04**	**0.134%**
Other payables * Beginning liability								
Other Payables	0.00	- 49,413.91	- 49,413.91	0.00	0.00	0.00	-49,413.91	- 0.008%
Total other payables	**0.00**	**- 49,413.91**	**- 49,413.91**	**0.00**	**0.00**	**0.00**	**-49,413.91**	**- 0.008%**
Total adjustments to cash	**0.00**	**- 800,801.57**	**- 800,801.57**	**0.00**	**0.00**	**0.00**	**-800,801.57**	**- 0.132%**

Legacy PECO

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◆ Change in Book and Market Value

	Cost	Market value	For more information
Opening balance	1,391,896,346.00	1,761,786,231.58	Beginning Assets
Miscellaneous Cash Receipts	504,415.84	504,415.84	See funding & disbursement summary
Sponsor Contributions Rate Payer Cont.	23,454,732.96	23,454,732.96	See funding & disbursement summary
Interportfolio Transfers In	206,306,470.86	206,306,470.86	See funding & disbursement summary
Security Receipts	19,694,938.81	21,733,871.52	See funding & disbursement summary
Total receipts	249,960,558.47	251,999,491.18	See funding & disbursement summary
Miscellaneous Cash Disbursements	- 504,122.67	- 504,122.67	See funding & disbursement summary
Interportfolio Transfers Out	- 209,460,479.86	- 209,460,479.86	See funding & disbursement summary
Security Deliveries	- 19,694,938.29	- 21,733,871.00	See funding & disbursement summary
Total disbursements	- 229,659,540.82	- 231,698,473.53	See funding & disbursement summary
Income received	41,560,836.53	41,560,836.53	See income & expense summary, cash activity detail
Expenses paid Fund expenses/taxes	- 14,188,295.05	- 14,188,295.05	See income & expense summary
Unrealized gain/loss change	0.00	- 50,164,334.61	See asset summary
Realized gain/loss Gain/loss	6,492,490.84	6,492,490.84	See realized gain/loss summary
Accrued income change	- 507,502.85	- 507,502.85	See income & expense summary
Total amortization expense	- 4,048,321.83	- 4,048,321.83	See fixed income amortization
Total OID/MKT accretion income	119,035.35	119,035.35	See fixed income amortization
Accrued expense change	819,588.46	819,588.46	See income & expense summary
Closing balance	1,442,445,195.10	1,762,170,746.07	Ending Assets

No decommissioning expense

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◆ Change in Cash Value

	Market value	Cost	For more information
Opening balance	50,435,499.87	50,436,060.39	
Miscellaneous cash receipts	378,864.24	378,864.24	See funding & disbursement summary
Sponsor contributions	23,454,732.96	23,454,732.96	See funding & disbursement summary
Interportfolio transfers in	206,306,470.86	206,306,470.86	See funding & disbursement summary
Total receipts	230,140,068.06	230,140,068.06	See funding & disbursement summary
Miscellaneous cash disbursements	- 504,122.67	- 504,122.67	See funding & disbursement summary
Interportfolio transfers out	- 209,460,479.86	- 209,460,479.86	See funding & disbursement summary
Total disbursements	- 209,964,602.53	- 209,964,602.53	See funding & disbursement summary
Income received	41,677,711.96	41,677,711.96	See income & expense summary, cash activity detail
Expenses paid	- 14,188,295.05	- 14,188,295.05	See income & expense summary
Capital changes	17,856,738.87	17,856,738.87	See capital change detail
Foreign currency bought	803,171.83	803,171.83	See foreign exchange summary
Foreign currency sold	- 803,171.83	- 803,171.83	See foreign exchange summary
Realized gain/loss	- 2,931.50	- 2,931.50	See realized gain/loss summary
Unrealized gain/loss	379.38	0.00	See asset summary
Securities bought Purchases	- 1,004,493,149.18	- 1,004,493,149.18	See investment transaction summary
Securities sold Sales	922,908,101.81	922,908,101.81	See investment transaction summary
Principal paydowns	3,187,460.33	3,187,460.33	See investment transaction summary
Closing balance	37,556,982.02	37,557,163.16	

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Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Unrealized gain/loss Translation	Unrealized gain/loss Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Cash								
Cash	- 11.46	32,046.87	32,228.01	0.00	-181.14	- 181.14	32,035.41	0.002%
Total cash	**- 11.46**	**32,046.87**	**32,228.01**	**0.00**	**-181.14**	**- 181.14**	**32,035.41**	**0.002%**
Invested cash								
Invested cash	45.39	9,653,641.61	9,653,641.61	0.00	0.00	0.00	9,653,687.00	0.548%
Total invested cash	**45.39**	**9,653,641.61**	**9,653,641.61**	**0.00**	**0.00**	**0.00**	**9,653,687.00**	**0.548%**
Total cash and cash equivalents	**388.45**	**37,556,982.02**	**37,557,163.16**	**0.00**	**-181.14**	**- 181.14**	**37,557,370.47**	**2.131%**
Adjustments To Cash								
Pending trade purchases Ending liability								
Pending trade purchases	0.00	- 18,353,707.94	- 18,353,765.23	0.00	57.29	57.29	-18,353,707.94	- 1.042%
Total pending trade purchases	**0.00**	**- 18,353,707.94**	**- 18,353,765.23**	**0.00**	**57.29**	**57.29**	**-18,353,707.94**	**- 1.042%**
Pending trade sales								
Pending trade sales	0.00	16,191,725.78	16,191,725.78	0.00	0.00	0.00	16,191,725.78	0.919%
Total pending trade sales	**0.00**	**16,191,725.78**	**16,191,725.78**	**0.00**	**0.00**	**0.00**	**16,191,725.78**	**0.919%**
Total adjustments to cash	**0.00**	**- 2,161,982.16**	**- 2,162,039.45**	**0.00**	**57.29**	**57.29**	**-2,161,982.16**	**- 0.123%**
Total Unrealized Gains						**342,838,204.96**		
Total Unrealized Losses						**- 23,112,653.99**		
Total	**5,851,967.47**	**1,756,318,778.60**	**1,436,693,227.63**	**320,831,061.12**	**-1,105,510.15**	**319,725,550.97**	**1,762,170,746.07**	**100.000%**

Total Cost incl. Accruals **1,442,445,195.10**

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Unrealized gain/loss Translation	Unrealized gain/loss Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Cash								
Cash	- 6.83	22,859.35	23,419.87	0.00	-560.52	- 560.52	22,852.52	0.001%
Total cash	**- 6.83**	**22,859.35**	**23,419.87**	**0.00**	**-560.52**	**- 560.52**	**22,852.52**	**0.001%**
Invested cash								
Invested cash	24.99	7,836,564.99	7,836,564.99	0.00	0.00	0.00	7,836,589.98	0.445%
Total invested cash	**24.99**	**7,836,564.99**	**7,836,564.99**	**0.00**	**0.00**	**0.00**	**7,836,589.98**	**0.445%**
Total cash and cash equivalents	**399.94**	**50,725,495.26**	**50,726,045.60**	**10.18**	**-560.52**	**- 550.34**	**50,725,895.20**	**2.879%**
Adjustments To Cash								
Pending trade purchases * Beginning liability								
Pending trade purchases	0.00	- 4,277,142.38	- 4,277,142.38	0.00	0.00	0.00	-4,277,142.38	- 0.243%
Total pending trade purchases	**0.00**	**- 4,277,142.38**	**- 4,277,142.38**	**0.00**	**0.00**	**0.00**	**-4,277,142.38**	**- 0.243%**
Pending trade sales								
Pending trade sales	0.00	1,976,970.05	1,976,970.05	0.00	0.00	0.00	1,976,970.05	0.112%
Total pending trade sales	**0.00**	**1,976,970.05**	**1,976,970.05**	**0.00**	**0.00**	**0.00**	**1,976,970.05**	**0.112%**
Other payables * Beginning liability								
Other Payables	0.00	- 125,551.60	- 125,551.60	0.00	0.00	0.00	-125,551.60	- 0.007%
Total other payables	**0.00**	**- 125,551.60**	**- 125,551.60**	**0.00**	**0.00**	**0.00**	**-125,551.60**	**- 0.007%**
Total adjustments to cash	**0.00**	**- 2,425,723.93**	**- 2,425,723.93**	**0.00**	**0.00**	**0.00**	**-2,425,723.93**	**- 0.138%**
Total Unrealized Gains						**376,172,854.42**		
Total Unrealized Losses						**- 6,282,968.84**		
Total	**5,539,881.86**	**1,756,246,349.72**	**1,386,356,464.14**	**370,756,040.06**	**-866,154.48**	**369,889,885.58**	**1,761,786,231.58**	**100.000%**

Total Cost incl. Accruals **1,391,896,346.00**

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◆ Change in Book and Market Value

	Cost	Market value	For more information
Opening balance	3,368,060,521.20	4,710,555,112.38	Beginning Assets
Interportfolio Transfers In	449,136,661.61	449,136,661.61	See funding & disbursement summary
Security Receipts	57,350,294.33	60,957,190.53	See funding & disbursement summary
Total receipts	506,486,955.94	510,093,852.14	See funding & disbursement summary
Interportfolio Transfers Out	- 449,136,661.61	- 449,136,661.61	See funding & disbursement summary
Security Deliveries	- 57,350,294.33	- 60,957,190.53	See funding & disbursement summary
Total disbursements	- 506,486,955.94	- 510,093,852.14	See funding & disbursement summary
Income received	123,059,638.95	123,059,638.95	See income & expense summary, cash activity detail
Expenses paid Fund expenses/taxes	50,495,526.01	- 50,495,526.01	See income & expense summary
Unrealized gain/loss change	0.00	- 204,584,929.29	See asset summary
Realized gain/loss Gain/loss	56,297,250.23	56,297,250.23	See realized gain/loss summary
Accrued income change	- 1,369,988.43	- 1,369,988.43	See income & expense summary
Total amortization expense	- 8,018,441.14	- 8,018,441.14	See fixed income amortization
Total OID/MKT accretion income	1,775,605.16	1,775,605.16	See fixed income amortization
Accrued expense change	2,340,272.79	2,340,272.79	See income & expense summary
Broker commissions recaptured	50.00	50.00	See income & expense summary
Return of capital	- 20,797.37	- 20,797.37	See capital change detail
Wash Sale Cost Adjustments	8.65	8.65	See investment transaction detail
Wash Sale Adjustment Reclassification	- 8.65	- 8.65	See investment transaction detail
Closing balance	3,491,628,585.38	4,629,538,247.27	Ending Assets

No rate payer contributions
No decommissioning expense

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Change in Cash Value

	Market value	Cost	For more information
Opening balance	129,382,912.65	129,504,808.71	
Miscellaneous cash receipts	- 358,746.85	- 358,746.85	See funding & disbursement summary
Interportfolio transfers in	449,136,661.61	449,136,661.61	See funding & disbursement summary
Total receipts	448,777,914.76	448,777,914.76	See funding & disbursement summary
Interportfolio transfers out	- 449,136,661.61	- 449,136,661.61	See funding & disbursement summary
Total disbursements	- 449,136,661.61	- 449,136,661.61	See funding & disbursement summary
Income received	123,113,315.16	123,113,315.16	See income & expense summary, cash activity detail
Expenses paid	- 50,495,526.01	- 50,495,526.01	See income & expense summary
Capital changes	96,749,294.48	96,749,294.48	See capital change detail
Foreign currency bought	2,187,776,979.13	2,187,776,979.13	See foreign exchange summary
Foreign currency sold	- 2,187,776,979.13	- 2,187,776,979.13	See foreign exchange summary
Realized gain/loss	9,841,460.98	9,841,460.98	See realized gain/loss summary
Mark-to-markets	- 3,065,737.45	- 3,065,737.45	See realized gain/loss summary
Unrealized gain/loss	91,413.08	0.00	See asset summary
Securities bought Purchases	- 2,913,017,669.96	- 2,913,017,669.96	See investment transaction summary
Securities sold Sales	2,696,852,598.07	2,696,852,598.07	See investment transaction summary
Principal paydowns	25,488,752.03	25,488,752.03	See investment transaction summary
Broker commissions recaptured	50.00	50.00	See income & expense summary
Closing balance	114,582,116.18	114,612,599.16	

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Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Derivative Offsets								
Equity futures								
Total equity futures	**0.00**	**- 590,625.00**	**- 590,340.62**	**- 284.38**	**0.00**	**- 284.38**	**-590,625.00**	**- 0.013%**
Fixed income futures								
Germany - EUR	0.00	- 6,306,101.97	- 6,272,826.02	- 48,133.95	14,858.00	- 33,275.95	-6,306,101.97	- 0.136%
United States - USD	0.00	- 160,061,023.44	- 160,351,104.63	290,081.19	0.00	290,081.19	-160,061,023.44	- 3.457%
Total fixed income futures	**0.00**	**- 166,367,125.41**	**- 166,623,930.65**	**241,947.24**	**14,858.00**	**256,805.24**	**-166,367,125.41**	**- 3.594%**
Total derivative offsets	**0.00**	**- 70,710,271.72**	**- 70,912,203.41**	**185,963.61**	**15,968.08**	**201,931.69**	**-70,710,271.72**	**- 1.527%**
Hedge Fund								
Hedge equity								
United States - USD	0.00	58,600,000.00	58,600,000.00	0.00	0.00	0.00	58,600,000.00	1.266%
Total hedge equity	**0.00**	**58,600,000.00**	**58,600,000.00**	**0.00**	**0.00**	**0.00**	**58,600,000.00**	**1.266%**
Total hedge fund	**0.00**	**58,600,000.00**	**58,600,000.00**	**0.00**	**0.00**	**0.00**	**58,600,000.00**	**1.266%**
Liabilities - Ending								
Swap liabilities								
Brazil - BRL	0.00	- 345,064.84	- 23,474.26	- 321,668.55	77.97	- 321,590.58	-345,064.84	- 0.007%
European Union - EUR	0.00	- 80,501.91	- 115,566.15	28,599.04	6,465.20	35,064.24	-80,501.91	- 0.002%
Japan - JPY	0.00	- 166,619.38	- 31,775.14	- 140,414.53	5,570.29	- 134,844.24	-166,619.38	- 0.004%
Mexico - MXN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000%
United Kingdom - GBP	0.00	- 8,447.24	- 35,563.92	24,790.14	2,326.54	27,116.68	-8,447.24	- 0.000%
United States - USD	0.00	- 3,272,695.89	- 968,790.52	- 2,303,905.37	0.00	- 2,303,905.37	-3,272,695.89	- 0.071%
Total swap liabilities	**0.00**	**- 3,873,329.26**	**- 1,175,169.99**	**- 2,712,599.27**	**14,440.00**	**- 2,698,159.27**	**-3,873,329.26**	**- 0.084%**
Obligation to return cash collateral hld								
United States - USD	0.00	- 2,300,000.00	- 2,300,000.00	0.00	0.00	0.00	-2,300,000.00	- 0.050%
Total obligation to return cash collateral hld	**0.00**	**- 2,300,000.00**	**- 2,300,000.00**	**0.00**	**0.00**	**0.00**	**-2,300,000.00**	**- 0.050%**

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Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Translation	Total	Market value incl. accruals	%
Liabilities - Ending								
Exchange cleared swap liabilities								
Australia - AUD	0.00	- 456,263.28	- 470,874.46	- 91,578.68	106,189.86	14,611.18	-456,263.28	- 0.010%
Canada - CAD	0.00	- 33,184.51	- 20,953.27	- 14,559.50	2,328.26	- 12,231.24	-33,184.51	- 0.001%
European Union - EUR	0.00	- 528,920.00	- 488,694.37	- 76,485.65	36,260.02	- 40,225.63	-528,920.00	- 0.011%
Japan - JPY	0.00	- 101,073.90	- 34,671.10	- 71,566.22	5,163.42	- 66,402.80	-101,073.90	- 0.002%
Mexico - MXN	0.00	- 109,617.68	- 68,679.46	- 51,590.42	10,652.20	- 40,938.22	-109,617.68	- 0.002%
United Kingdom - GBP	0.00	- 342,048.57	- 257,250.74	- 91,697.24	6,899.41	- 84,797.83	-342,048.57	- 0.007%
United States - USD	0.00	- 6,850,501.71	- 3,743,748.95	- 3,106,752.76	0.00	- 3,106,752.76	-6,850,501.71	- 0.148%
Total exchange cleared swap liabilities	**0.00**	**- 8,421,609.65**	**- 5,084,872.35**	**- 3,504,230.47**	**167,493.17**	**- 3,336,737.30**	**-8,421,609.65**	**- 0.182%**
Total liabilities	**0.00**	**- 14,594,938.91**	**- 8,560,042.34**	**- 6,216,829.74**	**181,933.17**	**- 6,034,896.57**	**-14,594,938.91**	**- 0.315%**
All Other								
Recoverable taxes								
Recoverable taxes	44,740.86	0.00	0.00	0.00	0.00	0.00	44,740.86	0.001%
Total recoverable taxes	**44,740.86**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**44,740.86**	**0.001%**
Total all other	**44,740.86**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**44,740.86**	**0.001%**
Cash and Cash Equivalents								
Repurchase agreements								
United States - USD	- 22,650.87	- 51,509,713.00	- 51,509,713.00	0.00	0.00	0.00	-51,532,363.87	- 1.113%
Total repurchase agreements	**- 22,650.87**	**- 51,509,713.00**	**- 51,509,713.00**	**0.00**	**0.00**	**0.00**	**-51,532,363.87**	**- 1.113%**
Cash & cash equivalent deriv. - futures								
United States - USD	0.00	- 96,280,687.50	- 96,333,402.11	52,714.61	0.00	52,714.61	-96,280,687.50	- 2.080%
Total cash & cash equivalent deriv. - futures	**0.00**	**- 96,280,687.50**	**- 96,333,402.11**	**52,714.61**	**0.00**	**52,714.61**	**-96,280,687.50**	**- 2.080%**
Cash & cash equiv deriv-margined options								
United Kingdom - GBP	0.00	33,208.81	31,334.25	2,984.64	-1,110.08	1,874.56	33,208.81	0.001%

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Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss: Market	Unrealized gain/loss: Translation	Unrealized gain/loss: Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Variation margin								
Variation Margin	0.00	139,559.09	139,559.63	0.00	-0.54	- 0.54	139,559.09	0.003%
Total variation margin	**0.00**	**139,559.09**	**139,559.63**	**0.00**	**-0.54**	**- 0.54**	**139,559.09**	**0.003%**
Cash collateral due to/from ccp broker								
Cash Collateral Due to/from CCP Broker	0.00	6,367,923.19	6,366,879.44	0.00	1,043.75	1,043.75	6,367,923.19	0.138%
Total cash collateral due to/from ccp broker	**0.00**	**6,367,923.19**	**6,366,879.44**	**0.00**	**1,043.75**	**1,043.75**	**6,367,923.19**	**0.138%**
Total cash and cash equivalents	**- 21,454.12**	**- 33,210,494.46**	**- 33,253,881.70**	**74,980.30**	**-31,593.06**	**43,387.24**	**-33,231,948.58**	**- 0.718%**
Adjustments To Cash								
Pending foreign exchange purchases * Ending liability								
Pending foreign exchange purchases	0.00	196,131,515.45	196,609,908.81	0.00	-478,393.36	- 478,393.36	196,131,515.45	4.237%
Total pending foreign exchange purchases	**0.00**	**196,131,515.45**	**196,609,908.81**	**0.00**	**-478,393.36**	**- 478,393.36**	**196,131,515.45**	**4.237%**
Pending foreign exchange sales								
Pending foreign exchange sales	0.00	- 195,798,186.85	- 196,609,908.81	0.00	811,721.96	811,721.96	-195,798,186.85	- 4.229%
Total pending foreign exchange sales	**0.00**	**- 195,798,186.85**	**- 196,609,908.81**	**0.00**	**811,721.96**	**811,721.96**	**-195,798,186.85**	**- 4.229%**
Pending trade purchases * Ending liability								
Pending trade purchases	0.00	- 34,325,787.18	- 34,629,917.16	0.00	304,129.98	304,129.98	-34,325,787.18	- 0.741%
Total pending trade purchases	**0.00**	**- 34,325,787.18**	**- 34,629,917.16**	**0.00**	**304,129.98**	**304,129.98**	**-34,325,787.18**	**- 0.741%**
Pending trade sales								
Pending trade sales	0.00	32,030,480.58	32,030,480.58	0.00	0.00	0.00	32,030,480.58	0.692%
Total pending trade sales	**0.00**	**32,030,480.58**	**32,030,480.58**	**0.00**	**0.00**	**0.00**	**32,030,480.58**	**0.692%**
Total adjustments to cash	**0.00**	**- 1,961,978.00**	**- 2,599,436.58**	**0.00**	**637,458.58**	**637,458.58**	**-1,961,978.00**	**- 0.042%**

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Translation	Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Cash (externally held)								
Cash (extemally held)	0.00	63,000.00	63,000.00	0.00	0.00	0.00	63,000.00	0.001%
Total cash (externally held)	**0.00**	**63,000.00**	**63,000.00**	**0.00**	**0.00**	**0.00**	**63,000.00**	**0.001%**
Futures initial margin								
Futures initial margin	0.00	79,000.00	79,000.00	0.00	0.00	0.00	79,000.00	0.002%
Total futures initial margin	**0.00**	**79,000.00**	**79,000.00**	**0.00**	**0.00**	**0.00**	**79,000.00**	**0.002%**
Variation margin								
Variation Margin	0.00	68,974.46	68,975.24	0.00	-0.78	- 0.78	68,974.46	0.001%
Total variation margin	**0.00**	**68,974.46**	**68,975.24**	**0.00**	**-0.78**	**- 0.78**	**68,974.46**	**0.001%**
Cash collateral due to/from ccp broker								
Cash Collateral Due to/from CCP Broker	0.00	8,906,959.17	9,006,238.97	0.00	-99,279.80	- 99,279.80	8,906,959.17	0.189%
Total cash collateral due to/from ccp broker	**0.00**	**8,906,959.17**	**9,006,238.97**	**0.00**	**-99,279.80**	**- 99,279.80**	**8,906,959.17**	**0.189%**
Total cash and cash equivalents	**29,323.11**	**65,476,331.85**	**65,588,343.35**	**9,884.56**	**-121,896.06**	**- 112,011.50**	**65,505,654.96**	**1.391%**
Adjustments To Cash								
Pending foreign exchange purchases *								
Pending foreign exchange purchases	0.00	193,782,445.07	194,516,884.51	0.00	-734,439.44	- 734,439.44	193,782,445.07	4.114%
Total pending foreign exchange purchases	**0.00**	**193,782,445.07**	**194,516,884.51**	**0.00**	**-734,439.44**	**- 734,439.44**	**193,782,445.07**	**4.114%**
Pending foreign exchange sales								
Pending foreign exchange sales	0.00	- 190,709,578.41	- 194,516,884.51	0.00	3,807,306.10	3,807,306.10	-190,709,578.41	- 4.049%
Total pending foreign exchange sales	**0.00**	**- 190,709,578.41**	**- 194,516,884.51**	**0.00**	**3,807,306.10**	**3,807,306.10**	**-190,709,578.41**	**- 4.049%**
Pending trade purchases *								
Pending trade purchases	0.00	- 3,531,777.39	- 3,531,777.39	0.00	0.00	0.00	-3,531,777.39	- 0.075%
Total pending trade purchases	**0.00**	**- 3,531,777.39**	**- 3,531,777.39**	**0.00**	**0.00**	**0.00**	**-3,531,777.39**	**- 0.075%**

* Beginning liability

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Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Translation	Total	Market value incl. accruals	%
Adjustments To Cash								
Pending trade sales								
Pending trade sales	0.00	3,335,821.80	3,335,821.80	0.00	0.00	0.00	3,335,821.80	0.071%
Total pending trade sales	**0.00**	**3,335,821.80**	**3,335,821.80**	**0.00**	**0.00**	**0.00**	**3,335,821.80**	**0.071%**
Other payables ✱ Beginning Liability								
Other Payables	0.00	- 358,746.85	- 358,746.85	0.00	0.00	0.00	-358,746.85	- 0.008%
Total other payables	**0.00**	**- 358,746.85**	**- 358,746.85**	**0.00**	**0.00**	**0.00**	**-358,746.85**	**- 0.008%**
Total adjustments to cash	**0.00**	**2,518,164.22**	**- 554,702.44**	**0.00**	**3,072,866.66**	**3,072,866.66**	**2,518,164.22**	**0.053%**
Total Unrealized Gains						**1,413,992,939.16**		
Total Unrealized Losses						**- 71,498,347.98**		
Total	**17,799,123.06**	**4,692,755,989.32**	**3,360,261,398.14**	**1,355,240,828.02**	**-12,746,236.84**	**1,342,494,591.18**	**4,710,555,112.38**	**100.000%**

Total Cost incl. Accruals **3,368,060,521.20**

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Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 1 2014

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	4,295	66,852.17	18	$69.64	$1,836.18	$1.01
Michigan Electric Coordinated System - DECO	ECAR	8,753	153,138.17	12	$70.53	$1,777.30	-0.16
Midwest ISO	ECAR	3,595	2,106,329.00	138	$37.42	$1,838.80	-70.92
Florida Power & Light	FRCC	104	19,741.00	12	$41.39	$60.00	$26.00
PJM Interconnection	MAAC	86,600	27,835,625.72	405	$79.96	$1,839.28	$0.03
ISO New England Inc.	NPCC	36,672	2,560,148.64	214	$145.60	$1,245.46	$0.00
New York Independent System Operator	NPCC	18,100	46,090.81	187	$129.38	$1,610.75	-23.30
Constellation Energy Control and Dispatch - City of Ruston, LA	SERC	3	59,018.00	1	$42.70	$42.70	$42.70
Duke Energy Corporation	SERC	14	6,056.00	20	$56.64	$400.00	$35.00
Entergy Arkansas, Inc.	SERC	3,971	10,451.85	7	$44.02	$1,832.87	-182.03
Entergy	SERC	3,646	264,179.38	27	$59.20	$1,786.38	-593.42
Southern Company Services, Inc.	SERC	1,545	4,892,005.47	40	$31.99	$560.00	$1.01
Tennessee Valley Authority ESO	SERC	25	1,640.00	27	$49.79	$97.00	$34.00
Ameren Transmission-Illinois	SERC	5,584	2,146,998.18	45	$41.31	$725.55	-908.22
Southwest Power Pool	SPP	17,947	894,523.44	46	$44.16	$1,673.76	-46.13
Arizona Public Service Company	WECC-AZNMS	67	130,288.00	23	$39.65	$61.00	$5.00
California Independent System Operator	WECC-CAMX	8,515	234,858.25	178	$42.57	$384.05	-949.26
PacifiCorp-East	WECC-NWPP	20	1,326.00	25	$48.55	$135.28	$26.00
Trading Hub-ADHUB	MAAC	20	100,709.60	15	$41.57	$54.60	$29.55
Trading Hub-AEPGenHub		13	38,648.00	2	$36.83	$44.20	$33.20
Trading Hub-COB	WECC-CAMX	105	136,316.40	20	$43.98	$220.00	$0.00
Trading Hub-Entergy (into)	SERC	3	410.00	1	$63.54	$65.00	$62.00
Trading Hub-Four Corners	WECC-AZNMS	5	1,489.00	26	$33.61	$35.50	$24.50
Trading Hub-Illinois Hub (MISO)	MAIN	2	14,296.00	4	$54.25	$54.25	$54.25
Trading Hub-Mead	WECC-AZNMS	60	17,259.00	26	$196.45	$175.00	$28.50
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	790	92,362.00	38	$88.27	$290.00	$0.00
Trading Hub-NEPOOL (Mass Hub)	NPCC	41	348,152.54	16	$56.92	$455.00	$35.25
Trading Hub-NIHUB	MAAC	50	54,330.90	9	$52.01	$41.70	$22.70
Trading Hub-NOB	WECC-NWPP	6	2,407.00	15	$179.62	$250.00	$49.50
Trading Hub-NP15	WECC-CAMX	3	34,060.00	17	$54.13	$64.00	$52.75
Trading Hub-Palo Verde	WECC-AZNMS	642	132,005.00	32	$123.85	$170.00	$20.74
Trading Hub-PJM West Hub	MAAC	89	2,673,962.20	17	$44.45	$73.05	$31.20
Trading Hub-SOCO (into)	SERC	1	25.00	6	$38.00	$38.00	$38.00
Trading Hub-SP15	WECC-CAMX	7	72,181.00	18	$44.12	$52.93	$37.50
Trading Hub-TVA (into)	SERC	21	50,576.00	6	$74.47	$175.00	$41.00

Description of Column Headings:

Product: TSIN abbreviation for the Balancing Authority.

NERC Region: Balancing Authority or Hub identified as point of delivery.

# of Lines: Number of lines of transaction data.

Standardized Quantity: Sum of quantities reported in MWH.
(Does not include sales at "FLAT RATE" or sales with an absolute value smaller than or equal to 1 MWH)

# of Sellers in Region: Count of sellers reporting sales in the Balancing Authority.

Standardized Price: i. Avg: Weighted average price (sum of non-transmission revenues weighted by reported quantity) in $/MWH.

(Does not include sales at “FLAT RATE” or sales with an absolute value smaller than or equal to 1 MWH)

ii. High: Highest reported price in $/MWH.
(Does not include sales at “FLAT RATE” or sales with an absolute value smaller than or equal to 1 MWH)

iii. Low: Lowest reported price in $/MWH.
(Does not include sales at “FLAT RATE” or sales with an absolute value smaller than or equal to 1 MWH)

All Sellers in Balancing Authority: Applicable reported price for all sellers in the Balancing Authority including your company. (Prices are calculated from unreviewed data in all EQR filings, and are meant to be merely indicative of prices in the region for the filing period.)

NOTE: Billing adjustments are not included in calculations. Because of the difference in calculation methods (see note on "Price" above) "Average Price" may be outside the range of high and low prices.

Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 1 2015

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	4,681	65,506.90	19	$31.86	$326.44	$1.01
Michigan Electric Coordinated System - DECO	ECAR	9,046	162,564.72	11	$31.67	$319.75	-0.02
Midwest ISO	ECAR	5,041	1,258,465.20	156	$32.05	$519.15	-15.96
Florida Power & Light	FRCC	62	39,476.00	13	$30.40	$40.00	$23.00
PJM Interconnection	MAAC	114,988	34,808,809.51	433	$48.08	$418.67	-85.39
ISO New England Inc.	NPCC	34,672	2,815,219.33	216	$85.09	$492.74	-339.51
New York Independent System Operator	NPCC	22,267	19,109.23	204	$54.61	$354.89	-12.81
Duke Energy Corporation	SERC	13	8,426.00	19	$28.09	$38.00	$23.00
Entergy Arkansas, Inc.	SERC	751	1,053.43	8	$25.92	$103.61	$6.28
Entergy	SERC	3,002	171,632.34	27	$27.83	$252.58	-216.01
Southern Company Services, Inc.	SERC	2,104	3,867,538.86	39	$40.52	$245.00	$1.34
Ameren Transmission-Illinois	SERC	5,930	2,257,405.49	44	$22.71	$365.93	-492.37
Southwest Power Pool	SPP	60,040	1,372,072.87	61	$24.09	$1,720.40	-187.30
Arizona Public Service Company	WECC-AZNMS	7	32,626.00	21	$36.92	$37.03	$21.50
California Independent System Operator	WECC-CAMX	10,748	1,120,510.75	191	$33.89	$370.44	-149.90
PacifiCorp-East	WECC-NWPP	3	2,515.00	24	$0.09	$22.00	$0.00
Trading Hub-ADHUB	MAAC	12	31,172.00	17	$38.05	$50.20	$34.50
Trading Hub-AEPGenHub		31	458,969.80	3	$46.72	$54.90	$33.20
Trading Hub-COB	WECC-CAMX	95	80,372.40	16	$60.48	$85.00	$0.00
Trading Hub-Illinois Hub (MISO)	MAIN	2	19,088.00	6	$51.75	$51.75	$51.75
Trading Hub-Indiana Hub (MISO)	MAAC	1	4,200.00	12	$32.05	$32.05	$32.05
Trading Hub-Mead	WECC-AZNMS	72	53,751.00	18	$106.53	$34.50	$16.50
Trading Hub-Michigan Hub (MISO)	ECAR	5	350,784.00	15	$41.05	$42.70	$35.35
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	834	156,276.00	34	$78.09	$42.00	$0.00
Trading Hub-NEPOOL (Mass Hub)	NPCC	58	262,103.20	16	$62.85	$174.75	$21.01
Trading Hub-NIHUB	MAAC	75	173,964.60	13	$35.58	$42.25	$24.35
Trading Hub-NP15	WECC-CAMX	66	48,960.00	16	$47.93	$50.88	$23.64
Trading Hub-Palo Verde	WECC-AZNMS	827	77,778.00	33	$280.46	$33.00	$16.50
Trading Hub-PJM West Hub	MAAC	2,226	1,560,737.80	25	$49.93	$415.09	$12.89
Trading Hub-SP15	WECC-CAMX	13	104,606.00	17	$44.40	$51.78	$5.00
Trading Hub-TVA (into)	SERC	9	7,280.00	10	$31.50	$65.00	$23.25

Description of Column Headings:

Product: TSIN abbreviation for the Balancing Authority.

NERC Region: Balancing Authority or Hub identified as point of delivery.

# of Lines: Number of lines of transaction data.

Standardized Quantity: Sum of quantities reported in MWH.
(Does not include sales at “FLAT RATE” or sales with an absolute value smaller than or equal to 1 MWH)

# of Sellers in Region: Count of sellers reporting sales in the Balancing Authority.

Standardized Price:
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All Sellers in Balancing Authority: Applicable reported price for all sellers in the Balancing Authority including your company. (Prices are calculated from unreviewed data in all EQR filings, and are meant to be merely indicative of prices in the region for the filing period.)

NOTE: Billing adjustments are not included in calculations. Because of the difference in calculation methods (see note on "Price" above) "Average Price" may be outside the range of high and low prices.

Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 1 2016

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	8,704	145,710.75	18	$22.61	$135.30	$1.01
Michigan Electric Coordinated System - DECO	ECAR	10,531	174,692.21	10	$21.73	$120.01	-0.09
Midwest ISO	ECAR	7,041	1,618,920.80	146	$28.49	$52.52	$6.36
Florida Power & Light	FRCC	23	14,798.00	13	$28.26	$34.00	$16.00
PJM Interconnection	MAAC	204,623	40,821,249.62	457	$28.10	$179.28	-347.31
Upper Peninsula Power Co.	MAIN	1		8			
Wisconsin Public Service Corporation	MAIN	272	1.05	6	$17.15	$17.15	$17.15
ISO New England Inc.	NPCC	28,298	3,840,894.51	218	$30.87	$366.18	-156.67
New York Independent System Operator	NPCC	16,046	14,592.54	205	$19.52	$1,090.80	-123.46
Wisconsin Energy Corporation	RFC	673	1,636.83	5	$25.69	$253.06	-8.84
Duke Energy Corporation	SERC	20	49,475.00	16	$23.95	$35.00	$15.00
Entergy Arkansas, Inc.	SERC	1,421	2,166.02	10	$19.21	$66.58	-21.94
Entergy	SERC	5,322	329,826.88	23	$16.29	$120.55	-82.85
Santee Cooper	SERC	1	3,600.00	11	$26.00	$26.00	$26.00
Southern Company Services, Inc.	SERC	1,332	2,345,003.64	36	$28.41	$126.00	$4.00
Tennessee Valley Authority ESO	SERC	2	540.00	19	$31.89	$33.00	$18.00
Ameren Transmission-Illinois	SERC	8,366	2,449,773.65	46	$21.23	$188.67	-36.15
Southwest Power Pool	SPP	20,208	492,939.75	123	$17.42	$1,092.60	-38.73
Arizona Public Service Company	WECC-AZNMS	4	32,920.00	21	$36.93	$37.03	$17.50
California Independent System Operator	WECC-CAMX	9,837	602,021.58	206	$17.63	$121.24	-290.34
PacifiCorp-East	WECC-NWPP	8	4,853.00	24	$27.99	$28.15	$20.00
Trading Hub-COB	WECC-CAMX	78	140,522.80	17	$38.21	$85.00	$0.00
Trading Hub-Four Corners	WECC-AZNMS	12	2,162.00	18	$15.13	$24.35	$13.50
Trading Hub-Mead	WECC-AZNMS	11	90,184.00	19	$26.11	$28.00	$17.75
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	1,617	195,613.00	30	$43.30	$42.00	$0.00
Trading Hub-NOB	WECC-NWPP	16	6,392.00	9	$13.65	$16.50	$8.25
Trading Hub-NP15	WECC-CAMX	3	75,015.00	19	$40.24	$45.63	$27.45
Trading Hub-Palo Verde	WECC-AZNMS	657	101,468.00	32	$71.62	$30.00	$10.00
Trading Hub-SP15	WECC-CAMX	16	209,490.00	17	$34.54	$48.59	$13.00

Description of Column Headings:

Product: TSIN abbreviation for the Balancing Authority.

NERC Region: Balancing Authority or Hub identified as point of delivery.

# of Lines: Number of lines of transaction data.

Standardized Quantity: Sum of quantities reported in MWH.
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NOTE: Billing adjustments are not included in calculations. Because of the difference in calculation methods (see note on "Price" above) "Average Price" may be outside the range of high and low prices.

Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 1 2017

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	6,223	88,600.71	16	$27.89	$205.53	$1.01
Michigan Electric Coordinated System - DECO	ECAR	9,100	165,697.41	8	$27.10	$206.54	-0.01
Midwest ISO	ECAR	1,826	953,598.60	166	$35.82	$62.44	$17.02
Florida Power & Light	FRCC	81	74,025.00	10	$30.50	$74.00	$17.00
PJM Interconnection	MAAC	244,990	39,178,551.06	466	$30.68	$157.49	$0.00
Upper Peninsula Power Co.	MAIN	2,086		8			
Wisconsin Public Service Corporation	MAIN	844	1.02	7	$24.30	$24.30	$24.30
ISO New England Inc.	NPCC	79,397	3,411,702.29	237	$37.12	$999.00	-166.70
New York Independent System Operator	NPCC	14,568	12,703.87	202	$59.83	$197.49	-107.18
Wisconsin Energy Corporation	RFC	1,335	4,405.59	5	$28.35	$211.12	$7.41
Duke Energy Corporation	SERC	19	3,147.00	17	$30.03	$52.00	$19.00
Entergy Arkansas, Inc.	SERC	1,045	1,559.89	5	$25.30	$87.17	$9.84
Entergy	SERC	3,562	95,335.78	17	$29.41	$753.56	-33.54
Southern Company Services, Inc.	SERC	1,954	2,664,879.45	37	$28.28	$195.00	$1.00
Tennessee Valley Authority ESO	SERC	21	27,765.00	17	$28.77	$34.00	$23.00
Ameren Transmission-Illinois	SERC	9,732	2,431,144.84	35	$24.82	$199.27	-160.50
Southwest Power Pool	SPP	276,891	1,938,305.66	143	$22.02	$1,254.13	-295.61
Arizona Public Service Company	WECC-AZNMS	1	32,385.00	19	$37.03	$37.03	$37.03
California Independent System Operator	WECC-CAMX	10,603	946,799.78	259	$31.86	$396.00	-148.82
PacifiCorp-East	WECC-NWPP	51	24,606.00	35	$29.41	$33.25	$0.00
Trading Hub-COB	WECC-CAMX	115	90,709.25	17	$46.02	$85.00	$0.00
Trading Hub-Four Corners	WECC-AZNMS	9	43,898.00	20	$30.45	$46.99	$20.00
Trading Hub-Mead	WECC-AZNMS	61	23,741.00	20	$22.82	$29.50	$5.00
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	2,050	216,862.00	33	$46.49	$75.00	$0.00
Trading Hub-NOB	WECC-NWPP	30	10,788.00	10	$18.66	$29.50	$5.00
Trading Hub-NP15	WECC-CAMX	7	72,116.00	18	$43.38	$49.95	$33.65
Trading Hub-Palo Verde	WECC-AZNMS	623	51,175.00	32	$208.08	$53.00	$0.00
Trading Hub-SP15	WECC-CAMX	18	173,534.00	16	$36.34	$48.59	$28.60

Description of Column Headings:

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Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 1 2018

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	7,749	93,560.43	15	$29.42	$279.65	-7.15
Michigan Electric Coordinated System - DECO	ECAR	8,763	181,144.17	9	$30.17	$278.14	-20.53
Midwest ISO	ECAR	1,789	718,076.60	174	$37.98	$169.00	$10.41
Florida Power & Light	FRCC	31	16,521.00	11	$59.15	$290.00	$20.00
PJM Interconnection	MAAC	226,516	39,150,617.57	505	$44.44	$586.22	$6.36
ISO New England Inc.	NPCC	190,191	2,687,034.31	235	$66.96	$1,877.01	-151.33
New York Independent System Operator	NPCC	127,019	1,562,674.01	206	$34.13	$277.78	-11.87
Duke Energy Corporation	SERC	5	993.00	23	$34.44	$38.00	$26.00
Entergy Arkansas, Inc.	SERC	394	372.26	7	$24.81	$72.63	$3.49
Entergy	SERC	3,272	261,035.75	18	$30.16	$621.41	-124.83
Southern Company Services, Inc.	SERC	1,498	2,589,477.96	44	$36.04	$1,375.00	$4.59
Tennessee Valley Authority ESO	SERC	5	13,780.00	21	$76.62	$200.00	$34.00
Ameren Transmission-Illinois	SERC	6,033	2,411,013.31	38	$25.47	$266.75	-294.22
Southwest Power Pool	SPP	222,703	2,129,251.81	155	$22.90	$1,552.32	-77.24
Arizona Public Service Company	WECC-AZNMS	1	32,385.00	21	$29.86	$29.86	$29.86
California Independent System Operator	WECC-CAMX	11,660	1,060,119.71	288	$31.57	$924.29	-104.51
PacifiCorp-East	WECC-NWPP	9	1,180.00	33	$22.32	$27.00	$15.00
Trading Hub-COB	WECC-CAMX	62	35,524.00	17	$36.23	$38.25	$6.00
Trading Hub-Four Corners	WECC-AZNMS	1	46,350.00	18	$23.05	$23.05	$23.05
Trading Hub-Mead	WECC-AZNMS	249	58,574.00	19	$49.45	$68.15	$12.00
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	2,769	498,023.25	34	$45.26	$50.00	$0.50
Trading Hub-NOB	WECC-NWPP	29	8,104.00	13	$29.52	$58.00	$1.00
Trading Hub-NP15	WECC-CAMX	8	1,158,027.00	17	$33.19	$37.15	$25.54
Trading Hub-Palo Verde	WECC-AZNMS	374	65,831.00	32	$113.72	$70.00	$10.00
Trading Hub-SOCO (into)	SERC	78	1,950.00	8	$71.47	$110.00	$46.40
Trading Hub-SP15	WECC-CAMX	11	83,250.98	14	$39.64	$48.59	$32.50

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Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 2 2014

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	4,354	53,660.54	18	$38.89	$496.04	-29.28
Michigan Electric Coordinated System - DECO	ECAR	8,674	120,867.53	12	$37.19	$486.52	-68.85
Midwest ISO	ECAR	4,503	1,851,331.40	153	$36.55	$900.00	-25.62
Florida Power & Light	FRCC	140	64,162.00	14	$47.02	$68.00	$26.00
PJM Interconnection	MAAC	119,319	26,430,738.24	408	$40.65	$509.40	-42.14
ISO New England Inc.	NPCC	44,583	3,314,965.30	206	$40.38	$335.04	$0.00
New York Independent System Operator	NPCC	18,982	32,273.19	191	$39.13	$995.57	-157.36
Constellation Energy Control and Dispatch - City of Ruston, LA	SERC	3	67,123.00	1	$43.80	$45.55	$42.70
Duke Energy Corporation	SERC	34	16,110.00	19	$45.13	$56.00	$30.00
Entergy Arkansas, Inc.	SERC	2,175	6,687.55	6	$39.38	$412.64	-50.35
Entergy	SERC	3,583	283,070.70	28	$16.74	$517.19	-263.55
Southern Company Services, Inc.	SERC	2,522	4,782,197.37	38	$31.28	$77.00	$0.00
Tennessee Valley Authority ESO	SERC	2	155.00	22	$55.39	$57.00	$55.00
Ameren Transmission-Illinois	SERC	5,995	2,388,866.80	45	$35.24	$473.55	-11.01
Southwest Power Pool	SPP	38,776	1,098,687.46	52	$37.05	$1,460.61	-56.09
Arizona Public Service Company	WECC-AZNMS	42	155,492.00	25	$40.10	$46.65	$21.00
California Independent System Operator	WECC-CAMX	8,634	280,362.62	171	$33.48	$762.48	-149.35
PacifiCorp-East	WECC-NWPP	12	134.00	24	$26.51	$40.00	$20.00
Trading Hub-ADHUB	MAAC	18	46,963.20	16	$37.04	$50.20	$29.55
Trading Hub-AEPGenHub		17	72,896.00	2	$43.04	$54.90	$33.20
Trading Hub-COB	WECC-CAMX	479	292,449.00	19	$49.28	$4,424.00	$0.00
Trading Hub-Entergy (into)	SERC	2	80.00	1	$33.75	$35.00	$30.00
Trading Hub-FE Hub		3	9,840.00	1	$42.48	$42.90	$42.45
Trading Hub-Four Corners	WECC-AZNMS	18	1,219.00	24	$32.83	$43.00	$25.00
Trading Hub-Illinois Hub (MISO)	MAIN	4	12,736.00	3	$51.96	$54.25	$28.95
Trading Hub-Indiana Hub (MISO)	MAAC	1	43,200.00	13	$40.65	$40.65	$40.65
Trading Hub-Mead	WECC-AZNMS	34	18,117.00	25	$191.05	$58.28	$24.50
Trading Hub-Michigan Hub (MISO)	ECAR	1	8,928.00	10	$32.10	$32.10	$32.10
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	1,865	214,924.00	39	$62.91	$60.00	$0.00
Trading Hub-NEPOOL (Mass Hub)	NPCC	56	372,334.62	14	$43.83	$73.00	$31.00
Trading Hub-NIHUB	MAAC	58	100,736.00	9	$53.92	$45.35	$24.35
Trading Hub-NOB	WECC-NWPP	26	7,833.00	15	$18.03	$34.00	$10.00
Trading Hub-NP15	WECC-CAMX	1	7,600.00	17	$38.25	$38.25	$38.25
Trading Hub-Palo Verde	WECC-AZNMS	664	147,474.05	34	$129.37	$62.50	$26.00
Trading Hub-PJM West Hub	MAAC	802	2,377,002.40	22	$43.53	$150.50	$10.90
Trading Hub-SP15	WECC-CAMX	18	97,135.00	18	$41.16	$52.93	$0.00
Trading Hub-TVA (into)	SERC	27	67,115.00	6	$48.56	$70.00	$30.00

Description of Column Headings:

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Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 2 2015

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Midwest ISO	ECAR	39,899	3,446,463.71	152	$27.38	$262.74	-165.19
Florida Power & Light	FRCC	104	77,756.00	15	$37.55	$56.00	$21.00
PJM Interconnection	MAAC	169,372	39,294,003.12	435	$32.68	$221.18	-229.98
ISO New England Inc.	NPCC	34,388	3,341,574.10	214	$27.52	$1,045.86	-139.18
New York Independent System Operator	NPCC	19,362	22,518.01	202	$24.46	$354.54	-183.43
Duke Energy Corporation	SERC	14	15,882.00	20	$43.20	$58.00	$25.00
Entergy	SERC	378	52,275.28	26	$25.12	$41.72	$20.31
Southern Company Services, Inc.	SERC	2,046	8,309,873.26	38	$30.87	$70.00	$1.01
Tennessee Valley Authority ESO	SERC	26	34,641.00	26	$33.49	$55.00	$22.00
Southwest Power Pool	SPP	55,800	1,516,826.01	98	$22.53	$1,289.23	-36.94
Arizona Public Service Company	WECC-AZNMS	26	46,443.00	24	$35.46	$41.75	$16.59
California Independent System Operator	WECC-CAMX	4,979	942,849.68	197	$29.29	$1,067.33	-122.01
PacifiCorp-East	WECC-NWPP	10	11,640.00	21	$37.86	$80.00	$29.00
Trading Hub-COB	WECC-CAMX	116	187,484.80	19	$36.39	$85.00	$0.00
Trading Hub-Four Corners	WECC-AZNMS	1	800.00	22	$45.00	$45.00	$45.00
Trading Hub-Mead	WECC-AZNMS	16	140,087.00	18	$37.70	$54.90	$18.00
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	1,329	683,165.00	36	$26.09	$265.00	$0.00
Trading Hub-NP15	WECC-CAMX	5	98,512.00	16	$37.10	$48.25	$24.45
Trading Hub-Palo Verde	WECC-AZNMS	520	414,154.00	35	$27.16	$60.00	$17.00
Trading Hub-SP15	WECC-CAMX	15	121,789.00	19	$44.34	$51.78	$13.00

Description of Column Headings:

Product: TSIN abbreviation for the Balancing Authority.

NERC Region: Balancing Authority or Hub identified as point of delivery.

# of Lines: Number of lines of transaction data.

Standardized Quantity: Sum of quantities reported in MWH.
(Does not include sales at “FLAT RATE” or sales with an absolute value smaller than or equal to 1 MWH)

# of Sellers in Region: Count of sellers reporting sales in the Balancing Authority.

Standardized Price:
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All Sellers in Balancing Authority: Applicable reported price for all sellers in the Balancing Authority including your company. (Prices are calculated from unreviewed data in all EQR filings, and are meant to be merely indicative of prices in the region for the filing period.)

NOTE: Billing adjustments are not included in calculations. Because of the difference in calculation methods (see note on "Price" above) "Average Price" may be outside the range of high and low prices.

Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 2 2016

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	7,794	91,300.46	17	$24.86	$169.16	-12.19
Michigan Electric Coordinated System - DECO	ECAR	10,185	120,937.12	9	$24.05	$225.24	-11.87
Midwest ISO	ECAR	5,748	1,549,658.00	149	$28.72	$54.50	$6.95
Florida Power & Light	FRCC	166	160,448.00	12	$32.56	$59.00	$14.00
PJM Interconnection	MAAC	193,313	38,912,443.14	451	$27.19	$194.46	-8.59
Upper Peninsula Power Co.	MAIN	22		8			
Wisconsin Public Service Corporation	MAIN	245	4.39	6	$20.45	$24.60	$15.32
ISO New England Inc.	NPCC	26,996	4,539,482.93	224	$22.18	$2,851.75	-156.80
New York Independent System Operator	NPCC	16,276	23,617.49	199	$29.90	$771.04	-34.43
Wisconsin Energy Corporation	RFC	406	1,324.92	5	$26.34	$168.98	-15.56
Duke Energy Corporation	SERC	11	6,030.00	16	$24.97	$33.00	$16.00
Entergy Arkansas, Inc.	SERC	1,597	3,410.34	10	$22.06	$80.07	-27.25
Entergy	SERC	4,830	253,133.47	22	$18.25	$549.33	-49.99
Southern Company Services, Inc.	SERC	1,541	3,010,696.01	40	$24.77	$81.26	$0.00
Tennessee Valley Authority ESO	SERC	20	28,706.00	24	$33.93	$50.00	$17.00
Ameren Transmission-Illinois	SERC	8,708	1,989,038.62	46	$23.83	$100.76	-26.83
Southwest Power Pool	SPP	54,096	1,616,903.01	122	$19.00	$987.70	-50.29
Arizona Public Service Company	WECC-AZNMS	23	42,360.00	23	$33.96	$37.03	$14.70
California Independent System Operator	WECC-CAMX	10,294	651,042.08	226	$17.32	$162.24	-70.69
PacifiCorp-East	WECC-NWPP	71	24,640.00	25	$17.34	$36.00	$1.00
Trading Hub-COB	WECC-CAMX	91	265,286.00	19	$40.82	$85.00	$0.00
Trading Hub-Four Corners	WECC-AZNMS	5	1,280.00	21	$13.66	$20.00	$12.00
Trading Hub-Mead	WECC-AZNMS	54	10,688.00	19	$47.40	$74.50	$14.00
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	2,435	359,253.00	32	$25.11	$70.00	$0.00
Trading Hub-NOB	WECC-NWPP	23	5,396.00	12	$16.87	$31.00	$5.00
Trading Hub-Palo Verde	WECC-AZNMS	702	96,355.00	34	$105.48	$65.03	$12.00
Trading Hub-SP15	WECC-CAMX	12	166,423.00	19	$38.27	$48.59	$6.00

Description of Column Headings:

Product: TSIN abbreviation for the Balancing Authority.

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# of Lines: Number of lines of transaction data.

Standardized Quantity: Sum of quantities reported in MWH.
(Does not include sales at "FLAT RATE" or sales with an absolute value smaller than or equal to 1 MWH)

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All Sellers in Balancing Authority: Applicable reported price for all sellers in the Balancing Authority including your company. (Prices are calculated from unreviewed data in all EQR filings, and are meant to be merely indicative of prices in the region for the filing period.)

NOTE: Billing adjustments are not included in calculations. Because of the difference in calculation methods (see note on "Price" above) "Average Price" may be outside the range of high and low prices.

Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 2 2017

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	9,134	79,974.22	14	$28.94	$186.33	$1.01
Michigan Electric Coordinated System - DECO	ECAR	8,842	146,431.71	8	$27.73	$190.98	-26.69
Midwest ISO	ECAR	3,589	998,440.20	166	$34.48	$63.78	$6.60
Florida Power & Light	FRCC	130	183,046.00	12	$37.29	$72.00	$19.00
PJM Interconnection	MAAC	249,922	38,444,641.40	476	$29.75	$161.21	-35.72
Upper Peninsula Power Co.	MAIN	1,673	14.12	8	$31.17	$55.81	$9.66
Wisconsin Public Service Corporation	MAIN	450	6.97	7	$20.01	$26.20	-0.12
ISO New England Inc.	NPCC	186,995	3,528,184.33	237	$29.15	$763.64	-173.57
New York Independent System Operator	NPCC	17,937	1,434,906.07	199	$18.70	$135.53	-148.55
Wisconsin Energy Corporation	RFC	1,333	6,188.36	5	$35.66	$1,990.67	-63.20
Duke Energy Corporation	SERC	8	725.00	19	$24.03	$30.00	$18.00
Entergy Arkansas, Inc.	SERC	709	1,095.19	5	$28.22	$171.41	$8.16
Entergy	SERC	4,871	329,352.55	17	$29.32	$323.24	-197.52
Southern Company Services, Inc.	SERC	2,548	1,267,100.00	40	$24.62	$65.00	$4.48
Tennessee Valley Authority ESO	SERC	32	68,034.00	20	$38.25	$51.00	$24.00
Ameren Transmission-Illinois	SERC	8,482	1,613,355.48	34	$25.83	$376.58	-94.01
Southwest Power Pool	SPP	240,519	2,188,761.36	147	$23.46	$4,520.55	-537.93
Arizona Public Service Company	WECC-AZNMS	2	32,869.00	22	$29.83	$29.86	$19.50
California Independent System Operator	WECC-CAMX	7,194	943,872.67	270	$24.63	$588.94	-73.96
PacifiCorp-East	WECC-NWPP	85	50,098.00	34	$38.56	$100.00	$0.00
Trading Hub-COB	WECC-CAMX	317	183,386.00	21	$34.40	$211.00	$0.00
Trading Hub-Four Corners	WECC-AZNMS	11	44,477.00	21	$26.65	$37.00	$6.75
Trading Hub-Mead	WECC-AZNMS	193	44,926.00	23	$56.26	$125.00	$10.00
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	2,681	378,827.63	33	$25.77	$65.00	$0.00
Trading Hub-NOB	WECC-NWPP	146	52,616.00	13	$19.12	$50.00	$0.00
Trading Hub-NP15	WECC-CAMX	7	703,183.00	18	$33.52	$49.95	$31.00
Trading Hub-Palo Verde	WECC-AZNMS	654	72,420.00	36	$224.38	$165.00	$0.00
Trading Hub-SP15	WECC-CAMX	13	167,731.00	18	$36.76	$48.59	$32.50

Description of Column Headings:

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Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 2 2018

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	7,680	61,237.41	15	$31.61	$382.91	-12.57
Michigan Electric Coordinated System - DECO	ECAR	8,748	115,743.52	9	$30.99	$386.64	-24.10
Midwest ISO	ECAR	2,389	929,853.20	180	$33.86	$76.97	$10.27
Florida Power & Light	FRCC	68	152,467.00	13	$35.43	$53.00	$21.00
PJM Interconnection	MAAC	3,635,032	44,431,519.85	515	$32.79	$497.93	-94.55
ISO New England Inc.	NPCC	143,912	1,396,830.82	236	$32.96	$395.24	-318.48
New York Independent System Operator	NPCC	183,317	1,431,347.53	206	$23.79	$1,485.44	-1684.72
Duke Energy Corporation	SERC	1	200.00	23	$39.00	$39.00	$39.00
Entergy Arkansas, Inc.	SERC	418	705.03	7	$27.93	$92.71	$10.93
Entergy	SERC	3,968	457,661.62	15	$23.61	$357.21	-27.99
Santee Cooper	SERC	7	15,600.00	14	$37.00	$40.00	$34.00
Southern Company Services, Inc.	SERC	1,394	2,514,966.11	49	$29.16	$60.00	$2.95
Tennessee Valley Authority ESO	SERC	14	27,235.00	23	$39.56	$45.00	$24.00
Ameren Transmission-Illinois	SERC	5,224	1,758,578.90	36	$29.74	$369.47	-1.42
Southwest Power Pool	SPP	231,757	2,166,895.51	164	$21.36	$1,471.02	-192.85
Arizona Public Service Company	WECC-AZNMS	22	37,560.00	20	$28.25	$29.86	$15.05
California Independent System Operator	WECC-CAMX	33,608	1,326,221.67	295	$16.22	$692.73	-28.56
PacifiCorp-East	WECC-NWPP	24	10,176.00	34	$45.90	$58.55	$11.00
Trading Hub-COB	WECC-CAMX	86	144,531.00	16	$17.15	$32.00	$0.00
Trading Hub-Mead	WECC-AZNMS	304	120,976.00	20	$33.61	$231.14	$0.00
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	2,733	373,593.45	35	$26.66	$319.30	-2.25
Trading Hub-NOB	WECC-NWPP	128	49,628.00	13	$18.75	$35.00	$7.00
Trading Hub-NP15	WECC-CAMX	16	1,611,575.00	14	$31.29	$36.10	$24.21
Trading Hub-Palo Verde	WECC-AZNMS	310	45,702.00	32	$140.65	$51.00	$10.00
Trading Hub-SP15	WECC-CAMX	10	114,160.15	16	$38.16	$48.59	$27.40

Description of Column Headings:

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Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 3 2014

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	4,127	31,791.69	21	$33.23	$439.91	-13.74
Michigan Electric Coordinated System - DECO	ECAR	8,231	85,347.09	12	$32.77	$359.77	-13.87
Midwest ISO	ECAR	2,380	969,130.40	151	$36.37	$261.64	-10.65
Florida Power & Light	FRCC	169	117,949.00	17	$43.82	$58.00	$27.00
PJM Interconnection	MAAC	151,136	38,687,841.34	419	$35.93	$235.64	-14.33
ISO New England Inc.	NPCC	46,474	4,565,592.12	207	$36.14	$558.00	$0.00
New York Independent System Operator	NPCC	19,749	37,615.37	198	$28.07	$237.62	-38.90
Duke Energy Corporation	SERC	12	5,465.00	19	$45.12	$48.00	$34.00
Entergy Arkansas, Inc.	SERC	3,447	9,494.86	6	$32.50	$262.07	-313.50
Entergy	SERC	4,392	467,202.29	28	$28.26	$286.92	-44.38
Southern Company Services, Inc.	SERC	2,394	6,330,163.66	39	$33.12	$63.00	$1.01
Tennessee Valley Authority ESO	SERC	13	4,322.00	20	$48.77	$60.00	$28.00
Ameren Transmission-Illinois	SERC	5,583	2,355,064.50	46	$30.31	$176.84	-10.18
Southwest Power Pool	SPP	60,213	1,306,433.03	54	$35.04	$1,311.52	-99.73
Arizona Public Service Company	WECC-AZNMS	71	192,544.00	23	$40.77	$59.68	$27.93
California Independent System Operator	WECC-CAMX	9,912	609,753.25	173	$43.72	$204.01	-150.00
PacifiCorp-East	WECC-NWPP	32	6,640.00	27	$50.63	$80.00	$0.00
Trading Hub-ADHUB	MAAC	20	60,260.80	19	$38.79	$52.75	$29.55
Trading Hub-AEPGenHub		1	22,080.00	2	$54.90	$54.90	$54.90
Trading Hub-COB	WECC-CAMX	185	441,569.40	20	$55.16	$85.00	$0.00
Trading Hub-FE Hub		1	2,208.00	1	$42.90	$42.90	$42.90
Trading Hub-Four Corners	WECC-AZNMS	10	6,000.00	23	$40.30	$43.50	$37.00
Trading Hub-Illinois Hub (MISO)	MAIN	2	23,392.00	4	$54.25	$54.25	$54.25
Trading Hub-Mead	WECC-AZNMS	6	17,224.00	22	$152.04	$45.75	$34.55
Trading Hub-Michigan Hub (MISO)	ECAR	1	15,120.00	10	$42.20	$42.20	$42.20
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	1,056	159,322.00	39	$74.35	$85.00	$0.00
Trading Hub-NEPOOL (Mass Hub)	NPCC	50	526,122.06	17	$44.04	$64.85	$26.00
Trading Hub-NIHUB	MAAC	58	141,016.00	10	$36.50	$45.35	$24.35
Trading Hub-NOB	WECC-NWPP	51	24,404.00	14	$44.96	$66.75	$33.00
Trading Hub-NP15	WECC-CAMX	2,209	86,000.00	19	$54.97	$98.25	$24.86
Trading Hub-Palo Verde	WECC-AZNMS	836	182,546.00	35	$143.69	$66.00	$0.05
Trading Hub-PJM West Hub	MAAC	2,283	3,154,400.00	23	$39.75	$114.74	$5.09
Trading Hub-SP15	WECC-CAMX	14	184,822.00	18	$44.33	$49.65	$5.00

Description of Column Headings:

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Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 3 2015

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	7,570	82,128.74	20	$28.26	$214.32	-26.87
Michigan Electric Coordinated System - DECO	ECAR	10,685	119,218.07	11	$26.85	$288.85	-26.76
Midwest ISO	ECAR	4,291	1,494,365.80	150	$36.00	$79.25	$6.68
Florida Power & Light	FRCC	69	49,324.00	15	$38.33	$51.00	$23.00
PJM Interconnection	MAAC	192,591	39,871,915.60	433	$31.80	$433.73	-107.95
Upper Peninsula Power Co.	MAIN	1,620	425.90	9	$32.30	$191.42	-6.93
Wisconsin Public Service Corporation	MAIN	2,038	705.94	7	$31.75	$284.73	-5.72
ISO New England Inc.	NPCC	38,349	5,033,336.44	215	$32.61	$787.45	-151.08
New York Independent System Operator	NPCC	21,082	21,845.43	200	$43.45	$565.74	-17.21
Wisconsin Energy Corporation	RFC	669	2,226.30	8	$27.11	$103.43	-27.34
Duke Energy Corporation	SERC	3	5,920.00	17	$35.05	$37.00	$31.00
Entergy Arkansas, Inc.	SERC	1,177	3,002.66	8	$28.54	$192.90	-20.72
Entergy	SERC	4,573	254,080.94	25	$24.42	$442.70	-551.39
Southern Company Services, Inc.	SERC	2,016	5,880,441.11	34	$31.44	$65.00	$0.75
Tennessee Valley Authority ESO	SERC	12	13,836.00	20	$35.44	$52.00	$28.00
Ameren Transmission-Illinois	SERC	10,119	2,386,937.12	45	$26.67	$213.00	-272.59
Southwest Power Pool	SPP	59,386	1,605,737.68	99	$23.19	$653.82	-37.90
Arizona Public Service Company	WECC-AZNMS	69	73,840.00	22	$37.05	$59.68	$17.75
Nevada Power Company	WECC-AZNMS	2	100.00	24	$39.75	$39.75	$39.75
California Independent System Operator	WECC-CAMX	9,289	898,135.43	196	$24.57	$154.66	-75.00
PacifiCorp-East	WECC-NWPP	28	3,893.00	24	$62.49	$175.00	$22.00
Trading Hub-COB	WECC-CAMX	191	206,879.00	19	$49.60	$117.00	$0.00
Trading Hub-Four Corners	WECC-AZNMS	85	33,944.00	20	$44.81	$85.00	$13.00
Trading Hub-Mead	WECC-AZNMS	16	52,427.00	23	$160.54	$48.00	$21.00
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	1,573	256,520.00	34	$62.31	$175.00	$0.00
Trading Hub-NOB	WECC-NWPP	2	25.00	13	$495.50	$27.50	$27.50
Trading Hub-NP15	WECC-CAMX	2,382	220,440.00	15	$41.21	$150.93	$23.29
Trading Hub-Palo Verde	WECC-AZNMS	950	168,448.00	34	$164.16	$85.00	$18.00
Trading Hub-SP15	WECC-CAMX	14	215,916.00	18	$42.63	$51.78	$15.00

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All Sellers in Balancing Authority: Applicable reported price for all sellers in the Balancing Authority including your company. (Prices are calculated from unreviewed data in all EQR filings, and are meant to be merely indicative of prices in the region for the filing period.)

NOTE: Billing adjustments are not included in calculations. Because of the difference in calculation methods (see note on "Price" above) "Average Price" may be outside the range of high and low prices.

Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 3 2016

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	4,928	38,469.93	14	$32.69	$316.56	-16.38
Michigan Electric Coordinated System - DECO	ECAR	10,252	107,422.82	9	$30.98	$323.94	-16.30
Midwest ISO	ECAR	2,398	1,334,882.80	153	$35.32	$92.50	$9.16
Florida Power & Light	FRCC	163	338,702.00	15	$37.06	$60.00	$21.00
PJM Interconnection	MAAC	191,158	40,048,147.35	459	$32.54	$198.40	-56.71
Upper Peninsula Power Co.	MAIN	828	15.33	8	$64.45	$159.85	$25.72
Wisconsin Public Service Corporation	MAIN	105	2.12	6	$20.42	$21.84	$18.99
ISO New England Inc.	NPCC	22,929	3,993,638.12	220	$34.94	$1,898.61	-342.45
New York Independent System Operator	NPCC	15,439	24,176.58	199	$41.33	$385.46	-47.57
Wisconsin Energy Corporation	RFC	738	1,576.32	5	$28.94	$294.96	-26.30
Duke Energy Corporation	SERC	16	5,901.00	19	$28.80	$53.00	$19.00
Entergy Arkansas, Inc.	SERC	1,324	4,550.09	10	$28.99	$382.44	-30.66
Entergy	SERC	4,960	499,254.89	23	$23.03	$463.55	-59.67
Southern Company Services, Inc.	SERC	1,910	3,668,356.28	40	$24.30	$82.75	$0.00
Tennessee Valley Authority ESO	SERC	48	93,664.00	21	$45.00	$60.00	$20.00
Ameren Transmission-Illinois	SERC	8,979	2,279,158.56	40	$28.81	$278.66	-107.14
Southwest Power Pool	SPP	217,193	2,290,860.10	128	$23.44	$1,280.61	-187.51
Arizona Public Service Company	WECC-AZNMS	70	67,697.00	21	$33.28	$39.28	$17.08
California Independent System Operator	WECC-CAMX	10,769	764,472.25	239	$23.50	$224.47	-163.68
PacifiCorp-East	WECC-NWPP	60	24,678.00	33	$38.22	$64.70	$12.00
Trading Hub-COB	WECC-CAMX	106	302,701.80	19	$37.81	$85.00	$0.00
Trading Hub-Four Corners	WECC-AZNMS	5	1,376.00	19	$27.14	$41.00	$16.00
Trading Hub-Mead	WECC-AZNMS	84	37,640.00	18	$52.95	$98.00	$21.50
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	1,528	153,370.30	33	$91.65	$74.00	$0.00
Trading Hub-NOB	WECC-NWPP	868	89,659.00	13	$36.23	$150.25	$18.73
Trading Hub-NP15	WECC-CAMX	73	69,600.00	17	$41.93	$62.21	$27.67
Trading Hub-Palo Verde	WECC-AZNMS	1,635	267,212.00	33	$101.83	$101.78	$0.00
Trading Hub-SP15	WECC-CAMX	282	364,894.00	16	$37.85	$70.43	$16.49

Description of Column Headings:

Product: TSIN abbreviation for the Balancing Authority.

NERC Region: Balancing Authority or Hub identified as point of delivery.

# of Lines: Number of lines of transaction data.

Standardized Quantity: Sum of quantities reported in MWH.
(Does not include sales at “FLAT RATE” or sales with an absolute value smaller than or equal to 1 MWH)

# of Sellers in Region: Count of sellers reporting sales in the Balancing Authority.

Standardized Price: i. Avg: Weighted average price (sum of non-transmission revenues weighted by reported quantity) in $/MWH.
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Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 3 2017

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	8,089	47,958.64	15	$28.61	$791.82	$1.01
Michigan Electric Coordinated System - DECO	ECAR	8,865	79,282.28	9	$27.63	$830.66	-0.01
Midwest ISO	ECAR	2,934	1,105,314.80	174	$36.19	$119.29	$12.45
Florida Power & Light	FRCC	145	213,653.00	12	$37.55	$74.00	$20.00
PJM Interconnection	MAAC	283,887	40,553,203.66	490	$30.05	$654.64	-45.94
Upper Peninsula Power Co.	MAIN	1,313	25.59	9	$29.99	$40.62	$24.86
Wisconsin Public Service Corporation	MAIN	253		8			
ISO New England Inc.	NPCC	218,031	3,664,250.26	229	$27.40	$458.77	-86.36
New York Independent System Operator	NPCC	18,026	1,433,991.17	199	$21.55	$609.65	-574.32
Wisconsin Energy Corporation	RFC	122	442.04	6	$30.88	$123.79	$18.21
Duke Energy Corporation	SERC	4	3,209.00	20	$32.02	$48.00	$30.00
Entergy Arkansas, Inc.	SERC	265	623.39	4	$26.59	$75.23	-10.16
Entergy	SERC	4,466	450,553.95	16	$28.60	$268.54	-25.06
Southern Company Services, Inc.	SERC	2,565	1,455,975.00	42	$25.58	$65.00	$4.48
Tennessee Valley Authority ESO	SERC	22	38,300.00	23	$36.03	$45.00	$22.00
Ameren Transmission-Illinois	SERC	9,273	2,314,481.87	34	$27.84	$615.32	-158.12
Southwest Power Pool	SPP	224,371	2,031,883.95	150	$22.51	$1,228.16	-243.44
Arizona Public Service Company	WECC-AZNMS	3	43,053.00	21	$32.03	$39.28	$18.00
California Independent System Operator	WECC-CAMX	5,332	2,026,734.63	265	$13.04	$687.75	-41.38
PacifiCorp-East	WECC-NWPP	57	17,461.00	36	$52.45	$150.00	$15.00
Trading Hub-COB	WECC-CAMX	44	74,253.00	19	$75.10	$130.00	$16.00
Trading Hub-Four Corners	WECC-AZNMS	4	43,258.00	21	$26.44	$45.15	$26.00
Trading Hub-Mead	WECC-AZNMS	532	24,197.00	20	$59.47	$697.85	$1.50
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	1,894	291,929.85	33	$68.75	$300.00	$1.00
Trading Hub-NOB	WECC-NWPP	47	44,011.00	9	$32.42	$50.00	$17.00
Trading Hub-NP15	WECC-CAMX	6	1,025,999.00	17	$33.89	$49.95	$31.00
Trading Hub-Palo Verde	WECC-AZNMS	383	117,819.00	36	$89.45	$144.63	-5.51
Trading Hub-SP15	WECC-CAMX	17	388,697.00	18	$37.95	$48.59	$32.50

Description of Column Headings:

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Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 3 2018

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	36,800	40,196.45	15	$31.70	$506.83	-13.31
Michigan Electric Coordinated System - DECO	ECAR	39,025	83,190.44	8	$32.51	$1,032.36	-47.59
Midwest ISO	ECAR	1,001	1,045,040.60	174	$32.55	$110.07	$16.74
Florida Power & Light	FRCC	62	214,768.00	15	$36.60	$110.00	$19.00
PJM Interconnection	MAAC	3,342,489	45,268,322.53	513	$32.92	$696.45	-82.33
ISO New England Inc.	NPCC	154,502	1,892,447.46	236	$41.52	$2,737.73	-151.46
New York Independent System Operator	NPCC	184,553	975,401.13	208	$29.75	$266.80	-1959.43
Duke Energy Corporation	SERC	5	1,194.00	24	$33.89	$44.00	$31.00
Entergy Arkansas, Inc.	SERC	292	1,063.08	6	$31.97	$95.98	$19.39
Entergy	SERC	4,505	402,505.96	15	$24.30	$207.48	$11.12
Santee Cooper	SERC	77	289,923.00	11	$32.80	$43.00	$21.00
Southern Company Services, Inc.	SERC	1,639	2,838,776.61	45	$30.38	$200.00	$4.59
Tennessee Valley Authority ESO	SERC	15	14,153.00	21	$44.32	$55.00	$32.00
Ameren Transmission-Illinois	SERC	23,599	2,254,876.09	43	$30.13	$3,500.00	-74.67
Southwest Power Pool	SPP	243,259	2,574,970.25	163	$21.80	$1,504.72	-149.88
Arizona Public Service Company	WECC-AZNMS	65	57,760.00	20	$29.93	$72.87	$15.05
California Independent System Operator	WECC-CAMX	34,682	970,339.16	295	$33.39	$1,021.32	-126.62
PacifiCorp-East	WECC-NWPP	101	27,716.00	32	$55.14	$450.00	$21.25
Trading Hub-COB	WECC-CAMX	97	221,737.00	20	$50.59	$320.00	$15.00
Trading Hub-Mead	WECC-AZNMS	411	149,189.00	21	$74.59	$500.00	$20.00
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	2,453	337,271.50	33	$88.12	$315.00	-30.75
Trading Hub-NOB	WECC-NWPP	66	20,666.00	11	$95.20	$78.25	$20.00
Trading Hub-NP15	WECC-CAMX	31	2,386,747.00	15	$36.12	$201.00	$30.19
Trading Hub-Palo Verde	WECC-AZNMS	1,174	110,912.00	32	$179.74	$667.44	$4.00
Trading Hub-SP15	WECC-CAMX	29	359,238.50	15	$43.74	$72.50	$30.25

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Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 4 2013

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	4,230	46,939.18	18	$32.38	$407.67	-20.27
Michigan Electric Coordinated System - DECO	ECAR	8,647	144,553.49	12	$31.61	$400.87	-20.58
Midwest ISO	ECAR	3,552	1,877,488.00	129	$33.47	$101.58	-97.37
Florida Power & Light	FRCC	136	48,672.00	12	$38.36	$56.00	$25.00
PJM Interconnection	MAAC	103,286	31,090,827.18	383	$36.95	$137.90	$0.38
ISO New England Inc.	NPCC	34,089	2,719,388.32	211	$50.67	$1,499.26	-94.43
New York Independent System Operator	NPCC	19,490	34,301.14	190	$50.08	$350.00	-78.94
Constellation Energy Control and Dispatch - City of Ruston, LA	SERC	4	58,595.00	4	$42.70	$42.70	$42.70
Duke Energy Corporation	SERC	18	7,771.00	16	$39.24	$52.00	$29.00
Entergy Arkansas, Inc.	SERC	446	1,141.41	7	$34.48	$249.00	$15.43
Entergy	SERC	1,893	552,577.20	38	$30.54	$194.76	$21.00
Southern Company Services, Inc.	SERC	1,898	4,425,389.33	44	$29.59	$78.36	$1.00
Tennessee Valley Authority ESO	SERC	35	13,966.00	30	$41.97	$53.00	$30.00
Ameren Transmission-Illinois	SERC	4,872	1,541,878.09	39	$28.29	$154.73	-686.54
Southwest Power Pool	SPP	2,754	502,390.00	26	$32.43	$186.26	-10.49
Arizona Public Service Company	WECC-AZNMS	6	55,071.00	22	$38.27	$44.64	$25.00
California Independent System Operator	WECC-CAMX	18,619	861,578.00	178	$36.27	$1,416.10	-1026.51
PacifiCorp-East	WECC-NWPP	17	1,777.00	25	$50.74	$67.00	$25.00
Trading Hub-ADHUB	MAAC	9	76,717.00	14	$42.14	$47.50	$33.90
Trading Hub-AEPGenHub		11	38,270.00	3	$37.47	$44.20	$33.20
Trading Hub-COB	WECC-CAMX	222	179,192.10	24	$45.53	$95.00	$0.00
Trading Hub-Entergy (into)	SERC	149	50,365.00	5	$35.43	$68.91	$5.00
Trading Hub-Four Corners	WECC-AZNMS	4	16,650.00	27	$28.20	$36.75	$26.75
Trading Hub-Illinois Hub (MISO)	MAIN	9	25,728.80	5	$45.39	$49.50	$27.65
Trading Hub-Mead	WECC-AZNMS	12	7,447.00	27	$35.67	$38.10	$29.25
Trading Hub-Michigan Hub (MISO)	ECAR	6	305,312.00	7	$38.94	$62.75	$31.00
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	592	93,039.00	38	$68.90	$100.00	$0.00
Trading Hub-NEPOOL (Mass Hub)	NPCC	38	375,186.27	15	$52.50	$94.00	$32.06
Trading Hub-NIHUB	MAAC	62	815,281.50	10	$36.21	$51.50	$22.70
Trading Hub-NP15	WECC-CAMX	2	21,360.00	16	$40.31	$43.75	$35.90
Trading Hub-Palo Verde	WECC-AZNMS	630	90,278.00	35	$108.02	$69.42	$0.00
Trading Hub-PJM West Hub	MAAC	37	1,557,288.00	16	$45.21	$73.05	$32.05
Trading Hub-SP15	WECC-CAMX	7	59,975.00	23	$45.45	$58.31	$34.00

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Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 4 2014

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	4,407	64,601.10	20	$33.80	$234.47	-2.09
Michigan Electric Coordinated System - DECO	ECAR	8,756	164,701.00	12	$30.66	$234.24	-2.06
Midwest ISO	ECAR	2,855	994,923.40	147	$33.80	$126.41	-34.64
Florida Power & Light	FRCC	57	24,834.00	15	$39.09	$47.00	$27.00
PJM Interconnection	MAAC	90,625	37,316,469.58	425	$36.17	$185.80	-53.96
ISO New England Inc.	NPCC	40,886	3,211,399.39	215	$41.17	$1,139.53	-160.14
New York Independent System Operator	NPCC	19,394	29,968.15	197	$36.56	$815.43	-61.83
Duke Energy Corporation	SERC	13	8,721.00	17	$33.83	$43.00	$26.00
Entergy Arkansas, Inc.	SERC	3,223	5,706.35	7	$30.46	$161.68	-300.01
Entergy	SERC	3,841	147,640.81	26	$33.85	$2,039.14	$8.22
Southern Company Services, Inc.	SERC	2,123	3,849,013.16	42	$40.20	$250.00	$17.00
Tennessee Valley Authority ESO	SERC	9	41,092.00	19	$43.60	$45.00	$29.00
Ameren Transmission-Illinois	SERC	5,726	2,439,330.80	43	$30.30	$117.41	-1.99
Southwest Power Pool	SPP	48,964	1,011,612.18	57	$32.37	$1,651.33	-98.94
Arizona Public Service Company	WECC-AZNMS	59	137,180.00	26	$39.13	$46.65	$20.00
California Independent System Operator	WECC-CAMX	15,729	772,793.90	181	$41.19	$3,265.33	-150.00
PacifiCorp-East	WECC-NWPP	10	6,170.00	25	$50.55	$68.00	$25.00
Trading Hub-ADHUB	MAAC	19	102,718.20	18	$33.18	$50.20	$29.55
Trading Hub-AEPGenHub		22	283,252.63	3	$47.07	$54.90	$33.20
Trading Hub-COB	WECC-CAMX	149	151,439.25	21	$55.00	$85.00	$0.00
Trading Hub-FE Hub		1	1,465.00	2	$42.90	$42.90	$42.90
Trading Hub-Four Corners	WECC-AZNMS	2	650.00	26	$40.92	$44.00	$36.00
Trading Hub-Illinois Hub (MISO)	MAIN	2	14,592.00	5	$54.25	$54.25	$54.25
Trading Hub-Mead	WECC-AZNMS	69	14,782.00	24	$197.59	$45.00	$20.00
Trading Hub-Michigan Hub (MISO)	ECAR	2	17,568.00	9	$31.52	$31.60	$31.45
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	1,012	126,086.00	41	$70.77	$65.00	$1.00
Trading Hub-NEPOOL (Mass Hub)	NPCC	40	169,468.10	16	$51.50	$91.48	$23.00
Trading Hub-NIHUB	MAAC	59	121,845.30	9	$35.13	$41.70	$25.45
Trading Hub-NP15	WECC-CAMX	2,210	81,505.00	19	$43.72	$91.03	$20.86
Trading Hub-Palo Verde	WECC-AZNMS	974	170,221.00	35	$138.99	$72.00	$20.00
Trading Hub-PJM West Hub	MAAC	2,286	3,126,423.30	24	$39.53	$120.70	$16.48
Trading Hub-SP15	WECC-CAMX	7	87,691.00	19	$41.24	$49.65	$20.00

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Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 4 2015

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	10,367	184,709.73	19	$24.59	$169.38	-0.07
Michigan Electric Coordinated System - DECO	ECAR	9,783	181,485.66	10	$23.63	$166.93	-0.07
Midwest ISO	ECAR	5,837	1,342,404.40	149	$31.19	$51.81	-50.39
Florida Power & Light	FRCC	57	33,799.00	14	$34.86	$45.00	$15.00
PJM Interconnection	MAAC	220,061	39,202,124.23	443	$27.81	$162.65	-23.40
Upper Peninsula Power Co.	MAIN	542	1.01	8	$21.89	$21.89	$21.89
Wisconsin Public Service Corporation	MAIN	665	11.23	7	$20.28	$24.76	$9.45
ISO New England Inc.	NPCC	33,260	3,370,626.06	226	$30.39	$355.02	-139.77
New York Independent System Operator	NPCC	25,197	42,812.78	191	$23.36	$260.50	-143.70
Wisconsin Energy Corporation	RFC	1,186	3,522.57	5	$25.74	$255.78	$3.44
Duke Energy Corporation	SERC	18	10,985.00	19	$23.42	$29.00	$17.50
Entergy Arkansas, Inc.	SERC	1,554	2,595.40	7	$21.47	$130.25	-45.25
Entergy	SERC	4,985	310,318.76	25	$17.52	$226.76	-64.13
Southern Company Services, Inc.	SERC	1,852	5,009,946.70	39	$27.53	$65.00	$1.00
Tennessee Valley Authority ESO	SERC	21	18,656.00	21	$25.59	$33.00	$18.00
Ameren Transmission-Illinois	SERC	10,236	2,487,800.89	44	$21.60	$194.25	-163.83
Southwest Power Pool	SPP	39,052	657,638.02	120	$19.63	$720.78	-70.30
Arizona Public Service Company	WECC-AZNMS	49	43,910.00	22	$33.32	$37.03	$15.09
California Independent System Operator	WECC-CAMX	15,018	950,455.06	207	$19.87	$144.01	-150.68
PacifiCorp-East	WECC-NWPP	13	15,748.00	25	$46.92	$47.28	$18.00
Trading Hub-COB	WECC-CAMX	138	139,988.20	20	$38.53	$85.00	$0.00
Trading Hub-Four Corners	WECC-AZNMS	14	86,748.00	20	$28.00	$35.00	$19.00
Trading Hub-Mead	WECC-AZNMS	513	73,876.00	20	$106.03	$49.90	$11.26
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	1,272	149,102.00	31	$108.64	$85.00	$0.00
Trading Hub-NP15	WECC-CAMX	77	73,420.00	16	$39.83	$48.25	$24.89
Trading Hub-Palo Verde	WECC-AZNMS	1,001	90,152.00	34	$166.04	$150.50	$0.49
Trading Hub-SP15	WECC-CAMX	13	100,204.00	17	$44.30	$51.78	$8.00

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Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 4 2016

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	5,953	76,761.33	16	$29.74	$221.10	$1.01
Michigan Electric Coordinated System - DECO	ECAR	10,017	187,109.75	9	$29.36	$225.30	-0.01
Midwest ISO	ECAR	3,055	1,312,662.60	162	$33.06	$88.05	$15.17
Florida Power & Light	FRCC	48	80,488.00	13	$33.45	$48.00	$19.00
PJM Interconnection	MAAC	233,652	39,462,285.42	463	$29.82	$227.13	-176.44
Upper Peninsula Power Co.	MAIN	736	36.00	8	$41.95	$105.87	$27.17
Wisconsin Public Service Corporation	MAIN	527	58.40	6	$32.33	$222.26	$21.08
ISO New England Inc.	NPCC	19,764	2,586,754.80	236	$37.27	$225.43	-60.26
New York Independent System Operator	NPCC	14,867	8,553.90	197	$55.82	$113.38	-19.66
Wisconsin Energy Corporation	RFC	900	2,951.05	5	$34.08	$175.11	$2.98
Duke Energy Corporation	SERC	2	844.00	17	$38.53	$39.00	$30.00
Entergy Arkansas, Inc.	SERC	1,190	2,078.32	5	$32.07	$413.58	$5.17
Entergy	SERC	4,482	332,265.36	18	$23.22	$295.30	-136.60
Southern Company Services, Inc.	SERC	1,958	2,686,811.03	41	$27.53	$83.00	$1.00
Tennessee Valley Authority ESO	SERC	20	29,025.00	19	$33.84	$55.00	$23.00
Ameren Transmission-Illinois	SERC	8,542	2,464,117.69	41	$26.17	$169.40	-62.76
Southwest Power Pool	SPP	276,782	1,745,807.40	145	$23.21	$1,540.47	-60.21
Arizona Public Service Company	WECC-AZNMS	30	38,447.00	21	$34.60	$37.03	$12.00
California Independent System Operator	WECC-CAMX	18,456	1,002,733.64	257	$21.56	$284.53	-141.90
PacifiCorp-East	WECC-NWPP	26	11,766.00	34	$24.45	$28.15	$12.00
Trading Hub-COB	WECC-CAMX	243	168,559.35	19	$39.25	$85.00	$0.00
Trading Hub-Four Corners	WECC-AZNMS	2	1,200.00	21	$30.00	$30.00	$30.00
Trading Hub-Mead	WECC-AZNMS	59	69,613.36	20	$37.53	$38.45	$18.00
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	1,904	207,224.00	32	$45.50	$60.00	$0.00
Trading Hub-NOB	WECC-NWPP	1		11			
Trading Hub-NP15	WECC-CAMX	4	28,720.00	18	$37.68	$38.65	$35.69
Trading Hub-Palo Verde	WECC-AZNMS	738	72,092.00	34	$183.17	$41.00	$5.00
Trading Hub-SP15	WECC-CAMX	12	198,084.00	18	$37.17	$48.59	$29.50

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Energy Sales and Bookouts by Balancing Authority

Summary of Data Reported in the FERC Electric Quarterly Report (EQR), by Seller

Exelon Generation Company, LLC : C000202

Report Period: Qtr. 4 2017

Balancing	NERC Region	# of Lines	Standardized Quantity	Total # of Sellers in Ctrl Area	Avg. Price	High Price	Low Price
Michigan Electric Coordinated System - CONS	ECAR	7,792	77,954.08	18	$27.52	$262.53	$1.01
Michigan Electric Coordinated System - DECO	ECAR	9,057	163,809.54	9	$27.72	$287.34	-0.01
Midwest ISO	ECAR	2,091	911,352.20	175	$34.20	$63.58	$11.03
Florida Power & Light	FRCC	58	52,163.00	11	$36.14	$52.00	$21.00
PJM Interconnection	MAAC	274,298	39,157,447.42	489	$32.08	$272.10	$11.18
ISO New England Inc.	NPCC	198,333	2,789,576.95	234	$50.53	$1,064.03	-112.38
New York Independent System Operator	NPCC	18,750	1,543,854.42	205	$24.62	$354.95	-50.90
Duke Energy Corporation	SERC	2	375.00	21	$28.00	$28.00	$28.00
Entergy Arkansas, Inc.	SERC	481	428.18	6	$25.36	$75.15	$15.27
Entergy	SERC	4,025	146,275.18	18	$27.80	$244.53	-0.89
Southern Company Services, Inc.	SERC	2,245	2,837,941.83	40	$27.95	$85.00	$4.44
Tennessee Valley Authority ESO	SERC	7	8,608.00	20	$31.34	$33.50	$24.00
Ameren Transmission-Illinois	SERC	5,985	2,273,195.50	38	$24.32	$242.47	-45.71
Southwest Power Pool	SPP	227,904	2,144,379.79	154	$21.05	$1,455.21	-402.88
Arizona Public Service Company	WECC-AZNMS	29	40,012.00	18	$28.60	$65.00	$17.15
Nevada Power Company	WECC-AZNMS	3	24.00	32	$35.67	$45.00	$29.00
California Independent System Operator	WECC-CAMX	9,367	1,307,301.08	285	$24.09	$728.46	-150.00
PacifiCorp-East	WECC-NWPP	6	121.00	34	$28.53	$45.00	$20.00
Trading Hub-COB	WECC-CAMX	146	126,820.25	19	$50.59	$85.00	$22.45
Trading Hub-Four Corners	WECC-AZNMS	2	49,750.00	22	$23.05	$23.05	$22.95
Trading Hub-Mead	WECC-AZNMS	1,482	172,340.00	21	$31.33	$385.43	$9.27
Trading Hub-Mid-Columbia (Mid-C)	WECC-NWPP	1,439	193,153.85	34	$65.59	$58.00	$1.00
Trading Hub-NOB	WECC-NWPP	13	4,600.00	12	$176.88	$31.00	$22.50
Trading Hub-NP15	WECC-CAMX	6	1,175,654.00	17	$34.03	$49.95	$31.00
Trading Hub-Palo Verde	WECC-AZNMS	1,719	247,287.00	32	$89.60	$292.45	$0.10
Trading Hub-SP15	WECC-CAMX	11	166,253.00	14	$37.01	$48.59	$32.50

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January 17, 2017

VIA eTARIFF FILING

PRIVILEGED MATERIALS HAVE BEEN REMOVED

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: ***Constellation Power Source Generation, LLC*, Docket No. ER17-___-000;**
***Exelon Generation Company, LLC*, Docket No. ER17-___-000;**
***Handsome Lake Energy, LLC*, Docket No. ER17-___-000;**
Reactive Service Rate Schedule Filings

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] Part 35 of the regulations of the Federal Energy Regulatory Commission ("FERC" or the "Commission"),[2] and the Constellation Power Source Generation, LLC ("CPSG") Offer of Settlement dated August 18, 2016,[3] (i) CPSG hereby submits for filing revised FERC Rate Schedule No. 2 ("CPSG Rate Schedule"), which sets forth the revised cost-based annual revenue requirement ("Revised CPSG ARR") for Reactive Service under Schedule 2 of the PJM Tariff; (ii) Exelon Generation hereby submits for filing FERC Rate Schedule No. 22 ("ExGen Rate Schedule"), which sets forth the revised cost-based annual revenue requirement ("Revised ExGen ARR") for Reactive Service under Schedule 2 of the PJM Tariff; and (iii) Handsome Lake Energy, LLC ("Handsome Lake") hereby submits for filing Rate Schedule FERC No. 2 ("HLE Rate Schedule"), which sets forth

1 16 U.S.C. § 824d (2012).

2 18 C.F.R. Pt. 35 (2016).

3 Offer of Settlement, Docket Nos. ER16-746-001, *et al*. (filed Aug. 18, 2106) (providing for CPSG, Exelon Generation Company, LLC ("Exelon Generation"), and Exelon Generation subsidiaries to file updated revenue requirements for Reactive Supply and Voltage Control from Generation Sources Service ("Reactive Service") under Schedule 2 of the PJM Open Access Transmission Tariff ("PJM Tariff") for their generation within the PJM Interconnection, L.L.C. ("PJM") footprint); *Constellation Power Source Generation, LLC*, 157 FERC ¶ 61,148 (2016) (approving the Offer of Settlement).

the revised cost-based annual revenue requirement ("Revised HLE ARR") for Reactive Service under Schedule 2 of the PJM Tariff.[4]

CPSG, Exelon Generation, and Handsome Lake (collectively, the "Applicants") respectfully request that the Commission accept respectively the CPSG Rate Schedule, ExGen Rate Schedule, and HLE Rate Schedule (the "Rate Schedules") for filing on or before March 18, 2017, and grant any necessary waivers to permit an effective date for the Rate Schedules of March 1, 2017.[5]

I. COMMUNICATIONS

All communications and service related to this application should be directed to the following individuals:

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[4] Because the cost support for the Revised CPSG ARR, Revised ExGen ARR, and Revised HLE ARR include cost allocations common to all of the generation facilities, the Applicants prepared a single filing consisting of this letter and the accompanying attachments (the "Filing"). The Filing is being submitted in accordance with the Commission's eTariff guidelines concurrently in three separate dockets under CPSG, Exelon Generation, and Handsome Lake, respectively, with the filing entity's corresponding eTariff record.

[5] PJM typically incorporates reactive service revenue requirements into Schedule 2 of the PJM Tariff effective the first day of the month in which the Commission accepts or approves the revenue requirement. In order to prevent retroactive billing, PJM interprets Schedule 2 to require effective dates no earlier than the first day of the month in which the Commission approves the revenue requirement. *See, e.g.,* Motion for Leave to Intervene Out of Time and Comments of PJM Interconnection, L.L.C. at 3, Docket No. EL05-20-000 (filed Dec. 1, 2004). The Commission has granted similar effective dates for other reactive power revenue requirements incorporated into Schedule 2 of the PJM Tariff. *See Ameren Energy Generating Co*., Docket No. ER09-337-000 (Mar. 30, 2009) (unreported) (establishing a March 1, 2009 effective date); *York Generation Co. LLC*, Docket No. ER07-1351-000 (Oct. 26, 2007) (unreported) (establishing an October 1, 2007 effective date); *see also Calpine Mid Merit, LLC*, 138 FERC ¶ 61,232 at P 1 (2012) (establishing a March 1, 2012 effective date).

Christopher A. Wilson
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II. DOCUMENTS SUBMITTED

This filing consists of the following:

1. Transmittal Letter;

2. Clean Constellation Power Source Generation, LLC FERC Rate Schedule No. 2 for Reactive Supply and Voltage Control from Generation Sources Service (Attachment A);

3. Redline Constellation Power Source Generation, LLC FERC Rate Schedule No. 2 for Reactive Supply and Voltage Control from Generation Sources Service (Attachment B);

4. Exelon Generation Company, LLC FERC Rate Schedule No. 22 for Reactive Supply and Voltage Control from Generation Sources Service (Attachment C);[6]

5. Clean Handsome Lake Energy, LLC Rate Schedule FERC No. 2 for Reactive Supply and Voltage Control from Generation Sources Service (Attachment D);

6. Redline Handsome Lake Energy, LLC Rate Schedule FERC No. 2 for Reactive Supply and Voltage Control from Generation Sources Service (Attachment E);

7. The testimony of Alan C. Heintz, with accompanying schedules and workpapers (Attachment F); and

8. Protective Agreement (Attachment G).

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[6] As discussed in Section III.B below, Exelon Generation currently receives Reactive Service compensation. However, that compensation is not set forth in an existing Exelon Generation rate schedule. Accordingly, unlike for CPSG and Handsome Lake, a redline of the Exelon Generation FERC Rate Schedule No. 22 is not included herein.

III. BACKGROUND

The Applicants are direct or indirect wholly owned subsidiaries of Exelon Corporation ("Exelon") that own nuclear, fossil, or hydroelectric generation located within the footprint of PJM. Each Applicant currently receives a monthly payment for the provision of Reactive Service pursuant to Schedule 2 of the PJM Tariff.

A. Exelon

Exelon is a publicly traded holding company, headquartered in Chicago, Illinois, with operations and business activities in 48 states, the District of Columbia, Canada, and the United Kingdom. Exelon was formed in 1999 to be the holding company resulting from the merger of Commonwealth Edison Company ("ComEd") and its subsidiaries and PECO Energy Company ("PECO") and its subsidiaries, which the Commission approved on April 12, 2000.[7] The merger was consummated on October 20, 2000. On March 9, 2012, the Commission authorized a subsequent merger between Exelon and Constellation Energy Group, Inc., the holding company that owned Baltimore Gas and Electric Company ("BGE") and other energy subsidiaries.[8] On November 20, 2014, the Commission authorized the merger between Exelon and Pepco Holdings, Inc. ("PHI"), the holding company that owned Potomac Electric Power Company ("Pepco"), Atlantic City Electric Company ("ACE"), and Delmarva Power & Light Company ("Delmarva").[9] ComEd, PECO, BGE, Pepco, ACE, and Delmarva do not currently own any generation facilities (except for certain behind-the-meter facilities) and do not receive any compensation for Reactive Service under Schedule 2 of the PJM Tariff.

B. Exelon Generation

Exelon Generation is one of the largest competitive power generators in the United States. The Commission authorized Exelon Generation to sell energy, capacity, and certain ancillary services at market-based rates.[10] Exelon Generation directly owns in PJM nuclear, fossil, and hydroelectric generation. Such facilities include generation facilities that ComEd and PECO transferred to Exelon Generation as part of their generation divestiture and restructuring to transmission and distribution utilities.[11]

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7 *Commonwealth Edison Co.*, 91 FERC ¶ 61,036 (2000).

8 *Exelon Corp.,* 138 FERC ¶ 61,167 (2012). The transaction was consummated on March 12, 2012.

9 *Exelon Corp.,* 149 FERC ¶ 61,148 (2014). The transaction was consummated on March 23, 2016.

10 *Exelon Generating Co.*, 93 FERC ¶ 61,140 (2000), *reh'g denied*, 95 FERC ¶ 61,309 (2001).

11 *See PECO Energy Co.¸* 90 FERC ¶ 61,269 (2000); *Commonwealth Edison Co.*, 91 FERC ¶ 61,033 (2000); *Commonwealth Edison Co.*, 93 FERC ¶ 61,040 (2000).

1. ComEd Zone

In the ComEd zone, Exelon Generation currently owns the following generation facilities: Braidwood 1 and 2; Byron 1 and 2; Dresden 2 and 3; LaSalle 1 and 2; Quad Cities 1 and 2;[12] and Southeast Chicago Energy Project 5-12. Exelon Generation receives from PJM an annual payment for Reactive Service allocated to the ComEd zone equal to $10,227,259. The payment is based on the zonal annual revenue requirement ("ARR") that ComEd developed in 1999 for its fleet.

On September 17, 1999, as amended on October 1, 1999, ComEd filed in Docket No. ER99-4470-000 proposed revisions to its Open Access Transmission Tariff ("OATT"). In addition to reducing rates for transmission and loss compensation service, the revisions added Reactive Service rates to Schedule 2, which previously did not include any charges for that ancillary service. The Commission accepted the revised and new rates subject to refund on November 30, 1999.[13] A settlement was filed on April 12, 2000, and approved by Commission on July 31, 2000.[14] The settled zonal rate for Reactive Service did not include any allocation of the zonal ARR to individual generation facilities.

ComEd joined PJM effective May 1, 2004. On January 12, 2004, PJM filed in Docket No. ER04-367-001 tariff revisions to incorporate ComEd's Reactive Service ARR into the PJM Tariff as a new zonal ARR. The Commission accepted for filing those tariff revisions on March 18, 2004.[15]

2. PECO Zone

In the PECO zone, Exelon Generation currently owns the following generation facilities: Limerick 1 and 2; Peach Bottom 2 and 3;[16] Chester 7-9; Conowingo 1-11; Croydon 11, 12, 21, 22, 31, 32, 41, and 42; Delaware 9-12; Eddystone 3, 4, 10, 20, 30, 40; Fairless Hills A and B; Falls 1-3; Moser 1-3; Muddy Run 1-8; Pennsbury 1 and 2; Richmond 91 and 92; Schuylkill 10 and 11; and Southwark 3-6. Exelon Generation receives from PJM an annual payment for Reactive Service allocated to the PECO zone equal to $8,503,076. The payment is based on the zonal ARR that PECO developed in 1998 for its fleet.[17]

In 1997, the Commission accepted for filing the OATT of the then Pennsylvania-New Jersey-Maryland Interconnection, but set for hearing the Reactive Service rates that PECO and

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12 Exelon Generation owns only 75 percent of the Quad Cities 1 and 2 generation facility.

13 *Commonwealth Edison Co.*, 89 FERC ¶ 61,252 (1999).

14 *Commonwealth Edison Co.*, 92 FERC ¶ 61,113 (2000).

15 *PJM Interconnection, L.L.C.*, 106 FERC ¶ 61,252 (2004).

16 Exelon Generation owns only 50 percent of the Peach Bottom 2 and 3 generation facility.

17 The current $8,503,076 annual payment reflects a reduction from the original 1998 ARR as a result of the divestiture of certain generation facilities and the agreement to allocate a *pro-rata* share of reactive payments associated with the divested facilities.

the other transmission owners would charge in their respective zones.[18] A settlement was filed on March 16, 1998, in Docket No. ER97-3189-005 and approved by the Commission on December 16, 1998.[19] The settled zonal rate for Reactive Service did not include any allocation of the zonal ARR to individual generation facilities.

3. Other Zones

In the Public Service Electric and Gas Company ("PSEG") zone, Exelon Generation currently owns 42.59% of the Salem 1 and 2 generation facility. Exelon Generation does not receive any discrete payment for Reactive Service allocated to the PSEG zone. However, the Salem 1 and 2 generation facility was owned by PECO at the time the Commission approved PECO's fleet-wide zonal ARR.

In the Jersey Central Power & Light Company ("JCP&L") and Metropolitan Edison Company ("MetEd") zones, Exelon Generation currently owns the Three Mile Island 1 ("TMI") and Oyster Creek generation facilities, for which Exelon Generation receives an ARR of $1,622,126 for Reactive Service allocated to the JCP&L zone, an ARR of $794,350 for Reactive Service allocated to the MetEd zone, and an ARR of $316,128 for Reactive Service allocated to the Pennsylvania Electric Company ("Penelec") zone. These payments are based on plant-specific ARRs accepted for the TMI and Oyster Creek facilities.

Exelon Generation owns TMI and Oyster Creek as a result of being the successor to AmerGen Energy Company, L.L.C. ("AmerGen").[20] AmerGen acquired TMI from JCP&L, MetEd, and Penelec (collectively, "GPU Energy")[21] and acquired Oyster Creek from JCP&L.[22] AmerGen established, and the Commission accepted, a plant-specific Reactive Service ARR for TMI. On January 20, 2000, as amended on July 26, 2000, AmerGen filed in Docket Nos. ER00-1177-000 and -001 a Reactive Power Compensation Agreement pursuant to which AmerGen would make available to GPU Energy the reactive power produced by TMI. The Reactive Service ARR for TMI was $1,460,683 and its recovery was allocated to the zones of the three former owners of TMI as follows: $350,205 to the JCP&L zone; $794,350 to the MetEd zone;

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18 *Pennsylvania-New Jersey-Maryland Interconnection,* 81 FERC ¶ 61,257 (1997).

19 *PECO Energy Co.,* Letter Order, Docket No. ER97-3189-005 (Dec. 16, 1998). The PECO zonal ARR amount was included in PJM's July 31, 2000 filing in Docket No. ER00-3327-000 to revise Schedule 2, which the Commission accepted for filing on September 25, 2000. *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER00-3327-000 (Sept. 25, 2000).

20 AmerGen was formed in 1997 as a joint venture between PECO and British Energy, Inc. ("British Energy"). Exelon Generation acquired British Energy's 50 percent interest in AmerGen in December 2003 and, effective January 8, 2009, AmerGen was merged into Exelon Generation.

21 *Jersey Central Power & Light Co.*, 87 FERC ¶ 61,014 (1999).

22 *Jersey Central Power & Light Co.*, 90 FERC ¶ 62,127 (2000).

and $316,128 to the Penelec zone. The Commission accepted for filing the Reactive Power Compensation Agreement and the ARR for TMI on August 30, 2000.[23]

On April 3, 2006, PJM filed in Docket No. ER06-833-000 revisions to the PJM Tariff to reflect in Schedule 2 the allocation of Reactive Service ARRs that JCP&L, MetEd, and Penelec had made to AmerGen and other owners of generation facilities.[24] The Commission accepted for filing PJM's tariff revisions on May 31, 2006.[25] The Reactive Service ARRs allocated to AmerGen in the MetEd and Penelec zones were, respectively, $794,349.96 and $316,128. Those amounts correspond to the allocations to those two zones of the ARR for TMI. The Reactive Service ARR allocated to AmerGen in the JCP&L zone was $1,662,126. Because AmerGen owned both TMI and Oyster Creek in the JCP&L zone, the $1,662,126 ARR represents the combination of the allocation of the ARR for TMI to the JCPL zone ($350,205) and the Reactive Service ARR for Oyster Creek.

C. CPSG

CPSG is authorized to sell energy, capacity, and certain ancillary services at market-based rates.[26] CPSG currently owns the following fossil-fueled generation facilities that are located in the BGE zone: Gould Street 3; Notch Cliff 1-8; Perryman1, 3, 4, 6, and 51; Philadelphia Road 1-4; Riverside 7 and 8; and Westport 5. On January 19, 2016, as supplemented on March 21, 2016, CPSG filed in Docket Nos. ER16-746-000, *et al*., FERC Rate Schedule No. 2, which identifies unit-specific Reactive Service ARRs for CPSG's generation facilities.[27] The Commission accepted for filing CPSG's rate schedule effective February 1, 2016.[28] CPSG currently receives from PJM an annual payment for Reactive Service equal to $1,240,269, which reflects the unit-specific ARRs in CPSG's Rate Schedule No. 2.

1. Settlement

In addition to accepting CPSG's rate schedule for filing, the CPSG Order instituted a proceeding pursuant to Section 206 of the FPA in Docket No. EL16-57-000, and established hearing and settlement judge procedures. On August 18, 2016, CPSG filed the Offer of

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23 *AmerGen Energy Co., L.L.C.*, Letter Order, Docket Nos. ER00-1177-000, *et al.* (Aug. 30, 2000).

24 PJM Interconnection, L.L.C., Docket No. ER06-833-000 (filed Apr. 3, 2006).

25 *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER06-833-000 (May 31, 2006).

26 *See AmerGen VT, LLC,* 90 FERC ¶ 61,307 at 61,995 (2000), *on reh'g, Baltimore Gas & Elec. Co.,* 91 FERC ¶ 61,270 (2000) (granting market-based rate authority to Constellation Power Source Generation, Inc., CPSG's predecessor in interest); *Constellation Power Source Generation, LLC*, Letter Order, Docket No. ER14-1169-000 (Mar. 11, 2014) (accepting for filing CPSG's notice of succession to Constellation Power Source Generation, Inc.).

27 Constellation Power Source Generation, LLC, Docket No. ER16-746-000 (filed Jan. 19, 2016); Response to Deficiency Letter, Docket No. ER16-746-000 (filed Mar. 21, 2016). The unit-specific ARRs did not include any compensation for Perryman 6, which became operational in June 2015.

28 *Constellation Power Source Generation, LLC*, 155 FERC ¶ 61,181 (2016) ("CPSG Order").

Settlement in Docket Nos. ER16-746-001, *et al*.,[29] which the Commission approved on November 22, 2016.[30] Significantly, among the terms and conditions in the Offer of Settlement are the requirements that (i) the cost of service calculation for Perryman 6 would be separate from that for the other CPSG units and (ii) Exelon Generation would concurrently file "separate rate schedules reflecting the revenue requirements for any other generation facility that Exelon, through its subsidiaries, owns in the PJM footprint and for which Reactive Service compensation is received or sought."[31] The Applicants' respective filings satisfy these Offer of Settlement requirements.

D. Handsome Lake

Handsome Lake owns a natural gas-fired generation facility located in PJM's Penelec zone. On January 11, 2002, Handsome Lake filed in Docket No. ER02-771-000 its Rate Schedule FERC No. 2 for Reactive Service seeking recovery of a plant-specific ARR of $301,186. The Commission accepted for filing Handsome Lake's Rate Schedule FERC No. 2 on March 8, 2002.[32] On December 13, 2002, Handsome Lake filed in Docket No. ER03-269-000 a revised Rate Schedule FERC No. 2 to include in the ARR calculation a composite income tax factor that had been inadvertently omitted from the filing in Docket No. ER02-771-000. The revision resulted in a new plant-specific ARR of $370,304, which the Commission accepted for filing on January 13, 2003.[33]

IV. DESCRIPTION OF REVENUE REQUIREMENTS FOR REACTIVE SERVICE

The Rate Schedules are cost-based rate schedules that represent updated revenue requirements for Reactive Service for the Applicants. The revenue requirements consist of the fixed costs attributable to reactive power production capability ("Fixed Capability Component"), and, where included, the increased generator and step-up transformer heating losses that result from the production of reactive power ("Heating Losses"). In addition, to the extent a facility is directed to modify its energy output to produce additional reactive power, Section 3.2.3B of Schedule 1 of PJM's Amended and Restated Operating Agreement, as amended and restated from time-to-time, addresses the ability for an Applicant to be compensated for lost opportunity

29 Offer of Settlement, Docket Nos. ER16-746-001, *et al*. (filed Aug. 18, 2016).

30 *See Constellation Power Source Generation, LLC*, 157 FERC ¶ 61,148 (2016).

31 Offer of Settlement, Paragraph 12. In addition to the facilities included in these filings, through a joint venture with an unaffiliated entity, Exelon owns an interest in the Calvert Cliffs nuclear facility within the BGE zone in PJM. Because the joint venture entity is not a party to, or otherwise included in, the Offer of Settlement, Calvert Cliffs is not subject to the filing requirement in the Offer of Settlement.

32 *Handsome Lake Energy, LLC*, Letter Order, Docket No. ER02-771-000 (Mar. 8, 2002).

33 *Handsome Lake Energy, LLC*, Letter Order, Docket No. ER03-269-000 (Jan. 13, 2003).

costs ("Lost Opportunity Costs").[34] Accordingly, Lost Opportunity Costs are not separately identified in the Rate Schedules.

A. Fixed Capability Component

As more fully described in the attached testimony of Alan C. Heintz, included herein as Attachment F, the proposed revenue requirements include the Fixed Capability Component designed to recover the portion of plant costs attributable to the reactive power capability of the units. The Fixed Capability Component has been calculated by first determining for each of Applicants' generation facilities the portion of the generator/excitation systems, accessory electric equipment, generator step-up transformers, and balance of plant used to produce reactive power consistent with the *AEP* methodology ("AEP Methodology").[35]

The Fixed Capability Component of the annual revenue requirement was then determined by applying a fixed charge rate. A levelized annual carrying cost approach is used to develop the annual revenue requirement, which is detailed in each facility's Schedule 3 to Mr. Heintz's testimony.

Public utilities are permitted to recover their cost of service together with a reasonable return on invested capital.[36] For merchant generators, "it has been the Commission's general policy to allow an [independent power producer] to use the authorized rate of return and return on common equity of an interconnected utility for reactive power compensation, because . . . an interconnected utility's return is a conservative estimate of a merchant generator's return because the merchant generator faces more risk."[37] As such, the Applicants are permitted to use the respective interconnected utility's cost structure and rate of return as a proxy in the ARR calculations. Significantly, in this instance, the Applicants' facilities include interconnections to

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34 Schedule 1, PJM Interconnection, L.L.C., Intra-PJM Tariffs, Amended and Restated Operating Agreement.

35 *American Elec. Power Serv. Corp.*, 88 FERC ¶ 61,141 (1999), *on reh'g*, 92 FERC ¶ 61,001 (2000).

36 *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944) (rates should "enable the company to operate successfully, to maintain financial integrity, to attract capital, and to compensate its investors for the risks assumed").

37 *Bluegrass Generation Co., L.L.C.*, 118 FERC ¶ 61,214 at P 86 (2007). *See also Duke Energy Fayette, LLC*, 104 FERC ¶ 61,090 (2003) (permitting Duke Energy Fayette to use a proxy based on the capital structure and rate of return of Allegheny Power); *Calpine Fox LLC*, 113 FERC ¶ 61,047 (2005) (permitting Calpine Fox to use the capital structure and rate of return of American Transmission Co., LLC in calculating its annual revenue requirement for reactive service); *Tenaska Virginia Partners*, 107 FERC ¶ 61,207 (2004); *Zion Energy LLC*, 133 FERC ¶ 61,262 (2010); *Lincoln Generating Facility, LLC*, Docket No. ER11-2366-000 (Jan. 25, 2011) (unreported); *Crete Energy Venture, LLC*, Docket No. ER11-3110-000 (Apr. 22, 2011) (unreported); *Union Power Partners, L.P.*, Docket No. ER14-296-000 (Dec. 27, 2013) (unreported); *Louisiana Generating LLC*, Docket No. ER14-2080-000 (July 25, 2014) (unreported); *Bayou Cove Peaking Power, LLC*, 150 FERC ¶ 61,215 (2015); *Big Cajun I Peaking Power LLC*, 151 FERC ¶ 61,195 (2015).

seven transmission owners. The return on common equity ("ROE") for those transmission owners range from 10.0 percent to 11.18 percent. While the Applicants could have used the authorized rate of return and return on common equity as an estimate of their return as merchant generators that face more risk, they are instead relying on the recent capital structure and return on common equity used by their affiliate, R.E. Ginna Nuclear Power Plant, LLC in Docket No. ER15-1047-000, consisting of a capital structure of 45 percent long-term debt and 55 percent common equity, a debt cost rate of 5 percent, and an ROE of 10.7 percent (a number very close to the arithmetic average of the high and low ends of the 10.0 percent to 11.18 percent ROE range noted above).[38]

Commission precedent provides for the application of the AEP Methodology to the Fixed Capability Component.[39] In the Wabash Order, the Commission highlighted the concern that:

> if the reactive power capability of a generating unit has degraded since the Commission approved the relevant reactive power revenue requirement (and the generating unit has not been refurbished or had generating equipment replaced), the payment for Reactive Supply and Voltage Control from that generating unit should reflect such circumstance.[40]

The Commission now requires inclusion of reactive power test reports "to support the reactive power allocator used in the *AEP* methodology."[41] Consistent with the Wabash Order, Mr. Heintz includes the reactive power test reports for those units for which such testing has been performed.[42] For purposes of this filing, the Applicants have used the test results in the

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38 *See* R.E. Ginna Nuclear Power Plant, LLC, Reliability Support Services Agreement between R.E. Ginna Nuclear Power Plant, LLC and Rochester Gas and Electric Corporation, Doc. No. ER15-1047-000, transmittal letter at pp. 15-19 and accompanying testimony (filed Feb. 13, 2015).

39 *Wabash Valley Power Assoc., Inc*., 154 FERC ¶ 61,245 at P 24 (2016) ("Wabash Order"); *see also American Elec. Power Serv. Corp.,* 80 FERC ¶ 63,006 at 65,079 (1997) (reactive allocator derived from nameplate rating).

40 Wabash Order, 154 FERC ¶ 61,245 at P 28.

41 *Id.* at P 29.

42 The units for which reactive testing has not yet been performed are Notch Cliff 4, 6, 7, and 8, Perryman 1, 3, and 4, Philadelphia Road 2-4, Conowingo 2 and 4, Croydon 21, 22, 31, 32, 41, and 42, and Handsome Lake 1-5 (collectively, the "Non-Tested Units"). Prior to October 1, 2014, the requirement to perform a reactive capability test as set forth in Attachment E of PJM Manual 14D: Generator Operational Requirements, applied to individual units with a nominal capacity greater than 70 MW, wind generating stations connected at a common bus with an aggregate rating greater than 70 MW, and all black start units. With Revision 29 of PJM Manual 14D, effective October 1, 2014, the requirement was modified to include, among other things, individual generating units with a gross nameplate rating greater than 20 MVA and generating plants or facilities with a gross aggregate nameplate rating greater than 75 MVA. To date, the Non-Tested Units have not yet been tested, but will be tested in accordance with PJM's 66-

(Continued…)

development of the reactive allocators.[43] For the Non-Tested Units, nameplate data was used by Mr. Heintz in the development of the reactive allocators. As Mr. Heintz explains, the use of nameplate data for the Non-Tested Units results in just and reasonable rates due to the fact that the Non-Tested Units are smaller, less expensive units, and especially given Mr. Heintz's other conservative assumptions, including use of the 15 percent allocator for the turbogenerator investment for all of the Applicants' units and the exclusion of the Heating Losses Component for the non-nuclear units.

B. Heating Losses Component

The proposed revenue requirements for the nuclear units include the Heating Losses Component. The Heating Losses Component includes losses that occur from resistive heating associated with armature winding and field winding of the generators, and of increased eddy currents in the generator and associated step-up transformer. These losses can be calculated as the real power consumed to produce reactive power, and therefore constitute a cost that is directly attributable to the production of reactive power. The calculation of these costs is further detailed in Mr. Heintz's testimony.

V. OTHER FILING REQUIREMENTS AND REQUEST FOR WAIVERS

1. 18 C.F.R. § 35.13(b)(1) – A list of documents submitted with this filing is included herein at Section II.

2. 18 C.F.R. § 35.13(b)(2) – The date on which the Applicants propose to make their respective rate changes effective is March 1, 2017.

3. 18 C.F.R. § 35.13(b)(3) – Copies of this filing have been sent to PJM.

4. 18 C.F.R. § 35.13(b)(4) – A brief description of the rate changes is provided herein at Section IV.

5. 18 C.F.R. § 35.13(b)(5) – A statement of the reasons for the rate changes is provided herein at Section III and Section IV.

6. 18 C.F.R. § 35.13(b)(6) – The Applicants hereby represent that no additional agreement, by contract or otherwise, is required for the filing of this rate.

7. 18 C.F.R. § 35.13(b)(7) – The Applicants hereby represent that there are no expenses or costs included in this filing that have been alleged or judged in any

month cycle. *See* PJM Manual 14D: Generator Operational Requirements Attachment E, Section E.2 at http://www.pjm.com /~/media/documents/manuals/ m14d.ashx.

[43] While the Applicants have elected to use the reactive test reports for the development of the reactive allocators, such use should not be construed as agreement or an acknowledgment that the test results reflect any degradation of the units.

administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

8. 18 C.F.R. § 35.13(c)(2) – No specifically assignable facilities have been or will be installed in connection with the proposed rate schedule.

The cost data consists of those items required to support the monthly revenue requirements for Reactive Service. Therefore, the Applicants respectfully request waiver of those provisions of Section 35.13 of the Commission's regulations which are not necessary for the fixed monthly charges for Reactive Service.

Additionally, the Applicants respectfully request that the Commission grant waiver of any of the Part 35 requirements that are not applicable to the filing and grant any other necessary waivers to permit their respective Rate Schedules to become effective as requested.

VI. EFFECTIVE DATE

Pursuant to PJM Tariff Schedule 2, the Applicants will be eligible to begin recovering their cost of providing reactive power within PJM on the first day of the month in which the Commission accepts or approves the revenue requirement. The Commission has regularly granted waiver of its notice requirements establishing effective dates less than sixty days after filing a new rate schedule when the filing is made prior to the requested effective date.[44] The Applicants thus respectfully request Commission action by March 18, 2017, to establish an effective date of March 1, 2017, under Schedule 2 of the PJM Tariff.

VII. REQUEST FOR PRIVILEGED TREATMENT

Pursuant to Section 388.112 of the Commission's regulations,[45] the Applicants respectfully request privileged treatment of Exhibit No. EXE-5, Generating Station Data and MVAR Test Results. Exhibit No. EXE-5 contains original equipment manufacturer ("OEM") data, vendor testing results, and MVAR test result documentation from which discrete data is used by Mr. Heintz in the non-privileged exhibits to his testimony. As reflected in Exhibit No. EXE-5, OEM data and vendor test result documents are marked by the OEM/vendor as proprietary (or by similar terms) or the materials are sourced from files subject to such treatment.

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44 *See, e.g., DeSoto County Generating Co., LLC,* 142 FERC ¶ 61,006 (2013) (effective date of filing fifty-six days after filing made); *Calpine Mid Merit,* LLC, 138 FERC ¶ 61,232 (2012) (effective date of filing thirty days after filing made); *Las Vegas Power Co., LLC*, 137 FERC ¶ 61,161 (2011) (effective date of filing one day after filing made); *Union Power Partners, L.P.*, 112 FERC ¶ 61,065 (effective date of filing one day after filing made), *on reh'g*, 113 FERC ¶ 61,272 (2005); *Hot Spring Power Co.*, *LP*, 113 FERC ¶ 61,088 (2005) (effective date of filing one day after filing made), *on reh'g*, 115 FERC ¶ 61,027, *on clarification*, 116 FERC ¶ 61,223 (2006); *Rockingham Power, L.L.C.*, 93 FERC ¶ 61,310 (2000) (effective date of filing one day after filing made).

45 18 C.F.R. § 388.112 (2016).

Accordingly, this information is "confidential . . . information obtained from a person and privileged or confidential."[46] Similarly, the MVAR test results contain confidential commercial data – the Applicants' propriety operating data – that is also "confidential . . . information obtained from a person and privileged or confidential."[47] Accordingly, good cause exists for the Commission to grant this request for privileged treatment of the information contained in Exhibit No. EXE-5.

In accordance with Section 388.112(b)(1) of the Commission's regulations, the non-public version of the filing containing Exhibit No. EXE-5 is submitted under separate cover labeled: CONTAINS PRIVILEGED MATERIALS – DO NOT RELEASE – HIGHLY SENSITIVE PROTECTED INFORMATION.[48] The public version of the filing is submitted under separate cover letter labeled: PRIVILEGED MATERIALS HAVE BEEN REMOVED." For the purpose of Sections 388.112(b)(2)(ii) and (iii) of the Commission's regulations, attached hereto as Attachment G is a proposed Protective Agreement based on the Commission's Model Protective Order.[49]

In accordance with Section 388.112(b)(2)(iii) of the Commission's regulations, the Applicants designate the following person to be contacted regarding a request for the privileged exhibit:

Neil L. Levy
King & Spalding LLP
1700 Pennsylvania Avenue, N.W.
Washington, DC 20006
(202) 626-5452
nlevy@kslaw.com

46 18 C.F.R. § 388.107(d) (2016).

47 *Id.*

48 Exhibit No. EXE-5 is in excess of 3,000 pages and, as a result, exceeds the Commission's eTariff and eFiling file size limitations. In consultation with Commission Staff with eTariff responsibility, the Applicants are separately hand-delivering CDs of Exhibit No. EXE-5 to the Commission as part of this filing.

49 The proposed Protective Agreement is identical to the "Model Protective Order" available on the Commission's website, but for (i) edits to make the Protective Agreement a bilateral agreement and (ii) minor formatting changes. The Model Protective Order is available at https://www.ferc.gov/legal/admin-lit.asp.

VIII. CONCLUSION

WHEREFORE, for the foregoing reasons, the Applicants respectfully request that the Commission (i) accept their respective Rate Schedules to become effective on March 1, 2017, and (ii) grant the waivers requested herein.

Respectfully submitted,

CONSTELLATION POWER SOURCE GENERATION, LLC
EXELON GENERATION COMPANY, LLC
HANDSOME LAKE ENERGY, LLC

By: */s/ Neil L. Levy*
Neil L. Levy
Bruce L. Richardson

Counsel for
Constellation Power Source Generation, LLC, Exelon Generation Company, LLC, and Handsome Lake Energy, LLC

Attachments
cc: General Counsel
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

Attachment A

Constellation Power Source Generation, LLC

FERC Rate Schedule No. 2
(Clean)

CONSTELLATION POWER SOURCE GENERATION, LLC
FERC RATE SCHEDULE NO. 2

Reactive Supply and Voltage Control from Generation Sources Service

Constellation Power Source Generation, LLC ("CPSG") provides Reactive Supply and Voltage Control from Generation Sources Service ("Reactive Supply Service") from certain generation facilities ("Facilities") within the Baltimore Gas and Electricity Company zone under the operational control of PJM Interconnection, L.L.C. This FERC Rate Schedule No. 2 sets forth CPSG's revenue requirement for Reactive Supply Service from the Facilities. This Rate Schedule shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

CPSG's monthly fixed revenue requirement consists of the sum of the charges for the Facilities specified below.

REVENUE REQUIREMENT:

Generation Facility	Monthly Revenue Requirement
Gould Street 3	$2,580.04
Notch Cliff CT 1	$3,354.04
Notch Cliff CT 2	$2,581.83
Notch Cliff CT 3	$2,581.83
Notch Cliff CT 4	$2,581.83
Notch Cliff CT 5	$3,473.33
Notch Cliff CT 6	$2,581.83
Notch Cliff CT 7	$2,581.83
Notch Cliff CT 8	$2,581.83
Perryman CT 1	$11,240.42
Perryman CT 3	$11,240.42
Perryman CT 4	$11,240.42
Perryman CT 6	$33,659.76
Perryman 51	$24,713.76
Philadelphia Road CT 1	$3,515.58
Philadelphia Road CT 2	$3,191.29
Philadelphia Road CT 3	$3,191.29
Philadelphia Road CT 4	$3,191.29
Riverside CT 7	$9,988.14
Riverside CT 8	$8,568.87
Westport CT 5	$9,670.03
Total Monthly Revenue Requirement	**$158,309.67**
Total Annual (Total Monthly x 12)	**$1,899,716.09**

PARTIAL MONTH REVENUE REQUIREMENT:

When a unit deactivation date is other than the first day of the month, the revenue requirement shall be a blended revenue requirement for the month of service in which the deactivation occurred ("Deactivation Month") as follows: the sum of (i) the total monthly revenue requirement prior to the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the number of days in the Deactivation Month prior to the unit deactivation date and (ii) the total monthly revenue requirement after the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the remaining number of days in the Deactivation Month from and including the unit deactivation date.

Attachment B

Constellation Power Source Generation, LLC

FERC Rate Schedule No. 2
(Redline)

CONSTELLATION POWER SOURCE GENERATION, LLC
FERC RATE SCHEDULE NO. 2

Reactive Supply and Voltage Control from Generation Sources Service

Constellation Power Source Generation, LLC ("CPSG") provides Reactive Supply and Voltage Control from Generation Sources Service ("Reactive Supply Service") from certain generation facilities ("Facilities") within the Baltimore Gas and Electricity Company zone under the operational control of PJM Interconnection, L.L.C. This FERC Rate Schedule No. 2 sets forth CPSG's revenue requirement for Reactive Supply Service from the Facilities. This Rate Schedule shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

CPSG's monthly fixed revenue requirement consists of the sum of the charges for the Facilities specified below.

REVENUE REQUIREMENT:

Generation Facility	**Monthly Revenue Requirement**
Gould Street 3	~~$13,312.97~~2,580.04
Notch Cliff CT 1	~~$2,399.79~~3,354.04
Notch Cliff CT 2	~~$2,399.79~~2,581.83
Notch Cliff CT 3	~~$2,399.79~~2,581.83
Notch Cliff CT 4	~~$2,399.79~~2,581.83
Notch Cliff CT 5	~~$2,399.79~~3,473.33
Notch Cliff CT 6	~~$2,399.79~~2,581.83
Notch Cliff CT 7	~~$2,399.79~~2,581.83
Notch Cliff CT 8	~~$2,399.79~~2,581.83
Perryman CT 1	~~$5,998.49~~11,240.42
Perryman CT ~~2~~3	~~$5,998.49~~11,240.42
Perryman CT ~~3~~4	~~$5,998.49~~11,240.42
Perryman CT ~~4~~6	~~$5,998.49~~33,659.76
Perryman 51	~~$27,465.53~~24,713.76
Philadelphia Road CT 1	~~$2,258.44~~3,515.58
Philadelphia Road CT 2	~~$2,258.44~~3,191.29
Philadelphia Road CT 3	~~$2,258.44~~3,191.29
Philadelphia Road CT 4	~~$2,258.44~~3,191.29
~~Riverside 4~~	~~$5,843.69~~
~~Riverside CT 6~~	~~$6,885.29~~
Riverside CT 7	~~$2,996.44~~9,988.14
Riverside CT 8	~~$2,996.44~~8,568.87
Westport CT 5	~~$10,356.87~~9,670.03
Total Monthly Revenue Requirement	**~~$122,083.25~~158,309.67**
Total Annual (Total Monthly x 12)	**~~$1,464,999.00~~1,899,716.09**
~~Without Riverside CT 6 and Perryman CT 2 Effective February 1, 2016~~	

~~Total Monthly Revenue Requirement~~	~~$109,199.47~~
~~Total Annual (Total Monthly x 12)~~	~~$1,310,393.64~~
~~Without Riverside 4 Effective June 1, 2016~~	
~~Total Monthly Revenue Requirement~~	~~$103,355.78~~
~~Total Annual (Total Monthly x 12)~~	~~$1,240,269.32~~

PARTIAL MONTH REVENUE REQUIREMENT:

When a unit deactivation date is other than the first day of the month, the revenue requirement shall be a blended revenue requirement for the month of service in which the deactivation occurred ("Deactivation Month") as follows: the sum of (i) the total monthly revenue requirement prior to the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the number of days in the Deactivation Month prior to the unit deactivation date and (ii) the total monthly revenue requirement after the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the remaining number of days in the Deactivation Month from and including the unit deactivation date.

Attachment C

Exelon Generation Company, LLC

FERC Rate Schedule No. 22
(Clean)

EXELON GENERATION COMPANY, LLC
FERC RATE SCHEDULE NO. 22

Reactive Supply and Voltage Control from Generation Sources Service

Exelon Generation Company, LLC ("ExGen") provides Reactive Supply and Voltage Control from Generation Sources Service ("Reactive Supply Service") from certain generation facilities ("Facilities") within the ComEd, JCPL, MetEd, PECO, and PSEG zones under the operational control of PJM Interconnection, L.L.C. This Rate Schedule FERC No. 22 sets forth ExGen's revenue requirement for Reactive Supply Service from the Facilities. This Rate Schedule shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

ExGen's revenue requirements for the ComEd, JCPL, MetEd, PECO, and PSEG zones are set forth below.

REVENUE REQUIREMENT:

Zone	Generation Facility	Monthly Revenue Requirement
ComEd	Braidwood 1	$184,013.49
	Braidwood 2	$202,439.94
	Byron 1	$155,449.24
	Byron 2	$174,146.94
	Dresden 2	$197,950.16
	Dresden 3	$195,562.09
	LaSalle 1	$127,548.74
	LaSalle 2	$152,248.83
	Quad Cities 1 (75%)	$106,949.55
	Quad Cities 2 (75%)	$112,269.04
	Southeast Chicago 5	$8,864.79
	Southeast Chicago 6	$8,864.79
	Southeast Chicago 7	$8,864.79
	Southeast Chicago 8	$8,864.79
	Southeast Chicago 9	$8,864.79
	Southeast Chicago 10	$8,864.79
	Southeast Chicago 11	$8,864.79
	Southeast Chicago 12	$8,864.79
	ComEd Zone Total Monthly Revenue Requirement	**$1,679,496.34**
	ComEd Zone Total Annual (Total Monthly x 12)	**$20,153,956.03**

JCPL	Oyster Creek 1	$183,320.14
	JCPL Zone Total Monthly Revenue Requirement	**$183,320.14**
	JCPL Zone Total Annual (Total Monthly x 12)	**$2,199,841.71**
MetEd	TMI	$25,653.72
	MetEd Zone Total Monthly Revenue Requirement	**$25,653.72**
	MetEd Zone Total Annual (Total Monthly x 12)	**$307,844.62**
PECO	Chester 7	$1,200.96
	Chester 8	$1,206.67
	Chester 9	$1,248.19
	Conowingo 1	$2,611.45
	Conowingo 2	$2,360.11
	Conowingo 3	$2,489.80
	Conowingo 4	$2,360.11
	Conowingo 5	$1,690.66
	Conowingo 6	$2,571.72
	Conowingo 7	$2,571.72
	Conowingo 8	$835.49
	Conowingo 9	$1,056.02
	Conowingo 10	$1,292.06
	Conowingo 11	$988.07
	Croydon 11	$3,259.03
	Croydon 12	$2,999.49
	Croydon 21	$3,463.22
	Croydon 22	$3,463.22
	Croydon 31	$3,463.22
	Croydon 32	$3,463.22
	Croydon 41	$3,463.22
	Croydon 42	$3,463.22
	Delaware 9	$1,261.57
	Delaware 10	$1,466.72
	Delaware 11	$1,455.38
	Delaware 12	$1,455.38
	Eddystone 3	$14,498.48
	Eddystone 4	$12,649.44

	Eddystone 10	$1,052.37
	Eddystone 20	$1,080.21
	Eddystone 30	$1,031.97
	Eddystone 40	$1,031.97
	Fairless Hills A	$6,004.83
	Fairless Hills B	$6,004.83
	Falls 1	$1,032.33
	Falls 2	$1,045.35
	Falls 3	$1,035.61
	Limerick 1	$108,446.42
	Limerick 2	$101,871.72
	Moser 1	$1,266.19
	Moser 2	$1,269.39
	Moser 3	$1,240.12
	Muddy Run 1	$4,658.52
	Muddy Run 2	$4,930.03
	Muddy Run 3	$4,338.87
	Muddy Run 4	$4,448.45
	Muddy Run 5	$4,977.46
	Muddy Run 6	$4,632.88
	Muddy Run 7	$4,632.88
	Muddy Run 8	$4,282.85
	Peach Bottom 2 (50%)	$108,606.41
	Peach Bottom 3 (50%)	$124,590.89
	Pennsbury 1	$287.42
	Pennsbury 2	$287.42
	Richmond 91	$2,582.33
	Richmond 92	$2,597.35
	Schuylkill 10	$2,072.86
	Schuylkill 11	$1,931.49
	Southwark 3	$1,912.19
	Southwark 4	$1,733.12
	Southwark 5	$1,877.92
	Southwark 6	$1,741.02
	PECO Zone Total Monthly Revenue Requirement	**$604,843.52**
	PECO Zone Total Annual (Total Monthly x 12)	**$7,258,122.19**

PSEG	Salem 1 (43%)	$15,406.47
	Salem 2 (43%)	$17,165.76
	PSEG Zone Total Monthly Revenue Requirement	**$32,572.22**
	PSEG Zone Total Annual (Total Monthly x 12)	**$390,866.69**
All Zones	**Total Monthly Revenue Requirement**	**$2,525,885.94**
	Total Annual (Total Monthly x 12)	**$30,310,631.23**

PARTIAL MONTH REVENUE REQUIREMENT:

When a unit deactivation date is other than the first day of the month, the revenue requirement shall be a blended revenue requirement for the month of service in which the deactivation occurred ("Deactivation Month") as follows: the sum of (i) the total monthly revenue requirement prior to the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the number of days in the Deactivation Month prior to the unit deactivation date and (ii) the total monthly revenue requirement after the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the remaining number of days in the Deactivation Month from and including the unit deactivation date.

Attachment D

Handsome Lake Energy, LLC

Rate Schedule FERC No. 2
(Clean)

HANDSOME LAKE ENERGY, LLC
RATE SCHEDULE FERC NO. 2

Reactive Supply and Voltage Control from Generation Sources Service

Handsome Lake Energy, LLC ("Handsome Lake") provides Reactive Supply and Voltage Control from Generation Sources Service ("Reactive Supply Service") from its natural-gas fueled electric generating facility located in Venango County, Pennsylvania ("Facility") within the Penelec zone under the operational control of PJM Interconnection, L.L.C. This Rate Schedule FERC No. 2 sets forth Handsome Lake's revenue requirement for Reactive Supply Service from the Facility. This Rate Schedule shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

Handsome Lake's monthly fixed revenue requirement consists of the charges set forth below.

REVENUE REQUIREMENT:

Generation Facility	**Monthly Revenue Requirement**
Handsome Lake 1	$3,143.41
Handsome Lake 2	$3,143.41
Handsome Lake 3	$3,143.41
Handsome Lake 4	$3,143.41
Handsome Lake 5	$3,143.41
Total Monthly Revenue Requirement	**$15,717.04**
Total Annual (Total Monthly x 12)	**$188,604.46**

PARTIAL MONTH REVENUE REQUIREMENT:

When a unit deactivation date is other than the first day of the month, the revenue requirement shall be a blended revenue requirement for the month of service in which the deactivation occurred ("Deactivation Month") as follows: the sum of (i) the total monthly revenue requirement prior to the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the number of days in the Deactivation Month prior to the unit deactivation date and (ii) the total monthly revenue requirement after the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the remaining number of days in the Deactivation Month from and including the unit deactivation date.

Attachment E

Handsome Lake Energy, LLC

Rate Schedule FERC No. 2
(Redline)

HANDSOME LAKE ENERGY, LLC
RATE SCHEDULE FERC NO. 2

Reactive ~~Power~~Supply and Voltage Control from Generation Sources Service

~~———~~ Handsome Lake Energy, LLC ("Handsome Lake") provides Reactive ~~Power~~Supply and Voltage Control from Generation Sources Service ("Reactive ~~Power~~Supply Service") from its natural-gas fueled electric generating facility located in Venango County, Pennsylvania ("Facility") ~~in~~within the ~~PJM~~Penelec zone under the operational control ~~area administered by the~~ of PJM Interconnection, L.L.C. ~~("PJM") in order to assist in maintaining transmission voltages within acceptable limits on the PJM transmission system.~~ This Rate Schedule FERC No. 2 sets forth Handsome Lake's revenue ~~requirements for the provision of Reactive Power, as contemplated by the revised Schedule 2 of the PJM Open Access Transmission Tariff, filed in Docket No. ER00-3327-000, which provides that PJM will pay generation owners their monthly revenue~~ requirement for Reactive ~~Power.~~

~~Handsome Lake's monthly revenue requirement consists of the sum of the charges for the following: (1) Fixed Capability Component; and (2) Heating Losses Component. Total charges for any 12 month period will not be less than the sum of the annual charges specified below.~~Supply Service from the Facility. This Rate Schedule ~~FERC No. 2~~ shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

~~**MONTHLY**~~ Handsome Lake's monthly fixed revenue requirement consists of the charges set forth below.

REVENUE REQUIREMENT:

~~**1) FIXED CAPABILITY COMPONENT**~~

~~The annual revenue requirement of the Fixed Capability Component is $362,659.~~
~~The monthly charge to PJM is $362,659/12 = $30,222.~~

~~**2) HEATING LOSSES COMPONENT**~~

~~The annual revenue requirement for the Heating Losses Component is $7,645~~
~~The monthly charge to PJM is $7,645/12 = $637.~~

Generation Facility	Monthly Revenue Requirement
Handsome Lake 1	$3,143.41
Handsome Lake 2	$3,143.41
Handsome Lake 3	$3,143.41
Handsome Lake 4	$3,143.41
Handsome Lake 5	$3,143.41
Total Monthly Revenue Requirement	**$15,717.04**
Total Annual (Total Monthly x 12)	**$188,604.46**

PARTIAL MONTH REVENUE REQUIREMENT:

When a unit deactivation date is other than the first day of the month, the revenue requirement shall be a blended revenue requirement for the month of service in which the deactivation occurred ("Deactivation Month") as follows: the sum of (i) the total monthly revenue requirement prior to the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the number of days in the Deactivation Month prior to the unit deactivation date and (ii) the total monthly revenue requirement after the rate change divided by the number of days in the Deactivation Month, with the quotient then multiplied by the remaining number of days in the Deactivation Month from and including the unit deactivation date.

Attachment F

Testimony and Exhibits

Exhibit No. EXE-1

Exhibit No. EXE-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Constellation Power Source Generation, LLC	**)**	**Docket No. ER17-___-000**
Exelon Generation Company, LLC	**)**	**Docket No. ER17-___-000**
Handsome Lake Energy, LLC	**)**	**Docket No. ER17-___-000**

PREPARED DIRECT TESTIMONY OF ALAN C. HEINTZ
ON BEHALF OF

CONSTELLATION POWER SOURCE GENERATION, LLC, EXELON GENERATION COMPANY, LLC, AND HANDSOME LAKE ENERGY, LLC

Date: January 17, 2017

ALAN C. HEINTZ

PREPARED DIRECT TESTIMONY AND EXHIBIT INDEX

Exhibit No. EXE-2 ..... Summary of Testimony Experience

Exhibit No. EXE-3 ..... Development of Reactive Costs by Unit

Schedule 1: Revenue Requirements by Generating Station

Schedule 2: Nuclear Generating Losses

Schedule 3: Calculations by Generating Station

Schedule 4: Input Data for Schedule 3

Schedule 5: Total Plant and GSU; Turbogenerator Investment

Schedule 6: Accessory Electrical Equipment

Schedule 7: Nuclear O&M Summary

Schedule 8: Non-nuclear O&M Summary

Exhibit No. EXE-4…. ..... Workpapers

Exhibit No. EXE-5……..Generating Station Data and MVAr Test Results

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Constellation Power Source Generation, LLC	**)**	**Docket No. ER17-___-000**
Exelon Generation Company, LLC	**)**	**Docket No. ER17-___-000**
Handsome Lake Energy, LLC	**)**	**Docket No. ER17-___-000**

PREPARED DIRECT TESTIMONY OF ALAN C. HEINTZ

Q: PLEASE STATE YOUR NAME, OCCUPATION AND ADDRESS.

A: My name is Alan C. Heintz. I am a Vice President of Brown, Williams, Moorhead & Quinn, Inc. ("BWMQ"). My business address is Brown, Williams, Moorhead & Quinn, Inc., 1155 Fifteenth Street, NW, Suite 1004, Washington, D.C., 20005.

Q: PLEASE DESCRIBE YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A: I provide consulting services on matters relating to wholesale rates (requirements and off-system power sales, transmission, ancillary service and reliability must run), as well as retail rates.

I was employed by the Federal Energy Regulatory Commission ("FERC" or "Commission") from November 1985 to February 1995. I served as a Public Utilities Specialist in the [Electric] Rate Filings Branch from November 1985 to October 1989. In November 1989, I was promoted to Section Chief in the Division of [Electric] Applications, and was responsible for supervising the review of the terms, conditions, and rates of electric rate applications for such services as interchange power, requirements power, and transmission. During my tenure with the FERC, I prepared or supervised the preparation of memoranda recommending acceptance, rejection,

deficiency, or investigation in hundreds of cases. These included cases that set important precedent on electric transmission pricing, such as the merger compliance transmission tariffs for Northeast Utilities; the first generation of open access transmission tariffs ("OATT") filed by utilities such as Entergy Services, Louisville Gas & Electric Co., Florida Power & Light Co., Kansas City Power & Light Co., and American Electric Power Co.; and the Pennsylvania Electric Company case involving Penntech Papers, Inc. I also taught a one-year course to FERC Staff and gave several presentations to the Edison Electric Institute Interconnection and Interchange Arrangements Committee on the pricing of power and transmission services.

Q: WHAT POSITIONS DID YOU HOLD AFTER YOU LEFT THE COMMISSION?

A: From February 1995 through October 2000, I was a Vice President of Stone & Webster Management Consultants, Inc. In this position, I provided consulting services to numerous electric utilities on matters involving requirements and off-system power rates, and rate and implementation strategies for developing OATT filings, and organizing Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs"). I also assisted several utilities in preparing their retail delivery services filings. I joined R.J. Rudden Associates, Inc. in November 2000 as a Vice President, where I continued providing consulting services to the electric industry. I joined BWMQ in February 2004.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A: During my tenure at the FERC, I was assigned to the Commission's advisory staff and, therefore, was precluded from testifying before the FERC. However, while at the FERC, I presented cases publicly to the FERC Commissioners at their bi-weekly public meetings

and was the technical contact to the Commissioners in numerous cases. Since leaving the employ of FERC, I have filed testimony before the FERC in numerous proceedings, as shown in Exhibit No. EXE-2. I have also testified before the British Columbia Utilities Commission in Canada, the Illinois Commerce Commission, the Maine Public Utilities Commission, the United States Court of Federal Claims, and the United States District Court in Florida. A summary of my testimony experience is contained in Exhibit No. EXE-2.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL EXPERIENCE.

A: I received the degree of Bachelor of Science in Business and the degree of Bachelor of Arts in Economics from the University of Colorado, Boulder, Colorado, in May 1982. I also received the degree of Master of Business Administration in Finance from the George Washington University in Washington, D.C., in December 1988.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A: I have prepared this testimony on behalf of Constellation Power Source Generation, LLC, Exelon Generation Company, LLC, and Handsome Lake Energy, LLC (collectively, the "Applicants"). The Applicants are direct or indirect wholly owned subsidiaries of Exelon Corporation ("Exelon"). The attached cost support establishes the cost-based charges for the supply of Reactive Supply and Voltage Control from Generation Sources Service ("Reactive Power") for the Applicants to markets controlled by PJM Interconnection, L.L.C. ("PJM"), an RTO.

Q: WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A: The purpose of my direct testimony is to explain and support the justness and reasonableness of the ancillary service rates for Reactive Power proposed by Applicants.

Reactive power ("VArs") is required to maintain the voltage to deliver real power ("MW") through transmission lines. When there is not enough VArs generated, the voltage may become unstable. I will support the calculation of the Reactive Power revenue requirements. My testimony is outlined as follows:

1. Identify all equipment associated with VAr production and the installed cost of the identified equipment. The equipment is divided into the following four categories: generators and exciters, generator step-up ("GSU") transformers, accessory electrical equipment and the balance of plant.
2. Explain the calculations for the reactive power allocation factor to be applied to the generators and exciters, GSU transformers, and accessory electrical equipment. I also explain the logic and calculation for the reactive allocation of the balance of plant.
3. Explain the application of the reactive power allocation factors to each category of equipment to determine the investment supporting the Reactive Power service.
4. Support the development and application of the fixed charge rates used to determine the revenue requirements for Reactive Power.
5. Support and explain the heating loss component of the revenue requirements for Reactive Power.

Q: PLEASE DESCRIBE EXELON'S GENERATING STATIONS PROVIDING REACTIVE POWER TO PJM.

A: There are 111 generating units at 31 generating stations included in the analysis. All the units are in the PJM footprint and are in the following states: Illinois, Maryland,

Pennsylvania and New Jersey. These facilities are nuclear, fossil, or hydroelectric generation facilities and are interconnected to one of seven transmission owners. Exhibit No. EXE-3, Schedule 1 lists each facility, generation type, and the interconnected transmission owner ("TO"). The exhibit also shows for each facility the proposed revised revenue requirements, consisting of two components – the fixed capability component revenue requirements and the heating losses component revenue requirements. Exhibit No. EXE-4, includes the workpapers and Exhibit No. EXE-5 includes the available generating station data and reactive power ("MVAr") test results.

Q: PLEASE DESCRIBE HOW THE REVENUE REQUIREMENT PER UNIT WERE CALCULATED.

A: The revenue requirement for each station is developed in Exhibit No. EXE-3, Schedule 3 and shown on Exhibit No. EXE-3, Schedule 1. The revenue requirement for each station was allocated to each unit based on the unit's VAr capability (measured in MVAr) as a percentage of the station's VAr capability. The monthly revenue requirement for each unit is shown for each Applicant on Exhibit No. EXE-3, Schedules 1a, 1b, and 1c.

Q: PLEASE EXPLAIN THE PURPOSE OF REACTIVE POWER AND HOW THE COST ASSOCIATED WITH REACTIVE POWER IS CALCULATED.

A**:** In Order No. 888, the Commission found that Reactive Power from generators was an ancillary service the cost of which should be separately assessed to customers. In *American Electric Power Service Corp.*, 80 FERC ¶ 63,006 (1997), *aff'd in part and rev'd in part*, 88 FERC ¶ 61,141 (1999) (Opinion No. 440) ("*AEP*") *order on reh'g*, 92 FERC ¶ 61,001 (2000) and *Dynegy Midwest Generation, Inc*., 121 FERC ¶ 61,025 (2007) (Opinion No. 498) ("*Dynegy I*"), *order on reh'g,* 125 FERC ¶ 61,280 (2009) ("*Dynegy*

II"), the Commission discussed the methodology for determining the cost of Reactive Power. The Reactive Power revenue requirements proposed herein was developed consistent with the methods described in *AEP* and *Dynegy I*. The methodology identifies the Reactive Power components with respect to four groups of investment: (1) the generator and exciter; (2) the GSU transformers; (3) accessory electrical equipment; and (4) balance of plant investment. *See Dynegy I*, 121 FERC at p. 61,086. Because these groups involve both real power and VArs, the *AEP* methodology includes an allocation factor to separate the components between real power and VArs. Finally, consistent with *Dynegy II*, the Reactive Power revenue requirements also includes heating losses, which are incurred as a portion of real power consumed to produce VArs and are priced at incremental fuel costs.

Q: HOW IS THE REACTIVE POWER CHARGE ASSESSED?

A: PJM obtains Reactive Power from generators and assesses transmission customers for Reactive Power under Schedule 2 of the PJM Open Access Transmission Tariff.

Q: FROM WHAT PERIOD DID YOU USE DATA AND WHY?

A: I used the Applicants' 2015 calendar year data because that is the most recent calendar year data available. However, since the new Perryman 6 unit was completed in 2015, but not classified beyond 3 digit FERC account balances, I used the 2016 plant balances and expenses as a proxy for a full year's costs. I also allocated 10% of the accessory electrical equipment consistent with *AEP* for Perryman 6.

Q: PLEASE EXPLAIN HOW YOU DETERMINED THE PLANT INVESTMENT ASSOCIATED WITH THE GENERATOR AND EXCITER, GSU

TRANSFORMERS, ACCESSORY ELECTRICAL EQUIPMENT AND BALANCE OF PLANT.

A: To the extent permitted by the accounting records provided to me by Applicants, I determined the installed cost of each of the four components. I calculated the generator/exciter portion as 15% of the turbogenerator investment after excluding components such as cooling towers and piping consistent with *AEP*, which is a conservative estimate compared to the 26% used in *AEP* and a review of reactive rate filings. Exhibit No. EXE-3, line 3 of Schedule 4 shows the total plant investment in these accounts, and these amounts are carried over to line 2 of Schedule 3 for each plant.

The plant investment associated with the GSU transformers was also identified through a study of accounting records provided to me by Applicants and is shown on line 4 of Schedule 4, as well as line 6 of Schedule 3 for each plant. Where the electronic records did not have the discreet costs of the GSU costs detailed, no investment was included.

The plant investment associated with the accessory electrical equipment is booked to Account 315 for steam plants, Account 334 for hydro plants, and Account 345 for other production plants and is shown on line 5 of Schedule 4, as well as line 10 of Schedule 3 for each plant. The plant investment for the balance of plant was determined by taking the total plant investment for each plant from the asset register and subtracting the plant investment of the three prior components (generator and exciter, GSU transformers, and accessory electrical equipment).

Q: PLEASE EXPLAIN HOW YOU DETERMINED THE REACTIVE POWER PORTION OF EACH OF THE FOUR COMPONENTS.

A: The reactive power portion of the plant investment is determined by multiplying the investment by the square of the reactive power rating (MVAr) to the square of the total power rating ("MVA") for each of the plants (MVAr^2 / MVA^2) ("Reactive Allocator"). This calculation is shown on line 3 of Schedule 3 for each plant, and lines 4, 8 and 12 of Schedule 3 for each plant reflects the total cost of the generator, exciter, and GSU investments multiplied by the Reactive Allocator on line 3. The design rating of the unit was used in calculating the Reactive Allocator unless the test results indicated the unit's design rating was not representative of the units' capabilities. The smaller units were never required to be tested ("Non-Tested Units"), therefore, the nameplate data for those unit was used. This treatment still results in just and reasonable rates, because the Non-Tested Units are smaller, less expensive units that account for only 4% of the revenue requirement and the conservative assumptions in my analysis, including the use of the 15 percent allocator for the turbogenerator investment for all units and, as discussed below, the exclusion of the heating losses component for the non-nuclear units.

For the accessory electrical equipment investment in Exhibit No. EXE-3, Schedule 6, each of the cost components, was carried forward to Exhibit No. EXE-3, lines 126-144 of Schedule 4 and to lines under the "Accessory Equip Allocator" heading of Exhibit EXE-3, Schedule 3 for each plant, where the portions allocable to the generator/exciter function are developed. The total allocated amount under that heading in Schedule 3 for each plant, is also shown at line 10 of each Schedule 3, where it is allocated to the reactive function.

The balance of plant ("BOP") investment is calculated on line 15 of Schedule 3 for each plant by subtracting the investment in the generator and exciter, GSU

transformers and accessory electrical equipment from the total investment in the plant shown on line 14. The reactive power portion of the balance of plant investment is determined by allocating the investment using the ratio of the maximum MVAr output of the fleet at the time of the system peak to the MVAr capability of the fleet times the ratio of the fleet exciter MW rating to the fleet generator MW rating. These calculations are shown on Schedule 4 lines 99-106. There are seven different BOP allocators, each relating to the TO owning the transmission to which each facility is interconnected. This is necessary since the transmission peaks in each of the zones occurs at different times. The design rating of the unit was used in calculating the BOP allocators unless the test results indicated the unit's design rating was not representative of the units' capabilities.

Q: PLEASE EXPLAIN HOW YOU CALCULATED THE REVENUE REQUIREMENT ASSOCIATED WITH THE REACTIVE POWER PORTION OF THE FOUR COMPONENTS OF PLANT INVESTMENT.

A: Exhibit No. EXE-3, Schedule 3 for each plant shows the development of the fixed charge rates for each plant. On line 18 of Schedule 3 for each plant, the reactive power portion of the generator and exciter, GSU transformers, accessory electrical equipment and the balance of plant are totaled, and the unit-specific fixed charge rate is applied at line 19. The annual revenue requirements are shown on line 20, which is the product of the reactive power portion of the investment and the fixed charge rate.

Q: PLEASE DESCRIBE THE CALCULATION OF THE FIXED CHARGE RATE.

A: The components to the fixed charge rate, set forth in Exhibit No. EXE-3, on lines 1-14, columns (e) to (h), of Schedule 3, include the following:

The Operation and Maintenance ("O&M") component for the generator and exciter, GSU transformers, and accessory electrical equipment is shown in lines 1-3, columns (e) to (h), of Schedule 3 and is the demand-related O&M for each plant. Because the Commission waived the requirement for Applicants to follow the uniform system of accounts, the O&M expense for each of the units was allocated to accounts 500-554 using proxy units whose O&M is reported by FERC account in Form Nos. 1 to be consistent with the allocations used in *AEP*, as discussed below.

The Administrative and General ("A&G") component of the fixed charge rate is shown on line 5, columns (e) to (h), of Schedule 3 for each plant and is developed under the "A&G" heading of Schedule 3 for each plant. The A&G amounts are sourced from Exhibit No. EXE- 3, lines 163 to 168 of Schedule 4. Since Exelon maintains separate organizations for nuclear and fossil units, the A&G for each organization was allocated to their respective units.

The fixed charge rate is reduced for the effect of accumulated deferred income taxes ("ADIT") shown on line 13, columns (e) to (h), of Schedule 3 for each plant and calculated beginning under the "Accumulated Deferred Income Taxes: heading of Schedule 3 for each plant.

The taxes other than income component is shown on line 9, columns (e) to (h), of Schedule 3 for each plant and calculated under the "Other Taxes" heading of Schedule 3 for each plant. The cash working capital component is one-eighth of O&M and A&G as shown on line 6 of Schedule 3 for each plant and includes production material and supplies and prepayments. The amounts included under the "Working Capital" heading of Schedule 3 for each plant for cash working capital, prepayments and materials and

supplies related to production are combined and then multiplied by the sum of return and income tax rates.

The depreciation component is calculated using the Commission's standard sinking fund method equal to return divided by the sum of one plus return to the *n* power, minus one, where *n* equals the depreciable life of the plant (R/(1+R)^n – 1) on line 10, columns (e) to (h), of Schedule 3 for each plant and calculated under the "Depreciation" heading of Schedule 3. The actual lives of the units were used as the depreciable life of the units as shown on Exhibit No. EXE-4, Schedule 2. I note that on December 7, 2016 the Future Energy Jobs Bill was signed into law by the Governor of Illinois and that Exelon Generation now expects Quad City, if selected in the Illinois Power Authority process, to continue operation for at least ten years as a result of this legislation. To be conservative, the longer operating license life (sixty years) was used to calculate the depreciation expense for this facility.

The income taxes component is calculated based on the average composite income tax ("CIT") rate for Applicants as follows: (CIT/(1-CIT) x (Return – straight line depreciation % + sinking fund depreciation %) x (1- (the weighted cost of debt / Return))). This is the standard calculation for levelized rates accepted by the Commission (see *AEP*, 88 FERC at p. 61,455) and is shown in Exhibit No. EXE-3 on line 12 of Schedule 3 for each plant and calculated under the "Income Taxes" heading of Schedule 3.

The return allowance is computed by multiplying the rate base by the proposed after-tax return of 8.14%, which consists of a 45% debt capital structure and a 10.7% rate

of return shown on Exhibit No. EXE-3, on lines 209-215 of Schedule 4. This is carried forward to each of the generating station cost of service calculations in Schedule 3.

Q: PLEASE DISCUSS HOW YOU HAVE DERIVED THE O&M EXPENSES USED IN THE CALCULATION MODEL.

A: The calculation model typically employs detailed O&M cost breakdowns based on FERC accounting. This level of detail is not maintained by Applicants in their expense accounting. See, for example, the expenses shown for nuclear facilities, Exhibit No. EXE-3, on lines 1-33 of Schedule 7, and similarly for non-nuclear facilities on Exhibit No. EXE-3, Schedule 8. To utilize the detail requested by the calculation model, I organized Applicants' expense data into four subtotals – O&M, A&G, Other taxes, and Depreciation.

The O&M subtotal was then distributed to FERC expense classifications by proxy allocators that I calculated based on existing FERC Form 1 data. There is a separate set of allocators for fossil units, hydro units and nuclear units. (See workpaper, Exhibit No. EXE-4, Schedule 1). See the final distribution for nuclear units, for example, at Exhibit No. EXE-3, lines 35 – 74 of Schedule 7. This and the similar calculation for non-nuclear units is the source of the detailed O&M expenses shown in Schedule 4 of Exhibit No. EXE-3 and utilized in the individual facility calculations, Schedule 3 of Exhibit No. EXE-3.

Q: PLEASE EXPLAIN WHY A HEATING LOSS COMPONENT IS INCLUDED IN THE PROPOSED RATES.

A: The creation of VArs results in an increase of current in the form of incremental current in addition to the current that flows due to the production of real power. This incremental

current flows inside the generator armature (stator) windings, inside the generator field (rotor) winding, and inside the GSU windings. Due to the electrical resistance in each of the generator and GSU windings, this incremental current causes real power to be consumed or "lost" in the form of heat. This loss of real power is a cost associated with the provision of Reactive Power that is properly recovered by Applicants. The Commission has accepted inclusion of a heating loss rate component in Reactive Power revenue requirements in numerous proceedings. *See, e.g.*, *Dynegy II*, 125 FERC ¶ 61,280, at P 29 (2008).

Q: HAVE YOU CALCULATED A HEATING LOSS COMPONENT FOR EACH GENERATING FACILITY?

A: No. I only calculated heating losses for the nuclear facilities, resulting in the revenue requirements being conservative.

Q: PLEASE EXPLAIN HOW YOU HAVE CALCULATED THE HEATING LOSSES COMPONENT OF THE REACTIVE POWER REVENUE REQUIREMENT FOR LOSSES THAT OCCUR IN THE GENERATOR.

A: The generator heating losses are calculated to measure losses associated with the armature windings and the field winding in the generator, as well as stray load losses. These calculations are shown on Exhibit No. EXE-3, Schedule 2. The generator heating losses were calculated by finding the actual average winding currents under two conditions. The first condition determines the winding current at the actual average real power produced by the generator during the test year, which determines how much current flows without any VAr production (*i.e.*, unity power factor). The second condition determines the respective winding current at the actual Apparent Power

produced by the generator during the test year, which includes both the current required to produce the average MW in the first condition, and includes the current required to produce the actual average VAr production. Thus, the difference between these two values will be the incremental current that is required to produce the Reactive Power and will also represent the current which creates the incremental heating losses. To incorporate stray losses in the calculation, I used a stray load loss factor from *Electric Power Research Institute's Technical Report TR-10720-V3S1*, page 3-2 2013 data, which are the most recent data available for calculating the heating losses.

Q: PLEASE EXPLAIN HOW THE GENERATOR FIELD WINDING CURRENT WAS DETERMINED AND HOW THIS DIFFERS FROM YOUR DETERMINATION OF THE GENERATOR STATOR WINDING CURRENT.

A: Again referring to Schedule 2, the stator winding current in each of the 3 phase windings can be calculated using a standard engineering formula. The winding currents are identified by using the curves published by each generator's manufacturer. These generator curves are commonly called "V" curves, or sometimes "VEE" curves, and are typically shaped like the letter V. The curves are a plot of Generator Output in Volt-Amperes on the Y-axis and Generator Field Current in Amperes on the X-axis. Various curves are plotted on each graph, which represent the relationship between the Generator Output in Volt-Amperes and the Generator Field Current at different power factors. By plotting the two conditions as mentioned above (MVA @ pf = 1.0, and MVA @ pf ave = Actual Average Power Factor), the two field currents were obtained from available curves for each unit. Once the Stator and Field currents were determined for each

condition as described, the Average Hourly Incremental Heating Losses are calculated on lines 4 and 9.

Q: PLEASE EXPLAIN HOW YOU CALCULATED THE HEATING LOSSES COMPONENT OF THE REACTIVE POWER REVENUE REQUIREMENT FOR LOSSES THAT OCCUR IN THE GENERATOR STEP UP TRANSFORMER.

A: The methodology used to calculate the GSU transformer currents utilizes the same formulas as used in determining the stator currents, as described above. These calculations are summarized on Schedule 2, lines 3 and 8 for the nuclear units. For most units, the current for each condition is the lower of the GSU current as compared to the stator current. This is because a station service load is electrically withdrawn between the generator terminals and the GSU low voltage terminals for most of the units. For the units that have the same current for the stator and the GSU, the station service is either electrically connected elsewhere or the station service is negligible. In each case where the station service load was connected between the generator and GSU terminals, I subtracted the station service MW and MVA from the generator gross output to arrive at the actual average hourly MW and actual average MVA as seen at the low voltage terminals of the GSU. Thus, the difference between the average hourly current at the average hourly MVA and the average hourly current at the average hourly MW represents the incremental current that flows through the GSU only due to the production of VArs. Once the GSU currents were determined for each condition as described, the Average Hourly Transformer Loss was determined.

Q: ONCE THE AVERAGE HOURLY GENERATOR LOSSES AND THE AVERAGE HOURLY GSU LOSSES WERE DETERMINED FOR EACH UNIT, PLEASE

EXPLAIN HOW YOU ARRIVED AT THE TOTAL COST OF HEATING LOSSES FOR EACH UNIT.

A: On the electronic workpapers for Schedule 2, the total hourly average losses were determined for both the generator and GSU, and two additional pieces of data were needed to complete the calculation. The first is the number of online run-hours for each unit during the test year, and the second is the average incremental cost for each unit during the test year. Thus, for each unit, I used the total hourly average losses multiplied by the number of online run-hours for the unit during the test year. I then multiplied that product by the average incremental cost for the unit during the test year. The result is the total incremental cost of heating losses associated with providing Reactive Power from the specific unit at issue. I then performed this same calculation for each plant analyzed and summed the individual plant totals to arrive at the total cost of heating losses associated with providing Reactive Power from the plants as set forth in Exhibit No. EXE-3, Schedule 2, and as transferred to Exhibit No. EXE-3, Schedule 1.

Q: IS YOUR APPROACH CONSISTENT WITH COMMISSION PRECEDENT?

A: Yes. I followed the approach for the fixed capability component as approved by the Commission in *AEP* and *Dynegy I* and the approach for the heating losses component as approved by the Commission *Dynegy II*.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Constellation Power Source Generation, LLC	)	**Docket No. ER17-___-000**
Exelon Generation Company, LLC	)	**Docket No. ER17-___-000**
Handsome Lake Energy, LLC	)	**Docket No. ER17-___-000**

AFFIDAVIT

I certify that the attached testimony in these proceedings and exhibits hereto annexed were prepared by me or under my direct supervision or were taken from other sources noted. The answers contained in my testimony are true and correct to the best of my knowledge, information, and belief.

Alan C. Heintz

Subscribed and sworn before me
this 12 day of January, 2017

Notary Public

My Commission expires: 3/10/18

NATHAN AGUIRRE
Notary Public
Montgomery County
Maryland
My Commission Expires Mar 10, 2018

Exhibit No. EXE-2

SUMMARY OF TESTIMONY EXPERIENCE
ALAN C. HEINTZ

#	JURISDICTION	CASE OR DOCKET NO.	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
1	FERC	ER95-836-000	Maine Public Service Company	1995	Rates, Terms and Conditions for Open Access Transmission Services
2	FERC	ER95-854-000	Kentucky Utilities Company	1995	Rates, Terms and Conditions for Open Access Transmission Services
3	FERC	ER95-1686-000 ER96-496-000	Northeast Utilities Service Company	1996	Rates, Terms and Conditions for Open Access Transmission Services
4	FERC	ER96--58-000	Allegheny Power Services Corporation	1995 & 1996	Rates, Terms and Conditions for Open Access Transmission Services
5	FERC	OA96-138-000	Consolidated Edison Company of New York, Inc.	1997	Rates, Terms and Conditions for Open Access Transmission Services
6	FERC	ER96-1208-000	Interstate Power Company	1996	Rates, Terms and Conditions for Open Access Transmission Services
7	British Columbia Utilities Commission		Bonneville Power Administration	1997	Rates, Terms and Conditions for Open Access Transmission Services
8	FERC	ER98-1438-000 EC98-24-000	Midwest ISO Transmission Owners	1998 & 1999	Rates, Terms and Conditions for Midwest ISO Tariff
9	FERC	EC98-2770-000 ER98-2770-000 ER98-2786-000	Midwest Independent System Operator Transmission Owners	1999	Reasonableness of the conditions to be placed on the merging parties

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#	JURISDICTION	CASE OR DOCKET NO.	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
10	Illinois Commerce Commission	99-0117	Commonwealth Edison Company	1998	Cost of service for Retail Distribution Services Tariff
11	FERC	ER99-3110-000	Nevada Power Company	1998	Rates, Terms and Conditions for Open Access Transmission Services
12	FERC	ER99-4415-000	Illinois Power Company	1999	Rates, Terms and Conditions for Open Access Transmission Services
13	FERC	ER99-4470-000	Commonwealth Edison Company	1999	Rates, Terms and Conditions for Open Access Transmission Services
14	U.S. District Court, FL	92-35-CIV-ORL-3A22	Florida Power and Light Company	1999	Rates, Terms and Conditions for Network Service in an anti-trust case
15	U.S. Court of Federal Claims, DC	97-268C	Carolina Power & Light Company	1999	Cost recovery of Decontamination & Decommissioning Fund Assessments
16	FERC	ER98-496-006 ER98-2160-004	Dynegy	1999	Rates for Must Run units
17	FERC	ER00-980-000	Bangor Hydro Electric Company	1999	Rates, Terms and Conditions for Open Access Transmission Services
18	Maine Public Utilities Commission	99-185	Bangor Hydro Electric Company	2000	Rates, Terms and Conditions for Open Access Transmission Services

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#	JURISDICTION	CASE OR DOCKET NO.	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
19	FERC	EL00-98-000, et al.	Dynegy Power Marketing, Inc.	2000	Nexus between fuel and emissions costs and the market prices in California
20	Illinois Commerce Commission	No. 01-0423	Commonwealth Edison Company	2001	Direct, Rebuttal and Surrebuttal: Cost of service for Retail Distribution Services Tariff
21	FERC	ER01-2992	Commonwealth Edison Company	2001	Rates, Terms and Conditions for Open Access Transmission Services
22	FERC	ER01-123.004	Midwest ISO Transmission Owners	2001	Super Region Adjustment for the MISO/ARTO Super Region
23	FERC	ER01-2999	Illinois Power Company	2001	Rates, Terms and Conditions for Open Access Transmission Services
24	FERC	ER01-3142, et. al	Midwest ISO Transmission Owners	2001	Revised treatment of Network Upgrades
25	FERC	ER01-3142, et. al	Midwest ISO Transmission Owners	2001	Uncertainties that support a higher ROE
26	FERC	EL000-95-045, et.al	Dynegy, Mirant, Reliant and Williams	2001 & 2002	Costing of emissions and start-up costs
27	FERC	EC02-23 & ER02-320	Trans-Elect, Inc.	2001 & 2002	Support of rates and ratemaking methodology for new transmission company
28	FERC		Sithe New Boston, LLC	2001 & 2002	Cost of Service for Must Run Unit
29	FERC	RM01-12	SeTrans	2002	Allocation of FTRs/CRRs

#	JURISDICTION	CASE OR DOCKET NO.	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
30	FERC	EL02-111	Midwest ISO Transmission Owners	2002	Through and Out Rates
31	FERC	ER02-2595	Midwest ISO Transmission Owners	2002	Cost Allocation for FTR and Market Administration
32	FERC	ER03-37	Sierra Pacific and Nevada Power	2003	Ancillary Service Rates
33	FERC	ER03-626	Empire District Electric Co.	2003	Cost of Service; Wholesale Requirements Customers
34	FERC	EL-02-25-001, et. al	Public Service Co. of Colorado	2003	Fuel Adjustment Clause
35	FERC	ER03-959	Exelon Framingham LLC, et al.	2003	Production Cost of Service
36	FERC	ER03-1187	Commonwealth Edison	2003	Black Start Rates
37	FERC	ER03-1223	Montana Megawatt	2003	Production Formula Rates
38	FERC	ER03-1335	Commonwealth Edison	2003	Transmission Tariff Rates
39	FERC	ER03-1354	Black Hills Power Company, et al.	2003	Joint transmission Tariff Rates
40	FERC	ER03-1328	Nevada Power	2003	Transmission Tariff Rates
41	FERC	EL02-111, et. Al	Midwest ISO Transmission Owners	2004	Long-term Transmission Pricing Plan
42	FERC	ER05-14	Sierra Pacific	2004	Transmission Tariff Rates
43	FERC	ER05-26	Mirant Kendall, LLC	2004	Reliability Must Run Agreement and Rates

#	JURISDICTION	CASE OR DOCKET NO.	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
44	Illinois Commerce Commission	No.04-0779	NICOR Gas Company	2004	Distribution Service Embedded Cost of Service Study
45	FERC	ER05-163	Milford Power Company LLC	2004	Reliability Must Run Agreement and Rates
46	FERC	EL02-111, et. al	Midwest ISO Transmission Owners	2004	Seams Elimination
47	FERC	EL00-95, et. al	Portland General Electric Company	2005	California Refund Proceeding
48	FERC	ER05-447	Midwest ISO Transmission Owners	2005	Schedule 10 & 17 Recovery for Grandfathered Agreements
49	FERC	EL02-111, et. al	Midwest ISO Transmission Owners	2005	Seams Elimination
50	FERC	ER05-860	Whiting Clean Energy	2005	Cost Based Power Rates
51	FERC	ER05-903	Cou. Ed. Energy Mass., Inc.	2005	Reliability Must Run Agreement aud Rates
52	FERC	EL02-111, et. al	Midwest ISO Transmission Owners	2005	Seams Elimination
53	FERC	ER05-1050	AmerGen Energy Company, L.L.C.	2005	Reactive power charges
54	Illinois Commerce Commission	No.05-0597	Commonwealth Edison Co.	2005	Distribution Service Embedded Cost of Service Study
55	FERC	ER05-1179	Berkshire Power Company, LLC	2005	Reliability Must Run Agreement and Rates
56	FERC	ER05-1243	Basin Electric Power Cooperative	2005	Revised Transmission Cost of Service

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#	JURISDICTION	CASE OR DOCKET NO.	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
57	FERC	ER05-1304 & ER05-1305	Mystic I, LLC and Mystic Development, LLC	2005	Reliability Must Run Agreement and Rates
58	FERC	ER05-273	Midwest ISO Transmission Owners	2005	Proper Pricing for Regional Non-firm Redirects
59	FERC	ER05-515	PHI and BGE	2005	Transmission Formula Rates
60	FERC	EL05-19	Southwestern Public Service Company	2005	Production rates and Fuel Adjustment Clause,
61	FERC	ER06-427	Mystic Development, LLC	2006	Reliability Must Run Agreement and Rates
62	FERC	ER06-822	Fore River Development, LLC	2006	Reliability Must Run Agreement and Rates
63	FERC	ER06-819	Consolidated Edison Energy Massachusetts, Inc	2006	Reliability Must Run Agreement and Rates
64	FERC	ER07-169	Ameren Energy Marketing Company	2006	Ancillary service rates
65	FERC	ER06-1549	Duquesne Light Company	2006	Transmission Formula Rates
66	FERC	ER07-170	Ameren Energy, Inc.	2006	Ancillary service rates
67	FERC	ER06-787	Idaho Power	2006 & 2007	Transmission Formula Rates
68	FERC	ER07-562	Trans-Allegheny Interstate Line Company	2007	Transmission Formula Rates
69	FERC	ER07-583	Commonwealth Edison	2007	Transmission Formula Rates
70	FERC	ER07-1171	Arizona Public Service Co.	2007	Transmission Formula Rates

#	JURISDICTION	CASE OR DOCKET NO.	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
71	Illinois Commerce Commission	No. 07-0566	Commonwealth Edison Co.	2007	Distribution Service Embedded Cost of Service Study
72	FERC	ER07-1371	Sierra Pacific Resources	2007	Transmission Rates
73	FERC	ER08-281	Oklahoma Gas & Electric	2007	Transmission Formula Rates
74	FERC	ER08-313	Southwestern Public Service	2007	Transmission Formula Rates
75	FERC	ER08-386	Potomac-Appalachian Transmission Highline, LLC	2007	Transmission Formula Rates
76	FERC	ER08-374	Atlantic Path 15, LLC	2007	Transmission Rates
77	Illinois Commerce Commission	No. 08-0363	NICOR Gas Company	2008	Distribution Service Embedded Cost of Service Study
78	FERC	ER08-951	PSEG Energy Resources & Trade, LLC	2008	Reactive Power Charges
79	FERC	ER08-1233	Public Service Gas & Electric Company	2008	Transmission Formula Rates
80	FERC	ER08-1457	PPL Electric Utilities Corp.	2008	Transmission Formula Rates
81	FERC	ER08-1584	Black Hills Power	2008	Transmission Formula Rates
82	FERC	ER08-1600	Basin Electric Power Coop	2008	Transmission Rates
83	FERC	ER09-36	Prairie Wind Transmission, LLC	2008	Transmission Formula Rates

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#	JURISDICTION	CASE OR DOCKET NO.	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
84	FERC	ER09-35	Tallgrass Transmission, LLC	2008	Transmission Formula Rates
85	FERC	ER09-75	Pioneers Transmission, LLC	2008	Transmission Formula Rates
86	FERC	ER09-255	Nebraska Public Power District	2008	Transmission Formula Rates
87	FERC	ER09-528	ITC Great Plains, LLC	2009	Transmission Formula Rates
88	Illinois Commerce Commission	ER08-0532	Commonwealth Edison Co.	2009	Distribution Service Embedded Cost of Service Study
89	FERC	ER08-370 & EL09-22	Otter Tail Power Co.	2009	Formula Transmission Rate
90	FERC	ER10-152	PPL Electric Utilities Corp.	2009	Revised Depreciation Method
91	FERC	ER09-1727	ALLETE. INC	2009	Formula Transmission Rate
92	FERC	ER10-230	KCP&L	2009	Formula Transmission Rates
93	FERC	ER10-455	Ameren Energy Marketing Company	2009	Reactive Power Rates
94	FERC	ER10-516	SCE&G	2010	Formula Transmission Rates
95	FERC	ER10-962	Union Electric Company	2010	Reactive Power Rates
96	FERC	ER10-1149	FP&L	2010	Formula Transmission Rates
97	FERC	ER10-1418	Exelon Generation	2010	Reliability Must Run

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#	JURISDICTION	CASE OR DOCKET NO.	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
98	FERC	ER10-1782	Tampa Electric Company	2010	Formula Transmission Rates
99	FERC	ER10-2061	Tampa Electric Company	2010	Formula Production Rates
100	FERC	ER11-1955	Dairyland Power Coop.	2011	Reactive Rates
101	FERC	ER05-6	MISO Transmission Owners	2010	Seams Elimination
102	FERC	ER11-2127	Terra Gen Dixie Valley	2010	Transmission Rates
103	FERC	ER09-1148	PPL Electric Utilities	2011	Formula Transmission Rates
104	FERC	ER11-3643	PacifiCorp	2011	Formula Transmission Rates
105	FERC	ER11-3826	Black Hills	2011	Transmission Rates
106	FERC	ER11-3643	Puget Sound Energy	2012	Formula Transmission Rates
107	FERC	ER12-1378	CLECO	2012	Formula Transmission Rates
108	FERC	ER12-1593	DATC	2012	Formula Transmission Rates
109	FERC	ER12-2274	PSE&G	2012	Abandonment Costs
110	FERC	ER12-2554	Transource Missouri, LLC	2012	Formula Transmission Rate
111	FERC	ER13-1187	MidAmerican	2013	Depreciation Rates under Formula
112	FERC	ER13-1207	PacifiCorp	2013	Regulation Service

#	Jurisdiction	Case or Docket No.	Client	Approximate Date	Subject Matter
113	FERC	EL13-48	PHI Companies	2013	Complaint involving Formula Rates
114	FERC	ER13-1207	PacifiCorp	2013	Depreciation Rates under Formula
115	FERC	ER13-1605	NV Energy	2013	Transmission and Ancillary Service Rates
116	FERC	ER13-782	ITC	2013	Transmission Formula Rate
117	FERC	ER13-1962 & EL13-76	AERG/AEM	2013	Reliability Must Run
118	FERC	ER14-108	Entergy	2013	Reactive Power Rates
119	FERC	ER14-1210	Illinois Power Marketing Company	2014	Reliability Must Run
120	FERC	ER14-1332	DATC Path 15, LLC	2014	Transmission Cost of Service
121	FERC	ER14-1382	Transource Missouri, LLC	2014	Transmission Formula
122	FERC	ER14-1425	Cheyenne L, F & P	2014	Transmission Rates
123	FERC	ER14-1661	MidAmerican Central California Transco, LLC	2014	Transmission Formula
124	FERC	ER14-1956	Panther Creek Power Operating, LLC	2014	Reactive Power Rates
125	FERC	ER14-1969	Public Service Company of Colorado	2014	Ancillary Services for Intermittent Resources
126	FERC	ER14-2502	Entergy Power, LLC EAM Nelson Holding, LLC	2014	Reactive Power Rates
127	FERC	ER14-2619	Illinois Power Marketing Company	2014	Reliability Must Run

#	Jurisdiction	Case or Docket No.	Client	Approximate Date	Subject Matter
128	FERC	ER14-2718	Illinois Power Marketing Company	2014	Reliability Must Run
129	FERC	ER14-2751 & ER14-2752	Xcel Energy Transmission Development Company, LLC and Xcel Energy Southwest Transmission Company, LLC	2014	Transmission Formula
130	FERC	ER15-13	Transource Wisconsin, Inc.	2014	Transmission Formula
131	FERC	ER15-279	Nebraska Public Power District	2014	Transmission Cost of Service
132	FERC	ER15-572	New York Transco, LLC	2015	Transmission Formula
133	FERC	ER15-948	Illinois Power Marking Company	2015	Reliability Must Run
134	FERC	ER15-958	Transource Kansas, LLC	2015	Transmission Formula
135	FERC	ER15-949	Southwestern Public Service Co.	2015	Demand Allocator
136	FERC	ER15-1047	R.E. Ginna Nuclear Power Plant, LLC	2015	Reliability Support Services Agreement
137	FERC	ER15-1510	First Energy Solutions Corp.	2015	Reactive Power Rates
138	FERC	EL15-51	City Water And Light Plant Of The City Of Jonesboro	2015	Reactive Power Rates
139	FERC	ER15-1682	TransCanyon DCR, LLC	2015	Transmission Formula
140	FERC	ER15-1719	R.E. Ginna Nuclear Power Plant, LLC	2015	Reliability Support Services Agreement
141	FERC	ER15-1775	Basin Electric Power Coop	2015	Transmission Formula
142	FERC	ER15-1809	ATX Southwest, LLC	2015	Transmission Formula
143	FERC	ER15-2102	New York Power Authority	2015	Transmission Formula
144	FERC	ER15-2239	NextEra Energy Transmission West, LLC	2015	Transmission Formula
145	FERC	ER15-2426	Northern Indiana Public Service Co.	2015	Reactive Power Rates

#	Jurisdiction	Case or Docket No.	Client	Approximate Date	Subject Matter
146	FERC	ER15-2594	South Central MCN LLC	2015	Transmission Formula
147	FERC	EL16-17	City of West Memphis	2015	Reactive Power Rates
148	FERC	EL16-18	Conway Corporation	2015	Reactive Power Rates
149	FERC	ER16-200 & 201	Duke Energy Indiana, Inc.	2015	Reactive Power Rates
150	FERC	EL16-14	Indiana Municipal Power Agency	2015	Reactive Power Rates
151	FERC	ER16-444	Wabash Valley Power Association, Inc.	2015	Reactive Power Rates
152	FERC	ER16-835	New York Power Authority	2015	Transmission Formula
153	FERC	EL15-85	New Hampshire Transmission LLC	2016	Formula Rates
154	FERC	ER16-1832	Entergy Louisiana, LLC	2016	Reactive Power Rates
155	FERC	ER16-2298	Duke Energy Kentucky, Inc.	2016	Reactive Power Rates
156	FERC	ER16-2716	NextEra Energy Transmission, MidAtlantic, LLC	2016	Transmission Formula
157	FERC	ER16-2717	NextEra Energy Transmission, Midwest, LLC	2016	Transmission Formula
158	FERC	ER16-2719	NextEra Energy Transmission, New York, Inc	2016	Transmission Formula
159	FERC	ER16-2720	NextEra Energy Transmission, Southwest, LLC	2016	Transmission Formula
160	FERC	ER17-706	GridLiance West Transco LLC	2016	Transmission Formula

Exhibit No. EXE-3

Revenue Requirements by Generating Station

	Name	Type	Interconnected TO	Fixed Revenue Requirement	Losses	Total
1	Braidwood 1 & 2	Nuclear	ComEd	$ 4,538,855	$ 98,587	$ 4,637,441
2	Byron 1 & 2	Nuclear	ComEd	$ 3,882,900	$ 72,254	$ 3,955,154
3	Dresden 2&3	Nuclear	ComEd	$ 4,678,804	$ 43,342	$ 4,722,147
4	LaSalle 1 & 2	Nuclear	ComEd	$ 3,307,715	$ 49,855	$ 3,357,571
5	Quad Cities 1 & 2 (75%)	Nuclear	ComEd	$ 2,536,264	$ 94,359	$ 2,630,623
6	SE Chicago 5-12	NG	ComEd	$ 851,020		$ 851,020
7	Perryman 6	NG	BGE	$ 403,917		$ 403,917
8	Gould Street 3	NG	BGE	$ 30,960		$ 30,960
9	Notch Cliff 1-8	Oil	BGE	$ 267,820		$ 267,820
10	Perryman 1,3,4,51 (excl. Unit 2)	Oil,NG	BGE	$ 701,220		$ 701,220
11	Philadelphia Rd 1-4	Oil	BGE	$ 157,074		$ 157,074
12	Riverside 7&8	Oil,NG	BGE	$ 222,684		$ 222,684
13	Westport 5	NG	BGE	$ 116,040		$ 116,040
14	Salem 1 & 2 (43%)	Nuclear	PSEG	$ 390,867		$ 390,867
15	Handsome Lake	NG	Penelec	$ 188,604		$ 188,604
16	TMI	Nuclear	MetEd	$ 307,460	$ 385	$ 307,845
17	Oyster Creek	Nuclear	JCPL	$ 2,183,969	$ 15,872	$ 2,199,842
18	Limerick 1 & 2	Nuclear	PECO	$ 2,515,295	$ 8,523	$ 2,523,818
19	Peach Bottom 2&3 (50%)	Nuclear	PECO	$ 2,787,328	$ 11,040	$ 2,798,368
20	Chester 7-9	Oil	PECO	$ 43,870		$ 43,870
21	Conowingo 1-11	Hydro	PECO	$ 249,927		$ 249,927
22	Croydon 11,12,21,22,31,32,41,42	Oil	PECO	$ 324,454		$ 324,454
23	Delaware 9-12	Oil	PECO	$ 67,668		$ 67,668
24	Eddystone 3,4,10,20,30,40	Oil	PECO	$ 376,133		$ 376,133
25	Fairless Hills A&B	NG	PECO	$ 144,116		$ 144,116
26	Falls1-3	Oil	PECO	$ 37,360		$ 37,360
27	Moser 1-3	Oil	PECO	$ 45,309		$ 45,309
28	Muddy Run 1-8	Pump.Stor.	PECO	$ 442,823		$ 442,823
29	Pennsbury 1&2	NG	PECO	$ 6,898		$ 6,898
30	Richmond 91&92	Oil	PECO	$ 62,156		$ 62,156
31	Schuylkill10&11	Oil	PECO	$ 48,052		$ 48,052
32	Southwark 3-6	NG	PECO	$ 87,171		$ 87,171
33	Total			$ 32,004,735	$ 394,217	$ 32,398,952

Reactive Revenue Requirement by Unit

Constellation Power Source Generation, LLC
Zone
BGE

Monthly Revenue Requirement	Gould Street	Notch Cliff	Perryman 1,3,4,6 51 (Excludes Unit 2)	Philadelphia Rd	Riverside	Westport	Total
Unit1		$ 3,354.04	$ 11,240.42	$ 3,515.58			
Unit 2		$ 2,581.83		$ 3,191.29			
Unit 3	$ 2,580.04	$ 2,581.83	$ 11,240.42	$ 3,191.29			
Unit 4		$ 2,581.83	$ 11,240.42	$ 3,191.29			
Unit 5		$ 3,473.33				$ 9,670.03	
Unit 6		$ 2,581.83	$ 33,659.76				
Unit 7		$ 2,581.83			$ 9,988.14		
Unit 8		$ 2,581.83			$ 8,568.87		
Unit 51			$ 24,713.76				
Total Monthly Revenue Requirement	$ 2,580.04	$ 22,318.34	$ 92,094.80	$ 13,089.46	$ 18,557.01	$ 9,670.03	$ 158,309.67
Total Annual Revenue Requirement							$ 1,899,716.09

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Reactive Revenue Requirement by Unit

Exelon Generation Company, LLC
Zone
Monthly Revenue Requirement

ComEd	Braidwood	Byron	Dresden	LaSalle	Quad Cities	SE Chicago	Total
Unit1	$ 184,013.49	$ 155,449.24		$ 127,548.74	$ 106,949.55		
Unit 2	$ 202,439.94	$ 174,146.94	$ 197,950.16	$ 152,248.83	$ 112,269.04		
Unit 3			$ 195,562.09				
Unit 4							
Unit 5						$ 8,864.79	
Unit 6						$ 8,864.79	
Unit 7						$ 8,864.79	
Unit 8						$ 8,864.79	
Unit 9						$ 8,864.79	
Unit 10						$ 8,864.79	
Unit 11						$ 8,864.79	
Unit 12						$ 8,864.79	
Total	$ 386,453.43	$ 329,596.18	$ 393,512.24	$ 279,797.57	$ 219,218.59	$ 70,918.33	$ 1,679,496.34
Total Zone Annual							$ 20,153,956.03

PECO	Limerick	Peach Bottom	Chester	Conowingo	Croydon	Delaware	Eddystone	Fairless Hills	Falls	Moser	Muddy Run	Pennsbury	Richmond	Schuylkill	Southwark	Total
Unit1	$ 108,446.42			$ 2,611.45					$ 1,032.33	$ 1,266.19	$ 4,658.52	$ 287.42				
Unit 2	$ 101,871.72	$ 108,606.41		$ 2,360.11					$ 1,045.35	$ 1,269.39	$ 4,930.03	$ 287.42				
Unit 3		$ 124,590.89		$ 2,489.80			$ 14,498.48		$ 1,035.61	$ 1,240.12	$ 4,338.87				$ 1,912.19	
Unit 4				$ 2,360.11			$ 12,649.44				$ 4,448.45				$ 1,733.12	
Unit 5				$ 1,690.66							$ 4,977.46				$ 1,877.92	
Unit 6				$ 2,571.72							$ 4,632.88				$ 1,741.02	
Unit 7			$ 1,200.96	$ 2,571.72							$ 4,632.88					
Unit 8			$ 1,206.67	$ 835.49							$ 4,282.85					
Unit 9			$ 1,248.19	$ 1,056.02		$ 1,261.57										
Unit 10				$ 1,292.06		$ 1,466.72	$ 1,052.37							$ 2,072.86		
Unit 11				$ 988.07	$ 3,259.03	$ 1,455.38								$ 1,931.49		
Unit 12					$ 2,999.49	$ 1,455.38										
Unit 21					$ 3,463.22											
Unit 22					$ 3,463.22											
Unit 31					$ 3,463.22											
Unit 32					$ 3,463.22											
Unit 41					$ 3,463.22											
Unit 42					$ 3,463.22											
Unit 20							$ 1,080.21									
Unit 30							$ 1,031.97									
Unit 40							$ 1,031.97									
Unit 91													$ 2,582.33			
Unit 92													$ 2,597.35			
Unit A								$ 6,004.83								
Unit B								$ 6,004.83								
Total	$ 210,318.14	$ 233,197.30	$ 3,655.82	$ 20,827.22	$ 27,037.84	$ 5,639.04	$ 31,344.44	$ 12,009.66	$ 3,113.29	$ 3,775.71	$ 36,901.95	$ 574.84	$ 5,179.67	$ 4,004.35	$ 7,264.25	$ 604,843.52
Total Zone Annual																$ 7,258,122.19

PSE&G	Salem
Unit1	$ 15,406.47
Unit 2	$ 17,165.76
Total	$ 32,572.22
Total Zone Annual	$ 390,866.69

MetEd	TMI
Unit 2	$ 25,653.72
Total	$ 25,653.72
Total Zone Annual	$ 307,844.62

JCP&L	Oyster Creek
Unit1	$ 183,320.14
Total	$ 183,320.14
Total Zone Annual	$ 2,199,841.71

All Zones	
Total Monthly Revenue Requirement	$ 2,525,885.94
Total Annual Revenue Requirement	$ 30,310,631.23

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Reactive Revenue Requirement by Unit

Handsome Lake Energy, LLC
Zone
Penelec

Monthly Revenue Requirement		Handsome Lake
Unit1	$	3,143.41
Unit 2	$	3,143.41
Unit 3	$	3,143.41
Unit 4	$	3,143.41
Unit 5	$	3,143.41
Total Monthly Revenue Requirement	$	15,717.04
Total Annual Revenue Requirement	$	188,604.46

Nuclear Generating Losses

		Braidwood		Byron		Dresden			LaSalle	
		BWD 1	BWD 2	BYR 1	BYR 2	DRE 2		LAS 1	LAS 2	
	Fuel Cost ($ / MW Hr)	$6.48	$7.09	$7.03	$6.92	$6.96	$6.65	$6.56	$6.98	
1	Gen Field Annual Loss (MW Hr)	5,346	5,602	4,160	3,647	1,101	2,049	2,431		2,808
2	Gen Armature Annual Loss (MW Hr)	1,215	1,310	920	780	1,001	1,687	732		620
3	GSU Annual Loss (MW Hr)	616	431	466	381			347		415
4	Total Annual Loss (MW Hr)	7,177	7,343	5,546	4,807	2,331	4,079	3,510		3,843
5	Cost of Heating Loss (Annual)	$ 46,519	$ 52,068	$ 39,002	$ 33,252	$ 16,220	$ 27,123	$ 23,036	$	26,819

		Limerick		Oyster Creek	Peach Bottom		Quad Cities		Three Mile Isl	
		LIM 1	LIM 2	OYS	PEA 2	PEA 3	QDE 1	QDE 2	TMI	
	Fuel Cost ($ / MW Hr)	$5.95	$6.00	$6.18	$6.63	$6.41	$6.67	$6.73	$6.82	
6	Gen Field Annual Loss (MW Hr)	361	721	1,100	203	250	1,716	1,898		35
7	Gen Armature Annual Loss (MW Hr)	81	175	1,037	419	728	4,400	4,698		11
8	GSU Annual Loss (MW Hr)	27	59	430	33	66	658	703		10
9	Total Annual Loss (MW Hr)	470	955	2,567	655	1,045	6,775	7,298		56
10	Cost of Heating Loss (Annual)	$ 2,794	$ 5,728	$ 15,872	$ 4,343	$ 6,697	$ 45,211	$ 49,148	$	385

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Unit Name: Braidwood 1 & 2 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 276,982,389	
2	Investment Generator & Exciter	Inputs Tab	41,547,358	
3	Reactive Allocator	(Line 71)	16.49%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**6,850,549**	
5				
6	GSU Transformer Investment	Inputs Tab	49,633,067	
7	Reactive Allocator	(Line 71)	16.49%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**8,183,764**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	2,482,481	
11	Reactive Allocator	(Line 71)	16.49%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**409,325**	
13				
14	Total Cost of Power Plant	Inputs Tab	1,484,090,250	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	1,390,427,343	
16	Balance of Plant Allocator	(Line 79)	0.1358%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	1,888,844	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	17,332,483	
19	Reactive Fixed Charge Rate	(Line 14(h))	26.1870%	
20	**Annual Reactive Rev Req**	(Line 14 * 18)	**4,538,855**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 4,538,855**	
23				
24				
25				
26				

(e)		(f)	(g)	(h)
Fixed Charge Rate for Reactive Plant				
		Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 140	382,031		
Other Expenses		156,675		
O&M	(sum line 1 & 2)	538,705	17,332,483	3.1081%
A&G		137,043,216	1,484,090,250	9.2342%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.1713%
Working Capital	Line 216	33,666,939	1,484,090,250	2.2685%
General Plant		-	1,484,090,250	0.0000%
Other Taxes	Line 196(c)	24,988,247	1,484,090,250	1.6837%
Depreciation	Line 168(c)			0.0814%
				8.1350%
Taxes (Federal/State/Local)	Line 180			2.9692%
ADIT	-Line 233(k)	($21,733,067)	1,484,090,250	-1.4644%
		(Sum Lines 1 to 11 , Col. (h))		26.1870%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		1,258.00						
		1,220.00						
	Total	2,478.00	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.92						
		0.90						
	Total	0.91	(Line 38 / 58)					
	MVA Capability (MVA)							
		1,362.95	(Line 31 / 41)					
		1,349.56	(Line 32 / 42)					
	Total	2,712.50	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		524.46	(SQRT (Line 51^2 - Line 31^2))					
		576.98	(SQRT (Line 52^2 - Line 32^2))					
	Total	1,101.44	(Sum Lines 62 to 64)					
	Reactive Allocator	16.5%	(Line 69^2 / Line 58^2)					
		ComEd is TO Fleet						
	Max. MVAr	2,187						
	Nameplate MVAr	4,856						
	Exciter MW	35						
	Generator MW	11,447						
	Balance of Plant Allocator	0.1358%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ 734,651	15%	$ 110,198
	Control&Power Cabling	$ 175,303,902	1%	$ 1,753,039
	Switch Board Equipment	$ 51,974,311	1%	$ 519,743
	Switching Equipment	$ 7,843,655	1%	$ 78,437
	Transformers	$ 702,163	3%	$ 21,065
	Aux Generator	$ 21,664,522	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	50%	$ -
	Structure	$ -	0%	$ -
	Misc	$ 19,860,488	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	1%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 278,083,692		$ 2,482,481

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	$ 32,492,207		
	Coolants and Water (Nuclear Plants Only)	$ 3,183,689		
	Steam Expenses	$ 19,969,572	19,969,572	
	Steam From Other Sources	$ -		
	Electric Expenses	$ -	-	
	Misc Steam (or Nuclear) Power Expenses	$ 2,040,158		
	Rents	$ 56,408,634	56,408,634	
	Allowances	$ 4,476,155	4,476,155	
	Maintenance Supervision and Engineering	$ -		
	Maintenance of Structures	$ 5,994,248	5,994,248	
	Maintenance of Boiler (or reactor) Plant	$ 467,205		
	Maintenance of Electric Plant	$ 15,446,317		
	Maintenance of Misc Steam (or Nuclear) Plant	$ 9,921,805	9,921,805	
	Other Power Production, & Other Expenses	$ 18,561,772	18,561,772	
	Total NonFuel Expenses	168,961,761	115,332,187	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		68.26%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation							
	Plant Var Allocators						
	Electric Expense Allocator	2.4733%	Line 4(c) / 1(c))				
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)				
	Other Demand Expense Allocator	0.1358%	Line 79				
	Production Plant Expenses						
	Total NonFuel Expenses	168,961,761	Line 116				
	Allowances	4,476,155	Line 109				
	Non-Fuel Production O&M	164,485,606	(Line 126 - 127)				
	Operating Expenses						
	Operations Supervision & Engineering	0	Line 102(c)				
	Electric Expenses	0	Line 106(c)				
	Maintenance of Electric Plant	15,446,317	Line 113(b)				
	Other Demand Related Expenses	115,332,187	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)				
	Total	130,778,503	(Sum Lines 131 to 134)				
						$	82,500
				Allocator	Allocated Amount		
	Maintenance of Electric Plant	15,446,317	Line 113(b)				
	Electric Expenses	0	Line 106(c)				
	Total Electric Expenses	15,446,317	(Line 138 + 139)	2.4733%	382,031	(Line 140(b) * (d))	
				Line 121			
	Other Demand Related Expenses	115,332,187	(Line 134)	0.1358%	156,675		
				Line 123			
	Balance of Plant Fixed Expenses				130,239,798.34	(Line 135(b) - Line 140(e) - Line 142(e))	

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		124,367,412	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		12,675,803	(allocated on plant labor)	
	Total		137,043,216		
Depreciation					
	Annual Depreciation Exp ...DE	25,369,064			
	Gross Production Plant Cost ... F	1,484,090,250	Line 14		
	SLDP=DE/F	1.7094%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	59			
	SFDP=(R/((1+R)^n-1)		0.0814%		
Income Taxes					
	Income Tax Calculation; (2015 Est Tax Rate)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.679%			
	e) Federal Income Tax Rate ("FIT")	35.000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.679%			
	g) Gross-Up Tax Factor ("GTF")	61.321%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.969%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	0.4500	0.0500	0.0225	
	Preferred Stock				
	Common Stock	0.5500	0.1070	0.0589	
	Total Cost of Capital "R"	1.0000	R=	0.0814	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		20,026,176		
	Payroll Taxes	7,269,439			
	Percentage Fixed O&M Excluding Allowances	68.2593%	Line 117		
	Fixed Payroll Taxes		4,962,071	(Line 193 * 194)	
	Total Other Taxes		24,988,247	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	Percentage Fixed O&M Excluding Allowances	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9692%				
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	2,488,211				
		100.000%				
	Production Related Prepayments	2,488,211	(Line 209 * 210)			
	Unit Specific M&S	300,703,432				
	Total	303,191,643	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9692%				
	Working Capital Costs	33,666,939	(Line 213 * 214)			

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Accumulated Deferred Income Taxes

Investment	1,484,090,250	Line 14
Asset Service Life	59	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 264,508,102

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	25,154,072	3.750%	55,653,384	11,796,829	11,796,829	694,243	265,429	425,717	1,385,389	21,733,067
2	25,154,072	7.219%	107,136,475	31,709,974	43,506,803	2,560,375	978,903	1,570,048	5,109,326	21,733,067
3	25,154,072	6.677%	99,092,706	28,598,724	72,105,527	4,243,410	1,622,374	2,602,102	8,467,886	21,733,067
4	25,154,072	6.177%	91,672,255	25,728,568	97,834,095	5,757,536	2,201,267	3,530,579	11,489,383	21,733,067
5	25,154,072	5.713%	84,786,076	23,065,063	120,899,158	7,114,915	2,720,231	4,362,937	14,198,084	21,733,067
6	25,154,072	5.285%	78,434,170	20,608,209	141,507,367	8,327,709	3,183,916	5,106,634	16,618,258	21,733,067
7	25,154,072	4.888%	72,542,331	18,329,305	159,836,671	9,406,388	3,596,325	5,768,091	18,770,804	21,733,067
8	25,154,072	4.522%	67,110,561	16,228,350	176,065,022	10,361,427	3,961,463	6,353,730	20,676,620	21,733,067
9	25,154,072	4.462%	66,220,107	15,883,932	191,948,954	11,296,196	4,318,851	6,926,940	22,541,988	21,733,067
10	25,154,072	4.461%	66,205,266	15,878,191	207,827,145	12,230,627	4,676,111	7,499,943	24,406,681	21,733,067
11	25,154,072	4.462%	66,220,107	15,883,932	223,711,077	13,165,397	5,033,499	8,073,153	26,272,049	21,733,067
12	25,154,072	4.461%	66,205,266	15,878,191	239,589,268	14,099,828	5,390,759	8,646,156	28,136,743	21,733,067
13	25,154,072	4.462%	66,220,107	15,883,932	255,473,200	15,034,598	5,748,147	9,219,366	30,002,110	21,733,067
14	25,154,072	4.461%	66,205,266	15,878,191	271,351,391	15,969,029	6,105,406	9,792,368	31,866,804	21,733,067
15	25,154,072	4.462%	66,220,107	15,883,932	287,235,323	16,903,799	6,462,795	10,365,578	33,732,172	21,733,067
16	25,154,072	4.461%	66,205,266	15,878,191	303,113,514	17,838,230	6,820,054	10,938,581	35,596,866	21,733,067
17	25,154,072	4.462%	66,220,107	15,883,932	318,997,446	18,773,000	7,177,443	11,511,791	37,462,233	21,733,067
18	25,154,072	4.461%	66,205,266	15,878,191	334,875,637	19,707,431	7,534,702	12,084,794	39,326,927	21,733,067
19	25,154,072	4.462%	66,220,107	15,883,932	350,759,568	20,642,201	7,892,090	12,658,004	41,192,295	21,733,067
20	25,154,072	4.461%	66,205,266	15,878,191	366,637,760	21,576,632	8,249,350	13,231,007	43,056,988	21,733,067
21	25,154,072	2.231%	33,110,053	3,077,294	369,715,054	21,757,731	8,318,589	13,342,058	43,418,378	21,733,067
22	25,154,072	0.000%	0	-9,729,344	359,985,710	21,185,159	8,099,678	12,990,951	42,275,789	21,733,067
23	25,154,072	0.000%	0	-9,729,344	350,256,367	20,612,587	7,880,768	12,639,845	41,133,200	21,733,067
24	25,154,072	0.000%	0	-9,729,344	340,527,023	20,040,015	7,661,858	12,288,738	39,990,611	21,733,067
25	25,154,072	0.000%	0	-9,729,344	330,797,680	19,467,443	7,442,948	11,937,631	38,848,022	21,733,067
26	25,154,072	0.000%	0	-9,729,344	321,068,336	18,894,872	7,224,038	11,586,524	37,705,433	21,733,067
27	25,154,072	0.000%	0	-9,729,344	311,338,993	18,322,300	7,005,127	11,235,417	36,562,844	21,733,067
28	25,154,072	0.000%	0	-9,729,344	301,609,649	17,749,728	6,786,217	10,884,311	35,420,256	21,733,067
29	25,154,072	0.000%	0	-9,729,344	291,880,306	17,177,156	6,567,307	10,533,204	34,277,667	21,733,067
30	25,154,072	0.000%	0	-9,729,344	282,150,962	16,604,584	6,348,397	10,182,097	33,135,078	21,733,067
31	25,154,072	0.000%	0	-9,729,344	272,421,619	16,032,012	6,129,486	9,830,990	31,992,489	21,733,067
32	25,154,072	0.000%	0	-9,729,344	262,692,275	15,459,440	5,910,576	9,479,883	30,849,900	21,733,067
33	25,154,072	0.000%	0	-9,729,344	252,962,932	14,886,869	5,691,666	9,128,777	29,707,311	21,733,067
34	25,154,072	0.000%	0	-9,729,344	243,233,588	14,314,297	5,472,756	8,777,670	28,564,722	21,733,067
35	25,154,072	0.000%	0	-9,729,344	233,504,245	13,741,725	5,253,846	8,426,563	27,422,133	21,733,067
36	25,154,072	0.000%	0	-9,729,344	223,774,901	13,169,153	5,034,935	8,075,456	26,279,544	21,733,067
37	25,154,072	0.000%	0	-9,729,344	214,045,558	12,596,581	4,816,025	7,724,349	25,136,956	21,733,067
38	25,154,072	0.000%	0	-9,729,344	204,316,214	12,024,009	4,597,115	7,373,243	23,994,367	21,733,067
39	25,154,072	0.000%	0	-9,729,344	194,586,870	11,451,437	4,378,205	7,022,136	22,851,778	21,733,067
40	25,154,072	0.000%	0	-9,729,344	184,857,527	10,878,865	4,159,294	6,671,029	21,709,189	21,733,067
41	25,154,072	0.000%	0	-9,729,344	175,128,183	10,306,294	3,940,384	6,319,922	20,566,600	21,733,067
42	25,154,072	0.000%	0	-9,729,344	165,398,840	9,733,722	3,721,474	5,968,816	19,424,011	21,733,067
43	25,154,072	0.000%	0	-9,729,344	155,669,496	9,161,150	3,502,564	5,617,709	18,281,422	21,733,067
44	25,154,072	0.000%	0	-9,729,344	145,940,153	8,588,578	3,283,653	5,266,602	17,138,833	21,733,067
45	25,154,072	0.000%	0	-9,729,344	136,210,809	8,016,006	3,064,743	4,915,495	15,996,244	21,733,067
46	25,154,072	0.000%	0	-9,729,344	126,481,466	7,443,434	2,845,833	4,564,388	14,853,656	21,733,067
47	25,154,072	0.000%	0	-9,729,344	116,752,122	6,870,862	2,626,923	4,213,282	13,711,067	21,733,067
48	25,154,072	0.000%	0	-9,729,344	107,022,779	6,298,291	2,408,013	3,862,175	12,568,478	21,733,067
49	25,154,072	0.000%	0	-9,729,344	97,293,435	5,725,719	2,189,102	3,511,068	11,425,889	21,733,067
50	25,154,072	0.000%	0	-9,729,344	87,564,092	5,153,147	1,970,192	3,159,961	10,283,300	21,733,067
51	25,154,072	0.000%	0	-9,729,344	77,834,748	4,580,575	1,751,282	2,808,854	9,140,711	21,733,067
52	25,154,072	0.000%	0	-9,729,344	68,105,405	4,008,003	1,532,372	2,457,748	7,998,122	21,733,067
53	25,154,072	0.000%	0	-9,729,344	58,376,061	3,435,431	1,313,461	2,106,641	6,855,533	21,733,067
54	25,154,072	0.000%	0	-9,729,344	48,646,718	2,862,859	1,094,551	1,755,534	5,712,944	21,733,067
55	25,154,072	0.000%	0	-9,729,344	38,917,374	2,290,287	875,641	1,404,427	4,570,356	21,733,067
56	25,154,072	0.000%	0	-9,729,344	29,188,031	1,717,716	656,731	1,053,320	3,427,767	21,733,067
57	25,154,072	0.000%	0	-9,729,344	19,458,687	1,145,144	437,820	702,214	2,285,178	21,733,067
58	25,154,072	0.000%	0	-9,729,344	9,729,344	572,572	218,910	351,107	1,142,589	21,733,067
59	25,154,072	0.000%	0	-9,729,344	0	0	0	0	0	21,733,067

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Unit Name: Byron 1 & 2 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 326,545,555	
2	Investment Generator & Exciter	Inputs Tab	48,981,833	
3	Reactive Allocator	(Line 71)	16.19%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**7,932,428**	
5				
6	GSU Transformer Investment	Inputs Tab	21,644,926	
7	Reactive Allocator	(Line 71)	16.19%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**3,505,316**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	2,870,875	
11	Reactive Allocator	(Line 71)	16.19%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**464,928**	
13				
14	Total Cost of Power Plant	Inputs Tab	1,391,617,170	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	1,318,119,535	
16	Balance of Plant Allocator	(Line 79)	0.1358%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	1,790,617	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	13,693,289	
19	Reactive Fixed Charge Rate	(Line 14(h))	28.3562%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**3,882,900**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 3,882,900**	
23				
24				
25				
26				

	(e)		(f)	(g)	(h)
	Fixed Charge Rate for Reactive Plant				
			Calculated Amt	Plant	FCR % (f) / (g)
	Electric Expenses	Line 140	396,890		
	Other Expenses		165,722		
	O&M	(sum line 1 & 2)	562,613	13,693,289	4.1087%
	A&G		130,828,027	1,391,617,170	9.4012%
	CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.1876%
	Working Capital	Line 216	29,115,524	1,391,617,170	2.0922%
	General Plant		-	1,391,617,170	0.0000%
	Other Taxes	Line 196(c)	39,504,797	1,391,617,170	2.8388%
	Depreciation	Line 168(c)			0.0814%
					8.1350%
	Taxes (Federal/State/Local)	Line 180			2.9758%
	ADIT	-Line 233(k)	($20,378,888)	1,391,617,170	-1.4644%
			(Sum Lines 1 to 11 , Col. (h))		28.3562%

SI-SSA-0010-4075

	(a)	(b)	(c)
Allocators			
	Real Power Capability (MW)		
		1,248.00	
		1,205.00	
		-	
	Total	2,453.00	(Sum Lines 31 to 33)
	Nominal Power Factor (pf)		
		0.93	
		0.90	
		-	
	Total	0.92	(Line 38 / 58)
	MVA Capability (MVA)		
		1,347.73	(Line 31 / 41)
		1,333.01	(Line 32 / 42)
		-	
	Total	2,680.75	(Sum Lines 51 to 53)
	Reactive Power Capability (MVAR)		
	(MVA^2 - MW^2)^0.5		
		508.80	(SQRT (Line 51^2 - Line 31^2))
		570.00	(SQRT (Line 52^2 - Line 32^2))
		-	
	Total	1,078.80	(Sum Lines 62 to 64)
	Reactive Allocator	16.2%	(Line 69^2 / Line 58^2)
		ComEd is TO Fleet	
	Max. MVAr	2,187	
	Nameplate MVAr	4,856	
	Exciter MW	35	
	Generator MW	11,447	
	Balance of Plant Allocator	0.1358%	(Line 75 / Line 76) * (Line 77 / Line 78)

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ 1,036,178	15%	$ 155,427
	Control&Power Cabling	$ 185,037,012	1%	$ 1,850,370
	Switch Board Equipment	$ 65,474,820	1%	$ 654,748
	Switching Equipment	$ 14,828,319	1%	$ 148,283
	Transformers	$ 1,267,080	3%	$ 38,012
	Aux Generator	$ 30,867,315	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ 48,068	50%	$ 24,034
	Structure	$ -	0%	$ -
	Misc	$ 18,414,787	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	1%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 316,973,581		$ 2,870,875

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	34,368,626	34,368,626	
	Coolants and Water (Nuclear Plants Only)	3,367,547		
	Steam Expenses	21,122,811	21,122,811	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	2,157,976		
	Rents	59,666,223	59,666,223	
	Allowances	4,734,652	4,734,652	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	6,340,415	6,340,415	
	Maintenance of Boiler (or reactor) Plant	494,186		
	Maintenance of Electric Plant	16,338,339		
	Maintenance of Misc Steam (or Nuclear) Plant	10,494,787	10,494,787	
	Other Power Production, & Other Expenses	19,633,712	19,633,712	
	Total NonFuel Expenses	178,719,274	156,361,227	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation				
	Plant Var Allocators			
	Electric Expense Allocator	2.4292%	Line 4(c) / 1(c))	
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)	
	Other Demand Expense Allocator	0.1358%	Line 79	
	Production Plant Expenses			
	Total NonFuel Expenses	178,719,274	Line 116	
	Allowances	4,734,652	Line 109	
	Non-Fuel Production O&M	173,984,622	(Line 126 - 127)	
	Operating Expenses			
	Operations Supervision & Engineering	34,368,626	Line 102(c)	
	Electric Expenses	0	Line 106(c)	
	Maintenance of Electric Plant	0	Line 113(b)	
	Other Demand Related Expenses	121,992,601	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)	
	Total	156,361,227	(Sum Lines 131 to 134)	

				Allocator	Allocated Amount	
	Maintenance of Electric Plant	16,338,339	Line 114(b)			
	Electric Expenses	0	Line 107(c)			
	Total Electric Expenses	16,338,339	(Line 138 + 139)	2.4292%	396,890	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	121,992,601	(Line 134)	0.1358%	165,722	
				Line 123		
	Balance of Plant Fixed Expenses				155,798,614	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		119,205,155	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		11,622,872	(allocated on plant labor)	
	Total		130,828,027		
Depreciation					
	Annual Depreciation Exp ...DE	23,586,732			
	Gross Production Plant Cost ... F	1,391,617,170	Line 14		
	SLDP=DE/F	1.6949%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	59			
	SFDP=(R/((1+R)^n-1)		0.0814%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.976%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		33,153,706		
	Payroll Taxes	7,259,232			
		0 87.4899%	Line 117		
	Fixed Payroll Taxes		6,351,091	(Line 193 * 194)	
	Total Other Taxes		39,504,797	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9758%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	2,333,171				
		100.000%				
	Production Related Prepayments	2,333,171	(Line 209 * 210)			
	Unit Specific M&S	259,714,161				
	Total	262,047,333	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9758%				
	Working Capital Costs	29,115,524	(Line 213 * 214)			

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Accumulated Deferred Income Taxes

Investment	1,391,617,170	Line 14
Asset Service Life	59	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 248,026,706

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	23,586,732	3.750%	52,185,644	11,061,773	11,061,773	650,985	248,890	399,191	1,299,066	20,378,888
2	23,586,732	7.219%	100,460,843	29,734,138	40,795,911	2,400,839	917,908	1,472,219	4,790,966	20,378,888
3	23,586,732	6.677%	92,918,278	26,816,749	67,612,660	3,979,005	1,521,285	2,439,966	7,940,256	20,378,888
4	23,586,732	6.177%	85,960,193	24,125,431	91,738,091	5,398,787	2,064,107	3,310,590	10,773,484	20,378,888
5	23,586,732	5.713%	79,503,089	21,627,888	113,365,979	6,671,588	2,550,735	4,091,084	13,313,407	20,378,888
6	23,586,732	5.285%	73,546,967	19,324,120	132,690,098	7,808,812	2,985,527	4,788,442	15,582,781	20,378,888
7	23,586,732	4.888%	68,022,247	17,187,213	149,877,311	8,820,280	3,372,240	5,408,684	17,601,203	20,378,888
8	23,586,732	4.522%	62,928,928	15,217,168	165,094,480	9,715,810	3,714,626	5,957,832	19,388,268	20,378,888
9	23,586,732	4.462%	62,093,958	14,894,210	179,988,690	10,592,334	4,049,746	6,495,325	21,137,405	20,378,888
10	23,586,732	4.461%	62,080,042	14,888,827	194,877,517	11,468,542	4,384,744	7,032,625	22,885,911	20,378,888
11	23,586,732	4.462%	62,093,958	14,894,210	209,771,727	12,345,066	4,719,864	7,570,118	24,635,048	20,378,888
12	23,586,732	4.461%	62,080,042	14,888,827	224,660,555	13,221,274	5,054,862	8,107,417	26,383,553	20,378,888
13	23,586,732	4.462%	62,093,958	14,894,210	239,554,765	14,097,798	5,389,982	8,644,911	28,132,691	20,378,888
14	23,586,732	4.461%	62,080,042	14,888,827	254,443,592	14,974,005	5,724,981	9,182,210	29,881,196	20,378,888
15	23,586,732	4.462%	62,093,958	14,894,210	269,337,802	15,850,530	6,060,101	9,719,703	31,630,334	20,378,888
16	23,586,732	4.461%	62,080,042	14,888,827	284,226,630	16,726,737	6,395,099	10,257,003	33,378,839	20,378,888
17	23,586,732	4.462%	62,093,958	14,894,210	299,120,840	17,603,261	6,730,219	10,794,496	35,127,976	20,378,888
18	23,586,732	4.461%	62,080,042	14,888,827	314,009,667	18,479,469	7,065,218	11,331,795	36,876,482	20,378,888
19	23,586,732	4.462%	62,093,958	14,894,210	328,903,878	19,355,993	7,400,337	11,869,289	38,625,619	20,378,888
20	23,586,732	4.461%	62,080,042	14,888,827	343,792,705	20,232,201	7,735,336	12,406,588	40,374,124	20,378,888
21	23,586,732	2.231%	31,046,979	2,885,549	346,678,254	20,402,015	7,800,261	12,510,720	40,712,996	20,378,888
22	23,586,732	0.000%	0	-9,123,112	337,555,142	19,865,120	7,594,991	12,181,490	39,641,601	20,378,888
23	23,586,732	0.000%	0	-9,123,112	328,432,030	19,328,225	7,389,721	11,852,261	38,570,207	20,378,888
24	23,586,732	0.000%	0	-9,123,112	319,308,918	18,791,330	7,184,451	11,523,031	37,498,812	20,378,888
25	23,586,732	0.000%	0	-9,123,112	310,185,806	18,254,435	6,979,181	11,193,802	36,427,417	20,378,888
26	23,586,732	0.000%	0	-9,123,112	301,062,694	17,717,540	6,773,911	10,864,572	35,356,023	20,378,888
27	23,586,732	0.000%	0	-9,123,112	291,939,582	17,180,644	6,568,641	10,535,343	34,284,628	20,378,888
28	23,586,732	0.000%	0	-9,123,112	282,816,470	16,643,749	6,363,371	10,206,114	33,213,233	20,378,888
29	23,586,732	0.000%	0	-9,123,112	273,693,359	16,106,854	6,158,101	9,876,884	32,141,839	20,378,888
30	23,586,732	0.000%	0	-9,123,112	264,570,247	15,569,959	5,952,831	9,547,655	31,070,444	20,378,888
31	23,586,732	0.000%	0	-9,123,112	255,447,135	15,033,064	5,747,561	9,218,425	29,999,050	20,378,888
32	23,586,732	0.000%	0	-9,123,112	246,324,023	14,496,169	5,542,291	8,889,196	28,927,655	20,378,888
33	23,586,732	0.000%	0	-9,123,112	237,200,911	13,959,274	5,337,020	8,559,966	27,856,260	20,378,888
34	23,586,732	0.000%	0	-9,123,112	228,077,799	13,422,378	5,131,750	8,230,737	26,784,866	20,378,888
35	23,586,732	0.000%	0	-9,123,112	218,954,687	12,885,483	4,926,480	7,901,507	25,713,471	20,378,888
36	23,586,732	0.000%	0	-9,123,112	209,831,575	12,348,588	4,721,210	7,572,278	24,642,076	20,378,888
37	23,586,732	0.000%	0	-9,123,112	200,708,463	11,811,693	4,515,940	7,243,048	23,570,682	20,378,888
38	23,586,732	0.000%	0	-9,123,112	191,585,351	11,274,798	4,310,670	6,913,819	22,499,287	20,378,888
39	23,586,732	0.000%	0	-9,123,112	182,462,239	10,737,903	4,105,400	6,584,589	21,427,893	20,378,888
40	23,586,732	0.000%	0	-9,123,112	173,339,127	10,201,008	3,900,130	6,255,360	20,356,498	20,378,888
41	23,586,732	0.000%	0	-9,123,112	164,216,015	9,664,112	3,694,860	5,926,130	19,285,103	20,378,888
42	23,586,732	0.000%	0	-9,123,112	155,092,903	9,127,217	3,489,590	5,596,901	18,213,709	20,378,888
43	23,586,732	0.000%	0	-9,123,112	145,969,791	8,590,322	3,284,320	5,267,671	17,142,314	20,378,888
44	23,586,732	0.000%	0	-9,123,112	136,846,679	8,053,427	3,079,050	4,938,442	16,070,919	20,378,888
45	23,586,732	0.000%	0	-9,123,112	127,723,567	7,516,532	2,873,780	4,609,213	14,999,525	20,378,888
46	23,586,732	0.000%	0	-9,123,112	118,600,455	6,979,637	2,668,510	4,279,983	13,928,130	20,378,888
47	23,586,732	0.000%	0	-9,123,112	109,477,343	6,442,742	2,463,240	3,950,754	12,856,736	20,378,888
48	23,586,732	0.000%	0	-9,123,112	100,354,231	5,905,847	2,257,970	3,621,524	11,785,341	20,378,888
49	23,586,732	0.000%	0	-9,123,112	91,231,120	5,368,951	2,052,700	3,292,295	10,713,946	20,378,888
50	23,586,732	0.000%	0	-9,123,112	82,108,008	4,832,056	1,847,430	2,963,065	9,642,552	20,378,888
51	23,586,732	0.000%	0	-9,123,112	72,984,896	4,295,161	1,642,160	2,633,836	8,571,157	20,378,888
52	23,586,732	0.000%	0	-9,123,112	63,861,784	3,758,266	1,436,890	2,304,606	7,499,762	20,378,888
53	23,586,732	0.000%	0	-9,123,112	54,738,672	3,221,371	1,231,620	1,975,377	6,428,368	20,378,888
54	23,586,732	0.000%	0	-9,123,112	45,615,560	2,684,476	1,026,350	1,646,147	5,356,973	20,378,888
55	23,586,732	0.000%	0	-9,123,112	36,492,448	2,147,581	821,080	1,316,918	4,285,579	20,378,888
56	23,586,732	0.000%	0	-9,123,112	27,369,336	1,610,685	615,810	987,688	3,214,184	20,378,888
57	23,586,732	0.000%	0	-9,123,112	18,246,224	1,073,790	410,540	658,459	2,142,789	20,378,888
58	23,586,732	0.000%	0	-9,123,112	9,123,112	536,895	205,270	329,229	1,071,395	20,378,888
59	23,586,732	0.000%	0	-9,123,112	0	0	0	0	0	20,378,888

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Unit Name: Chester 7-9 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 4,695,512	
2	Investment Generator & Exciter	Inputs Tab	704,327	
3	Reactive Allocator	(Line 71)	35.06%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**246,936**	
5				
6	GSU Transformer Investment	Inputs Tab	-	
7	Reactive Allocator	(Line 71)	35.06%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	502,862	
11	Reactive Allocator	(Line 71)	35.06%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**176,303**	
13				
14	Total Cost of Power Plant	Inputs Tab	9,133,168	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	7,925,979	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	4,294	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	427,533	
19	Reactive Fixed Charge Rate	(Line 14(h))	10.2612%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**43,870**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 43,870**	
23				
24				
25				
26				

(e)		(f)	(g)	(h)
Fixed Charge Rate for Reactive Plant				
		Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 140	352		
Other Expenses		52		
O&M	(sum line 1 & 2)	403	427,533	0.0944%
A&G		28,041	9,133,168	0.3070%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0056%
Working Capital	Line 216	10,340	9,133,168	0.1132%
General Plant		-	9,133,168	0.0000%
Other Taxes	Line 196(c)	5,780	9,133,168	0.0633%
Depreciation	Line 168(c)			0.0549%
				8.1350%
Taxes (Federal/State/Local)	Line 180			3.0241%
ADIT	-Line 233(k)	($140,315)	9,133,168	-1.5363%
		(Sum Lines 1 to 11 , Col. (h))		10.2612%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		15.14						
		15.16						
		14.48						
	Total	44.78	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.81						
		0.81						
		0.80						
	Total	0.81	(Line 38 / 58)					
	MVA Capability (MVA)							
		18.65	(Line 31 / 41)					
		18.72	(Line 32 / 42)					
		18.21	(Line 33 / 43)					
	Total	55.58	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		10.88	(SQRT (Line 51^2 - Line 31^2))					
		10.98	(SQRT (Line 52^2 - Line 32^2))					
		11.05	(SQRT (Line 53^2 - Line 33^2))					
	Total	32.91	(Sum Lines 62 to 64)					
	Reactive Allocator	35.1%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ 12,262	50%	$ 6,131
	Control&Power Cabling	$ 360,640	50%	$ 180,320
	Switch Board Equipment	$ -	50%	$ -
	Switching Equipment	$ 791,028	40%	$ 316,411
	Transformers	$ -	10%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ -	0%	$ -
	Misc	$ 560,700	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 1,724,631		$ 502,862

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	38,422	38,422	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	9,925	9,925	
	Steam From Other Sources	19,178		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	5,876		
	Rents	35,759	35,759	
	Allowances	1,445	1,445	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	14,987	14,987	
	Maintenance of Boiler (or reactor) Plant	6,427		
	Maintenance of Electric Plant	6,686		
	Maintenance of Misc Steam (or Nuclear) Plant	8,322	8,322	
	Other Power Production, & Other Expenses	25,242	25,242	
	Total NonFuel Expenses	172,268	134,102	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	5.2590%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	172,268	Line 116			
	Allowances	1,445	Line 109			
	Non-Fuel Production O&M	170,823	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	38,422	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	6,686	Line 113(b)			
	Other Demand Related Expenses	95,679	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	140,788	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	6,686	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	6,686	(Line 138 + 139)	5.2590%	352	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	95,679	(Line 134)	0.0542%	52	
				Line 123		
	Balance of Plant Fixed Expenses				140,384	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		8,214	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		19,827	(allocated on plant labor)	
	Total		28,041		
Depreciation					
	Annual Depreciation Exp ...DE	142,706			
	Gross Production Plant Cost ... F	9,133,168	Line 14		
	SLDP=DE/F	1.5625%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	64			
	SFDP=(R/((1+R)^n-1)		0.0549%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.024%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		5,780	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		5,780	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	3.0241%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
	Prepayments	68,701	
		100.000%	
	Production Related Prepayments	68,701	(Line 209 * 210)
	Unit Specific M&S	23,962	
	Total	92,663	(Line 211 + 212)
	Return on Working Capital	8.1350%	
	Taxes on Working Capital	3.0241%	
	Working Capital Costs	10,340	(Line 213 * 214)

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(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)

Accumulated Deferred Income Taxes

Investment		9,133,168	Line 14					NPV of Col (j)>	1,713,273	
Asset Service Life		64	Line 167							
Composite Tax Rate		38.6790%	Line 177							

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity = (f) *	Interest	Income Taxes = (g) *	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	= (f) * (Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	142,706	3.750%	342,494	77,276	77,276	4,548	1,739	2,789	9,075	140,315
2	142,706	7.219%	659,323	199,823	277,099	16,307	6,235	10,000	32,542	140,315
3	142,706	6.677%	609,822	180,676	457,774	26,940	10,300	16,520	53,760	140,315
4	142,706	6.177%	564,156	163,013	620,787	36,533	13,968	22,403	72,904	140,315
5	142,706	5.713%	521,778	146,621	767,408	45,162	17,267	27,694	90,122	140,315
6	142,706	5.285%	482,688	131,502	898,910	52,901	20,225	32,439	105,566	140,315
7	142,706	4.888%	446,429	117,477	1,016,387	59,814	22,869	36,679	119,362	140,315
8	142,706	4.522%	413,002	104,548	1,120,935	65,967	25,221	40,452	131,640	140,315
9	142,706	4.462%	407,522	102,428	1,223,363	71,995	27,526	44,148	143,669	140,315
10	142,706	4.461%	407,431	102,393	1,325,756	78,021	29,830	47,843	155,693	140,315
11	142,706	4.462%	407,522	102,428	1,428,185	84,049	32,134	51,539	167,722	140,315
12	142,706	4.461%	407,431	102,393	1,530,577	90,074	34,438	55,235	179,747	140,315
13	142,706	4.462%	407,522	102,428	1,633,006	96,102	36,743	58,931	191,776	140,315
14	142,706	4.461%	407,431	102,393	1,735,399	102,128	39,046	62,626	203,801	140,315
15	142,706	4.462%	407,522	102,428	1,837,827	108,156	41,351	66,322	215,830	140,315
16	142,706	4.461%	407,431	102,393	1,940,220	114,182	43,655	70,018	227,854	140,315
17	142,706	4.462%	407,522	102,428	2,042,648	120,210	45,960	73,714	239,883	140,315
18	142,706	4.461%	407,431	102,393	2,145,041	126,236	48,263	77,409	251,908	140,315
19	142,706	4.462%	407,522	102,428	2,247,469	132,264	50,568	81,105	263,937	140,315
20	142,706	4.461%	407,431	102,393	2,349,862	138,289	52,872	84,800	275,962	140,315
21	142,706	2.231%	203,761	23,616	2,373,478	139,679	53,403	85,653	278,735	140,315
22	142,706	0.000%	0	-55,197	2,318,281	136,431	52,161	83,661	272,253	140,315
23	142,706	0.000%	0	-55,197	2,263,083	133,182	50,919	81,669	265,771	140,315
24	142,706	0.000%	0	-55,197	2,207,886	129,934	49,677	79,677	259,288	140,315
25	142,706	0.000%	0	-55,197	2,152,689	126,686	48,436	77,685	252,806	140,315
26	142,706	0.000%	0	-55,197	2,097,492	123,437	47,194	75,693	246,324	140,315
27	142,706	0.000%	0	-55,197	2,042,295	120,189	45,952	73,701	239,842	140,315
28	142,706	0.000%	0	-55,197	1,987,098	116,941	44,710	71,709	233,360	140,315
29	142,706	0.000%	0	-55,197	1,931,901	113,692	43,468	69,717	226,877	140,315
30	142,706	0.000%	0	-55,197	1,876,703	110,444	42,226	67,725	220,395	140,315
31	142,706	0.000%	0	-55,197	1,821,506	107,196	40,984	65,733	213,913	140,315
32	142,706	0.000%	0	-55,197	1,766,309	103,947	39,742	63,742	207,431	140,315
33	142,706	0.000%	0	-55,197	1,711,112	100,699	38,500	61,750	200,949	140,315
34	142,706	0.000%	0	-55,197	1,655,915	97,451	37,258	59,758	194,466	140,315
35	142,706	0.000%	0	-55,197	1,600,718	94,202	36,016	57,766	187,984	140,315
36	142,706	0.000%	0	-55,197	1,545,520	90,954	34,774	55,774	181,502	140,315
37	142,706	0.000%	0	-55,197	1,490,323	87,706	33,532	53,782	175,020	140,315
38	142,706	0.000%	0	-55,197	1,435,126	84,457	32,290	51,790	168,537	140,315
39	142,706	0.000%	0	-55,197	1,379,929	81,209	31,048	49,798	162,055	140,315
40	142,706	0.000%	0	-55,197	1,324,732	77,960	29,806	47,806	155,573	140,315
41	142,706	0.000%	0	-55,197	1,269,535	74,712	28,565	45,814	149,091	140,315
42	142,706	0.000%	0	-55,197	1,214,337	71,464	27,323	43,822	142,609	140,315
43	142,706	0.000%	0	-55,197	1,159,140	68,215	26,081	41,830	136,126	140,315
44	142,706	0.000%	0	-55,197	1,103,943	64,967	24,839	39,838	129,644	140,315
45	142,706	0.000%	0	-55,197	1,048,746	61,719	23,597	37,847	123,162	140,315
46	142,706	0.000%	0	-55,197	993,549	58,470	22,355	35,855	116,680	140,315
47	142,706	0.000%	0	-55,197	938,352	55,222	21,113	33,863	110,198	140,315
48	142,706	0.000%	0	-55,197	883,155	51,974	19,871	31,871	103,715	140,315
49	142,706	0.000%	0	-55,197	827,957	48,725	18,629	29,879	97,233	140,315
50	142,706	0.000%	0	-55,197	772,760	45,477	17,387	27,887	90,751	140,315
51	142,706	0.000%	0	-55,197	717,563	42,229	16,145	25,895	84,269	140,315
52	142,706	0.000%	0	-55,197	662,366	38,980	14,903	23,903	77,787	140,315
53	142,706	0.000%	0	-55,197	607,169	35,732	13,661	21,911	71,304	140,315
54	142,706	0.000%	0	-55,197	551,972	32,484	12,419	19,919	64,822	140,315
55	142,706	0.000%	0	-55,197	496,774	29,235	11,177	17,927	58,340	140,315
56	142,706	0.000%	0	-55,197	441,577	25,987	9,935	15,935	51,858	140,315
57	142,706	0.000%	0	-55,197	386,380	22,738	8,694	13,943	45,375	140,315
58	142,706	0.000%	0	-55,197	331,183	19,490	7,452	11,952	38,893	140,315
59	142,706	0.000%	0	-55,197	275,986	16,242	6,210	9,960	32,411	140,315
60	142,706	0.000%	0	-55,197	220,789	12,993	4,968	7,968	25,929	140,315
61	142,706	0.000%	0	-55,197	165,591	9,745	3,726	5,976	19,447	140,315
62	142,706	0.000%	0	-55,197	110,394	6,497	2,484	3,984	12,964	140,315
63	142,706	0.000%	0	-55,197	55,197	3,248	1,242	1,992	6,482	140,315
64	142,706	0.000%	0	-55,197	0	0	0	0	0	140,315

Unit Name: Conowingo 1 - 11 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 143,524,274	
2	Investment Generator & Exciter	Inputs Tab	$ 21,528,641	
3	Reactive Allocator	(Line 87)	6.00%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**1,291,445**	
5				
6	GSU Transformer Investment	Inputs Tab	6,792,649	
7	Reactive Allocator	(Line 87)	6.00%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**407,473**	
9				
10	Allocated Acc Elec Equipment	(Line 115 , Column d)	2,248,765	
11	Reactive Allocator	(Line 87)	6.00%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**134,897**	
13				
14	Total Cost of Power Plant	Inputs Tab	380,084,794	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	349,514,738	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	189,366	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	2,023,182	
19	Reactive Fixed Charge Rate	(Line 14(h))	12.3531%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**249,927**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 249,927**	
23				
24				
25				
26				

	(e)		(f)	(g)	(h)
			Fixed Charge Rate for Reactive Plant		
			Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 156		31,568		
Other Expenses			1,249		
O&M	(sum line 1 & 2)		32,817	2,023,182	1.6221%
A&G			3,906,810	380,084,794	1.0279%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)				0.0379%
Working Capital	Line 222		582,080	380,084,794	0.1531%
General Plant			-	380,084,794	0.0000%
Other Taxes	Line 202(c)		-	380,084,794	0.0000%
Depreciation	Line 174(c)				0.0009%
					8.1350%
Taxes (Federal/State/Local)	Line 186				3.3191%
ADIT	-Line 239(k)		($7,384,692)	380,084,794	-1.9429%
			(Sum Lines 1 to 11 , Col. (h))		12.3531%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		40.20						
		48.00						
		42.20						
		48.00						
		37.10						
		44.60						
		44.10						
		110.90						
		108.40						
		114.50						
		112.20						
	Total	750.20	(Sum Lines 31 to 41)					
	Nominal Power Factor (pf)							
		0.88						
		0.90						
		0.89						
		0.90						
		0.95						
		0.88						
		0.88						
		1.00						
		0.99						
		0.99						
		0.99						
	Total	0.95	(Line 42 / 55)					
	MVA Capability (MVA)							
		45.89	(Line 31 / 45)					
		53.33	(Line 32 / 46)					
		47.52	(Line 33 / 47)					
		53.33	(Line 33 / 47)					
		39.05	(Line 33 / 47)					
		50.68	(Line 33 / 47)					
		50.11	(Line 33 / 47)					
		111.46	(Line 33 / 47)					
		109.27	(Line 33 / 47)					
		115.89	(Line 33 / 47)					
		112.99	(Line 33 / 47)					
	Total	789.54	(Sum Lines 59 to 69)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		22.13	(SQRT (Line 59^2 - Line 31^2))					
		23.25	(SQRT (Line 60^2 - Line 32^2))					
		21.85	(SQRT (Line 61^2 - Line 33^2))					
		23.25	(SQRT (Line 62^2 - Line 34^2))					
		12.19	(SQRT (Line 63^2 - Line 35^2))					
		24.07	(SQRT (Line 64^2 - Line 36^2))					
		23.80	(SQRT (Line 65^2 - Line 37^2))					
		11.13	(SQRT (Line 66^2 - Line 38^2))					
		13.79	(SQRT (Line 67^2 - Line 39^2))					
		17.90	(SQRT (Line 68^2 - Line 40^2))					
		13.35	(SQRT (Line 69^2 - Line 41^2))					
	Total	193.38	(Sum Lines 74 to 84)					
	Reactive Allocator	6.0%	(Line 85^2 / Line 70^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 91 / Line 92) * (Line 93 / Line 94)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Hydro & Steam**	**Allocated Amt**
	Storage Batteries	$ 136,064	30%	$ 40,819
	Control&Power Cabling	$ 3,179,427	15%	$ 476,914
	Switch Board Equipment	$ 1,973,492	30%	$ 592,048
	Switching Equipment	$ 2,017,595	20%	$ 403,519
	Transformers	$ 6,318,929	5%	$ 315,946
	Aux Generator	$ 101,173	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ 390,726	75%	$ 293,044
	Structure	$ 270,434	0%	$ -
	Misc	$ 15,212,502	0%	$ -
	Exciter & PPT	$ 126,475	100%	$ 126,475
	Station Grounding	$ -	0%	$ -
	Bus & Insulators	$ -	60%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 29,726,815		$ 2,248,765

O&M		**Total Non-Fuel**	**Fixed O&M**	
	(535) Operation Supervision and Engineering	1,036,292	1,036,292	
		0		
	(536) Water for Power	855,810	855,810	
	(537) Hydraulic Expenses	5,098,303		
	(538) Electric Expenses	1,685,208	1,685,208	
	(539) Miscellaneous Hydraulic Power Generation Ex	1,684,113		
	(540) Rents	243,307	243,307	
		0	-	
	(541) Mainentance Supervision and Engineering	575,100		
	(542) Maintenance of Structures	691,360	691,360	
	(543) Maintenance of Reservoirs, Dams, and Waterv	2,545,004		
	(544) Maintenance of Electric Plant	1,823,125		
	(545) Maintenance of Miscellaneous Hydraulic Plant	514,507	514,507	
			-	
	Total NonFuel Expenses	16,752,129	5,026,484	(Sum Lines 118 to 131)
	Percentage Fixed O&M Excluding Allowances		31.07%	(Line 132(c) / (Line 132(b) - Line 126(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	0.8998%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.4029%	(Col. (c) Line 139 * Line 148 + Line 137 * Line 148 / (Line148 + 150)			
	Other Demand Expense Allocator	0.0542%	Line 95			
	Production Plant Expenses					
	Total NonFuel Expenses	16,752,129	Line 132			
	Allowances	0	Line 125			
	Non-Fuel Production O&M	16,752,129	(Line 142 - 143)			
	Operating Expenses					
	Operations Supervision & Engineering	1,036,292	Line 118(c)			
	Electric Expenses	1,685,208	Line 122(c)			
	Maintenance of Electric Plant	1,823,125	Line 129(b)			
	Other Demand Related Expenses	2,304,983	Col. (c) Line 132 - Col (b) Line 148 - Col. (b) Line 147)			
	Total	6,849,608	(Sum Lines 147 to 150)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	1,823,125	Line 129(b)			
	Electric Expenses	1,685,208	Line 122(c)			
	Total Electric Expenses	3,508,333	(Line 154 + 155)	0.8998%	31,568	(Line 156(b) * (d))
				Line 137		
	Other Demand Related Expenses	2,304,983	(Line 150)	0.0542%	1,249	
				Line 139		
	Balance of Plant Fixed Expenses				6,816,791	(Line 151(b) - Line 156(e) - Line 158(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		2,067,560	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		1,839,251	(allocated on plant labor)	
	Total		3,906,810		
Depreciation					
	Annual Depreciation Exp ...DE	3,276,593			
	Gross Production Plant Cost ... F	380,084,794	Line 14		
	SLDP=DE/F	0.8621%	(Line 170 / 171)		
	Depreciable years (n)=1/SLDP	116			
	SFDP=(R/((1+R)^n-1)		0.0009%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.319%		

Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 191 to 193)

Other Taxes				
	Property Taxes		0	<Includes Payroll
	Payroll Taxes	-		
		31.0717%	Line 133	
	Fixed Payroll Taxes		-	(Line 199 * 200)
	Total Other Taxes		-	(Line 198 + 201)

		Plant		**Depreciation**	**Total**	
General Plant		-		-		
		0.000%		0.000%		
	Fixed General Plant	-		-		(Lines 206 *207)
	Return on General Plant	8.1350%	Line 194			
	Taxes on General Plant	3.3191%	Line 195			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 208 * 209)	-	-	

Working Capital			
	Prepayments	2,859,063	
		100.000%	
	Production Related Prepayments	2,859,063	(Line 215 * 216)
	Unit Specific M&S	2,222,784	
	Total	5,081,847	(Line 217 + 218)
	Return on Working Capital	8.1350%	
	Taxes on Working Capital	3.3191%	
	Working Capital Costs	582,080	(Line 219 * 220)

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Accumulated Deferred Income Taxes

Investment	380,084,794	Line 14
Asset Service Life	116	Line 173
Composite Tax Rate	38.6790%	Line 183

NPV of Col (j)> 90,766,369

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized
	Line 230 / 231		(b) * (c)	((d) - (b)) * Line 183	Accum. (e)	= (f) * (Line192+193)	= (f) * (Line191)	= (g) * (Line184)	(g) + (h) + (i)	PMT of NPV col. (j)
1	3,276,593	3.750%	14,253,180	4,245,634	4,245,634	249,856	95,527	153,214	498,596	7,384,692
2	3,276,593	7.219%	27,438,321	9,345,515	13,591,149	799,839	305,801	490,469	1,596,109	7,384,692
3	3,276,593	6.677%	25,378,262	8,548,704	22,139,853	1,302,930	498,147	798,970	2,600,047	7,384,692
4	3,276,593	6.177%	23,477,838	7,813,639	29,953,493	1,762,763	673,954	1,080,944	3,517,661	7,384,692
5	3,276,593	5.713%	21,714,244	7,131,499	37,084,992	2,182,452	834,412	1,338,301	4,355,165	7,384,692
6	3,276,593	5.285%	20,087,481	6,502,283	43,587,275	2,565,111	980,714	1,572,952	5,118,777	7,384,692
7	3,276,593	4.888%	18,578,545	5,918,642	49,505,917	2,913,423	1,113,883	1,786,540	5,813,847	7,384,692
8	3,276,593	4.522%	17,187,434	5,380,574	54,886,491	3,230,070	1,234,946	1,980,711	6,445,727	7,384,692
9	3,276,593	4.462%	16,959,383	5,292,367	60,178,858	3,541,526	1,354,024	2,171,699	7,067,249	7,384,692
10	3,276,593	4.461%	16,955,583	5,290,896	65,469,754	3,852,895	1,473,069	2,362,634	7,688,598	7,384,692
11	3,276,593	4.462%	16,959,383	5,292,367	70,762,121	4,164,351	1,592,148	2,553,622	8,310,120	7,384,692
12	3,276,593	4.461%	16,955,583	5,290,896	76,053,017	4,475,720	1,711,193	2,744,556	8,931,469	7,384,692
13	3,276,593	4.462%	16,959,383	5,292,367	81,345,384	4,787,176	1,830,271	2,935,544	9,552,991	7,384,692
14	3,276,593	4.461%	16,955,583	5,290,896	86,636,280	5,098,545	1,949,316	3,126,479	10,174,340	7,384,692
15	3,276,593	4.462%	16,959,383	5,292,367	91,928,647	5,410,001	2,068,395	3,317,467	10,795,862	7,384,692
16	3,276,593	4.461%	16,955,583	5,290,896	97,219,543	5,721,370	2,187,440	3,508,401	11,417,211	7,384,692
17	3,276,593	4.462%	16,959,383	5,292,367	102,511,910	6,032,826	2,306,518	3,699,389	12,038,733	7,384,692
18	3,276,593	4.461%	16,955,583	5,290,896	107,802,806	6,344,195	2,425,563	3,890,324	12,660,082	7,384,692
19	3,276,593	4.462%	16,959,383	5,292,367	113,095,172	6,655,651	2,544,641	4,081,312	13,281,604	7,384,692
20	3,276,593	4.461%	16,955,583	5,290,896	118,386,069	6,967,020	2,663,687	4,272,246	13,902,953	7,384,692
21	3,276,593	2.231%	8,479,692	2,012,507	120,398,575	7,085,456	2,708,968	4,344,873	14,139,297	7,384,692
22	3,276,593	0.000%	0	-1,267,353	119,131,222	7,010,872	2,680,452	4,299,137	13,990,462	7,384,692
23	3,276,593	0.000%	0	-1,267,353	117,863,869	6,936,289	2,651,937	4,253,402	13,841,627	7,384,692
24	3,276,593	0.000%	0	-1,267,353	116,596,515	6,861,705	2,623,422	4,207,666	13,692,793	7,384,692
25	3,276,593	0.000%	0	-1,267,353	115,329,162	6,787,121	2,594,906	4,161,931	13,543,958	7,384,692
26	3,276,593	0.000%	0	-1,267,353	114,061,808	6,712,537	2,566,391	4,116,195	13,395,123	7,384,692
27	3,276,593	0.000%	0	-1,267,353	112,794,455	6,637,954	2,537,875	4,070,460	13,246,288	7,384,692
28	3,276,593	0.000%	0	-1,267,353	111,527,101	6,563,370	2,509,360	4,024,724	13,097,454	7,384,692
29	3,276,593	0.000%	0	-1,267,353	110,259,748	6,488,786	2,480,844	3,978,989	12,948,619	7,384,692
30	3,276,593	0.000%	0	-1,267,353	108,992,395	6,414,202	2,452,329	3,933,253	12,799,784	7,384,692
31	3,276,593	0.000%	0	-1,267,353	107,725,041	6,339,619	2,423,813	3,887,518	12,650,950	7,384,692
32	3,276,593	0.000%	0	-1,267,353	106,457,688	6,265,035	2,395,298	3,841,782	12,502,115	7,384,692
33	3,276,593	0.000%	0	-1,267,353	105,190,334	6,190,451	2,366,783	3,796,047	12,353,280	7,384,692
34	3,276,593	0.000%	0	-1,267,353	103,922,981	6,115,867	2,338,267	3,750,311	12,204,446	7,384,692
35	3,276,593	0.000%	0	-1,267,353	102,655,627	6,041,284	2,309,752	3,704,576	12,055,611	7,384,692
36	3,276,593	0.000%	0	-1,267,353	101,388,274	5,966,700	2,281,236	3,658,840	11,906,776	7,384,692
37	3,276,593	0.000%	0	-1,267,353	100,120,921	5,892,116	2,252,721	3,613,105	11,757,941	7,384,692
38	3,276,593	0.000%	0	-1,267,353	98,853,567	5,817,532	2,224,205	3,567,369	11,609,107	7,384,692
39	3,276,593	0.000%	0	-1,267,353	97,586,214	5,742,949	2,195,690	3,521,634	11,460,272	7,384,692
40	3,276,593	0.000%	0	-1,267,353	96,318,860	5,668,365	2,167,174	3,475,898	11,311,437	7,384,692
41	3,276,593	0.000%	0	-1,267,353	95,051,507	5,593,781	2,138,659	3,430,163	11,162,603	7,384,692
42	3,276,593	0.000%	0	-1,267,353	93,784,153	5,519,197	2,110,143	3,384,427	11,013,768	7,384,692
43	3,276,593	0.000%	0	-1,267,353	92,516,800	5,444,614	2,081,628	3,338,692	10,864,933	7,384,692
44	3,276,593	0.000%	0	-1,267,353	91,249,447	5,370,030	2,053,113	3,292,956	10,716,099	7,384,692
45	3,276,593	0.000%	0	-1,267,353	89,982,093	5,295,446	2,024,597	3,247,221	10,567,264	7,384,692
46	3,276,593	0.000%	0	-1,267,353	88,714,740	5,220,862	1,996,082	3,201,485	10,418,429	7,384,692
47	3,276,593	0.000%	0	-1,267,353	87,447,386	5,146,279	1,967,566	3,155,750	10,269,594	7,384,692
48	3,276,593	0.000%	0	-1,267,353	86,180,033	5,071,695	1,939,051	3,110,014	10,120,760	7,384,692
49	3,276,593	0.000%	0	-1,267,353	84,912,680	4,997,111	1,910,535	3,064,279	9,971,925	7,384,692
50	3,276,593	0.000%	0	-1,267,353	83,645,326	4,922,527	1,882,020	3,018,543	9,823,090	7,384,692
51	3,276,593	0.000%	0	-1,267,353	82,377,973	4,847,944	1,853,504	2,972,808	9,674,256	7,384,692
52	3,276,593	0.000%	0	-1,267,353	81,110,619	4,773,360	1,824,989	2,927,072	9,525,421	7,384,692
53	3,276,593	0.000%	0	-1,267,353	79,843,266	4,698,776	1,796,473	2,881,337	9,376,586	7,384,692
54	3,276,593	0.000%	0	-1,267,353	78,575,912	4,624,192	1,767,958	2,835,601	9,227,752	7,384,692
55	3,276,593	0.000%	0	-1,267,353	77,308,559	4,549,609	1,739,443	2,789,866	9,078,917	7,384,692

294	56	3,276,593	0.000%	0	-1,267,353	76,041,206	4,475,025	1,710,927	2,744,130	8,930,082	7,384,692
295	57	3,276,593	0.000%	0	-1,267,353	74,773,852	4,400,441	1,682,412	2,698,395	8,781,247	7,384,692
296	58	3,276,593	0.000%	0	-1,267,353	73,506,499	4,325,857	1,653,896	2,652,659	8,632,413	7,384,692
297	59	3,276,593	0.000%	0	-1,267,353	72,239,145	4,251,274	1,625,381	2,606,924	8,483,578	7,384,692
298	60	3,276,593	0.000%	0	-1,267,353	70,971,792	4,176,690	1,596,865	2,561,188	8,334,743	7,384,692
299	61	3,276,593	0.000%	0	-1,267,353	69,704,438	4,102,106	1,568,350	2,515,453	8,185,909	7,384,692
300	62	3,276,593	0.000%	0	-1,267,353	68,437,085	4,027,522	1,539,834	2,469,717	8,037,074	7,384,692
301	63	3,276,593	0.000%	0	-1,267,353	67,169,732	3,952,939	1,511,319	2,423,982	7,888,239	7,384,692
302	64	3,276,593	0.000%	0	-1,267,353	65,902,378	3,878,355	1,482,804	2,378,246	7,739,405	7,384,692
303	65	3,276,593	0.000%	0	-1,267,353	64,635,025	3,803,771	1,454,288	2,332,511	7,590,570	7,384,692
304	66	3,276,593	0.000%	0	-1,267,353	63,367,671	3,729,187	1,425,773	2,286,775	7,441,735	7,384,692
305	67	3,276,593	0.000%	0	-1,267,353	62,100,318	3,654,604	1,397,257	2,241,040	7,292,900	7,384,692
306	68	3,276,593	0.000%	0	-1,267,353	60,832,964	3,580,020	1,368,742	2,195,304	7,144,066	7,384,692
307	69	3,276,593	0.000%	0	-1,267,353	59,565,611	3,505,436	1,340,226	2,149,569	6,995,231	7,384,692
308	70	3,276,593	0.000%	0	-1,267,353	58,298,258	3,430,852	1,311,711	2,103,833	6,846,396	7,384,692
309	71	3,276,593	0.000%	0	-1,267,353	57,030,904	3,356,269	1,283,195	2,058,098	6,697,562	7,384,692
310	72	3,276,593	0.000%	0	-1,267,353	55,763,551	3,281,685	1,254,680	2,012,362	6,548,727	7,384,692
311	73	3,276,593	0.000%	0	-1,267,353	54,496,197	3,207,101	1,226,164	1,966,627	6,399,892	7,384,692
312	74	3,276,593	0.000%	0	-1,267,353	53,228,844	3,132,517	1,197,649	1,920,891	6,251,057	7,384,692
313	75	3,276,593	0.000%	0	-1,267,353	51,961,490	3,057,934	1,169,134	1,875,156	6,102,223	7,384,692
314	76	3,276,593	0.000%	0	-1,267,353	50,694,137	2,983,350	1,140,618	1,829,420	5,953,388	7,384,692
315	77	3,276,593	0.000%	0	-1,267,353	49,426,784	2,908,766	1,112,103	1,783,685	5,804,553	7,384,692
316	78	3,276,593	0.000%	0	-1,267,353	48,159,430	2,834,182	1,083,587	1,737,949	5,655,719	7,384,692
317	79	3,276,593	0.000%	0	-1,267,353	46,892,077	2,759,599	1,055,072	1,692,214	5,506,884	7,384,692
318	80	3,276,593	0.000%	0	-1,267,353	45,624,723	2,685,015	1,026,556	1,646,478	5,358,049	7,384,692
319	81	3,276,593	0.000%	0	-1,267,353	44,357,370	2,610,431	998,041	1,600,743	5,209,215	7,384,692
320	82	3,276,593	0.000%	0	-1,267,353	43,090,016	2,535,847	969,525	1,555,007	5,060,380	7,384,692
321	83	3,276,593	0.000%	0	-1,267,353	41,822,663	2,461,264	941,010	1,509,272	4,911,545	7,384,692
322	84	3,276,593	0.000%	0	-1,267,353	40,555,310	2,386,680	912,494	1,463,536	4,762,710	7,384,692
323	85	3,276,593	0.000%	0	-1,267,353	39,287,956	2,312,096	883,979	1,417,801	4,613,876	7,384,692
324	86	3,276,593	0.000%	0	-1,267,353	38,020,603	2,237,512	855,464	1,372,065	4,465,041	7,384,692
325	87	3,276,593	0.000%	0	-1,267,353	36,753,249	2,162,929	826,948	1,326,330	4,316,206	7,384,692
326	88	3,276,593	0.000%	0	-1,267,353	35,485,896	2,088,345	798,433	1,280,594	4,167,372	7,384,692
327	89	3,276,593	0.000%	0	-1,267,353	34,218,542	2,013,761	769,917	1,234,859	4,018,537	7,384,692
328	90	3,276,593	0.000%	0	-1,267,353	32,951,189	1,939,177	741,402	1,189,123	3,869,702	7,384,692
329	91	3,276,593	0.000%	0	-1,267,353	31,683,836	1,864,594	712,886	1,143,388	3,720,868	7,384,692
330	92	3,276,593	0.000%	0	-1,267,353	30,416,482	1,790,010	684,371	1,097,652	3,572,033	7,384,692
331	93	3,276,593	0.000%	0	-1,267,353	29,149,129	1,715,426	655,855	1,051,917	3,423,198	7,384,692
332	94	3,276,593	0.000%	0	-1,267,353	27,881,775	1,640,842	627,340	1,006,181	3,274,363	7,384,692
333	95	3,276,593	0.000%	0	-1,267,353	26,614,422	1,566,259	598,824	960,446	3,125,529	7,384,692
334	96	3,276,593	0.000%	0	-1,267,353	25,347,069	1,491,675	570,309	914,710	2,976,694	7,384,692
335	97	3,276,593	0.000%	0	-1,267,353	24,079,715	1,417,091	541,794	868,975	2,827,859	7,384,692
336	98	3,276,593	0.000%	0	-1,267,353	22,812,362	1,342,507	513,278	823,239	2,679,025	7,384,692
337	99	3,276,593	0.000%	0	-1,267,353	21,545,008	1,267,924	484,763	777,504	2,530,190	7,384,692
338	100	3,276,593	0.000%	0	-1,267,353	20,277,655	1,193,340	456,247	731,768	2,381,355	7,384,692
339	101	3,276,593	0.000%	0	-1,267,353	19,010,301	1,118,756	427,732	686,033	2,232,521	7,384,692
340	102	3,276,593	0.000%	0	-1,267,353	17,742,948	1,044,172	399,216	640,297	2,083,686	7,384,692
341	103	3,276,593	0.000%	0	-1,267,353	16,475,595	969,589	370,701	594,562	1,934,851	7,384,692
342	104	3,276,593	0.000%	0	-1,267,353	15,208,241	895,005	342,185	548,826	1,786,016	7,384,692
343	105	3,276,593	0.000%	0	-1,267,353	13,940,888	820,421	313,670	503,091	1,637,182	7,384,692
344	106	3,276,593	0.000%	0	-1,267,353	12,673,534	745,837	285,155	457,355	1,488,347	7,384,692
345	107	3,276,593	0.000%	0	-1,267,353	11,406,181	671,254	256,639	411,620	1,339,512	7,384,692
346	108	3,276,593	0.000%	0	-1,267,353	10,138,827	596,670	228,124	365,884	1,190,678	7,384,692
347	109	3,276,593	0.000%	0	-1,267,353	8,871,474	522,086	199,608	320,149	1,041,843	7,384,692
348	110	3,276,593	0.000%	0	-1,267,353	7,604,121	447,502	171,093	274,413	893,008	7,384,692
349	111	3,276,593	0.000%	0	-1,267,353	6,336,767	372,919	142,577	228,678	744,174	7,384,692
350	112	3,276,593	0.000%	0	-1,267,353	5,069,414	298,335	114,062	182,942	595,339	7,384,692
351	113	3,276,593	0.000%	0	-1,267,353	3,802,060	223,751	85,546	137,207	446,504	7,384,692
352	114	3,276,593	0.000%	0	-1,267,353	2,534,707	149,167	57,031	91,471	297,669	7,384,692
353	115	3,276,593	0.000%	0	-1,267,353	1,267,353	74,584	28,515	45,736	148,835	7,384,692
354	116	3,276,593	0.000%	0	-1,267,353	0	0	0	0	0	7,384,692

Unit Name: Croydon 11,12,21,22,31,32,41,42 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 72,348,001	
2	Investment Generator & Exciter	Inputs Tab	$ 10,852,200	
3	Reactive Allocator	(Line 74)	17.98%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**1,950,882**	
5				
6	GSU Transformer Investment	Inputs Tab	1,420,756	
7	Reactive Allocator	(Line 74)	17.98%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**255,407**	
9				
10	Allocated Acc Elec Equipment	(Line 102 , Column d)	1,824,495	
11	Reactive Allocator	(Line 74)	17.98%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**327,986**	
13				
14	Total Cost of Power Plant	Inputs Tab	107,412,068	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	93,314,617	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	50,558	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	2,584,833	
19	Reactive Fixed Charge Rate	(Line 14(h))	12.5522%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**324,454**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 324,454**	
23				
24				
25				
26				

	(e)		(f)	(g)	(h)
			Fixed Charge Rate for Reactive Plant		
			Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 143		2,671		
Other Expenses			768		
O&M	(sum line 1 & 2)		3,439	2,584,833	0.1330%
A&G			406,492	107,412,068	0.3784%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)				0.0071%
Working Capital	Line 219		2,389,456	107,412,068	2.2246%
General Plant			-	107,412,068	0.0000%
Other Taxes	Line 199(c)		87,293	107,412,068	0.0813%
Depreciation	Line 171(c)				0.0814%
					8.1350%
Taxes (Federal/State/Local)	Line 183				2.9758%
ADIT	-Line 236(k)		($1,572,946)	107,412,068	-1.4644%
			(Sum Lines 1 to 11 , Col. (h))		12.5522%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		51.00						
		56.60						
		68.30						
		68.30						
		68.30						
		68.30						
		-						
		-						
	Total	380.80	(Sum Lines 31 to 38)					
	Nominal Power Factor (pf)							
		0.91						
		0.93						
		0.90						
		0.90						
		0.90						
		0.90						
		-						
		-						
	Total	0.91	(Line 38 / 60)					
	MVA Capability (MVA)							
			55.92	(Line 31 / 41)				
			61.12	(Line 32 / 42)				
			75.89	(Line 33 / 43)				
			75.89	(Line 34 / 44)				
			75.89	(Line 35 / 45)				
			75.89	(Line 36 / 46)				
			-					
			-					
	Total		420.60	(Sum Lines 52 to 59)				
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
			22.94	(SQRT (Line 52^2 - Line 31^2))				
			23.08	(SQRT (Line 53^2 - Line 32^2))				
			33.08	(SQRT (Line 54^2 - Line 33^2))				
			33.08	(SQRT (Line 55^2 - Line 34^2))				
			33.08	(SQRT (Line 56^2 - Line 35^2))				
			33.08	(SQRT (Line 57^2 - Line 36^2))				
			-					
			-					
	Total		178.33	(Sum Lines 64 to 71)				
	Reactive Allocator		18.0%	(Line 72^2 / Line 60^2)				
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 78 / Line 79) * (Line 80 / Line 81)					

	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ 64,719	50%	$ 32,360
	Control&Power Cabling	$ 2,578,451	50%	$ 1,289,225
	Switch Board Equipment	$ 239,413	50%	$ 119,706
	Switching Equipment	$ 745,807	40%	$ 298,323
	Transformers	$ 247,743	10%	$ 24,774
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ 56,420	0%	$ -
	Misc	$ 5,030,779	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ 75,133	80%	$ 60,107
	Capacitor Bank	$ -	0%	$ -
	Total	$ 9,038,464		$ 1,824,495

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	569,237	569,237	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	147,038	147,038	
	Steam From Other Sources	284,134		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	87,051		
	Rents	529,786	529,786	
	Allowances	21,408	21,408	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	222,036	222,036	
	Maintenance of Boiler (or reactor) Plant	95,213		
	Maintenance of Electric Plant	99,056		
	Maintenance of Misc Steam (or Nuclear) Plant	123,289	123,289	
	Other Power Production, & Other Expenses	373,967	373,967	
	Total NonFuel Expenses	2,552,217	1,986,762	(Sum Lines 105 to 118)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 119(c) / (Line 119(b) - Line 113(b)))

O&M Calculation			
	Plant Var Allocators		
	Electric Expense Allocator	2.6965%	Line 4(c) / 1(c))
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 126 * Line 135 + Line 124 * Line 135 / (Line135 + 137)
	Other Demand Expense Allocator	0.0542%	Line 82
	Production Plant Expenses		
	Total NonFuel Expenses	2,552,217	Line 119
	Allowances	21,408	Line 112
	Non-Fuel Production O&M	2,530,809	(Line 129 - 130)
	Operating Expenses		
	Operations Supervision & Engineering	569,237	Line 105(c)
	Electric Expenses	0	Line 109(c)
	Maintenance of Electric Plant	99,056	Line 116(b)
	Other Demand Related Expenses	1,417,525	Col. (c) Line 119 - Col (b) Line 135 - Col. (b) Line 134)
	Total	2,085,818	(Sum Lines 134 to 137)

				Allocator	Allocated Amount	
	Maintenance of Electric Plant	99,056	Line 116(b)			
	Electric Expenses	0	Line 109(c)			
	Total Electric Expenses	99,056	(Line 141 + 142)	2.6965%	2,671	(Line 143(b) * (d))
				Line 124		
	Other Demand Related Expenses	1,417,525	(Line 137)	0.0542%	768	
				Line 126		
	Balance of Plant Fixed Expenses				2,082,379	(Line 138(b) - Line 143(e) - Line 145(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		127,260	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		279,232	(allocated on plant labor)	
	Total		406,492		

Depreciation				
	Annual Depreciation Exp ...DE	1,820,544		
	Gross Production Plant Cost ... F	107,412,068	Line 14	
	SLDP=DE/F	1.6949%	(Line 167 / 168)	
	Depreciable years (n)=1/SLDP	59		
	SFDP=(R/((1+R)^n-1)		0.0814%	
Income Taxes				
	Income Tax Calculation; (Co's Sch. 2)			
	a) State Income Tax Rate ("SIT")	5.6600%		
	b) City/Local Income Tax Rate ("LIT")	0.0000%		
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%		
	d) Net of Fdrl tax SIT	3.6790%		
	e) Federal Income Tax Rate ("FIT")	35.0000%		
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%		
	g) Gross-Up Tax Factor ("GTF")	61.3210%		
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.976%	

Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 188 to 190)

Other Taxes				
	Property Taxes		87,293	<Includes Payroll
	Payroll Taxes			
	0	77.8446%	Line 120	
	Fixed Payroll Taxes		-	(Line 196 * 197)
	Total Other Taxes		87,293	(Line 195 + 198)

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 162
	Fixed General Plant	-		-		(Lines 203 *204)
	Return on General Plant	8.1350%	Line 191			
	Taxes on General Plant	2.9758%	Line 192			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 205 * 206)	-	-	

Working Capital			
	Prepayments	807,972	
		100.000%	
	Production Related Prepayments	807,972	(Line 212 * 213)
	Unit Specific M&S	20,697,756	
	Total	21,505,728	(Line 214 + 215)
	Return on Working Capital	8.1350%	
	Taxes on Working Capital	2.9758%	
	Working Capital Costs	2,389,456	(Line 216 * 217)

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)

Accumulated Deferred Income Taxes

Investment	107,412,068	Line 14		NPV of Col (j)>	19,143,959
Asset Service Life	59	Line 170			
Composite Tax Rate	38.6790%	Line 180			

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity = (f) * (Line189+190)	Interest = (f) * (Line188)	Income Taxes = (g) * (Line181)	Rev Req Impact (g) + (h) + (i)	Levelized PMT of NPV col. (j)
	Line 227 / 228		(b) * (c)	((d) - (b)) * Line 180	Accum. (e)					
1	1,820,544	3.750%	4,027,953	853,804	853,804	50,246	19,211	30,812	100,268	1,572,946
2	1,820,544	7.219%	7,754,077	2,295,031	3,148,835	185,309	70,849	113,633	369,791	1,572,946
3	1,820,544	6.677%	7,171,904	2,069,853	5,218,688	307,120	117,420	188,329	612,869	1,572,946
4	1,820,544	6.177%	6,634,843	1,862,123	7,080,811	416,706	159,318	255,528	831,552	1,572,946
5	1,820,544	5.713%	6,136,451	1,669,350	8,750,161	514,947	196,879	315,771	1,027,596	1,572,946
6	1,820,544	5.285%	5,676,728	1,491,534	10,241,694	602,724	230,438	369,596	1,202,758	1,572,946
7	1,820,544	4.888%	5,250,302	1,326,596	11,568,291	680,794	260,287	417,470	1,358,550	1,572,946
8	1,820,544	4.522%	4,857,174	1,174,538	12,742,829	749,915	286,714	459,856	1,496,485	1,572,946
9	1,820,544	4.462%	4,792,726	1,149,611	13,892,440	817,570	312,580	501,342	1,631,492	1,572,946
10	1,820,544	4.461%	4,791,652	1,149,195	15,041,635	885,200	338,437	542,814	1,766,451	1,572,946
11	1,820,544	4.462%	4,792,726	1,149,611	16,191,245	952,855	364,303	584,300	1,901,458	1,572,946
12	1,820,544	4.461%	4,791,652	1,149,195	17,340,441	1,020,485	390,160	625,772	2,036,416	1,572,946
13	1,820,544	4.462%	4,792,726	1,149,611	18,490,051	1,088,140	416,026	667,258	2,171,424	1,572,946
14	1,820,544	4.461%	4,791,652	1,149,195	19,639,246	1,155,770	441,883	708,730	2,306,382	1,572,946
15	1,820,544	4.462%	4,792,726	1,149,611	20,788,857	1,223,424	467,749	750,216	2,441,390	1,572,946
16	1,820,544	4.461%	4,791,652	1,149,195	21,938,052	1,291,054	493,606	791,687	2,576,348	1,572,946
17	1,820,544	4.462%	4,792,726	1,149,611	23,087,663	1,358,709	519,472	833,174	2,711,355	1,572,946
18	1,820,544	4.461%	4,791,652	1,149,195	24,236,858	1,426,339	545,329	874,645	2,846,314	1,572,946
19	1,820,544	4.462%	4,792,726	1,149,611	25,386,469	1,493,994	571,196	916,132	2,981,321	1,572,946
20	1,820,544	4.461%	4,791,652	1,149,195	26,535,664	1,561,624	597,052	957,603	3,116,280	1,572,946
21	1,820,544	2.231%	2,396,363	222,721	26,758,385	1,574,731	602,064	965,641	3,142,435	1,572,946
22	1,820,544	0.000%	0	-704,168	26,054,217	1,533,291	586,220	940,229	3,059,740	1,572,946
23	1,820,544	0.000%	0	-704,168	25,350,049	1,491,850	570,376	914,818	2,977,044	1,572,946
24	1,820,544	0.000%	0	-704,168	24,645,881	1,450,410	554,532	889,406	2,894,348	1,572,946
25	1,820,544	0.000%	0	-704,168	23,941,713	1,408,970	538,689	863,994	2,811,653	1,572,946
26	1,820,544	0.000%	0	-704,168	23,237,545	1,367,530	522,845	838,583	2,728,957	1,572,946
27	1,820,544	0.000%	0	-704,168	22,533,377	1,326,089	507,001	813,171	2,646,261	1,572,946
28	1,820,544	0.000%	0	-704,168	21,829,209	1,284,649	491,157	787,760	2,563,566	1,572,946
29	1,820,544	0.000%	0	-704,168	21,125,041	1,243,209	475,313	762,348	2,480,870	1,572,946
30	1,820,544	0.000%	0	-704,168	20,420,873	1,201,768	459,470	736,936	2,398,174	1,572,946
31	1,820,544	0.000%	0	-704,168	19,716,705	1,160,328	443,626	711,525	2,315,479	1,572,946
32	1,820,544	0.000%	0	-704,168	19,012,537	1,118,888	427,782	686,113	2,232,783	1,572,946
33	1,820,544	0.000%	0	-704,168	18,308,369	1,077,448	411,938	660,702	2,150,087	1,572,946
34	1,820,544	0.000%	0	-704,168	17,604,201	1,036,007	396,095	635,290	2,067,392	1,572,946
35	1,820,544	0.000%	0	-704,168	16,900,033	994,567	380,251	609,878	1,984,696	1,572,946
36	1,820,544	0.000%	0	-704,168	16,195,865	953,127	364,407	584,467	1,902,000	1,572,946
37	1,820,544	0.000%	0	-704,168	15,491,697	911,686	348,563	559,055	1,819,305	1,572,946
38	1,820,544	0.000%	0	-704,168	14,787,529	870,246	332,719	533,644	1,736,609	1,572,946
39	1,820,544	0.000%	0	-704,168	14,083,361	828,806	316,876	508,232	1,653,913	1,572,946
40	1,820,544	0.000%	0	-704,168	13,379,193	787,365	301,032	482,820	1,571,218	1,572,946
41	1,820,544	0.000%	0	-704,168	12,675,025	745,925	285,188	457,409	1,488,522	1,572,946
42	1,820,544	0.000%	0	-704,168	11,970,857	704,485	269,344	431,997	1,405,826	1,572,946
43	1,820,544	0.000%	0	-704,168	11,266,689	663,045	253,500	406,586	1,323,131	1,572,946
44	1,820,544	0.000%	0	-704,168	10,562,520	621,604	237,657	381,174	1,240,435	1,572,946
45	1,820,544	0.000%	0	-704,168	9,858,352	580,164	221,813	355,762	1,157,739	1,572,946
46	1,820,544	0.000%	0	-704,168	9,154,184	538,724	205,969	330,351	1,075,044	1,572,946
47	1,820,544	0.000%	0	-704,168	8,450,016	497,283	190,125	304,939	992,348	1,572,946
48	1,820,544	0.000%	0	-704,168	7,745,848	455,843	174,282	279,528	909,652	1,572,946
49	1,820,544	0.000%	0	-704,168	7,041,680	414,403	158,438	254,116	826,957	1,572,946
50	1,820,544	0.000%	0	-704,168	6,337,512	372,963	142,594	228,704	744,261	1,572,946
51	1,820,544	0.000%	0	-704,168	5,633,344	331,522	126,750	203,293	661,565	1,572,946
52	1,820,544	0.000%	0	-704,168	4,929,176	290,082	110,906	177,881	578,870	1,572,946
53	1,820,544	0.000%	0	-704,168	4,225,008	248,642	95,063	152,470	496,174	1,572,946
54	1,820,544	0.000%	0	-704,168	3,520,840	207,201	79,219	127,058	413,478	1,572,946
55	1,820,544	0.000%	0	-704,168	2,816,672	165,761	63,375	101,646	330,783	1,572,946
56	1,820,544	0.000%	0	-704,168	2,112,504	124,321	47,531	76,235	248,087	1,572,946
57	1,820,544	0.000%	0	-704,168	1,408,336	82,881	31,688	50,823	165,391	1,572,946
58	1,820,544	0.000%	0	-704,168	704,168	41,440	15,844	25,412	82,696	1,572,946
59	1,820,544	0.000%	0	-704,168	0	0	0	0	0	1,572,946

Unit Name: Delaware 9-12 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 6,730,407	
2	Investment Generator & Exciter	Inputs Tab	$ 1,009,561	
3	Reactive Allocator	(Line 71)	36.88%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**372,362**	
5				
6	GSU Transformer Investment	Inputs Tab	-	
7	Reactive Allocator	(Line 71)	36.88%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	655,447	
11	Reactive Allocator	(Line 71)	36.88%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**241,752**	
13				
14	Total Cost of Power Plant	Inputs Tab	13,528,361	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	11,863,353	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	6,428	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	620,541	
19	Reactive Fixed Charge Rate	(Line 14(h))	10.9048%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**67,668**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 67,668**	
23				
24				
25				
26				

(e)		(f)	(g)	(h)
Fixed Charge Rate for Reactive Plant				
		Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 140	785		
Other Expenses		110		
O&M	(sum line 1 & 2)	895	620,541	0.1442%
A&G		58,219	13,528,361	0.4303%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0080%
Working Capital	Line 216	60,440	13,528,361	0.4468%
General Plant		-	13,528,361	0.0000%
Other Taxes	Line 196(c)	27,880	13,528,361	0.2061%
Depreciation	Line 168(c)			0.0507%
				8.1350%
Taxes (Federal/State/Local)	Line 180			3.0332%
ADIT	-Line 233(k)	($209,633)	13,528,361	-1.5496%
		(Sum Lines 1 to 11 , Col. (h))		10.9048%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		16.90						
		13.40						
		13.70						
		13.40						
	Total	57.40	(Sum Lines 31 to 34)					
	Nominal Power Factor (pf)							
		0.84						
		0.77						
		0.78						
		0.78						
	Total	0.79	(Line 38 / 58)					
	MVA Capability (MVA)							
		20.17	(Line 31 / 41)					
		17.34	(Line 32 / 42)					
		17.63	(Line 33 / 43)					
		17.25	(Line 34 / 44)					
	Total	72.38	(Sum Lines 51 to 54)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		11.00	(SQRT (Line 51^2 - Line 31^2))					
		11.00	(SQRT (Line 52^2 - Line 32^2))					
		11.10	(SQRT (Line 53^2 - Line 33^2))					
		10.86	(SQRT (Line 54^2 - Line 34^2))					
	Total	43.96	(Sum Lines 62 to 65)					
	Reactive Allocator	36.9%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ 28,741	50%	$ 14,370
	Control&Power Cabling	$ 344,611	50%	$ 172,306
	Switch Board Equipment	$ 19,874	50%	$ 9,937
	Switching Equipment	$ 1,147,085	40%	$ 458,834
	Transformers	$ -	10%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ -	0%	$ -
	Misc	$ 370,485	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 1,910,796		$ 655,447

O&M		**Total Non-Fuel**	**Fixed O&M**		
	Production Expenses: Oper, Supv, & Engr	81,528	81,528		
	Coolants and Water (Nuclear Plants Only)	0			
	Steam Expenses	21,059	21,059		
	Steam From Other Sources	40,694			
	Electric Expenses	0	-		
	Misc Steam (or Nuclear) Power Expenses	12,468			
	Rents	75,877	75,877		
	Allowances	3,066	3,066		
	Maintenance Supervision and Engineering	0			
	Maintenance of Structures	31,801	31,801		
	Maintenance of Boiler (or reactor) Plant	13,637			
	Maintenance of Electric Plant	14,187			
	Maintenance of Misc Steam (or Nuclear) Plant	17,658	17,658		
	Other Power Production, & Other Expenses	53,560	53,560		
	Total NonFuel Expenses	365,535	284,549	(Sum Lines 102 to 115)	
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))	

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	5.5325%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	365,535	Line 116			
	Allowances	3,066	Line 109			
	Non-Fuel Production O&M	362,469	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	81,528	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	14,187	Line 113(b)			
	Other Demand Related Expenses	203,021	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	298,736	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	14,187	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	14,187	(Line 138 + 139)	5.5325%	785	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	203,021	(Line 134)	0.0542%	110	
				Line 123		
	Balance of Plant Fixed Expenses				297,841	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		18,226	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		39,992	(allocated on plant labor)	
	Total		58,219		
Depreciation					
	Annual Depreciation Exp ...DE	208,129			
	Gross Production Plant Cost ... F	13,528,361	Line 14		
	SLDP=DE/F	1.5385%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	65			
	SFDP=(R/((1+R)^n-1)		0.0507%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.033%		
Rate of Return					
	Rate Of Return = R	Weight	Cost Rate	Weighted Cost (b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		27,880	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		27,880	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	3.0332%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital				
	Prepayments	101,763		
		100.000%		
	Production Related Prepayments	101,763	(Line 209 * 210)	
	Unit Specific M&S	439,420		
	Total	541,183	(Line 211 + 212)	
	Return on Working Capital	8.1350%		
	Taxes on Working Capital	3.0332%		
	Working Capital Costs	60,440	(Line 213 * 214)	

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(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)

Accumulated Deferred Income Taxes

Investment	13,528,361	Line 14			NPV of Col (j)>	2,560,954
Asset Service Life	65	Line 167				
Composite Tax Rate	38.6790%	Line 177				

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity = (f) *	Interest	Income Taxes = (g) *	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	= (f) * (Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	208,129	3.750%	507,314	115,722	115,722	6,810	2,604	4,176	13,590	209,633
2	208,129	7.219%	976,612	297,242	412,964	24,303	9,292	14,903	48,497	209,633
3	208,129	6.677%	903,289	268,881	681,844	40,127	15,342	24,606	80,074	209,633
4	208,129	6.177%	835,647	242,718	924,562	54,410	20,803	33,365	108,578	209,633
5	208,129	5.713%	772,875	218,438	1,143,001	67,266	25,718	41,248	134,231	209,633
6	208,129	5.285%	714,974	196,043	1,339,043	78,803	30,128	48,323	157,254	209,633
7	208,129	4.888%	661,266	175,269	1,514,312	89,117	34,072	54,648	177,837	209,633
8	208,129	4.522%	611,752	156,118	1,670,430	98,305	37,585	60,281	196,171	209,633
9	208,129	4.462%	603,635	152,978	1,823,408	107,308	41,027	65,802	214,136	209,633
10	208,129	4.461%	603,500	152,926	1,976,334	116,307	44,468	71,321	232,096	209,633
11	208,129	4.462%	603,635	152,978	2,129,312	125,310	47,910	76,841	250,061	209,633
12	208,129	4.461%	603,500	152,926	2,282,238	134,310	51,350	82,360	268,020	209,633
13	208,129	4.462%	603,635	152,978	2,435,216	143,312	54,792	87,881	285,985	209,633
14	208,129	4.461%	603,500	152,926	2,588,142	152,312	58,233	93,399	303,945	209,633
15	208,129	4.462%	603,635	152,978	2,741,120	161,315	61,675	98,920	321,910	209,633
16	208,129	4.461%	603,500	152,926	2,894,045	170,315	65,116	104,439	339,869	209,633
17	208,129	4.462%	603,635	152,978	3,047,024	179,317	68,558	109,959	357,835	209,633
18	208,129	4.461%	603,500	152,926	3,199,949	188,317	71,999	115,478	375,794	209,633
19	208,129	4.462%	603,635	152,978	3,352,927	197,320	75,441	120,998	393,759	209,633
20	208,129	4.461%	603,500	152,926	3,505,853	206,319	78,882	126,517	411,718	209,633
21	208,129	2.231%	301,818	36,238	3,542,091	208,452	79,697	127,825	415,974	209,633
22	208,129	0.000%	0	-80,502	3,461,589	203,715	77,886	124,920	406,520	209,633
23	208,129	0.000%	0	-80,502	3,381,087	198,977	76,074	122,015	397,066	209,633
24	208,129	0.000%	0	-80,502	3,300,585	194,239	74,263	119,110	387,612	209,633
25	208,129	0.000%	0	-80,502	3,220,083	189,502	72,452	116,204	378,158	209,633
26	208,129	0.000%	0	-80,502	3,139,581	184,764	70,641	113,299	368,704	209,633
27	208,129	0.000%	0	-80,502	3,059,079	180,027	68,829	110,394	359,250	209,633
28	208,129	0.000%	0	-80,502	2,978,577	175,289	67,018	107,489	349,796	209,633
29	208,129	0.000%	0	-80,502	2,898,075	170,552	65,207	104,584	340,342	209,633
30	208,129	0.000%	0	-80,502	2,817,572	165,814	63,395	101,679	330,888	209,633
31	208,129	0.000%	0	-80,502	2,737,070	161,077	61,584	98,774	321,434	209,633
32	208,129	0.000%	0	-80,502	2,656,568	156,339	59,773	95,869	311,981	209,633
33	208,129	0.000%	0	-80,502	2,576,066	151,602	57,961	92,964	302,527	209,633
34	208,129	0.000%	0	-80,502	2,495,564	146,864	56,150	90,058	293,073	209,633
35	208,129	0.000%	0	-80,502	2,415,062	142,126	54,339	87,153	283,619	209,633
36	208,129	0.000%	0	-80,502	2,334,560	137,389	52,528	84,248	274,165	209,633
37	208,129	0.000%	0	-80,502	2,254,058	132,651	50,716	81,343	264,711	209,633
38	208,129	0.000%	0	-80,502	2,173,556	127,914	48,905	78,438	255,257	209,633
39	208,129	0.000%	0	-80,502	2,093,054	123,176	47,094	75,533	245,803	209,633
40	208,129	0.000%	0	-80,502	2,012,552	118,439	45,282	72,628	236,349	209,633
41	208,129	0.000%	0	-80,502	1,932,050	113,701	43,471	69,723	226,895	209,633
42	208,129	0.000%	0	-80,502	1,851,548	108,964	41,660	66,818	217,441	209,633
43	208,129	0.000%	0	-80,502	1,771,046	104,226	39,849	63,912	207,987	209,633
44	208,129	0.000%	0	-80,502	1,690,543	99,488	38,037	61,007	198,533	209,633
45	208,129	0.000%	0	-80,502	1,610,041	94,751	36,226	58,102	189,079	209,633
46	208,129	0.000%	0	-80,502	1,529,539	90,013	34,415	55,197	179,625	209,633
47	208,129	0.000%	0	-80,502	1,449,037	85,276	32,603	52,292	170,171	209,633
48	208,129	0.000%	0	-80,502	1,368,535	80,538	30,792	49,387	160,717	209,633
49	208,129	0.000%	0	-80,502	1,288,033	75,801	28,981	46,482	151,263	209,633
50	208,129	0.000%	0	-80,502	1,207,531	71,063	27,169	43,577	141,809	209,633
51	208,129	0.000%	0	-80,502	1,127,029	66,326	25,358	40,672	132,355	209,633
52	208,129	0.000%	0	-80,502	1,046,527	61,588	23,547	37,766	122,901	209,633
53	208,129	0.000%	0	-80,502	966,025	56,851	21,736	34,861	113,447	209,633
54	208,129	0.000%	0	-80,502	885,523	52,113	19,924	31,956	103,994	209,633
55	208,129	0.000%	0	-80,502	805,021	47,375	18,113	29,051	94,540	209,633
56	208,129	0.000%	0	-80,502	724,519	42,638	16,302	26,146	85,086	209,633
57	208,129	0.000%	0	-80,502	644,017	37,900	14,490	23,241	75,632	209,633
58	208,129	0.000%	0	-80,502	563,514	33,163	12,679	20,336	66,178	209,633
59	208,129	0.000%	0	-80,502	483,012	28,425	10,868	17,431	56,724	209,633
60	208,129	0.000%	0	-80,502	402,510	23,688	9,056	14,526	47,270	209,633
61	208,129	0.000%	0	-80,502	322,008	18,950	7,245	11,620	37,816	209,633
62	208,129	0.000%	0	-80,502	241,506	14,213	5,434	8,715	28,362	209,633
63	208,129	0.000%	0	-80,502	161,004	9,475	3,623	5,810	18,908	209,633
64	208,129	0.000%	0	-80,502	80,502	4,738	1,811	2,905	9,454	209,633
65	208,129	0.000%	0	-80,502	0	0	0	0	0	209,633

Unit Name: Dresden 2 & 3 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)		
					Fixed Charge Rate for Reactive Plant						
							Calculated Amt	Plant	FCR % (f) / (g)		
	Annual Revenue Requirement										
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 507,917,628		Electric Expenses	Line 140	294,104				
2	Investment Generator & Exciter	Inputs Tab	76,187,644		Other Expenses		146,200				
3	Reactive Allocator	(Line 71)	13.60%		O&M	(sum line 1 & 2)	440,304	17,543,922	2.5097%	**3.61%**	-1.0984%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**10,363,834**								
5					A&G		125,550,961	1,359,267,568	9.2367%	**9.00%**	0.2352%
6	GSU Transformer Investment	Inputs Tab	36,227,984		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.1633%	**0.18%**	-0.0120%
7	Reactive Allocator	(Line 71)	13.60%		Working Capital	Line 216	37,136,087	1,359,267,568	2.7321%	**2.75%**	-0.0195%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**4,928,106**		General Plant		-	1,359,267,568	0.0000%		0.0000%
9					Other Taxes	Line 196(c)	31,410,713	1,359,267,568	2.3109%	**2.31%**	0.0051%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	4,144,738		Depreciation	Line 168(c)			0.0752%	**0.0752%**	0.0000%
11	Reactive Allocator	(Line 71)	13.60%						8.1350%	**8.14%**	0.0000%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**563,810**		Taxes (Federal/State/Local)	Line 180			2.9859%	**2.99%**	0.0000%
13					ADIT	-Line 233(k)	($20,111,563)	1,359,267,568	-1.4796%	**-1.48%**	0.0000%
14	Total Cost of Power Plant	Inputs Tab	1,359,267,568				(Sum Lines 1 to 11 , Col. (h))		26.6691%		
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	1,242,707,203								
16	Balance of Plant Allocator	(Line 79)	0.1358%								
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	1,688,172								
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	17,543,922								
19	Reactive Fixed Charge Rate	(Line 14(h))	26.6691%								
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**4,678,804**								
21											
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 4,678,804**								
23											
24											
25											
26											

	(a)	(b)	(c)
Allocators			
	Real Power Capability (MW)		
		948.00	
		944.00	
		-	
	Total	1,892.00	(Sum Lines 31 to 33)
	Nominal Power Factor (pf)		
		0.93	
		0.93	
		-	
	Total	0.93	(Line 38 / 58)
	MVA Capability (MVA)		
		1,020.45	(Line 31 / 41)
		1,015.05	(Line 32 / 42)
		-	
	Total	2,035.51	(Sum Lines 51 to 53)
	Reactive Power Capability (MVAR)		
	(MVA^2 - MW^2)^0.5		
		377.65	(SQRT (Line 51^2 - Line 31^2))
		373.09	(SQRT (Line 52^2 - Line 32^2))
		-	
	Total	750.74	(Sum Lines 62 to 64)
	Reactive Allocator	13.6%	(Line 69^2 / Line 58^2)
		ComEd is TO Fleet	
	Max. MVAr	2,187	
	Nameplate MVAr	4,856	
	Exciter MW	35	
	Generator MW	11,447	
	Balance of Plant Allocator	0.1358%	(Line 75 / Line 76) * (Line 77 / Line 78)

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ 1,984,353	15%	$ 297,653
	Control&Power Cabling	$ 4,946,860	1%	$ 49,469
	Switch Board Equipment	$ -	1%	$ -
	Switching Equipment	$ 4,661,842	1%	$ 46,618
	Transformers	$ 12,219,855	3%	$ 366,596
	Aux Generator	$ 5,052,411	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ 153,468	50%	$ 76,734
	Structure	$ 31,844	0%	$ -
	Misc	$ 63,976,359	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ 4,948	1%	$ 49
	Bus & Insulators	$ 4,134,523	80%	$ 3,307,619
	Capacitor Bank	$ -	0%	$ -
	Total	$ 97,166,463		$ 4,144,738

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	30,319,889	30,319,889	
	Coolants and Water (Nuclear Plants Only)	2,970,838		
	Steam Expenses	18,634,475	18,634,475	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	1,903,760		
	Rents	52,637,346	52,637,346	
	Allowances	4,176,895	4,176,895	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	5,593,493	5,593,493	
	Maintenance of Boiler (or reactor) Plant	435,969		
	Maintenance of Electric Plant	14,413,629		
	Maintenance of Misc Steam (or Nuclear) Plant	9,258,467	9,258,467	
	Other Power Production, & Other Expenses	17,320,796	17,320,796	
	Total NonFuel Expenses	157,665,557	137,941,361	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	2.0405%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.1358%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	157,665,557	Line 116			
	Allowances	4,176,895	Line 109			
	Non-Fuel Production O&M	153,488,662	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	30,319,889	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	14,413,629	Line 113(b)			
	Other Demand Related Expenses	107,621,472	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	152,354,990	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	14,413,629	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	14,413,629	(Line 138 + 139)	2.0405%	294,104	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	107,621,472	(Line 134)	0.1358%	146,200	
				Line 123		
	Balance of Plant Fixed Expenses				151,914,687	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		113,729,176	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		11,821,786	(allocated on plant labor)	
	Total		125,550,961		
Depreciation					
	Annual Depreciation Exp ...DE	22,654,459			
	Gross Production Plant Cost ... F	1,359,267,568	Line 14		
	SLDP=DE/F	1.6667%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	60			
	SFDP=(R/((1+R)^n-1)		0.0752%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.986%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		25,219,637		
	Payroll Taxes	7,076,336			
	0	87.4899%	Line 117		
	Fixed Payroll Taxes		6,191,076	(Line 193 * 194)	
	Total Other Taxes		31,410,713	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9859%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	2,278,934				
		100.000%				
	Production Related Prepayments	2,278,934	(Line 209 * 210)			
	Unit Specific M&S	331,652,931				
	Total	333,931,865	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9859%				
	Working Capital Costs	37,136,087	(Line 213 * 214)			

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Accumulated Deferred Income Taxes

Investment	1,359,267,568	Line 14
Asset Service Life	60	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 244,957,426

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	PMT of NPV col. (j)
1	22,654,459	3.750%	50,972,534	10,953,148	10,953,148	644,593	246,446	395,271	1,286,309	20,111,563
2	22,654,459	7.219%	98,125,526	29,191,454	40,144,602	2,362,510	903,254	1,448,715	4,714,478	20,111,563
3	22,654,459	6.677%	90,758,296	26,341,883	66,486,484	3,912,730	1,495,946	2,399,325	7,808,000	20,111,563
4	22,654,459	6.177%	83,961,958	23,713,127	90,199,612	5,308,247	2,029,491	3,255,070	10,592,809	20,111,563
5	22,654,459	5.713%	77,654,956	21,273,642	111,473,254	6,560,201	2,508,148	4,022,781	13,091,130	20,111,563
6	22,654,459	5.285%	71,837,291	19,023,427	130,496,681	7,679,730	2,936,175	4,709,287	15,325,192	20,111,563
7	22,654,459	4.888%	66,440,999	16,936,196	147,432,877	8,676,425	3,317,240	5,320,470	17,314,135	20,111,563
8	22,654,459	4.522%	61,466,079	15,011,946	162,444,823	9,559,878	3,655,009	5,862,213	19,077,099	20,111,563
9	22,654,459	4.462%	60,650,519	14,696,496	177,141,319	10,424,767	3,985,680	6,392,571	20,803,017	20,111,563
10	22,654,459	4.461%	60,636,926	14,691,238	191,832,557	11,289,346	4,316,233	6,922,740	22,528,318	20,111,563
11	22,654,459	4.462%	60,650,519	14,696,496	206,529,053	12,154,235	4,646,904	7,453,098	24,254,237	20,111,563
12	22,654,459	4.461%	60,636,926	14,691,238	221,220,292	13,018,814	4,977,457	7,983,267	25,979,538	20,111,563
13	22,654,459	4.462%	60,650,519	14,696,496	235,916,787	13,883,703	5,308,128	8,513,625	27,705,456	20,111,563
14	22,654,459	4.461%	60,636,926	14,691,238	250,608,026	14,748,282	5,638,681	9,043,794	29,430,757	20,111,563
15	22,654,459	4.462%	60,650,519	14,696,496	265,304,521	15,613,171	5,969,352	9,574,153	31,156,675	20,111,563
16	22,654,459	4.461%	60,636,926	14,691,238	279,995,760	16,477,750	6,299,905	10,104,321	32,881,976	20,111,563
17	22,654,459	4.462%	60,650,519	14,696,496	294,692,256	17,342,639	6,630,576	10,634,680	34,607,895	20,111,563
18	22,654,459	4.461%	60,636,926	14,691,238	309,383,494	18,207,219	6,961,129	11,164,849	36,333,196	20,111,563
19	22,654,459	4.462%	60,650,519	14,696,496	324,079,990	19,072,107	7,291,800	11,695,207	38,059,114	20,111,563
20	22,654,459	4.461%	60,636,926	14,691,238	338,771,228	19,936,687	7,622,353	12,225,376	39,784,415	20,111,563
21	22,654,459	2.231%	30,325,259	2,966,989	341,738,217	20,111,294	7,689,110	12,332,447	40,132,851	20,111,563
22	22,654,459	0.000%	0	-8,762,518	332,975,698	19,595,620	7,491,953	12,016,230	39,103,803	20,111,563
23	22,654,459	0.000%	0	-8,762,518	324,213,180	19,079,946	7,294,797	11,700,013	38,074,756	20,111,563
24	22,654,459	0.000%	0	-8,762,518	315,450,662	18,564,271	7,097,640	11,383,797	37,045,708	20,111,563
25	22,654,459	0.000%	0	-8,762,518	306,688,143	18,048,597	6,900,483	11,067,580	36,016,661	20,111,563
26	22,654,459	0.000%	0	-8,762,518	297,925,625	17,532,923	6,703,327	10,751,364	34,987,613	20,111,563
27	22,654,459	0.000%	0	-8,762,518	289,163,107	17,017,249	6,506,170	10,435,147	33,958,566	20,111,563
28	22,654,459	0.000%	0	-8,762,518	280,400,588	16,501,575	6,309,013	10,118,931	32,929,518	20,111,563
29	22,654,459	0.000%	0	-8,762,518	271,638,070	15,985,900	6,111,857	9,802,714	31,900,471	20,111,563
30	22,654,459	0.000%	0	-8,762,518	262,875,551	15,470,226	5,914,700	9,486,497	30,871,424	20,111,563
31	22,654,459	0.000%	0	-8,762,518	254,113,033	14,954,552	5,717,543	9,170,281	29,842,376	20,111,563
32	22,654,459	0.000%	0	-8,762,518	245,350,515	14,438,878	5,520,387	8,854,064	28,813,329	20,111,563
33	22,654,459	0.000%	0	-8,762,518	236,587,996	13,923,204	5,323,230	8,537,848	27,784,281	20,111,563
34	22,654,459	0.000%	0	-8,762,518	227,825,478	13,407,529	5,126,073	8,221,631	26,755,234	20,111,563
35	22,654,459	0.000%	0	-8,762,518	219,062,960	12,891,855	4,928,917	7,905,415	25,726,186	20,111,563
36	22,654,459	0.000%	0	-8,762,518	210,300,441	12,376,181	4,731,760	7,589,198	24,697,139	20,111,563
37	22,654,459	0.000%	0	-8,762,518	201,537,923	11,860,507	4,534,603	7,272,981	23,668,091	20,111,563
38	22,654,459	0.000%	0	-8,762,518	192,775,404	11,344,833	4,337,447	6,956,765	22,639,044	20,111,563
39	22,654,459	0.000%	0	-8,762,518	184,012,886	10,829,158	4,140,290	6,640,548	21,609,996	20,111,563
40	22,654,459	0.000%	0	-8,762,518	175,250,368	10,313,484	3,943,133	6,324,332	20,580,949	20,111,563
41	22,654,459	0.000%	0	-8,762,518	166,487,849	9,797,810	3,745,977	6,008,115	19,551,902	20,111,563
42	22,654,459	0.000%	0	-8,762,518	157,725,331	9,282,136	3,548,820	5,691,898	18,522,854	20,111,563
43	22,654,459	0.000%	0	-8,762,518	148,962,812	8,766,462	3,351,663	5,375,682	17,493,807	20,111,563
44	22,654,459	0.000%	0	-8,762,518	140,200,294	8,250,787	3,154,507	5,059,465	16,464,759	20,111,563
45	22,654,459	0.000%	0	-8,762,518	131,437,776	7,735,113	2,957,350	4,743,249	15,435,712	20,111,563
46	22,654,459	0.000%	0	-8,762,518	122,675,257	7,219,439	2,760,193	4,427,032	14,406,664	20,111,563
47	22,654,459	0.000%	0	-8,762,518	113,912,739	6,703,765	2,563,037	4,110,816	13,377,617	20,111,563
48	22,654,459	0.000%	0	-8,762,518	105,150,221	6,188,090	2,365,880	3,794,599	12,348,569	20,111,563
49	22,654,459	0.000%	0	-8,762,518	96,387,702	5,672,416	2,168,723	3,478,382	11,319,522	20,111,563
50	22,654,459	0.000%	0	-8,762,518	87,625,184	5,156,742	1,971,567	3,162,166	10,290,475	20,111,563
51	22,654,459	0.000%	0	-8,762,518	78,862,665	4,641,068	1,774,410	2,845,949	9,261,427	20,111,563
52	22,654,459	0.000%	0	-8,762,518	70,100,147	4,125,394	1,577,253	2,529,733	8,232,380	20,111,563
53	22,654,459	0.000%	0	-8,762,518	61,337,629	3,609,719	1,380,097	2,213,516	7,203,332	20,111,563
54	22,654,459	0.000%	0	-8,762,518	52,575,110	3,094,045	1,182,940	1,897,299	6,174,285	20,111,563
55	22,654,459	0.000%	0	-8,762,518	43,812,592	2,578,371	985,783	1,581,083	5,145,237	20,111,563
56	22,654,459	0.000%	0	-8,762,518	35,050,074	2,062,697	788,627	1,264,866	4,116,190	20,111,563
57	22,654,459	0.000%	0	-8,762,518	26,287,555	1,547,023	591,470	948,650	3,087,142	20,111,563
58	22,654,459	0.000%	0	-8,762,518	17,525,037	1,031,348	394,313	632,433	2,058,095	20,111,563
59	22,654,459	0.000%	0	-8,762,518	8,762,518	515,674	197,157	316,217	1,029,047	20,111,563
60	22,654,459	0.000%	0	-8,762,518	0	0	0	0	0	20,111,563

Unit Name: Eddystone 3,4,10,20,30,40 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 62,382,060	
2	Investment Generator & Exciter	Inputs Tab	$ 9,357,309	
3	Reactive Allocator	(Line 71)	15.53%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**1,453,008**	
5				
6	GSU Transformer Investment	Inputs Tab	6,411,560	
7	Reactive Allocator	(Line 71)	15.53%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**995,590**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	3,656,031	
11	Reactive Allocator	(Line 71)	15.53%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**567,710**	
13				
14	Total Cost of Power Plant	Inputs Tab	400,131,998	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	380,707,098	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	206,266	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	3,222,574	
19	Reactive Fixed Charge Rate	(Line 14(h))	11.6718%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**376,133**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 376,133**	
23				
24				
25				
26				

	(e)		(f)	(g)	(h)
		Fixed Charge Rate for Reactive Plant			
			Calculated Amt	Plant	FCR % (f) / (g)
	Electric Expenses	Line 140	15,169		
	Other Expenses		5,049		
	O&M	(sum line 1 & 2)	20,218	3,222,574	0.6274%
	A&G		-	400,131,998	0.0000%
	CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0088%
	Working Capital	Line 216	2,296,730	400,131,998	0.5740%
	General Plant		-	400,131,998	0.0000%
	Other Taxes	Line 196(c)	3,170,443	400,131,998	0.7923%
	Depreciation	Line 168(c)			0.0507%
					8.1350%
	Taxes (Federal/State/Local)	Line 180			3.0332%
	ADIT	-Line 233(k)	($6,200,365)	400,131,998	-1.5496%
			(Sum Lines 1 to 11 , Col. (h))		11.6718%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		400.00						
		400.00						
		14.20						
		13.60						
		18.00						
		18.00						
		-						
	Total	863.80	(Sum Lines 31 to 37)					
	Nominal Power Factor (pf)							
		0.92						
		0.94						
		0.79						
		0.78						
		0.85						
		0.85						
		-						
	Total	0.92	(Line 38 / 58)					
	MVA Capability (MVA)							
		437.16	(Line 31 / 41)					
		427.35	(Line 32 / 42)					
		18.02	(Line 33 / 43)					
		17.55	(Line 34 / 44)					
		21.20	(Line 35 / 45)					
		21.20	(Line 36 / 46)					
	Total	942.48	(Sum Lines 51 to 57)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		176.37	(SQRT (Line 51^2 - Line 31^2))					
		150.43	(SQRT (Line 52^2 - Line 32^2))					
		11.09	(SQRT (Line 53^2 - Line 33^2))					
		11.09	(SQRT (Line 54^2 - Line 34^2))					
		11.20	(SQRT (Line 55^2 - Line 35^2))					
		11.20	(SQRT (Line 56^2 - Line 36^2))					
	Total	371.39	(Sum Lines 62 to 68)					
	Reactive Allocator	15.5%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Hydro & Steam**	**Allocated Amt**
	Storage Batteries	$ 351,463	**30%**	$ 105,439
	Control&Power Cabling	$ 19,978,318	**15%**	$ 2,996,748
	Switch Board Equipment	$ 484,897	**30%**	$ 145,469
	Switching Equipment	$ 2,041,877	**20%**	$ 408,375
	Transformers	$ -	**5%**	$ -
	Aux Generator	$ -	**0%**	$ -
	Fire Protection System	$ -	**0%**	$ -
	HVAC	$ -	**0%**	$ -
	Regulating Equipment	$ -	**75%**	$ -
	Structure	$ 167,065	**0%**	$ -
	Misc	$ 7,066,463	**0%**	$ -
	Exciter & PPT	$ -	**100%**	$ -
	Station Grounding	$ -	**0%**	$ -
	Bus & Insulators	$ -	**60%**	$ -
	Capacitor Bank	$ -	**0%**	$ -
	Total	$ 30,090,084		$ 3,656,031

O&M		**Total Non-Fuel**	**Fixed O&M**		
	Production Expenses: Oper, Supv, & Engr	3,742,503	3,742,503		
	Coolants and Water (Nuclear Plants Only)	0			
	Steam Expenses	966,716	966,716		
	Steam From Other Sources	1,868,066			
	Electric Expenses	0	-		
	Misc Steam (or Nuclear) Power Expenses	572,328			
	Rents	3,483,129	3,483,129		
	Allowances	140,748	140,748		
	Maintenance Supervision and Engineering	0			
	Maintenance of Structures	1,459,799	1,459,799		
	Maintenance of Boiler (or reactor) Plant	625,988			
	Maintenance of Electric Plant	651,254			
	Maintenance of Misc Steam (or Nuclear) Plant	810,576	810,576		
	Other Power Production, & Other Expenses	2,458,680	2,458,680		
	Total NonFuel Expenses	16,779,786	13,062,151	(Sum Lines 102 to 115)	
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))	

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	2.3292%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	16,779,786	Line 116			
	Allowances	140,748	Line 109			
	Non-Fuel Production O&M	16,639,038	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	3,742,503	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	651,254	Line 113(b)			
	Other Demand Related Expenses	9,319,648	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	13,713,405	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	651,254	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	651,254	(Line 138 + 139)	2.3292%	15,169	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	9,319,648	(Line 134)	0.0542%	5,049	
				Line 123		
	Balance of Plant Fixed Expenses				13,693,187	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		0	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		0	(allocated on plant labor)	
	Total		0		
Depreciation					
	Annual Depreciation Exp ...DE	6,155,877			
	Gross Production Plant Cost ... F	400,131,998	Line 14		
	SLDP=DE/F	1.5385%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	65			
	SFDP=(R/((1+R)^n-1)		0.0507%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.033%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		3,170,443	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		3,170,443	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	3.0332%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
	Prepayments	3,009,862	
		100.000%	
	Production Related Prepayments	3,009,862	(Line 209 * 210)
	Unit Specific M&S	17,555,085	
	Total	20,564,947	(Line 211 + 212)
	Return on Working Capital	8.1350%	
	Taxes on Working Capital	3.0332%	
	Working Capital Costs	2,296,730	(Line 213 * 214)

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Accumulated Deferred Income Taxes

Investment	400,131,998	Line 14
Asset Service Life	65	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 75,746,042

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity = (f) *	(h) Interest = (f) *	(i) Income Taxes = (g) *	(j) Rev Req Impact	(k) Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	(Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	6,155,877	3.750%	15,004,950	3,422,733	3,422,733	201,428	77,011	123,518	401,957	6,200,365
2	6,155,877	7.219%	28,885,529	8,791,602	12,214,335	718,814	274,823	440,784	1,434,420	6,200,365
3	6,155,877	6.677%	26,716,813	7,952,765	20,167,100	1,186,834	453,760	727,778	2,368,372	6,200,365
4	6,155,877	6.177%	24,716,154	7,178,929	27,346,029	1,609,314	615,286	986,847	3,211,447	6,200,365
5	6,155,877	5.713%	22,859,541	6,460,810	33,806,839	1,989,532	760,654	1,220,001	3,970,188	6,200,365
6	6,155,877	5.285%	21,146,976	5,798,407	39,605,247	2,330,769	891,118	1,429,251	4,651,138	6,200,365
7	6,155,877	4.888%	19,558,452	5,183,982	44,789,229	2,635,846	1,007,758	1,616,327	5,259,931	6,200,365
8	6,155,877	4.522%	18,093,969	4,617,535	49,406,763	2,907,588	1,111,652	1,782,962	5,802,202	6,200,365
9	6,155,877	4.462%	17,853,890	4,524,674	53,931,438	3,173,865	1,213,457	1,946,246	6,333,568	6,200,365
10	6,155,877	4.461%	17,849,888	4,523,127	58,454,564	3,440,051	1,315,228	2,109,474	6,864,753	6,200,365
11	6,155,877	4.462%	17,853,890	4,524,674	62,979,239	3,706,328	1,417,033	2,272,758	7,396,119	6,200,365
12	6,155,877	4.461%	17,849,888	4,523,127	67,502,366	3,972,514	1,518,803	2,435,985	7,927,303	6,200,365
13	6,155,877	4.462%	17,853,890	4,524,674	72,027,040	4,238,791	1,620,608	2,599,269	8,458,669	6,200,365
14	6,155,877	4.461%	17,849,888	4,523,127	76,550,167	4,504,977	1,722,379	2,762,497	8,989,853	6,200,365
15	6,155,877	4.462%	17,853,890	4,524,674	81,074,841	4,771,254	1,824,184	2,925,781	9,521,219	6,200,365
16	6,155,877	4.461%	17,849,888	4,523,127	85,597,968	5,037,440	1,925,954	3,089,009	10,052,404	6,200,365
17	6,155,877	4.462%	17,853,890	4,524,674	90,122,642	5,303,717	2,027,759	3,252,293	10,583,770	6,200,365
18	6,155,877	4.461%	17,849,888	4,523,127	94,645,769	5,569,903	2,129,530	3,415,521	11,114,954	6,200,365
19	6,155,877	4.462%	17,853,890	4,524,674	99,170,443	5,836,181	2,231,335	3,578,804	11,646,320	6,200,365
20	6,155,877	4.461%	17,849,888	4,523,127	103,693,570	6,102,367	2,333,105	3,742,032	12,177,504	6,200,365
21	6,155,877	2.231%	8,926,945	1,071,821	104,765,391	6,165,443	2,357,221	3,780,711	12,303,376	6,200,365
22	6,155,877	0.000%	0	-2,381,032	102,384,360	6,025,320	2,303,648	3,694,786	12,023,754	6,200,365
23	6,155,877	0.000%	0	-2,381,032	100,003,328	5,885,196	2,250,075	3,608,861	11,744,132	6,200,365
24	6,155,877	0.000%	0	-2,381,032	97,622,297	5,745,072	2,196,502	3,522,936	11,464,510	6,200,365
25	6,155,877	0.000%	0	-2,381,032	95,241,265	5,604,948	2,142,928	3,437,010	11,184,887	6,200,365
26	6,155,877	0.000%	0	-2,381,032	92,860,233	5,464,825	2,089,355	3,351,085	10,905,265	6,200,365
27	6,155,877	0.000%	0	-2,381,032	90,479,202	5,324,701	2,035,782	3,265,160	10,625,643	6,200,365
28	6,155,877	0.000%	0	-2,381,032	88,098,170	5,184,577	1,982,209	3,179,235	10,346,021	6,200,365
29	6,155,877	0.000%	0	-2,381,032	85,717,138	5,044,454	1,928,636	3,093,309	10,066,399	6,200,365
30	6,155,877	0.000%	0	-2,381,032	83,336,107	4,904,330	1,875,062	3,007,384	9,786,776	6,200,365
31	6,155,877	0.000%	0	-2,381,032	80,955,075	4,764,206	1,821,489	2,921,459	9,507,154	6,200,365
32	6,155,877	0.000%	0	-2,381,032	78,574,044	4,624,082	1,767,916	2,835,534	9,227,532	6,200,365
33	6,155,877	0.000%	0	-2,381,032	76,193,012	4,483,959	1,714,343	2,749,608	8,947,910	6,200,365
34	6,155,877	0.000%	0	-2,381,032	73,811,980	4,343,835	1,660,770	2,663,683	8,668,288	6,200,365
35	6,155,877	0.000%	0	-2,381,032	71,430,949	4,203,711	1,607,196	2,577,758	8,388,665	6,200,365
36	6,155,877	0.000%	0	-2,381,032	69,049,917	4,063,588	1,553,623	2,491,833	8,109,043	6,200,365
37	6,155,877	0.000%	0	-2,381,032	66,668,885	3,923,464	1,500,050	2,405,907	7,829,421	6,200,365
38	6,155,877	0.000%	0	-2,381,032	64,287,854	3,783,340	1,446,477	2,319,982	7,549,799	6,200,365
39	6,155,877	0.000%	0	-2,381,032	61,906,822	3,643,216	1,392,903	2,234,057	7,270,177	6,200,365
40	6,155,877	0.000%	0	-2,381,032	59,525,791	3,503,093	1,339,330	2,148,132	6,990,555	6,200,365
41	6,155,877	0.000%	0	-2,381,032	57,144,759	3,362,969	1,285,757	2,062,206	6,710,932	6,200,365
42	6,155,877	0.000%	0	-2,381,032	54,763,727	3,222,845	1,232,184	1,976,281	6,431,310	6,200,365
43	6,155,877	0.000%	0	-2,381,032	52,382,696	3,082,722	1,178,611	1,890,356	6,151,688	6,200,365
44	6,155,877	0.000%	0	-2,381,032	50,001,664	2,942,598	1,125,037	1,804,430	5,872,066	6,200,365
45	6,155,877	0.000%	0	-2,381,032	47,620,632	2,802,474	1,071,464	1,718,505	5,592,444	6,200,365
46	6,155,877	0.000%	0	-2,381,032	45,239,601	2,662,351	1,017,891	1,632,580	5,312,821	6,200,365
47	6,155,877	0.000%	0	-2,381,032	42,858,569	2,522,227	964,318	1,546,655	5,033,199	6,200,365
48	6,155,877	0.000%	0	-2,381,032	40,477,538	2,382,103	910,745	1,460,729	4,753,577	6,200,365
49	6,155,877	0.000%	0	-2,381,032	38,096,506	2,241,979	857,171	1,374,804	4,473,955	6,200,365
50	6,155,877	0.000%	0	-2,381,032	35,715,474	2,101,856	803,598	1,288,879	4,194,333	6,200,365
51	6,155,877	0.000%	0	-2,381,032	33,334,443	1,961,732	750,025	1,202,954	3,914,711	6,200,365
52	6,155,877	0.000%	0	-2,381,032	30,953,411	1,821,608	696,452	1,117,028	3,635,088	6,200,365
53	6,155,877	0.000%	0	-2,381,032	28,572,379	1,681,485	642,879	1,031,103	3,355,466	6,200,365
54	6,155,877	0.000%	0	-2,381,032	26,191,348	1,541,361	589,305	945,178	3,075,844	6,200,365
55	6,155,877	0.000%	0	-2,381,032	23,810,316	1,401,237	535,732	859,253	2,796,222	6,200,365
56	6,155,877	0.000%	0	-2,381,032	21,429,285	1,261,113	482,159	773,327	2,516,600	6,200,365
57	6,155,877	0.000%	0	-2,381,032	19,048,253	1,120,990	428,586	687,402	2,236,977	6,200,365
58	6,155,877	0.000%	0	-2,381,032	16,667,221	980,866	375,012	601,477	1,957,355	6,200,365
59	6,155,877	0.000%	0	-2,381,032	14,286,190	840,742	321,439	515,552	1,677,733	6,200,365
60	6,155,877	0.000%	0	-2,381,032	11,905,158	700,619	267,866	429,626	1,398,111	6,200,365
61	6,155,877	0.000%	0	-2,381,032	9,524,126	560,495	214,293	343,701	1,118,489	6,200,365
62	6,155,877	0.000%	0	-2,381,032	7,143,095	420,371	160,720	257,776	838,867	6,200,365
63	6,155,877	0.000%	0	-2,381,032	4,762,063	280,247	107,146	171,851	559,244	6,200,365
64	6,155,877	0.000%	0	-2,381,032	2,381,032	140,124	53,573	85,925	279,622	6,200,365
65	6,155,877	0.000%	0	-2,381,032	0	0	0	0	0	6,200,365

Unit Name: Fairless Hills A&B **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 20,090,347		Electric Expenses	Line 140	12,361		
2	Investment Generator & Exciter	Inputs Tab	$ 3,013,552		Other Expenses		2,302		
3	Reactive Allocator	(Line 71)	27.75%		O&M	(sum line 1 & 2)	14,664	883,698	1.6594%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**836,261**						
5					A&G		1,659,689	61,729,219	2.6887%
6	GSU Transformer Investment	Inputs Tab	51,347		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0580%
7	Reactive Allocator	(Line 71)	27.75%		Working Capital	Line 216	156,107	61,729,219	0.2529%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**14,249**		General Plant		-	61,729,219	0.0000%
9					Other Taxes	Line 196(c)	263,599	61,729,219	0.4270%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	5,071		Depreciation	Line 168(c)			1.1202%
11	Reactive Allocator	(Line 71)	27.75%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**1,407**		Taxes (Federal/State/Local)	Line 180			2.5332%
13					ADIT	-Line 233(k)	($349,408)	61,729,219	-0.5660%
14	Total Cost of Power Plant	Inputs Tab	61,729,219				(Sum Lines 1 to 11 , Col. (h))		16.3083%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	58,659,250						
16	Balance of Plant Allocator	(Line 79)	0.0542%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	31,781						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	883,698						
19	Reactive Fixed Charge Rate	(Line 14(h))	16.3083%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**144,116**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 144,116**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		30.00						
		30.00						
		-						
		-						
		-						
		-						
		-						
	Total	60.00	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.85						
		0.85						
		-						
		-						
		-						
		-						
		-						
	Total	0.85	(Line 38 / 58)					
	MVA Capability (MVA)							
		35.29	(Line 31 / 41)					
		35.29	(Line 32 / 42)					
		-						
	Total	70.59	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		18.59	(SQRT (Line 51^2 - Line 31^2))					
		18.59	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	37.18	(Sum Lines 62 to 64)					
	Reactive Allocator	27.8%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Hydro & Steam**	**Allocated Amt**
	Storage Batteries	$ 16,787	30%	$ 5,036
	Control&Power Cabling	$ 230	15%	$ 34
	Switch Board Equipment	$ -	30%	$ -
	Switching Equipment	$ -	20%	$ -
	Transformers	$ -	5%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ -	0%	$ -
	Misc	$ 154,657	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	0%	$ -
	Bus & Insulators	$ -	60%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 171,673		$ 5,071

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	1,706,571	1,706,571	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	440,820	440,820	
	Steam From Other Sources	851,833		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	260,980		
	Rents	1,588,297	1,588,297	
	Allowances	64,181	64,181	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	665,664	665,664	
	Maintenance of Boiler (or reactor) Plant	285,449		
	Maintenance of Electric Plant	296,970		
	Maintenance of Misc Steam (or Nuclear) Plant	369,620	369,620	
	Other Power Production, & Other Expenses	1,121,151	1,121,151	
	Total NonFuel Expenses	7,651,534	5,956,303	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	4.1625%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	7,651,534	Line 116			
	Allowances	64,181	Line 109			
	Non-Fuel Production O&M	7,587,353	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	1,706,571	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	296,970	Line 113(b)			
	Other Demand Related Expenses	4,249,732	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	6,253,273	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	296,970	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	296,970	(Line 138 + 139)	4.1625%	12,361	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	4,249,732	(Line 134)	0.0542%	2,302	
				Line 123		
	Balance of Plant Fixed Expenses				6,238,609	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		833,095	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		826,594	(allocated on plant labor)	
	Total		1,659,689		
Depreciation					
	Annual Depreciation Exp ...DE	2,286,267			
	Gross Production Plant Cost ... F	61,729,219	Line 14		
	SLDP=DE/F	3.7037%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	27			
	SFDP=(R/((1+R)^n-1)		1.1202%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.533%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		263,599	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		263,599	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.5332%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	464,338				
		100.000%				
	Production Related Prepayments	464,338	(Line 209 * 210)			
	Unit Specific M&S	998,961				
	Total	1,463,299	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.5332%				
	Working Capital Costs	156,107	(Line 213 * 214)			

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Accumulated Deferred Income Taxes

Investment	61,729,219	Line 14	NPV of Col (j)> 3,775,258
Asset Service Life	27	Line 167	
Composite Tax Rate	38.6790%	Line 177	

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	PMT of NPV col. (j)
1	2,286,267	3.750%	2,314,846	11,054	11,054	651	249	399	1,298	349,408
2	2,286,267	7.219%	4,456,232	839,321	850,375	50,045	19,133	30,688	99,866	349,408
3	2,286,267	6.677%	4,121,660	709,912	1,560,286	91,823	35,106	56,307	183,236	349,408
4	2,286,267	6.177%	3,813,014	590,530	2,150,816	126,576	48,393	77,617	252,586	349,408
5	2,286,267	5.713%	3,526,590	479,745	2,630,561	154,809	59,188	94,930	308,926	349,408
6	2,286,267	5.285%	3,262,389	377,554	3,008,115	177,028	67,683	108,555	353,265	349,408
7	2,286,267	4.888%	3,017,324	282,765	3,290,880	193,668	74,045	118,759	386,472	349,408
8	2,286,267	4.522%	2,791,395	195,378	3,486,259	205,166	78,441	125,810	409,417	349,408
9	2,286,267	4.462%	2,754,358	181,053	3,667,312	215,821	82,515	132,344	430,680	349,408
10	2,286,267	4.461%	2,753,740	180,814	3,848,126	226,462	86,583	138,869	451,914	349,408
11	2,286,267	4.462%	2,754,358	181,053	4,029,178	237,117	90,657	145,403	473,176	349,408
12	2,286,267	4.461%	2,753,740	180,814	4,209,992	247,758	94,725	151,928	494,411	349,408
13	2,286,267	4.462%	2,754,358	181,053	4,391,045	258,413	98,799	158,461	515,673	349,408
14	2,286,267	4.461%	2,753,740	180,814	4,571,859	269,054	102,867	164,987	536,907	349,408
15	2,286,267	4.462%	2,754,358	181,053	4,752,911	279,709	106,941	171,520	558,170	349,408
16	2,286,267	4.461%	2,753,740	180,814	4,933,725	290,350	111,009	178,045	579,404	349,408
17	2,286,267	4.462%	2,754,358	181,053	5,114,778	301,005	115,083	184,579	600,666	349,408
18	2,286,267	4.461%	2,753,740	180,814	5,295,592	311,646	119,151	191,104	621,901	349,408
19	2,286,267	4.462%	2,754,358	181,053	5,476,645	322,301	123,225	197,638	643,163	349,408
20	2,286,267	4.461%	2,753,740	180,814	5,657,459	332,941	127,293	204,163	664,397	349,408
21	2,286,267	2.231%	1,377,179	-351,626	5,305,832	312,248	119,381	191,474	623,103	349,408
22	2,286,267	0.000%	0	-884,305	4,421,527	260,207	99,484	159,561	519,253	349,408
23	2,286,267	0.000%	0	-884,305	3,537,221	208,165	79,587	127,649	415,402	349,408
24	2,286,267	0.000%	0	-884,305	2,652,916	156,124	59,691	95,737	311,552	349,408
25	2,286,267	0.000%	0	-884,305	1,768,611	104,083	39,794	63,825	207,701	349,408
26	2,286,267	0.000%	0	-884,305	884,305	52,041	19,897	31,912	103,851	349,408
27	2,286,267	0.000%	0	-884,305	0	0	0	0	0	349,408

Unit Name: Falls 1-3 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 5,518,050	
2	Investment Generator & Exciter	Inputs Tab	$ 827,708	
3	Reactive Allocator	(Line 71)	27.18%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**224,966**	
5				
6	GSU Transformer Investment	Inputs Tab	-	
7	Reactive Allocator	(Line 71)	27.18%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	312,817	
11	Reactive Allocator	(Line 71)	27.18%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**85,022**	
13				
14	Total Cost of Power Plant	Inputs Tab	7,829,474	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	6,688,950	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	3,624	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	313,612	
19	Reactive Fixed Charge Rate	(Line 14(h))	11.9127%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**37,360**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 37,360**	
23				
24				
25				
26				

(e)		(f)	(g)	(h)
Fixed Charge Rate for Reactive Plant				
		Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 140	527		
Other Expenses		100		
O&M	(sum line 1 & 2)	627	313,612	0.1999%
A&G		53,021	7,829,474	0.6772%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0122%
Working Capital	Line 216	93,281	7,829,474	1.1914%
General Plant		-	7,829,474	0.0000%
Other Taxes	Line 196(c)	11,386	7,829,474	0.1454%
Depreciation	Line 168(c)			0.0594%
				8.1350%
Taxes (Federal/State/Local)	Line 180			3.0148%
ADIT	-Line 233(k)	($119,220)	7,829,474	-1.5227%
		(Sum Lines 1 to 11 , Col. (h))		11.9127%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		18.46						
		18.08						
		18.26						
	Total	54.80	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.86						
		0.85						
		0.85						
	Total	0.85	(Line 38 / 58)					
	MVA Capability (MVA)							
		21.59	(Line 31 / 41)					
		21.25	(Line 32 / 42)					
		21.38	(Line 33 / 43)					
	Total	64.22	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		11.20	(SQRT (Line 51^2 - Line 31^2))					
		11.16	(SQRT (Line 52^2 - Line 32^2))					
		11.12	(SQRT (Line 53^2 - Line 33^2))					
	Total	33.48	(Sum Lines 62 to 64)					
	Reactive Allocator	27.2%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ 33,793	50%	$ 16,896
	Control&Power Cabling	$ 142,003	50%	$ 71,002
	Switch Board Equipment	$ -	50%	$ -
	Switching Equipment	$ 562,170	40%	$ 224,868
	Transformers	$ 512	10%	$ 51
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ 8,093	0%	$ -
	Misc	$ 380,300	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 1,126,870		$ 312,817

O&M		**Total Non-Fuel**	**Fixed O&M**		
	Production Expenses: Oper, Supv, & Engr	74,248	74,248		
	Coolants and Water (Nuclear Plants Only)	0			
	Steam Expenses	19,179	19,179		
	Steam From Other Sources	37,061			
	Electric Expenses	0	-		
	Misc Steam (or Nuclear) Power Expenses	11,355			
	Rents	69,103	69,103		
	Allowances	2,792	2,792		
	Maintenance Supervision and Engineering	0			
	Maintenance of Structures	28,961	28,961		
	Maintenance of Boiler (or reactor) Plant	12,419			
	Maintenance of Electric Plant	12,920			
	Maintenance of Misc Steam (or Nuclear) Plant	16,081	16,081		
	Other Power Production, & Other Expenses	48,778	48,778		
	Total NonFuel Expenses	332,898	259,143	(Sum Lines 102 to 115)	
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))	

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	4.0769%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	332,898	Line 116			
	Allowances	2,792	Line 109			
	Non-Fuel Production O&M	330,106	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	74,248	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	12,920	Line 113(b)			
	Other Demand Related Expenses	184,895	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	272,063	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	12,920	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	12,920	(Line 138 + 139)	4.0769%	527	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	184,895	(Line 134)	0.0542%	100	
				Line 123		
	Balance of Plant Fixed Expenses				271,436	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		16,599	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		36,422	(allocated on plant labor)	
	Total		53,021		
Depreciation					
	Annual Depreciation Exp ...DE	124,277			
	Gross Production Plant Cost ... F	7,829,474	Line 14		
	SLDP=DE/F	1.5873%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	63			
	SFDP=(R/((1+R)^n-1)		0.0594%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.015%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		11,386	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		11,386	(Line 192 + 195)	

	Plant		Depreciation	Total	
General Plant	-		-		
	0.000%		0.000%		Line 159
Fixed General Plant	-		-		(Lines 200 *201)
Return on General Plant	8.1350%	Line 188			
Taxes on General Plant	3.0148%	Line 189			
General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
Prepayments	58,895		
	100.000%		
Production Related Prepayments	58,895	(Line 209 * 210)	
Unit Specific M&S	777,716		
Total	836,611	(Line 211 + 212)	
Return on Working Capital	8.1350%		
Taxes on Working Capital	3.0148%		
Working Capital Costs	93,281	(Line 213 * 214)	

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(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)

Accumulated Deferred Income Taxes

Investment	7,829,474	Line 14		NPV of Col (j)>	1,454,902
Asset Service Life	63	Line 167			
Composite Tax Rate	38.6790%	Line 177			

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity = (f) *	Interest	Income Taxes = (g) *	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	= (f) * (Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	124,277	3.750%	293,605	65,494	65,494	3,854	1,474	2,364	7,691	119,220
2	124,277	7.219%	565,210	170,548	236,043	13,891	5,311	8,518	27,720	119,220
3	124,277	6.677%	522,774	154,135	390,177	22,962	8,779	14,080	45,821	119,220
4	124,277	6.177%	483,627	138,993	529,170	31,142	11,906	19,096	62,144	119,220
5	124,277	5.713%	447,298	124,941	654,111	38,494	14,717	23,605	76,817	119,220
6	124,277	5.285%	413,788	111,980	766,091	45,084	17,237	27,646	89,968	119,220
7	124,277	4.888%	382,705	99,957	866,048	50,967	19,486	31,253	101,706	119,220
8	124,277	4.522%	354,049	88,873	954,921	56,197	21,486	34,461	112,143	119,220
9	124,277	4.462%	349,351	87,056	1,041,977	61,320	23,444	37,602	122,367	119,220
10	124,277	4.461%	349,273	87,026	1,129,003	66,442	25,403	40,743	132,587	119,220
11	124,277	4.462%	349,351	87,056	1,216,060	71,565	27,361	43,884	142,811	119,220
12	124,277	4.461%	349,273	87,026	1,303,086	76,687	29,319	47,025	153,031	119,220
13	124,277	4.462%	349,351	87,056	1,390,142	81,810	31,278	50,167	163,255	119,220
14	124,277	4.461%	349,273	87,026	1,477,168	86,931	33,236	53,307	173,475	119,220
15	124,277	4.462%	349,351	87,056	1,564,224	92,055	35,195	56,449	183,698	119,220
16	124,277	4.461%	349,273	87,026	1,651,250	97,176	37,153	59,589	193,919	119,220
17	124,277	4.462%	349,351	87,056	1,738,306	102,299	39,112	62,731	204,142	119,220
18	124,277	4.461%	349,273	87,026	1,825,332	107,421	41,070	65,872	214,362	119,220
19	124,277	4.462%	349,351	87,056	1,912,389	112,544	43,029	69,013	224,586	119,220
20	124,277	4.461%	349,273	87,026	1,999,415	117,666	44,987	72,154	234,806	119,220
21	124,277	2.231%	174,676	19,494	2,018,908	118,813	45,425	72,857	237,095	119,220
22	124,277	0.000%	0	-48,069	1,970,839	115,984	44,344	71,122	231,450	119,220
23	124,277	0.000%	0	-48,069	1,922,770	113,155	43,262	69,388	225,805	119,220
24	124,277	0.000%	0	-48,069	1,874,700	110,326	42,181	67,653	220,160	119,220
25	124,277	0.000%	0	-48,069	1,826,631	107,497	41,099	65,918	214,515	119,220
26	124,277	0.000%	0	-48,069	1,778,562	104,668	40,018	64,184	208,870	119,220
27	124,277	0.000%	0	-48,069	1,730,493	101,839	38,936	62,449	203,225	119,220
28	124,277	0.000%	0	-48,069	1,682,423	99,011	37,855	60,714	197,579	119,220
29	124,277	0.000%	0	-48,069	1,634,354	96,182	36,773	58,980	191,934	119,220
30	124,277	0.000%	0	-48,069	1,586,285	93,353	35,691	57,245	186,289	119,220
31	124,277	0.000%	0	-48,069	1,538,216	90,524	34,610	55,510	180,644	119,220
32	124,277	0.000%	0	-48,069	1,490,147	87,695	33,528	53,776	174,999	119,220
33	124,277	0.000%	0	-48,069	1,442,077	84,866	32,447	52,041	169,354	119,220
34	124,277	0.000%	0	-48,069	1,394,008	82,037	31,365	50,306	163,709	119,220
35	124,277	0.000%	0	-48,069	1,345,939	79,208	30,284	48,571	158,064	119,220
36	124,277	0.000%	0	-48,069	1,297,870	76,380	29,202	46,837	152,418	119,220
37	124,277	0.000%	0	-48,069	1,249,800	73,551	28,121	45,102	146,773	119,220
38	124,277	0.000%	0	-48,069	1,201,731	70,722	27,039	43,367	141,128	119,220
39	124,277	0.000%	0	-48,069	1,153,662	67,893	25,957	41,633	135,483	119,220
40	124,277	0.000%	0	-48,069	1,105,593	65,064	24,876	39,898	129,838	119,220
41	124,277	0.000%	0	-48,069	1,057,523	62,235	23,794	38,163	124,193	119,220
42	124,277	0.000%	0	-48,069	1,009,454	59,406	22,713	36,429	118,548	119,220
43	124,277	0.000%	0	-48,069	961,385	56,577	21,631	34,694	112,903	119,220
44	124,277	0.000%	0	-48,069	913,316	53,749	20,550	32,959	107,257	119,220
45	124,277	0.000%	0	-48,069	865,246	50,920	19,468	31,224	101,612	119,220
46	124,277	0.000%	0	-48,069	817,177	48,091	18,386	29,490	95,967	119,220
47	124,277	0.000%	0	-48,069	769,108	45,262	17,305	27,755	90,322	119,220
48	124,277	0.000%	0	-48,069	721,039	42,433	16,223	26,020	84,677	119,220
49	124,277	0.000%	0	-48,069	672,969	39,604	15,142	24,286	79,032	119,220
50	124,277	0.000%	0	-48,069	624,900	36,775	14,060	22,551	73,387	119,220
51	124,277	0.000%	0	-48,069	576,831	33,946	12,979	20,816	67,742	119,220
52	124,277	0.000%	0	-48,069	528,762	31,118	11,897	19,082	62,096	119,220
53	124,277	0.000%	0	-48,069	480,692	28,289	10,816	17,347	56,451	119,220
54	124,277	0.000%	0	-48,069	432,623	25,460	9,734	15,612	50,806	119,220
55	124,277	0.000%	0	-48,069	384,554	22,631	8,652	13,878	45,161	119,220
56	124,277	0.000%	0	-48,069	336,485	19,802	7,571	12,143	39,516	119,220
57	124,277	0.000%	0	-48,069	288,415	16,973	6,489	10,408	33,871	119,220
58	124,277	0.000%	0	-48,069	240,346	14,144	5,408	8,673	28,226	119,220
59	124,277	0.000%	0	-48,069	192,277	11,315	4,326	6,939	22,581	119,220
60	124,277	0.000%	0	-48,069	144,208	8,487	3,245	5,204	16,935	119,220
61	124,277	0.000%	0	-48,069	96,138	5,658	2,163	3,469	11,290	119,220
62	124,277	0.000%	0	-48,069	48,069	2,829	1,082	1,735	5,645	119,220
63	124,277	0.000%	0	-48,069	0	0	0	0	0	119,220

Unit Name: Gould Street 3 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 4,694,859	
2	Investment Generator & Exciter	Inputs Tab	$ 704,229	
3	Reactive Allocator	(Line 71)	18.64%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**131,265**	
5				
6	GSU Transformer Investment	Inputs Tab	3,114	
7	Reactive Allocator	(Line 71)	18.64%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**580**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	107,738	
11	Reactive Allocator	(Line 71)	18.64%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**20,082**	
13				
14	Total Cost of Power Plant	Inputs Tab	18,406,803	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	17,591,722	
16	Balance of Plant Allocator	(Line 79)	0.0154%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	2,701	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	154,629	
19	Reactive Fixed Charge Rate	(Line 14(h))	20.0224%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**30,960**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 30,960**	
23				
24				
25				
26				

(e)		(f)	(g)	(h)
Fixed Charge Rate for Reactive Plant				
		Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 140	2,816		
Other Expenses		221		
O&M	(sum line 1 & 2)	3,037	154,629	1.9641%
A&G		856,274	18,406,803	4.6519%
CWC	From Col. (h): ((lines 3 + 5) * .125 * (lines 11 + 12)			0.0930%
Working Capital	Line 216	27,640	18,406,803	0.1502%
General Plant		-	18,406,803	0.0000%
Other Taxes	Line 196(c)	653,648	18,406,803	3.5511%
Depreciation	Line 168(c)			0.0250%
				8.1350%
Taxes (Federal/State/Local)	Line 180			3.1068%
ADIT	-Line 233(k)	($304,590)	18,406,803	-1.6548%
		(Sum Lines 1 to 11 , Col. (h))		20.0224%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		102.70						
		-						
		-						
	Total	102.70	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.90						
		-						
	Total	0.90	(Line 38 / 58)					
	MVA Capability (MVA)							
		113.86	(Line 31 / 41)					
		-						
		-						
	Total	113.86	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		49.16	(SQRT (Line 51^2 - Line 31^2))					
		-						
		-						
	Total	49.16	(Sum Lines 62 to 64)					
	Reactive Allocator	18.6%	(Line 69^2 / Line 58^2)					
		BGE is TO Fleet						
	Max. MVAr	27.50						
	Nameplate MVAr	571.22						
	Exciter MW	3.08						
	Generator MW	965.46						
	Balance of Plant Allocator	0.0154%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Hydro & Steam**	**Allocated Amt**
	Storage Batteries	$ 353,658	**30%**	$ 106,097
	Control&Power Cabling	$ 10,940	**15%**	$ 1,641
	Switch Board Equipment	$ -	**30%**	$ -
	Switching Equipment	$ -	**20%**	$ -
	Transformers	$ -	**5%**	$ -
	Aux Generator	$ -	**0%**	$ -
	Fire Protection System	$ -	**0%**	$ -
	HVAC	$ -	**0%**	$ -
	Regulating Equipment	$ -	**75%**	$ -
	Structure	$ -	**0%**	$ -
	Misc	$ -	**0%**	$ -
	Exciter & PPT	$ -	**100%**	$ -
	Station Grounding	$ -	**0%**	$ -
	Bus & Insulators	$ -	**60%**	$ -
	Capacitor Bank	$ -	**0%**	$ -
	Total	$ 364,598		$ 107,738

O&M		**Total Non-Fuel**	**Fixed O&M**		
	Production Expenses: Oper, Supv, & Engr	578,737	578,737		
	Coolants and Water (Nuclear Plants Only)	0			
	Steam Expenses	149,492	149,492		
	Steam From Other Sources	288,876			
	Electric Expenses	0	-		
	Misc Steam (or Nuclear) Power Expenses	88,504			
	Rents	538,628	538,628		
	Allowances	21,765	21,765		
	Maintenance Supervision and Engineering	0			
	Maintenance of Structures	225,742	225,742		
	Maintenance of Boiler (or reactor) Plant	96,802			
	Maintenance of Electric Plant	100,709			
	Maintenance of Misc Steam (or Nuclear) Plant	125,347	125,347		
	Other Power Production, & Other Expenses	380,208	380,208		
	Total NonFuel Expenses	2,594,809	2,019,918	(Sum Lines 102 to 115)	
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))	

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	2.7959%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0154%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	2,594,809	Line 116			
	Allowances	21,765	Line 109			
	Non-Fuel Production O&M	2,573,044	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	578,737	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	100,709	Line 113(b)			
	Other Demand Related Expenses	1,441,181	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	2,120,627	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	100,709	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	100,709	(Line 138 + 139)	2.7959%	2,816	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	1,441,181	(Line 134)	0.0154%	221	
				Line 123		
	Balance of Plant Fixed Expenses				2,117,590	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		767,400	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		88,874	(allocated on plant labor)	
	Total		856,274		
Depreciation					
	Annual Depreciation Exp ...DE	248,741			
	Gross Production Plant Cost ... F	18,406,803	Line 14		
	SLDP=DE/F	1.3514%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	74			
	SFDP=(R/((1+R)^n-1)		0.0250%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.107%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		653,648	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		653,648	(Line 192 + 195)	

	Plant		Depreciation	Total	
General Plant	-		-		
	0.000%		0.000%		Line 159
Fixed General Plant	-		-		(Lines 200 *201)
Return on General Plant	8.1350%	Line 188			
Taxes on General Plant	3.1068%	Line 189			
General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
Prepayments	138,459		
	100.000%		
Production Related Prepayments	138,459	(Line 209 * 210)	
Unit Specific M&S	107,407		
Total	245,866	(Line 211 + 212)	
Return on Working Capital	8.1350%		
Taxes on Working Capital	3.1068%		
Working Capital Costs	27,640	(Line 213 * 214)	

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Accumulated Deferred Income Taxes

Investment	18,406,803	Line 14	
Asset Service Life	74	Line 167	
Composite Tax Rate	38.6790%	Line 177	

NPV of Col (j)> 3,732,719

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	248,741	3.750%	690,255	170,773	170,773	10,050	3,842	6,163	20,055	304,590
2	248,741	7.219%	1,328,787	417,751	588,525	34,635	13,242	21,238	69,115	304,590
3	248,741	6.677%	1,229,022	379,163	967,688	56,948	21,773	34,921	113,643	304,590
4	248,741	6.177%	1,136,988	343,565	1,311,253	77,167	29,503	47,320	153,990	304,590
5	248,741	5.713%	1,051,581	310,531	1,621,784	95,442	36,490	58,526	190,458	304,590
6	248,741	5.285%	972,800	280,059	1,901,842	111,923	42,791	68,633	223,347	304,590
7	248,741	4.888%	899,725	251,794	2,153,636	126,742	48,457	77,719	252,917	304,590
8	248,741	4.522%	832,356	225,736	2,379,373	140,026	53,536	85,865	279,427	304,590
9	248,741	4.462%	821,312	221,465	2,600,838	153,059	58,519	93,857	305,436	304,590
10	248,741	4.461%	821,128	221,394	2,822,231	166,088	63,500	101,847	331,436	304,590
11	248,741	4.462%	821,312	221,465	3,043,696	179,122	68,483	109,839	357,444	304,590
12	248,741	4.461%	821,128	221,394	3,265,089	192,151	73,465	117,829	383,444	304,590
13	248,741	4.462%	821,312	221,465	3,486,554	205,184	78,447	125,821	409,452	304,590
14	248,741	4.461%	821,128	221,394	3,707,948	218,213	83,429	133,810	435,452	304,590
15	248,741	4.462%	821,312	221,465	3,929,412	231,246	88,412	141,802	461,460	304,590
16	248,741	4.461%	821,128	221,394	4,150,806	244,275	93,393	149,792	487,460	304,590
17	248,741	4.462%	821,312	221,465	4,372,271	257,308	98,376	157,784	513,468	304,590
18	248,741	4.461%	821,128	221,394	4,593,664	270,337	103,357	165,773	539,468	304,590
19	248,741	4.462%	821,312	221,465	4,815,129	283,370	108,340	173,766	565,476	304,590
20	248,741	4.461%	821,128	221,394	5,036,523	296,399	113,322	181,755	591,476	304,590
21	248,741	2.231%	410,656	62,627	5,099,150	300,085	114,731	184,015	598,831	304,590
22	248,741	0.000%	0	-96,210	5,002,939	294,423	112,566	180,543	587,532	304,590
23	248,741	0.000%	0	-96,210	4,906,729	288,761	110,401	177,071	576,234	304,590
24	248,741	0.000%	0	-96,210	4,810,519	283,099	108,237	173,599	564,935	304,590
25	248,741	0.000%	0	-96,210	4,714,308	277,437	106,072	170,127	553,636	304,590
26	248,741	0.000%	0	-96,210	4,618,098	271,775	103,907	166,655	542,337	304,590
27	248,741	0.000%	0	-96,210	4,521,887	266,113	101,742	163,183	531,039	304,590
28	248,741	0.000%	0	-96,210	4,425,677	260,451	99,578	159,711	519,740	304,590
29	248,741	0.000%	0	-96,210	4,329,467	254,789	97,413	156,239	508,441	304,590
30	248,741	0.000%	0	-96,210	4,233,256	249,127	95,248	152,767	497,143	304,590
31	248,741	0.000%	0	-96,210	4,137,046	243,465	93,084	149,295	485,844	304,590
32	248,741	0.000%	0	-96,210	4,040,836	237,803	90,919	145,823	474,545	304,590
33	248,741	0.000%	0	-96,210	3,944,625	232,141	88,754	142,351	463,247	304,590
34	248,741	0.000%	0	-96,210	3,848,415	226,479	86,589	138,879	451,948	304,590
35	248,741	0.000%	0	-96,210	3,752,204	220,817	84,425	135,407	440,649	304,590
36	248,741	0.000%	0	-96,210	3,655,994	215,155	82,260	131,935	429,350	304,590
37	248,741	0.000%	0	-96,210	3,559,784	209,493	80,095	128,463	418,052	304,590
38	248,741	0.000%	0	-96,210	3,463,573	203,831	77,930	124,991	406,753	304,590
39	248,741	0.000%	0	-96,210	3,367,363	198,169	75,766	121,519	395,454	304,590
40	248,741	0.000%	0	-96,210	3,271,153	192,507	73,601	118,047	384,156	304,590
41	248,741	0.000%	0	-96,210	3,174,942	186,845	71,436	114,575	372,857	304,590
42	248,741	0.000%	0	-96,210	3,078,732	181,183	69,271	111,103	361,558	304,590
43	248,741	0.000%	0	-96,210	2,982,522	175,521	67,107	107,631	350,260	304,590
44	248,741	0.000%	0	-96,210	2,886,311	169,859	64,942	104,159	338,961	304,590
45	248,741	0.000%	0	-96,210	2,790,101	164,197	62,777	100,688	327,662	304,590
46	248,741	0.000%	0	-96,210	2,693,890	158,535	60,613	97,216	316,364	304,590
47	248,741	0.000%	0	-96,210	2,597,680	152,873	58,448	93,744	305,065	304,590
48	248,741	0.000%	0	-96,210	2,501,470	147,211	56,283	90,272	293,766	304,590
49	248,741	0.000%	0	-96,210	2,405,259	141,550	54,118	86,800	282,467	304,590
50	248,741	0.000%	0	-96,210	2,309,049	135,888	51,954	83,328	271,169	304,590
51	248,741	0.000%	0	-96,210	2,212,839	130,226	49,789	79,856	259,870	304,590
52	248,741	0.000%	0	-96,210	2,116,628	124,564	47,624	76,384	248,571	304,590
53	248,741	0.000%	0	-96,210	2,020,418	118,902	45,459	72,912	237,273	304,590
54	248,741	0.000%	0	-96,210	1,924,207	113,240	43,295	69,440	225,974	304,590
55	248,741	0.000%	0	-96,210	1,827,997	107,578	41,130	65,968	214,675	304,590
56	248,741	0.000%	0	-96,210	1,731,787	101,916	38,965	62,496	203,377	304,590
57	248,741	0.000%	0	-96,210	1,635,576	96,254	36,800	59,024	192,078	304,590
58	248,741	0.000%	0	-96,210	1,539,366	90,592	34,636	55,552	180,779	304,590
59	248,741	0.000%	0	-96,210	1,443,156	84,930	32,471	52,080	169,480	304,590
60	248,741	0.000%	0	-96,210	1,346,945	79,268	30,306	48,608	158,182	304,590
61	248,741	0.000%	0	-96,210	1,250,735	73,606	28,142	45,136	146,883	304,590
62	248,741	0.000%	0	-96,210	1,154,524	67,944	25,977	41,664	135,584	304,590
63	248,741	0.000%	0	-96,210	1,058,314	62,282	23,812	38,192	124,286	304,590
64	248,741	0.000%	0	-96,210	962,104	56,620	21,647	34,720	112,987	304,590
65	248,741	0.000%	0	-96,210	865,893	50,958	19,483	31,248	101,688	304,590
66	248,741	0.000%	0	-96,210	769,683	45,296	17,318	27,776	90,390	304,590
67	248,741	0.000%	0	-96,210	673,473	39,634	15,153	24,304	79,091	304,590
68	248,741	0.000%	0	-96,210	577,262	33,972	12,988	20,832	67,792	304,590
69	248,741	0.000%	0	-96,210	481,052	28,310	10,824	17,360	56,493	304,590
70	248,741	0.000%	0	-96,210	384,841	22,648	8,659	13,888	45,195	304,590
71	248,741	0.000%	0	-96,210	288,631	16,986	6,494	10,416	33,896	304,590
72	248,741	0.000%	0	-96,210	192,421	11,324	4,329	6,944	22,597	304,590
73	248,741	0.000%	0	-96,210	96,210	5,662	2,165	3,472	11,299	304,590
74	248,741	0.000%	0	-96,210	0	0	0	0	0	304,590

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Unit Name: Handsome Lake **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 42,347,182		Electric Expenses	Line 140	3,767		
2	Investment Generator & Exciter	Inputs Tab	$ 6,352,077		Other Expenses		-		
3	Reactive Allocator	(Line 71)	27.75%		O&M	(sum line 1 & 2)	3,767	1,762,701	0.2137%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**1,762,701**						
5					A&G		-	85,825,302	0.0000%
6	GSU Transformer Investment	Inputs Tab	-		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0029%
7	Reactive Allocator	(Line 71)	27.75%		Working Capital	Line 216	94,367	85,825,302	0.1100%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**		General Plant		-	85,825,302	0.0000%
9					Other Taxes	Line 196(c)	163,782	85,825,302	0.1908%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	-		Depreciation	Line 168(c)			0.3725%
11	Reactive Allocator	(Line 71)	27.75%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**0**		Taxes (Federal/State/Local)	Line 180			2.7413%
13					ADIT	-Line 233(k)	($915,275)	85,825,302	-1.0664%
14	Total Cost of Power Plant	Inputs Tab	85,825,302				(Sum Lines 1 to 11 , Col. (h))		10.6997%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	79,473,225						
16	Balance of Plant Allocator	(Line 79)	0.0000%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	0						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	1,762,701						
19	Reactive Fixed Charge Rate	(Line 14(h))	10.6997%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**188,604**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 188,604**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		59.00						
		59.00						
		59.00						
		59.00						
		59.00						
		-						
		-						
	Total	295.00	(Sum Lines 31 to 37)					
	Nominal Power Factor (pf)							
		0.85						
		0.85						
		0.85						
		0.85						
		0.85						
		-						
		-						
	Total	0.85	(Line 38 / 58)					
	MVA Capability (MVA)							
		69.41	(Line 31 / 41)					
		69.41	(Line 32 / 42)					
		69.41	(Line 33 / 43)					
		69.41	(Line 34 / 44)					
		69.41	(Line 35 / 45)					
	Total	347.06	(Sum Lines 51 to 57)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		36.56	(SQRT (Line 51^2 - Line 31^2))					
		36.56	(SQRT (Line 52^2 - Line 32^2))					
		36.56	(SQRT (Line 53^2 - Line 33^2))					
		36.56	(SQRT (Line 54^2 - Line 34^2))					
		36.56	(SQRT (Line 55^2 - Line 35^2))					
	Total	182.82	(Sum Lines 62 to 68)					
	Reactive Allocator	27.8%	(Line 69^2 / Line 58^2)					
		PENELEC is TO Fleet						
	Max. MVAr	-						
	Nameplate MVAr	182.82						
	Exciter MW	1.03						
	Generator MW	295.00						
	Balance of Plant Allocator	0.0000%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Hydro & Steam**	**Allocated Amt**
	Storage Batteries	$ -	**30%**	$ -
	Control&Power Cabling	$ -	**15%**	$ -
	Switch Board Equipment	$ -	**30%**	$ -
	Switching Equipment	$ -	**20%**	$ -
	Transformers	$ -	**5%**	$ -
	Aux Generator	$ -	**0%**	$ -
	Fire Protection System	$ -	**0%**	$ -
	HVAC	$ -	**0%**	$ -
	Regulating Equipment	$ -	**75%**	$ -
	Structure	$ -	**0%**	$ -
	Misc	$ -	**0%**	$ -
	Exciter & PPT	$ -	**100%**	$ -
	Station Grounding	$ -	**0%**	$ -
	Bus & Insulators	$ -	**60%**	$ -
	Capacitor Bank	$ -	**0%**	$ -
	Total	$ -		$ -

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	520,067	520,067	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	134,337	134,337	
	Steam From Other Sources	259,591		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	79,532		
	Rents	484,024	484,024	
	Allowances	19,559	19,559	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	202,857	202,857	
	Maintenance of Boiler (or reactor) Plant	86,989		
	Maintenance of Electric Plant	90,500		
	Maintenance of Misc Steam (or Nuclear) Plant	112,639	112,639	
	Other Power Production, & Other Expenses	341,664	341,664	
	Total NonFuel Expenses	2,331,757	1,815,146	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation			
	Plant Var Allocators		
	Electric Expense Allocator	4.1625%	Line 4(c) / 1(c))
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)
	Other Demand Expense Allocator	0.0000%	Line 79
	Production Plant Expenses		
	Total NonFuel Expenses	2,331,757	Line 116
	Allowances	19,559	Line 109
	Non-Fuel Production O&M	2,312,198	(Line 126 - 127)
	Operating Expenses		
	Operations Supervision & Engineering	520,067	Line 102(c)
	Electric Expenses	0	Line 106(c)
	Maintenance of Electric Plant	90,500	Line 113(b)
	Other Demand Related Expenses	1,295,079	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)
	Total	1,905,646	(Sum Lines 131 to 134)

				Allocator	Allocated Amount	
	Maintenance of Electric Plant	90,500	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	90,500	(Line 138 + 139)	4.1625%	3,767	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	1,295,079	(Line 134)	0.0000%	-	
				Line 123		
	Balance of Plant Fixed Expenses				1,901,879	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		713,054	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		183,732	(allocated on plant labor)	
	Total		896,786		
Depreciation					
	Annual Depreciation Exp ...DE	2,145,633			
	Gross Production Plant Cost ... F	85,825,302	Line 14		
	SLDP=DE/F	2.5000%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	40			
	SFDP=(R/((1+R)^n-1)		0.3725%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.741%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		163,782	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		163,782	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.7413%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	645,593				
		100.000%				
	Production Related Prepayments	645,593	(Line 209 * 210)			
	Unit Specific M&S	222,045				
	Total	867,638	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.7413%				
	Working Capital Costs	94,367	(Line 213 * 214)			

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Accumulated Deferred Income Taxes

Investment	85,825,302	Line 14	NPV of Col (j)> 10,758,427
Asset Service Life	40	Line 167	
Composite Tax Rate	38.6790%	Line 177	

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity = (f) *	(h) Interest = (f) *	(i) Income Taxes = (g) *	(j) Rev Req Impact	(k) Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	(Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	2,145,633	3.750%	3,218,449	414,955	414,955	24,420	9,336	14,975	48,731	915,275
2	2,145,633	7.219%	6,195,729	1,566,537	1,981,491	116,611	44,584	71,507	232,701	915,275
3	2,145,633	6.677%	5,730,555	1,386,612	3,368,104	198,213	75,782	121,546	395,541	915,275
4	2,145,633	6.177%	5,301,429	1,220,630	4,588,734	270,047	103,247	165,596	538,889	915,275
5	2,145,633	5.713%	4,903,200	1,066,599	5,655,333	332,816	127,245	204,086	664,148	915,275
6	2,145,633	5.285%	4,535,867	924,519	6,579,852	387,224	148,047	237,450	772,721	915,275
7	2,145,633	4.888%	4,195,141	792,729	7,372,582	433,876	165,883	266,057	865,817	915,275
8	2,145,633	4.522%	3,881,020	671,231	8,043,812	473,378	180,986	290,280	944,644	915,275
9	2,145,633	4.462%	3,829,525	651,313	8,695,125	511,708	195,640	313,785	1,021,133	915,275
10	2,145,633	4.461%	3,828,667	650,981	9,346,106	550,018	210,287	337,277	1,097,582	915,275
11	2,145,633	4.462%	3,829,525	651,313	9,997,418	588,348	224,942	360,781	1,174,071	915,275
12	2,145,633	4.461%	3,828,667	650,981	10,648,399	626,658	239,589	384,273	1,250,520	915,275
13	2,145,633	4.462%	3,829,525	651,313	11,299,712	664,988	254,244	407,777	1,327,009	915,275
14	2,145,633	4.461%	3,828,667	650,981	11,950,693	703,298	268,891	431,270	1,403,458	915,275
15	2,145,633	4.462%	3,829,525	651,313	12,602,005	741,628	283,545	454,774	1,479,947	915,275
16	2,145,633	4.461%	3,828,667	650,981	13,252,986	779,938	298,192	478,266	1,556,396	915,275
17	2,145,633	4.462%	3,829,525	651,313	13,904,299	818,268	312,847	501,770	1,632,885	915,275
18	2,145,633	4.461%	3,828,667	650,981	14,555,280	856,578	327,494	525,262	1,709,334	915,275
19	2,145,633	4.462%	3,829,525	651,313	15,206,593	894,908	342,148	548,767	1,785,823	915,275
20	2,145,633	4.461%	3,828,667	650,981	15,857,573	933,218	356,795	572,259	1,862,272	915,275
21	2,145,633	2.231%	1,914,762	-89,298	15,768,275	927,963	354,786	569,036	1,851,785	915,275
22	2,145,633	0.000%	0	-829,909	14,938,366	879,123	336,113	539,087	1,754,323	915,275
23	2,145,633	0.000%	0	-829,909	14,108,457	830,283	317,440	509,138	1,656,861	915,275
24	2,145,633	0.000%	0	-829,909	13,278,547	781,443	298,767	479,188	1,559,398	915,275
25	2,145,633	0.000%	0	-829,909	12,448,638	732,602	280,094	449,239	1,461,936	915,275
26	2,145,633	0.000%	0	-829,909	11,618,729	683,762	261,421	419,290	1,364,473	915,275
27	2,145,633	0.000%	0	-829,909	10,788,820	634,922	242,748	389,341	1,267,011	915,275
28	2,145,633	0.000%	0	-829,909	9,958,911	586,082	224,075	359,391	1,169,549	915,275
29	2,145,633	0.000%	0	-829,909	9,129,001	537,242	205,403	329,442	1,072,086	915,275
30	2,145,633	0.000%	0	-829,909	8,299,092	488,402	186,730	299,493	974,624	915,275
31	2,145,633	0.000%	0	-829,909	7,469,183	439,561	168,057	269,543	877,161	915,275
32	2,145,633	0.000%	0	-829,909	6,639,274	390,721	149,384	239,594	779,699	915,275
33	2,145,633	0.000%	0	-829,909	5,809,365	341,881	130,711	209,645	682,237	915,275
34	2,145,633	0.000%	0	-829,909	4,979,455	293,041	112,038	179,696	584,774	915,275
35	2,145,633	0.000%	0	-829,909	4,149,546	244,201	93,365	149,746	487,312	915,275
36	2,145,633	0.000%	0	-829,909	3,319,637	195,361	74,692	119,797	389,850	915,275
37	2,145,633	0.000%	0	-829,909	2,489,728	146,520	56,019	89,848	292,387	915,275
38	2,145,633	0.000%	0	-829,909	1,659,818	97,680	37,346	59,899	194,925	915,275
39	2,145,633	0.000%	0	-829,909	829,909	48,840	18,673	29,949	97,462	915,275
40	2,145,633	0.000%	0	-829,909	0	0	0	0	0	915,275

Unit Name: LaSalle 1 & 2 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 322,991,066	
2	Investment Generator & Exciter	Inputs Tab	48,448,660	
3	Reactive Allocator	(Line 71)	16.38%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**7,938,051**	
5				
6	GSU Transformer Investment	Inputs Tab	4,672,421	
7	Reactive Allocator	(Line 71)	16.38%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**765,551**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	5,186,913	
11	Reactive Allocator	(Line 71)	16.38%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**849,848**	
13				
14	Total Cost of Power Plant	Inputs Tab	1,412,906,574	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	1,354,598,580	
16	Balance of Plant Allocator	(Line 79)	0.1358%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	1,840,172	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	11,393,621	
19	Reactive Fixed Charge Rate	(Line 14(h))	29.0313%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**3,307,715**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 3,307,715**	
23				
24				
25				
26				

	(e)		(f)	(g)	(h)
	Fixed Charge Rate for Reactive Plant				
			Calculated Amt	Plant	FCR % (f) / (g)
	Electric Expenses	Line 140	356,089		
	Other Expenses		146,963		
	O&M	(sum line 1 & 2)	503,052	11,393,621	4.4152%
	A&G		130,879,636	1,412,906,574	9.2631%
	CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.1901%
	Working Capital	Line 216	49,177,288	1,412,906,574	3.4806%
	General Plant		-	1,412,906,574	0.0000%
	Other Taxes	Line 196(c)	27,773,747	1,412,906,574	1.9657%
	Depreciation	Line 168(c)			0.0752%
					8.1350%
	Taxes (Federal/State/Local)	Line 180			2.9859%
	ADIT	-Line 233(k)	($20,905,199)	1,412,906,574	-1.4796%
			(Sum Lines 1 to 11 , Col. (h))		29.0313%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		1,194.00						
		1,183.00						
		-						
	Total	2,377.00	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.93						
		0.90						
		-						
	Total	0.91	(Line 38 / 58)					
	MVA Capability (MVA)							
		1,286.87	(Line 31 / 41)					
		1,314.44	(Line 32 / 42)					
		-						
	Total	2,601.32	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		480.00	(SQRT (Line 51^2 - Line 31^2))					
		572.95	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	1,052.95	(Sum Lines 62 to 64)					
	Reactive Allocator	16.4%	(Line 69^2 / Line 58^2)					
		ComEd is TO Fleet						
	Max. MVAr	2,187						
	Nameplate MVAr	4,856						
	Exciter MW	35						
	Generator MW	11,447						
	Balance of Plant Allocator	0.1358%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ 1,944,786	15%	$ 291,718
	Control&Power Cabling	$ 23,115,092	1%	$ 231,151
	Switch Board Equipment	$ 6,488,908	1%	$ 64,889
	Switching Equipment	$ 6,572,575	1%	$ 65,726
	Transformers	$ 2,026,797	3%	$ 60,804
	Aux Generator	$ 10,275,282	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	50%	$ -
	Structure	$ 445,431	0%	$ -
	Misc	$ 85,054,019	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	1%	$ -
	Bus & Insulators	$ 5,590,781	80%	$ 4,472,625
	Capacitor Bank	$ -	0%	$ -
	Total	$ 141,513,673		$ 5,186,913

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	30,478,210	30,478,210	
	Coolants and Water (Nuclear Plants Only)	2,986,351		
	Steam Expenses	18,731,778	18,731,778	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	1,913,700		
	Rents	52,912,201	52,912,201	
	Allowances	4,198,705	4,198,705	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	5,622,700	5,622,700	
	Maintenance of Boiler (or reactor) Plant	438,245		
	Maintenance of Electric Plant	14,488,892		
	Maintenance of Misc Steam (or Nuclear) Plant	9,306,811	9,306,811	
	Other Power Production, & Other Expenses	17,411,239	17,411,239	
	Total NonFuel Expenses	158,488,835	138,661,645	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	2.4577%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.1358%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	158,488,835	Line 116			
	Allowances	4,198,705	Line 109			
	Non-Fuel Production O&M	154,290,130	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	30,478,210	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	14,488,892	Line 113(b)			
	Other Demand Related Expenses	108,183,436	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	153,150,538	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	14,488,892	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	14,488,892	(Line 138 + 139)	2.4577%	356,089	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	108,183,436	(Line 134)	0.1358%	146,963	
				Line 123		
	Balance of Plant Fixed Expenses				152,647,486	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		118,779,529	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		12,100,106	(allocated on plant labor)	
	Total		130,879,636		
Depreciation					
	Annual Depreciation Exp ...DE	23,548,443			
	Gross Production Plant Cost ... F	1,412,906,574	Line 14		
	SLDP=DE/F	1.6667%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	60			
	SFDP=(R/((1+R)^n-1)		0.0752%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.986%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		21,480,427		
	Payroll Taxes	7,193,199			
		0 87.4899%	Line 117		
	Fixed Payroll Taxes		6,293,320	(Line 193 * 194)	
	Total Other Taxes		27,773,747	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9859%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	2,368,865				
		100.000%				
	Production Related Prepayments	2,368,865	(Line 209 * 210)			
	Unit Specific M&S	439,838,836				
	Total	442,207,701	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9859%				
	Working Capital Costs	49,177,288	(Line 213 * 214)			

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(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)

Accumulated Deferred Income Taxes

Investment	1,412,906,574	Line 14	NPV of Col (j)> 254,623,862
Asset Service Life	60	Line 167	
Composite Tax Rate	38.6790%	Line 177	

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity = (f) *	Interest = (f) *	Income Taxes = (g) *	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	(Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	23,548,443	3.750%	52,983,997	11,385,378	11,385,378	670,029	256,171	410,869	1,337,069	20,905,199
2	23,548,443	7.219%	101,997,726	30,343,398	41,728,776	2,455,738	938,897	1,505,883	4,900,519	20,905,199
3	23,548,443	6.677%	94,339,772	27,381,378	69,110,154	4,067,133	1,554,978	2,494,006	8,116,117	20,905,199
4	23,548,443	6.177%	87,275,239	24,648,887	93,759,041	5,517,720	2,109,578	3,383,521	11,010,819	20,905,199
5	23,548,443	5.713%	80,719,353	22,113,136	115,872,178	6,819,078	2,607,124	4,181,527	13,607,728	20,905,199
6	23,548,443	5.285%	74,672,112	19,774,124	135,646,302	7,982,785	3,052,042	4,895,124	15,929,950	20,905,199
7	23,548,443	4.888%	69,062,873	17,604,527	153,250,828	9,018,811	3,448,144	5,530,425	17,997,380	20,905,199
8	23,548,443	4.522%	63,891,635	15,604,343	168,855,172	9,937,127	3,799,241	6,093,546	19,829,914	20,905,199
9	23,548,443	4.462%	63,043,891	15,276,444	184,131,616	10,836,146	4,142,961	6,644,833	21,623,940	20,905,199
10	23,548,443	4.461%	63,029,762	15,270,980	199,402,596	11,734,843	4,486,558	7,195,923	23,417,324	20,905,199
11	23,548,443	4.462%	63,043,891	15,276,444	214,679,040	12,633,862	4,830,278	7,747,210	25,211,350	20,905,199
12	23,548,443	4.461%	63,029,762	15,270,980	229,950,020	13,532,559	5,173,875	8,298,300	27,004,734	20,905,199
13	23,548,443	4.462%	63,043,891	15,276,444	245,226,464	14,431,577	5,517,595	8,849,588	28,798,760	20,905,199
14	23,548,443	4.461%	63,029,762	15,270,980	260,497,444	15,330,275	5,861,192	9,400,678	30,592,145	20,905,199
15	23,548,443	4.462%	63,043,891	15,276,444	275,773,888	16,229,293	6,204,912	9,951,965	32,386,171	20,905,199
16	23,548,443	4.461%	63,029,762	15,270,980	291,044,868	17,127,990	6,548,510	10,503,055	34,179,555	20,905,199
17	23,548,443	4.462%	63,043,891	15,276,444	306,321,312	18,027,009	6,892,230	11,054,342	35,973,581	20,905,199
18	23,548,443	4.461%	63,029,762	15,270,980	321,592,292	18,925,706	7,235,827	11,605,432	37,766,965	20,905,199
19	23,548,443	4.462%	63,043,891	15,276,444	336,868,736	19,824,725	7,579,547	12,156,720	39,560,991	20,905,199
20	23,548,443	4.461%	63,029,762	15,270,980	352,139,716	20,723,422	7,923,144	12,707,810	41,354,376	20,905,199
21	23,548,443	2.231%	31,521,946	3,084,071	355,223,787	20,904,920	7,992,535	12,819,106	41,716,561	20,905,199
22	23,548,443	0.000%	0	-9,108,302	346,115,485	20,368,896	7,787,598	12,490,411	40,646,906	20,905,199
23	23,548,443	0.000%	0	-9,108,302	337,007,182	19,832,873	7,582,662	12,161,716	39,577,250	20,905,199
24	23,548,443	0.000%	0	-9,108,302	327,898,880	19,296,849	7,377,725	11,833,021	38,507,595	20,905,199
25	23,548,443	0.000%	0	-9,108,302	318,790,578	18,760,826	7,172,788	11,504,326	37,437,939	20,905,199
26	23,548,443	0.000%	0	-9,108,302	309,682,276	18,224,802	6,967,851	11,175,631	36,368,284	20,905,199
27	23,548,443	0.000%	0	-9,108,302	300,573,974	17,688,778	6,762,914	10,846,936	35,298,629	20,905,199
28	23,548,443	0.000%	0	-9,108,302	291,465,671	17,152,755	6,557,978	10,518,241	34,228,973	20,905,199
29	23,548,443	0.000%	0	-9,108,302	282,357,369	16,616,731	6,353,041	10,189,546	33,159,318	20,905,199
30	23,548,443	0.000%	0	-9,108,302	273,249,067	16,080,708	6,148,104	9,860,851	32,089,662	20,905,199
31	23,548,443	0.000%	0	-9,108,302	264,140,765	15,544,684	5,943,167	9,532,156	31,020,007	20,905,199
32	23,548,443	0.000%	0	-9,108,302	255,032,462	15,008,660	5,738,230	9,203,461	29,950,351	20,905,199
33	23,548,443	0.000%	0	-9,108,302	245,924,160	14,472,637	5,533,294	8,874,766	28,880,696	20,905,199
34	23,548,443	0.000%	0	-9,108,302	236,815,858	13,936,613	5,328,357	8,546,071	27,811,041	20,905,199
35	23,548,443	0.000%	0	-9,108,302	227,707,556	13,400,590	5,123,420	8,217,376	26,741,385	20,905,199
36	23,548,443	0.000%	0	-9,108,302	218,599,253	12,864,566	4,918,483	7,888,681	25,671,730	20,905,199
37	23,548,443	0.000%	0	-9,108,302	209,490,951	12,328,542	4,713,546	7,559,986	24,602,074	20,905,199
38	23,548,443	0.000%	0	-9,108,302	200,382,649	11,792,519	4,508,610	7,231,291	23,532,419	20,905,199
39	23,548,443	0.000%	0	-9,108,302	191,274,347	11,256,495	4,303,673	6,902,595	22,462,764	20,905,199
40	23,548,443	0.000%	0	-9,108,302	182,166,045	10,720,472	4,098,736	6,573,900	21,393,108	20,905,199
41	23,548,443	0.000%	0	-9,108,302	173,057,742	10,184,448	3,893,799	6,245,205	20,323,453	20,905,199
42	23,548,443	0.000%	0	-9,108,302	163,949,440	9,648,425	3,688,862	5,916,510	19,253,797	20,905,199
43	23,548,443	0.000%	0	-9,108,302	154,841,138	9,112,401	3,483,926	5,587,815	18,184,142	20,905,199
44	23,548,443	0.000%	0	-9,108,302	145,732,836	8,576,377	3,278,989	5,259,120	17,114,487	20,905,199
45	23,548,443	0.000%	0	-9,108,302	136,624,533	8,040,354	3,074,052	4,930,425	16,044,831	20,905,199
46	23,548,443	0.000%	0	-9,108,302	127,516,231	7,504,330	2,869,115	4,601,730	14,975,176	20,905,199
47	23,548,443	0.000%	0	-9,108,302	118,407,929	6,968,307	2,664,178	4,273,035	13,905,520	20,905,199
48	23,548,443	0.000%	0	-9,108,302	109,299,627	6,432,283	2,459,242	3,944,340	12,835,865	20,905,199
49	23,548,443	0.000%	0	-9,108,302	100,191,325	5,896,259	2,254,305	3,615,645	11,766,210	20,905,199
50	23,548,443	0.000%	0	-9,108,302	91,083,022	5,360,236	2,049,368	3,286,950	10,696,554	20,905,199
51	23,548,443	0.000%	0	-9,108,302	81,974,720	4,824,212	1,844,431	2,958,255	9,626,899	20,905,199
52	23,548,443	0.000%	0	-9,108,302	72,866,418	4,288,189	1,639,494	2,629,560	8,557,243	20,905,199
53	23,548,443	0.000%	0	-9,108,302	63,758,116	3,752,165	1,434,558	2,300,865	7,487,588	20,905,199
54	23,548,443	0.000%	0	-9,108,302	54,649,813	3,216,142	1,229,621	1,972,170	6,417,932	20,905,199
55	23,548,443	0.000%	0	-9,108,302	45,541,511	2,680,118	1,024,684	1,643,475	5,348,277	20,905,199
56	23,548,443	0.000%	0	-9,108,302	36,433,209	2,144,094	819,747	1,314,780	4,278,622	20,905,199
57	23,548,443	0.000%	0	-9,108,302	27,324,907	1,608,071	614,810	986,085	3,208,966	20,905,199
58	23,548,443	0.000%	0	-9,108,302	18,216,604	1,072,047	409,874	657,390	2,139,311	20,905,199
59	23,548,443	0.000%	0	-9,108,302	9,108,302	536,024	204,937	328,695	1,069,655	20,905,199
60	23,548,443	0.000%	0	-9,108,302	0	0	0	0	0	20,905,199

Unit Name: Limerick 1 & 2 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 195,863,167		Electric Expenses	Line 140	240,476		
2	Investment Generator & Exciter	Inputs Tab	29,379,475		Other Expenses		53,964		
3	Reactive Allocator	(Line 71)	12.02%		O&M	(sum line 1 & 2)	294,440	9,164,142	3.2130%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**3,530,844**						
5					A&G		129,059,930	1,222,406,959	10.5579%
6	GSU Transformer Investment	Inputs Tab	41,192,118		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.1911%
7	Reactive Allocator	(Line 71)	12.02%		Working Capital	Line 216	35,602,957	1,222,406,959	2.9125%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**4,950,494**		General Plant		-	1,222,406,959	0.0000%
9					Other Taxes	Line 196(c)	10,408,455	1,222,406,959	0.8515%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	491,006		Depreciation	Line 168(c)			0.0814%
11	Reactive Allocator	(Line 71)	12.02%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**59,009**		Taxes (Federal/State/Local)	Line 180			2.9692%
13					ADIT	-Line 233(k)	($17,900,968)	1,222,406,959	-1.4644%
14	Total Cost of Power Plant	Inputs Tab	1,222,406,959				(Sum Lines 1 to 11 , Col. (h))		27.4471%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	1,151,344,360						
16	Balance of Plant Allocator	(Line 79)	0.0542%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	623,795						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	9,164,142						
19	Reactive Fixed Charge Rate	(Line 14(h))	27.4471%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**2,515,295**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 2,515,295**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		1,182.00						
		1,143.00						
		-						
	Total	2,325.00	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.93						
		0.94						
		-						
	Total	0.94	(Line 38 / 58)					
	MVA Capability (MVA)							
		1,265.52	(Line 31 / 41)					
		1,213.38	(Line 32 / 42)					
		-						
	Total	2,478.90	(Sum Lines 51 to 52)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		452.14	(SQRT (Line 51^2 - Line 31^2))					
		407.22	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	859.36	(Sum Lines 62 to 64)					
	Reactive Allocator	12.0%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ 1,414,202	15%	$ 212,130
	Control&Power Cabling	$ 23,319,901	1%	$ 233,199
	Switch Board Equipment	$ 1,188,580	1%	$ 11,886
	Switching Equipment	$ 228,627	1%	$ 2,286
	Transformers	$ 1,050,152	3%	$ 31,505
	Aux Generator	$ 5,506,158	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	50%	$ -
	Structure	$ 301,814	0%	$ -
	Misc	$ 76,645,785	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	1%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 109,655,219		$ 491,006

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	28,060,813	28,060,813	
	Coolants and Water (Nuclear Plants Only)	2,749,487		
	Steam Expenses	17,246,057	17,246,057	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	1,761,914		
	Rents	48,715,440	48,715,440	
	Allowances	3,865,683	3,865,683	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	5,176,733	5,176,733	
	Maintenance of Boiler (or reactor) Plant	403,486		
	Maintenance of Electric Plant	13,339,698		
	Maintenance of Misc Steam (or Nuclear) Plant	8,568,637	8,568,637	
	Other Power Production, & Other Expenses	16,030,257	16,030,257	
	Total NonFuel Expenses	145,918,204	127,663,619	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation

	Plant Var Allocators					
	Electric Expense Allocator	1.8027%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	145,918,204	Line 116			
	Allowances	3,865,683	Line 109			
	Non-Fuel Production O&M	142,052,522	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	28,060,813	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	13,339,698	Line 113(b)			
	Other Demand Related Expenses	99,602,806	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131			
	Total	141,003,317	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	13,339,698	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	13,339,698	(Line 138 + 139)	1.8027%	240,476	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	99,602,806	(Line 134)	0.0542%	53,964	
				Line 123		
	Balance of Plant Fixed Expenses				140,708,877	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		116,605,447	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		12,454,484	(allocated on plant labor)	
	Total		129,059,930		
Depreciation					
	Annual Depreciation Exp ...DE	20,895,845			
	Gross Production Plant Cost ... F	1,222,406,959	Line 14		
	SLDP=DE/F	1.7094%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	59			
	SFDP=(R/((1+R)^n-1)		0.0814%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.969%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		3,969,570		
	Payroll Taxes	7,359,580			
		0 87.4899%	Line 117		
	Fixed Payroll Taxes		6,438,885	(Line 193 * 194)	
	Total Other Taxes		10,408,455	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9692%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	2,049,475				
		100.000%				
	Production Related Prepayments	2,049,475	(Line 209 * 210)			
	Unit Specific M&S	318,577,209				
	Total	320,626,684	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9692%				
	Working Capital Costs	35,602,957	(Line 213 * 214)			

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Accumulated Deferred Income Taxes

Investment	1,222,406,959	Line 14
Asset Service Life	59	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 217,868,519

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	20,718,762	3.750%	45,840,261	9,716,745	9,716,745	571,830	218,627	350,652	1,141,109	17,900,968
2	20,718,762	7.219%	88,245,558	26,118,690	35,835,434	2,108,915	806,297	1,293,208	4,208,421	17,900,968
3	20,718,762	6.677%	81,620,113	23,556,033	59,391,468	3,495,188	1,336,308	2,143,284	6,974,780	17,900,968
4	20,718,762	6.177%	75,508,078	21,191,959	80,583,427	4,742,335	1,813,127	2,908,047	9,463,509	17,900,968
5	20,718,762	5.713%	69,836,110	18,998,099	99,581,526	5,860,373	2,240,584	3,593,639	11,694,596	17,900,968
6	20,718,762	5.285%	64,604,208	16,974,452	116,555,977	6,859,319	2,622,509	4,206,203	13,688,032	17,900,968
7	20,718,762	4.888%	59,751,252	15,097,377	131,653,354	7,747,800	2,962,200	4,751,028	15,461,029	17,900,968
8	20,718,762	4.522%	55,277,243	13,366,875	145,020,229	8,534,440	3,262,955	5,233,404	17,030,800	17,900,968
9	20,718,762	4.462%	54,543,799	13,083,186	158,103,415	9,304,386	3,557,327	5,705,543	18,567,255	17,900,968
10	20,718,762	4.461%	54,531,574	13,078,458	171,181,873	10,074,053	3,851,592	6,177,510	20,103,156	17,900,968
11	20,718,762	4.462%	54,543,799	13,083,186	184,265,059	10,843,999	4,145,964	6,649,648	21,639,611	17,900,968
12	20,718,762	4.461%	54,531,574	13,078,458	197,343,516	11,613,666	4,440,229	7,121,616	23,175,511	17,900,968
13	20,718,762	4.462%	54,543,799	13,083,186	210,426,702	12,383,611	4,734,601	7,593,754	24,711,967	17,900,968
14	20,718,762	4.461%	54,531,574	13,078,458	223,505,160	13,153,279	5,028,866	8,065,722	26,247,867	17,900,968
15	20,718,762	4.462%	54,543,799	13,083,186	236,588,346	13,923,224	5,323,238	8,537,860	27,784,322	17,900,968
16	20,718,762	4.461%	54,531,574	13,078,458	249,666,803	14,692,891	5,617,503	9,009,828	29,320,222	17,900,968
17	20,718,762	4.462%	54,543,799	13,083,186	262,749,989	15,462,837	5,911,875	9,481,966	30,856,678	17,900,968
18	20,718,762	4.461%	54,531,574	13,078,458	275,828,447	16,232,504	6,206,140	9,953,934	32,392,578	17,900,968
19	20,718,762	4.462%	54,543,799	13,083,186	288,911,633	17,002,450	6,500,512	10,426,072	33,929,033	17,900,968
20	20,718,762	4.461%	54,531,574	13,078,458	301,990,091	17,772,117	6,794,777	10,898,040	35,464,934	17,900,968
21	20,718,762	2.231%	27,271,899	2,534,688	304,524,779	17,921,283	6,851,808	10,989,510	35,762,601	17,900,968
22	20,718,762	0.000%	0	-8,013,810	296,510,969	17,449,671	6,671,497	10,700,312	34,821,480	17,900,968
23	20,718,762	0.000%	0	-8,013,810	288,497,159	16,978,058	6,491,186	10,411,115	33,880,359	17,900,968
24	20,718,762	0.000%	0	-8,013,810	280,483,349	16,506,445	6,310,875	10,121,917	32,939,238	17,900,968
25	20,718,762	0.000%	0	-8,013,810	272,469,539	16,034,832	6,130,565	9,832,720	31,998,117	17,900,968
26	20,718,762	0.000%	0	-8,013,810	264,455,729	15,563,220	5,950,254	9,543,522	31,056,995	17,900,968
27	20,718,762	0.000%	0	-8,013,810	256,441,919	15,091,607	5,769,943	9,254,324	30,115,874	17,900,968
28	20,718,762	0.000%	0	-8,013,810	248,428,109	14,619,994	5,589,632	8,965,127	29,174,753	17,900,968
29	20,718,762	0.000%	0	-8,013,810	240,414,299	14,148,381	5,409,322	8,675,929	28,233,632	17,900,968
30	20,718,762	0.000%	0	-8,013,810	232,400,489	13,676,769	5,229,011	8,386,731	27,292,511	17,900,968
31	20,718,762	0.000%	0	-8,013,810	224,386,679	13,205,156	5,048,700	8,097,534	26,351,390	17,900,968
32	20,718,762	0.000%	0	-8,013,810	216,372,869	12,733,543	4,868,390	7,808,336	25,410,269	17,900,968
33	20,718,762	0.000%	0	-8,013,810	208,359,059	12,261,931	4,688,079	7,519,138	24,469,148	17,900,968
34	20,718,762	0.000%	0	-8,013,810	200,345,249	11,790,318	4,507,768	7,229,941	23,528,027	17,900,968
35	20,718,762	0.000%	0	-8,013,810	192,331,439	11,318,705	4,327,457	6,940,743	22,586,906	17,900,968
36	20,718,762	0.000%	0	-8,013,810	184,317,629	10,847,092	4,147,147	6,651,546	21,645,785	17,900,968
37	20,718,762	0.000%	0	-8,013,810	176,303,819	10,375,480	3,966,836	6,362,348	20,704,664	17,900,968
38	20,718,762	0.000%	0	-8,013,810	168,290,009	9,903,867	3,786,525	6,073,150	19,763,543	17,900,968
39	20,718,762	0.000%	0	-8,013,810	160,276,199	9,432,254	3,606,214	5,783,953	18,822,421	17,900,968
40	20,718,762	0.000%	0	-8,013,810	152,262,389	8,960,642	3,425,904	5,494,755	17,881,300	17,900,968
41	20,718,762	0.000%	0	-8,013,810	144,248,579	8,489,029	3,245,593	5,205,557	16,940,179	17,900,968
42	20,718,762	0.000%	0	-8,013,810	136,234,769	8,017,416	3,065,282	4,916,360	15,999,058	17,900,968
43	20,718,762	0.000%	0	-8,013,810	128,220,959	7,545,803	2,884,972	4,627,162	15,057,937	17,900,968
44	20,718,762	0.000%	0	-8,013,810	120,207,149	7,074,191	2,704,661	4,337,965	14,116,816	17,900,968
45	20,718,762	0.000%	0	-8,013,810	112,193,339	6,602,578	2,524,350	4,048,767	13,175,695	17,900,968
46	20,718,762	0.000%	0	-8,013,810	104,179,530	6,130,965	2,344,039	3,759,569	12,234,574	17,900,968
47	20,718,762	0.000%	0	-8,013,810	96,165,720	5,659,353	2,163,729	3,470,372	11,293,453	17,900,968
48	20,718,762	0.000%	0	-8,013,810	88,151,910	5,187,740	1,983,418	3,181,174	10,352,332	17,900,968
49	20,718,762	0.000%	0	-8,013,810	80,138,100	4,716,127	1,803,107	2,891,976	9,411,211	17,900,968
50	20,718,762	0.000%	0	-8,013,810	72,124,290	4,244,514	1,622,797	2,602,779	8,470,090	17,900,968
51	20,718,762	0.000%	0	-8,013,810	64,110,480	3,772,902	1,442,486	2,313,581	7,528,969	17,900,968
52	20,718,762	0.000%	0	-8,013,810	56,096,670	3,301,289	1,262,175	2,024,383	6,587,848	17,900,968
53	20,718,762	0.000%	0	-8,013,810	48,082,860	2,829,676	1,081,864	1,735,186	5,646,726	17,900,968
54	20,718,762	0.000%	0	-8,013,810	40,069,050	2,358,064	901,554	1,445,988	4,705,605	17,900,968
55	20,718,762	0.000%	0	-8,013,810	32,055,240	1,886,451	721,243	1,156,791	3,764,484	17,900,968
56	20,718,762	0.000%	0	-8,013,810	24,041,430	1,414,838	540,932	867,593	2,823,363	17,900,968
57	20,718,762	0.000%	0	-8,013,810	16,027,620	943,225	360,621	578,395	1,882,242	17,900,968
58	20,718,762	0.000%	0	-8,013,810	8,013,810	471,613	180,311	289,198	941,121	17,900,968
59	20,718,762	0.000%	0	-8,013,810	0	0	0	0	0	17,900,968

Unit Name: Moser 1-3 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 5,376,210	
2	Investment Generator & Exciter	Inputs Tab	$ 806,431	
3	Reactive Allocator	(Line 71)	32.04%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**258,383**	
5				
6	GSU Transformer Investment	Inputs Tab	-	
7	Reactive Allocator	(Line 71)	32.04%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	371,713	
11	Reactive Allocator	(Line 71)	32.04%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**119,098**	
13				
14	Total Cost of Power Plant	Inputs Tab	8,301,032	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	7,122,888	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	3,859	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	381,340	
19	Reactive Fixed Charge Rate	(Line 14(h))	11.8814%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**45,309**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 45,309**	
23				
24				
25				
26				

	(e)		(f)	(g)	(h)
	Fixed Charge Rate for Reactive Plant				
			Calculated Amt	Plant	FCR % (f) / (g)
	Electric Expenses	Line 140	621		
	Other Expenses		100		
	O&M	(sum line 1 & 2)	721	381,340	0.1891%
	A&G		53,021	8,301,032	0.6387%
	CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0115%
	Working Capital	Line 216	101,135	8,301,032	1.2183%
	General Plant		-	8,301,032	0.0000%
	Other Taxes	Line 196(c)	11,386	8,301,032	0.1372%
	Depreciation	Line 168(c)			0.0594%
					8.1350%
	Taxes (Federal/State/Local)	Line 180			3.0148%
	ADIT	-Line 233(k)	($126,401)	8,301,032	-1.5227%
			(Sum Lines 1 to 11 , Col. (h))		11.8814%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		16.00						
		16.38						
		16.50						
	Total	48.88	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.82						
		0.82						
		0.83						
	Total	0.82	(Line 38 / 58)					
	MVA Capability (MVA)							
		19.46	(Line 31 / 41)					
		19.95	(Line 32 / 42)					
		19.88	(Line 33 / 43)					
	Total	59.30	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		11.08	(SQRT (Line 51^2 - Line 31^2))					
		11.39	(SQRT (Line 52^2 - Line 32^2))					
		11.09	(SQRT (Line 53^2 - Line 33^2))					
	Total	33.56	(Sum Lines 62 to 64)					
	Reactive Allocator	32.0%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ 9,365	50%	$ 4,683
	Control&Power Cabling	$ 262,801	50%	$ 131,401
	Switch Board Equipment	$ -	50%	$ -
	Switching Equipment	$ 589,074	40%	$ 235,629
	Transformers	$ -	10%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ 13,093	0%	$ -
	Misc	$ 490,974	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 1,365,306		$ 371,713

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	74,248	74,248	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	19,179	19,179	
	Steam From Other Sources	37,061		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	11,355		
	Rents	69,103	69,103	
	Allowances	2,792	2,792	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	28,961	28,961	
	Maintenance of Boiler (or reactor) Plant	12,419		
	Maintenance of Electric Plant	12,920		
	Maintenance of Misc Steam (or Nuclear) Plant	16,081	16,081	
	Other Power Production, & Other Expenses	48,778	48,778	
	Total NonFuel Expenses	332,898	259,143	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	4.8060%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	332,898	Line 116			
	Allowances	2,792	Line 109			
	Non-Fuel Production O&M	330,106	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	74,248	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	12,920	Line 113(b)			
	Other Demand Related Expenses	184,895	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	272,063	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	12,920	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	12,920	(Line 138 + 139)	4.8060%	621	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	184,895	(Line 134)	0.0542%	100	
				Line 123		
	Balance of Plant Fixed Expenses				271,342	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		16,599	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		36,422	(allocated on plant labor)	
	Total		53,021		
Depreciation					
	Annual Depreciation Exp ...DE	131,762			
	Gross Production Plant Cost ... F	8,301,032	Line 14		
	SLDP=DE/F	1.5873%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	63			
	SFDP=(R/((1+R)^n-1)		0.0594%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.015%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		11,386	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		11,386	(Line 192 + 195)	
		Plant		**Depreciation**	**Total**
General Plant		-		-	
		0.000%		0.000%	Line 159
	Fixed General Plant	-		-	(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188		
	Taxes on General Plant	3.0148%	Line 189		
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-
Working Capital					
	Prepayments	62,442			
		100.000%			
	Production Related Prepayments	62,442	(Line 209 * 210)		
	Unit Specific M&S	844,613			
	Total	907,055	(Line 211 + 212)		
	Return on Working Capital	8.1350%			
	Taxes on Working Capital	3.0148%			
	Working Capital Costs	101,135	(Line 213 * 214)		

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Accumulated Deferred Income Taxes

Investment	8,301,032	Line 14
Asset Service Life	63	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 1,542,529

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	PMT of NPV col. (j)
1	131,762	3.750%	311,289	69,439	69,439	4,086	1,562	2,506	8,155	126,401
2	131,762	7.219%	599,252	180,820	250,259	14,728	5,631	9,031	29,390	126,401
3	131,762	6.677%	554,260	163,418	413,677	24,345	9,308	14,929	48,581	126,401
4	131,762	6.177%	512,755	147,364	561,041	33,017	12,623	20,247	65,887	126,401
5	131,762	5.713%	474,238	132,466	693,507	40,813	15,604	25,027	81,444	126,401
6	131,762	5.285%	438,710	118,724	812,231	47,800	18,275	29,311	95,386	126,401
7	131,762	4.888%	405,754	105,977	918,208	54,037	20,660	33,136	107,832	126,401
8	131,762	4.522%	375,373	94,226	1,012,435	59,582	22,780	36,536	118,898	126,401
9	131,762	4.462%	370,392	92,300	1,104,734	65,014	24,857	39,867	129,737	126,401
10	131,762	4.461%	370,309	92,267	1,197,002	70,444	26,933	43,197	140,573	126,401
11	131,762	4.462%	370,392	92,300	1,289,301	75,875	29,009	46,528	151,412	126,401
12	131,762	4.461%	370,309	92,267	1,381,569	81,305	31,085	49,857	162,248	126,401
13	131,762	4.462%	370,392	92,300	1,473,868	86,737	33,162	53,188	173,087	126,401
14	131,762	4.461%	370,309	92,267	1,566,136	92,167	35,238	56,518	183,923	126,401
15	131,762	4.462%	370,392	92,300	1,658,435	97,599	37,315	59,849	194,762	126,401
16	131,762	4.461%	370,309	92,267	1,750,703	103,029	39,391	63,178	205,598	126,401
17	131,762	4.462%	370,392	92,300	1,843,002	108,461	41,468	66,509	216,437	126,401
18	131,762	4.461%	370,309	92,267	1,935,270	113,891	43,544	69,839	227,273	126,401
19	131,762	4.462%	370,392	92,300	2,027,569	119,322	45,620	73,170	238,112	126,401
20	131,762	4.461%	370,309	92,267	2,119,837	124,752	47,696	76,499	248,948	126,401
21	131,762	2.231%	185,196	20,668	2,140,504	125,969	48,161	77,245	251,375	126,401
22	131,762	0.000%	0	-50,964	2,089,540	122,969	47,015	75,406	245,390	126,401
23	131,762	0.000%	0	-50,964	2,038,575	119,970	45,868	73,567	239,405	126,401
24	131,762	0.000%	0	-50,964	1,987,611	116,971	44,721	71,728	233,420	126,401
25	131,762	0.000%	0	-50,964	1,936,647	113,972	43,575	69,889	227,435	126,401
26	131,762	0.000%	0	-50,964	1,885,682	110,972	42,428	68,049	221,450	126,401
27	131,762	0.000%	0	-50,964	1,834,718	107,973	41,281	66,210	215,465	126,401
28	131,762	0.000%	0	-50,964	1,783,753	104,974	40,134	64,371	209,479	126,401
29	131,762	0.000%	0	-50,964	1,732,789	101,975	38,988	62,532	203,494	126,401
30	131,762	0.000%	0	-50,964	1,681,825	98,975	37,841	60,693	197,509	126,401
31	131,762	0.000%	0	-50,964	1,630,860	95,976	36,694	58,854	191,524	126,401
32	131,762	0.000%	0	-50,964	1,579,896	92,977	35,548	57,014	185,539	126,401
33	131,762	0.000%	0	-50,964	1,528,932	89,978	34,401	55,175	179,554	126,401
34	131,762	0.000%	0	-50,964	1,477,967	86,978	33,254	53,336	173,569	126,401
35	131,762	0.000%	0	-50,964	1,427,003	83,979	32,108	51,497	167,584	126,401
36	131,762	0.000%	0	-50,964	1,376,038	80,980	30,961	49,658	161,598	126,401
37	131,762	0.000%	0	-50,964	1,325,074	77,981	29,814	47,818	155,613	126,401
38	131,762	0.000%	0	-50,964	1,274,110	74,981	28,667	45,979	149,628	126,401
39	131,762	0.000%	0	-50,964	1,223,145	71,982	27,521	44,140	143,643	126,401
40	131,762	0.000%	0	-50,964	1,172,181	68,983	26,374	42,301	137,658	126,401
41	131,762	0.000%	0	-50,964	1,121,216	65,984	25,227	40,462	131,673	126,401
42	131,762	0.000%	0	-50,964	1,070,252	62,984	24,081	38,623	125,688	126,401
43	131,762	0.000%	0	-50,964	1,019,288	59,985	22,934	36,783	119,703	126,401
44	131,762	0.000%	0	-50,964	968,323	56,986	21,787	34,944	113,717	126,401
45	131,762	0.000%	0	-50,964	917,359	53,987	20,641	33,105	107,732	126,401
46	131,762	0.000%	0	-50,964	866,395	50,987	19,494	31,266	101,747	126,401
47	131,762	0.000%	0	-50,964	815,430	47,988	18,347	29,427	95,762	126,401
48	131,762	0.000%	0	-50,964	764,466	44,989	17,200	27,588	89,777	126,401
49	131,762	0.000%	0	-50,964	713,501	41,990	16,054	25,748	83,792	126,401
50	131,762	0.000%	0	-50,964	662,537	38,990	14,907	23,909	77,807	126,401
51	131,762	0.000%	0	-50,964	611,573	35,991	13,760	22,070	71,822	126,401
52	131,762	0.000%	0	-50,964	560,608	32,992	12,614	20,231	65,836	126,401
53	131,762	0.000%	0	-50,964	509,644	29,993	11,467	18,392	59,851	126,401
54	131,762	0.000%	0	-50,964	458,679	26,993	10,320	16,553	53,866	126,401
55	131,762	0.000%	0	-50,964	407,715	23,994	9,174	14,713	47,881	126,401
56	131,762	0.000%	0	-50,964	356,751	20,995	8,027	12,874	41,896	126,401
57	131,762	0.000%	0	-50,964	305,786	17,996	6,880	11,035	35,911	126,401
58	131,762	0.000%	0	-50,964	254,822	14,996	5,733	9,196	29,926	126,401
59	131,762	0.000%	0	-50,964	203,858	11,997	4,587	7,357	23,941	126,401
60	131,762	0.000%	0	-50,964	152,893	8,998	3,440	5,518	17,955	126,401
61	131,762	0.000%	0	-50,964	101,929	5,999	2,293	3,678	11,970	126,401
62	131,762	0.000%	0	-50,964	50,964	2,999	1,147	1,839	5,985	126,401
63	131,762	0.000%	0	-50,964	0	0	0	0	0	126,401

Unit Name: Muddy Run 1-8 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 105,729,817	
2	Investment Generator & Exciter	Inputs Tab	$ 15,859,473	
3	Reactive Allocator	(Line 71)	16.69%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**2,647,720**	
5				
6	GSU Transformer Investment	Inputs Tab	4,657,845	
7	Reactive Allocator	(Line 71)	16.69%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**777,622**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	2,914,002	
11	Reactive Allocator	(Line 71)	16.69%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**486,489**	
13				
14	Total Cost of Power Plant	Inputs Tab	261,421,690	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	237,990,370	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	128,942	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	4,040,774	
19	Reactive Fixed Charge Rate	(Line 14(h))	10.9589%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**442,823**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 442,823**	
23				
24				
25				
26				

	(e)		(f)	(g)	(h)
			Fixed Charge Rate for Reactive Plant		
			Calculated Amt	Plant	FCR % (f) / (g)
	Electric Expenses	Line 140	10,946		
	Other Expenses		156		
	O&M	(sum line 1 & 2)	11,102	4,040,774	0.2748%
	A&G		1,887,948	261,421,690	0.7222%
	CWC	From Col. (h): ((lines 3 + 5) * .125 * (lines 11 + 12)			0.0140%
	Working Capital	Line 216	221,491	261,421,690	0.0847%
	General Plant		-	261,421,690	0.0000%
	Other Taxes	Line 196(c)	692,571	261,421,690	0.2649%
	Depreciation	Line 168(c)			0.0198%
					8.1350%
	Taxes (Federal/State/Local)	Line 180			3.1285%
	ADIT	-Line 233(k)	($4,404,884)	261,421,690	-1.6850%
			(Sum Lines 1 to 11 , Col. (h))		10.9589%

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	(a)	(b)	(c)
Allocators			
	Real Power Capability (MW)		
		122.10	
		123.70	
		124.00	
		125.00	
		122.00	
		117.00	
	Total	733.80	(Sum Lines 31 to 36)
	Nominal Power Factor (pf)		
		0.91	
		0.90	
		0.93	
		0.92	
		0.90	
		0.91	
	Total	0.91	(Line 38 / 58)
	MVA Capability (MVA)		
		133.73	(Line 31 / 41)
		137.14	(Line 32 / 42)
		134.05	(Line 33 / 43)
		135.72	(Line 34 / 44)
		135.56	(Line 35 / 45)
		128.01	(Line 36 / 46)
	Total	804.22	(Sum Lines 51 to 56)
	Reactive Power Capability (MVAR)		
	(MVA^2 - MW^2)^0.5		
		54.56	(SQRT (Line 51^2 - Line 31^2))
		59.21	(SQRT (Line 52^2 - Line 32^2))
		50.94	(SQRT (Line 53^2 - Line 33^2))
		52.87	(SQRT (Line 54^2 - Line 34^2))
		59.09	(SQRT (Line 55^2 - Line 35^2))
		51.93	(SQRT (Line 56^2 - Line 36^2))
	Total	328.60	(Sum Lines 62 to 67)
	Reactive Allocator	16.7%	(Line 69^2 / Line 58^2)
		PECO is TO Fleet	
	Max. MVAr	360.90	
	Nameplate MVAr	2,852.52	
	Exciter MW	28.75	
	Generator MW	6,714.69	
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Hydro & Steam**	**Allocated Amt**
	Storage Batteries	$ 129,233	**30%**	$ 38,770
	Control&Power Cabling	$ 4,929,960	**15%**	$ 739,494
	Switch Board Equipment	$ 1,669,534	**30%**	$ 500,860
	Switching Equipment	$ 6,130,553	**20%**	$ 1,226,111
	Transformers	$ 589,215	**5%**	$ 29,461
	Aux Generator	$ 120,583	**0%**	$ -
	Fire Protection System	$ -	**0%**	$ -
	HVAC	$ -	**0%**	$ -
	Regulating Equipment	$ 505,742	**75%**	$ 379,306
	Structure	$ -	**0%**	$ -
	Misc	$ 29,526,543	**0%**	$ -
	Exciter & PPT	$ -	**100%**	$ -
	Station Grounding	$ 181,000	**0%**	$ -
	Bus & Insulators	$ -	**60%**	$ -
	Capacitor Bank	$ -	**0%**	$ -
	Total	$ 43,782,362		$ 2,914,002

O&M		**Total Non-Fuel**	**Fixed O&M**	
	(535) Operation Supervision and Engineering	129,116	129,116	
		0		
	(536) Water for Power	106,629	106,629	
	(537) Hydraulic Expenses	635,221		
	(538) Electric Expenses	209,968	209,968	
	(539) Miscellaneous Hydraulic Power Generation Expen	209,831		
	(540) Rents	30,315	30,315	
		0	-	
	(541) Mainentance Supervision and Engineering	71,654		
	(542) Maintenance of Structures	86,140	86,140	
	(543) Maintenance of Reservoirs, Dams, and Waterways	317,094		
	(544) Maintenance of Electric Plant	227,151		
	(545) Maintenance of Miscellaneous Hydraulic Plant	64,105	64,105	
	Total NonFuel Expenses	2,087,224	626,272	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		31.07%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	2.5042%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	1.0805%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	2,087,224	Line 116			
	Allowances	0	Line 109			
	Non-Fuel Production O&M	2,087,224	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	129,116	Line 102(c)			
	Electric Expenses	209,968	Line 106(c)			
	Maintenance of Electric Plant	227,151	Line 113(b)			
	Other Demand Related Expenses	287,188	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	853,424	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	227,151	Line 113(b)			
	Electric Expenses	209,968	Line 106(c)			
	Total Electric Expenses	437,119	(Line 138 + 139)	2.5042%	10,946	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	287,188	(Line 134)	0.0542%	156	
				Line 123		
	Balance of Plant Fixed Expenses				842,322	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		1,887,948	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		0	(allocated on plant labor)	
	Total		1,887,948		
Depreciation					
	Annual Depreciation Exp ...DE	3,395,087			
	Gross Production Plant Cost ... F	261,421,690	Line 14		
	SLDP=DE/F	1.2987%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	77			
	SFDP=(R/((1+R)^n-1)		0.0198%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.128%		
Rate of Return					
	Rate Of Return = R	Weight	Cost Rate	Weighted Cost (b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		692,571	<Includes Payroll	
	Payroll Taxes				
		31.0717%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		692,571	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	3.1285%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital				
	Prepayments	1,966,459		
		100.000%		
	Production Related Prepayments	1,966,459	(Line 209 * 210)	
	Unit Specific M&S	-		
	Total	1,966,459	(Line 211 + 212)	
	Return on Working Capital	8.1350%		
	Taxes on Working Capital	3.1285%		
	Working Capital Costs	221,491	(Line 213 * 214)	

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Accumulated Deferred Income Taxes

Investment	261,421,690	Line 14	NPV of Col (j)> 54,016,043
Asset Service Life	77	Line 167	
Composite Tax Rate	38.6790%	Line 177	

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity = (f) *	(h) Interest = (f) *	(i) Income Taxes = (g) *	(j) Rev Req Impact	(k) Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	(f) * (Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	3,395,087	3.750%	9,803,313	2,478,638	2,478,638	145,868	55,769	89,448	291,085	4,404,884
2	3,395,087	7.219%	18,872,032	5,986,328	8,464,965	498,163	190,462	305,479	994,104	4,404,884
3	3,395,087	6.677%	17,455,126	5,438,283	13,903,248	818,206	312,823	501,732	1,632,761	4,404,884
4	3,395,087	6.177%	16,148,018	4,932,706	18,835,954	1,108,496	423,809	679,741	2,212,046	4,404,884
5	3,395,087	5.713%	14,935,021	4,463,531	23,299,485	1,371,175	524,238	840,818	2,736,231	4,404,884
6	3,395,087	5.285%	13,816,136	4,030,758	27,330,243	1,608,385	614,930	986,278	3,209,593	4,404,884
7	3,395,087	4.888%	12,778,292	3,629,330	30,959,573	1,821,971	696,590	1,117,251	3,635,812	4,404,884
8	3,395,087	4.522%	11,821,489	3,259,248	34,218,821	2,013,778	769,923	1,234,869	4,018,570	4,404,884
9	3,395,087	4.462%	11,664,636	3,198,579	37,417,400	2,202,014	841,891	1,350,297	4,394,202	4,404,884
10	3,395,087	4.461%	11,662,022	3,197,568	40,614,968	2,390,191	913,837	1,465,689	4,769,717	4,404,884
11	3,395,087	4.462%	11,664,636	3,198,579	43,813,546	2,578,427	985,805	1,581,117	5,145,349	4,404,884
12	3,395,087	4.461%	11,662,022	3,197,568	47,011,114	2,766,604	1,057,750	1,696,509	5,520,863	4,404,884
13	3,395,087	4.462%	11,664,636	3,198,579	50,209,693	2,954,840	1,129,718	1,811,938	5,896,496	4,404,884
14	3,395,087	4.461%	11,662,022	3,197,568	53,407,261	3,143,017	1,201,663	1,927,330	6,272,010	4,404,884
15	3,395,087	4.462%	11,664,636	3,198,579	56,605,839	3,331,254	1,273,631	2,042,758	6,647,643	4,404,884
16	3,395,087	4.461%	11,662,022	3,197,568	59,803,407	3,519,431	1,345,577	2,158,150	7,023,157	4,404,884
17	3,395,087	4.462%	11,664,636	3,198,579	63,001,986	3,707,667	1,417,545	2,273,578	7,398,790	4,404,884
18	3,395,087	4.461%	11,662,022	3,197,568	66,199,554	3,895,844	1,489,490	2,388,970	7,774,304	4,404,884
19	3,395,087	4.462%	11,664,636	3,198,579	69,398,132	4,084,080	1,561,458	2,504,399	8,149,937	4,404,884
20	3,395,087	4.461%	11,662,022	3,197,568	72,595,700	4,272,257	1,633,403	2,619,791	8,525,451	4,404,884
21	3,395,087	2.231%	5,832,318	942,697	73,538,397	4,327,735	1,654,614	2,653,810	8,636,159	4,404,884
22	3,395,087	0.000%	0	-1,313,186	72,225,211	4,250,454	1,625,067	2,606,421	8,481,942	4,404,884
23	3,395,087	0.000%	0	-1,313,186	70,912,025	4,173,173	1,595,521	2,559,031	8,327,724	4,404,884
24	3,395,087	0.000%	0	-1,313,186	69,598,840	4,095,892	1,565,974	2,511,642	8,173,507	4,404,884
25	3,395,087	0.000%	0	-1,313,186	68,285,654	4,018,611	1,536,427	2,464,252	8,019,290	4,404,884
26	3,395,087	0.000%	0	-1,313,186	66,972,468	3,941,330	1,506,881	2,416,863	7,865,073	4,404,884
27	3,395,087	0.000%	0	-1,313,186	65,659,283	3,864,049	1,477,334	2,369,473	7,710,856	4,404,884
28	3,395,087	0.000%	0	-1,313,186	64,346,097	3,786,768	1,447,787	2,322,084	7,556,639	4,404,884
29	3,395,087	0.000%	0	-1,313,186	63,032,911	3,709,487	1,418,241	2,274,694	7,402,422	4,404,884
30	3,395,087	0.000%	0	-1,313,186	61,719,726	3,632,206	1,388,694	2,227,305	7,248,205	4,404,884
31	3,395,087	0.000%	0	-1,313,186	60,406,540	3,554,925	1,359,147	2,179,915	7,093,988	4,404,884
32	3,395,087	0.000%	0	-1,313,186	59,093,354	3,477,644	1,329,600	2,132,526	6,939,770	4,404,884
33	3,395,087	0.000%	0	-1,313,186	57,780,169	3,400,363	1,300,054	2,085,137	6,785,553	4,404,884
34	3,395,087	0.000%	0	-1,313,186	56,466,983	3,323,082	1,270,507	2,037,747	6,631,336	4,404,884
35	3,395,087	0.000%	0	-1,313,186	55,153,797	3,245,801	1,240,960	1,990,358	6,477,119	4,404,884
36	3,395,087	0.000%	0	-1,313,186	53,840,612	3,168,520	1,211,414	1,942,968	6,322,902	4,404,884
37	3,395,087	0.000%	0	-1,313,186	52,527,426	3,091,239	1,181,867	1,895,579	6,168,685	4,404,884
38	3,395,087	0.000%	0	-1,313,186	51,214,241	3,013,958	1,152,320	1,848,189	6,014,468	4,404,884
39	3,395,087	0.000%	0	-1,313,186	49,901,055	2,936,677	1,122,774	1,800,800	5,860,251	4,404,884
40	3,395,087	0.000%	0	-1,313,186	48,587,869	2,859,396	1,093,227	1,753,410	5,706,033	4,404,884
41	3,395,087	0.000%	0	-1,313,186	47,274,684	2,782,115	1,063,680	1,706,021	5,551,816	4,404,884
42	3,395,087	0.000%	0	-1,313,186	45,961,498	2,704,834	1,034,134	1,658,631	5,397,599	4,404,884
43	3,395,087	0.000%	0	-1,313,186	44,648,312	2,627,553	1,004,587	1,611,242	5,243,382	4,404,884
44	3,395,087	0.000%	0	-1,313,186	43,335,127	2,550,272	975,040	1,563,852	5,089,165	4,404,884
45	3,395,087	0.000%	0	-1,313,186	42,021,941	2,472,991	945,494	1,516,463	4,934,948	4,404,884
46	3,395,087	0.000%	0	-1,313,186	40,708,755	2,395,710	915,947	1,469,073	4,780,731	4,404,884
47	3,395,087	0.000%	0	-1,313,186	39,395,570	2,318,429	886,400	1,421,684	4,626,514	4,404,884
48	3,395,087	0.000%	0	-1,313,186	38,082,384	2,241,148	856,854	1,374,295	4,472,296	4,404,884
49	3,395,087	0.000%	0	-1,313,186	36,769,198	2,163,867	827,307	1,326,905	4,318,079	4,404,884
50	3,395,087	0.000%	0	-1,313,186	35,456,013	2,086,586	797,760	1,279,516	4,163,862	4,404,884
51	3,395,087	0.000%	0	-1,313,186	34,142,827	2,009,305	768,214	1,232,126	4,009,645	4,404,884
52	3,395,087	0.000%	0	-1,313,186	32,829,641	1,932,024	738,667	1,184,737	3,855,428	4,404,884
53	3,395,087	0.000%	0	-1,313,186	31,516,456	1,854,743	709,120	1,137,347	3,701,211	4,404,884
54	3,395,087	0.000%	0	-1,313,186	30,203,270	1,777,462	679,574	1,089,958	3,546,994	4,404,884
55	3,395,087	0.000%	0	-1,313,186	28,890,084	1,700,181	650,027	1,042,568	3,392,777	4,404,884
56	3,395,087	0.000%	0	-1,313,186	27,576,899	1,622,900	620,480	995,179	3,238,560	4,404,884
57	3,395,087	0.000%	0	-1,313,186	26,263,713	1,545,620	590,934	947,789	3,084,342	4,404,884
58	3,395,087	0.000%	0	-1,313,186	24,950,527	1,468,339	561,387	900,400	2,930,125	4,404,884
59	3,395,087	0.000%	0	-1,313,186	23,637,342	1,391,058	531,840	853,010	2,775,908	4,404,884
60	3,395,087	0.000%	0	-1,313,186	22,324,156	1,313,777	502,294	805,621	2,621,691	4,404,884
61	3,395,087	0.000%	0	-1,313,186	21,010,970	1,236,496	472,747	758,231	2,467,474	4,404,884
62	3,395,087	0.000%	0	-1,313,186	19,697,785	1,159,215	443,200	710,842	2,313,257	4,404,884
63	3,395,087	0.000%	0	-1,313,186	18,384,599	1,081,934	413,653	663,453	2,159,040	4,404,884
64	3,395,087	0.000%	0	-1,313,186	17,071,414	1,004,653	384,107	616,063	2,004,823	4,404,884
65	3,395,087	0.000%	0	-1,313,186	15,758,228	927,372	354,560	568,674	1,850,605	4,404,884
66	3,395,087	0.000%	0	-1,313,186	14,445,042	850,091	325,013	521,284	1,696,388	4,404,884
67	3,395,087	0.000%	0	-1,313,186	13,131,857	772,810	295,467	473,895	1,542,171	4,404,884
68	3,395,087	0.000%	0	-1,313,186	11,818,671	695,529	265,920	426,505	1,387,954	4,404,884
69	3,395,087	0.000%	0	-1,313,186	10,505,485	618,248	236,373	379,116	1,233,737	4,404,884
70	3,395,087	0.000%	0	-1,313,186	9,192,300	540,967	206,827	331,726	1,079,520	4,404,884
71	3,395,087	0.000%	0	-1,313,186	7,879,114	463,686	177,280	284,337	925,303	4,404,884
72	3,395,087	0.000%	0	-1,313,186	6,565,928	386,405	147,733	236,947	771,086	4,404,884
73	3,395,087	0.000%	0	-1,313,186	5,252,743	309,124	118,187	189,558	616,868	4,404,884
74	3,395,087	0.000%	0	-1,313,186	3,939,557	231,843	88,640	142,168	462,651	4,404,884
75	3,395,087	0.000%	0	-1,313,186	2,626,371	154,562	59,093	94,779	308,434	4,404,884
76	3,395,087	0.000%	0	-1,313,186	1,313,186	77,281	29,547	47,389	154,217	4,404,884
77	3,395,087	0.000%	0	-1,313,186	0	0	0	0	0	4,404,884

Unit Name: Notch Cliff 1-8 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 20,738,180		Electric Expenses	Line 144	1,914		
2	Investment Generator & Exciter	Inputs Tab	$ 3,110,727		Other Expenses		83		
3	Reactive Allocator	(Line 75)	33.78%		O&M	(sum line 1 & 2)	1,997	2,411,909	0.0828%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**1,050,691**						
5					A&G		255,689	41,084,404	0.6224%
6	GSU Transformer Investment	Inputs Tab	-		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0098%
7	Reactive Allocator	(Line 75)	33.78%		Working Capital	Line 215	49,132	41,084,404	0.1196%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**		General Plant		-	41,084,404	0.0000%
9					Other Taxes	Line 195(c)	222,581	41,084,404	0.5418%
10	Allocated Acc Elec Equipment	(Line 103 , Column d)	4,014,649		Depreciation	Line 167(c)			0.0814%
11	Reactive Allocator	(Line 75)	33.78%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**1,356,003**		Taxes (Federal/State/Local)	Line 179			2.9758%
13					ADIT	-Line 232(k)	($601,641)	41,084,404	-1.4644%
14	Total Cost of Power Plant	Inputs Tab	41,084,404				(Sum Lines 1 to 11 , Col. (h))		11.1041%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	33,959,028						
16	Balance of Plant Allocator	(Line 79)	0.0154%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	5,215						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	2,411,909						
19	Reactive Fixed Charge Rate	(Line 14(h))	11.1041%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**267,820**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 267,820**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		12.80						
		18.00						
		18.00						
		18.00						
		12.50						
		18.00						
		18.00						
		18.00						
	Total	133.30	(Sum Lines 31 to 38)					
	Nominal Power Factor (pf)							
		0.66						
		0.85						
		0.85						
		0.85						
		0.64						
		0.85						
		0.85						
		0.85						
	Total	0.80	(Line 39 / 61)					
	MVA Capability (MVA)							
		19.34	(Line 31 / 42)					
		21.18	(Line 32 / 43)					
		21.18	(Line 33 / 44)					
		21.18	(Line 34 / 45)					
		19.53	(Line 35 / 46)					
		21.18	(Line 36 / 47)					
		21.18	(Line 37 / 48)					
		21.18	(Line 38 / 49)					
	Total	165.93	(Sum Lines 53 to 60)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		14.49	(SQRT (Line 53^2 - Line 31^2))					
		11.16	(SQRT (Line 54^2 - Line 32^2))					
		11.16	(SQRT (Line 55^2 - Line 33^2))					
		11.16	(SQRT (Line 56^2 - Line 34^2))					
		15.01	(SQRT (Line 57^2 - Line 35^2))					
		11.16	(SQRT (Line 58^2 - Line 36^2))					
		11.16	(SQRT (Line 59^2 - Line 37^2))					
		11.16	(SQRT (Line 60^2 - Line 38^2))					
	Total	96.43	(Sum Lines 65 to 72)					
	Reactive Allocator	33.8%	(Line 73^2 / Line 61^2)					
		BGE is TO Fleet						
	Max. MVAr	27.50						
	Nameplate MVAr	571.22						
	Exciter MW	3.08						
	Generator MW	965.46						
	Balance of Plant Allocator	0.0154%	(Line 79 / Line 80) * (Line 81 / Line 82)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ -	50%	$ -
	Control&Power Cabling	$ 33,556	50%	$ 16,778
	Switch Board Equipment	$ 237,988	50%	$ 118,994
	Switching Equipment	$ 981,137	40%	$ 392,455
	Transformers	$ 57,272	10%	$ 5,727
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ 4,640,268	75%	$ 3,480,201
	Structure	$ 6,922	0%	$ -
	Misc	$ 118,909	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ 9,880	5%	$ 494
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 6,085,933		$ 4,014,649

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	217,043	217,043	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	56,064	56,064	
	Steam From Other Sources	108,337		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	33,192		
	Rents	202,000	202,000	
	Allowances	8,163	8,163	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	84,660	84,660	
	Maintenance of Boiler (or reactor) Plant	36,303		
	Maintenance of Electric Plant	37,769		
	Maintenance of Misc Steam (or Nuclear) Plant	47,008	47,008	
	Other Power Production, & Other Expenses	142,589	142,589	
	Total NonFuel Expenses	973,126	757,526	(Sum Lines 106 to 119)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 120(c) / (Line 120(b) - Line 114(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	5.0665%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 127 * Line 136 + Line 125 * Line 136 / (Line136 + 138)			
	Other Demand Expense Allocator	0.0154%	Line 83			
	Production Plant Expenses					
	Total NonFuel Expenses	973,126	Line 120			
	Allowances	8,163	Line 113			
	Non-Fuel Production O&M	964,964	(Line 130 - 131)			
	Operating Expenses					
	Operations Supervision & Engineering	217,043	Line 106(c)			
	Electric Expenses	0	Line 110(c)			
	Maintenance of Electric Plant	37,769	Line 117(b)			
	Other Demand Related Expenses	540,483	Col. (c) Line 120 - Col (b) Line 136 - Col. (b) Line 135			
	Total	795,295	(Sum Lines 135 to 138)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	37,769	Line 117(b)			
	Electric Expenses	0	Line 110(c)			
	Total Electric Expenses	37,769	(Line 142 + 143)	5.0665%	1,914	(Line 144(b) * (d))
				Line 125		
	Other Demand Related Expenses	540,483	(Line 138)	0.0154%	83	
				Line 127		
	Balance of Plant Fixed Expenses				793,298	(Line 139(b) - Line 144(e) - Line 146(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		145,511	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		110,179	(allocated on plant labor)	
	Total		255,689		
Depreciation					
	Annual Depreciation Exp ...DE	696,346			
	Gross Production Plant Cost ... F	41,084,404	Line 14		
	SLDP=DE/F	1.6949%	(Line 163 / 164)		
	Depreciable years (n)=1/SLDP	59			
	SFDP=(R/((1+R)^n-1)		0.0814%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.976%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 184 to 186)
Other Taxes					
	Property Taxes		222,581	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 121		
	Fixed Payroll Taxes		-	(Line 192 * 193)	
	Total Other Taxes		222,581	(Line 191 + 194)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 158
	Fixed General Plant	-		-		(Lines 199 *200)
	Return on General Plant	8.1350%	Line 187			
	Taxes on General Plant	2.9758%	Line 188			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 201 * 202)	-	-	
Working Capital						
	Prepayments	309,044				
		100.000%				
	Production Related Prepayments	309,044	(Line 208 * 209)			
	Unit Specific M&S	133,154				
	Total	442,198	(Line 210 + 211)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9758%				
	Working Capital Costs	49,132	(Line 212 * 213)			

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Accumulated Deferred Income Taxes

Investment	41,084,404	Line 14
Asset Service Life	59	Line 166
Composite Tax Rate	38.6790%	Line 176

NPV of Col (j)> 7,322,437

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized PMT of NPV
	Line 223 / 224		(b) * (c)	((d) - (b)) * Line 176	Accum. (e)	= (f) * (Line185+186)	= (f) * (Line184)	= (g) * (Line177)	(g) + (h) + (i)	col. (j)
1	696,346	3.750%	1,540,665	326,574	326,574	19,219	7,348	11,785	38,352	601,641
2	696,346	7.219%	2,965,883	877,834	1,204,409	70,879	27,099	43,464	141,443	601,641
3	696,346	6.677%	2,743,206	791,705	1,996,113	117,471	44,913	72,035	234,418	601,641
4	696,346	6.177%	2,537,784	712,250	2,708,363	159,387	60,938	97,738	318,063	601,641
5	696,346	5.713%	2,347,152	638,515	3,346,879	196,964	75,305	120,780	393,049	601,641
6	696,346	5.285%	2,171,311	570,502	3,917,380	230,538	88,141	141,368	460,047	601,641
7	696,346	4.888%	2,008,206	507,414	4,424,794	260,399	99,558	159,679	519,636	601,641
8	696,346	4.522%	1,857,837	449,253	4,874,048	286,838	109,666	175,892	572,396	601,641
9	696,346	4.462%	1,833,186	439,718	5,313,766	312,715	119,560	191,760	624,035	601,641
10	696,346	4.461%	1,832,775	439,560	5,753,326	338,583	129,450	207,623	675,656	601,641
11	696,346	4.462%	1,833,186	439,718	6,193,044	364,461	139,343	223,491	727,295	601,641
12	696,346	4.461%	1,832,775	439,560	6,632,604	390,329	149,234	239,353	778,916	601,641
13	696,346	4.462%	1,833,186	439,718	7,072,322	416,206	159,127	255,222	830,555	601,641
14	696,346	4.461%	1,832,775	439,560	7,511,881	442,074	169,017	271,084	882,176	601,641
15	696,346	4.462%	1,833,186	439,718	7,951,600	467,952	178,911	286,953	933,815	601,641
16	696,346	4.461%	1,832,775	439,560	8,391,159	493,820	188,801	302,815	985,436	601,641
17	696,346	4.462%	1,833,186	439,718	8,830,878	519,697	198,695	318,683	1,037,075	601,641
18	696,346	4.461%	1,832,775	439,560	9,270,437	545,565	208,585	334,546	1,088,696	601,641
19	696,346	4.462%	1,833,186	439,718	9,710,156	571,443	218,479	350,414	1,140,336	601,641
20	696,346	4.461%	1,832,775	439,560	10,149,715	597,311	228,369	366,277	1,191,956	601,641
21	696,346	2.231%	916,593	85,189	10,234,905	602,324	230,285	369,351	1,201,961	601,641
22	696,346	0.000%	0	-269,340	9,965,565	586,474	224,225	359,631	1,170,330	601,641
23	696,346	0.000%	0	-269,340	9,696,226	570,623	218,165	349,912	1,138,700	601,641
24	696,346	0.000%	0	-269,340	9,426,886	554,772	212,105	340,192	1,107,069	601,641
25	696,346	0.000%	0	-269,340	9,157,546	538,922	206,045	330,472	1,075,439	601,641
26	696,346	0.000%	0	-269,340	8,888,207	523,071	199,985	320,752	1,043,808	601,641
27	696,346	0.000%	0	-269,340	8,618,867	507,220	193,925	311,033	1,012,177	601,641
28	696,346	0.000%	0	-269,340	8,349,528	491,370	187,864	301,313	980,547	601,641
29	696,346	0.000%	0	-269,340	8,080,188	475,519	181,804	291,593	948,916	601,641
30	696,346	0.000%	0	-269,340	7,810,848	459,668	175,744	281,873	917,286	601,641
31	696,346	0.000%	0	-269,340	7,541,509	443,818	169,684	272,154	885,655	601,641
32	696,346	0.000%	0	-269,340	7,272,169	427,967	163,624	262,434	854,025	601,641
33	696,346	0.000%	0	-269,340	7,002,830	412,117	157,564	252,714	822,394	601,641
34	696,346	0.000%	0	-269,340	6,733,490	396,266	151,504	242,994	790,764	601,641
35	696,346	0.000%	0	-269,340	6,464,150	380,415	145,443	233,274	759,133	601,641
36	696,346	0.000%	0	-269,340	6,194,811	364,565	139,383	223,555	727,503	601,641
37	696,346	0.000%	0	-269,340	5,925,471	348,714	133,323	213,835	695,872	601,641
38	696,346	0.000%	0	-269,340	5,656,132	332,863	127,263	204,115	664,241	601,641
39	696,346	0.000%	0	-269,340	5,386,792	317,013	121,203	194,395	632,611	601,641
40	696,346	0.000%	0	-269,340	5,117,452	301,162	115,143	184,676	600,980	601,641
41	696,346	0.000%	0	-269,340	4,848,113	285,311	109,083	174,956	569,350	601,641
42	696,346	0.000%	0	-269,340	4,578,773	269,461	103,022	165,236	537,719	601,641
43	696,346	0.000%	0	-269,340	4,309,434	253,610	96,962	155,516	506,089	601,641
44	696,346	0.000%	0	-269,340	4,040,094	237,760	90,902	145,797	474,458	601,641
45	696,346	0.000%	0	-269,340	3,770,754	221,909	84,842	136,077	442,828	601,641
46	696,346	0.000%	0	-269,340	3,501,415	206,058	78,782	126,357	411,197	601,641
47	696,346	0.000%	0	-269,340	3,232,075	190,208	72,722	116,637	379,567	601,641
48	696,346	0.000%	0	-269,340	2,962,736	174,357	66,662	106,917	347,936	601,641
49	696,346	0.000%	0	-269,340	2,693,396	158,506	60,601	97,198	316,305	601,641
50	696,346	0.000%	0	-269,340	2,424,056	142,656	54,541	87,478	284,675	601,641
51	696,346	0.000%	0	-269,340	2,154,717	126,805	48,481	77,758	253,044	601,641
52	696,346	0.000%	0	-269,340	1,885,377	110,954	42,421	68,038	221,414	601,641
53	696,346	0.000%	0	-269,340	1,616,038	95,104	36,361	58,319	189,783	601,641
54	696,346	0.000%	0	-269,340	1,346,698	79,253	30,301	48,599	158,153	601,641
55	696,346	0.000%	0	-269,340	1,077,358	63,403	24,241	38,879	126,522	601,641
56	696,346	0.000%	0	-269,340	808,019	47,552	18,180	29,159	94,892	601,641
57	696,346	0.000%	0	-269,340	538,679	31,701	12,120	19,440	63,261	601,641
58	696,346	0.000%	0	-269,340	269,340	15,851	6,060	9,720	31,631	601,641
59	696,346	0.000%	0	-269,340	0	0	0	0	0	601,641

Unit Name: Oyster Creek **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 30,406,806		Electric Expenses	Line 140	251,050		
2	Investment Generator & Exciter	Inputs Tab	4,561,021		Other Expenses		89,230		
3	Reactive Allocator	(Line 71)	17.55%		O&M	(sum line 1 & 2)	340,280	4,703,710	7.2343%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**800,623**						
5					A&G		83,751,770	360,225,425	23.2498%
6	GSU Transformer Investment	Inputs Tab	19,820,373		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.4195%
7	Reactive Allocator	(Line 71)	17.55%		Working Capital	Line 216	12,182,966	360,225,425	3.3820%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**3,479,189**		General Plant		-	360,225,425	0.0000%
9					Other Taxes	Line 196(c)	8,192,927	360,225,425	2.2744%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	16,976		Depreciation	Line 168(c)			0.1663%
11	Reactive Allocator	(Line 71)	17.55%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**2,980**		Taxes (Federal/State/Local)	Line 180			2.8753%
13					ADIT	-Line 233(k)	($4,704,150)	360,225,425	-1.3059%
14	Total Cost of Power Plant	Inputs Tab	360,225,425				(Sum Lines 1 to 11 , Col. (h))		46.4308%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	335,827,055						
16	Balance of Plant Allocator	(Line 79)	0.1253%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	420,918						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	4,703,710						
19	Reactive Fixed Charge Rate	(Line 14(h))	46.4308%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**2,183,969**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 2,183,969**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		621.20						
		-						
		-						
	Total	621.20	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.91						
		-						
		-						
	Total	0.91	(Line 38 / 58)					
	MVA Capability (MVA)							
		684.14	(Line 31 / 41)					
		-						
		-						
	Total	684.14	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		286.63	(SQRT (Line 51^2 - Line 31^2))					
		-						
		-						
	Total	286.63	(Sum Lines 62 to 64)					
	Reactive Allocator	17.6%	(Line 69^2 / Line 58^2)					
		JCPL is TO Fleet						
	Max. MVAr	112.60						
	Nameplate MVAr	286.63						
	Exciter MW	1.98						
	Generator MW	621.20						
	Balance of Plant Allocator	0.1253%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ -	**15%**	$ -
	Control&Power Cabling	$ -	**1%**	$ -
	Switch Board Equipment	$ -	**1%**	$ -
	Switching Equipment	$ -	**1%**	$ -
	Transformers	$ 565,862	**3%**	$ 16,976
	Aux Generator	$ -	**0%**	$ -
	Fire Protection System	$ -	**0%**	$ -
	HVAC	$ -	**0%**	$ -
	Regulating Equipment	$ -	**50%**	$ -
	Structure	$ -	**0%**	$ -
	Misc	$ 8,662,556	**0%**	$ -
	Exciter & PPT	$ -	**100%**	$ -
	Station Grounding	$ -	**1%**	$ -
	Bus & Insulators	$ -	**80%**	$ -
	Capacitor Bank	$ -	**0%**	$ -
	Total	$ 9,228,418		$ 16,976

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	20,056,606	20,056,606	
	Coolants and Water (Nuclear Plants Only)	1,965,210		
	Steam Expenses	12,326,705	12,326,705	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	1,259,337		
	Rents	34,819,603	34,819,603	
	Allowances	2,763,016	2,763,016	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	3,700,095	3,700,095	
	Maintenance of Boiler (or reactor) Plant	288,393		
	Maintenance of Electric Plant	9,534,615		
	Maintenance of Misc Steam (or Nuclear) Plant	6,124,475	6,124,475	
	Other Power Production, & Other Expenses	11,457,706	11,457,706	
	Total NonFuel Expenses	104,295,761	91,248,206	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	2.6330%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.1253%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	104,295,761	Line 116			
	Allowances	2,763,016	Line 109			
	Non-Fuel Production O&M	101,532,745	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	20,056,606	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	9,534,615	Line 113(b)			
	Other Demand Related Expenses	71,191,600	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	100,782,821	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	9,534,615	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	9,534,615	(Line 138 + 139)	2.6330%	251,050	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	71,191,600	(Line 134)	0.1253%	89,230	
				Line 123		
	Balance of Plant Fixed Expenses				100,442,541	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		75,639,559	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		8,112,211	(allocated on plant labor)	
	Total		83,751,770		
Depreciation					
	Annual Depreciation Exp ...DE	7,204,508			
	Gross Production Plant Cost ... F	360,225,425	Line 14		
	SLDP=DE/F	2.0000%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	50			
	SFDP=(R/((1+R)^n-1)		0.1663%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.875%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		3,465,238		
	Payroll Taxes	5,403,699			
	0	87.4899%	Line 117		
	Fixed Payroll Taxes		4,727,688	(Line 193 * 194)	
	Total Other Taxes		8,192,927	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.8753%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	603,950				
		100.000%				
	Production Related Prepayments	603,950	(Line 209 * 210)			
	Unit Specific M&S	110,046,662				
	Total	110,650,613	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.8753%				
	Working Capital Costs	12,182,966	(Line 213 * 214)			

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Accumulated Deferred Income Taxes

Investment	360,225,425	Line 14
Asset Service Life	50	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 56,667,797

(a) Yr.	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity = (f) *	Interest	Income Taxes = (g) *	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	= (f) * (Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	7,204,508	3.750%	13,508,453	2,438,303	2,438,303	143,494	54,862	87,992	286,348	4,704,150
2	7,204,508	7.219%	26,004,673	7,271,716	9,710,019	571,435	218,475	350,409	1,140,319	4,704,150
3	7,204,508	6.677%	24,052,252	6,516,539	16,226,557	954,933	365,098	585,574	1,905,605	4,704,150
4	7,204,508	6.177%	22,251,124	5,819,881	22,046,438	1,297,433	496,045	795,599	2,589,077	4,704,150
5	7,204,508	5.713%	20,579,679	5,173,382	27,219,820	1,601,886	612,446	982,293	3,196,625	4,704,150
6	7,204,508	5.285%	19,037,914	4,577,043	31,796,863	1,871,245	715,429	1,147,466	3,734,141	4,704,150
7	7,204,508	4.888%	17,607,819	4,023,896	35,820,759	2,108,052	805,967	1,292,678	4,206,697	4,704,150
8	7,204,508	4.522%	16,289,394	3,513,943	39,334,702	2,314,847	885,031	1,419,487	4,619,365	4,704,150
9	7,204,508	4.462%	16,073,258	3,430,344	42,765,046	2,516,723	962,214	1,543,280	5,022,216	4,704,150
10	7,204,508	4.461%	16,069,656	3,428,950	46,193,996	2,718,517	1,039,365	1,667,022	5,424,903	4,704,150
11	7,204,508	4.462%	16,073,258	3,430,344	49,624,340	2,920,392	1,116,548	1,790,814	5,827,754	4,704,150
12	7,204,508	4.461%	16,069,656	3,428,950	53,053,290	3,122,186	1,193,699	1,914,556	6,230,441	4,704,150
13	7,204,508	4.462%	16,073,258	3,430,344	56,483,634	3,324,062	1,270,882	2,038,348	6,633,292	4,704,150
14	7,204,508	4.461%	16,069,656	3,428,950	59,912,585	3,525,856	1,348,033	2,162,090	7,035,979	4,704,150
15	7,204,508	4.462%	16,073,258	3,430,344	63,342,928	3,727,731	1,425,216	2,285,882	7,438,829	4,704,150
16	7,204,508	4.461%	16,069,656	3,428,950	66,771,879	3,929,525	1,502,367	2,409,624	7,841,516	4,704,150
17	7,204,508	4.462%	16,073,258	3,430,344	70,202,223	4,131,401	1,579,550	2,533,416	8,244,367	4,704,150
18	7,204,508	4.461%	16,069,656	3,428,950	73,631,173	4,333,195	1,656,701	2,657,158	8,647,054	4,704,150
19	7,204,508	4.462%	16,073,258	3,430,344	77,061,517	4,535,070	1,733,884	2,780,950	9,049,905	4,704,150
20	7,204,508	4.461%	16,069,656	3,428,950	80,490,467	4,736,864	1,811,036	2,904,692	9,452,592	4,704,150
21	7,204,508	2.231%	8,036,629	321,856	80,812,323	4,755,805	1,818,277	2,916,307	9,490,390	4,704,150
22	7,204,508	0.000%	0	-2,786,632	78,025,692	4,591,812	1,755,578	2,815,745	9,163,135	4,704,150
23	7,204,508	0.000%	0	-2,786,632	75,239,060	4,427,819	1,692,879	2,715,183	8,835,880	4,704,150
24	7,204,508	0.000%	0	-2,786,632	72,452,428	4,263,825	1,630,180	2,614,620	8,508,625	4,704,150
25	7,204,508	0.000%	0	-2,786,632	69,665,796	4,099,832	1,567,480	2,514,058	8,181,371	4,704,150
26	7,204,508	0.000%	0	-2,786,632	66,879,164	3,935,839	1,504,781	2,413,496	7,854,116	4,704,150
27	7,204,508	0.000%	0	-2,786,632	64,092,532	3,771,846	1,442,082	2,312,933	7,526,861	4,704,150
28	7,204,508	0.000%	0	-2,786,632	61,305,901	3,607,852	1,379,383	2,212,371	7,199,606	4,704,150
29	7,204,508	0.000%	0	-2,786,632	58,519,269	3,443,859	1,316,684	2,111,809	6,872,351	4,704,150
30	7,204,508	0.000%	0	-2,786,632	55,732,637	3,279,866	1,253,984	2,011,246	6,545,096	4,704,150
31	7,204,508	0.000%	0	-2,786,632	52,946,005	3,115,872	1,191,285	1,910,684	6,217,842	4,704,150
32	7,204,508	0.000%	0	-2,786,632	50,159,373	2,951,879	1,128,586	1,810,122	5,890,587	4,704,150
33	7,204,508	0.000%	0	-2,786,632	47,372,741	2,787,886	1,065,887	1,709,559	5,563,332	4,704,150
34	7,204,508	0.000%	0	-2,786,632	44,586,109	2,623,893	1,003,187	1,608,997	5,236,077	4,704,150
35	7,204,508	0.000%	0	-2,786,632	41,799,478	2,459,899	940,488	1,508,435	4,908,822	4,704,150
36	7,204,508	0.000%	0	-2,786,632	39,012,846	2,295,906	877,789	1,407,873	4,581,568	4,704,150
37	7,204,508	0.000%	0	-2,786,632	36,226,214	2,131,913	815,090	1,307,310	4,254,313	4,704,150
38	7,204,508	0.000%	0	-2,786,632	33,439,582	1,967,919	752,391	1,206,748	3,927,058	4,704,150
39	7,204,508	0.000%	0	-2,786,632	30,652,950	1,803,926	689,691	1,106,186	3,599,803	4,704,150
40	7,204,508	0.000%	0	-2,786,632	27,866,318	1,639,933	626,992	1,005,623	3,272,548	4,704,150
41	7,204,508	0.000%	0	-2,786,632	25,079,687	1,475,940	564,293	905,061	2,945,293	4,704,150
42	7,204,508	0.000%	0	-2,786,632	22,293,055	1,311,946	501,594	804,499	2,618,039	4,704,150
43	7,204,508	0.000%	0	-2,786,632	19,506,423	1,147,953	438,895	703,936	2,290,784	4,704,150
44	7,204,508	0.000%	0	-2,786,632	16,719,791	983,960	376,195	603,374	1,963,529	4,704,150
45	7,204,508	0.000%	0	-2,786,632	13,933,159	819,966	313,496	502,812	1,636,274	4,704,150
46	7,204,508	0.000%	0	-2,786,632	11,146,527	655,973	250,797	402,249	1,309,019	4,704,150
47	7,204,508	0.000%	0	-2,786,632	8,359,896	491,980	188,098	301,687	981,764	4,704,150
48	7,204,508	0.000%	0	-2,786,632	5,573,264	327,987	125,398	201,125	654,510	4,704,150
49	7,204,508	0.000%	0	-2,786,632	2,786,632	163,993	62,699	100,562	327,255	4,704,150
50	7,204,508	0.000%	0	-2,786,632	0	0	0	0	0	4,704,150

Unit Name: Peach Bottom 2 & 3 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 324,475,609		Electric Expenses	Line 140	190,062		
2	Investment Generator & Exciter	Inputs Tab	48,671,341		Other Expenses		30,664		
3	Reactive Allocator	(Line 71)	16.72%		O&M	(sum line 1 & 2)	220,727	15,844,823	1.3931%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**8,135,921**						
5					A&G		60,144,971	1,360,681,860	4.4202%
6	GSU Transformer Investment	Inputs Tab	41,363,873		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0808%
7	Reactive Allocator	(Line 71)	16.72%		Working Capital	Line 216	23,058,146	1,360,681,860	1.6946%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**6,914,401**		General Plant		-	1,360,681,860	0.0000%
9					Other Taxes	Line 196(c)	3,982,382	1,360,681,860	0.2927%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	636,592		Depreciation	Line 168(c)			0.0752%
11	Reactive Allocator	(Line 71)	16.72%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**106,413**		Taxes (Federal/State/Local)	Line 180			2.9795%
13					ADIT	-Line 233(k)	($20,132,488)	1,360,681,860	-1.4796%
14	Total Cost of Power Plant	Inputs Tab	1,360,681,860				(Sum Lines 1 to 11 , Col. (h))		17.5914%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	1,270,010,053						
16	Balance of Plant Allocator	(Line 79)	0.0542%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	688,087						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	15,844,823						
19	Reactive Fixed Charge Rate	(Line 14(h))	17.5914%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**2,787,328**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 2,787,328**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		1,150.00						
		1,195.40						
		-						
	Total	2,345.40	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.93						
		0.90						
		-						
	Total	0.91	(Line 38 / 58)					
	MVA Capability (MVA)							
		1,243.24	(Line 31 / 41)					
		1,328.22	(Line 32 / 42)					
		-						
	Total	2,571.47	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		472.39	(SQRT (Line 51^2 - Line 31^2))					
		578.96	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	1,051.35	(Sum Lines 62 to 64)					
	Reactive Allocator	16.7%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ 2,015,820	15%	$ 302,373
	Control&Power Cabling	$ 19,695,956	1%	$ 196,960
	Switch Board Equipment	$ 11,507,453	1%	$ 115,075
	Switching Equipment	$ 625,734	1%	$ 6,257
	Transformers	$ 1,862,746	3%	$ 55,882
	Aux Generator	$ 129,640	0%	$ -
	Fire Protection System	$ 126,725	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ 794	50%	$ 397
	Structure	$ 25,625	0%	$ -
	Misc	$ 28,280,047	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ 20,693	1%	$ 207
	Bus & Insulators	$ (50,699)	80%	$ (40,559)
	Capacitor Bank	$ -	0%	$ -
	Total	$ 64,240,533		$ 636,592

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	15,945,051	15,945,051	
	Coolants and Water (Nuclear Plants Only)	1,562,346		
	Steam Expenses	9,799,760	9,799,760	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	1,001,176		
	Rents	27,681,670	27,681,670	
	Allowances	2,196,604	2,196,604	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	2,941,585	2,941,585	
	Maintenance of Boiler (or reactor) Plant	229,273		
	Maintenance of Electric Plant	7,580,042		
	Maintenance of Misc Steam (or Nuclear) Plant	4,868,973	4,868,973	
	Other Power Production, & Other Expenses	9,108,904	9,108,904	
	Total NonFuel Expenses	82,915,386	72,542,547	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	2.5074%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	82,915,386	Line 116			
	Allowances	2,196,604	Line 109			
	Non-Fuel Production O&M	80,718,781	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	15,945,051	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	7,580,042	Line 113(b)			
	Other Demand Related Expenses	56,597,497	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	80,122,590	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	7,580,042	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	7,580,042	(Line 138 + 139)	2.5074%	190,062	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	56,597,497	(Line 134)	0.0542%	30,664	
				Line 123		
	Balance of Plant Fixed Expenses				79,901,863	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		54,201,596	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		5,943,375	(allocated on plant labor)	
	Total		60,144,971		

Depreciation				
	Annual Depreciation Exp ...DE	22,868,603		
	Gross Production Plant Cost ... F	1,360,681,860	Line 14	
	SLDP=DE/F	1.6807%	(Line 164 / 165)	
	Depreciable years (n)=1/SLDP	60		
	SFDP=(R/((1+R)^n-1)		0.0752%	
Income Taxes				
	Income Tax Calculation; (Co's Sch. 2)			
	a) State Income Tax Rate ("SIT")	5.6600%		
	b) City/Local Income Tax Rate ("LIT")	0.0000%		
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%		
	d) Net of Fdrl tax SIT	3.6790%		
	e) Federal Income Tax Rate ("FIT")	35.0000%		
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%		
	g) Gross-Up Tax Factor ("GTF")	61.3210%		
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.979%	

				Weighted Cost	
Rate of Return					
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)

Other Taxes					
	Property Taxes		862,588		
	Payroll Taxes	3,565,892			
	0	87.4899%	Line 117		
	Fixed Payroll Taxes		3,119,794	(Line 193 * 194)	
	Total Other Taxes		3,982,382	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9795%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
	Prepayments	2,281,305	
		100.000%	
	Production Related Prepayments	2,281,305	(Line 209 * 210)
	Unit Specific M&S	205,179,355	
	Total	207,460,660	(Line 211 + 212)
	Return on Working Capital	8.1350%	
	Taxes on Working Capital	2.9795%	
	Working Capital Costs	23,058,146	(Line 213 * 214)

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Accumulated Deferred Income Taxes

Investment	1,360,681,860	Line 14
Asset Service Life	60	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 245,212,300

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	22,678,031	3.750%	51,025,570	10,964,545	10,964,545	645,263	246,702	395,682	1,287,648	20,132,488
2	22,678,031	7.219%	98,227,623	29,221,827	40,186,371	2,364,968	904,193	1,450,222	4,719,383	20,132,488
3	22,678,031	6.677%	90,852,728	26,369,291	66,555,662	3,916,801	1,497,502	2,401,821	7,816,125	20,132,488
4	22,678,031	6.177%	84,049,318	23,737,800	90,293,463	5,313,770	2,031,603	3,258,457	10,603,830	20,132,488
5	22,678,031	5.713%	77,735,755	21,295,777	111,589,240	6,567,027	2,510,758	4,026,966	13,104,751	20,132,488
6	22,678,031	5.285%	71,912,036	19,043,221	130,632,460	7,687,720	2,939,230	4,714,187	15,341,138	20,132,488
7	22,678,031	4.888%	66,510,129	16,953,817	147,586,278	8,685,452	3,320,691	5,326,006	17,332,150	20,132,488
8	22,678,031	4.522%	61,530,034	15,027,566	162,613,844	9,569,825	3,658,811	5,868,312	19,096,948	20,132,488
9	22,678,031	4.462%	60,713,625	14,711,787	177,325,631	10,435,613	3,989,827	6,399,222	20,824,663	20,132,488
10	22,678,031	4.461%	60,700,018	14,706,524	192,032,155	11,301,092	4,320,723	6,929,943	22,551,759	20,132,488
11	22,678,031	4.462%	60,713,625	14,711,787	206,743,943	12,166,881	4,651,739	7,460,853	24,279,473	20,132,488
12	22,678,031	4.461%	60,700,018	14,706,524	221,450,467	13,032,360	4,982,636	7,991,573	26,006,569	20,132,488
13	22,678,031	4.462%	60,713,625	14,711,787	236,162,254	13,898,149	5,313,651	8,522,484	27,734,283	20,132,488
14	22,678,031	4.461%	60,700,018	14,706,524	250,868,778	14,763,628	5,644,548	9,053,204	29,461,379	20,132,488
15	22,678,031	4.462%	60,713,625	14,711,787	265,580,566	15,629,416	5,975,563	9,584,114	31,189,093	20,132,488
16	22,678,031	4.461%	60,700,018	14,706,524	280,287,090	16,494,895	6,306,460	10,114,835	32,916,189	20,132,488
17	22,678,031	4.462%	60,713,625	14,711,787	294,998,877	17,360,684	6,637,475	10,645,745	34,643,904	20,132,488
18	22,678,031	4.461%	60,700,018	14,706,524	309,705,401	18,226,163	6,968,372	11,176,465	36,371,000	20,132,488
19	22,678,031	4.462%	60,713,625	14,711,787	324,417,189	19,091,952	7,299,387	11,707,376	38,098,714	20,132,488
20	22,678,031	4.461%	60,700,018	14,706,524	339,123,713	19,957,431	7,630,284	12,238,096	39,825,810	20,132,488
21	22,678,031	2.231%	30,356,812	2,970,076	342,093,789	20,132,219	7,697,110	12,345,278	40,174,608	20,132,488
22	22,678,031	0.000%	0	-8,771,636	333,322,153	19,616,009	7,499,748	12,028,733	39,144,490	20,132,488
23	22,678,031	0.000%	0	-8,771,636	324,550,518	19,099,798	7,302,387	11,712,187	38,114,372	20,132,488
24	22,678,031	0.000%	0	-8,771,636	315,778,882	18,583,587	7,105,025	11,395,642	37,084,254	20,132,488
25	22,678,031	0.000%	0	-8,771,636	307,007,246	18,067,376	6,907,663	11,079,096	36,054,135	20,132,488
26	22,678,031	0.000%	0	-8,771,636	298,235,611	17,551,166	6,710,301	10,762,550	35,024,017	20,132,488
27	22,678,031	0.000%	0	-8,771,636	289,463,975	17,034,955	6,512,939	10,446,005	33,993,899	20,132,488
28	22,678,031	0.000%	0	-8,771,636	280,692,340	16,518,744	6,315,578	10,129,459	32,963,781	20,132,488
29	22,678,031	0.000%	0	-8,771,636	271,920,704	16,002,533	6,118,216	9,812,914	31,933,663	20,132,488
30	22,678,031	0.000%	0	-8,771,636	263,149,068	15,486,323	5,920,854	9,496,368	30,903,545	20,132,488
31	22,678,031	0.000%	0	-8,771,636	254,377,433	14,970,112	5,723,492	9,179,822	29,873,426	20,132,488
32	22,678,031	0.000%	0	-8,771,636	245,605,797	14,453,901	5,526,130	8,863,277	28,843,308	20,132,488
33	22,678,031	0.000%	0	-8,771,636	236,834,161	13,937,690	5,328,769	8,546,731	27,813,190	20,132,488
34	22,678,031	0.000%	0	-8,771,636	228,062,526	13,421,480	5,131,407	8,230,186	26,783,072	20,132,488
35	22,678,031	0.000%	0	-8,771,636	219,290,890	12,905,269	4,934,045	7,913,640	25,752,954	20,132,488
36	22,678,031	0.000%	0	-8,771,636	210,519,255	12,389,058	4,736,683	7,597,094	24,722,836	20,132,488
37	22,678,031	0.000%	0	-8,771,636	201,747,619	11,872,847	4,539,321	7,280,549	23,692,718	20,132,488
38	22,678,031	0.000%	0	-8,771,636	192,975,983	11,356,637	4,341,960	6,964,003	22,662,599	20,132,488
39	22,678,031	0.000%	0	-8,771,636	184,204,348	10,840,426	4,144,598	6,647,458	21,632,481	20,132,488
40	22,678,031	0.000%	0	-8,771,636	175,432,712	10,324,215	3,947,236	6,330,912	20,602,363	20,132,488
41	22,678,031	0.000%	0	-8,771,636	166,661,077	9,808,004	3,749,874	6,014,366	19,572,245	20,132,488
42	22,678,031	0.000%	0	-8,771,636	157,889,441	9,291,794	3,552,512	5,697,821	18,542,127	20,132,488
43	22,678,031	0.000%	0	-8,771,636	149,117,805	8,775,583	3,355,151	5,381,275	17,512,009	20,132,488
44	22,678,031	0.000%	0	-8,771,636	140,346,170	8,259,372	3,157,789	5,064,730	16,481,890	20,132,488
45	22,678,031	0.000%	0	-8,771,636	131,574,534	7,743,161	2,960,427	4,748,184	15,451,772	20,132,488
46	22,678,031	0.000%	0	-8,771,636	122,802,899	7,226,951	2,763,065	4,431,638	14,421,654	20,132,488
47	22,678,031	0.000%	0	-8,771,636	114,031,263	6,710,740	2,565,703	4,115,093	13,391,536	20,132,488
48	22,678,031	0.000%	0	-8,771,636	105,259,627	6,194,529	2,368,342	3,798,547	12,361,418	20,132,488
49	22,678,031	0.000%	0	-8,771,636	96,487,992	5,678,318	2,170,980	3,482,002	11,331,300	20,132,488
50	22,678,031	0.000%	0	-8,771,636	87,716,356	5,162,108	1,973,618	3,165,456	10,301,182	20,132,488
51	22,678,031	0.000%	0	-8,771,636	78,944,720	4,645,897	1,776,256	2,848,910	9,271,063	20,132,488
52	22,678,031	0.000%	0	-8,771,636	70,173,085	4,129,686	1,578,894	2,532,365	8,240,945	20,132,488
53	22,678,031	0.000%	0	-8,771,636	61,401,449	3,613,475	1,381,533	2,215,819	7,210,827	20,132,488
54	22,678,031	0.000%	0	-8,771,636	52,629,814	3,097,265	1,184,171	1,899,274	6,180,709	20,132,488
55	22,678,031	0.000%	0	-8,771,636	43,858,178	2,581,054	986,809	1,582,728	5,150,591	20,132,488
56	22,678,031	0.000%	0	-8,771,636	35,086,542	2,064,843	789,447	1,266,182	4,120,473	20,132,488
57	22,678,031	0.000%	0	-8,771,636	26,314,907	1,548,632	592,085	949,637	3,090,354	20,132,488
58	22,678,031	0.000%	0	-8,771,636	17,543,271	1,032,422	394,724	633,091	2,060,236	20,132,488
59	22,678,031	0.000%	0	-8,771,636	8,771,636	516,211	197,362	316,546	1,030,118	20,132,488
60	22,678,031	0.000%	0	-8,771,636	0	0	0	0	0	20,132,488

Unit Name: Pennsbury 1&2 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 568,704		Electric Expenses	Line 140	1,706		
2	Investment Generator & Exciter	Inputs Tab	$ 85,306		Other Expenses		318		
3	Reactive Allocator	(Line 71)	27.75%		O&M	(sum line 1 & 2)	2,024	28,093	7.2049%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**23,672**						
5					A&G		205,412	3,820,667	5.3763%
6	GSU Transformer Investment	Inputs Tab	-		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.1732%
7	Reactive Allocator	(Line 71)	27.75%		Working Capital	Line 216	17,742	3,820,667	0.4644%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**		General Plant		-	3,820,667	0.0000%
9					Other Taxes	Line 196(c)	55,959	3,820,667	1.4646%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	8,655		Depreciation	Line 168(c)			0.1663%
11	Reactive Allocator	(Line 71)	27.75%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**2,402**		Taxes (Federal/State/Local)	Line 180			2.8753%
13					ADIT	-Line 233(k)	($49,894)	3,820,667	-1.3059%
14	Total Cost of Power Plant	Inputs Tab	3,820,667				(Sum Lines 1 to 11 , Col. (h))		24.5541%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	3,726,706						
16	Balance of Plant Allocator	(Line 79)	0.0542%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	2,019						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	28,093						
19	Reactive Fixed Charge Rate	(Line 14(h))	24.5541%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**6,898**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 6,898**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		2.50						
		2.50						
		-						
	Total	5.00	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.85						
		0.85						
		-						
	Total	0.85	(Line 38 / 58)					
	MVA Capability (MVA)							
		2.94	(Line 31 / 41)					
		2.94	(Line 32 / 42)					
		-						
	Total	5.88	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		1.55	(SQRT (Line 51^2 - Line 31^2))					
		1.55	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	3.10	(Sum Lines 62 to 64)					
	Reactive Allocator	27.8%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ -	50%	$ -
	Control&Power Cabling	$ 17,310	50%	$ 8,655
	Switch Board Equipment	$ -	50%	$ -
	Switching Equipment	$ -	40%	$ -
	Transformers	$ -	10%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ -	0%	$ -
	Misc	$ 224,796	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 242,106		$ 8,655

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	235,561	235,561	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	60,847	60,847	
	Steam From Other Sources	117,580		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	36,024		
	Rents	219,236	219,236	
	Allowances	8,859	8,859	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	91,883	91,883	
	Maintenance of Boiler (or reactor) Plant	39,401		
	Maintenance of Electric Plant	40,991		
	Maintenance of Misc Steam (or Nuclear) Plant	51,019	51,019	
	Other Power Production, & Other Expenses	154,755	154,755	
	Total NonFuel Expenses	1,056,155	822,159	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	4.1625%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	1,056,155	Line 116			
	Allowances	8,859	Line 109			
	Non-Fuel Production O&M	1,047,296	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	235,561	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	40,991	Line 113(b)			
	Other Demand Related Expenses	586,598	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	863,151	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	40,991	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	40,991	(Line 138 + 139)	4.1625%	1,706	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	586,598	(Line 134)	0.0542%	318	
				Line 123		
	Balance of Plant Fixed Expenses				861,127	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		95,853	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		109,559	(allocated on plant labor)	
	Total		205,412		
Depreciation					
	Annual Depreciation Exp ...DE	76,413			
	Gross Production Plant Cost ... F	3,820,667	Line 14		
	SLDP=DE/F	2.0000%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	50			
	SFDP=(R/((1+R)^n-1)		0.1663%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.875%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		55,959	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		55,959	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.8753%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	28,740				
		100.000%				
	Production Related Prepayments	28,740	(Line 209 * 210)			
	Unit Specific M&S	132,405				
	Total	161,144	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.8753%				
	Working Capital Costs	17,742	(Line 213 * 214)			

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(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)

Accumulated Deferred Income Taxes

Investment	3,820,667	Line 14		NPV of Col (j)>	601,037
Asset Service Life	50	Line 167			
Composite Tax Rate	38.6790%	Line 177			

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity = (f) *	Interest = (f) *	Income Taxes = (g) *	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	(Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	76,413	3.750%	143,275	25,861	25,861	1,522	582	933	3,037	49,894
2	76,413	7.219%	275,814	77,126	102,988	6,061	2,317	3,717	12,095	49,894
3	76,413	6.677%	255,106	69,117	172,104	10,128	3,872	6,211	20,211	49,894
4	76,413	6.177%	236,003	61,728	233,832	13,761	5,261	8,438	27,461	49,894
5	76,413	5.713%	218,275	54,871	288,702	16,990	6,496	10,419	33,904	49,894
6	76,413	5.285%	201,922	48,546	337,248	19,847	7,588	12,170	39,606	49,894
7	76,413	4.888%	186,754	42,679	379,927	22,359	8,548	13,711	44,618	49,894
8	76,413	4.522%	172,771	37,270	417,197	24,552	9,387	15,056	48,994	49,894
9	76,413	4.462%	170,478	36,383	453,580	26,693	10,206	16,369	53,267	49,894
10	76,413	4.461%	170,440	36,369	489,948	28,833	11,024	17,681	57,538	49,894
11	76,413	4.462%	170,478	36,383	526,332	30,975	11,842	18,994	61,811	49,894
12	76,413	4.461%	170,440	36,369	562,700	33,115	12,661	20,306	66,082	49,894
13	76,413	4.462%	170,478	36,383	599,084	35,256	13,479	21,619	70,355	49,894
14	76,413	4.461%	170,440	36,369	635,452	37,396	14,298	22,932	74,626	49,894
15	76,413	4.462%	170,478	36,383	671,836	39,538	15,116	24,245	78,899	49,894
16	76,413	4.461%	170,440	36,369	708,204	41,678	15,935	25,557	83,170	49,894
17	76,413	4.462%	170,478	36,383	744,587	43,819	16,753	26,870	87,442	49,894
18	76,413	4.461%	170,440	36,369	780,956	45,959	17,572	28,183	91,713	49,894
19	76,413	4.462%	170,478	36,383	817,339	48,100	18,390	29,496	95,986	49,894
20	76,413	4.461%	170,440	36,369	853,708	50,241	19,208	30,808	100,257	49,894
21	76,413	2.231%	85,239	3,414	857,122	50,442	19,285	30,931	100,658	49,894
22	76,413	0.000%	0	-29,556	827,566	48,702	18,620	29,865	97,187	49,894
23	76,413	0.000%	0	-29,556	798,010	46,963	17,955	28,798	93,716	49,894
24	76,413	0.000%	0	-29,556	768,454	45,224	17,290	27,732	90,245	49,894
25	76,413	0.000%	0	-29,556	738,898	43,484	16,625	26,665	86,774	49,894
26	76,413	0.000%	0	-29,556	709,342	41,745	15,960	25,598	83,303	49,894
27	76,413	0.000%	0	-29,556	679,786	40,005	15,295	24,532	79,832	49,894
28	76,413	0.000%	0	-29,556	650,230	38,266	14,630	23,465	76,361	49,894
29	76,413	0.000%	0	-29,556	620,674	36,527	13,965	22,399	72,890	49,894
30	76,413	0.000%	0	-29,556	591,118	34,787	13,300	21,332	69,419	49,894
31	76,413	0.000%	0	-29,556	561,562	33,048	12,635	20,265	65,948	49,894
32	76,413	0.000%	0	-29,556	532,006	31,309	11,970	19,199	62,477	49,894
33	76,413	0.000%	0	-29,556	502,451	29,569	11,305	18,132	59,006	49,894
34	76,413	0.000%	0	-29,556	472,895	27,830	10,640	17,066	55,536	49,894
35	76,413	0.000%	0	-29,556	443,339	26,090	9,975	15,999	52,065	49,894
36	76,413	0.000%	0	-29,556	413,783	24,351	9,310	14,932	48,594	49,894
37	76,413	0.000%	0	-29,556	384,227	22,612	8,645	13,866	45,123	49,894
38	76,413	0.000%	0	-29,556	354,671	20,872	7,980	12,799	41,652	49,894
39	76,413	0.000%	0	-29,556	325,115	19,133	7,315	11,733	38,181	49,894
40	76,413	0.000%	0	-29,556	295,559	17,394	6,650	10,666	34,710	49,894
41	76,413	0.000%	0	-29,556	266,003	15,654	5,985	9,599	31,239	49,894
42	76,413	0.000%	0	-29,556	236,447	13,915	5,320	8,533	27,768	49,894
43	76,413	0.000%	0	-29,556	206,891	12,176	4,655	7,466	24,297	49,894
44	76,413	0.000%	0	-29,556	177,335	10,436	3,990	6,400	20,826	49,894
45	76,413	0.000%	0	-29,556	147,780	8,697	3,325	5,333	17,355	49,894
46	76,413	0.000%	0	-29,556	118,224	6,957	2,660	4,266	13,884	49,894
47	76,413	0.000%	0	-29,556	88,668	5,218	1,995	3,200	10,413	49,894
48	76,413	0.000%	0	-29,556	59,112	3,479	1,330	2,133	6,942	49,894
49	76,413	0.000%	0	-29,556	29,556	1,739	665	1,067	3,471	49,894
50	76,413	0.000%	0	-29,556	0	0	0	0	0	49,894

Unit Name: Perryman 1,3,4,51 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 177,706,677		Electric Expenses	Line 140	9,996		
2	Investment Generator & Exciter	Inputs Tab	$ 26,656,002		Other Expenses		598		
3	Reactive Allocator	(Line 71)	24.50%		O&M	(sum line 1 & 2)	10,593	6,796,562	0.1559%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**6,531,683**						
5					A&G		1,533,660	250,720,971	0.6117%
6	GSU Transformer Investment	Inputs Tab	784,897		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0105%
7	Reactive Allocator	(Line 71)	24.50%		Working Capital	Line 216	1,682,364	250,720,971	0.6710%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**192,328**		General Plant		-	250,720,971	0.0000%
9					Other Taxes	Line 196(c)	2,143,070	250,720,971	0.8548%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	156,257		Depreciation	Line 168(c)			0.2483%
11	Reactive Allocator	(Line 71)	24.50%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**38,289**		Taxes (Federal/State/Local)	Line 180			2.8113%
13					ADIT	-Line 233(k)	($2,999,980)	250,720,971	-1.1965%
14	Total Cost of Power Plant	Inputs Tab	250,720,971				(Sum Lines 1 to 11 , Col. (h))		12.3019%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	223,123,816						
16	Balance of Plant Allocator	(Line 79)	0.0154%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	34,263						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	6,796,562						
19	Reactive Fixed Charge Rate	(Line 14(h))	12.3019%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**836,106**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 836,106**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		53.00						
		53.00						
		53.00						
		53.00						
		144.90						
	Total	356.90	(Sum Lines 31 to 35)					
	Nominal Power Factor (pf)							
		0.85						
		0.85						
		0.85						
		0.85						
		0.90						
	Total	0.87	(Line 38 / 58)					
	MVA Capability (MVA)							
		62.35	(Line 31 / 41)					
		62.35	(Line 32 / 42)					
		62.35	(Line 33 / 43)					
		62.35	(Line 34 / 44)					
		161.90	(Line 35 / 45)					
	Total	411.31	(Sum Lines 51 to 55)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		32.85	(SQRT (Line 51^2 - Line 31^2))					
		32.85	(SQRT (Line 52^2 - Line 32^2))					
		32.85	(SQRT (Line 53^2 - Line 33^2))					
		32.85	(SQRT (Line 54^2 - Line 34^2))					
		72.22	(SQRT (Line 55^2 - Line 35^2))					
	Total	203.60	(Sum Lines 62 to 66)					
	Reactive Allocator	24.5%	(Line 69^2 / Line 58^2)					
		BGE is TO Fleet						
	Max. MVAr	27.50						
	Nameplate MVAr	571.22						
	Exciter MW	3.08						
	Generator MW	965.46						
	Balance of Plant Allocator	0.0154%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ -	**50%**	$ -
	Control&Power Cabling	$ -	**50%**	$ -
	Switch Board Equipment	$ -	**50%**	$ -
	Switching Equipment	$ 59,681	**40%**	$ 23,872
	Transformers	$ -	**10%**	$ -
	Aux Generator	$ -	**0%**	$ -
	Fire Protection System	$ -	**0%**	$ -
	HVAC	$ -	**0%**	$ -
	Regulating Equipment	$ 176,513	**75%**	$ 132,385
	Structure	$ -	**0%**	$ -
	Misc	$ 21,318,503	**0%**	$ -
	Exciter & PPT	$ -	**100%**	$ -
	Station Grounding	$ -	**5%**	$ -
	Bus & Insulators	$ -	**80%**	$ -
	Capacitor Bank	$ -	**0%**	$ -
	Total	$ 21,554,696		$ 156,257

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	1,562,813	1,562,813	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	403,686	403,686	
	Steam From Other Sources	780,076		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	238,995		
	Rents	1,454,502	1,454,502	
	Allowances	58,774	58,774	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	609,590	609,590	
	Maintenance of Boiler (or reactor) Plant	261,403		
	Maintenance of Electric Plant	271,954		
	Maintenance of Misc Steam (or Nuclear) Plant	338,484	338,484	
	Other Power Production, & Other Expenses	1,026,708	1,026,708	
	Total NonFuel Expenses	7,006,986	5,454,558	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	3.6755%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0154%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	7,006,986	Line 116			
	Allowances	58,774	Line 109			
	Non-Fuel Production O&M	6,948,212	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	1,562,813	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	271,954	Line 113(b)			
	Other Demand Related Expenses	3,891,745	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	5,726,511	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	271,954	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	271,954	(Line 138 + 139)	3.6755%	9,996	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	3,891,745	(Line 134)	0.0154%	598	
				Line 123		
	Balance of Plant Fixed Expenses				5,715,918	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		757,586	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		776,075	(allocated on plant labor)	
	Total		1,533,660		
Depreciation					
	Annual Depreciation Exp ...DE	5,571,577			
	Gross Production Plant Cost ... F	250,720,971	Line 14		
	SLDP=DE/F	2.2222%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	45			
	SFDP=(R/((1+R)^n-1)		0.2483%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.811%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		2,143,070	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		2,143,070	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.8113%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	1,885,966				
		100.000%				
	Production Related Prepayments	1,885,966	(Line 209 * 210)			
	Unit Specific M&S	13,483,260				
	Total	15,369,227	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.8113%				
	Working Capital Costs	1,682,364	(Line 213 * 214)			

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Accumulated Deferred Income Taxes

Investment	250,720,971	Line 14
Asset Service Life	45	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 35,785,300

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity = (f) *	(h) Interest = (f) *	(i) Income Taxes = (g) *	(j) Rev Req Impact	(k) Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	(Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	5,571,577	3.750%	9,402,036	1,481,583	1,481,583	87,191	33,336	53,467	173,993	2,999,980
2	5,571,577	7.219%	18,099,547	4,845,693	6,327,277	372,360	142,364	228,335	743,059	2,999,980
3	5,571,577	6.677%	16,740,639	4,320,082	10,647,358	626,597	239,566	384,236	1,250,398	2,999,980
4	5,571,577	6.177%	15,487,034	3,835,200	14,482,558	852,299	325,858	522,638	1,700,794	2,999,980
5	5,571,577	5.713%	14,323,689	3,385,229	17,867,787	1,051,519	402,025	644,802	2,098,347	2,999,980
6	5,571,577	5.285%	13,250,603	2,970,171	20,837,958	1,226,314	468,854	751,988	2,447,156	2,999,980
7	5,571,577	4.888%	12,255,241	2,585,174	23,423,132	1,378,451	527,020	845,280	2,750,752	2,999,980
8	5,571,577	4.522%	11,337,602	2,230,241	25,653,373	1,509,701	577,201	925,764	3,012,666	2,999,980
9	5,571,577	4.462%	11,187,170	2,172,055	27,825,428	1,637,526	626,072	1,004,148	3,267,746	2,999,980
10	5,571,577	4.461%	11,184,662	2,171,085	29,996,513	1,765,295	674,922	1,082,496	3,522,713	2,999,980
11	5,571,577	4.462%	11,187,170	2,172,055	32,168,569	1,893,120	723,793	1,160,880	3,777,793	2,999,980
12	5,571,577	4.461%	11,184,662	2,171,085	34,339,654	2,020,889	772,642	1,239,229	4,032,760	2,999,980
13	5,571,577	4.462%	11,187,170	2,172,055	36,511,709	2,148,714	821,513	1,317,613	4,287,840	2,999,980
14	5,571,577	4.461%	11,184,662	2,171,085	38,682,794	2,276,482	870,363	1,395,962	4,542,807	2,999,980
15	5,571,577	4.462%	11,187,170	2,172,055	40,854,849	2,404,308	919,234	1,474,346	4,797,888	2,999,980
16	5,571,577	4.461%	11,184,662	2,171,085	43,025,935	2,532,076	968,084	1,552,694	5,052,854	2,999,980
17	5,571,577	4.462%	11,187,170	2,172,055	45,197,990	2,659,902	1,016,955	1,631,078	5,307,935	2,999,980
18	5,571,577	4.461%	11,184,662	2,171,085	47,369,075	2,787,670	1,065,804	1,709,427	5,562,901	2,999,980
19	5,571,577	4.462%	11,187,170	2,172,055	49,541,130	2,915,495	1,114,675	1,787,811	5,817,982	2,999,980
20	5,571,577	4.461%	11,184,662	2,171,085	51,712,215	3,043,264	1,163,525	1,866,160	6,072,949	2,999,980
21	5,571,577	2.231%	5,593,585	8,512	51,720,728	3,043,765	1,163,716	1,866,467	6,073,948	2,999,980
22	5,571,577	0.000%	0	-2,155,030	49,565,697	2,916,941	1,115,228	1,788,698	5,820,867	2,999,980
23	5,571,577	0.000%	0	-2,155,030	47,410,667	2,790,118	1,066,740	1,710,928	5,567,786	2,999,980
24	5,571,577	0.000%	0	-2,155,030	45,255,637	2,663,294	1,018,252	1,633,159	5,314,705	2,999,980
25	5,571,577	0.000%	0	-2,155,030	43,100,606	2,536,471	969,764	1,555,389	5,061,624	2,999,980
26	5,571,577	0.000%	0	-2,155,030	40,945,576	2,409,647	921,275	1,477,620	4,808,542	2,999,980
27	5,571,577	0.000%	0	-2,155,030	38,790,546	2,282,824	872,787	1,399,850	4,555,461	2,999,980
28	5,571,577	0.000%	0	-2,155,030	36,635,515	2,156,000	824,299	1,322,081	4,302,380	2,999,980
29	5,571,577	0.000%	0	-2,155,030	34,480,485	2,029,177	775,811	1,244,311	4,049,299	2,999,980
30	5,571,577	0.000%	0	-2,155,030	32,325,455	1,902,353	727,323	1,166,542	3,796,218	2,999,980
31	5,571,577	0.000%	0	-2,155,030	30,170,424	1,775,529	678,835	1,088,772	3,543,136	2,999,980
32	5,571,577	0.000%	0	-2,155,030	28,015,394	1,648,706	630,346	1,011,003	3,290,055	2,999,980
33	5,571,577	0.000%	0	-2,155,030	25,860,364	1,521,882	581,858	933,234	3,036,974	2,999,980
34	5,571,577	0.000%	0	-2,155,030	23,705,333	1,395,059	533,370	855,464	2,783,893	2,999,980
35	5,571,577	0.000%	0	-2,155,030	21,550,303	1,268,235	484,882	777,695	2,530,812	2,999,980
36	5,571,577	0.000%	0	-2,155,030	19,395,273	1,141,412	436,394	699,925	2,277,731	2,999,980
37	5,571,577	0.000%	0	-2,155,030	17,240,243	1,014,588	387,905	622,156	2,024,649	2,999,980
38	5,571,577	0.000%	0	-2,155,030	15,085,212	887,765	339,417	544,386	1,771,568	2,999,980
39	5,571,577	0.000%	0	-2,155,030	12,930,182	760,941	290,929	466,617	1,518,487	2,999,980
40	5,571,577	0.000%	0	-2,155,030	10,775,152	634,118	242,441	388,847	1,265,406	2,999,980
41	5,571,577	0.000%	0	-2,155,030	8,620,121	507,294	193,953	311,078	1,012,325	2,999,980
42	5,571,577	0.000%	0	-2,155,030	6,465,091	380,471	145,465	233,308	759,244	2,999,980
43	5,571,577	0.000%	0	-2,155,030	4,310,061	253,647	96,976	155,539	506,162	2,999,980
44	5,571,577	0.000%	0	-2,155,030	2,155,030	126,824	48,488	77,769	253,081	2,999,980
45	5,571,577	0.000%	0	-2,155,030	0	0	0	0	0	2,999,980

Unit Name: Perryman 6 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 88,242,961		Electric Expenses	Line 140	-		
2	Investment Generator & Exciter	Inputs Tab	$ 13,236,444		Other Expenses		-		
3	Reactive Allocator	(Line 71)	27.75%		O&M	(sum line 1 & 2)	-	3,688,910	0.0000%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**3,673,113**						
5					A&G		-	116,109,159	0.0000%
6	GSU Transformer Investment	Inputs Tab	-		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0000%
7	Reactive Allocator	(Line 71)	27.75%		Working Capital	Line 216	93,619	116,109,159	0.0806%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**		General Plant		-	116,109,159	0.0000%
9					Other Taxes	Line 196(c)	-	116,109,159	0.0000%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	-		Depreciation	Line 168(c)			0.8611%
11	Reactive Allocator	(Line 71)	27.75%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**0**		Taxes (Federal/State/Local)	Line 180			2.5840%
13					ADIT	-Line 233(k)	($825,789)	116,109,159	-0.7112%
14	Total Cost of Power Plant	Inputs Tab	116,109,159				(Sum Lines 1 to 11 , Col. (h))		10.9495%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	102,872,715						
16	Balance of Plant Allocator	(Line 79)	0.0154%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	15,797						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	3,688,910						
19	Reactive Fixed Charge Rate	(Line 14(h))	10.9495%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**403,917**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 403,917**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		141.06						
		-						
		-						
	Total	141.06	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.85						
		-						
		-						
	Total	0.85	(Line 38 / 58)					
	MVA Capability (MVA)							
		165.95	(Line 31 / 41)					
		-						
		-						
	Total	165.95	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		87.42	(SQRT (Line 51^2 - Line 31^2))					
		-						
		-						
	Total	87.42	(Sum Lines 62 to 64)					
	Reactive Allocator	27.8%	(Line 69^2 / Line 58^2)					
		BGE is TO Fleet						
	Max. MVAr	27.50						
	Nameplate MVAr	571.22						
	Exciter MW	3.08						
	Generator MW	965.46						
	Balance of Plant Allocator	0.0154%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)	
Accessory Equip Allocator					
		Investment	**Cumb. Turbine**	**Allocated Amt**	
	Storage Batteries	$ -	50%	$ -	
	Control&Power Cabling	$ -	50%	$ -	
	Switch Board Equipment	$ -	50%	$ -	
	Switching Equipment	$ -	40%	$ -	
	Transformers	$ -	10%	$ -	
	Aux Generator	$ -	0%	$ -	
	Fire Protection System	$ -	0%	$ -	
	HVAC	$ -	0%	$ -	
	Regulating Equipment	$ -	75%	$ -	
	Structure	$ -	0%	$ -	
	Misc	$ -	0%	$ -	
	Exciter & PPT	$ -	100%	$ -	
	Station Grounding	$ -	5%	$ -	
	Bus & Insulators	$ -	80%	$ -	
	Capacitor Bank	$ -	0%	$ -	
	Total	$ -		$ -	
O&M		**Total Non-Fuel**	**Fixed O&M**		
	Production Expenses: Oper, Supv, & Engr	1	1		
	Coolants and Water (Nuclear Plants Only)	0			
	Steam Expenses	0	-		
	Steam From Other Sources	0			
	Electric Expenses	0	-		
	Misc Steam (or Nuclear) Power Expenses	0			
	Rents	0	-		
	Allowances	0	-		
	Maintenance Supervision and Engineering	0			
	Maintenance of Structures	0	-		
	Maintenance of Boiler (or reactor) Plant	0			
	Maintenance of Electric Plant	0			
	Maintenance of Misc Steam (or Nuclear) Plant	0	-		
	Other Power Production, & Other Expenses	0	-		
	Total NonFuel Expenses	1	1	(Sum Lines 102 to 115)	
	Percentage Fixed O&M Excluding Allowances		100.00%	(Line 116(c) / (Line 116(b) - Line 110(b)))	
O&M Calculation					
	Plant Var Allocators				
	Electric Expense Allocator	4.1625%	Line 4(c) / 1(c))		
	Operations Suprv & Engrg Allocator	#DIV/0!	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)		
	Other Demand Expense Allocator	0.0154%	Line 79		
	Production Plant Expenses				
	Total NonFuel Expenses	1	Line 116		
	Allowances	0	Line 109		
	Non-Fuel Production O&M	1	(Line 126 - 127)		
	Operating Expenses				
	Operations Supervision & Engineering	1	Line 102(c)		
	Electric Expenses	0	Line 106(c)		
	Maintenance of Electric Plant	0	Line 113(b)		
	Other Demand Related Expenses	0	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)		
	Total	1	(Sum Lines 131 to 134)		
				Allocator	Allocated Amount
	Maintenance of Electric Plant	0	Line 113(b)		
	Electric Expenses	0	Line 106(c)		
	Total Electric Expenses	0	(Line 138 + 139)	4.1625%	- (Line 140(b) * (d))
				Line 121	
	Other Demand Related Expenses	0	(Line 134)	0.0154%	-
				Line 123	
	Balance of Plant Fixed Expenses				1 (Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		0	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		0	(allocated on plant labor)	
	Total		0		
Depreciation					
	Annual Depreciation Exp ...DE	3,870,305			
	Gross Production Plant Cost ... F	116,109,159	Line 14		
	SLDP=DE/F	3.3333%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	30			
	SFDP=(R/((1+R)^n-1)		0.8611%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.584%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		0	<Includes Payroll	
	Payroll Taxes				
		100.0000%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		-	(Line 192 + 195)	

	Plant		Depreciation	Total	
General Plant	-		-		
	0.000%		0.000%		Line 159
Fixed General Plant	-		-		(Lines 200 *201)
Return on General Plant	8.1350%	Line 188			
Taxes on General Plant	2.5840%	Line 189			
General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
Prepayments	873,393		
	100.000%		
Production Related Prepayments	873,393	(Line 209 * 210)	
Unit Specific M&S	-		
Total	873,393	(Line 211 + 212)	
Return on Working Capital	8.1350%		
Taxes on Working Capital	2.5840%		
Working Capital Costs	93,619	(Line 213 * 214)	

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Accumulated Deferred Income Taxes

Investment	116,109,159	Line 14
Asset Service Life	30	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 9,179,383

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	3,870,305	3.750%	4,354,093	187,124	187,124	11,012	4,210	6,753	21,975	825,789
2	3,870,305	7.219%	8,381,920	1,745,048	1,932,172	113,708	43,474	69,727	226,909	825,789
3	3,870,305	6.677%	7,752,609	1,501,636	3,433,808	202,080	77,261	123,917	403,258	825,789
4	3,870,305	6.177%	7,172,063	1,277,087	4,710,895	277,236	105,995	170,004	553,235	825,789
5	3,870,305	5.713%	6,633,316	1,068,705	5,779,600	340,129	130,041	208,571	678,741	825,789
6	3,870,305	5.285%	6,136,369	876,491	6,656,091	391,711	149,762	240,201	781,674	825,789
7	3,870,305	4.888%	5,675,416	698,199	7,354,289	432,800	165,472	265,397	863,669	825,789
8	3,870,305	4.522%	5,250,456	533,829	7,888,118	464,216	177,483	284,662	926,360	825,789
9	3,870,305	4.462%	5,180,791	506,883	8,395,000	494,046	188,888	302,954	985,887	825,789
10	3,870,305	4.461%	5,179,630	506,434	8,901,434	523,849	200,282	321,230	1,045,361	825,789
11	3,870,305	4.462%	5,180,791	506,883	9,408,317	553,679	211,687	339,522	1,104,888	825,789
12	3,870,305	4.461%	5,179,630	506,434	9,914,750	583,483	223,082	357,798	1,164,363	825,789
13	3,870,305	4.462%	5,180,791	506,883	10,421,633	613,313	234,487	376,090	1,223,890	825,789
14	3,870,305	4.461%	5,179,630	506,434	10,928,066	643,117	245,881	394,366	1,283,364	825,789
15	3,870,305	4.462%	5,180,791	506,883	11,434,949	672,947	257,286	412,658	1,342,891	825,789
16	3,870,305	4.461%	5,179,630	506,434	11,941,382	702,750	268,681	430,934	1,402,365	825,789
17	3,870,305	4.462%	5,180,791	506,883	12,448,265	732,580	280,086	449,226	1,461,892	825,789
18	3,870,305	4.461%	5,179,630	506,434	12,954,699	762,384	291,481	467,502	1,521,366	825,789
19	3,870,305	4.462%	5,180,791	506,883	13,461,581	792,214	302,886	485,794	1,580,893	825,789
20	3,870,305	4.461%	5,179,630	506,434	13,968,015	822,018	314,280	504,069	1,640,367	825,789
21	3,870,305	2.231%	2,590,395	-495,056	13,472,958	792,884	303,142	486,204	1,582,229	825,789
22	3,870,305	0.000%	0	-1,496,995	11,975,963	704,785	269,459	432,181	1,406,426	825,789
23	3,870,305	0.000%	0	-1,496,995	10,478,968	616,687	235,777	378,159	1,230,623	825,789
24	3,870,305	0.000%	0	-1,496,995	8,981,972	528,589	202,094	324,136	1,054,820	825,789
25	3,870,305	0.000%	0	-1,496,995	7,484,977	440,491	168,412	270,113	879,016	825,789
26	3,870,305	0.000%	0	-1,496,995	5,987,982	352,393	134,730	216,091	703,213	825,789
27	3,870,305	0.000%	0	-1,496,995	4,490,986	264,295	101,047	162,068	527,410	825,789
28	3,870,305	0.000%	0	-1,496,995	2,993,991	176,196	67,365	108,045	351,607	825,789
29	3,870,305	0.000%	0	-1,496,995	1,496,995	88,098	33,682	54,023	175,803	825,789
30	3,870,305	0.000%	0	-1,496,995	0	0	0	0	0	825,789

Unit Name: Philadelphia Rd 1-4 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 16,996,875		Electric Expenses	Line 140	1,210		
2	Investment Generator & Exciter	Inputs Tab	$ 2,549,531		Other Expenses		57		
3	Reactive Allocator	(Line 71)	31.36%		O&M	(sum line 1 & 2)	1,266	1,216,879	0.1040%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**799,423**						
5					A&G		107,408	18,270,877	0.5879%
6	GSU Transformer Investment	Inputs Tab	-		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0096%
7	Reactive Allocator	(Line 71)	31.36%		Working Capital	Line 216	178,629	18,270,877	0.9777%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**		General Plant		-	18,270,877	0.0000%
9					Other Taxes	Line 196(c)	264,526	18,270,877	1.4478%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	1,324,305		Depreciation	Line 168(c)			0.1117%
11	Reactive Allocator	(Line 71)	31.36%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**415,245**		Taxes (Federal/State/Local)	Line 180			2.9334%
13					ADIT	-Line 233(k)	($255,638)	18,270,877	-1.3992%
14	Total Cost of Power Plant	Inputs Tab	18,270,877				(Sum Lines 1 to 11 , Col. (h))		12.9079%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	14,397,041						
16	Balance of Plant Allocator	(Line 79)	0.0154%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	2,211						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	1,216,879						
19	Reactive Fixed Charge Rate	(Line 14(h))	12.9079%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**157,074**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 157,074**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		13.40						
		18.00						
		18.00						
		18.00						
	Total	67.40	(Sum Lines 31 to 34)					
	Nominal Power Factor (pf)							
		0.74						
		0.85						
		0.85						
		0.85						
	Total	0.82	(Line 38 / 58)					
	MVA Capability (MVA)							
		18.18	(Line 31 / 41)					
		21.18	(Line 32 / 42)					
		21.18	(Line 33 / 43)					
		21.18	(Line 34 / 44)					
	Total	81.71	(Sum Lines 51 to 54)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		12.29	(SQRT (Line 51^2 - Line 31^2))					
		11.16	(SQRT (Line 52^2 - Line 32^2))					
		11.16	(SQRT (Line 53^2 - Line 33^2))					
		11.16	(SQRT (Line 54^2 - Line 34^2))					
	Total	45.76	(Sum Lines 62 to 65)					
	Reactive Allocator	31.4%	(Line 69^2 / Line 58^2)					
		BGE is TO Fleet						
	Max. MVAr	27.50						
	Nameplate MVAr	571.22						
	Exciter MW	3.08						
	Generator MW	965.46						
	Balance of Plant Allocator	0.0154%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ -	50%	$ -
	Control&Power Cabling	$ -	50%	$ -
	Switch Board Equipment	$ 2,648,610	50%	$ 1,324,305
	Switching Equipment	$ -	40%	$ -
	Transformers	$ -	10%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ -	0%	$ -
	Misc	$ 412,515	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 3,061,125		$ 1,324,305

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	147,788	147,788	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	38,175	38,175	
	Steam From Other Sources	73,768		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	22,601		
	Rents	137,546	137,546	
	Allowances	5,558	5,558	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	57,646	57,646	
	Maintenance of Boiler (or reactor) Plant	24,720		
	Maintenance of Electric Plant	25,717		
	Maintenance of Misc Steam (or Nuclear) Plant	32,009	32,009	
	Other Power Production, & Other Expenses	97,091	97,091	
	Total NonFuel Expenses	662,620	515,814	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	4.7034%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0154%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	662,620	Line 116			
	Allowances	5,558	Line 109			
	Non-Fuel Production O&M	657,062	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	147,788	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	25,717	Line 113(b)			
	Other Demand Related Expenses	368,025	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	541,531	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	25,717	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	25,717	(Line 138 + 139)	4.7034%	1,210	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	368,025	(Line 134)	0.0154%	57	
				Line 123		
	Balance of Plant Fixed Expenses				540,265	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		70,095	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		37,313	(allocated on plant labor)	
	Total		107,408		
Depreciation					
	Annual Depreciation Exp ...DE	332,198			
	Gross Production Plant Cost ... F	18,270,877	Line 14		
	SLDP=DE/F	1.8182%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	55			
	SFDP=(R/((1+R)^n-1)		0.1117%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.933%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		264,526	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		264,526	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9334%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	137,437				
		100.000%				
	Production Related Prepayments	137,437	(Line 209 * 210)			
	Unit Specific M&S	1,476,433				
	Total	1,613,870	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9334%				
	Working Capital Costs	178,629	(Line 213 * 214)			

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Accumulated Deferred Income Taxes

Investment	18,270,877	Line 14
Asset Service Life	55	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 3,099,870

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	332,198	3.750%	685,158	136,521	136,521	8,034	3,072	4,927	16,033	255,638
2	332,198	7.219%	1,318,975	381,675	518,197	30,496	11,659	18,700	60,856	255,638
3	332,198	6.677%	1,219,946	343,372	861,569	50,703	19,385	31,092	101,180	255,638
4	332,198	6.177%	1,128,592	308,037	1,169,607	68,831	26,316	42,208	137,356	255,638
5	332,198	5.713%	1,043,815	275,247	1,444,853	85,030	32,509	52,141	169,680	255,638
6	332,198	5.285%	965,616	245,000	1,689,853	99,448	38,022	60,982	198,452	255,638
7	332,198	4.888%	893,080	216,944	1,906,797	112,215	42,903	68,811	223,929	255,638
8	332,198	4.522%	826,209	191,079	2,097,875	123,460	47,202	75,707	246,369	255,638
9	332,198	4.462%	815,247	186,838	2,284,714	134,455	51,406	82,449	268,311	255,638
10	332,198	4.461%	815,064	186,768	2,471,481	145,447	55,608	89,189	290,244	255,638
11	332,198	4.462%	815,247	186,838	2,658,320	156,442	59,812	95,932	312,186	255,638
12	332,198	4.461%	815,064	186,768	2,845,088	167,433	64,014	102,672	334,120	255,638
13	332,198	4.462%	815,247	186,838	3,031,926	178,429	68,218	109,414	356,062	255,638
14	332,198	4.461%	815,064	186,768	3,218,694	189,420	72,421	116,154	377,995	255,638
15	332,198	4.462%	815,247	186,838	3,405,532	200,416	76,624	122,897	399,937	255,638
16	332,198	4.461%	815,064	186,768	3,592,300	211,407	80,827	129,637	421,870	255,638
17	332,198	4.462%	815,247	186,838	3,779,138	222,402	85,031	136,379	443,812	255,638
18	332,198	4.461%	815,064	186,768	3,965,906	233,394	89,233	143,119	465,746	255,638
19	332,198	4.462%	815,247	186,838	4,152,745	244,389	93,437	149,862	487,688	255,638
20	332,198	4.461%	815,064	186,768	4,339,512	255,380	97,639	156,602	509,621	255,638
21	332,198	2.231%	407,623	29,174	4,368,686	257,097	98,295	157,655	513,047	255,638
22	332,198	0.000%	0	-128,491	4,240,196	249,536	95,404	153,018	497,958	255,638
23	332,198	0.000%	0	-128,491	4,111,705	241,974	92,513	148,381	482,868	255,638
24	332,198	0.000%	0	-128,491	3,983,214	234,412	89,622	143,744	467,778	255,638
25	332,198	0.000%	0	-128,491	3,854,723	226,850	86,731	139,107	452,689	255,638
26	332,198	0.000%	0	-128,491	3,726,232	219,289	83,840	134,470	437,599	255,638
27	332,198	0.000%	0	-128,491	3,597,742	211,727	80,949	129,833	422,509	255,638
28	332,198	0.000%	0	-128,491	3,469,251	204,165	78,058	125,196	407,420	255,638
29	332,198	0.000%	0	-128,491	3,340,760	196,604	75,167	120,559	392,330	255,638
30	332,198	0.000%	0	-128,491	3,212,269	189,042	72,276	115,922	377,241	255,638
31	332,198	0.000%	0	-128,491	3,083,779	181,480	69,385	111,286	362,151	255,638
32	332,198	0.000%	0	-128,491	2,955,288	173,919	66,494	106,649	347,061	255,638
33	332,198	0.000%	0	-128,491	2,826,797	166,357	63,603	102,012	331,972	255,638
34	332,198	0.000%	0	-128,491	2,698,306	158,795	60,712	97,375	316,882	255,638
35	332,198	0.000%	0	-128,491	2,569,815	151,234	57,821	92,738	301,792	255,638
36	332,198	0.000%	0	-128,491	2,441,325	143,672	54,930	88,101	286,703	255,638
37	332,198	0.000%	0	-128,491	2,312,834	136,110	52,039	83,464	271,613	255,638
38	332,198	0.000%	0	-128,491	2,184,343	128,549	49,148	78,827	256,524	255,638
39	332,198	0.000%	0	-128,491	2,055,852	120,987	46,257	74,190	241,434	255,638
40	332,198	0.000%	0	-128,491	1,927,362	113,425	43,366	69,553	226,344	255,638
41	332,198	0.000%	0	-128,491	1,798,871	105,864	40,475	64,917	211,255	255,638
42	332,198	0.000%	0	-128,491	1,670,380	98,302	37,584	60,280	196,165	255,638
43	332,198	0.000%	0	-128,491	1,541,889	90,740	34,693	55,643	181,075	255,638
44	332,198	0.000%	0	-128,491	1,413,399	83,179	31,801	51,006	165,986	255,638
45	332,198	0.000%	0	-128,491	1,284,908	75,617	28,910	46,369	150,896	255,638
46	332,198	0.000%	0	-128,491	1,156,417	68,055	26,019	41,732	135,807	255,638
47	332,198	0.000%	0	-128,491	1,027,926	60,493	23,128	37,095	120,717	255,638
48	332,198	0.000%	0	-128,491	899,435	52,932	20,237	32,458	105,627	255,638
49	332,198	0.000%	0	-128,491	770,945	45,370	17,346	27,821	90,538	255,638
50	332,198	0.000%	0	-128,491	642,454	37,808	14,455	23,184	75,448	255,638
51	332,198	0.000%	0	-128,491	513,963	30,247	11,564	18,548	60,358	255,638
52	332,198	0.000%	0	-128,491	385,472	22,685	8,673	13,911	45,269	255,638
53	332,198	0.000%	0	-128,491	256,982	15,123	5,782	9,274	30,179	255,638
54	332,198	0.000%	0	-128,491	128,491	7,562	2,891	4,637	15,090	255,638
55	332,198	0.000%	0	-128,491	0	0	0	0	0	255,638

Unit Name: Quad Cities 1 & 2 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 345,327,838	
2	Investment Generator & Exciter	Inputs Tab	51,799,176	
3	Reactive Allocator	(Line 71)	10.98%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**5,688,558**	
5				
6	GSU Transformer Investment	Inputs Tab	25,326,658	
7	Reactive Allocator	(Line 71)	10.98%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**2,781,360**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	2,665,593	
11	Reactive Allocator	(Line 71)	10.98%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**292,734**	
13				
14	Total Cost of Power Plant	Inputs Tab	1,046,110,329	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	966,318,902	
16	Balance of Plant Allocator	(Line 79)	0.1358%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	1,312,709	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	10,075,360	
19	Reactive Fixed Charge Rate	(Line 14(h))	25.1729%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**2,536,264**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 2,536,264**	
23				
24				
25				
26				

(e)		(f)	(g)	(h)
Fixed Charge Rate for Reactive Plant				
		Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 140	170,624		
Other Expenses		105,061		
O&M	(sum line 1 & 2)	275,686	10,075,360	2.7362%
A&G		90,659,395	1,046,110,329	8.6663%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.1585%
Working Capital	Line 216	30,066,107	1,046,110,329	2.8741%
General Plant		-	1,046,110,329	0.0000%
Other Taxes	Line 196(c)	10,683,702	1,046,110,329	1.0213%
Depreciation	Line 168(c)			0.0752%
				8.1350%
Taxes (Federal/State/Local)	Line 180			2.9859%
ADIT	-Line 233(k)	($15,478,125)	1,046,110,329	-1.4796%
		(Sum Lines 1 to 11 , Col. (h))		25.1729%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		961.00						
		980.00						
		-						
	Total	1,941.00	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.95						
		0.94						
		-						
	Total	0.94	(Line 38 / 58)					
	MVA Capability (MVA)							
		1,016.93	(Line 31 / 41)					
		1,040.34	(Line 32 / 42)					
		-						
	Total	2,057.27	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		332.61	(SQRT (Line 51^2 - Line 31^2))					
		349.15	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	681.76	(Sum Lines 62 to 64)					
	Reactive Allocator	11.0%	(Line 69^2 / Line 58^2)					
		ComEd is TO Fleet						
	Max. MVAr	2,187						
	Nameplate MVAr	4,856						
	Exciter MW	35						
	Generator MW	11,447						
	Balance of Plant Allocator	0.1358%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ 2,133,713	15%	$ 320,057
	Control&Power Cabling	$ 7,403,630	1%	$ 74,036
	Switch Board Equipment	$ 2,898,057	1%	$ 28,981
	Switching Equipment	$ 3,872,699	1%	$ 38,727
	Transformers	$ 8,262,803	3%	$ 247,884
	Aux Generator	$ 3,321,149	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	50%	$ -
	Structure	$ 133,041	0%	$ -
	Misc	$ 35,712,768	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ 2,051	1%	$ 21
	Bus & Insulators	$ 2,444,859	80%	$ 1,955,887
	Capacitor Bank	$ -	0%	$ -
	Total	$ 66,184,772		$ 2,665,593

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	21,788,348	21,788,348	
	Coolants and Water (Nuclear Plants Only)	2,134,891		
	Steam Expenses	13,391,026	13,391,026	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	1,368,072		
	Rents	37,826,023	37,826,023	
	Allowances	3,001,582	3,001,582	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	4,019,572	4,019,572	
	Maintenance of Boiler (or reactor) Plant	313,294		
	Maintenance of Electric Plant	10,357,860		
	Maintenance of Misc Steam (or Nuclear) Plant	6,653,280	6,653,280	
	Other Power Production, & Other Expenses	12,446,996	12,446,996	
	Total NonFuel Expenses	113,300,945	99,126,828	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	1.6473%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.1358%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	113,300,945	Line 116			
	Allowances	3,001,582	Line 109			
	Non-Fuel Production O&M	110,299,363	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	21,788,348	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	10,357,860	Line 113(b)			
	Other Demand Related Expenses	77,338,479	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	109,484,688	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	10,357,860	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	10,357,860	(Line 138 + 139)	1.6473%	170,624	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	77,338,479	(Line 134)	0.1358%	105,061	
				Line 123		
	Balance of Plant Fixed Expenses				109,209,002	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		82,058,738	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		8,600,657	(allocated on plant labor)	
	Total		90,659,395		

Depreciation				
	Annual Depreciation Exp ...DE	17,435,172	Reflects life extension to 2032	
	Gross Production Plant Cost ... F	1,046,110,329	Line 14	
	SLDP=DE/F	1.6667%	(Line 164 / 165)	
	Depreciable years (n)=1/SLDP	60		
	SFDP=(R/((1+R)^n-1)		0.0752%	
Income Taxes				
	Income Tax Calculation; (Co's Sch. 2)			
	a) State Income Tax Rate ("SIT")	5.6600%		
	b) City/Local Income Tax Rate ("LIT")	0.0000%		
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%		
	d) Net of Fdrl tax SIT	3.6790%		
	e) Federal Income Tax Rate ("FIT")	35.0000%		
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%		
	g) Gross-Up Tax Factor ("GTF")	61.3210%		
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.986%	

Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)

Other Taxes					
	Property Taxes		6,042,855		
	Payroll Taxes	5,304,440			
	0	87.4899%	Line 117		
	Fixed Payroll Taxes		4,640,846	(Line 193 * 194)	
	Total Other Taxes		10,683,702	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9859%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
	Prepayments	1,753,898	
		100.000%	
	Production Related Prepayments	1,753,898	(Line 209 * 210)
	Unit Specific M&S	268,603,913	
	Total	270,357,811	(Line 211 + 212)
	Return on Working Capital	8.1350%	
	Taxes on Working Capital	2.9859%	
	Working Capital Costs	30,066,107	(Line 213 * 214)

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Accumulated Deferred Income Taxes

Investment	1,046,110,329	Line 14
Asset Service Life	60	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 188,522,481

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	17,435,172	3.750%	39,229,137	8,429,688	8,429,688	496,087	189,668	304,206	989,961	15,478,125
2	17,435,172	7.219%	75,518,705	22,466,130	30,895,817	1,818,219	695,156	1,114,950	3,628,325	15,478,125
3	17,435,172	6.677%	69,848,787	20,273,062	51,168,879	3,011,289	1,151,300	1,846,552	6,009,141	15,478,125
4	17,435,172	6.177%	64,618,235	18,249,937	69,418,816	4,085,297	1,561,923	2,505,145	8,152,366	15,478,125
5	17,435,172	5.713%	59,764,283	16,372,477	85,791,293	5,048,818	1,930,304	3,095,985	10,075,107	15,478,125
6	17,435,172	5.285%	55,286,931	14,640,682	100,431,975	5,910,422	2,259,719	3,624,330	11,794,471	15,478,125
7	17,435,172	4.888%	51,133,873	13,034,320	113,466,295	6,677,491	2,552,992	4,094,705	13,325,188	15,478,125
8	17,435,172	4.522%	47,305,109	11,553,393	125,019,688	7,357,409	2,812,943	4,511,637	14,681,988	15,478,125
9	17,435,172	4.462%	46,677,443	11,310,618	136,330,306	8,023,039	3,067,432	4,919,807	16,010,278	15,478,125
10	17,435,172	4.461%	46,666,982	11,306,572	147,636,878	8,688,430	3,321,830	5,327,832	17,338,092	15,478,125
11	17,435,172	4.462%	46,677,443	11,310,618	158,947,496	9,354,060	3,576,319	5,736,003	18,666,382	15,478,125
12	17,435,172	4.461%	46,666,982	11,306,572	170,254,067	10,019,452	3,830,717	6,144,028	19,994,196	15,478,125
13	17,435,172	4.462%	46,677,443	11,310,618	181,564,685	10,685,082	4,085,205	6,552,199	21,322,486	15,478,125
14	17,435,172	4.461%	46,666,982	11,306,572	192,871,257	11,350,473	4,339,603	6,960,224	22,650,301	15,478,125
15	17,435,172	4.462%	46,677,443	11,310,618	204,181,875	12,016,103	4,594,092	7,368,395	23,978,590	15,478,125
16	17,435,172	4.461%	46,666,982	11,306,572	215,488,446	12,681,495	4,848,490	7,776,420	25,306,405	15,478,125
17	17,435,172	4.462%	46,677,443	11,310,618	226,799,064	13,347,125	5,102,979	8,184,590	26,634,694	15,478,125
18	17,435,172	4.461%	46,666,982	11,306,572	238,105,636	14,012,517	5,357,377	8,592,615	27,962,509	15,478,125
19	17,435,172	4.462%	46,677,443	11,310,618	249,416,254	14,678,147	5,611,866	9,000,786	29,290,798	15,478,125
20	17,435,172	4.461%	46,666,982	11,306,572	260,722,825	15,343,538	5,866,264	9,408,811	30,618,613	15,478,125
21	17,435,172	2.231%	23,338,721	2,283,434	263,006,259	15,477,918	5,917,641	9,491,214	30,886,773	15,478,125
22	17,435,172	0.000%	0	-6,743,750	256,262,509	15,081,049	5,765,906	9,247,850	30,094,805	15,478,125
23	17,435,172	0.000%	0	-6,743,750	249,518,759	14,684,179	5,614,172	9,004,485	29,302,836	15,478,125
24	17,435,172	0.000%	0	-6,743,750	242,775,008	14,287,309	5,462,438	8,761,121	28,510,868	15,478,125
25	17,435,172	0.000%	0	-6,743,750	236,031,258	13,890,440	5,310,703	8,517,756	27,718,899	15,478,125
26	17,435,172	0.000%	0	-6,743,750	229,287,508	13,493,570	5,158,969	8,274,392	26,926,931	15,478,125
27	17,435,172	0.000%	0	-6,743,750	222,543,758	13,096,700	5,007,235	8,031,027	26,134,962	15,478,125
28	17,435,172	0.000%	0	-6,743,750	215,800,007	12,699,830	4,855,500	7,787,663	25,342,994	15,478,125
29	17,435,172	0.000%	0	-6,743,750	209,056,257	12,302,961	4,703,766	7,544,299	24,551,025	15,478,125
30	17,435,172	0.000%	0	-6,743,750	202,312,507	11,906,091	4,552,031	7,300,934	23,759,057	15,478,125
31	17,435,172	0.000%	0	-6,743,750	195,568,757	11,509,221	4,400,297	7,057,570	22,967,088	15,478,125
32	17,435,172	0.000%	0	-6,743,750	188,825,007	11,112,352	4,248,563	6,814,205	22,175,119	15,478,125
33	17,435,172	0.000%	0	-6,743,750	182,081,256	10,715,482	4,096,828	6,570,841	21,383,151	15,478,125
34	17,435,172	0.000%	0	-6,743,750	175,337,506	10,318,612	3,945,094	6,327,476	20,591,182	15,478,125
35	17,435,172	0.000%	0	-6,743,750	168,593,756	9,921,743	3,793,360	6,084,112	19,799,214	15,478,125
36	17,435,172	0.000%	0	-6,743,750	161,850,006	9,524,873	3,641,625	5,840,747	19,007,245	15,478,125
37	17,435,172	0.000%	0	-6,743,750	155,106,255	9,128,003	3,489,891	5,597,383	18,215,277	15,478,125
38	17,435,172	0.000%	0	-6,743,750	148,362,505	8,731,133	3,338,156	5,354,018	17,423,308	15,478,125
39	17,435,172	0.000%	0	-6,743,750	141,618,755	8,334,264	3,186,422	5,110,654	16,631,340	15,478,125
40	17,435,172	0.000%	0	-6,743,750	134,875,005	7,937,394	3,034,688	4,867,289	15,839,371	15,478,125
41	17,435,172	0.000%	0	-6,743,750	128,131,254	7,540,524	2,882,953	4,623,925	15,047,402	15,478,125
42	17,435,172	0.000%	0	-6,743,750	121,387,504	7,143,655	2,731,219	4,380,560	14,255,434	15,478,125
43	17,435,172	0.000%	0	-6,743,750	114,643,754	6,746,785	2,579,484	4,137,196	13,463,465	15,478,125
44	17,435,172	0.000%	0	-6,743,750	107,900,004	6,349,915	2,427,750	3,893,832	12,671,497	15,478,125
45	17,435,172	0.000%	0	-6,743,750	101,156,254	5,953,046	2,276,016	3,650,467	11,879,528	15,478,125
46	17,435,172	0.000%	0	-6,743,750	94,412,503	5,556,176	2,124,281	3,407,103	11,087,560	15,478,125
47	17,435,172	0.000%	0	-6,743,750	87,668,753	5,159,306	1,972,547	3,163,738	10,295,591	15,478,125
48	17,435,172	0.000%	0	-6,743,750	80,925,003	4,762,436	1,820,813	2,920,374	9,503,623	15,478,125
49	17,435,172	0.000%	0	-6,743,750	74,181,253	4,365,567	1,669,078	2,677,009	8,711,654	15,478,125
50	17,435,172	0.000%	0	-6,743,750	67,437,502	3,968,697	1,517,344	2,433,645	7,919,686	15,478,125
51	17,435,172	0.000%	0	-6,743,750	60,693,752	3,571,827	1,365,609	2,190,280	7,127,717	15,478,125
52	17,435,172	0.000%	0	-6,743,750	53,950,002	3,174,958	1,213,875	1,946,916	6,335,748	15,478,125
53	17,435,172	0.000%	0	-6,743,750	47,206,252	2,778,088	1,062,141	1,703,551	5,543,780	15,478,125
54	17,435,172	0.000%	0	-6,743,750	40,462,501	2,381,218	910,406	1,460,187	4,751,811	15,478,125
55	17,435,172	0.000%	0	-6,743,750	33,718,751	1,984,349	758,672	1,216,822	3,959,843	15,478,125
56	17,435,172	0.000%	0	-6,743,750	26,975,001	1,587,479	606,938	973,458	3,167,874	15,478,125
57	17,435,172	0.000%	0	-6,743,750	20,231,251	1,190,609	455,203	730,093	2,375,906	15,478,125
58	17,435,172	0.000%	0	-6,743,750	13,487,500	793,739	303,469	486,729	1,583,937	15,478,125
59	17,435,172	0.000%	0	-6,743,750	6,743,750	396,870	151,734	243,364	791,969	15,478,125
60	17,435,172	0.000%	0	-6,743,750	0	0	0	0	0	15,478,125

Unit Name: Richmond 91&92 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 20,218,692	
2	Investment Generator & Exciter	Inputs Tab	$ 3,032,804	
3	Reactive Allocator	(Line 71)	15.82%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**479,754**	
5				
6	GSU Transformer Investment	Inputs Tab	355,663	
7	Reactive Allocator	(Line 71)	15.82%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**56,262**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	305,256	
11	Reactive Allocator	(Line 71)	15.82%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**48,288**	
13				
14	Total Cost of Power Plant	Inputs Tab	29,467,537	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	25,773,814	
16	Balance of Plant Allocator	(Line 79)	0.0542%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	13,964	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	598,268	
19	Reactive Fixed Charge Rate	(Line 14(h))	10.3893%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**62,156**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 62,156**	
23				
24				
25				
26				

(e)		(f)	(g)	(h)
Fixed Charge Rate for Reactive Plant				
		Calculated Amt	Plant	FCR % (f) / (g)
Electric Expenses	Line 140	589		
Other Expenses		192		
O&M	(sum line 1 & 2)	782	598,268	0.1306%
A&G		101,883	29,467,537	0.3457%
CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0066%
Working Capital	Line 216	34,057	29,467,537	0.1156%
General Plant		-	29,467,537	0.0000%
Other Taxes	Line 196(c)	21,879	29,467,537	0.0742%
Depreciation	Line 168(c)			0.0752%
				8.1350%
Taxes (Federal/State/Local)	Line 180			2.9859%
ADIT	-Line 233(k)	($435,998)	29,467,537	-1.4796%
		(Sum Lines 1 to 11 , Col. (h))		10.3893%

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		53.30						
		52.80						
		-						
	Total	106.10	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.92						
		0.92						
		-						
	Total	0.92	(Line 38 / 58)					
	MVA Capability (MVA)							
		58.06	(Line 31 / 41)					
		57.58	(Line 32 / 42)					
		-						
	Total	115.64	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		23.03	(SQRT (Line 51^2 - Line 31^2))					
		22.97	(SQRT (Line 52^2 - Line 32^2))					
	Total	45.99	(Sum Lines 62 to 64)					
	Reactive Allocator	15.8%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ 110,173	50%	$ 55,087
	Control&Power Cabling	$ 376,173	50%	$ 188,087
	Switch Board Equipment	$ 31,046	50%	$ 15,523
	Switching Equipment	$ 98,992	40%	$ 39,597
	Transformers	$ 69,638	10%	$ 6,964
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ 41,045	0%	$ -
	Misc	$ 2,183,819	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 2,910,886		$ 305,256

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	142,673	142,673	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	36,854	36,854	
	Steam From Other Sources	71,215		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	21,819		
	Rents	132,785	132,785	
	Allowances	5,366	5,366	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	55,651	55,651	
	Maintenance of Boiler (or reactor) Plant	23,864		
	Maintenance of Electric Plant	24,827		
	Maintenance of Misc Steam (or Nuclear) Plant	30,901	30,901	
	Other Power Production, & Other Expenses	93,731	93,731	
	Total NonFuel Expenses	639,686	497,961	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	2.3728%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	639,686	Line 116			
	Allowances	5,366	Line 109			
	Non-Fuel Production O&M	634,320	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	142,673	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	24,827	Line 113(b)			
	Other Demand Related Expenses	355,288	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	522,788	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	24,827	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	24,827	(Line 138 + 139)	2.3728%	589	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	355,288	(Line 134)	0.0542%	192	
				Line 123		
	Balance of Plant Fixed Expenses				522,007	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		31,896	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		69,987	(allocated on plant labor)	
	Total		101,883		
Depreciation					
	Annual Depreciation Exp ...DE	491,126			
	Gross Production Plant Cost ... F	29,467,537	Line 14		
	SLDP=DE/F	1.6667%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	60			
	SFDP=(R/((1+R)^n-1)		0.0752%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.986%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		21,879	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		21,879	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9859%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	221,660				
		100.000%				
	Production Related Prepayments	221,660	(Line 209 * 210)			
	Unit Specific M&S	84,581				
	Total	306,241	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9859%				
	Working Capital Costs	34,057	(Line 213 * 214)			

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Accumulated Deferred Income Taxes

Investment	29,467,537	Line 14
Asset Service Life	60	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 5,310,428

(a) Yr.	(b) SL Deprec Line 224 / 225	(c) MACRS	(d) Tax Deprec (b) * (c)	(e) Def Inc Taxes ((d) - (b)) * Line 177	(f) ADIT Accum. (e)	(g) Return on Equity = (f) * (Line186+187)	(h) Interest = (f) * (Line185)	(i) Income Taxes = (g) * (Line178)	(j) Rev Req Impact (g) + (h) + (i)	(k) Levelized PMT of NPV col. (j)
1	491,126	3.750%	1,105,033	237,453	237,453	13,974	5,343	8,569	27,886	435,998
2	491,126	7.219%	2,127,262	632,841	870,294	51,217	19,582	31,407	102,205	435,998
3	491,126	6.677%	1,967,547	571,065	1,441,359	84,824	32,431	52,015	169,270	435,998
4	491,126	6.177%	1,820,210	514,076	1,955,436	115,077	43,997	70,567	229,641	435,998
5	491,126	5.713%	1,683,480	461,191	2,416,627	142,218	54,374	87,210	283,802	435,998
6	491,126	5.285%	1,557,359	412,409	2,829,035	166,489	63,653	102,093	332,235	435,998
7	491,126	4.888%	1,440,373	367,159	3,196,195	188,096	71,914	115,342	375,353	435,998
8	491,126	4.522%	1,332,522	325,444	3,521,638	207,248	79,237	127,087	413,572	435,998
9	491,126	4.462%	1,314,842	318,605	3,840,243	225,998	86,405	138,584	450,988	435,998
10	491,126	4.461%	1,314,547	318,491	4,158,735	244,742	93,572	150,078	488,391	435,998
11	491,126	4.462%	1,314,842	318,605	4,477,340	263,491	100,740	161,576	525,807	435,998
12	491,126	4.461%	1,314,547	318,491	4,795,831	282,235	107,906	173,069	563,210	435,998
13	491,126	4.462%	1,314,842	318,605	5,114,436	300,985	115,075	184,567	600,626	435,998
14	491,126	4.461%	1,314,547	318,491	5,432,927	319,728	122,241	196,060	638,029	435,998
15	491,126	4.462%	1,314,842	318,605	5,751,532	338,478	129,409	207,558	675,445	435,998
16	491,126	4.461%	1,314,547	318,491	6,070,023	357,221	136,576	219,051	712,848	435,998
17	491,126	4.462%	1,314,842	318,605	6,388,628	375,971	143,744	230,549	750,264	435,998
18	491,126	4.461%	1,314,547	318,491	6,707,119	394,714	150,910	242,043	787,667	435,998
19	491,126	4.462%	1,314,842	318,605	7,025,724	413,464	158,079	253,540	825,083	435,998
20	491,126	4.461%	1,314,547	318,491	7,344,215	432,207	165,245	265,034	862,486	435,998
21	491,126	2.231%	657,421	64,321	7,408,537	435,992	166,692	267,355	870,039	435,998
22	491,126	0.000%	0	-189,962	7,218,574	424,813	162,418	260,500	847,731	435,998
23	491,126	0.000%	0	-189,962	7,028,612	413,634	158,144	253,644	825,422	435,998
24	491,126	0.000%	0	-189,962	6,838,649	402,455	153,870	246,789	803,113	435,998
25	491,126	0.000%	0	-189,962	6,648,687	391,275	149,595	239,934	780,805	435,998
26	491,126	0.000%	0	-189,962	6,458,724	380,096	145,321	233,079	758,496	435,998
27	491,126	0.000%	0	-189,962	6,268,762	368,917	141,047	226,223	736,187	435,998
28	491,126	0.000%	0	-189,962	6,078,799	357,737	136,773	219,368	713,878	435,998
29	491,126	0.000%	0	-189,962	5,888,837	346,558	132,499	212,513	691,570	435,998
30	491,126	0.000%	0	-189,962	5,698,874	335,379	128,225	205,658	669,261	435,998
31	491,126	0.000%	0	-189,962	5,508,912	324,199	123,951	198,802	646,952	435,998
32	491,126	0.000%	0	-189,962	5,318,949	313,020	119,676	191,947	624,644	435,998
33	491,126	0.000%	0	-189,962	5,128,987	301,841	115,402	185,092	602,335	435,998
34	491,126	0.000%	0	-189,962	4,939,024	290,662	111,128	178,237	580,026	435,998
35	491,126	0.000%	0	-189,962	4,749,062	279,482	106,854	171,381	557,718	435,998
36	491,126	0.000%	0	-189,962	4,559,099	268,303	102,580	164,526	535,409	435,998
37	491,126	0.000%	0	-189,962	4,369,137	257,124	98,306	157,671	513,100	435,998
38	491,126	0.000%	0	-189,962	4,179,175	245,944	94,031	150,816	490,791	435,998
39	491,126	0.000%	0	-189,962	3,989,212	234,765	89,757	143,960	468,483	435,998
40	491,126	0.000%	0	-189,962	3,799,250	223,586	85,483	137,105	446,174	435,998
41	491,126	0.000%	0	-189,962	3,609,287	212,407	81,209	130,250	423,865	435,998
42	491,126	0.000%	0	-189,962	3,419,325	201,227	76,935	123,395	401,557	435,998
43	491,126	0.000%	0	-189,962	3,229,362	190,048	72,661	116,539	379,248	435,998
44	491,126	0.000%	0	-189,962	3,039,400	178,869	68,386	109,684	356,939	435,998
45	491,126	0.000%	0	-189,962	2,849,437	167,689	64,112	102,829	334,631	435,998
46	491,126	0.000%	0	-189,962	2,659,475	156,510	59,838	95,974	312,322	435,998
47	491,126	0.000%	0	-189,962	2,469,512	145,331	55,564	89,118	290,013	435,998
48	491,126	0.000%	0	-189,962	2,279,550	134,152	51,290	82,263	267,704	435,998
49	491,126	0.000%	0	-189,962	2,089,587	122,972	47,016	75,408	245,396	435,998
50	491,126	0.000%	0	-189,962	1,899,625	111,793	42,742	68,553	223,087	435,998
51	491,126	0.000%	0	-189,962	1,709,662	100,614	38,467	61,697	200,778	435,998
52	491,126	0.000%	0	-189,962	1,519,700	89,434	34,193	54,842	178,470	435,998
53	491,126	0.000%	0	-189,962	1,329,737	78,255	29,919	47,987	156,161	435,998
54	491,126	0.000%	0	-189,962	1,139,775	67,076	25,645	41,132	133,852	435,998
55	491,126	0.000%	0	-189,962	949,812	55,896	21,371	34,276	111,544	435,998
56	491,126	0.000%	0	-189,962	759,850	44,717	17,097	27,421	89,235	435,998
57	491,126	0.000%	0	-189,962	569,887	33,538	12,822	20,566	66,926	435,998
58	491,126	0.000%	0	-189,962	379,925	22,359	8,548	13,711	44,617	435,998
59	491,126	0.000%	0	-189,962	189,962	11,179	4,274	6,855	22,309	435,998
60	491,126	0.000%	0	-189,962	0	0	0	0	0	435,998

Unit Name: Riverside 7&8 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 13,013,142		Electric Expenses	Line 140	1,042		
2	Investment Generator & Exciter	Inputs Tab	$ 1,951,971		Other Expenses		35		
3	Reactive Allocator	(Line 71)	43.26%		O&M	(sum line 1 & 2)	1,078	1,856,869	0.0580%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**844,385**						
5					A&G		264,104	39,227,656	0.6733%
6	GSU Transformer Investment	Inputs Tab	350,500		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0101%
7	Reactive Allocator	(Line 71)	43.26%		Working Capital	Line 216	196,945	39,227,656	0.5021%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**151,620**		General Plant		-	39,227,656	0.0000%
9					Other Taxes	Line 196(c)	379,744	39,227,656	0.9681%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	1,977,658		Depreciation	Line 168(c)			0.1117%
11	Reactive Allocator	(Line 71)	43.26%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**855,497**		Taxes (Federal/State/Local)	Line 180			2.9334%
13					ADIT	-Line 233(k)	($548,855)	39,227,656	-1.3992%
14	Total Cost of Power Plant	Inputs Tab	39,227,656				(Sum Lines 1 to 11 , Col. (h))		11.9925%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	34,947,527						
16	Balance of Plant Allocator	(Line 79)	0.0154%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	5,367						
18		(Line 4 + 8 + 12 + 17)	1,856,869						
19	Reactive Fixed Charge Rate	(Line 14(h))	11.9925%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**222,684**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 222,684**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		24.30						
		21.30						
		-						
	Total	45.60	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.75						
		0.76						
		-						
	Total	0.75	(Line 38 / 58)					
	MVA Capability (MVA)							
		32.40	(Line 31 / 41)					
		28.14	(Line 32 / 42)					
		-						
	Total	60.54	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		21.43	(SQRT (Line 51^2 - Line 31^2))					
		18.39	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	39.82	(Sum Lines 62 to 64)					
	Reactive Allocator	43.3%	(Line 69^2 / Line 58^2)					
		BGE is TO Fleet						
	Max. MVAr	27.50						
	Nameplate MVAr	571.22						
	Exciter MW	3.08						
	Generator MW	965.46						
	Balance of Plant Allocator	0.0154%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ 61,893	50%	$ 30,947
	Control&Power Cabling	$ 2,209,028	50%	$ 1,104,514
	Switch Board Equipment	$ 738,213	50%	$ 369,107
	Switching Equipment	$ 518,931	40%	$ 207,572
	Transformers	$ 98,872	10%	$ 9,887
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ 7,984	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ 306,814	75%	$ 230,110
	Structure	$ 4,701	0%	$ -
	Misc	$ -	0%	$ -
	Exciter & PPT	$ 15,989	100%	$ 15,989
	Station Grounding	$ 190,636	5%	$ 9,532
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 4,153,061		$ 1,977,658

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	92,302	92,302	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	23,842	23,842	
	Steam From Other Sources	46,073		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	14,115		
	Rents	85,905	85,905	
	Allowances	3,471	3,471	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	36,003	36,003	
	Maintenance of Boiler (or reactor) Plant	15,439		
	Maintenance of Electric Plant	16,062		
	Maintenance of Misc Steam (or Nuclear) Plant	19,991	19,991	
	Other Power Production, & Other Expenses	60,639	60,639	
	Total NonFuel Expenses	413,844	322,155	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	6.4887%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0154%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	413,844	Line 116			
	Allowances	3,471	Line 109			
	Non-Fuel Production O&M	410,372	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	92,302	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	16,062	Line 113(b)			
	Other Demand Related Expenses	229,853	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	338,217	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	16,062	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	16,062	(Line 138 + 139)	6.4887%	1,042	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	229,853	(Line 134)	0.0154%	35	
				Line 123		
	Balance of Plant Fixed Expenses				337,139	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		240,209	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		23,895	(allocated on plant labor)	
	Total		264,104		
Depreciation					
	Annual Depreciation Exp ...DE	713,230			
	Gross Production Plant Cost ... F	39,227,656	Line 14		
	SLDP=DE/F	1.8182%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	55			
	SFDP=(R/((1+R)^n-1)		0.1117%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.933%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		379,744	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		379,744	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9334%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	295,077				
		100.000%				
	Production Related Prepayments	295,077	(Line 209 * 210)			
	Unit Specific M&S	1,484,268				
	Total	1,779,345	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9334%				
	Working Capital Costs	196,945	(Line 213 * 214)			

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(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)

Accumulated Deferred Income Taxes

Investment		39,227,656	Line 14					NPV of Col (j)>	6,655,435	
Asset Service Life		55	Line 167							
Composite Tax Rate		38.6790%	Line 177							

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity = (f) * (Line186+187)	Interest = (f) * (Line185)	Income Taxes = (g) * (Line178)	Rev Req Impact (g) + (h) + (i)	Levelized PMT of NPV col. (j)
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)					
1	713,230	3.750%	1,471,037	293,112	293,112	17,250	6,595	10,578	34,422	548,855
2	713,230	7.219%	2,831,845	819,459	1,112,571	65,475	25,033	40,150	130,657	548,855
3	713,230	6.677%	2,619,231	737,222	1,849,793	108,860	41,620	66,754	217,235	548,855
4	713,230	6.177%	2,423,092	661,358	2,511,151	147,781	56,501	90,621	294,903	548,855
5	713,230	5.713%	2,241,076	590,956	3,102,106	182,559	69,797	111,947	364,303	548,855
6	713,230	5.285%	2,073,182	526,016	3,628,122	213,515	81,633	130,930	426,077	548,855
7	713,230	4.888%	1,917,448	465,779	4,093,901	240,926	92,113	147,738	480,777	548,855
8	713,230	4.522%	1,773,875	410,247	4,504,148	265,069	101,343	162,543	528,955	548,855
9	713,230	4.462%	1,750,338	401,143	4,905,291	288,676	110,369	177,019	576,065	548,855
10	713,230	4.461%	1,749,946	400,991	5,306,282	312,275	119,391	191,490	623,156	548,855
11	713,230	4.462%	1,750,338	401,143	5,707,425	335,882	128,417	205,966	670,265	548,855
12	713,230	4.461%	1,749,946	400,991	6,108,416	359,480	137,439	220,437	717,357	548,855
13	713,230	4.462%	1,750,338	401,143	6,509,559	383,088	146,465	234,913	764,466	548,855
14	713,230	4.461%	1,749,946	400,991	6,910,550	406,686	155,487	249,384	811,557	548,855
15	713,230	4.462%	1,750,338	401,143	7,311,693	430,293	164,513	263,860	858,666	548,855
16	713,230	4.461%	1,749,946	400,991	7,712,685	453,891	173,535	278,331	905,758	548,855
17	713,230	4.462%	1,750,338	401,143	8,113,828	477,499	182,561	292,807	952,867	548,855
18	713,230	4.461%	1,749,946	400,991	8,514,819	501,097	191,583	307,278	999,958	548,855
19	713,230	4.462%	1,750,338	401,143	8,915,962	524,704	200,609	321,754	1,047,067	548,855
20	713,230	4.461%	1,749,946	400,991	9,316,953	548,303	209,631	336,225	1,094,159	548,855
21	713,230	2.231%	875,169	62,636	9,379,589	551,989	211,041	338,485	1,101,515	548,855
22	713,230	0.000%	0	-275,870	9,103,719	535,754	204,834	328,530	1,069,117	548,855
23	713,230	0.000%	0	-275,870	8,827,849	519,519	198,627	318,574	1,036,720	548,855
24	713,230	0.000%	0	-275,870	8,551,979	503,284	192,420	308,619	1,004,322	548,855
25	713,230	0.000%	0	-275,870	8,276,108	487,049	186,212	298,663	971,925	548,855
26	713,230	0.000%	0	-275,870	8,000,238	470,814	180,005	288,708	939,527	548,855
27	713,230	0.000%	0	-275,870	7,724,368	454,579	173,798	278,752	907,130	548,855
28	713,230	0.000%	0	-275,870	7,448,497	438,344	167,591	268,797	874,732	548,855
29	713,230	0.000%	0	-275,870	7,172,627	422,109	161,384	258,842	842,335	548,855
30	713,230	0.000%	0	-275,870	6,896,757	405,874	155,177	248,886	809,937	548,855
31	713,230	0.000%	0	-275,870	6,620,887	389,639	148,970	238,931	777,540	548,855
32	713,230	0.000%	0	-275,870	6,345,016	373,404	142,763	228,975	745,142	548,855
33	713,230	0.000%	0	-275,870	6,069,146	357,169	136,556	219,020	712,745	548,855
34	713,230	0.000%	0	-275,870	5,793,276	340,934	130,349	209,064	680,347	548,855
35	713,230	0.000%	0	-275,870	5,517,406	324,699	124,142	199,109	647,950	548,855
36	713,230	0.000%	0	-275,870	5,241,535	308,464	117,935	189,153	615,552	548,855
37	713,230	0.000%	0	-275,870	4,965,665	292,229	111,727	179,198	583,155	548,855
38	713,230	0.000%	0	-275,870	4,689,795	275,994	105,520	169,243	550,757	548,855
39	713,230	0.000%	0	-275,870	4,413,924	259,759	99,313	159,287	518,360	548,855
40	713,230	0.000%	0	-275,870	4,138,054	243,524	93,106	149,332	485,962	548,855
41	713,230	0.000%	0	-275,870	3,862,184	227,290	86,899	139,376	453,565	548,855
42	713,230	0.000%	0	-275,870	3,586,314	211,055	80,692	129,421	421,167	548,855
43	713,230	0.000%	0	-275,870	3,310,443	194,820	74,485	119,465	388,770	548,855
44	713,230	0.000%	0	-275,870	3,034,573	178,585	68,278	109,510	356,372	548,855
45	713,230	0.000%	0	-275,870	2,758,703	162,350	62,071	99,554	323,975	548,855
46	713,230	0.000%	0	-275,870	2,482,832	146,115	55,864	89,599	291,577	548,855
47	713,230	0.000%	0	-275,870	2,206,962	129,880	49,657	79,644	259,180	548,855
48	713,230	0.000%	0	-275,870	1,931,092	113,645	43,450	69,688	226,782	548,855
49	713,230	0.000%	0	-275,870	1,655,222	97,410	37,242	59,733	194,385	548,855
50	713,230	0.000%	0	-275,870	1,379,351	81,175	31,035	49,777	161,987	548,855
51	713,230	0.000%	0	-275,870	1,103,481	64,940	24,828	39,822	129,590	548,855
52	713,230	0.000%	0	-275,870	827,611	48,705	18,621	29,866	97,192	548,855
53	713,230	0.000%	0	-275,870	551,741	32,470	12,414	19,911	64,795	548,855
54	713,230	0.000%	0	-275,870	275,870	16,235	6,207	9,955	32,397	548,855
55	713,230	0.000%	0	-275,870	0	0	0	0	0	548,855

Unit Name: Salem 1 & 2 **Cost Year:** 2015

	(a)	(b)	(c)	(d)
	Annual Revenue Requirement			
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 80,714,327	
2	Investment Generator & Exciter	Inputs Tab	12,107,149	
3	Reactive Allocator	(Line 71)	8.55%	
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**1,035,096**	
5				
6	GSU Transformer Investment	Inputs Tab	14,618,814	
7	Reactive Allocator	(Line 71)	8.55%	
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**1,249,830**	
9				
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	4,591	
11	Reactive Allocator	(Line 71)	8.55%	
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**393**	
13				
14	Total Cost of Power Plant	Inputs Tab	583,671,743	
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	556,941,189	
16	Balance of Plant Allocator	(Line 79)	0.0824%	
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	458,977	
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	2,744,296	
19	Reactive Fixed Charge Rate	(Line 14(h))	33.1230%	
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**908,992**	
21				
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 908,992**	
23				
24				
25				
26				

	(e)		(f)	(g)	(h)
	Fixed Charge Rate for Reactive Plant				
			Calculated Amt	Plant	FCR % (f) / (g)
	Electric Expenses	Line 140	105,622		
	Other Expenses		50,679		
	O&M	(sum line 1 & 2)	156,301	2,744,296	5.6955%
	A&G		72,135,570	583,671,743	12.3589%
	CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.2507%
	Working Capital	Line 216	17,567,796	583,671,743	3.0099%
	General Plant		-	583,671,743	0.0000%
	Other Taxes	Line 196(c)	12,141,110	583,671,743	2.0801%
	Depreciation	Line 168(c)			0.0814%
					8.1350%
	Taxes (Federal/State/Local)	Line 180			2.9758%
	ADIT	-Line 233(k)	($8,547,308)	583,671,743	-1.4644%
			(Sum Lines 1 to 11 , Col. (h))		33.1230%

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	(a)	(b)	(c)
Allocators			
	Real Power Capability (MW)		
		1,236.80	
		1,190.00	
		-	
	Total	2,426.80	(Sum Lines 31 to 33)
	Nominal Power Factor (pf)		
		0.96	
		0.95	
		-	
	Total	0.96	(Line 38 / 58)
	MVA Capability (MVA)		
		1,285.65	(Line 31 / 41)
		1,252.63	(Line 32 / 42)
		-	
	Total	2,538.29	(Sum Lines 51 to 53)
	Reactive Power Capability (MVAR)		
	(MVA^2 - MW^2)^0.5		
		351.05	(SQRT (Line 51^2 - Line 31^2))
		391.13	(SQRT (Line 52^2 - Line 32^2))
		-	
	Total	742.18	(Sum Lines 62 to 64)
	Reactive Allocator	8.5%	(Line 69^2 / Line 58^2)
		PSEG is TO Fleet	
	Max. MVAr	287.66	
	Nameplate MVAr	742.18	
	Exciter MW	5.16	
	Generator MW	2,426.80	
	Balance of Plant Allocator	0.0824%	(Line 75 / Line 76) * (Line 77 / Line 78)

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	(a)	(b)	(c)	(d)	
Accessory Equip Allocator		**Investment**	**Nuclear**	**Allocated Amt**	
	Storage Batteries	$ -	15%	$ -	
	Control&Power Cabling	$ 459,119	1%	$ 4,591	
	Switch Board Equipment	$ -	1%	$ -	
	Switching Equipment	$ -	1%	$ -	
	Transformers	$ -	3%	$ -	
	Aux Generator	$ -	0%	$ -	
	Fire Protection System	$ 22,085,749	0%	$ -	
	HVAC	$ -	0%	$ -	
	Regulating Equipment	$ -	50%	$ -	
	Structure	$ -	0%	$ -	
	Misc	$ 16,168,621	0%	$ -	
	Exciter & PPT	$ -	100%	$ -	
	Station Grounding	$ -	1%	$ -	
	Bus & Insulators	$ -	80%	$ -	
	Capacitor Bank	$ -	0%	$ -	
	Total	$ 38,713,489		$ 4,591	
O&M		**Total Non-Fuel**	**Fixed O&M**		
	Production Expenses: Oper, Supv, & Engr	17,325,181	17,325,181		
	Coolants and Water (Nuclear Plants Only)	1,697,576			
	Steam Expenses	10,647,982	10,647,982		
	Steam From Other Sources	0			
	Electric Expenses	0	-		
	Misc Steam (or Nuclear) Power Expenses	1,087,833			
	Rents	30,077,667	30,077,667		
	Allowances	2,386,732	2,386,732		
	Maintenance Supervision and Engineering	0			
	Maintenance of Structures	3,196,195	3,196,195		
	Maintenance of Boiler (or reactor) Plant	249,118			
	Maintenance of Electric Plant	8,236,136			
	Maintenance of Misc Steam (or Nuclear) Plant	5,290,409	5,290,409		
	Other Power Production, & Other Expenses	9,897,329	9,897,329		
	Total NonFuel Expenses	90,092,158	78,821,495	(Sum Lines 102 to 115)	
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))	
O&M Calculation					
	Plant Var Allocators				
	Electric Expense Allocator	1.2824%	Line 4(c) / 1(c))		
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)		
	Other Demand Expense Allocator	0.0824%	Line 79		
	Production Plant Expenses				
	Total NonFuel Expenses	90,092,158	Line 116		
	Allowances	2,386,732	Line 109		
	Non-Fuel Production O&M	87,705,426	(Line 126 - 127)		
	Operating Expenses				
	Operations Supervision & Engineering	17,325,181	Line 102(c)		
	Electric Expenses	0	Line 106(c)		
	Maintenance of Electric Plant	8,236,136	Line 113(b)		
	Other Demand Related Expenses	61,496,314	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)		
	Total	87,057,631	(Sum Lines 131 to 134)		
				Allocator	Allocated Amount
	Maintenance of Electric Plant	8,236,136	Line 113(b)		
	Electric Expenses	0	Line 106(c)		
	Total Electric Expenses	8,236,136	(Line 138 + 139)	1.2824%	105,622 (Line 140(b) * (d))
				Line 121	
	Other Demand Related Expenses	61,496,314	(Line 134)	0.0824%	50,679
				Line 123	
	Balance of Plant Fixed Expenses				86,901,330 (Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		64,855,997	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		7,279,573	(allocated on plant labor)	
	Total		72,135,570		

Depreciation				
	Annual Depreciation Exp ...DE	9,892,741		
	Gross Production Plant Cost ... F	583,671,743	Line 14	
	SLDP=DE/F	1.6949%	(Line 164 / 165)	
	Depreciable years (n)=1/SLDP	59		
	SFDP=(R/((1+R)^n-1)		0.0814%	
Income Taxes				
	Income Tax Calculation; (Co's Sch. 2)			
	a) State Income Tax Rate ("SIT")	5.6600%		
	b) City/Local Income Tax Rate ("LIT")	0.0000%		
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%		
	d) Net of Fdrl tax SIT	3.6790%		
	e) Federal Income Tax Rate ("FIT")	35.0000%		
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%		
	g) Gross-Up Tax Factor ("GTF")	61.3210%		
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.976%	

				Weighted Cost	
Rate of Return					
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)

Other Taxes					
	Property Taxes		8,570,246		
	Payroll Taxes	4,081,461			
	0	87.4899%	Line 117		
	Fixed Payroll Taxes		3,570,864	(Line 193 * 194)	
	Total Other Taxes		12,141,109.84	(Line 192 + 195)	

		Plant		**Depreciation**	**Total**	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9758%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
	Prepayments	-	
		100.000%	
	Production Related Prepayments	-	(Line 209 * 210)
	Unit Specific M&S	158,114,762	
	Total	158,114,762	(Line 211 + 212)
	Return on Working Capital	8.1350%	
	Taxes on Working Capital	2.9758%	
	Working Capital Costs	17,567,796	(Line 213 * 214)

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Accumulated Deferred Income Taxes

Investment	583,671,743	Line 14
Asset Service Life	59	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 104,027,302

(a) Yr.	(b) SL Deprec Line 224 / 225	(c) MACRS	(d) Tax Deprec (b) * (c)	(e) Def Inc Taxes ((d) - (b)) * Line 177	(f) ADIT Accum. (e)	(g) Return on Equity = (f) * (Line186+187)	(h) Interest = (f) * (Line185)	(i) Income Taxes = (g) * (Line178)	(j) Rev Req Impact (g) + (h) + (i)	(k) Levelized PMT of NPV col. (j)
1	9,892,741	3.750%	21,887,690	4,639,526	4,639,526	273,036	104,389	167,428	544,854	8,547,308
2	9,892,741	7.219%	42,135,263	12,471,085	17,110,611	1,006,959	384,989	617,478	2,009,426	8,547,308
3	9,892,741	6.677%	38,971,762	11,247,474	28,358,086	1,668,873	638,057	1,023,370	3,330,300	8,547,308
4	9,892,741	6.177%	36,053,404	10,118,683	38,476,768	2,264,358	865,727	1,388,527	4,518,612	8,547,308
5	9,892,741	5.713%	33,345,167	9,071,164	47,547,932	2,798,196	1,069,828	1,715,882	5,583,906	8,547,308
6	9,892,741	5.285%	30,847,052	8,104,918	55,652,849	3,275,170	1,252,189	2,008,367	6,535,726	8,547,308
7	9,892,741	4.888%	28,529,875	7,208,657	62,861,506	3,699,400	1,414,384	2,268,509	7,382,292	8,547,308
8	9,892,741	4.522%	26,393,636	6,382,381	69,243,887	4,075,003	1,557,987	2,498,832	8,131,823	8,547,308
9	9,892,741	4.462%	26,043,433	6,246,926	75,490,813	4,442,634	1,698,543	2,724,268	8,865,445	8,547,308
10	9,892,741	4.461%	26,037,596	6,244,668	81,735,482	4,810,133	1,839,048	2,949,622	9,598,803	8,547,308
11	9,892,741	4.462%	26,043,433	6,246,926	87,982,408	5,177,765	1,979,604	3,175,057	10,332,426	8,547,308
12	9,892,741	4.461%	26,037,596	6,244,668	94,227,076	5,545,263	2,120,109	3,400,411	11,065,784	8,547,308
13	9,892,741	4.462%	26,043,433	6,246,926	100,474,003	5,912,895	2,260,665	3,625,846	11,799,406	8,547,308
14	9,892,741	4.461%	26,037,596	6,244,668	106,718,671	6,280,394	2,401,170	3,851,200	12,532,764	8,547,308
15	9,892,741	4.462%	26,043,433	6,246,926	112,965,597	6,648,025	2,541,726	4,076,636	13,266,387	8,547,308
16	9,892,741	4.461%	26,037,596	6,244,668	119,210,266	7,015,524	2,682,231	4,301,990	13,999,745	8,547,308
17	9,892,741	4.462%	26,043,433	6,246,926	125,457,192	7,383,156	2,822,787	4,527,425	14,733,367	8,547,308
18	9,892,741	4.461%	26,037,596	6,244,668	131,701,860	7,750,654	2,963,292	4,752,779	15,466,725	8,547,308
19	9,892,741	4.462%	26,043,433	6,246,926	137,948,786	8,118,286	3,103,848	4,978,214	16,200,348	8,547,308
20	9,892,741	4.461%	26,037,596	6,244,668	144,193,455	8,485,785	3,244,353	5,203,568	16,933,706	8,547,308
21	9,892,741	2.231%	13,021,717	1,210,256	145,403,711	8,557,008	3,271,583	5,247,243	17,075,835	8,547,308
22	9,892,741	0.000%	0	-3,826,413	141,577,298	8,331,824	3,185,489	5,109,158	16,626,471	8,547,308
23	9,892,741	0.000%	0	-3,826,413	137,750,884	8,106,640	3,099,395	4,971,072	16,177,107	8,547,308
24	9,892,741	0.000%	0	-3,826,413	133,924,471	7,881,455	3,013,301	4,832,987	15,727,743	8,547,308
25	9,892,741	0.000%	0	-3,826,413	130,098,057	7,656,271	2,927,206	4,694,902	15,278,379	8,547,308
26	9,892,741	0.000%	0	-3,826,413	126,271,644	7,431,086	2,841,112	4,556,816	14,829,015	8,547,308
27	9,892,741	0.000%	0	-3,826,413	122,445,230	7,205,902	2,755,018	4,418,731	14,379,651	8,547,308
28	9,892,741	0.000%	0	-3,826,413	118,618,817	6,980,717	2,668,923	4,280,646	13,930,286	8,547,308
29	9,892,741	0.000%	0	-3,826,413	114,792,403	6,755,533	2,582,829	4,142,560	13,480,922	8,547,308
30	9,892,741	0.000%	0	-3,826,413	110,965,990	6,530,349	2,496,735	4,004,475	13,031,558	8,547,308
31	9,892,741	0.000%	0	-3,826,413	107,139,577	6,305,164	2,410,640	3,866,390	12,582,194	8,547,308
32	9,892,741	0.000%	0	-3,826,413	103,313,163	6,079,980	2,324,546	3,728,304	12,132,830	8,547,308
33	9,892,741	0.000%	0	-3,826,413	99,486,750	5,854,795	2,238,452	3,590,219	11,683,466	8,547,308
34	9,892,741	0.000%	0	-3,826,413	95,660,336	5,629,611	2,152,358	3,452,134	11,234,102	8,547,308
35	9,892,741	0.000%	0	-3,826,413	91,833,923	5,404,426	2,066,263	3,314,048	10,784,738	8,547,308
36	9,892,741	0.000%	0	-3,826,413	88,007,509	5,179,242	1,980,169	3,175,963	10,335,374	8,547,308
37	9,892,741	0.000%	0	-3,826,413	84,181,096	4,954,057	1,894,075	3,037,878	9,886,010	8,547,308
38	9,892,741	0.000%	0	-3,826,413	80,354,682	4,728,873	1,807,980	2,899,792	9,436,646	8,547,308
39	9,892,741	0.000%	0	-3,826,413	76,528,269	4,503,689	1,721,886	2,761,707	8,987,282	8,547,308
40	9,892,741	0.000%	0	-3,826,413	72,701,855	4,278,504	1,635,792	2,623,622	8,537,918	8,547,308
41	9,892,741	0.000%	0	-3,826,413	68,875,442	4,053,320	1,549,697	2,485,536	8,088,553	8,547,308
42	9,892,741	0.000%	0	-3,826,413	65,049,029	3,828,135	1,463,603	2,347,451	7,639,189	8,547,308
43	9,892,741	0.000%	0	-3,826,413	61,222,615	3,602,951	1,377,509	2,209,366	7,189,825	8,547,308
44	9,892,741	0.000%	0	-3,826,413	57,396,202	3,377,766	1,291,415	2,071,280	6,740,461	8,547,308
45	9,892,741	0.000%	0	-3,826,413	53,569,788	3,152,582	1,205,320	1,933,195	6,291,097	8,547,308
46	9,892,741	0.000%	0	-3,826,413	49,743,375	2,927,398	1,119,226	1,795,109	5,841,733	8,547,308
47	9,892,741	0.000%	0	-3,826,413	45,916,961	2,702,213	1,033,132	1,657,024	5,392,369	8,547,308
48	9,892,741	0.000%	0	-3,826,413	42,090,548	2,477,029	947,037	1,518,939	4,943,005	8,547,308
49	9,892,741	0.000%	0	-3,826,413	38,264,134	2,251,844	860,943	1,380,853	4,493,641	8,547,308
50	9,892,741	0.000%	0	-3,826,413	34,437,721	2,026,660	774,849	1,242,768	4,044,277	8,547,308
51	9,892,741	0.000%	0	-3,826,413	30,611,308	1,801,475	688,754	1,104,683	3,594,913	8,547,308
52	9,892,741	0.000%	0	-3,826,413	26,784,894	1,576,291	602,660	966,597	3,145,549	8,547,308
53	9,892,741	0.000%	0	-3,826,413	22,958,481	1,351,107	516,566	828,512	2,696,184	8,547,308
54	9,892,741	0.000%	0	-3,826,413	19,132,067	1,125,922	430,472	690,427	2,246,820	8,547,308
55	9,892,741	0.000%	0	-3,826,413	15,305,654	900,738	344,377	552,341	1,797,456	8,547,308
56	9,892,741	0.000%	0	-3,826,413	11,479,240	675,553	258,283	414,256	1,348,092	8,547,308
57	9,892,741	0.000%	0	-3,826,413	7,652,827	450,369	172,189	276,171	898,728	8,547,308
58	9,892,741	0.000%	0	-3,826,413	3,826,413	225,184	86,094	138,085	449,364	8,547,308
59	9,892,741	0.000%	0	-3,826,413	0	0	0	0	0	8,547,308

Unit Name: Schuylkill 10&11 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 4,345,038		Electric Expenses	Line 140	559		
2	Investment Generator & Exciter	Inputs Tab	$ 651,756		Other Expenses		93		
3	Reactive Allocator	(Line 71)	31.02%		O&M	(sum line 1 & 2)	652	262,479	0.2485%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**202,172**						
5					A&G		436,251	5,934,123	7.3516%
6	GSU Transformer Investment	Inputs Tab	-		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.1059%
7	Reactive Allocator	(Line 71)	31.02%		Working Capital	Line 216	42,809	5,934,123	0.7214%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**		General Plant		-	5,934,123	0.0000%
9					Other Taxes	Line 196(c)	11,465	5,934,123	0.1932%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	185,511		Depreciation	Line 168(c)			0.0594%
11	Reactive Allocator	(Line 71)	31.02%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**57,545**		Taxes (Federal/State/Local)	Line 180			3.0148%
13					ADIT	-Line 233(k)	($90,359)	5,934,123	-1.5227%
14	Total Cost of Power Plant	Inputs Tab	5,934,123				(Sum Lines 1 to 11 , Col. (h))		18.3071%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	5,096,857						
16	Balance of Plant Allocator	(Line 79)	0.0542%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	2,761						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	262,479						
19	Reactive Fixed Charge Rate	(Line 14(h))	18.3071%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**48,052**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 48,052**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		14.30						
		19.00						
		-						
	Total	33.30	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.79						
		0.86						
		-						
	Total	0.83	(Line 38 / 58)					
	MVA Capability (MVA)							
		18.22	(Line 31 / 41)					
		22.02	(Line 32 / 42)					
		-						
	Total	40.23	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		11.29	(SQRT (Line 51^2 - Line 31^2))					
		11.12	(SQRT (Line 52^2 - Line 32^2))					
		-						
	Total	22.41	(Sum Lines 62 to 64)					
	Reactive Allocator	31.0%	(Line 69^2 / Line 58^2)					
		PECO is TO Fleet						
	Max. MVAr	360.90						
	Nameplate MVAr	2,852.52						
	Exciter MW	28.75						
	Generator MW	6,714.69						
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ 8,355	50%	$ 4,178
	Control&Power Cabling	$ 207,889	50%	$ 103,944
	Switch Board Equipment	$ 8,299	50%	$ 4,150
	Switching Equipment	$ 183,098	40%	$ 73,239
	Transformers	$ -	10%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ 41,588	0%	$ -
	Misc	$ 104,130	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 553,360		$ 185,511

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	69,047	69,047	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	17,835	17,835	
	Steam From Other Sources	34,465		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	10,559		
	Rents	64,262	64,262	
	Allowances	2,597	2,597	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	26,932	26,932	
	Maintenance of Boiler (or reactor) Plant	11,549		
	Maintenance of Electric Plant	12,015		
	Maintenance of Misc Steam (or Nuclear) Plant	14,955	14,955	
	Other Power Production, & Other Expenses	45,361	45,361	
	Total NonFuel Expenses	309,577	240,989	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation

	Plant Var Allocators					
	Electric Expense Allocator	4.6529%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0542%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	309,577	Line 116			
	Allowances	2,597	Line 109			
	Non-Fuel Production O&M	306,980	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	69,047	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	12,015	Line 113(b)			
	Other Demand Related Expenses	171,942	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)			
	Total	253,004	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	12,015	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	12,015	(Line 138 + 139)	4.6529%	559	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	171,942	(Line 134)	0.0542%	93	
				Line 123		
	Balance of Plant Fixed Expenses				252,352	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		395,698	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		40,553	(allocated on plant labor)	
	Total		436,251		
Depreciation					
	Annual Depreciation Exp ...DE	94,192			
	Gross Production Plant Cost ... F	5,934,123	Line 14		
	SLDP=DE/F	1.5873%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	63			
	SFDP=(R/((1+R)^n-1)		0.0594%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		3.015%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		11,465	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		11,465	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	3.0148%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	44,637				
		100.000%				
	Production Related Prepayments	44,637	(Line 209 * 210)			
	Unit Specific M&S	339,302				
	Total	383,940	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	3.0148%				
	Working Capital Costs	42,809	(Line 213 * 214)			

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(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)

Accumulated Deferred Income Taxes

Investment	5,934,123	Line 14	NPV of Col (j)> 1,102,701
Asset Service Life	63	Line 167	
Composite Tax Rate	38.6790%	Line 177	

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity	Interest	Income Taxes	Rev Req Impact	Levelized
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	PMT of NPV col. (j)
1	94,192	3.750%	222,530	49,640	49,640	2,921	1,117	1,791	5,830	90,359
2	94,192	7.219%	428,384	129,262	178,902	10,528	4,025	6,456	21,010	90,359
3	94,192	6.677%	396,221	116,822	295,723	17,403	6,654	10,672	34,729	90,359
4	94,192	6.177%	366,551	105,345	401,069	23,603	9,024	14,474	47,100	90,359
5	94,192	5.713%	339,016	94,695	495,764	29,176	11,155	17,891	58,221	90,359
6	94,192	5.285%	313,618	84,872	580,636	34,170	13,064	20,954	68,188	90,359
7	94,192	4.888%	290,060	75,760	656,396	38,629	14,769	23,688	77,085	90,359
8	94,192	4.522%	268,341	67,359	723,755	42,593	16,284	26,118	84,996	90,359
9	94,192	4.462%	264,781	65,982	789,736	46,476	17,769	28,500	92,745	90,359
10	94,192	4.461%	264,721	65,959	855,695	50,358	19,253	30,880	100,491	90,359
11	94,192	4.462%	264,781	65,982	921,677	54,241	20,738	33,261	108,239	90,359
12	94,192	4.461%	264,721	65,959	987,636	58,122	22,222	35,641	115,985	90,359
13	94,192	4.462%	264,781	65,982	1,053,618	62,005	23,706	38,022	123,734	90,359
14	94,192	4.461%	264,721	65,959	1,119,577	65,887	25,190	40,403	131,480	90,359
15	94,192	4.462%	264,781	65,982	1,185,558	69,770	26,675	42,784	139,229	90,359
16	94,192	4.461%	264,721	65,959	1,251,517	73,652	28,159	45,164	146,975	90,359
17	94,192	4.462%	264,781	65,982	1,317,499	77,535	29,644	47,545	154,724	90,359
18	94,192	4.461%	264,721	65,959	1,383,458	81,416	31,128	49,925	162,470	90,359
19	94,192	4.462%	264,781	65,982	1,449,440	85,300	32,612	52,307	170,218	90,359
20	94,192	4.461%	264,721	65,959	1,515,398	89,181	34,096	54,687	177,964	90,359
21	94,192	2.231%	132,390	14,775	1,530,173	90,051	34,429	55,220	179,700	90,359
22	94,192	0.000%	0	-36,433	1,493,740	87,907	33,609	53,905	175,421	90,359
23	94,192	0.000%	0	-36,433	1,457,308	85,763	32,789	52,590	171,142	90,359
24	94,192	0.000%	0	-36,433	1,420,875	83,618	31,970	51,276	166,864	90,359
25	94,192	0.000%	0	-36,433	1,384,442	81,474	31,150	49,961	162,585	90,359
26	94,192	0.000%	0	-36,433	1,348,010	79,330	30,330	48,646	158,307	90,359
27	94,192	0.000%	0	-36,433	1,311,577	77,186	29,510	47,331	154,028	90,359
28	94,192	0.000%	0	-36,433	1,275,144	75,042	28,691	46,017	149,750	90,359
29	94,192	0.000%	0	-36,433	1,238,711	72,898	27,871	44,702	145,471	90,359
30	94,192	0.000%	0	-36,433	1,202,279	70,754	27,051	43,387	141,193	90,359
31	94,192	0.000%	0	-36,433	1,165,846	68,610	26,232	42,072	136,914	90,359
32	94,192	0.000%	0	-36,433	1,129,413	66,466	25,412	40,758	132,635	90,359
33	94,192	0.000%	0	-36,433	1,092,981	64,322	24,592	39,443	128,357	90,359
34	94,192	0.000%	0	-36,433	1,056,548	62,178	23,772	38,128	124,078	90,359
35	94,192	0.000%	0	-36,433	1,020,115	60,034	22,953	36,813	119,800	90,359
36	94,192	0.000%	0	-36,433	983,683	57,890	22,133	35,499	115,521	90,359
37	94,192	0.000%	0	-36,433	947,250	55,746	21,313	34,184	111,243	90,359
38	94,192	0.000%	0	-36,433	910,817	53,602	20,493	32,869	106,964	90,359
39	94,192	0.000%	0	-36,433	874,385	51,458	19,674	31,554	102,685	90,359
40	94,192	0.000%	0	-36,433	837,952	49,313	18,854	30,240	98,407	90,359
41	94,192	0.000%	0	-36,433	801,519	47,169	18,034	28,925	94,128	90,359
42	94,192	0.000%	0	-36,433	765,086	45,025	17,214	27,610	89,850	90,359
43	94,192	0.000%	0	-36,433	728,654	42,881	16,395	26,295	85,571	90,359
44	94,192	0.000%	0	-36,433	692,221	40,737	15,575	24,980	81,293	90,359
45	94,192	0.000%	0	-36,433	655,788	38,593	14,755	23,666	77,014	90,359
46	94,192	0.000%	0	-36,433	619,356	36,449	13,936	22,351	72,736	90,359
47	94,192	0.000%	0	-36,433	582,923	34,305	13,116	21,036	68,457	90,359
48	94,192	0.000%	0	-36,433	546,490	32,161	12,296	19,721	64,178	90,359
49	94,192	0.000%	0	-36,433	510,058	30,017	11,476	18,407	59,900	90,359
50	94,192	0.000%	0	-36,433	473,625	27,873	10,657	17,092	55,621	90,359
51	94,192	0.000%	0	-36,433	437,192	25,729	9,837	15,777	51,343	90,359
52	94,192	0.000%	0	-36,433	400,760	23,585	9,017	14,462	47,064	90,359
53	94,192	0.000%	0	-36,433	364,327	21,441	8,197	13,148	42,786	90,359
54	94,192	0.000%	0	-36,433	327,894	19,297	7,378	11,833	38,507	90,359
55	94,192	0.000%	0	-36,433	291,462	17,153	6,558	10,518	34,228	90,359
56	94,192	0.000%	0	-36,433	255,029	15,008	5,738	9,203	29,950	90,359
57	94,192	0.000%	0	-36,433	218,596	12,864	4,918	7,889	25,671	90,359
58	94,192	0.000%	0	-36,433	182,163	10,720	4,099	6,574	21,393	90,359
59	94,192	0.000%	0	-36,433	145,731	8,576	3,279	5,259	17,114	90,359
60	94,192	0.000%	0	-36,433	109,298	6,432	2,459	3,944	12,836	90,359
61	94,192	0.000%	0	-36,433	72,865	4,288	1,639	2,630	8,557	90,359
62	94,192	0.000%	0	-36,433	36,433	2,144	820	1,315	4,279	90,359
63	94,192	0.000%	0	-36,433	0	0	0	0	0	90,359

Unit Name: SE Chicago 5-12 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 9,173,232		Electric Expenses	Line 145	47,928		
2	Investment Generator & Exciter	Inputs Tab	$ 19,802,693		Other Expenses		1,555		
3	Reactive Allocator	(Line 76)	27.75%		O&M	(sum line 1 & 2)	49,483	7,068,860	0.7000%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**5,495,247**						
5					A&G		527,536	187,439,853	0.2814%
6	GSU Transformer Investment	Inputs Tab	4,873,891		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0132%
7	Reactive Allocator	(Line 76)	27.75%		Working Capital	Line 215	178,678	187,439,853	0.0953%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**1,352,505**		General Plant		-	187,439,853	0.0000%
9					Other Taxes	Line 195(c)	150,320	187,439,853	0.0802%
10	Allocated Acc Elec Equipment	(Line 104 , Column d)	-		Depreciation	Line 167(c)			0.8611%
11	Reactive Allocator	(Line 76)	27.75%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**0**		Taxes (Federal/State/Local)	Line 179			2.5840%
13					ADIT	-Line 232(k)	($1,333,105)	187,439,853	-0.7112%
14	Total Cost of Power Plant	Inputs Tab	187,439,853				(Sum Lines 1 to 11 , Col. (h))		12.0390%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	162,763,269						
16	Balance of Plant Allocator	(Line 79)	0.1358%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	221,108						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	7,068,860						
19	Reactive Fixed Charge Rate	(Line 14(h))	12.0390%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**851,020**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 851,020**						
23									
24									
25									
26									

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	(a)	(b)	(c)
Allocators			
	Real Power Capability (MW)		
		38.30	
		38.30	
		38.30	
		38.30	
		38.30	
		38.30	
		38.30	
		38.30	
	Total	306.40	(Sum Lines 31 to 38)
	Nominal Power Factor (pf)		
		0.85	
		0.85	
		0.85	
		0.85	
		0.85	
		0.85	
		0.85	
		0.85	
	Total	0.85	(Line 40 / 62)
	MVA Capability (MVA)		
		45.06	(Line 31 / 43)
		45.06	(Line 32 / 44)
		45.06	(Line 33 / 45)
		45.06	(Line 34 / 46)
		45.06	(Line 35 / 47)
		45.06	(Line 36 / 48)
		45.06	(Line 37 / 49)
		45.06	(Line 38 / 50)
	Total	360.47	(Sum Lines 54 to 61)
	Reactive Power Capability (MVAR)		
	(MVA^2 - MW^2)^0.5		
		23.74	(SQRT (Line 54^2 - Line 31^2))
		23.74	(SQRT (Line 55^2 - Line 32^2))
		23.74	(SQRT (Line 56^2 - Line 33^2))
		23.74	(SQRT (Line 57^2 - Line 34^2))
		23.74	(SQRT (Line 58^2 - Line 35^2))
		23.74	(SQRT (Line 59^2 - Line 36^2))
		23.74	(SQRT (Line 60^2 - Line 37^2))
		23.74	(SQRT (Line 61^2 - Line 38^2))
	Total	189.89	(Sum Lines 66 to 73)
	Reactive Allocator	27.8%	(Line 74^2 / Line 62^2)
		ComEd is TO Fleet	
	Max. MVAr	2,187	
	Nameplate MVAr	4,856	
	Exciter MW	35	
	Generator MW	11,447	
	Balance of Plant Allocator	0.1358%	(Line 80 / Line 81) * (Line 82 / Line 83)

	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ -	50%	$ -
	Control&Power Cabling	$ -	50%	$ -
	Switch Board Equipment	$ -	50%	$ -
	Switching Equipment	$ -	40%	$ -
	Transformers	$ -	10%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ -	0%	$ -
	Misc	$ 9,173,232	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 9,173,232		$ -

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	459,763	459,763	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	118,760	118,760	
	Steam From Other Sources	229,490		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	70,310		
	Rents	427,899	427,899	
	Allowances	17,291	17,291	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	179,335	179,335	
	Maintenance of Boiler (or reactor) Plant	76,902		
	Maintenance of Electric Plant	80,006		
	Maintenance of Misc Steam (or Nuclear) Plant	99,578	99,578	
	Other Power Production, & Other Expenses	302,046	302,046	
	Total NonFuel Expenses	2,061,381	1,604,673	(Sum Lines 107 to 120)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 121(c) / (Line 121(b) - Line 115(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	59.9052%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 128 * Line 137 + Line 126 * Line 137 / (Line137 + 139)			
	Other Demand Expense Allocator	0.1358%	Line 84			
	Production Plant Expenses					
	Total NonFuel Expenses	2,061,381	Line 121			
	Allowances	17,291	Line 114			
	Non-Fuel Production O&M	2,044,090	(Line 131 - 132)			
	Operating Expenses					
	Operations Supervision & Engineering	459,763	Line 107(c)			
	Electric Expenses	0	Line 111(c)			
	Maintenance of Electric Plant	80,006	Line 118(b)			
	Other Demand Related Expenses	1,144,910	Col. (c) Line 121 - Col (b) Line 137 - Col. (b) Line 136)			
	Total	1,684,679	(Sum Lines 136 to 139)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	80,006	Line 118(b)			
	Electric Expenses	0	Line 111(c)			
	Total Electric Expenses	80,006	(Line 143 + 144)	59.9052%	47,928	(Line 145(b) * (d))
				Line 126		
	Other Demand Related Expenses	1,144,910	(Line 139)	0.1358%	1,555	
				Line 128		
	Balance of Plant Fixed Expenses				1,635,196	(Line 140(b) - Line 145(e) - Line 147(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		314,901	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		212,635	(allocated on plant labor)	
	Total		527,536		
Depreciation					
	Annual Depreciation Exp ...DE	6,247,995			
	Gross Production Plant Cost ... F	187,439,853	Line 14		
	SLDP=DE/F	3.3333%	(Line 163 / 164)		
	Depreciable years (n)=1/SLDP	30			
	SFDP=(R/((1+R)^n-1)		0.8611%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.584%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 184 to 186)
Other Taxes					
	Property Taxes		150,320	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 122		
	Fixed Payroll Taxes		-	(Line 192 * 193)	
	Total Other Taxes		150,320	(Line 191 + 194)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 158
	Fixed General Plant	-		-		(Lines 199 *200)
	Return on General Plant	8.1350%	Line 187			
	Taxes on General Plant	2.5840%	Line 188			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 201 * 202)	-	-	
Working Capital						
	Prepayments	1,409,955				
		100.000%				
	Production Related Prepayments	1,409,955	(Line 208 * 209)			
	Unit Specific M&S	256,975				
	Total	1,666,930	(Line 210 + 211)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.5840%				
	Working Capital Costs	178,678	(Line 212 * 213)			

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Accumulated Deferred Income Taxes

Investment	187,439,853	Line 14	NPV of Col (j)> 14,818,660
Asset Service Life	30	Line 166	
Composite Tax Rate	38.6790%	Line 176	

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity = (f) * (Line185+186)	Interest = (f) * (Line184)	Income Taxes = (g) * (Line177)	Rev Req Impact (g) + (h) + (i)	Levelized PMT of NPV col. (j)
	Line 223 / 224		(b) * (c)	((d) - (b)) * Line 176	Accum. (e)					
1	6,247,995	3.750%	7,028,994	302,083	302,083	17,778	6,797	10,901	35,476	1,333,105
2	6,247,995	7.219%	13,531,283	2,817,103	3,119,186	183,564	70,182	112,563	366,309	1,333,105
3	6,247,995	6.677%	12,515,359	2,424,154	5,543,339	326,226	124,725	200,045	650,995	1,333,105
4	6,247,995	6.177%	11,578,160	2,061,654	7,604,994	447,554	171,112	274,445	893,111	1,333,105
5	6,247,995	5.713%	10,708,439	1,725,255	9,330,249	549,085	209,931	336,704	1,095,720	1,333,105
6	6,247,995	5.285%	9,906,196	1,414,956	10,745,204	632,355	241,767	387,767	1,261,889	1,333,105
7	6,247,995	4.888%	9,162,060	1,127,131	11,872,336	698,687	267,128	428,442	1,394,256	1,333,105
8	6,247,995	4.522%	8,476,030	861,782	12,734,117	749,403	286,518	459,541	1,495,462	1,333,105
9	6,247,995	4.462%	8,363,566	818,282	13,552,399	797,559	304,929	489,071	1,591,559	1,333,105
10	6,247,995	4.461%	8,361,692	817,557	14,369,956	845,672	323,324	518,574	1,687,570	1,333,105
11	6,247,995	4.462%	8,363,566	818,282	15,188,237	893,828	341,735	548,104	1,783,667	1,333,105
12	6,247,995	4.461%	8,361,692	817,557	16,005,794	941,941	360,130	577,608	1,879,679	1,333,105
13	6,247,995	4.462%	8,363,566	818,282	16,824,076	990,097	378,542	607,137	1,975,776	1,333,105
14	6,247,995	4.461%	8,361,692	817,557	17,641,633	1,038,210	396,937	636,641	2,071,788	1,333,105
15	6,247,995	4.462%	8,363,566	818,282	18,459,915	1,086,366	415,348	666,170	2,167,885	1,333,105
16	6,247,995	4.461%	8,361,692	817,557	19,277,471	1,134,479	433,743	695,674	2,263,896	1,333,105
17	6,247,995	4.462%	8,363,566	818,282	20,095,753	1,182,635	452,154	725,204	2,359,993	1,333,105
18	6,247,995	4.461%	8,361,692	817,557	20,913,310	1,230,748	470,549	754,707	2,456,005	1,333,105
19	6,247,995	4.462%	8,363,566	818,282	21,731,592	1,278,904	488,961	784,237	2,552,102	1,333,105
20	6,247,995	4.461%	8,361,692	817,557	22,549,148	1,327,017	507,356	813,740	2,648,114	1,333,105
21	6,247,995	2.231%	4,181,783	-799,190	21,749,958	1,279,985	489,374	784,900	2,554,259	1,333,105
22	6,247,995	0.000%	0	-2,416,662	19,333,296	1,137,764	434,999	697,689	2,270,452	1,333,105
23	6,247,995	0.000%	0	-2,416,662	16,916,634	995,544	380,624	610,477	1,986,646	1,333,105
24	6,247,995	0.000%	0	-2,416,662	14,499,972	853,323	326,249	523,266	1,702,839	1,333,105
25	6,247,995	0.000%	0	-2,416,662	12,083,310	711,103	271,874	436,055	1,419,033	1,333,105
26	6,247,995	0.000%	0	-2,416,662	9,666,648	568,882	217,500	348,844	1,135,226	1,333,105
27	6,247,995	0.000%	0	-2,416,662	7,249,986	426,662	163,125	261,633	851,420	1,333,105
28	6,247,995	0.000%	0	-2,416,662	4,833,324	284,441	108,750	174,422	567,613	1,333,105
29	6,247,995	0.000%	0	-2,416,662	2,416,662	142,221	54,375	87,211	283,807	1,333,105
30	6,247,995	0.000%	0	-2,416,662	0	0	0	0	0	1,333,105

Unit Name: Southwark 3-6 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 6,463,264		Electric Expenses	Line 140	761		
2	Investment Generator & Exciter	Inputs Tab	$ 969,490		Other Expenses		102		
3	Reactive Allocator	(Line 71)	38.50%		O&M	(sum line 1 & 2)	863	724,193	0.1192%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**373,301**						
5					A&G		54,060	10,963,535	0.4931%
6	GSU Transformer Investment	Inputs Tab	2,616		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0082%
7	Reactive Allocator	(Line 71)	38.50%		Working Capital	Line 216	59,159	10,963,535	0.5396%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**1,007**		General Plant		-	10,963,535	0.0000%
9					Other Taxes	Line 196(c)	11,609	10,963,535	0.1059%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	895,880		Depreciation	Line 168(c)			0.7901%
11	Reactive Allocator	(Line 71)	38.50%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**344,957**		Taxes (Federal/State/Local)	Line 180			2.6006%
13					ADIT	-Line 233(k)	($82,733)	10,963,535	-0.7546%
14	Total Cost of Power Plant	Inputs Tab	10,963,535				(Sum Lines 1 to 11 , Col. (h))		12.0370%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	9,095,550						
16	Balance of Plant Allocator	(Line 79)	0.0542%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	4,928						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	724,193						
19	Reactive Fixed Charge Rate	(Line 14(h))	12.0370%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**87,171**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 87,171**						
23									
24									
25									
26									

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	(a)	(b)	(c)
Allocators			
	Real Power Capability (MW)		
		12.80	
		14.88	
		12.88	
		14.66	
	Total	55.22	(Sum Lines 31 to 34)
	Nominal Power Factor (pf)		
		0.76	
		0.81	
		0.77	
		0.80	
	Total	0.78	(Line 38 / 58)
	MVA Capability (MVA)		
		16.93	(Line 31 / 41)
		18.48	(Line 32 / 42)
		16.81	(Line 33 / 43)
		18.26	(Line 34 / 44)
	Total	70.49	(Sum Lines 51 to 54)
	Reactive Power Capability (MVAR)		
	(MVA^2 - MW^2)^0.5		
		11.08	(SQRT (Line 51^2 - Line 31^2))
		10.97	(SQRT (Line 52^2 - Line 32^2))
		10.81	(SQRT (Line 53^2 - Line 33^2))
		10.88	(SQRT (Line 54^2 - Line 34^2))
	Total	43.74	(Sum Lines 62 to 65)
	Reactive Allocator	38.5%	(Line 69^2 / Line 58^2)
		PECO is TO Fleet	
	Max. MVAr	360.90	
	Nameplate MVAr	2,852.52	
	Exciter MW	28.75	
	Generator MW	6,714.69	
	Balance of Plant Allocator	0.0542%	(Line 75 / Line 76) * (Line 77 / Line 78)

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator				
		Investment	**Cumb. Turbine**	**Allocated Amt**
	Storage Batteries	$ 40,019	50%	$ 20,009
	Control&Power Cabling	$ 65,482	50%	$ 32,741
	Switch Board Equipment	$ 1,638,273	50%	$ 819,137
	Switching Equipment	$ 59,982	40%	$ 23,993
	Transformers	$ -	10%	$ -
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ -	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ -	75%	$ -
	Structure	$ 11,054	0%	$ -
	Misc	$ 781,212	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	5%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 2,596,022		$ 895,880

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	75,704	75,704	
	Coolants and Water (Nuclear Plants Only)	0		
	Steam Expenses	19,555	19,555	
	Steam From Other Sources	37,788		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	11,577		
	Rents	70,458	70,458	
	Allowances	2,847	2,847	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	29,529	29,529	
	Maintenance of Boiler (or reactor) Plant	12,663		
	Maintenance of Electric Plant	13,174		
	Maintenance of Misc Steam (or Nuclear) Plant	16,397	16,397	
	Other Power Production, & Other Expenses	49,735	49,735	
	Total NonFuel Expenses	339,425	264,224	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation				
	Plant Var Allocators			
	Electric Expense Allocator	5.7757%	Line 4(c) / 1(c))	
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)	
	Other Demand Expense Allocator	0.0542%	Line 79	
	Production Plant Expenses			
	Total NonFuel Expenses	339,425	Line 116	
	Allowances	2,847	Line 109	
	Non-Fuel Production O&M	336,578	(Line 126 - 127)	
	Operating Expenses			
	Operations Supervision & Engineering	75,704	Line 102(c)	
	Electric Expenses	0	Line 106(c)	
	Maintenance of Electric Plant	13,174	Line 113(b)	
	Other Demand Related Expenses	188,520	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)	
	Total	277,398	(Sum Lines 131 to 134)	

				Allocator	Allocated Amount	
	Maintenance of Electric Plant	13,174	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	13,174	(Line 138 + 139)	5.7757%	761	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	188,520	(Line 134)	0.0542%	102	
				Line 123		
	Balance of Plant Fixed Expenses				276,535	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		16,925	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		37,136	(allocated on plant labor)	
	Total		54,060		
Depreciation					
	Annual Depreciation Exp ...DE	353,662			
	Gross Production Plant Cost ... F	10,963,535	Line 14		
	SLDP=DE/F	3.2258%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	31			
	SFDP=(R/((1+R)^n-1)		0.7901%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.601%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		11,609	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		11,609	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.6006%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	82,470				
		100.000%				
	Production Related Prepayments	82,470	(Line 209 * 210)			
	Unit Specific M&S	468,585				
	Total	551,055	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.6006%				
	Working Capital Costs	59,159	(Line 213 * 214)			

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(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)

Accumulated Deferred Income Taxes

Investment		10,963,535	Line 14					NPV of Col (j)>	926,978	
Asset Service Life		31	Line 167							
Composite Tax Rate		38.6790%	Line 177							

Yr.	SL Deprec	MACRS	Tax Deprec	Def Inc Taxes	ADIT	Return on Equity = (f) *	Interest = (f) *	Income Taxes = (g) *	Rev Req Impact	Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	(Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	353,662	3.750%	411,133	22,229	22,229	1,308	500	802	2,611	82,733
2	353,662	7.219%	791,458	169,335	191,564	11,274	4,310	6,913	22,497	82,733
3	353,662	6.677%	732,035	146,351	337,914	19,886	7,603	12,194	39,684	82,733
4	353,662	6.177%	677,218	125,148	463,062	27,251	10,419	16,711	54,381	82,733
5	353,662	5.713%	626,347	105,472	568,534	33,458	12,792	20,517	66,767	82,733
6	353,662	5.285%	579,423	87,322	655,856	38,597	14,757	23,668	77,022	82,733
7	353,662	4.888%	535,898	70,487	726,343	42,745	16,343	26,212	85,300	82,733
8	353,662	4.522%	495,771	54,966	781,309	45,980	17,579	28,195	91,755	82,733
9	353,662	4.462%	489,193	52,422	833,731	49,065	18,759	30,087	97,911	82,733
10	353,662	4.461%	489,083	52,379	886,110	52,148	19,937	31,977	104,062	82,733
11	353,662	4.462%	489,193	52,422	938,532	55,233	21,117	33,869	110,219	82,733
12	353,662	4.461%	489,083	52,379	990,911	58,315	22,296	35,759	116,370	82,733
13	353,662	4.462%	489,193	52,422	1,043,333	61,400	23,475	37,651	122,526	82,733
14	353,662	4.461%	489,083	52,379	1,095,713	64,483	24,654	39,541	128,678	82,733
15	353,662	4.462%	489,193	52,422	1,148,134	67,568	25,833	41,433	134,834	82,733
16	353,662	4.461%	489,083	52,379	1,200,514	70,650	27,012	43,323	140,985	82,733
17	353,662	4.462%	489,193	52,422	1,252,936	73,735	28,191	45,215	147,142	82,733
18	353,662	4.461%	489,083	52,379	1,305,315	76,818	29,370	47,105	153,293	82,733
19	353,662	4.462%	489,193	52,422	1,357,737	79,903	30,549	48,997	159,449	82,733
20	353,662	4.461%	489,083	52,379	1,410,116	82,985	31,728	50,887	165,600	82,733
21	353,662	2.231%	244,596	-42,186	1,367,931	80,503	30,778	49,365	160,646	82,733
22	353,662	0.000%	0	-136,793	1,231,138	72,452	27,701	44,429	144,582	82,733
23	353,662	0.000%	0	-136,793	1,094,345	64,402	24,623	39,492	128,517	82,733
24	353,662	0.000%	0	-136,793	957,552	56,352	21,545	34,556	112,452	82,733
25	353,662	0.000%	0	-136,793	820,759	48,302	18,467	29,619	96,388	82,733
26	353,662	0.000%	0	-136,793	683,965	40,251	15,389	24,683	80,323	82,733
27	353,662	0.000%	0	-136,793	547,172	32,201	12,311	19,746	64,259	82,733
28	353,662	0.000%	0	-136,793	410,379	24,151	9,234	14,810	48,194	82,733
29	353,662	0.000%	0	-136,793	273,586	16,101	6,156	9,873	32,129	82,733
30	353,662	0.000%	0	-136,793	136,793	8,050	3,078	4,937	16,065	82,733
31	353,662	0.000%	0	-136,793	0	0	0	0	0	82,733

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Unit Name: TMI **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 13,661,046		Electric Expenses	Line 140	203,229		
2	Investment Generator & Exciter	Inputs Tab	2,049,157		Other Expenses		6,467		
3	Reactive Allocator	(Line 71)	12.76%		O&M	(sum line 1 & 2)	209,696	444,856	47.1379%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**261,563**						
5					A&G		90,370,810	1,001,621,380	9.0225%
6	GSU Transformer Investment	Inputs Tab	-		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.7807%
7	Reactive Allocator	(Line 71)	12.76%		Working Capital	Line 216	18,368,466	1,001,621,380	1.8339%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**0**		General Plant		-	1,001,621,380	0.0000%
9					Other Taxes	Line 196(c)	6,240,261	1,001,621,380	0.6230%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	797,453		Depreciation	Line 168(c)			0.0752%
11	Reactive Allocator	(Line 71)	12.76%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**101,790**		Taxes (Federal/State/Local)	Line 180			2.9859%
13					ADIT	-Line 233(k)	($14,819,872)	1,001,621,380	-1.4796%
14	Total Cost of Power Plant	Inputs Tab	1,001,621,380				(Sum Lines 1 to 11 , Col. (h))		69.1144%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	998,774,770						
16	Balance of Plant Allocator	(Line 79)	0.0082%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	81,504						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	444,856						
19	Reactive Fixed Charge Rate	(Line 14(h))	69.1144%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**307,460**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 307,460**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		888.00						
		-						
		-						
	Total	888.00	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.93						
		-						
		-						
	Total	0.93	(Line 38 / 58)					
	MVA Capability (MVA)							
		950.75	(Line 31 / 41)					
		-						
		-						
	Total	950.75	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		339.68	(SQRT (Line 51^2 - Line 31^2))					
		-						
		-						
	Total	339.68	(Sum Lines 62 to 64)					
	Reactive Allocator	12.8%	(Line 69^2 / Line 58^2)					
		MetEd is TO Fleet						
	Max. MVAr	15.32						
	Nameplate MVAr	339.68						
	Exciter MW	1.61						
	Generator MW	888.00						
	Balance of Plant Allocator	0.0082%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)
Accessory Equip Allocator		**Investment**	**Nuclear**	**Allocated Amt**
	Storage Batteries	$ -	15%	$ -
	Control&Power Cabling	$ -	1%	$ -
	Switch Board Equipment	$ -	1%	$ -
	Switching Equipment	$ -	1%	$ -
	Transformers	$ 1,804,433	3%	$ 54,133
	Aux Generator	$ -	0%	$ -
	Fire Protection System	$ 194,043	0%	$ -
	HVAC	$ -	0%	$ -
	Regulating Equipment	$ 1,486,640	50%	$ 743,320
	Structure	$ -	0%	$ -
	Misc	$ 10,382,696	0%	$ -
	Exciter & PPT	$ -	100%	$ -
	Station Grounding	$ -	1%	$ -
	Bus & Insulators	$ -	80%	$ -
	Capacitor Bank	$ -	0%	$ -
	Total	$ 13,867,813		$ 797,453

O&M		**Total Non-Fuel**	**Fixed O&M**	
	Production Expenses: Oper, Supv, & Engr	22,327,877	22,327,877	
	Coolants and Water (Nuclear Plants Only)	2,187,756		
	Steam Expenses	13,722,618	13,722,618	
	Steam From Other Sources	0		
	Electric Expenses	0	-	
	Misc Steam (or Nuclear) Power Expenses	1,401,948		
	Rents	38,762,682	38,762,682	
	Allowances	3,075,908	3,075,908	
	Maintenance Supervision and Engineering	0		
	Maintenance of Structures	4,119,106	4,119,106	
	Maintenance of Boiler (or reactor) Plant	321,052		
	Maintenance of Electric Plant	10,614,344		
	Maintenance of Misc Steam (or Nuclear) Plant	6,818,030	6,818,030	
	Other Power Production, & Other Expenses	12,755,212	12,755,212	
	Total NonFuel Expenses	116,106,533	101,581,433	(Sum Lines 102 to 115)
	Percentage Fixed O&M Excluding Allowances		87.49%	(Line 116(c) / (Line 116(b) - Line 110(b)))

O&M Calculation						
	Plant Var Allocators					
	Electric Expense Allocator	1.9147%	Line 4(c) / 1(c))			
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)			
	Other Demand Expense Allocator	0.0082%	Line 79			
	Production Plant Expenses					
	Total NonFuel Expenses	116,106,533	Line 116			
	Allowances	3,075,908	Line 109			
	Non-Fuel Production O&M	113,030,625	(Line 126 - 127)			
	Operating Expenses					
	Operations Supervision & Engineering	22,327,877	Line 102(c)			
	Electric Expenses	0	Line 106(c)			
	Maintenance of Electric Plant	10,614,344	Line 113(b)			
	Other Demand Related Expenses	79,253,555	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131			
	Total	112,195,777	(Sum Lines 131 to 134)			
				Allocator	Allocated Amount	
	Maintenance of Electric Plant	10,614,344	Line 113(b)			
	Electric Expenses	0	Line 106(c)			
	Total Electric Expenses	10,614,344	(Line 138 + 139)	1.9147%	203,229	(Line 140(b) * (d))
				Line 121		
	Other Demand Related Expenses	79,253,555	(Line 134)	0.0082%	6,467	
				Line 123		
	Balance of Plant Fixed Expenses				111,986,081	(Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		80,763,143	(directly assigned)	
	Nuclear Overhead Expenses ("OH" tab)		9,607,667	(allocated on plant labor)	
	Total		90,370,810		
Depreciation					
	Annual Depreciation Exp ...DE	16,693,690			
	Gross Production Plant Cost ... F	1,001,621,380	Line 14		
	SLDP=DE/F	1.6667%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	60			
	SFDP=(R/((1+R)^n-1)		0.0752%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.986%		
Rate of Return					
	Rate Of Return = R	Weight	Cost Rate	Weighted Cost (b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		1,186,903		
	Payroll Taxes	5,775,935			
		0 87.4899%	Line 117		
	Fixed Payroll Taxes		5,053,357	(Line 193 * 194)	
	Total Other Taxes		6,240,261	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
	0	0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9859%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	

Working Capital			
	Prepayments	1,679,308	
		100.000%	
	Production Related Prepayments	1,679,308	(Line 209 * 210)
	Unit Specific M&S	163,491,998	
	Total	165,171,306	(Line 211 + 212)
	Return on Working Capital	8.1350%	
	Taxes on Working Capital	2.9859%	
	Working Capital Costs	18,368,466	(Line 213 * 214)

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Accumulated Deferred Income Taxes

Investment	1,001,621,380	Line 14	NPV of Col (j)> 180,505,002
Asset Service Life	60	Line 167	
Composite Tax Rate	38.6790%	Line 177	

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity	(h) Interest	(i) Income Taxes	(j) Rev Req Impact	(k) Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	= (f) * (Line186+187)	= (f) * (Line185)	= (g) * (Line178)	(g) + (h) + (i)	col. (j)
1	16,693,690	3.750%	37,560,802	8,071,190	8,071,190	474,990	181,602	291,268	947,860	14,819,872
2	16,693,690	7.219%	72,307,047	21,510,691	29,581,881	1,740,894	665,592	1,067,533	3,474,019	14,819,872
3	16,693,690	6.677%	66,878,260	19,410,890	48,992,771	2,883,225	1,102,337	1,768,022	5,753,584	14,819,872
4	16,693,690	6.177%	61,870,153	17,473,804	66,466,575	3,911,558	1,495,498	2,398,606	7,805,662	14,819,872
5	16,693,690	5.713%	57,222,629	15,676,189	82,142,763	4,834,102	1,848,212	2,964,319	9,646,633	14,819,872
6	16,693,690	5.285%	52,935,690	14,018,043	96,160,807	5,659,063	2,163,618	3,470,194	11,292,876	14,819,872
7	16,693,690	4.888%	48,959,253	12,479,997	108,640,804	6,393,511	2,444,418	3,920,565	12,758,494	14,819,872
8	16,693,690	4.522%	45,293,319	11,062,051	119,702,854	7,044,513	2,693,314	4,319,766	14,057,593	14,819,872
9	16,693,690	4.462%	44,692,346	10,829,600	130,532,455	7,681,835	2,936,980	4,710,578	15,329,393	14,819,872
10	16,693,690	4.461%	44,682,330	10,825,726	141,358,181	8,318,929	3,180,559	5,101,250	16,600,738	14,819,872
11	16,693,690	4.462%	44,692,346	10,829,600	152,187,781	8,956,251	3,424,225	5,492,063	17,872,539	14,819,872
12	16,693,690	4.461%	44,682,330	10,825,726	163,013,507	9,593,345	3,667,804	5,882,735	19,143,884	14,819,872
13	16,693,690	4.462%	44,692,346	10,829,600	173,843,107	10,230,667	3,911,470	6,273,547	20,415,684	14,819,872
14	16,693,690	4.461%	44,682,330	10,825,726	184,668,834	10,867,761	4,155,049	6,664,220	21,687,029	14,819,872
15	16,693,690	4.462%	44,692,346	10,829,600	195,498,434	11,505,083	4,398,715	7,055,032	22,958,829	14,819,872
16	16,693,690	4.461%	44,682,330	10,825,726	206,324,160	12,142,177	4,642,294	7,445,704	24,230,175	14,819,872
17	16,693,690	4.462%	44,692,346	10,829,600	217,153,760	12,779,499	4,885,960	7,836,516	25,501,975	14,819,872
18	16,693,690	4.461%	44,682,330	10,825,726	227,979,486	13,416,593	5,129,538	8,227,189	26,773,320	14,819,872
19	16,693,690	4.462%	44,692,346	10,829,600	238,809,087	14,053,915	5,373,204	8,618,001	28,045,120	14,819,872
20	16,693,690	4.461%	44,682,330	10,825,726	249,634,813	14,691,009	5,616,783	9,008,673	29,316,465	14,819,872
21	16,693,690	2.231%	22,346,173	2,186,324	251,821,137	14,819,674	5,665,976	9,087,572	29,573,222	14,819,872
22	16,693,690	0.000%	0	-6,456,952	245,364,184	14,439,682	5,520,694	8,854,558	28,814,934	14,819,872
23	16,693,690	0.000%	0	-6,456,952	238,907,232	14,059,691	5,375,413	8,621,543	28,056,646	14,819,872
24	16,693,690	0.000%	0	-6,456,952	232,450,280	13,679,699	5,230,131	8,388,528	27,298,358	14,819,872
25	16,693,690	0.000%	0	-6,456,952	225,993,328	13,299,707	5,084,850	8,155,514	26,540,071	14,819,872
26	16,693,690	0.000%	0	-6,456,952	219,536,376	12,919,716	4,939,568	7,922,499	25,781,783	14,819,872
27	16,693,690	0.000%	0	-6,456,952	213,079,423	12,539,724	4,794,287	7,689,484	25,023,495	14,819,872
28	16,693,690	0.000%	0	-6,456,952	206,622,471	12,159,732	4,649,006	7,456,470	24,265,208	14,819,872
29	16,693,690	0.000%	0	-6,456,952	200,165,519	11,779,741	4,503,724	7,223,455	23,506,920	14,819,872
30	16,693,690	0.000%	0	-6,456,952	193,708,567	11,399,749	4,358,443	6,990,440	22,748,632	14,819,872
31	16,693,690	0.000%	0	-6,456,952	187,251,614	11,019,758	4,213,161	6,757,426	21,990,344	14,819,872
32	16,693,690	0.000%	0	-6,456,952	180,794,662	10,639,766	4,067,880	6,524,411	21,232,057	14,819,872
33	16,693,690	0.000%	0	-6,456,952	174,337,710	10,259,774	3,922,598	6,291,396	20,473,769	14,819,872
34	16,693,690	0.000%	0	-6,456,952	167,880,758	9,879,783	3,777,317	6,058,381	19,715,481	14,819,872
35	16,693,690	0.000%	0	-6,456,952	161,423,806	9,499,791	3,632,036	5,825,367	18,957,193	14,819,872
36	16,693,690	0.000%	0	-6,456,952	154,966,853	9,119,799	3,486,754	5,592,352	18,198,906	14,819,872
37	16,693,690	0.000%	0	-6,456,952	148,509,901	8,739,808	3,341,473	5,359,337	17,440,618	14,819,872
38	16,693,690	0.000%	0	-6,456,952	142,052,949	8,359,816	3,196,191	5,126,323	16,682,330	14,819,872
39	16,693,690	0.000%	0	-6,456,952	135,595,997	7,979,824	3,050,910	4,893,308	15,924,042	14,819,872
40	16,693,690	0.000%	0	-6,456,952	129,139,044	7,599,833	2,905,629	4,660,293	15,165,755	14,819,872
41	16,693,690	0.000%	0	-6,456,952	122,682,092	7,219,841	2,760,347	4,427,279	14,407,467	14,819,872
42	16,693,690	0.000%	0	-6,456,952	116,225,140	6,839,849	2,615,066	4,194,264	13,649,179	14,819,872
43	16,693,690	0.000%	0	-6,456,952	109,768,188	6,459,858	2,469,784	3,961,249	12,890,892	14,819,872
44	16,693,690	0.000%	0	-6,456,952	103,311,236	6,079,866	2,324,503	3,728,235	12,132,604	14,819,872
45	16,693,690	0.000%	0	-6,456,952	96,854,283	5,699,875	2,179,221	3,495,220	11,374,316	14,819,872
46	16,693,690	0.000%	0	-6,456,952	90,397,331	5,319,883	2,033,940	3,262,205	10,616,028	14,819,872
47	16,693,690	0.000%	0	-6,456,952	83,940,379	4,939,891	1,888,659	3,029,191	9,857,741	14,819,872
48	16,693,690	0.000%	0	-6,456,952	77,483,427	4,559,900	1,743,377	2,796,176	9,099,453	14,819,872
49	16,693,690	0.000%	0	-6,456,952	71,026,474	4,179,908	1,598,096	2,563,161	8,341,165	14,819,872
50	16,693,690	0.000%	0	-6,456,952	64,569,522	3,799,916	1,452,814	2,330,147	7,582,877	14,819,872
51	16,693,690	0.000%	0	-6,456,952	58,112,570	3,419,925	1,307,533	2,097,132	6,824,590	14,819,872
52	16,693,690	0.000%	0	-6,456,952	51,655,618	3,039,933	1,162,251	1,864,117	6,066,302	14,819,872
53	16,693,690	0.000%	0	-6,456,952	45,198,666	2,659,941	1,016,970	1,631,103	5,308,014	14,819,872
54	16,693,690	0.000%	0	-6,456,952	38,741,713	2,279,950	871,689	1,398,088	4,549,726	14,819,872
55	16,693,690	0.000%	0	-6,456,952	32,284,761	1,899,958	726,407	1,165,073	3,791,439	14,819,872
56	16,693,690	0.000%	0	-6,456,952	25,827,809	1,519,967	581,126	932,059	3,033,151	14,819,872
57	16,693,690	0.000%	0	-6,456,952	19,370,857	1,139,975	435,844	699,044	2,274,863	14,819,872
58	16,693,690	0.000%	0	-6,456,952	12,913,904	759,983	290,563	466,029	1,516,575	14,819,872
59	16,693,690	0.000%	0	-6,456,952	6,456,952	379,992	145,281	233,015	758,288	14,819,872
60	16,693,690	0.000%	0	-6,456,952	0	0	0	0	0	14,819,872

Unit Name: Westport 5 **Cost Year:** 2015

	(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)
					Fixed Charge Rate for Reactive Plant				
							Calculated Amt	Plant	FCR % (f) / (g)
	Annual Revenue Requirement								
1	Turbogenerator Account 314, 323, 343 or 344	Inputs Tab	$ 31,650,720		Electric Expenses	Line 140	750		
2	Investment Generator & Exciter	Inputs Tab	4,747,608		Other Expenses		75		
3	Reactive Allocator	(Line 71)	14.62%		O&M	(sum line 1 & 2)	825	911,476	0.0905%
4	**Reactive Cost of Generator/Exciter**	(Line 2 * 3)	**694,214**						
5					A&G		250,357	38,050,323	0.6580%
6	GSU Transformer Investment	Inputs Tab	337,384		CWC	From Col. (h): ((lines 3 + 5) *.125 * (lines 11 + 12)			0.0103%
7	Reactive Allocator	(Line 71)	14.62%		Working Capital	Line 216	45,779	38,050,323	0.1203%
8	**Reactive Cost of GSU Transformers**	(Line 6 * 7)	**49,334**		General Plant		-	38,050,323	0.0000%
9					Other Taxes	Line 196(c)	775,741	38,050,323	2.0387%
10	Allocated Acc Elec Equipment	(Line 99 , Column d)	1,114,980		Depreciation	Line 168(c)			0.1309%
11	Reactive Allocator	(Line 71)	14.62%						8.1350%
12	**Reactive Cost of Acc Elec Eqpt**	(Line 10 * 11)	**163,037**		Taxes (Federal/State/Local)	Line 180			2.9108%
13					ADIT	-Line 233(k)	($518,834)	38,050,323	-1.3635%
14	Total Cost of Power Plant	Inputs Tab	38,050,323				(Sum Lines 1 to 11 , Col. (h))		12.7310%
15	Balance of Plant	(Line 14 - 10 - 6 - 2)	31,850,350						
16	Balance of Plant Allocator	(Line 79)	0.0154%						
17	Reactive Cost Attr to Balance of Plant	(Line 15 * 16)	4,891						
18	Total Reactive Investment	(Line 4 + 8 + 12 + 17)	911,476						
19	Reactive Fixed Charge Rate	(Line 14(h))	12.7310%						
20	**Annual Reactive Rev Req**	(Line 19 * 18)	**116,040**						
21									
22	**Total Annual Revenue Requirement**	(Line 20)	**$ 116,040**						
23									
24									
25									
26									

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Allocators								
	Real Power Capability (MW)							
		118.50						
		-						
		-						
	Total	118.50	(Sum Lines 31 to 33)					
	Nominal Power Factor (pf)							
		0.92						
		-						
		-						
	Total	0.92	(Line 38 / 58)					
	MVA Capability (MVA)							
		128.25	(Line 31 / 41)					
		-	(Line 32 / 42)					
		-						
	Total	128.25	(Sum Lines 51 to 53)					
	Reactive Power Capability (MVAR)							
	(MVA^2 - MW^2)^0.5							
		49.04	(SQRT (Line 51^2 - Line 31^2))					
		-	(SQRT (Line 52^2 - Line 32^2))					
		-	(SQRT (Line 53^2 - Line 33^2))					
	Total	49.04	(Sum Lines 62 to 64)					
	Reactive Allocator	14.6%	(Line 69^2 / Line 58^2)					
		BGE is TO Fleet						
	Max. MVAr	27.50						
	Nameplate MVAr	571.22						
	Exciter MW	3.08						
	Generator MW	965.46						
	Balance of Plant Allocator	0.0154%	(Line 75 / Line 76) * (Line 77 / Line 78)					

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	(a)	(b)	(c)	(d)	
Accessory Equip Allocator					
		Investment	**Cumb. Turbine**	**Allocated Amt**	
	Storage Batteries	$ -	50%	$ -	
	Control&Power Cabling	-	50%	$ -	
	Switch Board Equipment	-	50%	$ -	
	Switching Equipment	-	40%	$ -	
	Transformers	-	10%	$ -	
	Aux Generator	-	0%	$ -	
	Fire Protection System	-	0%	$ -	
	HVAC	-	0%	$ -	
	Regulating Equipment	1,486,640	75%	$ 1,114,980	
	Structure	-	0%	$ -	
	Misc	217,121	0%	$ -	
	Exciter & PPT	-	100%	$ -	
	Station Grounding	-	5%	$ -	
	Bus & Insulators	-	80%	$ -	
	Capacitor Bank	-	0%	$ -	
	Total	$ 1,703,761		$ 1,114,980	
O&M		**Total Non-Fuel**	**Fixed O&M**		
	Production Expenses: Oper, Supv, & Engr	196,400	196,400		
	Coolants and Water (Nuclear Plants Only)	0			
	Steam Expenses	50,732	50,732		
	Steam From Other Sources	98,033			
	Electric Expenses	0	-		
	Misc Steam (or Nuclear) Power Expenses	30,035			
	Rents	182,789	182,789		
	Allowances	7,386	7,386		
	Maintenance Supervision and Engineering	0			
	Maintenance of Structures	76,608	76,608		
	Maintenance of Boiler (or reactor) Plant	32,851			
	Maintenance of Electric Plant	34,177			
	Maintenance of Misc Steam (or Nuclear) Plant	42,538	42,538		
	Other Power Production, & Other Expenses	129,027	129,027		
	Total NonFuel Expenses	880,575	685,480	(Sum Lines 102 to 115)	
	Percentage Fixed O&M Excluding Allowances		77.84%	(Line 116(c) / (Line 116(b) - Line 110(b)))	
O&M Calculation					
	Plant Var Allocators				
	Electric Expense Allocator	2.1934%	Line 4(c) / 1(c))		
	Operations Suprv & Engrg Allocator	0.0000%	(Col. (c) Line 123 * Line 132 + Line 121 * Line 132 / (Line132 + 134)		
	Other Demand Expense Allocator	0.0154%	Line 79		
	Production Plant Expenses				
	Total NonFuel Expenses	880,575	Line 116		
	Allowances	7,386	Line 109		
	Non-Fuel Production O&M	873,189	(Line 126 - 127)		
	Operating Expenses				
	Operations Supervision & Engineering	196,400	Line 102(c)		
	Electric Expenses	0	Line 106(c)		
	Maintenance of Electric Plant	34,177	Line 113(b)		
	Other Demand Related Expenses	489,079	Col. (c) Line 116 - Col (b) Line 132 - Col. (b) Line 131)		
	Total	719,656	(Sum Lines 131 to 134)		
				Allocator	Allocated Amount
	Maintenance of Electric Plant	34,177	Line 113(b)		
	Electric Expenses	0	Line 106(c)		
	Total Electric Expenses	34,177	(Line 138 + 139)	2.1934%	750 (Line 140(b) * (d))
				Line 121	
	Other Demand Related Expenses	489,079	(Line 134)	0.0154%	75
				Line 123	
	Balance of Plant Fixed Expenses				718,832 (Line 135(b) - Line 140(e) - Line 142(e))

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	(a)	(b)	(c)	(d)	(e)
A&G					
	Plant specific A&G		144,258	(directly assigned)	
	Non-Nuclear Overhead Expenses ("OH" tab)		106,099	(allocated on plant labor)	
	Total		250,357		
Depreciation					
	Annual Depreciation Exp ...DE	717,931			
	Gross Production Plant Cost ... F	38,050,323	Line 14		
	SLDP=DE/F	1.8868%	(Line 164 / 165)		
	Depreciable years (n)=1/SLDP	53			
	SFDP=(R/((1+R)^n-1)		0.1309%		
Income Taxes					
	Income Tax Calculation; (Co's Sch. 2)				
	a) State Income Tax Rate ("SIT")	5.6600%			
	b) City/Local Income Tax Rate ("LIT")	0.0000%			
	c) Less: SIT/LIT deductible for Federal=35%	-1.9810%			
	d) Net of Fdrl tax SIT	3.6790%			
	e) Federal Income Tax Rate ("FIT")	35.0000%			
	f) Gross Income Tax Rate ("GIT")...CIT	38.6790%			
	g) Gross-Up Tax Factor ("GTF")	61.3210%			
	(CIT/(1-CIT))*(R- line 166 + line 168)*(1-WLTD/R)		2.911%		
Rate of Return				Weighted Cost	
	Rate Of Return = R	Weight	Cost Rate	(b) * (c)	
	Long-Term Debt "WLTD"	45.000%	5.000%	2.250%	
	Preferred Stock				
	Common Stock	55.000%	10.700%	5.885%	
	Total Cost of Capital "R"	100.000%	R=	8.135%	(Sum Lines 185 to 187)
Other Taxes					
	Property Taxes		775,741	<Includes Payroll	
	Payroll Taxes				
		77.8446%	Line 117		
	Fixed Payroll Taxes		-	(Line 193 * 194)	
	Total Other Taxes		775,740.9	(Line 192 + 195)	

		Plant		Depreciation	Total	
General Plant		-		-		
		0.000%		0.000%		Line 159
	Fixed General Plant	-		-		(Lines 200 *201)
	Return on General Plant	8.1350%	Line 188			
	Taxes on General Plant	2.9108%	Line 189			
	General Plant Costs (Return, Taxes & Depr.)	-	(Line 202 * 203)	-	-	
Working Capital						
	Prepayments	286,221				
		100.000%				
	Production Related Prepayments	286,221	(Line 209 * 210)			
	Unit Specific M&S	128,223				
	Total	414,445	(Line 211 + 212)			
	Return on Working Capital	8.1350%				
	Taxes on Working Capital	2.9108%				
	Working Capital Costs	45,779	(Line 213 * 214)			

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Accumulated Deferred Income Taxes

Investment	38,050,323	Line 14
Asset Service Life	53	Line 167
Composite Tax Rate	38.6790%	Line 177

NPV of Col (j)> 6,276,766

(a) Yr.	(b) SL Deprec	(c) MACRS	(d) Tax Deprec	(e) Def Inc Taxes	(f) ADIT	(g) Return on Equity = (f) *	(h) Interest = (f) *	(i) Income Taxes = (g) *	(j) Rev Req Impact	(k) Levelized PMT of NPV
	Line 224 / 225		(b) * (c)	((d) - (b)) * Line 177	Accum. (e)	(Line186+187)	(Line185)	(Line178)	(g) + (h) + (i)	col. (j)
1	717,931	3.750%	1,426,887	274,217	274,217	16,138	6,170	9,896	32,203	518,834
2	717,931	7.219%	2,746,853	784,767	1,058,984	62,321	23,827	38,216	124,364	518,834
3	717,931	6.677%	2,540,620	704,998	1,763,982	103,810	39,690	63,658	207,157	518,834
4	717,931	6.177%	2,350,368	631,411	2,395,393	140,969	53,896	86,444	281,309	518,834
5	717,931	5.713%	2,173,815	563,121	2,958,514	174,109	66,567	106,765	347,440	518,834
6	717,931	5.285%	2,010,960	500,131	3,458,645	203,541	77,820	124,814	406,174	518,834
7	717,931	4.888%	1,859,900	441,702	3,900,347	229,535	87,758	140,753	458,047	518,834
8	717,931	4.522%	1,720,636	387,836	4,288,183	252,360	96,484	154,749	503,593	518,834
9	717,931	4.462%	1,697,805	379,006	4,667,189	274,664	105,012	168,427	548,103	518,834
10	717,931	4.461%	1,697,425	378,859	5,046,048	296,960	113,536	182,099	592,595	518,834
11	717,931	4.462%	1,697,805	379,006	5,425,054	319,264	122,064	195,776	637,104	518,834
12	717,931	4.461%	1,697,425	378,859	5,803,912	341,560	130,588	209,448	681,596	518,834
13	717,931	4.462%	1,697,805	379,006	6,182,918	363,865	139,116	223,125	726,106	518,834
14	717,931	4.461%	1,697,425	378,859	6,561,776	386,161	147,640	236,798	770,598	518,834
15	717,931	4.462%	1,697,805	379,006	6,940,782	408,465	156,168	250,475	815,107	518,834
16	717,931	4.461%	1,697,425	378,859	7,319,641	430,761	164,692	264,147	859,600	518,834
17	717,931	4.462%	1,697,805	379,006	7,698,647	453,065	173,220	277,824	904,109	518,834
18	717,931	4.461%	1,697,425	378,859	8,077,505	475,361	181,744	291,496	948,601	518,834
19	717,931	4.462%	1,697,805	379,006	8,456,511	497,666	190,271	305,174	993,111	518,834
20	717,931	4.461%	1,697,425	378,859	8,835,370	519,961	198,796	318,846	1,037,603	518,834
21	717,931	2.231%	848,903	50,659	8,886,028	522,943	199,936	320,674	1,043,552	518,834
22	717,931	0.000%	0	-277,688	8,608,340	506,601	193,688	310,653	1,010,941	518,834
23	717,931	0.000%	0	-277,688	8,330,651	490,259	187,440	300,632	978,330	518,834
24	717,931	0.000%	0	-277,688	8,052,963	473,917	181,192	290,611	945,719	518,834
25	717,931	0.000%	0	-277,688	7,775,275	457,575	174,944	280,590	913,108	518,834
26	717,931	0.000%	0	-277,688	7,497,586	441,233	168,696	270,568	880,497	518,834
27	717,931	0.000%	0	-277,688	7,219,898	424,891	162,448	260,547	847,886	518,834
28	717,931	0.000%	0	-277,688	6,942,210	408,549	156,200	250,526	815,275	518,834
29	717,931	0.000%	0	-277,688	6,664,521	392,207	149,952	240,505	782,664	518,834
30	717,931	0.000%	0	-277,688	6,386,833	375,865	143,704	230,484	750,053	518,834
31	717,931	0.000%	0	-277,688	6,109,144	359,523	137,456	220,463	717,442	518,834
32	717,931	0.000%	0	-277,688	5,831,456	343,181	131,208	210,442	684,831	518,834
33	717,931	0.000%	0	-277,688	5,553,768	326,839	124,960	200,421	652,220	518,834
34	717,931	0.000%	0	-277,688	5,276,079	310,497	118,712	190,400	619,609	518,834
35	717,931	0.000%	0	-277,688	4,998,391	294,155	112,464	180,379	586,998	518,834
36	717,931	0.000%	0	-277,688	4,720,702	277,813	106,216	170,358	554,387	518,834
37	717,931	0.000%	0	-277,688	4,443,014	261,471	99,968	160,337	521,776	518,834
38	717,931	0.000%	0	-277,688	4,165,326	245,129	93,720	150,316	489,165	518,834
39	717,931	0.000%	0	-277,688	3,887,637	228,787	87,472	140,295	456,554	518,834
40	717,931	0.000%	0	-277,688	3,609,949	212,445	81,224	130,274	423,943	518,834
41	717,931	0.000%	0	-277,688	3,332,261	196,104	74,976	120,253	391,332	518,834
42	717,931	0.000%	0	-277,688	3,054,572	179,762	68,728	110,232	358,721	518,834
43	717,931	0.000%	0	-277,688	2,776,884	163,420	62,480	100,211	326,110	518,834
44	717,931	0.000%	0	-277,688	2,499,195	147,078	56,232	90,189	293,499	518,834
45	717,931	0.000%	0	-277,688	2,221,507	130,736	49,984	80,168	260,888	518,834
46	717,931	0.000%	0	-277,688	1,943,819	114,394	43,736	70,147	228,277	518,834
47	717,931	0.000%	0	-277,688	1,666,130	98,052	37,488	60,126	195,666	518,834
48	717,931	0.000%	0	-277,688	1,388,442	81,710	31,240	50,105	163,055	518,834
49	717,931	0.000%	0	-277,688	1,110,754	65,368	24,992	40,084	130,444	518,834
50	717,931	0.000%	0	-277,688	833,065	49,026	18,744	30,063	97,833	518,834
51	717,931	0.000%	0	-277,688	555,377	32,684	12,496	20,042	65,222	518,834
52	717,931	0.000%	0	-277,688	277,688	16,342	6,248	10,021	32,611	518,834
53	717,931	0.000%	0	-277,688	0	0	0	0	0	518,834

Input Data For Schedule 3

Ownership for Jointly Owned Plants

	Description		Source	Total		Braidwood 1 & 2	Byron 1 & 2	Dresden 2 & 3	LaSalle 1 & 2
1	Turbogenerator, GUS and Accessory Electric Investment:				TO and Gen count>	ComEd (2)	ComEd (2)	ComEd (2)	ComEd (2)
2	Included TurboGenerator Investment	2015 Actual Data	Account 314,323, 333, 343 or 344	3,410,284,358		276,982,389	326,545,555	507,917,628	322,991,066
3	Investment Generator & Exciter	2015 Actual Data	15%	511,542,654		41,547,358	48,981,833	76,187,644	48,448,660
4	Value of GSU Transformers	2015 Actual Data		280,542,456		49,633,067	21,644,926	$ 36,227,984	$ 4,672,421
5	Total Accessory Elec Equipment - Gross Investment	2015 Actual Data	Account 315, 324, 334, 345	1,327,863,081	From row 144, below>	$ 278,083,692	$ 316,973,581	$ 97,166,463	$ 141,513,673
6	Installed Cost of Power Plant (excluding Nuclear ARC; Steam ARC)	2015 Actual Data	2015 Actual Data	13,317,492,271		$ 1,484,090,250	$ 1,391,617,170	$ 1,359,267,568	$ 1,412,906,574
7	Investment Generator & Exciter / Turbogenerator					15.000%	15.000%	15.000%	15.000%
8	Investment Generation & Exciter / Installed Cost of Power Plant					3.344%	3.520%	5.605%	3.429%
9						Source for Nucs: Excel file "1A - Unit PP&E Balances Dec 31 2015 (Legacy EXC)"			
10	**Allocators**								
11									
12	**Real Power Demonstrated Capability (gross MW)**								
13	Generator 1				Source: "Reactive Test Results - Excel.xlxs"	1,258.00	1,248.00	948.00	1,194.00
14	Generator 2					1,220.00	1,205.00	944.00	1,183.00
15	Generator 3								
16	Generator 4								
17	Generator 5								
18	Generator 6								
19	Generator 7								
20	Generator 8								
21	Generator 9								
22	Generator 10								
23	Generator 11								
24									
25	Total					2,478.00	2,453.00	1,892.00	2,377.00
26									
27	**Nominal Power Factor (pf)**								
28	Generator 1				Source: "Reactive Test Results - Excel.xlxs"	0.92	0.93	0.93	0.93
29	Generator 2				Tested Capability or Name Plate	0.90	0.90	0.93	0.90
30	Generator 3								
31	Generator 4								
32	Generator 5								
33	Generator 6								
34	Generator 7								
35	Generator 8								
36	Generator 9								
37	Generator 10								
38	Generator 11								
39									
40									
41	**Nameplate MVAr**								
42	Generator 1	(Nameplates, sqrt(MVA^2-MW^2))				524.46	508.80	377.65	480.00
43	Generator 2	(Nameplates, sqrt(MVA^2-MW^2))				576.98	570.00	373.09	572.95
44	Generator 3	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
45	Generator 4	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
46	Generator 5	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
47	Generator 6	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
48	Generator 7	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
49	Generator 8	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
50	Generator 9	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
51	Generator 10	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
52	Generator 11	(Nameplates, sqrt(MVA^2-MW^2))				-	-	-	-
53									
54									
55	Total					1,101.44	1,078.80	750.74	1,052.95
56									
57	**Exciter MW**								
58	Generator 1	Exciter Rating				4.41	4.41	1.96	3.48
59	Generator 1	Exciter Rating				4.82	4.82	1.99	3.27
60	Generator 2	Exciter Rating							
61	Generator 3	Exciter Rating							
62	Generator 4	Exciter Rating							
63	Generator 5	Exciter Rating							
64	Generator 6	Exciter Rating							
65	Generator 7	Exciter Rating							
66	Generator 8	Exciter Rating							
67	Generator 9	Exciter Rating							
68	Generator 10	Exciter Rating							
69	Generator 11	Exciter Rating				9.23	9.23	3.95	6.74
70									

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Input Data For Schedule 3

Ownership for Jointly Owned Plants

	Description	Source	Total	Braidwood 1 & 2	Byron 1 & 2	Dresden 2 & 3	LaSalle 1 & 2
71	**Generator MW**						
72	Generator 1	(pf*MVA)		1,258.00	1,248.00	948.00	1,194.00
73	Generator 2	(pf*MVA)		1,220.00	1,205.00	944.00	1,183.00
74	Generator 3	(pf*MVA)		-	-	-	-
75	Generator 4	(pf*MVA)		-	-	-	-
76	Generator 5	(pf*MVA)		-	-	-	-
77	Generator 6	(pf*MVA)		-	-	-	-
78	Generator 7	(pf*MVA)		-	-	-	-
79	Generator 8	(pf*MVA)		-	-	-	-
80	Generator 9	(pf*MVA)		-	-	-	-
81	Generator 10	(pf*MVA)		-	-	-	-
82	Generator 11	(pf*MVA)		-	-	-	-
83	Total			2,478.00	2,453.00	1,892.00	2,377.00
84							
85	**Generator MVA**						
86	Generator 1	MW/pf if not stated	Source: "Reactive Test Results - Excel.xlxs"	1,362.95	1,347.73	1,020.45	1,286.87
87	Generator 2	MW/pf if not stated		1,349.56	1,333.01	1,015.05	1,314.44
88	Generator 3	MW/pf if not stated					
89	Generator 4	MW/pf if not stated					
90	Generator 5	MW/pf if not stated					
91	Generator 6	MW/pf if not stated					
92	Generator 7	MW/pf if not stated					
93	Generator 8	MW/pf if not stated					
94	Generator 9	MW/pf if not stated					
95	Generator 10	MW/pf if not stated					
96	Generator 11	MW/pf if not stated					
97							
98	Total			2,712.50	2,680.75	2,035.51	2,601.32

99	Peak Hour	18	18	16	8	18	8	19	17				
100	Peak Day	9/3/2015	9/3/2015	7/20/2015	2/20/2015	7/20/2015	2/20/2015	2/19/2015	7/20/2015	ComEd (2)	ComEd (2)	ComEd (2)	ComEd (2)
101		**Average**	**ComEd**	**PECO**	**BG&E**	**JCPL**	**MetEd**	**Penelec**	**PSEG**				
102	Max. MVAr	2,991	2,187	361	27	113	15	-	288				
103	Nameplate MVAr	9,831	4,856	2,853	571	287	340	183	742	1,101.4	1,078.8	750.7	1,053.0
104	Exciter MW	76	35	29	3	2	2	1	5	9.2	9.2	3.9	6.7
105	Generator MW	23,359	11,447	6,715	965	621	888	295	2,427	2,478	2,453	1,892	2,377
106		**0.0992%**	**0.1358%**	**0.0542%**	**0.0154%**	**0.1253%**	**0.0082%**	**0.0000%**	**0.0824%**				
107					**Account 315, 324, 334, 345**								
108	**Accessory Equip Allocator**									**Full 315 Account Costs**			
109	Item		**Nuclear**	**Cumb. Turbine**	**Hydro & Steam**					**nuclear**	**nuclear**	**nuclear**	**nuclear**
110	Storage Batteries		15%	50%	30%					$ 110,198	$ 155,427	$ 297,653	$ 291,718
111	Control&Power Cabling		1%	50%	15%					$ 1,753,039	$ 1,850,370	$ 49,469	$ 231,151
112	Switch Board Equipment		1%	50%	30%					$ 519,743	$ 654,748	$ -	$ 64,889
113	Switching Equipment		1%	40%	20%					$ 78,437	$ 148,283	$ 46,618	$ 65,726
114	Transformers		3%	10%	5%					$ 21,065	$ 38,012	$ 366,596	$ 60,804
115	Aux Generator		0%	0%	0%					$ -	$ -	$ -	$ -
116	Fire Protection System		0%	0%	0%					$ -	$ -	$ -	$ -
117	HVAC		0%	0%	0%					$ -	$ -	$ -	$ -
118	Regulating Equipment		50%	75%	75%					$ -	$ 24,034	$ 76,734	$ -
119	Structure		0%	0%	0%					$ -	$ -	$ -	$ -
120	Misc		0%	0%	0%					$ -	$ -	$ -	$ -
121	Exciter & PPT		100%	100%	100%					$ -	$ -	$ -	$ -
122	Station Grounding		1%	5%	0%					$ -	$ -	$ 49	$ -
123	Bus & Insulators		80%	80%	60%					$ -	$ -	$ 3,307,619	$ 4,472,625
124	Capacitor Bank		0%	0%	0%					$ -	$ -	$ -	$ -
125										$ 2,482,481	$ 2,870,875	$ 4,144,738	$ 5,186,913
126			EXE-4, Sch 5 Allocation factors development							1%	1%	4%	4%

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Input Data For Schedule 3

Ownership for Jointly Owned Plants

	Description	Source	Total		Braidwood 1 & 2	Byron 1 & 2	Dresden 2 & 3	LaSalle 1 & 2
127	**Item**				**315 Account Costs**			
128	Storage Batteries	Actual 2015			$ 734,651	$ 1,036,178	$ 1,984,353	$ 1,944,786
129	Control&Power Cabling	Actual 2015			$ 175,303,902	$ 185,037,012	$ 4,946,860	$ 23,115,092
130	Switch Board Equipment	Actual 2015			$ 51,974,311	$ 65,474,820	$ -	$ 6,488,908
131	Switching Equipment	Actual 2015			$ 7,843,655	$ 14,828,319	$ 4,661,842	$ 6,572,575
132	Transformers	Actual 2015			$ 702,163	$ 1,267,080	$ 12,219,855	$ 2,026,797
133	Aux Generator	Actual 2015			$ 21,664,522	$ 30,867,315	$ 5,052,411	$ 10,275,282
134	Fire Protection System	Actual 2015			$ -	$ -	$ -	$ -
135	HVAC	Actual 2015			$ -	$ -	$ -	$ -
136	Regulating Equipment	Actual 2015			$ -	$ 48,068	$ 153,468	$ -
137	Structure	Actual 2015			$ -	$ -	$ 31,844	$ 445,431
138	Misc	Actual 2015			$ 19,860,488	$ 18,414,787	$ 63,976,359	$ 85,054,019
139	Exciter & PPT	Actual 2015			$ -	$ -	$ -	$ -
140	Station Grounding	Actual 2015			$ -	$ -	$ 4,948	$ -
141	Bus & Insulators	Actual 2015			$ -	$ -	$ 4,134,523	$ 5,590,781
142	Capacitor Bank	Actual 2015			$ -	$ -	$ -	$ -
143								
144	Total	$ 1,327,863,081	<ties to "Accessory Electric" excluding "Comm. Cumbust"		$ 278,083,692	$ 316,973,581	$ 97,166,463	$ 141,513,673
145								
146	**O&M Calculation**							
147	Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546			$ 32,492,207	$ 34,368,626	$ 30,319,889	$ 30,478,210
148	Coolants and Water (Nuclear Plants Only)	FERC Account 519			$ 3,183,689	$ 3,367,547	$ 2,970,838	$ 2,986,351
149	Steam Expenses	FERC Account 502, 520			$ 19,969,572	$ 21,122,811	$ 18,634,475	$ 18,731,778
150	Steam From Other Sources	FERC Account 503			$ -	$ -	$ -	$ -
151	Electric Expenses	FERC Account 505, 523 - Allocated based on			$ -	$ -	$ -	$ -
152	Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524 - Reduced from actual			$ 2,040,158	$ 2,157,976	$ 1,903,760	$ 1,913,700
153	Rents	FERC Account 507			$ 56,408,634	$ 59,666,223	$ 52,637,346	$ 52,912,201
154	Allowances	FERC Account 509			$ 4,476,155	$ 4,734,652	$ 4,176,895	$ 4,198,705
155	Maintenance Supervision and Engineering	FERC Account 510, 528			$ -	$ -	$ -	$ -
156	Maintenance of Structures	FERC Account 511, 529, 552			$ 5,994,248	$ 6,340,415	$ 5,593,493	$ 5,622,700
157	Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530			$ 467,205	$ 494,186	$ 435,969	$ 438,245
158	Maintenance of Electric Plant	FERC Account 513, 531, 554			$ 15,446,317	$ 16,338,339	$ 14,413,629	$ 14,488,892
159	Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532			$ 9,921,805	$ 10,494,787	$ 9,258,467	$ 9,306,811
160	Other Power Production, & Other Expenses	FERC Account 548-553; 557			$ 18,561,772	$ 19,633,712	$ 17,320,796	$ 17,411,239
161	TOTAL	Grand Total O&M	$ 1,382,760,846		$ 168,961,761	$ 178,719,274	$ 157,665,557	$ 158,488,835
162					$ 1,316,464,415	<ties to O&M total on "Sum Nucs"		
163	**A&G and Overhead Expenses**							
164	Plant specific A&G		$ 958,874,640		$ 124,367,412	$ 119,205,155	$ 113,729,176	$ 118,779,529
165					$ 950,205,753	<<ties to total on "Sum nucs"		
166	Nuclear Overhead Expenses ("OH" tab)		$ 149,932,850	Allocated on "Nuc. Labor" tab	$ 12,675,803	$ 11,622,872	$ 11,821,786	$ 12,100,106
167	Non-nuclear Overhead Expenses ("OH" tab)		$ 15,042,652	Allocated on "Sum non-nucs" tab				
168	Total		$ 164,975,502		$ 137,043,216	$ 130,828,027	$ 125,550,961	$ 130,879,636
169								
170								
171								
172								
173								
174								
175								
176	**Depreciation Exp**				Source of Lives: EXE4, Sch 2,"Plant Service Lives.xlsx"			
177				Project Life (yrs)>>>	58.5	59.0	60.0	60.0
178	Production Plant in Service Depreciation Expense		$ 229,249,849		$ 25,369,064	$ 23,586,732	$ 22,654,459	$ 23,548,443
179				= line 14 / line 177				
180	**Other Taxes**	Total	Allocator					
181	Plant Related & Property Taxes (Nucs only)	$ 123,977,347	Directly Assigned		$ 20,026,176	$ 33,153,706	$ 25,219,637	$ 21,480,427
182	Payroll Taxes (Nucs Only)	$ 60,289,214	Directly Assigned		$ 7,269,439	$ 7,259,232	$ 7,076,336	$ 7,193,199
183	Other Taxes (Pay & Property) (Non-Nucs)	$ 9,124,663	Directly Assigned					
184	Total Other Taxes	$ 193,391,223			$ 27,295,615	$ 40,412,937	$ 32,295,973	$ 28,673,627
185								
186								
187								
188								
189								
190								
191								
192								
193								
194								

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Input Data For Schedule 3

Ownership for Jointly Owned Plants

	Description	Source		Total		Braidwood 1 & 2	Byron 1 & 2	Dresden 2 & 3	LaSalle 1 & 2
195									
196									
197	**Prepayments**	Nuclear	17,837,119	10,638,927,515	Allocated on gross plant (except Salem and Calvert)	$ 2,488,211	$ 2,333,171	$ 2,278,934	$ 2,368,865
198		Fossil	50,151,394	6,667,142,786	Allocated on gross plant for Fossil Fleet				
199	Total		67,988,512			$ 2,488,211	$ 2,333,171	$ 2,278,934	$ 2,368,865
200									
201	**M&S**					Source: 2 - Unit Fuel Inventory (Nuc only)			
202	M&S - Fuel		$ 2,060,965,166	Directly Assigned	(use DR 2 and DR 3)	223,530,653	195,107,342	274,522,795	361,375,368
203	M&S - Fuel (undistributed)					-	-	-	-
204	M&S - Fossil Production		18,179,451	Allocated on "Sum non-nucs" tab					
205	M&S - Nuclear Production		$ 549,110,881	DA -- M&S for Nucs only		77,172,779	64,606,819	57,130,136	78,463,468
206	**TOTAL M&S**		$ 2,628,255,498			$ 300,703,432	$ 259,714,161	$ 331,652,931	$ 439,838,836
207									
208									
209	**RETURN (R)**								
210									

		$/mil	%	Cost	Weighted	
211						
212						
213	Long Term Debt	0.45	45.0%	5.00%	0.0225	=WCLTD <<Per ACH 9-29-16 (See below)
214	Proprietary Capital	0.55	55.0%	10.70%	0.0589	
215	Total (sum lines 22-23)	1.00	100%		0.0814	=R
216						
217						
218	**Income Taxes**					
219	State Marginal Rate (multi-state)	5.6600% <<Per ACH 9-29-16				
220						

		2016	2017 - 2020
221			
222	Jurisdiction1		
223			
224	Federal	35.00%	35.00%
	FIT on SIT	-1.65%	-1.98%
	Illinois2	0.72%	0.90%
	IL on SIT	-0.03%	-0.04%
	Pennsylvania2	1.10%	1.40%
	Maryland	0.54%	0.50%
	Other Separate	1.07%	1.30%
	NYS	0.00%	0.00%
	Other Unitary	1.31%	1.60%
	Marginal Tax Rate	38.06%	38.68%
	Effective State Rate	4.71%	5.66%

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Input Data For Schedule 3

	Description		Source		Limerick 1 & 2	Oyster Creek	Peach Bottom 2 & 3	Quad Cities 1 & 2	Salem 1 & 2	TMI	Chester 7-9	Conowingo 1 - 11	Croydon 11,12,21,22,31, 32,41,42
							50%	75%	42.59%				
1	Turbogenerator, GUS and Accessory Electric Investment:				PECO (2)	JCPL (1)	PECO (2)	ComEd (2)	PSEG (2)	MetEd (1)	PECO (3)	PECO (11)	PECO (8)
2	Included TurboGenerator Investment	2015 Actual Data	Account 314,323, 333, 34		195,863,167	30,406,806	324,475,609	345,327,838	80,714,327	13,661,046	4,695,512	143,524,274	72,348,001
3	Investment Generator & Exciter	2015 Actual Data	15%		29,379,475	4,561,021	48,671,341	51,799,176	12,107,149	2,049,157	704,327	21,528,641	10,852,200
4	Value of GSU Transformers	2015 Actual Data		$	41,192,118	$ 19,820,373	$ 41,363,873	$ 25,326,658	$ 14,618,814	$ -	$ -	$ 6,792,649	$ 1,420,756
5	Total Accessory Elec Equipment - Gross Investment	2015 Actual Data	Account 315, 324, 334, 34	$	109,655,219	$ 9,228,418	$ 64,240,533	$ 66,184,772	$ 38,713,489	$ 13,867,813	$ 1,724,631	$ 29,726,815	$ 9,038,464
6	Installed Cost of Power Plant (excluding Nuclear ARC; Steam ARC)	2015 Actual Data	2015 Actual Data	$	1,222,406,959	$ 360,225,425	$ 1,360,681,860	$ 1,046,110,329	$ 583,671,743	$ 1,001,621,380	$ 9,133,168	$ 380,084,794	$ 107,412,068
7	Investment Generator & Exciter / Turbogenerator				15.000%	15.000%	15.000%	15.000%	15.000%	15.000%	15.000%	15.000%	15.000%
8	Investment Generation & Exciter / Installed Cost of Power Plant				2.403%	1.266%	3.577%	4.952%	2.074%	0.205%	7.712%	5.664%	10.103%
9													
10	**Allocators**										$ 2,094,893,014		
11													
12	**Real Power Demonstrated Capability (gross MW)**												
13	Generator 1				1,182.00	621.20	1,150.00	961.00	1,236.80	888.00	15.14	40.20	51.00
14	Generator 2				1,143.00	-	1,195.40	980.00	1,190.00	-	15.16	48.00	56.60
15	Generator 3										14.48	42.20	68.30
16	Generator 4											48.00	68.30
17	Generator 5											37.10	68.30
18	Generator 6											44.60	68.30
19	Generator 7											44.10	68.30
20	Generator 8											110.90	68.30
21	Generator 9											108.40	
22	Generator 10											114.50	
23	Generator 11											112.20	
24												-	
25	Total				2,325.00	621.20	2,345.40	1,941.00	2,426.80	888.00	44.78	750.20	517.40
26													
27	**Nominal Power Factor (pf)**												
28	Generator 1				0.93	0.91	0.93	0.95	0.96	0.93	0.81	0.88	0.91
29	Generator 2				0.94	-	0.90	0.94	0.95		0.81	0.90	0.93
30	Generator 3										0.80	0.89	0.90
31	Generator 4											0.90	0.90
32	Generator 5											0.95	0.90
33	Generator 6											0.88	0.90
34	Generator 7											0.88	0.90
35	Generator 8											1.00	0.90
36	Generator 9											0.99	-
37	Generator 10											0.9880	
38	Generator 11											0.9930	
39													
40													
41	**Nameplate MVAr**												
42	Generator 1	(Nameplates, sqrt(MVA^2-MW^2))			451.95	286.63	206.70	332.61	351.05	339.68	12.77	19.29	31.13
43	Generator 2	(Nameplates, sqrt(MVA^2-MW^2))			424.55	-	237.12	349.15	391.13	-	12.83	17.44	28.65
44	Generator 3	(Nameplates, sqrt(MVA^2-MW^2))			-	-	-	-	-	-	13.27	18.39	33.08
45	Generator 4	(Nameplates, sqrt(MVA^2-MW^2))			-	-	-	-	-	-	-	17.44	33.08
46	Generator 5	(Nameplates, sqrt(MVA^2-MW^2))			-	-	-	-	-	-	-	12.49	33.08
47	Generator 6	(Nameplates, sqrt(MVA^2-MW^2))			-	-	-	-	-	-	-	19.00	33.08
48	Generator 7	(Nameplates, sqrt(MVA^2-MW^2))			-	-	-	-	-	-	-	19.00	33.08
49	Generator 8	(Nameplates, sqrt(MVA^2-MW^2))			-	-	-	-	-	-	-	6.17	33.08
50	Generator 9	(Nameplates, sqrt(MVA^2-MW^2))			-	-	-	-	-	-	-	7.80	-
51	Generator 10	(Nameplates, sqrt(MVA^2-MW^2))			-	-	-	-	-	-	-	9.55	-
52	Generator 11	(Nameplates, sqrt(MVA^2-MW^2))			-	-	-	-	-	-	-	7.30	-
53													
54													
55	Total				876.50	286.63	443.83	681.76	742.18	339.68	38.87	153.86	258.25
56													
57	**Exciter MW**												
58	Generator 1	Exciter Rating			3.81	1.98	2.97	2.28	6.00	1.61	0.09	0.28	0.12
59	Generator 1	Exciter Rating			3.81		4.43	2.28	6.00		0.09	0.28	0.12
60	Generator 2	Exciter Rating									0.09	0.28	0.12
61	Generator 3	Exciter Rating										0.28	0.12
62	Generator 4	Exciter Rating										0.28	0.12
63	Generator 5	Exciter Rating										0.28	0.12
64	Generator 6	Exciter Rating										0.28	0.12
65	Generator 7	Exciter Rating										0.28	0.12
66	Generator 8	Exciter Rating										0.36	
67	Generator 9	Exciter Rating										0.36	
68	Generator 10	Exciter Rating										0.36	
69	Generator 11	Exciter Rating			7.61	1.98	7.40	4.56	12.00	1.61	0.26	3.29	0.98
70													

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Input Data For Schedule 3

							50%	75%	42.59%			
	Description		**Source**	Limerick 1 & 2	Oyster Creek	Peach Bottom 2 & 3	Quad Cities 1 & 2	Salem 1 & 2	TMI	Chester 7-9	Conowingo 1 - 11	Croydon 11,12,21,22,31, 32,41,42
71	**Generator MW**							What is it?				
72	Generator 1	(pf*MVA)		1,181.51	621.20	503.20	961.00	1,236.80	888.00	17.76	35.04	69.21
73	Generator 2	(pf*MVA)		1,191.63	-	489.60	980.00	1,190.00	-	17.72	36.00	70.27
74	Generator 3	(pf*MVA)		-	-	-	-	-	-	17.39	35.52	68.30
75	Generator 4	(pf*MVA)		-	-	-	-	-	-	-	36.00	68.30
76	Generator 5	(pf*MVA)		-	-	-	-	-	-	-	38.00	68.30
77	Generator 6	(pf*MVA)		-	-	-	-	-	-	-	35.20	68.30
78	Generator 7	(pf*MVA)		-	-	-	-	-	-	-	35.20	68.30
79	Generator 8	(pf*MVA)		-	-	-	-	-	-	-	61.49	68.30
80	Generator 9	(pf*MVA)		-	-	-	-	-	-	-	61.31	-
81	Generator 10	(pf*MVA)		-	-	-	-	-	-	-	61.06	-
82	Generator 11	(pf*MVA)		-	-	-	-	-	-	-	61.37	-
83	Total			2,373.14	621.20	992.80	1,941.00	2,426.80	888.00	52.87	496.18	549.28
84												
85	**Generator MVA**											
86	Generator 1	MW/pf if not stated		1,265.00	684.14	544.00	1,016.93	1,285.65	950.75	21.88	40.00	75.89
87	Generator 2	MW/pf if not stated		1,265.00		544.00	1,040.34	1,252.63		21.88	40.00	75.89
88	Generator 3	MW/pf if not stated								21.88	40.00	75.89
89	Generator 4	MW/pf if not stated									40.00	75.89
90	Generator 5	MW/pf if not stated									40.00	75.89
91	Generator 6	MW/pf if not stated									40.00	75.89
92	Generator 7	MW/pf if not stated									40.00	75.89
93	Generator 8	MW/pf if not stated									61.80	75.89
94	Generator 9	MW/pf if not stated									61.80	
95	Generator 10	MW/pf if not stated									61.80	
96	Generator 11	MW/pf if not stated									61.80	
97												
98	Total			2,530.00	684.14	1,088.00	2,057.27	2,538.29	950.75	65.63	527.20	607.11

99	Peak Hour	18	18	16						2		
100	Peak Day	9/3/2015	9/3/2015	7/20/2015	PECO (2)	JCPL (1)	PECO (2)	ComEd (2)	PSEG (2)	MetEd (1)	PECO (3)	PECO (11)	PECO (8)
101		**Average**	**ComEd**	**PECO**						Page 2			
102	Max. MVAr	2,991	2,187	361									
103	Nameplate MVAr	9,831	4,856	2,853	876.5	286.6	443.8	681.8	742.2	339.7	38.9	153.9	258.3
104	Exciter MW	76	35	29	7.6	2.0	7.4	4.6	12.0	1.6	0.3	3.3	1.0
105	Generator MW	23,359	11,447	6,715	2,373	621	993	1,941	2,427	888	53	496	549
106		**0.0992%**	**0.1358%**	**0.0542%**									
107													

108	**Accessory Equip Allocator**																			
109	Item	**Nuclear**	**Cumb. Turbine**		**nuclear**		**nuclear**		**nuclear**		**nuclear**		**nuclear**		**nuclear**		**comb. Tur.**		**Hydro**		**comb. Tur.**
110	Storage Batteries	15%	50%	$	212,130	$	-	$	302,373	$	320,057	$	-	$	-	$	6,131	$	40,819	$	32,360
111	Control&Power Cabling	1%	50%	$	233,199	$	-	$	196,960	$	74,036	$	4,591	$	-	$	180,320	$	476,914	$	1,289,225
112	Switch Board Equipment	1%	50%	$	11,886	$	-	$	115,075	$	28,981	$	-	$	-	$	-	$	592,048	$	119,706
113	Switching Equipment	1%	40%	$	2,286	$	-	$	6,257	$	38,727	$	-	$	-	$	316,411	$	403,519	$	298,323
114	Transformers	3%	10%	$	31,505	$	16,976	$	55,882	$	247,884	$	-	$	54,133	$	-	$	315,946	$	24,774
115	Aux Generator	0%	0%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-
116	Fire Protection System	0%	0%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-
117	HVAC	0%	0%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-
118	Regulating Equipment	50%	75%	$	-	$	-	$	397	$	-	$	-	$	743,320	$	-	$	293,044	$	-
119	Structure	0%	0%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-
120	Misc	0%	0%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-
121	Exciter & PPT	100%	100%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	126,475	$	-
122	Station Grounding	1%	5%	$	-	$	-	$	207	$	21	$	-	$	-	$	-	$	-	$	-
123	Bus & Insulators	80%	80%	$	-	$	-	$	(40,559)	$	1,955,887	$	-	$	-	$	-	$	-	$	60,107
124	Capacitor Bank	0%	0%	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-	$	-
125				$	491,006	$	16,976	$	636,592	$	2,665,593	$	4,591	$	797,453	$	502,862	$	2,248,765	$	1,824,495
126			EXE-4, Sch 5 Allocation factors develop		0%		0%		1%		4%		0%		6%		29%		8%		20%

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Input Data For Schedule 3

	Description	Source		Limerick 1 & 2	Oyster Creek	Peach Bottom 2 & 3	Quad Cities 1 & 2	Salem 1 & 2	TMI	Chester 7-9	Conowingo 1 - 11	Croydon 11,12,21,22,31, 32,41,42
						50%	75%	42.59%				
127	**Item**											
128	Storage Batteries	Actual 2015	$ 1,414,202	$ -	$ 2,015,820	$ 2,133,713	$ -	$ -	$ 12,262	$ 136,064	$ 64,719
129	Control&Power Cabling	Actual 2015	$ 23,319,901	$ -	$ 19,695,956	$ 7,403,630	$ 459,119	$ -	$ 360,640	$ 3,179,427	$ 2,578,451
130	Switch Board Equipment	Actual 2015	$ 1,188,580	$ -	$ 11,507,453	$ 2,898,057	$ -	$ -	$ -	$ 1,973,492	$ 239,413
131	Switching Equipment	Actual 2015	$ 228,627	$ -	$ 625,734	$ 3,872,699	$ -	$ -	$ 791,028	$ 2,017,595	$ 745,807
132	Transformers	Actual 2015	$ 1,050,152	$ 565,862	$ 1,862,746	$ 8,262,803	$ -	$ 1,804,433	$ -	$ 6,318,929	$ 247,743
133	Aux Generator	Actual 2015	$ 5,506,158	$ -	$ 129,640	$ 3,321,149	$ -	$ -	$ -	$ 101,173	$ -
134	Fire Protection System	Actual 2015	$ -	$ -	$ 126,725	$ -	$ 22,085,749	$ 194,043	$ -	$ -	$ -
135	HVAC	Actual 2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
136	Regulating Equipment	Actual 2015	$ -	$ -	$ 794	$ -	$ -	$ 1,486,640	$ -	$ 390,726	$ -
137	Structure	Actual 2015	$ 301,814	$ -	$ 25,625	$ 133,041	$ -	$ -	$ -	$ 270,434	$ 56,420
138	Misc	Actual 2015	$ 76,645,785	$ 8,662,556	$ 28,280,047	$ 35,712,768	$ 16,168,621	$ 10,382,696	$ 560,700	$ 15,212,502	$ 5,030,779
139	Exciter & PPT	Actual 2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 126,475	$ -
140	Station Grounding	Actual 2015	$ -	$ -	$ 20,693	$ 2,051	$ -	$ -	$ -	$ -	$ -
141	Bus & Insulators	Actual 2015	$ -	$ -	$ (50,699)	$ 2,444,859	$ -	$ -	$ -	$ -	$ 75,133
142	Capacitor Bank	Actual 2015	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
143											
144	Total	$ 1,327,863,081 <ties to "Accessory Electr	$ 109,655,219	$ 9,228,418	$ 64,240,533	$ 66,184,772	$ 38,713,489	$ 13,867,813	$ 1,724,631	$ 29,726,815	$ 9,038,464
145											
146	**O&M Calculation**									Hydro Distribution	
147	Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546	$ 28,060,813	$ 20,056,606	$ 15,945,051	$ 21,788,348	$ 17,325,181	$ 22,327,877	$ 38,422	$ 1,036,292	$ 569,237
148	Coolants and Water (Nuclear Plants Only)	FERC Account 519	$ 2,749,487	$ 1,965,210	$ 1,562,346	$ 2,134,891	$ 1,697,576	$ 2,187,756	$ -	$ -	$ -
149	Steam Expenses	FERC Account 502, 520	$ 17,246,057	$ 12,326,705	$ 9,799,760	$ 13,391,026	$ 10,647,982	$ 13,722,618	$ 9,925	$ 855,810	$ 147,038
150	Steam From Other Sources	FERC Account 503	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,178	$ 5,098,303	$ 284,134
151	Electric Expenses	FERC Account 505, 523 - Allocated based on	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,685,208	$ -
152	Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524 - Reduced from actual	$ 1,761,914	$ 1,259,337	$ 1,001,176	$ 1,368,072	$ 1,087,833	$ 1,401,948	$ 5,876	$ 1,684,113	$ 87,051
153	Rents	FERC Account 507	$ 48,715,440	$ 34,819,603	$ 27,681,670	$ 37,826,023	$ 30,077,667	$ 38,762,682	$ 35,759	$ 243,307	$ 529,786
154	Allowances	FERC Account 509	$ 3,865,683	$ 2,763,016	$ 2,196,604	$ 3,001,582	$ 2,386,732	$ 3,075,908	$ 1,445	$ -	$ 21,408
155	Maintenance Supervision and Engineering	FERC Account 510, 528	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 575,100	$ -
156	Maintenance of Structures	FERC Account 511, 529, 552	$ 5,176,733	$ 3,700,095	$ 2,941,585	$ 4,019,572	$ 3,196,195	$ 4,119,106	$ 14,987	$ 691,360	$ 222,036
157	Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530	$ 403,486	$ 288,393	$ 229,273	$ 313,294	$ 249,118	$ 321,052	$ 6,427	$ 2,545,004	$ 95,213
158	Maintenance of Electric Plant	FERC Account 513, 531, 554	$ 13,339,698	$ 9,534,615	$ 7,580,042	$ 10,357,860	$ 8,236,136	$ 10,614,344	$ 6,686	$ 1,823,125	$ 99,056
159	Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532	$ 8,568,637	$ 6,124,475	$ 4,868,973	$ 6,653,280	$ 5,290,409	$ 6,818,030	$ 8,322	$ 514,507	$ 123,289
160	Other Power Production, & Other Expenses	FERC Account 548-553; 557	$ 16,030,257	$ 11,457,706	$ 9,108,904	$ 12,446,996	$ 9,897,329	$ 12,755,212	$ 25,242	$ -	$ 373,967
161	TOTAL	Grand Total O&M	$ 145,918,204	$ 104,295,761	$ 82,915,386	$ 113,300,945	$ 90,092,158	$ 116,106,533	$ 172,268	$ 16,752,129	$ 2,552,217
162									$ 66,296,431		
163	**A&G and Overhead Expenses**										
164	Plant specific A&G		$ 116,605,447	$ 75,639,559	$ 54,201,596	$ 82,058,738	$ 64,855,997	$ 80,763,143	$ 8,214	$ 2,067,560	$ 127,260
165									$ 8,668,887		
166	Nuclear Overhead Expenses ("OH" tab)		$ 12,454,484	$ 8,112,211	$ 5,943,375	$ 8,600,657	$ 7,279,573	$ 9,607,667			
167	Non-nuclear Overhead Expenses ("OH" tab)								$ 19,827	$ 1,839,251	$ 279,232
168	Total		$ 129,059,930	$ 83,751,770	$ 60,144,971	$ 90,659,395	$ 72,135,570	$ 90,370,810	$ 28,041	$ 3,906,810	$ 406,492
169											
170											
171											
172											
173											
174											
175								Schedule 6			
176	**Depreciation Exp**							Page 3			
177				58.5	50.0	59.5	60.0	59.0	60.0	64	116	59
178	Production Plant in Service Depreciation Expense		$ 20,895,845	$ 7,204,508	$ 22,868,603	$ 17,435,172	$ 9,892,741	$ 16,693,690	$ 142,706	$ 3,276,593	$ 1,820,544
179									$ 39,100,591		$ 0
180	**Other Taxes**	Total							0.01866472	53.57701706	
181	Plant Related & Property Taxes (Nucs only)	$ 123,977,347	$ 3,969,570	$ 3,465,238	$ 862,588	$ 6,042,855	$ 8,570,246	$ 1,186,903			
182	Payroll Taxes (Nucs Only)	$ 60,289,214	$ 7,359,580	$ 5,403,699	$ 3,565,892	$ 5,304,440	$ 4,081,461	$ 5,775,935			
183	Other Taxes (Pay & Property) (Non-Nucs)	$ 9,124,663							$ 5,780	$ -	$ 87,293
184	Total Other Taxes	$ 193,391,223	$ 11,329,150	$ 8,868,938	$ 4,428,481	$ 11,347,295	$ 12,651,707	$ 6,962,839	$ 5,780	$ -	$ 87,293
185											
186											
187											
188											
189											
190											
191											
192											
193											
194											

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Input Data For Schedule 3

	Description	Source	Limerick 1 & 2	Oyster Creek	Peach Bottom 2 & 3 (50%)	Quad Cities 1 & 2 (75%)	Salem 1 & 2 (42.59%)	TMI	Chester 7-9	Conowingo 1 - 11	Croydon 11,12,21,22,31, 32,41,42
195											
196											
197	**Prepayments**	Nuclear	$ 2,049,475	$ 603,950	$ 2,281,305	$ 1,753,898		$ 1,679,308			
198		Fossil							$ 68,701	$ 2,859,063	$ 807,972
199	Total		$ 2,049,475	$ 603,950	$ 2,281,305	$ 1,753,898	$ -	$ 1,679,308	$ 68,701	$ 2,859,063	$ 807,972
200											
201	**M&S**								Source: Fuels Inventory 2015 (see Dec 2015 tab) -- column M		
202	M&S - Fuel		240,511,541	84,615,318	169,273,105	218,443,011	112,762,574	126,670,672			20,360,296
203	M&S - Fuel (undistributed)		-	-	-	-	-	-	-	-	-
204	M&S - Fossil Production								23,962	2,222,784	337,460
205	M&S - Nuclear Production		78,065,668	25,431,344	35,906,250	50,160,902	45,352,188	36,821,326			
206	**TOTAL M&S**		$ 318,577,209	$ 110,046,662	$ 205,179,355	$ 268,603,913	$ 158,114,762	$ 163,491,998	$ 23,962	$ 2,222,784	$ 20,697,756
207											
208											
209	**RETURN (R)**										
210											
211											

		$/mil	%
212			
213	Long Term Debt	0.45	45.0%
214	Proprietary Capital	0.55	55.0%
215	Total (sum lines 22-23)	1.00	100%
216			
217			
218	**Income Taxes**		
219	State Marginal Rate (multi-state)	5.6600% <<Per ACH 9-29-16	
220			
221			
222		Jurisdiction1	
223			
224		Federal	
		FIT on SIT	
		Illinois2	
		IL on SIT	
		Pennsylvania2	
		Maryland	
		Other Separate	
		NYS	
		Other Unitary	
		Marginal Tax Rate	
		Effective State Rate	

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Input Data For Schedule 3

	Description		Source	Delaware 9-12	Eddystone 3,4,10,20,30,40	Fairless Hills A&B	Falls 1-3	Gould Street 3	Handsome Lake	Moser 1-3	Muddy Run 1-8
1	Turbogenerator, GUS and Accessory Electric Investment:			PECO (4)	PECO (6)	PECO (2)	PECO (3)	BGE (1)	PENELEC (5)	PECO (3)	PECO (8)
2	Included TurboGenerator Investment	2015 Actual Data	Account 314,323, 333, 34	6,730,407	62,382,060	20,090,347	5,518,050	4,694,859	42,347,182	5,376,210	105,729,817
3	Investment Generator & Exciter	2015 Actual Data	15%	1,009,561	9,357,309	3,013,552	827,708	704,229	6,352,077	806,431	15,859,473
4	Value of GSU Transformers	2015 Actual Data		$ -	$ 6,411,560	$ 51,347	$ -	$ 3,114	$ -	$ -	$ 4,657,845
5	Total Accessory Elec Equipment - Gross Investment	2015 Actual Data	Account 315, 324, 334, 34	$ 1,910,796	$ 30,090,084	$ 171,673	$ 1,126,870	$ 364,598	$ -	$ 1,365,306	$ 43,782,362
6	Installed Cost of Power Plant (excluding Nuclear ARC; Steam ARC)	2015 Actual Data	2015 Actual Data	$ 13,528,361	$ 400,131,998	61,729,219	7,829,474	$ 18,406,803	$ 85,825,302	$ 8,301,032	$ 261,421,690
7	Investment Generator & Exciter / Turbogenerator			15.000%	15.000%	15.000%		15.000%	15.000%	15.000%	15.000%
8	Investment Generation & Exciter / Installed Cost of Power Plant			7.463%	2.339%	4.882%		3.826%	7.401%	9.715%	6.067%
9											
10	**Allocators**										
11											
12	**Real Power Demonstrated Capability (gross MW)**										
13	Generator 1			16.90	400.00	30.00	18.46	102.70	59.00	16.00	122.10
14	Generator 2			13.40	400.00	30.00	18.08		59.00	16.38	123.70
15	Generator 3			13.70	14.20		18.26		59.00	16.50	124.00
16	Generator 4			13.40	13.60				59.00		125.00
17	Generator 5				18.00				59.00		122.00
18	Generator 6				18.00						117.00
19	Generator 7										126.00
20	Generator 8										126.00
21	Generator 9										
22	Generator 10										
23	Generator 11										
24											
25	Total			57.40	863.80	60.00	54.80	102.70	295.00	48.88	985.80
26											
27	**Nominal Power Factor (pf)**										
28	Generator 1			0.84	0.92	0.85	0.86	0.90	0.85	0.82	0.91
29	Generator 2			0.77	0.94	0.85	0.85		0.85	0.82	0.90
30	Generator 3			0.78	0.79		0.85		0.85	0.83	0.93
31	Generator 4			0.78	0.78				0.85		0.92
32	Generator 5				0.85				0.85		0.90
33	Generator 6				0.85						0.91
34	Generator 7										0.91
35	Generator 8										0.93
36	Generator 9										
37	Generator 10										
38	Generator 11										
39											
40											
41	**Nameplate MVAr**										
42	Generator 1	(Nameplates, sqrt(MVA^2-MW^2))		11.94	185.59	18.59	12.97	49.16	36.56	14.24	45.28
43	Generator 2	(Nameplates, sqrt(MVA^2-MW^2))		13.88	161.92	18.59	13.13	-	36.56	14.27	47.92
44	Generator 3	(Nameplates, sqrt(MVA^2-MW^2))		13.77	13.47	-	13.01	-	36.56	13.94	42.18
45	Generator 4	(Nameplates, sqrt(MVA^2-MW^2))		13.77	13.83	-	-	-	36.56	-	43.24
46	Generator 5	(Nameplates, sqrt(MVA^2-MW^2))		-	13.21	-	-	-	36.56	-	48.38
47	Generator 6	(Nameplates, sqrt(MVA^2-MW^2))		-	13.21	-	-	-	-	-	45.03
48	Generator 7	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	45.03
49	Generator 8	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	41.63
50	Generator 9	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	-
51	Generator 10	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	-
52	Generator 11	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-	-	-	-	-	-
53											
54											
55	Total			53.37	401.23	37.18	39.10	49.16	182.82	42.45	358.71
56				per ACH 10-10 email							
57	**Exciter MW**			same as Chester	same as Chester						
58	Generator 1	Exciter Rating		0.09	0.09	0.10	0.09	0.30	0.21	0.09	0.53
59	Generator 1	Exciter Rating		0.09	0.09	0.13	0.09		0.21	0.09	0.53
60	Generator 2	Exciter Rating		0.09	0.09		0.09		0.21	0.09	0.53
61	Generator 3	Exciter Rating		0.09	0.09				0.21		0.53
62	Generator 4	Exciter Rating			1.70				0.21		0.53
63	Generator 5	Exciter Rating			1.70						0.53
64	Generator 6	Exciter Rating									0.53
65	Generator 7	Exciter Rating									
66	Generator 8	Exciter Rating									
67	Generator 9	Exciter Rating									
68	Generator 10	Exciter Rating									
69	Generator 11	Exciter Rating		0.34	3.74	0.23	0.26	0.30	1.03	0.26	3.68
70											

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	Description		Source	Delaware 9-12	Eddystone 3,4,10,20,30,40	Fairless Hills A&B	Falls 1-3	Gould Street 3	Handsome Lake	Moser 1-3	Muddy Run 1-8
71	**Generator MW**										
72	Generator 1	(pf*MVA)		18.34	420.90	30.00	21.38	102.70	59.00	20.55	101.34
73	Generator 2	(pf*MVA)		16.91	430.56	30.00	21.28	-	59.00	20.53	100.12
74	Generator 3	(pf*MVA)		17.00	17.24	-	21.35	-	59.00	20.75	102.68
75	Generator 4	(pf*MVA)		17.00	16.96	-	-	-	59.00	-	102.23
76	Generator 5	(pf*MVA)		-	21.23	-	-	-	59.00	-	99.90
77	Generator 6	(pf*MVA)		-	21.23	-	-	-	-	-	101.45
78	Generator 7	(pf*MVA)		-	-	-	-	-	-	-	101.45
79	Generator 8	(pf*MVA)		-	-	-	-	-	-	-	102.90
80	Generator 9	(pf*MVA)		-	-	-	-	-	-	-	-
81	Generator 10	(pf*MVA)		-	-	-	-	-	-	-	-
82	Generator 11	(pf*MVA)		-	-	-	-	-	-	-	-
83	Total			69.25	928.11	60.00	64.00	102.70	295.00	61.83	812.08
84											
85	**Generator MVA**										
86	Generator 1	MW/pf if not stated		21.88	460.00	35.29	25.00	113.86	69.41	25.00	111.00
87	Generator 2	MW/pf if not stated		21.88	460.00	35.29	25.00		69.41	25.00	111.00
88	Generator 3	MW/pf if not stated		21.88	21.88		25.00		69.41	25.00	111.00
89	Generator 4	MW/pf if not stated		21.88	21.88				69.41		111.00
90	Generator 5	MW/pf if not stated			25.00				69.41		111.00
91	Generator 6	MW/pf if not stated			25.00						111.00
92	Generator 7	MW/pf if not stated									111.00
93	Generator 8	MW/pf if not stated									111.00
94	Generator 9	MW/pf if not stated									
95	Generator 10	MW/pf if not stated									
96	Generator 11	MW/pf if not stated									
97											
98	Total			87.52	1,013.76	70.59	75.00	113.86	347.06	75.00	888.00

99	Peak Hour	18	18	16							
100	Peak Day	9/3/2015	9/3/2015	7/20/2015	PECO (4)	PECO (6)	PECO (2)	PECO (3)	BGE (1)	PENELEC (5)	PECO (3)	PECO (8)
101		**Average**	**ComEd**	**PECO**								
102	Max. MVAr	2,991	2,187	361								
103	Nameplate MVAr	9,831	4,856	2,853	53.4	401.2	37.2	39.1	49.2	182.8	42.5	358.7
104	Exciter MW	76	35	29	0.3	3.7	0.2	0.3	0.3	1.0	0.3	3.7
105	Generator MW	23,359	11,447	6,715	69	928	60	64	103	295	62	812
106		**0.0992%**	**0.1358%**	**0.0542%**								

107											
108	**Accessory Equip Allocator**										
109	Item	**Nuclear**	**Cumb. Turbine**	**comb. Tur.**	**steam**	**steam**	**comb. Tur.**	**steam**	**comb. Tur**	**comb. Tur.**	**hydro**
110	Storage Batteries	15%	50%	$ 14,370	$ 105,438.80	$ 8,394	$ 16,896	$ 176,829	$ -	$ 4,683	$ 38,770
111	Control&Power Cabling	1%	50%	$ 172,306	$ 2,996,747.75	$ 115	$ 71,002	$ 5,470	$ -	$ 131,401	$ 739,494
112	Switch Board Equipment	1%	50%	$ 9,937	$ 145,469.23	$ -	$ -	$ -	$ -	$ -	$ 500,860
113	Switching Equipment	1%	40%	$ 458,834	$ 408,375.42	$ -	$ 224,868	$ -	$ -	$ 235,629	$ 1,226,111
114	Transformers	3%	10%	$ -	$ -	$ -	$ 51	$ -	$ -	$ -	$ 29,461
115	Aux Generator	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
116	Fire Protection System	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
117	HVAC	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
118	Regulating Equipment	50%	75%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 379,306
119	Structure	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
120	Misc	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
121	Exciter & PPT	100%	100%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
122	Station Grounding	1%	5%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
123	Bus & Insulators	80%	80%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
124	Capacitor Bank	0%	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
125				$ 655,447	$ 3,656,031	$ 8,508	$ 312,817	$ 182,299	$ -	$ 371,713	$ 2,914,002
126		EXE-4, Sch 5 Allocation factors develop		34%	12%	5%	28%	50%	#DIV/0!	27%	7%

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	Description	Source		Delaware 9-12	Eddystone 3,4,10,20,30,40	Fairless Hills A&B	Falls 1-3	Gould Street 3	Handsome Lake	Moser 1-3	Muddy Run 1-8
127	**Item**							Nothing in the detailed accounting			
128	Storage Batteries	Actual 2015		$ 28,741	$ 351,463	$ 16,787	$ 33,793	$ 353,658	$ -	$ 9,365	$ 129,233
129	Control&Power Cabling	Actual 2015		$ 344,611	$ 19,978,318	$ 230	$ 142,003	$ 10,940	$ -	$ 262,801	$ 4,929,960
130	Switch Board Equipment	Actual 2015		$ 19,874	$ 484,897	$ -	$ -	$ -	$ -	$ -	$ 1,669,534
131	Switching Equipment	Actual 2015		$ 1,147,085	$ 2,041,877	$ -	$ 562,170	$ -	$ -	$ 589,074	$ 6,130,553
132	Transformers	Actual 2015		$ -	$ -	$ -	$ 512	$ -	$ -	$ -	$ 589,215
133	Aux Generator	Actual 2015		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 120,583
134	Fire Protection System	Actual 2015		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
135	HVAC	Actual 2015		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
136	Regulating Equipment	Actual 2015		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 505,742
137	Structure	Actual 2015		$ -	$ 167,065	$ -	$ 8,093	$ -	$ -	$ 13,093	$ -
138	Misc	Actual 2015		$ 370,485	$ 7,066,463	$ 154,657	$ 380,300	$ -	$ -	$ 490,974	$ 29,526,543
139	Exciter & PPT	Actual 2015		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
140	Station Grounding	Actual 2015		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 181,000
141	Bus & Insulators	Actual 2015		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
142	Capacitor Bank	Actual 2015		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
143											
144	Total	$ 1,327,863,081	<ties to "Accessory Electr	$ 1,910,796	$ 30,090,084	$ 171,673	$ 1,126,870	$ 364,598	$ -	$ 1,365,306	$ 43,782,362
145											
146	**O&M Calculation**										Hydro Distribution
147	Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546		$ 81,528	$ 3,742,503	$ 1,706,571	$ 74,248	$ 578,737	$ 520,067	$ 74,248	$ 129,116
148	Coolants and Water (Nuclear Plants Only)	FERC Account 519		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
149	Steam Expenses	FERC Account 502, 520		$ 21,059	$ 966,716	$ 440,820	$ 19,179	$ 149,492	$ 134,337	$ 19,179	$ 106,629
150	Steam From Other Sources	FERC Account 503		$ 40,694	$ 1,868,066	$ 851,833	$ 37,061	$ 288,876	$ 259,591	$ 37,061	$ 635,221
151	Electric Expenses	FERC Account 505, 523 - Allocated based on		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 209,968
152	Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524 - Reduced from actual		$ 12,468	$ 572,328	$ 260,980	$ 11,355	$ 88,504	$ 79,532	$ 11,355	$ 209,831
153	Rents	FERC Account 507		$ 75,877	$ 3,483,129	$ 1,588,297	$ 69,103	$ 538,628	$ 484,024	$ 69,103	$ 30,315
154	Allowances	FERC Account 509		$ 3,066	$ 140,748	$ 64,181	$ 2,792	$ 21,765	$ 19,559	$ 2,792	$ -
155	Maintenance Supervision and Engineering	FERC Account 510, 528		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 71,654
156	Maintenance of Structures	FERC Account 511, 529, 552		$ 31,801	$ 1,459,799	$ 665,664	$ 28,961	$ 225,742	$ 202,857	$ 28,961	$ 86,140
157	Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530		$ 13,637	$ 625,988	$ 285,449	$ 12,419	$ 96,802	$ 86,989	$ 12,419	$ 317,094
158	Maintenance of Electric Plant	FERC Account 513, 531, 554		$ 14,187	$ 651,254	$ 296,970	$ 12,920	$ 100,709	$ 90,500	$ 12,920	$ 227,151
159	Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532		$ 17,658	$ 810,576	$ 369,620	$ 16,081	$ 125,347	$ 112,639	$ 16,081	$ 64,105
160	Other Power Production, & Other Expenses	FERC Account 548-553; 557		$ 53,560	$ 2,458,680	$ 1,121,151	$ 48,778	$ 380,208	$ 341,664	$ 48,778	$ -
161	TOTAL	Grand Total O&M		$ 365,535	$ 16,779,786	$ 7,651,534	$ 332,898	$ 2,594,809	$ 2,331,757	$ 332,898	$ 2,087,224
162											
163	**A&G and Overhead Expenses**										
164	Plant specific A&G			$ 18,226	$ -	$ 833,095	$ 16,599	$ 767,400	$ 713,054	$ 16,599	$ 1,887,948
165											
166	Nuclear Overhead Expenses ("OH" tab)										
167	Non-nuclear Overhead Expenses ("OH" tab)			$ 39,992	$ -	$ 826,594	$ 36,422	$ 88,874	$ 183,732	$ 36,422	$ -
168	Total			$ 58,219	$ -	$ 1,659,689	$ 53,021	$ 856,274	$ 896,786	$ 53,021	$ 1,887,948
169											
170											
171											
172											
173											
174											
175											
176	**Depreciation Exp**										
177				65	65	27	63	74	40	63	77
178	Production Plant in Service Depreciation Expense			$ 208,129	$ 6,155,877	$ 2,286,267	$ 124,277	$ 248,741	$ 2,145,633	$ 131,762	$ 3,395,087
179				$ 0	$ 0	$ 0	$ -	$ 0	$ 0	$ 0	$ 0
180	**Other Taxes**		Total								
181	Plant Related & Property Taxes (Nucs only)		$ 123,977,347								
182	Payroll Taxes (Nucs Only)		$ 60,289,214								
183	Other Taxes (Pay & Property) (Non-Nucs)		$ 9,124,663	$ 27,880	$ 3,170,443	$ 263,599	$ 11,386	$ 653,648	$ 163,782	$ 11,386	$ 692,571
184	Total Other Taxes		$ 193,391,223	$ 27,880	$ 3,170,443	$ 263,599	$ 11,386	$ 653,648	$ 163,782	$ 11,386	$ 692,571
185											
186											
187											
188											
189											
190											
191											
192											
193											
194											

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	Description	Source	Delaware 9-12	Eddystone 3,4,10,20,30,40	Fairless Hills A&B	Falls 1-3	Gould Street 3	Handsome Lake	Moser 1-3	Muddy Run 1-8
195										
196										
197	**Prepayments**	Nuclear								
198		Fossil	$ 101,763	$ 3,009,862	$ 464,338	$ 58,895	$ 138,459	$ 645,593	$ 62,442	$ 1,966,459
199	Total		$ 101,763	$ 3,009,862	$ 464,338	$ 58,895	$ 138,459	$ 645,593	$ 62,442	$ 1,966,459
200										
201	**M&S**									
202	M&S - Fuel		391,088	15,721,025		733,700			800,596	
203	M&S - Fuel (undistributed)		-	-	-	-	-	-	-	-
204	M&S - Fossil Production		48,332	1,834,061	998,961	44,017	107,407	222,045	44,017	-
205	M&S - Nuclear Production									
206	**TOTAL M&S**		$ 439,420	$ 17,555,085	$ 998,961	$ 777,716	$ 107,407	$ 222,045	$ 844,613	$ -
207										
208										
209	**RETURN (R)**									
210										
211										
212		$/mil	%							
213	Long Term Debt	0.45	45.0%							
214	Proprietary Capital	0.55	55.0%							
215	Total (sum lines 22-23)	1.00	100%							
216										
217										
218	**Income Taxes**									
219	State Marginal Rate (multi-state)	5.6600% <<Per ACH 9-29-16								
220										
221										
222		Jurisdiction1								
223										
224		Federal								
		FIT on SIT								
		Illinois2								
		IL on SIT								
		Pennsylvania2								
		Maryland								
		Other Separate								
		NYS								
		Other Unitary								
		Marginal Tax Rate								
		Effective State Rate								

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Input Data For Schedule 3

	Description		Source	Notch Cliff 1-8	Pennsbury 1&2	Perryman 1,3,4,51	Perryman 6	Philadelphia Rd 1-4	Richmond 91&92	Riverside 7&8	Schuylkill 10&11
1	Turbogenerator, GUS and Accessory Electric Investment:			BGE (8)	PECO (2)	BGE (5)	BGE (1)	BGE (4)	PECO (2)	BGE (2)	PECO (2)
2	Included TurboGenerator Investment	2015 Actual Data	Account 314,323, 333, 34	20,738,180	568,704	177,706,677	88,242,961	16,996,875	20,218,692	13,013,142	4,345,038
3	Investment Generator & Exciter	2015 Actual Data	15%	3,110,727	85,306	26,656,002	13,236,444	2,549,531	3,032,804	1,951,971	651,756
4	Value of GSU Transformers	2015 Actual Data		$ -	$ -	$ 784,897	$ -	$ -	$ 355,663	$ 350,500	-
5	Total Accessory Elec Equipment - Gross Investment	2015 Actual Data	Account 315, 324, 334, 34	$ 6,085,933	$ 242,106	$ 21,554,696	$ 20,899,649	$ 3,061,125	$ 2,910,886	$ 4,153,061	$ 553,360
6	Installed Cost of Power Plant (excluding Nuclear ARC; Steam ARC)	2015 Actual Data	2015 Actual Data	$ 41,084,404	$ 3,820,667	$ 250,720,971	$ 116,109,159	$ 18,270,877	$ 29,467,537	$ 39,227,656	5,934,123
7	Investment Generator & Exciter / Turbogenerator			15.000%	15.000%	15.000%	15.000%	15.000%	15.000%	15.000%	15.000%
8	Investment Generation & Exciter / Installed Cost of Power Plant			7.572%	2.233%	10.632%	11.400%	13.954%	10.292%	4.976%	10.983%
9											
10	**Allocators**										
11											
12	**Real Power Demonstrated Capability (gross MW)**										
13	Generator 1			12.80	2.50	53.00	141.06	13.40	53.30	24.30	14.30
14	Generator 2			18.00	2.50	53.00		18.00	52.80	21.30	19.00
15	Generator 3			18.00		53.00		18.00			
16	Generator 4			18.00		53.00		18.00			
17	Generator 5			12.50		144.90					
18	Generator 6			18.00							
19	Generator 7			18.00							
20	Generator 8			18.00							
21	Generator 9										
22	Generator 10										
23	Generator 11										
24											
25	Total			133.30	5.00	356.90	141.06	67.40	106.10	45.60	33.30
26											
27	**Nominal Power Factor (pf)**										
28	Generator 1			0.66	0.85	0.85	0.85	0.74	0.92	0.75	0.79
29	Generator 2			0.85	0.85	0.85		0.85	0.92	0.76	0.86
30	Generator 3			0.85		0.85		0.85			
31	Generator 4			0.85		0.85		0.85			
32	Generator 5			0.64		0.90					
33	Generator 6			0.85							
34	Generator 7			0.85							
35	Generator 8			0.85							
36	Generator 9										
37	Generator 10										
38	Generator 11										
39											
40											
41	**Nameplate MVAr**										
42	Generator 1	(Nameplates, sqrt(MVA^2-MW^2))		14.49	1.55	32.85	87.42	12.29	28.78	21.43	13.55
43	Generator 2	(Nameplates, sqrt(MVA^2-MW^2))		11.16	1.55	32.85		11.16	28.94	18.39	12.63
44	Generator 3	(Nameplates, sqrt(MVA^2-MW^2))		11.16	-	32.85		11.16	-	-	-
45	Generator 4	(Nameplates, sqrt(MVA^2-MW^2))		11.16	-	32.85		11.16	-	-	-
46	Generator 5	(Nameplates, sqrt(MVA^2-MW^2))		15.01	-	72.22		-	-	-	-
47	Generator 6	(Nameplates, sqrt(MVA^2-MW^2))		11.16	-	-		-	-	-	-
48	Generator 7	(Nameplates, sqrt(MVA^2-MW^2))		11.16	-	-		-	-	-	-
49	Generator 8	(Nameplates, sqrt(MVA^2-MW^2))		11.16	-	-		-	-	-	-
50	Generator 9	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-		-	-	-	-
51	Generator 10	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-		-	-	-	-
52	Generator 11	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-		-	-	-	-
53											
54											
55	Total			96.43	3.10	203.60	87.42	45.76	57.72	39.82	26.18
56											
57	**Exciter MW**										same as Chester
58	Generator 1	Exciter Rating		0.05		0.08	0.29	0.05	0.11	0.14	0.09
59	Generator 1	Exciter Rating		0.05		0.08		0.05	0.11	0.14	0.09
60	Generator 2	Exciter Rating		0.05		0.08		0.05			
61	Generator 3	Exciter Rating		0.05		0.08		0.05			
62	Generator 4	Exciter Rating		0.05		0.61					
63	Generator 5	Exciter Rating		0.05		0.29					
64	Generator 6	Exciter Rating		0.05							
65	Generator 7	Exciter Rating		0.05							
66	Generator 8	Exciter Rating		0.05							
67	Generator 9	Exciter Rating									
68	Generator 10	Exciter Rating									
69	Generator 11	Exciter Rating		0.49	-	1.21	0.29	0.20	0.22	0.28	0.17
70											

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	Description		Source	Notch Cliff 1-8	Pennsbury 1&2	Perryman 1,3,4,51	Perryman 6	Philadelphia Rd 1-4	Richmond 91&92	Riverside 7&8	Schuylkill 10&11
71	**Generator MW**										
72	Generator 1	(pf*MVA)		12.80	2.50	53.00	141.06	13.40	66.61	24.30	17.18
73	Generator 2	(pf*MVA)		18.00	2.50	53.00		18.00	66.54	21.30	21.58
74	Generator 3	(pf*MVA)		18.00	-	53.00		18.00	-	-	-
75	Generator 4	(pf*MVA)		18.00	-	53.00		18.00	-	-	-
76	Generator 5	(pf*MVA)		12.50	-	144.90		-	-	-	-
77	Generator 6	(pf*MVA)		18.00	-	-		-	-	-	-
78	Generator 7	(pf*MVA)		18.00	-	-		-	-	-	-
79	Generator 8	(pf*MVA)		18.00	-	-		-	-	-	-
80	Generator 9	(pf*MVA)		-	-	-		-	-	-	-
81	Generator 10	(pf*MVA)		-	-	-		-	-	-	-
82	Generator 11	(pf*MVA)		-	-	-		-	-	-	-
83	Total			133.30	5.00	356.90	141.06	67.40	133.15	45.60	38.75
84											
85	**Generator MVA**										
86	Generator 1	MW/pf if not stated		19.34	2.94	62.35	165.95	18.18	72.56	32.40	21.88
87	Generator 2	MW/pf if not stated		21.18	2.94	62.35		21.18	72.56	28.14	25.00
88	Generator 3	MW/pf if not stated		21.18		62.35		21.18			
89	Generator 4	MW/pf if not stated		21.18		62.35		21.18			
90	Generator 5	MW/pf if not stated		19.53		161.90					
91	Generator 6	MW/pf if not stated		21.18							
92	Generator 7	MW/pf if not stated		21.18							
93	Generator 8	MW/pf if not stated		21.18							
94	Generator 9	MW/pf if not stated									
95	Generator 10	MW/pf if not stated									
96	Generator 11	MW/pf if not stated									
97											
98	Total			165.93	5.88	411.31	165.95	81.71	145.12	60.54	46.88

99	Peak Hour	18	18	16							
100	Peak Day	9/3/2015	9/3/2015	7/20/2015	BGE (8)	PECO (2)	BGE (5)		BGE (4)	PECO (2)	BGE (2)	PECO (2)
101		**Average**	**ComEd**	**PECO**								
102	Max. MVAr	2,991	2,187	361								
103	Nameplate MVAr	9,831	4,856	2,853	96.4	3.1	203.6	87.4	45.8	57.7	39.8	26.2
104	Exciter MW	76	35	29	0.5	-	1.2	0.3	0.2	0.2	0.3	0.2
105	Generator MW	23,359	11,447	6,715	133	5	357	141	67	133	46	39
106		**0.0992%**	**0.1358%**	**0.0542%**								
107												

108	**Accessory Equip Allocator**										
109	Item	**Nuclear**	**Cumb. Turbine**	**comb. Tur.**	**comb. Tur.**	**comb. Tur.**	**comb. Tur.**	**comb. Tur.**	**comb. Tur.**	**comb. Tur.**	**comb. Tur.**
110	Storage Batteries	15%	50%	$ -	$ -	$ -		$ -	$ 55,087	$ 30,947	$ 4,178
111	Control&Power Cabling	1%	50%	$ 16,778	$ 8,655	$ -		$ -	$ 188,087	$ 1,104,514	$ 103,944
112	Switch Board Equipment	1%	50%	$ 118,994	$ -	$ -		$ 1,324,305	$ 15,523	$ 369,107	$ 4,150
113	Switching Equipment	1%	40%	$ 392,455	$ -	$ 23,872		$ -	$ 39,597	$ 207,572	$ 73,239
114	Transformers	3%	10%	$ 5,727	$ -	$ -		$ -	$ 6,964	$ 9,887	$ -
115	Aux Generator	0%	0%	$ -	$ -	$ -		$ -	$ -	$ -	$ -
116	Fire Protection System	0%	0%	$ -	$ -	$ -		$ -	$ -	$ -	$ -
117	HVAC	0%	0%	$ -	$ -	$ -		$ -	$ -	$ -	$ -
118	Regulating Equipment	50%	75%	$ 3,480,201	$ -	$ 132,385		$ -	$ -	$ 230,110	$ -
119	Structure	0%	0%	$ -	$ -	$ -		$ -	$ -	$ -	$ -
120	Misc	0%	0%	$ -	$ -	$ -		$ -	$ -	$ -	$ -
121	Exciter & PPT	100%	100%	$ -	$ -	$ -		$ -	$ -	$ 15,989	$ -
122	Station Grounding	1%	5%	$ 494	$ -	$ -		$ -	$ -	$ 9,532	$ -
123	Bus & Insulators	80%	80%	$ -	$ -	$ -		$ -	$ -	$ -	$ -
124	Capacitor Bank	0%	0%	$ -	$ -	$ -		$ -	$ -	$ -	$ -
125				$ 4,014,649	$ 8,655	$ 156,257	$ 2,089,965	$ 1,324,305	$ 305,256	$ 1,977,658	$ 185,511
126			EXE-4, Sch 5 Allocation factors develop	66%	4%	1%	10%	43%	10%	48%	34%

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	Description	Source		Notch Cliff 1-8	Pennsbury 1&2	Perryman 1,3,4,51	Perryman 6	Philadelphia Rd 1-4	Richmond 91&92	Riverside 7&8	Schuylkill 10&11
127	**Item**										
128	Storage Batteries	Actual 2015		$ -	$ -	$ -		$ -	$ 110,173	$ 61,893	$ 8,355
129	Control&Power Cabling	Actual 2015		$ 33,556	$ 17,310	$ -		$ -	$ 376,173	$ 2,209,028	$ 207,889
130	Switch Board Equipment	Actual 2015		$ 237,988	$ -	$ -		$ 2,648,610	$ 31,046	$ 738,213	$ 8,299
131	Switching Equipment	Actual 2015		$ 981,137	$ -	$ 59,681		$ -	$ 98,992	$ 518,931	$ 183,098
132	Transformers	Actual 2015		$ 57,272	$ -	$ -		$ -	$ 69,638	$ 98,872	$ -
133	Aux Generator	Actual 2015		$ -	$ -	$ -		$ -	$ -	$ -	$ -
134	Fire Protection System	Actual 2015		$ -	$ -	$ -		$ -	$ -	$ 7,984	$ -
135	HVAC	Actual 2015		$ -	$ -	$ -		$ -	$ -	$ -	$ -
136	Regulating Equipment	Actual 2015		$ 4,640,268	$ -	$ 176,513		$ -	$ -	$ 306,814	$ -
137	Structure	Actual 2015		$ 6,922	$ -	$ -		$ -	$ 41,045	$ 4,701	$ 41,588
138	Misc	Actual 2015		$ 118,909	$ 224,796	$ 21,318,503		$ 412,515	$ 2,183,819	$ -	$ 104,130
139	Exciter & PPT	Actual 2015		$ -	$ -	$ -		$ -	$ -	$ 15,989	$ -
140	Station Grounding	Actual 2015		$ 9,880	$ -	$ -		$ -	$ -	$ 190,636	$ -
141	Bus & Insulators	Actual 2015		$ -	$ -	$ -		$ -	$ -	$ -	$ -
142	Capacitor Bank	Actual 2015		$ -	$ -	$ -		$ -	$ -	$ -	$ -
143											
144	Total	$ 1,327,863,081	<ties to "Accessory Electr	$ 6,085,933	$ 242,106	$ 21,554,696	$ 20,899,649	$ 3,061,125	$ 2,910,886	$ 4,153,061	$ 553,360
145											
146	**O&M Calculation**										
147	Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546		$ 217,043	$ 235,561	$ 1,562,813	$ 1	$ 147,788	$ 142,673	$ 92,302	$ 69,047
148	Coolants and Water (Nuclear Plants Only)	FERC Account 519		$ -	$ -	$ -		$ -	$ -	$ -	$ -
149	Steam Expenses	FERC Account 502, 520		$ 56,064	$ 60,847	$ 403,686		$ 38,175	$ 36,854	$ 23,842	$ 17,835
150	Steam From Other Sources	FERC Account 503		$ 108,337	$ 117,580	$ 780,076		$ 73,768	$ 71,215	$ 46,073	$ 34,465
151	Electric Expenses	FERC Account 505, 523 - Allocated based on		$ -	$ -	$ -		$ -	$ -	$ -	$ -
152	Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524 - Reduced from actual		$ 33,192	$ 36,024	$ 238,995		$ 22,601	$ 21,819	$ 14,115	$ 10,559
153	Rents	FERC Account 507		$ 202,000	$ 219,236	$ 1,454,502		$ 137,546	$ 132,785	$ 85,905	$ 64,262
154	Allowances	FERC Account 509		$ 8,163	$ 8,859	$ 58,774		$ 5,558	$ 5,366	$ 3,471	$ 2,597
155	Maintenance Supervision and Engineering	FERC Account 510, 528		$ -	$ -	$ -		$ -	$ -	$ -	$ -
156	Maintenance of Structures	FERC Account 511, 529, 552		$ 84,660	$ 91,883	$ 609,590		$ 57,646	$ 55,651	$ 36,003	$ 26,932
157	Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530		$ 36,303	$ 39,401	$ 261,403		$ 24,720	$ 23,864	$ 15,439	$ 11,549
158	Maintenance of Electric Plant	FERC Account 513, 531, 554		$ 37,769	$ 40,991	$ 271,954		$ 25,717	$ 24,827	$ 16,062	$ 12,015
159	Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532		$ 47,008	$ 51,019	$ 338,484		$ 32,009	$ 30,901	$ 19,991	$ 14,955
160	Other Power Production, & Other Expenses	FERC Account 548-553; 557		$ 142,589	$ 154,755	$ 1,026,708		$ 97,091	$ 93,731	$ 60,639	$ 45,361
161	TOTAL	Grand Total O&M		$ 973,126	$ 1,056,155	$ 7,006,986	$ 1	$ 662,620	$ 639,686	$ 413,844	$ 309,577
162											
163	**A&G and Overhead Expenses**										
164	Plant specific A&G			$ 145,511	$ 95,853	$ 757,586	$ -	$ 70,095	$ 31,896	$ 240,209	$ 395,698
165											
166	Nuclear Overhead Expenses ("OH" tab)										
167	Non-nuclear Overhead Expenses ("OH" tab)			$ 110,179	$ 109,559	$ 776,075	$ -	$ 37,313	$ 69,987	$ 23,895	$ 40,553
168	Total			$ 255,689	$ 205,412	$ 1,533,660	$ -	$ 107,408	$ 101,883	$ 264,104	$ 436,251
169											
170											
171											
172											
173											
174											
175											
176	**Depreciation Exp**										
177				59	50	45	30	55	60	55	63
178	Production Plant in Service Depreciation Expense			$ 696,346	$ 76,413	$ 5,571,577	$ 3,870,305	$ 332,198	$ 491,126	$ 713,230	$ 94,192
179				$ 0	$ 0	0	0	$ 0	$ 0	$ 0	0
180	**Other Taxes**	Total									
181	Plant Related & Property Taxes (Nucs only)	$ 123,977,347									
182	Payroll Taxes (Nucs Only)	$ 60,289,214									
183	Other Taxes (Pay & Property) (Non-Nucs)	$ 9,124,663	$	222,581	$ 55,959	$ 2,143,070	$ -	$ 264,526	$ 21,879	$ 379,744	$ 11,465
184	Total Other Taxes	$ 193,391,223	$	222,581	$ 55,959	$ 2,143,070	$ -	$ 264,526	$ 21,879	$ 379,744	$ 11,465
185											
186											
187											
188											
189											
190											
191											
192											
193											
194											

	Description	Source	Notch Cliff 1-8	Pennsbury 1&2	Perryman 1,3,4,51	Perryman 6	Philadelphia Rd 1-4	Richmond 91&92	Riverside 7&8	Schuylkill 10&11
195										
196										
197	**Prepayments**	Nuclear								
198		Fossil	$ 309,044	$ 28,740	$ 1,885,966	$ 873,393	$ 137,437	$ 221,660	$ 295,077	$ 44,637
199	Total		$ 309,044	$ 28,740	$ 1,885,966	$ 873,393	$ 137,437	$ 221,660	$ 295,077	$ 44,637
200										
201	**M&S**									
202	M&S - Fuel				12,545,353	-	1,431,339		1,455,390	290,293
203	M&S - Fuel (undistributed)		-	-	-		-	-	-	-
204	M&S - Fossil Production		133,154	132,405	937,907	-	45,094	84,581	28,878	49,009
205	M&S - Nuclear Production									
206	**TOTAL M&S**		$ 133,154	$ 132,405	$ 13,483,260	$ -	$ 1,476,433	$ 84,581	$ 1,484,268	$ 339,302
207										
208										
209	**RETURN (R)**									
210										
211										
212		$/mil	%							
213	Long Term Debt	0.45	45.0%							
214	Proprietary Capital	0.55	55.0%							
215	Total (sum lines 22-23)	1.00	100%							
216										
217										
218	**Income Taxes**									
219	State Marginal Rate (multi-state)	5.6600% <<Per ACH 9-29-16								
220										
221										
222		Jurisdiction1								
223										
224		Federal								
		FIT on SIT								
		Illinois2								
		IL on SIT								
		Pennsylvania2								
		Maryland								
		Other Separate								
		NYS								
		Other Unitary								
		Marginal Tax Rate								
		Effective State Rate								

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Input Data For Schedule 3

	Description		Source	SE Chicago 5-12	Southwark 3-6	Westport 5
1	Turbogenerator, GUS and Accessory Electric Investment:			ComEd (8)	PECO (4)	BGE (1)
2	Included TurboGenerator Investment	2015 Actual Data	Account 314,323, 333, 34	132,017,953	6,463,264	31,650,720
3	Investment Generator & Exciter	2015 Actual Data	15%	19,802,693	969,490	4,747,608
4	Value of GSU Transformers	2015 Actual Data		$ 4,873,891	$ 2,616	$ 337,384
5	Total Accessory Elec Equipment - Gross Investment	2015 Actual Data	Account 315, 324, 334, 34	$ 9,173,232	$ 2,596,022	$ 1,703,761
6	Installed Cost of Power Plant (excluding Nuclear ARC; Steam ARC)	2015 Actual Data	2015 Actual Data	$ 187,439,853	$ 10,963,535	38,050,323
7	Investment Generator & Exciter / Turbogenerator			15.000%	15.000%	15.000%
8	Investment Generation & Exciter / Installed Cost of Power Plant			10.565%	8.843%	12.477%
9						
10	**Allocators**					
11						
12	**Real Power Demonstrated Capability (gross MW)**					
13	Generator 1			38.30	12.80	118.50
14	Generator 2			38.30	14.88	
15	Generator 3			38.30	12.88	
16	Generator 4			38.30	14.66	
17	Generator 5			38.30		
18	Generator 6			38.30		
19	Generator 7			38.30		
20	Generator 8			38.30		
21	Generator 9					
22	Generator 10					
23	Generator 11					
24						
25	Total			306.40	55.22	118.50
26						
27	**Nominal Power Factor (pf)**					
28	Generator 1			0.85	0.76	0.92
29	Generator 2			0.85	0.81	
30	Generator 3			0.85	0.77	
31	Generator 4			0.85	0.80	
32	Generator 5			0.85		
33	Generator 6			0.85		
34	Generator 7			0.85		
35	Generator 8			0.85		
36	Generator 9					
37	Generator 10					
38	Generator 11					
39						
40						
41	**Nameplate MVAr**					
42	Generator 1	(Nameplates, sqrt(MVA^2-MW^2))		23.74	16.36	49.04
43	Generator 2	(Nameplates, sqrt(MVA^2-MW^2))		23.74	14.83	-
44	Generator 3	(Nameplates, sqrt(MVA^2-MW^2))		23.74	16.07	-
45	Generator 4	(Nameplates, sqrt(MVA^2-MW^2))		23.74	14.90	-
46	Generator 5	(Nameplates, sqrt(MVA^2-MW^2))		23.74	-	-
47	Generator 6	(Nameplates, sqrt(MVA^2-MW^2))		23.74	-	-
48	Generator 7	(Nameplates, sqrt(MVA^2-MW^2))		23.74	-	-
49	Generator 8	(Nameplates, sqrt(MVA^2-MW^2))		23.74	-	-
50	Generator 9	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-
51	Generator 10	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-
52	Generator 11	(Nameplates, sqrt(MVA^2-MW^2))		-	-	-
53						
54						
55	Total			189.89	62.17	49.04
56						
57	**Exciter MW**				same as Chester	
58	Generator 1	Exciter Rating		0.10	0.09	0.31
59	Generator 1	Exciter Rating		0.10	0.09	
60	Generator 2	Exciter Rating		0.10	0.09	
61	Generator 3	Exciter Rating		0.10	0.09	
62	Generator 4	Exciter Rating		0.10		
63	Generator 5	Exciter Rating		0.10		
64	Generator 6	Exciter Rating		0.10		
65	Generator 7	Exciter Rating		0.10		
66	Generator 8	Exciter Rating				
67	Generator 9	Exciter Rating				
68	Generator 10	Exciter Rating				
69	Generator 11	Exciter Rating		0.82	0.34	0.31
70						

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	Description		Source	SE Chicago 5-12	Southwark 3-6	Westport 5
71	**Generator MW**					
72	Generator 1	(pf*MVA)		38.30	18.90	118.50
73	Generator 2	(pf*MVA)		38.30	20.13	-
74	Generator 3	(pf*MVA)		38.30	19.15	-
75	Generator 4	(pf*MVA)		38.30	20.08	-
76	Generator 5	(pf*MVA)		38.30	-	-
77	Generator 6	(pf*MVA)		38.30	-	-
78	Generator 7	(pf*MVA)		38.30	-	-
79	Generator 8	(pf*MVA)		38.30	-	-
80	Generator 9	(pf*MVA)		-	-	-
81	Generator 10	(pf*MVA)		-	-	-
82	Generator 11	(pf*MVA)		-	-	-
83	Total			306.40	78.25	118.50
84						
85	**Generator MVA**					
86	Generator 1	MW/pf if not stated		45.06	25.00	128.25
87	Generator 2	MW/pf if not stated		45.06	25.00	
88	Generator 3	MW/pf if not stated		45.06	25.00	
89	Generator 4	MW/pf if not stated		45.06	25.00	
90	Generator 5	MW/pf if not stated		45.06		
91	Generator 6	MW/pf if not stated		45.06		
92	Generator 7	MW/pf if not stated		45.06		
93	Generator 8	MW/pf if not stated		45.06		
94	Generator 9	MW/pf if not stated				
95	Generator 10	MW/pf if not stated				
96	Generator 11	MW/pf if not stated				
97						
98	Total			360.47	100.00	128.25

99	Peak Hour	18	18	16				
100	Peak Day	9/3/2015	9/3/2015	7/20/2015	ComEd (8)		PECO (4)	BGE (1)
101		**Average**	**ComEd**	**PECO**				
102	Max. MVAr	2,991	2,187	361				
103	Nameplate MVAr	9,831	4,856	2,853	189.9		62.2	49.0
104	Exciter MW	76	35	29	0.8		0.3	0.3
105	Generator MW	23,359	11,447	6,715	306		78	119
106		**0.0992%**	**0.1358%**	**0.0542%**				
107								
108	**Accessory Equip Allocator**							
109	Item		**Nuclear**	**Cumb. Turbine**	**comb. Tur.**		**comb. Tur.**	**comb. Tur.**
110	Storage Batteries		15%	50%	$ -		$ 20,009	$ -
111	Control&Power Cabling		1%	50%	$ -		$ 32,741	$ -
112	Switch Board Equipment		1%	50%	$ -		$ 819,137	$ -
113	Switching Equipment		1%	40%	$ -		$ 23,993	$ -
114	Transformers		3%	10%	$ -		$ -	$ -
115	Aux Generator		0%	0%	$ -		$ -	$ -
116	Fire Protection System		0%	0%	$ -		$ -	$ -
117	HVAC		0%	0%	$ -		$ -	$ -
118	Regulating Equipment		50%	75%	$ -		$ -	$ 1,114,980
119	Structure		0%	0%	$ -		$ -	$ -
120	Misc		0%	0%	$ -		$ -	$ -
121	Exciter & PPT		100%	100%	$ -		$ -	$ -
122	Station Grounding		1%	5%	$ -		$ -	$ -
123	Bus & Insulators		80%	80%	$ -		$ -	$ -
124	Capacitor Bank		0%	0%	$ -		$ -	$ -
125					$ -		$ 895,880	$ 1,114,980
126			EXE-4, Sch 5 Allocation factors develop		0%		35%	65%

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	Description	Source		SE Chicago 5-12	Southwark 3-6	Westport 5
127	**Item**					
128	Storage Batteries	Actual 2015		$ -	$ 40,019	$ -
129	Control&Power Cabling	Actual 2015		$ -	$ 65,482	$ -
130	Switch Board Equipment	Actual 2015		$ -	$ 1,638,273	$ -
131	Switching Equipment	Actual 2015		$ -	$ 59,982	$ -
132	Transformers	Actual 2015		$ -	$ -	$ -
133	Aux Generator	Actual 2015		$ -	$ -	$ -
134	Fire Protection System	Actual 2015		$ -	$ -	$ -
135	HVAC	Actual 2015		$ -	$ -	$ -
136	Regulating Equipment	Actual 2015		$ -	$ -	$ 1,486,640
137	Structure	Actual 2015		$ -	$ 11,054	$ -
138	Misc	Actual 2015		$ 9,173,232	$ 781,212	$ 217,121
139	Exciter & PPT	Actual 2015		$ -	$ -	$ -
140	Station Grounding	Actual 2015		$ -	$ -	$ -
141	Bus & Insulators	Actual 2015		$ -	$ -	$ -
142	Capacitor Bank	Actual 2015		$ -	$ -	$ -
143						
144	Total	$ 1,327,863,081	<ties to "Accessory Electr	$ 9,173,232	$ 2,596,022	$ 1,703,761
145						
146	**O&M Calculation**					
147	Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546		$ 459,763	$ 75,704	$ 196,400
148	Coolants and Water (Nuclear Plants Only)	FERC Account 519		$ -	$ -	$ -
149	Steam Expenses	FERC Account 502, 520		$ 118,760	$ 19,555	$ 50,732
150	Steam From Other Sources	FERC Account 503		$ 229,490	$ 37,788	$ 98,033
151	Electric Expenses	FERC Account 505, 523 - Allocated based on		$ -	$ -	$ -
152	Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524 - Reduced from actual		$ 70,310	$ 11,577	$ 30,035
153	Rents	FERC Account 507		$ 427,899	$ 70,458	$ 182,789
154	Allowances	FERC Account 509		$ 17,291	$ 2,847	$ 7,386
155	Maintenance Supervision and Engineering	FERC Account 510, 528		$ -	$ -	$ -
156	Maintenance of Structures	FERC Account 511, 529, 552		$ 179,335	$ 29,529	$ 76,608
157	Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530		$ 76,902	$ 12,663	$ 32,851
158	Maintenance of Electric Plant	FERC Account 513, 531, 554		$ 80,006	$ 13,174	$ 34,177
159	Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532		$ 99,578	$ 16,397	$ 42,538
160	Other Power Production, & Other Expenses	FERC Account 548-553; 557		$ 302,046	$ 49,735	$ 129,027
161	TOTAL	Grand Total O&M		$ 2,061,381	$ 339,425	$ 880,575
162						
163	**A&G and Overhead Expenses**					
164	Plant specific A&G			$ 314,901	$ 16,925	$ 144,258
165						
166	Nuclear Overhead Expenses ("OH" tab)					
167	Non-nuclear Overhead Expenses ("OH" tab)			$ 212,635	$ 37,136	$ 106,099
168	Total			$ 527,536	$ 54,060	$ 250,357
169						
170						
171						
172						
173						
174						
175						
176	**Depreciation Exp**					
177				30	31	53
178	Production Plant in Service Depreciation Expense			$ 6,247,995	$ 353,662	$ 717,931
179				$ 0	$ 0	$ 0
180	**Other Taxes**		Total			
181	Plant Related & Property Taxes (Nucs only)		$ 123,977,347			
182	Payroll Taxes (Nucs Only)		$ 60,289,214			
183	Other Taxes (Pay & Property) (Non-Nucs)		$ 9,124,663	$ 150,320	$ 11,609	$ 775,741
184	Total Other Taxes		$ 193,391,223	$ 150,320	$ 11,609	$ 775,741
185						
186						
187						
188						
189						
190						
191						
192						
193						
194						

	Description	Source	SE Chicago 5-12	Southwark 3-6	Westport 5
195					
196					
197	**Prepayments**	Nuclear			
198		Fossil	$ 1,409,955	$ 82,470	$ 286,221
199	Total		$ 1,409,955	$ 82,470	$ 286,221
200					
201	**M&S**				
202	M&S - Fuel			423,706	
203	M&S - Fuel (undistributed)		-	-	-
204	M&S - Fossil Production		256,975	44,880	128,223
205	M&S - Nuclear Production				
206	**TOTAL M&S**		$ 256,975	$ 468,585	$ 128,223
207					
208					
209	**RETURN (R)**				
210					
211					

		$/mil	%
212			
213	Long Term Debt	0.45	45.0%
214	Proprietary Capital	0.55	55.0%
215	Total (sum lines 22-23)	1.00	100%
216			
217			
218	**Income Taxes**		
219	State Marginal Rate (multi-state)	5.6600% <<Per ACH 9-29-16	
220			
221			
222		Jurisdiction1	
223			
224		Federal	
		FIT on SIT	
		Illinois2	
		IL on SIT	
		Pennsylvania2	
		Maryland	
		Other Separate	
		NYS	
		Other Unitary	
		Marginal Tax Rate	
		Effective State Rate	

Total Plant and GSU

	RTO	PJM		RTO	PJM								
	Abv Long Discription	(Multiple Items)		Sum of Book Cost	Column Labels						GSU investment Not booked	GSU investment From	
	Row Labels	Sum of Book Cost		Row Labels	321	322	344	346	353	to Access Elect Eq	Access Elect Equi	Total GSU	
1	Braidwood	1,484,090,250		Braidwood							-	49,633,067	49,633,067
2	Byron	1,391,617,170		Byron							-	21,644,926	21,644,926
3	Chester	9,133,168		Chester							-	-	-
4	Common Combustions	604,207		Common Combustions							-	-	-
5	Conemaugh	-	Sold	Conowingo							-	6,792,649	6,792,649
6	Conowingo	380,084,794		Croydon							-	1,420,756	1,420,756
7	Crane	5,147,586	Solar Exclude	Delaware							-	-	-
8	Cromby	1,281,727	Retired	Dresden							-	36,227,984	36,227,984
9	Croydon	107,412,068		Eddystone							-	6,411,560	6,411,560
10	Delaware	13,528,361									-	51,347	51,347
11	Dresden	1,359,267,568		Falls							-	-	-
12	Eddystone	400,131,998		Fort Smallwood							-	-	-
13	Fairless Hills	61,729,219		Gould St							-	3,114	3,114
14	Falls	7,829,474		Handsome Lake							-	-	-
15	Fort Smallwood	1,659,201		LaSalle	6,184						6,184	4,666,236	4,672,421
16	Gould St	18,406,803		Limerick							-	41,192,118	41,192,118
17	Handsome Lake	85,825,302		Moser							-	-	-
18	LaSalle	1,412,906,574		Muddy Run							-	4,657,845	4,657,845
19	Limerick	1,222,406,959		Notch Cliff							-	-	-
20	Merrill Ck	1,614,923	Not a gen.	Oyster Ck							-	19,820,373	19,820,373
21	Moser	8,301,032		Peach Bottom							-	41,363,873	41,363,873
22	Muddy Run	261,421,690		Pennsbury							-	-	-
23	Notch Cliff	41,084,404		Perryman							-	784,897	784,897
24	Oyster Ck	360,225,425		Philadelphia Rd							-	-	-
25	Peach Bottom	1,360,681,860		Quad Cities	217,244						217,244	25,109,413	25,326,658
26	Pennsbury	3,820,667		Richmond							-	355,663	355,663
27	Perryman	254,874,882		Riverside			21,939				21,939	328,562	350,500
28	Philadelphia Rd	18,270,877		Salem							-	14,618,814	14,618,814
29	Quad Cities	1,046,110,329		Schuylkill							-	-	-
30	Richmond	29,467,537		SE Chicago				249,688			249,688	4,624,203	4,873,891
31	Riverside	39,227,656		Southwark							-	2,616	2,616
32	Salem	583,671,743		TMI							-	-	-
33	Schuylkill	5,934,123		Westport					48,771		48,771	288,614	337,384
34	SE Chicago	187,439,853		Grand Total	223,429	-	21,939	249,688	48,771		543,826	279,998,630	280,542,456
35	Southwark	10,963,535											
36	TMI	1,001,621,380											
37	Westport	38,050,323											
38	Grand Total	14,625,578,846											
39		14,617,534,609	less Crumby & Merrill Creek & Crane										

Turbogenerator Investment

		TurboGen Investment	From Accessory Electric Acct	Total
1	Braidwood	276,982,389	-	276,982,389
2	Byron	326,517,030	28,526	326,545,555
3	Chester	4,695,512	-	4,695,512
4	Common Combustions	292,357	-	292,357
5	Conowingo	143,524,274	-	143,524,274
6	Croydon	72,348,001	-	72,348,001
7	Delaware	6,730,407	-	6,730,407
8	Dresden	507,917,628	-	507,917,628
9	Eddystone	62,382,060	-	62,382,060
10	Fairless Hills	20,090,347	-	20,090,347
11	Falls	5,518,050	-	5,518,050
12	Fort Smallwood	3,771	-	3,771
13	Gould St	4,694,859	-	4,694,859
14	Handsome Lake	42,347,182	-	42,347,182
15	LaSalle	322,991,066	-	322,991,066
16	Limerick	195,863,167	-	195,863,167
17	Moser	5,376,210	-	5,376,210
18	Muddy Run	105,729,817	-	105,729,817
19	Notch Cliff	20,738,180	-	20,738,180
20	Oyster Ck	30,406,806	-	30,406,806
21	Peach Bottom	324,475,609	-	324,475,609
22	Pennsbury	568,704	-	568,704
23	Perryman	177,835,602	-	177,835,602
24	Philadelphia Rd	11,650,034	5,346,841	16,996,875
25	Quad Cities	345,327,838	-	345,327,838
26	Richmond	20,218,692	-	20,218,692
27	Riverside	13,013,142	-	13,013,142
28	Salem	80,714,327	-	80,714,327
29	Schuylkill	4,345,038	-	4,345,038
30	SE Chicago	132,017,953	-	132,017,953
31	Southwark	6,463,264	-	6,463,264
32	TMI	13,661,046	-	13,661,046
33	Westport	31,650,720	-	31,650,720
		3,317,091,083		
		-		
		3,317,091,083		

	RTO	PJM							
	Detailed Book Cost	Column Labels							
	Row Labels	314	323	333	343	344	Grand Total	Excluded	Included
*	Braidwood								276,982,389
*	Byron								326,517,030
*	Chester								4,695,512
*	Common Combustions								292,357
*	Conowingo								143,524,274
*	Croydon								72,348,001
*	Delaware								6,730,407
*	Dresden								507,917,628
*	Eddystone								62,382,060
*	Fairless Hills								20,090,347
*	Falls								5,518,050
*	Fort Smallwood								3,771
*	Gould St								4,694,859
*	Handsome Lake								42,347,182
*	LaSalle								322,991,066
*	Limerick								195,863,167
*	Moser								5,376,210
*	Muddy Run								105,729,817
*	Notch Cliff								20,738,180
*	Oyster Ck								30,406,806
*	Peach Bottom								324,475,609
*	Pennsbury								568,704
*	Perryman								177,835,602
*	Philadelphia Rd								11,650,034
*	Quad Cities								345,327,838
*	Richmond								20,218,692
*	Riverside								13,013,142
*	Salem								80,714,327
*	Schuylkill								4,345,038
*	SE Chicago								132,017,953
*	Southwark								6,463,264
*	TMI								13,661,046
*	Westport								31,650,720
*	Total								3,317,091,083

ACCESSORY ELECTRICAL EQUIPMENT

	Row Labels	Grand Total	TurboGen	GSU	Storage Batteries	Control&Power Cabling	Switch Board Equipment	Switching Equipment	Transformers	Aux Generator
1	Braidwood	134,750,783	-	49,633,067	734,651	175,303,902	51,974,311	7,843,655	702,163	21,664,522
2	Byron	112,229,473	28,526	21,644,926	1,036,178	185,037,012	65,474,820	14,828,319	1,267,080	30,867,315
3	Chester	1,724,631	-	-	12,262	360,640	-	791,028	-	-
4	Common Combustions	44,507	-	-	-	-		-	-	-
5	Conowingo	38,570,503	-	6,792,649	136,064	3,179,427	1,973,492	2,017,595	6,318,929	101,173
6	Crane	1,763,925	-	-	-	-		-	-	-
7	Croydon	10,459,221	-	1,420,756	64,719	2,578,451	239,413	745,807	247,743	-
8	Delaware	1,910,796	-	-	28,741	344,611	19,874	1,147,085	-	-
9	Dresden	121,457,544	-	36,227,984	1,984,353	4,946,860		4,661,842	12,219,855	5,052,411
10	Eddystone	37,516,746	-	6,411,560	351,463	19,978,318	484,897	2,041,877	-	-
11	Fairless Hills	559,367	-	51,347	16,787	230	-	-	-	-
12	Falls	1,296,752	-	-	33,793	142,003		562,170	512	-
13	Fort Smallwood	229,561	-	-	-	257,127	3,425	-	-	-
14	Gould St	120,655	-	3,114	353,658	10,940	-	-	-	-
15	Handsome Lake	9,841	-	-	-			-	-	-
16	LaSalle	91,943,066	-	4,666,236	1,944,786	23,115,092	6,488,908	6,572,575	2,026,797	10,275,282
17	Limerick	152,931,562	-	41,192,118	1,414,202	23,319,901	1,188,580	228,627	1,050,152	5,506,158
18	Moser	1,539,315	-	-	9,365	262,801		589,074	-	-
19	Muddy Run	49,533,204	-	4,657,845	129,233	4,929,960	1,669,534	6,130,553	589,215	120,583
20	Notch Cliff	5,115,261	-	-	-	33,556	237,988	981,137	57,272	-
21	Oyster Ck	29,048,791	-	19,820,373	-	-	-	-	565,862	-
22	Peach Bottom	112,905,096	-	41,363,873	2,015,820	19,695,956	11,507,453	625,734	1,862,746	129,640
23	Pennsbury	242,106	-	-	-	17,310	-	-	-	-
24	Perryman	22,843,595	5,346,841	784,897	-	-	-	59,681	-	-
25	Philadelphia Rd	2,100,938	-	-	-	-	2,648,610	-	-	-
26	Quad Cities	76,259,093	-	25,109,413	2,133,713	7,403,630	2,898,057	3,872,699	8,262,803	3,321,149
27	Richmond	3,266,852	-	355,663	110,173	376,173	31,046	98,992	69,638	-
28	Riverside	4,370,438	-	328,562	61,893	2,209,028	738,213	518,931	98,872	-
29	Salem	57,321,438	-	14,618,814	-	459,119	-	-	-	-
30	Schuylkill	553,360	-	-	8,355	207,889	8,299	183,098	-	-
31	SE Chicago	13,797,435	-	4,624,203	-	-	-	-	-	-
32	Southwark	2,598,638	-	2,616	40,019	65,482	1,638,273	59,982	-	-
33	TMI	12,600,036	-	-	-	-	-	-	1,804,433	-
34	Westport	2,063,236	-	288,614	-	-	-	-	-	-
35	Total	1,103,677,764	5,375,366	279,998,630	12,620,227	474,235,420	149,225,194	54,560,461	37,144,073	77,038,233

Detailed

	Row Labels	Grand Total	TurboGen	GSU	Storage Batteries	Control&Power Cabling	Switch Board Equipment	Switching Equipment	Transformers	Aux Generator
*	Braidwood	134,750,783	-	49,633,067	734,651	175,303,902	51,974,311	7,843,655	702,163	21,664,522
*	Byron	112,229,473	28,526	21,644,926	1,036,178	185,037,012	65,474,820	14,828,319	1,267,080	30,867,315
*	Chester	1,724,631	-	-	12,262	360,640	-	791,028	-	-
*	Common Combustions	44,507	-	-	-	-	-	-	-	-
*	Conowingo	38,570,503	-	6,792,649	136,064	3,179,427	1,973,492	2,017,595	6,318,929	101,173
*	Crane	1,763,925	-	-	-	-	-	-	-	-
*	Croydon	10,459,221	-	1,420,756	64,719	2,578,451	239,413	745,807	247,743	-
*	Delaware	1,910,796	-	-	28,741	344,611	19,874	1,147,085	-	-
*	Dresden	121,457,544	-	36,227,984	1,984,353	4,946,860	3,310,657	4,661,842	12,219,855	5,052,411
*	Eddystone	37,516,746	-	6,411,560	351,463	19,978,318	484,897	2,041,877	-	-
*	Fairless Hills	559,367	-	51,347	16,787	230	-	-	-	-
*	Falls	1,296,752	-	-	33,793	142,003	169,882	562,170	512	-
*	Fort Smallwood	229,561	-	-	-	257,127	3,425	-	-	-
*	Gould St	120,655	-	3,114	353,658	10,940	-	-	-	-
*	Handsome Lake	9,841	-	-	-	-	-	-	-	-
*	LaSalle	91,943,066	-	4,666,236	1,944,786	23,115,092	6,488,908	6,572,575	2,026,797	10,275,282
*	Limerick	152,931,562	-	41,192,118	1,414,202	23,319,901	1,188,580	228,627	1,050,152	5,506,158
*	Moser	1,539,315	-	-	9,365	262,801	174,009	589,074	-	-
*	Muddy Run	49,533,204	-	4,657,845	129,233	4,929,960	1,669,534	6,130,553	589,215	120,583
*	Notch Cliff	5,115,261	-	-	-	33,556	237,988	981,137	57,272	-
*	Oyster Ck	29,048,791	-	19,820,373	-	-	-	-	565,862	-
*	Peach Bottom	112,905,096	-	41,363,873	2,015,820	19,695,956	11,507,453	625,734	1,862,746	129,640
*	Pennsbury	242,106	-	-	-	17,310	-	-	-	-
*	Perryman	22,843,595	5,346,841	784,897	-	-	-	59,681	-	-
*	Philadelphia Rd	2,100,938	-	-	-	-	2,648,610	-	-	-
*	Quad Cities	76,259,093	-	25,109,413	2,133,713	7,403,630	2,898,057	3,872,699	8,262,803	3,321,149
*	Richmond	3,266,852	-	355,663	110,173	376,173	31,046	98,992	69,638	-
*	Riverside	4,370,438	-	328,562	61,893	2,209,028	738,213	518,931	98,872	-
*	Salem	57,321,438	-	14,618,814	-	459,119	-	-	-	-
*	Schuylkill	553,360	-	-	8,355	207,889	8,299	183,098	-	-
*	SE Chicago	13,797,435	-	4,624,203	-	-	-	-	-	-
*	Southwark	2,598,638	-	2,616	40,019	65,482	1,638,273	59,982	-	-
*	TMI	12,600,036	-	-	-	-	-	-	1,804,433	-
*	Westport	2,063,236	-	288,614	-	-	-	-	-	-

ACCESSORY ELECTRICAL EQUIPMENT

	Row Labels	Fire Protection System	HVAC	Regulating Equipment	Structure	Misc.	Exciter & PPT	Station Grounding	Bus & Insulators	Capacitor Bank
1	Braidwood	-	-	-	-	19,860,488	-	-	-	-
2	Byron	-	-	48,068	-	18,414,787	-	-	-	-
3	Chester	-	-	-	-	560,700	-	-	-	-
4	Common Combustions	-	-	-	-	44,507	-	-	-	-
5	Conowingo	-	-	390,726	270,434	15,212,502	126,475	-	-	-
6	Crane	-	-	-	-	-	-	-	-	-
7	Croydon	-	-	-	56,420	5,030,779	-	-	75,133	-
8	Delaware	-	-	-	-	370,485	-	-	-	-
9	Dresden	-	-	153,468	31,844	63,976,359	-	4,948	4,134,523	-
10	Eddystone	-	-	-	167,065	7,066,463	-	-	-	-
11	Fairless Hills	-	-	-	-	154,657	-	-	-	-
12	Falls	-	-	-	8,093	380,300	-	-	-	-
13	Fort Smallwood	-	-	-	-	24,461	-	-	-	-
14	Gould St	-	-	-	-	-	-	-	-	-
15	Handsome Lake	-	-	-	-	-	-	-	-	-
16	LaSalle	-	-	-	445,431	85,054,019	-	-	5,590,781	-
17	Limerick	-	-	-	301,814	76,645,785	-	-	-	-
18	Moser	-	-	-	13,093	490,974	-	-	-	-
19	Muddy Run	-	-	505,742	-	29,526,543	-	181,000	-	-
20	Notch Cliff	-	-	4,640,268	6,922	118,909	-	9,880	-	-
21	Oyster Ck	-	-	-	-	8,662,556	-	-	-	-
22	Peach Bottom	126,725	-	794	25,625	28,280,047	-	20,693	(50,699)	-
23	Pennsbury	-	-	-	-	224,796	-	-	-	-
24	Perryman	-	-	176,513	-	21,318,503	-	-	-	-
25	Philadelphia Rd	-	-	-	-	412,515	-	-	-	-
26	Quad Cities	-	-	-	133,041	35,712,768	-	2,051	2,444,859	-
27	Richmond	-	-	-	41,045	2,183,819	-	-	-	-
28	Riverside	7,984	-	306,814	4,701	-	15,989	190,636	-	-
29	Salem	22,085,749	-	-	-	16,168,621	-	-	-	-
30	Schuylkill	-	-	-	41,588	104,130	-	-	-	-
31	SE Chicago	-	-	-	-	9,173,232	-	-	-	-
32	Southwark	-	-	-	11,054	781,212	-	-	-	-
33	TMI	194,043	-	-	-	10,382,696	-	-	-	-
34	Westport	-	-	1,486,640	-	217,121	-	-	-	-
35	Total	22,414,501	-	7,709,033	1,558,170	456,554,732	142,463	409,208	12,194,598	-

ACCESSORY ELECTRICAL EQUIPMENT

	Detailed Row Labels	Fire Protection System	HVAC	Regulating Equipment	Structure	Misc.	Exciter & PPT	Station Grounding	Bus & Insulators	Capacitor Bank
*	Braidwood	-	-	-	-	19,860,488	-	-	-	-
*	Byron	-	-	48,068	-	18,414,787	-	-	-	-
*	Chester	-	-	-	-	560,700	-	-	-	-
*	Common Combustions	-	-	-	-	44,507	-	-	-	-
*	Conowingo	-	-	390,726	270,434	15,212,502	126,475	-	-	-
*	Crane	-	-	-	-	-	-	-	-	-
*	Croydon	-	-	-	56,420	5,030,779	-	-	75,133	-
*	Delaware	-	-	-	-	370,485	-	-	-	-
*	Dresden	-	-	153,468	31,844	63,976,359	-	4,948	4,134,523	-
*	Eddystone	-	-	-	167,065	7,066,463	-	-	-	-
*	Fairless Hills	-	-	-	-	154,657	-	-	-	-
*	Falls	-	-	-	8,093	380,300	-	-	-	-
*	Fort Smallwood	-	-	-	-	24,461	-	-	-	-
*	Gould St	-	-	-	-	-	-	-	-	-
*	Handsome Lake	-	-	-	-	-	-	-	-	-
*	LaSalle	-	-	-	445,431	85,054,019	-	-	5,590,781	-
*	Limerick	-	-	-	301,814	76,645,785	-	-	-	-
*	Moser	-	-	-	13,093	490,974	-	-	-	-
*	Muddy Run	-	-	505,742	-	29,526,543	-	181,000	-	-
*	Notch Cliff	-	-	4,640,268	6,922	118,909	-	9,880	-	-
*	Oyster Ck	-	-	-	-	8,662,556	-	-	-	-
*	Peach Bottom	126,725	-	794	25,625	28,280,047	-	20,693	(50,699)	-
*	Pennsbury	-	-	-	-	224,796	-	-	-	-
*	Perryman	-	-	176,513	-	21,318,503	-	-	-	-
*	Philadelphia Rd	-	-	-	-	412,515	-	-	-	-
*	Quad Cities	-	-	-	133,041	35,712,768	-	2,051	2,444,859	-
*	Richmond	-	-	-	41,045	2,183,819	-	-	-	-
*	Riverside	7,984	-	306,814	4,701	-	15,989	190,636	-	-
*	Salem	22,085,749	-	-	-	16,168,621	-	-	-	-
*	Schuylkill	-	-	-	41,588	104,130	-	-	-	-
*	SE Chicago	-	-	-	-	9,173,232	-	-	-	-
*	Southwark	-	-	-	11,054	781,212	-	-	-	-
*	TMI	194,043	-	-	-	10,382,696	-	-	-	-
*	Westport	-	-	1,486,640	-	217,121	-	-	-	-

Nuclear O&M Summary

			Braidwood 1 & 2	Byron 1 & 2	Dresden 1 & 2	LaSalle 1 & 2	Limerick 1 & 2	Oyster Creek	Peach Bottom 1 & 2	Quad Cities 1 & 2	Salem 1 & 2 (43%) calculated distribution	TMI
	Actual Expenses											
1	Base Payroll-	O&M	81,450,672	81,108,827	80,164,265	81,600,844	84,313,954	60,913,807	81,687,586	79,370,819	46,153,924.79	64,952,235
2	Stock Comp	O&M	1,317,081	1,303,487	1,101,284	1,207,840	1,673,407	1,077,097	1,790,154	904,370	759,317.92	1,246,508
3	Other Premium-	O&M	2,943,203	3,062,667	3,156,797	4,009,934		4,698,364	3,114,732	3,561,854	1,796,616.67	2,465,069
4	Overtime --	O&M	11,993,688	11,310,015	11,077,125	12,914,844	13,309,556	6,895,440	9,771,487	9,359,575	6,340,510.65	6,062,675
5	Contracting - Operations.	O&M	41,650,145	54,103,838	37,296,828	48,436,886	44,395,567	12,614,103	37,509,342	35,587,992	22,805,380.03	20,746,805
6	Contracting - Non-Operations.	O&M	8,976,034	6,962,858	7,261,212	6,660,558		10,617,668	11,172,140	6,873,256	4,283,307.08	9,316,811
7	Contracting - Outsourced.	O&M	1,357,861	1,505,001	1,091,113	3,285,717	1,425,522	405,221	1,371,239	1,122,938	846,405.26	831,536
8	Staff Augmentation.	O&M	337,894	45,705	268,522	372,212	800,199	320,339	851,129	(5,713)	218,856.79	351,596
9	Materials and Tools	O&M	18,935,184	19,316,877	16,248,410			6,753,723	18,562,963	14,292,834	6,887,838.97	10,133,298
10	Licensing and Telecom.	A&G	32,239	34,907	19,312	20,679	81,222	23,436	42,289	20,241	20,077.62	100,110
11	Regulatory Fees and Permits	A&G	19,831,531	19,662,343	19,971,004	19,970,543	17,519,098	13,663,846	17,220,208	20,018,016	10,821,511.78	12,073,062
12	Transportation & Fleet Service	A&G	276,041	256,581	214,130	239,946		-	572,164	163,723	126,074.73	31,160
13	Facilities, Rentals & Utils	A&G	1,150,629	1,081,940	762,047	913,307	277,986	867,972	31,916	341,442	397,215.60	780,689
14	Office Expense.	A&G	993,879	690,122	763,170	923,958	701,345	504,988	593,094	318,285	401,724.16	235,517
15	Charity and Contributions	A&G	139,115	31,998	26,957	86,181	50,645	40,421	28,400	29,415	31,700.64	30,064
16	Memberships, Dues & Subscrip	A&G	12,669	11,700	13,092	14,669	15,948	7,190	17,984	11,506	7,667.12	30,884
17	Seminars and Training.	A&G	35,204	78,086	115,188	106,393	107,267	81,876	53,320	56,748	46,407.91	12,296
18	Travel, Entertainment & Reimb.	A&G	2,043,258	2,564,261	1,620,295	2,116,449	2,678,097	1,570,009	2,143,327	2,008,466	1,225,492.48	1,601,189
19	InterCompany.	A&G	2,955,342	1,833,864	3,348,948	3,667,776	2,862,789	910,077	1,861,828	763,729	1,332,362.88	2,040,554
20												
21	Total Depreciation	Depreciation	39,203,314	38,603,318	62,194,479	39,145,902	33,598,920	37,290,080	45,507,821	43,271,711	17,015,247	38,072,513
22	Total Insurance	A&G	4,844,360	4,808,976	4,336,015	4,795,414	5,186,848	2,746,321	1,818,626	2,718,756	2,287,552.77	2,627,838
23	Payroll Taxes..	Other Tax	7,269,439	7,259,232	7,076,336	7,193,199	7,359,580	5,403,699	7,131,785	7,072,586	4,081,460.78	5,775,935
24	Property Taxes	Other Tax	20,026,176	33,153,706	25,219,637	21,480,427	3,904,607	2,350,996	1,715,677	8,057,140	8,483,245.57	1,135,951
25	Other Taxes	Other Tax	-	-	-	-	64,962	1,114,242	9,499	-	87,000.32	50,952
26	Pension.	A&G	20,936,860	20,518,770	19,902,343	20,444,497	20,527,026	10,591,350	19,635,722	20,127,780	11,174,851.65	11,438,570
27	Fringe Benefits.	A&G	14,211,257	14,149,184	13,782,272	14,070,516	14,335,773	10,143,334	14,024,640	13,835,682	7,944,886.85	10,853,347
28	Incentive-	A&G	13,817,545	13,710,077	13,099,747	13,424,324	13,493,665	8,847,381	13,380,470	13,216,515	7,537,739.83	9,472,036
29	Allocated O&M	A&G	31,233,648	28,639,186	29,129,317	29,815,109	30,688,308	19,988,786	29,289,390	28,256,448	16,616,899.65	23,673,646
30	BSC Services-	A&G	7,396,232	6,843,306	6,956,360	7,976,336	7,392,990	6,144,197	7,928,675	7,645,090	4,265,702.19	6,453,857
31	Non Nuclear Expense	A&G	2,002	-	-	-	-	-	-	-	146.52	-
32	Other Expenses--	A&G	4,455,601	4,289,853	(331,022)	193,433	686,440	(491,623)	(238,860)	(120,190)	617,982.95	(691,674)
33												
34	Total		359,828,102	376,940,685	365,885,185	345,087,893	307,451,721	226,094,338	328,598,746	318,881,015	184,615,109	241,905,028

SI-SSA-0010-4257

Nuclear O&M Summary

35	**Proxy - Average of 5 Nuclear Units**		Nuclear	< "Fossil & Hydro & Nuclear O&M Proxy Breakout.xlsx"							84,020,036	82,961,325
36	Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546	19.23%								1,818,626	2,718,756
37	Coolants and Water (Nuclear Plants Only)	FERC Account 519	1.88%								85,838,662	85,680,080
38	Steam Expenses	FERC Account 502, 520	11.82%									
39	Steam From Other Sources	FERC Account 503	0.00%									
40	Electric Expenses	FERC Account 505, 523	0.00%									
41	Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524	1.21%									
42	Rents	FERC Account 507	33.39%									
43	Allowances	FERC Account 509	2.65%									
44	Maintenance Supervision and Engineering	FERC Account 510, 528	0.00%									
45	Maintenance of Structures	FERC Account 511, 529, 552	3.55%									
46	Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530	0.28%									
47	Maintenance of Electric Plant	FERC Account 513, 531, 554	9.14%									
48	Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532	5.87%									
49	Other Power Production, & Other Expenses	FERC Account 548-553; 557	10.99%									
50	Total O&M		100.00%									
51												
52	**Componentized O&M**											

			Braidwood 1 & 2	Byron 1 & 2	Dresden 1 & 2	LaSalle 1 & 2	Limerick 1 & 2	Oyster Creek	Peach Bottom 1 & 2	Quad Cities 1 & 2	Salem 1 & 2 (43%)	TMI
53												
54	Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546	32,492,207	34,368,626	30,319,889	30,478,210	28,060,813	20,056,606	31,890,101	29,051,131	17,325,181	22,327,877
55	Coolants and Water (Nuclear Plants Only)	FERC Account 519	3,183,689	3,367,547	2,970,838	2,986,351	2,749,487	1,965,210	3,124,693	2,846,522	1,697,576	2,187,756
56	Steam Expenses	FERC Account 502, 520	19,969,572	21,122,811	18,634,475	18,731,778	17,246,057	12,326,705	19,599,521	17,854,702	10,647,982	13,722,618
57	Steam From Other Sources	FERC Account 503	-	-	-	-	-	-	-	-	-	-
58	Electric Expenses	FERC Account 505, 523	-	-	-	-	-	-	-	-	-	-
59	Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524	2,040,158	2,157,976	1,903,760	1,913,700	1,761,914	1,259,337	2,002,352	1,824,095	1,087,833	1,401,948
60	Rents	FERC Account 507	56,408,634	59,666,223	52,637,346	52,912,201	48,715,440	34,819,603	55,363,339	50,434,698	30,077,667	38,762,682
61	Allowances	FERC Account 509	4,476,155	4,734,652	4,176,895	4,198,705	3,865,683	2,763,016	4,393,209	4,002,110	2,386,732	3,075,908
62	Maintenance Supervision and Engineering	FERC Account 510, 528	-	-	-	-	-	-	-	-	-	-
63	Maintenance of Structures	FERC Account 511, 529, 552	5,994,248	6,340,415	5,593,493	5,622,700	5,176,733	3,700,095	5,883,170	5,359,429	3,196,195	4,119,106
64	Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530	467,205	494,186	435,969	438,245	403,486	288,393	458,547	417,725	249,118	321,052
65	Maintenance of Electric Plant	FERC Account 513, 531, 554	15,446,317	16,338,339	14,413,629	14,488,892	13,339,698	9,534,615	15,160,085	13,810,480	8,236,136	10,614,344
66	Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532	9,921,805	10,494,787	9,258,467	9,306,811	8,568,637	6,124,475	9,737,946	8,871,039	5,290,409	6,818,030
67	Other Power Production, & Other Expenses	FERC Account 548-553; 557	18,561,772	19,633,712	17,320,796	17,411,239	16,030,257	11,457,706	18,217,809	16,595,995	9,897,329	12,755,212
68	O&M	Sum lines 53-66	168,961,761	178,719,274	157,665,557	158,488,835	145,918,204	104,295,761	165,830,771	151,067,926	90,092,158	116,106,533
69	A&G	Sum A&G lines above	124,367,412	119,205,155	113,729,176	118,779,529	116,605,447	75,639,559	108,403,193	109,411,651	64,855,997	80,763,143
70	Depreciation	Line 21	39,203,314	38,603,318	62,194,479	39,145,902	33,598,920	37,290,080	45,507,821	43,271,711	17,015,247	38,072,513
71	Property Tax and Other Tax	Line 24 & 25	20,026,176	33,153,706	25,219,637	21,480,427	3,969,570	3,465,238	1,725,176	8,057,140	8,570,246	1,186,903
72	Payroll	Line 23	7,269,439	7,259,232	7,076,336	7,193,199	7,359,580	5,403,699	7,131,785	7,072,586	4,081,461	5,775,935
73	Total O&M	Sum lines 67-71	359,828,102	376,940,685	365,885,185	345,087,893	307,451,721	226,094,338	328,598,746	318,881,015	184,615,109	241,905,028

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Non-nuclear O&M Summary

			Total	Chester	Conowingo	Croyden	Delaware Station	Eddystone	Fairless Hills
1	O&M	$	66,296,430	$ 172,268	$ 16,752,129	$ 2,552,217	$ 365,535	$ 16,779,786	$ 7,651,534
2	A&G	$	8,668,887	$ 8,214	$ 2,067,560	$ 127,260	$ 18,226		$ 833,095
3	DEPR	$	40,425,810	$ 7,267	$ 6,605,136	$ 129,843	$ 18,596		$ 3,643,397
4	OTR TX	$	13,072,583	$ 5,780	$ 3,947,920	$ 87,293	$ 27,880	$ 3,170,443	$ 263,599
		$	128,463,710	$ 193,529	$ 29,372,744	$ 2,896,613	$ 430,238	$ 19,950,230	$ 12,391,625
				$ 128,463,710					
	LABOR -- These plants	$	28,471,791	$ 88,325	$ 8,193,348	$ 1,243,903	$ 178,155	$ 6,760,484	$ 3,682,245
	LABOR -- Other fossil plants	$	38,539,019	< Source: "2015 Exelon Power Adjusted O&M View (recast SMM 9-2 control total.xlxs"					
	TOTAL non-nuc labor	$	67,010,810						
	Non-nuclear allocators (these plants)			0.001318076	0.12226905	0.018562715	0.002658599		0.05495002

	Average of Units		Fossil	
5	Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546	22.30%	(535) Operation Supervision and Engineering
6	Coolants and Water (Nuclear Plants Only)	FERC Account 519	0.00%	
7	Steam Expenses	FERC Account 502, 520	5.76%	(536) Water for Power
8	Steam From Other Sources	FERC Account 503	11.13%	(537) Hydraulic Expenses
9	Electric Expenses	FERC Account 505, 523	0.00%	(538) Electric Expenses
10	Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524	3.41%	(539) Miscellaneous Hydraulic Power Generation Expenses
11	Rents	FERC Account 507	20.76%	(540) Rents
12	Allowances	FERC Account 509	0.84%	
13	Maintenance Supervision and Engineering	FERC Account 510, 528	0.00%	(541) Maintenance Supervision and Engineering
14	Maintenance of Structures	FERC Account 511, 529, 552	8.70%	(542) Maintenance of Structures
15	Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530	3.73%	(543) Maintenance of Reservoirs, Dams, and Waterways
16	Maintenance of Electric Plant	FERC Account 513, 531, 554	3.88%	(544) Maintenance of Electric Plant
17	Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532	4.83%	(545) Maintenance of Miscellaneous Hydraulic Plant
18	Other Power Production, & Other Expenses	FERC Account 548-553; 557	14.65%	
19	Total O&M		100.00%	

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Non-nuclear O&M Summary

	Componentized O&M		Chester	Conowingo	Croyden	Delaware Station	Eddy 3&4	Fairless Hills
20	Production Expenses: Oper, Supv, & Engr	FERC Account 500, 517, 546	38,422	3,736,335	569,237	81,528	3,742,503	1,706,571
21	Coolants and Water (Nuclear Plants Only)	FERC Account 519	-	-	-	-	-	-
22	Steam Expenses	FERC Account 502, 520	9,925	965,123	147,038	21,059	966,716	440,820
23	Steam From Other Sources	FERC Account 503	19,178	1,864,987	284,134	40,694	1,868,066	851,833
24	Electric Expenses	FERC Account 505, 523	-	-	-	-	-	-
25	Misc Steam (or Nuclear) Power Expenses	FERC Account 506, 524	5,876	571,384	87,051	12,468	572,328	260,980
26	Rents	FERC Account 507	35,759	3,477,388	529,786	75,877	3,483,129	1,588,297
27	Allowances	FERC Account 509	1,445	140,516	21,408	3,066	140,748	64,181
28	Maintenance Supervision and Engineering	FERC Account 510, 528	-	-	-	-	-	-
29	Maintenance of Structures	FERC Account 511, 529, 552	14,987	1,457,393	222,036	31,801	1,459,799	665,664
30	Maintenance of Boiler (or reactor) Plant	FERC Account 512, 530	6,427	624,956	95,213	13,637	625,988	285,449
31	Maintenance of Electric Plant	FERC Account 513, 531, 554	6,686	650,181	99,056	14,187	651,254	296,970
32	Maintenance of Misc Steam (or Nuclear) Plant	FERC Account 514, 515, 532	8,322	809,240	123,289	17,658	810,576	369,620
33	Other Power Production, & Other Expenses	FERC Account 548-553; 557	25,242	2,454,627	373,967	53,560	2,458,680	1,121,151
34	Total O&M	Sum lines 20-33	172,268	16,752,129	2,552,217	365,535	16,779,786	7,651,534
35	A&G	Line 2	8,214	2,067,560	127,260	18,226	-	833,095
36	Depreciation	Line 3	7,267	6,605,136	129,843	18,596	-	3,643,397
37	Property, Payroll and Other Taxes	Line 4	5,780		87,293	27,880	3,170,443	263,599
		Total	193,529	25,424,824	2,896,613	430,238	19,950,230	12,391,625

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Non-nuclear O&M Summary

		Falls	Gould St.	Handsome Lake	Moser	Muddy Run	Notch Cliff	Pennsbury	Perryman
1	O&M	$ 332,898	$ 2,594,809	$ 2,331,757	$ 332,898	$ 2,087,224	$ 973,126	$ 1,056,155	$ 7,006,986
2	A&G	$ 16,599	$ 767,400	$ 713,054	$ 16,599	$ 1,887,948	$ 145,511	$ 95,853	$ 757,586
3	DEPR	$ 16,936	$ 1,041,577	$ 3,405,815	$ 16,936	$ 3,638,807	$ 2,297,886	$ 194,037	$ 7,335,545
4	OTR TX	$ 11,386	$ 653,648	$ 163,782	$ 11,386	$ 692,571	$ 222,581	$ 55,959	$ 2,143,070
		$ 377,819	$ 5,057,434	$ 6,614,408	$ 377,819	$ 8,306,550	$ 3,639,105	$ 1,402,004	$ 17,243,187
	LABOR -- These plants	$ 162,248	$ 395,908	$ 818,474	$ 162,248	$ -	$ 490,815	$ 488,053	$ 3,457,195
	LABOR -- Other fossil plants								
	TOTAL non-nuc labor								
	Non-nuclear allocators (these plants)	0.002421224	0.005908128	0.012214064	0.002421224	0	0.007324409	0.0072832	0.051591602

	Average of Units	Hydro	Conowingo	Muddy Run
5	Production Expenses: Oper, Supv, & Engr	6.19%	1,036,292	129,116
6	Coolants and Water (Nuclear Plants Only)		-	-
7	Steam Expenses	5.11%	855,810	106,629
8	Steam From Other Sources	30.43%	5,098,303	635,221
9	Electric Expenses	10.06%	1,685,208	209,968
10	Misc Steam (or Nuclear) Power Expenses	10.05%	1,684,113	209,831
11	Rents	1.45%	243,307	30,315
12	Allowances		-	-
13	Maintenance Supervision and Engineering	3.43%	575,100	71,654
14	Maintenance of Structures	4.13%	691,360	86,140
15	Maintenance of Boiler (or reactor) Plant	15.19%	2,545,004	317,094
16	Maintenance of Electric Plant	10.88%	1,823,125	227,151
17	Maintenance of Misc Steam (or Nuclear) Plant	3.07%	514,507	64,105
18	Other Power Production, & Other Expenses			
19	Total O&M	100.00%	16,752,129	2,087,224

NOTE: Fossil and Hydro expense distribution shares
&M

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Non-nuclear O&M Summary

	Componentized O&M	Falls	Gould St.	Handsome Lake	Moser	Muddy Run	Notch Cliff	Pennsbury	Perryman
20	Production Expenses: Oper, Supv, & Engr	74,248	578,737	520,067	74,248	465,527	217,043	235,561	1,562,813
21	Coolants and Water (Nuclear Plants Only)	-	-	-	-	-	-	-	-
22	Steam Expenses	19,179	149,492	134,337	19,179	120,249	56,064	60,847	403,686
23	Steam From Other Sources	37,061	288,876	259,591	37,061	232,367	108,337	117,580	780,076
24	Electric Expenses	-	-	-	-	-	-	-	-
25	Misc Steam (or Nuclear) Power Expenses	11,355	88,504	79,532	11,355	71,191	33,192	36,024	238,995
26	Rents	69,103	538,628	484,024	69,103	433,264	202,000	219,236	1,454,502
27	Allowances	2,792	21,765	19,559	2,792	17,508	8,163	8,859	58,774
28	Maintenance Supervision and Engineering	-	-	-	-	-	-	-	-
29	Maintenance of Structures	28,961	225,742	202,857	28,961	181,583	84,660	91,883	609,590
30	Maintenance of Boiler (or reactor) Plant	12,419	96,802	86,989	12,419	77,866	36,303	39,401	261,403
31	Maintenance of Electric Plant	12,920	100,709	90,500	12,920	81,009	37,769	40,991	271,954
32	Maintenance of Misc Steam (or Nuclear) Plant	16,081	125,347	112,639	16,081	100,827	47,008	51,019	338,484
33	Other Power Production, & Other Expenses	48,778	380,208	341,664	48,778	305,833	142,589	154,755	1,026,708
34	Total O&M	332,898	2,594,809	2,331,757	332,898	2,087,224	973,126	1,056,155	7,006,986
35	A&G	16,599	767,400	713,054	16,599	1,887,948	145,511	95,853	757,586
36	Depreciation	16,936	1,041,577	3,405,815	16,936	3,638,807	2,297,886	194,037	7,335,545
37	Property, Payroll and Other Taxes	11,386	653,648	163,782	11,386	692,571	222,581	55,959	2,143,070
		377,819	5,057,434	6,614,408	377,819	8,306,550	3,639,105	1,402,004	17,243,187

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Non-nuclear O&M Summary

		Philadelphia Road	Richmond	Riverside	Schuylkill	SCEP	Southwark	Westport
1	O&M	$ 662,620	$ 639,686	$ 413,844	$ 309,577	$ 2,061,381	$ 339,425	$ 880,575
2	A&G	$ 70,095	$ 31,896	$ 240,209	$ 395,698	$ 314,901	$ 16,925	$ 144,258
3	DEPR	$ 893,706	$ 32,544	$ 1,911,250	$ 9,250	$ 6,252,881	$ 17,268	$ 2,957,132
4	OTR TX	$ 264,526	$ 21,879	$ 379,744	$ 11,465	$ 150,320	$ 11,609	$ 775,741
		$ 1,890,947	$ 726,005	$ 2,945,046	$ 725,990	$ 8,779,484	$ 385,227	$ 4,757,705
	LABOR -- These plants	$ 166,220	$ 311,771	$ 106,446	$ 180,651	$ 947,230	$ 165,430	$ 472,641
	LABOR -- Other fossil plants							
	TOTAL non-nuc labor							
	Non-nuclear allocators (these plants)	0.002480492	0.004652548	0.001588492	0.002695846	0.014135483	0.002468699	0.007053208
	Average of Units							
5	Production Expenses: Oper, Supv, & Engr							
6	Coolants and Water (Nuclear Plants Only)							
7	Steam Expenses							
8	Steam From Other Sources							
9	Electric Expenses							
10	Misc Steam (or Nuclear) Power Expenses							
11	Rents							
12	Allowances							
13	Maintenance Supervision and Engineering							
14	Maintenance of Structures							
15	Maintenance of Boiler (or reactor) Plant							
16	Maintenance of Electric Plant							
17	Maintenance of Misc Steam (or Nuclear) Plant							
18	Other Power Production, & Other Expenses							
19	Total O&M							

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Non-nuclear O&M Summary

	Componentized O&M	Philadelphia Road	Richmond	Riverside	Schuylkill	SCEP	Southwark	Westport
20	Production Expenses: Oper, Supv, & Engr	147,788	142,673	92,302	69,047	459,763	75,704	196,400
21	Coolants and Water (Nuclear Plants Only)	-	-	-	-	-	-	-
22	Steam Expenses	38,175	36,854	23,842	17,835	118,760	19,555	50,732
23	Steam From Other Sources	73,768	71,215	46,073	34,465	229,490	37,788	98,033
24	Electric Expenses	-	-	-	-	-	-	-
25	Misc Steam (or Nuclear) Power Expenses	22,601	21,819	14,115	10,559	70,310	11,577	30,035
26	Rents	137,546	132,785	85,905	64,262	427,899	70,458	182,789
27	Allowances	5,558	5,366	3,471	2,597	17,291	2,847	7,386
28	Maintenance Supervision and Engineering	-	-	-	-	-	-	-
29	Maintenance of Structures	57,646	55,651	36,003	26,932	179,335	29,529	76,608
30	Maintenance of Boiler (or reactor) Plant	24,720	23,864	15,439	11,549	76,902	12,663	32,851
31	Maintenance of Electric Plant	25,717	24,827	16,062	12,015	80,006	13,174	34,177
32	Maintenance of Misc Steam (or Nuclear) Plant	32,009	30,901	19,991	14,955	99,578	16,397	42,538
33	Other Power Production, & Other Expenses	97,091	93,731	60,639	45,361	302,046	49,735	129,027
34	Total O&M	662,620	639,686	413,844	309,577	2,061,381	339,425	880,575
35	A&G	70,095	31,896	240,209	395,698	314,901	16,925	144,258
36	Depreciation	893,706	32,544	1,911,250	9,250	6,252,881	17,268	2,957,132
37	Property, Payroll and Other Taxes	264,526	21,879	379,744	11,465	150,320	11,609	775,741
		1,890,947	726,005	2,945,046	725,990	8,779,484	385,227	4,757,705

SI-SSA-0010-4264

Exhibit No. EXE-4

FOSSIL/HYDRO/NUCLEAR O AND M PROXY BREAKDOWN

Fossil Proxy	%		Carpenter Common	Carpenter 1	Carpenter 2	Hot Spring E	Lake Catheri	Lake Catherine	Mabelvale 1	Mabelvale 3	Remmel Cor	Remmel 1	Remmel 2	Remmel 3	White Bluff Co	White Bluff 1	White Bluff 2
92,922,409	22%	Production Expenses: Oper, Supv, & Engr	-	-	-	23,995	949,514	797,611	42,786	42,786	-	-	-	-	796,056	1,003,971	1,035,494
-	0%	Coolants and Water (Nuclear Plants Only)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24,002,539	6%	Steam Expenses	-	-	-	-		860,221	-	-	-	-	-	-	1,246,088	-	-
46,382,102	11%	Steam From Other Sources	118,335	2,033	3,651	-	-	-	-	-	129,832	374	48	64	-	-	-
-	0%	Steam Transferred (Cr)	-	-	-	-		-	-	-	-	-	-	-	-	-	-
14,210,289	3%	Electric Expenses	-	-	-	316,765	27,006	565,700	30,207	30,183	-	-	-	-	214,442	194,990	194,113
86,482,428	21%	Misc Steam (or Nuclear) Power Expenses	-	-	-	2,645	689,447	476,171	29,921	29,921	3,036	4,283	19,364	7,463	1,698,964	649,818	807,491
3,494,622	1%	Rents	152,778	1,373	1,420	23,898		19,394	3,590	2,912	109,982	189	142	189	67,422	22,304	22,960
-	0%	Allowances	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36,245,280	9%	Maintenance Supervision and Engineering	8,862	3,825	3,957	-	-	-	-	-	8,164	528	396	528	-	-	-
15,542,612	4%	Maintenance of Structures	81,679	-	-	23,814		20,833	26,654	12,628	6,101	-	-	-	533,515	26,579	26,160
16,169,950	4%	Maintenance of Boiler (or reactor) Plant	283,897	2,744	4,328	-	44,352	2,096,552	(31)	(31)	304,173	5,385	-	-	583,832	4,024,905	5,071,956
20,125,738	5%	Maintenance of Electric Plant	170,139	9,220	74,290	510	26,124	412,117	35,637	16,421	175,123	7,951	2,380	2,042	838,699	715,649	844,637
61,046,422	15%	Maintenance of Misc Steam (or Nuclear) Plant	63,031	2,899	2,999			27,817	(2,533)	(2,750)	219,066	6,081	300	400	1,097,751	(57,327)	(63,665)
416,624,391	100%																

Hydro Proxyy			Consumers		Appalachian		Penn. Power	
		C. Hydraulic Power Generation	1997	1996	1997	1996	1997	1996
	%	Operation						
3,757,027	7%	(535) Operation Supervision and Engineering	711614	650528	746048	845655	363490	439692
2,309,333	4%	(536) Water for Power	1014382	953299	12446	12594	171398	145214
19,420,852	35%	(537) Hydraulic Expenses	3487080	15259456	360910	550028	-236622	0
4,873,395	9%	(538) Electric Expenses	1377354	1410986	575818	431396	536990	540851
5,582,448	10%	(539) Miscellaneous Hydraulic Power Generation Expens	1035844	940865	1431736	1600768	345141	228094
940,895	2%	(540) Rents	-477	4251	366701	432695	68094	69631
1,898,369	3%	(541) Maintenance Supervision and Engineering	308118	307982	700537	508305	29419	44008
1,972,053	4%	(542) Maintenance of Structures	467378	841226	351287	267448	19903	24811
8,439,384	15%	(543) Maintenance of Reservoirs, Dams, and Waterways	2704111	2474125	545912	487416	2106109	121711
5,750,867	10%	(544) Maintenance of Electric Plant	886409	2354650	1119041	1071545	141498	177724
1,271,565	2%	(545) Maintenance of Miscellaneous Hydraulic Plant	463708	186369	203717	310246	46843	60682
56,216,188	100%							

Nuclear Proxy

row_literal	2013	2014	2015		
Plant Name	Prairie Island	Prairie Island	Prairie Island		
Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear	Nuclear	Nuclear		
Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional	Conventional		
Year Originally Constructed	1973	1973	1973		
Year Last Unit was Installed	1974	1974	1974		
Total Installed Cap (Max Gen Name Plate Ratings-MW)	1186.20	1186.20	1186.20		
Net Peak Demand on Plant - MW (60 minutes)	1106	1112	1109		
Plant Hours Connected to Load	8760	8760	8760		
Net Continuous Plant Capability (Megawatts)	1092	1092	1092		
When Not Limited by Condenser Water	1092	1092	1092		
When Limited by Condenser Water	1040	1040	1040		
Average Number of Employees	723	735	673		
Net Generation, Exclusive of Plant Use - KWh	7,714,143,000	8,383,200,000	7,374,711,000		
Cost of Plant: Land and Land Rights	361,732	361,732	361,732		
Structures and Improvements	244,334,949	272,770,914	302,394,576		
Equipment Costs	1,412,694,111	1,473,681,172	1,624,594,259		
Asset Retirement Costs	8,904,951		174,529,690		
Total Cost	1,666,295,743	1,921,343,508	2,101,880,257		
Cost per KW of Installed Capacity (line 17/5) Including	1,405	1,620	1,772		
Production Expenses: Oper, Supv, & Engr	46,343,435	47,983,862	40,006,456	44,777,918	19.23%
Coolants and Water (Nuclear Plants Only)	4,078,764	4,556,348	4,527,336	4,387,483	1.88%
Steam Expenses	25,788,024	29,153,538	27,619,391	27,520,318	11.82%
Steam From Other Sources	0	0	0	0	0.00%
Steam Transferred (Cr)	0	0	0	0	0.00%
Electric Expenses	2,813,977	3,438,751	2,181,969	2,811,566	1.21%
Misc Steam (or Nuclear) Power Expenses	74,225,075	80,830,743	78,156,514	77,737,444	33.39%
Rents	5,990,962	6,344,104	6,170,870	6,168,645	2.65%
Allowances	0	0	0	0	0.00%
Maintenance Supervision and Engineering	12,240,482	8,175,195	4,366,565	8,260,747	3.55%
Maintenance of Structures	599,086	646,661	685,835	643,861	0.28%
Maintenance of Boiler (or reactor) Plant	19,004,939	22,018,742	22,836,604	21,286,762	9.14%
Maintenance of Electric Plant	11,427,245	14,595,954	14,996,893	13,673,364	5.87%
Maintenance of Misc Steam (or Nuclear) Plant	19,359,524	25,519,990	31,861,122	25,580,212	10.99%
Total Production Expenses	301,006,168	321,890,212	298,442,774	232,848,319	100.00%

SI-SSA-0010-4266

FOSSIL/HYDRO/NUCLEAR O AND M PROXY BREAKDOWN

Independenc	Independenc	Independence	Lewis Creek C	Lewis Creek 1	Lewis Creek 2	Sabine Comr	Sabine 1	Sabine 2	Sabine 3	Sabine 4	Sabine 5	Attala Commor	Attala 1	Baxter Wilson (	Baxter Wilson '	Baxter Wilson 2	Gerald Andrus	Hinds	Rex Brown C	Rex Brown 3
589,763	180,315	186,810	1,022,737	280,436	276,310	572,066	1,011,112	327,866	228,084	667,875	529,098	384,027	462,483	1,725,269	491,166	646,639	2,030,826	383,104	475,043	66,184
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
400,540	9,328	10,293	176,623	158,475	158,476	1,576	2,140,696	239,126	9,258	256,020	1,320	-	-	1,095,523	604	3,404	210,897	-	698,609	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
655,554	64,921	69,433	159,070	321,056	321,089	(7,397)	822,176	17,900	193	8,681	11,204	138,346	105,307	880,997	351	492	6,739	287	237,196	49
927,195	166,199	210,269	1,526,917	474,071	439,983	255,145	2,340,189	140,684	116,882	214,632	259,115	1,959,873	1,844,598	1,018,238	325,619	440,534	1,414,611	375,707	485,621	47,908
17,889	4,956	4,987	22,550	12,414	10,127	13,965	14,562	8,023	8,023	10,572	12,426	84,056	48,599	20,956	15,359	15,545	52,020	7,026	21,313	1,187
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	189,901	103,719	105,694	77,860	113,135	39,170	77,595	116,195	88,561	125,727	19,903	112,435	95,032	45,119	394,213	5,136	105,942	3,136
235,432	12,201	20,167	391,586	6,999	3,602	17,085	758,600	20,840	2,683	1,264	5,575	25,394	129,021	203,785	16,656	9,830	319,219	321	454,505	2,804
313,768	572,775	1,945,625	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
178,895	465,873	1,744,069	391,586	6,999	3,602	17,085	758,600	20,840	2,683	1,264	5,575	25,394	129,021	203,785	16,656	9,830	319,219	321	454,505	2,804
511,970	98,824	132,334	47,577	1,291,036	354,581	578,463	194,439	569,732	602,192	1,041,243	2,718,114	-	-	448,944	1,702,939	2,074,040	1,799,798	-	294,660	108,184

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FOSSIL/HYDRO/NUCLEAR O AND M PROXY BREAKDOWN

Rex Brown 4	Rex Brown	Ouachita Common	Ouachita 1 EAI	Ouachita 2 EAI	Calcasieu Common	Calcasieu 1	Calcasieu 2	Nelson Common	Nelson 4 EGSL	Nelson 6 EGSL	Ouachita EGSL Common	Ouachita 3 EGSL	Riverbend 1 EGSL	Willow Glen Common	Willow Glen 2 EGSL	Willow Glen 4 EGSL	Acadia	Buras 8 ELL	Little Gypsy Common	Little Gypsy 1 ELL
243,458	15,119	1,243,949	193,536	200,288	84,155	220,634	236,629	12,543	732,073	791,446	623,144	523,647	21,554,396	1,103,665	301,890	718,995	835,641	19,620	1,094,367	249,299
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	128	139	(186,124)	709,982	592,307	-	195	6,418,645	990,682	20,604	11,232	-	29	816,413	11,197
-	-	-	-	-	-	-	-	-	-	-	-	-	22,033,918	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
148	7	90,723	221,279	182,824	496,832	4,105	4,463	(97,967)	1,351,266	1,101,362	45,807	222,897	-	25,904	10,237	86,879	-	245	827,310	3,149
132,992	5,924	969,428	183,384	188,438	243,019	296,338	166,808	149,631	564,742	91,503	482,236	400,403	22,852,424	1,102,933	199,890	509,228	1,940,062	42,508	1,158,356	141,206
10,621	172	17,412	13,424	11,752	13,525	4,170	4,534	4,631	18,895	16,061	7,151	11,980	767,496	18,849	16,892	19,375	2,331	312	18,581	9,615
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61,001	126	169,602	45,054	43,108	11,040	4,802	5,221	350,339	57,336	278,877	76,959	10,339	12,455,781	36	28,187	23,212	-	3,971	396,549	61,043
34,980	8	108,270	56,631	77,836	6,311	9,904	1,388	13,704	38,322	328,334	54,284	16,827	4,639,802	560,525	20,867	25,538	-	14	171,360	124,101
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)	(0)
34,980	8	-	-	-	6,311	9,904	1,388	13,704	38,322	328,334	54,284	16,827	4,639,802	560,525	20,867	25,538	-	14	171,360	124,101
402,633	-	-	-	-	-	51	56	185,358	1,332,439	4,116,476	-	79	11,187,705	282,786	1,225,725	662,140	-	(3)	564,882	655,899

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FOSSIL/HYDRO/NUCLEAR O AND M PROXY BREAKDOWN

Little Gypsy 2 ELL	Little Gypsy 3 ELL	Ninemile Common	Ninemile 3 ELL	Ninemile 4 ELL	Ninemile 5 ELL	Perryville Common	Perryville 1 ELL	Perryville 2 ELL	Sterlington 7 ELL	Waterford 1 & 2 Common	Waterford 1 ELL	Waterford 2 ELL	Waterford 3 ELL	Waterford 4 ELL	Michoud Common	Michoud 2 ENO	Michoud 3 ENO	Total ETI	Nelson 6 Common	Nelson 6 ETI
418,399	570,591	1,113,948	135,336	777,399	823,047	700,420	530,535	160,405	383,483	359,408	545,536	391,600	27,120,515	801	2,619,608	550,298	646,480	-	148,012	529,536
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
654	29,281	1,061,075	3,199	16,033	3,459	-	843	234	31,931	769,722	617	617	4,132,587	-	96,677	2,223	47,036	-	2,312	410,685
-	-	-	-	-	-	-	-	-	-	-	-	-	24,093,846	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5,626	7,394	1,369,061	2,219	13,141	10,931	622,018	7,252	29,452	19,863	690,320	5,303	5,303	-	4,886	101,758	19,179	43,596	-	(183)	788,865
256,565	333,546	1,286,836	155,467	457,885	431,989	2,561,721	315,945	89,925	336,009	747,398	302,441	231,056	23,345,613	22	745,467	197,328	359,587	-	234,335	970,340
12,773	19,110	30,932	2,220	19,073	19,320	31,500	9,332	2,565	19,785	16,478	17,102	13,531	1,320,801	-	15,636	11,443	17,511	-	11,379	9,394
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47,232	69,891	568,013	23,955	67,341	65,466	323,255	30,920	12,552	54,449	154,107	133,902	25,018	18,201,375	-	249,100	47,640	52,779	-	3,702	187,269
58,260	156,785	1,227,675	10,069	237,706	86,888	65,958	410	1,375	145,593	184,768	22,846	15,699	1,975,554	2,828	468,685	15,137	65,270	-	90,052	241,281
(0)	(0)	(3)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(5)	(0)	-	-	-	-	-	-
58,260	156,784	1,227,671	10,069	237,705	86,887	65,958	410	1,375	145,593	184,767	22,846	15,699	1,975,549	2,828	468,685	15,137	65,270	-	-	-
283,612	915,059	644,926	211,751	2,364,175	2,444,491	-	(97)	(27)	63,382	638,489	436,526	415,039	8,308,669	-	110,861	1,727,417	1,892,220	-	10,805	3,019,347

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SERVICE LIVES OF GENERATING STATIONS

		Commer.	Retr. Or License	Yrs	Avg	
Braidwood	#1	7/88		2046	58	58.5
	#2	10/88		2047	59	
Byron	#1	9/85		2044	59	59
	#2	8/87		2046	59	
Dresden	#2		1970	2030	60	60
	#3		1971	2031	60	
LaSalle	#1	1/84				60
	#2	10/84				
Limerick	#1	2/86		2044	58	58.5
	#2	1/90		2049	59	
Oyster Ck	#1	12/69		2019		50
				(Exelon stated ret. date)		
Peach Bottom	#2	7/74		2033	59	59.5
	#3	12/74		2034	60	
Quad Cities	#1	12/72		2018	46	46
	#2	12/72		2018	46	
				(Exelon stated ret. date)		
Salem	#1	6/77		2036	59	59
	#2	10/81		2040	59	
TMI	#1	9/74		2034	60	60
Chester			1969	2033	64	
Conowingo			1929	2045	116	116
Croydon			1974	2033	59	
Delaware			1968	2033	65	
Eddystone			1968	2033	65	
Fairless Hills			1996	2023	27	
Falls			1970	2033	63	
Gould St	#3		1951	2025	74	
Handsome Lake			2001	2041	40	
Moser			1970	2033	63	
Muddy Run			1968	2045	77	77
Notch Cliff			1969	2028	59	
Pennsbury					50 (est)	
Perryman	1- 4		1972	2033	61	
Perryman		5	1995	2033	38	45
Perryman		6	2015	2055	40	
Perryman Ave					41	
Philadelphia Rd			1970	2025	55	
Richmond			1973	2033	60	
Riverside	#5		1970	2025	55	
Schuylkill			1970	2033	63	
SE Chicago	8-NG		2002	2032	30	
Southwark			2002	2033	31	
Westport			1969	2022	53	

		2015
ExGen Corp Operating Expenses - Before Co-Owner Billing Credits	$	-
Adjustments:		
UK	$	-
ENP	$	-
Exclusions	$	-
ExGen Corp. to Allocate	**$**	**-**
Constellation Unit-Related OH to Allocate	**$**	**164,975,502**
Constellation Wholesale - Unit Related	$	92,544,129
Constellation Wholesale - Not-Unit Related	$	68,977,996
Constellation Retail	$	204,635,410
Power Site	$	122,670,995
Nuclear Site	$	1,222,684,098
UK	$	601,754
ENP	$	2,520,783
Total Labor	**$**	**1,714,635,165**
% Unit-Related		83.9%
% Non-Unit-Related		16.1%
ExGen Corp OH to Allocate	$	-
Amount Allocated to Power	$	-
Amount Allocated to Nuclear	$	-
Total ExGen Corp. OH Allocated to Generation Units	$	-
Constellation Unit-Related OH to Allocate	$	164,975,502
Amount Allocated to Power	$	15,042,652.42
Amount Allocated to Nuclear	$	149,932,850
Total Constellation Unit-Related OH Allocated to Generation Units	$	164,975,502
Amount Allocated to Power	$	15,042,652
Amount Allocated to Nuclear	$	149,932,850
Total Allocated to Generation Units	$	164,975,502

A

PA Maintenance (58502, 58722)	% of Effort - MW	% of Effort - MWh	Management Estimate %	FTE Equivalent
Eddystone	37%	57%	60%	
Fairless/Pennsbury	18%	17%	20%	
PA CT's/Lamokin	45%	26%	20%	
SCEP	0%	0%	0%	0
Handsome Lake	0%	0%	0%	0
Total	100%	100%	100%	0

PA Maintenance – PA maintenance Staff & related expenses

B

PA Admin (58720)	% of Effort - MW	% of Effort - MWh	Management Estimate %	FTE Equivalent
Eddystone	24%	26%	30%	
Fairless/Pennsbury	2%	8%	15%	
PA CTs	28%	12%	5%	
SCEP	9%	5%	0%	
Handsome Lake	8%	5%	5%	
MD CTs & GS	29%	44%	45%	
Total	100%	100%	100%	0%

PA Admin – Peaking Administrative Support & Overhead

C

MD Admin/Maintenance (58711, 83023, 83093, 83095, 83098)	% of Effort - MW	% of Effort - MWh	Management Estimate %	FTE Equivalent
MD Gas (incl GS3)	36%	36%	20%	
MD Oil	33%	6%	10%	
Perryman 5 1/6	30%	58%	60%	
SCEP (Admin only)			10%	
Total	100%	100%	100%	0%

MD Admin – MD Headcount and Support. Roughly 35 FTEs

NEW ALLOCATORS (A, B, C MAPPED TO "D")

A

PA Maintenance (58502, 58722)	% of Effort - MW	% of Effort - MWh	Management Estimate %	FTE Equivalent
Eddystone	37%	57%	60.00%	
Fairless/Pennsbury	18%	17%	20.00%	
Croydon	16%	12%	8.81%	
Chester	2%	1%	0.88%	
Delaware	3%	1%	1.26%	
Eddystone CTs	4%	1%	1.35%	
Falls	3%	1%	1.15%	
Moser	3%	1%	1.15%	
Southwark	3%	1%	1.17%	
Richmond	6%	3%	2.21%	
Schuylkill	2%	1%	0.67%	
SCEP	0%	0%	0.00%	0
Handsome Lake	0%	0%	0.00%	0
Total	96%	97%	98.65%	0

<Less than 100% because Lamokin excluded

B

PA Admin (58720)	% of Effort - MW	% of Effort - MWh	Management Estimate %	FTE Equivalent
Eddystone	24%	26%	30.00%	
Fairless/Pennsbury	2%	8%	15.00%	
Croydon	12%		2.20%	
Chester	1%	0%	0.22%	
Delaware	2%	1%	0.32%	
Eddystone CTs	2%	1%	0.34%	
Falls	2%	1%	0.29%	
Moser	2%	1%	0.29%	
Southwark	2%	1%	0.29%	
Richmond	3%	1%	0.55%	
Schuylkill	1%	0%	0.17%	
SCEP	9%	5%	0.00%	
Handsome Lake	8%	5%	5.00%	
Perryman 1-4			14.59%	
Phila Rd			4.31%	
Riverside 7/8			2.76%	
Westport 5			8.20%	
Gould St 3			6.87%	
Notch Cliff			8.26%	
MD CTs & GS	29%	44%	0.00%	
Total	98%	93%	99.66%	0%

<Spread on MW

<Less than 100% because Lamokin excluded

CALCULATED VALUES

MD Admin/Maint Calculated (incl share of PA Admin)	MW	% of Effort - MW	% of Effort - MWh	Calculated Weight	FTE Equivalent
Perryman 1-4	206	23%	4%	6.73%	
Perryman 51	147.6	16%	28%	31.79%	
Perryman 6	131	14%	30%	28.21%	
Phila Rd	60.9	7%	1%	1.99%	
Riverside 7/8	39	4%	1%	1.27%	
Westport 5	115.8	13%	14%	7.03%	
Gould St 3	97	11%	13%	5.89%	
Notch Cliff	116.7	13%	9%	7.08%	
Total	914	100%	100%	90.00%	
SCEP		*0%*	*0%*	*10.00%*	

PA CTs Share of PA Maintenance	MW	% of Effort - MW	% of Effort - MWh	Calculated Weight	FTE Equivalent
Croydon	391	16%	12%	8.81%	
Chester	39	2%	1%	0.88%	
Delaware	56	3%	1%	1.26%	
Eddystone CTs	60	4%	1%	1.35%	
Falls	51	3%	1%	1.15%	
Moser	51	3%	1%	1.15%	
Southwark	52	3%	1%	1.17%	
Richmond	98	6%	3%	2.21%	
Schuylkill	30	2%	1%	0.67%	
Lamokin	60	4%	3%	1.35%	
Total	888	45%	26%	20.00%	0%
Eddystone 3/4 and Fairless		*55%*	*74%*	*80%*	

D

PA CTs Share of PA Admin	MW	% of Effort - MW	% of Effort - MWh	Calculated Weight	FTE Equivalent
Croydon	391	12%	5%	2.20%	
Chester	39	1%	0%	0.22%	
Delaware	56	2%	1%	0.32%	
Eddystone CTs	60	2%	1%	0.34%	
Falls	51	2%	1%	0.29%	
Moser	51	2%	1%	0.29%	
Southwark	52	2%	1%	0.29%	
Richmond	98	3%	1%	0.55%	
Schuylkill	30	1%	0%	0.17%	
Lamokin	60	2%	2%	0.34%	
Total	888	28%	12%	5.00%	0%
Eddystone 3/4, Fairless, SCEP, Handsome Lake, MD CT/GS		*72%*	*88%*	*95%*	

PA CTs Share of PA CT Ops	MW	% of Effort - MW	% of Effort - MWh	Calculated Weight	FTE Equivalent
Croydon	391	47%	52%	47%	
Chester	39	5%	4%	5%	
Delaware	56	7%	6%	7%	
Eddystone	60	7%	6%	7%	
Falls	51	6%	5%	6%	
Moser	51	6%	5%	6%	
Southwark	52	6%	5%	6%	
Richmond	98	12%	14%	12%	
Schuylkill	30	4%	3%	4%	
Total	828	100%	100%	100%	0%

MD Admin/Maintenance (58711, 83023, 83093, 83095, 83098)		% of Effort - MW	% of Effort - MWh	Management Estimate %	FTE Equivalent
Perryman 1-4	206	23%	4%	6.73%	
Perryman 51	147.6	16%	28%	31.79%	
Perryman 6	131	14%	30%	28.21%	
Phila Rd	60.9	7%	1%	1.99%	
Riverside 7/8	39	4%	1%	1.27%	
Westport 5	115.8	13%	14%	7.03%	
Gould St 3	97	11%	13%	5.89%	
Notch Cliff	116.7	13%	9%	7.08%	
SCEP (Admin only)				10.00%	
Total		100%	100%	100.00%	0%

Accessory Equip Allocator Account 315, 324, 334, 345
NUCLEAR FLEET
The following allocation factors pertain to the nuclear fleet. The values are based on a very general assessment of plant design and a subjective interpretation of the category definitions using Exhibit A-38 as guidance. There was no review performed of actual design information or plant accounting dollars to support the development of the allocation factors provided below.

Item		Comment
Storage Batteries	15%	A large portion of storage station battery capacity is dedicated to nuclear safety-related functions such as numerous valve actuators, back-up inverters and relaying/ annunciators/controls. The remaining balance-of-plant battery capacity would be largely dedicated to the seal oil and lube oil backup pumps.
Control&Power Cabling	1%	AVR/ generator / exciter cabling is very small when compared to the overall control and power cable systems in a nuclear generating facility.
Switch Board Equipment	1%	The nuclear plant control rooms contain a vast array of switchboard equipment dedicated to plant functions not associated with vendor supplied package systems. The allocation to AVR, exciter, and generator would be a relatively small component of the non-packaged systems.
Switching Equipment	1%	This category excludes main generator breakers. The remaining switching equipment associated with generator / exciter is fraction of the large switching network in a nuclear facility. The largest would be the seal oil pumps (AC and DC), lube oil pumps (AC and DC), stator water pumps, and AVR contactor / field circuit breaker. The transmission system operators (PECo, ComEd, etc.) on the PJM system own the Exelon nuclear plant output circuit breakers, with the exception of TMI and Nine Mile Point whose breakers are Exelon owned.
Transformers	3%	As instructed during the 8/5/16 telecon, this account does not include the main transformer (GSU). The excitation system power is self-fed from the turbine generator such that no significant auxiliary transformer power is used. Aux power is supplied to the lube oil, seal oil and stator water pumps, and miscellaneous equipment. The capacity is no more than 3% of the total auxiliary power.
Aux Generator	0%	The main generator and exciter would be off-line when the emergency and station black out diesel generators are in use. They do not contribute to main generator power generation.
Fire Protection System	0%	As instructed during the 8/5/16 telecon, the fire deluge system to mitigate shaft seal oil and hydrogen fires is not in this account.
HVAC	0%	As instructed during the 8/5/16 telecon, HVAC is not allocated in this account.
Regulating Equipment	50%	The main generator Automatic Voltage Regulator (AVR) used to control excitation (and VAR generation) is significant, but its allocation factor is reduced by other regulating systems such as the Reactor Recirc ASDs, battery inverters, etc.
Structure	0%	As instructed during the 8/5/16 telecon, HVAC is not allocated in this account.
Misc.	0%	None
Exciter & PPT	100%	The AVR, exciter, and subsystems are control reactive power generation
Station Grounding	1%	The AVR / Exciter Generator is relatively simple and a small subset of all equipment grounding in the plant. The generator armature uses a distribution transformer to achieve grounding, but the overall allocation of capital for this system is small when compared to the grounding installations through in the plant.
Bus & Insulators	80%	The IsoPhase bus and switchyard high voltage insulator systems comprise a major portion of this category when compared to the remaining plant buses.
Capacitor Bank	0%	Capacitor banks are used to control reactive power. However, they are the property of the transmission system owner.

Accessory Equipment Allocator -- FOSSIL & HYDRO

	CTs	Notes (Combustion Turbine Units)	Hydro & Steam Units	Notes (Hydro & Steam Units)
Storage Batteries	50%	Battery load is split between equipment directly related to power production (generator emergency lube oil, seal oil pump) and auxiliary load (fire pump, relays, etc.)	30%	A significant percentage of battery load at Hydro and Steam units relates to plant auxiliary equipment (fire pump, auxiliary dc circuits, relays, etc.).
Control & Power Cabling	50%	This percentage most likely reflects DCS, exciter, AVR, and breaker DC load as compared to total control and power cabling load. Other load reflects control and powering of auxiliary equipment such as annunciators, fuel valves, fire protection, auxiliary breaker, etc. as well as any cabling associated with 480V AC systems.	15%	A significant percentage of control and power cabling at Hydro and Steam sites is associated with auxiliary systems. 15% is assumed to be the load related directly to power generation.
Switch Board Equipment	50%	This portion is made up of relaying, annunciators, exciter, AVR, or DCS controls relating to generator or transformer as compared to plant auxiliaries.	30%	This portion is made up of relaying, annunciators, exciter, AVR, or DCS controls relating to generator or transformer as compared to plant auxiliaries.
Switching Equipment	40%	This percentage is made up of generator breakers and auxiliary breakers supplying power to equipment such as lube oil pumps.	20%	This percentage is made up of generator breakers and auxiliary breakers supplying power to equipment such as lube oil pumps.
Transformers	10%	Most of the auxiliary load that transformers serve does not relate directly to power production, such as water treatment, fire pump, CEMS module distribution power, etc. This number excludes GSUs.	5%	This is assumed to be the portion of total transformer investment serving load relatable to power production (oil pumps, etc.) This number excludes GSUs.
Aux. Generator	0%	None present directly for power generation - only for backup power.	0%	None present directly for power generation - only for backup power.
Fire Protection System	0%	No direct contribution towards power generation.	0%	No direct contribution towards power generation.
HVAC	0%	No direct contribution towards power generation.	0%	No direct contribution towards power generation.
Regulating Equipment	75%	The Automatic Voltage Regulator (AVR) is directly attributed towards power production, but Static Frequency Converters (SFCs), including static start systems, or motor control equipment are not.	75%	The Automatic Voltage Regulator (AVR) is directly attributed towards power production, but Static Frequency Converters (SFCs), including static start systems, or motor control equipment are not.
Structure	0%	No direct contribution towards power generation.	0%	No direct contribution towards power generation.
Misc.	0%	No direct contribution towards power generation.	0%	No direct contribution towards power generation.
Exciter & PPT	100%	All such equipment used for control of power produced (MVARs).	100%	All such equipment used for control of power produced (MVARs).
Station Grounding	5%	5% is assumed to be the cost of generator and transformer neutral grounding as compared to the entire site grounding system.	0%	Generator and transformer neutral grounding is a very small percentage of total grounding at Hydro and Steam sites.
Bus & Insulators	80%	The majority of bus-work in Combustion Turbine (CT) sites runs from generator to generator breaker and towards to point-of-interconnection.	60%	This is an estimate of bus-work running from generator to point-of-interconnection as compared to other bus-work that exists on site.
Capacitor Bank	0%	Item not owned by Generation.	0%	Item not owned by Generation.

Perryman 6 General Ledger Balances

Company	Utility Account	Retirement Unit	Major Location	Gl Account	Month	Book Cost	Ldg Work Order Number
20028 Constell Power Src Gen	GEN 341.03 CMBT-Str & Impvm-Gas	Non-unitized	Perryman - Unit 6	106000 Complete const not class	Dec-16	$1,161,091.54	028C13013
20028 Constell Power Src Gen	GEN 342.03 CMBT-Fuel Holdrs-Gas	Non-unitized	Perryman - Unit 6	106000 Complete const not class		$1,161,091.54	028C13013
20028 Constell Power Src Gen	GEN 344.03 CMBT-Generators-Gas T	Non-unitized	Perryman - Unit 6	106000 Complete const not class	Dec-16	$88,242,960.94	028C13013
20028 Constell Power Src Gen	GEN 345.03 CMBT-Acces Elec-Gas T	Non-unitized	Perryman - Unit 6	106000 Complete const not class		$20,899,648.61	028C13013
20028 Constell Power Src Gen	GEN 346.03 CMBT-Misc Pwr Plt-Gas	Non-unitized	Perryman - Unit 6	106000 Complete const not class	Dec-16	$4,644,366.29	028C13013
20028 Constell Power Src Gen	GEN 346.09 CCGT-Misc Equip	Non-unitized	Perryman - Unit 6	106000 Complete const not class	Dec-16	$0.00	028C13013
						$116,109,158.92	

Summary of Heating Losses

	BWD 1	BWD 2	BYR 1	BYR 2	DRE 2	DRE 3	LAS 1	LAS 2	LIM 1	LIM 2	OYS	PEA 2	PEA 3	QDE 1	QDE 2	TMI	Fleet Total
Fuel Cost ($ / MW Hr)	**$6.48**	**$7.09**	**$7.03**	**$6.92**	**$6.96**	**$6.65**	**$6.56**	**$6.98**	**$5.95**	**$6.00**	**$6.18**	**$6.63**	**$6.41**	**$6.67**	**$6.73**	**$6.82**	
	Based on Individual Hour Computations - Negative VARs Excluded																
Gen Field Annual Loss (MW Hr)	5,345.88	5,602.13	4,159.74	3,646.64	1,101.13	2,048.68	2,430.62	2,808.18	360.73	721.05	1,099.61	202.87	249.84	1,716.19	1,897.71	35.04	
Gen Armature Annual Loss (MW Hr)	1,214.95	1,309.73	920.12	779.96	1,001.02	1,686.71	732.18	619.69	81.33	175.06	1,037.40	419.16	728.47	4,399.95	4,697.61	11.12	
GSU Annual Loss (MW Hr)	616.43	431.05	466.34	380.66	228.99	343.48	347.20	415.05	27.46	59.25	430.45	33.10	66.25	658.41	702.78	10.26	
Total Annual Loss (MW Hr)	7,177.27	7,342.91	5,546.20	4,807.26	2,331.14	4,078.87	3,510.00	3,842.91	469.52	955.36	2,567.46	655.12	1,044.56	6,774.55	7,298.09	56.41	
Cost of Heating Loss (Annual)	46,518.74	52,067.84	39,001.98	33,252.30	16,219.62	27,122.87	23,036.50	26,818.93	2,794.47	5,728.05	15,872.31	4,343.33	6,696.68	45,210.61	49,148.25	384.63	394,217.11

SI-SSA-0010-4276

Exhibit No. EXE-5

Public Version

Exhibit No. EXE 5 - Generating Station Data and MVAR Test Results - contains privileged materials, which have been removed from the public version of this filing.

Privileged Version

Exhibit No. EXE 5 - Generating Station Data and MVAR Test Results - contains privileged materials, which have been hand-delivered to the Commission on CDs under separate cover and labeled with: CONTAINS PRIVILEGED MATERIALS – DO NOT RELEASE – HIGHLY SENSITIVE PROTECTED INFORMATION.

Attachment G

Protective Agreement

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Constellation Power Source Generation, LLC	**)**	**Docket No. ER17-___-000**
Exelon Generation Company, LLC	**)**	**Docket No. ER17-___-000**
Handsome Lake Energy, LLC	**)**	**Docket No. ER17-___-000**

PROTECTIVE AGREEMENT

1. This Protective Agreement shall govern the use of all Privileged Materials produced by, or on behalf of, any Participant. Notwithstanding any order terminating this proceeding, this Protective Agreement shall remain in effect until specifically modified or terminated by the Presiding Administrative Law Judge ("Presiding Judge") (which includes the Chief Administrative Law Judge) or the Federal Energy Regulatory Commission ("Commission").

2. This Protective Agreement applies to the following two categories of materials: (A) A Participant may designate as privileged those materials which customarily are treated by that Participant as sensitive or proprietary, which are not available to the public, and which, if disclosed freely, would subject that Participant or its customers to risk of competitive disadvantage or other business injury; and (B) A Participant shall designate as p privileged those materials which contain critical energy infrastructure information, as defined in 18 C.F.R. § 388.113(c)(1) ("Critical Energy Infrastructure Information").

3. Definitions – For purposes of this Agreement:

(a) The term "Participant" shall mean a Participant as defined in 18 C.F.R. § 385.102(b).

(b) (1) The term "Privileged Materials" means (A) materials filed with the Commission by a Participant pursuant to 18 C.F.R. § 388.112 and designated as privileged; (B) materials (including depositions) provided by a Participant in response to discovery requests and designated by such Participant as privileged; (C) any information contained in or obtained from such designated materials; (D) any other materials which are made subject to this Protective Agreement by the Presiding Judge, by the Commission, by any court or other body having appropriate authority, or by agreement of the Participants; (E) notes of Privileged Materials; and (F) copies of Privileged Materials. The Participant producing the Privileged Materials shall physically mark them on each page as "PRIVILEGED MATERIALS" or with words of similar import as long as the term "Privileged Materials" is included in that designation to indicate that they are Privileged Materials. If the Privileged Materials contain Critical Energy Infrastructure Information, the Participant producing such information shall additionally mark on each page containing such information the words "Contains Critical Energy Infrastructure Information – Do Not Release."

(2) The term "Notes of Privileged Materials" means memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses materials described in Paragraph 3(b)(1). Notes of Privileged Materials are subject to the same restrictions provided in this Protective Agreement for Privileged Materials except as specifically provided in this Protective Agreement.

(3) Privileged Materials shall not include (A) any information or document that has been filed with and accepted into the public files of the Commission, or contained in the public files of any other federal or state agency, or any federal or state court, unless the information or document has been determined to be privileged by such agency or court, or (B) information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Protective Agreement. Privileged Materials do include any information or document contained in the files of the Commission that has been designated as Critical Energy Infrastructure Information.

(c) The term "Non-Disclosure Certificate" shall mean the certificate annexed hereto by which Participants who have been granted access to Privileged Materials shall certify their understanding that such access to Privileged Materials is provided pursuant to the terms and restrictions of this Protective Agreement, and that such Participants have read the Protective Agreement and agree to be bound by it. All Non-Disclosure Certificates shall be served on all parties on the official service list maintained by the Secretary in this proceeding.

(d) The term "Reviewing Representative" shall mean a person who has signed a Non-Disclosure Certificate and who is:

(1) Commission Trial Staff designated as such in this proceeding;

(2) an attorney who has made an appearance in this proceeding for a Participant;

(3) attorneys, paralegals, and other employees associated for purposes of this case with an attorney described in Subparagraph (2);

(4) an expert or an employee of an expert retained by a Participant for the purpose of advising, preparing for or testifying in this proceeding;

(5) a person designated as a Reviewing Representative by order of the Presiding Judge or the Commission; or

(6) employees or other representatives of Participants appearing in this proceeding with significant responsibility for this docket.

4. Privileged Materials shall be made available under the terms of this Protective Agreement only to Participants and only through their Reviewing Representatives as provided in Paragraphs 7-9.

5. Privileged Materials shall remain available to Participants until the later of the date that an order terminating this proceeding becomes no longer subject to judicial review, or the date that

any other Commission proceeding relating to the Privileged Material is concluded and no longer subject to judicial review. If requested to do so in writing after that date, the Participants shall, within fifteen days of such request, return the Privileged Materials (excluding Notes of Privileged Materials) to the Participant that produced them, or shall destroy the materials, except that copies of filings, official transcripts and exhibits in this proceeding that contain Privileged Materials, and Notes of Privileged Material may be retained, if they are maintained in accordance with Paragraph 6, below. Within such time period each Participant, if requested to do so, shall also submit to the producing Participant an affidavit stating that, to the best of its knowledge, all Privileged Materials and all Notes of Privileged Materials have been returned or have been destroyed or will be maintained in accordance with Paragraph 6. To the extent Privileged Materials are not returned or destroyed, they shall remain subject to the Protective Agreement.

6. All Privileged Materials shall be maintained by the Participant in a secure place. Access to those materials shall be limited to those Reviewing Representatives specifically authorized pursuant to Paragraphs 8-9. The Secretary shall place any Privileged Materials filed with the Commission in a non-public file. By placing such documents in a non-public file, the Commission is not making a determination of any claim of privilege. The Commission retains the right to make determinations regarding any claim of privilege and the discretion to release information necessary to carry out its jurisdictional responsibilities. For documents submitted to Commission Trial Staff ("Staff"), Staff shall follow the notification procedures of 18 C.F.R. § 388.112 before making public any Privileged Materials.

7. Privileged Materials shall be treated as privileged by each Participant and by the Reviewing Representative in accordance with the certificate executed pursuant to Paragraph 9. Privileged Materials shall not be used except as necessary for the conduct of this proceeding, nor shall they be disclosed in any manner to any person except a Reviewing Representative who is engaged in the conduct of this proceeding and who needs to know the information in order to carry out that person's responsibilities in this proceeding. Reviewing Representatives may make copies of Privileged Materials, but such copies become Privileged Materials. Reviewing Representatives may make notes of Privileged Materials, which shall be treated as Notes of Privileged Materials if they disclose the contents of Privileged Materials.

8. (a) If a Reviewing Representative's scope of employment includes the marketing of energy, the direct supervision of any employee or employees whose duties include the marketing of energy, the provision of consulting services to any person whose duties include the marketing of energy, or the direct supervision of any employee or employees whose duties include the marketing of energy, such Reviewing Representative may not use information contained in any Privileged Materials obtained through this proceeding to give any Participant or any competitor of any Participant a commercial advantage.

(b) In the event that a Participant wishes to designate as a Reviewing Representative a person not described in Paragraph 3 (d) above, the Participant shall seek agreement from the Participant providing the Privileged Materials. If an agreement is reached that person shall be a Reviewing Representative pursuant to Paragraphs 3(d) above with respect to those materials. If no agreement is reached, the Participant shall submit the disputed designation to the Presiding Judge for resolution.

9. (a) A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Privileged Materials pursuant to this Protective Agreement unless that Reviewing Representative has first executed a Non-Disclosure Certificate; provided, that if an attorney qualified as a Reviewing Representative has executed such a certificate, the paralegals, secretarial and clerical personnel under the attorney's instruction, supervision or control need not do so. A copy of each Non-Disclosure Certificate shall be provided to counsel for the Participant asserting privilege prior to disclosure of any Privileged Material to that Reviewing Representative.

(b) Attorneys qualified as Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this Protective Agreement.

10. Any Reviewing Representative may disclose Privileged Materials to any other Reviewing Representative as long as the disclosing Reviewing Representative and the receiving Reviewing Representative both have executed a Non-Disclosure Certificate. In the event that any Reviewing Representative to whom the Privileged Materials are disclosed ceases to be engaged in these proceedings, or is employed or retained for a position whose occupant is not qualified to be a Reviewing Representative under Paragraph 3(d), access to Privileged Materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Non-Disclosure Certificate shall continue to be bound by the provisions of this Protective Agreement and the certification.

11. Subject to Paragraph 18, the Commission shall resolve any disputes arising under this Protective Agreement, unless a Presiding Administrative Law Judge has been appointed in which case the Presiding Administrative Law Judge shall resolve any disputes arising under this Protective Agreement. Prior to presenting any dispute under this Protective Agreement to the Commission or Presiding Administrative Law Judge, the parties to the dispute shall use their best efforts to resolve it. Any Participant that contests the designation of materials as privileged shall notify the Participant that provided the privileged materials by specifying in writing the materials the designation of which is contested. This Protective Agreement shall automatically cease to apply to such materials five (5) business days after the notification is made unless the designator, within said 5-day period, files a motion with the Commission or Presiding Administrative Law Judge, with supporting affidavits, demonstrating that the materials should continue to be privileged. In any challenge to the designation of materials as privileged, the burden of proof shall be on the Participant seeking privilege. If the Commission or Presiding Administrative Law Judge finds that the materials at issue are not entitled to privilege, the procedures of Paragraph 18 shall apply.

The procedures described above shall not apply to privileged materials designated by a Participant as Critical Energy Infrastructure Information. Materials so designated shall remain privileged and subject to the provisions of this Protective Agreement, unless a Participant requests and obtains a determination from the Commission's Critical Energy Infrastructure Information Coordinator that such materials need not remain privileged.

12. All copies of all documents reflecting Privileged Materials, including the portion of the hearing testimony, exhibits, transcripts, briefs and other documents which refer to Privileged

Materials, shall be filed and served in sealed envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Protective Agreement. Such documents shall be marked "PRIVILEGED MATERIALS" and shall be filed under seal and served under seal upon the Presiding Judge and all Reviewing Representatives who are on the service list. Such documents containing Critical Energy Infrastructure Information shall be additionally marked "Contains Critical Energy Infrastructure Information – Do Not Release." For anything filed under seal, redacted versions or, where an entire document is privileged, a letter indicating such, will also be filed with the Commission and served on all Participants on the service list and the Presiding Judge. Counsel for the producing Participant shall provide to all Participants who request the same, a list of Reviewing Representatives who are entitled to receive such material. Counsel shall take all reasonable precautions necessary to assure that Privileged Materials are not distributed to unauthorized persons.

13. If any Participant desires to include, utilize or refer to any Privileged Materials or information derived therefrom in testimony or exhibits during the hearing in these proceedings in such a manner that might require disclosure of such material to persons other than reviewing representatives, such Participant shall first notify both counsel for the disclosing Participant and the Presiding Judge of such desire, identifying with particularity each of the Privileged Materials. Thereafter, use of such Privileged Material will be governed by procedures determined by the Presiding Judge.

14. Nothing in this Protective Agreement shall be construed as precluding any Participant from objecting to the use of Privileged Materials on any legal grounds.

15. Nothing in this Protective Agreement shall preclude any Participant from requesting the Presiding Judge, the Commission, or any other body having appropriate authority, to find that this Protective Agreement should not apply to all or any materials previously designated as Privileged Materials pursuant to this Protective Agreement. The Presiding Judge may alter or amend this Protective Agreement as circumstances warrant at any time during the course of this proceeding.

16. Each Participant governed by this Protective Agreement has the right to seek changes in it as appropriate from the Presiding Judge or the Commission.

17. All Privileged Materials filed with the Commission, the Presiding Judge, or any other judicial or administrative body, in support of, or as a part of, a motion, other pleading, brief, or other document, shall be filed and served in sealed envelopes or other appropriate containers bearing prominent markings indicating that the contents include Privileged Materials subject to this Protective Agreement. Such documents containing Critical Energy Infrastructure Information shall be additionally marked "Contains Critical Energy Infrastructure Information – Do Not Release."

18. If the Commission or Presiding Judge finds at any time in the course of this proceeding that all or part of the Privileged Materials need not be privileged, those materials shall, nevertheless, be subject to the privilege afforded by this Protective Agreement for three (3) business days from the date of issuance of a determination of the Presiding Judge or the Commission, and if the Participant seeking privilege files an interlocutory appeal or requests that the issue be certified to the Commission, for an additional seven (7) business days. None of the

Participants waives its rights to seek additional administrative or judicial remedies after the Presiding Judge's decision respecting Privileged Materials or Reviewing Representatives, or the Commission's denial of any appeal thereof. The provisions of 18 C.F.R. § 388.112 and § 388.113 shall apply to any requests under the Freedom of Information Act. (5 U.S.C. § 552) for Privileged Materials in the files of the Commission.

19. Nothing in this Protective Agreement shall be deemed to preclude any Participant from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced in this proceeding under this Protective Agreement.

20. None of the Participants waives the right to pursue any other legal or equitable remedies that may be available in the event of actual or anticipated disclosure of Privileged Materials.

21. The contents of Privileged Materials or any other form of information that copies or discloses Privileged Materials shall not be disclosed to anyone other than in accordance with this Protective Agreement and shall be used only in connection with this (these) proceeding(s). Any violation of this Protective Agreement and of any Non-Disclosure Certificate executed hereunder shall constitute a breach of an order of the Commission.

22. This Protective Agreement may be executed in one or more counterparts each of which shall be deemed an original and all of which shall be deemed one and the same Protective Agreement. Delivery of an executed counterpart of this Protective Agreement by email transmitting a PDF or similar image will be deemed as effective as delivery of an originally executed counterpart. Delivery of an executed counterpart of this Protective Agreement shall be made to:

Neil L. Levy
King & Spalding LLP
1700 Pennsylvania Avenue, N.W.
Washington, DC 20006
(202) 626-5452

or

nlevy@kslaw.com

Delivery of an executed Non-Disclosure Certificate also is to be made to the above.

The undersigned Participant hereby agrees to the foregoing terms of this Protective Agreement.

By: _____

Printed Name: _____

Title: _____

Representing: _____

Date: _____

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Constellation Power Source Generation, LLC	**)**	**Docket No. ER17-___-000**
Exelon Generation Company, LLC	**)**	**Docket No. ER17-___-000**
Handsome Lake Energy, LLC	**)**	**Docket No. ER17-___-000**

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Privileged Materials is provided to me pursuant to the terms and restrictions of the Protective Agreement in this proceeding, that I have been given a copy of and have read the Protective Agreement, and that I agree to be bound by it. I understand that the contents of the Privileged Materials, any notes or other memoranda, or any other form of information that copies or discloses Privileged Materials shall not be disclosed to anyone other than in accordance with that Protective Agreement. I acknowledge that a violation of this certificate constitutes a breach of the Protective Agreement.

By: _____

Printed Name: _____

Title: _____

Representing: _____

Date: _____

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Alexander C. Stern
Assistant General Regulatory Counsel

Law Department
80 Park Plaza, T5G, Newark, NJ 07102
tel: 973.430.5754 fax:973.430.5983
Alexander.Stern@PSEG.com

PSEG
Services Corporation

January 25, 2013

VIA ELECTRONIC FILING

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Public Service Enterprise Group Incorporated
2012 FERC Form 566

Dear Ms. Bose:

In accordance with 18 C.F.R. Part 46.3, the following indirect subsidiaries of Public Service Enterprise Group Incorporated ("PSEG") report that they had no sales of electric energy to purchasers, other than those purchasing for resale during any of the three preceding years:

- PSEG Energy Resources & Trade LLC
- PSEG Fossil LLC
- PSEG New Haven LLC
- PSEG Nuclear LLC
- PSEG Power Connecticut LLC
- PSEG Power New York LLC

Please do not hesitate to contact me if you should have any questions.

Respectfully submitted,

Alexander C. Stern

Alexander C. Stern

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Document Content(s)

PSEG Power Form 566 2013-01-25.PDF.....1-1

Filing Deadline: March 31, 2017

Federal Energy Regulatory Commission
2016 FERC Form 580 Interrogatory on Fuel and Energy Purchase Practices

Title 18, U.S.C. 1001 makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Refer to the general guidance and directions provided in the 2016 FERC Form 580 Desk Reference to complete the interrogatory. Included herein is Appendix A *Coal Contract Types* and a *Glossary* of terms used. Terms highlighted in blue are defined in the glossary.

1a Enter the exact legal name of the filing Utility (as company is registered with the Commission).

Utility name:	PSEG Nuclear LLC

1b Identify the principal contact person for clarification and additional information concerning your Utility's fuel procurement.

Name	Address					Telephone	Email address
	street	suite	city	state	zip code		
David F. Caffery	80 Park Plaza	T19	Newark	NJ	07102	(973) 430-6821	David.Caffery@pseg.com

1c Identify the principal contact person for clarification and additional information concerning your Utility's energy purchases (purchased power).

Name	Address					Telephone	Email address
	street	suite	city	state	zip code		
Lathrop Craig	80 Park Plaza	T19	Newark	NJ	07102	(973) 430-7268	Lathrop.Craig@pseg.com

SI-SSA-0010-4290

2.

a. Provide the following information regarding non-transmission related wholesale automatic adjustment clauses (AACs) your Utility had on file with the Commission during calendar years 2014 and 2015. Note: use the add and delete row buttons to manage information entry.

Docket number under which rate schedule containing AAC through which costs were passed during 2014 and/or 2015 was accepted for filing by FERC	Is this AAC a fuel adjustment clause (FAC)	Tariff volume number containing AAC	Rate schedule number containing AAC	Date rate schedule was first accepted for filing by the Commission	First effective date of rate schedule	Was rate schedule superseded or abandoned during 2014-2015? If so, provide dates	Identify service agreement within rate schedule containing AAC

If the Utility had no non-transmission-related wholesale AACs during the reporting years, check here: ☒

Add Row (+) Delete Row (-)

b. If any of the Utility's wholesale rate and/or service agreements containing an AAC listed in Question 2a, that was used during 2014 and/or 2015, was filed with the Commission before January 1, 1990, attach an electronic copy of it with this filing. List the documents you are submitting below. Note: once this information is submitted electronically in a text-searchable format it will not be necessary to submit it in future Form 580 filings. See: http://www.ferc.gov/docs-filing/elibrary/accept-file-formats.asp for listing of Commission-accepted document types.

File name with extension	Document/ File Description:

Add Row (+) Delete Row (-)

NOTE: If the Utility for which you are filing did not have any rate/service schedules on file with the Commission allowing the automatic adjustment of fuel and/or fuel-related items subject to 18 CFR 35.14 during 2014-15, STOP HERE, you are finished. File your responses to questions 1 and 2 with the Commission. Otherwise, continue with the questions that follow.

SI-SSA-0010-4291

3. If during the 2014-2015 period, the Utility had any contracts or agreements for the purchase of either energy or capacity under which all or any portion of the purchase costs were passed through a fuel adjustment clause (FAC), for each purchase from a PURPA Qualifying Facility (QF) or Independent Power Producer (IPP), provide the information requested in the non-shaded columns of the table below. Provide the information separately for each reporting year 2014 and 2015. Do not report purchased power where none of the costs were recovered through a FAC. Fill-in the non-shaded columns and either the "Only energy charges" columns OR "The total cost of the purchase of economic power" columns, whichever apply.

If the Utility did not recover any purchased power costs through a FAC, check here: ☒

					Cost item/s recovered through a FAC					
					Only energy charges		***The total cost of the purchase of economic power***			
Year	Seller name	Purchase cost ($)	Annual amount recovered through an AAC ($)	Does the Commission-accepted FAC used to recover this cost allow for automatic recovery of purchased power costs?	Was the total of such charges less than the total avoided variable costs?	Was economic dispatch used to determine whether the charges were less than avoided costs?	Was the total cost of purchased power less than the total avoided variable costs?	Was the duration of the purchased power equal to or less than twelve months?	Did the FAC used for cost recovery include the system reserve capacity criteria by which the system operator decides whether a reliability purchase is required?	If the purchased power was wind-generated, was the avoided cost comparison done on a contract-by-contract basis?

Add Row (+) Delete Row (-)

SI-SSA-0010-4292

4a If emission allowance costs were incurred by the Utility in 2014 and/or 2015 and were recovered through a FAC, provide the following information.

Origin of emission allowance cost	Dollar value of emission allowance cost passed through a FAC		Docket number, if any, of Commission acceptance of emission allowance cost recovery through a FAC	Date Commission accepted FAC recovery of emission allowance costs
	2014	2015		

Add Row (+) Delete Row (-)

4b Were emission allowance costs recovered in any other method than through a FAC? No

If yes, how were they recovered? Include specific Commission rate schedule and service agreement notations.

SI-SSA-0010-4293

5. Provide the information requested below regarding the Utility's fuel procurement policies and practices in place during 2014 and/or 2015 for fuels whose costs were subject to 18 CFR 35.14. **Note: Responses to this question may be filed as Privileged. To do so, skip this question now and answer it via the Fuel Procurement Policies and Practices Privileged Addendum provided. Otherwise, answer it here and your responses will be made public.**

Are you filing the Question 5 Privileged Addendum?		
a1. How often does Utility management review the fuel procurement process?	Select value:	
a2. When was the last review?		
a3. Who conducted the last review? (Last, First, MI) & (Title)		
a4. What was covered in the last review?		
b1. Does the Utility have a policy on fuel inventory levels?		
b2. Does the policy state under what circumstance/s fuel inventory is increased or decreased?		
☐ Utility has no policy on fuel inventory levels.		
b3. When was the fuel inventory policy last reviewed, and who last approved it?		
b4. Who made the working decisions to change inventory levels? (Last, First, MI) & (Title)		

c. Describe any use by the Utility of systematic procedures for periodic market investigations of fuel costs and availability, particularly prior to renewal or renegotiation of contracts.

d. Describe any environmental constraints which influenced the Utility's fuel purchase practices.

e. What quality characteristics were routinely specified in the Utility's fuel contracts?

Fuel	*Energy Content*	*Sulfur Content*	*Ash Content*	*Moisture Content*	*Other*
Coal	☐	☐	☐	☐	
Oil	☐	☐	☐	☐	
Natural gas	☐	☐	☐	☐	
Other	☐	☐	☐	☐	

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f. What percentage of the Utility's fuel was purchased from utility-controlled (i.e. affiliate) sources?	%	0%	>0-25%	25-50%	50-75%	75-100%
	Coal	☐	☐	☐	☐	☐
	Oil	☐	☐	☐	☐	☐
	Natural gas	☐	☐	☐	☐	☐
	Other	☐	☐	☐	☐	☐

g1. How were potential fuel suppliers qualified?
g2. What criteria are used to rank bidders?
g3. How were credit and performance ratings of potential fuel suppliers checked?

g4. Do you automatically select the lowest bidder?	Y ☐ N ☐
If not, what criteria are used for selection and negotiation of the fuel contract?	

g5. Describe the procurement procedures used on your most recent fuel procurement contract for both:	
- the purchase from a non-affiliated company	
- the purchase from an affiliated company	

h. Do the Utility's purchase policy practices differ for associated companies?	Y ☐ N ☐
If so, what generally are the differences?	

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6. For each fuel supply contract, of longer than one year in duration, in force at any time during 2014 and/or 2015, where costs were subject to 18 CFR 35.14, (including informal agreements with *associated companies*), provide the requested information. Report the information individually for each contract, *for each calendar year.* [No response to any part of Question 6 for fuel oil no. 2 is necessary.] Report all fuels consumed for electric power generation and thermal energy associated with the production of electricity. Information for only coal, natural gas, and oil should be reported.

Contract 1

a. Contract specifications

Use the add, or delete buttons to manage contract records — Add Contract (+) — Del Contract (-)

Contract ID / number	Reporting year	Contract signing date	Contract expiration date	Is contract evergreen ?	Contract type: Coal (choose from list)	Contract type: Gas supply (choose from list)	Contract type: Gas transportation (choose from list)	Fuel quantity: Gas ($x10^3$ mmbtu)	Fuel quantity: Oil ($x10^3$ bbls)	Fuel quantity: Coal ($x10^3$ tons)	Fuel quality: Gas (Btu/ft^3)	Fuel quality: Pipeline quality? (Y/N)	Fuel quality: Oil (Btu/gal)	Fuel quality: Coal (Btu/lb)	Impurity content: Sulfur content (%weight)	Impurity content: Ash content (%weight)	Impurity content: Moisture (%)

b. Delivered characteristics

Fuel origin: Primary State / Country of Origin	Fuel origin: Type of purchase point	Fuel destination: Total fuel transportation distance (mi.) from Utility's receipt point to plant	Fuel quantity: Gas ($x10^3$ mmbtu)	Fuel quantity: Oil ($x10^3$ bbls)	Fuel quantity: Coal ($x10^3$ tons)	Fuel quantity: Coal ($x10^3$ tons) not delivered by end of contract year	Fuel quality: Gas (Btu/ft^3)	Fuel quality: Pipeline quality? (Y/N)	Fuel quality: Oil (Btu/gal)	Fuel quality: Coal (Btu/lb)	Impurity content: Sulfur content (%weight)	Impurity content: Ash content (% weight)	Impurity content: Moisture (%)	Fuel cost (see desk reference): Actual weighted average fuel price paid **FOB origin**/year (cents/mmBtu)	Fuel cost (see desk reference): Actual weighted average fuel price paid **FOB plant**/year (cents/mmBtu)
1.	*Destination Plant:*							*Enter Plant Not Listed:*							

Use the add, delete and copy buttons to manage Delivery characteristics information for each Contract : Add Delivery (+) — Del Delivery (-) — Copy Delivery

c. Fuel and transportation contract affiliates

Name of any entity affiliated with the Utility that is involved in the procurement or transportation of its fuel	Type of affiliation	Affiliated entity involvement with the Utility

Add Row (+) — Delete Row (-)

SI-SSA-0010-4296

7. For each fuel supply contract, including informal agreements with associated or affiliated companies in force at any time during 2014 or 2015 WHERE CONTRACT SHORTFALL COSTS WERE PASSED THROUGH an FAC subject to 18 CFR 35.14, provide for each contract separately the information requested below. Only report the information requested for shortfalls that occurred under your contracts during reporting years 2014 or 2015 and that are not under dispute i.e. parties agree there was indeed a shortfall.

a) Cause of the shortfall [e.g., disruption in production, fuel not meeting quality specifications, dispute over contract provisions, a disruption in supplier's transportation system or other (specify)].	b) Amount of shortfall costs passed through the FAC	c) Utility or Supplier-caused?	d) Did contract contain a provision for shortfall consequences?

Add Row (+) Delete Row (-)

8. For each fuel supply contract that was bought-out or bought-down, including informal agreements with associated or affiliated companies in force at any time during 2014 or 2015 WHERE CONTRACT BUY-OUT AND/OR BUY-DOWN COSTS WERE PASSED THROUGH an FAC subject to 18 CFR 35.14, provide for each contract separately the information requested below. Only report the information requested for contract buy-downs and buy-outs that occurred under your contracts during reporting years 2014 or 2015 and that are not under dispute i.e. parties agree there was indeed a shortfall.

a) Type of change (buy-down, buy-out, renegotiation or other)	b) Effective date of buy-out or buy-down (mm/dd/yy).	c) Amount of any buy-out and buy-down costs that were passed through the FAC ($xx).	d) Docket number of Commission waiver, if any, allowing recovery of contract buy-down and buy-out costs through the FAC.

Add Row (+) Delete Row (-)

SI-SSA-0010-4297

APPENDIX A

Coal Contract Types

1. Base Price plus Escalation

Different components of the price escalate (or de-escalate) as a function of changing economic conditions (indices).

2. Price Renegotiation

The price is renegotiated at predetermined intervals, usually one year. This type of contract, frequently known as an “EVERGREEN CONTRACT,” may also contain provisions for price adjustments between renegotiations.

3. Price Tied to Market

Price tied to the price of coal being sold in a particular market. Product and market area are defined in the contract. Contract may contain a "Most Favored Nations" clause, *i.e.*, supplier will not sell to any utility at a price lower than your utility is paying.

4. Cost-Plus Contract with a Fixed Fee Provision

Purchaser agrees to pay all producer costs plus a management fee. Some contracts provide for payment of both a management fee and a profit. This contract has a *Fixed Fee* provision.

5. Cost-Plus Contract with an Incentive Fee Provision

Purchaser agrees to pay all producer costs plus a management fee. Some contracts provide for payment of both a management fee and a profit. This contract has an *Incentive Fee* provision, *i.e.*, a variable fee that is tied to various productivity and cost reduction incentives.

6. Fixed-Price Contract

Price is fixed over the life of the contract.

Glossary

Term	Definition
Annual weighted average	An average taken over a 12-month period in which each item being averaged is multiplied by a number (weight) based on the item's relative importance. The result is summed and the total is divided by the sum of the weights.
Associated (affiliated) companies	Companies or persons that directly or indirectly through one or more intermediaries, control, or are controlled by, or are under common control with the account company. (see 18 CFR Part 101 for more information)
Automatic adjustment clause (AAC)	A provision of a rate schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility.
Avoided variable costs	All identified and documented variable costs (costs that change or vary with usage, output or production, e.g., fuel costs) that would have been incurred by the buyer had a particular purchase not been made. Such costs include, but are not limited to, those associated with fuel, start-up, shut-down or any purchases that would have been made in lieu of the purchase made.
Base price plus escalation	Different components of the price escalate (or de-escalate) as a function of changing economic conditions (indices).
Contract buy-downs	Costs paid in compensation to suppliers for reducing the contract amount to below the minimum requirement.
Contract buy-outs	Buy-out costs are compensation paid to suppliers for ending a contract before the previously agreed upon contract expiration date.
Capacity	Electricity available to provide to a market during a defined period.
Commission cite	Reference to a Commission document/issuance.
Contract ID/ number	Unique contract identifier that the Utility uses internally to identify a contract.
Cost-plus contract with a fixed fee provision	Purchaser agrees to pay all producer costs plus a management fee. Some contracts provide for payment of both a management fee and a profit. This contract has a Fixed Fee provision.
Cost-plus contract with an incentive fee provision	Purchaser agrees to pay all producer costs plus a management fee. Some contracts provide for payment of both a management fee and a profit. This contract has an Incentive Fee provision, i.e., a variable fee that is tied to various productivity and cost reduction incentives.
Economic power	Power or energy purchased over a period of twelve months or less where the total cost of the purchase is less than the buyer's total avoided variable cost.
Effective date of rate schedule	The date upon which service is approved by FERC to begin.
EIA	EIA is an acronym for Energy Information Administration.
EIA code	Unique identification number assigned by EIA to utilities and plants.
Emission allowance	an authorization by the Administrator under the Acid Rain Program to emit a specified limited amount of sulfur dioxide during or after a specified calendar year (see 40 CFR Part 72)
Energy charge	That portion of the charge for electric service based upon the electric energy (kWh) consumed or billed.
Evergreen contract	A contract that is renewed automatically or by notice from year to year until canceled by either party.
Filing year	The year the data is collected.

Term	Definition
Fixed-price contract	Price is fixed over the life of the contract.
FOB	FOB is an acronym for Free On Board. The term FOB (often seen as f.o.b.) is commonly used when shipping goods to indicate who pays loading and transportation costs, and/or the point at which the responsibility of the goods transfers from shipper to buyer. FOB origin is the term used when the ownership/liability of goods passes from the seller to the buyer at the time the goods leave the origin. FOB plant designates that the seller is responsible for the goods until the buyer takes possession at the delivery point. This is important in determining who is responsible for lost or damaged goods when they are in transit from the seller to the buyer. The buyer is responsible when shipped FOB origin and the seller is responsible when shipped FOB delivery point.
Hourly economic dispatch	A forward-looking process by which the system personnel responsible for selecting the source(s) of energy to be used by the company to meet its loads in the next hour are free to, and do in fact, decide which available energy resources will be used and in what amount solely on the basis of the relative projected energy costs of those resources for that hour with the goal of minimizing total production cost for that hour.
Independent Power Producer (IPP)	A generator who provides either capacity or wholesale power to utilities. IPPs operate in the franchised territories of host utilities and do not possess transmission facilities or sell electricity on the retail market.
Price renegotiation	The price is renegotiated at predetermined intervals, usually one year. This type of contract, frequently known as an “Evergreen Contract,” may also contain provisions for price adjustments between renegotiations.
Price tied to market	Price tied to the price of coal being sold in a particular market. Product and market area are defined in the contract. Contract may contain a "Most Favored Nations" clause, i.e., supplier will not sell to any utility at a price lower than your utility is paying.
Qualifying Facility (QF)	A QF is a generating facility which meets the requirements for QF status under the Public Utility Regulatory Policies Act of 1978 and 18 CFR Part 292 of the Commission's regulations, and which has either self-certified with the Commission or has obtained FERC certification of QF status. There are two types of QFs: cogeneration facilities and small power production facilities.
Rate schedule	The rates, charges, and provisions under which service is supplied to customers.
Receipt point	Where the Utility or Utility's contracted agent takes possession of the fuel.
Reliability purchase	An energy purchase made when a utility does not have sufficient generating capability to meet its own load plus its planning reserve requirement.
Renewable Energy Credit (REC)	A tax credit offered by some states as an incentive for the installation and operation of renewable energy systems such as solar or wind power.
Reporting year	The time period to which the data provided in the FERC-580 applies.
Service schedule	A document describing the kinds of services to be furnished to the identified parties at the rates specified.
Shortfall	Contracted less delivered amount.
System reserve capacity criteria	Planning criteria used to determine when a reliability purchase is made.
Total avoided variable cost	All identified and documented variable costs that would have been incurred by the buyer had a particular purchase not been made.
Utility name	The exact legal name of the Utility

Filing Deadline: October 31, 2018

Federal Energy Regulatory Commission
2016 FERC Form 580 Interrogatory on Fuel and Energy Purchase Practices

Title 18, U.S.C. 1001 makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Refer to the general guidance and directions provided in the 2018 FERC Form 580 Desk Reference to complete the interrogatory. Included herein is Appendix A *Coal Contract Types* and a *Glossary* of terms used. Terms highlighted in blue are defined in the glossary.

1a Enter the exact legal name of the filing Utility (as company is registered with the Commission).

Utility name:	PSEG Nuclear LLC

1b Identify the principal contact person for clarification and additional information concerning your Utility's fuel procurement.

Name	Address					Telephone	Email address
	street	suite	city	state	zip code		
Kory Dyer	PSEG Nuclear LLC Purchas	NDC7	Hancocks Bridge	NJ	08038	(856) 339-1140	Kory.Dyer@pseg.com

1c Identify the principal contact person for clarification and additional information concerning your Utility's energy purchases (purchased power).

Name	Address					Telephone	Email address
	street	suite	city	state	zip code		
Lathrop Craig	80 Park Plaza	T19	Newark	NJ	07102	(973) 430-7268	Lathrop.Craig@pseg.com

SI-SSA-0010-4301

2.

a. Provide the following information regarding non-transmission related wholesale automatic adjustment clauses (AACs) your Utility had on file with the Commission during calendar years 2016 and 2017. Note: use the add and delete row buttons to manage information entry.

Docket number under which rate schedule containing AAC through which costs were passed during 2016 and/or 2017 was accepted for filing by FERC	Is this AAC a fuel adjustment clause (FAC)	Tariff volume number containing AAC	Rate schedule number containing AAC	Date rate schedule was first accepted for filing by the Commission	First effective date of rate schedule	Was rate schedule superseded or abandoned during 2016-2017? If so, provide dates	Identify service agreement within rate schedule containing AAC

If the Utility had no non-transmission-related wholesale AACs during the reporting years, check here: ☒

Add Row (+) Delete Row (-)

b. If any of the Utility's wholesale rate and/or service agreements containing an AAC listed in Question 2a, that was used during 2016 and/or 2017, was filed with the Commission before January 1, 1990, attach an electronic copy of it with this filing. List the documents you are submitting below. Note: once this information is submitted electronically in a text-searchable format it will not be necessary to submit it in future Form 580 filings. See: http://www.ferc.gov/docs-filing/elibrary/accept-file-formats.asp for listing of Commission-accepted document types.

File name with extension	Document/ File Description:

Add Row (+) Delete Row (-)

NOTE: If the Utility for which you are filing did not have any rate/service schedules on file with the Commission allowing the automatic adjustment of fuel and/or fuel-related items subject to 18 CFR 35.14 during 2016-17, STOP HERE, you are finished. File your responses to questions 1 and 2 with the Commission. Otherwise, continue with the questions that follow.

SI-SSA-0010-4302

3. If during the 2016-2017 period, the Utility had any contracts or agreements for the purchase of either energy or capacity under which all or any portion of the purchase costs were passed through a fuel adjustment clause (FAC), for each purchase from a PURPA Qualifying Facility (QF) or Independent Power Producer (IPP), provide the information requested in the non-shaded columns of the table below. Provide the information separately for each reporting year 2016 and 2017. Do not report purchased power where none of the costs were recovered through a FAC. Fill-in the non-shaded columns and either the "Only energy charges" columns OR "The total cost of the purchase of economic power" columns, whichever apply.

If the Utility did not recover any purchased power costs through a FAC, check here: ☒

					Cost item/s recovered through a FAC					
					Only energy charges		***The total cost of the purchase of economic power***			
Year	Seller name	Purchase cost ($)	Annual amount recovered through an AAC ($)	Does the Commission-accepted FAC used to recover this cost allow for automatic recovery of purchased power costs?	Was the total of such charges less than the total avoided variable costs?	Was economic dispatch used to determine whether the charges were less than avoided costs?	Was the total cost of purchased power less than the total avoided variable costs?	Was the duration of the purchased power equal to or less than twelve months?	Did the FAC used for cost recovery include the system reserve capacity criteria by which the system operator decides whether a reliability purchase is required?	If the purchased power was wind-generated, was the avoided cost comparison done on a contract-by-contract basis?

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SI-SSA-0010-4303

4a If emission allowance costs were incurred by the Utility in 2016 and/or 2017 and were recovered through a FAC, provide the following information.

Origin of emission allowance cost	Dollar value of emission allowance cost passed through a FAC		Docket number, if any, of Commission acceptance of emission allowance cost recovery through a FAC	Date Commission accepted FAC recovery of emission allowance costs
	2016	2017		

Add Row (+) Delete Row (-)

4b Were emission allowance costs recovered in any other method than through a FAC? No

If yes, how were they recovered? Include specific Commission rate schedule and service agreement notations.

SI-SSA-0010-4304

5. Provide the information requested below regarding the Utility's fuel procurement policies and practices in place during 2016 and/or 2017 for fuels whose costs were subject to 18 CFR 35.14. **Note: Responses to this question may be filed as Privileged. To do so, skip this question now and answer it via the Fuel Procurement Policies and Practices Privileged Addendum provided. Otherwise, answer it here and your responses will be made public.**

Are you filing the Question 5 Privileged Addendum?		
a1. How often does Utility management review the fuel procurement process?	Select value:	
a2. When was the last review?		
a3. Who conducted the last review? (Last, First, MI) & (Title)		
a4. What was covered in the last review?		
b1. Does the Utility have a policy on fuel inventory levels?		
b2. Does the policy state under what circumstance/s fuel inventory is increased or decreased?		
☐ Utility has no policy on fuel inventory levels.		
b3. When was the fuel inventory policy last reviewed, and who last approved it?		
b4. Who made the working decisions to change inventory levels? (Last, First, MI) & (Title)		

c. Describe any use by the Utility of systematic procedures for periodic market investigations of fuel costs and availability, particularly prior to renewal or renegotiation of contracts.

d. Describe any environmental constraints which influenced the Utility's fuel purchase practices.

e. What quality characteristics were routinely specified in the Utility's fuel contracts?

Fuel	*Energy Content*	*Sulfur Content*	*Ash Content*	*Moisture Content*	*Other*
Coal	☐	☐	☐	☐	
Oil	☐	☐	☐	☐	
Natural gas	☐	☐	☐	☐	
Other	☐	☐	☐	☐	

SI-SSA-0010-4305

f. What percentage of the Utility's fuel was purchased from utility-controlled (i.e. affiliate) sources?	%	0%	>0-25%	25-50%	50-75%	75-100%
	Coal	☐	☐	☐	☐	☐
	Oil	☐	☐	☐	☐	☐
	Natural gas	☐	☐	☐	☐	☐
	Other	☐	☐	☐	☐	☐

g1. How were potential fuel suppliers qualified?
g2. What criteria are used to rank bidders?
g3. How were credit and performance ratings of potential fuel suppliers checked?

g4. Do you automatically select the lowest bidder?	Y ☐ N ☐
If not, what criteria are used for selection and negotiation of the fuel contract?	

g5. Describe the procurement procedures used on your most recent fuel procurement contract for both:	
- the purchase from a non-affiliated company	
- the purchase from an affiliated company	

h. Do the Utility's purchase policy practices differ for associated companies?	Y ☐ N ☐
If so, what generally are the differences?	

SI-SSA-0010-4306

6. For each fuel supply contract, of longer than one year in duration, in force at any time during 2016 and/or 2017, where costs were subject to 18 CFR 35.14, (including informal agreements with *associated companies*), provide the requested information. Report the information individually for each contract, *for each calendar year.* [No response to any part of Question 6 for fuel oil no. 2 is necessary.] Report all fuels consumed for electric power generation and thermal energy associated with the production of electricity. Information for only coal, natural gas, and oil should be reported.

Contract 1

a. Contract specifications

Use the add, or delete buttons to manage contract records — Add Contract (+) — Del Contract (-)

Contract ID / number	Reporting year	Contract signing date	Contract expiration date	Is contract evergreen ?	Contract type: Coal (choose from list)	Contract type: Gas supply (choose from list)	Contract type: Gas transportation (choose from list)	Fuel quantity: Gas ($x10^3$ mmbtu)	Fuel quantity: Oil ($x10^3$ bbls)	Fuel quantity: Coal ($x10^3$ tons)	Fuel quality: Gas (Btu/ft^3)	Fuel quality: Pipeline quality? (Y/N)	Fuel quality: Oil (Btu/gal)	Fuel quality: Coal (Btu/lb)	Impurity content: Sulfur content (%weight)	Impurity content: Ash content (%weight)	Impurity content: Moisture (%)

b. Delivered characteristics

Fuel origin: Primary State / Country of Origin	Fuel origin: Type of purchase point	Fuel destination: Total fuel transportation distance (mi.) from Utility's receipt point to plant	Fuel quantity: Gas ($x10^3$ mmbtu)	Fuel quantity: Oil ($x10^3$ bbls)	Fuel quantity: Coal ($x10^3$ tons)	Fuel quantity: Coal ($x10^3$ tons) not delivered by end of contract year	Fuel quality: Gas (Btu/ft^3)	Fuel quality: Pipeline quality? (Y/N)	Fuel quality: Oil (Btu/gal)	Fuel quality: Coal (Btu/lb)	Impurity content: Sulfur content (%weight)	Impurity content: Ash content (% weight)	Impurity content: Moisture (%)	Fuel cost (see desk reference): Actual weighted average fuel price paid **FOB origin**/year (cents/mmBtu)	Fuel cost (see desk reference): Actual weighted average fuel price paid **FOB plant**/year (cents/mmBtu)
1.	*Destination Plant:*							*Enter Plant Not Listed:*							

Use the add, delete and copy buttons to manage Delivery characteristics information for each Contract : Add Delivery (+) — Del Delivery (-) — Copy Delivery

c. Fuel and transportation contract affiliates

Name of any entity affiliated with the Utility that is involved in the procurement or transportation of its fuel	Type of affiliation	Affiliated entity involvement with the Utility

Add Row (+) — Delete Row (-)

SI-SSA-0010-4307

7. For each fuel supply contract, including informal agreements with associated or affiliated companies in force at any time during 2016 or 2017 WHERE CONTRACT SHORTFALL COSTS WERE PASSED THROUGH an FAC subject to 18 CFR 35.14, provide for each contract separately the information requested below. Only report the information requested for shortfalls that occurred under your contracts during reporting years 2016 or 2017 and that are not under dispute i.e. parties agree there was indeed a shortfall.

a) Cause of the shortfall [e.g., disruption in production, fuel not meeting quality specifications, dispute over contract provisions, a disruption in supplier's transportation system or other (specify)].	b) Amount of shortfall costs passed through the FAC	c) Utility or Supplier-caused?	d) Did contract contain a provision for shortfall consequences?

Add Row (+) Delete Row (-)

8. For each fuel supply contract that was bought-out or bought-down, including informal agreements with associated or affiliated companies in force at any time during 2016 or 2017 WHERE CONTRACT BUY-OUT AND/OR BUY-DOWN COSTS WERE PASSED THROUGH an FAC subject to 18 CFR 35.14, provide for each contract separately the information requested below. Only report the information requested for contract buy-downs and buy-outs that occurred under your contracts during reporting years 2016 or 2017 and that are not under dispute i.e. parties agree there was indeed a shortfall.

a) Type of change (buy-down, buy-out, renegotiation or other)	b) Effective date of buy-out or buy-down (mm/dd/yy).	c) Amount of any buy-out and buy-down costs that were passed through the FAC ($xx).	d) Docket number of Commission waiver, if any, allowing recovery of contract buy-down and buy-out costs through the FAC.

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SI-SSA-0010-4308

APPENDIX A

Coal Contract Types

1. Base Price plus Escalation

Different components of the price escalate (or de-escalate) as a function of changing economic conditions (indices).

2. Price Renegotiation

The price is renegotiated at predetermined intervals, usually one year. This type of contract, frequently known as an “EVERGREEN CONTRACT,” may also contain provisions for price adjustments between renegotiations.

3. Price Tied to Market

Price tied to the price of coal being sold in a particular market. Product and market area are defined in the contract. Contract may contain a "Most Favored Nations" clause, *i.e.*, supplier will not sell to any utility at a price lower than your utility is paying.

4. Cost-Plus Contract with a Fixed Fee Provision

Purchaser agrees to pay all producer costs plus a management fee. Some contracts provide for payment of both a management fee and a profit. This contract has a *Fixed Fee* provision.

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Purchaser agrees to pay all producer costs plus a management fee. Some contracts provide for payment of both a management fee and a profit. This contract has an *Incentive Fee* provision, *i.e.*, a variable fee that is tied to various productivity and cost reduction incentives.

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Price is fixed over the life of the contract.

Glossary

Term	Definition
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Base price plus escalation	Different components of the price escalate (or de-escalate) as a function of changing economic conditions (indices).
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Capacity	Electricity available to provide to a market during a defined period.
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Hourly economic dispatch	A forward-looking process by which the system personnel responsible for selecting the source(s) of energy to be used by the company to meet its loads in the next hour are free to, and do in fact, decide which available energy resources will be used and in what amount solely on the basis of the relative projected energy costs of those resources for that hour with the goal of minimizing total production cost for that hour.
Independent Power Producer (IPP)	A generator who provides either capacity or wholesale power to utilities. IPPs operate in the franchised territories of host utilities and do not possess transmission facilities or sell electricity on the retail market.
Price renegotiation	The price is renegotiated at predetermined intervals, usually one year. This type of contract, frequently known as an “Evergreen Contract,” may also contain provisions for price adjustments between renegotiations.
Price tied to market	Price tied to the price of coal being sold in a particular market. Product and market area are defined in the contract. Contract may contain a "Most Favored Nations" clause, i.e., supplier will not sell to any utility at a price lower than your utility is paying.
Qualifying Facility (QF)	A QF is a generating facility which meets the requirements for QF status under the Public Utility Regulatory Policies Act of 1978 and 18 CFR Part 292 of the Commission's regulations, and which has either self-certified with the Commission or has obtained FERC certification of QF status. There are two types of QFs: cogeneration facilities and small power production facilities.
Rate schedule	The rates, charges, and provisions under which service is supplied to customers.
Receipt point	Where the Utility or Utility's contracted agent takes possession of the fuel.
Reliability purchase	An energy purchase made when a utility does not have sufficient generating capability to meet its own load plus its planning reserve requirement.
Renewable Energy Credit (REC)	A tax credit offered by some states as an incentive for the installation and operation of renewable energy systems such as solar or wind power.
Reporting year	The time period to which the data provided in the FERC-580 applies.
Service schedule	A document describing the kinds of services to be furnished to the identified parties at the rates specified.
Shortfall	Contracted less delivered amount.
System reserve capacity criteria	Planning criteria used to determine when a reliability purchase is made.
Total avoided variable cost	All identified and documented variable costs that would have been incurred by the buyer had a particular purchase not been made.
Utility name	The exact legal name of the Utility

Filing Deadline: December 31, 2014

Federal Energy Regulatory Commission
2014 FERC Form 580 Interrogatory on Fuel and Energy Purchase Practices

Title 18, U.S.C. 1001 makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Refer to the general guidance and directions provided in the 2014 FERC Form 580 Desk Reference to complete the interrogatory. Included herein is Appendix A *Coal Contract Types* and a *Glossary* of terms used. Terms highlighted in blue are defined in the glossary.

1a Enter the exact legal name of the filing Utility (as company is registered with the Commission).

Utility name:	PSEG Nuclear LLC

1b Identify the principal contact person for clarification and additional information concerning your Utility's fuel procurement.

Name	Address					Telephone	Email address
	street	suite	city	state	zip code		
John P. Scarlata	80 Park Plaza	T19	Newark	NJ	07102	(973) 430-6803	John.Scarlata@pseg.com

1c Identify the principal contact person for clarification and additional information concerning your Utility's energy purchases (purchased power).

Name	Address					Telephone	Email address
	street	suite	city	state	zip code		
Lathrop Craig	80 Park Plaza	T19	Newark	NJ	07102	(973) 430-7268	Lathrop.Craig@pseg.com

SI-SSA-0010-4312

2.

a. Provide the following information regarding non-transmission related wholesale automatic adjustment clauses (AACs) your Utility had on file with the Commission during calendar years 2012 and 2013. Note: use the add and delete row buttons to manage information entry.

Docket number under which rate schedule containing AAC through which costs were passed during 2012 and/or 2013 was accepted for filing by FERC	Is this AAC a fuel adjustment clause (FAC)	Tariff volume number containing AAC	Rate schedule number containing AAC	Date rate schedule was first accepted for filing by the Commission	First effective date of rate schedule	Was rate schedule superseded or abandoned during 2012-2013? If so, provide dates	Identify service agreement within rate schedule containing AAC

If the Utility had no non-transmission-related wholesale AACs during the reporting years, check here: ☒

Add Row (+) Delete Row (-)

b. If any of the Utility's wholesale rate and/or service agreements containing an AAC listed in Question 2a, that was used during 2012 and/or 2013, was filed with the Commission before January 1, 1990, attach an electronic copy of it with this filing. List the documents you are submitting below. Note: once this information is submitted electronically in a text-searchable format it will not be necessary to submit it in future Form 580 filings. See: http://www.ferc.gov/docs-filing/elibrary/accept-file-formats.asp for listing of Commission-accepted document types.

File name with extension	Document/ File Description:

Add Row (+) Delete Row (-)

NOTE: If the Utility for which you are filing did not have any rate/service schedules on file with the Commission allowing the automatic adjustment of fuel and/or fuel-related items subject to 18 CFR 35.14 during 2012-13, STOP HERE, you are finished. File your responses to questions 1 and 2 with the Commission. Otherwise, continue with the questions that follow.

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3. If during the 2012-2013 period, the Utility had any contracts or agreements for the purchase of either energy or capacity under which all or any portion of the purchase costs were passed through a fuel adjustment clause (FAC), for each purchase from a PURPA Qualifying Facility (QF) or Independent Power Producer (IPP), provide the information requested in the non-shaded columns of the table below. Provide the information separately for each reporting year 2012 and 2013. Do not report purchased power where none of the costs were recovered through a FAC. Fill-in the non-shaded columns and either the "Only energy charges" columns OR "The total cost of the purchase of economic power" columns, whichever apply.

If the Utility did not recover any purchased power costs through a FAC, check here: ☒

					Cost item/s recovered through a FAC					
					Only energy charges		***The total cost of the purchase of economic power***			
Year	Seller name	Purchase cost ($)	Annual amount recovered through an AAC ($)	Does the Commission-accepted FAC used to recover this cost allow for automatic recovery of purchased power costs?	Was the total of such charges less than the total avoided variable costs?	Was economic dispatch used to determine whether the charges were less than avoided costs?	Was the total cost of purchased power less than the total avoided variable costs?	Was the duration of the purchased power equal to or less than twelve months?	Did the FAC used for cost recovery include the system reserve capacity criteria by which the system operator decides whether a reliability purchase is required?	If the purchased power was wind-generated, was the avoided cost comparison done on a contract-by-contract basis?

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4a If emission allowance costs were incurred by the Utility in 2012 and/or 2013 and were recovered through a FAC, provide the following information.

Origin of emission allowance cost	Dollar value of emission allowance cost passed through a FAC		Docket number, if any, of Commission acceptance of emission allowance cost recovery through a FAC	Date Commission accepted FAC recovery of emission allowance costs
	2012	2013		

Add Row (+) Delete Row (-)

4b Were emission allowance costs recovered in any other method than through a FAC? No

If yes, how were they recovered? Include specific Commission rate schedule and service agreement notations.

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5. Provide the information requested below regarding the Utility's fuel procurement policies and practices in place during 2012 and/or 2013 for fuels whose costs were subject to 18 CFR 35.14. **Note: Responses to this question may be filed as Privileged. To do so, skip this question now and answer it via the Fuel Procurement Policies and Practices Privileged Addendum provided. Otherwise, answer it here and your responses will be made public.**

Are you filing the Question 5 Privileged Addendum?		
a1. How often does Utility management review the fuel procurement process?	Select value:	
a2. When was the last review?		
a3. Who conducted the last review? (Last, First, MI) & (Title)		
a4. What was covered in the last review?		
b1. Does the Utility have a policy on fuel inventory levels?		
b2. Does the policy state under what circumstance/s fuel inventory is increased or decreased?		
☐ Utility has no policy on fuel inventory levels.		
b3. When was the fuel inventory policy last reviewed, and who last approved it?		
b4. Who made the working decisions to change inventory levels? (Last, First, MI) & (Title)		

c. Describe any use by the Utility of systematic procedures for periodic market investigations of fuel costs and availability, particularly prior to renewal or renegotiation of contracts.

d. Describe any environmental constraints which influenced the Utility's fuel purchase practices.

e. What quality characteristics were routinely specified in the Utility's fuel contracts?

Fuel	*Energy Content*	*Sulfur Content*	*Ash Content*	*Moisture Content*	*Other*
Coal	☐	☐	☐	☐	
Oil	☐	☐	☐	☐	
Natural gas	☐	☐	☐	☐	
Other	☐	☐	☐	☐	

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f. What percentage of the Utility's fuel was purchased from utility-controlled (i.e. affiliate) sources?	%	0%	>0-25%	25-50%	50-75%	75-100%
	Coal	☐	☐	☐	☐	☐
	Oil	☐	☐	☐	☐	☐
	Natural gas	☐	☐	☐	☐	☐
	Other	☐	☐	☐	☐	☐

g1. How were potential fuel suppliers qualified?
g2. What criteria are used to rank bidders?
g3. How were credit and performance ratings of potential fuel suppliers checked?

g4. Do you automatically select the lowest bidder?	Y ☐ N ☐
If not, what criteria are used for selection and negotiation of the fuel contract?	

g5. Describe the procurement procedures used on your most recent fuel procurement contract for both:	
- the purchase from a non-affiliated company	
- the purchase from an affiliated company	

h. Do the Utility's purchase policy practices differ for associated companies?	Y ☐ N ☐
If so, what generally are the differences?	

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6. For each fuel supply contract, of longer than one year in duration, in force at any time during 2012 and/or 2013, where costs were subject to 18 CFR 35.14, (including informal agreements with *associated companies*), provide the requested information. Report the information individually for each contract, *for each calendar year.* [No response to any part of Question 6 for fuel oil no. 2 is necessary.] Report all fuels consumed for electric power generation and thermal energy associated with the production of electricity. Information for only coal, natural gas, and oil should be reported.

Contract 1

a. Contract specifications

Use the add, or delete buttons to manage contract records — Add Contract (+) — Del Contract (-)

Contract ID / number	Reporting year	Contract signing date	Contract expiration date	Is contract evergreen ?	Contract type: Coal (choose from list)	Contract type: Gas supply (choose from list)	Contract type: Gas transportation (choose from list)	Fuel quantity: Gas ($x10^3$ mmbtu)	Fuel quantity: Oil ($x10^3$ bbls)	Fuel quantity: Coal ($x10^3$ tons)	Fuel quality: Gas (Btu/ft^3)	Fuel quality: Pipeline quality? (Y/N)	Fuel quality: Oil (Btu/gal)	Fuel quality: Coal (Btu/lb)	Impurity content: Sulfur content (%weight)	Impurity content: Ash content (%weight)	Impurity content: Moisture (%)

b. Delivered characteristics

Fuel origin: Primary State / Country of Origin	Fuel origin: Type of purchase point	Fuel destination: Total fuel transportation distance (mi.) from Utility's receipt point to plant	Fuel quantity: Gas ($x10^3$ mmbtu)	Fuel quantity: Oil ($x10^3$ bbls)	Fuel quantity: Coal ($x10^3$ tons)	Fuel quantity: Coal ($x10^3$ tons) not delivered by end of contract year	Fuel quality: Gas (Btu/ft^3)	Fuel quality: Pipeline quality? (Y/N)	Fuel quality: Oil (Btu/gal)	Fuel quality: Coal (Btu/lb)	Impurity content: Sulfur content (%weight)	Impurity content: Ash content (% weight)	Impurity content: Moisture (%)	Fuel cost (see desk reference): Actual weighted average fuel price paid **FOB origin**/year (cents/mmBtu)	Fuel cost (see desk reference): Actual weighted average fuel price paid **FOB plant**/year (cents/mmBtu)
1.	*Destination Plant:*							*Enter Plant Not Listed:*							

Use the add, delete and copy buttons to manage Delivery characteristics information for each Contract : Add Delivery (+) — Del Delivery (-) — Copy Delivery

c. Fuel and transportation contract affiliates

Name of any entity affiliated with the Utility that is involved in the procurement or transportation of its fuel	Type of affiliation	Affiliated entity involvement with the Utility

Add Row (+) — Delete Row (-)

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7. For each fuel supply contract, including informal agreements with associated or affiliated companies in force at any time during 2012 or 2013 WHERE CONTRACT SHORTFALL COSTS WERE PASSED THROUGH an FAC subject to 18 CFR 35.14, provide for each contract separately the information requested below. Only report the information requested for shortfalls that occurred under your contracts during reporting years 2012 or 2013 and that are not under dispute i.e. parties agree there was indeed a shortfall.

a) Cause of the shortfall [e.g., disruption in production, fuel not meeting quality specifications, dispute over contract provisions, a disruption in supplier's transportation system or other (specify)].	b) Amount of shortfall costs passed through the FAC	c) Utility or Supplier-caused?	d) Did contract contain a provision for shortfall consequences?

Add Row (+) Delete Row (-)

8. For each fuel supply contract that was bought-out or bought-down, including informal agreements with associated or affiliated companies in force at any time during 2012 or 2013 WHERE CONTRACT BUY-OUT AND/OR BUY-DOWN COSTS WERE PASSED THROUGH an FAC subject to 18 CFR 35.14, provide for each contract separately the information requested below. Only report the information requested for contract buy-downs and buy-outs that occurred under your contracts during reporting years 2012 or 2013 and that are not under dispute i.e. parties agree there was indeed a shortfall.

a) Type of change (buy-down, buy-out, renegotiation or other)	b) Effective date of buy-out or buy-down (mm/dd/yy).	c) Amount of any buy-out and buy-down costs that were passed through the FAC ($xx).	d) Docket number of Commission waiver, if any, allowing recovery of contract buy-down and buy-out costs through the FAC.

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APPENDIX A

Coal Contract Types

1. Base Price plus Escalation

Different components of the price escalate (or de-escalate) as a function of changing economic conditions (indices).

2. Price Renegotiation

The price is renegotiated at predetermined intervals, usually one year. This type of contract, frequently known as an “EVERGREEN CONTRACT,” may also contain provisions for price adjustments between renegotiations.

3. Price Tied to Market

Price tied to the price of coal being sold in a particular market. Product and market area are defined in the contract. Contract may contain a "Most Favored Nations" clause, *i.e.*, supplier will not sell to any utility at a price lower than your utility is paying.

4. Cost-Plus Contract with a Fixed Fee Provision

Purchaser agrees to pay all producer costs plus a management fee. Some contracts provide for payment of both a management fee and a profit. This contract has a *Fixed Fee* provision.

5. Cost-Plus Contract with an Incentive Fee Provision

Purchaser agrees to pay all producer costs plus a management fee. Some contracts provide for payment of both a management fee and a profit. This contract has an *Incentive Fee* provision, *i.e.*, a variable fee that is tied to various productivity and cost reduction incentives.

6. Fixed-Price Contract

Price is fixed over the life of the contract.

Glossary

Term	Definition
Annual weighted average	An average taken over a 12-month period in which each item being averaged is multiplied by a number (weight) based on the item's relative importance. The result is summed and the total is divided by the sum of the weights.
Associated (affiliated) companies	Companies or persons that directly or indirectly through one or more intermediaries, control, or are controlled by, or are under common control with the account company. (see 18 CFR Part 101 for more information)
Automatic adjustment clause (AAC)	A provision of a rate schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility.
Avoided variable costs	All identified and documented variable costs (costs that change or vary with usage, output or production, e.g., fuel costs) that would have been incurred by the buyer had a particular purchase not been made. Such costs include, but are not limited to, those associated with fuel, start-up, shut-down or any purchases that would have been made in lieu of the purchase made.
Base price plus escalation	Different components of the price escalate (or de-escalate) as a function of changing economic conditions (indices).
Contract buy-downs	Costs paid in compensation to suppliers for reducing the contract amount to below the minimum requirement.
Contract buy-outs	Buy-out costs are compensation paid to suppliers for ending a contract before the previously agreed upon contract expiration date.
Capacity	Electricity available to provide to a market during a defined period.
Commission cite	Reference to a Commission document/issuance.
Contract ID/ number	Unique contract identifier that the Utility uses internally to identify a contract.
Cost-plus contract with a fixed fee provision	Purchaser agrees to pay all producer costs plus a management fee. Some contracts provide for payment of both a management fee and a profit. This contract has a Fixed Fee provision.
Cost-plus contract with an incentive fee provision	Purchaser agrees to pay all producer costs plus a management fee. Some contracts provide for payment of both a management fee and a profit. This contract has an Incentive Fee provision, i.e., a variable fee that is tied to various productivity and cost reduction incentives.
Economic power	Power or energy purchased over a period of twelve months or less where the total cost of the purchase is less than the buyer's total avoided variable cost.
Effective date of rate schedule	The date upon which service is approved by FERC to begin.
EIA	EIA is an acronym for Energy Information Administration.
EIA code	Unique identification number assigned by EIA to utilities and plants.
Emission allowance	an authorization by the Administrator under the Acid Rain Program to emit a specified limited amount of sulfur dioxide during or after a specified calendar year (see 40 CFR Part 72)
Energy charge	That portion of the charge for electric service based upon the electric energy (kWh) consumed or billed.
Evergreen contract	A contract that is renewed automatically or by notice from year to year until canceled by either party.
Filing year	The year the data is collected.

Term	Definition
Fixed-price contract	Price is fixed over the life of the contract.
FOB	FOB is an acronym for Free On Board. The term FOB (often seen as f.o.b.) is commonly used when shipping goods to indicate who pays loading and transportation costs, and/or the point at which the responsibility of the goods transfers from shipper to buyer. FOB origin is the term used when the ownership/liability of goods passes from the seller to the buyer at the time the goods leave the origin. FOB plant designates that the seller is responsible for the goods until the buyer takes possession at the delivery point. This is important in determining who is responsible for lost or damaged goods when they are in transit from the seller to the buyer. The buyer is responsible when shipped FOB origin and the seller is responsible when shipped FOB delivery point.
Hourly economic dispatch	A forward-looking process by which the system personnel responsible for selecting the source(s) of energy to be used by the company to meet its loads in the next hour are free to, and do in fact, decide which available energy resources will be used and in what amount solely on the basis of the relative projected energy costs of those resources for that hour with the goal of minimizing total production cost for that hour.
Independent Power Producer (IPP)	A generator who provides either capacity or wholesale power to utilities. IPPs operate in the franchised territories of host utilities and do not possess transmission facilities or sell electricity on the retail market.
Price renegotiation	The price is renegotiated at predetermined intervals, usually one year. This type of contract, frequently known as an “Evergreen Contract,” may also contain provisions for price adjustments between renegotiations.
Price tied to market	Price tied to the price of coal being sold in a particular market. Product and market area are defined in the contract. Contract may contain a "Most Favored Nations" clause, i.e., supplier will not sell to any utility at a price lower than your utility is paying.
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Utility name	The exact legal name of the Utility

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Grid Resilience in Regional Transmission Organizations and Independent System Operators	)))	Docket No. AD18-7-000

COMMENTS OF EXELON CORPORATION

Resilience is an increasingly important concern in the face of significant man-made and natural threats to the bulk power system. Foreign adversaries and other bad actors have already demonstrated an interest in attacking the bulk power system, as the Commission and RTOs have recognized. Yet the system's vulnerability to these threats is growing, due to exit of numerous fuel-secure baseload generators from the market, combined with an increased reliance on natural gas generators susceptible to fuel supply interruption. Fuel security is thus a serious emerging issue affecting grid resilience. PJM acknowledges that its reliability studies do not include consideration of "the resilience of the system with various potential [resource] portfolios nor the risks associated with significant disruptive events," and that PJM "needs to understand the fuel-supply risks in an environment trending toward greater reliance on natural gas supply and delivery."[1]

In a recent scoping document and letter to stakeholders, PJM indicated its intent to conduct a study in the coming few months to "perform targeted analyses to identify fuel security risks that could affect specific locations on the system," including "the deliverability logistics of fuel supplies during stressed conditions over time."[2] PJM then intends to model various contingencies

[1] PJM Interconnection, L.L.C., *Valuing Fuel Security*, at 1 (Apr. 30, 2018) ("PJM Fuel Security"), http://www.pjm.com/-/media/library/reports-notices/special-reports/2018/20180430-valuing-fuel-security.ashx?la=en.
[2] *Id.* at 2.

and propose market-based solutions to improve system resilience. Exelon strongly supports that initiative—though PJM should also model and consider the environmental impacts of different approaches to ensuring resilience. Nevertheless, PJM's proposal only underscores the need for the Commission's leadership.

Put simply: unless PJM is modeling the right scenarios, its analysis of fuel security vulnerabilities, and the solutions it will propose based on that analysis, will not necessarily ensure resilience. Yet PJM lacks access to the information needed to assess which risks it should plan its system to meet. PJM has identified obstacles it faces in obtaining the information necessary to assess cyber and supply chain threats, and has called on the Commission "to provide intelligence and metrics to apply to resilience vulnerability and threat analyses, such that they can then guide and anchor subsequent RTO planning, market design, and/or operations directives."[3] Below, we explain how the Commission should answer that call.

First, the Commission should direct PJM and other RTOs to conduct studies on fuel security in their regions. Recently, ISO-New England analyzed fuel security in that region and identified fuel insecurity as a major threat. The ISO-New England study not only identifies a fuel security problem in the region; it also provides a strong foundation for stakeholder discussions and planning to reduce fuel insecurity and increase grid resilience. PJM should conduct a similarly rigorous study to define the fuel security threats to PJM—which existing studies already suggest are present and immediate—and enable PJM to better address man-made and natural threats to the bulk power system. In particular, PJM should focus on potential RTO vulnerability to gas pipeline disruptions, and assess the degree to which oil-fueled resources can support grid resilience. A

[3] Comments and Responses of PJM Interconnection, L.L.C., FERC Docket No. AD18-7-000, at 32 (Mar. 9, 2018) ("PJM Response").

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study by Navigant Consulting, Inc. (attached as Exhibit A) indicates that contribution of oil-fueled resources diminishes rapidly as the length of a resilience-related event extends beyond four days.

Second, while PJM and other RTOs are studying fuel security in their regions, the federal government should develop a design-basis threat ("DBT") to identify resilience threats and provide a baseline against which PJM and other RTOs can measure their efforts at creating a resilient grid. As explained in detail in an affidavit from Dr. Paul Stockton, former Assistant Secretary of Defense for Homeland Defense and Americas' Security Affairs (attached as Exhibit B), the DBT tool is well-suited to identify man-made threats to the bulk power system and guide efforts to address those threats. The Commission, together with the Department of Energy, should lead the effort to develop a DBT, with input from the national security agencies, so that RTOs can ground their efforts to protect the grid in up-to-date and reliable threat information drawn from intelligence sources. If the DBT is not yet ready when PJM begins its modeling of various contingencies, PJM should nevertheless vet its scenarios with the Department of Energy and Department of Homeland Security and address their feedback, so that PJM can implement market changes on its proposed timeline of May 2019; however, as soon as the DBT is completed, the Commission should require PJM to update its modeling and analysis in light of the threats identified as part of the DBT. To the extent PJM cannot implement market rule changes that consider the DBT in time for the May 2019 Base Residual Auction, PJM can then move quickly to adopt any needed changes to market rules in time for the 2020 Base Residual Auction in light of its enhanced understanding of the region's fuel security vulnerabilities.

Finally, the Commission should explicitly clarify that RTOs and transmission owners should consider resiliency in their transmission planning and in RTO market design. Transmission owners should retain their traditional authority to consider resilience in transmission planning for

local projects as well as planning on the distribution grid, while the RTOs must explicitly add resilience considerations to their regional transmission planning and market design. The Commission should then review RTO filings under Sections 205 and/or 206 to ensure the adoption and implementation of any needed reforms to address the vulnerabilities identified by the DBT tool. RTOs should additionally be required to model the emissions consequences of potential resilience solutions.

I. The Resilience Threat Suggests That Existing Market Structures Are Not Just and Reasonable.

Grid resilience is a serious and growing concern: the Nation is increasingly reliant on natural gas-fired generation, and thus on the natural gas transmission system, at the same time as that infrastructure has become more susceptible to disruption and attack by foreign enemies. Yet the Commission has not, to date, addressed resilience in the tariffs governing the operation of the organized markets. This latent risk calls into question whether the market rules and transmission planning criteria remain just and reasonable under the Federal Power Act.

Ensuring that the grid is resilient in the face of man-made and natural threats is an increasing concern that requires urgent attention. Prolonged disruption to the grid would have an immense and devastating impact on the daily lives of Americans. Critical systems would be incapacitated, including electric and natural gas heating at residential, commercial, and industrial locations; water treatment plants; the food distribution system; the medical system; and communications networks.[4] National security would be at risk. Military facilities and other

[4] Exhibit A to Comments of Exelon Corp., Prepared Direct Testimony of Dr. Paul Stockton on Behalf of Exelon Corp. at 9-10, Docket No. RM18-1-000 (Oct. 23, 2017) (attached hereto as Exhibit B-1).

national security organizations depend on power to function. A prolonged period without power would severely hamper their ability to protect the nation.[5]

As the Department of Energy has recognized, "[f]uel assurance is a growing consideration for the electricity system" and a major threat to system resilience.[6] As resilient nuclear generators announce retirements in growing numbers, the grid irreversibly loses a set of reliable, fuel-secure resources that contribute greatly to overall fuel diversity. For example, between 2012 and 2016, 4,666 MW of nuclear generating capacity—or about 4.7% of the country's total—announced retirements.[7] Twelve more nuclear reactors, representing 11,109 MW of capacity, have announced retirements since 2016.[8] Still other nuclear retirements have been avoided only by state programs that compensate these plants' zero-emissions attributes. FirstEnergy's announcement last month that it intends to shutter Beaver Valley, Davis-Besse, and Perry—amounting to 3,942 MW of capacity—indicates a critical inflection point, and urgent action is needed to prevent further nuclear retirements. Widespread nuclear retirements irreversibly remove an integral foundational resource from the grid.

As fuel-secure resources retire, the energy supply is increasingly dependent on natural gas. In the PJM region, 90% of the new installed capacity over the last five years and more than 90% of planned capacity in the interconnection queue is gas fueled.[9] Yet overreliance on natural gas

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[5] *Id.* at 6, 10.
[6] U.S. Dep't of Energy, *Staff Report to the Secretary on Electricity Markets and Reliability* at 11-12 (Aug. 2017), https://bit.ly/2KNEnzJ ("DOE Staff Report").
[7] *Id.* at 29.
[8] *Id.* at 30; this figure also includes the capacity of Beaver Valley, Davis-Besse, and Perry.
[9] *See* PJM Interconnection L.L.C., *2020-/21 RPM Base Residual Auction Results*, at 21, Table 8, http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx?la=en; *see also* IHS Markit, *Ensuring Resilient and Efficient PJM Electricity Supply* (April 2018), https://bit.ly/2rju3GE (discussing increasing reliance on natural gas generation); ICF, *The Impact of Fuel Supply Security on Grid Resilience—Interim Report* (May 5, 2018) ("ICF Study") (same) (attached to comments of Nuclear Energy Institute).

poses serious risks to the resilience of the grid. Natural gas generators often lack on-site fuel. Instead, they rely on a pipeline network to distribute fuel, which could easily be disrupted by a man-made or natural event.[10] In fact, a PJM study found that a single gas pipeline in the PJM region serves more than 11,000 MW of generation, and a recent study by ICF examining generation clusters in PJM and New York found that more than 18,000 MW of generation would be at risk from an extended pipeline outage[11]—all in the most densely populated parts of the Eastern United States.[12] The loss of that pipeline alone—whether from an earthquake, a cyberattack, a physical attack, or some other event—could wreak havoc in the region and nationally.

Fuel insecurity due to increased reliance on natural gas is a particular problem for the Eastern MAAC ("EMAAC") portion of PJM.[13] The region does not produce much gas locally; it is supplied by several large, discrete pipelines; it lacks significant storage; its dual-fuel capability may be less robust than believed; and it has a significant demand for natural gas as a heating fuel during the winter season, which usually takes priority over power generation demand. All of these factors, combined with the increasing demand for and reliance on natural gas for power generation, create acute vulnerability to natural and man-made threats. Other areas of PJM may have vulnerabilities similar to those of EMAAC, or may develop vulnerabilities in future years as natural gas capacity continues to displace other types of resources.

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[10] There are areas within the pipeline system where disruption events could have cascading effects on generation resources. ICF Study at 44.
[11] *Id.* at 6-8, 30-32.
[12] PJM Transmission Expansion Advisory Committee, *Reliability Analysis Update* (Sept. 14, 2017), http://pjm.com/-/media/committees-groups/committees/teac/20170914/20170914-reliability-analysis-updates.ashx.
[13] The Eastern MAAC portion of PJM contains the zones of Atlantic City Electric (AE), Delmarva Power & Light (DPL), Jersey Central Power & Light (JCPL), PECO Energy (PECO), Public Service Electric & Gas (PSE&G) and Rockland Electric (RE).

Recent studies show that fuel security is not a hypothetical concern. The recent Cold Snap demonstrated areas of vulnerability in the PJM system.[14] Over the course of eleven days in December 2017 and January 2018, PJM maintains the region generally performed well, but one notable area for future improvement was fuel security. If the Cold Snap had been longer or had occurred outside of the holiday period and weekend, when loads are generally moderated, the level of system stress would have been much greater. Many fewer gas generators were online at the end of the Cold Snap than at the beginning; and forced outages of gas generation due to fuel supply issues increased more than five-fold over the six-day period studied by PJM, from 1.1 GW to nearly 6 GW.[15] In some regions of the RTO, there was no natural gas to be had; the natural gas could not be transported to the generator.[16] To improve fuel security in light of the RTO's increasing reliance on natural gas, PJM determined that it needs to continue to improve gas-electric coordination capabilities, as well as the tracking and transportation of fuel oil supply.[17]

Dual-fuel generators, which can run on natural gas as well as another type of fuel, such as oil, have historically been seen as a hedge against the risk of gas supply interruption. But dual-fuel units provide a false sense of security: the limited storage and restricted delivery of fuel to dual-fuel and oil-only plants in the PJM region is itself a threat to resilience. A natural gas pipeline incident can take many months to be fully resolved; indeed, a pipeline rupture involving the Tetco Delmont Line 27 was not fully resolved for over six months.[18] Yet oil-fueled generation cannot

[14] As the Department of Energy explained in its recent Staff Report, fuel security was also an issue in the Polar Vortex of 2014, where "[m]any natural gas-fired generators had their fuel supplied curtailed." DOE Staff Report at 98.
[15] PJM Interconnection, *PJM Cold Snap Performance Dec. 28, 2017 to Jan. 7, 2018*, at 13 (Feb. 26, 2018) ("PJM Cold Snap Report"), http://www.pjm.com/-/media/library/reports-notices/weather-related/20180226-january-2018-cold-weather-event-report.ashx.
[16] *Id.* at 16.
[17] *Id.* at 33.
[18] ICF Report at 5.

reliably provide power in the event of a prolonged event. A study performed by Navigant (*see* Exhibit A) confirms that, in the PJM region, more than 50 percent of dual-fuel and oil-only capacity would be offline due to a lack of fuel after four days of full-load operation, and nearly 80 percent would be offline after seven days.[19]

Moreover, once oil stores are depleted, they cannot be quickly replenished.[20] Most oil capacity in PJM relies on trucks to deliver oil. That delivery often takes five to ten days under normal conditions.[21] In times of extreme weather, delivery is often delayed up to three additional days.[22] In an extreme weather or man-made event that lasts more than four days, oil-burning units run the very real risk of running out of oil that they cannot replenish.[23] That is in part because of slow delivery, and in part because in such events, other sources—such as oil heating demand, and hospitals and government institutions running oil-fired generators—will compete for a largely fixed supply of oil trucks and other oil delivery assets for whatever oil can be delivered.[24] The problem would only be compounded if multiple events occurred close in time, increasing demand and making delivery logistics more challenging. Indeed, as PJM recognized, fuel resupply can be

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[19] Exhibit A, Navigant Consulting, Inc., *PJM Liquid Fuel Survey and Research Results and Recommendations*, at 4 (Apr. 25, 2018) ("PJM Liquid Fuel Survey").
[20] ICF Study at 43 (explaining that the industry has less than 10-15 days of inventory on-site and that the loss of gas-only capacity "would not be unlike the loss of a major transmission line"); *id.* at 12, 41-42 (discussing challenges of timely refueling).
[21] PJM Liquid Fuel Survey at 5.
[22] *Id*.
[23] Environmental permit limitations also threaten to restrict a dual-fuel plant's ability to continue to operate at peak levels for an extended period of time. Although permit limits might be waived in an emergency situation, it is irresponsible to plan a system with the expectation of invoking emergency waiver authorities. Moreover, exceeding permit limits to serve load in an emergency comes at an environmental cost that should not be ignored—especially when retiring nuclear units could have met the need without imposing environmental externalities. As PJM further studies fuel security in its region and develops solutions to ensure sufficient fuel-secure resources, it should also consider the environmental consequences of its proposed solutions.
[24] PJM Liquid Fuel Survey at 5; ICF Study at 43 (replenishing oil is a "significant logistical challenge[]" when the need is unanticipated and widespread).

a significant problem for coal units as well as oil. PJM reported that, during the Cold Snap, "about 28 percent of combined coal and oil units (by ICAP MW) with on-site fuel inventories reported issues with fuel resupply due to fuel transportation constraints."[25] Coal units faced barge resupply delays due in part to frozen rivers.[26]

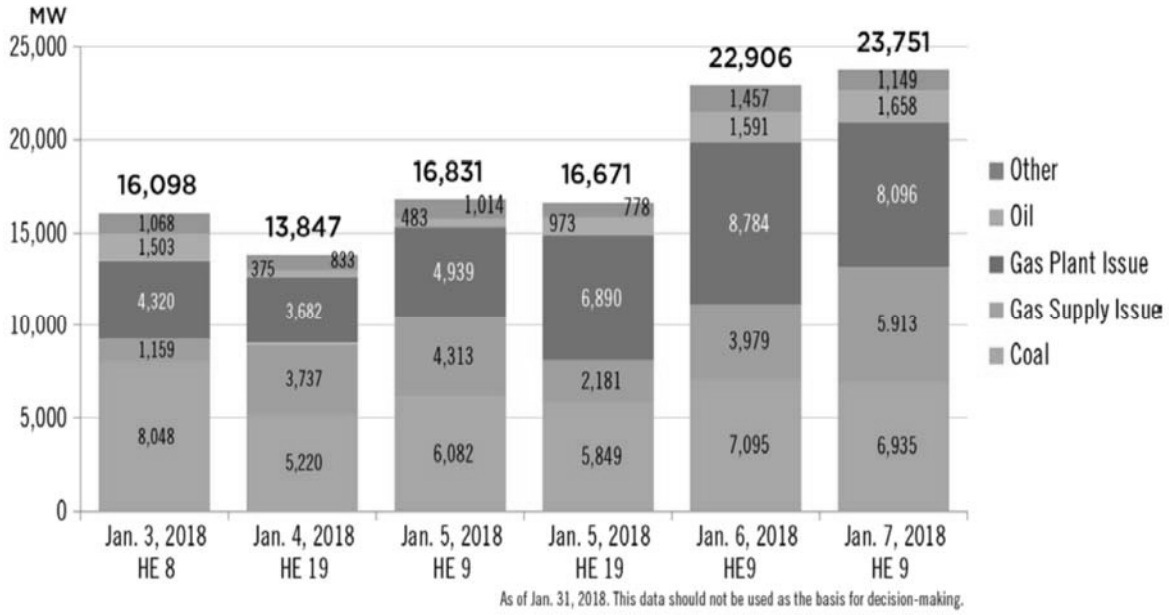
A recent study by the National Energy Technology Laboratory ("NETL") likewise highlighted potential vulnerabilities resulting from overdependence on natural gas supplies. The study analyzed the conditions in ERCOT and every Commission jurisdictional-market except CAISO during the 2017-18 Cold Snap (which it calls the "Bomb Cyclone"). The study described the various fuel sources that enabled the grid to sustainably operate at times of extreme stress and identified a number of key takeaways from the event, including that the natural gas fuel supply rapidly depleted due to delivery constraints and was barely able to meet surging demand.[27]

The NETL report erred, however, in describing coal as the "most resilient form of generation."[28] Its basis for that conclusion was that coal provided the largest incremental increase in output during the Cold Snap,[29] but that is only because coal plants were sitting idle. The better measure of resilience is whether a plant was able to operate during extreme conditions, both during the period of peak stress, as well as through a long-duration event. By that measure, nuclear was by far the most resilient type of generation. In PJM, nuclear provided 35.5 GW of reliable (and clean) power each day of the Cold Snap and suffered only a 200 MW derate at one plant.[30] That

[25] PJM Cold Snap Report at 16.
[26] *Id.*
[27] National Energy Technology Laboratory, *Reliability, Resilience and the Oncoming Wave of Retiring Baseload Units, Volume 1: The Critical Role of Thermal Units During Extreme Weather Events*, at 1-2 (Mar. 13, 2018), https://bit.ly/2I7rtLc ("NETL Report").
[28] *Id.* at 18.
[29] *Id.* at 18-19.
[30] *Id.* at 14, Exhibit 1-10.

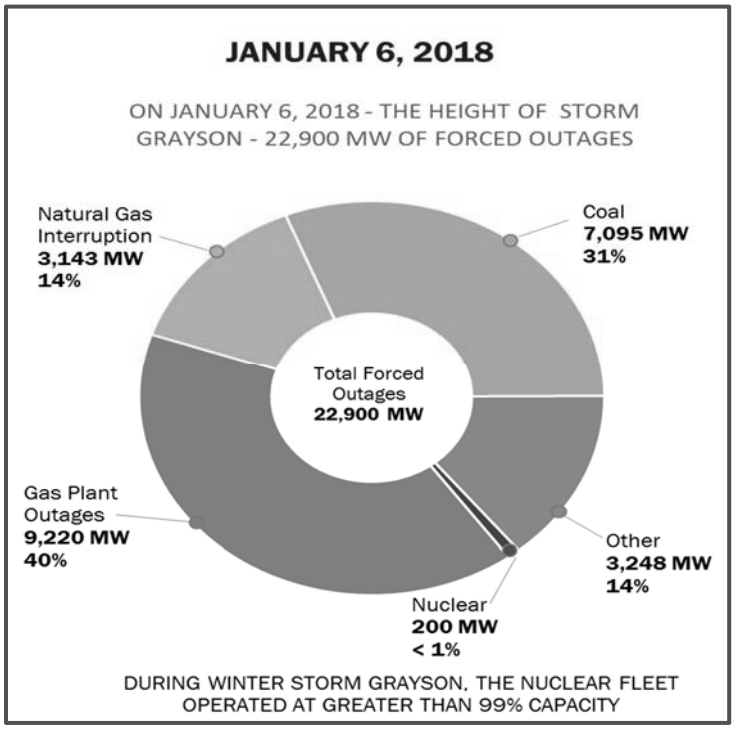
amounts to a nuclear forced outage rate of less than 1 percent. Coal, by contrast, suffered between 5.2 GW and 8 GW of forced outages over the six-day period, which amounts to between a 9 percent and 15 percent peak-hour forced outage rate during the highest stress period of the Cold Snap.[31] Gas and oil fared significantly worse. On the final day of the Cold Snap, gas, dual-fuel, and oil generators suffered nearly 16 GW in forced outages, and over the course of the entire event, the peak-hour forced outage rate for gas and oil ranged from 17 percent to 42 percent.[32] Gas supply issues were a major cause of these high outage rates. Gas supply issues accounted for over 50 percent of gas outages on the second day of the Cold Snap; nearly 47 percent on the third day; and over 42 percent on the last day.[33] The following charts summarize this data.

Forced Outages in PJM During the Cold Snap[34]



[31] PJM Cold Snap Report, at 16, Fig. 14.
[32] *Id.*
[33] *Id.*
[34] *Id.*

Forced Outages in PJM on January 6, 2018[35]



Some have argued that the fact that the grid passed through these events without any blackouts shows that the system is working as intended. But such self-assurance ignores the facts and is a grave mistake. These weather events were not nearly as severe as the Polar Vortex in 2014, as NETL points out;[36] and more importantly, they were simply cold weather events, not cold weather combined with a major natural gas system disruption or other compounding problem.[37]

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[35] PJM Interconnection L.L.C., *Cold Weather Summary December 27, 2017 - January 7, 2018* (Jan. 9, 2018), http://www.pjm.com/-/media/committees-groups/committees/oc/20180109/20180109-item-07-cold-weather-testing.ashx.

[36] NETL Report at 20.

[37] The cold weather events of 2014 and 2017-18 were not isolated incidents. There were also severe cold spells in, for example, 1977-78 and 1978-79. *See, e.g.,* Patricia M. Dare, *A Study of the Severity of the Midwestern Winters of 1977 and 1978 Using Heating Degree Days Determined from Both Measured and Wind Chill Temperatures*, 62 Bull. Am. Meteorological Soc'y 974 (1981). And during a 1994 cold spell, PJM and Virginia Power curtailed firm customers to maintain system reliability, and non-firm gas supply was interrupted—and this was at a time that the system was much less reliant on natural gas than it is today. NERC, *Report on Electric Utilities' Response to the Cold Wave of January 1994*, at 2, 6 (Apr. 11, 1994), https://bit.ly/2ruUIk1.

PJM recognizes that its existing reliability standards do not account for the "potential fuel security risks" that result from "increased reliance on any one resource type," and that the Capacity Performance product does not encompass, and is not intended to encompass, systemic risks to resilience that are "beyond the ability of any individual unit owner to control through more secure fuel contracts or investment in particular units."[38] These systemic risks include common-mode failures resulting from fuel supply disruptions that affect a large number of units.

Moreover, the most concerning threats to fuel security are man-made, not weather-related—and traditional reliability analyses are not well-suited to analyze system resilience during high-impact, low-probability events intentionally instigated by malicious actors to maximize societal harm. Malicious actors must be presumed to know about our vulnerabilities, and should be expected to target them.[39] Indeed, in just the last few months, a number of significant attacks on the bulk power system have come to light. For example, in March, the federal government announced that Russian hackers had conducted a cyberattack targeting nuclear power plants.[40] Similarly, natural gas companies announced in April that a cyberattack on the data network for natural gas pipelines forced the temporary shutdown of computer communications with customers.[41] More generally, an increasing number of academic studies, energy industry reports,

[38] PJM Fuel Security at 2.
[39] Exhibit B, Dr. Paul Stockton, *Fuel Resilience for the Bulk Power System: Threat-Based Modeling and Analysis*, at 5, 23 (May 8, 2018) ("Stockton Report").
[40] *See, e.g.,* Nicole Perlroth & David E. Sanger, *Cyberattacks Put Russian Fingers on the Switch at Power Plants, U.S. Says*, N.Y. Times (Mar. 15, 2018), https://www.nytimes.com/2018/03/15/us/politics/russia-cyberattacks.html.
[41] *See, e.g.*, Clifford Krauss, *Cyberattack Shows Vulnerability of Gas Pipeline Network*, N.Y. Times (Apr. 4, 2018), https://www.nytimes.com/2018/04/04/business/energy-environment/pipeline-cyberattack.html.

and unclassified government assessments have identified cyber-attacks on the energy infrastructure as an increasingly severe threat.[42]

The attacks observed so far do not represent the full scope of the threat. Adversaries likely have more effective and destructive tools that they have not yet implemented, instead waiting for a time when they will be most devastating. Similarly, adversaries have not yet attacked in coordinated fashion that would cause cascading ramifications throughout the system. But that is not out of the question. For example, a multi-pronged attack on the supply chain could wreak havoc on the bulk power system. An adversary could attack the software, firmware, hardware, or network services of the gas pipeline system, for example, which could trigger widespread failures across the gas distribution system and the bulk power system more generally.[43] The grid needs to be resilient enough to withstand the real threat of cyberattacks by enemy nations and other malevolent groups.

In sum, as the grid moves toward greater reliance on natural gas, the vulnerability of the grid to natural gas supply interruption will grow. If current trends are left unchecked, the system will become significantly less resilient than it is today.

II. PJM's Over-Reliance on Natural Gas Poses Resilience Risks and Requires a Study Similar to the One Conducted by ISO-New England.

The importance of grid resilience, and threats to it, are broadly recognized—and so too is the need for a deeper and more rigorous understanding of the Nation's vulnerabilities.[44] Some RTOs identified specific resiliency concerns in their March 9 filing. PJM, for example, identified

[42] Stockton Report at 6-7.
[43] *Id.* at 6; *see also* DOE Staff Report at 8 (noting that "[c]ybersecurity is a critical component to ensuring the reliable and resilient operation of the Nation's energy infrastructure").
[44] *See, e.g.,* DOE Staff Report at 100 ("More work is needed to define, quantify, and value resilience.").

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a number of risks posed by high-impact, low frequency events. Those risks include a significant loss or disruption of infrastructure; a significant loss or disruption of control systems; a significant loss or disruption of interdependent systems like gas pipelines, communications networks, and water utilities; a degraded capacity to black start; and a significant loss of wholesale supply.[45]

Only ISO-New England, however, has done a detailed study of fuel security as a potential cause of grid vulnerability, in an Operational Fuel Security Analysis published in January 2018. Its findings were sobering.[46] The study modeled twenty-three possible scenarios that could occur in the 2024/2025 winter. In every scenario except the most optimistic, emergency actions were necessary to ensure that enough power was available to supply the grid.[47] In 19 of the 23 scenarios, load-shedding resulted.[48] Moreover, the load-shedding was significant. Six of those 19 scenarios resulted in more than 50 hours of load-shedding; a scenario in which a larger number of fuel-secure resources retire than is expected resulted in *105 hours* of load-shedding over 16 days.[49] The loss of a pipeline compressor was projected to result in *138 hours* of load-shedding over 17 days, even assuming increased LNG imports and more frequent refilling of oil tanks.[50]

The study identified fuel security as the most important factor threatening resilience in New England, and the growing dependence on natural gas was critical in causing, and exacerbating, fuel-security vulnerability.[51] ISO-New England explained: "Current trends are pushing the New England power system on a path toward greater fuel-security risks. These trends include the

[45] PJM Response at 12-13.
[46] ISO-New England, *Operational Fuel-Security Analysis* (Jan. 17, 2018), https://bit.ly/2DGjZx7.
[47] *Id.* at 8.
[48] *Id.*
[49] *Id.* at 40
[50] *Id.* at 43-44.
[51] *Id.* at 4.

increasing retirements of power plants with fuel stored onsite (nuclear, coal and oil); the growth in power plants dependent on natural gas, a fuel that's delivered just in time; growing demand for natural gas from local gas utilities in both New England and the Maritimes, which will likely leave less for power plants; and an increase in renewable resources with variable production."[52] The study will help frame the ongoing discussion among stakeholders, regulators, and policy makers around improving fuel security and resilience in New England.

Every ISO/RTO—and particularly PJM—should conduct a careful analysis of fuel security issues similar to ISO-New England's study, in order to identify any fuel security issues and provide a groundwork for future policy decisions. PJM, in particular, needs to conduct such a study given the tremendous increase in the retirement of fuel-secure nuclear plants in PJM, the growing reliance on gas (which will increase as a result of nuclear retirement), and the inability of back-up fuel at natural gas-fired plants to meaningfully respond to an extended gas outage event.[53]

The ideal study would have the following key components. Rather than focusing on short-term weather conditions, as past studies have done, a study should go further and conduct a season-long analysis. The RTO should model its system over a simulated winter with a range of weather conditions, including conditions similar to those seen in recent severe winters.[54] That will enable PJM and other RTOs to understand their resilience challenges over the course of an entire winter season.[55] The study should incorporate reasonable assumptions with respect to oil fuel capability and resupply, and it should take into account a range of future retirement scenarios (particularly in

[52] *Id.* at 53.
[53] *See supra* Section I.
[54] *See supra* note 37 (noting the severe winters of 1977-78 and 1978-79).
[55] For example, the 2016 Spectra Pipeline explosion in western Pennsylvania took six months to repair. Debra Erdley, *6 Months After Salem Township Explosion, Spectra Energy Has Gas Pipelines Running*, TribLive.com (Nov. 18, 2016), http://triblive.com/local/westmoreland/11496039-74/pipeline-spectra-explosion.

the aftermath of the significant nuclear retirements recently announced) and a range of critical infrastructure outage scenarios that have been vetted by the Department of Energy and Department of Homeland Security, each of which have critical, classified information about the nature of the threats that face the bulk power system. At a minimum, in each scenario, the study should analyze the frequency and magnitude of load shed, the frequency and magnitude of reserve shortages, and regional energy prices. A comprehensive study with these components would provide a strong foundation on which PJM and other RTOs can assess and plan for resiliency to natural threats to the bulk power system.

III. Exelon Supports PJM's Proposed Fuel Security Analysis, But an RTO-Led Study Is Not Adequate to Ensure Resilience.

To its credit, PJM recently announced its intent to "perform targeted analyses to identify fuel security risks that could affect specific locations on the system," including "the deliverability logistics of fuel supplies during stressed conditions over time," in order to "better understand reliability outcomes resulting from the current capability of local onsite fuel and back-up fuel."[56] PJM's goal is "to identify potential system vulnerabilities and to determine attributes such as requirements for amounts of on-site fuel and dual-fuel capability, among others, to ensure that peak demands can be met during realistic but extreme contingency scenarios in various supply portfolios."[57] PJM correctly acknowledges that its reliability analyses and market rules are not currently designed to achieve fuel security for the 65 million people it serves.[58]

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[56] PJM Fuel Security at 2; *see also* ICF Study at 44 ("While the interstate pipeline network is robust and highly interconnected, there are locations within the system where disruption events could have cascading implications on generation resources. RTO/ISOs should review the interrelationship between existing and planned gas-fired generation facilities and the upstream gas infrastructure and related power transmission systems.").
[57] PJM Fuel Security at 2.
[58] *Id.* at 1.

Exelon strongly supports these analyses. Performing a robust fuel security analysis that considers credible natural gas supply disruption scenarios and realistic dual fuel resupply timeframes is a vital first step toward addressing resilience. In addition, PJM should consider the emissions implications of reliance on dual-fuel resources to replace gas-fired resources during periods of natural gas disruption. In New England for example, two million barrels of oil were burned this winter in less than two weeks—more than twice the amount burned in New England during the entire preceding year.

Nevertheless, RTO-led fuel-security analyses and modeling by themselves are not sufficient to address bulk power system resilience, because PJM and other RTOs lack the information needed to identify the key contingencies that should be modeled. For example, in its scoping document for its fuel security initiative, PJM identifies potential "disruptions to fuel delivery systems" that it would model, including "[r]eduction of a realistic percentage of delivery capability on particular constrained portions of pipelines in the PJM regions," and "a few realistic but extreme contingencies such as a *force majeure* event on key delivery facilities."[59] But PJM and other RTOs do not have the full body of knowledge needed to assess what types of disruptions should be modeled, what reductions in delivery capability are "realistic," and what particular "extreme contingencies" are realistic.[60]

Thus, the notion that RTOs should lead the process of identifying threats is dangerously misguided. PJM's scoping document appears to contemplate that PJM would interface with government agencies only after it has developed its fuel-security modeling.[61] That approach makes little sense. While PJM should certainly begin the process of analyzing potential system

[59] *Id.* at 4.
[60] *Id.*
[61] *Id.* at 3.

vulnerabilities and developing a model to plan for them, government involvement is essential in the modeling stage. PJM's proposal would require the RTOs to guess at the vulnerabilities they should be planning for and then submit their guesses to the Commission for approval.[62] Instead, as detailed below, the Commission, together with the Department of Energy (DOE) and federal agencies tasked with intelligence gathering and national security, should lead the effort to identify the threats that the system should be planned to meet. These federal agencies, not the RTOs, have access to the relevant information regarding threats to system resilience.[63]

IV. A Design-Basis Threat Is Needed to Judge Resilience and Guide Action.

In order to design a resilient grid, it is essential for planners and policymakers to know what threats must be addressed. Once the relevant threats are identified, the system can then be planned to meet those threats. In particular, planners need to know what man-made threats they must plan to address. As PJM has put it, "[t]o define potential fuel-security criteria, PJM needs to understand the fuel-supply risks in an environment trending towards greater reliance on natural gas supply and delivery."[64]

Other federal agencies have tools that can assist in this process. Specifically, national security agencies throughout the federal government use DBTs to identify man-made threats posed by foreign adversaries and other malevolent actors and to mitigate the risk from those threats.[65] At its most basic, a DBT is a document that provides guidelines to the relevant industry about threats facing the industry, so that the industry can guard against those threats. For example, the Nuclear Regulatory Commission has created a DBT for nuclear power plants and related

[62] PJM Response at 81; PJM Fuel Security at 3.
[63] PJM Fuel Security at 3.
[64] *Id.* at 1.
[65] Stockton Report at 16-17.

facilities.[66] That DBT imposes security requirements on nuclear power plants based on analyses of various factors, such as the potential for a terrorist threat or the potential for an attack assisted by workers at the facility. Comparable examples exist at other agencies. The Department of Defense has created a DBT to support anti-terrorism and force protection standards; the Department of Homeland Security's DBT considers the characteristics of adversaries that might threaten federal facilities.[67] The Commission, together with other government agencies, should lead an effort to develop a DBT directed at grid resilience. The development of this DBT should begin immediately, while PJM is conducting its fuel security study, so that PJM can move quickly to adopt appropriate market rules changes in light of the DBT and the study results.

A. A DBT Would Provide Significant Benefits.

Currently, RTOs lack the information they need to assess man-made threats to resilience, such as terrorist attacks or attacks by enemy nations. They are largely on their own in attempting to identify resilience threats. They do not receive input on intelligence issues from the federal government.[68] Nor do they even have much guidance on the size and type of events that could cause severe disruption.[69] This information gap makes it nearly impossible for RTOs to effectively plan for resilience in the face of man-made threats: they do not know the risks, so they cannot plan effectively to avoid them. In fact, PJM emphasized in its March 9 filing that "there needs to be a process for vulnerability threat verification. The Commission needs to provide intelligence and

[66] *See, e.g.,* United States Nuclear Regulatory Commission, *Backgrounder on Nuclear Security*, https://www.nrc.gov/reading-rm/doc-collections/fact-sheets/security-enhancements.html (last visited May 8, 2018); United States Nuclear Regulatory Commission, *Frequently Asked Questions about NRC's Design Basis Threat Final Rule*, https://www.nrc.gov/security/faq-dbtfr.html (last visited May 8, 2018).
[67] Stockton Report at 16-17.
[68] *Id.* at 13.
[69] *Id.*

metrics to apply to resilience vulnerability and threat analyses, such that they can then guide and anchor subsequent RTO planning, market design, and/or operations directives. Overall there needs to be better information made available to the RTOs on the above-identified risks to enable the RTOs to assess the risks."[70] The need for assistance from the federal government is particularly high when it comes to sensitive or classified information that only the federal government can access.[71]

The Commission can answer this call for help. A DBT for RTOs would go a long way toward increasing the resilience of the nation's power grid by providing a foundation for reforms to address man-made threats. In the first instance, the systematic and holistic analysis would enable the Commission and RTOs to more fully and accurately understand the grid's vulnerabilities to man-made threats. Then, armed with accurate information and a full understanding of the risks inherent in the grid, RTOs and transmission owning entities could better plan to mitigate those risks. For example, the Commission could order the RTOs to adopt tariff changes that address the threats identified in the DBT. Moreover, a DBT could ensure that resilience planning is consistent and coordinated across RTOs and other entities.

To be clear, PJM should not wait for the DBT to be completed before beginning its modeling and analysis, or even before proposing initial market rule changes to address resilience; but the Commission should at least direct PJM to consult with the Department of Energy and Department of Homeland Security in selecting scenarios to model, and to incorporate any feedback these agencies provide. PJM can then remain on target to adopt market rules changes by May 2019.

[70] PJM Response at 32.
[71] *Id.* at 52.

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In the meantime, the federal government, led by the Commission, should complete its development of the DBT addressing the man-made threats to the grid. The Commission should then direct PJM to revisit its modeling and analysis in light of the DBT. To the extent any needed revisions to the market rules cannot be implemented in time for the 2019 Base Residual Auction, PJM can at least propose their adoption for the 2020 Base Residual Auction. Additionally, PJM should include the expected environmental impacts (including carbon emissions) of any solutions it considers.

B. The DBT Should Build on Existing Efforts and Incorporate Man-made Threats.

Prior NERC studies have already been completed that could serve as a foundation for the DBT. For example, in February 2018, NERC produced its report *ERO Reliability Priorities—RISC Recommendations to the NERC Board of Trustees* that outlined some of the current risks facing the electric grid.[72] Multiple risk profiles identified fuel vulnerabilities as potential issues. But more analysis is necessary. Fundamentally, the DBT should address all man-made threats to the grid. At a high level, the following types of serious risk should be studied and analyzed in a DBT: cyber and physical security threats, whether from nation-state actors, terrorist groups, or insider threats; pipeline disruptions in general; and other resilience risks to transmission, generation, and distribution.

As to fuel security specifically, various risks created by man-made threats should be explicitly incorporated into the DBT. *First*, the DBT should address the number of gas transmission pipelines that adversaries could interrupt.[73] For example, planning for an N-1

[72] NERC, *ERO Reliability Priorities—RISC Recommendations to the NERC Board of Trustees* (Feb. 2018), https://bit.ly/2KKielG.
[73] Stockton Report at 17-18.

contingency for gas transmission would not be sufficient if an adversary targeted multiple pipelines simultaneously. The federal government should provide guidance about the appropriate scale of attack for which the RTOs should plan. In this context in particular, the DBT should address regional differences that arise given different regions' topology and gas pipeline availability.

Second, the DBT should address the duration of gas system interruptions.[74] Natural gas systems could face extended outages if an attack destroyed multiple critical transmission system nodes, compressor stations, communications infrastructure, other critical assets, or other power generation.[75] RTOs need to be aware of the scope of the possible outage so that they can prepare, and they need information from the government in order to do so.

Finally, the DBT should address factors that might make it difficult to resupply at the exact moment that resupply is needed.[76] For example, RTOs need to understand how man-made actions that are timed to exploit bad weather conditions can affect the resilience of the grid. An attack on a gas pipeline during a cold snap could wreak havoc on a system that is already running low on natural gas because it has been operating at peak capacity for days. As another example, RTOs need to understand the barriers to resupplying secondary fuel for dual-fuel generators in stressed or disrupted conditions.

C. The Government, not the RTOs, Should Develop the DBT.

The Commission should take the lead on crafting the DBT.[77] The Commission is intimately familiar with the RTOs and their practices and has the jurisdictional responsibility to ensure that the market rules are just and reasonable. It can lead discussions with stakeholders,

[74] *Id.* at 18-19.
[75] *Id.* at 19.
[76] *Id.* at 19-21.
[77] *Id.* at 21-22.

including RTOs, NERC, and other bulk power system entities, to gather information about what knowledge gaps the DBT can fill, and it can bring that information to the DBT development process. After that process is complete, it also has the authority to require the RTOs to make changes in response to the DBT. The Commission should work closely with the DOE.[78] DOE employees are subject-matter experts who deeply understand the threats to the energy sector, and they have access to data and analysis from sources such as the National Laboratory system to aid in identifying the risks that need to be addressed in the DBT.[79]

Other federal agencies, too, should have input into the DBT to ensure that the full scope of intelligence and national security threats are built into the DBT. For example, the Department of Homeland Security has expertise on cybersecurity issues and can provide intelligence regarding physical threats to fuel infrastructure.[80] Likewise, the Department of Defense can provide information about the broader national security context that can be incorporated into the DBT.[81]

A multi-agency process will necessarily require some level of coordination. One form that may take—though certainly not the only option—is using existing interagency coordination mechanisms.[82] The National Security Council and the Homeland Security Council both have established processes for coordinating the security-related activities of executive departments and agencies. Either could establish a Policy Coordination Committee and working groups that could work to develop the DBT. No matter the form the coordination takes, though, the important point is that the relevant government agencies work together to craft a DBT that considers the various areas of expertise each agency brings to the process.

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[78] *Id.* at 22.
[79] *Id.*
[80] *Id.*
[81] *Id.* at 22-23.
[82] *Id.*

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D. The DBT can be Implemented Without Exposing Classified Information.

A strong and comprehensive DBT will necessarily require sensitive national security information known only to certain people in the federal government. As a result, it will depend on classified information. However, RTOs largely operate in an unclassified environment. The DBT needs to be usable by the RTOs and others who must plan for resiliency, and it will not be useful if it cannot be reviewed.

Given those realities, the DBT should take a two-phased approach. First, RTO personnel with security clearances should work with the Commission, DOE, and other federal agencies to determine details about the risks included in the DBT, such as how many pipelines could safely be assumed to be disrupted in an attack and how long the pipelines could be disrupted.[83] Then, those teams should construct guidance documents that does not include classified information.[84] That document should share relevant unclassified assumptions and information with RTO planners so that the planners can assess how the RTO would respond to the risks and plan to address them.

In addition, the RTOs are not the only organizations that should have access to the DBT. Transmission owners, as well as other stakeholders, should be able to access and use the DBT. Transmission owners also need to have a thorough understanding of the threats they need to protect against to ensure resiliency of their facilities.

Once the RTOs, transmission owners, and other stakeholders have the DBT, they should work in concert with the Commission to develop solutions to alleviate the risks identified. These solutions could be market-based in the first instance. Market reforms, for example, could ensure that units that currently make important contributions to system-wide resiliency are sufficiently

[83] *Id.* at 24.
[84] *Id.* at 24-25.

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compensated for the resilience attributes they provide and are not forced into retirement. Market reforms should address risk with a high degree of certainty and by minimizing total system costs.

V. The Commission Must Require The RTOs To Consider Resilience In Their Market Design and Transmission Planning.

Building system resilience is key to ensuring that the bulk power system is able to survive any major man-made or natural threats that the grid faces. As described above, these threats are real and growing. A DBT and an in-depth study of resource availability and fuel security will likely only uncover additional areas for attention. The RTOs are at the front line of managing the bulk power system and have an integral role in planning for resilience. To ensure that the RTOs can properly plan for major risks and build a resilient system, the Commission must eliminate any uncertainty and explicitly clarify that RTOs have the obligation to consider resilience in their market rules and transmission planning. The Commission should make clear that the failure to incorporate resilience concepts into RTO tariffs renders them unjust and unreasonable.

Along these lines, Exelon supports PJM's recommendation in its comments that the Commission initiate a rulemaking to articulate the role of RTOs in planning for resilience.[85] Exelon also supports PJM's recommendation that the Commission encourage RTOs to bring forward market-based solutions to the resilience challenges.[86] In addition, as both PJM and ISO-New England recognize in their comments, there may be limited instances where markets are

[85] PJM Response at 81.
[86] *Id.* at 74-75; *see also* PJM Fuel Security at 5.

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insufficient to address resilience challenges. In such cases, RTOs should be able to identify and propose cost-based recovery options for generation resources when appropriate.[87]

To be sure, this consideration of resilience should supplement, but not supplant, the authority of transmission owners to adopt resilience considerations in their local transmission and distribution planning efforts. Transmission owners should continue to be able to plan for and make decisions related to resilience. For example, it may be appropriate to impose a higher standard of resiliency for elements or regions of the transmission system that serve significant load or critical infrastructure, such as Washington, DC or New York City, or defense-critical electric infrastructure.

But the current transmission planning process is not adequate alone. RTOs should be required to consider resilience as an independent planning obligation separate and apart from the transmission planning process established under Order Nos. 890 and 1000. System resilience requires considerations of market features that are broader than contemplated in the current transmission planning. Ensuring fuel security, in particular, is a key component of resilience planning. Along those lines, the RTOs should both incorporate resilience into the planning process and develop market-based approaches to incentivize the retention of resilient resources. This could be accomplished through the development of new products or through modifying existing market design elements and transmission planning criteria. Resilience also requires consideration of sensitive national security issues that go well beyond the transmission planning process. A DBT

[87] A model similar to the RMR provisions of RTO tariffs could be adopted if market mechanisms are insufficient to retain resources needed for fuel security.

will be a first step in incorporating national security concerns into resilience planning, but should not be the last.

The Commission ultimately would be responsible, under Sections 205 and 206, for reviewing or ordering RTO tariff changes needed to address the threats identified, and for ensuring that those changes are implemented.

CONCLUSION

The Commission has rightly recognized that resilience is an important and growing concern given the rising number of man-made and natural threats to the bulk power system. As planning for resilience continues to develop, three major steps would meaningfully contribute to planning for and creating a more resilient grid. First, PJM should conduct a study into fuel security in the region, just as ISO-New England recently did, to identify fuel security risks and create a basis for discussion for addressing them. In conducting this study, PJM should be required to consult with and incorporate the recommendations of the Department of Energy and the Department of Homeland Security in its modeling scenarios. Second, the government should create a DBT to identify resilience threats. The DBT would serve as a baseline against which the RTOs can plan for resilience. Finally, the Commission should explicitly require RTOs to consider resilience in their market design and transmission planning criteria, and propose any appropriate reforms for the Commission's review and approval. For example, if the RTOs and the Commission determine, in light of the DBT, that resilience is threatened because power plants making resilience-focused contributions to the grid are not being adequately compensated for those attributes, then the Commission can order the RTOs to develop products to address this deficiency and submit them for Commission approval under Sections 205 or 206. Such proposals should also

identify and consider environmental consequences. Together, these three steps will go a long way toward creating a more resilient grid.

May 9, 2018

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 9th day of May, 2018.

/s/ *Marianne Alvarez*

_____

Marianne Alvarez
Exelon Corporation

Exhibit A

NAVIGANT

PJM Liquid Fuel Survey and Research Results and Recommendations

Prepared for:

Exelon

Submitted by:
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Reference No.: [201434]
04/25/2018

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NAVIGANT

PJM Liquid Fuel Survey and Research Results and Recommendations

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NAVIGANT

PJM Liquid Fuel Survey and Research Results and Recommendations

BACKGROUND AND OVERVIEW

Exelon requested Navigant Consulting, Inc. (Navigant) to assess the fuel reliability of the dual-fueled (i.e., gas and oil) and oil-only units within the PJM RTO when called upon to generate electricity during periods when the natural gas supply is curtailed or eliminated entirely. These gas curtailment periods may be the result of extreme weather events, major gas infrastructure failures and/or interruption due to other events such as terrorism.

To complete this assessment, information was gathered through a confidential survey and from publicly available sources such as Title V operating permits or data provided by state agencies. The combination of the survey and research efforts provided liquid fuel tank capacity` information on nearly 74% of the dual-fuel and oil-only fueled units representing nearly 80% of the dual-fuel and oil only fueled MWs within PJM. This level of information provides strong confidence on the analysis results and our conclusions.

Survey

Navigant identified 26 companies owning 72 plants within PJM that had dual-fuel (gas/oil) or oil-only burning capabilities. These 72 plants represent 199 units and a total of 35,518 MWs of capacity. Navigant was able to contact 25 of the 26 companies owning 71 of the 72 plants requesting their participation in the survey. Eight companies representing 62 units and 9,898 MWs of capacity agreed to provide survey information.

The survey consisted of nine questions addressing the following areas:

- Design capacity of on-site fuel oil storage.
- Typical winter operating capacity of on-site fuel oil storage.
- Number of full load operating hours given the design capacity of on-site fuel oil storage and the winter operating fuel oil inventory typically carried.
- Primary and secondary (backup) fuel oil delivery methods.
- Typical lead times for delivery of fuel oil once an order is placed.
- Difficulty and estimated/actual delay of obtaining fuel oil during an extreme weather event.
- Identification of operating permit conditions which could potentially limit the burning of fuel oil.
- Determination of whether fuel oil is purchased under contract or not.

Details of the survey and resulting participation and results are included in Appendix A of this document.

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Research Using Publicly Available Sources

To supplement the survey, Navigant researched publicly available data such as Title V operating permits and/or data provided by state agencies related to on-site fuel oil storage capacities as well as potential limitations to burning fuel oil due to existing operational permits. This research provided on-site fuel storage information for an additional 85 units representing 18,278 MWs of capacity. The summary of this research is included in Appendix A.

Table 1 provides a summary of the survey and research data used to conduct the analysis and develop our conclusions regarding the fuel oil storage capacities at dual-fuel and oil-only fueled plants in PJM.

TABLE 1
On-Site Fuel Storage Summary Data

Source	# of Plants	# of Units	# of MWs
Navigant Survey	17	62	9,898
Navigant Research Using Publicly Available Data	37	85	18,278
Sum of Survey and Research	54	147	28,176
Total in PJM	72	199	35,518
% of Total*	75.0%	73.8%	79.3%

* While the survey and secondary research resulted in information on the majority of studied plants, we were unable to gather fuel oil storage tank capacity information on 25% of the identified plants representing slightly more than 20% of the related MW's of capacity.

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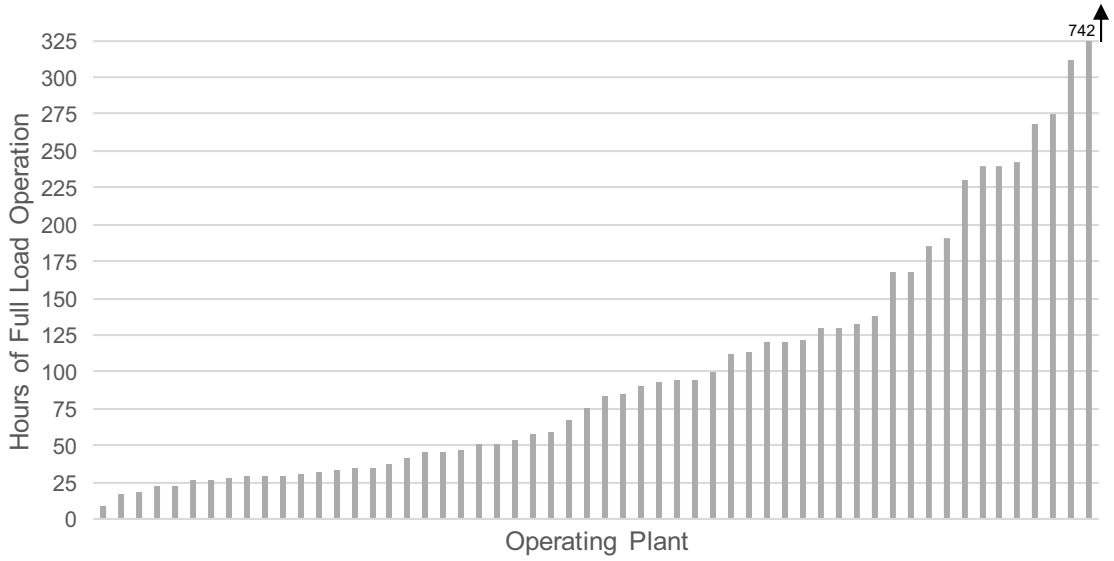
ANALYSIS

The data demonstrate that dual-fuel and oil-only plants do not typically maintain on site the full amount of fuel oil that is capable of being stored. For example, the average plant, weighted by capacity, has a design capacity that would allow it to run at full load for 195 hours (8.1 days), but only maintains sufficient oil on site to allow it to run at full load for 107 hours, or slightly more than four days. A distribution of the number of hours that dual fuel and oil-only plants in PJM are capable of running at full load given their typical on-site winter fuel oil inventory.

Graph 1
Distribution of Winter Inventory Liquid Fuel Full Load Operating Hours



Graph 2 and the related table below demonstrate how quickly dual-fuel and oil-only fueled capacity drops off over the length of time an event occurs. As shown, more than 50% of the capacity would be off line within 4 days and more than 75% would be off-line within six days. Moreover, even if tanks were filled to their design capacity, more than 50% of the capacity would be off-line within six days and 75% of the capacity would be off-line within nine days.

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Graph 2
Liquid Fuel Generation Capability Analysis
Available Liquid Fuel Capacity Over Event Duration

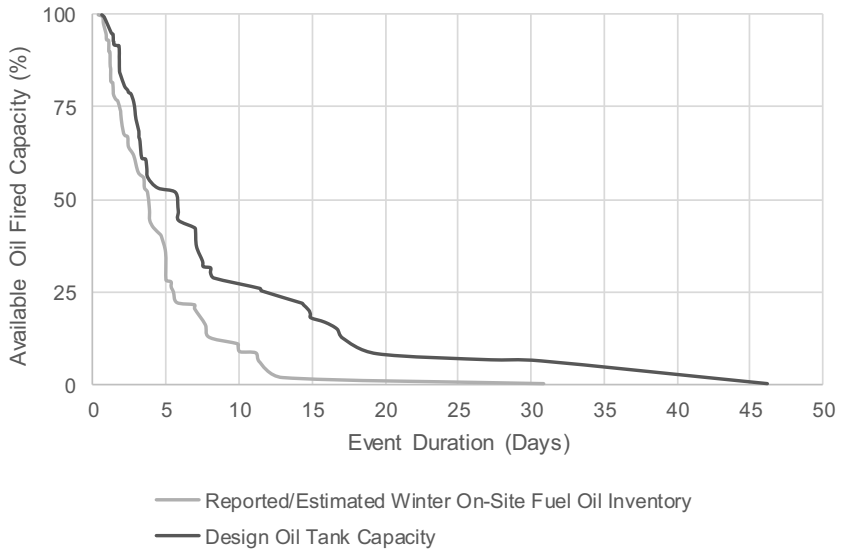

Table 2
Liquid Fuel Capacity Loss for Event Duration

Description	Event Day 2	Event Day 3	Event Day 4	Event Day 5	Event Day 6	Event Day 7
Winter Oil Inventory Loss of Capacity (MWs)	8,854	11,969	16,168	18,057	21,854	22,344
Winter Oil Inventory Loss of Capacity (%)	31.4%	42.5%	57.4%	64.1%	77.6%	79.3%
Design Oil Storage Loss of Capacity (MWs)	5,412	8,854	12,394	13,490	15,623	16,398
Design Oil Storage Loss of Capacity (%)	19.2%	31.4%	44.0%	47.9%	55.4%	58.2%

* Assumes continuous full-load operation, burning fuel oil on site (without resupply)

We believe these figures under-estimate the loss of capacity for the following reasons:

- Due to fuel contaminant settlement issues, some portion of the fuel in any tank (approximately 2-3%) will be unusable without incurring operational issues.
- Continuous operation of these units without some experiencing unplanned outages or derates is very unlikely.

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- Absent an emergency declaration, these plants typically are required to meet certain environmental conditions that may impact their ability operate continuously over a long period of time. Indeed, 63% of the plants had other operational permit limits which could potentially limit the burning of fuel oil.

The survey data also show that once a tank is empty, it cannot necessarily be refilled promptly to allow for continued operation.

Even under normal conditions, 88% of the survey respondents reported that an order to refill fuel tanks can take between 5 and 10 days to be refilled. In the case of extreme weather, the majority of the survey respondents reported that they had experienced additional delays of 3 days or more for fuel oil deliveries.

Plants would face an even greater challenge in refilling their tanks promptly if the entire dual-fuel and oil-only PJM fleet were simultaneously trying to refill their tanks, and if they were competing for scarce delivery sources with other fuel oil users, such as hospitals, governmental institutions, and others operating generators. The total gallons of on-site winter fuel storage for the plants is more than 195 million gallons. Logistics for refilling this level of fuel oil in a reasonable amount of time would likely exceed the current delivery capabilities. Assuming a capacity of 11,600 gallons for a fuel delivery truck, nearly 17,000 trips would be required to refill to on-site winter storage capacity. And that ignores other competing users of fuel oil that might also seek delivery.

Based on actual reported delay times and on the delivery logistics it is reasonable to assume that fuel oil refills will require 8 days or more in the event of extreme weather or another event that makes travel or communications challenging. If this occurs, more than 20,000 MWs of capacity would be in a position of unreliability due to lack of necessary fuel supply. Only 20% of dual fuel and oil-only capacity currently maintain more than 8 days of fuel on-site, and only 32% of dual fuel and oil-only capacity have tanks designed to hold more than 8 days of fuel on-site.

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RECOMMENDATIONS

Overall, and based on this analysis and our experience, we believe there are sufficient questions regarding the reliability of the dual-fuel and oil only fueled capacity within PJM during natural gas curtailment periods. In particular, if a curtailment event lasts longer than a few days, significant quantities of dual fuel and oil-only resources could be forced out due to a lack of fuel, and be unable to timely receive new fuel supplies. We recommend a more in-depth analysis that incorporates mandatory responses to a more comprehensive survey as a cost-effective means to define specific areas and levels of risk for which reasonable steps can be taken to minimize and/or mitigate these risks.

The January 2018 report for ISO New England titled "Operational Fuel-Security Analysis" reached a set of conclusions that are, in part, similar to those stated here. The report stated that *"… the foremost risk to current and future power system reliability revolves around fuel security – the ability of power plants to get the fuel they need to run, when they need it."* The Dual-Fuel Replenishment scenario that lowered the number of times oil tanks were filled to just once during the winter showed 46 hours of load shedding over 10 days. Lastly, the report referenced the logistics and ability of trucks to deliver fuel-oil refills to power plants during extreme weather events.

We note PJM previously took actions to protect system reliability following the Polar Vortex event. We believe this report identifies a level of uncertainty and risk associated with the dual-fuel and oil only fueled units in PJM and deserves additional scrutiny through a more comprehensive analysis.

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APPENDIX A

Summary Results
PJM Liquid Fuel Power Plant Survey

CONTACTS	COUNT	PERCENT
# Companies Contacted	25	96%
# Companies Not Contacte	1	4%
Total Companies in Study	26	
# Plants Contacted	71	99%
# Plants Not Contacted	1	1%
Total Plants in Study	72	
Capacity (MW) Contacted	35,488	100%
Capacity (MW) Not Contact	30	0%
Total Capacity (MW) in Stu	35,518	

RESPONSES	COUNT	PERCENT
# Companies Responded (of contacted	14	56%
# Companies Not Responded (of conta	11	44%
# Plants Responded (of contacted)	27	38%
# Plants Not Responded (of contacted)	44	62%
Total Capacity Responded (of contacte	15,019	42%
Total Copacity Not Responded (of cont	20,469	58%

PARTICIPATION	COUNT	PERCENT
# Companies Participating (of responded)	8	57%
# Companies Not Participating (of respon	6	43%
# Plants Participating (of responded)	18	67%
# Plants Not Paritcpating (of responded)	9	33%
% Total Plants Participating (of Total)		25%
Total Capacity Participating (of respondec	10,099	67%
Total Copacity Not Participating (of respo	4,920	33%
% Total Capacity Participating (of Total)		28%

SURVEY DATA RECEIVED	COUNT	PERCENT OF TOTAL
# Units Data Received	62	31%
# Plants Data Received	17	24%
# Companies Data Receivec	7	27%
# MW Data Received	9,898	28%

Data Source Summary
Survey and Secondary Research

Source	Plants	Units	MW
Survey Responses (Permit and Tank Info)	17	62	9,898
Research (Permit and Tank Info)	34	80	17,040
Research (Permit Info Only)	9	21	3,148
Research (Tank Info Only)	3	5	1,238
Total Survey+Research	63	168	31,324
Total in Study	72	199	35,518
Survey+Research % of Total	**88%**	**84%**	**88%**

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NAVIGANT

PJM Liquid Fuel Survey and Research Results and Recommendations

NAVIGANT

Combined Cycle, Simple Cycle and Steam Unit Liquid Fuel Capability Survey

March 2018

Navigant contact information: Megan Kuc / 312-583-6925 / megan.kuc@navigant.com
Bob Ruhlman / 706-754-0957 / rruhlman@navigant.com

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PJM Liquid Fuel Survey and Research Results and Recommendations

Instructions:
1. Please enter your contact information in cells C13 thru C16 (Note: The contact information will be automatically replicated in the other plant sheets in case one person is filling out the survey for all the plants.)
2. Please verify the information provided in cells C19 thru C30.
3. Answer questions 1 thru 9.

Legend:	
	Data supplied by Navigant
	Data supplied by survey respondent
	Drop down menu selection
	Formula calculation

Contact Information	
Name	
Position	
Telephone Number	
Email Address	

Plant Generating Unit Information	Response	Comments
Plant Name	ABC	
# Combined Cycle (CC) blocks with dual fuel capability		
Total CC capacity (Net MW, winter rating) with dual fuel capability - Burning 100% gas		
Total CC capacity (Net MW, winter rating) with dual fuel capability - Burning 100% oil		
# Simple Cycle CT (SCCT) units with dual fuel capability		
Total SCCT capacity (Net MW, winter rating) with dual fuel capability - Burning 100% gas		
Total SCCT capacity (Net MW, winter rating) with dual fuel capability - Burning 100% oil		
# Steam units with dual fuel or oil only capability		
Total Steam unit capacity (Net MW, winter rating) with dual fuel or only capability - Burning 100% gas		
Total Steam unit capacity (Net MW, winter rating) with dual fuel or only capability - Burning 100% oil		
Total CC, SSCT and Steam unit capacity with dual fuel capability - Burning 100% gas	0	
Total CC, SSCT and Steam unit capacity with dual fuel capability - Burning 100% oil	0	

No.	Question	Response
1	What is the total design fuel oil storage capability at the plant (gallons)?	
2	What is the average (i.e., typical) amount of fuel oil stored at the plant during the winter (i.e., starting December 1) season (gallons)?	
3	With the fuel oil inventory at the level shown in question 1, approximately how many **hours** of operation at full load can be sustained for **all** the dual fuel capable units running simultaneously?	
4	What is the primary method for delivering fuel oil to the plant?	
	If "Other", please provide explanation	
5	How long does it typically take to get the fuel oil tank(s) refilled to the winter operating levels specified in question 2 once an order has been placed?	
6	Please specify the backup method for fuel oil delivery if one exists.	Does not exist
7	Has this plant tried to get fuel oil delivered during an extreme weather event (e.g., polar vortex) during which gas supplies were curtailed or went away entirely?	
	If "Yes", please describe how much the normal delivery time was impacted by the event.	
	If "No", please estimate how you think delivery would be impacted in such an event.	
8	Do any operating permits limit the plants ability to burn fuel oil or distillate aside from exceeding permit operating limits such as particulate, opacity, etc.?	
	If "Yes", please specify the limits by type. For example: 1) air permit with instantaneous or over some averaging period tonnage limit; 2) time of day operation limits (i.e. noise); 3) other, etc.	
9	Is fuel oil purchasing done under contract?	

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Grid Resilience in Regional Transmission Organizations and Independent System Operators	)))	Docket No. AD18-7-000

DECLARATION OF DALE R PROBASCO

I, Dale R Probasco, declare under penalty of perjury that the foregoing is true and correct.

Dale R. Probasco

Executed: Washington, DC
May 8, 2018

Exhibit B

SONECON

FUEL RESILIENCE FOR THE BULK POWER SYSTEM: THREAT-BASED MODELING AND ANALYSIS

Paul Stockton, May 8, 2018

My name is Paul Stockton. I am the Managing Director of Sonecon, LLC, a security and economic advisory firm in Washington, D.C. On October 23, 2017, I submitted testimony (attached as Exhibit 1) on the *Proposed Rule on Grid Reliability and Resilience Pricing* (Docket No. RM18-1-000) on behalf of Exelon Corporation that examined how an increased reliance on natural gas for power generation is creating new risks to electric grid resilience and U.S. national security. In supplemental testimony on November 7, 2017 (attached as Exhibit 2), I found that Bulk Power System entities lack the data they need to assess fuel system resilience against cyber and physical attacks by Russia and other potential adversaries. I recommended that the Federal Energy Regulatory Commission (Commission) coordinate with the Department of Energy and other partners to fill that gap, and develop a design basis threat (DBT) to help Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) assess and mitigate potential gaps in fuel resilience

This filing addresses the additional assessment challenges and opportunities for progress identified in the Commission's January 8, 2018 order on *Grid Resilience in Regional Transmission Organizations and Independent System Operators* (Docket No. AD18-7-000).[1] My filing also builds on the responses that the Commission has received to that Order. I have five principal findings and recommendations:

1. The gap is widening between what RTOs and ISOs know about the threat and the knowledge they need to assess and ensure resilience. PJM's response to the Grid Resilience Order emphasized that RTOs face "obstacles in obtaining information necessary to assess cyber security threats."[2] The need to improve RTO/ISO access to that information is greater than ever. Army Lieutenant General Paul Nakasone, Commander of US Cyber Command and Director of the National Security Agency, stated in March 2018 that cyber threats to U.S. infrastructure constitute "a critical vulnerability in the nation's armor" and pose a growing danger to U.S. national security.[3] Since the Commission issued its Grid Resilience Order, threats to U.S. energy infrastructure have intensified. This testimony reviews emerging challenges to fuel resilience and the imperative to

[1] *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,012 (2018) ("Grid Resilience Order").
[2] PJM Interconnection, L.L.C, "COMMENTS AND RESPONSES OF PJM INTERCONNECTION, L.L.C.," *Response to Grid Resilience in Regional Transmission Organization and Independent System Operators* (AD18-7-000), March 9, 2018, p. 52.
[3] Lieutenant General Paul Nakasone, *Confirmation Hearing Before the United States Senate Committee on Armed Services (Advance Policy Questions)*, March 1, 2018, p. 8.

give RTOs and ISOs a realistic, government-vetted foundation for resilience assessments beyond typical N-1 contingencies for gas pipeline interruptions. My testimony also examines an additional risk examined by ISO-New England: that dual-fuel generators will fail to compensate for gas interruptions in the severe events to come.[4]

2. Assessing and mitigating gaps in fuel resilience can help achieve key U.S. national security goals. In December 2017 the White House issued the *National Security Strategy of the United States of America* (Strategy).[5] The Strategy highlights the growing severity of cyber threats to energy infrastructure, provides a strategic framework to ensure that improvements in fuel resilience can help deter attacks on the United States, and – if deterrence fails – help the U.S. military defeat our adversaries. My testimony examines these opportunities to contribute to national security and explains why the Department of Defense and other Federal departments have knowledge, expertise, and compelling incentives to help the Commission bolster RTO/ISO resilience assessments.

3. Government entities should provide RTOs and ISO with the information essential for accurate resilience assessments before those assessments are made. PJM not only emphasized the need for improved access to data on the threat, but also proposed a way to obtain that access. PJM urged the Commission to collaborate with the Department of Energy (DOE) and other partners "to provide intelligence and metrics to apply to resilience vulnerability and threat analysis that can guide and anchor subsequent RTO planning, market design, and/or operations directives."[6] Specifically, PJM proposes that after RTOs and ISOs develop their own assessments of vulnerabilities and threats, the Commission would verify the reasonableness of those assessments. Once verified, the assessments could provide the basis for RTO/ISO actions under their planning and operations authorities.[7] PJM's proposal would provide a far stronger basis to assess and remedy shortfalls in fuel resilience than exists today.

However, given gaps in the threat data that the government currently provides to RTOs and ISOs, their initial assessments are almost certain to be grounded on incomplete (and potentially faulty) information. It would be more efficient and effective to provide RTOs and ISOs with the data they need at the front end of the assessment process. My testimony therefore recommends that the Commission and its partners provide RTOs and ISOs with information on key planning factors *before* these entities conduct their assessments, so that such assessments can be informed by key, region-specific considerations. Considerations may include the number of pipelines that RTOs and ISOs should assume will be disrupted, the length of those disruptions, and other factors to be identified though discussions with the North American Electricity Reliability Corporation (NERC) and other industry partners.

---

[4] ISO New England, *Operational Fuel-Security Analysis*, January 17, 2018, p. 14. Recent results from an Exelon-commissioned study by Navigant Consulting also highlight this potential risk. See: Navigant Consulting, Inc. (for Exelon), *PJM Liquid Fuel Survey and Research Results and Recommendations*, May 8, 2018 (attached to Exelon comments).

[5] President Donald J. Trump, *National Security Strategy of the United States of America*, December 2017.

[6] PJM Interconnection, L.L.C, "COMMENTS AND RESPONSES OF PJM INTERCONNECTION, L.L.C.," *Response to Grid Resilience in Regional Transmission Organization and Independent System Operators* (AD18-7-000), March 9, 2018, p. 5.

[7] *Ibid.*

SI-SSA-0010-4368

4. The Commission should help lead the DBT development process. The Commission has an absolutely vital role to play in developing a design basis threat for fuel resilience. The Grid Resilience Order not only recognizes that "we must remain vigilant with respect to resilience challenges," but also provides a potential basis for additional Commission actions to strengthen resilience, including those associated with assessing the impact and likelihood of resilience risks.[8] My testimony identifies specific initiatives for the Commission to consider, including regulatory proceedings and informal discussions with RTOs and ISOs to determine how DBTs can best support their resilience studies.

I also recommend that the Commission collaborate with the Department of Energy (DOE) and other Federal interagency partners to gather and synthesize necessary threat data. The Department of Energy is the Sector-Specific Agency for the energy sector and has deep expertise on emerging threats to fuel resilience. This testimony examines how DOE's proposal to develop an energy sector model could be especially valuable for supporting RTO and ISO resilience assessments.[9] However, other Federal departments and agencies also have data that will be useful for developing a design basis threat, including the Department of Homeland Security (DHS) and the Department of Defense (DOD). The Commission should support DOE in leading an interagency process to create a DBT. Utilizing the Policy Coordination Committee (PCC) system under the auspices of either the National Security Council or Homeland Security Council (HSC) could offer an especially efficient mechanism to facilitate such interagency coordination.[10]

5. Create a phased, two-level process to distribute *and protect* DBTs. It will be imperative to protect the data in DBTs from potential adversaries. One option to do so would be to classify DBTs at the Secret level or higher. However, most RTOs and ISOs have only a very small number of personnel cleared for access to classified data, and many employees who help conduct resilience assessments may lack such clearances. The *Fixing America's Surface Transportation (FAST) Act* amendments to the Federal Power Act (FPA) direct the Secretary of Energy to "facilitate, and to the extent practicable, expedite" adequate security clearances for key industry personnel.[11] Over time, that process (and the associated expansion of BPS entity capabilities to store classified materials) should enable the distribution of classified DBT material to more RTO and ISO personnel than is possible today.

Nevertheless, the number of transmission system planners and other personnel that will need to participate in resilience assessments is so great that it will not be practical for all of them to have clearances. The Commission and its partners should consider developing a phased DBT distribution process at two levels of protection.

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[8] Grid Resilience Order, pp. 1, 10, and 13.

[9] Bruce Walker, *Testimony Before the United States Senate Committee on Energy and Natural Resources*, January 23, 2018, p. 2, https://www.energy.senate.gov/public/index.cfm/files/serve?File_id=165FF5C6-CB75-437E-9742-F90A1F0B580C.

[10] President Donald J. Trump, *National Security Presidential Memorandum - 4: Organization of the National Security Council, the Homeland Security Council, and Subcommittees*, April 4, 2017, https://www.whitehouse.gov/presidential-actions/national-security-presidential-memorandum-4/.

[11] 16 U.S.C. § 824o–1, Section (e), https://www.law.cornell.edu/uscode/text/16/824o-1.

- Phase 1 (Secret level or higher): Cleared RTO/ISO personnel would collaborate with government partners to determine the number and duration of pipeline disruptions their organizations should adopt as planning factors. Cleared personnel would also leverage the TPL-001-4 methodologies to account for the criticality of disrupted infrastructure.[12] Based on that analysis, cleared personnel would distribute For Official Use Only (FOUO) assumptions to RTO/ISO planners regarding how much gas-fueled generation they should assume will be lost in a given location and how long those losses will last.

- Phase 2 (FOUO): Planners would use those planning factors to assess system resilience, identify potential gaps, and develop mitigation measures. FPA information sharing and protection mechanisms could be applied to help protect these resilience assessments and their underlying data. The Commission recently incorporated its Critical Energy Infrastructure Information scheme into a broader Critical Electric Infrastructure Information (CEII) program, per FAST Act amendment requirements.[13] The new CEII scheme created criteria and procedures to designate certain information as critical and prohibit unauthorized disclosure of this information.[14] DOE and the Commission should consider leveraging this mechanism to help protect DBTs and related data. The Commission and its partners could also consider using the Traffic Light Protocol (TLP) system to safeguard DBTs.[15] In addition, the Commission and DOE should consult with industry on how the DBT distribution process can leverage existing systems operated by the Electricity Subsector Information Sharing and Analysis Center (E-ISAC) and other proven mechanisms.

I. FUEL RESILIENCE AS A CHALLENGE FOR NATIONAL SECURITY

The foundational importance of the electric grid makes it a prime target for attack. DOE's *Quadrennial Energy Review 1.2* (2017) emphasizes that the reliability of the grid "underpins virtually every sector of the modern U.S. economy … [and] is a growing and essential component of national security."[16] In turn, ensuring the availability of fuel for power generation is essential to the reliability of the grid, and thus also to the resilience of the United States.

My previous testimony examined three overarching challenges to such resilience: *First*, reliance on a single fuel creates the danger of "common mode failures" where a lack of natural gas incapacitates multiple generators at the same time. *Second*, rising gas-electric interdependencies create dangers of mutually-reinforcing failures. *Third*, such failures could help create "black sky"

[12] North American Electric Reliability Corporation, *TPL-001-4 — Transmission System Planning Performance Requirements*, effective January 1, 2015.
[13] See: *Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information*, 157 FERC ¶ 61,123 (2016).
[14] 16 U.S.C. § 824o–1, Section (d)(2), https://www.law.cornell.edu/uscode/text/16/824o-1.
[15] "Traffic Light Protocol (TLP) Definitions and Usage," *United States Computer Emergency Readiness Team*, n.d.a., https://www.us-cert.gov/tlp.
[16] Department of Energy, *Quadrennial Energy Review – Transforming the Nation's Electricity System: Second Installment of the QER*, January 2017, p. 4-2. A recent DOE report also states that reliable electric service is "essential to the modern economy," and that the grid is a "national security asset." See: Department of Energy, *Staff Report to the Secretary on Electricity Markets and Reliability*, August 2017, pp. 11 and 61.

power outages, which would entail outages lasting a month or more over multiple regions of the United States.[17]

The Grid Resilience Order provides an opportunity to conduct a more sharply focused, detailed analysis of threats to fuel resilience. The intensifying threat provides an imperative to do so, most notably to support national defense. Grid-provided power is essential for the ports, transportation systems, and other civilian-owned assets and infrastructure on which DOD increasingly depends to deploy and sustain forces abroad. We must assume that Russia and other potential adversaries recognize that dependence. Grid owners and operators are making major improvements to the resilience of their own systems against cyber and physical attacks, consistent with mandatory reliability standards established by the North American Electric Reliability Corporation. But adversaries can also attack the grid indirectly, by disrupting the flow of natural gas that provides the primary source of fuel for power generation in growing portions of the United States. The net effect of these trends: threats to fuel resilience constitute a potentially devastating threat to U.S. security.

Recent factors have heightened the importance of strengthening fuel resilience and helping RTOs and ISOs acquire the U.S. government data they need to assess resilience shortfalls. Cyber threats to fuel resilience continue to intensify. Challenges to the availability of secondary fuel for duel-fuel generators, which provide a critical hedge against gas supply interruptions in many U.S. regions, are also intensifying. Moreover, the issuance of the U.S. *National Security Strategy* in December 2017 has provided a new basis on which to understand the importance of such resilience, and to account for the benefits of resilient power generation for deterring and defeating attacks on the United States.

A. INTENSIFYING THREATS TO FUEL RESILIENCE

In responding to the Commission's Grid Resilience Order, New England ISO (NE-ISO) provided an especially vivid assessment of the degree to which power generation is at risk to fuel interruptions – especially in the flow of natural gas. ISO-NE found that:

> In New England, the most significant resilience challenge is fuel security – or the assurance that power plants will have or be able to obtain the fuel they need to run, particularly in winter – especially against the backdrop of coal, oil, and nuclear unit retirements, constrained fuel infrastructure, and the difficulty in permitting and operating dual-fuel generating capability.[18]

New England is far from the only region where disruptions of natural gas flows could jeopardize grid reliability.[19] A DOE-sponsored report titled *Reliability, Resilience and the Oncoming Wave*

[17] Paul Stockton, *Prepared Direct Testimony (On Behalf of Exelon Corporation) on Grid Reliability and Resilience Pricing* (Docket No. RM18-1-000), October 23, 2017, p. 8.
[18] ISO New England, Inc. "RESPONSE OF ISO NEW ENGLAND INC.," *Response to Grid Resilience in Regional Transmission Organization and Independent System Operators* (AD18-7-000), March 9, 2018, p. 1, https://www.iso-ne.com/static-assets/documents/2018/03/ad18-7_iso_response_to_grid_resilience.pdf.
[19] As examined later in this filing, PJM is also launching an analysis of fuel resilience that includes an especially valuable assessment of severe contingency risks to power generation.

of Retiring Baseload Units: The Critical Role of Thermal Units During Extreme Weather Events (March 2018) notes that many RTOs and ISOs will face a combined challenge of inadequate natural gas pipeline infrastructure and competing demands for fuel from users apart from power generators.[20] Premature retirements of nuclear power plants and the loss of other baseload generation assets will exacerbate the resulting risks to grid resilience. In New York ISO, for example, such retirements could result in "severe reliability, let alone resilience, issues."[21]

However, these studies suffer from a key limitation: they focus almost entirely on severe weather events such as the "Bomb Cyclone" which struck the Mid-Atlantic and Northeast from December 27, 2017 to January 8, 2018. To be sure, it is vital to assess the threats that severe weather and other natural hazards pose to fuel resilience for power generation. Such assessments will be especially useful to account for much more catastrophic risk to the flow of natural gas, including earthquakes in the Cascadia and New Madrid Seismic Zones. Ground liquefaction and other effects from major earthquakes in these areas could produce extensive, difficult-to-repair damage to critical gas transmission lines and to the grid itself, creating disruptions across a significant portion of the Pacific Northwest and Southern and Midwestern states, respectively.[22]

But Mother Nature does not conduct reconnaissance of natural gas systems to identify critical nodes and vulnerabilities. Nor do natural hazards selectively strike nodes where they can create the greatest impact and exploit the growing interdependencies between gas and electric systems. And while hurricanes, severe cold snaps, and earthquakes can pose immense challenges to fuel resilience, they are not part of a long-term strategic competition to undermine U.S. preeminence and hold U.S. security, the national economy, and public health and safety at risk.

Potential adversaries such as Russia and China present just such a challenge and are honing their cyber capabilities to attack U.S. natural gas systems and other energy infrastructure. The National Defense Strategy of the United States of America (January 2018) emphasizes that the "central challenge to U.S. prosperity and security is *the re-emergence of long-term, strategic competition*" by Russia, China, and other "revisionist powers" [emphasis in the original].[23]

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[20] National Energy Technology Laboratory (Department of Energy), *Reliability, Resilience and the Oncoming Wave of Retiring Baseload Units – Volume I: The Critical Role of Thermal Units During Extreme Weather Events*, March 13, 2018, pp. 4, 14, 22, and 3, https://www.netl.doe.gov/energy-analyses/temp/ReliabilityandtheOncomingWaveofRetiringBaseloadUnitsVolumeITheCriticalRoleofThermalUnits_031318.pdf.

[21] *Ibid*., at p. 30.

[22] Federal Emergency Management Agency, *Cascadia Rising 2016 Exercise: Joint Multi-State After-Action Report*, September 6, 2016, p. 5, https://www.fema.gov/media-library-data/1484078710188-2e6b753f3f9c6037dd22922cde32e3dd/CR16_AAR_508.pdf; Central United States Earthquake Consortium, *CAPSTONE-14: AFTER-ACTION REPORT,* July 2014, p. 15, http://www.cusec.org/capstone14/documents/CAPSTONE-14_AAR.pdf.

[23] U.S. Department of Defense, *Summary of the National Defense Strategy of the United States of America*, January 2018, p. 2, https://www.defense.gov/Portals/1/Documents/pubs/2018-National-Defense-Strategy-Summary.pdf.

For example, a growing number of academic studies, energy industry reports, and unclassified government assessments document the increasingly severe cyber threats confronting U.S. energy infrastructure. Some of these reports focus exclusively on the "exponential" growth of threats to the Oil and Natural Gas (ONG) subsector.[24] Others examine the implications of the near-constant (and increasingly sophisticated) cyberattacks on Middle Eastern oil and natural gas systems for U.S. system owners.[25] However, because adversaries could employ multiple attack vectors across both the electricity and ONG subsectors, a more comprehensive overview of cyber threats offers the best perspective for assessing fuel resilience challenges.

In April 2018, attacks on the electronic data interchanges used by pipeline operators and other energy sector companies garnered extensive headlines. The attacks temporarily disrupted customer billing, scheduling, and document-sharing, but do not appear to have affected industrial control systems or other operational technology networks and components that help control the flow of natural gas to power generators and other customers.[26]

Threats to operational technology (OT) systems are much more concerning, and are also on the rise. On March 15, 2018, the Department of Homeland Security (DHS) revealed that Russia has a sophisticated cyber campaign underway that has enabled that nation to access OT systems in the energy sector, and position its cyber warriors to shut down or intentionally mis-operate critical energy system components.[27] Natural gas systems and BPS entities rely on OT systems to conduct their operations on a day-to-day basis. Both are taking measures to secure those systems, and to strengthen their ability to fall back on manual operations if cyberattacks disrupt industrial control systems. Nevertheless, the scale and sophistication of Russia's efforts to "prepare the battlefield" for possible future attacks exemplifies the imperative to go beyond traditional N-1 or N-2 assumptions regarding potential fuel interruptions.

Adversaries have already demonstrated the ability to disrupt oil and natural gas systems by employing data wiper modules to effectively destroy targeted systems. The 2012 attack on the Saudi Arabian ONG firm Saudi Aramco wiped data from 30,000 Windows-based computers,

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[24] See, for example, Joseph R. Dancy and Victoria A. Dancy, "Terrorism and Oil & Gas Pipeline Infrastructure: Vulnerability and Potential Liability for Cybersecurity Attacks," *Oil and Gas, Natural Resources, and Energy Journal* Vol. 2, No. 6 (March 2017). See also: Blake Sobczak, Hannah Northey and Peter Behr, "Cyber raises threat against America's energy backbone," *E&E News*, May 23, 2017, https://www.eenews.net/stories/1060054924/.

[25] Dragos Inc., *TRISIS Malware: Analysis of Safety System Targeted Malware*, December 13, 2017, https://dragos.com/blog/trisis/TRISIS-01.pdf; Andy Greenberg, "Unprecedented Malware Targets Industrial Safety Systems in the Middle East," *WIRED*, December 14, 2017, https://www.wired.com/story/triton-malware-targets-industrial-safety-systems-in-the-middle-east/.

[26] Cyber experts and sources familiar with the response effort suspect was profit-driven, rather than an attempt to disrupt gas flows. See: Blake Sobczak, "Attack on natural gas network shows rising cyberthreat," *E&E News*, April 6, 2018, https://www.eenews.net/stories/1060078327; Clifford Krauss, "Cyberattack Shows Vulnerability of Gas Pipeline Network," *The New York Times*, April 4, 2018, https://www.nytimes.com/2018/04/04/business/energy-environment/pipeline-cyberattack.html; Naureen S. Malik, Ryan Collins, and Meenal Vamburkar, "Cyberattack Pings Data Systems of At Least Four Gas Networks," *Bloomberg*, last updated April 4, 2018, https://www.bloomberg.com/news/articles/2018-04-03/day-after-cyber-attack-a-third-gas-pipeline-data-system-shuts.

[27] "Alert (TA18-074A): Russian Government Cyber Activity Targeting Energy and Other Critical Infrastructure Sectors," *United States Computer Emergency Readiness Team*, March 15, 2018, https://www.us-cert.gov/ncas/alerts/TA18-074A.

though it did not affect industrial control systems (ICS).[28] More recent attacks on energy sector infrastructure, however, have included wiper modules that target those ICS systems and other OT components,[29] which could exacerbate the lasting effects of a more complex attack.

Over the past few months, potential adversaries have conducted "test drives" of additional ways to attack the grid and other critical infrastructure. The Dragonfly campaign, which is still ongoing today, enables adversaries to use utility vendors and other trusted third parties to conduct attacks on targeted systems.[30] Triton malware (in use since at least September 2017) enables adversaries to corrupt the safety systems that monitor and protect the performance of key system components, creating new pathways for adversaries to sabotage energy infrastructure.[31] Adversary malware can also prevent gas pipeline and energy system operators from understanding the status of their own systems, exacerbating the risks and potential consequences of system mis-operation.[32]

Additional government warnings of campaigns against energy sector infrastructure occur almost monthly. In March 2018, DHS alerted sector companies that researchers had identified a vulnerability which gave adversaries the ability to overwrite authorization passwords, modify the configuration of grid protection systems, and – potentially – cause them to fail in the midst of a cyberattack.[33] In April 2018, an unprecedented joint alert by the United States and the United Kingdom warned infrastructure owners and operators that Russia is conducting yet another campaign. In this attack vector, Russian operatives exploit network routers and other network devices to maintain persistent presence in infrastructure system and "potentially lay the foundation for future offensive operations." In particular, "actor controlling a router between Industrial Control Systems – Supervisory Control and Data Acquisition (ICS-SCADA) sensors and

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[28] Jim Finkle, "Exclusive: Insiders suspected in Saudi cyber attack," *Reuters*, September 7, 2012, https://www.reuters.com/article/net-us-saudi-aramco-hack/exclusive-insiders-suspected-in-saudi-cyber-attack-idUSBRE8860CR20120907.

[29] Michael J. Assante, "Confirmation of a Coordinated Attack on the Ukrainian Power Grid," *SANS Industrial Control Systems*, January 9, 2016, https://ics.sans.org/blog/2016/01/09/confirmation-of-a-coordinated-attack-on-the-ukrainian-power-grid.

[30] "Alert (TA17-293A): Advanced Persistent Threat Activity Targeting Energy and Other Critical Infrastructure Sectors," *United States Computer Emergency Readiness Team*, October 20, 2017, https://www.us-cert.gov/ncas/alerts/TA17-293A.

[31] Andy Greenberg, "Unprecedented Malware Targets Industrial Safety Systems in the Middle East," *WIRED*, December 14, 2017, https://www.wired.com/story/triton-malware-targets-industrial-safety-systems-in-the-middle-east/; and Nicole Perlroth and Clifford Krauss, "A Cyberattack in Saudi Arabia Had a Deadly Goal. Experts Fear Another Try.," *New York Times*, March 15, 2018, https://www.nytimes.com/2018/03/15/technology/saudi-arabia-hacks-cyberattacks.html.

[32] Dragos, Inc, *CRASHOVERRIDE: Analysis of the Threat to Electric Grid Operations*, June 13, 2017, p. 24, https://dragos.com/blog/crashoverride/CrashOverride-01.pdf.

[33] "Advisory (ICSA-18-067-01): Siemens SIPROTEC 4, SIPROTEC Compact, DIGSI 4, and EN100 Ethernet Module," *Industrial Control Systems Cyber Emergency Response Team*, March 8, 2018, https://ics-cert.us-cert.gov/advisories/ICSA-18-067-01; "Positive Technologies detected critical vulnerabilities in Siemens equipment for electrical substations," *Positive Technologies*, April 10, 2018, https://www.ptsecurity.com/ww-en/about/news/291863/. Fortunately, the vulnerabilities were first disclosed to the device manufacturer, who released updates for the majority of vulnerable products. See: Siemens Product CERT, *SSA-203306: Password Vulnerabilities in SIPROTEC 4 and SIPROTEC Compact Relay Families*, March 8, 2018, https://cert-portal.siemens.com/productcert/pdf/ssa-203306.pdf.

controllers in a critical infrastructure – such as the Energy Sector – can manipulate the messages, creating dangerous configurations that could lead to loss of service or physical destruction."[34]

Concerning as they are, these demonstrated adversary capabilities fail to represent the true scale and severity of the threat confronting the U.S. grid. Russia, China, North Korea, and other potential adversaries have powerful incentives to hold their most destructive cyber capabilities in reserve; doing so helps hobble U.S. efforts at building protections against such weapons.

Supply chain corruption poses an especially significant challenge in this regard.[35] If adversaries are able to corrupt the product development and production process for widely-used gas system components, they could gain the ability to later sabotage or covertly control those components, and launch simultaneous attacks on multiple pipelines. Doing so would cause common mode failures, disrupting power generation over wide areas. Electric grid owners and operators often find it difficult to ensure the integrity of their supply chains, and already face the risk that adversaries will exploit software vulnerabilities in their own widely-used components.[36] Grid resilience assessments should also account for the corruption of widely-distributed natural gas system components.

As in the bulk power system, owners and operators of natural gas systems are working diligently to meet these emerging threats. The Transportation Security Administration has also recently updated and expanded its voluntary guidelines for securing pipelines in modest but helpful ways.[37] But adversaries are seeking to improve their ability to disrupt the flow of gas at least as rapidly. William Evanina, director of the National Counterintelligence and Security Center in the Office of the Director of National Intelligence, offered an overall assessment of this risk to fuel supplies in March 2017. He noted that "if we have a cyberattack from one of our adversaries, and they hit the power grid in the East Coast," federal authorities have a good handle on the amount of time it would take to recover. However, "If the natural gas is shut off ... [there's] not even an estimate."[38]

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[34] "Alert (TA18-106A): Russian State-Sponsored Cyber Actors Targeting Network Infrastructure Devices," *United States Computer Emergency Readiness Team*, April 16, 2018, https://www.us-cert.gov/ncas/alerts/TA18-106A.

[35] In July 2016, FERC directed NERC to develop a Supply Chain Risk Management reliability standard for BES entities, which is currently available in draft form (Standard CIP-013-1). NERC intends the standard to "mitigate cyber security risks to the reliable operation of the Bulk Electric System (BES) by implementing security controls for supply chain risk management of BES Cyber Systems." See: North American Electric Reliability Corporation, *CIP-013-1 – Cyber Security - Supply Chain Risk Management*, July 2017, p. 3, https://www.nerc.com/pa/Stand/Project%20201603%20Cyber%20Security%20Supply%20Chain%20Managem/CIP-013-1_Clean_071117.pdf. Without similar strategies for natural gas systems, however, potential supply chain vulnerabilities that could have cascading effects in the Bulk Power System remain.

[36] Idaho National Laboratory, *Cyber Threat and Vulnerability Analysis of the U.S. Electric Sector*, August 2016, p. 20, https://www.energy.gov/sites/prod/files/2017/01/f34/Cyber%20Threat%20and%20Vulnerability%20Analysis%20of%20the%20U.S.%20Electric%20Sector.pdf.

[37] Department of Homeland Security, *Pipeline Security Guidelines*, March 2018, https://www.tsa.gov/sites/default/files/pipeline_security_guidelines.pdf. TSA has not established the equivalent of NERC's mandatory reliability standards for the ONG subsector. See: Peter Behr and Blake Sobczak, "TSA to expand gas pipeline cybersecurity oversight," *E&E News*, December 22, 2017, https://www.eenews.net/stories/1060069743.

[38] Blake Sobczak, Hannah Northey and Peter Behr, "Cyber raises threat against America's energy backbone," *E&E News*, May 23, 2017, https://www.eenews.net/stories/1060054924/.

DBTs to support fuel resilience assessments can play a critical role in creating such estimates and addressing key vulnerabilities to power generation.

B. AN ADDITIONAL RISK FACTOR: RESUPPLYING DUAL-FUEL GENERATORS

A crucial means to hedge against the risk of natural gas disruptions has been maintain a level of fuel diversity, including the construction of dual-fuel generators. In addition to their primary fuel (natural gas), these dual-fuel generators can use diesel, no. 2 fuel oil, or other secondary sources of fuel to sustain operations when gas flows are disrupted.[39] This dual-fuel capability can bolster system reliability and improve resilience against extreme events.[40] As a result, some regions have developed financial incentives to encourage utilities to build and/or retain dual-fuel generators and associated on-site fuel storage. However, trends in generation technology (in part due to environmental pressures) have caused a shift away from dual-capable generators.[41] PJM and other RTOs and ISOs are developing additional incentives for generation asset owners to retain and construct such generators. Those initiatives are valuable and should be sustained.

Measures to ensure that dual-fuel generators are prepared to operate in severe weather events will also be essential. In the 2011 Southwestern "Big Chill," for example, a quarter of dual-capable generating units that attempted to switch fuels failed to do so successfully due to inadequately maintained switching equipment or derating.[42] In the 2014 Polar Vortex, owners of dual-fuel generators faced a number of other problems, including unit startup failures and run-times restricted by environmental regulations.[43]

However, even if asset owners dramatically increase the number of dual-fuel generators that can operate when natural gas supplies are interrupted, several factors limit the ability to rely on dual-fueled resources especially as the duration of gas unavailability increases. For example, on-site storage is general very limited.[44] Air and other permits may limit the duration of operations on alternative fuel (though BPS entities acting in compliance with grid security emergency orders may have the enforcement of environmental violations waived).[45] Another potentially devastating

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[39] Electric Infrastructure Security (EIS) Council, *E-PRO Handbook II: Volume 1 – Fuel* (Washington, D.C.: EIS Council, 2016), p. 24.

[40] ISO New England, *Operational Fuel-Security Analysis*, January 17, 2018, p. 52; North American Electric Reliability Corporation, *2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power Phase II: A Vulnerability and Scenario Assessment for the North American Bulk Power System*, May 2013, p. 4, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf.

[41] North American Electric Reliability Corporation, *2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power Phase II: A Vulnerability and Scenario Assessment for the North American Bulk Power System*, May 2013, p. 76 and 85, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf.

[42] Federal Energy Regulatory Commission and North American Electric Reliability Corporation, *Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011: Causes and Recommendations*, August 2011, pp. 151-152.

[43] PJM Interconnection, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events*, May 8, 2014, p. 39.

[44] Navigant Consulting, Inc. (for Exelon), *PJM Liquid Fuel Survey and Research Results and Recommendations*, May 8, 2018, pp. 3-4 (attached to Exelon comments).

[45] 16 U.S.C. § 824o-1, Section (f), https://www.law.cornell.edu/uscode/text/16/824o-1.

problem is the resupply of secondary fuel. A recent study by Navigant found that roughly 50% of dual-fuel units with typical winter levels of oil storage would need fuel oil resupplies after three days.[46] If cyber or physical attacks disrupt the flow of gas for longer periods, resupplying secondary fuels will be essential to sustain power generation.

Conducting resupply operations in the face of cyber or physical attacks on U.S. infrastructure will pose enormous challenges. If natural gas interruptions and other factors create blackouts, dual-fuel generators will be competing for resupply against many thousands of other customers in most states, including those operating backup generators for water systems, hospitals, cell towers, and other critical facilities. A coincident cold weather event could increase demand for back up fuel for ordinary household and business heating purposes, exacerbating the situation. An overwhelming mismatch will emerge between the capacity of fuel contractors to resupply such customers and the demand for them to do so. Even in severe weather events such as the 2014 Polar Vortex, suppliers began exhausting their inventories and cut back on delivery to generators.[47] Cyber and physical attacks that specially target gas infrastructure for disruption and seek to exploit gas-electric interdependences to create long duration outages will create much more serious problems for secondary fuel resupply.

ISO-NE highlights an additional "unquantifiable X factor:" fuel delivery logistics in the face of a "withering delivery supply chain." A recent study by ISO-NE notes that as more and more oil-fired power plants have retired, the delivery supply chain has declined as well.[48] And while the study focuses on oil, rapid restructuring is also underway in the refining and delivery infrastructure for other liquid fuels for generators, especially as the transition accelerates towards ultra-low sulfur diesel fuel.

Neither the Energy Information Agency nor any other organization of which I am aware has conducted a comprehensive study of the implications of this restructuring (and resulting loss of system capacity) for secondary fuel resupply in natural or manmade disasters. However, given the importance of dual-fuel generators as a hedge against attacks on gas transmission systems, it would be helpful to account for such risks as part of an overall DBT to support fuel resilience assessments.

C. FUEL RESILIENCE: OPPORTUNITIES TO HELP ACHIEVE U.S. NATIONAL SECURITY GOALS

Russia and other potential adversaries will not disrupt the flow of natural gas as an end in itself. Rather, given the growing dependence of power generation on interruptible fuel, and the reliance of all other critical infrastructure sectors on the availability of electric power, attacks on natural gas systems will aim to inflict devastating damage to public health and safety and the national economy and jeopardize the ability of the United States to project military power abroad. The 2017 U.S. *National Security Strategy* notes that cyber weapons "enable adversaries to attempt strategic

[46] Navigant Consulting, Inc. (for Exelon), *PJM Liquid Fuel Survey and Research Results and Recommendations*, May 8, 2018, p. 4.
[47] PJM Interconnection, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events*, May 8, 2014, p. 40.
[48] ISO New England, *Operational Fuel-Security Analysis*, January 17, 2018, pp. 14 and 16.

attacks against the United States -- without resorting to nuclear weapons -- in ways that could cripple our economy and our ability to deploy our military forces."[49]

This broader strategic context provides the starting point to develop a design basis threat for fuel resilience. While it is (barely) conceivable that an adversary will attack a single natural gas pipeline, perhaps as a demonstration of its ability to do so, cyberattacks that strike multiple gas transmission systems at the same time will be better attuned to achieve the crippling effects highlighted in the *National Security Strategy* (NSS).

The NSS offers a number of additional benefits for framing a design basis threat. Especially valuable, the Strategy helps clarify how assessing and remedying gaps in fuel resilience can help deter cyberattacks against the United States. The Strategy notes that to deter adversaries from attacking, it will be necessary to convince them that they will suffer "swift and costly consequences" if they strike the grid or other U.S. targets.[50] Ensuring that power generators can continue to provide electricity to military bases and supporting Defense critical infrastructure, even in the face of a sustained campaign against the U.S. energy sector, can bolster such deterrence.

Improving fuel resilience can also help deter attacks through a different means. In addition to deterring adversaries by being able to inflict unacceptable costs on them, the United States can also discourage attacks by making adversaries doubt that such attacks can inflict the disruptive effects they seek. The *National Security Strategy* notes that "A stronger and more resilient critical infrastructure will strengthen deterrence by creating doubt in our adversaries that they can achieve their objectives."[51] Bolstering such "deterrence by denial" constitutes a benefit of strengthening fuel resilience.

Another way in which the NSS supports the development of a DBT is by highlighting the degree to which the Department of Defense and DOE's other Federal partners have "skin in the game" to assess and improve fuel resilience. It is altogether fitting and proper that *National Security Presidential Memorandum - 4: Organization of the National Security Council, the Homeland Security Council, and Subcommittees* (April 2017) specifies that the Secretary of Energy shall be a "regular attendee" of both Councils.[52] Resilient electricity and fuel supplies for generation are vital to national and homeland security. That same importance provides compelling incentives for DOD, DHS, and other Federal agencies to help the Commission and DOE develop an accurate design basis threat. In particular, providing such a DBT will enable RTOs, ISOs, and other BPS entities to assess the vulnerability of their fuel supplies much more effectively than they can today, and, as needed, to develop pricing initiatives and other measures to ensure that military bases and other key national and homeland security facilities will have the resilient power they need.

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[49] President Donald J. Trump, *National Security Strategy of the United States of America*, December 2017, 27.
[50] *Ibid*., at p. 28.
[51] *Ibid*., at p. 13.
[52] President Donald J. Trump, *National Security Presidential Memorandum - 4: Organization of the National Security Council, the Homeland Security Council, and Subcommittees*, April 4, 2017, https://www.whitehouse.gov/presidential-actions/national-security-presidential-memorandum-4/.

The *National Security Strategy* also provides a further benefit for assessing and strengthening resilience – one that is closely aligned with the purposes and requirements in the Commission's Grid Resilience Order. The Commission noted that "we must remain vigilant with respect to resilience challenges, because affordable and reliable electricity is vital to the country's economic and national security."[53] Accordingly, the order directs RTOs and ISOs to offer comments to clarify the attributes of resilience. Respondents are then asked to help "(1) determine which risks to the grid we are going to protect against, and (2) identify the steps, if any, needed to ensure those risks are addressed."[54]

The NSS provides *foundational* guidance to address these issues and assess the value of resilient sources of generation. To deter and (if necessary) defeat attacks against the United States, the nation cannot depend solely on fuel supplies that adversaries are able to interrupt via cyberattacks and other means. By developing a design basis threat to help RTOs and ISOs assess the risks of fuel interruptions, the Commission and its partners can take a decisive step to strengthen grid resilience against rapidly intensifying threats.

II. GAPS IN THREAT AND VULNERABILITY DATA AVAILABLE TO BPS ENTITIES, AND IMPLICATIONS FOR ASSESSING FUEL RESILIENCE

The Federal government currently leaves RTOs and ISOs largely on their own to characterize threats to their fuel resilience. This approach is likely to produce disparate planning assumptions regarding the scale and severity of such threats. The government's "hands off" approach also limits opportunities for appropriate intelligence-related input from the Department of Energy and other Federal departments and agencies to support the development of a vetted, appropriately-informed DBT.

This lack of Federal support is especially notable given the risk that fuel supply interruptions could jeopardize the flow of power on which military bases and other national security assets depend. General Nakasone, Commander of U.S. Cyber Command, told Congress in March 2017 that "It is paramount that the U.S. public and private sectors work together to create shared understanding of the threat in order to better defend our national security interests."[55] Yet only limited guidance exists on the scale and characteristics of the extreme events that should be used as a basis for assessing the impact of fuel system interruptions on grid reliability and resilience.[56]

BPS entities would benefit from far more extensive support. In particular, using appropriate intelligence sources, the Federal government could provide these entities with an assessment of the severity and nature of attacks that they must be prepared to confront. Such an assessment could

[53] Grid Resilience Order, p. 1.
[54] Grid Resilience Order, p. 13.
[55] Lieutenant General Paul Nakasone, *Confirmation Hearing Before the United States Senate Committee on Armed Services (Advance Policy Questions)*, March 1, 2018, p. 9.
[56] *See*, *e.g.*, NERC, *2016 Long-Term Reliability Assessment*, December 2016, p. 21. The assessment notes that "As part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electric reliability."

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also help entities account for specific risks to fuel resilience, including the risk that adversaries will target their attacks to exploit interdependencies between gas and electric infrastructure.

Responses to the Grid Resilience Order have highlighted the degree to which RTOs and ISOs lack the data they need to assess threats to their resilience, and their desire for governmental assistance to fill those gaps. Dr. David Patton, Market Monitor for MISO, NYISO and ISO-NE, noted that "Without first identifying in detail the contingencies and associated reliability risks to the system, there is no way to quantify a resilience requirement."[57] PJM similarly emphasized the need for Federal support on identifying and assessing risks: "there needs to a process for vulnerability threat verification. The Commission needs to provide intelligence and metrics to apply to resilience vulnerability and threat analyses, such that they can then guide and anchor subsequent RTO planning, market design, and/or operations directives. Overall there needs to be better information made available to the RTOs on the above-identified risks to enable the RTOs to assess the risks. This information could be supplied from a wide range of federal agencies and interdependent systems."[58] Filling this gap with a DBT will be essential for establishing the objective, analytically sound assessment system needed to achieve the goals of the proposed Rule.

The need for government support to help BPS entities understand the threats they confront is especially significant for cyber risks. PJM notes that "There are obstacles to obtaining information necessary to assess cyber security threats because RTOs can only base their threat assessments on open source information and certain classified intelligence, but the information from classified sources is limited and does not provide a full and complete understanding needed to detect and respond to cyber-attacks. In addition, RTOs lack access to all relevant information about supply chain threats which pose a significant risk to the electric industry. Without this information, the electric industry is unable to help to mitigate certain risks that may be associated with such threats."[59]

In particular, RTOs and ISOs are at risk of drastically underestimating the number of pipelines that adversaries will disrupt in an attack and the duration of the outage. Many of the filings to the Commission indicate that N-1 or N-2 planning factors are currently used to assess fuel resilience. PJM, for example, notes that "the PJM studies that have been conducted to date have focused on identifying specific vulnerabilities such as the loss of a substation or common mode outages such as the loss of generation fed from common gas infrastructure, but have not taken into consideration the effects associated with the loss of multiple substations or critical system components as could be contemplated in a coordinated physical attack."[60]

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[57] Potomac Economics, "COMMENTS OF POTOMAC ECONOMICS, LTD.," *Response to Grid Reliability and Resilience Pricing Notice Inviting Comments* (RM18-1-000), October 20, 2017, p. 5, https://www.potomaceconomics.com/wp-content/uploads/2017/10/Potomac-Economics-Comments-on-Grid-Resilience.pdf; Michael Kuser, Tom Kleckner, Rory D. Sweeney, and Amanda Durish Cook, "RTOs Reject NOPR; Say Fuel Risks Exaggerated," *RTO Insider*, October 24, 2017, https://www.rtoinsider.com/market-monitor-nuclear-coal-nopr-iso-ne-78297/.

[58] PJM Interconnection, L.L.C, "COMMENTS AND RESPONSES OF PJM INTERCONNECTION, L.L.C.," *Response to Grid Resilience in Regional Transmission Organization and Independent System Operators (AD18-7-000)*, March 9, 2018, p. 32, http://pjm.com/-/media/documents/ferc/filings/2018/20180309-ad18-7-000.ashx.

[59] *Ibid*., at pp. 52-53.

[60] PJM Interconnection, L.L.C, "COMMENTS AND RESPONSES OF PJM INTERCONNECTION, L.L.C.," *Response to Grid Resilience in Regional Transmission Organization and Independent System Operators (AD18-7-000)*, March 9, 2018, pp. 35-36, http://pjm.com/-/media/documents/ferc/filings/2018/20180309-ad18-7-000.ashx.

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PJM deserves great credit for proposing how the Commission can provide the threat data needed provide a stronger foundation for assessing and mitigating risks. PJM recommends that the Commission should:

> establish a process, either informally through one or more of the Commission's existing offices, or formally through a filing process, that would allow an RTO to receive verification as to the reasonableness of vulnerability and threat assessments based on information that may be available to the Commission but not available to the RTOs because of national security issues. Those assessments, once verified, could then form the basis for RTO actions under its own planning or operations authority consistent with its tariffs. In coordination with other federal agencies the Commission needs to provide intelligence and metrics to apply to resilience threat analyses that can then guide and anchor subsequent RTO planning, market or operations directives."[61]

PJM's proposal would provide a far stronger basis to assess and remedy shortfalls in fuel resilience than exists today. Moreover, an immediate opportunity has emerged to apply this approach. On April 30, 2018, PJM launched a new initiative to identify and model system vulnerabilities to fuel interruptions and other disturbances. This analysis will "study a few realistic but extreme contingencies such as a force majeure event on key delivery facilities" for natural gas.[62] Given the gaps in government-provided threat data that PJM has identified, the challenge will remain of determining how far these contingencies should go beyond traditional N-1 planning factors. Having the Commission verify the reasonableness of the extreme contingencies used in the new study will be enormously helpful.

At the same time, the Commission and its partners should begin developing an even more efficient and effective basis for future resilience assessments. The Commission should provide threat and vulnerability data at the start of the analytic process, rather than leaving RTOs and ISOs to devise their own assessments (based on limited and potentially faulty information) and then having the Commission verify that they had used accurate and realistic planning factors. The section that follows examines how the Commission and its partners can provide a design basis threat to RTO/ISOs at the outset of their analysis of system resilience.

III. DEVELOPING AND DESIGNING A DESIGN BASIS THREAT TO STRENGTHEN FUEL RESILIENCE

Federal commissions, departments, and their industry partners already use design basis threats to help support resilience assessments and identify potential requirements for mitigation measures. These existing DBTs provide models that might be adapted to help develop an equivalent foundation for RTOs, ISOs, and other BPS entities to assess fuel resilience. However, a DBT for fuel resilience will also need to address the special challenges that confront power generation.

[61] *Ibid*., at p. 81.

[62] PJM, Valuing Fuel Security, April 30, 2018, p. 4, http://www.pjm.com/-/media/library/reports-notices/special-reports/2018/20180430-valuing-fuel-security.ashx?la=en

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The section that follows summarizes my previous testimony on existing DBTs. I then recommend specific planning factors that a fuel resilience DBT should include, propose an interagency process to develop that foundation for resilience assessments, and suggest ways in which FERC and its partners might distribute DBTs while also protecting them from potential attackers.

A. CURRENT DBT PROGRAMS

From an energy sector perspective, an especially useful precedent to leverage lies in the DBT that the Nuclear Regulatory Commission (NRC) created for nuclear power plants and related facilities.[63] As noted in my previous testimony to the Commission, the requirement to establish this DBT and the basic threats it should comprise are specified in the *Energy Policy Act* of 2005.[64] These threats include "multiple, coordinated groups of attackers, suicide attacks and cyber threats," as well as other potential attack vectors.[65]

The NRC also regularly reviews and revises the DBT to keep pace with evolving threats. In particular, the NRC monitors domestic and foreign threat intelligence in an attempt to stay ahead of potential adversaries, issues periodic threat advisories and annual reviews, and will use this information to update the DBT as required.[66] While the DBT focuses on manmade threats, the NRC also provides earthquake engineering criteria for nuclear power plants and other guidance related to natural hazards.[67]

The NRC's DBT model offers valuable insights for developing a DBT for fuel resilience. For example, given the evolving threat to gas pipelines and other fuel supplies, it will be essential that the fuel resilience DBT be periodically updated as well. The nuclear DBT also provides a model of the appropriate level of detail for characterizing key threat vectors in an unclassified manner. In addition, existing mechanisms for the Department of Energy to share classified information with BPS entities could also be used to supplement unclassified DBT descriptions. Finally, just as the NRC sets standards for both natural and manmade hazards, the fuel resilience DBT should as well.

Even when Congress has not established statutory requirements for DBTs, Federal departments have issued them to help strengthen resilience and security across a range of critical facilities and functions. For example, DOD provides DBTs to support anti-terrorism and force protection standards, and mitigation measures based on requirements generated internally by the

[63] The NRC's DBT provide performance-based requirements which allow each facility to develop site-specific strategies. It applies to commercial nuclear power reactors and Category I Fuel Cycle Facilities. See: "Frequently Asked Questions About NRC's Design Basis Threat Final Rule," *United States Nuclear Regulatory Commission*, last updated August 11, 2017, https://www.nrc.gov/security/faq-dbtfr.html.
[64] 42 U.S.C. § 2210e (2005), https://www.ferc.gov/enforcement/enforce-res/EPAct2005.pdf.
[65] 10 CFR § 73.1 (2010), https://www.gpo.gov/fdsys/pkg/CFR-2010-title10-vol2/pdf/CFR-2010-title10-vol2-sec73-1.pdf.
[66] "Threat Assessment," *United States Nuclear Regulatory Commission*, last updated August 14, 2017, https://www.nrc.gov/security/domestic/phys-protect/threat.html.
[67] "Appendix S to Part 50—Earthquake Engineering Criteria for Nuclear Power Plants," *United States Nuclear Regulatory Commission*, last updated August 29, 2017, https://www.nrc.gov/reading-rm/doc-collections/cfr/part050/part050-apps.html.

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Department.[68] DHS also provides a DBT that establishes "the type, composition, and capabilities of adversaries" who might threaten Federal facilities.[69]

As in the case of the DOD and DHS models, the Commission and its partners can develop a DBT to support fuel resilience studies without a legislative requirement to do so. However, BPS entities will need a unique set of planning factors and threat assessments, focused on gas-electric interdependencies and related energy sector challenges.

B. KEY COMPONENTS OF A DESIGN BASIS THREAT FOR FUEL RESILIENCE

RTOs and ISOs are exceptionally well positioned to identify the elements of a DBT that they would find most helpful to support their analysis of fuel resilience against manmade threats. The Commission should consider conducting informal discussions with them and with other appropriate BPS entities to receive their views on DBT priorities and planning factors. To provide a starting point for those discussions, the items below might be addressed as options for inclusion.

1. The number of gas transmission pipelines that adversaries will interrupt

Unless a DBT accounts for the risk that adversaries will strike multiple transmission pipelines and supporting infrastructure at the same time, RTOs and ISOs are likely to assume that only a single pipeline will be disrupted. In some regions of the United States, even such an N-1 gas contingency could produce catastrophic effects on power generation. For example, ISO-NE notes that given the limited number of pipelines and supporting gas infrastructure in New England, the loss of even a single natural gas compressor station or other gas system facility "would result in frequent energy shortages that would require frequent and long periods of rolling blackouts." [70] In such infrastructure-constrained regions, assuming that adversaries will attack only one pipeline could provide an appropriate starting point to assess fuel resilience, since adversaries would not need to attack additional pipelines in order to achieve catastrophic effects on grid reliability and on critical electricity-dependent facilities and functions.

Even RTOs and ISOs with much more robust gas infrastructure view N-1 contingencies as a stringent foundation for assessing resilience. For example, PJM notes that "Modeling the loss of an entire pipeline is ultraconservative as the nature of the pipeline system and the relatively slow speed of the movement of gas would argue that more limited disturbances should be modeled."[71] Modeling very limited attacks that fail to fully halt gas flows in a single pipeline would indeed be useful as part of an overall portfolio of contingences for analyzing fuel resilience. However, N-1 (or lesser) contingencies will fall drastically short of the number of pipelines that adversaries could simultaneously target. If a crisis with the United States is so dire than an adversary will launch

[68] See: Department of Defense, *DOD Security Engineering Facilities Planning Manual*, September 2008, https://www.wbdg.org/FFC/DOD/UFC/ufc_4_020_01_2008.pdf.
[69] See: Department of Homeland Security, *The Risk Management Process for Federal Facilities: An Interagency Security Committee Standard: 2nd Edition*, November 2016, https://www.dhs.gov/publication/isc-risk-management-process.
[70] ISO New England, *Operational Fuel-Security Analysis*, January 17, 2018, p. 50.
[71] PJM Interconnection, L.L.C, "COMMENTS AND RESPONSES OF PJM INTERCONNECTION, L.L.C.," *Response to Grid Resilience in Regional Transmission Organization and Independent System Operators (AD18-7-000)*, March 9, 2018, p. 60, http://pjm.com/-/media/documents/ferc/filings/2018/20180309-ad18-7-000.ashx.

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cyber or physical attacks on gas systems, despite the risk of provoking an overwhelming response by U.S. forces, adversaries may seek to disrupt military bases and other critical facilities on a vastly greater scale than can be achieved by attacking a single pipeline.

The Commission and its Federal partners should not leave BPS entities to make such threat-related national security assessments on their own. As previously noted, RTO and ISO responses to the Grid Resilience Rule have emphasized that they lack the classified data on cyber threats they need to analyze fuel resilience. But they also face a broader problem. To establish a consistent, nationwide framework for analysis, RTOs and ISOs need government-vetted guidance on the overall scale of fuel system attacks they should assume will occur. PJM notes that while its current process to model fuel resilience contingencies complies with applicable NERC standards, "this process lacks an overall national regulatory framework as well as the regulatory support to ensure that there is cooperation in identification of vulnerabilities and threats on the gas pipelines, modeling efforts and the sharing of system topology so as to make the modeling of contingencies accurate and meaningful."[72]

One of the most valuable features of the Grid Resilience Order is the Commission's focus on the risks of common mode failures. In requesting RTOs/ISOs to describe how they assess threats to resilience, the Commission asked: "should RTOs/ISOs identify as a resilience threat the potential for multiple outages that are correlated (e.g., a correlated generator outage event, such as a wide-scale disruption to fuel supply that could result in outages of a greater number of generating facilities)?"[73] This filing argues that it is absolutely imperative to do so. As I noted above, these adversaries could, for example, corrupt the supply chain of commonly-used network components, enabling them to exploit a single vulnerability to cause widespread failures. Other potential sources of common failure modes in natural gas supplies could provide equivalent wide-area threats to power generation.

A fuel resilience DBT can assist RTOs and ISOs by specifying the number of pipelines that they should assume will be simultaneously disrupted. Because regions of the United States vary so widely in terms of gas system topology, and the degree to which redundant pipelines provide a hedge against N-1 or N-2 contingencies, the DBT must account for such regional differences. For example, the DBT might specify that adversaries will disrupt 50% percent of major transmission pipelines or regional gas flows (with the actual figure to be determined through an interagency DBT development process). The Commission should consider engaging with RTOs and ISOs to examine how the DBT can best provide a consistent, nationwide framework for fuel resilience assessments while also accounting for regional variations in gas system topology and other factors.

2. The duration of gas system interruptions

Attacks on natural gas systems will rarely create an immediate, "all or nothing" situation for power generators. The pressure of natural gas in each section of gas transmission pipelines typically

[72] PJM Interconnection, L.L.C, "COMMENTS AND RESPONSES OF PJM INTERCONNECTION, L.L.C.," *Response to Grid Resilience in Regional Transmission Organization and Independent System Operators* (AD18-7-000), March 9, 2018, p. 5, http://pjm.com/-/media/documents/ferc/filings/2018/20180309-ad18-7-000.ashx.
[73] Grid Resilience Order, p. 14.

ranges from 200 pounds to 1,500 pounds per square inch, depending on the type of area in which the pipeline is operating.[74] If adversaries attack those pipelines and the compressor stations that maintain the pressure within them, gas could continue to flow to generators at gradually diminishing levels rather than being abruptly halted. Moreover, once attacks occur, gas companies have extensive plans and capabilities in place to restore service as quickly as possible. The combination of sustained post-attack gas flows and rapid restoration could enable generators to face only brief, low-impact interruptions.

But interruptions could also last far longer. Physical attacks that destroy multiple critical transmission system nodes, including key compressor stations, will require the repair and replacement of equipment on a scale never before experienced. These operations would also have to go forward in the face of disrupted transportation systems, communications infrastructure, and other assets critical for restoration support if adversaries conduct multi-sector attacks. The greatest challenge, however, will likely be power outages – in part due to gas shortages – which deny power to the compression stations and other critical gas facilities required to sustain and restore service.

The fuel resilience DBT should specify the duration of gas interruptions that RTOs and ISOs should assume will occur (and must be prepared for). As with estimates of the number of pipelines adversaries will attack, without the benefit of government-vetted planning factors, resilience studies will vary widely in terms of projected event duration.

3. Additional Planning Factors

Over time, DOE and the Commission might supplement DBTs with additional considerations to provide a more thorough, detailed basis for assessing fuel resilience. Assumptions about weather could provide one such supplement. As in the Polar Vortex, Bomb Cyclone and other severe weather events, extended cold snaps can spike demand for gas and lead to curtailments in supplies to power generators (especially those that lack firm, higher-cost contracts).[75] Attacks on gas that occurred during such events, or that were timed to exploit the occurrence of hurricanes or other natural disasters, could contribute to much greater resilience challenges than would otherwise confront BPS entities.[76]

Assumptions regarding secondary fuel resupply capacity for dual-fuel generators would also help make resilience assessments more robust. As discussed in Section II, dual-fuel generators provide a crucial hedge against interruptions in gas supplies in many regions of the United States. Yet the durability of such dual-fuel alternatives and the resilience of the resupply system for the oil and distillates that generators will require is increasingly uncertain – especially in terms of the ability of that system to meet generation needs in a severely disrupted environment where fuel demand will dwarf delivery capacity.

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[74] "How Does the Natural Gas Delivery System Work?," *American Gas Association*, n.d.a, https://www.aga.org/natural-gas/delivery/how-does-the-natural-gas-delivery-system-work-/.

[75] Electric Infrastructure Security (EIS) Council, *E-PRO Handbook II: Volume 1 – Fuel* (Washington, D.C.: EIS Council, 2016), p. 213.

[76] Department of Energy, *Resilience of the U.S. Electricity System: A Multi-Hazard Perspective*, August 18, 2016, p. 29, https://www.energy.gov/sites/prod/files/2017/01/f34/Resilience%20of%20the%20U.S.%20Electricity%20System%20A%20Multi-Hazard%20Perspective.pdf.

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RTOs and ISOs are currently left on their own to determine how, if at all, to account for the risk that resupply operations will fail precisely when they are most vital. Over time, the fuel resilience DBT should provide a consistent planning framework to consider such risks (adapted to account for regional variations in secondary fuel infrastructure). The prerequisite for doing so will be for DOE and the ONG subsector to provide a much stronger factual basis to assess the resilience of that infrastructure than currently exists.

NERC can provide a crucial source of guidance in shaping the scope and evolution of the DBT development process. NERC has been facilitating increasingly close coordination between BPS entities and natural gas companies to address fuel resilience and interdependency challenges. NERC notes that:

> With increased growth in gas usage comes greater reliance and associated risk due to the dependency that each industry now has on the other. The operational impact of these dependencies requires gas and electric system operators to actively coordinate planning and operations. The goal of the coordination is to ensure that both the gas and electric systems remain secure and reliable during normal, abnormal and emergency conditions.[77]

Accordingly, NERC has offered a set of recommendations on opportunities for gas-electric coordination, many of which might be supported by DBT data to facilitate broader assessments of fuel resilience and collaborative mitigation measures. For example, NERC recommends that gas and electric companies identify "each pipeline (interstate and intrastate) that operates within the electric footprint and mapping the associated electric resources that are dependent upon those pipelines."[78] On that basis, NERC recommends that companies could then identify "gas single element contingencies and how those contingencies will impact the electric infrastructure."[79] However, against threats from Russia or other capable adversaries, such N-1 contingencies will be inadequate as a basis for resilience assessments. Government-provided DBT data will be needed to help RTOs and ISOs account for the risk that adversaries will disrupt pipelines on a much greater scale, and analyze the implications for power generation and grid resilience.

In turn, the DBT could support NERC initiatives on grid reliability. NERC and its industry partners are evaluating opportunities to modify the planning guidance in TPL-001-4 – *Transmission System Planning Performance Requirements*. The standard currently requires entities to assess the impacts of "extreme events," including the loss of "a large gas pipeline into a region or multiple regions that have significant gas-fired generation," and evaluate possible mitigation actions.[80] As those modification efforts go forward, NERC and its industry partners should consider how DBT material might support the analysis and planning process for resilience against gas supply interruptions beyond N-1.

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[77] North American Electric Reliability Corporation, *Reliability Guideline: Gas and Electrical Operational Coordination Considerations*, approved December 13, 2017, p. 1.
[78] North American Electric Reliability Corporation, *Reliability Guideline: Gas and Electrical Operational Coordination Considerations*, approved December 13, 2017, p. 5.
[79] *Ibid*.
[80] North American Electric Reliability Corporation, *TPL-001-4 — Transmission System Planning Performance Requirements*, Table 1, Steady State, 3.a.i., effective January 1, 2015.

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C. ENERGY INFRASTRUCTURE MODELING

DOE has proposed an energy sector modeling initiative that would be enormously helpful for developing a fuel resilience DBT – and which the DBT development process might, in turn, be able to support. Current models of interdependent gas-electric infrastructure and functions do not provide an adequate basis to assess and mitigate gaps in nationwide fuel resilience, especially as the transition to electric-powered gas compressors and other system modernizations go forward. Bruce Walker, Assistant Secretary of DOE's Office of Electricity Delivery and Energy Reliability, emphasizes that "we need an in-depth understanding of the resilience of our electricity and related infrastructure in order to know how best to either modify existing market structures or build new resiliency standards into the system."[81]

DOE's proposed modeling initiative is crucial for meeting these requirements. In particular, Assistant Secretary Walker has proposed the development of a North American energy model that integrates ongoing resilience planning efforts at local, state, and regional levels, filling any gaps and harmonizing any inconsistencies between their efforts.[82]

The DBT development process should be structured to capitalize on the findings of this modeling initiative. For example, given the importance of natural gas from Canada for U.S. power generation, the creation of an integrated, cross-sector model for North America can help guide the development of planning factors on the scale and length of gas interruptions that fuel resilience assessments ought to encompass. The Commission and its partners should also help ensure that support flows in the reverse direction. As RTOs and ISOs use the DBT to refine their resilience studies and advance mitigation initiatives to fill any gaps they identify, their findings and plans for improvement (shared and protected as appropriate) can help update DOE's proposed model.

D. BUILDING AN INTERAGENCY DEVELOPMENT PROCESS

A number of RTO and ISO responses to the Grid Resilience Rule have emphasized the need for the Commission to build a stronger foundation for fuel resilience assessments. The Commission can play an especially valuable role in helping these organizations acquire the threat data they need to make realistic, prudent assumptions about the scale and severity of the fuel interruptions they should expect in a major attack by Russia or other highly capable adversaries.

One such Commission role would be to conduct informal discussions with NERC, RTOs/ISOs, and other appropriate BPS entities on what they believe a design basis threat should comprise, and the gaps in threat data that are most necessary to for the government to fill. Other Federal departments and agencies, especially the Department of Energy, could also provide valuable recommendations on the scope and structure of the DBT.

On the basis of those discussions and responses that RTOs and ISOs have already made to the Grid Resilience Order, the Commission could then establish additional procedures to propose and

[81] Bruce Walker, *Testimony Before the United States Senate Committee on Energy and Natural Resources*, January 23, 2018, p. 2, https://www.energy.senate.gov/public/index.cfm/files/serve?File_id=165FF5C6-CB75-437E-9742-F90A1F0B580C.
[82] *Ibid*.

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request formal input on the creation of a design basis threat and the mechanisms by which it would be distributed (as discussed in the next section of my filing).

The Commission should also partner with the Department of Energy to jointly lead the interagency process needed to integrate Federal-wide input into the fuel resilience DBT. DOE is the Sector-Specific Agency for the energy sector. Department personnel have an especially strong understanding of emerging threats to the sector, and can draw on the National Laboratory system and other sources of data and analysis to build the planning factors vital so support RTO and ISO resilience assessments.

The DBT will also benefit from input from the Department of Homeland Security (DHS). The Department's National Cybersecurity and Communications Integration Center (NCCIC) is "the Nation's flagship cyber defense, incident response, and operational integration center," and can provide a unique, integrated perspective on emerging cyber resilience challenges.[83] In particular, NCCIC's United States Computer Emergency Readiness Team (US-CERT) program offers BPS entities a leading source of data on cyber threats. Other components in DHS, including the Office of Infrastructure Protection, will be essential for providing data for the DBT on physical threats to fuel infrastructure.[84]

The Department of Defense can make key contributions to the DBT as well. DOD components will be able to contribute to threat assessments and help ISOs and RTOs account for the broader national security context for their resilience studies. The Department will also have a vested interest in doing so. If attacks on fuel supplies help create long duration, wide area power outages, the ability of DOD installations, ports, and other supporting infrastructure to project power abroad and assist disaster management at home will be at increasing risk. DOD has powerful incentives to help BPS entities strengthen fuel resilience; providing Defense input into the creation of a design basis threat provides a valuable, extraordinarily low-cost means to do so.

To help FERC incorporate input from other Federal departments and agencies, existing interagency coordination mechanisms provide an ideal opportunity for progress. Either the National Security Council (NSC) or the Homeland Security Council (HSC) could provide for the necessary coordination. Under *National Security Presidential Memorandum - 4: Organization of the National Security Council, the Homeland Security Council, and Subcommittees* (April 2017), the NSC advises the President with respect to the integration of domestic, foreign, and military policies pertaining to national security. The HSC is responsible for advising the President on matters pertaining to homeland security. Both Councils are also responsible for "the effective coordination of the security-related activities and functions of the executive departments and agencies."[85] In addition, both include the Secretary of Energy as a regular attendee.

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[83] "About Us," *United States Computer Emergency Readiness Team*, n.d.a, https://www.us-cert.gov/about-us.
[84] "Office of Infrastructure Protection," *Department of Homeland Security*, last updated July 12, 2017, https://www.dhs.gov/office-infrastructure-protection.
[85] President Donald J. Trump, *National Security Presidential Memorandum - 4: Organization of the National Security Council, the Homeland Security Council, and Subcommittees*, April 4, 2017, https://www.whitehouse.gov/presidential-actions/national-security-presidential-memorandum-4/.

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Attacks on fuel supplies for power generation could affect both national and homeland security. Accordingly, depending on their other priorities and broader ongoing efforts related to U.S. infrastructure resilience, either the NSC or HSC could help coordinate the development of a fuel resilience DBT. In either case, the Policy Coordination Committee (PCC) process could offer a useful coordination framework for the DBT effort. NSPD-4 states that "Management and development of national security polices by multiple executive departments and agencies typically shall be accomplished by the PCCs," with subordinate working groups as needed.[86] A working group to facilitate the development of the DBT might provide an especially useful starting point for interagency coordination. Nevertheless, the Commission and its industry partners will also need to help guide the DBT development process to ensure that the resulting product meets their priorities and analytic requirements to strengthen fuel resilience.

E. DISTRIBUTING AND PROTECTING DBTs AND SUPPORTING DATA

We can be sure that Russia and other potential adversaries are collecting every scrap of information that might help them identify and exploit vulnerabilities in the flow of fuel for U.S. power generation. As fuel resilience assessments go forward, and the Commission and its partners support those assessments by developing a design basis threat, it will be essential to avoid giving adversaries a roadmap for striking the energy sector or otherwise assist their attack planning and execution.

The most obvious way to protect the DBTs and their supporting data is to classify them at the Secret level or higher. However, most RTOs and ISOs have only a very small number of personnel cleared for access to such classified data and no authorized facilities to store the material, and many employees who help conduct resilience assessments may lack required clearances.

The FAST Act amendments to the Federal Power Act provide an opportunity to close this gap. The Act specifies that: "the Secretary shall facilitate and, to the extent practicable, expedite the acquisition of adequate security clearances by key personnel of any entity subject to the requirements of this section, to enable optimum communication with Federal agencies regarding threats to the security of the critical electric infrastructure."[87]

However, the backlog in applications for Federal government clearances is enormous and growing. Hundreds of thousands of clearance requests are awaiting the necessary investigations and the time required to complete those investigations is growing longer and longer.[88] The Commission cannot wait for RTOs and ISOs to significantly increase their number of cleared personnel to develop and distribute fuel resilience DBTs. Moreover, the total number of transmission system planners and other relevant personnel that will need to participate in resilience assessments is so great that it will not be practical for them all to have clearances.

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[86] *Ibid*.
[87] 16 U.S.C. § 824o–1, Section (e), https://www.law.cornell.edu/uscode/text/16/824o-1.
[88] Government Accountability Office, *Personnel Security Clearances: Additional Actions Needed to Ensure Quality, Address Timeliness, and Reduce Investigation Backlog* (GAO-18-29), December 2017, p. 32, https://www.gao.gov/assets/690/688918.pdf.

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While DOE and its Federal partners should continue to press for industry personnel to get considered for the clearances their work requires, and support efforts by BPS entities to get the facilities they need to transmit and store classified materials, a more realistic solution is need for the near term. A two-phased approach to DBT analysis and distribution can provide such a solution.

Phase 1 (Secret level or higher)

Based on classified information regarding threats to the Oil and Natural Gas subsector, cleared RTO/ISO personnel should partner with experts from the Commission, DOE and other appropriate Federal agencies to determine how many pipelines they should assume will be disrupted in an attack by Russia or other high-capability adversaries, and how long they should expect those interruptions to last. Cleared personnel would also leverage the TPL-001-4 methodologies to account for the criticality of specific critical infrastructure components that these attacks would disrupt.[89]

Based on that classified analysis, cleared personnel would distribute For Official Use Only (FOUO) assumptions to the broader team of RTO/ISO planners, specifying: 1) how much gas-fueled generation they should assume will be lost in a given location; 2) how long those disruptions will last; and 3) other planning factors needed to support resilience assessments.

Phase 2 (For Official Use Only)

These FOUO assessments should be targeted to help RTO/ISO planners assess 'downstream' impacts and consequences on BPS operations. The planners could then use this data to survey each generating station to determine the gas transmission (and LDC) for each generating unit; assess if alternate or dual gas transportation arrangements are in place; the type of transportation and supply contract (firm vs. interruptible); and the maximum amount of dual fuel, if any is available, to determine the impact of any natural gas transportation outage on individual generators. Planners also should collect information on secondary fuel supply contracts to analyze 'common mode' limitations (many generators turning toward same supplier at the same time), as well as information on the curtailment of gas supply/transportation to non-residential customers. With these estimates regarding disruptions to gas generation, planners can perform system assessments and recommend corresponding mitigations.

The Commission and DOE should partner with industry to examine how existing mechanisms to share sensitive information can be used to protect these FOUO assessments. A prime opportunity to do so lies in the information sharing and protection mechanisms required by the Federal Power Act (FPA). The *Fixing America's Surface Transportation (FAST) Act* (2015) amendments to the FPA require the Commission, in consultation with the Secretary of Energy, to establish criteria and procedures to designate certain information – Critical Electric Infrastructure Information (CEII) – as critical and prohibit its unauthorized disclosure.[90] In establishing those criteria, the

[89] North American Electric Reliability Corporation, *TPL-001-4 — Transmission System Planning Performance Requirements*, effective January 1, 2015.
[90] 16 U.S.C. § 824o–1, Section (d)(2), https://www.law.cornell.edu/uscode/text/16/824o-1.

Commission also leveraged and subsumed its long-established scheme to protect Critical *Energy* Infrastructure Information.[91] That joint mechanism might be leveraged to help protect sensitive FOUO DBT information.

The Traffic Light Protocol (TLP) offers another promising option for securely sharing FOUO fuel resilience planning assumptions. TLP is "a set of designations used to ensure that sensitive information is shared with the appropriate audience," using traditional traffic light colors to indicate three levels of expected sharing boundaries.[92] TLP:RED – the most restrictive designation – could be potential a starting point for safeguarding the sharing of fuel resilience information. The Commission and DOE should also consult with industry on how the DBT distribution process can leverage existing systems operated by the Electricity Subsector Information Sharing and Analysis Center and other proven mechanisms.

CONCLUSION

The Commission's issuance of the Grid Resilience Order marks a decisive step forward to strengthen the resilience of the bulk power system. Based on the Order and the responses by PJM, ISO-NE, and other RTOs and ISOs, the Commission now has the opportunity to help these organizations provide a stronger data-based foundation to analyze and remedy shortfalls in resilience.

Threats to the flow of natural gas on which power generation depends are intensifying in many regions of the United States. The time has come to fill the gaps in threat data that RTOs and ISOs highlighted in their responses to the Order and – in so doing – help strengthen both grid resilience and U.S. national security.

[91] *Regulations Implementing FAST Act Section 61003 – Critical Electric Infrastructure Security and Amending Critical Energy Infrastructure Information*, 157 FERC ¶ 61,123 (2016).

[92] There is a fourth designation – WHITE – which provides no boundaries, allowing for unlimited distribution. See: "Traffic Light Protocol (TLP) Definitions and Usage," *United States Computer Emergency Readiness Team*, n.d.a., https://www.us-cert.gov/tlp.

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Grid Resilience in Regional Transmission Organizations and Independent System Operators	)))	Docket No. AD18-7-000

DECLARATION OF PAUL STOCKTON

I, Paul Stockton, declare under penalty of perjury that the foregoing is true and correct.

Executed: Washington, DC
May 8, 2018

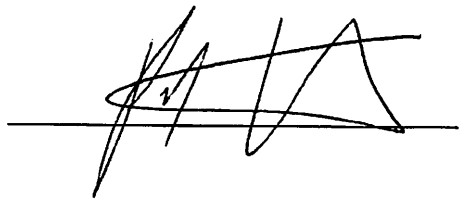

Exhibit B-1

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	**)**	**Docket No. RM18-1-000**

PREPARED DIRECT TESTIMONY OF

DR. PAUL STOCKTON

ON BEHALF OF

EXELON CORPORATION

OCTOBER 23, 2017

I. BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Paul Stockton. My business address is 325 7th Street NW, Suite 250, Washington D.C. 20004.

Q. DR. STOCKTON, BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am the Managing Director of Sonecon LLC, a security and economic advisory firm in Washington, DC.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS, EMPLOYMENT EXPERIENCE, AND EDUCATIONAL BACKGROUND

A. I graduated with a Bachelor of Arts degree s*umma cum laude* from Dartmouth College and received a Ph.D. from Harvard University. From June 2009 until January 2013, I served as the Assistant Secretary of Defense for Homeland Defense and Americas' Security Affairs. In that position, I was responsible for Defense Critical Infrastructure Protection and led the creation of the Department's Mission Assurance Strategy. I also served as the Domestic Crisis Manager for the Department of Defense (DOD) and was responsible for Defense continuity of operations. I was the principal civilian advisor to the Secretary of Defense for providing Defense support to Federal Emergency Management Agency, the Department of Energy (DOE) and other Federal departments in Superstorm Sandy, Hurricane Irene, and other disasters. In addition, I was responsible for developing and overseeing the implementation of DOD security policy in the Western Hemisphere, including U.S.-Canada

cooperation on Defense-related issues concerning energy sector resilience. From January 2012 until January 2017, I served as a Special Government Employee for the Department of Defense, and helped conduct studies to strengthen deterrence of cyberattacks, counter insider threats, and meet other infrastructure resilience challenges. I was twice awarded the DOD Medal for Distinguished Public Service, the Pentagon's highest civilian honor, and a Distinguished Public Service Medal from the Department of Homeland Security.

Q. WHO IS SPONSORING YOUR TESTIMONY?

A. My testimony is sponsored by Exelon. My testimony reflects my informed opinion and does not necessarily reflect the perspectives and policies of the Department of Defense or any other government department or agency.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. In June 2016, I testified at the Commission's Reliability Technical Conference in Docket AD16-15-000.

Q. PLEASE DESCRIBE THE BASIS FOR YOUR FAMILIARITY WITH GRID RESLIANCE PLANNING EFFORTS.

A. In addition to my professional experience, I am the author of multiple works that examine the severe threats to energy sector resilience, and analyze measures that policymakers and stakeholders can take to reduce those risks. In 2016, I authored *Superstorm Sandy: Implications for Designing a Post-Cyber Attack Power Restoration System*, published by Johns Hopkins University Applied Physics Laboratory; *Electric Grid Protection Handbook*

II, Volume 1: Resilient Fuel Resources for Power Generation in Black Sky Events, published by the Electric Infrastructure Security Council; and co-authored the Homeland Security Advisory Council's *Final Report by the Cybersecurity Subcommittee: Incident Response.* I am also widely published on other issues of homeland security, national defense and infrastructure resilience, including *Resilience for Black Sky Days: Supplementing Reliability Metrics for Extraordinary and Hazardous Events*, prepared for the National Association of Regulatory Utility Commissioners.

II. PURPOSE OF TESTIMONY AND CONCLUSIONS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I examine how the increased reliance on natural gas for power generation is creating new risks to electric grid resilience, and analyze the implications for U.S. national security. I evaluate the adequacy of current measures to assess and mitigate these risks. I also propose measures to strengthen the resilience of the grid, and meet the challenges highlighted by the Department of Energy.

Q. COULD YOU PLEASE SUMMARIZE YOUR CONCLUSIONS?

A. I believe that this proceeding provides an opportunity to address the risks created by the growing dependence of the electric grid on natural gas as a fuel source. My testimony addresses three overall findings. *First*, the growing dependence of power generation on natural gas poses potential risks to U.S. national security. *Second*, current initiatives to identify and mitigate risks arising from gas-electric system interdependencies are not adequate. *Third*, before the Commission can decide on appropriate actions to help

strengthen fuel resilience, I believe that significant additional analysis will first be required to clarify the attributes of fuel resilience, develop metrics to assess them, and specify the threat against which fuel resilience should be measured. In particular, I recommend that a government agency (in consultation with appropriate Bulk Power System (BPS) entities) establish a Design Basis Threat (DBT) to help assess fuel resilience for power generation and that FERC gather additional data on the current status of resilience efforts. Finally, the Commission, in conjunction with other agencies, should implement measures that will ensure that resiliency is preserved.

Q. PLEASE SUMMARIZE YOUR FIRST FINDING. WHAT ARE THE POTENTIAL RISKS TO U.S. SECURITY POSED BY EMERGING THREATS TO ELECTRIC AND GAS SYSTEMS?

A. Russia, China, North Korea, and other potential adversaries may seek to disrupt U.S. defense capabilities by attacking the critical infrastructure on which our military bases rely. DOD's Mission Assurance Strategy emphasizes that "The Department of Defense's ability to ensure the performance of its Mission-Essential Functions (MEFs) is at growing risk. Potential adversaries are seeking asymmetric means to cripple our force projection, warfighting, and sustainment capabilities by targeting critical Defense and supporting civilian capabilities and assets – within the United States and abroad –on which our forces depend."[1]

[1] Department of Defense, *Mission Assurance Strategy*, April 2012, p. 1, http://policy.defense.gov/Portals/11/Documents/MA_Strategy_Final_7May12.pdf.

The power grid and fuel supplies for power generation are potential targets for these adversaries. While military installations and other national security facilities are strengthening their emergency power capabilities to serve their critical loads, long duration, wide area power outages could jeopardize their ability to execute their MEFs. We must assume that adversaries know this – and, accordingly, that in future conflicts they will attack the power grid and the flow of gas on which power generation increasingly relies.

Q. PLEASE SUMMARIZE YOUR SECOND FINDING. ARE CURRENT EFFORTS TO IDENTIFY AND MITIGATE RISKS STEMMING FROM INCREASED RELIANCE ON NATURAL GAS ADEQUATE TO ENSURE RESILIENCE?

A. No. Existing BPS reliability standards focus on protecting and maintaining the reliability of BPS systems and functions. These standards do not apply to the gas systems that are increasingly vital for power generation. Indeed, no mandatory standards exist for gas system reliability that are remotely equivalent to those that help strengthen the BPS against attack. Current efforts to provide dual-fuel capability for natural gas plants are not sufficient. While some planning efforts have begun, they do not go far enough.

Q. PLEASE SUMMARIZE YOUR THIRD FINDING. HOW CAN THE COMMISSION BEST ADVANCE GRID RESILIENCE?

A. As measures go forward to strengthen fuel resilience, and thereby bolster U.S. security, Commissioners should take a holistic approach that will involve collaboration with a range of government and private sector entities. Work should begin immediately to develop a detailed assessment of the risks being created by increasing gas-electric system

interdependencies. In my testimony that follows, I highlight a number of requirements for further analysis, including reporting requirements for RTOs to understand the current state of resiliency.

The Commission also should seek the creation of a DBT to help assess the resilience of fuel supplies for power generation and the potential value of measures taken to improve that resilience. Modelled on the approach of the Nuclear Regulatory Commission, a DBT should consider the type, composition, and nature of risks to resiliency including both catastrophic natural and manmade hazards.[2] That DBT should account for the risk –indeed, the likelihood – that if a major power decides to attack the U.S. energy sector, they will not merely strike a single pipeline, but seek to disrupt *all* major pipelines in a given region. Finally, implementation measures should be taken to ensure that the threat is appropriately mitigated and resiliency is preserved.

III. EMERGING RISKS TO RESILIENCY

Q. DID THE DEPARTMENT OF ENERGY FIND A RISK TO RESILIENCY FROM RELIANCE ON NATURAL GAS?

A. Yes. DOE's Notice of Proposed Rulemaking takes a crucial step forward to clarify these risks and highlight the value of measures to mitigate them. From 2002 until 2016, the share of electricity generated by gas-fired units increased from 18% to about 34% while the share

[2] *See* Nuclear Regulatory Commission Glossary, Design Basis Threat; https://www.nrc.gov/reading-rm/basic-ref/glossary/design-basis-threat-dbt.html (defining a design basis threat); 10 CFR § 73.1(a) (outlining particular threats).

generated by coal fell from about 50% to about 30%.[3] Risks of mutually-reinforcing failures between gas and electric systems have grown accordingly. DOE found that "the electric sector's growing reliance on natural gas raises concerns regarding the ability to maintain BPS reliability when facing constraints on the natural gas delivery systems."[4] Other key BPS stakeholders have reached similar conclusions. For example, Gerry Cauley, President and CEO of NERC, emphasizes that "[g]rowing reliance on natural gas continues to raise reliability concerns regarding the ability of both gas and electric infrastructures to maintain the BPS reliability at acceptable levels."[5]

Q. WHAT SPECIFIC RISKS DO YOU SEE?

A. In addition to the risks specified in the Notice, I would call the Commission's attention to three specific challenges: *First*, reliance on a single fuel creates the danger of "common-mode failures" where a lack of natural gas incapacitates multiple generators at the same time. *Second*, such failures could help create "black sky" power outages, which would entail outages lasting a month or more over multiple regions of the United States.[6] *Third*, rising gas-electric interdependencies create dangers of mutually-reinforcing failures.

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[3] United States Department of Energy, Staff Report to the Secretary on Electricity Markets and Reliability 90 (August 2017).

[4] North American Electric Reliability Corporation, *Short-Term Special Assessment: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation*, May 2016, p. 12.

[5] Gerry Cauley letter to Energy Secretary Rick Perry, May 9, 2017.

[6] Paul Stockton, *Resilience for Black Sky Days: Supplementing Reliability Metrics for Extraordinary and Hazardous Events*, at 3, National Association of Regulatory Utility Commissioners (2014).

Q. PLEASE DESCRIBE HOW RELIANCE ON A SINGLE FUEL CAN MAGNIFY RISKS OF COMMON-MODE FAILURES.

A. Increased dependence on a single type of fuel heightens the risks of common mode failures: that is, the danger that a single attack vector (especially via cyber means) could enable the adversary to disrupt fuel supplies for power generation across major portions of the United States. A significant interruption of the natural gas supply available for electric generation can dramatically reduce the supply of electricity available to serve load. For example, a large-scale disruption of a natural gas pipeline would prevent that pipeline from delivering natural gas to the generators it serves. It would also incapacitate any downstream pipeline dependent on it as a source of gas. Because gas is delivered close in time to its use as a fuel for electric generation, the system would have little time to respond to the loss of a pipeline. Preserving a diverse generation mix that relies on multiple sources of fuel is essential to reducing this risk.

Q. WHAT WOULD BE THE CONSEQUENCES OF A "BLACK SKY" OUTAGE?

A. A black sky power outage would inflict immense disruption on national security, the U. S. economy, and public health and safety.

Q. WHY WOULD THE HARM BE SO SEVERE?

A. Many critical infrastructure systems and facilities have backup power generators and stored on-site fuel to keep them operating for a few days in a limited power outage. However, in a black sky event, the extensive length and geographic scope of power outages would soon produce failures in emergency power assets and the infrastructure system that rely on them.

Blackouts of this severity would cause cascading failures across multiple critical infrastructure sectors. As highlighted in recent hurricane events, generators will quickly break down through overuse. Demand for replacing them in a wide-area outage will rapidly outstrip available supplies, given the vast number of facilities that will require such replacements. Moreover, on-site fuel supplies for emergency generators will quickly be depleted. Massive, multi-sector requirements for fuel resupply will emerge. Contractors responsible for sustain resupply operations will be unable to meet these requirements, especially since transportation systems, refinery operations, and other systems on which these contractors depend will also be disrupted in a black sky outage. Hospitals would exhaust their ability to rely on backup power. Food manufacturing and distribution networks would cease to function. Other critical infrastructure sectors would also likely collapse. For example, water, wastewater, and cellular systems rely on a functioning power grid and are not currently prepared for such an event. A black sky event would likely disable those systems for sustained periods of time leaving them unavailable to the public. Finally, national defense installations would begin to fail. Domestic military facilities can operate without power for short periods of time but most are not designed to be independent of the electric grid for extended periods of time. Electric power is necessary to keep them in operation because they require access to transportation fuel, communication networks, water and wastewater systems that need electricity to operate. The net result: black sky outages will have catastrophic effects on national security, the U.S. economy, and public safety. Adversaries seeking to achieve such effects will therefore be all the more tempted to build capabilities to create black sky events, and exploit the gas-electric interdependencies that could contribute to the severity of future blackouts..

Q. HOW COULD GAS-ELECTRIC INTERDEPENDENCIES CREATE MUTUALLY REINFORCING FAILURES?

As natural gas has become an increasingly important fuel for electric generation, natural gas pipelines have also come to rely on electricity to function. Key components of gas pipeline systems, including the compressors and industrial control systems that keep gas flowing to power generators and other users, are more reliant on electric power. Gas pipeline systems need compression pumps to sustain the flow of gas. Historically, these compressors were fueled with gas taken from the pipelines themselves. However, in many regions of the United States, these compressors are being replaced by variable speed electric-powered units to reduce onsite methane emissions and increase compressor efficiency. Black sky outages could interrupt the flow of electricity to these units, and (in a classic case of spiraling effects) magnify those outages by disrupting gas deliveries to power generators essential for power restoration.[7] Some compression stations do have emergency power generators and at least some on-site fuel to sustain operations in a blackout. However, as noted above, fuel resupply operations for these stations will be at risk of catastrophic disruption in long duration, wide area outages. These growing interdependencies create risks of cascading, mutually-reinforcing failures across both the electricity and oil and natural gas energy subsectors.[8] Because of the need for generators to receive natural gas

[7] Electric Infrastructure Protection (EPRO) Handbook II (Vol 1 – Fuel), July 18, 2016, at 24, http://www.eiscouncil.com/App_Data/Upload/149e7a61-5d8e-4af3-bdbf-68dce1b832b0.pdf.s

[8] Electric Infrastructure Protection (EPRO) Handbook II (Vol 1 – Fuel), July 18, 2016, at 21, http://www.eiscouncil.com/App_Data/Upload/149e7a61-5d8e-4af3-bdbf-68dce1b832b0.pdf.s

fuel and the need for electricity by natural gas pipelines to deliver that fuel, a significant interruption of the supply of natural gas can start a chain of events that result in interruption of electricity, which can cause the loss of power to gas compressors, which can cause further interruptions of generator fuel supply, cascading toward a broader system outage. The result: *gas and electric systems will be vulnerable to mutually-reinforcing failures when such outages begin.*

Q. WHAT TYPES OF HAZARDS COULD CAUSE THESE FAILURES?

A. Both natural and manmade hazards pose risks. While I describe a few such potential vulnerabilities below, the Commission, in coordination with other knowledgeable agencies, should consider as many other such threats as possible and similarly develop and implement measures to ensure they are understood.

Q. WHAT ARE THE NATURAL HAZARDS THAT COULD CREATE SUCH MUTUALLY REINFORCING GAS-ELECTRIC SYSTEM FAILURES?

A. Catastrophic earthquakes could inflict massive damage on gas and electric infrastructure, and foster mutually-reinforcing failures between them that produce black sky outages. For example, a catastrophic earthquake in the New Madrid Seismic Zone would pose significant risks to PJM. Similar seismically active regions pose risks elsewhere. Other catastrophic natural hazards could also create such risks. Moreover, once a naturally-induced blackout was underway, adversaries could also exploit the resulting disruptions in gas-electric system interdependencies, and exacerbate the interruption of natural gas flows for power generation.

Q. WHAT ARE THE MANMADE RISKS?

A. In recent months, potential adversaries have staged sophisticated, multi-phase intrusion campaigns against the energy sector to insert Advanced Persistent Threats into our energy systems.[9] These efforts are part of a long-term trend towards increased severity in the cyber threats confronting electric and gas systems –a trend that is certain to continue. Coordinated physical attacks on critical gas and electric system infrastructure components pose an additional threat. Such attacks could come from the type of kinetic threats seen in the 2013 attack on the Metcalf substation in California[10], but also from unmanned aerial vehicles carrying advanced payloads and other non-traditional attack vectors. Combined cyber-physical attacks could magnify such risks of disruption.

Q. IN ADDITION TO THE CHANGE IN THE GENERATION MIX, WHAT ADDITIONAL FACTORS HAVE HEIGHTENED THE RISKS?

A. Electricity plays an increasingly important role in the operation of all other infrastructure sectors. DOE notes that "[t]he reliability of the electric system underpins virtually every sector of the modern U.S. economy, which depends on electricity – including sectors from food production to banking to health care. Electricity is at the center of key infrastructure systems that support these activities –transportation, oil and gas production, water, finance,

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[9] U.S. Computer Emergency Readiness Team, "Advanced Persistent Threat Activity Targeting Energy and Other Critical Infrastructure Sectors, October 21, 2017, at https://www.us-cert.gov/ncas/alerts/TA17-293A

[10] Rebecca Smith, *Assault on California Power Station Raises Alarm on Potential for Terrorism,* Wall St. J., Feb. 5, 2014.

and information and communications technology. Electricity-dependent critical infrastructures represent the core underlying lifeline framework that supports the American economy and society."[11] This "electrification of everything" heightens the potential payoff to adversaries of attacking the grid and its fuel supplies, and reinforces the imperative to mitigate the risks of increased reliance on natural gas for power generation.

IV. CURRENT EFFORTS TO IDENTIFY AND MITIGATE RISKS TO RESILIENCY

Q. WHICH STAKEHOLDERS HAVE A ROLE TO PLAY IN PRESERVING THE RESILIENCY OF THE GRID?

A. By issuing the proposed rule, the Department of Energy has taken a critical step forward to facilitate progress on resilience. Other key stakeholders include the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation (NERC), the Regional Transmission Organizations and Independent System Operators overseen by FERC, and other BPS entities. Commissioners and other entities may also wish to consult with the Department of Homeland Security, the Department of Transportation, and the Department of Defense, and other federal and state agencies.

Q. HAVE THE RELEVANT STAKEHOLDERS ADQUATELY CONSIDERED THE RISKS TO RESILIENCY?

[11] Department of Energy, *Quadrennial Energy Review – Transforming the Nation's Electricity System: Second Installment of the QER*, January 2017, p. 7-3.

A. Stakeholders are making progress, but significant gaps remain in assessing risks to resilience and developing mitigation options. In particular, stakeholders need to account for the growing severity of the threat and the implications for adversary exploitation of gas-electric interdependencies. To the best of my knowledge, for example, no RTO has performed a comprehensive analysis of whether the system can survive the disruption of multiple natural gas pipelines system for an extended period of time.

Q. FERC HAS APPROVED MANDATORY RELIABILITY STANDARDS FOR THE BULK ELECTRIC SYSTEM. DO THE RELIABILITY STANDARDS AIM TO ENSURE RESILIENCY?

A. No. As noted above, NERC reliability standards apply to electric infrastructure, not gas transmission lines and other fuel systems on which the grid depends. Moreover, these standards focus on reliability, not resilience. Studies conducted for the National Association of Regulatory Commissioners and other studies have highlighted significant ways in which resilience differs from reliability. These studies have also examined why traditional metrics for assessing reliability are inadequate for resilience.[12]

Q. DO EFFORTS TO PROVIDE DUAL-FUEL CAPABILITIES TO NATURAL GAS UNITS PROVIDE ADEQUATE RESILIENCE AGAINST THIS THREAT?

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[12] *Resilience for Black Sky Days: Supplementing Reliability Metrics for Extraordinary and Hazardous Events*, National Association of Regulatory Utility Commissioners, February 2014), available at http://www.sonecon.com/docs/studies/Resilience_for_Black_Sky_Days_Stockton_Sonecon_FINAL_ONLINE_Feb5.pdf; Sayanti Mukhopadhyay, Public Utility Commissions to Foster Resilience Investment in Power Grid Infrastructure, available at http://www.sciencedirect.com/science/article/pii/S1877042816300052

A. Not yet. Generators that are able to utilize a secondary source of fuel if natural gas supplies are interrupted can provide a critical bulwark against cross-sector failure. Given that value, some markets have developed financial incentives to encourage the construction and retention of dual-fuel generators. However, there are indications that existing incentives may not be adequate. Moreover, these generators typically have enough secondary feel stored on site to operate for very limited periods. After that, fuel resupply will be essential to sustain their operations if natural gas flows remain interrupted. However, the same factors that will disrupt the resupply of fuel for emergency power generators will apply to resupply of the secondary fuels typically employed for dual-fuel generators. Demand for such fuel in a long duration, wide area outage will be vastly greater than the capacity of contractors to conduct resupply operations. This is especially true since such operations would need to go forward in severely disrupted environments, especially in terms of refining and transportation system functionality.

Q. HOW IMPORTANT IS ON-SITE FUEL STORAGE FOR ENSURING GENERATION RESILIENCE, AND WHAT ARE THE APPROPRIATE STANDARDS FOR RESILIENCE PRICING ELIGIBILITY?

A. Nuclear power plants can operate for many months between refueling operations. Accordingly, they can make special contributions to grid resilience. The proposed Rule also makes the case that because coal generators typically have many weeks of fuel supplies stored on-site, they are also highly resilient. However, much more comprehensive and systematic analysis of such issues should go forward before final decisions are made on eligibility and market design changes. Moreover, as these criteria design options are

developed, it will be vital to avoid crafting them in ways that favor one source of generation over another for reasons irrelevant to grid resilience.

Q. WHAT CURRENT ANALYTIC INITIATIVES ARE UNDERWAY THAT COULD HELP ASSESS CURRENT FUEL RESILIENCE AND REQUIREMENTS FOR PROGRESS UNDER THE NOPR?

A. Valuable studies have already been conducted on the risks that interruptions in gas supplies pose to BPS reliability.[13] NERC is now conducting a much-needed special reliability assessment to determine impacts of a single point of disruption of natural gas facilities.[14] Along with other industry initiatives, PJM is conducting especially important studies of the potential risks created by increased reliance on natural gas, including in its *Natural Gas Contingency Scenario Analysis*.[15] I commend PJM for taking these critical steps forward. These and other industry studies analysis can provide a useful model for BPS entities

[13] See: North American Electric Reliability Corporation, *Short-Term Special Assessment: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation*, May 2016; Federal Energy Regulatory Commission, *Gas-Electric Coordination Quarterly Report to the Commission*, Docket No. AD12-12-000, December 18, 2014; Department of Energy, *Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector*, February 2015; American Electric Power, *Gas-Electric Harmonization: An AEP Perspective*, 2014; Midcontinent Independent System Operator, *Electric-Gas Coordination*, February 2015; and Eastern Interconnection Planning Collaborative, *Gas-Electric System Interface Study*, December 2014.

[14] *See* Agenda Item 3a, Special Assessment: Single Points of Disruption on Natural Gas Infrastructure, MRC Informational Session (April 13, 2017), *available at* http://www.nerc.com/gov/bot/MRC/Agenda%20Highlights%20nad%20Minutes%202013/MRC_Informational_Session_Conference_Call_and_Webinar_Agenda_April_13_2017.pdf.

[15] http://pjm.com/-/media/committees-groups/committees/teac/20170914/20170914-reliability-analysis-updates.ashx

nationwide to adapt to meet their own assessment requirements and fuel resilience challenges. However, as I discuss below, I believe other efforts are necessary.

V. ADVANCING GRID RESILIENCE

Q. WHAT ACTIONS SHOULD THE COMMISSION TAKE?

A. The Commission should obtain the analyses necessary to determine what actions to take next. For one, relevant information from the RTOs covered by the NOPR would help in this determination. Next, the Commission should collaborate with other agencies to conduct a DBT analysis.

Q. WHAT ADDITIONAL INFORMATION WOULD BE HELPFUL FROM THE RTOS?

A. PJM's analysis provides an extremely useful starting point, but it should be expanded. For example, analysis by RTOs should consider the loss of multiple pipelines simultaneously, as might occur in a coordinated physical or cyberattack. As noted above, any major power willing to take the risks of attacking a single U.S. pipeline may well decide to strike on a much more massive scale to disrupt U.S. defense capabilities, and seek to disrupt all flows of gas for power generation in a given RTO or ISO service area.

Useful additional information would include data from each generator on:

- For the primary fuel source:
    - Fuel source type.
    - On-site inventory reported as average days based on continuous full output.

- The nature of the fuel supply arrangement (e.g., firm gas, long-term coal contract, purchases of oil on the spot market, etc.).
- The primary method of fuel delivery (e.g., firm pipeline transportation, rail, barge, truck, etc.).
- Environmental permitting limitations.

- For the secondary or back-up fuel (if any):
  - Fuel source type.
  - On-site inventory reported as average days based on continuous full output. For oil and diesel this should include both the actual inventory and the maximum potential that can be stored on-site.
  - The nature of the fuel supply arrangement.
  - The primary method of fuel delivery.
  - Environmental permitting limitations.

The RTOs should also conduct a series of studies:

- A fuel reliance analysis detailing the impact on the organized market's ability to serve load if the supply of a particular fuel type is interrupted, or if the supply of a combination of fuel types is interrupted. The analysis should include:
  - How much load would not be served if a particular fuel type were unavailable for any reason.
  - How long primary inventories would last at generators' full output
  - How long secondary inventories would last at generators' full output
  - A generator's ability to resupply from existing secondary fuel inventories that are not on site.
  - The market's ability to increase production of remaining fuels, including diesel fuel, to meet increased need for the fuel in light of other demands for that fuel.

- A load impact analysis detailing the consequences if load is unable to be served for a prolonged period of time. This analysis should detail multiple disruption and time combinations (e.g., 50% of load for one week, 75% of load for two weeks, etc). The analysis should include:

- The financial impact to economy of the region.
- The impact to the security of the region (e.g., loss of other critical infrastructure and life sustaining services).

- A contingency analysis detailing the ability of the system to withstand (for both short- and long-term) electric and gas failures. This analysis should model both existing and future generation mixes. The analysis should include:
  - Single gas pipeline failure.
  - Multiple gas pipeline failures (including shared right of ways and crossings).
  - Coordinated attacks on the organized market's 3 of 4 biggest pipelines.
  - Loss of all pipelines controlled by single company whether as a result of a physical or cyber attack.
  - Coordinated gas pipeline/electric failures.
- The RTOs should also conduct an assessment of the adequacy of existing capacity constructs in light of the resiliency findings, and suggestions of what changes need to be made.

Q. DO THE RELIABILITY STANDARDS SUGGEST THAT THIS ANALYSIS IS APPROPRIATE?

A. NERC Reliability Standard TPL-001-4 directs transmission planners to assess the impact of extreme events, and if the analysis determines that such events cause cascading outages, the transmission planner should evaluate possible actions to reduce the likelihood or mitigate the consequences and adverse impacts to reliability.[16] I recommend that large-scale disruptions of gas supplies be included in such analysis. I also propose that planners

[16] *See* Requirements R 3.2 and R 3.5 of Standard TPL-001-4 – Transmission System Planning Requirements.

include contingency analysis of severe disruptions in secondary fuel resupply for dual fuel generators, and disruption of fuel resupply for backup power generators that serve critical natural gas compression stations and other key gathering and transmission infrastructure. Finally, planners should conduct sensitivity analysis on the degree to which retaining a mix of fuel-resilient generation assets, including nuclear assets, can help reinforce the resilience of the BPS as a whole.

Q. HOW COULD A DESIGN BASIS THREAT ASSIST THE COMMISSION?

A. At present, BPS entities lack a government-approved assessment of the threat against which they should measure the resilience of their fuel supplies. The Nuclear Regulatory Commission provides its licensees with a DBT to help design safeguard systems for the U.S. nuclear fleet. Fuel resilience issues pose a very different range of challenges. A DBT would help the Commission support analysis and mitigation of risks to fuel resilience. That effort should be led by a U.S. agency with access to appropriate threat information. The development of a DBT should also go forward in full consultation with the electric power industry, NERC, the E-ISAC, and other key sources of expertise. The design of the DBT should also leverage "best practices" developed by the NRC, and draw lessons learned from the NRC's past efforts that can help accelerate and improve the creation of a DBT for resilience.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

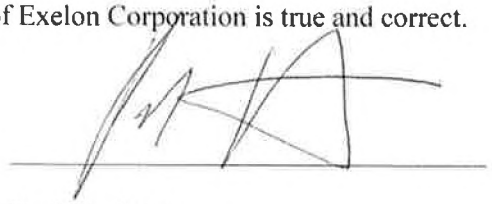
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)	RM18-1-000

DECLARATION OF DR. PAUL STOCKTON

I, Paul Stockton, declare under penalty of perjury that the foregoing Prepared Direct Testimony of Dr. Paul Stockton on Behalf of Exelon Corporation is true and correct.

Executed: October 23, 2017



Paul Stockton

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Exhibit B-2

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	**)**	**Docket No. RM18-1-000**

SUPPLEMENTAL TESTIMONY OF

DR. PAUL STOCKTON

ON BEHALF OF

EXELON CORPORATION

November 7, 2017

20171107-5164 FERC PDF (Unofficial) 11/7/2017 2:23:07 PM

My name is Paul Stockton. I am the Managing Director of Sonecon, LLC, a security and economic advisory firm in Washington, D.C. I submitted initial testimony in this docket on behalf of Exelon outlining the risks to the resilience of fuel supplies for power generation, especially those related to natural gas, and proposed steps to mitigate those risks. This additional testimony is designed to expand on my earlier submission.

Bulk Power System (BPS) entities cannot adequately assess the resilience of their fuel supplies for power generation because they lack the necessary analytic framework. In particular, neither the Department of Energy (DOE) nor any other Federal agency has provided BPS entities with a description of the threat against which fuel resilience should be measured. Without the ability to anticipate the likely scope and severity of an attack on natural gas pipelines and other sources of fuel, the Federal Energy Regulatory Commission (FERC) and the entities it regulates cannot measure the adequacy of current fuel resilience measures, or evaluate the potential benefits of additional mitigation options.

In my initial testimony,[1] I recommended the establishment of a Design Basis Threat (DBT) to support such assessments. Government-vetted DBTs already provide descriptions of threats to other infrastructure sectors to help guide their evaluation of security requirements and mitigation measures. For example, the Nuclear Regulatory Commission (NRC) provides a DBT to owners of commercial nuclear generators to help them ensure the adequacy of their security measures against manmade threats. In this testimony, I examine how a DBT for fuel resilience might provide unique benefits for assessing the current status of that resilience, and for evaluating options to mitigate gaps that may emerge against increasingly severe threats. My

[1] Testimony of Paul Stockton at p. 4-5.

testimony presents three overall findings on why developing a DBT is so vital for addressing fuel resilience and recommendations on how that development process should go forward.

First, I explain the need for a DBT. Without a government-vetted DBT, RTOs and other BPS entities are left to develop their own characterizations of the threat, leading to disparate analytic frameworks for assessing the scale and potential impact of fuel interruptions.

Second, I recommend an approach to determine the threat characteristics that the DBT should comprise. The DBT established by the Nuclear Regulatory Commission for commercial nuclear power reactors provide a useful precedent and model for developing a DBT focused on fuel resilience. DBTs provided by the Department of Homeland Security (DHS), the Department of Defense (DOD), and other Federal departments and agencies provide additional models for consideration. However, a fuel resilience DBT would need to focus on specific threats of fuel supply interruption, including those related to gas-electric system interdependencies and the risks of cascading fuel-related infrastructure failures that adversaries could create. Those threat characterizations should also account for both natural and manmade hazards that could inflict the simultaneous disruption of multiple gas pipelines and other fuel supply systems in multi-state regions. Analytic efforts conducted by NERC, entities at the direction of the Electricity Subsector Coordinating Council (ESCC), and BPS entities can also help identify the key threat characteristics that the fuel resilience DBT should encompass.

Third, I discuss the path forward to develop a DBT for fuel resilience. One promising option would be for the Department of Energy to lead the development of the DBT, in close coordination with the Commission, other Federal departments and agencies, BPS entities, the ESCC, NERC, and additional stakeholders in grid resilience with expertise on emerging threats. Such a DBT could also be structured in a "tiered" fashion, with a baseline DBT provided to all

BPS entities at the level of "For Official Use Only" and supplementary DBTs provided as needed at higher levels of classification to cleared industry personnel.

I. The Need for a DBT

The Department of Energy's *Staff Report to the Secretary on Electricity Markets and Reliability* (August 2017) highlights the need to "develop policy metrics and tools for evaluating BPS-wide provision of resilience and considering all aspects of the electricity system that contribute to resilience," including fuel supply and storage, and other factors critical to grid reliability and resilience.[2]

A growing number of RTOs and other BPS entities are developing and applying such evaluative tools. In particular, these entities are either assessing or planning to assess potential risks to their fuel supplies, especially natural gas, and the potential impact of fuel interruptions on grid reliability. PJM, for example, has conducted pioneering studies of the potential risks created by increased reliance on natural gas, including in its *Natural Gas Contingency Scenario Analysis*.[3] These studies are essential to address the resilience challenges identified in the NOPR.

However, the DOE Staff Report also identifies a critical gap for conducting such assessments. The Report cites PJM's finding that "criteria for resilience are not explicitly defined or quantified today."[4] The Report goes on to recommend that "Each RTO/ISO should strive to explicitly define resilience on its system and conduct resource diversity assessments to more

[2] Department of Energy, *Staff Report to the Secretary on Electricity Markets and Reliability*, August 2017, p. 128.
[3] Transmission Expansion Advisory Committee, "Reliability Analysis Update," *PJM Interconnection*, September 14, 2017, http://pjm.com/-/media/committees-groups/committees/teac/20170914/20170914-reliability-analysis-updates.ashx.
[4] PJM Interconnection, *PJM's Evolving Resource Mix and System Reliability*, March 2017, p. 6.

fully understand the resilience of different resource portfolios. Federal, state, and local work to define and support system-wide resilience is also needed."[5]

Providing a DBT offers a uniquely valuable opportunity for such Federal support. The Federal government currently leaves RTOs and ISOs largely on their own to characterize threats to their fuel resilience. This approach is likely to produce disparate planning assumptions regarding the scale and severity of such threats. The government's "hands off" approach also limits opportunities for appropriate intelligence-related input from the Department of Energy and other Federal departments and agencies to support the development of a vetted, appropriately informed DBT. This lack of Federal support is especially notable given the risk that fuel supply interruptions could jeopardize the flow of power on which military bases and other national security assets depend. To help strengthen U.S. security, the Federal government should work with BPS entities and other resilience stakeholders to develop a vetted, intelligence-informed DBT for assessing and mitigating risks fuel resilience.

A DBT of this kind would also help RTO and ISO efforts to meet the underlying assessment problems posed by the proposed Rule. In commenting on the Rule, David Patton, Market Monitor for MISO, NYISO and ISO-NE, noted that "Without first identifying in detail the contingencies and associated reliability risks to the system, there is no way to quantify a resilience requirement."[6] Filling this gap with a DBT will be essential for establishing the objective, analytically sound assessment system needed to achieve the goals of the proposed

[5] Department of Energy, *Staff Report to the Secretary on Electricity Markets and Reliability*, August 2017, p. 128.

[6] Comments of Potomac Economics, Ltd., Docket No. RM18-1 (Oct. 20, 2017) at 5; Michael Kuser, Tom Kleckner, Rory D. Sweeney, Amanda Durish Cook, "RTOs Reject NOPR; Say Fuel Risks Exaggerated," *RTO Insider*, October 24, 2017, https://www.rtoinsider.com/market-monitor-nuclear-coal-nopr-iso-ne-78297/.

Rule. The need for a consistent, government-vetted DBT is further highlighted by the threat assumptions that undergird recent fuel resilience studies. While excellent as far as they go, these studies typically focus on assessing the consequences of the interruption of a single major gas pipeline. That is helpful but not sufficient. Any major power willing to accept the risks associated with attacking a single U.S. pipeline may well decide to strike on a much more massive scale, and seek to disrupt all flows of gas for power generation in a given RTO or ISO service area. Specifying the extent of such anticipated fuel interruptions will be essential to provide a foundation for assessing BPS fuel resilience, and for analyzing the cost-effectiveness of various options to mitigate the emerging threat.

II. Existing DBT Models and Special Requirements for a Fuel Resilience DBT

To accelerate the development of a DBT for fuel resilience, one promising approach would be to borrow from existing DBT models and adapt them to the special fuel-related challenges posed by catastrophic natural and manmade hazards. Most significantly, the NRC has created a DBT for nuclear power plants and related facilities.[7] The requirement to establish this DBT and the basic threats it should comprise are specified in the *Energy Policy Act* of 2005.[8] These threats include "multiple, coordinated groups of attackers, suicide attacks and cyber threats," as well as other potential attack vectors.[9]

[7] The NRC's DBT provide performance-based requirements which allow each facility to develop site-specific strategies. It applies to commercial nuclear power reactors and Category I Fuel Cycle Facilities. See: "Frequently Asked Questions About NRC's Design Basis Threat Final Rule," United States Nuclear Regulatory Commission, last updated August 11, 2017, https://www.nrc.gov/security/faq-dbtfr.html.
[8] 42 USC § 2210e (2005), https://www.ferc.gov/enforcement/enforce-res/EPAct2005.pdf.
[9] 10 CFR § 73.1 (2010), https://www.gpo.gov/fdsys/pkg/CFR-2010-title10-vol2/pdf/CFR-2010-title10-vol2-sec73-1.pdf.

The NRC also regularly reviews and revises the DBT to keep pace with evolving threats. In particular, the NRC monitors domestic and foreign threat intelligence in an attempt to stay ahead of potential adversaries, issues periodic threat advisories and annual reviews, and will use this information to update the DBT as required.[10] While the DBT focuses on manmade threats, the NRC also provides earthquake engineering criteria for nuclear power plants and other guidance related to natural hazards.[11]

The NRC DBT scheme offers valuable models for establishing a fuel resilience DBT. For example, given the evolving threat to gas pipelines and other fuel supplies, it will be essential that the fuel resilience DBT be periodically updated as well. The nuclear DBT also provides a model of the appropriate level of detail for characterizing key threat vectors in an unclassified manner. In addition, existing mechanisms for the Department of Energy to share classified information with BPS entities could also be used to supplement unclassified DBT descriptions. Finally, just as the NRC sets standards for both natural and manmade hazards, the fuel resilience DBT should as well.

Even when Congress has not established statutory requirements for DBTs, Federal departments have issued them to help strengthen resilience and security across a range of critical facilities and functions. For example, DOD provides DBTs to support anti-terrorism and force protection standards, and mitigation measures based on requirements generated internally by the Department.[12] DHS also provides a DBT that establishes "the type, composition, and capabilities

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[10] "Threat Assessment," *United States Nuclear Regulatory Commission*, last updated August 14, 2017, https://www.nrc.gov/security/domestic/phys-protect/threat.html.
[11] "Appendix S to Part 50—Earthquake Engineering Criteria for Nuclear Power Plants," *United States Nuclear Regulatory Commission*, last updated August 29, 2017, https://www.nrc.gov/reading-rm/doc-collections/cfr/part050/part050-apps.html.
[12] *See* Department of Defense, DOD Security Engineering Facilities Planning Manual, September 2008, https://www.wbdg.org/FFC/DOD/UFC/ufc_4_020_01_2008.pdf

of adversaries" who might threaten Federal facilities. DHS uses the best available intelligence information and other relevant sources of data to develop and maintain the DBT. The baseline DBT provided by DHS is designated For Official Use Only (FOUO). In addition, DHS provides supplementary information as needed on specific threats and mitigation options, including at higher levels of classification.[13] A similar tiered approach to provide both an FOUO DBT and other threat assessments at higher levels of classification (to be provided to cleared BPS personnel) might also offer a useful design model for a fuel resilience DBT.

While these models from other departments are useful, a fuel-oriented DBT will need to focus on a different set of resilience challenges and threat vectors than those for nuclear power plants or Federal facilities. NERC Reliability Standard TPL-001-4 provides a valuable starting point. TPL-001-4 directs Transmission planners to assess the impact of extreme events, and if the analysis determines that such events could cause cascading outages, the Transmission planner should evaluate possible actions to reduce their likelihood or mitigate the consequences and adverse impacts to reliability.[14] To ensure that those assessments account for the risks posed by increasing reliance on gas for power generation, NERC is now considering a recommendation that "NERC registered entities should consider the loss of key natural gas infrastructure in their planning studies."[15] A DBT for fuel resilience could provide valuable support for such analysis

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[13] See: Department of Homeland Security, *The Risk Management Process for Federal Facilities: An Interagency Security Committee Standard: 2nd Edition*, November 2016, https://www.dhs.gov/publication/isc-risk-management-process.

[14] *See* Requirements R 3.2 and R 3.5 of Standard TPL-001-4 – Transmission System Planning Requirements.

[15] Thomas Coleman, "Special Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System" (presentation at NERC Board of Trustees Meeting, New Orleans, LA November 9, 2017). http://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Presentations_November_2017.pdf.

by specifying the scope and severity of the gas infrastructure losses that entities should use in their studies.

However, no such DBT exists today. Only limited guidance exists on the scale and characteristics of the extreme events that should be used as a basis for assessing the impact of fuel system interruptions on grid reliability and resilience.[16] BPS entities would benefit from far more extensive support. In particular, using appropriate intelligence sources, it would be helpful if the Federal government could provide these entities with an assessment of the scale and nature of attacks that they must be prepared to confront. Such an assessment could also help entities account for specific risks to fuel resilience, including the risk that adversaries will target their attacks to exploit interdependencies between gas and electric infrastructure.

As a starting point to develop a Design Basis Threat for fuel resilience, NERC and other industry stakeholders have already produced studies that highlight key resilience challenges to address in such a DBT. In particular, three NERC studies have examined both the characteristics of natural and manmade hazards that could cause catastrophic outages, as well as possible mitigation measures to adopt against the risks they pose.[17] These and other studies are useful starting points, but also have gaps in terms of characterizing the threat to fuel supplies. Filling those gaps will be necessary for developing a fuel resilience DBT.

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[16] *See*, *e.g.*, NERC, *2016 Long-Term Reliability Assessment*, December 2016, p. 21. The assessment notes that "As part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electric reliability."

[17] NERC noted that coordinated cyber or physical attacks "could damage or destroy key system components, significantly degrade system operating conditions, and, in extreme cases, result in prolonged outages to large parts of the system." See: NERC, *2015 Long Term Reliability Assessment*, December 2015, p. 27.

The first NERC study is a joint analysis with the Department of Energy to examine the risk of high impact, low frequency events. Particularly useful is the study's analysis of coordinated cyber/physical attacks to the BPS.[18] The report warns that coordinated cyber/physical attacks will purposefully target multiple vulnerable points on the system, and that sophisticated adversaries will adapt to protective measures to maximize disruptions. Such attacks "could result in long-term (irreparable) damage to key system components in multiple simultaneous or near-simultaneous strikes… quickly bring[ing] the system outside the protection provided by current planning and operating practices."[19]A coordinated cyber/physical attack, as described, would likely result in extended outages over a wide geographic area.

The second study examines severe disruptions to the BPS, and stems from the work of the *High Impact, Low Frequency* report. Much like that report, the *Severe Impact Resilience* study focuses primarily on coordinated cyber and physical attacks.[20] The study cautions that a coordinated physical attack on critical nodes in the grid can cause extensive damage to equipment that is difficult to replace, with significant impact to the system as a whole. Similarly, coordinated cyberattacks could cause simultaneous disruptions or misoperation that could be detrimental to system integrity.[21] While *Severe Impact Resilience* treats cyber and physical attacks as separate threats, a future Design Basis Threat should assume advanced adversaries will conduct attacks in both domains near-simultaneously.

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[18] The study also assesses the risks of pandemic illness and geomagnetic/electromagnetic disturbances. For more information, see: NERC and the Department of Energy, *High-Impact, Low-Frequency (HILF) Event Risk to the North American Bulk Power System*, June 2010.
[19] HILF Report, p. 26
[20] Like the *High Impact, Low Frequency* report, it also includes geomagnetic disturbances among the key threats for particularly severe events. See: NERC, *Severe Impact Resilience: Considerations and Recommendations*, May 2012, p. 1.
[21] NERC, *Severe Impact Resilience: Considerations and Recommendations*, May 2012, p. 1.

In a third study, NERC examined the cyberattack scenario in greater detail in a parallel effort from a cyber-focused task force. This study focuses on two primary attack vectors: 1) a coordinated attack which disables or impairs multiple control systems; and 2) intruders gaining control to purposefully misoperate the system, causing outages and/or damage. The potential ramifications are severe. If successful, adversaries could inflict losses of load and generation that cause system instability, and, ultimately, system collapse and widespread blackouts.[22]

Other industry initiatives could also be leveraged to create a DBT for fuel resilience. For example, NERC Standard CIP-014-2, *Physical Security*, provides a methodology for Transmission owners and operators to conduct their own assessment of potential physical threats and vulnerabilities.[23] NERC's *Geomagnetic Disturbance Planning Guide* provides yet another approach to assessing potential threats and system design requirements.[24] While neither of these guiding documents establishes a Design Basis Threat, they do provide useful methodological approaches that might be valuable in developing a DBT for fuel resilience.

The Department of Energy has also sponsored a study by ICF International to establish a 'baseline' of adversarial threats to the North American electric grid. The report provides an in-depth examination of an array of physical and cyber threats, including combined cyber-physical events.[25]

However, none of these studies provides a detailed analysis of the fuel resilience challenges identified in the NOPR. Nor are any of them adequate to capture the risks created by

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[22] NERC, *Cyber Attack Task Force: Final Report,* May 2012, p. 2.
[23] *See* NERC Standard CIP-014-2, *Physical Security*, May 2015, http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=CIP-014-2&title=Physical%20Security&jurisdiction=United%20States.
[24] NERC, *Geomagnetic Disturbance Planning Guide*, December 2013, p. 9.
[25] ICF International, *Electric Grid Security and Resilience: Establishing a Baseline for Adversarial Threats*, June 2016, p. 19.

gas-electric interdependencies, common failure modes,[26] duel-fuel resupply challenges and other threats I examined in my previous testimony. The threat of common failure modes is particularly concerning, as an increasing number of gas generators depend on a limited number of pipelines to deliver fuel required for power generation. Pipeline disruptions that lead to a shortage and/or outage of natural gas could therefore incapacitate multiple generators at the same time, increasing the scope and severity of the resulting power outages A single attack vector (especially via cyber means) could enable the adversary to disrupt fuel supplies for power generation across major portions of the United States. A DBT that can help BPS entities assess resilience against these threats will need to go far beyond any previous study of interruption scenarios.

As I outlined in my original testimony, the DBT should study both natural and manmade risks the system. Manmade risks could include threats from international actors, such as Russia or China, as well as terrorist organizations. The DBT should account for both physical and cybersecurity risks. For physical attacks, the DBT should encompass both familiar attack vectors as well as threats emerging from new technologies, such as unmanned aerial vehicles carrying advanced payloads. Finally, the DBT should account for the possibility that adversaries will combine cyber and physical attacks to create especially significant challenges to fuel supply systems.

[26] NERC will be presenting a Special Assessment: Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System to its Board for approval on Nov. 9, 2017. *See* Item 8c, Agenda, Board of Trustees, Nov. 9, 2017; Special Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System, Preliminary Findings, Board of Trustees, Nov. 9, 2017, located at http://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Presentations_November_2017.pdf.

Catastrophic earthquakes and other natural hazards can also inflict catastrophic damage on fuel infrastructure. Accordingly, I recommend that the DBT include both manmade and natural hazards. Given the importance of dual fuel generators as an option to mitigate the risks posed by gas system disruptions, I also propose that planners include contingency analysis of severe disruptions in secondary fuel supplies for dual fuel generators, and disruption of fuel resupply for backup power generators that serve critical natural gas compression stations and other key gathering and Transmission infrastructure. Finally, planners should conduct sensitivity analysis on the degree to which retaining a mix of fuel-resilient generation assets, including nuclear assets, can help reinforce the resilience of the BPS as a whole.

III. The Path to a Fuel Resilience DBT

Developing a DBT will require the input of multiple stakeholders. I recommend the Department of Energy lead a multistage effort in consultation with the Commission and other grid resilience stakeholders. As the Sector-Specific Agency (SSA) for the energy sector, including both the electricity and oil and natural gas (ONG) subsectors, DOE is especially well positioned to serve as the government lead for this effort. Close coordination with other Federal departments and agencies will also be required, especially those with: 1) SSA responsibilities concerning specific fuel supplies; and 2) information on the evolving threat that could supplement DOE's own extensive expertise. The ESCC, NERC, BPS asset owners and operators, and other resilience stakeholders could also play valuable roles in guiding this process.

Most important, close coordination will also be required with BPS entities to ensure that the DBT incorporates their own analytic priorities and requirements for support. The ESCC and other appropriate entities might support this BPS engagement process as well.

Given the increasing severity of threats to fuel resilience and the need for timely assessments of those challenges, I also recommend that the development of the DBT go forward in a phased process. DOE might first bring stakeholders together to produce a rapidly-available, top-level assessment of threat vectors and characteristics, equivalent to that which the NRC provides to the nuclear fleet in its publicly-available DBT descriptions. For example, this basic DBT could specify the percentage of gas pipelines that BPS entities should assume will be disrupted (and for how long). Follow-on DBTs could then address the more detailed challenges raised by gas-electric interdependencies and the threat vectors by which adversaries may seek to exploit them.

I also recommend that the fuel resilience DBT be structured in a "tiered" fashion, with a baseline DBT provided to BPS entities at the level of "For Official Use Only" and supplementary DBTs provided as needed at higher levels of classification to cleared industry personnel.

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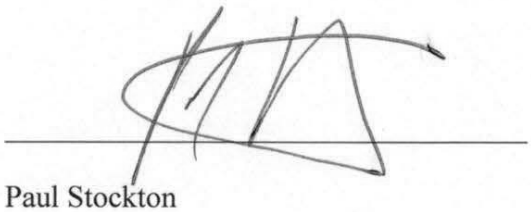
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)	**Docket No. RM18-1-000**

DECLARATION OF PAUL STOCKTON

I declare, under penalty of perjury, that the foregoing Supplemental Testimony is true and correct.



Executed: November 7, 2017

Washington, DC

Paul Stockton

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Grid Resilience in Regional Transmission Organizations and Independent System Operators	)))	Docket No. AD18-7-000

REPLY COMMENTS OF EXELON CORPORATION

The Commission initiated this proceeding because it recognized that it did not yet know what it needed to know. The Commission terminated the proposed rulemaking in RM18-1-000 but emphasized it "must remain vigilant with respect to resilience challenges."[1] Thus, it opened this docket to define resilience, learn what steps the RTOs are currently taking, and evaluate whether additional efforts are necessary.[2] The Commission correctly decided to understand the *problem* before jumping to a *solution*.

Numerous commenters, though, leap straight to discussion of solutions. They debate whether resilience is properly advanced through NERC or through the organized markets; whether solutions addressing resilience can be adopted in a market-based manner or whether they will require command-and-control regulation; and what types of resilience-related reforms are most cost-effective. All of this discussion, while extremely important, ignores the critical first step. The Commission cannot assess what solution should be implemented, who should implement it, and how, until it first understands the problem it needs to solve.

What the Commission needs now is simply information: a design-basis threat (DBT) analysis conducted in conjunction with appropriate national security agencies that the Commission can then use to guide studies regarding resilience. Only after the Commission knows the

[1] *Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012, at P 17 (2018).
[2] *Id.* at P 18.

vulnerabilities of the grid can it turn to these policy considerations to identify the appropriate solution.

These steps need to be taken deliberately and thoughtfully and with appropriate consideration of the environmental consequences, but should occur as quickly as possible. The Commission needs to immediately work with its sister agencies to create a DBT and require the RTOs to submit reports analyzing their risks in light of it and their plans to address those risks. Preliminary analyses in both ISO-NE and PJM suggest that, at least in those markets, the risks of a disruption to the natural gas supply are too great to continue to be allowed to persist, and could result in significant hours of unserved energy due to the loss of multiple gas pipelines. This risk is exacerbated by the retirement of additional nuclear resources in PJM.[3] Rapid action by the Commission to generate the necessary information and appropriate response is essential to ensure the resilience of the grid.

I. The Commission Should Immediately Develop a Design-Basis Threat and Order RTOs to Assess and Report Their Vulnerabilities In Light of the DBT.

Commenters spilled much ink debating how a resilience policy should be implemented. Some commenters argued that resilience is just a form of reliability and should be addressed through reform of the existing reliability standards.[4] Others argued that resilience-related policies are the death-knell for markets,[5] or that resilience solutions should be evaluated using a

[3] ICF, The Impact of Fuel Supply Security on Grid Resilience in PJM – Final Report, June 8, 2018, at 1-2 ("ICF Study").

[4] *See, e.g.*, Comments of The North American Electric Reliability Corporation, Docket No. AD18-7-000 (May 9, 2018) at 6-15; Comments of American Petroleum Institute, Docket No. AD18-7-000 (May 9, 2018) at 2-3 ("API Comments"); Reply Comment of the PJM Consumers Representatives, Docket No. AD18-7-000 (May 9, 2018) at 11-16; Comments of Organization of MISO States, Docket No. AD18-7-000 (May 9, 2018) at 7; Reply Comments of American Public Power Association, Docket No. AD18-7-000 (May 9, 2018) at 7-12; Reply Comments of First Energy Solutions Corp., Docket No. AD18-7-000 (May 9, 2018) at 16.

[5] *See, e.g.*, API Comments at 2; Reply Comments of Calpine Corporation, Docket No. AD18-7-000 (May 9, 2018) at 4 ("Calpine Comments"); Reply Comments of Clean Energy Advocates,

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cost-benefit analysis.[6] But all of these arguments are premature: they analyze proposed resilience solutions without sufficient information about the range of threats to system resilience that need to be addressed. Other arguments focus almost entirely on historical reliability threats rather than considering plausible threats in the future. Before determining which solutions should be implemented to address resilience vulnerabilities—both manmade and natural—the Commission must work with other government agencies to create a DBT to identify the vulnerabilities that need to be addressed. The Commission must also order the RTOs to study their vulnerabilities in light of the DBT and their plans to address those vulnerabilities. That should be the primary goal at this stage of developing a policy to ensure a resilient grid.

Numerous commenters take the position that resilience should be addressed through the NERC reliability standards.[7] This focus on NERC, though, starts from a false premise. It assumes a narrow range of resiliency problems to be addressed: problems that can be effectively managed through engineering standards that fall within the scope of Section 215 of the Federal Power Act. But that assumption may well be incorrect. While reliability standards are indisputably important to addressing certain dimensions of resilience—such as the hardening of critical transmission infrastructure—they cannot be readily used to address other potential dimensions to resilience.

Docket No. AD18-7-000 (May 9, 2018) at 16; Comments of NRG Energy on Resilience Filings, Docket No. AD18-7-000 (May 9, 2018) at 6; Comments of the Electric Power Supply Association, Docket No. AD18-7-000 (May 9, 2018) at 5.

[6] *See, e.g.*, Comments of the Organization of PJM States, Docket No. AD18-7-000 (May 9, 2018) at 3; Comments of Institute for Policy Integrity at New York University School of Law, Docket No. AD18-7-000 (May 9, 2018) at 7; Reply Comments of the PJM Consumer Representatives, Docket No. AD18-7-000 (May 9, 2018) ("PJM Consumer Representatives Comments") at 17-20; Comments of the MISO Docket No. AD18-7-000 (May 9, 2018) at 15; Allison Silverstein, et al., *A Customer-focused Framework for Electric System Resilience*, at 53-63, Docket No. AD 18-7-000 (May 9, 2018) ("Silverstein").

[7] *See supra* n.4.

For example, the ISO-NE study indicates that a major threat to resilience in that region is the grid's overdependence on a natural gas infrastructure that is highly vulnerable to disruption.[8] The same may be true in the Mid-Atlantic/New York region —an initial study prepared by ICF for NEI, for example, found a potential pipeline outage could result in up to 27 GW of electric generation being interrupted of which 18 GW are in PJM[9]—but a thorough study is needed addressing a wide range of contingencies, informed by the national security establishment. A solution to fuel security vulnerability might be the development of a market-based product to value units with significant fuel on-site. But that type of solution falls well outside the scope of NERC's role and the engineering-based reliability standards that NERC implements. The Commission should not assume that NERC is the answer before it fully understands the nature of the threats and problems to be solved.

Another strain of criticism in the comments is that resilience-related policies will be the death knell for markets.[10] API, for instance, claims that resilience efforts will cause a move away from market-based solutions and toward command-and-control regulation.[11] But API and others assume away the ability of the Commission do to what it has historically done, which is address issues through the creation of attributes that can be procured competitively. Once the Commission has sufficient information about which resilience vulnerabilities exist and need to be fixed, it can quickly move to implement necessary actions consistent with its existing market design.

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[8] ISO-New England, *Operational Fuel-Security Analysis* (Jan. 17, 2018), at 6-9, https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf.
[9] ICF Study at 1.
[10] *See supra* n.5.
[11] API Comments at 2.

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Arguments about the cost-effectiveness of various resilience solutions also are premature.[12] The PJM Consumers Representatives, for example, propose a framework "that accounts for the time-sensitive and probabilistic nature of identifiable disruptive events" that can be used to evaluate the costs and benefits of resilience efforts.[13] Likewise, the Silverstein Report proposes a cost-benefit framework and assesses the value of the resilience solutions proposed in the Report.[14] But the problem with a cost-benefit framework in the context of national security-related threats to resilience is that a probabilistic analysis may be very difficult to conduct with any accuracy. Unlike severe weather events, national security threats cannot readily be modeled based on history. Accordingly, where the national security agencies establish a genuine threat to resilience, that determination should suffice to warrant actions to mitigate the threat. To the extent that a cost-benefit framework is attempted, it is necessary to identify what vulnerability the proposed reform addresses and the comparative consequences of inaction.[15] The inquiry should span a wide range of scenarios, both manmade and natural, and consider outage of extended duration, weather and cascading events. Without preparing a DBT to identify the grid's vulnerabilities and the potential consequences of those vulnerabilities, it is impossible to fairly evaluate the value of a proposed reform.

Therefore, the Commission need not resolve the debate among these commenters at this time. Rather, the Commission's goal now should be more fundamental: to gather information about resilience threats and vulnerabilities. Only with more information will it be possible to

[12] *See supra* n.6.
[13] PJM Consumers Representatives Comments, at 18-20.
[14] Silverstein at 53-63. Any cost/benefit analysis must also account for environmental costs. Comments of Exelon Corporation, Docket No. AD 18-7-0002, at 2 (May 9, 2018).
[15] In addition, any such analysis should also consider the environmental impacts of any proposed solutions.

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evaluate the best ways to address resilience. There are two ways the Commission should collect this needed information. The Commission should pursue both with urgency.

First, the Commission should develop a DBT. As described in Exelon's Reply comments, a DBT would identify potential threats to the electric grid. The Commission should lead the effort to develop a DBT. The Commission should facilitate input from the RTOs, NERC, and other entities to determine what information gaps the DBT could fill. Then, the Commission should lead an inter-agency process of developing the DBT. Input from the Department of Energy and the national security agencies will be crucial to ensuring that the relevant expertise is incorporated into the DBT and man-made threats are comprehensively considered. The DBT should not shy away from classified information; only by incorporating every information source can the DBT be an effective tool to identify vulnerabilities to the grid. RTO representatives with classified clearance can create guidance documents that will enable the RTOs to implement the findings of the DBT without exposing classified information.

Second, the Commission should order RTOs to conduct studies to assess their vulnerabilities in light of the DBT and report back to the Commission.[16] Individual studies by RTOs will enable them to more fully understand how the general threats identified in the DBT apply to their specific markets. Armed with that information, RTOs will be able to assess which resilience vulnerabilities are most significant and which resilience solutions are most important.

It is crucial that these RTO studies be informed by the DBT. PJM proposes to undertake a study in the interim, and Exelon supports PJM's initiative. However, as outlined in Exelon's comments in the PJM stakeholder process, PJM does not have access to the information from the

[16] Under Sections 301(b) and 309 of the Federal Power Act, the Commission has well-established authority to issue orders directed to the RTOs requiring them to report information relevant to the Commission's statutory responsibilities. *See* 16 U.S.C. §§ 825b, 825h.

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Department of Energy and the national security agencies needed for it to assess fully what contingencies to model.[17] Accordingly, PJM's study is likely to underestimate the true vulnerability of the system, and worse yet, may be used to justify inaction on the critical issue of fuel security. The Commission should make clear that RTOs must ultimately perform resilience studies reflecting the DBT, and that to the extent RTOs seek to get a head start on their modeling and analyses, they must include a broad range of potential contingencies.

II. Fuel Security Presents an Urgent Risk.

While a DBT and RTO analysis is needed to develop a full understanding of the scope of resilience vulnerabilities, the information already available to date suggests that fuel insecurity presents an urgent threat to resilience. The energy supply is growing increasingly dependent on natural gas. In PJM, 90% of newly installed capacity over the last five years relies on natural gas.[18] This heavy dependence on gas poses real threats to fuel security and resilience. Natural gas generators rely on a network of pipelines for fuel delivery, which are susceptible to both natural and man-made disruptions as well as cascading failures. Dual-fuel generators, which have traditionally been seen as a hedge against this risk, do not provide a reliable back-up over long-term events. As shown in a study by Navigant that was attached to Exelon's comments, many dual-fuel generators do not store enough fuel onsite to survive a disruption longer than

[17] Exelon also notes the overall concern that PJM's proposed approach underestimates the range of threats and the potential duration of critical infrastructure outages (particularly gas transmission facility outages) that the PJM region faces. As a result, any PJM fuel security study based on these underestimated input assumptions will be severely inadequate. Exelon has raised these concerns with PJM and recommended solutions in its comments on PJM's proposed fuel security study. Those comments are attached as Exhibit A.

[18] *See* PJM Interconnection L.L.C., *2021/22 RPM Base Residual Auction Results*, at 22, Table 8, http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en; *see also* IHS Markit, *Ensuring Resilient and Efficient PJM Electricity Supply* (April 2018), *available at* https://www.nuclearmatters.com/report-21; ICF, *The Impact of Fuel Supply Security on Grid Resilience—Interim Report* (May 5, 2018) (same).

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several days. In the PJM region, more than half of the dual-fuel and oil-only capacity has enough fuel for only four days of full-load operations, and nearly 80 percent of the capacity cannot run longer than seven days.[19]

The serious threat that fuel security poses to resilience was confirmed in the recent Operational Fuel Security Analysis conducted by ISO-New England. The study analyzed how fuel security will affect grid vulnerability in the future. Specifically, the study modeled twenty-three possible scenarios that could occur in the 2024/2025 winter. In every scenario but one, emergency actions were necessary to ensure that enough power was available to supply the grid.[20] In 19 of the 23 scenarios, load-shedding was necessary.[21] The study determined that fuel security was the greatest threat to resilience in the New England Region.

Similarly, the recent ICF study highlighted fuel security threats in PJM. Assuming additional nuclear retirements, a significant gas infrastructure event could result in a loss of 18 GW of gas-fired generation in PJM, part of a total of 27 GW loss in the whole Mid-Atlantic/New York region. In that scenario, up to 22% of the area's load would be at risk of being shed at peak demand. Over a 60-day event, load shedding in PJM alone could occur in 280 hours over 34 days.[22]

The risk to resilience posed by the increasing reliance on natural gas was recently emphasized by Bruce Walker, Assistant Secretary for the Office of Electricity in the Department of Energy. Mr. Walker explained that the infrastructure necessary to serve natural gas needs is vulnerable to attack, and that "dependency on our pipelines . . . has effectively doubled and

[19] Exelon Reply Comments, Docket No. AD18-7-000 (May 9, 2018), Ex. A, Navigant Consulting, Inc., *PJM Liquid Fuel Survey and Research Results and Recommendations*, at 4 (Apr. 25, 2018).
[20] *Id.* at 8.
[21] *Id.*
[22] ICF Study, at 1.

tripled the amount of critical infrastructure that is necessary for us to protect predominantly on a cyber front but also from a physical security front."[23] This is a significant and growing challenge to ensuring the North American energy system is resilient.[24]

Some commenters say that fuel security is not a threat and there are no new circumstances that warrant special attention to the issue of fuel security.[25] But the Department of Energy disagrees, and it possesses the necessary information and expertise to make the appropriate judgment. As the Department of Energy has recognized, "[f]uel assurance is a growing consideration for the electricity system" and a major threat to system resilience.[26] Those who think nothing has changed are ignoring reality. Indeed, this is one reason why it is important to conduct a DBT: it will clarify growing threats to fuel security and ground further analysis and action in evidence and intelligence assessments.[27]

The results of the PJM 2021/2022 Base Residual Auction provide a significant new data point that has become available since the last round of comments in this docket. They show a significant loss in nuclear generation capacity in PJM.[28] This year, only 22,000 MW out of the 32,700 MW of nuclear power that was offered cleared in the auction; 33% of MW offered did

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[23] Transcript of webinar, Gridwise Alliance, Department of Energy's Office of Electricity Delivery and Energy Reliability 2018 Priorities, at 3.
[24] *Id.* at 3.
[25] *E.g.,* Comment of Consumer and Public Interest Advocates, Docket No. AD18-7-000 (May 9, 2018) at 4-5.
[26] U.S. Dep't of Energy, *Staff Report to the Secretary on Electricity Markets and Reliability* at 11-12 (Aug. 2017), https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf ("DOE Staff Report").
[27] NERC, the reliability watchdog for the North American transmission grid, highlighted the fact that "growing reliance on natural gas continues to raise BPS reliability concerns" in its recent Summer Assessment report. *See* NERC's 2018 Summer Reliability Assessment at 6.
[28] PJM, 2021-2022 RPM Base Residual Action Results, at 3, available at http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en.

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not clear. This was down from 27,000 MW of nuclear power that cleared last year.[29] That is an impending loss of nearly one-fourth of nuclear generating capacity in PJM, which represents an increase in uncleared nuclear capacity of over 200 percent compared to the previous year. Once the plants retire, that loss is irreversible. If these units retire, the result will likely be even greater reliance on natural gas generators—which will increase the risk of fuel insecurity and further undermine grid resilience.[30] Further, the retirement of these nuclear units will result in a more limited option set for policymakers to address fuel insecurity going forward.

Accordingly, there is a particular need for RTOs to evaluate the risk of major gas contingencies as they assess resilience concerns. Commenters have recognized the impact natural gas has on grid resilience.[31] Calpine Corporation, for example, noted that greater communication and coordination between pipelines, local distribution companies, and RTOs is necessary so that RTOs can predict and recover from disruptive events to the natural gas supply and distribution.[32] PSEG, too, commented that there are delivery risks associated with natural gas and that excessive reliance on natural gas, which delivers supply as needed, can expose customers to electricity disruption.[33] The recent ICF report found that 18 GW of electric generation in PJM could be lost and significant hours of unserved energy would result from the

[29] Gavin Bade, Utility Dive, PJM Loses A Quarter Of Its Nuke Capacity In latest Power Auction, May 23, 2018, *available at* https://www.utilitydive.com/news/pjm-loses-a-quarter-of-its-nuke-capacity-in-latest-power-auction/524247/; *see also* PJM, 2021-2022 RPM Base Residual Action Results.

[30] This likely replacement of retiring nuclear resources with gas-fired resources will significantly impact air emissions, which are an increasingly important state policy concern. That illustrates why environmental ramifications of any fuel security solutions must be considered in any cost/benefit analysis.

[31] NERC Comments, at 18-19.

[32] Calpine Comments, at 9-10.

[33] Motion to Intervene and Reply Comments of the PSEG Companies Docket, No. AD18-7-000 (May 9, 2018) at 3, 16 ("PSEG Comments").

loss of multiple natural gas pipelines.[34] RTOs should keep considerations of gas contingencies in the forefront of any assessment of fuel security.

Given the pressing need, the Commission should require the RTOs to move forward with their fuel security studies with urgency. While many commenters argue that the Commission should focus its attention on improving gas-electric coordination, that analysis is only part of the story.[35] Gas-electric coordination is important, [36] but it is not a resilience issue. The resilience threat stems from interruption of the natural gas supply, not from a lack of coordination between the natural gas and electric systems. The Commission should instead focus its attention on the true resilience threat: the growing level of fuel insecurity.

III. Transmission Is An Important Element of Resilience.

Exelon agrees with commenters that argue that transmission is a key component of resilience planning.[37] The grid needs both the supply resources capable of producing power sufficient to serve load even under extreme contingencies, as well as the transmission infrastructure necessary to move that electricity to customers at all times. RTOs and transmission owners both need to consider the goal of grid resilience in making their investment decisions.

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[34] ICF Study at 1.

[35] *E.g.,* Reply Comments of the Environmental Defense Fund, No. AD18-7-000 (May 9, 2018) at 11-25; PJM Consumer Representatives Comments at 37-39; Reply Comments of PJM Interconnection, L.L.C., Docket No. AD18-7-000 (May 9, 2018) at 5-8; Comments of the Electric Power Supply Association, Docket No. AD18-7-000 (May 9, 2018) at 16-17.

[36] While further gas/electric coordination improvements are important, the Commission has already worked extensively on this issue, harvesting the low-hanging, most beneficial improvements; while further improvements may be possible, they will have diminishing returns compared to those already made.

[37] Comments of WIRES, Docket No. AD18-7-000 (May 9, 2018) at 2; Reply Comments of the American Wind Energy Association and the American Council on Renewable Energy, Docket No. AD18-7-000 (May 9, 2018) at 32-37; Reply Comments of the PJM Transmission Owners Agreement-Administrative Committee, Docket No. AD18-7-000 (May 9, 2018) at 5-6.

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First, RTOs should incorporate resilience considerations into the regional transmission planning process. Transmission planning should eliminate *existing* vulnerabilities to the system, and also ensure that *new* vulnerabilities are not created. Such steps are appropriate even when the more resilient solution may be more costly. For example, transmission planners should strive to reduce the number of critical substations in favor of creating new substations. Such an approach may be more expensive than making additional use of existing substations but the resilience considerations may justify the additional cost. Transmission planners might also consider putting new transmission lines on new rights-of-way rather than adding lines to existing rights-of-way, even though higher costs may result. The Commission should clarify that solutions that are more resilient may be appropriate even if they are more expensive.

Second, transmission owners have an important role to play in ensuring the resilience of the system outside the regional transmission process. The Commission should ensure that transmission owners can incorporate resilience considerations in the planning process for their local transmission and distribution systems. For example, transmission owners need to have the ability to reinvest in their equipment, harden their systems, and create microgrids where appropriate. Moreover, in addition to having access to the DBT, they should also continue to conduct extreme event analysis to guide their planning. They should be allowed to take these actions to reinforce the resilience of their systems even when doing so goes beyond NERC criteria. Such steps are particularly important in areas of the country with critical local infrastructure, such as the Washington D.C. region, densely populated areas or areas with Defense Critical Electric Infrastructure.

IV. FERC Should Pursue Energy Pricing Reform.

Numerous commenters suggest that energy price reforms should play a central role in advancing the Commission's resilience goals.[38] PJM itself has recognized that the current market design is flawed and that because certain units "are not able to set clearing prices, those clearing prices are artificially lower than they should be."[39] Exelon agrees, and has emphasized elsewhere that this clear market flaw must be corrected.[40] And, as PSEG correctly notes, this market flaw does have consequences for resilience: "technologies such as nuclear plants with high operating factors do not receive the proper level of energy market payments which contributes to the economic challenges they face."[41]

Thus, energy price reforms are an important goal for the Commission and the RTOs to pursue expeditiously regardless of whether these reforms are the focus of this resilience docket. In other words, unjust and unreasonable energy market prices should be rectified regardless of whether that is done as part of any resilience matter or on their own. Price formation proceedings are pending at the Commission,[42] and various reforms are at different stages at the Commission and in RTO stakeholder processes. Some proposed changes, such as PJM's fast-start pricing

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[38] *See, e.g.*, Reply Comments of Talen Energy Corporation, Docket No. AD18-7-000 (May 9, 2018) at 2 ("Accurate price signals are critical to a resilient electric grid."); Calpine Comments at 5 ("[A]ll generation resources are under-compensated, potentially resulting in inefficient retirements of generating resources and the failure to invest in needed upgrades or new facilities.").

[39] Comments and Responses of PJM Interconnection, L.L.C, Docket No. AD18-7-000 (May 9, 2018) at 74-75.

[40] Reply Brief of Exelon Corporation, Docket No. EL18-34-000 (Mar. 14, 2018) at 1.

[41] PSEG Comments, at 18.

[42] *See, e.g.,* Final Rule, Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators, 163 FERC ¶ 61,041 (2018) (modifying rules for uplift allocation); *PJM Interconnection, L.L.C.,* 161 FERC ¶ 61,295 (2017) (opening Section 206 proceeding on fast start pricing); Order Directing Reports, Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators, 153 FERC ¶ 61,221 (2015) (requiring RTOs to submit reports on price formation).

proceeding in EL18-34, have completed the comment process and are awaiting a Commission order. Those matters are ready for resolution now, and the Commission should not delay in taking action. The Commission should not wait on the DBT and RTO analyses outlined above in order to continue the process of energy market reform. Those reforms are independently justified on their own merits—ensuring that energy market prices reflect the true cost of serving load.

As part of these efforts, the Commission and the RTOs must incorporate into their analyses the expected environmental impacts (including carbon emissions) of any market reforms. Environmental consequences of power generation are directly related to the severe weather events that are in part the genesis of this proceeding. So, for example, if a region plans to meet its fuel security challenges by retaining resources that burn coal or by incentivizing the addition of oil storage, it will be contributing to the very problem it is trying to solve. Planning a generation system that is resilient must include planning for a system that is both able to withstand interruptions and also does not contribute to interruptions by exacerbating climate change. As the RTOs study their vulnerabilities and propose solutions, and as the Commission reviews any filings, the environmental consequences deserve appropriate weight.

CONCLUSION

The Commission has taken the appropriate first step by opening this resilience docket. It now should complete the process of gathering the information needed to ensure that the markets it oversees remain just and reasonable. In light of significant fuel security risks in ISO-NE, PJM, and elsewhere, the Commission should first work with its coordinate federal agencies to develop the DBT and then require market operators to analyze their risks and submit their plans to address them. The Commission can then move rapidly to adopt the appropriate policy response to reduce or eliminate those resilience risks.

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EXHIBIT A

Exelon Feedback on Valuing Fuel Security Scope

PJM's market rules are not designed to consider, let alone ensure, the fuel security needed to serve the 65 million people in the PJM region or to value fuel secure, resilient resources. PJM has properly identified fuel security as an unaddressed resilience risk that must be further analyzed and addressed through reforms that adequately value the resilience contributions of fuel-secure resources and ensure fuel-security is preserved. Exelon supports PJM fully in this effort.

But PJM's approach is too narrow. Specifically, PJM underestimates the range of threats and the potential duration of critical infrastructure outages (particularly gas transmission facility outages) that the PJM region faces. As a result, any PJM fuel security study based on these underestimated input assumptions will be severely inadequate. Thus, as elaborated (on pages 5 - 9) below, Exelon recommends several enhancements to PJM's study so it reflects all credible and reasonably foreseeable fuel security challenges over foreseeable durations. For example, Exelon recommends that PJM consider long-term pipeline outages and/or underground storage restrictions affecting multiple facilities and pipeline components. Exelon also proposes a baseline scenario from which PJM should calibrate needed market reforms. Further, Exelon suggests modification to the timing of the proposed "phased approach" that PJM plans to undertake, so that critical national security inputs from government agencies regarding threat priorities can be incorporated in a timely manner into PJM's fuel security study. Finally, solving PJM's fuel security challenges may lead to significant environmental impacts if the emissions implications of potential future fleet compositions are not taken into account. Thus, PJM should calculate and make available the environmental costs and impacts of its current resource portfolio during stressed conditions as well as that of the expected portfolio of resources as a result of any potential fuel security solutions. Exelon has attached a report by Dr. Paul Stockton, former Assistant

Secretary of Defense for Homeland Defense and America's Security Affairs, further describing many of these recommendations.

Fuel Security Poses a Significant Resilience Risk

PJM is correct to undertake an analysis of fuel security at this time. PJM's aggregate supply portfolio is quickly transitioning toward an over-reliance upon gas-fired resources that will challenge system resilience and could result in significant hours of unserved energy if multiple natural gas pipelines are interrupted for an extended period of time.[1] In 2005, coal and nuclear resources generated 91% of the electricity on the PJM system. Over time, state and federal policy initiatives aimed at reducing environmental emissions, a wholesale market design that ignores fuel security, technology improvements, and overall economics spurred a shift from coal to natural gas and renewable generation. From 2010 to 2016 in PJM, coal-fired units made up 79% of the megawatts retired, and natural gas and renewables made up 87% of new megawatts placed in service.[2] Recent retirement announcements (including TMI, Beaver Valley, Davis-Besse and Perry) reflect that in excess of 5,000 MW of nuclear resources plan to retire in PJM in the near future. Reflecting further potential financial struggles by nuclear resources, in the 2018 PJM Base Residual Auction, 10.6 GW of nuclear capacity representing 30% of the nuclear capacity in the PJM region did not clear, a 200% increase from the previous year. At the same time, nuclear resources have been the most resilient, fuel-secure resources in PJM, reflecting stellar performance during the 2014 Polar Vortex, the 2017/18 cold snap and other extreme events.

The nuclear resources facing premature retirement will be replaced with natural gas resources and its "just-in-time" fuel delivery system with very finite back up capability. This trend poses significant common mode failure risks that PJM does not consider as part of its current resource adequacy

[1] ICF, *The Impact of Fuel Supply Security on Grid Resilience in PJM- Final Report*, *Page 2* (June 8, 2018)
[2] PJM Interconnection, *PJM's Evolving Resource Mix and System Reliability*, Page 9 (March 30, 2017)

construct. Numerous reliability and resilience experts have recently expressed concern with this trend. For example, NERC points out in its recent Summer Assessment report that "the growing reliance on natural gas continues to raise BPS reliability concerns."[3] PJM has found that a single gas pipeline in the PJM region serves more than 11,000 MW of generation,[4] and a recent study by ICF examining generation clusters in PJM and New York found that 18,000 MW[5] of generation in PJM alone would be at risk from an extended pipeline outage[6]—all in the most densely populated parts of the Eastern United States.

Throughout the history of the industry, system operators have avoided an over-reliance on one resource type for good reason - system resilience requires fuel security that is fostered by fuel diversity. For example, in a report on the coal strike of 1977-78, both the diversity of generation fuel types and diversity of fuel supply sources were cited as major factors in permitting the industry to minimize the adverse impact of the strike.[7] When system operators have failed to account for fuel security, impacts have been dramatic for consumers. For example, during a 1994 cold spell, non-firm gas supply was interrupted resulting in PJM and Virginia Power curtailing firm electric customers to maintain system reliability, and that was at a time that the system was much less reliant on natural gas than it is today.[8]

As described above, absent swift action to value fuel security, the trend of fuel secure resource retirements will continue, and they will be replaced predominantly with natural gas resources reliant

[3] NERC's 2018 Summer Reliability Assessment, Page 6. *See also* National Academics of Sciences, Engineering, and Medicine, *Enhancing the Resilience of the Nation's Electricity System,* page 82 (2017) (finding that "constraints in natural gas infrastructure have resulted in shedding of electric load, and growing interdependency of the two systems poses a vulnerability that could lead to a large-area, long duration blackout.")
[4] PJM Transmission Expansion Advisory Committee, Reliability Analysis Update (Sept. 14, 2017), http://pjm.com/-/media/committees-groups/committees/teac/20170914/20170914-reliability-analysis-updates.ashx.
[5] Part of a total of 27,000 MW in the whole Mid-Atlantic region.
[6] ICF, *The Impact of Fuel Supply Security on Grid Resilience—Final Report,* Page 1 (June 8, 2018)
[7] NERC, *The Coal Strike of 1977-78: Its Impact on Electric Bulk Power Supply in North America* (May 30, 1978)
[8] Report by the Blue Ribbon Task Force to the NERC Board of Trustees, *Report on Electric Utilities' Response to the Cold Wave of January 1994* (April 11, 1994)

upon gas pipeline delivery and storage as well as finite back up fuel sources. PJM's analysis should carefully consider the limits of such a portfolio during high-impact, low-frequency events caused by both weather and man-made contingencies and determine the needed fuel security constraints to appropriately mitigate the tremendous risks inherent during such scenarios. The grid is changing faster than anyone anticipated, and the consequences of inaction are permanent, particularly when it comes to nuclear resource retirements. Further, the grid and its vulnerabilities are well understood by our adversaries.

PJM's Proposed Phase I Analysis Is Too Narrow

Performing a robust fuel security analysis, as proposed by PJM in Phase I, is the first and most critical step in the entire PJM initiative. PJM should commence the Phase I analytics immediately in order to define a reasonable baseline scenario that can be used as the basis for taking action to ensure resilience starting with the 2019 Base Residual Auction. This baseline scenario can be modified later to the extent that more information becomes known, but PJM should not delay in moving to develop its initial version.

However, PJM's approach as drafted in its April 30, 2018 scoping document is too narrow and will not sufficiently inform the incremental resilience needs of PJM customers. PJM proposes to extend the recent experiences of the Polar Vortex and the recent Cold Snap to simulate the occurrence of high-impact, low-frequency events, employing a 12-14 day event duration assumption. PJM will stress-test the system under various fuel supply disruption scenarios to understand reliability outcomes resulting from the current capability of local onsite fuel and back-up fuel. However, constraining the study assumptions to the severity and duration of recent historical weather events is the equivalent of what the government and the airline industry did on September 10, 2001 and fails to reflect all realistic potential scenarios that PJM could face. As Dr. Stockton suggests, PJM needs to modify its disruption

scenarios and stress testing in both scope and duration taking into account not just weather events that have already transpired, but realistic scenarios caused by manmade interruptions. As elaborated below, Dr. Stockton generally concludes that since adversaries would attack more than one pipeline, PJM should expand the scope of its study to consider multiple simultaneous pipeline outages and/or restrictions on storage and assume that repair of such infrastructure could take many months. For example, the 2016 Spectra Pipeline explosion in Western Pennsylvania took six months to repair under ideal non-winter, blue sky conditions. According to Spectra, this event was caused by corrosion near a weld that progressed faster than usual causing the pipeline to fail, and could have been far worse if caused by a calculated attack coupled with a cyber-attack during an extreme weather event.[9] A poorly defined study will lead to a poorly defined solution and continued vulnerabilities and exposure to risk that threaten the health and safety of the consumers throughout PJM, as well as national security.

Exelon's Proposed Modifications To The Phase I Analysis

Dr. Stockton's recommendations are set out in the attached memo, *Valuing Fuel Security: Recommendations on Study Scope and Simulated Disruptions*. Dr. Stockton recommends the scope of the analysis be expanded to include multiple pipelines and/or storage facilities and recommends extension of the duration of the disruption scenarios to comport with man-made threats.

To this end, Exelon suggests that PJM should consider the following principles when developing the Phase I analysis.

- Evaluate a full 90-day winter. While the specific events (extreme weather and man-made infrastructure disruptions) that PJM analyzes may not last the whole winter, extremely stressful events can cause later resilience issues even after the event itself

[9] Debra Erdley, *6 Months After Salem Township Explosion, Spectra Energy Has Gas Pipelines Running*, TribLive.com (Nov. 18, 2016), http://triblive.com/local/westmoreland/11496039-74/pipeline-spectra-explosion.

has passed. For example, if the collective oil inventory is depleted in a weather event, the system may have difficulty meeting load later in the season even with more normal conditions due to lack of oil resource availability. A Navigant study confirms that, in the PJM region, more than 50% of dual-fuel and oil-only resources would be offline due to a lack of fuel after four days of full-load operation, and nearly 80% would be offline after seven days.[10] Efforts to refill oil tanks during a cold winter present numerous additional challenges. Thus, PJM's analysis should cover the full winter, even if the individual disruptions are shorter than the entire winter.

- Develop a "stress weather" scenario that combines a multi-week extreme cold snap with an overall colder-than-average winter. Resilience issues can arise from a multi-week extremely cold period like that experienced this past winter, but can also arise from the cumulative effect of an overall cold winter, with multiple cold periods. In performing the full winter analysis we suggest above, PJM should develop a full-winter "stress weather" scenario that includes a 14-day extreme period with temperatures and wind-chill comparable to the 2013/14 Polar Vortex, but also includes overall average temperatures over the course of the entire winter consistent with the coldest historic winter.
- Examine infrastructure disruption scenarios lasting at least 90 days. PJM's proposal to limit the duration of the analysis to at most 14 days is not adequate to describe the potential duration of infrastructure disruptions. Major pipeline disruptions can, and have in the past (such as the recent Spectra disruption discussed above), lasted up to six months. Thus, a full-winter, 90-day disruption is quite plausible and an appropriate stress case to consider. A full winter-long disruption is also consistent with the duration

[10] Navigant Consulting, Inc., *PJM Liquid Fuel Survey and Research Results and Recommendations* (Apr. 25, 2018) ("PJM Liquid Fuel Survey") attached to Exelon's May 9, 2018 Response in FERC Docket No. AD18-7.

ISO-New England utilized in developing its recent Operational Fuel Security analysis. While it may be appropriate to also consider shorter-duration infrastructure disruption events (such as 15, 30, and 60 days), a full winter-long disruption should serve as the baseline scenario used to develop a market-base resilience solution.

- Consider broader gas system disruptions when developing infrastructure stress events. As Dr. Stockton elaborates in his attached report, gas system disruptions that should be studied include multiple pipeline outages as well as disruptions of other gas system components such as storage facilities, network connected components and other facilities. While a range of potential infrastructure disruption scenarios are possible, in developing the baseline stress scenario, PJM should consider the most disruptive gas contingency in terms of gas generation affected. A recent study conducted by ICF showed that an extended pipeline outage would put 18,000 MW of generation in PJM at risk.[11] In follow up work by ICF that included a plausible amount of premature nuclear generation retirements in PJM and loss of multiple gas pipelines for a long duration, ICF found there would be as much as 280 hours of unserved energy which would impact customers, businesses and commu**n**ities.[12]
- Consider the effect of priority heating demand on any gas contingency. LDC heating demand typically has priority over power generation demand. Because of this, a full disruption of a given pipeline is not necessary to fully cut off the supply of gas for downstream power generators. Accordingly, in modeling its infrastructure development scenarios, PJM should assume that gas generators downstream of the gas contingency have no access to gas for the duration of the disruption, due to being pushed out by higher priority heating load. EIA data over the past two winters (Dec-Jan) confirms this

[11] ICF, *The Impact of Fuel Supply Security on Grid Resilience in PJM-Final Report*, Page 2 (June 8, 2018)
[12] ICF, *The Impact of Fuel Supply Security on Grid Resilience in PJM-Final Report*, Page 2 (June 8, 2018)

point; it shows that with between 25% and 40% of gas generation resources unavailable, there may be ”no gas for electric generation” due to other requirements like home heating load. [13] Similarly, a 2014 Eastern Interconnection Planning Collaborative report showed that about 38.7 GW of the gas-capable generation in PJM is located behind LDC citygates, the points at which interstate or intrastate pipelines transfer gas to the local delivery system.[14]

- Evaluate simultaneous weather and man-made infrastructure/cyber events. The highest stress resilience scenarios arise when extreme weather co-occurs with an infrastructure disruption. Therefore, any baseline scenario should jointly consider the extreme weather scenario as occurring simultaneous with a high-impact, 90-day infrastructure disruption scenario.
- Evaluate all scenarios against a range of future generation portfolios. Exelon agrees with PJM’s proposed generation portfolio scenarios (“base,” “stressed” and “high stressed”). Any weather and infrastructure disruption scenario should be evaluated under each generation portfolio.
- Consider scenarios that assume no “help” from other regions as those other regions may be struggling themselves to serve their load and have no excess to spare.
- Consider a summer stress scenario. Considerable attention has been devoted to winter periods, but given changes in summer load and other factors, it would be prudent for PJM to also consider a high-stress summer scenario.

Given these principles, Exelon proposes the following scenario as a reasonable baseline for developing a resilience solution.

[13] EIA, Natural Gas Consumption by End Use Data, Release Date 05/31/2018
[14] Eastern Interconnection Planning Collaborative, *Gas-Electric System Interface Study Existing Natural Gas-Electric System Interfaces*, Page 19 (April 4, 2014).

- A "stress weather" winter, combining a 14-day period of extreme cold and wind chill (consistent with those experienced during the 2013/14 Polar Vortex) with full-winter average temperatures consistent with the most extreme winter over history.
- A significant 90-day disruption of the pipeline system entering Eastern PJM that is sufficient to cause all gas generation within MAAC to have no access to gas for the entire winter, given the priority of heating load coupled with extreme winter temperatures.
- Generator forced outages consistent with those observed under recent winter stress conditions.
- Modeling of backup liquid fuel capability that considers expected fleet storage levels and limited re-supply capability especially as would occur during winter stress conditions and/or during a long-term outage where secondary supply impacts (e.g., refinery outages as a result of insufficient electric service) could exacerbate re-supply problems.
- Evaluate this scenario using PJM's proposed "base," "stressed," and "high-stressed" generation portfolios. The high stressed generation portfolio should not assume that only nuclear resources that did not clear will retire, rather it should assume that all financially stressed nuclear resources will retire.[15]

This scenario combines plausible extreme weather and man-made infrastructure disruption scenarios consistent with observed historical events. This scenario is consistent with the guidance provided by Dr. Stockton in his attached memo and aligns with the first manmade disruption scenario he recommends

[15] While failing to clear a capacity auction is a clear indication of likely financial stress, some nuclear resources that clear may also be under financial stress and thus candidates for retirement. *See* ICF*, The Impact of Fuel Supply Security on Grid Resilience in PJM – Final Report* (June 8, 2018)

that proposes PJM examines a reduction of a realistic percentage of delivery capability on particularly constrained portions of pipelines and/or storage facilities in the PJM region.[16]

While this scenario should serve as the baseline for any solution, PJM should consider a range of other scenarios varying along the various identified dimensions (such as weather; number, impact, and duration of infrastructure/cyber disruptions; availability of liquid fuel resupply) to further inform the stakeholder discussion. Consistent with Dr. Stockton's recommendation, PJM should also evaluate a realistic but extreme contingency scenario that disrupts 80% of the natural gas pipeline infrastructure across the entire PJM region for six months. This scenario represents the severe threat that a major state adversary might pose. This scenario should be conducted using the same assumptions as described above for the baseline scenario.

Exelon Recommends that PJM Coordinate with Federal Agencies on Resilience Threats Now

PJM's "Phase III: Ongoing Coordination" is a critical part of the overall success of this effort. While PJM should immediately begin modeling Phase I as suggested by Exelon, PJM must have additional input from DOD, DHS, FERC, and DOE to assess the level of fuel security necessary to protect our Nation or its studies will miss critical threats. PJM must consult with and incorporate the recommendations of the DOE and other national security organizations in its modeling scenarios now. Dr. Stockton also highlights the need for PJM to reach out to FERC, DOE, and other Federal partners for a near-term review of the disruption scenarios he recommends.[17] Over the long term, PJM's effort should be informed by a design-basis threat (DBT) from the federal government to identify resilience threats and provide a baseline against which PJM can measure its efforts at creating a resilient grid. While a specific DBT may not be available in the first phase due to timing, PJM should consult with the

[16] Paul Stockton, *Valuing Fuel Security: Recommendations on Study Scope and Simulated Disruptions*, Page 2 (May 29, 2018).
[17] Paul Stockton, *Valuing Fuel Security: Recommendations on Study Scope and Simulated Disruptions*, Page 6 (May 29, 2018)

organizations to obtain initial feedback on national security threats to consider in the first year it conducts its analysis, and thereafter, PJM should build a model sufficiently robust to include a DBT once established and share with the DOE, on a classified basis, the threats that can debilitate the PJM system.

PJM Should Provide Transparency on Environmental Impacts

For each of the scenarios that PJM models, it should provide transparency into the environmental and emissions costs that will result. Stakeholders should be provided a comparative analysis that shows the current emissions profile in PJM and changes to that profile under the various scenarios that are being analyzed in PJM's Valuing Fuel Security effort.

New England's fuel security challenges are well known. As a result of retirements of fuel secure resources and increased reliance on dual fuel natural gas-fired generators, that region must turn to burning oil when the system is stressed. This past winter, two million barrels of oil were burned in less than two weeks—more than double the amount burned in the region the entire year before. The carbon and other air pollution impacts of those circumstances are troubling for two reasons. First, they challenge the ability of those regions to meet their emissions goals now and in the future. Second, they stand to exacerbate the severe weather events that are interrupting electric service to customers in the first place.

In PJM, this risk is even more significant. If PJM plans to meet its fuel security challenges by retaining resources that burn coal or by incentivizing the addition of oil storage, it will be contributing to the very problem it is trying to solve. Planning a generation system that is resilient must include planning for a system that is both able to withstand interruptions and also does not contribute to interruptions by exacerbating climate change. To prevent future instances like this, PJM must include within its analysis an evaluation of the emissions implications of greater reliance on coal and dual fuel resources during periods of natural gas disruption.

Feedback on Next Steps

Exelon is encouraged by PJM's willingness to work with stakeholders on this important resilience issue. We support PJM's effort to prioritize this issue of critical importance and push for a resolution in advance of the May 2019 Base Residual Auction. To that end, Exelon recommends that PJM incorporate Exelon's suggested improvements into its proposal. In addition, PJM should provide updates at future MRC meetings, and request that PJM also provide regular milestone reports on the progress of each phase. Such reports will enable stakeholders to provide additional feedback on the analysis contemporaneous with the undertaking, instead of only at the end when it is too late for PJM to act on any suggestions. Exelon also requests that PJM provide stakeholders with additional detail on the specifics behind the disruptions to fuel delivery systems that will be analyzed, and the composition of the three portfolios that PJM will be analyzing. We look forward to engaging with PJM on these efforts.

SONECON

VALUING FUEL SECURITY: RECOMMENDATIONS ON STUDY SCOPE AND SIMULATED DISRUPTIONS

Paul Stockton
June 8, 2018

PJM's study on *Valuing Fuel Security* is timely and urgently needed. PJM and its member companies serve many thousands of facilities vital for national defense, the U.S. economy, and public health and safety. That makes the region's grid – and the fuel supplies on which it depends – potential targets for cyber and physical attacks.

The study provides a strong foundation to assess these threats to fuel supplies. In an April 30, 2018 message outlining the study, PJM President and CEO Andrew L. Ott noted that the study will "simulate disruptions to fuel systems that could be the result of credible extreme events such as coordinated physical or cyber-attacks, extreme weather, etc."[1] Developing weather contingencies to study will be easy; ample historical data is available to help do so. No equivalent basis exists for developing contingencies for cyber or physical attacks. Moreover, as PJM has previously emphasized, RTOs face obstacles in acquiring the government data they need to assess cyber threats.[2]

But it would be a grave mistake to do what is easy and focus the study solely on extreme weather. Coordinated cyber or physical attacks can create fuel disruptions far more catastrophic that those caused by the 2018 bomb cyclone or any other severe weather events to date. The Department of Energy (DOE) warns that cyber threats are becoming increasingly severe, and that the risks of physical attacks on natural gas systems merit special concern.[3] PJM is making a unique (and uniquely valuable) contribution to national security and grid resilience by structuring the study to encompass manmade threats.

This letter offers three recommendations to support the study. First, to support Phase I of the study, I propose specific disruption scenarios for the study to employ. It is not credible that a potential adversary such as Russia or China will attack a single pipeline and/or storage facility. If those nations are going to strike the U.S. energy sector, and risk incurring an overwhelming military response, they are much more likely to attack as many pipelines and/or storage facilities

[1] Andrew L. Ott (letter to PJM Members), April 30, 2018, http://www.pjm.com/-/media/committees-groups/committees/mrc/20180508-special/20180508-ott-fuel-security-member-letter.ashx.
[2] PJM Interconnection, L.L.C, "COMMENTS AND RESPONSES OF PJM INTERCONNECTION, L.L.C.," *Response to Grid Resilience in Regional Transmission Organization and Independent System Operators* (AD18-7-000), March 9, 2018, p. 52.
[3] Department of Energy, *Multiyear Plan for Energy Sector Cybersecurity*, March 2018, p. 3.

as possible to disrupt the flow of power to defense installations and other national security-related assets. Nor is it credible that disruptions caused by manmade threats will last 14 days or less. If adversaries conduct coordinated high explosive attacks against critical gas infrastructure, many months could be required to repair pipelines and restore the flow of gas. Consistent with the study's proposed structure, PJM should use two disruption scenarios to assess manmade risks to fuel security:

- Reduction of a realistic percentage of delivery capability on particular constrained portions of pipelines and disruption of storage facilities in the PJM region: assume that adversaries interrupt the flow of gas on two major pipelines for three months, including in the coastal region. This scenario constitutes a limited threat to fuel supplies.

- Realistic but extreme contingency: assume that adversaries disrupt 80 percent of the gas pipelines in the PJM region as a whole for six months. This scenario represents the severe threat that a major state adversary might pose, reflecting the outcome of combined high explosive and cyberattacks on all major pipelines in the region, potentially combined with attacks on gas storage facilities and other critical gas infrastructure components.

The most likely way that adversaries could create an 80 percent disruption would be to exploit common failure modes in the natural gas systems that serve the PJM region. As will be discussed later in this study, adversaries may be able to disrupt widely-distributed gas system components in a single cyberattack, by exploiting supply chain vulnerabilities and related threat vectors which DHS recently attributed to Russian actors.[4] PJM may also want to adopt a sub-regional approach to model realistic but extreme contingencies. For example, in certain coastal portions of the PJM service area, physical attacks on a small number of major pipelines could disrupt 80 percent of that sub-region's pipeline capacity and potentially cause disruption of storage for extended periods.

PJM may find it useful to model additional contingencies as well. However, given the critical military installations and other national security facilities in the PJM service area, this area will be *ground zero* if Russia, China, or other potential adversaries launch comprehensive attacks to disrupt the flow of natural gas for power generation. Such attacks could also spread disruptions to New York and other regions that are densely populated and vital to the U.S. economy. The realistic but extreme scenario proposed in this paper will be essential to assess fuel security against such threats.

Second, the PJM study approach notes that Phase I will incorporate locational variations in system infrastructure, such as the proximity of generators to gas production facilities co-located with gas fields in the Marcellus. This granularity will greatly improve the accuracy of company-specific models. However, we should also assume that in a comprehensive attack on gas flows, adversaries will target all types of infrastructure components that might be vulnerable to high-consequence cyber or physical attacks, ranging from key nodes in gathering and refining

[4] "Alert (TA18-074A): Russian Government Cyber Activity Targeting Energy and Other Critical Infrastructure Sectors," *United States Computer Emergency Readiness Team*, last revised March 16, 2018, https://www.us-cert.gov/ncas/alerts/TA18-074A.

facilities to storage facilities. Modeling initiatives in Phase I should account for the risk of such multi-component attacks.

My third recommendation is that PJM launch Phase III of the study ("Ongoing Coordination") at the same time that it begins executing Phase I. The first phase involves identifying system vulnerabilities and developing fuel security criteria to assess them. Given the severity of threats to fuel resilience and the length of time the government requires to identify security needs in the PJM footprint, PJM should not delay work on this first phase of the study until such information is available. The third phase calls for collaboration with government agencies to address concerns related to cyber and physical security. However, precisely because so much time may be required to reach government-industry agreement on threat data priorities and sharing mechanisms, PJM should immediately reach out to FERC and other appropriate agencies to begin that consensus-building process. The analysis that follows offers specific recommendations on how to structure that coordination.

I. DISRUPTION SCENARIOS FOR PHASE I

PJM defines fuel security as "the ability of the system's supply portfolio, given its fuel supply dependencies, to continue serving electricity demand through credible disturbance events, such as *coordinated physical or cyberattacks* or extreme weather that could lead to disruptions in fuel delivery systems, which would impact the availability of generation over extended periods of time."[5]

Manmade and weather threats to fuel resilience are not mutually exclusive. Indeed, as Phase I goes forward, PJM may want to consider adding a dual-disruption scenario: i.e., cyber or physical attacks occurring in the midst of a severe, extended winter freeze, when heating demand and risks of gas curtailment to power generators would be most extreme.

Initially, however, PJM should develop manmade disruption scenarios that help scope fuel security vulnerabilities against high-capability nation states (Al-Qaeda and other terrorist organizations will constitute lesser included cases). Two factors will be most important in developing disruption scenarios and assessing their impact on power generation: the number of pipelines and/or storage facilities that adversaries will be able to disrupt, and how long fuel interruptions will last.

A. NUMBER OF PIPELINES DISRUPTED AND STORAGE FACILITIES CONSTRAINED

Threat assessments by the Transportation Security Agency (TSA) provide the starting point for scoping the threat to pipelines, storage facilities, and other gas infrastructure components in the PJM region. TSA has regulatory authority for pipeline security under P.L. 107-71 and P.L. 110-53 (though TSA relies on voluntary industry compliance with the agencies' security guidance, versus the mandatory relatability standards that NERC issues for the bulk power system) and provides a Pipeline Threat Assessment (For Official Use Only).[6] However, TSA has not updated

[5] PJM Interconnection, LLC, *Valuing Fuel Security*, April 30, 2018, p. 1.
[6] Aviation and Transportation Security Act, Public Law 107-71, *U.S. Statutes at Large* 115 (2001); Implementing

that document since 2011. DOE and the Department of Homeland Security have provided more recent assessments. Both Departments have found that cyber threats to electric and natural gas systems are rapidly intensifying.[7] My May 10, 2018 testimony to FERC examines these threats.

U.S. reliance on natural gas for power generation has been increasing along with adversary capabilities to attack pipelines and storage sites in the PJM region and beyond. The net result: according to Bruce Walker, Assistant Secretary of Energy for Electricity Delivery and Energy Reliability, this "increased dependency on our pipelines" has "effectively doubled and tripled the amount of critical infrastructure that is necessary for us to protect predominantly on a cyber front but also from a physical security front."[8]

The expansion of natural gas infrastructure in the Marcellus and other areas can benefit fuel security. Where redundant pipeline systems exist to serve power generators, the loss of a single pipeline may have little or no effect. But other portions of the PJM region have much less gas infrastructure redundancy. In coastal regions of New Jersey and Maryland, for example, the loss of even two major pipelines and/or storage facilities could have major effects on power generation. Accordingly, as PJM already envisions, it will be important to employ disruption scenarios to identify fuel security risks that could affect specific locations of the system.

The question remains of how many disruptions of pipelines and other gas system components these scenarios should entail. It is (barely) conceivable that in an escalating crisis, Russia or another potential adversary might attack a single pipeline or storage site to demonstrate their ability to hold the gas transmission system at risk, and/or threaten further attacks unless the United States acceded to whatever demands they were making. But it is far more likely that adversaries will attack on a larger scale. If a crisis with the United States is so dire than an adversary will launch cyber or physical attacks on gas systems, despite the risk of provoking an overwhelming response by U.S. forces, we should expect that the enemy will seek to deal us a crippling blow.

For cyberattacks, the actual number of pipelines in the PJM footprint that adversaries will be able to disrupt will vary with their ability to exploit common modes of failure, and conduct simultaneous attacks on multiple pipelines in the region. Supply chain corruption poses an especially significant challenge in this regard.[9] If adversaries are able to corrupt the development

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Recommendations of the 9/11 Commission Act, Public Law 110-53, *U.S. Statutes at Large* 121 (2007); Peter Behr and Blake Sobczak, "TSA to expand gas pipeline cybersecurity oversight," *E&E News*, December 22, 2017, https://www.eenews.net/stories/1060069743; Transportation Security Agency, *Pipeline Threat Assessment*, January 18, 2011.

[7] Department of Energy, *Multiyear Plan for Energy Sector Cybersecurity*, March 2018, p. 3; Transportation Security Administration, *Pipeline Security Guidelines*, March 2018, p. 1.

[8] Bruce Walker, (speech delivered at the GridWise Alliance 2018 Spring Group Meetings, Chicago, IL, May 11, 2018).

[9] In July 2016, FERC directed NERC to develop a Supply Chain Risk Management reliability standard for BES entities, which is currently available (Standard CIP-013-1). NERC intends the standard to "mitigate cyber security risks to the reliable operation of the Bulk Electric System (BES) by implementing security controls for supply chain risk management of BES Cyber Systems." See: North American Electric Reliability Corporation, *CIP-013-1 – Cyber Security - Supply Chain Risk Management*, July 2017, p. 3, https://www.nerc.com/pa/Stand/Project%20201603%20Cyber%20Security%20Supply%20Chain%20Managem/CIP

and production process for widely-used gas system software and hardware components, they could gain the ability to later sabotage or covertly control those components, and attack multiple pipelines at the same moment. Doing so would cause common mode failures, disrupting power generation over wide areas. Conducting special forces-type physical attacks on multiple compressor stations, storage facilities, and pipelines would entail greater coordination and pre-attack planning challenges.[10] However, because of the massive damage that vehicle-borne improvised explosive devices (VBIEDs) or other kinetic attacks could create,[11] adversaries seeking to maximize disruption to power generation will have strong incentives to conduct such attacks against critical gas infrastructure nodes.

Given the variations in adversary capabilities to conduct such large scale cyber and physical attacks, PJM should consider employing credible high- and low-threat scenarios of cyber and physical attacks. At the low end, the disruptive scenario should assume that adversaries interrupt the flow of gas on two major pipelines. At the higher end, reflecting the risk of common mode failures *combined* with carefully targeted attacks using high explosives, a "realistic but extreme" contingency should reflect the disruption of 80 percent of major pipelines in the PJM region, as well as severe disruptions in gas storage.

B. DURATION OF FUEL INTERRUPTIONS

The impact of pipeline system attacks on power generation will also depend on how long gas interruptions last. From a cyber perspective, a primary threat for extend-duration interruptions will come from Advanced Persistent Threats hidden in gas system networks and components, which – unless entirely eradiated – will launch repeated attacks based on timing or system conditions.[12] However, physical attacks offer special risks of extend gas supply disruptions. Attackers have frequently used high explosives against gas pipelines in the Middle East and elsewhere to halt gas flows and require extensive, time-consuming repairs.[13] Fortunately, no such attacks have yet occurred in the United States. But terrorists have employed truck bombs with tons of explosives against other U.S. targets in Oklahoma City and beyond all too often.

Even corrosion-induced pipeline failures can take many months to repair. In the case of the 2016 Spectra pipeline explosion, for example, repairs took six months to complete.[14] Gas companies would no doubt seek to accelerate the restoration of service if the United States were in the midst

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-013-1_Clean_071117.pdf. FERC issued a Notice of Proposed Rulemaking proposing to approve this standard with some additional requirements. *See* Supply Chain Risk Management Reliability Standards, 162 FERC ¶ 61,044 (2018). Without similar strategies for natural gas systems, however, potential supply chain vulnerabilities that could have cascading effects in the Bulk Power System remain.

[10] Mark Galeotti, "The Three Faces of Russian Spetsnaz in Syria," *War on the Rocks*, March 21, 2016, https://warontherocks.com/2016/03/the-three-faces-of-russian-spetsnaz-in-syria/.

[11] Department of Homeland Security and National Academy of Sciences, *IED Attack: Improvised Explosive Devices*, July 8, 2015, https://www.dhs.gov/xlibrary/assets/prep_ied_fact_sheet.pdf.

[12] Homeland Security Advisory Council, *Final Report of the Cybersecurity Subcommittee: Part I—Incident Response*, June 2016, p. 7.

[13] "IS-linked militants claim attack on Sinai pipeline to Jordan," *Middle East Eye*, January 8, 2016, http://www.middleeasteye.net/news/linked-militants-claim-attack-sinai-pipeline-jordan-2114845158.

[14] Debra Erdley, "6 months after Salem Township explosion, Spectra Energy has gas pipelines running," *Tribune Review*, November 18, 2016, http://triblive.com/local/westmoreland/11496039-74/pipeline-spectra-explosion.

of a national security crisis. However, multi-point physical attacks would create unprecedented challenges for restoring gas flows. The Spectra repair operation took place in blue sky conditions. Efforts to repair gas systems after attacks by Russia or China would need to go forward in a much more challenging environment, especially if the electric grid and communications systems were affected as well. A truck bomb carrying tons of high explosives would create damage far more extensive than in the Spectra incident or any previous U.S. pipeline failure – potentially over multiple, carefully-selected sites in the PJM region.

As with assumptions on the number of pipelines and/or storage facilities that an adversary will attack, PJM should consider adopting low- and high-end estimates of gas interruptions, and combine those risk factors into two consolidated disruption scenarios. The low could assume that adversaries will halt the flow of gas on two major pipelines for 3 months. The higher end "realistic but extreme" scenario would posit the disruption of 80 percent of the major pipelines including storage facilities in the PJM region for 6 months.

C. ATTACKS ON MULTIPLE TYPES OF SYSTEM COMPONENTS

PJM's proposed study approach for Phase I emphasizes the need for the stakeholder process to account for local variations in gas infrastructure and the resulting implications for fuel security. The proposal notes that generation located "on top of a Marcellus shale field does not face the same fuel security issues as a generator more distant from supply and connected to a lateral pipeline served by a single natural gas distribution company."[15] Accounting for such variations will greatly improve model accuracy.

However, as these system-specific modeling efforts go forward, it would be a mistake to assume that adversaries will only attack pipelines and the compression stations that serve them. The NERC *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System* (November 2017) notes that gas storage facilities and other gas infrastructure components are critical for enabling the electric industry to meet its load-serving obligations.[16]

Industrial control systems and other network-connected electronic devices and control mechanisms are embedded across many of these gas system components, from production, gathering, and processing facilities to local distribution company infrastructure. All such connected systems may be vulnerable to cyberattacks or supply chain exploitation (including the introduction of corrupted software though Russian threat vectors recently identified by DHS).[17] Depending on the configuration of specific gas systems, physical attacks against crucial but

[15] PJM Interconnection, LLC, *Valuing Fuel Security*, April 30, 2018, p. 3.
[16] North American Electric Reliability Corporation, *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruption on the Natural Gas System*, November 2017, p. *vii*.
[17] "Alert (TA18-074A): Russian Government Cyber Activity Targeting Energy and Other Critical Infrastructure Sectors," *United States Computer Emergency Readiness Team*, last revised March 16, 2018, https://www.us-cert.gov/ncas/alerts/TA18-074A.

unprotected system components could also produce long-term disruptions to fuel supplies for power generation.

The net result: factors such as generator proximity to the Marcellus shale field may not automatically translate into reduced vulnerability. As location-specific modeling goes forward, Phase I should account for the risk of attacks on multiple types of gas system components, especially if they offer adversaries alternative and more efficient means of interrupting fuel flows than by attacking pipelines alone.

II. ONGOING COOPERATION: ADVANTAGES OF AN EARLY LAUNCH FOR PHASE III

The study overview notes that "PJM anticipates overlap between phases" as the initiative goes forward. While Phase I should be initiated as soon as possible, PJM should also consider a rapid start for the "Ongoing Coordination" called for in Phase III.

PJM has already found that "There are obstacles to obtaining information necessary to assess cyber security threats because RTOs can only base their threat assessments on open source information and certain classified intelligence, but the information from classified sources is limited and does not provide a full and complete understanding needed to detect and respond to cyber-attacks."[18] PJM similarly emphasized the need for Federal support on identifying and assessing risks: "there needs to be a process for vulnerability threat verification. The Commission needs to provide intelligence and metrics to apply to resilience vulnerability and threat analyses, such that they can then guide and anchor subsequent RTO planning, market design, and/or operations directives. Overall there needs to be better information made available to the RTOs on the above-identified risks to enable the RTOs to assess the risks. This information could be supplied from a wide range of federal agencies and interdependent systems."[19]

Phase III should be structured to fill these gaps to support fuel security assessments for both cyber and physical threats. Ideally, PJM could reach out to FERC, DOE, and other Federal partners for a near-term review of the disruption scenarios provided in this paper. However, over the longer term, PJM should collaborate with these partners to develop a more holistic design basis threat to assess and mitigate gaps in grid resilience.

Government assistance in developing a design basis threat will be especially important for incorporating national security considerations into fuel security assessments. Assistant Secretary Walker recently stated that "I don't know that the RTOs or NERC have the visibility or proposer information to determine if something is a national security issue." Indeed, "with the various

[18] PJM Interconnection, L.L.C, "COMMENTS AND RESPONSES OF PJM INTERCONNECTION, L.L.C.," *Response to Grid Resilience in Regional Transmission Organization and Independent System Operators (AD18-7-000)*, March 9, 2018, pp. 52-3, http://pjm.com/-/media/documents/ferc/filings/2018/20180309-ad18-7-000.ashx.

[19] PJM "COMMENTS AND RESPONSES OF PJM INTERCONNECTION, p. 32

intelligence agencies we have throughout the federal government" as well the Department of Defense, "we have different information" than RTOs and NERC.[20]

As PJM moves forward in the Phase III process, it will be essential to build a secure process so that this government information can help guide PJM fuel resilience assessments. PJM and its member companies serve a broad array of military installations and other facilities vital to national security, and are already taking aggressive measures to ensure these facilities have the power they require. The Valuing Fuel Security study offers a timely and much-need opportunity to further reinforce such resilience. Basing PJM's analysis on realistic, credible assessments of the threat is a prerequisite for ensuring that the initiative succeeds.

[20] Gavin Bade, "DOE's Walker: National Security Assessment Broader than Grid Reliability, Utility Dive, April 20, 2018, https://utilitydive.com/news/does-walker-national-security-assessment-broader-than-grid-reliability/521852/

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PSEG Services Corporation

September 6, 2017

VIA ETARIFF

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: PSEG Keys Energy Center LLC
Docket No. ER17-2426-000
Application for Market-Based Rate Authorization and Request for Waivers and Blanket Approvals

Dear Secretary Bose:

On September 1, 2017, PSEG Keys Energy Center LLC submitted an application in the above-captioned matter for market-based rate authorization and request for waivers and blanket approvals. A review of the filing shows the application was not in the XML package submitted through eTariff. Please accept the application included with this filing.

Thank you for your attention to this matter.

Respectfully submitted,

Cara J. Lewis
Cara J. Lewis

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PSEG Keys Energy Center LLC) Docket No. ER17-__-000

APPLICATION FOR MARKET-BASED RATE AUTHORIZATION AND REQUEST FOR WAIVERS AND BLANKET APPROVALS

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] Rules 204 and 205 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission" or "FERC"),[2] and Part 35 of the Commission's regulations,[3] PSEG Keys Energy Center LLC ("PSEG Keys" or "Applicant") hereby requests that the Commission: (1) accept the proposed market-based rate tariff for PSEG Keys; (2) authorize PSEG Keys to sell energy, capacity, and certain ancillary services at market-based rates; (3) grant such waivers and blanket authorizations as the Commission has granted to other entities with market-based rate authorization; and (4) find that a change in status report is not required.[4]

I. COMMUNICATIONS

PSEG Keys respectfully requests that all service and correspondence related to this matter be directed to the following individuals:

[1] 16 U.S.C. § 824d (2012).

[2] 18 C.F.R. §§ 385.204, 385.205 (2011).

[3] 18 C.F.R. Part 35 (2017).

[4] This filing is being submitted independently of the PSEG Companies' Triennial Market Power Update, which is currently pending before the Commission ("December 2016 Triennial Filing") in Docket Nos. ER10-1768-004, *et al*. For convenience, the Triennial Market Power Update is attached as Appendix F. The Triennial Market Power Update also identifies the entities the comprise the PSEG Companies.

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II. DESCRIPTION OF PSEG Keys AND ITS AFFILIATES

A. PSEG Keys

PSEG Keys, a Delaware limited liability company, is a direct subsidiary of PSEG Fossil LLC ("PSEG Fossil"), which is a direct subsidiary of PSEG Power LLC ("PSEG Power"), a direct subsidiary of Public Service Enterprise Group Incorporated ("PSEG"), a publicly traded company. PSEG Keys is currently constructing a new natural gas-fired, power plant in Prince George's County, Maryland (the "PSEG Keys Energy Center"). The PSEG Keys Energy Center, a 755 MW combined cycle plant, is targeted to be in commercial operation by June 1, 2018. The Maryland electricity ratepayer is not subsidizing or guaranteeing any portion of the revenue of the plant. The plant will participate in the capacity and energy markets established by PJM Interconnection, L.L.C. ("PJM") for wholesale electric generators. All of the output of the PSEG Keys Energy Center will be sold to PSEG Keys' affiliate, PSEG Energy Resources & Trade LLC ("PSEG ER&T").

B. PSEG Keys's Affiliates

1. Public Service Electric and Gas Company ("PSE&G")

PSE&G is a public utility operating company engaged primarily in the transmission of electricity, and the provision of gas and electric distribution service in the State of New Jersey. During the study period, PSE&G owned less than 140 MW of solar

generation, 8 MW of Energy Efficiency and 91 MWs of Demand Response but otherwise did not own or operate any electric generation facilities. PSE&G is a member of the PJM, a FERC-approved Regional Transmission Organization, and has made all of its transmission facilities available for open access transmission service pursuant to the PJM Open Access Transmission Tariff ("OATT") administered by PJM. PSE&G is authorized to sell power at market-based rates and makes wholesale sales falling within several different categories, as described below.

Non-utility generation ("NUG") output. PSE&G's NUG output expired in 2015 and 2016 pursuant to the terms of the NUG contracts. PSE&G currently has no further NUG obligations, other than 0.6 MW of energy associated with the former Kinsley Landfill which no longer operates.

Solar. In 2007, the New Jersey legislature passed Regional Greenhouse Gas Initiative ("RGGI") legislation authorizing state utilities to invest in renewable resources such as wind or solar in order to promote increased use of renewable resources within the state and in turn reduce greenhouse gas emissions. *See* L. 2007, c. 340, codified at N.J.S.A. 48:98-1. The New Jersey Board Public Utilities ("BPU") has approved two (2) PSE&G Solar 4 All® (S4A) programs under which PSE&G has sited, designed and built twenty-nine (29) grid connected solar facilities. PSE&G currently owns and operates approximately 125MW-dc of grid connected solar under the S4A program. In 2016, PSE&G received NJBPU approval of its Solar 4 All Extension II filing to install an additional 33 MW-dc of grid connected solar on landfills and brownfields in the PSE&G electric service territory to begin in 2017.

2. PSEG Energy Resources & Trade LLC ("PSEG ER&T")

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil and PSEG Nuclear, each wholly-owned subsidiaries of PSEG Power, as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission.[5]

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

Basic Generation Service ("BGS") Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 *et seq.,* which initiated the transition from a regulated to a competitive retail power market in New Jersey, BPU annually approves statewide auctions to determine the entities that will supply BGS in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSEG ER&T has participated directly in all of the auctions for BGS supply held since 2004, has been a winning bidder in these auctions and has incurred contractual commitments to provide supply to BGS

[5] *Public Service Electric and Gas Company, et al*., 88 FERC ¶ 61,299 (1999).

load pursuant to BPU approved contracts beginning with the 2004 auction and continuing to the present

Basic Gas Supply Service ("BGSS") Gas Contract. In an April 16, 2002 order, the BPU approved a full requirements contract for the provision of gas supply by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the BPU, PSEG ER&T assumed, through capacity release, FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract remains in effect and provides for annual renewals unless terminated by either party on 12 months' advance written notice.

Long Island Power Authority ("LIPA") Fuel Supply: On November 26, 2013, PSEG ER&T executed an agreement with the LIPA under which ER&T began providing fuel supply and power supply management activities for LIPA on January 1, 2015.

3. PSEG Fossil LLC ("PSEG Fossil")

PSEG Fossil is an Exempt Wholesale Generator ("EWG")[6] and is authorized to sell power at market-based rates. PSEG Fossil owns and operates electric generation facilities located within PJM and sells their entire output to its affiliate PSEG ER&T.[7] The assets of PSEG Fossil (and its subsidiary, PSEG Keys Energy Center LLC ("PSEG Keys")) are located entirely within PJM. However, PSEG Fossil's subsidiaries PSEG

[6] *PSEG Fossil LLC*, Docket No. EG00-3-000, 89 FERC ¶ 62,237 (December 20, 1999); *PSEG Fossil LLC*, 95 FERC ¶ 61,405 (June 14, 2001); *PSEG Fossil LLC*, 99 FERC ¶ 62,167 (June 10, 2002).

[7] These contracts were originally approved by the Commission as cost-based contracts. *See Public Service Electric and Gas Company*, *et al*., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Fossil obtained market based rate authority covering sales from its generating units.

Power Connecticut LLC ("PSEG Power CT"), PSEG Power New York LLC ("Power New York") and PSEG New Haven LLC ("PSEG New Haven") own facilities in ISO New England Inc. ("ISO-NE") and New York Independent System Operator Inc. ("NYISO"). PSEG Fossil also co-owns certain facilities in PJM.

PSEG Fossil and its subsidiaries PSEG Power CT and PSEG Keys have begun constructing three new gas-fired generation units. PSEG Fossil is constructing Sewaren 7,[8] a 540 MW combined cycle unit in Woodbridge, New Jersey which is expected to be reach commercial operations by no later than June 1, 2018. PSEG Keys is constructing a 755 MW combined cycle unit in Prince George's County, Maryland which is expected to reach commercial operations by no later than June 1, 2018. PSEG Power CT is constructing Bridgeport 5, a 485 MW combined cycle unit in Bridgeport, Connecticut which is expected to be in service in 2019. On June 1, 2017, PSEG Fossil retired Hudson 2 (659 MW nameplate rating) and Mercer Units 1 and 2 (652 MW nameplate rating).

PSEG Fossil satisfies most of the electricity needs of its plants from PJM under PJM's "station power" Tariff provisions. PSEG Fossil procures gas supply for its plants from PSEG ER&T and receives gas distribution service from PSE&G at a rate approved by the BPU on May 29, 2013.[9]

4. PSEG Power CT

PSEG Power CT, a Connecticut limited liability company, is an EWG that owns and operates electric generation facilities in the State of Connecticut and is authorized to

[8] Once Sewaren 7 begins commercial operation, PSEG Fossil plans to retire Sewaren 1, 2, 3 and 4.

[9] BPU Docket No. GM12100935 (May 29, 2013).

sell power at market-based rates.[10] Both of PSEG Power CT's generation facilities, Bridgeport Harbor and New Haven Harbor, are located in the State of Connecticut within the market administered by ISO-NE. PSEG Power CT sells the output of its generation facilities to its affiliate PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority. As noted above, PSEG Power CT is currently constructing Bridgeport 5, a 485 MW combined cycle unit in Bridgeport, Connecticut which is expected to be in service in 2019.

5. PSEG New Haven

PSEG New Haven is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG New Haven owns and operates a facility (the "New Haven facility") in New Haven, Connecticut with a nameplate rating of 181 MWs. The New Haven facility is located within the New Haven Harbor generation station. The New Haven facility is interconnected to the adjacent United Illuminating East Shore Substation using a 115 kV underground cable. PSEG New Haven has no other generation assets. The commercial operation date for the New Haven facility was June 1, 2012 and PSEG New Haven has obtained MBR authority from FERC.[11]

The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[12] pursuant to a Connecticut statute that sought proposals

[10] *Wisvest Corporation,* et al., 101 FERC ¶ 61,166 (2002).

[11] *PSEG New Haven LLC*, Docket No. ER12-1250-000, *et al*., (May 29, 2012).

[12] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control ("DPUC"). PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

for peaking generation in Connecticut.[13] All of the energy and capacity of the New Haven facility is sold into the ISO New England ("ISO-NE") markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA[14] has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder. The 181 MW nameplate rating of the New Haven Facility has not been included in the capacity controlled by PSEG for purposes of Dr. Morris' market power analysis.

5. PSEG Nuclear LLC

PSEG Nuclear is an EWG[15] and is authorized to sell power at market-based rates. PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission.[16] The assets of PSEG Nuclear are located entirely within PJM.

6. Pavant Solar LLC, San Isabel Solar LLC and Bison Solar LLC

PSEG Power Ventures portfolio includes three (3) solar companies with market-based rate authority: (1) *Pavant Solar II LLC*[17] is a QF which owns a 50 MW (AC) solar

[13] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

[14] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

[15] *PSEG Nuclear LLC*, 97 FERC ¶ 62,191 (November 30, 2001).

[16] *Public Service Electric and Gas Company*, *et al*., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Nuclear obtained market based rate authority from the FERC (Docket No. ER08-448).

[17] *Pavant Solar II LLC*, Docket No. QF16-1072-000.

facility in Fillmore Utah; (2) *San Isabel Solar LLC*[18] is a QF which owns a 30 MW (AC) solar facility in Las Animas County, Colorado; and (3) *Bison Solar LLC*[19] is a QF which owns a 30 MW (AC) solar facility 25 miles north of Fort Collins, Colorado.

7. PSEG Energy Solutions LLC

PSEG Energy Solutions LLC ("PSEG Solutions") is a Delaware limited liability company and a direct subsidiary of PSEG ER&T. PSEG Solutions obtained market-based rate authority[20] and will operate within the PJM, NYISO and ISO-NE markets. Energy Solutions has contracted with PSEG ER&T to purchase power from the regional transmission organization ("RTO") at wholesale and sell it to retail customers. PSEG Solutions will not own or operate any generation assets. PSEG Solutions has begun its retail business in 2017.

C. Affiliated Generation Ownership

A list of the PSEG Keys' affiliated domestic FERC jurisdictional generation assets owned is contained in Appendix B attached hereto.[21] Those additional subsidiaries of PSEG Keys that may be considered relevant to this request are described below:

Public Service Enterprise Group Incorporated ("PSEG"). PSEG, a New Jersey corporation, is a public utility holding company engaged in, among other things, the generation of electric energy and the transmission, distribution and sale of electricity and natural gas through its subsidiaries.

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[18] *San Isabel Solar LLC*, Docket No. QF16-712-000.

[19] *Bison Solar LLC*, Docket No. QF16-711-001.

[20] *See* Letter Order dated December 21, 2016 in Docket No. ER16-2725-000.

[21] Appendix B excludes generation assets located in Hawaii as well as generation assets in which PSEG's interest is limited to a leveraged lease interest.

PSEG Power LLC. PSEG Power was formed in 1999 to acquire the former generation assets of PSE&G. PSEG Power, a Delaware limited liability company, does not directly own any generation facilities or engage in any FERC jurisdictional activities but is the parent company of several FERC jurisdictional entities, including PSEG ER&T (and its subsidiary PSEG Solutions), PSEG Fossil, PSEG Nuclear, PSEG Power CT, PSEG New Haven and PSEG Power Ventures (which owns PSEG Solar Source LLC).

PSEG Power Ventures LLC ("Power Ventures") and PSEG Solar Source LLC. PSEG Power Ventures is a Delaware Limited Liability company and a direct subsidiary of PSEG Power. PSEG Power Ventures owns 100% interest in PSEG Solar Source LLC and has an in-direct ownership interest in a domestic power plant in Hawaii. PSEG Solar Source owns approximately 349 MWs DC (274 MW AC) of solar capacity across the United States, including a combined 92 MWs[22] (72 MW AC) of solar capacity in PJM and approximately the following amount of MWs in the following states all through separate project companies which have all obtained QF status:

- 15 MWs (12 MW AC) in Florida;
- 92 MWs in PJM (72 MW AC) – 12 MWs in Ohio, 2 MWs in New Jersey, 15 MWs in Delaware, 50 MWs in North Carolina and 13 MWs in Maryland;
- 45 MWs in Arizona (34 MW AC) – 25 MW Queen, approximately 20 MW Badger;
- 13 MWs (10 MW AC) in Texas;

[22] The 92 MWs are attributed to four (7) separate project companies that have QF status: PSEG Solar Hackettstown LLC (2 MW); PSEG Solar Delaware LLC (15 MW), Rockfish Solar LLC (13 MWs) Meadows Solar (26 MW), Turkey Creek (17 MW) Hemlock Solar (7 MW) in North Carolina and PSEG Solar Ohio LLC (12 MW).

- 34 MWs (25 MW AC) in California;[23]
- 4 MWs (3 MW AC) in Vermont;
- 74 MW (60 MW AC) in Colorado (to be in operation in 2016) – 38 MWs for San Isabel and 36 MWs for Bison;
- 62 MW (50 MW AC) in Utah;
- 10.5 MW (8 MW AC) in Oregon; and
- 47.2 MW (36 MW AC) in North Carolina.

PSEG Resources LLC ("Resources") is a New Jersey limited liability company that, through its subsidiaries owns interests, through leveraged leases, in various generation stations and other real estate holdings. Pursuant to the terms of these triple net leases, the lessee, not Resources, has all operational responsibility and control over the leased generation stations.

PSEG Power New York LLC. PSEG Power NY is a Delaware limited liability company and an EWG that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 835 MW combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a FERC-approved cost-based contract.[24]

PSEG Long Island LLC ("PSEG Long Island") and Long Island Electric Utility Servco, LLC ("Servco") are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution system ("T&D") on Long

[23] The 28 MWs (DC) are associated with the Shasta Solar Facility in California (4 MW), Whitehorn Solar (3 MWs) the Columbia Solar Project (19 MW). All have obtained QF status.

[24] *PSEG Power New York Inc.*, Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither PSEG Long Island nor Servco will be FERC jurisdictional public utilities as neither will exercise ultimate decision making authority over the T&D system in Long Island. PSEG Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[25]

D. Affiliated Transmission Ownership

With the exception of the electric transmission assets owned by PSE&G, all of which are located within the PJM RTO, and the generation interconnection facilities owned by the various EWG and QF affiliates listed herein, neither PSEG Keys nor any of its affiliates own or operate FERC jurisdictional electric or natural gas transmission facilities within the United States. As discussed below, FERC granted PSE&G a Hinshaw exemption in 1954, finding that it was exempt from the provisions of the Natural Gas Act.

E. JOINTLY OWNED FACILITIES

PSEG Nuclear is a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear is the operator of Salem and Exelon Generation is the operator of Peach Bottom.[26] PSEG Fossil is approximately a 23% joint owner in the Conemaugh and Keystone generating stations

[25] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), *order dismissing request for rehearing*, 145 FERC ¶ 61,183 (2013).

[26] A letter of concurrence supporting the allocation of plant output based on ownership interests is attached in Appendix E. The ownership percentages have not changed since the date of this letter. PSEG Nuclear owns a 50% interest in Peach Bottom and a 57.41% interest in Salem.

located in Pennsylvania. An affiliate of NRG Energy is the operator.[27] Accordingly, for purposes of the December 2016 triennial analysis, the capacity of Salem, Peach Bottom, Conemaugh and Keystone was attributed to PSEG in accordance with PSEG's ownership interests in these facilities.

PSEG Fossil and Jersey Central Power and Light Company ("JCP&L") are each 50% co-owners of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to the unit. Accordingly, for the purpose of the December 2016 triennial market power analysis, the entire unit capacity – nominally 400 MWs – was assigned to JCP&L.[28]

III. REQUEST FOR MARKET-BASED RATE AUTHORITY

PSEG Keys respectfully requests authorization to sell electric energy, capacity, and ancillary services at market-based rates in the PJM market. The Commission allows wholesale sales of energy and capacity at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, the ability to exercise horizontal and vertical market power in any relevant market.[29] As demonstrated below, neither PSEG Keys nor

[27] A letter of concurrence supporting the allocation of plant output based on ownership interest is attached in Appendix E. The ownership percentages have not changed since the date of this letter.

[28] A letter of concurrence supporting this determination is attached in Appendix E. The ownership percentages have not changed since the date of this letter.

[29] *See* 18 C.F.R. §§ 35.37 and 35.38 (2011); and *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Montana Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011).

its affiliates have the ability to exercise market power in the PJM geographic market. Accordingly, PSEG Keys meets the Commission's requirements for receiving authority to make sales of energy, capacity and ancillary services at market-based rates.

(1) PSEG Keys Fully Satisfy the Commission's Standards For Authority to Make Power Sales at Market-Based Rates

Pursuant to Order No. 697[30] and 697-A,[31] an applicant seeking market-based rate authority must demonstrate that, in the relevant markets, it does not possess horizontal or vertical market power. The Commission allows power sales at market-based rates if the seller (and any affiliates) do not have, or have adequately mitigated, horizontal and vertical market power. The Commission requires that an applicant seeking market-based rate authority show that it does not possess horizontal market power by demonstrating that it and its affiliates can pass the market power screen, "unless the seller and its affiliates do not own or control generation capacity or all of their capacity is fully committed."[32] To demonstrate that an applicant does not possess vertical market power, it must show that it lacks market power and does not control any other barrier to market entry in the relevant markets.[33] In addition, as established in the December 2016 triennial

[30] *Market-Based Rates For Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 119 FERC ¶ 61,295 (2007).

[31] *Market-Based Rates For Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 123 FERC ¶ 61,055 (2008).

[32] Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, 153 FERC ¶ 61,065, at p. 28 (2015) ("Order No. 816); see also 18 C.F.R. § 35.37(c)(1); Order No. 697 at p. 62.

[33] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, at p. 8, FERC Stats. & Regs. ¶ 31,252, clarified, 121 FERC ¶ 61,260 (2007), order on reh'g, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, clarified, 124 ¶61,055, order on reh'g, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), order on reh'g, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), order on reh'g, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010). Applicants must (continued…)

analysis, neither PSEG Keys nor any of its affiliate have any market power concerns or have adequately mitigated same.[34]

A. Horizontal Market Power

The Commission evaluates whether a seller can exercise horizontal market power in a relevant market through two indicative screens: (1) a pivotal supplier analysis; and (2) a wholesale market share analysis. If a seller passes both screens, there will be a rebuttable presumption that the seller lacks market power.[35] Each indicative screen is applied with respect to "relevant geographic markets" for an applicant's generating units. The Commission requires that an applicant seeking market-based rate authority show it does not possess horizontal market power by demonstrating that it and its affiliates can pass the market power screen, "unless the seller and its affiliates do not own or control generation capacity or all of their capacity is fully committed."[36]

Applicants located in ISOs/RTOs possessing sufficient market structure may consider the geographic region under the control of the ISO/RTO as the relevant default geographic region for purposes of completing their generation market power analyses.[37] However, where the Commission has previously found a "submarket" to exist within a boundary of an RTO, such finding is controlling as to the scope of the relevant

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also comply with affiliate abuse restrictions; however, again, such regulations are inapplicable to Applicant. *See* 18 C.F.R. § 35.39.

[34] Triennial Market Power Update in Compliance with Order No. 697, *PSEG Energy Resources & Trade LLC, et al.*, Docket Nos. ER10-1768-004 (December 28, 2016) ("December 2016 Triennial Filing").

[35] 18 C.F.R. § 35.37(c)(1) (2011).

[36] *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 153 FERC ¶ 61,065, at p. 28 (2015) ("Order No. 816"); see also 18 C.F.R. § 35.37(c)(1); Order No. 697 at p. 62.

[37] Order No. 697 at PP 231, 235.

geographic market for all generation units located within that submarket for the application of the indicative screens and any delivered price test that may be performed. The Commission further listed several such submarkets, including PJM East ("PJME"),[38] PJM East of 5004/5005 ("PJM50") and PJM East of AP South ("PJMAP") that would be relevant to an MBR analysis for applicants in the Northeast Region.[39]

As shown in the attached Appendix G, Dr. John Morris has updated Applicant's market power analysis that was submitted in the December 2016 Triennial Filing. Specifically, Dr. Morris' update of the market-based rate screens accounts for the addition of the 755 MWs from the PSEG Keys Energy Center and the retirements of the Mercer and Hudson generating plants (1252 MWs).[40] Dr. Morris' updated analysis shows that there has been only a minor increase in the market power with the addition of the PSEG Key Energy Center since the December 2016 Triennial Filing. This minor increase should not be viewed to impact the factors that Dr. Morris relied upon in his findings in the December 2016 Triennial Filing that the PSEG Companies with market-based rate authority have satisfied the requirements demonstrating that they lack horizontal and vertical market power. Specifically, Dr. Morris analysis shows that with the addition of PSEG Keys, the PSEG Companies still pass all of the pivotal suppler

[38] Order No. 697 at P 236 (citing *Exelon Corp.*, 112 FERC ¶ 61,011, *reh'g denied*, 113 FERC ¶ 61,299 (2005)). FERC eliminated the Northern PSEG zone as a default submarket in Order No. 697-A at P 99.

[39] Order Conditionally Authorizing Merger and Disposition of Jurisdictional Facilities, *Exelon Corporation, et al.*, 138 FERC ¶ 61,167 (2012).

[40] Affidavit of Dr. John R. Morris at 1 (dated September 1, 2017), Attached as Appendix G.

analysis ("PSA") screens for all of the relevant markets, namely, PJM, PJMAP, PJME and PJM50.[41]

Dr. Morris' analysis also shows that the PSEG Companies failed only an additional two screens with the addition of PSEG Keys, each by a small quantity, as compared to the December 2016 Triennial Filing in the wholesale market share analysis ("WMSA").[42] Specifically, for PJME, the PSEG Companies failed one market concentration (HHI) screen for the Available Economic Capacity ("AEC"); however, this screen was only 156 above the screening threshold of 2,500.[43] Notably, the PSEG Companies were below the 2500 HHI level for all of the other seasons, which means that the PSEG Companies have little ability to exercise market power even with the addition of PSEG Keys. In addition, for PJME, with the addition of PSEG Keys, the PSEG Companies also failed one additional market share screen for Economic Capacity ("EC") by 0.3 percent above the established threshold of 20 percent.[44] Although the PSEG Companies market shares are greater than the 20 percent screen, their market shares are

[41] *See* attached Appendix A-1, at p. 1. The pivotal supplier analysis ("PSA") focuses on the ability of a seller to exercise unilateral market power. The screen assesses whether market demand can be met during peak times without the applicant and its affiliates. If demand can be met without the applicant and its affiliates, the applicant passes that the PSA screen.

[42] *Id.* The wholesale market share analysis ("WMSA") is applied each season to determine whether an applicant has a dominant market position based on the total number of megawatts of uncommitted capacity owned or controlled by the applicant and its affiliates in relation to the uncommitted capacity of the entire relevant wholesale electricity market. The established threshold is 20 percent; a supplier who has less than 20 percent market share in the relevant market for all seasons passes the WMSA screen.

[43] *See* attached Appendix A-2 at p. 2.

[44] *Id.*

well below the 35 percent threshold that is typically used for imputing unilateral market power.[45]

In sum, with the addition of PSEG Keys (and the retirement of Hudson and Mercer Generation Station), the PSEG Companies failed the market share screen for EC in 5 periods in this update compared to 4 periods in the analysis for the December 2016 Triennial Filing.[46] Therefore, overall, the PSEG Companies have a change in the result in one screen for one period out of a total of 80 periods that were analyzed between EC and AEC for PJME and PJM50.[47] Based on the minor changes in the results since the December 2016 Triennial Filing, we submit that Dr. Morris' determination that PSEG Companies could not exercise horizontal market power still stands with the addition of PSEG Keys. As stated by Dr. Morris in his affidavit:

> Although there are some minor differences in the results from those presented with the December Affidavit, the differences are not material and do not change the conclusions made at that time. Under the standards utilized by the Commission, continuing market-based rates for PSEG and all of its Northeastern affiliates remain in the public interest.[48]

Moreover, Applicants rely on the same RTO monitoring and mitigation described in the December 2016 Triennial Filing to show that it has met the standards necessary to obtain market-based rate authority. Accordingly, it is clear that PSEG Keys has satisfied the standards necessary for market-based rate authority.

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[45] *See*, *e.g.*, U.S. Department of Justice, 1984 Merger Guidelines, at Section 3.12, available at https://www.justice.gov/sites/default/files/atr/legacy/2007/07/11/11249.pdf ("the Department is likely to challenge the merger of any firm with a market share of at least one percent with the leading firm in the market, provided the leading firm has a market share that is at least 35 percent.").

[46] *See* Attached Appendix A-2.

[47] *Id.*

[48] Affidavit of Dr. John R. Morris at 2 (dated September 1, 2017), Attached as Appendix G.

B. Vertical Market Power

1. The Applicants Lack Transmission Market Power and Cannot Erect Entry Barriers.

In its previous order accepting the PSEG Companies triennial market power analysis for the Northeast Region, the Commission found that the submittal satisfied the Commission's requirements for market-based rates regarding vertical market power.[49] There have been no subsequent changes in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. As demonstrated below, PSEG Keys and its affiliates are not able to exercise vertical market power.

PSEG Keys nor its affiliates are able to exercise transmission market power. Neither PSEG Keys nor is affiliates, except PSE&G, own transmission assets in the U.S. other than incidental generator interconnection facilities. PSE&G owns transmission facilities in PJM, but transmission service over those facilities is provided under the PJM Open Access Transmission Tariff.

In addition, neither PSEG Keys nor its affiliates are able to exercise vertical market power in wholesale energy markets through affiliation, ownership or control of inputs to electric power production. As required by Section 35.37(e) of the Commission's regulations, Applicant provides the following information:

(1) PSE&G owns and operates a natural gas distribution system that receives interstate pipeline gas within the State of New Jersey and distributes that

[49] *PSEG Energy Resources & Trade, LLC, et al,* Letter Order, June 29, 2011, Docket No. ER99-3151-017. In addition, in that letter order the Commission found that the submittal satisfied the Commission's requirements for market-based rates regarding horizontal market power.

gas to its customers within the State of New Jersey. The distribution system consists of 18,050 miles of gas distribution pipe and an additional 62 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3 and peak-shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers. Service over such distribution facilities is made available pursuant to state regulated tariffs on an open access type basis. PSE&G was granted a Hinshaw exemption from the FERC in 1954.[50] The gas distribution rates paid by PSEG Fossil to PSE&G have been set at rates approved by the BPU in an order dated May 29, 2013.

(2) Certain of the PSEG Key's affiliates own sites within the Northeast Region that would be suitable for future generating facilities. These include space at many of the existing generating sites of PSEG Fossil and at the sites of PSEG Power NY and PSEG Power CT. PSEG Nuclear's Salem facility may also be suitable for future construction. PSE&G also owns certain sites that would be suitable for generating facilities, but under New Jersey's Electric Discount and Energy Competition Act, N.J.S.A 48:3-43 et seq., PSE&G is effectively barred from owning and operating generation except "on site" generation for supply and Class I renewable energy resources as defined in N.J.S.A. 48:3-98.1.

[50] 13 F.P.C. 1348 (1954).

(3) Neither PSEG Keys nor any of its affiliates own or control any physical coal supply resources or own or control who may access transportation of coal supplies.

(4) As required by section 35.37(e)(4) of the Commission's regulations, PSEG Keys and its affiliates state that they have not erected barriers to entry into any market, including the PJM, NYISO or ISO-NE market and will not erect barriers to entry into any markets.

IV. SELLER CATEGORY

The PSEG Companies own or control more than 500 MW of electric generation in the Northeast Region and include an entity that owns transmission facilities in the Northeast Region. Therefore, PSEG Keys is a Category 2 Seller in the Northeast Region.

PSEG Keys qualifies as a Category 1 seller in the Central, Northwest, Southeast, Southwest and Southwest Power Pool regions. As shown by a review of Appendix B, PSEG Keys nor its affiliates own or control in the aggregate more than 500 MWs of electric generation in any of such regions. Moreover, PSEG Keys: (i) does not own, operate or control transmission facilities other than limited equipment necessary to connect individual generating facilities to the transmission grid in such regions; (ii) is not affiliated with anyone that owns, operates or controls transmission facilities in such regions; and (iii) is not affiliated with a franchised public utility in such regions. Finally, as discussed above, neither PSEG Keys nor its affiliates raise other vertical market power issues.

V. REQUEST FOR WAIVERS, BLANKET AUTHORITY AND ADDITIONAL FINDING

PSEG Keys respectfully request that the Commission grant their waivers and blanket authorization consistent with those granted to other entities with market-based rate authority.[51] Specifically, PSEG Keys requests the following:

- Waiver of the accounting, reporting, and other requirements of Parts 41, 101, and 141 of the Commission's regulations, with the exception of 18 C.F.R. §§ 141.14 and 141.15;
- Waiver of the full filing requirements of subparts B and C of Part 35 of the Commission's regulations, except the transmittal requirements of 18 C.F.R. §§ 35.12(a), 35. 13(b), and the notification of succession and cancellation of service requirements of 18 C.F.R. §§ 35.15 and 35.16;
- Blanket authorization under Section 204 of the FPA and Part 34 of the Commission's regulations for future issuances of securities and assumptions of liability; and
- Such other appropriate waivers and authorizations as the Commission may deem appropriate.

VI. APPENDIX OF ASSETS

As required by section 35.37(b) of the Commission's regulations, Appendix B to this application provides an appendix of assets in the form provided in Appendix B of Subpart H of Part 35 of the Commission's regulations.

[51] *See* Order No. 697 at PP 984, 999, & n. 1126.

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VII. EFFECTIVE DATE

PSEG Keys respectfully requests that the Commission accept PSEG Key's tariff effective on November 1, 2017.

VIII. DOCUMENTS SUBMITTED WITH FILING

The following documents are submitted with this application.

- Appendix A: Updated Market Power Analysis
    - A-1 PSEG 2016 MBR for PJM – Add Keys and Retire Mercer and Hudson
    - A-2 Delivered Price Test
- Appendix B: Appendix of Assets
- Appendix C: Appendix of Transmission Assets
- Appendix D: Appendix of Long Term Purchase Agreements
- Appendix E: PSEG Key's Tariff
- Appendix F: December 2016 Triennial Filing
- Appendix G: Affidavit of John Morris

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IX. CONCLUSION

PSEG Keys respectfully requests that the Commission: (1) accept for filing the proposed market-based rate tariff for PSEG Keys contained herein; (2) authorize PSEG Keys to sell energy, capacity, and certain ancillary services at market-based rates; and (3) grant such waivers and blanket authorizations as the Commission has granted to other entities with market-based rate authorization, as described herein.

Respectfully submitted,

PSEG Keys Energy Center LLC

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Dated: September 1, 2017

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PSEG Services Corporation

September 1, 2017

VIA ETARIFF

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: PSEG Keys Energy Center LLC
Docket No. ER17-_____-000
Application for Market-Based Rate Authorization and Request for Waivers and Blanket Approvals

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act, Rules 204 and 205 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), and Part 35 of the Commission's regulations, PSEG Keys Energy Center LLC ("PSEG Keys" or "Applicant") hereby submits for filing an application for market-based rate authorization and request for waivers and blanket approvals. The enclosed application requests that the Commission: (1) accept for filing the proposed market-based rate tariff for PSEG Keys contained herein; (2) authorize PSEG Keys to sell energy, capacity, and certain ancillary services at market-based rates; (3) grant such waivers and blanket authorizations as the Commission has granted to other entities with market-based rate authorization; and (4) find that a change in status report is not required.

In addition to the application, the following documents are included:

- Appendix A: Updated Market Power Analysis
  - A-1 PSEG 2016 MBR for PJM – Add Keys and Retire Mercer and Hudson
  - A-2 Delivered Price Test
- Appendix B: Appendix of Assets
- Appendix C: Appendix of Transmission Assets
- Appendix D: Appendix of Long Term Purchase Agreements

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- Appendix E: PSEG Keys' Tariff
- Appendix F: December 2016 Triennial Filing
- Appendix G: Affidavit of John Morris

Thank you for your attention to this matter.

Respectfully submitted,

Cara J. Lewis

Cara J. Lewis

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1. **Availability.** PSEG Keys Energy Center LLC ("PSEG Keys" or "Seller") will make wholesale electric energy, capacity, and ancillary services available under this Tariff to any purchaser for resale, except as prohibited below.

2. **Applicability.** This Tariff is applicable to all sales of energy, capacity, and ancillary services by PSEG Keys not otherwise subject to a particular rate schedule of PSEG Keys.

3. **Rates.** All sales shall be made at the rates established between the purchaser and PSEG Keys.

4. **Other Terms and Conditions.** All other terms and conditions shall be established by agreement between the purchaser and PSEG Keys.

5. **Compliance with Commission Regulations.** PSEG Keys shall comply with the provisions of 18 C.F.R. Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning PSEG Key's market-based rate authority, including orders in which the Commission authorizes PSEG Keys to engage in affiliate sales under this Tariff or otherwise restricts or limits the PSEG Key's market-based rate authority. Failure to comply with the applicable provisions of 18 C.F.R. Part 35, Subpart H, and with any orders of the Commission concerning PSEG Key's market-based rate authority, will constitute a violation of this Tariff.

6. **Limitations and Exemptions Regarding Market Based Rate Authority.** PSEG Keys does not have any limitations on its market-based rate authority except as other provided in this Tariff. The Commission granted Seller in Docket No. ER17-___-000 the following waivers and blanket authorization: (a) waiver of Subparts B and C of Part 35 of the Commission's regulations requiring the filing of cost-of-service information, except for sections 35.12(a), 35.13(b), 35.15 and 35.16; (b) waiver of the requirements of Part 41 and Part 101; (c) waiver of Part 141 of the Commission's regulations concerning accounting and reporting requirements, with the exception of 18 C.F.R. §§ 141.14 and 141.15; and (d) blanket approval as to Section 204 of the FPA and Part 34 of the Commission's regulations for all future issuances of securities and debt and assumption of liabilities.

7. **Ancillary Services.**

   Third-party ancillary services: PSEG Keys offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier.

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Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

8. **Seller Category.** PSEG Keys is a Category 2 Seller in the Northeast Region and a Category 1 seller in the Central, Northwest, Southeast, Southwest and Southwest Power Pool regions, as defined by 18 C.F.R. 35.36(a),

9. **Effective Date.** This Tariff is effective on the date specified by the Commission. This Tariff shall continue in effect until terminated or changed in accordance with any applicable regulatory requirements.

PSEG 2016 MBR for PJM - Add Keys and Retire Mercer and Hudson

	PSA		WMSA							
			Winter		Spring		Summer		Fall	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result
PJM Interconnection	36,491	Pass	8.7	Pass	7.0	Pass	7.5	Pass	7.6	Pass
PJM East	4,853	Pass	27.1	Fail	22.1	Fail	25.8	Fail	24.4	Fail
PJM East of 5004/05	5,977	Pass	22.3	Fail	18.9	Pass	21.3	Fail	21.1	Fail
PJM East of AP South	8,190	Pass	17.0	Pass	14.1	Pass	16.9	Pass	15.6	Pass

Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	9,244	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	195	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	1,943	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	152	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	176,531	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	1,943	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	195	Row B; Table2Data
H	Uncommitted Capacity Imports	7,448	Calculated
I	Study Area Reserve Requirement	8,187	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	63,588	
	Load		
L	Balancing Area Annual Peak Load	143,633	Loads
M	Average Daily Peak Native Load in Peak Month	121,600	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	22,034	
P	Net Uncommitted Supply (K-O)	41,555	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,064	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	7,600	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	7600	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	6,516	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	14	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	162	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	27,983	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	14	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,375	Calculated
I	Study Area Reserve Requirement	1,724	Gendata
J	Amount of Line I Attributable to Seller, if any	176	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	15,220	
	Load		
L	Balancing Area Annual Peak Load	30,240	Loads
M	Average Daily Peak Native Load in Peak Month	24,093	Loads
N	Amount of Line M Attributable to Seller, if any	2,269	SellerLoads
O	Wholesale Load (L-M)	6,148	
P	Net Uncommitted Supply (K-O)	9,072	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,219	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	6,537
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	6537
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,284	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	105	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	52,316	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,214	Calculated
I	Study Area Reserve Requirement	2,975	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	20,577	
	Load		
L	Balancing Area Annual Peak Load	52,190	Loads
M	Average Daily Peak Native Load in Peak Month	42,368	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	9,822	
P	Net Uncommitted Supply (K-O)	10,754	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,777	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,319	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	6319	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,284	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	84	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	75,968	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,371	Calculated
I	Study Area Reserve Requirement	4,032	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	25,567	
	Load		
L	Balancing Area Annual Peak Load	70,729	Loads
M	Average Daily Peak Native Load in Peak Month	58,108	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	12,621	
P	Net Uncommitted Supply (K-O)	12,946	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,756	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	4,455	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	4455	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	10,727	9,986	9,244	9,986	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	195	195	195	195	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	1,643	1,944	1,943	1,944	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	464	1,377	212	1,296	SellerGendata
E	Uncommitted Capacity Imports	214	204	138	117	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	108,842	91,954	109,399	91,992	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	106,988	90,430	107,540	90,648	F - G
I	Study Area Reserve Requirement	7,474	6,516	7,991	6,470	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	7,335	6,385	7,817	6,352	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	182,501	179,517	176,531	179,517	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	1,643	1,944	1,943	1,944	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	195	195	195	195	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	7,895	24,764	4,042	23,293	Gendata; Row D
P	Uncommitted Capacity Imports	11,783	12,069	7,462	6,950	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	73,514	71,755	66,343	67,922	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,036	5,409	5,389	5,596	
S	Total Seasonal Uncommitted Capacity (Q+R)	80,550	77,164	71,731	73,518	
T	**Applicant's Market Share** (R÷S)	8.7%	7.0%	7.5%	7.6%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	11,997	12,273	7,600	7,067	
V	SIL Value	11,997	12,273	7,600	7,067	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,051	7,284	6,516	7,284	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	22	14	14	14	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	348	1,005	149	945	SellerGendata
E	Uncommitted Capacity Imports	201	159	147	144	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	18,303	15,919	20,901	16,346	Loads
G	Amount of Line F Attributable to Seller, if any	1,749	1,434	1,764	1,268	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	16,553	14,485	19,137	15,078	F - G
I	Study Area Reserve Requirement	1,258	1,168	1,659	1,211	Gendata
J	Amount of Line I Attributable to Seller, if any	130	122	165	110	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	1,128	1,046	1,494	1,101	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	27,695	27,839	27,983	27,839	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	22	14	14	14	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,198	3,840	641	3,612	Gendata; Row D
P	Uncommitted Capacity Imports	7,301	8,671	6,390	7,715	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	16,139	17,152	13,115	15,777	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	6,002	4,868	4,571	5,090	
S	Total Seasonal Uncommitted Capacity (Q+R)	22,141	22,019	17,686	20,867	
T	**Applicant's Market Share** (R÷S)	27.1%	22.1%	25.8%	24.4%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	7,502	8,830	6,537	7,859	
V	SIL Value	7,502	8,830	6,537	7,859	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,819	8,052	7,284	8,052	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	381	1,111	167	1,045	SellerGendata
E	Uncommitted Capacity Imports	160	90	94	68	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	35,188	30,080	37,518	30,214	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	33,334	28,556	35,658	28,871	F - G
I	Study Area Reserve Requirement	2,450	2,184	2,889	2,189	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,311	2,054	2,715	2,071	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	52,819	52,568	52,316	52,568	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	2,285	7,252	1,198	6,821	Gendata; Row D
P	Uncommitted Capacity Imports	7,944	8,203	6,225	6,035	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	22,869	22,937	18,998	20,867	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	6,569	5,349	5,150	5,585	
S	Total Seasonal Uncommitted Capacity (Q+R)	29,438	28,286	24,148	26,453	
T	**Applicant's Market Share** (R÷S)	22.3%	18.9%	21.3%	21.1%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Pass**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	8,104	8,293	6,319	6,103	
V	SIL Value	8,104	8,293	6,319	6,103	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,819	8,052	7,284	8,052	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	381	1,111	167	1,045	SellerGendata
E	Uncommitted Capacity Imports	185	113	76	80	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	48,658	41,074	51,437	41,155	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	46,804	39,551	49,577	39,811	F - G
I	Study Area Reserve Requirement	3,496	3,025	3,935	2,991	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	3,358	2,895	3,762	2,873	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	77,913	76,941	75,968	76,941	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,370	10,614	1,739	9,983	Gendata; Row D
P	Uncommitted Capacity Imports	7,712	8,743	4,379	5,988	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	32,129	32,652	25,297	30,289	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	6,594	5,372	5,132	5,597	
S	Total Seasonal Uncommitted Capacity (Q+R)	38,723	38,024	30,429	35,886	
T	**Applicant's Market Share** (R÷S)	17.0%	14.1%	16.9%	15.6%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,897	8,856	4,455	6,068	
V	SIL Value	7,897	8,856	4,455	6,068	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Delivered Price Test - PJM50 Market (Add Keys Energy Center and Retire Mercer and Hudson)

Available Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$62.03	2,122	24,238	22,116	6,776	Yes	8.8	Yes	1,026	Yes
Spring/Fall	Peak	$35.73	2,938	26,888	23,950	6,776	Yes	10.9	Yes	1,087	Yes
Spring/Fall	Off Peak	$29.46	2,449	19,640	17,191	6,776	Yes	12.5	Yes	1,338	Yes
Summer	Top 1%	$148.44	1,013	22,436	21,423	9,933	Yes	4.5	Yes	1,065	Yes
Summer	Top 10%	$64.59	1,131	20,913	19,782	9,933	Yes	5.4	Yes	1,018	Yes
Summer	Peak	$35.56	2,744	23,132	20,388	9,933	Yes	11.9	Yes	1,051	Yes
Summer	Off Peak	$24.88	2,212	15,801	13,590	9,933	Yes	14.0	Yes	1,768	Yes
Winter	Top 10%	$185.57	1,549	25,782	24,233	6,073	Yes	6.0	Yes	1,018	Yes
Winter	Peak	$47.55	0	19,398	19,398	6,073	Yes	0.0	Yes	1,421	Yes
Winter	Off Peak	$50.16	0	18,024	18,024	6,073	Yes	0.0	Yes	1,592	Yes

Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$62.03	8,328	54,898	46,569	40,893	Yes	15.2	Yes	1,118	Yes
Spring/Fall	Peak	$35.73	8,067	50,911	42,844	28,923	Yes	15.8	Yes	1,091	Yes
Spring/Fall	Off-Peak	$29.46	6,604	42,360	35,756	24,614	Yes	15.6	Yes	1,144	Yes
Summer	Top 1%	$148.44	8,167	59,150	50,984	51,071	No	13.8	Yes	1,122	Yes
Summer	Top 10%	$64.59	8,177	55,871	47,694	47,510	Yes	14.6	Yes	1,106	Yes
Summer	Peak	$35.56	8,124	51,799	43,675	36,423	Yes	15.7	Yes	1,081	Yes
Summer	Off Peak	$24.88	7,000	42,890	35,889	29,051	Yes	16.3	Yes	1,166	Yes
Winter	Top 10%	$185.57	6,650	55,530	48,880	41,770	Yes	12.0	Yes	1,106	Yes
Winter	Peak	$47.55	4,612	43,963	39,351	34,380	Yes	10.5	Yes	1,207	Yes
Winter	Off Peak	$50.16	4,610	39,966	35,356	30,307	Yes	11.5	Yes	1,281	Yes

Delivered Price Test - PJME Market (Add Keys Energy Center and Retire Mercer and Hudson)

Available Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$57.82	2,123	17,335	15,212	3,806	Yes	12.2	Yes	1,152	Yes
Spring/Fall	Peak	$32.73	2,294	19,270	16,977	3,806	Yes	11.9	Yes	1,263	Yes
Spring/Fall	Off Peak	$26.67	1,619	16,678	15,059	3,806	Yes	9.7	Yes	1,534	Yes
Summer	Top 1%	$145.63	976	13,601	12,625	6,174	Yes	7.2	Yes	1,280	Yes
Summer	Top 10%	$63.88	1,118	12,863	11,745	6,174	Yes	8.7	Yes	1,123	Yes
Summer	Peak	$29.67	2,332	13,884	11,551	6,174	Yes	16.8	Yes	1,381	Yes
Summer	Off Peak	$21.25	1,282	11,019	9,738	6,174	Yes	11.6	Yes	2,645	No
Winter	Top 10%	$193.51	2,034	20,388	18,354	2,710	Yes	10.0	Yes	1,174	Yes
Winter	Peak	$50.59	0	14,721	14,721	2,710	Yes	0.0	Yes	1,541	Yes
Winter	Off Peak	$50.94	0	13,827	13,827	2,710	Yes	0.0	Yes	1,786	Yes

Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$57.82	7,708	35,402	27,694	22,528	Yes	21.8	No	1,197	Yes
Spring/Fall	Peak	$32.73	6,634	32,603	25,969	15,404	Yes	20.3	No	1,179	Yes
Spring/Fall	Off-Peak	$26.67	5,077	28,456	23,379	13,106	Yes	17.8	Yes	1,241	Yes
Summer	Top 1%	$145.63	7,431	35,422	27,991	29,462	No	21.0	No	1,204	Yes
Summer	Top 10%	$63.88	7,437	33,714	26,276	27,143	No	22.1	No	1,200	Yes
Summer	Peak	$29.67	6,935	31,187	24,252	20,217	Yes	22.2	No	1,231	Yes
Summer	Off Peak	$21.25	5,169	26,733	21,564	16,090	Yes	19.3	Yes	1,272	Yes
Winter	Top 10%	$193.51	6,125	34,665	28,540	21,263	Yes	17.7	Yes	1,142	Yes
Winter	Peak	$50.59	3,988	26,323	22,335	17,939	Yes	15.1	Yes	1,255	Yes
Winter	Off Peak	$50.94	3,997	22,913	18,916	15,660	Yes	17.4	Yes	1,451	Yes

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1. **Availability.** PSEG Keys Energy Center LLC ("PSEG Keys" or "Seller") will make wholesale electric energy, capacity, and ancillary services available under this Tariff to any purchaser for resale, except as prohibited below.

2. **Applicability.** This Tariff is applicable to all sales of energy, capacity, and ancillary services by PSEG Keys not otherwise subject to a particular rate schedule of PSEG Keys.

3. **Rates.** All sales shall be made at the rates established between the purchaser and PSEG Keys.

4. **Other Terms and Conditions.** All other terms and conditions shall be established by agreement between the purchaser and PSEG Keys.

5. **Compliance with Commission Regulations.** PSEG Keys shall comply with the provisions of 18 C.F.R. Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning PSEG Key's market-based rate authority, including orders in which the Commission authorizes PSEG Keys to engage in affiliate sales under this Tariff or otherwise restricts or limits the PSEG Key's market-based rate authority. Failure to comply with the applicable provisions of 18 C.F.R. Part 35, Subpart H, and with any orders of the Commission concerning PSEG Key's market-based rate authority, will constitute a violation of this Tariff.

6. **Limitations and Exemptions Regarding Market Based Rate Authority.** PSEG Keys does not have any limitations on its market-based rate authority except as other provided in this Tariff. The Commission granted Seller in Docket No. ER17-___-000 the following waivers and blanket authorization: (a) waiver of Subparts B and C of Part 35 of the Commission's regulations requiring the filing of cost-of-service information, except for sections 35.12(a), 35.13(b), 35.15 and 35.16; (b) waiver of the requirements of Part 41 and Part 101; (c) waiver of Part 141 of the Commission's regulations concerning accounting and reporting requirements, with the exception of 18 C.F.R. §§ 141.14 and 141.15; and (d) blanket approval as to Section 204 of the FPA and Part 34 of the Commission's regulations for all future issuances of securities and debt and assumption of liabilities.

7. **Ancillary Services.**

   Third-party ancillary services: PSEG Keys offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier.

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Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

8. **Seller Category.** PSEG Keys is a Category 2 Seller in the Northeast Region and a Category 1 seller in the Central, Northwest, Southeast, Southwest and Southwest Power Pool regions, as defined by 18 C.F.R. 35.36(a),

9. **Effective Date.** This Tariff is effective on the date specified by the Commission. This Tariff shall continue in effect until terminated or changed in accordance with any applicable regulatory requirements.

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DAVID K. RICHTER
LAW DEPARTMENT

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PSEG Services Corporation

December 28, 2016

ELECRONICALLY AND VIA OVERNIGHT MAIL

Kimberly J. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Triennial Market Power Update in Compliance with Order No. 697:
***PSEG Energy Resources & Trade LLC*, Docket No. ER99-3151-____;**
***Public Service Electric and Gas Company*, Docket No. ER97-837-____;**
***PSEG Power Connecticut LLC*, Docket No. ER03-327 -___;**
***PSEG Fossil LLC*, Docket No. ER08-447-___;**
***PSEG Nuclear LLC*, ER08-448-___; and**
***PSEG New Haven LLC*, ER12-1250-___**
Pavant Solar II LLC, ER16-1925-___
San Isabel Solar LLC, ER16-1926-___
Bison Solar LLC, ER16-1924-___
PSEG Energy Solutions LLC, ER16-2725-___

Dear Secretary Bose:

Pursuant to the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), PSEG Energy Resources & Trade LLC ("PSEG ER&T"), Public Service Electric and Gas Company ("PSE&G"), PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Fossil LLC ("PSEG Fossil"), PSEG Nuclear LLC ("PSEG Nuclear"), PSEG New Haven LLC ("PSEG New Haven") Pavant Solar II LLC, San Isabel Solar LLC, Bison Solar LLC and PSEG Energy Solutions LLC (collectively the "Applicants" or "PSEG") hereby jointly submit for filing their updated market power analysis in support of their continued eligibility to engage in market-based rates

transactions. This market power analysis satisfies the requirements of Order No. 697[1] for the filing of updated market power analyses on a regional schedule basis by holders of market-based rate certificates and their affiliates. In accordance with the regional schedule for those utilities in the Northeast Region, as modified by the MBR Clarifying Order, this filing is being made by the December 2016 deadline.[2] In conformance with the Commission's requirements, except when expressly noted otherwise, the market power analysis is based on activity during the study period from December 1, 2014 through November 30, 2015 ("study period").

PSEG, through its subsidiary PSE&G, owns transmission facilities within the Northeast Region. Specifically, PSE&G owns transmission facilities in the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization. PSEG Power LLC and its subsidiaries do not own any transmission facilities other than transmission to connect generating units to the grid in PJM, the New York Independent System Operator, Inc. ("NYISO") and ISO New England Inc. ("ISO-NE").

In their original applications for market-based rate authority and previously-submitted updates to the Commission, PSEG ER&T, PSE&G, PSEG Power CT, PSEG Fossil, PSEG Nuclear and PSEG New Haven demonstrated that they and their affiliates: (a) do not exercise generation market power; (b) lack the ability to manipulate access to transmission facilities that they own or control; and (c) cannot erect any other barriers to market entry. As further demonstrated herein and in the Affidavit of Dr. John R. Morris attached hereto in the appendices, Applicants continue to satisfy the Commission's requirements to sell energy, capacity and ancillary services at market-based rates and thus should be permitted to continue to make such sales.

I. SERVICE AND COMMUNICATION

All service and correspondence related to this matter should be directed to the following individuals:

[1] 18 C.F.R. Part 35, Subpart H (2007); Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, 119 FERC ¶ 61,295, ("Order No. 697" or "MBR Order"), *order clarifying final rule*, 121 FERC ¶ 61,260 (2007) ("MBR Clarifying Order"), *order on reh'g and clarification*, 123 FERC ¶ 61,055 (2008) FERC Stats. & Regs ¶ 31,268 ("Order No. 697-A"), *order on reh'g and clarification*, 124 FERC ¶ 61,055 (2008) ("SIL Allocation Order").

[2] This filing is made on the three year anniversary of the December 2013 deadline set forth in Order No. 697 Appendix D.

As to the Applicants Generally:

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Applicants request waiver of Rule 203(b)(3)[3] so that a copy of any communications in these proceedings may be served on all persons listed above.

II. DESCRIPTION OF THE APPLICANTS AND RELEVANT AFFILIATES

A. The Applicants

The Applicants are each wholly owned, direct and indirect subsidiaries of Public Service Enterprise Group Incorporated ("PSEG"). PSEG is a public utility holding company engaged in, among other things, the generation of electric energy and the transmission, distribution and sale of electricity and natural gas through its subsidiaries.

1. Public Service Electric and Gas Company

PSE&G is a public utility operating company engaged primarily in the transmission of electricity, and the provision of gas and electric distribution service in the State of New Jersey. During the study period, PSE&G owned less than 140 MW of solar generation, 8 MW of Energy Efficiency and 91 MWs of Demand Response but otherwise did not own or operate any electric generation facilities. PSE&G is a member of the PJM Regional Transmission Organization and has made all of its transmission facilities available for open access transmission service pursuant to the PJM Open Access

[3] 18 C.F.R. § 385.203(b)(3).

Transmission Tariff ("OATT") administered by PJM. PSE&G is authorized to sell power at market-based rates and makes wholesale sales falling within several different categories, as described below.

Non-utility generation ("NUG") output. PSE&G's NUG output expired in 2015 and 2016 pursuant to the terms of the NUG contracts. PSE&G currently has no further NUG obligations, other than 0.6 MW of energy associated with the former Kinsley Landfill which no longer operates. .

Solar. In 2007, the New Jersey legislature passed Regional Greenhouse Gas Initiative ("RGGI") legislation authorizing state utilities to invest in renewable resources such as wind or solar in order to promote increased use of renewable resources within the state and in turn reduce greenhouse gas emissions. *See* L. 2007, c. 340, codified at N.J.S.A. 48:98-1. The NJBPU has approved two (2) PSE&G Solar 4 All® (S4A) programs under which PSE&G has sited, designed and built twenty-nine (29) grid connected solar facilities. PSE&G currently owns and operates approximately 115MW-dc of grid connected solar under the S4A program. PSE&G expects the S4A fleet to increase to approximately 125MW-dc by the end of 2016. In 2016, PSE&G received NJBPU approval of its Solar 4 All Extension II filing to install an additional 33MW-dc of grid connected solar on landfills and brownfields in the PSE&G electric service territory.

2. PSEG Energy Resources & Trade LLC

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil and PSEG Nuclear, each wholly-owned subsidiaries of PSEG Power LLC ("PSEG Power"), as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission.

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

BGS Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 *et seq.,* which initiated the transition from a regulated to a competitive retail power market in New Jersey, BPU annually approves statewide auctions to determine the entities that will supply Basic Generation Service ("BGS") in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSEG ER&T has participated directly in all of the auctions for BGS supply held since 2004, has been a winning bidder in these auctions and has incurred contractual

commitments to provide supply to BGS load pursuant to BPU approved contracts beginning with the 2004 auction and continuing to the present

BGSS Gas Contract. By order issued April 16, 2002, the BPU approved a full requirements contract for the provision of gas supply by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the BPU, PSEG ER&T assumed, through capacity release, FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract remains in effect and provides for annual renewals unless terminated by either party on 12 months' advance written notice.

LIPA Fuel Supply: On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which ER&T will provide fuel supply and power supply management activities for LIPA beginning on January 1, 2015.

3. PSEG Fossil LLC

PSEG Fossil is an Exempt Wholesale Generator ("EWG") and is authorized to sell power at market-based rates. PSEG Fossil owns and operates electric generation facilities located within PJM and sells their entire output to its affiliate PSEG ER&T.[4] The assets of PSEG Fossil (and its subsidiary, PSEG Keys Energy Center LLC ("PSEG Keys")) are located entirely within PJM. However, PSEG Fossil's subsidiaries PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Power New York LLC and PSEG New Haven LLC own facilities in ISO-NE and NYISO. As noted below, PSEG Fossil also co-owns certain facilities in PJM.

PSEG Fossil and its subsidiaries PSEG Power CT and PSEG Keys are currently beginning construction on three new gas-fired generation units. PSEG Fossil is constructing Sewaren 7[5] which is a 540 MW combined cycle unit in Woodbridge, New Jersey which is expected to be in-service in 2018, PSEG Keys is constructing a 755 MW combined cycle unit in Prince George's County, Maryland which is expected to be in service in 2018 and PSEG Power CT is constructing Bridgeport 5, a 485 MW combined cycle unit in Bridgeport, Connecticut which is expected to be in service in 2019.

Since the last triennial filing in December 2013 PSEG Fossil has retired 1,813.5 MWs (nameplate) inclusive of the following units:

Kearny 9 (18.6 MW)
Bergen 3 (18.6 MW)

[4]These contracts were originally approved by the Commission as cost-based contracts. *See Public Service Electric and Gas Company*, et al., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Fossil obtained market based rate authority covering sales from its generating units.

[5] Once Sewaren 7 begins commercial operation, PSEG Fossil plans to retire Sewaren 1, 2, 3 and 4.

Bridgeport 2 (179.5 MW)
Burlington 8 (18.6 MW
Burlington 9 (162.4 MW)
Burlington 11 (162.4 MW)
Edison 1 (167.4 MW)
Edison 2 (167.4 MW)
Edison 3 (167.4 MW)
Essex 10 (167.4 MW)
Essex 11 (167.4 MW)
Essex 12 (167.4 MW)
Mercer 3 (115.2 MW)
National Park (18.6 MW)
Sewaren 6 (115.2 MW)

In addition, PSEG Fossil, LLC notified PJM of its intent to retire Hudson 2 (659 MW nameplate rating) and Mercer Units 1 and 2 (652MW nameplate rating) by June 1, 2017.

PSEG Fossil satisfies most of the electricity needs of its plants from PJM under PJM's "station power" Tariff provisions. PSEG Fossil procures gas supply for its plants from PSEG ER&T and receives gas distribution service from PSE&G at a rate approved by the BPU on May 29, 2013.[6]

4. PSEG Power Connecticut LLC

PSEG Power CT is a Connecticut limited liability company and an EWG that owns and operates electric generation facilities in the State of Connecticut and is authorized to sell power at market-based rates.[7] Both of PSEG Power CT's generation facilities, Bridgeport Harbor and New Haven Harbor, are located in the State of Connecticut within the market administered by ISO-NE. PSEG Power CT sells the output of its generation facilities to its affiliate PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority. As noted above, PSEG Power CT is currently constructing Bridgeport 5, a 485 MW combined cycle unit in Bridgeport, Connecticut which is expected to be in service in 2019.

5. PSEG New Haven LLC

PSEG New Haven is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG New Haven owns and operates a facility (the "New Haven facility") in New Haven, Connecticut with a nameplate rating of 181 MWs. The New Haven facility is located within the New Haven Harbor generation station. The New Haven facility is interconnected to the adjacent United Illuminating East Shore Substation using a 115 KV underground cable. PSEG New Haven has no other

[6] BPU Docket No. GM12100935 (May 29, 2013).
[7] *Wisvest Corporation,* et al., 101 FERC ¶ 61,166 (2002).

generation assets. The commercial operation date for the New Haven facility was June 1, 2012 and PSEG New Haven has obtained MBR authority from FERC.[8]

The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[9] pursuant to a Connecticut statute that sought proposals for peaking generation in Connecticut.[10] All of the energy and capacity of the New Haven facility is sold into the ISO New England ("ISO-NE") markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA[11] has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder. The 181 MW nameplate rating of the New Haven Facility has not been included in the capacity controlled by PSEG for purposes of Dr. Morris' market power analysis.

6. PSEG Nuclear LLC

PSEG Nuclear is an EWG[12] and is authorized to sell power at market-based rates. PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission.[13] The assets of PSEG Nuclear are located entirely within PJM. PSEG Nuclear performed the following uprates since the last triennial filing: (1) an uprate of 120 MWs at its Hope Creek plant in 2014, which increased its nameplate rating to 1290 MWs, (2) an uprate to Peach Bottom 2 and 3 which increases PSEG's share of the nameplate MWs by 241 MWs for a updated nameplate of 704 MW for Peach Bottom 2 and 689 MWs for Peach Bottom 3.

7. Pavant Solar LLC, San Isabel Solar LLC and Bison Solar LLC

PSEG Power Ventures portfolio includes three (3) solar companies with market-based rate authority: (1) *Pavant Solar II LLC*[14] is a QF which owns a 50 MW (AC) solar facility in Fillmore Utah; (2) *San Isabel Solar LLC*[15] is a QF which owns a 30 MW (AC)

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[8] *PSEG New Haven LLC*, Docket No. ER12-1250-000, et al., (May 29, 2012).

[9] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control (DPUC). PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

[10] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

[11] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

[12] *PSEG Nuclear LLC*, 97 FERC ¶ 62,191 (November 30, 2001).

[13] *Public Service Electric and Gas Company*, et al., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Nuclear obtained market based rate authority from the FERC.

[14] *Pavant Solar II LLC*, Docket No. QF16-1072-000.

[15] *San Isabel Solar LLC*, Docket No. QF16-712-000.

solar facility in Las Animas County, Colorado and (3) *Bison Solar LLC*[16] is a QF which owns a 30 MW (AC) solar facility 25 miles north of Fort Collins, Colorado.

8. PSEG Energy Solutions LLC

PSEG Energy Solutions LLC ("PSEG Solutions") is a Delaware limited liability company and a direct subsidiary of PSEG ER&T. PSEG Solutions obtained market-based rate authority[17] and will operate within the PJM Interconnection, L.L.C. ("PJM"), New York Independent System Operator, Inc. ("NYISO") and ISO New England Inc. ("ISO-NE") markets. Energy Solutions will purchase power from the regional transmission organization ("RTO") at wholesale and sell it to retail customers. PSEG Solutions will not own or operate any generation assets. PSEG Solutions proposes to begin its retail business on January 1, 2017.

OTHER RELEVANT AFFILIATES

PSEG is also the direct or indirect parent of certain other subsidiaries engaged in energy related activities, as discussed below.

7. Affiliated Generation Ownership.

A list of the Applicants' affiliated domestic FERC jurisdictional generation assets owned is contained in Appendix B attached hereto. [18] Those additional subsidiaries of PSEG that may be considered relevant to this market power update for the Northeast Region are described below:

PSEG Power LLC ("PSEG Power") was formed in 1999 to acquire the former generation assets of PSE&G. PSEG Power, a Delaware limited liability company, does not directly own any generation facilities or engage in any FERC jurisdictional activities but is the parent company of several FERC jurisdictional entities, including Applicants PSEG ER&T (and it subsidiary PSEG Energy Solutions LLC), PSEG Fossil, PSEG Nuclear, PSEG Power CT, PSEG New Haven and PSEG Power Ventures LLC (which owns PSEG Solar Source LLC).

PSEG Power Ventures LLC and PSEG Solar Source LLC. PSEG Power Ventures LLC ("Power Ventures") is a Delaware Limited Liability company and a direct subsidiary of PSEG Power. PSEG Power Ventures owns 100% interest in PSEG Solar Source LLC and has an in-direct ownership interest in a domestic power plant in Hawaii. PSEG Solar Source owns approximately 349 MWs DC (274 MW AC) of solar capacity across the United States, including a combined 92

[16] *Bison Solar LLC*, Docket No. QF16-711-001.
[17] See Letter Order dated December 21, 2016 in Docket No. ER16-2725-000.
[18] Appendix B excludes generation assets located in Hawaii as well as generation assets in which PSEG's interest is limited to a leveraged lease interest.

MWs[19] (72 MW AC) of solar capacity in PJM and approximately the following amount of MWs in the following states all through separate project companies which have all obtained QF status.

- 15 MWs (12 MW AC) in Florida,
- 92 MWs in PJM (72 MW AC) – 12 MWs in Ohio, 2 MW in New Jersey, 15 MW in Delaware, 50 MW in North Carolina and 13 MW in Maryland
- 45 MWs in Arizona (34 MW AC) – 25 MW Queen, approximately 20 MW Badger
- 13 MWs (10 MW AC) in Texas,
- 34 MWs (25 MW AC) in California[20]
- 4 MWs (3 MW AC) in Vermont and
- 74 MW (60 MW AC) in Colorado (to be in operation in 2016) – 38 MWs for San Isabel and 36 MWs for Bison
- 62 MW (50 MW AC) in Utah (to be in operation in 2016).
- 10.5 MW (8 MW AC) in Oregon (to be in operation in 2016).

PSEG Resources LLC ("Resources") is a New Jersey limited liability company that provides energy infrastructure financing in developed countries. Resources invests primarily in energy-related financial transactions and manages a diversified portfolio of investments including leveraged leases. Resources owns interests, through leveraged leases, in various generation stations. Pursuant to the terms of these triple net leases, the lessee, not Resources, has all operational responsibility and control over the leased generation stations.

PSEG Power New York LLC ("PSEG Power NY") is a Delaware limited liability company and an EWG that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 750 MW combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a FERC-approved cost-based contract.[21]

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[19] The 92MWs are attributed to four (7) separate project companies that have QF status: PSEG Solar Hackettstown LLC (2 MW); PSEG Solar Delaware LLC (15 MW), Rockfish Solar LLC (13 MWs) Meadows Solar (26 MW), Turkey Creek (17 MW) Hemlock Solar (7 MW) in North Carolina and PSEG Solar Ohio LLC (12 MW).

[20] The 28MWs (DC) are associated with the Shasta Solar Facility in California (4 MW), Whitehorn Solar (3 MWs) the Columbia Solar Project (19 MW). All have obtained QF status.

[21] *PSEG Power New York Inc.*, Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

PSEG Keys Energy Center LLC ("PSEG Keys") is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG Keys was formed to construct, operate and maintain the Keys Energy Center, a 755MW combined cycle power plant in Prince Georges County, Maryland. Construction began in 2015 and is expected to be completed in 2018 at which time the capacity will be available in the PJM market. All of the output of the Keys Energy Center will be sold to PSEG Keys affiliate, PSEG ER&T.

PSEG Long Island LLC ("Long Island") and Long Island Electric Utility Servco, LLC ("Servco") are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution system ("T&D") on Long Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither Long Island nor Servco will be FERC jurisdictional public utilities as neither will exercise ultimate decision making authority over the T&D system in Long Island. Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[22]

8. Affiliated Transmission Ownership

With the exception of the electric transmission assets owned by Applicant PSE&G, all of which are located within the PJM RTO, and the generation interconnection facilities owned by the various EWG and QF affiliates listed herein, the Applicants, nor their affiliates have any affiliates that own or operate FERC jurisdictional electric or natural gas transmission facilities within the United States[23]. As discussed below, FERC granted PSE&G a Hinshaw exemption in 1954, finding that it was exempt from the provisions of the Natural Gas Act.

B. JOINTLY OWNED FACILITIES

PSEG Nuclear is a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear is the operator of Salem and Exelon Generation is the operator of Peach Bottom.[24] PSEG Fossil is approximately a 23% joint owner in the Conemaugh and Keystone generating stations located in Pennsylvania. An affiliate of NRG Energy is the operator.[25] Accordingly, for

[22] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), *order dismissing request for rehearing*, 145 FERC ¶ 61,183 (2013).

[23] PSEG Power LLC is a 10% owner of the PennEast Pipeline Company LLC which has filed an application for approval to construct and operate a natural gas transmission line.

[24] A letter of concurrence supporting the allocation of plant output based on ownership interests is attached in Appendix E. The ownership percentages have not changed since the date of this letter. PSEG Nuclear owns a 50% interest in Peach Bottom and a 57.41% interest in Salem.

[25] A letter of concurrence supporting the allocation of plant output based on ownership interest is attached in Appendix E. The ownership percentages have not changed since the date of this letter.

purposes of this market power analysis, the capacity of Salem, Peach Bottom, Conemaugh and Keystone has been attributed to PSEG in accordance with PSEG's ownership interests in these facilities.

PSEG Fossil and Jersey Central Power and Light Company ("JCP&L") are each 50% co-owners of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to the unit. Accordingly, for the purpose of this market power analysis, the entire unit capacity – nominally 400 MWs – has been assigned to JCP&L.[26]

III. Applicants Fully Satisfy The Commission's Standards For Authority to Make Power Sales At Market-Based Rates.

The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, horizontal and vertical market power.[27] The Commission has also codified affiliate restrictions in its regulations which must be satisfied on an ongoing basis. In previous submissions for market-based rate authority the Applicants PSE&G, PSEG ER&T, PSEG Power CT, PSEG Fossil, PSEG Nuclear, and PSEG New Haven, demonstrated compliance with each of these requirements. As detailed herein and in the attached affidavit, the Applicants continue to meet these standards.

A. The Applicants Lack, Or Have Effectively Mitigated, Any Horizontal Market Power

In the MBR Order, the Commission established two indicative screens: a pivotal supplier screen based on the control area's annual peak demand and a wholesale market share screen applied on a seasonal basis. If an applicant passes both screens, there is a rebuttable presumption that the applicant does not possess horizontal market power. Each indicative screen is applied with respect to "relevant geographic markets" for an applicant's generating units.

Applicants located in ISOs/RTOs possessing sufficient market structure may consider the geographic region under the control of the ISO/RTO as the relevant default geographic region for purposes of completing their generation market power analyses.[28] However, where the Commission has previously found a "submarket" to exist within a boundary of an RTO, such finding is controlling as to the scope of the relevant geographic market for all generation units located within that submarket for the application of the indicative screens and any delivered price test that may be performed. The Commission further listed several such submarkets, including PJM East ("PJME"),

[26] A letter of concurrence supporting this determination is attached in Appendix E. The ownership percentages have not changed since the date of this letter.
[27] MBR Order, FERC Stats. & Regs. ¶ 31,252 at P 62, 399, 408, 440.
[28] *MBR Order at* PP. 231 and 235.

Connecticut and Southwest Connecticut.[29] Subsequent to the MBR order, in approving a merger between Exelon Corporation and Constellation Energy Group, Inc., the Commission identified additional submarkets in PJM - PJM East of 5004/5005 ("PJM50") and PJM East of AP South ("PJMAP") - that would be relevant to an MBR analysis for applicants in the Northeast Region.[30]

As discussed below and in the attached Affidavit of Dr. John Morris contained in Appendix A, Applicants have conducted market power analyses of the entire PJM RTO, the PJME, PJM50 and PJMAP submarkets, the entire NYISO, the entire ISO-NE, the Connecticut submarket and the Southwest Connecticut submarket for the study period. The results are set forth below.

1. Indicative Screens

a. Pivotal Supplier Analysis

The pivotal supplier analysis ("PSA") focuses on the ability of a seller to exercise unilateral market power.[31] The screen assesses whether market demand can be met during peak times without the applicant and its affiliates. If demand can be met without the applicant and its affiliates, the applicant passes that the PSA screen. The Affidavit of Dr. John Morris, attached hereto as Appendix A, finds that the Applicants pass the PSA screen for all relevant markets: PJM, NYISO, ISO-NE, Connecticut, Southwest Connecticut, PJMAP, PJME and PJM50.[32]

b. Wholesale Market Share Analysis

The wholesale market share analysis ("WMSA") is applied each season to determine whether an applicant has a dominant market position based on the total number of megawatts of uncommitted capacity owned or controlled by the applicant and its affiliates in relation to the uncommitted capacity of the entire relevant wholesale electricity market.[33] The established threshold is 20 percent; a supplier who has less than 20 percent market share in the relevant market for all seasons passes the WMSA screen.

In his Affidavit Dr. Morris finds that the Applicants pass the WMSA screen for PJM, NYISO, ISO-NE, Connecticut, Southwest Connecticut and PJMAP but do not pass the WMSA screen for the PJME and PJM50 submarkets.[34]

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[29] *Order No. 697* at P 236 (citing *Exelon Corp.*, 112 FERC ¶ 61,011, *reh'g denied*, 113 FERC ¶ 61, 299 (2005)). FERC eliminated the Northern PSEG zone as a default submarket in Order No. 697-A, P 99.

[30] Order Conditionally Authorizing Merger and Disposition of Jurisdictional Facilities, *Exelon Corporation, et al.*, 138 FERC ¶ 61,167 (2012).

[31] *AEP I* at P 72.

[32] *See* Morris Affidavit, at 15-29.

[33] *AEP I,* P 100.

[34] *See* Morris Affidavit, at 15-29.

c. Results of Indicative Screen Analysis

As shown in Dr. Morris's affidavit, Applicants therefore pass both indicative screen tests for PJM RTO, NYISO, ISO-NE, Connecticut and Southwest Connecticut and PJMAP. For PJME and PJM50, the Applicants pass the PSA but do not pass the WMSA.

2. Delivered Price Test Analysis For PJME and PJM50 Submarkets

In accordance with the MBR Order, applicants who fail either indicative screen test can rebut the presumption of market power through the submission of a delivered price test analysis ("DPT"). Applicants may submit this study at the same time that the results of the indicative screens are provided.[35] The DPT is based on two measurements of potential market power: economic capacity ("EC") and available economic capacity ("AEC"). EC is the capacity that can be delivered to a destination market for 105 percent or less than the market price. AEC is calculated by subtracting native load commitments from EC. Both calculations are performed for ten different season and load conditions.

In applying the DPT, "[a] showing of an HHI less than 2,500 in the relevant market for all season/load conditions for sellers that have also shown that they are not pivotal and do not possess a 20 percent or greater market share in any of the season/load conditions would constitute a showing of a lack of market power, absent compelling contrary evidence from intervenors."[36] However, while meeting these threshold benchmarks provides "safe harbor" protection, the Commission has found in numerous other cases that applicants lack market power even when they exceed one or more of the thresholds for particular study periods. As stated in *Public Service Company of New Mexico*, 115 FERC ¶ 61,090, P 38 (2006), "the Commission weights the results of both the economic and available economic capacity tests and considers the arguments of the applicant and intervenors." (footnote omitted.) [37]

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[35] *Order No. 697,* P 76.

[36] *Order No. 697* at P 111.

[37] Indeed, in that case, the applicant was deemed "on balance" to have adequately rebutted a showing of market power mitigation for the PNM control area where the results exceeded the 20% safe harbor in two cases under the AEC measure and in all 10 cases at values between 35% and 41% under the EC measure. *See, e.g.*, *Kansas City Power and Light Company, et al.*, Docket Nos. ER99-1005-011 et al. (August 12, 2010) (finding no market power where applicant had EC market shares in the 40-60% range and had significant HHI failures in the KCPL and GMO markets); *Cordova Energy Company LLC et al,* Docket Nos. ER99-2156-011, *et al.*, November 13, 2007 (finding no market power in case where applicant had EC market shares in PACE control area between 53.1% and 60.0%, HHIs between 2,958 and 3,696 and was pivotal in 8 out of 10 periods.); *PacifiCorp*, Letter Order, Docket Nos. ER97-2801-007, *et al.*, February 1, 2007; *Tucson Elec. Power Co.*, 116 FERC ¶ 61,051 (2006)(finding market power standard satisfied where applicant had EC market shares above 20% in all ten season/load periods in the Tucson control area, exceeded the 2,500 HHI threshold in eight periods, and was pivotal in 5 periods); *PacifiCorp*, 115 FERC ¶ 61,349 (2006) (finding that applicants rebutted presumption of market power in the PacifiCorp East control area where under available economic capacity measure, market share is less than 20% in 8 season/load periods and 28% in the summer and winter off-peak periods, HHI does not exceed 2500 in any season/load period and applicants are not pivotal); *Kansas City Power & Light Co.*, 113 FERC ¶ 61,074 (2005) (finding

a. Results of the DPT for PJM50 Submarket

For both the AEC and EC, PSEG passes all screens in all periods except for the pivotal supplier screen in the Summer Top 1% period.

b. Results of the DPT for PJME Submarket

With respect to AEC, PSEG passes all the screens in all 10 periods. With respect to the EC, PSEG passes the Market Concentration screens in all periods. It also passes the Pivotal Supplier Screen in 8 of 10 periods, and passes the Market Share Screen in 6 of 10 periods. PSEG's market shares are never above 25 percent. Although greater than the 20 percent screen, PSEG's market shares are well below the 35 percent threshold that is typically used for imputing unilateral market power.

3. Analysis of DPT Results

Based on his analysis of the overall results, Dr. Morris concludes that, although PSEG fails limited number of screens, the failures are substantially below levels that typically indicate market power. As set forth in his Affidavit, Dr. Morris states that:

> Although PSEG fails some screens in the PJME destination market, the overall results are not indicative of PSEG having market power. To begin, PSEG passes all the AEC screens and all market concentration (HHI) screens for EC. The HHI levels in all periods, capacity types, and areas are below the screening threshold of 2,500, and typically substantially below this level. In terms of the DPT for market rate authority and under the 2010 DOJ and FTC Horizontal Merger Guidelines, the market is not highly concentrated.[38] The low HHI levels mean that PSEG has little ability to exercise market power in coordination with other suppliers. It also passes all the AEC pivotal supplier screens, and most of the EC pivotal supplier screens. This means that typically PSEG's generation is not necessary to serve load; and when its generation is necessary, its forward sale commitments are sufficient so that its uncommitted generation is not necessary to serve the remaining load. Finally, PSEG's market shares are never above 15 percent in PJM50 and for AEC in PJM East. Its market shares for EC are never above 25 percent in PJM East. Although greater than the 20 percent screen, PSEG's market shares are

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no market power in the KCPL control area where applicant had EC market shares above 20% in all periods, exceeded the HHI 2,500 threshold in 5 of 10 periods and was pivotal supplier in 1 period); *Acadia Power Partners, L.P.*, 113 FERC ¶ 61,073 (2005) (finding no market power in the Cleco Power home control where, utilizing the EC measure, the applicant exceeded the thresholds set for all season/load periods using the market share measure, one season/load period using the market concentration measure, and for all season/load periods using the pivotal supplier measure).

[38] See U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Issued August 19, 2010, at Section 5.3, available at http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

well below the 35 percent threshold that is typically used for imputing unilateral market power.[39]

Dr. Morris's conclusion is consistent with Commission precedent finding a lack of market power in cases in which the DPT results included more instances of findings outside of the "safe harbor" thresholds and at higher levels than exist here.[40] In these circumstances, Dr. Morris's analysis successfully rebuts any inference of market power created by the WMSA screen failures for PJME.

4. Existing RTO/ISO Mitigation Rules Also Eliminate The Potential for Exercising Market Power In the PJME, PJME PJM50 and PJMAP Submarkets

PJM mitigation rules eliminate the potential for the exercise of market power in the PJME submarket. The MBR Order specifically contemplated that RTO/ISO mitigation rules may serve as evidence that any market power has been adequately mitigated. The Commission declared, "We believe the added protections provided in structured markets with market monitoring and mitigation generally result in a market where prices are transparent and attempts to exercise of market power will be sufficiently mitigated."[41] The Order on Rehearing went even further and specifically created a presumption that any potential market power had been adequately mitigated by an established and effective RTO market monitoring scheme.[42]

Taking account of the pervasive PJM mitigation rule, Dr. Morris concludes that these rules "fully address the potential for PSEG to exercise market power" in PJME.[43] Accordingly, PJM's mitigation schemes in place are sufficient to rebut any inference of market power created by the failure to pass the WMSA screens in PJME and PJM50.

In addition, in the Applicants' last triennial approval order, the Commission found that "the PJM market monitoring and mitigation rules are sufficient to address market power concerns in the PJM-East submarket."[44]

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[39] *See*, *e.g.*, U.S. Department of Justice, 1984 Merger Guidelines, at Section 3.12, available at https://www.justice.gov/sites/default/files/atr/legacy/2007/07/11/11249.pdf ("the Department is likely to challenge the merger of any firm with a market share of at least one percent with the leading firm in the market, provided the leading firm has a market share that is at least 35 percent.")

[40] *See Public Service Company of New Mexico*, 115 FERC ¶ 61,090 (2006) discussed above and cases discussed in fn. 38 above.

[41] MBR Order at P 241.

[42] Order No. 697A at P 111.

[43] Morris Affidavit, pp. 24-26.

[44] *See* October 14, 2014 letter order approving Applicants' prior triennial market update in Docket No. ER10-1789-003 et al. at page 3.

a. The Applicants Lack Transmission Market Power and Cannot Erect Entry Barriers.

In its previous order accepting PSEG's triennial market power analysis for the Northeast Region, the Commission found that the submittal satisfied the Commission's requirements for market-based rates regarding vertical market power.[45] There have been no subsequent changes in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. As demonstrated below, neither Applicants nor any of its affiliates are able to exercise vertical market power.

Applicants are not able to exercise transmission market power. Neither Applicants nor any of their affiliates, except PSE&G, own transmission assets in the U.S. other than incidental generator interconnection facilities. PSE&G owns transmission facilities in PJM but transmission service over those facilities is provided under the PJM Open Access Transmission Tariff.

In addition, neither Applicants nor their affiliates are able to exercise vertical market power in wholesale energy markets through affiliation, ownership or control of inputs to electric power production. As required by Section 35.37(e) of the Commission's regulations, Applicants provide the following information:

(1) PSE&G owns and operates a natural gas distribution system that receives interstate pipeline gas within the State of New Jersey and distributes that gas to its customers within the State of New Jersey. The distribution system consists of 18,050 miles of gas distribution pipe and an additional 62 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3 and peak-shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers. Service over such distribution facilities is made available pursuant to state regulated tariffs on an open access type basis. PSE&G was granted a Hinshaw exemption from the FERC in 1954.[46] The gas distribution rates paid by PSEG Fossil to PSE&G have been set at rates approved by the BPU in an order dated May 29, 2013.

(2) Certain of the Applicants and their affiliates own sites within the Northeast Region that would be suitable for future generating facilities. These include space at many of the existing generating sites of PSEG Fossil and at the sites of PSEG Power NY and PSEG Power CT. PSEG Nuclear's Salem facility may also be suitable for future construction. PSE&G also owns certain sites that would be suitable for generating facilities, but under New Jersey's Electric Discount and Energy Competition Act, N.J.S.A 48:3-43 et seq., PSE&G is effectively barred from owning and operating

[45] *Id.*
[46] 13 F.P.C. 1348 (1954).

generation except "on site" generation for supply and Class I renewable energy resources as defined in N.J.S.A. 48:3-98.1.

(3) Neither Applicants nor any of their affiliates own or control any physical coal supply resources or own or control who may access transportation of coal supplies.

(4) As required by section 35.37(e)(4) of the Commission's regulations, Applicants and its affiliates state that they have not erected barriers to entry into any market, including the PJM, NYISO or ISO-NE market and will not erect barriers to entry into any markets.

IV. REQUEST FOR CONFIDENTIAL TREATMENT

Under separate cover via UPS Overnight this office is submitting compact disks containing the workpapers of Dr. John Morris supporting his analysis in Appendix A, as required by the Commission's April 2004 Order.[47] The CD (of which six copies are included) contains: (i) proprietary information provided by Energy Velocity under an agreement that requires confidential treatment to be requested for these materials; (ii) modeling and computer programs that are the proprietary intellectual property of Economists Incorporated, the firm which employs Dr. Morris; (iii) commercially sensitive information about Applicants and their affiliates; and (iv) documents and information deemed to be confidential by PJM and ISO-NE. Accordingly, Applicants respectfully request confidential treatment for CD and the workpapers pursuant to 18 C.F.R. § 388.112 (2006), consistent with the confidential treatment accorded other applicants submitting such proprietary and commercially sensitive data.[48] Pursuant to the Commission's rules, the public version of this filing contains all materials submitted herein except for CD, which is labeled as "PRIVILEGED AND CONFIDENTIAL/NON-PUBLIC."

V. SERVICE

This filing has been served on all parties on the official service list as currently maintained by Commission in the above-referenced dockets. Applicants are also providing a copy to the New Jersey Board of Public Utilities and the New Jersey Division of Rate Counsel.

VI. ENCLOSURES

Applicants enclose the following:

- An original filing;

[47] AEP II, 107 FERC at P 61,087-88.

[48] *See, e.g., Idaho Power Company*, Docket No. ER97-1481-009 (February 3, 2006) (submission of revised Pivotal Supplier Screen and Market Share Screen calculations including similar data).

- Appendix A – Affidavit of Dr. John R. Morris;[49]
- Appendix B – List of Entities with Market-Based Rates Authority and Their Generation Assets. (This is an appendix listing the filing entities and all their energy affiliates and their associated assets);
- Appendix C – List of Entities with Market-Based Rate Authority and Their Transmission Assets;
- Appendix D – List of Long Term Power Purchase Agreements;
- Appendix E – Letters of concurrence regarding the control of certain jointly owned generation facilities;
- Appendix F – Form of notice suitable for publication in the Federal Register.

[49] Compact disks, as described above, containing the workpapers for the Affidavit of John R. Morris in Appendix A are being sent concurrently with this filing via UPS Overnight. As noted *supra*, privileged treatment is being requested for Dr. Morris's confidential workpapers submitted with the non-public version of this filing.

VII. CONCLUSION.

Applicants respectfully request the Commission

(i) to accept this market power compliance filing as meeting the Commission's requirements under Order No. 697 for the continuation of market-based rate authority for Applicants PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG New Haven LLC, PSEG Nuclear LLC, PSEG Fossil LLC, Pavant Solar II, LLC, Bison Solar LLC , San Isabel Solar LLC and PSEG Energy Solutions LLC;

(ii) to grant the request for confidential treatment; and

(iii) to grant such other relief or waivers as may be appropriate or necessary.

Respectfully submitted,

Public Service Electric and Gas Company
PSEG Energy Resources & Trade LLC
PSEG Power Connecticut LLC
PSEG Fossil LLC
PSEG Nuclear LLC
PSEG New Haven LLC
Pavant Solar II, LLC
Bison Solar, LLC
San Isabel Solar, LLC
PSEG Energy Solutions LLC

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Dated: December 28, 2016
Newark, New Jersey

Appendix A
Affidavit of
Dr. John R. Morris

Appendix B
List of Entities with Market-Based Rate Authority and Their Generation Assets

Appendix C
List of Entities with Market-Based Rate Authority and Their Transmission Assets

Appendix D
Long Term Power Purchase Agreements

Appendix E
Letters of concurrence regarding the control of certain jointly owned generation facilities

Appendix F Form of notice suitable for publication in the Federal Register

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PSEG Energy Resources & Trade LLC	Docket No. ER99-3151-___
Public Service Electric and Gas Company	Docket No. ER97-837-___
PSEG Power Connecticut LLC	Docket No. ER03-327-_____
PSEG Fossil LLC	Docket No. ER08-447-_____
PSEG Nuclear LLC	Docket No. ER08-448-_____
PSEG New Haven LLC	Docket No. ER12-1250-___
Pavant Solar II LLC	Docket No. ER16-1926-____
San Isabel Solar LLC	Docket No.ER16-1925-____
Bison Solar LLC	Docket No.ER16-1924-____
PSEG Energy Solutions LLC	Docket No. ER16-2725-____

NOTICE OF FILING
( )

Take notice that on December 28, 2016: (i) PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG New Haven LLC, PSEG Fossil LLC, PSEG Nuclear LLC, Pavant II Solar LLC, Bison Solar LLC, San Isabel Solar LLC and PSEG Energy Solutions LLC tendered for filing their joint triennial market power update in compliance with Order No. 679 and with prior Commission Orders granting them market-based rate authority in Docket Nos. ER99-3151, ER97-837, ER03-327, ER08-447 ER08-448, DR-12-1250, ER16-1926, ER16-1925, ER16-1924 and ER16-2725 respectively.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR §§ 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file

electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).
Kimberly J. Bose
Secretary

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Public Service Electric and Gas Company	)	ER97-837-____
PSEG Energy Resources & Trade LLC	)	ER99-3151-____
PSEG Power Connecticut LLC	)	ER03-327-____
PSEG Fossil LLC	)	ER08-447-____
PSEG Nuclear LLC	)	ER08-448-____
PSEG New Haven LLC	) Docket Nos.	ER12-1250-____
Pavant II Solar LLC	)	ER16-1926-____
Bison Solar LLC	)	ER16-1925-____
San Isabel Solar LLC	)	ER16-1924-____
PSEG Energy Solutions LLC	)	ER16-2725-____

Report & Affidavit of
Dr. John R. Morris

December 22, 2016

Public Service Enterprise Group Incorporated Northeast Region Market Power Study

1. Introduction

My name is Dr. John R. Morris. I am a Principal at Economists Incorporated, an economic consulting firm located at 2121 K Street, NW, Washington, DC 20037. I have a bachelor's degree in economics from Georgetown University, and I have a master's degree and a Ph.D. in economics from the University of Washington. I have been studying and consulting within energy industries since joining the Federal Trade Commission in 1985. Since joining Economists Incorporated in 1992, I have consulted on many mergers involving electric and gas companies, examined competitive issues relating to utility rates, provided market power studies for applications for market-based rate authority, and studied market power issues in state restructuring proceedings. I have published articles on competition and energy matters, and I have spoken on numerous occasions concerning competition in natural gas, electric power and other industries. I have previously been accepted as an expert witness on energy matters before the Federal Energy Regulatory Commission ("FERC" or "Commission"), state commissions and in federal court. A complete listing of my experience, publications and testimony is contained in my resume, presented in Exhibit PEG-2.

Public Service Enterprise Group Incorporated ("PSEG") asked that I prepare a market power study for its subsidiaries that have market-based rate authority in the Northeast Region.[1] These subsidiaries are: Public Service Electric and Gas

[1] The Northeast Region includes ISO-New England Inc. ("ISO-NE"), Connecticut, Southwest Connecticut, New York Independent System Operator, Inc. ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), PJM East, PJM East of 5004/5005 and PJM East of AP South.

("PSE&G"), PSEG Energy Resources & Trade LLC ("PSEG ER&T"), PSEG Fossil LLC ("PSEG Fossil"), PSEG Nuclear LLC ("PSEG Nuclear"), PSEG Power Connecticut LLC ("PSEG Power CT"). PSEG New Haven LLC ("PSEG New Haven") Pavant II Solar LLC, Bison Solar LLC and San Isabel Solar LLC.[2] The purpose of this study is to determine whether these PSEG entities have market power in any Northeast Region market under the Commission's Pivotal Supplier Analysis ("PSA") and Wholesale Market Share Analysis ("WMSA") screens as articulated in FERC Order No. 697 and if the Applicants do fail any of the screens, whether they otherwise lack market power under the Delivered Price Test ("DPT") or are subject to sufficient mitigation to guard against any market power concerns.[3]

PSEG

PSEG is a public utility holding company headquartered in in Newark, New Jersey. Through its subsidiaries, PSEG engages in the generation, transmission, distribution and sale of electric energy, and distribution and sale of natural gas to commercial, residential, and industrial customers primarily in the Northeastern and Mid-Atlantic United States. PSEG, through its subsidiaries, owns approximately 11,300 MW of seasonal generation capacity located in the Northeast Region.[4]

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[2] Pavant II Solar LLC, Bison Solar LLC and San Isabel Solar LLC all have QF status.

[3] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 119 FERC ¶ 61,295, ("Order No. 697" or "MBR Order"), *order clarifying final rule*, 121 FERC ¶ 61,260 (2007) ("MBR Clarifying Order"), *order on reh'g and clarification*, 123 FERC ¶ 61,055 (2008) FERC Stats. & Regs ¶ 31,268 ("Order No. 697-A"), *order on reh'g and clarification*, 124 FERC ¶ 61,055 (2008) ("SIL Allocation Order").

[4] *See* Exhibit PEG-3 (accounting for retirements).

PSE&G

PSE&G is a public utility operating company engaged primarily in the transmission of electricity and the provision of gas and electric distribution service in the State of New Jersey. It is New Jersey's oldest and largest investor-owned utility. PSE&G was founded in 1903 and is based in Newark, New Jersey. It is a member of the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization and has made all of its transmission facilities available for open access transmission service pursuant to the PJM Open Access Transmission Tariff ("OATT") administered by PJM. The company also owns and operates 18,050 miles of gas distribution pipe and an additional 62 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3. During the study period, PSE&G owned less than 140 MW of solar generation, 8 MW of Energy Efficiency and 91 MWs of Demand Response but otherwise did not own or operate any electric generation facilities.

PSEG ER&T

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil and PSEG Nuclear, each wholly-owned subsidiaries of PSEG Power LLC ("PSEG Power"), as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission. PSEG ER&T also makes wholesale sales of natural gas.

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

BGS Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 *et seq.,* which initiated the transition from a regulated to a competitive retail power market in New Jersey, the New Jersey Board of Public Utilities ("BPU") annually approves statewide auctions to determine the entities that will supply Basic Generation Service ("BGS") in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSE&G's affiliate, PSEG ER&T, has participated directly in all of the auctions for BGS supply held since 2004 and has consistently won tranches in those auctions, including auctions for BGS service within the franchised service territory of PSE&G.

BGSS Gas Contract. By order issued April 16, 2002, the BPU approved a full requirements contract for the provision of gas supply by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the BPU, PSEG ER&T assumed, through capacity release, PSE&G's FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract, which currently remains in effect, provides for annual renewals unless terminated by either party on 12 months' advance written notice.

LIPA Fuel Supply. On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which

ER&T provides fuel supply and power supply management activities for LIPA as of January 1, 2015.

PSEG Fossil

PSEG Fossil owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission under the umbrella of PSEG Fossil's market-based rate authority.[5] The assets of PSEG Fossil are located entirely within PJM.[6] Since the last triennial filing in 2013, PSEG Fossil has retired approximately 1,800 MW of capacity in the eastern portion of PJM. Much of this capacity was retired at the end of May 2015. We included this capacity in the Winter and Spring season screens and exclude the capacity for the Summer and Fall screens.

PSEG Fossil is approximately a 23 percent joint owner of interests in the Conemaugh and Keystone generating stations located in Pennsylvania. An affiliate of NRG Energy is the operator.[7] PSEG Fossil is a 50 percent co-owner with Jersey Central Power and Light Company ("JCP&L") of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to

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[5] *Public Service Electric and Gas Company, et al*., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000).

[6] PSEG Fossil's subsidiaries PSEG Power Connecticut LLC, PSEG New Haven LLC and PSEG Power New York LLC own generation units in Connecticut and New York respectively.

[7] A letter of concurrence supporting the allocation of these facilities' output based on ownership interests is attached in our workpapers.

the unit. Accordingly, for the purpose of this market power analysis, the entire unit capacity, nominally 400 MWs, has been assigned to JCP&L.[8]

PSEG Power CT

PSEG Power CT owns the Bridgeport Harbor and New Haven Harbor generation facilities located in the state of Connecticut within ISO-NE and is authorized to sell power at market-based rates.[9] The output of these facilities is sold to PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority. PSEG Power CT is currently constructing Bridgeport 5, a 485 MW gas-fired combined cycle in Bridgeport, Connecticut, which is expected in service in 2019.

PSEG New Haven

PSEG New Haven owns and operates the New Haven facility, a gas-fired plant located in New Haven, CT that entered service in June 2012 with a nameplate capacity of 181.5 MW. The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[10] pursuant to a Connecticut statute that sought proposals for peaking generation in Connecticut.[11] All of the energy and capacity of the New Haven facility is sold

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[8] A letter of concurrence supporting the allocation of this facility's output to JCP&L is attached in our workpapers.

[9] *Wisvest Corporation, et al*., 101 FERC ¶ 61,166 (2002).

[10] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control (DPUC). PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

[11] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

into the ISO-NE markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder.[12] As such, neither PSEG New Haven nor any other PSEG affiliate has operational control of the New Haven facility. As a result, the capacity of the facility is not attributable to PSEG for the purpose of this market power analysis.

PSEG Nuclear

PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission in accordance with PSEG Nuclear's market-based rate authority.[13] PSEG Nuclear is the owner of Hope Creek and a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear operates the Salem plant and Exelon Generation is the operator of Peach Bottom.[14] Since the last triennial filing, uprates at Peach Bottom and Hope Creek plants have increased PSEG Nuclear's capacity at those facilities.

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[12] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

[13] *Public Service Electric and Gas Company, et al*., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000).

[14] A letter of concurrence supporting the allocation of plant output based on ownership interests is attached in our workpapers.

Other Subsidiaries

PSEG is also the direct or indirect parent of certain other subsidiaries engaged in energy related activities in the United States. Those additional subsidiaries of PSEG that may be considered relevant to this market power update for the PJM region are as follows.

PSEG Power LLC is a Delaware limited liability company. It does not directly own any generation facilities or engage in any FERC jurisdictional activities but it is the parent company of several FERC jurisdictional entities, including applicants PSEG ER&T, PSEG Fossil and PSEG Nuclear.

PSEG Power Ventures LLC ("Power Ventures") is a Delaware Limited Liability company and a direct subsidiary of PSEG Power. PSEG Power Ventures owns 100% interest in PSEG Solar Source LLC and has an in-direct ownership interest in a domestic power plant in Hawaii. PSEG Solar Source owns approximately 349 MWs DC (274 MW AC) of solar capacity across the United States, including a combined 92 MWs (72 MW AC) of solar capacity in PJM.[15] All of PSEG Solar Source's solar capacity has obtained QF status. Because all of this capacity is QF capacity, per Order No. 816 this capacity is not included in the market power analyses.[16]

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[15] The 42MWs are attributed to four (7) separate project companies that have QF status: PSEG Solar Hackettstown LLC (2 MW); PSEG Solar Delaware LLC (15 MW), Rockfish Solar LLC (13 MWs) Meadows Solar (26 MW), Turkey Creek (17 MW) Hemlock Solar (7 MW) in North Carolina and PSEG Solar Ohio LLC (12 MW).

[16] *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 816, 80 *Fed. Reg*. 67056 (2015), FERC STAT & REGS ¶ 31,374, P55 (2015), *reh'g denied and clarification*, Order No. 816-A, 155 FERC ¶ 61,188 (2016) ("… qualifying facilities that are exempt from FPA section 205 and facilities that are behind-the-meter facilities do not need to be reported in the asset appendix or indicative screens." (note omitted))

PSEG Resources LLC ("Resources") is a New Jersey limited liability company that provides energy infrastructure financing in developed countries. PSEG Resources invests primarily in energy-related financial transactions and manages a diversified portfolio of investments including leveraged leases. PSEG Resources owns interests, through leveraged leases, in various generation stations. Pursuant to the terms of these triple net leases, the lessee, not Resources, has all operational responsibility and control over the leased generation stations.

PSEG Power New York LLC ("PSEG Power NY") is a Delaware limited liability company that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 750 MW combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a cost-based contract.[17]

PSEG Keys Energy Center LLC ("PSEG Keys"), direct subsidiary of PSEG Fossil, was formed to construct, operate, and maintain the Keys Energy Center, a 755 gas-fired combined cycle facility located in Prince George's County, Maryland. Construction began in 2015 and is scheduled to be completed in 2018. All the capacity and energy from PSEG Keys will be sold to PSEG ER&T.

PSEG Energy Solutions LLC ("PSEG Solutions") is a direct subsidiary of PSEG ER&T that is schedule to begin retail operations in the Northeast Region in

[17] *PSEG Power New York Inc.,* Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

January 2017. It has obtained market-rate authority to allow it to sell excess energy in wholesale markets.[18]

PSEG Long Island LLC ("Long Island") and Long Island Electric Utility Servco, LLC ("Servco") are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution ("T&D") system on Long Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither Long Island nor Servco are FERC jurisdictional public utilities, as neither will exercise ultimate decision making authority over the T&D system in Long Island. Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[19]

When an applicant has affiliates in the relevant market, the Commission considers the combined capacity of all the affiliated entities in its market power assessment.[20] Accordingly, I have included the capacity controlled by PSE&G, PSEG ER&T, PSEG Power CT, PSEG Fossil, PSEG Nuclear, and PSEG Power New York (which on a combined basis constitutes the capacity of all of PSEG's affiliates not excluded for a reason explained above). Future references in this Affidavit to PSEG are inclusive of the foregoing entities.

The primary purpose of this study is to determine whether PSEG passes the PSA and WMSA screen thresholds in ISO-NE, the NYISO and PJM. In the PSA, the Commission requires applicants to examine whether the generation owned by

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[18] *See* December 21, 2016 letter order approving Energy Solutions request for market-based rate authority in Docket No. ER16-2725-000.

[19] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), order dismissing request for rehearing, 145 FERC ¶ 61,183 (2013).

[20] *Heartland Energy Services, Inc.,* 68 FERC ¶ 61,223 at 62,061-62,062 (1994).

the applicant is necessary to serve wholesale demand within a balancing authority area. The applicant first calculates the total generation capacity for an area. This is the total of generation in the balancing authority area plus the import capability to the area.[21] From this total, the applicant subtracts out firm contractual commitments, native load obligations, and operating reserves, giving uncommitted capacity for the area. Net uncommitted capacity is calculated by subtracting a wholesale load proxy from uncommitted capacity. Net uncommitted capacity is then compared to the applicant's uncommitted capacity within the area. When the applicant's uncommitted capacity is less than the net uncommitted capacity for the area, then all wholesale demand could be served without energy from the applicant and the applicant passes the PSA screen. When the applicant's uncommitted capacity is greater than the net uncommitted capacity, then the applicant does not pass the screen because its capacity is necessary to meet wholesale peak loads in the market.

In the WMSA, the Commission requires applicants to examine whether the generation owned by the applicant is 20 percent or more of the uncommitted capacity in each of four seasons under average daily peak conditions for the season. The applicant first calculates the total generation capacity for an area. The applicant then adds the import capability to the area. From this total, the applicant subtracts out planned outages and deratings, long-term firm contractual commitments, native load obligations, and operating reserves. The sum gives the total uncommitted capacity. The applicant then calculates its share by dividing its uncommitted capacity by the total uncommitted capacity. When the applicant's share is less than 20 percent, the applicant passes the WMSA screen.

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[21] Import capability is the lesser of either the simultaneous import limit ("SIL") into the area or available capacity in interconnected balancing authority areas. Available capacity is equal to total generation capacity in an area less outages and derating, a native load proxy and operating reserves.

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The Commission presumes that an applicant does not have market power when it passes both the PSA and WMSA screens. If the applicant fails either of the screens, then the applicant may present other analyses to demonstrate that it does not possess market power. Alternatively, the applicant may propose mitigation measures or accept the Commission's default mitigation measures to demonstrate that it has mitigated market power.

2. New England

2.1. Overview of Electric Power Markets in New England

New England operates a competitive wholesale power market. Substantial restructuring has taken place in New England, and many of the vertically integrated utilities have sold either most or all of their generation assets. The traditional utilities often have standard offer obligations to serve retail customers, but utilities often fulfill these obligations by securing supplies in competitive wholesale markets. For example, a utility may secure contracts in which the supplier agrees to provide power for 30 percent of the utility's standard offer obligation. The transmission system is managed by ISO-NE. The market has a market monitor and market power mitigation program in place to identify and to mitigate any potential exercise of market power.

2.2. Geographic Markets

In the case of generation wholly located in an RTO, such as ISO-NE, the Commission accepts the RTO as the relevant destination market.[22] When the Commission has identified a sub-market within an RTO, the applicant must also provide market power screens for the relevant sub-markets.[23] In New England,

[22] Order No. 697 at PP 231, 235.

[23] Order No. 697 at P 236.

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the Commission has identified two submarkets: Connecticut and Southwest Connecticut.[24] PSEG owns the Bridgeport Harbor plant in Southwest Connecticut. PSEG also owns the New Haven Harbor 1 unit in Connecticut and PSEG New Haven owns the New Haven facility. When the applicant does not own the transmission system, as in the instant case, the applicant needs to provide an analysis only for the balancing authority area to which the generation is interconnected.[25] Accordingly, the PSA and WMSA are provided for the ISO-NE balancing authority area, and also for Connecticut and Southwest Connecticut.

2.3. Data Sources and Analysis

The data source for generation is ISO-NE Seasonal Claimed Capability (SCC) Reports.[26] Summer and winter capacities were taken from the November 2015 report. Planned outages are from the ISO-NE Form 714. Planned outages for Connecticut and Southwest Connecticut are prorated based on their shares of the total generation capacity in ISO-NE. PSEG's generation capacity in ISO-NE consists of the New Haven facility, New Haven Harbor and Bridgeport Harbor. PSEG's Northeast Region generation facilities are presented in Exhibit PEG-3.

Load data for ISO-NE are from Energy Velocity. Energy Velocity also provides load data by New England ISO zone, thus loads are calculated by sub-market as well. PSEG load obligations in New England come from PSEG's agreements to supply standard offer generation within Rhode Island. The data were supplied by PSEG.

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[24] *Id*.

[25] Order No. 697 at footnotes 215, 217.

[26] See http://www.iso-ne.com/genrtion_resrcs/snl_clmd_cap/index.html.

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Import capability was taken from the ISO-NE's December 20, 2016 FERC filing.[27] This report indicates that the simultaneous transfer limits in all seasons is 4,548 MW for the ISO-NE as a whole, 3,050 MW for Connecticut, and 2,370 (Spring) to 3,200 MW (Summer) for Southwest Connecticut. PSEG has no firm transmission rights into New England.

Operating reserves are calculated as follows. ISO-NE Operating Procedure No. 8 specifies spinning reserves (or 10-minute reserves) equal to the size of the loss of the largest unit times a Contingency Reserve Adjustment Factor ("CRAF").[28] The CRAF in 2015 was 1.25.[29] The largest unit is the 1,400 MW (summer capacity) Seabrook Unit 1. In addition, 30-minute reserves require capacity to cover 50 percent of the loss of a second contingency (i.e., the second largest unit) plus 160 MW for daylight-savings time periods and 180 MW during standard time (i.e., winter). The second largest unit is the 1,200 MW (summer capacity) Millstone Unit 3. Thus, in total, operating reserves are 2,510 MW in summer.[30] Operating reserves for Connecticut and Southwest Connecticut are based on resource needs in forward reserve auctions for 2015.[31]

2.4. Results

Exhibit PEG-4 summarizes the results for the PSA and the WMSA in New England. Exhibit PEG-5 shows the calculations to determine whether PSEG is a

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[27] ISO New England Inc. Simultaneous Import Limit for 2015, *Guidance on Simultaneous Transmission Import Limit Studies*; Docket No. AD10-02, December 20, 2016.

[28] ISO New England Operating Procedure No. 8, at 5-6, available at https://www.iso-ne.com/participate/rules-procedures/operating-procedures.

[29] ISO New England, Inc. 2015 Regional System Plan ("Regional System Plan"), available at https://www.iso-ne.com/static-assets/documents/2015/11/rsp15_final_110515.docx, at 68.

[30] 2,510 MW = 1,400 MW x 1.25 + 50% x 1,200 MW + 160.

[31] ISO New England, Inc. 2015 Regional System Plan ("Regional System Plan"), available at https://www.iso-ne.com/static-assets/documents/2015/11/rsp15_final_110515.docx, Table 4.12 at p.70.

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pivotal supplier in the three New England destination markets. PSEG passes the PSA screen in all areas. Exhibit PEG-6 presents the WMSA results for the destination areas in New England. PSEG easily passes the WMSA in all areas.

3. New York

3.1. Overview of Electric Power Markets in New York

New York also has a competitive wholesale power market. Substantial restructuring has taken place in New York, and the investor-owned vertically integrated utilities have sold either most or all of their generation assets. These utilities often have standard offer obligations to serve retail customers, and utilities can fulfill these obligations by securing supplies in competitive wholesale markets. The transmission system is operated by the NYISO, which also operates a competitive wholesale market. The market has a market monitor and market power mitigation program in place to identify and to mitigate any potential exercise of market power.

3.2. Geographic Markets

In the case of generation wholly located in an RTO such as the New York ISO, the Commission has accepted the RTO as the relevant destination market.[32] PSEG only owns generation in Albany, New York. In addition, when the applicant does not own the transmission system, as in the instant case, the applicant needs to provide an analysis only for the balancing authority area to which the generation is interconnected.[33] Accordingly, the PSA and WMSA are provided for the NYISO only.

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[32] Order No. 697 at PP 231, 235.

[33] Order No. 697 at footnotes 215, 217.

3.3. Data Sources and Analysis

The principal data source for generation is the Energy Velocity Market-Operations database. Planned outages are from the FERC Form 714. PSEG's generation capacity in New York consists of its ownership of the Bethlehem Energy Center in Albany, which has winter capacity of 845 MW. Information for PSEG's Northeast Region generation is presented in Exhibit PEG-3.

Load data for NYISO were downloaded from Energy Velocity.

Import capability comes from the most recent NYISO SIL filing as of December 19, 2016.[34] This filing indicates that ISO simultaneous import capability ranges from 6,850 MW in spring to 7,695 MW in summer. NYISO does not recognize physical imports, accordingly, all the SIL import capability is allocated pro rata, except for a 265 MW reservation that PSEG has from PJM to New York on the Linden VFT DC transmission line.

Operating reserves are calculated as follows. The NYISO Locational Reserve Requirements specify 30-minute total reserves equal to twice the 10-minute reserve necessary to replace the operating capability loss caused by the most severe contingency under normal transfer conditions. Thus, the operating reserves for the NYISO are 2,620 MW for each season.[35]

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[34] New York Independent System Operator, Inc., *Informational Filing Regarding the Simultaneous Import Limitation Study*, Docket No. AD10-2, December 19, 2016.

[35] NYISO Locational Reserve Requirements, Table 2, available at http://www.nyiso.com/public/webdocs/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf

3.4. Results

Exhibit PEG-7 shows the calculations to determine whether PSEG is a pivotal supplier in New York, and PSEG passes the PSA screen. Exhibit PEG-8 presents the WMSA results for New York, and PSEG easily passes the WMSA.

4. PJM

4.1. Overview of Electric Power Markets in PJM

PJM operates a competitive wholesale power market and serves as the regional RTO for an area that covers all or parts of 13 states and the District of Columbia. PJM also plans and operates the transmission system within the RTO. Monitoring Analytics acts as the market monitor, and has a market power mitigation program in place to identify and mitigate any potential exercise of market power.

4.2. Geographic Markets

PSEG owns both generation and transmission facilities in PJM. In the case of generation wholly located in an RTO such as PJM, the Commission has accepted the RTO as the relevant destination market.[36] When the Commission has identified a sub-market within an RTO, the applicant must also provide market power screens for the relevant sub-markets.[37] In PJM, the Commission has identified three submarkets: PJM East ("PJME"), PJM East of 5004/5005 ("PJM50") and PJM East of AP-South ("PJMAP").[38] The PSA and WMSA are provided for PJM and for the PJME, PJM50 and PJMAP sub-markets.

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[36] Order No. 697 at PP 231, 235.

[37] Order No. 697 at P 236.

[38] *Id*. *See also* Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, Order No. 697-A, 73 FR 25832 (May 7, 2008), FERC

4.3. Data Sources and Analysis

The principal data source for generation is the Energy Velocity Market-Ops database. Generation within PJM was assigned to submarket consistent with the definitions in PJM's SIL Study.[39] Planned outages are from the FERC Form 714. In addition, for the sub-market analysis, planned outages were allocated to PJME based on the share of total PJME generation, by season. Information for PSEG's generation in PJM and PJME is presented in Exhibit PEG-3.

Load data for PJM was downloaded from Energy Velocity. Energy Velocity also provides load data by PJM zone, thus loads are calculated for the PJM sub-markets as well.

Import capability was taken from the 2015 Simultaneous Import Limit Study Report.[40] This report indicates simultaneous transfer limits of 11,997 MW in the winter and 7,600 MW in summer. Additionally, this report indicates transmission capabilities of the PJM sub-markets. The report conservatively uses the reported SIL as the SIL amount to be allocated pro rata. This is a simplifying assumption because PSEG has no firm transmission reservations into PJM and it effectively excludes the additional 8,500 MW of firm reservations into PJM in the base case of the SIL study.

Stats, & Regs. ¶ 31,268 (2008) at P 90; Order Conditionally Authorizing Merger and Disposition of Jurisdictional Facilities, *Exelon Corporation, et al.*, 138 FERC ¶ 61,167 (2012).

[39] PJM Interconnection, L.L.C., *Informational Filing of 2015 Simultaneous Import Limit Study Report for PJM Region*, Docket No. AD1-2-007, September 2, 2016, Accession No. 20160902-5155.

[40] *Id*.

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Operating reserves are calculated according to PJM Manual 13 as the sum of Day Ahead Scheduling Reserves (Operating), Contingency (Primary) and Synchronized (Spinning Reserve) Requirements.[41]

Data on PSEG's long-term contracts come from PSEG. The contracts were included in the area where the energy is delivered under the contract. For contracts delivered to the Western Hub in PJM, the contracts were included in the PJM, PJM50, and PJMAP destinations and not the PJME destination.

4.4. Results

Exhibit PEG-9 summarizes the results for the PSA and the WMSA in PJM. Exhibit PEG-10 shows the calculations to determine whether PSEG is a pivotal supplier in the four PJM destination markets. PSEG passes the PSA screen for all four destinations. Exhibit PEG-11 presents the WMSA results for the destination markets in PJM. PSEG easily passes the WMSA in PJM and PJM east of AP South, but has greater than a 20 percent market share in the PJM East and PJM East of 5004/5005 destination markets.

5. Delivered Price Test

When an applicant does not pass either the PSA or WMSA for a destination market, the Commission invites the applicant to provide additional information via a delivered price test ("DPT"). PSEG requested that I perform a DPT for the PJM East and PJM East of 5004/5005 sub-markets. Accordingly, I now discuss the DPT for these sub-markets.

[41] PJM Manual 13 - Emergency Operations, at 17, available at http://pjm.com/~/media/documents/manuals/m13.ashx

5.1. Overview of the DPT

The DPT utilizes substantially more information than the PSA or the WMSA, including additional information on generation ownership, generation costs, demand conditions, and transmission limits. The Commission considers two types of capacity: Economic Capacity ("EC") and Available Economic Capacity ("AEC"). EC is the capacity that can be delivered to a destination market for 105 percent or less than the market price. AEC is calculated by subtracting load commitments from EC. EC and AEC are calculated for a number of different seasonal and load conditions.

Because we do not know the firm retail obligations of the competitive suppliers, as explained below, the AEC calculation is based on the assumption that market participants serve load in proportion to their generation capacity and that 70 percent of load obligations are contracted more than one year from delivery.

For both the EC and AEC measures, the Commission prescribes three screens: (1) a pivotal supplier screen; (2) a market share screen; and (3) a Herfindahl-Hirschman Index ("HHI") screen. The HHI is the sum of the squared market shares of the firms in the market. So a market with four firms of market shares of 40, 30, 20, and 10 percent would have an HHI of 3,000 (this is calculated as $40^2 + 30^2 + 20^2 + 10^2 = 1{,}600 + 900 + 400 + 100 = 3{,}000$). A monopolist would produce a HHI of 10,000 and 10 equally-sized firms would produce a HHI of 1,000.

Although the Commission has not drawn bright lines for its review of DPT results, it has given general guidance. When (1) the applicant is not pivotal; (2) the applicants' market share is less than 20 percent; and (3) the HHI is below 2,500, the Commission is likely to conclude that the applicant does not have market power. The three standards establish a "safe harbor" for lack of market power, unless intervenors present clear and convincing contrary evidence. The Commission has also determined in some cases that an applicant did not have

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market power when the analysis showed isolated HHI and market share results above screening levels. Finally, despite the DPT results, the Commission may conclude that an applicant does not have market power if other evidence, such as historical sales data, indicates that the DPT results do not reflect the actual competition in the marketplace.

A detailed description of data sources and methods to prepare the data for the DPT is presented in Exhibit PEG-12. An overview of the sources and methods used at Economists Incorporated for conducting the DPT is presented here.

The DPT is calculated for 10 representative periods, three for each of three seasonal conditions plus a summer super peak period. The three seasons are spring/fall, summer, and winter. Each season is divided into (1) top 10 percent of peak hours; (2) remaining peak hours; and (3) off-peak hours. In addition, there is a summer super peak period which is comprised to the top 1 percent (10 hours) of summer peak hours. These ten periods cover the range of load conditions for each season, and for the year as a whole.

The primary source for generation data is Energy Velocity. In addition to generation capacity, Energy Velocity provides data on ownership (including holding companies), fully-loaded heat rates, emission rates, and generation availability. Generation is included for all of PJM and NYISO, which is the only first-tier balancing authority area in which PSEG owns generation. Unit capabilities are derated to account for seasonal maintenance and likely plant unavailability due to forced outages. Because demand in PJM peaks in summer and winter, the planned outages are assumed to be during the spring/fall season.

The transmission system is represented by contract paths between balancing authority areas and within PJM. Limits between regions in PJM are from Energy Velocity.

Market prices come from hourly prices reported by PJM.

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As in the PSA and WMSA, load data come from Energy Velocity. To compute load requirements for market participants, we apportion the total load in each market area in New York and PJM to all suppliers in proportion to their respective generation capacities. We assumed 70 percent of load is committed for a year or longer and the remaining 30 percent is contracted for shorter periods.[42] To account for their greater load obligations, we assume that Dominion, which does not operate in a restructured retail market, has 100 percent responsibility for its allocation of load and that AEP, which operates in a partly restructured retail market, has 90 percent of its allocation as opposed to the standard 70 percent.

The DPT and market share calculations were calculated using the Power Acquisition Screening System developed at Economists Incorporated. The mathematical details are presented in Exhibit PEG-13.

5.2. Results of the DPT for PJM50 Sub-market

The results of the DPT for PJM50 are presented in Exhibit PEG-14. The top part of the exhibit shows the results for AEC. PSEG passes the Pivotal Supplier Screen in all 10 periods. PSEG also passes both the Market Share Screens and the HHI Screens in all 10 periods.

The lower part of Exhibit PEG-14 shows the results for EC in PJM50. PSEG passes all the screens in all the periods, except for the pivotal supplier screen in the Summer Top 1% period.

[42] This is a reasonable estimate for the long-term load coverage since this number is generally between 60 and 80 percent for most generation suppliers in restructured markets.

5.3. Results of the DPT for PJME Sub-market

The results of the DPT for PJME are presented in Exhibit PEG-15. The top part of the exhibit shows the results for AEC. PSEG passes all the screens for AEC.

The lower part of Exhibit PEG-15 shows the results for EC in PJME. PSEG passes the Market Concentration screens in all periods. It passes the Market share screens in six of ten periods, and its market share is never more than 25 percent. It passes the pivotal supplier screen in eight of ten periods.

5.4. Analysis of the DPT Results

Although PSEG fails some screens, the overall results are not indicative of PSEG having market power. To begin, PSEG passes all the AEC screens and all market concentration (HHI) screens for EC. The HHI levels in all periods, capacity types, and areas are below the screening threshold of 2,500, and typically substantially below this level. In terms of the DPT for market rate authority and under the 2010 DOJ and FTC Horizontal Merger Guidelines, the market is not highly concentrated.[43] The low HHI levels mean that PSEG has little ability to exercise market power in coordination with other suppliers. It also passes all the AEC pivotal supplier screens, and most of the EC pivotal supplier screens. This means that typically PSEG's generation is not necessary to serve load; and when its generation is necessary, its forward sale commitments are sufficient so that its uncommitted generation is not necessary to serve the remaining load. Finally, PSEG's market shares are never above 15 percent in PJM50 and for AEC in PJM East. Its market shares for EC are never above 25 percent in PJM East. Although greater than the 20 percent screen, PSEG's

[43] See U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Issued August 19, 2010, at Section 5.3, available at http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

market shares are well below the 35 percent threshold that is typically used for imputing unilateral market power.[44]

5.5. Mitigation

PJM has a Commission-approved market monitoring and mitigation plan in place to ensure that generation facilities cannot exercise market power. The Commission has stated that Commission-approved market monitoring and mitigation plans are sufficient to mitigate market power in RTO markets.[45] In particular, the Commission found in connection with PSEG's last triennial filing that the PJM market monitoring and mitigation rules are sufficient to address market power concerns.[46]

Under the local market power mitigation procedures in PJM, if a supplier fails the "three pivotal supplier test" (TPS), it is offer-capped by the Market Monitor. The Market Monitor's TPS test is applied on an ongoing basis, potentially as frequently as every 5 minutes, to reflect day-ahead and real-time operating conditions. These offer caps provide direct protection against the exercise of locational market power by suppliers in PJME, PJM50, PJMAP and elsewhere.

The protection against the exercise of market power is enhanced by "must offer" requirements under PJM's Operating Agreement. These mandate that generation resources that are used to meet capacity requirements in PJM and

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[44] *See*, *e.g.*, U.S. Department of Justice, 1984 Merger Guidelines, at Section 3.12, available at https://www.justice.gov/sites/default/files/atr/legacy/2007/07/11/11249.pdf ("the Department is likely to challenge the merger of any firm with a market share of at least one percent with the leading firm in the market, provided the leading firm has a market share that is at least 35 percent.")..

[45] Order No. 697 at P 241.

[46] *See* October 14, 2014 letter order approving Applicants' prior triennial market update in Docket No. ER10-1789-003 et al. at page 3.

that are not subject to an outage must offer their available capacity in PJM's day-ahead energy market.[47] PJM has also implemented a Reliability Pricing Model (RPM) to secure sufficient capacity to meet its requirements through a series of auctions, including a Base Residual Auction (BRA) held annually for capacity 3 years in advance, and incremental auctions held at varying intervals prior to the delivery year. Various features of the RPM process work to prevent the exercise of market power in capacity markets in PJM. First, the RPM model includes bid cap rules designed to mitigate the potential exercise of market power. Second, RPM includes a must-offer requirement pursuant to which all generating units that have available capacity must bid into the RPM auctions or face disqualification from being recognized as capacity resources (and therefore from receiving any capacity payments) in the delivery year.

In addition to the local market power mitigation described above, the presence of market monitoring within PJM lessens potential concerns that PSEG might be able to exercise market power notwithstanding the indicative DPT screens. The Market Monitor has the specific responsibility under the market monitoring plan to monitor the potential of any market participant to exercise market power. To perform its market monitoring function, the Market Monitor can file reports or complaints with the Commission and other government agencies to address various market concerns including market power. The Market Monitor can also make its view known to the Commission staff and PJM members in cases where PJM does not follow its recommendations concerning complaints or requested rule changes. In addition, the Market Monitor can consult with regulatory bodies, including state commissions, regarding the need for specific investigations and monitoring activities, and to consider and evaluate additional enforcement mechanisms. The Market Monitor can also act on specific

[47] *See* PJM Operating Agreement at 1.10.1A(d).

complaints that have been filed by market participants to examine any potential market power issues.

In sum, the local market power mitigation rules, the role of the Market Monitor, the existence of must-offer requirements and PJM's RPM auctions address the potential for PSEG to exercise market power.

6. Vertical Market Power

In determining whether the market-based rates are in the public interest, the Commission also considers whether the Applicant has transmission market power or can erect barriers to entry.[48] None of these factors are relevant in the instant case. First, other than incidental generator interconnection facilities and the transmission assets owned by PSE&G in PJM, no transmission assets are owned by the Applicants or any of their affiliates in ISO-NE and NYISO. Transmission service over PSE&G's transmission facilities is provided under the PJM Open Access Transmission Tariff. Thus, consistent with Commission precedent, Applicants have alleviated any concerns regarding potential transmission market power. Second, PSEG has no ability to erect barriers to entry. As explained in Applicants' previous initial applications for market-based rate authority and triennial market power reports, PSEG is unable to erect barriers to entry. There has been no change in facts since the submission of those applications that would alter this conclusion.

The Commission is concerned with the ownership of natural gas pipelines or natural gas distribution facilities and the possibility that they may be used to exercise market power in electricity markets. PSEG does not own or operate any

[48] Order No. 697 at PP 397, 399.

FERC jurisdictional natural gas pipelines in PJM, ISO-NE or NYISO.[49] PSE&G owns natural gas distribution facilities in the State of New Jersey including peak-shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers.

7. Conclusion

PSEG and its subsidiaries do not have market power in New England, New York or PJM. PSEG is not a pivotal supplier in New England, New York or PJM. PSEG's market shares in the WMSA are below the Commission's 20 percent screening threshold in each of these market areas. PSEG is also not a pivotal supplier in the Connecticut or Southwest Connecticut sub-markets and its market shares in the WMSA are below 20 percent in these sub-markets. PSEG fails the WMSA screens in only the PJME and PJM50 sub-markets. For these sub-markets, we conducted a DPT analysis. PSEG passes all the DPT screens for the PJM50 submarket, and it only fails the Market Share Screen in the PJME submarket. Its market shares are never above 25 percent, a level that the Commission has accepted in other market-based rate matters.[50] As such, they are not evidence of actual market power.

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[49] PSEG Power LLC currently owns a 10 percent interest in the PennEast Pipeline Company LLC which has filed an application with FERC for construction and operation of a gas transmission line.

[50] *See*, *e.g.*, *Dogwood Energy, LLC*, 135 FERC ¶ 61,089 (2011) (under the AEC measure, Dogwood failed the market share screen in seven of ten periods, with market shares ranging from 32.7% to 39.6%); *Kansas City Power & Light Company and KCP&L Greater Missouri Operation Company*, Docket No. ER10-2074-001 et al., Supplement to Change in Status Filing at 11 (Feb. 4, 2013) (accepted by Letter Order, November 22, 2013) (market shares for AEC ranging from 17 to 36%); *Shell Energy N.A. (US), L.P.*, 135 FERC ¶ 61,090 (2011) (under the AEC measure, Shell failed the market share screen for seven of ten periods, with market shares ranging from 29.3% to 37.0%); *Calpine Energy Services, L.P.*, 137 FERC ¶ 61,085 at P 21 (2011) (under the AEC measure, Calpine failed the market share screen in all ten periods, with market shares ranging from 20.4% to 28.9%); *Wildcat Power Holdings, LLC*, 136 FERC ¶ 61,013 at P 14 (2011) ("When the available economic capacity measure is used, Wildcat Power's market shares range from 22 to 24 percent in the three summer super peak and winter

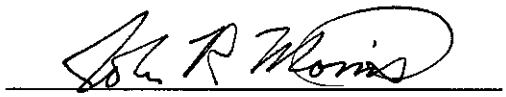
Further, PSEG operates under New England's, New York's, and PJM's market power mitigation programs, which mitigate PSEG's potential market power. Therefore, under standards for market-based rate authority articulated by the Commission in Order No. 697, PSEG has no ability to exercise market power in the relevant markets, and maintaining market-rate authority in New England, New York and PJM would be in the public interest.

Therefore, I recommend that the Commission continue to authorize PSEG to sell electric power in Northeast Region wholesale markets at market-based rates.

super peak season/load periods and zero percent in the remainder of the season/load periods."); *LS Power Marketing*, LLC,139 FERC ¶ 61,140 at P 23 (2012) (under the AEC measure, LS Power failed the market share screen in all ten periods, with market shares ranging from 20.4% to 28.9%); *Gila River Power, L.P.*, Docket Nos. ER05-1178-015, et al., Second Supplement to Updated Market Power Analysis at 4 (Jan. 12, 2011) (accepted by Letter Order, April 5, 2011) (market shares for AEC ranging from 21 to 23% in four season/load periods).

Pursuant to 28 U.S.C. §1746, I state under penalty of perjury that the foregoing is true and correct to the best of my information, knowledge, and belief.

Executed on this 22rd day of December 2016.



John R. Morris, Ph.D.
Principal
Economists Incorporated

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EXPERIENCE AND QUALIFICATIONS OF

Dr. John R. Morris

OVERVIEW	Dr. Morris, a recognized expert in studying competition in energy industries, currently is a Principal at Economists Incorporated. He began his research of competition in energy industries in 1985 while working for the Federal Trade Commission. Since joining Economists Incorporated in 1992, he has consulted on many mergers and acquisitions involving energy companies, examined competitive issues relating to rates, and studied issues in state restructuring proceedings. He has published articles on competition and energy matters, and he has spoken on numerous occasions concerning competition in natural gas, electric power and other industries. He has been accepted as an expert witness on energy matters before the Federal Energy Regulatory Commission, state regulatory commissions, and in federal court.
EDUCATION	Ph.D., University of Washington, August 1985 Dissertation: *Intellectual Property: Creating, Pricing, Copying* • M.A., University of Washington, December 1983 • A.B., Georgetown University, May 1981
PRESENT POSITION	Dr. Morris is a *Principal* at Economists Incorporated, an economic consulting firm located at 2121 K Street, NW, Suite 1100, Washington, DC 20037. (202-223-4700) Economists Incorporated studies competition and regulation in many industries in the United States and in other countries. It is a leading firm in studying the competitive effects of mergers and acquisitions.
PREVIOUS EXPERIENCE	*Senior Vice President*, Economists Incorporated, December 2001 – December 2002 • *Vice President*, Economists Incorporated, December 1995 – December 2001 • *Senior Economist*, Economists Incorporated, June 1992 – December 1995 • *Economic Tutorial Leader*, Stanford University (Stanford in Washington), April 1993 – June 1995 • *Visiting Assistant Professor,* Department of Business Economics and Public Policy, School of Business, Indiana University, September 1991 – May 1992 • *Assistant to the Director for Antitrust,* Bureau of Economics, Federal Trade Commission, November 1989 – August 1991 • *Economic Advisor,* Office of Commissioner Machol, Federal Trade Commission, December 1988 – October 1989 • *Economist,* Division of Antitrust, Bureau of Economics, Federal Trade Commission, October 1985 – December 1988
MEMBERSHIPS	Member, International Association of Energy Economics • Associate, Energy Bar Association • Member, American Economic Association • Member, Western Economic Association International • Associate, American Bar Association

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AWARDS & HONORS

Award for Excellence in Law Enforcement, Federal Trade Commission, 1988 • Graduate School Scholarship, University of Washington, 1984 • Graduated Cum Laude Georgetown University, 1981 • Senior Comprehensive Passed with Distinction, Georgetown University, 1981

TESTIMONY BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Affidavit, Alabama Power Company, *et al.*, ER17-514-000 (2016) • Affidavits (3), Alabama Power Company, *et al*., EL15-39-000 (2016) • Affidavit, Combined Locks Energy Center, LLC, *et al.* , ER10-3042-004 (2015) • Affidavit, Alabama Power Company, *et al*., EL15-39-000 (2015) • Affidavit, PJM Interconnection, L.L.C., ER15-623-000 (2015) • Affidavit, Southern Indiana Gas and Electric Co. d/b/a Vectren Energy Delivery of Indiana, Inc., ER10-1338-000 (2014) • Affidavit, Quantum Choctaw Power, LLC *et al*., ER12-458-007 (2014) • Affidavit, NRG Power Marketing LLC, *et al.*, ER10-2265-004 *et al.* (2014) • Affidavit, TransCanada Entities, ER10-2870-004 *et al*. (2014) • Affidavit, Tampa Electric Company, ER10-1437-002 (2014) • Affidavit, Kendall Green Energy LLC, ER14-1363-003 (2014) • Affidavit, Quantum Lake Power, LP, ER13-1489-000 (2014) • Affidavit, NRG Power Marketing LLC, *et al.* ER10-2265-002 (2014) • Affidavit, NRG Yield, Inc., *et al*., EC14-101-000 (2014) • Affidavit, Community Wind Farm 1 et al., ER14-1668-000 (2014) • Seaway Crude Pipeline Company LLC, OR15-6-000 (2014) • Affidavit, Public Service Electric and Gas Company *et al.*, ER10-1789-003 (2013) • Affidavits, NRG Energy Holdings, Inc., Edison Mission Energy, EC14-14-000 (2013) • Affidavit, Silver Merger Sub, Inc., *et al.*, EC13-128-000 (2013) • Prepared Answering Testimony, Deposition, and Hearing, Puget Sound Energy, Inc., *et al.*, EL01-10-085 (2012) • Affidavit, Wisconsin Public Service Corporation, *et al*., ER10-1894-004 (2012) • Affidavit, PSEG New Haven LLC, ER12-1250-000 (2012) • Affidavit, Enterprise Product Partners L.P. and Enbridge, Inc., OR12-4-000 (2012) • Affidavit, Southern Indiana Gas and Electric Co., ER10-1338-001 (2011) • Affidavit, TransCanada Power Marketing Ltd. *et al.*, ER10-2780-001 (2011) • Affidavit, Tampa Electric Company, ER10-1476-001 (2011) • Affidavit, Cedar Creek Wind Energy, LLC, ER11-2577-000 (2010) • Affidavit, Public Service Electric and Gas Company *et al.*, ER97-837-014 (2010) • Affidavit, Morris Energy Group, LLC v. PSEG Energy Resources & Trade LLC; PSEG Fossil LLC; and PSEG Power LLC, EL10-79-000 (2010) • Affidavit, UGI Storage Company and UGI Central Penn Gas, Inc., CP10-23-000 (2010) • Prepared Answering Testimony, People of the State of California, *ex rel*; Bill Lockyer, Attorney General of the State of California v. Powerex Corp., *et al.*, EL02-71-000 (2009) • Affidavit, Integrys Energy Services, Inc. v. New Brunswick Power Generation Corporation, EL09-32-002 (2009) • Affidavit, People of the State of California, *ex rel*; Edmund G. Brown Jr. Attorney General of the State of California v. Powerex Corp., *et al.*, EL09-56-000 (2009) • Affidavit, San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, EL00-95-000 (2009) • Affidavit, Troy Energy, LLC, *et al.*, ER02-25-010 (2009) • Affidavit, Combined Locks Energy Center, LLC,

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et al., ER01-2659-015 (2009) • Prepared Direct Testimony and Deposition, Energy Transfer Partners, *et al*., IN06-3-003 (2009) • Prepared Direct Testimony and Hearing, Mobil Pipe Line Company, OR07-21-000 (2009) • Idaho Power Company, ER06-787-002 (2009) • Affidavit, Southern Indiana Gas and Electric Co. d/b/a Vectren Energy Delivery of Indiana, Inc. ER96-2734-007 (2008) • Affidavit, Choctaw Gas Generation, LLC, *et al.* ER08-1332-002 • Affidavit, TransCanada Energy Sales Ltd., ER09-328-001 (2008) • Prepared Direct Testimony and Deposition, Oasis Pipeline L.P., *et al.*, IN06-3-004 (2008) • Affidavit, Tampa Electric Company, ER99-2342-012 (2008) • Affidavit, ANP Bellingham Energy Company, LLC, *et al.*, ER00-2117-005 (2008) • Affidavit, SUEZ Energy Marketing, NA, *et al.*, ER06-169-003 (2008) • Affidavit, TransCanada Energy Marketing ULC, *et al.*, ER07-1274-001 (2008) • Affidavit, Georgia-Pacific Brewton LLC, *et al.*, ER08-1126-000 (2008) • Affidavit, Montgomery L'Energia Power Partners LP, ER08-864-000 (2008) • Affidavit (with Joseph P. Kalt), Energy Transfer Partners, *et al*., IN06-3-002 (2008) • Affidavit, Energy Transfer Partners, *et al*., IN06-3-002 (2008) • Affidavit, TransCanada Maine Wind Development Inc., ER08-685-000 (2008) • Affidavit (with Joseph P. Kalt), Energy Transfer Partners, *et al*., IN06-3-000 (2007) • Affidavit, Energy Transfer Partners, *et al*., IN06-3-000 (2007) • Affidavit, The People of the State of Illinois, *ex rel.* Illinois Attorney General Lisa Madigan v. Exelon Generation Co., LLC, *et al.*, EL07-47-000 (2007) • Affidavit, Baltimore Gas and Electric Company, ER07-576-000 (2007) • Affidavit, Trans-Allegheny Interstate Line Company, ER07-562-000 (2007) • Affidavit, TransCanada Energy Marketing Ltd., *et al.*, ER07-331-000 (2006) • Affidavit, Tampa Electric Company, ER99-2342-000, ER07-173-000 (2006) • Affidavit, Koch Supply & Trading, LP, ER07-100-000 (2006) • WPS Resources Corporation and Peoples Energy Corporation, EC06-152-000 (2006) • Affidavit, Sabine Cogen, LP, ER06-744-000 (2006) • Affidavit, Air Liquide Large Industries U.S. LP, ER06-743-000 (2006) • Affidavit, ANP Bellingham Energy Company, LLC., *et al.*, ER00-2117-000 (2005) • Affidavit, Duke Energy Corporation and Cinergy Corp., EC05-103-000 (2005) • Affidavit, El Paso Marketing, L.P., *et al.*, ER95-428-000 (2005) • Affidavit, TransCanada Energy Ltd., *et al.*, ER95-692-000 (2005) • Affidavit, Granite Ridge Energy, LLC, ER00-1147-000, ER05-287-001 (2005) • Affidavit, TransCanada Power (Castleton) LLC, ER05-743-000 (2005) • Affidavit, Tampa Electric Company, *et al*., ER99-2342-003 (2005) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-035 and Wisconsin Public Service Corporation, ER95-1528-010 (2005) • Affidavit, Wisconsin River Power Company, ER05-453-000 (2005) • Affidavit, Upper Peninsula Power Company, ER05-89-001 (2005) • Affidavit, Southern Indiana Gas and Electric Company, ER96-2734-003 (2004) • Affidavit, Tampa Electric Company, *et al*., ER99-2342-003 (2004) • Affidavits, TransCanada Hydro Northeast, Inc., *et al*., EC05-12-000, ER05-111-000 (2004) • Affidavits, Dominion Energy New England,

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Inc., *et al*., EC05-4-000, ER05-34-000 (2004) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-033 and Wisconsin Public Service Corporation, ER95-1528-008 (2004) • Affidavit, NorthPoint Energy Solutions Inc. ER04-1244-000 (2004) • Affidavit, Union Power Partners, L.P., ER01-930-004 (2004) • Affidavit, Panda Gila River, L.P., ER01-931-004 (2004) • Affidavit, Dominion Energy Kewaunee, Inc., ER04-318-000 (2003) • Affidavit, TPS GP, Inc., TPG LP, Inc., Panda GS V, LLC & Panda GS VI, LLC, EC03-90-000 (2003) • Affidavit, Berkshire Power Company, L.L.C. *et al.*, ER99-3502-001 (2002) • Affidavit, El Paso Merchant Energy, L.P., ER95-428-024 (2002) • Affidavit, Tampa Electric Company, ER99-2342-001 (2002) • Affidavit, Hardee Power Partners Limited, ER99-2341-001 (2002) • Affidavit, TECO-PANDA Generating Company, L.P., ER02-1000-000 (2002) • Affidavit, Commonwealth Chesapeake Company, LLC, ER99-415-004 (2002) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-031 and Wisconsin Public Service Corporation, ER95-1528-006 (2001) • Affidavit, TPS McAdams, LLC and TPS Dell, LLC, ER02-507-000 and ER02-510-000 (2001) • Affidavits, Prepared Direct Testimony, and Hearing, CPUC v. El Paso Natural Gas Company, et al., RP00-241-000 (2000-2001), Affidavit, El Paso Energy Corporation and The Coastal Corporation, EC00-73-000, (2000) • Affidavit, El Paso Energy Corporation and Sonat Inc., EC99-73-000 (1999) • Prepared Testimony, San Diego Gas & Electric Company and Enova Energy, Inc., EC97-12-000 (1997) • Prepared Testimony and Hearing, Wisconsin Electric Power Co., Northern States Power Co. (Minnesota), Northern States Power Co. (Wisconsin), and Cenerprise, Inc., EC95-16-000 (1996)

TESTIMONY BEFORE STATE REGULATORY COMMISSIONS

Prepared Direct Testimony, In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018, by Duke Energy Florida, Inc., FPSC Docket No. 140111-EI (2014) • Affidavit and Prepared Testimony, In The Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 14 Electric and B.P.U.N.J. No. 14 Gas Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and for Approval of a Gas Weather Normalization Clause; A Pension Expense Tracker; and for Other Appropriate Relief, BPU Docket No. GR09050422, New Jersey Board of Public Utilities (2010) • Prepared Direct Testimony, Application of Wisconsin Power and Light Company for Issuance of a Certificate of Public Convenience and Necessity for Construction and Placement in Operation of an Approximately 300 MW Coal-Fired Baseload Facility and an Application for Approval of Fixed Financial Parameters and Capital Cost Rate-Making Principles for the Baseload Facility, Docket No. 6680-CE-170, Public Service Commission of Wisconsin (2008) • Prepared Rebuttal Testimony and Hearing, In the Matter of the Joint Petition of Public Service Electric and Gas Company and

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Exelon Corporation for Approval of a Change in Control of Public Service Electric and Gas Company, and Related Authorizations, BPU Docket No. EM05020106, OAL Docket No. PUC-01874-05, New Jersey Board of Public Utilities (2005, 2006) • Affidavit, Application of Duke Energy Corporation for Authorization to Enter Into a Business Combination Transaction with Cinergy Corp., Docket No. 2005-210-E, Public Service Commission Of South Carolina (2005) • Prepared Rebuttal Testimony and Hearing, Joint Application of PECO Energy Company and Public Service Electric and Gas Company for Approval of the Merger of Public Service Enterprise Group Incorporated with and into Exelon Corporation, Docket No. A-110550F0160, Pennsylvania Public Utility Commission (2005) • Prepared Direct Testimony and Hearing, Application of Washington Gas Light Company for amendments to Rate Schedule No. 9, Firm Delivery Gas Supplier Agreement of its Gas Tariff, Docket No. PUE-2004-00085 (2005) • Prepared Direct Testimony, Application of Wisconsin Public Service Corporation for a Certificate of Public Convenience and Necessity for Construction of A Large Electric Generating Plant with Associated Facilities, known as Weston 4, at Its Existing Weston Generating Station Located in Marathon County, Docket No. 6690-CE-187, Public Service Commission of Wisconsin (2004) • Prepared Direct Testimony, Metromedia Energy, Inc. - Regarding Washington Gas Light Company's Plan to Return Customers to Sales Service Effective December 1, 2003, Docket No. PUE-2003-00536 (2004) • Report (with Mark Frankena) and Testimony, Analysis of Competitive Implications: An investigations into whether electric industry restructuring and competition in the provision of retail electric service is in the public interest, Louisiana Public Service Commission Docket No. U-21453, U-20925 (SC), U-22092 (SC) (Subdocket A) (2000) • Report and Hearing, Atlantic City Electric Company: Audit of Restructuring, New Jersey Board of Public Utilities, Docket No. EA97060395 (1998) • Prepared Testimony and Hearing, Proceeding on Motion of the Commission to Redesign Niagara Mohawk Power Corporation’s Current SC-7 Service Classification and Implement a New SC-7-A Service Classification, Case 94-E-0172, New York Public Service Commission (1995)

TESTIMONY BEFORE FEDERAL COURTS

Report, Deposition, and Bench Trial, FTC v. Arch Coal, Inc., et al., Civil Action 04-0534 (JDB), U.S. Dist. Court, Dist. of Columbia (2004) • Report, Deposition and Jury Trial, Trigen v. OG&E, CIV-96-1595L, U.S. Dist. Court, Western Dist. of Oklahoma (1998)

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TESTIMONY BEFORE STATE COURTS	Affidavit, Retail Energy Supply Association, *et al.* v. Public Service Commission of the State of New York, *et al.*, Index No. 870-16, State of New York, Supreme Court, County of Albany (2016) • Affidavit, City Public Service Board of San Antonio vs. Public Utility Commission of Texas, et al., No. 97-02917, District Court of Travis County, Texas, 200th Judicial District (1997)
OTHER TESTIMONY	Report, Metromedia Energy, Inc. v. Mirant Americas Energy Marketing, RE: 18 198 Y 18484 03 (2005) • Report and Deposition, King Provision Corporation v. Burger King Corporation and Grand Metropolitan PLC*,* 90-05718-CA, 4th Cir., Duval Co., Florida (1992) • Deposition, West Texas Transmission L.P. v. Enron Corp. et al., SA 88 CA 0638, W.D. Texas, San Antonio Division (1988)
PUBLICATIONS	"Geographic Market Delineation in LMP Electric Power Markets," *Electricity Journal* 23(3) (April 2010): 49-60 • "The Likely Effect of the Proposed Exelon-PSEG Merger on Wholesale Electricity Prices," *Electricity Journal* 21(1) (Jan./Feb. 2008): 45-54 • "FERC MBR Screens: The Good, the Bad, and the Ugly," *Public Utilities Fortnightly* 143(7) (July 2005): 37-42 • "Finding Market Power in Power Markets," *International Journal of the Economics of Business*, 7(2) (July 2000): 167-178 • "Why Applicants Should Use Computer Simulation Models to Comply with the FERC's New Merger Policy," with Mark Frankena, *Public Utilities Fortnightly*, 135(3) (February 1, 1997): 22-26 • *Electric Utility Mergers,* with Mark Frankena and Bruce Owen, Chapters 1, 4, & 5, 1994 • "International Trade and Antitrust: Comments," *University of Cincinnati Law Review*, 61(3) (1993): 945-953 • "Upstream Vertical Integration with Automatic Price Adjustments," *Journal of Regulatory Economics* 4 (1992): 279-287 • "Should the U.S. Department of Justice deviate from the 5% price test for market definition on a case-by-case basis?" with Gale Mosteller, *International Merger Law*, April 1992 • "Defining Markets for Merger Analysis," with Gale Mosteller, *Antitrust Bulletin* 36 (Fall 1991): 599-640 • "Analyzing Agreements Among Competitors: What Does the Future Hold?" with Jim Langenfeld, *Antitrust Bulletin* 36 (Fall 1991): 651-679 • "In Defense of Antitrust," with Jim Langenfeld, *Regulation* 14(2) (Spring 1991): (Letters) 2-4 • "Enforcement of Property Rights and the Provision of Public Good Attributes," *Information Economics and Policy* 3 (1988): 91-108
WORKING PAPERS	"Advertising Restrictions as Rent Increasing Costs," FTC Bureau of Economics Working Paper No. 196, May 1992 • "Rent Increasing Costs: The Antitrust Implications from a Paradox in Value Theory," FTC Bureau of Economics Working Paper No. 182, November 1990 • "The Relationship Between Industrial Sales Prices and Concentration of Natural Gas Pipelines," FTC Bureau of Economics Working Paper No. 168, November 1988 • "Deregulation by Vertical Integration?" FTC Bureau of Economics Working Paper No. 166, November 1988

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PRESENTATIONS & PROFESSIONAL ACTIVITIES

Comments (with 7 others), Notice of Inquiry: Modifications to Commission Requirements for Review of Transactions under Section 203 of the Federal Power Act and Market-Based Rate Applications under Section 205 of the Federal Power Act, Docket No. RM16-21-000, Federal Energy Regulatory Commission, November 28, 2016 • Report, PJM Interconnection, L.L.C., Docket No. ER15-623-000, Federal Energy Regulatory Commission, January 20, 2015 • Comments, Notice of Inquiry: Analysis of Horizontal Market Power under the Federal Power Act, Docket No. RM11-14-000, Federal Energy Regulatory Commission, May 23, 2011 • Comments, Position Limits for Derivatives, RIN 3038–AD15 and 3038–AD16, Commodity Futures Trading Commission, March 28, 2011 • Comments, Guidance on Simultaneous Transmission Import Limit Studies, AD10-2-000, Federal Energy Regulatory Commission, February 12, 2010 • "Geographic Market Delineation in LMP Electric Power Markets," presentation before representatives of the Federal Energy Regulatory Commission, U.S. Department of Justice, and U.S. Federal Trade Commission, January 27, 2010 • Comments, Notices of Intent to determine that 15 natural gas financial basis contracts traded on the Intercontinental Exchange, Inc. are Significant Price Discovery Contracts, Commodity Futures Trading Commission, October 26, 2009 • "Efficacy of Vertical Integration in Energy Industries with Applications to Proposed Standards of Conduct for Transmission Providers," submitted to FERC by Santee Cooper in Docket No. RM07-1-000 (2007) • Chair, Antitrust Committee, Energy Bar Association, 2004–2005 • "Competition in the Natural Gas Industry: An Antitrust Perspective, presentation to staff of the Federal Energy Regulatory Commission," March 28, 2005 • Vice Chair, Antitrust Committee, Energy Bar Association, 2003–2004 • "Weston 4 Effect on Wholesale Competition in WUMS," submitted to the Public Service Commission of Wisconsin by Wisconsin Public Service Corporation in Docket No. 6690-CE-187, September 26, 2003 • "Computer Models In The Electric Power Industry," presented to staff of the Federal Trade Commission, Washington, DC, June 11, 2002 • "TECO EnergySource Market Share Analysis," submitted to FERC by TECO EnergySource, Inc. in Docket No. ER96-1563-017, September 10, 2001 • "Finding Market Power in Power Markets," presented to staff of the Federal Trade Commission, Washington, DC, June 20, 2001 • "A Study of Marketing Affiliate and Other Affiliate Holdings of Firm Capacity on Interstate Natural Gas Pipelines and the Effects on Natural Gas Markets," April 30, 2001, submitted to FERC by the Interstate Natural Gas Association of America in Docket No. PL00-1-003 • "Why We Should Use Computer Models to Unveil Market Power," presented at the Sixth DOE–NARUC National Electricity Forum, Brown Convention Center, Houston, TX, September 16, 1998 • Comments, *Agency Information Collection and Dissemination Activities: Comment Request*, U.S. Department of Energy, Energy Information Administration, August 28, 1998 • Comments, *Revised filing Requirements Under Part 33 of the Commission's Regulations*, Federal Energy

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Regulatory Commission Docket No. RM98-4-000, August 21, 1998 • "Use of Computer Simulation Models to Unveil Market Power," presented to staff of the Federal Trade Commission, Federal Energy Regulatory Commission and U.S. Department of Justice, Federal Trade Commission, Washington, DC, April 10, 1998 • "Use of Computer Simulation Models to Unveil Market Power: The Primergy Case," presented to the Bureau of Economics, Federal Trade Commission, Washington, DC , December 8, 1997 • "Use of Computer Simulation Models to Unveil Market Power," presented at the 29th Annual Conference of the Institute of Public Utilities, Williamsburg, Virginia, December 3, 1997 • **"**Mergers and Market Power," presented at the National Association of State Utility Consumer Advocates Mid-Year Meeting, Charleston, South Carolina, June 9, 1997 • "Market Power Analysis: An Economic Perspective," (with Mark Frankena), presented at the Strategic Research Institute Conference on The Legal Challenges of Restructuring, Arlington, Virginia, April 16, 1997 • "Mergers and Market Power," presented at the Edison Electric Institute Workshop on FERC Merger Policy Guidelines, Arlington, Virginia, April 1, 1997 • "New Approaches to Controlling Distribution Company Market Power," presented at the New York Energy Efficiency Council Conference on Innovative Solutions to a Changing Energy Market, New York Athletic Club, February 7, 1997 • Description of the Western Power Model, with Mark Frankena, Exhibit 8 to Prepared Testimony Before the Nevada Public Service Commission, January 31, 1997 • Reviewer, American Bar Association, Section of Antitrust Law, *Manual on the Economics of Antitrust Law, 14th Supplement*, 1995 • Referee, *Quarterly Journal of Business and Economics*, 1994—1995 • Reviewer, American Bar Association, Section of Antitrust Law, *Manual on the Economics of Antitrust Law, 10th Supplement*, 1993 • Expert Witness, Federal American Inn of Court, Washington, DC, Winter 1993 • "Advertising Restrictions as Rent Increasing Costs," presented at a *Contemporary Policy Issues* Session of the Western Economics Association's 67th Annual Conference, July 1992 • "Let's Make Merger Policy 'Fully Consonant With Economic Theory,'" presented at a *Contemporary Policy Issues* Session of the Western Economics Association's 67th Annual Conference, July 1992 • "Advertising Restrictions as Rent Increasing Costs," Seminar, Department of Business Economics, Indiana University, October 1991 • "International Trade and Antitrust: Comments," presented at a *Contemporary Policy Issues* Session of the Western Economics Association's 66th Annual Conference, July 1991 • Discussant, Western Economics Association's 66th Annual Conference, July 1991 • Horizontal Restraints Cases at the Federal Trade Commission: From *American Medical Association* through the Present," with Jim Langenfeld, presented at the 60th Annual Conference of the Southern Economics Association, November 1990 • "Defining Markets for Merger Analysis," with Gale Mosteller, presented at a *Contemporary Policy Issues* Session of the Western Economics Association's 65th Annual Conference, cosponsored by the *Antitrust Bulletin* and the

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Antitrust and Trade Regulation Section of the Federal Bar Association, July 1990 • "Analyzing Agreements Among Competitors: What Does the Future Hold?" with Jim Langenfeld, presented at a *Contemporary Policy Issues* Session of the Western Economics Association's 65th Annual Conference, cosponsored by the *Antitrust Bulletin* and the Antitrust and Trade Regulation Section of the Federal Bar Association, July 1990 • "The Relationship Between Industrial Sales Prices and Concentration of Natural Gas Pipelines," Seminar, Office of Economic Policy, Federal Energy Regulatory Commission, Summer 1989 • "The Relationship Between Industrial Sales Prices and Concentration of Natural Gas Pipelines," Seminar, Economic Analysis Group, Antitrust Division, U.S. Department of Justice, February 1989 • "Deregulation by Vertical Integration?" Seminar, Department of Business Economics, Indiana University, January 1989 • Discussant, Industrial Organization Society Session, Annual Meeting of the American Economics Association, December 1988 • "Concentration and Price in the Natural Gas Industry," Seminar, Federal Trade Commission, July 1988 • "Relevant Measures of Concentration for Antitrust Policy," presented at an Industrial Organization Society Session of the 57th Annual Conference of the Southern Economics Association, November 1987

Northeast Region Generation Owned and Controlled by PSEG

Owner	Plant Name	State	Owned Capacity		Controlled Capacity	
			Winter Seasonal Capacity	Summer Seasonal Capacity	Winter Seasonal Capacity	Summer Seasonal Capacity
ISO - New England						
PSEG Power CT	Bridgeport Station 2	CT	148	130	148	130
PSEG Power CT	Bridgeport Station 3	CT	385	383	385	383
PSEG Power CT	Bridgeport Station 4	CT	20	15	20	15
PSEG Power CT	New Haven Harbor 1	CT	455	448	455	448
PSEG New Haven	New Haven Harbor GT2	CT	61	61	0	0
PSEG New Haven	New Haven Harbor GT3	CT	61	61	0	0
PSEG New Haven	New Haven Harbor GT4	CT	61	61	0	0
Total ISO - New England Capacity			**1,190**	**1,158**	**1,008**	**976**
New York ISO						
PSEG Power NY	Bethlehem Energy Center CC	NY	845	754	845	754
Total New York ISO Capacity			**845**	**754**	**845**	**754**
PJM						
PSEG Fossil	Conemaugh 1	PA	191	191	191	191
PSEG Fossil	Conemaugh 2	PA	191	191	191	191
PSEG Fossil	Conemaugh A[1]	PA	1	1	1	1
PSEG Fossil	Conemaugh B	PA	1	1	1	1
PSEG Fossil	Conemaugh C	PA	1	1	1	1
PSEG Fossil	Conemaugh D	PA	1	1	1	1
PSEG Power	Conemaugh Hydroelectric Plant 1[2]	PA	1	1	1	1
PSEG Power	Conemaugh Hydroelectric Plant 2	PA	1	1	1	1
PSEG Fossil	Keystone 1[3]	PA	194	194	194	194
PSEG Fossil	Keystone 2	PA	194	194	194	194
PSEG Fossil	Keystone 3	PA	1	1	1	1
PSEG Fossil	Keystone 4	PA	1	1	1	1
PSEG Fossil	Keystone 5	PA	1	1	1	1
PSEG Fossil	Keystone 6	PA	1	1	1	1
PSEG Solar Source LLC	Wyandot Solar Farm	OH	12	12	12	12

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Northeast Region Generation Owned and Controlled by PSEG

Owner	Plant Name	State	Owned Capacity		Controlled Capacity	
			Winter Seasonal Capacity	Summer Seasonal Capacity	Winter Seasonal Capacity	Summer Seasonal Capacity
PJM East						
PSEG Fossil	Bergen 3[7]	NJ	21	21	21	21
PSEG Fossil	Bergen CC1	NJ	628	628	628	628
PSEG Fossil	Bergen CC2	NJ	550	555	550	555
PSEG Fossil	Burlington 8[7]	NJ	21	21	21	21
PSEG Fossil	Burlington 9[10]	NJ	184	184	184	184
PSEG Fossil	Burlington 11[7]	NJ	184	184	184	184
PSEG Fossil	Burlington 121	NJ	42	42	42	42
PSEG Fossil	Burlington 122	NJ	42	42	42	42
PSEG Fossil	Burlington 123	NJ	42	42	42	42
PSEG Fossil	Burlington 124	NJ	42	42	42	42
PSEG Fossil	Edison 1[7]	NJ	168	168	168	168
PSEG Fossil	Edison 2[7]	NJ	168	168	168	168
PSEG Fossil	Edison 3[7]	NJ	168	168	168	168
PSEG Fossil	Essex 9	NJ	81	81	81	81
PSEG Fossil	Essex 10[7]	NJ	168	168	168	168
PSEG Fossil	Essex 11[7]	NJ	168	168	168	168
PSEG Fossil	Essex 12[7]	NJ	168	168	168	168
PSEG Nuclear	Hope Creek 1	NJ	1,161	1,161	1,161	1,161
PSEG Fossil	Hudson 2	NJ	608	608	608	608
PSEG Fossil	Kearny 9[8]	NJ	21	21	21	21
PSEG Fossil	Kearny 12	NJ	175	175	175	175
PSEG Fossil	Kearny 13	NJ	0	178	0	178
PSEG Fossil	Kearny 14	NJ	0	89	0	89
PSEG Fossil	Linden 1	NJ	455	458	455	458
PSEG Fossil	Linden 2	NJ	775	778	775	778
PSEG Fossil	Linden 7	NJ	84	84	84	84
PSEG Fossil	Linden 8	NJ	84	84	84	84
PSEG Fossil	Linden GT5	NJ	86	86	86	86
PSEG Fossil	Linden GT6	NJ	86	86	86	86
PSEG Hackettstown LLC	Mars Solar Garden	NJ	2	2	2	2
PSEG Fossil	Mercer 1	NJ	316	316	316	316
PSEG Fossil	Mercer 2	NJ	316	316	316	316

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Northeast Region Generation Owned and Controlled by PSEG

			Owned Capacity		Controlled Capacity	
Owner	**Plant Name**	**State**	**Winter Seasonal Capacity**	**Summer Seasonal Capacity**	**Winter Seasonal Capacity**	**Summer Seasonal Capacity**
PSEG Fossil	Mercer GT3[9]	NJ	115	115	115	115
PSEG Solar Source LLC	Milford Solar Farm	DE	15	15	15	15
PSEG Fossil	National Park GT1[7]	NJ	21	21	21	21
PSEG Nuclear	Salem 1[4]	NJ	674	674	674	674
PSEG Nuclear	Salem 2	NJ	665	665	665	665
PSEG Nuclear	Salem GT3	NJ	22	22	22	22
PSEG Fossil	Sewaren 1	NJ	104	104	104	104
PSEG Fossil	Sewaren 2	NJ	118	118	118	118
PSEG Fossil	Sewaren 3	NJ	107	107	107	107
PSEG Fossil	Sewaren 4	NJ	124	124	124	124
PSEG Fossil	Sewaren 6[7]	NJ	105	105	105	105
PSE&G	Solar 4 All Units	NJ	78	78	78	78
PSEG Fossil	Yards Creek 1[5]	NJ	70	70	0	0
PSEG Fossil	Yards Creek 2	NJ	70	70	0	0
PSEG Fossil	Yards Creek 3	NJ	60	60	0	0
PJM 5004/5005						
PSEG Nuclear	Peach Bottom 2[6]	PA	561	561	561	561
PSEG Nuclear	Peach Bottom 3	PA	561	561	561	561
Total PJM Capacity			**11,272**	**11,550**	**11,072**	**11,350**
Total Northeast Region Capacity			**13,307**	**13,462**	**12,926**	**13,080**

Source: PSEG.

Notes:

[1] PSEG Fossil has a 22.5% interest in the Conemaugh coal-fired units.

[2] PSEG Global has a 4% interest in the Conemaugh Hydroelectric facility.

[3] PSEG Fossil has a 22.84% ownership interest in the Keystone facility.

[4] PSEG Nuclear has a 57.41% interest in the Salem Nuclear facility.

[5] PSEG Fossil has a 50% interest in the Yards Creek facility. Yards Creek is operated by Jersey Central Power & Light, and thus is controlled by JCP&L in the analysis.

[6] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear facility.

[7] Unit retired on 06/01/2015

[8] Unit retired on 08/31/2014

[9] Unit retired on 07/31/2015

[10] Unit retired on 06/30/2014

Scenario 1 PSEG 2016 MBR for ISONE

	PSA		WMSA							
			Winter		Spring		Summer		Fall	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result
ISO New England	8,715	Pass	5.4	Pass	5.2	Pass	6.5	Pass	6.0	Pass
Connecticut	3,388	Pass	11.8	Pass	11.3	Pass	14.3	Pass	13.3	Pass
Southwest Connecticut	1,701	Pass	16.4	Pass	15.7	Pass	14.9	Pass	13.0	Pass

Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **ISONE**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	16	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	190	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	30,892	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	16	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,358	Calculated
I	Study Area Reserve Requirement	2,510	Gendata
J	Amount of Line I Attributable to Seller, if any	3	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	16,073	
	Load		
L	Balancing Area Annual Peak Load	24,054	Loads
M	Average Daily Peak Native Load in Peak Month	17,708	Loads
N	Amount of Line M Attributable to Seller, if any	10	SellerLoads
O	Wholesale Load (L-M)	6,346	
P	Net Uncommitted Supply (K-O)	9,728	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,012	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	4,548	
	% of SIL for Seller's imported capacity →	0.04	
	% of SIL for Other's imported capacity →	0.96	
	SIL Value →	4548	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **CT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	843	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	102	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	7,524	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	2,948	Calculated
I	Study Area Reserve Requirement	689	Gendata
J	Amount of Line I Attributable to Seller, if any	10	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	5,674	
	Load		
L	Balancing Area Annual Peak Load	6,419	Loads
M	Average Daily Peak Native Load in Peak Month	5,054	Loads
N	Amount of Line M Attributable to Seller, if any	14	SellerLoads
O	Wholesale Load (L-M)	1,365	
P	Net Uncommitted Supply (K-O)	4,309	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	920	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	3,050	
	% of SIL for Seller's imported capacity →	0.03	
	% of SIL for Other's imported capacity →	0.97	
	SIL Value →	3050	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **SWCT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	400	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	98	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	2,090	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	3,102	Calculated
I	Study Area Reserve Requirement	205	Gendata
J	Amount of Line I Attributable to Seller, if any	0	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	2,985	
	Load		
L	Balancing Area Annual Peak Load	3,286	Loads
M	Average Daily Peak Native Load in Peak Month	2,500	Loads
N	Amount of Line M Attributable to Seller, if any	0	SellerLoads
O	Wholesale Load (L-M)	786	
P	Net Uncommitted Supply (K-O)	2,199	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	498	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	3,200	
	% of SIL for Seller's imported capacity →	0.03	
	% of SIL for Other's imported capacity →	0.97	
	SIL Value →	3200	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II – Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **ISONE**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	860	852	843	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	12	16	16	16	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	29	87	7	79	SellerGendata
E	Uncommitted Capacity Imports	222	188	177	188	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	16,956	14,847	17,687	15,178	Loads
G	Amount of Line F Attributable to Seller, if any	113	102	39	5	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	16,843	14,745	17,648	15,173	F - G
I	Study Area Reserve Requirement	2,530	2,510	2,510	2,510	Gendata
J	Amount of Line I Attributable to Seller, if any	16	20	10	3	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,514	2,490	2,500	2,507	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	32,149	30,892	29,634	30,892	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	12	16	16	16	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,097	3,148	229	2,881	Gendata; Row D
P	Uncommitted Capacity Imports	4,326	4,360	4,371	4,360	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	16,033	14,885	13,644	14,707	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	911	815	948	935	
S	Total Seasonal Uncommitted Capacity (Q+R)	16,944	15,700	14,592	15,642	
T	**Applicant's Market Share (R÷S)**	5.4%	5.2%	6.5%	6.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	4,548	4,548	4,548	4,548	
V	SIL Value	4,548	4,548	4,548	4,548	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II – Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **CT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	860	852	843	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	29	87	7	79	SellerGendata
E	Uncommitted Capacity Imports	106	93	93	94	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	4,207	3,642	4,503	3,772	Loads
G	Amount of Line F Attributable to Seller, if any	113	102	39	5	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	4,093	3,540	4,464	3,766	F - G
I	Study Area Reserve Requirement	683	683	689	683	Gendata
J	Amount of Line I Attributable to Seller, if any	21	22	10	3	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	662	661	679	680	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	8,048	7,786	7,524	7,786	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	275	793	58	726	Gendata; Row D
P	Uncommitted Capacity Imports	2,944	2,957	2,957	2,956	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	5,963	5,749	5,279	5,570	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	802	734	881	857	
S	Total Seasonal Uncommitted Capacity (Q+R)	6,765	6,482	6,160	6,427	
T	**Applicant's Market Share** (R÷S)	11.8%	11.3%	14.3%	13.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	3,050	3,050	3,050	3,050	
V	SIL Value	3,050	3,050	3,050	3,050	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II – Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **SWCT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	407	404	400	404	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	14	41	3	38	SellerGendata
E	Uncommitted Capacity Imports	86	68	91	101	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	2,048	1,758	2,178	1,766	Loads
G	Amount of Line F Attributable to Seller, if any	0	0	0	0	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	2,048	1,758	2,178	1,766	F - G
I	Study Area Reserve Requirement	209	206	205	206	Gendata
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	209	206	205	206	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	2,321	2,206	2,090	2,206	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	79	225	16	206	Gendata; Row D
P	Uncommitted Capacity Imports	2,454	2,302	3,109	3,089	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	2,439	2,318	2,799	3,116	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	479	430	488	467	
S	Total Seasonal Uncommitted Capacity (Q+R)	2,918	2,748	3,287	3,583	
T	**Applicant's Market Share** (R÷S)	16.4%	15.7%	14.9%	13.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	2,540	2,370	3,200	3,190	
V	SIL Value	2,540	2,370	3,200	3,190	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **NYISO**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	757	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	265	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	585	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	42,506	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,265	Calculated
I	Study Area Reserve Requirement	2,620	Gendata
J	Amount of Line I Attributable to Seller, if any	0	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	22,514	
	Load		
L	Balancing Area Annual Peak Load	31,138	Loads
M	Average Daily Peak Native Load in Peak Month	25,244	Loads
N	Amount of Line M Attributable to Seller, if any	0	SellerLoads
O	Wholesale Load (L-M)	5,894	
P	Net Uncommitted Supply (K-O)	16,620	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,607	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,850	
	% of SIL for Seller's imported capacity →	0.09	
	% of SIL for Other's imported capacity →	0.91	
	SIL Value →	6850	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **NYISO**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	870	814	757	814	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	265	265	265	265	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	71	115	13	92	SellerGendata
E	Uncommitted Capacity Imports	731	600	582	640	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	21,006	18,974	23,056	19,579	Loads
G	Amount of Line F Attributable to Seller, if any	0	0	0	0	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	21,006	18,974	23,056	19,579	F - G
I	Study Area Reserve Requirement	2,620	2,620	2,620	2,620	Gendata
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,620	2,620	2,620	2,620	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	40,162	41,334	42,506	41,334	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,277	5,820	726	4,652	Gendata; Row D
P	Uncommitted Capacity Imports	6,904	6,924	6,268	7,055	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	20,162	20,843	22,372	21,538	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	1,795	1,564	1,591	1,627	
S	Total Seasonal Uncommitted Capacity (Q+R)	21,958	22,407	23,963	23,166	
T	**Applicant's Market Share** (R÷S)	8.2%	7.0%	6.6%	7.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,635	7,524	6,850	7,695	
V	SIL Value	7,635	7,524	6,850	7,695	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Scenario 1 PSEG 2016 MBR for PJM										
	PSA		WMSA							
			Winter		Spring		Summer		Fall	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result
PJM Interconnection	35,891	Pass	9.5	Pass	7.7	Pass	8.3	Pass	8.3	Pass
PJM East	3,572	Pass	32.7	Fail	27.0	Fail	32.9	Fail	29.7	Fail
PJM East of 5004/05	5,389	Pass	24.3	Fail	20.7	Fail	23.7	Fail	23.1	Fail
PJM East of AP South	7,602	Pass	18.5	Pass	15.5	Pass	18.8	Pass	17.0	Pass

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	9,844	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	195	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	1,943	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	152	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	175,931	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	1,943	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	195	Row B; Table2Data
H	Uncommitted Capacity Imports	7,448	Calculated
I	Study Area Reserve Requirement	8,187	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	63,588	
	Load		
L	Balancing Area Annual Peak Load	143,633	Loads
M	Average Daily Peak Native Load in Peak Month	121,600	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	22,034	
P	Net Uncommitted Supply (K-O)	41,555	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,664	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	7,600	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	7600	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	14	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	88	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	26,628	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	14	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,449	Calculated
I	Study Area Reserve Requirement	1,724	Gendata
J	Amount of Line I Attributable to Seller, if any	176	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	15,220	
	Load		
L	Balancing Area Annual Peak Load	30,240	Loads
M	Average Daily Peak Native Load in Peak Month	24,093	Loads
N	Amount of Line M Attributable to Seller, if any	2,269	SellerLoads
O	Wholesale Load (L-M)	6,148	
P	Net Uncommitted Supply (K-O)	9,072	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,500	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,537	
	% of SIL for Seller's imported capacity →	0.01	
	% of SIL for Other's imported capacity →	0.99	
	SIL Value →	6537	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	107	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	51,729	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,212	Calculated
I	Study Area Reserve Requirement	2,975	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	20,577	
	Load		
L	Balancing Area Annual Peak Load	52,190	Loads
M	Average Daily Peak Native Load in Peak Month	42,368	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	9,822	
P	Net Uncommitted Supply (K-O)	10,754	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,365	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,319	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	6319	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	85	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	75,381	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,370	Calculated
I	Study Area Reserve Requirement	4,032	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	25,567	
	Load		
L	Balancing Area Annual Peak Load	70,729	Loads
M	Average Daily Peak Native Load in Peak Month	58,108	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	12,621	
P	Net Uncommitted Supply (K-O)	12,946	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,344	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	4,455	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	4455	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	11,339	10,592	9,844	10,592	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	195	195	195	195	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	1,643	1,944	1,943	1,944	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	491	1,461	225	1,374	SellerGendata
E	Uncommitted Capacity Imports	214	204	138	117	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	108,842	91,954	109,399	91,992	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	106,988	90,430	107,540	90,648	F - G
I	Study Area Reserve Requirement	7,474	6,516	7,991	6,470	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	7,335	6,385	7,817	6,352	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	181,889	178,911	175,931	178,911	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	1,643	1,944	1,943	1,944	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	195	195	195	195	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	7,868	24,681	4,028	23,215	Gendata; Row D
P	Uncommitted Capacity Imports	11,783	12,069	7,462	6,950	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	72,929	71,233	65,756	67,394	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,622	5,931	5,975	6,123	
S	Total Seasonal Uncommitted Capacity (Q+R)	80,550	77,164	71,731	73,518	
T	**Applicant's Market Share** (R÷S)	9.5%	7.7%	8.3%	8.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	11,997	12,273	7,600	7,067	
V	SIL Value	11,997	12,273	7,600	7,067	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	22	14	14	14	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	121	72	78	68	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	18,303	15,919	20,901	16,346	Loads
G	Amount of Line F Attributable to Seller, if any	1,749	1,434	1,764	1,268	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	16,553	14,485	19,137	15,078	F - G
I	Study Area Reserve Requirement	1,258	1,168	1,659	1,211	Gendata
J	Amount of Line I Attributable to Seller, if any	130	122	165	110	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	1,128	1,046	1,494	1,101	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	26,328	26,478	26,628	26,478	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	22	14	14	14	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,139	3,653	610	3,436	Gendata; Row D
P	Uncommitted Capacity Imports	7,381	8,758	6,459	7,791	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	14,911	16,065	11,860	14,667	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,230	5,954	5,826	6,199	
S	Total Seasonal Uncommitted Capacity (Q+R)	22,141	22,019	17,686	20,867	
T	**Applicant's Market Share** (R÷S)	32.7%	27.0%	32.9%	29.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	7,502	8,830	6,537	7,859	
V	SIL Value	7,502	8,830	6,537	7,859	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	162	91	95	69	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	35,188	30,080	37,518	30,214	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	33,334	28,556	35,658	28,871	F - G
I	Study Area Reserve Requirement	2,450	2,184	2,889	2,189	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,311	2,054	2,715	2,071	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	52,220	51,975	51,729	51,975	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	2,259	7,170	1,184	6,744	Gendata; Row D
P	Uncommitted Capacity Imports	7,942	8,202	6,224	6,034	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	22,294	22,424	18,423	20,350	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,144	5,861	5,725	6,103	
S	Total Seasonal Uncommitted Capacity (Q+R)	29,438	28,286	24,148	26,453	
T	**Applicant's Market Share** (R÷S)	24.3%	20.7%	23.7%	23.1%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	8,104	8,293	6,319	6,103	
V	SIL Value	8,104	8,293	6,319	6,103	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	187	115	77	81	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	48,658	41,074	51,437	41,155	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	46,804	39,551	49,577	39,811	F - G
I	Study Area Reserve Requirement	3,496	3,025	3,935	2,991	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	3,358	2,895	3,762	2,873	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	77,314	76,348	75,381	76,348	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,344	10,532	1,726	9,907	Gendata; Row D
P	Uncommitted Capacity Imports	7,710	8,741	4,378	5,987	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	31,554	32,139	24,722	29,772	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,169	5,885	5,707	6,115	
S	Total Seasonal Uncommitted Capacity (Q+R)	38,723	38,024	30,429	35,886	
T	**Applicant's Market Share** (R÷S)	18.5%	15.5%	18.8%	17.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,897	8,856	4,455	6,068	
V	SIL Value	7,897	8,856	4,455	6,068	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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DATA AND ASSUMPTIONS FOR ECONOMISTS INCORPORATED'S DELIVERED PRICE TEST STUDY FOR PSEG

This exhibit describes data and assumptions used in the delivered price test study ("study") carried out by Economists Incorporated for PSEG. Because the data are voluminous, we provide them in electronic workpapers. In those workpapers, the Files.xlsx spreadsheet provides a brief description of the organization of the data files.

This Exhibit has six sections. Section I discusses the study's representative periods. Section II discusses the geographic region and balancing authority areas. Section III discusses generation resources, including adjustments to generating capacity for seasons, maintenance, water availability, and long-term contracts. Section IV discusses transmission, including transmission pricing and losses. Section V discusses market prices. Section VI discusses the load data.

I. Periods

The study calculates market shares and concentration indexes for electric energy for ten representative periods during the year. The year is divided into three seasons (spring/fall, summer and winter). Spring/fall and winter seasons are divided into three periods based on days of the week, times of day and load levels. Summer is divided into four periods based on days of the week, times of day and load levels. Each calculation of market shares and concentration indexes reflects average conditions (e.g., average loads) during one of the resulting ten periods during the year (e.g., Summer Low Peak).

The study places each of the periods in each season into three condition categories: off-peak, low peak, and spike. Transmission pricing (see Section

IV.B below) and plant availability (see Section III.A.2 below) vary among these three categories.

Table I-1 summarizes the ten periods for the destination markets.

Table I-1– Definition of Ten Periods for Destination Market

Number	*Season*	*Time*	*Condition*	*Hours*	*Description**
1	Spring/Fall	Top 10%	Spike	203	Top 10% of peak hours
2	Spring/Fall	Peak	Peak	1829	Remaining peak hours
3	Spring/Fall	Off-peak	Off-Peak	2360	Off-peak hours
4	Summer	Top 1%	Spike	11	Top 1% of peak hours
5	Summer	Top 10%	Spike	106	Top 10% of peak hours
6	Summer	Peak	Peak	950	Remaining peak hours
7	Summer	Off-peak	Off-Peak	1152	Off-peak hours
8	Winter	Top 10%	Spike	101	Top 10% of peak hours
9	Winter	Peak	Peak	907	Remaining peak hours
10	Winter	Off-peak	Off-Peak	1152	Off-peak Hours

Note: *Peak hours include hours ending 8 a.m. through 11 p.m. Eastern Time weekdays, excluding six major holidays. Off-peak hours = Hours ending 12 a.m. through 7 a.m. on weekdays and all weekend and holiday hours.

The Off-peak periods are all NERC holidays and weekend hours plus weekdays from the hour ending at midnight EPT until the hour ending at 0700.[1] The Off-peak periods have off-peak transmission pricing and plant availability.

In order to define the Top 1% and Top 10% periods for a given season, we removed all Off-peak hours from that season. We then ranked the remaining (peak) hours based on load levels in the destination market by season. We then defined as the Top 1% as the 1 percent of these remaining hours in which loads in the destination market were highest and the Top 10% as the highest 10 percent of peak hours based on load levels. These periods have spike transmission pricing and plant availability.

[1] Major holidays are New Year's, Memorial Day, 4th of July, Labor Day, Thanksgiving and Christmas. Major holidays are included in the Weekend period.

The Peak periods are weekdays from the hour ending at 0800 until the hour ending at 2300 EPT, excluding hours in the Top 10% periods and major holidays. The Low Peak period has on-peak transmission pricing and plant availability.

II. Geographic Coverage and Market Areas

The study includes market areas that correspond to the balancing authority areas used by the North American Electric Reliability Council (NERC), and PJM submarkets as defined by FERC. Table II-1 lists these market areas and their abbreviations. There are two study destination markets, PJM East and PJM East of 5004/5005.

Table II-1– List of Eastern Market Areas and Study Destinations

Abbreviation	*Full Name*	*Study Destination*
PJME	PJM East	Yes
PJM50	PJM East of 5004/5005	Yes
PJMS	PJM East of AP South	
PJM	PJM	
NYISO	New York ISO	

III. Generation

A. Generation Capacity and Ownership

The study includes generating units located in the areas that are (1) connected to the power grid, (2) not exclusively used for self-generation, and (3) either in a plant used primarily for electric generation or a Qualifying Facility.

1. Generating Unit Data

The study uses data for summer and winter capability at the unit level reported in the Energy Velocity (EV) database available from Ventyx. The units include all

units with a status of operating, standby, cold standby, restart, mothballed, testing, or under construction that went online before November 30, 2015 and with a retirement date after November 30, 2015. We exclude generation units that are less than 5 MW unless they are owned by PSEG.

2. Ownership

The study uses relies on Ventyx determination of plant and unit ownership. When Ventyx reports a holding company, the ownership is assigned to the holding company. For PSEG generation, the study relies upon Appendix B data from market-based rate filings and updates from the companies to determine plant ownership and seasonal capability. Operational control of PSEG units is consistent with the methodology used for market-based rates.

3. Seasonal variation in capability

The study uses seasonal capability data from EV. Spring/fall capacities are the average of summer and winter capacities.

4. Adjustments to Generating Capability

The generating capability figures used for each period are obtained by multiplying the seasonal capabilities by an availability factor, which is based on the period, unit location, and NERC General Availability Data Systems (GADS) category of the unit. The GADS database gives national average operating information for generating units by unit type and size. For example, it gives data for coal-fired steam units with capacities between 300 MW and 399 MW.

For each period and each generating unit, the availability factor adjusts for the following.

a) Unplanned outage rates by GADS category

For a given GADS category, the study assumes that unplanned (forced) outage rates (as a share of generating capability available after allowing for planned outages) are constant across seasons and generating units throughout the Region, regardless of owner. Based on GADS data for 2007 through 2011, the study calculates an equivalent forced outage rate (EIFOR), which measures the share of generating capability in a GADS category that is not available because of forced outages. The computation is EIFOR = (FOH)/AH, where FOH is number of forced outage hours and AH is total hours available for generation after planned outages (but before forced outages).[2]

b) Planned outage rates by GADS category and season

With four exceptions (hydro, pumped storage, wind, and solar units), the study assumes that the planned outage rate is constant for all generating units for a given GADS category and season. For a given GADS category, the share of hours of generating capability that is not available as a result of planned outages is computed as (POH + POEH)/PH; where PH are the period hours, POH are the hours not available because of planned outages, and POEH are the hours not available because of planned outage extensions

The study assumes that balancing authority areas are both summer and winter peaking. Therefore, the study assumes that all planned outages for thermal units occur during spring/fall.

[2] EIFOR differs slightly from the EFOR provided in the GADS data. EIFOR provides a better measure of a forced outage rate for peaking units that are operated a small percentage of the year.

c) Variation in hydro availability across seasons and periods

In general, utilities use hydro facilities to generate energy during the hours when energy prices are highest, subject to constraints imposed by availability of water and reservoir capacity. In order to incorporate these constraints, the study proceeds in the following manner.

First, the study uses EIA Form 923 monthly production data for the period 2011 to 2015 to compute average hourly hydro generation by season. Average hourly generation is then divided by hydro capability to give an average hourly hydro operating rate by season.

Second, depending upon the level of the hydro operating rate for a given season, the study calculates availability factors for the spike, low peak and off-peak periods. When the historical seasonal operating rate is below 30 percent, the availability factor for each period in the season is set equal to the operating rate; the 30 percent figure is an assumed "run of river" constraint. The study assumes that prospectively the maximum operating rate is 90 percent; this is the assumed "maximum rate" constraint. When the historical seasonal operating rate is above 90 percent, the availability factor for each period is set to 90 percent.

When the seasonal operating rate is above the run of river constraint and below the maximum rate, we reason that the hydro generator owner would be likely to produce a higher level of energy during spike hours, when energy prices are highest, than during low peak hours, and that the owner would be likely to produce a higher level during low peak than during off-peak hours.

Based on this reasoning, when the seasonal operating rate is between the run of river constraint and the maximum rate, as is the case for each of the three

seasons, the study uses a spike availability factor of 90 percent, which is the assumed maximum operating rate, and off-peak availability factor of 30 percent, which is the assumed run-of-river constraint, and a calculated availability factor for the peak periods, as described below.

The seasonal peak availability factor is calculated using actual total seasonal hydro generation. The study then computes the hydro generation during all spike and off-peak hours, assuming the generation rates implied by the spike and off-peak derate factors computed in the manner described above. The study then calculates total peak hydro generation as the difference between total seasonal hydro generation and the sum of hydro generation during all spike and off-peak hours. The seasonal low peak availability factor is computed as total low peak hydro generation divided first by the number of hours in the off-peak period and then by hydro generating capacity.

d) Variation in pumped storage availability across seasons and periods

We assume that pumped storage units have 90 percent availability during Top 1% and Top 10% periods, 50 percent availability during Low Peak periods, and no availability during off-peak periods.

e) Wind availability

For each area, we calculate average operating rates from 2011 to 2015 by season from EIA-923 data. The average operating rates are the availability factors.

f) Solar availability

Availability for solar power is also calculated based on average operating rates from 2011 through 2015 reported in EIA-923. There is little solar power during

off-peak periods because of darkness. Accordingly, solar availability is weighted to on-peak periods.

B. Variable Costs of Generation

The study uses variable costs of generation that include fuel costs, sulfur dioxide and nitrogen oxide emissions costs, and variable operations and maintenance (VOM) costs. The study calculates fuel costs from unit heat rates and Platts' Gas Daily spot prices at the unit's reported natural gas hub by Energy Velocity, #2 Diesel, Low-Sulfur – Industrial for the East Coast, and Residual Fuel Oil sales to end users for the East Coast for the test period. Natural gas prices vary by hub, but were $2.67 per mmBtu at TETCO M3, the hub with the largest reported capacity in the study. Fuel costs for other fuels are based upon the average fuel costs reported in the EV data for each fuel type. Emissions prices during the test year were $2 per ton for SO2 year-round and $300 per ton for NOx in the summer season. CO_2 costs for units located in Regional Greenhouse Gas Initiative (RGGI) states are $5.21/ton, which is based upon RGGI Auction results in Dec 2014. Units in Montgomery County, MD have an additional $5/ton carbon tax on CO_2 emissions. VOM costs are from the EV database.

C. Long-term Contracts

We reviewed Appendix B data from market-based rate filings, FERC Form 1 filings, and Electric Quarterly Report ("EQR") data to obtain data on long-term contracts. Where the market-based rate filing indicates a change of operational control, we include a contract transferring control to the buyer. We leave the generation unit in the BAA where it is physically interconnected to the transmission system. When the buyer is a load-serving entity in another BAA, we give a priority firm transmission path to the BAA with the load.

Long-term contracts that expire prior to January 1, 2015 are not included in the study. Long-term contracts that expire between January 1, 2015 and July 31,

2015 are included only in the seasons for which they are in effect. Contracts that expire after August 31, 2015 are included in the study.

IV. Transmission

A. Transmission Network

The study incorporates a contract path transmission network for modeling purposes. Transmission pricing between balancing authority areas is represented by a traditional contract path transmission network in which the direct physical connections between balancing authority areas are also the individually priced links from which contract paths are constructed.

B. Transmission and Ancillary Services Pricing and Losses

As specified by the Commission's Appendix A, the study generally uses ceiling prices for transmission service from Schedules 1, 2 and 8 of the utility's *pro forma* open-access transmission tariff. Transmission providers may require transmission customers to purchase ancillary services under Schedule 1 (scheduling, system control and dispatch) and Schedule 2 (reactive supply and voltage control). Schedule 8 gives the rates for non-firm point-to-point transmission service. The study uses transmission prices from tariffs.

When we have tariffs available, we calculate rates for off-peak, peak and spike categories. Because of discounting and the nature of baseload purchases, off-peak rates are often lower than peak rates.[3] We use two steps to determine off-peak rates. Step 1: When a utility posts off-peak hourly rates, we use the posted rates. Step 2: When a utility does not post off-peak hourly rates, we calculate an hourly off-peak rate based on other tariff information. To calculate hourly off-

[3] For transactions longer than one hour, the *pro forma* tariff caps the amount that the purchaser pays per day by the daily rate, and the amount that the purchaser pays per week by the weekly rate.

peak rates, we divide the weekly rate by 168, the number of hours in a week. When tariffs specify fees on a per transaction basis, we divide them by 25 to put them on a per MW basis.

We use similar steps to determine peak rates. Step 1: When a utility posts maximum hourly rates in its tariff, we use the maximum tariff rates. Step 2: When a utility does not post off-peak hourly rates, we calculate a peak rate based on other tariff information. To calculate hourly peak rates, we divide the weekly rate by 80—the "Appalachian" method. When tariffs specify fees on a per transaction basis, we divide them by 25 to put them on a per MW basis.

For spike periods, we use ceiling hourly rates from tariffs, when available. Otherwise, we use the Appalachian method.

Whenever practical, the study uses loss rates from tariffs. When these methods did not provide a loss rate for a particular utility, the study assumes that losses are three percent per utility.[4] The study assumes that transmission customers pay losses in-kind. That is, if area A exports 100 MW to area B and the losses are 3 percent, only 97 MW arrive at area B.

For areas where tariffs are not available, rates and losses are the average by period for all the reporting areas.

C. Transfer Capability and SILs

The geographic market includes only PJM and NYISO. The SILs for PJM East and PJM East of 5004/5005 comes from the 2015 Simultaneous Import Limit

[4] Losses of 3 percent are representative of the industry. See, FERC Open Access NOPR, *FERC Stats & Regs*, ¶32,514 at 33,150 (1995).

Study filed by PJM on September 2, 2016.[5] The total imports into the destination markets may be less than the actual ability to import into the destination because not all the generation capability owned or controlled by load-serving entities within the destination markets studied in PJM have been identified in the data.

V. Market Prices

The study used December 2014-November 2015 real-time hourly prices from the RTO LMP for PJM East and PJM East of 5004/5005. Table V-1 shows the PJM East of 5004/5005 market prices in each of the ten periods, and Table V-2 shows the PJM East market prices.

Table V-1 – PJM East of 5004/5005 Market Prices ($/MWh)

Time	*Spring/Fall*	*Summer*	*Winter*
Top 1%	-----	$148.44	-----
Top 10%	$62.03	$64.59	$185.57
Low Peak	$35.73	$35.56	$47.55
Off-Peak	$29.46	$24.88	$50.16

Table V-2 – PJM East Market Prices ($/MWh)

Time	*Spring/Fall*	*Summer*	*Winter*
Top 1%	-----	$145.63	-----
Top 10%	$57.82	$63.88	$193.51
Low Peak	$32.73	$29.67	$50.59
Off-Peak	$26.67	$21.25	$50.94

[5] PJM Interconnection, L.L.C., *Informational Filing of 2015 Simultaneous Import Limit Study Report for PJM Region*, Docket No. AD1-2-007, September 2, 2016, Accession No. 20160902-5155.

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VI. Load and Contract Obligations for AEC Calculations

Load data come from PJM for PJM and from Energy Velocity for the other supply areas.

To compute load requirements for market participants in New York and PJM, we apportion the total load in each market area in New York and PJM to all suppliers in proportion to their respective generation capacities. We assumed 70 percent of load is committed for a year or longer and the remaining 30 percent is contracted for shorter periods.[6] To account for their greater load obligations, we assume that Dominion has 100 percent responsibility for its allocation of load and that AEP has 90 percent of its allocation as opposed to the standard 70 percent.

[6] This is a reasonable estimate for the long-term load coverage since this number is generally between 60 and 80 percent for most generation suppliers.

Technical Appendix:

Methods Used to Compute Concentration

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This Exhibit describes the methods used to calculate market shares and concentration in destination markets.

Allocation of scarce transmission capability is accomplished using linear and nonlinear programs that model generation dispatch and the contract path transmission system. This Exhibit provides an overview of the structure of the programs and presents the equations.

Overview of Linear Program

The linear program models control areas as nodes in a transmission system. Each node has a demand for and a supply of electric energy. The supply is based on the generators at the node and potential deliveries to the node via transmission links from other control areas. The linear program allows for net import and export limits to and from an individual control area. Given generation capability and costs and transmission capability and costs, the linear program finds the least-cost solution that satisfies the specified loads. Costs are defined as dispatch (generation) costs plus transmission costs including losses plus the default cost for "unserved" load. For each solution, the linear program determines the quantities produced in, exported from, and imported into each control area.

The Mathematical Equations

The linear program to be solved is given below:

Minimize Total Cost: $Cost = GC + TC + UC$

Subject to:

(1) Generation: $TG_a = \sum_{u}^{u \in a} G_{a,u}$ for each area *a*;

(2) Imports: $YI_a = \sum_{b}^{a,b \in network} (1 - h_{b,a}) T_{b,a}$ for each area *a*;

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(3)	Exports:	$YE_a = \sum_{b}^{a,b \in network} T_{a,b}$	for each area *a*;
(4)	Net Imports:	$Y_a = YI_a - YE_a$	for each area *a*;
(5)	Supply/Demand Balance:	$TG_a + Y_a + U_a = D_a$	for each area *a*;
(6)	Generation Cost:	$GC = \sum_{a} \sum_{u}^{u \in a} d_{a,u} G_{a,u}$	for each area *a*;
(7)	Transmission Cost:	$TC = \sum_{a,b}^{a,b \in network} r_{a,b} T_{a,b}$	for each path *a* to *b*;
(8)	Unfilled Demand Cost:	$UC = \sum_{a} pU_a$	for each area *a*;
(9)	Generation Limits:	$g\min_{a,u} \le G_{a,u} \le g\max_{a,u}$	for each unit *u* in each area *a*;
(10)	Transmission Limits:	$t\min_{a,b} \le T_{a,b} \le t\max_{a,b}$	for each link *a* to *b* in the transmission network; and
(11)	Net Import Limits	$Y\min_{a} \le Y_a \le Y\max_{a}$	for each area *a*;

where:

a,b	are subscripts for control/transmission areas;
Cost	is total system cost;
$d_{a,u}$	is the dispatch cost of unit *u* in area *a*;
D_a	is demand for power in area *a*;
$G_{a,u}$	is generation output of unit *u* in area *a*;
GC	is total system generation cost;
$G\max_{a,u}$	is the maximum output of unit *u* in area *a*;
$G\min_{a,u}$	is the minimum output of unit *u* in area *a*;
$h_{b,a}$	is the fraction of power lost to resistance from moving power from area *b* to area *a*;
N	is a subscript to identify simultaneous transmission constraint *n*;
P	is the default price;
$r_{a,b}$	is the transmission rate from area *a* to area *b*;

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$T_{a,b}$	is the power flow from area *a* to area *b*;
TC	is total system transportation expenses;
TG_a	is total generation output in area *a*;
t $\max_{a,b}$	is the maximum power flow from area *a* to area *b*;
t $\min_{a,b}$	is the minimum power flow from area *a* to area *b*;
U	is a subscript to identify units in an area;
U_a	is the amount of demand in area *a* not met by generation or imports
UC	is total system cost of not meeting demand;
Y_a	is net imports into area *a*;
YE_a	is total exports from area *a*; and
YI_a	is total imports into area *a*;
Y $\min_a$	is minimum net imports in area *a;*
Y $\max_a$	is maximum net imports in area *a.*

This linear program is solved using the BDMLP solver in GAMS. In order to calculate concentration for different destinations, seasons, and periods, the PASS GAMS program loops through the destinations, seasons, and periods with calls to Solvers to solve the linear programs. Loads, unit availability and transmission availability are adjusted for each season-period combination.

Calculating Concentration

Transmission allocation is accomplished in four steps. In the first step the linear program finds the net-back prices in all control areas given a price at the destination control area equal to 105 percent of the pre-merger price. Suppose the pre-merger price at the destination, control area A, is $20/MWh. Then all generation capability with a dispatch cost of $21/MWh or less in the destination area would be included in the market because $21 is 105 percent of $20. If transmission cost (including losses) is $5/MWh from control area B to A, then the net-back price at B would be $16/MWh, which is the $21/MWh less the $5/MWh transmission cost between B and A. Then, all generation capability at B with dispatch costs equal to or less than $16/MWh would be included in the market if there were no transmission constraints. Calculation of net-back prices is

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accomplished by setting the default price, *p*, equal to 105 percent of the pre-merger price at the destination, setting load at the destination to a high number and loads elsewhere to zero, setting transmission limits high enough so that the transmission system is not constrained, and setting a limited amount of generation in each area with a zero dispatch cost. The shadow prices produced by the linear program will be *p* at the destination and the relevant net-back prices in other areas.

In the second step, one calculates Economic Capacity (EC) and Available Economic Capacity (AEC) in each area. These values are then used to limit generation capability. The ownership shares of AEC and EC are calculated for each node in the system.

In the third step, the linear program determines the amount of energy that can be imported into an area given available EC (or AEC) and limits on transmission capacity. This is accomplished by limiting generation in each area to the capacity amount (EC or AEC), giving generation outside the destination market a lower cost than generation inside the destination market, and minimizing cost to serve a large load at the destination market. The amount of generation supplied to the destination is the maximum that can be imported into the destination market.

In the fourth step, transmission is allocated by the following non-linear program:

Minimize Loss: $$Loss = \sum_{\alpha}\left(\frac{C_{\alpha}^{2}}{Y_{Dest}s_{\alpha}} - 2C_{\alpha}\right)$$

Subject to:

(1) Pre Shares: $$s_{\alpha} = \frac{C\max_{\alpha}}{\sum_{\beta} C\max_{\beta}}$$ for each area α;

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(2)	Allocated Shares:	$A_\alpha = \frac{C_\alpha}{Y_{Dest}}$	for each area α;
(3)	Imports:	$YI_a = \sum_b^{a,b \in network} (1 - h_{b,a}) T_{b,a}$	for each area *a*;
(4)	Exports:	$YE_a = \sum_b^{a,b \in network} T_{a,b}$	for each area *a*;
(5)	Net Imports:	$Y_a = YI_a - YE_a$	for each area *a*;
(6)	Supply/Demand Balance:	$C_a + Y_a + U_a = D_a$	for each area *a*;
(7)	Capacity Limits:	$c\min_a \le C_a \le C\max_a$	for each area *a*;
(8)	Transmission Limits:	$t\min_{a,b} \le T_{a,b} \le t\max_{a,b}$	for each link *a* to *b* in the transmission network; and
(9)	Max Import Limit	Y_{Dest} = Maximum imports from step 3;	

where:

a,b	are subscripts for control/transmission areas;
α,β	are subscripts for control/transmission areas other than the destination market;
s_α	Is area α's share of capacity outside of the destination;
A_α	is area α's share of allocated capacity outside of the destination;
Loss	is the loss function to be minimized.

The loss function is derived from the weighted squared-errors between the pre-allocation shares and the post-allocation shares, where Y_{Dest}/s_α are the weights. For each source control area, the weighted squared-error is given by:[1]

$$W_\alpha = \frac{Y_{Dest}}{s_\alpha}(A_\alpha - s_\alpha)^2.$$

[1] This exposition ignores the adjustments necessary to give priority to minimum transfer levels from a source area to the destination.

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Accordingly, the sum of the weighted squared-errors gives rise to the loss function, which can be seen by:

$$\begin{aligned} Loss &= \sum_{\alpha} W_{\alpha} \\ &= \sum_{\alpha} \frac{Y_{Dest}}{s_{\alpha}} (A_{\alpha} - s_{\alpha})^2 \\ &= \sum_{\alpha} \frac{Y_{Dest}}{s_{\alpha}} (A_{\alpha}^2 - 2 s_{\alpha} A_{\alpha} + s_{\alpha}^2) \\ &= \sum_{\alpha} \left(\frac{C_{\alpha}^2}{Y_{Dest} s_{\alpha}} - 2 C_{\alpha} \right) + \text{constant}. \end{aligned}$$

The resulting shares from minimizing this loss functions preserve the relative shares of capacity behind any transmission constraint going to the destination. This can be seen from the following LaGrangian equation to be minimized:

$$L = \sum_{i} \left(\frac{C_i^2}{Y_{Dest} s_i} - 2 C_i \right) + \lambda \left(T - \sum_{i} C_i \right),$$

where *T* is the transmission limit affecting control areas *i*. The first order conditions are:

$$\frac{\partial L}{\partial C_i} = \frac{2 C_i}{Y_{Dest} s_i} - 2 - \lambda = 0,$$

which can be rearranged to give:

$$A_i = \frac{C_i}{Y_{Dest}} = \left(\frac{2 + \lambda}{2} \right) s_i,$$

which shows that the allocated market shares of those areas affected by the transmission constraint are proportional to their shares of capacity before the transmission allocation. Moreover, this is the only transmission allocation

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method that maintains the relative shares of capacity behind any binding transmission constraint in the allocation process.

This non-linear program is solved using the COINIPOPT solver in GAMS. The calculated capacities from the nonlinear program above less transmission losses determine the capacities for the market share calculations for sources outside of the destination market. The capacities within the destination market are given full weights.

Market concentration is the HHI, which is the sum of the squared market shares. Mathematically,

$$HHI = \sum_{i=1}^{n} S_i^2,$$

where S_i is the allocated share of firm *i* and *n* is the number of firms in the market. The summary sheets combine all the firms with shares of 0.7 percent or less (other than Applicants) into the "Other" category. The collective share of the Other category does not directly enter the HHI calculation other than the represented capacity as each independent entity enters the HHI calculation. For example, if ten firms with 0.5 percent shares were in the Other category, the HHI contribution of the Other category would be 0.625 (= 10 x .5 x .5 = 10 x .0625) and ***not*** 25.

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Delivered Price Test - PJM50 Market

Available Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$62.03	2,498	24,613	22,116	6,776	Yes	10.1	Yes	1,024	Yes
Spring/Fall	Peak	$35.73	2,927	26,894	23,967	6,776	Yes	10.9	Yes	1,085	Yes
Spring/Fall	Off Peak	$29.46	1,775	18,948	17,173	6,776	Yes	9.4	Yes	1,358	Yes
Summer	Top 1%	$148.44	1,443	22,909	21,466	9,933	Yes	6.3	Yes	1,042	Yes
Summer	Top 10%	$64.59	1,562	21,384	19,822	9,933	Yes	7.3	Yes	1,000	Yes
Summer	Peak	$35.56	2,009	22,352	20,344	9,933	Yes	9.0	Yes	1,055	Yes
Summer	Off Peak	$24.88	2,103	15,701	13,598	9,933	Yes	13.4	Yes	1,772	Yes
Winter	Top 10%	$185.57	1,921	26,153	24,233	6,073	Yes	7.3	Yes	1,008	Yes
Winter	Peak	$47.55	0	19,398	19,398	6,073	Yes	0.0	Yes	1,421	Yes
Winter	Off Peak	$50.16	0	18,024	18,024	6,073	Yes	0.0	Yes	1,592	Yes

Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$62.03	8,704	55,273	46,570	40,893	Yes	15.7	Yes	1,124	Yes
Spring/Fall	Peak	$35.73	7,678	50,521	42,844	28,923	Yes	15.2	Yes	1,084	Yes
Spring/Fall	Off-Peak	$29.46	5,932	41,688	35,756	24,614	Yes	14.2	Yes	1,133	Yes
Summer	Top 1%	$148.44	8,597	59,581	50,984	51,071	No	14.4	Yes	1,126	Yes
Summer	Top 10%	$64.59	8,608	56,301	47,694	47,510	Yes	15.3	Yes	1,112	Yes
Summer	Peak	$35.56	7,389	51,064	43,675	36,423	Yes	14.5	Yes	1,069	Yes
Summer	Off Peak	$24.88	6,266	42,155	35,889	29,051	Yes	14.9	Yes	1,152	Yes
Winter	Top 10%	$185.57	7,022	55,902	48,880	41,770	Yes	12.6	Yes	1,108	Yes
Winter	Peak	$47.55	4,602	43,979	39,377	34,380	Yes	10.5	Yes	1,206	Yes
Winter	Off Peak	$50.16	4,475	39,851	35,376	30,307	Yes	11.2	Yes	1,281	Yes

SI-SSA-0010-4618

Delivered Price Test - PJME Market

Available Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$57.82	3,225	20,600	17,375	3,806	Yes	15.7	Yes	1,179	Yes
Spring/Fall	Peak	$32.73	2,065	20,408	18,343	3,806	Yes	10.1	Yes	1,228	Yes
Spring/Fall	Off Peak	$26.67	1,276	18,023	16,747	3,806	Yes	7.1	Yes	1,669	Yes
Summer	Top 1%	$145.63	2,279	16,425	14,145	6,174	Yes	13.9	Yes	1,216	Yes
Summer	Top 10%	$63.88	2,402	15,949	13,547	6,174	Yes	15.1	Yes	1,267	Yes
Summer	Peak	$29.67	2,199	15,336	13,136	6,174	Yes	14.3	Yes	1,375	Yes
Summer	Off Peak	$21.25	976	13,909	12,933	6,174	Yes	7.0	Yes	1,979	Yes
Winter	Top 10%	$193.51	2,969	22,743	19,774	2,710	Yes	13.1	Yes	1,199	Yes
Winter	Peak	$50.59	0	15,998	15,998	2,710	Yes	0.0	Yes	1,606	Yes
Winter	Off Peak	$50.94	0	15,146	15,146	2,710	Yes	0.0	Yes	1,967	Yes

Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$57.82	8,677	36,450	27,773	22,528	Yes	23.8	No	1,252	Yes
Spring/Fall	Peak	$32.73	6,520	32,603	26,084	15,404	Yes	20.0	Yes	1,171	Yes
Spring/Fall	Off-Peak	$26.67	4,934	28,457	23,523	13,106	Yes	17.3	Yes	1,233	Yes
Summer	Top 1%	$145.63	8,551	36,587	28,036	29,462	No	23.4	No	1,264	Yes
Summer	Top 10%	$63.88	8,553	34,879	26,326	27,143	No	24.5	No	1,270	Yes
Summer	Peak	$29.67	6,853	31,187	24,334	20,217	Yes	22.0	No	1,224	Yes
Summer	Off Peak	$21.25	5,060	26,734	21,674	16,090	Yes	18.9	Yes	1,264	Yes
Winter	Top 10%	$193.51	7,105	35,709	28,603	21,263	Yes	19.9	Yes	1,181	Yes
Winter	Peak	$50.59	4,573	26,985	22,412	17,939	Yes	16.9	Yes	1,268	Yes
Winter	Off Peak	$50.94	4,449	23,450	19,001	15,660	Yes	19.0	Yes	1,461	Yes

SI-SSA-0010-4619

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Appendix E Letters of concurrence regarding the control of certain jointly owned generation facilities

KEYSTONE-CONEMAUGH PROJECTS

682 Philadelphia Street – 2nd floor
Indiana, Pennsylvania 15701

724-349-1205

MAILING ADDRESS
P.O. BOX 68
INDIANA, PA 15701

GEORGIANNA R. STENGER, ESQ.
ADMINISTRATIVE MANAGER
DIRECT DIAL 724-357-1713

December 1, 2007

Addressed to:

Conemaugh Power LLC
Constellation Power Source Generation, Inc.
Duquesne Conemaugh LLC
Exelon Generation Company, LLC
PPL Montour, LLC
PSEG Fossil LLC
Reliant Energy Mid-Atlantic Power Holdings, LLC
UGI Development Company

Re: Joint Owners of the Conemaugh Electric Generating Station (collectively, the "Owners") statement of ownership and control

Dear Owners:

This letter sets forth the understanding of the degree of ownership and control exercised by each of the Owners with respect to the jointly-owned Conemaugh Electric Generating Station for purposes of facilitating compliance with the requirements of FERC Order No. 697.[1]

The Owners and Reliant Energy Northeast Management Company (the "Operator") each confirm its concurrence with the following statement of facts relating to the Conemaugh Electric Generating Station:

1. The Owners jointly own the Conemaugh Electric Generating Station, consisting of two 850 MW net pulverized coal fired once-through boilers and related facilities having a combined rated seasonal net generating capacity of 1,712 MW (1,884 MW nameplate), located in East Wheatfield and West Wheatfield Townships, Indiana County, Pennsylvania (the "Station").

[1] Not all of the Owners agree as to whether Order No. 697 requires the submission of a letter of concurrence when the putative submitting party is not claiming that it does not control its percentage ownership share of a jointly-owned unit. Notwithstanding, all of the Owners have no objection to submission of this letter by an Owner which does believe that such a submission is required.

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2. As of the date hereof, the Station is collectively owned by the Owners as tenants-in-common, each holding an undivided interest in the Station (and all real and personal property comprising the same) in the respective ownership percentages set forth below:

Owner	Ownership Interest
Conemaugh Power LLC	3.72%
Constellation Power Source Generation, Inc.	10.56%
Duquesne Conemaugh LLC	3.83%
Exelon Generation Company, LLC	20.72%
PPL Montour, LLC	16.25%
PSEG Fossil LLC	22.50%
Reliant Energy Mid-Atlantic Power Holdings, LLC	16.45%
UGI Development Company	5.97%

3. Each of the Owners is deemed to control the generating capacity of the Station in accordance with its respective ownership percentage as set forth in the preceding paragraph for purposes of facilitating compliance with the requirements of FERC Order No. 697.

Please indicate your company's concurrence to the above statement of facts by executing this letter in the space provided below your company's name at the foot hereof.

Sincerely yours,

Georgianna R. Stenger
Administrative Manager
Keystone-Conemaugh Projects

To the Owners of the Conemaugh Electric Generating Station
December 1, 2007
Page 4

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

Owners:

Acknowledged and Agreed to this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

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Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this 14 day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: Anthony F. Pelz

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

To the Owners of the Conemaugh Electric Generating Station
December 1, 2007
Page 3

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this 1 day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: Kenneth Kaufman

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this 1st day of December, 2007.

PPL MONTOUR, LLC

By: Dennis J. Murphy
DENNIS J. MURPHY

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

To the Owners of the Conemaugh Electric Generating Station
December 1, 2007
Page 4

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this 13th day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: James V. Lacher

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

Owners:

Acknowledged and Agreed to this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

Operator:

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY NORTHEAST
MANAGEMENT COMPANY

By: _____

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KEYSTONE-CONEMAUGH PROJECTS

682 Philadelphia Street 2nd floor
Indiana, Pennsylvania 15701

724-349-1205

MAILING ADDRESS
P.O. BOX 68
INDIANA, PA 15701

GEORGIANNA R. STENGER, ESQ.
ADMINISTRATIVE MANAGER
DIRECT DIAL: 724-357-1713

December 1, 2007

Addressed to:

Constellation Power Source Generation, Inc.
Duquesne Keystone LLC
Exelon Generation Company, LLC
Keystone Power LLC
PPL Montour, LLC
PSEG Fossil LLC
Reliant Energy Mid-Atlantic Power Holdings, LLC

Re: Joint Owners of the Keystone Electric Generating Station (collectively, the "Owners") statement of ownership and control

Dear Owners:

This letter sets forth the understanding of the degree of ownership and control exercised by each of the Owners with respect to the jointly-owned Keystone Electric Generating Station for purposes of facilitating compliance with the requirements of FERC Order No. 697.[1]

The Owners and Reliant Energy Northeast Management Company (the "Operator") each confirm its concurrence with the following statement of facts relating to the Keystone Electric Generating Station:

1. The Owners jointly own the Keystone Electric Generating Station, consisting of two 850 MW net pulverized coal fired once-through boilers and related facilities having a combined rated seasonal net generating capacity of 1,712 MW (1,884 MW nameplate), located in Plumcreek, South Bend and Cowanshannock Townships, Armstrong County, Pennsylvania, and Armstrong Township, Indiana County, Pennsylvania (the "Station").

[1] Not all of the Owners agree as to whether Order No. 697 requires the submission of a letter of concurrence when the putative submitting party is not claiming that it does not control its percentage ownership share of a jointly-owned unit. Notwithstanding, all of the Owners have no objection to submission of this letter by an Owner which does believe that such a submission is required.

2. As of the date hereof, the Station is collectively owned by the Owners as tenants-in-common, each holding an undivided interest in the Station (and all real and personal property comprising the same) in the respective ownership percentages set forth below:

Owner	Ownership Interest
Constellation Power Source Generation, Inc.	20.99%
Duquesne Keystone LLC	2.47%
Exelon Generation Company, LLC	20.99%
Keystone Power LLC	3.70%
PPL Montour, LLC	12.34%
PSEG Fossil LLC	22.84%
Reliant Energy Mid-Atlantic Power Holdings, LLC	16.67%

3. Each of the Owners is deemed to control the generating capacity of the Station in accordance with its respective ownership percentage as set forth in the preceding paragraph for purposes of facilitating compliance with the requirements of FERC Order No. 697.

Please indicate your company's concurrence to the above statement of facts by executing this letter in the space provided below your company's name at the foot hereof.

Sincerely yours,

Georgianna R. Stenger
Administrative Manager
Keystone-Conemaugh Projects

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Owners:

Acknowledged and Agreed to
this __ _ day of December, 2007

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this __ . _ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this _ _ . day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ___ . day of December, 2007.

KEYSTONE POWER LLC

By. _ ___ _ _ _____

Acknowledged and Agreed to
this ___ _ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _ __ _____

Owners:

Acknowledged and Agreed to this ___ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to this 14 day of December, 2007.

DUQUESNE KEYSTONE LLC

By: Anthony F. Pelz

Acknowledged and Agreed to this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to this ____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to this ____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

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Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this 1 day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: Kenneth Kaiser

Acknowledged and Agreed to
this _____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this __. day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

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Owners:

Acknowledged and Agreed to this ___ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

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Owners:

Acknowledged and Agreed to this __ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to this __ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to this 13th day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Owners:

Acknowledged and Agreed to
this __ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this 16 day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: James D. Lash

Operator:

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY NORTHEAST
MANAGEMENT COMPANY

By: Jaime D Lach

Thomas P. Joyce
Senior Vice President

P.O. Box 236, Hancocks Bridge, NJ 08038
tel: 856.339.1100 fax: 856.339.1104
email: Thomas.Joyce@pseg.com

PSEG
Nuclear L.L.C.

Carol Peterson
Vice President Finance
Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

Letter Regarding Control of Jointly-Owned Nuclear Facilities

Dear Ms. Peterson:

In connection with its upcoming compliance filings pursuant to Order No. 697,[1] PSEG Nuclear LLC ("PSEG") is submitting this letter in order to set forth its understanding of, and is requesting Exelon Generation Company LLC's ("Exelon") concurrence on, the respective level of control exercised by both companies with respect to the two nuclear facilities that they jointly own.[2]

PSEG avers and requests Exelon's concurrence on the following:

1. PSEG and Exelon jointly own and control two nuclear power plants, Peach Bottom Atomic Power Station located in Delta, PA and the Salem Nuclear Generating Station in Lower Alloways Creek, NJ.

2. In accordance with the Joint Owners Agreement for Peach Bottom dated November 24, 1971, as amended on thereafter, between the Parties, PSEG and Exelon each own 50% of the generating station. Under the Agreement, Exelon is the designated operator of Peach Bottom.

3. In accordance with the Joint Owners Agreement for Salem dated November 24, 1971, as amended thereafter, between the Parties, Exelon owns 42.59% and PSEG owns 57.41% of the generating station. Under the Agreement, PSEG is the designated operator of Salem.

4. Section 4.1 of each of the Joint Owners' Agreements states, "The signatories shall be entitled to shares of the installed capacity, available capacity, operating capacity and hourly energy generation of the Station in proportion to their ownership . . .."

[1] *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, 119 FERC ¶ 61,295 (2007).

[2] PSEG has requested a letter of concurrence from Exelon in order to facilitate the Commission's review of the market power analysis submitted by PSEG with respect to facilities it jointly owns with Exelon. Exelon has no objection to PSEG's submission of this letter as part of PSEG's compliance filing,.

Thomas P. Joyce
Senior Vice President

P.O. Box 236, Hancocks Bridge, NJ 08038
tel: 856.339.1100 fax: 856.339.1104
email: Thomas.Joyce@pseg.com

PSEG
Nuclear L.L.C.

5. Section 11.1 of each of the Joint Owners' Agreements provides that the generating station will be operated by the party designated as operator for the mutual benefit of PSEG and Exelon.

6. In Order No. 697 the Commission stated that under "where a jointly-owned generation facility is operated by one of the joint-owners for the benefit of and on behalf of all of the joint-owners . . . it may be reasonable to allocate capacity based on ownership percentages...." Order No. 697 at P 188.

7. In accordance with the guidance provided in Order No. 697 and with the language of each of the joint owners' agreements, PSEG and Exelon should be deemed to control each of the nuclear facilities' output in line with their proportionate ownership share of each facility. As such, PSEG and Exelon should each be deemed to control 50% of Peach Bottom's output, and PSEG should be deemed to control 57.41% of Salem's output with Exelon controlling 42.59%.

Please indicate Exelon's concurrence to the above by executing the Acknowledgement and Agreement section below.

Sincerely

Thomas P. Joyce
Senior Vice President – Operations

Acknowledged and Agreed to
this 21 day of December, 2007.

Carol Peterson
Vice President Finance, Exelon Nuclear, and
an officer of Exelon Generation Company, LLC

JOINT LETTER OF CONCURRENCE

Regulations of the Federal Energy Regulatory Commission (the "FERC") require each public utility with market-based rate authority to file an updated market power analysis every three years in accordance with a schedule adopted in *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stat. & Regs., Regulations Preambles ¶ 31,252 (2007) ("Order No. 697"). See, 18 CFR § 35.37(a)(1). Each public utility with market-based rate authority may also be required to file a change-in-status report regarding certain changes in circumstances that occur between the dates on which its triennial market power analyses are filed. 18 CFR § 35.42. Among other matters, the market power analysis is to address the amount of generation capacity that the affected utility owns or controls. Where more than one public utility owns a generating facility, FERC requires the utility that is submitting a market power analysis seek a "letter of concurrence" from the other affected co-owning public utilities that identifies the degree to which each public utility controls the generating facility, and to submit the letter with its filing. *See* FERC Order No. 697, 119 FERC ¶ 61,295, P 187 (2007).

The Yards Creek Pumped Storage Hydroelectric Project (the "Yards Creek Project") is a FERC-licensed pumped-storage hydroelectric project with a nameplate capacity of 400 MWs, and is located in Pahaquarry and Blairstown Townships, in Warren County, New Jersey. *See* FERC Project No. P-2309.

PSEG Fossil LLC ("PSEG") and Jersey Central Power & Light Company ("JCPL") each own, as tenants in common with the other, an undivided 50% interest in the Yards Creek Project. Accordingly, if and when PSEG or JCPL submit an updated market power analysis to the FERC, each will be subject to FERC's requirement to seek a "letter of concurrence" regarding the degree to which each controls the Yards Creek Project.

Both PSEG and JCP&L (and their affiliates) own transmission facilities and provide wholesale electric service in the Northeast region, as defined in Order No. 697. Pursuant to the schedule adopted in Order No. 697, PSEG and JCP&L are each required to submit an updated market power analysis to the FERC for markets within the Northeast region in December 2010. PSEG and/or JCP&L may also be obligated to file a change-in-status report or other market power analyses before its subsequent triennial market power analysis for the Northeast region is scheduled to be filed. Therefore, for the sole purpose of enabling either PSEG or JCP&L to submit a market power analysis that addresses, among other issues (to the extent necessary), the scope of each party's control of the Yards Creek Project, PSEG and JCP&L each aver and agree as follows:

1. JCP&L operates and maintains the Yards Creek Project pursuant to the Yards Creek Pumped Storage Hydroelectric Generating Station Operating Agreement, which is dated October 6, 1965 (the "Operating Agreement').

2. Article 2 of the Operating Agreement designates JCP&L as holding sole responsibility for the operations and maintenance the Yards Creek Project. Article 2 further provides that JCPL shall operate the Yards Creek project in the same manner as if JCPL had the complete ownership interest in the Yards Creek Project.

3. JCP&L does, in fact, operate and control the Yards Creek Project in the same manner as if JCP&L had the complete ownership interest in the Yards Creek Project in accordance with Article 2 of the Operating Agreement.

4. Accordingly, PSEG and JCP&L each agree and concur that for the purpose of the market power analyses required by Order No. 697, JCPL shall be deemed to control the Yards Creek Project generation capacity and electric energy output.

ACKNOWLEDGED AND AGREED:

Richard P. Lopriore
President, PSEG Fossil LLC

Dated: 12/21/10

ACKNOWLEDGED AND AGREED:

Dean Stathis
Director, Regulated Commodity Sourcing
Jersey Central Power & Light Company

Dated: 12/08/2010

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G	ER99-3151-000	NA*	NA*	NA*	NA*	PJM	Northeast	NA*
PSEG ER&T	ER97-837-000	NA*	NA*	NA*	NA*	PJM, NYISO, NE-ISO	Northeast, Central, Southwest Power Pool, Southeast, Southwest, Northwest	NA*
PSEG Fossil	ER08-447-000	Bergen CC1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Bergen CC2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2002
PSEG Fossil	ER08-447-000	Burlington 12.1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Conemaugh 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/21/1970
PSEG Fossil	ER08-447-000	Conemaugh 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/27/1971
PSEG Fossil	ER08-447-000	Conemaugh A	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh B	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh C	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh D	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Global	N/A	Conemaugh Hydroelectric Plant 1	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Global	N/A	Conemaugh Hydroelectric Plant 2	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Fossil	ER08-447-000	Essex 9	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/1/1990
PSEG Nuclear	ER08-448-000	Hope Creek 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/20/1986
PSEG Fossil	ER08-447-000	Hudson 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	12/18/1968
PSEG Fossil	ER08-447-000	Kearny 12	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/1/2001
PSEG Fossil	ER08-447-000	Kearny 13	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Kearny 14	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Keystone 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/24/1967
PSEG Fossil	ER08-447-000	Keystone 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/23/1968
PSEG Fossil	ER08-447-000	Keystone 3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Linden 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM,	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 7	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Linden 8	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995

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PSEG Fossil	ER08-447-000	Linden GT5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Linden GT6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Mercer 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	12/19/1960
PSEG Fossil	ER08-447-000	Mercer 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/4/1961
PSEG Nuclear	ER08-448-000	Peach Bottom 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	7/5/1974
PSEG Nuclear	ER08-448-000	Peach Bottom 3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/23/1974
PSEG Nuclear	ER08-448-000	Salem 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/30/1977
PSEG Nuclear	ER08-448-000	Salem 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	10/13/1981
PSEG Nuclear	ER08-448-000	Salem GT3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/17/1971
PSEG Fossil	ER08-447-000	Sewaren 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	12/1/1948
PSEG Fossil	ER08-447-000	Sewaren 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/30/1948
PSEG Fossil	ER08-447-000	Sewaren 3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	10/16/1949
PSEG Fossil	ER08-447-000	Sewaren 4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/30/1951
PSEG Fossil	ER08-447-000	Yards Creek 1	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	11/26/1965
PSEG Fossil	ER08-447-000	Yards Creek 2	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	12/22/1965
PSEG Fossil	ER08-447-000	Yards Creek 3	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	9/3/1965
PSEG Power CT	ER03-327-000	Bridgeport Harbor 3	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	8/1/1968
PSEG Power CT	ER03-327-000	Bridgeport Harbor 4	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	10/30/1967
PSEG New Haven LLC	ER12-1250-000	New Haven 2	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 3	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 4	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG Power CT	ER03-327-000	New Haven Harbor 1	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	7/1/1975
PSEG Power NY	N/A*	Bethlehem Energy Center CC	PSEG Power NY	PSEG ER&T	12/6/2002	NYISO	Northeast	7/1/2005
PSEG Solar Source LLC	N/A*	Mars Solar Garden	PSEG Solar Hackettstown LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	9/9/2009
PSEG Solar Source LLC	N/A*	JEA Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	SERC	Southeast	9/28/2010
PSEG Solar Source LLC	N/A*	Wyandot Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	4/6/2010
PSEG Solar Source LLC	N/A*	Queen Creek Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	AZ-NV-SNV	Southwest	11/14/2012
PSEG Solar Source LLC	N/A*	Milford Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	12/27/2012
PSEG Solar Source LLC	N/A	Badger Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ACC	West	10/15/2013
PSEG Solar Source LLC	N/A	Shasta Solar Farm	PSEG Solar California LLC	PG&E	12/16/2013	CAISO	West	3/1/2014

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PSEG Solar Source LLC	N/A	Newman Solar Farm (Texas)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	El Paso Electric	Southwest	12/30/2014
PSEG Solar Source LLC	N/A	Whitcomb Solar Farm (Vermont)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ISO New England	Northeast	10/30/2014
PSEG Solar Source LLC	N/A	Rockfish Solar LLC, Southern Maryland	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	7/10/2015
PSEG Solar Source LLC	N/A	Columbia Solar, Pittsburg, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PG&E	West	10/21/2015
PSEG Solar Source LLC	N/A	Whitehorn Solar, Livermore, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Authority	West	2/17/2016
PSEG Solar Source LLC	N/A	Meadows Solar, Martin County, NC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	6/9/2016
PSEG Solar Source LLC	ER16-1924-000	Bison Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Administration, Colorado-Missouri Region	West	8/1/2016
PSEG Solar Source LLC	ER16-1925-000	Pavant Solar II LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp East	West	8/1/2016
PSEG Solar Source LLC	N/A	Obsidian - Black Cap	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp West	West	11/1/2016
PSEG Solar Source LLC	N/A	Hemlock Solar	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	N/A	Turkey Creek	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	ER16-1926-000	San Isabel Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Public Service Company of Colorado	West	8/1/2016
PSE&G (Solar 4 All)	N/A*	Trenton, 500-520 Brunswick Ave., Trenton, NJ 08638	PSE&G	PSE&G	N/A	PJM	Northeast	10/07/2010 (Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Barringer High School (NPS), 90 Parker St., Newark, NJ 07104	PSE&G	PSE&G	N/A	PJM	Northeast	09/24/2010 (Commercial Operation)
PSE&G (Solar		Park Elementary						10/20/2010

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4 All)	N/A*	School, 120 Manchester	PSE&G	PSE&G	N/A	PJM	Northeast	(Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Linden, South Wood Avenue, Linden, NJ 07036	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Yardville, Broad Street, Hamilton, NJ 08611	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Silver Lake, 410 Silver Lake Avenue, Edison, NJ 08817	PSE&G	PSE&G	N/A	PJM	Northeast	11/09/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Central HQ, 472 Weston Canal Road, Franklin, NJ 08873	PSE&G	PSE&G	N/A	PJM	Northeast	11/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Edison Training, 234 Pierson Avenue, Edison, NJ 08837	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All)	N/A*	WEA Texas Bayonne, 30-100 Pulaski Street, Bayonne, NJ 07002	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2010
PSE&G (Solar 4 All)	N/A*	Matrix Building A, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/24/2011
PSE&G (Solar 4 All)	N/A*	Matrix Building B, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/14/2011
PSE&G (Solar 4 All)	N/A*	Camden Street School, 281 Camden Street Newark, New Jersey 07103	PSE&G	PSE&G	N/A*	PJM	Northeast	1/12/2011

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PSE&G (Solar 4 All)	N/A*	New Central High School, 246 18th Ave, Newark, NJ 07108	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Rider University Solar Farm, Lawrenceville, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2011
PSE&G (Solar 4 All)	N/A*	Mill Creek Solar Farm, Burlington Township, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	11/30/2011
PSE&G (Solar 4 All)	N/A*	PSE&G Thorofare Solar Farm, West Deptford	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	Raritan Center – Warehouse Solar, Edison, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	NJMC – Landfill Solar, Kearny, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All	N/A	Matrix – Stults Rd., South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	5/31/2011
PSE&G (Solar 4 All)	N/A*	Metro Division HQ, Clifton, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	7/9/2012
PSE&G (Solar 4 All)	N/A*	Black Rock-Matrix, South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	3/20/2012
PSE&G (Solar 4 All)	N/A*	Food Bank Solar Farm, Hillside, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	8/16/2012
PSE&G (Solar 4 All)	N/A*	Hackensack Solar Farm, Hackensack, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2012
PSE&G (Solar 4 All)	N/A*	Moorestown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/14/2013
PSE&G (Solar 4 All)	N/A*	Seg 2 (Pole attached solar units)	PSE&G	PSE&G	N/A*	PJM	Northeast	7/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Kinsley Solar Sewell, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014

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PSE&G (Solar 4 All Extension)	N/A*	Parkland Solar Bordentown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014
PSE&G (Solar 4 All Extension)	N/A*	L&D Solar Mt. Holly, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Hopewell Valley Central HS	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2015
PSE&G (Solar 4 All Extension)	N/A*	ILR Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016
PSE&G (Solar 4 All Extension)	N/A*	Caldwell Waste Treatment Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016
[i] PSEG Fossil has a 22.5% interest in the Conemaugh coal fired plants.								
[ii] PSEG Global has a 4% interest Conemaugh Hydroelectric plants.								
[iii] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear Plants.								
[iv] PSEG Nuclear has a 57.41% interest in the Salem Nuclear Plants.								
[v] JCP&L – Jersey Central Power & Light Company								
[vi] PSEG Fossil has a 50% interest in each of the Yards Creek facilities.								
[vii] CL&P – The Connecticut Light and Power Company.								
[viii] PSEG Power Ventures has a 100% ownership in PSEG Hackettstown LLC.								
[ix] PSEG Power Ventures has a 100% ownership interest in PSEG Solar Source LLC								
[x] All solar assets are using AC MW ratings. PSEG's previous triennial listed the DC ratings.								
[xi] PG&E -- Pacific Gas and Electric Company								
[xii] PSE&G started installations of pole units in September of 2009. As of November 30, 2016, a total of 174,630								

Appendix B

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
NA*	NA*	NA*	
NA*	NA*	NA*	
775.2	775.2	N	
625.6	625.6	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
210.6	210.6	N	
210.6	210.6	N	
0.625	0.625	N	[i]
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
1	1	N	[ii]
1	1	N	
93.6	93.6	N	
1,290.70	1,290.70	N	
659.7	659.7	N	
242	242	N	
242	242	N	
121	121	N	
213.8	213.8	N	
213.8	213.8	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
677.8	677.8	N	
677.8	677.8	N	
96.1	96.1	N	
96.1	96.1	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
96.1	96.1	N	
96.1	96.1	N	
326.4	326.4	N	
326.4	326.4	N	
704	704	N	[iii]
689	689	N	
671.7	671.7	N	[iv]
671.7	671.7	N	
24	24	N	
110.8	110.8	N	
107.5	107.5	N	
107.5	107.5	N	
126.5	126.5	N	
68.5	68.5	N	[v]
68.5	68.5	N	[vi]
56.4	56.4	N	
399.5	399.5	N	
18.6	18.6	N	
60.5	60.5	N	[vii]
60.5	60.5	N	
60.5	60.5	N	
460.3	460.3	N	
893.2	893.2	N	
2	2	N	[viii]
12.6	12.6	N	[ix]
10.1	10.1	N	[x]
19	19	N	
12	12	N	
15	15	N	
1.5	1.5	N	[xi]

Appendix B

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
10.2	10.2	N	
2.2	2.2	N	
10.3	10.3	N	
19	19	N	
3	3	N	
20	20	N	
30	30	N	
50	50	N	
8	8	N	
5	5	N	
13.5	13.5	N	
30	30	N	
1.14	1.14	N	
0.64	0.64	N	
		N	

Appendix B

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
0.55	0.55	N	
3	3	N	
3.7	3.7	N	
1.75	1.75	N	
0.76	0.76	N	
0.64	0.64	N	
1.5	1.5	N	
		N	
1.5	1.5	N	
1	1	N	
0.83	0.83	N	
		N	

Appendix B

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
0.5	0.5	N	
		N	
0.67	0.67	N	
3.5	3.5	N	
0.75	0.75	N	
2	2	N	
2.5	2.5	N	
2.5	2.5	N	
0.57	0.57	N	
2.5	2.5	N	
1	1	N	
1	1	N	
0.93	0.93	N	
38.5	38.5	N	[xii]
8.8	8.8	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
7.9	7.9	N	
10	10	N	
1	1	N	
6.6	6.6	N	
2	2	N	

panels and 38.5 MW capacity have been installe

Asset Appendix: Transmission/Natural Gas Assets
Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas St
Location

Filing Entity and its Energy Affiliates	Cite to Order Accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Market / Balancing Authority	Geograph
PSEG ER&T	NA	NA	NA	NA	NA	NA	N
PSEG Power CT	NA	NA	NA	NA	NA	NA	N
PSEG New Haven	NA	NA	NA	NA	NA	NA	N
PSEG Fossil	NA	NA	NA	NA	NA	NA	N
PSEG Nuclear	NA	NA	NA	NA	NA	NA	N
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	Jointly Owned by PSE&G and others	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	Owned by others	PJM	N/A*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	Owned by others	PJM	NA*	PJM	North

PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	Jointly Owned by PSE&G and others	PJM	N/A*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 230 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 230kV Lines	Owned by Others	PJM	N/A	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 138 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 69 kV Lines	PSE&G	PJM	NA*	PJM	North

orage Facilities

ic Region	Size (e.g., length and kV for electric length and diameter for pipeline, and capacity for gas storage)	End Note Number (Enter text in End Notes Sheet
A	NA	NA
A	NA	NA
A	NA	NA
A	NA	NA
A	NA	NA
ıeast	Approximately 272 combined miles.	
ıeast	Approximately 151 combined miles.	
ıeast	Approximately 64 combined miles	
ıeast	Approximately 32 combined miles.	
ıeast	Approximately 20 combined miles.	

least	Approximately 3.76 combined Miles
least	Approximately 750 combined miles.
least	Approximately 39 combined miles
least	Approximately 228 combined miles.
least	Approximately 235 combined miles.

Asset Appendix: Long Term Purchased Power Agreements

Filing Entity and its Energy Affiliates	Docket No. where MBR Authority Granted	Seller Name	Amount of PPA (MW)	Market / Balancing Authority	Geographic Region	Start Date (mo/day/year)

End Date (mo/day/year)	End Note

Document Content(s)

PSEG 2016 Triennial Transmittal FINAL.DOC.....1-27

Exhibit A - Morris Affidavit - PSEG Triennial.PDF.....28-109

Exhibit E - Letters of Concurrence - PSEG Triennial.PDF.....110-134

Appendix B - Generation Assets - PSEG Triennial.XLSX.....135-146

Appendix C - Triennial - Transmission Chart.XLSX.....147-150

Appendix D - Long Term Contracts - Triennial.XLSX.....151-152

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UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

PSEG Keys Energy Center LLC	)	Docket No.	ER17-____-000

Affidavit of
Dr. John R. Morris

September 1, 2017

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Public Service Enterprise Group Incorporated
Northeast Region Market Power Study

1. My name is Dr. John R. Morris. I am a Principal at Economists Incorporated, an economic consulting firm located at 2121 K Street, NW, Washington, DC 20037. I am the same Dr. John R. Morris who filed Public Service Enterprise Group Incorporated's ("PSEG") market power study for the Northeast Region in December 2016 under this docket. See Report & Affidavit of Dr. John R. Morris, FERC Accession Number 20161228-5212, December 28, 2016, and hereinafter the "December Affidavit". PSEG has asked that I update the market power study for the PJM market and relevant submarkets in order to account for the addition of Keys Energy Center, a natural gas combined cycle plant with a generating capacity of 755 MW currently under construction in Prince Georges County, Maryland to PSEG's fleet and the retirements of Hudson (620 MW capacity) and Mercer (632 MW capacity) Generating Stations located in New Jersey.[1] PSEG also requested that I perform a delivered price test ("DPT") for the PJM East and PJM East of 5004/5005 sub-markets.

2. Per PSEG's requests, I updated the market power study submitted in December 2016 by adding Keys Energy Center in the PJM East of 5004/5005 submarket and retiring Hudson and Mercer from the PJM East market. Market sizes were adjusted accordingly. Those were the only changes made to the data. All methods are the same as in the December Affidavit.

[1] PJM Interconnection, L.L.C. ("PJM"), PJM East, PJM East of 5004/5005 and PJM East of AP South.

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3. The results of the pivotal supplier and market share assessments are provided in Exhibit No. PEG-2. The DPT results are presented in Exhibit No. PEG-3.

4. Although there are some minor differences in the results from those presented with the December Affidavit, the differences are not material and do not change the conclusions made at that time. Under the standards utilized by the Commission, continuing market-based rates for PSEG and all of its Northeastern affiliates remain in the public interest.

5. This concludes my affidavit.

Pursuant to 28 U.S.C. §1746, I state under penalty of perjury that the foregoing is true and correct to the best of my information, knowledge, and belief.

Executed on this 1st day of September 2017.

John R. Morris, Ph.D.
Principal
Economists Incorporated

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FERC rendition of the electronically filed tariff records in Docket No. ER17-02426-000
Filing Data:
CID: C008749
Filing Title: PSEG Keys Market Base Rate Tariff
Company Filing Identifier: 1
Type of Filing Code: 400
Associated Filing Identifier:
Tariff Title: PSEG Keys Market Based Rate Tariff
Tariff ID: 1
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Market Based Rate Tariff, Market Based Rate Tariff, 1.0.0, A
Record Narative Name: Market Based Rate Tariff
Tariff Record ID: 1000
Tariff Record Collation Value: 1000 Tariff Record Parent Identifier: 0
Proposed Date: 2017-09-01
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

1. **Availability.** PSEG Keys Energy Center LLC ("PSEG Keys" or "Seller") will make wholesale electric energy, capacity, and ancillary services available under this Tariff to any purchaser for resale, except as prohibited below.

2. **Applicability.** This Tariff is applicable to all sales of energy, capacity, and ancillary services by PSEG Keys not otherwise subject to a particular rate schedule of PSEG Keys.

3. **Rates.** All sales shall be made at the rates established between the purchaser and PSEG Keys.

4. **Other Terms and Conditions.** All other terms and conditions shall be established by agreement between the purchaser and PSEG Keys.

5. **Compliance with Commission Regulations.** PSEG Keys shall comply with the provisions of 18 C.F.R. Part 35, Subpart H, as applicable, and with any conditions the Commission imposes in its orders concerning PSEG Key's market-based rate authority, including orders in which the Commission authorizes PSEG Keys to engage in affiliate sales under this Tariff or otherwise restricts or limits the PSEG Key's market-based rate authority. Failure to comply with the applicable provisions of 18 C.F.R. Part 35, Subpart H, and with any orders of the Commission concerning PSEG Key's market-based rate authority, will constitute a violation of this Tariff.

6. **Limitations and Exemptions Regarding Market Based Rate Authority.** PSEG Keys does not have any limitations on its market-based rate authority except as other provided in this Tariff. The Commission granted Seller in Docket No. ER17-___-000 the following waivers and blanket authorization: (a) waiver of Subparts B and C of Part 35 of the Commission's regulations requiring the filing of cost-of-service information, except for sections 35.12(a), 35.13(b), 35.15 and 35.16; (b) waiver of the requirements of Part 41 and Part 101; (c) waiver of Part 141 of the Commission's regulations concerning

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accounting and reporting requirements, with the exception of 18 C.F.R. §§ 141.14 and 141.15; and (d) blanket approval as to Section 204 of the FPA and Part 34 of the Commission's regulations for all future issuances of securities and debt and assumption of liabilities.

7. **Ancillary Services.**

Third-party ancillary services: PSEG Keys offers Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental. Sales will not include the following: (1) sales to an RTO or an ISO, *i.e.*, where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

8. **Seller Category.** PSEG Keys is a Category 2 Seller in the Northeast Region and a Category 1 seller in the Central, Northwest, Southeast, Southwest and Southwest Power Pool regions, as defined by 18 C.F.R. 35.36(a),

9. **Effective Date.** This Tariff is effective on the date specified by the Commission. This Tariff shall continue in effect until terminated or changed in accordance with any applicable regulatory requirements.

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Document Content(s)

MBR transmittal letter PSEG Keys.PDF.....1-2

Tariff - Keys.PDF.....3-4

Appendix A-1 - PSEG 2016 MBR for PJM.PDF.....5-13

Appendix A-2 - Delivered Price Test.PDF.....14-15

Appendix E - Tariff - Keys.PDF.....16-17

Appendix F - December 2016 Triennial Report.PDF.....18-170

Appendix G - Affidavit of John Morris.PDF.....171-173

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Cara J. Lewis
Associate General Regulatory Counsel

Law Department
80 Park Plaza, T5G, Newark, NJ 07102
tel: 973.430.8836 fax: 973.430.5983
Cara.Lewis@PSEG.com

PSEG Services Corporation

October 4, 2017

VIA EFILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: PSEG Keys Energy Center LLC
Docket No. ER17-2426-000
Application for Market-Based Rate Authorization and Request for Waivers and Blanket Approvals

Dear Secretary Bose:

On September 1, 2017, PSEG Keys Energy Center LLC ("PSEG Keys") submitted an application in the above-referenced matter for market-based rate authorization and request for waivers and blanket approvals. This letter clarifies that, in addition to the waivers requested in the September 1, 2017 application, PSEG Keys is seeking the waivers set forth in Order No. 807, *Open Access and Priority Rights on Interconnection Customer's Interconnection Facilities*, Order No. 807, 150 FERC ¶ 61,211, Docket No. RM14-11-000 (2015).

PSEG Keys does not own or control any transmission facilities other than the interconnection facilities necessary to interconnect PSEG Keys. The generator interconnection facilities that PSEG Keys owns and controls are limited and discrete radial facilities that do not form an integrated transmission grid that are used solely to interconnect PSEG Keys' facility to the grid. PSEG Keys affirms to the Commission that it (together with its affiliates) is eligible for priority rights and waiver under Order No. 807, *Id.* at P 165, such that Keys Energy Center LLC and its affiliates are immune from the Open Access Requirements to the extent set forth under Order No. 807, without the need for further filings or orders.

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In addition, we are resubmitting three attachments, specifically Appendix B, Appendix C and Appendix D, to conform to the Federal Energy Regulatory Commission's formatting and heading descriptions. In addition, we are resubmitting Appendices A-1 and A-2 in Excel format as required by the Commission's regulations.

Thank you for your attention to this matter.

Respectfully submitted,

Cara J. Lewis

Cara J. Lewis

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Market Based Rates Assessments

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Scenario

Scenario Number	1	
Scenario Name	PSEG 2016 MBR for PJM	
Data	MBRA Data v501 PSEG 2016 PJM and NE.xlsx	
Applicant	PSEG	Public Service Enterprise Group Inc
Period	Dec 2014 — Nov 2015	

Fill-in white cells with parameters and then click on Run button or type Ctrl+Shift+R.

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Destinations

PJM
PJME
PJM50
PJMAP

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Results

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PSEG 2016 MBR for PJM - Add Keys and Retire Mercer and H

	PSA		WM			
			Winter		Spring	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result
PJM Interconnection	36,491	Pass	8.7	Pass	7.0	Pass
PJM East	4,853	Pass	27.1	Fail	22.1	Fail
PJM East of 5004/05	5,977	Pass	22.3	Fail	18.9	Pass
PJM East of AP South	8,190	Pass	17.0	Pass	14.1	Pass

Hudson			
SA			
Summer		Fall	
Share (%)	Result	Share (%)	Result
7.5	Pass	7.6	Pass
25.8	Fail	24.4	Fail
21.3	Fail	21.1	Fail
16.9	Pass	15.6	Pass

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	9,244	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	195	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	1,943	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	152	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	176,531	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	1,943	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	195	Row B; Table2Data
H	Uncommitted Capacity Imports	7,448	Calculated
I	Study Area Reserve Requirement	8,187	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	63,588	
	Load		
L	Balancing Area Annual Peak Load	143,633	Loads
M	Average Daily Peak Native Load in Peak Month	121,600	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	22,034	
P	Net Uncommitted Supply (K-O)	41,555	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,064	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	7,600
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	7600
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	6,516	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	14	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	162	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	27,983	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	14	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,375	Calculated
I	Study Area Reserve Requirement	1,724	Gendata
J	Amount of Line I Attributable to Seller, if any	176	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	15,220	
	Load		
L	Balancing Area Annual Peak Load	30,240	Loads
M	Average Daily Peak Native Load in Peak Month	24,093	Loads
N	Amount of Line M Attributable to Seller, if any	2,269	SellerLoads
O	Wholesale Load (L-M)	6,148	
P	Net Uncommitted Supply (K-O)	9,072	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,219	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	6,537
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	6537
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,284	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	105	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	52,316	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,214	Calculated
I	Study Area Reserve Requirement	2,975	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	20,577	
	Load		
L	Balancing Area Annual Peak Load	52,190	Loads
M	Average Daily Peak Native Load in Peak Month	42,368	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	9,822	
P	Net Uncommitted Supply (K-O)	10,754	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,777	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,319	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	6319	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,284	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	84	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	75,968	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,371	Calculated
I	Study Area Reserve Requirement	4,032	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	25,567	
	Load		
L	Balancing Area Annual Peak Load	70,729	Loads
M	Average Daily Peak Native Load in Peak Month	58,108	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	12,621	
P	Net Uncommitted Supply (K-O)	12,946	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,756	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	4,455
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	4455
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	10,727	9,986	9,244	9,986	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	195	195	195	195	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	1,643	1,944	1,943	1,944	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	464	1,377	212	1,296	SellerGendata
E	Uncommitted Capacity Imports	214	204	138	117	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	108,842	91,954	109,399	91,992	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	106,988	90,430	107,540	90,648	F - G
I	Study Area Reserve Requirement	7,474	6,516	7,991	6,470	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	7,335	6,385	7,817	6,352	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	182,501	179,517	176,531	179,517	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	1,643	1,944	1,943	1,944	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	195	195	195	195	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	7,895	24,764	4,042	23,293	Gendata; Row D
P	Uncommitted Capacity Imports	11,783	12,069	7,462	6,950	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	73,514	71,755	66,343	67,922	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,036	5,409	5,389	5,596	
S	Total Seasonal Uncommitted Capacity (Q+R)	80,550	77,164	71,731	73,518	
T	**Applicant's Market Share** (R÷S)	8.7%	7.0%	7.5%	7.6%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	11,997	12,273	7,600	7,067	
V	SIL Value	11,997	12,273	7,600	7,067	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season: Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,051	7,284	6,516	7,284	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	22	14	14	14	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	348	1,005	149	945	SellerGendata
E	Uncommitted Capacity Imports	201	159	147	144	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	18,303	15,919	20,901	16,346	Loads
G	Amount of Line F Attributable to Seller, if any	1,749	1,434	1,764	1,268	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	16,553	14,485	19,137	15,078	F - G
I	Study Area Reserve Requirement	1,258	1,168	1,659	1,211	Gendata
J	Amount of Line I Attributable to Seller, if any	130	122	165	110	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	1,128	1,046	1,494	1,101	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	27,695	27,839	27,983	27,839	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	22	14	14	14	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,198	3,840	641	3,612	Gendata; Row D
P	Uncommitted Capacity Imports	7,301	8,671	6,390	7,715	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	16,139	17,152	13,115	15,777	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	6,002	4,868	4,571	5,090	
S	Total Seasonal Uncommitted Capacity (Q+R)	22,141	22,019	17,686	20,867	
T	**Applicant's Market Share** (R÷S)	27.1%	22.1%	25.8%	24.4%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	7,502	8,830	6,537	7,859	
V	SIL Value	7,502	8,830	6,537	7,859	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,819	8,052	7,284	8,052	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	381	1,111	167	1,045	SellerGendata
E	Uncommitted Capacity Imports	160	90	94	68	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	35,188	30,080	37,518	30,214	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	33,334	28,556	35,658	28,871	F - G
I	Study Area Reserve Requirement	2,450	2,184	2,889	2,189	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,311	2,054	2,715	2,071	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	52,819	52,568	52,316	52,568	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	2,285	7,252	1,198	6,821	Gendata; Row D
P	Uncommitted Capacity Imports	7,944	8,203	6,225	6,035	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	22,869	22,937	18,998	20,867	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	6,569	5,349	5,150	5,585	
S	Total Seasonal Uncommitted Capacity (Q+R)	29,438	28,286	24,148	26,453	
T	**Applicant's Market Share** (R÷S)	22.3%	18.9%	21.3%	21.1%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Pass**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	8,104	8,293	6,319	6,103	
V	SIL Value	8,104	8,293	6,319	6,103	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,819	8,052	7,284	8,052	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	381	1,111	167	1,045	SellerGendata
E	Uncommitted Capacity Imports	185	113	76	80	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	48,658	41,074	51,437	41,155	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	46,804	39,551	49,577	39,811	F - G
I	Study Area Reserve Requirement	3,496	3,025	3,935	2,991	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	3,358	2,895	3,762	2,873	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	77,913	76,941	75,968	76,941	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,370	10,614	1,739	9,983	Gendata; Row D
P	Uncommitted Capacity Imports	7,712	8,743	4,379	5,988	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	32,129	32,652	25,297	30,289	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	6,594	5,372	5,132	5,597	
S	Total Seasonal Uncommitted Capacity (Q+R)	38,723	38,024	30,429	35,886	
T	**Applicant's Market Share** (R÷S)	17.0%	14.1%	16.9%	15.6%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,897	8,856	4,455	6,068	
V	SIL Value	7,897	8,856	4,455	6,068	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Sets and SIL Data

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Areas		Owners	
Code	**Name**	**Code**	**Name**
CT	Connecticut	PSEG	Public Service Enterprise Group Inc
HQ	Hydro Quebec		
ISONE	ISO New England		
ISONE_CT	ISONE Excluding CT		
ISONE_SWCT	ISONE Excluding SWCT		
MISO	Midwest ISO		
NB	New Brunswick		
NYISO	New York		
ONT	Ontario		
PJM	PJM Interconnection		
PJM_50	PJM Excluding PJM50		
PJM_AP	PJM Excluding PJMAP		
PJM_E	PJM Excluding PJME		
PJM50	PJM East of 5004/05		
PJMAP	PJM East of AP South		
PJME	PJM East		
SWCT	Southwest Connecticut		

Season	
Code	**Name**
SPR	Spring
SUM	Summer
FAL	Fall
WIN	Winter

Area	Season	SIL	Comment
ISONE	SPR	4548	ISONE 2015 SIL filing; Docket No. AD10-02, Table 1
ISONE	SUM	4548	ISONE 2015 SIL filing; Docket No. AD10-02, Table 1
ISONE	FAL	4548	ISONE 2015 SIL filing; Docket No. AD10-02, Table 1
ISONE	WIN	4548	ISONE 2015 SIL filing; Docket No. AD10-02, Table 1
NYISO	SPR	7524	NYISO 2015 SIL filing; Docket No. AD10-02, Slide 4
NYISO	SUM	6850	NYISO 2015 SIL filing; Docket No. AD10-02, Slide 4
NYISO	FAL	7695	NYISO 2015 SIL filing; Docket No. AD10-02, Slide 4
NYISO	WIN	7635	NYISO 2015 SIL filing; Docket No. AD10-02, Slide 4
PJM	SPR	12273	PJM 2015 Simultaneous Import Limit Study
PJM	SUM	7600	PJM 2015 Simultaneous Import Limit Study
PJM	FAL	7067	PJM 2015 Simultaneous Import Limit Study
PJM	WIN	11997	PJM 2015 Simultaneous Import Limit Study
PJME	SPR	8830	PJM 2015 Simultaneous Import Limit Study
PJME	SUM	6537	PJM 2015 Simultaneous Import Limit Study
PJME	FAL	7859	PJM 2015 Simultaneous Import Limit Study
PJME	WIN	7502	PJM 2015 Simultaneous Import Limit Study
PJM50	SPR	8293	PJM 2015 Simultaneous Import Limit Study
PJM50	SUM	6319	PJM 2015 Simultaneous Import Limit Study
PJM50	FAL	6103	PJM 2015 Simultaneous Import Limit Study
PJM50	WIN	8104	PJM 2015 Simultaneous Import Limit Study
PJMAP	SPR	8856	PJM 2015 Simultaneous Import Limit Study
PJMAP	SUM	4455	PJM 2015 Simultaneous Import Limit Study
PJMAP	FAL	6068	PJM 2015 Simultaneous Import Limit Study
PJMAP	WIN	7897	PJM 2015 Simultaneous Import Limit Study
CT	SPR	3050	ISONE 2015 SIL filing; Docket No. AD10-02, Table 2
CT	SUM	3050	ISONE 2015 SIL filing; Docket No. AD10-02, Table 2
CT	FAL	3050	ISONE 2015 SIL filing; Docket No. AD10-02, Table 2
CT	WIN	3050	ISONE 2015 SIL filing; Docket No. AD10-02, Table 2
SWCT	SPR	2370	ISONE 2015 SIL filing; Docket No. AD10-02, Table 2
SWCT	SUM	3200	ISONE 2015 SIL filing; Docket No. AD10-02, Table 2
SWCT	FAL	3190	ISONE 2015 SIL filing; Docket No. AD10-02, Table 2
SWCT	WIN	2540	ISONE 2015 SIL filing; Docket No. AD10-02, Table 2

Area	First Tier Areas	Note: No more than 6 First Tier Areas for each destination Area.
CT	ISONE_CT	
CT	NYISO	
ISONE	HQ	
ISONE	NB	
ISONE	NYISO	
NYISO	HQ	
NYISO	ISONE	
NYISO	ONT	
NYISO	PJM	
PJM	MISO	
PJM	NYISO	
PJM50	NYISO	
PJM50	PJM_50	
PJMAP	NYISO	
PJMAP	PJM_AP	
PJME	NYISO	
PJME	PJM_E	
SWCT	ISONE_SWCT	
SWCT	NYISO	

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Market Data

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AREA	SEASON	MONTH	CAPACITY	PLANNED OUTAGE
ISONE	WIN	1	33,009	160
ISONE	WIN	2	33,009	1,187
ISONE	SPR	3	31,743	2,362
ISONE	SPR	4	31,743	4,595
ISONE	SPR	5	31,743	2,746
ISONE	SUM	6	30,477	627
ISONE	SUM	7	30,477	80
ISONE	SUM	8	30,477	0
ISONE	FAL	9	31,743	482
ISONE	FAL	10	31,743	6,598
ISONE	FAL	11	31,743	1,801
ISONE	WIN	12	33,009	2,033
NYISO	WIN	1	41,032	3,180
NYISO	WIN	2	41,032	3,568
NYISO	SPR	3	42,148	6,026
NYISO	SPR	4	42,148	7,520
NYISO	SPR	5	42,148	4,259
NYISO	SUM	6	43,263	1,496
NYISO	SUM	7	43,263	440
NYISO	SUM	8	43,263	281
NYISO	FAL	9	42,148	1,327
NYISO	FAL	10	42,148	7,477
NYISO	FAL	11	42,148	5,426
NYISO	WIN	12	41,032	3,297
PJM	WIN	1	193,228	3,616
PJM	WIN	2	193,228	7,609
PJM	SPR	3	189,502	19,290
PJM	SPR	4	189,502	34,834
PJM	SPR	5	189,502	24,301
PJM	SUM	6	185,775	4,660
PJM	SUM	7	185,775	4,535
PJM	SUM	8	185,775	3,566
PJM	FAL	9	189,502	3,993
PJM	FAL	10	189,502	46,567
PJM	FAL	11	189,502	23,207
PJM	WIN	12	193,228	13,851
PJME	WIN	1	35,746	669
PJME	WIN	2	35,746	1,408
PJME	SPR	3	35,122	3,575
PJME	SPR	4	35,122	6,456
PJME	SPR	5	35,122	4,504
PJME	SUM	6	34,499	865
PJME	SUM	7	34,499	842
PJME	SUM	8	34,499	662
PJME	FAL	9	35,122	740
PJME	FAL	10	35,122	8,631
PJME	FAL	11	35,122	4,301
PJME	WIN	12	35,746	2,562
PJM50	WIN	1	61,638	1,153
PJM50	WIN	2	61,638	2,427
PJM50	SPR	3	60,619	6,171

PJM50	SPR	4	60,619	11,143
PJM50	SPR	5	60,619	7,774
PJM50	SUM	6	59,600	1,495
PJM50	SUM	7	59,600	1,455
PJM50	SUM	8	59,600	1,144
PJM50	FAL	9	60,619	1,277
PJM50	FAL	10	60,619	14,896
PJM50	FAL	11	60,619	7,424
PJM50	WIN	12	61,638	4,418
PJMAP	WIN	1	86,732	1,623
PJMAP	WIN	2	86,732	3,415
PJMAP	SPR	3	84,992	8,652
PJMAP	SPR	4	84,992	15,623
PJMAP	SPR	5	84,992	10,899
PJMAP	SUM	6	83,252	2,088
PJMAP	SUM	7	83,252	2,032
PJMAP	SUM	8	83,252	1,598
PJMAP	FAL	9	84,992	1,791
PJMAP	FAL	10	84,992	20,885
PJMAP	FAL	11	84,992	10,408
PJMAP	WIN	12	86,732	6,217
CT	WIN	1	8,908	43
CT	WIN	2	8,908	320
CT	SPR	3	8,638	643
CT	SPR	4	8,638	1,250
CT	SPR	5	8,638	747
CT	SUM	6	8,367	172
CT	SUM	7	8,367	22
CT	SUM	8	8,367	0
CT	FAL	9	8,638	131
CT	FAL	10	8,638	1,795
CT	FAL	11	8,638	490
CT	WIN	12	8,908	549
SWCT	WIN	1	2,728	13
SWCT	WIN	2	2,728	98
SWCT	SPR	3	2,609	194
SWCT	SPR	4	2,609	378
SWCT	SPR	5	2,609	226
SWCT	SUM	6	2,490	51
SWCT	SUM	7	2,490	7
SWCT	SUM	8	2,490	0
SWCT	FAL	9	2,609	40
SWCT	FAL	10	2,609	542
SWCT	FAL	11	2,609	148
SWCT	WIN	12	2,728	168
PJM_E	WIN	1	157,482	2,947
PJM_E	WIN	2	157,482	6,201
PJM_E	SPR	3	154,380	15,715
PJM_E	SPR	4	154,380	28,378
PJM_E	SPR	5	154,380	19,797
PJM_E	SUM	6	151,276	3,795
PJM_E	SUM	7	151,276	3,693

PJM_E	SUM	8	151,276	2,904
PJM_E	FAL	9	154,380	3,253
PJM_E	FAL	10	154,380	37,936
PJM_E	FAL	11	154,380	18,906
PJM_E	WIN	12	157,482	11,289
PJM_50	WIN	1	131,590	2,463
PJM_50	WIN	2	131,590	5,182
PJM_50	SPR	3	128,883	13,119
PJM_50	SPR	4	128,883	23,691
PJM_50	SPR	5	128,883	16,527
PJM_50	SUM	6	126,175	3,165
PJM_50	SUM	7	126,175	3,080
PJM_50	SUM	8	126,175	2,422
PJM_50	FAL	9	128,883	2,716
PJM_50	FAL	10	128,883	31,671
PJM_50	FAL	11	128,883	15,783
PJM_50	WIN	12	131,590	9,433
PJM_AP	WIN	1	106,496	1992.92823
PJM_AP	WIN	2	106,496	4193.636864
PJM_AP	SPR	3	104,510	10638.39907
PJM_AP	SPR	4	104,510	19210.88611
PJM_AP	SPR	5	104,510	13401.95623
PJM_AP	SUM	6	102,523	2571.697914
PJM_AP	SUM	7	102,523	2502.714601
PJM_AP	SUM	8	102,523	1967.955957
PJM_AP	FAL	9	104,510	2202.132062
PJM_AP	FAL	10	104,510	25681.61376
PJM_AP	FAL	11	104,510	12798.61727
PJM_AP	WIN	12	106,496	7633.863084
ISONE_CT	WIN	1	24101	116.8214729
ISONE_CT	WIN	2	24101	866.6693023
ISONE_CT	SPR	3	23105.5	1719.282708
ISONE_CT	SPR	4	23105.5	3344.667249
ISONE_CT	SPR	5	23105.5	1998.793529
ISONE_CT	SUM	6	22110	454.8666207
ISONE_CT	SUM	7	22110	58.03720839
ISONE_CT	SUM	8	22110	0
ISONE_CT	FAL	9	23105.5	350.8443121
ISONE_CT	FAL	10	23105.5	4802.636455
ISONE_CT	FAL	11	23105.5	1310.934868
ISONE_CT	WIN	12	24101	1484.36284
ISONE_SV	WIN	1	38304	3166.77694
ISONE_SV	WIN	2	38304	3469.901421
ISONE_SV	SPR	3	39538.5	5831.864033
ISONE_SV	SPR	4	39538.5	7142.33075
ISONE_SV	SPR	5	39538.5	4033.302555
ISONE_SV	SUM	6	40773	1444.773501
ISONE_SV	SUM	7	40773	433.4639236
ISONE_SV	SUM	8	40773	281
ISONE_SV	FAL	9	39538.5	1287.38377
ISONE_SV	FAL	10	39538.5	6934.701477
ISONE_SV	FAL	11	39538.5	5277.97338

ISONE_SV	WIN	12	38304	3128.984489
MISO	WIN	1	131672	11845
MISO	WIN	2	131672	13214
MISO	SPR	3	128694	22181
MISO	SPR	4	128694	31160
MISO	SPR	5	128694	19117
MISO	SUM	6	125715	8163
MISO	SUM	7	125715	6429
MISO	SUM	8	125715	7498
MISO	FAL	9	128694	7327
MISO	FAL	10	128694	28881
MISO	FAL	11	128694	23062
MISO	WIN	12	131672	16145
HQ	WIN	1	1600	
HQ	WIN	2	1600	
HQ	SPR	3	1600	
HQ	SPR	4	1600	
HQ	SPR	5	1600	
HQ	SUM	6	1600	
HQ	SUM	7	1600	
HQ	SUM	8	1600	
HQ	FAL	9	1600	
HQ	FAL	10	1600	
HQ	FAL	11	1600	
HQ	WIN	12	1600	
NB	WIN	1	700	
NB	WIN	2	700	
NB	SPR	3	700	
NB	SPR	4	700	
NB	SPR	5	700	
NB	SUM	6	700	
NB	SUM	7	700	
NB	SUM	8	700	
NB	FAL	9	700	
NB	FAL	10	700	
NB	FAL	11	700	
NB	WIN	12	700	
ONT	WIN	1	2000	
ONT	WIN	2	2000	
ONT	SPR	3	2000	
ONT	SPR	4	2000	
ONT	SPR	5	2000	
ONT	SUM	6	2000	
ONT	SUM	7	2000	
ONT	SUM	8	2000	
ONT	FAL	9	2000	
ONT	FAL	10	2000	
ONT	FAL	11	2000	
ONT	WIN	12	2000	

OPERATING RESERVES
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AREA	SEASON	MONTH	MONTHLY PEAK	AVERAGE OF DAILY PEAKS	AVERAGE PEAK LOAD
ISONE	WIN	1	20,250	18,279	17,102
ISONE	WIN	2	19,842	18,706	17,627
ISONE	SPR	3	18,571	16,574	15,703
ISONE	SPR	4	16,256	14,476	14,104
ISONE	SPR	5	19,251	15,054	14,734
ISONE	SUM	6	20,552	16,344	15,863
ISONE	SUM	7	24,049	19,328	18,451
ISONE	SUM	8	23,918	19,593	18,748
ISONE	FAL	9	24,054	17,708	16,983
ISONE	FAL	10	16,000	14,896	14,116
ISONE	FAL	11	17,464	15,619	14,436
ISONE	WIN	12	19,549	17,395	16,141
NYISO	WIN	1	24,648	22,185	21,213
NYISO	WIN	2	24,144	22,753	21,810
NYISO	SPR	3	23,122	20,375	19,786
NYISO	SPR	4	19,521	18,070	17,846
NYISO	SPR	5	24,285	19,689	19,291
NYISO	SUM	6	28,100	21,898	21,151
NYISO	SUM	7	31,138	25,244	23,924
NYISO	SUM	8	30,543	25,219	24,092
NYISO	FAL	9	31,058	23,171	22,314
NYISO	FAL	10	20,088	18,634	18,073
NYISO	FAL	11	21,086	19,373	18,348
NYISO	WIN	12	23,095	21,266	19,995
PJM	WIN	1	136,197	113,143	110,383
PJM	WIN	2	143,129	120,571	115,419
PJM	SPR	3	125,702	101,164	96,614
PJM	SPR	4	96,382	85,837	84,772
PJM	SPR	5	120,840	97,456	94,475
PJM	SUM	6	137,287	112,016	105,683
PJM	SUM	7	143,633	121,600	112,418
PJM	SUM	8	139,650	119,659	110,097
PJM	FAL	9	141,210	108,560	103,492
PJM	FAL	10	94,825	86,436	84,806
PJM	FAL	11	104,505	90,826	87,678
PJM	WIN	12	114,047	104,239	100,723
PJME	WIN	1	22,689	19,562	18,552
PJME	WIN	2	23,089	20,275	19,238
PJME	SPR	3	20,797	17,539	16,563
PJME	SPR	4	16,898	15,085	14,503
PJME	SPR	5	23,792	17,729	16,692
PJME	SUM	6	28,594	20,918	19,375
PJME	SUM	7	30,240	24,093	21,813
PJME	SUM	8	28,490	23,725	21,516
PJME	FAL	9	28,892	20,583	19,289
PJME	FAL	10	16,632	15,378	14,658
PJME	FAL	11	18,203	16,081	15,091
PJME	WIN	12	20,455	18,355	17,117
PJM50	WIN	1	43,897	37,253	35,771
PJM50	WIN	2	46,431	39,397	37,264
PJM50	SPR	3	39,919	33,628	31,681

PJM50	SPR	4	32,196	28,131	27,346
PJM50	SPR	5	42,827	32,678	31,213
PJM50	SUM	6	49,920	37,983	35,477
PJM50	SUM	7	52,190	42,368	38,788
PJM50	SUM	8	49,932	41,804	38,288
PJM50	FAL	9	50,400	37,121	35,096
PJM50	FAL	10	30,663	28,115	27,154
PJM50	FAL	11	34,153	29,840	28,393
PJM50	WIN	12	38,612	34,311	32,528
PJMAP	WIN	1	63,258	51,713	49,346
PJMAP	WIN	2	68,082	55,601	52,023
PJMAP	SPR	3	57,321	46,282	43,112
PJMAP	SPR	4	43,505	38,406	37,156
PJMAP	SPR	5	58,385	45,334	42,955
PJMAP	SUM	6	68,900	53,071	49,231
PJMAP	SUM	7	70,729	58,108	53,080
PJMAP	SUM	8	67,496	57,013	51,999
PJMAP	FAL	9	67,017	50,547	47,540
PJMAP	FAL	10	42,894	38,591	37,172
PJMAP	FAL	11	47,489	40,816	38,752
PJMAP	WIN	12	52,677	46,814	44,605
CT	WIN	1	5,123	4,547	4,239
CT	WIN	2	5,186	4,689	4,421
CT	SPR	3	4,720	4,047	3,830
CT	SPR	4	3,903	3,490	3,387
CT	SPR	5	4,691	3,819	3,709
CT	SUM	6	5,776	4,288	4,078
CT	SUM	7	6,419	5,054	4,655
CT	SUM	8	6,237	5,122	4,776
CT	FAL	9	6,332	4,542	4,318
CT	FAL	10	3,990	3,630	3,436
CT	FAL	11	4,287	3,856	3,561
CT	WIN	12	4,830	4,274	3,960
SWCT	WIN	1	2,527	2,227	2,071
SWCT	WIN	2	2,541	2,297	2,152
SWCT	SPR	3	2,375	2,010	1,879
SWCT	SPR	4	1,926	1,696	1,636
SWCT	SPR	5	2,317	1,833	1,760
SWCT	SUM	6	2,868	2,082	1,946
SWCT	SUM	7	3,286	2,500	2,278
SWCT	SUM	8	3,170	2,531	2,311
SWCT	FAL	9	3,194	2,207	2,066
SWCT	FAL	10	1,923	1,662	1,545
SWCT	FAL	11	2,079	1,847	1,686
SWCT	WIN	12	2,354	2,086	1,922
PJM_E	WIN	1	113,508	93,582	91,831
PJM_E	WIN	2	120,040	100,296	96,181
PJM_E	SPR	3	104,905	83,625	80,051
PJM_E	SPR	4	79,484	70,752	70,269
PJM_E	SPR	5	97,048	79,727	77,784
PJM_E	SUM	6	108,694	91,098	86,308
PJM_E	SUM	7	113,393	97,507	90,605

PJM_E	SUM	8	111,159	95,934	88,581
PJM_E	FAL	9	112,318	87,977	84,203
PJM_E	FAL	10	78,193	71,058	70,148
PJM_E	FAL	11	86,302	74,744	72,587
PJM_E	WIN	12	93,592	85,884	83,605
PJM_50	WIN	1	92,300	75,890	74,612
PJM_50	WIN	2	96,699	81,174	78,155
PJM_50	SPR	3	85,783	67,536	64,932
PJM_50	SPR	4	64,186	57,706	57,426
PJM_50	SPR	5	78,013	64,778	63,263
PJM_50	SUM	6	87,367	74,033	70,206
PJM_50	SUM	7	91,444	79,232	73,630
PJM_50	SUM	8	89,717	77,855	71,809
PJM_50	FAL	9	90,810	71,439	68,396
PJM_50	FAL	10	64,162	58,321	57,652
PJM_50	FAL	11	70,352	60,985	59,285
PJM_50	WIN	12	75,435	69,928	68,194
PJM_AP	WIN	1	72,940	61,430	61,038
PJM_AP	WIN	2	75,048	64,970	63,396
PJM_AP	SPR	3	68,381	54,882	53,501
PJM_AP	SPR	4	52,878	47,431	47,617
PJM_AP	SPR	5	62,455	52,122	51,520
PJM_AP	SUM	6	68,388	58,945	56,453
PJM_AP	SUM	7	72,904	63,491	59,338
PJM_AP	SUM	8	72,154	62,646	58,098
PJM_AP	FAL	9	74,193	58,013	55,953
PJM_AP	FAL	10	51,931	47,845	47,634
PJM_AP	FAL	11	57,016	50,010	48,925
PJM_AP	WIN	12	61,370	57,425	56,117
ISONE_	WIN	1	15,127	13,732	12,863
ISONE_	WIN	2	14,656	14,016	13,206
ISONE_	SPR	3	13,851	12,527	11,873
ISONE_	SPR	4	12,353	10,986	10,717
ISONE_	SPR	5	14,560	11,235	11,025
ISONE_	SUM	6	14,776	12,056	11,785
ISONE_	SUM	7	17,630	14,274	13,796
ISONE_	SUM	8	17,681	14,471	13,972
ISONE_	FAL	9	17,722	13,166	12,665
ISONE_	FAL	10	12,010	11,266	10,680
ISONE_	FAL	11	13,177	11,763	10,875
ISONE_	WIN	12	14,719	13,120	12,181
ISONE_	WIN	1	17,723	16,052	15,031
ISONE_	WIN	2	17,301	16,409	15,475
ISONE_	SPR	3	16,196	14,565	13,824
ISONE_	SPR	4	14,330	12,780	12,468
ISONE_	SPR	5	16,934	13,222	12,975
ISONE_	SUM	6	17,684	14,263	13,917
ISONE_	SUM	7	20,763	16,828	16,172
ISONE_	SUM	8	20,748	17,062	16,437
ISONE_	FAL	9	20,860	15,500	14,917
ISONE_	FAL	10	14,077	13,235	12,571
ISONE_	FAL	11	15,385	13,772	12,749

ISONE_	WIN	12	17,195	15,308	14,219
MISO	WIN	1	106,328	89,297	88,094
MISO	WIN	2	100,942	91,388	89,821
MISO	SPR	3	97,439	79,455	78,190
MISO	SPR	4	79,431	73,829	73,710
MISO	SPR	5	93,937	79,825	79,290
MISO	SUM	6	107,294	94,020	90,412
MISO	SUM	7	120,024	104,058	97,809
MISO	SUM	8	114,496	99,995	94,055
MISO	FAL	9	113,562	93,059	89,482
MISO	FAL	10	84,211	76,814	76,084
MISO	FAL	11	83,762	77,467	75,660
MISO	WIN	12	92,832	85,055	83,596

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COMMENT

AREA	SOURCE	SEASON	SELLER	REMOTE	CONTRACT	ROW

DESCRIPTION	CAPACITY

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Seller Data

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AREA	SEASON	MONTH	CAPACITY	PLANNED OUTAGE
ISONE	WIN	1	860	4.16856009
ISONE	WIN	2	860	30.92550517
ISONE	SPR	3	852	63.3602054
ISONE	SPR	4	852	123.2600101
ISONE	SPR	5	852	73.66093312
ISONE	SUM	6	843	17.34294714
ISONE	SUM	7	843	2.212816222
ISONE	SUM	8	843	0
ISONE	FAL	9	852	12.92955927
ISONE	FAL	10	852	176.9901081
ISONE	FAL	11	852	48.311486
ISONE	WIN	12	860	52.96676664
NYISO	WIN	1	870	67.42542406
NYISO	WIN	2	870	75.65217391
NYISO	SPR	3	814	116.3094134
NYISO	SPR	4	814	145.1455009
NYISO	SPR	5	814	82.20408091
NYISO	SUM	6	757	26.17645563
NYISO	SUM	7	757	7.698957539
NYISO	SUM	8	757	4.916834246
NYISO	FAL	9	814	25.61277656
NYISO	FAL	10	814	144.3155466
NYISO	FAL	11	814	104.7286553
NYISO	WIN	12	870	69.90617079
PJM	WIN	1	10727	200.741259
PJM	WIN	2	10727	422.4115708
PJM	SPR	3	9985.5	1016.455209
PJM	SPR	4	9985.5	1835.521034
PJM	SPR	5	9985.5	1280.501712
PJM	SUM	6	9244	231.8774862
PJM	SUM	7	9244	225.6575966
PJM	SUM	8	9244	177.441012
PJM	FAL	9	9985.5	210.4046474
PJM	FAL	10	9985.5	2453.772406
PJM	FAL	11	9985.5	1222.85516
PJM	WIN	12	10727	768.9345074
PJME	WIN	1	8051	150.6635477
PJME	WIN	2	8051	317.0351036
PJME	SPR	3	7283.5	741.4101962
PJME	SPR	4	7283.5	1338.843068
PJME	SPR	5	7283.5	934.0077334
PJME	SUM	6	6516	163.448042
PJME	SUM	7	6516	159.0637061
PJME	SUM	8	6516	125.0763343
PJME	FAL	9	7283.5	153.4707576
PJME	FAL	10	7283.5	1789.800342
PJME	FAL	11	7283.5	891.9598975
PJME	WIN	12	8051	577.113053
PJM50	WIN	1	8819	165.0356263
PJM50	WIN	2	8819	347.2776771
PJM50	SPR	3	8051.5	819.5873131

PJM50	SPR	4	8051.5	1480.015783
PJM50	SPR	5	8051.5	1032.493069
PJM50	SUM	6	7284	182.7126363
PJM50	SUM	7	7284	177.8115462
PJM50	SUM	8	7284	139.8182963
PJM50	FAL	9	8051.5	169.6532992
PJM50	FAL	10	8051.5	1978.523712
PJM50	FAL	11	8051.5	986.0115487
PJM50	WIN	12	8819	632.1649502
PJMAP	WIN	1	8819	165.0356263
PJMAP	WIN	2	8819	347.2776771
PJMAP	SPR	3	8051.5	819.5873131
PJMAP	SPR	4	8051.5	1480.015783
PJMAP	SPR	5	8051.5	1032.493069
PJMAP	SUM	6	7284	182.7126363
PJMAP	SUM	7	7284	177.8115462
PJMAP	SUM	8	7284	139.8182963
PJMAP	FAL	9	8051.5	169.6532992
PJMAP	FAL	10	8051.5	1978.523712
PJMAP	FAL	11	8051.5	986.0115487
PJMAP	WIN	12	8819	632.1649502
CT	WIN	1	860	4.16856009
CT	WIN	2	860	30.92550517
CT	SPR	3	851.5	63.3602054
CT	SPR	4	851.5	123.2600101
CT	SPR	5	851.5	73.66093312
CT	SUM	6	843	17.34294714
CT	SUM	7	843	2.212816222
CT	SUM	8	843	0
CT	FAL	9	851.5	12.92955927
CT	FAL	10	851.5	176.9901081
CT	FAL	11	851.5	48.311486
CT	WIN	12	860	52.96676664
SWCT	WIN	1	407	1.972795298
SWCT	WIN	2	407	14.63567512
SWCT	SPR	3	403.5	30.02447784
SWCT	SPR	4	403.5	58.40917683
SWCT	SPR	5	403.5	34.90567999
SWCT	SUM	6	400	8.229156413
SWCT	SUM	7	400	1.04997211
SWCT	SUM	8	400	0
SWCT	FAL	9	403.5	6.126925621
SWCT	FAL	10	403.5	83.87023911
SWCT	FAL	11	403.5	22.89334656
SWCT	WIN	12	407	25.06683026
PJM_E	WIN	1	2676	50.0777113
PJM_E	WIN	2	2676	105.3764672
PJM_E	SPR	3	2702	275.0450127
PJM_E	SPR	4	2702	496.6779665
PJM_E	SPR	5	2702	346.493979
PJM_E	SUM	6	2728	68.42944422
PJM_E	SUM	7	2728	66.59389046

PJM_E	SUM	8	2728	52.3646777
PJM_E	FAL	9	2702	56.93388988
PJM_E	FAL	10	2702	663.9720636
PJM_E	FAL	11	2702	330.8952623
PJM_E	WIN	12	2676	191.8214544
PJM_50	WIN	1	1908	35.70563272
PJM_50	WIN	2	1908	75.13389364
PJM_50	SPR	3	1934	196.8678959
PJM_50	SPR	4	1934	355.5052506
PJM_50	SPR	5	1934	248.0086437
PJM_50	SUM	6	1960	49.16484995
PJM_50	SUM	7	1960	47.84605033
PJM_50	SUM	8	1960	37.62271565
PJM_50	FAL	9	1934	40.75134827
PJM_50	FAL	10	1934	475.2486939
PJM_50	FAL	11	1934	236.8436111
PJM_50	WIN	12	1908	136.7695572
PJM_AP	WIN	1	1908	35.70563272
PJM_AP	WIN	2	1908	75.13389364
PJM_AP	SPR	3	1934	196.8678959
PJM_AP	SPR	4	1934	355.5052506
PJM_AP	SPR	5	1934	248.0086437
PJM_AP	SUM	6	1960	49.16484995
PJM_AP	SUM	7	1960	47.84605033
PJM_AP	SUM	8	1960	37.62271565
PJM_AP	FAL	9	1934	40.75134827
PJM_AP	FAL	10	1934	475.2486939
PJM_AP	FAL	11	1934	236.8436111
PJM_AP	WIN	12	1908	136.7695572
ISONE_CT	WIN	1	0	0
ISONE_CT	WIN	2	0	0
ISONE_CT	SPR	3	0	0
ISONE_CT	SPR	4	0	0
ISONE_CT	SPR	5	0	0
ISONE_CT	SUM	6	0	0
ISONE_CT	SUM	7	0	0
ISONE_CT	SUM	8	0	0
ISONE_CT	FAL	9	0	0
ISONE_CT	FAL	10	0	0
ISONE_CT	FAL	11	0	0
ISONE_CT	WIN	12	0	0
ISONE_SWCT	WIN	1	453	37.45170096
ISONE_SWCT	WIN	2	453	41.03658479
ISONE_SWCT	SPR	3	448	66.07926671
ISONE_SWCT	SPR	4	448	80.927809
ISONE_SWCT	SPR	5	448	45.70025531
ISONE_SWCT	SUM	6	443	15.69751211
ISONE_SWCT	SUM	7	443	4.709599935
ISONE_SWCT	SUM	8	443	3.053074338
ISONE_SWCT	FAL	9	448	14.58699568
ISONE_SWCT	FAL	10	448	78.57521813
ISONE_SWCT	FAL	11	448	59.80328222

ISONE_SWCT	WIN	12	453	37.00475077

OPERATING RESERVES REMOTE
24.86308439
23.71683735
22.97618919
19.45556888
16.95020909
17.9533467
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120.213
137.028
133.779
122.094
98.61
145.977
155.211
175.788
163.248
164.217
78.318
87.039
120.213
149.283
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AREA	SEASON	MONTH	MONTHLY PEAK	AVERAGE OF DAILY PEAKS	AVERAGE PEAK LOAD
ISONE	WIN	1	199	163	137
ISONE	WIN	2	186	167	142
ISONE	SPR	3	170	142	119
ISONE	SPR	4	126	111	95
ISONE	SPR	5	130	108	92
ISONE	SUM	6	147	120	104
ISONE	SUM	7	97	14	6
ISONE	SUM	8	21	10	6
ISONE	FAL	9	30	10	6
ISONE	FAL	10	28	10	5
ISONE	FAL	11	15	6	5
ISONE	WIN	12	90	79	62
NYISO	WIN	1	-	-	-
NYISO	WIN	2	-	-	-
NYISO	SPR	3	-	-	-
NYISO	SPR	4	-	-	-
NYISO	SPR	5	-	-	-
NYISO	SUM	6	-	-	-
NYISO	SUM	7	-	-	-
NYISO	SUM	8	-	-	-
NYISO	FAL	9	-	-	-
NYISO	FAL	10	-	-	-
NYISO	FAL	11	-	-	-
NYISO	WIN	12	-	-	-
PJM	WIN	1	2619	2,226	1943.770833
PJM	WIN	2	2569	2,286	1994.203125
PJM	SPR	3	2328	1,923	1645.230114
PJM	SPR	4	1859	1,592	1356.894886
PJM	SPR	5	2671	1,901	1569.2375
PJM	SUM	6	2854	1,927	1627.855114
PJM	SUM	7	3259	2398.419355	1986.122283
PJM	SUM	8	3038	2380.967742	1964.178571
PJM	FAL	9	3051	1948.333333	1650.395833
PJM	FAL	10	1490	1379.612903	1160.579545
PJM	FAL	11	1668	1438.366667	1219.353125
PJM	WIN	12	2109	1912.806452	1624.127841
PJME	WIN	1	2404	2051.387097	1793.068452
PJME	WIN	2	2347	2099.464286	1831.190625
PJME	SPR	3	2142	1784.806452	1528.315341
PJME	SPR	4	1730	1494.1	1276.332386
PJME	SPR	5	2561	1810.16129	1496.7625
PJME	SUM	6	2723	1822.066667	1541.497159
PJME	SUM	7	3084	2269.290323	1884.228261
PJME	SUM	8	2864	2254.870968	1867.083333
PJME	FAL	9	2881	1842.333333	1569.869048
PJME	FAL	10	1374	1290.774194	1094.701705
PJME	FAL	11	1527	1334.6	1139.365625
PJME	WIN	12	2109	1912.806452	1624.127841
PJM50	WIN	1	2619	2226.419355	1943.770833
PJM50	WIN	2	2569	2285.964286	1994.203125
PJM50	SPR	3	2328	1923	1645.230114

PJM50	SPR	4	1859	1592.333333	1356.894886
PJM50	SPR	5	2671	1901.225806	1569.2375
PJM50	SUM	6	2854	1926.9	1627.855114
PJM50	SUM	7	3259	2398.419355	1986.122283
PJM50	SUM	8	3038	2380.967742	1964.178571
PJM50	FAL	9	3051	1948.333333	1650.395833
PJM50	FAL	10	1490	1379.612903	1160.579545
PJM50	FAL	11	1668	1438.366667	1219.353125
PJM50	WIN	12	2109	1912.806452	1624.127841
PJMAP	WIN	1	2619	2226.419355	1943.770833
PJMAP	WIN	2	2569	2285.964286	1994.203125
PJMAP	SPR	3	2328	1923	1645.230114
PJMAP	SPR	4	1859	1592.333333	1356.894886
PJMAP	SPR	5	2671	1901.225806	1569.2375
PJMAP	SUM	6	2854	1926.9	1627.855114
PJMAP	SUM	7	3259	2398.419355	1986.122283
PJMAP	SUM	8	3038	2380.967742	1964.178571
PJMAP	FAL	9	3051	1948.333333	1650.395833
PJMAP	FAL	10	1490	1379.612903	1160.579545
PJMAP	FAL	11	1668	1438.366667	1219.353125
PJMAP	WIN	12	2109	1912.806452	1624.127841
CT	WIN	1	199	162.6451613	136.639881
CT	WIN	2	186	167	141.753125
CT	SPR	3	170	141.9032258	119.4801136
CT	SPR	4	126	110.8	95.02272727
CT	SPR	5	130	108.1612903	92.2375
CT	SUM	6	147	120.4666667	103.65625
CT	SUM	7	97	14.03225806	6.192934783
CT	SUM	8	21	10.25806452	6.366071429
CT	FAL	9	30	10.1	6.023809524
CT	FAL	10	28	9.548387097	5.321022727
CT	FAL	11	15	5.766666667	5.05625
CT	WIN	12	90	78.77419355	61.94318182
SWCT	WIN	1	0	0	0
SWCT	WIN	2	0	0	0
SWCT	SPR	3	0	0	0
SWCT	SPR	4	0	0	0
SWCT	SPR	5	0	0	0
SWCT	SUM	6	0	0	0
SWCT	SUM	7	0	0	0
SWCT	SUM	8	0	0	0
SWCT	FAL	9	0	0	0
SWCT	FAL	10	0	0	0
SWCT	FAL	11	0	0	0
SWCT	WIN	12	0	0	0
PJM_E	WIN	1	215	4.023433457	150.702381
PJM_E	WIN	2	222	8.741993914	163.0125
PJM_E	SPR	3	186	18.93352049	116.9147727
PJM_E	SPR	4	129	23.71260462	80.5625
PJM_E	SPR	5	110	14.1059725	72.475
PJM_E	SUM	6	131	3.286018033	86.35795455
PJM_E	SUM	7	175	4.271968779	101.8940217

PJM_E	SUM	8	174	3.339975777	97.0952381
PJM_E	FAL	9	170	3.582073012	80.52678571
PJM_E	FAL	10	116	28.50509229	65.87784091
PJM_E	FAL	11	141	17.26729533	79.9875
PJM_E	WIN	12	0	0	0
PJM_50	WIN	1	0	0	0
PJM_50	WIN	2	0	0	0
PJM_50	SPR	3	0	0	0
PJM_50	SPR	4	0	0	0
PJM_50	SPR	5	0	0	0
PJM_50	SUM	6	0	0	0
PJM_50	SUM	7	0	0	0
PJM_50	SUM	8	0	0	0
PJM_50	FAL	9	0	0	0
PJM_50	FAL	10	0	0	0
PJM_50	FAL	11	0	0	0
PJM_50	WIN	12	0	0	0
PJM_AP	WIN	1	0	0	0
PJM_AP	WIN	2	0	0	0
PJM_AP	SPR	3	0	0	0
PJM_AP	SPR	4	0	0	0
PJM_AP	SPR	5	0	0	0
PJM_AP	SUM	6	0	0	0
PJM_AP	SUM	7	0	0	0
PJM_AP	SUM	8	0	0	0
PJM_AP	FAL	9	0	0	0
PJM_AP	FAL	10	0	0	0
PJM_AP	FAL	11	0	0	0
PJM_AP	WIN	12	0	0	0
ISONE_	WIN	1	0	0	0
ISONE_	WIN	2	0	0	0
ISONE_	SPR	3	0	0	0
ISONE_	SPR	4	0	0	0
ISONE_	SPR	5	0	0	0
ISONE_	SUM	6	0	0	0
ISONE_	SUM	7	0	0	0
ISONE_	SUM	8	0	0	0
ISONE_	FAL	9	0	0	0
ISONE_	FAL	10	0	0	0
ISONE_	FAL	11	0	0	0
ISONE_	WIN	12	0	0	0
ISONE_	WIN	1	199	16.45229248	136.639881
ISONE_	WIN	2	186	16.84945865	141.753125
ISONE_	SPR	3	170	25.07472174	119.4801136
ISONE_	SPR	4	126	22.76094628	95.02272727
ISONE_	SPR	5	130	13.2612348	92.2375
ISONE_	SUM	6	147	5.208880992	103.65625
ISONE_	SUM	7	97	1.031221656	6.192934783
ISONE_	SUM	8	21	0.144728129	6.366071429
ISONE_	FAL	9	30	0.976807747	6.023809524
ISONE_	FAL	10	28	4.910951133	5.321022727
ISONE_	FAL	11	15	2.002342039	5.05625

ISONE_	WIN	12	90	7.351937239	61.94318182

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COMMENT

AREA	SEASON	DESCRIPTION	SALE	PURCHASE
ISONE	WIN	Bridgewater	10	0
ISONE	SPR	Bridgewater	14	0
ISONE	SUM	Bridgewater	14	0
ISONE	FAL	Bridgewater	14	0
ISONE	WIN	VEPP Inc.	2	0
ISONE	SPR	VEPP Inc.	2	0
ISONE	SUM	VEPP Inc.	2	0
ISONE	FAL	VEPP Inc.	2	0
PJM	WIN	LES Project Holdings	14	0
PJM	SPR	LES Project Holdings	14	0
PJM	SUM	LES Project Holdings	14	0
PJM	FAL	LES Project Holdings	14	0
PJM	WIN	Ocean Energy Holdings	9	0
PJM	SPR	Ocean Energy Holdings	9	0
PJM	SUM	Ocean Energy Holdings	9	0
PJM	FAL	Ocean Energy Holdings	9	0
PJM	WIN	BP	34	0
PJM	SPR	BP	0	0
PJM	SUM	BP	0	0
PJM	FAL	BP	0	0
PJM	WIN	Citigroup	94	0
PJM	SPR	Citigroup	75	0
PJM	SUM	Citigroup	75	0
PJM	FAL	Citigroup	75	0
PJM	WIN	Direct Energy	556	0
PJM	SPR	Direct Energy	650	0
PJM	SUM	Direct Energy	650	0
PJM	FAL	Direct Energy	650	0
PJM	WIN	EDF	8	0
PJM	SPR	EDF	0	0
PJM	SUM	EDF	0	0
PJM	FAL	EDF	0	0
PJM	WIN	Energy America	305	0
PJM	SPR	Energy America	460	0
PJM	SUM	Energy America	460	0
PJM	FAL	Energy America	460	0
PJM	WIN	Exelon	66	0
PJM	SPR	Exelon	100	0
PJM	SUM	Exelon	100	0
PJM	FAL	Exelon	100	0
PJM	WIN	Nextera	523	0
PJM	SPR	Nextera	602	0
PJM	SUM	Nextera	601	0
PJM	FAL	Nextera	602	0
PJM	WIN	American Electric Power	10	0
PJM	SPR	American Electric Power	10	0
PJM	SUM	American Electric Power	10	0
PJM	FAL	American Electric Power	10	0
PJM	WIN	M&M Mars	2	0
PJM	SPR	M&M Mars	2	0
PJM	SUM	M&M Mars	2	0
PJM	FAL	M&M Mars	2	0
PJM	WIN	SMECO	10	0
PJM	SPR	SMECO	10	0

PJM	SUM	SMECO	10	0
PJM	FAL	SMECO	10	0
PJM	WIN	JP Morgan	0	195
PJM	SPR	JP Morgan	0	195
PJM	SUM	JP Morgan	0	195
PJM	FAL	JP Morgan	0	195
PJM	WIN	Delaware Municipal Electric Corporatio	12	0
PJM	SPR	Delaware Municipal Electric Corporatio	12	0
PJM	SUM	Delaware Municipal Electric Corporatio	12	0
PJM	FAL	Delaware Municipal Electric Corporatio	12	0
ISONE_CT	WIN	Bridgewater	10	0
ISONE_CT	SPR	Bridgewater	14	0
ISONE_CT	SUM	Bridgewater	14	0
ISONE_CT	FAL	Bridgewater	14	0
ISONE_SWCT	WIN	Bridgewater	10	0
ISONE_SWCT	SPR	Bridgewater	14	0
ISONE_SWCT	SUM	Bridgewater	14	0
ISONE_SWCT	FAL	Bridgewater	14	0
ISONE_CT	WIN	VEPP Inc.	2	0
ISONE_CT	SPR	VEPP Inc.	2	0
ISONE_CT	SUM	VEPP Inc.	2	0
ISONE_CT	FAL	VEPP Inc.	2	0
ISONE_SWCT	WIN	VEPP Inc.	2	0
ISONE_SWCT	SPR	VEPP Inc.	2	0
ISONE_SWCT	SUM	VEPP Inc.	2	0
ISONE_SWCT	FAL	VEPP Inc.	2	0
PJM_E	WIN	LES Project Holdings	14	0
PJM_E	SPR	LES Project Holdings	14	0
PJM_E	SUM	LES Project Holdings	14	0
PJM_E	FAL	LES Project Holdings	14	0
PJM_E	WIN	Ocean Energy Holdings	9	0
PJM_E	SPR	Ocean Energy Holdings	9	0
PJM_E	SUM	Ocean Energy Holdings	9	0
PJM_E	FAL	Ocean Energy Holdings	9	0
PJM_E	WIN	BP	34	0
PJM_E	SPR	BP	0	0
PJM_E	SUM	BP	0	0
PJM_E	FAL	BP	0	0
PJM_E	WIN	Citigroup	94	0
PJM_E	SPR	Citigroup	75	0
PJM_E	SUM	Citigroup	75	0
PJM_E	FAL	Citigroup	75	0
PJM_E	WIN	Direct Energy	556	0
PJM_E	SPR	Direct Energy	650	0
PJM_E	SUM	Direct Energy	650	0
PJM_E	FAL	Direct Energy	650	0
PJME	WIN	EDF	8	0
PJME	SPR	EDF	0	0
PJME	SUM	EDF	0	0
PJME	FAL	EDF	0	0
PJM_E	WIN	Energy America	305	0
PJM_E	SPR	Energy America	460	0
PJM_E	SUM	Energy America	460	0
PJM_E	FAL	Energy America	460	0
PJM_E	WIN	Exelon	66	0

PJM_E	SPR	Exelon	100	0
PJM_E	SUM	Exelon	100	0
PJM_E	FAL	Exelon	100	0
PJM_E	WIN	Nextera	523	0
PJM_E	SPR	Nextera	602	0
PJM_E	SUM	Nextera	601	0
PJM_E	FAL	Nextera	602	0
PJM_E	WIN	American Electric Power	10	0
PJM_E	SPR	American Electric Power	10	0
PJM_E	SUM	American Electric Power	10	0
PJM_E	FAL	American Electric Power	10	0
PJME	WIN	M&M Mars	2	0
PJME	SPR	M&M Mars	2	0
PJME	SUM	M&M Mars	2	0
PJME	FAL	M&M Mars	2	0
PJM_E	WIN	SMECO	10	0
PJM_E	SPR	SMECO	10	0
PJM_E	SUM	SMECO	10	0
PJM_E	FAL	SMECO	10	0
PJM_E	WIN	JP Morgan	0	195
PJM_E	SPR	JP Morgan	0	195
PJM_E	SUM	JP Morgan	0	195
PJM_E	FAL	JP Morgan	0	195
PJME	WIN	Delaware Municipal Electric Corporatio	12	0
PJME	SPR	Delaware Municipal Electric Corporatio	12	0
PJME	SUM	Delaware Municipal Electric Corporatio	12	0
PJME	FAL	Delaware Municipal Electric Corporatio	12	0
PJM50	WIN	LES Project Holdings	14	0
PJM50	SPR	LES Project Holdings	14	0
PJM50	SUM	LES Project Holdings	14	0
PJM50	FAL	LES Project Holdings	14	0
PJM_50	WIN	Ocean Energy Holdings	9	0
PJM_50	SPR	Ocean Energy Holdings	9	0
PJM_50	SUM	Ocean Energy Holdings	9	0
PJM_50	FAL	Ocean Energy Holdings	9	0
PJM_50	WIN	BP	34	0
PJM_50	SPR	BP	0	0
PJM_50	SUM	BP	0	0
PJM_50	FAL	BP	0	0
PJM_50	WIN	Citigroup	94	0
PJM_50	SPR	Citigroup	75	0
PJM_50	SUM	Citigroup	75	0
PJM_50	FAL	Citigroup	75	0
PJM_50	WIN	Direct Energy	556	0
PJM_50	SPR	Direct Energy	650	0
PJM_50	SUM	Direct Energy	650	0
PJM_50	FAL	Direct Energy	650	0
PJM50	WIN	EDF	8	0
PJM50	SPR	EDF	0	0
PJM50	SUM	EDF	0	0
PJM50	FAL	EDF	0	0
PJM_50	WIN	Energy America	305	0
PJM_50	SPR	Energy America	460	0
PJM_50	SUM	Energy America	460	0
PJM_50	FAL	Energy America	460	0

PJM_50	WIN	Exelon	66	0
PJM_50	SPR	Exelon	100	0
PJM_50	SUM	Exelon	100	0
PJM_50	FAL	Exelon	100	0
PJM_50	WIN	Nextera	523	0
PJM_50	SPR	Nextera	602	0
PJM_50	SUM	Nextera	601	0
PJM_50	FAL	Nextera	602	0
PJM_50	WIN	American Electric Power	10	0
PJM_50	SPR	American Electric Power	10	0
PJM_50	SUM	American Electric Power	10	0
PJM_50	FAL	American Electric Power	10	0
PJM50	WIN	M&M Mars	2	0
PJM50	SPR	M&M Mars	2	0
PJM50	SUM	M&M Mars	2	0
PJM50	FAL	M&M Mars	2	0
PJM_50	WIN	SMECO	10	0
PJM_50	SPR	SMECO	10	0
PJM_50	SUM	SMECO	10	0
PJM_50	FAL	SMECO	10	0
PJM_50	WIN	JP Morgan	0	195
PJM_50	SPR	JP Morgan	0	195
PJM_50	SUM	JP Morgan	0	195
PJM_50	FAL	JP Morgan	0	195
PJM50	WIN	Delaware Municipal Electric Corporatio	12	0
PJM50	SPR	Delaware Municipal Electric Corporatio	12	0
PJM50	SUM	Delaware Municipal Electric Corporatio	12	0
PJM50	FAL	Delaware Municipal Electric Corporatio	12	0
PJMAP	WIN	LES Project Holdings	14	0
PJMAP	SPR	LES Project Holdings	14	0
PJMAP	SUM	LES Project Holdings	14	0
PJMAP	FAL	LES Project Holdings	14	0
PJM_AP	WIN	Ocean Energy Holdings	9	0
PJM_AP	SPR	Ocean Energy Holdings	9	0
PJM_AP	SUM	Ocean Energy Holdings	9	0
PJM_AP	FAL	Ocean Energy Holdings	9	0
PJM_AP	WIN	BP	34	0
PJM_AP	SPR	BP	0	0
PJM_AP	SUM	BP	0	0
PJM_AP	FAL	BP	0	0
PJM_AP	WIN	Citigroup	94	0
PJM_AP	SPR	Citigroup	75	0
PJM_AP	SUM	Citigroup	75	0
PJM_AP	FAL	Citigroup	75	0
PJM_AP	WIN	Direct Energy	556	0
PJM_AP	SPR	Direct Energy	650	0
PJM_AP	SUM	Direct Energy	650	0
PJM_AP	FAL	Direct Energy	650	0
PJMAP	WIN	EDF	8	0
PJMAP	SPR	EDF	0	0
PJMAP	SUM	EDF	0	0
PJMAP	FAL	EDF	0	0
PJM_AP	WIN	Energy America	305	0
PJM_AP	SPR	Energy America	460	0
PJM_AP	SUM	Energy America	460	0

PJM_AP	FAL	Energy America	460	0
PJM_AP	WIN	Exelon	66	0
PJM_AP	SPR	Exelon	100	0
PJM_AP	SUM	Exelon	100	0
PJM_AP	FAL	Exelon	100	0
PJM_AP	WIN	Nextera	523	0
PJM_AP	SPR	Nextera	602	0
PJM_AP	SUM	Nextera	601	0
PJM_AP	FAL	Nextera	602	0
PJM_AP	WIN	American Electric Power	10	0
PJM_AP	SPR	American Electric Power	10	0
PJM_AP	SUM	American Electric Power	10	0
PJM_AP	FAL	American Electric Power	10	0
PJMAP	WIN	M&M Mars	2	0
PJMAP	SPR	M&M Mars	2	0
PJMAP	SUM	M&M Mars	2	0
PJMAP	FAL	M&M Mars	2	0
PJM_AP	WIN	SMECO	10	0
PJM_AP	SPR	SMECO	10	0
PJM_AP	SUM	SMECO	10	0
PJM_AP	FAL	SMECO	10	0
PJM_AP	WIN	JP Morgan	0	195
PJM_AP	SPR	JP Morgan	0	195
PJM_AP	SUM	JP Morgan	0	195
PJM_AP	FAL	JP Morgan	0	195
PJMAP	WIN	Delaware Municipal Electric Corporatio	12	0
PJMAP	SPR	Delaware Municipal Electric Corporatio	12	0
PJMAP	SUM	Delaware Municipal Electric Corporatio	12	0
PJMAP	FAL	Delaware Municipal Electric Corporatio	12	0

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Delivered Price Test - PJM50 Market (Add Keys Energy Center and F

Available Economic Capacity

					Pivotal Supplier Screen			Market Sh
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)
Spring/Fall	Top 10%	$62.03	2,122	24,238	22,116	6,776	Yes	8.8
Spring/Fall	Peak	$35.73	2,938	26,888	23,950	6,776	Yes	10.9
Spring/Fall	Off Peak	$29.46	2,449	19,640	17,191	6,776	Yes	12.5
Summer	Top 1%	$148.44	1,013	22,436	21,423	9,933	Yes	4.5
Summer	Top 10%	$64.59	1,131	20,913	19,782	9,933	Yes	5.4
Summer	Peak	$35.56	2,744	23,132	20,388	9,933	Yes	11.9
Summer	Off Peak	$24.88	2,212	15,801	13,590	9,933	Yes	14.0
Winter	Top 10%	$185.57	1,549	25,782	24,233	6,073	Yes	6.0
Winter	Peak	$47.55	0	19,398	19,398	6,073	Yes	0.0
Winter	Off Peak	$50.16	0	18,024	18,024	6,073	Yes	0.0

Economic Capacity

					Pivotal Supplier Screen			Market Sh
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)
Spring/Fall	Top 10%	$62.03	8,328	54,898	46,569	40,893	Yes	15.2
Spring/Fall	Peak	$35.73	8,067	50,911	42,844	28,923	Yes	15.8
Spring/Fall	Off-Peak	$29.46	6,604	42,360	35,756	24,614	Yes	15.6
Summer	Top 1%	$148.44	8,167	59,150	50,984	51,071	No	13.8
Summer	Top 10%	$64.59	8,177	55,871	47,694	47,510	Yes	14.6
Summer	Peak	$35.56	8,124	51,799	43,675	36,423	Yes	15.7
Summer	Off Peak	$24.88	7,000	42,890	35,889	29,051	Yes	16.3
Winter	Top 10%	$185.57	6,650	55,530	48,880	41,770	Yes	12.0
Winter	Peak	$47.55	4,612	43,963	39,351	34,380	Yes	10.5
Winter	Off Peak	$50.16	4,610	39,966	35,356	30,307	Yes	11.5

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are Screen	Market Concentration Screen	
Pass?	HHI	Pass?
Yes	1,026	Yes
Yes	1,087	Yes
Yes	1,338	Yes
Yes	1,065	Yes
Yes	1,018	Yes
Yes	1,051	Yes
Yes	1,768	Yes
Yes	1,018	Yes
Yes	1,421	Yes
Yes	1,592	Yes

are Screen	Market Concentration Screen	
Pass?	HHI	Pass?
Yes	1,118	Yes
Yes	1,091	Yes
Yes	1,144	Yes
Yes	1,122	Yes
Yes	1,106	Yes
Yes	1,081	Yes
Yes	1,166	Yes
Yes	1,106	Yes
Yes	1,207	Yes
Yes	1,281	Yes

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Delivered Price Test - PJME Market (Add Keys Energy Center and R

Available Economic Capacity

					Pivotal Supplier Screen			Market Sh
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)
Spring/Fall	Top 10%	$57.82	2,123	17,335	15,212	3,806	Yes	12.2
Spring/Fall	Peak	$32.73	2,294	19,270	16,977	3,806	Yes	11.9
Spring/Fall	Off Peak	$26.67	1,619	16,678	15,059	3,806	Yes	9.7
Summer	Top 1%	$145.63	976	13,601	12,625	6,174	Yes	7.2
Summer	Top 10%	$63.88	1,118	12,863	11,745	6,174	Yes	8.7
Summer	Peak	$29.67	2,332	13,884	11,551	6,174	Yes	16.8
Summer	Off Peak	$21.25	1,282	11,019	9,738	6,174	Yes	11.6
Winter	Top 10%	$193.51	2,034	20,388	18,354	2,710	Yes	10.0
Winter	Peak	$50.59	0	14,721	14,721	2,710	Yes	0.0
Winter	Off Peak	$50.94	0	13,827	13,827	2,710	Yes	0.0

Economic Capacity

					Pivotal Supplier Screen			Market Sh
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)
Spring/Fall	Top 10%	$57.82	7,708	35,402	27,694	22,528	Yes	21.8
Spring/Fall	Peak	$32.73	6,634	32,603	25,969	15,404	Yes	20.3
Spring/Fall	Off-Peak	$26.67	5,077	28,456	23,379	13,106	Yes	17.8
Summer	Top 1%	$145.63	7,431	35,422	27,991	29,462	No	21.0
Summer	Top 10%	$63.88	7,437	33,714	26,276	27,143	No	22.1
Summer	Peak	$29.67	6,935	31,187	24,252	20,217	Yes	22.2
Summer	Off Peak	$21.25	5,169	26,733	21,564	16,090	Yes	19.3
Winter	Top 10%	$193.51	6,125	34,665	28,540	21,263	Yes	17.7
Winter	Peak	$50.59	3,988	26,323	22,335	17,939	Yes	15.1
Winter	Off Peak	$50.94	3,997	22,913	18,916	15,660	Yes	17.4

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are Screen	Market Concentration Screen	
Pass?	HHI	Pass?
Yes	1,152	Yes
Yes	1,263	Yes
Yes	1,534	Yes
Yes	1,280	Yes
Yes	1,123	Yes
Yes	1,381	Yes
Yes	2,645	No
Yes	1,174	Yes
Yes	1,541	Yes
Yes	1,786	Yes

are Screen	Market Concentration Screen	
Pass?	HHI	Pass?
No	1,197	Yes
No	1,179	Yes
Yes	1,241	Yes
No	1,204	Yes
No	1,200	Yes
No	1,231	Yes
Yes	1,272	Yes
Yes	1,142	Yes
Yes	1,255	Yes
Yes	1,451	Yes

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region	In-service Date
PSE&G	ER99-3151-000	NA*	NA*	NA*	NA*	PJM	Northeast	NA*
PSEG ER&T	ER97-837-000	NA*	NA*	NA*	NA*	PJM, NYISO, NE-ISO	Northeast, Central, Southwest Power Pool, Southeast, Southwest, Northwest	NA*
PSEG Fossil	ER08-447-000	Bergen CC1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Bergen CC2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2002
PSEG Fossil	ER08-447-000	Burlington 12.1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Conemaugh 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/21/1970
PSEG Fossil	ER08-447-000	Conemaugh 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/27/1971
PSEG Fossil	ER08-447-000	Conemaugh A	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh B	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh C	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh D	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Global	N/A	Conemaugh Hydroelectric Plant 1	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Global	N/A	Conemaugh Hydroelectric Plant 2	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Fossil	ER08-447-000	Essex 9	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/1/1990
PSEG Nuclear	ER08-448-000	Hope Creek 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/20/1986
PSEG Fossil	ER08-447-000	Kearny 12	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/1/2001
PSEG Fossil	ER08-447-000	Kearny 13	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Kearny 14	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Keystone 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/24/1967
PSEG Fossil	ER08-447-000	Keystone 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/23/1968
PSEG Fossil	ER08-447-000	Keystone 3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Linden 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM,	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 7	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Linden 8	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Linden GT5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Linden GT6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Nuclear	ER08-448-000	Peach Bottom 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	7/5/1974
PSEG Nuclear	ER08-448-000	Peach Bottom 3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/23/1974

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region	In-service Date
PSEG Nuclear	ER08-448-000	Salem 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/30/1977
PSEG Nuclear	ER08-448-000	Salem 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	10/13/1981
PSEG Nuclear	ER08-448-000	Salem GT3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/17/1971
PSEG Fossil	ER08-447-000	Sewaren 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	12/1/1948
PSEG Fossil	ER08-447-000	Sewaren 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/30/1948
PSEG Fossil	ER08-447-000	Sewaren 3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	10/16/1949
PSEG Fossil	ER08-447-000	Sewaren 4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/30/1951
PSEG Fossil	ER08-447-000	Yards Creek 1	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	11/26/1965
PSEG Fossil	ER08-447-000	Yards Creek 2	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	12/22/1965
PSEG Fossil	ER08-447-000	Yards Creek 3	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	9/3/1965
PSEG Power CT	ER03-327-000	Bridgeport Harbor 3	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	8/1/1968
PSEG Power CT	ER03-327-000	Bridgeport Harbor 4	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	10/30/1967
PSEG New Haven LLC	ER12-1250-000	New Haven 2	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 3	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 4	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG Power CT	ER03-327-000	New Haven Harbor 1	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	7/1/1975
PSEG Power NY	N/A*	Bethlehem Energy Center CC	PSEG Power NY	PSEG ER&T	12/6/2002	NYISO	Northeast	7/1/2005
PSEG Solar Source LLC	N/A*	Mars Solar Garden	PSEG Solar Hackettstown LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	9/9/2009
PSEG Solar Source LLC	N/A*	JEA Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	SERC	Southeast	9/28/2010
PSEG Solar Source LLC	N/A*	Wyandot Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	4/6/2010
PSEG Solar Source LLC	N/A*	Queen Creek Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	AZ-NV-SNV	Southwest	11/14/2012
PSEG Solar Source LLC	N/A*	Milford Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	12/27/2012
PSEG Solar Source LLC	N/A	Badger Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ACC	West	10/15/2013
PSEG Solar Source LLC	N/A	Shasta Solar Farm	PSEG Solar California LLC	PG&E	12/16/2013	CAISO	West	3/1/2014
PSEG Solar Source LLC	N/A	Newman Solar Farm (Texas)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	El Paso Electric	Southwest	12/30/2014
PSEG Solar Source LLC	N/A	Whitcomb Solar Farm (Vermont)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ISO New England	Northeast	10/30/2014
PSEG Solar Source LLC	N/A	Rockfish Solar LLC, Southern Maryland	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	7/10/2015
PSEG Solar Source LLC	N/A	Columbia Solar, Pittsburg, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PG&E	West	10/21/2015

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Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSEG Solar Source LLC	N/A	Whitehorn Solar, Livermore, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Authority	West	2/17/2016
PSEG Solar Source LLC	N/A	Meadows Solar, Martin County, NC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	6/9/2016
PSEG Solar Source LLC	ER16-1924-000	Bison Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Administration, Colorado-Missouri Region	West	8/1/2016
PSEG Solar Source LLC	ER16-1925-000	Pavant Solar II LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp East	West	8/1/2016
PSEG Solar Source LLC	N/A	Obsidian - Black Cap	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp West	West	11/1/2016
PSEG Solar Source LLC	N/A	Hemlock Solar	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	N/A	Turkey Creek	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	ER16-1926-000	San Isabel Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Public Service Company of Colorado	West	8/1/2016
PSE&G (Solar 4 All)	N/A*	Trenton, 500-520 Brunswick Ave., Trenton, NJ 08638	PSE&G	PSE&G	N/A	PJM	Northeast	10/07/2010 (Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Barringer High School (NPS), 90 Parker St., Newark, NJ 07104	PSE&G	PSE&G	N/A	PJM	Northeast	09/24/2010 (Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Park Elementary School, 120 Manchester	PSE&G	PSE&G	N/A	PJM	Northeast	10/20/2010 (Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Linden, South Wood Avenue, Linden, NJ 07036	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Yardville, Broad Street, Hamilton, NJ 08611	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Silver Lake, 410 Silver Lake Avenue, Edison, NJ 08817	PSE&G	PSE&G	N/A	PJM	Northeast	11/09/2010 (Energized)

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G (Solar 4 All)	N/A*	Central HQ, 472 Weston Canal Road, Franklin, NJ 08873	PSE&G	PSE&G	N/A	PJM	Northeast	11/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Edison Training, 234 Pierson Avenue, Edison, NJ 08837	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All)	N/A*	WEA Texas Bayonne, 30-100 Pulaski Street, Bayonne, NJ 07002	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2010
PSE&G (Solar 4 All)	N/A*	Matrix Building A, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/24/2011
PSE&G (Solar 4 All)	N/A*	Matrix Building B, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/14/2011
PSE&G (Solar 4 All)	N/A*	Camden Street School, 281 Camden Street Newark, New Jersey 07103	PSE&G	PSE&G	N/A*	PJM	Northeast	1/12/2011
PSE&G (Solar 4 All)	N/A*	New Central High School, 246 18th Ave, Newark, NJ 07108	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Rider University Solar Farm, Lawrenceville, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2011
PSE&G (Solar 4 All)	N/A*	Mill Creek Solar Farm, Burlington Township, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	11/30/2011
PSE&G (Solar 4 All)	N/A*	PSE&G Thorofare Solar Farm, West Deptford	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011

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Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region	In-service Date
PSE&G (Solar 4 All)	N/A*	Raritan Center – Warehouse Solar, Edison, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	NJMC – Landfill Solar, Kearny, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All	N/A	Matrix – Stults Rd., South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	5/31/2011
PSE&G (Solar 4 All)	N/A*	Metro Division HQ, Clifton, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	7/9/2012
PSE&G (Solar 4 All)	N/A*	Black Rock-Matrix, South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	3/20/2012
PSE&G (Solar 4 All)	N/A*	Food Bank Solar Farm, Hillside, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	8/16/2012
PSE&G (Solar 4 All)	N/A*	Hackensack Solar Farm, Hackensack, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2012
PSE&G (Solar 4 All)	N/A*	Moorestown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/14/2013
PSE&G (Solar 4 All)	N/A*	Seg 2 (Pole attached solar units)	PSE&G	PSE&G	N/A*	PJM	Northeast	7/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Kinsley Solar Sewell, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014
PSE&G (Solar 4 All Extension)	N/A*	Parkland Solar Bordentown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014
PSE&G (Solar 4 All Extension)	N/A*	L&D Solar Mt. Holly, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Hopewell Valley Central HS	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2015
PSE&G (Solar 4 All Extension)	N/A*	ILR Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016
PSE&G (Solar 4 All Extension)	N/A*	Caldwell Waste Treatment Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016
[i] PSEG Fossil has a 22.5% interest in the Conemaugh coal fired plants.								
[ii] PSEG Global has a 4% interest Conemaugh Hydroelectric plants.								
[iii] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear Plants.								
[iv] PSEG Nuclear has a 57.41% interest in the Salem Nuclear Plants.								
[v] JCP&L – Jersey Central Power & Light Company								

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region	In-service Date
[vi] PSEG Fossil has a 50% interest in each of the Yards Creek facilities.								
[vii] CL&P – The Connecticut Light and Power Company.								
[viii] PSEG Power Ventures has a 100% ownership in PSEG Hackettstown LLC.								
[ix] PSEG Power Ventures has a 100% ownership interest in PSEG Solar Source LLC								
[x] All solar assets are using AC MW ratings. PSEG's previous triennial listed the DC ratings.								
[xi] PG&E -- Pacific Gas and Electric Company								
[xii] PSE&G started installations of pole units in September of 2009. As of November 30, 2016, a total of 174,630								

Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing (MW)**	**Rating: Methodology Used in [K]: (N)amplate, (S)easonal, 5-yr (U)nits, 5-yr (E)IA, (A)lternative**	**End Note Number (Enter text in End Notes Sheet**
NA*	NA*	NA*	
NA*	NA*	NA*	
775.2	775.2	N	
625.6	625.6	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
219.5	219.5	N	
219.5	219.5	N	
0.625	0.625	N	[i]
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
1	1	N	[ii]
1	1	N	
93.6	93.6	N	
1,290.70	1,290.70	N	
242	242	N	
242	242	N	
121	121	N	
213.8	213.8	N	
213.8	213.8	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
677.8	677.8	N	
677.8	677.8	N	
96.1	96.1	N	
96.1	96.1	N	
96.1	96.1	N	
96.1	96.1	N	
703.8	703.8	N	[iii]
688.5	688.5	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing (MW)	Rating: Methodology Used in [K]: (N)amplate, (S)easonal, 5-yr (U)nits, 5-yr (E)IA, (A)lternative	End Note Number (Enter text in End Notes Sheet
671.7	671.7	N	[iv]
671.7	671.7	N	
24	24	N	
110.8	110.8	N	
107.5	107.5	N	
107.5	107.5	N	
126.5	126.5	N	
69.3	69.3	N	[v]
69.3	69.3	N	[vi]
69.3	69.3	N	
399.5	399.5	N	
18.6	18.6	N	
60.5	60.5	N	[vii]
60.5	60.5	N	
60.5	60.5	N	
460.3	460.3	N	
893.2	893.2	N	
2	2	N	[viii]
12.6	12.6	N	[ix]
10.1	10.1	N	[x]
19	19	N	
12	12	N	
15	15	N	
1.5	1.5	N	[xi]
10.2	10.2	N	
2.2	2.2	N	
10.3	10.3	N	
19	19	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing (MW)	Rating: Methodology Used in [K]: (N)amplate, (S)easonal, 5-yr (U)nits, 5-yr (E)IA, (A)lternative	End Note Number (Enter text in End Notes Sheet
3	3	N	
20	20	N	
30	30	N	
50	50	N	
8	8	N	
5	5	N	
13.5	13.5	N	
30	30	N	
1.14	1.14	N	
0.64	0.64	N	
0.55	0.55	N N	
3	3	N	
3.7	3.7	N	
1.75	1.75	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing (MW)	Rating: Methodology Used in [K]: (N)amplate, (S)easonal, 5-yr (U)nits, 5-yr (E)IA, (A)lternative	End Note Number (Enter text in End Notes Sheet
0.76	0.76	N	
0.64	0.64	N	
1.5	1.5	N	
		N	
1.5	1.5	N	
1	1	N	
0.83	0.83	N	
		N	
0.5	0.5	N	
		N	
0.67	0.67	N	
3.5	3.5	N	
0.75	0.75	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing (MW)	Rating: Methodology Used in [K]: (N)amplate, (S)easonal, 5-yr (U)nits, 5-yr (E)IA, (A)lternative	End Note Number (Enter text in End Notes Sheet
2	2	N	
2.5	2.5	N	
2.5	2.5	N	
0.57	0.57	N	
2.5	2.5	N	
1	1	N	
1	1	N	
0.93	0.93	N	
38.5	38.5	N	[xii]
8.8	8.8	N	
7.9	7.9	N	
10	10	N	
1	1	N	
6.6	6.6	N	
2	2	N	

Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing (MW)**	**Rating: Methodology Used in [K]: (N)amplate, (S)easonal, 5-yr (U)nits, 5-yr (E)IA, (A)lternative**	**End Note Number (Enter text in End Notes Sheet**
panels and 38.5 MW capacity have been installed.			

Asset Appendix: Transmission/Natural Gas Assets
Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Ga
Location

Filing Entity and its Energy Affiliates	Cite to Order Accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Market / Balancing Authority Area	Geographic Region
PSEG ER&T	NA	NA	NA	NA	NA	NA	NA
PSEG Power CT	NA	NA	NA	NA	NA	NA	NA
PSEG New Haven	NA	NA	NA	NA	NA	NA	NA
PSEG Fossil	NA	NA	NA	NA	NA	NA	NA
PSEG Nuclear	NA	NA	NA	NA	NA	NA	NA
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	PSE&G	PJM	NA*	PJM	Northeast
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	Jointly Owned by PSE&G and others	PJM	NA*	PJM	Northeast
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	Owned by others	PJM	N/A*	PJM	Northeast
PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	PSE&G	PJM	NA*	PJM	Northeast
PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	Owned by others	PJM	NA*	PJM	Northeast

PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	Jointly Owned by PSE&G and others	PJM	N/A*	PJM	Northeast
PSE&G	96 FERC ¶ 61,061	Combined 230 kV Lines	PSE&G	PJM	NA*	PJM	Northeast
PSE&G	96 FERC ¶ 61,061	Combined 230kV Lines	Owned by Others	PJM	N/A	PJM	Northeast
PSE&G	96 FERC ¶ 61,061	Combined 138 kV Lines	PSE&G	PJM	NA*	PJM	Northeast
PSE&G	96 FERC ¶ 61,061	Combined 69 kV Lines	PSE&G	PJM	NA*	PJM	Northeast

as Storage Facilities	
Size	
Size (e.g., length and kV for electric, length and diameter for pipeline, and capacity for gas storage)	**End Note Number (Enter text in End Notes Sheet**
NA	NA
NA	NA
NA	NA
NA	NA
NA	NA
Approximately 272 combined miles.	
Approximately 151 combined miles.	
Approximately 64 combined miles	
Approximately 32 combined miles.	
Approximately 20 combined miles.	

Approximat
ely 3.76
combined
Miles

Approximat
ely 750
combined
miles.
Approximat
ely 39
combined
miles
Approximat
ely 228
combined
miles.
Approximat
ely 235
combined
miles.

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Asset Appendix: Long Term Purchased Power Agreements (PP/

			Location			
Filing Entity and its Energy Affiliates	Seller Name	Amount of PPA (MW)	Market / Balancing Authority Area (Source)	Market / Balancing Authority Area (Sink)	Geographic Region (Sink)	Start Date (mo/da/yr)

(i) does not include contracts entered into by PSE&G pursuant to State run Basic Generat

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A) (i)

End Date (mo/da/yr)	Type of PPA (Unit or System	End Note Number (Enter in Test in End Notes Sheet

ion Service auction

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PSEG
Services Corporation

By ELECTRONIC FILING
The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

May 25, 2018

Re: Notice of Non-Material Change in Status of PSEG Affiliates:

PSEG Energy Resources & Trade LLC	**ER10-1789-005**
PSEG Energy Solutions LLC	**ER10-1768-004**
PSEG Fossil LLC	**ER10-1770-004**
PSEG New Haven LLC	**ER10-1771-004**
PSEG Nuclear LLC	**ER10-1793-004**
PSEG Power Connecticut LLC	**ER12-1250-004**
Pavant Solar II LLC	**ER16-1924-002**
Bison Solar LLC	**ER16-1925-002**
San Isabel Solar LLC	**ER16-1926-002**
Public Service Electric and Gas Company	**ER16-2725-002**
PSEG Energy Solutions	**ER16-2725-002**
PSEG Keys Energy Center LLC	**ER17-2426-000**
(collectively, PSEG Affiliates)	

Dear Secretary Bose:

Pursuant to section 35.42(a)(1) of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[1] the PSEG Affiliates submit this notice of non-material change in status. On November 24, 2017, the Commission accepted for filing the application of PSEG Keys Energy Center LLC ("PSEG Keys") for market-based rate authority.[2] In addition, on November 21, 2017, the Commission accepted the PSEG Affiliates updated market power analysis for the Northeast region and granted the PSEG Affiliates continuing authority to sell electric energy, capacity and ancillary service at market-based rates.[3]

[1] 18 C.F.R. Part 35.42 (2017).

[2] *PSEG Keys Energy Center LLC*, Docket No. ER17-2426-000 (November 24, 2017).

[3] *PSEG Energy Resources & Trade LLC, et al*., Docket Nos. ER10-1789-000, *et al*., (November 21, 2017).

Accordingly, each of the PSEG Affiliates has been authorized to make market-based rate sales pursuant to a filed tariff.

The purpose of this filing is to supplement the information contained in PSEG Keys' application for market-based rate authority[4] to reflect the commencement of test power deliveries from the new 585 MW Sewaren 7 plant, which is targeted to be in operation in June 2018. This notice also reflects the retirements of Sewaren units 1, 2, 3 and 4, which will retire once Sewaren 7 begins commercial operation. This change does not affect the basis upon which the Commission relied when it granted PSEG Keys' application for market-based rate authorization or the updated market power analyses submitted in the Triennial Review supporting the market-based rate authorization for the other PSEG Affiliates.

I. DESCRIPTION OF THE PSEG AFFILIATES

A. PSEG Fossil Sewaren Urban Renewal LLC

PSEG Fossil Sewaren Urban Renewal LLC, New Jersey LLC ("PSEG Sewaren"), is a direct subsidiary of PSEG Fossil LLC ("PSEG Fossil"), which is a direct subsidiary of PSEG Power LLC ("PSEG Power"), a direct subsidiary of Public Service Enterprise Group Incorporated ("PSEG"), a publicly traded company. PSEG Sewaren constructed a new, natural gas-fired, power plant and related electrical facilities required for interconnection of the plant to electric grid, on property that it owns in Woodbridge, New Jersey (the "Sewaren 7").[5] Prior to becoming commercially operational, PSEG Sewaren leased Sewaren 7 to PSEG Fossil. The Sewaren 7 generating facilities comprise a highly-efficient, dual-fuel, combined-cycle plant with a nameplate rating of 585 MW. Sewaren 7 was first connected to the electric grid on April 27, 2018 and is expected to reach commercial operation in June, 2018. PSEG Fossil will be solely responsible for all operations and maintenance for Sewaren 7 under the lease, and will have exclusive control over decisions regarding dispatch or the submission of bids or offers for plant operation. The New Jersey electricity ratepayer is not subsidizing or guaranteeing any portion of the revenue of the plant. The plant will participate in the capacity and energy markets administered by PJM Interconnection, L.L.C. ("PJM") for wholesale electric generators. All of the output of the Sewaren 7 will be sold to PSEG Fossil's affiliate, PSEG Energy Resources & Trade LLC ("PSEG ER&T").

B. Public Service Electric and Gas Company ("PSE&G")

PSE&G is a public utility operating company engaged primarily in the transmission of electricity, and the provision of gas and electric distribution service in the State of New Jersey. During the study period, PSE&G owned less than 140 MW of solar generation, 8 MW of Energy Efficiency and 91 MWs of Demand Response but otherwise did not own or operate any electric generation facilities. PSE&G is a member of the PJM, a FERC-approved Regional Transmission Organization, and has made all of its transmission facilities available for open access transmission service pursuant to the Open Access Transmission Tariff ("OATT") administered

[4] PSEG Keys Energy Center LLC, Application for Market-based Rate Authorization and Request for Waivers and Blanket Approvals, Docket No. ER17-2426-000 (filed September 1, 2017, amended October 4, 2017) ("PSEG Keys Application").

[5] Once Sewaren 7 begins commercial operations, PSEG Fossil will retire Sewaren 1, 2, 3 and 4.

by PJM. PSE&G is authorized to sell power at market-based rates and makes wholesale sales falling within several different categories, as described below.

Non-utility generation ("NUG") output. PSE&G's NUG output expired in 2015 and 2016 pursuant to the terms of the NUG contracts. PSE&G currently has no further NUG obligations, other than 0.6 MW of energy associated with the former Kinsley Landfill which no longer operates.

Solar. In 2007, the New Jersey legislature passed Regional Greenhouse Gas Initiative ("RGGI") legislation authorizing state utilities to invest in renewable resources such as wind or solar in order to promote increased use of renewable resources within the state and in turn reduce greenhouse gas emissions. See L. 2007, c. 340, codified at N.J.S.A. 48:98-1. The New Jersey Board of Public Utilities ("NJBPU") has approved two (2) PSE&G Solar 4 All® (S4A) programs under which PSE&G has sited, designed and built twenty-nine (29) grid connected solar facilities. PSE&G currently owns and operates approximately 125 MW DC of grid connected solar under the S4A program. In 2016, PSE&G received NJBPU approval of its Solar 4 All Extension II filing to install an additional 33 MW-DC of grid connected solar on landfills and brownfields in the PSE&G electric service territory to begin in 2017.

C. PSEG Energy Resources & Trade LLC ("PSEG ER&T")

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil LLC ("PSEG Fossil") and PSEG Nuclear LLC ("PSEG Nuclear"), each wholly-owned subsidiaries of PSEG Power, as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission.[6]

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

1. Basic Generation Services ("BGS") Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 et seq., which initiated the transition from a regulated to a competitive retail power market in New Jersey, the NJBPU annually approves statewide auctions to determine the entities that will supply Basic Generation Service ("BGS") in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSEG ER&T has participated directly in all of the auctions for BGS supply held since 2004, has been a winning bidder in these auctions and has incurred contractual commitments to provide supply to BGS load pursuant to NJBPU approved contracts beginning with the 2004 auction and continuing to the present.

2. Basic Gas Supply Service ("BGSS") Gas Contract. By order issued April 16, 2002, the NJBPU approved a full requirements contract for the provision of gas supply

[6] *Public Service Electric and Gas Company, et al*., 88 FERC ¶ 61,299 (1999).

by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the NJBPU, PSEG ER&T assumed, through capacity release, FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract remains in effect and provides for annual renewals unless terminated by either party on 12 months' advance written notice.

3. Long Island Power Authority ("LIPA") Fuel Supply: On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which ER&T will provide fuel supply and power supply management activities for LIPA beginning on January 1, 2015.

D. PSEG Fossil

PSEG Fossil is an Exempt Wholesale Generator ("EWG")[7] and is authorized to sell power at market-based rates. PSEG Fossil owns and operates electric generation facilities located within PJM and sells their entire output to its affiliate PSEG ER&T.[8] The assets of PSEG Fossil (and its subsidiary, PSEG Sewaren) are located entirely within PJM. However, PSEG Fossil's subsidiaries PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Power New York LLC ("PSEG Power NY") and PSEG New Haven LLC ("PSEG New Haven") own facilities in ISO New England Inc. ("ISO-NE") and the New York Independent System Operator, Inc. ("NYISO"). As noted below, PSEG Fossil also co-owns certain facilities in PJM.

PSEG Fossil's subsidiaries, PSEG Power CT, PSEG Keys and PSEG Sewaren, are currently constructing three new gas-fired generation units. PSEG Sewaren is constructing Sewaren7,[9] which is a 585 MW (nameplate rating) combined cycle unit in Woodbridge, New Jersey which is expected to reach commercial operations in June 1, 2018. PSEG Power CT is constructing Bridgeport 5, a 485 MW combined cycle unit in Bridgeport, Connecticut which is expected to be in service in 2019. Once Sewaren 7 begins commercial operations, Sewaren 1, 2, 3 and 4 will be retired.

PSEG Fossil satisfies most of the electricity needs of its plants from PJM under PJM's "station power" Tariff provisions. PSEG Fossil procures gas supply for its plants from PSEG ER&T and receives gas distribution service from PSE&G at rates approved by the NJBPU on May 29, 2013.[10]

E. PSEG Power CT

[7] PSEG Fossil LLC, Docket No. EG00-3-000, 89 FERC ¶ 62,237 (December 20, 1999); PSEG Fossil LLC, 95 FERC ¶ 61,405 (June 14, 2001); PSEG Fossil LLC, 99 FERC ¶ 62,167 (June 10, 2002).

[8] These contracts were originally approved by the Commission as cost-based contracts. *See Public Service Electric and Gas Company*, et al., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Fossil obtained market based rate authority covering sales from its generating units.

[9] Once Sewaren 7 begins commercial operations, PSEG Fossil plans to retire Sewaren 1, 2, 3 and 4.

[10] NJBPU Docket No. GM12100935 (May 29, 2013).

PSEG Power CT is a Connecticut limited liability company and an EWG that owns and operates electric generation facilities in the State of Connecticut and is authorized to sell power at market-based rates.[11] Both of PSEG Power CT's generation facilities, Bridgeport Harbor and New Haven Harbor, are located in the State of Connecticut within the market administered by ISO-NE. PSEG Power CT sells the output of its generation facilities to its affiliate PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority. As noted above, PSEG Power CT is currently constructing Bridgeport 5, a 485 MW combined cycle unit in Bridgeport, Connecticut which is expected to be in service in 2019.

F. PSEG New Haven

PSEG New Haven is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG New Haven owns and operates a facility (the "New Haven facility") in New Haven, Connecticut with a nameplate rating of 181 MWs. The New Haven facility is located within the New Haven Harbor generation station. The New Haven facility is interconnected to the adjacent United Illuminating East Shore Substation using a 115 KV underground cable. PSEG New Haven has no other generation assets. The commercial operation date for the New Haven facility was June 1, 2012 and PSEG New Haven has obtained MBR authority from FERC.[12]

The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[13] pursuant to a Connecticut statute that sought proposals for peaking generation in Connecticut.[14] All of the energy and capacity of the New Haven facility is sold into the ISO-NE markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA[15] has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder. The 181 MW nameplate rating of the New Haven Facility was not included in PSEG's triennial analysis.

G. PSEG Nuclear

PSEG Nuclear is an EWG[16] and is authorized to sell power at market-based rates. PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire

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[11] *Wisvest Corporation,* et al., 101 FERC ¶ 61,166 (2002).

[12] *PSEG New Haven LLC*, Docket No. ER12-1250-000, *et al*., (May 29, 2012).

[13] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control. PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

[14] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

[15] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

[16] *PSEG Nuclear LLC*, 97 FERC ¶ 62,191 (November 30, 2001).

output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission.[17] The assets of PSEG Nuclear are located entirely within PJM.

H. Pavant Solar LLC, San Isabel Solar LLC and Bison Solar LLC

PSEG Power Ventures portfolio includes three (3) solar companies with market-based rate authority: (1) Pavant Solar II LLC[18] is a QF which owns a 50 MW (AC) solar facility in Fillmore Utah; (2) San Isabel Solar LLC[19] is a QF which owns a 30 MW (AC) solar facility in Las Animas County, Colorado; and (3) Bison Solar LLC[20] is a QF which owns a 30 MW (AC) solar facility 25 miles north of Fort Collins, Colorado.

I. PSEG Energy Solutions LLC

PSEG Energy Solutions LLC ("PSEG Solutions") is a Delaware limited liability company and a direct subsidiary of PSEG ER&T. PSEG Solutions obtained market-based rate authority[21] and will operate within the PJM, NYISO and ISO-NE markets. PSEG Solutions will purchase power from the regional transmission organization ("RTO") at wholesale and sell it to retail customers. PSEG Solutions will not own or operate any generation assets. PSEG Solutions began its retail business in 2017.

II. Affiliated Generation Ownership

A list of the Applicants' affiliated domestic FERC jurisdictional generation assets owned is contained in Appendix B attached hereto.[22] Those additional subsidiaries of PSEG that may be considered relevant to this request are described below:

(1) Public Service Enterprise Group Incorporated ("PSEG"). PSEG, a New Jersey corporation, is a public utility holding company engaged in, among other things, the generation of electric energy and the transmission, distribution and sale of electricity and natural gas through its subsidiaries.

(2) PSEG Power LLC. PSEG Power was formed in 1999 to acquire the former generation assets of PSE&G. PSEG Power, a Delaware limited liability company, does not directly own any generation facilities or engage in any FERC jurisdictional activities but is the parent company of several FERC jurisdictional entities, including Applicants PSEG ER&T (and

[17] *Public Service Electric and Gas Company, et al.,* 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Nuclear obtained market-based rate authority.

[18] *Pavant Solar II LLC*, Docket No. QF16-1072-000.

[19] *San Isabel Solar LLC*, Docket No. QF16-712-000.

[20] *Bison Solar LLC*, Docket No. QF16-711-001.

[21] *See* Letter Order dated December 21, 2016 in Docket No. ER16-2725-000.

[22] Appendix B excludes generation assets located in Hawaii as well as generation assets in which PSEG's interest is limited to a leveraged lease interest. *See* PSEG Keys Application, Docket No. ER17-2426, attached Appendix B.

its subsidiary PSEG Solutions), PSEG Fossil, PSEG Nuclear, PSEG Power CT, PSEG New Haven and PSEG Power Ventures (which owns PSEG Solar Source).

(3) PSEG Power Ventures LLC ("Power Ventures") and PSEG Solar Source LLC. PSEG Power Ventures is a Delaware Limited Liability company and a direct subsidiary of PSEG Power. PSEG Power Ventures owns 100% interest in PSEG Solar Source and has an indirect ownership interest in a domestic power plant in Hawaii. PSEG Solar Source owns approximately 414 MWs DC (325 MW AC) of solar capacity across the United States, including a combined 146 MWs[23] (113 MW AC) of solar capacity in PJM and approximately the following amount of MWs in the following states, all through separate project companies which have obtained QF status.

- 15 MWs (12 MW AC) in Florida
- 146 MWs in PJM (113 MW AC) – 12 MW in Ohio, 2 MW in New Jersey, 15 MW in Delaware, 103 MW in North Carolina and 13 MW in Maryland
- 45 MWs in Arizona (34 MW AC) – 25 MW Queen, approximately 20 MW Badger
- 13 MWs (10 MW AC) in Texas
- 34 MWs (25 MW AC) in California[24]
- 4 MWs (3 MW AC) in Vermont and
- 74 MWs (60 MW AC) in Colorado – 38 MW (San Isabel) and 36 MW (Bison)
- 62 MW (50 MW AC) in Utah
- 10.5 MW (8 MW AC) in Oregon
- 103 MW (79 MW AC) in North Carolina
- 11 MW DC (9 MW AC) in Long Island NY

(4) PSEG Resources LLC ("Resources"). Resources is a New Jersey limited liability company that provides energy infrastructure financing in developed countries. Resources invests primarily in energy-related financial transactions and manages a diversified portfolio of investments including leveraged leases. Resources owns interests, through leveraged leases, in various generation stations. Pursuant to the terms of these triple net leases, the lessee, not Resources, has all operational responsibility and control over the leased generation stations.

(5) PSEG Power NY. PSEG Power NY is a Delaware limited liability company and an EWG that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 750 MW (nameplate rating) combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a FERC-approved cost-based contract.[25]

[23] The 146 MWs are attributed to four (9) separate project companies that have QF status: PSEG Solar Hackettstown LLC (2 MW); PSEG Solar Delaware LLC (15 MW), Rockfish Solar LLC (13 MWs), Meadows Solar (26 MW), Turkey Creek (17 MW) Hemlock Solar (7 MW), Cork Oak (26 MW), Sunflower (21 MW) in North Carolina and PSEG Solar Ohio LLC (12 MW).

[24] The 28 MWs (DC) are associated with the Shasta Solar Facility in California (4 MW), Whitethorn Solar (3 MWs) the Columbia Solar Project (34 MW). All have obtained QF status.

[25] *PSEG Power New York Inc.*, Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

(6) PSEG Keys. PSEG Keys is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG Keys was formed to construct, operate and maintain the Keys Energy Center, a 755MW combined cycle power plant in Prince Georges County, Maryland. Construction began in 2015 and is expected to be completed by June 1, 2018 at which time the capacity and energy will be available in the PJM market. All of the output of the Keys Energy Center will be sold to PSEG Keys affiliate, PSEG ER&T.

(7) PSEG Long Island LLC ("Long Island") and Long Island Electric Utility Servco, LLC ("Servco"). Long Island and Servco are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution system ("T&D") on Long Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither Long Island nor Servco are FERC jurisdictional public utilities as neither exercises ultimate decision making authority over the T&D system in Long Island. Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[26]

III. Affiliated Transmission Ownership

With the exception of the electric transmission assets owned by PSE&G, all of which are located within the PJM RTO, and the generation interconnection facilities owned by the various EWG and QF affiliates listed herein, none of the PSEG Affiliates own or operate FERC jurisdictional electric or natural gas transmission facilities within the United States. As discussed below, FERC granted PSE&G a Hinshaw exemption in 1954, finding that it was exempt from the provisions of the Natural Gas Act.

A. Jointly Owned Facilities

PSEG Nuclear is a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear is the operator of Salem and Exelon Generation is the operator of Peach Bottom. PSEG Fossil is approximately a 23% joint owner in the Conemaugh and Keystone generating stations located in Pennsylvania. As of the date of this filing, an affiliate of NRG Energy is the operator. Accordingly, for purposes of the December 2016 triennial analysis, the capacity of Salem, Peach Bottom, Conemaugh and Keystone was attributed to PSEG in accordance with PSEG's ownership interests in these facilities.

PSEG Fossil and Jersey Central Power and Light Company ("JCP&L") are each 50% co-owners of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to the unit. Accordingly, for the purpose of the December 2016 triennial market power analysis, the entire unit capacity – nominally 400 MWs – was assigned to JCP&L.

IV. NOTICE OF CHANGE IN STATUS

[26] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), *order dismissing request for rehearing*, 145 FERC ¶ 61,183 (2013).

The PSEG Affiliates submit this Notice of Change in Status to report to the Commission its addition of Sewaren 7 to the generation fleet attributable to PSEG Fossil. Sewaren 7 is a highly efficient, dual-fuel 585 MW combined-cycle plant (nameplate) that is targeted to be in-service in June, 2018. Once Sewaren 7 is in-service, Sewaren 1-4 will be retired.

The addition of Sewaren 7 and the retirements of Sewaren 1-4 results in an increase in excess of 100 MW in the PSEG Affiliate's generation capacity, but does not materially affect the conditions the Commission relied upon in granting PSEG Keys' market-based rate authority or the PSEG Affiliates' Triennial application. As discussed further below, the addition of Sewaren 7 and retirements of Sewaren 1-4 raises no market power concerns. While the PSEG Affiliates understand that the submission of indicative screens is not required for this change in status,[27] the PSEG Affiliates nevertheless submit the indicative screens to show that the addition of Sewaren 7 and retirements of Sewaren 1-4 does not have a material impact on the PSEG Affiliates market power.

V. UPDATED MARKET-BASED RATE ANALYSIS

As demonstrated in the attached market power screens, the PSEG Affiliates continue to lack market power in generation, despite adding Sewaren 7's generation capacity and retiring Sewaren 1-4's generation capacity. Further, PSEG Affiliates' addition of Sewaren 7 has no material impact on the vertical market power analysis submitted to the Commission in the PSEG Keys' application.

A. Horizontal Market Power

The Commission evaluates whether a seller can exercise horizontal market power in a relevant market through two indicative screens: (1) a pivotal supplier analysis; and (2) a wholesale market share analysis. If a seller passes both screens, there will be a rebuttable presumption that the seller lacks market power.[28] Each indicative screen is applied with respect to the "relevant geographic markets" for an applicant's generating units. The Commission requires that an applicant seeking market-based rate authority show it does not possess horizontal market power by demonstrating that it and its affiliates can pass the market power screen, "unless the seller and its affiliates do not own or control generation capacity or all of their capacity is fully committed."

Applicants that are located in ISOs/RTOs possessing sufficient market structure may consider the geographic region under the control of the ISO/RTO as the relevant default geographic region for purposes of completing their generation market power analyses. However, where the Commission has previously found a "submarket" to exist within a boundary of an RTO, such finding is controlling as to the scope of the relevant geographic market for all generation units located within that submarket for the application of the indicative screens and any delivered price test that may be performed. The Commission further listed several such submarkets, including PJM East ("PJME"), PJM East of 5004/5005 ("PJM50") and PJM East of

[27] *See Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 816, 153 FERC ¶ 61,065, at P 293 (2015), *order on reh'g and clarify*., Order No. 679-A. 155 FERC ¶ 61,188 (2016).

[28] 18 C.F.R. § 35.37(c)(1) (2011).

AP South ("PJMAP") that would be relevant to an MBR analysis for applicants in the Northeast Region.

As shown in the attached Appendix C, Dr. John Morris has updated the market power analysis that was submitted in the December 2016 Triennial Filing[29] and the market power study for the PJM market and relevant submarkets that were submitted on September 1, 2017 in support of PSEG Keys Application.[30] Specifically, Dr. Morris has updated the market-based rate screens contained in the PSEG Keys Application to account for the addition of the 585 MWs from the PSEG Sewaren unit and the retirements of the Sewaren 1-4 units at the same location (452.3 MWs). Dr. Morris also moved the test year of the analysis forward by one year from December 2014-November 2015 to December 2015-November 2016 because this is the latest period for which FERC Form 714 data on unplanned generator outages is available.[31] Dr. Morris also updated the overall market sizes of the PJM market and submarkets, along with the first tier areas of NYISO and MISO.[32] Finally, Dr. Morris updated load data both for the applicant and for the overall markets in the study.[33] All methods are the same as in Dr. Morris' December 2016 Affidavit.

Dr. Morris' updated analysis shows that there has been a minor decrease in the market power with the addition of Sewaren 7 since the September 2017 PSEG Keys Application. This minor decrease should not be viewed to impact the factors that Dr. Morris relied upon in his findings in either the PSEG Keys MBR Filing or the December 2016 Triennial Filing that the PSEG Affiliates with market-based rate authority have satisfied the requirements demonstrating that they lack horizontal and vertical market power. Specifically, Dr. Morris analysis shows that with the addition of Sewaren 7, the PSEG Affiliates pass all of the pivotal supplier analysis ("PSA") screens for all of the relevant markets, namely, PJM, PJMAP, PJME and PJM50.[34]

Dr. Morris' analysis also shows that the PSEG Affiliates pass two additional screens as compared to the PSEG Keys Application in the wholesale market share analysis ("WMSA").[35]

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[29] PSEG Energy Resources & Trade LLC, *et al*., Docket Nos. ER10-1789-000, *et al*., (filed December 29, 2016) ("December 2016 Triennial Filing"), attached Exhibit A, Report of Affidavit of Dr. John R. Morris ("December 2016 Affidavit"); PSEG Keys Energy Center LLC, Docket No. ER17-2426-000 (filed September 1, 2017 and amended on October 4, 2017); attached Appendix G, Affidavit of John Morris.

[30] *See* PSEG Keys Application attached Appendices A-1, A-2.

[31] PSEG Energy Resources & Trade LLC, *et al*., Notice of Non-material Change in Status, Docket No. ER18-__-000, (filed May 25, 2018), attached Appendix C, Affidavit of Dr. John R. Morris P 2 ("Morris Affidavit").

[32] *Id.*

[33] *Id.*

[34] *See* attached Appendix A-1. The pivotal supplier analysis ("PSA") focuses on the ability of a seller to exercise unilateral market power. The screen assesses whether market demand can be met during peak times without the applicant and its affiliates. If demand can be met without the applicant and its affiliates, the applicant passes that the PSA screen.

[35] *Id.* The wholesale market share analysis ("WMSA") is applied each season to determine whether an applicant has a dominant market position based on the total number of megawatts of uncommitted capacity owned or controlled by the applicant and its affiliates in relation to the uncommitted capacity of the entire relevant

Notably, in the updated analysis, the PSEG Affiliates now pass the PJM50 for summer and fall. As a result, we submit that Dr. Morris' determination that the PSEG Affiliates could not exercise horizontal market power still stands with the addition of Sewaren 7 (and the retirement of Sewaren 1-4). As stated by Dr. Morris in his affidavit:

> Although there are some minor differences in the results from those presented with the December Affidavit, the differences are not material and do not change the conclusions made at that time. Under the standards utilized by the Commission, continuing market-based rates for PSEG and all of its Northeastern affiliates remain in the public interest. In addition, granting market-rate authority to the Sewaren LLC would also be in the public interest.[36]

Moreover, to the extent necessary, the PSEG Affiliates rely on the same PJM RTO monitoring and mitigation described in the December 2016 Triennial Filing to show that they have met the standards necessary to obtain market-based rate authority. Accordingly, it is clear that with the addition of Sewaren 7 that PSEG Fossil and the other PSEG Affiliates continue to satisfy the standards necessary for market-based rate authority.

B. Vertical Market Power

1. The Applicants Lack Transmission Market Power and Cannot Erect Entry Barriers.

In its previous order accepting PSEG Affiliates' triennial market power analysis for the Northeast Region, the Commission found that the submittal satisfied the Commission's requirements for market-based rates regarding vertical market power.[37] As demonstrated below, the PSEG Affiliates are not able to exercise vertical market power.

PSE&G is the only PSEG Affiliate that owns transmission assets in the U.S. other than incidental generator interconnection facilities. PSE&G owns transmission facilities in PJM, but transmission service over those facilities is provided under the PJM Open Access Transmission Tariff.

In addition, none of the PSEG Affiliates are able to exercise vertical market power in wholesale energy markets through affiliation, ownership or control of inputs to electric power production. As required by Section 35.37(e) of the Commission's regulations, the PSEG Affiliates provide the following information:

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wholesale electricity market. The established threshold is 20 percent; a supplier who has less than 20 percent market share in the relevant market for all seasons passes the WMSA screen.

[36] Morris Affidavit PP 4, 6.

[37] *PSEG Energy Resources & Trade, LLC, et al,* Letter Order, June 29, 2011, Docket No. ER99-3151-017. In addition, in that letter order the Commission found that the submittal satisfied the Commission's requirements for market-based rates regarding horizontal market power.

(a) PSE&G owns and operates a natural gas distribution system that receives interstate pipeline gas within the State of New Jersey and distributes that gas to its customers within the State of New Jersey. The distribution system consists of approximately 18,050 miles of gas distribution pipe and an additional 62 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3 and peak-shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers. Service over such distribution facilities is made available pursuant to state regulated tariffs on an open access type basis. PSE&G was granted a Hinshaw exemption from the FERC in 1954.[38] The gas distribution rates paid by PSEG Fossil to PSE&G have been set at rates approved by the NJBPU in an order dated May 29, 2013.

(b) Certain of the PSEG Affiliates or their affiliates own sites within the Northeast Region that would be suitable for future generating facilities. These include space at many of the existing generating sites of PSEG Fossil and at the sites of PSEG Power NY and PSEG Power CT. PSEG Nuclear's Salem facility may also be suitable for future construction. PSE&G also owns certain sites that would be suitable for generating facilities, but under New Jersey's Electric Discount and Energy Competition Act, N.J.S.A 48:3-43 et seq., PSE&G is effectively barred from owning and operating generation except "on site" generation and Class I renewable energy resources as defined in N.J.S.A. 48:3-98.1.

(c) Neither the PSEG Affiliates nor any of their affiliates own or control any physical coal supply resources or own or control who may access transportation of coal supplies.

(d) As required by section 35.37(e)(4) of the Commission's regulations, the PSEG Affiliates state that they have not erected barriers to entry into any market, including the PJM, NYISO or ISO-NE market and will not erect barriers to entry into any markets.

VI. DOCUMENTS SUBMITTED WITH FILING

The following documents are submitted with this application.[39]

Appendix A-1: Summary of Market Power Analysis for PJM
Appendix A-2: Market Power Analysis for PJM
Appendix B: December 2016 Triennial Filing
Appendix C: Affidavit of John Morris

VII. CONCLUSION

Based on the foregoing, the PSEG Affiliates submit that, with the addition of Sewaren 7 and retirements of Sewaren 1-4, they continue to lack horizontal and vertical market power and otherwise continue to satisfy the Commission's market-based rate eligibility criteria. In short,

[38] 13 F.P.C. 1348 (1954).

[39] In the event that the Commission deems it necessary to submit an Appendix B (generation assets), the PSEG Affiliates request waiver of such requirement given that the asset appendix would be the same as the one submitted in the PSEG Keys Application, but for the inclusion of the 585 MWs for Sewaren 7 and the retirements of Sewaren 1, 2, 3 and 4 (452.3 MWs).

adding Sewaren 7 to the PSEG Affiliates generation assets raises no market power concerns and does not materially affect the conditions the Commission relied on in granting PSEG Keys' and the PSEG Affiliates' demonstrations in the Triennial Review for the continuation of authorization to sell energy, capacity, and certain ancillary services at market-based rates.

Respectfully submitted,

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Dated: May 25, 2018

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ATTACHMENT A-1

PSEG MBR Change in Status - Sewaren

	PSA		WMSA							
			Winter		Spring		Summer		Fall	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result
PJM Interconnection	38,360	Pass	7.2	Pass	6.1	Pass	6.5	Pass	6.5	Pass
PJM East	4,274	Pass	26.5	Fail	22.1	Fail	25.7	Fail	24.1	Fail
PJM East of 5004/05	5,937	Pass	20.5	Fail	18.0	Pass	19.8	Pass	19.6	Pass
PJM East of AP South	10,506	Pass	14.6	Pass	12.7	Pass	14.2	Pass	13.6	Pass

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ATTACHMENT A-2

Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	9,378	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	195	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	1,943	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	70	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	186,588	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	1,943	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	195	Row B; Table2Data
H	Uncommitted Capacity Imports	7,530	Calculated
I	Study Area Reserve Requirement	8,674	Gendata
J	Amount of Line I Attributable to Seller, if any	228	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	62,196	
	Load		
L	Balancing Area Annual Peak Load	152,177	Loads
M	Average Daily Peak Native Load in Peak Month	132,696	Loads
N	Amount of Line M Attributable to Seller, if any	3,073	SellerLoads
O	Wholesale Load (L-M)	19,482	
P	Net Uncommitted Supply (K-O)	42,715	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,399	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	7,600	
	% of SIL for Seller's imported capacity →	0.01	
	% of SIL for Other's imported capacity →	0.99	
	SIL Value →	7600	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	6,650	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	14	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	152	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	27,691	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	14	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,385	Calculated
I	Study Area Reserve Requirement	1,767	Gendata
J	Amount of Line I Attributable to Seller, if any	202	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	13,259	
	Load		
L	Balancing Area Annual Peak Load	30,992	Loads
M	Average Daily Peak Native Load in Peak Month	25,852	Loads
N	Amount of Line M Attributable to Seller, if any	2,695	SellerLoads
O	Wholesale Load (L-M)	5,139	
P	Net Uncommitted Supply (K-O)	8,120	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	3,890	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,537	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	6537	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,418	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	105	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	52,989	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,214	Calculated
I	Study Area Reserve Requirement	3,049	Gendata
J	Amount of Line I Attributable to Seller, if any	210	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	18,909	
	Load		
L	Balancing Area Annual Peak Load	53,493	Loads
M	Average Daily Peak Native Load in Peak Month	44,768	Loads
N	Amount of Line M Attributable to Seller, if any	2,992	SellerLoads
O	Wholesale Load (L-M)	8,725	
P	Net Uncommitted Supply (K-O)	10,184	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,293	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,319	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	6319	
	Do Total Imports exceed the SIL Value? →	No	

SI-SSA-0010-4772

Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,418	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	88	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	80,051	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,367	Calculated
I	Study Area Reserve Requirement	4,162	Gendata
J	Amount of Line I Attributable to Seller, if any	210	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	26,286	
	Load		
L	Balancing Area Annual Peak Load	73,026	Loads
M	Average Daily Peak Native Load in Peak Month	61,476	Loads
N	Amount of Line M Attributable to Seller, if any	2,992	SellerLoads
O	Wholesale Load (L-M)	11,550	
P	Net Uncommitted Supply (K-O)	14,736	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,275	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	4,455	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	4455	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	10,859	10,119	9,378	10,119	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	195	195	195	195	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	1,643	1,944	1,943	1,944	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	452	1,512	93	1,131	SellerGendata
E	Uncommitted Capacity Imports	91	89	68	53	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	99,674	86,411	116,161	92,587	Loads
G	Amount of Line F Attributable to Seller, if any	1,573	1,308	2,340	1,568	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	98,102	85,102	113,821	91,019	F - G
I	Study Area Reserve Requirement	6,756	6,230	8,317	6,641	Gendata
J	Amount of Line I Attributable to Seller, if any	119	117	202	143	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	6,637	6,113	8,116	6,498	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	193,335	189,962	186,588	189,962	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	1,643	1,944	1,943	1,944	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	195	195	195	195	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	8,043	28,377	1,841	21,225	Gendata; Row D
P	Uncommitted Capacity Imports	11,906	12,184	7,532	7,014	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	93,908	84,302	72,090	79,982	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,359	5,522	5,064	5,580	
S	Total Seasonal Uncommitted Capacity (Q+R)	101,266	89,823	77,154	85,562	
T	**Applicant's Market Share** (R÷S)	7.3%	6.1%	6.6%	6.5%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	11,997	12,273	7,600	7,067	
V	SIL Value	11,997	12,273	7,600	7,067	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,182	7,416	6,650	7,416	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	22	14	14	14	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	340	1,108	66	829	SellerGendata
E	Uncommitted Capacity Imports	156	135	128	113	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	16,761	14,806	21,675	16,148	Loads
G	Amount of Line F Attributable to Seller, if any	1,499	1,253	2,058	1,350	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	15,261	13,553	19,617	14,798	F - G
I	Study Area Reserve Requirement	1,150	1,117	1,651	1,345	Gendata
J	Amount of Line I Attributable to Seller, if any	113	112	177	123	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	1,037	1,005	1,473	1,222	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	27,568	27,630	27,691	27,630	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	22	14	14	14	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,147	4,127	273	3,087	Gendata; Row D
P	Uncommitted Capacity Imports	7,346	8,695	6,409	7,746	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	17,491	17,653	12,750	16,282	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	6,364	5,064	4,463	5,214	
S	Total Seasonal Uncommitted Capacity (Q+R)	23,854	22,717	17,213	21,496	
T	**Applicant's Market Share** (R÷S)	26.7%	22.3%	25.9%	24.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	7,502	8,830	6,537	7,859	
V	SIL Value	7,502	8,830	6,537	7,859	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,951	8,185	7,418	8,185	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	372	1,223	73	914	SellerGendata
E	Uncommitted Capacity Imports	118	69	95	61	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	31,965	27,526	38,884	30,032	Loads
G	Amount of Line F Attributable to Seller, if any	1,524	1,270	2,340	1,568	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	30,441	26,256	36,544	28,465	F - G
I	Study Area Reserve Requirement	2,203	2,058	2,874	2,416	Gendata
J	Amount of Line I Attributable to Seller, if any	115	114	202	143	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,088	1,944	2,672	2,273	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	53,711	53,350	52,989	53,350	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	2,234	7,970	523	5,961	Gendata; Row D
P	Uncommitted Capacity Imports	7,986	8,224	6,224	6,042	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	26,970	25,434	19,502	22,722	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,022	5,618	4,870	5,591	
S	Total Seasonal Uncommitted Capacity (Q+R)	33,992	31,052	24,372	28,313	
T	**Applicant's Market Share** (R÷S)	20.7%	18.1%	20.0%	19.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	8,104	8,293	6,319	6,103	
V	SIL Value	8,104	8,293	6,319	6,103	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,951	8,185	7,418	8,185	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	372	1,223	73	914	SellerGendata
E	Uncommitted Capacity Imports	140	90	81	74	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	44,121	37,780	53,385	41,231	Loads
G	Amount of Line F Attributable to Seller, if any	1,524	1,270	2,340	1,568	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	42,598	36,510	51,045	39,663	F - G
I	Study Area Reserve Requirement	3,105	2,881	3,898	3,332	Gendata
J	Amount of Line I Attributable to Seller, if any	115	114	202	143	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,990	2,767	3,696	3,189	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	82,251	81,151	80,051	81,151	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,422	12,123	790	9,067	Gendata; Row D
P	Uncommitted Capacity Imports	7,757	8,766	4,374	5,994	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	41,035	38,546	28,922	35,255	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,044	5,639	4,856	5,604	
S	Total Seasonal Uncommitted Capacity (Q+R)	48,079	44,185	33,778	40,859	
T	**Applicant's Market Share** (R÷S)	14.7%	12.8%	14.4%	13.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,897	8,856	4,455	6,068	
V	SIL Value	7,897	8,856	4,455	6,068	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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ATTACHMENT B

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PSEG Services Corporation

December 28, 2016

ELECRONICALLY AND VIA OVERNIGHT MAIL

Kimberly J. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Triennial Market Power Update in Compliance with Order No. 697:
***PSEG Energy Resources & Trade LLC*, Docket No. ER99-3151-____;**
***Public Service Electric and Gas Company*, Docket No. ER97-837-____;**
***PSEG Power Connecticut LLC*, Docket No. ER03-327 -___;**
***PSEG Fossil LLC*, Docket No. ER08-447-___;**
***PSEG Nuclear LLC*, ER08-448-___; and**
***PSEG New Haven LLC*, ER12-1250-___**
Pavant Solar II LLC, ER16-1925-___
San Isabel Solar LLC, ER16-1926-___
Bison Solar LLC, ER16-1924-___
PSEG Energy Solutions LLC, ER16-2725-___

Dear Secretary Bose:

Pursuant to the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), PSEG Energy Resources & Trade LLC ("PSEG ER&T"), Public Service Electric and Gas Company ("PSE&G"), PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Fossil LLC ("PSEG Fossil"), PSEG Nuclear LLC ("PSEG Nuclear"), PSEG New Haven LLC ("PSEG New Haven") Pavant Solar II LLC, San Isabel Solar LLC, Bison Solar LLC and PSEG Energy Solutions LLC (collectively the "Applicants" or "PSEG") hereby jointly submit for filing their updated market power analysis in support of their continued eligibility to engage in market-based rates

transactions. This market power analysis satisfies the requirements of Order No. 697[1] for the filing of updated market power analyses on a regional schedule basis by holders of market-based rate certificates and their affiliates. In accordance with the regional schedule for those utilities in the Northeast Region, as modified by the MBR Clarifying Order, this filing is being made by the December 2016 deadline.[2] In conformance with the Commission's requirements, except when expressly noted otherwise, the market power analysis is based on activity during the study period from December 1, 2014 through November 30, 2015 ("study period").

PSEG, through its subsidiary PSE&G, owns transmission facilities within the Northeast Region. Specifically, PSE&G owns transmission facilities in the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization. PSEG Power LLC and its subsidiaries do not own any transmission facilities other than transmission to connect generating units to the grid in PJM, the New York Independent System Operator, Inc. ("NYISO") and ISO New England Inc. ("ISO-NE").

In their original applications for market-based rate authority and previously-submitted updates to the Commission, PSEG ER&T, PSE&G, PSEG Power CT, PSEG Fossil, PSEG Nuclear and PSEG New Haven demonstrated that they and their affiliates: (a) do not exercise generation market power; (b) lack the ability to manipulate access to transmission facilities that they own or control; and (c) cannot erect any other barriers to market entry. As further demonstrated herein and in the Affidavit of Dr. John R. Morris attached hereto in the appendices, Applicants continue to satisfy the Commission's requirements to sell energy, capacity and ancillary services at market-based rates and thus should be permitted to continue to make such sales.

I. SERVICE AND COMMUNICATION

All service and correspondence related to this matter should be directed to the following individuals:

[1] 18 C.F.R. Part 35, Subpart H (2007); Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, 119 FERC ¶ 61,295, ("Order No. 697" or "MBR Order"), *order clarifying final rule*, 121 FERC ¶ 61,260 (2007) ("MBR Clarifying Order"), *order on reh'g and clarification*, 123 FERC ¶ 61,055 (2008) FERC Stats. & Regs ¶ 31,268 ("Order No. 697-A"), *order on reh'g and clarification*, 124 FERC ¶ 61,055 (2008) ("SIL Allocation Order").

[2] This filing is made on the three year anniversary of the December 2013 deadline set forth in Order No. 697 Appendix D.

As to the Applicants Generally:

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Applicants request waiver of Rule 203(b)(3)[3] so that a copy of any communications in these proceedings may be served on all persons listed above.

II. DESCRIPTION OF THE APPLICANTS AND RELEVANT AFFILIATES

A. The Applicants

The Applicants are each wholly owned, direct and indirect subsidiaries of Public Service Enterprise Group Incorporated ("PSEG"). PSEG is a public utility holding company engaged in, among other things, the generation of electric energy and the transmission, distribution and sale of electricity and natural gas through its subsidiaries.

1. Public Service Electric and Gas Company

PSE&G is a public utility operating company engaged primarily in the transmission of electricity, and the provision of gas and electric distribution service in the State of New Jersey. During the study period, PSE&G owned less than 140 MW of solar generation, 8 MW of Energy Efficiency and 91 MWs of Demand Response but otherwise did not own or operate any electric generation facilities. PSE&G is a member of the PJM Regional Transmission Organization and has made all of its transmission facilities available for open access transmission service pursuant to the PJM Open Access

[3] 18 C.F.R. § 385.203(b)(3).

Transmission Tariff ("OATT") administered by PJM. PSE&G is authorized to sell power at market-based rates and makes wholesale sales falling within several different categories, as described below.

Non-utility generation ("NUG") output. PSE&G's NUG output expired in 2015 and 2016 pursuant to the terms of the NUG contracts. PSE&G currently has no further NUG obligations, other than 0.6 MW of energy associated with the former Kinsley Landfill which no longer operates. .

Solar. In 2007, the New Jersey legislature passed Regional Greenhouse Gas Initiative ("RGGI") legislation authorizing state utilities to invest in renewable resources such as wind or solar in order to promote increased use of renewable resources within the state and in turn reduce greenhouse gas emissions. *See* L. 2007, c. 340, codified at N.J.S.A. 48:98-1. The NJBPU has approved two (2) PSE&G Solar 4 All® (S4A) programs under which PSE&G has sited, designed and built twenty-nine (29) grid connected solar facilities. PSE&G currently owns and operates approximately 115MW-dc of grid connected solar under the S4A program. PSE&G expects the S4A fleet to increase to approximately 125MW-dc by the end of 2016. In 2016, PSE&G received NJBPU approval of its Solar 4 All Extension II filing to install an additional 33MW-dc of grid connected solar on landfills and brownfields in the PSE&G electric service territory.

2. PSEG Energy Resources & Trade LLC

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil and PSEG Nuclear, each wholly-owned subsidiaries of PSEG Power LLC ("PSEG Power"), as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission.

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

BGS Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 *et seq.,* which initiated the transition from a regulated to a competitive retail power market in New Jersey, BPU annually approves statewide auctions to determine the entities that will supply Basic Generation Service ("BGS") in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSEG ER&T has participated directly in all of the auctions for BGS supply held since 2004, has been a winning bidder in these auctions and has incurred contractual

commitments to provide supply to BGS load pursuant to BPU approved contracts beginning with the 2004 auction and continuing to the present

BGSS Gas Contract. By order issued April 16, 2002, the BPU approved a full requirements contract for the provision of gas supply by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the BPU, PSEG ER&T assumed, through capacity release, FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract remains in effect and provides for annual renewals unless terminated by either party on 12 months' advance written notice.

LIPA Fuel Supply: On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which ER&T will provide fuel supply and power supply management activities for LIPA beginning on January 1, 2015.

3. PSEG Fossil LLC

PSEG Fossil is an Exempt Wholesale Generator ("EWG") and is authorized to sell power at market-based rates. PSEG Fossil owns and operates electric generation facilities located within PJM and sells their entire output to its affiliate PSEG ER&T.[4] The assets of PSEG Fossil (and its subsidiary, PSEG Keys Energy Center LLC ("PSEG Keys")) are located entirely within PJM. However, PSEG Fossil's subsidiaries PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Power New York LLC and PSEG New Haven LLC own facilities in ISO-NE and NYISO. As noted below, PSEG Fossil also co-owns certain facilities in PJM.

PSEG Fossil and its subsidiaries PSEG Power CT and PSEG Keys are currently beginning construction on three new gas-fired generation units. PSEG Fossil is constructing Sewaren 7[5] which is a 540 MW combined cycle unit in Woodbridge, New Jersey which is expected to be in-service in 2018, PSEG Keys is constructing a 755 MW combined cycle unit in Prince George's County, Maryland which is expected to be in service in 2018 and PSEG Power CT is constructing Bridgeport 5, a 485 MW combined cycle unit in Bridgeport, Connecticut which is expected to be in service in 2019.

Since the last triennial filing in December 2013 PSEG Fossil has retired 1,813.5 MWs (nameplate) inclusive of the following units:

Kearny 9 (18.6 MW)
Bergen 3 (18.6 MW)

[4] These contracts were originally approved by the Commission as cost-based contracts. *See Public Service Electric and Gas Company*, et al., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Fossil obtained market based rate authority covering sales from its generating units.

[5] Once Sewaren 7 begins commercial operation, PSEG Fossil plans to retire Sewaren 1, 2, 3 and 4.

Bridgeport 2 (179.5 MW)
Burlington 8 (18.6 MW
Burlington 9 (162.4 MW)
Burlington 11 (162.4 MW)
Edison 1 (167.4 MW)
Edison 2 (167.4 MW)
Edison 3 (167.4 MW)
Essex 10 (167.4 MW)
Essex 11 (167.4 MW)
Essex 12 (167.4 MW)
Mercer 3 (115.2 MW)
National Park (18.6 MW)
Sewaren 6 (115.2 MW)

In addition, PSEG Fossil, LLC notified PJM of its intent to retire Hudson 2 (659 MW nameplate rating) and Mercer Units 1 and 2 (652MW nameplate rating) by June 1, 2017.

PSEG Fossil satisfies most of the electricity needs of its plants from PJM under PJM's "station power" Tariff provisions. PSEG Fossil procures gas supply for its plants from PSEG ER&T and receives gas distribution service from PSE&G at a rate approved by the BPU on May 29, 2013.[6]

4. PSEG Power Connecticut LLC

PSEG Power CT is a Connecticut limited liability company and an EWG that owns and operates electric generation facilities in the State of Connecticut and is authorized to sell power at market-based rates.[7] Both of PSEG Power CT's generation facilities, Bridgeport Harbor and New Haven Harbor, are located in the State of Connecticut within the market administered by ISO-NE. PSEG Power CT sells the output of its generation facilities to its affiliate PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority. As noted above, PSEG Power CT is currently constructing Bridgeport 5, a 485 MW combined cycle unit in Bridgeport, Connecticut which is expected to be in service in 2019.

5. PSEG New Haven LLC

PSEG New Haven is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG New Haven owns and operates a facility (the "New Haven facility") in New Haven, Connecticut with a nameplate rating of 181 MWs. The New Haven facility is located within the New Haven Harbor generation station. The New Haven facility is interconnected to the adjacent United Illuminating East Shore Substation using a 115 KV underground cable. PSEG New Haven has no other

[6] BPU Docket No. GM12100935 (May 29, 2013).
[7] *Wisvest Corporation,* et al., 101 FERC ¶ 61,166 (2002).

generation assets. The commercial operation date for the New Haven facility was June 1, 2012 and PSEG New Haven has obtained MBR authority from FERC.[8]

The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[9] pursuant to a Connecticut statute that sought proposals for peaking generation in Connecticut.[10] All of the energy and capacity of the New Haven facility is sold into the ISO New England ("ISO-NE") markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA[11] has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder. The 181 MW nameplate rating of the New Haven Facility has not been included in the capacity controlled by PSEG for purposes of Dr. Morris' market power analysis.

6. PSEG Nuclear LLC

PSEG Nuclear is an EWG[12] and is authorized to sell power at market-based rates. PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission.[13] The assets of PSEG Nuclear are located entirely within PJM. PSEG Nuclear performed the following uprates since the last triennial filing: (1) an uprate of 120 MWs at its Hope Creek plant in 2014, which increased its nameplate rating to 1290 MWs, (2) an uprate to Peach Bottom 2 and 3 which increases PSEG's share of the nameplate MWs by 241 MWs for a updated nameplate of 704 MW for Peach Bottom 2 and 689 MWs for Peach Bottom 3.

7. Pavant Solar LLC, San Isabel Solar LLC and Bison Solar LLC

PSEG Power Ventures portfolio includes three (3) solar companies with market-based rate authority: (1) *Pavant Solar II LLC*[14] is a QF which owns a 50 MW (AC) solar facility in Fillmore Utah; (2) *San Isabel Solar LLC*[15] is a QF which owns a 30 MW (AC)

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[8] *PSEG New Haven LLC*, Docket No. ER12-1250-000, et al., (May 29, 2012).

[9] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control (DPUC). PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

[10] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

[11] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

[12] *PSEG Nuclear LLC*, 97 FERC ¶ 62,191 (November 30, 2001).

[13] *Public Service Electric and Gas Company*, et al., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Nuclear obtained market based rate authority from the FERC.

[14] *Pavant Solar II LLC*, Docket No. QF16-1072-000.

[15] *San Isabel Solar LLC*, Docket No. QF16-712-000.

solar facility in Las Animas County, Colorado and (3) *Bison Solar LLC*[16] is a QF which owns a 30 MW (AC) solar facility 25 miles north of Fort Collins, Colorado.

8. PSEG Energy Solutions LLC

PSEG Energy Solutions LLC ("PSEG Solutions") is a Delaware limited liability company and a direct subsidiary of PSEG ER&T. PSEG Solutions obtained market-based rate authority[17] and will operate within the PJM Interconnection, L.L.C. ("PJM"), New York Independent System Operator, Inc. ("NYISO") and ISO New England Inc. ("ISO-NE") markets. Energy Solutions will purchase power from the regional transmission organization ("RTO") at wholesale and sell it to retail customers. PSEG Solutions will not own or operate any generation assets. PSEG Solutions proposes to begin its retail business on January 1, 2017.

OTHER RELEVANT AFFILIATES

PSEG is also the direct or indirect parent of certain other subsidiaries engaged in energy related activities, as discussed below.

7. Affiliated Generation Ownership.

A list of the Applicants' affiliated domestic FERC jurisdictional generation assets owned is contained in Appendix B attached hereto. [18] Those additional subsidiaries of PSEG that may be considered relevant to this market power update for the Northeast Region are described below:

PSEG Power LLC ("PSEG Power") was formed in 1999 to acquire the former generation assets of PSE&G. PSEG Power, a Delaware limited liability company, does not directly own any generation facilities or engage in any FERC jurisdictional activities but is the parent company of several FERC jurisdictional entities, including Applicants PSEG ER&T (and it subsidiary PSEG Energy Solutions LLC), PSEG Fossil, PSEG Nuclear, PSEG Power CT, PSEG New Haven and PSEG Power Ventures LLC (which owns PSEG Solar Source LLC).

PSEG Power Ventures LLC and PSEG Solar Source LLC. PSEG Power Ventures LLC ("Power Ventures") is a Delaware Limited Liability company and a direct subsidiary of PSEG Power. PSEG Power Ventures owns 100% interest in PSEG Solar Source LLC and has an in-direct ownership interest in a domestic power plant in Hawaii. PSEG Solar Source owns approximately 349 MWs DC (274 MW AC) of solar capacity across the United States, including a combined 92

[16] *Bison Solar LLC*, Docket No. QF16-711-001.
[17] See Letter Order dated December 21, 2016 in Docket No. ER16-2725-000.
[18] Appendix B excludes generation assets located in Hawaii as well as generation assets in which PSEG's interest is limited to a leveraged lease interest.

MWs[19] (72 MW AC) of solar capacity in PJM and approximately the following amount of MWs in the following states all through separate project companies which have all obtained QF status.

- 15 MWs (12 MW AC) in Florida,
- 92 MWs in PJM (72 MW AC) – 12 MWs in Ohio, 2 MW in New Jersey, 15 MW in Delaware, 50 MW in North Carolina and 13 MW in Maryland
- 45 MWs in Arizona (34 MW AC) – 25 MW Queen, approximately 20 MW Badger
- 13 MWs (10 MW AC) in Texas,
- 34 MWs (25 MW AC) in California[20]
- 4 MWs (3 MW AC) in Vermont and
- 74 MW (60 MW AC) in Colorado (to be in operation in 2016) – 38 MWs for San Isabel and 36 MWs for Bison
- 62 MW (50 MW AC) in Utah (to be in operation in 2016).
- 10.5 MW (8 MW AC) in Oregon (to be in operation in 2016).

PSEG Resources LLC ("Resources") is a New Jersey limited liability company that provides energy infrastructure financing in developed countries. Resources invests primarily in energy-related financial transactions and manages a diversified portfolio of investments including leveraged leases. Resources owns interests, through leveraged leases, in various generation stations. Pursuant to the terms of these triple net leases, the lessee, not Resources, has all operational responsibility and control over the leased generation stations.

PSEG Power New York LLC ("PSEG Power NY") is a Delaware limited liability company and an EWG that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 750 MW combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a FERC-approved cost-based contract.[21]

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[19] The 92MWs are attributed to four (7) separate project companies that have QF status: PSEG Solar Hackettstown LLC (2 MW); PSEG Solar Delaware LLC (15 MW), Rockfish Solar LLC (13 MWs) Meadows Solar (26 MW), Turkey Creek (17 MW) Hemlock Solar (7 MW) in North Carolina and PSEG Solar Ohio LLC (12 MW).

[20] The 28MWs (DC) are associated with the Shasta Solar Facility in California (4 MW), Whitehorn Solar (3 MWs) the Columbia Solar Project (19 MW). All have obtained QF status.

[21] *PSEG Power New York Inc.*, Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

PSEG Keys Energy Center LLC ("PSEG Keys") is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG Keys was formed to construct, operate and maintain the Keys Energy Center, a 755MW combined cycle power plant in Prince Georges County, Maryland. Construction began in 2015 and is expected to be completed in 2018 at which time the capacity will be available in the PJM market. All of the output of the Keys Energy Center will be sold to PSEG Keys affiliate, PSEG ER&T.

PSEG Long Island LLC ("Long Island") and Long Island Electric Utility Servco, LLC ("Servco") are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution system ("T&D") on Long Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither Long Island nor Servco will be FERC jurisdictional public utilities as neither will exercise ultimate decision making authority over the T&D system in Long Island. Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[22]

8. Affiliated Transmission Ownership

With the exception of the electric transmission assets owned by Applicant PSE&G, all of which are located within the PJM RTO, and the generation interconnection facilities owned by the various EWG and QF affiliates listed herein, the Applicants, nor their affiliates have any affiliates that own or operate FERC jurisdictional electric or natural gas transmission facilities within the United States[23]. As discussed below, FERC granted PSE&G a Hinshaw exemption in 1954, finding that it was exempt from the provisions of the Natural Gas Act.

B. JOINTLY OWNED FACILITIES

PSEG Nuclear is a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear is the operator of Salem and Exelon Generation is the operator of Peach Bottom.[24] PSEG Fossil is approximately a 23% joint owner in the Conemaugh and Keystone generating stations located in Pennsylvania. An affiliate of NRG Energy is the operator.[25] Accordingly, for

[22] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), *order dismissing request for rehearing*, 145 FERC ¶ 61,183 (2013).

[23] PSEG Power LLC is a 10% owner of the PennEast Pipeline Company LLC which has filed an application for approval to construct and operate a natural gas transmission line.

[24] A letter of concurrence supporting the allocation of plant output based on ownership interests is attached in Appendix E. The ownership percentages have not changed since the date of this letter. PSEG Nuclear owns a 50% interest in Peach Bottom and a 57.41% interest in Salem.

[25] A letter of concurrence supporting the allocation of plant output based on ownership interest is attached in Appendix E. The ownership percentages have not changed since the date of this letter.

purposes of this market power analysis, the capacity of Salem, Peach Bottom, Conemaugh and Keystone has been attributed to PSEG in accordance with PSEG's ownership interests in these facilities.

PSEG Fossil and Jersey Central Power and Light Company ("JCP&L") are each 50% co-owners of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to the unit. Accordingly, for the purpose of this market power analysis, the entire unit capacity – nominally 400 MWs – has been assigned to JCP&L.[26]

III. Applicants Fully Satisfy The Commission's Standards For Authority to Make Power Sales At Market-Based Rates.

The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, horizontal and vertical market power.[27] The Commission has also codified affiliate restrictions in its regulations which must be satisfied on an ongoing basis. In previous submissions for market-based rate authority the Applicants PSE&G, PSEG ER&T, PSEG Power CT, PSEG Fossil, PSEG Nuclear, and PSEG New Haven, demonstrated compliance with each of these requirements. As detailed herein and in the attached affidavit, the Applicants continue to meet these standards.

A. The Applicants Lack, Or Have Effectively Mitigated, Any Horizontal Market Power

In the MBR Order, the Commission established two indicative screens: a pivotal supplier screen based on the control area's annual peak demand and a wholesale market share screen applied on a seasonal basis. If an applicant passes both screens, there is a rebuttable presumption that the applicant does not possess horizontal market power. Each indicative screen is applied with respect to "relevant geographic markets" for an applicant's generating units.

Applicants located in ISOs/RTOs possessing sufficient market structure may consider the geographic region under the control of the ISO/RTO as the relevant default geographic region for purposes of completing their generation market power analyses.[28] However, where the Commission has previously found a "submarket" to exist within a boundary of an RTO, such finding is controlling as to the scope of the relevant geographic market for all generation units located within that submarket for the application of the indicative screens and any delivered price test that may be performed. The Commission further listed several such submarkets, including PJM East ("PJME"),

[26] A letter of concurrence supporting this determination is attached in Appendix E. The ownership percentages have not changed since the date of this letter.
[27] MBR Order, FERC Stats. & Regs. ¶ 31,252 at P 62, 399, 408, 440.
[28] *MBR Order at* PP. 231 and 235.

Connecticut and Southwest Connecticut.[29] Subsequent to the MBR order, in approving a merger between Exelon Corporation and Constellation Energy Group, Inc., the Commission identified additional submarkets in PJM - PJM East of 5004/5005 ("PJM50") and PJM East of AP South ("PJMAP") - that would be relevant to an MBR analysis for applicants in the Northeast Region.[30]

As discussed below and in the attached Affidavit of Dr. John Morris contained in Appendix A, Applicants have conducted market power analyses of the entire PJM RTO, the PJME, PJM50 and PJMAP submarkets, the entire NYISO, the entire ISO-NE, the Connecticut submarket and the Southwest Connecticut submarket for the study period. The results are set forth below.

1. Indicative Screens

a. Pivotal Supplier Analysis

The pivotal supplier analysis ("PSA") focuses on the ability of a seller to exercise unilateral market power.[31] The screen assesses whether market demand can be met during peak times without the applicant and its affiliates. If demand can be met without the applicant and its affiliates, the applicant passes that the PSA screen. The Affidavit of Dr. John Morris, attached hereto as Appendix A, finds that the Applicants pass the PSA screen for all relevant markets: PJM, NYISO, ISO-NE, Connecticut, Southwest Connecticut, PJMAP, PJME and PJM50.[32]

b. Wholesale Market Share Analysis

The wholesale market share analysis ("WMSA") is applied each season to determine whether an applicant has a dominant market position based on the total number of megawatts of uncommitted capacity owned or controlled by the applicant and its affiliates in relation to the uncommitted capacity of the entire relevant wholesale electricity market.[33] The established threshold is 20 percent; a supplier who has less than 20 percent market share in the relevant market for all seasons passes the WMSA screen.

In his Affidavit Dr. Morris finds that the Applicants pass the WMSA screen for PJM, NYISO, ISO-NE, Connecticut, Southwest Connecticut and PJMAP but do not pass the WMSA screen for the PJME and PJM50 submarkets.[34]

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[29] *Order No. 697* at P 236 (citing *Exelon Corp.*, 112 FERC ¶ 61,011, *reh'g denied*, 113 FERC ¶ 61, 299 (2005)). FERC eliminated the Northern PSEG zone as a default submarket in Order No. 697-A, P 99.

[30] Order Conditionally Authorizing Merger and Disposition of Jurisdictional Facilities, *Exelon Corporation, et al.*, 138 FERC ¶ 61,167 (2012).

[31] *AEP I* at P 72.

[32] *See* Morris Affidavit, at 15-29.

[33] *AEP I,* P 100.

[34] *See* Morris Affidavit, at 15-29.

c. Results of Indicative Screen Analysis

As shown in Dr. Morris's affidavit, Applicants therefore pass both indicative screen tests for PJM RTO, NYISO, ISO-NE, Connecticut and Southwest Connecticut and PJMAP. For PJME and PJM50, the Applicants pass the PSA but do not pass the WMSA.

2. Delivered Price Test Analysis For PJME and PJM50 Submarkets

In accordance with the MBR Order, applicants who fail either indicative screen test can rebut the presumption of market power through the submission of a delivered price test analysis ("DPT"). Applicants may submit this study at the same time that the results of the indicative screens are provided.[35] The DPT is based on two measurements of potential market power: economic capacity ("EC") and available economic capacity ("AEC"). EC is the capacity that can be delivered to a destination market for 105 percent or less than the market price. AEC is calculated by subtracting native load commitments from EC. Both calculations are performed for ten different season and load conditions.

In applying the DPT, "[a] showing of an HHI less than 2,500 in the relevant market for all season/load conditions for sellers that have also shown that they are not pivotal and do not possess a 20 percent or greater market share in any of the season/load conditions would constitute a showing of a lack of market power, absent compelling contrary evidence from intervenors."[36] However, while meeting these threshold benchmarks provides "safe harbor" protection, the Commission has found in numerous other cases that applicants lack market power even when they exceed one or more of the thresholds for particular study periods. As stated in *Public Service Company of New Mexico*, 115 FERC ¶ 61,090, P 38 (2006), "the Commission weights the results of both the economic and available economic capacity tests and considers the arguments of the applicant and intervenors." (footnote omitted.) [37]

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[35] *Order No. 697,* P 76.

[36] *Order No. 697* at P 111.

[37] Indeed, in that case, the applicant was deemed "on balance" to have adequately rebutted a showing of market power mitigation for the PNM control area where the results exceeded the 20% safe harbor in two cases under the AEC measure and in all 10 cases at values between 35% and 41% under the EC measure. *See, e.g.*, *Kansas City Power and Light Company, et al.*, Docket Nos. ER99-1005-011 et al. (August 12, 2010) (finding no market power where applicant had EC market shares in the 40-60% range and had significant HHI failures in the KCPL and GMO markets); *Cordova Energy Company LLC et al,* Docket Nos. ER99-2156-011, *et al.*, November 13, 2007 (finding no market power in case where applicant had EC market shares in PACE control area between 53.1% and 60.0%, HHIs between 2,958 and 3,696 and was pivotal in 8 out of 10 periods.); *PacifiCorp*, Letter Order, Docket Nos. ER97-2801-007, *et al.*, February 1, 2007; *Tucson Elec. Power Co.*, 116 FERC ¶ 61,051 (2006)(finding market power standard satisfied where applicant had EC market shares above 20% in all ten season/load periods in the Tucson control area, exceeded the 2,500 HHI threshold in eight periods, and was pivotal in 5 periods); *PacifiCorp*, 115 FERC ¶ 61,349 (2006) (finding that applicants rebutted presumption of market power in the PacifiCorp East control area where under available economic capacity measure, market share is less than 20% in 8 season/load periods and 28% in the summer and winter off-peak periods, HHI does not exceed 2500 in any season/load period and applicants are not pivotal); *Kansas City Power & Light Co.*, 113 FERC ¶ 61,074 (2005) (finding

a. Results of the DPT for PJM50 Submarket

For both the AEC and EC, PSEG passes all screens in all periods except for the pivotal supplier screen in the Summer Top 1% period.

b. Results of the DPT for PJME Submarket

With respect to AEC, PSEG passes all the screens in all 10 periods. With respect to the EC, PSEG passes the Market Concentration screens in all periods. It also passes the Pivotal Supplier Screen in 8 of 10 periods, and passes the Market Share Screen in 6 of 10 periods. PSEG's market shares are never above 25 percent. Although greater than the 20 percent screen, PSEG's market shares are well below the 35 percent threshold that is typically used for imputing unilateral market power.

3. Analysis of DPT Results

Based on his analysis of the overall results, Dr. Morris concludes that, although PSEG fails limited number of screens, the failures are substantially below levels that typically indicate market power. As set forth in his Affidavit, Dr. Morris states that:

> Although PSEG fails some screens in the PJME destination market, the overall results are not indicative of PSEG having market power. To begin, PSEG passes all the AEC screens and all market concentration (HHI) screens for EC. The HHI levels in all periods, capacity types, and areas are below the screening threshold of 2,500, and typically substantially below this level. In terms of the DPT for market rate authority and under the 2010 DOJ and FTC Horizontal Merger Guidelines, the market is not highly concentrated.[38] The low HHI levels mean that PSEG has little ability to exercise market power in coordination with other suppliers. It also passes all the AEC pivotal supplier screens, and most of the EC pivotal supplier screens. This means that typically PSEG's generation is not necessary to serve load; and when its generation is necessary, its forward sale commitments are sufficient so that its uncommitted generation is not necessary to serve the remaining load. Finally, PSEG's market shares are never above 15 percent in PJM50 and for AEC in PJM East. Its market shares for EC are never above 25 percent in PJM East. Although greater than the 20 percent screen, PSEG's market shares are

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no market power in the KCPL control area where applicant had EC market shares above 20% in all periods, exceeded the HHI 2,500 threshold in 5 of 10 periods and was pivotal supplier in 1 period); *Acadia Power Partners, L.P.*, 113 FERC ¶ 61,073 (2005) (finding no market power in the Cleco Power home control where, utilizing the EC measure, the applicant exceeded the thresholds set for all season/load periods using the market share measure, one season/load period using the market concentration measure, and for all season/load periods using the pivotal supplier measure).

[38] See U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Issued August 19, 2010, at Section 5.3, available at http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

> well below the 35 percent threshold that is typically used for imputing unilateral market power.[39]

Dr. Morris's conclusion is consistent with Commission precedent finding a lack of market power in cases in which the DPT results included more instances of findings outside of the "safe harbor" thresholds and at higher levels than exist here.[40] In these circumstances, Dr. Morris's analysis successfully rebuts any inference of market power created by the WMSA screen failures for PJME.

4. Existing RTO/ISO Mitigation Rules Also Eliminate The Potential for Exercising Market Power In the PJME, PJME PJM50 and PJMAP Submarkets

PJM mitigation rules eliminate the potential for the exercise of market power in the PJME submarket. The MBR Order specifically contemplated that RTO/ISO mitigation rules may serve as evidence that any market power has been adequately mitigated. The Commission declared, "We believe the added protections provided in structured markets with market monitoring and mitigation generally result in a market where prices are transparent and attempts to exercise of market power will be sufficiently mitigated."[41] The Order on Rehearing went even further and specifically created a presumption that any potential market power had been adequately mitigated by an established and effective RTO market monitoring scheme.[42]

Taking account of the pervasive PJM mitigation rule, Dr. Morris concludes that these rules "fully address the potential for PSEG to exercise market power" in PJME.[43] Accordingly, PJM's mitigation schemes in place are sufficient to rebut any inference of market power created by the failure to pass the WMSA screens in PJME and PJM50.

In addition, in the Applicants' last triennial approval order, the Commission found that "the PJM market monitoring and mitigation rules are sufficient to address market power concerns in the PJM-East submarket."[44]

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[39] *See*, *e.g.*, U.S. Department of Justice, 1984 Merger Guidelines, at Section 3.12, available at https://www.justice.gov/sites/default/files/atr/legacy/2007/07/11/11249.pdf ("the Department is likely to challenge the merger of any firm with a market share of at least one percent with the leading firm in the market, provided the leading firm has a market share that is at least 35 percent.")

[40] *See Public Service Company of New Mexico*, 115 FERC ¶ 61,090 (2006) discussed above and cases discussed in fn. 38 above.

[41] MBR Order at P 241.

[42] Order No. 697A at P 111.

[43] Morris Affidavit, pp. 24-26.

[44] *See* October 14, 2014 letter order approving Applicants' prior triennial market update in Docket No. ER10-1789-003 et al. at page 3.

a. The Applicants Lack Transmission Market Power and Cannot Erect Entry Barriers.

In its previous order accepting PSEG's triennial market power analysis for the Northeast Region, the Commission found that the submittal satisfied the Commission's requirements for market-based rates regarding vertical market power.[45] There have been no subsequent changes in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. As demonstrated below, neither Applicants nor any of its affiliates are able to exercise vertical market power.

Applicants are not able to exercise transmission market power. Neither Applicants nor any of their affiliates, except PSE&G, own transmission assets in the U.S. other than incidental generator interconnection facilities. PSE&G owns transmission facilities in PJM but transmission service over those facilities is provided under the PJM Open Access Transmission Tariff.

In addition, neither Applicants nor their affiliates are able to exercise vertical market power in wholesale energy markets through affiliation, ownership or control of inputs to electric power production. As required by Section 35.37(e) of the Commission's regulations, Applicants provide the following information:

(1) PSE&G owns and operates a natural gas distribution system that receives interstate pipeline gas within the State of New Jersey and distributes that gas to its customers within the State of New Jersey. The distribution system consists of 18,050 miles of gas distribution pipe and an additional 62 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3 and peak-shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers. Service over such distribution facilities is made available pursuant to state regulated tariffs on an open access type basis. PSE&G was granted a Hinshaw exemption from the FERC in 1954.[46] The gas distribution rates paid by PSEG Fossil to PSE&G have been set at rates approved by the BPU in an order dated May 29, 2013.

(2) Certain of the Applicants and their affiliates own sites within the Northeast Region that would be suitable for future generating facilities. These include space at many of the existing generating sites of PSEG Fossil and at the sites of PSEG Power NY and PSEG Power CT. PSEG Nuclear's Salem facility may also be suitable for future construction. PSE&G also owns certain sites that would be suitable for generating facilities, but under New Jersey's Electric Discount and Energy Competition Act, N.J.S.A 48:3-43 et seq., PSE&G is effectively barred from owning and operating

[45] *Id.*
[46] 13 F.P.C. 1348 (1954).

generation except "on site" generation for supply and Class I renewable energy resources as defined in N.J.S.A. 48:3-98.1.

(3) Neither Applicants nor any of their affiliates own or control any physical coal supply resources or own or control who may access transportation of coal supplies.

(4) As required by section 35.37(e)(4) of the Commission's regulations, Applicants and its affiliates state that they have not erected barriers to entry into any market, including the PJM, NYISO or ISO-NE market and will not erect barriers to entry into any markets.

IV. REQUEST FOR CONFIDENTIAL TREATMENT

Under separate cover via UPS Overnight this office is submitting compact disks containing the workpapers of Dr. John Morris supporting his analysis in Appendix A, as required by the Commission's April 2004 Order.[47] The CD (of which six copies are included) contains: (i) proprietary information provided by Energy Velocity under an agreement that requires confidential treatment to be requested for these materials; (ii) modeling and computer programs that are the proprietary intellectual property of Economists Incorporated, the firm which employs Dr. Morris; (iii) commercially sensitive information about Applicants and their affiliates; and (iv) documents and information deemed to be confidential by PJM and ISO-NE. Accordingly, Applicants respectfully request confidential treatment for CD and the workpapers pursuant to 18 C.F.R. § 388.112 (2006), consistent with the confidential treatment accorded other applicants submitting such proprietary and commercially sensitive data.[48] Pursuant to the Commission's rules, the public version of this filing contains all materials submitted herein except for CD, which is labeled as "PRIVILEGED AND CONFIDENTIAL/NON-PUBLIC."

V. SERVICE

This filing has been served on all parties on the official service list as currently maintained by Commission in the above-referenced dockets. Applicants are also providing a copy to the New Jersey Board of Public Utilities and the New Jersey Division of Rate Counsel.

VI. ENCLOSURES

Applicants enclose the following:

- An original filing;

[47] AEP II, 107 FERC at P 61,087-88.

[48] *See, e.g., Idaho Power Company*, Docket No. ER97-1481-009 (February 3, 2006) (submission of revised Pivotal Supplier Screen and Market Share Screen calculations including similar data).

- Appendix A – Affidavit of Dr. John R. Morris;[49]
- Appendix B – List of Entities with Market-Based Rates Authority and Their Generation Assets. (This is an appendix listing the filing entities and all their energy affiliates and their associated assets);
- Appendix C – List of Entities with Market-Based Rate Authority and Their Transmission Assets;
- Appendix D – List of Long Term Power Purchase Agreements;
- Appendix E – Letters of concurrence regarding the control of certain jointly owned generation facilities;
- Appendix F – Form of notice suitable for publication in the Federal Register.

[49] Compact disks, as described above, containing the workpapers for the Affidavit of John R. Morris in Appendix A are being sent concurrently with this filing via UPS Overnight. As noted *supra*, privileged treatment is being requested for Dr. Morris's confidential workpapers submitted with the non-public version of this filing.

VII. CONCLUSION.

Applicants respectfully request the Commission

(i) to accept this market power compliance filing as meeting the Commission's requirements under Order No. 697 for the continuation of market-based rate authority for Applicants PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG New Haven LLC, PSEG Nuclear LLC, PSEG Fossil LLC, Pavant Solar II, LLC, Bison Solar LLC , San Isabel Solar LLC and PSEG Energy Solutions LLC;

(ii) to grant the request for confidential treatment; and

(iii) to grant such other relief or waivers as may be appropriate or necessary.

Respectfully submitted,

Public Service Electric and Gas Company
PSEG Energy Resources & Trade LLC
PSEG Power Connecticut LLC
PSEG Fossil LLC
PSEG Nuclear LLC
PSEG New Haven LLC
Pavant Solar II, LLC
Bison Solar, LLC
San Isabel Solar, LLC
PSEG Energy Solutions LLC

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Dated: December 28, 2016
Newark, New Jersey

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Appendix A
Affidavit of
Dr. John R. Morris

Appendix B
List of Entities with Market-Based Rate Authority and Their Generation Assets

Appendix C
List of Entities with Market-Based Rate Authority and Their Transmission Assets

Appendix D
Long Term Power Purchase Agreements

Appendix E Letters of concurrence regarding the control of certain jointly owned generation facilities

Appendix F Form of notice suitable for publication in the Federal Register

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PSEG Energy Resources & Trade LLC	Docket No. ER99-3151-___
Public Service Electric and Gas Company	Docket No. ER97-837-___
PSEG Power Connecticut LLC	Docket No. ER03-327-_____
PSEG Fossil LLC	Docket No. ER08-447-_____
PSEG Nuclear LLC	Docket No. ER08-448-_____
PSEG New Haven LLC	Docket No. ER12-1250-___
Pavant Solar II LLC	Docket No. ER16-1926-____
San Isabel Solar LLC	Docket No.ER16-1925-____
Bison Solar LLC	Docket No.ER16-1924-____
PSEG Energy Solutions LLC	Docket No. ER16-2725-____

NOTICE OF FILING
( )

Take notice that on December 28, 2016: (i) PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG New Haven LLC, PSEG Fossil LLC, PSEG Nuclear LLC, Pavant II Solar LLC, Bison Solar LLC, San Isabel Solar LLC and PSEG Energy Solutions LLC tendered for filing their joint triennial market power update in compliance with Order No. 679 and with prior Commission Orders granting them market-based rate authority in Docket Nos. ER99-3151, ER97-837, ER03-327, ER08-447 ER08-448, DR-12-1250, ER16-1926, ER16-1925, ER16-1924 and ER16-2725 respectively.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR §§ 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file

electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).
Kimberly J. Bose
Secretary

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Public Service Electric and Gas Company	)	ER97-837-____
PSEG Energy Resources & Trade LLC	)	ER99-3151-____
PSEG Power Connecticut LLC	)	ER03-327-____
PSEG Fossil LLC	)	ER08-447-____
PSEG Nuclear LLC	)	ER08-448-____
PSEG New Haven LLC	) Docket Nos.	ER12-1250-____
Pavant II Solar LLC	)	ER16-1926-____
Bison Solar LLC	)	ER16-1925-____
San Isabel Solar LLC	)	ER16-1924-____
PSEG Energy Solutions LLC	)	ER16-2725-____

Report & Affidavit of
Dr. John R. Morris

December 22, 2016

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Public Service Enterprise Group Incorporated Northeast Region Market Power Study

1. Introduction

My name is Dr. John R. Morris. I am a Principal at Economists Incorporated, an economic consulting firm located at 2121 K Street, NW, Washington, DC 20037. I have a bachelor's degree in economics from Georgetown University, and I have a master's degree and a Ph.D. in economics from the University of Washington. I have been studying and consulting within energy industries since joining the Federal Trade Commission in 1985. Since joining Economists Incorporated in 1992, I have consulted on many mergers involving electric and gas companies, examined competitive issues relating to utility rates, provided market power studies for applications for market-based rate authority, and studied market power issues in state restructuring proceedings. I have published articles on competition and energy matters, and I have spoken on numerous occasions concerning competition in natural gas, electric power and other industries. I have previously been accepted as an expert witness on energy matters before the Federal Energy Regulatory Commission ("FERC" or "Commission"), state commissions and in federal court. A complete listing of my experience, publications and testimony is contained in my resume, presented in Exhibit PEG-2.

Public Service Enterprise Group Incorporated ("PSEG") asked that I prepare a market power study for its subsidiaries that have market-based rate authority in the Northeast Region.[1] These subsidiaries are: Public Service Electric and Gas

[1] The Northeast Region includes ISO-New England Inc. ("ISO-NE"), Connecticut, Southwest Connecticut, New York Independent System Operator, Inc. ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), PJM East, PJM East of 5004/5005 and PJM East of AP South.

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("PSE&G"), PSEG Energy Resources & Trade LLC ("PSEG ER&T"), PSEG Fossil LLC ("PSEG Fossil"), PSEG Nuclear LLC ("PSEG Nuclear"), PSEG Power Connecticut LLC ("PSEG Power CT"). PSEG New Haven LLC ("PSEG New Haven") Pavant II Solar LLC, Bison Solar LLC and San Isabel Solar LLC.[2] The purpose of this study is to determine whether these PSEG entities have market power in any Northeast Region market under the Commission's Pivotal Supplier Analysis ("PSA") and Wholesale Market Share Analysis ("WMSA") screens as articulated in FERC Order No. 697 and if the Applicants do fail any of the screens, whether they otherwise lack market power under the Delivered Price Test ("DPT") or are subject to sufficient mitigation to guard against any market power concerns.[3]

PSEG

PSEG is a public utility holding company headquartered in in Newark, New Jersey. Through its subsidiaries, PSEG engages in the generation, transmission, distribution and sale of electric energy, and distribution and sale of natural gas to commercial, residential, and industrial customers primarily in the Northeastern and Mid-Atlantic United States. PSEG, through its subsidiaries, owns approximately 11,300 MW of seasonal generation capacity located in the Northeast Region.[4]

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[2] Pavant II Solar LLC, Bison Solar LLC and San Isabel Solar LLC all have QF status.

[3] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 119 FERC ¶ 61,295, ("Order No. 697" or "MBR Order"), *order clarifying final rule*, 121 FERC ¶ 61,260 (2007) ("MBR Clarifying Order"), *order on reh'g and clarification*, 123 FERC ¶ 61,055 (2008) FERC Stats. & Regs ¶ 31,268 ("Order No. 697-A"), *order on reh'g and clarification*, 124 FERC ¶ 61,055 (2008) ("SIL Allocation Order").

[4] *See* Exhibit PEG-3 (accounting for retirements).

PSE&G

PSE&G is a public utility operating company engaged primarily in the transmission of electricity and the provision of gas and electric distribution service in the State of New Jersey. It is New Jersey's oldest and largest investor-owned utility. PSE&G was founded in 1903 and is based in Newark, New Jersey. It is a member of the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization and has made all of its transmission facilities available for open access transmission service pursuant to the PJM Open Access Transmission Tariff ("OATT") administered by PJM. The company also owns and operates 18,050 miles of gas distribution pipe and an additional 62 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3. During the study period, PSE&G owned less than 140 MW of solar generation, 8 MW of Energy Efficiency and 91 MWs of Demand Response but otherwise did not own or operate any electric generation facilities.

PSEG ER&T

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil and PSEG Nuclear, each wholly-owned subsidiaries of PSEG Power LLC ("PSEG Power"), as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission. PSEG ER&T also makes wholesale sales of natural gas.

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

BGS Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 *et seq.,* which initiated the transition from a regulated to a competitive retail power market in New Jersey, the New Jersey Board of Public Utilities ("BPU") annually approves statewide auctions to determine the entities that will supply Basic Generation Service ("BGS") in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSE&G's affiliate, PSEG ER&T, has participated directly in all of the auctions for BGS supply held since 2004 and has consistently won tranches in those auctions, including auctions for BGS service within the franchised service territory of PSE&G.

BGSS Gas Contract. By order issued April 16, 2002, the BPU approved a full requirements contract for the provision of gas supply by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the BPU, PSEG ER&T assumed, through capacity release, PSE&G's FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract, which currently remains in effect, provides for annual renewals unless terminated by either party on 12 months' advance written notice.

LIPA Fuel Supply. On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which

ER&T provides fuel supply and power supply management activities for LIPA as of January 1, 2015.

PSEG Fossil

PSEG Fossil owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission under the umbrella of PSEG Fossil's market-based rate authority.[5] The assets of PSEG Fossil are located entirely within PJM.[6] Since the last triennial filing in 2013, PSEG Fossil has retired approximately 1,800 MW of capacity in the eastern portion of PJM. Much of this capacity was retired at the end of May 2015. We included this capacity in the Winter and Spring season screens and exclude the capacity for the Summer and Fall screens.

PSEG Fossil is approximately a 23 percent joint owner of interests in the Conemaugh and Keystone generating stations located in Pennsylvania. An affiliate of NRG Energy is the operator.[7] PSEG Fossil is a 50 percent co-owner with Jersey Central Power and Light Company ("JCP&L") of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to

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[5] *Public Service Electric and Gas Company, et al*., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000).

[6] PSEG Fossil's subsidiaries PSEG Power Connecticut LLC, PSEG New Haven LLC and PSEG Power New York LLC own generation units in Connecticut and New York respectively.

[7] A letter of concurrence supporting the allocation of these facilities' output based on ownership interests is attached in our workpapers.

the unit. Accordingly, for the purpose of this market power analysis, the entire unit capacity, nominally 400 MWs, has been assigned to JCP&L.[8]

PSEG Power CT

PSEG Power CT owns the Bridgeport Harbor and New Haven Harbor generation facilities located in the state of Connecticut within ISO-NE and is authorized to sell power at market-based rates.[9] The output of these facilities is sold to PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority. PSEG Power CT is currently constructing Bridgeport 5, a 485 MW gas-fired combined cycle in Bridgeport, Connecticut, which is expected in service in 2019.

PSEG New Haven

PSEG New Haven owns and operates the New Haven facility, a gas-fired plant located in New Haven, CT that entered service in June 2012 with a nameplate capacity of 181.5 MW. The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[10] pursuant to a Connecticut statute that sought proposals for peaking generation in Connecticut.[11] All of the energy and capacity of the New Haven facility is sold

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[8] A letter of concurrence supporting the allocation of this facility's output to JCP&L is attached in our workpapers.

[9] *Wisvest Corporation, et al*., 101 FERC ¶ 61,166 (2002).

[10] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control (DPUC). PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

[11] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

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into the ISO-NE markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder.[12] As such, neither PSEG New Haven nor any other PSEG affiliate has operational control of the New Haven facility. As a result, the capacity of the facility is not attributable to PSEG for the purpose of this market power analysis.

PSEG Nuclear

PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission in accordance with PSEG Nuclear's market-based rate authority.[13] PSEG Nuclear is the owner of Hope Creek and a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear operates the Salem plant and Exelon Generation is the operator of Peach Bottom.[14] Since the last triennial filing, uprates at Peach Bottom and Hope Creek plants have increased PSEG Nuclear's capacity at those facilities.

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[12] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

[13] *Public Service Electric and Gas Company, et al*., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000).

[14] A letter of concurrence supporting the allocation of plant output based on ownership interests is attached in our workpapers.

Other Subsidiaries

PSEG is also the direct or indirect parent of certain other subsidiaries engaged in energy related activities in the United States. Those additional subsidiaries of PSEG that may be considered relevant to this market power update for the PJM region are as follows.

PSEG Power LLC is a Delaware limited liability company. It does not directly own any generation facilities or engage in any FERC jurisdictional activities but it is the parent company of several FERC jurisdictional entities, including applicants PSEG ER&T, PSEG Fossil and PSEG Nuclear.

PSEG Power Ventures LLC ("Power Ventures") is a Delaware Limited Liability company and a direct subsidiary of PSEG Power. PSEG Power Ventures owns 100% interest in PSEG Solar Source LLC and has an in-direct ownership interest in a domestic power plant in Hawaii. PSEG Solar Source owns approximately 349 MWs DC (274 MW AC) of solar capacity across the United States, including a combined 92 MWs (72 MW AC) of solar capacity in PJM.[15] All of PSEG Solar Source's solar capacity has obtained QF status. Because all of this capacity is QF capacity, per Order No. 816 this capacity is not included in the market power analyses.[16]

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[15] The 42MWs are attributed to four (7) separate project companies that have QF status: PSEG Solar Hackettstown LLC (2 MW); PSEG Solar Delaware LLC (15 MW), Rockfish Solar LLC (13 MWs) Meadows Solar (26 MW), Turkey Creek (17 MW) Hemlock Solar (7 MW) in North Carolina and PSEG Solar Ohio LLC (12 MW).

[16] *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 816, 80 *Fed. Reg*. 67056 (2015), FERC STAT & REGS ¶ 31,374, P55 (2015), *reh'g denied and clarification*, Order No. 816-A, 155 FERC ¶ 61,188 (2016) ("… qualifying facilities that are exempt from FPA section 205 and facilities that are behind-the-meter facilities do not need to be reported in the asset appendix or indicative screens." (note omitted))

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PSEG Resources LLC ("Resources") is a New Jersey limited liability company that provides energy infrastructure financing in developed countries. PSEG Resources invests primarily in energy-related financial transactions and manages a diversified portfolio of investments including leveraged leases. PSEG Resources owns interests, through leveraged leases, in various generation stations. Pursuant to the terms of these triple net leases, the lessee, not Resources, has all operational responsibility and control over the leased generation stations.

PSEG Power New York LLC ("PSEG Power NY") is a Delaware limited liability company that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 750 MW combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a cost-based contract.[17]

PSEG Keys Energy Center LLC ("PSEG Keys"), direct subsidiary of PSEG Fossil, was formed to construct, operate, and maintain the Keys Energy Center, a 755 gas-fired combined cycle facility located in Prince George's County, Maryland. Construction began in 2015 and is scheduled to be completed in 2018. All the capacity and energy from PSEG Keys will be sold to PSEG ER&T.

PSEG Energy Solutions LLC ("PSEG Solutions") is a direct subsidiary of PSEG ER&T that is schedule to begin retail operations in the Northeast Region in

[17] *PSEG Power New York Inc.,* Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

January 2017. It has obtained market-rate authority to allow it to sell excess energy in wholesale markets.[18]

PSEG Long Island LLC ("Long Island") and Long Island Electric Utility Servco, LLC ("Servco") are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution ("T&D") system on Long Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither Long Island nor Servco are FERC jurisdictional public utilities, as neither will exercise ultimate decision making authority over the T&D system in Long Island. Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[19]

When an applicant has affiliates in the relevant market, the Commission considers the combined capacity of all the affiliated entities in its market power assessment.[20] Accordingly, I have included the capacity controlled by PSE&G, PSEG ER&T, PSEG Power CT, PSEG Fossil, PSEG Nuclear, and PSEG Power New York (which on a combined basis constitutes the capacity of all of PSEG's affiliates not excluded for a reason explained above). Future references in this Affidavit to PSEG are inclusive of the foregoing entities.

The primary purpose of this study is to determine whether PSEG passes the PSA and WMSA screen thresholds in ISO-NE, the NYISO and PJM. In the PSA, the Commission requires applicants to examine whether the generation owned by

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[18] *See* December 21, 2016 letter order approving Energy Solutions request for market-based rate authority in Docket No. ER16-2725-000.

[19] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), order dismissing request for rehearing, 145 FERC ¶ 61,183 (2013).

[20] *Heartland Energy Services, Inc.,* 68 FERC ¶ 61,223 at 62,061-62,062 (1994).

the applicant is necessary to serve wholesale demand within a balancing authority area. The applicant first calculates the total generation capacity for an area. This is the total of generation in the balancing authority area plus the import capability to the area.[21] From this total, the applicant subtracts out firm contractual commitments, native load obligations, and operating reserves, giving uncommitted capacity for the area. Net uncommitted capacity is calculated by subtracting a wholesale load proxy from uncommitted capacity. Net uncommitted capacity is then compared to the applicant's uncommitted capacity within the area. When the applicant's uncommitted capacity is less than the net uncommitted capacity for the area, then all wholesale demand could be served without energy from the applicant and the applicant passes the PSA screen. When the applicant's uncommitted capacity is greater than the net uncommitted capacity, then the applicant does not pass the screen because its capacity is necessary to meet wholesale peak loads in the market.

In the WMSA, the Commission requires applicants to examine whether the generation owned by the applicant is 20 percent or more of the uncommitted capacity in each of four seasons under average daily peak conditions for the season. The applicant first calculates the total generation capacity for an area. The applicant then adds the import capability to the area. From this total, the applicant subtracts out planned outages and deratings, long-term firm contractual commitments, native load obligations, and operating reserves. The sum gives the total uncommitted capacity. The applicant then calculates its share by dividing its uncommitted capacity by the total uncommitted capacity. When the applicant's share is less than 20 percent, the applicant passes the WMSA screen.

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[21] Import capability is the lesser of either the simultaneous import limit ("SIL") into the area or available capacity in interconnected balancing authority areas. Available capacity is equal to total generation capacity in an area less outages and derating, a native load proxy and operating reserves.

The Commission presumes that an applicant does not have market power when it passes both the PSA and WMSA screens. If the applicant fails either of the screens, then the applicant may present other analyses to demonstrate that it does not possess market power. Alternatively, the applicant may propose mitigation measures or accept the Commission's default mitigation measures to demonstrate that it has mitigated market power.

2. New England

2.1. Overview of Electric Power Markets in New England

New England operates a competitive wholesale power market. Substantial restructuring has taken place in New England, and many of the vertically integrated utilities have sold either most or all of their generation assets. The traditional utilities often have standard offer obligations to serve retail customers, but utilities often fulfill these obligations by securing supplies in competitive wholesale markets. For example, a utility may secure contracts in which the supplier agrees to provide power for 30 percent of the utility's standard offer obligation. The transmission system is managed by ISO-NE. The market has a market monitor and market power mitigation program in place to identify and to mitigate any potential exercise of market power.

2.2. Geographic Markets

In the case of generation wholly located in an RTO, such as ISO-NE, the Commission accepts the RTO as the relevant destination market.[22] When the Commission has identified a sub-market within an RTO, the applicant must also provide market power screens for the relevant sub-markets.[23] In New England,

[22] Order No. 697 at PP 231, 235.

[23] Order No. 697 at P 236.

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the Commission has identified two submarkets: Connecticut and Southwest Connecticut.[24] PSEG owns the Bridgeport Harbor plant in Southwest Connecticut. PSEG also owns the New Haven Harbor 1 unit in Connecticut and PSEG New Haven owns the New Haven facility. When the applicant does not own the transmission system, as in the instant case, the applicant needs to provide an analysis only for the balancing authority area to which the generation is interconnected.[25] Accordingly, the PSA and WMSA are provided for the ISO-NE balancing authority area, and also for Connecticut and Southwest Connecticut.

2.3. Data Sources and Analysis

The data source for generation is ISO-NE Seasonal Claimed Capability (SCC) Reports.[26] Summer and winter capacities were taken from the November 2015 report. Planned outages are from the ISO-NE Form 714. Planned outages for Connecticut and Southwest Connecticut are prorated based on their shares of the total generation capacity in ISO-NE. PSEG's generation capacity in ISO-NE consists of the New Haven facility, New Haven Harbor and Bridgeport Harbor. PSEG's Northeast Region generation facilities are presented in Exhibit PEG-3.

Load data for ISO-NE are from Energy Velocity. Energy Velocity also provides load data by New England ISO zone, thus loads are calculated by sub-market as well. PSEG load obligations in New England come from PSEG's agreements to supply standard offer generation within Rhode Island. The data were supplied by PSEG.

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[24] *Id*.

[25] Order No. 697 at footnotes 215, 217.

[26] See http://www.iso-ne.com/genrtion_resrcs/snl_clmd_cap/index.html.

Import capability was taken from the ISO-NE's December 20, 2016 FERC filing.[27] This report indicates that the simultaneous transfer limits in all seasons is 4,548 MW for the ISO-NE as a whole, 3,050 MW for Connecticut, and 2,370 (Spring) to 3,200 MW (Summer) for Southwest Connecticut. PSEG has no firm transmission rights into New England.

Operating reserves are calculated as follows. ISO-NE Operating Procedure No. 8 specifies spinning reserves (or 10-minute reserves) equal to the size of the loss of the largest unit times a Contingency Reserve Adjustment Factor ("CRAF").[28] The CRAF in 2015 was 1.25.[29] The largest unit is the 1,400 MW (summer capacity) Seabrook Unit 1. In addition, 30-minute reserves require capacity to cover 50 percent of the loss of a second contingency (i.e., the second largest unit) plus 160 MW for daylight-savings time periods and 180 MW during standard time (i.e., winter). The second largest unit is the 1,200 MW (summer capacity) Millstone Unit 3. Thus, in total, operating reserves are 2,510 MW in summer.[30] Operating reserves for Connecticut and Southwest Connecticut are based on resource needs in forward reserve auctions for 2015.[31]

2.4. Results

Exhibit PEG-4 summarizes the results for the PSA and the WMSA in New England. Exhibit PEG-5 shows the calculations to determine whether PSEG is a

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[27] ISO New England Inc. Simultaneous Import Limit for 2015, *Guidance on Simultaneous Transmission Import Limit Studies*; Docket No. AD10-02, December 20, 2016.

[28] ISO New England Operating Procedure No. 8, at 5-6, available at https://www.iso-ne.com/participate/rules-procedures/operating-procedures.

[29] ISO New England, Inc. 2015 Regional System Plan ("Regional System Plan"), available at https://www.iso-ne.com/static-assets/documents/2015/11/rsp15_final_110515.docx, at 68.

[30] 2,510 MW = 1,400 MW x 1.25 + 50% x 1,200 MW + 160.

[31] ISO New England, Inc. 2015 Regional System Plan ("Regional System Plan"), available at https://www.iso-ne.com/static-assets/documents/2015/11/rsp15_final_110515.docx, Table 4.12 at p.70.

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pivotal supplier in the three New England destination markets. PSEG passes the PSA screen in all areas. Exhibit PEG-6 presents the WMSA results for the destination areas in New England. PSEG easily passes the WMSA in all areas.

3. New York

3.1. Overview of Electric Power Markets in New York

New York also has a competitive wholesale power market. Substantial restructuring has taken place in New York, and the investor-owned vertically integrated utilities have sold either most or all of their generation assets. These utilities often have standard offer obligations to serve retail customers, and utilities can fulfill these obligations by securing supplies in competitive wholesale markets. The transmission system is operated by the NYISO, which also operates a competitive wholesale market. The market has a market monitor and market power mitigation program in place to identify and to mitigate any potential exercise of market power.

3.2. Geographic Markets

In the case of generation wholly located in an RTO such as the New York ISO, the Commission has accepted the RTO as the relevant destination market.[32] PSEG only owns generation in Albany, New York. In addition, when the applicant does not own the transmission system, as in the instant case, the applicant needs to provide an analysis only for the balancing authority area to which the generation is interconnected.[33] Accordingly, the PSA and WMSA are provided for the NYISO only.

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[32] Order No. 697 at PP 231, 235.

[33] Order No. 697 at footnotes 215, 217.

3.3. Data Sources and Analysis

The principal data source for generation is the Energy Velocity Market-Operations database. Planned outages are from the FERC Form 714. PSEG's generation capacity in New York consists of its ownership of the Bethlehem Energy Center in Albany, which has winter capacity of 845 MW. Information for PSEG's Northeast Region generation is presented in Exhibit PEG-3.

Load data for NYISO were downloaded from Energy Velocity.

Import capability comes from the most recent NYISO SIL filing as of December 19, 2016.[34] This filing indicates that ISO simultaneous import capability ranges from 6,850 MW in spring to 7,695 MW in summer. NYISO does not recognize physical imports, accordingly, all the SIL import capability is allocated pro rata, except for a 265 MW reservation that PSEG has from PJM to New York on the Linden VFT DC transmission line.

Operating reserves are calculated as follows. The NYISO Locational Reserve Requirements specify 30-minute total reserves equal to twice the 10-minute reserve necessary to replace the operating capability loss caused by the most severe contingency under normal transfer conditions. Thus, the operating reserves for the NYISO are 2,620 MW for each season.[35]

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[34] New York Independent System Operator, Inc., *Informational Filing Regarding the Simultaneous Import Limitation Study*, Docket No. AD10-2, December 19, 2016.

[35] NYISO Locational Reserve Requirements, Table 2, available at http://www.nyiso.com/public/webdocs/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf

3.4. Results

Exhibit PEG-7 shows the calculations to determine whether PSEG is a pivotal supplier in New York, and PSEG passes the PSA screen. Exhibit PEG-8 presents the WMSA results for New York, and PSEG easily passes the WMSA.

4. PJM

4.1. Overview of Electric Power Markets in PJM

PJM operates a competitive wholesale power market and serves as the regional RTO for an area that covers all or parts of 13 states and the District of Columbia. PJM also plans and operates the transmission system within the RTO. Monitoring Analytics acts as the market monitor, and has a market power mitigation program in place to identify and mitigate any potential exercise of market power.

4.2. Geographic Markets

PSEG owns both generation and transmission facilities in PJM. In the case of generation wholly located in an RTO such as PJM, the Commission has accepted the RTO as the relevant destination market.[36] When the Commission has identified a sub-market within an RTO, the applicant must also provide market power screens for the relevant sub-markets.[37] In PJM, the Commission has identified three submarkets: PJM East ("PJME"), PJM East of 5004/5005 ("PJM50") and PJM East of AP-South ("PJMAP").[38] The PSA and WMSA are provided for PJM and for the PJME, PJM50 and PJMAP sub-markets.

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[36] Order No. 697 at PP 231, 235.

[37] Order No. 697 at P 236.

[38] *Id*. *See also* Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, Order No. 697-A, 73 FR 25832 (May 7, 2008), FERC

4.3. Data Sources and Analysis

The principal data source for generation is the Energy Velocity Market-Ops database. Generation within PJM was assigned to submarket consistent with the definitions in PJM's SIL Study.[39] Planned outages are from the FERC Form 714. In addition, for the sub-market analysis, planned outages were allocated to PJME based on the share of total PJME generation, by season. Information for PSEG's generation in PJM and PJME is presented in Exhibit PEG-3.

Load data for PJM was downloaded from Energy Velocity. Energy Velocity also provides load data by PJM zone, thus loads are calculated for the PJM sub-markets as well.

Import capability was taken from the 2015 Simultaneous Import Limit Study Report.[40] This report indicates simultaneous transfer limits of 11,997 MW in the winter and 7,600 MW in summer. Additionally, this report indicates transmission capabilities of the PJM sub-markets. The report conservatively uses the reported SIL as the SIL amount to be allocated pro rata. This is a simplifying assumption because PSEG has no firm transmission reservations into PJM and it effectively excludes the additional 8,500 MW of firm reservations into PJM in the base case of the SIL study.

Stats, & Regs. ¶ 31,268 (2008) at P 90; Order Conditionally Authorizing Merger and Disposition of Jurisdictional Facilities, *Exelon Corporation, et al.*, 138 FERC ¶ 61,167 (2012).

[39] PJM Interconnection, L.L.C., *Informational Filing of 2015 Simultaneous Import Limit Study Report for PJM Region*, Docket No. AD1-2-007, September 2, 2016, Accession No. 20160902-5155.

[40] *Id*.

Operating reserves are calculated according to PJM Manual 13 as the sum of Day Ahead Scheduling Reserves (Operating), Contingency (Primary) and Synchronized (Spinning Reserve) Requirements.[41]

Data on PSEG's long-term contracts come from PSEG. The contracts were included in the area where the energy is delivered under the contract. For contracts delivered to the Western Hub in PJM, the contracts were included in the PJM, PJM50, and PJMAP destinations and not the PJME destination.

4.4. Results

Exhibit PEG-9 summarizes the results for the PSA and the WMSA in PJM. Exhibit PEG-10 shows the calculations to determine whether PSEG is a pivotal supplier in the four PJM destination markets. PSEG passes the PSA screen for all four destinations. Exhibit PEG-11 presents the WMSA results for the destination markets in PJM. PSEG easily passes the WMSA in PJM and PJM east of AP South, but has greater than a 20 percent market share in the PJM East and PJM East of 5004/5005 destination markets.

5. Delivered Price Test

When an applicant does not pass either the PSA or WMSA for a destination market, the Commission invites the applicant to provide additional information via a delivered price test ("DPT"). PSEG requested that I perform a DPT for the PJM East and PJM East of 5004/5005 sub-markets. Accordingly, I now discuss the DPT for these sub-markets.

[41] PJM Manual 13 - Emergency Operations, at 17, available at http://pjm.com/~/media/documents/manuals/m13.ashx

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5.1. Overview of the DPT

The DPT utilizes substantially more information than the PSA or the WMSA, including additional information on generation ownership, generation costs, demand conditions, and transmission limits. The Commission considers two types of capacity: Economic Capacity ("EC") and Available Economic Capacity ("AEC"). EC is the capacity that can be delivered to a destination market for 105 percent or less than the market price. AEC is calculated by subtracting load commitments from EC. EC and AEC are calculated for a number of different seasonal and load conditions.

Because we do not know the firm retail obligations of the competitive suppliers, as explained below, the AEC calculation is based on the assumption that market participants serve load in proportion to their generation capacity and that 70 percent of load obligations are contracted more than one year from delivery.

For both the EC and AEC measures, the Commission prescribes three screens: (1) a pivotal supplier screen; (2) a market share screen; and (3) a Herfindahl-Hirschman Index ("HHI") screen. The HHI is the sum of the squared market shares of the firms in the market. So a market with four firms of market shares of 40, 30, 20, and 10 percent would have an HHI of 3,000 (this is calculated as $40^2 + 30^2 + 20^2 + 10^2 = 1{,}600 + 900 + 400 + 100 = 3{,}000$). A monopolist would produce a HHI of 10,000 and 10 equally-sized firms would produce a HHI of 1,000.

Although the Commission has not drawn bright lines for its review of DPT results, it has given general guidance. When (1) the applicant is not pivotal; (2) the applicants' market share is less than 20 percent; and (3) the HHI is below 2,500, the Commission is likely to conclude that the applicant does not have market power. The three standards establish a "safe harbor" for lack of market power, unless intervenors present clear and convincing contrary evidence. The Commission has also determined in some cases that an applicant did not have

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market power when the analysis showed isolated HHI and market share results above screening levels. Finally, despite the DPT results, the Commission may conclude that an applicant does not have market power if other evidence, such as historical sales data, indicates that the DPT results do not reflect the actual competition in the marketplace.

A detailed description of data sources and methods to prepare the data for the DPT is presented in Exhibit PEG-12. An overview of the sources and methods used at Economists Incorporated for conducting the DPT is presented here.

The DPT is calculated for 10 representative periods, three for each of three seasonal conditions plus a summer super peak period. The three seasons are spring/fall, summer, and winter. Each season is divided into (1) top 10 percent of peak hours; (2) remaining peak hours; and (3) off-peak hours. In addition, there is a summer super peak period which is comprised to the top 1 percent (10 hours) of summer peak hours. These ten periods cover the range of load conditions for each season, and for the year as a whole.

The primary source for generation data is Energy Velocity. In addition to generation capacity, Energy Velocity provides data on ownership (including holding companies), fully-loaded heat rates, emission rates, and generation availability. Generation is included for all of PJM and NYISO, which is the only first-tier balancing authority area in which PSEG owns generation. Unit capabilities are derated to account for seasonal maintenance and likely plant unavailability due to forced outages. Because demand in PJM peaks in summer and winter, the planned outages are assumed to be during the spring/fall season.

The transmission system is represented by contract paths between balancing authority areas and within PJM. Limits between regions in PJM are from Energy Velocity.

Market prices come from hourly prices reported by PJM.

As in the PSA and WMSA, load data come from Energy Velocity. To compute load requirements for market participants, we apportion the total load in each market area in New York and PJM to all suppliers in proportion to their respective generation capacities. We assumed 70 percent of load is committed for a year or longer and the remaining 30 percent is contracted for shorter periods.[42] To account for their greater load obligations, we assume that Dominion, which does not operate in a restructured retail market, has 100 percent responsibility for its allocation of load and that AEP, which operates in a partly restructured retail market, has 90 percent of its allocation as opposed to the standard 70 percent.

The DPT and market share calculations were calculated using the Power Acquisition Screening System developed at Economists Incorporated. The mathematical details are presented in Exhibit PEG-13.

5.2. Results of the DPT for PJM50 Sub-market

The results of the DPT for PJM50 are presented in Exhibit PEG-14. The top part of the exhibit shows the results for AEC. PSEG passes the Pivotal Supplier Screen in all 10 periods. PSEG also passes both the Market Share Screens and the HHI Screens in all 10 periods.

The lower part of Exhibit PEG-14 shows the results for EC in PJM50. PSEG passes all the screens in all the periods, except for the pivotal supplier screen in the Summer Top 1% period.

[42] This is a reasonable estimate for the long-term load coverage since this number is generally between 60 and 80 percent for most generation suppliers in restructured markets.

5.3. Results of the DPT for PJME Sub-market

The results of the DPT for PJME are presented in Exhibit PEG-15. The top part of the exhibit shows the results for AEC. PSEG passes all the screens for AEC.

The lower part of Exhibit PEG-15 shows the results for EC in PJME. PSEG passes the Market Concentration screens in all periods. It passes the Market share screens in six of ten periods, and its market share is never more than 25 percent. It passes the pivotal supplier screen in eight of ten periods.

5.4. Analysis of the DPT Results

Although PSEG fails some screens, the overall results are not indicative of PSEG having market power. To begin, PSEG passes all the AEC screens and all market concentration (HHI) screens for EC. The HHI levels in all periods, capacity types, and areas are below the screening threshold of 2,500, and typically substantially below this level. In terms of the DPT for market rate authority and under the 2010 DOJ and FTC Horizontal Merger Guidelines, the market is not highly concentrated.[43] The low HHI levels mean that PSEG has little ability to exercise market power in coordination with other suppliers. It also passes all the AEC pivotal supplier screens, and most of the EC pivotal supplier screens. This means that typically PSEG's generation is not necessary to serve load; and when its generation is necessary, its forward sale commitments are sufficient so that its uncommitted generation is not necessary to serve the remaining load. Finally, PSEG's market shares are never above 15 percent in PJM50 and for AEC in PJM East. Its market shares for EC are never above 25 percent in PJM East. Although greater than the 20 percent screen, PSEG's

[43] See U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Issued August 19, 2010, at Section 5.3, available at http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

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market shares are well below the 35 percent threshold that is typically used for imputing unilateral market power.[44]

5.5. Mitigation

PJM has a Commission-approved market monitoring and mitigation plan in place to ensure that generation facilities cannot exercise market power. The Commission has stated that Commission-approved market monitoring and mitigation plans are sufficient to mitigate market power in RTO markets.[45] In particular, the Commission found in connection with PSEG's last triennial filing that the PJM market monitoring and mitigation rules are sufficient to address market power concerns.[46]

Under the local market power mitigation procedures in PJM, if a supplier fails the "three pivotal supplier test" (TPS), it is offer-capped by the Market Monitor. The Market Monitor's TPS test is applied on an ongoing basis, potentially as frequently as every 5 minutes, to reflect day-ahead and real-time operating conditions. These offer caps provide direct protection against the exercise of locational market power by suppliers in PJME, PJM50, PJMAP and elsewhere.

The protection against the exercise of market power is enhanced by "must offer" requirements under PJM's Operating Agreement. These mandate that generation resources that are used to meet capacity requirements in PJM and

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[44] *See*, *e.g.*, U.S. Department of Justice, 1984 Merger Guidelines, at Section 3.12, available at https://www.justice.gov/sites/default/files/atr/legacy/2007/07/11/11249.pdf ("the Department is likely to challenge the merger of any firm with a market share of at least one percent with the leading firm in the market, provided the leading firm has a market share that is at least 35 percent.")..

[45] Order No. 697 at P 241.

[46] *See* October 14, 2014 letter order approving Applicants' prior triennial market update in Docket No. ER10-1789-003 et al. at page 3.

that are not subject to an outage must offer their available capacity in PJM's day-ahead energy market.[47] PJM has also implemented a Reliability Pricing Model (RPM) to secure sufficient capacity to meet its requirements through a series of auctions, including a Base Residual Auction (BRA) held annually for capacity 3 years in advance, and incremental auctions held at varying intervals prior to the delivery year. Various features of the RPM process work to prevent the exercise of market power in capacity markets in PJM. First, the RPM model includes bid cap rules designed to mitigate the potential exercise of market power. Second, RPM includes a must-offer requirement pursuant to which all generating units that have available capacity must bid into the RPM auctions or face disqualification from being recognized as capacity resources (and therefore from receiving any capacity payments) in the delivery year.

In addition to the local market power mitigation described above, the presence of market monitoring within PJM lessens potential concerns that PSEG might be able to exercise market power notwithstanding the indicative DPT screens. The Market Monitor has the specific responsibility under the market monitoring plan to monitor the potential of any market participant to exercise market power. To perform its market monitoring function, the Market Monitor can file reports or complaints with the Commission and other government agencies to address various market concerns including market power. The Market Monitor can also make its view known to the Commission staff and PJM members in cases where PJM does not follow its recommendations concerning complaints or requested rule changes. In addition, the Market Monitor can consult with regulatory bodies, including state commissions, regarding the need for specific investigations and monitoring activities, and to consider and evaluate additional enforcement mechanisms. The Market Monitor can also act on specific

[47] *See* PJM Operating Agreement at 1.10.1A(d).

complaints that have been filed by market participants to examine any potential market power issues.

In sum, the local market power mitigation rules, the role of the Market Monitor, the existence of must-offer requirements and PJM's RPM auctions address the potential for PSEG to exercise market power.

6. Vertical Market Power

In determining whether the market-based rates are in the public interest, the Commission also considers whether the Applicant has transmission market power or can erect barriers to entry.[48] None of these factors are relevant in the instant case. First, other than incidental generator interconnection facilities and the transmission assets owned by PSE&G in PJM, no transmission assets are owned by the Applicants or any of their affiliates in ISO-NE and NYISO. Transmission service over PSE&G's transmission facilities is provided under the PJM Open Access Transmission Tariff. Thus, consistent with Commission precedent, Applicants have alleviated any concerns regarding potential transmission market power. Second, PSEG has no ability to erect barriers to entry. As explained in Applicants' previous initial applications for market-based rate authority and triennial market power reports, PSEG is unable to erect barriers to entry. There has been no change in facts since the submission of those applications that would alter this conclusion.

The Commission is concerned with the ownership of natural gas pipelines or natural gas distribution facilities and the possibility that they may be used to exercise market power in electricity markets. PSEG does not own or operate any

[48] Order No. 697 at PP 397, 399.

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FERC jurisdictional natural gas pipelines in PJM, ISO-NE or NYISO.[49] PSE&G owns natural gas distribution facilities in the State of New Jersey including peak-shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers.

7. Conclusion

PSEG and its subsidiaries do not have market power in New England, New York or PJM. PSEG is not a pivotal supplier in New England, New York or PJM. PSEG's market shares in the WMSA are below the Commission's 20 percent screening threshold in each of these market areas. PSEG is also not a pivotal supplier in the Connecticut or Southwest Connecticut sub-markets and its market shares in the WMSA are below 20 percent in these sub-markets. PSEG fails the WMSA screens in only the PJME and PJM50 sub-markets. For these sub-markets, we conducted a DPT analysis. PSEG passes all the DPT screens for the PJM50 submarket, and it only fails the Market Share Screen in the PJME submarket. Its market shares are never above 25 percent, a level that the Commission has accepted in other market-based rate matters.[50] As such, they are not evidence of actual market power.

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[49] PSEG Power LLC currently owns a 10 percent interest in the PennEast Pipeline Company LLC which has filed an application with FERC for construction and operation of a gas transmission line.

[50] *See*, *e.g.*, *Dogwood Energy, LLC*, 135 FERC ¶ 61,089 (2011) (under the AEC measure, Dogwood failed the market share screen in seven of ten periods, with market shares ranging from 32.7% to 39.6%); *Kansas City Power & Light Company and KCP&L Greater Missouri Operation Company*, Docket No. ER10-2074-001 et al., Supplement to Change in Status Filing at 11 (Feb. 4, 2013) (accepted by Letter Order, November 22, 2013) (market shares for AEC ranging from 17 to 36%); *Shell Energy N.A. (US), L.P.*, 135 FERC ¶ 61,090 (2011) (under the AEC measure, Shell failed the market share screen for seven of ten periods, with market shares ranging from 29.3% to 37.0%); *Calpine Energy Services, L.P.*, 137 FERC ¶ 61,085 at P 21 (2011) (under the AEC measure, Calpine failed the market share screen in all ten periods, with market shares ranging from 20.4% to 28.9%); *Wildcat Power Holdings, LLC*, 136 FERC ¶ 61,013 at P 14 (2011) ("When the available economic capacity measure is used, Wildcat Power's market shares range from 22 to 24 percent in the three summer super peak and winter

Further, PSEG operates under New England's, New York's, and PJM's market power mitigation programs, which mitigate PSEG's potential market power. Therefore, under standards for market-based rate authority articulated by the Commission in Order No. 697, PSEG has no ability to exercise market power in the relevant markets, and maintaining market-rate authority in New England, New York and PJM would be in the public interest.

Therefore, I recommend that the Commission continue to authorize PSEG to sell electric power in Northeast Region wholesale markets at market-based rates.

super peak season/load periods and zero percent in the remainder of the season/load periods."); *LS Power Marketing*, LLC,139 FERC ¶ 61,140 at P 23 (2012) (under the AEC measure, LS Power failed the market share screen in all ten periods, with market shares ranging from 20.4% to 28.9%); *Gila River Power, L.P.*, Docket Nos. ER05-1178-015, et al., Second Supplement to Updated Market Power Analysis at 4 (Jan. 12, 2011) (accepted by Letter Order, April 5, 2011) (market shares for AEC ranging from 21 to 23% in four season/load periods).

Pursuant to 28 U.S.C. §1746, I state under penalty of perjury that the foregoing is true and correct to the best of my information, knowledge, and belief.

Executed on this 22rd day of December 2016.

John R. Morris, Ph.D.
Principal
Economists Incorporated

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EXPERIENCE AND QUALIFICATIONS OF

Dr. John R. Morris

OVERVIEW	Dr. Morris, a recognized expert in studying competition in energy industries, currently is a Principal at Economists Incorporated. He began his research of competition in energy industries in 1985 while working for the Federal Trade Commission. Since joining Economists Incorporated in 1992, he has consulted on many mergers and acquisitions involving energy companies, examined competitive issues relating to rates, and studied issues in state restructuring proceedings. He has published articles on competition and energy matters, and he has spoken on numerous occasions concerning competition in natural gas, electric power and other industries. He has been accepted as an expert witness on energy matters before the Federal Energy Regulatory Commission, state regulatory commissions, and in federal court.
EDUCATION	Ph.D., University of Washington, August 1985 Dissertation: *Intellectual Property: Creating, Pricing, Copying* • M.A., University of Washington, December 1983 • A.B., Georgetown University, May 1981
PRESENT POSITION	Dr. Morris is a *Principal* at Economists Incorporated, an economic consulting firm located at 2121 K Street, NW, Suite 1100, Washington, DC 20037. (202-223-4700) Economists Incorporated studies competition and regulation in many industries in the United States and in other countries. It is a leading firm in studying the competitive effects of mergers and acquisitions.
PREVIOUS EXPERIENCE	*Senior Vice President*, Economists Incorporated, December 2001 – December 2002 • *Vice President*, Economists Incorporated, December 1995 – December 2001 • *Senior Economist*, Economists Incorporated, June 1992 – December 1995 • *Economic Tutorial Leader*, Stanford University (Stanford in Washington), April 1993 – June 1995 • *Visiting Assistant Professor,* Department of Business Economics and Public Policy, School of Business, Indiana University, September 1991 – May 1992 • *Assistant to the Director for Antitrust,* Bureau of Economics, Federal Trade Commission, November 1989 – August 1991 • *Economic Advisor,* Office of Commissioner Machol, Federal Trade Commission, December 1988 – October 1989 • *Economist,* Division of Antitrust, Bureau of Economics, Federal Trade Commission, October 1985 – December 1988
MEMBERSHIPS	Member, International Association of Energy Economics • Associate, Energy Bar Association • Member, American Economic Association • Member, Western Economic Association International • Associate, American Bar Association

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AWARDS & HONORS

Award for Excellence in Law Enforcement, Federal Trade Commission, 1988 • Graduate School Scholarship, University of Washington, 1984 • Graduated Cum Laude Georgetown University, 1981 • Senior Comprehensive Passed with Distinction, Georgetown University, 1981

TESTIMONY BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Affidavit, Alabama Power Company, *et al.*, ER17-514-000 (2016) • Affidavits (3), Alabama Power Company, *et al*., EL15-39-000 (2016) • Affidavit, Combined Locks Energy Center, LLC, *et al.* , ER10-3042-004 (2015) • Affidavit, Alabama Power Company, *et al*., EL15-39-000 (2015) • Affidavit, PJM Interconnection, L.L.C., ER15-623-000 (2015) • Affidavit, Southern Indiana Gas and Electric Co. d/b/a Vectren Energy Delivery of Indiana, Inc., ER10-1338-000 (2014) • Affidavit, Quantum Choctaw Power, LLC *et al*., ER12-458-007 (2014) • Affidavit, NRG Power Marketing LLC, *et al.*, ER10-2265-004 *et al.* (2014) • Affidavit, TransCanada Entities, ER10-2870-004 *et al*. (2014) • Affidavit, Tampa Electric Company, ER10-1437-002 (2014) • Affidavit, Kendall Green Energy LLC, ER14-1363-003 (2014) • Affidavit, Quantum Lake Power, LP, ER13-1489-000 (2014) • Affidavit, NRG Power Marketing LLC, *et al.* ER10-2265-002 (2014) • Affidavit, NRG Yield, Inc., *et al*., EC14-101-000 (2014) • Affidavit, Community Wind Farm 1 et al., ER14-1668-000 (2014) • Seaway Crude Pipeline Company LLC, OR15-6-000 (2014) • Affidavit, Public Service Electric and Gas Company *et al.*, ER10-1789-003 (2013) • Affidavits, NRG Energy Holdings, Inc., Edison Mission Energy, EC14-14-000 (2013) • Affidavit, Silver Merger Sub, Inc., *et al.*, EC13-128-000 (2013) • Prepared Answering Testimony, Deposition, and Hearing, Puget Sound Energy, Inc., *et al.*, EL01-10-085 (2012) • Affidavit, Wisconsin Public Service Corporation, *et al*., ER10-1894-004 (2012) • Affidavit, PSEG New Haven LLC, ER12-1250-000 (2012) • Affidavit, Enterprise Product Partners L.P. and Enbridge, Inc., OR12-4-000 (2012) • Affidavit, Southern Indiana Gas and Electric Co., ER10-1338-001 (2011) • Affidavit, TransCanada Power Marketing Ltd. *et al.*, ER10-2780-001 (2011) • Affidavit, Tampa Electric Company, ER10-1476-001 (2011) • Affidavit, Cedar Creek Wind Energy, LLC, ER11-2577-000 (2010) • Affidavit, Public Service Electric and Gas Company *et al.*, ER97-837-014 (2010) • Affidavit, Morris Energy Group, LLC v. PSEG Energy Resources & Trade LLC; PSEG Fossil LLC; and PSEG Power LLC, EL10-79-000 (2010) • Affidavit, UGI Storage Company and UGI Central Penn Gas, Inc., CP10-23-000 (2010) • Prepared Answering Testimony, People of the State of California, *ex rel*; Bill Lockyer, Attorney General of the State of California v. Powerex Corp., *et al.*, EL02-71-000 (2009) • Affidavit, Integrys Energy Services, Inc. v. New Brunswick Power Generation Corporation, EL09-32-002 (2009) • Affidavit, People of the State of California, *ex rel*; Edmund G. Brown Jr. Attorney General of the State of California v. Powerex Corp., *et al.*, EL09-56-000 (2009) • Affidavit, San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, EL00-95-000 (2009) • Affidavit, Troy Energy, LLC, *et al.*, ER02-25-010 (2009) • Affidavit, Combined Locks Energy Center, LLC,

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et al., ER01-2659-015 (2009) • Prepared Direct Testimony and Deposition, Energy Transfer Partners, *et al*., IN06-3-003 (2009) • Prepared Direct Testimony and Hearing, Mobil Pipe Line Company, OR07-21-000 (2009) • Idaho Power Company, ER06-787-002 (2009) • Affidavit, Southern Indiana Gas and Electric Co. d/b/a Vectren Energy Delivery of Indiana, Inc. ER96-2734-007 (2008) • Affidavit, Choctaw Gas Generation, LLC, *et al.* ER08-1332-002 • Affidavit, TransCanada Energy Sales Ltd., ER09-328-001 (2008) • Prepared Direct Testimony and Deposition, Oasis Pipeline L.P., *et al.*, IN06-3-004 (2008) • Affidavit, Tampa Electric Company, ER99-2342-012 (2008) • Affidavit, ANP Bellingham Energy Company, LLC, *et al.*, ER00-2117-005 (2008) • Affidavit, SUEZ Energy Marketing, NA, *et al.*, ER06-169-003 (2008) • Affidavit, TransCanada Energy Marketing ULC, *et al.*, ER07-1274-001 (2008) • Affidavit, Georgia-Pacific Brewton LLC, *et al.*, ER08-1126-000 (2008) • Affidavit, Montgomery L'Energia Power Partners LP, ER08-864-000 (2008) • Affidavit (with Joseph P. Kalt), Energy Transfer Partners, *et al*., IN06-3-002 (2008) • Affidavit, Energy Transfer Partners, *et al*., IN06-3-002 (2008) • Affidavit, TransCanada Maine Wind Development Inc., ER08-685-000 (2008) • Affidavit (with Joseph P. Kalt), Energy Transfer Partners, *et al*., IN06-3-000 (2007) • Affidavit, Energy Transfer Partners, *et al*., IN06-3-000 (2007) • Affidavit, The People of the State of Illinois, *ex rel.* Illinois Attorney General Lisa Madigan v. Exelon Generation Co., LLC, *et al.*, EL07-47-000 (2007) • Affidavit, Baltimore Gas and Electric Company, ER07-576-000 (2007) • Affidavit, Trans-Allegheny Interstate Line Company, ER07-562-000 (2007) • Affidavit, TransCanada Energy Marketing Ltd., *et al.*, ER07-331-000 (2006) • Affidavit, Tampa Electric Company, ER99-2342-000, ER07-173-000 (2006) • Affidavit, Koch Supply & Trading, LP, ER07-100-000 (2006) • WPS Resources Corporation and Peoples Energy Corporation, EC06-152-000 (2006) • Affidavit, Sabine Cogen, LP, ER06-744-000 (2006) • Affidavit, Air Liquide Large Industries U.S. LP, ER06-743-000 (2006) • Affidavit, ANP Bellingham Energy Company, LLC., *et al.*, ER00-2117-000 (2005) • Affidavit, Duke Energy Corporation and Cinergy Corp., EC05-103-000 (2005) • Affidavit, El Paso Marketing, L.P., *et al.*, ER95-428-000 (2005) • Affidavit, TransCanada Energy Ltd., *et al.*, ER95-692-000 (2005) • Affidavit, Granite Ridge Energy, LLC, ER00-1147-000, ER05-287-001 (2005) • Affidavit, TransCanada Power (Castleton) LLC, ER05-743-000 (2005) • Affidavit, Tampa Electric Company, *et al*., ER99-2342-003 (2005) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-035 and Wisconsin Public Service Corporation, ER95-1528-010 (2005) • Affidavit, Wisconsin River Power Company, ER05-453-000 (2005) • Affidavit, Upper Peninsula Power Company, ER05-89-001 (2005) • Affidavit, Southern Indiana Gas and Electric Company, ER96-2734-003 (2004) • Affidavit, Tampa Electric Company, *et al*., ER99-2342-003 (2004) • Affidavits, TransCanada Hydro Northeast, Inc., *et al*., EC05-12-000, ER05-111-000 (2004) • Affidavits, Dominion Energy New England,

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Inc., *et al*., EC05-4-000, ER05-34-000 (2004) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-033 and Wisconsin Public Service Corporation, ER95-1528-008 (2004) • Affidavit, NorthPoint Energy Solutions Inc. ER04-1244-000 (2004) • Affidavit, Union Power Partners, L.P., ER01-930-004 (2004) • Affidavit, Panda Gila River, L.P., ER01-931-004 (2004) • Affidavit, Dominion Energy Kewaunee, Inc., ER04-318-000 (2003) • Affidavit, TPS GP, Inc., TPG LP, Inc., Panda GS V, LLC & Panda GS VI, LLC, EC03-90-000 (2003) • Affidavit, Berkshire Power Company, L.L.C. *et al.*, ER99-3502-001 (2002) • Affidavit, El Paso Merchant Energy, L.P., ER95-428-024 (2002) • Affidavit, Tampa Electric Company, ER99-2342-001 (2002) • Affidavit, Hardee Power Partners Limited, ER99-2341-001 (2002) • Affidavit, TECO-PANDA Generating Company, L.P., ER02-1000-000 (2002) • Affidavit, Commonwealth Chesapeake Company, LLC, ER99-415-004 (2002) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-031 and Wisconsin Public Service Corporation, ER95-1528-006 (2001) • Affidavit, TPS McAdams, LLC and TPS Dell, LLC, ER02-507-000 and ER02-510-000 (2001) • Affidavits, Prepared Direct Testimony, and Hearing, CPUC v. El Paso Natural Gas Company, et al., RP00-241-000 (2000-2001), Affidavit, El Paso Energy Corporation and The Coastal Corporation, EC00-73-000, (2000) • Affidavit, El Paso Energy Corporation and Sonat Inc., EC99-73-000 (1999) • Prepared Testimony, San Diego Gas & Electric Company and Enova Energy, Inc., EC97-12-000 (1997) • Prepared Testimony and Hearing, Wisconsin Electric Power Co., Northern States Power Co. (Minnesota), Northern States Power Co. (Wisconsin), and Cenerprise, Inc., EC95-16-000 (1996)

TESTIMONY BEFORE STATE REGULATORY COMMISSIONS

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Northeast Region Generation Owned and Controlled by PSEG

			Owned Capacity		Controlled Capacity	
Owner	**Plant Name**	**State**	**Winter Seasonal Capacity**	**Summer Seasonal Capacity**	**Winter Seasonal Capacity**	**Summer Seasonal Capacity**
ISO - New England						
PSEG Power CT	Bridgeport Station 2	CT	148	130	148	130
PSEG Power CT	Bridgeport Station 3	CT	385	383	385	383
PSEG Power CT	Bridgeport Station 4	CT	20	15	20	15
PSEG Power CT	New Haven Harbor 1	CT	455	448	455	448
PSEG New Haven	New Haven Harbor GT2	CT	61	61	0	0
PSEG New Haven	New Haven Harbor GT3	CT	61	61	0	0
PSEG New Haven	New Haven Harbor GT4	CT	61	61	0	0
Total ISO - New England Capacity			**1,190**	**1,158**	**1,008**	**976**
New York ISO						
PSEG Power NY	Bethlehem Energy Center CC	NY	845	754	845	754
Total New York ISO Capacity			**845**	**754**	**845**	**754**
PJM						
PSEG Fossil	Conemaugh 1	PA	191	191	191	191
PSEG Fossil	Conemaugh 2	PA	191	191	191	191
PSEG Fossil	Conemaugh A[1]	PA	1	1	1	1
PSEG Fossil	Conemaugh B	PA	1	1	1	1
PSEG Fossil	Conemaugh C	PA	1	1	1	1
PSEG Fossil	Conemaugh D	PA	1	1	1	1
PSEG Power	Conemaugh Hydroelectric Plant 1[2]	PA	1	1	1	1
PSEG Power	Conemaugh Hydroelectric Plant 2	PA	1	1	1	1
PSEG Fossil	Keystone 1[3]	PA	194	194	194	194
PSEG Fossil	Keystone 2	PA	194	194	194	194
PSEG Fossil	Keystone 3	PA	1	1	1	1
PSEG Fossil	Keystone 4	PA	1	1	1	1
PSEG Fossil	Keystone 5	PA	1	1	1	1
PSEG Fossil	Keystone 6	PA	1	1	1	1
PSEG Solar Source LLC	Wyandot Solar Farm	OH	12	12	12	12

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Northeast Region Generation Owned and Controlled by PSEG

Owner	Plant Name	State	Owned Capacity		Controlled Capacity	
			Winter Seasonal Capacity	Summer Seasonal Capacity	Winter Seasonal Capacity	Summer Seasonal Capacity
PJM East						
PSEG Fossil	Bergen 3[7]	NJ	21	21	21	21
PSEG Fossil	Bergen CC1	NJ	628	628	628	628
PSEG Fossil	Bergen CC2	NJ	550	555	550	555
PSEG Fossil	Burlington 8[7]	NJ	21	21	21	21
PSEG Fossil	Burlington 9[10]	NJ	184	184	184	184
PSEG Fossil	Burlington 11[7]	NJ	184	184	184	184
PSEG Fossil	Burlington 121	NJ	42	42	42	42
PSEG Fossil	Burlington 122	NJ	42	42	42	42
PSEG Fossil	Burlington 123	NJ	42	42	42	42
PSEG Fossil	Burlington 124	NJ	42	42	42	42
PSEG Fossil	Edison 1[7]	NJ	168	168	168	168
PSEG Fossil	Edison 2[7]	NJ	168	168	168	168
PSEG Fossil	Edison 3[7]	NJ	168	168	168	168
PSEG Fossil	Essex 9	NJ	81	81	81	81
PSEG Fossil	Essex 10[7]	NJ	168	168	168	168
PSEG Fossil	Essex 11[7]	NJ	168	168	168	168
PSEG Fossil	Essex 12[7]	NJ	168	168	168	168
PSEG Nuclear	Hope Creek 1	NJ	1,161	1,161	1,161	1,161
PSEG Fossil	Hudson 2	NJ	608	608	608	608
PSEG Fossil	Kearny 9[8]	NJ	21	21	21	21
PSEG Fossil	Kearny 12	NJ	175	175	175	175
PSEG Fossil	Kearny 13	NJ	0	178	0	178
PSEG Fossil	Kearny 14	NJ	0	89	0	89
PSEG Fossil	Linden 1	NJ	455	458	455	458
PSEG Fossil	Linden 2	NJ	775	778	775	778
PSEG Fossil	Linden 7	NJ	84	84	84	84
PSEG Fossil	Linden 8	NJ	84	84	84	84
PSEG Fossil	Linden GT5	NJ	86	86	86	86
PSEG Fossil	Linden GT6	NJ	86	86	86	86
PSEG Hackettstown LLC	Mars Solar Garden	NJ	2	2	2	2
PSEG Fossil	Mercer 1	NJ	316	316	316	316
PSEG Fossil	Mercer 2	NJ	316	316	316	316

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Northeast Region Generation Owned and Controlled by PSEG

			Owned Capacity		Controlled Capacity	
Owner	**Plant Name**	**State**	**Winter Seasonal Capacity**	**Summer Seasonal Capacity**	**Winter Seasonal Capacity**	**Summer Seasonal Capacity**
PSEG Fossil	Mercer GT3[9]	NJ	115	115	115	115
PSEG Solar Source LLC	Milford Solar Farm	DE	15	15	15	15
PSEG Fossil	National Park GT1[7]	NJ	21	21	21	21
PSEG Nuclear	Salem 1[4]	NJ	674	674	674	674
PSEG Nuclear	Salem 2	NJ	665	665	665	665
PSEG Nuclear	Salem GT3	NJ	22	22	22	22
PSEG Fossil	Sewaren 1	NJ	104	104	104	104
PSEG Fossil	Sewaren 2	NJ	118	118	118	118
PSEG Fossil	Sewaren 3	NJ	107	107	107	107
PSEG Fossil	Sewaren 4	NJ	124	124	124	124
PSEG Fossil	Sewaren 6[7]	NJ	105	105	105	105
PSE&G	Solar 4 All Units	NJ	78	78	78	78
PSEG Fossil	Yards Creek 1[5]	NJ	70	70	0	0
PSEG Fossil	Yards Creek 2	NJ	70	70	0	0
PSEG Fossil	Yards Creek 3	NJ	60	60	0	0
PJM 5004/5005						
PSEG Nuclear	Peach Bottom 2[6]	PA	561	561	561	561
PSEG Nuclear	Peach Bottom 3	PA	561	561	561	561
Total PJM Capacity			**11,272**	**11,550**	**11,072**	**11,350**
Total Northeast Region Capacity			**13,307**	**13,462**	**12,926**	**13,080**

Source: PSEG.
Notes:
[1] PSEG Fossil has a 22.5% interest in the Conemaugh coal-fired units.
[2] PSEG Global has a 4% interest in the Conemaugh Hydroelectric facility.
[3] PSEG Fossil has a 22.84% ownership interest in the Keystone facility.
[4] PSEG Nuclear has a 57.41% interest in the Salem Nuclear facility.
[5] PSEG Fossil has a 50% interest in the Yards Creek facility. Yards Creek is operated by Jersey Central Power & Light, and thus is controlled by JCP&L in the analysis.
[6] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear facility.
[7] Unit retired on 06/01/2015
[8] Unit retired on 08/31/2014
[9] Unit retired on 07/31/2015
[10] Unit retired on 06/30/2014

Scenario 1 PSEG 2016 MBR for ISONE

	PSA		WMSA							
			Winter		Spring		Summer		Fall	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result
ISO New England	8,715	Pass	5.4	Pass	5.2	Pass	6.5	Pass	6.0	Pass
Connecticut	3,388	Pass	11.8	Pass	11.3	Pass	14.3	Pass	13.3	Pass
Southwest Connecticut	1,701	Pass	16.4	Pass	15.7	Pass	14.9	Pass	13.0	Pass

Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **ISONE**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	16	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	190	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	30,892	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	16	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,358	Calculated
I	Study Area Reserve Requirement	2,510	Gendata
J	Amount of Line I Attributable to Seller, if any	3	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	16,073	
	Load		
L	Balancing Area Annual Peak Load	24,054	Loads
M	Average Daily Peak Native Load in Peak Month	17,708	Loads
N	Amount of Line M Attributable to Seller, if any	10	SellerLoads
O	Wholesale Load (L-M)	6,346	
P	Net Uncommitted Supply (K-O)	9,728	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,012	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	4,548
% of SIL for Seller's imported capacity →	0.04
% of SIL for Other's imported capacity →	0.96
SIL Value →	4548
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **CT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	843	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	102	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	7,524	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	2,948	Calculated
I	Study Area Reserve Requirement	689	Gendata
J	Amount of Line I Attributable to Seller, if any	10	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	5,674	
	Load		
L	Balancing Area Annual Peak Load	6,419	Loads
M	Average Daily Peak Native Load in Peak Month	5,054	Loads
N	Amount of Line M Attributable to Seller, if any	14	SellerLoads
O	Wholesale Load (L-M)	1,365	
P	Net Uncommitted Supply (K-O)	4,309	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	920	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	3,050	
	% of SIL for Seller's imported capacity →	0.03	
	% of SIL for Other's imported capacity →	0.97	
	SIL Value →	3050	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **SWCT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	400	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	98	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	2,090	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	3,102	Calculated
I	Study Area Reserve Requirement	205	Gendata
J	Amount of Line I Attributable to Seller, if any	0	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	2,985	
	Load		
L	Balancing Area Annual Peak Load	3,286	Loads
M	Average Daily Peak Native Load in Peak Month	2,500	Loads
N	Amount of Line M Attributable to Seller, if any	0	SellerLoads
O	Wholesale Load (L-M)	786	
P	Net Uncommitted Supply (K-O)	2,199	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	498	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	3,200	
	% of SIL for Seller's imported capacity →	0.03	
	% of SIL for Other's imported capacity →	0.97	
	SIL Value →	3200	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II – Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **ISONE**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	860	852	843	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	12	16	16	16	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	29	87	7	79	SellerGendata
E	Uncommitted Capacity Imports	222	188	177	188	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	16,956	14,847	17,687	15,178	Loads
G	Amount of Line F Attributable to Seller, if any	113	102	39	5	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	16,843	14,745	17,648	15,173	F - G
I	Study Area Reserve Requirement	2,530	2,510	2,510	2,510	Gendata
J	Amount of Line I Attributable to Seller, if any	16	20	10	3	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,514	2,490	2,500	2,507	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	32,149	30,892	29,634	30,892	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	12	16	16	16	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,097	3,148	229	2,881	Gendata; Row D
P	Uncommitted Capacity Imports	4,326	4,360	4,371	4,360	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	16,033	14,885	13,644	14,707	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	911	815	948	935	
S	Total Seasonal Uncommitted Capacity (Q+R)	16,944	15,700	14,592	15,642	
T	**Applicant's Market Share (R÷S)**	5.4%	5.2%	6.5%	6.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	4,548	4,548	4,548	4,548	
V	SIL Value	4,548	4,548	4,548	4,548	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II – Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **CT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	860	852	843	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	29	87	7	79	SellerGendata
E	Uncommitted Capacity Imports	106	93	93	94	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	4,207	3,642	4,503	3,772	Loads
G	Amount of Line F Attributable to Seller, if any	113	102	39	5	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	4,093	3,540	4,464	3,766	F - G
I	Study Area Reserve Requirement	683	683	689	683	Gendata
J	Amount of Line I Attributable to Seller, if any	21	22	10	3	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	662	661	679	680	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	8,048	7,786	7,524	7,786	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	275	793	58	726	Gendata; Row D
P	Uncommitted Capacity Imports	2,944	2,957	2,957	2,956	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	5,963	5,749	5,279	5,570	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	802	734	881	857	
S	Total Seasonal Uncommitted Capacity (Q+R)	6,765	6,482	6,160	6,427	
T	**Applicant's Market Share** (R÷S)	11.8%	11.3%	14.3%	13.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	3,050	3,050	3,050	3,050	
V	SIL Value	3,050	3,050	3,050	3,050	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II – Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **SWCT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	407	404	400	404	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	14	41	3	38	SellerGendata
E	Uncommitted Capacity Imports	86	68	91	101	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	2,048	1,758	2,178	1,766	Loads
G	Amount of Line F Attributable to Seller, if any	0	0	0	0	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	2,048	1,758	2,178	1,766	F - G
I	Study Area Reserve Requirement	209	206	205	206	Gendata
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	209	206	205	206	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	2,321	2,206	2,090	2,206	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	79	225	16	206	Gendata; Row D
P	Uncommitted Capacity Imports	2,454	2,302	3,109	3,089	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	2,439	2,318	2,799	3,116	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	479	430	488	467	
S	Total Seasonal Uncommitted Capacity (Q+R)	2,918	2,748	3,287	3,583	
T	**Applicant's Market Share** (R÷S)	16.4%	15.7%	14.9%	13.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	2,540	2,370	3,200	3,190	
V	SIL Value	2,540	2,370	3,200	3,190	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **NYISO**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	757	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	265	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	585	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	42,506	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,265	Calculated
I	Study Area Reserve Requirement	2,620	Gendata
J	Amount of Line I Attributable to Seller, if any	0	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	22,514	
	Load		
L	Balancing Area Annual Peak Load	31,138	Loads
M	Average Daily Peak Native Load in Peak Month	25,244	Loads
N	Amount of Line M Attributable to Seller, if any	0	SellerLoads
O	Wholesale Load (L-M)	5,894	
P	Net Uncommitted Supply (K-O)	16,620	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,607	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,850	
	% of SIL for Seller's imported capacity →	0.09	
	% of SIL for Other's imported capacity →	0.91	
	SIL Value →	6850	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **NYISO**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	870	814	757	814	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	265	265	265	265	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	71	115	13	92	SellerGendata
E	Uncommitted Capacity Imports	731	600	582	640	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	21,006	18,974	23,056	19,579	Loads
G	Amount of Line F Attributable to Seller, if any	0	0	0	0	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	21,006	18,974	23,056	19,579	F - G
I	Study Area Reserve Requirement	2,620	2,620	2,620	2,620	Gendata
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,620	2,620	2,620	2,620	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	40,162	41,334	42,506	41,334	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,277	5,820	726	4,652	Gendata; Row D
P	Uncommitted Capacity Imports	6,904	6,924	6,268	7,055	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	20,162	20,843	22,372	21,538	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	1,795	1,564	1,591	1,627	
S	Total Seasonal Uncommitted Capacity (Q+R)	21,958	22,407	23,963	23,166	
T	**Applicant's Market Share** (R÷S)	8.2%	7.0%	6.6%	7.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,635	7,524	6,850	7,695	
V	SIL Value	7,635	7,524	6,850	7,695	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Scenario 1 PSEG 2016 MBR for PJM										
	PSA		WMSA							
			Winter		Spring		Summer		Fall	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result
PJM Interconnection	35,891	Pass	9.5	Pass	7.7	Pass	8.3	Pass	8.3	Pass
PJM East	3,572	Pass	32.7	Fail	27.0	Fail	32.9	Fail	29.7	Fail
PJM East of 5004/05	5,389	Pass	24.3	Fail	20.7	Fail	23.7	Fail	23.1	Fail
PJM East of AP South	7,602	Pass	18.5	Pass	15.5	Pass	18.8	Pass	17.0	Pass

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	9,844	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	195	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	1,943	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	152	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	175,931	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	1,943	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	195	Row B; Table2Data
H	Uncommitted Capacity Imports	7,448	Calculated
I	Study Area Reserve Requirement	8,187	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	63,588	
	Load		
L	Balancing Area Annual Peak Load	143,633	Loads
M	Average Daily Peak Native Load in Peak Month	121,600	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	22,034	
P	Net Uncommitted Supply (K-O)	41,555	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,664	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	7,600	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	7600	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	14	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	88	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	26,628	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	14	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,449	Calculated
I	Study Area Reserve Requirement	1,724	Gendata
J	Amount of Line I Attributable to Seller, if any	176	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	15,220	
	Load		
L	Balancing Area Annual Peak Load	30,240	Loads
M	Average Daily Peak Native Load in Peak Month	24,093	Loads
N	Amount of Line M Attributable to Seller, if any	2,269	SellerLoads
O	Wholesale Load (L-M)	6,148	
P	Net Uncommitted Supply (K-O)	9,072	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,500	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,537	
	% of SIL for Seller's imported capacity →	0.01	
	% of SIL for Other's imported capacity →	0.99	
	SIL Value →	6537	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	107	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	51,729	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,212	Calculated
I	Study Area Reserve Requirement	2,975	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	20,577	
	Load		
L	Balancing Area Annual Peak Load	52,190	Loads
M	Average Daily Peak Native Load in Peak Month	42,368	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	9,822	
P	Net Uncommitted Supply (K-O)	10,754	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,365	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,319	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	6319	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	85	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	75,381	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,370	Calculated
I	Study Area Reserve Requirement	4,032	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	25,567	
	Load		
L	Balancing Area Annual Peak Load	70,729	Loads
M	Average Daily Peak Native Load in Peak Month	58,108	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	12,621	
P	Net Uncommitted Supply (K-O)	12,946	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,344	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	4,455	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	4455	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	11,339	10,592	9,844	10,592	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	195	195	195	195	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	1,643	1,944	1,943	1,944	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	491	1,461	225	1,374	SellerGendata
E	Uncommitted Capacity Imports	214	204	138	117	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	108,842	91,954	109,399	91,992	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	106,988	90,430	107,540	90,648	F - G
I	Study Area Reserve Requirement	7,474	6,516	7,991	6,470	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	7,335	6,385	7,817	6,352	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	181,889	178,911	175,931	178,911	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	1,643	1,944	1,943	1,944	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	195	195	195	195	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	7,868	24,681	4,028	23,215	Gendata; Row D
P	Uncommitted Capacity Imports	11,783	12,069	7,462	6,950	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	72,929	71,233	65,756	67,394	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,622	5,931	5,975	6,123	
S	Total Seasonal Uncommitted Capacity (Q+R)	80,550	77,164	71,731	73,518	
T	**Applicant's Market Share** (R÷S)	9.5%	7.7%	8.3%	8.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	11,997	12,273	7,600	7,067	
V	SIL Value	11,997	12,273	7,600	7,067	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	22	14	14	14	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	121	72	78	68	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	18,303	15,919	20,901	16,346	Loads
G	Amount of Line F Attributable to Seller, if any	1,749	1,434	1,764	1,268	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	16,553	14,485	19,137	15,078	F - G
I	Study Area Reserve Requirement	1,258	1,168	1,659	1,211	Gendata
J	Amount of Line I Attributable to Seller, if any	130	122	165	110	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	1,128	1,046	1,494	1,101	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	26,328	26,478	26,628	26,478	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	22	14	14	14	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,139	3,653	610	3,436	Gendata; Row D
P	Uncommitted Capacity Imports	7,381	8,758	6,459	7,791	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	14,911	16,065	11,860	14,667	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,230	5,954	5,826	6,199	
S	Total Seasonal Uncommitted Capacity (Q+R)	22,141	22,019	17,686	20,867	
T	**Applicant's Market Share** (R÷S)	32.7%	27.0%	32.9%	29.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	7,502	8,830	6,537	7,859	
V	SIL Value	7,502	8,830	6,537	7,859	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	162	91	95	69	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	35,188	30,080	37,518	30,214	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	33,334	28,556	35,658	28,871	F - G
I	Study Area Reserve Requirement	2,450	2,184	2,889	2,189	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,311	2,054	2,715	2,071	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	52,220	51,975	51,729	51,975	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	2,259	7,170	1,184	6,744	Gendata; Row D
P	Uncommitted Capacity Imports	7,942	8,202	6,224	6,034	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	22,294	22,424	18,423	20,350	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,144	5,861	5,725	6,103	
S	Total Seasonal Uncommitted Capacity (Q+R)	29,438	28,286	24,148	26,453	
T	**Applicant's Market Share** (R÷S)	24.3%	20.7%	23.7%	23.1%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	8,104	8,293	6,319	6,103	
V	SIL Value	8,104	8,293	6,319	6,103	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	187	115	77	81	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	48,658	41,074	51,437	41,155	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	46,804	39,551	49,577	39,811	F - G
I	Study Area Reserve Requirement	3,496	3,025	3,935	2,991	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	3,358	2,895	3,762	2,873	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	77,314	76,348	75,381	76,348	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,344	10,532	1,726	9,907	Gendata; Row D
P	Uncommitted Capacity Imports	7,710	8,741	4,378	5,987	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	31,554	32,139	24,722	29,772	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,169	5,885	5,707	6,115	
S	Total Seasonal Uncommitted Capacity (Q+R)	38,723	38,024	30,429	35,886	
T	**Applicant's Market Share** (R÷S)	18.5%	15.5%	18.8%	17.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,897	8,856	4,455	6,068	
V	SIL Value	7,897	8,856	4,455	6,068	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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DATA AND ASSUMPTIONS FOR ECONOMISTS INCORPORATED'S DELIVERED PRICE TEST STUDY FOR PSEG

This exhibit describes data and assumptions used in the delivered price test study ("study") carried out by Economists Incorporated for PSEG. Because the data are voluminous, we provide them in electronic workpapers. In those workpapers, the Files.xlsx spreadsheet provides a brief description of the organization of the data files.

This Exhibit has six sections. Section I discusses the study's representative periods. Section II discusses the geographic region and balancing authority areas. Section III discusses generation resources, including adjustments to generating capacity for seasons, maintenance, water availability, and long-term contracts. Section IV discusses transmission, including transmission pricing and losses. Section V discusses market prices. Section VI discusses the load data.

I. Periods

The study calculates market shares and concentration indexes for electric energy for ten representative periods during the year. The year is divided into three seasons (spring/fall, summer and winter). Spring/fall and winter seasons are divided into three periods based on days of the week, times of day and load levels. Summer is divided into four periods based on days of the week, times of day and load levels. Each calculation of market shares and concentration indexes reflects average conditions (e.g., average loads) during one of the resulting ten periods during the year (e.g., Summer Low Peak).

The study places each of the periods in each season into three condition categories: off-peak, low peak, and spike. Transmission pricing (see Section

IV.B below) and plant availability (see Section III.A.2 below) vary among these three categories.

Table I-1 summarizes the ten periods for the destination markets.

Table I-1– Definition of Ten Periods for Destination Market

Number	*Season*	*Time*	*Condition*	*Hours*	*Description**
1	Spring/Fall	Top 10%	Spike	203	Top 10% of peak hours
2	Spring/Fall	Peak	Peak	1829	Remaining peak hours
3	Spring/Fall	Off-peak	Off-Peak	2360	Off-peak hours
4	Summer	Top 1%	Spike	11	Top 1% of peak hours
5	Summer	Top 10%	Spike	106	Top 10% of peak hours
6	Summer	Peak	Peak	950	Remaining peak hours
7	Summer	Off-peak	Off-Peak	1152	Off-peak hours
8	Winter	Top 10%	Spike	101	Top 10% of peak hours
9	Winter	Peak	Peak	907	Remaining peak hours
10	Winter	Off-peak	Off-Peak	1152	Off-peak Hours

Note: *Peak hours include hours ending 8 a.m. through 11 p.m. Eastern Time weekdays, excluding six major holidays. Off-peak hours = Hours ending 12 a.m. through 7 a.m. on weekdays and all weekend and holiday hours.

The Off-peak periods are all NERC holidays and weekend hours plus weekdays from the hour ending at midnight EPT until the hour ending at 0700.[1] The Off-peak periods have off-peak transmission pricing and plant availability.

In order to define the Top 1% and Top 10% periods for a given season, we removed all Off-peak hours from that season. We then ranked the remaining (peak) hours based on load levels in the destination market by season. We then defined as the Top 1% as the 1 percent of these remaining hours in which loads in the destination market were highest and the Top 10% as the highest 10 percent of peak hours based on load levels. These periods have spike transmission pricing and plant availability.

[1] Major holidays are New Year's, Memorial Day, 4th of July, Labor Day, Thanksgiving and Christmas. Major holidays are included in the Weekend period.

The Peak periods are weekdays from the hour ending at 0800 until the hour ending at 2300 EPT, excluding hours in the Top 10% periods and major holidays. The Low Peak period has on-peak transmission pricing and plant availability.

II. Geographic Coverage and Market Areas

The study includes market areas that correspond to the balancing authority areas used by the North American Electric Reliability Council (NERC), and PJM submarkets as defined by FERC. Table II-1 lists these market areas and their abbreviations. There are two study destination markets, PJM East and PJM East of 5004/5005.

Table II-1– List of Eastern Market Areas and Study Destinations

Abbreviation	*Full Name*	*Study Destination*
PJME	PJM East	Yes
PJM50	PJM East of 5004/5005	Yes
PJMS	PJM East of AP South	
PJM	PJM	
NYISO	New York ISO	

III. Generation

A. Generation Capacity and Ownership

The study includes generating units located in the areas that are (1) connected to the power grid, (2) not exclusively used for self-generation, and (3) either in a plant used primarily for electric generation or a Qualifying Facility.

1. Generating Unit Data

The study uses data for summer and winter capability at the unit level reported in the Energy Velocity (EV) database available from Ventyx. The units include all

units with a status of operating, standby, cold standby, restart, mothballed, testing, or under construction that went online before November 30, 2015 and with a retirement date after November 30, 2015. We exclude generation units that are less than 5 MW unless they are owned by PSEG.

2. Ownership

The study uses relies on Ventyx determination of plant and unit ownership. When Ventyx reports a holding company, the ownership is assigned to the holding company. For PSEG generation, the study relies upon Appendix B data from market-based rate filings and updates from the companies to determine plant ownership and seasonal capability. Operational control of PSEG units is consistent with the methodology used for market-based rates.

3. Seasonal variation in capability

The study uses seasonal capability data from EV. Spring/fall capacities are the average of summer and winter capacities.

4. Adjustments to Generating Capability

The generating capability figures used for each period are obtained by multiplying the seasonal capabilities by an availability factor, which is based on the period, unit location, and NERC General Availability Data Systems (GADS) category of the unit. The GADS database gives national average operating information for generating units by unit type and size. For example, it gives data for coal-fired steam units with capacities between 300 MW and 399 MW.

For each period and each generating unit, the availability factor adjusts for the following.

a) Unplanned outage rates by GADS category

For a given GADS category, the study assumes that unplanned (forced) outage rates (as a share of generating capability available after allowing for planned outages) are constant across seasons and generating units throughout the Region, regardless of owner. Based on GADS data for 2007 through 2011, the study calculates an equivalent forced outage rate (EIFOR), which measures the share of generating capability in a GADS category that is not available because of forced outages. The computation is EIFOR = (FOH)/AH, where FOH is number of forced outage hours and AH is total hours available for generation after planned outages (but before forced outages).[2]

b) Planned outage rates by GADS category and season

With four exceptions (hydro, pumped storage, wind, and solar units), the study assumes that the planned outage rate is constant for all generating units for a given GADS category and season. For a given GADS category, the share of hours of generating capability that is not available as a result of planned outages is computed as (POH + POEH)/PH; where PH are the period hours, POH are the hours not available because of planned outages, and POEH are the hours not available because of planned outage extensions

The study assumes that balancing authority areas are both summer and winter peaking. Therefore, the study assumes that all planned outages for thermal units occur during spring/fall.

[2] EIFOR differs slightly from the EFOR provided in the GADS data. EIFOR provides a better measure of a forced outage rate for peaking units that are operated a small percentage of the year.

c) Variation in hydro availability across seasons and periods

In general, utilities use hydro facilities to generate energy during the hours when energy prices are highest, subject to constraints imposed by availability of water and reservoir capacity. In order to incorporate these constraints, the study proceeds in the following manner.

First, the study uses EIA Form 923 monthly production data for the period 2011 to 2015 to compute average hourly hydro generation by season. Average hourly generation is then divided by hydro capability to give an average hourly hydro operating rate by season.

Second, depending upon the level of the hydro operating rate for a given season, the study calculates availability factors for the spike, low peak and off-peak periods. When the historical seasonal operating rate is below 30 percent, the availability factor for each period in the season is set equal to the operating rate; the 30 percent figure is an assumed "run of river" constraint. The study assumes that prospectively the maximum operating rate is 90 percent; this is the assumed "maximum rate" constraint. When the historical seasonal operating rate is above 90 percent, the availability factor for each period is set to 90 percent.

When the seasonal operating rate is above the run of river constraint and below the maximum rate, we reason that the hydro generator owner would be likely to produce a higher level of energy during spike hours, when energy prices are highest, than during low peak hours, and that the owner would be likely to produce a higher level during low peak than during off-peak hours.

Based on this reasoning, when the seasonal operating rate is between the run of river constraint and the maximum rate, as is the case for each of the three

seasons, the study uses a spike availability factor of 90 percent, which is the assumed maximum operating rate, and off-peak availability factor of 30 percent, which is the assumed run-of-river constraint, and a calculated availability factor for the peak periods, as described below.

The seasonal peak availability factor is calculated using actual total seasonal hydro generation. The study then computes the hydro generation during all spike and off-peak hours, assuming the generation rates implied by the spike and off-peak derate factors computed in the manner described above. The study then calculates total peak hydro generation as the difference between total seasonal hydro generation and the sum of hydro generation during all spike and off-peak hours. The seasonal low peak availability factor is computed as total low peak hydro generation divided first by the number of hours in the off-peak period and then by hydro generating capacity.

d) Variation in pumped storage availability across seasons and periods

We assume that pumped storage units have 90 percent availability during Top 1% and Top 10% periods, 50 percent availability during Low Peak periods, and no availability during off-peak periods.

e) Wind availability

For each area, we calculate average operating rates from 2011 to 2015 by season from EIA-923 data. The average operating rates are the availability factors.

f) Solar availability

Availability for solar power is also calculated based on average operating rates from 2011 through 2015 reported in EIA-923. There is little solar power during

off-peak periods because of darkness. Accordingly, solar availability is weighted to on-peak periods.

B. Variable Costs of Generation

The study uses variable costs of generation that include fuel costs, sulfur dioxide and nitrogen oxide emissions costs, and variable operations and maintenance (VOM) costs. The study calculates fuel costs from unit heat rates and Platts' Gas Daily spot prices at the unit's reported natural gas hub by Energy Velocity, #2 Diesel, Low-Sulfur – Industrial for the East Coast, and Residual Fuel Oil sales to end users for the East Coast for the test period. Natural gas prices vary by hub, but were $2.67 per mmBtu at TETCO M3, the hub with the largest reported capacity in the study. Fuel costs for other fuels are based upon the average fuel costs reported in the EV data for each fuel type. Emissions prices during the test year were $2 per ton for SO2 year-round and $300 per ton for NOx in the summer season. CO_2 costs for units located in Regional Greenhouse Gas Initiative (RGGI) states are $5.21/ton, which is based upon RGGI Auction results in Dec 2014. Units in Montgomery County, MD have an additional $5/ton carbon tax on CO_2 emissions. VOM costs are from the EV database.

C. Long-term Contracts

We reviewed Appendix B data from market-based rate filings, FERC Form 1 filings, and Electric Quarterly Report ("EQR") data to obtain data on long-term contracts. Where the market-based rate filing indicates a change of operational control, we include a contract transferring control to the buyer. We leave the generation unit in the BAA where it is physically interconnected to the transmission system. When the buyer is a load-serving entity in another BAA, we give a priority firm transmission path to the BAA with the load.

Long-term contracts that expire prior to January 1, 2015 are not included in the study. Long-term contracts that expire between January 1, 2015 and July 31,

2015 are included only in the seasons for which they are in effect. Contracts that expire after August 31, 2015 are included in the study.

IV. Transmission

A. Transmission Network

The study incorporates a contract path transmission network for modeling purposes. Transmission pricing between balancing authority areas is represented by a traditional contract path transmission network in which the direct physical connections between balancing authority areas are also the individually priced links from which contract paths are constructed.

B. Transmission and Ancillary Services Pricing and Losses

As specified by the Commission's Appendix A, the study generally uses ceiling prices for transmission service from Schedules 1, 2 and 8 of the utility's *pro forma* open-access transmission tariff. Transmission providers may require transmission customers to purchase ancillary services under Schedule 1 (scheduling, system control and dispatch) and Schedule 2 (reactive supply and voltage control). Schedule 8 gives the rates for non-firm point-to-point transmission service. The study uses transmission prices from tariffs.

When we have tariffs available, we calculate rates for off-peak, peak and spike categories. Because of discounting and the nature of baseload purchases, off-peak rates are often lower than peak rates.[3] We use two steps to determine off-peak rates. Step 1: When a utility posts off-peak hourly rates, we use the posted rates. Step 2: When a utility does not post off-peak hourly rates, we calculate an hourly off-peak rate based on other tariff information. To calculate hourly off-

[3] For transactions longer than one hour, the *pro forma* tariff caps the amount that the purchaser pays per day by the daily rate, and the amount that the purchaser pays per week by the weekly rate.

peak rates, we divide the weekly rate by 168, the number of hours in a week. When tariffs specify fees on a per transaction basis, we divide them by 25 to put them on a per MW basis.

We use similar steps to determine peak rates. Step 1: When a utility posts maximum hourly rates in its tariff, we use the maximum tariff rates. Step 2: When a utility does not post off-peak hourly rates, we calculate a peak rate based on other tariff information. To calculate hourly peak rates, we divide the weekly rate by 80—the "Appalachian" method. When tariffs specify fees on a per transaction basis, we divide them by 25 to put them on a per MW basis.

For spike periods, we use ceiling hourly rates from tariffs, when available. Otherwise, we use the Appalachian method.

Whenever practical, the study uses loss rates from tariffs. When these methods did not provide a loss rate for a particular utility, the study assumes that losses are three percent per utility.[4] The study assumes that transmission customers pay losses in-kind. That is, if area A exports 100 MW to area B and the losses are 3 percent, only 97 MW arrive at area B.

For areas where tariffs are not available, rates and losses are the average by period for all the reporting areas.

C. Transfer Capability and SILs

The geographic market includes only PJM and NYISO. The SILs for PJM East and PJM East of 5004/5005 comes from the 2015 Simultaneous Import Limit

[4] Losses of 3 percent are representative of the industry. See, FERC Open Access NOPR, *FERC Stats & Regs*, ¶32,514 at 33,150 (1995).

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Study filed by PJM on September 2, 2016.[5] The total imports into the destination markets may be less than the actual ability to import into the destination because not all the generation capability owned or controlled by load-serving entities within the destination markets studied in PJM have been identified in the data.

V. Market Prices

The study used December 2014-November 2015 real-time hourly prices from the RTO LMP for PJM East and PJM East of 5004/5005. Table V-1 shows the PJM East of 5004/5005 market prices in each of the ten periods, and Table V-2 shows the PJM East market prices.

Table V-1 – PJM East of 5004/5005 Market Prices ($/MWh)

Time	*Spring/Fall*	*Summer*	*Winter*
Top 1%	-----	$148.44	-----
Top 10%	$62.03	$64.59	$185.57
Low Peak	$35.73	$35.56	$47.55
Off-Peak	$29.46	$24.88	$50.16

Table V-2 – PJM East Market Prices ($/MWh)

Time	*Spring/Fall*	*Summer*	*Winter*
Top 1%	-----	$145.63	-----
Top 10%	$57.82	$63.88	$193.51
Low Peak	$32.73	$29.67	$50.59
Off-Peak	$26.67	$21.25	$50.94

[5] PJM Interconnection, L.L.C., *Informational Filing of 2015 Simultaneous Import Limit Study Report for PJM Region*, Docket No. AD1-2-007, September 2, 2016, Accession No. 20160902-5155.

VI. Load and Contract Obligations for AEC Calculations

Load data come from PJM for PJM and from Energy Velocity for the other supply areas.

To compute load requirements for market participants in New York and PJM, we apportion the total load in each market area in New York and PJM to all suppliers in proportion to their respective generation capacities. We assumed 70 percent of load is committed for a year or longer and the remaining 30 percent is contracted for shorter periods.[6] To account for their greater load obligations, we assume that Dominion has 100 percent responsibility for its allocation of load and that AEP has 90 percent of its allocation as opposed to the standard 70 percent.

[6] This is a reasonable estimate for the long-term load coverage since this number is generally between 60 and 80 percent for most generation suppliers.

Technical Appendix:

Methods Used to Compute Concentration

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December 2016

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This Exhibit describes the methods used to calculate market shares and concentration in destination markets.

Allocation of scarce transmission capability is accomplished using linear and nonlinear programs that model generation dispatch and the contract path transmission system. This Exhibit provides an overview of the structure of the programs and presents the equations.

Overview of Linear Program

The linear program models control areas as nodes in a transmission system. Each node has a demand for and a supply of electric energy. The supply is based on the generators at the node and potential deliveries to the node via transmission links from other control areas. The linear program allows for net import and export limits to and from an individual control area. Given generation capability and costs and transmission capability and costs, the linear program finds the least-cost solution that satisfies the specified loads. Costs are defined as dispatch (generation) costs plus transmission costs including losses plus the default cost for "unserved" load. For each solution, the linear program determines the quantities produced in, exported from, and imported into each control area.

The Mathematical Equations

The linear program to be solved is given below:

Minimize Total Cost: $Cost = GC + TC + UC$

Subject to:

(1) Generation: $TG_a = \sum_{u}^{u \in a} G_{a,u}$ for each area *a*;

(2) Imports: $YI_a = \sum_{b}^{a,b \in network} (1 - h_{b,a}) T_{b,a}$ for each area *a*;

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(3)	Exports:	$YE_a = \sum_{b}^{a,b \in network} T_{a,b}$	for each area *a*;
(4)	Net Imports:	$Y_a = YI_a - YE_a$	for each area *a*;
(5)	Supply/Demand Balance:	$TG_a + Y_a + U_a = D_a$	for each area *a*;
(6)	Generation Cost:	$GC = \sum_{a} \sum_{u}^{u \in a} d_{a,u} G_{a,u}$	for each area *a*;
(7)	Transmission Cost:	$TC = \sum_{a,b}^{a,b \in network} r_{a,b} T_{a,b}$	for each path *a* to *b*;
(8)	Unfilled Demand Cost:	$UC = \sum_{a} pU_a$	for each area *a*;
(9)	Generation Limits:	$g\min_{a,u} \le G_{a,u} \le g\max_{a,u}$	for each unit *u* in each area *a*;
(10)	Transmission Limits:	$t\min_{a,b} \le T_{a,b} \le t\max_{a,b}$	for each link *a* to *b* in the transmission network; and
(11)	Net Import Limits	$Y\min_{a} \le Y_a \le Y\max_{a}$	for each area *a*;

where:

a,b	are subscripts for control/transmission areas;
Cost	is total system cost;
$d_{a,u}$	is the dispatch cost of unit *u* in area *a*;
D_a	is demand for power in area *a*;
$G_{a,u}$	is generation output of unit *u* in area *a*;
GC	is total system generation cost;
$G\max_{a,u}$	is the maximum output of unit *u* in area *a*;
$G\min_{a,u}$	is the minimum output of unit *u* in area *a*;
$h_{b,a}$	is the fraction of power lost to resistance from moving power from area *b* to area *a*;
N	is a subscript to identify simultaneous transmission constraint *n*;
P	is the default price;
$r_{a,b}$	is the transmission rate from area *a* to area *b*;

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$T_{a,b}$	is the power flow from area *a* to area *b*;
TC	is total system transportation expenses;
TG_a	is total generation output in area *a*;
t $\max_{a,b}$	is the maximum power flow from area *a* to area *b*;
t $\min_{a,b}$	is the minimum power flow from area *a* to area *b*;
U	is a subscript to identify units in an area;
U_a	is the amount of demand in area *a* not met by generation or imports
UC	is total system cost of not meeting demand;
Y_a	is net imports into area *a*;
YE_a	is total exports from area *a*; and
YI_a	is total imports into area *a*;
Y $\min_a$	is minimum net imports in area *a;*
Y $\max_a$	is maximum net imports in area *a.*

This linear program is solved using the BDMLP solver in GAMS. In order to calculate concentration for different destinations, seasons, and periods, the PASS GAMS program loops through the destinations, seasons, and periods with calls to Solvers to solve the linear programs. Loads, unit availability and transmission availability are adjusted for each season-period combination.

Calculating Concentration

Transmission allocation is accomplished in four steps. In the first step the linear program finds the net-back prices in all control areas given a price at the destination control area equal to 105 percent of the pre-merger price. Suppose the pre-merger price at the destination, control area A, is $20/MWh. Then all generation capability with a dispatch cost of $21/MWh or less in the destination area would be included in the market because $21 is 105 percent of $20. If transmission cost (including losses) is $5/MWh from control area B to A, then the net-back price at B would be $16/MWh, which is the $21/MWh less the $5/MWh transmission cost between B and A. Then, all generation capability at B with dispatch costs equal to or less than $16/MWh would be included in the market if there were no transmission constraints. Calculation of net-back prices is

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accomplished by setting the default price, *p*, equal to 105 percent of the pre-merger price at the destination, setting load at the destination to a high number and loads elsewhere to zero, setting transmission limits high enough so that the transmission system is not constrained, and setting a limited amount of generation in each area with a zero dispatch cost. The shadow prices produced by the linear program will be *p* at the destination and the relevant net-back prices in other areas.

In the second step, one calculates Economic Capacity (EC) and Available Economic Capacity (AEC) in each area. These values are then used to limit generation capability. The ownership shares of AEC and EC are calculated for each node in the system.

In the third step, the linear program determines the amount of energy that can be imported into an area given available EC (or AEC) and limits on transmission capacity. This is accomplished by limiting generation in each area to the capacity amount (EC or AEC), giving generation outside the destination market a lower cost than generation inside the destination market, and minimizing cost to serve a large load at the destination market. The amount of generation supplied to the destination is the maximum that can be imported into the destination market.

In the fourth step, transmission is allocated by the following non-linear program:

Minimize Loss: $$Loss = \sum_{\alpha}\left(\frac{C_{\alpha}^{2}}{Y_{Dest}s_{\alpha}} - 2C_{\alpha}\right)$$

Subject to:

(1) Pre Shares: $$s_{\alpha} = \frac{C\max_{\alpha}}{\sum_{\beta} C\max_{\beta}}$$ for each area α;

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(2)	Allocated Shares:	$A_\alpha = \frac{C_\alpha}{Y_{Dest}}$	for each area α;
(3)	Imports:	$YI_a = \sum_b^{a,b \in network} (1 - h_{b,a}) T_{b,a}$	for each area *a*;
(4)	Exports:	$YE_a = \sum_b^{a,b \in network} T_{a,b}$	for each area *a*;
(5)	Net Imports:	$Y_a = YI_a - YE_a$	for each area *a*;
(6)	Supply/Demand Balance:	$C_a + Y_a + U_a = D_a$	for each area *a*;
(7)	Capacity Limits:	$c\min_a \le C_a \le C\max_a$	for each area *a*;
(8)	Transmission Limits:	$t\min_{a,b} \le T_{a,b} \le t\max_{a,b}$	for each link *a* to *b* in the transmission network; and
(9)	Max Import Limit	Y_{Dest} = Maximum imports from step 3;	

where:

a,b	are subscripts for control/transmission areas;
α,β	are subscripts for control/transmission areas other than the destination market;
s_α	Is area α's share of capacity outside of the destination;
A_α	is area α's share of allocated capacity outside of the destination;
Loss	is the loss function to be minimized.

The loss function is derived from the weighted squared-errors between the pre-allocation shares and the post-allocation shares, where Y_{Dest}/s_α are the weights. For each source control area, the weighted squared-error is given by:[1]

$$W_\alpha = \frac{Y_{Dest}}{s_\alpha}(A_\alpha - s_\alpha)^2.$$

[1] This exposition ignores the adjustments necessary to give priority to minimum transfer levels from a source area to the destination.

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Accordingly, the sum of the weighted squared-errors gives rise to the loss function, which can be seen by:

$$\begin{aligned} Loss &= \sum_{\alpha} W_{\alpha} \\ &= \sum_{\alpha} \frac{Y_{Dest}}{s_{\alpha}} (A_{\alpha} - s_{\alpha})^2 \\ &= \sum_{\alpha} \frac{Y_{Dest}}{s_{\alpha}} (A_{\alpha}^2 - 2 s_{\alpha} A_{\alpha} + s_{\alpha}^2) \\ &= \sum_{\alpha} \left(\frac{C_{\alpha}^2}{Y_{Dest} s_{\alpha}} - 2 C_{\alpha} \right) + \text{constant}. \end{aligned}$$

The resulting shares from minimizing this loss functions preserve the relative shares of capacity behind any transmission constraint going to the destination. This can be seen from the following LaGrangian equation to be minimized:

$$L = \sum_{i} \left(\frac{C_i^2}{Y_{Dest} s_i} - 2 C_i \right) + \lambda \left(T - \sum_{i} C_i \right),$$

where *T* is the transmission limit affecting control areas *i*. The first order conditions are:

$$\frac{\partial L}{\partial C_i} = \frac{2 C_i}{Y_{Dest} s_i} - 2 - \lambda = 0,$$

which can be rearranged to give:

$$A_i = \frac{C_i}{Y_{Dest}} = \left(\frac{2 + \lambda}{2} \right) s_i,$$

which shows that the allocated market shares of those areas affected by the transmission constraint are proportional to their shares of capacity before the transmission allocation. Moreover, this is the only transmission allocation

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method that maintains the relative shares of capacity behind any binding transmission constraint in the allocation process.

This non-linear program is solved using the COINIPOPT solver in GAMS. The calculated capacities from the nonlinear program above less transmission losses determine the capacities for the market share calculations for sources outside of the destination market. The capacities within the destination market are given full weights.

Market concentration is the HHI, which is the sum of the squared market shares. Mathematically,

$$HHI = \sum_{i=1}^{n} S_i^2,$$

where S_i is the allocated share of firm *i* and *n* is the number of firms in the market. The summary sheets combine all the firms with shares of 0.7 percent or less (other than Applicants) into the "Other" category. The collective share of the Other category does not directly enter the HHI calculation other than the represented capacity as each independent entity enters the HHI calculation. For example, if ten firms with 0.5 percent shares were in the Other category, the HHI contribution of the Other category would be 0.625 (= 10 x .5 x .5 = 10 x .0625) and ***not*** 25.

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Delivered Price Test - PJM50 Market

Available Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$62.03	2,498	24,613	22,116	6,776	Yes	10.1	Yes	1,024	Yes
Spring/Fall	Peak	$35.73	2,927	26,894	23,967	6,776	Yes	10.9	Yes	1,085	Yes
Spring/Fall	Off Peak	$29.46	1,775	18,948	17,173	6,776	Yes	9.4	Yes	1,358	Yes
Summer	Top 1%	$148.44	1,443	22,909	21,466	9,933	Yes	6.3	Yes	1,042	Yes
Summer	Top 10%	$64.59	1,562	21,384	19,822	9,933	Yes	7.3	Yes	1,000	Yes
Summer	Peak	$35.56	2,009	22,352	20,344	9,933	Yes	9.0	Yes	1,055	Yes
Summer	Off Peak	$24.88	2,103	15,701	13,598	9,933	Yes	13.4	Yes	1,772	Yes
Winter	Top 10%	$185.57	1,921	26,153	24,233	6,073	Yes	7.3	Yes	1,008	Yes
Winter	Peak	$47.55	0	19,398	19,398	6,073	Yes	0.0	Yes	1,421	Yes
Winter	Off Peak	$50.16	0	18,024	18,024	6,073	Yes	0.0	Yes	1,592	Yes

Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$62.03	8,704	55,273	46,570	40,893	Yes	15.7	Yes	1,124	Yes
Spring/Fall	Peak	$35.73	7,678	50,521	42,844	28,923	Yes	15.2	Yes	1,084	Yes
Spring/Fall	Off-Peak	$29.46	5,932	41,688	35,756	24,614	Yes	14.2	Yes	1,133	Yes
Summer	Top 1%	$148.44	8,597	59,581	50,984	51,071	No	14.4	Yes	1,126	Yes
Summer	Top 10%	$64.59	8,608	56,301	47,694	47,510	Yes	15.3	Yes	1,112	Yes
Summer	Peak	$35.56	7,389	51,064	43,675	36,423	Yes	14.5	Yes	1,069	Yes
Summer	Off Peak	$24.88	6,266	42,155	35,889	29,051	Yes	14.9	Yes	1,152	Yes
Winter	Top 10%	$185.57	7,022	55,902	48,880	41,770	Yes	12.6	Yes	1,108	Yes
Winter	Peak	$47.55	4,602	43,979	39,377	34,380	Yes	10.5	Yes	1,206	Yes
Winter	Off Peak	$50.16	4,475	39,851	35,376	30,307	Yes	11.2	Yes	1,281	Yes

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Delivered Price Test - PJME Market

Available Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$57.82	3,225	20,600	17,375	3,806	Yes	15.7	Yes	1,179	Yes
Spring/Fall	Peak	$32.73	2,065	20,408	18,343	3,806	Yes	10.1	Yes	1,228	Yes
Spring/Fall	Off Peak	$26.67	1,276	18,023	16,747	3,806	Yes	7.1	Yes	1,669	Yes
Summer	Top 1%	$145.63	2,279	16,425	14,145	6,174	Yes	13.9	Yes	1,216	Yes
Summer	Top 10%	$63.88	2,402	15,949	13,547	6,174	Yes	15.1	Yes	1,267	Yes
Summer	Peak	$29.67	2,199	15,336	13,136	6,174	Yes	14.3	Yes	1,375	Yes
Summer	Off Peak	$21.25	976	13,909	12,933	6,174	Yes	7.0	Yes	1,979	Yes
Winter	Top 10%	$193.51	2,969	22,743	19,774	2,710	Yes	13.1	Yes	1,199	Yes
Winter	Peak	$50.59	0	15,998	15,998	2,710	Yes	0.0	Yes	1,606	Yes
Winter	Off Peak	$50.94	0	15,146	15,146	2,710	Yes	0.0	Yes	1,967	Yes

Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$57.82	8,677	36,450	27,773	22,528	Yes	23.8	No	1,252	Yes
Spring/Fall	Peak	$32.73	6,520	32,603	26,084	15,404	Yes	20.0	Yes	1,171	Yes
Spring/Fall	Off-Peak	$26.67	4,934	28,457	23,523	13,106	Yes	17.3	Yes	1,233	Yes
Summer	Top 1%	$145.63	8,551	36,587	28,036	29,462	No	23.4	No	1,264	Yes
Summer	Top 10%	$63.88	8,553	34,879	26,326	27,143	No	24.5	No	1,270	Yes
Summer	Peak	$29.67	6,853	31,187	24,334	20,217	Yes	22.0	No	1,224	Yes
Summer	Off Peak	$21.25	5,060	26,734	21,674	16,090	Yes	18.9	Yes	1,264	Yes
Winter	Top 10%	$193.51	7,105	35,709	28,603	21,263	Yes	19.9	Yes	1,181	Yes
Winter	Peak	$50.59	4,573	26,985	22,412	17,939	Yes	16.9	Yes	1,268	Yes
Winter	Off Peak	$50.94	4,449	23,450	19,001	15,660	Yes	19.0	Yes	1,461	Yes

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Appendix E Letters of concurrence regarding the control of certain jointly owned generation facilities

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KEYSTONE-CONEMAUGH PROJECTS

682 Philadelphia Street – 2nd floor
Indiana, Pennsylvania 15701

724-349-1205

MAILING ADDRESS
P.O. BOX 68
INDIANA, PA 15701

GEORGIANNA R. STENGER, ESQ.
ADMINISTRATIVE MANAGER
DIRECT DIAL 724-357-1713

December 1, 2007

Addressed to:

Conemaugh Power LLC
Constellation Power Source Generation, Inc.
Duquesne Conemaugh LLC
Exelon Generation Company, LLC
PPL Montour, LLC
PSEG Fossil LLC
Reliant Energy Mid-Atlantic Power Holdings, LLC
UGI Development Company

Re: Joint Owners of the Conemaugh Electric Generating Station (collectively, the "Owners") statement of ownership and control

Dear Owners:

This letter sets forth the understanding of the degree of ownership and control exercised by each of the Owners with respect to the jointly-owned Conemaugh Electric Generating Station for purposes of facilitating compliance with the requirements of FERC Order No. 697.[1]

The Owners and Reliant Energy Northeast Management Company (the "Operator") each confirm its concurrence with the following statement of facts relating to the Conemaugh Electric Generating Station:

1. The Owners jointly own the Conemaugh Electric Generating Station, consisting of two 850 MW net pulverized coal fired once-through boilers and related facilities having a combined rated seasonal net generating capacity of 1,712 MW (1,884 MW nameplate), located in East Wheatfield and West Wheatfield Townships, Indiana County, Pennsylvania (the "Station").

[1] Not all of the Owners agree as to whether Order No. 697 requires the submission of a letter of concurrence when the putative submitting party is not claiming that it does not control its percentage ownership share of a jointly-owned unit. Notwithstanding, all of the Owners have no objection to submission of this letter by an Owner which does believe that such a submission is required.

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2. As of the date hereof, the Station is collectively owned by the Owners as tenants-in-common, each holding an undivided interest in the Station (and all real and personal property comprising the same) in the respective ownership percentages set forth below:

Owner	Ownership Interest
Conemaugh Power LLC	3.72%
Constellation Power Source Generation, Inc.	10.56%
Duquesne Conemaugh LLC	3.83%
Exelon Generation Company, LLC	20.72%
PPL Montour, LLC	16.25%
PSEG Fossil LLC	22.50%
Reliant Energy Mid-Atlantic Power Holdings, LLC	16.45%
UGI Development Company	5.97%

3. Each of the Owners is deemed to control the generating capacity of the Station in accordance with its respective ownership percentage as set forth in the preceding paragraph for purposes of facilitating compliance with the requirements of FERC Order No. 697.

Please indicate your company's concurrence to the above statement of facts by executing this letter in the space provided below your company's name at the foot hereof.

Sincerely yours,

Georgianna R. Stenger
Administrative Manager
Keystone-Conemaugh Projects

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

Owners:

Acknowledged and Agreed to this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

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Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this 14 day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: Anthony F. Pekny

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this 1 day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: Kenneth Kaufman

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this 1st day of December, 2007.

PPL MONTOUR, LLC

By: Dennis J. Murphy
Dennis J. Murphy

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20160328-5240 FERC PDF (Unofficial) 3/28/2016 8:31:36 AM

To the Owners of the Conemaugh Electric Generating Station
December 1, 2007
Page 4

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this 13th day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: James V. Lacher

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20160328-5240 FERC PDF (Unofficial) 5/23/2008 8:31:36 PM

Owners:

Acknowledged and Agreed to this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20160328-5240 FERC PDF (Unofficial) 5/23/2008 8:31:36 PM

Operator:

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY NORTHEAST
MANAGEMENT COMPANY

By: _____

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KEYSTONE-CONEMAUGH PROJECTS

682 Philadelphia Street 2nd floor
Indiana, Pennsylvania 15701

724-349-1205

MAILING ADDRESS
P.O BOX 68
INDIANA, PA 15701

GEORGIANNA R. STENGER, ESQ.
ADMINISTRATIVE MANAGER
DIRECT DIAL: 724-357-1713

December 1, 2007

Addressed to:

Constellation Power Source Generation, Inc.
Duquesne Keystone LLC
Exelon Generation Company, LLC
Keystone Power LLC
PPL Montour, LLC
PSEG Fossil LLC
Reliant Energy Mid-Atlantic Power Holdings, LLC

Re: Joint Owners of the Keystone Electric Generating Station (collectively, the "Owners") statement of ownership and control

Dear Owners:

This letter sets forth the understanding of the degree of ownership and control exercised by each of the Owners with respect to the jointly-owned Keystone Electric Generating Station for purposes of facilitating compliance with the requirements of FERC Order No. 697.[1]

The Owners and Reliant Energy Northeast Management Company (the "Operator") each confirm its concurrence with the following statement of facts relating to the Keystone Electric Generating Station:

1. The Owners jointly own the Keystone Electric Generating Station, consisting of two 850 MW net pulverized coal fired once-through boilers and related facilities having a combined rated seasonal net generating capacity of 1,712 MW (1,884 MW nameplate), located in Plumcreek, South Bend and Cowanshannock Townships, Armstrong County, Pennsylvania, and Armstrong Township, Indiana County, Pennsylvania (the "Station").

[1] Not all of the Owners agree as to whether Order No. 697 requires the submission of a letter of concurrence when the putative submitting party is not claiming that it does not control its percentage ownership share of a jointly-owned unit. Notwithstanding, all of the Owners have no objection to submission of this letter by an Owner which does believe that such a submission is required.

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2. As of the date hereof, the Station is collectively owned by the Owners as tenants-in-common, each holding an undivided interest in the Station (and all real and personal property comprising the same) in the respective ownership percentages set forth below:

Owner	Ownership Interest
Constellation Power Source Generation, Inc.	20.99%
Duquesne Keystone LLC	2.47%
Exelon Generation Company, LLC	20.99%
Keystone Power LLC	3.70%
PPL Montour, LLC	12.34%
PSEG Fossil LLC	22.84%
Reliant Energy Mid-Atlantic Power Holdings, LLC	16.67%

3. Each of the Owners is deemed to control the generating capacity of the Station in accordance with its respective ownership percentage as set forth in the preceding paragraph for purposes of facilitating compliance with the requirements of FERC Order No. 697.

Please indicate your company's concurrence to the above statement of facts by executing this letter in the space provided below your company's name at the foot hereof.

Sincerely yours,

Georgianna R. Stenger
Administrative Manager
Keystone-Conemaugh Projects

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Owners:

Acknowledged and Agreed to
this __ _ day of December, 2007

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _ _ . _ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this _ _ . day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ___ . day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ___ _ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

To the Owners of the Keystone Electric Generating Station
December 1, 2007
Page 4

Owners:

Acknowledged and Agreed to this ___ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to this 14 day of December, 2007.

DUQUESNE KEYSTONE LLC

By: Anthony F. Pelz

Acknowledged and Agreed to this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to this ____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to this ____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

20160328-5240 FERC PDF (Unofficial) 12/28/2007 8:31:58 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this 1 day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: Kenneth Kaiser

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

20160328-5240 FERC PDF (Unofficial) 12/28/2007 8:31:58 PM

Owners:

Acknowledged and Agreed to this ___ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Owners:

Acknowledged and Agreed to
this __ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this __ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this 13th day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

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Owners:

Acknowledged and Agreed to
this __ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: James D. Lash

20160328-5240 FERC PDF (Unofficial) 12/28/2007 8:31:36 PM

Operator:

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY NORTHEAST
MANAGEMENT COMPANY

By: Jaime D Lach

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Thomas P. Joyce
Senior Vice President

P.O. Box 236, Hancocks Bridge, NJ 08038
tel: 856.339.1100 fax: 856.339.1104
email: Thomas.Joyce@pseg.com

PSEG
Nuclear L.L.C.

Carol Peterson
Vice President Finance
Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

Letter Regarding Control of Jointly-Owned Nuclear Facilities

Dear Ms. Peterson:

In connection with its upcoming compliance filings pursuant to Order No. 697,[1] PSEG Nuclear LLC ("PSEG") is submitting this letter in order to set forth its understanding of, and is requesting Exelon Generation Company LLC's ("Exelon") concurrence on, the respective level of control exercised by both companies with respect to the two nuclear facilities that they jointly own.[2]

PSEG avers and requests Exelon's concurrence on the following:

1. PSEG and Exelon jointly own and control two nuclear power plants, Peach Bottom Atomic Power Station located in Delta, PA and the Salem Nuclear Generating Station in Lower Alloways Creek, NJ.

2. In accordance with the Joint Owners Agreement for Peach Bottom dated November 24, 1971, as amended on thereafter, between the Parties, PSEG and Exelon each own 50% of the generating station. Under the Agreement, Exelon is the designated operator of Peach Bottom.

3. In accordance with the Joint Owners Agreement for Salem dated November 24, 1971, as amended thereafter, between the Parties, Exelon owns 42.59% and PSEG owns 57.41% of the generating station. Under the Agreement, PSEG is the designated operator of Salem.

4. Section 4.1 of each of the Joint Owners' Agreements states, "The signatories shall be entitled to shares of the installed capacity, available capacity, operating capacity and hourly energy generation of the Station in proportion to their ownership . . .."

[1] *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, 119 FERC ¶ 61,295 (2007).

[2] PSEG has requested a letter of concurrence from Exelon in order to facilitate the Commission's review of the market power analysis submitted by PSEG with respect to facilities it jointly owns with Exelon. Exelon has no objection to PSEG's submission of this letter as part of PSEG's compliance filing,.

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Thomas P. Joyce
Senior Vice President

P.O. Box 236, Hancocks Bridge, NJ 08038
tel: 856.339.1100 fax: 856.339.1104
email: Thomas.Joyce@pseg.com

PSEG
Nuclear L.L.C.

5. Section 11.1 of each of the Joint Owners' Agreements provides that the generating station will be operated by the party designated as operator for the mutual benefit of PSEG and Exelon.

6. In Order No. 697 the Commission stated that under "where a jointly-owned generation facility is operated by one of the joint-owners for the benefit of and on behalf of all of the joint-owners . . . it may be reasonable to allocate capacity based on ownership percentages...." Order No. 697 at P 188.

7. In accordance with the guidance provided in Order No. 697 and with the language of each of the joint owners' agreements, PSEG and Exelon should be deemed to control each of the nuclear facilities' output in line with their proportionate ownership share of each facility. As such, PSEG and Exelon should each be deemed to control 50% of Peach Bottom's output, and PSEG should be deemed to control 57.41% of Salem's output with Exelon controlling 42.59%.

Please indicate Exelon's concurrence to the above by executing the Acknowledgement and Agreement section below.

Sincerely

Thomas P. Joyce
Senior Vice President – Operations

Acknowledged and Agreed to
this 21 day of December, 2007.

Carol Peterson
Vice President Finance, Exelon Nuclear, and
an officer of Exelon Generation Company, LLC

20160328-5240 FERC PDF (Unofficial) 5/23/2016 8:31:05 AM

JOINT LETTER OF CONCURRENCE

Regulations of the Federal Energy Regulatory Commission (the "FERC") require each public utility with market-based rate authority to file an updated market power analysis every three years in accordance with a schedule adopted in *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stat. & Regs., Regulations Preambles ¶ 31,252 (2007) ("Order No. 697"). See, 18 CFR § 35.37(a)(1). Each public utility with market-based rate authority may also be required to file a change-in-status report regarding certain changes in circumstances that occur between the dates on which its triennial market power analyses are filed. 18 CFR § 35.42. Among other matters, the market power analysis is to address the amount of generation capacity that the affected utility owns or controls. Where more than one public utility owns a generating facility, FERC requires the utility that is submitting a market power analysis seek a "letter of concurrence" from the other affected co-owning public utilities that identifies the degree to which each public utility controls the generating facility, and to submit the letter with its filing. *See* FERC Order No. 697, 119 FERC ¶ 61,295, P 187 (2007).

The Yards Creek Pumped Storage Hydroelectric Project (the "Yards Creek Project") is a FERC-licensed pumped-storage hydroelectric project with a nameplate capacity of 400 MWs, and is located in Pahaquarry and Blairstown Townships, in Warren County, New Jersey. *See* FERC Project No. P-2309.

PSEG Fossil LLC ("PSEG") and Jersey Central Power & Light Company ("JCPL") each own, as tenants in common with the other, an undivided 50% interest in the Yards Creek Project. Accordingly, if and when PSEG or JCPL submit an updated market power analysis to the FERC, each will be subject to FERC's requirement to seek a "letter of concurrence" regarding the degree to which each controls the Yards Creek Project.

Both PSEG and JCP&L (and their affiliates) own transmission facilities and provide wholesale electric service in the Northeast region, as defined in Order No. 697. Pursuant to the schedule adopted in Order No. 697, PSEG and JCP&L are each required to submit an updated market power analysis to the FERC for markets within the Northeast region in December 2010. PSEG and/or JCP&L may also be obligated to file a change-in-status report or other market power analyses before its subsequent triennial market power analysis for the Northeast region is scheduled to be filed. Therefore, for the sole purpose of enabling either PSEG or JCP&L to submit a market power analysis that addresses, among other issues (to the extent necessary), the scope of each party's control of the Yards Creek Project, PSEG and JCP&L each aver and agree as follows:

1. JCP&L operates and maintains the Yards Creek Project pursuant to the Yards Creek Pumped Storage Hydroelectric Generating Station Operating Agreement, which is dated October 6, 1965 (the "Operating Agreement').

2. Article 2 of the Operating Agreement designates JCP&L as holding sole responsibility for the operations and maintenance the Yards Creek Project. Article 2 further provides that JCPL shall operate the Yards Creek project in the same manner as if JCPL had the complete ownership interest in the Yards Creek Project.

3. JCP&L does, in fact, operate and control the Yards Creek Project in the same manner as if JCP&L had the complete ownership interest in the Yards Creek Project in accordance with Article 2 of the Operating Agreement.

4. Accordingly, PSEG and JCP&L each agree and concur that for the purpose of the market power analyses required by Order No. 697, JCPL shall be deemed to control the Yards Creek Project generation capacity and electric energy output.

ACKNOWLEDGED AND AGREED:

Richard P. Lopriore
President, PSEG Fossil LLC

Dated: 12/21/10

ACKNOWLEDGED AND AGREED:

Dean Stathis
Director, Regulated Commodity Sourcing
Jersey Central Power & Light Company

Dated: 12/08/2010

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G	ER99-3151-000	NA*	NA*	NA*	NA*	PJM	Northeast	NA*
PSEG ER&T	ER97-837-000	NA*	NA*	NA*	NA*	PJM, NYISO, NE-ISO	Northeast, Central, Southwest Power Pool, Southeast, Southwest, Northwest	NA*
PSEG Fossil	ER08-447-000	Bergen CC1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Bergen CC2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2002
PSEG Fossil	ER08-447-000	Burlington 12.1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Conemaugh 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/21/1970
PSEG Fossil	ER08-447-000	Conemaugh 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/27/1971
PSEG Fossil	ER08-447-000	Conemaugh A	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh B	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh C	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh D	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Global	N/A	Conemaugh Hydroelectric Plant 1	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Global	N/A	Conemaugh Hydroelectric Plant 2	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Fossil	ER08-447-000	Essex 9	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/1/1990
PSEG Nuclear	ER08-448-000	Hope Creek 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/20/1986
PSEG Fossil	ER08-447-000	Hudson 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	12/18/1968
PSEG Fossil	ER08-447-000	Kearny 12	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/1/2001
PSEG Fossil	ER08-447-000	Kearny 13	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Kearny 14	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Keystone 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/24/1967
PSEG Fossil	ER08-447-000	Keystone 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/23/1968
PSEG Fossil	ER08-447-000	Keystone 3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Linden 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM,	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 7	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Linden 8	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSEG Fossil	ER08-447-000	Linden GT5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Linden GT6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Mercer 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	12/19/1960
PSEG Fossil	ER08-447-000	Mercer 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/4/1961
PSEG Nuclear	ER08-448-000	Peach Bottom 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	7/5/1974
PSEG Nuclear	ER08-448-000	Peach Bottom 3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/23/1974
PSEG Nuclear	ER08-448-000	Salem 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/30/1977
PSEG Nuclear	ER08-448-000	Salem 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	10/13/1981
PSEG Nuclear	ER08-448-000	Salem GT3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/17/1971
PSEG Fossil	ER08-447-000	Sewaren 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	12/1/1948
PSEG Fossil	ER08-447-000	Sewaren 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/30/1948
PSEG Fossil	ER08-447-000	Sewaren 3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	10/16/1949
PSEG Fossil	ER08-447-000	Sewaren 4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/30/1951
PSEG Fossil	ER08-447-000	Yards Creek 1	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	11/26/1965
PSEG Fossil	ER08-447-000	Yards Creek 2	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	12/22/1965
PSEG Fossil	ER08-447-000	Yards Creek 3	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	9/3/1965
PSEG Power CT	ER03-327-000	Bridgeport Harbor 3	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	8/1/1968
PSEG Power CT	ER03-327-000	Bridgeport Harbor 4	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	10/30/1967
PSEG New Haven LLC	ER12-1250-000	New Haven 2	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 3	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 4	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG Power CT	ER03-327-000	New Haven Harbor 1	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	7/1/1975
PSEG Power NY	N/A*	Bethlehem Energy Center CC	PSEG Power NY	PSEG ER&T	12/6/2002	NYISO	Northeast	7/1/2005
PSEG Solar Source LLC	N/A*	Mars Solar Garden	PSEG Solar Hackettstown LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	9/9/2009
PSEG Solar Source LLC	N/A*	JEA Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	SERC	Southeast	9/28/2010
PSEG Solar Source LLC	N/A*	Wyandot Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	4/6/2010
PSEG Solar Source LLC	N/A*	Queen Creek Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	AZ-NV-SNV	Southwest	11/14/2012
PSEG Solar Source LLC	N/A*	Milford Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	12/27/2012
PSEG Solar Source LLC	N/A	Badger Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ACC	West	10/15/2013
PSEG Solar Source LLC	N/A	Shasta Solar Farm	PSEG Solar California LLC	PG&E	12/16/2013	CAISO	West	3/1/2014

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSEG Solar Source LLC	N/A	Newman Solar Farm (Texas)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	El Paso Electric	Southwest	12/30/2014
PSEG Solar Source LLC	N/A	Whitcomb Solar Farm (Vermont)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ISO New England	Northeast	10/30/2014
PSEG Solar Source LLC	N/A	Rockfish Solar LLC, Southern Maryland	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	7/10/2015
PSEG Solar Source LLC	N/A	Columbia Solar, Pittsburg, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PG&E	West	10/21/2015
PSEG Solar Source LLC	N/A	Whitehorn Solar, Livermore, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Authority	West	2/17/2016
PSEG Solar Source LLC	N/A	Meadows Solar, Martin County, NC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	6/9/2016
PSEG Solar Source LLC	ER16-1924-000	Bison Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Administration, Colorado-Missouri Region	West	8/1/2016
PSEG Solar Source LLC	ER16-1925-000	Pavant Solar II LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp East	West	8/1/2016
PSEG Solar Source LLC	N/A	Obsidian - Black Cap	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp West	West	11/1/2016
PSEG Solar Source LLC	N/A	Hemlock Solar	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	N/A	Turkey Creek	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	ER16-1926-000	San Isabel Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Public Service Company of Colorado	West	8/1/2016
PSE&G (Solar 4 All)	N/A*	Trenton, 500-520 Brunswick Ave., Trenton, NJ 08638	PSE&G	PSE&G	N/A	PJM	Northeast	10/07/2010 (Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Barringer High School (NPS), 90 Parker St., Newark, NJ 07104	PSE&G	PSE&G	N/A	PJM	Northeast	09/24/2010 (Commercial Operation)
PSE&G (Solar		Park Elementary						10/20/2010

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G (Solar 4 All)	N/A*	Elementary) School, 120 Manchester	PSE&G	PSE&G	N/A	PJM	Northeast	(Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Linden, South Wood Avenue, Linden, NJ 07036	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Yardville, Broad Street, Hamilton, NJ 08611	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Silver Lake, 410 Silver Lake Avenue, Edison, NJ 08817	PSE&G	PSE&G	N/A	PJM	Northeast	11/09/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Central HQ, 472 Weston Canal Road, Franklin, NJ 08873	PSE&G	PSE&G	N/A	PJM	Northeast	11/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Edison Training, 234 Pierson Avenue, Edison, NJ 08837	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All)	N/A*	WEA Texas Bayonne, 30-100 Pulaski Street, Bayonne, NJ 07002	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2010
PSE&G (Solar 4 All)	N/A*	Matrix Building A, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/24/2011
PSE&G (Solar 4 All)	N/A*	Matrix Building B, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/14/2011
PSE&G (Solar 4 All)	N/A*	Camden Street School, 281 Camden Street Newark, New Jersey 07103	PSE&G	PSE&G	N/A*	PJM	Northeast	1/12/2011

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Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G (Solar 4 All)	N/A*	New Central High School, 246 18th Ave, Newark, NJ 07108	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Rider University Solar Farm, Lawrenceville, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2011
PSE&G (Solar 4 All)	N/A*	Mill Creek Solar Farm, Burlington Township, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	11/30/2011
PSE&G (Solar 4 All)	N/A*	PSE&G Thorofare Solar Farm, West Deptford	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	Raritan Center – Warehouse Solar, Edison, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	NJMC – Landfill Solar, Kearny, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All	N/A	Matrix – Stults Rd., South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	5/31/2011
PSE&G (Solar 4 All)	N/A*	Metro Division HQ, Clifton, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	7/9/2012
PSE&G (Solar 4 All)	N/A*	Black Rock-Matrix, South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	3/20/2012
PSE&G (Solar 4 All)	N/A*	Food Bank Solar Farm, Hillside, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	8/16/2012
PSE&G (Solar 4 All)	N/A*	Hackensack Solar Farm, Hackensack, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2012
PSE&G (Solar 4 All)	N/A*	Moorestown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/14/2013
PSE&G (Solar 4 All)	N/A*	Seg 2 (Pole attached solar units)	PSE&G	PSE&G	N/A*	PJM	Northeast	7/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Kinsley Solar Sewell, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G (Solar 4 All Extension)	N/A*	Parkland Solar Bordentown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014
PSE&G (Solar 4 All Extension)	N/A*	L&D Solar Mt. Holly, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Hopewell Valley Central HS	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2015
PSE&G (Solar 4 All Extension)	N/A*	ILR Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016
PSE&G (Solar 4 All Extension)	N/A*	Caldwell Waste Treatment Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016
[i] PSEG Fossil has a 22.5% interest in the Conemaugh coal fired plants.								
[ii] PSEG Global has a 4% interest Conemaugh Hydroelectric plants.								
[iii] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear Plants.								
[iv] PSEG Nuclear has a 57.41% interest in the Salem Nuclear Plants.								
[v] JCP&L – Jersey Central Power & Light Company								
[vi] PSEG Fossil has a 50% interest in each of the Yards Creek facilities.								
[vii] CL&P – The Connecticut Light and Power Company.								
[viii] PSEG Power Ventures has a 100% ownership in PSEG Hackettstown LLC.								
[ix] PSEG Power Ventures has a 100% ownership interest in PSEG Solar Source LLC								
[x] All solar assets are using AC MW ratings. PSEG's previous triennial listed the DC ratings.								
[xi] PG&E -- Pacific Gas and Electric Company								
[xii] PSE&G started installations of pole units in September of 2009. As of November 30, 2016, a total of 174,630								

Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing**	**Capacity Rating: Methodology Used in K**	**End Note Number (Enter text in End Notes Sheet**
NA*	NA*	NA*	
NA*	NA*	NA*	
775.2	775.2	N	
625.6	625.6	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
210.6	210.6	N	
210.6	210.6	N	
0.625	0.625	N	[i]
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
1	1	N	[ii]
1	1	N	
93.6	93.6	N	
1,290.70	1,290.70	N	
659.7	659.7	N	
242	242	N	
242	242	N	
121	121	N	
213.8	213.8	N	
213.8	213.8	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
677.8	677.8	N	
677.8	677.8	N	
96.1	96.1	N	
96.1	96.1	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
96.1	96.1	N	
96.1	96.1	N	
326.4	326.4	N	
326.4	326.4	N	
704	704	N	[iii]
689	689	N	
671.7	671.7	N	[iv]
671.7	671.7	N	
24	24	N	
110.8	110.8	N	
107.5	107.5	N	
107.5	107.5	N	
126.5	126.5	N	
68.5	68.5	N	[v]
68.5	68.5	N	[vi]
56.4	56.4	N	
399.5	399.5	N	
18.6	18.6	N	
60.5	60.5	N	[vii]
60.5	60.5	N	
60.5	60.5	N	
460.3	460.3	N	
893.2	893.2	N	
2	2	N	[viii]
12.6	12.6	N	[ix]
10.1	10.1	N	[x]
19	19	N	
12	12	N	
15	15	N	
1.5	1.5	N	[xi]

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Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
10.2	10.2	N	
2.2	2.2	N	
10.3	10.3	N	
19	19	N	
3	3	N	
20	20	N	
30	30	N	
50	50	N	
8	8	N	
5	5	N	
13.5	13.5	N	
30	30	N	
1.14	1.14	N	
0.64	0.64	N	
		N	

Appendix B

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
0.55	0.55	N	
3	3	N	
3.7	3.7	N	
1.75	1.75	N	
0.76	0.76	N	
0.64	0.64	N	
1.5	1.5	N	
		N	
1.5	1.5	N	
1	1	N	
0.83	0.83	N	
		N	

Appendix B

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
0.5	0.5	N	
		N	
0.67	0.67	N	
3.5	3.5	N	
0.75	0.75	N	
2	2	N	
2.5	2.5	N	
2.5	2.5	N	
0.57	0.57	N	
2.5	2.5	N	
1	1	N	
1	1	N	
0.93	0.93	N	
38.5	38.5	N	[xii]
8.8	8.8	N	

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Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
7.9	7.9	N	
10	10	N	
1	1	N	
6.6	6.6	N	
2	2	N	

panels and 38.5 MW capacity have been installe

Asset Appendix: Transmission/Natural Gas Assets
Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas St
Location

Filing Entity and its Energy Affiliates	Cite to Order Accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Market / Balancing Authority	Geograph
PSEG ER&T	NA	NA	NA	NA	NA	NA	N
PSEG Power CT	NA	NA	NA	NA	NA	NA	N
PSEG New Haven	NA	NA	NA	NA	NA	NA	N
PSEG Fossil	NA	NA	NA	NA	NA	NA	N
PSEG Nuclear	NA	NA	NA	NA	NA	NA	N
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	Jointly Owned by PSE&G and others	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	Owned by others	PJM	N/A*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	Owned by others	PJM	NA*	PJM	North

PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	Jointly Owned by PSE&G and others	PJM	N/A*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 230 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 230kV Lines	Owned by Others	PJM	N/A	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 138 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 69 kV Lines	PSE&G	PJM	NA*	PJM	North

orage Facilities

ic Region	Size (e.g., length and kV for electric length and diameter for pipeline, and capacity for gas storage)	End Note Number (Enter text in End Notes Sheet
	Size	
A	NA	NA
A	NA	NA
A	NA	NA
A	NA	NA
A	NA	NA
ıeast	Approximately 272 combined miles.	
ıeast	Approximately 151 combined miles.	
ıeast	Approximately 64 combined miles	
ıeast	Approximately 32 combined miles.	
ıeast	Approximately 20 combined miles.	

least	Approximately 3.76 combined Miles
least	Approximately 750 combined miles.
least	Approximately 39 combined miles
least	Approximately 228 combined miles.
least	Approximately 235 combined miles.

Asset Appendix: Long Term Purchased Power Agreements

Filing Entity and its Energy Affiliates	Docket No. where MBR Authority Granted	Seller Name	Amount of PPA (MW)	Market / Balancing Authority	Geographic Region	Start Date (mo/day/year)

End Date (mo/day/year)	End Note

Document Content(s)

PSEG 2016 Triennial Transmittal FINAL.DOC.....1-27

Exhibit A - Morris Affidavit - PSEG Triennial.PDF.....28-109

Exhibit E - Letters of Concurrence - PSEG Triennial.PDF.....110-134

Appendix B - Generation Assets - PSEG Triennial.XLSX.....135-146

Appendix C - Triennial - Transmission Chart.XLSX.....147-150

Appendix D - Long Term Contracts - Triennial.XLSX.....151-152

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ATTACHMENT C

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UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

PSEG Fossil Sewaren Urban Renewal Entity LLC	))))	Docket No. ER17-____-000

Affidavit of
Dr. John R. Morris

May 25, 2018

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Public Service Enterprise Group Incorporated
Sewaren Market Power Study

1. My name is Dr. John R. Morris. I am a Principal at Economists Incorporated, an economic consulting firm located at 2121 K Street, NW, Washington, DC 20037. I am the same Dr. John R. Morris who filed Public Service Enterprise Group Incorporated's ("PSEG") market power study for the Northeast Region in December 2016 under this docket. See Report & Affidavit of Dr. John R. Morris, FERC Accession Number 20161228-5212, December 28, 2016. I also filed a Change in Status application to reflect the addition of Keys Energy Center and the retirement of Hudson and Mercer generating stations in September 2017 for PSEG in Docket No. ER17-2426-000. PSEG has asked that I update the September 2017 market power study for the PJM market and relevant submarkets in order to account for the addition of PSEG Fossil Sewaren Urban Renewal Entity LLC, hereinafter "Sewaren LLC", which owns Sewaren Unit 7, a natural gas combined cycle plant with a generating capacity of 585 MW currently under construction in Woodbridge Township, New Jersey. When Sewaren LLC enters service, PSEG will retire Sewaren Units 1-4 at the same location.[1]

2. Per PSEG's request, I added the new 585 MW Sewaren Unit 7 in the PJM East market and retired Sewaren Units 1-4, which are located in PJM East. I moved the test year of the analysis forward by one year from December 2014-November 2015 to December 2015-November 2016, as this is the latest period for which FERC Form 714 data on unplanned generator outages is

[1] The relevant markets are PJM Interconnection, L.L.C. ("PJM"), PJM East, PJM East of 5004/5005 and PJM East of AP South.

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available. I also updated the overall market sizes of the PJM market and submarkets, along with the first tier areas of NYISO and MISO. I updated load data both for the applicant and for the overall markets in the study. All methods are the same as in the December Affidavit.

3. The results of the pivotal supplier and market share assessments are provided in Exhibit No. PEG-2.

4. Although there are some minor differences in the results from those presented with the December Affidavit, the differences are not material and do not change the conclusions made at that time.

5. Although there are some Wholesale Market Share screen failures in the PJM East and PJM 5004/5005 submarkets, Sewaren LLC and most of the PSEG generation is located in PJM, which has Commission approved market power monitoring and mitigation. The Commission has adopted a rebuttable presumption that existing Commission approved RTO/ISO market monitoring and mitigation is sufficient to address any market power concerns. See Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 240-42, P 246, P 290; Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 111.

6. Under the standards utilized by the Commission, continuing market-based rates for PSEG and all of its Northeastern affiliates remain in the public interest. In addition, granting market-rate authority to the Sewaren LLC would also be in the public interest.

7. This concludes my affidavit.

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Pursuant to 28 U.S.C. §1746, I state under penalty of perjury that the foregoing is true and correct to the best of my information, knowledge, and belief.

Executed on this 25th day of May 2018.

John R. Morris, Ph.D.

Principal

Economists Incorporated

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Document Content(s)

PSEG Change in Status.PDF.....1-183

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PSEG
Services Corporation

By ELECTRONIC FILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

June 29, 2018

Re: Supplement to Notice of Non-Material Change in Status of PSEG Affiliates:

PSEG Energy Resources & Trade LLC	ER10-1789-___
PSEG Energy Solutions LLC	ER16-2725-___
PSEG Fossil LLC	ER10-1770-___
PSEG New Haven LLC	ER12-1250-___
PSEG Nuclear LLC	ER10-1771-___
PSEG Power Connecticut LLC	ER10-1793-___
Pavant Solar II LLC	ER16-1925-___
Bison Solar LLC	ER16-1924-___
San Isabel Solar LLC	ER16-1926-___
Public Service Electric and Gas Company	ER10-1768-___
PSEG Keys Energy Center LLC	ER17-2426-___

Dear Ms. Bose:

On May 25, 2018, the PSEG Affiliates submitted a notice of non-material change in status ("Notice") pursuant to section 35.42(a)(1) of the regulations of the Federal Energy Regulatory Commission ("Commission").[1] The PSEG Affiliates are submitting this supplement to the Notice to include: (1) Appendix B – Generation Assets; and (2) Appendix A-3 in Excel format as required by the Commission's regulations.

Please feel free to contact me at (973) 430-8836 if you have any questions about this matter.

Very truly yours,

Cara J. Lewis

Cara J. Lewis

[1] 18 C.F.R. Part 35.42 (2017).

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G	ER99-3151-000	NA*	NA*	NA*	NA*	PJM	Northeast	NA*
PSEG ER&T	ER97-837-000	NA*	NA*	NA*	NA*	PJM, NYISO, NE-ISO	Northeast, Central, Southwest Power Pool, Southeast, Southwest, Northwest	NA*
PSEG Fossil	ER08-447-000	Bergen CC1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Bergen CC2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2002
PSEG Fossil	ER08-447-000	Burlington 12.1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Conemaugh 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/21/1970
PSEG Fossil	ER08-447-000	Conemaugh 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/27/1971
PSEG Fossil	ER08-447-000	Conemaugh A	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh B	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh C	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh D	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Global	N/A	Conemaugh Hydroelectric Plant 1	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Global	N/A	Conemaugh Hydroelectric Plant 2	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Fossil	ER08-447-000	Essex 9	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/1/1990
PSEG Nuclear	ER08-448-000	Hope Creek 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/20/1986
PSEG Fossil	ER08-447-000	Kearny 12	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/1/2001
PSEG Fossil	ER08-447-000	Kearny 13	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Kearny 14	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Keystone 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/24/1967
PSEG Fossil	ER08-447-000	Keystone 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/23/1968
PSEG Fossil	ER08-447-000	Keystone 3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Linden 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM,	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 7	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Linden 8	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Linden GT5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000

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Asset Appendix: Generation Assets								
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PSEG Fossil	ER08-447-000	Linden GT6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Keys Energy Center LLC	ER17-2426-000	PSEG Keys Energy Center	PSEG Keys Energy Center	PSEG ER&T	N/A	PJM	Northeast	7/3/2018
PSEG Nuclear	ER08-448-000	Peach Bottom 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	7/5/1974
PSEG Nuclear	ER08-448-000	Peach Bottom 3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/23/1974
PSEG Nuclear	ER08-448-000	Salem 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/30/1977
PSEG Nuclear	ER08-448-000	Salem 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	10/13/1981
PSEG Nuclear	ER08-448-000	Salem GT3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/17/1971
PSEG Fossil	N/A	Sewaren 7	PSEG Sewaren Urban Renewal	PSEG ER&T	N/A	PJM	Northeast	6/6/2018
PSEG Fossil	ER08-447-000	Yards Creek 1	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	11/26/1965
PSEG Fossil	ER08-447-000	Yards Creek 2	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	12/22/1965
PSEG Fossil	ER08-447-000	Yards Creek 3	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	9/3/1965
PSEG Power CT	ER03-327-000	Bridgeport Harbor 3	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	8/1/1968
PSEG Power CT	ER03-327-000	Bridgeport Harbor 4	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	10/30/1967
PSEG New Haven LLC	ER12-1250-000	New Haven 2	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 3	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 4	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG Power CT	ER03-327-000	New Haven Harbor 1	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	7/1/1975
PSEG Power NY	N/A*	Bethlehem Energy Center CC	PSEG Power NY	PSEG ER&T	12/6/2002	NYISO	Northeast	7/1/2005
PSEG Solar Source LLC	N/A*	Mars Solar Garden	PSEG Solar Hackettstown LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	9/9/2009
PSEG Solar Source LLC	N/A*	JEA Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	SERC	Southeast	9/28/2010
PSEG Solar Source LLC	N/A*	Wyandot Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	4/6/2010
PSEG Solar Source LLC	N/A*	Queen Creek Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	AZ-NV-SNV	Southwest	11/14/2012
PSEG Solar Source LLC	N/A*	Milford Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	12/27/2012
PSEG Solar Source LLC	N/A	Badger Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ACC	West	10/15/2013
PSEG Solar Source LLC	N/A	Shasta Solar Farm	PSEG Solar California LLC	PG&E	N/A	CAISO	West	3/1/2014
PSEG Solar Source LLC	N/A	Newman Solar Farm (Texas)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	El Paso Electric	Southwest	12/30/2014
PSEG Solar Source LLC	N/A	Whitcomb Solar Farm (Vermont)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ISO New England	Northeast	10/30/2014

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PSEG Solar Source LLC	N/A	Rockfish Solar LLC, Southern Maryland	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	7/10/2015
PSEG Solar Source LLC	N/A	Columbia Solar, Pittsburg, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PG&E	West	10/21/2015
PSEG Solar Source LLC	N/A	Whitehorn Solar, Livermore, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Authority	West	2/17/2016
PSEG Solar Source LLC	N/A	Meadows Solar, Martin County, NC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	6/9/2016
PSEG Solar Source LLC	ER16-1924-000	Bison Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Administration, Colorado-Missouri Region	West	8/1/2016
PSEG Solar Source LLC	ER16-1925-000	Pavant Solar II LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp East	West	8/1/2016
PSEG Solar Source LLC	N/A	Obsidian - Black Cap	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp West	West	11/1/2016
PSEG Solar Source LLC	N/A	Hemlock Solar	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	N/A	Turkey Creek	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	ER16-1926-000	San Isabel Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Public Service Company of Colorado	West	8/1/2016
PSEG Solar Source LLC	N/A*	Cork Oak Solar	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/29/2017
PSEG Solar Source LLC	ER17-1746	Sunflower Solar	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/29/2017
PSEG Solar Source LLC	N/A*	SL Babylon/Solar Liberty	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	LIPA	Northeast	12/4/2017
PSEG Solar Source LLC	N/A*	HXNAir Solar One	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/21/2017
PSE&G (Solar 4 All)	N/A*	Trenton, 500-520 Brunswick Ave., Trenton, NJ 08638	PSE&G	PSE&G	N/A	PJM	Northeast	10/07/2010 (Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Barringer High School (NPS), 90 Parker St., Newark, NJ 07104	PSE&G	PSE&G	N/A	PJM	Northeast	09/24/2010 (Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Park Elementary School, 120 Manchester	PSE&G	PSE&G	N/A	PJM	Northeast	10/20/2010 (Commercial Operation)

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PSE&G (Solar 4 All)	N/A*	Linden, South Wood Avenue, Linden, NJ 07036	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Yardville, Broad Street, Hamilton, NJ 08611	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Silver Lake, 410 Silver Lake Avenue, Edison, NJ 08817	PSE&G	PSE&G	N/A	PJM	Northeast	11/09/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Central HQ, 472 Weston Canal Road, Franklin, NJ 08873	PSE&G	PSE&G	N/A	PJM	Northeast	11/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Edison Training, 234 Pierson Avenue, Edison, NJ 08837	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All)	N/A*	WEA Texas Bayonne, 30-100 Pulaski Street, Bayonne, NJ 07002	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2010
PSE&G (Solar 4 All)	N/A*	Matrix Building A, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/24/2011
PSE&G (Solar 4 All)	N/A*	Matrix Building B, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/14/2011
PSE&G (Solar 4 All)	N/A*	Camden Street School, 281 Camden Street Newark, New Jersey 07103	PSE&G	PSE&G	N/A*	PJM	Northeast	1/12/2011
PSE&G (Solar 4 All)	N/A*	New Central High School, 246 18th Ave, Newark, NJ 07108	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Rider University Solar Farm, Lawrenceville, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2011

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PSE&G (Solar 4 All)	N/A*	Mill Creek Solar Farm, Burlington Township, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	11/30/2011
PSE&G (Solar 4 All)	N/A*	PSE&G Thorofare Solar Farm, West Deptford	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	Raritan Center – Warehouse Solar, Edison, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	NJMC – Landfill Solar, Kearny, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All	N/A	Matrix – Stults Rd., South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	5/31/2011
PSE&G (Solar 4 All)	N/A*	Metro Division HQ, Clifton, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	7/9/2012
PSE&G (Solar 4 All)	N/A*	Black Rock-Matrix, South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	3/20/2012
PSE&G (Solar 4 All)	N/A*	Food Bank Solar Farm, Hillside, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	8/16/2012
PSE&G (Solar 4 All)	N/A*	Hackensack Solar Farm, Hackensack, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2012
PSE&G (Solar 4 All)	N/A*	Moorestown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/14/2013
PSE&G (Solar 4 All)	N/A*	Seg 2 (Pole attached solar units)	PSE&G	PSE&G	N/A*	PJM	Northeast	7/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Kinsley Solar Sewell, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014
PSE&G (Solar 4 All Extension)	N/A*	Parkland Solar Bordentown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014
PSE&G (Solar 4 All Extension)	N/A*	L&D Solar Mt. Holly, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Hopewell Valley Central HS	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2015
PSE&G (Solar 4 All Extension)	N/A*	ILR Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016
PSE&G (Solar 4 All Extension)	N/A*	Caldwell Waste Treatment Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016

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[i] PSEG Fossil has a 22.5% interest in the Conemaugh coal fired plants.								
[ii] PSEG Global has a 4% interest Conemaugh Hydroelectric plants.								
[iii] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear Plants.								
[iv] PSEG Nuclear has a 57.41% interest in the Salem Nuclear Plants.								
[v] JCP&L – Jersey Central Power & Light Company								
[vi] PSEG Fossil has a 50% interest in each of the Yards Creek facilities.								
[vii] CL&P – The Connecticut Light and Power Company.								
[viii] PSEG Power Ventures has a 100% ownership in PSEG Hackettstown LLC.								
[ix] PSEG Power Ventures has a 100% ownership interest in PSEG Solar Source LLC								
[x] All solar assets are using AC MW ratings. PSEG's previous triennial listed the DC ratings.								
[xi] PG&E -- Pacific Gas and Electric Company								
[xii] PSE&G started installations of pole units in September of 2009. As of November 30, 2016, a total of 174,630								

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
NA*	NA*	NA*	
NA*	NA*	NA*	
775.2	775.2	N	
625.6	625.6	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
219.5	219.5	N	
219.5	219.5	N	
0.625	0.625	N	[i]
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
1	1	N	[ii]
1	1	N	
93.6	93.6	N	
1,290.70	1,290.70	N	
242	242	N	
242	242	N	
121	121	N	
213.8	213.8	N	
213.8	213.8	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
677.8	677.8	N	
677.8	677.8	N	
96.1	96.1	N	
96.1	96.1	N	
96.1	96.1	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
96.1	96.1	N	
755	755	N	
703.8	703.8	N	[iii]
688.5	688.5	N	
671.7	671.7	N	[iv]
671.7	671.7	N	
24	24	N	
585	585	N	
69.3	69.3	N	[v]
69.3	69.3	N	[vi]
69.3	69.3	N	
399.5	399.5	N	
18.6	18.6	N	
60.5	60.5	N	[vii]
60.5	60.5	N	
60.5	60.5	N	
460.3	460.3	N	
893.2	893.2	N	
2	2	N	[viii]
12.6	12.6	N	[ix]
10.1	10.1	N	[x]
19	19	N	
12	12	N	
15	15	N	
3	3	N	[xi]
10.2	10.2	N	
2.2	2.2	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
10.3	10.3	N	
19	19	N	
3	3	N	
20	20	N	
30	30	N	
50	50	N	
8	8	N	
5	5	N	
13.5	13.5	N	
30	30	N	
20	20	N	
16	16	N	
8.9	8.9	N	
5	5	N	
1.14	1.14	N	
0.64	0.64	N	
0.55	0.55	N N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
3	3	N	
3.7	3.7	N	
1.75	1.75	N	
0.76	0.76	N	
0.64	0.64	N	
1.5	1.5	N N	
1.5	1.5	N	
1	1	N	
0.83	0.83	N N	
0.5	0.5	N N	
0.67	0.67	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
3.5	3.5	N	
0.75	0.75	N	
2	2	N	
2.5	2.5	N	
2.5	2.5	N	
0.57	0.57	N	
2.5	2.5	N	
1	1	N	
1	1	N	
0.93	0.93	N	
38.5	38.5	N	[xii]
8.8	8.8	N	
7.9	7.9	N	
10	10	N	
1	1	N	
6.6	6.6	N	
2	2	N	

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Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing**	**Capacity Rating: Methodology Used in K**	**End Note Number (Enter text in End Notes Sheet**
panels and 38.5 MW capacity have been installed.			

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Market Based Rates Assessments

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Scenario

Scenario Number	1	
Scenario Name	PSEG 2016 MBR for PJM	
Data	MBRA Data v501 PSEG 2016 PJM Sewaren 20180525.	
Applicant	PSEG	Public Service Enterprise Group Inc
Period	Dec 2015 — Nov 2016	

Fill-in white cells with parameters and then click on Run button or type Ctrl+Shift+R.

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Results

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Scenario 1 PSEG 2016 MBR for PJM

	PSA		WM			
			Winter		Spring	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result
PJM Interconnection	38,315	Pass	7.3	Pass	6.1	Pass
PJM East	4,229	Pass	26.7	Fail	22.3	Fail
PJM East of 5004/05	5,892	Pass	20.7	Fail	18.1	Pass
PJM East of AP South	10,461	Pass	14.7	Pass	12.8	Pass

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SA			
Summer		Fall	
Share (%)	Result	Share (%)	Result
6.6	Pass	6.5	Pass
25.9	Fail	24.3	Fail
20.0	Pass	19.7	Pass
14.4	Pass	13.7	Pass

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	9,378	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	195	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	1,943	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	70	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	186,588	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	1,943	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	195	Row B; Table2Data
H	Uncommitted Capacity Imports	7,530	Calculated
I	Study Area Reserve Requirement	8,674	Gendata
J	Amount of Line I Attributable to Seller, if any	228	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	62,196	
	Load		
L	Balancing Area Annual Peak Load	152,177	Loads
M	Average Daily Peak Native Load in Peak Month	132,696	Loads
N	Amount of Line M Attributable to Seller, if any	3,073	SellerLoads
O	Wholesale Load (L-M)	19,482	
P	Net Uncommitted Supply (K-O)	42,715	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,399	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	7,600
% of SIL for Seller's imported capacity →	0.01
% of SIL for Other's imported capacity →	0.99
SIL Value →	7600
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	6,650	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	14	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	152	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	27,691	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	14	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,385	Calculated
I	Study Area Reserve Requirement	1,767	Gendata
J	Amount of Line I Attributable to Seller, if any	202	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	13,259	
	Load		
L	Balancing Area Annual Peak Load	30,992	Loads
M	Average Daily Peak Native Load in Peak Month	25,852	Loads
N	Amount of Line M Attributable to Seller, if any	2,695	SellerLoads
O	Wholesale Load (L-M)	5,139	
P	Net Uncommitted Supply (K-O)	8,120	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	3,890	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	6,537
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	6537
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,418	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	105	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	52,989	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,214	Calculated
I	Study Area Reserve Requirement	3,049	Gendata
J	Amount of Line I Attributable to Seller, if any	210	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	18,909	
	Load		
L	Balancing Area Annual Peak Load	53,493	Loads
M	Average Daily Peak Native Load in Peak Month	44,768	Loads
N	Amount of Line M Attributable to Seller, if any	2,992	SellerLoads
O	Wholesale Load (L-M)	8,725	
P	Net Uncommitted Supply (K-O)	10,184	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,293	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	6,319
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	6319
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,418	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	88	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	80,051	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,367	Calculated
I	Study Area Reserve Requirement	4,162	Gendata
J	Amount of Line I Attributable to Seller, if any	210	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	26,286	
	Load		
L	Balancing Area Annual Peak Load	73,026	Loads
M	Average Daily Peak Native Load in Peak Month	61,476	Loads
N	Amount of Line M Attributable to Seller, if any	2,992	SellerLoads
O	Wholesale Load (L-M)	11,550	
P	Net Uncommitted Supply (K-O)	14,736	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,275	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	4,455
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	4455
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season: Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	10,859	10,119	9,378	10,119	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	195	195	195	195	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	1,643	1,944	1,943	1,944	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	452	1,512	93	1,131	SellerGendata
E	Uncommitted Capacity Imports	91	89	68	53	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	99,674	86,411	116,161	92,587	Loads
G	Amount of Line F Attributable to Seller, if any	1,573	1,308	2,340	1,568	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	98,102	85,102	113,821	91,019	F - G
I	Study Area Reserve Requirement	6,756	6,230	8,317	6,641	Gendata
J	Amount of Line I Attributable to Seller, if any	119	117	202	143	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	6,637	6,113	8,116	6,498	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	193,335	189,962	186,588	189,962	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	1,643	1,944	1,943	1,944	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	195	195	195	195	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	8,043	28,377	1,841	21,225	Gendata; Row D
P	Uncommitted Capacity Imports	11,906	12,184	7,532	7,014	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	93,908	84,302	72,090	79,982	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,359	5,522	5,064	5,580	
S	Total Seasonal Uncommitted Capacity (Q+R)	101,266	89,823	77,154	85,562	
T	**Applicant's Market Share** (R÷S)	7.3%	6.1%	6.6%	6.5%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	11,997	12,273	7,600	7,067	
V	SIL Value	11,997	12,273	7,600	7,067	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,182	7,416	6,650	7,416	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	22	14	14	14	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	340	1,108	66	829	SellerGendata
E	Uncommitted Capacity Imports	156	135	128	113	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	16,761	14,806	21,675	16,148	Loads
G	Amount of Line F Attributable to Seller, if any	1,499	1,253	2,058	1,350	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	15,261	13,553	19,617	14,798	F - G
I	Study Area Reserve Requirement	1,150	1,117	1,651	1,345	Gendata
J	Amount of Line I Attributable to Seller, if any	113	112	177	123	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	1,037	1,005	1,473	1,222	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	27,568	27,630	27,691	27,630	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	22	14	14	14	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,147	4,127	273	3,087	Gendata; Row D
P	Uncommitted Capacity Imports	7,346	8,695	6,409	7,746	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	17,491	17,653	12,750	16,282	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	6,364	5,064	4,463	5,214	
S	Total Seasonal Uncommitted Capacity (Q+R)	23,854	22,717	17,213	21,496	
T	**Applicant's Market Share** (R÷S)	26.7%	22.3%	25.9%	24.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	7,502	8,830	6,537	7,859	
V	SIL Value	7,502	8,830	6,537	7,859	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,951	8,185	7,418	8,185	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	372	1,223	73	914	SellerGendata
E	Uncommitted Capacity Imports	118	69	95	61	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	31,965	27,526	38,884	30,032	Loads
G	Amount of Line F Attributable to Seller, if any	1,524	1,270	2,340	1,568	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	30,441	26,256	36,544	28,465	F - G
I	Study Area Reserve Requirement	2,203	2,058	2,874	2,416	Gendata
J	Amount of Line I Attributable to Seller, if any	115	114	202	143	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,088	1,944	2,672	2,273	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	53,711	53,350	52,989	53,350	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	2,234	7,970	523	5,961	Gendata; Row D
P	Uncommitted Capacity Imports	7,986	8,224	6,224	6,042	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	26,970	25,434	19,502	22,722	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,022	5,618	4,870	5,591	
S	Total Seasonal Uncommitted Capacity (Q+R)	33,992	31,052	24,372	28,313	
T	**Applicant's Market Share** (R÷S)	20.7%	18.1%	20.0%	19.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	8,104	8,293	6,319	6,103	
V	SIL Value	8,104	8,293	6,319	6,103	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,951	8,185	7,418	8,185	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	372	1,223	73	914	SellerGendata
E	Uncommitted Capacity Imports	140	90	81	74	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	44,121	37,780	53,385	41,231	Loads
G	Amount of Line F Attributable to Seller, if any	1,524	1,270	2,340	1,568	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	42,598	36,510	51,045	39,663	F - G
I	Study Area Reserve Requirement	3,105	2,881	3,898	3,332	Gendata
J	Amount of Line I Attributable to Seller, if any	115	114	202	143	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,990	2,767	3,696	3,189	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	82,251	81,151	80,051	81,151	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,422	12,123	790	9,067	Gendata; Row D
P	Uncommitted Capacity Imports	7,757	8,766	4,374	5,994	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	41,035	38,546	28,922	35,255	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,044	5,639	4,856	5,604	
S	Total Seasonal Uncommitted Capacity (Q+R)	48,079	44,185	33,778	40,859	
T	**Applicant's Market Share** (R÷S)	14.7%	12.8%	14.4%	13.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,897	8,856	4,455	6,068	
V	SIL Value	7,897	8,856	4,455	6,068	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Sets and SIL Data

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Areas		Owners	
Code	**Name**	**Code**	**Name**
MISO	Midwest ISO	PSEG	Public Service Enterprise Group Inc
NYISO	New York		
PJM	PJM Interconnection		
PJM_50	PJM Excluding PJM50		
PJM_AP	PJM Excluding PJMAP		
PJM_E	PJM Excluding PJME		
PJM50	PJM East of 5004/05		
PJMAP	PJM East of AP South		
PJME	PJM East		

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Season	
Code	**Name**
SPR	Spring
SUM	Summer
FAL	Fall
WIN	Winter

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Area	Season	SIL	Comment
PJM	SPR	12273	PJM 2015 Simultaneous Import Limit Study
PJM	SUM	7600	PJM 2015 Simultaneous Import Limit Study
PJM	FAL	7067	PJM 2015 Simultaneous Import Limit Study
PJM	WIN	11997	PJM 2015 Simultaneous Import Limit Study
PJME	SPR	8830	PJM 2015 Simultaneous Import Limit Study
PJME	SUM	6537	PJM 2015 Simultaneous Import Limit Study
PJME	FAL	7859	PJM 2015 Simultaneous Import Limit Study
PJME	WIN	7502	PJM 2015 Simultaneous Import Limit Study
PJM50	SPR	8293	PJM 2015 Simultaneous Import Limit Study
PJM50	SUM	6319	PJM 2015 Simultaneous Import Limit Study
PJM50	FAL	6103	PJM 2015 Simultaneous Import Limit Study
PJM50	WIN	8104	PJM 2015 Simultaneous Import Limit Study
PJMAP	SPR	8856	PJM 2015 Simultaneous Import Limit Study
PJMAP	SUM	4455	PJM 2015 Simultaneous Import Limit Study
PJMAP	FAL	6068	PJM 2015 Simultaneous Import Limit Study
PJMAP	WIN	7897	PJM 2015 Simultaneous Import Limit Study

Area	First Tier Areas	Note: No more than 6 First Tier Areas for each destination Area.
PJM	MISO	
PJM	NYISO	
PJM50	NYISO	
PJM50	PJM_50	
PJMAP	NYISO	
PJMAP	PJM_AP	
PJME	NYISO	
PJME	PJM_E	

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Market Data

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AREA	SEASON	MONTH	CAPACITY	PLANNED OUTAGE
NYISO	WIN	1	42,375	3,911
NYISO	WIN	2	42,375	4,197
NYISO	SPR	3	41,172	6,005
NYISO	SPR	4	41,172	9,262
NYISO	SPR	5	41,172	3,751
NYISO	SUM	6	39,969	796
NYISO	SUM	7	39,969	805
NYISO	SUM	8	39,969	910
NYISO	FAL	9	41,172	2,029
NYISO	FAL	10	41,172	9,548
NYISO	FAL	11	41,172	6,419
NYISO	WIN	12	42,375	3,142
PJM	WIN	1	204,194	4,773
PJM	WIN	2	204,194	7,522
PJM	SPR	3	200,080	20,892
PJM	SPR	4	200,080	46,574
PJM	SPR	5	200,080	22,201
PJM	SUM	6	195,966	4,655
PJM	SUM	7	195,966	237
PJM	SUM	8	195,966	910
PJM	FAL	9	200,080	3,112
PJM	FAL	10	200,080	39,568
PJM	FAL	11	200,080	24,388
PJM	WIN	12	204,194	13,188
PJME	WIN	1	35,750	836
PJME	WIN	2	35,750	1,317
PJME	SPR	3	35,046	3,659
PJME	SPR	4	35,046	8,158
PJME	SPR	5	35,046	3,889
PJME	SUM	6	34,341	816
PJME	SUM	7	34,341	42
PJME	SUM	8	34,341	159
PJME	FAL	9	35,046	545
PJME	FAL	10	35,046	6,931
PJME	FAL	11	35,046	4,272
PJME	WIN	12	35,750	2,309
PJM50	WIN	1	62,662	1,465
PJM50	WIN	2	62,662	2,308
PJM50	SPR	3	61,535	6,425
PJM50	SPR	4	61,535	14,324
PJM50	SPR	5	61,535	6,828
PJM50	SUM	6	60,407	1,435
PJM50	SUM	7	60,407	73
PJM50	SUM	8	60,407	281
PJM50	FAL	9	61,535	957
PJM50	FAL	10	61,535	12,169
PJM50	FAL	11	61,535	7,501
PJM50	WIN	12	62,662	4,047
PJMAP	WIN	1	91,202	2,132
PJMAP	WIN	2	91,202	3,360
PJMAP	SPR	3	89,336	9,328

PJMAP	SPR	4	89,336	20,795
PJMAP	SPR	5	89,336	9,913
PJMAP	SUM	6	87,469	2,078
PJMAP	SUM	7	87,469	106
PJMAP	SUM	8	87,469	406
PJMAP	FAL	9	89,336	1,390
PJMAP	FAL	10	89,336	17,667
PJMAP	FAL	11	89,336	10,889
PJMAP	WIN	12	91,202	5,890
PJM_E	WIN	1	168,444	3,937
PJM_E	WIN	2	168,444	6,205
PJM_E	SPR	3	165,035	17,233
PJM_E	SPR	4	165,035	38,416
PJM_E	SPR	5	165,035	18,312
PJM_E	SUM	6	161,625	3,839
PJM_E	SUM	7	161,625	195
PJM_E	SUM	8	161,625	751
PJM_E	FAL	9	165,035	2,567
PJM_E	FAL	10	165,035	32,637
PJM_E	FAL	11	165,035	20,116
PJM_E	WIN	12	168,444	10,879
PJM_50	WIN	1	141,532	3,308
PJM_50	WIN	2	141,532	5,214
PJM_50	SPR	3	138,546	14,467
PJM_50	SPR	4	138,546	32,250
PJM_50	SPR	5	138,546	15,373
PJM_50	SUM	6	135,559	3,220
PJM_50	SUM	7	135,559	164
PJM_50	SUM	8	135,559	629
PJM_50	FAL	9	138,546	2,155
PJM_50	FAL	10	138,546	27,399
PJM_50	FAL	11	138,546	16,887
PJM_50	WIN	12	141,532	9,141
PJM_AP	WIN	1	112,992	2,641
PJM_AP	WIN	2	112,992	4,162
PJM_AP	SPR	3	110,745	11,564
PJM_AP	SPR	4	110,745	25,779
PJM_AP	SPR	5	110,745	12,288
PJM_AP	SUM	6	108,497	2,577
PJM_AP	SUM	7	108,497	131
PJM_AP	SUM	8	108,497	504
PJM_AP	FAL	9	110,745	1,722
PJM_AP	FAL	10	110,745	21,901
PJM_AP	FAL	11	110,745	13,499
PJM_AP	WIN	12	112,992	7,298
MISO	WIN	1	183,745	11,845
MISO	WIN	2	183,745	13,214
MISO	SPR	3	179,902	22,181
MISO	SPR	4	179,902	31,160
MISO	SPR	5	179,902	19,117
MISO	SUM	6	176,059	8,163
MISO	SUM	7	176,059	6,429

MISO	SUM	8	176,059	7,498
MISO	FAL	9	179,902	7,327
MISO	FAL	10	179,902	28,881
MISO	FAL	11	179,902	23,062
MISO	WIN	12	183,745	16,145

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AREA	SEASON	MONTH	MONTHLY PEAK	AVERAGE OF DAILY PEAKS	AVERAGE PEAK LOAD
NYISO	WIN	1	23,317	21,135	20,442
NYISO	WIN	2	23,301	20,827	19,848
NYISO	SPR	3	21,234	18,697	18,157
NYISO	SPR	4	20,173	17,906	17,719
NYISO	SPR	5	25,061	18,866	18,308
NYISO	SUM	6	26,286	22,415	21,209
NYISO	SUM	7	31,187	26,299	25,606
NYISO	SUM	8	32,076	27,129	25,111
NYISO	FAL	9	29,637	22,307	21,394
NYISO	FAL	10	21,143	18,697	18,217
NYISO	FAL	11	26,848	19,630	18,309
NYISO	WIN	12	21,254	20,142	18,879
PJM	WIN	1	129,775	109,463	107,474
PJM	WIN	2	121,307	103,878	100,450
PJM	SPR	3	106,497	89,530	86,259
PJM	SPR	4	99,868	86,664	84,984
PJM	SPR	5	121,540	90,069	87,988
PJM	SUM	6	134,752	113,737	104,204
PJM	SUM	7	150,826	128,598	123,071
PJM	SUM	8	152,177	132,696	121,208
PJM	FAL	9	142,092	110,389	103,577
PJM	FAL	10	102,277	87,670	86,550
PJM	FAL	11	105,171	90,942	87,635
PJM	WIN	12	104,494	94,919	91,099
PJME	WIN	1	21,350	18,481	17,769
PJME	WIN	2	21,162	17,962	16,867
PJME	SPR	3	18,138	15,588	14,660
PJME	SPR	4	16,803	15,031	14,387
PJME	SPR	5	23,845	16,304	15,372
PJME	SUM	6	25,217	20,821	18,716
PJME	SUM	7	30,668	25,247	23,531
PJME	SUM	8	30,992	25,852	22,778
PJME	FAL	9	29,146	20,177	18,619
PJME	FAL	10	19,352	15,573	14,861
PJME	FAL	11	22,289	16,282	14,965
PJME	WIN	12	18,025	16,926	15,645
PJM50	WIN	1	41,374	35,364	34,388
PJM50	WIN	2	40,902	33,996	32,335
PJM50	SPR	3	33,605	28,694	27,196
PJM50	SPR	4	32,555	27,801	26,948
PJM50	SPR	5	42,130	29,682	28,433
PJM50	SUM	6	44,644	37,204	33,847
PJM50	SUM	7	53,493	44,768	42,189
PJM50	SUM	8	53,118	45,448	40,617
PJM50	FAL	9	50,923	36,593	34,119
PJM50	FAL	10	35,164	28,728	27,820
PJM50	FAL	11	41,077	30,204	28,159
PJM50	WIN	12	33,646	31,039	29,171
PJMAP	WIN	1	60,322	49,742	47,974
PJMAP	WIN	2	57,551	47,206	44,577
PJMAP	SPR	3	47,812	39,760	37,365

PJMAP	SPR	4	46,155	38,384	36,990
PJMAP	SPR	5	57,683	40,750	38,985
PJMAP	SUM	6	60,457	51,652	46,812
PJMAP	SUM	7	73,026	61,476	57,809
PJMAP	SUM	8	71,663	62,236	55,535
PJMAP	FAL	9	68,834	50,417	46,839
PJMAP	FAL	10	49,092	39,560	38,174
PJMAP	FAL	11	57,447	41,655	38,679
PJMAP	WIN	12	45,563	42,355	39,813
PJM_E	WIN	1	108,425	90,982	89,705
PJM_E	WIN	2	100,146	85,916	83,583
PJM_E	SPR	3	88,359	73,942	71,599
PJM_E	SPR	4	83,064	71,634	70,597
PJM_E	SPR	5	97,695	73,764	72,617
PJM_E	SUM	6	109,535	92,915	85,488
PJM_E	SUM	7	120,158	103,352	99,540
PJM_E	SUM	8	121,185	106,843	98,430
PJM_E	FAL	9	112,947	90,213	84,958
PJM_E	FAL	10	82,924	72,098	71,689
PJM_E	FAL	11	82,883	74,660	72,670
PJM_E	WIN	12	86,469	77,993	75,454
PJM_50	WIN	1	88,401	74,099	73,086
PJM_50	WIN	2	80,405	69,883	68,115
PJM_50	SPR	3	72,892	60,836	59,063
PJM_50	SPR	4	67,313	58,863	58,036
PJM_50	SPR	5	79,410	60,387	59,556
PJM_50	SUM	6	90,108	76,532	70,358
PJM_50	SUM	7	97,334	83,831	80,881
PJM_50	SUM	8	99,059	87,247	80,591
PJM_50	FAL	9	91,170	73,797	69,458
PJM_50	FAL	10	67,112	58,942	58,730
PJM_50	FAL	11	64,095	60,737	59,476
PJM_50	WIN	12	70,847	63,880	61,928
PJM_AP	WIN	1	69,453	59,721	59,500
PJM_AP	WIN	2	63,756	56,672	55,873
PJM_AP	SPR	3	58,686	49,770	48,894
PJM_AP	SPR	4	53,712	48,280	47,994
PJM_AP	SPR	5	63,857	49,319	49,004
PJM_AP	SUM	6	74,295	62,085	57,392
PJM_AP	SUM	7	77,800	67,123	65,262
PJM_AP	SUM	8	80,514	70,460	65,673
PJM_AP	FAL	9	73,259	59,973	56,738
PJM_AP	FAL	10	53,185	48,110	48,377
PJM_AP	FAL	11	47,725	49,287	48,956
PJM_AP	WIN	12	58,930	52,564	51,286
MISO	WIN	1	97,753	86,934	85,534
MISO	WIN	2	93,742	82,714	81,237
MISO	SPR	3	84,269	75,364	74,207
MISO	SPR	4	79,241	73,507	73,366
MISO	SPR	5	95,170	78,725	77,495
MISO	SUM	6	112,332	98,951	92,990
MISO	SUM	7	120,764	105,024	102,199

MISO	SUM	8	119,860	105,194	101,044
MISO	FAL	9	114,750	92,759	88,854
MISO	FAL	10	90,297	78,398	77,534
MISO	FAL	11	81,775	75,958	74,460
MISO	WIN	12	87,091	80,969	79,008

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COMMENT

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AREA	SOURCE	SEASON	SELLER	REMOTE	CONTRACT	ROW

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DESCRIPTION	CAPACITY

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Seller Data

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AREA	SEASON	MONTH	CAPACITY	PLANNED OUTAGE
NYISO	WIN	1	870	80.29663717
NYISO	WIN	2	870	86.16849558
NYISO	SPR	3	814	118.6502356
NYISO	SPR	4	814	183.0039104
NYISO	SPR	5	814	74.11441028
NYISO	SUM	6	757	15.07598389
NYISO	SUM	7	757	15.24644099
NYISO	SUM	8	757	17.23510721
NYISO	FAL	9	814	40.09014622
NYISO	FAL	10	814	188.6548625
NYISO	FAL	11	814	126.8302851
NYISO	WIN	12	870	64.50831858
PJM	WIN	1	10,859	253.827277
PJM	WIN	2	10,859	400.0186
PJM	SPR	3	10,119	1056.555888
PJM	SPR	4	10,119	2355.352954
PJM	SPR	5	10,119	1122.754991
PJM	SUM	6	9,378	222.7661431
PJM	SUM	7	9,378	11.34169193
PJM	SUM	8	9,378	43.54826858
PJM	FAL	9	10,119	157.3809076
PJM	FAL	10	10,119	2001.043623
PJM	FAL	11	10,119	1233.356547
PJM	WIN	12	10,859	701.3354555
PJME	WIN	1	8182	191.2528576
PJME	WIN	2	8182	301.4045662
PJME	SPR	3	7416	774.3656138
PJME	SPR	4	7416	1726.273411
PJME	SPR	5	7416	822.8839264
PJME	SUM	6	6650	157.9649021
PJME	SUM	7	6650	8.04246655
PJME	SUM	8	6650	30.8803568
PJME	FAL	9	7416	115.3468213
PJME	FAL	10	7416	1466.594802
PJME	FAL	11	7416	903.9454618
PJME	WIN	12	8182	528.4396995
PJM50	WIN	1	8951	209.2281017
PJM50	WIN	2	8951	329.732617
PJM50	SPR	3	8184.5	854.6110256
PJM50	SPR	4	8184.5	1905.16245
PJM50	SPR	5	8184.5	908.1571596
PJM50	SUM	6	7418	176.2080667
PJM50	SUM	7	7418	8.971280732
PJM50	SUM	8	7418	34.44668973
PJM50	FAL	9	8184.5	127.2999
PJM50	FAL	10	8184.5	1618.57405
PJM50	FAL	11	8184.5	997.6188824
PJM50	WIN	12	8951	578.106056
PJMAP	WIN	1	8951	209.2281017
PJMAP	WIN	2	8951	329.732617
PJMAP	SPR	3	8184.5	854.6110256

PJMAP	SPR	4	8184.5	1905.16245
PJMAP	SPR	5	8184.5	908.1571596
PJMAP	SUM	6	7418	176.2080667
PJMAP	SUM	7	7418	8.971280732
PJMAP	SUM	8	7418	34.44668973
PJMAP	FAL	9	8184.5	127.2999
PJMAP	FAL	10	8184.5	1618.57405
PJMAP	FAL	11	8184.5	997.6188824
PJMAP	WIN	12	8951	578.106056
PJM_E	WIN	1	2677	62.57441942
PJM_E	WIN	2	2677	98.61403371
PJM_E	SPR	3	2702.5	282.1902739
PJM_E	SPR	4	2702.5	629.0795432
PJM_E	SPR	5	2702.5	299.8710641
PJM_E	SUM	6	2728	64.80124103
PJM_E	SUM	7	2728	3.299225376
PJM_E	SUM	8	2728	12.66791178
PJM_E	FAL	9	2702.5	42.03408637
PJM_E	FAL	10	2702.5	534.4488205
PJM_E	FAL	11	2702.5	329.4110856
PJM_E	WIN	12	2677	172.895756
PJM_50	WIN	1	1908	44.59917529
PJM_50	WIN	2	1908	70.28598294
PJM_50	SPR	3	1934	201.9448621
PJM_50	SPR	4	1934	450.1905038
PJM_50	SPR	5	1934	214.5978309
PJM_50	SUM	6	1960	46.5580764
PJM_50	SUM	7	1960	2.370411194
PJM_50	SUM	8	1960	9.101578845
PJM_50	FAL	9	1934	30.0810076
PJM_50	FAL	10	1934	382.4695722
PJM_50	FAL	11	1934	235.7376649
PJM_50	WIN	12	1908	123.2293995
PJM_AP	WIN	1	1908	44.59917529
PJM_AP	WIN	2	1908	70.28598294
PJM_AP	SPR	3	1934	201.9448621
PJM_AP	SPR	4	1934	450.1905038
PJM_AP	SPR	5	1934	214.5978309
PJM_AP	SUM	6	1960	46.5580764
PJM_AP	SUM	7	1960	2.370411194
PJM_AP	SUM	8	1960	9.101578845
PJM_AP	FAL	9	1934	30.0810076
PJM_AP	FAL	10	1934	382.4695722
PJM_AP	FAL	11	1934	235.7376649
PJM_AP	WIN	12	1908	123.2293995

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106.59
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145.0600245
185.008084
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175.8494061
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94.02534921
101.118
120.3972485
121.4950349
98.56380777
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149.7211391
167.1839788
209.928553
227.9062339
200.5730199
113.6769314
115.7052291
102.771
120.3972485
121.4950349
98.56380777

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0
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0
0
0
3.819

AREA	SEASON	MONTH	MONTHLY PEAK	AVERAGE OF DAILY PEAKS	AVERAGE PEAK LOAD
NYISO	WIN	1	-	-	-
NYISO	WIN	2	-	-	-
NYISO	SPR	3	-	-	-
NYISO	SPR	4	-	-	-
NYISO	SPR	5	-	-	-
NYISO	SUM	6	-	-	-
NYISO	SUM	7	-	-	-
NYISO	SUM	8	-	-	-
NYISO	FAL	9	-	-	-
NYISO	FAL	10	-	-	-
NYISO	FAL	11	-	-	-
NYISO	WIN	12	-	-	-
PJM	WIN	1	2,187	1,908	1,680
PJM	WIN	2	2,208	1,834	1,583
PJM	SPR	3	1,793	1,551	1,317
PJM	SPR	4	1,699	1,453	1,253
PJM	SPR	5	2,681	1,603	1,354
PJM	SUM	6	2,933	2,306	1,903
PJM	SUM	7	3,683	2,992	2,615
PJM	SUM	8	3,998	3,073	2,503
PJM	FAL	9	3,519	2,220	1,863
PJM	FAL	10	1,994	1,622	1,390
PJM	FAL	11	2,030	1,716	1,451
PJM	WIN	12	1,870	1,712	1,456
PJME	WIN	1	2071.82422	1,811	1598.633077
PJME	WIN	2	2087.87738	1,741	1506.097893
PJME	SPR	3	1699.30127	1,477	1258.054799
PJME	SPR	4	1613.83134	1,385	1198.903841
PJME	SPR	5	2595.69673	1,539	1303.230943
PJME	SUM	6	2544.91271	2,013	1670.812832
PJME	SUM	7	3245.75586	2620.463546	2298.973997
PJME	SUM	8	3538.68543	2695.381386	2205.210453
PJME	FAL	9	3085.0773	1927.826885	1633.467359
PJME	FAL	10	1735.6674	1377.55915	1197.477072
PJME	FAL	11	1649.56753	1424.046758	1218.505107
PJME	WIN	12	1774	1630.935484	1392.605114
PJM50	WIN	1	2112.23243	1843.396131	1627.49382
PJM50	WIN	2	2131.49184	1770.955132	1531.939171
PJM50	SPR	3	1729.18961	1499.662979	1276.360292
PJM50	SPR	4	1641.05254	1405.943822	1215.40429
PJM50	SPR	5	2626.68665	1559.4767	1319.067449
PJM50	SUM	6	2933.05226	2305.630737	1903.335218
PJM50	SUM	7	3682.95707	2992.478437	2614.982471
PJM50	SUM	8	3998.35498	3073.014376	2502.605508
PJM50	FAL	9	3518.82491	2220.474087	1862.733948
PJM50	FAL	10	1994.33213	1622.031246	1390.147201
PJM50	FAL	11	2029.9163	1715.635242	1450.924655
PJM50	WIN	12	1803	1654.451613	1411.298295
PJMAP	WIN	1	2112.23243	1843.396131	1627.49382
PJMAP	WIN	2	2131.49184	1770.955132	1531.939171
PJMAP	SPR	3	1729.18961	1499.662979	1276.360292

PJMAP	SPR	4	1641.05254	1405.943822	1215.40429
PJMAP	SPR	5	2626.68665	1559.4767	1319.067449
PJMAP	SUM	6	2933.05226	2305.630737	1903.335218
PJMAP	SUM	7	3682.95707	2992.478437	2614.982471
PJMAP	SUM	8	3998.35498	3073.014376	2502.605508
PJMAP	FAL	9	3518.82491	2220.474087	1862.733948
PJMAP	FAL	10	1994.33213	1622.031246	1390.147201
PJMAP	FAL	11	2029.9163	1715.635242	1450.924655
PJMAP	WIN	12	1803	1654.451613	1411.298295
PJM_E	WIN	1	114.85733	2.684770542	80.95252853
PJM_E	WIN	2	119.72045	4.410204144	76.42658753
PJM_E	SPR	3	93.4001	9.752673377	58.76250864
PJM_E	SPR	4	85.12579	19.81531659	54.39960196
PJM_E	SPR	5	85.02786	9.434743702	51.10709568
PJM_E	SUM	6	388.13955	9.219913685	232.5223862
PJM_E	SUM	7	437.20121	0.528748287	316.0084735
PJM_E	SUM	8	459.66955	2.134550333	297.3950549
PJM_E	FAL	9	433.74761	6.746414246	229.2665884
PJM_E	FAL	10	258.66473	51.15376868	192.6701299
PJM_E	FAL	11	380.34877	46.36118454	232.4195477
PJM_E	WIN	12	96	6.200221358	63.03977273
PJM_50	WIN	1	74.44912	1.74023551	52.09178512
PJM_50	WIN	2	76.10599	2.80355572	50.58530935
PJM_50	SPR	3	63.51176	6.631785735	40.45701549
PJM_50	SPR	4	57.90459	13.47885033	37.89915286
PJM_50	SPR	5	54.03794	5.996083096	35.27058943
PJM_50	SUM	6	0	0	0
PJM_50	SUM	7	0	0	0
PJM_50	SUM	8	0	0	0
PJM_50	FAL	9	0	0	0
PJM_50	FAL	10	0	0	0
PJM_50	FAL	11	0	0	0
PJM_50	WIN	12	67	4.327237823	44.34659091
PJM_AF	WIN	1	74.44912	1.74023551	52.09178513
PJM_AF	WIN	2	76.10599	2.80355572	50.58530935
PJM_AF	SPR	3	63.51176	6.631785735	40.45701549
PJM_AF	SPR	4	57.90459	13.47885033	37.89915286
PJM_AF	SPR	5	54.03794	5.996083096	35.27058943
PJM_AF	SUM	6	0	0	-2.72848E-12
PJM_AF	SUM	7	0	0	0
PJM_AF	SUM	8	0	0	0
PJM_AF	FAL	9	0	0	0
PJM_AF	FAL	10	0	0	0
PJM_AF	FAL	11	0	0	0
PJM_AF	WIN	12	67	4.327237823	44.34659091

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COMMENT

AREA	SEASON	DESCRIPTION	SALE	PURCHASE
PJM	WIN	LES Project Holdings	14	0
PJM	SPR	LES Project Holdings	14	0
PJM	SUM	LES Project Holdings	14	0
PJM	FAL	LES Project Holdings	14	0
PJM	WIN	Ocean Energy Holdings	9	0
PJM	SPR	Ocean Energy Holdings	9	0
PJM	SUM	Ocean Energy Holdings	9	0
PJM	FAL	Ocean Energy Holdings	9	0
PJM	WIN	BP	34	0
PJM	SPR	BP	0	0
PJM	SUM	BP	0	0
PJM	FAL	BP	0	0
PJM	WIN	Citigroup	94	0
PJM	SPR	Citigroup	75	0
PJM	SUM	Citigroup	75	0
PJM	FAL	Citigroup	75	0
PJM	WIN	Direct Energy	556	0
PJM	SPR	Direct Energy	650	0
PJM	SUM	Direct Energy	650	0
PJM	FAL	Direct Energy	650	0
PJM	WIN	EDF	8	0
PJM	SPR	EDF	0	0
PJM	SUM	EDF	0	0
PJM	FAL	EDF	0	0
PJM	WIN	Energy America	305	0
PJM	SPR	Energy America	460	0
PJM	SUM	Energy America	460	0
PJM	FAL	Energy America	460	0
PJM	WIN	Exelon	66	0
PJM	SPR	Exelon	100	0
PJM	SUM	Exelon	100	0
PJM	FAL	Exelon	100	0
PJM	WIN	Nextera	523	0
PJM	SPR	Nextera	602	0
PJM	SUM	Nextera	601	0
PJM	FAL	Nextera	602	0
PJM	WIN	American Electric Power	10	0
PJM	SPR	American Electric Power	10	0
PJM	SUM	American Electric Power	10	0
PJM	FAL	American Electric Power	10	0
PJM	WIN	M&M Mars	2	0
PJM	SPR	M&M Mars	2	0
PJM	SUM	M&M Mars	2	0
PJM	FAL	M&M Mars	2	0
PJM	WIN	SMECO	10	0
PJM	SPR	SMECO	10	0
PJM	SUM	SMECO	10	0
PJM	FAL	SMECO	10	0
PJM	WIN	JP Morgan	0	195
PJM	SPR	JP Morgan	0	195
PJM	SUM	JP Morgan	0	195
PJM	FAL	JP Morgan	0	195
PJM	WIN	Delaware Municipal Electric Corporatio	12	0
PJM	SPR	Delaware Municipal Electric Corporatio	12	0

PJM	SUM	Delaware Municipal Electric Corporatio	12	0
PJM	FAL	Delaware Municipal Electric Corporatio	12	0
PJM_E	WIN	LES Project Holdings	14	0
PJM_E	SPR	LES Project Holdings	14	0
PJM_E	SUM	LES Project Holdings	14	0
PJM_E	FAL	LES Project Holdings	14	0
PJM_E	WIN	Ocean Energy Holdings	9	0
PJM_E	SPR	Ocean Energy Holdings	9	0
PJM_E	SUM	Ocean Energy Holdings	9	0
PJM_E	FAL	Ocean Energy Holdings	9	0
PJM_E	WIN	BP	34	0
PJM_E	SPR	BP	0	0
PJM_E	SUM	BP	0	0
PJM_E	FAL	BP	0	0
PJM_E	WIN	Citigroup	94	0
PJM_E	SPR	Citigroup	75	0
PJM_E	SUM	Citigroup	75	0
PJM_E	FAL	Citigroup	75	0
PJM_E	WIN	Direct Energy	556	0
PJM_E	SPR	Direct Energy	650	0
PJM_E	SUM	Direct Energy	650	0
PJM_E	FAL	Direct Energy	650	0
PJME	WIN	EDF	8	0
PJME	SPR	EDF	0	0
PJME	SUM	EDF	0	0
PJME	FAL	EDF	0	0
PJM_E	WIN	Energy America	305	0
PJM_E	SPR	Energy America	460	0
PJM_E	SUM	Energy America	460	0
PJM_E	FAL	Energy America	460	0
PJM_E	WIN	Exelon	66	0
PJM_E	SPR	Exelon	100	0
PJM_E	SUM	Exelon	100	0
PJM_E	FAL	Exelon	100	0
PJM_E	WIN	Nextera	523	0
PJM_E	SPR	Nextera	602	0
PJM_E	SUM	Nextera	601	0
PJM_E	FAL	Nextera	602	0
PJM_E	WIN	American Electric Power	10	0
PJM_E	SPR	American Electric Power	10	0
PJM_E	SUM	American Electric Power	10	0
PJM_E	FAL	American Electric Power	10	0
PJME	WIN	M&M Mars	2	0
PJME	SPR	M&M Mars	2	0
PJME	SUM	M&M Mars	2	0
PJME	FAL	M&M Mars	2	0
PJM_E	WIN	SMECO	10	0
PJM_E	SPR	SMECO	10	0
PJM_E	SUM	SMECO	10	0
PJM_E	FAL	SMECO	10	0
PJM_E	WIN	JP Morgan	0	195
PJM_E	SPR	JP Morgan	0	195
PJM_E	SUM	JP Morgan	0	195
PJM_E	FAL	JP Morgan	0	195
PJME	WIN	Delaware Municipal Electric Corporatio	12	0

PJME	SPR	Delaware Municipal Electric Corporatio	12	0
PJME	SUM	Delaware Municipal Electric Corporatio	12	0
PJME	FAL	Delaware Municipal Electric Corporatio	12	0
PJM50	WIN	LES Project Holdings	14	0
PJM50	SPR	LES Project Holdings	14	0
PJM50	SUM	LES Project Holdings	14	0
PJM50	FAL	LES Project Holdings	14	0
PJM_50	WIN	Ocean Energy Holdings	9	0
PJM_50	SPR	Ocean Energy Holdings	9	0
PJM_50	SUM	Ocean Energy Holdings	9	0
PJM_50	FAL	Ocean Energy Holdings	9	0
PJM_50	WIN	BP	34	0
PJM_50	SPR	BP	0	0
PJM_50	SUM	BP	0	0
PJM_50	FAL	BP	0	0
PJM_50	WIN	Citigroup	94	0
PJM_50	SPR	Citigroup	75	0
PJM_50	SUM	Citigroup	75	0
PJM_50	FAL	Citigroup	75	0
PJM_50	WIN	Direct Energy	556	0
PJM_50	SPR	Direct Energy	650	0
PJM_50	SUM	Direct Energy	650	0
PJM_50	FAL	Direct Energy	650	0
PJM50	WIN	EDF	8	0
PJM50	SPR	EDF	0	0
PJM50	SUM	EDF	0	0
PJM50	FAL	EDF	0	0
PJM_50	WIN	Energy America	305	0
PJM_50	SPR	Energy America	460	0
PJM_50	SUM	Energy America	460	0
PJM_50	FAL	Energy America	460	0
PJM_50	WIN	Exelon	66	0
PJM_50	SPR	Exelon	100	0
PJM_50	SUM	Exelon	100	0
PJM_50	FAL	Exelon	100	0
PJM_50	WIN	Nextera	523	0
PJM_50	SPR	Nextera	602	0
PJM_50	SUM	Nextera	601	0
PJM_50	FAL	Nextera	602	0
PJM_50	WIN	American Electric Power	10	0
PJM_50	SPR	American Electric Power	10	0
PJM_50	SUM	American Electric Power	10	0
PJM_50	FAL	American Electric Power	10	0
PJM50	WIN	M&M Mars	2	0
PJM50	SPR	M&M Mars	2	0
PJM50	SUM	M&M Mars	2	0
PJM50	FAL	M&M Mars	2	0
PJM_50	WIN	SMECO	10	0
PJM_50	SPR	SMECO	10	0
PJM_50	SUM	SMECO	10	0
PJM_50	FAL	SMECO	10	0
PJM_50	WIN	JP Morgan	0	195
PJM_50	SPR	JP Morgan	0	195
PJM_50	SUM	JP Morgan	0	195
PJM_50	FAL	JP Morgan	0	195

PJM50	WIN	Delaware Municipal Electric Corporatio	12	0
PJM50	SPR	Delaware Municipal Electric Corporatio	12	0
PJM50	SUM	Delaware Municipal Electric Corporatio	12	0
PJM50	FAL	Delaware Municipal Electric Corporatio	12	0
PJMAP	WIN	LES Project Holdings	14	0
PJMAP	SPR	LES Project Holdings	14	0
PJMAP	SUM	LES Project Holdings	14	0
PJMAP	FAL	LES Project Holdings	14	0
PJM_AP	WIN	Ocean Energy Holdings	9	0
PJM_AP	SPR	Ocean Energy Holdings	9	0
PJM_AP	SUM	Ocean Energy Holdings	9	0
PJM_AP	FAL	Ocean Energy Holdings	9	0
PJM_AP	WIN	BP	34	0
PJM_AP	SPR	BP	0	0
PJM_AP	SUM	BP	0	0
PJM_AP	FAL	BP	0	0
PJM_AP	WIN	Citigroup	94	0
PJM_AP	SPR	Citigroup	75	0
PJM_AP	SUM	Citigroup	75	0
PJM_AP	FAL	Citigroup	75	0
PJM_AP	WIN	Direct Energy	556	0
PJM_AP	SPR	Direct Energy	650	0
PJM_AP	SUM	Direct Energy	650	0
PJM_AP	FAL	Direct Energy	650	0
PJMAP	WIN	EDF	8	0
PJMAP	SPR	EDF	0	0
PJMAP	SUM	EDF	0	0
PJMAP	FAL	EDF	0	0
PJM_AP	WIN	Energy America	305	0
PJM_AP	SPR	Energy America	460	0
PJM_AP	SUM	Energy America	460	0
PJM_AP	FAL	Energy America	460	0
PJM_AP	WIN	Exelon	66	0
PJM_AP	SPR	Exelon	100	0
PJM_AP	SUM	Exelon	100	0
PJM_AP	FAL	Exelon	100	0
PJM_AP	WIN	Nextera	523	0
PJM_AP	SPR	Nextera	602	0
PJM_AP	SUM	Nextera	601	0
PJM_AP	FAL	Nextera	602	0
PJM_AP	WIN	American Electric Power	10	0
PJM_AP	SPR	American Electric Power	10	0
PJM_AP	SUM	American Electric Power	10	0
PJM_AP	FAL	American Electric Power	10	0
PJMAP	WIN	M&M Mars	2	0
PJMAP	SPR	M&M Mars	2	0
PJMAP	SUM	M&M Mars	2	0
PJMAP	FAL	M&M Mars	2	0
PJM_AP	WIN	SMECO	10	0
PJM_AP	SPR	SMECO	10	0
PJM_AP	SUM	SMECO	10	0
PJM_AP	FAL	SMECO	10	0
PJM_AP	WIN	JP Morgan	0	195
PJM_AP	SPR	JP Morgan	0	195
PJM_AP	SUM	JP Morgan	0	195

PJM_AP	FAL	JP Morgan	0	195
PJMAP	WIN	Delaware Municipal Electric Corporatio	12	0
PJMAP	SPR	Delaware Municipal Electric Corporatio	12	0
PJMAP	SUM	Delaware Municipal Electric Corporatio	12	0
PJMAP	FAL	Delaware Municipal Electric Corporatio	12	0

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Document Content(s)

PSEG Sewaren Change in Status Letter.PDF.....1-1

FINAL Appendix B - Generation Assets Change in Status.XLSX.....2-19

Appendix A-3 PSEG Sewaren MBR Program.XLSX.....20-69

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Cara J. Lewis
Associate General Regulatory Counsel

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Cara.Lewis@PSEG.com

PSEG Services Corporation

October 12, 2017

VIA EFILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: ***PSEG Energy Resources & Trade LLC*****, Docket No. ER10-1789-005;**
Public Service Electric and Gas Company**, Docket No. ER10-1768-004;**
PSEG Power Connecticut LLC**, Docket No. ER10-1793-004;**
PSEG Fossil LLC**, Docket No. ER10-1770-004;**
PSEG Nuclear LLC**, ER10-1771-004;**
PSEG New Haven LLC**, ER12-1250-004**
***Pavant Solar II LLC,* ER16-1925-002**
***San Isabel Solar LLC,* ER16-1926-002**
***Bison Solar LLC,* ER16-1924-002**
***PSEG Energy Solutions LLC,* ER16-2725-002**

Dear Secretary Bose:

On December 28, 2016, PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG Fossil LLC, PSEG Nuclear LLC, PSEG New Haven LLC, Pavant Solar II LLC, San Isabel Solar LLC, Bison Solar LLC, and PSEG Energy Solutions LLC, ("Applicants") jointly submitted their updated market power analysis in support of their continued eligibility to engage in market-based rate transactions.

Applicants' application included the Report & Affidavit of Dr. John R. Morris ("Morris Affidavit"), which contained the following exhibits: PEG-2; PEG-3; PEG-4; PEG-5; PEG-6; PEG-7; PEG-8; PEG-9; PEG-10; and PEG-11. In the instant filing, Applicants are resubmitting the above-mentioned exhibits to the Morris Affidavit in Excel format as required by the Commission's regulations.

Thank you for your attention to this matter.

Respectfully submitted,

Cara J. Lewis
Cara J. Lewis

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Northeast Region Generation Owned and Controlled by PS

Owner	Plant Name	State	Owned Capacity: Winter Seasonal Capacity	Owned Capacity: Summer Seasonal Capacity
ISO - New England				
PSEG Power CT	Bridgeport Station 2	CT	148	130
PSEG Power CT	Bridgeport Station 3	CT	385	383
PSEG Power CT	Bridgeport Station 4	CT	20	15
PSEG Power CT	New Haven Harbor 1	CT	455	448
PSEG New Haven	New Haven Harbor GT2	CT	61	61
PSEG New Haven	New Haven Harbor GT3	CT	61	61
PSEG New Haven	New Haven Harbor GT4	CT	61	61
Total ISO - New England Capacity			**1,190**	**1,158**
New York ISO				
PSEG Power NY	Bethlehem Energy Center CC	NY	845	754
Total New York ISO Capacity			**845**	**754**
PJM				
PSEG Fossil	Conemaugh 1	PA	191	191
PSEG Fossil	Conemaugh 2	PA	191	191
PSEG Fossil	Conemaugh A[1]	PA	1	1
PSEG Fossil	Conemaugh B	PA	1	1
PSEG Fossil	Conemaugh C	PA	1	1
PSEG Fossil	Conemaugh D	PA	1	1
PSEG Power	Conemaugh Hydroelectric Plant 1[2]	PA	1	1
PSEG Power	Conemaugh Hydroelectric Plant 2	PA	1	1
PSEG Fossil	Keystone 1[3]	PA	194	194
PSEG Fossil	Keystone 2	PA	194	194
PSEG Fossil	Keystone 3	PA	1	1
PSEG Fossil	Keystone 4	PA	1	1
PSEG Fossil	Keystone 5	PA	1	1
PSEG Fossil	Keystone 6	PA	1	1
PSEG Solar Source LLC	Wyandot Solar Farm	OH	12	12

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Northeast Region Generation Owned and Controlled by PS

Owner	Plant Name	State	Owned Capacity Winter Seasonal Capacity	Owned Capacity Summer Seasonal Capacity
PJM East				
PSEG Fossil	Bergen 3[7]	NJ	21	21
PSEG Fossil	Bergen CC1	NJ	628	628
PSEG Fossil	Bergen CC2	NJ	550	555
PSEG Fossil	Burlington 8[7]	NJ	21	21
PSEG Fossil	Burlington 9[10]	NJ	184	184
PSEG Fossil	Burlington 11[7]	NJ	184	184
PSEG Fossil	Burlington 121	NJ	42	42
PSEG Fossil	Burlington 122	NJ	42	42
PSEG Fossil	Burlington 123	NJ	42	42
PSEG Fossil	Burlington 124	NJ	42	42
PSEG Fossil	Edison 1[7]	NJ	168	168
PSEG Fossil	Edison 2[7]	NJ	168	168
PSEG Fossil	Edison 3[7]	NJ	168	168
PSEG Fossil	Essex 9	NJ	81	81
PSEG Fossil	Essex 10[7]	NJ	168	168
PSEG Fossil	Essex 11[7]	NJ	168	168
PSEG Fossil	Essex 12[7]	NJ	168	168
PSEG Nuclear	Hope Creek 1	NJ	1,161	1,161
PSEG Fossil	Hudson 2	NJ	608	608
PSEG Fossil	Kearny 9[8]	NJ	21	21
PSEG Fossil	Kearny 12	NJ	175	175
PSEG Fossil	Kearny 13	NJ	0	178
PSEG Fossil	Kearny 14	NJ	0	89
PSEG Fossil	Linden 1	NJ	455	458
PSEG Fossil	Linden 2	NJ	775	778
PSEG Fossil	Linden 7	NJ	84	84
PSEG Fossil	Linden 8	NJ	84	84
PSEG Fossil	Linden GT5	NJ	86	86
PSEG Fossil	Linden GT6	NJ	86	86
PSEG Hackettstown LLC	Mars Solar Garden	NJ	2	2
PSEG Fossil	Mercer 1	NJ	316	316
PSEG Fossil	Mercer 2	NJ	316	316
PSEG Fossil	Mercer GT3[9]	NJ	115	115
PSEG Solar Source LLC	Milford Solar Farm	DE	15	15
PSEG Fossil	National Park GT1[7]	NJ	21	21
PSEG Nuclear	Salem 1[4]	NJ	674	674
PSEG Nuclear	Salem 2	NJ	665	665
PSEG Nuclear	Salem GT3	NJ	22	22
PSEG Fossil	Sewaren 1	NJ	104	104
PSEG Fossil	Sewaren 2	NJ	118	118
PSEG Fossil	Sewaren 3	NJ	107	107
PSEG Fossil	Sewaren 4	NJ	124	124
PSEG Fossil	Sewaren 6[7]	NJ	105	105
PSE&G	Solar 4 All Units	NJ	78	78
PSEG Fossil	Yards Creek 1[5]	NJ	70	70
PSEG Fossil	Yards Creek 2	NJ	70	70
PSEG Fossil	Yards Creek 3	NJ	60	60
PJM 5004/5005				
PSEG Nuclear	Peach Bottom 2[6]	PA	561	561

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Northeast Region Generation Owned and Controlled by PS

			Owned Capacity	
Owner	**Plant Name**	**State**	**Winter Seasonal Capacity**	**Summer Seasonal Capacity**
PSEG Nuclear	Peach Bottom 3	PA	561	561
Total PJM Capacity			**11,272**	**11,550**
Total Northeast Region Capacity			**13,307**	**13,462**

Source: PSEG.
Notes:
[1] PSEG Fossil has a 22.5% interest in the Conemaugh coal-fired units.
[2] PSEG Global has a 4% interest in the Conemaugh Hydroelectric facility.
[3] PSEG Fossil has a 22.84% ownership interest in the Keystone facility.
[4] PSEG Nuclear has a 57.41% interest in the Salem Nuclear facility.
[5] PSEG Fossil has a 50% interest in the Yards Creek facility. Yards Creek is operated by Jersey Central Power & by JCP&L in the analysis.
[6] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear facility.
[7] Unit retired on 06/01/2015
[8] Unit retired on 08/31/2014
[9] Unit retired on 07/31/2015

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EG

Controlled Capacity	
Winter Seasonal Capacity	**Summer Seasonal Capacity**
148	130
385	383
20	15
455	448
0	0
0	0
0	0
1,008	**976**
845	754
845	**754**
191	191
191	191
1	1
1	1
1	1
1	1
1	1
1	1
194	194
194	194
1	1
1	1
1	1
1	1
12	12

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EG

Controlled Capacity	
Winter Seasonal Capacity	Summer Seasonal Capacity
21	21
628	628
550	555
21	21
184	184
184	184
42	42
42	42
42	42
42	42
168	168
168	168
168	168
81	81
168	168
168	168
168	168
1,161	1,161
608	608
21	21
175	175
0	178
0	89
455	458
775	778
84	84
84	84
86	86
86	86
2	2
316	316
316	316
115	115
15	15
21	21
674	674
665	665
22	22
104	104
118	118
107	107
124	124
105	105
78	78
0	0
0	0
0	0
561	561

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EG

Controlled Capacity	
Winter Seasonal Capacity	**Summer Seasonal Capacity**
561	561
11,072	**11,350**
12,926	**13,080**

Light, and thus is controlled

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Northeast Region Generation Owned and Controlled by PS

Owner	Plant Name	State	Owned Capacity: Winter Seasonal Capacity	Owned Capacity: Summer Seasonal Capacity
ISO - New England				
PSEG Power CT	Bridgeport Station 2	CT	148	130
PSEG Power CT	Bridgeport Station 3	CT	385	383
PSEG Power CT	Bridgeport Station 4	CT	20	15
PSEG Power CT	New Haven Harbor 1	CT	455	448
PSEG New Haven	New Haven Harbor GT2	CT	61	61
PSEG New Haven	New Haven Harbor GT3	CT	61	61
PSEG New Haven	New Haven Harbor GT4	CT	61	61
Total ISO - New England Capacity			**1,190**	**1,158**
New York ISO				
PSEG Power NY	Bethlehem Energy Center CC	NY	845	754
Total New York ISO Capacity			**845**	**754**
PJM				
PSEG Fossil	Conemaugh 1	PA	191	191
PSEG Fossil	Conemaugh 2	PA	191	191
PSEG Fossil	Conemaugh A[1]	PA	1	1
PSEG Fossil	Conemaugh B	PA	1	1
PSEG Fossil	Conemaugh C	PA	1	1
PSEG Fossil	Conemaugh D	PA	1	1
PSEG Power	Conemaugh Hydroelectric Plant 1[2]	PA	1	1
PSEG Power	Conemaugh Hydroelectric Plant 2	PA	1	1
PSEG Fossil	Keystone 1[3]	PA	194	194
PSEG Fossil	Keystone 2	PA	194	194
PSEG Fossil	Keystone 3	PA	1	1
PSEG Fossil	Keystone 4	PA	1	1
PSEG Fossil	Keystone 5	PA	1	1
PSEG Fossil	Keystone 6	PA	1	1
PSEG Solar Source LLC	Wyandot Solar Farm	OH	12	12

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Northeast Region Generation Owned and Controlled by PS

Owner	Plant Name	State	Owned Capacity Winter Seasonal Capacity	Owned Capacity Summer Seasonal Capacity
PJM East				
PSEG Fossil	Bergen 3[7]	NJ	21	21
PSEG Fossil	Bergen CC1	NJ	628	628
PSEG Fossil	Bergen CC2	NJ	550	555
PSEG Fossil	Burlington 8[7]	NJ	21	21
PSEG Fossil	Burlington 9[10]	NJ	184	184
PSEG Fossil	Burlington 11[7]	NJ	184	184
PSEG Fossil	Burlington 121	NJ	42	42
PSEG Fossil	Burlington 122	NJ	42	42
PSEG Fossil	Burlington 123	NJ	42	42
PSEG Fossil	Burlington 124	NJ	42	42
PSEG Fossil	Edison 1[7]	NJ	168	168
PSEG Fossil	Edison 2[7]	NJ	168	168
PSEG Fossil	Edison 3[7]	NJ	168	168
PSEG Fossil	Essex 9	NJ	81	81
PSEG Fossil	Essex 10[7]	NJ	168	168
PSEG Fossil	Essex 11[7]	NJ	168	168
PSEG Fossil	Essex 12[7]	NJ	168	168
PSEG Nuclear	Hope Creek 1	NJ	1,161	1,161
PSEG Fossil	Hudson 2	NJ	608	608
PSEG Fossil	Kearny 9[8]	NJ	21	21
PSEG Fossil	Kearny 12	NJ	175	175
PSEG Fossil	Kearny 13	NJ	0	178
PSEG Fossil	Kearny 14	NJ	0	89
PSEG Fossil	Linden 1	NJ	455	458
PSEG Fossil	Linden 2	NJ	775	778
PSEG Fossil	Linden 7	NJ	84	84
PSEG Fossil	Linden 8	NJ	84	84
PSEG Fossil	Linden GT5	NJ	86	86
PSEG Fossil	Linden GT6	NJ	86	86
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PSEG Fossil	Mercer 2	NJ	316	316
PSEG Fossil	Mercer GT3[9]	NJ	115	115
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PSEG Nuclear	Salem 1[4]	NJ	674	674
PSEG Nuclear	Salem 2	NJ	665	665
PSEG Nuclear	Salem GT3	NJ	22	22
PSEG Fossil	Sewaren 1	NJ	104	104
PSEG Fossil	Sewaren 2	NJ	118	118
PSEG Fossil	Sewaren 3	NJ	107	107
PSEG Fossil	Sewaren 4	NJ	124	124
PSEG Fossil	Sewaren 6[7]	NJ	105	105
PSE&G	Solar 4 All Units	NJ	78	78
PSEG Fossil	Yards Creek 1[5]	NJ	70	70
PSEG Fossil	Yards Creek 2	NJ	70	70
PSEG Fossil	Yards Creek 3	NJ	60	60
PJM 5004/5005				
PSEG Nuclear	Peach Bottom 2[6]	PA	561	561

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Northeast Region Generation Owned and Controlled by PS

Owner	Plant Name	State	Owned Capacity: Winter Seasonal Capacity	Owned Capacity: Summer Seasonal Capacity
PSEG Nuclear	Peach Bottom 3	PA	561	561
Total PJM Capacity			**11,272**	**11,550**
Total Northeast Region Capacity			**13,307**	**13,462**

Source: PSEG.
Notes:
[1] PSEG Fossil has a 22.5% interest in the Conemaugh coal-fired units.
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EG

Controlled Capacity	
Winter Seasonal Capacity	**Summer Seasonal Capacity**
148	130
385	383
20	15
455	448
0	0
0	0
0	0
1,008	**976**
845	754
845	**754**
191	191
191	191
1	1
1	1
1	1
1	1
1	1
1	1
194	194
194	194
1	1
1	1
1	1
1	1
12	12

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EG

Controlled Capacity	
Winter Seasonal Capacity	**Summer Seasonal Capacity**
21	21
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550	555
21	21
184	184
184	184
42	42
42	42
42	42
42	42
168	168
168	168
168	168
81	81
168	168
168	168
168	168
1,161	1,161
608	608
21	21
175	175
0	178
0	89
455	458
775	778
84	84
84	84
86	86
86	86
2	2
316	316
316	316
115	115
15	15
21	21
674	674
665	665
22	22
104	104
118	118
107	107
124	124
105	105
78	78
0	0
0	0
0	0
561	561

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EG

Controlled Capacity	
Winter Seasonal Capacity	**Summer Seasonal Capacity**
561	561
11,072	**11,350**
12,926	**13,080**

Light, and thus is controlled

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Scenario 1 PSEG 2016 MBR for ISONE

	PSA		WM			
			Winter		Spring	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result
ISO New England	8,715	Pass	5.4	Pass	5.2	Pass
Connecticut	3,388	Pass	11.8	Pass	11.3	Pass
Southwest Connecticut	1,701	Pass	16.4	Pass	15.7	Pass

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SA			
Summer		Fall	
Share (%)	Result	Share (%)	Result
6.5	Pass	6.0	Pass
14.3	Pass	13.3	Pass
14.9	Pass	13.0	Pass

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **ISONE**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	16	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	190	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	30,892	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	16	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,358	Calculated
I	Study Area Reserve Requirement	2,510	Gendata
J	Amount of Line I Attributable to Seller, if any	3	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	16,073	
	Load		
L	Balancing Area Annual Peak Load	24,054	Loads
M	Average Daily Peak Native Load in Peak Month	17,708	Loads
N	Amount of Line M Attributable to Seller, if any	10	SellerLoads
O	Wholesale Load (L-M)	6,346	
P	Net Uncommitted Supply (K-O)	9,728	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,012	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	4,548	
	% of SIL for Seller's imported capacity →	0.04	
	% of SIL for Other's imported capacity →	0.96	
	SIL Value →	4548	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **CT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	843	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	102	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	7,524	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	2,948	Calculated
I	Study Area Reserve Requirement	689	Gendata
J	Amount of Line I Attributable to Seller, if any	10	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	5,674	
	Load		
L	Balancing Area Annual Peak Load	6,419	Loads
M	Average Daily Peak Native Load in Peak Month	5,054	Loads
N	Amount of Line M Attributable to Seller, if any	14	SellerLoads
O	Wholesale Load (L-M)	1,365	
P	Net Uncommitted Supply (K-O)	4,309	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	920	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	3,050
% of SIL for Seller's imported capacity →	0.03
% of SIL for Other's imported capacity →	0.97
SIL Value →	3050
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **SWCT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	400	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	98	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	2,090	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	3,102	Calculated
I	Study Area Reserve Requirement	205	Gendata
J	Amount of Line I Attributable to Seller, if any	0	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	2,985	
	Load		
L	Balancing Area Annual Peak Load	3,286	Loads
M	Average Daily Peak Native Load in Peak Month	2,500	Loads
N	Amount of Line M Attributable to Seller, if any	0	SellerLoads
O	Wholesale Load (L-M)	786	
P	Net Uncommitted Supply (K-O)	2,199	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	498	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	3,200	
	% of SIL for Seller's imported capacity →	0.03	
	% of SIL for Other's imported capacity →	0.97	
	SIL Value →	3200	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **ISONE**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)				
A	Installed Capacity (inside the study area)	860	852	843	852
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	12	16	16	16
D	Seasonal Average Planned Outages	29	87	7	79
E	Uncommitted Capacity Imports	222	188	177	188
	Capacity Deductions				
F	Average Peak Native Load in the Season	16,956	14,847	17,687	15,178
G	Amount of Line F Attributable to Seller, if any	113	102	39	5
H	Amount of Line F Attributable to Non-Affiliates, if any	16,843	14,745	17,648	15,173
I	Study Area Reserve Requirement	2,530	2,510	2,510	2,510
J	Amount of Line I Attributable to Seller, if any	16	20	10	3
K	Amount of Line I Attributable to Non-Affiliates, if any	2,514	2,490	2,500	2,507
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	32,149	30,892	29,634	30,892
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	12	16	16	16
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
O	Seasonal Average Planned Outages	1,097	3,148	229	2,881
P	Uncommitted Capacity Imports	4,326	4,360	4,371	4,360
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	16,033	14,885	13,644	14,707
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	911	815	948	935
S	Total Seasonal Uncommitted Capacity (Q+R)	16,944	15,700	14,592	15,642
T	**Applicant's Market Share (R÷S)**	5.4%	5.2%	6.5%	6.0%
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**
U	Total Imports, as filed by Seller (E+P)	4,548	4,548	4,548	4,548
V	SIL Value	4,548	4,548	4,548	4,548
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No

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Reference
SellerGendata Table2Data SellerInMarket Table2Data SellerInMarket; Table2Data SellerGendata Calculated
Loads SellerLoads F - G Gendata SellerGendata I - J
Gendata; Row A Table2Data SellerInMarket Table2Data SellerInMarket; Table2 Data Gendata; Row D Calculated

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **CT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)				
A	Installed Capacity (inside the study area)	860	852	843	852
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
D	Seasonal Average Planned Outages	29	87	7	79
E	Uncommitted Capacity Imports	106	93	93	94
	Capacity Deductions				
F	Average Peak Native Load in the Season	4,207	3,642	4,503	3,772
G	Amount of Line F Attributable to Seller, if any	113	102	39	5
H	Amount of Line F Attributable to Non-Affiliates, if any	4,093	3,540	4,464	3,766
I	Study Area Reserve Requirement	683	683	689	683
J	Amount of Line I Attributable to Seller, if any	21	22	10	3
K	Amount of Line I Attributable to Non-Affiliates, if any	662	661	679	680
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	8,048	7,786	7,524	7,786
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
O	Seasonal Average Planned Outages	275	793	58	726
P	Uncommitted Capacity Imports	2,944	2,957	2,957	2,956
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	5,963	5,749	5,279	5,570
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	802	734	881	857
S	Total Seasonal Uncommitted Capacity (Q+R)	6,765	6,482	6,160	6,427
T	**Applicant's Market Share** (R÷S)	11.8%	11.3%	14.3%	13.3%
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**
U	Total Imports, as filed by Seller (E+P)	3,050	3,050	3,050	3,050
V	SIL Value	3,050	3,050	3,050	3,050
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No

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Reference
SellerGendata Table2Data SellerInMarket Table2Data SellerInMarket; Table2Data SellerGendata Calculated
Loads SellerLoads F - G Gendata SellerGendata I - J
Gendata; Row A Table2Data SellerInMarket Table2Data SellerInMarket; Table2 Data Gendata; Row D Calculated

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **SWCT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)				
A	Installed Capacity (inside the study area)	407	404	400	404
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
D	Seasonal Average Planned Outages	14	41	3	38
E	Uncommitted Capacity Imports	86	68	91	101
	Capacity Deductions				
F	Average Peak Native Load in the Season	2,048	1,758	2,178	1,766
G	Amount of Line F Attributable to Seller, if any	0	0	0	0
H	Amount of Line F Attributable to Non-Affiliates, if any	2,048	1,758	2,178	1,766
I	Study Area Reserve Requirement	209	206	205	206
J	Amount of Line I Attributable to Seller, if any	0	0	0	0
K	Amount of Line I Attributable to Non-Affiliates, if any	209	206	205	206
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	2,321	2,206	2,090	2,206
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
O	Seasonal Average Planned Outages	79	225	16	206
P	Uncommitted Capacity Imports	2,454	2,302	3,109	3,089
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	2,439	2,318	2,799	3,116
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	479	430	488	467
S	Total Seasonal Uncommitted Capacity (Q+R)	2,918	2,748	3,287	3,583
T	**Applicant's Market Share** (R÷S)	16.4%	15.7%	14.9%	13.0%
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**
U	Total Imports, as filed by Seller (E+P)	2,540	2,370	3,200	3,190
V	SIL Value	2,540	2,370	3,200	3,190
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No

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Reference
SellerGendata Table2Data SellerInMarket Table2Data SellerInMarket; Table2Data SellerGendata Calculated
Loads SellerLoads F - G Gendata SellerGendata I - J
Gendata; Row A Table2Data SellerInMarket Table2Data SellerInMarket; Table2 Data Gendata; Row D Calculated

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **NYISO**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	757	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	265	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	585	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	42,506	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,265	Calculated
I	Study Area Reserve Requirement	2,620	Gendata
J	Amount of Line I Attributable to Seller, if any	0	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	22,514	
	Load		
L	Balancing Area Annual Peak Load	31,138	Loads
M	Average Daily Peak Native Load in Peak Month	25,244	Loads
N	Amount of Line M Attributable to Seller, if any	0	SellerLoads
O	Wholesale Load (L-M)	5,894	
P	Net Uncommitted Supply (K-O)	16,620	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,607	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	6,850
% of SIL for Seller's imported capacity →	0.09
% of SIL for Other's imported capacity →	0.91
SIL Value →	6850
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **NYISO**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)				
A	Installed Capacity (inside the study area)	870	814	757	814
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0
B1	Long-Term Firm Purchases (from outside the study area)	265	265	265	265
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
D	Seasonal Average Planned Outages	71	115	13	92
E	Uncommitted Capacity Imports	731	600	582	640
	Capacity Deductions				
F	Average Peak Native Load in the Season	21,006	18,974	23,056	19,579
G	Amount of Line F Attributable to Seller, if any	0	0	0	0
H	Amount of Line F Attributable to Non-Affiliates, if any	21,006	18,974	23,056	19,579
I	Study Area Reserve Requirement	2,620	2,620	2,620	2,620
J	Amount of Line I Attributable to Seller, if any	0	0	0	0
K	Amount of Line I Attributable to Non-Affiliates, if any	2,620	2,620	2,620	2,620
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	40,162	41,334	42,506	41,334
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
O	Seasonal Average Planned Outages	3,277	5,820	726	4,652
P	Uncommitted Capacity Imports	6,904	6,924	6,268	7,055
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	20,162	20,843	22,372	21,538
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	1,795	1,564	1,591	1,627
S	Total Seasonal Uncommitted Capacity (Q+R)	21,958	22,407	23,963	23,166
T	**Applicant's Market Share** (R÷S)	8.2%	7.0%	6.6%	7.0%
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**
U	Total Imports, as filed by Seller (E+P)	7,635	7,524	6,850	7,695
V	SIL Value	7,635	7,524	6,850	7,695
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No

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Reference
SellerGendata Table2Data SellerInMarket Table2Data SellerInMarket; Table2Data SellerGendata Calculated
Loads SellerLoads F - G Gendata SellerGendata I - J
Gendata; Row A Table2Data SellerInMarket Table2Data SellerInMarket; Table2 Data Gendata; Row D Calculated

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Scenario 1 PSEG 2016 MBR for PJM						
	PSA		WM			
			Winter		Spring	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result
PJM Interconnection	35,891	Pass	9.5	Pass	7.7	Pass
PJM East	3,572	Pass	32.7	Fail	27.0	Fail
PJM East of 5004/05	5,389	Pass	24.3	Fail	20.7	Fail
PJM East of AP South	7,602	Pass	18.5	Pass	15.5	Pass

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SA			
Summer		Fall	
Share (%)	Result	Share (%)	Result
8.3	Pass	8.3	Pass
32.9	Fail	29.7	Fail
23.7	Fail	23.1	Fail
18.8	Pass	17.0	Pass

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	9,844	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	195	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	1,943	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	152	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	175,931	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	1,943	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	195	Row B; Table2Data
H	Uncommitted Capacity Imports	7,448	Calculated
I	Study Area Reserve Requirement	8,187	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	63,588	
	Load		
L	Balancing Area Annual Peak Load	143,633	Loads
M	Average Daily Peak Native Load in Peak Month	121,600	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	22,034	
P	Net Uncommitted Supply (K-O)	41,555	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,664	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	7,600
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	7600
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	14	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	88	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	26,628	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	14	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,449	Calculated
I	Study Area Reserve Requirement	1,724	Gendata
J	Amount of Line I Attributable to Seller, if any	176	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	15,220	
	Load		
L	Balancing Area Annual Peak Load	30,240	Loads
M	Average Daily Peak Native Load in Peak Month	24,093	Loads
N	Amount of Line M Attributable to Seller, if any	2,269	SellerLoads
O	Wholesale Load (L-M)	6,148	
P	Net Uncommitted Supply (K-O)	9,072	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,500	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P)	**Pass**	
	(Fail if Line Q > Line P)		

Total Imports (Sum D, H) as filed by Seller →	6,537
% of SIL for Seller's imported capacity →	0.01
% of SIL for Other's imported capacity →	0.99
SIL Value →	6537
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	107	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	51,729	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,212	Calculated
I	Study Area Reserve Requirement	2,975	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	20,577	
	Load		
L	Balancing Area Annual Peak Load	52,190	Loads
M	Average Daily Peak Native Load in Peak Month	42,368	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	9,822	
P	Net Uncommitted Supply (K-O)	10,754	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,365	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	6,319
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	6319
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	85	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	75,381	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,370	Calculated
I	Study Area Reserve Requirement	4,032	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	25,567	
	Load		
L	Balancing Area Annual Peak Load	70,729	Loads
M	Average Daily Peak Native Load in Peak Month	58,108	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	12,621	
P	Net Uncommitted Supply (K-O)	12,946	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,344	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P)	**Pass**	
	(Fail if Line Q > Line P)		

Total Imports (Sum D, H) as filed by Seller →	4,455
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	4455
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	11,339	10,592	9,844	10,592	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	195	195	195	195	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	1,643	1,944	1,943	1,944	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	491	1,461	225	1,374	SellerGendata
E	Uncommitted Capacity Imports	214	204	138	117	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	108,842	91,954	109,399	91,992	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	106,988	90,430	107,540	90,648	F - G
I	Study Area Reserve Requirement	7,474	6,516	7,991	6,470	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	7,335	6,385	7,817	6,352	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	181,889	178,911	175,931	178,911	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	1,643	1,944	1,943	1,944	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	195	195	195	195	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	7,868	24,681	4,028	23,215	Gendata; Row D
P	Uncommitted Capacity Imports	11,783	12,069	7,462	6,950	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	72,929	71,233	65,756	67,394	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,622	5,931	5,975	6,123	
S	Total Seasonal Uncommitted Capacity (Q+R)	80,550	77,164	71,731	73,518	
T	**Applicant's Market Share** (R÷S)	9.5%	7.7%	8.3%	8.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	11,997	12,273	7,600	7,067	
V	SIL Value	11,997	12,273	7,600	7,067	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	22	14	14	14	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	121	72	78	68	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	18,303	15,919	20,901	16,346	Loads
G	Amount of Line F Attributable to Seller, if any	1,749	1,434	1,764	1,268	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	16,553	14,485	19,137	15,078	F - G
I	Study Area Reserve Requirement	1,258	1,168	1,659	1,211	Gendata
J	Amount of Line I Attributable to Seller, if any	130	122	165	110	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	1,128	1,046	1,494	1,101	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	26,328	26,478	26,628	26,478	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	22	14	14	14	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,139	3,653	610	3,436	Gendata; Row D
P	Uncommitted Capacity Imports	7,381	8,758	6,459	7,791	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	14,911	16,065	11,860	14,667	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,230	5,954	5,826	6,199	
S	Total Seasonal Uncommitted Capacity (Q+R)	22,141	22,019	17,686	20,867	
T	**Applicant's Market Share** (R÷S)	32.7%	27.0%	32.9%	29.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	7,502	8,830	6,537	7,859	
V	SIL Value	7,502	8,830	6,537	7,859	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	162	91	95	69	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	35,188	30,080	37,518	30,214	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	33,334	28,556	35,658	28,871	F - G
I	Study Area Reserve Requirement	2,450	2,184	2,889	2,189	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,311	2,054	2,715	2,071	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	52,220	51,975	51,729	51,975	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	2,259	7,170	1,184	6,744	Gendata; Row D
P	Uncommitted Capacity Imports	7,942	8,202	6,224	6,034	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	22,294	22,424	18,423	20,350	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,144	5,861	5,725	6,103	
S	Total Seasonal Uncommitted Capacity (Q+R)	29,438	28,286	24,148	26,453	
T	**Applicant's Market Share** (R÷S)	24.3%	20.7%	23.7%	23.1%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	8,104	8,293	6,319	6,103	
V	SIL Value	8,104	8,293	6,319	6,103	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	187	115	77	81	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	48,658	41,074	51,437	41,155	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	46,804	39,551	49,577	39,811	F - G
I	Study Area Reserve Requirement	3,496	3,025	3,935	2,991	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	3,358	2,895	3,762	2,873	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	77,314	76,348	75,381	76,348	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,344	10,532	1,726	9,907	Gendata; Row D
P	Uncommitted Capacity Imports	7,710	8,741	4,378	5,987	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	31,554	32,139	24,722	29,772	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,169	5,885	5,707	6,115	
S	Total Seasonal Uncommitted Capacity (Q+R)	38,723	38,024	30,429	35,886	
T	**Applicant's Market Share** (R÷S)	18.5%	15.5%	18.8%	17.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,897	8,856	4,455	6,068	
V	SIL Value	7,897	8,856	4,455	6,068	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Document Content(s)

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PSEG
Services Corporation

November 13, 2014

Kimberly J. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Notice of Non-Material Change in Status
***PSEG Energy Resources & Trade LLC*, Docket No. ER10-1789-____;**
***Public Service Electric and Gas Company*, Docket No. ER10-1768-___;**
***PSEG Power Connecticut LLC,* Docket No. ER10-1793-____;**
***PSEG Fossil LLC,* Docket No. ER10-1770-___;**
***PSEG Nuclear LLC,* ER10-1771-____;**
***PSEG New Haven LLC,* ER12-1250-____:**

Dear Secretary Bose:

PSEG Energy Resources & Trade LLC ("PSEG ERT") hereby submits for filing this notice of a non-material change in status, in compliance with the reporting requirements adopted by the Federal Energy Regulatory Commission ("Commission") in Order No. 652.[1] Specifically, PSEG ERT hereby notifies the Commission that it has executed with the Long Island Power Authority ("LIPA") a Contract Providing Power Supply Management Services dated November 26, 2013 ("the 2013 Contract"). Under the 2013 Contract, which will be fully implemented on January 1, 2015, PSEG ERT will provide LIPA with Power Supply Management Front and Back Office Services ("PSMFB Services").[2] Such PSMFB Services are, in all respects pertaining to the sale or transmission of electric energy, the same services that Consolidated Edison Energy, Inc. ("Con Edison Energy") has been providing to LIPA since January 1, 2010 pursuant to an agreement between Con Edison Energy and LIPA dated December 1, 2008 (the "2008 Contract").[3]

[1] Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority, 110 FERC ¶ 61,097 (Order No. 652), order on reh'g, 111 FERC ¶ 61,413 (2005) (Order No. 652-A).

[2] While the 2013 Contract will be fully implemented on January 1, 2015, to begin the transition from Con Edison Energy to PSEG ERT, PSEG ERT began performing PSMFB Services as to LIPA's rights (i) to seven must-take qualifying facilities (about 230 MW) on September 16, 2014; (ii) to 29 oil combustion generating units (about 1,520 MW) on October 14, 2014; and (iii) to four Northport steam generating units (about 1,600 MW) on October 28, 2014.

[3] Currently, two affiliates of PSEG ERT (PSEG Long Island LLC and Long Island Electric Utility Servco LLC) provide certain management, operations and maintenance services to LIPA with respect to LIPA's transmission and distribution system. In *PSEG Long Island LLC*, 145 FERC ¶ 61,010 at P 4 (2013), the Commission disclaimed jurisdiction under Section 201(e) of the Federal Power Act over these two affiliates based on a finding that LIPA and its Board will retain ultimate control and decision-making authority over the transmission and distribution facilities.

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In connection with the 2008 Contract between Con Edison Energy and LIPA, on April 7, 2009, Con Edison Energy submitted to the Commission a notice of a non-material change in status, which was accepted by the Commission by letter order on June 8, 2009.[4] Con Edison Energy's April 7, 2009 notice is attached hereto as Attachment A, and the Commission's June 8, 2009 acceptance letter is attached hereto as Attachment B.

Like Con Edison Energy's change in status notification, PSEG ERT hereby submits this notice of a non-material change in status, notifying the Commission that, as of January 1, 2015, it will take over the functions that are currently performed by Con Edison Energy under the 2008 Contract.[5] PSEG ERT's execution of the 2013 Contract and its performance of services thereunder will not provide PSEG ERT with ownership of, or control over, the Power Supply Resources. PSEG ERT will perform services under the 2013 Contract as an agent for, or representative of, LIPA (in the same manner that Con Edison Energy currently performs services for LIPA), and, therefore, control over the Power Supply Resources at all times will remain with LIPA, as it did with respect to the 2008 Contract between Con Edison Energy and LIPA. Thus, PSEG ERT's execution of the 2013 Contract and its performance of the services on behalf of LIPA do not constitute a material change in status as contemplated by the Commission's regulations.[6]

PSEG ERT also notes that, on December 23, 2013, PSEG ERT and its affiliates with market-based rate authorization except PSEG New Haven LLC submitted their triennial market power update with the Commission in Docket Nos. ER99-3151 et al.[7] In that filing (at page 5), PSEG ERT provided the Commission with notice of the 2013 Contract, stating: "On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which ER&T will provide fuel supply and power supply management activities for LIPA beginning on January 1, 2015." The Commission accepted this triennial update filing on October 14, 2014.

In sum, PSEG ERT hereby notifies the Commission of the foregoing non-material change in status and requests that the Commission accept this filing on the same grounds that it accepted the April 8, 2009 Con Edison Energy filing.

Sincerely,

Jodi L. Moskowitz

[4] *See* June 8, 2009 Letter Order accepting Con Edison Energy's notice of change in status in Docket Nos. ER98-2491-015 et al.

[5] *See supra* n.2 at 1.

[6] In Order 652, the Commission stated that the requirement to make a change in status filing is triggered by a change in "ownership" or "control" of generation or transmission facilities. Order 652 at PP 2, 18.

[7] PSEG New Haven LLC was not included in the 2013 triennial market power update because it received initial MBR authority on May 29, 2012 in Docket No. ER12-1250-00 and therefore was not yet due to make a triennial update filing.

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Document Content(s)

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November 14, 2014

Kimberly J. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Supplemental Notice of Non-Material Change in Status
***PSEG Energy Resources & Trade LLC*, Docket No. ER10-1789-004;**
***Public Service Electric and Gas Company*, Docket No. ER10-1768-003;**
***PSEG Power Connecticut LLC,* Docket No. ER10-1793-003;**
***PSEG Fossil LLC,* Docket No. ER10-1770-003;**
***PSEG Nuclear LLC,* ER10-1771-003;**
***PSEG New Haven LLC,* ER12-1250-003:**

Dear Secretary Bose:

PSEG Energy Resources & Trade LLC ("PSEG ERT") hereby submits for filing this notice of a non-material change in status,[1] in compliance with the reporting requirements adopted by the Federal Energy Regulatory Commission ("Commission") in Order No. 652.[2] Specifically, PSEG ERT hereby notifies the Commission that it has executed with the Long Island Power Authority ("LIPA") a Contract Providing Power Supply Management Services dated November 26, 2013 ("the 2013 Contract"). Under the 2013 Contract, which will be fully implemented on January 1, 2015, PSEG ERT will provide LIPA with Power Supply Management Front and Back Office Services ("PSMFB Services").[3] Such PSMFB Services are, in all respects pertaining to the sale or transmission of electric energy, the same services that Consolidated Edison Energy, Inc. ("Con Edison Energy") has been providing to LIPA since January 1, 2010 pursuant to an agreement between Con Edison Energy and LIPA dated December 1, 2008 (the "2008 Contract").[4]

[1] This notice supplements the notice that was filed on November 13, 2014 (Accession No.: 201411135228).

[2] Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority, 110 FERC ¶ 61,097 (Order No. 652), order on reh'g, 111 FERC ¶ 61,413 (2005) (Order No. 652-A).

[3] While the 2013 Contract will be fully implemented on January 1, 2015, to begin the transition from Con Edison Energy to PSEG ERT, PSEG ERT began performing PSMFB Services as to LIPA's rights (i) to seven must-take qualifying facilities (about 230 MW) on September 16, 2014; (ii) to 29 oil combustion generating units (about 1,520 MW) on October 14, 2014; and (iii) to four Northport steam generating units (about 1,600 MW) on October 28, 2014.

[4] Currently, two affiliates of PSEG ERT (PSEG Long Island LLC and Long Island Electric Utility Servco LLC) provide certain management, operations and maintenance services to LIPA with respect to LIPA's transmission and distribution system. In *PSEG Long Island LLC*, 145 FERC ¶ 61,010 at P 4 (2013), the Commission disclaimed jurisdiction under Section 201(e) of the Federal Power Act over these two affiliates based on a finding that LIPA and its Board will retain ultimate control and decision-making authority over the transmission and distribution facilities.

20141114-5149 FERC PDF (Unofficial) 11/14/2014 1:49:39 PM

In connection with the 2008 Contract between Con Edison Energy and LIPA, on April 7, 2009, Con Edison Energy submitted to the Commission a notice of a non-material change in status, which was accepted by the Commission by letter order on June 8, 2009.[5] Con Edison Energy's April 7, 2009 notice is attached hereto as Attachment A, and the Commission's June 8, 2009 acceptance letter is attached hereto as Attachment B.

Like Con Edison Energy's change in status notification, PSEG ERT hereby submits this notice of a non-material change in status, notifying the Commission that, as of January 1, 2015, it will take over the functions that are currently performed by Con Edison Energy under the 2008 Contract.[6] PSEG ERT's execution of the 2013 Contract and its performance of services thereunder will not provide PSEG ERT with ownership of, or control over, the Power Supply Resources. PSEG ERT will perform services under the 2013 Contract as an agent for, or representative of, LIPA (in the same manner that Con Edison Energy currently performs services for LIPA), and, therefore, control over the Power Supply Resources at all times will remain with LIPA, as it did with respect to the 2008 Contract between Con Edison Energy and LIPA. Thus, PSEG ERT's execution of the 2013 Contract and its performance of the services on behalf of LIPA do not constitute a material change in status as contemplated by the Commission's regulations.[7]

PSEG ERT also notes that, on December 23, 2013, PSEG ERT and its affiliates with market-based rate authorization except PSEG New Haven LLC submitted their triennial market power update with the Commission in Docket Nos. ER99-3151 et al.[8] In that filing (at page 5), PSEG ERT provided the Commission with notice of the 2013 Contract, stating: "On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which ER&T will provide fuel supply and power supply management activities for LIPA beginning on January 1, 2015." The Commission accepted this triennial update filing on October 14, 2014.

In sum, PSEG ERT hereby notifies the Commission of the foregoing non-material change in status and requests that the Commission accept this filing on the same grounds that it accepted the April 8, 2009 Con Edison Energy filing.

Sincerely,

Jodi L. Moskowitz

[5] *See* June 8, 2009 Letter Order accepting Con Edison Energy's notice of change in status in Docket Nos. ER98-2491-015 et al.

[6] *See supra* n.2 at 1.

[7] In Order 652, the Commission stated that the requirement to make a change in status filing is triggered by a change in "ownership" or "control" of generation or transmission facilities. Order 652 at PP 2, 18.

[8] PSEG New Haven LLC was not included in the 2013 triennial market power update because it received initial MBR authority on May 29, 2012 in Docket No. ER12-1250-00 and therefore was not yet due to make a triennial update filing.

20141114-5149 FERC PDF (Unofficial) 11/14/2014 1:49:39 PM

Attachment A

ConEdison Energy
Solving The Wholesale Power Puzzle

April 7, 2009

Hon. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re:	***Consolidated Edison Energy, Inc.***	***Dkt. No. ER98-2491-___***
	Consolidated Edison Company of New York, Inc.	***Dkt. No. ER99-2251-___***
	Orange and Rockland Utilities, Inc.	***Dkt. No. ER99-2252-___***
	Consolidated Edison Solutions, Inc.	***Dkt. No. ER97-705- ___***

Notification of Non-Material Change in Status

Dear Ms. Bose:

Consolidated Edison Energy, Inc. ("Con Edison Energy") submits for filing this notice of a non-material change in status, in compliance with the reporting requirements adopted by the Federal Energy Regulatory Commission ("Commission") in Order No. 652.[1] The change in circumstance is the execution by Con Edison Energy and the Long Island Power Authority ("LIPA") of a Contract for Providing Power Supply Management Front and Back Office Services dated December 1, 2008 ("Contract").[2]

Con Edison Energy does not believe that it has obtained control over the facilities affected by the Contract and, thus, that the Contract is not a change in status as contemplated by the Commission's regulations. Nevertheless, even if the Contract were deemed to convey control to Con Edison Energy, this change in status does not reflect a material change from the characteristics the Commission relied upon in granting CEE market-based rate authorization[3] or the results of the last triennial market power analysis submitted on behalf of Con Edison Energy and its affiliates ("the Con Edison Companies).[4]

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[1] *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority*, 110 FERC ¶ 61,097 (Order No. 652), *order on reh'g*, 111 FERC ¶ 61,413 (2005) (Order No. 652-A).

[2] The Contract is conditioned upon its approval by the New York State Comptroller, which was granted on March 13, 2009.

[3] *Consolidated Edison Energy, Inc.*, 83 FERC ¶ 61,236 (1998).

[4] The Commission recently accepted a triennial market power analysis on behalf of the Con Edison Companies. *Consolidated Edison Company of New York, Inc.*, Dkt. No. ER99-2251-003,

Under the Contract, Con Edison Energy will provide specified services, as an agent, to LIPA with respect to certain resources (referred to in the Contract as "Power Supply Resources") that LIPA will use to serve its retail load, including (i) electric generating facilities owned by or under contract to LIPA having a total rating of 6,683 MW, (ii) LIPA's long-term transmission rights over the Cross Sound Cable and the Neptune Cable ("CSC and Neptune"), and (iii) LIPA's rights to certain emissions credits, transmission congestion contracts and financial transmission rights. The services that Con Edison Energy will perform on behalf of LIPA with respect to the Power Supply Resources include (i) the purchase and sale of capacity, energy, ancillary services, and transmission congestion contracts to meet the needs of LIPA's retail customers; (ii) the bidding and scheduling in wholesale electric markets of energy, capacity and ancillary services associated with the Power Supply Resources in order to serve the requirements of LIPA's retail load; and (iii) associated accounting, settlement, dispute resolution support, and reporting.

Commencing on January 1, 2010 and continuing for a base term of five years, Con Edison Energy will assume full responsibility for bidding and scheduling all of the Power Supply Resources in wholesale electric markets. In mid to late-2009, Con Edison Energy may undertake limited bidding and scheduling activities for one or more of the Power Supply Resources as part of training and pre-implementation preparations for bidding and scheduling activities.

Con Edison Energy's execution of the Contract and its performance of services thereunder do not vest Con Edison Energy with ownership of, or control over, the Power Supply Resources. The Contract does not alter the ownership of the Power Supply Resources in any respect. Because Con Edison Energy will perform services under the Contract as an agent for or representative of LIPA, control over the Power Supply Resources will remain with LIPA, as LIPA acknowledges in the enclosed concurrence letter. Thus, Con Edison Energy's execution of the Contract and its performance of services for LIPA do not constitute a material change in status as contemplated by the Commission's regulations.

With respect to LIPA's transmission rights over the CSC and Neptune, these transmission facilities are operationally controlled by ISO New England and PJM Interconnection, with transmission service scheduled over each facility pursuant to

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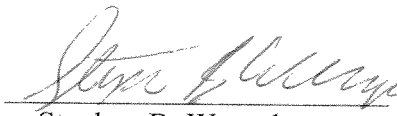
et al., *Letter Order*, June 24, 2008. At the time it was filed, that analysis included the following Con Edison Companies with market-based rate authority: Newington Energy, L.L.C.; CED Rock Springs, Inc.; Consolidated Edison Energy Massachusetts; Lakewood Cogeneration, L.P.; and Ocean Peaking Power, L.L.C. The Commission subsequently authorized the transfer of these companies to North American Energy Alliance, LLC. *See Consolidated Edison Development, Inc. et al.*, 123 FERC ¶ 61,022 (2008). As such, this non-material change in status is not being filed in the dockets in which these divested companies received market-based rate authority.

specific rules set forth in the ISO-NE and PJM Open Access Transmission Tariffs on file with the Commission. In contracting for long-term transmission service rights over CSC and Neptune, LIPA did not acquire any ownership or operational control over those transmission facilities. Accordingly, by executing the Contract, LIPA did not convey to Con Edison Energy any operational control over the CSC or Neptune transmission facilities.

Even if the Contract were deemed to vest Con Edison Energy with control over the Power Supply Resources and with localized market power, that change in status would not reflect a material change from the characteristics the Commission relied upon in granting Con Edison Energy market-based rate authorization or in the results of the last triennial market power analysis submitted on behalf of Con Edison Energy and its affiliates. Currently, a subsidiary of National Grid USA manages LIPA's generation and energy portfolio.[5] Notwithstanding those services, the Commission recently concluded that the National Grid USA subsidiary satisfies the Commission's standards for market-based rate authority.[6] As a successor to the National Grid USA subsidiary, Con Edison Energy will manage LIPA's generation and energy portfolio after the current arrangement between LIPA and the National Grid USA subsidiary expires. Under the Contract, Con Edison Energy has no responsibility with respect to operation or management of LIPA's transmission and distribution systems. Accordingly, the Commission's prior conclusion and rationale apply equally to Con Edison Energy.

Accordingly, Con Edison Energy advises the Commission of the foregoing non-material change in status and requests that the Commission accept this filing and confirm Con Edison Energy's continued authorization to sell power at market-based rates.

Respectfully submitted,

By: 

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914-993-2149

[5] *Niagara Mohawk Power Corporation, et al.*, 123 FERC ¶61,175, PP 13-14 (May 16, 2008).

[6] *Id.* at P 35 (the New York Independent System Operator's Market Mitigation Plan is sufficient to address market power concerns in the New York City and Long Island submarkets).

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Attachment B

20090608-5049 FERC PDF (Unofficial) 06/08/2009 1:49:39 PM

FEDERAL ENERGY REGULATORY COMMISSION
Washington, D.C. 20426

In Reply Refer To:

Consolidated Edison Energy, Inc.	Docket Nos. ER98-2491-015
Consolidated Edison Company of New York, Inc.	ER99-2251-009
Orange and Rockland Utilities, Inc.	ER99-2252-010
Consolidated Edison Solutions, Inc.	ER97-705-020
(collectively, ConEdison)	

June 8, 2009

Mr. Stephen B. Wemple
Vice President, Regulatory Affairs
Con Edison Competitive Shared Services for Consolidated Edison Energy, Inc.
701 Westchester Avenue
Suite 201 West
White Plains, New York 10604

Reference: Notice of Change in Status

Dear Mr. Wemple:

Pursuant to the authority delegated to the Director, Division of Tariffs and Market Development - West, under 18 C.F.R. § 375.307, your submittal filed in the referenced dockets is accepted for filing.

On April 8, 2009, you filed on behalf of ConEdison a notice of change in status to inform the Commission that ConEdison entered into a Contract for Providing Power Supply Management Front and Back Office Services with Long Island Power Authority. You state that the execution of this contract does not affect the conditions the Commission relied upon when granting ConEdison market-based rate authority. Based on your representations, the notice of change in status is accepted for filing.

Your filing was noticed on April 8, 2009, with comments, protests or interventions due on or before April 29, 2009. None was filed.

This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, or practice affecting such rate or service provided for in the filed documents; nor shall such action be deemed as recognition of any claimed contractual right or obligation affecting or relating to such service or rate; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by

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the Commission in any proceeding now pending or hereafter instituted by or against any of the applicant(s).

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Questions regarding the above order should be directed to:

Federal Energy Regulatory Commission
Attn: Ryan Anderson
Phone: (202) 502-8122
Office of Energy Market Regulation
888 First Street, N.E.
Washington, D.C. 20426

Sincerely,

Steve P. Rodgers, Director
Division of Tariffs and Market
Development - West

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Jodi L. Moskowitz
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PSEG
Services Corporation

December 23, 2013

ELECTRONICALLY AND VIA FEDERAL EXPRESS

Kimberly J. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Triennial Market Power Update and Revised Market-Based Rates Tariff in Compliance with Order No. 697:

***PSEG Energy Resources & Trade LLC*, Docket No. ER99-3151-____;**

***Public Service Electric and Gas Company*, Docket No. ER97-837-____;**

***PSEG Power Connecticut LLC*, Docket No. ER03-327 -___;**

***PSEG Fossil LLC*, Docket No. ER08-447-___;**

***PSEG Nuclear LLC*, ER08-448-___; and**

***PSEG New Haven LLC*, ER12-1250-___**

Dear Secretary Bose:

Pursuant to the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), PSEG Energy Resources & Trade LLC ("PSEG ER&T"), Public Service Electric and Gas Company ("PSE&G"), PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Fossil LLC ("PSEG Fossil"), PSEG Nuclear LLC ("PSEG Nuclear") and PSEG New Haven LLC ("PSEG New Haven") (collectively the "Applicants" or "PSEG") hereby jointly submit for filing their updated market power analysis in support of their continued eligibility to engage in market-based rates transactions. This market power analysis satisfies the requirements of Order No. 697[1] for the filing of updated market power analyses on a regional schedule basis by holders of market-based rate certificates and their affiliates. In accordance with the regional

[1] 18 C.F.R. Part 35, Subpart H (2007); Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, 119 FERC ¶ 61,295, ("Order No. 697" or "MBR Order"), *order clarifying final rule*, 121 FERC ¶ 61,260 (2007) ("MBR Clarifying Order"), *order on reh'g and clarification*, 123 FERC ¶ 61,055 (2008) FERC Stats. & Regs ¶ 31,268 ("Order No. 697-A"), *order on reh'g and clarification*, 124 FERC ¶ 61,055 (2008) ("SIL Allocation Order").

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schedule for those utilities in the Northeast Region, as modified by the MBR Clarifying Order, this filing is being made by the December 2013 deadline.[2] In conformance with the Commission's requirements, except when expressly noted otherwise, the market power analysis is based on activity during the study period from December 1, 2011 through November 30, 2012 ("study period").

PSEG, through its subsidiary PSE&G, owns transmission facilities within the Northeast Region. Specifically, PSE&G owns transmission facilities in the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization. PSEG Power LLC and its subsidiaries do not own any transmission facilities other than transmission to connect generating units to the grid in PJM, the New York Independent System Operator, Inc. ("NYISO") and ISO New England Inc. ("ISO-NE").

In their original applications for market-based rate authority and previously-submitted updates to the Commission, PSEG ER&T, PSE&G, PSEG Power CT, PSEG Fossil, PSEG Nuclear and PSEG New Haven demonstrated that they and their affiliates: (a) do not exercise generation market power; (b) lack the ability to manipulate access to transmission facilities that they own or control; and (c) cannot erect any other barriers to market entry. As further demonstrated herein and in the Affidavit of Dr. John R. Morris attached hereto in the appendices, Applicants continue to satisfy the Commission's requirements to sell energy, capacity and ancillary services at market-based rates and thus should be permitted to continue to make such sales.

I. SERVICE AND COMMUNICATION

All service and correspondence related to this matter should be directed to the following individuals:

As to the Applicants Generally:

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Chief NERC Officer
PSEG Services Corporation
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Newark, NJ 07102
(973) 430-6409
(973) 430-5983 (facsimile)
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[2] This filing is made on the three year anniversary of the December 2010 deadline set forth in Order No. 697 Appendix D.

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David K. Richter, Esq.
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Applicants request waiver of Rule 203(b)(3)[3] so that a copy of any communications in these proceedings may be served on all persons listed above.

II. DESCRIPTION OF THE APPLICANTS AND RELEVANT AFFILIATES

A. The Applicants

The Applicants are each wholly owned, direct and indirect subsidiaries of Public Service Enterprise Group Incorporated ("PSEG"). PSEG is a public utility holding company engaged in, among other things, the generation of electric energy and the transmission, distribution and sale of electricity and natural gas through its subsidiaries.

1. Public Service Electric and Gas Company

PSE&G is a public utility operating company engaged primarily in the transmission of electricity, and the provision of gas and electric distribution service in the State of New Jersey. During the study period, PSE&G owned less than 100 MW of solar generation and otherwise did not own or operate any electric generation facilities. PSE&G is a member of the PJM Regional Transmission Organization and has made all of its transmission facilities available for open access transmission service pursuant to the PJM Open Access Transmission Tariff ("OATT") administered by PJM. PSE&G is authorized to sell power at market-based rates and makes wholesale sales falling within several different categories, as described below.

Non-utility generation ("NUG") output. Pursuant to certain long-term contracts entered into under the Public Utility Regulatory Policy Act of 1978 ("PURPA") or restructured successor contracts to PURPA contracts that PSE&G originally entered into with Qualifying Facilities ("QFs"), PSE&G has a continuing obligation to purchase certain quantities of energy and capacity. The total maximum quantity that PSE&G is

[3] 18 C.F.R. § 385.203(b)(3).

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contractually obligated to purchase from non-utility generators ("NUGs") is approximately 257 MW in installed capacity and associated energy. PSE&G sells the energy quantities purchased under these contracts into the PJM-administered spot market pursuant to its market-based rate authority. With respect to capacity from the facilities, PSE&G receives non-unit specific capacity rights covering the vast bulk of its capacity purchases – about 195 MWs – which are settled financially with the counterparty. The remainder of the capacity purchased by PSE&G under three (3) NUG contracts – about 62 MWs – is bid directly into the RPM auctions. Since PSE&G has a contractually-based obligation to offer the NUG capacity into the market, which obligation is also set forth in a New Jersey Board of Public Utilities ("BPU") Order approving a rate stipulation involving PSE&G,[4] the capacity has not been attributed to PSE&G for purposes of this market power analysis.

Solar. In 2007, the New Jersey legislature passed Regional Greenhouse Gas Initiative ("RGGI") legislation authorizing state utilities to invest in renewable resources such as wind or solar in order to promote increased use of renewable resources within the state and in turn reduce greenhouse gas emissions. *See* L. 2007, c. 340, codified at N.J.S.A. 48:98-1. In the fall of 2009, the BPU approved PSE&G's "Solar 4 All" program under which PSE&G is able to install, own and operate on a regulated basis solar generation up to a maximum of 80 MWs DC. PSE&G currently owns and operates approximately 77 MWs DC of solar power under the Solar 4 All program. In May 2013, the BPU approved PSE&G's "Solar 4 All Extension" to allow PSE&G to install, own and operate an additional 45 MWs DC of solar generation.

2. PSEG Energy Resources & Trade LLC

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil and PSEG Nuclear, each wholly-owned subsidiaries of PSEG Power LLC ("PSEG Power"), as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission.

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

BGS Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 *et seq.*, which initiated the transition from a regulated to a competitive retail power market in New Jersey, BPU annually approves statewide auctions to determine the entities that will supply Basic

[4] The stipulation states that "the parties agree that the Company will continue to sell NUG power into the PJM Spot Market unless and until the Board determines that a different selling protocol is appropriate." *In the Matter of Public Service Electric and Gas Company for Approval of Changes in Electric Rates*, Docket No. ER02050303, ¶ 18 (2003).

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Generation Service ("BGS") in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSEG ER&T has participated directly in all of the auctions for BGS supply held since 2004, has been a winning bidder in these auctions and has incurred contractual commitments to provide supply to BGS load pursuant to BPU approved contracts beginning with the 2004 auction and continuing to the present

RMR Tariff for PJM Units. As explained in PSEG ER&T's 2010 triennial submission, ER&T began providing reliability services to PJM pursuant to Reliability Must-Run ("RMR") tariffs covering operations at PSEG Fossil's Hudson 1 generating unit in 2005. The RMR tariff for the Hudson 1 unit expired effective as of December 7, 2011. Additionally, the Hudson 1 unit and its 454.8 MWs were retired when the RMR was terminated.

BGSS Gas Contract. By order issued April 16, 2002, the BPU approved a full requirements contract for the provision of gas supply by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the BPU, PSEG ER&T assumed, through capacity release, FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract remains in effect and provides for annual renewals unless terminated by either party on 12 months' advance written notice.

LIPA Fuel Supply: On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which ER&T will provide fuel supply and power supply management activities for LIPA beginning on January 1, 2015.

3. PSEG Fossil LLC

PSEG Fossil is an Exempt Wholesale Generator ("EWG") and is authorized to sell power at market-based rates. PSEG Fossil owns and operates electric generation facilities located within PJM and sells their entire output to its affiliate PSEG ER&T.[5] The assets of PSEG Fossil are located entirely within PJM. However, PSEG Fossil's subsidiaries PSEG Power Connecticut LLC, PSEG Power New York LLC and PSEG New Haven LLC own facilities in ISO-NE and NYISO. As noted below, PSEG Fossil also co-owns certain facilities in PJM.

[5]These contracts were originally approved by the Commission as cost-based contracts. *See Public Service Electric and Gas Company*, et al., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Fossil obtained market based rate authority covering sales from its generating units.

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On December 7, 2011, PSE&G retired Hudson 1 and its 454.8 MW (and the accompanying RMR Agreement). Additionally, on June 1, 2012, PSEG Fossil energized six (6) new combustion turbines at its Kearny site in New Jersey. Four (4) units – designated "Kearny 13" - have a combined generator nameplate rating of 242 MWs. Two (2) other units – designated "Kearny 14" - have a combined generator nameplate rating of 142.3 MWs. The addition of this new peaking generation coincided with the retirement of Kearny 10 and 11 with nameplate ratings of 146.3 MWs each.

PSEG Fossil notified PJM in April 2010 that it planned to retire Kearny 9, a unit with a capacity nameplate rating of 18.6 MW, on or about March 2013. However, in November 2011, PSEG Fossil notified PJM that, although Kearny 9 would not have any capacity commitments after May 31, 2013, it would be available for energy and ancillary services. In addition, PSEG Fossil has notified PJM that it will retire the following units on the following dates:

Burlington 9 – June 1, 2014
Salem 3 – June 1, 2015[6]
Bergen 3 – June 1, 2015
Burlington 8 – June 1, 2015
National Park – June 1, 2015
Mercer 3 – June 1, 2015
Sewaren 6 – June 1, 2015
Burlington 11 – June 1, 2015
Edison 1 – 3 – June 1, 2015
Essex 10 – 12 – June 1, 2015

PSEG Fossil satisfies most of the electricity needs of its plants from PJM under PJM's "station power" Tariff provisions and receives station power for its National Park station from PSE&G under a retail tariff approved by the BPU. PSEG Fossil procures gas supply for its plants from PSEG ER&T and receives gas distribution service from PSE&G at a rate approved by the BPU on May 29, 2013.[7]

4. PSEG Power Connecticut LLC

PSEG Power CT is a Connecticut limited liability company and an EWG that owns and operates electric generation facilities in the State of Connecticut and is authorized to sell power at market-based rates.[8] Both of PSEG Power CT's generation facilities, Bridgeport Harbor and New Haven Harbor, are located in the State of Connecticut within the market administered by ISO-NE. PSEG Power CT sells the output of its generation facilities to its affiliate PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority.

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[6] No longer available as a capacity resource in PJM though still available to supply emergency back-up generation for the Salem 1 and 2 nuclear units.
[7] BPU Docket No. GM12100935 (May 29, 2013).
[8] *Wisvest Corporation,* et al., 101 FERC ¶ 61,166 (2002).

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5. PSEG New Haven LLC

PSEG New Haven is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG New Haven owns and operates a facility (the "New Haven facility") in New Haven, Connecticut with a nameplate rating of 181 MWs. The New Haven facility is located within the New Haven Harbor generation station. The New Haven facility is interconnected to the adjacent United Illuminating East Shore Substation using a 115 KV underground cable. PSEG New Haven has no other generation assets. The commercial operation date for the New Haven facility was June 1, 2012 and PSEG New Haven has obtained MBR authority from FERC.[9]

The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[10] pursuant to a Connecticut statute that sought proposals for peaking generation in Connecticut.[11] All of the energy and capacity of the New Haven facility is sold into the ISO New England ("ISO-NE") markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA[12] has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder. The 181 MW nameplate rating of the New Haven Facility has not been included in the capacity controlled by PSEG for purposes of Dr. Morris' market power analysis.

6. PSEG Nuclear LLC

PSEG Nuclear is an EWG[13] and is authorized to sell power at market-based rates. PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission.[14] The assets of PSEG Nuclear are located entirely within PJM. PSEG Nuclear performed an uprate of 120 MWs at its Hope Creek plant in 2009, which increased its nameplate rating to 1290 MWs.

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[9] *PSEG New Haven LLC*, Docket No. ER12-1250-000, et al., (May 29, 2012).

[10] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control (DPUC). PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

[11] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

[12] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

[13] *PSEG Nuclear LLC*, 97 FERC ¶ 62,191 (November 30, 2001).

[14] *Public Service Electric and Gas Company*, et al., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Nuclear obtained market based rate authority from the FERC.

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OTHER RELEVANT AFFILIATES

PSEG is also the direct or indirect parent of certain other subsidiaries engaged in energy related activities, as discussed below.

7. Affiliated Generation Ownership.

A list of the Applicants' affiliated domestic FERC jurisdictional generation assets owned is contained in Appendix B attached hereto. [15] Those additional subsidiaries of PSEG that may be considered relevant to this market power update for the Northeast Region are described below:

PSEG Power LLC ("PSEG Power") was formed in 1999 to acquire the former generation assets of PSE&G. PSEG Power, a Delaware limited liability company, does not directly own any generation facilities or engage in any FERC jurisdictional activities but is the parent company of several FERC jurisdictional entities, including Applicants PSEG ER&T, PSEG Fossil, PSEG Nuclear, PSEG Power CT and PSEG New Haven.

PSEG Global LLC ("PSEG Global") is an indirect subsidiary of PSEG and owns an indirect interest in a domestic power plant in Hawaii.[16]

PSEG Solar Source LLC ("Solar Source") A PSEG Global subsidiary, PSEG Solar Source LLC owns a combined 29 MWs[17] of solar capacity in PJM, about 15 MWs in Florida, 37 MWs in Arizona and 3 MWs in California, all through separate project companies which have all obtained QF status.[18] By the end of 2013, all of the Solar Source facilities will be transferred to a new subsidiary of PSEG Power – PSEG Power Ventures LLC - which will be a Delaware limited liability company that will not itself be an operating company. As a result, these companies will become subsidiaries of PSEG Power rather than subsidiaries of

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[15] Appendix B excludes generation assets located in Hawaii as well as generation assets in which PSEG's interest is limited to a leveraged lease interest.

[16] PSEG Global previously owned indirect interests in facilities in California and New Hampshire and a hydro plant in Pennsylvania. Since the last PSEG triennial market power update, PSEG Global has (i) sold its 40% interest in Bridgewater Holdings LLC (the New Hampshire facility) on May 11, 2012 (ii) shut down operations of its plants in California on February 24, 2012 and (iii) sold its interest in Pennsylvania Renewable Resource's two 7.5 MW (net) hydro facilities in May 2011.

[17] The 29MWs are attributed to three (3) separate project companies that have QF status: PSEG Solar Source Hackettstown (2 MW); PSEG Solar Source Delaware (15 MW) and PSEG Solar Source Ohio (12 MW).

[18] The 3MWs (DC) are associated with the Shasta Solar Facility in California, which began testing energy on December 20, 2013. PSEG Global is also under contract to purchase ownership of the Acacia Solar Project, which is expected to produce 20 MW DC beginning in the first quarter 2014. Both Shasta and Acacia will have QF status.

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PSEG Global. This is simply a change in upstream ownership that will not affect the operations of the facilities.[19]

PSEG Resources LLC ("Resources") is a New Jersey limited liability company that provides energy infrastructure financing in developed countries. Resources invests primarily in energy-related financial transactions and manages a diversified portfolio of investments including leveraged leases. Resources owns interests, through leveraged leases, in various generation stations. Pursuant to the terms of these triple net leases, the lessee, not Resources, has all operational responsibility and control over the leased generation stations.

PSEG Power New York LLC ("PSEG Power NY") is a Delaware limited liability company and an EWG that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 750 MW combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a FERC-approved cost-based contract.[20]

PSEG Long Island LLC ("Long Island") and Long Island Electric Utility Servco, LLC ("Servco") are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution system ("T&D") on Long Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither Long Island nor Servco will be FERC jurisdictional public utilities as neither will exercise ultimate decision making authority over the T&D system in Long Island. Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[21]

8. Affiliated Transmission Ownership

With the exception of the electric transmission assets owned by Applicant PSE&G, all of which are located within the PJM RTO, and the generation interconnection facilities owned by the various EWG and QF affiliates listed herein, the Applicants do not have any affiliates that own or operate FERC jurisdictional electric or natural gas transmission facilities within the United States. As discussed below, FERC granted PSE&G a Hinshaw exemption in 1954, finding that it was exempt from the provisions of the Natural Gas Act.

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[19] It should be noted that the Hawaii generating facility referenced above will also be transferred to PSEG Power Ventures LLC as of the end of 2013.

[20] *PSEG Power New York Inc.*, Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

[21] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), *order dismissing request for rehearing*, 145 FERC ¶ 61,183 (2013).

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B. JOINTLY OWNED FACILITIES

PSEG Nuclear is a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear is the operator of Salem and Exelon Generation is the operator of Peach Bottom.[22] PSEG Fossil is approximately a 23% joint owner in the Conemaugh and Keystone generating stations located in Pennsylvania. An affiliate of NRG Energy is the operator.[23] Accordingly, for purposes of this market power analysis, the capacity of Salem, Peach Bottom, Conemaugh and Keystone has been attributed to PSEG in accordance with PSEG's ownership interests in these facilities.

PSEG Fossil and Jersey Central Power and Light Company ("JCP&L") are each 50% co-owners of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to the unit. Accordingly, for the purpose of this market power analysis, the entire unit capacity – nominally 400 MWs – has been assigned to JCP&L.[24]

III. Applicants Fully Satisfy The Commission's Standards For Authority to Make Power Sales At Market-Based Rates.

The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, horizontal and vertical market power.[25] The Commission has also codified affiliate restrictions in its regulations which must be satisfied on an ongoing basis. In previous submissions for market-based rate authority the Applicants PSE&G, PSEG ER&T, PSEG Power CT, PSEG Fossil, PSEG Nuclear and PSEG New Haven demonstrated compliance with each of these requirements. As detailed herein and in the attached affidavit, the Applicants continue to meet these standards.

A. The Applicants Lack, Or Have Effectively Mitigated, Any Horizontal Market Power

In the MBR Order, the Commission established two indicative screens: a pivotal supplier screen based on the control area's annual peak demand and a wholesale market share screen applied on a seasonal basis. If an applicant passes both screens, there is a rebuttable presumption that the applicant does not possess generation market power.

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[22] A letter of concurrence supporting the allocation of plant output based on ownership interests is attached in Appendix D. The ownership percentages have not changed since the date of this letter. PSEG Nuclear owns a 50% interest in Peach Bottom and a 57.41% interest in Salem.

[23] A letter of concurrence supporting the allocation of plant output based on ownership interest is attached in Appendix D. The ownership percentages have not changed since the date of this letter.

[24] A letter of concurrence supporting this determination is attached in Appendix D. The ownership percentages have not changed since the date of this letter.

[25] MBR Order, FERC Stats. & Regs. ¶ 31,252 at P 62, 399, 408, 440.

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Each indicative screen is applied with respect to "relevant geographic markets" for an applicant's generating units.

Applicants located in ISOs/RTOs possessing sufficient market structure may consider the geographic region under the control of the ISO/RTO as the relevant default geographic region for purposes of completing their generation market power analyses.[26] However, where the Commission has previously found a "submarket" to exist within a boundary of an RTO, such finding is controlling as to the scope of the relevant geographic market for all generation units located within that submarket for the application of the indicative screens and any delivered price test that may be performed. The Commission further listed several such submarkets, including PJM East ("PJME"), Connecticut and Southwest Connecticut.[27] Subsequent to the MBR order, in approving a merger between Exelon Corporation and Constellation Energy Group, Inc., the Commission identified additional submarkets in PJM - PJM East of 5004/5005 ("PJM50") and PJM East of AP South ("PJMAP") - that would be relevant to an MBR analysis for applicants in the Northeast Region.[28]

As discussed below and in the attached Affidavit of Dr. John Morris contained in Appendix A, Applicants have conducted market power analyses of the entire PJM RTO, the PJME, PJM50 and PJMAP submarkets, the entire NYISO, the entire ISO-NE, the Connecticut submarket and the Southwest Connecticut submarket for the study period. The results are set forth below.

1. Indicative Screens

a. Pivotal Supplier Analysis

The pivotal supplier analysis ("PSA") focuses on the ability of a seller to exercise unilateral market power.[29] The screen assesses whether market demand can be met during peak times without the applicant and its affiliates. If demand can be met without the applicant and its affiliates, the applicant passes that the PSA screen. The Affidavit of Dr. John Morris, attached hereto as Appendix A, finds that the Applicants pass the PSA screen for all relevant markets: PJM, NYISO, ISO-NE, Connecticut, Southwest Connecticut, PJMAP, PJME and PJM50.[30]

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[26] *MBR Order at* PP. 231 and 235.

[27] *Order No. 697* at P 236 (citing *Exelon Corp.*, 112 FERC ¶ 61,011, *reh'g denied*, 113 FERC ¶ 61, 299 (2005)). FERC eliminated the Northern PSEG zone as a default submarket in Order No. 697-A, P 99.

[28] Order Conditionally Authorizing Merger and Disposition of Jurisdictional Facilities, *Exelon Corporation, et al.*, 138 FERC ¶ 61,167 (2012).

[29] *AEP I* at P 72.

[30] *See* Morris Affidavit, at 15-28.

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b. Wholesale Market Share Analysis

The wholesale market share analysis ("WMSA") is applied each season to determine whether an applicant has a dominant market position based on the total number of megawatts of uncommitted capacity owned or controlled by the applicant and its affiliates in relation to the uncommitted capacity of the entire relevant wholesale electricity market.[31] The established threshold is 20 percent; a supplier who has less than 20 percent market share in the relevant market for all seasons passes the WMSA screen.

In his Affidavit Dr. Morris finds that the Applicants pass the WMSA screen for PJM, NYISO, ISO-NE, Connecticut, Southwest Connecticut and PJMAP but do not pass the WMSA screen for the PJME and PJM50 submarkets.[32]

c. Results of Indicative Screen Analysis

As shown in Dr. Morris's affidavit, Applicants therefore pass both indicative screen tests for PJM RTO, NYISO, ISO-NE, Connecticut, Southwest Connecticut and PJMAP. For PJME and PJM50, the Applicants pass the PSA but do not pass the WMSA.

2. Delivered Price Test Analysis For PJME and PJM50 Submarkets

In accordance with the MBR Order, applicants who fail either indicative screen test can rebut the presumption of market power through the submission of a delivered price test analysis ("DPT"). Applicants may submit this study at the same time that the results of the indicative screens are provided.[33] The DPT is based on two measurements of potential market power: economic capacity ("EC") and available economic capacity ("AEC"). EC is the capacity that can be delivered to a destination market for 105 percent or less than the market price. AEC is calculated by subtracting native load commitments from EC. Both calculations are performed for twelve different seasonal and load conditions.

In applying the DPT, "[a] showing of an HHI less than 2,500 in the relevant market for all season/load conditions for sellers that have also shown that they are not pivotal and do not possess a 20 percent or greater market share in any of the season/load conditions would constitute a showing of a lack of market power, absent compelling contrary evidence from intervenors."[34] However, while meeting these threshold benchmarks provides "safe harbor" protection, the Commission has found in numerous other cases that applicants lack market power even when they exceed one or more of the thresholds for particular study periods. As stated in *Public Service Company of New Mexico*, 115 FERC ¶ 61,090, P 38 (2006), "the Commission weights the results of both

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[31] *AEP I*, P 100.
[32] *See* Morris Affidavit, at 15-29.
[33] *Order No. 697*, P 76.
[34] *Order No. 697* at P 111.

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the economic and available economic capacity tests and considers the arguments of the applicant and intervenors." (footnote omitted.) [35]

a. Results of the DPT for PJM50 Submarket

With respect to AEC, PSEG passes all screens in all periods. For EC, PSEG passes the HHI Screen and market share screens for all periods but does not pass the PSA screen in 6 of 10 periods.

b. Results of the DPT for PJME Submarket

With respect to AEC, PSEG passes all screens in all periods. For EC, PSEG does not pass the PSA screen in 2 of 10 periods and has marginal Market Share screen failures in 4 of 10 periods.

3. Analysis of DPT Results

Based on his analysis of the overall results, Dr. Morris concludes that, although PSEG fails limited number of screens, the failures appear to be more in the nature of technical violations and not indicators of market power. As set forth in his Affidavit, Dr. Morris states that:

> Although PSEG fails some of the screens for EC in both the PJM50 and the PJME destination markets, the overall results are not indicative of PSEG having market power. To begin, PSEG passes all the market concentration (HHI) screens. The HHI levels in all periods, capacity types, and areas are below the screening threshold of 2,500, and typically

[35] Indeed, in that case, the applicant was deemed "on balance" to have adequately rebutted a showing of market power mitigation for the PNM control area where the results exceeded the 20% safe harbor in two cases under the AEC measure and in all 10 cases at values between 35% and 41% under the EC measure. *See, e.g., Kansas City Power and Light Company, et al.*, Docket Nos. ER99-1005-011 et al. (August 12, 2010) (finding no market power where applicant had EC market shares in the 40-60% range and had significant HHI failures in the KCPL and GMO markets); *Cordova Energy Company LLC et al,* Docket Nos. ER99-2156-011, *et al.*, November 13, 2007 (finding no market power in case where applicant had EC market shares in PACE control area between 53.1% and 60.0%, HHIs between 2,958 and 3,696 and was pivotal in 8 out of 10 periods.); *PacifiCorp*, Letter Order, Docket Nos. ER97-2801-007, *et al.*, February 1, 2007; *Tucson Elec. Power Co.*, 116 FERC ¶ 61,051 (2006)(finding market power standard satisfied where applicant had EC market shares above 20% in all ten season/load periods in the Tucson control area, exceeded the 2,500 HHI threshold in eight periods, and was pivotal in 5 periods); *PacifiCorp*, 115 FERC ¶ 61,349 (2006) (finding that applicants rebutted presumption of market power in the PacifiCorp East control area where under available economic capacity measure, market share is less than 20% in 8 season/load periods and 28% in the summer and winter off-peak periods, HHI does not exceed 2500 in any season/load period and applicants are not pivotal); *Kansas City Power & Light Co.*, 113 FERC ¶ 61,074 (2005) (finding no market power in the KCPL control area where applicant had EC market shares above 20% in all periods, exceeded the HHI 2,500 threshold in 5 of 10 periods and was pivotal supplier in 1 period); *Acadia Power Partners, L.P.*, 113 FERC ¶ 61,073 (2005) (finding no market power in the Cleco Power home control where, utilizing the EC measure, the applicant exceeded the thresholds set for all season/load periods using the market share measure, one season/load period using the market concentration measure, and for all season/load periods using the pivotal supplier measure).

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> substantially below this level. In terms of the DPT for market rate authority and under the 2010 DOJ and FTC Horizontal Merger Guidelines, the market is not highly concentrated.[36] The low HHI levels mean that PSEG has little ability to exercise market power in coordination with other suppliers. It also passes all pivotal supplier screens for AEC. This shows that, given commitments to serve load, its generation was not necessary to serve remaining wholesale load. In other words, although PSEG fails the pivotal supplier tests for some periods with EC, once accounting for its actual forward sales commitments, PSEG's uncommitted generation is not necessary to meet total demand in any of the regions in any period. Thus, PSEG has little to no ability to exercise unilateral market power. Finally, PSEG's market shares are not above 20 percent for any of the Market Share Screens, except only four (4) periods for EC in PJM East. Although greater than 20 percent, PSEG's market shares during these four (4) periods are not substantially above 20 percent. The highest share is only 22.4 percent. Hence, although PSEG fails the Market Share Screens and the Pivotal Supplier Screens for EC in some instances, the failures are more in the nature of technical violations and not true indicators of market power.[37]

As noted above, Dr. Morris' conclusion that the limited DPT screen failures identified through his study are "in the nature of technical violations" is consistent with Commission precedent finding a lack of market power in cases in which the DPT results included more instances of findings outside of the "safe harbor" thresholds and at higher levels than exist here.[38] In these circumstances, Dr. Morris's analysis successfully rebuts any inference of market power created by the WMSA screen failures for PJME and PJM50.

4. Existing RTO/ISO Mitigation Rules Also Eliminate The Potential for Exercising Market Power In the PJME, PJME PJM50 and PJMAP Submarkets

PJM mitigation rules eliminate the potential for the exercise of market power in the PJME and PJM50 submarkets. The MBR Order specifically contemplated that RTO/ISO mitigation rules may serve as evidence that any market power has been adequately mitigated. The Commission declared, "We believe the added protections provided in structured markets with market monitoring and mitigation generally result in a market where prices are transparent and attempts to exercise of market power will be sufficiently mitigated."[39] The Order on Rehearing went even further and specifically

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[36] See U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Issued August 19, 2010, at Section 5.3, available at http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

[37] Morris Affidavit at 32-33.

[38] *See Public Service Company of New Mexico*, 115 FERC ¶ 61,090 (2006) discussed above and cases discussed in fn. 38 above.

[39] MBR Order at P 241.

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created a presumption that any potential market power had been adequately mitigated by an established and effective RTO market monitoring scheme.[40]

Taking account of the pervasive PJM mitigation rule, Dr. Morris concludes that these rules "address the potential for PSEG to exercise market power" in PJME and PJM50.[41] Accordingly, PJM's mitigation schemes in place are sufficient to rebut any inference of market power created by the failure to pass the WMSA screens in PJME and PJM50.

In addition, in the Applicants' last triennial approval order, the Commission found that "the PJM market monitoring and mitigation rules are sufficient to address market power concerns in the PJM-East submarket."[42]

a. The Applicants Lack Transmission Market Power and Cannot Erect Entry Barriers.

In its previous order accepting PSEG's triennial market power analysis for the Northeast Region, the Commission found that the submittal satisfied the Commission's requirements for market-based rates regarding vertical market power.[43] There have been no subsequent changes in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. As demonstrated below, neither Applicants nor any of its affiliates are able to exercise vertical market power.

Applicants are not able to exercise transmission market power. Neither Applicants nor any of their affiliates, except PSE&G, own transmission assets in the U.S. other than incidental generator interconnection facilities. PSE&G owns transmission facilities in PJM but transmission service over those facilities is provided under the PJM Open Access Transmission Tariff.

In addition, neither Applicants nor their affiliates are able to exercise vertical market power in wholesale energy markets through affiliation, ownership or control of inputs to electric power production. As required by Section 35.37(e) of the Commission's regulations, Applicants provide the following information:

(1) PSE&G owns and operates a natural gas distribution system that receives interstate pipeline gas within the State of New Jersey and distributes that gas to its customers within the State of New Jersey. The distribution system consists of 17,709.5 miles of gas distribution pipe and an additional 61.5 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3 and peak-

[40] Order No. 697A at P 111.
[41] Morris Affidavit, pp. 35.
[42] *See* June 29, 2011 letter order approving Applicants' prior triennial market update in Docket No. ER99-3151-017 at page 4.
[43] *Id.*

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shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers. Service over such distribution facilities is made available pursuant to state regulated tariffs on an open access type basis. PSE&G was granted a Hinshaw exemption from the FERC in 1954.[44] The gas distribution rates paid by PSEG Fossil to PSE&G have been set at rates approved by the BPU in an order dated May 29, 2013.

(2) Certain of the Applicants and their affiliates own sites within the Northeast Region that would be suitable for future generating facilities. These include space at many of the existing generating sites of PSEG Fossil and at the sites of PSEG Power NY and PSEG Power CT. PSEG Nuclear's Salem facility may also be suitable for future construction. PSE&G also owns certain sites that would be suitable for generating facilities, but under New Jersey's Electric Discount and Energy Competition Act, N.J.S.A 48:3-43 et seq., PSE&G is effectively barred from owning and operating generation except "on site" generation for supply and Class I renewable energy resources as defined in N.J.S.A. 48:3-98.1.

(3) Neither Applicants nor any of their affiliates own or control any physical coal supply resources or ownership or control over who may access transportation of coal supplies.

(4) As required by section 35.37(e)(4) of the Commission's regulations, Applicants state that they have not erected barriers to entry into the PJM, NYISO or ISO-NE market and will not erect barriers to entry into those markets.

IV. REQUEST FOR CONFIDENTIAL TREATMENT

Under separate cover via UPS Overnight this office is submitting compact disks containing the workpapers of Dr. John Morris supporting his analysis in Appendix A, as required by the Commission's April 2004 Order.[45] Disk 1 (of which six copies are included) contains publicly available information. Disk 2 (of which one copy is included) contains: (i) proprietary information provided by Energy Velocity under an agreement that requires confidential treatment to be requested for these materials; (ii) modeling and computer programs that are the proprietary intellectual property of Economists Incorporated, the firm which employs Dr. Morris; (iii) commercially sensitive information about Applicants and their affiliates; and (iv) documents and information deemed to be confidential by PJM and ISO-NE. Accordingly, Applicants respectfully request confidential treatment for Disk 2 pursuant to 18 C.F.R. § 388.112 (2006), consistent with the confidential treatment accorded other applicants submitting such proprietary and commercially sensitive data.[46] Pursuant to the Commission's rules,

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[44] 13 F.P.C. 1348 (1954).

[45] AEP II, 107 FERC at P 61,087-88.

[46] *See, e.g., Idaho Power Company*, Docket No. ER97-1481-009 (February 3, 2006) (submission of revised Pivotal Supplier Screen and Market Share Screen calculations including similar data).

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the public version of this filing contains all materials submitted herein except for Disk 2, which is labeled as "PRIVILEGED AND CONFIDENTIAL/NON-PUBLIC."

V. SERVICE

This filing has been served on all parties on the official service list as currently maintained by Commission in the above-referenced dockets. Applicants are also providing a copy to the New Jersey Board of Public Utilities and the New Jersey Division of Rate Counsel.

VI. ENCLOSURES

Applicants enclose the following:

- An original filing;
- Appendix A – Affidavit of Dr. John R. Morris;[47]
- Appendix B – List of Entities with Market-Based Rates Authority and Their Generation Assets. (This is an appendix listing the filing entities and all their energy affiliates and their associated assets);
- Appendix C – List of Entities with Market-Based Rate Authority and Their Transmission Assets;
- Appendix D – Letters of concurrence regarding the control of certain jointly owned generation facilities;
- Appendix E – Form of notice suitable for publication in the Federal Register.

VII. CONCLUSION.

Applicants respectfully request the Commission:

i. to accept this market power compliance filing as meeting the Commission's requirements under Order No. 697 for the continuation of market-based rate authority for Applicants PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG New Haven LLC, PSEG Nuclear LLC and PSEG Fossil LLC;

ii. to grant the request for confidential treatment; and

iii. to grant such other relief or waivers as may be appropriate or necessary.

[47] Compact disks, as described above, containing the workpapers for the Affidavit of John R. Morris in Appendix A are being sent concurrently with this filing via UPS Overnight. As noted *supra*, privileged treatment is being requested for Dr. Morris's confidential workpapers submitted with the non-public version of this filing.

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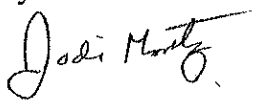
Respectfully submitted,

Public Service Electric and Gas Company
PSEG Energy Resources & Trade LLC
PSEG Power Connecticut LLC
PSEG Fossil LLC
PSEG Nuclear LLC
PSEG New Haven LLC

By:



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Dated: December 23, 2013
Newark, New Jersey

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Appendix A
Affidavit of
Dr. John R. Morris

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UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Public Service Electric and Gas Company	)	ER97-837-__
PSEG Energy Resources & Trade LLC	)	ER99-3151-__
PSEG Power Connecticut LLC	)	ER03-327-__
PSEG Fossil LLC	)	ER08-447-__
PSEG Nuclear LLC	)	ER08-448-__
PSEG New Haven LLC	)	ER12-1250-___

Docket Nos.

Report & Affidavit of
Dr. John R. Morris

December 23, 2013

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Public Service Enterprise Group Incorporated Northeast Region Market Power Study

1. Introduction

My name is Dr. John R. Morris. I am a Principal at Economists Incorporated, an economic consulting firm located at 2121 K Street, NW, Washington, DC 20037. I have a bachelor's degree in economics from Georgetown University, and I have a master's degree and a Ph.D. in economics from the University of Washington. I have been studying and consulting within energy industries since joining the Federal Trade Commission in 1985. Since joining Economists Incorporated in 1992, I have consulted on many mergers involving electric and gas companies, examined competitive issues relating to utility rates, provided market power studies for applications for market-based rate authority, and studied market power issues in state restructuring proceedings. I have published articles on competition and energy matters, and I have spoken on numerous occasions concerning competition in natural gas, electric power and other industries. I have previously been accepted as an expert witness on energy matters before the Federal Energy Regulatory Commission ("FERC" or "Commission"), state commissions and in federal court. A complete listing of my experience, publications and testimony is contained in my resume, presented in Exhibit PEG-2.

Public Service Enterprise Group Incorporated ("PSEG") asked that I prepare a market power study for its subsidiaries that have market-based rate authority in the Northeast Region.[1] These subsidiaries are: Public Service Electric and Gas

[1] The Northeast Region includes ISO-New England Inc. ("ISO-NE"), Connecticut, Southwest Connecticut, New York Independent System Operator, Inc. ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), PJM East, PJM East of 5004/5005 and PJM East of AP South.

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("PSE&G"), PSEG Energy Resources & Trade LLC ("PSEG ER&T"), PSEG Fossil LLC ("PSEG Fossil"), PSEG Nuclear LLC ("PSEG Nuclear"), PSEG Power Connecticut LLC ("PSEG Power CT") and PSEG New Haven LLC ("PSEG New Haven"). The purpose of this study is to determine whether these PSEG entities have market power in any Northeast Region market under the Commission's Pivotal Supplier Analysis ("PSA") and Wholesale Market Share Analysis ("WMSA") screens as articulated in FERC Order No. 697 and if the Applicants do fail any of the screens, whether they otherwise lack market power under the Delivered Price Test ("DPT") or are subject to sufficient mitigation to guard against any market power concerns.[2]

PSEG

PSEG is a public utility holding company headquartered in in Newark, New Jersey. Through its subsidiaries, PSEG engages in the generation, transmission, distribution and sale of electric energy, and distribution and sale of natural gas to commercial, residential, and industrial customers primarily in the Northeastern and Mid-Atlantic United States. PSEG, through its subsidiaries, owns approximately 13,000 MW of seasonal generation capacity located in the Northeast Region.[3]

PSE&G

PSE&G is a public utility operating company engaged primarily in the transmission of electricity and the provision of gas and electric distribution service in the State of New Jersey. It is New Jersey's oldest and largest investor-owned

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[2] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 119 FERC ¶ 61,295, ("Order No. 697" or "MBR Order"), *order clarifying final rule*, 121 FERC ¶ 61,260 (2007) ("MBR Clarifying Order"), *order on reh'g and clarification*, 123 FERC ¶ 61,055 (2008) FERC Stats. & Regs ¶ 31,268 ("Order No. 697-A"), *order on reh'g and clarification*, 124 FERC ¶ 61,055 (2008) ("SIL Allocation Order").

[3] *See* Exhibit PEG-3.

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utility. PSE&G was founded in 1903 and is based in Newark, New Jersey. It is a member of the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization and has made all of its transmission facilities available for open access transmission service pursuant to the PJM Open Access Transmission Tariff ("OATT") administered by PJM. The company also owns and operates 17,709.5 miles of gas distribution pipe and an additional 61.5 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3.

PSEG ER&T

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil and PSEG Nuclear, each wholly-owned subsidiaries of PSEG Power LLC ("PSEG Power"), as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission. PSEG ER&T also makes wholesale sales of natural gas.

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

BGS Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 *et seq.*, which initiated the transition from a regulated to a competitive retail power market in New Jersey, the New Jersey Board of Public Utilities ("BPU") annually approves statewide auctions to determine the entities that will supply Basic Generation Service ("BGS") in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation

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service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSE&G's affiliate, PSEG ER&T, has participated directly in all of the auctions for BGS supply held since 2004 and has consistently won tranches in those auctions, including auctions for BGS service within the franchised service territory of PSE&G.

BGSS Gas Contract. By order issued April 16, 2002, the BPU approved a full requirements contract for the provision of gas supply by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the BPU, PSEG ER&T assumed, through capacity release, PSE&G's FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract, which currently remains in effect, provides for annual renewals unless terminated by either party on 12 months' advance written notice.

LIPA Fuel Supply. On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which ER&T will provide fuel supply and power supply management activities for LIPA beginning on January 1, 2015.

PSEG Fossil

PSEG Fossil owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission under the umbrella of PSEG Fossil's

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market-based rate authority.[4] The assets of PSEG Fossil are located entirely within PJM.[5] As explained in PSEG ER&T's previous triennial submission, ER&T began providing reliability services to PJM pursuant to Reliability Must-Run ("RMR") tariffs covering operations at PSEG Fossil's Sewaren and Hudson 1 generating units in 2005. The RMR tariff for the Sewaren units expired effective as of September 1, 2008. The RMR tariff for the Hudson 1 unit expired effective as of December 7, 2011. Additionally, the Hudson 1 unit and its 454.8 MWs were retired when the RMR was terminated. Thus, the capacity attributable to Hudson 1 is not included in the subject market power analysis.

PSEG Fossil is approximately a 23 percent joint owner of interests in the Conemaugh and Keystone generating stations located in Pennsylvania. An affiliate of NRG Energy is the operator.[6] PSEG Fossil is a 50 percent co-owner with Jersey Central Power and Light Company ("JCP&L") of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to the unit. Accordingly, for the purpose of this market power analysis, the entire unit capacity, nominally 400 MWs, has been assigned to JCP&L.[7]

PSEG Power CT

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4 *Public Service Electric and Gas Company, et al.*, 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000).

5 PSEG Fossil's subsidiaries PSEG Power Connecticut LLC, PSEG New Haven LLC and PSEG Power New York LLC own generation units in Connecticut and New York respectively.

6 A letter of concurrence supporting the allocation of these facilities' output based on ownership interests is attached in our workpapers.

7 A letter of concurrence supporting the allocation of this facility's output to JCP&L is attached in our workpapers.

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PSEG Power CT owns the Bridgeport Harbor and New Haven Harbor generation facilities located in the state of Connecticut within ISO-NE and is authorized to sell power at market-based rates.[8] The output of these facilities is sold to PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority.

PSEG New Haven

PSEG New Haven owns and operates the New Haven facility, a gas-fired plant located in New Haven, CT that entered service in June 2012 with a nameplate capacity of 181.5 MW. The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[9] pursuant to a Connecticut statute that sought proposals for peaking generation in Connecticut.[10] All of the energy and capacity of the New Haven facility is sold into the ISO-NE markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder.[11] As such, neither PSEG New Haven nor any other PSEG affiliate has operational control of

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[8] *Wisvest Corporation, et al.*, 101 FERC ¶ 61,166 (2002).

[9] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control (DPUC). PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

[10] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

[11] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

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the New Haven facility. As a result, the capacity of the facility is not attributable to PSEG for the purpose of this market power analysis.

PSEG Nuclear

PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission in accordance with PSEG Nuclear's market-based rate authority.[12] PSEG Nuclear is a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear operates the Salem plant and Exelon Generation is the operator of Peach Bottom.[13]

Other Subsidiaries

PSEG is also the direct or indirect parent of certain other subsidiaries engaged in energy related activities in the United States. Those additional subsidiaries of PSEG that may be considered relevant to this market power update for the PJM region are as follows.

PSEG Power LLC is a Delaware limited liability company. It does not directly own any generation facilities or engage in any FERC jurisdictional activities but it is the parent company of several FERC jurisdictional entities, including applicants PSEG ER&T, PSEG Fossil and PSEG Nuclear.

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[12] *Public Service Electric and Gas Company, et al.*, 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000).

[13] A letter of concurrence supporting the allocation of plant output based on ownership interests is attached in our workpapers.

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PSEG Global LLC ("PSEG Global") is an indirect subsidiary of PSEG and owns an indirect interest in a domestic power plant in Hawaii.[14]

PSEG Solar Source LLC ("Solar Source") is a PSEG Global subsidiary that owns a combined 29 MWs of solar capacity in the PJM region (through three separate project companies), about 15 MWs in Florida, 37 MWs in Arizona and 3 MWs in California, all through separate project companies which have all obtained QF status.[15] By the end of 2013, all of the Solar Source facilities will be transferred to a new subsidiary of PSEG Power – PSEG Power Ventures LLC - which will be a Delaware limited liability company that will not itself be an operating company. As a result, these companies will become subsidiaries of PSEG Power rather than subsidiaries of PSEG Global. This is simply a change in upstream ownership that will not affect the operations of the facilities.[16]

PSEG Resources LLC ("Resources") is a New Jersey limited liability company that provides energy infrastructure financing in developed countries. PSEG Resources invests primarily in energy-related financial transactions and manages a diversified portfolio of investments including leveraged leases. PSEG Resources owns interests, through leveraged leases, in various generation stations. Pursuant to the terms of these triple net leases, the lessee, not

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[14] PSEG Global previously owned indirect interests in facilities in California and New Hampshire and a hydro plant in Pennsylvania. Since the last PSEG triennial market power update, PSEG Global has (i) sold its 40 percent interest in Bridgewater Holdings LLC (the New Hampshire facility) on May 11, 2012 (ii) shut down operations of its plants in California on February 24, 2012 and (iii) sold its interest in Pennsylvania Renewable Resource's two 7.5 MW (net) hydro facilities in May 2011..

[15] The 3MWs (DC) are associated with the Shasta Solar Facility in California, which began testing energy on December 20, 2013. PSEG Global is also under contract to purchase ownership of the Acacia Solar Project, which is expected to produce 20 MW DC beginning in the first quarter 2014. Both Shasta and Acacia will have QF status.

[16] It should be noted that the Hawaii generating facility referenced above will also be transferred to PSEG Power Ventures LLC as of the end of 2013.

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Resources, has all operational responsibility and control over the leased generation stations.

PSEG Power New York LLC ("PSEG Power NY") is a Delaware limited liability company that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 750 MW combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a cost-based contract.[17]

PSEG Long Island LLC ("Long Island") and Long Island Electric Utility Servco, LLC ("Servco") are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution ("T&D") system on Long Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither Long Island nor Servco are FERC jurisdictional public utilities, as neither will exercise ultimate decision making authority over the T&D system in Long Island. Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[18]

When an applicant has affiliates in the relevant market, the Commission considers the combined capacity of all the affiliated entities in its market power assessment.[19] Accordingly, I have included the capacity controlled by PSE&G,

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[17] *PSEG Power New York Inc.*, Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

[18] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), order dismissing request for rehearing, 145 FERC ¶ 61,183 (2013).

[19] *Heartland Energy Services, Inc.*, 68 FERC ¶ 61,223 at 62,061-62,062 (1994).

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PSEG ER&T, PSEG Power CT, PSEG Fossil, PSEG Nuclear, PSEG Global subsidiaries and PSEG Power New York (which on a combined basis constitutes the capacity of all of PSEG's affiliates). Future references in this Affidavit to PSEG are inclusive of the foregoing entities.

The primary purpose of this study is to determine whether PSEG passes the PSA and WMSA screen thresholds in ISO-NE, the NYISO and PJM. In the PSA, the Commission requires applicants to examine whether the generation owned by the applicant is necessary to serve wholesale demand within a balancing authority area. The applicant first calculates the total generation capacity for an area. This is the total of generation in the balancing authority area plus the import capability to the area.[20] From this total, the applicant subtracts out firm contractual commitments, native load obligations, and operating reserves, giving uncommitted capacity for the area. Net uncommitted capacity is calculated by subtracting a wholesale load proxy from uncommitted capacity. Net uncommitted capacity is then compared to the applicant's uncommitted capacity within the area. When the applicant's uncommitted capacity is less than the net uncommitted capacity for the area, then all wholesale demand could be served without energy from the applicant and the applicant passes the PSA screen. When the applicant's uncommitted capacity is greater than the net uncommitted capacity, then the applicant does not pass the screen because its capacity is necessary to meet wholesale peak loads in the market.

In the WMSA, the Commission requires applicants to examine whether the generation owned by the applicant is 20 percent or more of the uncommitted capacity in each of four seasons under average daily peak conditions for the

[20] Import capability is the lesser of either the simultaneous import limit ("SIL") into the area or available capacity in interconnected balancing authority areas. Available capacity is equal to total generation capacity in an area less outages and derating, a native load proxy and operating reserves.

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season. The applicant first calculates the total generation capacity for an area. The applicant then adds the import capability to the area. From this total, the applicant subtracts out planned outages and deratings, long-term firm contractual commitments, native load obligations, and operating reserves. The sum gives the total uncommitted capacity. The applicant then calculates its share by dividing its uncommitted capacity by the total uncommitted capacity. When the applicant's share is less than 20 percent, the applicant passes the WMSA screen.

The Commission presumes that an applicant does not have market power when it passes both the PSA and WMSA screens. If the applicant fails either of the screens, then the applicant may present other analyses to demonstrate that it does not possess market power. Alternatively, the applicant may propose mitigation measures or accept the Commission's default mitigation measures to demonstrate that it has mitigated market power.

2. New England

2.1. Overview of Electric Power Markets in New England

New England operates a competitive wholesale power market. Substantial restructuring has taken place in New England, and many of the vertically integrated utilities have sold either most or all of their generation assets. The traditional utilities often have standard offer obligations to serve retail customers, but utilities often fulfill these obligations by securing supplies in competitive wholesale markets. For example, a utility may secure contracts in which the supplier agrees to provide power for 30 percent of the utility's standard offer obligation. The transmission system is managed by ISO-NE. The market has a market monitor and market power mitigation program in place to identify and to mitigate any potential exercise of market power.

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2.2. Geographic Markets

In the case of generation wholly located in an RTO, such as ISO-NE, the Commission accepts the RTO as the relevant destination market.[21] When the Commission has identified a sub-market within an RTO, the applicant must also provide market power screens for the relevant sub-markets.[22] In New England, the Commission has identified two submarkets: Connecticut and Southwest Connecticut.[23] PSEG owns the Bridgeport Harbor plant in Southwest Connecticut. PSEG also owns the New Haven Harbor 1 unit in Connecticut and PSEG New Haven owns the New Haven facility. When the applicant does not own the transmission system, as in the instant case, the applicant needs to provide an analysis only for the balancing authority area to which the generation is interconnected.[24] Accordingly, the PSA and WMSA are provided for the ISO-NE balancing authority area, and also for Connecticut and Southwest Connecticut.

2.3. Data Sources and Analysis

The data source for generation is ISO-NE Seasonal Claimed Capability (SCC) Reports.[25] Generation for December 2011, January-March 2012 and August 2012 are directly from these monthly reports, and the minimum of the values of these months is taken as generation for other months, to be conservative. Planned outages are from the ISO-NE Form 714. Planned outages for Connecticut and Southwest Connecticut are prorated based on their shares of the total generation capacity in ISO-NE. PSEG's generation capacity in

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[21] Order No. 697 at PP 231, 235.

[22] Order No. 697 at P 236.

[23] *Id.*

[24] Order No. 697 at footnotes 215, 217.

[25] See http://www.iso-ne.com/genrtion_resrcs/snl_clmd_cap/index.html.

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ISO-NE consists of the New Haven facility, New Haven Harbor and Bridgeport Harbor. PSEG's Northeast Region generation facilities are presented in Exhibit PEG-3.

Load data for ISO-NE are from Energy Velocity. Energy Velocity also provides load data by New England ISO zone, thus loads are calculated by sub-market as well. PSEG load obligations in New England come from PSEG's agreements to supply standard offer generation within Rhode Island. The data were supplied by PSEG.

Import capability was taken from the ISO-NE's November 20, 2013 FERC filing.[26] This report indicates that the simultaneous transfer limits in all seasons is 4,548 MW for the ISO-NE as a whole, 2,500 MW for Connecticut, and 2,450 (Winter) to 3,200 MW (Summer) for Southwest Connecticut. The Table 1 and Table 2 data for the SILs are presented in workpapers.

Operating reserves are calculated as follows. ISO-NE Operating Procedure No. 8 specifies spinning reserves (or 10-minute reserves) equal to the size of the loss of the largest unit.[27] The largest unit is the 1,400 MW (summer capacity) Seabrook Unit 1. In addition, 30-minute reserves require capacity to cover 50 percent of the loss of a second contingency (i.e., the second largest unit). The second largest unit is the 1,200 MW (summer capacity) Millstone Unit 3. Thus, in total, operating reserves are 2,000 MW in summer.[28] Operating reserves for

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[26] ISO New England Inc. Simultaneous Import Limit, *Guidance on Simultaneous Transmission Import Limit Studies*; Docket No. AD10-02-002, November 20, 2012.

[27] ISO New England Operating Procedure No. 8, at 5-6, available at http://www.iso-ne.com/rules_proceds/operating/isone/op8/op8_rto_final.pdf.

[28] 2,000 MW = 1,400 MW + 50% x 1,200 MW.

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Connecticut and Southwest Connecticut are based on resources offered for the summer 2012 and winter 2012/2013 forward reserve auction.[29]

2.4. PSA-Entire New England

Exhibit PEG-4 shows the calculations to determine whether PSEG passes the PSA screen in the ISO-NE balancing authority area. The peak load in 2012 occurred in July. The ISO-NE balancing authority area had 31,969 MW of generation capability in the summer of 2012. In addition, 4,548 MW of imports in summer of 2012 were available to serve load. Therefore there were 36,517 MW of total generation resources. Of this amount, 30,993 MW of the generation, and 4,260 MW of the imports are from non-affiliate sources. Thus, total non-affiliate generation resources are 35,274 MW. From the total generation resources, it is necessary to subtract native load obligations and operating reserves. Native load obligations for ISO-NE were calculated to be 20,917 MW. Operating reserves were 2,000 MW. Subtracting native load obligations and operating reserves from total generation resources gives uncommitted supply of 13,600 MW.

The proxy for the wholesale load is the difference between the peak load of 25,880 MW and the native load proxy of 20,917 MW. Therefore, the proxy for the wholesale load is 4,963 MW. Subtracting the wholesale load from total uncommitted supply gives net uncommitted supply of 8,637 MW.

In comparison, PSEG has 955 MW of uncommitted capacity from its generation assets. Additionally, PSEG has 288 MW of imports from its generation assets. After subtracting 314 MW of load and 61 MW of reserves, PSEG has a total of 868 MW of uncommitted capacity. This leaves other

[29] ISO New England, Inc. 2012 Regional System Plan ("Regional System Plan"), available at http://www.iso-ne.com/trans/rsp/2012/, Table 4.9 at p.56.

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generation companies with 7,769 MW of net uncommitted supply. Accordingly, as Exhibit PEG-4 shows, PSEG passes the PSA screen in New England.

2.5. WMSA-Entire New England ISO

Exhibit PEG-5 presents the WMSA. Similar to the PSA calculation for uncommitted capacity, total generation resources equal the sum of the generation in the balancing authority area and available imports. From this total, planned outage and derating, native load obligations, and operating reserves are subtracted to give uncommitted capacity. PSEG's uncommitted supply ranges from 816 MW in fall to 890 MW in summer. PSEG's share of uncommitted capacity ranges from 4.5 percent in winter to 5.6 percent in summer. These shares are substantially below the 20 percent screening threshold adopted by the Commission. Therefore, PSEG passes the WMSA screen in this area.

2.6. PSA-Connecticut

Exhibit PEG-6 shows the calculations to determine whether PSEG passes the PSA screen in the Connecticut area. The peak load in 2012 in the Connecticut area occurred in July. The Connecticut area had 7,979 MW of generation capability in the summer of 2012. In addition, 2,500 MW of imports in summer of 2012 were available to serve load. Therefore there were 10,479 MW of total generation resources. Of this amount, 7,013 MW of the generation, and 2,444 MW of the imports are from non-affiliate sources. Thus, total non-affiliate generation resources are 9,457 MW. From the total generation resources, it is necessary to subtract native load obligations and operating reserves. Native load obligations for the Connecticut area were calculated to be 5,425 MW. Operating reserves were 765 MW.[30] Subtracting native load obligations and operating reserves from total generation resources gives uncommitted supply of 4,289 MW.

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[30] *See* ISO New England Inc., 2012 Regional System Plan, November 2, 2012, Table 4-9 at 56.

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The proxy for the wholesale load is the difference between the peak load of 6,957 MW and the native load proxy of 5,425 MW. Therefore, the proxy for the wholesale load is 1,532 MW. Subtracting the wholesale load from total uncommitted supply gives net uncommitted supply of 2,757 MW.

In comparison, PSEG has 872 MW of uncommitted capacity from its generation assets. Additionally, PSEG has 56 MW of imports for a total of 928 MW of uncommitted capacity. This leaves other generation companies with 1,829 MW of net uncommitted supply. Accordingly, as Exhibit PEG-6 shows, PSEG passes the PSA screen in the Connecticut area.

2.7. WMSA-Connecticut

Exhibit PEG-7 presents the WMSA. Similar to the PSA calculation for uncommitted capacity, total generation resources equal the sum of the generation in the balancing authority area and available imports. From this total, planned outage and derating, native load obligations, and operating reserves are subtracted to give uncommitted capacity. PSEG's uncommitted supply ranges from 810 MW in fall to 918 MW in summer. PSEG's share of uncommitted capacity ranges from 15.8 percent in spring to 18.5 percent in summer. These shares are below the 20 percent screening threshold adopted by the Commission. Therefore, PSEG passes the WMSA screen in the Connecticut area.

2.8. PSA-Southwest Connecticut

Exhibit PEG-8 shows the calculations to determine whether PSEG passes the PSA screen in the Southwest Connecticut area. The peak load in 2012 occurred in July. The Southwest Connecticut area had 2,798 MW of generation capability in the summer of 2012. In addition, 3,200 MW of imports in summer of 2012 were available to serve load. Therefore there were 5,998 MW of total generation resources. Of this amount, 2,270 MW of the generation, and 3,100 MW of the imports are from non-affiliate sources. Thus, total non-affiliate

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generation resources are 5,370 MW. From the total generation resources, it is necessary to subtract native load obligations and operating reserves. Native load obligations for Southwest Connecticut were calculated to be 2,687 MW. Operating reserves were 0 MW.[31] Subtracting native load obligations and operating reserves from total generation resources gives uncommitted supply of 3,311 MW. The proxy for the wholesale load is the difference between the peak load of 3,419 MW and the native load proxy of 2,687 MW. Therefore, the proxy for the wholesale load is 732 MW. Subtracting the wholesale load from total uncommitted supply gives net uncommitted supply of 2,579 MW.

In comparison, PSEG has 528 MW of uncommitted capacity from its generation assets. Additionally, PSEG has 100 MW of imports for a total of 628 MW of uncommitted capacity. This leaves other generation companies with 1,951 MW of net uncommitted supply. Accordingly, as Exhibit PEG-8 shows, PSEG passes the PSA screen in the Southwest Connecticut area.

2.9. WMSA-Southwest Connecticut

Exhibit PEG-9 presents the WMSA. Similar to the PSA calculation for uncommitted capacity, total generation resources equal the sum of the generation in the Southwest Connecticut area and available imports. From this total, planned outage and derating, native load obligations, and operating reserves are subtracted to give uncommitted capacity. PSEG's uncommitted supply ranges from 545 MW in fall to 616 MW in summer. PSEG's share of uncommitted capacity ranges from 15.3 percent in spring to 17.0 percent in winter. These shares are below the 20 percent screening threshold adopted by the Commission in for all seasons. Therefore, PSEG passes the WMSA screen in the Southwest Connecticut area.

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[31] See ISO New England Inc., 2012 Regional System Plan, November 2, 2012, Table 4-9 at 56.

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3. New York

3.1. Overview of Electric Power Markets in New York

New York also has a competitive wholesale power market. Substantial restructuring has taken place in New York, and the investor-owned vertically integrated utilities have sold either most or all of their generation assets. These utilities often have standard offer obligations to serve retail customers, and utilities can fulfill these obligations by securing supplies in competitive wholesale markets. The transmission system is operated by the NYISO, which also operates a competitive wholesale market. The market has a market monitor and market power mitigation program in place to identify and to mitigate any potential exercise of market power.

3.2. Geographic Markets

In the case of generation wholly located in an RTO such as the New York ISO, the Commission has accepted the RTO as the relevant destination market.[32] PSEG only owns generation in Albany, New York. In addition, when the applicant does not own the transmission system, as in the instant case, the applicant needs to provide an analysis only for the balancing authority area to which the generation is interconnected.[33] Accordingly, the PSA and WMSA are provided for the NYISO only.

3.3. Data Sources and Analysis

The principal data source for generation is the Energy Velocity Market-Operations database. Planned outages are from the FERC Form 714. PSEG's

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[32] Order No. 697 at PP 231, 235.

[33] Order No. 697 at footnotes 215, 217.

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generation capacity in New York consists of its ownership of the Bethlehem Energy Center in Albany, which has winter capacity of 845 MW. Information for PSEG's Northeast Region generation is presented in Exhibit PEG-3.

Load data for the NYISO were downloaded from Energy Velocity.

Import capability comes from the most recent NYISO SIL filing as of December 19, 2013.[34] This filing indicates that ISO simultaneous import capability ranges from 7,360 MW in spring to 8,130 MW in fall. NYISO does not recognize physical imports, accordingly, all the SIL import capability is allocated pro rata, except for a 250 MW reservation that PSEG has from PJM to New York. The Table 1 and Table 2 SIL data in the study is presented in workpapers.

Operating reserves are calculated as follows. The NYISO Locational Reserve Requirements specify 30-minute total reserves equal to one and one half the 10-minute reserve necessary to replace the operating capability loss caused by the most severe contingency under normal transfer conditions. Thus, the operating reserves for the NYISO are 1,965 MW for each season.[35]

3.4. PSA-NYISO

Exhibit PEG-10 shows the calculations to determine whether PSEG passes the PSA screen in the NYISO balancing authority area. The peak load in 2012 occurred in July. The NYISO had 38,493 MW of generation capability in the summer of 2012. In addition, 7,820 MW of imports in summer were available to serve load. Therefore, there were 46,313 MW of total generation resources. Of this amount, 37,739 MW of the generation, and 6,465 MW of the imports are from

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[34] New York Independent System Operator, Inc., *Informational Filing Regarding the Simultaneous Import Limitation Study*, Docket No. AD10-2-001, December 19, 2013.

[35] NYISO Locational Reserve Requirements, Table 2, available at http://www.nyiso.com/public/webdocs/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf

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non-affiliate sources. Thus, total non-affiliate generation resources are 44,204 MW. From the total generation resources, it is necessary to subtract native load obligations and operating reserves. Native load obligations for NYISO were calculated to be 27,324 MW. Operating reserves were 1,965 MW. Subtracting native load obligations and operating reserves from total generation resources gives uncommitted supply of 17,024 MW. The proxy for the wholesale load is the difference between the peak load of 32,439 MW and the native load proxy of 27,324 MW. Therefore, the proxy for the wholesale load is 5,116 MW. Subtracting the wholesale load from total uncommitted supply gives net uncommitted supply of 11,909 MW.

In comparison, PSEG has 716 MW of uncommitted capacity from its generation assets in New York, and 1,355 MW of imports for a total of 2,071 MW of uncommitted capacity. This leaves other generation companies with 9,838 MW of net uncommitted supply. Accordingly, as Exhibit PEG-10 shows, PSEG passes the PSA screen in the New York ISO.

3.5. WMSA-NYISO

Exhibit PEG-11 presents the WMSA for the NYISO. Similar to the PSA calculation for uncommitted capacity, total generation resources equal the sum of the generation in the balancing authority area and available imports. From this total, planned outage and derating, native load obligations, and operating reserves are subtracted to give uncommitted capacity. PSEG's uncommitted supply ranges from 1,264 MW in spring to 1,381 MW in summer. PSEG's share of uncommitted capacity ranges from 5.9 percent in winter to 7.2 percent in summer. These shares are below the 20 percent screening threshold adopted by the Commission. Therefore, PSEG passes the WMSA screen in the NYISO.

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4. PJM

4.1. Overview of Electric Power Markets in PJM

PJM operates a competitive wholesale power market and serves as the regional RTO for an area that covers all or parts of 13 states and the District of Columbia. PJM also plans and operates the transmission system within the RTO. Monitoring Analytics acts as the market monitor, and has a market power mitigation program in place to identify and mitigate any potential exercise of market power.

4.2. Geographic Markets

PSEG owns both generation and transmission facilities in PJM. In the case of generation wholly located in an RTO such as PJM, the Commission has accepted the RTO as the relevant destination market.[36] When the Commission has identified a sub-market within an RTO, the applicant must also provide market power screens for the relevant sub-markets.[37] In PJM, the Commission has identified three submarkets: PJM East ("PJME"), PJM East of 5004/5005 ("PJM50") and PJM East of AP-South ("PJMAP").[38] The PSA and WMSA are provided for PJM and for the PJME, PJM50 and PJMAP sub-markets.

4.3. Data Sources and Analysis

The principal data source for generation is the Energy Velocity Market-Ops database. Generation within PJM was assigned to submarket consistent with the

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[36] Order No. 697 at PP 231, 235.

[37] Order No. 697 at P 236.

[38] *Id. See also* Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, Order No. 697-A, 73 FR 25832 (May 7, 2008), FERC Stats, & Regs. ¶ 31,268 (2008) at P 90; Order Conditionally Authorizing Merger and Disposition of Jurisdictional Facilities, *Exelon Corporation, et al.*, 138 FERC ¶ 61,167 (2012).

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definitions in PJM's SIL Study.[39] Planned outages are from the FERC Form 714. In addition, for the sub-market analysis, planned outages were allocated to PJME based on the share of total PJME generation, by season. Information for PSEG's generation in PJM and PJME is presented in Exhibit PEG-3.

Load data for PJM was downloaded from Energy Velocity. Energy Velocity also provides load data by PJM zone, thus loads are calculated for the PJM sub-markets as well.

Import capability was taken from the 2012 Simultaneous Import Limit Study Report.[40] This report indicates simultaneous transfer limits of 10,194 MW in the winter and 8,434 MW in summer. Additionally, this report indicates transmission capabilities of the PJM sub-markets. The report conservatively uses the reported SIL as the SIL amount to be allocated pro rata. This is a simplifying assumption because PSEG has no firm transmission reservations into PJM and it effectively excludes the additional 4,000 MW of net imports into PJM in the base case of the SIL study. The Table 1 and Table 2 data for the study are presented in workpapers.

Operating reserves are calculated according to PJM Manual 13 as the sum of Day Ahead Scheduling Reserves (Operating), Contingency (Primary) and Synchronized (Spinning Reserve) Requirements.[41]

Data on PSEG's long-term contracts come from PSEG. The contracts were included in the area where the energy is delivered under the contract. For

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[39] PJM Interconnection, L.L.C., 2012 Simultaneous Import Limit Study Report, *Guidance on Simultaneous Import Limit Studies*, Docket No. AD1-2-002, October 2, 2013.

[40] *Id.*

[41] PJM Manual 13 - Emergency Operations, at 17, available at http://pjm.com/~/media/documents/manuals/m13.ashx

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contracts delivered to the Western Hub in PJM, the contracts were included in the PJM, PJM50, and PJMAP destinations and not the PJME destination.

4.4. PSA – PJM

Exhibit PEG-12 shows the calculations to determine whether PSEG passes the PSA screen in the PJM balancing authority area. The peak load in 2012 occurred in July. PJM had 193,478 MW of generation capability in the summer of 2012. In addition, 8,434 MW of imports in summer were available to serve load. Therefore, there were 201,912 MW of total generation resources. Of this amount, 182,128 MW of the generation, and 8,310 MW of the imports are from non-affiliate sources. Thus, total non-affiliate generation resources are 192,545 MW. From the total generation resources, it is necessary to subtract native load obligations and operating reserves. Native load obligations for PJM were calculated to be 133,565 MW. Operating reserves were 12,510 MW. Subtracting native load obligations and operating reserves from total generation resources gives uncommitted supply of 55,837 MW. The proxy for the wholesale load is the difference between the peak load of 154,339 MW and the native load proxy of 133,565 MW. Therefore, the proxy for the wholesale load is 20,774 MW. Subtracting the wholesale load from total uncommitted supply gives net uncommitted supply of 35,063 MW.

In comparison, PSEG has 5,362 MW of uncommitted capacity from its generation assets in PJM, and 124 MW of imports, for a total of 5,486 MW of uncommitted capacity. This leaves other generation companies with 29,577 MW of net uncommitted supply. Accordingly, as Exhibit PEG-12 shows, PSEG passes the PSA screen in PJM as a whole.

4.5. WMSA – Entire PJM

Exhibit PEG-13 presents the WMSA for PJM. Similar to the PSA calculation for uncommitted capacity, total generation resources equal the sum of the generation in the balancing authority area and available imports. From this total,

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planned outage and derating, native load obligations, and operating reserves are subtracted to give uncommitted capacity. PSEG's uncommitted supply ranges from 5,393 MW in spring to 6,118 MW in summer. PSEG's share of uncommitted capacity ranges from 4.7 percent in winter to 5.5 percent in summer. These shares are below the 20 percent screening threshold adopted by the Commission. Therefore, PSEG passes the WMSA screen in PJM as a whole.

4.6. PSA – PJME Sub-market

Exhibit PEG-14 shows the calculations to determine whether PSEG passes the PSA screen in the PJME sub-market of PJM's balancing authority area. The peak load in 2012 occurred in July. The PJME sub-market area had 34,847 MW of generation capability in the summer of 2012. In addition, 6,993 MW of imports in summer were available to serve load. Therefore, there were 41,840 MW of total generation resources. Of this amount, 25,407 MW of the generation, and 6,883 MW of the imports are from non-affiliate sources. Thus, total non-affiliate generation resources are 32,277 MW. From the total generation resources, it is necessary to subtract native load obligations and operating reserves. Native load obligations for the PJME sub-market were calculated to be 26,061 MW. Operating reserves were 2,551 MW. Subtracting native load obligations and operating reserves from total generation resources gives uncommitted supply of 13,229 MW. The proxy for the wholesale load is the difference between the peak load of 32,542 MW and the native load proxy of 26,061 MW. Therefore, the proxy for the wholesale load is 6,481 MW. Subtracting the wholesale load from total uncommitted supply gives net uncommitted supply of 6,747 MW.

In comparison, PSEG has 5,695 MW of uncommitted capacity from its generation assets in PJME and 110 MW of imports, for a total of 5,805 MW of uncommitted capacity. This leaves other generation companies with 942 MW of net uncommitted supply. Accordingly, as Exhibit PEG-14 shows, PSEG passes the PSA screen in PJME.

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4.7. WMSA – PJME Sub-market

Exhibit PEG-15 presents the WMSA for the PJME sub-market. Similar to the PSA calculation for uncommitted capacity, total generation resources equal the sum of the generation in the balancing authority area and available imports. From this total, planned outage and derating, native load obligations, and operating reserves are subtracted to give uncommitted capacity. PSEG's uncommitted supply ranges from 5,886 MW in spring to 6,546 MW in fall. PSEG's share of uncommitted capacity ranges from 27.1 percent in winter to 37.2 percent in summer. These shares are above the 20 percent screening threshold adopted by the Commission. Therefore, PSEG fails the WMSA screen in the PJME sub-market.

4.8. PSA – PJM East of 5004/5005 Sub-market

Exhibit PEG-16 shows the calculations to determine whether PSEG passes the PSA screen in the PJM50 sub-market of PJM's balancing authority area. The peak load in 2012 occurred in July. The PJM50 sub-market area had 59,995 MW of generation capability in the summer of 2012. In addition, 7,956 MW of imports in summer were available to serve load. Therefore, there were 67,951 MW of total generation resources. Of this amount, 49,433 MW of the generation, and 7,870 MW of the imports are from non-affiliate sources. Thus, total non-affiliate generation resources are 59,410 MW. From the total generation resources, it is necessary to subtract native load obligations and operating reserves. Native load obligations for the PJM50 sub-market were calculated to be 46,146 MW. Operating reserves were 4,400 MW. Subtracting native load obligations and operating reserves from total generation resources gives uncommitted supply of 17,404 MW. The proxy for the wholesale load is the difference between the peak load of 56,172 MW and the native load proxy of 46,146 MW. Therefore, the proxy for the wholesale load is 10,025 MW. Subtracting the wholesale load from total uncommitted supply gives net uncommitted supply of 7,379 MW.

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In comparison, PSEG has 4,988 MW of uncommitted capacity from its generation assets in PJM50 and 86 MW of imports, for a total of 5,074 MW of uncommitted capacity. This leaves other generation companies with 2,305 MW of net uncommitted supply. Accordingly, as Exhibit PEG-10 shows, PSEG passes the PSA screen in PJM50.

4.9. WMSA – PJM East of 5004/5005 Sub-market

Exhibit PEG-17 presents the WMSA for the PJM50 sub-market. Similar to the PSA calculation for uncommitted capacity, total generation resources equal the sum of the generation in the balancing authority area and available imports. From this total, planned outage and derating, native load obligations, and operating reserves are subtracted to give uncommitted capacity. PSEG's uncommitted supply ranges from 4,882 MW in spring to 5,709 MW in summer. PSEG's share of uncommitted capacity ranges from 16.5 percent in winter to 23.8 percent in summer. The summer share is above the 20 percent screening threshold adopted by the Commission. Therefore, PSEG fails the WMSA screen in the PJM50 sub-market.

4.10. PSA – PJM East of AP South Sub-market

Exhibit PEG-18 shows the calculations to determine whether PSEG passes the PSA screen in the PJMAP sub-market of PJM's balancing authority area. The peak load in 2012 occurred in July. The PJMAP sub-market area had 82,198 MW of generation capability in the summer of 2012. In addition, 7,489 MW of imports in summer were available to serve load. Therefore, there were 89,687 MW of total generation resources. Of this amount, 73,743 MW of the generation, and 7,393 MW of the imports are from non-affiliate sources. Thus, total non-affiliate generation resources are 81,136 MW. From the total generation resources, it is necessary to subtract native load obligations and operating reserves. Native load obligations for the PJMAP sub-market were calculated to be 62,753 MW. Operating reserves were 5,911 MW. Subtracting native load obligations and operating reserves from total generation resources gives

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uncommitted supply of 21,023 MW. The proxy for the wholesale load is the difference between the peak load of 75,082 MW and the native load proxy of 62,753 MW. Therefore, the proxy for the wholesale load is 12,329 MW. Subtracting the wholesale load from total uncommitted supply gives net uncommitted supply of 8,694 MW.

In comparison, PSEG has 4,988 MW of uncommitted capacity from its generation assets in PJMAP and 96 MW of imports, for a total of 5,084 MW of uncommitted capacity. This leaves other generation companies with 3,610 MW of net uncommitted supply. Accordingly, as Exhibit PEG-18 shows, PSEG passes the PSA screen in PJMAP.

4.11. WMSA – PJM East of AP South Sub-market

Exhibit PEG-19 presents the WMSA for the PJMAP sub-market. Similar to the PSA calculation for uncommitted capacity, total generation resources equal the sum of the generation in the balancing authority area and available imports. From this total, planned outage and derating, native load obligations, and operating reserves are subtracted to give uncommitted capacity. PSEG's uncommitted supply ranges from 4,876 MW in spring to 5,718 MW in summer. PSEG's share of uncommitted capacity ranges from 14.0 percent in winter to 19.0 percent in summer.

These shares are below the 20 percent screening threshold adopted by the Commission. Therefore, PSEG passes the WMSA screen in the PJMAP sub-market.

5. Delivered Price Test

When an applicant does not pass either the PSA or WMSA for a destination market, the Commission invites the applicant to provide additional information via a delivered price test ("DPT"). PSEG requested that I perform a DPT for the PJM

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East and PJM East of 5004/5005 sub-markets. Accordingly, I now discuss the DPT for these sub-markets.

5.1. Overview of the DPT

The DPT utilizes substantially more information than the PSA or the WMSA, including additional information on generation ownership, generation costs, demand conditions, and transmission limits. The Commission considers two types of capacity: Economic Capacity ("EC") and Available Economic Capacity ("AEC"). EC is the capacity that can be delivered to a destination market for 105 percent or less than the market price. AEC is calculated by subtracting load commitments from EC. EC and AEC are calculated for a number of different seasonal and load conditions.

Because we do not know the firm retail obligations of the competitive suppliers, as explained below, the AEC calculation is based on the assumption that market participants serve load in proportion to their generation capacity and that 70 percent of load obligations are contracted more than one year from delivery.

For both the EC and AEC measures, the Commission prescribes three screens: (1) a pivotal supplier screen; (2) a market share screen; and (3) a Herfindahl-Hirschman Index ("HHI") screen. The HHI is the sum of the squared market shares of the firms in the market. So a market with four firms of market shares of 40, 30, 20, and 10 percent would have an HHI of 3,000 (this is calculated as $40^2 + 30^2 + 20^2 + 10^2 = 1{,}600 + 900 + 400 + 100 = 3{,}000$). A monopolist would produce a HHI of 10,000 and 10 equally-sized firms would produce a HHI of 1,000.

Although the Commission has not drawn bright lines for its review of DPT results, it has given general guidance. When (1) the applicant is not pivotal; (2) the applicants' market share is less than 20 percent; and (3) the HHI is below 2,500, the Commission is likely to conclude that the applicant does not have

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market power. The three standards establish a "safe harbor" for lack of market power, unless intervenors present clear and convincing contrary evidence. The Commission has also determined in some cases that an applicant did not have market power when the analysis showed isolated HHI and market share results above screening levels. Finally, despite the DPT results, the Commission may conclude that an applicant does not have market power if other evidence, such as historical sales data, indicates that the DPT results do not reflect the actual competition in the marketplace.

A detailed description of data sources and methods to prepare the data for the DPT is presented in Exhibit PEG-20. An overview of the sources and methods used at Economists Incorporated for conducting the DPT is presented here.

The DPT is calculated for 10 representative periods, three for each of three seasonal conditions plus a summer super peak period. The three seasons are spring/fall, summer, and winter. Each season is divided into (1) top 10 percent of peak hours; (2) remaining peak hours; and (3) off-peak hours. In addition, there is a summer super peak period which is comprised to the top 1 percent (10 hours) of summer peak hours. These ten periods cover the range of load conditions for each season, and for the year as a whole.

The primary source for generation data is Energy Velocity. In addition to generation capacity, Energy Velocity provides data on ownership (including holding companies), fully-loaded heat rates, emission rates, and generation availability. Generation is included for all of PJM and for surrounding areas. Unit capabilities are derated to account for seasonal maintenance and likely plant unavailability due to forced outages. Because demand in PJM peaks in summer and winter, the planned outages are assumed to be during the spring/fall season.

The transmission system is represented by contract paths between balancing authority areas and within PJM. Limits between regions in PJM are from Energy Velocity.

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Market prices come from hourly prices reported by PJM.

As in the PSA and WMSA, load data come from Energy Velocity. To compute load requirements for market participants, we apportion the total load in each market area in New York and PJM to all suppliers in proportion to their respective generation capacities. We assumed 70 percent of load is committed for a year or longer and the remaining 30 percent is contracted for shorter periods.[42] To account for their greater load obligations, we assume that Dominion, which does not operate in a restructured retail market, has 100 percent responsibility for its allocation of load and that AEP, which operates in a partly restructured retail market, has 90 percent of its allocation as opposed to the standard 70 percent.

The DPT and market share calculations were calculated using the Power Acquisition Screening System developed at Economists Incorporated. The mathematical details are presented in Exhibit PEG-21.

5.2. Results of the DPT for PJM50 Sub-market

The results of the DPT for PJM50 are presented in Exhibit PEG-22. The top part of the exhibit shows the results for AEC. PSEG passes the Pivotal Supplier Screen in all 10 periods. PSEG also passes both the Market Share Screens and the HHI Screens in all 10 periods.

The lower part of Exhibit PEG-22 shows the results for EC in PJM50. PSEG passes the Pivotal Supplier Screen in 4 out of 10 periods. PSEG passes the Market Share Screens and HHI Screens in all 10 periods.

[42] This is a reasonable estimate for the long-term load coverage since this number is generally between 60 and 80 percent for most generation suppliers in restructured markets.

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5.3. Results of the DPT for PJME Sub-market

The results of the DPT for PJME are presented in Exhibit PEG-23. The top part of the exhibit shows the results for AEC. PSEG passes the Pivotal Supplier Screen in all 10 periods. It also passes the Market Share Screens and the HHI Screens in all 10 periods.

The lower part of Exhibit PEG-23 shows the results for EC in PJME. PSEG passes the Pivotal Supplier Screen in 8 out of 10 periods. PSEG passes the Market Share Screens in 6 periods, and passes the HHI Screens in all 10 periods.

5.4. Analysis of the DPT Results

Although PSEG fails some of the screens for EC in both the PJM50 and the PJME destination markets, the overall results are not indicative of PSEG having market power. To begin, PSEG passes all the market concentration (HHI) screens. The HHI levels in all periods, capacity types, and areas are below the screening threshold of 2,500, and typically substantially below this level. In terms of the DPT for market rate authority and under the 2010 DOJ and FTC Horizontal Merger Guidelines, the market is not highly concentrated.[43] The low HHI levels mean that PSEG has little ability to exercise market power in coordination with other suppliers. It also passes all pivotal supplier screens for AEC. This shows that, given commitments to serve load, its generation was not necessary to serve remaining wholesale load. In other words, although PSEG fails the pivotal supplier tests for some periods with EC, once accounting for its expected forward sales commitments, PSEG's uncommitted generation is not necessary to meet total demand in any of the regions in any period. Thus, PSEG has little to no

[43] See U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Issued August 19, 2010, at Section 5.3, available at http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

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ability to exercise unilateral market power given current market conditions. Finally, PSEG's market shares are not above 20 percent for any of the Market Share Screens, except in only four (4) periods for EC in PJM East. Although greater than 20 percent, PSEG's market shares during these four (4) periods are not substantially above 20 percent. The highest share is only 22.4 percent. Hence, although PSEG fails the Market Share Screens and the Pivotal Supplier Screens for EC in some instances, the failures are more in the nature of technical violations and not true indicators of market power.

5.5. Mitigation

PJM has a Commission-approved market monitoring and mitigation plan in place to ensure that generation facilities cannot exercise market power. The Commission has stated in general that Commission-approved market monitoring and mitigation plans are sufficient to mitigate market power in RTO markets.[44] In particular, the Commission found in connection with PSEG's last triennial filing that the PJM market monitoring and mitigation rules are sufficient to address market power concerns.[45]

Under the local market power mitigation procedures in PJM, if a supplier fails the "three pivotal supplier test" (TPS), it is offer-capped by the Market Monitor. The Market Monitor's TPS test is applied on an ongoing basis, potentially as frequently as every 5 minutes, to reflect day-ahead and real-time operating conditions. These offer caps provide direct protection against the exercise of locational market power by suppliers in PJME, PJM50, PJMAP and elsewhere.

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[44] Order No. 697 at P 241.

[45] *PSEG Energy Resources and Trade*, Docket Nos. ER99-3151-017, et al. (June 29, 2011).

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The protection against the exercise of market power is enhanced by "must offer" requirements under PJM's Operating Agreement. These mandate that generation resources that are used to meet capacity requirements in PJM and that are not subject to an outage must offer their available capacity in PJM's day-ahead energy market.[46] PJM has also implemented a Reliability Pricing Model (RPM) to secure sufficient capacity to meet its requirements through a series of auctions, including a Base Residual Auction (BRA) held annually for capacity 3 years in advance, and incremental auctions held at varying intervals prior to the delivery year. Various features of the RPM process work to prevent the exercise of market power in capacity markets in PJM. First, if PJM's Market Monitor determines that the market structure test is failed, bids of those failing the test are cost-capped. Second, RPM includes a must-offer requirement pursuant to which all generating units that have available capacity must bid into the RPM auctions or face disqualification from being recognized as capacity resources (and therefore from receiving any capacity payments) in the delivery year.

In addition to the local market power mitigation described above, the presence of market monitoring within PJM lessens potential concerns that PSEG might be able to exercise market power notwithstanding the indicative DPT screens. The Market Monitor has the specific responsibility under the market monitoring plan to monitor the potential of any market participant to exercise market power. To perform its market monitoring function, the Market Monitor can file reports or complaints with the Commission and other government agencies to address various market concerns including market power. The Market Monitor can also make its view known to the Commission staff and PJM members in cases where PJM does not follow its recommendations concerning complaints or requested rule changes. In addition, the Market Monitor can consult with regulatory bodies, including state commissions, regarding the need for specific

[46] *See* PJM Operating Agreement at 1.10.1A(d).

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investigations and monitoring activities, and to consider and evaluate additional enforcement mechanisms. The Market Monitor can also act on specific complaints that have been filed by market participants to examine any potential market power issues.

In sum, the local market power mitigation rules, the role of the Market Monitor, the existence of must-offer requirements and PJM's RPM auctions address any potential for PSEG to exercise market power.

6. Vertical Market Power

In determining whether the market-based rates are in the public interest, the Commission also considers whether the Applicant has transmission market power or can erect barriers to entry.[47] None of these factors are relevant in the instant case. First, other than incidental generator interconnection facilities and the transmission assets owned by PSE&G in PJM, no transmission assets are owned by the Applicants or any of their affiliates in ISO-NE and NYISO. Transmission service over PSE&G's transmission facilities is provided under the PJM Open Access Transmission Tariff. Thus, consistent with Commission precedent, Applicants have alleviated any concerns regarding potential transmission market power. Second, PSEG has no ability to erect barriers to entry. As explained in Applicants' previous initial applications for market-based rate authority and triennial market power reports, PSEG is unable to erect barriers to entry. There has been no change in facts since the submission of those applications that would alter this conclusion.

The Commission is concerned with the ownership of natural gas pipelines or natural gas distribution facilities and the possibility that they may be used to

[47] Order No. 697 at PP 397, 399.

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exercise market power in electricity markets. PSEG does not own or operate any FERC jurisdictional natural gas pipelines in PJM, ISO-NE or NYISO. PSE&G owns natural gas distribution facilities in the State of New Jersey including peak-shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers.

7. Conclusion

PSEG and its subsidiaries do not have market power in New England, New York or PJM. PSEG is not a pivotal supplier in New England, New York or PJM. PSEG's market shares in the WMSA are below the Commission's 20 percent screening threshold in each of these market areas. PSEG is also not a pivotal supplier in the Connecticut or Southwest Connecticut sub-markets and its market shares in the WMSA are below 20 percent in these sub-markets. PSEG fails the WMSA screens in only the PJME and PJM50 sub-markets. For these sub-markets, we conducted a DPT analysis. PSEG passes all the DPT screens for AEC in both submarkets, and it fails the Market Share Screens and the Pivotal Supplier Screens in only a few instances for EC. Accordingly, the market share screen failures are more of a technical nature than true indicators of market power. As such, they are not evidence of actual market power.

Further, PSEG operates under New England's, New York's, and PJM's market power mitigation programs, which mitigate PSEG's potential market power. Therefore, under standards for market-based rate authority articulated by the Commission in Order No. 697, PSEG has no ability to exercise market power in the relevant markets, and maintaining market-rate authority in New England, New York and PJM would be in the public interest.

Therefore, I recommend that the Commission continue to authorize PSEG to sell electric power in Northeast Region wholesale markets at market-based rates.

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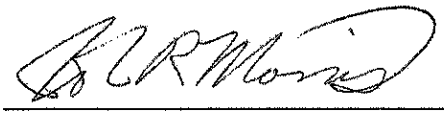
Pursuant to 28 U.S.C. §1746, I state under penalty of perjury that the foregoing is true and correct to the best of my information, knowledge, and belief.

Executed on this 23rd day of December 2013.



John R. Morris, Ph.D.
Principal
Economists Incorporated

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EXPERIENCE AND QUALIFICATIONS OF

Dr. John R. Morris

OVERVIEW	Dr. Morris, a recognized expert in studying competition in energy industries, currently is a Principal at Economists Incorporated. He began his research of competition in energy industries in 1985 while working for the Federal Trade Commission. Since joining Economists Incorporated in 1992, he has consulted on many mergers and acquisitions involving energy companies, examined competitive issues relating to rates, and studied issues in state restructuring proceedings. He has published articles on competition and energy matters, and he has spoken on numerous occasions concerning competition in natural gas, electric power and other industries. He has been accepted as an expert witness on energy matters before the Federal Energy Regulatory Commission, state regulatory commissions, and in federal court.
EDUCATION	Ph.D., University of Washington, August 1985 Dissertation: *Intellectual Property: Creating, Pricing, Copying* • M.A., University of Washington, December 1983 • A.B., Georgetown University, May 1981
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PREVIOUS EXPERIENCE	*Senior Vice President*, Economists Incorporated, December 2001 – December 2002 • *Vice President*, Economists Incorporated, December 1995 – December 2001 • *Senior Economist*, Economists Incorporated, June 1992 – December 1995 • *Economic Tutorial Leader*, Stanford University (Stanford in Washington), April 1993 – June 1995 • *Visiting Assistant Professor*, Department of Business Economics and Public Policy, School of Business, Indiana University, September 1991 – May 1992 • *Assistant to the Director for Antitrust*, Bureau of Economics, Federal Trade Commission, November 1989 – August 1991 • *Economic Advisor*, Office of Commissioner Machol, Federal Trade Commission, December 1988 – October 1989 • *Economist*, Division of Antitrust, Bureau of Economics, Federal Trade Commission, October 1985 – December 1988
MEMBERSHIPS	Member, International Association of Energy Economics • Associate, Energy Bar Association • Member, American Economic Association • Member, Western Economic Association International • Associate, American Bar Association

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AWARDS & HONORS

Award for Excellence in Law Enforcement, Federal Trade Commission, 1988 • Graduate School Scholarship, University of Washington, 1984 • Graduated Cum Laude Georgetown University, 1981 • Senior Comprehensive Passed with Distinction, Georgetown University, 1981

TESTIMONY BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Affidavit, NRG Energy Holdings, Inc., *et al.*, EC14-14-000 • Affidavit, Silver Merger Sub, Inc., *et al.*, EC13-128-000 • Prepared Answering Testimony and Deposition, Puget Sound Energy, Inc., *et al.*, EL01-10-085 (2012) • Affidavit, Wisconsin Public Service Corporation, *et al.*, ER10-1894-004 (2012) • Affidavit, PSEG New Haven LLC, ER12-1250-000 (2012) • Affidavit, Enterprise Product Partners L.P. and Enbridge, Inc., OR12-4-000 (2012) • Affidavit, Southern Indiana Gas and Electric Co., ER10-1338-001 (2011) • Affidavit, TransCanada Power Marketing Ltd. *et al.*, ER10-2780-001 (2011) • Affidavit, Tampa Electric Company, ER10-1476-001 (2011) • Affidavit, Cedar Creek Wind Energy, LLC, ER11-2577-000 (2010) • Affidavit, Public Service Electric and Gas Company *et al.*, ER97-837-014 (2010) • Affidavit, Morris Energy Group, LLC v. PSEG Energy Resources & Trade LLC; PSEG Fossil LLC; and PSEG Power LLC, EL10-79-000 (2010) • Affidavit, UGI Storage Company and UGI Central Penn Gas, Inc., CP10-23-000 (2010) • Prepared Answering Testimony, People of the State of California, *ex rel*; Bill Lockyer, Attorney General of the State of California v. Powerex Corp., *et al.*, EL02-71-000 (2009) • Affidavit, Integrys Energy Services, Inc. v. New Brunswick Power Generation Corporation, EL09-32-002 (2009) • Affidavit, People of the State of California, *ex rel*; Edmund G. Brown Jr. Attorney General of the State of California v. Powerex Corp., *et al.*, EL09-56-000 (2009) • Affidavit, San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, EL00-95-000 (2009) • Affidavit, Troy Energy, LLC, *et al.*, ER02-25-010 (2009) • Affidavit, Combined Locks Energy Center, LLC, *et al.*, ER01-2659-015 (2009) • Prepared Direct Testimony and Deposition, Energy Transfer Partners, *et al.*, IN06-3-003 (2009) • Prepared Direct Testimony and Hearing, Mobil Pipe Line Company, OR07-21-000 (2009) • Idaho Power Company, ER06-787-002 (2009) • Affidavit, Southern Indiana Gas and Electric Co. d/b/a Vectren Energy Delivery of Indiana, Inc. ER96-2734-007 (2008) • Affidavit, Choctaw Gas Generation, LLC, *et al.* ER08-1332-002 • Affidavit, TransCanada Energy Sales Ltd., ER09-328-001 (2008) • Prepared Direct Testimony and Deposition, Oasis Pipeline L.P., *et al.*, IN06-3-004 (2008) • Affidavit, Tampa Electric Company, ER99-2342-012 (2008) • Affidavit, ANP Bellingham Energy Company, LLC, *et al.*, ER00-2117-005 (2008) • Affidavit, SUEZ Energy Marketing, NA, *et al.*, ER06-169-003 (2008) • Affidavit, TransCanada Energy Marketing ULC, *et al.*, ER07-1274-001 (2008) • Affidavit, Georgia-Pacific Brewton LLC, *et al.*, ER08-1126-000 (2008) • Affidavit, Montgomery L'Energia Power Partners LP, ER08-864-000 (2008) • Affidavit (with Joseph P. Kalt), Energy Transfer Partners, *et al.*, IN06-3-002 (2008) • Affidavit, Energy Transfer

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Partners, *et al.*, IN06-3-002 (2008) • Affidavit, TransCanada Maine Wind Development Inc., ER08-685-000 (2008) • Affidavit (with Joseph P. Kalt), Energy Transfer Partners, *et al.*, IN06-3-000 (2007) • Affidavit, Energy Transfer Partners, *et al.*, IN06-3-000 (2007) • Affidavit, The People of the State of Illinois, *ex rel.* Illinois Attorney General Lisa Madigan v. Exelon Generation Co., LLC, *et al.*, EL07-47-000 (2007) • Affidavit, Baltimore Gas and Electric Company, ER07-576-000 (2007) • Affidavit, Trans-Allegheny Interstate Line Company, ER07-562-000 (2007) • Affidavit, TransCanada Energy Marketing Ltd., *et al.*, ER07-331-000 (2006) • Affidavit, Tampa Electric Company, ER99-2342-000, ER07-173-000 (2006) • Affidavit, Koch Supply & Trading, LP, ER07-100-000 (2006) • WPS Resources Corporation and Peoples Energy Corporation, EC06-152-000 (2006) • Affidavit, Sabine Cogen, LP, ER06-744-000 (2006) • Affidavit, Air Liquide Large Industries U.S. LP, ER06-743-000 (2006) • Affidavit, ANP Bellingham Energy Company, LLC., *et al.*, ER00-2117-000 (2005) • Affidavit, Duke Energy Corporation and Cinergy Corp., EC05-103-000 (2005) • Affidavit, El Paso Marketing, L.P., *et al.*, ER95-428-000 (2005) • Affidavit, TransCanada Energy Ltd., *et al.*, ER95-692-000 (2005) • Affidavit, Granite Ridge Energy, LLC, ER00-1147-000, ER05-287-001 (2005) • Affidavit, TransCanada Power (Castleton) LLC, ER05-743-000 (2005) • Affidavit, Tampa Electric Company, *et al.*, ER99-2342-003 (2005) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-035 and Wisconsin Public Service Corporation, ER95-1528-010 (2005) • Affidavit, Wisconsin River Power Company, ER05-453-000 (2005) • Affidavit, Upper Peninsula Power Company, ER05-89-001 (2005) • Affidavit, Southern Indiana Gas and Electric Company, ER96-2734-003 (2004) • Affidavit, Tampa Electric Company, *et al.*, ER99-2342-003 (2004) • Affidavits, TransCanada Hydro Northeast, Inc., *et al.*, EC05-12-000, ER05-111-000 (2004) • Affidavits, Dominion Energy New England, Inc., *et al.*, EC05-4-000, ER05-34-000 (2004) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-033 and Wisconsin Public Service Corporation, ER95-1528-008 (2004) • Affidavit, NorthPoint Energy Solutions Inc. ER04-1244-000 (2004) • Affidavit, Union Power Partners, L.P., ER01-930-004 (2004) • Affidavit, Panda Gila River, L.P., ER01-931-004 (2004) • Affidavit, Dominion Energy Kewaunee, Inc., ER04-318-000 (2003) • Affidavit, TPS GP, Inc., TPG LP, Inc., Panda GS V, LLC & Panda GS VI, LLC, EC03-90-000 (2003) • Affidavit, Berkshire Power Company, L.L.C. *et al.*, ER99-3502-001 (2002) • Affidavit, El Paso Merchant Energy, L.P., ER95-428-024 (2002) • Affidavit, Tampa Electric Company, ER99-2342-001 (2002) • Affidavit, Hardee Power Partners Limited, ER99-2341-001 (2002) • Affidavit, TECO-PANDA Generating Company, L.P., ER02-1000-000 (2002) • Affidavit, Commonwealth Chesapeake Company, LLC, ER99-415-004 (2002) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-031 and

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Wisconsin Public Service Corporation, ER95-1528-006 (2001) • Affidavit, TPS McAdams, LLC and TPS Dell, LLC, ER02-507-000 and ER02-510-000 (2001) • Affidavits, Prepared Direct Testimony, and Hearing, CPUC v. El Paso Natural Gas Company, et al., RP00-241-000 (2000-2001), Affidavit, El Paso Energy Corporation and The Coastal Corporation, EC00-73-000, (2000) • Affidavit, El Paso Energy Corporation and Sonat Inc., EC99-73-000 (1999) • Prepared Testimony, San Diego Gas & Electric Company and Enova Energy, Inc., EC97-12-000 (1997) • Prepared Testimony and Hearing, Wisconsin Electric Power Co., Northern States Power Co. (Minnesota), Northern States Power Co. (Wisconsin), and Cenerprise, Inc., EC95-16-000 (1996)

TESTIMONY BEFORE STATE REGULATORY COMMISSIONS

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Northeast Region Generation Owned and Controlled by PSEG

Owner	Plant Name	State	Owned Capacity		Controlled Capacity	
			Winter Seasonal Capacity	Summer Seasonal Capacity	Winter Seasonal Capacity	Summer Seasonal Capacity
ISO - New England						
PSEG Power CT	Bridgeport Harbor 2	CT	148	130	148	130
PSEG Power CT	Bridgeport Harbor 3	CT	385	383	385	383
PSEG Power CT	Bridgeport Harbor 4	CT	20	15	20	15
PSEG Power CT	New Haven Harbor 1	CT	455	448	455	448
PSEG New Haven	New Haven Harbor GT2	CT	61	61	0	0
PSEG New Haven	New Haven Harbor GT3	CT	61	61	0	0
PSEG New Haven	New Haven Harbor GT4	CT	61	61	0	0
Total ISO - New England Capacity			**1,190**	**1,158**	**1,008**	**976**
New York ISO						
PSEG Power NY	Bethlehem Energy Center CC	NY	845	754	845	754
Total New York ISO Capacity			**845**	**754**	**845**	**754**
PJM						
PSEG Fossil	Conemaugh 1	PA	191	191	191	191
PSEG Fossil	Conemaugh 2	PA	191	191	191	191
PSEG Fossil	Conemaugh A[1]	PA	1	1	1	1
PSEG Fossil	Conemaugh B	PA	1	1	1	1
PSEG Fossil	Conemaugh C	PA	1	1	1	1
PSEG Fossil	Conemaugh D	PA	1	1	1	1
PSEG Global	Conemaugh Hydroelectric Plant 1[2]	PA	1	1	1	1
PSEG Global	Conemaugh Hydroelectric Plant 2	PA	1	1	1	1
PSEG Fossil	Keystone 1[3]	PA	194	194	194	194
PSEG Fossil	Keystone 2	PA	194	194	194	194
PSEG Fossil	Keystone 3	PA	1	1	1	1
PSEG Fossil	Keystone 4	PA	1	1	1	1
PSEG Fossil	Keystone 5	PA	1	1	1	1
PSEG Fossil	Keystone 6	PA	1	1	1	1
PSEG Solar Source LLC	Wyandot Solar Farm	OH	12	12	12	12

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Northeast Region Generation Owned and Controlled by PSEG

Owner	Plant Name	State	Owned Capacity		Controlled Capacity	
			Winter Seasonal Capacity	Summer Seasonal Capacity	Winter Seasonal Capacity	Summer Seasonal Capacity
PJM East						
PSEG Fossil	Bergen 3	NJ	21	21	21	21
PSEG Fossil	Bergen CC1	NJ	628	628	628	628
PSEG Fossil	Bergen CC2	NJ	550	555	550	555
PSEG Fossil	Burlington 8	NJ	21	21	21	21
PSEG Fossil	Burlington 9	NJ	184	184	184	184
PSEG Fossil	Burlington 11	NJ	184	184	184	184
PSEG Fossil	Burlington 121	NJ	42	42	42	42
PSEG Fossil	Burlington 122	NJ	42	42	42	42
PSEG Fossil	Burlington 123	NJ	42	42	42	42
PSEG Fossil	Burlington 124	NJ	42	42	42	42
PSEG Fossil	Edison 1	NJ	168	168	168	168
PSEG Fossil	Edison 2	NJ	168	168	168	168
PSEG Fossil	Edison 3	NJ	168	168	168	168
PSEG Fossil	Essex 9	NJ	81	81	81	81
PSEG Fossil	Essex 10	NJ	168	168	168	168
PSEG Fossil	Essex 11	NJ	168	168	168	168
PSEG Fossil	Essex 12	NJ	168	168	168	168
PSEG Nuclear	Hope Creek 1	NJ	1,161	1,161	1,161	1,161
PSEG Fossil	Hudson 2	NJ	608	608	608	608
PSEG Fossil	Kearny 9	NJ	21	21	21	21
PSEG Fossil	Kearny 12	NJ	175	175	175	175
PSEG Fossil	Kearny 13	NJ	0	178	0	178
PSEG Fossil	Kearny 14	NJ	0	89	0	89
PSEG Fossil	Linden 1	NJ	455	458	455	458
PSEG Fossil	Linden 2	NJ	775	778	775	778
PSEG Fossil	Linden 7	NJ	84	84	84	84
PSEG Fossil	Linden 8	NJ	84	80	84	80
PSEG Fossil	Linden GT5	NJ	86	86	86	86
PSEG Fossil	Linden GT6	NJ	86	86	86	86
PSEG Hackettstown LLC	Mars Solar Garden	NJ	2	2	2	2
PSEG Fossil	Mercer 1	NJ	316	316	316	316
PSEG Fossil	Mercer 2	NJ	316	316	316	316

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Northeast Region Generation Owned and Controlled by PSEG

Owner	Plant Name	State	Owned Capacity		Controlled Capacity	
			Winter Seasonal Capacity	Summer Seasonal Capacity	Winter Seasonal Capacity	Summer Seasonal Capacity
PSEG Fossil	Mercer GT3	NJ	115	115	115	115
PSEG Solar Source LLC	Milford Solar Farm	NJ	15	15	15	15
PSEG Fossil	National Park GT1	NJ	21	21	21	21
PSEG Nuclear	Salem 1[4]	NJ	674	674	674	674
PSEG Nuclear	Salem 2	NJ	665	665	665	665
PSEG Nuclear	Salem GT3	NJ	22	22	22	22
PSEG Fossil	Sewaren 1	NJ	104	104	104	104
PSEG Fossil	Sewaren 2	NJ	118	118	118	118
PSEG Fossil	Sewaren 3	NJ	107	107	107	107
PSEG Fossil	Sewaren 4	NJ	124	124	124	124
PSEG Fossil	Sewaren 6	NJ	105	105	105	105
PSE&G	Solar 4 All Units	NJ	77	77	77	77
PSEG Fossil	Yards Creek 1[5]	NJ	70	70	0	0
PSEG Fossil	Yards Creek 2	NJ	70	70	0	0
PSEG Fossil	Yards Creek 3	NJ	60	60	0	0
PJM 5004/5005						
PSEG Nuclear	Peach Bottom 2[6]	PA	561	561	561	561
PSEG Nuclear	Peach Bottom 3	PA	561	561	561	561
Total PJM Capacity			**11,272**	**11,546**	**11,072**	**11,346**
Total Northeast Region Capacity			**13,307**	**13,457**	**12,925**	**13,076**

Source: PSEG.

Notes:

[1] PSEG Fossil has a 22.5% interest in the Conemaugh coal-fired units.

[2] PSEG Global has a 4% interest in the Conemaugh Hydroelectric facility.

[3] PSEG Fossil has a 22.84% ownership interest in the Keystone facility.

[4] PSEG Nuclear has a 57.41% interest in the Salem Nuclear facility.

[5] PSEG Fossil has a 50% interest in the Yards Creek facility. Yards Creek is operated by Jersey Central Power & Light, and thus is controlled by JCP&L in the analysis.

[6] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear facility.

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Pivotal Supplier Assessment - ISONE

Row	Description	(MW)	Source
	Applicant and Affiliate Capacity		
[A]	Installed Generation	976	ISONE SCC Report
[B]	Long-term Firm Purchases	0	PSEG
[C]	Long-term Firm Sales	-21	PSEG
[D]	Available Imports	288	Calculated: PSA Calcs
	Non-Affiliate Capacity		
[E]	Installed Generation	30,993	ISONE SCC Report
[F]	Long-term Firm Purchases	21	Calculated: PSA Calcs
[G]	Long-term Firm Sales	0	Calculated: PSA Calcs
[H]	Available Imports	4,260	Calculated
[I]	Balancing authority reserve requirement	-2,000	FERC Form 714
[J]	Applicant reserve requirement	-61	Reserves Workpapers
[K]	Total uncommitted supply	13,600	Sum [A] through [I] plus [M]
	Load		
[L]	Balancing area annual peak load	25,880	Load Workpapers
[M]	Average daily peak native load in peak month	-20,917	Load Workpapers
[N]	Amount in [M] attributable to Applicant	-314	Load Workpapers
[O]	Wholesale Load	4,963	[L] + [M]
[P]	Net Uncommitted Supply	8,637	[K] - [O]
[Q]	Applicant's Uncommitted Capacity	868	Sum [A], [B], [C], [D], [J], [N]
[R]	**PSA Screen Result**	**Pass**	

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Wholesale Market Share Assessment - ISONE

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Source
	Applicant and Affiliate Capacity					
[A]	Installed Generation	1,008	992	976	992	ISONE SCC Report
[B]	Long-term Firm Purchases	0	0	0	0	PSEG
[C]	Long-term Firm Sales	-21	-21	-21	-21	PSEG
[D]	Seasonal Average Planned Outages	-37	-93	-5	-120	See Text
[E]	Available Imports	192	195	235	191	Calculated
	Capacity Deductions					
[F]	Average peak native load in season	-16,267	-14,906	-18,579	-15,421	Load Workpapers
[G]	Amount of [F] attributable to Applicant	-203	-147	-234	-165	Load Workpapers
[H]	Amount of [F] attributable to Others	-16,064	-14,759	-18,345	-15,256	Load Workpapers
[I]	Balancing area reserve requirement	-2,000	-2,000	-2,000	-2,000	See Text
[J]	Amount of [I] attributable to Applicant	-59	-62	-61	-62	See Text
[K]	Amount of [I] attributable to Others	-1,941	-1,938	-1,939	-1,938	Calculated
	Non-Affiliated Capacity					
[L]	Installed Generation	33,400	30,977	30,993	30,977	Generation Workpapers
[M]	Long-term Firm Purchases	21	21	21	21	PSEG
[N]	Long-term Firm Sales	0	0	0	0	PSEG
[O]	Seasonal Average Planned Outages	-1,233	-2,907	-149	-3,732	FERC Form 714
[P]	Available Imports	4,356	4,353	4,313	4,357	Calculated
	Supply Calculation					
[Q]	Total competing supply	18,538	15,747	14,895	14,429	Sum [H], [K], [L], [M], [N], [O], [P]
[R]	Applicant's uncommitted capacity	881	864	890	816	Sum [A], [B], [C], [D], [E], [G], [J]
[S]	Total seasonal uncommitted capacity	19,418	16,611	15,785	15,245	Sum [Q], [R]
[T]	**Applicant's Market Share**	4.5%	5.2%	5.6%	5.4%	= [R] / [S]
[U]	**Results**	**Pass**	**Pass**	**Pass**	**Pass**	

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Pivotal Supplier Assessment - CT

Row	Description	(MW)	Source
	Applicant and Affiliate Capacity		
[A]	Installed Generation	976	ISONE SCC Report
[B]	Long-term Firm Purchases	0	PSEG
[C]	Long-term Firm Sales	-10	PSEG
[D]	Available Imports	56	Calculated: PSA Calcs
	Non-Affiliate Capacity		
[E]	Installed Generation	7,003	ISONE SCC Report
[F]	Long-term Firm Purchases	10	Calculated: PSA Calcs
[G]	Long-term Firm Sales	0	Calculated: PSA Calcs
[H]	Available Imports	2,444	Calculated
[I]	Balancing authority reserve requirement	-765	FERC Form 714
[J]	Applicant reserve requirement	-94	Reserves Workpapers
[K]	Total uncommitted supply	4,289	Sum [A] through [I] plus [M]
	Load		
[L]	Balancing area annual peak load	6,957	Load Workpapers
[M]	Average daily peak native load in peak month	-5,425	Load Workpapers
[N]	Amount in [M] attributable to Applicant	0	Load Workpapers
[O]	Wholesale Load	1,532	[L] + [M]
[P]	Net Uncommitted Supply	2,757	[K] - [O]
[Q]	Applicant's Uncommitted Capacity	928	Sum [A], [B], [C], [D], [J], [N]
[R]	**PSA Screen Result**	**Pass**	

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Wholesale Market Share Assessment - CT

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Source
	Applicant and Affiliate Capacity					
[A]	Installed Generation	1,008	992	976	992	ISONE SCC Report
[B]	Long-term Firm Purchases	0	0	0	0	PSEG
[C]	Long-term Firm Sales	-10	-10	-10	-10	PSEG
[D]	Seasonal Average Planned Outages	-37	-93	-5	-120	See Text
[E]	Available Imports	45	47	50	49	Calculated
	Capacity Deductions					
[F]	Average peak native load in season	-3,966	-3,637	-4,720	-3,790	Load Workpapers
[G]	Amount of [F] attributable to Applicant	0	0	0	0	Load Workpapers
[H]	Amount of [F] attributable to Others	-3,966	-3,637	-4,720	-3,790	Load Workpapers
[I]	Balancing area reserve requirement	-837	-837	-765	-813	See Text
[J]	Amount of [I] attributable to Applicant	-102	-104	-94	-101	See Text
[K]	Amount of [I] attributable to Others	-735	-733	-671	-712	Calculated
	Non-Affiliated Capacity					
[L]	Installed Generation	7,255	6,987	7,003	6,987	Generation Workpapers
[M]	Long-term Firm Purchases	10	10	10	10	PSEG
[N]	Long-term Firm Sales	0	0	0	0	PSEG
[O]	Seasonal Average Planned Outages	-268	-656	-34	-842	FERC Form 714
[P]	Available Imports	2,455	2,453	2,450	2,451	Calculated
	Supply Calculation					
[Q]	Total competing supply	4,751	4,425	4,038	4,104	Sum [H], [K], [L], [M], [N], [O], [P]
[R]	Applicant's uncommitted capacity	904	832	918	810	Sum [A], [B], [C], [D], [E], [G], [J]
[S]	Total seasonal uncommitted capacity	5,655	5,257	4,956	4,914	Sum [Q], [R]
[T]	**Applicant's Market Share**	16.0%	15.8%	18.5%	16.5%	= [R] / [S]
[U]	**Results**	**Pass**	**Pass**	**Pass**	**Pass**	

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Pivotal Supplier Assessment - SWCT

Row	Description	(MW)	Source
	Applicant and Affiliate Capacity		
[A]	Installed Generation	528	ISONE SCC Report
[B]	Long-term Firm Purchases	0	PSEG
[C]	Long-term Firm Sales	0	PSEG
[D]	Available Imports	100	Calculated: PSA Calcs
	Non-Affiliate Capacity		
[E]	Installed Generation	2,270	ISONE SCC Report
[F]	Long-term Firm Purchases	0	Calculated: PSA Calcs
[G]	Long-term Firm Sales	0	Calculated: PSA Calcs
[H]	Available Imports	3,100	Calculated
[I]	Balancing authority reserve requirement	0	FERC Form 714
[J]	Applicant reserve requirement	0	Reserves Workpapers
[K]	Total uncommitted supply	3,311	Sum [A] through [I] plus [M]
	Load		
[L]	Balancing area annual peak load	3,419	Load Workpapers
[M]	Average daily peak native load in peak month	-2,687	Load Workpapers
[N]	Amount in [M] attributable to Applicant	0	Load Workpapers
[O]	Wholesale Load	732	[L] + [M]
[P]	Net Uncommitted Supply	2,579	[K] - [O]
[Q]	Applicant's Uncommitted Capacity	628	Sum [A], [B], [C], [D], [J], [N]
[R]	**PSA Screen Result**	**Pass**	

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Wholesale Market Share Assessment - SWCT

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Source
	Applicant and Affiliate Capacity					
[A]	Installed Generation	553	541	528	541	ISONE SCC Report
[B]	Long-term Firm Purchases	0	0	0	0	PSEG
[C]	Long-term Firm Sales	0	0	0	0	PSEG
[D]	Seasonal Average Planned Outages	-20	-51	-3	-65	See Text
[E]	Available Imports	63	78	91	76	Calculated
	Capacity Deductions					
[F]	Average peak native load in season	-1,927	-1,742	-2,281	-1,800	Load Workpapers
[G]	Amount of [F] attributable to Applicant	0	0	0	0	Load Workpapers
[H]	Amount of [F] attributable to Others	-1,927	-1,742	-2,281	-1,800	Load Workpapers
[I]	Balancing area reserve requirement	-50	-50	0	-33	See Text
[J]	Amount of [I] attributable to Applicant	-9	-10	0	-6	See Text
[K]	Amount of [I] attributable to Others	-41	-40	0	-27	Calculated
	Non-Affiliated Capacity					
[L]	Installed Generation	2,535	2,257	2,270	2,257	Generation Workpapers
[M]	Long-term Firm Purchases	0	0	0	0	PSEG
[N]	Long-term Firm Sales	0	0	0	0	PSEG
[O]	Seasonal Average Planned Outages	-94	-212	-11	-272	FERC Form 714
[P]	Available Imports	2,387	2,822	3,109	2,744	Calculated
	Supply Calculation					
[Q]	Total competing supply	2,860	3,085	3,087	2,902	Sum [H], [K], [L], [M], [N], [O], [P]
[R]	Applicant's uncommitted capacity	587	559	616	545	Sum [A], [B], [C], [D], [E], [G], [J]
[S]	Total seasonal uncommitted capacity	3,447	3,644	3,704	3,447	Sum [Q], [R]
[T]	**Applicant's Market Share**	17.0%	15.3%	16.6%	15.8%	= [R] / [S]
[U]	**Results**	**Pass**	**Pass**	**Pass**	**Pass**	

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Pivotal Supplier Assessment - NYISO

Row	Description	(MW)	Source
	Applicant and Affiliate Capacity		
[A]	Installed Generation	754	PSEG
[B]	Long-term Firm Purchases	250	PSEG
[C]	Long-term Firm Sales	0	PSEG
[D]	Available Imports	1,105	Calculated: PSA Calcs
	Non-Affiliate Capacity		
[E]	Installed Generation	37,739	Energy Velocity
[F]	Long-term Firm Purchases	0	Calculated: PSA Calcs
[G]	Long-term Firm Sales	0	Calculated: PSA Calcs
[H]	Available Imports	6,465	Calculated
[I]	Balancing authority reserve requirement	-1,965	FERC Form 714
[J]	Applicant reserve requirement	-38	Reserves Workpapers
[K]	Total uncommitted supply	17,024	Sum [A] through [I] plus [M]
	Load		
[L]	Balancing area annual peak load	32,439	Load Workpapers
[M]	Average daily peak native load in peak month	-27,324	Load Workpapers
[N]	Amount in [M] attributable to Applicant	0	Load Workpapers
[O]	Wholesale Load	5,116	[L] + [M]
[P]	Net Uncommitted Supply	11,909	[K] - [O]
[Q]	Applicant's Uncommitted Capacity	2,071	Sum [A], [B], [C], [D], [J], [N]
[R]	**PSA Screen Result**	**Pass**	

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Wholesale Market Share Assessment - NYISO

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Source
	Applicant and Affiliate Capacity					
[A]	Installed Generation	845	800	754	800	PSEG
[B]	Long-term Firm Purchases	250	250	250	250	PSEG
[C]	Long-term Firm Sales	0	0	0	0	PSEG
[D]	Seasonal Average Planned Outages	-83	-120	-17	-88	See Text
[E]	Available Imports	390	374	433	428	Calculated
	Capacity Deductions					
[F]	Average peak native load in season	-20,039	-18,956	-24,247	-19,462	Load Workpapers
[G]	Amount of [F] attributable to Applicant	0	0	0	0	Load Workpapers
[H]	Amount of [F] attributable to Others	-20,039	-18,956	-24,247	-19,462	Load Workpapers
[I]	Balancing area reserve requirement	-1,965	-1,965	-1,965	-1,965	See Text
[J]	Amount of [I] attributable to Applicant	-41	-40	-38	-40	See Text
[K]	Amount of [I] attributable to Others	-1,924	-1,925	-1,927	-1,925	Calculated
	Non-Affiliated Capacity					
[L]	Installed Generation	39,981	38,860	37,739	38,860	Generation Workpapers
[M]	Long-term Firm Purchases	0	0	0	0	PSEG
[N]	Long-term Firm Sales	0	0	0	0	PSEG
[O]	Seasonal Average Planned Outages	-3,927	-5,828	-868	-4,296	FERC Form 714
[P]	Available Imports	7,459	6,736	7,137	7,452	Calculated
	Supply Calculation					
[Q]	Total competing supply	21,549	18,886	17,834	20,628	Sum [H], [K], [L], [M], [N], [O], [P]
[R]	Applicant's uncommitted capacity	1,361	1,264	1,381	1,350	Sum [A], [B], [C], [D], [E], [G], [J]
[S]	Total seasonal uncommitted capacity	22,910	20,150	19,215	21,978	Sum [Q], [R]
[T]	**Applicant's Market Share**	5.9%	6.3%	7.2%	6.1%	= [R] / [S]
[U]	**Results**	**Pass**	**Pass**	**Pass**	**Pass**	

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Pivotal Supplier Assessment - PJM

Row	Description	(MW)	Source
	Applicant and Affiliate Capacity		
[A]	Installed Generation	11,350	PSEG
[B]	Long-term Firm Purchases	13	PSEG
[C]	Long-term Firm Sales	-2,120	PSEG
[D]	Available Imports	124	Calculated: PSA Calcs
	Non-Affiliate Capacity		
[E]	Installed Generation	182,128	Energy Velocity
[F]	Long-term Firm Purchases	2,120	Calculated: PSA Calcs
[G]	Long-term Firm Sales	-13	Calculated: PSA Calcs
[H]	Available Imports	8,310	Calculated
[I]	Balancing authority reserve requirement	-12,510	FERC Form 714
[J]	Applicant reserve requirement	-734	Reserves Workpapers
[K]	Total uncommitted supply	55,837	Sum [A] through [I] plus [M]
	Load		
[L]	Balancing area annual peak load	154,339	Load Workpapers
[M]	Average daily peak native load in peak month	-133,565	Load Workpapers
[N]	Amount in [M] attributable to Applicant	-3,147	Load Workpapers
[O]	Wholesale Load	20,774	[L] + [M]
[P]	Net Uncommitted Supply	35,063	[K] - [O]
[Q]	Applicant's Uncommitted Capacity	5,486	Sum [A], [B], [C], [D], [J], [N]
[R]	**PSA Screen Result**	**Pass**	

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Wholesale Market Share Assessment - PJM

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Source
	Applicant and Affiliate Capacity					
[A]	Installed Generation	11,072	11,211	11,350	11,211	PSEG
[B]	Long-term Firm Purchases	10	10	13	13	PSEG
[C]	Long-term Firm Sales	-2,020	-2,020	-2,120	-2,120	PSEG
[D]	Seasonal Average Planned Outages	-577	-1,597	-98	-1,053	See Text
[E]	Available Imports	102	53	101	67	Calculated
	Capacity Deductions					
[F]	Average peak native load in season	-64,797	-59,065	-76,078	-60,754	Load Workpapers
[G]	Amount of [F] attributable to Applicant	-2,023	-1,705	-2,413	-1,551	Load Workpapers
[H]	Amount of [F] attributable to Others	-62,775	-57,360	-73,665	-59,204	Load Workpapers
[I]	Balancing area reserve requirement	-10,044	-9,853	-12,170	-9,859	See Text
[J]	Amount of [I] attributable to Applicant	-550	-559	-714	-559	See Text
[K]	Amount of [I] attributable to Others	-9,494	-9,295	-11,456	-9,300	Calculated
	Non-Affiliated Capacity					
[L]	Installed Generation	191,003	186,566	182,128	186,566	Generation Workpapers
[M]	Long-term Firm Purchases	2,020	2,020	2,120	2,120	PSEG
[N]	Long-term Firm Sales	-10	-10	-13	-13	PSEG
[O]	Seasonal Average Planned Outages	-9,962	-26,571	-1,580	-17,520	FERC Form 714
[P]	Available Imports	10,092	5,589	8,333	6,962	Calculated
	Supply Calculation					
[Q]	Total competing supply	120,875	100,939	105,867	109,611	Sum [H], [K], [L], [M], [N], [O], [P]
[R]	Applicant's uncommitted capacity	6,013	5,393	6,118	6,008	Sum [A], [B], [C], [D], [E], [G], [J]
[S]	Total seasonal uncommitted capacity	126,888	106,332	111,985	115,619	Sum [Q], [R]
[T]	**Applicant's Market Share**	4.7%	5.1%	5.5%	5.2%	= [R] / [S]
[U]	**Results**	**Pass**	**Pass**	**Pass**	**Pass**	

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Pivotal Supplier Assessment - PJME

Row	Description	(MW)	Source
	Applicant and Affiliate Capacity		
[A]	Installed Generation	9,440	PSEG
[B]	Long-term Firm Purchases	13	PSEG
[C]	Long-term Firm Sales	0	PSEG
[D]	Available Imports	110	Calculated: PSA Calcs
	Non-Affiliate Capacity		
[E]	Installed Generation	25,407	Energy Velocity
[F]	Long-term Firm Purchases	0	Calculated: PSA Calcs
[G]	Long-term Firm Sales	-13	Calculated: PSA Calcs
[H]	Available Imports	6,883	Calculated
[I]	Balancing authority reserve requirement	-2,551	FERC Form 714
[J]	Applicant reserve requirement	-610	Reserves Workpapers
[K]	Total uncommitted supply	13,229	Sum [A] through [I] plus [M]
	Load		
[L]	Balancing area annual peak load	32,542	Load Workpapers
[M]	Average daily peak native load in peak month	-26,061	Load Workpapers
[N]	Amount in [M] attributable to Applicant	-3,147	Load Workpapers
[O]	Wholesale Load	6,481	[L] + [M]
[P]	Net Uncommitted Supply	6,747	[K] - [O]
[Q]	Applicant's Uncommitted Capacity	5,805	Sum [A], [B], [C], [D], [J], [N]
[R]	**PSA Screen Result**	**Pass**	

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Wholesale Market Share Assessment - PJME

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Source
	Applicant and Affiliate Capacity					
[A]	Installed Generation	9,162	9,301	9,440	9,301	PSEG
[B]	Long-term Firm Purchases	10	10	13	13	PSEG
[C]	Long-term Firm Sales	0	0	0	0	PSEG
[D]	Seasonal Average Planned Outages	-478	-1,325	-82	-873	See Text
[E]	Available Imports	106	69	104	120	Calculated
	Capacity Deductions					
[F]	Average peak native load in season	-16,787	-15,583	-21,699	-16,078	Load Workpapers
[G]	Amount of [F] attributable to Applicant	-2,023	-1,705	-2,413	-1,551	Load Workpapers
[H]	Amount of [F] attributable to Others	-14,764	-13,878	-19,286	-14,528	Load Workpapers
[I]	Balancing area reserve requirement	-1,770	-1,880	-2,441	-1,872	See Text
[J]	Amount of [I] attributable to Applicant	-455	-463	-594	-464	See Text
[K]	Amount of [I] attributable to Others	-1,314	-1,417	-1,848	-1,408	Calculated
	Non-Affiliated Capacity					
[L]	Installed Generation	27,384	26,396	25,407	26,396	Generation Workpapers
[M]	Long-term Firm Purchases	0	0	0	0	PSEG
[N]	Long-term Firm Sales	-10	-10	-13	-13	PSEG
[O]	Seasonal Average Planned Outages	-1,428	-3,759	-220	-2,479	FERC Form 714
[P]	Available Imports	7,161	4,501	6,889	8,248	Calculated
	Supply Calculation					
[Q]	Total competing supply	17,029	11,833	10,929	16,216	Sum [H], [K], [L], [M], [N], [O], [P]
[R]	Applicant's uncommitted capacity	6,322	5,886	6,468	6,546	Sum [A], [B], [C], [D], [E], [G], [J]
[S]	Total seasonal uncommitted capacity	23,351	17,720	17,397	22,762	Sum [Q], [R]
[T]	**Applicant's Market Share**	27.1%	33.2%	37.2%	28.8%	= [R] / [S]
[U]	**Results**	**Fail**	**Fail**	**Fail**	**Fail**	

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Pivotal Supplier Assessment - PJM50

Row	Description	(MW)	Source
	Applicant and Affiliate Capacity		
[A]	Installed Generation	10,562	PSEG
[B]	Long-term Firm Purchases	13	PSEG
[C]	Long-term Firm Sales	-2,120	PSEG
[D]	Available Imports	86	Calculated: PSA Calcs
	Non-Affiliate Capacity		
[E]	Installed Generation	49,433	Energy Velocity
[F]	Long-term Firm Purchases	2,120	Calculated: PSA Calcs
[G]	Long-term Firm Sales	-13	Calculated: PSA Calcs
[H]	Available Imports	7,870	Calculated
[I]	Balancing authority reserve requirement	-4,400	FERC Form 714
[J]	Applicant reserve requirement	-320	Reserves Workpapers
[K]	Total uncommitted supply	17,404	Sum [A] through [I] plus [M]
	Load		
[L]	Balancing area annual peak load	56,172	Load Workpapers
[M]	Average daily peak native load in peak month	-46,146	Load Workpapers
[N]	Amount in [M] attributable to Applicant	-3,147	Load Workpapers
[O]	Wholesale Load	10,025	[L] + [M]
[P]	Net Uncommitted Supply	7,379	[K] - [O]
[Q]	Applicant's Uncommitted Capacity	5,074	Sum [A], [B], [C], [D], [J], [N]
[R]	**PSA Screen Result**	**Pass**	

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Wholesale Market Share Assessment - PJM50

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Source
	Applicant and Affiliate Capacity					
[A]	Installed Generation	10,284	10,423	10,562	10,423	PSEG
[B]	Long-term Firm Purchases	10	10	13	13	PSEG
[C]	Long-term Firm Sales	-2,020	-2,020	-2,120	-2,120	PSEG
[D]	Seasonal Average Planned Outages	-565	-1,574	-97	-1,037	See Text
[E]	Available Imports	90	58	84	84	Calculated
	Capacity Deductions					
[F]	Average peak native load in season	-32,138	-29,308	-39,213	-30,175	Load Workpapers
[G]	Amount of [F] attributable to Applicant	-2,023	-1,705	-2,413	-1,551	Load Workpapers
[H]	Amount of [F] attributable to Others	-30,115	-27,603	-36,800	-28,624	Load Workpapers
[I]	Balancing area reserve requirement	-3,293	-3,383	-4,227	-3,359	See Text
[J]	Amount of [I] attributable to Applicant	-298	-310	-320	-309	See Text
[K]	Amount of [I] attributable to Others	-2,996	-3,074	-3,908	-3,049	Calculated
	Non-Affiliated Capacity					
[L]	Installed Generation	52,755	51,094	49,433	51,094	Generation Workpapers
[M]	Long-term Firm Purchases	2,020	2,020	2,120	2,120	PSEG
[N]	Long-term Firm Sales	-10	-10	-13	-13	PSEG
[O]	Seasonal Average Planned Outages	-2,723	-7,187	-424	-4,740	FERC Form 714
[P]	Available Imports	8,779	5,459	7,872	7,987	Calculated
	Supply Calculation					
[Q]	Total competing supply	27,711	20,700	18,281	24,775	Sum [H], [K], [L], [M], [N], [O], [P]
[R]	Applicant's uncommitted capacity	5,478	4,882	5,709	5,502	Sum [A], [B], [C], [D], [E], [G], [J]
[S]	Total seasonal uncommitted capacity	33,189	25,581	23,990	30,278	Sum [Q], [R]
[T]	**Applicant's Market Share**	16.5%	19.1%	23.8%	18.2%	= [R] / [S]
[U]	**Results**	**Pass**	**Pass**	**Fail**	**Pass**	

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Pivotal Supplier Assessment - PJMAP

Row	Description	(MW)	Source
	Applicant and Affiliate Capacity		
[A]	Installed Generation	10,562	PSEG
[B]	Long-term Firm Purchases	13	PSEG
[C]	Long-term Firm Sales	-2,120	PSEG
[D]	Available Imports	96	Calculated: PSA Calcs
	Non-Affiliate Capacity		
[E]	Installed Generation	71,636	Energy Velocity
[F]	Long-term Firm Purchases	2,120	Calculated: PSA Calcs
[G]	Long-term Firm Sales	-13	Calculated: PSA Calcs
[H]	Available Imports	7,393	Calculated
[I]	Balancing authority reserve requirement	-5,911	FERC Form 714
[J]	Applicant reserve requirement	-320	Reserves Workpapers
[K]	Total uncommitted supply	21,023	Sum [A] through [I] plus [M]
	Load		
[L]	Balancing area annual peak load	75,082	Load Workpapers
[M]	Average daily peak native load in peak month	-62,753	Load Workpapers
[N]	Amount in [M] attributable to Applicant	-3,147	Load Workpapers
[O]	Wholesale Load	12,329	[L] + [M]
[P]	Net Uncommitted Supply	8,694	[K] - [O]
[Q]	Applicant's Uncommitted Capacity	5,084	Sum [A], [B], [C], [D], [J], [N]
[R]	**PSA Screen Result**	**Pass**	

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Wholesale Market Share Assessment - PJMAP

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Source
	Applicant and Affiliate Capacity					
[A]	Installed Generation	10,284	10,423	10,562	10,423	PSEG
[B]	Long-term Firm Purchases	10	10	13	13	PSEG
[C]	Long-term Firm Sales	-2,020	-2,020	-2,120	-2,120	PSEG
[D]	Seasonal Average Planned Outages	-565	-1,574	-97	-1,037	See Text
[E]	Available Imports	59	52	93	97	Calculated
	Capacity Deductions					
[F]	Average peak native load in season	-43,409	-39,676	-53,132	-41,102	Load Workpapers
[G]	Amount of [F] attributable to Applicant	-2,023	-1,705	-2,413	-1,551	Load Workpapers
[H]	Amount of [F] attributable to Others	-41,386	-37,970	-50,719	-39,552	Load Workpapers
[I]	Balancing area reserve requirement	-4,570	-4,608	-5,710	-4,574	See Text
[J]	Amount of [I] attributable to Applicant	-298	-310	-320	-309	See Text
[K]	Amount of [I] attributable to Others	-4,272	-4,298	-5,390	-4,264	Calculated
	Non-Affiliated Capacity					
[L]	Installed Generation	76,274	73,955	71,636	73,955	Generation Workpapers
[M]	Long-term Firm Purchases	2,020	2,020	2,120	2,120	PSEG
[N]	Long-term Firm Sales	-10	-10	-13	-13	PSEG
[O]	Seasonal Average Planned Outages	-3,949	-10,443	-616	-6,887	FERC Form 714
[P]	Available Imports	4,829	4,294	7,396	7,871	Calculated
	Supply Calculation					
[Q]	Total competing supply	33,506	27,547	24,413	33,231	Sum [H], [K], [L], [M], [N], [O], [P]
[R]	Applicant's uncommitted capacity	5,447	4,876	5,718	5,515	Sum [A], [B], [C], [D], [E], [G], [J]
[S]	Total seasonal uncommitted capacity	38,953	32,423	30,132	38,746	Sum [Q], [R]
[T]	**Applicant's Market Share**	14.0%	15.0%	19.0%	14.2%	= [R] / [S]
[U]	**Results**	**Pass**	**Pass**	**Pass**	**Pass**	

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DATA AND ASSUMPTIONS FOR ECONOMISTS INCORPORATED'S DELIVERED PRICE TEST STUDY FOR PSEG

This exhibit describes data and assumptions used in the delivered price test study ("study") carried out by Economists Incorporated for PSEG. Because the data are voluminous, we provide them in electronic workpapers. In those workpapers, the Files.xlsx spreadsheet provides a brief description of the organization of the data files.

This Exhibit has six sections. Section I discusses the study's representative periods. Section II discusses the geographic region and balancing authority areas. Section III discusses generation resources, including adjustments to generating capacity for seasons, maintenance, water availability, and long-term contracts. Section IV discusses transmission, including transmission pricing and losses. Section V discusses market prices. Section VI discusses the load data.

I. Periods

The study calculates market shares and concentration indexes for electric energy for ten representative periods during the year. The year is divided into three seasons (spring/fall, summer and winter). Spring/fall and winter seasons are divided into three periods based on days of the week, times of day and load levels. Summer is divided into four periods based on days of the week, times of day and load levels. Each calculation of market shares and concentration indexes reflects average conditions (e.g., average loads) during one of the resulting ten periods during the year (e.g., Summer Low Peak).

The study places each of the periods in each season into three condition categories: off-peak, low peak, and spike. Transmission pricing (see Section

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IV.B below) and plant availability (see Section III.A.2 below) vary among these three categories.

Table I-1 summarizes the ten periods for the destination markets.

Table I-1– Definition of Ten Periods for Destination Market

Number	*Season*	*Time*	*Condition*	*Hours*	*Description**
1	Spring/Fall	Top 10%	Spike	102	Top 5% of peak hours
2	Spring/Fall	Low Peak	Low Peak	1727	Remaining peak hours
3	Spring/Fall	Off-peak	Off-Peak	2360	Off-peak hours
4	Summer	Top 1%	Spike	10	Top 10% of peak hours
5	Summer	Top 10%	Spike	102	Next 10% of peak hours
6	Summer	Low Peak	Low Peak	871	Remaining peak hours
7	Summer	Off-peak	Off-Peak	1184	Off-peak hours
8	Winter	Top 10%	Spike	102	Next 10% of peak hours
9	Winter	Low Peak	Low Peak	871	Remaining peak hours
10	Winter	Off-peak	Off-Peak	1136	Off-peak Hours

Note: *Peak hours include hours ending 7 a.m. through 10 p.m. Central Time weekdays, excluding six major holidays. Off-peak hours = Hours ending 11 p.m. through 6 a.m. on weekdays and all weekend and holiday hours.

The Off-peak periods are all NERC holidays and weekend hours plus weekdays from the hour ending at midnight EPT until the hour ending at 0700.[1] The Off-peak periods have off-peak transmission pricing and plant availability.

In order to define the Top 1% and Top 10% periods for a given season, we removed all Off-peak hours from that season. We then ranked the remaining (peak) hours based on load levels in the destination market by season. We then defined as the Top 1% as the 1 percent of these remaining hours in which loads in the destination market were highest and the Top 10% as the highest 10 percent of peak hours based on load levels. These periods have spike transmission pricing and plant availability.

[1] Major holidays are New Year's, Memorial Day, 4th of July, Labor Day, Thanksgiving and Christmas. Major holidays are included in the Weekend period.

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The Low Peak periods are weekdays from the hour ending at 0800 until the hour ending at 2300 EPT, excluding hours in the Top 10% periods and major holidays. The Low Peak period has on-peak transmission pricing and plant availability.

It is important to divide the year initially into three seasons to avoid aggregating across hours in which the suppliers in the market that have available economic capacity (e.g., summer peaking vs. winter peaking utilities) are different. In addition, the division of the year into three seasons makes it possible to take into account seasonal differences in generation availability, contracts, transmission pricing, and transfer capability.

II. Geographic Coverage and Market Areas

The study includes market areas that correspond to the balancing authority areas used by the North American Electric Reliability Council (NERC), and PJM submarkets as defined by FERC. Table II-1 lists these market areas and their abbreviations. There are two study destination markets, PJM East and PJM East of 5004/5005.

Table II-1– List of Eastern Market Areas and Study Destinations

Abbreviation	*Full Name*	*Study Destination*
PJME	PJM East	Yes
PJMC	PJM East of 5004/5005	Yes
PJMS	PJM East of AP South	
PJM	PJM	
NYISO	New York ISO	
DUK	Duke Energy Carolinas	
CPLE	Carolina Power & Light East	
CPLW	Carolina Power & Light West	
LGEE	Louisville Gas & Electric	
OVEC	Ohio Valley Electric Corp.	
TVA	Tennessee Valley Authority	
EKPC	Eastern Kentucky Power Cooperative	

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III. Generation

A. Generation Capacity and Ownership

The study includes generating units located in the areas that are (1) connected to the power grid, (2) not exclusively used for self-generation, and (3) either in a plant used primarily for electric generation or a Qualifying Facility.

1. Generating Unit Data

The study uses data for summer and winter capability at the unit level reported in the Energy Velocity (EV) database available from Ventyx. The units include all units with a status of operating, standby, cold standby, restart, mothballed, testing, or under construction that will be online before November 30, 2012 and a retirement date after November 30, 2012. We exclude generation units that are less than 5 MW unless they are owned by PSEG.

2. Ownership

The study uses relies on Ventyx determination of plant and ownership. When Ventyx reports a holding company, the ownership is assigned to the holding company. For PSEG generation, the study relies upon Appendix B data from market-based rate filings and updates from the companies to determine plant ownership and seasonal capability. Operational control of PSEG units is consistent with the methodology used for market-based rates.

3. Seasonal variation in capability

The study uses seasonal capability data from EV. Spring/fall capacities are the average of summer and winter capacities.

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4. Adjustments to Generating Capability

The generating capability figures used for each period are obtained by multiplying the seasonal capabilities by an availability factor, which is based on the period, unit location, and NERC General Availability Data Systems (GADS) category of the unit. The GADS database gives national average operating information for generating units by unit type and size. For example, it gives data for coal-fired steam units with capacities between 300 MW and 399 MW.

For each period and each generating unit, the availability factor adjusts for the following.

a) Unplanned outage rates by GADS category

For a given GADS category, the study assumes that unplanned (forced) outage rates (as a share of generating capability available after allowing for planned outages) are constant across seasons and generating units throughout the Region, regardless of owner. Based on GADS data for 2007 through 2011, which are the most recent data in the EV database, the study calculates an equivalent forced outage rate (EIFOR), which measures the share of generating capability in a GADS category that is not available because of forced outages. The computation is EIFOR = (FOH)/AH, where FOH is number of forced outage hours and AH is total hours available for generation after planned outages (but before forced outages).[2]

b) Planned outage rates by GADS category and season

With four exceptions (hydro, pumped storage, wind, and solar units), the study assumes that the planned outage rate is constant for all generating units for a

[2] EIFOR differs slightly from the EFOR provided in the GADS data. EIFOR provides a better measure of a forced outage rate for peaking units that are operated a small percentage of the year.

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given GADS category and season. For a given GADS category, the share of hours of generating capability that is not available as a result of planned outages is computed as (POH + POEH)/PH; where PH are the period hours, POH are the hours not available because of planned outages, and POEH are the hours not available because of planned outage extensions

The study assumes that balancing authority areas are both summer and winter peaking. Therefore, the study assumes that all planned outages for thermal units occur during spring/fall.

c) Variation in hydro availability across seasons and periods

In general, utilities use hydro facilities to generate energy during the hours when energy prices are highest, subject to constraints imposed by availability of water and reservoir capacity. In order to incorporate these constraints, the study proceeds in the following manner.

First, the study uses EIA Form 923 monthly production data for the period 2011 to 2012 to compute average hourly hydro generation by season. Average hourly generation is then divided by hydro capability to give an average hourly hydro operating rate by season.

Second, depending upon the level of the hydro operating rate for a given season, the study calculates availability factors for the spike, low peak and off-peak periods. When the historical seasonal operating rate is below 30 percent, the availability factor for each period in the season is set equal to the operating rate; the 30 percent figure is an assumed "run of river" constraint. The study assumes that prospectively the maximum operating rate is 90 percent; this is the assumed "maximum rate" constraint. When the historical seasonal operating rate is above 90 percent, the availability factor for each period is set to 90 percent.

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When the seasonal operating rate is above the run of river constraint and below the maximum rate, we reason that the hydro generator owner would be likely to produce a higher level of energy during spike hours, when energy prices are highest, than during low peak hours, and that the owner would be likely to produce a higher level during low peak than during off-peak hours.

Based on this reasoning, when the seasonal operating rate is between the run of river constraint and the maximum rate, as is the case for each of the three seasons, the study uses a spike availability factor of 90 percent, which is the assumed maximum operating rate, and off-peak availability factor of 30 percent, which is the assumed run-of-river constraint, and a calculated availability factor for the low peak periods, as described below.

The seasonal low peak availability factor is calculated with actual total seasonal hydro generation. The study then computes the hydro generation during all spike and off-peak hours, assuming the generation rates implied by the spike and off-peak derate factors computed in the manner described above. The study then calculates total low peak hydro generation as the difference between total seasonal hydro generation and the sum of hydro generation during all spike and off-peak hours. The seasonal low peak availability factor is computed as total low peak hydro generation divided first by the number of hours in the off-peak period and then by hydro generating capacity.

d) Variation in pumped storage availability across seasons and periods

We assume that pumped storage units have 90 percent availability during Top 1% and Top 10% periods, 50 percent availability during Low Peak periods, and no availability during off-peak periods.

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e) Wind availability

For each area-owner combination, we calculate average operating rates in 2011 and 2012 by season from EIA-923 data. The average operating rates are the availability factors. When operating rates are not available for an owner in an area, we use the average operating rate for that area.

f) Solar availability

Availability for solar power is also calculated based on average operating rates for 2011 and 2012 reported in EIA-923. There is little solar power during off-peak periods because of darkness. Accordingly, solar availability is weighted to on-peak periods.

B. Variable Costs of Generation

The study uses variable costs of generation that include fuel costs, sulfur dioxide and nitrogen oxide emissions costs, and variable operations and maintenance (VOM) costs. The study calculates fuel costs from unit heat rates and Platts' Gas Daily spot prices at the unit's reported natural gas hub by Energy Velocity, #2 Diesel, Low-Sulfur – Industrial for the East Coast, and Residual Fuel Oil sales to end users for the East Coast for the years 2011-2012. Natural gas prices vary by hub, but were $3.78 per mmBtu at TETCO M3, the hub with the largest reported capacity in the study. The prices for oil units are as follows: #2 fuel oil $20.43 per mmBtu, and residual fuel oil $14.47 per mmBtu. Fuel costs for other fuels are based upon the average fuel costs reported in the EV data for each fuel type. Emissions prices for 2011-2012 are $0.75 per ton for SO2 year-round and $39 per ton for NOx in the summer season. CO_2 costs for units located in Regional Greenhouse Gas Initiative (RGGI) states are $1.93/ton, which is based upon RGGI Auction results in 2012. Units in Montgomery County, MD have an

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additional $5/ton carbon tax on CO_2 emissions. VOM costs are from the EV database.

C. Long-term Contracts

We reviewed Appendix B data from market-based rate filings and FERC Form 1 filings to obtain data on long-term contracts. Where the market-based rate filing indicates a change of operational control, we include a contract transferring control to the buyer. We leave the generation unit in the BAA where it is physically interconnected to the transmission system. When the buyer is a load-serving entity in another BAA, we give a priority firm transmission path to the BAA with the load.

Long-term contracts that expire prior to December 1, 2011 are not included in the study. Long-term contracts that expire between December 1, 2011 and August 31, 2012 are included only in the seasons for which they are in effect. Contracts that expire after September 1, 2012 are included in the study.

IV. Transmission

A. Transmission Network

The study incorporates a contract path transmission network for modeling purposes. Transmission pricing between balancing authority areas is represented by a traditional contract path transmission network in which the direct physical connections between balancing authority areas are also the individually priced links from which contract paths are constructed.

B. Transmission and Ancillary Services Pricing and Losses

As specified by the Commission's Appendix A, the study generally uses ceiling prices for transmission service from Schedules 1, 2 and 8 of the utility's *pro*

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forma open-access transmission tariff. Transmission providers may require transmission customers to purchase ancillary services under Schedule 1 (scheduling, system control and dispatch) and Schedule 2 (reactive supply and voltage control). Schedule 8 gives the rates for non-firm point-to-point transmission service. The study uses transmission prices from tariffs.

When we have tariffs available, we calculate rates for off-peak, peak and spike categories. Because of discounting and the nature of baseload purchases, off-peak rates are often lower than peak rates.[3] We use two steps to determine off-peak rates. Step 1: When a utility posts off-peak hourly rates, we use the posted rates. Step 2: When a utility does not post off-peak hourly rates, we calculate an hourly off-peak rate based on other tariff information. To calculate hourly off-peak rates, we divide the weekly rate by 168, the number of hours in a week. When tariffs specify fees on a per transaction basis, we divide them by 25 to put them on a per MW basis.

We use similar steps to determine peak rates. Step 1: When a utility posts maximum hourly rates in its tariff, we use the maximum tariff rates. Step 2: When a utility does not post off-peak hourly rates, we calculate a peak rate based on other tariff information. To calculate hourly peak rates, we divide the weekly rate by 80—the "Appalachian" method. When tariffs specify fees on a per transaction basis, we divide them by 25 to put them on a per MW basis.

For spike periods, we use ceiling hourly rates from tariffs, when available. Otherwise, we use the Appalachian method.

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[3] For transactions longer than one hour, the *pro forma* tariff caps the amount that the purchaser pays per day by the daily rate, and the amount that the purchaser pays per week by the weekly rate.

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Whenever practical, the study uses loss rates from tariffs. When these methods did not provide a loss rate for a particular utility, the study assumes that losses are three percent per utility.[4] The study assumes that transmission customers pay losses in-kind. That is, if area A exports 100 MW to area B and the losses are 3 percent, only 97 MW arrive at area B.

For areas where tariffs are not available, rates and losses are the average by period for all the reporting areas.

C. Transfer Capability and SILs

The geographic market includes only PJM and first tier BAAs. Per the recent *NRG/GenOn* order, transmission into a destination market from first tier areas is to be limited only by the simultaneous import limit ("SIL").[5] Accordingly, the transfer capability from each first tier area to the destination market is set to 99,999 MW. The SIL for PJM East and PJM East of 5004/5005 comes from the 2012 Simultaneous Import Limit Study Report filed by PJM on October 1, 2013.[6] The total imports into the destination markets may be less than the actual ability to import into the destination because not all the generation capability owned or controlled by load-serving entities within the destination markets studied in PJM have been identified in the data.

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[4] Losses of 3 percent are representative of the industry. See, FERC Open Access NOPR, *FERC Stats & Regs*, ¶32,514 at 33,150 (1995).

[5] *See*, NRG Energy, Inc. and GenOn Energy, Inc., 114 FERC ¶61,207, P 63, note 112 (2012).

[6] PJM, 2012 Simultaneous Import Study Report, *Guidance on Simultaneous Import Limit Studies*, Docket No. AD10-2-002, October 1, 2013, at 3.

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V. Market Prices

The study used December 2011-November 2012 real-time hourly prices from the RTO LMP for PJM East and PJM East of 5004/5005. Table V-1 shows the PJM East of 5004/5005 market prices in each of the ten periods, and Table V-2 shows the PJM East market prices.

Table V-1 – PJM East of 5004/5005 Market Prices ($/MWh)

Time	*Spring/Fall*	*Summer*	*Winter*
Top 1%	-----	$181.98	-----
Top 10%	$66.65	$107.58	$60.87
Low Peak	$38.72	$42.40	$34.68
Off-Peak	$28.24	$28.32	$30.46

Table V-2 – PJM East Market Prices ($/MWh)

Time	*Spring/Fall*	*Summer*	*Winter*
Top 1%	-----	$188.24	-----
Top 10%	$66.52	$109.22	$61.53
Low Peak	$37.36	$42.17	$34.72
Off-Peak	$27.77	$28.67	$29.97

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VI. Load and Contract Obligations for AEC Calculations

Load data come from PJM for PJM and from Energy Velocity for the other supply areas.

To compute load requirements for market participants in New York and PJM, we apportion the total load in each market area in New York and PJM to all suppliers in proportion to their respective generation capacities. We assumed 70 percent of load is committed for a year or longer and the remaining 30 percent is contracted for shorter periods.[7] To account for their greater load obligations, we assume that Dominion has 100 percent responsibility for its allocation of load and that AEP has 90 percent of its allocation as opposed to the standard 70 percent. Utilities south of PJM have traditional load obligations and have 100 percent load responsibility for their respective planning area loads. Small utilities for which have not load data available were not imputed a share of PJM or NYISO load were assumed to have no AEC.

[7] This is a reasonable estimate for the long-term load coverage since this number is generally between 60 and 80 percent for most generation suppliers.

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Technical Appendix:

Methods Used to Compute Concentration

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This Exhibit describes the methods used to calculate market shares and concentration in destination markets.

Allocation of scarce transmission capability is accomplished using linear and nonlinear programs that model generation dispatch and the contract path transmission system. This Exhibit provides an overview of the structure of the programs and presents the equations.

Overview of Linear Program

The linear program models control areas as nodes in a transmission system. Each node has a demand for and a supply of electric energy. The supply is based on the generators at the node and potential deliveries to the node via transmission links from other control areas. The linear program allows for net import and export limits to and from an individual control area. Given generation capability and costs and transmission capability and costs, the linear program finds the least-cost solution that satisfies the specified loads. Costs are defined as dispatch (generation) costs plus transmission costs including losses plus the default cost for "unserved" load. For each solution, the linear program determines the quantities produced in, exported from, and imported into each control area.

The Mathematical Equations

The linear program to be solved is given below:

Minimize Total Cost: $Cost = GC + TC + UC$

Subject to:

(1) Generation: $TG_a = \sum_{u}^{u \in a} G_{a,u}$ for each area *a*;

(2) Imports: $YI_a = \sum_{b}^{a,b \in network} (1 - h_{b,a}) T_{b,a}$ for each area *a*;

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(3)	Exports:	$YE_a = \sum_{b}^{a,b \in network} T_{a,b}$	for each area *a*;
(4)	Net Imports:	$Y_a = YI_a - YE_a$	for each area *a*;
(5)	Supply/Demand Balance:	$TG_a + Y_a + U_a = D_a$	for each area *a*;
(6)	Generation Cost:	$GC = \sum_{a} \sum_{u}^{u \in a} d_{a,u} G_{a,u}$	for each area *a*;
(7)	Transmission Cost:	$TC = \sum_{a,b}^{a,b \in network} r_{a,b} T_{a,b}$	for each path *a* to *b*;
(8)	Unfilled Demand Cost:	$UC = \sum_{a} pU_a$	for each area *a*;
(9)	Generation Limits:	$g\min_{a,u} \le G_{a,u} \le g\max_{a,u}$	for each unit *u* in each area *a*;
(10)	Transmission Limits:	$t\min_{a,b} \le T_{a,b} \le t\max_{a,b}$	for each link *a* to *b* in the transmission network; and
(11)	Net Import Limits	$Y\min_{a} \le Y_a \le Y\max_{a}$	for each area *a*;

where:

a,b	are subscripts for control/transmission areas;
Cost	is total system cost;
$d_{a,u}$	is the dispatch cost of unit *u* in area *a*;
D_a	is demand for power in area *a*;
$G_{a,u}$	is generation output of unit *u* in area *a*;
GC	is total system generation cost;
$G\max_{a,u}$	is the maximum output of unit *u* in area *a*;
$G\min_{a,u}$	is the minimum output of unit *u* in area *a*;
$h_{b,a}$	is the fraction of power lost to resistance from moving power from area *b* to area *a*;
N	is a subscript to identify simultaneous transmission constraint *n*;
P	is the default price;
$r_{a,b}$	is the transmission rate from area *a* to area *b*;

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$T_{a,b}$	is the power flow from area *a* to area *b*;
TC	is total system transportation expenses;
TG_a	is total generation output in area *a*;
$t\max_{a,b}$	is the maximum power flow from area *a* to area *b*;
$t\min_{a,b}$	is the minimum power flow from area *a* to area *b*;
U	is a subscript to identify units in an area;
U_a	is the amount of demand in area *a* not met by generation or imports
UC	is total system cost of not meeting demand;
Y_a	is net imports into area *a*;
YE_a	is total exports from area *a*; and
YI_a	is total imports into area *a*;
$Y\min_a$	is minimum net imports in area *a;*
$Y\max_a$	is maximum net imports in area *a.*

This linear program is solved using the BDMLP solver in GAMS. In order to calculate concentration for different destinations, seasons, and periods, the PASS GAMS program loops through the destinations, seasons, and periods with calls to Solvers to solve the linear programs. Loads, unit availability and transmission availability are adjusted for each season-period combination.

Calculating Concentration

Transmission allocation is accomplished in four steps. In the first step the linear program finds the net-back prices in all control areas given a price at the destination control area equal to 105 percent of the pre-merger price. Suppose the pre-merger price at the destination, control area A, is $20/MWh. Then all generation capability with a dispatch cost of $21/MWh or less in the destination area would be included in the market because $21 is 105 percent of $20. If transmission cost (including losses) is $5/MWh from control area B to A, then the net-back price at B would be $16/MWh, which is the $21/MWh less the $5/MWh transmission cost between B and A. Then, all generation capability at B with dispatch costs equal to or less than $16/MWh would be included in the market if there were no transmission constraints. Calculation of net-back prices is

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accomplished by setting the default price, *p*, equal to 105 percent of the pre-merger price at the destination, setting load at the destination to a high number and loads elsewhere to zero, setting transmission limits high enough so that the transmission system is not constrained, and setting a limited amount of generation in each area with a zero dispatch cost. The shadow prices produced by the linear program will be *p* at the destination and the relevant net-back prices in other areas.

In the second step, one calculates Economic Capacity (EC) and Available Economic Capacity (AEC) in each area. These values are then used to limit generation capability. The ownership shares of AEC and EC are calculated for each node in the system.

In the third step, the linear program determines the amount of energy that can be imported into an area given available EC (or AEC) and limits on transmission capacity. This is accomplished by limiting generation in each area to the capacity amount (EC or AEC), giving generation outside the destination market a lower cost than generation inside the destination market, and minimizing cost to serve a large load at the destination market. The amount of generation supplied to the destination is the maximum that can be imported into the destination market.

In the fourth step, transmission is allocated by the following non-linear program:

Minimize Loss: $$Loss = \sum_{\alpha}\left(\frac{C_{\alpha}^{2}}{Y_{Dest}s_{\alpha}} - 2C_{\alpha}\right)$$

Subject to:

(1) Pre Shares: $$s_{\alpha} = \frac{C\max_{\alpha}}{\sum_{\beta} C\max_{\beta}}$$ for each area α;

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(2)	Allocated Shares:	$A_\alpha = \frac{C_\alpha}{Y_{Dest}}$	for each area α;
(3)	Imports:	$YI_a = \sum_b^{a,b \in network} (1 - h_{b,a}) T_{b,a}$	for each area *a*;
(4)	Exports:	$YE_a = \sum_b^{a,b \in network} T_{a,b}$	for each area *a*;
(5)	Net Imports:	$Y_a = YI_a - YE_a$	for each area *a*;
(6)	Supply/Demand Balance:	$C_a + Y_a + U_a = D_a$	for each area *a*;
(7)	Capacity Limits:	$c\min_a \le C_a \le C\max_a$	for each area *a*;
(8)	Transmission Limits:	$t\min_{a,b} \le T_{a,b} \le t\max_{a,b}$	for each link *a* to *b* in the transmission network; and
(9)	Max Import Limit	Y_{Dest} = Maximum imports from step 3;	

where:

a,b	are subscripts for control/transmission areas;
α,β	are subscripts for control/transmission areas other than the destination market;
s_α	Is area α's share of capacity outside of the destination;
A_α	is area α's share of allocated capacity outside of the destination;
Loss	is the loss function to be minimized.

The loss function is derived from the weighted squared-errors between the pre-allocation shares and the post-allocation shares, where Y_{Dest}/s_α are the weights. For each source control area, the weighted squared-error is given by:[1]

$$W_\alpha = \frac{Y_{Dest}}{s_\alpha}(A_\alpha - s_\alpha)^2.$$

[1] This exposition ignores the adjustments necessary to give priority to minimum transfer levels from a source area to the destination.

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Accordingly, the sum of the weighted squared-errors gives rise to the loss function, which can be seen by:

$$\begin{aligned} Loss &= \sum_{\alpha} W_{\alpha} \\ &= \sum_{\alpha} \frac{Y_{Dest}}{s_{\alpha}} (A_{\alpha} - s_{\alpha})^2 \\ &= \sum_{\alpha} \frac{Y_{Dest}}{s_{\alpha}} (A_{\alpha}^2 - 2s_{\alpha}A_{\alpha} + s_{\alpha}^2) \\ &= \sum_{\alpha} \left(\frac{C_{\alpha}^2}{Y_{Dest}s_{\alpha}} - 2C_{\alpha} \right) + \text{constant}. \end{aligned}$$

The resulting shares from minimizing this loss functions preserve the relative shares of capacity behind any transmission constraint going to the destination. This can be seen from the following LaGrangian equation to be minimized:

$$L = \sum_{i} \left(\frac{C_i^2}{Y_{Dest}s_i} - 2C_i \right) + \lambda \left(T - \sum_{i} C_i \right),$$

where T is the transmission limit affecting control areas i. The first order conditions are:

$$\frac{\partial L}{\partial C_i} = \frac{2C_i}{Y_{Dest}s_i} - 2 - \lambda = 0,$$

which can be rearranged to give:

$$A_i = \frac{C_i}{Y_{Dest}} = \left(\frac{2+\lambda}{2} \right) s_i,$$

which shows that the allocated market shares of those areas affected by the transmission constraint are proportional to their shares of capacity before the transmission allocation. Moreover, this is the only transmission allocation

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method that maintains the relative shares of capacity behind any binding transmission constraint in the allocation process.

This non-linear program is solved using the COINIPOPT solver in GAMS. The calculated capacities from the nonlinear program above less transmission losses determine the capacities for the market share calculations for sources outside of the destination market. The capacities within the destination market are given full weights.

Market concentration is the HHI, which is the sum of the squared market shares. Mathematically,

$$HHI = \sum_{i=1}^{n} S_i^2,$$

where S_i is the allocated share of firm i and n is the number of firms in the market. The summary sheets combine all the firms with shares of 0.7 percent or less (other than Applicants) into the "Other" category. The collective share of the Other category does not directly enter the HHI calculation other than the represented capacity as each independent entity enters the HHI calculation. For example, if ten firms with 0.5 percent shares were in the Other category, the HHI contribution of the Other category would be 0.625 (= 10 x .5 x .5 = 10 x .0625) and ***not*** 25.

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Delivered Price Test - PJM50 Market

Available Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$66.65	3,078	19,358	16,279	8,673	Yes	15.9	Yes	1,098	Yes
Spring/Fall	Peak	$38.72	2,630	19,022	16,391	8,673	Yes	13.8	Yes	1,243	Yes
Spring/Fall	Off Peak	$28.24	1,734	16,504	14,770	8,673	Yes	10.5	Yes	1,866	Yes
Summer	Top 1%	$181.98	3,042	24,903	21,861	11,158	Yes	12.2	Yes	779	Yes
Summer	Top 10%	$107.58	3,023	23,063	20,040	11,158	Yes	13.1	Yes	772	Yes
Summer	Peak	$42.40	2,146	18,599	16,454	11,158	Yes	11.5	Yes	1,185	Yes
Summer	Off Peak	$28.32	1,438	16,621	15,184	11,158	Yes	8.6	Yes	1,974	Yes
Winter	Top 10%	$60.87	3,254	19,604	16,351	4,232	Yes	16.6	Yes	1,077	Yes
Winter	Peak	$34.68	2,106	19,013	16,907	4,232	Yes	11.1	Yes	1,031	Yes
Winter	Off Peak	$30.46	1,813	17,222	15,409	4,232	Yes	10.5	Yes	1,269	Yes

Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$66.65	6,902	40,678	33,776	37,015	No	17.0	Yes	1,072	Yes
Spring/Fall	Peak	$38.72	5,780	37,871	32,091	28,730	Yes	15.3	Yes	1,063	Yes
Spring/Fall	Off-Peak	$28.24	4,672	31,612	26,940	24,161	Yes	14.8	Yes	1,144	Yes
Summer	Top 1%	$181.98	8,360	56,794	48,434	54,098	No	14.7	Yes	982	Yes
Summer	Top 10%	$107.58	8,058	53,182	45,125	50,483	No	15.2	Yes	970	Yes
Summer	Peak	$42.40	6,134	41,727	35,594	37,816	No	14.7	Yes	1,002	Yes
Summer	Off Peak	$28.32	4,969	34,461	29,492	30,107	No	14.4	Yes	1,114	Yes
Winter	Top 10%	$60.87	7,159	43,468	36,309	36,538	No	16.5	Yes	1,020	Yes
Winter	Peak	$34.68	5,554	39,565	34,010	31,493	Yes	14.0	Yes	1,002	Yes
Winter	Off Peak	$30.46	5,169	36,342	31,173	27,514	Yes	14.2	Yes	1,067	Yes

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Delivered Price Test - PJME Market

Available Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$66.52	2,829	15,453	12,624	5,066	Yes	18.3	Yes	1,013	Yes
Spring/Fall	Peak	$37.36	2,355	15,053	12,698	5,066	Yes	15.6	Yes	1,157	Yes
Spring/Fall	Off Peak	$27.77	1,475	13,045	11,570	5,066	Yes	11.3	Yes	1,821	Yes
Summer	Top 1%	$188.24	2,824	17,006	14,183	7,158	Yes	16.6	Yes	758	Yes
Summer	Top 10%	$109.22	2,788	16,125	13,336	7,158	Yes	17.3	Yes	735	Yes
Summer	Peak	$42.17	1,883	14,324	12,441	7,158	Yes	13.1	Yes	1,091	Yes
Summer	Off Peak	$28.67	1,358	12,776	11,418	7,158	Yes	10.6	Yes	1,783	Yes
Winter	Top 10%	$61.53	3,075	15,865	12,790	2,000	Yes	19.4	Yes	1,100	Yes
Winter	Peak	$34.72	1,905	14,650	12,745	2,000	Yes	13.0	Yes	1,113	Yes
Winter	Off Peak	$29.97	1,644	13,685	12,041	2,000	Yes	12.0	Yes	1,395	Yes

Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$66.52	6,408	29,458	23,050	20,334	Yes	21.8	No	1,062	Yes
Spring/Fall	Peak	$37.36	5,291	27,246	21,955	15,287	Yes	19.4	Yes	1,043	Yes
Spring/Fall	Off-Peak	$27.77	4,154	22,271	18,118	12,928	Yes	18.6	Yes	1,165	Yes
Summer	Top 1%	$188.24	7,825	35,682	27,857	31,201	No	21.9	No	1,037	Yes
Summer	Top 10%	$109.22	7,523	33,548	26,025	28,872	No	22.4	No	1,027	Yes
Summer	Peak	$42.17	5,605	29,694	24,089	20,912	Yes	18.9	Yes	989	Yes
Summer	Off Peak	$28.67	4,589	25,425	20,836	16,785	Yes	18.1	Yes	1,072	Yes
Winter	Top 10%	$61.53	6,691	30,759	24,068	19,164	Yes	21.8	No	1,068	Yes
Winter	Peak	$34.72	5,087	27,734	22,647	16,525	Yes	18.3	Yes	1,006	Yes
Winter	Off Peak	$29.97	4,710	25,791	21,081	14,299	Yes	18.3	Yes	1,054	Yes

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Appendix B
List of Entities with Market-Based Rate Authority and Their Generation Assets

Market Based Rate Authority and Generation Assets									
						LOCATION			
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region (per Appendix D)	In-service Date	Nameplate Rating (MW)
PSE&G	ER99-3151-000	NA*	NA*	NA*	NA*	PJM	Northeast	NA*	NA*
PSEG ER&T	ER97-837-000	NA*	NA*	NA*	NA*	PJM, NYPP, NE-ISO	Northeast, Central, Southwest Power Pool, Southeast, Southwest, Northwest	NA*	NA*
PSEG Fossil	ER08-447-000	Bergen 3	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	07/07/1967	18.6
PSEG Fossil	ER08-447-000	Bergen CC1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/1995	775.2
PSEG Fossil	ER08-447-000	Bergen CC2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/2002	625.6
PSEG Fossil	ER08-447-000	Burlington 8	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/02/1967	18.6
PSEG Fossil	ER08-447-000	Burlington 9	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	05/11/1972	162.4
PSEG Fossil	ER08-447-000	Burlington 11	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/05/1972	162.4
PSEG Fossil	ER08-447-000	Burlington 12.1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/2000	60.5
PSEG Fossil	ER08-447-000	Burlington 12.2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/2000	60.5
PSEG Fossil	ER08-447-000	Burlington 12.3	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/2000	60.5
PSEG Fossil	ER08-447-000	Burlington 12.4	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/2000	60.5
PSEG Fossil	ER08-447-000	Conemaugh 1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	05/21/1970	210.6
PSEG Fossil	ER08-447-000	Conemaugh 2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	05/27/1971	210.6
PSEG Fossil	ER08-447-000	Conemaugh A	PSEG Fossil[1]	PSEG ER&T	08/21/2000	PJM	Northeast	02/01/1970	0.625
PSEG Fossil	ER08-447-000	Conemaugh B	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	02/01/1970	0.625
PSEG Fossil	ER08-447-000	Conemaugh C	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	02/01/1970	0.625
PSEG Fossil	ER08-447-000	Conemaugh D	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	02/01/1970	0.625
PSEG Global	N/A	Conemaugh Hydroelectric Plant 1	PSEG Global[2]	PSEG ER&T	02/01/1989	PJM	Northeast	02/01/1989	1.0

[1] PSEG Fossil has a 22.5% interest in the Conemaugh coal fired plants.
[2] PSEG Global has a 4% interest Conemaugh Hydroelectric plants.

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Market Based Rate Authority and Generation Assets									
						Location			
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region (per Appendix D)	In-service Date	Nameplate Rating (MW)
PSEG Global	N/A	Conemaugh Hydroelectric Plant 2	PSEG Global	PSEG ER&T	02/01/1989	PJM	Northeast	02/01/1989	1.0
PSEG Fossil	ER08-447-000	Edison 1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	05/06/1971	167.4
PSEG Fossil	ER08-447-000	Edison 2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/23/1971	167.4
PSEG Fossil	ER08-447-000	Edison 3	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/30/1971	167.4
PSEG Fossil	ER08-447-000	Essex 9	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	07/01/1990	93.6
PSEG Fossil	ER08-447-000	Essex 10	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/28/1971	167.4
PSEG Fossil	ER08-447-000	Essex 11	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	12/23/1971	167.4
PSEG Fossil	ER08-447-000	Essex 12	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/08/1971	167.4
PSEG Nuclear	ER08-448-000	Hope Creek 1	PSEG Nuclear	PSEG ER&T	08/21/2000	PJM	Northeast	12/20/1986	1,290.7[3]
PSEG Fossil	ER08-447-000	Hudson 2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	12/18/1968	659.7
PSEG Fossil	ER08-447-000	Kearny 9	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	05/24/1967	18.6
PSEG Fossil	ER08-447-000	Kearny 12	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	08/01/2001	242.0
PSEG Fossil	ER08-447-000	Kearny 13	PSEG Fossil	PSEG ER&T	06/01/2012	PJM	Northeast	06/01/2012	242.0
PSEG Fossil	ER08-447-000	Kearny 14	PSEG Fossil	PSEG ER&T	06/01/2012	PJM	Northeast	06/01/2012	121.0
PSEG Fossil	ER08-447-000	Keystone 1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	08/24/1967	213.8
PSEG Fossil	ER08-447-000	Keystone 2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	07/23/1968	213.8
PSEG Fossil	ER08-447-000	Keystone 3	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	11/23/1968	0.625
PSEG Fossil	ER08-447-000	Keystone 4	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	11/23/1968	0.625
PSEG Fossil	ER08-447-000	Keystone 5	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	11/23/1968	0.625
PSEG Fossil	ER08-447-000	Keystone 6	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	11/23/1968	0.625
PSEG Fossil	ER08-447-000	Linden 1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	04/01/2006	677.8
PSEG Fossil	ER08-447-000	Linden 2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM,	Northeast	04/01/2006	677.8
PSEG Fossil	ER08-447-000	Linden 7	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/1995	96.1
PSEG Fossil	ER08-447-000	Linden 8	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/1995	96.1
PSEG Fossil	ER08-447-000	Linden GT5	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/2000	96.1
PSEG Fossil	ER08-447-000	Linden GT6	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/2000	96.1

[3] Please note that this number is 120 MW higher than the nameplate rating number provided in Appendix B of the 2010 triennial filing in Docket No. ER08-448-007 and the PSEG New Haven initial MBR filing in Docket No. ER12-1250-000. This is due to the fact that a capacity increase associated with an uprate to the Hope Creek nuclear unit was inadvertently not included in the nameplate number included in Appendix B. This capacity uprate was, however, discussed in the 2007 and 2010 triennial applications themselves.

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Market Based Rate Authority and Generation Assets									
						Location			
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region (per Appendix D)	In-service Date	Nameplate Rating (MW)
PSEG Fossil	ER08-447-000	Mercer 1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	12/19/1960	326.4
PSEG Fossil	ER08-447-000	Mercer 2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/04/1961	326.4
PSEG Fossil	ER08-447-000	Mercer GT3	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	11/30/1967	115.2
PSEG Fossil	ER08-447-000	National Park GT1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/04/1969	18.6
PSEG Nuclear	ER08-448-000	Peach Bottom 2	PSEG Nuclear[4]	PSEG ER&T	08/21/2000	PJM	Northeast	07/05/1974	576.0
PSEG Nuclear	ER08-448-000	Peach Bottom 3	PSEG Nuclear	PSEG ER&T	08/21/2000	PJM	Northeast	12/23/1974	576.0
PSEG Nuclear	ER08-448-000	Salem 1	PSEG Nuclear[5]	PSEG ER&T	08/21/2000	PJM	Northeast	06/30/1977	671.7
PSEG Nuclear	ER08-448-000	Salem 2	PSEG Nuclear	PSEG ER&T	08/21/2000	PJM	Northeast	10/13/1981	671.7
PSEG Nuclear	ER08-448-000	Salem GT3	PSEG Nuclear	PSEG ER&T	08/21/2000	PJM	Northeast	06/17/1971	24.0
PSEG Fossil	ER08-447-000	Sewaren 1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	12/01/1948	110.8
PSEG Fossil	ER08-447-000	Sewaren 2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	11/30/1948	107.5
PSEG Fossil	ER08-447-000	Sewaren 3	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	10/16/1949	116.3
PSEG Fossil	ER08-447-000	Sewaren 4	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	07/30/1951	126.5
PSEG Fossil	ER08-447-000	Sewaren 6	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	11/17/1965	115.2
PSEG Fossil	ER08-447-000	Yards Creek 1[6]	PSEG Fossil	JCP&L[7]	08/21/2000	PJM	Northeast	11/26/1965	68.5
PSEG Fossil	ER08-447-000	Yards Creek 2	PSEG Fossil	JCP&L	08/21/2000	PJM	Northeast	12/22/1965	68.5
PSEG Fossil	ER08-447-000	Yards Creek 3	PSEG Fossil	JCP&L	08/21/2000	PJM	Northeast	09/03/1965	56.4
PSEG Power CT	ER03-327-000	Bridgeport Harbor 2	PSEG Power CT	PSEG ER&T	12/06/2002	ISO-NE	Northeast	08/01/1961	179.5
PSEG Power CT	ER03-327-000	Bridgeport Harbor 3	PSEG Power CT	PSEG ER&T	12/06/2002	ISO-NE	Northeast	08/01/1968	399.5
PSEG Power CT	ER03-327-000	Bridgeport Harbor 4	PSEG Power CT	PSEG ER&T	12/06/2002	ISO-NE	Northeast	10/30/1967	18.6
PSEG New Haven LLC	ER12-1250-000	New Haven 2	PSEG New Haven LLC	CL&P[8]	06/01/2012	ISO-NE	Northeast	06/01/2012	60.5

[4] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear Plants.
[5] PSEG Nuclear has a 57.41% interest in the Salem Nuclear Plants.
[6] PSEG Fossil has a 50% interest in each of the Yards Creek facilities.
[7] Jersey Central Power & Light Company
[8] The Connecticut Light and Power Company.

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Market Based Rate Authority and Generation Assets									
						LOCATION			
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region (per Appendix D)	In-service Date	Nameplate Rating (MW)
PSEG New Haven LLC	ER12-1250-000	New Haven 3	PSEG New Haven LLC	CL&P	06/01/2012	ISO-NE	Northeast	06/01/2012	60.5
PSEG New Haven LLC	ER12-1250-000	New Haven 4	PSEG New Haven LLC	CL&P	06/01/2012	ISO-NE	Northeast	06/01/2012	60.5
PSEG Power CT	ER03-327-000	New Haven Harbor 1	PSEG Power CT	PSEG ER&T	12/06/2002	ISO-NE	Northeast	07/01/1975	460.3
PSEG Power NY	N/A*	Bethlehem Energy Center CC	PSEG Power NY	PSEG ER&T	12/06/2002	NYISO	Northeast	07/01/2005	893.2
PSEG Solar Source LLC	N/A*	Mars Solar Garden	PSEG Solar Hackettstown LLC[9]	PSEG Solar Source LLC	N/A	PJM	Northeast	09/09/2009	2.2
PSEG Solar Source LLC	N/A*	JEA Solar Farm	PSEG Solar Source LLC[10]	PSEG Solar Source LLC	N/A	SERC	Southeast	09/28/2010	15.0
PSEG Solar Source LLC	N/A*	Wyandot Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	04/06/2010	12.0
PSEG Solar Source LLC	N/A*	Queen Creek Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	AZ-NV-SNV	Southwest	11/14/2012	25.0
PSEG Solar Source LLC	N/A*	Milford Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ACC	Northeast	12/27/2012	15.0
PSEG Solar Source LLC	N/A	Badger Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ACC	West	10/15/2013	19.0
PSEG Solar Source LLC	N/A	Shasta Solar Farm	PSEG Solar California LLC	PG&E[11]	12/16/2013	CAISO	Southwest	03/01/2014[12]	4.4
PSE&G (Solar 4 All)	N/A*	Trenton, 500-520 Brunswick Ave., Trenton, NJ 08638	PSE&G	PSE&G	N/A	PJM	Northeast	10/07/2010 (Commercial Operation)	1.26

[9] PSEG Global has a 100% ownership in PSEG Hackettstown LLC.
[10] PSEG Global has a 100% ownership interest in PSEG Solar Source LLC.
[11] Pacific Gas & Electric Company.
[12] Anticipated.

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Market Based Rate Authority and Generation Assets									
						Location			
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region (per Appendix D)	In-service Date	Nameplate Rating (MW)
PSE&G (Solar 4 All)	N/A*	Barringer High School (NPS), 90 Parker St., Newark, NJ 07104	PSE&G	PSE&G	N/A	PJM	Northeast	09/24/2010 (Commercial Operation)	0.65
PSE&G (Solar 4 All)	N/A*	Park Elementary School, 120 Manchester Place, Newark, NJ 07104-1704	PSE&G	PSE&G	N/A	PJM	Northeast	10/20/2010 (Commercial Operation)	0.51
PSE&G (Solar 4 All)	N/A*	Linden, South Wood Avenue, Linden, NJ 07036	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010	3.20
PSE&G (Solar 4 All)	N/A*	Yardville, Broad Street, Hamilton, NJ 08611	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010	4.3
PSE&G (Solar 4 All)	N/A*	Silver Lake, 410 Silver Lake Avenue, Edison, NJ 08817	PSE&G	PSE&G	N/A	PJM	Northeast	11/09/2010 (Energized)	2.02
PSE&G (Solar 4 All)	N/A*	Central HQ, 472 Weston Canal Road, Franklin, NJ 08873	PSE&G	PSE&G	N/A	PJM	Northeast	11/19/2010 (Energized)	0.92
PSE&G (Solar 4 All)	N/A*	Edison Training, 234 Pierson Avenue, Edison, NJ 08837	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011	0.71
PSE&G (Solar 4 All)	N/A*	WEA Texas Bayonne, 30-100 Pulaski Street, Bayonne, NJ 07002	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2010	1.75

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Market Based Rate Authority and Generation Assets									
						Location			
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region (per Appendix D)	In-service Date	Nameplate Rating (MW)
PSE&G (Solar 4 All)	N/A*	Matrix Building A, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	01/24/2011	1.69
PSE&G (Solar 4 All)	N/A*	Matrix Building B, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	01/14/2011	1.17
PSE&G (Solar 4 All)	N/A*	Camden Street School, 281 Camden Street Newark, New Jersey 07103	PSE&G	PSE&G	N/A*	PJM	Northeast	01/12/2011	0.91
PSE&G (Solar 4 All)	N/A*	New Central High School, 246 18th Ave, Newark, NJ 07108	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2010 (Energized)	0.50
PSE&G (Solar 4 All)	N/A*	Rider University Solar Farm, Lawrenceville, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2011	0.74
PSE&G (Solar 4 All)	N/A*	Mill Creek Solar Farm, Burlington Township, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	11/30/2011	3.82
PSE&G (Solar 4 All)	N/A*	PSE&G Thorofare Solar Farm, West Deptford	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011	0.72

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Market Based Rate Authority and Generation Assets									
						Location			
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region (per Appendix D)	In-service Date	Nameplate Rating (MW)
PSE&G (Solar 4 All)	N/A*	Raritan Center – Warehouse Solar, Edison, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011	2.22
PSE&G (Solar 4 All)	N/A*	NJMC – Landfill Solar, Kearny, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011	3.0
PSE&G (Solar 4 All	N/A	Matrix – Stults Rd., South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	05/31/2011	2.98
PSE&G (Solar 4 All)	N/A*	Metro Division HQ, Clifton, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	07/09/2012	0.7
PSE&G (Solar 4 All)	N/A*	Black Rock-Matrix, South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	03/20/2012	3.0
PSE&G (Solar 4 All)	N/A*	Food Bank Solar Farm, Hillside, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	08/16/2012	1.1
PSE&G (Solar 4 All)	N/A*	Hackensack Solar Farm, Hackensack, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2012	1.1
PSE&G (Solar 4 All)	N/A*	Moorestown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/14/2013	1.1
PSE&G (Solar 4 All)	N/A*	Seg 2 (Pole attached solar units)[13]	PSE&G	PSE&G	N/A*	PJM	Northeast	12/31/2012	38.3

*N/A means not applicable.

[13] PSE&G started installations of pole units in September of 2009. Through the end of October 2013, a total of 173,894 panels and 38.3 MW capacity will have been installed.

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20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Appendix C
List of Entities with Market-Based Rate Authority and Their Transmission Assets

Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas Storage Facilities (as of December 5, 2013)

Filing Entity and its Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per Appendix D)	
PSEG ER&T	NA	NA	NA	NA	NA	NA	NA
PSEG Power CT	NA	NA	NA	NA	NA	NA	NA
PSEG New Haven	NA	NA	NA	NA	NA	NA	NA
PSEG Fossil	NA	NA	NA	NA	NA	NA	NA
PSEG Nuclear	NA	NA	NA	NA	NA	NA	NA
PSE&G	Combined 500 kV Lines	PSE&G	PJM	NA*	PJM	Northeast	Approximately 179 combined miles.
PSE&G	Combined 500 kV Lines	Jointly Owned by PSE&G and others	PJM	NA*	PJM	Northeast	Approximately 151 combined miles.
PSE&G	Combined 500 kV Lines	Owned by others	PJM	N/A*	PJM	Northeast	Approximately 76 combined miles
PSE&G	Combined 345 kV Lines	PSE&G	PJM	NA*	PJM	Northeast	Approximately 15 combined miles.
PSE&G	Combined 345 kV Lines	Owned by others	PJM	NA*	PJM	Northeast	Approximately 6 combined miles.
PSE&G	Combined 230 kV Lines	PSE&G	PJM	NA*	PJM	Northeast	Approximately 453 combined miles.
PSE&G	Combined 230kV Lines	Owned by Others	PJM	N/A	PJM	Northeast	Approximately 44 combined miles
PSE&G	Combined 138 kV Lines	PSE&G	PJM	NA*	PJM	Northeast	Approximately 391 combined miles.
PSE&G	Combined 69 kV Lines	PSE&G	PJM	NA*	PJM	Northeast	Approximately 176 combined miles.

*if the field is not applicable please indicate so by inputting (NA).

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20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Appendix D
Letters of concurrence regarding the control of certain jointly owned generation facilities

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

KEYSTONE-CONEMAUGH PROJECTS

682 Philadelphia Street – 2nd floor
Indiana, Pennsylvania 15701

724-349-1205

MAILING ADDRESS
P.O. BOX 68
INDIANA, PA 15701

GEORGIANNA R. STENGER, ESQ.
ADMINISTRATIVE MANAGER
DIRECT DIAL 724-357-1713

December 1, 2007

Addressed to:

Conemaugh Power LLC
Constellation Power Source Generation, Inc.
Duquesne Conemaugh LLC
Exelon Generation Company, LLC
PPL Montour, LLC
PSEG Fossil LLC
Reliant Energy Mid-Atlantic Power Holdings, LLC
UGI Development Company

Re: Joint Owners of the Conemaugh Electric Generating Station (collectively, the "Owners") statement of ownership and control

Dear Owners:

This letter sets forth the understanding of the degree of ownership and control exercised by each of the Owners with respect to the jointly-owned Conemaugh Electric Generating Station for purposes of facilitating compliance with the requirements of FERC Order No. 697.[1]

The Owners and Reliant Energy Northeast Management Company (the "Operator") each confirm its concurrence with the following statement of facts relating to the Conemaugh Electric Generating Station:

1. The Owners jointly own the Conemaugh Electric Generating Station, consisting of two 850 MW net pulverized coal fired once-through boilers and related facilities having a combined rated seasonal net generating capacity of 1,712 MW (1,884 MW nameplate), located in East Wheatfield and West Wheatfield Townships, Indiana County, Pennsylvania (the "Station").

---

1 Not all of the Owners agree as to whether Order No. 697 requires the submission of a letter of concurrence when the putative submitting party is not claiming that it does not control its percentage ownership share of a jointly-owned unit. Notwithstanding, all of the Owners have no objection to submission of this letter by an Owner which does believe that such a submission is required.

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2. As of the date hereof, the Station is collectively owned by the Owners as tenants-in-common, each holding an undivided interest in the Station (and all real and personal property comprising the same) in the respective ownership percentages set forth below:

Owner	Ownership Interest
Conemaugh Power LLC	3.72%
Constellation Power Source Generation, Inc.	10.56%
Duquesne Conemaugh LLC	3.83%
Exelon Generation Company, LLC	20.72%
PPL Montour, LLC	16.25%
PSEG Fossil LLC	22.50%
Reliant Energy Mid-Atlantic Power Holdings, LLC	16.45%
UGI Development Company	5.97%

3. Each of the Owners is deemed to control the generating capacity of the Station in accordance with its respective ownership percentage as set forth in the preceding paragraph for purposes of facilitating compliance with the requirements of FERC Order No. 697.

Please indicate your company's concurrence to the above statement of facts by executing this letter in the space provided below your company's name at the foot hereof.

Sincerely yours,

Georgianna R. Stenger
Administrative Manager
Keystone-Conemaugh Projects

SI-SSA-0010-5177

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this 14 day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: Anthony F. Pekny

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this 1 day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: Kenneth Kaufman

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this 1st day of December, 2007.

PPL MONTOUR, LLC

By: Dennis J. Murphy
DENNIS J. MURPHY

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this 13th day of December, 2007.

PSEG FOSSIL LLC

By: [signature]

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: James V. Lacher

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Operator:

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY NORTHEAST
MANAGEMENT COMPANY

By: _____

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KEYSTONE-CONEMAUGH PROJECTS

682 Philadelphia Street 2nd floor
Indiana, Pennsylvania 15701

724-349-1205

MAILING ADDRESS
P.O BOX 68
INDIANA, PA 15701

GEORGIANNA R. STENGER, ESQ.
ADMINISTRATIVE MANAGER
DIRECT DIAL: 724-357-1713

December 1, 2007

Addressed to:

Constellation Power Source Generation, Inc.
Duquesne Keystone LLC
Exelon Generation Company, LLC
Keystone Power LLC
PPL Montour, LLC
PSEG Fossil LLC
Reliant Energy Mid-Atlantic Power Holdings, LLC

Re: Joint Owners of the Keystone Electric Generating Station (collectively, the "Owners") statement of ownership and control

Dear Owners:

This letter sets forth the understanding of the degree of ownership and control exercised by each of the Owners with respect to the jointly-owned Keystone Electric Generating Station for purposes of facilitating compliance with the requirements of FERC Order No. 697.[1]

The Owners and Reliant Energy Northeast Management Company (the "Operator") each confirm its concurrence with the following statement of facts relating to the Keystone Electric Generating Station:

1. The Owners jointly own the Keystone Electric Generating Station, consisting of two 850 MW net pulverized coal fired once-through boilers and related facilities having a combined rated seasonal net generating capacity of 1,712 MW (1,884 MW nameplate), located in Plumcreek, South Bend and Cowanshannock Townships, Armstrong County, Pennsylvania, and Armstrong Township, Indiana County, Pennsylvania (the "Station").

---

1 Not all of the Owners agree as to whether Order No. 697 requires the submission of a letter of concurrence when the putative submitting party is not claiming that it does not control its percentage ownership share of a jointly-owned unit. Notwithstanding, all of the Owners have no objection to submission of this letter by an Owner which does believe that such a submission is required.

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

2. As of the date hereof, the Station is collectively owned by the Owners as tenants-in-common, each holding an undivided interest in the Station (and all real and personal property comprising the same) in the respective ownership percentages set forth below:

Owner	Ownership Interest
Constellation Power Source Generation, Inc.	20.99%
Duquesne Keystone LLC	2.47%
Exelon Generation Company, LLC	20.99%
Keystone Power LLC	3.70%
PPL Montour, LLC	12.34%
PSEG Fossil LLC	22.84%
Reliant Energy Mid-Atlantic Power Holdings, LLC	16.67%

3. Each of the Owners is deemed to control the generating capacity of the Station in accordance with its respective ownership percentage as set forth in the preceding paragraph for purposes of facilitating compliance with the requirements of FERC Order No. 697.

Please indicate your company's concurrence to the above statement of facts by executing this letter in the space provided below your company's name at the foot hereof.

Sincerely yours,

Georgianna R. Steiger
Administrative Manager
Keystone-Conemaugh Projects

SI-SSA-0010-5188

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this __ _ day of December, 2007

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this __ . _ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this _ __ . day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ___ . day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this __ _ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this ___ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this 14 day of December, 2007.

DUQUESNE KEYSTONE LLC

By: Arthur F. Pelly

Acknowledged and Agreed to
this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this 1 day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: Kenneth Kaiser

Acknowledged and Agreed to
this _____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this __. day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this ___ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this 13th day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this __ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this 16 day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: James D. Lech

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Operator:

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY NORTHEAST
MANAGEMENT COMPANY

By: Jaime D Lach

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Thomas P. Joyce
Senior Vice President

P.O. Box 236, Hancocks Bridge, NJ 08038
tel: 856.339.1100 fax: 856.339.1104
email: Thomas.Joyce@pseg.com

PSEG
Nuclear L.L.C.

Carol Peterson
Vice President Finance
Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

Letter Regarding Control of Jointly-Owned Nuclear Facilities

Dear Ms. Peterson:

In connection with its upcoming compliance filings pursuant to Order No. 697,[1] PSEG Nuclear LLC ("PSEG") is submitting this letter in order to set forth its understanding of, and is requesting Exelon Generation Company LLC's ("Exelon") concurrence on, the respective level of control exercised by both companies with respect to the two nuclear facilities that they jointly own.[2]

PSEG avers and requests Exelon's concurrence on the following:

1. PSEG and Exelon jointly own and control two nuclear power plants, Peach Bottom Atomic Power Station located in Delta, PA and the Salem Nuclear Generating Station in Lower Alloways Creek, NJ.

2. In accordance with the Joint Owners Agreement for Peach Bottom dated November 24, 1971, as amended on thereafter, between the Parties, PSEG and Exelon each own 50% of the generating station. Under the Agreement, Exelon is the designated operator of Peach Bottom.

3. In accordance with the Joint Owners Agreement for Salem dated November 24, 1971, as amended thereafter, between the Parties, Exelon owns 42.59% and PSEG owns 57.41% of the generating station. Under the Agreement, PSEG is the designated operator of Salem.

4. Section 4.1 of each of the Joint Owners' Agreements states, "The signatories shall be entitled to shares of the installed capacity, available capacity, operating capacity and hourly energy generation of the Station in proportion to their ownership . . .."

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[1] *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, 119 FERC ¶ 61,295 (2007).

[2] PSEG has requested a letter of concurrence from Exelon in order to facilitate the Commission's review of the market power analysis submitted by PSEG with respect to facilities it jointly owns with Exelon. Exelon has no objection to PSEG's submission of this letter as part of PSEG's compliance filing,.

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Thomas P. Joyce
Senior Vice President

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tel: 856.339.1100 fax: 856.339.1104
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PSEG
Nuclear L.L.C.

5. Section 11.1 of each of the Joint Owners' Agreements provides that the generating station will be operated by the party designated as operator for the mutual benefit of PSEG and Exelon.

6. In Order No. 697 the Commission stated that under "where a jointly-owned generation facility is operated by one of the joint-owners for the benefit of and on behalf of all of the joint-owners . . . it may be reasonable to allocate capacity based on ownership percentages...." Order No. 697 at P 188.

7. In accordance with the guidance provided in Order No. 697 and with the language of each of the joint owners' agreements, PSEG and Exelon should be deemed to control each of the nuclear facilities' output in line with their proportionate ownership share of each facility. As such, PSEG and Exelon should each be deemed to control 50% of Peach Bottom's output, and PSEG should be deemed to control 57.41% of Salem's output with Exelon controlling 42.59%.

Please indicate Exelon's concurrence to the above by executing the Acknowledgement and Agreement section below.

Sincerely

Thomas P. Joyce
Senior Vice President – Operations

Acknowledged and Agreed to
this 21 day of DECEMBER, 2007.

Carol Peterson
Vice President Finance, Exelon Nuclear, and
an officer of Exelon Generation Company, LLC

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JOINT LETTER OF CONCURRENCE

Regulations of the Federal Energy Regulatory Commission (the "FERC") require each public utility with market-based rate authority to file an updated market power analysis every three years in accordance with a schedule adopted in *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stat. & Regs., Regulations Preambles ¶ 31,252 (2007) ("Order No. 697"). See, 18 CFR § 35.37(a)(1). Each public utility with market-based rate authority may also be required to file a change-in-status report regarding certain changes in circumstances that occur between the dates on which its triennial market power analyses are filed. 18 CFR § 35.42. Among other matters, the market power analysis is to address the amount of generation capacity that the affected utility owns or controls. Where more than one public utility owns a generating facility, FERC requires the utility that is submitting a market power analysis seek a "letter of concurrence" from the other affected co-owning public utilities that identifies the degree to which each public utility controls the generating facility, and to submit the letter with its filing. *See* FERC Order No. 697, 119 FERC ¶ 61,295, P 187 (2007).

The Yards Creek Pumped Storage Hydroelectric Project (the "Yards Creek Project") is a FERC-licensed pumped-storage hydroelectric project with a nameplate capacity of 400 MWs, and is located in Pahaquarry and Blairstown Townships, in Warren County, New Jersey. *See* FERC Project No. P-2309.

PSEG Fossil LLC ("PSEG") and Jersey Central Power & Light Company ("JCPL") each own, as tenants in common with the other, an undivided 50% interest in the Yards Creek Project. Accordingly, if and when PSEG or JCPL submit an updated market power analysis to the FERC, each will be subject to FERC's requirement to seek a "letter of concurrence" regarding the degree to which each controls the Yards Creek Project.

Both PSEG and JCP&L (and their affiliates) own transmission facilities and provide wholesale electric service in the Northeast region, as defined in Order No. 697. Pursuant to the schedule adopted in Order No. 697, PSEG and JCP&L are each required to submit an updated market power analysis to the FERC for markets within the Northeast region in December 2010. PSEG and/or JCP&L may also be obligated to file a change-in-status report or other market power analyses before its subsequent triennial market power analysis for the Northeast region is scheduled to be filed. Therefore, for the sole purpose of enabling either PSEG or JCP&L to submit a market power analysis that addresses, among other issues (to the extent necessary), the scope of each party's control of the Yards Creek Project, PSEG and JCP&L each aver and agree as follows:

1. JCP&L operates and maintains the Yards Creek Project pursuant to the Yards Creek Pumped Storage Hydroelectric Generating Station Operating Agreement, which is dated October 6, 1965 (the "Operating Agreement').

2. Article 2 of the Operating Agreement designates JCP&L as holding sole responsibility for the operations and maintenance the Yards Creek Project. Article 2 further provides that JCPL shall operate the Yards Creek project in the same manner as if JCPL had the complete ownership interest in the Yards Creek Project.

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3. JCP&L does, in fact, operate and control the Yards Creek Project in the same manner as if JCP&L had the complete ownership interest in the Yards Creek Project in accordance with Article 2 of the Operating Agreement.

4. Accordingly, PSEG and JCP&L each agree and concur that for the purpose of the market power analyses required by Order No. 697, JCPL shall be deemed to control the Yards Creek Project generation capacity and electric energy output.

ACKNOWLEDGED AND AGREED:

Richard P. Lopriore
President, PSEG Fossil LLC

Dated: 12/21/10

ACKNOWLEDGED AND AGREED:

Dean Stathis
Director, Regulated Commodity Sourcing
Jersey Central Power & Light Company

Dated: 12/08/2010

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Appendix E
Form of notice suitable for publication in the Federal Register

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PSEG Energy Resources & Trade LLC	Docket No. ER99-3151-___
Public Service Electric and Gas Company	Docket No. ER97-837-___
PSEG Power Connecticut LLC	) Docket No. ER03-327-____
PSEG Fossil LLC	)
	) Docket No. ER08-447-____
PSEG Nuclear LLC and	Docket No. ER08-448-____
PSEG New Haven LLC,	Docket No. ER12-1250-___

NOTICE OF FILING
( )

Take notice that on December 23, 2013 that: (i) PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG New Haven LLC, PSEG Fossil LLC and PSEG Nuclear LLC tendered for filing their joint triennial market power update in compliance with Order No. 679 and with prior Commission Orders granting them market-based rate authority in Docket Nos. ER99-3151, ER97-837, ER03-327, ER08-447 ER08-448 and DR-12-1250 respectively.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR §§ 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

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Comment Date: 5:00 pm Eastern Time on (insert date).
Kimberly J. Bose
Secretary

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Document Content(s)

PSEG Triennial Filing 2013.PDF.....1-144

20131227-0024 FERC PDF (Unofficial) 12/26/2013

David K. Richter
Associate General Regulatory and Property Counsel

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ORIGINAL

PSEG
Services Corporation

December 23, 2013

FILED
SECRETARY OF THE
COMMISSION
2013 DEC 26 A 11:35
FEDERAL ENERGY
REGULATORY COMMISSION

VIA UPS

Kimberly J. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Triennial Market Power Update and Revised Market-Based Rates Tariff in Compliance with Order No. 697:

PSEG Energy Resources & Trade LLC -> ER10-1789-003
Public Service Electric and Gas Company -> ER10-1768-002
PSEG Power Connecticut LLC -> ER10-1793-002
PSEG Fossil LLC -> ER10-1770-002
PSEG Nuclear LLC -> ER10-1771-002
PSEG New Haven LLC -> ER12-1250-002

Dear Secretary Bose:

20131223-5279

Earlier today, PSEG Energy Resources & Trade LLC ("PSEG ER&T"), Public Service Electric and Gas Company ("PSE&G"), PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Fossil LLC ("PSEG Fossil"), PSEG Nuclear LLC ("PSEG Nuclear") and PSEG New Haven LLC ("PSEG New Haven") (collectively the "Applicants" or "PSEG") jointly submitted their Triennial Market Power Update. Enclosed with this transmittal letter, please find CD-ROMs containing the workpapers of Dr. John Morris supporting his analysis in support of that filing.

More specifically, these CD-ROMs contain the following materials:

- Disk 1 (of which six copies are included) contains publicly available information.
- Disk 2 (of which one copy is included) contains: (i) proprietary information provided by Energy Velocity under an agreement that requires confidential treatment to be requested for these materials; (ii) modeling and computer programs that are the proprietary intellectual property of Economists Incorporated, the firm by which Dr. Morris is employed; (iii)

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commercially sensitive information about Applicants and their affiliates; and (iv) documents and information deemed to be confidential by PJM, NYISO and ISO-NE.

Accordingly, Applicants respectfully request confidential treatment for Disk 2 pursuant to 18 C.F.R. § 388.112 (2006), consistent with the confidential treatment accorded other applicants submitting such proprietary and commercially sensitive data.[1] Pursuant to the Commission's rules, the public version of this filing contains all materials submitted herein except for Disk 2, which is labeled as "PRIVILEGED AND CONFIDENTIAL/NON-PUBLIC.

Thank you for your attention to this matter. Please direct any questions concerning this submission or the request for privileged treatment to the undersigned.

Respectfully submitted,

Public Service Electric and Gas Company
PSEG Energy Resources & Trade LLC
PSEG Power Connecticut LLC
PSEG Fossil LLC
PSEG Nuclear LLC
PSEG New Haven LLC

By: _____

David K. Richter, Esq.
Associate General Regulatory and Property Counsel PSEG Services Corporation

Enclosures

[1] *See, e.g., Idaho Power Company*, Docket No. ER97-1481-009 (February 3, 2006) (submission of revised Pivotal Supplier Screen and Market Share Screen calculations including similar data).

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DAVID K. RICHTER
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PSEG Services Corporation

December 28, 2016

ELECRONICALLY AND VIA OVERNIGHT MAIL

Kimberly J. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Triennial Market Power Update in Compliance with Order No. 697:
***PSEG Energy Resources & Trade LLC*, Docket No. ER99-3151-____;**
***Public Service Electric and Gas Company*, Docket No. ER97-837-____;**
***PSEG Power Connecticut LLC*, Docket No. ER03-327 -___;**
***PSEG Fossil LLC*, Docket No. ER08-447-___;**
***PSEG Nuclear LLC*, ER08-448-___; and**
***PSEG New Haven LLC*, ER12-1250-___**
Pavant Solar II LLC, ER16-1925-___
San Isabel Solar LLC, ER16-1926-___
Bison Solar LLC, ER16-1924-___
PSEG Energy Solutions LLC, ER16-2725-___

Dear Secretary Bose:

Pursuant to the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), PSEG Energy Resources & Trade LLC ("PSEG ER&T"), Public Service Electric and Gas Company ("PSE&G"), PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Fossil LLC ("PSEG Fossil"), PSEG Nuclear LLC ("PSEG Nuclear"), PSEG New Haven LLC ("PSEG New Haven") Pavant Solar II LLC, San Isabel Solar LLC, Bison Solar LLC and PSEG Energy Solutions LLC (collectively the "Applicants" or "PSEG") hereby jointly submit for filing their updated market power analysis in support of their continued eligibility to engage in market-based rates

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transactions. This market power analysis satisfies the requirements of Order No. 697[1] for the filing of updated market power analyses on a regional schedule basis by holders of market-based rate certificates and their affiliates. In accordance with the regional schedule for those utilities in the Northeast Region, as modified by the MBR Clarifying Order, this filing is being made by the December 2016 deadline.[2] In conformance with the Commission's requirements, except when expressly noted otherwise, the market power analysis is based on activity during the study period from December 1, 2014 through November 30, 2015 ("study period").

PSEG, through its subsidiary PSE&G, owns transmission facilities within the Northeast Region. Specifically, PSE&G owns transmission facilities in the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization. PSEG Power LLC and its subsidiaries do not own any transmission facilities other than transmission to connect generating units to the grid in PJM, the New York Independent System Operator, Inc. ("NYISO") and ISO New England Inc. ("ISO-NE").

In their original applications for market-based rate authority and previously-submitted updates to the Commission, PSEG ER&T, PSE&G, PSEG Power CT, PSEG Fossil, PSEG Nuclear and PSEG New Haven demonstrated that they and their affiliates: (a) do not exercise generation market power; (b) lack the ability to manipulate access to transmission facilities that they own or control; and (c) cannot erect any other barriers to market entry. As further demonstrated herein and in the Affidavit of Dr. John R. Morris attached hereto in the appendices, Applicants continue to satisfy the Commission's requirements to sell energy, capacity and ancillary services at market-based rates and thus should be permitted to continue to make such sales.

I. SERVICE AND COMMUNICATION

All service and correspondence related to this matter should be directed to the following individuals:

[1] 18 C.F.R. Part 35, Subpart H (2007); Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, 119 FERC ¶ 61,295, ("Order No. 697" or "MBR Order"), *order clarifying final rule*, 121 FERC ¶ 61,260 (2007) ("MBR Clarifying Order"), *order on reh'g and clarification*, 123 FERC ¶ 61,055 (2008) FERC Stats. & Regs ¶ 31,268 ("Order No. 697-A"), *order on reh'g and clarification*, 124 FERC ¶ 61,055 (2008) ("SIL Allocation Order").

[2] This filing is made on the three year anniversary of the December 2013 deadline set forth in Order No. 697 Appendix D.

As to the Applicants Generally:

Kenneth Carretta, Esq.
Deputy General Counsel
PSEG Services Corporation
80 Park Plaza, T5G
Newark, NJ 07102
(973) 430-6462
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Associate General Regulatory and Property Counsel
PSEG Services Corporation
80 Park Plaza, T5G
Newark, NJ 07102
(973) 430-6451
(973) 430-5983 (facsimile)
David.Richter@PSEG.com

Applicants request waiver of Rule 203(b)(3)[3] so that a copy of any communications in these proceedings may be served on all persons listed above.

II. DESCRIPTION OF THE APPLICANTS AND RELEVANT AFFILIATES

A. The Applicants

The Applicants are each wholly owned, direct and indirect subsidiaries of Public Service Enterprise Group Incorporated ("PSEG"). PSEG is a public utility holding company engaged in, among other things, the generation of electric energy and the transmission, distribution and sale of electricity and natural gas through its subsidiaries.

1. Public Service Electric and Gas Company

PSE&G is a public utility operating company engaged primarily in the transmission of electricity, and the provision of gas and electric distribution service in the State of New Jersey. During the study period, PSE&G owned less than 140 MW of solar generation, 8 MW of Energy Efficiency and 91 MWs of Demand Response but otherwise did not own or operate any electric generation facilities. PSE&G is a member of the PJM Regional Transmission Organization and has made all of its transmission facilities available for open access transmission service pursuant to the PJM Open Access

[3] 18 C.F.R. § 385.203(b)(3).

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Transmission Tariff ("OATT") administered by PJM. PSE&G is authorized to sell power at market-based rates and makes wholesale sales falling within several different categories, as described below.

Non-utility generation ("NUG") output. PSE&G's NUG output expired in 2015 and 2016 pursuant to the terms of the NUG contracts. PSE&G currently has no further NUG obligations, other than 0.6 MW of energy associated with the former Kinsley Landfill which no longer operates. .

Solar. In 2007, the New Jersey legislature passed Regional Greenhouse Gas Initiative ("RGGI") legislation authorizing state utilities to invest in renewable resources such as wind or solar in order to promote increased use of renewable resources within the state and in turn reduce greenhouse gas emissions. *See* L. 2007, c. 340, codified at N.J.S.A. 48:98-1. The NJBPU has approved two (2) PSE&G Solar 4 All® (S4A) programs under which PSE&G has sited, designed and built twenty-nine (29) grid connected solar facilities. PSE&G currently owns and operates approximately 115MW-dc of grid connected solar under the S4A program. PSE&G expects the S4A fleet to increase to approximately 125MW-dc by the end of 2016. In 2016, PSE&G received NJBPU approval of its Solar 4 All Extension II filing to install an additional 33MW-dc of grid connected solar on landfills and brownfields in the PSE&G electric service territory.

2. PSEG Energy Resources & Trade LLC

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil and PSEG Nuclear, each wholly-owned subsidiaries of PSEG Power LLC ("PSEG Power"), as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission.

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

BGS Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 *et seq.,* which initiated the transition from a regulated to a competitive retail power market in New Jersey, BPU annually approves statewide auctions to determine the entities that will supply Basic Generation Service ("BGS") in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSEG ER&T has participated directly in all of the auctions for BGS supply held since 2004, has been a winning bidder in these auctions and has incurred contractual

commitments to provide supply to BGS load pursuant to BPU approved contracts beginning with the 2004 auction and continuing to the present

BGSS Gas Contract. By order issued April 16, 2002, the BPU approved a full requirements contract for the provision of gas supply by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the BPU, PSEG ER&T assumed, through capacity release, FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract remains in effect and provides for annual renewals unless terminated by either party on 12 months' advance written notice.

LIPA Fuel Supply: On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which ER&T will provide fuel supply and power supply management activities for LIPA beginning on January 1, 2015.

3. PSEG Fossil LLC

PSEG Fossil is an Exempt Wholesale Generator ("EWG") and is authorized to sell power at market-based rates. PSEG Fossil owns and operates electric generation facilities located within PJM and sells their entire output to its affiliate PSEG ER&T.[4] The assets of PSEG Fossil (and its subsidiary, PSEG Keys Energy Center LLC ("PSEG Keys")) are located entirely within PJM. However, PSEG Fossil's subsidiaries PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Power New York LLC and PSEG New Haven LLC own facilities in ISO-NE and NYISO. As noted below, PSEG Fossil also co-owns certain facilities in PJM.

PSEG Fossil and its subsidiaries PSEG Power CT and PSEG Keys are currently beginning construction on three new gas-fired generation units. PSEG Fossil is constructing Sewaren 7[5] which is a 540 MW combined cycle unit in Woodbridge, New Jersey which is expected to be in-service in 2018, PSEG Keys is constructing a 755 MW combined cycle unit in Prince George's County, Maryland which is expected to be in service in 2018 and PSEG Power CT is constructing Bridgeport 5, a 485 MW combined cycle unit in Bridgeport, Connecticut which is expected to be in service in 2019.

Since the last triennial filing in December 2013 PSEG Fossil has retired 1,813.5 MWs (nameplate) inclusive of the following units:

Kearny 9 (18.6 MW)
Bergen 3 (18.6 MW)

[4]These contracts were originally approved by the Commission as cost-based contracts. *See Public Service Electric and Gas Company*, et al., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Fossil obtained market based rate authority covering sales from its generating units.

[5] Once Sewaren 7 begins commercial operation, PSEG Fossil plans to retire Sewaren 1, 2, 3 and 4.

Bridgeport 2 (179.5 MW)
Burlington 8 (18.6 MW
Burlington 9 (162.4 MW)
Burlington 11 (162.4 MW)
Edison 1 (167.4 MW)
Edison 2 (167.4 MW)
Edison 3 (167.4 MW)
Essex 10 (167.4 MW)
Essex 11 (167.4 MW)
Essex 12 (167.4 MW)
Mercer 3 (115.2 MW)
National Park (18.6 MW)
Sewaren 6 (115.2 MW)

In addition, PSEG Fossil, LLC notified PJM of its intent to retire Hudson 2 (659 MW nameplate rating) and Mercer Units 1 and 2 (652MW nameplate rating) by June 1, 2017.

PSEG Fossil satisfies most of the electricity needs of its plants from PJM under PJM's "station power" Tariff provisions. PSEG Fossil procures gas supply for its plants from PSEG ER&T and receives gas distribution service from PSE&G at a rate approved by the BPU on May 29, 2013.[6]

4. PSEG Power Connecticut LLC

PSEG Power CT is a Connecticut limited liability company and an EWG that owns and operates electric generation facilities in the State of Connecticut and is authorized to sell power at market-based rates.[7] Both of PSEG Power CT's generation facilities, Bridgeport Harbor and New Haven Harbor, are located in the State of Connecticut within the market administered by ISO-NE. PSEG Power CT sells the output of its generation facilities to its affiliate PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority. As noted above, PSEG Power CT is currently constructing Bridgeport 5, a 485 MW combined cycle unit in Bridgeport, Connecticut which is expected to be in service in 2019.

5. PSEG New Haven LLC

PSEG New Haven is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG New Haven owns and operates a facility (the "New Haven facility") in New Haven, Connecticut with a nameplate rating of 181 MWs. The New Haven facility is located within the New Haven Harbor generation station. The New Haven facility is interconnected to the adjacent United Illuminating East Shore Substation using a 115 KV underground cable. PSEG New Haven has no other

[6] BPU Docket No. GM12100935 (May 29, 2013).
[7] *Wisvest Corporation,* et al., 101 FERC ¶ 61,166 (2002).

generation assets. The commercial operation date for the New Haven facility was June 1, 2012 and PSEG New Haven has obtained MBR authority from FERC.[8]

The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[9] pursuant to a Connecticut statute that sought proposals for peaking generation in Connecticut.[10] All of the energy and capacity of the New Haven facility is sold into the ISO New England ("ISO-NE") markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA[11] has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder. The 181 MW nameplate rating of the New Haven Facility has not been included in the capacity controlled by PSEG for purposes of Dr. Morris' market power analysis.

6. PSEG Nuclear LLC

PSEG Nuclear is an EWG[12] and is authorized to sell power at market-based rates. PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission.[13] The assets of PSEG Nuclear are located entirely within PJM. PSEG Nuclear performed the following uprates since the last triennial filing: (1) an uprate of 120 MWs at its Hope Creek plant in 2014, which increased its nameplate rating to 1290 MWs, (2) an uprate to Peach Bottom 2 and 3 which increases PSEG's share of the nameplate MWs by 241 MWs for a updated nameplate of 704 MW for Peach Bottom 2 and 689 MWs for Peach Bottom 3.

7. Pavant Solar LLC, San Isabel Solar LLC and Bison Solar LLC

PSEG Power Ventures portfolio includes three (3) solar companies with market-based rate authority: (1) *Pavant Solar II LLC*[14] is a QF which owns a 50 MW (AC) solar facility in Fillmore Utah; (2) *San Isabel Solar LLC*[15] is a QF which owns a 30 MW (AC)

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[8] *PSEG New Haven LLC*, Docket No. ER12-1250-000, et al., (May 29, 2012).

[9] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control (DPUC). PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

[10] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

[11] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

[12] *PSEG Nuclear LLC*, 97 FERC ¶ 62,191 (November 30, 2001).

[13] *Public Service Electric and Gas Company*, et al., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Nuclear obtained market based rate authority from the FERC.

[14] *Pavant Solar II LLC*, Docket No. QF16-1072-000.

[15] *San Isabel Solar LLC*, Docket No. QF16-712-000.

solar facility in Las Animas County, Colorado and (3) *Bison Solar LLC*[16] is a QF which owns a 30 MW (AC) solar facility 25 miles north of Fort Collins, Colorado.

8. PSEG Energy Solutions LLC

PSEG Energy Solutions LLC ("PSEG Solutions") is a Delaware limited liability company and a direct subsidiary of PSEG ER&T. PSEG Solutions obtained market-based rate authority[17] and will operate within the PJM Interconnection, L.L.C. ("PJM"), New York Independent System Operator, Inc. ("NYISO") and ISO New England Inc. ("ISO-NE") markets. Energy Solutions will purchase power from the regional transmission organization ("RTO") at wholesale and sell it to retail customers. PSEG Solutions will not own or operate any generation assets. PSEG Solutions proposes to begin its retail business on January 1, 2017.

OTHER RELEVANT AFFILIATES

PSEG is also the direct or indirect parent of certain other subsidiaries engaged in energy related activities, as discussed below.

7. Affiliated Generation Ownership.

A list of the Applicants' affiliated domestic FERC jurisdictional generation assets owned is contained in Appendix B attached hereto. [18] Those additional subsidiaries of PSEG that may be considered relevant to this market power update for the Northeast Region are described below:

PSEG Power LLC ("PSEG Power") was formed in 1999 to acquire the former generation assets of PSE&G. PSEG Power, a Delaware limited liability company, does not directly own any generation facilities or engage in any FERC jurisdictional activities but is the parent company of several FERC jurisdictional entities, including Applicants PSEG ER&T (and it subsidiary PSEG Energy Solutions LLC), PSEG Fossil, PSEG Nuclear, PSEG Power CT, PSEG New Haven and PSEG Power Ventures LLC (which owns PSEG Solar Source LLC).

PSEG Power Ventures LLC and PSEG Solar Source LLC. PSEG Power Ventures LLC ("Power Ventures") is a Delaware Limited Liability company and a direct subsidiary of PSEG Power. PSEG Power Ventures owns 100% interest in PSEG Solar Source LLC and has an in-direct ownership interest in a domestic power plant in Hawaii. PSEG Solar Source owns approximately 349 MWs DC (274 MW AC) of solar capacity across the United States, including a combined 92

[16] *Bison Solar LLC*, Docket No. QF16-711-001.
[17] See Letter Order dated December 21, 2016 in Docket No. ER16-2725-000.
[18] Appendix B excludes generation assets located in Hawaii as well as generation assets in which PSEG's interest is limited to a leveraged lease interest.

MWs[19] (72 MW AC) of solar capacity in PJM and approximately the following amount of MWs in the following states all through separate project companies which have all obtained QF status.

- 15 MWs (12 MW AC) in Florida,
- 92 MWs in PJM (72 MW AC) – 12 MWs in Ohio, 2 MW in New Jersey, 15 MW in Delaware, 50 MW in North Carolina and 13 MW in Maryland
- 45 MWs in Arizona (34 MW AC) – 25 MW Queen, approximately 20 MW Badger
- 13 MWs (10 MW AC) in Texas,
- 34 MWs (25 MW AC) in California[20]
- 4 MWs (3 MW AC) in Vermont and
- 74 MW (60 MW AC) in Colorado (to be in operation in 2016) – 38 MWs for San Isabel and 36 MWs for Bison
- 62 MW (50 MW AC) in Utah (to be in operation in 2016).
- 10.5 MW (8 MW AC) in Oregon (to be in operation in 2016).

PSEG Resources LLC ("Resources") is a New Jersey limited liability company that provides energy infrastructure financing in developed countries. Resources invests primarily in energy-related financial transactions and manages a diversified portfolio of investments including leveraged leases. Resources owns interests, through leveraged leases, in various generation stations. Pursuant to the terms of these triple net leases, the lessee, not Resources, has all operational responsibility and control over the leased generation stations.

PSEG Power New York LLC ("PSEG Power NY") is a Delaware limited liability company and an EWG that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 750 MW combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a FERC-approved cost-based contract.[21]

[19] The 92MWs are attributed to four (7) separate project companies that have QF status: PSEG Solar Hackettstown LLC (2 MW); PSEG Solar Delaware LLC (15 MW), Rockfish Solar LLC (13 MWs) Meadows Solar (26 MW), Turkey Creek (17 MW) Hemlock Solar (7 MW) in North Carolina and PSEG Solar Ohio LLC (12 MW).

[20] The 28MWs (DC) are associated with the Shasta Solar Facility in California (4 MW), Whitehorn Solar (3 MWs) the Columbia Solar Project (19 MW). All have obtained QF status.

[21] *PSEG Power New York Inc.*, Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

PSEG Keys Energy Center LLC ("PSEG Keys") is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG Keys was formed to construct, operate and maintain the Keys Energy Center, a 755MW combined cycle power plant in Prince Georges County, Maryland. Construction began in 2015 and is expected to be completed in 2018 at which time the capacity will be available in the PJM market. All of the output of the Keys Energy Center will be sold to PSEG Keys affiliate, PSEG ER&T.

PSEG Long Island LLC ("Long Island") and Long Island Electric Utility Servco, LLC ("Servco") are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution system ("T&D") on Long Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither Long Island nor Servco will be FERC jurisdictional public utilities as neither will exercise ultimate decision making authority over the T&D system in Long Island. Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[22]

8. Affiliated Transmission Ownership

With the exception of the electric transmission assets owned by Applicant PSE&G, all of which are located within the PJM RTO, and the generation interconnection facilities owned by the various EWG and QF affiliates listed herein, the Applicants, nor their affiliates have any affiliates that own or operate FERC jurisdictional electric or natural gas transmission facilities within the United States[23]. As discussed below, FERC granted PSE&G a Hinshaw exemption in 1954, finding that it was exempt from the provisions of the Natural Gas Act.

B. JOINTLY OWNED FACILITIES

PSEG Nuclear is a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear is the operator of Salem and Exelon Generation is the operator of Peach Bottom.[24] PSEG Fossil is approximately a 23% joint owner in the Conemaugh and Keystone generating stations located in Pennsylvania. An affiliate of NRG Energy is the operator.[25] Accordingly, for

[22] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), *order dismissing request for rehearing*, 145 FERC ¶ 61,183 (2013).

[23] PSEG Power LLC is a 10% owner of the PennEast Pipeline Company LLC which has filed an application for approval to construct and operate a natural gas transmission line.

[24] A letter of concurrence supporting the allocation of plant output based on ownership interests is attached in Appendix E. The ownership percentages have not changed since the date of this letter. PSEG Nuclear owns a 50% interest in Peach Bottom and a 57.41% interest in Salem.

[25] A letter of concurrence supporting the allocation of plant output based on ownership interest is attached in Appendix E. The ownership percentages have not changed since the date of this letter.

purposes of this market power analysis, the capacity of Salem, Peach Bottom, Conemaugh and Keystone has been attributed to PSEG in accordance with PSEG's ownership interests in these facilities.

PSEG Fossil and Jersey Central Power and Light Company ("JCP&L") are each 50% co-owners of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to the unit. Accordingly, for the purpose of this market power analysis, the entire unit capacity – nominally 400 MWs – has been assigned to JCP&L.[26]

III. Applicants Fully Satisfy The Commission's Standards For Authority to Make Power Sales At Market-Based Rates.

The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, horizontal and vertical market power.[27] The Commission has also codified affiliate restrictions in its regulations which must be satisfied on an ongoing basis. In previous submissions for market-based rate authority the Applicants PSE&G, PSEG ER&T, PSEG Power CT, PSEG Fossil, PSEG Nuclear, and PSEG New Haven, demonstrated compliance with each of these requirements. As detailed herein and in the attached affidavit, the Applicants continue to meet these standards.

A. The Applicants Lack, Or Have Effectively Mitigated, Any Horizontal Market Power

In the MBR Order, the Commission established two indicative screens: a pivotal supplier screen based on the control area's annual peak demand and a wholesale market share screen applied on a seasonal basis. If an applicant passes both screens, there is a rebuttable presumption that the applicant does not possess horizontal market power. Each indicative screen is applied with respect to "relevant geographic markets" for an applicant's generating units.

Applicants located in ISOs/RTOs possessing sufficient market structure may consider the geographic region under the control of the ISO/RTO as the relevant default geographic region for purposes of completing their generation market power analyses.[28] However, where the Commission has previously found a "submarket" to exist within a boundary of an RTO, such finding is controlling as to the scope of the relevant geographic market for all generation units located within that submarket for the application of the indicative screens and any delivered price test that may be performed. The Commission further listed several such submarkets, including PJM East ("PJME"),

[26] A letter of concurrence supporting this determination is attached in Appendix E. The ownership percentages have not changed since the date of this letter.
[27] MBR Order, FERC Stats. & Regs. ¶ 31,252 at P 62, 399, 408, 440.
[28] *MBR Order at* PP. 231 and 235.

Connecticut and Southwest Connecticut.[29] Subsequent to the MBR order, in approving a merger between Exelon Corporation and Constellation Energy Group, Inc., the Commission identified additional submarkets in PJM - PJM East of 5004/5005 ("PJM50") and PJM East of AP South ("PJMAP") - that would be relevant to an MBR analysis for applicants in the Northeast Region.[30]

As discussed below and in the attached Affidavit of Dr. John Morris contained in Appendix A, Applicants have conducted market power analyses of the entire PJM RTO, the PJME, PJM50 and PJMAP submarkets, the entire NYISO, the entire ISO-NE, the Connecticut submarket and the Southwest Connecticut submarket for the study period. The results are set forth below.

1. Indicative Screens

a. Pivotal Supplier Analysis

The pivotal supplier analysis ("PSA") focuses on the ability of a seller to exercise unilateral market power.[31] The screen assesses whether market demand can be met during peak times without the applicant and its affiliates. If demand can be met without the applicant and its affiliates, the applicant passes that the PSA screen. The Affidavit of Dr. John Morris, attached hereto as Appendix A, finds that the Applicants pass the PSA screen for all relevant markets: PJM, NYISO, ISO-NE, Connecticut, Southwest Connecticut, PJMAP, PJME and PJM50.[32]

b. Wholesale Market Share Analysis

The wholesale market share analysis ("WMSA") is applied each season to determine whether an applicant has a dominant market position based on the total number of megawatts of uncommitted capacity owned or controlled by the applicant and its affiliates in relation to the uncommitted capacity of the entire relevant wholesale electricity market.[33] The established threshold is 20 percent; a supplier who has less than 20 percent market share in the relevant market for all seasons passes the WMSA screen.

In his Affidavit Dr. Morris finds that the Applicants pass the WMSA screen for PJM, NYISO, ISO-NE, Connecticut, Southwest Connecticut and PJMAP but do not pass the WMSA screen for the PJME and PJM50 submarkets.[34]

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[29] *Order No. 697* at P 236 (citing *Exelon Corp.*, 112 FERC ¶ 61,011, *reh'g denied*, 113 FERC ¶ 61, 299 (2005)). FERC eliminated the Northern PSEG zone as a default submarket in Order No. 697-A, P 99.

[30] Order Conditionally Authorizing Merger and Disposition of Jurisdictional Facilities, *Exelon Corporation, et al.*, 138 FERC ¶ 61,167 (2012).

[31] *AEP I* at P 72.

[32] *See* Morris Affidavit, at 15-29.

[33] *AEP I,* P 100.

[34] *See* Morris Affidavit, at 15-29.

c. Results of Indicative Screen Analysis

As shown in Dr. Morris's affidavit, Applicants therefore pass both indicative screen tests for PJM RTO, NYISO, ISO-NE, Connecticut and Southwest Connecticut and PJMAP. For PJME and PJM50, the Applicants pass the PSA but do not pass the WMSA.

2. Delivered Price Test Analysis For PJME and PJM50 Submarkets

In accordance with the MBR Order, applicants who fail either indicative screen test can rebut the presumption of market power through the submission of a delivered price test analysis ("DPT"). Applicants may submit this study at the same time that the results of the indicative screens are provided.[35] The DPT is based on two measurements of potential market power: economic capacity ("EC") and available economic capacity ("AEC"). EC is the capacity that can be delivered to a destination market for 105 percent or less than the market price. AEC is calculated by subtracting native load commitments from EC. Both calculations are performed for ten different season and load conditions.

In applying the DPT, "[a] showing of an HHI less than 2,500 in the relevant market for all season/load conditions for sellers that have also shown that they are not pivotal and do not possess a 20 percent or greater market share in any of the season/load conditions would constitute a showing of a lack of market power, absent compelling contrary evidence from intervenors."[36] However, while meeting these threshold benchmarks provides "safe harbor" protection, the Commission has found in numerous other cases that applicants lack market power even when they exceed one or more of the thresholds for particular study periods. As stated in *Public Service Company of New Mexico*, 115 FERC ¶ 61,090, P 38 (2006), "the Commission weights the results of both the economic and available economic capacity tests and considers the arguments of the applicant and intervenors." (footnote omitted.) [37]

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[35] *Order No. 697,* P 76.

[36] *Order No. 697* at P 111.

[37] Indeed, in that case, the applicant was deemed "on balance" to have adequately rebutted a showing of market power mitigation for the PNM control area where the results exceeded the 20% safe harbor in two cases under the AEC measure and in all 10 cases at values between 35% and 41% under the EC measure. *See, e.g.*, *Kansas City Power and Light Company, et al.*, Docket Nos. ER99-1005-011 et al. (August 12, 2010) (finding no market power where applicant had EC market shares in the 40-60% range and had significant HHI failures in the KCPL and GMO markets); *Cordova Energy Company LLC et al,* Docket Nos. ER99-2156-011, *et al.*, November 13, 2007 (finding no market power in case where applicant had EC market shares in PACE control area between 53.1% and 60.0%, HHIs between 2,958 and 3,696 and was pivotal in 8 out of 10 periods.); *PacifiCorp*, Letter Order, Docket Nos. ER97-2801-007, *et al.*, February 1, 2007; *Tucson Elec. Power Co.*, 116 FERC ¶ 61,051 (2006)(finding market power standard satisfied where applicant had EC market shares above 20% in all ten season/load periods in the Tucson control area, exceeded the 2,500 HHI threshold in eight periods, and was pivotal in 5 periods); *PacifiCorp*, 115 FERC ¶ 61,349 (2006) (finding that applicants rebutted presumption of market power in the PacifiCorp East control area where under available economic capacity measure, market share is less than 20% in 8 season/load periods and 28% in the summer and winter off-peak periods, HHI does not exceed 2500 in any season/load period and applicants are not pivotal); *Kansas City Power & Light Co.*, 113 FERC ¶ 61,074 (2005) (finding

a. Results of the DPT for PJM50 Submarket

For both the AEC and EC, PSEG passes all screens in all periods except for the pivotal supplier screen in the Summer Top 1% period.

b. Results of the DPT for PJME Submarket

With respect to AEC, PSEG passes all the screens in all 10 periods. With respect to the EC, PSEG passes the Market Concentration screens in all periods. It also passes the Pivotal Supplier Screen in 8 of 10 periods, and passes the Market Share Screen in 6 of 10 periods. PSEG's market shares are never above 25 percent. Although greater than the 20 percent screen, PSEG's market shares are well below the 35 percent threshold that is typically used for imputing unilateral market power.

3. Analysis of DPT Results

Based on his analysis of the overall results, Dr. Morris concludes that, although PSEG fails limited number of screens, the failures are substantially below levels that typically indicate market power. As set forth in his Affidavit, Dr. Morris states that:

> Although PSEG fails some screens in the PJME destination market, the overall results are not indicative of PSEG having market power. To begin, PSEG passes all the AEC screens and all market concentration (HHI) screens for EC. The HHI levels in all periods, capacity types, and areas are below the screening threshold of 2,500, and typically substantially below this level. In terms of the DPT for market rate authority and under the 2010 DOJ and FTC Horizontal Merger Guidelines, the market is not highly concentrated.[38] The low HHI levels mean that PSEG has little ability to exercise market power in coordination with other suppliers. It also passes all the AEC pivotal supplier screens, and most of the EC pivotal supplier screens. This means that typically PSEG's generation is not necessary to serve load; and when its generation is necessary, its forward sale commitments are sufficient so that its uncommitted generation is not necessary to serve the remaining load. Finally, PSEG's market shares are never above 15 percent in PJM50 and for AEC in PJM East. Its market shares for EC are never above 25 percent in PJM East. Although greater than the 20 percent screen, PSEG's market shares are

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no market power in the KCPL control area where applicant had EC market shares above 20% in all periods, exceeded the HHI 2,500 threshold in 5 of 10 periods and was pivotal supplier in 1 period); *Acadia Power Partners, L.P.*, 113 FERC ¶ 61,073 (2005) (finding no market power in the Cleco Power home control where, utilizing the EC measure, the applicant exceeded the thresholds set for all season/load periods using the market share measure, one season/load period using the market concentration measure, and for all season/load periods using the pivotal supplier measure).

[38] See U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Issued August 19, 2010, at Section 5.3, available at http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

> well below the 35 percent threshold that is typically used for imputing unilateral market power.[39]

Dr. Morris's conclusion is consistent with Commission precedent finding a lack of market power in cases in which the DPT results included more instances of findings outside of the "safe harbor" thresholds and at higher levels than exist here.[40] In these circumstances, Dr. Morris's analysis successfully rebuts any inference of market power created by the WMSA screen failures for PJME.

4. Existing RTO/ISO Mitigation Rules Also Eliminate The Potential for Exercising Market Power In the PJME, PJME PJM50 and PJMAP Submarkets

PJM mitigation rules eliminate the potential for the exercise of market power in the PJME submarket. The MBR Order specifically contemplated that RTO/ISO mitigation rules may serve as evidence that any market power has been adequately mitigated. The Commission declared, "We believe the added protections provided in structured markets with market monitoring and mitigation generally result in a market where prices are transparent and attempts to exercise of market power will be sufficiently mitigated."[41] The Order on Rehearing went even further and specifically created a presumption that any potential market power had been adequately mitigated by an established and effective RTO market monitoring scheme.[42]

Taking account of the pervasive PJM mitigation rule, Dr. Morris concludes that these rules "fully address the potential for PSEG to exercise market power" in PJME.[43] Accordingly, PJM's mitigation schemes in place are sufficient to rebut any inference of market power created by the failure to pass the WMSA screens in PJME and PJM50.

In addition, in the Applicants' last triennial approval order, the Commission found that "the PJM market monitoring and mitigation rules are sufficient to address market power concerns in the PJM-East submarket."[44]

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[39] *See*, *e.g.*, U.S. Department of Justice, 1984 Merger Guidelines, at Section 3.12, available at https://www.justice.gov/sites/default/files/atr/legacy/2007/07/11/11249.pdf ("the Department is likely to challenge the merger of any firm with a market share of at least one percent with the leading firm in the market, provided the leading firm has a market share that is at least 35 percent.")

[40] *See Public Service Company of New Mexico*, 115 FERC ¶ 61,090 (2006) discussed above and cases discussed in fn. 38 above.

[41] MBR Order at P 241.

[42] Order No. 697A at P 111.

[43] Morris Affidavit, pp. 24-26.

[44] *See* October 14, 2014 letter order approving Applicants' prior triennial market update in Docket No. ER10-1789-003 et al. at page 3.

a. The Applicants Lack Transmission Market Power and Cannot Erect Entry Barriers.

In its previous order accepting PSEG's triennial market power analysis for the Northeast Region, the Commission found that the submittal satisfied the Commission's requirements for market-based rates regarding vertical market power.[45] There have been no subsequent changes in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. As demonstrated below, neither Applicants nor any of its affiliates are able to exercise vertical market power.

Applicants are not able to exercise transmission market power. Neither Applicants nor any of their affiliates, except PSE&G, own transmission assets in the U.S. other than incidental generator interconnection facilities. PSE&G owns transmission facilities in PJM but transmission service over those facilities is provided under the PJM Open Access Transmission Tariff.

In addition, neither Applicants nor their affiliates are able to exercise vertical market power in wholesale energy markets through affiliation, ownership or control of inputs to electric power production. As required by Section 35.37(e) of the Commission's regulations, Applicants provide the following information:

(1) PSE&G owns and operates a natural gas distribution system that receives interstate pipeline gas within the State of New Jersey and distributes that gas to its customers within the State of New Jersey. The distribution system consists of 18,050 miles of gas distribution pipe and an additional 62 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3 and peak-shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers. Service over such distribution facilities is made available pursuant to state regulated tariffs on an open access type basis. PSE&G was granted a Hinshaw exemption from the FERC in 1954.[46] The gas distribution rates paid by PSEG Fossil to PSE&G have been set at rates approved by the BPU in an order dated May 29, 2013.

(2) Certain of the Applicants and their affiliates own sites within the Northeast Region that would be suitable for future generating facilities. These include space at many of the existing generating sites of PSEG Fossil and at the sites of PSEG Power NY and PSEG Power CT. PSEG Nuclear's Salem facility may also be suitable for future construction. PSE&G also owns certain sites that would be suitable for generating facilities, but under New Jersey's Electric Discount and Energy Competition Act, N.J.S.A 48:3-43 et seq., PSE&G is effectively barred from owning and operating

[45] *Id.*
[46] 13 F.P.C. 1348 (1954).

generation except "on site" generation for supply and Class I renewable energy resources as defined in N.J.S.A. 48:3-98.1.

(3) Neither Applicants nor any of their affiliates own or control any physical coal supply resources or own or control who may access transportation of coal supplies.

(4) As required by section 35.37(e)(4) of the Commission's regulations, Applicants and its affiliates state that they have not erected barriers to entry into any market, including the PJM, NYISO or ISO-NE market and will not erect barriers to entry into any markets.

IV. REQUEST FOR CONFIDENTIAL TREATMENT

Under separate cover via UPS Overnight this office is submitting compact disks containing the workpapers of Dr. John Morris supporting his analysis in Appendix A, as required by the Commission's April 2004 Order.[47] The CD (of which six copies are included) contains: (i) proprietary information provided by Energy Velocity under an agreement that requires confidential treatment to be requested for these materials; (ii) modeling and computer programs that are the proprietary intellectual property of Economists Incorporated, the firm which employs Dr. Morris; (iii) commercially sensitive information about Applicants and their affiliates; and (iv) documents and information deemed to be confidential by PJM and ISO-NE. Accordingly, Applicants respectfully request confidential treatment for CD and the workpapers pursuant to 18 C.F.R. § 388.112 (2006), consistent with the confidential treatment accorded other applicants submitting such proprietary and commercially sensitive data.[48] Pursuant to the Commission's rules, the public version of this filing contains all materials submitted herein except for CD, which is labeled as "PRIVILEGED AND CONFIDENTIAL/NON-PUBLIC."

V. SERVICE

This filing has been served on all parties on the official service list as currently maintained by Commission in the above-referenced dockets. Applicants are also providing a copy to the New Jersey Board of Public Utilities and the New Jersey Division of Rate Counsel.

VI. ENCLOSURES

Applicants enclose the following:

- An original filing;

[47] AEP II, 107 FERC at P 61,087-88.

[48] *See, e.g., Idaho Power Company*, Docket No. ER97-1481-009 (February 3, 2006) (submission of revised Pivotal Supplier Screen and Market Share Screen calculations including similar data).

- Appendix A – Affidavit of Dr. John R. Morris;[49]
- Appendix B – List of Entities with Market-Based Rates Authority and Their Generation Assets. (This is an appendix listing the filing entities and all their energy affiliates and their associated assets);
- Appendix C – List of Entities with Market-Based Rate Authority and Their Transmission Assets;
- Appendix D – List of Long Term Power Purchase Agreements;
- Appendix E – Letters of concurrence regarding the control of certain jointly owned generation facilities;
- Appendix F – Form of notice suitable for publication in the Federal Register.

[49] Compact disks, as described above, containing the workpapers for the Affidavit of John R. Morris in Appendix A are being sent concurrently with this filing via UPS Overnight. As noted *supra*, privileged treatment is being requested for Dr. Morris's confidential workpapers submitted with the non-public version of this filing.

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VII. CONCLUSION.

Applicants respectfully request the Commission

(i) to accept this market power compliance filing as meeting the Commission's requirements under Order No. 697 for the continuation of market-based rate authority for Applicants PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG New Haven LLC, PSEG Nuclear LLC, PSEG Fossil LLC, Pavant Solar II, LLC, Bison Solar LLC , San Isabel Solar LLC and PSEG Energy Solutions LLC;

(ii) to grant the request for confidential treatment; and

(iii) to grant such other relief or waivers as may be appropriate or necessary.

Respectfully submitted,

Public Service Electric and Gas Company
PSEG Energy Resources & Trade LLC
PSEG Power Connecticut LLC
PSEG Fossil LLC
PSEG Nuclear LLC
PSEG New Haven LLC
Pavant Solar II, LLC
Bison Solar, LLC
San Isabel Solar, LLC
PSEG Energy Solutions LLC

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Dated: December 28, 2016
Newark, New Jersey

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Appendix A
Affidavit of
Dr. John R. Morris

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Appendix B
List of Entities with Market-Based Rate Authority and Their Generation Assets

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Appendix C
List of Entities with Market-Based Rate Authority and Their Transmission Assets

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Appendix D
Long Term Power Purchase Agreements

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Appendix E
Letters of concurrence regarding the control of certain jointly owned generation facilities

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Appendix F
Form of notice suitable for publication in the Federal Register

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PSEG Energy Resources & Trade LLC	Docket No. ER99-3151-___
Public Service Electric and Gas Company	Docket No. ER97-837-___
PSEG Power Connecticut LLC	Docket No. ER03-327-_____
PSEG Fossil LLC	Docket No. ER08-447-_____
PSEG Nuclear LLC	Docket No. ER08-448-_____
PSEG New Haven LLC	Docket No. ER12-1250-___
Pavant Solar II LLC	Docket No. ER16-1926-____
San Isabel Solar LLC	Docket No.ER16-1925-____
Bison Solar LLC	Docket No.ER16-1924-____
PSEG Energy Solutions LLC	Docket No. ER16-2725-____

NOTICE OF FILING
( )

Take notice that on December 28, 2016: (i) PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG New Haven LLC, PSEG Fossil LLC, PSEG Nuclear LLC, Pavant II Solar LLC, Bison Solar LLC, San Isabel Solar LLC and PSEG Energy Solutions LLC tendered for filing their joint triennial market power update in compliance with Order No. 679 and with prior Commission Orders granting them market-based rate authority in Docket Nos. ER99-3151, ER97-837, ER03-327, ER08-447 ER08-448, DR-12-1250, ER16-1926, ER16-1925, ER16-1924 and ER16-2725 respectively.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR §§ 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file

electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

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Comment Date: 5:00 pm Eastern Time on (insert date).
Kimberly J. Bose
Secretary

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UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Public Service Electric and Gas Company	)	ER97-837-____
PSEG Energy Resources & Trade LLC	)	ER99-3151-____
PSEG Power Connecticut LLC	)	ER03-327-____
PSEG Fossil LLC	)	ER08-447-____
PSEG Nuclear LLC	)	ER08-448-____
PSEG New Haven LLC	) Docket Nos.	ER12-1250-____
Pavant II Solar LLC	)	ER16-1926-____
Bison Solar LLC	)	ER16-1925-____
San Isabel Solar LLC	)	ER16-1924-____
PSEG Energy Solutions LLC	)	ER16-2725-____

Report & Affidavit of
Dr. John R. Morris

December 22, 2016

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Public Service Enterprise Group Incorporated Northeast Region Market Power Study

1. Introduction

My name is Dr. John R. Morris. I am a Principal at Economists Incorporated, an economic consulting firm located at 2121 K Street, NW, Washington, DC 20037. I have a bachelor's degree in economics from Georgetown University, and I have a master's degree and a Ph.D. in economics from the University of Washington. I have been studying and consulting within energy industries since joining the Federal Trade Commission in 1985. Since joining Economists Incorporated in 1992, I have consulted on many mergers involving electric and gas companies, examined competitive issues relating to utility rates, provided market power studies for applications for market-based rate authority, and studied market power issues in state restructuring proceedings. I have published articles on competition and energy matters, and I have spoken on numerous occasions concerning competition in natural gas, electric power and other industries. I have previously been accepted as an expert witness on energy matters before the Federal Energy Regulatory Commission ("FERC" or "Commission"), state commissions and in federal court. A complete listing of my experience, publications and testimony is contained in my resume, presented in Exhibit PEG-2.

Public Service Enterprise Group Incorporated ("PSEG") asked that I prepare a market power study for its subsidiaries that have market-based rate authority in the Northeast Region.[1] These subsidiaries are: Public Service Electric and Gas

[1] The Northeast Region includes ISO-New England Inc. ("ISO-NE"), Connecticut, Southwest Connecticut, New York Independent System Operator, Inc. ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), PJM East, PJM East of 5004/5005 and PJM East of AP South.

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("PSE&G"), PSEG Energy Resources & Trade LLC ("PSEG ER&T"), PSEG Fossil LLC ("PSEG Fossil"), PSEG Nuclear LLC ("PSEG Nuclear"), PSEG Power Connecticut LLC ("PSEG Power CT"). PSEG New Haven LLC ("PSEG New Haven") Pavant II Solar LLC, Bison Solar LLC and San Isabel Solar LLC.[2] The purpose of this study is to determine whether these PSEG entities have market power in any Northeast Region market under the Commission's Pivotal Supplier Analysis ("PSA") and Wholesale Market Share Analysis ("WMSA") screens as articulated in FERC Order No. 697 and if the Applicants do fail any of the screens, whether they otherwise lack market power under the Delivered Price Test ("DPT") or are subject to sufficient mitigation to guard against any market power concerns.[3]

PSEG

PSEG is a public utility holding company headquartered in in Newark, New Jersey. Through its subsidiaries, PSEG engages in the generation, transmission, distribution and sale of electric energy, and distribution and sale of natural gas to commercial, residential, and industrial customers primarily in the Northeastern and Mid-Atlantic United States. PSEG, through its subsidiaries, owns approximately 11,300 MW of seasonal generation capacity located in the Northeast Region.[4]

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[2] Pavant II Solar LLC, Bison Solar LLC and San Isabel Solar LLC all have QF status.

[3] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 119 FERC ¶ 61,295, ("Order No. 697" or "MBR Order"), *order clarifying final rule*, 121 FERC ¶ 61,260 (2007) ("MBR Clarifying Order"), *order on reh'g and clarification*, 123 FERC ¶ 61,055 (2008) FERC Stats. & Regs ¶ 31,268 ("Order No. 697-A"), *order on reh'g and clarification*, 124 FERC ¶ 61,055 (2008) ("SIL Allocation Order").

[4] *See* Exhibit PEG-3 (accounting for retirements).

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PSE&G

PSE&G is a public utility operating company engaged primarily in the transmission of electricity and the provision of gas and electric distribution service in the State of New Jersey. It is New Jersey's oldest and largest investor-owned utility. PSE&G was founded in 1903 and is based in Newark, New Jersey. It is a member of the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization and has made all of its transmission facilities available for open access transmission service pursuant to the PJM Open Access Transmission Tariff ("OATT") administered by PJM. The company also owns and operates 18,050 miles of gas distribution pipe and an additional 62 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3. During the study period, PSE&G owned less than 140 MW of solar generation, 8 MW of Energy Efficiency and 91 MWs of Demand Response but otherwise did not own or operate any electric generation facilities.

PSEG ER&T

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil and PSEG Nuclear, each wholly-owned subsidiaries of PSEG Power LLC ("PSEG Power"), as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission. PSEG ER&T also makes wholesale sales of natural gas.

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

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BGS Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 *et seq.,* which initiated the transition from a regulated to a competitive retail power market in New Jersey, the New Jersey Board of Public Utilities ("BPU") annually approves statewide auctions to determine the entities that will supply Basic Generation Service ("BGS") in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSE&G's affiliate, PSEG ER&T, has participated directly in all of the auctions for BGS supply held since 2004 and has consistently won tranches in those auctions, including auctions for BGS service within the franchised service territory of PSE&G.

BGSS Gas Contract. By order issued April 16, 2002, the BPU approved a full requirements contract for the provision of gas supply by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the BPU, PSEG ER&T assumed, through capacity release, PSE&G's FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract, which currently remains in effect, provides for annual renewals unless terminated by either party on 12 months' advance written notice.

LIPA Fuel Supply. On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which

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ER&T provides fuel supply and power supply management activities for LIPA as of January 1, 2015.

PSEG Fossil

PSEG Fossil owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission under the umbrella of PSEG Fossil's market-based rate authority.[5] The assets of PSEG Fossil are located entirely within PJM.[6] Since the last triennial filing in 2013, PSEG Fossil has retired approximately 1,800 MW of capacity in the eastern portion of PJM. Much of this capacity was retired at the end of May 2015. We included this capacity in the Winter and Spring season screens and exclude the capacity for the Summer and Fall screens.

PSEG Fossil is approximately a 23 percent joint owner of interests in the Conemaugh and Keystone generating stations located in Pennsylvania. An affiliate of NRG Energy is the operator.[7] PSEG Fossil is a 50 percent co-owner with Jersey Central Power and Light Company ("JCP&L") of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to

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[5] *Public Service Electric and Gas Company, et al*., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000).

[6] PSEG Fossil's subsidiaries PSEG Power Connecticut LLC, PSEG New Haven LLC and PSEG Power New York LLC own generation units in Connecticut and New York respectively.

[7] A letter of concurrence supporting the allocation of these facilities' output based on ownership interests is attached in our workpapers.

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the unit. Accordingly, for the purpose of this market power analysis, the entire unit capacity, nominally 400 MWs, has been assigned to JCP&L.[8]

PSEG Power CT

PSEG Power CT owns the Bridgeport Harbor and New Haven Harbor generation facilities located in the state of Connecticut within ISO-NE and is authorized to sell power at market-based rates.[9] The output of these facilities is sold to PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority. PSEG Power CT is currently constructing Bridgeport 5, a 485 MW gas-fired combined cycle in Bridgeport, Connecticut, which is expected in service in 2019.

PSEG New Haven

PSEG New Haven owns and operates the New Haven facility, a gas-fired plant located in New Haven, CT that entered service in June 2012 with a nameplate capacity of 181.5 MW. The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[10] pursuant to a Connecticut statute that sought proposals for peaking generation in Connecticut.[11] All of the energy and capacity of the New Haven facility is sold

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[8] A letter of concurrence supporting the allocation of this facility's output to JCP&L is attached in our workpapers.

[9] *Wisvest Corporation, et al*., 101 FERC ¶ 61,166 (2002).

[10] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control (DPUC). PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

[11] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

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into the ISO-NE markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder.[12] As such, neither PSEG New Haven nor any other PSEG affiliate has operational control of the New Haven facility. As a result, the capacity of the facility is not attributable to PSEG for the purpose of this market power analysis.

PSEG Nuclear

PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission in accordance with PSEG Nuclear's market-based rate authority.[13] PSEG Nuclear is the owner of Hope Creek and a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear operates the Salem plant and Exelon Generation is the operator of Peach Bottom.[14] Since the last triennial filing, uprates at Peach Bottom and Hope Creek plants have increased PSEG Nuclear's capacity at those facilities.

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[12] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

[13] *Public Service Electric and Gas Company, et al*., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000).

[14] A letter of concurrence supporting the allocation of plant output based on ownership interests is attached in our workpapers.

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Other Subsidiaries

PSEG is also the direct or indirect parent of certain other subsidiaries engaged in energy related activities in the United States. Those additional subsidiaries of PSEG that may be considered relevant to this market power update for the PJM region are as follows.

PSEG Power LLC is a Delaware limited liability company. It does not directly own any generation facilities or engage in any FERC jurisdictional activities but it is the parent company of several FERC jurisdictional entities, including applicants PSEG ER&T, PSEG Fossil and PSEG Nuclear.

PSEG Power Ventures LLC ("Power Ventures") is a Delaware Limited Liability company and a direct subsidiary of PSEG Power. PSEG Power Ventures owns 100% interest in PSEG Solar Source LLC and has an in-direct ownership interest in a domestic power plant in Hawaii. PSEG Solar Source owns approximately 349 MWs DC (274 MW AC) of solar capacity across the United States, including a combined 92 MWs (72 MW AC) of solar capacity in PJM.[15] All of PSEG Solar Source's solar capacity has obtained QF status. Because all of this capacity is QF capacity, per Order No. 816 this capacity is not included in the market power analyses.[16]

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[15] The 42MWs are attributed to four (7) separate project companies that have QF status: PSEG Solar Hackettstown LLC (2 MW); PSEG Solar Delaware LLC (15 MW), Rockfish Solar LLC (13 MWs) Meadows Solar (26 MW), Turkey Creek (17 MW) Hemlock Solar (7 MW) in North Carolina and PSEG Solar Ohio LLC (12 MW).

[16] *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 816, 80 *Fed. Reg*. 67056 (2015), FERC STAT & REGS ¶ 31,374, P55 (2015), *reh'g denied and clarification*, Order No. 816-A, 155 FERC ¶ 61,188 (2016) ("… qualifying facilities that are exempt from FPA section 205 and facilities that are behind-the-meter facilities do not need to be reported in the asset appendix or indicative screens." (note omitted))

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PSEG Resources LLC ("Resources") is a New Jersey limited liability company that provides energy infrastructure financing in developed countries. PSEG Resources invests primarily in energy-related financial transactions and manages a diversified portfolio of investments including leveraged leases. PSEG Resources owns interests, through leveraged leases, in various generation stations. Pursuant to the terms of these triple net leases, the lessee, not Resources, has all operational responsibility and control over the leased generation stations.

PSEG Power New York LLC ("PSEG Power NY") is a Delaware limited liability company that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 750 MW combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a cost-based contract.[17]

PSEG Keys Energy Center LLC ("PSEG Keys"), direct subsidiary of PSEG Fossil, was formed to construct, operate, and maintain the Keys Energy Center, a 755 gas-fired combined cycle facility located in Prince George's County, Maryland. Construction began in 2015 and is scheduled to be completed in 2018. All the capacity and energy from PSEG Keys will be sold to PSEG ER&T.

PSEG Energy Solutions LLC ("PSEG Solutions") is a direct subsidiary of PSEG ER&T that is schedule to begin retail operations in the Northeast Region in

[17] *PSEG Power New York Inc.,* Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

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January 2017. It has obtained market-rate authority to allow it to sell excess energy in wholesale markets.[18]

PSEG Long Island LLC ("Long Island") and Long Island Electric Utility Servco, LLC ("Servco") are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution ("T&D") system on Long Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither Long Island nor Servco are FERC jurisdictional public utilities, as neither will exercise ultimate decision making authority over the T&D system in Long Island. Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[19]

When an applicant has affiliates in the relevant market, the Commission considers the combined capacity of all the affiliated entities in its market power assessment.[20] Accordingly, I have included the capacity controlled by PSE&G, PSEG ER&T, PSEG Power CT, PSEG Fossil, PSEG Nuclear, and PSEG Power New York (which on a combined basis constitutes the capacity of all of PSEG's affiliates not excluded for a reason explained above). Future references in this Affidavit to PSEG are inclusive of the foregoing entities.

The primary purpose of this study is to determine whether PSEG passes the PSA and WMSA screen thresholds in ISO-NE, the NYISO and PJM. In the PSA, the Commission requires applicants to examine whether the generation owned by

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[18] *See* December 21, 2016 letter order approving Energy Solutions request for market-based rate authority in Docket No. ER16-2725-000.

[19] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), order dismissing request for rehearing, 145 FERC ¶ 61,183 (2013).

[20] *Heartland Energy Services, Inc.,* 68 FERC ¶ 61,223 at 62,061-62,062 (1994).

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the applicant is necessary to serve wholesale demand within a balancing authority area. The applicant first calculates the total generation capacity for an area. This is the total of generation in the balancing authority area plus the import capability to the area.[21] From this total, the applicant subtracts out firm contractual commitments, native load obligations, and operating reserves, giving uncommitted capacity for the area. Net uncommitted capacity is calculated by subtracting a wholesale load proxy from uncommitted capacity. Net uncommitted capacity is then compared to the applicant's uncommitted capacity within the area. When the applicant's uncommitted capacity is less than the net uncommitted capacity for the area, then all wholesale demand could be served without energy from the applicant and the applicant passes the PSA screen. When the applicant's uncommitted capacity is greater than the net uncommitted capacity, then the applicant does not pass the screen because its capacity is necessary to meet wholesale peak loads in the market.

In the WMSA, the Commission requires applicants to examine whether the generation owned by the applicant is 20 percent or more of the uncommitted capacity in each of four seasons under average daily peak conditions for the season. The applicant first calculates the total generation capacity for an area. The applicant then adds the import capability to the area. From this total, the applicant subtracts out planned outages and deratings, long-term firm contractual commitments, native load obligations, and operating reserves. The sum gives the total uncommitted capacity. The applicant then calculates its share by dividing its uncommitted capacity by the total uncommitted capacity. When the applicant's share is less than 20 percent, the applicant passes the WMSA screen.

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[21] Import capability is the lesser of either the simultaneous import limit ("SIL") into the area or available capacity in interconnected balancing authority areas. Available capacity is equal to total generation capacity in an area less outages and derating, a native load proxy and operating reserves.

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The Commission presumes that an applicant does not have market power when it passes both the PSA and WMSA screens. If the applicant fails either of the screens, then the applicant may present other analyses to demonstrate that it does not possess market power. Alternatively, the applicant may propose mitigation measures or accept the Commission's default mitigation measures to demonstrate that it has mitigated market power.

2. New England

2.1. Overview of Electric Power Markets in New England

New England operates a competitive wholesale power market. Substantial restructuring has taken place in New England, and many of the vertically integrated utilities have sold either most or all of their generation assets. The traditional utilities often have standard offer obligations to serve retail customers, but utilities often fulfill these obligations by securing supplies in competitive wholesale markets. For example, a utility may secure contracts in which the supplier agrees to provide power for 30 percent of the utility's standard offer obligation. The transmission system is managed by ISO-NE. The market has a market monitor and market power mitigation program in place to identify and to mitigate any potential exercise of market power.

2.2. Geographic Markets

In the case of generation wholly located in an RTO, such as ISO-NE, the Commission accepts the RTO as the relevant destination market.[22] When the Commission has identified a sub-market within an RTO, the applicant must also provide market power screens for the relevant sub-markets.[23] In New England,

[22] Order No. 697 at PP 231, 235.

[23] Order No. 697 at P 236.

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the Commission has identified two submarkets: Connecticut and Southwest Connecticut.[24] PSEG owns the Bridgeport Harbor plant in Southwest Connecticut. PSEG also owns the New Haven Harbor 1 unit in Connecticut and PSEG New Haven owns the New Haven facility. When the applicant does not own the transmission system, as in the instant case, the applicant needs to provide an analysis only for the balancing authority area to which the generation is interconnected.[25] Accordingly, the PSA and WMSA are provided for the ISO-NE balancing authority area, and also for Connecticut and Southwest Connecticut.

2.3. Data Sources and Analysis

The data source for generation is ISO-NE Seasonal Claimed Capability (SCC) Reports.[26] Summer and winter capacities were taken from the November 2015 report. Planned outages are from the ISO-NE Form 714. Planned outages for Connecticut and Southwest Connecticut are prorated based on their shares of the total generation capacity in ISO-NE. PSEG's generation capacity in ISO-NE consists of the New Haven facility, New Haven Harbor and Bridgeport Harbor. PSEG's Northeast Region generation facilities are presented in Exhibit PEG-3.

Load data for ISO-NE are from Energy Velocity. Energy Velocity also provides load data by New England ISO zone, thus loads are calculated by sub-market as well. PSEG load obligations in New England come from PSEG's agreements to supply standard offer generation within Rhode Island. The data were supplied by PSEG.

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[24] *Id*.

[25] Order No. 697 at footnotes 215, 217.

[26] See http://www.iso-ne.com/genrtion_resrcs/snl_clmd_cap/index.html.

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Import capability was taken from the ISO-NE's December 20, 2016 FERC filing.[27] This report indicates that the simultaneous transfer limits in all seasons is 4,548 MW for the ISO-NE as a whole, 3,050 MW for Connecticut, and 2,370 (Spring) to 3,200 MW (Summer) for Southwest Connecticut. PSEG has no firm transmission rights into New England.

Operating reserves are calculated as follows. ISO-NE Operating Procedure No. 8 specifies spinning reserves (or 10-minute reserves) equal to the size of the loss of the largest unit times a Contingency Reserve Adjustment Factor ("CRAF").[28] The CRAF in 2015 was 1.25.[29] The largest unit is the 1,400 MW (summer capacity) Seabrook Unit 1. In addition, 30-minute reserves require capacity to cover 50 percent of the loss of a second contingency (i.e., the second largest unit) plus 160 MW for daylight-savings time periods and 180 MW during standard time (i.e., winter). The second largest unit is the 1,200 MW (summer capacity) Millstone Unit 3. Thus, in total, operating reserves are 2,510 MW in summer.[30] Operating reserves for Connecticut and Southwest Connecticut are based on resource needs in forward reserve auctions for 2015.[31]

2.4. Results

Exhibit PEG-4 summarizes the results for the PSA and the WMSA in New England. Exhibit PEG-5 shows the calculations to determine whether PSEG is a

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[27] ISO New England Inc. Simultaneous Import Limit for 2015, *Guidance on Simultaneous Transmission Import Limit Studies*; Docket No. AD10-02, December 20, 2016.

[28] ISO New England Operating Procedure No. 8, at 5-6, available at https://www.iso-ne.com/participate/rules-procedures/operating-procedures.

[29] ISO New England, Inc. 2015 Regional System Plan ("Regional System Plan"), available at https://www.iso-ne.com/static-assets/documents/2015/11/rsp15_final_110515.docx, at 68.

[30] 2,510 MW = 1,400 MW x 1.25 + 50% x 1,200 MW + 160.

[31] ISO New England, Inc. 2015 Regional System Plan ("Regional System Plan"), available at https://www.iso-ne.com/static-assets/documents/2015/11/rsp15_final_110515.docx, Table 4.12 at p.70.

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pivotal supplier in the three New England destination markets. PSEG passes the PSA screen in all areas. Exhibit PEG-6 presents the WMSA results for the destination areas in New England. PSEG easily passes the WMSA in all areas.

3. New York

3.1. Overview of Electric Power Markets in New York

New York also has a competitive wholesale power market. Substantial restructuring has taken place in New York, and the investor-owned vertically integrated utilities have sold either most or all of their generation assets. These utilities often have standard offer obligations to serve retail customers, and utilities can fulfill these obligations by securing supplies in competitive wholesale markets. The transmission system is operated by the NYISO, which also operates a competitive wholesale market. The market has a market monitor and market power mitigation program in place to identify and to mitigate any potential exercise of market power.

3.2. Geographic Markets

In the case of generation wholly located in an RTO such as the New York ISO, the Commission has accepted the RTO as the relevant destination market.[32] PSEG only owns generation in Albany, New York. In addition, when the applicant does not own the transmission system, as in the instant case, the applicant needs to provide an analysis only for the balancing authority area to which the generation is interconnected.[33] Accordingly, the PSA and WMSA are provided for the NYISO only.

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[32] Order No. 697 at PP 231, 235.

[33] Order No. 697 at footnotes 215, 217.

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3.3. Data Sources and Analysis

The principal data source for generation is the Energy Velocity Market-Operations database. Planned outages are from the FERC Form 714. PSEG's generation capacity in New York consists of its ownership of the Bethlehem Energy Center in Albany, which has winter capacity of 845 MW. Information for PSEG's Northeast Region generation is presented in Exhibit PEG-3.

Load data for NYISO were downloaded from Energy Velocity.

Import capability comes from the most recent NYISO SIL filing as of December 19, 2016.[34] This filing indicates that ISO simultaneous import capability ranges from 6,850 MW in spring to 7,695 MW in summer. NYISO does not recognize physical imports, accordingly, all the SIL import capability is allocated pro rata, except for a 265 MW reservation that PSEG has from PJM to New York on the Linden VFT DC transmission line.

Operating reserves are calculated as follows. The NYISO Locational Reserve Requirements specify 30-minute total reserves equal to twice the 10-minute reserve necessary to replace the operating capability loss caused by the most severe contingency under normal transfer conditions. Thus, the operating reserves for the NYISO are 2,620 MW for each season.[35]

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[34] New York Independent System Operator, Inc., *Informational Filing Regarding the Simultaneous Import Limitation Study*, Docket No. AD10-2, December 19, 2016.

[35] NYISO Locational Reserve Requirements, Table 2, available at http://www.nyiso.com/public/webdocs/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf

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3.4. Results

Exhibit PEG-7 shows the calculations to determine whether PSEG is a pivotal supplier in New York, and PSEG passes the PSA screen. Exhibit PEG-8 presents the WMSA results for New York, and PSEG easily passes the WMSA.

4. PJM

4.1. Overview of Electric Power Markets in PJM

PJM operates a competitive wholesale power market and serves as the regional RTO for an area that covers all or parts of 13 states and the District of Columbia. PJM also plans and operates the transmission system within the RTO. Monitoring Analytics acts as the market monitor, and has a market power mitigation program in place to identify and mitigate any potential exercise of market power.

4.2. Geographic Markets

PSEG owns both generation and transmission facilities in PJM. In the case of generation wholly located in an RTO such as PJM, the Commission has accepted the RTO as the relevant destination market.[36] When the Commission has identified a sub-market within an RTO, the applicant must also provide market power screens for the relevant sub-markets.[37] In PJM, the Commission has identified three submarkets: PJM East ("PJME"), PJM East of 5004/5005 ("PJM50") and PJM East of AP-South ("PJMAP").[38] The PSA and WMSA are provided for PJM and for the PJME, PJM50 and PJMAP sub-markets.

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[36] Order No. 697 at PP 231, 235.

[37] Order No. 697 at P 236.

[38] *Id*. *See also* Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, Order No. 697-A, 73 FR 25832 (May 7, 2008), FERC

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4.3. Data Sources and Analysis

The principal data source for generation is the Energy Velocity Market-Ops database. Generation within PJM was assigned to submarket consistent with the definitions in PJM's SIL Study.[39] Planned outages are from the FERC Form 714. In addition, for the sub-market analysis, planned outages were allocated to PJME based on the share of total PJME generation, by season. Information for PSEG's generation in PJM and PJME is presented in Exhibit PEG-3.

Load data for PJM was downloaded from Energy Velocity. Energy Velocity also provides load data by PJM zone, thus loads are calculated for the PJM sub-markets as well.

Import capability was taken from the 2015 Simultaneous Import Limit Study Report.[40] This report indicates simultaneous transfer limits of 11,997 MW in the winter and 7,600 MW in summer. Additionally, this report indicates transmission capabilities of the PJM sub-markets. The report conservatively uses the reported SIL as the SIL amount to be allocated pro rata. This is a simplifying assumption because PSEG has no firm transmission reservations into PJM and it effectively excludes the additional 8,500 MW of firm reservations into PJM in the base case of the SIL study.

Stats, & Regs. ¶ 31,268 (2008) at P 90; Order Conditionally Authorizing Merger and Disposition of Jurisdictional Facilities, *Exelon Corporation, et al.*, 138 FERC ¶ 61,167 (2012).

[39] PJM Interconnection, L.L.C., *Informational Filing of 2015 Simultaneous Import Limit Study Report for PJM Region*, Docket No. AD1-2-007, September 2, 2016, Accession No. 20160902-5155.

[40] *Id*.

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Operating reserves are calculated according to PJM Manual 13 as the sum of Day Ahead Scheduling Reserves (Operating), Contingency (Primary) and Synchronized (Spinning Reserve) Requirements.[41]

Data on PSEG's long-term contracts come from PSEG. The contracts were included in the area where the energy is delivered under the contract. For contracts delivered to the Western Hub in PJM, the contracts were included in the PJM, PJM50, and PJMAP destinations and not the PJME destination.

4.4. Results

Exhibit PEG-9 summarizes the results for the PSA and the WMSA in PJM. Exhibit PEG-10 shows the calculations to determine whether PSEG is a pivotal supplier in the four PJM destination markets. PSEG passes the PSA screen for all four destinations. Exhibit PEG-11 presents the WMSA results for the destination markets in PJM. PSEG easily passes the WMSA in PJM and PJM east of AP South, but has greater than a 20 percent market share in the PJM East and PJM East of 5004/5005 destination markets.

5. Delivered Price Test

When an applicant does not pass either the PSA or WMSA for a destination market, the Commission invites the applicant to provide additional information via a delivered price test ("DPT"). PSEG requested that I perform a DPT for the PJM East and PJM East of 5004/5005 sub-markets. Accordingly, I now discuss the DPT for these sub-markets.

[41] PJM Manual 13 - Emergency Operations, at 17, available at http://pjm.com/~/media/documents/manuals/m13.ashx

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5.1. Overview of the DPT

The DPT utilizes substantially more information than the PSA or the WMSA, including additional information on generation ownership, generation costs, demand conditions, and transmission limits. The Commission considers two types of capacity: Economic Capacity ("EC") and Available Economic Capacity ("AEC"). EC is the capacity that can be delivered to a destination market for 105 percent or less than the market price. AEC is calculated by subtracting load commitments from EC. EC and AEC are calculated for a number of different seasonal and load conditions.

Because we do not know the firm retail obligations of the competitive suppliers, as explained below, the AEC calculation is based on the assumption that market participants serve load in proportion to their generation capacity and that 70 percent of load obligations are contracted more than one year from delivery.

For both the EC and AEC measures, the Commission prescribes three screens: (1) a pivotal supplier screen; (2) a market share screen; and (3) a Herfindahl-Hirschman Index ("HHI") screen. The HHI is the sum of the squared market shares of the firms in the market. So a market with four firms of market shares of 40, 30, 20, and 10 percent would have an HHI of 3,000 (this is calculated as $40^2 + 30^2 + 20^2 + 10^2 = 1{,}600 + 900 + 400 + 100 = 3{,}000$). A monopolist would produce a HHI of 10,000 and 10 equally-sized firms would produce a HHI of 1,000.

Although the Commission has not drawn bright lines for its review of DPT results, it has given general guidance. When (1) the applicant is not pivotal; (2) the applicants' market share is less than 20 percent; and (3) the HHI is below 2,500, the Commission is likely to conclude that the applicant does not have market power. The three standards establish a "safe harbor" for lack of market power, unless intervenors present clear and convincing contrary evidence. The Commission has also determined in some cases that an applicant did not have

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market power when the analysis showed isolated HHI and market share results above screening levels. Finally, despite the DPT results, the Commission may conclude that an applicant does not have market power if other evidence, such as historical sales data, indicates that the DPT results do not reflect the actual competition in the marketplace.

A detailed description of data sources and methods to prepare the data for the DPT is presented in Exhibit PEG-12. An overview of the sources and methods used at Economists Incorporated for conducting the DPT is presented here.

The DPT is calculated for 10 representative periods, three for each of three seasonal conditions plus a summer super peak period. The three seasons are spring/fall, summer, and winter. Each season is divided into (1) top 10 percent of peak hours; (2) remaining peak hours; and (3) off-peak hours. In addition, there is a summer super peak period which is comprised to the top 1 percent (10 hours) of summer peak hours. These ten periods cover the range of load conditions for each season, and for the year as a whole.

The primary source for generation data is Energy Velocity. In addition to generation capacity, Energy Velocity provides data on ownership (including holding companies), fully-loaded heat rates, emission rates, and generation availability. Generation is included for all of PJM and NYISO, which is the only first-tier balancing authority area in which PSEG owns generation. Unit capabilities are derated to account for seasonal maintenance and likely plant unavailability due to forced outages. Because demand in PJM peaks in summer and winter, the planned outages are assumed to be during the spring/fall season.

The transmission system is represented by contract paths between balancing authority areas and within PJM. Limits between regions in PJM are from Energy Velocity.

Market prices come from hourly prices reported by PJM.

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As in the PSA and WMSA, load data come from Energy Velocity. To compute load requirements for market participants, we apportion the total load in each market area in New York and PJM to all suppliers in proportion to their respective generation capacities. We assumed 70 percent of load is committed for a year or longer and the remaining 30 percent is contracted for shorter periods.[42] To account for their greater load obligations, we assume that Dominion, which does not operate in a restructured retail market, has 100 percent responsibility for its allocation of load and that AEP, which operates in a partly restructured retail market, has 90 percent of its allocation as opposed to the standard 70 percent.

The DPT and market share calculations were calculated using the Power Acquisition Screening System developed at Economists Incorporated. The mathematical details are presented in Exhibit PEG-13.

5.2. Results of the DPT for PJM50 Sub-market

The results of the DPT for PJM50 are presented in Exhibit PEG-14. The top part of the exhibit shows the results for AEC. PSEG passes the Pivotal Supplier Screen in all 10 periods. PSEG also passes both the Market Share Screens and the HHI Screens in all 10 periods.

The lower part of Exhibit PEG-14 shows the results for EC in PJM50. PSEG passes all the screens in all the periods, except for the pivotal supplier screen in the Summer Top 1% period.

[42] This is a reasonable estimate for the long-term load coverage since this number is generally between 60 and 80 percent for most generation suppliers in restructured markets.

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5.3. Results of the DPT for PJME Sub-market

The results of the DPT for PJME are presented in Exhibit PEG-15. The top part of the exhibit shows the results for AEC. PSEG passes all the screens for AEC.

The lower part of Exhibit PEG-15 shows the results for EC in PJME. PSEG passes the Market Concentration screens in all periods. It passes the Market share screens in six of ten periods, and its market share is never more than 25 percent. It passes the pivotal supplier screen in eight of ten periods.

5.4. Analysis of the DPT Results

Although PSEG fails some screens, the overall results are not indicative of PSEG having market power. To begin, PSEG passes all the AEC screens and all market concentration (HHI) screens for EC. The HHI levels in all periods, capacity types, and areas are below the screening threshold of 2,500, and typically substantially below this level. In terms of the DPT for market rate authority and under the 2010 DOJ and FTC Horizontal Merger Guidelines, the market is not highly concentrated.[43] The low HHI levels mean that PSEG has little ability to exercise market power in coordination with other suppliers. It also passes all the AEC pivotal supplier screens, and most of the EC pivotal supplier screens. This means that typically PSEG's generation is not necessary to serve load; and when its generation is necessary, its forward sale commitments are sufficient so that its uncommitted generation is not necessary to serve the remaining load. Finally, PSEG's market shares are never above 15 percent in PJM50 and for AEC in PJM East. Its market shares for EC are never above 25 percent in PJM East. Although greater than the 20 percent screen, PSEG's

[43] See U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Issued August 19, 2010, at Section 5.3, available at http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

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market shares are well below the 35 percent threshold that is typically used for imputing unilateral market power.[44]

5.5. Mitigation

PJM has a Commission-approved market monitoring and mitigation plan in place to ensure that generation facilities cannot exercise market power. The Commission has stated that Commission-approved market monitoring and mitigation plans are sufficient to mitigate market power in RTO markets.[45] In particular, the Commission found in connection with PSEG's last triennial filing that the PJM market monitoring and mitigation rules are sufficient to address market power concerns.[46]

Under the local market power mitigation procedures in PJM, if a supplier fails the "three pivotal supplier test" (TPS), it is offer-capped by the Market Monitor. The Market Monitor's TPS test is applied on an ongoing basis, potentially as frequently as every 5 minutes, to reflect day-ahead and real-time operating conditions. These offer caps provide direct protection against the exercise of locational market power by suppliers in PJME, PJM50, PJMAP and elsewhere.

The protection against the exercise of market power is enhanced by "must offer" requirements under PJM's Operating Agreement. These mandate that generation resources that are used to meet capacity requirements in PJM and

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[44] *See*, *e.g.*, U.S. Department of Justice, 1984 Merger Guidelines, at Section 3.12, available at https://www.justice.gov/sites/default/files/atr/legacy/2007/07/11/11249.pdf ("the Department is likely to challenge the merger of any firm with a market share of at least one percent with the leading firm in the market, provided the leading firm has a market share that is at least 35 percent.")..

[45] Order No. 697 at P 241.

[46] *See* October 14, 2014 letter order approving Applicants' prior triennial market update in Docket No. ER10-1789-003 et al. at page 3.

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that are not subject to an outage must offer their available capacity in PJM's day-ahead energy market.[47] PJM has also implemented a Reliability Pricing Model (RPM) to secure sufficient capacity to meet its requirements through a series of auctions, including a Base Residual Auction (BRA) held annually for capacity 3 years in advance, and incremental auctions held at varying intervals prior to the delivery year. Various features of the RPM process work to prevent the exercise of market power in capacity markets in PJM. First, the RPM model includes bid cap rules designed to mitigate the potential exercise of market power. Second, RPM includes a must-offer requirement pursuant to which all generating units that have available capacity must bid into the RPM auctions or face disqualification from being recognized as capacity resources (and therefore from receiving any capacity payments) in the delivery year.

In addition to the local market power mitigation described above, the presence of market monitoring within PJM lessens potential concerns that PSEG might be able to exercise market power notwithstanding the indicative DPT screens. The Market Monitor has the specific responsibility under the market monitoring plan to monitor the potential of any market participant to exercise market power. To perform its market monitoring function, the Market Monitor can file reports or complaints with the Commission and other government agencies to address various market concerns including market power. The Market Monitor can also make its view known to the Commission staff and PJM members in cases where PJM does not follow its recommendations concerning complaints or requested rule changes. In addition, the Market Monitor can consult with regulatory bodies, including state commissions, regarding the need for specific investigations and monitoring activities, and to consider and evaluate additional enforcement mechanisms. The Market Monitor can also act on specific

[47] *See* PJM Operating Agreement at 1.10.1A(d).

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complaints that have been filed by market participants to examine any potential market power issues.

In sum, the local market power mitigation rules, the role of the Market Monitor, the existence of must-offer requirements and PJM's RPM auctions address the potential for PSEG to exercise market power.

6. Vertical Market Power

In determining whether the market-based rates are in the public interest, the Commission also considers whether the Applicant has transmission market power or can erect barriers to entry.[48] None of these factors are relevant in the instant case. First, other than incidental generator interconnection facilities and the transmission assets owned by PSE&G in PJM, no transmission assets are owned by the Applicants or any of their affiliates in ISO-NE and NYISO. Transmission service over PSE&G's transmission facilities is provided under the PJM Open Access Transmission Tariff. Thus, consistent with Commission precedent, Applicants have alleviated any concerns regarding potential transmission market power. Second, PSEG has no ability to erect barriers to entry. As explained in Applicants' previous initial applications for market-based rate authority and triennial market power reports, PSEG is unable to erect barriers to entry. There has been no change in facts since the submission of those applications that would alter this conclusion.

The Commission is concerned with the ownership of natural gas pipelines or natural gas distribution facilities and the possibility that they may be used to exercise market power in electricity markets. PSEG does not own or operate any

[48] Order No. 697 at PP 397, 399.

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FERC jurisdictional natural gas pipelines in PJM, ISO-NE or NYISO.[49] PSE&G owns natural gas distribution facilities in the State of New Jersey including peak-shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers.

7. Conclusion

PSEG and its subsidiaries do not have market power in New England, New York or PJM. PSEG is not a pivotal supplier in New England, New York or PJM. PSEG's market shares in the WMSA are below the Commission's 20 percent screening threshold in each of these market areas. PSEG is also not a pivotal supplier in the Connecticut or Southwest Connecticut sub-markets and its market shares in the WMSA are below 20 percent in these sub-markets. PSEG fails the WMSA screens in only the PJME and PJM50 sub-markets. For these sub-markets, we conducted a DPT analysis. PSEG passes all the DPT screens for the PJM50 submarket, and it only fails the Market Share Screen in the PJME submarket. Its market shares are never above 25 percent, a level that the Commission has accepted in other market-based rate matters.[50] As such, they are not evidence of actual market power.

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[49] PSEG Power LLC currently owns a 10 percent interest in the PennEast Pipeline Company LLC which has filed an application with FERC for construction and operation of a gas transmission line.

[50] *See*, *e.g.*, *Dogwood Energy, LLC*, 135 FERC ¶ 61,089 (2011) (under the AEC measure, Dogwood failed the market share screen in seven of ten periods, with market shares ranging from 32.7% to 39.6%); *Kansas City Power & Light Company and KCP&L Greater Missouri Operation Company*, Docket No. ER10-2074-001 et al., Supplement to Change in Status Filing at 11 (Feb. 4, 2013) (accepted by Letter Order, November 22, 2013) (market shares for AEC ranging from 17 to 36%); *Shell Energy N.A. (US), L.P.*, 135 FERC ¶ 61,090 (2011) (under the AEC measure, Shell failed the market share screen for seven of ten periods, with market shares ranging from 29.3% to 37.0%); *Calpine Energy Services, L.P.*, 137 FERC ¶ 61,085 at P 21 (2011) (under the AEC measure, Calpine failed the market share screen in all ten periods, with market shares ranging from 20.4% to 28.9%); *Wildcat Power Holdings, LLC*, 136 FERC ¶ 61,013 at P 14 (2011) ("When the available economic capacity measure is used, Wildcat Power's market shares range from 22 to 24 percent in the three summer super peak and winter

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Further, PSEG operates under New England's, New York's, and PJM's market power mitigation programs, which mitigate PSEG's potential market power. Therefore, under standards for market-based rate authority articulated by the Commission in Order No. 697, PSEG has no ability to exercise market power in the relevant markets, and maintaining market-rate authority in New England, New York and PJM would be in the public interest.

Therefore, I recommend that the Commission continue to authorize PSEG to sell electric power in Northeast Region wholesale markets at market-based rates.

super peak season/load periods and zero percent in the remainder of the season/load periods."); *LS Power Marketing*, LLC,139 FERC ¶ 61,140 at P 23 (2012) (under the AEC measure, LS Power failed the market share screen in all ten periods, with market shares ranging from 20.4% to 28.9%); *Gila River Power, L.P.*, Docket Nos. ER05-1178-015, et al., Second Supplement to Updated Market Power Analysis at 4 (Jan. 12, 2011) (accepted by Letter Order, April 5, 2011) (market shares for AEC ranging from 21 to 23% in four season/load periods).

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Pursuant to 28 U.S.C. §1746, I state under penalty of perjury that the foregoing is true and correct to the best of my information, knowledge, and belief.

Executed on this 22rd day of December 2016.

John R. Morris, Ph.D.
Principal
Economists Incorporated

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EXPERIENCE AND QUALIFICATIONS OF

Dr. John R. Morris

OVERVIEW	Dr. Morris, a recognized expert in studying competition in energy industries, currently is a Principal at Economists Incorporated. He began his research of competition in energy industries in 1985 while working for the Federal Trade Commission. Since joining Economists Incorporated in 1992, he has consulted on many mergers and acquisitions involving energy companies, examined competitive issues relating to rates, and studied issues in state restructuring proceedings. He has published articles on competition and energy matters, and he has spoken on numerous occasions concerning competition in natural gas, electric power and other industries. He has been accepted as an expert witness on energy matters before the Federal Energy Regulatory Commission, state regulatory commissions, and in federal court.
EDUCATION	Ph.D., University of Washington, August 1985 Dissertation: *Intellectual Property: Creating, Pricing, Copying* • M.A., University of Washington, December 1983 • A.B., Georgetown University, May 1981
PRESENT POSITION	Dr. Morris is a *Principal* at Economists Incorporated, an economic consulting firm located at 2121 K Street, NW, Suite 1100, Washington, DC 20037. (202-223-4700) Economists Incorporated studies competition and regulation in many industries in the United States and in other countries. It is a leading firm in studying the competitive effects of mergers and acquisitions.
PREVIOUS EXPERIENCE	*Senior Vice President*, Economists Incorporated, December 2001 – December 2002 • *Vice President*, Economists Incorporated, December 1995 – December 2001 • *Senior Economist*, Economists Incorporated, June 1992 – December 1995 • *Economic Tutorial Leader*, Stanford University (Stanford in Washington), April 1993 – June 1995 • *Visiting Assistant Professor,* Department of Business Economics and Public Policy, School of Business, Indiana University, September 1991 – May 1992 • *Assistant to the Director for Antitrust,* Bureau of Economics, Federal Trade Commission, November 1989 – August 1991 • *Economic Advisor,* Office of Commissioner Machol, Federal Trade Commission, December 1988 – October 1989 • *Economist,* Division of Antitrust, Bureau of Economics, Federal Trade Commission, October 1985 – December 1988
MEMBERSHIPS	Member, International Association of Energy Economics • Associate, Energy Bar Association • Member, American Economic Association • Member, Western Economic Association International • Associate, American Bar Association

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AWARDS & HONORS

Award for Excellence in Law Enforcement, Federal Trade Commission, 1988 • Graduate School Scholarship, University of Washington, 1984 • Graduated Cum Laude Georgetown University, 1981 • Senior Comprehensive Passed with Distinction, Georgetown University, 1981

TESTIMONY BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Affidavit, Alabama Power Company, *et al.*, ER17-514-000 (2016) • Affidavits (3), Alabama Power Company, *et al*., EL15-39-000 (2016) • Affidavit, Combined Locks Energy Center, LLC, *et al.* , ER10-3042-004 (2015) • Affidavit, Alabama Power Company, *et al*., EL15-39-000 (2015) • Affidavit, PJM Interconnection, L.L.C., ER15-623-000 (2015) • Affidavit, Southern Indiana Gas and Electric Co. d/b/a Vectren Energy Delivery of Indiana, Inc., ER10-1338-000 (2014) • Affidavit, Quantum Choctaw Power, LLC *et al*., ER12-458-007 (2014) • Affidavit, NRG Power Marketing LLC, *et al.*, ER10-2265-004 *et al.* (2014) • Affidavit, TransCanada Entities, ER10-2870-004 *et al*. (2014) • Affidavit, Tampa Electric Company, ER10-1437-002 (2014) • Affidavit, Kendall Green Energy LLC, ER14-1363-003 (2014) • Affidavit, Quantum Lake Power, LP, ER13-1489-000 (2014) • Affidavit, NRG Power Marketing LLC, *et al.* ER10-2265-002 (2014) • Affidavit, NRG Yield, Inc., *et al*., EC14-101-000 (2014) • Affidavit, Community Wind Farm 1 et al., ER14-1668-000 (2014) • Seaway Crude Pipeline Company LLC, OR15-6-000 (2014) • Affidavit, Public Service Electric and Gas Company *et al.*, ER10-1789-003 (2013) • Affidavits, NRG Energy Holdings, Inc., Edison Mission Energy, EC14-14-000 (2013) • Affidavit, Silver Merger Sub, Inc., *et al.*, EC13-128-000 (2013) • Prepared Answering Testimony, Deposition, and Hearing, Puget Sound Energy, Inc., *et al.*, EL01-10-085 (2012) • Affidavit, Wisconsin Public Service Corporation, *et al*., ER10-1894-004 (2012) • Affidavit, PSEG New Haven LLC, ER12-1250-000 (2012) • Affidavit, Enterprise Product Partners L.P. and Enbridge, Inc., OR12-4-000 (2012) • Affidavit, Southern Indiana Gas and Electric Co., ER10-1338-001 (2011) • Affidavit, TransCanada Power Marketing Ltd. *et al.*, ER10-2780-001 (2011) • Affidavit, Tampa Electric Company, ER10-1476-001 (2011) • Affidavit, Cedar Creek Wind Energy, LLC, ER11-2577-000 (2010) • Affidavit, Public Service Electric and Gas Company *et al.*, ER97-837-014 (2010) • Affidavit, Morris Energy Group, LLC v. PSEG Energy Resources & Trade LLC; PSEG Fossil LLC; and PSEG Power LLC, EL10-79-000 (2010) • Affidavit, UGI Storage Company and UGI Central Penn Gas, Inc., CP10-23-000 (2010) • Prepared Answering Testimony, People of the State of California, *ex rel*; Bill Lockyer, Attorney General of the State of California v. Powerex Corp., *et al.*, EL02-71-000 (2009) • Affidavit, Integrys Energy Services, Inc. v. New Brunswick Power Generation Corporation, EL09-32-002 (2009) • Affidavit, People of the State of California, *ex rel*; Edmund G. Brown Jr. Attorney General of the State of California v. Powerex Corp., *et al.*, EL09-56-000 (2009) • Affidavit, San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, EL00-95-000 (2009) • Affidavit, Troy Energy, LLC, *et al.*, ER02-25-010 (2009) • Affidavit, Combined Locks Energy Center, LLC,

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et al., ER01-2659-015 (2009) • Prepared Direct Testimony and Deposition, Energy Transfer Partners, *et al*., IN06-3-003 (2009) • Prepared Direct Testimony and Hearing, Mobil Pipe Line Company, OR07-21-000 (2009) • Idaho Power Company, ER06-787-002 (2009) • Affidavit, Southern Indiana Gas and Electric Co. d/b/a Vectren Energy Delivery of Indiana, Inc. ER96-2734-007 (2008) • Affidavit, Choctaw Gas Generation, LLC, *et al.* ER08-1332-002 • Affidavit, TransCanada Energy Sales Ltd., ER09-328-001 (2008) • Prepared Direct Testimony and Deposition, Oasis Pipeline L.P., *et al.*, IN06-3-004 (2008) • Affidavit, Tampa Electric Company, ER99-2342-012 (2008) • Affidavit, ANP Bellingham Energy Company, LLC, *et al.*, ER00-2117-005 (2008) • Affidavit, SUEZ Energy Marketing, NA, *et al.*, ER06-169-003 (2008) • Affidavit, TransCanada Energy Marketing ULC, *et al.*, ER07-1274-001 (2008) • Affidavit, Georgia-Pacific Brewton LLC, *et al.*, ER08-1126-000 (2008) • Affidavit, Montgomery L'Energia Power Partners LP, ER08-864-000 (2008) • Affidavit (with Joseph P. Kalt), Energy Transfer Partners, *et al*., IN06-3-002 (2008) • Affidavit, Energy Transfer Partners, *et al*., IN06-3-002 (2008) • Affidavit, TransCanada Maine Wind Development Inc., ER08-685-000 (2008) • Affidavit (with Joseph P. Kalt), Energy Transfer Partners, *et al*., IN06-3-000 (2007) • Affidavit, Energy Transfer Partners, *et al*., IN06-3-000 (2007) • Affidavit, The People of the State of Illinois, *ex rel.* Illinois Attorney General Lisa Madigan v. Exelon Generation Co., LLC, *et al.*, EL07-47-000 (2007) • Affidavit, Baltimore Gas and Electric Company, ER07-576-000 (2007) • Affidavit, Trans-Allegheny Interstate Line Company, ER07-562-000 (2007) • Affidavit, TransCanada Energy Marketing Ltd., *et al.*, ER07-331-000 (2006) • Affidavit, Tampa Electric Company, ER99-2342-000, ER07-173-000 (2006) • Affidavit, Koch Supply & Trading, LP, ER07-100-000 (2006) • WPS Resources Corporation and Peoples Energy Corporation, EC06-152-000 (2006) • Affidavit, Sabine Cogen, LP, ER06-744-000 (2006) • Affidavit, Air Liquide Large Industries U.S. LP, ER06-743-000 (2006) • Affidavit, ANP Bellingham Energy Company, LLC., *et al.*, ER00-2117-000 (2005) • Affidavit, Duke Energy Corporation and Cinergy Corp., EC05-103-000 (2005) • Affidavit, El Paso Marketing, L.P., *et al.*, ER95-428-000 (2005) • Affidavit, TransCanada Energy Ltd., *et al.*, ER95-692-000 (2005) • Affidavit, Granite Ridge Energy, LLC, ER00-1147-000, ER05-287-001 (2005) • Affidavit, TransCanada Power (Castleton) LLC, ER05-743-000 (2005) • Affidavit, Tampa Electric Company, *et al*., ER99-2342-003 (2005) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-035 and Wisconsin Public Service Corporation, ER95-1528-010 (2005) • Affidavit, Wisconsin River Power Company, ER05-453-000 (2005) • Affidavit, Upper Peninsula Power Company, ER05-89-001 (2005) • Affidavit, Southern Indiana Gas and Electric Company, ER96-2734-003 (2004) • Affidavit, Tampa Electric Company, *et al*., ER99-2342-003 (2004) • Affidavits, TransCanada Hydro Northeast, Inc., *et al*., EC05-12-000, ER05-111-000 (2004) • Affidavits, Dominion Energy New England,

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Inc., *et al*., EC05-4-000, ER05-34-000 (2004) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-033 and Wisconsin Public Service Corporation, ER95-1528-008 (2004) • Affidavit, NorthPoint Energy Solutions Inc. ER04-1244-000 (2004) • Affidavit, Union Power Partners, L.P., ER01-930-004 (2004) • Affidavit, Panda Gila River, L.P., ER01-931-004 (2004) • Affidavit, Dominion Energy Kewaunee, Inc., ER04-318-000 (2003) • Affidavit, TPS GP, Inc., TPG LP, Inc., Panda GS V, LLC & Panda GS VI, LLC, EC03-90-000 (2003) • Affidavit, Berkshire Power Company, L.L.C. *et al.*, ER99-3502-001 (2002) • Affidavit, El Paso Merchant Energy, L.P., ER95-428-024 (2002) • Affidavit, Tampa Electric Company, ER99-2342-001 (2002) • Affidavit, Hardee Power Partners Limited, ER99-2341-001 (2002) • Affidavit, TECO-PANDA Generating Company, L.P., ER02-1000-000 (2002) • Affidavit, Commonwealth Chesapeake Company, LLC, ER99-415-004 (2002) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-031 and Wisconsin Public Service Corporation, ER95-1528-006 (2001) • Affidavit, TPS McAdams, LLC and TPS Dell, LLC, ER02-507-000 and ER02-510-000 (2001) • Affidavits, Prepared Direct Testimony, and Hearing, CPUC v. El Paso Natural Gas Company, et al., RP00-241-000 (2000-2001), Affidavit, El Paso Energy Corporation and The Coastal Corporation, EC00-73-000, (2000) • Affidavit, El Paso Energy Corporation and Sonat Inc., EC99-73-000 (1999) • Prepared Testimony, San Diego Gas & Electric Company and Enova Energy, Inc., EC97-12-000 (1997) • Prepared Testimony and Hearing, Wisconsin Electric Power Co., Northern States Power Co. (Minnesota), Northern States Power Co. (Wisconsin), and Cenerprise, Inc., EC95-16-000 (1996)

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Northeast Region Generation Owned and Controlled by PSEG

Owner	Plant Name	State	Owned Capacity		Controlled Capacity	
			Winter Seasonal Capacity	Summer Seasonal Capacity	Winter Seasonal Capacity	Summer Seasonal Capacity
ISO - New England						
PSEG Power CT	Bridgeport Station 2	CT	148	130	148	130
PSEG Power CT	Bridgeport Station 3	CT	385	383	385	383
PSEG Power CT	Bridgeport Station 4	CT	20	15	20	15
PSEG Power CT	New Haven Harbor 1	CT	455	448	455	448
PSEG New Haven	New Haven Harbor GT2	CT	61	61	0	0
PSEG New Haven	New Haven Harbor GT3	CT	61	61	0	0
PSEG New Haven	New Haven Harbor GT4	CT	61	61	0	0
Total ISO - New England Capacity			**1,190**	**1,158**	**1,008**	**976**
New York ISO						
PSEG Power NY	Bethlehem Energy Center CC	NY	845	754	845	754
Total New York ISO Capacity			**845**	**754**	**845**	**754**
PJM						
PSEG Fossil	Conemaugh 1	PA	191	191	191	191
PSEG Fossil	Conemaugh 2	PA	191	191	191	191
PSEG Fossil	Conemaugh A[1]	PA	1	1	1	1
PSEG Fossil	Conemaugh B	PA	1	1	1	1
PSEG Fossil	Conemaugh C	PA	1	1	1	1
PSEG Fossil	Conemaugh D	PA	1	1	1	1
PSEG Power	Conemaugh Hydroelectric Plant 1[2]	PA	1	1	1	1
PSEG Power	Conemaugh Hydroelectric Plant 2	PA	1	1	1	1
PSEG Fossil	Keystone 1[3]	PA	194	194	194	194
PSEG Fossil	Keystone 2	PA	194	194	194	194
PSEG Fossil	Keystone 3	PA	1	1	1	1
PSEG Fossil	Keystone 4	PA	1	1	1	1
PSEG Fossil	Keystone 5	PA	1	1	1	1
PSEG Fossil	Keystone 6	PA	1	1	1	1
PSEG Solar Source LLC	Wyandot Solar Farm	OH	12	12	12	12

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Northeast Region Generation Owned and Controlled by PSEG

Owner	Plant Name	State	Owned Capacity		Controlled Capacity	
			Winter Seasonal Capacity	Summer Seasonal Capacity	Winter Seasonal Capacity	Summer Seasonal Capacity
PJM East						
PSEG Fossil	Bergen 3[7]	NJ	21	21	21	21
PSEG Fossil	Bergen CC1	NJ	628	628	628	628
PSEG Fossil	Bergen CC2	NJ	550	555	550	555
PSEG Fossil	Burlington 8[7]	NJ	21	21	21	21
PSEG Fossil	Burlington 9[10]	NJ	184	184	184	184
PSEG Fossil	Burlington 11[7]	NJ	184	184	184	184
PSEG Fossil	Burlington 121	NJ	42	42	42	42
PSEG Fossil	Burlington 122	NJ	42	42	42	42
PSEG Fossil	Burlington 123	NJ	42	42	42	42
PSEG Fossil	Burlington 124	NJ	42	42	42	42
PSEG Fossil	Edison 1[7]	NJ	168	168	168	168
PSEG Fossil	Edison 2[7]	NJ	168	168	168	168
PSEG Fossil	Edison 3[7]	NJ	168	168	168	168
PSEG Fossil	Essex 9	NJ	81	81	81	81
PSEG Fossil	Essex 10[7]	NJ	168	168	168	168
PSEG Fossil	Essex 11[7]	NJ	168	168	168	168
PSEG Fossil	Essex 12[7]	NJ	168	168	168	168
PSEG Nuclear	Hope Creek 1	NJ	1,161	1,161	1,161	1,161
PSEG Fossil	Hudson 2	NJ	608	608	608	608
PSEG Fossil	Kearny 9[8]	NJ	21	21	21	21
PSEG Fossil	Kearny 12	NJ	175	175	175	175
PSEG Fossil	Kearny 13	NJ	0	178	0	178
PSEG Fossil	Kearny 14	NJ	0	89	0	89
PSEG Fossil	Linden 1	NJ	455	458	455	458
PSEG Fossil	Linden 2	NJ	775	778	775	778
PSEG Fossil	Linden 7	NJ	84	84	84	84
PSEG Fossil	Linden 8	NJ	84	84	84	84
PSEG Fossil	Linden GT5	NJ	86	86	86	86
PSEG Fossil	Linden GT6	NJ	86	86	86	86
PSEG Hackettstown LLC	Mars Solar Garden	NJ	2	2	2	2
PSEG Fossil	Mercer 1	NJ	316	316	316	316
PSEG Fossil	Mercer 2	NJ	316	316	316	316

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Northeast Region Generation Owned and Controlled by PSEG

			Owned Capacity		Controlled Capacity	
Owner	**Plant Name**	**State**	**Winter Seasonal Capacity**	**Summer Seasonal Capacity**	**Winter Seasonal Capacity**	**Summer Seasonal Capacity**
PSEG Fossil	Mercer GT3[9]	NJ	115	115	115	115
PSEG Solar Source LLC	Milford Solar Farm	DE	15	15	15	15
PSEG Fossil	National Park GT1[7]	NJ	21	21	21	21
PSEG Nuclear	Salem 1[4]	NJ	674	674	674	674
PSEG Nuclear	Salem 2	NJ	665	665	665	665
PSEG Nuclear	Salem GT3	NJ	22	22	22	22
PSEG Fossil	Sewaren 1	NJ	104	104	104	104
PSEG Fossil	Sewaren 2	NJ	118	118	118	118
PSEG Fossil	Sewaren 3	NJ	107	107	107	107
PSEG Fossil	Sewaren 4	NJ	124	124	124	124
PSEG Fossil	Sewaren 6[7]	NJ	105	105	105	105
PSE&G	Solar 4 All Units	NJ	78	78	78	78
PSEG Fossil	Yards Creek 1[5]	NJ	70	70	0	0
PSEG Fossil	Yards Creek 2	NJ	70	70	0	0
PSEG Fossil	Yards Creek 3	NJ	60	60	0	0
PJM 5004/5005						
PSEG Nuclear	Peach Bottom 2[6]	PA	561	561	561	561
PSEG Nuclear	Peach Bottom 3	PA	561	561	561	561
Total PJM Capacity			**11,272**	**11,550**	**11,072**	**11,350**
Total Northeast Region Capacity			**13,307**	**13,462**	**12,926**	**13,080**

Source: PSEG.

Notes:

[1] PSEG Fossil has a 22.5% interest in the Conemaugh coal-fired units.

[2] PSEG Global has a 4% interest in the Conemaugh Hydroelectric facility.

[3] PSEG Fossil has a 22.84% ownership interest in the Keystone facility.

[4] PSEG Nuclear has a 57.41% interest in the Salem Nuclear facility.

[5] PSEG Fossil has a 50% interest in the Yards Creek facility. Yards Creek is operated by Jersey Central Power & Light, and thus is controlled by JCP&L in the analysis.

[6] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear facility.

[7] Unit retired on 06/01/2015

[8] Unit retired on 08/31/2014

[9] Unit retired on 07/31/2015

[10] Unit retired on 06/30/2014

Scenario 1 PSEG 2016 MBR for ISONE

	PSA		WMSA							
			Winter		Spring		Summer		Fall	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result
ISO New England	8,715	Pass	5.4	Pass	5.2	Pass	6.5	Pass	6.0	Pass
Connecticut	3,388	Pass	11.8	Pass	11.3	Pass	14.3	Pass	13.3	Pass
Southwest Connecticut	1,701	Pass	16.4	Pass	15.7	Pass	14.9	Pass	13.0	Pass

Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **ISONE**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	16	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	190	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	30,892	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	16	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,358	Calculated
I	Study Area Reserve Requirement	2,510	Gendata
J	Amount of Line I Attributable to Seller, if any	3	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	16,073	
	Load		
L	Balancing Area Annual Peak Load	24,054	Loads
M	Average Daily Peak Native Load in Peak Month	17,708	Loads
N	Amount of Line M Attributable to Seller, if any	10	SellerLoads
O	Wholesale Load (L-M)	6,346	
P	Net Uncommitted Supply (K-O)	9,728	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,012	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	4,548	
	% of SIL for Seller's imported capacity →	0.04	
	% of SIL for Other's imported capacity →	0.96	
	SIL Value →	4548	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **CT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	843	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	102	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	7,524	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	2,948	Calculated
I	Study Area Reserve Requirement	689	Gendata
J	Amount of Line I Attributable to Seller, if any	10	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	5,674	
	Load		
L	Balancing Area Annual Peak Load	6,419	Loads
M	Average Daily Peak Native Load in Peak Month	5,054	Loads
N	Amount of Line M Attributable to Seller, if any	14	SellerLoads
O	Wholesale Load (L-M)	1,365	
P	Net Uncommitted Supply (K-O)	4,309	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	920	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	3,050	
	% of SIL for Seller's imported capacity →	0.03	
	% of SIL for Other's imported capacity →	0.97	
	SIL Value →	3050	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **SWCT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	400	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	98	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	2,090	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	3,102	Calculated
I	Study Area Reserve Requirement	205	Gendata
J	Amount of Line I Attributable to Seller, if any	0	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	2,985	
	Load		
L	Balancing Area Annual Peak Load	3,286	Loads
M	Average Daily Peak Native Load in Peak Month	2,500	Loads
N	Amount of Line M Attributable to Seller, if any	0	SellerLoads
O	Wholesale Load (L-M)	786	
P	Net Uncommitted Supply (K-O)	2,199	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	498	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	3,200	
	% of SIL for Seller's imported capacity →	0.03	
	% of SIL for Other's imported capacity →	0.97	
	SIL Value →	3200	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II – Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **ISONE**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	860	852	843	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	12	16	16	16	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	29	87	7	79	SellerGendata
E	Uncommitted Capacity Imports	222	188	177	188	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	16,956	14,847	17,687	15,178	Loads
G	Amount of Line F Attributable to Seller, if any	113	102	39	5	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	16,843	14,745	17,648	15,173	F - G
I	Study Area Reserve Requirement	2,530	2,510	2,510	2,510	Gendata
J	Amount of Line I Attributable to Seller, if any	16	20	10	3	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,514	2,490	2,500	2,507	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	32,149	30,892	29,634	30,892	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	12	16	16	16	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,097	3,148	229	2,881	Gendata; Row D
P	Uncommitted Capacity Imports	4,326	4,360	4,371	4,360	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	16,033	14,885	13,644	14,707	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	911	815	948	935	
S	Total Seasonal Uncommitted Capacity (Q+R)	16,944	15,700	14,592	15,642	
T	**Applicant's Market Share (R÷S)**	5.4%	5.2%	6.5%	6.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	4,548	4,548	4,548	4,548	
V	SIL Value	4,548	4,548	4,548	4,548	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II – Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **CT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	860	852	843	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	29	87	7	79	SellerGendata
E	Uncommitted Capacity Imports	106	93	93	94	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	4,207	3,642	4,503	3,772	Loads
G	Amount of Line F Attributable to Seller, if any	113	102	39	5	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	4,093	3,540	4,464	3,766	F - G
I	Study Area Reserve Requirement	683	683	689	683	Gendata
J	Amount of Line I Attributable to Seller, if any	21	22	10	3	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	662	661	679	680	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	8,048	7,786	7,524	7,786	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	275	793	58	726	Gendata; Row D
P	Uncommitted Capacity Imports	2,944	2,957	2,957	2,956	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	5,963	5,749	5,279	5,570	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	802	734	881	857	
S	Total Seasonal Uncommitted Capacity (Q+R)	6,765	6,482	6,160	6,427	
T	**Applicant's Market Share** (R÷S)	11.8%	11.3%	14.3%	13.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	3,050	3,050	3,050	3,050	
V	SIL Value	3,050	3,050	3,050	3,050	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II – Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **SWCT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	407	404	400	404	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	14	41	3	38	SellerGendata
E	Uncommitted Capacity Imports	86	68	91	101	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	2,048	1,758	2,178	1,766	Loads
G	Amount of Line F Attributable to Seller, if any	0	0	0	0	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	2,048	1,758	2,178	1,766	F - G
I	Study Area Reserve Requirement	209	206	205	206	Gendata
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	209	206	205	206	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	2,321	2,206	2,090	2,206	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	79	225	16	206	Gendata; Row D
P	Uncommitted Capacity Imports	2,454	2,302	3,109	3,089	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	2,439	2,318	2,799	3,116	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	479	430	488	467	
S	Total Seasonal Uncommitted Capacity (Q+R)	2,918	2,748	3,287	3,583	
T	**Applicant's Market Share** (R÷S)	16.4%	15.7%	14.9%	13.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	2,540	2,370	3,200	3,190	
V	SIL Value	2,540	2,370	3,200	3,190	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **NYISO**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	757	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	265	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	585	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	42,506	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,265	Calculated
I	Study Area Reserve Requirement	2,620	Gendata
J	Amount of Line I Attributable to Seller, if any	0	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	22,514	
	Load		
L	Balancing Area Annual Peak Load	31,138	Loads
M	Average Daily Peak Native Load in Peak Month	25,244	Loads
N	Amount of Line M Attributable to Seller, if any	0	SellerLoads
O	Wholesale Load (L-M)	5,894	
P	Net Uncommitted Supply (K-O)	16,620	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,607	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,850	
	% of SIL for Seller's imported capacity →	0.09	
	% of SIL for Other's imported capacity →	0.91	
	SIL Value →	6850	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **NYISO**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	870	814	757	814	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	265	265	265	265	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	71	115	13	92	SellerGendata
E	Uncommitted Capacity Imports	731	600	582	640	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	21,006	18,974	23,056	19,579	Loads
G	Amount of Line F Attributable to Seller, if any	0	0	0	0	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	21,006	18,974	23,056	19,579	F - G
I	Study Area Reserve Requirement	2,620	2,620	2,620	2,620	Gendata
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,620	2,620	2,620	2,620	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	40,162	41,334	42,506	41,334	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,277	5,820	726	4,652	Gendata; Row D
P	Uncommitted Capacity Imports	6,904	6,924	6,268	7,055	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	20,162	20,843	22,372	21,538	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	1,795	1,564	1,591	1,627	
S	Total Seasonal Uncommitted Capacity (Q+R)	21,958	22,407	23,963	23,166	
T	**Applicant's Market Share** (R÷S)	8.2%	7.0%	6.6%	7.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,635	7,524	6,850	7,695	
V	SIL Value	7,635	7,524	6,850	7,695	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Scenario 1 PSEG 2016 MBR for PJM										
	PSA		WMSA							
			Winter		Spring		Summer		Fall	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result
PJM Interconnection	35,891	Pass	9.5	Pass	7.7	Pass	8.3	Pass	8.3	Pass
PJM East	3,572	Pass	32.7	Fail	27.0	Fail	32.9	Fail	29.7	Fail
PJM East of 5004/05	5,389	Pass	24.3	Fail	20.7	Fail	23.7	Fail	23.1	Fail
PJM East of AP South	7,602	Pass	18.5	Pass	15.5	Pass	18.8	Pass	17.0	Pass

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	9,844	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	195	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	1,943	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	152	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	175,931	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	1,943	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	195	Row B; Table2Data
H	Uncommitted Capacity Imports	7,448	Calculated
I	Study Area Reserve Requirement	8,187	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	63,588	
	Load		
L	Balancing Area Annual Peak Load	143,633	Loads
M	Average Daily Peak Native Load in Peak Month	121,600	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	22,034	
P	Net Uncommitted Supply (K-O)	41,555	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,664	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	7,600	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	7600	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	14	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	88	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	26,628	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	14	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,449	Calculated
I	Study Area Reserve Requirement	1,724	Gendata
J	Amount of Line I Attributable to Seller, if any	176	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	15,220	
	Load		
L	Balancing Area Annual Peak Load	30,240	Loads
M	Average Daily Peak Native Load in Peak Month	24,093	Loads
N	Amount of Line M Attributable to Seller, if any	2,269	SellerLoads
O	Wholesale Load (L-M)	6,148	
P	Net Uncommitted Supply (K-O)	9,072	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,500	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,537	
	% of SIL for Seller's imported capacity →	0.01	
	% of SIL for Other's imported capacity →	0.99	
	SIL Value →	6537	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	107	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	51,729	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,212	Calculated
I	Study Area Reserve Requirement	2,975	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	20,577	
	Load		
L	Balancing Area Annual Peak Load	52,190	Loads
M	Average Daily Peak Native Load in Peak Month	42,368	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	9,822	
P	Net Uncommitted Supply (K-O)	10,754	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,365	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,319	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	6319	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	85	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	75,381	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,370	Calculated
I	Study Area Reserve Requirement	4,032	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	25,567	
	Load		
L	Balancing Area Annual Peak Load	70,729	Loads
M	Average Daily Peak Native Load in Peak Month	58,108	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	12,621	
P	Net Uncommitted Supply (K-O)	12,946	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,344	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	4,455	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	4455	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	11,339	10,592	9,844	10,592	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	195	195	195	195	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	1,643	1,944	1,943	1,944	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	491	1,461	225	1,374	SellerGendata
E	Uncommitted Capacity Imports	214	204	138	117	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	108,842	91,954	109,399	91,992	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	106,988	90,430	107,540	90,648	F - G
I	Study Area Reserve Requirement	7,474	6,516	7,991	6,470	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	7,335	6,385	7,817	6,352	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	181,889	178,911	175,931	178,911	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	1,643	1,944	1,943	1,944	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	195	195	195	195	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	7,868	24,681	4,028	23,215	Gendata; Row D
P	Uncommitted Capacity Imports	11,783	12,069	7,462	6,950	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	72,929	71,233	65,756	67,394	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,622	5,931	5,975	6,123	
S	Total Seasonal Uncommitted Capacity (Q+R)	80,550	77,164	71,731	73,518	
T	**Applicant's Market Share** (R÷S)	9.5%	7.7%	8.3%	8.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	11,997	12,273	7,600	7,067	
V	SIL Value	11,997	12,273	7,600	7,067	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	22	14	14	14	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	121	72	78	68	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	18,303	15,919	20,901	16,346	Loads
G	Amount of Line F Attributable to Seller, if any	1,749	1,434	1,764	1,268	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	16,553	14,485	19,137	15,078	F - G
I	Study Area Reserve Requirement	1,258	1,168	1,659	1,211	Gendata
J	Amount of Line I Attributable to Seller, if any	130	122	165	110	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	1,128	1,046	1,494	1,101	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	26,328	26,478	26,628	26,478	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	22	14	14	14	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,139	3,653	610	3,436	Gendata; Row D
P	Uncommitted Capacity Imports	7,381	8,758	6,459	7,791	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	14,911	16,065	11,860	14,667	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,230	5,954	5,826	6,199	
S	Total Seasonal Uncommitted Capacity (Q+R)	22,141	22,019	17,686	20,867	
T	**Applicant's Market Share** (R÷S)	32.7%	27.0%	32.9%	29.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	7,502	8,830	6,537	7,859	
V	SIL Value	7,502	8,830	6,537	7,859	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	162	91	95	69	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	35,188	30,080	37,518	30,214	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	33,334	28,556	35,658	28,871	F - G
I	Study Area Reserve Requirement	2,450	2,184	2,889	2,189	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,311	2,054	2,715	2,071	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	52,220	51,975	51,729	51,975	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	2,259	7,170	1,184	6,744	Gendata; Row D
P	Uncommitted Capacity Imports	7,942	8,202	6,224	6,034	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	22,294	22,424	18,423	20,350	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,144	5,861	5,725	6,103	
S	Total Seasonal Uncommitted Capacity (Q+R)	29,438	28,286	24,148	26,453	
T	**Applicant's Market Share** (R÷S)	24.3%	20.7%	23.7%	23.1%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	8,104	8,293	6,319	6,103	
V	SIL Value	8,104	8,293	6,319	6,103	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	187	115	77	81	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	48,658	41,074	51,437	41,155	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	46,804	39,551	49,577	39,811	F - G
I	Study Area Reserve Requirement	3,496	3,025	3,935	2,991	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	3,358	2,895	3,762	2,873	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	77,314	76,348	75,381	76,348	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,344	10,532	1,726	9,907	Gendata; Row D
P	Uncommitted Capacity Imports	7,710	8,741	4,378	5,987	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	31,554	32,139	24,722	29,772	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,169	5,885	5,707	6,115	
S	Total Seasonal Uncommitted Capacity (Q+R)	38,723	38,024	30,429	35,886	
T	**Applicant's Market Share** (R÷S)	18.5%	15.5%	18.8%	17.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,897	8,856	4,455	6,068	
V	SIL Value	7,897	8,856	4,455	6,068	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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DATA AND ASSUMPTIONS FOR ECONOMISTS INCORPORATED'S DELIVERED PRICE TEST STUDY FOR PSEG

This exhibit describes data and assumptions used in the delivered price test study ("study") carried out by Economists Incorporated for PSEG. Because the data are voluminous, we provide them in electronic workpapers. In those workpapers, the Files.xlsx spreadsheet provides a brief description of the organization of the data files.

This Exhibit has six sections. Section I discusses the study's representative periods. Section II discusses the geographic region and balancing authority areas. Section III discusses generation resources, including adjustments to generating capacity for seasons, maintenance, water availability, and long-term contracts. Section IV discusses transmission, including transmission pricing and losses. Section V discusses market prices. Section VI discusses the load data.

I. Periods

The study calculates market shares and concentration indexes for electric energy for ten representative periods during the year. The year is divided into three seasons (spring/fall, summer and winter). Spring/fall and winter seasons are divided into three periods based on days of the week, times of day and load levels. Summer is divided into four periods based on days of the week, times of day and load levels. Each calculation of market shares and concentration indexes reflects average conditions (e.g., average loads) during one of the resulting ten periods during the year (e.g., Summer Low Peak).

The study places each of the periods in each season into three condition categories: off-peak, low peak, and spike. Transmission pricing (see Section

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IV.B below) and plant availability (see Section III.A.2 below) vary among these three categories.

Table I-1 summarizes the ten periods for the destination markets.

Table I-1– Definition of Ten Periods for Destination Market

Number	*Season*	*Time*	*Condition*	*Hours*	*Description**
1	Spring/Fall	Top 10%	Spike	203	Top 10% of peak hours
2	Spring/Fall	Peak	Peak	1829	Remaining peak hours
3	Spring/Fall	Off-peak	Off-Peak	2360	Off-peak hours
4	Summer	Top 1%	Spike	11	Top 1% of peak hours
5	Summer	Top 10%	Spike	106	Top 10% of peak hours
6	Summer	Peak	Peak	950	Remaining peak hours
7	Summer	Off-peak	Off-Peak	1152	Off-peak hours
8	Winter	Top 10%	Spike	101	Top 10% of peak hours
9	Winter	Peak	Peak	907	Remaining peak hours
10	Winter	Off-peak	Off-Peak	1152	Off-peak Hours

Note: *Peak hours include hours ending 8 a.m. through 11 p.m. Eastern Time weekdays, excluding six major holidays. Off-peak hours = Hours ending 12 a.m. through 7 a.m. on weekdays and all weekend and holiday hours.

The Off-peak periods are all NERC holidays and weekend hours plus weekdays from the hour ending at midnight EPT until the hour ending at 0700.[1] The Off-peak periods have off-peak transmission pricing and plant availability.

In order to define the Top 1% and Top 10% periods for a given season, we removed all Off-peak hours from that season. We then ranked the remaining (peak) hours based on load levels in the destination market by season. We then defined as the Top 1% as the 1 percent of these remaining hours in which loads in the destination market were highest and the Top 10% as the highest 10 percent of peak hours based on load levels. These periods have spike transmission pricing and plant availability.

[1] Major holidays are New Year's, Memorial Day, 4th of July, Labor Day, Thanksgiving and Christmas. Major holidays are included in the Weekend period.

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The Peak periods are weekdays from the hour ending at 0800 until the hour ending at 2300 EPT, excluding hours in the Top 10% periods and major holidays. The Low Peak period has on-peak transmission pricing and plant availability.

II. Geographic Coverage and Market Areas

The study includes market areas that correspond to the balancing authority areas used by the North American Electric Reliability Council (NERC), and PJM submarkets as defined by FERC. Table II-1 lists these market areas and their abbreviations. There are two study destination markets, PJM East and PJM East of 5004/5005.

Table II-1– List of Eastern Market Areas and Study Destinations

Abbreviation	*Full Name*	*Study Destination*
PJME	PJM East	Yes
PJM50	PJM East of 5004/5005	Yes
PJMS	PJM East of AP South	
PJM	PJM	
NYISO	New York ISO	

III. Generation

A. Generation Capacity and Ownership

The study includes generating units located in the areas that are (1) connected to the power grid, (2) not exclusively used for self-generation, and (3) either in a plant used primarily for electric generation or a Qualifying Facility.

1. Generating Unit Data

The study uses data for summer and winter capability at the unit level reported in the Energy Velocity (EV) database available from Ventyx. The units include all

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units with a status of operating, standby, cold standby, restart, mothballed, testing, or under construction that went online before November 30, 2015 and with a retirement date after November 30, 2015. We exclude generation units that are less than 5 MW unless they are owned by PSEG.

2. Ownership

The study uses relies on Ventyx determination of plant and unit ownership. When Ventyx reports a holding company, the ownership is assigned to the holding company. For PSEG generation, the study relies upon Appendix B data from market-based rate filings and updates from the companies to determine plant ownership and seasonal capability. Operational control of PSEG units is consistent with the methodology used for market-based rates.

3. Seasonal variation in capability

The study uses seasonal capability data from EV. Spring/fall capacities are the average of summer and winter capacities.

4. Adjustments to Generating Capability

The generating capability figures used for each period are obtained by multiplying the seasonal capabilities by an availability factor, which is based on the period, unit location, and NERC General Availability Data Systems (GADS) category of the unit. The GADS database gives national average operating information for generating units by unit type and size. For example, it gives data for coal-fired steam units with capacities between 300 MW and 399 MW.

For each period and each generating unit, the availability factor adjusts for the following.

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a) Unplanned outage rates by GADS category

For a given GADS category, the study assumes that unplanned (forced) outage rates (as a share of generating capability available after allowing for planned outages) are constant across seasons and generating units throughout the Region, regardless of owner. Based on GADS data for 2007 through 2011, the study calculates an equivalent forced outage rate (EIFOR), which measures the share of generating capability in a GADS category that is not available because of forced outages. The computation is EIFOR = (FOH)/AH, where FOH is number of forced outage hours and AH is total hours available for generation after planned outages (but before forced outages).[2]

b) Planned outage rates by GADS category and season

With four exceptions (hydro, pumped storage, wind, and solar units), the study assumes that the planned outage rate is constant for all generating units for a given GADS category and season. For a given GADS category, the share of hours of generating capability that is not available as a result of planned outages is computed as (POH + POEH)/PH; where PH are the period hours, POH are the hours not available because of planned outages, and POEH are the hours not available because of planned outage extensions

The study assumes that balancing authority areas are both summer and winter peaking. Therefore, the study assumes that all planned outages for thermal units occur during spring/fall.

[2] EIFOR differs slightly from the EFOR provided in the GADS data. EIFOR provides a better measure of a forced outage rate for peaking units that are operated a small percentage of the year.

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c) Variation in hydro availability across seasons and periods

In general, utilities use hydro facilities to generate energy during the hours when energy prices are highest, subject to constraints imposed by availability of water and reservoir capacity. In order to incorporate these constraints, the study proceeds in the following manner.

First, the study uses EIA Form 923 monthly production data for the period 2011 to 2015 to compute average hourly hydro generation by season. Average hourly generation is then divided by hydro capability to give an average hourly hydro operating rate by season.

Second, depending upon the level of the hydro operating rate for a given season, the study calculates availability factors for the spike, low peak and off-peak periods. When the historical seasonal operating rate is below 30 percent, the availability factor for each period in the season is set equal to the operating rate; the 30 percent figure is an assumed “run of river” constraint. The study assumes that prospectively the maximum operating rate is 90 percent; this is the assumed “maximum rate” constraint. When the historical seasonal operating rate is above 90 percent, the availability factor for each period is set to 90 percent.

When the seasonal operating rate is above the run of river constraint and below the maximum rate, we reason that the hydro generator owner would be likely to produce a higher level of energy during spike hours, when energy prices are highest, than during low peak hours, and that the owner would be likely to produce a higher level during low peak than during off-peak hours.

Based on this reasoning, when the seasonal operating rate is between the run of river constraint and the maximum rate, as is the case for each of the three

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seasons, the study uses a spike availability factor of 90 percent, which is the assumed maximum operating rate, and off-peak availability factor of 30 percent, which is the assumed run-of-river constraint, and a calculated availability factor for the peak periods, as described below.

The seasonal peak availability factor is calculated using actual total seasonal hydro generation. The study then computes the hydro generation during all spike and off-peak hours, assuming the generation rates implied by the spike and off-peak derate factors computed in the manner described above. The study then calculates total peak hydro generation as the difference between total seasonal hydro generation and the sum of hydro generation during all spike and off-peak hours. The seasonal low peak availability factor is computed as total low peak hydro generation divided first by the number of hours in the off-peak period and then by hydro generating capacity.

d) Variation in pumped storage availability across seasons and periods

We assume that pumped storage units have 90 percent availability during Top 1% and Top 10% periods, 50 percent availability during Low Peak periods, and no availability during off-peak periods.

e) Wind availability

For each area, we calculate average operating rates from 2011 to 2015 by season from EIA-923 data. The average operating rates are the availability factors.

f) Solar availability

Availability for solar power is also calculated based on average operating rates from 2011 through 2015 reported in EIA-923. There is little solar power during

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off-peak periods because of darkness. Accordingly, solar availability is weighted to on-peak periods.

B. Variable Costs of Generation

The study uses variable costs of generation that include fuel costs, sulfur dioxide and nitrogen oxide emissions costs, and variable operations and maintenance (VOM) costs. The study calculates fuel costs from unit heat rates and Platts' Gas Daily spot prices at the unit's reported natural gas hub by Energy Velocity, #2 Diesel, Low-Sulfur – Industrial for the East Coast, and Residual Fuel Oil sales to end users for the East Coast for the test period. Natural gas prices vary by hub, but were $2.67 per mmBtu at TETCO M3, the hub with the largest reported capacity in the study. Fuel costs for other fuels are based upon the average fuel costs reported in the EV data for each fuel type. Emissions prices during the test year were $2 per ton for SO2 year-round and $300 per ton for NOx in the summer season. CO_2 costs for units located in Regional Greenhouse Gas Initiative (RGGI) states are $5.21/ton, which is based upon RGGI Auction results in Dec 2014. Units in Montgomery County, MD have an additional $5/ton carbon tax on CO_2 emissions. VOM costs are from the EV database.

C. Long-term Contracts

We reviewed Appendix B data from market-based rate filings, FERC Form 1 filings, and Electric Quarterly Report ("EQR") data to obtain data on long-term contracts. Where the market-based rate filing indicates a change of operational control, we include a contract transferring control to the buyer. We leave the generation unit in the BAA where it is physically interconnected to the transmission system. When the buyer is a load-serving entity in another BAA, we give a priority firm transmission path to the BAA with the load.

Long-term contracts that expire prior to January 1, 2015 are not included in the study. Long-term contracts that expire between January 1, 2015 and July 31,

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2015 are included only in the seasons for which they are in effect. Contracts that expire after August 31, 2015 are included in the study.

IV. Transmission

A. Transmission Network

The study incorporates a contract path transmission network for modeling purposes. Transmission pricing between balancing authority areas is represented by a traditional contract path transmission network in which the direct physical connections between balancing authority areas are also the individually priced links from which contract paths are constructed.

B. Transmission and Ancillary Services Pricing and Losses

As specified by the Commission's Appendix A, the study generally uses ceiling prices for transmission service from Schedules 1, 2 and 8 of the utility's *pro forma* open-access transmission tariff. Transmission providers may require transmission customers to purchase ancillary services under Schedule 1 (scheduling, system control and dispatch) and Schedule 2 (reactive supply and voltage control). Schedule 8 gives the rates for non-firm point-to-point transmission service. The study uses transmission prices from tariffs.

When we have tariffs available, we calculate rates for off-peak, peak and spike categories. Because of discounting and the nature of baseload purchases, off-peak rates are often lower than peak rates.[3] We use two steps to determine off-peak rates. Step 1: When a utility posts off-peak hourly rates, we use the posted rates. Step 2: When a utility does not post off-peak hourly rates, we calculate an hourly off-peak rate based on other tariff information. To calculate hourly off-

[3] For transactions longer than one hour, the *pro forma* tariff caps the amount that the purchaser pays per day by the daily rate, and the amount that the purchaser pays per week by the weekly rate.

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peak rates, we divide the weekly rate by 168, the number of hours in a week. When tariffs specify fees on a per transaction basis, we divide them by 25 to put them on a per MW basis.

We use similar steps to determine peak rates. Step 1: When a utility posts maximum hourly rates in its tariff, we use the maximum tariff rates. Step 2: When a utility does not post off-peak hourly rates, we calculate a peak rate based on other tariff information. To calculate hourly peak rates, we divide the weekly rate by 80—the "Appalachian" method. When tariffs specify fees on a per transaction basis, we divide them by 25 to put them on a per MW basis.

For spike periods, we use ceiling hourly rates from tariffs, when available. Otherwise, we use the Appalachian method.

Whenever practical, the study uses loss rates from tariffs. When these methods did not provide a loss rate for a particular utility, the study assumes that losses are three percent per utility.[4] The study assumes that transmission customers pay losses in-kind. That is, if area A exports 100 MW to area B and the losses are 3 percent, only 97 MW arrive at area B.

For areas where tariffs are not available, rates and losses are the average by period for all the reporting areas.

C. Transfer Capability and SILs

The geographic market includes only PJM and NYISO. The SILs for PJM East and PJM East of 5004/5005 comes from the 2015 Simultaneous Import Limit

[4] Losses of 3 percent are representative of the industry. See, FERC Open Access NOPR, *FERC Stats & Regs*, ¶32,514 at 33,150 (1995).

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Study filed by PJM on September 2, 2016.[5] The total imports into the destination markets may be less than the actual ability to import into the destination because not all the generation capability owned or controlled by load-serving entities within the destination markets studied in PJM have been identified in the data.

V. Market Prices

The study used December 2014-November 2015 real-time hourly prices from the RTO LMP for PJM East and PJM East of 5004/5005. Table V-1 shows the PJM East of 5004/5005 market prices in each of the ten periods, and Table V-2 shows the PJM East market prices.

Table V-1 – PJM East of 5004/5005 Market Prices ($/MWh)

Time	*Spring/Fall*	*Summer*	*Winter*
Top 1%	-----	$148.44	-----
Top 10%	$62.03	$64.59	$185.57
Low Peak	$35.73	$35.56	$47.55
Off-Peak	$29.46	$24.88	$50.16

Table V-2 – PJM East Market Prices ($/MWh)

Time	*Spring/Fall*	*Summer*	*Winter*
Top 1%	-----	$145.63	-----
Top 10%	$57.82	$63.88	$193.51
Low Peak	$32.73	$29.67	$50.59
Off-Peak	$26.67	$21.25	$50.94

[5] PJM Interconnection, L.L.C., *Informational Filing of 2015 Simultaneous Import Limit Study Report for PJM Region*, Docket No. AD1-2-007, September 2, 2016, Accession No. 20160902-5155.

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VI. Load and Contract Obligations for AEC Calculations

Load data come from PJM for PJM and from Energy Velocity for the other supply areas.

To compute load requirements for market participants in New York and PJM, we apportion the total load in each market area in New York and PJM to all suppliers in proportion to their respective generation capacities. We assumed 70 percent of load is committed for a year or longer and the remaining 30 percent is contracted for shorter periods.[6] To account for their greater load obligations, we assume that Dominion has 100 percent responsibility for its allocation of load and that AEP has 90 percent of its allocation as opposed to the standard 70 percent.

[6] This is a reasonable estimate for the long-term load coverage since this number is generally between 60 and 80 percent for most generation suppliers.

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Technical Appendix:

Methods Used to Compute Concentration

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December 2016

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This Exhibit describes the methods used to calculate market shares and concentration in destination markets.

Allocation of scarce transmission capability is accomplished using linear and nonlinear programs that model generation dispatch and the contract path transmission system. This Exhibit provides an overview of the structure of the programs and presents the equations.

Overview of Linear Program

The linear program models control areas as nodes in a transmission system. Each node has a demand for and a supply of electric energy. The supply is based on the generators at the node and potential deliveries to the node via transmission links from other control areas. The linear program allows for net import and export limits to and from an individual control area. Given generation capability and costs and transmission capability and costs, the linear program finds the least-cost solution that satisfies the specified loads. Costs are defined as dispatch (generation) costs plus transmission costs including losses plus the default cost for "unserved" load. For each solution, the linear program determines the quantities produced in, exported from, and imported into each control area.

The Mathematical Equations

The linear program to be solved is given below:

Minimize Total Cost: $Cost = GC + TC + UC$

Subject to:

(1) Generation: $TG_a = \sum_{u}^{u \in a} G_{a,u}$ for each area *a*;

(2) Imports: $YI_a = \sum_{b}^{a,b \in network} (1 - h_{b,a}) T_{b,a}$ for each area *a*;

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(3)	Exports:	$YE_a = \sum_{b}^{a,b \in network} T_{a,b}$	for each area *a*;
(4)	Net Imports:	$Y_a = YI_a - YE_a$	for each area *a*;
(5)	Supply/Demand Balance:	$TG_a + Y_a + U_a = D_a$	for each area *a*;
(6)	Generation Cost:	$GC = \sum_{a} \sum_{u}^{u \in a} d_{a,u} G_{a,u}$	for each area *a*;
(7)	Transmission Cost:	$TC = \sum_{a,b}^{a,b \in network} r_{a,b} T_{a,b}$	for each path *a* to *b*;
(8)	Unfilled Demand Cost:	$UC = \sum_{a} pU_a$	for each area *a*;
(9)	Generation Limits:	$g\min_{a,u} \le G_{a,u} \le g\max_{a,u}$	for each unit *u* in each area *a*;
(10)	Transmission Limits:	$t\min_{a,b} \le T_{a,b} \le t\max_{a,b}$	for each link *a* to *b* in the transmission network; and
(11)	Net Import Limits	$Y\min_{a} \le Y_a \le Y\max_{a}$	for each area *a*;

where:

a,b	are subscripts for control/transmission areas;
Cost	is total system cost;
$d_{a,u}$	is the dispatch cost of unit *u* in area *a*;
D_a	is demand for power in area *a*;
$G_{a,u}$	is generation output of unit *u* in area *a*;
GC	is total system generation cost;
$G\max_{a,u}$	is the maximum output of unit *u* in area *a*;
$G\min_{a,u}$	is the minimum output of unit *u* in area *a*;
$h_{b,a}$	is the fraction of power lost to resistance from moving power from area *b* to area *a*;
N	is a subscript to identify simultaneous transmission constraint *n*;
P	is the default price;
$r_{a,b}$	is the transmission rate from area *a* to area *b*;

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$T_{a,b}$	is the power flow from area *a* to area *b*;
TC	is total system transportation expenses;
TG_a	is total generation output in area *a*;
$t\max_{a,b}$	is the maximum power flow from area *a* to area *b*;
$t\min_{a,b}$	is the minimum power flow from area *a* to area *b*;
U	is a subscript to identify units in an area;
U_a	is the amount of demand in area *a* not met by generation or imports
UC	is total system cost of not meeting demand;
Y_a	is net imports into area *a*;
YE_a	is total exports from area *a*; and
YI_a	is total imports into area *a*;
$Y\min_a$	is minimum net imports in area *a;*
$Y\max_a$	is maximum net imports in area *a.*

This linear program is solved using the BDMLP solver in GAMS. In order to calculate concentration for different destinations, seasons, and periods, the PASS GAMS program loops through the destinations, seasons, and periods with calls to Solvers to solve the linear programs. Loads, unit availability and transmission availability are adjusted for each season-period combination.

Calculating Concentration

Transmission allocation is accomplished in four steps. In the first step the linear program finds the net-back prices in all control areas given a price at the destination control area equal to 105 percent of the pre-merger price. Suppose the pre-merger price at the destination, control area A, is $20/MWh. Then all generation capability with a dispatch cost of $21/MWh or less in the destination area would be included in the market because $21 is 105 percent of $20. If transmission cost (including losses) is $5/MWh from control area B to A, then the net-back price at B would be $16/MWh, which is the $21/MWh less the $5/MWh transmission cost between B and A. Then, all generation capability at B with dispatch costs equal to or less than $16/MWh would be included in the market if there were no transmission constraints. Calculation of net-back prices is

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accomplished by setting the default price, *p*, equal to 105 percent of the pre-merger price at the destination, setting load at the destination to a high number and loads elsewhere to zero, setting transmission limits high enough so that the transmission system is not constrained, and setting a limited amount of generation in each area with a zero dispatch cost. The shadow prices produced by the linear program will be *p* at the destination and the relevant net-back prices in other areas.

In the second step, one calculates Economic Capacity (EC) and Available Economic Capacity (AEC) in each area. These values are then used to limit generation capability. The ownership shares of AEC and EC are calculated for each node in the system.

In the third step, the linear program determines the amount of energy that can be imported into an area given available EC (or AEC) and limits on transmission capacity. This is accomplished by limiting generation in each area to the capacity amount (EC or AEC), giving generation outside the destination market a lower cost than generation inside the destination market, and minimizing cost to serve a large load at the destination market. The amount of generation supplied to the destination is the maximum that can be imported into the destination market.

In the fourth step, transmission is allocated by the following non-linear program:

Minimize Loss: $$Loss = \sum_{\alpha}\left(\frac{C_{\alpha}^{2}}{Y_{Dest}s_{\alpha}} - 2C_{\alpha}\right)$$

Subject to:

(1) Pre Shares: $$s_{\alpha} = \frac{C\max_{\alpha}}{\sum_{\beta} C\max_{\beta}}$$ for each area α;

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(2)	Allocated Shares:	$A_\alpha = \frac{C_\alpha}{Y_{Dest}}$	for each area α;
(3)	Imports:	$YI_a = \sum_b^{a,b \in network} (1 - h_{b,a}) T_{b,a}$	for each area *a*;
(4)	Exports:	$YE_a = \sum_b^{a,b \in network} T_{a,b}$	for each area *a*;
(5)	Net Imports:	$Y_a = YI_a - YE_a$	for each area *a*;
(6)	Supply/Demand Balance:	$C_a + Y_a + U_a = D_a$	for each area *a*;
(7)	Capacity Limits:	$c\min_a \le C_a \le C\max_a$	for each area *a*;
(8)	Transmission Limits:	$t\min_{a,b} \le T_{a,b} \le t\max_{a,b}$	for each link *a* to *b* in the transmission network; and
(9)	Max Import Limit	Y_{Dest} = Maximum imports from step 3;	

where:

a,b	are subscripts for control/transmission areas;
α,β	are subscripts for control/transmission areas other than the destination market;
s_α	Is area α's share of capacity outside of the destination;
A_α	is area α's share of allocated capacity outside of the destination;
Loss	is the loss function to be minimized.

The loss function is derived from the weighted squared-errors between the pre-allocation shares and the post-allocation shares, where Y_{Dest}/s_α are the weights. For each source control area, the weighted squared-error is given by:[1]

$$W_\alpha = \frac{Y_{Dest}}{s_\alpha}(A_\alpha - s_\alpha)^2.$$

[1] This exposition ignores the adjustments necessary to give priority to minimum transfer levels from a source area to the destination.

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Accordingly, the sum of the weighted squared-errors gives rise to the loss function, which can be seen by:

$$\begin{aligned} Loss &= \sum_{\alpha} W_{\alpha} \\ &= \sum_{\alpha} \frac{Y_{Dest}}{s_{\alpha}} (A_{\alpha} - s_{\alpha})^2 \\ &= \sum_{\alpha} \frac{Y_{Dest}}{s_{\alpha}} (A_{\alpha}^2 - 2 s_{\alpha} A_{\alpha} + s_{\alpha}^2) \\ &= \sum_{\alpha} \left(\frac{C_{\alpha}^2}{Y_{Dest} s_{\alpha}} - 2 C_{\alpha} \right) + \text{constant}. \end{aligned}$$

The resulting shares from minimizing this loss functions preserve the relative shares of capacity behind any transmission constraint going to the destination. This can be seen from the following LaGrangian equation to be minimized:

$$L = \sum_{i} \left(\frac{C_i^2}{Y_{Dest} s_i} - 2 C_i \right) + \lambda \left(T - \sum_{i} C_i \right),$$

where *T* is the transmission limit affecting control areas *i*. The first order conditions are:

$$\frac{\partial L}{\partial C_i} = \frac{2 C_i}{Y_{Dest} s_i} - 2 - \lambda = 0,$$

which can be rearranged to give:

$$A_i = \frac{C_i}{Y_{Dest}} = \left(\frac{2 + \lambda}{2} \right) s_i,$$

which shows that the allocated market shares of those areas affected by the transmission constraint are proportional to their shares of capacity before the transmission allocation. Moreover, this is the only transmission allocation

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method that maintains the relative shares of capacity behind any binding transmission constraint in the allocation process.

This non-linear program is solved using the COINIPOPT solver in GAMS. The calculated capacities from the nonlinear program above less transmission losses determine the capacities for the market share calculations for sources outside of the destination market. The capacities within the destination market are given full weights.

Market concentration is the HHI, which is the sum of the squared market shares. Mathematically,

$$HHI = \sum_{i=1}^{n} S_i^2,$$

where S_i is the allocated share of firm *i* and *n* is the number of firms in the market. The summary sheets combine all the firms with shares of 0.7 percent or less (other than Applicants) into the "Other" category. The collective share of the Other category does not directly enter the HHI calculation other than the represented capacity as each independent entity enters the HHI calculation. For example, if ten firms with 0.5 percent shares were in the Other category, the HHI contribution of the Other category would be 0.625 (= 10 x .5 x .5 = 10 x .0625) and ***not*** 25.

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Delivered Price Test - PJM50 Market

Available Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$62.03	2,498	24,613	22,116	6,776	Yes	10.1	Yes	1,024	Yes
Spring/Fall	Peak	$35.73	2,927	26,894	23,967	6,776	Yes	10.9	Yes	1,085	Yes
Spring/Fall	Off Peak	$29.46	1,775	18,948	17,173	6,776	Yes	9.4	Yes	1,358	Yes
Summer	Top 1%	$148.44	1,443	22,909	21,466	9,933	Yes	6.3	Yes	1,042	Yes
Summer	Top 10%	$64.59	1,562	21,384	19,822	9,933	Yes	7.3	Yes	1,000	Yes
Summer	Peak	$35.56	2,009	22,352	20,344	9,933	Yes	9.0	Yes	1,055	Yes
Summer	Off Peak	$24.88	2,103	15,701	13,598	9,933	Yes	13.4	Yes	1,772	Yes
Winter	Top 10%	$185.57	1,921	26,153	24,233	6,073	Yes	7.3	Yes	1,008	Yes
Winter	Peak	$47.55	0	19,398	19,398	6,073	Yes	0.0	Yes	1,421	Yes
Winter	Off Peak	$50.16	0	18,024	18,024	6,073	Yes	0.0	Yes	1,592	Yes

Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$62.03	8,704	55,273	46,570	40,893	Yes	15.7	Yes	1,124	Yes
Spring/Fall	Peak	$35.73	7,678	50,521	42,844	28,923	Yes	15.2	Yes	1,084	Yes
Spring/Fall	Off-Peak	$29.46	5,932	41,688	35,756	24,614	Yes	14.2	Yes	1,133	Yes
Summer	Top 1%	$148.44	8,597	59,581	50,984	51,071	No	14.4	Yes	1,126	Yes
Summer	Top 10%	$64.59	8,608	56,301	47,694	47,510	Yes	15.3	Yes	1,112	Yes
Summer	Peak	$35.56	7,389	51,064	43,675	36,423	Yes	14.5	Yes	1,069	Yes
Summer	Off Peak	$24.88	6,266	42,155	35,889	29,051	Yes	14.9	Yes	1,152	Yes
Winter	Top 10%	$185.57	7,022	55,902	48,880	41,770	Yes	12.6	Yes	1,108	Yes
Winter	Peak	$47.55	4,602	43,979	39,377	34,380	Yes	10.5	Yes	1,206	Yes
Winter	Off Peak	$50.16	4,475	39,851	35,376	30,307	Yes	11.2	Yes	1,281	Yes

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Delivered Price Test - PJME Market

Available Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$57.82	3,225	20,600	17,375	3,806	Yes	15.7	Yes	1,179	Yes
Spring/Fall	Peak	$32.73	2,065	20,408	18,343	3,806	Yes	10.1	Yes	1,228	Yes
Spring/Fall	Off Peak	$26.67	1,276	18,023	16,747	3,806	Yes	7.1	Yes	1,669	Yes
Summer	Top 1%	$145.63	2,279	16,425	14,145	6,174	Yes	13.9	Yes	1,216	Yes
Summer	Top 10%	$63.88	2,402	15,949	13,547	6,174	Yes	15.1	Yes	1,267	Yes
Summer	Peak	$29.67	2,199	15,336	13,136	6,174	Yes	14.3	Yes	1,375	Yes
Summer	Off Peak	$21.25	976	13,909	12,933	6,174	Yes	7.0	Yes	1,979	Yes
Winter	Top 10%	$193.51	2,969	22,743	19,774	2,710	Yes	13.1	Yes	1,199	Yes
Winter	Peak	$50.59	0	15,998	15,998	2,710	Yes	0.0	Yes	1,606	Yes
Winter	Off Peak	$50.94	0	15,146	15,146	2,710	Yes	0.0	Yes	1,967	Yes

Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$57.82	8,677	36,450	27,773	22,528	Yes	23.8	No	1,252	Yes
Spring/Fall	Peak	$32.73	6,520	32,603	26,084	15,404	Yes	20.0	Yes	1,171	Yes
Spring/Fall	Off-Peak	$26.67	4,934	28,457	23,523	13,106	Yes	17.3	Yes	1,233	Yes
Summer	Top 1%	$145.63	8,551	36,587	28,036	29,462	No	23.4	No	1,264	Yes
Summer	Top 10%	$63.88	8,553	34,879	26,326	27,143	No	24.5	No	1,270	Yes
Summer	Peak	$29.67	6,853	31,187	24,334	20,217	Yes	22.0	No	1,224	Yes
Summer	Off Peak	$21.25	5,060	26,734	21,674	16,090	Yes	18.9	Yes	1,264	Yes
Winter	Top 10%	$193.51	7,105	35,709	28,603	21,263	Yes	19.9	Yes	1,181	Yes
Winter	Peak	$50.59	4,573	26,985	22,412	17,939	Yes	16.9	Yes	1,268	Yes
Winter	Off Peak	$50.94	4,449	23,450	19,001	15,660	Yes	19.0	Yes	1,461	Yes

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Appendix E Letters of concurrence regarding the control of certain jointly owned generation facilities

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KEYSTONE-CONEMAUGH PROJECTS

682 Philadelphia Street – 2nd floor
Indiana, Pennsylvania 15701

724-349-1205

MAILING ADDRESS
P.O. BOX 68
INDIANA, PA 15701

GEORGIANNA R. STENGER, ESQ.
ADMINISTRATIVE MANAGER
DIRECT DIAL 724-357-1713

December 1, 2007

Addressed to:

Conemaugh Power LLC
Constellation Power Source Generation, Inc.
Duquesne Conemaugh LLC
Exelon Generation Company, LLC
PPL Montour, LLC
PSEG Fossil LLC
Reliant Energy Mid-Atlantic Power Holdings, LLC
UGI Development Company

Re: Joint Owners of the Conemaugh Electric Generating Station (collectively, the "Owners") statement of ownership and control

Dear Owners:

This letter sets forth the understanding of the degree of ownership and control exercised by each of the Owners with respect to the jointly-owned Conemaugh Electric Generating Station for purposes of facilitating compliance with the requirements of FERC Order No. 697.[1]

The Owners and Reliant Energy Northeast Management Company (the "Operator") each confirm its concurrence with the following statement of facts relating to the Conemaugh Electric Generating Station:

1. The Owners jointly own the Conemaugh Electric Generating Station, consisting of two 850 MW net pulverized coal fired once-through boilers and related facilities having a combined rated seasonal net generating capacity of 1,712 MW (1,884 MW nameplate), located in East Wheatfield and West Wheatfield Townships, Indiana County, Pennsylvania (the "Station").

[1] Not all of the Owners agree as to whether Order No. 697 requires the submission of a letter of concurrence when the putative submitting party is not claiming that it does not control its percentage ownership share of a jointly-owned unit. Notwithstanding, all of the Owners have no objection to submission of this letter by an Owner which does believe that such a submission is required.

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2. As of the date hereof, the Station is collectively owned by the Owners as tenants-in-common, each holding an undivided interest in the Station (and all real and personal property comprising the same) in the respective ownership percentages set forth below:

Owner	Ownership Interest
Conemaugh Power LLC	3.72%
Constellation Power Source Generation, Inc.	10.56%
Duquesne Conemaugh LLC	3.83%
Exelon Generation Company, LLC	20.72%
PPL Montour, LLC	16.25%
PSEG Fossil LLC	22.50%
Reliant Energy Mid-Atlantic Power Holdings, LLC	16.45%
UGI Development Company	5.97%

3. Each of the Owners is deemed to control the generating capacity of the Station in accordance with its respective ownership percentage as set forth in the preceding paragraph for purposes of facilitating compliance with the requirements of FERC Order No. 697.

Please indicate your company's concurrence to the above statement of facts by executing this letter in the space provided below your company's name at the foot hereof.

Sincerely yours,

Georgianna R. Stenger
Administrative Manager
Keystone-Conemaugh Projects

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Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this 14 day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: Anthony F. Pekny

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

SI-SSA-0010-5321

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this 1 day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: Kenneth Kaufman

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this 1st day of December, 2007.

PPL MONTOUR, LLC

By: Dennis J. Murphy
DENNIS J. MURPHY

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this 13th day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: James V. Lacher

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Operator:

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY NORTHEAST
MANAGEMENT COMPANY

By: _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

KEYSTONE-CONEMAUGH PROJECTS

682 Philadelphia Street 2nd floor
Indiana, Pennsylvania 15701

724-349-1205

MAILING ADDRESS
P.O BOX 68
INDIANA, PA 15701

GEORGIANNA R. STENGER, ESQ.
ADMINISTRATIVE MANAGER
DIRECT DIAL 724-357-1713

December 1, 2007

Addressed to:

Constellation Power Source Generation, Inc.
Duquesne Keystone LLC
Exelon Generation Company, LLC
Keystone Power LLC
PPL Montour, LLC
PSEG Fossil LLC
Reliant Energy Mid-Atlantic Power Holdings, LLC

Re: Joint Owners of the Keystone Electric Generating Station (collectively, the "Owners") statement of ownership and control

Dear Owners:

This letter sets forth the understanding of the degree of ownership and control exercised by each of the Owners with respect to the jointly-owned Keystone Electric Generating Station for purposes of facilitating compliance with the requirements of FERC Order No. 697.[1]

The Owners and Reliant Energy Northeast Management Company (the "Operator") each confirm its concurrence with the following statement of facts relating to the Keystone Electric Generating Station:

1. The Owners jointly own the Keystone Electric Generating Station, consisting of two 850 MW net pulverized coal fired once-through boilers and related facilities having a combined rated seasonal net generating capacity of 1,712 MW (1,884 MW nameplate), located in Plumcreek, South Bend and Cowanshannock Townships, Armstrong County, Pennsylvania, and Armstrong Township, Indiana County, Pennsylvania (the "Station").

[1] Not all of the Owners agree as to whether Order No. 697 requires the submission of a letter of concurrence when the putative submitting party is not claiming that it does not control its percentage ownership share of a jointly-owned unit. Notwithstanding, all of the Owners have no objection to submission of this letter by an Owner which does believe that such a submission is required.

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2. As of the date hereof, the Station is collectively owned by the Owners as tenants-in-common, each holding an undivided interest in the Station (and all real and personal property comprising the same) in the respective ownership percentages set forth below:

Owner	Ownership Interest
Constellation Power Source Generation, Inc.	20.99%
Duquesne Keystone LLC	2.47%
Exelon Generation Company, LLC	20.99%
Keystone Power LLC	3.70%
PPL Montour, LLC	12.34%
PSEG Fossil LLC	22.84%
Reliant Energy Mid-Atlantic Power Holdings, LLC	16.67%

3. Each of the Owners is deemed to control the generating capacity of the Station in accordance with its respective ownership percentage as set forth in the preceding paragraph for purposes of facilitating compliance with the requirements of FERC Order No. 697.

Please indicate your company's concurrence to the above statement of facts by executing this letter in the space provided below your company's name at the foot hereof.

Sincerely yours,

Georgianna R. Stenger
Administrative Manager
Keystone-Conemaugh Projects

SI-SSA-0010-5329

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Owners:

Acknowledged and Agreed to
this __ _ day of December, 2007

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this __ . _ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this _ _ . day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ___ . day of December, 2007.

KEYSTONE POWER LLC

By. _ ___ _ _ _____

Acknowledged and Agreed to
this ___ _ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _ __ _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Owners:

Acknowledged and Agreed to
this ___ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this 14 day of December, 2007.

DUQUESNE KEYSTONE LLC

By: Anthony F. Pelz

Acknowledged and Agreed to
this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this 1 day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: Kenneth Kaiser

Acknowledged and Agreed to
this _____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this __. day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

SI-SSA-0010-5332

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Owners:

Acknowledged and Agreed to this _ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _

Acknowledged and Agreed to this ___ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _

Acknowledged and Agreed to this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _

Acknowledged and Agreed to this __ day of December, 2007.

KEYSTONE POWER LLC

By:

Acknowledged and Agreed to this __ day of December, 2007.

PPL MONTOUR, LLC

By: _

Acknowledged and Agreed to this ___ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to this ____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Owners:

Acknowledged and Agreed to
this __ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this __ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this 13th day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Owners:

Acknowledged and Agreed to
this __ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this 16 day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: James D. Lash

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Operator:

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY NORTHEAST
MANAGEMENT COMPANY

By: Jaime D Lach

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Thomas P. Joyce
Senior Vice President

P.O. Box 236, Hancocks Bridge, NJ 08038
tel: 856.339.1100 fax: 856.339.1104
email: Thomas.Joyce@pseg.com

PSEG
Nuclear L.L.C.

Carol Peterson
Vice President Finance
Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

Letter Regarding Control of Jointly-Owned Nuclear Facilities

Dear Ms. Peterson:

In connection with its upcoming compliance filings pursuant to Order No. 697,[1] PSEG Nuclear LLC ("PSEG") is submitting this letter in order to set forth its understanding of, and is requesting Exelon Generation Company LLC's ("Exelon") concurrence on, the respective level of control exercised by both companies with respect to the two nuclear facilities that they jointly own.[2]

PSEG avers and requests Exelon's concurrence on the following:

1. PSEG and Exelon jointly own and control two nuclear power plants, Peach Bottom Atomic Power Station located in Delta, PA and the Salem Nuclear Generating Station in Lower Alloways Creek, NJ.

2. In accordance with the Joint Owners Agreement for Peach Bottom dated November 24, 1971, as amended on thereafter, between the Parties, PSEG and Exelon each own 50% of the generating station. Under the Agreement, Exelon is the designated operator of Peach Bottom.

3. In accordance with the Joint Owners Agreement for Salem dated November 24, 1971, as amended thereafter, between the Parties, Exelon owns 42.59% and PSEG owns 57.41% of the generating station. Under the Agreement, PSEG is the designated operator of Salem.

4. Section 4.1 of each of the Joint Owners' Agreements states, "The signatories shall be entitled to shares of the installed capacity, available capacity, operating capacity and hourly energy generation of the Station in proportion to their ownership . . .."

[1] *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, 119 FERC ¶ 61,295 (2007).

[2] PSEG has requested a letter of concurrence from Exelon in order to facilitate the Commission's review of the market power analysis submitted by PSEG with respect to facilities it jointly owns with Exelon. Exelon has no objection to PSEG's submission of this letter as part of PSEG's compliance filing,.

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Thomas P. Joyce
Senior Vice President

P.O. Box 236, Hancocks Bridge, NJ 08038
tel: 856.339.1100 fax: 856.339.1104
email: Thomas.Joyce@pseg.com

PSEG
Nuclear L.L.C.

5. Section 11.1 of each of the Joint Owners' Agreements provides that the generating station will be operated by the party designated as operator for the mutual benefit of PSEG and Exelon.

6. In Order No. 697 the Commission stated that under "where a jointly-owned generation facility is operated by one of the joint-owners for the benefit of and on behalf of all of the joint-owners . . . it may be reasonable to allocate capacity based on ownership percentages...." Order No. 697 at P 188.

7. In accordance with the guidance provided in Order No. 697 and with the language of each of the joint owners' agreements, PSEG and Exelon should be deemed to control each of the nuclear facilities' output in line with their proportionate ownership share of each facility. As such, PSEG and Exelon should each be deemed to control 50% of Peach Bottom's output, and PSEG should be deemed to control 57.41% of Salem's output with Exelon controlling 42.59%.

Please indicate Exelon's concurrence to the above by executing the Acknowledgement and Agreement section below.

Sincerely

Thomas P. Joyce
Senior Vice President – Operations

Acknowledged and Agreed to
this 21 day of December, 2007.

Carol Peterson
Vice President Finance, Exelon Nuclear, and
an officer of Exelon Generation Company, LLC

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JOINT LETTER OF CONCURRENCE

Regulations of the Federal Energy Regulatory Commission (the "FERC") require each public utility with market-based rate authority to file an updated market power analysis every three years in accordance with a schedule adopted in *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stat. & Regs., Regulations Preambles ¶ 31,252 (2007) ("Order No. 697"). See, 18 CFR § 35.37(a)(1). Each public utility with market-based rate authority may also be required to file a change-in-status report regarding certain changes in circumstances that occur between the dates on which its triennial market power analyses are filed. 18 CFR § 35.42. Among other matters, the market power analysis is to address the amount of generation capacity that the affected utility owns or controls. Where more than one public utility owns a generating facility, FERC requires the utility that is submitting a market power analysis seek a "letter of concurrence" from the other affected co-owning public utilities that identifies the degree to which each public utility controls the generating facility, and to submit the letter with its filing. *See* FERC Order No. 697, 119 FERC ¶ 61,295, P 187 (2007).

The Yards Creek Pumped Storage Hydroelectric Project (the "Yards Creek Project") is a FERC-licensed pumped-storage hydroelectric project with a nameplate capacity of 400 MWs, and is located in Pahaquarry and Blairstown Townships, in Warren County, New Jersey. *See* FERC Project No. P-2309.

PSEG Fossil LLC ("PSEG") and Jersey Central Power & Light Company ("JCPL") each own, as tenants in common with the other, an undivided 50% interest in the Yards Creek Project. Accordingly, if and when PSEG or JCPL submit an updated market power analysis to the FERC, each will be subject to FERC's requirement to seek a "letter of concurrence" regarding the degree to which each controls the Yards Creek Project.

Both PSEG and JCP&L (and their affiliates) own transmission facilities and provide wholesale electric service in the Northeast region, as defined in Order No. 697. Pursuant to the schedule adopted in Order No. 697, PSEG and JCP&L are each required to submit an updated market power analysis to the FERC for markets within the Northeast region in December 2010. PSEG and/or JCP&L may also be obligated to file a change-in-status report or other market power analyses before its subsequent triennial market power analysis for the Northeast region is scheduled to be filed. Therefore, for the sole purpose of enabling either PSEG or JCP&L to submit a market power analysis that addresses, among other issues (to the extent necessary), the scope of each party's control of the Yards Creek Project, PSEG and JCP&L each aver and agree as follows:

1. JCP&L operates and maintains the Yards Creek Project pursuant to the Yards Creek Pumped Storage Hydroelectric Generating Station Operating Agreement, which is dated October 6, 1965 (the "Operating Agreement').

2. Article 2 of the Operating Agreement designates JCP&L as holding sole responsibility for the operations and maintenance the Yards Creek Project. Article 2 further provides that JCPL shall operate the Yards Creek project in the same manner as if JCPL had the complete ownership interest in the Yards Creek Project.

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3. JCP&L does, in fact, operate and control the Yards Creek Project in the same manner as if JCP&L had the complete ownership interest in the Yards Creek Project in accordance with Article 2 of the Operating Agreement.

4. Accordingly, PSEG and JCP&L each agree and concur that for the purpose of the market power analyses required by Order No. 697, JCPL shall be deemed to control the Yards Creek Project generation capacity and electric energy output.

ACKNOWLEDGED AND AGREED:

Richard P. Lopriore
President, PSEG Fossil LLC

Dated: 12/21/10

ACKNOWLEDGED AND AGREED:

Dean Stathis
Director, Regulated Commodity Sourcing
Jersey Central Power & Light Company

Dated: 12/08/2010

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name (Plant or Unit Name)	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region	In-service Date
PSE&G	ER99-3151-000	NA*	NA*	NA*	NA*	PJM	Northeast	NA*
PSEG ER&T	ER97-837-000	NA*	NA*	NA*	NA*	PJM, NYISO, NE-ISO	Northeast, Central, Southwest Power Pool, Southeast, Southwest, Northwest	NA*
PSEG Fossil	ER08-447-000	Bergen CC1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Bergen CC2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2002
PSEG Fossil	ER08-447-000	Burlington 12.1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Conemaugh 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/21/1970
PSEG Fossil	ER08-447-000	Conemaugh 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/27/1971
PSEG Fossil	ER08-447-000	Conemaugh A	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh B	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh C	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh D	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Global	N/A	Conemaugh Hydroelectric Plant 1	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Global	N/A	Conemaugh Hydroelectric Plant 2	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Fossil	ER08-447-000	Essex 9	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/1/1990
PSEG Nuclear	ER08-448-000	Hope Creek 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/20/1986
PSEG Fossil	ER08-447-000	Hudson 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	12/18/1968
PSEG Fossil	ER08-447-000	Kearny 12	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/1/2001
PSEG Fossil	ER08-447-000	Kearny 13	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Kearny 14	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Keystone 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/24/1967
PSEG Fossil	ER08-447-000	Keystone 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/23/1968
PSEG Fossil	ER08-447-000	Keystone 3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Linden 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM,	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 7	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Linden 8	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSEG Fossil	ER08-447-000	Linden GT5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Linden GT6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Mercer 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	12/19/1960
PSEG Fossil	ER08-447-000	Mercer 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/4/1961
PSEG Nuclear	ER08-448-000	Peach Bottom 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	7/5/1974
PSEG Nuclear	ER08-448-000	Peach Bottom 3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/23/1974
PSEG Nuclear	ER08-448-000	Salem 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/30/1977
PSEG Nuclear	ER08-448-000	Salem 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	10/13/1981
PSEG Nuclear	ER08-448-000	Salem GT3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/17/1971
PSEG Fossil	ER08-447-000	Sewaren 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	12/1/1948
PSEG Fossil	ER08-447-000	Sewaren 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/30/1948
PSEG Fossil	ER08-447-000	Sewaren 3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	10/16/1949
PSEG Fossil	ER08-447-000	Sewaren 4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/30/1951
PSEG Fossil	ER08-447-000	Yards Creek 1	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	11/26/1965
PSEG Fossil	ER08-447-000	Yards Creek 2	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	12/22/1965
PSEG Fossil	ER08-447-000	Yards Creek 3	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	9/3/1965
PSEG Power CT	ER03-327-000	Bridgeport Harbor 3	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	8/1/1968
PSEG Power CT	ER03-327-000	Bridgeport Harbor 4	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	10/30/1967
PSEG New Haven LLC	ER12-1250-000	New Haven 2	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 3	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 4	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG Power CT	ER03-327-000	New Haven Harbor 1	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	7/1/1975
PSEG Power NY	N/A*	Bethlehem Energy Center CC	PSEG Power NY	PSEG ER&T	12/6/2002	NYISO	Northeast	7/1/2005
PSEG Solar Source LLC	N/A*	Mars Solar Garden	PSEG Solar Hackettstown LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	9/9/2009
PSEG Solar Source LLC	N/A*	JEA Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	SERC	Southeast	9/28/2010
PSEG Solar Source LLC	N/A*	Wyandot Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	4/6/2010
PSEG Solar Source LLC	N/A*	Queen Creek Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	AZ-NV-SNV	Southwest	11/14/2012
PSEG Solar Source LLC	N/A*	Milford Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	12/27/2012
PSEG Solar Source LLC	N/A	Badger Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ACC	West	10/15/2013
PSEG Solar Source LLC	N/A	Shasta Solar Farm	PSEG Solar California LLC	PG&E	12/16/2013	CAISO	West	3/1/2014

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSEG Solar Source LLC	N/A	Newman Solar Farm (Texas)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	El Paso Electric	Southwest	12/30/2014
PSEG Solar Source LLC	N/A	Whitcomb Solar Farm (Vermont)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ISO New England	Northeast	10/30/2014
PSEG Solar Source LLC	N/A	Rockfish Solar LLC, Southern Maryland	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	7/10/2015
PSEG Solar Source LLC	N/A	Columbia Solar, Pittsburg, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PG&E	West	10/21/2015
PSEG Solar Source LLC	N/A	Whitehorn Solar, Livermore, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Authority	West	2/17/2016
PSEG Solar Source LLC	N/A	Meadows Solar, Martin County, NC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	6/9/2016
PSEG Solar Source LLC	ER16-1924-000	Bison Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Administration, Colorado-Missouri Region	West	8/1/2016
PSEG Solar Source LLC	ER16-1925-000	Pavant Solar II LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp East	West	8/1/2016
PSEG Solar Source LLC	N/A	Obsidian - Black Cap	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp West	West	11/1/2016
PSEG Solar Source LLC	N/A	Hemlock Solar	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	N/A	Turkey Creek	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	ER16-1926-000	San Isabel Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Public Service Company of Colorado	West	8/1/2016
PSE&G (Solar 4 All)	N/A*	Trenton, 500-520 Brunswick Ave., Trenton, NJ 08638	PSE&G	PSE&G	N/A	PJM	Northeast	10/07/2010 (Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Barringer High School (NPS), 90 Parker St., Newark, NJ 07104	PSE&G	PSE&G	N/A	PJM	Northeast	09/24/2010 (Commercial Operation)
PSE&G (Solar		Park Elementary						10/20/2010

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
4 All)	N/A*	School, 120 Manchester	PSE&G	PSE&G	N/A	PJM	Northeast	(Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Linden, South Wood Avenue, Linden, NJ 07036	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Yardville, Broad Street, Hamilton, NJ 08611	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Silver Lake, 410 Silver Lake Avenue, Edison, NJ 08817	PSE&G	PSE&G	N/A	PJM	Northeast	11/09/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Central HQ, 472 Weston Canal Road, Franklin, NJ 08873	PSE&G	PSE&G	N/A	PJM	Northeast	11/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Edison Training, 234 Pierson Avenue, Edison, NJ 08837	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All)	N/A*	WEA Texas Bayonne, 30-100 Pulaski Street, Bayonne, NJ 07002	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2010
PSE&G (Solar 4 All)	N/A*	Matrix Building A, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/24/2011
PSE&G (Solar 4 All)	N/A*	Matrix Building B, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/14/2011
PSE&G (Solar 4 All)	N/A*	Camden Street School, 281 Camden Street Newark, New Jersey 07103	PSE&G	PSE&G	N/A*	PJM	Northeast	1/12/2011

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G (Solar 4 All)	N/A*	New Central High School, 246 18th Ave, Newark, NJ 07108	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Rider University Solar Farm, Lawrenceville, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2011
PSE&G (Solar 4 All)	N/A*	Mill Creek Solar Farm, Burlington Township, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	11/30/2011
PSE&G (Solar 4 All)	N/A*	PSE&G Thorofare Solar Farm, West Deptford	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	Raritan Center – Warehouse Solar, Edison, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	NJMC – Landfill Solar, Kearny, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All	N/A	Matrix – Stults Rd., South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	5/31/2011
PSE&G (Solar 4 All)	N/A*	Metro Division HQ, Clifton, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	7/9/2012
PSE&G (Solar 4 All)	N/A*	Black Rock-Matrix, South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	3/20/2012
PSE&G (Solar 4 All)	N/A*	Food Bank Solar Farm, Hillside, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	8/16/2012
PSE&G (Solar 4 All)	N/A*	Hackensack Solar Farm, Hackensack, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2012
PSE&G (Solar 4 All)	N/A*	Moorestown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/14/2013
PSE&G (Solar 4 All)	N/A*	Seg 2 (Pole attached solar units)	PSE&G	PSE&G	N/A*	PJM	Northeast	7/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Kinsley Solar Sewell, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G (Solar 4 All Extension)	N/A*	Parkland Solar Bordentown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014
PSE&G (Solar 4 All Extension)	N/A*	L&D Solar Mt. Holly, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Hopewell Valley Central HS	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2015
PSE&G (Solar 4 All Extension)	N/A*	ILR Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016
PSE&G (Solar 4 All Extension)	N/A*	Caldwell Waste Treatment Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016
[i] PSEG Fossil has a 22.5% interest in the Conemaugh coal fired plants.								
[ii] PSEG Global has a 4% interest Conemaugh Hydroelectric plants.								
[iii] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear Plants.								
[iv] PSEG Nuclear has a 57.41% interest in the Salem Nuclear Plants.								
[v] JCP&L – Jersey Central Power & Light Company								
[vi] PSEG Fossil has a 50% interest in each of the Yards Creek facilities.								
[vii] CL&P – The Connecticut Light and Power Company.								
[viii] PSEG Power Ventures has a 100% ownership in PSEG Hackettstown LLC.								
[ix] PSEG Power Ventures has a 100% ownership interest in PSEG Solar Source LLC								
[x] All solar assets are using AC MW ratings. PSEG's previous triennial listed the DC ratings.								
[xi] PG&E -- Pacific Gas and Electric Company								
[xii] PSE&G started installations of pole units in September of 2009. As of November 30, 2016, a total of 174,630								

Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing**	**Capacity Rating: Methodology Used in K**	**End Note Number (Enter text in End Notes Sheet**
NA*	NA*	NA*	
NA*	NA*	NA*	
775.2	775.2	N	
625.6	625.6	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
210.6	210.6	N	
210.6	210.6	N	
0.625	0.625	N	[i]
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
1	1	N	[ii]
1	1	N	
93.6	93.6	N	
1,290.70	1,290.70	N	
659.7	659.7	N	
242	242	N	
242	242	N	
121	121	N	
213.8	213.8	N	
213.8	213.8	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
677.8	677.8	N	
677.8	677.8	N	
96.1	96.1	N	
96.1	96.1	N	

Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing**	**Capacity Rating: Methodology Used in K**	**End Note Number (Enter text in End Notes Sheet**
96.1	96.1	N	
96.1	96.1	N	
326.4	326.4	N	
326.4	326.4	N	
704	704	N	[iii]
689	689	N	
671.7	671.7	N	[iv]
671.7	671.7	N	
24	24	N	
110.8	110.8	N	
107.5	107.5	N	
107.5	107.5	N	
126.5	126.5	N	
68.5	68.5	N	[v]
68.5	68.5	N	[vi]
56.4	56.4	N	
399.5	399.5	N	
18.6	18.6	N	
60.5	60.5	N	[vii]
60.5	60.5	N	
60.5	60.5	N	
460.3	460.3	N	
893.2	893.2	N	
2	2	N	[viii]
12.6	12.6	N	[ix]
10.1	10.1	N	[x]
19	19	N	
12	12	N	
15	15	N	
1.5	1.5	N	[xi]

Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing**	**Capacity Rating: Methodology Used in K**	**End Note Number (Enter text in End Notes Sheet**
10.2	10.2	N	
2.2	2.2	N	
10.3	10.3	N	
19	19	N	
3	3	N	
20	20	N	
30	30	N	
50	50	N	
8	8	N	
5	5	N	
13.5	13.5	N	
30	30	N	
1.14	1.14	N	
0.64	0.64	N	
		N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
0.55	0.55	N	
3	3	N	
3.7	3.7	N	
1.75	1.75	N	
0.76	0.76	N	
0.64	0.64	N	
1.5	1.5	N	
		N	
1.5	1.5	N	
1	1	N	
0.83	0.83	N	
		N	

Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing**	**Capacity Rating: Methodology Used in K**	**End Note Number (Enter text in End Notes Sheet**
0.5	0.5	N	
		N	
0.67	0.67	N	
3.5	3.5	N	
0.75	0.75	N	
2	2	N	
2.5	2.5	N	
2.5	2.5	N	
0.57	0.57	N	
2.5	2.5	N	
1	1	N	
1	1	N	
0.93	0.93	N	
38.5	38.5	N	[xii]
8.8	8.8	N	

Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing**	**Capacity Rating: Methodology Used in K**	**End Note Number (Enter text in End Notes Sheet**
7.9	7.9	N	
10	10	N	
1	1	N	
6.6	6.6	N	
2	2	N	

panels and 38.5 MW capacity have been installe

Asset Appendix: Transmission/Natural Gas Assets
Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas St
Location

Filing Entity and its Energy Affiliates	Cite to Order Accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Market / Balancing Authority	Geograph
PSEG ER&T	NA	NA	NA	NA	NA	NA	N
PSEG Power CT	NA	NA	NA	NA	NA	NA	N
PSEG New Haven	NA	NA	NA	NA	NA	NA	N
PSEG Fossil	NA	NA	NA	NA	NA	NA	N
PSEG Nuclear	NA	NA	NA	NA	NA	NA	N
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	Jointly Owned by PSE&G and others	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	Owned by others	PJM	N/A*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	Owned by others	PJM	NA*	PJM	North

PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	Jointly Owned by PSE&G and others	PJM	N/A*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 230 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 230kV Lines	Owned by Others	PJM	N/A	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 138 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 69 kV Lines	PSE&G	PJM	NA*	PJM	North

:orage Facilities

	Size	
ic Region	**Size (e.g., length and kV for electric length and diameter for pipeline, and capacity for gas storage)**	**End Note Number (Enter text in End Notes Sheet**
A	NA	NA
A	NA	NA
A	NA	NA
A	NA	NA
A	NA	NA
ıeast	Approximately 272 combined miles.	
ıeast	Approximately 151 combined miles.	
ıeast	Approximately 64 combined miles	
ıeast	Approximately 32 combined miles.	
ıeast	Approximately 20 combined miles.	

ıeast	Approximately 3.76 combined Miles
ıeast	Approximately 750 combined miles.
ıeast	Approximately 39 combined miles
ıeast	Approximately 228 combined miles.
ıeast	Approximately 235 combined miles.

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Asset Appendix: Long Term Purchased Power Agreements

Filing Entity and its Energy Affiliates	Docket No. where MBR Authority Granted	Seller Name	Amount of PPA (MW)	Market / Balancing Authority	Geographic Region	Start Date (mo/day/year)

End Date (mo/day/year)	End Note

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Document Content(s)

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Exhibit E - Letters of Concurrence - PSEG Triennial.PDF.....110-134

Appendix B - Generation Assets - PSEG Triennial.XLSX.....135-146

Appendix C - Triennial - Transmission Chart.XLSX.....147-150

Appendix D - Long Term Contracts - Triennial.XLSX.....151-152

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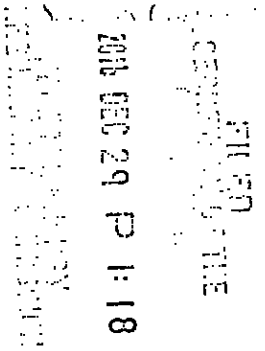
ORIGINAL

PSEG

Public



VIA OVERNIGHT MAIL
Kimberly J. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426
December 23, 2013

RE: Triennial Market Power Update and Revised Market-Based Rates Tariff in Compliance with Order No. 697:

***PSEG Energy Resources & Trade LLC*, Docket No. ~~ER99-3151-~~ ER10-1789-005;**

***Public Service Electric and Gas Company*, Docket No. ~~ER97-837-~~ ER10-1768-004;**

***PSEG Power Connecticut LLC*, Docket No. ~~ER03-327-~~ ER10-1793-004**

***PSEG Fossil LLC*, Docket No. ~~ER08-447-~~ ER10-1770-004**

***PSEG Nuclear LLC*, ~~ER08-448-~~, and ER10-1771-004**

***PSEG New Haven LLC*, ER12-1250-004**

Pavant Solar II LLC, ER16-1925-002

San Isabel Solar LLC, ER16-1926-002

Bison Solar LLC, ER16-1924-002

PSEG Energy Solutions LLC, ER16-2725-002

Dear Secretary Bose:

Earlier today, PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG Fossil LLC, PSEG Nuclear LLC, PSEG New Haven LLC, Pavant Solar II LLC, San Isabel Solar LLC, Bison Solar LLC and PSEG Energy Solutions LLC (collectively the "Applicants" or "PSEG") jointly submitted their Triennial Market Power Update.

Enclosed with this transmittal letter, please find CD-ROMs containing the workpapers of Dr. John Morris supporting his analysis in support of that filing. This CD-ROM (of which six copies are included) contains: (i) proprietary information provided by Energy Velocity under an agreement that requires confidential treatment to be requested for these materials; (ii) modeling and computer programs that are the

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proprietary intellectual property of Economists Incorporated, the firm by which Dr. Morris is employed; (iii) commercially sensitive information about Applicants and their affiliates; and (iv) documents and information deemed to be confidential by PJM, NYISO and ISO-NE. Accordingly, Applicants respectfully request confidential treatment for the CD-ROM pursuant to 18 C.F.R. (J 388.112 (2006), consistent with the confidential treatment accorded other applicants submitting such proprietary and commercially sensitive data. Pursuant to the Commission's rules, the public version of this filing contains all materials submitted herein except for the CD-ROM, which is labeled as "PRIVILEGED AND CONFIDENTIAL/NON-PUBLIC.

Thank you for your attention to this matter. Please direct any questions concerning this submission or the request for privileged treatment to the undersigned.

Respectfully submitted,
Public Service Electric and Gas Company
PSEG Energy Resources & Trade LLC
PSEG Power Connecticut LLC
PSEG Fossil LLC
PSEG Nuclear LLC
PSEG New Haven LLC
Pavant Solar II LLC
San Isabel Solar LLC
Bison Solar LLC
PSEG Energy Solutions LLC

By:

David K. Richter, Esq.
Associate General Regulatory and Property Counsel
PSEG Services Corporation

Enclosures

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Document Content(s)

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Cara J. Lewis
General Federal Regulatory Counsel

Law Department
80 Park Plaza, T5G, Newark, NJ 07102-4194
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PSEG
Services Corporation

By ELECTRONIC FILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

June 29, 2018

Re: Supplement to Notice of Non-Material Change in Status of PSEG Affiliates:

PSEG Energy Resources & Trade LLC	ER10-1789-___
PSEG Energy Solutions LLC	ER16-2725-___
PSEG Fossil LLC	ER10-1770-___
PSEG New Haven LLC	ER12-1250-___
PSEG Nuclear LLC	ER10-1771-___
PSEG Power Connecticut LLC	ER10-1793-___
Pavant Solar II LLC	ER16-1925-___
Bison Solar LLC	ER16-1924-___
San Isabel Solar LLC	ER16-1926-___
Public Service Electric and Gas Company	ER10-1768-___
PSEG Keys Energy Center LLC	ER17-2426-___

Dear Ms. Bose:

On May 25, 2018, the PSEG Affiliates submitted a notice of non-material change in status ("Notice") pursuant to section 35.42(a)(1) of the regulations of the Federal Energy Regulatory Commission ("Commission").[1] The PSEG Affiliates are submitting this supplement to the Notice to include: (1) Appendix B – Generation Assets; and (2) Appendix A-3 in Excel format as required by the Commission's regulations.

Please feel free to contact me at (973) 430-8836 if you have any questions about this matter.

Very truly yours,

Cara J. Lewis

Cara J. Lewis

[1] 18 C.F.R. Part 35.42 (2017).

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G	ER99-3151-000	NA*	NA*	NA*	NA*	PJM	Northeast	NA*
PSEG ER&T	ER97-837-000	NA*	NA*	NA*	NA*	PJM, NYISO, NE-ISO	Northeast, Central, Southwest Power Pool, Southeast, Southwest, Northwest	NA*
PSEG Fossil	ER08-447-000	Bergen CC1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Bergen CC2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2002
PSEG Fossil	ER08-447-000	Burlington 12.1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Conemaugh 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/21/1970
PSEG Fossil	ER08-447-000	Conemaugh 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/27/1971
PSEG Fossil	ER08-447-000	Conemaugh A	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh B	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh C	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh D	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Global	N/A	Conemaugh Hydroelectric Plant 1	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Global	N/A	Conemaugh Hydroelectric Plant 2	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Fossil	ER08-447-000	Essex 9	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/1/1990
PSEG Nuclear	ER08-448-000	Hope Creek 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/20/1986
PSEG Fossil	ER08-447-000	Kearny 12	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/1/2001
PSEG Fossil	ER08-447-000	Kearny 13	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Kearny 14	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Keystone 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/24/1967
PSEG Fossil	ER08-447-000	Keystone 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/23/1968
PSEG Fossil	ER08-447-000	Keystone 3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Linden 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM,	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 7	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Linden 8	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Linden GT5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000

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PSEG Fossil	ER08-447-000	Linden GT6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Keys Energy Center LLC	ER17-2426-000	PSEG Keys Energy Center	PSEG Keys Energy Center	PSEG ER&T	N/A	PJM	Northeast	7/3/2018
PSEG Nuclear	ER08-448-000	Peach Bottom 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	7/5/1974
PSEG Nuclear	ER08-448-000	Peach Bottom 3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/23/1974
PSEG Nuclear	ER08-448-000	Salem 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/30/1977
PSEG Nuclear	ER08-448-000	Salem 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	10/13/1981
PSEG Nuclear	ER08-448-000	Salem GT3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/17/1971
PSEG Fossil	N/A	Sewaren 7	PSEG Sewaren Urban Renewal	PSEG ER&T	N/A	PJM	Northeast	6/6/2018
PSEG Fossil	ER08-447-000	Yards Creek 1	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	11/26/1965
PSEG Fossil	ER08-447-000	Yards Creek 2	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	12/22/1965
PSEG Fossil	ER08-447-000	Yards Creek 3	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	9/3/1965
PSEG Power CT	ER03-327-000	Bridgeport Harbor 3	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	8/1/1968
PSEG Power CT	ER03-327-000	Bridgeport Harbor 4	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	10/30/1967
PSEG New Haven LLC	ER12-1250-000	New Haven 2	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 3	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 4	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG Power CT	ER03-327-000	New Haven Harbor 1	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	7/1/1975
PSEG Power NY	N/A*	Bethlehem Energy Center CC	PSEG Power NY	PSEG ER&T	12/6/2002	NYISO	Northeast	7/1/2005
PSEG Solar Source LLC	N/A*	Mars Solar Garden	PSEG Solar Hackettstown LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	9/9/2009
PSEG Solar Source LLC	N/A*	JEA Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	SERC	Southeast	9/28/2010
PSEG Solar Source LLC	N/A*	Wyandot Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	4/6/2010
PSEG Solar Source LLC	N/A*	Queen Creek Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	AZ-NV-SNV	Southwest	11/14/2012
PSEG Solar Source LLC	N/A*	Milford Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	12/27/2012
PSEG Solar Source LLC	N/A	Badger Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ACC	West	10/15/2013
PSEG Solar Source LLC	N/A	Shasta Solar Farm	PSEG Solar California LLC	PG&E	N/A	CAISO	West	3/1/2014
PSEG Solar Source LLC	N/A	Newman Solar Farm (Texas)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	El Paso Electric	Southwest	12/30/2014
PSEG Solar Source LLC	N/A	Whitcomb Solar Farm (Vermont)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ISO New England	Northeast	10/30/2014

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PSEG Solar Source LLC	N/A	Rockfish Solar LLC, Southern Maryland	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	7/10/2015
PSEG Solar Source LLC	N/A	Columbia Solar, Pittsburg, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PG&E	West	10/21/2015
PSEG Solar Source LLC	N/A	Whitehorn Solar, Livermore, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Authority	West	2/17/2016
PSEG Solar Source LLC	N/A	Meadows Solar, Martin County, NC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	6/9/2016
PSEG Solar Source LLC	ER16-1924-000	Bison Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Administration, Colorado-Missouri Region	West	8/1/2016
PSEG Solar Source LLC	ER16-1925-000	Pavant Solar II LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp East	West	8/1/2016
PSEG Solar Source LLC	N/A	Obsidian - Black Cap	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp West	West	11/1/2016
PSEG Solar Source LLC	N/A	Hemlock Solar	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	N/A	Turkey Creek	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	ER16-1926-000	San Isabel Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Public Service Company of Colorado	West	8/1/2016
PSEG Solar Source LLC	N/A*	Cork Oak Solar	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/29/2017
PSEG Solar Source LLC	ER17-1746	Sunflower Solar	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/29/2017
PSEG Solar Source LLC	N/A*	SL Babylon/Solar Liberty	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	LIPA	Northeast	12/4/2017
PSEG Solar Source LLC	N/A*	HXNAir Solar One	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/21/2017
PSE&G (Solar 4 All)	N/A*	Trenton, 500-520 Brunswick Ave., Trenton, NJ 08638	PSE&G	PSE&G	N/A	PJM	Northeast	10/07/2010 (Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Barringer High School (NPS), 90 Parker St., Newark, NJ 07104	PSE&G	PSE&G	N/A	PJM	Northeast	09/24/2010 (Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Park Elementary School, 120 Manchester	PSE&G	PSE&G	N/A	PJM	Northeast	10/20/2010 (Commercial Operation)

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PSE&G (Solar 4 All)	N/A*	Linden, South Wood Avenue, Linden, NJ 07036	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Yardville, Broad Street, Hamilton, NJ 08611	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Silver Lake, 410 Silver Lake Avenue, Edison, NJ 08817	PSE&G	PSE&G	N/A	PJM	Northeast	11/09/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Central HQ, 472 Weston Canal Road, Franklin, NJ 08873	PSE&G	PSE&G	N/A	PJM	Northeast	11/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Edison Training, 234 Pierson Avenue, Edison, NJ 08837	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All)	N/A*	WEA Texas Bayonne, 30-100 Pulaski Street, Bayonne, NJ 07002	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2010
PSE&G (Solar 4 All)	N/A*	Matrix Building A, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/24/2011
PSE&G (Solar 4 All)	N/A*	Matrix Building B, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/14/2011
PSE&G (Solar 4 All)	N/A*	Camden Street School, 281 Camden Street Newark, New Jersey 07103	PSE&G	PSE&G	N/A*	PJM	Northeast	1/12/2011
PSE&G (Solar 4 All)	N/A*	New Central High School, 246 18th Ave, Newark, NJ 07108	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Rider University Solar Farm, Lawrenceville, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2011

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PSE&G (Solar 4 All)	N/A*	Mill Creek Solar Farm, Burlington Township, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	11/30/2011
PSE&G (Solar 4 All)	N/A*	PSE&G Thorofare Solar Farm, West Deptford	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	Raritan Center – Warehouse Solar, Edison, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	NJMC – Landfill Solar, Kearny, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All	N/A	Matrix – Stults Rd., South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	5/31/2011
PSE&G (Solar 4 All)	N/A*	Metro Division HQ, Clifton, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	7/9/2012
PSE&G (Solar 4 All)	N/A*	Black Rock-Matrix, South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	3/20/2012
PSE&G (Solar 4 All)	N/A*	Food Bank Solar Farm, Hillside, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	8/16/2012
PSE&G (Solar 4 All)	N/A*	Hackensack Solar Farm, Hackensack, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2012
PSE&G (Solar 4 All)	N/A*	Moorestown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/14/2013
PSE&G (Solar 4 All)	N/A*	Seg 2 (Pole attached solar units)	PSE&G	PSE&G	N/A*	PJM	Northeast	7/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Kinsley Solar Sewell, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014
PSE&G (Solar 4 All Extension)	N/A*	Parkland Solar Bordentown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014
PSE&G (Solar 4 All Extension)	N/A*	L&D Solar Mt. Holly, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Hopewell Valley Central HS	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2015
PSE&G (Solar 4 All Extension)	N/A*	ILR Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016
PSE&G (Solar 4 All Extension)	N/A*	Caldwell Waste Treatment Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016

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Asset Appendix: Generation Assets								
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Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
[i] PSEG Fossil has a 22.5% interest in the Conemaugh coal fired plants.								
[ii] PSEG Global has a 4% interest Conemaugh Hydroelectric plants.								
[iii] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear Plants.								
[iv] PSEG Nuclear has a 57.41% interest in the Salem Nuclear Plants.								
[v] JCP&L – Jersey Central Power & Light Company								
[vi] PSEG Fossil has a 50% interest in each of the Yards Creek facilities.								
[vii] CL&P – The Connecticut Light and Power Company.								
[viii] PSEG Power Ventures has a 100% ownership in PSEG Hackettstown LLC.								
[ix] PSEG Power Ventures has a 100% ownership interest in PSEG Solar Source LLC								
[x] All solar assets are using AC MW ratings. PSEG's previous triennial listed the DC ratings.								
[xi] PG&E -- Pacific Gas and Electric Company								
[xii] PSE&G started installations of pole units in September of 2009. As of November 30, 2016, a total of 174,630								

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
NA*	NA*	NA*	
NA*	NA*	NA*	
775.2	775.2	N	
625.6	625.6	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
219.5	219.5	N	
219.5	219.5	N	
0.625	0.625	N	[i]
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
1	1	N	[ii]
1	1	N	
93.6	93.6	N	
1,290.70	1,290.70	N	
242	242	N	
242	242	N	
121	121	N	
213.8	213.8	N	
213.8	213.8	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
677.8	677.8	N	
677.8	677.8	N	
96.1	96.1	N	
96.1	96.1	N	
96.1	96.1	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
96.1	96.1	N	
755	755	N	
703.8	703.8	N	[iii]
688.5	688.5	N	
671.7	671.7	N	[iv]
671.7	671.7	N	
24	24	N	
585	585	N	
69.3	69.3	N	[v]
69.3	69.3	N	[vi]
69.3	69.3	N	
399.5	399.5	N	
18.6	18.6	N	
60.5	60.5	N	[vii]
60.5	60.5	N	
60.5	60.5	N	
460.3	460.3	N	
893.2	893.2	N	
2	2	N	[viii]
12.6	12.6	N	[ix]
10.1	10.1	N	[x]
19	19	N	
12	12	N	
15	15	N	
3	3	N	[xi]
10.2	10.2	N	
2.2	2.2	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
10.3	10.3	N	
19	19	N	
3	3	N	
20	20	N	
30	30	N	
50	50	N	
8	8	N	
5	5	N	
13.5	13.5	N	
30	30	N	
20	20	N	
16	16	N	
8.9	8.9	N	
5	5	N	
1.14	1.14	N	
0.64	0.64	N	
0.55	0.55	N N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
3	3	N	
3.7	3.7	N	
1.75	1.75	N	
0.76	0.76	N	
0.64	0.64	N	
1.5	1.5	N N	
1.5	1.5	N	
1	1	N	
0.83	0.83	N N	
0.5	0.5	N N	
0.67	0.67	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
3.5	3.5	N	
0.75	0.75	N	
2	2	N	
2.5	2.5	N	
2.5	2.5	N	
0.57	0.57	N	
2.5	2.5	N	
1	1	N	
1	1	N	
0.93	0.93	N	
38.5	38.5	N	[xii]
8.8	8.8	N	
7.9	7.9	N	
10	10	N	
1	1	N	
6.6	6.6	N	
2	2	N	

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Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing**	**Capacity Rating: Methodology Used in K**	**End Note Number (Enter text in End Notes Sheet**
panels and 38.5 MW capacity have been installed.			

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Market Based Rates Assessments

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Scenario

Scenario Number	1	
Scenario Name	PSEG 2016 MBR for PJM	
Data	MBRA Data v501 PSEG 2016 PJM Sewaren 20180525.	
Applicant	PSEG	Public Service Enterprise Group Inc
Period	Dec 2015 — Nov 2016	

Fill-in white cells with parameters and then click on Run button or type Ctrl+Shift+R.

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Results

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Scenario 1 PSEG 2016 MBR for PJM

	PSA		WM			
			Winter		Spring	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result
PJM Interconnection	38,315	Pass	7.3	Pass	6.1	Pass
PJM East	4,229	Pass	26.7	Fail	22.3	Fail
PJM East of 5004/05	5,892	Pass	20.7	Fail	18.1	Pass
PJM East of AP South	10,461	Pass	14.7	Pass	12.8	Pass

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SA			
Summer		Fall	
Share (%)	Result	Share (%)	Result
6.6	Pass	6.5	Pass
25.9	Fail	24.3	Fail
20.0	Pass	19.7	Pass
14.4	Pass	13.7	Pass

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	9,378	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	195	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	1,943	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	70	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	186,588	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	1,943	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	195	Row B; Table2Data
H	Uncommitted Capacity Imports	7,530	Calculated
I	Study Area Reserve Requirement	8,674	Gendata
J	Amount of Line I Attributable to Seller, if any	228	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	62,196	
	Load		
L	Balancing Area Annual Peak Load	152,177	Loads
M	Average Daily Peak Native Load in Peak Month	132,696	Loads
N	Amount of Line M Attributable to Seller, if any	3,073	SellerLoads
O	Wholesale Load (L-M)	19,482	
P	Net Uncommitted Supply (K-O)	42,715	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,399	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	7,600
% of SIL for Seller's imported capacity →	0.01
% of SIL for Other's imported capacity →	0.99
SIL Value →	7600
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	6,650	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	14	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	152	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	27,691	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	14	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,385	Calculated
I	Study Area Reserve Requirement	1,767	Gendata
J	Amount of Line I Attributable to Seller, if any	202	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	13,259	
	Load		
L	Balancing Area Annual Peak Load	30,992	Loads
M	Average Daily Peak Native Load in Peak Month	25,852	Loads
N	Amount of Line M Attributable to Seller, if any	2,695	SellerLoads
O	Wholesale Load (L-M)	5,139	
P	Net Uncommitted Supply (K-O)	8,120	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	3,890	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	6,537
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	6537
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,418	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	105	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	52,989	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,214	Calculated
I	Study Area Reserve Requirement	3,049	Gendata
J	Amount of Line I Attributable to Seller, if any	210	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	18,909	
	Load		
L	Balancing Area Annual Peak Load	53,493	Loads
M	Average Daily Peak Native Load in Peak Month	44,768	Loads
N	Amount of Line M Attributable to Seller, if any	2,992	SellerLoads
O	Wholesale Load (L-M)	8,725	
P	Net Uncommitted Supply (K-O)	10,184	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,293	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P)	**Pass**	
	(Fail if Line Q > Line P)		

Total Imports (Sum D, H) as filed by Seller →	6,319
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	6319
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,418	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	88	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	80,051	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,367	Calculated
I	Study Area Reserve Requirement	4,162	Gendata
J	Amount of Line I Attributable to Seller, if any	210	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	26,286	
	Load		
L	Balancing Area Annual Peak Load	73,026	Loads
M	Average Daily Peak Native Load in Peak Month	61,476	Loads
N	Amount of Line M Attributable to Seller, if any	2,992	SellerLoads
O	Wholesale Load (L-M)	11,550	
P	Net Uncommitted Supply (K-O)	14,736	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,275	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P)	**Pass**	
	(Fail if Line Q > Line P)		

Total Imports (Sum D, H) as filed by Seller →	4,455
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	4455
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season: Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	10,859	10,119	9,378	10,119	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	195	195	195	195	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	1,643	1,944	1,943	1,944	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	452	1,512	93	1,131	SellerGendata
E	Uncommitted Capacity Imports	91	89	68	53	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	99,674	86,411	116,161	92,587	Loads
G	Amount of Line F Attributable to Seller, if any	1,573	1,308	2,340	1,568	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	98,102	85,102	113,821	91,019	F - G
I	Study Area Reserve Requirement	6,756	6,230	8,317	6,641	Gendata
J	Amount of Line I Attributable to Seller, if any	119	117	202	143	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	6,637	6,113	8,116	6,498	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	193,335	189,962	186,588	189,962	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	1,643	1,944	1,943	1,944	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	195	195	195	195	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	8,043	28,377	1,841	21,225	Gendata; Row D
P	Uncommitted Capacity Imports	11,906	12,184	7,532	7,014	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	93,908	84,302	72,090	79,982	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,359	5,522	5,064	5,580	
S	Total Seasonal Uncommitted Capacity (Q+R)	101,266	89,823	77,154	85,562	
T	**Applicant's Market Share** (R÷S)	7.3%	6.1%	6.6%	6.5%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	11,997	12,273	7,600	7,067	
V	SIL Value	11,997	12,273	7,600	7,067	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,182	7,416	6,650	7,416	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	22	14	14	14	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	340	1,108	66	829	SellerGendata
E	Uncommitted Capacity Imports	156	135	128	113	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	16,761	14,806	21,675	16,148	Loads
G	Amount of Line F Attributable to Seller, if any	1,499	1,253	2,058	1,350	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	15,261	13,553	19,617	14,798	F - G
I	Study Area Reserve Requirement	1,150	1,117	1,651	1,345	Gendata
J	Amount of Line I Attributable to Seller, if any	113	112	177	123	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	1,037	1,005	1,473	1,222	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	27,568	27,630	27,691	27,630	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	22	14	14	14	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,147	4,127	273	3,087	Gendata; Row D
P	Uncommitted Capacity Imports	7,346	8,695	6,409	7,746	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	17,491	17,653	12,750	16,282	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	6,364	5,064	4,463	5,214	
S	Total Seasonal Uncommitted Capacity (Q+R)	23,854	22,717	17,213	21,496	
T	**Applicant's Market Share** (R÷S)	26.7%	22.3%	25.9%	24.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	7,502	8,830	6,537	7,859	
V	SIL Value	7,502	8,830	6,537	7,859	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,951	8,185	7,418	8,185	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	372	1,223	73	914	SellerGendata
E	Uncommitted Capacity Imports	118	69	95	61	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	31,965	27,526	38,884	30,032	Loads
G	Amount of Line F Attributable to Seller, if any	1,524	1,270	2,340	1,568	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	30,441	26,256	36,544	28,465	F - G
I	Study Area Reserve Requirement	2,203	2,058	2,874	2,416	Gendata
J	Amount of Line I Attributable to Seller, if any	115	114	202	143	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,088	1,944	2,672	2,273	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	53,711	53,350	52,989	53,350	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	2,234	7,970	523	5,961	Gendata; Row D
P	Uncommitted Capacity Imports	7,986	8,224	6,224	6,042	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	26,970	25,434	19,502	22,722	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,022	5,618	4,870	5,591	
S	Total Seasonal Uncommitted Capacity (Q+R)	33,992	31,052	24,372	28,313	
T	**Applicant's Market Share** (R÷S)	20.7%	18.1%	20.0%	19.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	8,104	8,293	6,319	6,103	
V	SIL Value	8,104	8,293	6,319	6,103	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,951	8,185	7,418	8,185	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	372	1,223	73	914	SellerGendata
E	Uncommitted Capacity Imports	140	90	81	74	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	44,121	37,780	53,385	41,231	Loads
G	Amount of Line F Attributable to Seller, if any	1,524	1,270	2,340	1,568	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	42,598	36,510	51,045	39,663	F - G
I	Study Area Reserve Requirement	3,105	2,881	3,898	3,332	Gendata
J	Amount of Line I Attributable to Seller, if any	115	114	202	143	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,990	2,767	3,696	3,189	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	82,251	81,151	80,051	81,151	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,422	12,123	790	9,067	Gendata; Row D
P	Uncommitted Capacity Imports	7,757	8,766	4,374	5,994	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	41,035	38,546	28,922	35,255	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,044	5,639	4,856	5,604	
S	Total Seasonal Uncommitted Capacity (Q+R)	48,079	44,185	33,778	40,859	
T	**Applicant's Market Share** (R÷S)	14.7%	12.8%	14.4%	13.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,897	8,856	4,455	6,068	
V	SIL Value	7,897	8,856	4,455	6,068	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Sets and SIL Data

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Areas		Owners	
Code	**Name**	**Code**	**Name**
MISO	Midwest ISO	PSEG	Public Service Enterprise Group Inc
NYISO	New York		
PJM	PJM Interconnection		
PJM_50	PJM Excluding PJM50		
PJM_AP	PJM Excluding PJMAP		
PJM_E	PJM Excluding PJME		
PJM50	PJM East of 5004/05		
PJMAP	PJM East of AP South		
PJME	PJM East		

Season	
Code	**Name**
SPR	Spring
SUM	Summer
FAL	Fall
WIN	Winter

Area	Season	SIL	Comment
PJM	SPR	12273	PJM 2015 Simultaneous Import Limit Study
PJM	SUM	7600	PJM 2015 Simultaneous Import Limit Study
PJM	FAL	7067	PJM 2015 Simultaneous Import Limit Study
PJM	WIN	11997	PJM 2015 Simultaneous Import Limit Study
PJME	SPR	8830	PJM 2015 Simultaneous Import Limit Study
PJME	SUM	6537	PJM 2015 Simultaneous Import Limit Study
PJME	FAL	7859	PJM 2015 Simultaneous Import Limit Study
PJME	WIN	7502	PJM 2015 Simultaneous Import Limit Study
PJM50	SPR	8293	PJM 2015 Simultaneous Import Limit Study
PJM50	SUM	6319	PJM 2015 Simultaneous Import Limit Study
PJM50	FAL	6103	PJM 2015 Simultaneous Import Limit Study
PJM50	WIN	8104	PJM 2015 Simultaneous Import Limit Study
PJMAP	SPR	8856	PJM 2015 Simultaneous Import Limit Study
PJMAP	SUM	4455	PJM 2015 Simultaneous Import Limit Study
PJMAP	FAL	6068	PJM 2015 Simultaneous Import Limit Study
PJMAP	WIN	7897	PJM 2015 Simultaneous Import Limit Study

Area	First Tier Areas	Note: No more than 6 First Tier Areas for each destination Area.
PJM	MISO	
PJM	NYISO	
PJM50	NYISO	
PJM50	PJM_50	
PJMAP	NYISO	
PJMAP	PJM_AP	
PJME	NYISO	
PJME	PJM_E	

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Market Data

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AREA	SEASON	MONTH	CAPACITY	PLANNED OUTAGE
NYISO	WIN	1	42,375	3,911
NYISO	WIN	2	42,375	4,197
NYISO	SPR	3	41,172	6,005
NYISO	SPR	4	41,172	9,262
NYISO	SPR	5	41,172	3,751
NYISO	SUM	6	39,969	796
NYISO	SUM	7	39,969	805
NYISO	SUM	8	39,969	910
NYISO	FAL	9	41,172	2,029
NYISO	FAL	10	41,172	9,548
NYISO	FAL	11	41,172	6,419
NYISO	WIN	12	42,375	3,142
PJM	WIN	1	204,194	4,773
PJM	WIN	2	204,194	7,522
PJM	SPR	3	200,080	20,892
PJM	SPR	4	200,080	46,574
PJM	SPR	5	200,080	22,201
PJM	SUM	6	195,966	4,655
PJM	SUM	7	195,966	237
PJM	SUM	8	195,966	910
PJM	FAL	9	200,080	3,112
PJM	FAL	10	200,080	39,568
PJM	FAL	11	200,080	24,388
PJM	WIN	12	204,194	13,188
PJME	WIN	1	35,750	836
PJME	WIN	2	35,750	1,317
PJME	SPR	3	35,046	3,659
PJME	SPR	4	35,046	8,158
PJME	SPR	5	35,046	3,889
PJME	SUM	6	34,341	816
PJME	SUM	7	34,341	42
PJME	SUM	8	34,341	159
PJME	FAL	9	35,046	545
PJME	FAL	10	35,046	6,931
PJME	FAL	11	35,046	4,272
PJME	WIN	12	35,750	2,309
PJM50	WIN	1	62,662	1,465
PJM50	WIN	2	62,662	2,308
PJM50	SPR	3	61,535	6,425
PJM50	SPR	4	61,535	14,324
PJM50	SPR	5	61,535	6,828
PJM50	SUM	6	60,407	1,435
PJM50	SUM	7	60,407	73
PJM50	SUM	8	60,407	281
PJM50	FAL	9	61,535	957
PJM50	FAL	10	61,535	12,169
PJM50	FAL	11	61,535	7,501
PJM50	WIN	12	62,662	4,047
PJMAP	WIN	1	91,202	2,132
PJMAP	WIN	2	91,202	3,360
PJMAP	SPR	3	89,336	9,328

PJMAP	SPR	4	89,336	20,795
PJMAP	SPR	5	89,336	9,913
PJMAP	SUM	6	87,469	2,078
PJMAP	SUM	7	87,469	106
PJMAP	SUM	8	87,469	406
PJMAP	FAL	9	89,336	1,390
PJMAP	FAL	10	89,336	17,667
PJMAP	FAL	11	89,336	10,889
PJMAP	WIN	12	91,202	5,890
PJM_E	WIN	1	168,444	3,937
PJM_E	WIN	2	168,444	6,205
PJM_E	SPR	3	165,035	17,233
PJM_E	SPR	4	165,035	38,416
PJM_E	SPR	5	165,035	18,312
PJM_E	SUM	6	161,625	3,839
PJM_E	SUM	7	161,625	195
PJM_E	SUM	8	161,625	751
PJM_E	FAL	9	165,035	2,567
PJM_E	FAL	10	165,035	32,637
PJM_E	FAL	11	165,035	20,116
PJM_E	WIN	12	168,444	10,879
PJM_50	WIN	1	141,532	3,308
PJM_50	WIN	2	141,532	5,214
PJM_50	SPR	3	138,546	14,467
PJM_50	SPR	4	138,546	32,250
PJM_50	SPR	5	138,546	15,373
PJM_50	SUM	6	135,559	3,220
PJM_50	SUM	7	135,559	164
PJM_50	SUM	8	135,559	629
PJM_50	FAL	9	138,546	2,155
PJM_50	FAL	10	138,546	27,399
PJM_50	FAL	11	138,546	16,887
PJM_50	WIN	12	141,532	9,141
PJM_AP	WIN	1	112,992	2,641
PJM_AP	WIN	2	112,992	4,162
PJM_AP	SPR	3	110,745	11,564
PJM_AP	SPR	4	110,745	25,779
PJM_AP	SPR	5	110,745	12,288
PJM_AP	SUM	6	108,497	2,577
PJM_AP	SUM	7	108,497	131
PJM_AP	SUM	8	108,497	504
PJM_AP	FAL	9	110,745	1,722
PJM_AP	FAL	10	110,745	21,901
PJM_AP	FAL	11	110,745	13,499
PJM_AP	WIN	12	112,992	7,298
MISO	WIN	1	183,745	11,845
MISO	WIN	2	183,745	13,214
MISO	SPR	3	179,902	22,181
MISO	SPR	4	179,902	31,160
MISO	SPR	5	179,902	19,117
MISO	SUM	6	176,059	8,163
MISO	SUM	7	176,059	6,429

MISO	SUM	8	176,059	7,498
MISO	FAL	9	179,902	7,327
MISO	FAL	10	179,902	28,881
MISO	FAL	11	179,902	23,062
MISO	WIN	12	183,745	16,145

OPERATING RESERVES
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AREA	SEASON	MONTH	MONTHLY PEAK	AVERAGE OF DAILY PEAKS	AVERAGE PEAK LOAD
NYISO	WIN	1	23,317	21,135	20,442
NYISO	WIN	2	23,301	20,827	19,848
NYISO	SPR	3	21,234	18,697	18,157
NYISO	SPR	4	20,173	17,906	17,719
NYISO	SPR	5	25,061	18,866	18,308
NYISO	SUM	6	26,286	22,415	21,209
NYISO	SUM	7	31,187	26,299	25,606
NYISO	SUM	8	32,076	27,129	25,111
NYISO	FAL	9	29,637	22,307	21,394
NYISO	FAL	10	21,143	18,697	18,217
NYISO	FAL	11	26,848	19,630	18,309
NYISO	WIN	12	21,254	20,142	18,879
PJM	WIN	1	129,775	109,463	107,474
PJM	WIN	2	121,307	103,878	100,450
PJM	SPR	3	106,497	89,530	86,259
PJM	SPR	4	99,868	86,664	84,984
PJM	SPR	5	121,540	90,069	87,988
PJM	SUM	6	134,752	113,737	104,204
PJM	SUM	7	150,826	128,598	123,071
PJM	SUM	8	152,177	132,696	121,208
PJM	FAL	9	142,092	110,389	103,577
PJM	FAL	10	102,277	87,670	86,550
PJM	FAL	11	105,171	90,942	87,635
PJM	WIN	12	104,494	94,919	91,099
PJME	WIN	1	21,350	18,481	17,769
PJME	WIN	2	21,162	17,962	16,867
PJME	SPR	3	18,138	15,588	14,660
PJME	SPR	4	16,803	15,031	14,387
PJME	SPR	5	23,845	16,304	15,372
PJME	SUM	6	25,217	20,821	18,716
PJME	SUM	7	30,668	25,247	23,531
PJME	SUM	8	30,992	25,852	22,778
PJME	FAL	9	29,146	20,177	18,619
PJME	FAL	10	19,352	15,573	14,861
PJME	FAL	11	22,289	16,282	14,965
PJME	WIN	12	18,025	16,926	15,645
PJM50	WIN	1	41,374	35,364	34,388
PJM50	WIN	2	40,902	33,996	32,335
PJM50	SPR	3	33,605	28,694	27,196
PJM50	SPR	4	32,555	27,801	26,948
PJM50	SPR	5	42,130	29,682	28,433
PJM50	SUM	6	44,644	37,204	33,847
PJM50	SUM	7	53,493	44,768	42,189
PJM50	SUM	8	53,118	45,448	40,617
PJM50	FAL	9	50,923	36,593	34,119
PJM50	FAL	10	35,164	28,728	27,820
PJM50	FAL	11	41,077	30,204	28,159
PJM50	WIN	12	33,646	31,039	29,171
PJMAP	WIN	1	60,322	49,742	47,974
PJMAP	WIN	2	57,551	47,206	44,577
PJMAP	SPR	3	47,812	39,760	37,365

PJMAP	SPR	4	46,155	38,384	36,990
PJMAP	SPR	5	57,683	40,750	38,985
PJMAP	SUM	6	60,457	51,652	46,812
PJMAP	SUM	7	73,026	61,476	57,809
PJMAP	SUM	8	71,663	62,236	55,535
PJMAP	FAL	9	68,834	50,417	46,839
PJMAP	FAL	10	49,092	39,560	38,174
PJMAP	FAL	11	57,447	41,655	38,679
PJMAP	WIN	12	45,563	42,355	39,813
PJM_E	WIN	1	108,425	90,982	89,705
PJM_E	WIN	2	100,146	85,916	83,583
PJM_E	SPR	3	88,359	73,942	71,599
PJM_E	SPR	4	83,064	71,634	70,597
PJM_E	SPR	5	97,695	73,764	72,617
PJM_E	SUM	6	109,535	92,915	85,488
PJM_E	SUM	7	120,158	103,352	99,540
PJM_E	SUM	8	121,185	106,843	98,430
PJM_E	FAL	9	112,947	90,213	84,958
PJM_E	FAL	10	82,924	72,098	71,689
PJM_E	FAL	11	82,883	74,660	72,670
PJM_E	WIN	12	86,469	77,993	75,454
PJM_50	WIN	1	88,401	74,099	73,086
PJM_50	WIN	2	80,405	69,883	68,115
PJM_50	SPR	3	72,892	60,836	59,063
PJM_50	SPR	4	67,313	58,863	58,036
PJM_50	SPR	5	79,410	60,387	59,556
PJM_50	SUM	6	90,108	76,532	70,358
PJM_50	SUM	7	97,334	83,831	80,881
PJM_50	SUM	8	99,059	87,247	80,591
PJM_50	FAL	9	91,170	73,797	69,458
PJM_50	FAL	10	67,112	58,942	58,730
PJM_50	FAL	11	64,095	60,737	59,476
PJM_50	WIN	12	70,847	63,880	61,928
PJM_AP	WIN	1	69,453	59,721	59,500
PJM_AP	WIN	2	63,756	56,672	55,873
PJM_AP	SPR	3	58,686	49,770	48,894
PJM_AP	SPR	4	53,712	48,280	47,994
PJM_AP	SPR	5	63,857	49,319	49,004
PJM_AP	SUM	6	74,295	62,085	57,392
PJM_AP	SUM	7	77,800	67,123	65,262
PJM_AP	SUM	8	80,514	70,460	65,673
PJM_AP	FAL	9	73,259	59,973	56,738
PJM_AP	FAL	10	53,185	48,110	48,377
PJM_AP	FAL	11	47,725	49,287	48,956
PJM_AP	WIN	12	58,930	52,564	51,286
MISO	WIN	1	97,753	86,934	85,534
MISO	WIN	2	93,742	82,714	81,237
MISO	SPR	3	84,269	75,364	74,207
MISO	SPR	4	79,241	73,507	73,366
MISO	SPR	5	95,170	78,725	77,495
MISO	SUM	6	112,332	98,951	92,990
MISO	SUM	7	120,764	105,024	102,199

MISO	SUM	8	119,860	105,194	101,044
MISO	FAL	9	114,750	92,759	88,854
MISO	FAL	10	90,297	78,398	77,534
MISO	FAL	11	81,775	75,958	74,460
MISO	WIN	12	87,091	80,969	79,008

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COMMENT

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AREA	SOURCE	SEASON	SELLER	REMOTE	CONTRACT	ROW

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DESCRIPTION	CAPACITY

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Seller Data

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AREA	SEASON	MONTH	CAPACITY	PLANNED OUTAGE
NYISO	WIN	1	870	80.29663717
NYISO	WIN	2	870	86.16849558
NYISO	SPR	3	814	118.6502356
NYISO	SPR	4	814	183.0039104
NYISO	SPR	5	814	74.11441028
NYISO	SUM	6	757	15.07598389
NYISO	SUM	7	757	15.24644099
NYISO	SUM	8	757	17.23510721
NYISO	FAL	9	814	40.09014622
NYISO	FAL	10	814	188.6548625
NYISO	FAL	11	814	126.8302851
NYISO	WIN	12	870	64.50831858
PJM	WIN	1	10,859	253.827277
PJM	WIN	2	10,859	400.0186
PJM	SPR	3	10,119	1056.555888
PJM	SPR	4	10,119	2355.352954
PJM	SPR	5	10,119	1122.754991
PJM	SUM	6	9,378	222.7661431
PJM	SUM	7	9,378	11.34169193
PJM	SUM	8	9,378	43.54826858
PJM	FAL	9	10,119	157.3809076
PJM	FAL	10	10,119	2001.043623
PJM	FAL	11	10,119	1233.356547
PJM	WIN	12	10,859	701.3354555
PJME	WIN	1	8182	191.2528576
PJME	WIN	2	8182	301.4045662
PJME	SPR	3	7416	774.3656138
PJME	SPR	4	7416	1726.273411
PJME	SPR	5	7416	822.8839264
PJME	SUM	6	6650	157.9649021
PJME	SUM	7	6650	8.04246655
PJME	SUM	8	6650	30.8803568
PJME	FAL	9	7416	115.3468213
PJME	FAL	10	7416	1466.594802
PJME	FAL	11	7416	903.9454618
PJME	WIN	12	8182	528.4396995
PJM50	WIN	1	8951	209.2281017
PJM50	WIN	2	8951	329.732617
PJM50	SPR	3	8184.5	854.6110256
PJM50	SPR	4	8184.5	1905.16245
PJM50	SPR	5	8184.5	908.1571596
PJM50	SUM	6	7418	176.2080667
PJM50	SUM	7	7418	8.971280732
PJM50	SUM	8	7418	34.44668973
PJM50	FAL	9	8184.5	127.2999
PJM50	FAL	10	8184.5	1618.57405
PJM50	FAL	11	8184.5	997.6188824
PJM50	WIN	12	8951	578.106056
PJMAP	WIN	1	8951	209.2281017
PJMAP	WIN	2	8951	329.732617
PJMAP	SPR	3	8184.5	854.6110256

PJMAP	SPR	4	8184.5	1905.16245
PJMAP	SPR	5	8184.5	908.1571596
PJMAP	SUM	6	7418	176.2080667
PJMAP	SUM	7	7418	8.971280732
PJMAP	SUM	8	7418	34.44668973
PJMAP	FAL	9	8184.5	127.2999
PJMAP	FAL	10	8184.5	1618.57405
PJMAP	FAL	11	8184.5	997.6188824
PJMAP	WIN	12	8951	578.106056
PJM_E	WIN	1	2677	62.57441942
PJM_E	WIN	2	2677	98.61403371
PJM_E	SPR	3	2702.5	282.1902739
PJM_E	SPR	4	2702.5	629.0795432
PJM_E	SPR	5	2702.5	299.8710641
PJM_E	SUM	6	2728	64.80124103
PJM_E	SUM	7	2728	3.299225376
PJM_E	SUM	8	2728	12.66791178
PJM_E	FAL	9	2702.5	42.03408637
PJM_E	FAL	10	2702.5	534.4488205
PJM_E	FAL	11	2702.5	329.4110856
PJM_E	WIN	12	2677	172.895756
PJM_50	WIN	1	1908	44.59917529
PJM_50	WIN	2	1908	70.28598294
PJM_50	SPR	3	1934	201.9448621
PJM_50	SPR	4	1934	450.1905038
PJM_50	SPR	5	1934	214.5978309
PJM_50	SUM	6	1960	46.5580764
PJM_50	SUM	7	1960	2.370411194
PJM_50	SUM	8	1960	9.101578845
PJM_50	FAL	9	1934	30.0810076
PJM_50	FAL	10	1934	382.4695722
PJM_50	FAL	11	1934	235.7376649
PJM_50	WIN	12	1908	123.2293995
PJM_AP	WIN	1	1908	44.59917529
PJM_AP	WIN	2	1908	70.28598294
PJM_AP	SPR	3	1934	201.9448621
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PJM_AP	SPR	5	1934	214.5978309
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PJM_AP	SUM	8	1960	9.101578845
PJM_AP	FAL	9	1934	30.0810076
PJM_AP	FAL	10	1934	382.4695722
PJM_AP	FAL	11	1934	235.7376649
PJM_AP	WIN	12	1908	123.2293995

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AREA	SEASON	MONTH	MONTHLY PEAK	AVERAGE OF DAILY PEAKS	AVERAGE PEAK LOAD
NYISO	WIN	1	-	-	-
NYISO	WIN	2	-	-	-
NYISO	SPR	3	-	-	-
NYISO	SPR	4	-	-	-
NYISO	SPR	5	-	-	-
NYISO	SUM	6	-	-	-
NYISO	SUM	7	-	-	-
NYISO	SUM	8	-	-	-
NYISO	FAL	9	-	-	-
NYISO	FAL	10	-	-	-
NYISO	FAL	11	-	-	-
NYISO	WIN	12	-	-	-
PJM	WIN	1	2,187	1,908	1,680
PJM	WIN	2	2,208	1,834	1,583
PJM	SPR	3	1,793	1,551	1,317
PJM	SPR	4	1,699	1,453	1,253
PJM	SPR	5	2,681	1,603	1,354
PJM	SUM	6	2,933	2,306	1,903
PJM	SUM	7	3,683	2,992	2,615
PJM	SUM	8	3,998	3,073	2,503
PJM	FAL	9	3,519	2,220	1,863
PJM	FAL	10	1,994	1,622	1,390
PJM	FAL	11	2,030	1,716	1,451
PJM	WIN	12	1,870	1,712	1,456
PJME	WIN	1	2071.82422	1,811	1598.633077
PJME	WIN	2	2087.87738	1,741	1506.097893
PJME	SPR	3	1699.30127	1,477	1258.054799
PJME	SPR	4	1613.83134	1,385	1198.903841
PJME	SPR	5	2595.69673	1,539	1303.230943
PJME	SUM	6	2544.91271	2,013	1670.812832
PJME	SUM	7	3245.75586	2620.463546	2298.973997
PJME	SUM	8	3538.68543	2695.381386	2205.210453
PJME	FAL	9	3085.0773	1927.826885	1633.467359
PJME	FAL	10	1735.6674	1377.55915	1197.477072
PJME	FAL	11	1649.56753	1424.046758	1218.505107
PJME	WIN	12	1774	1630.935484	1392.605114
PJM50	WIN	1	2112.23243	1843.396131	1627.49382
PJM50	WIN	2	2131.49184	1770.955132	1531.939171
PJM50	SPR	3	1729.18961	1499.662979	1276.360292
PJM50	SPR	4	1641.05254	1405.943822	1215.40429
PJM50	SPR	5	2626.68665	1559.4767	1319.067449
PJM50	SUM	6	2933.05226	2305.630737	1903.335218
PJM50	SUM	7	3682.95707	2992.478437	2614.982471
PJM50	SUM	8	3998.35498	3073.014376	2502.605508
PJM50	FAL	9	3518.82491	2220.474087	1862.733948
PJM50	FAL	10	1994.33213	1622.031246	1390.147201
PJM50	FAL	11	2029.9163	1715.635242	1450.924655
PJM50	WIN	12	1803	1654.451613	1411.298295
PJMAP	WIN	1	2112.23243	1843.396131	1627.49382
PJMAP	WIN	2	2131.49184	1770.955132	1531.939171
PJMAP	SPR	3	1729.18961	1499.662979	1276.360292

PJMAP	SPR	4	1641.05254	1405.943822	1215.40429
PJMAP	SPR	5	2626.68665	1559.4767	1319.067449
PJMAP	SUM	6	2933.05226	2305.630737	1903.335218
PJMAP	SUM	7	3682.95707	2992.478437	2614.982471
PJMAP	SUM	8	3998.35498	3073.014376	2502.605508
PJMAP	FAL	9	3518.82491	2220.474087	1862.733948
PJMAP	FAL	10	1994.33213	1622.031246	1390.147201
PJMAP	FAL	11	2029.9163	1715.635242	1450.924655
PJMAP	WIN	12	1803	1654.451613	1411.298295
PJM_E	WIN	1	114.85733	2.684770542	80.95252853
PJM_E	WIN	2	119.72045	4.410204144	76.42658753
PJM_E	SPR	3	93.4001	9.752673377	58.76250864
PJM_E	SPR	4	85.12579	19.81531659	54.39960196
PJM_E	SPR	5	85.02786	9.434743702	51.10709568
PJM_E	SUM	6	388.13955	9.219913685	232.5223862
PJM_E	SUM	7	437.20121	0.528748287	316.0084735
PJM_E	SUM	8	459.66955	2.134550333	297.3950549
PJM_E	FAL	9	433.74761	6.746414246	229.2665884
PJM_E	FAL	10	258.66473	51.15376868	192.6701299
PJM_E	FAL	11	380.34877	46.36118454	232.4195477
PJM_E	WIN	12	96	6.200221358	63.03977273
PJM_50	WIN	1	74.44912	1.74023551	52.09178512
PJM_50	WIN	2	76.10599	2.80355572	50.58530935
PJM_50	SPR	3	63.51176	6.631785735	40.45701549
PJM_50	SPR	4	57.90459	13.47885033	37.89915286
PJM_50	SPR	5	54.03794	5.996083096	35.27058943
PJM_50	SUM	6	0	0	0
PJM_50	SUM	7	0	0	0
PJM_50	SUM	8	0	0	0
PJM_50	FAL	9	0	0	0
PJM_50	FAL	10	0	0	0
PJM_50	FAL	11	0	0	0
PJM_50	WIN	12	67	4.327237823	44.34659091
PJM_AF	WIN	1	74.44912	1.74023551	52.09178513
PJM_AF	WIN	2	76.10599	2.80355572	50.58530935
PJM_AF	SPR	3	63.51176	6.631785735	40.45701549
PJM_AF	SPR	4	57.90459	13.47885033	37.89915286
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PJM_AF	SUM	7	0	0	0
PJM_AF	SUM	8	0	0	0
PJM_AF	FAL	9	0	0	0
PJM_AF	FAL	10	0	0	0
PJM_AF	FAL	11	0	0	0
PJM_AF	WIN	12	67	4.327237823	44.34659091

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COMMENT

AREA	SEASON	DESCRIPTION	SALE	PURCHASE
PJM	WIN	LES Project Holdings	14	0
PJM	SPR	LES Project Holdings	14	0
PJM	SUM	LES Project Holdings	14	0
PJM	FAL	LES Project Holdings	14	0
PJM	WIN	Ocean Energy Holdings	9	0
PJM	SPR	Ocean Energy Holdings	9	0
PJM	SUM	Ocean Energy Holdings	9	0
PJM	FAL	Ocean Energy Holdings	9	0
PJM	WIN	BP	34	0
PJM	SPR	BP	0	0
PJM	SUM	BP	0	0
PJM	FAL	BP	0	0
PJM	WIN	Citigroup	94	0
PJM	SPR	Citigroup	75	0
PJM	SUM	Citigroup	75	0
PJM	FAL	Citigroup	75	0
PJM	WIN	Direct Energy	556	0
PJM	SPR	Direct Energy	650	0
PJM	SUM	Direct Energy	650	0
PJM	FAL	Direct Energy	650	0
PJM	WIN	EDF	8	0
PJM	SPR	EDF	0	0
PJM	SUM	EDF	0	0
PJM	FAL	EDF	0	0
PJM	WIN	Energy America	305	0
PJM	SPR	Energy America	460	0
PJM	SUM	Energy America	460	0
PJM	FAL	Energy America	460	0
PJM	WIN	Exelon	66	0
PJM	SPR	Exelon	100	0
PJM	SUM	Exelon	100	0
PJM	FAL	Exelon	100	0
PJM	WIN	Nextera	523	0
PJM	SPR	Nextera	602	0
PJM	SUM	Nextera	601	0
PJM	FAL	Nextera	602	0
PJM	WIN	American Electric Power	10	0
PJM	SPR	American Electric Power	10	0
PJM	SUM	American Electric Power	10	0
PJM	FAL	American Electric Power	10	0
PJM	WIN	M&M Mars	2	0
PJM	SPR	M&M Mars	2	0
PJM	SUM	M&M Mars	2	0
PJM	FAL	M&M Mars	2	0
PJM	WIN	SMECO	10	0
PJM	SPR	SMECO	10	0
PJM	SUM	SMECO	10	0
PJM	FAL	SMECO	10	0
PJM	WIN	JP Morgan	0	195
PJM	SPR	JP Morgan	0	195
PJM	SUM	JP Morgan	0	195
PJM	FAL	JP Morgan	0	195
PJM	WIN	Delaware Municipal Electric Corporatio	12	0
PJM	SPR	Delaware Municipal Electric Corporatio	12	0

PJM	SUM	Delaware Municipal Electric Corporatio	12	0
PJM	FAL	Delaware Municipal Electric Corporatio	12	0
PJM_E	WIN	LES Project Holdings	14	0
PJM_E	SPR	LES Project Holdings	14	0
PJM_E	SUM	LES Project Holdings	14	0
PJM_E	FAL	LES Project Holdings	14	0
PJM_E	WIN	Ocean Energy Holdings	9	0
PJM_E	SPR	Ocean Energy Holdings	9	0
PJM_E	SUM	Ocean Energy Holdings	9	0
PJM_E	FAL	Ocean Energy Holdings	9	0
PJM_E	WIN	BP	34	0
PJM_E	SPR	BP	0	0
PJM_E	SUM	BP	0	0
PJM_E	FAL	BP	0	0
PJM_E	WIN	Citigroup	94	0
PJM_E	SPR	Citigroup	75	0
PJM_E	SUM	Citigroup	75	0
PJM_E	FAL	Citigroup	75	0
PJM_E	WIN	Direct Energy	556	0
PJM_E	SPR	Direct Energy	650	0
PJM_E	SUM	Direct Energy	650	0
PJM_E	FAL	Direct Energy	650	0
PJME	WIN	EDF	8	0
PJME	SPR	EDF	0	0
PJME	SUM	EDF	0	0
PJME	FAL	EDF	0	0
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PJM_E	SUM	Energy America	460	0
PJM_E	FAL	Energy America	460	0
PJM_E	WIN	Exelon	66	0
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PJM_E	SPR	Nextera	602	0
PJM_E	SUM	Nextera	601	0
PJM_E	FAL	Nextera	602	0
PJM_E	WIN	American Electric Power	10	0
PJM_E	SPR	American Electric Power	10	0
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PJM_E	FAL	American Electric Power	10	0
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PJM_E	SUM	SMECO	10	0
PJM_E	FAL	SMECO	10	0
PJM_E	WIN	JP Morgan	0	195
PJM_E	SPR	JP Morgan	0	195
PJM_E	SUM	JP Morgan	0	195
PJM_E	FAL	JP Morgan	0	195
PJME	WIN	Delaware Municipal Electric Corporatio	12	0

PJME	SPR	Delaware Municipal Electric Corporatio	12	0
PJME	SUM	Delaware Municipal Electric Corporatio	12	0
PJME	FAL	Delaware Municipal Electric Corporatio	12	0
PJM50	WIN	LES Project Holdings	14	0
PJM50	SPR	LES Project Holdings	14	0
PJM50	SUM	LES Project Holdings	14	0
PJM50	FAL	LES Project Holdings	14	0
PJM_50	WIN	Ocean Energy Holdings	9	0
PJM_50	SPR	Ocean Energy Holdings	9	0
PJM_50	SUM	Ocean Energy Holdings	9	0
PJM_50	FAL	Ocean Energy Holdings	9	0
PJM_50	WIN	BP	34	0
PJM_50	SPR	BP	0	0
PJM_50	SUM	BP	0	0
PJM_50	FAL	BP	0	0
PJM_50	WIN	Citigroup	94	0
PJM_50	SPR	Citigroup	75	0
PJM_50	SUM	Citigroup	75	0
PJM_50	FAL	Citigroup	75	0
PJM_50	WIN	Direct Energy	556	0
PJM_50	SPR	Direct Energy	650	0
PJM_50	SUM	Direct Energy	650	0
PJM_50	FAL	Direct Energy	650	0
PJM50	WIN	EDF	8	0
PJM50	SPR	EDF	0	0
PJM50	SUM	EDF	0	0
PJM50	FAL	EDF	0	0
PJM_50	WIN	Energy America	305	0
PJM_50	SPR	Energy America	460	0
PJM_50	SUM	Energy America	460	0
PJM_50	FAL	Energy America	460	0
PJM_50	WIN	Exelon	66	0
PJM_50	SPR	Exelon	100	0
PJM_50	SUM	Exelon	100	0
PJM_50	FAL	Exelon	100	0
PJM_50	WIN	Nextera	523	0
PJM_50	SPR	Nextera	602	0
PJM_50	SUM	Nextera	601	0
PJM_50	FAL	Nextera	602	0
PJM_50	WIN	American Electric Power	10	0
PJM_50	SPR	American Electric Power	10	0
PJM_50	SUM	American Electric Power	10	0
PJM_50	FAL	American Electric Power	10	0
PJM50	WIN	M&M Mars	2	0
PJM50	SPR	M&M Mars	2	0
PJM50	SUM	M&M Mars	2	0
PJM50	FAL	M&M Mars	2	0
PJM_50	WIN	SMECO	10	0
PJM_50	SPR	SMECO	10	0
PJM_50	SUM	SMECO	10	0
PJM_50	FAL	SMECO	10	0
PJM_50	WIN	JP Morgan	0	195
PJM_50	SPR	JP Morgan	0	195
PJM_50	SUM	JP Morgan	0	195
PJM_50	FAL	JP Morgan	0	195

PJM50	WIN	Delaware Municipal Electric Corporatio	12	0
PJM50	SPR	Delaware Municipal Electric Corporatio	12	0
PJM50	SUM	Delaware Municipal Electric Corporatio	12	0
PJM50	FAL	Delaware Municipal Electric Corporatio	12	0
PJMAP	WIN	LES Project Holdings	14	0
PJMAP	SPR	LES Project Holdings	14	0
PJMAP	SUM	LES Project Holdings	14	0
PJMAP	FAL	LES Project Holdings	14	0
PJM_AP	WIN	Ocean Energy Holdings	9	0
PJM_AP	SPR	Ocean Energy Holdings	9	0
PJM_AP	SUM	Ocean Energy Holdings	9	0
PJM_AP	FAL	Ocean Energy Holdings	9	0
PJM_AP	WIN	BP	34	0
PJM_AP	SPR	BP	0	0
PJM_AP	SUM	BP	0	0
PJM_AP	FAL	BP	0	0
PJM_AP	WIN	Citigroup	94	0
PJM_AP	SPR	Citigroup	75	0
PJM_AP	SUM	Citigroup	75	0
PJM_AP	FAL	Citigroup	75	0
PJM_AP	WIN	Direct Energy	556	0
PJM_AP	SPR	Direct Energy	650	0
PJM_AP	SUM	Direct Energy	650	0
PJM_AP	FAL	Direct Energy	650	0
PJMAP	WIN	EDF	8	0
PJMAP	SPR	EDF	0	0
PJMAP	SUM	EDF	0	0
PJMAP	FAL	EDF	0	0
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PJM_AP	SPR	Energy America	460	0
PJM_AP	SUM	Energy America	460	0
PJM_AP	FAL	Energy America	460	0
PJM_AP	WIN	Exelon	66	0
PJM_AP	SPR	Exelon	100	0
PJM_AP	SUM	Exelon	100	0
PJM_AP	FAL	Exelon	100	0
PJM_AP	WIN	Nextera	523	0
PJM_AP	SPR	Nextera	602	0
PJM_AP	SUM	Nextera	601	0
PJM_AP	FAL	Nextera	602	0
PJM_AP	WIN	American Electric Power	10	0
PJM_AP	SPR	American Electric Power	10	0
PJM_AP	SUM	American Electric Power	10	0
PJM_AP	FAL	American Electric Power	10	0
PJMAP	WIN	M&M Mars	2	0
PJMAP	SPR	M&M Mars	2	0
PJMAP	SUM	M&M Mars	2	0
PJMAP	FAL	M&M Mars	2	0
PJM_AP	WIN	SMECO	10	0
PJM_AP	SPR	SMECO	10	0
PJM_AP	SUM	SMECO	10	0
PJM_AP	FAL	SMECO	10	0
PJM_AP	WIN	JP Morgan	0	195
PJM_AP	SPR	JP Morgan	0	195
PJM_AP	SUM	JP Morgan	0	195

PJM_AP	FAL	JP Morgan	0	195
PJMAP	WIN	Delaware Municipal Electric Corporatio	12	0
PJMAP	SPR	Delaware Municipal Electric Corporatio	12	0
PJMAP	SUM	Delaware Municipal Electric Corporatio	12	0
PJMAP	FAL	Delaware Municipal Electric Corporatio	12	0

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Document Content(s)

PSEG Sewaren Change in Status Letter.PDF.....1-1

FINAL Appendix B - Generation Assets Change in Status.XLSX.....2-19

Appendix A-3 PSEG Sewaren MBR Program.XLSX.....20-69

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Cara J. Lewis
General Federal Regulatory Counsel

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80 Park Plaza, T5G, Newark, NJ 07102-4194
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PSEG
Services Corporation

By ELECTRONIC FILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

June 29, 2018

Re: Supplement to Notice of Non-Material Change in Status of PSEG Affiliates:

PSEG Energy Resources & Trade LLC	ER10-1789-___
PSEG Energy Solutions LLC	ER16-2725-___
PSEG Fossil LLC	ER10-1770-___
PSEG New Haven LLC	ER12-1250-___
PSEG Nuclear LLC	ER10-1771-___
PSEG Power Connecticut LLC	ER10-1793-___
Pavant Solar II LLC	ER16-1925-___
Bison Solar LLC	ER16-1924-___
San Isabel Solar LLC	ER16-1926-___
Public Service Electric and Gas Company	ER10-1768-___
PSEG Keys Energy Center LLC	ER17-2426-___

Dear Ms. Bose:

On May 25, 2018, the PSEG Affiliates submitted a notice of non-material change in status ("Notice") pursuant to section 35.42(a)(1) of the regulations of the Federal Energy Regulatory Commission ("Commission").[1] The PSEG Affiliates are submitting this supplement to the Notice to include: (1) Appendix B – Generation Assets; and (2) Appendix A-3 in Excel format as required by the Commission's regulations.

Please feel free to contact me at (973) 430-8836 if you have any questions about this matter.

Very truly yours,

Cara J. Lewis

Cara J. Lewis

[1] 18 C.F.R. Part 35.42 (2017).

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G	ER99-3151-000	NA*	NA*	NA*	NA*	PJM	Northeast	NA*
PSEG ER&T	ER97-837-000	NA*	NA*	NA*	NA*	PJM, NYISO, NE-ISO	Northeast, Central, Southwest Power Pool, Southeast, Southwest, Northwest	NA*
PSEG Fossil	ER08-447-000	Bergen CC1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Bergen CC2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2002
PSEG Fossil	ER08-447-000	Burlington 12.1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Conemaugh 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/21/1970
PSEG Fossil	ER08-447-000	Conemaugh 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/27/1971
PSEG Fossil	ER08-447-000	Conemaugh A	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh B	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh C	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh D	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Global	N/A	Conemaugh Hydroelectric Plant 1	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Global	N/A	Conemaugh Hydroelectric Plant 2	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Fossil	ER08-447-000	Essex 9	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/1/1990
PSEG Nuclear	ER08-448-000	Hope Creek 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/20/1986
PSEG Fossil	ER08-447-000	Kearny 12	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/1/2001
PSEG Fossil	ER08-447-000	Kearny 13	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Kearny 14	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Keystone 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/24/1967
PSEG Fossil	ER08-447-000	Keystone 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/23/1968
PSEG Fossil	ER08-447-000	Keystone 3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Linden 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM,	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 7	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Linden 8	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Linden GT5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000

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Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSEG Fossil	ER08-447-000	Linden GT6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Keys Energy Center LLC	ER17-2426-000	PSEG Keys Energy Center	PSEG Keys Energy Center	PSEG ER&T	N/A	PJM	Northeast	7/3/2018
PSEG Nuclear	ER08-448-000	Peach Bottom 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	7/5/1974
PSEG Nuclear	ER08-448-000	Peach Bottom 3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/23/1974
PSEG Nuclear	ER08-448-000	Salem 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/30/1977
PSEG Nuclear	ER08-448-000	Salem 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	10/13/1981
PSEG Nuclear	ER08-448-000	Salem GT3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/17/1971
PSEG Fossil	N/A	Sewaren 7	PSEG Sewaren Urban Renewal	PSEG ER&T	N/A	PJM	Northeast	6/6/2018
PSEG Fossil	ER08-447-000	Yards Creek 1	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	11/26/1965
PSEG Fossil	ER08-447-000	Yards Creek 2	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	12/22/1965
PSEG Fossil	ER08-447-000	Yards Creek 3	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	9/3/1965
PSEG Power CT	ER03-327-000	Bridgeport Harbor 3	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	8/1/1968
PSEG Power CT	ER03-327-000	Bridgeport Harbor 4	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	10/30/1967
PSEG New Haven LLC	ER12-1250-000	New Haven 2	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 3	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 4	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG Power CT	ER03-327-000	New Haven Harbor 1	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	7/1/1975
PSEG Power NY	N/A*	Bethlehem Energy Center CC	PSEG Power NY	PSEG ER&T	12/6/2002	NYISO	Northeast	7/1/2005
PSEG Solar Source LLC	N/A*	Mars Solar Garden	PSEG Solar Hackettstown LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	9/9/2009
PSEG Solar Source LLC	N/A*	JEA Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	SERC	Southeast	9/28/2010
PSEG Solar Source LLC	N/A*	Wyandot Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	4/6/2010
PSEG Solar Source LLC	N/A*	Queen Creek Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	AZ-NV-SNV	Southwest	11/14/2012
PSEG Solar Source LLC	N/A*	Milford Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	12/27/2012
PSEG Solar Source LLC	N/A	Badger Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ACC	West	10/15/2013
PSEG Solar Source LLC	N/A	Shasta Solar Farm	PSEG Solar California LLC	PG&E	N/A	CAISO	West	3/1/2014
PSEG Solar Source LLC	N/A	Newman Solar Farm (Texas)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	El Paso Electric	Southwest	12/30/2014
PSEG Solar Source LLC	N/A	Whitcomb Solar Farm (Vermont)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ISO New England	Northeast	10/30/2014

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Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSEG Solar Source LLC	N/A	Rockfish Solar LLC, Southern Maryland	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	7/10/2015
PSEG Solar Source LLC	N/A	Columbia Solar, Pittsburg, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PG&E	West	10/21/2015
PSEG Solar Source LLC	N/A	Whitehorn Solar, Livermore, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Authority	West	2/17/2016
PSEG Solar Source LLC	N/A	Meadows Solar, Martin County, NC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	6/9/2016
PSEG Solar Source LLC	ER16-1924-000	Bison Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Administration, Colorado-Missouri Region	West	8/1/2016
PSEG Solar Source LLC	ER16-1925-000	Pavant Solar II LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp East	West	8/1/2016
PSEG Solar Source LLC	N/A	Obsidian - Black Cap	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp West	West	11/1/2016
PSEG Solar Source LLC	N/A	Hemlock Solar	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	N/A	Turkey Creek	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	ER16-1926-000	San Isabel Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Public Service Company of Colorado	West	8/1/2016
PSEG Solar Source LLC	N/A*	Cork Oak Solar	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/29/2017
PSEG Solar Source LLC	ER17-1746	Sunflower Solar	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/29/2017
PSEG Solar Source LLC	N/A*	SL Babylon/Solar Liberty	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	LIPA	Northeast	12/4/2017
PSEG Solar Source LLC	N/A*	HXNAir Solar One	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/21/2017
PSE&G (Solar 4 All)	N/A*	Trenton, 500-520 Brunswick Ave., Trenton, NJ 08638	PSE&G	PSE&G	N/A	PJM	Northeast	10/07/2010 (Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Barringer High School (NPS), 90 Parker St., Newark, NJ 07104	PSE&G	PSE&G	N/A	PJM	Northeast	09/24/2010 (Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Park Elementary School, 120 Manchester	PSE&G	PSE&G	N/A	PJM	Northeast	10/20/2010 (Commercial Operation)

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Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G (Solar 4 All)	N/A*	Linden, South Wood Avenue, Linden, NJ 07036	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Yardville, Broad Street, Hamilton, NJ 08611	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Silver Lake, 410 Silver Lake Avenue, Edison, NJ 08817	PSE&G	PSE&G	N/A	PJM	Northeast	11/09/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Central HQ, 472 Weston Canal Road, Franklin, NJ 08873	PSE&G	PSE&G	N/A	PJM	Northeast	11/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Edison Training, 234 Pierson Avenue, Edison, NJ 08837	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All)	N/A*	WEA Texas Bayonne, 30-100 Pulaski Street, Bayonne, NJ 07002	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2010
PSE&G (Solar 4 All)	N/A*	Matrix Building A, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/24/2011
PSE&G (Solar 4 All)	N/A*	Matrix Building B, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/14/2011
PSE&G (Solar 4 All)	N/A*	Camden Street School, 281 Camden Street Newark, New Jersey 07103	PSE&G	PSE&G	N/A*	PJM	Northeast	1/12/2011
PSE&G (Solar 4 All)	N/A*	New Central High School, 246 18th Ave, Newark, NJ 07108	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Rider University Solar Farm, Lawrenceville, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2011

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Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G (Solar 4 All)	N/A*	Mill Creek Solar Farm, Burlington Township, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	11/30/2011
PSE&G (Solar 4 All)	N/A*	PSE&G Thorofare Solar Farm, West Deptford	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	Raritan Center – Warehouse Solar, Edison, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	NJMC – Landfill Solar, Kearny, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All	N/A	Matrix – Stults Rd., South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	5/31/2011
PSE&G (Solar 4 All)	N/A*	Metro Division HQ, Clifton, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	7/9/2012
PSE&G (Solar 4 All)	N/A*	Black Rock-Matrix, South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	3/20/2012
PSE&G (Solar 4 All)	N/A*	Food Bank Solar Farm, Hillside, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	8/16/2012
PSE&G (Solar 4 All)	N/A*	Hackensack Solar Farm, Hackensack, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2012
PSE&G (Solar 4 All)	N/A*	Moorestown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/14/2013
PSE&G (Solar 4 All)	N/A*	Seg 2 (Pole attached solar units)	PSE&G	PSE&G	N/A*	PJM	Northeast	7/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Kinsley Solar Sewell, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014
PSE&G (Solar 4 All Extension)	N/A*	Parkland Solar Bordentown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014
PSE&G (Solar 4 All Extension)	N/A*	L&D Solar Mt. Holly, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Hopewell Valley Central HS	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2015
PSE&G (Solar 4 All Extension)	N/A*	ILR Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016
PSE&G (Solar 4 All Extension)	N/A*	Caldwell Waste Treatment Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016

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Asset Appendix: Generation Assets								
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Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
[i] PSEG Fossil has a 22.5% interest in the Conemaugh coal fired plants.								
[ii] PSEG Global has a 4% interest Conemaugh Hydroelectric plants.								
[iii] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear Plants.								
[iv] PSEG Nuclear has a 57.41% interest in the Salem Nuclear Plants.								
[v] JCP&L – Jersey Central Power & Light Company								
[vi] PSEG Fossil has a 50% interest in each of the Yards Creek facilities.								
[vii] CL&P – The Connecticut Light and Power Company.								
[viii] PSEG Power Ventures has a 100% ownership in PSEG Hackettstown LLC.								
[ix] PSEG Power Ventures has a 100% ownership interest in PSEG Solar Source LLC								
[x] All solar assets are using AC MW ratings. PSEG's previous triennial listed the DC ratings.								
[xi] PG&E -- Pacific Gas and Electric Company								
[xii] PSE&G started installations of pole units in September of 2009. As of November 30, 2016, a total of 174,630								

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
NA*	NA*	NA*	
NA*	NA*	NA*	
775.2	775.2	N	
625.6	625.6	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
219.5	219.5	N	
219.5	219.5	N	
0.625	0.625	N	[i]
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
1	1	N	[ii]
1	1	N	
93.6	93.6	N	
1,290.70	1,290.70	N	
242	242	N	
242	242	N	
121	121	N	
213.8	213.8	N	
213.8	213.8	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
677.8	677.8	N	
677.8	677.8	N	
96.1	96.1	N	
96.1	96.1	N	
96.1	96.1	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
96.1	96.1	N	
755	755	N	
703.8	703.8	N	[iii]
688.5	688.5	N	
671.7	671.7	N	[iv]
671.7	671.7	N	
24	24	N	
585	585	N	
69.3	69.3	N	[v]
69.3	69.3	N	[vi]
69.3	69.3	N	
399.5	399.5	N	
18.6	18.6	N	
60.5	60.5	N	[vii]
60.5	60.5	N	
60.5	60.5	N	
460.3	460.3	N	
893.2	893.2	N	
2	2	N	[viii]
12.6	12.6	N	[ix]
10.1	10.1	N	[x]
19	19	N	
12	12	N	
15	15	N	
3	3	N	[xi]
10.2	10.2	N	
2.2	2.2	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
10.3	10.3	N	
19	19	N	
3	3	N	
20	20	N	
30	30	N	
50	50	N	
8	8	N	
5	5	N	
13.5	13.5	N	
30	30	N	
20	20	N	
16	16	N	
8.9	8.9	N	
5	5	N	
1.14	1.14	N	
0.64	0.64	N	
0.55	0.55	N N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
3	3	N	
3.7	3.7	N	
1.75	1.75	N	
0.76	0.76	N	
0.64	0.64	N	
1.5	1.5	N N	
1.5	1.5	N	
1	1	N	
0.83	0.83	N N	
0.5	0.5	N N	
0.67	0.67	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
3.5	3.5	N	
0.75	0.75	N	
2	2	N	
2.5	2.5	N	
2.5	2.5	N	
0.57	0.57	N	
2.5	2.5	N	
1	1	N	
1	1	N	
0.93	0.93	N	
38.5	38.5	N	[xii]
8.8	8.8	N	
7.9	7.9	N	
10	10	N	
1	1	N	
6.6	6.6	N	
2	2	N	

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Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing**	**Capacity Rating: Methodology Used in K**	**End Note Number (Enter text in End Notes Sheet**
panels and 38.5 MW capacity have been installed.			

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Scenario

Scenario Number	1	
Scenario Name	PSEG 2016 MBR for PJM	
Data	MBRA Data v501 PSEG 2016 PJM Sewaren 20180525.	
Applicant	PSEG	Public Service Enterprise Group Inc
Period	Dec 2015 — Nov 2016	

Fill-in white cells with parameters and then click on Run button or type Ctrl+Shift+R.

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Results

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Scenario 1 PSEG 2016 MBR for PJM

	PSA		WM			
			Winter		Spring	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result
PJM Interconnection	38,315	Pass	7.3	Pass	6.1	Pass
PJM East	4,229	Pass	26.7	Fail	22.3	Fail
PJM East of 5004/05	5,892	Pass	20.7	Fail	18.1	Pass
PJM East of AP South	10,461	Pass	14.7	Pass	12.8	Pass

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SA			
Summer		Fall	
Share (%)	Result	Share (%)	Result
6.6	Pass	6.5	Pass
25.9	Fail	24.3	Fail
20.0	Pass	19.7	Pass
14.4	Pass	13.7	Pass

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	9,378	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	195	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	1,943	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	70	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	186,588	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	1,943	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	195	Row B; Table2Data
H	Uncommitted Capacity Imports	7,530	Calculated
I	Study Area Reserve Requirement	8,674	Gendata
J	Amount of Line I Attributable to Seller, if any	228	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	62,196	
	Load		
L	Balancing Area Annual Peak Load	152,177	Loads
M	Average Daily Peak Native Load in Peak Month	132,696	Loads
N	Amount of Line M Attributable to Seller, if any	3,073	SellerLoads
O	Wholesale Load (L-M)	19,482	
P	Net Uncommitted Supply (K-O)	42,715	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,399	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	7,600
% of SIL for Seller's imported capacity →	0.01
% of SIL for Other's imported capacity →	0.99
SIL Value →	7600
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	6,650	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	14	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	152	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	27,691	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	14	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,385	Calculated
I	Study Area Reserve Requirement	1,767	Gendata
J	Amount of Line I Attributable to Seller, if any	202	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	13,259	
	Load		
L	Balancing Area Annual Peak Load	30,992	Loads
M	Average Daily Peak Native Load in Peak Month	25,852	Loads
N	Amount of Line M Attributable to Seller, if any	2,695	SellerLoads
O	Wholesale Load (L-M)	5,139	
P	Net Uncommitted Supply (K-O)	8,120	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	3,890	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	6,537
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	6537
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,418	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	105	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	52,989	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,214	Calculated
I	Study Area Reserve Requirement	3,049	Gendata
J	Amount of Line I Attributable to Seller, if any	210	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	18,909	
	Load		
L	Balancing Area Annual Peak Load	53,493	Loads
M	Average Daily Peak Native Load in Peak Month	44,768	Loads
N	Amount of Line M Attributable to Seller, if any	2,992	SellerLoads
O	Wholesale Load (L-M)	8,725	
P	Net Uncommitted Supply (K-O)	10,184	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,293	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	6,319
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	6319
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,418	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	88	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	80,051	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,367	Calculated
I	Study Area Reserve Requirement	4,162	Gendata
J	Amount of Line I Attributable to Seller, if any	210	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	26,286	
	Load		
L	Balancing Area Annual Peak Load	73,026	Loads
M	Average Daily Peak Native Load in Peak Month	61,476	Loads
N	Amount of Line M Attributable to Seller, if any	2,992	SellerLoads
O	Wholesale Load (L-M)	11,550	
P	Net Uncommitted Supply (K-O)	14,736	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,275	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	4,455
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	4455
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season: Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	10,859	10,119	9,378	10,119	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	195	195	195	195	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	1,643	1,944	1,943	1,944	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	452	1,512	93	1,131	SellerGendata
E	Uncommitted Capacity Imports	91	89	68	53	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	99,674	86,411	116,161	92,587	Loads
G	Amount of Line F Attributable to Seller, if any	1,573	1,308	2,340	1,568	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	98,102	85,102	113,821	91,019	F - G
I	Study Area Reserve Requirement	6,756	6,230	8,317	6,641	Gendata
J	Amount of Line I Attributable to Seller, if any	119	117	202	143	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	6,637	6,113	8,116	6,498	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	193,335	189,962	186,588	189,962	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	1,643	1,944	1,943	1,944	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	195	195	195	195	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	8,043	28,377	1,841	21,225	Gendata; Row D
P	Uncommitted Capacity Imports	11,906	12,184	7,532	7,014	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	93,908	84,302	72,090	79,982	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,359	5,522	5,064	5,580	
S	Total Seasonal Uncommitted Capacity (Q+R)	101,266	89,823	77,154	85,562	
T	**Applicant's Market Share** (R÷S)	7.3%	6.1%	6.6%	6.5%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	11,997	12,273	7,600	7,067	
V	SIL Value	11,997	12,273	7,600	7,067	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,182	7,416	6,650	7,416	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	22	14	14	14	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	340	1,108	66	829	SellerGendata
E	Uncommitted Capacity Imports	156	135	128	113	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	16,761	14,806	21,675	16,148	Loads
G	Amount of Line F Attributable to Seller, if any	1,499	1,253	2,058	1,350	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	15,261	13,553	19,617	14,798	F - G
I	Study Area Reserve Requirement	1,150	1,117	1,651	1,345	Gendata
J	Amount of Line I Attributable to Seller, if any	113	112	177	123	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	1,037	1,005	1,473	1,222	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	27,568	27,630	27,691	27,630	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	22	14	14	14	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,147	4,127	273	3,087	Gendata; Row D
P	Uncommitted Capacity Imports	7,346	8,695	6,409	7,746	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	17,491	17,653	12,750	16,282	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	6,364	5,064	4,463	5,214	
S	Total Seasonal Uncommitted Capacity (Q+R)	23,854	22,717	17,213	21,496	
T	**Applicant's Market Share** (R÷S)	26.7%	22.3%	25.9%	24.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	7,502	8,830	6,537	7,859	
V	SIL Value	7,502	8,830	6,537	7,859	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,951	8,185	7,418	8,185	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	372	1,223	73	914	SellerGendata
E	Uncommitted Capacity Imports	118	69	95	61	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	31,965	27,526	38,884	30,032	Loads
G	Amount of Line F Attributable to Seller, if any	1,524	1,270	2,340	1,568	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	30,441	26,256	36,544	28,465	F - G
I	Study Area Reserve Requirement	2,203	2,058	2,874	2,416	Gendata
J	Amount of Line I Attributable to Seller, if any	115	114	202	143	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,088	1,944	2,672	2,273	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	53,711	53,350	52,989	53,350	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	2,234	7,970	523	5,961	Gendata; Row D
P	Uncommitted Capacity Imports	7,986	8,224	6,224	6,042	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	26,970	25,434	19,502	22,722	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,022	5,618	4,870	5,591	
S	Total Seasonal Uncommitted Capacity (Q+R)	33,992	31,052	24,372	28,313	
T	**Applicant's Market Share** (R÷S)	20.7%	18.1%	20.0%	19.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	8,104	8,293	6,319	6,103	
V	SIL Value	8,104	8,293	6,319	6,103	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,951	8,185	7,418	8,185	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	372	1,223	73	914	SellerGendata
E	Uncommitted Capacity Imports	140	90	81	74	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	44,121	37,780	53,385	41,231	Loads
G	Amount of Line F Attributable to Seller, if any	1,524	1,270	2,340	1,568	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	42,598	36,510	51,045	39,663	F - G
I	Study Area Reserve Requirement	3,105	2,881	3,898	3,332	Gendata
J	Amount of Line I Attributable to Seller, if any	115	114	202	143	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,990	2,767	3,696	3,189	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	82,251	81,151	80,051	81,151	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,422	12,123	790	9,067	Gendata; Row D
P	Uncommitted Capacity Imports	7,757	8,766	4,374	5,994	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	41,035	38,546	28,922	35,255	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,044	5,639	4,856	5,604	
S	Total Seasonal Uncommitted Capacity (Q+R)	48,079	44,185	33,778	40,859	
T	**Applicant's Market Share** (R÷S)	14.7%	12.8%	14.4%	13.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,897	8,856	4,455	6,068	
V	SIL Value	7,897	8,856	4,455	6,068	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Sets and SIL Data

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Areas		Owners	
Code	**Name**	**Code**	**Name**
MISO	Midwest ISO	PSEG	Public Service Enterprise Group Inc
NYISO	New York		
PJM	PJM Interconnection		
PJM_50	PJM Excluding PJM50		
PJM_AP	PJM Excluding PJMAP		
PJM_E	PJM Excluding PJME		
PJM50	PJM East of 5004/05		
PJMAP	PJM East of AP South		
PJME	PJM East		

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Season	
Code	**Name**
SPR	Spring
SUM	Summer
FAL	Fall
WIN	Winter

Area	Season	SIL	Comment
PJM	SPR	12273	PJM 2015 Simultaneous Import Limit Study
PJM	SUM	7600	PJM 2015 Simultaneous Import Limit Study
PJM	FAL	7067	PJM 2015 Simultaneous Import Limit Study
PJM	WIN	11997	PJM 2015 Simultaneous Import Limit Study
PJME	SPR	8830	PJM 2015 Simultaneous Import Limit Study
PJME	SUM	6537	PJM 2015 Simultaneous Import Limit Study
PJME	FAL	7859	PJM 2015 Simultaneous Import Limit Study
PJME	WIN	7502	PJM 2015 Simultaneous Import Limit Study
PJM50	SPR	8293	PJM 2015 Simultaneous Import Limit Study
PJM50	SUM	6319	PJM 2015 Simultaneous Import Limit Study
PJM50	FAL	6103	PJM 2015 Simultaneous Import Limit Study
PJM50	WIN	8104	PJM 2015 Simultaneous Import Limit Study
PJMAP	SPR	8856	PJM 2015 Simultaneous Import Limit Study
PJMAP	SUM	4455	PJM 2015 Simultaneous Import Limit Study
PJMAP	FAL	6068	PJM 2015 Simultaneous Import Limit Study
PJMAP	WIN	7897	PJM 2015 Simultaneous Import Limit Study

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Area	First Tier Areas	Note: No more than 6 First Tier Areas for each destination Area.
PJM	MISO	
PJM	NYISO	
PJM50	NYISO	
PJM50	PJM_50	
PJMAP	NYISO	
PJMAP	PJM_AP	
PJME	NYISO	
PJME	PJM_E	

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Market Data

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AREA	SEASON	MONTH	CAPACITY	PLANNED OUTAGE
NYISO	WIN	1	42,375	3,911
NYISO	WIN	2	42,375	4,197
NYISO	SPR	3	41,172	6,005
NYISO	SPR	4	41,172	9,262
NYISO	SPR	5	41,172	3,751
NYISO	SUM	6	39,969	796
NYISO	SUM	7	39,969	805
NYISO	SUM	8	39,969	910
NYISO	FAL	9	41,172	2,029
NYISO	FAL	10	41,172	9,548
NYISO	FAL	11	41,172	6,419
NYISO	WIN	12	42,375	3,142
PJM	WIN	1	204,194	4,773
PJM	WIN	2	204,194	7,522
PJM	SPR	3	200,080	20,892
PJM	SPR	4	200,080	46,574
PJM	SPR	5	200,080	22,201
PJM	SUM	6	195,966	4,655
PJM	SUM	7	195,966	237
PJM	SUM	8	195,966	910
PJM	FAL	9	200,080	3,112
PJM	FAL	10	200,080	39,568
PJM	FAL	11	200,080	24,388
PJM	WIN	12	204,194	13,188
PJME	WIN	1	35,750	836
PJME	WIN	2	35,750	1,317
PJME	SPR	3	35,046	3,659
PJME	SPR	4	35,046	8,158
PJME	SPR	5	35,046	3,889
PJME	SUM	6	34,341	816
PJME	SUM	7	34,341	42
PJME	SUM	8	34,341	159
PJME	FAL	9	35,046	545
PJME	FAL	10	35,046	6,931
PJME	FAL	11	35,046	4,272
PJME	WIN	12	35,750	2,309
PJM50	WIN	1	62,662	1,465
PJM50	WIN	2	62,662	2,308
PJM50	SPR	3	61,535	6,425
PJM50	SPR	4	61,535	14,324
PJM50	SPR	5	61,535	6,828
PJM50	SUM	6	60,407	1,435
PJM50	SUM	7	60,407	73
PJM50	SUM	8	60,407	281
PJM50	FAL	9	61,535	957
PJM50	FAL	10	61,535	12,169
PJM50	FAL	11	61,535	7,501
PJM50	WIN	12	62,662	4,047
PJMAP	WIN	1	91,202	2,132
PJMAP	WIN	2	91,202	3,360
PJMAP	SPR	3	89,336	9,328

PJMAP	SPR	4	89,336	20,795
PJMAP	SPR	5	89,336	9,913
PJMAP	SUM	6	87,469	2,078
PJMAP	SUM	7	87,469	106
PJMAP	SUM	8	87,469	406
PJMAP	FAL	9	89,336	1,390
PJMAP	FAL	10	89,336	17,667
PJMAP	FAL	11	89,336	10,889
PJMAP	WIN	12	91,202	5,890
PJM_E	WIN	1	168,444	3,937
PJM_E	WIN	2	168,444	6,205
PJM_E	SPR	3	165,035	17,233
PJM_E	SPR	4	165,035	38,416
PJM_E	SPR	5	165,035	18,312
PJM_E	SUM	6	161,625	3,839
PJM_E	SUM	7	161,625	195
PJM_E	SUM	8	161,625	751
PJM_E	FAL	9	165,035	2,567
PJM_E	FAL	10	165,035	32,637
PJM_E	FAL	11	165,035	20,116
PJM_E	WIN	12	168,444	10,879
PJM_50	WIN	1	141,532	3,308
PJM_50	WIN	2	141,532	5,214
PJM_50	SPR	3	138,546	14,467
PJM_50	SPR	4	138,546	32,250
PJM_50	SPR	5	138,546	15,373
PJM_50	SUM	6	135,559	3,220
PJM_50	SUM	7	135,559	164
PJM_50	SUM	8	135,559	629
PJM_50	FAL	9	138,546	2,155
PJM_50	FAL	10	138,546	27,399
PJM_50	FAL	11	138,546	16,887
PJM_50	WIN	12	141,532	9,141
PJM_AP	WIN	1	112,992	2,641
PJM_AP	WIN	2	112,992	4,162
PJM_AP	SPR	3	110,745	11,564
PJM_AP	SPR	4	110,745	25,779
PJM_AP	SPR	5	110,745	12,288
PJM_AP	SUM	6	108,497	2,577
PJM_AP	SUM	7	108,497	131
PJM_AP	SUM	8	108,497	504
PJM_AP	FAL	9	110,745	1,722
PJM_AP	FAL	10	110,745	21,901
PJM_AP	FAL	11	110,745	13,499
PJM_AP	WIN	12	112,992	7,298
MISO	WIN	1	183,745	11,845
MISO	WIN	2	183,745	13,214
MISO	SPR	3	179,902	22,181
MISO	SPR	4	179,902	31,160
MISO	SPR	5	179,902	19,117
MISO	SUM	6	176,059	8,163
MISO	SUM	7	176,059	6,429

MISO	SUM	8	176,059	7,498
MISO	FAL	9	179,902	7,327
MISO	FAL	10	179,902	28,881
MISO	FAL	11	179,902	23,062
MISO	WIN	12	183,745	16,145

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AREA	SEASON	MONTH	MONTHLY PEAK	AVERAGE OF DAILY PEAKS	AVERAGE PEAK LOAD
NYISO	WIN	1	23,317	21,135	20,442
NYISO	WIN	2	23,301	20,827	19,848
NYISO	SPR	3	21,234	18,697	18,157
NYISO	SPR	4	20,173	17,906	17,719
NYISO	SPR	5	25,061	18,866	18,308
NYISO	SUM	6	26,286	22,415	21,209
NYISO	SUM	7	31,187	26,299	25,606
NYISO	SUM	8	32,076	27,129	25,111
NYISO	FAL	9	29,637	22,307	21,394
NYISO	FAL	10	21,143	18,697	18,217
NYISO	FAL	11	26,848	19,630	18,309
NYISO	WIN	12	21,254	20,142	18,879
PJM	WIN	1	129,775	109,463	107,474
PJM	WIN	2	121,307	103,878	100,450
PJM	SPR	3	106,497	89,530	86,259
PJM	SPR	4	99,868	86,664	84,984
PJM	SPR	5	121,540	90,069	87,988
PJM	SUM	6	134,752	113,737	104,204
PJM	SUM	7	150,826	128,598	123,071
PJM	SUM	8	152,177	132,696	121,208
PJM	FAL	9	142,092	110,389	103,577
PJM	FAL	10	102,277	87,670	86,550
PJM	FAL	11	105,171	90,942	87,635
PJM	WIN	12	104,494	94,919	91,099
PJME	WIN	1	21,350	18,481	17,769
PJME	WIN	2	21,162	17,962	16,867
PJME	SPR	3	18,138	15,588	14,660
PJME	SPR	4	16,803	15,031	14,387
PJME	SPR	5	23,845	16,304	15,372
PJME	SUM	6	25,217	20,821	18,716
PJME	SUM	7	30,668	25,247	23,531
PJME	SUM	8	30,992	25,852	22,778
PJME	FAL	9	29,146	20,177	18,619
PJME	FAL	10	19,352	15,573	14,861
PJME	FAL	11	22,289	16,282	14,965
PJME	WIN	12	18,025	16,926	15,645
PJM50	WIN	1	41,374	35,364	34,388
PJM50	WIN	2	40,902	33,996	32,335
PJM50	SPR	3	33,605	28,694	27,196
PJM50	SPR	4	32,555	27,801	26,948
PJM50	SPR	5	42,130	29,682	28,433
PJM50	SUM	6	44,644	37,204	33,847
PJM50	SUM	7	53,493	44,768	42,189
PJM50	SUM	8	53,118	45,448	40,617
PJM50	FAL	9	50,923	36,593	34,119
PJM50	FAL	10	35,164	28,728	27,820
PJM50	FAL	11	41,077	30,204	28,159
PJM50	WIN	12	33,646	31,039	29,171
PJMAP	WIN	1	60,322	49,742	47,974
PJMAP	WIN	2	57,551	47,206	44,577
PJMAP	SPR	3	47,812	39,760	37,365

PJMAP	SPR	4	46,155	38,384	36,990
PJMAP	SPR	5	57,683	40,750	38,985
PJMAP	SUM	6	60,457	51,652	46,812
PJMAP	SUM	7	73,026	61,476	57,809
PJMAP	SUM	8	71,663	62,236	55,535
PJMAP	FAL	9	68,834	50,417	46,839
PJMAP	FAL	10	49,092	39,560	38,174
PJMAP	FAL	11	57,447	41,655	38,679
PJMAP	WIN	12	45,563	42,355	39,813
PJM_E	WIN	1	108,425	90,982	89,705
PJM_E	WIN	2	100,146	85,916	83,583
PJM_E	SPR	3	88,359	73,942	71,599
PJM_E	SPR	4	83,064	71,634	70,597
PJM_E	SPR	5	97,695	73,764	72,617
PJM_E	SUM	6	109,535	92,915	85,488
PJM_E	SUM	7	120,158	103,352	99,540
PJM_E	SUM	8	121,185	106,843	98,430
PJM_E	FAL	9	112,947	90,213	84,958
PJM_E	FAL	10	82,924	72,098	71,689
PJM_E	FAL	11	82,883	74,660	72,670
PJM_E	WIN	12	86,469	77,993	75,454
PJM_50	WIN	1	88,401	74,099	73,086
PJM_50	WIN	2	80,405	69,883	68,115
PJM_50	SPR	3	72,892	60,836	59,063
PJM_50	SPR	4	67,313	58,863	58,036
PJM_50	SPR	5	79,410	60,387	59,556
PJM_50	SUM	6	90,108	76,532	70,358
PJM_50	SUM	7	97,334	83,831	80,881
PJM_50	SUM	8	99,059	87,247	80,591
PJM_50	FAL	9	91,170	73,797	69,458
PJM_50	FAL	10	67,112	58,942	58,730
PJM_50	FAL	11	64,095	60,737	59,476
PJM_50	WIN	12	70,847	63,880	61,928
PJM_AP	WIN	1	69,453	59,721	59,500
PJM_AP	WIN	2	63,756	56,672	55,873
PJM_AP	SPR	3	58,686	49,770	48,894
PJM_AP	SPR	4	53,712	48,280	47,994
PJM_AP	SPR	5	63,857	49,319	49,004
PJM_AP	SUM	6	74,295	62,085	57,392
PJM_AP	SUM	7	77,800	67,123	65,262
PJM_AP	SUM	8	80,514	70,460	65,673
PJM_AP	FAL	9	73,259	59,973	56,738
PJM_AP	FAL	10	53,185	48,110	48,377
PJM_AP	FAL	11	47,725	49,287	48,956
PJM_AP	WIN	12	58,930	52,564	51,286
MISO	WIN	1	97,753	86,934	85,534
MISO	WIN	2	93,742	82,714	81,237
MISO	SPR	3	84,269	75,364	74,207
MISO	SPR	4	79,241	73,507	73,366
MISO	SPR	5	95,170	78,725	77,495
MISO	SUM	6	112,332	98,951	92,990
MISO	SUM	7	120,764	105,024	102,199

MISO	SUM	8	119,860	105,194	101,044
MISO	FAL	9	114,750	92,759	88,854
MISO	FAL	10	90,297	78,398	77,534
MISO	FAL	11	81,775	75,958	74,460
MISO	WIN	12	87,091	80,969	79,008

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COMMENT

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AREA	SOURCE	SEASON	SELLER	REMOTE	CONTRACT	ROW

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DESCRIPTION	CAPACITY

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Seller Data

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AREA	SEASON	MONTH	CAPACITY	PLANNED OUTAGE
NYISO	WIN	1	870	80.29663717
NYISO	WIN	2	870	86.16849558
NYISO	SPR	3	814	118.6502356
NYISO	SPR	4	814	183.0039104
NYISO	SPR	5	814	74.11441028
NYISO	SUM	6	757	15.07598389
NYISO	SUM	7	757	15.24644099
NYISO	SUM	8	757	17.23510721
NYISO	FAL	9	814	40.09014622
NYISO	FAL	10	814	188.6548625
NYISO	FAL	11	814	126.8302851
NYISO	WIN	12	870	64.50831858
PJM	WIN	1	10,859	253.827277
PJM	WIN	2	10,859	400.0186
PJM	SPR	3	10,119	1056.555888
PJM	SPR	4	10,119	2355.352954
PJM	SPR	5	10,119	1122.754991
PJM	SUM	6	9,378	222.7661431
PJM	SUM	7	9,378	11.34169193
PJM	SUM	8	9,378	43.54826858
PJM	FAL	9	10,119	157.3809076
PJM	FAL	10	10,119	2001.043623
PJM	FAL	11	10,119	1233.356547
PJM	WIN	12	10,859	701.3354555
PJME	WIN	1	8182	191.2528576
PJME	WIN	2	8182	301.4045662
PJME	SPR	3	7416	774.3656138
PJME	SPR	4	7416	1726.273411
PJME	SPR	5	7416	822.8839264
PJME	SUM	6	6650	157.9649021
PJME	SUM	7	6650	8.04246655
PJME	SUM	8	6650	30.8803568
PJME	FAL	9	7416	115.3468213
PJME	FAL	10	7416	1466.594802
PJME	FAL	11	7416	903.9454618
PJME	WIN	12	8182	528.4396995
PJM50	WIN	1	8951	209.2281017
PJM50	WIN	2	8951	329.732617
PJM50	SPR	3	8184.5	854.6110256
PJM50	SPR	4	8184.5	1905.16245
PJM50	SPR	5	8184.5	908.1571596
PJM50	SUM	6	7418	176.2080667
PJM50	SUM	7	7418	8.971280732
PJM50	SUM	8	7418	34.44668973
PJM50	FAL	9	8184.5	127.2999
PJM50	FAL	10	8184.5	1618.57405
PJM50	FAL	11	8184.5	997.6188824
PJM50	WIN	12	8951	578.106056
PJMAP	WIN	1	8951	209.2281017
PJMAP	WIN	2	8951	329.732617
PJMAP	SPR	3	8184.5	854.6110256

PJMAP	SPR	4	8184.5	1905.16245
PJMAP	SPR	5	8184.5	908.1571596
PJMAP	SUM	6	7418	176.2080667
PJMAP	SUM	7	7418	8.971280732
PJMAP	SUM	8	7418	34.44668973
PJMAP	FAL	9	8184.5	127.2999
PJMAP	FAL	10	8184.5	1618.57405
PJMAP	FAL	11	8184.5	997.6188824
PJMAP	WIN	12	8951	578.106056
PJM_E	WIN	1	2677	62.57441942
PJM_E	WIN	2	2677	98.61403371
PJM_E	SPR	3	2702.5	282.1902739
PJM_E	SPR	4	2702.5	629.0795432
PJM_E	SPR	5	2702.5	299.8710641
PJM_E	SUM	6	2728	64.80124103
PJM_E	SUM	7	2728	3.299225376
PJM_E	SUM	8	2728	12.66791178
PJM_E	FAL	9	2702.5	42.03408637
PJM_E	FAL	10	2702.5	534.4488205
PJM_E	FAL	11	2702.5	329.4110856
PJM_E	WIN	12	2677	172.895756
PJM_50	WIN	1	1908	44.59917529
PJM_50	WIN	2	1908	70.28598294
PJM_50	SPR	3	1934	201.9448621
PJM_50	SPR	4	1934	450.1905038
PJM_50	SPR	5	1934	214.5978309
PJM_50	SUM	6	1960	46.5580764
PJM_50	SUM	7	1960	2.370411194
PJM_50	SUM	8	1960	9.101578845
PJM_50	FAL	9	1934	30.0810076
PJM_50	FAL	10	1934	382.4695722
PJM_50	FAL	11	1934	235.7376649
PJM_50	WIN	12	1908	123.2293995
PJM_AP	WIN	1	1908	44.59917529
PJM_AP	WIN	2	1908	70.28598294
PJM_AP	SPR	3	1934	201.9448621
PJM_AP	SPR	4	1934	450.1905038
PJM_AP	SPR	5	1934	214.5978309
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PJM_AP	SUM	7	1960	2.370411194
PJM_AP	SUM	8	1960	9.101578845
PJM_AP	FAL	9	1934	30.0810076
PJM_AP	FAL	10	1934	382.4695722
PJM_AP	FAL	11	1934	235.7376649
PJM_AP	WIN	12	1908	123.2293995

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AREA	SEASON	MONTH	MONTHLY PEAK	AVERAGE OF DAILY PEAKS	AVERAGE PEAK LOAD
NYISO	WIN	1	-	-	-
NYISO	WIN	2	-	-	-
NYISO	SPR	3	-	-	-
NYISO	SPR	4	-	-	-
NYISO	SPR	5	-	-	-
NYISO	SUM	6	-	-	-
NYISO	SUM	7	-	-	-
NYISO	SUM	8	-	-	-
NYISO	FAL	9	-	-	-
NYISO	FAL	10	-	-	-
NYISO	FAL	11	-	-	-
NYISO	WIN	12	-	-	-
PJM	WIN	1	2,187	1,908	1,680
PJM	WIN	2	2,208	1,834	1,583
PJM	SPR	3	1,793	1,551	1,317
PJM	SPR	4	1,699	1,453	1,253
PJM	SPR	5	2,681	1,603	1,354
PJM	SUM	6	2,933	2,306	1,903
PJM	SUM	7	3,683	2,992	2,615
PJM	SUM	8	3,998	3,073	2,503
PJM	FAL	9	3,519	2,220	1,863
PJM	FAL	10	1,994	1,622	1,390
PJM	FAL	11	2,030	1,716	1,451
PJM	WIN	12	1,870	1,712	1,456
PJME	WIN	1	2071.82422	1,811	1598.633077
PJME	WIN	2	2087.87738	1,741	1506.097893
PJME	SPR	3	1699.30127	1,477	1258.054799
PJME	SPR	4	1613.83134	1,385	1198.903841
PJME	SPR	5	2595.69673	1,539	1303.230943
PJME	SUM	6	2544.91271	2,013	1670.812832
PJME	SUM	7	3245.75586	2620.463546	2298.973997
PJME	SUM	8	3538.68543	2695.381386	2205.210453
PJME	FAL	9	3085.0773	1927.826885	1633.467359
PJME	FAL	10	1735.6674	1377.55915	1197.477072
PJME	FAL	11	1649.56753	1424.046758	1218.505107
PJME	WIN	12	1774	1630.935484	1392.605114
PJM50	WIN	1	2112.23243	1843.396131	1627.49382
PJM50	WIN	2	2131.49184	1770.955132	1531.939171
PJM50	SPR	3	1729.18961	1499.662979	1276.360292
PJM50	SPR	4	1641.05254	1405.943822	1215.40429
PJM50	SPR	5	2626.68665	1559.4767	1319.067449
PJM50	SUM	6	2933.05226	2305.630737	1903.335218
PJM50	SUM	7	3682.95707	2992.478437	2614.982471
PJM50	SUM	8	3998.35498	3073.014376	2502.605508
PJM50	FAL	9	3518.82491	2220.474087	1862.733948
PJM50	FAL	10	1994.33213	1622.031246	1390.147201
PJM50	FAL	11	2029.9163	1715.635242	1450.924655
PJM50	WIN	12	1803	1654.451613	1411.298295
PJMAP	WIN	1	2112.23243	1843.396131	1627.49382
PJMAP	WIN	2	2131.49184	1770.955132	1531.939171
PJMAP	SPR	3	1729.18961	1499.662979	1276.360292

PJMAP	SPR	4	1641.05254	1405.943822	1215.40429
PJMAP	SPR	5	2626.68665	1559.4767	1319.067449
PJMAP	SUM	6	2933.05226	2305.630737	1903.335218
PJMAP	SUM	7	3682.95707	2992.478437	2614.982471
PJMAP	SUM	8	3998.35498	3073.014376	2502.605508
PJMAP	FAL	9	3518.82491	2220.474087	1862.733948
PJMAP	FAL	10	1994.33213	1622.031246	1390.147201
PJMAP	FAL	11	2029.9163	1715.635242	1450.924655
PJMAP	WIN	12	1803	1654.451613	1411.298295
PJM_E	WIN	1	114.85733	2.684770542	80.95252853
PJM_E	WIN	2	119.72045	4.410204144	76.42658753
PJM_E	SPR	3	93.4001	9.752673377	58.76250864
PJM_E	SPR	4	85.12579	19.81531659	54.39960196
PJM_E	SPR	5	85.02786	9.434743702	51.10709568
PJM_E	SUM	6	388.13955	9.219913685	232.5223862
PJM_E	SUM	7	437.20121	0.528748287	316.0084735
PJM_E	SUM	8	459.66955	2.134550333	297.3950549
PJM_E	FAL	9	433.74761	6.746414246	229.2665884
PJM_E	FAL	10	258.66473	51.15376868	192.6701299
PJM_E	FAL	11	380.34877	46.36118454	232.4195477
PJM_E	WIN	12	96	6.200221358	63.03977273
PJM_50	WIN	1	74.44912	1.74023551	52.09178512
PJM_50	WIN	2	76.10599	2.80355572	50.58530935
PJM_50	SPR	3	63.51176	6.631785735	40.45701549
PJM_50	SPR	4	57.90459	13.47885033	37.89915286
PJM_50	SPR	5	54.03794	5.996083096	35.27058943
PJM_50	SUM	6	0	0	0
PJM_50	SUM	7	0	0	0
PJM_50	SUM	8	0	0	0
PJM_50	FAL	9	0	0	0
PJM_50	FAL	10	0	0	0
PJM_50	FAL	11	0	0	0
PJM_50	WIN	12	67	4.327237823	44.34659091
PJM_AF	WIN	1	74.44912	1.74023551	52.09178513
PJM_AF	WIN	2	76.10599	2.80355572	50.58530935
PJM_AF	SPR	3	63.51176	6.631785735	40.45701549
PJM_AF	SPR	4	57.90459	13.47885033	37.89915286
PJM_AF	SPR	5	54.03794	5.996083096	35.27058943
PJM_AF	SUM	6	0	0	-2.72848E-12
PJM_AF	SUM	7	0	0	0
PJM_AF	SUM	8	0	0	0
PJM_AF	FAL	9	0	0	0
PJM_AF	FAL	10	0	0	0
PJM_AF	FAL	11	0	0	0
PJM_AF	WIN	12	67	4.327237823	44.34659091

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COMMENT

AREA	SEASON	DESCRIPTION	SALE	PURCHASE
PJM	WIN	LES Project Holdings	14	0
PJM	SPR	LES Project Holdings	14	0
PJM	SUM	LES Project Holdings	14	0
PJM	FAL	LES Project Holdings	14	0
PJM	WIN	Ocean Energy Holdings	9	0
PJM	SPR	Ocean Energy Holdings	9	0
PJM	SUM	Ocean Energy Holdings	9	0
PJM	FAL	Ocean Energy Holdings	9	0
PJM	WIN	BP	34	0
PJM	SPR	BP	0	0
PJM	SUM	BP	0	0
PJM	FAL	BP	0	0
PJM	WIN	Citigroup	94	0
PJM	SPR	Citigroup	75	0
PJM	SUM	Citigroup	75	0
PJM	FAL	Citigroup	75	0
PJM	WIN	Direct Energy	556	0
PJM	SPR	Direct Energy	650	0
PJM	SUM	Direct Energy	650	0
PJM	FAL	Direct Energy	650	0
PJM	WIN	EDF	8	0
PJM	SPR	EDF	0	0
PJM	SUM	EDF	0	0
PJM	FAL	EDF	0	0
PJM	WIN	Energy America	305	0
PJM	SPR	Energy America	460	0
PJM	SUM	Energy America	460	0
PJM	FAL	Energy America	460	0
PJM	WIN	Exelon	66	0
PJM	SPR	Exelon	100	0
PJM	SUM	Exelon	100	0
PJM	FAL	Exelon	100	0
PJM	WIN	Nextera	523	0
PJM	SPR	Nextera	602	0
PJM	SUM	Nextera	601	0
PJM	FAL	Nextera	602	0
PJM	WIN	American Electric Power	10	0
PJM	SPR	American Electric Power	10	0
PJM	SUM	American Electric Power	10	0
PJM	FAL	American Electric Power	10	0
PJM	WIN	M&M Mars	2	0
PJM	SPR	M&M Mars	2	0
PJM	SUM	M&M Mars	2	0
PJM	FAL	M&M Mars	2	0
PJM	WIN	SMECO	10	0
PJM	SPR	SMECO	10	0
PJM	SUM	SMECO	10	0
PJM	FAL	SMECO	10	0
PJM	WIN	JP Morgan	0	195
PJM	SPR	JP Morgan	0	195
PJM	SUM	JP Morgan	0	195
PJM	FAL	JP Morgan	0	195
PJM	WIN	Delaware Municipal Electric Corporatio	12	0
PJM	SPR	Delaware Municipal Electric Corporatio	12	0

PJM	SUM	Delaware Municipal Electric Corporatio	12	0
PJM	FAL	Delaware Municipal Electric Corporatio	12	0
PJM_E	WIN	LES Project Holdings	14	0
PJM_E	SPR	LES Project Holdings	14	0
PJM_E	SUM	LES Project Holdings	14	0
PJM_E	FAL	LES Project Holdings	14	0
PJM_E	WIN	Ocean Energy Holdings	9	0
PJM_E	SPR	Ocean Energy Holdings	9	0
PJM_E	SUM	Ocean Energy Holdings	9	0
PJM_E	FAL	Ocean Energy Holdings	9	0
PJM_E	WIN	BP	34	0
PJM_E	SPR	BP	0	0
PJM_E	SUM	BP	0	0
PJM_E	FAL	BP	0	0
PJM_E	WIN	Citigroup	94	0
PJM_E	SPR	Citigroup	75	0
PJM_E	SUM	Citigroup	75	0
PJM_E	FAL	Citigroup	75	0
PJM_E	WIN	Direct Energy	556	0
PJM_E	SPR	Direct Energy	650	0
PJM_E	SUM	Direct Energy	650	0
PJM_E	FAL	Direct Energy	650	0
PJME	WIN	EDF	8	0
PJME	SPR	EDF	0	0
PJME	SUM	EDF	0	0
PJME	FAL	EDF	0	0
PJM_E	WIN	Energy America	305	0
PJM_E	SPR	Energy America	460	0
PJM_E	SUM	Energy America	460	0
PJM_E	FAL	Energy America	460	0
PJM_E	WIN	Exelon	66	0
PJM_E	SPR	Exelon	100	0
PJM_E	SUM	Exelon	100	0
PJM_E	FAL	Exelon	100	0
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PJM_E	SPR	Nextera	602	0
PJM_E	SUM	Nextera	601	0
PJM_E	FAL	Nextera	602	0
PJM_E	WIN	American Electric Power	10	0
PJM_E	SPR	American Electric Power	10	0
PJM_E	SUM	American Electric Power	10	0
PJM_E	FAL	American Electric Power	10	0
PJME	WIN	M&M Mars	2	0
PJME	SPR	M&M Mars	2	0
PJME	SUM	M&M Mars	2	0
PJME	FAL	M&M Mars	2	0
PJM_E	WIN	SMECO	10	0
PJM_E	SPR	SMECO	10	0
PJM_E	SUM	SMECO	10	0
PJM_E	FAL	SMECO	10	0
PJM_E	WIN	JP Morgan	0	195
PJM_E	SPR	JP Morgan	0	195
PJM_E	SUM	JP Morgan	0	195
PJM_E	FAL	JP Morgan	0	195
PJME	WIN	Delaware Municipal Electric Corporatio	12	0

PJME	SPR	Delaware Municipal Electric Corporatio	12	0
PJME	SUM	Delaware Municipal Electric Corporatio	12	0
PJME	FAL	Delaware Municipal Electric Corporatio	12	0
PJM50	WIN	LES Project Holdings	14	0
PJM50	SPR	LES Project Holdings	14	0
PJM50	SUM	LES Project Holdings	14	0
PJM50	FAL	LES Project Holdings	14	0
PJM_50	WIN	Ocean Energy Holdings	9	0
PJM_50	SPR	Ocean Energy Holdings	9	0
PJM_50	SUM	Ocean Energy Holdings	9	0
PJM_50	FAL	Ocean Energy Holdings	9	0
PJM_50	WIN	BP	34	0
PJM_50	SPR	BP	0	0
PJM_50	SUM	BP	0	0
PJM_50	FAL	BP	0	0
PJM_50	WIN	Citigroup	94	0
PJM_50	SPR	Citigroup	75	0
PJM_50	SUM	Citigroup	75	0
PJM_50	FAL	Citigroup	75	0
PJM_50	WIN	Direct Energy	556	0
PJM_50	SPR	Direct Energy	650	0
PJM_50	SUM	Direct Energy	650	0
PJM_50	FAL	Direct Energy	650	0
PJM50	WIN	EDF	8	0
PJM50	SPR	EDF	0	0
PJM50	SUM	EDF	0	0
PJM50	FAL	EDF	0	0
PJM_50	WIN	Energy America	305	0
PJM_50	SPR	Energy America	460	0
PJM_50	SUM	Energy America	460	0
PJM_50	FAL	Energy America	460	0
PJM_50	WIN	Exelon	66	0
PJM_50	SPR	Exelon	100	0
PJM_50	SUM	Exelon	100	0
PJM_50	FAL	Exelon	100	0
PJM_50	WIN	Nextera	523	0
PJM_50	SPR	Nextera	602	0
PJM_50	SUM	Nextera	601	0
PJM_50	FAL	Nextera	602	0
PJM_50	WIN	American Electric Power	10	0
PJM_50	SPR	American Electric Power	10	0
PJM_50	SUM	American Electric Power	10	0
PJM_50	FAL	American Electric Power	10	0
PJM50	WIN	M&M Mars	2	0
PJM50	SPR	M&M Mars	2	0
PJM50	SUM	M&M Mars	2	0
PJM50	FAL	M&M Mars	2	0
PJM_50	WIN	SMECO	10	0
PJM_50	SPR	SMECO	10	0
PJM_50	SUM	SMECO	10	0
PJM_50	FAL	SMECO	10	0
PJM_50	WIN	JP Morgan	0	195
PJM_50	SPR	JP Morgan	0	195
PJM_50	SUM	JP Morgan	0	195
PJM_50	FAL	JP Morgan	0	195

PJM50	WIN	Delaware Municipal Electric Corporatio	12	0
PJM50	SPR	Delaware Municipal Electric Corporatio	12	0
PJM50	SUM	Delaware Municipal Electric Corporatio	12	0
PJM50	FAL	Delaware Municipal Electric Corporatio	12	0
PJMAP	WIN	LES Project Holdings	14	0
PJMAP	SPR	LES Project Holdings	14	0
PJMAP	SUM	LES Project Holdings	14	0
PJMAP	FAL	LES Project Holdings	14	0
PJM_AP	WIN	Ocean Energy Holdings	9	0
PJM_AP	SPR	Ocean Energy Holdings	9	0
PJM_AP	SUM	Ocean Energy Holdings	9	0
PJM_AP	FAL	Ocean Energy Holdings	9	0
PJM_AP	WIN	BP	34	0
PJM_AP	SPR	BP	0	0
PJM_AP	SUM	BP	0	0
PJM_AP	FAL	BP	0	0
PJM_AP	WIN	Citigroup	94	0
PJM_AP	SPR	Citigroup	75	0
PJM_AP	SUM	Citigroup	75	0
PJM_AP	FAL	Citigroup	75	0
PJM_AP	WIN	Direct Energy	556	0
PJM_AP	SPR	Direct Energy	650	0
PJM_AP	SUM	Direct Energy	650	0
PJM_AP	FAL	Direct Energy	650	0
PJMAP	WIN	EDF	8	0
PJMAP	SPR	EDF	0	0
PJMAP	SUM	EDF	0	0
PJMAP	FAL	EDF	0	0
PJM_AP	WIN	Energy America	305	0
PJM_AP	SPR	Energy America	460	0
PJM_AP	SUM	Energy America	460	0
PJM_AP	FAL	Energy America	460	0
PJM_AP	WIN	Exelon	66	0
PJM_AP	SPR	Exelon	100	0
PJM_AP	SUM	Exelon	100	0
PJM_AP	FAL	Exelon	100	0
PJM_AP	WIN	Nextera	523	0
PJM_AP	SPR	Nextera	602	0
PJM_AP	SUM	Nextera	601	0
PJM_AP	FAL	Nextera	602	0
PJM_AP	WIN	American Electric Power	10	0
PJM_AP	SPR	American Electric Power	10	0
PJM_AP	SUM	American Electric Power	10	0
PJM_AP	FAL	American Electric Power	10	0
PJMAP	WIN	M&M Mars	2	0
PJMAP	SPR	M&M Mars	2	0
PJMAP	SUM	M&M Mars	2	0
PJMAP	FAL	M&M Mars	2	0
PJM_AP	WIN	SMECO	10	0
PJM_AP	SPR	SMECO	10	0
PJM_AP	SUM	SMECO	10	0
PJM_AP	FAL	SMECO	10	0
PJM_AP	WIN	JP Morgan	0	195
PJM_AP	SPR	JP Morgan	0	195
PJM_AP	SUM	JP Morgan	0	195

PJM_AP	FAL	JP Morgan	0	195
PJMAP	WIN	Delaware Municipal Electric Corporatio	12	0
PJMAP	SPR	Delaware Municipal Electric Corporatio	12	0
PJMAP	SUM	Delaware Municipal Electric Corporatio	12	0
PJMAP	FAL	Delaware Municipal Electric Corporatio	12	0

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Appendix A-3 PSEG Sewaren MBR Program.XLSX.....20-69

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PSEG
Services Corporation

By ELECTRONIC FILING
The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

May 25, 2018

Re: Notice of Non-Material Change in Status of PSEG Affiliates:

PSEG Energy Resources & Trade LLC	**ER10-1789-005**
PSEG Energy Solutions LLC	**ER10-1768-004**
PSEG Fossil LLC	**ER10-1770-004**
PSEG New Haven LLC	**ER10-1771-004**
PSEG Nuclear LLC	**ER10-1793-004**
PSEG Power Connecticut LLC	**ER12-1250-004**
Pavant Solar II LLC	**ER16-1924-002**
Bison Solar LLC	**ER16-1925-002**
San Isabel Solar LLC	**ER16-1926-002**
Public Service Electric and Gas Company	**ER16-2725-002**
PSEG Energy Solutions	**ER16-2725-002**
PSEG Keys Energy Center LLC	**ER17-2426-000**
(collectively, PSEG Affiliates)	

Dear Secretary Bose:

Pursuant to section 35.42(a)(1) of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[1] the PSEG Affiliates submit this notice of non-material change in status. On November 24, 2017, the Commission accepted for filing the application of PSEG Keys Energy Center LLC ("PSEG Keys") for market-based rate authority.[2] In addition, on November 21, 2017, the Commission accepted the PSEG Affiliates updated market power analysis for the Northeast region and granted the PSEG Affiliates continuing authority to sell electric energy, capacity and ancillary service at market-based rates.[3]

[1] 18 C.F.R. Part 35.42 (2017).

[2] *PSEG Keys Energy Center LLC*, Docket No. ER17-2426-000 (November 24, 2017).

[3] *PSEG Energy Resources & Trade LLC, et al*., Docket Nos. ER10-1789-000, *et al*., (November 21, 2017).

Accordingly, each of the PSEG Affiliates has been authorized to make market-based rate sales pursuant to a filed tariff.

The purpose of this filing is to supplement the information contained in PSEG Keys' application for market-based rate authority[4] to reflect the commencement of test power deliveries from the new 585 MW Sewaren 7 plant, which is targeted to be in operation in June 2018. This notice also reflects the retirements of Sewaren units 1, 2, 3 and 4, which will retire once Sewaren 7 begins commercial operation. This change does not affect the basis upon which the Commission relied when it granted PSEG Keys' application for market-based rate authorization or the updated market power analyses submitted in the Triennial Review supporting the market-based rate authorization for the other PSEG Affiliates.

I. DESCRIPTION OF THE PSEG AFFILIATES

A. PSEG Fossil Sewaren Urban Renewal LLC

PSEG Fossil Sewaren Urban Renewal LLC, New Jersey LLC ("PSEG Sewaren"), is a direct subsidiary of PSEG Fossil LLC ("PSEG Fossil"), which is a direct subsidiary of PSEG Power LLC ("PSEG Power"), a direct subsidiary of Public Service Enterprise Group Incorporated ("PSEG"), a publicly traded company. PSEG Sewaren constructed a new, natural gas-fired, power plant and related electrical facilities required for interconnection of the plant to electric grid, on property that it owns in Woodbridge, New Jersey (the "Sewaren 7").[5] Prior to becoming commercially operational, PSEG Sewaren leased Sewaren 7 to PSEG Fossil. The Sewaren 7 generating facilities comprise a highly-efficient, dual-fuel, combined-cycle plant with a nameplate rating of 585 MW. Sewaren 7 was first connected to the electric grid on April 27, 2018 and is expected to reach commercial operation in June, 2018. PSEG Fossil will be solely responsible for all operations and maintenance for Sewaren 7 under the lease, and will have exclusive control over decisions regarding dispatch or the submission of bids or offers for plant operation. The New Jersey electricity ratepayer is not subsidizing or guaranteeing any portion of the revenue of the plant. The plant will participate in the capacity and energy markets administered by PJM Interconnection, L.L.C. ("PJM") for wholesale electric generators. All of the output of the Sewaren 7 will be sold to PSEG Fossil's affiliate, PSEG Energy Resources & Trade LLC ("PSEG ER&T").

B. Public Service Electric and Gas Company ("PSE&G")

PSE&G is a public utility operating company engaged primarily in the transmission of electricity, and the provision of gas and electric distribution service in the State of New Jersey. During the study period, PSE&G owned less than 140 MW of solar generation, 8 MW of Energy Efficiency and 91 MWs of Demand Response but otherwise did not own or operate any electric generation facilities. PSE&G is a member of the PJM, a FERC-approved Regional Transmission Organization, and has made all of its transmission facilities available for open access transmission service pursuant to the Open Access Transmission Tariff ("OATT") administered

[4] PSEG Keys Energy Center LLC, Application for Market-based Rate Authorization and Request for Waivers and Blanket Approvals, Docket No. ER17-2426-000 (filed September 1, 2017, amended October 4, 2017) ("PSEG Keys Application").

[5] Once Sewaren 7 begins commercial operations, PSEG Fossil will retire Sewaren 1, 2, 3 and 4.

by PJM. PSE&G is authorized to sell power at market-based rates and makes wholesale sales falling within several different categories, as described below.

Non-utility generation ("NUG") output. PSE&G's NUG output expired in 2015 and 2016 pursuant to the terms of the NUG contracts. PSE&G currently has no further NUG obligations, other than 0.6 MW of energy associated with the former Kinsley Landfill which no longer operates.

Solar. In 2007, the New Jersey legislature passed Regional Greenhouse Gas Initiative ("RGGI") legislation authorizing state utilities to invest in renewable resources such as wind or solar in order to promote increased use of renewable resources within the state and in turn reduce greenhouse gas emissions. See L. 2007, c. 340, codified at N.J.S.A. 48:98-1. The New Jersey Board of Public Utilities ("NJBPU") has approved two (2) PSE&G Solar 4 All® (S4A) programs under which PSE&G has sited, designed and built twenty-nine (29) grid connected solar facilities. PSE&G currently owns and operates approximately 125 MW DC of grid connected solar under the S4A program. In 2016, PSE&G received NJBPU approval of its Solar 4 All Extension II filing to install an additional 33 MW-DC of grid connected solar on landfills and brownfields in the PSE&G electric service territory to begin in 2017.

C. PSEG Energy Resources & Trade LLC ("PSEG ER&T")

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil LLC ("PSEG Fossil") and PSEG Nuclear LLC ("PSEG Nuclear"), each wholly-owned subsidiaries of PSEG Power, as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission.[6]

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

1. Basic Generation Services ("BGS") Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 et seq., which initiated the transition from a regulated to a competitive retail power market in New Jersey, the NJBPU annually approves statewide auctions to determine the entities that will supply Basic Generation Service ("BGS") in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSEG ER&T has participated directly in all of the auctions for BGS supply held since 2004, has been a winning bidder in these auctions and has incurred contractual commitments to provide supply to BGS load pursuant to NJBPU approved contracts beginning with the 2004 auction and continuing to the present.

2. Basic Gas Supply Service ("BGSS") Gas Contract. By order issued April 16, 2002, the NJBPU approved a full requirements contract for the provision of gas supply

[6] *Public Service Electric and Gas Company, et al*., 88 FERC ¶ 61,299 (1999).

by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the NJBPU, PSEG ER&T assumed, through capacity release, FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract remains in effect and provides for annual renewals unless terminated by either party on 12 months' advance written notice.

3. Long Island Power Authority ("LIPA") Fuel Supply: On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which ER&T will provide fuel supply and power supply management activities for LIPA beginning on January 1, 2015.

D. PSEG Fossil

PSEG Fossil is an Exempt Wholesale Generator ("EWG")[7] and is authorized to sell power at market-based rates. PSEG Fossil owns and operates electric generation facilities located within PJM and sells their entire output to its affiliate PSEG ER&T.[8] The assets of PSEG Fossil (and its subsidiary, PSEG Sewaren) are located entirely within PJM. However, PSEG Fossil's subsidiaries PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Power New York LLC ("PSEG Power NY") and PSEG New Haven LLC ("PSEG New Haven") own facilities in ISO New England Inc. ("ISO-NE") and the New York Independent System Operator, Inc. ("NYISO"). As noted below, PSEG Fossil also co-owns certain facilities in PJM.

PSEG Fossil's subsidiaries, PSEG Power CT, PSEG Keys and PSEG Sewaren, are currently constructing three new gas-fired generation units. PSEG Sewaren is constructing Sewaren7,[9] which is a 585 MW (nameplate rating) combined cycle unit in Woodbridge, New Jersey which is expected to reach commercial operations in June 1, 2018. PSEG Power CT is constructing Bridgeport 5, a 485 MW combined cycle unit in Bridgeport, Connecticut which is expected to be in service in 2019. Once Sewaren 7 begins commercial operations, Sewaren 1, 2, 3 and 4 will be retired.

PSEG Fossil satisfies most of the electricity needs of its plants from PJM under PJM's "station power" Tariff provisions. PSEG Fossil procures gas supply for its plants from PSEG ER&T and receives gas distribution service from PSE&G at rates approved by the NJBPU on May 29, 2013.[10]

E. PSEG Power CT

[7] PSEG Fossil LLC, Docket No. EG00-3-000, 89 FERC ¶ 62,237 (December 20, 1999); PSEG Fossil LLC, 95 FERC ¶ 61,405 (June 14, 2001); PSEG Fossil LLC, 99 FERC ¶ 62,167 (June 10, 2002).

[8] These contracts were originally approved by the Commission as cost-based contracts. *See Public Service Electric and Gas Company*, et al., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Fossil obtained market based rate authority covering sales from its generating units.

[9] Once Sewaren 7 begins commercial operations, PSEG Fossil plans to retire Sewaren 1, 2, 3 and 4.

[10] NJBPU Docket No. GM12100935 (May 29, 2013).

PSEG Power CT is a Connecticut limited liability company and an EWG that owns and operates electric generation facilities in the State of Connecticut and is authorized to sell power at market-based rates.[11] Both of PSEG Power CT's generation facilities, Bridgeport Harbor and New Haven Harbor, are located in the State of Connecticut within the market administered by ISO-NE. PSEG Power CT sells the output of its generation facilities to its affiliate PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority. As noted above, PSEG Power CT is currently constructing Bridgeport 5, a 485 MW combined cycle unit in Bridgeport, Connecticut which is expected to be in service in 2019.

F. PSEG New Haven

PSEG New Haven is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG New Haven owns and operates a facility (the "New Haven facility") in New Haven, Connecticut with a nameplate rating of 181 MWs. The New Haven facility is located within the New Haven Harbor generation station. The New Haven facility is interconnected to the adjacent United Illuminating East Shore Substation using a 115 KV underground cable. PSEG New Haven has no other generation assets. The commercial operation date for the New Haven facility was June 1, 2012 and PSEG New Haven has obtained MBR authority from FERC.[12]

The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[13] pursuant to a Connecticut statute that sought proposals for peaking generation in Connecticut.[14] All of the energy and capacity of the New Haven facility is sold into the ISO-NE markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA[15] has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder. The 181 MW nameplate rating of the New Haven Facility was not included in PSEG's triennial analysis.

G. PSEG Nuclear

PSEG Nuclear is an EWG[16] and is authorized to sell power at market-based rates. PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire

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[11] *Wisvest Corporation,* et al., 101 FERC ¶ 61,166 (2002).

[12] *PSEG New Haven LLC*, Docket No. ER12-1250-000, *et al*., (May 29, 2012).

[13] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control. PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

[14] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

[15] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

[16] *PSEG Nuclear LLC*, 97 FERC ¶ 62,191 (November 30, 2001).

output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission.[17] The assets of PSEG Nuclear are located entirely within PJM.

H. Pavant Solar LLC, San Isabel Solar LLC and Bison Solar LLC

PSEG Power Ventures portfolio includes three (3) solar companies with market-based rate authority: (1) Pavant Solar II LLC[18] is a QF which owns a 50 MW (AC) solar facility in Fillmore Utah; (2) San Isabel Solar LLC[19] is a QF which owns a 30 MW (AC) solar facility in Las Animas County, Colorado; and (3) Bison Solar LLC[20] is a QF which owns a 30 MW (AC) solar facility 25 miles north of Fort Collins, Colorado.

I. PSEG Energy Solutions LLC

PSEG Energy Solutions LLC ("PSEG Solutions") is a Delaware limited liability company and a direct subsidiary of PSEG ER&T. PSEG Solutions obtained market-based rate authority[21] and will operate within the PJM, NYISO and ISO-NE markets. PSEG Solutions will purchase power from the regional transmission organization ("RTO") at wholesale and sell it to retail customers. PSEG Solutions will not own or operate any generation assets. PSEG Solutions began its retail business in 2017.

II. Affiliated Generation Ownership

A list of the Applicants' affiliated domestic FERC jurisdictional generation assets owned is contained in Appendix B attached hereto.[22] Those additional subsidiaries of PSEG that may be considered relevant to this request are described below:

(1) Public Service Enterprise Group Incorporated ("PSEG"). PSEG, a New Jersey corporation, is a public utility holding company engaged in, among other things, the generation of electric energy and the transmission, distribution and sale of electricity and natural gas through its subsidiaries.

(2) PSEG Power LLC. PSEG Power was formed in 1999 to acquire the former generation assets of PSE&G. PSEG Power, a Delaware limited liability company, does not directly own any generation facilities or engage in any FERC jurisdictional activities but is the parent company of several FERC jurisdictional entities, including Applicants PSEG ER&T (and

[17] *Public Service Electric and Gas Company, et al.,* 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Nuclear obtained market-based rate authority.

[18] *Pavant Solar II LLC*, Docket No. QF16-1072-000.

[19] *San Isabel Solar LLC*, Docket No. QF16-712-000.

[20] *Bison Solar LLC*, Docket No. QF16-711-001.

[21] *See* Letter Order dated December 21, 2016 in Docket No. ER16-2725-000.

[22] Appendix B excludes generation assets located in Hawaii as well as generation assets in which PSEG's interest is limited to a leveraged lease interest. *See* PSEG Keys Application, Docket No. ER17-2426, attached Appendix B.

its subsidiary PSEG Solutions), PSEG Fossil, PSEG Nuclear, PSEG Power CT, PSEG New Haven and PSEG Power Ventures (which owns PSEG Solar Source).

(3) PSEG Power Ventures LLC ("Power Ventures") and PSEG Solar Source LLC. PSEG Power Ventures is a Delaware Limited Liability company and a direct subsidiary of PSEG Power. PSEG Power Ventures owns 100% interest in PSEG Solar Source and has an indirect ownership interest in a domestic power plant in Hawaii. PSEG Solar Source owns approximately 414 MWs DC (325 MW AC) of solar capacity across the United States, including a combined 146 MWs[23] (113 MW AC) of solar capacity in PJM and approximately the following amount of MWs in the following states, all through separate project companies which have obtained QF status.

- 15 MWs (12 MW AC) in Florida
- 146 MWs in PJM (113 MW AC) – 12 MW in Ohio, 2 MW in New Jersey, 15 MW in Delaware, 103 MW in North Carolina and 13 MW in Maryland
- 45 MWs in Arizona (34 MW AC) – 25 MW Queen, approximately 20 MW Badger
- 13 MWs (10 MW AC) in Texas
- 34 MWs (25 MW AC) in California[24]
- 4 MWs (3 MW AC) in Vermont and
- 74 MWs (60 MW AC) in Colorado – 38 MW (San Isabel) and 36 MW (Bison)
- 62 MW (50 MW AC) in Utah
- 10.5 MW (8 MW AC) in Oregon
- 103 MW (79 MW AC) in North Carolina
- 11 MW DC (9 MW AC) in Long Island NY

(4) PSEG Resources LLC ("Resources"). Resources is a New Jersey limited liability company that provides energy infrastructure financing in developed countries. Resources invests primarily in energy-related financial transactions and manages a diversified portfolio of investments including leveraged leases. Resources owns interests, through leveraged leases, in various generation stations. Pursuant to the terms of these triple net leases, the lessee, not Resources, has all operational responsibility and control over the leased generation stations.

(5) PSEG Power NY. PSEG Power NY is a Delaware limited liability company and an EWG that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 750 MW (nameplate rating) combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a FERC-approved cost-based contract.[25]

[23] The 146 MWs are attributed to four (9) separate project companies that have QF status: PSEG Solar Hackettstown LLC (2 MW); PSEG Solar Delaware LLC (15 MW), Rockfish Solar LLC (13 MWs), Meadows Solar (26 MW), Turkey Creek (17 MW) Hemlock Solar (7 MW), Cork Oak (26 MW), Sunflower (21 MW) in North Carolina and PSEG Solar Ohio LLC (12 MW).

[24] The 28 MWs (DC) are associated with the Shasta Solar Facility in California (4 MW), Whitethorn Solar (3 MWs) the Columbia Solar Project (34 MW). All have obtained QF status.

[25] *PSEG Power New York Inc.*, Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

(6) PSEG Keys. PSEG Keys is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG Keys was formed to construct, operate and maintain the Keys Energy Center, a 755MW combined cycle power plant in Prince Georges County, Maryland. Construction began in 2015 and is expected to be completed by June 1, 2018 at which time the capacity and energy will be available in the PJM market. All of the output of the Keys Energy Center will be sold to PSEG Keys affiliate, PSEG ER&T.

(7) PSEG Long Island LLC ("Long Island") and Long Island Electric Utility Servco, LLC ("Servco"). Long Island and Servco are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution system ("T&D") on Long Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither Long Island nor Servco are FERC jurisdictional public utilities as neither exercises ultimate decision making authority over the T&D system in Long Island. Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[26]

III. Affiliated Transmission Ownership

With the exception of the electric transmission assets owned by PSE&G, all of which are located within the PJM RTO, and the generation interconnection facilities owned by the various EWG and QF affiliates listed herein, none of the PSEG Affiliates own or operate FERC jurisdictional electric or natural gas transmission facilities within the United States. As discussed below, FERC granted PSE&G a Hinshaw exemption in 1954, finding that it was exempt from the provisions of the Natural Gas Act.

A. Jointly Owned Facilities

PSEG Nuclear is a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear is the operator of Salem and Exelon Generation is the operator of Peach Bottom. PSEG Fossil is approximately a 23% joint owner in the Conemaugh and Keystone generating stations located in Pennsylvania. As of the date of this filing, an affiliate of NRG Energy is the operator. Accordingly, for purposes of the December 2016 triennial analysis, the capacity of Salem, Peach Bottom, Conemaugh and Keystone was attributed to PSEG in accordance with PSEG's ownership interests in these facilities.

PSEG Fossil and Jersey Central Power and Light Company ("JCP&L") are each 50% co-owners of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to the unit. Accordingly, for the purpose of the December 2016 triennial market power analysis, the entire unit capacity – nominally 400 MWs – was assigned to JCP&L.

IV. NOTICE OF CHANGE IN STATUS

[26] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), *order dismissing request for rehearing*, 145 FERC ¶ 61,183 (2013).

The PSEG Affiliates submit this Notice of Change in Status to report to the Commission its addition of Sewaren 7 to the generation fleet attributable to PSEG Fossil. Sewaren 7 is a highly efficient, dual-fuel 585 MW combined-cycle plant (nameplate) that is targeted to be in-service in June, 2018. Once Sewaren 7 is in-service, Sewaren 1-4 will be retired.

The addition of Sewaren 7 and the retirements of Sewaren 1-4 results in an increase in excess of 100 MW in the PSEG Affiliate's generation capacity, but does not materially affect the conditions the Commission relied upon in granting PSEG Keys' market-based rate authority or the PSEG Affiliates' Triennial application. As discussed further below, the addition of Sewaren 7 and retirements of Sewaren 1-4 raises no market power concerns. While the PSEG Affiliates understand that the submission of indicative screens is not required for this change in status,[27] the PSEG Affiliates nevertheless submit the indicative screens to show that the addition of Sewaren 7 and retirements of Sewaren 1-4 does not have a material impact on the PSEG Affiliates market power.

V. UPDATED MARKET-BASED RATE ANALYSIS

As demonstrated in the attached market power screens, the PSEG Affiliates continue to lack market power in generation, despite adding Sewaren 7's generation capacity and retiring Sewaren 1-4's generation capacity. Further, PSEG Affiliates' addition of Sewaren 7 has no material impact on the vertical market power analysis submitted to the Commission in the PSEG Keys' application.

A. Horizontal Market Power

The Commission evaluates whether a seller can exercise horizontal market power in a relevant market through two indicative screens: (1) a pivotal supplier analysis; and (2) a wholesale market share analysis. If a seller passes both screens, there will be a rebuttable presumption that the seller lacks market power.[28] Each indicative screen is applied with respect to the "relevant geographic markets" for an applicant's generating units. The Commission requires that an applicant seeking market-based rate authority show it does not possess horizontal market power by demonstrating that it and its affiliates can pass the market power screen, "unless the seller and its affiliates do not own or control generation capacity or all of their capacity is fully committed."

Applicants that are located in ISOs/RTOs possessing sufficient market structure may consider the geographic region under the control of the ISO/RTO as the relevant default geographic region for purposes of completing their generation market power analyses. However, where the Commission has previously found a "submarket" to exist within a boundary of an RTO, such finding is controlling as to the scope of the relevant geographic market for all generation units located within that submarket for the application of the indicative screens and any delivered price test that may be performed. The Commission further listed several such submarkets, including PJM East ("PJME"), PJM East of 5004/5005 ("PJM50") and PJM East of

[27] *See Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 816, 153 FERC ¶ 61,065, at P 293 (2015), *order on reh'g and clarify*., Order No. 679-A. 155 FERC ¶ 61,188 (2016).

[28] 18 C.F.R. § 35.37(c)(1) (2011).

AP South ("PJMAP") that would be relevant to an MBR analysis for applicants in the Northeast Region.

As shown in the attached Appendix C, Dr. John Morris has updated the market power analysis that was submitted in the December 2016 Triennial Filing[29] and the market power study for the PJM market and relevant submarkets that were submitted on September 1, 2017 in support of PSEG Keys Application.[30] Specifically, Dr. Morris has updated the market-based rate screens contained in the PSEG Keys Application to account for the addition of the 585 MWs from the PSEG Sewaren unit and the retirements of the Sewaren 1-4 units at the same location (452.3 MWs). Dr. Morris also moved the test year of the analysis forward by one year from December 2014-November 2015 to December 2015-November 2016 because this is the latest period for which FERC Form 714 data on unplanned generator outages is available.[31] Dr. Morris also updated the overall market sizes of the PJM market and submarkets, along with the first tier areas of NYISO and MISO.[32] Finally, Dr. Morris updated load data both for the applicant and for the overall markets in the study.[33] All methods are the same as in Dr. Morris' December 2016 Affidavit.

Dr. Morris' updated analysis shows that there has been a minor decrease in the market power with the addition of Sewaren 7 since the September 2017 PSEG Keys Application. This minor decrease should not be viewed to impact the factors that Dr. Morris relied upon in his findings in either the PSEG Keys MBR Filing or the December 2016 Triennial Filing that the PSEG Affiliates with market-based rate authority have satisfied the requirements demonstrating that they lack horizontal and vertical market power. Specifically, Dr. Morris analysis shows that with the addition of Sewaren 7, the PSEG Affiliates pass all of the pivotal supplier analysis ("PSA") screens for all of the relevant markets, namely, PJM, PJMAP, PJME and PJM50.[34]

Dr. Morris' analysis also shows that the PSEG Affiliates pass two additional screens as compared to the PSEG Keys Application in the wholesale market share analysis ("WMSA").[35]

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[29] PSEG Energy Resources & Trade LLC, *et al*., Docket Nos. ER10-1789-000, *et al*., (filed December 29, 2016) ("December 2016 Triennial Filing"), attached Exhibit A, Report of Affidavit of Dr. John R. Morris ("December 2016 Affidavit"); PSEG Keys Energy Center LLC, Docket No. ER17-2426-000 (filed September 1, 2017 and amended on October 4, 2017); attached Appendix G, Affidavit of John Morris.

[30] *See* PSEG Keys Application attached Appendices A-1, A-2.

[31] PSEG Energy Resources & Trade LLC, *et al*., Notice of Non-material Change in Status, Docket No. ER18-__-000, (filed May 25, 2018), attached Appendix C, Affidavit of Dr. John R. Morris P 2 ("Morris Affidavit").

[32] *Id.*

[33] *Id.*

[34] *See* attached Appendix A-1. The pivotal supplier analysis ("PSA") focuses on the ability of a seller to exercise unilateral market power. The screen assesses whether market demand can be met during peak times without the applicant and its affiliates. If demand can be met without the applicant and its affiliates, the applicant passes that the PSA screen.

[35] *Id.* The wholesale market share analysis ("WMSA") is applied each season to determine whether an applicant has a dominant market position based on the total number of megawatts of uncommitted capacity owned or controlled by the applicant and its affiliates in relation to the uncommitted capacity of the entire relevant

Notably, in the updated analysis, the PSEG Affiliates now pass the PJM50 for summer and fall. As a result, we submit that Dr. Morris' determination that the PSEG Affiliates could not exercise horizontal market power still stands with the addition of Sewaren 7 (and the retirement of Sewaren 1-4). As stated by Dr. Morris in his affidavit:

> Although there are some minor differences in the results from those presented with the December Affidavit, the differences are not material and do not change the conclusions made at that time. Under the standards utilized by the Commission, continuing market-based rates for PSEG and all of its Northeastern affiliates remain in the public interest. In addition, granting market-rate authority to the Sewaren LLC would also be in the public interest.[36]

Moreover, to the extent necessary, the PSEG Affiliates rely on the same PJM RTO monitoring and mitigation described in the December 2016 Triennial Filing to show that they have met the standards necessary to obtain market-based rate authority. Accordingly, it is clear that with the addition of Sewaren 7 that PSEG Fossil and the other PSEG Affiliates continue to satisfy the standards necessary for market-based rate authority.

B. Vertical Market Power

1. The Applicants Lack Transmission Market Power and Cannot Erect Entry Barriers.

In its previous order accepting PSEG Affiliates' triennial market power analysis for the Northeast Region, the Commission found that the submittal satisfied the Commission's requirements for market-based rates regarding vertical market power.[37] As demonstrated below, the PSEG Affiliates are not able to exercise vertical market power.

PSE&G is the only PSEG Affiliate that owns transmission assets in the U.S. other than incidental generator interconnection facilities. PSE&G owns transmission facilities in PJM, but transmission service over those facilities is provided under the PJM Open Access Transmission Tariff.

In addition, none of the PSEG Affiliates are able to exercise vertical market power in wholesale energy markets through affiliation, ownership or control of inputs to electric power production. As required by Section 35.37(e) of the Commission's regulations, the PSEG Affiliates provide the following information:

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wholesale electricity market. The established threshold is 20 percent; a supplier who has less than 20 percent market share in the relevant market for all seasons passes the WMSA screen.

[36] Morris Affidavit PP 4, 6.

[37] *PSEG Energy Resources & Trade, LLC, et al,* Letter Order, June 29, 2011, Docket No. ER99-3151-017. In addition, in that letter order the Commission found that the submittal satisfied the Commission's requirements for market-based rates regarding horizontal market power.

(a) PSE&G owns and operates a natural gas distribution system that receives interstate pipeline gas within the State of New Jersey and distributes that gas to its customers within the State of New Jersey. The distribution system consists of approximately 18,050 miles of gas distribution pipe and an additional 62 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3 and peak-shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers. Service over such distribution facilities is made available pursuant to state regulated tariffs on an open access type basis. PSE&G was granted a Hinshaw exemption from the FERC in 1954.[38] The gas distribution rates paid by PSEG Fossil to PSE&G have been set at rates approved by the NJBPU in an order dated May 29, 2013.

(b) Certain of the PSEG Affiliates or their affiliates own sites within the Northeast Region that would be suitable for future generating facilities. These include space at many of the existing generating sites of PSEG Fossil and at the sites of PSEG Power NY and PSEG Power CT. PSEG Nuclear's Salem facility may also be suitable for future construction. PSE&G also owns certain sites that would be suitable for generating facilities, but under New Jersey's Electric Discount and Energy Competition Act, N.J.S.A 48:3-43 et seq., PSE&G is effectively barred from owning and operating generation except "on site" generation and Class I renewable energy resources as defined in N.J.S.A. 48:3-98.1.

(c) Neither the PSEG Affiliates nor any of their affiliates own or control any physical coal supply resources or own or control who may access transportation of coal supplies.

(d) As required by section 35.37(e)(4) of the Commission's regulations, the PSEG Affiliates state that they have not erected barriers to entry into any market, including the PJM, NYISO or ISO-NE market and will not erect barriers to entry into any markets.

VI. DOCUMENTS SUBMITTED WITH FILING

The following documents are submitted with this application.[39]

Appendix A-1: Summary of Market Power Analysis for PJM
Appendix A-2: Market Power Analysis for PJM
Appendix B: December 2016 Triennial Filing
Appendix C: Affidavit of John Morris

VII. CONCLUSION

Based on the foregoing, the PSEG Affiliates submit that, with the addition of Sewaren 7 and retirements of Sewaren 1-4, they continue to lack horizontal and vertical market power and otherwise continue to satisfy the Commission's market-based rate eligibility criteria. In short,

[38] 13 F.P.C. 1348 (1954).

[39] In the event that the Commission deems it necessary to submit an Appendix B (generation assets), the PSEG Affiliates request waiver of such requirement given that the asset appendix would be the same as the one submitted in the PSEG Keys Application, but for the inclusion of the 585 MWs for Sewaren 7 and the retirements of Sewaren 1, 2, 3 and 4 (452.3 MWs).

adding Sewaren 7 to the PSEG Affiliates generation assets raises no market power concerns and does not materially affect the conditions the Commission relied on in granting PSEG Keys' and the PSEG Affiliates' demonstrations in the Triennial Review for the continuation of authorization to sell energy, capacity, and certain ancillary services at market-based rates.

Respectfully submitted,

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Dated: May 25, 2018

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ATTACHMENT A-1

PSEG MBR Change in Status - Sewaren

	PSA		WMSA							
			Winter		Spring		Summer		Fall	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result
PJM Interconnection	38,360	Pass	7.2	Pass	6.1	Pass	6.5	Pass	6.5	Pass
PJM East	4,274	Pass	26.5	Fail	22.1	Fail	25.7	Fail	24.1	Fail
PJM East of 5004/05	5,937	Pass	20.5	Fail	18.0	Pass	19.8	Pass	19.6	Pass
PJM East of AP South	10,506	Pass	14.6	Pass	12.7	Pass	14.2	Pass	13.6	Pass

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ATTACHMENT A-2

Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	9,378	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	195	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	1,943	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	70	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	186,588	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	1,943	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	195	Row B; Table2Data
H	Uncommitted Capacity Imports	7,530	Calculated
I	Study Area Reserve Requirement	8,674	Gendata
J	Amount of Line I Attributable to Seller, if any	228	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	62,196	
	Load		
L	Balancing Area Annual Peak Load	152,177	Loads
M	Average Daily Peak Native Load in Peak Month	132,696	Loads
N	Amount of Line M Attributable to Seller, if any	3,073	SellerLoads
O	Wholesale Load (L-M)	19,482	
P	Net Uncommitted Supply (K-O)	42,715	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,399	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	7,600	
	% of SIL for Seller's imported capacity →	0.01	
	% of SIL for Other's imported capacity →	0.99	
	SIL Value →	7600	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	6,650	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	14	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	152	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	27,691	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	14	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,385	Calculated
I	Study Area Reserve Requirement	1,767	Gendata
J	Amount of Line I Attributable to Seller, if any	202	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	13,259	
	Load		
L	Balancing Area Annual Peak Load	30,992	Loads
M	Average Daily Peak Native Load in Peak Month	25,852	Loads
N	Amount of Line M Attributable to Seller, if any	2,695	SellerLoads
O	Wholesale Load (L-M)	5,139	
P	Net Uncommitted Supply (K-O)	8,120	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	3,890	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,537	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	6537	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,418	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	105	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	52,989	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,214	Calculated
I	Study Area Reserve Requirement	3,049	Gendata
J	Amount of Line I Attributable to Seller, if any	210	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	18,909	
	Load		
L	Balancing Area Annual Peak Load	53,493	Loads
M	Average Daily Peak Native Load in Peak Month	44,768	Loads
N	Amount of Line M Attributable to Seller, if any	2,992	SellerLoads
O	Wholesale Load (L-M)	8,725	
P	Net Uncommitted Supply (K-O)	10,184	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,293	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,319	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	6319	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,418	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	88	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	80,051	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,367	Calculated
I	Study Area Reserve Requirement	4,162	Gendata
J	Amount of Line I Attributable to Seller, if any	210	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	26,286	
	Load		
L	Balancing Area Annual Peak Load	73,026	Loads
M	Average Daily Peak Native Load in Peak Month	61,476	Loads
N	Amount of Line M Attributable to Seller, if any	2,992	SellerLoads
O	Wholesale Load (L-M)	11,550	
P	Net Uncommitted Supply (K-O)	14,736	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	4,275	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	4,455	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	4455	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	10,859	10,119	9,378	10,119	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	195	195	195	195	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	1,643	1,944	1,943	1,944	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	452	1,512	93	1,131	SellerGendata
E	Uncommitted Capacity Imports	91	89	68	53	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	99,674	86,411	116,161	92,587	Loads
G	Amount of Line F Attributable to Seller, if any	1,573	1,308	2,340	1,568	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	98,102	85,102	113,821	91,019	F - G
I	Study Area Reserve Requirement	6,756	6,230	8,317	6,641	Gendata
J	Amount of Line I Attributable to Seller, if any	119	117	202	143	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	6,637	6,113	8,116	6,498	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	193,335	189,962	186,588	189,962	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	1,643	1,944	1,943	1,944	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	195	195	195	195	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	8,043	28,377	1,841	21,225	Gendata; Row D
P	Uncommitted Capacity Imports	11,906	12,184	7,532	7,014	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	93,908	84,302	72,090	79,982	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,359	5,522	5,064	5,580	
S	Total Seasonal Uncommitted Capacity (Q+R)	101,266	89,823	77,154	85,562	
T	**Applicant's Market Share** (R÷S)	7.3%	6.1%	6.6%	6.5%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	11,997	12,273	7,600	7,067	
V	SIL Value	11,997	12,273	7,600	7,067	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,182	7,416	6,650	7,416	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	22	14	14	14	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	340	1,108	66	829	SellerGendata
E	Uncommitted Capacity Imports	156	135	128	113	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	16,761	14,806	21,675	16,148	Loads
G	Amount of Line F Attributable to Seller, if any	1,499	1,253	2,058	1,350	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	15,261	13,553	19,617	14,798	F - G
I	Study Area Reserve Requirement	1,150	1,117	1,651	1,345	Gendata
J	Amount of Line I Attributable to Seller, if any	113	112	177	123	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	1,037	1,005	1,473	1,222	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	27,568	27,630	27,691	27,630	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	22	14	14	14	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,147	4,127	273	3,087	Gendata; Row D
P	Uncommitted Capacity Imports	7,346	8,695	6,409	7,746	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	17,491	17,653	12,750	16,282	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	6,364	5,064	4,463	5,214	
S	Total Seasonal Uncommitted Capacity (Q+R)	23,854	22,717	17,213	21,496	
T	**Applicant's Market Share** (R÷S)	26.7%	22.3%	25.9%	24.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	7,502	8,830	6,537	7,859	
V	SIL Value	7,502	8,830	6,537	7,859	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,951	8,185	7,418	8,185	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	372	1,223	73	914	SellerGendata
E	Uncommitted Capacity Imports	118	69	95	61	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	31,965	27,526	38,884	30,032	Loads
G	Amount of Line F Attributable to Seller, if any	1,524	1,270	2,340	1,568	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	30,441	26,256	36,544	28,465	F - G
I	Study Area Reserve Requirement	2,203	2,058	2,874	2,416	Gendata
J	Amount of Line I Attributable to Seller, if any	115	114	202	143	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,088	1,944	2,672	2,273	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	53,711	53,350	52,989	53,350	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	2,234	7,970	523	5,961	Gendata; Row D
P	Uncommitted Capacity Imports	7,986	8,224	6,224	6,042	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	26,970	25,434	19,502	22,722	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,022	5,618	4,870	5,591	
S	Total Seasonal Uncommitted Capacity (Q+R)	33,992	31,052	24,372	28,313	
T	**Applicant's Market Share** (R÷S)	20.7%	18.1%	20.0%	19.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	8,104	8,293	6,319	6,103	
V	SIL Value	8,104	8,293	6,319	6,103	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2015 — Nov 2016**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	8,951	8,185	7,418	8,185	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	372	1,223	73	914	SellerGendata
E	Uncommitted Capacity Imports	140	90	81	74	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	44,121	37,780	53,385	41,231	Loads
G	Amount of Line F Attributable to Seller, if any	1,524	1,270	2,340	1,568	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	42,598	36,510	51,045	39,663	F - G
I	Study Area Reserve Requirement	3,105	2,881	3,898	3,332	Gendata
J	Amount of Line I Attributable to Seller, if any	115	114	202	143	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,990	2,767	3,696	3,189	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	82,251	81,151	80,051	81,151	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,422	12,123	790	9,067	Gendata; Row D
P	Uncommitted Capacity Imports	7,757	8,766	4,374	5,994	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	41,035	38,546	28,922	35,255	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,044	5,639	4,856	5,604	
S	Total Seasonal Uncommitted Capacity (Q+R)	48,079	44,185	33,778	40,859	
T	**Applicant's Market Share** (R÷S)	14.7%	12.8%	14.4%	13.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,897	8,856	4,455	6,068	
V	SIL Value	7,897	8,856	4,455	6,068	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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ATTACHMENT B

20161228-5240 FERC PDF (Unofficial) 12/28/2016 3:16:58 PM

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PSEG Services Corporation

December 28, 2016

ELECRONICALLY AND VIA OVERNIGHT MAIL

Kimberly J. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Triennial Market Power Update in Compliance with Order No. 697:
***PSEG Energy Resources & Trade LLC*, Docket No. ER99-3151-____;**
***Public Service Electric and Gas Company*, Docket No. ER97-837-____;**
***PSEG Power Connecticut LLC*, Docket No. ER03-327 -___;**
***PSEG Fossil LLC*, Docket No. ER08-447-___;**
***PSEG Nuclear LLC*, ER08-448-___; and**
***PSEG New Haven LLC*, ER12-1250-___**
Pavant Solar II LLC, ER16-1925-___
San Isabel Solar LLC, ER16-1926-___
Bison Solar LLC, ER16-1924-___
PSEG Energy Solutions LLC, ER16-2725-___

Dear Secretary Bose:

Pursuant to the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), PSEG Energy Resources & Trade LLC ("PSEG ER&T"), Public Service Electric and Gas Company ("PSE&G"), PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Fossil LLC ("PSEG Fossil"), PSEG Nuclear LLC ("PSEG Nuclear"), PSEG New Haven LLC ("PSEG New Haven") Pavant Solar II LLC, San Isabel Solar LLC, Bison Solar LLC and PSEG Energy Solutions LLC (collectively the "Applicants" or "PSEG") hereby jointly submit for filing their updated market power analysis in support of their continued eligibility to engage in market-based rates

transactions. This market power analysis satisfies the requirements of Order No. 697[1] for the filing of updated market power analyses on a regional schedule basis by holders of market-based rate certificates and their affiliates. In accordance with the regional schedule for those utilities in the Northeast Region, as modified by the MBR Clarifying Order, this filing is being made by the December 2016 deadline.[2] In conformance with the Commission's requirements, except when expressly noted otherwise, the market power analysis is based on activity during the study period from December 1, 2014 through November 30, 2015 ("study period").

PSEG, through its subsidiary PSE&G, owns transmission facilities within the Northeast Region. Specifically, PSE&G owns transmission facilities in the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization. PSEG Power LLC and its subsidiaries do not own any transmission facilities other than transmission to connect generating units to the grid in PJM, the New York Independent System Operator, Inc. ("NYISO") and ISO New England Inc. ("ISO-NE").

In their original applications for market-based rate authority and previously-submitted updates to the Commission, PSEG ER&T, PSE&G, PSEG Power CT, PSEG Fossil, PSEG Nuclear and PSEG New Haven demonstrated that they and their affiliates: (a) do not exercise generation market power; (b) lack the ability to manipulate access to transmission facilities that they own or control; and (c) cannot erect any other barriers to market entry. As further demonstrated herein and in the Affidavit of Dr. John R. Morris attached hereto in the appendices, Applicants continue to satisfy the Commission's requirements to sell energy, capacity and ancillary services at market-based rates and thus should be permitted to continue to make such sales.

I. SERVICE AND COMMUNICATION

All service and correspondence related to this matter should be directed to the following individuals:

[1] 18 C.F.R. Part 35, Subpart H (2007); Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, 119 FERC ¶ 61,295, ("Order No. 697" or "MBR Order"), *order clarifying final rule*, 121 FERC ¶ 61,260 (2007) ("MBR Clarifying Order"), *order on reh'g and clarification*, 123 FERC ¶ 61,055 (2008) FERC Stats. & Regs ¶ 31,268 ("Order No. 697-A"), *order on reh'g and clarification*, 124 FERC ¶ 61,055 (2008) ("SIL Allocation Order").

[2] This filing is made on the three year anniversary of the December 2013 deadline set forth in Order No. 697 Appendix D.

As to the Applicants Generally:

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Applicants request waiver of Rule 203(b)(3)[3] so that a copy of any communications in these proceedings may be served on all persons listed above.

II. DESCRIPTION OF THE APPLICANTS AND RELEVANT AFFILIATES

A. The Applicants

The Applicants are each wholly owned, direct and indirect subsidiaries of Public Service Enterprise Group Incorporated ("PSEG"). PSEG is a public utility holding company engaged in, among other things, the generation of electric energy and the transmission, distribution and sale of electricity and natural gas through its subsidiaries.

1. Public Service Electric and Gas Company

PSE&G is a public utility operating company engaged primarily in the transmission of electricity, and the provision of gas and electric distribution service in the State of New Jersey. During the study period, PSE&G owned less than 140 MW of solar generation, 8 MW of Energy Efficiency and 91 MWs of Demand Response but otherwise did not own or operate any electric generation facilities. PSE&G is a member of the PJM Regional Transmission Organization and has made all of its transmission facilities available for open access transmission service pursuant to the PJM Open Access

[3] 18 C.F.R. § 385.203(b)(3).

Transmission Tariff ("OATT") administered by PJM. PSE&G is authorized to sell power at market-based rates and makes wholesale sales falling within several different categories, as described below.

Non-utility generation ("NUG") output. PSE&G's NUG output expired in 2015 and 2016 pursuant to the terms of the NUG contracts. PSE&G currently has no further NUG obligations, other than 0.6 MW of energy associated with the former Kinsley Landfill which no longer operates. .

Solar. In 2007, the New Jersey legislature passed Regional Greenhouse Gas Initiative ("RGGI") legislation authorizing state utilities to invest in renewable resources such as wind or solar in order to promote increased use of renewable resources within the state and in turn reduce greenhouse gas emissions. *See* L. 2007, c. 340, codified at N.J.S.A. 48:98-1. The NJBPU has approved two (2) PSE&G Solar 4 All® (S4A) programs under which PSE&G has sited, designed and built twenty-nine (29) grid connected solar facilities. PSE&G currently owns and operates approximately 115MW-dc of grid connected solar under the S4A program. PSE&G expects the S4A fleet to increase to approximately 125MW-dc by the end of 2016. In 2016, PSE&G received NJBPU approval of its Solar 4 All Extension II filing to install an additional 33MW-dc of grid connected solar on landfills and brownfields in the PSE&G electric service territory.

2. PSEG Energy Resources & Trade LLC

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil and PSEG Nuclear, each wholly-owned subsidiaries of PSEG Power LLC ("PSEG Power"), as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission.

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

BGS Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 *et seq.,* which initiated the transition from a regulated to a competitive retail power market in New Jersey, BPU annually approves statewide auctions to determine the entities that will supply Basic Generation Service ("BGS") in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSEG ER&T has participated directly in all of the auctions for BGS supply held since 2004, has been a winning bidder in these auctions and has incurred contractual

commitments to provide supply to BGS load pursuant to BPU approved contracts beginning with the 2004 auction and continuing to the present

BGSS Gas Contract. By order issued April 16, 2002, the BPU approved a full requirements contract for the provision of gas supply by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the BPU, PSEG ER&T assumed, through capacity release, FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract remains in effect and provides for annual renewals unless terminated by either party on 12 months' advance written notice.

LIPA Fuel Supply: On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which ER&T will provide fuel supply and power supply management activities for LIPA beginning on January 1, 2015.

3. PSEG Fossil LLC

PSEG Fossil is an Exempt Wholesale Generator ("EWG") and is authorized to sell power at market-based rates. PSEG Fossil owns and operates electric generation facilities located within PJM and sells their entire output to its affiliate PSEG ER&T.[4] The assets of PSEG Fossil (and its subsidiary, PSEG Keys Energy Center LLC ("PSEG Keys")) are located entirely within PJM. However, PSEG Fossil's subsidiaries PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Power New York LLC and PSEG New Haven LLC own facilities in ISO-NE and NYISO. As noted below, PSEG Fossil also co-owns certain facilities in PJM.

PSEG Fossil and its subsidiaries PSEG Power CT and PSEG Keys are currently beginning construction on three new gas-fired generation units. PSEG Fossil is constructing Sewaren 7[5] which is a 540 MW combined cycle unit in Woodbridge, New Jersey which is expected to be in-service in 2018, PSEG Keys is constructing a 755 MW combined cycle unit in Prince George's County, Maryland which is expected to be in service in 2018 and PSEG Power CT is constructing Bridgeport 5, a 485 MW combined cycle unit in Bridgeport, Connecticut which is expected to be in service in 2019.

Since the last triennial filing in December 2013 PSEG Fossil has retired 1,813.5 MWs (nameplate) inclusive of the following units:

Kearny 9 (18.6 MW)
Bergen 3 (18.6 MW)

[4]These contracts were originally approved by the Commission as cost-based contracts. *See Public Service Electric and Gas Company*, et al., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Fossil obtained market based rate authority covering sales from its generating units.

[5] Once Sewaren 7 begins commercial operation, PSEG Fossil plans to retire Sewaren 1, 2, 3 and 4.

Bridgeport 2 (179.5 MW)
Burlington 8 (18.6 MW
Burlington 9 (162.4 MW)
Burlington 11 (162.4 MW)
Edison 1 (167.4 MW)
Edison 2 (167.4 MW)
Edison 3 (167.4 MW)
Essex 10 (167.4 MW)
Essex 11 (167.4 MW)
Essex 12 (167.4 MW)
Mercer 3 (115.2 MW)
National Park (18.6 MW)
Sewaren 6 (115.2 MW)

In addition, PSEG Fossil, LLC notified PJM of its intent to retire Hudson 2 (659 MW nameplate rating) and Mercer Units 1 and 2 (652MW nameplate rating) by June 1, 2017.

PSEG Fossil satisfies most of the electricity needs of its plants from PJM under PJM's "station power" Tariff provisions. PSEG Fossil procures gas supply for its plants from PSEG ER&T and receives gas distribution service from PSE&G at a rate approved by the BPU on May 29, 2013.[6]

4. PSEG Power Connecticut LLC

PSEG Power CT is a Connecticut limited liability company and an EWG that owns and operates electric generation facilities in the State of Connecticut and is authorized to sell power at market-based rates.[7] Both of PSEG Power CT's generation facilities, Bridgeport Harbor and New Haven Harbor, are located in the State of Connecticut within the market administered by ISO-NE. PSEG Power CT sells the output of its generation facilities to its affiliate PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority. As noted above, PSEG Power CT is currently constructing Bridgeport 5, a 485 MW combined cycle unit in Bridgeport, Connecticut which is expected to be in service in 2019.

5. PSEG New Haven LLC

PSEG New Haven is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG New Haven owns and operates a facility (the "New Haven facility") in New Haven, Connecticut with a nameplate rating of 181 MWs. The New Haven facility is located within the New Haven Harbor generation station. The New Haven facility is interconnected to the adjacent United Illuminating East Shore Substation using a 115 KV underground cable. PSEG New Haven has no other

[6] BPU Docket No. GM12100935 (May 29, 2013).
[7] *Wisvest Corporation,* et al., 101 FERC ¶ 61,166 (2002).

generation assets. The commercial operation date for the New Haven facility was June 1, 2012 and PSEG New Haven has obtained MBR authority from FERC.[8]

The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[9] pursuant to a Connecticut statute that sought proposals for peaking generation in Connecticut.[10] All of the energy and capacity of the New Haven facility is sold into the ISO New England ("ISO-NE") markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA[11] has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder. The 181 MW nameplate rating of the New Haven Facility has not been included in the capacity controlled by PSEG for purposes of Dr. Morris' market power analysis.

6. PSEG Nuclear LLC

PSEG Nuclear is an EWG[12] and is authorized to sell power at market-based rates. PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission.[13] The assets of PSEG Nuclear are located entirely within PJM. PSEG Nuclear performed the following uprates since the last triennial filing: (1) an uprate of 120 MWs at its Hope Creek plant in 2014, which increased its nameplate rating to 1290 MWs, (2) an uprate to Peach Bottom 2 and 3 which increases PSEG's share of the nameplate MWs by 241 MWs for a updated nameplate of 704 MW for Peach Bottom 2 and 689 MWs for Peach Bottom 3.

7. Pavant Solar LLC, San Isabel Solar LLC and Bison Solar LLC

PSEG Power Ventures portfolio includes three (3) solar companies with market-based rate authority: (1) *Pavant Solar II LLC*[14] is a QF which owns a 50 MW (AC) solar facility in Fillmore Utah; (2) *San Isabel Solar LLC*[15] is a QF which owns a 30 MW (AC)

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[8] *PSEG New Haven LLC*, Docket No. ER12-1250-000, et al., (May 29, 2012).

[9] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control (DPUC). PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

[10] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

[11] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

[12] *PSEG Nuclear LLC*, 97 FERC ¶ 62,191 (November 30, 2001).

[13] *Public Service Electric and Gas Company*, et al., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Nuclear obtained market based rate authority from the FERC.

[14] *Pavant Solar II LLC*, Docket No. QF16-1072-000.

[15] *San Isabel Solar LLC*, Docket No. QF16-712-000.

solar facility in Las Animas County, Colorado and (3) *Bison Solar LLC*[16] is a QF which owns a 30 MW (AC) solar facility 25 miles north of Fort Collins, Colorado.

8. PSEG Energy Solutions LLC

PSEG Energy Solutions LLC ("PSEG Solutions") is a Delaware limited liability company and a direct subsidiary of PSEG ER&T. PSEG Solutions obtained market-based rate authority[17] and will operate within the PJM Interconnection, L.L.C. ("PJM"), New York Independent System Operator, Inc. ("NYISO") and ISO New England Inc. ("ISO-NE") markets. Energy Solutions will purchase power from the regional transmission organization ("RTO") at wholesale and sell it to retail customers. PSEG Solutions will not own or operate any generation assets. PSEG Solutions proposes to begin its retail business on January 1, 2017.

OTHER RELEVANT AFFILIATES

PSEG is also the direct or indirect parent of certain other subsidiaries engaged in energy related activities, as discussed below.

7. Affiliated Generation Ownership.

A list of the Applicants' affiliated domestic FERC jurisdictional generation assets owned is contained in Appendix B attached hereto. [18] Those additional subsidiaries of PSEG that may be considered relevant to this market power update for the Northeast Region are described below:

PSEG Power LLC ("PSEG Power") was formed in 1999 to acquire the former generation assets of PSE&G. PSEG Power, a Delaware limited liability company, does not directly own any generation facilities or engage in any FERC jurisdictional activities but is the parent company of several FERC jurisdictional entities, including Applicants PSEG ER&T (and it subsidiary PSEG Energy Solutions LLC), PSEG Fossil, PSEG Nuclear, PSEG Power CT, PSEG New Haven and PSEG Power Ventures LLC (which owns PSEG Solar Source LLC).

PSEG Power Ventures LLC and PSEG Solar Source LLC. PSEG Power Ventures LLC ("Power Ventures") is a Delaware Limited Liability company and a direct subsidiary of PSEG Power. PSEG Power Ventures owns 100% interest in PSEG Solar Source LLC and has an in-direct ownership interest in a domestic power plant in Hawaii. PSEG Solar Source owns approximately 349 MWs DC (274 MW AC) of solar capacity across the United States, including a combined 92

[16] *Bison Solar LLC*, Docket No. QF16-711-001.
[17] See Letter Order dated December 21, 2016 in Docket No. ER16-2725-000.
[18] Appendix B excludes generation assets located in Hawaii as well as generation assets in which PSEG's interest is limited to a leveraged lease interest.

MWs[19] (72 MW AC) of solar capacity in PJM and approximately the following amount of MWs in the following states all through separate project companies which have all obtained QF status.

- 15 MWs (12 MW AC) in Florida,
- 92 MWs in PJM (72 MW AC) – 12 MWs in Ohio, 2 MW in New Jersey, 15 MW in Delaware, 50 MW in North Carolina and 13 MW in Maryland
- 45 MWs in Arizona (34 MW AC) – 25 MW Queen, approximately 20 MW Badger
- 13 MWs (10 MW AC) in Texas,
- 34 MWs (25 MW AC) in California[20]
- 4 MWs (3 MW AC) in Vermont and
- 74 MW (60 MW AC) in Colorado (to be in operation in 2016) – 38 MWs for San Isabel and 36 MWs for Bison
- 62 MW (50 MW AC) in Utah (to be in operation in 2016).
- 10.5 MW (8 MW AC) in Oregon (to be in operation in 2016).

PSEG Resources LLC ("Resources") is a New Jersey limited liability company that provides energy infrastructure financing in developed countries. Resources invests primarily in energy-related financial transactions and manages a diversified portfolio of investments including leveraged leases. Resources owns interests, through leveraged leases, in various generation stations. Pursuant to the terms of these triple net leases, the lessee, not Resources, has all operational responsibility and control over the leased generation stations.

PSEG Power New York LLC ("PSEG Power NY") is a Delaware limited liability company and an EWG that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 750 MW combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a FERC-approved cost-based contract.[21]

[19] The 92MWs are attributed to four (7) separate project companies that have QF status: PSEG Solar Hackettstown LLC (2 MW); PSEG Solar Delaware LLC (15 MW), Rockfish Solar LLC (13 MWs) Meadows Solar (26 MW), Turkey Creek (17 MW) Hemlock Solar (7 MW) in North Carolina and PSEG Solar Ohio LLC (12 MW).

[20] The 28MWs (DC) are associated with the Shasta Solar Facility in California (4 MW), Whitehorn Solar (3 MWs) the Columbia Solar Project (19 MW). All have obtained QF status.

[21] *PSEG Power New York Inc.*, Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

PSEG Keys Energy Center LLC ("PSEG Keys") is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG Keys was formed to construct, operate and maintain the Keys Energy Center, a 755MW combined cycle power plant in Prince Georges County, Maryland. Construction began in 2015 and is expected to be completed in 2018 at which time the capacity will be available in the PJM market. All of the output of the Keys Energy Center will be sold to PSEG Keys affiliate, PSEG ER&T.

PSEG Long Island LLC ("Long Island") and Long Island Electric Utility Servco, LLC ("Servco") are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution system ("T&D") on Long Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither Long Island nor Servco will be FERC jurisdictional public utilities as neither will exercise ultimate decision making authority over the T&D system in Long Island. Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[22]

8. Affiliated Transmission Ownership

With the exception of the electric transmission assets owned by Applicant PSE&G, all of which are located within the PJM RTO, and the generation interconnection facilities owned by the various EWG and QF affiliates listed herein, the Applicants, nor their affiliates have any affiliates that own or operate FERC jurisdictional electric or natural gas transmission facilities within the United States[23]. As discussed below, FERC granted PSE&G a Hinshaw exemption in 1954, finding that it was exempt from the provisions of the Natural Gas Act.

B. JOINTLY OWNED FACILITIES

PSEG Nuclear is a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear is the operator of Salem and Exelon Generation is the operator of Peach Bottom.[24] PSEG Fossil is approximately a 23% joint owner in the Conemaugh and Keystone generating stations located in Pennsylvania. An affiliate of NRG Energy is the operator.[25] Accordingly, for

[22] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), *order dismissing request for rehearing*, 145 FERC ¶ 61,183 (2013).

[23] PSEG Power LLC is a 10% owner of the PennEast Pipeline Company LLC which has filed an application for approval to construct and operate a natural gas transmission line.

[24] A letter of concurrence supporting the allocation of plant output based on ownership interests is attached in Appendix E. The ownership percentages have not changed since the date of this letter. PSEG Nuclear owns a 50% interest in Peach Bottom and a 57.41% interest in Salem.

[25] A letter of concurrence supporting the allocation of plant output based on ownership interest is attached in Appendix E. The ownership percentages have not changed since the date of this letter.

purposes of this market power analysis, the capacity of Salem, Peach Bottom, Conemaugh and Keystone has been attributed to PSEG in accordance with PSEG's ownership interests in these facilities.

PSEG Fossil and Jersey Central Power and Light Company ("JCP&L") are each 50% co-owners of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to the unit. Accordingly, for the purpose of this market power analysis, the entire unit capacity – nominally 400 MWs – has been assigned to JCP&L.[26]

III. Applicants Fully Satisfy The Commission's Standards For Authority to Make Power Sales At Market-Based Rates.

The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, horizontal and vertical market power.[27] The Commission has also codified affiliate restrictions in its regulations which must be satisfied on an ongoing basis. In previous submissions for market-based rate authority the Applicants PSE&G, PSEG ER&T, PSEG Power CT, PSEG Fossil, PSEG Nuclear, and PSEG New Haven, demonstrated compliance with each of these requirements. As detailed herein and in the attached affidavit, the Applicants continue to meet these standards.

A. The Applicants Lack, Or Have Effectively Mitigated, Any Horizontal Market Power

In the MBR Order, the Commission established two indicative screens: a pivotal supplier screen based on the control area's annual peak demand and a wholesale market share screen applied on a seasonal basis. If an applicant passes both screens, there is a rebuttable presumption that the applicant does not possess horizontal market power. Each indicative screen is applied with respect to "relevant geographic markets" for an applicant's generating units.

Applicants located in ISOs/RTOs possessing sufficient market structure may consider the geographic region under the control of the ISO/RTO as the relevant default geographic region for purposes of completing their generation market power analyses.[28] However, where the Commission has previously found a "submarket" to exist within a boundary of an RTO, such finding is controlling as to the scope of the relevant geographic market for all generation units located within that submarket for the application of the indicative screens and any delivered price test that may be performed. The Commission further listed several such submarkets, including PJM East ("PJME"),

[26] A letter of concurrence supporting this determination is attached in Appendix E. The ownership percentages have not changed since the date of this letter.
[27] MBR Order, FERC Stats. & Regs. ¶ 31,252 at P 62, 399, 408, 440.
[28] *MBR Order at* PP. 231 and 235.

Connecticut and Southwest Connecticut.[29] Subsequent to the MBR order, in approving a merger between Exelon Corporation and Constellation Energy Group, Inc., the Commission identified additional submarkets in PJM - PJM East of 5004/5005 ("PJM50") and PJM East of AP South ("PJMAP") - that would be relevant to an MBR analysis for applicants in the Northeast Region.[30]

As discussed below and in the attached Affidavit of Dr. John Morris contained in Appendix A, Applicants have conducted market power analyses of the entire PJM RTO, the PJME, PJM50 and PJMAP submarkets, the entire NYISO, the entire ISO-NE, the Connecticut submarket and the Southwest Connecticut submarket for the study period. The results are set forth below.

1. Indicative Screens

a. Pivotal Supplier Analysis

The pivotal supplier analysis ("PSA") focuses on the ability of a seller to exercise unilateral market power.[31] The screen assesses whether market demand can be met during peak times without the applicant and its affiliates. If demand can be met without the applicant and its affiliates, the applicant passes that the PSA screen. The Affidavit of Dr. John Morris, attached hereto as Appendix A, finds that the Applicants pass the PSA screen for all relevant markets: PJM, NYISO, ISO-NE, Connecticut, Southwest Connecticut, PJMAP, PJME and PJM50.[32]

b. Wholesale Market Share Analysis

The wholesale market share analysis ("WMSA") is applied each season to determine whether an applicant has a dominant market position based on the total number of megawatts of uncommitted capacity owned or controlled by the applicant and its affiliates in relation to the uncommitted capacity of the entire relevant wholesale electricity market.[33] The established threshold is 20 percent; a supplier who has less than 20 percent market share in the relevant market for all seasons passes the WMSA screen.

In his Affidavit Dr. Morris finds that the Applicants pass the WMSA screen for PJM, NYISO, ISO-NE, Connecticut, Southwest Connecticut and PJMAP but do not pass the WMSA screen for the PJME and PJM50 submarkets.[34]

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[29] *Order No. 697* at P 236 (citing *Exelon Corp.*, 112 FERC ¶ 61,011, *reh'g denied*, 113 FERC ¶ 61, 299 (2005)). FERC eliminated the Northern PSEG zone as a default submarket in Order No. 697-A, P 99.

[30] Order Conditionally Authorizing Merger and Disposition of Jurisdictional Facilities, *Exelon Corporation, et al.*, 138 FERC ¶ 61,167 (2012).

[31] *AEP I* at P 72.

[32] *See* Morris Affidavit, at 15-29.

[33] *AEP I,* P 100.

[34] *See* Morris Affidavit, at 15-29.

c. Results of Indicative Screen Analysis

As shown in Dr. Morris's affidavit, Applicants therefore pass both indicative screen tests for PJM RTO, NYISO, ISO-NE, Connecticut and Southwest Connecticut and PJMAP. For PJME and PJM50, the Applicants pass the PSA but do not pass the WMSA.

2. Delivered Price Test Analysis For PJME and PJM50 Submarkets

In accordance with the MBR Order, applicants who fail either indicative screen test can rebut the presumption of market power through the submission of a delivered price test analysis ("DPT"). Applicants may submit this study at the same time that the results of the indicative screens are provided.[35] The DPT is based on two measurements of potential market power: economic capacity ("EC") and available economic capacity ("AEC"). EC is the capacity that can be delivered to a destination market for 105 percent or less than the market price. AEC is calculated by subtracting native load commitments from EC. Both calculations are performed for ten different season and load conditions.

In applying the DPT, "[a] showing of an HHI less than 2,500 in the relevant market for all season/load conditions for sellers that have also shown that they are not pivotal and do not possess a 20 percent or greater market share in any of the season/load conditions would constitute a showing of a lack of market power, absent compelling contrary evidence from intervenors."[36] However, while meeting these threshold benchmarks provides "safe harbor" protection, the Commission has found in numerous other cases that applicants lack market power even when they exceed one or more of the thresholds for particular study periods. As stated in *Public Service Company of New Mexico*, 115 FERC ¶ 61,090, P 38 (2006), "the Commission weights the results of both the economic and available economic capacity tests and considers the arguments of the applicant and intervenors." (footnote omitted.) [37]

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[35] *Order No. 697,* P 76.

[36] *Order No. 697* at P 111.

[37] Indeed, in that case, the applicant was deemed "on balance" to have adequately rebutted a showing of market power mitigation for the PNM control area where the results exceeded the 20% safe harbor in two cases under the AEC measure and in all 10 cases at values between 35% and 41% under the EC measure. *See, e.g.*, *Kansas City Power and Light Company, et al.*, Docket Nos. ER99-1005-011 et al. (August 12, 2010) (finding no market power where applicant had EC market shares in the 40-60% range and had significant HHI failures in the KCPL and GMO markets); *Cordova Energy Company LLC et al,* Docket Nos. ER99-2156-011, *et al.*, November 13, 2007 (finding no market power in case where applicant had EC market shares in PACE control area between 53.1% and 60.0%, HHIs between 2,958 and 3,696 and was pivotal in 8 out of 10 periods.); *PacifiCorp*, Letter Order, Docket Nos. ER97-2801-007, *et al.*, February 1, 2007; *Tucson Elec. Power Co.*, 116 FERC ¶ 61,051 (2006)(finding market power standard satisfied where applicant had EC market shares above 20% in all ten season/load periods in the Tucson control area, exceeded the 2,500 HHI threshold in eight periods, and was pivotal in 5 periods); *PacifiCorp*, 115 FERC ¶ 61,349 (2006) (finding that applicants rebutted presumption of market power in the PacifiCorp East control area where under available economic capacity measure, market share is less than 20% in 8 season/load periods and 28% in the summer and winter off-peak periods, HHI does not exceed 2500 in any season/load period and applicants are not pivotal); *Kansas City Power & Light Co.*, 113 FERC ¶ 61,074 (2005) (finding

a. Results of the DPT for PJM50 Submarket

For both the AEC and EC, PSEG passes all screens in all periods except for the pivotal supplier screen in the Summer Top 1% period.

b. Results of the DPT for PJME Submarket

With respect to AEC, PSEG passes all the screens in all 10 periods. With respect to the EC, PSEG passes the Market Concentration screens in all periods. It also passes the Pivotal Supplier Screen in 8 of 10 periods, and passes the Market Share Screen in 6 of 10 periods. PSEG's market shares are never above 25 percent. Although greater than the 20 percent screen, PSEG's market shares are well below the 35 percent threshold that is typically used for imputing unilateral market power.

3. Analysis of DPT Results

Based on his analysis of the overall results, Dr. Morris concludes that, although PSEG fails limited number of screens, the failures are substantially below levels that typically indicate market power. As set forth in his Affidavit, Dr. Morris states that:

> Although PSEG fails some screens in the PJME destination market, the overall results are not indicative of PSEG having market power. To begin, PSEG passes all the AEC screens and all market concentration (HHI) screens for EC. The HHI levels in all periods, capacity types, and areas are below the screening threshold of 2,500, and typically substantially below this level. In terms of the DPT for market rate authority and under the 2010 DOJ and FTC Horizontal Merger Guidelines, the market is not highly concentrated.[38] The low HHI levels mean that PSEG has little ability to exercise market power in coordination with other suppliers. It also passes all the AEC pivotal supplier screens, and most of the EC pivotal supplier screens. This means that typically PSEG's generation is not necessary to serve load; and when its generation is necessary, its forward sale commitments are sufficient so that its uncommitted generation is not necessary to serve the remaining load. Finally, PSEG's market shares are never above 15 percent in PJM50 and for AEC in PJM East. Its market shares for EC are never above 25 percent in PJM East. Although greater than the 20 percent screen, PSEG's market shares are

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no market power in the KCPL control area where applicant had EC market shares above 20% in all periods, exceeded the HHI 2,500 threshold in 5 of 10 periods and was pivotal supplier in 1 period); *Acadia Power Partners, L.P.*, 113 FERC ¶ 61,073 (2005) (finding no market power in the Cleco Power home control where, utilizing the EC measure, the applicant exceeded the thresholds set for all season/load periods using the market share measure, one season/load period using the market concentration measure, and for all season/load periods using the pivotal supplier measure).

[38] See U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Issued August 19, 2010, at Section 5.3, available at http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

well below the 35 percent threshold that is typically used for imputing unilateral market power.[39]

Dr. Morris's conclusion is consistent with Commission precedent finding a lack of market power in cases in which the DPT results included more instances of findings outside of the "safe harbor" thresholds and at higher levels than exist here.[40] In these circumstances, Dr. Morris's analysis successfully rebuts any inference of market power created by the WMSA screen failures for PJME.

4. Existing RTO/ISO Mitigation Rules Also Eliminate The Potential for Exercising Market Power In the PJME, PJME PJM50 and PJMAP Submarkets

PJM mitigation rules eliminate the potential for the exercise of market power in the PJME submarket. The MBR Order specifically contemplated that RTO/ISO mitigation rules may serve as evidence that any market power has been adequately mitigated. The Commission declared, "We believe the added protections provided in structured markets with market monitoring and mitigation generally result in a market where prices are transparent and attempts to exercise of market power will be sufficiently mitigated."[41] The Order on Rehearing went even further and specifically created a presumption that any potential market power had been adequately mitigated by an established and effective RTO market monitoring scheme.[42]

Taking account of the pervasive PJM mitigation rule, Dr. Morris concludes that these rules "fully address the potential for PSEG to exercise market power" in PJME.[43] Accordingly, PJM's mitigation schemes in place are sufficient to rebut any inference of market power created by the failure to pass the WMSA screens in PJME and PJM50.

In addition, in the Applicants' last triennial approval order, the Commission found that "the PJM market monitoring and mitigation rules are sufficient to address market power concerns in the PJM-East submarket."[44]

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[39] *See*, *e.g.*, U.S. Department of Justice, 1984 Merger Guidelines, at Section 3.12, available at https://www.justice.gov/sites/default/files/atr/legacy/2007/07/11/11249.pdf ("the Department is likely to challenge the merger of any firm with a market share of at least one percent with the leading firm in the market, provided the leading firm has a market share that is at least 35 percent.")

[40] *See Public Service Company of New Mexico*, 115 FERC ¶ 61,090 (2006) discussed above and cases discussed in fn. 38 above.

[41] MBR Order at P 241.

[42] Order No. 697A at P 111.

[43] Morris Affidavit, pp. 24-26.

[44] *See* October 14, 2014 letter order approving Applicants' prior triennial market update in Docket No. ER10-1789-003 et al. at page 3.

a. The Applicants Lack Transmission Market Power and Cannot Erect Entry Barriers.

In its previous order accepting PSEG's triennial market power analysis for the Northeast Region, the Commission found that the submittal satisfied the Commission's requirements for market-based rates regarding vertical market power.[45] There have been no subsequent changes in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. As demonstrated below, neither Applicants nor any of its affiliates are able to exercise vertical market power.

Applicants are not able to exercise transmission market power. Neither Applicants nor any of their affiliates, except PSE&G, own transmission assets in the U.S. other than incidental generator interconnection facilities. PSE&G owns transmission facilities in PJM but transmission service over those facilities is provided under the PJM Open Access Transmission Tariff.

In addition, neither Applicants nor their affiliates are able to exercise vertical market power in wholesale energy markets through affiliation, ownership or control of inputs to electric power production. As required by Section 35.37(e) of the Commission's regulations, Applicants provide the following information:

(1) PSE&G owns and operates a natural gas distribution system that receives interstate pipeline gas within the State of New Jersey and distributes that gas to its customers within the State of New Jersey. The distribution system consists of 18,050 miles of gas distribution pipe and an additional 62 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3 and peak-shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers. Service over such distribution facilities is made available pursuant to state regulated tariffs on an open access type basis. PSE&G was granted a Hinshaw exemption from the FERC in 1954.[46] The gas distribution rates paid by PSEG Fossil to PSE&G have been set at rates approved by the BPU in an order dated May 29, 2013.

(2) Certain of the Applicants and their affiliates own sites within the Northeast Region that would be suitable for future generating facilities. These include space at many of the existing generating sites of PSEG Fossil and at the sites of PSEG Power NY and PSEG Power CT. PSEG Nuclear's Salem facility may also be suitable for future construction. PSE&G also owns certain sites that would be suitable for generating facilities, but under New Jersey's Electric Discount and Energy Competition Act, N.J.S.A 48:3-43 et seq., PSE&G is effectively barred from owning and operating

[45] *Id.*
[46] 13 F.P.C. 1348 (1954).

generation except "on site" generation for supply and Class I renewable energy resources as defined in N.J.S.A. 48:3-98.1.

(3) Neither Applicants nor any of their affiliates own or control any physical coal supply resources or own or control who may access transportation of coal supplies.

(4) As required by section 35.37(e)(4) of the Commission's regulations, Applicants and its affiliates state that they have not erected barriers to entry into any market, including the PJM, NYISO or ISO-NE market and will not erect barriers to entry into any markets.

IV. REQUEST FOR CONFIDENTIAL TREATMENT

Under separate cover via UPS Overnight this office is submitting compact disks containing the workpapers of Dr. John Morris supporting his analysis in Appendix A, as required by the Commission's April 2004 Order.[47] The CD (of which six copies are included) contains: (i) proprietary information provided by Energy Velocity under an agreement that requires confidential treatment to be requested for these materials; (ii) modeling and computer programs that are the proprietary intellectual property of Economists Incorporated, the firm which employs Dr. Morris; (iii) commercially sensitive information about Applicants and their affiliates; and (iv) documents and information deemed to be confidential by PJM and ISO-NE. Accordingly, Applicants respectfully request confidential treatment for CD and the workpapers pursuant to 18 C.F.R. § 388.112 (2006), consistent with the confidential treatment accorded other applicants submitting such proprietary and commercially sensitive data.[48] Pursuant to the Commission's rules, the public version of this filing contains all materials submitted herein except for CD, which is labeled as "PRIVILEGED AND CONFIDENTIAL/NON-PUBLIC."

V. SERVICE

This filing has been served on all parties on the official service list as currently maintained by Commission in the above-referenced dockets. Applicants are also providing a copy to the New Jersey Board of Public Utilities and the New Jersey Division of Rate Counsel.

VI. ENCLOSURES

Applicants enclose the following:

- An original filing;

[47] AEP II, 107 FERC at P 61,087-88.

[48] *See, e.g., Idaho Power Company*, Docket No. ER97-1481-009 (February 3, 2006) (submission of revised Pivotal Supplier Screen and Market Share Screen calculations including similar data).

- Appendix A – Affidavit of Dr. John R. Morris;[49]
- Appendix B – List of Entities with Market-Based Rates Authority and Their Generation Assets. (This is an appendix listing the filing entities and all their energy affiliates and their associated assets);
- Appendix C – List of Entities with Market-Based Rate Authority and Their Transmission Assets;
- Appendix D – List of Long Term Power Purchase Agreements;
- Appendix E – Letters of concurrence regarding the control of certain jointly owned generation facilities;
- Appendix F – Form of notice suitable for publication in the Federal Register.

[49] Compact disks, as described above, containing the workpapers for the Affidavit of John R. Morris in Appendix A are being sent concurrently with this filing via UPS Overnight. As noted *supra*, privileged treatment is being requested for Dr. Morris's confidential workpapers submitted with the non-public version of this filing.

VII. CONCLUSION.

Applicants respectfully request the Commission

(i) to accept this market power compliance filing as meeting the Commission's requirements under Order No. 697 for the continuation of market-based rate authority for Applicants PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG New Haven LLC, PSEG Nuclear LLC, PSEG Fossil LLC, Pavant Solar II, LLC, Bison Solar LLC , San Isabel Solar LLC and PSEG Energy Solutions LLC;

(ii) to grant the request for confidential treatment; and

(iii) to grant such other relief or waivers as may be appropriate or necessary.

Respectfully submitted,

Public Service Electric and Gas Company
PSEG Energy Resources & Trade LLC
PSEG Power Connecticut LLC
PSEG Fossil LLC
PSEG Nuclear LLC
PSEG New Haven LLC
Pavant Solar II, LLC
Bison Solar, LLC
San Isabel Solar, LLC
PSEG Energy Solutions LLC

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Dated: December 28, 2016
Newark, New Jersey

Appendix A
Affidavit of
Dr. John R. Morris

Appendix B
List of Entities with Market-Based Rate Authority and Their Generation Assets

Appendix C
List of Entities with Market-Based Rate Authority and Their Transmission Assets

Appendix D
Long Term Power Purchase Agreements

Appendix E Letters of concurrence regarding the control of certain jointly owned generation facilities

Appendix F Form of notice suitable for publication in the Federal Register

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PSEG Energy Resources & Trade LLC	Docket No. ER99-3151-___
Public Service Electric and Gas Company	Docket No. ER97-837-___
PSEG Power Connecticut LLC	Docket No. ER03-327-_____
PSEG Fossil LLC	Docket No. ER08-447-_____
PSEG Nuclear LLC	Docket No. ER08-448-_____
PSEG New Haven LLC	Docket No. ER12-1250-___
Pavant Solar II LLC	Docket No. ER16-1926-____
San Isabel Solar LLC	Docket No.ER16-1925-____
Bison Solar LLC	Docket No.ER16-1924-____
PSEG Energy Solutions LLC	Docket No. ER16-2725-____

NOTICE OF FILING
( )

Take notice that on December 28, 2016: (i) PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG New Haven LLC, PSEG Fossil LLC, PSEG Nuclear LLC, Pavant II Solar LLC, Bison Solar LLC, San Isabel Solar LLC and PSEG Energy Solutions LLC tendered for filing their joint triennial market power update in compliance with Order No. 679 and with prior Commission Orders granting them market-based rate authority in Docket Nos. ER99-3151, ER97-837, ER03-327, ER08-447 ER08-448, DR-12-1250, ER16-1926, ER16-1925, ER16-1924 and ER16-2725 respectively.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR §§ 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file

electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).
Kimberly J. Bose
Secretary

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Public Service Electric and Gas Company	)	ER97-837-____
PSEG Energy Resources & Trade LLC	)	ER99-3151-____
PSEG Power Connecticut LLC	)	ER03-327-____
PSEG Fossil LLC	)	ER08-447-____
PSEG Nuclear LLC	)	ER08-448-____
PSEG New Haven LLC	) Docket Nos.	ER12-1250-____
Pavant II Solar LLC	)	ER16-1926-____
Bison Solar LLC	)	ER16-1925-____
San Isabel Solar LLC	)	ER16-1924-____
PSEG Energy Solutions LLC	)	ER16-2725-____

Report & Affidavit of
Dr. John R. Morris

December 22, 2016

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Public Service Enterprise Group Incorporated Northeast Region Market Power Study

1. Introduction

My name is Dr. John R. Morris. I am a Principal at Economists Incorporated, an economic consulting firm located at 2121 K Street, NW, Washington, DC 20037. I have a bachelor's degree in economics from Georgetown University, and I have a master's degree and a Ph.D. in economics from the University of Washington. I have been studying and consulting within energy industries since joining the Federal Trade Commission in 1985. Since joining Economists Incorporated in 1992, I have consulted on many mergers involving electric and gas companies, examined competitive issues relating to utility rates, provided market power studies for applications for market-based rate authority, and studied market power issues in state restructuring proceedings. I have published articles on competition and energy matters, and I have spoken on numerous occasions concerning competition in natural gas, electric power and other industries. I have previously been accepted as an expert witness on energy matters before the Federal Energy Regulatory Commission ("FERC" or "Commission"), state commissions and in federal court. A complete listing of my experience, publications and testimony is contained in my resume, presented in Exhibit PEG-2.

Public Service Enterprise Group Incorporated ("PSEG") asked that I prepare a market power study for its subsidiaries that have market-based rate authority in the Northeast Region.[1] These subsidiaries are: Public Service Electric and Gas

[1] The Northeast Region includes ISO-New England Inc. ("ISO-NE"), Connecticut, Southwest Connecticut, New York Independent System Operator, Inc. ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), PJM East, PJM East of 5004/5005 and PJM East of AP South.

("PSE&G"), PSEG Energy Resources & Trade LLC ("PSEG ER&T"), PSEG Fossil LLC ("PSEG Fossil"), PSEG Nuclear LLC ("PSEG Nuclear"), PSEG Power Connecticut LLC ("PSEG Power CT"). PSEG New Haven LLC ("PSEG New Haven") Pavant II Solar LLC, Bison Solar LLC and San Isabel Solar LLC.[2] The purpose of this study is to determine whether these PSEG entities have market power in any Northeast Region market under the Commission's Pivotal Supplier Analysis ("PSA") and Wholesale Market Share Analysis ("WMSA") screens as articulated in FERC Order No. 697 and if the Applicants do fail any of the screens, whether they otherwise lack market power under the Delivered Price Test ("DPT") or are subject to sufficient mitigation to guard against any market power concerns.[3]

PSEG

PSEG is a public utility holding company headquartered in in Newark, New Jersey. Through its subsidiaries, PSEG engages in the generation, transmission, distribution and sale of electric energy, and distribution and sale of natural gas to commercial, residential, and industrial customers primarily in the Northeastern and Mid-Atlantic United States. PSEG, through its subsidiaries, owns approximately 11,300 MW of seasonal generation capacity located in the Northeast Region.[4]

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[2] Pavant II Solar LLC, Bison Solar LLC and San Isabel Solar LLC all have QF status.

[3] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 119 FERC ¶ 61,295, ("Order No. 697" or "MBR Order"), *order clarifying final rule*, 121 FERC ¶ 61,260 (2007) ("MBR Clarifying Order"), *order on reh'g and clarification*, 123 FERC ¶ 61,055 (2008) FERC Stats. & Regs ¶ 31,268 ("Order No. 697-A"), *order on reh'g and clarification*, 124 FERC ¶ 61,055 (2008) ("SIL Allocation Order").

[4] *See* Exhibit PEG-3 (accounting for retirements).

PSE&G

PSE&G is a public utility operating company engaged primarily in the transmission of electricity and the provision of gas and electric distribution service in the State of New Jersey. It is New Jersey's oldest and largest investor-owned utility. PSE&G was founded in 1903 and is based in Newark, New Jersey. It is a member of the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization and has made all of its transmission facilities available for open access transmission service pursuant to the PJM Open Access Transmission Tariff ("OATT") administered by PJM. The company also owns and operates 18,050 miles of gas distribution pipe and an additional 62 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3. During the study period, PSE&G owned less than 140 MW of solar generation, 8 MW of Energy Efficiency and 91 MWs of Demand Response but otherwise did not own or operate any electric generation facilities.

PSEG ER&T

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil and PSEG Nuclear, each wholly-owned subsidiaries of PSEG Power LLC ("PSEG Power"), as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission. PSEG ER&T also makes wholesale sales of natural gas.

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

BGS Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 *et seq.,* which initiated the transition from a regulated to a competitive retail power market in New Jersey, the New Jersey Board of Public Utilities ("BPU") annually approves statewide auctions to determine the entities that will supply Basic Generation Service ("BGS") in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSE&G's affiliate, PSEG ER&T, has participated directly in all of the auctions for BGS supply held since 2004 and has consistently won tranches in those auctions, including auctions for BGS service within the franchised service territory of PSE&G.

BGSS Gas Contract. By order issued April 16, 2002, the BPU approved a full requirements contract for the provision of gas supply by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the BPU, PSEG ER&T assumed, through capacity release, PSE&G's FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract, which currently remains in effect, provides for annual renewals unless terminated by either party on 12 months' advance written notice.

LIPA Fuel Supply. On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which

ER&T provides fuel supply and power supply management activities for LIPA as of January 1, 2015.

PSEG Fossil

PSEG Fossil owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission under the umbrella of PSEG Fossil's market-based rate authority.[5] The assets of PSEG Fossil are located entirely within PJM.[6] Since the last triennial filing in 2013, PSEG Fossil has retired approximately 1,800 MW of capacity in the eastern portion of PJM. Much of this capacity was retired at the end of May 2015. We included this capacity in the Winter and Spring season screens and exclude the capacity for the Summer and Fall screens.

PSEG Fossil is approximately a 23 percent joint owner of interests in the Conemaugh and Keystone generating stations located in Pennsylvania. An affiliate of NRG Energy is the operator.[7] PSEG Fossil is a 50 percent co-owner with Jersey Central Power and Light Company ("JCP&L") of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to

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[5] *Public Service Electric and Gas Company, et al*., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000).

[6] PSEG Fossil's subsidiaries PSEG Power Connecticut LLC, PSEG New Haven LLC and PSEG Power New York LLC own generation units in Connecticut and New York respectively.

[7] A letter of concurrence supporting the allocation of these facilities' output based on ownership interests is attached in our workpapers.

the unit. Accordingly, for the purpose of this market power analysis, the entire unit capacity, nominally 400 MWs, has been assigned to JCP&L.[8]

PSEG Power CT

PSEG Power CT owns the Bridgeport Harbor and New Haven Harbor generation facilities located in the state of Connecticut within ISO-NE and is authorized to sell power at market-based rates.[9] The output of these facilities is sold to PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority. PSEG Power CT is currently constructing Bridgeport 5, a 485 MW gas-fired combined cycle in Bridgeport, Connecticut, which is expected in service in 2019.

PSEG New Haven

PSEG New Haven owns and operates the New Haven facility, a gas-fired plant located in New Haven, CT that entered service in June 2012 with a nameplate capacity of 181.5 MW. The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[10] pursuant to a Connecticut statute that sought proposals for peaking generation in Connecticut.[11] All of the energy and capacity of the New Haven facility is sold

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[8] A letter of concurrence supporting the allocation of this facility's output to JCP&L is attached in our workpapers.

[9] *Wisvest Corporation, et al*., 101 FERC ¶ 61,166 (2002).

[10] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control (DPUC). PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

[11] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

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into the ISO-NE markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder.[12] As such, neither PSEG New Haven nor any other PSEG affiliate has operational control of the New Haven facility. As a result, the capacity of the facility is not attributable to PSEG for the purpose of this market power analysis.

PSEG Nuclear

PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission in accordance with PSEG Nuclear's market-based rate authority.[13] PSEG Nuclear is the owner of Hope Creek and a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear operates the Salem plant and Exelon Generation is the operator of Peach Bottom.[14] Since the last triennial filing, uprates at Peach Bottom and Hope Creek plants have increased PSEG Nuclear's capacity at those facilities.

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[12] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

[13] *Public Service Electric and Gas Company, et al*., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000).

[14] A letter of concurrence supporting the allocation of plant output based on ownership interests is attached in our workpapers.

Other Subsidiaries

PSEG is also the direct or indirect parent of certain other subsidiaries engaged in energy related activities in the United States. Those additional subsidiaries of PSEG that may be considered relevant to this market power update for the PJM region are as follows.

PSEG Power LLC is a Delaware limited liability company. It does not directly own any generation facilities or engage in any FERC jurisdictional activities but it is the parent company of several FERC jurisdictional entities, including applicants PSEG ER&T, PSEG Fossil and PSEG Nuclear.

PSEG Power Ventures LLC ("Power Ventures") is a Delaware Limited Liability company and a direct subsidiary of PSEG Power. PSEG Power Ventures owns 100% interest in PSEG Solar Source LLC and has an in-direct ownership interest in a domestic power plant in Hawaii. PSEG Solar Source owns approximately 349 MWs DC (274 MW AC) of solar capacity across the United States, including a combined 92 MWs (72 MW AC) of solar capacity in PJM.[15] All of PSEG Solar Source's solar capacity has obtained QF status. Because all of this capacity is QF capacity, per Order No. 816 this capacity is not included in the market power analyses.[16]

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[15] The 42MWs are attributed to four (7) separate project companies that have QF status: PSEG Solar Hackettstown LLC (2 MW); PSEG Solar Delaware LLC (15 MW), Rockfish Solar LLC (13 MWs) Meadows Solar (26 MW), Turkey Creek (17 MW) Hemlock Solar (7 MW) in North Carolina and PSEG Solar Ohio LLC (12 MW).

[16] *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 816, 80 *Fed. Reg*. 67056 (2015), FERC STAT & REGS ¶ 31,374, P55 (2015), *reh'g denied and clarification*, Order No. 816-A, 155 FERC ¶ 61,188 (2016) ("… qualifying facilities that are exempt from FPA section 205 and facilities that are behind-the-meter facilities do not need to be reported in the asset appendix or indicative screens." (note omitted))

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PSEG Resources LLC ("Resources") is a New Jersey limited liability company that provides energy infrastructure financing in developed countries. PSEG Resources invests primarily in energy-related financial transactions and manages a diversified portfolio of investments including leveraged leases. PSEG Resources owns interests, through leveraged leases, in various generation stations. Pursuant to the terms of these triple net leases, the lessee, not Resources, has all operational responsibility and control over the leased generation stations.

PSEG Power New York LLC ("PSEG Power NY") is a Delaware limited liability company that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 750 MW combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a cost-based contract.[17]

PSEG Keys Energy Center LLC ("PSEG Keys"), direct subsidiary of PSEG Fossil, was formed to construct, operate, and maintain the Keys Energy Center, a 755 gas-fired combined cycle facility located in Prince George's County, Maryland. Construction began in 2015 and is scheduled to be completed in 2018. All the capacity and energy from PSEG Keys will be sold to PSEG ER&T.

PSEG Energy Solutions LLC ("PSEG Solutions") is a direct subsidiary of PSEG ER&T that is schedule to begin retail operations in the Northeast Region in

[17] *PSEG Power New York Inc.,* Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

January 2017. It has obtained market-rate authority to allow it to sell excess energy in wholesale markets.[18]

PSEG Long Island LLC ("Long Island") and Long Island Electric Utility Servco, LLC ("Servco") are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution ("T&D") system on Long Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither Long Island nor Servco are FERC jurisdictional public utilities, as neither will exercise ultimate decision making authority over the T&D system in Long Island. Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[19]

When an applicant has affiliates in the relevant market, the Commission considers the combined capacity of all the affiliated entities in its market power assessment.[20] Accordingly, I have included the capacity controlled by PSE&G, PSEG ER&T, PSEG Power CT, PSEG Fossil, PSEG Nuclear, and PSEG Power New York (which on a combined basis constitutes the capacity of all of PSEG's affiliates not excluded for a reason explained above). Future references in this Affidavit to PSEG are inclusive of the foregoing entities.

The primary purpose of this study is to determine whether PSEG passes the PSA and WMSA screen thresholds in ISO-NE, the NYISO and PJM. In the PSA, the Commission requires applicants to examine whether the generation owned by

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[18] *See* December 21, 2016 letter order approving Energy Solutions request for market-based rate authority in Docket No. ER16-2725-000.

[19] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), order dismissing request for rehearing, 145 FERC ¶ 61,183 (2013).

[20] *Heartland Energy Services, Inc.,* 68 FERC ¶ 61,223 at 62,061-62,062 (1994).

the applicant is necessary to serve wholesale demand within a balancing authority area. The applicant first calculates the total generation capacity for an area. This is the total of generation in the balancing authority area plus the import capability to the area.[21] From this total, the applicant subtracts out firm contractual commitments, native load obligations, and operating reserves, giving uncommitted capacity for the area. Net uncommitted capacity is calculated by subtracting a wholesale load proxy from uncommitted capacity. Net uncommitted capacity is then compared to the applicant's uncommitted capacity within the area. When the applicant's uncommitted capacity is less than the net uncommitted capacity for the area, then all wholesale demand could be served without energy from the applicant and the applicant passes the PSA screen. When the applicant's uncommitted capacity is greater than the net uncommitted capacity, then the applicant does not pass the screen because its capacity is necessary to meet wholesale peak loads in the market.

In the WMSA, the Commission requires applicants to examine whether the generation owned by the applicant is 20 percent or more of the uncommitted capacity in each of four seasons under average daily peak conditions for the season. The applicant first calculates the total generation capacity for an area. The applicant then adds the import capability to the area. From this total, the applicant subtracts out planned outages and deratings, long-term firm contractual commitments, native load obligations, and operating reserves. The sum gives the total uncommitted capacity. The applicant then calculates its share by dividing its uncommitted capacity by the total uncommitted capacity. When the applicant's share is less than 20 percent, the applicant passes the WMSA screen.

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[21] Import capability is the lesser of either the simultaneous import limit ("SIL") into the area or available capacity in interconnected balancing authority areas. Available capacity is equal to total generation capacity in an area less outages and derating, a native load proxy and operating reserves.

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The Commission presumes that an applicant does not have market power when it passes both the PSA and WMSA screens. If the applicant fails either of the screens, then the applicant may present other analyses to demonstrate that it does not possess market power. Alternatively, the applicant may propose mitigation measures or accept the Commission's default mitigation measures to demonstrate that it has mitigated market power.

2. New England

2.1. Overview of Electric Power Markets in New England

New England operates a competitive wholesale power market. Substantial restructuring has taken place in New England, and many of the vertically integrated utilities have sold either most or all of their generation assets. The traditional utilities often have standard offer obligations to serve retail customers, but utilities often fulfill these obligations by securing supplies in competitive wholesale markets. For example, a utility may secure contracts in which the supplier agrees to provide power for 30 percent of the utility's standard offer obligation. The transmission system is managed by ISO-NE. The market has a market monitor and market power mitigation program in place to identify and to mitigate any potential exercise of market power.

2.2. Geographic Markets

In the case of generation wholly located in an RTO, such as ISO-NE, the Commission accepts the RTO as the relevant destination market.[22] When the Commission has identified a sub-market within an RTO, the applicant must also provide market power screens for the relevant sub-markets.[23] In New England,

[22] Order No. 697 at PP 231, 235.

[23] Order No. 697 at P 236.

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the Commission has identified two submarkets: Connecticut and Southwest Connecticut.[24] PSEG owns the Bridgeport Harbor plant in Southwest Connecticut. PSEG also owns the New Haven Harbor 1 unit in Connecticut and PSEG New Haven owns the New Haven facility. When the applicant does not own the transmission system, as in the instant case, the applicant needs to provide an analysis only for the balancing authority area to which the generation is interconnected.[25] Accordingly, the PSA and WMSA are provided for the ISO-NE balancing authority area, and also for Connecticut and Southwest Connecticut.

2.3. Data Sources and Analysis

The data source for generation is ISO-NE Seasonal Claimed Capability (SCC) Reports.[26] Summer and winter capacities were taken from the November 2015 report. Planned outages are from the ISO-NE Form 714. Planned outages for Connecticut and Southwest Connecticut are prorated based on their shares of the total generation capacity in ISO-NE. PSEG's generation capacity in ISO-NE consists of the New Haven facility, New Haven Harbor and Bridgeport Harbor. PSEG's Northeast Region generation facilities are presented in Exhibit PEG-3.

Load data for ISO-NE are from Energy Velocity. Energy Velocity also provides load data by New England ISO zone, thus loads are calculated by sub-market as well. PSEG load obligations in New England come from PSEG's agreements to supply standard offer generation within Rhode Island. The data were supplied by PSEG.

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[24] *Id*.

[25] Order No. 697 at footnotes 215, 217.

[26] See http://www.iso-ne.com/genrtion_resrcs/snl_clmd_cap/index.html.

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Import capability was taken from the ISO-NE's December 20, 2016 FERC filing.[27] This report indicates that the simultaneous transfer limits in all seasons is 4,548 MW for the ISO-NE as a whole, 3,050 MW for Connecticut, and 2,370 (Spring) to 3,200 MW (Summer) for Southwest Connecticut. PSEG has no firm transmission rights into New England.

Operating reserves are calculated as follows. ISO-NE Operating Procedure No. 8 specifies spinning reserves (or 10-minute reserves) equal to the size of the loss of the largest unit times a Contingency Reserve Adjustment Factor ("CRAF").[28] The CRAF in 2015 was 1.25.[29] The largest unit is the 1,400 MW (summer capacity) Seabrook Unit 1. In addition, 30-minute reserves require capacity to cover 50 percent of the loss of a second contingency (i.e., the second largest unit) plus 160 MW for daylight-savings time periods and 180 MW during standard time (i.e., winter). The second largest unit is the 1,200 MW (summer capacity) Millstone Unit 3. Thus, in total, operating reserves are 2,510 MW in summer.[30] Operating reserves for Connecticut and Southwest Connecticut are based on resource needs in forward reserve auctions for 2015.[31]

2.4. Results

Exhibit PEG-4 summarizes the results for the PSA and the WMSA in New England. Exhibit PEG-5 shows the calculations to determine whether PSEG is a

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[27] ISO New England Inc. Simultaneous Import Limit for 2015, *Guidance on Simultaneous Transmission Import Limit Studies*; Docket No. AD10-02, December 20, 2016.

[28] ISO New England Operating Procedure No. 8, at 5-6, available at https://www.iso-ne.com/participate/rules-procedures/operating-procedures.

[29] ISO New England, Inc. 2015 Regional System Plan ("Regional System Plan"), available at https://www.iso-ne.com/static-assets/documents/2015/11/rsp15_final_110515.docx, at 68.

[30] 2,510 MW = 1,400 MW x 1.25 + 50% x 1,200 MW + 160.

[31] ISO New England, Inc. 2015 Regional System Plan ("Regional System Plan"), available at https://www.iso-ne.com/static-assets/documents/2015/11/rsp15_final_110515.docx, Table 4.12 at p.70.

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pivotal supplier in the three New England destination markets. PSEG passes the PSA screen in all areas. Exhibit PEG-6 presents the WMSA results for the destination areas in New England. PSEG easily passes the WMSA in all areas.

3. New York

3.1. Overview of Electric Power Markets in New York

New York also has a competitive wholesale power market. Substantial restructuring has taken place in New York, and the investor-owned vertically integrated utilities have sold either most or all of their generation assets. These utilities often have standard offer obligations to serve retail customers, and utilities can fulfill these obligations by securing supplies in competitive wholesale markets. The transmission system is operated by the NYISO, which also operates a competitive wholesale market. The market has a market monitor and market power mitigation program in place to identify and to mitigate any potential exercise of market power.

3.2. Geographic Markets

In the case of generation wholly located in an RTO such as the New York ISO, the Commission has accepted the RTO as the relevant destination market.[32] PSEG only owns generation in Albany, New York. In addition, when the applicant does not own the transmission system, as in the instant case, the applicant needs to provide an analysis only for the balancing authority area to which the generation is interconnected.[33] Accordingly, the PSA and WMSA are provided for the NYISO only.

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[32] Order No. 697 at PP 231, 235.

[33] Order No. 697 at footnotes 215, 217.

3.3. Data Sources and Analysis

The principal data source for generation is the Energy Velocity Market-Operations database. Planned outages are from the FERC Form 714. PSEG's generation capacity in New York consists of its ownership of the Bethlehem Energy Center in Albany, which has winter capacity of 845 MW. Information for PSEG's Northeast Region generation is presented in Exhibit PEG-3.

Load data for NYISO were downloaded from Energy Velocity.

Import capability comes from the most recent NYISO SIL filing as of December 19, 2016.[34] This filing indicates that ISO simultaneous import capability ranges from 6,850 MW in spring to 7,695 MW in summer. NYISO does not recognize physical imports, accordingly, all the SIL import capability is allocated pro rata, except for a 265 MW reservation that PSEG has from PJM to New York on the Linden VFT DC transmission line.

Operating reserves are calculated as follows. The NYISO Locational Reserve Requirements specify 30-minute total reserves equal to twice the 10-minute reserve necessary to replace the operating capability loss caused by the most severe contingency under normal transfer conditions. Thus, the operating reserves for the NYISO are 2,620 MW for each season.[35]

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[34] New York Independent System Operator, Inc., *Informational Filing Regarding the Simultaneous Import Limitation Study*, Docket No. AD10-2, December 19, 2016.

[35] NYISO Locational Reserve Requirements, Table 2, available at http://www.nyiso.com/public/webdocs/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf

3.4. Results

Exhibit PEG-7 shows the calculations to determine whether PSEG is a pivotal supplier in New York, and PSEG passes the PSA screen. Exhibit PEG-8 presents the WMSA results for New York, and PSEG easily passes the WMSA.

4. PJM

4.1. Overview of Electric Power Markets in PJM

PJM operates a competitive wholesale power market and serves as the regional RTO for an area that covers all or parts of 13 states and the District of Columbia. PJM also plans and operates the transmission system within the RTO. Monitoring Analytics acts as the market monitor, and has a market power mitigation program in place to identify and mitigate any potential exercise of market power.

4.2. Geographic Markets

PSEG owns both generation and transmission facilities in PJM. In the case of generation wholly located in an RTO such as PJM, the Commission has accepted the RTO as the relevant destination market.[36] When the Commission has identified a sub-market within an RTO, the applicant must also provide market power screens for the relevant sub-markets.[37] In PJM, the Commission has identified three submarkets: PJM East ("PJME"), PJM East of 5004/5005 ("PJM50") and PJM East of AP-South ("PJMAP").[38] The PSA and WMSA are provided for PJM and for the PJME, PJM50 and PJMAP sub-markets.

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[36] Order No. 697 at PP 231, 235.

[37] Order No. 697 at P 236.

[38] *Id*. *See also* Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, Order No. 697-A, 73 FR 25832 (May 7, 2008), FERC

4.3. Data Sources and Analysis

The principal data source for generation is the Energy Velocity Market-Ops database. Generation within PJM was assigned to submarket consistent with the definitions in PJM's SIL Study.[39] Planned outages are from the FERC Form 714. In addition, for the sub-market analysis, planned outages were allocated to PJME based on the share of total PJME generation, by season. Information for PSEG's generation in PJM and PJME is presented in Exhibit PEG-3.

Load data for PJM was downloaded from Energy Velocity. Energy Velocity also provides load data by PJM zone, thus loads are calculated for the PJM sub-markets as well.

Import capability was taken from the 2015 Simultaneous Import Limit Study Report.[40] This report indicates simultaneous transfer limits of 11,997 MW in the winter and 7,600 MW in summer. Additionally, this report indicates transmission capabilities of the PJM sub-markets. The report conservatively uses the reported SIL as the SIL amount to be allocated pro rata. This is a simplifying assumption because PSEG has no firm transmission reservations into PJM and it effectively excludes the additional 8,500 MW of firm reservations into PJM in the base case of the SIL study.

Stats, & Regs. ¶ 31,268 (2008) at P 90; Order Conditionally Authorizing Merger and Disposition of Jurisdictional Facilities, *Exelon Corporation, et al.*, 138 FERC ¶ 61,167 (2012).

[39] PJM Interconnection, L.L.C., *Informational Filing of 2015 Simultaneous Import Limit Study Report for PJM Region*, Docket No. AD1-2-007, September 2, 2016, Accession No. 20160902-5155.

[40] *Id*.

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Operating reserves are calculated according to PJM Manual 13 as the sum of Day Ahead Scheduling Reserves (Operating), Contingency (Primary) and Synchronized (Spinning Reserve) Requirements.[41]

Data on PSEG's long-term contracts come from PSEG. The contracts were included in the area where the energy is delivered under the contract. For contracts delivered to the Western Hub in PJM, the contracts were included in the PJM, PJM50, and PJMAP destinations and not the PJME destination.

4.4. Results

Exhibit PEG-9 summarizes the results for the PSA and the WMSA in PJM. Exhibit PEG-10 shows the calculations to determine whether PSEG is a pivotal supplier in the four PJM destination markets. PSEG passes the PSA screen for all four destinations. Exhibit PEG-11 presents the WMSA results for the destination markets in PJM. PSEG easily passes the WMSA in PJM and PJM east of AP South, but has greater than a 20 percent market share in the PJM East and PJM East of 5004/5005 destination markets.

5. Delivered Price Test

When an applicant does not pass either the PSA or WMSA for a destination market, the Commission invites the applicant to provide additional information via a delivered price test ("DPT"). PSEG requested that I perform a DPT for the PJM East and PJM East of 5004/5005 sub-markets. Accordingly, I now discuss the DPT for these sub-markets.

[41] PJM Manual 13 - Emergency Operations, at 17, available at http://pjm.com/~/media/documents/manuals/m13.ashx

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5.1. Overview of the DPT

The DPT utilizes substantially more information than the PSA or the WMSA, including additional information on generation ownership, generation costs, demand conditions, and transmission limits. The Commission considers two types of capacity: Economic Capacity ("EC") and Available Economic Capacity ("AEC"). EC is the capacity that can be delivered to a destination market for 105 percent or less than the market price. AEC is calculated by subtracting load commitments from EC. EC and AEC are calculated for a number of different seasonal and load conditions.

Because we do not know the firm retail obligations of the competitive suppliers, as explained below, the AEC calculation is based on the assumption that market participants serve load in proportion to their generation capacity and that 70 percent of load obligations are contracted more than one year from delivery.

For both the EC and AEC measures, the Commission prescribes three screens: (1) a pivotal supplier screen; (2) a market share screen; and (3) a Herfindahl-Hirschman Index ("HHI") screen. The HHI is the sum of the squared market shares of the firms in the market. So a market with four firms of market shares of 40, 30, 20, and 10 percent would have an HHI of 3,000 (this is calculated as $40^2 + 30^2 + 20^2 + 10^2 = 1,600 + 900 + 400 + 100 = 3,000$). A monopolist would produce a HHI of 10,000 and 10 equally-sized firms would produce a HHI of 1,000.

Although the Commission has not drawn bright lines for its review of DPT results, it has given general guidance. When (1) the applicant is not pivotal; (2) the applicants' market share is less than 20 percent; and (3) the HHI is below 2,500, the Commission is likely to conclude that the applicant does not have market power. The three standards establish a "safe harbor" for lack of market power, unless intervenors present clear and convincing contrary evidence. The Commission has also determined in some cases that an applicant did not have

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market power when the analysis showed isolated HHI and market share results above screening levels. Finally, despite the DPT results, the Commission may conclude that an applicant does not have market power if other evidence, such as historical sales data, indicates that the DPT results do not reflect the actual competition in the marketplace.

A detailed description of data sources and methods to prepare the data for the DPT is presented in Exhibit PEG-12. An overview of the sources and methods used at Economists Incorporated for conducting the DPT is presented here.

The DPT is calculated for 10 representative periods, three for each of three seasonal conditions plus a summer super peak period. The three seasons are spring/fall, summer, and winter. Each season is divided into (1) top 10 percent of peak hours; (2) remaining peak hours; and (3) off-peak hours. In addition, there is a summer super peak period which is comprised to the top 1 percent (10 hours) of summer peak hours. These ten periods cover the range of load conditions for each season, and for the year as a whole.

The primary source for generation data is Energy Velocity. In addition to generation capacity, Energy Velocity provides data on ownership (including holding companies), fully-loaded heat rates, emission rates, and generation availability. Generation is included for all of PJM and NYISO, which is the only first-tier balancing authority area in which PSEG owns generation. Unit capabilities are derated to account for seasonal maintenance and likely plant unavailability due to forced outages. Because demand in PJM peaks in summer and winter, the planned outages are assumed to be during the spring/fall season.

The transmission system is represented by contract paths between balancing authority areas and within PJM. Limits between regions in PJM are from Energy Velocity.

Market prices come from hourly prices reported by PJM.

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As in the PSA and WMSA, load data come from Energy Velocity. To compute load requirements for market participants, we apportion the total load in each market area in New York and PJM to all suppliers in proportion to their respective generation capacities. We assumed 70 percent of load is committed for a year or longer and the remaining 30 percent is contracted for shorter periods.[42] To account for their greater load obligations, we assume that Dominion, which does not operate in a restructured retail market, has 100 percent responsibility for its allocation of load and that AEP, which operates in a partly restructured retail market, has 90 percent of its allocation as opposed to the standard 70 percent.

The DPT and market share calculations were calculated using the Power Acquisition Screening System developed at Economists Incorporated. The mathematical details are presented in Exhibit PEG-13.

5.2. Results of the DPT for PJM50 Sub-market

The results of the DPT for PJM50 are presented in Exhibit PEG-14. The top part of the exhibit shows the results for AEC. PSEG passes the Pivotal Supplier Screen in all 10 periods. PSEG also passes both the Market Share Screens and the HHI Screens in all 10 periods.

The lower part of Exhibit PEG-14 shows the results for EC in PJM50. PSEG passes all the screens in all the periods, except for the pivotal supplier screen in the Summer Top 1% period.

[42] This is a reasonable estimate for the long-term load coverage since this number is generally between 60 and 80 percent for most generation suppliers in restructured markets.

5.3. Results of the DPT for PJME Sub-market

The results of the DPT for PJME are presented in Exhibit PEG-15. The top part of the exhibit shows the results for AEC. PSEG passes all the screens for AEC.

The lower part of Exhibit PEG-15 shows the results for EC in PJME. PSEG passes the Market Concentration screens in all periods. It passes the Market share screens in six of ten periods, and its market share is never more than 25 percent. It passes the pivotal supplier screen in eight of ten periods.

5.4. Analysis of the DPT Results

Although PSEG fails some screens, the overall results are not indicative of PSEG having market power. To begin, PSEG passes all the AEC screens and all market concentration (HHI) screens for EC. The HHI levels in all periods, capacity types, and areas are below the screening threshold of 2,500, and typically substantially below this level. In terms of the DPT for market rate authority and under the 2010 DOJ and FTC Horizontal Merger Guidelines, the market is not highly concentrated.[43] The low HHI levels mean that PSEG has little ability to exercise market power in coordination with other suppliers. It also passes all the AEC pivotal supplier screens, and most of the EC pivotal supplier screens. This means that typically PSEG's generation is not necessary to serve load; and when its generation is necessary, its forward sale commitments are sufficient so that its uncommitted generation is not necessary to serve the remaining load. Finally, PSEG's market shares are never above 15 percent in PJM50 and for AEC in PJM East. Its market shares for EC are never above 25 percent in PJM East. Although greater than the 20 percent screen, PSEG's

[43] See U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Issued August 19, 2010, at Section 5.3, available at http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

market shares are well below the 35 percent threshold that is typically used for imputing unilateral market power.[44]

5.5. Mitigation

PJM has a Commission-approved market monitoring and mitigation plan in place to ensure that generation facilities cannot exercise market power. The Commission has stated that Commission-approved market monitoring and mitigation plans are sufficient to mitigate market power in RTO markets.[45] In particular, the Commission found in connection with PSEG's last triennial filing that the PJM market monitoring and mitigation rules are sufficient to address market power concerns.[46]

Under the local market power mitigation procedures in PJM, if a supplier fails the "three pivotal supplier test" (TPS), it is offer-capped by the Market Monitor. The Market Monitor's TPS test is applied on an ongoing basis, potentially as frequently as every 5 minutes, to reflect day-ahead and real-time operating conditions. These offer caps provide direct protection against the exercise of locational market power by suppliers in PJME, PJM50, PJMAP and elsewhere.

The protection against the exercise of market power is enhanced by "must offer" requirements under PJM's Operating Agreement. These mandate that generation resources that are used to meet capacity requirements in PJM and

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[44] *See*, *e.g.*, U.S. Department of Justice, 1984 Merger Guidelines, at Section 3.12, available at https://www.justice.gov/sites/default/files/atr/legacy/2007/07/11/11249.pdf ("the Department is likely to challenge the merger of any firm with a market share of at least one percent with the leading firm in the market, provided the leading firm has a market share that is at least 35 percent.")..

[45] Order No. 697 at P 241.

[46] *See* October 14, 2014 letter order approving Applicants' prior triennial market update in Docket No. ER10-1789-003 et al. at page 3.

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that are not subject to an outage must offer their available capacity in PJM's day-ahead energy market.[47] PJM has also implemented a Reliability Pricing Model (RPM) to secure sufficient capacity to meet its requirements through a series of auctions, including a Base Residual Auction (BRA) held annually for capacity 3 years in advance, and incremental auctions held at varying intervals prior to the delivery year. Various features of the RPM process work to prevent the exercise of market power in capacity markets in PJM. First, the RPM model includes bid cap rules designed to mitigate the potential exercise of market power. Second, RPM includes a must-offer requirement pursuant to which all generating units that have available capacity must bid into the RPM auctions or face disqualification from being recognized as capacity resources (and therefore from receiving any capacity payments) in the delivery year.

In addition to the local market power mitigation described above, the presence of market monitoring within PJM lessens potential concerns that PSEG might be able to exercise market power notwithstanding the indicative DPT screens. The Market Monitor has the specific responsibility under the market monitoring plan to monitor the potential of any market participant to exercise market power. To perform its market monitoring function, the Market Monitor can file reports or complaints with the Commission and other government agencies to address various market concerns including market power. The Market Monitor can also make its view known to the Commission staff and PJM members in cases where PJM does not follow its recommendations concerning complaints or requested rule changes. In addition, the Market Monitor can consult with regulatory bodies, including state commissions, regarding the need for specific investigations and monitoring activities, and to consider and evaluate additional enforcement mechanisms. The Market Monitor can also act on specific

[47] *See* PJM Operating Agreement at 1.10.1A(d).

complaints that have been filed by market participants to examine any potential market power issues.

In sum, the local market power mitigation rules, the role of the Market Monitor, the existence of must-offer requirements and PJM's RPM auctions address the potential for PSEG to exercise market power.

6. Vertical Market Power

In determining whether the market-based rates are in the public interest, the Commission also considers whether the Applicant has transmission market power or can erect barriers to entry.[48] None of these factors are relevant in the instant case. First, other than incidental generator interconnection facilities and the transmission assets owned by PSE&G in PJM, no transmission assets are owned by the Applicants or any of their affiliates in ISO-NE and NYISO. Transmission service over PSE&G's transmission facilities is provided under the PJM Open Access Transmission Tariff. Thus, consistent with Commission precedent, Applicants have alleviated any concerns regarding potential transmission market power. Second, PSEG has no ability to erect barriers to entry. As explained in Applicants' previous initial applications for market-based rate authority and triennial market power reports, PSEG is unable to erect barriers to entry. There has been no change in facts since the submission of those applications that would alter this conclusion.

The Commission is concerned with the ownership of natural gas pipelines or natural gas distribution facilities and the possibility that they may be used to exercise market power in electricity markets. PSEG does not own or operate any

[48] Order No. 697 at PP 397, 399.

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FERC jurisdictional natural gas pipelines in PJM, ISO-NE or NYISO.[49] PSE&G owns natural gas distribution facilities in the State of New Jersey including peak-shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers.

7. Conclusion

PSEG and its subsidiaries do not have market power in New England, New York or PJM. PSEG is not a pivotal supplier in New England, New York or PJM. PSEG's market shares in the WMSA are below the Commission's 20 percent screening threshold in each of these market areas. PSEG is also not a pivotal supplier in the Connecticut or Southwest Connecticut sub-markets and its market shares in the WMSA are below 20 percent in these sub-markets. PSEG fails the WMSA screens in only the PJME and PJM50 sub-markets. For these sub-markets, we conducted a DPT analysis. PSEG passes all the DPT screens for the PJM50 submarket, and it only fails the Market Share Screen in the PJME submarket. Its market shares are never above 25 percent, a level that the Commission has accepted in other market-based rate matters.[50] As such, they are not evidence of actual market power.

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[49] PSEG Power LLC currently owns a 10 percent interest in the PennEast Pipeline Company LLC which has filed an application with FERC for construction and operation of a gas transmission line.

[50] *See*, *e.g.*, *Dogwood Energy, LLC*, 135 FERC ¶ 61,089 (2011) (under the AEC measure, Dogwood failed the market share screen in seven of ten periods, with market shares ranging from 32.7% to 39.6%); *Kansas City Power & Light Company and KCP&L Greater Missouri Operation Company*, Docket No. ER10-2074-001 et al., Supplement to Change in Status Filing at 11 (Feb. 4, 2013) (accepted by Letter Order, November 22, 2013) (market shares for AEC ranging from 17 to 36%); *Shell Energy N.A. (US), L.P.*, 135 FERC ¶ 61,090 (2011) (under the AEC measure, Shell failed the market share screen for seven of ten periods, with market shares ranging from 29.3% to 37.0%); *Calpine Energy Services, L.P.*, 137 FERC ¶ 61,085 at P 21 (2011) (under the AEC measure, Calpine failed the market share screen in all ten periods, with market shares ranging from 20.4% to 28.9%); *Wildcat Power Holdings, LLC*, 136 FERC ¶ 61,013 at P 14 (2011) ("When the available economic capacity measure is used, Wildcat Power's market shares range from 22 to 24 percent in the three summer super peak and winter

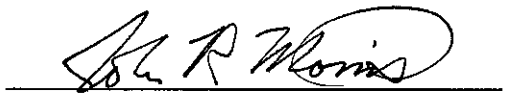
Further, PSEG operates under New England's, New York's, and PJM's market power mitigation programs, which mitigate PSEG's potential market power. Therefore, under standards for market-based rate authority articulated by the Commission in Order No. 697, PSEG has no ability to exercise market power in the relevant markets, and maintaining market-rate authority in New England, New York and PJM would be in the public interest.

Therefore, I recommend that the Commission continue to authorize PSEG to sell electric power in Northeast Region wholesale markets at market-based rates.

super peak season/load periods and zero percent in the remainder of the season/load periods."); *LS Power Marketing*, LLC,139 FERC ¶ 61,140 at P 23 (2012) (under the AEC measure, LS Power failed the market share screen in all ten periods, with market shares ranging from 20.4% to 28.9%); *Gila River Power, L.P.*, Docket Nos. ER05-1178-015, et al., Second Supplement to Updated Market Power Analysis at 4 (Jan. 12, 2011) (accepted by Letter Order, April 5, 2011) (market shares for AEC ranging from 21 to 23% in four season/load periods).

Pursuant to 28 U.S.C. §1746, I state under penalty of perjury that the foregoing is true and correct to the best of my information, knowledge, and belief.

Executed on this 22rd day of December 2016.



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EXPERIENCE AND QUALIFICATIONS OF

Dr. John R. Morris

OVERVIEW	Dr. Morris, a recognized expert in studying competition in energy industries, currently is a Principal at Economists Incorporated. He began his research of competition in energy industries in 1985 while working for the Federal Trade Commission. Since joining Economists Incorporated in 1992, he has consulted on many mergers and acquisitions involving energy companies, examined competitive issues relating to rates, and studied issues in state restructuring proceedings. He has published articles on competition and energy matters, and he has spoken on numerous occasions concerning competition in natural gas, electric power and other industries. He has been accepted as an expert witness on energy matters before the Federal Energy Regulatory Commission, state regulatory commissions, and in federal court.
EDUCATION	Ph.D., University of Washington, August 1985 Dissertation: *Intellectual Property: Creating, Pricing, Copying* • M.A., University of Washington, December 1983 • A.B., Georgetown University, May 1981
PRESENT POSITION	Dr. Morris is a *Principal* at Economists Incorporated, an economic consulting firm located at 2121 K Street, NW, Suite 1100, Washington, DC 20037. (202-223-4700) Economists Incorporated studies competition and regulation in many industries in the United States and in other countries. It is a leading firm in studying the competitive effects of mergers and acquisitions.
PREVIOUS EXPERIENCE	*Senior Vice President*, Economists Incorporated, December 2001 – December 2002 • *Vice President*, Economists Incorporated, December 1995 – December 2001 • *Senior Economist*, Economists Incorporated, June 1992 – December 1995 • *Economic Tutorial Leader*, Stanford University (Stanford in Washington), April 1993 – June 1995 • *Visiting Assistant Professor,* Department of Business Economics and Public Policy, School of Business, Indiana University, September 1991 – May 1992 • *Assistant to the Director for Antitrust,* Bureau of Economics, Federal Trade Commission, November 1989 – August 1991 • *Economic Advisor,* Office of Commissioner Machol, Federal Trade Commission, December 1988 – October 1989 • *Economist,* Division of Antitrust, Bureau of Economics, Federal Trade Commission, October 1985 – December 1988
MEMBERSHIPS	Member, International Association of Energy Economics • Associate, Energy Bar Association • Member, American Economic Association • Member, Western Economic Association International • Associate, American Bar Association

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AWARDS & HONORS

Award for Excellence in Law Enforcement, Federal Trade Commission, 1988 • Graduate School Scholarship, University of Washington, 1984 • Graduated Cum Laude Georgetown University, 1981 • Senior Comprehensive Passed with Distinction, Georgetown University, 1981

TESTIMONY BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Affidavit, Alabama Power Company, *et al.*, ER17-514-000 (2016) • Affidavits (3), Alabama Power Company, *et al*., EL15-39-000 (2016) • Affidavit, Combined Locks Energy Center, LLC, *et al.* , ER10-3042-004 (2015) • Affidavit, Alabama Power Company, *et al*., EL15-39-000 (2015) • Affidavit, PJM Interconnection, L.L.C., ER15-623-000 (2015) • Affidavit, Southern Indiana Gas and Electric Co. d/b/a Vectren Energy Delivery of Indiana, Inc., ER10-1338-000 (2014) • Affidavit, Quantum Choctaw Power, LLC *et al*., ER12-458-007 (2014) • Affidavit, NRG Power Marketing LLC, *et al.*, ER10-2265-004 *et al.* (2014) • Affidavit, TransCanada Entities, ER10-2870-004 *et al*. (2014) • Affidavit, Tampa Electric Company, ER10-1437-002 (2014) • Affidavit, Kendall Green Energy LLC, ER14-1363-003 (2014) • Affidavit, Quantum Lake Power, LP, ER13-1489-000 (2014) • Affidavit, NRG Power Marketing LLC, *et al.* ER10-2265-002 (2014) • Affidavit, NRG Yield, Inc., *et al*., EC14-101-000 (2014) • Affidavit, Community Wind Farm 1 et al., ER14-1668-000 (2014) • Seaway Crude Pipeline Company LLC, OR15-6-000 (2014) • Affidavit, Public Service Electric and Gas Company *et al.*, ER10-1789-003 (2013) • Affidavits, NRG Energy Holdings, Inc., Edison Mission Energy, EC14-14-000 (2013) • Affidavit, Silver Merger Sub, Inc., *et al.*, EC13-128-000 (2013) • Prepared Answering Testimony, Deposition, and Hearing, Puget Sound Energy, Inc., *et al.*, EL01-10-085 (2012) • Affidavit, Wisconsin Public Service Corporation, *et al*., ER10-1894-004 (2012) • Affidavit, PSEG New Haven LLC, ER12-1250-000 (2012) • Affidavit, Enterprise Product Partners L.P. and Enbridge, Inc., OR12-4-000 (2012) • Affidavit, Southern Indiana Gas and Electric Co., ER10-1338-001 (2011) • Affidavit, TransCanada Power Marketing Ltd. *et al.*, ER10-2780-001 (2011) • Affidavit, Tampa Electric Company, ER10-1476-001 (2011) • Affidavit, Cedar Creek Wind Energy, LLC, ER11-2577-000 (2010) • Affidavit, Public Service Electric and Gas Company *et al.*, ER97-837-014 (2010) • Affidavit, Morris Energy Group, LLC v. PSEG Energy Resources & Trade LLC; PSEG Fossil LLC; and PSEG Power LLC, EL10-79-000 (2010) • Affidavit, UGI Storage Company and UGI Central Penn Gas, Inc., CP10-23-000 (2010) • Prepared Answering Testimony, People of the State of California, *ex rel*; Bill Lockyer, Attorney General of the State of California v. Powerex Corp., *et al.*, EL02-71-000 (2009) • Affidavit, Integrys Energy Services, Inc. v. New Brunswick Power Generation Corporation, EL09-32-002 (2009) • Affidavit, People of the State of California, *ex rel*; Edmund G. Brown Jr. Attorney General of the State of California v. Powerex Corp., *et al.*, EL09-56-000 (2009) • Affidavit, San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, EL00-95-000 (2009) • Affidavit, Troy Energy, LLC, *et al.*, ER02-25-010 (2009) • Affidavit, Combined Locks Energy Center, LLC,

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et al., ER01-2659-015 (2009) • Prepared Direct Testimony and Deposition, Energy Transfer Partners, *et al*., IN06-3-003 (2009) • Prepared Direct Testimony and Hearing, Mobil Pipe Line Company, OR07-21-000 (2009) • Idaho Power Company, ER06-787-002 (2009) • Affidavit, Southern Indiana Gas and Electric Co. d/b/a Vectren Energy Delivery of Indiana, Inc. ER96-2734-007 (2008) • Affidavit, Choctaw Gas Generation, LLC, *et al.* ER08-1332-002 • Affidavit, TransCanada Energy Sales Ltd., ER09-328-001 (2008) • Prepared Direct Testimony and Deposition, Oasis Pipeline L.P., *et al.*, IN06-3-004 (2008) • Affidavit, Tampa Electric Company, ER99-2342-012 (2008) • Affidavit, ANP Bellingham Energy Company, LLC, *et al.*, ER00-2117-005 (2008) • Affidavit, SUEZ Energy Marketing, NA, *et al.*, ER06-169-003 (2008) • Affidavit, TransCanada Energy Marketing ULC, *et al.*, ER07-1274-001 (2008) • Affidavit, Georgia-Pacific Brewton LLC, *et al.*, ER08-1126-000 (2008) • Affidavit, Montgomery L'Energia Power Partners LP, ER08-864-000 (2008) • Affidavit (with Joseph P. Kalt), Energy Transfer Partners, *et al*., IN06-3-002 (2008) • Affidavit, Energy Transfer Partners, *et al*., IN06-3-002 (2008) • Affidavit, TransCanada Maine Wind Development Inc., ER08-685-000 (2008) • Affidavit (with Joseph P. Kalt), Energy Transfer Partners, *et al*., IN06-3-000 (2007) • Affidavit, Energy Transfer Partners, *et al*., IN06-3-000 (2007) • Affidavit, The People of the State of Illinois, *ex rel.* Illinois Attorney General Lisa Madigan v. Exelon Generation Co., LLC, *et al.*, EL07-47-000 (2007) • Affidavit, Baltimore Gas and Electric Company, ER07-576-000 (2007) • Affidavit, Trans-Allegheny Interstate Line Company, ER07-562-000 (2007) • Affidavit, TransCanada Energy Marketing Ltd., *et al.*, ER07-331-000 (2006) • Affidavit, Tampa Electric Company, ER99-2342-000, ER07-173-000 (2006) • Affidavit, Koch Supply & Trading, LP, ER07-100-000 (2006) • WPS Resources Corporation and Peoples Energy Corporation, EC06-152-000 (2006) • Affidavit, Sabine Cogen, LP, ER06-744-000 (2006) • Affidavit, Air Liquide Large Industries U.S. LP, ER06-743-000 (2006) • Affidavit, ANP Bellingham Energy Company, LLC., *et al.*, ER00-2117-000 (2005) • Affidavit, Duke Energy Corporation and Cinergy Corp., EC05-103-000 (2005) • Affidavit, El Paso Marketing, L.P., *et al.*, ER95-428-000 (2005) • Affidavit, TransCanada Energy Ltd., *et al.*, ER95-692-000 (2005) • Affidavit, Granite Ridge Energy, LLC, ER00-1147-000, ER05-287-001 (2005) • Affidavit, TransCanada Power (Castleton) LLC, ER05-743-000 (2005) • Affidavit, Tampa Electric Company, *et al*., ER99-2342-003 (2005) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-035 and Wisconsin Public Service Corporation, ER95-1528-010 (2005) • Affidavit, Wisconsin River Power Company, ER05-453-000 (2005) • Affidavit, Upper Peninsula Power Company, ER05-89-001 (2005) • Affidavit, Southern Indiana Gas and Electric Company, ER96-2734-003 (2004) • Affidavit, Tampa Electric Company, *et al*., ER99-2342-003 (2004) • Affidavits, TransCanada Hydro Northeast, Inc., *et al*., EC05-12-000, ER05-111-000 (2004) • Affidavits, Dominion Energy New England,

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Inc., *et al*., EC05-4-000, ER05-34-000 (2004) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-033 and Wisconsin Public Service Corporation, ER95-1528-008 (2004) • Affidavit, NorthPoint Energy Solutions Inc. ER04-1244-000 (2004) • Affidavit, Union Power Partners, L.P., ER01-930-004 (2004) • Affidavit, Panda Gila River, L.P., ER01-931-004 (2004) • Affidavit, Dominion Energy Kewaunee, Inc., ER04-318-000 (2003) • Affidavit, TPS GP, Inc., TPG LP, Inc., Panda GS V, LLC & Panda GS VI, LLC, EC03-90-000 (2003) • Affidavit, Berkshire Power Company, L.L.C. *et al.*, ER99-3502-001 (2002) • Affidavit, El Paso Merchant Energy, L.P., ER95-428-024 (2002) • Affidavit, Tampa Electric Company, ER99-2342-001 (2002) • Affidavit, Hardee Power Partners Limited, ER99-2341-001 (2002) • Affidavit, TECO-PANDA Generating Company, L.P., ER02-1000-000 (2002) • Affidavit, Commonwealth Chesapeake Company, LLC, ER99-415-004 (2002) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-031 and Wisconsin Public Service Corporation, ER95-1528-006 (2001) • Affidavit, TPS McAdams, LLC and TPS Dell, LLC, ER02-507-000 and ER02-510-000 (2001) • Affidavits, Prepared Direct Testimony, and Hearing, CPUC v. El Paso Natural Gas Company, et al., RP00-241-000 (2000-2001), Affidavit, El Paso Energy Corporation and The Coastal Corporation, EC00-73-000, (2000) • Affidavit, El Paso Energy Corporation and Sonat Inc., EC99-73-000 (1999) • Prepared Testimony, San Diego Gas & Electric Company and Enova Energy, Inc., EC97-12-000 (1997) • Prepared Testimony and Hearing, Wisconsin Electric Power Co., Northern States Power Co. (Minnesota), Northern States Power Co. (Wisconsin), and Cenerprise, Inc., EC95-16-000 (1996)

TESTIMONY BEFORE STATE REGULATORY COMMISSIONS

Prepared Direct Testimony, In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018, by Duke Energy Florida, Inc., FPSC Docket No. 140111-EI (2014) • Affidavit and Prepared Testimony, In The Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 14 Electric and B.P.U.N.J. No. 14 Gas Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and for Approval of a Gas Weather Normalization Clause; A Pension Expense Tracker; and for Other Appropriate Relief, BPU Docket No. GR09050422, New Jersey Board of Public Utilities (2010) • Prepared Direct Testimony, Application of Wisconsin Power and Light Company for Issuance of a Certificate of Public Convenience and Necessity for Construction and Placement in Operation of an Approximately 300 MW Coal-Fired Baseload Facility and an Application for Approval of Fixed Financial Parameters and Capital Cost Rate-Making Principles for the Baseload Facility, Docket No. 6680-CE-170, Public Service Commission of Wisconsin (2008) • Prepared Rebuttal Testimony and Hearing, In the Matter of the Joint Petition of Public Service Electric and Gas Company and

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Exelon Corporation for Approval of a Change in Control of Public Service Electric and Gas Company, and Related Authorizations, BPU Docket No. EM05020106, OAL Docket No. PUC-01874-05, New Jersey Board of Public Utilities (2005, 2006) • Affidavit, Application of Duke Energy Corporation for Authorization to Enter Into a Business Combination Transaction with Cinergy Corp., Docket No. 2005-210-E, Public Service Commission Of South Carolina (2005) • Prepared Rebuttal Testimony and Hearing, Joint Application of PECO Energy Company and Public Service Electric and Gas Company for Approval of the Merger of Public Service Enterprise Group Incorporated with and into Exelon Corporation, Docket No. A-110550F0160, Pennsylvania Public Utility Commission (2005) • Prepared Direct Testimony and Hearing, Application of Washington Gas Light Company for amendments to Rate Schedule No. 9, Firm Delivery Gas Supplier Agreement of its Gas Tariff, Docket No. PUE-2004-00085 (2005) • Prepared Direct Testimony, Application of Wisconsin Public Service Corporation for a Certificate of Public Convenience and Necessity for Construction of A Large Electric Generating Plant with Associated Facilities, known as Weston 4, at Its Existing Weston Generating Station Located in Marathon County, Docket No. 6690-CE-187, Public Service Commission of Wisconsin (2004) • Prepared Direct Testimony, Metromedia Energy, Inc. - Regarding Washington Gas Light Company's Plan to Return Customers to Sales Service Effective December 1, 2003, Docket No. PUE-2003-00536 (2004) • Report (with Mark Frankena) and Testimony, Analysis of Competitive Implications: An investigations into whether electric industry restructuring and competition in the provision of retail electric service is in the public interest, Louisiana Public Service Commission Docket No. U-21453, U-20925 (SC), U-22092 (SC) (Subdocket A) (2000) • Report and Hearing, Atlantic City Electric Company: Audit of Restructuring, New Jersey Board of Public Utilities, Docket No. EA97060395 (1998) • Prepared Testimony and Hearing, Proceeding on Motion of the Commission to Redesign Niagara Mohawk Power Corporation’s Current SC-7 Service Classification and Implement a New SC-7-A Service Classification, Case 94-E-0172, New York Public Service Commission (1995)

TESTIMONY BEFORE FEDERAL COURTS

Report, Deposition, and Bench Trial, FTC v. Arch Coal, Inc., et al., Civil Action 04-0534 (JDB), U.S. Dist. Court, Dist. of Columbia (2004) • Report, Deposition and Jury Trial, Trigen v. OG&E, CIV-96-1595L, U.S. Dist. Court, Western Dist. of Oklahoma (1998)

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TESTIMONY BEFORE STATE COURTS	Affidavit, Retail Energy Supply Association, *et al.* v. Public Service Commission of the State of New York, *et al.*, Index No. 870-16, State of New York, Supreme Court, County of Albany (2016) • Affidavit, City Public Service Board of San Antonio vs. Public Utility Commission of Texas, et al., No. 97-02917, District Court of Travis County, Texas, 200th Judicial District (1997)
OTHER TESTIMONY	Report, Metromedia Energy, Inc. v. Mirant Americas Energy Marketing, RE: 18 198 Y 18484 03 (2005) • Report and Deposition, King Provision Corporation v. Burger King Corporation and Grand Metropolitan PLC*,* 90-05718-CA, 4th Cir., Duval Co., Florida (1992) • Deposition, West Texas Transmission L.P. v. Enron Corp. et al., SA 88 CA 0638, W.D. Texas, San Antonio Division (1988)
PUBLICATIONS	"Geographic Market Delineation in LMP Electric Power Markets," *Electricity Journal* 23(3) (April 2010): 49-60 • "The Likely Effect of the Proposed Exelon-PSEG Merger on Wholesale Electricity Prices," *Electricity Journal* 21(1) (Jan./Feb. 2008): 45-54 • "FERC MBR Screens: The Good, the Bad, and the Ugly," *Public Utilities Fortnightly* 143(7) (July 2005): 37-42 • "Finding Market Power in Power Markets," *International Journal of the Economics of Business*, 7(2) (July 2000): 167-178 • "Why Applicants Should Use Computer Simulation Models to Comply with the FERC's New Merger Policy," with Mark Frankena, *Public Utilities Fortnightly*, 135(3) (February 1, 1997): 22-26 • *Electric Utility Mergers,* with Mark Frankena and Bruce Owen, Chapters 1, 4, & 5, 1994 • "International Trade and Antitrust: Comments," *University of Cincinnati Law Review*, 61(3) (1993): 945-953 • "Upstream Vertical Integration with Automatic Price Adjustments," *Journal of Regulatory Economics* 4 (1992): 279-287 • "Should the U.S. Department of Justice deviate from the 5% price test for market definition on a case-by-case basis?" with Gale Mosteller, *International Merger Law*, April 1992 • "Defining Markets for Merger Analysis," with Gale Mosteller, *Antitrust Bulletin* 36 (Fall 1991): 599-640 • "Analyzing Agreements Among Competitors: What Does the Future Hold?" with Jim Langenfeld, *Antitrust Bulletin* 36 (Fall 1991): 651-679 • "In Defense of Antitrust," with Jim Langenfeld, *Regulation* 14(2) (Spring 1991): (Letters) 2-4 • "Enforcement of Property Rights and the Provision of Public Good Attributes," *Information Economics and Policy* 3 (1988): 91-108
WORKING PAPERS	"Advertising Restrictions as Rent Increasing Costs," FTC Bureau of Economics Working Paper No. 196, May 1992 • "Rent Increasing Costs: The Antitrust Implications from a Paradox in Value Theory," FTC Bureau of Economics Working Paper No. 182, November 1990 • "The Relationship Between Industrial Sales Prices and Concentration of Natural Gas Pipelines," FTC Bureau of Economics Working Paper No. 168, November 1988 • "Deregulation by Vertical Integration?" FTC Bureau of Economics Working Paper No. 166, November 1988

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PRESENTATIONS & PROFESSIONAL ACTIVITIES

Comments (with 7 others), Notice of Inquiry: Modifications to Commission Requirements for Review of Transactions under Section 203 of the Federal Power Act and Market-Based Rate Applications under Section 205 of the Federal Power Act, Docket No. RM16-21-000, Federal Energy Regulatory Commission, November 28, 2016 • Report, PJM Interconnection, L.L.C., Docket No. ER15-623-000, Federal Energy Regulatory Commission, January 20, 2015 • Comments, Notice of Inquiry: Analysis of Horizontal Market Power under the Federal Power Act, Docket No. RM11-14-000, Federal Energy Regulatory Commission, May 23, 2011 • Comments, Position Limits for Derivatives, RIN 3038–AD15 and 3038–AD16, Commodity Futures Trading Commission, March 28, 2011 • Comments, Guidance on Simultaneous Transmission Import Limit Studies, AD10-2-000, Federal Energy Regulatory Commission, February 12, 2010 • "Geographic Market Delineation in LMP Electric Power Markets," presentation before representatives of the Federal Energy Regulatory Commission, U.S. Department of Justice, and U.S. Federal Trade Commission, January 27, 2010 • Comments, Notices of Intent to determine that 15 natural gas financial basis contracts traded on the Intercontinental Exchange, Inc. are Significant Price Discovery Contracts, Commodity Futures Trading Commission, October 26, 2009 • "Efficacy of Vertical Integration in Energy Industries with Applications to Proposed Standards of Conduct for Transmission Providers," submitted to FERC by Santee Cooper in Docket No. RM07-1-000 (2007) • Chair, Antitrust Committee, Energy Bar Association, 2004–2005 • "Competition in the Natural Gas Industry: An Antitrust Perspective, presentation to staff of the Federal Energy Regulatory Commission," March 28, 2005 • Vice Chair, Antitrust Committee, Energy Bar Association, 2003–2004 • "Weston 4 Effect on Wholesale Competition in WUMS," submitted to the Public Service Commission of Wisconsin by Wisconsin Public Service Corporation in Docket No. 6690-CE-187, September 26, 2003 • "Computer Models In The Electric Power Industry," presented to staff of the Federal Trade Commission, Washington, DC, June 11, 2002 • "TECO EnergySource Market Share Analysis," submitted to FERC by TECO EnergySource, Inc. in Docket No. ER96-1563-017, September 10, 2001 • "Finding Market Power in Power Markets," presented to staff of the Federal Trade Commission, Washington, DC, June 20, 2001 • "A Study of Marketing Affiliate and Other Affiliate Holdings of Firm Capacity on Interstate Natural Gas Pipelines and the Effects on Natural Gas Markets," April 30, 2001, submitted to FERC by the Interstate Natural Gas Association of America in Docket No. PL00-1-003 • "Why We Should Use Computer Models to Unveil Market Power," presented at the Sixth DOE–NARUC National Electricity Forum, Brown Convention Center, Houston, TX, September 16, 1998 • Comments, *Agency Information Collection and Dissemination Activities: Comment Request*, U.S. Department of Energy, Energy Information Administration, August 28, 1998 • Comments, *Revised filing Requirements Under Part 33 of the Commission's Regulations*, Federal Energy

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Regulatory Commission Docket No. RM98-4-000, August 21, 1998 • "Use of Computer Simulation Models to Unveil Market Power," presented to staff of the Federal Trade Commission, Federal Energy Regulatory Commission and U.S. Department of Justice, Federal Trade Commission, Washington, DC, April 10, 1998 • "Use of Computer Simulation Models to Unveil Market Power: The Primergy Case," presented to the Bureau of Economics, Federal Trade Commission, Washington, DC , December 8, 1997 • "Use of Computer Simulation Models to Unveil Market Power," presented at the 29th Annual Conference of the Institute of Public Utilities, Williamsburg, Virginia, December 3, 1997 • **"**Mergers and Market Power," presented at the National Association of State Utility Consumer Advocates Mid-Year Meeting, Charleston, South Carolina, June 9, 1997 • "Market Power Analysis: An Economic Perspective," (with Mark Frankena), presented at the Strategic Research Institute Conference on The Legal Challenges of Restructuring, Arlington, Virginia, April 16, 1997 • "Mergers and Market Power," presented at the Edison Electric Institute Workshop on FERC Merger Policy Guidelines, Arlington, Virginia, April 1, 1997 • "New Approaches to Controlling Distribution Company Market Power," presented at the New York Energy Efficiency Council Conference on Innovative Solutions to a Changing Energy Market, New York Athletic Club, February 7, 1997 • Description of the Western Power Model, with Mark Frankena, Exhibit 8 to Prepared Testimony Before the Nevada Public Service Commission, January 31, 1997 • Reviewer, American Bar Association, Section of Antitrust Law, *Manual on the Economics of Antitrust Law, 14th Supplement*, 1995 • Referee, *Quarterly Journal of Business and Economics*, 1994—1995 • Reviewer, American Bar Association, Section of Antitrust Law, *Manual on the Economics of Antitrust Law, 10th Supplement*, 1993 • Expert Witness, Federal American Inn of Court, Washington, DC, Winter 1993 • "Advertising Restrictions as Rent Increasing Costs," presented at a *Contemporary Policy Issues* Session of the Western Economics Association's 67th Annual Conference, July 1992 • "Let's Make Merger Policy 'Fully Consonant With Economic Theory,'" presented at a *Contemporary Policy Issues* Session of the Western Economics Association's 67th Annual Conference, July 1992 • "Advertising Restrictions as Rent Increasing Costs," Seminar, Department of Business Economics, Indiana University, October 1991 • "International Trade and Antitrust: Comments," presented at a *Contemporary Policy Issues* Session of the Western Economics Association's 66th Annual Conference, July 1991 • Discussant, Western Economics Association's 66th Annual Conference, July 1991 • Horizontal Restraints Cases at the Federal Trade Commission: From *American Medical Association* through the Present," with Jim Langenfeld, presented at the 60th Annual Conference of the Southern Economics Association, November 1990 • "Defining Markets for Merger Analysis," with Gale Mosteller, presented at a *Contemporary Policy Issues* Session of the Western Economics Association's 65th Annual Conference, cosponsored by the *Antitrust Bulletin* and the

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Antitrust and Trade Regulation Section of the Federal Bar Association, July 1990 • "Analyzing Agreements Among Competitors: What Does the Future Hold?" with Jim Langenfeld, presented at a *Contemporary Policy Issues* Session of the Western Economics Association's 65th Annual Conference, cosponsored by the *Antitrust Bulletin* and the Antitrust and Trade Regulation Section of the Federal Bar Association, July 1990 • "The Relationship Between Industrial Sales Prices and Concentration of Natural Gas Pipelines," Seminar, Office of Economic Policy, Federal Energy Regulatory Commission, Summer 1989 • "The Relationship Between Industrial Sales Prices and Concentration of Natural Gas Pipelines," Seminar, Economic Analysis Group, Antitrust Division, U.S. Department of Justice, February 1989 • "Deregulation by Vertical Integration?" Seminar, Department of Business Economics, Indiana University, January 1989 • Discussant, Industrial Organization Society Session, Annual Meeting of the American Economics Association, December 1988 • "Concentration and Price in the Natural Gas Industry," Seminar, Federal Trade Commission, July 1988 • "Relevant Measures of Concentration for Antitrust Policy," presented at an Industrial Organization Society Session of the 57th Annual Conference of the Southern Economics Association, November 1987

Northeast Region Generation Owned and Controlled by PSEG

Owner	Plant Name	State	Owned Capacity		Controlled Capacity	
			Winter Seasonal Capacity	Summer Seasonal Capacity	Winter Seasonal Capacity	Summer Seasonal Capacity
ISO - New England						
PSEG Power CT	Bridgeport Station 2	CT	148	130	148	130
PSEG Power CT	Bridgeport Station 3	CT	385	383	385	383
PSEG Power CT	Bridgeport Station 4	CT	20	15	20	15
PSEG Power CT	New Haven Harbor 1	CT	455	448	455	448
PSEG New Haven	New Haven Harbor GT2	CT	61	61	0	0
PSEG New Haven	New Haven Harbor GT3	CT	61	61	0	0
PSEG New Haven	New Haven Harbor GT4	CT	61	61	0	0
Total ISO - New England Capacity			**1,190**	**1,158**	**1,008**	**976**
New York ISO						
PSEG Power NY	Bethlehem Energy Center CC	NY	845	754	845	754
Total New York ISO Capacity			**845**	**754**	**845**	**754**
PJM						
PSEG Fossil	Conemaugh 1	PA	191	191	191	191
PSEG Fossil	Conemaugh 2	PA	191	191	191	191
PSEG Fossil	Conemaugh A[1]	PA	1	1	1	1
PSEG Fossil	Conemaugh B	PA	1	1	1	1
PSEG Fossil	Conemaugh C	PA	1	1	1	1
PSEG Fossil	Conemaugh D	PA	1	1	1	1
PSEG Power	Conemaugh Hydroelectric Plant 1[2]	PA	1	1	1	1
PSEG Power	Conemaugh Hydroelectric Plant 2	PA	1	1	1	1
PSEG Fossil	Keystone 1[3]	PA	194	194	194	194
PSEG Fossil	Keystone 2	PA	194	194	194	194
PSEG Fossil	Keystone 3	PA	1	1	1	1
PSEG Fossil	Keystone 4	PA	1	1	1	1
PSEG Fossil	Keystone 5	PA	1	1	1	1
PSEG Fossil	Keystone 6	PA	1	1	1	1
PSEG Solar Source LLC	Wyandot Solar Farm	OH	12	12	12	12

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Northeast Region Generation Owned and Controlled by PSEG

Owner	Plant Name	State	Owned Capacity		Controlled Capacity	
			Winter Seasonal Capacity	Summer Seasonal Capacity	Winter Seasonal Capacity	Summer Seasonal Capacity
PJM East						
PSEG Fossil	Bergen 3[7]	NJ	21	21	21	21
PSEG Fossil	Bergen CC1	NJ	628	628	628	628
PSEG Fossil	Bergen CC2	NJ	550	555	550	555
PSEG Fossil	Burlington 8[7]	NJ	21	21	21	21
PSEG Fossil	Burlington 9[10]	NJ	184	184	184	184
PSEG Fossil	Burlington 11[7]	NJ	184	184	184	184
PSEG Fossil	Burlington 121	NJ	42	42	42	42
PSEG Fossil	Burlington 122	NJ	42	42	42	42
PSEG Fossil	Burlington 123	NJ	42	42	42	42
PSEG Fossil	Burlington 124	NJ	42	42	42	42
PSEG Fossil	Edison 1[7]	NJ	168	168	168	168
PSEG Fossil	Edison 2[7]	NJ	168	168	168	168
PSEG Fossil	Edison 3[7]	NJ	168	168	168	168
PSEG Fossil	Essex 9	NJ	81	81	81	81
PSEG Fossil	Essex 10[7]	NJ	168	168	168	168
PSEG Fossil	Essex 11[7]	NJ	168	168	168	168
PSEG Fossil	Essex 12[7]	NJ	168	168	168	168
PSEG Nuclear	Hope Creek 1	NJ	1,161	1,161	1,161	1,161
PSEG Fossil	Hudson 2	NJ	608	608	608	608
PSEG Fossil	Kearny 9[8]	NJ	21	21	21	21
PSEG Fossil	Kearny 12	NJ	175	175	175	175
PSEG Fossil	Kearny 13	NJ	0	178	0	178
PSEG Fossil	Kearny 14	NJ	0	89	0	89
PSEG Fossil	Linden 1	NJ	455	458	455	458
PSEG Fossil	Linden 2	NJ	775	778	775	778
PSEG Fossil	Linden 7	NJ	84	84	84	84
PSEG Fossil	Linden 8	NJ	84	84	84	84
PSEG Fossil	Linden GT5	NJ	86	86	86	86
PSEG Fossil	Linden GT6	NJ	86	86	86	86
PSEG Hackettstown LLC	Mars Solar Garden	NJ	2	2	2	2
PSEG Fossil	Mercer 1	NJ	316	316	316	316
PSEG Fossil	Mercer 2	NJ	316	316	316	316

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Northeast Region Generation Owned and Controlled by PSEG

			Owned Capacity		Controlled Capacity	
Owner	**Plant Name**	**State**	**Winter Seasonal Capacity**	**Summer Seasonal Capacity**	**Winter Seasonal Capacity**	**Summer Seasonal Capacity**
PSEG Fossil	Mercer GT3[9]	NJ	115	115	115	115
PSEG Solar Source LLC	Milford Solar Farm	DE	15	15	15	15
PSEG Fossil	National Park GT1[7]	NJ	21	21	21	21
PSEG Nuclear	Salem 1[4]	NJ	674	674	674	674
PSEG Nuclear	Salem 2	NJ	665	665	665	665
PSEG Nuclear	Salem GT3	NJ	22	22	22	22
PSEG Fossil	Sewaren 1	NJ	104	104	104	104
PSEG Fossil	Sewaren 2	NJ	118	118	118	118
PSEG Fossil	Sewaren 3	NJ	107	107	107	107
PSEG Fossil	Sewaren 4	NJ	124	124	124	124
PSEG Fossil	Sewaren 6[7]	NJ	105	105	105	105
PSE&G	Solar 4 All Units	NJ	78	78	78	78
PSEG Fossil	Yards Creek 1[5]	NJ	70	70	0	0
PSEG Fossil	Yards Creek 2	NJ	70	70	0	0
PSEG Fossil	Yards Creek 3	NJ	60	60	0	0
PJM 5004/5005						
PSEG Nuclear	Peach Bottom 2[6]	PA	561	561	561	561
PSEG Nuclear	Peach Bottom 3	PA	561	561	561	561
Total PJM Capacity			**11,272**	**11,550**	**11,072**	**11,350**
Total Northeast Region Capacity			**13,307**	**13,462**	**12,926**	**13,080**

Source: PSEG.
Notes:
[1] PSEG Fossil has a 22.5% interest in the Conemaugh coal-fired units.
[2] PSEG Global has a 4% interest in the Conemaugh Hydroelectric facility.
[3] PSEG Fossil has a 22.84% ownership interest in the Keystone facility.
[4] PSEG Nuclear has a 57.41% interest in the Salem Nuclear facility.
[5] PSEG Fossil has a 50% interest in the Yards Creek facility. Yards Creek is operated by Jersey Central Power & Light, and thus is controlled by JCP&L in the analysis.
[6] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear facility.
[7] Unit retired on 06/01/2015
[8] Unit retired on 08/31/2014
[9] Unit retired on 07/31/2015
[10] Unit retired on 06/30/2014

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Scenario 1 PSEG 2016 MBR for ISONE

	PSA		WMSA							
			Winter		Spring		Summer		Fall	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result
ISO New England	8,715	Pass	5.4	Pass	5.2	Pass	6.5	Pass	6.0	Pass
Connecticut	3,388	Pass	11.8	Pass	11.3	Pass	14.3	Pass	13.3	Pass
Southwest Connecticut	1,701	Pass	16.4	Pass	15.7	Pass	14.9	Pass	13.0	Pass

Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **ISONE**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	16	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	190	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	30,892	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	16	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,358	Calculated
I	Study Area Reserve Requirement	2,510	Gendata
J	Amount of Line I Attributable to Seller, if any	3	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	16,073	
	Load		
L	Balancing Area Annual Peak Load	24,054	Loads
M	Average Daily Peak Native Load in Peak Month	17,708	Loads
N	Amount of Line M Attributable to Seller, if any	10	SellerLoads
O	Wholesale Load (L-M)	6,346	
P	Net Uncommitted Supply (K-O)	9,728	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,012	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	4,548	
	% of SIL for Seller's imported capacity →	0.04	
	% of SIL for Other's imported capacity →	0.96	
	SIL Value →	4548	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **CT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	843	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	102	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	7,524	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	2,948	Calculated
I	Study Area Reserve Requirement	689	Gendata
J	Amount of Line I Attributable to Seller, if any	10	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	5,674	
	Load		
L	Balancing Area Annual Peak Load	6,419	Loads
M	Average Daily Peak Native Load in Peak Month	5,054	Loads
N	Amount of Line M Attributable to Seller, if any	14	SellerLoads
O	Wholesale Load (L-M)	1,365	
P	Net Uncommitted Supply (K-O)	4,309	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	920	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	3,050	
	% of SIL for Seller's imported capacity →	0.03	
	% of SIL for Other's imported capacity →	0.97	
	SIL Value →	3050	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **SWCT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	400	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	98	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	2,090	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	3,102	Calculated
I	Study Area Reserve Requirement	205	Gendata
J	Amount of Line I Attributable to Seller, if any	0	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	2,985	
	Load		
L	Balancing Area Annual Peak Load	3,286	Loads
M	Average Daily Peak Native Load in Peak Month	2,500	Loads
N	Amount of Line M Attributable to Seller, if any	0	SellerLoads
O	Wholesale Load (L-M)	786	
P	Net Uncommitted Supply (K-O)	2,199	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	498	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	3,200	
	% of SIL for Seller's imported capacity →	0.03	
	% of SIL for Other's imported capacity →	0.97	
	SIL Value →	3200	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II – Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **ISONE**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	860	852	843	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	12	16	16	16	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	29	87	7	79	SellerGendata
E	Uncommitted Capacity Imports	222	188	177	188	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	16,956	14,847	17,687	15,178	Loads
G	Amount of Line F Attributable to Seller, if any	113	102	39	5	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	16,843	14,745	17,648	15,173	F - G
I	Study Area Reserve Requirement	2,530	2,510	2,510	2,510	Gendata
J	Amount of Line I Attributable to Seller, if any	16	20	10	3	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,514	2,490	2,500	2,507	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	32,149	30,892	29,634	30,892	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	12	16	16	16	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,097	3,148	229	2,881	Gendata; Row D
P	Uncommitted Capacity Imports	4,326	4,360	4,371	4,360	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	16,033	14,885	13,644	14,707	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	911	815	948	935	
S	Total Seasonal Uncommitted Capacity (Q+R)	16,944	15,700	14,592	15,642	
T	**Applicant's Market Share (R÷S)**	5.4%	5.2%	6.5%	6.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	4,548	4,548	4,548	4,548	
V	SIL Value	4,548	4,548	4,548	4,548	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II – Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **CT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	860	852	843	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	29	87	7	79	SellerGendata
E	Uncommitted Capacity Imports	106	93	93	94	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	4,207	3,642	4,503	3,772	Loads
G	Amount of Line F Attributable to Seller, if any	113	102	39	5	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	4,093	3,540	4,464	3,766	F - G
I	Study Area Reserve Requirement	683	683	689	683	Gendata
J	Amount of Line I Attributable to Seller, if any	21	22	10	3	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	662	661	679	680	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	8,048	7,786	7,524	7,786	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	275	793	58	726	Gendata; Row D
P	Uncommitted Capacity Imports	2,944	2,957	2,957	2,956	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	5,963	5,749	5,279	5,570	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	802	734	881	857	
S	Total Seasonal Uncommitted Capacity (Q+R)	6,765	6,482	6,160	6,427	
T	**Applicant's Market Share** (R÷S)	11.8%	11.3%	14.3%	13.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	3,050	3,050	3,050	3,050	
V	SIL Value	3,050	3,050	3,050	3,050	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II – Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **SWCT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	407	404	400	404	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	14	41	3	38	SellerGendata
E	Uncommitted Capacity Imports	86	68	91	101	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	2,048	1,758	2,178	1,766	Loads
G	Amount of Line F Attributable to Seller, if any	0	0	0	0	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	2,048	1,758	2,178	1,766	F - G
I	Study Area Reserve Requirement	209	206	205	206	Gendata
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	209	206	205	206	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	2,321	2,206	2,090	2,206	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	79	225	16	206	Gendata; Row D
P	Uncommitted Capacity Imports	2,454	2,302	3,109	3,089	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	2,439	2,318	2,799	3,116	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	479	430	488	467	
S	Total Seasonal Uncommitted Capacity (Q+R)	2,918	2,748	3,287	3,583	
T	**Applicant's Market Share** (R÷S)	16.4%	15.7%	14.9%	13.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	2,540	2,370	3,200	3,190	
V	SIL Value	2,540	2,370	3,200	3,190	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

SI-SSA-0010-5603

Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **NYISO**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	757	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	265	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	585	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	42,506	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,265	Calculated
I	Study Area Reserve Requirement	2,620	Gendata
J	Amount of Line I Attributable to Seller, if any	0	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	22,514	
	Load		
L	Balancing Area Annual Peak Load	31,138	Loads
M	Average Daily Peak Native Load in Peak Month	25,244	Loads
N	Amount of Line M Attributable to Seller, if any	0	SellerLoads
O	Wholesale Load (L-M)	5,894	
P	Net Uncommitted Supply (K-O)	16,620	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,607	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,850	
	% of SIL for Seller's imported capacity →	0.09	
	% of SIL for Other's imported capacity →	0.91	
	SIL Value →	6850	
	Do Total Imports exceed the SIL Value? →	No	

SI-SSA-0010-5604

Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **NYISO**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	870	814	757	814	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	265	265	265	265	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	71	115	13	92	SellerGendata
E	Uncommitted Capacity Imports	731	600	582	640	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	21,006	18,974	23,056	19,579	Loads
G	Amount of Line F Attributable to Seller, if any	0	0	0	0	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	21,006	18,974	23,056	19,579	F - G
I	Study Area Reserve Requirement	2,620	2,620	2,620	2,620	Gendata
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,620	2,620	2,620	2,620	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	40,162	41,334	42,506	41,334	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,277	5,820	726	4,652	Gendata; Row D
P	Uncommitted Capacity Imports	6,904	6,924	6,268	7,055	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	20,162	20,843	22,372	21,538	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	1,795	1,564	1,591	1,627	
S	Total Seasonal Uncommitted Capacity (Q+R)	21,958	22,407	23,963	23,166	
T	**Applicant's Market Share** (R÷S)	8.2%	7.0%	6.6%	7.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,635	7,524	6,850	7,695	
V	SIL Value	7,635	7,524	6,850	7,695	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

SI-SSA-0010-5605

Scenario 1 PSEG 2016 MBR for PJM										
	PSA		WMSA							
			Winter		Spring		Summer		Fall	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result
PJM Interconnection	35,891	Pass	9.5	Pass	7.7	Pass	8.3	Pass	8.3	Pass
PJM East	3,572	Pass	32.7	Fail	27.0	Fail	32.9	Fail	29.7	Fail
PJM East of 5004/05	5,389	Pass	24.3	Fail	20.7	Fail	23.7	Fail	23.1	Fail
PJM East of AP South	7,602	Pass	18.5	Pass	15.5	Pass	18.8	Pass	17.0	Pass

SI-SSA-0010-5606

Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	9,844	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	195	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	1,943	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	152	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	175,931	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	1,943	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	195	Row B; Table2Data
H	Uncommitted Capacity Imports	7,448	Calculated
I	Study Area Reserve Requirement	8,187	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	63,588	
	Load		
L	Balancing Area Annual Peak Load	143,633	Loads
M	Average Daily Peak Native Load in Peak Month	121,600	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	22,034	
P	Net Uncommitted Supply (K-O)	41,555	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,664	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	7,600	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	7600	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	14	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	88	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	26,628	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	14	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,449	Calculated
I	Study Area Reserve Requirement	1,724	Gendata
J	Amount of Line I Attributable to Seller, if any	176	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	15,220	
	Load		
L	Balancing Area Annual Peak Load	30,240	Loads
M	Average Daily Peak Native Load in Peak Month	24,093	Loads
N	Amount of Line M Attributable to Seller, if any	2,269	SellerLoads
O	Wholesale Load (L-M)	6,148	
P	Net Uncommitted Supply (K-O)	9,072	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,500	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,537	
	% of SIL for Seller's imported capacity →	0.01	
	% of SIL for Other's imported capacity →	0.99	
	SIL Value →	6537	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	107	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	51,729	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,212	Calculated
I	Study Area Reserve Requirement	2,975	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	20,577	
	Load		
L	Balancing Area Annual Peak Load	52,190	Loads
M	Average Daily Peak Native Load in Peak Month	42,368	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	9,822	
P	Net Uncommitted Supply (K-O)	10,754	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,365	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,319	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	6319	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	85	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	75,381	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,370	Calculated
I	Study Area Reserve Requirement	4,032	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	25,567	
	Load		
L	Balancing Area Annual Peak Load	70,729	Loads
M	Average Daily Peak Native Load in Peak Month	58,108	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	12,621	
P	Net Uncommitted Supply (K-O)	12,946	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,344	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	4,455	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	4455	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	11,339	10,592	9,844	10,592	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	195	195	195	195	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	1,643	1,944	1,943	1,944	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	491	1,461	225	1,374	SellerGendata
E	Uncommitted Capacity Imports	214	204	138	117	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	108,842	91,954	109,399	91,992	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	106,988	90,430	107,540	90,648	F - G
I	Study Area Reserve Requirement	7,474	6,516	7,991	6,470	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	7,335	6,385	7,817	6,352	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	181,889	178,911	175,931	178,911	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	1,643	1,944	1,943	1,944	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	195	195	195	195	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	7,868	24,681	4,028	23,215	Gendata; Row D
P	Uncommitted Capacity Imports	11,783	12,069	7,462	6,950	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	72,929	71,233	65,756	67,394	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,622	5,931	5,975	6,123	
S	Total Seasonal Uncommitted Capacity (Q+R)	80,550	77,164	71,731	73,518	
T	**Applicant's Market Share** (R÷S)	9.5%	7.7%	8.3%	8.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	11,997	12,273	7,600	7,067	
V	SIL Value	11,997	12,273	7,600	7,067	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	22	14	14	14	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	121	72	78	68	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	18,303	15,919	20,901	16,346	Loads
G	Amount of Line F Attributable to Seller, if any	1,749	1,434	1,764	1,268	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	16,553	14,485	19,137	15,078	F - G
I	Study Area Reserve Requirement	1,258	1,168	1,659	1,211	Gendata
J	Amount of Line I Attributable to Seller, if any	130	122	165	110	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	1,128	1,046	1,494	1,101	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	26,328	26,478	26,628	26,478	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	22	14	14	14	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,139	3,653	610	3,436	Gendata; Row D
P	Uncommitted Capacity Imports	7,381	8,758	6,459	7,791	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	14,911	16,065	11,860	14,667	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,230	5,954	5,826	6,199	
S	Total Seasonal Uncommitted Capacity (Q+R)	22,141	22,019	17,686	20,867	
T	**Applicant's Market Share** (R÷S)	32.7%	27.0%	32.9%	29.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	7,502	8,830	6,537	7,859	
V	SIL Value	7,502	8,830	6,537	7,859	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	162	91	95	69	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	35,188	30,080	37,518	30,214	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	33,334	28,556	35,658	28,871	F - G
I	Study Area Reserve Requirement	2,450	2,184	2,889	2,189	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,311	2,054	2,715	2,071	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	52,220	51,975	51,729	51,975	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	2,259	7,170	1,184	6,744	Gendata; Row D
P	Uncommitted Capacity Imports	7,942	8,202	6,224	6,034	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	22,294	22,424	18,423	20,350	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,144	5,861	5,725	6,103	
S	Total Seasonal Uncommitted Capacity (Q+R)	29,438	28,286	24,148	26,453	
T	**Applicant's Market Share** (R÷S)	24.3%	20.7%	23.7%	23.1%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	8,104	8,293	6,319	6,103	
V	SIL Value	8,104	8,293	6,319	6,103	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	187	115	77	81	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	48,658	41,074	51,437	41,155	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	46,804	39,551	49,577	39,811	F - G
I	Study Area Reserve Requirement	3,496	3,025	3,935	2,991	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	3,358	2,895	3,762	2,873	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	77,314	76,348	75,381	76,348	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,344	10,532	1,726	9,907	Gendata; Row D
P	Uncommitted Capacity Imports	7,710	8,741	4,378	5,987	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	31,554	32,139	24,722	29,772	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,169	5,885	5,707	6,115	
S	Total Seasonal Uncommitted Capacity (Q+R)	38,723	38,024	30,429	35,886	
T	**Applicant's Market Share** (R÷S)	18.5%	15.5%	18.8%	17.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,897	8,856	4,455	6,068	
V	SIL Value	7,897	8,856	4,455	6,068	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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DATA AND ASSUMPTIONS FOR ECONOMISTS INCORPORATED'S DELIVERED PRICE TEST STUDY FOR PSEG

This exhibit describes data and assumptions used in the delivered price test study ("study") carried out by Economists Incorporated for PSEG. Because the data are voluminous, we provide them in electronic workpapers. In those workpapers, the Files.xlsx spreadsheet provides a brief description of the organization of the data files.

This Exhibit has six sections. Section I discusses the study's representative periods. Section II discusses the geographic region and balancing authority areas. Section III discusses generation resources, including adjustments to generating capacity for seasons, maintenance, water availability, and long-term contracts. Section IV discusses transmission, including transmission pricing and losses. Section V discusses market prices. Section VI discusses the load data.

I. Periods

The study calculates market shares and concentration indexes for electric energy for ten representative periods during the year. The year is divided into three seasons (spring/fall, summer and winter). Spring/fall and winter seasons are divided into three periods based on days of the week, times of day and load levels. Summer is divided into four periods based on days of the week, times of day and load levels. Each calculation of market shares and concentration indexes reflects average conditions (e.g., average loads) during one of the resulting ten periods during the year (e.g., Summer Low Peak).

The study places each of the periods in each season into three condition categories: off-peak, low peak, and spike. Transmission pricing (see Section

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IV.B below) and plant availability (see Section III.A.2 below) vary among these three categories.

Table I-1 summarizes the ten periods for the destination markets.

Table I-1– Definition of Ten Periods for Destination Market

Number	*Season*	*Time*	*Condition*	*Hours*	*Description**
1	Spring/Fall	Top 10%	Spike	203	Top 10% of peak hours
2	Spring/Fall	Peak	Peak	1829	Remaining peak hours
3	Spring/Fall	Off-peak	Off-Peak	2360	Off-peak hours
4	Summer	Top 1%	Spike	11	Top 1% of peak hours
5	Summer	Top 10%	Spike	106	Top 10% of peak hours
6	Summer	Peak	Peak	950	Remaining peak hours
7	Summer	Off-peak	Off-Peak	1152	Off-peak hours
8	Winter	Top 10%	Spike	101	Top 10% of peak hours
9	Winter	Peak	Peak	907	Remaining peak hours
10	Winter	Off-peak	Off-Peak	1152	Off-peak Hours

Note: *Peak hours include hours ending 8 a.m. through 11 p.m. Eastern Time weekdays, excluding six major holidays. Off-peak hours = Hours ending 12 a.m. through 7 a.m. on weekdays and all weekend and holiday hours.

The Off-peak periods are all NERC holidays and weekend hours plus weekdays from the hour ending at midnight EPT until the hour ending at 0700.[1] The Off-peak periods have off-peak transmission pricing and plant availability.

In order to define the Top 1% and Top 10% periods for a given season, we removed all Off-peak hours from that season. We then ranked the remaining (peak) hours based on load levels in the destination market by season. We then defined as the Top 1% as the 1 percent of these remaining hours in which loads in the destination market were highest and the Top 10% as the highest 10 percent of peak hours based on load levels. These periods have spike transmission pricing and plant availability.

[1] Major holidays are New Year's, Memorial Day, 4th of July, Labor Day, Thanksgiving and Christmas. Major holidays are included in the Weekend period.

The Peak periods are weekdays from the hour ending at 0800 until the hour ending at 2300 EPT, excluding hours in the Top 10% periods and major holidays. The Low Peak period has on-peak transmission pricing and plant availability.

II. Geographic Coverage and Market Areas

The study includes market areas that correspond to the balancing authority areas used by the North American Electric Reliability Council (NERC), and PJM submarkets as defined by FERC. Table II-1 lists these market areas and their abbreviations. There are two study destination markets, PJM East and PJM East of 5004/5005.

Table II-1– List of Eastern Market Areas and Study Destinations

Abbreviation	*Full Name*	*Study Destination*
PJME	PJM East	Yes
PJM50	PJM East of 5004/5005	Yes
PJMS	PJM East of AP South	
PJM	PJM	
NYISO	New York ISO	

III. Generation

A. Generation Capacity and Ownership

The study includes generating units located in the areas that are (1) connected to the power grid, (2) not exclusively used for self-generation, and (3) either in a plant used primarily for electric generation or a Qualifying Facility.

1. Generating Unit Data

The study uses data for summer and winter capability at the unit level reported in the Energy Velocity (EV) database available from Ventyx. The units include all

units with a status of operating, standby, cold standby, restart, mothballed, testing, or under construction that went online before November 30, 2015 and with a retirement date after November 30, 2015. We exclude generation units that are less than 5 MW unless they are owned by PSEG.

2. Ownership

The study uses relies on Ventyx determination of plant and unit ownership. When Ventyx reports a holding company, the ownership is assigned to the holding company. For PSEG generation, the study relies upon Appendix B data from market-based rate filings and updates from the companies to determine plant ownership and seasonal capability. Operational control of PSEG units is consistent with the methodology used for market-based rates.

3. Seasonal variation in capability

The study uses seasonal capability data from EV. Spring/fall capacities are the average of summer and winter capacities.

4. Adjustments to Generating Capability

The generating capability figures used for each period are obtained by multiplying the seasonal capabilities by an availability factor, which is based on the period, unit location, and NERC General Availability Data Systems (GADS) category of the unit. The GADS database gives national average operating information for generating units by unit type and size. For example, it gives data for coal-fired steam units with capacities between 300 MW and 399 MW.

For each period and each generating unit, the availability factor adjusts for the following.

a) Unplanned outage rates by GADS category

For a given GADS category, the study assumes that unplanned (forced) outage rates (as a share of generating capability available after allowing for planned outages) are constant across seasons and generating units throughout the Region, regardless of owner. Based on GADS data for 2007 through 2011, the study calculates an equivalent forced outage rate (EIFOR), which measures the share of generating capability in a GADS category that is not available because of forced outages. The computation is EIFOR = (FOH)/AH, where FOH is number of forced outage hours and AH is total hours available for generation after planned outages (but before forced outages).[2]

b) Planned outage rates by GADS category and season

With four exceptions (hydro, pumped storage, wind, and solar units), the study assumes that the planned outage rate is constant for all generating units for a given GADS category and season. For a given GADS category, the share of hours of generating capability that is not available as a result of planned outages is computed as (POH + POEH)/PH; where PH are the period hours, POH are the hours not available because of planned outages, and POEH are the hours not available because of planned outage extensions

The study assumes that balancing authority areas are both summer and winter peaking. Therefore, the study assumes that all planned outages for thermal units occur during spring/fall.

[2] EIFOR differs slightly from the EFOR provided in the GADS data. EIFOR provides a better measure of a forced outage rate for peaking units that are operated a small percentage of the year.

c) Variation in hydro availability across seasons and periods

In general, utilities use hydro facilities to generate energy during the hours when energy prices are highest, subject to constraints imposed by availability of water and reservoir capacity. In order to incorporate these constraints, the study proceeds in the following manner.

First, the study uses EIA Form 923 monthly production data for the period 2011 to 2015 to compute average hourly hydro generation by season. Average hourly generation is then divided by hydro capability to give an average hourly hydro operating rate by season.

Second, depending upon the level of the hydro operating rate for a given season, the study calculates availability factors for the spike, low peak and off-peak periods. When the historical seasonal operating rate is below 30 percent, the availability factor for each period in the season is set equal to the operating rate; the 30 percent figure is an assumed "run of river" constraint. The study assumes that prospectively the maximum operating rate is 90 percent; this is the assumed "maximum rate" constraint. When the historical seasonal operating rate is above 90 percent, the availability factor for each period is set to 90 percent.

When the seasonal operating rate is above the run of river constraint and below the maximum rate, we reason that the hydro generator owner would be likely to produce a higher level of energy during spike hours, when energy prices are highest, than during low peak hours, and that the owner would be likely to produce a higher level during low peak than during off-peak hours.

Based on this reasoning, when the seasonal operating rate is between the run of river constraint and the maximum rate, as is the case for each of the three

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seasons, the study uses a spike availability factor of 90 percent, which is the assumed maximum operating rate, and off-peak availability factor of 30 percent, which is the assumed run-of-river constraint, and a calculated availability factor for the peak periods, as described below.

The seasonal peak availability factor is calculated using actual total seasonal hydro generation. The study then computes the hydro generation during all spike and off-peak hours, assuming the generation rates implied by the spike and off-peak derate factors computed in the manner described above. The study then calculates total peak hydro generation as the difference between total seasonal hydro generation and the sum of hydro generation during all spike and off-peak hours. The seasonal low peak availability factor is computed as total low peak hydro generation divided first by the number of hours in the off-peak period and then by hydro generating capacity.

d) Variation in pumped storage availability across seasons and periods

We assume that pumped storage units have 90 percent availability during Top 1% and Top 10% periods, 50 percent availability during Low Peak periods, and no availability during off-peak periods.

e) Wind availability

For each area, we calculate average operating rates from 2011 to 2015 by season from EIA-923 data. The average operating rates are the availability factors.

f) Solar availability

Availability for solar power is also calculated based on average operating rates from 2011 through 2015 reported in EIA-923. There is little solar power during

off-peak periods because of darkness. Accordingly, solar availability is weighted to on-peak periods.

B. Variable Costs of Generation

The study uses variable costs of generation that include fuel costs, sulfur dioxide and nitrogen oxide emissions costs, and variable operations and maintenance (VOM) costs. The study calculates fuel costs from unit heat rates and Platts' Gas Daily spot prices at the unit's reported natural gas hub by Energy Velocity, #2 Diesel, Low-Sulfur – Industrial for the East Coast, and Residual Fuel Oil sales to end users for the East Coast for the test period. Natural gas prices vary by hub, but were $2.67 per mmBtu at TETCO M3, the hub with the largest reported capacity in the study. Fuel costs for other fuels are based upon the average fuel costs reported in the EV data for each fuel type. Emissions prices during the test year were $2 per ton for SO2 year-round and $300 per ton for NOx in the summer season. CO_2 costs for units located in Regional Greenhouse Gas Initiative (RGGI) states are $5.21/ton, which is based upon RGGI Auction results in Dec 2014. Units in Montgomery County, MD have an additional $5/ton carbon tax on CO_2 emissions. VOM costs are from the EV database.

C. Long-term Contracts

We reviewed Appendix B data from market-based rate filings, FERC Form 1 filings, and Electric Quarterly Report ("EQR") data to obtain data on long-term contracts. Where the market-based rate filing indicates a change of operational control, we include a contract transferring control to the buyer. We leave the generation unit in the BAA where it is physically interconnected to the transmission system. When the buyer is a load-serving entity in another BAA, we give a priority firm transmission path to the BAA with the load.

Long-term contracts that expire prior to January 1, 2015 are not included in the study. Long-term contracts that expire between January 1, 2015 and July 31,

2015 are included only in the seasons for which they are in effect. Contracts that expire after August 31, 2015 are included in the study.

IV. Transmission

A. Transmission Network

The study incorporates a contract path transmission network for modeling purposes. Transmission pricing between balancing authority areas is represented by a traditional contract path transmission network in which the direct physical connections between balancing authority areas are also the individually priced links from which contract paths are constructed.

B. Transmission and Ancillary Services Pricing and Losses

As specified by the Commission's Appendix A, the study generally uses ceiling prices for transmission service from Schedules 1, 2 and 8 of the utility's *pro forma* open-access transmission tariff. Transmission providers may require transmission customers to purchase ancillary services under Schedule 1 (scheduling, system control and dispatch) and Schedule 2 (reactive supply and voltage control). Schedule 8 gives the rates for non-firm point-to-point transmission service. The study uses transmission prices from tariffs.

When we have tariffs available, we calculate rates for off-peak, peak and spike categories. Because of discounting and the nature of baseload purchases, off-peak rates are often lower than peak rates.[3] We use two steps to determine off-peak rates. Step 1: When a utility posts off-peak hourly rates, we use the posted rates. Step 2: When a utility does not post off-peak hourly rates, we calculate an hourly off-peak rate based on other tariff information. To calculate hourly off-

[3] For transactions longer than one hour, the *pro forma* tariff caps the amount that the purchaser pays per day by the daily rate, and the amount that the purchaser pays per week by the weekly rate.

peak rates, we divide the weekly rate by 168, the number of hours in a week. When tariffs specify fees on a per transaction basis, we divide them by 25 to put them on a per MW basis.

We use similar steps to determine peak rates. Step 1: When a utility posts maximum hourly rates in its tariff, we use the maximum tariff rates. Step 2: When a utility does not post off-peak hourly rates, we calculate a peak rate based on other tariff information. To calculate hourly peak rates, we divide the weekly rate by 80—the "Appalachian" method. When tariffs specify fees on a per transaction basis, we divide them by 25 to put them on a per MW basis.

For spike periods, we use ceiling hourly rates from tariffs, when available. Otherwise, we use the Appalachian method.

Whenever practical, the study uses loss rates from tariffs. When these methods did not provide a loss rate for a particular utility, the study assumes that losses are three percent per utility.[4] The study assumes that transmission customers pay losses in-kind. That is, if area A exports 100 MW to area B and the losses are 3 percent, only 97 MW arrive at area B.

For areas where tariffs are not available, rates and losses are the average by period for all the reporting areas.

C. Transfer Capability and SILs

The geographic market includes only PJM and NYISO. The SILs for PJM East and PJM East of 5004/5005 comes from the 2015 Simultaneous Import Limit

[4] Losses of 3 percent are representative of the industry. See, FERC Open Access NOPR, *FERC Stats & Regs*, ¶32,514 at 33,150 (1995).

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Study filed by PJM on September 2, 2016.[5] The total imports into the destination markets may be less than the actual ability to import into the destination because not all the generation capability owned or controlled by load-serving entities within the destination markets studied in PJM have been identified in the data.

V. Market Prices

The study used December 2014-November 2015 real-time hourly prices from the RTO LMP for PJM East and PJM East of 5004/5005. Table V-1 shows the PJM East of 5004/5005 market prices in each of the ten periods, and Table V-2 shows the PJM East market prices.

Table V-1 – PJM East of 5004/5005 Market Prices ($/MWh)

Time	*Spring/Fall*	*Summer*	*Winter*
Top 1%	-----	$148.44	-----
Top 10%	$62.03	$64.59	$185.57
Low Peak	$35.73	$35.56	$47.55
Off-Peak	$29.46	$24.88	$50.16

Table V-2 – PJM East Market Prices ($/MWh)

Time	*Spring/Fall*	*Summer*	*Winter*
Top 1%	-----	$145.63	-----
Top 10%	$57.82	$63.88	$193.51
Low Peak	$32.73	$29.67	$50.59
Off-Peak	$26.67	$21.25	$50.94

[5] PJM Interconnection, L.L.C., *Informational Filing of 2015 Simultaneous Import Limit Study Report for PJM Region*, Docket No. AD1-2-007, September 2, 2016, Accession No. 20160902-5155.

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VI. Load and Contract Obligations for AEC Calculations

Load data come from PJM for PJM and from Energy Velocity for the other supply areas.

To compute load requirements for market participants in New York and PJM, we apportion the total load in each market area in New York and PJM to all suppliers in proportion to their respective generation capacities. We assumed 70 percent of load is committed for a year or longer and the remaining 30 percent is contracted for shorter periods.[6] To account for their greater load obligations, we assume that Dominion has 100 percent responsibility for its allocation of load and that AEP has 90 percent of its allocation as opposed to the standard 70 percent.

[6] This is a reasonable estimate for the long-term load coverage since this number is generally between 60 and 80 percent for most generation suppliers.

Technical Appendix:

Methods Used to Compute Concentration

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This Exhibit describes the methods used to calculate market shares and concentration in destination markets.

Allocation of scarce transmission capability is accomplished using linear and nonlinear programs that model generation dispatch and the contract path transmission system. This Exhibit provides an overview of the structure of the programs and presents the equations.

Overview of Linear Program

The linear program models control areas as nodes in a transmission system. Each node has a demand for and a supply of electric energy. The supply is based on the generators at the node and potential deliveries to the node via transmission links from other control areas. The linear program allows for net import and export limits to and from an individual control area. Given generation capability and costs and transmission capability and costs, the linear program finds the least-cost solution that satisfies the specified loads. Costs are defined as dispatch (generation) costs plus transmission costs including losses plus the default cost for "unserved" load. For each solution, the linear program determines the quantities produced in, exported from, and imported into each control area.

The Mathematical Equations

The linear program to be solved is given below:

Minimize Total Cost: $Cost = GC + TC + UC$

Subject to:

(1) Generation: $TG_a = \sum_{u}^{u \in a} G_{a,u}$ for each area *a*;

(2) Imports: $YI_a = \sum_{b}^{a,b \in network} (1 - h_{b,a}) T_{b,a}$ for each area *a*;

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(3)	Exports:	$YE_a = \sum_{b}^{a,b \in network} T_{a,b}$	for each area *a*;
(4)	Net Imports:	$Y_a = YI_a - YE_a$	for each area *a*;
(5)	Supply/Demand Balance:	$TG_a + Y_a + U_a = D_a$	for each area *a*;
(6)	Generation Cost:	$GC = \sum_{a} \sum_{u}^{u \in a} d_{a,u} G_{a,u}$	for each area *a*;
(7)	Transmission Cost:	$TC = \sum_{a,b}^{a,b \in network} r_{a,b} T_{a,b}$	for each path *a* to *b*;
(8)	Unfilled Demand Cost:	$UC = \sum_{a} pU_a$	for each area *a*;
(9)	Generation Limits:	$g\min_{a,u} \le G_{a,u} \le g\max_{a,u}$	for each unit *u* in each area *a*;
(10)	Transmission Limits:	$t\min_{a,b} \le T_{a,b} \le t\max_{a,b}$	for each link *a* to *b* in the transmission network; and
(11)	Net Import Limits	$Y\min_{a} \le Y_a \le Y\max_{a}$	for each area *a*;

where:

a,b	are subscripts for control/transmission areas;
Cost	is total system cost;
$d_{a,u}$	is the dispatch cost of unit *u* in area *a*;
D_a	is demand for power in area *a*;
$G_{a,u}$	is generation output of unit *u* in area *a*;
GC	is total system generation cost;
$G\max_{a,u}$	is the maximum output of unit *u* in area *a*;
$G\min_{a,u}$	is the minimum output of unit *u* in area *a*;
$h_{b,a}$	is the fraction of power lost to resistance from moving power from area *b* to area *a*;
N	is a subscript to identify simultaneous transmission constraint *n*;
P	is the default price;
$r_{a,b}$	is the transmission rate from area *a* to area *b*;

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$T_{a,b}$	is the power flow from area *a* to area *b*;
TC	is total system transportation expenses;
TG_a	is total generation output in area *a*;
t $\max_{a,b}$	is the maximum power flow from area *a* to area *b*;
t $\min_{a,b}$	is the minimum power flow from area *a* to area *b*;
U	is a subscript to identify units in an area;
U_a	is the amount of demand in area *a* not met by generation or imports
UC	is total system cost of not meeting demand;
Y_a	is net imports into area *a*;
YE_a	is total exports from area *a*; and
YI_a	is total imports into area *a*;
Y $\min_a$	is minimum net imports in area *a;*
Y $\max_a$	is maximum net imports in area *a.*

This linear program is solved using the BDMLP solver in GAMS. In order to calculate concentration for different destinations, seasons, and periods, the PASS GAMS program loops through the destinations, seasons, and periods with calls to Solvers to solve the linear programs. Loads, unit availability and transmission availability are adjusted for each season-period combination.

Calculating Concentration

Transmission allocation is accomplished in four steps. In the first step the linear program finds the net-back prices in all control areas given a price at the destination control area equal to 105 percent of the pre-merger price. Suppose the pre-merger price at the destination, control area A, is $20/MWh. Then all generation capability with a dispatch cost of $21/MWh or less in the destination area would be included in the market because $21 is 105 percent of $20. If transmission cost (including losses) is $5/MWh from control area B to A, then the net-back price at B would be $16/MWh, which is the $21/MWh less the $5/MWh transmission cost between B and A. Then, all generation capability at B with dispatch costs equal to or less than $16/MWh would be included in the market if there were no transmission constraints. Calculation of net-back prices is

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accomplished by setting the default price, *p*, equal to 105 percent of the pre-merger price at the destination, setting load at the destination to a high number and loads elsewhere to zero, setting transmission limits high enough so that the transmission system is not constrained, and setting a limited amount of generation in each area with a zero dispatch cost. The shadow prices produced by the linear program will be *p* at the destination and the relevant net-back prices in other areas.

In the second step, one calculates Economic Capacity (EC) and Available Economic Capacity (AEC) in each area. These values are then used to limit generation capability. The ownership shares of AEC and EC are calculated for each node in the system.

In the third step, the linear program determines the amount of energy that can be imported into an area given available EC (or AEC) and limits on transmission capacity. This is accomplished by limiting generation in each area to the capacity amount (EC or AEC), giving generation outside the destination market a lower cost than generation inside the destination market, and minimizing cost to serve a large load at the destination market. The amount of generation supplied to the destination is the maximum that can be imported into the destination market.

In the fourth step, transmission is allocated by the following non-linear program:

Minimize Loss: $$Loss = \sum_{\alpha}\left(\frac{C_{\alpha}^{2}}{Y_{Dest}s_{\alpha}} - 2C_{\alpha}\right)$$

Subject to:

(1) Pre Shares: $$s_{\alpha} = \frac{C\max_{\alpha}}{\sum_{\beta} C\max_{\beta}}$$ for each area α;

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(2)	Allocated Shares:	$A_\alpha = \frac{C_\alpha}{Y_{Dest}}$	for each area α;
(3)	Imports:	$YI_a = \sum_b^{a,b \in network} (1 - h_{b,a}) T_{b,a}$	for each area *a*;
(4)	Exports:	$YE_a = \sum_b^{a,b \in network} T_{a,b}$	for each area *a*;
(5)	Net Imports:	$Y_a = YI_a - YE_a$	for each area *a*;
(6)	Supply/Demand Balance:	$C_a + Y_a + U_a = D_a$	for each area *a*;
(7)	Capacity Limits:	$c\min_a \le C_a \le C\max_a$	for each area *a*;
(8)	Transmission Limits:	$t\min_{a,b} \le T_{a,b} \le t\max_{a,b}$	for each link *a* to *b* in the transmission network; and
(9)	Max Import Limit	Y_{Dest} = Maximum imports from step 3;	

where:

a,b	are subscripts for control/transmission areas;
α,β	are subscripts for control/transmission areas other than the destination market;
s_α	Is area α's share of capacity outside of the destination;
A_α	is area α's share of allocated capacity outside of the destination;
Loss	is the loss function to be minimized.

The loss function is derived from the weighted squared-errors between the pre-allocation shares and the post-allocation shares, where Y_{Dest}/s_α are the weights. For each source control area, the weighted squared-error is given by:[1]

$$W_\alpha = \frac{Y_{Dest}}{s_\alpha}(A_\alpha - s_\alpha)^2.$$

[1] This exposition ignores the adjustments necessary to give priority to minimum transfer levels from a source area to the destination.

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Accordingly, the sum of the weighted squared-errors gives rise to the loss function, which can be seen by:

$$\begin{aligned} Loss &= \sum_{\alpha} W_{\alpha} \\ &= \sum_{\alpha} \frac{Y_{Dest}}{s_{\alpha}} (A_{\alpha} - s_{\alpha})^2 \\ &= \sum_{\alpha} \frac{Y_{Dest}}{s_{\alpha}} (A_{\alpha}^2 - 2 s_{\alpha} A_{\alpha} + s_{\alpha}^2) \\ &= \sum_{\alpha} \left(\frac{C_{\alpha}^2}{Y_{Dest} s_{\alpha}} - 2 C_{\alpha} \right) + \text{constant}. \end{aligned}$$

The resulting shares from minimizing this loss functions preserve the relative shares of capacity behind any transmission constraint going to the destination. This can be seen from the following LaGrangian equation to be minimized:

$$L = \sum_{i} \left(\frac{C_i^2}{Y_{Dest} s_i} - 2 C_i \right) + \lambda \left(T - \sum_{i} C_i \right),$$

where *T* is the transmission limit affecting control areas *i*. The first order conditions are:

$$\frac{\partial L}{\partial C_i} = \frac{2 C_i}{Y_{Dest} s_i} - 2 - \lambda = 0,$$

which can be rearranged to give:

$$A_i = \frac{C_i}{Y_{Dest}} = \left(\frac{2 + \lambda}{2} \right) s_i,$$

which shows that the allocated market shares of those areas affected by the transmission constraint are proportional to their shares of capacity before the transmission allocation. Moreover, this is the only transmission allocation

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method that maintains the relative shares of capacity behind any binding transmission constraint in the allocation process.

This non-linear program is solved using the COINIPOPT solver in GAMS. The calculated capacities from the nonlinear program above less transmission losses determine the capacities for the market share calculations for sources outside of the destination market. The capacities within the destination market are given full weights.

Market concentration is the HHI, which is the sum of the squared market shares. Mathematically,

$$HHI = \sum_{i=1}^{n} S_i^2,$$

where S_i is the allocated share of firm *i* and *n* is the number of firms in the market. The summary sheets combine all the firms with shares of 0.7 percent or less (other than Applicants) into the "Other" category. The collective share of the Other category does not directly enter the HHI calculation other than the represented capacity as each independent entity enters the HHI calculation. For example, if ten firms with 0.5 percent shares were in the Other category, the HHI contribution of the Other category would be 0.625 (= 10 x .5 x .5 = 10 x .0625) and ***not*** 25.

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Delivered Price Test - PJM50 Market

Available Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$62.03	2,498	24,613	22,116	6,776	Yes	10.1	Yes	1,024	Yes
Spring/Fall	Peak	$35.73	2,927	26,894	23,967	6,776	Yes	10.9	Yes	1,085	Yes
Spring/Fall	Off Peak	$29.46	1,775	18,948	17,173	6,776	Yes	9.4	Yes	1,358	Yes
Summer	Top 1%	$148.44	1,443	22,909	21,466	9,933	Yes	6.3	Yes	1,042	Yes
Summer	Top 10%	$64.59	1,562	21,384	19,822	9,933	Yes	7.3	Yes	1,000	Yes
Summer	Peak	$35.56	2,009	22,352	20,344	9,933	Yes	9.0	Yes	1,055	Yes
Summer	Off Peak	$24.88	2,103	15,701	13,598	9,933	Yes	13.4	Yes	1,772	Yes
Winter	Top 10%	$185.57	1,921	26,153	24,233	6,073	Yes	7.3	Yes	1,008	Yes
Winter	Peak	$47.55	0	19,398	19,398	6,073	Yes	0.0	Yes	1,421	Yes
Winter	Off Peak	$50.16	0	18,024	18,024	6,073	Yes	0.0	Yes	1,592	Yes

Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$62.03	8,704	55,273	46,570	40,893	Yes	15.7	Yes	1,124	Yes
Spring/Fall	Peak	$35.73	7,678	50,521	42,844	28,923	Yes	15.2	Yes	1,084	Yes
Spring/Fall	Off-Peak	$29.46	5,932	41,688	35,756	24,614	Yes	14.2	Yes	1,133	Yes
Summer	Top 1%	$148.44	8,597	59,581	50,984	51,071	No	14.4	Yes	1,126	Yes
Summer	Top 10%	$64.59	8,608	56,301	47,694	47,510	Yes	15.3	Yes	1,112	Yes
Summer	Peak	$35.56	7,389	51,064	43,675	36,423	Yes	14.5	Yes	1,069	Yes
Summer	Off Peak	$24.88	6,266	42,155	35,889	29,051	Yes	14.9	Yes	1,152	Yes
Winter	Top 10%	$185.57	7,022	55,902	48,880	41,770	Yes	12.6	Yes	1,108	Yes
Winter	Peak	$47.55	4,602	43,979	39,377	34,380	Yes	10.5	Yes	1,206	Yes
Winter	Off Peak	$50.16	4,475	39,851	35,376	30,307	Yes	11.2	Yes	1,281	Yes

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Exhibit PEG-15
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Delivered Price Test - PJME Market

Available Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$57.82	3,225	20,600	17,375	3,806	Yes	15.7	Yes	1,179	Yes
Spring/Fall	Peak	$32.73	2,065	20,408	18,343	3,806	Yes	10.1	Yes	1,228	Yes
Spring/Fall	Off Peak	$26.67	1,276	18,023	16,747	3,806	Yes	7.1	Yes	1,669	Yes
Summer	Top 1%	$145.63	2,279	16,425	14,145	6,174	Yes	13.9	Yes	1,216	Yes
Summer	Top 10%	$63.88	2,402	15,949	13,547	6,174	Yes	15.1	Yes	1,267	Yes
Summer	Peak	$29.67	2,199	15,336	13,136	6,174	Yes	14.3	Yes	1,375	Yes
Summer	Off Peak	$21.25	976	13,909	12,933	6,174	Yes	7.0	Yes	1,979	Yes
Winter	Top 10%	$193.51	2,969	22,743	19,774	2,710	Yes	13.1	Yes	1,199	Yes
Winter	Peak	$50.59	0	15,998	15,998	2,710	Yes	0.0	Yes	1,606	Yes
Winter	Off Peak	$50.94	0	15,146	15,146	2,710	Yes	0.0	Yes	1,967	Yes

Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$57.82	8,677	36,450	27,773	22,528	Yes	23.8	No	1,252	Yes
Spring/Fall	Peak	$32.73	6,520	32,603	26,084	15,404	Yes	20.0	Yes	1,171	Yes
Spring/Fall	Off-Peak	$26.67	4,934	28,457	23,523	13,106	Yes	17.3	Yes	1,233	Yes
Summer	Top 1%	$145.63	8,551	36,587	28,036	29,462	No	23.4	No	1,264	Yes
Summer	Top 10%	$63.88	8,553	34,879	26,326	27,143	No	24.5	No	1,270	Yes
Summer	Peak	$29.67	6,853	31,187	24,334	20,217	Yes	22.0	No	1,224	Yes
Summer	Off Peak	$21.25	5,060	26,734	21,674	16,090	Yes	18.9	Yes	1,264	Yes
Winter	Top 10%	$193.51	7,105	35,709	28,603	21,263	Yes	19.9	Yes	1,181	Yes
Winter	Peak	$50.59	4,573	26,985	22,412	17,939	Yes	16.9	Yes	1,268	Yes
Winter	Off Peak	$50.94	4,449	23,450	19,001	15,660	Yes	19.0	Yes	1,461	Yes

SI-SSA-0010-5636

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Appendix E Letters of concurrence regarding the control of certain jointly owned generation facilities

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KEYSTONE-CONEMAUGH PROJECTS

682 Philadelphia Street – 2nd floor
Indiana, Pennsylvania 15701

724-349-1205

MAILING ADDRESS
P.O. BOX 68
INDIANA, PA 15701

GEORGIANNA R. STENGER, ESQ.
ADMINISTRATIVE MANAGER
DIRECT DIAL 724-357-1713

December 1, 2007

Addressed to:

Conemaugh Power LLC
Constellation Power Source Generation, Inc.
Duquesne Conemaugh LLC
Exelon Generation Company, LLC
PPL Montour, LLC
PSEG Fossil LLC
Reliant Energy Mid-Atlantic Power Holdings, LLC
UGI Development Company

Re: Joint Owners of the Conemaugh Electric Generating Station (collectively, the "Owners") statement of ownership and control

Dear Owners:

This letter sets forth the understanding of the degree of ownership and control exercised by each of the Owners with respect to the jointly-owned Conemaugh Electric Generating Station for purposes of facilitating compliance with the requirements of FERC Order No. 697.[1]

The Owners and Reliant Energy Northeast Management Company (the "Operator") each confirm its concurrence with the following statement of facts relating to the Conemaugh Electric Generating Station:

1. The Owners jointly own the Conemaugh Electric Generating Station, consisting of two 850 MW net pulverized coal fired once-through boilers and related facilities having a combined rated seasonal net generating capacity of 1,712 MW (1,884 MW nameplate), located in East Wheatfield and West Wheatfield Townships, Indiana County, Pennsylvania (the "Station").

---

1 Not all of the Owners agree as to whether Order No. 697 requires the submission of a letter of concurrence when the putative submitting party is not claiming that it does not control its percentage ownership share of a jointly-owned unit. Notwithstanding, all of the Owners have no objection to submission of this letter by an Owner which does believe that such a submission is required.

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2. As of the date hereof, the Station is collectively owned by the Owners as tenants-in-common, each holding an undivided interest in the Station (and all real and personal property comprising the same) in the respective ownership percentages set forth below:

Owner	Ownership Interest
Conemaugh Power LLC	3.72%
Constellation Power Source Generation, Inc.	10.56%
Duquesne Conemaugh LLC	3.83%
Exelon Generation Company, LLC	20.72%
PPL Montour, LLC	16.25%
PSEG Fossil LLC	22.50%
Reliant Energy Mid-Atlantic Power Holdings, LLC	16.45%
UGI Development Company	5.97%

3. Each of the Owners is deemed to control the generating capacity of the Station in accordance with its respective ownership percentage as set forth in the preceding paragraph for purposes of facilitating compliance with the requirements of FERC Order No. 697.

Please indicate your company's concurrence to the above statement of facts by executing this letter in the space provided below your company's name at the foot hereof.

Sincerely yours,

Georgianna R. Stenger
Administrative Manager
Keystone-Conemaugh Projects

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20160328-5240 FERC PDF (Unofficial) 5/23/2016 8:31:16 PM

Owners:

Acknowledged and Agreed to this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20160328-5240 FERC PDF (Unofficial) 12/28/2007 8:31:36 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this 14 day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: Anthony F. Pekny

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20160328-5240 FERC PDF (Unofficial) 5/23/2008 8:31:16 5804 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this 1 day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: Kenneth Kaufman

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this 1st day of December, 2007.

PPL MONTOUR, LLC

By: Dennis J. Murphy
DENNIS J. MURPHY

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20160328-5240 FERC PDF (Unofficial) 3/28/2016 8:31:36 AM

To the Owners of the Conemaugh Electric Generating Station
December 1, 2007
Page 4

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this 13th day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: James V. Lacher

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20160328-5240 FERC PDF (Unofficial) 5/23/2008 8:31:36 PM

Owners:

Acknowledged and Agreed to this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

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Operator:

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY NORTHEAST
MANAGEMENT COMPANY

By: _____

20160328-5240 FERC PDF (Unofficial) 5/23/2018 6:31:65804 PM

KEYSTONE-CONEMAUGH PROJECTS

682 Philadelphia Street 2nd floor
Indiana, Pennsylvania 15701

724-349-1205

MAILING ADDRESS
P.O BOX 68
INDIANA, PA 15701

GEORGIANNA R. STENGER, ESQ.
ADMINISTRATIVE MANAGER
DIRECT DIAL: 724-357-1713

December 1, 2007

Addressed to:

Constellation Power Source Generation, Inc.
Duquesne Keystone LLC
Exelon Generation Company, LLC
Keystone Power LLC
PPL Montour, LLC
PSEG Fossil LLC
Reliant Energy Mid-Atlantic Power Holdings, LLC

Re: Joint Owners of the Keystone Electric Generating Station (collectively, the "Owners") statement of ownership and control

Dear Owners:

This letter sets forth the understanding of the degree of ownership and control exercised by each of the Owners with respect to the jointly-owned Keystone Electric Generating Station for purposes of facilitating compliance with the requirements of FERC Order No. 697.[1]

The Owners and Reliant Energy Northeast Management Company (the "Operator") each confirm its concurrence with the following statement of facts relating to the Keystone Electric Generating Station:

1. The Owners jointly own the Keystone Electric Generating Station, consisting of two 850 MW net pulverized coal fired once-through boilers and related facilities having a combined rated seasonal net generating capacity of 1,712 MW (1,884 MW nameplate), located in Plumcreek, South Bend and Cowanshannock Townships, Armstrong County, Pennsylvania, and Armstrong Township, Indiana County, Pennsylvania (the "Station").

[1] Not all of the Owners agree as to whether Order No. 697 requires the submission of a letter of concurrence when the putative submitting party is not claiming that it does not control its percentage ownership share of a jointly-owned unit. Notwithstanding, all of the Owners have no objection to submission of this letter by an Owner which does believe that such a submission is required.

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2. As of the date hereof, the Station is collectively owned by the Owners as tenants-in-common, each holding an undivided interest in the Station (and all real and personal property comprising the same) in the respective ownership percentages set forth below:

Owner	Ownership Interest
Constellation Power Source Generation, Inc.	20.99%
Duquesne Keystone LLC	2.47%
Exelon Generation Company, LLC	20.99%
Keystone Power LLC	3.70%
PPL Montour, LLC	12.34%
PSEG Fossil LLC	22.84%
Reliant Energy Mid-Atlantic Power Holdings, LLC	16.67%

3. Each of the Owners is deemed to control the generating capacity of the Station in accordance with its respective ownership percentage as set forth in the preceding paragraph for purposes of facilitating compliance with the requirements of FERC Order No. 697.

Please indicate your company's concurrence to the above statement of facts by executing this letter in the space provided below your company's name at the foot hereof.

Sincerely yours,

Georgianna R. Stenger
Administrative Manager
Keystone-Conemaugh Projects

To the Owners of the Keystone Electric Generating Station
December 1, 2007
Page 3

Owners:

Acknowledged and Agreed to
this __ _ day of December, 2007

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this __ . _ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this _ _ . day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ___ . day of December, 2007.

KEYSTONE POWER LLC

By. _ ___ _ _ _____

Acknowledged and Agreed to
this ___ _ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _ __ _____

Owners:

Acknowledged and Agreed to this ___ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to this 14 day of December, 2007.

DUQUESNE KEYSTONE LLC

By: Anthony F. Pelz

Acknowledged and Agreed to this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to this ____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to this ____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

20160328-5240 FERC PDF (Unofficial) 12/28/2007 8:31:58 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this 1 day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: Kenneth Kaiser

Acknowledged and Agreed to
this _____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this __. day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Owners:

Acknowledged and Agreed to this ___ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to this ___ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Owners:

Acknowledged and Agreed to
this __ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this __ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this 13th day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Owners:

Acknowledged and Agreed to
this __ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: James D. Lash

20160328-5240 FERC PDF (Unofficial) 12/28/2007 8:31:36 PM

Operator:

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY NORTHEAST
MANAGEMENT COMPANY

By: Jaime D Lach

20160328-5240 FERC PDF (Unofficial) 5/23/2008 6:31:16 PM

Thomas P. Joyce
Senior Vice President

P.O. Box 236, Hancocks Bridge, NJ 08038
tel: 856.339.1100 fax: 856.339.1104
email: Thomas.Joyce@pseg.com

PSEG
Nuclear L.L.C.

Carol Peterson
Vice President Finance
Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

Letter Regarding Control of Jointly-Owned Nuclear Facilities

Dear Ms. Peterson:

In connection with its upcoming compliance filings pursuant to Order No. 697,[1] PSEG Nuclear LLC ("PSEG") is submitting this letter in order to set forth its understanding of, and is requesting Exelon Generation Company LLC's ("Exelon") concurrence on, the respective level of control exercised by both companies with respect to the two nuclear facilities that they jointly own.[2]

PSEG avers and requests Exelon's concurrence on the following:

1. PSEG and Exelon jointly own and control two nuclear power plants, Peach Bottom Atomic Power Station located in Delta, PA and the Salem Nuclear Generating Station in Lower Alloways Creek, NJ.

2. In accordance with the Joint Owners Agreement for Peach Bottom dated November 24, 1971, as amended on thereafter, between the Parties, PSEG and Exelon each own 50% of the generating station. Under the Agreement, Exelon is the designated operator of Peach Bottom.

3. In accordance with the Joint Owners Agreement for Salem dated November 24, 1971, as amended thereafter, between the Parties, Exelon owns 42.59% and PSEG owns 57.41% of the generating station. Under the Agreement, PSEG is the designated operator of Salem.

4. Section 4.1 of each of the Joint Owners' Agreements states, "The signatories shall be entitled to shares of the installed capacity, available capacity, operating capacity and hourly energy generation of the Station in proportion to their ownership . . .."

[1] *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, 119 FERC ¶ 61,295 (2007).

[2] PSEG has requested a letter of concurrence from Exelon in order to facilitate the Commission's review of the market power analysis submitted by PSEG with respect to facilities it jointly owns with Exelon. Exelon has no objection to PSEG's submission of this letter as part of PSEG's compliance filing,.

Thomas P. Joyce
Senior Vice President

P.O. Box 236, Hancocks Bridge, NJ 08038
tel: 856.339.1100 fax: 856.339.1104
email: Thomas.Joyce@pseg.com

PSEG
Nuclear L.L.C.

5. Section 11.1 of each of the Joint Owners' Agreements provides that the generating station will be operated by the party designated as operator for the mutual benefit of PSEG and Exelon.

6. In Order No. 697 the Commission stated that under "where a jointly-owned generation facility is operated by one of the joint-owners for the benefit of and on behalf of all of the joint-owners . . . it may be reasonable to allocate capacity based on ownership percentages...." Order No. 697 at P 188.

7. In accordance with the guidance provided in Order No. 697 and with the language of each of the joint owners' agreements, PSEG and Exelon should be deemed to control each of the nuclear facilities' output in line with their proportionate ownership share of each facility. As such, PSEG and Exelon should each be deemed to control 50% of Peach Bottom's output, and PSEG should be deemed to control 57.41% of Salem's output with Exelon controlling 42.59%.

Please indicate Exelon's concurrence to the above by executing the Acknowledgement and Agreement section below.

Sincerely

Thomas P. Joyce
Senior Vice President – Operations

Acknowledged and Agreed to
this 21 day of December, 2007.

Carol Peterson
Vice President Finance, Exelon Nuclear, and
an officer of Exelon Generation Company, LLC

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JOINT LETTER OF CONCURRENCE

Regulations of the Federal Energy Regulatory Commission (the "FERC") require each public utility with market-based rate authority to file an updated market power analysis every three years in accordance with a schedule adopted in *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stat. & Regs., Regulations Preambles ¶ 31,252 (2007) ("Order No. 697"). See, 18 CFR § 35.37(a)(1). Each public utility with market-based rate authority may also be required to file a change-in-status report regarding certain changes in circumstances that occur between the dates on which its triennial market power analyses are filed. 18 CFR § 35.42. Among other matters, the market power analysis is to address the amount of generation capacity that the affected utility owns or controls. Where more than one public utility owns a generating facility, FERC requires the utility that is submitting a market power analysis seek a "letter of concurrence" from the other affected co-owning public utilities that identifies the degree to which each public utility controls the generating facility, and to submit the letter with its filing. *See* FERC Order No. 697, 119 FERC ¶ 61,295, P 187 (2007).

The Yards Creek Pumped Storage Hydroelectric Project (the "Yards Creek Project") is a FERC-licensed pumped-storage hydroelectric project with a nameplate capacity of 400 MWs, and is located in Pahaquarry and Blairstown Townships, in Warren County, New Jersey. *See* FERC Project No. P-2309.

PSEG Fossil LLC ("PSEG") and Jersey Central Power & Light Company ("JCPL") each own, as tenants in common with the other, an undivided 50% interest in the Yards Creek Project. Accordingly, if and when PSEG or JCPL submit an updated market power analysis to the FERC, each will be subject to FERC's requirement to seek a "letter of concurrence" regarding the degree to which each controls the Yards Creek Project.

Both PSEG and JCP&L (and their affiliates) own transmission facilities and provide wholesale electric service in the Northeast region, as defined in Order No. 697. Pursuant to the schedule adopted in Order No. 697, PSEG and JCP&L are each required to submit an updated market power analysis to the FERC for markets within the Northeast region in December 2010. PSEG and/or JCP&L may also be obligated to file a change-in-status report or other market power analyses before its subsequent triennial market power analysis for the Northeast region is scheduled to be filed. Therefore, for the sole purpose of enabling either PSEG or JCP&L to submit a market power analysis that addresses, among other issues (to the extent necessary), the scope of each party's control of the Yards Creek Project, PSEG and JCP&L each aver and agree as follows:

1. JCP&L operates and maintains the Yards Creek Project pursuant to the Yards Creek Pumped Storage Hydroelectric Generating Station Operating Agreement, which is dated October 6, 1965 (the "Operating Agreement').

2. Article 2 of the Operating Agreement designates JCP&L as holding sole responsibility for the operations and maintenance the Yards Creek Project. Article 2 further provides that JCPL shall operate the Yards Creek project in the same manner as if JCPL had the complete ownership interest in the Yards Creek Project.

3. JCP&L does, in fact, operate and control the Yards Creek Project in the same manner as if JCP&L had the complete ownership interest in the Yards Creek Project in accordance with Article 2 of the Operating Agreement.

4. Accordingly, PSEG and JCP&L each agree and concur that for the purpose of the market power analyses required by Order No. 697, JCPL shall be deemed to control the Yards Creek Project generation capacity and electric energy output.

ACKNOWLEDGED AND AGREED:

Richard P. Lopriore
President, PSEG Fossil LLC

Dated: 12/21/10

ACKNOWLEDGED AND AGREED:

Dean Stathis
Director, Regulated Commodity Sourcing
Jersey Central Power & Light Company

Dated: 12/08/2010

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G	ER99-3151-000	NA*	NA*	NA*	NA*	PJM	Northeast	NA*
PSEG ER&T	ER97-837-000	NA*	NA*	NA*	NA*	PJM, NYISO, NE-ISO	Northeast, Central, Southwest Power Pool, Southeast, Southwest, Northwest	NA*
PSEG Fossil	ER08-447-000	Bergen CC1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Bergen CC2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2002
PSEG Fossil	ER08-447-000	Burlington 12.1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Conemaugh 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/21/1970
PSEG Fossil	ER08-447-000	Conemaugh 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/27/1971
PSEG Fossil	ER08-447-000	Conemaugh A	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh B	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh C	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh D	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Global	N/A	Conemaugh Hydroelectric Plant 1	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Global	N/A	Conemaugh Hydroelectric Plant 2	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Fossil	ER08-447-000	Essex 9	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/1/1990
PSEG Nuclear	ER08-448-000	Hope Creek 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/20/1986
PSEG Fossil	ER08-447-000	Hudson 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	12/18/1968
PSEG Fossil	ER08-447-000	Kearny 12	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/1/2001
PSEG Fossil	ER08-447-000	Kearny 13	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Kearny 14	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Keystone 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/24/1967
PSEG Fossil	ER08-447-000	Keystone 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/23/1968
PSEG Fossil	ER08-447-000	Keystone 3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Linden 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM,	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 7	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Linden 8	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995

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PSEG Fossil	ER08-447-000	Linden GT5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Linden GT6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Mercer 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	12/19/1960
PSEG Fossil	ER08-447-000	Mercer 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/4/1961
PSEG Nuclear	ER08-448-000	Peach Bottom 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	7/5/1974
PSEG Nuclear	ER08-448-000	Peach Bottom 3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/23/1974
PSEG Nuclear	ER08-448-000	Salem 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/30/1977
PSEG Nuclear	ER08-448-000	Salem 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	10/13/1981
PSEG Nuclear	ER08-448-000	Salem GT3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/17/1971
PSEG Fossil	ER08-447-000	Sewaren 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	12/1/1948
PSEG Fossil	ER08-447-000	Sewaren 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/30/1948
PSEG Fossil	ER08-447-000	Sewaren 3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	10/16/1949
PSEG Fossil	ER08-447-000	Sewaren 4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/30/1951
PSEG Fossil	ER08-447-000	Yards Creek 1	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	11/26/1965
PSEG Fossil	ER08-447-000	Yards Creek 2	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	12/22/1965
PSEG Fossil	ER08-447-000	Yards Creek 3	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	9/3/1965
PSEG Power CT	ER03-327-000	Bridgeport Harbor 3	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	8/1/1968
PSEG Power CT	ER03-327-000	Bridgeport Harbor 4	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	10/30/1967
PSEG New Haven LLC	ER12-1250-000	New Haven 2	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 3	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 4	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG Power CT	ER03-327-000	New Haven Harbor 1	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	7/1/1975
PSEG Power NY	N/A*	Bethlehem Energy Center CC	PSEG Power NY	PSEG ER&T	12/6/2002	NYISO	Northeast	7/1/2005
PSEG Solar Source LLC	N/A*	Mars Solar Garden	PSEG Solar Hackettstown LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	9/9/2009
PSEG Solar Source LLC	N/A*	JEA Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	SERC	Southeast	9/28/2010
PSEG Solar Source LLC	N/A*	Wyandot Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	4/6/2010
PSEG Solar Source LLC	N/A*	Queen Creek Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	AZ-NV-SNV	Southwest	11/14/2012
PSEG Solar Source LLC	N/A*	Milford Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	12/27/2012
PSEG Solar Source LLC	N/A	Badger Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ACC	West	10/15/2013
PSEG Solar Source LLC	N/A	Shasta Solar Farm	PSEG Solar California LLC	PG&E	12/16/2013	CAISO	West	3/1/2014

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PSEG Solar Source LLC	N/A	Newman Solar Farm (Texas)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	El Paso Electric	Southwest	12/30/2014
PSEG Solar Source LLC	N/A	Whitcomb Solar Farm (Vermont)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ISO New England	Northeast	10/30/2014
PSEG Solar Source LLC	N/A	Rockfish Solar LLC, Southern Maryland	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	7/10/2015
PSEG Solar Source LLC	N/A	Columbia Solar, Pittsburg, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PG&E	West	10/21/2015
PSEG Solar Source LLC	N/A	Whitehorn Solar, Livermore, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Authority	West	2/17/2016
PSEG Solar Source LLC	N/A	Meadows Solar, Martin County, NC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	6/9/2016
PSEG Solar Source LLC	ER16-1924-000	Bison Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Administration, Colorado-Missouri Region	West	8/1/2016
PSEG Solar Source LLC	ER16-1925-000	Pavant Solar II LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp East	West	8/1/2016
PSEG Solar Source LLC	N/A	Obsidian - Black Cap	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp West	West	11/1/2016
PSEG Solar Source LLC	N/A	Hemlock Solar	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	N/A	Turkey Creek	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	ER16-1926-000	San Isabel Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Public Service Company of Colorado	West	8/1/2016
PSE&G (Solar 4 All)	N/A*	Trenton, 500-520 Brunswick Ave., Trenton, NJ 08638	PSE&G	PSE&G	N/A	PJM	Northeast	10/07/2010 (Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Barringer High School (NPS), 90 Parker St., Newark, NJ 07104	PSE&G	PSE&G	N/A	PJM	Northeast	09/24/2010 (Commercial Operation)
PSE&G (Solar		Park Elementary						10/20/2010

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Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G (Solar 4 All)	N/A*	Elementary) School, 120 Manchester	PSE&G	PSE&G	N/A	PJM	Northeast	(Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Linden, South Wood Avenue, Linden, NJ 07036	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Yardville, Broad Street, Hamilton, NJ 08611	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Silver Lake, 410 Silver Lake Avenue, Edison, NJ 08817	PSE&G	PSE&G	N/A	PJM	Northeast	11/09/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Central HQ, 472 Weston Canal Road, Franklin, NJ 08873	PSE&G	PSE&G	N/A	PJM	Northeast	11/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Edison Training, 234 Pierson Avenue, Edison, NJ 08837	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All)	N/A*	WEA Texas Bayonne, 30-100 Pulaski Street, Bayonne, NJ 07002	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2010
PSE&G (Solar 4 All)	N/A*	Matrix Building A, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/24/2011
PSE&G (Solar 4 All)	N/A*	Matrix Building B, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/14/2011
PSE&G (Solar 4 All)	N/A*	Camden Street School, 281 Camden Street Newark, New Jersey 07103	PSE&G	PSE&G	N/A*	PJM	Northeast	1/12/2011

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PSE&G (Solar 4 All)	N/A*	New Central High School, 246 18th Ave, Newark, NJ 07108	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Rider University Solar Farm, Lawrenceville, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2011
PSE&G (Solar 4 All)	N/A*	Mill Creek Solar Farm, Burlington Township, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	11/30/2011
PSE&G (Solar 4 All)	N/A*	PSE&G Thorofare Solar Farm, West Deptford	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	Raritan Center – Warehouse Solar, Edison, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	NJMC – Landfill Solar, Kearny, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All	N/A	Matrix – Stults Rd., South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	5/31/2011
PSE&G (Solar 4 All)	N/A*	Metro Division HQ, Clifton, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	7/9/2012
PSE&G (Solar 4 All)	N/A*	Black Rock-Matrix, South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	3/20/2012
PSE&G (Solar 4 All)	N/A*	Food Bank Solar Farm, Hillside, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	8/16/2012
PSE&G (Solar 4 All)	N/A*	Hackensack Solar Farm, Hackensack, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2012
PSE&G (Solar 4 All)	N/A*	Moorestown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/14/2013
PSE&G (Solar 4 All)	N/A*	Seg 2 (Pole attached solar units)	PSE&G	PSE&G	N/A*	PJM	Northeast	7/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Kinsley Solar Sewell, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014

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PSE&G (Solar 4 All Extension)	N/A*	Parkland Solar Bordentown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014
PSE&G (Solar 4 All Extension)	N/A*	L&D Solar Mt. Holly, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Hopewell Valley Central HS	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2015
PSE&G (Solar 4 All Extension)	N/A*	ILR Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016
PSE&G (Solar 4 All Extension)	N/A*	Caldwell Waste Treatment Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016
[i] PSEG Fossil has a 22.5% interest in the Conemaugh coal fired plants.								
[ii] PSEG Global has a 4% interest Conemaugh Hydroelectric plants.								
[iii] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear Plants.								
[iv] PSEG Nuclear has a 57.41% interest in the Salem Nuclear Plants.								
[v] JCP&L – Jersey Central Power & Light Company								
[vi] PSEG Fossil has a 50% interest in each of the Yards Creek facilities.								
[vii] CL&P – The Connecticut Light and Power Company.								
[viii] PSEG Power Ventures has a 100% ownership in PSEG Hackettstown LLC.								
[ix] PSEG Power Ventures has a 100% ownership interest in PSEG Solar Source LLC								
[x] All solar assets are using AC MW ratings. PSEG's previous triennial listed the DC ratings.								
[xi] PG&E -- Pacific Gas and Electric Company								
[xii] PSE&G started installations of pole units in September of 2009. As of November 30, 2016, a total of 174,630								

Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing**	**Capacity Rating: Methodology Used in K**	**End Note Number (Enter text in End Notes Sheet**
NA*	NA*	NA*	
NA*	NA*	NA*	
775.2	775.2	N	
625.6	625.6	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
210.6	210.6	N	
210.6	210.6	N	
0.625	0.625	N	[i]
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
1	1	N	[ii]
1	1	N	
93.6	93.6	N	
1,290.70	1,290.70	N	
659.7	659.7	N	
242	242	N	
242	242	N	
121	121	N	
213.8	213.8	N	
213.8	213.8	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
677.8	677.8	N	
677.8	677.8	N	
96.1	96.1	N	
96.1	96.1	N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
96.1	96.1	N	
96.1	96.1	N	
326.4	326.4	N	
326.4	326.4	N	
704	704	N	[iii]
689	689	N	
671.7	671.7	N	[iv]
671.7	671.7	N	
24	24	N	
110.8	110.8	N	
107.5	107.5	N	
107.5	107.5	N	
126.5	126.5	N	
68.5	68.5	N	[v]
68.5	68.5	N	[vi]
56.4	56.4	N	
399.5	399.5	N	
18.6	18.6	N	
60.5	60.5	N	[vii]
60.5	60.5	N	
60.5	60.5	N	
460.3	460.3	N	
893.2	893.2	N	
2	2	N	[viii]
12.6	12.6	N	[ix]
10.1	10.1	N	[x]
19	19	N	
12	12	N	
15	15	N	
1.5	1.5	N	[xi]

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Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
10.2	10.2	N	
2.2	2.2	N	
10.3	10.3	N	
19	19	N	
3	3	N	
20	20	N	
30	30	N	
50	50	N	
8	8	N	
5	5	N	
13.5	13.5	N	
30	30	N	
1.14	1.14	N	
0.64	0.64	N	
		N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
0.55	0.55	N	
3	3	N	
3.7	3.7	N	
1.75	1.75	N	
0.76	0.76	N	
0.64	0.64	N	
1.5	1.5	N	
		N	
1.5	1.5	N	
1	1	N	
0.83	0.83	N	
		N	

Appendix B

Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing**	**Capacity Rating: Methodology Used in K**	**End Note Number (Enter text in End Notes Sheet**
0.5	0.5	N	
		N	
0.67	0.67	N	
3.5	3.5	N	
0.75	0.75	N	
2	2	N	
2.5	2.5	N	
2.5	2.5	N	
0.57	0.57	N	
2.5	2.5	N	
1	1	N	
1	1	N	
0.93	0.93	N	
38.5	38.5	N	[xii]
8.8	8.8	N	

Appendix B

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
7.9	7.9	N	
10	10	N	
1	1	N	
6.6	6.6	N	
2	2	N	

panels and 38.5 MW capacity have been installe

Asset Appendix: Transmission/Natural Gas Assets
Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas St
Location

Filing Entity and its Energy Affiliates	Cite to Order Accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Market / Balancing Authority	Geograph
PSEG ER&T	NA	NA	NA	NA	NA	NA	N
PSEG Power CT	NA	NA	NA	NA	NA	NA	N
PSEG New Haven	NA	NA	NA	NA	NA	NA	N
PSEG Fossil	NA	NA	NA	NA	NA	NA	N
PSEG Nuclear	NA	NA	NA	NA	NA	NA	N
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	Jointly Owned by PSE&G and others	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	Owned by others	PJM	N/A*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	Owned by others	PJM	NA*	PJM	North

PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	Jointly Owned by PSE&G and others	PJM	N/A*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 230 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 230kV Lines	Owned by Others	PJM	N/A	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 138 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 69 kV Lines	PSE&G	PJM	NA*	PJM	North

orage Facilities

ic Region	Size (e.g., length and kV for electric length and diameter for pipeline, and capacity for gas storage)	End Note Number (Enter text in End Notes Sheet
A	NA	NA
A	NA	NA
A	NA	NA
A	NA	NA
A	NA	NA
ıeast	Approximately 272 combined miles.	
ıeast	Approximately 151 combined miles.	
ıeast	Approximately 64 combined miles	
ıeast	Approximately 32 combined miles.	
ıeast	Approximately 20 combined miles.	

ıeast	Approximately 3.76 combined Miles
ıeast	Approximately 750 combined miles.
ıeast	Approximately 39 combined miles
ıeast	Approximately 228 combined miles.
ıeast	Approximately 235 combined miles.

Asset Appendix: Long Term Purchased Power Agreements

Filing Entity and its Energy Affiliates	Docket No. where MBR Authority Granted	Seller Name	Amount of PPA (MW)	Market / Balancing Authority	Geographic Region	Start Date (mo/day/year)

End Date (mo/day/year)	End Note

Document Content(s)

PSEG 2016 Triennial Transmittal FINAL.DOC.....1-27

Exhibit A - Morris Affidavit - PSEG Triennial.PDF.....28-109

Exhibit E - Letters of Concurrence - PSEG Triennial.PDF.....110-134

Appendix B - Generation Assets - PSEG Triennial.XLSX.....135-146

Appendix C - Triennial - Transmission Chart.XLSX.....147-150

Appendix D - Long Term Contracts - Triennial.XLSX.....151-152

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ATTACHMENT C

20180525-5240 FERC PDF (Unofficial) 5/25/2018 3:36:30 PM

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

PSEG Fossil Sewaren Urban Renewal Entity LLC	))))	Docket No. ER17-____-000

Affidavit of
Dr. John R. Morris

May 25, 2018

20180525-5240 FERC PDF (Unofficial) 5/25/2018 3:36:30 PM

Public Service Enterprise Group Incorporated
Sewaren Market Power Study

1. My name is Dr. John R. Morris. I am a Principal at Economists Incorporated, an economic consulting firm located at 2121 K Street, NW, Washington, DC 20037. I am the same Dr. John R. Morris who filed Public Service Enterprise Group Incorporated's ("PSEG") market power study for the Northeast Region in December 2016 under this docket. See Report & Affidavit of Dr. John R. Morris, FERC Accession Number 20161228-5212, December 28, 2016. I also filed a Change in Status application to reflect the addition of Keys Energy Center and the retirement of Hudson and Mercer generating stations in September 2017 for PSEG in Docket No. ER17-2426-000. PSEG has asked that I update the September 2017 market power study for the PJM market and relevant submarkets in order to account for the addition of PSEG Fossil Sewaren Urban Renewal Entity LLC, hereinafter "Sewaren LLC", which owns Sewaren Unit 7, a natural gas combined cycle plant with a generating capacity of 585 MW currently under construction in Woodbridge Township, New Jersey. When Sewaren LLC enters service, PSEG will retire Sewaren Units 1-4 at the same location.[1]

2. Per PSEG's request, I added the new 585 MW Sewaren Unit 7 in the PJM East market and retired Sewaren Units 1-4, which are located in PJM East. I moved the test year of the analysis forward by one year from December 2014-November 2015 to December 2015-November 2016, as this is the latest period for which FERC Form 714 data on unplanned generator outages is

[1] The relevant markets are PJM Interconnection, L.L.C. ("PJM"), PJM East, PJM East of 5004/5005 and PJM East of AP South.

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available. I also updated the overall market sizes of the PJM market and submarkets, along with the first tier areas of NYISO and MISO. I updated load data both for the applicant and for the overall markets in the study. All methods are the same as in the December Affidavit.

3. The results of the pivotal supplier and market share assessments are provided in Exhibit No. PEG-2.

4. Although there are some minor differences in the results from those presented with the December Affidavit, the differences are not material and do not change the conclusions made at that time.

5. Although there are some Wholesale Market Share screen failures in the PJM East and PJM 5004/5005 submarkets, Sewaren LLC and most of the PSEG generation is located in PJM, which has Commission approved market power monitoring and mitigation. The Commission has adopted a rebuttable presumption that existing Commission approved RTO/ISO market monitoring and mitigation is sufficient to address any market power concerns. See Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 240-42, P 246, P 290; Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 111.

6. Under the standards utilized by the Commission, continuing market-based rates for PSEG and all of its Northeastern affiliates remain in the public interest. In addition, granting market-rate authority to the Sewaren LLC would also be in the public interest.

7. This concludes my affidavit.

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Pursuant to 28 U.S.C. §1746, I state under penalty of perjury that the foregoing is true and correct to the best of my information, knowledge, and belief.

Executed on this 25th day of May 2018.

John R. Morris, Ph.D.

Principal

Economists Incorporated

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Document Content(s)

PSEG Change in Status.PDF.....1-183

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Jodi L. Moskowitz
Deputy General Counsel & Chief NERC Officer

Law Department
80 Park Plaza – T5G, Newark, New Jersey 07102-4194
tel: 973.430.6409 fax: 973.430.5983
email: jodi.moskowitz@pseg.com

PSEG
Services Corporation

November 14, 2014

Kimberly J. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Supplemental Notice of Non-Material Change in Status
***PSEG Energy Resources & Trade LLC*, Docket No. ER10-1789-004;**
***Public Service Electric and Gas Company*, Docket No. ER10-1768-003;**
***PSEG Power Connecticut LLC,* Docket No. ER10-1793-003;**
***PSEG Fossil LLC,* Docket No. ER10-1770-003;**
***PSEG Nuclear LLC,* ER10-1771-003;**
***PSEG New Haven LLC,* ER12-1250-003:**

Dear Secretary Bose:

PSEG Energy Resources & Trade LLC ("PSEG ERT") hereby submits for filing this notice of a non-material change in status,[1] in compliance with the reporting requirements adopted by the Federal Energy Regulatory Commission ("Commission") in Order No. 652.[2] Specifically, PSEG ERT hereby notifies the Commission that it has executed with the Long Island Power Authority ("LIPA") a Contract Providing Power Supply Management Services dated November 26, 2013 ("the 2013 Contract"). Under the 2013 Contract, which will be fully implemented on January 1, 2015, PSEG ERT will provide LIPA with Power Supply Management Front and Back Office Services ("PSMFB Services").[3] Such PSMFB Services are, in all respects pertaining to the sale or transmission of electric energy, the same services that Consolidated Edison Energy, Inc. ("Con Edison Energy") has been providing to LIPA since January 1, 2010 pursuant to an agreement between Con Edison Energy and LIPA dated December 1, 2008 (the "2008 Contract").[4]

[1] This notice supplements the notice that was filed on November 13, 2014 (Accession No.: 201411135228).

[2] Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority, 110 FERC ¶ 61,097 (Order No. 652), order on reh'g, 111 FERC ¶ 61,413 (2005) (Order No. 652-A).

[3] While the 2013 Contract will be fully implemented on January 1, 2015, to begin the transition from Con Edison Energy to PSEG ERT, PSEG ERT began performing PSMFB Services as to LIPA's rights (i) to seven must-take qualifying facilities (about 230 MW) on September 16, 2014; (ii) to 29 oil combustion generating units (about 1,520 MW) on October 14, 2014; and (iii) to four Northport steam generating units (about 1,600 MW) on October 28, 2014.

[4] Currently, two affiliates of PSEG ERT (PSEG Long Island LLC and Long Island Electric Utility Servco LLC) provide certain management, operations and maintenance services to LIPA with respect to LIPA's transmission and distribution system. In *PSEG Long Island LLC*, 145 FERC ¶ 61,010 at P 4 (2013), the Commission disclaimed jurisdiction under Section 201(e) of the Federal Power Act over these two affiliates based on a finding that LIPA and its Board will retain ultimate control and decision-making authority over the transmission and distribution facilities.

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In connection with the 2008 Contract between Con Edison Energy and LIPA, on April 7, 2009, Con Edison Energy submitted to the Commission a notice of a non-material change in status, which was accepted by the Commission by letter order on June 8, 2009.[5] Con Edison Energy's April 7, 2009 notice is attached hereto as Attachment A, and the Commission's June 8, 2009 acceptance letter is attached hereto as Attachment B.

Like Con Edison Energy's change in status notification, PSEG ERT hereby submits this notice of a non-material change in status, notifying the Commission that, as of January 1, 2015, it will take over the functions that are currently performed by Con Edison Energy under the 2008 Contract.[6] PSEG ERT's execution of the 2013 Contract and its performance of services thereunder will not provide PSEG ERT with ownership of, or control over, the Power Supply Resources. PSEG ERT will perform services under the 2013 Contract as an agent for, or representative of, LIPA (in the same manner that Con Edison Energy currently performs services for LIPA), and, therefore, control over the Power Supply Resources at all times will remain with LIPA, as it did with respect to the 2008 Contract between Con Edison Energy and LIPA. Thus, PSEG ERT's execution of the 2013 Contract and its performance of the services on behalf of LIPA do not constitute a material change in status as contemplated by the Commission's regulations.[7]

PSEG ERT also notes that, on December 23, 2013, PSEG ERT and its affiliates with market-based rate authorization except PSEG New Haven LLC submitted their triennial market power update with the Commission in Docket Nos. ER99-3151 et al.[8] In that filing (at page 5), PSEG ERT provided the Commission with notice of the 2013 Contract, stating: "On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which ER&T will provide fuel supply and power supply management activities for LIPA beginning on January 1, 2015." The Commission accepted this triennial update filing on October 14, 2014.

In sum, PSEG ERT hereby notifies the Commission of the foregoing non-material change in status and requests that the Commission accept this filing on the same grounds that it accepted the April 8, 2009 Con Edison Energy filing.

Sincerely,

Jodi L. Moskowitz

[5] *See* June 8, 2009 Letter Order accepting Con Edison Energy's notice of change in status in Docket Nos. ER98-2491-015 et al.

[6] *See supra* n.2 at 1.

[7] In Order 652, the Commission stated that the requirement to make a change in status filing is triggered by a change in "ownership" or "control" of generation or transmission facilities. Order 652 at PP 2, 18.

[8] PSEG New Haven LLC was not included in the 2013 triennial market power update because it received initial MBR authority on May 29, 2012 in Docket No. ER12-1250-00 and therefore was not yet due to make a triennial update filing.

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Attachment A

ConEdison Energy
Solving The Wholesale Power Puzzle

April 7, 2009

Hon. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re:	***Consolidated Edison Energy, Inc.***	***Dkt. No. ER98-2491-___***
	Consolidated Edison Company of New York, Inc.	***Dkt. No. ER99-2251-___***
	Orange and Rockland Utilities, Inc.	***Dkt. No. ER99-2252-___***
	Consolidated Edison Solutions, Inc.	***Dkt. No. ER97-705- ___***

Notification of Non-Material Change in Status

Dear Ms. Bose:

Consolidated Edison Energy, Inc. ("Con Edison Energy") submits for filing this notice of a non-material change in status, in compliance with the reporting requirements adopted by the Federal Energy Regulatory Commission ("Commission") in Order No. 652.[1] The change in circumstance is the execution by Con Edison Energy and the Long Island Power Authority ("LIPA") of a Contract for Providing Power Supply Management Front and Back Office Services dated December 1, 2008 ("Contract").[2]

Con Edison Energy does not believe that it has obtained control over the facilities affected by the Contract and, thus, that the Contract is not a change in status as contemplated by the Commission's regulations. Nevertheless, even if the Contract were deemed to convey control to Con Edison Energy, this change in status does not reflect a material change from the characteristics the Commission relied upon in granting CEE market-based rate authorization[3] or the results of the last triennial market power analysis submitted on behalf of Con Edison Energy and its affiliates ("the Con Edison Companies).[4]

---

[1] *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority*, 110 FERC ¶ 61,097 (Order No. 652), *order on reh'g*, 111 FERC ¶ 61,413 (2005) (Order No. 652-A).

[2] The Contract is conditioned upon its approval by the New York State Comptroller, which was granted on March 13, 2009.

[3] *Consolidated Edison Energy, Inc.*, 83 FERC ¶ 61,236 (1998).

[4] The Commission recently accepted a triennial market power analysis on behalf of the Con Edison Companies. *Consolidated Edison Company of New York, Inc.*, Dkt. No. ER99-2251-003,

Under the Contract, Con Edison Energy will provide specified services, as an agent, to LIPA with respect to certain resources (referred to in the Contract as "Power Supply Resources") that LIPA will use to serve its retail load, including (i) electric generating facilities owned by or under contract to LIPA having a total rating of 6,683 MW, (ii) LIPA's long-term transmission rights over the Cross Sound Cable and the Neptune Cable ("CSC and Neptune"), and (iii) LIPA's rights to certain emissions credits, transmission congestion contracts and financial transmission rights. The services that Con Edison Energy will perform on behalf of LIPA with respect to the Power Supply Resources include (i) the purchase and sale of capacity, energy, ancillary services, and transmission congestion contracts to meet the needs of LIPA's retail customers; (ii) the bidding and scheduling in wholesale electric markets of energy, capacity and ancillary services associated with the Power Supply Resources in order to serve the requirements of LIPA's retail load; and (iii) associated accounting, settlement, dispute resolution support, and reporting.

Commencing on January 1, 2010 and continuing for a base term of five years, Con Edison Energy will assume full responsibility for bidding and scheduling all of the Power Supply Resources in wholesale electric markets. In mid to late-2009, Con Edison Energy may undertake limited bidding and scheduling activities for one or more of the Power Supply Resources as part of training and pre-implementation preparations for bidding and scheduling activities.

Con Edison Energy's execution of the Contract and its performance of services thereunder do not vest Con Edison Energy with ownership of, or control over, the Power Supply Resources. The Contract does not alter the ownership of the Power Supply Resources in any respect. Because Con Edison Energy will perform services under the Contract as an agent for or representative of LIPA, control over the Power Supply Resources will remain with LIPA, as LIPA acknowledges in the enclosed concurrence letter. Thus, Con Edison Energy's execution of the Contract and its performance of services for LIPA do not constitute a material change in status as contemplated by the Commission's regulations.

With respect to LIPA's transmission rights over the CSC and Neptune, these transmission facilities are operationally controlled by ISO New England and PJM Interconnection, with transmission service scheduled over each facility pursuant to

---

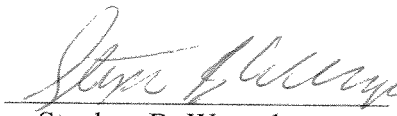
et al., *Letter Order*, June 24, 2008. At the time it was filed, that analysis included the following Con Edison Companies with market-based rate authority: Newington Energy, L.L.C.; CED Rock Springs, Inc.; Consolidated Edison Energy Massachusetts; Lakewood Cogeneration, L.P.; and Ocean Peaking Power, L.L.C. The Commission subsequently authorized the transfer of these companies to North American Energy Alliance, LLC. *See Consolidated Edison Development, Inc. et al.*, 123 FERC ¶ 61,022 (2008). As such, this non-material change in status is not being filed in the dockets in which these divested companies received market-based rate authority.

specific rules set forth in the ISO-NE and PJM Open Access Transmission Tariffs on file with the Commission. In contracting for long-term transmission service rights over CSC and Neptune, LIPA did not acquire any ownership or operational control over those transmission facilities. Accordingly, by executing the Contract, LIPA did not convey to Con Edison Energy any operational control over the CSC or Neptune transmission facilities.

Even if the Contract were deemed to vest Con Edison Energy with control over the Power Supply Resources and with localized market power, that change in status would not reflect a material change from the characteristics the Commission relied upon in granting Con Edison Energy market-based rate authorization or in the results of the last triennial market power analysis submitted on behalf of Con Edison Energy and its affiliates. Currently, a subsidiary of National Grid USA manages LIPA's generation and energy portfolio.[5] Notwithstanding those services, the Commission recently concluded that the National Grid USA subsidiary satisfies the Commission's standards for market-based rate authority.[6] As a successor to the National Grid USA subsidiary, Con Edison Energy will manage LIPA's generation and energy portfolio after the current arrangement between LIPA and the National Grid USA subsidiary expires. Under the Contract, Con Edison Energy has no responsibility with respect to operation or management of LIPA's transmission and distribution systems. Accordingly, the Commission's prior conclusion and rationale apply equally to Con Edison Energy.

Accordingly, Con Edison Energy advises the Commission of the foregoing non-material change in status and requests that the Commission accept this filing and confirm Con Edison Energy's continued authorization to sell power at market-based rates.

Respectfully submitted,

By: 

Stephen B. Wemple
Vice President, Regulatory Affair
Con Edison Competitive Shared Services
for Consolidated Edison Energy, Inc.
701 Westchester Ave. Suite 201 West
White Plains, NY 10604
wemples@conedcss.com
914-993-2149

[5] *Niagara Mohawk Power Corporation, et al.*, 123 FERC ¶61,175, PP 13-14 (May 16, 2008).

[6] *Id.* at P 35 (the New York Independent System Operator's Market Mitigation Plan is sufficient to address market power concerns in the New York City and Long Island submarkets).

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Attachment B

20090608-5049 FERC PDF (Unofficial) 06/08/2009 1:49:39 PM

FEDERAL ENERGY REGULATORY COMMISSION
Washington, D.C. 20426

In Reply Refer To:

Consolidated Edison Energy, Inc.	Docket Nos. ER98-2491-015
Consolidated Edison Company of New York, Inc.	ER99-2251-009
Orange and Rockland Utilities, Inc.	ER99-2252-010
Consolidated Edison Solutions, Inc.	ER97-705-020
(collectively, ConEdison)	

June 8, 2009

Mr. Stephen B. Wemple
Vice President, Regulatory Affairs
Con Edison Competitive Shared Services for Consolidated Edison Energy, Inc.
701 Westchester Avenue
Suite 201 West
White Plains, New York 10604

Reference: Notice of Change in Status

Dear Mr. Wemple:

Pursuant to the authority delegated to the Director, Division of Tariffs and Market Development - West, under 18 C.F.R. § 375.307, your submittal filed in the referenced dockets is accepted for filing.

On April 8, 2009, you filed on behalf of ConEdison a notice of change in status to inform the Commission that ConEdison entered into a Contract for Providing Power Supply Management Front and Back Office Services with Long Island Power Authority. You state that the execution of this contract does not affect the conditions the Commission relied upon when granting ConEdison market-based rate authority. Based on your representations, the notice of change in status is accepted for filing.

Your filing was noticed on April 8, 2009, with comments, protests or interventions due on or before April 29, 2009. None was filed.

This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, or practice affecting such rate or service provided for in the filed documents; nor shall such action be deemed as recognition of any claimed contractual right or obligation affecting or relating to such service or rate; and such acceptance is without prejudice to any findings or orders which have been or may hereafter be made by

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the Commission in any proceeding now pending or hereafter instituted by or against any of the applicant(s).

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Questions regarding the above order should be directed to:

Federal Energy Regulatory Commission
Attn: Ryan Anderson
Phone: (202) 502-8122
Office of Energy Market Regulation
888 First Street, N.E.
Washington, D.C. 20426

Sincerely,

Steve P. Rodgers, Director
Division of Tariffs and Market
Development - West

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Document Content(s)

2014-11-14 Non-Material Change in Status.PDF.....1-9

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Jodi L. Moskowitz
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PSEG
Services Corporation

December 23, 2013

ELECTRONICALLY AND VIA FEDERAL EXPRESS

Kimberly J. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Triennial Market Power Update and Revised Market-Based Rates Tariff in Compliance with Order No. 697:

***PSEG Energy Resources & Trade LLC*, Docket No. ER99-3151-____;**

***Public Service Electric and Gas Company*, Docket No. ER97-837-____;**

***PSEG Power Connecticut LLC*, Docket No. ER03-327 -___;**

***PSEG Fossil LLC*, Docket No. ER08-447-___;**

***PSEG Nuclear LLC*, ER08-448-___; and**

***PSEG New Haven LLC*, ER12-1250-___**

Dear Secretary Bose:

Pursuant to the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), PSEG Energy Resources & Trade LLC ("PSEG ER&T"), Public Service Electric and Gas Company ("PSE&G"), PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Fossil LLC ("PSEG Fossil"), PSEG Nuclear LLC ("PSEG Nuclear") and PSEG New Haven LLC ("PSEG New Haven") (collectively the "Applicants" or "PSEG") hereby jointly submit for filing their updated market power analysis in support of their continued eligibility to engage in market-based rates transactions. This market power analysis satisfies the requirements of Order No. 697[1] for the filing of updated market power analyses on a regional schedule basis by holders of market-based rate certificates and their affiliates. In accordance with the regional

[1] 18 C.F.R. Part 35, Subpart H (2007); Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, 119 FERC ¶ 61,295, ("Order No. 697" or "MBR Order"), *order clarifying final rule*, 121 FERC ¶ 61,260 (2007) ("MBR Clarifying Order"), *order on reh'g and clarification*, 123 FERC ¶ 61,055 (2008) FERC Stats. & Regs ¶ 31,268 ("Order No. 697-A"), *order on reh'g and clarification*, 124 FERC ¶ 61,055 (2008) ("SIL Allocation Order").

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schedule for those utilities in the Northeast Region, as modified by the MBR Clarifying Order, this filing is being made by the December 2013 deadline.[2] In conformance with the Commission's requirements, except when expressly noted otherwise, the market power analysis is based on activity during the study period from December 1, 2011 through November 30, 2012 ("study period").

PSEG, through its subsidiary PSE&G, owns transmission facilities within the Northeast Region. Specifically, PSE&G owns transmission facilities in the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization. PSEG Power LLC and its subsidiaries do not own any transmission facilities other than transmission to connect generating units to the grid in PJM, the New York Independent System Operator, Inc. ("NYISO") and ISO New England Inc. ("ISO-NE").

In their original applications for market-based rate authority and previously-submitted updates to the Commission, PSEG ER&T, PSE&G, PSEG Power CT, PSEG Fossil, PSEG Nuclear and PSEG New Haven demonstrated that they and their affiliates: (a) do not exercise generation market power; (b) lack the ability to manipulate access to transmission facilities that they own or control; and (c) cannot erect any other barriers to market entry. As further demonstrated herein and in the Affidavit of Dr. John R. Morris attached hereto in the appendices, Applicants continue to satisfy the Commission's requirements to sell energy, capacity and ancillary services at market-based rates and thus should be permitted to continue to make such sales.

I. SERVICE AND COMMUNICATION

All service and correspondence related to this matter should be directed to the following individuals:

As to the Applicants Generally:

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Vice President – Regulatory
PSEG Services Corporation
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Newark, NJ 07102
(973) 430-8058
(973) 430-5983 (facsimile)
Tamara.Linde@PSEG.com

Jodi L. Moskowitz, Esq.
General Regulatory Counsel – Operations and Compliance
Chief NERC Officer
PSEG Services Corporation
80 Park Plaza, T5G
Newark, NJ 07102
(973) 430-6409
(973) 430-5983 (facsimile)
Jodi.Moskowitz @PSEG.com

[2] This filing is made on the three year anniversary of the December 2010 deadline set forth in Order No. 697 Appendix D.

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David K. Richter, Esq.
Associate General Regulatory and Property Counsel
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Applicants request waiver of Rule 203(b)(3)[3] so that a copy of any communications in these proceedings may be served on all persons listed above.

II. DESCRIPTION OF THE APPLICANTS AND RELEVANT AFFILIATES

A. The Applicants

The Applicants are each wholly owned, direct and indirect subsidiaries of Public Service Enterprise Group Incorporated ("PSEG"). PSEG is a public utility holding company engaged in, among other things, the generation of electric energy and the transmission, distribution and sale of electricity and natural gas through its subsidiaries.

1. Public Service Electric and Gas Company

PSE&G is a public utility operating company engaged primarily in the transmission of electricity, and the provision of gas and electric distribution service in the State of New Jersey. During the study period, PSE&G owned less than 100 MW of solar generation and otherwise did not own or operate any electric generation facilities. PSE&G is a member of the PJM Regional Transmission Organization and has made all of its transmission facilities available for open access transmission service pursuant to the PJM Open Access Transmission Tariff ("OATT") administered by PJM. PSE&G is authorized to sell power at market-based rates and makes wholesale sales falling within several different categories, as described below.

Non-utility generation ("NUG") output. Pursuant to certain long-term contracts entered into under the Public Utility Regulatory Policy Act of 1978 ("PURPA") or restructured successor contracts to PURPA contracts that PSE&G originally entered into with Qualifying Facilities ("QFs"), PSE&G has a continuing obligation to purchase certain quantities of energy and capacity. The total maximum quantity that PSE&G is

[3] 18 C.F.R. § 385.203(b)(3).

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contractually obligated to purchase from non-utility generators ("NUGs") is approximately 257 MW in installed capacity and associated energy. PSE&G sells the energy quantities purchased under these contracts into the PJM-administered spot market pursuant to its market-based rate authority. With respect to capacity from the facilities, PSE&G receives non-unit specific capacity rights covering the vast bulk of its capacity purchases – about 195 MWs – which are settled financially with the counterparty. The remainder of the capacity purchased by PSE&G under three (3) NUG contracts – about 62 MWs – is bid directly into the RPM auctions. Since PSE&G has a contractually-based obligation to offer the NUG capacity into the market, which obligation is also set forth in a New Jersey Board of Public Utilities ("BPU") Order approving a rate stipulation involving PSE&G,[4] the capacity has not been attributed to PSE&G for purposes of this market power analysis.

Solar. In 2007, the New Jersey legislature passed Regional Greenhouse Gas Initiative ("RGGI") legislation authorizing state utilities to invest in renewable resources such as wind or solar in order to promote increased use of renewable resources within the state and in turn reduce greenhouse gas emissions. *See* L. 2007, c. 340, codified at N.J.S.A. 48:98-1. In the fall of 2009, the BPU approved PSE&G's "Solar 4 All" program under which PSE&G is able to install, own and operate on a regulated basis solar generation up to a maximum of 80 MWs DC. PSE&G currently owns and operates approximately 77 MWs DC of solar power under the Solar 4 All program. In May 2013, the BPU approved PSE&G's "Solar 4 All Extension" to allow PSE&G to install, own and operate an additional 45 MWs DC of solar generation.

2. PSEG Energy Resources & Trade LLC

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil and PSEG Nuclear, each wholly-owned subsidiaries of PSEG Power LLC ("PSEG Power"), as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission.

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

BGS Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 *et seq.*, which initiated the transition from a regulated to a competitive retail power market in New Jersey, BPU annually approves statewide auctions to determine the entities that will supply Basic

[4] The stipulation states that "the parties agree that the Company will continue to sell NUG power into the PJM Spot Market unless and until the Board determines that a different selling protocol is appropriate." *In the Matter of Public Service Electric and Gas Company for Approval of Changes in Electric Rates*, Docket No. ER02050303, ¶ 18 (2003).

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Generation Service ("BGS") in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSEG ER&T has participated directly in all of the auctions for BGS supply held since 2004, has been a winning bidder in these auctions and has incurred contractual commitments to provide supply to BGS load pursuant to BPU approved contracts beginning with the 2004 auction and continuing to the present

RMR Tariff for PJM Units. As explained in PSEG ER&T's 2010 triennial submission, ER&T began providing reliability services to PJM pursuant to Reliability Must-Run ("RMR") tariffs covering operations at PSEG Fossil's Hudson 1 generating unit in 2005. The RMR tariff for the Hudson 1 unit expired effective as of December 7, 2011. Additionally, the Hudson 1 unit and its 454.8 MWs were retired when the RMR was terminated.

BGSS Gas Contract. By order issued April 16, 2002, the BPU approved a full requirements contract for the provision of gas supply by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the BPU, PSEG ER&T assumed, through capacity release, FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract remains in effect and provides for annual renewals unless terminated by either party on 12 months' advance written notice.

LIPA Fuel Supply: On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which ER&T will provide fuel supply and power supply management activities for LIPA beginning on January 1, 2015.

3. PSEG Fossil LLC

PSEG Fossil is an Exempt Wholesale Generator ("EWG") and is authorized to sell power at market-based rates. PSEG Fossil owns and operates electric generation facilities located within PJM and sells their entire output to its affiliate PSEG ER&T.[5] The assets of PSEG Fossil are located entirely within PJM. However, PSEG Fossil's subsidiaries PSEG Power Connecticut LLC, PSEG Power New York LLC and PSEG New Haven LLC own facilities in ISO-NE and NYISO. As noted below, PSEG Fossil also co-owns certain facilities in PJM.

[5]These contracts were originally approved by the Commission as cost-based contracts. *See Public Service Electric and Gas Company*, et al., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Fossil obtained market based rate authority covering sales from its generating units.

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On December 7, 2011, PSE&G retired Hudson 1 and its 454.8 MW (and the accompanying RMR Agreement). Additionally, on June 1, 2012, PSEG Fossil energized six (6) new combustion turbines at its Kearny site in New Jersey. Four (4) units – designated "Kearny 13" - have a combined generator nameplate rating of 242 MWs. Two (2) other units – designated "Kearny 14" - have a combined generator nameplate rating of 142.3 MWs. The addition of this new peaking generation coincided with the retirement of Kearny 10 and 11 with nameplate ratings of 146.3 MWs each.

PSEG Fossil notified PJM in April 2010 that it planned to retire Kearny 9, a unit with a capacity nameplate rating of 18.6 MW, on or about March 2013. However, in November 2011, PSEG Fossil notified PJM that, although Kearny 9 would not have any capacity commitments after May 31, 2013, it would be available for energy and ancillary services. In addition, PSEG Fossil has notified PJM that it will retire the following units on the following dates:

Burlington 9 – June 1, 2014
Salem 3 – June 1, 2015[6]
Bergen 3 – June 1, 2015
Burlington 8 – June 1, 2015
National Park – June 1, 2015
Mercer 3 – June 1, 2015
Sewaren 6 – June 1, 2015
Burlington 11 – June 1, 2015
Edison 1 – 3 – June 1, 2015
Essex 10 – 12 – June 1, 2015

PSEG Fossil satisfies most of the electricity needs of its plants from PJM under PJM's "station power" Tariff provisions and receives station power for its National Park station from PSE&G under a retail tariff approved by the BPU. PSEG Fossil procures gas supply for its plants from PSEG ER&T and receives gas distribution service from PSE&G at a rate approved by the BPU on May 29, 2013.[7]

4. PSEG Power Connecticut LLC

PSEG Power CT is a Connecticut limited liability company and an EWG that owns and operates electric generation facilities in the State of Connecticut and is authorized to sell power at market-based rates.[8] Both of PSEG Power CT's generation facilities, Bridgeport Harbor and New Haven Harbor, are located in the State of Connecticut within the market administered by ISO-NE. PSEG Power CT sells the output of its generation facilities to its affiliate PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority.

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[6] No longer available as a capacity resource in PJM though still available to supply emergency back-up generation for the Salem 1 and 2 nuclear units.
[7] BPU Docket No. GM12100935 (May 29, 2013).
[8] *Wisvest Corporation,* et al., 101 FERC ¶ 61,166 (2002).

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5. PSEG New Haven LLC

PSEG New Haven is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG New Haven owns and operates a facility (the "New Haven facility") in New Haven, Connecticut with a nameplate rating of 181 MWs. The New Haven facility is located within the New Haven Harbor generation station. The New Haven facility is interconnected to the adjacent United Illuminating East Shore Substation using a 115 KV underground cable. PSEG New Haven has no other generation assets. The commercial operation date for the New Haven facility was June 1, 2012 and PSEG New Haven has obtained MBR authority from FERC.[9]

The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[10] pursuant to a Connecticut statute that sought proposals for peaking generation in Connecticut.[11] All of the energy and capacity of the New Haven facility is sold into the ISO New England ("ISO-NE") markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA[12] has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder. The 181 MW nameplate rating of the New Haven Facility has not been included in the capacity controlled by PSEG for purposes of Dr. Morris' market power analysis.

6. PSEG Nuclear LLC

PSEG Nuclear is an EWG[13] and is authorized to sell power at market-based rates. PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission.[14] The assets of PSEG Nuclear are located entirely within PJM. PSEG Nuclear performed an uprate of 120 MWs at its Hope Creek plant in 2009, which increased its nameplate rating to 1290 MWs.

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[9] *PSEG New Haven LLC*, Docket No. ER12-1250-000, et al., (May 29, 2012).

[10] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control (DPUC). PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

[11] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

[12] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

[13] *PSEG Nuclear LLC*, 97 FERC ¶ 62,191 (November 30, 2001).

[14] *Public Service Electric and Gas Company*, et al., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Nuclear obtained market based rate authority from the FERC.

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OTHER RELEVANT AFFILIATES

PSEG is also the direct or indirect parent of certain other subsidiaries engaged in energy related activities, as discussed below.

7. Affiliated Generation Ownership.

A list of the Applicants' affiliated domestic FERC jurisdictional generation assets owned is contained in Appendix B attached hereto. [15] Those additional subsidiaries of PSEG that may be considered relevant to this market power update for the Northeast Region are described below:

PSEG Power LLC ("PSEG Power") was formed in 1999 to acquire the former generation assets of PSE&G. PSEG Power, a Delaware limited liability company, does not directly own any generation facilities or engage in any FERC jurisdictional activities but is the parent company of several FERC jurisdictional entities, including Applicants PSEG ER&T, PSEG Fossil, PSEG Nuclear, PSEG Power CT and PSEG New Haven.

PSEG Global LLC ("PSEG Global") is an indirect subsidiary of PSEG and owns an indirect interest in a domestic power plant in Hawaii.[16]

PSEG Solar Source LLC ("Solar Source") A PSEG Global subsidiary, PSEG Solar Source LLC owns a combined 29 MWs[17] of solar capacity in PJM, about 15 MWs in Florida, 37 MWs in Arizona and 3 MWs in California, all through separate project companies which have all obtained QF status.[18] By the end of 2013, all of the Solar Source facilities will be transferred to a new subsidiary of PSEG Power – PSEG Power Ventures LLC - which will be a Delaware limited liability company that will not itself be an operating company. As a result, these companies will become subsidiaries of PSEG Power rather than subsidiaries of

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[15] Appendix B excludes generation assets located in Hawaii as well as generation assets in which PSEG's interest is limited to a leveraged lease interest.

[16] PSEG Global previously owned indirect interests in facilities in California and New Hampshire and a hydro plant in Pennsylvania. Since the last PSEG triennial market power update, PSEG Global has (i) sold its 40% interest in Bridgewater Holdings LLC (the New Hampshire facility) on May 11, 2012 (ii) shut down operations of its plants in California on February 24, 2012 and (iii) sold its interest in Pennsylvania Renewable Resource's two 7.5 MW (net) hydro facilities in May 2011.

[17] The 29MWs are attributed to three (3) separate project companies that have QF status: PSEG Solar Source Hackettstown (2 MW); PSEG Solar Source Delaware (15 MW) and PSEG Solar Source Ohio (12 MW).

[18] The 3MWs (DC) are associated with the Shasta Solar Facility in California, which began testing energy on December 20, 2013. PSEG Global is also under contract to purchase ownership of the Acacia Solar Project, which is expected to produce 20 MW DC beginning in the first quarter 2014. Both Shasta and Acacia will have QF status.

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PSEG Global. This is simply a change in upstream ownership that will not affect the operations of the facilities.[19]

PSEG Resources LLC ("Resources") is a New Jersey limited liability company that provides energy infrastructure financing in developed countries. Resources invests primarily in energy-related financial transactions and manages a diversified portfolio of investments including leveraged leases. Resources owns interests, through leveraged leases, in various generation stations. Pursuant to the terms of these triple net leases, the lessee, not Resources, has all operational responsibility and control over the leased generation stations.

PSEG Power New York LLC ("PSEG Power NY") is a Delaware limited liability company and an EWG that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 750 MW combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a FERC-approved cost-based contract.[20]

PSEG Long Island LLC ("Long Island") and Long Island Electric Utility Servco, LLC ("Servco") are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution system ("T&D") on Long Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither Long Island nor Servco will be FERC jurisdictional public utilities as neither will exercise ultimate decision making authority over the T&D system in Long Island. Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[21]

8. Affiliated Transmission Ownership

With the exception of the electric transmission assets owned by Applicant PSE&G, all of which are located within the PJM RTO, and the generation interconnection facilities owned by the various EWG and QF affiliates listed herein, the Applicants do not have any affiliates that own or operate FERC jurisdictional electric or natural gas transmission facilities within the United States. As discussed below, FERC granted PSE&G a Hinshaw exemption in 1954, finding that it was exempt from the provisions of the Natural Gas Act.

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[19] It should be noted that the Hawaii generating facility referenced above will also be transferred to PSEG Power Ventures LLC as of the end of 2013.

[20] *PSEG Power New York Inc.*, Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

[21] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), *order dismissing request for rehearing*, 145 FERC ¶ 61,183 (2013).

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B. JOINTLY OWNED FACILITIES

PSEG Nuclear is a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear is the operator of Salem and Exelon Generation is the operator of Peach Bottom.[22] PSEG Fossil is approximately a 23% joint owner in the Conemaugh and Keystone generating stations located in Pennsylvania. An affiliate of NRG Energy is the operator.[23] Accordingly, for purposes of this market power analysis, the capacity of Salem, Peach Bottom, Conemaugh and Keystone has been attributed to PSEG in accordance with PSEG's ownership interests in these facilities.

PSEG Fossil and Jersey Central Power and Light Company ("JCP&L") are each 50% co-owners of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to the unit. Accordingly, for the purpose of this market power analysis, the entire unit capacity – nominally 400 MWs – has been assigned to JCP&L.[24]

III. Applicants Fully Satisfy The Commission's Standards For Authority to Make Power Sales At Market-Based Rates.

The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, horizontal and vertical market power.[25] The Commission has also codified affiliate restrictions in its regulations which must be satisfied on an ongoing basis. In previous submissions for market-based rate authority the Applicants PSE&G, PSEG ER&T, PSEG Power CT, PSEG Fossil, PSEG Nuclear and PSEG New Haven demonstrated compliance with each of these requirements. As detailed herein and in the attached affidavit, the Applicants continue to meet these standards.

A. The Applicants Lack, Or Have Effectively Mitigated, Any Horizontal Market Power

In the MBR Order, the Commission established two indicative screens: a pivotal supplier screen based on the control area's annual peak demand and a wholesale market share screen applied on a seasonal basis. If an applicant passes both screens, there is a rebuttable presumption that the applicant does not possess generation market power.

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[22] A letter of concurrence supporting the allocation of plant output based on ownership interests is attached in Appendix D. The ownership percentages have not changed since the date of this letter. PSEG Nuclear owns a 50% interest in Peach Bottom and a 57.41% interest in Salem.

[23] A letter of concurrence supporting the allocation of plant output based on ownership interest is attached in Appendix D. The ownership percentages have not changed since the date of this letter.

[24] A letter of concurrence supporting this determination is attached in Appendix D. The ownership percentages have not changed since the date of this letter.

[25] MBR Order, FERC Stats. & Regs. ¶ 31,252 at P 62, 399, 408, 440.

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Each indicative screen is applied with respect to "relevant geographic markets" for an applicant's generating units.

Applicants located in ISOs/RTOs possessing sufficient market structure may consider the geographic region under the control of the ISO/RTO as the relevant default geographic region for purposes of completing their generation market power analyses.[26] However, where the Commission has previously found a "submarket" to exist within a boundary of an RTO, such finding is controlling as to the scope of the relevant geographic market for all generation units located within that submarket for the application of the indicative screens and any delivered price test that may be performed. The Commission further listed several such submarkets, including PJM East ("PJME"), Connecticut and Southwest Connecticut.[27] Subsequent to the MBR order, in approving a merger between Exelon Corporation and Constellation Energy Group, Inc., the Commission identified additional submarkets in PJM - PJM East of 5004/5005 ("PJM50") and PJM East of AP South ("PJMAP") - that would be relevant to an MBR analysis for applicants in the Northeast Region.[28]

As discussed below and in the attached Affidavit of Dr. John Morris contained in Appendix A, Applicants have conducted market power analyses of the entire PJM RTO, the PJME, PJM50 and PJMAP submarkets, the entire NYISO, the entire ISO-NE, the Connecticut submarket and the Southwest Connecticut submarket for the study period. The results are set forth below.

1. Indicative Screens

a. Pivotal Supplier Analysis

The pivotal supplier analysis ("PSA") focuses on the ability of a seller to exercise unilateral market power.[29] The screen assesses whether market demand can be met during peak times without the applicant and its affiliates. If demand can be met without the applicant and its affiliates, the applicant passes that the PSA screen. The Affidavit of Dr. John Morris, attached hereto as Appendix A, finds that the Applicants pass the PSA screen for all relevant markets: PJM, NYISO, ISO-NE, Connecticut, Southwest Connecticut, PJMAP, PJME and PJM50.[30]

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[26] *MBR Order at* PP. 231 and 235.

[27] *Order No. 697* at P 236 (citing *Exelon Corp.*, 112 FERC ¶ 61,011, *reh'g denied*, 113 FERC ¶ 61, 299 (2005)). FERC eliminated the Northern PSEG zone as a default submarket in Order No. 697-A, P 99.

[28] Order Conditionally Authorizing Merger and Disposition of Jurisdictional Facilities, *Exelon Corporation, et al.*, 138 FERC ¶ 61,167 (2012).

[29] *AEP I* at P 72.

[30] *See* Morris Affidavit, at 15-28.

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b. Wholesale Market Share Analysis

The wholesale market share analysis ("WMSA") is applied each season to determine whether an applicant has a dominant market position based on the total number of megawatts of uncommitted capacity owned or controlled by the applicant and its affiliates in relation to the uncommitted capacity of the entire relevant wholesale electricity market.[31] The established threshold is 20 percent; a supplier who has less than 20 percent market share in the relevant market for all seasons passes the WMSA screen.

In his Affidavit Dr. Morris finds that the Applicants pass the WMSA screen for PJM, NYISO, ISO-NE, Connecticut, Southwest Connecticut and PJMAP but do not pass the WMSA screen for the PJME and PJM50 submarkets.[32]

c. Results of Indicative Screen Analysis

As shown in Dr. Morris's affidavit, Applicants therefore pass both indicative screen tests for PJM RTO, NYISO, ISO-NE, Connecticut, Southwest Connecticut and PJMAP. For PJME and PJM50, the Applicants pass the PSA but do not pass the WMSA.

2. Delivered Price Test Analysis For PJME and PJM50 Submarkets

In accordance with the MBR Order, applicants who fail either indicative screen test can rebut the presumption of market power through the submission of a delivered price test analysis ("DPT"). Applicants may submit this study at the same time that the results of the indicative screens are provided.[33] The DPT is based on two measurements of potential market power: economic capacity ("EC") and available economic capacity ("AEC"). EC is the capacity that can be delivered to a destination market for 105 percent or less than the market price. AEC is calculated by subtracting native load commitments from EC. Both calculations are performed for twelve different seasonal and load conditions.

In applying the DPT, "[a] showing of an HHI less than 2,500 in the relevant market for all season/load conditions for sellers that have also shown that they are not pivotal and do not possess a 20 percent or greater market share in any of the season/load conditions would constitute a showing of a lack of market power, absent compelling contrary evidence from intervenors."[34] However, while meeting these threshold benchmarks provides "safe harbor" protection, the Commission has found in numerous other cases that applicants lack market power even when they exceed one or more of the thresholds for particular study periods. As stated in *Public Service Company of New Mexico*, 115 FERC ¶ 61,090, P 38 (2006), "the Commission weights the results of both

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[31] *AEP I*, P 100.
[32] *See* Morris Affidavit, at 15-29.
[33] *Order No. 697*, P 76.
[34] *Order No. 697* at P 111.

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the economic and available economic capacity tests and considers the arguments of the applicant and intervenors." (footnote omitted.) [35]

a. Results of the DPT for PJM50 Submarket

With respect to AEC, PSEG passes all screens in all periods. For EC, PSEG passes the HHI Screen and market share screens for all periods but does not pass the PSA screen in 6 of 10 periods.

b. Results of the DPT for PJME Submarket

With respect to AEC, PSEG passes all screens in all periods. For EC, PSEG does not pass the PSA screen in 2 of 10 periods and has marginal Market Share screen failures in 4 of 10 periods.

3. Analysis of DPT Results

Based on his analysis of the overall results, Dr. Morris concludes that, although PSEG fails limited number of screens, the failures appear to be more in the nature of technical violations and not indicators of market power. As set forth in his Affidavit, Dr. Morris states that:

> Although PSEG fails some of the screens for EC in both the PJM50 and the PJME destination markets, the overall results are not indicative of PSEG having market power. To begin, PSEG passes all the market concentration (HHI) screens. The HHI levels in all periods, capacity types, and areas are below the screening threshold of 2,500, and typically

[35] Indeed, in that case, the applicant was deemed "on balance" to have adequately rebutted a showing of market power mitigation for the PNM control area where the results exceeded the 20% safe harbor in two cases under the AEC measure and in all 10 cases at values between 35% and 41% under the EC measure. *See, e.g., Kansas City Power and Light Company, et al.*, Docket Nos. ER99-1005-011 et al. (August 12, 2010) (finding no market power where applicant had EC market shares in the 40-60% range and had significant HHI failures in the KCPL and GMO markets); *Cordova Energy Company LLC et al,* Docket Nos. ER99-2156-011, *et al.*, November 13, 2007 (finding no market power in case where applicant had EC market shares in PACE control area between 53.1% and 60.0%, HHIs between 2,958 and 3,696 and was pivotal in 8 out of 10 periods.); *PacifiCorp*, Letter Order, Docket Nos. ER97-2801-007, *et al.*, February 1, 2007; *Tucson Elec. Power Co.*, 116 FERC ¶ 61,051 (2006)(finding market power standard satisfied where applicant had EC market shares above 20% in all ten season/load periods in the Tucson control area, exceeded the 2,500 HHI threshold in eight periods, and was pivotal in 5 periods); *PacifiCorp*, 115 FERC ¶ 61,349 (2006) (finding that applicants rebutted presumption of market power in the PacifiCorp East control area where under available economic capacity measure, market share is less than 20% in 8 season/load periods and 28% in the summer and winter off-peak periods, HHI does not exceed 2500 in any season/load period and applicants are not pivotal); *Kansas City Power & Light Co.*, 113 FERC ¶ 61,074 (2005) (finding no market power in the KCPL control area where applicant had EC market shares above 20% in all periods, exceeded the HHI 2,500 threshold in 5 of 10 periods and was pivotal supplier in 1 period); *Acadia Power Partners, L.P.*, 113 FERC ¶ 61,073 (2005) (finding no market power in the Cleco Power home control where, utilizing the EC measure, the applicant exceeded the thresholds set for all season/load periods using the market share measure, one season/load period using the market concentration measure, and for all season/load periods using the pivotal supplier measure).

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> substantially below this level. In terms of the DPT for market rate authority and under the 2010 DOJ and FTC Horizontal Merger Guidelines, the market is not highly concentrated.[36] The low HHI levels mean that PSEG has little ability to exercise market power in coordination with other suppliers. It also passes all pivotal supplier screens for AEC. This shows that, given commitments to serve load, its generation was not necessary to serve remaining wholesale load. In other words, although PSEG fails the pivotal supplier tests for some periods with EC, once accounting for its actual forward sales commitments, PSEG's uncommitted generation is not necessary to meet total demand in any of the regions in any period. Thus, PSEG has little to no ability to exercise unilateral market power. Finally, PSEG's market shares are not above 20 percent for any of the Market Share Screens, except only four (4) periods for EC in PJM East. Although greater than 20 percent, PSEG's market shares during these four (4) periods are not substantially above 20 percent. The highest share is only 22.4 percent. Hence, although PSEG fails the Market Share Screens and the Pivotal Supplier Screens for EC in some instances, the failures are more in the nature of technical violations and not true indicators of market power.[37]

As noted above, Dr. Morris' conclusion that the limited DPT screen failures identified through his study are "in the nature of technical violations" is consistent with Commission precedent finding a lack of market power in cases in which the DPT results included more instances of findings outside of the "safe harbor" thresholds and at higher levels than exist here.[38] In these circumstances, Dr. Morris's analysis successfully rebuts any inference of market power created by the WMSA screen failures for PJME and PJM50.

4. Existing RTO/ISO Mitigation Rules Also Eliminate The Potential for Exercising Market Power In the PJME, PJME PJM50 and PJMAP Submarkets

PJM mitigation rules eliminate the potential for the exercise of market power in the PJME and PJM50 submarkets. The MBR Order specifically contemplated that RTO/ISO mitigation rules may serve as evidence that any market power has been adequately mitigated. The Commission declared, "We believe the added protections provided in structured markets with market monitoring and mitigation generally result in a market where prices are transparent and attempts to exercise of market power will be sufficiently mitigated."[39] The Order on Rehearing went even further and specifically

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[36] See U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Issued August 19, 2010, at Section 5.3, available at http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

[37] Morris Affidavit at 32-33.

[38] *See Public Service Company of New Mexico*, 115 FERC ¶ 61,090 (2006) discussed above and cases discussed in fn. 38 above.

[39] MBR Order at P 241.

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created a presumption that any potential market power had been adequately mitigated by an established and effective RTO market monitoring scheme.[40]

Taking account of the pervasive PJM mitigation rule, Dr. Morris concludes that these rules "address the potential for PSEG to exercise market power" in PJME and PJM50.[41] Accordingly, PJM's mitigation schemes in place are sufficient to rebut any inference of market power created by the failure to pass the WMSA screens in PJME and PJM50.

In addition, in the Applicants' last triennial approval order, the Commission found that "the PJM market monitoring and mitigation rules are sufficient to address market power concerns in the PJM-East submarket."[42]

a. The Applicants Lack Transmission Market Power and Cannot Erect Entry Barriers.

In its previous order accepting PSEG's triennial market power analysis for the Northeast Region, the Commission found that the submittal satisfied the Commission's requirements for market-based rates regarding vertical market power.[43] There have been no subsequent changes in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. As demonstrated below, neither Applicants nor any of its affiliates are able to exercise vertical market power.

Applicants are not able to exercise transmission market power. Neither Applicants nor any of their affiliates, except PSE&G, own transmission assets in the U.S. other than incidental generator interconnection facilities. PSE&G owns transmission facilities in PJM but transmission service over those facilities is provided under the PJM Open Access Transmission Tariff.

In addition, neither Applicants nor their affiliates are able to exercise vertical market power in wholesale energy markets through affiliation, ownership or control of inputs to electric power production. As required by Section 35.37(e) of the Commission's regulations, Applicants provide the following information:

(1) PSE&G owns and operates a natural gas distribution system that receives interstate pipeline gas within the State of New Jersey and distributes that gas to its customers within the State of New Jersey. The distribution system consists of 17,709.5 miles of gas distribution pipe and an additional 61.5 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3 and peak-

[40] Order No. 697A at P 111.
[41] Morris Affidavit, pp. 35.
[42] *See* June 29, 2011 letter order approving Applicants' prior triennial market update in Docket No. ER99-3151-017 at page 4.
[43] *Id.*

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shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers. Service over such distribution facilities is made available pursuant to state regulated tariffs on an open access type basis. PSE&G was granted a Hinshaw exemption from the FERC in 1954.[44] The gas distribution rates paid by PSEG Fossil to PSE&G have been set at rates approved by the BPU in an order dated May 29, 2013.

(2) Certain of the Applicants and their affiliates own sites within the Northeast Region that would be suitable for future generating facilities. These include space at many of the existing generating sites of PSEG Fossil and at the sites of PSEG Power NY and PSEG Power CT. PSEG Nuclear's Salem facility may also be suitable for future construction. PSE&G also owns certain sites that would be suitable for generating facilities, but under New Jersey's Electric Discount and Energy Competition Act, N.J.S.A 48:3-43 et seq., PSE&G is effectively barred from owning and operating generation except "on site" generation for supply and Class I renewable energy resources as defined in N.J.S.A. 48:3-98.1.

(3) Neither Applicants nor any of their affiliates own or control any physical coal supply resources or ownership or control over who may access transportation of coal supplies.

(4) As required by section 35.37(e)(4) of the Commission's regulations, Applicants state that they have not erected barriers to entry into the PJM, NYISO or ISO-NE market and will not erect barriers to entry into those markets.

IV. REQUEST FOR CONFIDENTIAL TREATMENT

Under separate cover via UPS Overnight this office is submitting compact disks containing the workpapers of Dr. John Morris supporting his analysis in Appendix A, as required by the Commission's April 2004 Order.[45] Disk 1 (of which six copies are included) contains publicly available information. Disk 2 (of which one copy is included) contains: (i) proprietary information provided by Energy Velocity under an agreement that requires confidential treatment to be requested for these materials; (ii) modeling and computer programs that are the proprietary intellectual property of Economists Incorporated, the firm which employs Dr. Morris; (iii) commercially sensitive information about Applicants and their affiliates; and (iv) documents and information deemed to be confidential by PJM and ISO-NE. Accordingly, Applicants respectfully request confidential treatment for Disk 2 pursuant to 18 C.F.R. § 388.112 (2006), consistent with the confidential treatment accorded other applicants submitting such proprietary and commercially sensitive data.[46] Pursuant to the Commission's rules,

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[44] 13 F.P.C. 1348 (1954).

[45] AEP II, 107 FERC at P 61,087-88.

[46] *See, e.g., Idaho Power Company*, Docket No. ER97-1481-009 (February 3, 2006) (submission of revised Pivotal Supplier Screen and Market Share Screen calculations including similar data).

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the public version of this filing contains all materials submitted herein except for Disk 2, which is labeled as "PRIVILEGED AND CONFIDENTIAL/NON-PUBLIC."

V. SERVICE

This filing has been served on all parties on the official service list as currently maintained by Commission in the above-referenced dockets. Applicants are also providing a copy to the New Jersey Board of Public Utilities and the New Jersey Division of Rate Counsel.

VI. ENCLOSURES

Applicants enclose the following:

- An original filing;
- Appendix A – Affidavit of Dr. John R. Morris;[47]
- Appendix B – List of Entities with Market-Based Rates Authority and Their Generation Assets. (This is an appendix listing the filing entities and all their energy affiliates and their associated assets);
- Appendix C – List of Entities with Market-Based Rate Authority and Their Transmission Assets;
- Appendix D – Letters of concurrence regarding the control of certain jointly owned generation facilities;
- Appendix E – Form of notice suitable for publication in the Federal Register.

VII. CONCLUSION.

Applicants respectfully request the Commission:

i. to accept this market power compliance filing as meeting the Commission's requirements under Order No. 697 for the continuation of market-based rate authority for Applicants PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG New Haven LLC, PSEG Nuclear LLC and PSEG Fossil LLC;

ii. to grant the request for confidential treatment; and

iii. to grant such other relief or waivers as may be appropriate or necessary.

[47] Compact disks, as described above, containing the workpapers for the Affidavit of John R. Morris in Appendix A are being sent concurrently with this filing via UPS Overnight. As noted *supra*, privileged treatment is being requested for Dr. Morris's confidential workpapers submitted with the non-public version of this filing.

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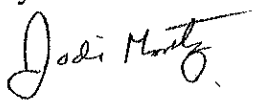
Respectfully submitted,

Public Service Electric and Gas Company
PSEG Energy Resources & Trade LLC
PSEG Power Connecticut LLC
PSEG Fossil LLC
PSEG Nuclear LLC
PSEG New Haven LLC

By:



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Dated: December 23, 2013
Newark, New Jersey

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Appendix A
Affidavit of
Dr. John R. Morris

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UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Public Service Electric and Gas Company	)	ER97-837-__
PSEG Energy Resources & Trade LLC	)	ER99-3151-__
PSEG Power Connecticut LLC	)	ER03-327-__
PSEG Fossil LLC	) Docket Nos.	ER08-447-__
PSEG Nuclear LLC	)	ER08-448-__
PSEG New Haven LLC	)	ER12-1250-___

Report & Affidavit of
Dr. John R. Morris

December 23, 2013

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Public Service Enterprise Group Incorporated Northeast Region Market Power Study

1. Introduction

My name is Dr. John R. Morris. I am a Principal at Economists Incorporated, an economic consulting firm located at 2121 K Street, NW, Washington, DC 20037. I have a bachelor's degree in economics from Georgetown University, and I have a master's degree and a Ph.D. in economics from the University of Washington. I have been studying and consulting within energy industries since joining the Federal Trade Commission in 1985. Since joining Economists Incorporated in 1992, I have consulted on many mergers involving electric and gas companies, examined competitive issues relating to utility rates, provided market power studies for applications for market-based rate authority, and studied market power issues in state restructuring proceedings. I have published articles on competition and energy matters, and I have spoken on numerous occasions concerning competition in natural gas, electric power and other industries. I have previously been accepted as an expert witness on energy matters before the Federal Energy Regulatory Commission ("FERC" or "Commission"), state commissions and in federal court. A complete listing of my experience, publications and testimony is contained in my resume, presented in Exhibit PEG-2.

Public Service Enterprise Group Incorporated ("PSEG") asked that I prepare a market power study for its subsidiaries that have market-based rate authority in the Northeast Region.[1] These subsidiaries are: Public Service Electric and Gas

[1] The Northeast Region includes ISO-New England Inc. ("ISO-NE"), Connecticut, Southwest Connecticut, New York Independent System Operator, Inc. ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), PJM East, PJM East of 5004/5005 and PJM East of AP South.

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("PSE&G"), PSEG Energy Resources & Trade LLC ("PSEG ER&T"), PSEG Fossil LLC ("PSEG Fossil"), PSEG Nuclear LLC ("PSEG Nuclear"), PSEG Power Connecticut LLC ("PSEG Power CT") and PSEG New Haven LLC ("PSEG New Haven"). The purpose of this study is to determine whether these PSEG entities have market power in any Northeast Region market under the Commission's Pivotal Supplier Analysis ("PSA") and Wholesale Market Share Analysis ("WMSA") screens as articulated in FERC Order No. 697 and if the Applicants do fail any of the screens, whether they otherwise lack market power under the Delivered Price Test ("DPT") or are subject to sufficient mitigation to guard against any market power concerns.[2]

PSEG

PSEG is a public utility holding company headquartered in in Newark, New Jersey. Through its subsidiaries, PSEG engages in the generation, transmission, distribution and sale of electric energy, and distribution and sale of natural gas to commercial, residential, and industrial customers primarily in the Northeastern and Mid-Atlantic United States. PSEG, through its subsidiaries, owns approximately 13,000 MW of seasonal generation capacity located in the Northeast Region.[3]

PSE&G

PSE&G is a public utility operating company engaged primarily in the transmission of electricity and the provision of gas and electric distribution service in the State of New Jersey. It is New Jersey's oldest and largest investor-owned

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[2] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 119 FERC ¶ 61,295, ("Order No. 697" or "MBR Order"), *order clarifying final rule*, 121 FERC ¶ 61,260 (2007) ("MBR Clarifying Order"), *order on reh'g and clarification*, 123 FERC ¶ 61,055 (2008) FERC Stats. & Regs ¶ 31,268 ("Order No. 697-A"), *order on reh'g and clarification*, 124 FERC ¶ 61,055 (2008) ("SIL Allocation Order").

[3] *See* Exhibit PEG-3.

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utility. PSE&G was founded in 1903 and is based in Newark, New Jersey. It is a member of the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization and has made all of its transmission facilities available for open access transmission service pursuant to the PJM Open Access Transmission Tariff ("OATT") administered by PJM. The company also owns and operates 17,709.5 miles of gas distribution pipe and an additional 61.5 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3.

PSEG ER&T

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil and PSEG Nuclear, each wholly-owned subsidiaries of PSEG Power LLC ("PSEG Power"), as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission. PSEG ER&T also makes wholesale sales of natural gas.

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

BGS Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 *et seq.*, which initiated the transition from a regulated to a competitive retail power market in New Jersey, the New Jersey Board of Public Utilities ("BPU") annually approves statewide auctions to determine the entities that will supply Basic Generation Service ("BGS") in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation

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service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSE&G's affiliate, PSEG ER&T, has participated directly in all of the auctions for BGS supply held since 2004 and has consistently won tranches in those auctions, including auctions for BGS service within the franchised service territory of PSE&G.

BGSS Gas Contract. By order issued April 16, 2002, the BPU approved a full requirements contract for the provision of gas supply by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the BPU, PSEG ER&T assumed, through capacity release, PSE&G's FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract, which currently remains in effect, provides for annual renewals unless terminated by either party on 12 months' advance written notice.

LIPA Fuel Supply. On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which ER&T will provide fuel supply and power supply management activities for LIPA beginning on January 1, 2015.

PSEG Fossil

PSEG Fossil owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission under the umbrella of PSEG Fossil's

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market-based rate authority.[4] The assets of PSEG Fossil are located entirely within PJM.[5] As explained in PSEG ER&T's previous triennial submission, ER&T began providing reliability services to PJM pursuant to Reliability Must-Run ("RMR") tariffs covering operations at PSEG Fossil's Sewaren and Hudson 1 generating units in 2005. The RMR tariff for the Sewaren units expired effective as of September 1, 2008. The RMR tariff for the Hudson 1 unit expired effective as of December 7, 2011. Additionally, the Hudson 1 unit and its 454.8 MWs were retired when the RMR was terminated. Thus, the capacity attributable to Hudson 1 is not included in the subject market power analysis.

PSEG Fossil is approximately a 23 percent joint owner of interests in the Conemaugh and Keystone generating stations located in Pennsylvania. An affiliate of NRG Energy is the operator.[6] PSEG Fossil is a 50 percent co-owner with Jersey Central Power and Light Company ("JCP&L") of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to the unit. Accordingly, for the purpose of this market power analysis, the entire unit capacity, nominally 400 MWs, has been assigned to JCP&L.[7]

PSEG Power CT

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4 *Public Service Electric and Gas Company, et al.*, 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000).

5 PSEG Fossil's subsidiaries PSEG Power Connecticut LLC, PSEG New Haven LLC and PSEG Power New York LLC own generation units in Connecticut and New York respectively.

6 A letter of concurrence supporting the allocation of these facilities' output based on ownership interests is attached in our workpapers.

7 A letter of concurrence supporting the allocation of this facility's output to JCP&L is attached in our workpapers.

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PSEG Power CT owns the Bridgeport Harbor and New Haven Harbor generation facilities located in the state of Connecticut within ISO-NE and is authorized to sell power at market-based rates.[8] The output of these facilities is sold to PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority.

PSEG New Haven

PSEG New Haven owns and operates the New Haven facility, a gas-fired plant located in New Haven, CT that entered service in June 2012 with a nameplate capacity of 181.5 MW. The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[9] pursuant to a Connecticut statute that sought proposals for peaking generation in Connecticut.[10] All of the energy and capacity of the New Haven facility is sold into the ISO-NE markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder.[11] As such, neither PSEG New Haven nor any other PSEG affiliate has operational control of

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[8] *Wisvest Corporation, et al.*, 101 FERC ¶ 61,166 (2002).

[9] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control (DPUC). PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

[10] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

[11] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

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the New Haven facility. As a result, the capacity of the facility is not attributable to PSEG for the purpose of this market power analysis.

PSEG Nuclear

PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission in accordance with PSEG Nuclear's market-based rate authority.[12] PSEG Nuclear is a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear operates the Salem plant and Exelon Generation is the operator of Peach Bottom.[13]

Other Subsidiaries

PSEG is also the direct or indirect parent of certain other subsidiaries engaged in energy related activities in the United States. Those additional subsidiaries of PSEG that may be considered relevant to this market power update for the PJM region are as follows.

PSEG Power LLC is a Delaware limited liability company. It does not directly own any generation facilities or engage in any FERC jurisdictional activities but it is the parent company of several FERC jurisdictional entities, including applicants PSEG ER&T, PSEG Fossil and PSEG Nuclear.

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[12] *Public Service Electric and Gas Company, et al.*, 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000).

[13] A letter of concurrence supporting the allocation of plant output based on ownership interests is attached in our workpapers.

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PSEG Global LLC ("PSEG Global") is an indirect subsidiary of PSEG and owns an indirect interest in a domestic power plant in Hawaii.[14]

PSEG Solar Source LLC ("Solar Source") is a PSEG Global subsidiary that owns a combined 29 MWs of solar capacity in the PJM region (through three separate project companies), about 15 MWs in Florida, 37 MWs in Arizona and 3 MWs in California, all through separate project companies which have all obtained QF status.[15] By the end of 2013, all of the Solar Source facilities will be transferred to a new subsidiary of PSEG Power – PSEG Power Ventures LLC - which will be a Delaware limited liability company that will not itself be an operating company. As a result, these companies will become subsidiaries of PSEG Power rather than subsidiaries of PSEG Global. This is simply a change in upstream ownership that will not affect the operations of the facilities.[16]

PSEG Resources LLC ("Resources") is a New Jersey limited liability company that provides energy infrastructure financing in developed countries. PSEG Resources invests primarily in energy-related financial transactions and manages a diversified portfolio of investments including leveraged leases. PSEG Resources owns interests, through leveraged leases, in various generation stations. Pursuant to the terms of these triple net leases, the lessee, not

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[14] PSEG Global previously owned indirect interests in facilities in California and New Hampshire and a hydro plant in Pennsylvania. Since the last PSEG triennial market power update, PSEG Global has (i) sold its 40 percent interest in Bridgewater Holdings LLC (the New Hampshire facility) on May 11, 2012 (ii) shut down operations of its plants in California on February 24, 2012 and (iii) sold its interest in Pennsylvania Renewable Resource's two 7.5 MW (net) hydro facilities in May 2011..

[15] The 3MWs (DC) are associated with the Shasta Solar Facility in California, which began testing energy on December 20, 2013. PSEG Global is also under contract to purchase ownership of the Acacia Solar Project, which is expected to produce 20 MW DC beginning in the first quarter 2014. Both Shasta and Acacia will have QF status.

[16] It should be noted that the Hawaii generating facility referenced above will also be transferred to PSEG Power Ventures LLC as of the end of 2013.

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Resources, has all operational responsibility and control over the leased generation stations.

PSEG Power New York LLC ("PSEG Power NY") is a Delaware limited liability company that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 750 MW combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a cost-based contract.[17]

PSEG Long Island LLC ("Long Island") and Long Island Electric Utility Servco, LLC ("Servco") are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution ("T&D") system on Long Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither Long Island nor Servco are FERC jurisdictional public utilities, as neither will exercise ultimate decision making authority over the T&D system in Long Island. Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[18]

When an applicant has affiliates in the relevant market, the Commission considers the combined capacity of all the affiliated entities in its market power assessment.[19] Accordingly, I have included the capacity controlled by PSE&G,

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[17] *PSEG Power New York Inc.*, Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

[18] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), order dismissing request for rehearing, 145 FERC ¶ 61,183 (2013).

[19] *Heartland Energy Services, Inc.*, 68 FERC ¶ 61,223 at 62,061-62,062 (1994).

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PSEG ER&T, PSEG Power CT, PSEG Fossil, PSEG Nuclear, PSEG Global subsidiaries and PSEG Power New York (which on a combined basis constitutes the capacity of all of PSEG's affiliates). Future references in this Affidavit to PSEG are inclusive of the foregoing entities.

The primary purpose of this study is to determine whether PSEG passes the PSA and WMSA screen thresholds in ISO-NE, the NYISO and PJM. In the PSA, the Commission requires applicants to examine whether the generation owned by the applicant is necessary to serve wholesale demand within a balancing authority area. The applicant first calculates the total generation capacity for an area. This is the total of generation in the balancing authority area plus the import capability to the area.[20] From this total, the applicant subtracts out firm contractual commitments, native load obligations, and operating reserves, giving uncommitted capacity for the area. Net uncommitted capacity is calculated by subtracting a wholesale load proxy from uncommitted capacity. Net uncommitted capacity is then compared to the applicant's uncommitted capacity within the area. When the applicant's uncommitted capacity is less than the net uncommitted capacity for the area, then all wholesale demand could be served without energy from the applicant and the applicant passes the PSA screen. When the applicant's uncommitted capacity is greater than the net uncommitted capacity, then the applicant does not pass the screen because its capacity is necessary to meet wholesale peak loads in the market.

In the WMSA, the Commission requires applicants to examine whether the generation owned by the applicant is 20 percent or more of the uncommitted capacity in each of four seasons under average daily peak conditions for the

[20] Import capability is the lesser of either the simultaneous import limit ("SIL") into the area or available capacity in interconnected balancing authority areas. Available capacity is equal to total generation capacity in an area less outages and derating, a native load proxy and operating reserves.

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season. The applicant first calculates the total generation capacity for an area. The applicant then adds the import capability to the area. From this total, the applicant subtracts out planned outages and deratings, long-term firm contractual commitments, native load obligations, and operating reserves. The sum gives the total uncommitted capacity. The applicant then calculates its share by dividing its uncommitted capacity by the total uncommitted capacity. When the applicant's share is less than 20 percent, the applicant passes the WMSA screen.

The Commission presumes that an applicant does not have market power when it passes both the PSA and WMSA screens. If the applicant fails either of the screens, then the applicant may present other analyses to demonstrate that it does not possess market power. Alternatively, the applicant may propose mitigation measures or accept the Commission's default mitigation measures to demonstrate that it has mitigated market power.

2. New England

2.1. Overview of Electric Power Markets in New England

New England operates a competitive wholesale power market. Substantial restructuring has taken place in New England, and many of the vertically integrated utilities have sold either most or all of their generation assets. The traditional utilities often have standard offer obligations to serve retail customers, but utilities often fulfill these obligations by securing supplies in competitive wholesale markets. For example, a utility may secure contracts in which the supplier agrees to provide power for 30 percent of the utility's standard offer obligation. The transmission system is managed by ISO-NE. The market has a market monitor and market power mitigation program in place to identify and to mitigate any potential exercise of market power.

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2.2. Geographic Markets

In the case of generation wholly located in an RTO, such as ISO-NE, the Commission accepts the RTO as the relevant destination market.[21] When the Commission has identified a sub-market within an RTO, the applicant must also provide market power screens for the relevant sub-markets.[22] In New England, the Commission has identified two submarkets: Connecticut and Southwest Connecticut.[23] PSEG owns the Bridgeport Harbor plant in Southwest Connecticut. PSEG also owns the New Haven Harbor 1 unit in Connecticut and PSEG New Haven owns the New Haven facility. When the applicant does not own the transmission system, as in the instant case, the applicant needs to provide an analysis only for the balancing authority area to which the generation is interconnected.[24] Accordingly, the PSA and WMSA are provided for the ISO-NE balancing authority area, and also for Connecticut and Southwest Connecticut.

2.3. Data Sources and Analysis

The data source for generation is ISO-NE Seasonal Claimed Capability (SCC) Reports.[25] Generation for December 2011, January-March 2012 and August 2012 are directly from these monthly reports, and the minimum of the values of these months is taken as generation for other months, to be conservative. Planned outages are from the ISO-NE Form 714. Planned outages for Connecticut and Southwest Connecticut are prorated based on their shares of the total generation capacity in ISO-NE. PSEG's generation capacity in

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[21] Order No. 697 at PP 231, 235.

[22] Order No. 697 at P 236.

[23] *Id.*

[24] Order No. 697 at footnotes 215, 217.

[25] See http://www.iso-ne.com/genrtion_resrcs/snl_clmd_cap/index.html.

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ISO-NE consists of the New Haven facility, New Haven Harbor and Bridgeport Harbor. PSEG's Northeast Region generation facilities are presented in Exhibit PEG-3.

Load data for ISO-NE are from Energy Velocity. Energy Velocity also provides load data by New England ISO zone, thus loads are calculated by sub-market as well. PSEG load obligations in New England come from PSEG's agreements to supply standard offer generation within Rhode Island. The data were supplied by PSEG.

Import capability was taken from the ISO-NE's November 20, 2013 FERC filing.[26] This report indicates that the simultaneous transfer limits in all seasons is 4,548 MW for the ISO-NE as a whole, 2,500 MW for Connecticut, and 2,450 (Winter) to 3,200 MW (Summer) for Southwest Connecticut. The Table 1 and Table 2 data for the SILs are presented in workpapers.

Operating reserves are calculated as follows. ISO-NE Operating Procedure No. 8 specifies spinning reserves (or 10-minute reserves) equal to the size of the loss of the largest unit.[27] The largest unit is the 1,400 MW (summer capacity) Seabrook Unit 1. In addition, 30-minute reserves require capacity to cover 50 percent of the loss of a second contingency (i.e., the second largest unit). The second largest unit is the 1,200 MW (summer capacity) Millstone Unit 3. Thus, in total, operating reserves are 2,000 MW in summer.[28] Operating reserves for

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[26] ISO New England Inc. Simultaneous Import Limit, *Guidance on Simultaneous Transmission Import Limit Studies*; Docket No. AD10-02-002, November 20, 2012.

[27] ISO New England Operating Procedure No. 8, at 5-6, available at http://www.iso-ne.com/rules_proceds/operating/isone/op8/op8_rto_final.pdf.

[28] 2,000 MW = 1,400 MW + 50% x 1,200 MW.

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Connecticut and Southwest Connecticut are based on resources offered for the summer 2012 and winter 2012/2013 forward reserve auction.[29]

2.4. PSA-Entire New England

Exhibit PEG-4 shows the calculations to determine whether PSEG passes the PSA screen in the ISO-NE balancing authority area. The peak load in 2012 occurred in July. The ISO-NE balancing authority area had 31,969 MW of generation capability in the summer of 2012. In addition, 4,548 MW of imports in summer of 2012 were available to serve load. Therefore there were 36,517 MW of total generation resources. Of this amount, 30,993 MW of the generation, and 4,260 MW of the imports are from non-affiliate sources. Thus, total non-affiliate generation resources are 35,274 MW. From the total generation resources, it is necessary to subtract native load obligations and operating reserves. Native load obligations for ISO-NE were calculated to be 20,917 MW. Operating reserves were 2,000 MW. Subtracting native load obligations and operating reserves from total generation resources gives uncommitted supply of 13,600 MW.

The proxy for the wholesale load is the difference between the peak load of 25,880 MW and the native load proxy of 20,917 MW. Therefore, the proxy for the wholesale load is 4,963 MW. Subtracting the wholesale load from total uncommitted supply gives net uncommitted supply of 8,637 MW.

In comparison, PSEG has 955 MW of uncommitted capacity from its generation assets. Additionally, PSEG has 288 MW of imports from its generation assets. After subtracting 314 MW of load and 61 MW of reserves, PSEG has a total of 868 MW of uncommitted capacity. This leaves other

[29] ISO New England, Inc. 2012 Regional System Plan ("Regional System Plan"), available at http://www.iso-ne.com/trans/rsp/2012/, Table 4.9 at p.56.

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generation companies with 7,769 MW of net uncommitted supply. Accordingly, as Exhibit PEG-4 shows, PSEG passes the PSA screen in New England.

2.5. WMSA-Entire New England ISO

Exhibit PEG-5 presents the WMSA. Similar to the PSA calculation for uncommitted capacity, total generation resources equal the sum of the generation in the balancing authority area and available imports. From this total, planned outage and derating, native load obligations, and operating reserves are subtracted to give uncommitted capacity. PSEG's uncommitted supply ranges from 816 MW in fall to 890 MW in summer. PSEG's share of uncommitted capacity ranges from 4.5 percent in winter to 5.6 percent in summer. These shares are substantially below the 20 percent screening threshold adopted by the Commission. Therefore, PSEG passes the WMSA screen in this area.

2.6. PSA-Connecticut

Exhibit PEG-6 shows the calculations to determine whether PSEG passes the PSA screen in the Connecticut area. The peak load in 2012 in the Connecticut area occurred in July. The Connecticut area had 7,979 MW of generation capability in the summer of 2012. In addition, 2,500 MW of imports in summer of 2012 were available to serve load. Therefore there were 10,479 MW of total generation resources. Of this amount, 7,013 MW of the generation, and 2,444 MW of the imports are from non-affiliate sources. Thus, total non-affiliate generation resources are 9,457 MW. From the total generation resources, it is necessary to subtract native load obligations and operating reserves. Native load obligations for the Connecticut area were calculated to be 5,425 MW. Operating reserves were 765 MW.[30] Subtracting native load obligations and operating reserves from total generation resources gives uncommitted supply of 4,289 MW.

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[30] *See* ISO New England Inc., 2012 Regional System Plan, November 2, 2012, Table 4-9 at 56.

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The proxy for the wholesale load is the difference between the peak load of 6,957 MW and the native load proxy of 5,425 MW. Therefore, the proxy for the wholesale load is 1,532 MW. Subtracting the wholesale load from total uncommitted supply gives net uncommitted supply of 2,757 MW.

In comparison, PSEG has 872 MW of uncommitted capacity from its generation assets. Additionally, PSEG has 56 MW of imports for a total of 928 MW of uncommitted capacity. This leaves other generation companies with 1,829 MW of net uncommitted supply. Accordingly, as Exhibit PEG-6 shows, PSEG passes the PSA screen in the Connecticut area.

2.7. WMSA-Connecticut

Exhibit PEG-7 presents the WMSA. Similar to the PSA calculation for uncommitted capacity, total generation resources equal the sum of the generation in the balancing authority area and available imports. From this total, planned outage and derating, native load obligations, and operating reserves are subtracted to give uncommitted capacity. PSEG's uncommitted supply ranges from 810 MW in fall to 918 MW in summer. PSEG's share of uncommitted capacity ranges from 15.8 percent in spring to 18.5 percent in summer. These shares are below the 20 percent screening threshold adopted by the Commission. Therefore, PSEG passes the WMSA screen in the Connecticut area.

2.8. PSA-Southwest Connecticut

Exhibit PEG-8 shows the calculations to determine whether PSEG passes the PSA screen in the Southwest Connecticut area. The peak load in 2012 occurred in July. The Southwest Connecticut area had 2,798 MW of generation capability in the summer of 2012. In addition, 3,200 MW of imports in summer of 2012 were available to serve load. Therefore there were 5,998 MW of total generation resources. Of this amount, 2,270 MW of the generation, and 3,100 MW of the imports are from non-affiliate sources. Thus, total non-affiliate

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generation resources are 5,370 MW. From the total generation resources, it is necessary to subtract native load obligations and operating reserves. Native load obligations for Southwest Connecticut were calculated to be 2,687 MW. Operating reserves were 0 MW.[31] Subtracting native load obligations and operating reserves from total generation resources gives uncommitted supply of 3,311 MW. The proxy for the wholesale load is the difference between the peak load of 3,419 MW and the native load proxy of 2,687 MW. Therefore, the proxy for the wholesale load is 732 MW. Subtracting the wholesale load from total uncommitted supply gives net uncommitted supply of 2,579 MW.

In comparison, PSEG has 528 MW of uncommitted capacity from its generation assets. Additionally, PSEG has 100 MW of imports for a total of 628 MW of uncommitted capacity. This leaves other generation companies with 1,951 MW of net uncommitted supply. Accordingly, as Exhibit PEG-8 shows, PSEG passes the PSA screen in the Southwest Connecticut area.

2.9. WMSA-Southwest Connecticut

Exhibit PEG-9 presents the WMSA. Similar to the PSA calculation for uncommitted capacity, total generation resources equal the sum of the generation in the Southwest Connecticut area and available imports. From this total, planned outage and derating, native load obligations, and operating reserves are subtracted to give uncommitted capacity. PSEG's uncommitted supply ranges from 545 MW in fall to 616 MW in summer. PSEG's share of uncommitted capacity ranges from 15.3 percent in spring to 17.0 percent in winter. These shares are below the 20 percent screening threshold adopted by the Commission in for all seasons. Therefore, PSEG passes the WMSA screen in the Southwest Connecticut area.

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[31] See ISO New England Inc., 2012 Regional System Plan, November 2, 2012, Table 4-9 at 56.

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3. New York

3.1. Overview of Electric Power Markets in New York

New York also has a competitive wholesale power market. Substantial restructuring has taken place in New York, and the investor-owned vertically integrated utilities have sold either most or all of their generation assets. These utilities often have standard offer obligations to serve retail customers, and utilities can fulfill these obligations by securing supplies in competitive wholesale markets. The transmission system is operated by the NYISO, which also operates a competitive wholesale market. The market has a market monitor and market power mitigation program in place to identify and to mitigate any potential exercise of market power.

3.2. Geographic Markets

In the case of generation wholly located in an RTO such as the New York ISO, the Commission has accepted the RTO as the relevant destination market.[32] PSEG only owns generation in Albany, New York. In addition, when the applicant does not own the transmission system, as in the instant case, the applicant needs to provide an analysis only for the balancing authority area to which the generation is interconnected.[33] Accordingly, the PSA and WMSA are provided for the NYISO only.

3.3. Data Sources and Analysis

The principal data source for generation is the Energy Velocity Market-Operations database. Planned outages are from the FERC Form 714. PSEG's

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[32] Order No. 697 at PP 231, 235.

[33] Order No. 697 at footnotes 215, 217.

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generation capacity in New York consists of its ownership of the Bethlehem Energy Center in Albany, which has winter capacity of 845 MW. Information for PSEG's Northeast Region generation is presented in Exhibit PEG-3.

Load data for the NYISO were downloaded from Energy Velocity.

Import capability comes from the most recent NYISO SIL filing as of December 19, 2013.[34] This filing indicates that ISO simultaneous import capability ranges from 7,360 MW in spring to 8,130 MW in fall. NYISO does not recognize physical imports, accordingly, all the SIL import capability is allocated pro rata, except for a 250 MW reservation that PSEG has from PJM to New York. The Table 1 and Table 2 SIL data in the study is presented in workpapers.

Operating reserves are calculated as follows. The NYISO Locational Reserve Requirements specify 30-minute total reserves equal to one and one half the 10-minute reserve necessary to replace the operating capability loss caused by the most severe contingency under normal transfer conditions. Thus, the operating reserves for the NYISO are 1,965 MW for each season.[35]

3.4. PSA-NYISO

Exhibit PEG-10 shows the calculations to determine whether PSEG passes the PSA screen in the NYISO balancing authority area. The peak load in 2012 occurred in July. The NYISO had 38,493 MW of generation capability in the summer of 2012. In addition, 7,820 MW of imports in summer were available to serve load. Therefore, there were 46,313 MW of total generation resources. Of this amount, 37,739 MW of the generation, and 6,465 MW of the imports are from

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[34] New York Independent System Operator, Inc., *Informational Filing Regarding the Simultaneous Import Limitation Study*, Docket No. AD10-2-001, December 19, 2013.

[35] NYISO Locational Reserve Requirements, Table 2, available at http://www.nyiso.com/public/webdocs/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf

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non-affiliate sources. Thus, total non-affiliate generation resources are 44,204 MW. From the total generation resources, it is necessary to subtract native load obligations and operating reserves. Native load obligations for NYISO were calculated to be 27,324 MW. Operating reserves were 1,965 MW. Subtracting native load obligations and operating reserves from total generation resources gives uncommitted supply of 17,024 MW. The proxy for the wholesale load is the difference between the peak load of 32,439 MW and the native load proxy of 27,324 MW. Therefore, the proxy for the wholesale load is 5,116 MW. Subtracting the wholesale load from total uncommitted supply gives net uncommitted supply of 11,909 MW.

In comparison, PSEG has 716 MW of uncommitted capacity from its generation assets in New York, and 1,355 MW of imports for a total of 2,071 MW of uncommitted capacity. This leaves other generation companies with 9,838 MW of net uncommitted supply. Accordingly, as Exhibit PEG-10 shows, PSEG passes the PSA screen in the New York ISO.

3.5. WMSA-NYISO

Exhibit PEG-11 presents the WMSA for the NYISO. Similar to the PSA calculation for uncommitted capacity, total generation resources equal the sum of the generation in the balancing authority area and available imports. From this total, planned outage and derating, native load obligations, and operating reserves are subtracted to give uncommitted capacity. PSEG's uncommitted supply ranges from 1,264 MW in spring to 1,381 MW in summer. PSEG's share of uncommitted capacity ranges from 5.9 percent in winter to 7.2 percent in summer. These shares are below the 20 percent screening threshold adopted by the Commission. Therefore, PSEG passes the WMSA screen in the NYISO.

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4. PJM

4.1. Overview of Electric Power Markets in PJM

PJM operates a competitive wholesale power market and serves as the regional RTO for an area that covers all or parts of 13 states and the District of Columbia. PJM also plans and operates the transmission system within the RTO. Monitoring Analytics acts as the market monitor, and has a market power mitigation program in place to identify and mitigate any potential exercise of market power.

4.2. Geographic Markets

PSEG owns both generation and transmission facilities in PJM. In the case of generation wholly located in an RTO such as PJM, the Commission has accepted the RTO as the relevant destination market.[36] When the Commission has identified a sub-market within an RTO, the applicant must also provide market power screens for the relevant sub-markets.[37] In PJM, the Commission has identified three submarkets: PJM East ("PJME"), PJM East of 5004/5005 ("PJM50") and PJM East of AP-South ("PJMAP").[38] The PSA and WMSA are provided for PJM and for the PJME, PJM50 and PJMAP sub-markets.

4.3. Data Sources and Analysis

The principal data source for generation is the Energy Velocity Market-Ops database. Generation within PJM was assigned to submarket consistent with the

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[36] Order No. 697 at PP 231, 235.

[37] Order No. 697 at P 236.

[38] *Id. See also* Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, Order No. 697-A, 73 FR 25832 (May 7, 2008), FERC Stats, & Regs. ¶ 31,268 (2008) at P 90; Order Conditionally Authorizing Merger and Disposition of Jurisdictional Facilities, *Exelon Corporation, et al.*, 138 FERC ¶ 61,167 (2012).

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definitions in PJM's SIL Study.[39] Planned outages are from the FERC Form 714. In addition, for the sub-market analysis, planned outages were allocated to PJME based on the share of total PJME generation, by season. Information for PSEG's generation in PJM and PJME is presented in Exhibit PEG-3.

Load data for PJM was downloaded from Energy Velocity. Energy Velocity also provides load data by PJM zone, thus loads are calculated for the PJM sub-markets as well.

Import capability was taken from the 2012 Simultaneous Import Limit Study Report.[40] This report indicates simultaneous transfer limits of 10,194 MW in the winter and 8,434 MW in summer. Additionally, this report indicates transmission capabilities of the PJM sub-markets. The report conservatively uses the reported SIL as the SIL amount to be allocated pro rata. This is a simplifying assumption because PSEG has no firm transmission reservations into PJM and it effectively excludes the additional 4,000 MW of net imports into PJM in the base case of the SIL study. The Table 1 and Table 2 data for the study are presented in workpapers.

Operating reserves are calculated according to PJM Manual 13 as the sum of Day Ahead Scheduling Reserves (Operating), Contingency (Primary) and Synchronized (Spinning Reserve) Requirements.[41]

Data on PSEG's long-term contracts come from PSEG. The contracts were included in the area where the energy is delivered under the contract. For

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[39] PJM Interconnection, L.L.C., 2012 Simultaneous Import Limit Study Report, *Guidance on Simultaneous Import Limit Studies*, Docket No. AD1-2-002, October 2, 2013.

[40] *Id.*

[41] PJM Manual 13 - Emergency Operations, at 17, available at http://pjm.com/~/media/documents/manuals/m13.ashx

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contracts delivered to the Western Hub in PJM, the contracts were included in the PJM, PJM50, and PJMAP destinations and not the PJME destination.

4.4. PSA – PJM

Exhibit PEG-12 shows the calculations to determine whether PSEG passes the PSA screen in the PJM balancing authority area. The peak load in 2012 occurred in July. PJM had 193,478 MW of generation capability in the summer of 2012. In addition, 8,434 MW of imports in summer were available to serve load. Therefore, there were 201,912 MW of total generation resources. Of this amount, 182,128 MW of the generation, and 8,310 MW of the imports are from non-affiliate sources. Thus, total non-affiliate generation resources are 192,545 MW. From the total generation resources, it is necessary to subtract native load obligations and operating reserves. Native load obligations for PJM were calculated to be 133,565 MW. Operating reserves were 12,510 MW. Subtracting native load obligations and operating reserves from total generation resources gives uncommitted supply of 55,837 MW. The proxy for the wholesale load is the difference between the peak load of 154,339 MW and the native load proxy of 133,565 MW. Therefore, the proxy for the wholesale load is 20,774 MW. Subtracting the wholesale load from total uncommitted supply gives net uncommitted supply of 35,063 MW.

In comparison, PSEG has 5,362 MW of uncommitted capacity from its generation assets in PJM, and 124 MW of imports, for a total of 5,486 MW of uncommitted capacity. This leaves other generation companies with 29,577 MW of net uncommitted supply. Accordingly, as Exhibit PEG-12 shows, PSEG passes the PSA screen in PJM as a whole.

4.5. WMSA – Entire PJM

Exhibit PEG-13 presents the WMSA for PJM. Similar to the PSA calculation for uncommitted capacity, total generation resources equal the sum of the generation in the balancing authority area and available imports. From this total,

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planned outage and derating, native load obligations, and operating reserves are subtracted to give uncommitted capacity. PSEG's uncommitted supply ranges from 5,393 MW in spring to 6,118 MW in summer. PSEG's share of uncommitted capacity ranges from 4.7 percent in winter to 5.5 percent in summer. These shares are below the 20 percent screening threshold adopted by the Commission. Therefore, PSEG passes the WMSA screen in PJM as a whole.

4.6. PSA – PJME Sub-market

Exhibit PEG-14 shows the calculations to determine whether PSEG passes the PSA screen in the PJME sub-market of PJM's balancing authority area. The peak load in 2012 occurred in July. The PJME sub-market area had 34,847 MW of generation capability in the summer of 2012. In addition, 6,993 MW of imports in summer were available to serve load. Therefore, there were 41,840 MW of total generation resources. Of this amount, 25,407 MW of the generation, and 6,883 MW of the imports are from non-affiliate sources. Thus, total non-affiliate generation resources are 32,277 MW. From the total generation resources, it is necessary to subtract native load obligations and operating reserves. Native load obligations for the PJME sub-market were calculated to be 26,061 MW. Operating reserves were 2,551 MW. Subtracting native load obligations and operating reserves from total generation resources gives uncommitted supply of 13,229 MW. The proxy for the wholesale load is the difference between the peak load of 32,542 MW and the native load proxy of 26,061 MW. Therefore, the proxy for the wholesale load is 6,481 MW. Subtracting the wholesale load from total uncommitted supply gives net uncommitted supply of 6,747 MW.

In comparison, PSEG has 5,695 MW of uncommitted capacity from its generation assets in PJME and 110 MW of imports, for a total of 5,805 MW of uncommitted capacity. This leaves other generation companies with 942 MW of net uncommitted supply. Accordingly, as Exhibit PEG-14 shows, PSEG passes the PSA screen in PJME.

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4.7. WMSA – PJME Sub-market

Exhibit PEG-15 presents the WMSA for the PJME sub-market. Similar to the PSA calculation for uncommitted capacity, total generation resources equal the sum of the generation in the balancing authority area and available imports. From this total, planned outage and derating, native load obligations, and operating reserves are subtracted to give uncommitted capacity. PSEG's uncommitted supply ranges from 5,886 MW in spring to 6,546 MW in fall. PSEG's share of uncommitted capacity ranges from 27.1 percent in winter to 37.2 percent in summer. These shares are above the 20 percent screening threshold adopted by the Commission. Therefore, PSEG fails the WMSA screen in the PJME sub-market.

4.8. PSA – PJM East of 5004/5005 Sub-market

Exhibit PEG-16 shows the calculations to determine whether PSEG passes the PSA screen in the PJM50 sub-market of PJM's balancing authority area. The peak load in 2012 occurred in July. The PJM50 sub-market area had 59,995 MW of generation capability in the summer of 2012. In addition, 7,956 MW of imports in summer were available to serve load. Therefore, there were 67,951 MW of total generation resources. Of this amount, 49,433 MW of the generation, and 7,870 MW of the imports are from non-affiliate sources. Thus, total non-affiliate generation resources are 59,410 MW. From the total generation resources, it is necessary to subtract native load obligations and operating reserves. Native load obligations for the PJM50 sub-market were calculated to be 46,146 MW. Operating reserves were 4,400 MW. Subtracting native load obligations and operating reserves from total generation resources gives uncommitted supply of 17,404 MW. The proxy for the wholesale load is the difference between the peak load of 56,172 MW and the native load proxy of 46,146 MW. Therefore, the proxy for the wholesale load is 10,025 MW. Subtracting the wholesale load from total uncommitted supply gives net uncommitted supply of 7,379 MW.

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In comparison, PSEG has 4,988 MW of uncommitted capacity from its generation assets in PJM50 and 86 MW of imports, for a total of 5,074 MW of uncommitted capacity. This leaves other generation companies with 2,305 MW of net uncommitted supply. Accordingly, as Exhibit PEG-10 shows, PSEG passes the PSA screen in PJM50.

4.9. WMSA – PJM East of 5004/5005 Sub-market

Exhibit PEG-17 presents the WMSA for the PJM50 sub-market. Similar to the PSA calculation for uncommitted capacity, total generation resources equal the sum of the generation in the balancing authority area and available imports. From this total, planned outage and derating, native load obligations, and operating reserves are subtracted to give uncommitted capacity. PSEG's uncommitted supply ranges from 4,882 MW in spring to 5,709 MW in summer. PSEG's share of uncommitted capacity ranges from 16.5 percent in winter to 23.8 percent in summer. The summer share is above the 20 percent screening threshold adopted by the Commission. Therefore, PSEG fails the WMSA screen in the PJM50 sub-market.

4.10. PSA – PJM East of AP South Sub-market

Exhibit PEG-18 shows the calculations to determine whether PSEG passes the PSA screen in the PJMAP sub-market of PJM's balancing authority area. The peak load in 2012 occurred in July. The PJMAP sub-market area had 82,198 MW of generation capability in the summer of 2012. In addition, 7,489 MW of imports in summer were available to serve load. Therefore, there were 89,687 MW of total generation resources. Of this amount, 73,743 MW of the generation, and 7,393 MW of the imports are from non-affiliate sources. Thus, total non-affiliate generation resources are 81,136 MW. From the total generation resources, it is necessary to subtract native load obligations and operating reserves. Native load obligations for the PJMAP sub-market were calculated to be 62,753 MW. Operating reserves were 5,911 MW. Subtracting native load obligations and operating reserves from total generation resources gives

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uncommitted supply of 21,023 MW. The proxy for the wholesale load is the difference between the peak load of 75,082 MW and the native load proxy of 62,753 MW. Therefore, the proxy for the wholesale load is 12,329 MW. Subtracting the wholesale load from total uncommitted supply gives net uncommitted supply of 8,694 MW.

In comparison, PSEG has 4,988 MW of uncommitted capacity from its generation assets in PJMAP and 96 MW of imports, for a total of 5,084 MW of uncommitted capacity. This leaves other generation companies with 3,610 MW of net uncommitted supply. Accordingly, as Exhibit PEG-18 shows, PSEG passes the PSA screen in PJMAP.

4.11. WMSA – PJM East of AP South Sub-market

Exhibit PEG-19 presents the WMSA for the PJMAP sub-market. Similar to the PSA calculation for uncommitted capacity, total generation resources equal the sum of the generation in the balancing authority area and available imports. From this total, planned outage and derating, native load obligations, and operating reserves are subtracted to give uncommitted capacity. PSEG's uncommitted supply ranges from 4,876 MW in spring to 5,718 MW in summer. PSEG's share of uncommitted capacity ranges from 14.0 percent in winter to 19.0 percent in summer.

These shares are below the 20 percent screening threshold adopted by the Commission. Therefore, PSEG passes the WMSA screen in the PJMAP sub-market.

5. Delivered Price Test

When an applicant does not pass either the PSA or WMSA for a destination market, the Commission invites the applicant to provide additional information via a delivered price test ("DPT"). PSEG requested that I perform a DPT for the PJM

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East and PJM East of 5004/5005 sub-markets. Accordingly, I now discuss the DPT for these sub-markets.

5.1. Overview of the DPT

The DPT utilizes substantially more information than the PSA or the WMSA, including additional information on generation ownership, generation costs, demand conditions, and transmission limits. The Commission considers two types of capacity: Economic Capacity ("EC") and Available Economic Capacity ("AEC"). EC is the capacity that can be delivered to a destination market for 105 percent or less than the market price. AEC is calculated by subtracting load commitments from EC. EC and AEC are calculated for a number of different seasonal and load conditions.

Because we do not know the firm retail obligations of the competitive suppliers, as explained below, the AEC calculation is based on the assumption that market participants serve load in proportion to their generation capacity and that 70 percent of load obligations are contracted more than one year from delivery.

For both the EC and AEC measures, the Commission prescribes three screens: (1) a pivotal supplier screen; (2) a market share screen; and (3) a Herfindahl-Hirschman Index ("HHI") screen. The HHI is the sum of the squared market shares of the firms in the market. So a market with four firms of market shares of 40, 30, 20, and 10 percent would have an HHI of 3,000 (this is calculated as $40^2 + 30^2 + 20^2 + 10^2 = 1{,}600 + 900 + 400 + 100 = 3{,}000$). A monopolist would produce a HHI of 10,000 and 10 equally-sized firms would produce a HHI of 1,000.

Although the Commission has not drawn bright lines for its review of DPT results, it has given general guidance. When (1) the applicant is not pivotal; (2) the applicants' market share is less than 20 percent; and (3) the HHI is below 2,500, the Commission is likely to conclude that the applicant does not have

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market power. The three standards establish a "safe harbor" for lack of market power, unless intervenors present clear and convincing contrary evidence. The Commission has also determined in some cases that an applicant did not have market power when the analysis showed isolated HHI and market share results above screening levels. Finally, despite the DPT results, the Commission may conclude that an applicant does not have market power if other evidence, such as historical sales data, indicates that the DPT results do not reflect the actual competition in the marketplace.

A detailed description of data sources and methods to prepare the data for the DPT is presented in Exhibit PEG-20. An overview of the sources and methods used at Economists Incorporated for conducting the DPT is presented here.

The DPT is calculated for 10 representative periods, three for each of three seasonal conditions plus a summer super peak period. The three seasons are spring/fall, summer, and winter. Each season is divided into (1) top 10 percent of peak hours; (2) remaining peak hours; and (3) off-peak hours. In addition, there is a summer super peak period which is comprised to the top 1 percent (10 hours) of summer peak hours. These ten periods cover the range of load conditions for each season, and for the year as a whole.

The primary source for generation data is Energy Velocity. In addition to generation capacity, Energy Velocity provides data on ownership (including holding companies), fully-loaded heat rates, emission rates, and generation availability. Generation is included for all of PJM and for surrounding areas. Unit capabilities are derated to account for seasonal maintenance and likely plant unavailability due to forced outages. Because demand in PJM peaks in summer and winter, the planned outages are assumed to be during the spring/fall season.

The transmission system is represented by contract paths between balancing authority areas and within PJM. Limits between regions in PJM are from Energy Velocity.

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Market prices come from hourly prices reported by PJM.

As in the PSA and WMSA, load data come from Energy Velocity. To compute load requirements for market participants, we apportion the total load in each market area in New York and PJM to all suppliers in proportion to their respective generation capacities. We assumed 70 percent of load is committed for a year or longer and the remaining 30 percent is contracted for shorter periods.[42] To account for their greater load obligations, we assume that Dominion, which does not operate in a restructured retail market, has 100 percent responsibility for its allocation of load and that AEP, which operates in a partly restructured retail market, has 90 percent of its allocation as opposed to the standard 70 percent.

The DPT and market share calculations were calculated using the Power Acquisition Screening System developed at Economists Incorporated. The mathematical details are presented in Exhibit PEG-21.

5.2. Results of the DPT for PJM50 Sub-market

The results of the DPT for PJM50 are presented in Exhibit PEG-22. The top part of the exhibit shows the results for AEC. PSEG passes the Pivotal Supplier Screen in all 10 periods. PSEG also passes both the Market Share Screens and the HHI Screens in all 10 periods.

The lower part of Exhibit PEG-22 shows the results for EC in PJM50. PSEG passes the Pivotal Supplier Screen in 4 out of 10 periods. PSEG passes the Market Share Screens and HHI Screens in all 10 periods.

[42] This is a reasonable estimate for the long-term load coverage since this number is generally between 60 and 80 percent for most generation suppliers in restructured markets.

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5.3. Results of the DPT for PJME Sub-market

The results of the DPT for PJME are presented in Exhibit PEG-23. The top part of the exhibit shows the results for AEC. PSEG passes the Pivotal Supplier Screen in all 10 periods. It also passes the Market Share Screens and the HHI Screens in all 10 periods.

The lower part of Exhibit PEG-23 shows the results for EC in PJME. PSEG passes the Pivotal Supplier Screen in 8 out of 10 periods. PSEG passes the Market Share Screens in 6 periods, and passes the HHI Screens in all 10 periods.

5.4. Analysis of the DPT Results

Although PSEG fails some of the screens for EC in both the PJM50 and the PJME destination markets, the overall results are not indicative of PSEG having market power. To begin, PSEG passes all the market concentration (HHI) screens. The HHI levels in all periods, capacity types, and areas are below the screening threshold of 2,500, and typically substantially below this level. In terms of the DPT for market rate authority and under the 2010 DOJ and FTC Horizontal Merger Guidelines, the market is not highly concentrated.[43] The low HHI levels mean that PSEG has little ability to exercise market power in coordination with other suppliers. It also passes all pivotal supplier screens for AEC. This shows that, given commitments to serve load, its generation was not necessary to serve remaining wholesale load. In other words, although PSEG fails the pivotal supplier tests for some periods with EC, once accounting for its expected forward sales commitments, PSEG's uncommitted generation is not necessary to meet total demand in any of the regions in any period. Thus, PSEG has little to no

[43] See U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Issued August 19, 2010, at Section 5.3, available at http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

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ability to exercise unilateral market power given current market conditions. Finally, PSEG's market shares are not above 20 percent for any of the Market Share Screens, except in only four (4) periods for EC in PJM East. Although greater than 20 percent, PSEG's market shares during these four (4) periods are not substantially above 20 percent. The highest share is only 22.4 percent. Hence, although PSEG fails the Market Share Screens and the Pivotal Supplier Screens for EC in some instances, the failures are more in the nature of technical violations and not true indicators of market power.

5.5. Mitigation

PJM has a Commission-approved market monitoring and mitigation plan in place to ensure that generation facilities cannot exercise market power. The Commission has stated in general that Commission-approved market monitoring and mitigation plans are sufficient to mitigate market power in RTO markets.[44] In particular, the Commission found in connection with PSEG's last triennial filing that the PJM market monitoring and mitigation rules are sufficient to address market power concerns.[45]

Under the local market power mitigation procedures in PJM, if a supplier fails the "three pivotal supplier test" (TPS), it is offer-capped by the Market Monitor. The Market Monitor's TPS test is applied on an ongoing basis, potentially as frequently as every 5 minutes, to reflect day-ahead and real-time operating conditions. These offer caps provide direct protection against the exercise of locational market power by suppliers in PJME, PJM50, PJMAP and elsewhere.

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[44] Order No. 697 at P 241.

[45] *PSEG Energy Resources and Trade*, Docket Nos. ER99-3151-017, et al. (June 29, 2011).

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The protection against the exercise of market power is enhanced by "must offer" requirements under PJM's Operating Agreement. These mandate that generation resources that are used to meet capacity requirements in PJM and that are not subject to an outage must offer their available capacity in PJM's day-ahead energy market.[46] PJM has also implemented a Reliability Pricing Model (RPM) to secure sufficient capacity to meet its requirements through a series of auctions, including a Base Residual Auction (BRA) held annually for capacity 3 years in advance, and incremental auctions held at varying intervals prior to the delivery year. Various features of the RPM process work to prevent the exercise of market power in capacity markets in PJM. First, if PJM's Market Monitor determines that the market structure test is failed, bids of those failing the test are cost-capped. Second, RPM includes a must-offer requirement pursuant to which all generating units that have available capacity must bid into the RPM auctions or face disqualification from being recognized as capacity resources (and therefore from receiving any capacity payments) in the delivery year.

In addition to the local market power mitigation described above, the presence of market monitoring within PJM lessens potential concerns that PSEG might be able to exercise market power notwithstanding the indicative DPT screens. The Market Monitor has the specific responsibility under the market monitoring plan to monitor the potential of any market participant to exercise market power. To perform its market monitoring function, the Market Monitor can file reports or complaints with the Commission and other government agencies to address various market concerns including market power. The Market Monitor can also make its view known to the Commission staff and PJM members in cases where PJM does not follow its recommendations concerning complaints or requested rule changes. In addition, the Market Monitor can consult with regulatory bodies, including state commissions, regarding the need for specific

[46] *See* PJM Operating Agreement at 1.10.1A(d).

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investigations and monitoring activities, and to consider and evaluate additional enforcement mechanisms. The Market Monitor can also act on specific complaints that have been filed by market participants to examine any potential market power issues.

In sum, the local market power mitigation rules, the role of the Market Monitor, the existence of must-offer requirements and PJM's RPM auctions address any potential for PSEG to exercise market power.

6. Vertical Market Power

In determining whether the market-based rates are in the public interest, the Commission also considers whether the Applicant has transmission market power or can erect barriers to entry.[47] None of these factors are relevant in the instant case. First, other than incidental generator interconnection facilities and the transmission assets owned by PSE&G in PJM, no transmission assets are owned by the Applicants or any of their affiliates in ISO-NE and NYISO. Transmission service over PSE&G's transmission facilities is provided under the PJM Open Access Transmission Tariff. Thus, consistent with Commission precedent, Applicants have alleviated any concerns regarding potential transmission market power. Second, PSEG has no ability to erect barriers to entry. As explained in Applicants' previous initial applications for market-based rate authority and triennial market power reports, PSEG is unable to erect barriers to entry. There has been no change in facts since the submission of those applications that would alter this conclusion.

The Commission is concerned with the ownership of natural gas pipelines or natural gas distribution facilities and the possibility that they may be used to

[47] Order No. 697 at PP 397, 399.

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exercise market power in electricity markets. PSEG does not own or operate any FERC jurisdictional natural gas pipelines in PJM, ISO-NE or NYISO. PSE&G owns natural gas distribution facilities in the State of New Jersey including peak-shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers.

7. Conclusion

PSEG and its subsidiaries do not have market power in New England, New York or PJM. PSEG is not a pivotal supplier in New England, New York or PJM. PSEG's market shares in the WMSA are below the Commission's 20 percent screening threshold in each of these market areas. PSEG is also not a pivotal supplier in the Connecticut or Southwest Connecticut sub-markets and its market shares in the WMSA are below 20 percent in these sub-markets. PSEG fails the WMSA screens in only the PJME and PJM50 sub-markets. For these sub-markets, we conducted a DPT analysis. PSEG passes all the DPT screens for AEC in both submarkets, and it fails the Market Share Screens and the Pivotal Supplier Screens in only a few instances for EC. Accordingly, the market share screen failures are more of a technical nature than true indicators of market power. As such, they are not evidence of actual market power.

Further, PSEG operates under New England's, New York's, and PJM's market power mitigation programs, which mitigate PSEG's potential market power. Therefore, under standards for market-based rate authority articulated by the Commission in Order No. 697, PSEG has no ability to exercise market power in the relevant markets, and maintaining market-rate authority in New England, New York and PJM would be in the public interest.

Therefore, I recommend that the Commission continue to authorize PSEG to sell electric power in Northeast Region wholesale markets at market-based rates.

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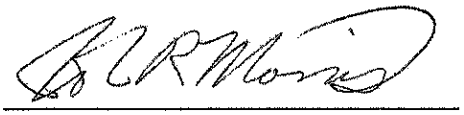
Pursuant to 28 U.S.C. §1746, I state under penalty of perjury that the foregoing is true and correct to the best of my information, knowledge, and belief.

Executed on this 23rd day of December 2013.



John R. Morris, Ph.D.
Principal
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EXPERIENCE AND QUALIFICATIONS OF

Dr. John R. Morris

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MEMBERSHIPS	Member, International Association of Energy Economics • Associate, Energy Bar Association • Member, American Economic Association • Member, Western Economic Association International • Associate, American Bar Association

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Award for Excellence in Law Enforcement, Federal Trade Commission, 1988 • Graduate School Scholarship, University of Washington, 1984 • Graduated Cum Laude Georgetown University, 1981 • Senior Comprehensive Passed with Distinction, Georgetown University, 1981

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September 10, 2001 • "Finding Market Power in Power Markets," presented to staff of the Federal Trade Commission, Washington, DC, June 20, 2001 • "A Study of Marketing Affiliate and Other Affiliate Holdings of Firm Capacity on Interstate Natural Gas Pipelines and the Effects on Natural Gas Markets," April 30, 2001, submitted to FERC by the Interstate Natural Gas Association of America in Docket No. PL00-1-003 • "Why We Should Use Computer Models to Unveil Market Power," presented at the Sixth DOE–NARUC National Electricity Forum, Brown Convention Center, Houston, TX, September 16, 1998 • Comments, *Agency Information Collection and Dissemination Activities: Comment Request,* U.S. Department of Energy, Energy Information Administration, August 28, 1998 • Comments, *Revised filing Requirements Under Part 33 of the Commission's Regulations*, Federal Energy Regulatory Commission Docket No. RM98-4-000, August 21, 1998 • "Use of Computer Simulation Models to Unveil Market Power," presented to staff of the Federal Trade Commission, Federal Energy Regulatory Commission and U.S. Department of Justice, Federal Trade Commission, Washington, DC, April 10, 1998 • "Use of Computer Simulation Models to Unveil Market Power: The Primergy Case," presented to the Bureau of Economics, Federal Trade Commission, Washington, DC , December 8, 1997 • "Use of Computer Simulation Models to Unveil Market Power," presented at the 29th Annual Conference of the Institute of Public Utilities, Williamsburg, Virginia, December 3, 1997 • "Mergers and Market Power," presented at the National Association of State Utility Consumer Advocates Mid-Year Meeting, Charleston, South Carolina, June 9, 1997 • "Market Power Analysis: An Economic Perspective," (with Mark Frankena), presented at the Strategic Research Institute Conference on The Legal Challenges of Restructuring, Arlington, Virginia, April 16, 1997 • "Mergers and Market Power," presented at the Edison Electric Institute Workshop on FERC Merger Policy Guidelines, Arlington, Virginia, April 1, 1997 • "New Approaches to Controlling Distribution Company Market Power," presented at the New York Energy Efficiency Council Conference on Innovative Solutions to a Changing Energy Market, New York Athletic Club, February 7, 1997 • Description of the Western Power Model, with Mark Frankena, Exhibit 8 to Prepared Testimony Before the Nevada Public Service Commission, January 31, 1997 • Reviewer, American Bar Association, Section of Antitrust Law, *Manual on the Economics of Antitrust Law, 14th Supplement*, 1995 • Referee, *Quarterly Journal of Business and Economics*, 1994—1995 • Reviewer, American Bar Association, Section of Antitrust Law, *Manual on the Economics of Antitrust Law, 10th Supplement,* 1993 • Expert Witness, Federal American Inn of Court, Washington, DC, Winter 1993 • "Advertising Restrictions as Rent Increasing Costs," presented at a *Contemporary Policy Issues* Session of the Western Economics Association's 67th Annual Conference, July 1992 • "Let's Make Merger Policy 'Fully Consonant With Economic Theory,'" presented at a *Contemporary Policy Issues*

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Session of the Western Economics Association's 67th Annual Conference, July 1992 • "Advertising Restrictions as Rent Increasing Costs," Seminar, Department of Business Economics, Indiana University, October 1991 • "International Trade and Antitrust: Comments," presented at a *Contemporary Policy Issues* Session of the Western Economics Association's 66th Annual Conference, July 1991 • Discussant, Western Economics Association's 66th Annual Conference, July 1991 • Horizontal Restraints Cases at the Federal Trade Commission: From *American Medical Association* through the Present," with Jim Langenfeld, presented at the 60th Annual Conference of the Southern Economics Association, November 1990 • "Defining Markets for Merger Analysis," with Gale Mosteller, presented at a *Contemporary Policy Issues* Session of the Western Economics Association's 65th Annual Conference, cosponsored by the *Antitrust Bulletin* and the Antitrust and Trade Regulation Section of the Federal Bar Association, July 1990 • "Analyzing Agreements Among Competitors: What Does the Future Hold?" with Jim Langenfeld, presented at a *Contemporary Policy Issues* Session of the Western Economics Association's 65th Annual Conference, cosponsored by the *Antitrust Bulletin* and the Antitrust and Trade Regulation Section of the Federal Bar Association, July 1990 • "The Relationship Between Industrial Sales Prices and Concentration of Natural Gas Pipelines," Seminar, Office of Economic Policy, Federal Energy Regulatory Commission, Summer 1989 • "The Relationship Between Industrial Sales Prices and Concentration of Natural Gas Pipelines," Seminar, Economic Analysis Group, Antitrust Division, U.S. Department of Justice, February 1989 • "Deregulation by Vertical Integration?" Seminar, Department of Business Economics, Indiana University, January 1989 • Discussant, Industrial Organization Society Session, Annual Meeting of the American Economics Association, December 1988 • "Concentration and Price in the Natural Gas Industry," Seminar, Federal Trade Commission, July 1988 • "Relevant Measures of Concentration for Antitrust Policy," presented at an Industrial Organization Society Session of the 57th Annual Conference of the Southern Economics Association, November 1987

Northeast Region Generation Owned and Controlled by PSEG

Owner	Plant Name	State	Owned Capacity		Controlled Capacity	
			Winter Seasonal Capacity	Summer Seasonal Capacity	Winter Seasonal Capacity	Summer Seasonal Capacity
ISO - New England						
PSEG Power CT	Bridgeport Harbor 2	CT	148	130	148	130
PSEG Power CT	Bridgeport Harbor 3	CT	385	383	385	383
PSEG Power CT	Bridgeport Harbor 4	CT	20	15	20	15
PSEG Power CT	New Haven Harbor 1	CT	455	448	455	448
PSEG New Haven	New Haven Harbor GT2	CT	61	61	0	0
PSEG New Haven	New Haven Harbor GT3	CT	61	61	0	0
PSEG New Haven	New Haven Harbor GT4	CT	61	61	0	0
Total ISO - New England Capacity			**1,190**	**1,158**	**1,008**	**976**
New York ISO						
PSEG Power NY	Bethlehem Energy Center CC	NY	845	754	845	754
Total New York ISO Capacity			**845**	**754**	**845**	**754**
PJM						
PSEG Fossil	Conemaugh 1	PA	191	191	191	191
PSEG Fossil	Conemaugh 2	PA	191	191	191	191
PSEG Fossil	Conemaugh A[1]	PA	1	1	1	1
PSEG Fossil	Conemaugh B	PA	1	1	1	1
PSEG Fossil	Conemaugh C	PA	1	1	1	1
PSEG Fossil	Conemaugh D	PA	1	1	1	1
PSEG Global	Conemaugh Hydroelectric Plant 1[2]	PA	1	1	1	1
PSEG Global	Conemaugh Hydroelectric Plant 2	PA	1	1	1	1
PSEG Fossil	Keystone 1[3]	PA	194	194	194	194
PSEG Fossil	Keystone 2	PA	194	194	194	194
PSEG Fossil	Keystone 3	PA	1	1	1	1
PSEG Fossil	Keystone 4	PA	1	1	1	1
PSEG Fossil	Keystone 5	PA	1	1	1	1
PSEG Fossil	Keystone 6	PA	1	1	1	1
PSEG Solar Source LLC	Wyandot Solar Farm	OH	12	12	12	12

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Northeast Region Generation Owned and Controlled by PSEG

Owner	Plant Name	State	Owned Capacity		Controlled Capacity	
			Winter Seasonal Capacity	Summer Seasonal Capacity	Winter Seasonal Capacity	Summer Seasonal Capacity
PJM East						
PSEG Fossil	Bergen 3	NJ	21	21	21	21
PSEG Fossil	Bergen CC1	NJ	628	628	628	628
PSEG Fossil	Bergen CC2	NJ	550	555	550	555
PSEG Fossil	Burlington 8	NJ	21	21	21	21
PSEG Fossil	Burlington 9	NJ	184	184	184	184
PSEG Fossil	Burlington 11	NJ	184	184	184	184
PSEG Fossil	Burlington 121	NJ	42	42	42	42
PSEG Fossil	Burlington 122	NJ	42	42	42	42
PSEG Fossil	Burlington 123	NJ	42	42	42	42
PSEG Fossil	Burlington 124	NJ	42	42	42	42
PSEG Fossil	Edison 1	NJ	168	168	168	168
PSEG Fossil	Edison 2	NJ	168	168	168	168
PSEG Fossil	Edison 3	NJ	168	168	168	168
PSEG Fossil	Essex 9	NJ	81	81	81	81
PSEG Fossil	Essex 10	NJ	168	168	168	168
PSEG Fossil	Essex 11	NJ	168	168	168	168
PSEG Fossil	Essex 12	NJ	168	168	168	168
PSEG Nuclear	Hope Creek 1	NJ	1,161	1,161	1,161	1,161
PSEG Fossil	Hudson 2	NJ	608	608	608	608
PSEG Fossil	Kearny 9	NJ	21	21	21	21
PSEG Fossil	Kearny 12	NJ	175	175	175	175
PSEG Fossil	Kearny 13	NJ	0	178	0	178
PSEG Fossil	Kearny 14	NJ	0	89	0	89
PSEG Fossil	Linden 1	NJ	455	458	455	458
PSEG Fossil	Linden 2	NJ	775	778	775	778
PSEG Fossil	Linden 7	NJ	84	84	84	84
PSEG Fossil	Linden 8	NJ	84	80	84	80
PSEG Fossil	Linden GT5	NJ	86	86	86	86
PSEG Fossil	Linden GT6	NJ	86	86	86	86
PSEG Hackettstown LLC	Mars Solar Garden	NJ	2	2	2	2
PSEG Fossil	Mercer 1	NJ	316	316	316	316
PSEG Fossil	Mercer 2	NJ	316	316	316	316

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Northeast Region Generation Owned and Controlled by PSEG

Owner	Plant Name	State	Owned Capacity		Controlled Capacity	
			Winter Seasonal Capacity	Summer Seasonal Capacity	Winter Seasonal Capacity	Summer Seasonal Capacity
PSEG Fossil	Mercer GT3	NJ	115	115	115	115
PSEG Solar Source LLC	Milford Solar Farm	NJ	15	15	15	15
PSEG Fossil	National Park GT1	NJ	21	21	21	21
PSEG Nuclear	Salem 1[4]	NJ	674	674	674	674
PSEG Nuclear	Salem 2	NJ	665	665	665	665
PSEG Nuclear	Salem GT3	NJ	22	22	22	22
PSEG Fossil	Sewaren 1	NJ	104	104	104	104
PSEG Fossil	Sewaren 2	NJ	118	118	118	118
PSEG Fossil	Sewaren 3	NJ	107	107	107	107
PSEG Fossil	Sewaren 4	NJ	124	124	124	124
PSEG Fossil	Sewaren 6	NJ	105	105	105	105
PSE&G	Solar 4 All Units	NJ	77	77	77	77
PSEG Fossil	Yards Creek 1[5]	NJ	70	70	0	0
PSEG Fossil	Yards Creek 2	NJ	70	70	0	0
PSEG Fossil	Yards Creek 3	NJ	60	60	0	0
PJM 5004/5005						
PSEG Nuclear	Peach Bottom 2[6]	PA	561	561	561	561
PSEG Nuclear	Peach Bottom 3	PA	561	561	561	561
Total PJM Capacity			**11,272**	**11,546**	**11,072**	**11,346**
Total Northeast Region Capacity			**13,307**	**13,457**	**12,925**	**13,076**

Source: PSEG.

Notes:

[1] PSEG Fossil has a 22.5% interest in the Conemaugh coal-fired units.

[2] PSEG Global has a 4% interest in the Conemaugh Hydroelectric facility.

[3] PSEG Fossil has a 22.84% ownership interest in the Keystone facility.

[4] PSEG Nuclear has a 57.41% interest in the Salem Nuclear facility.

[5] PSEG Fossil has a 50% interest in the Yards Creek facility. Yards Creek is operated by Jersey Central Power & Light, and thus is controlled by JCP&L in the analysis.

[6] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear facility.

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Pivotal Supplier Assessment - ISONE

Row	Description	(MW)	Source
	Applicant and Affiliate Capacity		
[A]	Installed Generation	976	ISONE SCC Report
[B]	Long-term Firm Purchases	0	PSEG
[C]	Long-term Firm Sales	-21	PSEG
[D]	Available Imports	288	Calculated: PSA Calcs
	Non-Affiliate Capacity		
[E]	Installed Generation	30,993	ISONE SCC Report
[F]	Long-term Firm Purchases	21	Calculated: PSA Calcs
[G]	Long-term Firm Sales	0	Calculated: PSA Calcs
[H]	Available Imports	4,260	Calculated
[I]	Balancing authority reserve requirement	-2,000	FERC Form 714
[J]	Applicant reserve requirement	-61	Reserves Workpapers
[K]	Total uncommitted supply	13,600	Sum [A] through [I] plus [M]
	Load		
[L]	Balancing area annual peak load	25,880	Load Workpapers
[M]	Average daily peak native load in peak month	-20,917	Load Workpapers
[N]	Amount in [M] attributable to Applicant	-314	Load Workpapers
[O]	Wholesale Load	4,963	[L] + [M]
[P]	Net Uncommitted Supply	8,637	[K] - [O]
[Q]	Applicant's Uncommitted Capacity	868	Sum [A], [B], [C], [D], [J], [N]
[R]	**PSA Screen Result**	**Pass**	

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Wholesale Market Share Assessment - ISONE

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Source
	Applicant and Affiliate Capacity					
[A]	Installed Generation	1,008	992	976	992	ISONE SCC Report
[B]	Long-term Firm Purchases	0	0	0	0	PSEG
[C]	Long-term Firm Sales	-21	-21	-21	-21	PSEG
[D]	Seasonal Average Planned Outages	-37	-93	-5	-120	See Text
[E]	Available Imports	192	195	235	191	Calculated
	Capacity Deductions					
[F]	Average peak native load in season	-16,267	-14,906	-18,579	-15,421	Load Workpapers
[G]	Amount of [F] attributable to Applicant	-203	-147	-234	-165	Load Workpapers
[H]	Amount of [F] attributable to Others	-16,064	-14,759	-18,345	-15,256	Load Workpapers
[I]	Balancing area reserve requirement	-2,000	-2,000	-2,000	-2,000	See Text
[J]	Amount of [I] attributable to Applicant	-59	-62	-61	-62	See Text
[K]	Amount of [I] attributable to Others	-1,941	-1,938	-1,939	-1,938	Calculated
	Non-Affiliated Capacity					
[L]	Installed Generation	33,400	30,977	30,993	30,977	Generation Workpapers
[M]	Long-term Firm Purchases	21	21	21	21	PSEG
[N]	Long-term Firm Sales	0	0	0	0	PSEG
[O]	Seasonal Average Planned Outages	-1,233	-2,907	-149	-3,732	FERC Form 714
[P]	Available Imports	4,356	4,353	4,313	4,357	Calculated
	Supply Calculation					
[Q]	Total competing supply	18,538	15,747	14,895	14,429	Sum [H], [K], [L], [M], [N], [O], [P]
[R]	Applicant's uncommitted capacity	881	864	890	816	Sum [A], [B], [C], [D], [E], [G], [J]
[S]	Total seasonal uncommitted capacity	19,418	16,611	15,785	15,245	Sum [Q], [R]
[T]	**Applicant's Market Share**	4.5%	5.2%	5.6%	5.4%	= [R] / [S]
[U]	**Results**	**Pass**	**Pass**	**Pass**	**Pass**	

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Pivotal Supplier Assessment - CT

Row	Description	(MW)	Source
	Applicant and Affiliate Capacity		
[A]	Installed Generation	976	ISONE SCC Report
[B]	Long-term Firm Purchases	0	PSEG
[C]	Long-term Firm Sales	-10	PSEG
[D]	Available Imports	56	Calculated: PSA Calcs
	Non-Affiliate Capacity		
[E]	Installed Generation	7,003	ISONE SCC Report
[F]	Long-term Firm Purchases	10	Calculated: PSA Calcs
[G]	Long-term Firm Sales	0	Calculated: PSA Calcs
[H]	Available Imports	2,444	Calculated
[I]	Balancing authority reserve requirement	-765	FERC Form 714
[J]	Applicant reserve requirement	-94	Reserves Workpapers
[K]	Total uncommitted supply	4,289	Sum [A] through [I] plus [M]
	Load		
[L]	Balancing area annual peak load	6,957	Load Workpapers
[M]	Average daily peak native load in peak month	-5,425	Load Workpapers
[N]	Amount in [M] attributable to Applicant	0	Load Workpapers
[O]	Wholesale Load	1,532	[L] + [M]
[P]	Net Uncommitted Supply	2,757	[K] - [O]
[Q]	Applicant's Uncommitted Capacity	928	Sum [A], [B], [C], [D], [J], [N]
[R]	**PSA Screen Result**	**Pass**	

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Wholesale Market Share Assessment - CT

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Source
	Applicant and Affiliate Capacity					
[A]	Installed Generation	1,008	992	976	992	ISONE SCC Report
[B]	Long-term Firm Purchases	0	0	0	0	PSEG
[C]	Long-term Firm Sales	-10	-10	-10	-10	PSEG
[D]	Seasonal Average Planned Outages	-37	-93	-5	-120	See Text
[E]	Available Imports	45	47	50	49	Calculated
	Capacity Deductions					
[F]	Average peak native load in season	-3,966	-3,637	-4,720	-3,790	Load Workpapers
[G]	Amount of [F] attributable to Applicant	0	0	0	0	Load Workpapers
[H]	Amount of [F] attributable to Others	-3,966	-3,637	-4,720	-3,790	Load Workpapers
[I]	Balancing area reserve requirement	-837	-837	-765	-813	See Text
[J]	Amount of [I] attributable to Applicant	-102	-104	-94	-101	See Text
[K]	Amount of [I] attributable to Others	-735	-733	-671	-712	Calculated
	Non-Affiliated Capacity					
[L]	Installed Generation	7,255	6,987	7,003	6,987	Generation Workpapers
[M]	Long-term Firm Purchases	10	10	10	10	PSEG
[N]	Long-term Firm Sales	0	0	0	0	PSEG
[O]	Seasonal Average Planned Outages	-268	-656	-34	-842	FERC Form 714
[P]	Available Imports	2,455	2,453	2,450	2,451	Calculated
	Supply Calculation					
[Q]	Total competing supply	4,751	4,425	4,038	4,104	Sum [H], [K], [L], [M], [N], [O], [P]
[R]	Applicant's uncommitted capacity	904	832	918	810	Sum [A], [B], [C], [D], [E], [G], [J]
[S]	Total seasonal uncommitted capacity	5,655	5,257	4,956	4,914	Sum [Q], [R]
[T]	**Applicant's Market Share**	16.0%	15.8%	18.5%	16.5%	= [R] / [S]
[U]	**Results**	**Pass**	**Pass**	**Pass**	**Pass**	

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Pivotal Supplier Assessment - SWCT

Row	Description	(MW)	Source
	Applicant and Affiliate Capacity		
[A]	Installed Generation	528	ISONE SCC Report
[B]	Long-term Firm Purchases	0	PSEG
[C]	Long-term Firm Sales	0	PSEG
[D]	Available Imports	100	Calculated: PSA Calcs
	Non-Affiliate Capacity		
[E]	Installed Generation	2,270	ISONE SCC Report
[F]	Long-term Firm Purchases	0	Calculated: PSA Calcs
[G]	Long-term Firm Sales	0	Calculated: PSA Calcs
[H]	Available Imports	3,100	Calculated
[I]	Balancing authority reserve requirement	0	FERC Form 714
[J]	Applicant reserve requirement	0	Reserves Workpapers
[K]	Total uncommitted supply	3,311	Sum [A] through [I] plus [M]
	Load		
[L]	Balancing area annual peak load	3,419	Load Workpapers
[M]	Average daily peak native load in peak month	-2,687	Load Workpapers
[N]	Amount in [M] attributable to Applicant	0	Load Workpapers
[O]	Wholesale Load	732	[L] + [M]
[P]	Net Uncommitted Supply	2,579	[K] - [O]
[Q]	Applicant's Uncommitted Capacity	628	Sum [A], [B], [C], [D], [J], [N]
[R]	**PSA Screen Result**	**Pass**	

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Wholesale Market Share Assessment - SWCT

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Source
	Applicant and Affiliate Capacity					
[A]	Installed Generation	553	541	528	541	ISONE SCC Report
[B]	Long-term Firm Purchases	0	0	0	0	PSEG
[C]	Long-term Firm Sales	0	0	0	0	PSEG
[D]	Seasonal Average Planned Outages	-20	-51	-3	-65	See Text
[E]	Available Imports	63	78	91	76	Calculated
	Capacity Deductions					
[F]	Average peak native load in season	-1,927	-1,742	-2,281	-1,800	Load Workpapers
[G]	Amount of [F] attributable to Applicant	0	0	0	0	Load Workpapers
[H]	Amount of [F] attributable to Others	-1,927	-1,742	-2,281	-1,800	Load Workpapers
[I]	Balancing area reserve requirement	-50	-50	0	-33	See Text
[J]	Amount of [I] attributable to Applicant	-9	-10	0	-6	See Text
[K]	Amount of [I] attributable to Others	-41	-40	0	-27	Calculated
	Non-Affiliated Capacity					
[L]	Installed Generation	2,535	2,257	2,270	2,257	Generation Workpapers
[M]	Long-term Firm Purchases	0	0	0	0	PSEG
[N]	Long-term Firm Sales	0	0	0	0	PSEG
[O]	Seasonal Average Planned Outages	-94	-212	-11	-272	FERC Form 714
[P]	Available Imports	2,387	2,822	3,109	2,744	Calculated
	Supply Calculation					
[Q]	Total competing supply	2,860	3,085	3,087	2,902	Sum [H], [K], [L], [M], [N], [O], [P]
[R]	Applicant's uncommitted capacity	587	559	616	545	Sum [A], [B], [C], [D], [E], [G], [J]
[S]	Total seasonal uncommitted capacity	3,447	3,644	3,704	3,447	Sum [Q], [R]
[T]	**Applicant's Market Share**	17.0%	15.3%	16.6%	15.8%	= [R] / [S]
[U]	**Results**	**Pass**	**Pass**	**Pass**	**Pass**	

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Pivotal Supplier Assessment - NYISO

Row	Description	(MW)	Source
	Applicant and Affiliate Capacity		
[A]	Installed Generation	754	PSEG
[B]	Long-term Firm Purchases	250	PSEG
[C]	Long-term Firm Sales	0	PSEG
[D]	Available Imports	1,105	Calculated: PSA Calcs
	Non-Affiliate Capacity		
[E]	Installed Generation	37,739	Energy Velocity
[F]	Long-term Firm Purchases	0	Calculated: PSA Calcs
[G]	Long-term Firm Sales	0	Calculated: PSA Calcs
[H]	Available Imports	6,465	Calculated
[I]	Balancing authority reserve requirement	-1,965	FERC Form 714
[J]	Applicant reserve requirement	-38	Reserves Workpapers
[K]	Total uncommitted supply	17,024	Sum [A] through [I] plus [M]
	Load		
[L]	Balancing area annual peak load	32,439	Load Workpapers
[M]	Average daily peak native load in peak month	-27,324	Load Workpapers
[N]	Amount in [M] attributable to Applicant	0	Load Workpapers
[O]	Wholesale Load	5,116	[L] + [M]
[P]	Net Uncommitted Supply	11,909	[K] - [O]
[Q]	Applicant's Uncommitted Capacity	2,071	Sum [A], [B], [C], [D], [J], [N]
[R]	**PSA Screen Result**	**Pass**	

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Wholesale Market Share Assessment - NYISO

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Source
	Applicant and Affiliate Capacity					
[A]	Installed Generation	845	800	754	800	PSEG
[B]	Long-term Firm Purchases	250	250	250	250	PSEG
[C]	Long-term Firm Sales	0	0	0	0	PSEG
[D]	Seasonal Average Planned Outages	-83	-120	-17	-88	See Text
[E]	Available Imports	390	374	433	428	Calculated
	Capacity Deductions					
[F]	Average peak native load in season	-20,039	-18,956	-24,247	-19,462	Load Workpapers
[G]	Amount of [F] attributable to Applicant	0	0	0	0	Load Workpapers
[H]	Amount of [F] attributable to Others	-20,039	-18,956	-24,247	-19,462	Load Workpapers
[I]	Balancing area reserve requirement	-1,965	-1,965	-1,965	-1,965	See Text
[J]	Amount of [I] attributable to Applicant	-41	-40	-38	-40	See Text
[K]	Amount of [I] attributable to Others	-1,924	-1,925	-1,927	-1,925	Calculated
	Non-Affiliated Capacity					
[L]	Installed Generation	39,981	38,860	37,739	38,860	Generation Workpapers
[M]	Long-term Firm Purchases	0	0	0	0	PSEG
[N]	Long-term Firm Sales	0	0	0	0	PSEG
[O]	Seasonal Average Planned Outages	-3,927	-5,828	-868	-4,296	FERC Form 714
[P]	Available Imports	7,459	6,736	7,137	7,452	Calculated
	Supply Calculation					
[Q]	Total competing supply	21,549	18,886	17,834	20,628	Sum [H], [K], [L], [M], [N], [O], [P]
[R]	Applicant's uncommitted capacity	1,361	1,264	1,381	1,350	Sum [A], [B], [C], [D], [E], [G], [J]
[S]	Total seasonal uncommitted capacity	22,910	20,150	19,215	21,978	Sum [Q], [R]
[T]	**Applicant's Market Share**	5.9%	6.3%	7.2%	6.1%	= [R] / [S]
[U]	**Results**	**Pass**	**Pass**	**Pass**	**Pass**	

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Pivotal Supplier Assessment - PJM

Row	Description	(MW)	Source
	Applicant and Affiliate Capacity		
[A]	Installed Generation	11,350	PSEG
[B]	Long-term Firm Purchases	13	PSEG
[C]	Long-term Firm Sales	-2,120	PSEG
[D]	Available Imports	124	Calculated: PSA Calcs
	Non-Affiliate Capacity		
[E]	Installed Generation	182,128	Energy Velocity
[F]	Long-term Firm Purchases	2,120	Calculated: PSA Calcs
[G]	Long-term Firm Sales	-13	Calculated: PSA Calcs
[H]	Available Imports	8,310	Calculated
[I]	Balancing authority reserve requirement	-12,510	FERC Form 714
[J]	Applicant reserve requirement	-734	Reserves Workpapers
[K]	Total uncommitted supply	55,837	Sum [A] through [I] plus [M]
	Load		
[L]	Balancing area annual peak load	154,339	Load Workpapers
[M]	Average daily peak native load in peak month	-133,565	Load Workpapers
[N]	Amount in [M] attributable to Applicant	-3,147	Load Workpapers
[O]	Wholesale Load	20,774	[L] + [M]
[P]	Net Uncommitted Supply	35,063	[K] - [O]
[Q]	Applicant's Uncommitted Capacity	5,486	Sum [A], [B], [C], [D], [J], [N]
[R]	**PSA Screen Result**	**Pass**	

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Wholesale Market Share Assessment - PJM

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Source
	Applicant and Affiliate Capacity					
[A]	Installed Generation	11,072	11,211	11,350	11,211	PSEG
[B]	Long-term Firm Purchases	10	10	13	13	PSEG
[C]	Long-term Firm Sales	-2,020	-2,020	-2,120	-2,120	PSEG
[D]	Seasonal Average Planned Outages	-577	-1,597	-98	-1,053	See Text
[E]	Available Imports	102	53	101	67	Calculated
	Capacity Deductions					
[F]	Average peak native load in season	-64,797	-59,065	-76,078	-60,754	Load Workpapers
[G]	Amount of [F] attributable to Applicant	-2,023	-1,705	-2,413	-1,551	Load Workpapers
[H]	Amount of [F] attributable to Others	-62,775	-57,360	-73,665	-59,204	Load Workpapers
[I]	Balancing area reserve requirement	-10,044	-9,853	-12,170	-9,859	See Text
[J]	Amount of [I] attributable to Applicant	-550	-559	-714	-559	See Text
[K]	Amount of [I] attributable to Others	-9,494	-9,295	-11,456	-9,300	Calculated
	Non-Affiliated Capacity					
[L]	Installed Generation	191,003	186,566	182,128	186,566	Generation Workpapers
[M]	Long-term Firm Purchases	2,020	2,020	2,120	2,120	PSEG
[N]	Long-term Firm Sales	-10	-10	-13	-13	PSEG
[O]	Seasonal Average Planned Outages	-9,962	-26,571	-1,580	-17,520	FERC Form 714
[P]	Available Imports	10,092	5,589	8,333	6,962	Calculated
	Supply Calculation					
[Q]	Total competing supply	120,875	100,939	105,867	109,611	Sum [H], [K], [L], [M], [N], [O], [P]
[R]	Applicant's uncommitted capacity	6,013	5,393	6,118	6,008	Sum [A], [B], [C], [D], [E], [G], [J]
[S]	Total seasonal uncommitted capacity	126,888	106,332	111,985	115,619	Sum [Q], [R]
[T]	**Applicant's Market Share**	4.7%	5.1%	5.5%	5.2%	= [R] / [S]
[U]	**Results**	**Pass**	**Pass**	**Pass**	**Pass**	

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Pivotal Supplier Assessment - PJME

Row	Description	(MW)	Source
	Applicant and Affiliate Capacity		
[A]	Installed Generation	9,440	PSEG
[B]	Long-term Firm Purchases	13	PSEG
[C]	Long-term Firm Sales	0	PSEG
[D]	Available Imports	110	Calculated: PSA Calcs
	Non-Affiliate Capacity		
[E]	Installed Generation	25,407	Energy Velocity
[F]	Long-term Firm Purchases	0	Calculated: PSA Calcs
[G]	Long-term Firm Sales	-13	Calculated: PSA Calcs
[H]	Available Imports	6,883	Calculated
[I]	Balancing authority reserve requirement	-2,551	FERC Form 714
[J]	Applicant reserve requirement	-610	Reserves Workpapers
[K]	Total uncommitted supply	13,229	Sum [A] through [I] plus [M]
	Load		
[L]	Balancing area annual peak load	32,542	Load Workpapers
[M]	Average daily peak native load in peak month	-26,061	Load Workpapers
[N]	Amount in [M] attributable to Applicant	-3,147	Load Workpapers
[O]	Wholesale Load	6,481	[L] + [M]
[P]	Net Uncommitted Supply	6,747	[K] - [O]
[Q]	Applicant's Uncommitted Capacity	5,805	Sum [A], [B], [C], [D], [J], [N]
[R]	**PSA Screen Result**	**Pass**	

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Wholesale Market Share Assessment - PJME

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Source
	Applicant and Affiliate Capacity					
[A]	Installed Generation	9,162	9,301	9,440	9,301	PSEG
[B]	Long-term Firm Purchases	10	10	13	13	PSEG
[C]	Long-term Firm Sales	0	0	0	0	PSEG
[D]	Seasonal Average Planned Outages	-478	-1,325	-82	-873	See Text
[E]	Available Imports	106	69	104	120	Calculated
	Capacity Deductions					
[F]	Average peak native load in season	-16,787	-15,583	-21,699	-16,078	Load Workpapers
[G]	Amount of [F] attributable to Applicant	-2,023	-1,705	-2,413	-1,551	Load Workpapers
[H]	Amount of [F] attributable to Others	-14,764	-13,878	-19,286	-14,528	Load Workpapers
[I]	Balancing area reserve requirement	-1,770	-1,880	-2,441	-1,872	See Text
[J]	Amount of [I] attributable to Applicant	-455	-463	-594	-464	See Text
[K]	Amount of [I] attributable to Others	-1,314	-1,417	-1,848	-1,408	Calculated
	Non-Affiliated Capacity					
[L]	Installed Generation	27,384	26,396	25,407	26,396	Generation Workpapers
[M]	Long-term Firm Purchases	0	0	0	0	PSEG
[N]	Long-term Firm Sales	-10	-10	-13	-13	PSEG
[O]	Seasonal Average Planned Outages	-1,428	-3,759	-220	-2,479	FERC Form 714
[P]	Available Imports	7,161	4,501	6,889	8,248	Calculated
	Supply Calculation					
[Q]	Total competing supply	17,029	11,833	10,929	16,216	Sum [H], [K], [L], [M], [N], [O], [P]
[R]	Applicant's uncommitted capacity	6,322	5,886	6,468	6,546	Sum [A], [B], [C], [D], [E], [G], [J]
[S]	Total seasonal uncommitted capacity	23,351	17,720	17,397	22,762	Sum [Q], [R]
[T]	**Applicant's Market Share**	27.1%	33.2%	37.2%	28.8%	= [R] / [S]
[U]	**Results**	**Fail**	**Fail**	**Fail**	**Fail**	

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Pivotal Supplier Assessment - PJM50

Row	Description	(MW)	Source
	Applicant and Affiliate Capacity		
[A]	Installed Generation	10,562	PSEG
[B]	Long-term Firm Purchases	13	PSEG
[C]	Long-term Firm Sales	-2,120	PSEG
[D]	Available Imports	86	Calculated: PSA Calcs
	Non-Affiliate Capacity		
[E]	Installed Generation	49,433	Energy Velocity
[F]	Long-term Firm Purchases	2,120	Calculated: PSA Calcs
[G]	Long-term Firm Sales	-13	Calculated: PSA Calcs
[H]	Available Imports	7,870	Calculated
[I]	Balancing authority reserve requirement	-4,400	FERC Form 714
[J]	Applicant reserve requirement	-320	Reserves Workpapers
[K]	Total uncommitted supply	17,404	Sum [A] through [I] plus [M]
	Load		
[L]	Balancing area annual peak load	56,172	Load Workpapers
[M]	Average daily peak native load in peak month	-46,146	Load Workpapers
[N]	Amount in [M] attributable to Applicant	-3,147	Load Workpapers
[O]	Wholesale Load	10,025	[L] + [M]
[P]	Net Uncommitted Supply	7,379	[K] - [O]
[Q]	Applicant's Uncommitted Capacity	5,074	Sum [A], [B], [C], [D], [J], [N]
[R]	**PSA Screen Result**	**Pass**	

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Wholesale Market Share Assessment - PJM50

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Source
	Applicant and Affiliate Capacity					
[A]	Installed Generation	10,284	10,423	10,562	10,423	PSEG
[B]	Long-term Firm Purchases	10	10	13	13	PSEG
[C]	Long-term Firm Sales	-2,020	-2,020	-2,120	-2,120	PSEG
[D]	Seasonal Average Planned Outages	-565	-1,574	-97	-1,037	See Text
[E]	Available Imports	90	58	84	84	Calculated
	Capacity Deductions					
[F]	Average peak native load in season	-32,138	-29,308	-39,213	-30,175	Load Workpapers
[G]	Amount of [F] attributable to Applicant	-2,023	-1,705	-2,413	-1,551	Load Workpapers
[H]	Amount of [F] attributable to Others	-30,115	-27,603	-36,800	-28,624	Load Workpapers
[I]	Balancing area reserve requirement	-3,293	-3,383	-4,227	-3,359	See Text
[J]	Amount of [I] attributable to Applicant	-298	-310	-320	-309	See Text
[K]	Amount of [I] attributable to Others	-2,996	-3,074	-3,908	-3,049	Calculated
	Non-Affiliated Capacity					
[L]	Installed Generation	52,755	51,094	49,433	51,094	Generation Workpapers
[M]	Long-term Firm Purchases	2,020	2,020	2,120	2,120	PSEG
[N]	Long-term Firm Sales	-10	-10	-13	-13	PSEG
[O]	Seasonal Average Planned Outages	-2,723	-7,187	-424	-4,740	FERC Form 714
[P]	Available Imports	8,779	5,459	7,872	7,987	Calculated
	Supply Calculation					
[Q]	Total competing supply	27,711	20,700	18,281	24,775	Sum [H], [K], [L], [M], [N], [O], [P]
[R]	Applicant's uncommitted capacity	5,478	4,882	5,709	5,502	Sum [A], [B], [C], [D], [E], [G], [J]
[S]	Total seasonal uncommitted capacity	33,189	25,581	23,990	30,278	Sum [Q], [R]
[T]	**Applicant's Market Share**	16.5%	19.1%	23.8%	18.2%	= [R] / [S]
[U]	**Results**	**Pass**	**Pass**	**Fail**	**Pass**	

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Pivotal Supplier Assessment - PJMAP

Row	Description	(MW)	Source
	Applicant and Affiliate Capacity		
[A]	Installed Generation	10,562	PSEG
[B]	Long-term Firm Purchases	13	PSEG
[C]	Long-term Firm Sales	-2,120	PSEG
[D]	Available Imports	96	Calculated: PSA Calcs
	Non-Affiliate Capacity		
[E]	Installed Generation	71,636	Energy Velocity
[F]	Long-term Firm Purchases	2,120	Calculated: PSA Calcs
[G]	Long-term Firm Sales	-13	Calculated: PSA Calcs
[H]	Available Imports	7,393	Calculated
[I]	Balancing authority reserve requirement	-5,911	FERC Form 714
[J]	Applicant reserve requirement	-320	Reserves Workpapers
[K]	Total uncommitted supply	21,023	Sum [A] through [I] plus [M]
	Load		
[L]	Balancing area annual peak load	75,082	Load Workpapers
[M]	Average daily peak native load in peak month	-62,753	Load Workpapers
[N]	Amount in [M] attributable to Applicant	-3,147	Load Workpapers
[O]	Wholesale Load	12,329	[L] + [M]
[P]	Net Uncommitted Supply	8,694	[K] - [O]
[Q]	Applicant's Uncommitted Capacity	5,084	Sum [A], [B], [C], [D], [J], [N]
[R]	**PSA Screen Result**	**Pass**	

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Wholesale Market Share Assessment - PJMAP

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Source
	Applicant and Affiliate Capacity					
[A]	Installed Generation	10,284	10,423	10,562	10,423	PSEG
[B]	Long-term Firm Purchases	10	10	13	13	PSEG
[C]	Long-term Firm Sales	-2,020	-2,020	-2,120	-2,120	PSEG
[D]	Seasonal Average Planned Outages	-565	-1,574	-97	-1,037	See Text
[E]	Available Imports	59	52	93	97	Calculated
	Capacity Deductions					
[F]	Average peak native load in season	-43,409	-39,676	-53,132	-41,102	Load Workpapers
[G]	Amount of [F] attributable to Applicant	-2,023	-1,705	-2,413	-1,551	Load Workpapers
[H]	Amount of [F] attributable to Others	-41,386	-37,970	-50,719	-39,552	Load Workpapers
[I]	Balancing area reserve requirement	-4,570	-4,608	-5,710	-4,574	See Text
[J]	Amount of [I] attributable to Applicant	-298	-310	-320	-309	See Text
[K]	Amount of [I] attributable to Others	-4,272	-4,298	-5,390	-4,264	Calculated
	Non-Affiliated Capacity					
[L]	Installed Generation	76,274	73,955	71,636	73,955	Generation Workpapers
[M]	Long-term Firm Purchases	2,020	2,020	2,120	2,120	PSEG
[N]	Long-term Firm Sales	-10	-10	-13	-13	PSEG
[O]	Seasonal Average Planned Outages	-3,949	-10,443	-616	-6,887	FERC Form 714
[P]	Available Imports	4,829	4,294	7,396	7,871	Calculated
	Supply Calculation					
[Q]	Total competing supply	33,506	27,547	24,413	33,231	Sum [H], [K], [L], [M], [N], [O], [P]
[R]	Applicant's uncommitted capacity	5,447	4,876	5,718	5,515	Sum [A], [B], [C], [D], [E], [G], [J]
[S]	Total seasonal uncommitted capacity	38,953	32,423	30,132	38,746	Sum [Q], [R]
[T]	**Applicant's Market Share**	14.0%	15.0%	19.0%	14.2%	= [R] / [S]
[U]	**Results**	**Pass**	**Pass**	**Pass**	**Pass**	

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DATA AND ASSUMPTIONS FOR ECONOMISTS INCORPORATED'S DELIVERED PRICE TEST STUDY FOR PSEG

This exhibit describes data and assumptions used in the delivered price test study ("study") carried out by Economists Incorporated for PSEG. Because the data are voluminous, we provide them in electronic workpapers. In those workpapers, the Files.xlsx spreadsheet provides a brief description of the organization of the data files.

This Exhibit has six sections. Section I discusses the study's representative periods. Section II discusses the geographic region and balancing authority areas. Section III discusses generation resources, including adjustments to generating capacity for seasons, maintenance, water availability, and long-term contracts. Section IV discusses transmission, including transmission pricing and losses. Section V discusses market prices. Section VI discusses the load data.

I. Periods

The study calculates market shares and concentration indexes for electric energy for ten representative periods during the year. The year is divided into three seasons (spring/fall, summer and winter). Spring/fall and winter seasons are divided into three periods based on days of the week, times of day and load levels. Summer is divided into four periods based on days of the week, times of day and load levels. Each calculation of market shares and concentration indexes reflects average conditions (e.g., average loads) during one of the resulting ten periods during the year (e.g., Summer Low Peak).

The study places each of the periods in each season into three condition categories: off-peak, low peak, and spike. Transmission pricing (see Section

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IV.B below) and plant availability (see Section III.A.2 below) vary among these three categories.

Table I-1 summarizes the ten periods for the destination markets.

Table I-1– Definition of Ten Periods for Destination Market

Number	*Season*	*Time*	*Condition*	*Hours*	*Description**
1	Spring/Fall	Top 10%	Spike	102	Top 5% of peak hours
2	Spring/Fall	Low Peak	Low Peak	1727	Remaining peak hours
3	Spring/Fall	Off-peak	Off-Peak	2360	Off-peak hours
4	Summer	Top 1%	Spike	10	Top 10% of peak hours
5	Summer	Top 10%	Spike	102	Next 10% of peak hours
6	Summer	Low Peak	Low Peak	871	Remaining peak hours
7	Summer	Off-peak	Off-Peak	1184	Off-peak hours
8	Winter	Top 10%	Spike	102	Next 10% of peak hours
9	Winter	Low Peak	Low Peak	871	Remaining peak hours
10	Winter	Off-peak	Off-Peak	1136	Off-peak Hours

Note: *Peak hours include hours ending 7 a.m. through 10 p.m. Central Time weekdays, excluding six major holidays. Off-peak hours = Hours ending 11 p.m. through 6 a.m. on weekdays and all weekend and holiday hours.

The Off-peak periods are all NERC holidays and weekend hours plus weekdays from the hour ending at midnight EPT until the hour ending at 0700.[1] The Off-peak periods have off-peak transmission pricing and plant availability.

In order to define the Top 1% and Top 10% periods for a given season, we removed all Off-peak hours from that season. We then ranked the remaining (peak) hours based on load levels in the destination market by season. We then defined as the Top 1% as the 1 percent of these remaining hours in which loads in the destination market were highest and the Top 10% as the highest 10 percent of peak hours based on load levels. These periods have spike transmission pricing and plant availability.

[1] Major holidays are New Year's, Memorial Day, 4th of July, Labor Day, Thanksgiving and Christmas. Major holidays are included in the Weekend period.

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The Low Peak periods are weekdays from the hour ending at 0800 until the hour ending at 2300 EPT, excluding hours in the Top 10% periods and major holidays. The Low Peak period has on-peak transmission pricing and plant availability.

It is important to divide the year initially into three seasons to avoid aggregating across hours in which the suppliers in the market that have available economic capacity (e.g., summer peaking vs. winter peaking utilities) are different. In addition, the division of the year into three seasons makes it possible to take into account seasonal differences in generation availability, contracts, transmission pricing, and transfer capability.

II. Geographic Coverage and Market Areas

The study includes market areas that correspond to the balancing authority areas used by the North American Electric Reliability Council (NERC), and PJM submarkets as defined by FERC. Table II-1 lists these market areas and their abbreviations. There are two study destination markets, PJM East and PJM East of 5004/5005.

Table II-1– List of Eastern Market Areas and Study Destinations

Abbreviation	*Full Name*	*Study Destination*
PJME	PJM East	Yes
PJMC	PJM East of 5004/5005	Yes
PJMS	PJM East of AP South	
PJM	PJM	
NYISO	New York ISO	
DUK	Duke Energy Carolinas	
CPLE	Carolina Power & Light East	
CPLW	Carolina Power & Light West	
LGEE	Louisville Gas & Electric	
OVEC	Ohio Valley Electric Corp.	
TVA	Tennessee Valley Authority	
EKPC	Eastern Kentucky Power Cooperative	

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III. Generation

A. Generation Capacity and Ownership

The study includes generating units located in the areas that are (1) connected to the power grid, (2) not exclusively used for self-generation, and (3) either in a plant used primarily for electric generation or a Qualifying Facility.

1. Generating Unit Data

The study uses data for summer and winter capability at the unit level reported in the Energy Velocity (EV) database available from Ventyx. The units include all units with a status of operating, standby, cold standby, restart, mothballed, testing, or under construction that will be online before November 30, 2012 and a retirement date after November 30, 2012. We exclude generation units that are less than 5 MW unless they are owned by PSEG.

2. Ownership

The study uses relies on Ventyx determination of plant and ownership. When Ventyx reports a holding company, the ownership is assigned to the holding company. For PSEG generation, the study relies upon Appendix B data from market-based rate filings and updates from the companies to determine plant ownership and seasonal capability. Operational control of PSEG units is consistent with the methodology used for market-based rates.

3. Seasonal variation in capability

The study uses seasonal capability data from EV. Spring/fall capacities are the average of summer and winter capacities.

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4. Adjustments to Generating Capability

The generating capability figures used for each period are obtained by multiplying the seasonal capabilities by an availability factor, which is based on the period, unit location, and NERC General Availability Data Systems (GADS) category of the unit. The GADS database gives national average operating information for generating units by unit type and size. For example, it gives data for coal-fired steam units with capacities between 300 MW and 399 MW.

For each period and each generating unit, the availability factor adjusts for the following.

a) Unplanned outage rates by GADS category

For a given GADS category, the study assumes that unplanned (forced) outage rates (as a share of generating capability available after allowing for planned outages) are constant across seasons and generating units throughout the Region, regardless of owner. Based on GADS data for 2007 through 2011, which are the most recent data in the EV database, the study calculates an equivalent forced outage rate (EIFOR), which measures the share of generating capability in a GADS category that is not available because of forced outages. The computation is EIFOR = (FOH)/AH, where FOH is number of forced outage hours and AH is total hours available for generation after planned outages (but before forced outages).[2]

b) Planned outage rates by GADS category and season

With four exceptions (hydro, pumped storage, wind, and solar units), the study assumes that the planned outage rate is constant for all generating units for a

[2] EIFOR differs slightly from the EFOR provided in the GADS data. EIFOR provides a better measure of a forced outage rate for peaking units that are operated a small percentage of the year.

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given GADS category and season. For a given GADS category, the share of hours of generating capability that is not available as a result of planned outages is computed as (POH + POEH)/PH; where PH are the period hours, POH are the hours not available because of planned outages, and POEH are the hours not available because of planned outage extensions

The study assumes that balancing authority areas are both summer and winter peaking. Therefore, the study assumes that all planned outages for thermal units occur during spring/fall.

c) Variation in hydro availability across seasons and periods

In general, utilities use hydro facilities to generate energy during the hours when energy prices are highest, subject to constraints imposed by availability of water and reservoir capacity. In order to incorporate these constraints, the study proceeds in the following manner.

First, the study uses EIA Form 923 monthly production data for the period 2011 to 2012 to compute average hourly hydro generation by season. Average hourly generation is then divided by hydro capability to give an average hourly hydro operating rate by season.

Second, depending upon the level of the hydro operating rate for a given season, the study calculates availability factors for the spike, low peak and off-peak periods. When the historical seasonal operating rate is below 30 percent, the availability factor for each period in the season is set equal to the operating rate; the 30 percent figure is an assumed "run of river" constraint. The study assumes that prospectively the maximum operating rate is 90 percent; this is the assumed "maximum rate" constraint. When the historical seasonal operating rate is above 90 percent, the availability factor for each period is set to 90 percent.

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When the seasonal operating rate is above the run of river constraint and below the maximum rate, we reason that the hydro generator owner would be likely to produce a higher level of energy during spike hours, when energy prices are highest, than during low peak hours, and that the owner would be likely to produce a higher level during low peak than during off-peak hours.

Based on this reasoning, when the seasonal operating rate is between the run of river constraint and the maximum rate, as is the case for each of the three seasons, the study uses a spike availability factor of 90 percent, which is the assumed maximum operating rate, and off-peak availability factor of 30 percent, which is the assumed run-of-river constraint, and a calculated availability factor for the low peak periods, as described below.

The seasonal low peak availability factor is calculated with actual total seasonal hydro generation. The study then computes the hydro generation during all spike and off-peak hours, assuming the generation rates implied by the spike and off-peak derate factors computed in the manner described above. The study then calculates total low peak hydro generation as the difference between total seasonal hydro generation and the sum of hydro generation during all spike and off-peak hours. The seasonal low peak availability factor is computed as total low peak hydro generation divided first by the number of hours in the off-peak period and then by hydro generating capacity.

d) Variation in pumped storage availability across seasons and periods

We assume that pumped storage units have 90 percent availability during Top 1% and Top 10% periods, 50 percent availability during Low Peak periods, and no availability during off-peak periods.

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e) Wind availability

For each area-owner combination, we calculate average operating rates in 2011 and 2012 by season from EIA-923 data. The average operating rates are the availability factors. When operating rates are not available for an owner in an area, we use the average operating rate for that area.

f) Solar availability

Availability for solar power is also calculated based on average operating rates for 2011 and 2012 reported in EIA-923. There is little solar power during off-peak periods because of darkness. Accordingly, solar availability is weighted to on-peak periods.

B. Variable Costs of Generation

The study uses variable costs of generation that include fuel costs, sulfur dioxide and nitrogen oxide emissions costs, and variable operations and maintenance (VOM) costs. The study calculates fuel costs from unit heat rates and Platts' Gas Daily spot prices at the unit's reported natural gas hub by Energy Velocity, #2 Diesel, Low-Sulfur – Industrial for the East Coast, and Residual Fuel Oil sales to end users for the East Coast for the years 2011-2012. Natural gas prices vary by hub, but were $3.78 per mmBtu at TETCO M3, the hub with the largest reported capacity in the study. The prices for oil units are as follows: #2 fuel oil $20.43 per mmBtu, and residual fuel oil $14.47 per mmBtu. Fuel costs for other fuels are based upon the average fuel costs reported in the EV data for each fuel type. Emissions prices for 2011-2012 are $0.75 per ton for SO2 year-round and $39 per ton for NOx in the summer season. CO_2 costs for units located in Regional Greenhouse Gas Initiative (RGGI) states are $1.93/ton, which is based upon RGGI Auction results in 2012. Units in Montgomery County, MD have an

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additional $5/ton carbon tax on CO_2 emissions. VOM costs are from the EV database.

C. Long-term Contracts

We reviewed Appendix B data from market-based rate filings and FERC Form 1 filings to obtain data on long-term contracts. Where the market-based rate filing indicates a change of operational control, we include a contract transferring control to the buyer. We leave the generation unit in the BAA where it is physically interconnected to the transmission system. When the buyer is a load-serving entity in another BAA, we give a priority firm transmission path to the BAA with the load.

Long-term contracts that expire prior to December 1, 2011 are not included in the study. Long-term contracts that expire between December 1, 2011 and August 31, 2012 are included only in the seasons for which they are in effect. Contracts that expire after September 1, 2012 are included in the study.

IV. Transmission

A. Transmission Network

The study incorporates a contract path transmission network for modeling purposes. Transmission pricing between balancing authority areas is represented by a traditional contract path transmission network in which the direct physical connections between balancing authority areas are also the individually priced links from which contract paths are constructed.

B. Transmission and Ancillary Services Pricing and Losses

As specified by the Commission's Appendix A, the study generally uses ceiling prices for transmission service from Schedules 1, 2 and 8 of the utility's *pro*

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forma open-access transmission tariff. Transmission providers may require transmission customers to purchase ancillary services under Schedule 1 (scheduling, system control and dispatch) and Schedule 2 (reactive supply and voltage control). Schedule 8 gives the rates for non-firm point-to-point transmission service. The study uses transmission prices from tariffs.

When we have tariffs available, we calculate rates for off-peak, peak and spike categories. Because of discounting and the nature of baseload purchases, off-peak rates are often lower than peak rates.[3] We use two steps to determine off-peak rates. Step 1: When a utility posts off-peak hourly rates, we use the posted rates. Step 2: When a utility does not post off-peak hourly rates, we calculate an hourly off-peak rate based on other tariff information. To calculate hourly off-peak rates, we divide the weekly rate by 168, the number of hours in a week. When tariffs specify fees on a per transaction basis, we divide them by 25 to put them on a per MW basis.

We use similar steps to determine peak rates. Step 1: When a utility posts maximum hourly rates in its tariff, we use the maximum tariff rates. Step 2: When a utility does not post off-peak hourly rates, we calculate a peak rate based on other tariff information. To calculate hourly peak rates, we divide the weekly rate by 80—the "Appalachian" method. When tariffs specify fees on a per transaction basis, we divide them by 25 to put them on a per MW basis.

For spike periods, we use ceiling hourly rates from tariffs, when available. Otherwise, we use the Appalachian method.

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[3] For transactions longer than one hour, the *pro forma* tariff caps the amount that the purchaser pays per day by the daily rate, and the amount that the purchaser pays per week by the weekly rate.

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Whenever practical, the study uses loss rates from tariffs. When these methods did not provide a loss rate for a particular utility, the study assumes that losses are three percent per utility.[4] The study assumes that transmission customers pay losses in-kind. That is, if area A exports 100 MW to area B and the losses are 3 percent, only 97 MW arrive at area B.

For areas where tariffs are not available, rates and losses are the average by period for all the reporting areas.

C. Transfer Capability and SILs

The geographic market includes only PJM and first tier BAAs. Per the recent *NRG/GenOn* order, transmission into a destination market from first tier areas is to be limited only by the simultaneous import limit ("SIL").[5] Accordingly, the transfer capability from each first tier area to the destination market is set to 99,999 MW. The SIL for PJM East and PJM East of 5004/5005 comes from the 2012 Simultaneous Import Limit Study Report filed by PJM on October 1, 2013.[6] The total imports into the destination markets may be less than the actual ability to import into the destination because not all the generation capability owned or controlled by load-serving entities within the destination markets studied in PJM have been identified in the data.

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[4] Losses of 3 percent are representative of the industry. See, FERC Open Access NOPR, *FERC Stats & Regs*, ¶32,514 at 33,150 (1995).

[5] *See*, NRG Energy, Inc. and GenOn Energy, Inc., 114 FERC ¶61,207, P 63, note 112 (2012).

[6] PJM, 2012 Simultaneous Import Study Report, *Guidance on Simultaneous Import Limit Studies*, Docket No. AD10-2-002, October 1, 2013, at 3.

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V. Market Prices

The study used December 2011-November 2012 real-time hourly prices from the RTO LMP for PJM East and PJM East of 5004/5005. Table V-1 shows the PJM East of 5004/5005 market prices in each of the ten periods, and Table V-2 shows the PJM East market prices.

Table V-1 – PJM East of 5004/5005 Market Prices ($/MWh)

Time	*Spring/Fall*	*Summer*	*Winter*
Top 1%	-----	$181.98	-----
Top 10%	$66.65	$107.58	$60.87
Low Peak	$38.72	$42.40	$34.68
Off-Peak	$28.24	$28.32	$30.46

Table V-2 – PJM East Market Prices ($/MWh)

Time	*Spring/Fall*	*Summer*	*Winter*
Top 1%	-----	$188.24	-----
Top 10%	$66.52	$109.22	$61.53
Low Peak	$37.36	$42.17	$34.72
Off-Peak	$27.77	$28.67	$29.97

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VI. Load and Contract Obligations for AEC Calculations

Load data come from PJM for PJM and from Energy Velocity for the other supply areas.

To compute load requirements for market participants in New York and PJM, we apportion the total load in each market area in New York and PJM to all suppliers in proportion to their respective generation capacities. We assumed 70 percent of load is committed for a year or longer and the remaining 30 percent is contracted for shorter periods.[7] To account for their greater load obligations, we assume that Dominion has 100 percent responsibility for its allocation of load and that AEP has 90 percent of its allocation as opposed to the standard 70 percent. Utilities south of PJM have traditional load obligations and have 100 percent load responsibility for their respective planning area loads. Small utilities for which have not load data available were not imputed a share of PJM or NYISO load were assumed to have no AEC.

[7] This is a reasonable estimate for the long-term load coverage since this number is generally between 60 and 80 percent for most generation suppliers.

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Technical Appendix:

Methods Used to Compute Concentration

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This Exhibit describes the methods used to calculate market shares and concentration in destination markets.

Allocation of scarce transmission capability is accomplished using linear and nonlinear programs that model generation dispatch and the contract path transmission system. This Exhibit provides an overview of the structure of the programs and presents the equations.

Overview of Linear Program

The linear program models control areas as nodes in a transmission system. Each node has a demand for and a supply of electric energy. The supply is based on the generators at the node and potential deliveries to the node via transmission links from other control areas. The linear program allows for net import and export limits to and from an individual control area. Given generation capability and costs and transmission capability and costs, the linear program finds the least-cost solution that satisfies the specified loads. Costs are defined as dispatch (generation) costs plus transmission costs including losses plus the default cost for "unserved" load. For each solution, the linear program determines the quantities produced in, exported from, and imported into each control area.

The Mathematical Equations

The linear program to be solved is given below:

Minimize Total Cost: $Cost = GC + TC + UC$

Subject to:

(1) Generation: $TG_a = \sum_{u}^{u \in a} G_{a,u}$ for each area *a*;

(2) Imports: $YI_a = \sum_{b}^{a,b \in network} (1 - h_{b,a}) T_{b,a}$ for each area *a*;

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(3)	Exports:	$YE_a = \sum_{b}^{a,b \in network} T_{a,b}$	for each area *a*;
(4)	Net Imports:	$Y_a = YI_a - YE_a$	for each area *a*;
(5)	Supply/Demand Balance:	$TG_a + Y_a + U_a = D_a$	for each area *a*;
(6)	Generation Cost:	$GC = \sum_{a} \sum_{u}^{u \in a} d_{a,u} G_{a,u}$	for each area *a*;
(7)	Transmission Cost:	$TC = \sum_{a,b}^{a,b \in network} r_{a,b} T_{a,b}$	for each path *a* to *b*;
(8)	Unfilled Demand Cost:	$UC = \sum_{a} pU_a$	for each area *a*;
(9)	Generation Limits:	$g\min_{a,u} \le G_{a,u} \le g\max_{a,u}$	for each unit *u* in each area *a*;
(10)	Transmission Limits:	$t\min_{a,b} \le T_{a,b} \le t\max_{a,b}$	for each link *a* to *b* in the transmission network; and
(11)	Net Import Limits	$Y\min_{a} \le Y_a \le Y\max_{a}$	for each area *a*;

where:

a,b	are subscripts for control/transmission areas;
Cost	is total system cost;
$d_{a,u}$	is the dispatch cost of unit *u* in area *a*;
D_a	is demand for power in area *a*;
$G_{a,u}$	is generation output of unit *u* in area *a*;
GC	is total system generation cost;
$G\max_{a,u}$	is the maximum output of unit *u* in area *a*;
$G\min_{a,u}$	is the minimum output of unit *u* in area *a*;
$h_{b,a}$	is the fraction of power lost to resistance from moving power from area *b* to area *a*;
N	is a subscript to identify simultaneous transmission constraint *n*;
P	is the default price;
$r_{a,b}$	is the transmission rate from area *a* to area *b*;

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$T_{a,b}$	is the power flow from area *a* to area *b*;
TC	is total system transportation expenses;
TG_a	is total generation output in area *a*;
$t\max_{a,b}$	is the maximum power flow from area *a* to area *b*;
$t\min_{a,b}$	is the minimum power flow from area *a* to area *b*;
U	is a subscript to identify units in an area;
U_a	is the amount of demand in area *a* not met by generation or imports
UC	is total system cost of not meeting demand;
Y_a	is net imports into area *a*;
YE_a	is total exports from area *a*; and
YI_a	is total imports into area *a*;
$Y\min_a$	is minimum net imports in area *a;*
$Y\max_a$	is maximum net imports in area *a.*

This linear program is solved using the BDMLP solver in GAMS. In order to calculate concentration for different destinations, seasons, and periods, the PASS GAMS program loops through the destinations, seasons, and periods with calls to Solvers to solve the linear programs. Loads, unit availability and transmission availability are adjusted for each season-period combination.

Calculating Concentration

Transmission allocation is accomplished in four steps. In the first step the linear program finds the net-back prices in all control areas given a price at the destination control area equal to 105 percent of the pre-merger price. Suppose the pre-merger price at the destination, control area A, is $20/MWh. Then all generation capability with a dispatch cost of $21/MWh or less in the destination area would be included in the market because $21 is 105 percent of $20. If transmission cost (including losses) is $5/MWh from control area B to A, then the net-back price at B would be $16/MWh, which is the $21/MWh less the $5/MWh transmission cost between B and A. Then, all generation capability at B with dispatch costs equal to or less than $16/MWh would be included in the market if there were no transmission constraints. Calculation of net-back prices is

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accomplished by setting the default price, *p*, equal to 105 percent of the pre-merger price at the destination, setting load at the destination to a high number and loads elsewhere to zero, setting transmission limits high enough so that the transmission system is not constrained, and setting a limited amount of generation in each area with a zero dispatch cost. The shadow prices produced by the linear program will be *p* at the destination and the relevant net-back prices in other areas.

In the second step, one calculates Economic Capacity (EC) and Available Economic Capacity (AEC) in each area. These values are then used to limit generation capability. The ownership shares of AEC and EC are calculated for each node in the system.

In the third step, the linear program determines the amount of energy that can be imported into an area given available EC (or AEC) and limits on transmission capacity. This is accomplished by limiting generation in each area to the capacity amount (EC or AEC), giving generation outside the destination market a lower cost than generation inside the destination market, and minimizing cost to serve a large load at the destination market. The amount of generation supplied to the destination is the maximum that can be imported into the destination market.

In the fourth step, transmission is allocated by the following non-linear program:

Minimize Loss: $$Loss = \sum_{\alpha}\left(\frac{C_{\alpha}^{2}}{Y_{Dest}s_{\alpha}} - 2C_{\alpha}\right)$$

Subject to:

(1) Pre Shares: $$s_{\alpha} = \frac{C\max_{\alpha}}{\sum_{\beta} C\max_{\beta}}$$ for each area α;

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(2)	Allocated Shares:	$A_\alpha = \frac{C_\alpha}{Y_{Dest}}$	for each area α;
(3)	Imports:	$YI_a = \sum_b^{a,b \in network} (1 - h_{b,a}) T_{b,a}$	for each area *a*;
(4)	Exports:	$YE_a = \sum_b^{a,b \in network} T_{a,b}$	for each area *a*;
(5)	Net Imports:	$Y_a = YI_a - YE_a$	for each area *a*;
(6)	Supply/Demand Balance:	$C_a + Y_a + U_a = D_a$	for each area *a*;
(7)	Capacity Limits:	$c\min_a \le C_a \le C\max_a$	for each area *a*;
(8)	Transmission Limits:	$t\min_{a,b} \le T_{a,b} \le t\max_{a,b}$	for each link *a* to *b* in the transmission network; and
(9)	Max Import Limit	Y_{Dest} = Maximum imports from step 3;	

where:

a,b	are subscripts for control/transmission areas;
α,β	are subscripts for control/transmission areas other than the destination market;
s_α	Is area α's share of capacity outside of the destination;
A_α	is area α's share of allocated capacity outside of the destination;
Loss	is the loss function to be minimized.

The loss function is derived from the weighted squared-errors between the pre-allocation shares and the post-allocation shares, where Y_{Dest}/s_α are the weights. For each source control area, the weighted squared-error is given by:[1]

$$W_\alpha = \frac{Y_{Dest}}{s_\alpha}(A_\alpha - s_\alpha)^2.$$

[1] This exposition ignores the adjustments necessary to give priority to minimum transfer levels from a source area to the destination.

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Accordingly, the sum of the weighted squared-errors gives rise to the loss function, which can be seen by:

$$\begin{aligned} Loss &= \sum_{\alpha} W_{\alpha} \\ &= \sum_{\alpha} \frac{Y_{Dest}}{s_{\alpha}} (A_{\alpha} - s_{\alpha})^2 \\ &= \sum_{\alpha} \frac{Y_{Dest}}{s_{\alpha}} (A_{\alpha}^2 - 2s_{\alpha}A_{\alpha} + s_{\alpha}^2) \\ &= \sum_{\alpha} \left(\frac{C_{\alpha}^2}{Y_{Dest}s_{\alpha}} - 2C_{\alpha} \right) + \text{constant}. \end{aligned}$$

The resulting shares from minimizing this loss functions preserve the relative shares of capacity behind any transmission constraint going to the destination. This can be seen from the following LaGrangian equation to be minimized:

$$L = \sum_{i} \left(\frac{C_i^2}{Y_{Dest}s_i} - 2C_i \right) + \lambda \left(T - \sum_{i} C_i \right),$$

where T is the transmission limit affecting control areas i. The first order conditions are:

$$\frac{\partial L}{\partial C_i} = \frac{2C_i}{Y_{Dest}s_i} - 2 - \lambda = 0,$$

which can be rearranged to give:

$$A_i = \frac{C_i}{Y_{Dest}} = \left(\frac{2+\lambda}{2} \right) s_i,$$

which shows that the allocated market shares of those areas affected by the transmission constraint are proportional to their shares of capacity before the transmission allocation. Moreover, this is the only transmission allocation

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method that maintains the relative shares of capacity behind any binding transmission constraint in the allocation process.

This non-linear program is solved using the COINIPOPT solver in GAMS. The calculated capacities from the nonlinear program above less transmission losses determine the capacities for the market share calculations for sources outside of the destination market. The capacities within the destination market are given full weights.

Market concentration is the HHI, which is the sum of the squared market shares. Mathematically,

$$HHI = \sum_{i=1}^{n} S_i^2,$$

where S_i is the allocated share of firm i and n is the number of firms in the market. The summary sheets combine all the firms with shares of 0.7 percent or less (other than Applicants) into the "Other" category. The collective share of the Other category does not directly enter the HHI calculation other than the represented capacity as each independent entity enters the HHI calculation. For example, if ten firms with 0.5 percent shares were in the Other category, the HHI contribution of the Other category would be 0.625 (= 10 x .5 x .5 = 10 x .0625) and ***not*** 25.

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Delivered Price Test - PJM50 Market

Available Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$66.65	3,078	19,358	16,279	8,673	Yes	15.9	Yes	1,098	Yes
Spring/Fall	Peak	$38.72	2,630	19,022	16,391	8,673	Yes	13.8	Yes	1,243	Yes
Spring/Fall	Off Peak	$28.24	1,734	16,504	14,770	8,673	Yes	10.5	Yes	1,866	Yes
Summer	Top 1%	$181.98	3,042	24,903	21,861	11,158	Yes	12.2	Yes	779	Yes
Summer	Top 10%	$107.58	3,023	23,063	20,040	11,158	Yes	13.1	Yes	772	Yes
Summer	Peak	$42.40	2,146	18,599	16,454	11,158	Yes	11.5	Yes	1,185	Yes
Summer	Off Peak	$28.32	1,438	16,621	15,184	11,158	Yes	8.6	Yes	1,974	Yes
Winter	Top 10%	$60.87	3,254	19,604	16,351	4,232	Yes	16.6	Yes	1,077	Yes
Winter	Peak	$34.68	2,106	19,013	16,907	4,232	Yes	11.1	Yes	1,031	Yes
Winter	Off Peak	$30.46	1,813	17,222	15,409	4,232	Yes	10.5	Yes	1,269	Yes

Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$66.65	6,902	40,678	33,776	37,015	No	17.0	Yes	1,072	Yes
Spring/Fall	Peak	$38.72	5,780	37,871	32,091	28,730	Yes	15.3	Yes	1,063	Yes
Spring/Fall	Off-Peak	$28.24	4,672	31,612	26,940	24,161	Yes	14.8	Yes	1,144	Yes
Summer	Top 1%	$181.98	8,360	56,794	48,434	54,098	No	14.7	Yes	982	Yes
Summer	Top 10%	$107.58	8,058	53,182	45,125	50,483	No	15.2	Yes	970	Yes
Summer	Peak	$42.40	6,134	41,727	35,594	37,816	No	14.7	Yes	1,002	Yes
Summer	Off Peak	$28.32	4,969	34,461	29,492	30,107	No	14.4	Yes	1,114	Yes
Winter	Top 10%	$60.87	7,159	43,468	36,309	36,538	No	16.5	Yes	1,020	Yes
Winter	Peak	$34.68	5,554	39,565	34,010	31,493	Yes	14.0	Yes	1,002	Yes
Winter	Off Peak	$30.46	5,169	36,342	31,173	27,514	Yes	14.2	Yes	1,067	Yes

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Delivered Price Test - PJME Market

Available Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$66.52	2,829	15,453	12,624	5,066	Yes	18.3	Yes	1,013	Yes
Spring/Fall	Peak	$37.36	2,355	15,053	12,698	5,066	Yes	15.6	Yes	1,157	Yes
Spring/Fall	Off Peak	$27.77	1,475	13,045	11,570	5,066	Yes	11.3	Yes	1,821	Yes
Summer	Top 1%	$188.24	2,824	17,006	14,183	7,158	Yes	16.6	Yes	758	Yes
Summer	Top 10%	$109.22	2,788	16,125	13,336	7,158	Yes	17.3	Yes	735	Yes
Summer	Peak	$42.17	1,883	14,324	12,441	7,158	Yes	13.1	Yes	1,091	Yes
Summer	Off Peak	$28.67	1,358	12,776	11,418	7,158	Yes	10.6	Yes	1,783	Yes
Winter	Top 10%	$61.53	3,075	15,865	12,790	2,000	Yes	19.4	Yes	1,100	Yes
Winter	Peak	$34.72	1,905	14,650	12,745	2,000	Yes	13.0	Yes	1,113	Yes
Winter	Off Peak	$29.97	1,644	13,685	12,041	2,000	Yes	12.0	Yes	1,395	Yes

Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$66.52	6,408	29,458	23,050	20,334	Yes	21.8	No	1,062	Yes
Spring/Fall	Peak	$37.36	5,291	27,246	21,955	15,287	Yes	19.4	Yes	1,043	Yes
Spring/Fall	Off-Peak	$27.77	4,154	22,271	18,118	12,928	Yes	18.6	Yes	1,165	Yes
Summer	Top 1%	$188.24	7,825	35,682	27,857	31,201	No	21.9	No	1,037	Yes
Summer	Top 10%	$109.22	7,523	33,548	26,025	28,872	No	22.4	No	1,027	Yes
Summer	Peak	$42.17	5,605	29,694	24,089	20,912	Yes	18.9	Yes	989	Yes
Summer	Off Peak	$28.67	4,589	25,425	20,836	16,785	Yes	18.1	Yes	1,072	Yes
Winter	Top 10%	$61.53	6,691	30,759	24,068	19,164	Yes	21.8	No	1,068	Yes
Winter	Peak	$34.72	5,087	27,734	22,647	16,525	Yes	18.3	Yes	1,006	Yes
Winter	Off Peak	$29.97	4,710	25,791	21,081	14,299	Yes	18.3	Yes	1,054	Yes

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Appendix B
List of Entities with Market-Based Rate Authority and Their Generation Assets

Market Based Rate Authority and Generation Assets									
						LOCATION			
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region (per Appendix D)	In-service Date	Nameplate Rating (MW)
PSE&G	ER99-3151-000	NA*	NA*	NA*	NA*	PJM	Northeast	NA*	NA*
PSEG ER&T	ER97-837-000	NA*	NA*	NA*	NA*	PJM, NYPP, NE-ISO	Northeast, Central, Southwest Power Pool, Southeast, Southwest, Northwest	NA*	NA*
PSEG Fossil	ER08-447-000	Bergen 3	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	07/07/1967	18.6
PSEG Fossil	ER08-447-000	Bergen CC1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/1995	775.2
PSEG Fossil	ER08-447-000	Bergen CC2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/2002	625.6
PSEG Fossil	ER08-447-000	Burlington 8	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/02/1967	18.6
PSEG Fossil	ER08-447-000	Burlington 9	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	05/11/1972	162.4
PSEG Fossil	ER08-447-000	Burlington 11	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/05/1972	162.4
PSEG Fossil	ER08-447-000	Burlington 12.1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/2000	60.5
PSEG Fossil	ER08-447-000	Burlington 12.2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/2000	60.5
PSEG Fossil	ER08-447-000	Burlington 12.3	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/2000	60.5
PSEG Fossil	ER08-447-000	Burlington 12.4	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/2000	60.5
PSEG Fossil	ER08-447-000	Conemaugh 1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	05/21/1970	210.6
PSEG Fossil	ER08-447-000	Conemaugh 2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	05/27/1971	210.6
PSEG Fossil	ER08-447-000	Conemaugh A	PSEG Fossil[1]	PSEG ER&T	08/21/2000	PJM	Northeast	02/01/1970	0.625
PSEG Fossil	ER08-447-000	Conemaugh B	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	02/01/1970	0.625
PSEG Fossil	ER08-447-000	Conemaugh C	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	02/01/1970	0.625
PSEG Fossil	ER08-447-000	Conemaugh D	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	02/01/1970	0.625
PSEG Global	N/A	Conemaugh Hydroelectric Plant 1	PSEG Global[2]	PSEG ER&T	02/01/1989	PJM	Northeast	02/01/1989	1.0

[1] PSEG Fossil has a 22.5% interest in the Conemaugh coal fired plants.
[2] PSEG Global has a 4% interest Conemaugh Hydroelectric plants.

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Market Based Rate Authority and Generation Assets									
						Location			
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region (per Appendix D)	In-service Date	Nameplate Rating (MW)
PSEG Global	N/A	Conemaugh Hydroelectric Plant 2	PSEG Global	PSEG ER&T	02/01/1989	PJM	Northeast	02/01/1989	1.0
PSEG Fossil	ER08-447-000	Edison 1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	05/06/1971	167.4
PSEG Fossil	ER08-447-000	Edison 2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/23/1971	167.4
PSEG Fossil	ER08-447-000	Edison 3	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/30/1971	167.4
PSEG Fossil	ER08-447-000	Essex 9	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	07/01/1990	93.6
PSEG Fossil	ER08-447-000	Essex 10	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/28/1971	167.4
PSEG Fossil	ER08-447-000	Essex 11	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	12/23/1971	167.4
PSEG Fossil	ER08-447-000	Essex 12	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/08/1971	167.4
PSEG Nuclear	ER08-448-000	Hope Creek 1	PSEG Nuclear	PSEG ER&T	08/21/2000	PJM	Northeast	12/20/1986	1,290.7[3]
PSEG Fossil	ER08-447-000	Hudson 2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	12/18/1968	659.7
PSEG Fossil	ER08-447-000	Kearny 9	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	05/24/1967	18.6
PSEG Fossil	ER08-447-000	Kearny 12	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	08/01/2001	242.0
PSEG Fossil	ER08-447-000	Kearny 13	PSEG Fossil	PSEG ER&T	06/01/2012	PJM	Northeast	06/01/2012	242.0
PSEG Fossil	ER08-447-000	Kearny 14	PSEG Fossil	PSEG ER&T	06/01/2012	PJM	Northeast	06/01/2012	121.0
PSEG Fossil	ER08-447-000	Keystone 1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	08/24/1967	213.8
PSEG Fossil	ER08-447-000	Keystone 2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	07/23/1968	213.8
PSEG Fossil	ER08-447-000	Keystone 3	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	11/23/1968	0.625
PSEG Fossil	ER08-447-000	Keystone 4	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	11/23/1968	0.625
PSEG Fossil	ER08-447-000	Keystone 5	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	11/23/1968	0.625
PSEG Fossil	ER08-447-000	Keystone 6	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	11/23/1968	0.625
PSEG Fossil	ER08-447-000	Linden 1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	04/01/2006	677.8
PSEG Fossil	ER08-447-000	Linden 2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM,	Northeast	04/01/2006	677.8
PSEG Fossil	ER08-447-000	Linden 7	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/1995	96.1
PSEG Fossil	ER08-447-000	Linden 8	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/1995	96.1
PSEG Fossil	ER08-447-000	Linden GT5	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/2000	96.1
PSEG Fossil	ER08-447-000	Linden GT6	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/01/2000	96.1

[3] Please note that this number is 120 MW higher than the nameplate rating number provided in Appendix B of the 2010 triennial filing in Docket No. ER08-448-007 and the PSEG New Haven initial MBR filing in Docket No. ER12-1250-000. This is due to the fact that a capacity increase associated with an uprate to the Hope Creek nuclear unit was inadvertently not included in the nameplate number included in Appendix B. This capacity uprate was, however, discussed in the 2007 and 2010 triennial applications themselves.

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Market Based Rate Authority and Generation Assets									
						Location			
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region (per Appendix D)	In-service Date	Nameplate Rating (MW)
PSEG Fossil	ER08-447-000	Mercer 1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	12/19/1960	326.4
PSEG Fossil	ER08-447-000	Mercer 2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/04/1961	326.4
PSEG Fossil	ER08-447-000	Mercer GT3	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	11/30/1967	115.2
PSEG Fossil	ER08-447-000	National Park GT1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	06/04/1969	18.6
PSEG Nuclear	ER08-448-000	Peach Bottom 2	PSEG Nuclear[4]	PSEG ER&T	08/21/2000	PJM	Northeast	07/05/1974	576.0
PSEG Nuclear	ER08-448-000	Peach Bottom 3	PSEG Nuclear	PSEG ER&T	08/21/2000	PJM	Northeast	12/23/1974	576.0
PSEG Nuclear	ER08-448-000	Salem 1	PSEG Nuclear[5]	PSEG ER&T	08/21/2000	PJM	Northeast	06/30/1977	671.7
PSEG Nuclear	ER08-448-000	Salem 2	PSEG Nuclear	PSEG ER&T	08/21/2000	PJM	Northeast	10/13/1981	671.7
PSEG Nuclear	ER08-448-000	Salem GT3	PSEG Nuclear	PSEG ER&T	08/21/2000	PJM	Northeast	06/17/1971	24.0
PSEG Fossil	ER08-447-000	Sewaren 1	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	12/01/1948	110.8
PSEG Fossil	ER08-447-000	Sewaren 2	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	11/30/1948	107.5
PSEG Fossil	ER08-447-000	Sewaren 3	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	10/16/1949	116.3
PSEG Fossil	ER08-447-000	Sewaren 4	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	07/30/1951	126.5
PSEG Fossil	ER08-447-000	Sewaren 6	PSEG Fossil	PSEG ER&T	08/21/2000	PJM	Northeast	11/17/1965	115.2
PSEG Fossil	ER08-447-000	Yards Creek 1[6]	PSEG Fossil	JCP&L[7]	08/21/2000	PJM	Northeast	11/26/1965	68.5
PSEG Fossil	ER08-447-000	Yards Creek 2	PSEG Fossil	JCP&L	08/21/2000	PJM	Northeast	12/22/1965	68.5
PSEG Fossil	ER08-447-000	Yards Creek 3	PSEG Fossil	JCP&L	08/21/2000	PJM	Northeast	09/03/1965	56.4
PSEG Power CT	ER03-327-000	Bridgeport Harbor 2	PSEG Power CT	PSEG ER&T	12/06/2002	ISO-NE	Northeast	08/01/1961	179.5
PSEG Power CT	ER03-327-000	Bridgeport Harbor 3	PSEG Power CT	PSEG ER&T	12/06/2002	ISO-NE	Northeast	08/01/1968	399.5
PSEG Power CT	ER03-327-000	Bridgeport Harbor 4	PSEG Power CT	PSEG ER&T	12/06/2002	ISO-NE	Northeast	10/30/1967	18.6
PSEG New Haven LLC	ER12-1250-000	New Haven 2	PSEG New Haven LLC	CL&P[8]	06/01/2012	ISO-NE	Northeast	06/01/2012	60.5

[4] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear Plants.
[5] PSEG Nuclear has a 57.41% interest in the Salem Nuclear Plants.
[6] PSEG Fossil has a 50% interest in each of the Yards Creek facilities.
[7] Jersey Central Power & Light Company
[8] The Connecticut Light and Power Company.

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Market Based Rate Authority and Generation Assets									
						LOCATION			
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region (per Appendix D)	In-service Date	Nameplate Rating (MW)
PSEG New Haven LLC	ER12-1250-000	New Haven 3	PSEG New Haven LLC	CL&P	06/01/2012	ISO-NE	Northeast	06/01/2012	60.5
PSEG New Haven LLC	ER12-1250-000	New Haven 4	PSEG New Haven LLC	CL&P	06/01/2012	ISO-NE	Northeast	06/01/2012	60.5
PSEG Power CT	ER03-327-000	New Haven Harbor 1	PSEG Power CT	PSEG ER&T	12/06/2002	ISO-NE	Northeast	07/01/1975	460.3
PSEG Power NY	N/A*	Bethlehem Energy Center CC	PSEG Power NY	PSEG ER&T	12/06/2002	NYISO	Northeast	07/01/2005	893.2
PSEG Solar Source LLC	N/A*	Mars Solar Garden	PSEG Solar Hackettstown LLC[9]	PSEG Solar Source LLC	N/A	PJM	Northeast	09/09/2009	2.2
PSEG Solar Source LLC	N/A*	JEA Solar Farm	PSEG Solar Source LLC[10]	PSEG Solar Source LLC	N/A	SERC	Southeast	09/28/2010	15.0
PSEG Solar Source LLC	N/A*	Wyandot Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	04/06/2010	12.0
PSEG Solar Source LLC	N/A*	Queen Creek Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	AZ-NV-SNV	Southwest	11/14/2012	25.0
PSEG Solar Source LLC	N/A*	Milford Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ACC	Northeast	12/27/2012	15.0
PSEG Solar Source LLC	N/A	Badger Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ACC	West	10/15/2013	19.0
PSEG Solar Source LLC	N/A	Shasta Solar Farm	PSEG Solar California LLC	PG&E[11]	12/16/2013	CAISO	Southwest	03/01/2014[12]	4.4
PSE&G (Solar 4 All)	N/A*	Trenton, 500-520 Brunswick Ave., Trenton, NJ 08638	PSE&G	PSE&G	N/A	PJM	Northeast	10/07/2010 (Commercial Operation)	1.26

[9] PSEG Global has a 100% ownership in PSEG Hackettstown LLC.
[10] PSEG Global has a 100% ownership interest in PSEG Solar Source LLC.
[11] Pacific Gas & Electric Company.
[12] Anticipated.

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Market Based Rate Authority and Generation Assets									
						Location			
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region (per Appendix D)	In-service Date	Nameplate Rating (MW)
PSE&G (Solar 4 All)	N/A*	Barringer High School (NPS), 90 Parker St., Newark, NJ 07104	PSE&G	PSE&G	N/A	PJM	Northeast	09/24/2010 (Commercial Operation)	0.65
PSE&G (Solar 4 All)	N/A*	Park Elementary School, 120 Manchester Place, Newark, NJ 07104-1704	PSE&G	PSE&G	N/A	PJM	Northeast	10/20/2010 (Commercial Operation)	0.51
PSE&G (Solar 4 All)	N/A*	Linden, South Wood Avenue, Linden, NJ 07036	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010	3.20
PSE&G (Solar 4 All)	N/A*	Yardville, Broad Street, Hamilton, NJ 08611	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010	4.3
PSE&G (Solar 4 All)	N/A*	Silver Lake, 410 Silver Lake Avenue, Edison, NJ 08817	PSE&G	PSE&G	N/A	PJM	Northeast	11/09/2010 (Energized)	2.02
PSE&G (Solar 4 All)	N/A*	Central HQ, 472 Weston Canal Road, Franklin, NJ 08873	PSE&G	PSE&G	N/A	PJM	Northeast	11/19/2010 (Energized)	0.92
PSE&G (Solar 4 All)	N/A*	Edison Training, 234 Pierson Avenue, Edison, NJ 08837	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011	0.71
PSE&G (Solar 4 All)	N/A*	WEA Texas Bayonne, 30-100 Pulaski Street, Bayonne, NJ 07002	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2010	1.75

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Market Based Rate Authority and Generation Assets									
						Location			
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region (per Appendix D)	In-service Date	Nameplate Rating (MW)
PSE&G (Solar 4 All)	N/A*	Matrix Building A, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	01/24/2011	1.69
PSE&G (Solar 4 All)	N/A*	Matrix Building B, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	01/14/2011	1.17
PSE&G (Solar 4 All)	N/A*	Camden Street School, 281 Camden Street Newark, New Jersey 07103	PSE&G	PSE&G	N/A*	PJM	Northeast	01/12/2011	0.91
PSE&G (Solar 4 All)	N/A*	New Central High School, 246 18th Ave, Newark, NJ 07108	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2010 (Energized)	0.50
PSE&G (Solar 4 All)	N/A*	Rider University Solar Farm, Lawrenceville, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2011	0.74
PSE&G (Solar 4 All)	N/A*	Mill Creek Solar Farm, Burlington Township, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	11/30/2011	3.82
PSE&G (Solar 4 All)	N/A*	PSE&G Thorofare Solar Farm, West Deptford	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011	0.72

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Market Based Rate Authority and Generation Assets									
						Location			
Filing Entity and its Energy Affiliates	Docket # where MBR authority was granted	Generation Name	Owned By	Controlled By	Date Control Transferred	Balancing Authority Area	Geographic Region (per Appendix D)	In-service Date	Nameplate Rating (MW)
PSE&G (Solar 4 All)	N/A*	Raritan Center – Warehouse Solar, Edison, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011	2.22
PSE&G (Solar 4 All)	N/A*	NJMC – Landfill Solar, Kearny, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011	3.0
PSE&G (Solar 4 All	N/A	Matrix – Stults Rd., South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	05/31/2011	2.98
PSE&G (Solar 4 All)	N/A*	Metro Division HQ, Clifton, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	07/09/2012	0.7
PSE&G (Solar 4 All)	N/A*	Black Rock-Matrix, South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	03/20/2012	3.0
PSE&G (Solar 4 All)	N/A*	Food Bank Solar Farm, Hillside, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	08/16/2012	1.1
PSE&G (Solar 4 All)	N/A*	Hackensack Solar Farm, Hackensack, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2012	1.1
PSE&G (Solar 4 All)	N/A*	Moorestown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/14/2013	1.1
PSE&G (Solar 4 All)	N/A*	Seg 2 (Pole attached solar units)[13]	PSE&G	PSE&G	N/A*	PJM	Northeast	12/31/2012	38.3

*N/A means not applicable.

[13] PSE&G started installations of pole units in September of 2009. Through the end of October 2013, a total of 173,894 panels and 38.3 MW capacity will have been installed.

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Appendix C
List of Entities with Market-Based Rate Authority and Their Transmission Assets

Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas Storage Facilities (as of December 5, 2013)

Filing Entity and its Energy Affiliates	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Location		Size
					Balancing Authority Area	Geographic Region (per Appendix D)	
PSEG ER&T	NA	NA	NA	NA	NA	NA	NA
PSEG Power CT	NA	NA	NA	NA	NA	NA	NA
PSEG New Haven	NA	NA	NA	NA	NA	NA	NA
PSEG Fossil	NA	NA	NA	NA	NA	NA	NA
PSEG Nuclear	NA	NA	NA	NA	NA	NA	NA
PSE&G	Combined 500 kV Lines	PSE&G	PJM	NA*	PJM	Northeast	Approximately 179 combined miles.
PSE&G	Combined 500 kV Lines	Jointly Owned by PSE&G and others	PJM	NA*	PJM	Northeast	Approximately 151 combined miles.
PSE&G	Combined 500 kV Lines	Owned by others	PJM	N/A*	PJM	Northeast	Approximately 76 combined miles
PSE&G	Combined 345 kV Lines	PSE&G	PJM	NA*	PJM	Northeast	Approximately 15 combined miles.
PSE&G	Combined 345 kV Lines	Owned by others	PJM	NA*	PJM	Northeast	Approximately 6 combined miles.
PSE&G	Combined 230 kV Lines	PSE&G	PJM	NA*	PJM	Northeast	Approximately 453 combined miles.
PSE&G	Combined 230kV Lines	Owned by Others	PJM	N/A	PJM	Northeast	Approximately 44 combined miles
PSE&G	Combined 138 kV Lines	PSE&G	PJM	NA*	PJM	Northeast	Approximately 391 combined miles.
PSE&G	Combined 69 kV Lines	PSE&G	PJM	NA*	PJM	Northeast	Approximately 176 combined miles.

*if the field is not applicable please indicate so by inputting (NA).

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Appendix D
Letters of concurrence regarding the control of certain jointly owned generation facilities

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KEYSTONE-CONEMAUGH PROJECTS

682 Philadelphia Street – 2nd floor
Indiana, Pennsylvania 15701

724-349-1205

MAILING ADDRESS
P.O. BOX 68
INDIANA, PA 15701

GEORGIANNA R. STENGER, ESQ.
ADMINISTRATIVE MANAGER
DIRECT DIAL 724-357-1713

December 1, 2007

Addressed to:

Conemaugh Power LLC
Constellation Power Source Generation, Inc.
Duquesne Conemaugh LLC
Exelon Generation Company, LLC
PPL Montour, LLC
PSEG Fossil LLC
Reliant Energy Mid-Atlantic Power Holdings, LLC
UGI Development Company

Re: Joint Owners of the Conemaugh Electric Generating Station (collectively, the "Owners") statement of ownership and control

Dear Owners:

This letter sets forth the understanding of the degree of ownership and control exercised by each of the Owners with respect to the jointly-owned Conemaugh Electric Generating Station for purposes of facilitating compliance with the requirements of FERC Order No. 697.[1]

The Owners and Reliant Energy Northeast Management Company (the "Operator") each confirm its concurrence with the following statement of facts relating to the Conemaugh Electric Generating Station:

1. The Owners jointly own the Conemaugh Electric Generating Station, consisting of two 850 MW net pulverized coal fired once-through boilers and related facilities having a combined rated seasonal net generating capacity of 1,712 MW (1,884 MW nameplate), located in East Wheatfield and West Wheatfield Townships, Indiana County, Pennsylvania (the "Station").

---

1 Not all of the Owners agree as to whether Order No. 697 requires the submission of a letter of concurrence when the putative submitting party is not claiming that it does not control its percentage ownership share of a jointly-owned unit. Notwithstanding, all of the Owners have no objection to submission of this letter by an Owner which does believe that such a submission is required.

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

2. As of the date hereof, the Station is collectively owned by the Owners as tenants-in-common, each holding an undivided interest in the Station (and all real and personal property comprising the same) in the respective ownership percentages set forth below:

Owner	Ownership Interest
Conemaugh Power LLC	3.72%
Constellation Power Source Generation, Inc.	10.56%
Duquesne Conemaugh LLC	3.83%
Exelon Generation Company, LLC	20.72%
PPL Montour, LLC	16.25%
PSEG Fossil LLC	22.50%
Reliant Energy Mid-Atlantic Power Holdings, LLC	16.45%
UGI Development Company	5.97%

3. Each of the Owners is deemed to control the generating capacity of the Station in accordance with its respective ownership percentage as set forth in the preceding paragraph for purposes of facilitating compliance with the requirements of FERC Order No. 697.

Please indicate your company's concurrence to the above statement of facts by executing this letter in the space provided below your company's name at the foot hereof.

Sincerely yours,

Georgianna R. Stenger
Administrative Manager
Keystone-Conemaugh Projects

SI-SSA-0010-5815

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this 14 day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: Anthony F. Pekny

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this 1 day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: Kenneth Kaufman

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this 1st day of December, 2007.

PPL MONTOUR, LLC

By: Dennis J. Murphy
DENNIS J. MURPHY

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this 13th day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: James V. Lacher

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Operator:

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY NORTHEAST
MANAGEMENT COMPANY

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

KEYSTONE-CONEMAUGH PROJECTS

682 Philadelphia Street 2nd floor
Indiana, Pennsylvania 15701

724-349-1205

MAILING ADDRESS
P.O BOX 68
INDIANA, PA 15701

GEORGIANNA R. STENGER, ESQ.
ADMINISTRATIVE MANAGER
DIRECT DIAL: 724-357-1713

December 1, 2007

Addressed to:

Constellation Power Source Generation, Inc.
Duquesne Keystone LLC
Exelon Generation Company, LLC
Keystone Power LLC
PPL Montour, LLC
PSEG Fossil LLC
Reliant Energy Mid-Atlantic Power Holdings, LLC

Re: Joint Owners of the Keystone Electric Generating Station (collectively, the "Owners") statement of ownership and control

Dear Owners:

This letter sets forth the understanding of the degree of ownership and control exercised by each of the Owners with respect to the jointly-owned Keystone Electric Generating Station for purposes of facilitating compliance with the requirements of FERC Order No. 697.[1]

The Owners and Reliant Energy Northeast Management Company (the "Operator") each confirm its concurrence with the following statement of facts relating to the Keystone Electric Generating Station:

1. The Owners jointly own the Keystone Electric Generating Station, consisting of two 850 MW net pulverized coal fired once-through boilers and related facilities having a combined rated seasonal net generating capacity of 1,712 MW (1,884 MW nameplate), located in Plumcreek, South Bend and Cowanshannock Townships, Armstrong County, Pennsylvania, and Armstrong Township, Indiana County, Pennsylvania (the "Station").

[1] Not all of the Owners agree as to whether Order No. 697 requires the submission of a letter of concurrence when the putative submitting party is not claiming that it does not control its percentage ownership share of a jointly-owned unit. Notwithstanding, all of the Owners have no objection to submission of this letter by an Owner which does believe that such a submission is required.

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2. As of the date hereof, the Station is collectively owned by the Owners as tenants-in-common, each holding an undivided interest in the Station (and all real and personal property comprising the same) in the respective ownership percentages set forth below:

Owner	Ownership Interest
Constellation Power Source Generation, Inc.	20.99%
Duquesne Keystone LLC	2.47%
Exelon Generation Company, LLC	20.99%
Keystone Power LLC	3.70%
PPL Montour, LLC	12.34%
PSEG Fossil LLC	22.84%
Reliant Energy Mid-Atlantic Power Holdings, LLC	16.67%

3. Each of the Owners is deemed to control the generating capacity of the Station in accordance with its respective ownership percentage as set forth in the preceding paragraph for purposes of facilitating compliance with the requirements of FERC Order No. 697.

Please indicate your company's concurrence to the above statement of facts by executing this letter in the space provided below your company's name at the foot hereof.

Sincerely yours,

Georgianna R. Steiger
Administrative Manager
Keystone-Conemaugh Projects

SI-SSA-0010-5826

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this __ _ day of December, 2007

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this __ . _ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this _ _ . day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ___ . day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this __ _ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this ___ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this 14 day of December, 2007.

DUQUESNE KEYSTONE LLC

By: Arthur F. Pelly

Acknowledged and Agreed to
this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

SI-SSA-0010-5828

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this 1 day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: Kenneth Kaiser

Acknowledged and Agreed to
this _____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this __. day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this ___ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this 13th day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Owners:

Acknowledged and Agreed to
this __ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this 16 day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: James D. Lech

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Operator:

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY NORTHEAST
MANAGEMENT COMPANY

By: Jaime D Lach

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Thomas P. Joyce
Senior Vice President

P.O. Box 236, Hancocks Bridge, NJ 08038
tel: 856.339.1100 fax: 856.339.1104
email: Thomas.Joyce@pseg.com

PSEG
Nuclear L.L.C.

Carol Peterson
Vice President Finance
Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

Letter Regarding Control of Jointly-Owned Nuclear Facilities

Dear Ms. Peterson:

In connection with its upcoming compliance filings pursuant to Order No. 697,[1] PSEG Nuclear LLC ("PSEG") is submitting this letter in order to set forth its understanding of, and is requesting Exelon Generation Company LLC's ("Exelon") concurrence on, the respective level of control exercised by both companies with respect to the two nuclear facilities that they jointly own.[2]

PSEG avers and requests Exelon's concurrence on the following:

1. PSEG and Exelon jointly own and control two nuclear power plants, Peach Bottom Atomic Power Station located in Delta, PA and the Salem Nuclear Generating Station in Lower Alloways Creek, NJ.

2. In accordance with the Joint Owners Agreement for Peach Bottom dated November 24, 1971, as amended on thereafter, between the Parties, PSEG and Exelon each own 50% of the generating station. Under the Agreement, Exelon is the designated operator of Peach Bottom.

3. In accordance with the Joint Owners Agreement for Salem dated November 24, 1971, as amended thereafter, between the Parties, Exelon owns 42.59% and PSEG owns 57.41% of the generating station. Under the Agreement, PSEG is the designated operator of Salem.

4. Section 4.1 of each of the Joint Owners' Agreements states, "The signatories shall be entitled to shares of the installed capacity, available capacity, operating capacity and hourly energy generation of the Station in proportion to their ownership . . .."

---

[1] *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, 119 FERC ¶ 61,295 (2007).

[2] PSEG has requested a letter of concurrence from Exelon in order to facilitate the Commission's review of the market power analysis submitted by PSEG with respect to facilities it jointly owns with Exelon. Exelon has no objection to PSEG's submission of this letter as part of PSEG's compliance filing,.

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Thomas P. Joyce
Senior Vice President

P.O. Box 236, Hancocks Bridge, NJ 08038
tel: 856.339.1100 fax: 856.339.1104
email: Thomas.Joyce@pseg.com

PSEG
Nuclear L.L.C.

5. Section 11.1 of each of the Joint Owners' Agreements provides that the generating station will be operated by the party designated as operator for the mutual benefit of PSEG and Exelon.

6. In Order No. 697 the Commission stated that under "where a jointly-owned generation facility is operated by one of the joint-owners for the benefit of and on behalf of all of the joint-owners . . . it may be reasonable to allocate capacity based on ownership percentages...." Order No. 697 at P 188.

7. In accordance with the guidance provided in Order No. 697 and with the language of each of the joint owners' agreements, PSEG and Exelon should be deemed to control each of the nuclear facilities' output in line with their proportionate ownership share of each facility. As such, PSEG and Exelon should each be deemed to control 50% of Peach Bottom's output, and PSEG should be deemed to control 57.41% of Salem's output with Exelon controlling 42.59%.

Please indicate Exelon's concurrence to the above by executing the Acknowledgement and Agreement section below.

Sincerely

Thomas P. Joyce
Senior Vice President – Operations

Acknowledged and Agreed to
this 21 day of DECEMBER, 2007.

Carol Peterson
Vice President Finance, Exelon Nuclear, and
an officer of Exelon Generation Company, LLC

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

JOINT LETTER OF CONCURRENCE

Regulations of the Federal Energy Regulatory Commission (the "FERC") require each public utility with market-based rate authority to file an updated market power analysis every three years in accordance with a schedule adopted in *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stat. & Regs., Regulations Preambles ¶ 31,252 (2007) ("Order No. 697"). See, 18 CFR § 35.37(a)(1). Each public utility with market-based rate authority may also be required to file a change-in-status report regarding certain changes in circumstances that occur between the dates on which its triennial market power analyses are filed. 18 CFR § 35.42. Among other matters, the market power analysis is to address the amount of generation capacity that the affected utility owns or controls. Where more than one public utility owns a generating facility, FERC requires the utility that is submitting a market power analysis seek a "letter of concurrence" from the other affected co-owning public utilities that identifies the degree to which each public utility controls the generating facility, and to submit the letter with its filing. *See* FERC Order No. 697, 119 FERC ¶ 61,295, P 187 (2007).

The Yards Creek Pumped Storage Hydroelectric Project (the "Yards Creek Project") is a FERC-licensed pumped-storage hydroelectric project with a nameplate capacity of 400 MWs, and is located in Pahaquarry and Blairstown Townships, in Warren County, New Jersey. *See* FERC Project No. P-2309.

PSEG Fossil LLC ("PSEG") and Jersey Central Power & Light Company ("JCPL") each own, as tenants in common with the other, an undivided 50% interest in the Yards Creek Project. Accordingly, if and when PSEG or JCPL submit an updated market power analysis to the FERC, each will be subject to FERC's requirement to seek a "letter of concurrence" regarding the degree to which each controls the Yards Creek Project.

Both PSEG and JCP&L (and their affiliates) own transmission facilities and provide wholesale electric service in the Northeast region, as defined in Order No. 697. Pursuant to the schedule adopted in Order No. 697, PSEG and JCP&L are each required to submit an updated market power analysis to the FERC for markets within the Northeast region in December 2010. PSEG and/or JCP&L may also be obligated to file a change-in-status report or other market power analyses before its subsequent triennial market power analysis for the Northeast region is scheduled to be filed. Therefore, for the sole purpose of enabling either PSEG or JCP&L to submit a market power analysis that addresses, among other issues (to the extent necessary), the scope of each party's control of the Yards Creek Project, PSEG and JCP&L each aver and agree as follows:

1. JCP&L operates and maintains the Yards Creek Project pursuant to the Yards Creek Pumped Storage Hydroelectric Generating Station Operating Agreement, which is dated October 6, 1965 (the "Operating Agreement').

2. Article 2 of the Operating Agreement designates JCP&L as holding sole responsibility for the operations and maintenance the Yards Creek Project. Article 2 further provides that JCPL shall operate the Yards Creek project in the same manner as if JCPL had the complete ownership interest in the Yards Creek Project.

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3. JCP&L does, in fact, operate and control the Yards Creek Project in the same manner as if JCP&L had the complete ownership interest in the Yards Creek Project in accordance with Article 2 of the Operating Agreement.

4. Accordingly, PSEG and JCP&L each agree and concur that for the purpose of the market power analyses required by Order No. 697, JCPL shall be deemed to control the Yards Creek Project generation capacity and electric energy output.

ACKNOWLEDGED AND AGREED:

Richard P. Lopriore
President, PSEG Fossil LLC

Dated: 12/21/10

ACKNOWLEDGED AND AGREED:

Dean Stathis
Director, Regulated Commodity Sourcing
Jersey Central Power & Light Company

Dated: 12/08/2010

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

Appendix E
Form of notice suitable for publication in the Federal Register

20131223-5279 FERC PDF (Unofficial) 12/23/2013 4:51:06 PM

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PSEG Energy Resources & Trade LLC		Docket No. ER99-3151-___
Public Service Electric and Gas Company		Docket No. ER97-837-___
PSEG Power Connecticut LLC	)	Docket No. ER03-327-_____
PSEG Fossil LLC	)	
	)	Docket No. ER08-447-_____
PSEG Nuclear LLC and		Docket No. ER08-448-_____
PSEG New Haven LLC,		Docket No. ER12-1250-___

NOTICE OF FILING
( )

Take notice that on December 23, 2013 that: (i) PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG New Haven LLC, PSEG Fossil LLC and PSEG Nuclear LLC tendered for filing their joint triennial market power update in compliance with Order No. 679 and with prior Commission Orders granting them market-based rate authority in Docket Nos. ER99-3151, ER97-837, ER03-327, ER08-447 ER08-448 and DR-12-1250 respectively.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR §§ 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

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Comment Date: 5:00 pm Eastern Time on (insert date).
Kimberly J. Bose
Secretary

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Document Content(s)

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20161230-0019 FERC PDF (Unofficial) 12/29/2016

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ORIGINAL

PSEG

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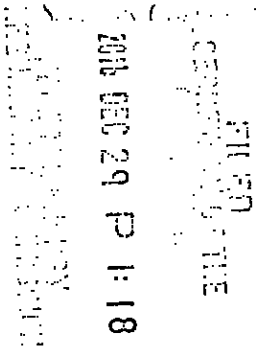

VIA OVERNIGHT MAIL
Kimberly J. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426
December 23, 2013

RE: Triennial Market Power Update and Revised Market-Based Rates Tariff in Compliance with Order No. 697:

***PSEG Energy Resources & Trade LLC*, Docket No. ~~ER99-3151-~~ ER10-1789-005;**

***Public Service Electric and Gas Company*, Docket No. ~~ER97-837-~~ ER10-1768-004;**

***PSEG Power Connecticut LLC*, Docket No. ~~ER03-327-~~ ER10-1793-004**

***PSEG Fossil LLC*, Docket No. ~~ER08-447-~~ ER10-1770-004**

***PSEG Nuclear LLC*, ~~ER08-448-~~, and ER10-1771-004**

***PSEG New Haven LLC*, ER12-1250-004**

Pavant Solar II LLC, ER16-1925-002

San Isabel Solar LLC, ER16-1926-002

Bison Solar LLC, ER16-1924-002

PSEG Energy Solutions LLC, ER16-2725-002

Dear Secretary Bose:

Earlier today, PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG Fossil LLC, PSEG Nuclear LLC, PSEG New Haven LLC, Pavant Solar II LLC, San Isabel Solar LLC, Bison Solar LLC and PSEG Energy Solutions LLC (collectively the "Applicants" or "PSEG") jointly submitted their Triennial Market Power Update.

Enclosed with this transmittal letter, please find CD-ROMs containing the workpapers of Dr. John Morris supporting his analysis in support of that filing. This CD-ROM (of which six copies are included) contains: (i) proprietary information provided by Energy Velocity under an agreement that requires confidential treatment to be requested for these materials; (ii) modeling and computer programs that are the

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proprietary intellectual property of Economists Incorporated, the firm by which Dr. Morris is employed; (iii) commercially sensitive information about Applicants and their affiliates; and (iv) documents and information deemed to be confidential by PJM, NYISO and ISO-NE. Accordingly, Applicants respectfully request confidential treatment for the CD-ROM pursuant to 18 C.F.R. (J 388.112 (2006), consistent with the confidential treatment accorded other applicants submitting such proprietary and commercially sensitive data. Pursuant to the Commission's rules, the public version of this filing contains all materials submitted herein except for the CD-ROM, which is labeled as "PRIVILEGED AND CONFIDENTIAL/NON-PUBLIC.

Thank you for your attention to this matter. Please direct any questions concerning this submission or the request for privileged treatment to the undersigned.

Respectfully submitted,
Public Service Electric and Gas Company
PSEG Energy Resources & Trade LLC
PSEG Power Connecticut LLC
PSEG Fossil LLC
PSEG Nuclear LLC
PSEG New Haven LLC
Pavant Solar II LLC
San Isabel Solar LLC
Bison Solar LLC
PSEG Energy Solutions LLC

By:

David K. Richter, Esq.
Associate General Regulatory and Property Counsel
PSEG Services Corporation

Enclosures

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Document Content(s)

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PSEG Services Corporation

December 28, 2016

ELECRONICALLY AND VIA OVERNIGHT MAIL

Kimberly J. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Triennial Market Power Update in Compliance with Order No. 697:
***PSEG Energy Resources & Trade LLC*, Docket No. ER99-3151-____;**
***Public Service Electric and Gas Company*, Docket No. ER97-837-____;**
***PSEG Power Connecticut LLC*, Docket No. ER03-327 -___;**
***PSEG Fossil LLC*, Docket No. ER08-447-___;**
***PSEG Nuclear LLC*, ER08-448-___; and**
***PSEG New Haven LLC*, ER12-1250-___**
Pavant Solar II LLC, ER16-1925-___
San Isabel Solar LLC, ER16-1926-___
Bison Solar LLC, ER16-1924-___
PSEG Energy Solutions LLC, ER16-2725-___

Dear Secretary Bose:

Pursuant to the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), PSEG Energy Resources & Trade LLC ("PSEG ER&T"), Public Service Electric and Gas Company ("PSE&G"), PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Fossil LLC ("PSEG Fossil"), PSEG Nuclear LLC ("PSEG Nuclear"), PSEG New Haven LLC ("PSEG New Haven") Pavant Solar II LLC, San Isabel Solar LLC, Bison Solar LLC and PSEG Energy Solutions LLC (collectively the "Applicants" or "PSEG") hereby jointly submit for filing their updated market power analysis in support of their continued eligibility to engage in market-based rates

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transactions. This market power analysis satisfies the requirements of Order No. 697[1] for the filing of updated market power analyses on a regional schedule basis by holders of market-based rate certificates and their affiliates. In accordance with the regional schedule for those utilities in the Northeast Region, as modified by the MBR Clarifying Order, this filing is being made by the December 2016 deadline.[2] In conformance with the Commission's requirements, except when expressly noted otherwise, the market power analysis is based on activity during the study period from December 1, 2014 through November 30, 2015 ("study period").

PSEG, through its subsidiary PSE&G, owns transmission facilities within the Northeast Region. Specifically, PSE&G owns transmission facilities in the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization. PSEG Power LLC and its subsidiaries do not own any transmission facilities other than transmission to connect generating units to the grid in PJM, the New York Independent System Operator, Inc. ("NYISO") and ISO New England Inc. ("ISO-NE").

In their original applications for market-based rate authority and previously-submitted updates to the Commission, PSEG ER&T, PSE&G, PSEG Power CT, PSEG Fossil, PSEG Nuclear and PSEG New Haven demonstrated that they and their affiliates: (a) do not exercise generation market power; (b) lack the ability to manipulate access to transmission facilities that they own or control; and (c) cannot erect any other barriers to market entry. As further demonstrated herein and in the Affidavit of Dr. John R. Morris attached hereto in the appendices, Applicants continue to satisfy the Commission's requirements to sell energy, capacity and ancillary services at market-based rates and thus should be permitted to continue to make such sales.

I. SERVICE AND COMMUNICATION

All service and correspondence related to this matter should be directed to the following individuals:

[1] 18 C.F.R. Part 35, Subpart H (2007); Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, 119 FERC ¶ 61,295, ("Order No. 697" or "MBR Order"), *order clarifying final rule*, 121 FERC ¶ 61,260 (2007) ("MBR Clarifying Order"), *order on reh'g and clarification*, 123 FERC ¶ 61,055 (2008) FERC Stats. & Regs ¶ 31,268 ("Order No. 697-A"), *order on reh'g and clarification*, 124 FERC ¶ 61,055 (2008) ("SIL Allocation Order").

[2] This filing is made on the three year anniversary of the December 2013 deadline set forth in Order No. 697 Appendix D.

As to the Applicants Generally:

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Applicants request waiver of Rule 203(b)(3)[3] so that a copy of any communications in these proceedings may be served on all persons listed above.

II. DESCRIPTION OF THE APPLICANTS AND RELEVANT AFFILIATES

A. The Applicants

The Applicants are each wholly owned, direct and indirect subsidiaries of Public Service Enterprise Group Incorporated ("PSEG"). PSEG is a public utility holding company engaged in, among other things, the generation of electric energy and the transmission, distribution and sale of electricity and natural gas through its subsidiaries.

1. Public Service Electric and Gas Company

PSE&G is a public utility operating company engaged primarily in the transmission of electricity, and the provision of gas and electric distribution service in the State of New Jersey. During the study period, PSE&G owned less than 140 MW of solar generation, 8 MW of Energy Efficiency and 91 MWs of Demand Response but otherwise did not own or operate any electric generation facilities. PSE&G is a member of the PJM Regional Transmission Organization and has made all of its transmission facilities available for open access transmission service pursuant to the PJM Open Access

[3] 18 C.F.R. § 385.203(b)(3).

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Transmission Tariff ("OATT") administered by PJM. PSE&G is authorized to sell power at market-based rates and makes wholesale sales falling within several different categories, as described below.

Non-utility generation ("NUG") output. PSE&G's NUG output expired in 2015 and 2016 pursuant to the terms of the NUG contracts. PSE&G currently has no further NUG obligations, other than 0.6 MW of energy associated with the former Kinsley Landfill which no longer operates. .

Solar. In 2007, the New Jersey legislature passed Regional Greenhouse Gas Initiative ("RGGI") legislation authorizing state utilities to invest in renewable resources such as wind or solar in order to promote increased use of renewable resources within the state and in turn reduce greenhouse gas emissions. *See* L. 2007, c. 340, codified at N.J.S.A. 48:98-1. The NJBPU has approved two (2) PSE&G Solar 4 All® (S4A) programs under which PSE&G has sited, designed and built twenty-nine (29) grid connected solar facilities. PSE&G currently owns and operates approximately 115MW-dc of grid connected solar under the S4A program. PSE&G expects the S4A fleet to increase to approximately 125MW-dc by the end of 2016. In 2016, PSE&G received NJBPU approval of its Solar 4 All Extension II filing to install an additional 33MW-dc of grid connected solar on landfills and brownfields in the PSE&G electric service territory.

2. PSEG Energy Resources & Trade LLC

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil and PSEG Nuclear, each wholly-owned subsidiaries of PSEG Power LLC ("PSEG Power"), as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission.

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

BGS Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 *et seq.,* which initiated the transition from a regulated to a competitive retail power market in New Jersey, BPU annually approves statewide auctions to determine the entities that will supply Basic Generation Service ("BGS") in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSEG ER&T has participated directly in all of the auctions for BGS supply held since 2004, has been a winning bidder in these auctions and has incurred contractual

commitments to provide supply to BGS load pursuant to BPU approved contracts beginning with the 2004 auction and continuing to the present

BGSS Gas Contract. By order issued April 16, 2002, the BPU approved a full requirements contract for the provision of gas supply by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the BPU, PSEG ER&T assumed, through capacity release, FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract remains in effect and provides for annual renewals unless terminated by either party on 12 months' advance written notice.

LIPA Fuel Supply: On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which ER&T will provide fuel supply and power supply management activities for LIPA beginning on January 1, 2015.

3. PSEG Fossil LLC

PSEG Fossil is an Exempt Wholesale Generator ("EWG") and is authorized to sell power at market-based rates. PSEG Fossil owns and operates electric generation facilities located within PJM and sells their entire output to its affiliate PSEG ER&T.[4] The assets of PSEG Fossil (and its subsidiary, PSEG Keys Energy Center LLC ("PSEG Keys")) are located entirely within PJM. However, PSEG Fossil's subsidiaries PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Power New York LLC and PSEG New Haven LLC own facilities in ISO-NE and NYISO. As noted below, PSEG Fossil also co-owns certain facilities in PJM.

PSEG Fossil and its subsidiaries PSEG Power CT and PSEG Keys are currently beginning construction on three new gas-fired generation units. PSEG Fossil is constructing Sewaren 7[5] which is a 540 MW combined cycle unit in Woodbridge, New Jersey which is expected to be in-service in 2018, PSEG Keys is constructing a 755 MW combined cycle unit in Prince George's County, Maryland which is expected to be in service in 2018 and PSEG Power CT is constructing Bridgeport 5, a 485 MW combined cycle unit in Bridgeport, Connecticut which is expected to be in service in 2019.

Since the last triennial filing in December 2013 PSEG Fossil has retired 1,813.5 MWs (nameplate) inclusive of the following units:

Kearny 9 (18.6 MW)
Bergen 3 (18.6 MW)

[4]These contracts were originally approved by the Commission as cost-based contracts. *See Public Service Electric and Gas Company*, et al., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Fossil obtained market based rate authority covering sales from its generating units.

[5] Once Sewaren 7 begins commercial operation, PSEG Fossil plans to retire Sewaren 1, 2, 3 and 4.

Bridgeport 2 (179.5 MW)
Burlington 8 (18.6 MW
Burlington 9 (162.4 MW)
Burlington 11 (162.4 MW)
Edison 1 (167.4 MW)
Edison 2 (167.4 MW)
Edison 3 (167.4 MW)
Essex 10 (167.4 MW)
Essex 11 (167.4 MW)
Essex 12 (167.4 MW)
Mercer 3 (115.2 MW)
National Park (18.6 MW)
Sewaren 6 (115.2 MW)

In addition, PSEG Fossil, LLC notified PJM of its intent to retire Hudson 2 (659 MW nameplate rating) and Mercer Units 1 and 2 (652MW nameplate rating) by June 1, 2017.

PSEG Fossil satisfies most of the electricity needs of its plants from PJM under PJM's "station power" Tariff provisions. PSEG Fossil procures gas supply for its plants from PSEG ER&T and receives gas distribution service from PSE&G at a rate approved by the BPU on May 29, 2013.[6]

4. PSEG Power Connecticut LLC

PSEG Power CT is a Connecticut limited liability company and an EWG that owns and operates electric generation facilities in the State of Connecticut and is authorized to sell power at market-based rates.[7] Both of PSEG Power CT's generation facilities, Bridgeport Harbor and New Haven Harbor, are located in the State of Connecticut within the market administered by ISO-NE. PSEG Power CT sells the output of its generation facilities to its affiliate PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority. As noted above, PSEG Power CT is currently constructing Bridgeport 5, a 485 MW combined cycle unit in Bridgeport, Connecticut which is expected to be in service in 2019.

5. PSEG New Haven LLC

PSEG New Haven is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG New Haven owns and operates a facility (the "New Haven facility") in New Haven, Connecticut with a nameplate rating of 181 MWs. The New Haven facility is located within the New Haven Harbor generation station. The New Haven facility is interconnected to the adjacent United Illuminating East Shore Substation using a 115 KV underground cable. PSEG New Haven has no other

[6] BPU Docket No. GM12100935 (May 29, 2013).
[7] *Wisvest Corporation,* et al., 101 FERC ¶ 61,166 (2002).

generation assets. The commercial operation date for the New Haven facility was June 1, 2012 and PSEG New Haven has obtained MBR authority from FERC.[8]

The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[9] pursuant to a Connecticut statute that sought proposals for peaking generation in Connecticut.[10] All of the energy and capacity of the New Haven facility is sold into the ISO New England ("ISO-NE") markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA[11] has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder. The 181 MW nameplate rating of the New Haven Facility has not been included in the capacity controlled by PSEG for purposes of Dr. Morris' market power analysis.

6. PSEG Nuclear LLC

PSEG Nuclear is an EWG[12] and is authorized to sell power at market-based rates. PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission.[13] The assets of PSEG Nuclear are located entirely within PJM. PSEG Nuclear performed the following uprates since the last triennial filing: (1) an uprate of 120 MWs at its Hope Creek plant in 2014, which increased its nameplate rating to 1290 MWs, (2) an uprate to Peach Bottom 2 and 3 which increases PSEG's share of the nameplate MWs by 241 MWs for a updated nameplate of 704 MW for Peach Bottom 2 and 689 MWs for Peach Bottom 3.

7. Pavant Solar LLC, San Isabel Solar LLC and Bison Solar LLC

PSEG Power Ventures portfolio includes three (3) solar companies with market-based rate authority: (1) *Pavant Solar II LLC*[14] is a QF which owns a 50 MW (AC) solar facility in Fillmore Utah; (2) *San Isabel Solar LLC*[15] is a QF which owns a 30 MW (AC)

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[8] *PSEG New Haven LLC*, Docket No. ER12-1250-000, et al., (May 29, 2012).

[9] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control (DPUC). PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

[10] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

[11] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

[12] *PSEG Nuclear LLC*, 97 FERC ¶ 62,191 (November 30, 2001).

[13] *Public Service Electric and Gas Company*, et al., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000). In 2008, PSEG Nuclear obtained market based rate authority from the FERC.

[14] *Pavant Solar II LLC*, Docket No. QF16-1072-000.

[15] *San Isabel Solar LLC*, Docket No. QF16-712-000.

solar facility in Las Animas County, Colorado and (3) *Bison Solar LLC*[16] is a QF which owns a 30 MW (AC) solar facility 25 miles north of Fort Collins, Colorado.

8. PSEG Energy Solutions LLC

PSEG Energy Solutions LLC ("PSEG Solutions") is a Delaware limited liability company and a direct subsidiary of PSEG ER&T. PSEG Solutions obtained market-based rate authority[17] and will operate within the PJM Interconnection, L.L.C. ("PJM"), New York Independent System Operator, Inc. ("NYISO") and ISO New England Inc. ("ISO-NE") markets. Energy Solutions will purchase power from the regional transmission organization ("RTO") at wholesale and sell it to retail customers. PSEG Solutions will not own or operate any generation assets. PSEG Solutions proposes to begin its retail business on January 1, 2017.

OTHER RELEVANT AFFILIATES

PSEG is also the direct or indirect parent of certain other subsidiaries engaged in energy related activities, as discussed below.

7. Affiliated Generation Ownership.

A list of the Applicants' affiliated domestic FERC jurisdictional generation assets owned is contained in Appendix B attached hereto. [18] Those additional subsidiaries of PSEG that may be considered relevant to this market power update for the Northeast Region are described below:

PSEG Power LLC ("PSEG Power") was formed in 1999 to acquire the former generation assets of PSE&G. PSEG Power, a Delaware limited liability company, does not directly own any generation facilities or engage in any FERC jurisdictional activities but is the parent company of several FERC jurisdictional entities, including Applicants PSEG ER&T (and it subsidiary PSEG Energy Solutions LLC), PSEG Fossil, PSEG Nuclear, PSEG Power CT, PSEG New Haven and PSEG Power Ventures LLC (which owns PSEG Solar Source LLC).

PSEG Power Ventures LLC and PSEG Solar Source LLC. PSEG Power Ventures LLC ("Power Ventures") is a Delaware Limited Liability company and a direct subsidiary of PSEG Power. PSEG Power Ventures owns 100% interest in PSEG Solar Source LLC and has an in-direct ownership interest in a domestic power plant in Hawaii. PSEG Solar Source owns approximately 349 MWs DC (274 MW AC) of solar capacity across the United States, including a combined 92

[16] *Bison Solar LLC*, Docket No. QF16-711-001.
[17] See Letter Order dated December 21, 2016 in Docket No. ER16-2725-000.
[18] Appendix B excludes generation assets located in Hawaii as well as generation assets in which PSEG's interest is limited to a leveraged lease interest.

MWs[19] (72 MW AC) of solar capacity in PJM and approximately the following amount of MWs in the following states all through separate project companies which have all obtained QF status.

- 15 MWs (12 MW AC) in Florida,
- 92 MWs in PJM (72 MW AC) – 12 MWs in Ohio, 2 MW in New Jersey, 15 MW in Delaware, 50 MW in North Carolina and 13 MW in Maryland
- 45 MWs in Arizona (34 MW AC) – 25 MW Queen, approximately 20 MW Badger
- 13 MWs (10 MW AC) in Texas,
- 34 MWs (25 MW AC) in California[20]
- 4 MWs (3 MW AC) in Vermont and
- 74 MW (60 MW AC) in Colorado (to be in operation in 2016) – 38 MWs for San Isabel and 36 MWs for Bison
- 62 MW (50 MW AC) in Utah (to be in operation in 2016).
- 10.5 MW (8 MW AC) in Oregon (to be in operation in 2016).

PSEG Resources LLC ("Resources") is a New Jersey limited liability company that provides energy infrastructure financing in developed countries. Resources invests primarily in energy-related financial transactions and manages a diversified portfolio of investments including leveraged leases. Resources owns interests, through leveraged leases, in various generation stations. Pursuant to the terms of these triple net leases, the lessee, not Resources, has all operational responsibility and control over the leased generation stations.

PSEG Power New York LLC ("PSEG Power NY") is a Delaware limited liability company and an EWG that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 750 MW combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a FERC-approved cost-based contract.[21]

[19] The 92MWs are attributed to four (7) separate project companies that have QF status: PSEG Solar Hackettstown LLC (2 MW); PSEG Solar Delaware LLC (15 MW), Rockfish Solar LLC (13 MWs) Meadows Solar (26 MW), Turkey Creek (17 MW) Hemlock Solar (7 MW) in North Carolina and PSEG Solar Ohio LLC (12 MW).

[20] The 28MWs (DC) are associated with the Shasta Solar Facility in California (4 MW), Whitehorn Solar (3 MWs) the Columbia Solar Project (19 MW). All have obtained QF status.

[21] *PSEG Power New York Inc.*, Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

PSEG Keys Energy Center LLC ("PSEG Keys") is a Delaware limited liability company and a direct subsidiary of PSEG Fossil. PSEG Keys was formed to construct, operate and maintain the Keys Energy Center, a 755MW combined cycle power plant in Prince Georges County, Maryland. Construction began in 2015 and is expected to be completed in 2018 at which time the capacity will be available in the PJM market. All of the output of the Keys Energy Center will be sold to PSEG Keys affiliate, PSEG ER&T.

PSEG Long Island LLC ("Long Island") and Long Island Electric Utility Servco, LLC ("Servco") are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution system ("T&D") on Long Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither Long Island nor Servco will be FERC jurisdictional public utilities as neither will exercise ultimate decision making authority over the T&D system in Long Island. Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[22]

8. Affiliated Transmission Ownership

With the exception of the electric transmission assets owned by Applicant PSE&G, all of which are located within the PJM RTO, and the generation interconnection facilities owned by the various EWG and QF affiliates listed herein, the Applicants, nor their affiliates have any affiliates that own or operate FERC jurisdictional electric or natural gas transmission facilities within the United States[23]. As discussed below, FERC granted PSE&G a Hinshaw exemption in 1954, finding that it was exempt from the provisions of the Natural Gas Act.

B. JOINTLY OWNED FACILITIES

PSEG Nuclear is a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear is the operator of Salem and Exelon Generation is the operator of Peach Bottom.[24] PSEG Fossil is approximately a 23% joint owner in the Conemaugh and Keystone generating stations located in Pennsylvania. An affiliate of NRG Energy is the operator.[25] Accordingly, for

[22] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), *order dismissing request for rehearing*, 145 FERC ¶ 61,183 (2013).

[23] PSEG Power LLC is a 10% owner of the PennEast Pipeline Company LLC which has filed an application for approval to construct and operate a natural gas transmission line.

[24] A letter of concurrence supporting the allocation of plant output based on ownership interests is attached in Appendix E. The ownership percentages have not changed since the date of this letter. PSEG Nuclear owns a 50% interest in Peach Bottom and a 57.41% interest in Salem.

[25] A letter of concurrence supporting the allocation of plant output based on ownership interest is attached in Appendix E. The ownership percentages have not changed since the date of this letter.

purposes of this market power analysis, the capacity of Salem, Peach Bottom, Conemaugh and Keystone has been attributed to PSEG in accordance with PSEG's ownership interests in these facilities.

PSEG Fossil and Jersey Central Power and Light Company ("JCP&L") are each 50% co-owners of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to the unit. Accordingly, for the purpose of this market power analysis, the entire unit capacity – nominally 400 MWs – has been assigned to JCP&L.[26]

III. Applicants Fully Satisfy The Commission's Standards For Authority to Make Power Sales At Market-Based Rates.

The Commission allows power sales at market-based rates if the seller and its affiliates do not have, or have adequately mitigated, horizontal and vertical market power.[27] The Commission has also codified affiliate restrictions in its regulations which must be satisfied on an ongoing basis. In previous submissions for market-based rate authority the Applicants PSE&G, PSEG ER&T, PSEG Power CT, PSEG Fossil, PSEG Nuclear, and PSEG New Haven, demonstrated compliance with each of these requirements. As detailed herein and in the attached affidavit, the Applicants continue to meet these standards.

A. The Applicants Lack, Or Have Effectively Mitigated, Any Horizontal Market Power

In the MBR Order, the Commission established two indicative screens: a pivotal supplier screen based on the control area's annual peak demand and a wholesale market share screen applied on a seasonal basis. If an applicant passes both screens, there is a rebuttable presumption that the applicant does not possess horizontal market power. Each indicative screen is applied with respect to "relevant geographic markets" for an applicant's generating units.

Applicants located in ISOs/RTOs possessing sufficient market structure may consider the geographic region under the control of the ISO/RTO as the relevant default geographic region for purposes of completing their generation market power analyses.[28] However, where the Commission has previously found a "submarket" to exist within a boundary of an RTO, such finding is controlling as to the scope of the relevant geographic market for all generation units located within that submarket for the application of the indicative screens and any delivered price test that may be performed. The Commission further listed several such submarkets, including PJM East ("PJME"),

[26] A letter of concurrence supporting this determination is attached in Appendix E. The ownership percentages have not changed since the date of this letter.
[27] MBR Order, FERC Stats. & Regs. ¶ 31,252 at P 62, 399, 408, 440.
[28] *MBR Order at* PP. 231 and 235.

Connecticut and Southwest Connecticut.[29] Subsequent to the MBR order, in approving a merger between Exelon Corporation and Constellation Energy Group, Inc., the Commission identified additional submarkets in PJM - PJM East of 5004/5005 ("PJM50") and PJM East of AP South ("PJMAP") - that would be relevant to an MBR analysis for applicants in the Northeast Region.[30]

As discussed below and in the attached Affidavit of Dr. John Morris contained in Appendix A, Applicants have conducted market power analyses of the entire PJM RTO, the PJME, PJM50 and PJMAP submarkets, the entire NYISO, the entire ISO-NE, the Connecticut submarket and the Southwest Connecticut submarket for the study period. The results are set forth below.

1. Indicative Screens

a. Pivotal Supplier Analysis

The pivotal supplier analysis ("PSA") focuses on the ability of a seller to exercise unilateral market power.[31] The screen assesses whether market demand can be met during peak times without the applicant and its affiliates. If demand can be met without the applicant and its affiliates, the applicant passes that the PSA screen. The Affidavit of Dr. John Morris, attached hereto as Appendix A, finds that the Applicants pass the PSA screen for all relevant markets: PJM, NYISO, ISO-NE, Connecticut, Southwest Connecticut, PJMAP, PJME and PJM50.[32]

b. Wholesale Market Share Analysis

The wholesale market share analysis ("WMSA") is applied each season to determine whether an applicant has a dominant market position based on the total number of megawatts of uncommitted capacity owned or controlled by the applicant and its affiliates in relation to the uncommitted capacity of the entire relevant wholesale electricity market.[33] The established threshold is 20 percent; a supplier who has less than 20 percent market share in the relevant market for all seasons passes the WMSA screen.

In his Affidavit Dr. Morris finds that the Applicants pass the WMSA screen for PJM, NYISO, ISO-NE, Connecticut, Southwest Connecticut and PJMAP but do not pass the WMSA screen for the PJME and PJM50 submarkets.[34]

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[29] *Order No. 697* at P 236 (citing *Exelon Corp.*, 112 FERC ¶ 61,011, *reh'g denied*, 113 FERC ¶ 61, 299 (2005)). FERC eliminated the Northern PSEG zone as a default submarket in Order No. 697-A, P 99.

[30] Order Conditionally Authorizing Merger and Disposition of Jurisdictional Facilities, *Exelon Corporation, et al.*, 138 FERC ¶ 61,167 (2012).

[31] *AEP I* at P 72.

[32] *See* Morris Affidavit, at 15-29.

[33] *AEP I,* P 100.

[34] *See* Morris Affidavit, at 15-29.

c. Results of Indicative Screen Analysis

As shown in Dr. Morris's affidavit, Applicants therefore pass both indicative screen tests for PJM RTO, NYISO, ISO-NE, Connecticut and Southwest Connecticut and PJMAP. For PJME and PJM50, the Applicants pass the PSA but do not pass the WMSA.

2. Delivered Price Test Analysis For PJME and PJM50 Submarkets

In accordance with the MBR Order, applicants who fail either indicative screen test can rebut the presumption of market power through the submission of a delivered price test analysis ("DPT"). Applicants may submit this study at the same time that the results of the indicative screens are provided.[35] The DPT is based on two measurements of potential market power: economic capacity ("EC") and available economic capacity ("AEC"). EC is the capacity that can be delivered to a destination market for 105 percent or less than the market price. AEC is calculated by subtracting native load commitments from EC. Both calculations are performed for ten different season and load conditions.

In applying the DPT, "[a] showing of an HHI less than 2,500 in the relevant market for all season/load conditions for sellers that have also shown that they are not pivotal and do not possess a 20 percent or greater market share in any of the season/load conditions would constitute a showing of a lack of market power, absent compelling contrary evidence from intervenors."[36] However, while meeting these threshold benchmarks provides "safe harbor" protection, the Commission has found in numerous other cases that applicants lack market power even when they exceed one or more of the thresholds for particular study periods. As stated in *Public Service Company of New Mexico*, 115 FERC ¶ 61,090, P 38 (2006), "the Commission weights the results of both the economic and available economic capacity tests and considers the arguments of the applicant and intervenors." (footnote omitted.) [37]

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[35] *Order No. 697,* P 76.

[36] *Order No. 697* at P 111.

[37] Indeed, in that case, the applicant was deemed "on balance" to have adequately rebutted a showing of market power mitigation for the PNM control area where the results exceeded the 20% safe harbor in two cases under the AEC measure and in all 10 cases at values between 35% and 41% under the EC measure. *See, e.g.*, *Kansas City Power and Light Company, et al.*, Docket Nos. ER99-1005-011 et al. (August 12, 2010) (finding no market power where applicant had EC market shares in the 40-60% range and had significant HHI failures in the KCPL and GMO markets); *Cordova Energy Company LLC et al,* Docket Nos. ER99-2156-011, *et al.*, November 13, 2007 (finding no market power in case where applicant had EC market shares in PACE control area between 53.1% and 60.0%, HHIs between 2,958 and 3,696 and was pivotal in 8 out of 10 periods.); *PacifiCorp*, Letter Order, Docket Nos. ER97-2801-007, *et al.*, February 1, 2007; *Tucson Elec. Power Co.*, 116 FERC ¶ 61,051 (2006)(finding market power standard satisfied where applicant had EC market shares above 20% in all ten season/load periods in the Tucson control area, exceeded the 2,500 HHI threshold in eight periods, and was pivotal in 5 periods); *PacifiCorp*, 115 FERC ¶ 61,349 (2006) (finding that applicants rebutted presumption of market power in the PacifiCorp East control area where under available economic capacity measure, market share is less than 20% in 8 season/load periods and 28% in the summer and winter off-peak periods, HHI does not exceed 2500 in any season/load period and applicants are not pivotal); *Kansas City Power & Light Co.*, 113 FERC ¶ 61,074 (2005) (finding

a. Results of the DPT for PJM50 Submarket

For both the AEC and EC, PSEG passes all screens in all periods except for the pivotal supplier screen in the Summer Top 1% period.

b. Results of the DPT for PJME Submarket

With respect to AEC, PSEG passes all the screens in all 10 periods. With respect to the EC, PSEG passes the Market Concentration screens in all periods. It also passes the Pivotal Supplier Screen in 8 of 10 periods, and passes the Market Share Screen in 6 of 10 periods. PSEG's market shares are never above 25 percent. Although greater than the 20 percent screen, PSEG's market shares are well below the 35 percent threshold that is typically used for imputing unilateral market power.

3. Analysis of DPT Results

Based on his analysis of the overall results, Dr. Morris concludes that, although PSEG fails limited number of screens, the failures are substantially below levels that typically indicate market power. As set forth in his Affidavit, Dr. Morris states that:

> Although PSEG fails some screens in the PJME destination market, the overall results are not indicative of PSEG having market power. To begin, PSEG passes all the AEC screens and all market concentration (HHI) screens for EC. The HHI levels in all periods, capacity types, and areas are below the screening threshold of 2,500, and typically substantially below this level. In terms of the DPT for market rate authority and under the 2010 DOJ and FTC Horizontal Merger Guidelines, the market is not highly concentrated.[38] The low HHI levels mean that PSEG has little ability to exercise market power in coordination with other suppliers. It also passes all the AEC pivotal supplier screens, and most of the EC pivotal supplier screens. This means that typically PSEG's generation is not necessary to serve load; and when its generation is necessary, its forward sale commitments are sufficient so that its uncommitted generation is not necessary to serve the remaining load. Finally, PSEG's market shares are never above 15 percent in PJM50 and for AEC in PJM East. Its market shares for EC are never above 25 percent in PJM East. Although greater than the 20 percent screen, PSEG's market shares are

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no market power in the KCPL control area where applicant had EC market shares above 20% in all periods, exceeded the HHI 2,500 threshold in 5 of 10 periods and was pivotal supplier in 1 period); *Acadia Power Partners, L.P.*, 113 FERC ¶ 61,073 (2005) (finding no market power in the Cleco Power home control where, utilizing the EC measure, the applicant exceeded the thresholds set for all season/load periods using the market share measure, one season/load period using the market concentration measure, and for all season/load periods using the pivotal supplier measure).

[38] See U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Issued August 19, 2010, at Section 5.3, available at http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

> well below the 35 percent threshold that is typically used for imputing unilateral market power.[39]

Dr. Morris's conclusion is consistent with Commission precedent finding a lack of market power in cases in which the DPT results included more instances of findings outside of the "safe harbor" thresholds and at higher levels than exist here.[40] In these circumstances, Dr. Morris's analysis successfully rebuts any inference of market power created by the WMSA screen failures for PJME.

4. Existing RTO/ISO Mitigation Rules Also Eliminate The Potential for Exercising Market Power In the PJME, PJME PJM50 and PJMAP Submarkets

PJM mitigation rules eliminate the potential for the exercise of market power in the PJME submarket. The MBR Order specifically contemplated that RTO/ISO mitigation rules may serve as evidence that any market power has been adequately mitigated. The Commission declared, "We believe the added protections provided in structured markets with market monitoring and mitigation generally result in a market where prices are transparent and attempts to exercise of market power will be sufficiently mitigated."[41] The Order on Rehearing went even further and specifically created a presumption that any potential market power had been adequately mitigated by an established and effective RTO market monitoring scheme.[42]

Taking account of the pervasive PJM mitigation rule, Dr. Morris concludes that these rules "fully address the potential for PSEG to exercise market power" in PJME.[43] Accordingly, PJM's mitigation schemes in place are sufficient to rebut any inference of market power created by the failure to pass the WMSA screens in PJME and PJM50.

In addition, in the Applicants' last triennial approval order, the Commission found that "the PJM market monitoring and mitigation rules are sufficient to address market power concerns in the PJM-East submarket."[44]

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[39] *See*, *e.g.*, U.S. Department of Justice, 1984 Merger Guidelines, at Section 3.12, available at https://www.justice.gov/sites/default/files/atr/legacy/2007/07/11/11249.pdf ("the Department is likely to challenge the merger of any firm with a market share of at least one percent with the leading firm in the market, provided the leading firm has a market share that is at least 35 percent.")

[40] *See Public Service Company of New Mexico*, 115 FERC ¶ 61,090 (2006) discussed above and cases discussed in fn. 38 above.

[41] MBR Order at P 241.

[42] Order No. 697A at P 111.

[43] Morris Affidavit, pp. 24-26.

[44] *See* October 14, 2014 letter order approving Applicants' prior triennial market update in Docket No. ER10-1789-003 et al. at page 3.

a. The Applicants Lack Transmission Market Power and Cannot Erect Entry Barriers.

In its previous order accepting PSEG's triennial market power analysis for the Northeast Region, the Commission found that the submittal satisfied the Commission's requirements for market-based rates regarding vertical market power.[45] There have been no subsequent changes in status that would reflect a departure from the characteristics the Commission relied upon in granting market-based rate authority. As demonstrated below, neither Applicants nor any of its affiliates are able to exercise vertical market power.

Applicants are not able to exercise transmission market power. Neither Applicants nor any of their affiliates, except PSE&G, own transmission assets in the U.S. other than incidental generator interconnection facilities. PSE&G owns transmission facilities in PJM but transmission service over those facilities is provided under the PJM Open Access Transmission Tariff.

In addition, neither Applicants nor their affiliates are able to exercise vertical market power in wholesale energy markets through affiliation, ownership or control of inputs to electric power production. As required by Section 35.37(e) of the Commission's regulations, Applicants provide the following information:

(1) PSE&G owns and operates a natural gas distribution system that receives interstate pipeline gas within the State of New Jersey and distributes that gas to its customers within the State of New Jersey. The distribution system consists of 18,050 miles of gas distribution pipe and an additional 62 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3 and peak-shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers. Service over such distribution facilities is made available pursuant to state regulated tariffs on an open access type basis. PSE&G was granted a Hinshaw exemption from the FERC in 1954.[46] The gas distribution rates paid by PSEG Fossil to PSE&G have been set at rates approved by the BPU in an order dated May 29, 2013.

(2) Certain of the Applicants and their affiliates own sites within the Northeast Region that would be suitable for future generating facilities. These include space at many of the existing generating sites of PSEG Fossil and at the sites of PSEG Power NY and PSEG Power CT. PSEG Nuclear's Salem facility may also be suitable for future construction. PSE&G also owns certain sites that would be suitable for generating facilities, but under New Jersey's Electric Discount and Energy Competition Act, N.J.S.A 48:3-43 et seq., PSE&G is effectively barred from owning and operating

[45] *Id.*
[46] 13 F.P.C. 1348 (1954).

generation except "on site" generation for supply and Class I renewable energy resources as defined in N.J.S.A. 48:3-98.1.

(3) Neither Applicants nor any of their affiliates own or control any physical coal supply resources or own or control who may access transportation of coal supplies.

(4) As required by section 35.37(e)(4) of the Commission's regulations, Applicants and its affiliates state that they have not erected barriers to entry into any market, including the PJM, NYISO or ISO-NE market and will not erect barriers to entry into any markets.

IV. REQUEST FOR CONFIDENTIAL TREATMENT

Under separate cover via UPS Overnight this office is submitting compact disks containing the workpapers of Dr. John Morris supporting his analysis in Appendix A, as required by the Commission's April 2004 Order.[47] The CD (of which six copies are included) contains: (i) proprietary information provided by Energy Velocity under an agreement that requires confidential treatment to be requested for these materials; (ii) modeling and computer programs that are the proprietary intellectual property of Economists Incorporated, the firm which employs Dr. Morris; (iii) commercially sensitive information about Applicants and their affiliates; and (iv) documents and information deemed to be confidential by PJM and ISO-NE. Accordingly, Applicants respectfully request confidential treatment for CD and the workpapers pursuant to 18 C.F.R. § 388.112 (2006), consistent with the confidential treatment accorded other applicants submitting such proprietary and commercially sensitive data.[48] Pursuant to the Commission's rules, the public version of this filing contains all materials submitted herein except for CD, which is labeled as "PRIVILEGED AND CONFIDENTIAL/NON-PUBLIC."

V. SERVICE

This filing has been served on all parties on the official service list as currently maintained by Commission in the above-referenced dockets. Applicants are also providing a copy to the New Jersey Board of Public Utilities and the New Jersey Division of Rate Counsel.

VI. ENCLOSURES

Applicants enclose the following:

- An original filing;

[47] AEP II, 107 FERC at P 61,087-88.
[48] *See, e.g., Idaho Power Company*, Docket No. ER97-1481-009 (February 3, 2006) (submission of revised Pivotal Supplier Screen and Market Share Screen calculations including similar data).

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- Appendix A – Affidavit of Dr. John R. Morris;[49]
- Appendix B – List of Entities with Market-Based Rates Authority and Their Generation Assets. (This is an appendix listing the filing entities and all their energy affiliates and their associated assets);
- Appendix C – List of Entities with Market-Based Rate Authority and Their Transmission Assets;
- Appendix D – List of Long Term Power Purchase Agreements;
- Appendix E – Letters of concurrence regarding the control of certain jointly owned generation facilities;
- Appendix F – Form of notice suitable for publication in the Federal Register.

[49] Compact disks, as described above, containing the workpapers for the Affidavit of John R. Morris in Appendix A are being sent concurrently with this filing via UPS Overnight. As noted *supra*, privileged treatment is being requested for Dr. Morris's confidential workpapers submitted with the non-public version of this filing.

VII. CONCLUSION.

Applicants respectfully request the Commission

(i) to accept this market power compliance filing as meeting the Commission's requirements under Order No. 697 for the continuation of market-based rate authority for Applicants PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG New Haven LLC, PSEG Nuclear LLC, PSEG Fossil LLC, Pavant Solar II, LLC, Bison Solar LLC , San Isabel Solar LLC and PSEG Energy Solutions LLC;

(ii) to grant the request for confidential treatment; and

(iii) to grant such other relief or waivers as may be appropriate or necessary.

Respectfully submitted,

Public Service Electric and Gas Company
PSEG Energy Resources & Trade LLC
PSEG Power Connecticut LLC
PSEG Fossil LLC
PSEG Nuclear LLC
PSEG New Haven LLC
Pavant Solar II, LLC
Bison Solar, LLC
San Isabel Solar, LLC
PSEG Energy Solutions LLC

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Dated: December 28, 2016
Newark, New Jersey

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Appendix A
Affidavit of
Dr. John R. Morris

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Appendix B
List of Entities with Market-Based Rate Authority and Their Generation Assets

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Appendix C
List of Entities with Market-Based Rate Authority and Their Transmission Assets

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Appendix D
Long Term Power Purchase Agreements

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Appendix E
Letters of concurrence regarding the control of certain jointly owned generation facilities

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Appendix F
Form of notice suitable for publication in the Federal Register

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PSEG Energy Resources & Trade LLC	Docket No. ER99-3151-___
Public Service Electric and Gas Company	Docket No. ER97-837-___
PSEG Power Connecticut LLC	Docket No. ER03-327-_____
PSEG Fossil LLC	Docket No. ER08-447-_____
PSEG Nuclear LLC	Docket No. ER08-448-_____
PSEG New Haven LLC	Docket No. ER12-1250-___
Pavant Solar II LLC	Docket No. ER16-1926-____
San Isabel Solar LLC	Docket No.ER16-1925-____
Bison Solar LLC	Docket No.ER16-1924-____
PSEG Energy Solutions LLC	Docket No. ER16-2725-____

NOTICE OF FILING
( )

Take notice that on December 28, 2016: (i) PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG New Haven LLC, PSEG Fossil LLC, PSEG Nuclear LLC, Pavant II Solar LLC, Bison Solar LLC, San Isabel Solar LLC and PSEG Energy Solutions LLC tendered for filing their joint triennial market power update in compliance with Order No. 679 and with prior Commission Orders granting them market-based rate authority in Docket Nos. ER99-3151, ER97-837, ER03-327, ER08-447 ER08-448, DR-12-1250, ER16-1926, ER16-1925, ER16-1924 and ER16-2725 respectively.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR §§ 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file

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electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).
Kimberly J. Bose
Secretary

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UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Public Service Electric and Gas Company	)	ER97-837-____
PSEG Energy Resources & Trade LLC	)	ER99-3151-____
PSEG Power Connecticut LLC	)	ER03-327-____
PSEG Fossil LLC	)	ER08-447-____
PSEG Nuclear LLC	)	ER08-448-____
PSEG New Haven LLC	) Docket Nos.	ER12-1250-____
Pavant II Solar LLC	)	ER16-1926-____
Bison Solar LLC	)	ER16-1925-____
San Isabel Solar LLC	)	ER16-1924-____
PSEG Energy Solutions LLC	)	ER16-2725-____

Report & Affidavit of
Dr. John R. Morris

December 22, 2016

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Public Service Enterprise Group Incorporated Northeast Region Market Power Study

1. Introduction

My name is Dr. John R. Morris. I am a Principal at Economists Incorporated, an economic consulting firm located at 2121 K Street, NW, Washington, DC 20037. I have a bachelor's degree in economics from Georgetown University, and I have a master's degree and a Ph.D. in economics from the University of Washington. I have been studying and consulting within energy industries since joining the Federal Trade Commission in 1985. Since joining Economists Incorporated in 1992, I have consulted on many mergers involving electric and gas companies, examined competitive issues relating to utility rates, provided market power studies for applications for market-based rate authority, and studied market power issues in state restructuring proceedings. I have published articles on competition and energy matters, and I have spoken on numerous occasions concerning competition in natural gas, electric power and other industries. I have previously been accepted as an expert witness on energy matters before the Federal Energy Regulatory Commission ("FERC" or "Commission"), state commissions and in federal court. A complete listing of my experience, publications and testimony is contained in my resume, presented in Exhibit PEG-2.

Public Service Enterprise Group Incorporated ("PSEG") asked that I prepare a market power study for its subsidiaries that have market-based rate authority in the Northeast Region.[1] These subsidiaries are: Public Service Electric and Gas

[1] The Northeast Region includes ISO-New England Inc. ("ISO-NE"), Connecticut, Southwest Connecticut, New York Independent System Operator, Inc. ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), PJM East, PJM East of 5004/5005 and PJM East of AP South.

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("PSE&G"), PSEG Energy Resources & Trade LLC ("PSEG ER&T"), PSEG Fossil LLC ("PSEG Fossil"), PSEG Nuclear LLC ("PSEG Nuclear"), PSEG Power Connecticut LLC ("PSEG Power CT"). PSEG New Haven LLC ("PSEG New Haven") Pavant II Solar LLC, Bison Solar LLC and San Isabel Solar LLC.[2] The purpose of this study is to determine whether these PSEG entities have market power in any Northeast Region market under the Commission's Pivotal Supplier Analysis ("PSA") and Wholesale Market Share Analysis ("WMSA") screens as articulated in FERC Order No. 697 and if the Applicants do fail any of the screens, whether they otherwise lack market power under the Delivered Price Test ("DPT") or are subject to sufficient mitigation to guard against any market power concerns.[3]

PSEG

PSEG is a public utility holding company headquartered in in Newark, New Jersey. Through its subsidiaries, PSEG engages in the generation, transmission, distribution and sale of electric energy, and distribution and sale of natural gas to commercial, residential, and industrial customers primarily in the Northeastern and Mid-Atlantic United States. PSEG, through its subsidiaries, owns approximately 11,300 MW of seasonal generation capacity located in the Northeast Region.[4]

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[2] Pavant II Solar LLC, Bison Solar LLC and San Isabel Solar LLC all have QF status.

[3] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, 119 FERC ¶ 61,295, ("Order No. 697" or "MBR Order"), *order clarifying final rule*, 121 FERC ¶ 61,260 (2007) ("MBR Clarifying Order"), *order on reh'g and clarification*, 123 FERC ¶ 61,055 (2008) FERC Stats. & Regs ¶ 31,268 ("Order No. 697-A"), *order on reh'g and clarification*, 124 FERC ¶ 61,055 (2008) ("SIL Allocation Order").

[4] *See* Exhibit PEG-3 (accounting for retirements).

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PSE&G

PSE&G is a public utility operating company engaged primarily in the transmission of electricity and the provision of gas and electric distribution service in the State of New Jersey. It is New Jersey's oldest and largest investor-owned utility. PSE&G was founded in 1903 and is based in Newark, New Jersey. It is a member of the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Organization and has made all of its transmission facilities available for open access transmission service pursuant to the PJM Open Access Transmission Tariff ("OATT") administered by PJM. The company also owns and operates 18,050 miles of gas distribution pipe and an additional 62 miles of gas transmission pipe, as that term is defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration Pipeline Safety Regulations Part 192, §192.3. During the study period, PSE&G owned less than 140 MW of solar generation, 8 MW of Energy Efficiency and 91 MWs of Demand Response but otherwise did not own or operate any electric generation facilities.

PSEG ER&T

PSEG ER&T does not own or operate any generation, transmission or distribution facilities. PSEG ER&T was formed to market the power that it purchases from its affiliates, including PSEG Fossil and PSEG Nuclear, each wholly-owned subsidiaries of PSEG Power LLC ("PSEG Power"), as well as from other sources, and to engage in wholesale marketing, brokering and trading and hedging activities. PSEG ER&T engages in the sale of electric energy, capacity and ancillary services pursuant to market-based rate authority granted by the Commission. PSEG ER&T also makes wholesale sales of natural gas.

Further details are provided with regard to the following wholesale power transactions or other arrangements to which PSEG ER&T is a party:

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BGS Electric Sales. Pursuant to the Electric Discount and Energy Competition Act of 1999, N.J.S.A. § 48:3-49 *et seq.,* which initiated the transition from a regulated to a competitive retail power market in New Jersey, the New Jersey Board of Public Utilities ("BPU") annually approves statewide auctions to determine the entities that will supply Basic Generation Service ("BGS") in New Jersey. BGS, known in other states as "provider of last resort" service or "default" service, is electric generation service provided to the customers of an electric distribution company that have not chosen an alternative power supplier. PSE&G and other New Jersey electric utilities with franchised service territories are required to obtain all electric supply requirements through this BGS auction on an annual basis for retail customers that do not purchase electric supply from third-party suppliers. PSE&G's affiliate, PSEG ER&T, has participated directly in all of the auctions for BGS supply held since 2004 and has consistently won tranches in those auctions, including auctions for BGS service within the franchised service territory of PSE&G.

BGSS Gas Contract. By order issued April 16, 2002, the BPU approved a full requirements contract for the provision of gas supply by PSEG ER&T to PSE&G for the purpose of satisfying all of PSE&G's retail gas service obligations. As part of the transaction approved by the BPU, PSEG ER&T assumed, through capacity release, PSE&G's FERC-jurisdictional gas transportation and storage contracts with interstate pipelines then held by PSE&G. The BGSS gas contract, which currently remains in effect, provides for annual renewals unless terminated by either party on 12 months' advance written notice.

LIPA Fuel Supply. On November 26, 2013, PSEG ER&T executed an agreement with the Long Island Power Authority ("LIPA") under which

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ER&T provides fuel supply and power supply management activities for LIPA as of January 1, 2015.

PSEG Fossil

PSEG Fossil owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission under the umbrella of PSEG Fossil's market-based rate authority.[5] The assets of PSEG Fossil are located entirely within PJM.[6] Since the last triennial filing in 2013, PSEG Fossil has retired approximately 1,800 MW of capacity in the eastern portion of PJM. Much of this capacity was retired at the end of May 2015. We included this capacity in the Winter and Spring season screens and exclude the capacity for the Summer and Fall screens.

PSEG Fossil is approximately a 23 percent joint owner of interests in the Conemaugh and Keystone generating stations located in Pennsylvania. An affiliate of NRG Energy is the operator.[7] PSEG Fossil is a 50 percent co-owner with Jersey Central Power and Light Company ("JCP&L") of the 400 MW Yards Creek pumped storage hydroelectric facility. JCP&L is the operator and makes dispatch decisions in accordance with the joint operating agreement applicable to

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[5] *Public Service Electric and Gas Company, et al*., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000).

[6] PSEG Fossil's subsidiaries PSEG Power Connecticut LLC, PSEG New Haven LLC and PSEG Power New York LLC own generation units in Connecticut and New York respectively.

[7] A letter of concurrence supporting the allocation of these facilities' output based on ownership interests is attached in our workpapers.

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the unit. Accordingly, for the purpose of this market power analysis, the entire unit capacity, nominally 400 MWs, has been assigned to JCP&L.[8]

PSEG Power CT

PSEG Power CT owns the Bridgeport Harbor and New Haven Harbor generation facilities located in the state of Connecticut within ISO-NE and is authorized to sell power at market-based rates.[9] The output of these facilities is sold to PSEG ER&T under an agreement entered into pursuant to PSEG Power CT's market-based rate authority. PSEG Power CT is currently constructing Bridgeport 5, a 485 MW gas-fired combined cycle in Bridgeport, Connecticut, which is expected in service in 2019.

PSEG New Haven

PSEG New Haven owns and operates the New Haven facility, a gas-fired plant located in New Haven, CT that entered service in June 2012 with a nameplate capacity of 181.5 MW. The New Haven facility was selected by the Connecticut Public Utilities Regulatory Authority ("PURA")[10] pursuant to a Connecticut statute that sought proposals for peaking generation in Connecticut.[11] All of the energy and capacity of the New Haven facility is sold

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[8] A letter of concurrence supporting the allocation of this facility's output to JCP&L is attached in our workpapers.

[9] *Wisvest Corporation, et al*., 101 FERC ¶ 61,166 (2002).

[10] *Re Review of Peaking Generation Projects*, Docket No. 08-01-01, Connecticut Department of Public Utility Control, June 25, 2008 ("Awards Decisions") (2008 WL 2587405 (Conn. D.P.U.C.)). The PURA is the successor to the Department of Public Utility Control (DPUC). PURA came into being in July 2011 as part of a reorganization of Connecticut state energy agencies. For consistency, this application refers to the agency as the PURA.

[11] Section 50 of Public Act 07-242, now codified at Section 16-243u of the Connecticut General Statutes.

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into the ISO-NE markets, as directed by the PURA, pursuant to the Amended Peaking Generation Cost of Service Contract for Differences ("CFD") with Connecticut Light and Power Company ("CL&P"). The CFD approved by the PURA has a 30-year term and provides that PSEG New Haven will be paid its cost of service for the energy and capacity supplied thereunder.[12] As such, neither PSEG New Haven nor any other PSEG affiliate has operational control of the New Haven facility. As a result, the capacity of the facility is not attributable to PSEG for the purpose of this market power analysis.

PSEG Nuclear

PSEG Nuclear owns and operates electric generation facilities located within PJM and sells its entire output to its affiliate PSEG ER&T pursuant to cost-based contracts approved by the Commission in accordance with PSEG Nuclear's market-based rate authority.[13] PSEG Nuclear is the owner of Hope Creek and a joint owner of the Salem and Peach Bottom nuclear plants with Exelon Generation LLC ("Exelon Generation"). PSEG Nuclear operates the Salem plant and Exelon Generation is the operator of Peach Bottom.[14] Since the last triennial filing, uprates at Peach Bottom and Hope Creek plants have increased PSEG Nuclear's capacity at those facilities.

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[12] The CFD was approved on October 29, 2010 in a letter order ruling on Motion Number 62 in Docket No. 08-01-01.

[13] *Public Service Electric and Gas Company, et al*., 88 FERC ¶ 61,299 (1999); *Public Service Electric and Gas Company*, Docket No. ER99-3151-001, Letter Order (issued February 4, 2000).

[14] A letter of concurrence supporting the allocation of plant output based on ownership interests is attached in our workpapers.

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Other Subsidiaries

PSEG is also the direct or indirect parent of certain other subsidiaries engaged in energy related activities in the United States. Those additional subsidiaries of PSEG that may be considered relevant to this market power update for the PJM region are as follows.

PSEG Power LLC is a Delaware limited liability company. It does not directly own any generation facilities or engage in any FERC jurisdictional activities but it is the parent company of several FERC jurisdictional entities, including applicants PSEG ER&T, PSEG Fossil and PSEG Nuclear.

PSEG Power Ventures LLC ("Power Ventures") is a Delaware Limited Liability company and a direct subsidiary of PSEG Power. PSEG Power Ventures owns 100% interest in PSEG Solar Source LLC and has an in-direct ownership interest in a domestic power plant in Hawaii. PSEG Solar Source owns approximately 349 MWs DC (274 MW AC) of solar capacity across the United States, including a combined 92 MWs (72 MW AC) of solar capacity in PJM.[15] All of PSEG Solar Source's solar capacity has obtained QF status. Because all of this capacity is QF capacity, per Order No. 816 this capacity is not included in the market power analyses.[16]

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[15] The 42MWs are attributed to four (7) separate project companies that have QF status: PSEG Solar Hackettstown LLC (2 MW); PSEG Solar Delaware LLC (15 MW), Rockfish Solar LLC (13 MWs) Meadows Solar (26 MW), Turkey Creek (17 MW) Hemlock Solar (7 MW) in North Carolina and PSEG Solar Ohio LLC (12 MW).

[16] *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 816, 80 *Fed. Reg*. 67056 (2015), FERC STAT & REGS ¶ 31,374, P55 (2015), *reh'g denied and clarification*, Order No. 816-A, 155 FERC ¶ 61,188 (2016) ("… qualifying facilities that are exempt from FPA section 205 and facilities that are behind-the-meter facilities do not need to be reported in the asset appendix or indicative screens." (note omitted))

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PSEG Resources LLC ("Resources") is a New Jersey limited liability company that provides energy infrastructure financing in developed countries. PSEG Resources invests primarily in energy-related financial transactions and manages a diversified portfolio of investments including leveraged leases. PSEG Resources owns interests, through leveraged leases, in various generation stations. Pursuant to the terms of these triple net leases, the lessee, not Resources, has all operational responsibility and control over the leased generation stations.

PSEG Power New York LLC ("PSEG Power NY") is a Delaware limited liability company that owns and operates the Bethlehem Energy Center ("BEC") located in the State of New York. The BEC Station is located within the NYISO and is an approximately 750 MW combined-cycle natural gas fired facility. PSEG Power NY sells the output of the BEC station to its affiliate PSEG ER&T pursuant to a cost-based contract.[17]

PSEG Keys Energy Center LLC ("PSEG Keys"), direct subsidiary of PSEG Fossil, was formed to construct, operate, and maintain the Keys Energy Center, a 755 gas-fired combined cycle facility located in Prince George's County, Maryland. Construction began in 2015 and is scheduled to be completed in 2018. All the capacity and energy from PSEG Keys will be sold to PSEG ER&T.

PSEG Energy Solutions LLC ("PSEG Solutions") is a direct subsidiary of PSEG ER&T that is schedule to begin retail operations in the Northeast Region in

[17] *PSEG Power New York Inc.,* Docket No. ER05-323-000, Letter Order (issued February 8, 2005).

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January 2017. It has obtained market-rate authority to allow it to sell excess energy in wholesale markets.[18]

PSEG Long Island LLC ("Long Island") and Long Island Electric Utility Servco, LLC ("Servco") are both New York limited liability companies created to provide management, operations and maintenance services to the Long Island Power Authority with respect to the transmission and distribution ("T&D") system on Long Island, New York pursuant to a 12-year Operations Service Agreement beginning on January 1, 2014. Neither Long Island nor Servco are FERC jurisdictional public utilities, as neither will exercise ultimate decision making authority over the T&D system in Long Island. Long Island and Servco have received a declaratory order from FERC confirming this status and disclaiming jurisdiction.[19]

When an applicant has affiliates in the relevant market, the Commission considers the combined capacity of all the affiliated entities in its market power assessment.[20] Accordingly, I have included the capacity controlled by PSE&G, PSEG ER&T, PSEG Power CT, PSEG Fossil, PSEG Nuclear, and PSEG Power New York (which on a combined basis constitutes the capacity of all of PSEG's affiliates not excluded for a reason explained above). Future references in this Affidavit to PSEG are inclusive of the foregoing entities.

The primary purpose of this study is to determine whether PSEG passes the PSA and WMSA screen thresholds in ISO-NE, the NYISO and PJM. In the PSA, the Commission requires applicants to examine whether the generation owned by

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[18] *See* December 21, 2016 letter order approving Energy Solutions request for market-based rate authority in Docket No. ER16-2725-000.

[19] *PSEG Long Island LLC*, 145 FERC ¶ 61,010 (2013), order dismissing request for rehearing, 145 FERC ¶ 61,183 (2013).

[20] *Heartland Energy Services, Inc.,* 68 FERC ¶ 61,223 at 62,061-62,062 (1994).

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the applicant is necessary to serve wholesale demand within a balancing authority area. The applicant first calculates the total generation capacity for an area. This is the total of generation in the balancing authority area plus the import capability to the area.[21] From this total, the applicant subtracts out firm contractual commitments, native load obligations, and operating reserves, giving uncommitted capacity for the area. Net uncommitted capacity is calculated by subtracting a wholesale load proxy from uncommitted capacity. Net uncommitted capacity is then compared to the applicant's uncommitted capacity within the area. When the applicant's uncommitted capacity is less than the net uncommitted capacity for the area, then all wholesale demand could be served without energy from the applicant and the applicant passes the PSA screen. When the applicant's uncommitted capacity is greater than the net uncommitted capacity, then the applicant does not pass the screen because its capacity is necessary to meet wholesale peak loads in the market.

In the WMSA, the Commission requires applicants to examine whether the generation owned by the applicant is 20 percent or more of the uncommitted capacity in each of four seasons under average daily peak conditions for the season. The applicant first calculates the total generation capacity for an area. The applicant then adds the import capability to the area. From this total, the applicant subtracts out planned outages and deratings, long-term firm contractual commitments, native load obligations, and operating reserves. The sum gives the total uncommitted capacity. The applicant then calculates its share by dividing its uncommitted capacity by the total uncommitted capacity. When the applicant's share is less than 20 percent, the applicant passes the WMSA screen.

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[21] Import capability is the lesser of either the simultaneous import limit ("SIL") into the area or available capacity in interconnected balancing authority areas. Available capacity is equal to total generation capacity in an area less outages and derating, a native load proxy and operating reserves.

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The Commission presumes that an applicant does not have market power when it passes both the PSA and WMSA screens. If the applicant fails either of the screens, then the applicant may present other analyses to demonstrate that it does not possess market power. Alternatively, the applicant may propose mitigation measures or accept the Commission's default mitigation measures to demonstrate that it has mitigated market power.

2. New England

2.1. Overview of Electric Power Markets in New England

New England operates a competitive wholesale power market. Substantial restructuring has taken place in New England, and many of the vertically integrated utilities have sold either most or all of their generation assets. The traditional utilities often have standard offer obligations to serve retail customers, but utilities often fulfill these obligations by securing supplies in competitive wholesale markets. For example, a utility may secure contracts in which the supplier agrees to provide power for 30 percent of the utility's standard offer obligation. The transmission system is managed by ISO-NE. The market has a market monitor and market power mitigation program in place to identify and to mitigate any potential exercise of market power.

2.2. Geographic Markets

In the case of generation wholly located in an RTO, such as ISO-NE, the Commission accepts the RTO as the relevant destination market.[22] When the Commission has identified a sub-market within an RTO, the applicant must also provide market power screens for the relevant sub-markets.[23] In New England,

[22] Order No. 697 at PP 231, 235.

[23] Order No. 697 at P 236.

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the Commission has identified two submarkets: Connecticut and Southwest Connecticut.[24] PSEG owns the Bridgeport Harbor plant in Southwest Connecticut. PSEG also owns the New Haven Harbor 1 unit in Connecticut and PSEG New Haven owns the New Haven facility. When the applicant does not own the transmission system, as in the instant case, the applicant needs to provide an analysis only for the balancing authority area to which the generation is interconnected.[25] Accordingly, the PSA and WMSA are provided for the ISO-NE balancing authority area, and also for Connecticut and Southwest Connecticut.

2.3. Data Sources and Analysis

The data source for generation is ISO-NE Seasonal Claimed Capability (SCC) Reports.[26] Summer and winter capacities were taken from the November 2015 report. Planned outages are from the ISO-NE Form 714. Planned outages for Connecticut and Southwest Connecticut are prorated based on their shares of the total generation capacity in ISO-NE. PSEG's generation capacity in ISO-NE consists of the New Haven facility, New Haven Harbor and Bridgeport Harbor. PSEG's Northeast Region generation facilities are presented in Exhibit PEG-3.

Load data for ISO-NE are from Energy Velocity. Energy Velocity also provides load data by New England ISO zone, thus loads are calculated by sub-market as well. PSEG load obligations in New England come from PSEG's agreements to supply standard offer generation within Rhode Island. The data were supplied by PSEG.

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[24] *Id*.

[25] Order No. 697 at footnotes 215, 217.

[26] See http://www.iso-ne.com/genrtion_resrcs/snl_clmd_cap/index.html.

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Import capability was taken from the ISO-NE's December 20, 2016 FERC filing.[27] This report indicates that the simultaneous transfer limits in all seasons is 4,548 MW for the ISO-NE as a whole, 3,050 MW for Connecticut, and 2,370 (Spring) to 3,200 MW (Summer) for Southwest Connecticut. PSEG has no firm transmission rights into New England.

Operating reserves are calculated as follows. ISO-NE Operating Procedure No. 8 specifies spinning reserves (or 10-minute reserves) equal to the size of the loss of the largest unit times a Contingency Reserve Adjustment Factor ("CRAF").[28] The CRAF in 2015 was 1.25.[29] The largest unit is the 1,400 MW (summer capacity) Seabrook Unit 1. In addition, 30-minute reserves require capacity to cover 50 percent of the loss of a second contingency (i.e., the second largest unit) plus 160 MW for daylight-savings time periods and 180 MW during standard time (i.e., winter). The second largest unit is the 1,200 MW (summer capacity) Millstone Unit 3. Thus, in total, operating reserves are 2,510 MW in summer.[30] Operating reserves for Connecticut and Southwest Connecticut are based on resource needs in forward reserve auctions for 2015.[31]

2.4. Results

Exhibit PEG-4 summarizes the results for the PSA and the WMSA in New England. Exhibit PEG-5 shows the calculations to determine whether PSEG is a

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[27] ISO New England Inc. Simultaneous Import Limit for 2015, *Guidance on Simultaneous Transmission Import Limit Studies*; Docket No. AD10-02, December 20, 2016.

[28] ISO New England Operating Procedure No. 8, at 5-6, available at https://www.iso-ne.com/participate/rules-procedures/operating-procedures.

[29] ISO New England, Inc. 2015 Regional System Plan ("Regional System Plan"), available at https://www.iso-ne.com/static-assets/documents/2015/11/rsp15_final_110515.docx, at 68.

[30] 2,510 MW = 1,400 MW x 1.25 + 50% x 1,200 MW + 160.

[31] ISO New England, Inc. 2015 Regional System Plan ("Regional System Plan"), available at https://www.iso-ne.com/static-assets/documents/2015/11/rsp15_final_110515.docx, Table 4.12 at p.70.

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pivotal supplier in the three New England destination markets. PSEG passes the PSA screen in all areas. Exhibit PEG-6 presents the WMSA results for the destination areas in New England. PSEG easily passes the WMSA in all areas.

3. New York

3.1. Overview of Electric Power Markets in New York

New York also has a competitive wholesale power market. Substantial restructuring has taken place in New York, and the investor-owned vertically integrated utilities have sold either most or all of their generation assets. These utilities often have standard offer obligations to serve retail customers, and utilities can fulfill these obligations by securing supplies in competitive wholesale markets. The transmission system is operated by the NYISO, which also operates a competitive wholesale market. The market has a market monitor and market power mitigation program in place to identify and to mitigate any potential exercise of market power.

3.2. Geographic Markets

In the case of generation wholly located in an RTO such as the New York ISO, the Commission has accepted the RTO as the relevant destination market.[32] PSEG only owns generation in Albany, New York. In addition, when the applicant does not own the transmission system, as in the instant case, the applicant needs to provide an analysis only for the balancing authority area to which the generation is interconnected.[33] Accordingly, the PSA and WMSA are provided for the NYISO only.

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[32] Order No. 697 at PP 231, 235.

[33] Order No. 697 at footnotes 215, 217.

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3.3. Data Sources and Analysis

The principal data source for generation is the Energy Velocity Market-Operations database. Planned outages are from the FERC Form 714. PSEG's generation capacity in New York consists of its ownership of the Bethlehem Energy Center in Albany, which has winter capacity of 845 MW. Information for PSEG's Northeast Region generation is presented in Exhibit PEG-3.

Load data for NYISO were downloaded from Energy Velocity.

Import capability comes from the most recent NYISO SIL filing as of December 19, 2016.[34] This filing indicates that ISO simultaneous import capability ranges from 6,850 MW in spring to 7,695 MW in summer. NYISO does not recognize physical imports, accordingly, all the SIL import capability is allocated pro rata, except for a 265 MW reservation that PSEG has from PJM to New York on the Linden VFT DC transmission line.

Operating reserves are calculated as follows. The NYISO Locational Reserve Requirements specify 30-minute total reserves equal to twice the 10-minute reserve necessary to replace the operating capability loss caused by the most severe contingency under normal transfer conditions. Thus, the operating reserves for the NYISO are 2,620 MW for each season.[35]

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[34] New York Independent System Operator, Inc., *Informational Filing Regarding the Simultaneous Import Limitation Study*, Docket No. AD10-2, December 19, 2016.

[35] NYISO Locational Reserve Requirements, Table 2, available at http://www.nyiso.com/public/webdocs/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf

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3.4. Results

Exhibit PEG-7 shows the calculations to determine whether PSEG is a pivotal supplier in New York, and PSEG passes the PSA screen. Exhibit PEG-8 presents the WMSA results for New York, and PSEG easily passes the WMSA.

4. PJM

4.1. Overview of Electric Power Markets in PJM

PJM operates a competitive wholesale power market and serves as the regional RTO for an area that covers all or parts of 13 states and the District of Columbia. PJM also plans and operates the transmission system within the RTO. Monitoring Analytics acts as the market monitor, and has a market power mitigation program in place to identify and mitigate any potential exercise of market power.

4.2. Geographic Markets

PSEG owns both generation and transmission facilities in PJM. In the case of generation wholly located in an RTO such as PJM, the Commission has accepted the RTO as the relevant destination market.[36] When the Commission has identified a sub-market within an RTO, the applicant must also provide market power screens for the relevant sub-markets.[37] In PJM, the Commission has identified three submarkets: PJM East ("PJME"), PJM East of 5004/5005 ("PJM50") and PJM East of AP-South ("PJMAP").[38] The PSA and WMSA are provided for PJM and for the PJME, PJM50 and PJMAP sub-markets.

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[36] Order No. 697 at PP 231, 235.

[37] Order No. 697 at P 236.

[38] *Id*. *See also* Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities, Order No. 697-A, 73 FR 25832 (May 7, 2008), FERC

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4.3. Data Sources and Analysis

The principal data source for generation is the Energy Velocity Market-Ops database. Generation within PJM was assigned to submarket consistent with the definitions in PJM's SIL Study.[39] Planned outages are from the FERC Form 714. In addition, for the sub-market analysis, planned outages were allocated to PJME based on the share of total PJME generation, by season. Information for PSEG's generation in PJM and PJME is presented in Exhibit PEG-3.

Load data for PJM was downloaded from Energy Velocity. Energy Velocity also provides load data by PJM zone, thus loads are calculated for the PJM sub-markets as well.

Import capability was taken from the 2015 Simultaneous Import Limit Study Report.[40] This report indicates simultaneous transfer limits of 11,997 MW in the winter and 7,600 MW in summer. Additionally, this report indicates transmission capabilities of the PJM sub-markets. The report conservatively uses the reported SIL as the SIL amount to be allocated pro rata. This is a simplifying assumption because PSEG has no firm transmission reservations into PJM and it effectively excludes the additional 8,500 MW of firm reservations into PJM in the base case of the SIL study.

Stats, & Regs. ¶ 31,268 (2008) at P 90; Order Conditionally Authorizing Merger and Disposition of Jurisdictional Facilities, *Exelon Corporation, et al.*, 138 FERC ¶ 61,167 (2012).

[39] PJM Interconnection, L.L.C., *Informational Filing of 2015 Simultaneous Import Limit Study Report for PJM Region*, Docket No. AD1-2-007, September 2, 2016, Accession No. 20160902-5155.

[40] *Id*.

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Operating reserves are calculated according to PJM Manual 13 as the sum of Day Ahead Scheduling Reserves (Operating), Contingency (Primary) and Synchronized (Spinning Reserve) Requirements.[41]

Data on PSEG's long-term contracts come from PSEG. The contracts were included in the area where the energy is delivered under the contract. For contracts delivered to the Western Hub in PJM, the contracts were included in the PJM, PJM50, and PJMAP destinations and not the PJME destination.

4.4. Results

Exhibit PEG-9 summarizes the results for the PSA and the WMSA in PJM. Exhibit PEG-10 shows the calculations to determine whether PSEG is a pivotal supplier in the four PJM destination markets. PSEG passes the PSA screen for all four destinations. Exhibit PEG-11 presents the WMSA results for the destination markets in PJM. PSEG easily passes the WMSA in PJM and PJM east of AP South, but has greater than a 20 percent market share in the PJM East and PJM East of 5004/5005 destination markets.

5. Delivered Price Test

When an applicant does not pass either the PSA or WMSA for a destination market, the Commission invites the applicant to provide additional information via a delivered price test ("DPT"). PSEG requested that I perform a DPT for the PJM East and PJM East of 5004/5005 sub-markets. Accordingly, I now discuss the DPT for these sub-markets.

[41] PJM Manual 13 - Emergency Operations, at 17, available at http://pjm.com/~/media/documents/manuals/m13.ashx

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5.1. Overview of the DPT

The DPT utilizes substantially more information than the PSA or the WMSA, including additional information on generation ownership, generation costs, demand conditions, and transmission limits. The Commission considers two types of capacity: Economic Capacity ("EC") and Available Economic Capacity ("AEC"). EC is the capacity that can be delivered to a destination market for 105 percent or less than the market price. AEC is calculated by subtracting load commitments from EC. EC and AEC are calculated for a number of different seasonal and load conditions.

Because we do not know the firm retail obligations of the competitive suppliers, as explained below, the AEC calculation is based on the assumption that market participants serve load in proportion to their generation capacity and that 70 percent of load obligations are contracted more than one year from delivery.

For both the EC and AEC measures, the Commission prescribes three screens: (1) a pivotal supplier screen; (2) a market share screen; and (3) a Herfindahl-Hirschman Index ("HHI") screen. The HHI is the sum of the squared market shares of the firms in the market. So a market with four firms of market shares of 40, 30, 20, and 10 percent would have an HHI of 3,000 (this is calculated as $40^2 + 30^2 + 20^2 + 10^2 = 1{,}600 + 900 + 400 + 100 = 3{,}000$). A monopolist would produce a HHI of 10,000 and 10 equally-sized firms would produce a HHI of 1,000.

Although the Commission has not drawn bright lines for its review of DPT results, it has given general guidance. When (1) the applicant is not pivotal; (2) the applicants' market share is less than 20 percent; and (3) the HHI is below 2,500, the Commission is likely to conclude that the applicant does not have market power. The three standards establish a "safe harbor" for lack of market power, unless intervenors present clear and convincing contrary evidence. The Commission has also determined in some cases that an applicant did not have

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market power when the analysis showed isolated HHI and market share results above screening levels. Finally, despite the DPT results, the Commission may conclude that an applicant does not have market power if other evidence, such as historical sales data, indicates that the DPT results do not reflect the actual competition in the marketplace.

A detailed description of data sources and methods to prepare the data for the DPT is presented in Exhibit PEG-12. An overview of the sources and methods used at Economists Incorporated for conducting the DPT is presented here.

The DPT is calculated for 10 representative periods, three for each of three seasonal conditions plus a summer super peak period. The three seasons are spring/fall, summer, and winter. Each season is divided into (1) top 10 percent of peak hours; (2) remaining peak hours; and (3) off-peak hours. In addition, there is a summer super peak period which is comprised to the top 1 percent (10 hours) of summer peak hours. These ten periods cover the range of load conditions for each season, and for the year as a whole.

The primary source for generation data is Energy Velocity. In addition to generation capacity, Energy Velocity provides data on ownership (including holding companies), fully-loaded heat rates, emission rates, and generation availability. Generation is included for all of PJM and NYISO, which is the only first-tier balancing authority area in which PSEG owns generation. Unit capabilities are derated to account for seasonal maintenance and likely plant unavailability due to forced outages. Because demand in PJM peaks in summer and winter, the planned outages are assumed to be during the spring/fall season.

The transmission system is represented by contract paths between balancing authority areas and within PJM. Limits between regions in PJM are from Energy Velocity.

Market prices come from hourly prices reported by PJM.

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As in the PSA and WMSA, load data come from Energy Velocity. To compute load requirements for market participants, we apportion the total load in each market area in New York and PJM to all suppliers in proportion to their respective generation capacities. We assumed 70 percent of load is committed for a year or longer and the remaining 30 percent is contracted for shorter periods.[42] To account for their greater load obligations, we assume that Dominion, which does not operate in a restructured retail market, has 100 percent responsibility for its allocation of load and that AEP, which operates in a partly restructured retail market, has 90 percent of its allocation as opposed to the standard 70 percent.

The DPT and market share calculations were calculated using the Power Acquisition Screening System developed at Economists Incorporated. The mathematical details are presented in Exhibit PEG-13.

5.2. Results of the DPT for PJM50 Sub-market

The results of the DPT for PJM50 are presented in Exhibit PEG-14. The top part of the exhibit shows the results for AEC. PSEG passes the Pivotal Supplier Screen in all 10 periods. PSEG also passes both the Market Share Screens and the HHI Screens in all 10 periods.

The lower part of Exhibit PEG-14 shows the results for EC in PJM50. PSEG passes all the screens in all the periods, except for the pivotal supplier screen in the Summer Top 1% period.

[42] This is a reasonable estimate for the long-term load coverage since this number is generally between 60 and 80 percent for most generation suppliers in restructured markets.

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5.3. Results of the DPT for PJME Sub-market

The results of the DPT for PJME are presented in Exhibit PEG-15. The top part of the exhibit shows the results for AEC. PSEG passes all the screens for AEC.

The lower part of Exhibit PEG-15 shows the results for EC in PJME. PSEG passes the Market Concentration screens in all periods. It passes the Market share screens in six of ten periods, and its market share is never more than 25 percent. It passes the pivotal supplier screen in eight of ten periods.

5.4. Analysis of the DPT Results

Although PSEG fails some screens, the overall results are not indicative of PSEG having market power. To begin, PSEG passes all the AEC screens and all market concentration (HHI) screens for EC. The HHI levels in all periods, capacity types, and areas are below the screening threshold of 2,500, and typically substantially below this level. In terms of the DPT for market rate authority and under the 2010 DOJ and FTC Horizontal Merger Guidelines, the market is not highly concentrated.[43] The low HHI levels mean that PSEG has little ability to exercise market power in coordination with other suppliers. It also passes all the AEC pivotal supplier screens, and most of the EC pivotal supplier screens. This means that typically PSEG's generation is not necessary to serve load; and when its generation is necessary, its forward sale commitments are sufficient so that its uncommitted generation is not necessary to serve the remaining load. Finally, PSEG's market shares are never above 15 percent in PJM50 and for AEC in PJM East. Its market shares for EC are never above 25 percent in PJM East. Although greater than the 20 percent screen, PSEG's

[43] See U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines*, Issued August 19, 2010, at Section 5.3, available at http://www.justice.gov/atr/public/guidelines/hmg-2010.html.

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market shares are well below the 35 percent threshold that is typically used for imputing unilateral market power.[44]

5.5. Mitigation

PJM has a Commission-approved market monitoring and mitigation plan in place to ensure that generation facilities cannot exercise market power. The Commission has stated that Commission-approved market monitoring and mitigation plans are sufficient to mitigate market power in RTO markets.[45] In particular, the Commission found in connection with PSEG's last triennial filing that the PJM market monitoring and mitigation rules are sufficient to address market power concerns.[46]

Under the local market power mitigation procedures in PJM, if a supplier fails the "three pivotal supplier test" (TPS), it is offer-capped by the Market Monitor. The Market Monitor's TPS test is applied on an ongoing basis, potentially as frequently as every 5 minutes, to reflect day-ahead and real-time operating conditions. These offer caps provide direct protection against the exercise of locational market power by suppliers in PJME, PJM50, PJMAP and elsewhere.

The protection against the exercise of market power is enhanced by "must offer" requirements under PJM's Operating Agreement. These mandate that generation resources that are used to meet capacity requirements in PJM and

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[44] *See*, *e.g.*, U.S. Department of Justice, 1984 Merger Guidelines, at Section 3.12, available at https://www.justice.gov/sites/default/files/atr/legacy/2007/07/11/11249.pdf ("the Department is likely to challenge the merger of any firm with a market share of at least one percent with the leading firm in the market, provided the leading firm has a market share that is at least 35 percent.")..

[45] Order No. 697 at P 241.

[46] *See* October 14, 2014 letter order approving Applicants' prior triennial market update in Docket No. ER10-1789-003 et al. at page 3.

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that are not subject to an outage must offer their available capacity in PJM's day-ahead energy market.[47] PJM has also implemented a Reliability Pricing Model (RPM) to secure sufficient capacity to meet its requirements through a series of auctions, including a Base Residual Auction (BRA) held annually for capacity 3 years in advance, and incremental auctions held at varying intervals prior to the delivery year. Various features of the RPM process work to prevent the exercise of market power in capacity markets in PJM. First, the RPM model includes bid cap rules designed to mitigate the potential exercise of market power. Second, RPM includes a must-offer requirement pursuant to which all generating units that have available capacity must bid into the RPM auctions or face disqualification from being recognized as capacity resources (and therefore from receiving any capacity payments) in the delivery year.

In addition to the local market power mitigation described above, the presence of market monitoring within PJM lessens potential concerns that PSEG might be able to exercise market power notwithstanding the indicative DPT screens. The Market Monitor has the specific responsibility under the market monitoring plan to monitor the potential of any market participant to exercise market power. To perform its market monitoring function, the Market Monitor can file reports or complaints with the Commission and other government agencies to address various market concerns including market power. The Market Monitor can also make its view known to the Commission staff and PJM members in cases where PJM does not follow its recommendations concerning complaints or requested rule changes. In addition, the Market Monitor can consult with regulatory bodies, including state commissions, regarding the need for specific investigations and monitoring activities, and to consider and evaluate additional enforcement mechanisms. The Market Monitor can also act on specific

[47] *See* PJM Operating Agreement at 1.10.1A(d).

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complaints that have been filed by market participants to examine any potential market power issues.

In sum, the local market power mitigation rules, the role of the Market Monitor, the existence of must-offer requirements and PJM's RPM auctions address the potential for PSEG to exercise market power.

6. Vertical Market Power

In determining whether the market-based rates are in the public interest, the Commission also considers whether the Applicant has transmission market power or can erect barriers to entry.[48] None of these factors are relevant in the instant case. First, other than incidental generator interconnection facilities and the transmission assets owned by PSE&G in PJM, no transmission assets are owned by the Applicants or any of their affiliates in ISO-NE and NYISO. Transmission service over PSE&G's transmission facilities is provided under the PJM Open Access Transmission Tariff. Thus, consistent with Commission precedent, Applicants have alleviated any concerns regarding potential transmission market power. Second, PSEG has no ability to erect barriers to entry. As explained in Applicants' previous initial applications for market-based rate authority and triennial market power reports, PSEG is unable to erect barriers to entry. There has been no change in facts since the submission of those applications that would alter this conclusion.

The Commission is concerned with the ownership of natural gas pipelines or natural gas distribution facilities and the possibility that they may be used to exercise market power in electricity markets. PSEG does not own or operate any

[48] Order No. 697 at PP 397, 399.

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FERC jurisdictional natural gas pipelines in PJM, ISO-NE or NYISO.[49] PSE&G owns natural gas distribution facilities in the State of New Jersey including peak-shaving, liquefied petroleum gas and liquefied natural gas facilities, which are used to provide distribution service to retail customers.

7. Conclusion

PSEG and its subsidiaries do not have market power in New England, New York or PJM. PSEG is not a pivotal supplier in New England, New York or PJM. PSEG's market shares in the WMSA are below the Commission's 20 percent screening threshold in each of these market areas. PSEG is also not a pivotal supplier in the Connecticut or Southwest Connecticut sub-markets and its market shares in the WMSA are below 20 percent in these sub-markets. PSEG fails the WMSA screens in only the PJME and PJM50 sub-markets. For these sub-markets, we conducted a DPT analysis. PSEG passes all the DPT screens for the PJM50 submarket, and it only fails the Market Share Screen in the PJME submarket. Its market shares are never above 25 percent, a level that the Commission has accepted in other market-based rate matters.[50] As such, they are not evidence of actual market power.

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[49] PSEG Power LLC currently owns a 10 percent interest in the PennEast Pipeline Company LLC which has filed an application with FERC for construction and operation of a gas transmission line.

[50] *See*, *e.g.*, *Dogwood Energy, LLC*, 135 FERC ¶ 61,089 (2011) (under the AEC measure, Dogwood failed the market share screen in seven of ten periods, with market shares ranging from 32.7% to 39.6%); *Kansas City Power & Light Company and KCP&L Greater Missouri Operation Company*, Docket No. ER10-2074-001 et al., Supplement to Change in Status Filing at 11 (Feb. 4, 2013) (accepted by Letter Order, November 22, 2013) (market shares for AEC ranging from 17 to 36%); *Shell Energy N.A. (US), L.P.*, 135 FERC ¶ 61,090 (2011) (under the AEC measure, Shell failed the market share screen for seven of ten periods, with market shares ranging from 29.3% to 37.0%); *Calpine Energy Services, L.P.*, 137 FERC ¶ 61,085 at P 21 (2011) (under the AEC measure, Calpine failed the market share screen in all ten periods, with market shares ranging from 20.4% to 28.9%); *Wildcat Power Holdings, LLC*, 136 FERC ¶ 61,013 at P 14 (2011) ("When the available economic capacity measure is used, Wildcat Power's market shares range from 22 to 24 percent in the three summer super peak and winter

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Further, PSEG operates under New England's, New York's, and PJM's market power mitigation programs, which mitigate PSEG's potential market power. Therefore, under standards for market-based rate authority articulated by the Commission in Order No. 697, PSEG has no ability to exercise market power in the relevant markets, and maintaining market-rate authority in New England, New York and PJM would be in the public interest.

Therefore, I recommend that the Commission continue to authorize PSEG to sell electric power in Northeast Region wholesale markets at market-based rates.

super peak season/load periods and zero percent in the remainder of the season/load periods."); *LS Power Marketing*, LLC,139 FERC ¶ 61,140 at P 23 (2012) (under the AEC measure, LS Power failed the market share screen in all ten periods, with market shares ranging from 20.4% to 28.9%); *Gila River Power, L.P.*, Docket Nos. ER05-1178-015, et al., Second Supplement to Updated Market Power Analysis at 4 (Jan. 12, 2011) (accepted by Letter Order, April 5, 2011) (market shares for AEC ranging from 21 to 23% in four season/load periods).

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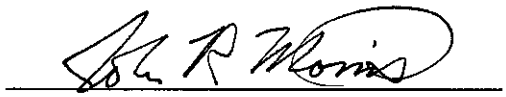
Pursuant to 28 U.S.C. §1746, I state under penalty of perjury that the foregoing is true and correct to the best of my information, knowledge, and belief.

Executed on this 22rd day of December 2016.



John R. Morris, Ph.D.
Principal
Economists Incorporated

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EXPERIENCE AND QUALIFICATIONS OF

Dr. John R. Morris

OVERVIEW	Dr. Morris, a recognized expert in studying competition in energy industries, currently is a Principal at Economists Incorporated. He began his research of competition in energy industries in 1985 while working for the Federal Trade Commission. Since joining Economists Incorporated in 1992, he has consulted on many mergers and acquisitions involving energy companies, examined competitive issues relating to rates, and studied issues in state restructuring proceedings. He has published articles on competition and energy matters, and he has spoken on numerous occasions concerning competition in natural gas, electric power and other industries. He has been accepted as an expert witness on energy matters before the Federal Energy Regulatory Commission, state regulatory commissions, and in federal court.
EDUCATION	Ph.D., University of Washington, August 1985 Dissertation: *Intellectual Property: Creating, Pricing, Copying* • M.A., University of Washington, December 1983 • A.B., Georgetown University, May 1981
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MEMBERSHIPS	Member, International Association of Energy Economics • Associate, Energy Bar Association • Member, American Economic Association • Member, Western Economic Association International • Associate, American Bar Association

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AWARDS & HONORS

Award for Excellence in Law Enforcement, Federal Trade Commission, 1988 • Graduate School Scholarship, University of Washington, 1984 • Graduated Cum Laude Georgetown University, 1981 • Senior Comprehensive Passed with Distinction, Georgetown University, 1981

TESTIMONY BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Affidavit, Alabama Power Company, *et al.*, ER17-514-000 (2016) • Affidavits (3), Alabama Power Company, *et al*., EL15-39-000 (2016) • Affidavit, Combined Locks Energy Center, LLC, *et al.* , ER10-3042-004 (2015) • Affidavit, Alabama Power Company, *et al*., EL15-39-000 (2015) • Affidavit, PJM Interconnection, L.L.C., ER15-623-000 (2015) • Affidavit, Southern Indiana Gas and Electric Co. d/b/a Vectren Energy Delivery of Indiana, Inc., ER10-1338-000 (2014) • Affidavit, Quantum Choctaw Power, LLC *et al*., ER12-458-007 (2014) • Affidavit, NRG Power Marketing LLC, *et al.*, ER10-2265-004 *et al.* (2014) • Affidavit, TransCanada Entities, ER10-2870-004 *et al*. (2014) • Affidavit, Tampa Electric Company, ER10-1437-002 (2014) • Affidavit, Kendall Green Energy LLC, ER14-1363-003 (2014) • Affidavit, Quantum Lake Power, LP, ER13-1489-000 (2014) • Affidavit, NRG Power Marketing LLC, *et al.* ER10-2265-002 (2014) • Affidavit, NRG Yield, Inc., *et al*., EC14-101-000 (2014) • Affidavit, Community Wind Farm 1 et al., ER14-1668-000 (2014) • Seaway Crude Pipeline Company LLC, OR15-6-000 (2014) • Affidavit, Public Service Electric and Gas Company *et al.*, ER10-1789-003 (2013) • Affidavits, NRG Energy Holdings, Inc., Edison Mission Energy, EC14-14-000 (2013) • Affidavit, Silver Merger Sub, Inc., *et al.*, EC13-128-000 (2013) • Prepared Answering Testimony, Deposition, and Hearing, Puget Sound Energy, Inc., *et al.*, EL01-10-085 (2012) • Affidavit, Wisconsin Public Service Corporation, *et al*., ER10-1894-004 (2012) • Affidavit, PSEG New Haven LLC, ER12-1250-000 (2012) • Affidavit, Enterprise Product Partners L.P. and Enbridge, Inc., OR12-4-000 (2012) • Affidavit, Southern Indiana Gas and Electric Co., ER10-1338-001 (2011) • Affidavit, TransCanada Power Marketing Ltd. *et al.*, ER10-2780-001 (2011) • Affidavit, Tampa Electric Company, ER10-1476-001 (2011) • Affidavit, Cedar Creek Wind Energy, LLC, ER11-2577-000 (2010) • Affidavit, Public Service Electric and Gas Company *et al.*, ER97-837-014 (2010) • Affidavit, Morris Energy Group, LLC v. PSEG Energy Resources & Trade LLC; PSEG Fossil LLC; and PSEG Power LLC, EL10-79-000 (2010) • Affidavit, UGI Storage Company and UGI Central Penn Gas, Inc., CP10-23-000 (2010) • Prepared Answering Testimony, People of the State of California, *ex rel*; Bill Lockyer, Attorney General of the State of California v. Powerex Corp., *et al.*, EL02-71-000 (2009) • Affidavit, Integrys Energy Services, Inc. v. New Brunswick Power Generation Corporation, EL09-32-002 (2009) • Affidavit, People of the State of California, *ex rel*; Edmund G. Brown Jr. Attorney General of the State of California v. Powerex Corp., *et al.*, EL09-56-000 (2009) • Affidavit, San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, EL00-95-000 (2009) • Affidavit, Troy Energy, LLC, *et al.*, ER02-25-010 (2009) • Affidavit, Combined Locks Energy Center, LLC,

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et al., ER01-2659-015 (2009) • Prepared Direct Testimony and Deposition, Energy Transfer Partners, *et al*., IN06-3-003 (2009) • Prepared Direct Testimony and Hearing, Mobil Pipe Line Company, OR07-21-000 (2009) • Idaho Power Company, ER06-787-002 (2009) • Affidavit, Southern Indiana Gas and Electric Co. d/b/a Vectren Energy Delivery of Indiana, Inc. ER96-2734-007 (2008) • Affidavit, Choctaw Gas Generation, LLC, *et al.* ER08-1332-002 • Affidavit, TransCanada Energy Sales Ltd., ER09-328-001 (2008) • Prepared Direct Testimony and Deposition, Oasis Pipeline L.P., *et al.*, IN06-3-004 (2008) • Affidavit, Tampa Electric Company, ER99-2342-012 (2008) • Affidavit, ANP Bellingham Energy Company, LLC, *et al.*, ER00-2117-005 (2008) • Affidavit, SUEZ Energy Marketing, NA, *et al.*, ER06-169-003 (2008) • Affidavit, TransCanada Energy Marketing ULC, *et al.*, ER07-1274-001 (2008) • Affidavit, Georgia-Pacific Brewton LLC, *et al.*, ER08-1126-000 (2008) • Affidavit, Montgomery L'Energia Power Partners LP, ER08-864-000 (2008) • Affidavit (with Joseph P. Kalt), Energy Transfer Partners, *et al*., IN06-3-002 (2008) • Affidavit, Energy Transfer Partners, *et al*., IN06-3-002 (2008) • Affidavit, TransCanada Maine Wind Development Inc., ER08-685-000 (2008) • Affidavit (with Joseph P. Kalt), Energy Transfer Partners, *et al*., IN06-3-000 (2007) • Affidavit, Energy Transfer Partners, *et al*., IN06-3-000 (2007) • Affidavit, The People of the State of Illinois, *ex rel.* Illinois Attorney General Lisa Madigan v. Exelon Generation Co., LLC, *et al.*, EL07-47-000 (2007) • Affidavit, Baltimore Gas and Electric Company, ER07-576-000 (2007) • Affidavit, Trans-Allegheny Interstate Line Company, ER07-562-000 (2007) • Affidavit, TransCanada Energy Marketing Ltd., *et al.*, ER07-331-000 (2006) • Affidavit, Tampa Electric Company, ER99-2342-000, ER07-173-000 (2006) • Affidavit, Koch Supply & Trading, LP, ER07-100-000 (2006) • WPS Resources Corporation and Peoples Energy Corporation, EC06-152-000 (2006) • Affidavit, Sabine Cogen, LP, ER06-744-000 (2006) • Affidavit, Air Liquide Large Industries U.S. LP, ER06-743-000 (2006) • Affidavit, ANP Bellingham Energy Company, LLC., *et al.*, ER00-2117-000 (2005) • Affidavit, Duke Energy Corporation and Cinergy Corp., EC05-103-000 (2005) • Affidavit, El Paso Marketing, L.P., *et al.*, ER95-428-000 (2005) • Affidavit, TransCanada Energy Ltd., *et al.*, ER95-692-000 (2005) • Affidavit, Granite Ridge Energy, LLC, ER00-1147-000, ER05-287-001 (2005) • Affidavit, TransCanada Power (Castleton) LLC, ER05-743-000 (2005) • Affidavit, Tampa Electric Company, *et al*., ER99-2342-003 (2005) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-035 and Wisconsin Public Service Corporation, ER95-1528-010 (2005) • Affidavit, Wisconsin River Power Company, ER05-453-000 (2005) • Affidavit, Upper Peninsula Power Company, ER05-89-001 (2005) • Affidavit, Southern Indiana Gas and Electric Company, ER96-2734-003 (2004) • Affidavit, Tampa Electric Company, *et al*., ER99-2342-003 (2004) • Affidavits, TransCanada Hydro Northeast, Inc., *et al*., EC05-12-000, ER05-111-000 (2004) • Affidavits, Dominion Energy New England,

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Inc., *et al*., EC05-4-000, ER05-34-000 (2004) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-033 and Wisconsin Public Service Corporation, ER95-1528-008 (2004) • Affidavit, NorthPoint Energy Solutions Inc. ER04-1244-000 (2004) • Affidavit, Union Power Partners, L.P., ER01-930-004 (2004) • Affidavit, Panda Gila River, L.P., ER01-931-004 (2004) • Affidavit, Dominion Energy Kewaunee, Inc., ER04-318-000 (2003) • Affidavit, TPS GP, Inc., TPG LP, Inc., Panda GS V, LLC & Panda GS VI, LLC, EC03-90-000 (2003) • Affidavit, Berkshire Power Company, L.L.C. *et al.*, ER99-3502-001 (2002) • Affidavit, El Paso Merchant Energy, L.P., ER95-428-024 (2002) • Affidavit, Tampa Electric Company, ER99-2342-001 (2002) • Affidavit, Hardee Power Partners Limited, ER99-2341-001 (2002) • Affidavit, TECO-PANDA Generating Company, L.P., ER02-1000-000 (2002) • Affidavit, Commonwealth Chesapeake Company, LLC, ER99-415-004 (2002) • Affidavit, Wisconsin Public Service Corporation, WPS Energy Services, Inc., and WPS Power Development, Inc., ER96-1088-031 and Wisconsin Public Service Corporation, ER95-1528-006 (2001) • Affidavit, TPS McAdams, LLC and TPS Dell, LLC, ER02-507-000 and ER02-510-000 (2001) • Affidavits, Prepared Direct Testimony, and Hearing, CPUC v. El Paso Natural Gas Company, et al., RP00-241-000 (2000-2001), Affidavit, El Paso Energy Corporation and The Coastal Corporation, EC00-73-000, (2000) • Affidavit, El Paso Energy Corporation and Sonat Inc., EC99-73-000 (1999) • Prepared Testimony, San Diego Gas & Electric Company and Enova Energy, Inc., EC97-12-000 (1997) • Prepared Testimony and Hearing, Wisconsin Electric Power Co., Northern States Power Co. (Minnesota), Northern States Power Co. (Wisconsin), and Cenerprise, Inc., EC95-16-000 (1996)

TESTIMONY BEFORE STATE REGULATORY COMMISSIONS

Prepared Direct Testimony, In re: Petition for Determination of Cost Effective Generation Alternative to Meet Need Prior to 2018, by Duke Energy Florida, Inc., FPSC Docket No. 140111-EI (2014) • Affidavit and Prepared Testimony, In The Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 14 Electric and B.P.U.N.J. No. 14 Gas Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and for Approval of a Gas Weather Normalization Clause; A Pension Expense Tracker; and for Other Appropriate Relief, BPU Docket No. GR09050422, New Jersey Board of Public Utilities (2010) • Prepared Direct Testimony, Application of Wisconsin Power and Light Company for Issuance of a Certificate of Public Convenience and Necessity for Construction and Placement in Operation of an Approximately 300 MW Coal-Fired Baseload Facility and an Application for Approval of Fixed Financial Parameters and Capital Cost Rate-Making Principles for the Baseload Facility, Docket No. 6680-CE-170, Public Service Commission of Wisconsin (2008) • Prepared Rebuttal Testimony and Hearing, In the Matter of the Joint Petition of Public Service Electric and Gas Company and

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Exelon Corporation for Approval of a Change in Control of Public Service Electric and Gas Company, and Related Authorizations, BPU Docket No. EM05020106, OAL Docket No. PUC-01874-05, New Jersey Board of Public Utilities (2005, 2006) • Affidavit, Application of Duke Energy Corporation for Authorization to Enter Into a Business Combination Transaction with Cinergy Corp., Docket No. 2005-210-E, Public Service Commission Of South Carolina (2005) • Prepared Rebuttal Testimony and Hearing, Joint Application of PECO Energy Company and Public Service Electric and Gas Company for Approval of the Merger of Public Service Enterprise Group Incorporated with and into Exelon Corporation, Docket No. A-110550F0160, Pennsylvania Public Utility Commission (2005) • Prepared Direct Testimony and Hearing, Application of Washington Gas Light Company for amendments to Rate Schedule No. 9, Firm Delivery Gas Supplier Agreement of its Gas Tariff, Docket No. PUE-2004-00085 (2005) • Prepared Direct Testimony, Application of Wisconsin Public Service Corporation for a Certificate of Public Convenience and Necessity for Construction of A Large Electric Generating Plant with Associated Facilities, known as Weston 4, at Its Existing Weston Generating Station Located in Marathon County, Docket No. 6690-CE-187, Public Service Commission of Wisconsin (2004) • Prepared Direct Testimony, Metromedia Energy, Inc. - Regarding Washington Gas Light Company's Plan to Return Customers to Sales Service Effective December 1, 2003, Docket No. PUE-2003-00536 (2004) • Report (with Mark Frankena) and Testimony, Analysis of Competitive Implications: An investigations into whether electric industry restructuring and competition in the provision of retail electric service is in the public interest, Louisiana Public Service Commission Docket No. U-21453, U-20925 (SC), U-22092 (SC) (Subdocket A) (2000) • Report and Hearing, Atlantic City Electric Company: Audit of Restructuring, New Jersey Board of Public Utilities, Docket No. EA97060395 (1998) • Prepared Testimony and Hearing, Proceeding on Motion of the Commission to Redesign Niagara Mohawk Power Corporation’s Current SC-7 Service Classification and Implement a New SC-7-A Service Classification, Case 94-E-0172, New York Public Service Commission (1995)

TESTIMONY BEFORE FEDERAL COURTS

Report, Deposition, and Bench Trial, FTC v. Arch Coal, Inc., et al., Civil Action 04-0534 (JDB), U.S. Dist. Court, Dist. of Columbia (2004) • Report, Deposition and Jury Trial, Trigen v. OG&E, CIV-96-1595L, U.S. Dist. Court, Western Dist. of Oklahoma (1998)

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TESTIMONY BEFORE STATE COURTS	Affidavit, Retail Energy Supply Association, *et al.* v. Public Service Commission of the State of New York, *et al.*, Index No. 870-16, State of New York, Supreme Court, County of Albany (2016) • Affidavit, City Public Service Board of San Antonio vs. Public Utility Commission of Texas, et al., No. 97-02917, District Court of Travis County, Texas, 200th Judicial District (1997)
OTHER TESTIMONY	Report, Metromedia Energy, Inc. v. Mirant Americas Energy Marketing, RE: 18 198 Y 18484 03 (2005) • Report and Deposition, King Provision Corporation v. Burger King Corporation and Grand Metropolitan PLC*,* 90-05718-CA, 4th Cir., Duval Co., Florida (1992) • Deposition, West Texas Transmission L.P. v. Enron Corp. et al., SA 88 CA 0638, W.D. Texas, San Antonio Division (1988)
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PRESENTATIONS & PROFESSIONAL ACTIVITIES

Comments (with 7 others), Notice of Inquiry: Modifications to Commission Requirements for Review of Transactions under Section 203 of the Federal Power Act and Market-Based Rate Applications under Section 205 of the Federal Power Act, Docket No. RM16-21-000, Federal Energy Regulatory Commission, November 28, 2016 • Report, PJM Interconnection, L.L.C., Docket No. ER15-623-000, Federal Energy Regulatory Commission, January 20, 2015 • Comments, Notice of Inquiry: Analysis of Horizontal Market Power under the Federal Power Act, Docket No. RM11-14-000, Federal Energy Regulatory Commission, May 23, 2011 • Comments, Position Limits for Derivatives, RIN 3038–AD15 and 3038–AD16, Commodity Futures Trading Commission, March 28, 2011 • Comments, Guidance on Simultaneous Transmission Import Limit Studies, AD10-2-000, Federal Energy Regulatory Commission, February 12, 2010 • "Geographic Market Delineation in LMP Electric Power Markets," presentation before representatives of the Federal Energy Regulatory Commission, U.S. Department of Justice, and U.S. Federal Trade Commission, January 27, 2010 • Comments, Notices of Intent to determine that 15 natural gas financial basis contracts traded on the Intercontinental Exchange, Inc. are Significant Price Discovery Contracts, Commodity Futures Trading Commission, October 26, 2009 • "Efficacy of Vertical Integration in Energy Industries with Applications to Proposed Standards of Conduct for Transmission Providers," submitted to FERC by Santee Cooper in Docket No. RM07-1-000 (2007) • Chair, Antitrust Committee, Energy Bar Association, 2004–2005 • "Competition in the Natural Gas Industry: An Antitrust Perspective, presentation to staff of the Federal Energy Regulatory Commission," March 28, 2005 • Vice Chair, Antitrust Committee, Energy Bar Association, 2003–2004 • "Weston 4 Effect on Wholesale Competition in WUMS," submitted to the Public Service Commission of Wisconsin by Wisconsin Public Service Corporation in Docket No. 6690-CE-187, September 26, 2003 • "Computer Models In The Electric Power Industry," presented to staff of the Federal Trade Commission, Washington, DC, June 11, 2002 • "TECO EnergySource Market Share Analysis," submitted to FERC by TECO EnergySource, Inc. in Docket No. ER96-1563-017, September 10, 2001 • "Finding Market Power in Power Markets," presented to staff of the Federal Trade Commission, Washington, DC, June 20, 2001 • "A Study of Marketing Affiliate and Other Affiliate Holdings of Firm Capacity on Interstate Natural Gas Pipelines and the Effects on Natural Gas Markets," April 30, 2001, submitted to FERC by the Interstate Natural Gas Association of America in Docket No. PL00-1-003 • "Why We Should Use Computer Models to Unveil Market Power," presented at the Sixth DOE–NARUC National Electricity Forum, Brown Convention Center, Houston, TX, September 16, 1998 • Comments, *Agency Information Collection and Dissemination Activities: Comment Request*, U.S. Department of Energy, Energy Information Administration, August 28, 1998 • Comments, *Revised filing Requirements Under Part 33 of the Commission's Regulations*, Federal Energy

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Antitrust and Trade Regulation Section of the Federal Bar Association, July 1990 • "Analyzing Agreements Among Competitors: What Does the Future Hold?" with Jim Langenfeld, presented at a *Contemporary Policy Issues* Session of the Western Economics Association's 65th Annual Conference, cosponsored by the *Antitrust Bulletin* and the Antitrust and Trade Regulation Section of the Federal Bar Association, July 1990 • "The Relationship Between Industrial Sales Prices and Concentration of Natural Gas Pipelines," Seminar, Office of Economic Policy, Federal Energy Regulatory Commission, Summer 1989 • "The Relationship Between Industrial Sales Prices and Concentration of Natural Gas Pipelines," Seminar, Economic Analysis Group, Antitrust Division, U.S. Department of Justice, February 1989 • "Deregulation by Vertical Integration?" Seminar, Department of Business Economics, Indiana University, January 1989 • Discussant, Industrial Organization Society Session, Annual Meeting of the American Economics Association, December 1988 • "Concentration and Price in the Natural Gas Industry," Seminar, Federal Trade Commission, July 1988 • "Relevant Measures of Concentration for Antitrust Policy," presented at an Industrial Organization Society Session of the 57th Annual Conference of the Southern Economics Association, November 1987

Northeast Region Generation Owned and Controlled by PSEG

Owner	Plant Name	State	Owned Capacity		Controlled Capacity	
			Winter Seasonal Capacity	Summer Seasonal Capacity	Winter Seasonal Capacity	Summer Seasonal Capacity
ISO - New England						
PSEG Power CT	Bridgeport Station 2	CT	148	130	148	130
PSEG Power CT	Bridgeport Station 3	CT	385	383	385	383
PSEG Power CT	Bridgeport Station 4	CT	20	15	20	15
PSEG Power CT	New Haven Harbor 1	CT	455	448	455	448
PSEG New Haven	New Haven Harbor GT2	CT	61	61	0	0
PSEG New Haven	New Haven Harbor GT3	CT	61	61	0	0
PSEG New Haven	New Haven Harbor GT4	CT	61	61	0	0
Total ISO - New England Capacity			**1,190**	**1,158**	**1,008**	**976**
New York ISO						
PSEG Power NY	Bethlehem Energy Center CC	NY	845	754	845	754
Total New York ISO Capacity			**845**	**754**	**845**	**754**
PJM						
PSEG Fossil	Conemaugh 1	PA	191	191	191	191
PSEG Fossil	Conemaugh 2	PA	191	191	191	191
PSEG Fossil	Conemaugh A[1]	PA	1	1	1	1
PSEG Fossil	Conemaugh B	PA	1	1	1	1
PSEG Fossil	Conemaugh C	PA	1	1	1	1
PSEG Fossil	Conemaugh D	PA	1	1	1	1
PSEG Power	Conemaugh Hydroelectric Plant 1[2]	PA	1	1	1	1
PSEG Power	Conemaugh Hydroelectric Plant 2	PA	1	1	1	1
PSEG Fossil	Keystone 1[3]	PA	194	194	194	194
PSEG Fossil	Keystone 2	PA	194	194	194	194
PSEG Fossil	Keystone 3	PA	1	1	1	1
PSEG Fossil	Keystone 4	PA	1	1	1	1
PSEG Fossil	Keystone 5	PA	1	1	1	1
PSEG Fossil	Keystone 6	PA	1	1	1	1
PSEG Solar Source LLC	Wyandot Solar Farm	OH	12	12	12	12

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Northeast Region Generation Owned and Controlled by PSEG

Owner	Plant Name	State	Owned Capacity		Controlled Capacity	
			Winter Seasonal Capacity	Summer Seasonal Capacity	Winter Seasonal Capacity	Summer Seasonal Capacity
PJM East						
PSEG Fossil	Bergen 3[7]	NJ	21	21	21	21
PSEG Fossil	Bergen CC1	NJ	628	628	628	628
PSEG Fossil	Bergen CC2	NJ	550	555	550	555
PSEG Fossil	Burlington 8[7]	NJ	21	21	21	21
PSEG Fossil	Burlington 9[10]	NJ	184	184	184	184
PSEG Fossil	Burlington 11[7]	NJ	184	184	184	184
PSEG Fossil	Burlington 121	NJ	42	42	42	42
PSEG Fossil	Burlington 122	NJ	42	42	42	42
PSEG Fossil	Burlington 123	NJ	42	42	42	42
PSEG Fossil	Burlington 124	NJ	42	42	42	42
PSEG Fossil	Edison 1[7]	NJ	168	168	168	168
PSEG Fossil	Edison 2[7]	NJ	168	168	168	168
PSEG Fossil	Edison 3[7]	NJ	168	168	168	168
PSEG Fossil	Essex 9	NJ	81	81	81	81
PSEG Fossil	Essex 10[7]	NJ	168	168	168	168
PSEG Fossil	Essex 11[7]	NJ	168	168	168	168
PSEG Fossil	Essex 12[7]	NJ	168	168	168	168
PSEG Nuclear	Hope Creek 1	NJ	1,161	1,161	1,161	1,161
PSEG Fossil	Hudson 2	NJ	608	608	608	608
PSEG Fossil	Kearny 9[8]	NJ	21	21	21	21
PSEG Fossil	Kearny 12	NJ	175	175	175	175
PSEG Fossil	Kearny 13	NJ	0	178	0	178
PSEG Fossil	Kearny 14	NJ	0	89	0	89
PSEG Fossil	Linden 1	NJ	455	458	455	458
PSEG Fossil	Linden 2	NJ	775	778	775	778
PSEG Fossil	Linden 7	NJ	84	84	84	84
PSEG Fossil	Linden 8	NJ	84	84	84	84
PSEG Fossil	Linden GT5	NJ	86	86	86	86
PSEG Fossil	Linden GT6	NJ	86	86	86	86
PSEG Hackettstown LLC	Mars Solar Garden	NJ	2	2	2	2
PSEG Fossil	Mercer 1	NJ	316	316	316	316
PSEG Fossil	Mercer 2	NJ	316	316	316	316

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Northeast Region Generation Owned and Controlled by PSEG

			Owned Capacity		Controlled Capacity	
Owner	**Plant Name**	**State**	**Winter Seasonal Capacity**	**Summer Seasonal Capacity**	**Winter Seasonal Capacity**	**Summer Seasonal Capacity**
PSEG Fossil	Mercer GT3[9]	NJ	115	115	115	115
PSEG Solar Source LLC	Milford Solar Farm	DE	15	15	15	15
PSEG Fossil	National Park GT1[7]	NJ	21	21	21	21
PSEG Nuclear	Salem 1[4]	NJ	674	674	674	674
PSEG Nuclear	Salem 2	NJ	665	665	665	665
PSEG Nuclear	Salem GT3	NJ	22	22	22	22
PSEG Fossil	Sewaren 1	NJ	104	104	104	104
PSEG Fossil	Sewaren 2	NJ	118	118	118	118
PSEG Fossil	Sewaren 3	NJ	107	107	107	107
PSEG Fossil	Sewaren 4	NJ	124	124	124	124
PSEG Fossil	Sewaren 6[7]	NJ	105	105	105	105
PSE&G	Solar 4 All Units	NJ	78	78	78	78
PSEG Fossil	Yards Creek 1[5]	NJ	70	70	0	0
PSEG Fossil	Yards Creek 2	NJ	70	70	0	0
PSEG Fossil	Yards Creek 3	NJ	60	60	0	0
PJM 5004/5005						
PSEG Nuclear	Peach Bottom 2[6]	PA	561	561	561	561
PSEG Nuclear	Peach Bottom 3	PA	561	561	561	561
Total PJM Capacity			**11,272**	**11,550**	**11,072**	**11,350**
Total Northeast Region Capacity			**13,307**	**13,462**	**12,926**	**13,080**

Source: PSEG.

Notes:

[1] PSEG Fossil has a 22.5% interest in the Conemaugh coal-fired units.

[2] PSEG Global has a 4% interest in the Conemaugh Hydroelectric facility.

[3] PSEG Fossil has a 22.84% ownership interest in the Keystone facility.

[4] PSEG Nuclear has a 57.41% interest in the Salem Nuclear facility.

[5] PSEG Fossil has a 50% interest in the Yards Creek facility. Yards Creek is operated by Jersey Central Power & Light, and thus is controlled by JCP&L in the analysis.

[6] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear facility.

[7] Unit retired on 06/01/2015

[8] Unit retired on 08/31/2014

[9] Unit retired on 07/31/2015

[10] Unit retired on 06/30/2014

Scenario 1 PSEG 2016 MBR for ISONE

	PSA		WMSA							
			Winter		Spring		Summer		Fall	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result
ISO New England	8,715	Pass	5.4	Pass	5.2	Pass	6.5	Pass	6.0	Pass
Connecticut	3,388	Pass	11.8	Pass	11.3	Pass	14.3	Pass	13.3	Pass
Southwest Connecticut	1,701	Pass	16.4	Pass	15.7	Pass	14.9	Pass	13.0	Pass

Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **ISONE**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	16	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	190	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	30,892	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	16	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,358	Calculated
I	Study Area Reserve Requirement	2,510	Gendata
J	Amount of Line I Attributable to Seller, if any	3	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	16,073	
	Load		
L	Balancing Area Annual Peak Load	24,054	Loads
M	Average Daily Peak Native Load in Peak Month	17,708	Loads
N	Amount of Line M Attributable to Seller, if any	10	SellerLoads
O	Wholesale Load (L-M)	6,346	
P	Net Uncommitted Supply (K-O)	9,728	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,012	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	4,548	
	% of SIL for Seller's imported capacity →	0.04	
	% of SIL for Other's imported capacity →	0.96	
	SIL Value →	4548	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **CT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	843	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	102	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	7,524	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	2,948	Calculated
I	Study Area Reserve Requirement	689	Gendata
J	Amount of Line I Attributable to Seller, if any	10	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	5,674	
	Load		
L	Balancing Area Annual Peak Load	6,419	Loads
M	Average Daily Peak Native Load in Peak Month	5,054	Loads
N	Amount of Line M Attributable to Seller, if any	14	SellerLoads
O	Wholesale Load (L-M)	1,365	
P	Net Uncommitted Supply (K-O)	4,309	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	920	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	3,050	
	% of SIL for Seller's imported capacity →	0.03	
	% of SIL for Other's imported capacity →	0.97	
	SIL Value →	3050	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **SWCT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	400	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	98	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	2,090	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	3,102	Calculated
I	Study Area Reserve Requirement	205	Gendata
J	Amount of Line I Attributable to Seller, if any	0	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	2,985	
	Load		
L	Balancing Area Annual Peak Load	3,286	Loads
M	Average Daily Peak Native Load in Peak Month	2,500	Loads
N	Amount of Line M Attributable to Seller, if any	0	SellerLoads
O	Wholesale Load (L-M)	786	
P	Net Uncommitted Supply (K-O)	2,199	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	498	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	3,200	
	% of SIL for Seller's imported capacity →	0.03	
	% of SIL for Other's imported capacity →	0.97	
	SIL Value →	3200	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II – Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **ISONE**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	860	852	843	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	12	16	16	16	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	29	87	7	79	SellerGendata
E	Uncommitted Capacity Imports	222	188	177	188	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	16,956	14,847	17,687	15,178	Loads
G	Amount of Line F Attributable to Seller, if any	113	102	39	5	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	16,843	14,745	17,648	15,173	F - G
I	Study Area Reserve Requirement	2,530	2,510	2,510	2,510	Gendata
J	Amount of Line I Attributable to Seller, if any	16	20	10	3	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,514	2,490	2,500	2,507	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	32,149	30,892	29,634	30,892	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	12	16	16	16	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,097	3,148	229	2,881	Gendata; Row D
P	Uncommitted Capacity Imports	4,326	4,360	4,371	4,360	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	16,033	14,885	13,644	14,707	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	911	815	948	935	
S	Total Seasonal Uncommitted Capacity (Q+R)	16,944	15,700	14,592	15,642	
T	**Applicant's Market Share (R÷S)**	5.4%	5.2%	6.5%	6.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	4,548	4,548	4,548	4,548	
V	SIL Value	4,548	4,548	4,548	4,548	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II – Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **CT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	860	852	843	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	29	87	7	79	SellerGendata
E	Uncommitted Capacity Imports	106	93	93	94	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	4,207	3,642	4,503	3,772	Loads
G	Amount of Line F Attributable to Seller, if any	113	102	39	5	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	4,093	3,540	4,464	3,766	F - G
I	Study Area Reserve Requirement	683	683	689	683	Gendata
J	Amount of Line I Attributable to Seller, if any	21	22	10	3	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	662	661	679	680	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	8,048	7,786	7,524	7,786	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	275	793	58	726	Gendata; Row D
P	Uncommitted Capacity Imports	2,944	2,957	2,957	2,956	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	5,963	5,749	5,279	5,570	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	802	734	881	857	
S	Total Seasonal Uncommitted Capacity (Q+R)	6,765	6,482	6,160	6,427	
T	**Applicant's Market Share** (R÷S)	11.8%	11.3%	14.3%	13.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	3,050	3,050	3,050	3,050	
V	SIL Value	3,050	3,050	3,050	3,050	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II – Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **SWCT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	407	404	400	404	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	14	41	3	38	SellerGendata
E	Uncommitted Capacity Imports	86	68	91	101	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	2,048	1,758	2,178	1,766	Loads
G	Amount of Line F Attributable to Seller, if any	0	0	0	0	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	2,048	1,758	2,178	1,766	F - G
I	Study Area Reserve Requirement	209	206	205	206	Gendata
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	209	206	205	206	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	2,321	2,206	2,090	2,206	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	79	225	16	206	Gendata; Row D
P	Uncommitted Capacity Imports	2,454	2,302	3,109	3,089	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	2,439	2,318	2,799	3,116	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	479	430	488	467	
S	Total Seasonal Uncommitted Capacity (Q+R)	2,918	2,748	3,287	3,583	
T	**Applicant's Market Share** (R÷S)	16.4%	15.7%	14.9%	13.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	2,540	2,370	3,200	3,190	
V	SIL Value	2,540	2,370	3,200	3,190	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **NYISO**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	757	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	265	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	585	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	42,506	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,265	Calculated
I	Study Area Reserve Requirement	2,620	Gendata
J	Amount of Line I Attributable to Seller, if any	0	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	22,514	
	Load		
L	Balancing Area Annual Peak Load	31,138	Loads
M	Average Daily Peak Native Load in Peak Month	25,244	Loads
N	Amount of Line M Attributable to Seller, if any	0	SellerLoads
O	Wholesale Load (L-M)	5,894	
P	Net Uncommitted Supply (K-O)	16,620	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,607	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,850	
	% of SIL for Seller's imported capacity →	0.09	
	% of SIL for Other's imported capacity →	0.91	
	SIL Value →	6850	
	Do Total Imports exceed the SIL Value? →	No	

SI-SSA-0010-5921

Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **NYISO**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	870	814	757	814	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	265	265	265	265	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	71	115	13	92	SellerGendata
E	Uncommitted Capacity Imports	731	600	582	640	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	21,006	18,974	23,056	19,579	Loads
G	Amount of Line F Attributable to Seller, if any	0	0	0	0	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	21,006	18,974	23,056	19,579	F - G
I	Study Area Reserve Requirement	2,620	2,620	2,620	2,620	Gendata
J	Amount of Line I Attributable to Seller, if any	0	0	0	0	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,620	2,620	2,620	2,620	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	40,162	41,334	42,506	41,334	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,277	5,820	726	4,652	Gendata; Row D
P	Uncommitted Capacity Imports	6,904	6,924	6,268	7,055	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	20,162	20,843	22,372	21,538	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	1,795	1,564	1,591	1,627	
S	Total Seasonal Uncommitted Capacity (Q+R)	21,958	22,407	23,963	23,166	
T	**Applicant's Market Share** (R÷S)	8.2%	7.0%	6.6%	7.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,635	7,524	6,850	7,695	
V	SIL Value	7,635	7,524	6,850	7,695	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Scenario 1 PSEG 2016 MBR for PJM										
	PSA		WMSA							
			Winter		Spring		Summer		Fall	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result	Share (%)	Result
PJM Interconnection	35,891	Pass	9.5	Pass	7.7	Pass	8.3	Pass	8.3	Pass
PJM East	3,572	Pass	32.7	Fail	27.0	Fail	32.9	Fail	29.7	Fail
PJM East of 5004/05	5,389	Pass	24.3	Fail	20.7	Fail	23.7	Fail	23.1	Fail
PJM East of AP South	7,602	Pass	18.5	Pass	15.5	Pass	18.8	Pass	17.0	Pass

SI-SSA-0010-5923

Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	9,844	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	195	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	1,943	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	152	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	175,931	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	1,943	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	195	Row B; Table2Data
H	Uncommitted Capacity Imports	7,448	Calculated
I	Study Area Reserve Requirement	8,187	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	63,588	
	Load		
L	Balancing Area Annual Peak Load	143,633	Loads
M	Average Daily Peak Native Load in Peak Month	121,600	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	22,034	
P	Net Uncommitted Supply (K-O)	41,555	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,664	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	7,600	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	7600	
	Do Total Imports exceed the SIL Value? →	No	

SI-SSA-0010-5924

Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	14	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	88	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	26,628	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	14	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,449	Calculated
I	Study Area Reserve Requirement	1,724	Gendata
J	Amount of Line I Attributable to Seller, if any	176	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	15,220	
	Load		
L	Balancing Area Annual Peak Load	30,240	Loads
M	Average Daily Peak Native Load in Peak Month	24,093	Loads
N	Amount of Line M Attributable to Seller, if any	2,269	SellerLoads
O	Wholesale Load (L-M)	6,148	
P	Net Uncommitted Supply (K-O)	9,072	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,500	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,537	
	% of SIL for Seller's imported capacity →	0.01	
	% of SIL for Other's imported capacity →	0.99	
	SIL Value →	6537	
	Do Total Imports exceed the SIL Value? →	No	

SI-SSA-0010-5925

Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	107	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	51,729	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,212	Calculated
I	Study Area Reserve Requirement	2,975	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	20,577	
	Load		
L	Balancing Area Annual Peak Load	52,190	Loads
M	Average Daily Peak Native Load in Peak Month	42,368	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	9,822	
P	Net Uncommitted Supply (K-O)	10,754	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,365	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,319	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	6319	
	Do Total Imports exceed the SIL Value? →	No	

SI-SSA-0010-5926

Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	85	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	75,381	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,370	Calculated
I	Study Area Reserve Requirement	4,032	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	25,567	
	Load		
L	Balancing Area Annual Peak Load	70,729	Loads
M	Average Daily Peak Native Load in Peak Month	58,108	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	12,621	
P	Net Uncommitted Supply (K-O)	12,946	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,344	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	4,455	
	% of SIL for Seller's imported capacity →	0.02	
	% of SIL for Other's imported capacity →	0.98	
	SIL Value →	4455	
	Do Total Imports exceed the SIL Value? →	No	

SI-SSA-0010-5927

Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	11,339	10,592	9,844	10,592	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	195	195	195	195	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	1,643	1,944	1,943	1,944	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	491	1,461	225	1,374	SellerGendata
E	Uncommitted Capacity Imports	214	204	138	117	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	108,842	91,954	109,399	91,992	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	106,988	90,430	107,540	90,648	F - G
I	Study Area Reserve Requirement	7,474	6,516	7,991	6,470	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	7,335	6,385	7,817	6,352	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	181,889	178,911	175,931	178,911	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	1,643	1,944	1,943	1,944	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	195	195	195	195	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	7,868	24,681	4,028	23,215	Gendata; Row D
P	Uncommitted Capacity Imports	11,783	12,069	7,462	6,950	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	72,929	71,233	65,756	67,394	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,622	5,931	5,975	6,123	
S	Total Seasonal Uncommitted Capacity (Q+R)	80,550	77,164	71,731	73,518	
T	**Applicant's Market Share** (R÷S)	9.5%	7.7%	8.3%	8.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	11,997	12,273	7,600	7,067	
V	SIL Value	11,997	12,273	7,600	7,067	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	22	14	14	14	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	121	72	78	68	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	18,303	15,919	20,901	16,346	Loads
G	Amount of Line F Attributable to Seller, if any	1,749	1,434	1,764	1,268	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	16,553	14,485	19,137	15,078	F - G
I	Study Area Reserve Requirement	1,258	1,168	1,659	1,211	Gendata
J	Amount of Line I Attributable to Seller, if any	130	122	165	110	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	1,128	1,046	1,494	1,101	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	26,328	26,478	26,628	26,478	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	22	14	14	14	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,139	3,653	610	3,436	Gendata; Row D
P	Uncommitted Capacity Imports	7,381	8,758	6,459	7,791	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	14,911	16,065	11,860	14,667	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,230	5,954	5,826	6,199	
S	Total Seasonal Uncommitted Capacity (Q+R)	22,141	22,019	17,686	20,867	
T	**Applicant's Market Share** (R÷S)	32.7%	27.0%	32.9%	29.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	7,502	8,830	6,537	7,859	
V	SIL Value	7,502	8,830	6,537	7,859	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	162	91	95	69	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	35,188	30,080	37,518	30,214	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	33,334	28,556	35,658	28,871	F - G
I	Study Area Reserve Requirement	2,450	2,184	2,889	2,189	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,311	2,054	2,715	2,071	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	52,220	51,975	51,729	51,975	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	2,259	7,170	1,184	6,744	Gendata; Row D
P	Uncommitted Capacity Imports	7,942	8,202	6,224	6,034	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	22,294	22,424	18,423	20,350	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,144	5,861	5,725	6,103	
S	Total Seasonal Uncommitted Capacity (Q+R)	29,438	28,286	24,148	26,453	
T	**Applicant's Market Share** (R÷S)	24.3%	20.7%	23.7%	23.1%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	8,104	8,293	6,319	6,103	
V	SIL Value	8,104	8,293	6,319	6,103	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	187	115	77	81	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	48,658	41,074	51,437	41,155	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	46,804	39,551	49,577	39,811	F - G
I	Study Area Reserve Requirement	3,496	3,025	3,935	2,991	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	3,358	2,895	3,762	2,873	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	77,314	76,348	75,381	76,348	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,344	10,532	1,726	9,907	Gendata; Row D
P	Uncommitted Capacity Imports	7,710	8,741	4,378	5,987	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	31,554	32,139	24,722	29,772	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,169	5,885	5,707	6,115	
S	Total Seasonal Uncommitted Capacity (Q+R)	38,723	38,024	30,429	35,886	
T	**Applicant's Market Share** (R÷S)	18.5%	15.5%	18.8%	17.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,897	8,856	4,455	6,068	
V	SIL Value	7,897	8,856	4,455	6,068	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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DATA AND ASSUMPTIONS FOR ECONOMISTS INCORPORATED'S DELIVERED PRICE TEST STUDY FOR PSEG

This exhibit describes data and assumptions used in the delivered price test study ("study") carried out by Economists Incorporated for PSEG. Because the data are voluminous, we provide them in electronic workpapers. In those workpapers, the Files.xlsx spreadsheet provides a brief description of the organization of the data files.

This Exhibit has six sections. Section I discusses the study's representative periods. Section II discusses the geographic region and balancing authority areas. Section III discusses generation resources, including adjustments to generating capacity for seasons, maintenance, water availability, and long-term contracts. Section IV discusses transmission, including transmission pricing and losses. Section V discusses market prices. Section VI discusses the load data.

I. Periods

The study calculates market shares and concentration indexes for electric energy for ten representative periods during the year. The year is divided into three seasons (spring/fall, summer and winter). Spring/fall and winter seasons are divided into three periods based on days of the week, times of day and load levels. Summer is divided into four periods based on days of the week, times of day and load levels. Each calculation of market shares and concentration indexes reflects average conditions (e.g., average loads) during one of the resulting ten periods during the year (e.g., Summer Low Peak).

The study places each of the periods in each season into three condition categories: off-peak, low peak, and spike. Transmission pricing (see Section

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IV.B below) and plant availability (see Section III.A.2 below) vary among these three categories.

Table I-1 summarizes the ten periods for the destination markets.

Table I-1– Definition of Ten Periods for Destination Market

Number	*Season*	*Time*	*Condition*	*Hours*	*Description**
1	Spring/Fall	Top 10%	Spike	203	Top 10% of peak hours
2	Spring/Fall	Peak	Peak	1829	Remaining peak hours
3	Spring/Fall	Off-peak	Off-Peak	2360	Off-peak hours
4	Summer	Top 1%	Spike	11	Top 1% of peak hours
5	Summer	Top 10%	Spike	106	Top 10% of peak hours
6	Summer	Peak	Peak	950	Remaining peak hours
7	Summer	Off-peak	Off-Peak	1152	Off-peak hours
8	Winter	Top 10%	Spike	101	Top 10% of peak hours
9	Winter	Peak	Peak	907	Remaining peak hours
10	Winter	Off-peak	Off-Peak	1152	Off-peak Hours

Note: *Peak hours include hours ending 8 a.m. through 11 p.m. Eastern Time weekdays, excluding six major holidays. Off-peak hours = Hours ending 12 a.m. through 7 a.m. on weekdays and all weekend and holiday hours.

The Off-peak periods are all NERC holidays and weekend hours plus weekdays from the hour ending at midnight EPT until the hour ending at 0700.[1] The Off-peak periods have off-peak transmission pricing and plant availability.

In order to define the Top 1% and Top 10% periods for a given season, we removed all Off-peak hours from that season. We then ranked the remaining (peak) hours based on load levels in the destination market by season. We then defined as the Top 1% as the 1 percent of these remaining hours in which loads in the destination market were highest and the Top 10% as the highest 10 percent of peak hours based on load levels. These periods have spike transmission pricing and plant availability.

[1] Major holidays are New Year's, Memorial Day, 4th of July, Labor Day, Thanksgiving and Christmas. Major holidays are included in the Weekend period.

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The Peak periods are weekdays from the hour ending at 0800 until the hour ending at 2300 EPT, excluding hours in the Top 10% periods and major holidays. The Low Peak period has on-peak transmission pricing and plant availability.

II. Geographic Coverage and Market Areas

The study includes market areas that correspond to the balancing authority areas used by the North American Electric Reliability Council (NERC), and PJM submarkets as defined by FERC. Table II-1 lists these market areas and their abbreviations. There are two study destination markets, PJM East and PJM East of 5004/5005.

Table II-1– List of Eastern Market Areas and Study Destinations

Abbreviation	*Full Name*	*Study Destination*
PJME	PJM East	Yes
PJM50	PJM East of 5004/5005	Yes
PJMS	PJM East of AP South	
PJM	PJM	
NYISO	New York ISO	

III. Generation

A. Generation Capacity and Ownership

The study includes generating units located in the areas that are (1) connected to the power grid, (2) not exclusively used for self-generation, and (3) either in a plant used primarily for electric generation or a Qualifying Facility.

1. Generating Unit Data

The study uses data for summer and winter capability at the unit level reported in the Energy Velocity (EV) database available from Ventyx. The units include all

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units with a status of operating, standby, cold standby, restart, mothballed, testing, or under construction that went online before November 30, 2015 and with a retirement date after November 30, 2015. We exclude generation units that are less than 5 MW unless they are owned by PSEG.

2. Ownership

The study uses relies on Ventyx determination of plant and unit ownership. When Ventyx reports a holding company, the ownership is assigned to the holding company. For PSEG generation, the study relies upon Appendix B data from market-based rate filings and updates from the companies to determine plant ownership and seasonal capability. Operational control of PSEG units is consistent with the methodology used for market-based rates.

3. Seasonal variation in capability

The study uses seasonal capability data from EV. Spring/fall capacities are the average of summer and winter capacities.

4. Adjustments to Generating Capability

The generating capability figures used for each period are obtained by multiplying the seasonal capabilities by an availability factor, which is based on the period, unit location, and NERC General Availability Data Systems (GADS) category of the unit. The GADS database gives national average operating information for generating units by unit type and size. For example, it gives data for coal-fired steam units with capacities between 300 MW and 399 MW.

For each period and each generating unit, the availability factor adjusts for the following.

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a) Unplanned outage rates by GADS category

For a given GADS category, the study assumes that unplanned (forced) outage rates (as a share of generating capability available after allowing for planned outages) are constant across seasons and generating units throughout the Region, regardless of owner. Based on GADS data for 2007 through 2011, the study calculates an equivalent forced outage rate (EIFOR), which measures the share of generating capability in a GADS category that is not available because of forced outages. The computation is EIFOR = (FOH)/AH, where FOH is number of forced outage hours and AH is total hours available for generation after planned outages (but before forced outages).[2]

b) Planned outage rates by GADS category and season

With four exceptions (hydro, pumped storage, wind, and solar units), the study assumes that the planned outage rate is constant for all generating units for a given GADS category and season. For a given GADS category, the share of hours of generating capability that is not available as a result of planned outages is computed as (POH + POEH)/PH; where PH are the period hours, POH are the hours not available because of planned outages, and POEH are the hours not available because of planned outage extensions

The study assumes that balancing authority areas are both summer and winter peaking. Therefore, the study assumes that all planned outages for thermal units occur during spring/fall.

[2] EIFOR differs slightly from the EFOR provided in the GADS data. EIFOR provides a better measure of a forced outage rate for peaking units that are operated a small percentage of the year.

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c) Variation in hydro availability across seasons and periods

In general, utilities use hydro facilities to generate energy during the hours when energy prices are highest, subject to constraints imposed by availability of water and reservoir capacity. In order to incorporate these constraints, the study proceeds in the following manner.

First, the study uses EIA Form 923 monthly production data for the period 2011 to 2015 to compute average hourly hydro generation by season. Average hourly generation is then divided by hydro capability to give an average hourly hydro operating rate by season.

Second, depending upon the level of the hydro operating rate for a given season, the study calculates availability factors for the spike, low peak and off-peak periods. When the historical seasonal operating rate is below 30 percent, the availability factor for each period in the season is set equal to the operating rate; the 30 percent figure is an assumed “run of river” constraint. The study assumes that prospectively the maximum operating rate is 90 percent; this is the assumed “maximum rate” constraint. When the historical seasonal operating rate is above 90 percent, the availability factor for each period is set to 90 percent.

When the seasonal operating rate is above the run of river constraint and below the maximum rate, we reason that the hydro generator owner would be likely to produce a higher level of energy during spike hours, when energy prices are highest, than during low peak hours, and that the owner would be likely to produce a higher level during low peak than during off-peak hours.

Based on this reasoning, when the seasonal operating rate is between the run of river constraint and the maximum rate, as is the case for each of the three

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seasons, the study uses a spike availability factor of 90 percent, which is the assumed maximum operating rate, and off-peak availability factor of 30 percent, which is the assumed run-of-river constraint, and a calculated availability factor for the peak periods, as described below.

The seasonal peak availability factor is calculated using actual total seasonal hydro generation. The study then computes the hydro generation during all spike and off-peak hours, assuming the generation rates implied by the spike and off-peak derate factors computed in the manner described above. The study then calculates total peak hydro generation as the difference between total seasonal hydro generation and the sum of hydro generation during all spike and off-peak hours. The seasonal low peak availability factor is computed as total low peak hydro generation divided first by the number of hours in the off-peak period and then by hydro generating capacity.

d) Variation in pumped storage availability across seasons and periods

We assume that pumped storage units have 90 percent availability during Top 1% and Top 10% periods, 50 percent availability during Low Peak periods, and no availability during off-peak periods.

e) Wind availability

For each area, we calculate average operating rates from 2011 to 2015 by season from EIA-923 data. The average operating rates are the availability factors.

f) Solar availability

Availability for solar power is also calculated based on average operating rates from 2011 through 2015 reported in EIA-923. There is little solar power during

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off-peak periods because of darkness. Accordingly, solar availability is weighted to on-peak periods.

B. Variable Costs of Generation

The study uses variable costs of generation that include fuel costs, sulfur dioxide and nitrogen oxide emissions costs, and variable operations and maintenance (VOM) costs. The study calculates fuel costs from unit heat rates and Platts' Gas Daily spot prices at the unit's reported natural gas hub by Energy Velocity, #2 Diesel, Low-Sulfur – Industrial for the East Coast, and Residual Fuel Oil sales to end users for the East Coast for the test period. Natural gas prices vary by hub, but were $2.67 per mmBtu at TETCO M3, the hub with the largest reported capacity in the study. Fuel costs for other fuels are based upon the average fuel costs reported in the EV data for each fuel type. Emissions prices during the test year were $2 per ton for SO2 year-round and $300 per ton for NOx in the summer season. CO_2 costs for units located in Regional Greenhouse Gas Initiative (RGGI) states are $5.21/ton, which is based upon RGGI Auction results in Dec 2014. Units in Montgomery County, MD have an additional $5/ton carbon tax on CO_2 emissions. VOM costs are from the EV database.

C. Long-term Contracts

We reviewed Appendix B data from market-based rate filings, FERC Form 1 filings, and Electric Quarterly Report ("EQR") data to obtain data on long-term contracts. Where the market-based rate filing indicates a change of operational control, we include a contract transferring control to the buyer. We leave the generation unit in the BAA where it is physically interconnected to the transmission system. When the buyer is a load-serving entity in another BAA, we give a priority firm transmission path to the BAA with the load.

Long-term contracts that expire prior to January 1, 2015 are not included in the study. Long-term contracts that expire between January 1, 2015 and July 31,

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2015 are included only in the seasons for which they are in effect. Contracts that expire after August 31, 2015 are included in the study.

IV. Transmission

A. Transmission Network

The study incorporates a contract path transmission network for modeling purposes. Transmission pricing between balancing authority areas is represented by a traditional contract path transmission network in which the direct physical connections between balancing authority areas are also the individually priced links from which contract paths are constructed.

B. Transmission and Ancillary Services Pricing and Losses

As specified by the Commission's Appendix A, the study generally uses ceiling prices for transmission service from Schedules 1, 2 and 8 of the utility's *pro forma* open-access transmission tariff. Transmission providers may require transmission customers to purchase ancillary services under Schedule 1 (scheduling, system control and dispatch) and Schedule 2 (reactive supply and voltage control). Schedule 8 gives the rates for non-firm point-to-point transmission service. The study uses transmission prices from tariffs.

When we have tariffs available, we calculate rates for off-peak, peak and spike categories. Because of discounting and the nature of baseload purchases, off-peak rates are often lower than peak rates.[3] We use two steps to determine off-peak rates. Step 1: When a utility posts off-peak hourly rates, we use the posted rates. Step 2: When a utility does not post off-peak hourly rates, we calculate an hourly off-peak rate based on other tariff information. To calculate hourly off-

[3] For transactions longer than one hour, the *pro forma* tariff caps the amount that the purchaser pays per day by the daily rate, and the amount that the purchaser pays per week by the weekly rate.

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peak rates, we divide the weekly rate by 168, the number of hours in a week. When tariffs specify fees on a per transaction basis, we divide them by 25 to put them on a per MW basis.

We use similar steps to determine peak rates. Step 1: When a utility posts maximum hourly rates in its tariff, we use the maximum tariff rates. Step 2: When a utility does not post off-peak hourly rates, we calculate a peak rate based on other tariff information. To calculate hourly peak rates, we divide the weekly rate by 80—the "Appalachian" method. When tariffs specify fees on a per transaction basis, we divide them by 25 to put them on a per MW basis.

For spike periods, we use ceiling hourly rates from tariffs, when available. Otherwise, we use the Appalachian method.

Whenever practical, the study uses loss rates from tariffs. When these methods did not provide a loss rate for a particular utility, the study assumes that losses are three percent per utility.[4] The study assumes that transmission customers pay losses in-kind. That is, if area A exports 100 MW to area B and the losses are 3 percent, only 97 MW arrive at area B.

For areas where tariffs are not available, rates and losses are the average by period for all the reporting areas.

C. Transfer Capability and SILs

The geographic market includes only PJM and NYISO. The SILs for PJM East and PJM East of 5004/5005 comes from the 2015 Simultaneous Import Limit

[4] Losses of 3 percent are representative of the industry. See, FERC Open Access NOPR, *FERC Stats & Regs*, ¶32,514 at 33,150 (1995).

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Study filed by PJM on September 2, 2016.[5] The total imports into the destination markets may be less than the actual ability to import into the destination because not all the generation capability owned or controlled by load-serving entities within the destination markets studied in PJM have been identified in the data.

V. Market Prices

The study used December 2014-November 2015 real-time hourly prices from the RTO LMP for PJM East and PJM East of 5004/5005. Table V-1 shows the PJM East of 5004/5005 market prices in each of the ten periods, and Table V-2 shows the PJM East market prices.

Table V-1 – PJM East of 5004/5005 Market Prices ($/MWh)

Time	*Spring/Fall*	*Summer*	*Winter*
Top 1%	-----	$148.44	-----
Top 10%	$62.03	$64.59	$185.57
Low Peak	$35.73	$35.56	$47.55
Off-Peak	$29.46	$24.88	$50.16

Table V-2 – PJM East Market Prices ($/MWh)

Time	*Spring/Fall*	*Summer*	*Winter*
Top 1%	-----	$145.63	-----
Top 10%	$57.82	$63.88	$193.51
Low Peak	$32.73	$29.67	$50.59
Off-Peak	$26.67	$21.25	$50.94

[5] PJM Interconnection, L.L.C., *Informational Filing of 2015 Simultaneous Import Limit Study Report for PJM Region*, Docket No. AD1-2-007, September 2, 2016, Accession No. 20160902-5155.

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VI. Load and Contract Obligations for AEC Calculations

Load data come from PJM for PJM and from Energy Velocity for the other supply areas.

To compute load requirements for market participants in New York and PJM, we apportion the total load in each market area in New York and PJM to all suppliers in proportion to their respective generation capacities. We assumed 70 percent of load is committed for a year or longer and the remaining 30 percent is contracted for shorter periods.[6] To account for their greater load obligations, we assume that Dominion has 100 percent responsibility for its allocation of load and that AEP has 90 percent of its allocation as opposed to the standard 70 percent.

[6] This is a reasonable estimate for the long-term load coverage since this number is generally between 60 and 80 percent for most generation suppliers.

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Technical Appendix:

Methods Used to Compute Concentration

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December 2016

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This Exhibit describes the methods used to calculate market shares and concentration in destination markets.

Allocation of scarce transmission capability is accomplished using linear and nonlinear programs that model generation dispatch and the contract path transmission system. This Exhibit provides an overview of the structure of the programs and presents the equations.

Overview of Linear Program

The linear program models control areas as nodes in a transmission system. Each node has a demand for and a supply of electric energy. The supply is based on the generators at the node and potential deliveries to the node via transmission links from other control areas. The linear program allows for net import and export limits to and from an individual control area. Given generation capability and costs and transmission capability and costs, the linear program finds the least-cost solution that satisfies the specified loads. Costs are defined as dispatch (generation) costs plus transmission costs including losses plus the default cost for "unserved" load. For each solution, the linear program determines the quantities produced in, exported from, and imported into each control area.

The Mathematical Equations

The linear program to be solved is given below:

Minimize Total Cost: $Cost = GC + TC + UC$

Subject to:

(1) Generation: $TG_a = \sum_{u}^{u \in a} G_{a,u}$ for each area *a*;

(2) Imports: $YI_a = \sum_{b}^{a,b \in network} (1 - h_{b,a}) T_{b,a}$ for each area *a*;

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(3)	Exports:	$YE_a = \sum_{b}^{a,b \in network} T_{a,b}$	for each area *a*;
(4)	Net Imports:	$Y_a = YI_a - YE_a$	for each area *a*;
(5)	Supply/Demand Balance:	$TG_a + Y_a + U_a = D_a$	for each area *a*;
(6)	Generation Cost:	$GC = \sum_{a} \sum_{u}^{u \in a} d_{a,u} G_{a,u}$	for each area *a*;
(7)	Transmission Cost:	$TC = \sum_{a,b}^{a,b \in network} r_{a,b} T_{a,b}$	for each path *a* to *b*;
(8)	Unfilled Demand Cost:	$UC = \sum_{a} pU_a$	for each area *a*;
(9)	Generation Limits:	$g\min_{a,u} \le G_{a,u} \le g\max_{a,u}$	for each unit *u* in each area *a*;
(10)	Transmission Limits:	$t\min_{a,b} \le T_{a,b} \le t\max_{a,b}$	for each link *a* to *b* in the transmission network; and
(11)	Net Import Limits	$Y\min_{a} \le Y_a \le Y\max_{a}$	for each area *a*;

where:

a,b	are subscripts for control/transmission areas;
Cost	is total system cost;
$d_{a,u}$	is the dispatch cost of unit *u* in area *a*;
D_a	is demand for power in area *a*;
$G_{a,u}$	is generation output of unit *u* in area *a*;
GC	is total system generation cost;
$G\max_{a,u}$	is the maximum output of unit *u* in area *a*;
$G\min_{a,u}$	is the minimum output of unit *u* in area *a*;
$h_{b,a}$	is the fraction of power lost to resistance from moving power from area *b* to area *a*;
N	is a subscript to identify simultaneous transmission constraint *n*;
P	is the default price;
$r_{a,b}$	is the transmission rate from area *a* to area *b*;

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$T_{a,b}$	is the power flow from area *a* to area *b*;
TC	is total system transportation expenses;
TG_a	is total generation output in area *a*;
$t\max_{a,b}$	is the maximum power flow from area *a* to area *b*;
$t\min_{a,b}$	is the minimum power flow from area *a* to area *b*;
U	is a subscript to identify units in an area;
U_a	is the amount of demand in area *a* not met by generation or imports
UC	is total system cost of not meeting demand;
Y_a	is net imports into area *a*;
YE_a	is total exports from area *a*; and
YI_a	is total imports into area *a*;
$Y\min_a$	is minimum net imports in area *a;*
$Y\max_a$	is maximum net imports in area *a.*

This linear program is solved using the BDMLP solver in GAMS. In order to calculate concentration for different destinations, seasons, and periods, the PASS GAMS program loops through the destinations, seasons, and periods with calls to Solvers to solve the linear programs. Loads, unit availability and transmission availability are adjusted for each season-period combination.

Calculating Concentration

Transmission allocation is accomplished in four steps. In the first step the linear program finds the net-back prices in all control areas given a price at the destination control area equal to 105 percent of the pre-merger price. Suppose the pre-merger price at the destination, control area A, is $20/MWh. Then all generation capability with a dispatch cost of $21/MWh or less in the destination area would be included in the market because $21 is 105 percent of $20. If transmission cost (including losses) is $5/MWh from control area B to A, then the net-back price at B would be $16/MWh, which is the $21/MWh less the $5/MWh transmission cost between B and A. Then, all generation capability at B with dispatch costs equal to or less than $16/MWh would be included in the market if there were no transmission constraints. Calculation of net-back prices is

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accomplished by setting the default price, *p*, equal to 105 percent of the pre-merger price at the destination, setting load at the destination to a high number and loads elsewhere to zero, setting transmission limits high enough so that the transmission system is not constrained, and setting a limited amount of generation in each area with a zero dispatch cost. The shadow prices produced by the linear program will be *p* at the destination and the relevant net-back prices in other areas.

In the second step, one calculates Economic Capacity (EC) and Available Economic Capacity (AEC) in each area. These values are then used to limit generation capability. The ownership shares of AEC and EC are calculated for each node in the system.

In the third step, the linear program determines the amount of energy that can be imported into an area given available EC (or AEC) and limits on transmission capacity. This is accomplished by limiting generation in each area to the capacity amount (EC or AEC), giving generation outside the destination market a lower cost than generation inside the destination market, and minimizing cost to serve a large load at the destination market. The amount of generation supplied to the destination is the maximum that can be imported into the destination market.

In the fourth step, transmission is allocated by the following non-linear program:

Minimize Loss: $$Loss = \sum_{\alpha}\left(\frac{C_{\alpha}^{2}}{Y_{Dest}s_{\alpha}} - 2C_{\alpha}\right)$$

Subject to:

(1) Pre Shares: $$s_{\alpha} = \frac{C\max_{\alpha}}{\sum_{\beta} C\max_{\beta}}$$ for each area α;

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(2)	Allocated Shares:	$A_\alpha = \frac{C_\alpha}{Y_{Dest}}$	for each area α;
(3)	Imports:	$YI_a = \sum_b^{a,b \in network} (1 - h_{b,a}) T_{b,a}$	for each area *a*;
(4)	Exports:	$YE_a = \sum_b^{a,b \in network} T_{a,b}$	for each area *a*;
(5)	Net Imports:	$Y_a = YI_a - YE_a$	for each area *a*;
(6)	Supply/Demand Balance:	$C_a + Y_a + U_a = D_a$	for each area *a*;
(7)	Capacity Limits:	$c\min_a \le C_a \le C\max_a$	for each area *a*;
(8)	Transmission Limits:	$t\min_{a,b} \le T_{a,b} \le t\max_{a,b}$	for each link *a* to *b* in the transmission network; and
(9)	Max Import Limit	Y_{Dest} = Maximum imports from step 3;	

where:

a,b	are subscripts for control/transmission areas;
α,β	are subscripts for control/transmission areas other than the destination market;
s_α	Is area α's share of capacity outside of the destination;
A_α	is area α's share of allocated capacity outside of the destination;
Loss	is the loss function to be minimized.

The loss function is derived from the weighted squared-errors between the pre-allocation shares and the post-allocation shares, where Y_{Dest}/s_α are the weights. For each source control area, the weighted squared-error is given by:[1]

$$W_\alpha = \frac{Y_{Dest}}{s_\alpha}(A_\alpha - s_\alpha)^2.$$

[1] This exposition ignores the adjustments necessary to give priority to minimum transfer levels from a source area to the destination.

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Accordingly, the sum of the weighted squared-errors gives rise to the loss function, which can be seen by:

$$\begin{aligned} Loss &= \sum_{\alpha} W_{\alpha} \\ &= \sum_{\alpha} \frac{Y_{Dest}}{s_{\alpha}} (A_{\alpha} - s_{\alpha})^2 \\ &= \sum_{\alpha} \frac{Y_{Dest}}{s_{\alpha}} (A_{\alpha}^2 - 2 s_{\alpha} A_{\alpha} + s_{\alpha}^2) \\ &= \sum_{\alpha} \left(\frac{C_{\alpha}^2}{Y_{Dest} s_{\alpha}} - 2 C_{\alpha} \right) + \text{constant}. \end{aligned}$$

The resulting shares from minimizing this loss functions preserve the relative shares of capacity behind any transmission constraint going to the destination. This can be seen from the following LaGrangian equation to be minimized:

$$L = \sum_{i} \left(\frac{C_i^2}{Y_{Dest} s_i} - 2 C_i \right) + \lambda \left(T - \sum_{i} C_i \right),$$

where *T* is the transmission limit affecting control areas *i*. The first order conditions are:

$$\frac{\partial L}{\partial C_i} = \frac{2 C_i}{Y_{Dest} s_i} - 2 - \lambda = 0,$$

which can be rearranged to give:

$$A_i = \frac{C_i}{Y_{Dest}} = \left(\frac{2 + \lambda}{2} \right) s_i,$$

which shows that the allocated market shares of those areas affected by the transmission constraint are proportional to their shares of capacity before the transmission allocation. Moreover, this is the only transmission allocation

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method that maintains the relative shares of capacity behind any binding transmission constraint in the allocation process.

This non-linear program is solved using the COINIPOPT solver in GAMS. The calculated capacities from the nonlinear program above less transmission losses determine the capacities for the market share calculations for sources outside of the destination market. The capacities within the destination market are given full weights.

Market concentration is the HHI, which is the sum of the squared market shares. Mathematically,

$$HHI = \sum_{i=1}^{n} S_i^2,$$

where S_i is the allocated share of firm *i* and *n* is the number of firms in the market. The summary sheets combine all the firms with shares of 0.7 percent or less (other than Applicants) into the "Other" category. The collective share of the Other category does not directly enter the HHI calculation other than the represented capacity as each independent entity enters the HHI calculation. For example, if ten firms with 0.5 percent shares were in the Other category, the HHI contribution of the Other category would be 0.625 (= 10 x .5 x .5 = 10 x .0625) and ***not*** 25.

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Delivered Price Test - PJM50 Market

Available Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$62.03	2,498	24,613	22,116	6,776	Yes	10.1	Yes	1,024	Yes
Spring/Fall	Peak	$35.73	2,927	26,894	23,967	6,776	Yes	10.9	Yes	1,085	Yes
Spring/Fall	Off Peak	$29.46	1,775	18,948	17,173	6,776	Yes	9.4	Yes	1,358	Yes
Summer	Top 1%	$148.44	1,443	22,909	21,466	9,933	Yes	6.3	Yes	1,042	Yes
Summer	Top 10%	$64.59	1,562	21,384	19,822	9,933	Yes	7.3	Yes	1,000	Yes
Summer	Peak	$35.56	2,009	22,352	20,344	9,933	Yes	9.0	Yes	1,055	Yes
Summer	Off Peak	$24.88	2,103	15,701	13,598	9,933	Yes	13.4	Yes	1,772	Yes
Winter	Top 10%	$185.57	1,921	26,153	24,233	6,073	Yes	7.3	Yes	1,008	Yes
Winter	Peak	$47.55	0	19,398	19,398	6,073	Yes	0.0	Yes	1,421	Yes
Winter	Off Peak	$50.16	0	18,024	18,024	6,073	Yes	0.0	Yes	1,592	Yes

Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$62.03	8,704	55,273	46,570	40,893	Yes	15.7	Yes	1,124	Yes
Spring/Fall	Peak	$35.73	7,678	50,521	42,844	28,923	Yes	15.2	Yes	1,084	Yes
Spring/Fall	Off-Peak	$29.46	5,932	41,688	35,756	24,614	Yes	14.2	Yes	1,133	Yes
Summer	Top 1%	$148.44	8,597	59,581	50,984	51,071	No	14.4	Yes	1,126	Yes
Summer	Top 10%	$64.59	8,608	56,301	47,694	47,510	Yes	15.3	Yes	1,112	Yes
Summer	Peak	$35.56	7,389	51,064	43,675	36,423	Yes	14.5	Yes	1,069	Yes
Summer	Off Peak	$24.88	6,266	42,155	35,889	29,051	Yes	14.9	Yes	1,152	Yes
Winter	Top 10%	$185.57	7,022	55,902	48,880	41,770	Yes	12.6	Yes	1,108	Yes
Winter	Peak	$47.55	4,602	43,979	39,377	34,380	Yes	10.5	Yes	1,206	Yes
Winter	Off Peak	$50.16	4,475	39,851	35,376	30,307	Yes	11.2	Yes	1,281	Yes

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Delivered Price Test - PJME Market

Available Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Wholesale Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$57.82	3,225	20,600	17,375	3,806	Yes	15.7	Yes	1,179	Yes
Spring/Fall	Peak	$32.73	2,065	20,408	18,343	3,806	Yes	10.1	Yes	1,228	Yes
Spring/Fall	Off Peak	$26.67	1,276	18,023	16,747	3,806	Yes	7.1	Yes	1,669	Yes
Summer	Top 1%	$145.63	2,279	16,425	14,145	6,174	Yes	13.9	Yes	1,216	Yes
Summer	Top 10%	$63.88	2,402	15,949	13,547	6,174	Yes	15.1	Yes	1,267	Yes
Summer	Peak	$29.67	2,199	15,336	13,136	6,174	Yes	14.3	Yes	1,375	Yes
Summer	Off Peak	$21.25	976	13,909	12,933	6,174	Yes	7.0	Yes	1,979	Yes
Winter	Top 10%	$193.51	2,969	22,743	19,774	2,710	Yes	13.1	Yes	1,199	Yes
Winter	Peak	$50.59	0	15,998	15,998	2,710	Yes	0.0	Yes	1,606	Yes
Winter	Off Peak	$50.94	0	15,146	15,146	2,710	Yes	0.0	Yes	1,967	Yes

Economic Capacity

					Pivotal Supplier Screen			Market Share Screen		Market Concentration Screen	
Season	Time of Day	Market Price	PSEG MW	Market Size	Rival Capacity	Average Load	Pass?	Market Share (%)	Pass?	HHI	Pass?
Spring/Fall	Top 10%	$57.82	8,677	36,450	27,773	22,528	Yes	23.8	No	1,252	Yes
Spring/Fall	Peak	$32.73	6,520	32,603	26,084	15,404	Yes	20.0	Yes	1,171	Yes
Spring/Fall	Off-Peak	$26.67	4,934	28,457	23,523	13,106	Yes	17.3	Yes	1,233	Yes
Summer	Top 1%	$145.63	8,551	36,587	28,036	29,462	No	23.4	No	1,264	Yes
Summer	Top 10%	$63.88	8,553	34,879	26,326	27,143	No	24.5	No	1,270	Yes
Summer	Peak	$29.67	6,853	31,187	24,334	20,217	Yes	22.0	No	1,224	Yes
Summer	Off Peak	$21.25	5,060	26,734	21,674	16,090	Yes	18.9	Yes	1,264	Yes
Winter	Top 10%	$193.51	7,105	35,709	28,603	21,263	Yes	19.9	Yes	1,181	Yes
Winter	Peak	$50.59	4,573	26,985	22,412	17,939	Yes	16.9	Yes	1,268	Yes
Winter	Off Peak	$50.94	4,449	23,450	19,001	15,660	Yes	19.0	Yes	1,461	Yes

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Appendix E
Letters of concurrence regarding the control of certain jointly owned generation facilities

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KEYSTONE-CONEMAUGH PROJECTS

682 Philadelphia Street – 2nd floor
Indiana, Pennsylvania 15701

724-349-1205

MAILING ADDRESS
P.O. BOX 68
INDIANA, PA 15701

GEORGIANNA R. STENGER, ESQ.
ADMINISTRATIVE MANAGER
DIRECT DIAL 724-357-1713

December 1, 2007

Addressed to:

Conemaugh Power LLC
Constellation Power Source Generation, Inc.
Duquesne Conemaugh LLC
Exelon Generation Company, LLC
PPL Montour, LLC
PSEG Fossil LLC
Reliant Energy Mid-Atlantic Power Holdings, LLC
UGI Development Company

Re: Joint Owners of the Conemaugh Electric Generating Station (collectively, the "Owners") statement of ownership and control

Dear Owners:

This letter sets forth the understanding of the degree of ownership and control exercised by each of the Owners with respect to the jointly-owned Conemaugh Electric Generating Station for purposes of facilitating compliance with the requirements of FERC Order No. 697.[1]

The Owners and Reliant Energy Northeast Management Company (the "Operator") each confirm its concurrence with the following statement of facts relating to the Conemaugh Electric Generating Station:

1. The Owners jointly own the Conemaugh Electric Generating Station, consisting of two 850 MW net pulverized coal fired once-through boilers and related facilities having a combined rated seasonal net generating capacity of 1,712 MW (1,884 MW nameplate), located in East Wheatfield and West Wheatfield Townships, Indiana County, Pennsylvania (the "Station").

[1] Not all of the Owners agree as to whether Order No. 697 requires the submission of a letter of concurrence when the putative submitting party is not claiming that it does not control its percentage ownership share of a jointly-owned unit. Notwithstanding, all of the Owners have no objection to submission of this letter by an Owner which does believe that such a submission is required.

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2. As of the date hereof, the Station is collectively owned by the Owners as tenants-in-common, each holding an undivided interest in the Station (and all real and personal property comprising the same) in the respective ownership percentages set forth below:

Owner	Ownership Interest
Conemaugh Power LLC	3.72%
Constellation Power Source Generation, Inc.	10.56%
Duquesne Conemaugh LLC	3.83%
Exelon Generation Company, LLC	20.72%
PPL Montour, LLC	16.25%
PSEG Fossil LLC	22.50%
Reliant Energy Mid-Atlantic Power Holdings, LLC	16.45%
UGI Development Company	5.97%

3. Each of the Owners is deemed to control the generating capacity of the Station in accordance with its respective ownership percentage as set forth in the preceding paragraph for purposes of facilitating compliance with the requirements of FERC Order No. 697.

Please indicate your company's concurrence to the above statement of facts by executing this letter in the space provided below your company's name at the foot hereof.

Sincerely yours,

Georgianna R. Stenger
Administrative Manager
Keystone-Conemaugh Projects

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Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

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Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

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Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this 14 day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: Anthony F. Pekny

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

SI-SSA-0010-5959

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Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this 1 day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: Kenneth Kaufman

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

SI-SSA-0010-5960

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Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this 1st day of December, 2007.

PPL MONTOUR, LLC

By: Dennis J. Murphy
DENNIS J. MURPHY

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

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Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this 13th day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: James V. Lacher

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONEMAUGH POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

DUQUESNE CONEMAUGH LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

UGI DEVELOPMENT COMPANY

By: _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Operator:

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY NORTHEAST
MANAGEMENT COMPANY

By: _____

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KEYSTONE-CONEMAUGH PROJECTS

682 Philadelphia Street 2nd floor
Indiana, Pennsylvania 15701

724-349-1205

MAILING ADDRESS
P.O BOX 68
INDIANA, PA 15701

GEORGIANNA R. STENGER, ESQ.
ADMINISTRATIVE MANAGER
DIRECT DIAL 724-357-1713

December 1, 2007

Addressed to:

Constellation Power Source Generation, Inc.
Duquesne Keystone LLC
Exelon Generation Company, LLC
Keystone Power LLC
PPL Montour, LLC
PSEG Fossil LLC
Reliant Energy Mid-Atlantic Power Holdings, LLC

Re: Joint Owners of the Keystone Electric Generating Station (collectively, the "Owners") statement of ownership and control

Dear Owners:

This letter sets forth the understanding of the degree of ownership and control exercised by each of the Owners with respect to the jointly-owned Keystone Electric Generating Station for purposes of facilitating compliance with the requirements of FERC Order No. 697.[1]

The Owners and Reliant Energy Northeast Management Company (the "Operator") each confirm its concurrence with the following statement of facts relating to the Keystone Electric Generating Station:

1. The Owners jointly own the Keystone Electric Generating Station, consisting of two 850 MW net pulverized coal fired once-through boilers and related facilities having a combined rated seasonal net generating capacity of 1,712 MW (1,884 MW nameplate), located in Plumcreek, South Bend and Cowanshannock Townships, Armstrong County, Pennsylvania, and Armstrong Township, Indiana County, Pennsylvania (the "Station").

[1] Not all of the Owners agree as to whether Order No. 697 requires the submission of a letter of concurrence when the putative submitting party is not claiming that it does not control its percentage ownership share of a jointly-owned unit. Notwithstanding, all of the Owners have no objection to submission of this letter by an Owner which does believe that such a submission is required.

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2. As of the date hereof, the Station is collectively owned by the Owners as tenants-in-common, each holding an undivided interest in the Station (and all real and personal property comprising the same) in the respective ownership percentages set forth below:

Owner	Ownership Interest
Constellation Power Source Generation, Inc.	20.99%
Duquesne Keystone LLC	2.47%
Exelon Generation Company, LLC	20.99%
Keystone Power LLC	3.70%
PPL Montour, LLC	12.34%
PSEG Fossil LLC	22.84%
Reliant Energy Mid-Atlantic Power Holdings, LLC	16.67%

3. Each of the Owners is deemed to control the generating capacity of the Station in accordance with its respective ownership percentage as set forth in the preceding paragraph for purposes of facilitating compliance with the requirements of FERC Order No. 697.

Please indicate your company's concurrence to the above statement of facts by executing this letter in the space provided below your company's name at the foot hereof.

Sincerely yours,

Georgianna R. Stenger
Administrative Manager
Keystone-Conemaugh Projects

SI-SSA-0010-5967

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Owners:

Acknowledged and Agreed to
this __ _ day of December, 2007

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this __ . _ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this _ _ . day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ___ . day of December, 2007.

KEYSTONE POWER LLC

By. _ ___ _ _ _____

Acknowledged and Agreed to
this ___ _ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _ __ _____

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Owners:

Acknowledged and Agreed to
this ___ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this 14 day of December, 2007.

DUQUESNE KEYSTONE LLC

By: Anthony F. Pelz

Acknowledged and Agreed to
this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Owners:

Acknowledged and Agreed to
this _____ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this 1 day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: Kenneth Kaiser

Acknowledged and Agreed to
this _____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this __. day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

SI-SSA-0010-5970

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Owners:

Acknowledged and Agreed to this _ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _

Acknowledged and Agreed to this ___ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _

Acknowledged and Agreed to this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _

Acknowledged and Agreed to this __ day of December, 2007.

KEYSTONE POWER LLC

By:

Acknowledged and Agreed to this __ day of December, 2007.

PPL MONTOUR, LLC

By: _

Acknowledged and Agreed to this ___ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to this ____ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

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Owners:

Acknowledged and Agreed to
this __ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this __ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this _____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this 13th day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this ___ day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: _____

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Owners:

Acknowledged and Agreed to
this __ day of December, 2007.

CONSTELLATION POWER SOURCE GENERATION, INC.

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

DUQUESNE KEYSTONE LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

EXELON GENERATION COMPANY, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

KEYSTONE POWER LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PPL MONTOUR, LLC

By: _____

Acknowledged and Agreed to
this ____ day of December, 2007.

PSEG FOSSIL LLC

By: _____

Acknowledged and Agreed to
this 16 day of December, 2007.

RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

By: James D. Lash

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Operator:

Acknowledged and Agreed to
this 18 day of December, 2007.

RELIANT ENERGY NORTHEAST
MANAGEMENT COMPANY

By: Jaime D Lach

20161228-5212 FERC PDF (Unofficial) 12/28/2016 11:58:46 AM

Thomas P. Joyce
Senior Vice President

P.O. Box 236, Hancocks Bridge, NJ 08038
tel: 856.339.1100 fax: 856.339.1104
email: Thomas.Joyce@pseg.com

PSEG
Nuclear L.L.C.

Carol Peterson
Vice President Finance
Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

Letter Regarding Control of Jointly-Owned Nuclear Facilities

Dear Ms. Peterson:

In connection with its upcoming compliance filings pursuant to Order No. 697,[1] PSEG Nuclear LLC ("PSEG") is submitting this letter in order to set forth its understanding of, and is requesting Exelon Generation Company LLC's ("Exelon") concurrence on, the respective level of control exercised by both companies with respect to the two nuclear facilities that they jointly own.[2]

PSEG avers and requests Exelon's concurrence on the following:

1. PSEG and Exelon jointly own and control two nuclear power plants, Peach Bottom Atomic Power Station located in Delta, PA and the Salem Nuclear Generating Station in Lower Alloways Creek, NJ.

2. In accordance with the Joint Owners Agreement for Peach Bottom dated November 24, 1971, as amended on thereafter, between the Parties, PSEG and Exelon each own 50% of the generating station. Under the Agreement, Exelon is the designated operator of Peach Bottom.

3. In accordance with the Joint Owners Agreement for Salem dated November 24, 1971, as amended thereafter, between the Parties, Exelon owns 42.59% and PSEG owns 57.41% of the generating station. Under the Agreement, PSEG is the designated operator of Salem.

4. Section 4.1 of each of the Joint Owners' Agreements states, "The signatories shall be entitled to shares of the installed capacity, available capacity, operating capacity and hourly energy generation of the Station in proportion to their ownership . . .."

[1] *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, 119 FERC ¶ 61,295 (2007).

[2] PSEG has requested a letter of concurrence from Exelon in order to facilitate the Commission's review of the market power analysis submitted by PSEG with respect to facilities it jointly owns with Exelon. Exelon has no objection to PSEG's submission of this letter as part of PSEG's compliance filing,.

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Thomas P. Joyce
Senior Vice President

P.O. Box 236, Hancocks Bridge, NJ 08038
tel: 856.339.1100 fax: 856.339.1104
email: Thomas.Joyce@pseg.com

PSEG
Nuclear L.L.C.

5. Section 11.1 of each of the Joint Owners' Agreements provides that the generating station will be operated by the party designated as operator for the mutual benefit of PSEG and Exelon.

6. In Order No. 697 the Commission stated that under "where a jointly-owned generation facility is operated by one of the joint-owners for the benefit of and on behalf of all of the joint-owners . . . it may be reasonable to allocate capacity based on ownership percentages...." Order No. 697 at P 188.

7. In accordance with the guidance provided in Order No. 697 and with the language of each of the joint owners' agreements, PSEG and Exelon should be deemed to control each of the nuclear facilities' output in line with their proportionate ownership share of each facility. As such, PSEG and Exelon should each be deemed to control 50% of Peach Bottom's output, and PSEG should be deemed to control 57.41% of Salem's output with Exelon controlling 42.59%.

Please indicate Exelon's concurrence to the above by executing the Acknowledgement and Agreement section below.

Sincerely

Thomas P. Joyce
Senior Vice President – Operations

Acknowledged and Agreed to
this 21 day of December, 2007.

Carol Peterson
Vice President Finance, Exelon Nuclear, and
an officer of Exelon Generation Company, LLC

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JOINT LETTER OF CONCURRENCE

Regulations of the Federal Energy Regulatory Commission (the "FERC") require each public utility with market-based rate authority to file an updated market power analysis every three years in accordance with a schedule adopted in *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stat. & Regs., Regulations Preambles ¶ 31,252 (2007) ("Order No. 697"). See, 18 CFR § 35.37(a)(1). Each public utility with market-based rate authority may also be required to file a change-in-status report regarding certain changes in circumstances that occur between the dates on which its triennial market power analyses are filed. 18 CFR § 35.42. Among other matters, the market power analysis is to address the amount of generation capacity that the affected utility owns or controls. Where more than one public utility owns a generating facility, FERC requires the utility that is submitting a market power analysis seek a "letter of concurrence" from the other affected co-owning public utilities that identifies the degree to which each public utility controls the generating facility, and to submit the letter with its filing. *See* FERC Order No. 697, 119 FERC ¶ 61,295, P 187 (2007).

The Yards Creek Pumped Storage Hydroelectric Project (the "Yards Creek Project") is a FERC-licensed pumped-storage hydroelectric project with a nameplate capacity of 400 MWs, and is located in Pahaquarry and Blairstown Townships, in Warren County, New Jersey. *See* FERC Project No. P-2309.

PSEG Fossil LLC ("PSEG") and Jersey Central Power & Light Company ("JCPL") each own, as tenants in common with the other, an undivided 50% interest in the Yards Creek Project. Accordingly, if and when PSEG or JCPL submit an updated market power analysis to the FERC, each will be subject to FERC's requirement to seek a "letter of concurrence" regarding the degree to which each controls the Yards Creek Project.

Both PSEG and JCP&L (and their affiliates) own transmission facilities and provide wholesale electric service in the Northeast region, as defined in Order No. 697. Pursuant to the schedule adopted in Order No. 697, PSEG and JCP&L are each required to submit an updated market power analysis to the FERC for markets within the Northeast region in December 2010. PSEG and/or JCP&L may also be obligated to file a change-in-status report or other market power analyses before its subsequent triennial market power analysis for the Northeast region is scheduled to be filed. Therefore, for the sole purpose of enabling either PSEG or JCP&L to submit a market power analysis that addresses, among other issues (to the extent necessary), the scope of each party's control of the Yards Creek Project, PSEG and JCP&L each aver and agree as follows:

1. JCP&L operates and maintains the Yards Creek Project pursuant to the Yards Creek Pumped Storage Hydroelectric Generating Station Operating Agreement, which is dated October 6, 1965 (the "Operating Agreement').

2. Article 2 of the Operating Agreement designates JCP&L as holding sole responsibility for the operations and maintenance the Yards Creek Project. Article 2 further provides that JCPL shall operate the Yards Creek project in the same manner as if JCPL had the complete ownership interest in the Yards Creek Project.

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3. JCP&L does, in fact, operate and control the Yards Creek Project in the same manner as if JCP&L had the complete ownership interest in the Yards Creek Project in accordance with Article 2 of the Operating Agreement.

4. Accordingly, PSEG and JCP&L each agree and concur that for the purpose of the market power analyses required by Order No. 697, JCPL shall be deemed to control the Yards Creek Project generation capacity and electric energy output.

ACKNOWLEDGED AND AGREED:

Richard P. Lopriore
President, PSEG Fossil LLC

Dated: 12/21/10

ACKNOWLEDGED AND AGREED:

Dean Stathis
Director, Regulated Commodity Sourcing
Jersey Central Power & Light Company

Dated: 12/08/2010

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Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G	ER99-3151-000	NA*	NA*	NA*	NA*	PJM	Northeast	NA*
PSEG ER&T	ER97-837-000	NA*	NA*	NA*	NA*	PJM, NYISO, NE-ISO	Northeast, Central, Southwest Power Pool, Southeast, Southwest, Northwest	NA*
PSEG Fossil	ER08-447-000	Bergen CC1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Bergen CC2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2002
PSEG Fossil	ER08-447-000	Burlington 12.1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Burlington 12.4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Conemaugh 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/21/1970
PSEG Fossil	ER08-447-000	Conemaugh 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	5/27/1971
PSEG Fossil	ER08-447-000	Conemaugh A	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh B	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh C	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Fossil	ER08-447-000	Conemaugh D	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	2/1/1970
PSEG Global	N/A	Conemaugh Hydroelectric Plant 1	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Global	N/A	Conemaugh Hydroelectric Plant 2	PSEG Global	PSEG ER&T	2/1/1989	PJM	Northeast	2/1/1989
PSEG Fossil	ER08-447-000	Essex 9	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/1/1990
PSEG Nuclear	ER08-448-000	Hope Creek 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/20/1986
PSEG Fossil	ER08-447-000	Hudson 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	12/18/1968
PSEG Fossil	ER08-447-000	Kearny 12	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/1/2001
PSEG Fossil	ER08-447-000	Kearny 13	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Kearny 14	PSEG Fossil	PSEG ER&T	6/1/2012	PJM	Northeast	6/1/2012
PSEG Fossil	ER08-447-000	Keystone 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	8/24/1967
PSEG Fossil	ER08-447-000	Keystone 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/23/1968
PSEG Fossil	ER08-447-000	Keystone 3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Keystone 6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/23/1968
PSEG Fossil	ER08-447-000	Linden 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM,	Northeast	4/1/2006
PSEG Fossil	ER08-447-000	Linden 7	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995
PSEG Fossil	ER08-447-000	Linden 8	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/1995

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSEG Fossil	ER08-447-000	Linden GT5	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Linden GT6	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/1/2000
PSEG Fossil	ER08-447-000	Mercer 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	12/19/1960
PSEG Fossil	ER08-447-000	Mercer 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	6/4/1961
PSEG Nuclear	ER08-448-000	Peach Bottom 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	7/5/1974
PSEG Nuclear	ER08-448-000	Peach Bottom 3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	12/23/1974
PSEG Nuclear	ER08-448-000	Salem 1	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/30/1977
PSEG Nuclear	ER08-448-000	Salem 2	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	10/13/1981
PSEG Nuclear	ER08-448-000	Salem GT3	PSEG Nuclear	PSEG ER&T	8/21/2000	PJM	Northeast	6/17/1971
PSEG Fossil	ER08-447-000	Sewaren 1	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	12/1/1948
PSEG Fossil	ER08-447-000	Sewaren 2	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	11/30/1948
PSEG Fossil	ER08-447-000	Sewaren 3	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	10/16/1949
PSEG Fossil	ER08-447-000	Sewaren 4	PSEG Fossil	PSEG ER&T	8/21/2000	PJM	Northeast	7/30/1951
PSEG Fossil	ER08-447-000	Yards Creek 1	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	11/26/1965
PSEG Fossil	ER08-447-000	Yards Creek 2	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	12/22/1965
PSEG Fossil	ER08-447-000	Yards Creek 3	PSEG Fossil	JCP&L	8/21/2000	PJM	Northeast	9/3/1965
PSEG Power CT	ER03-327-000	Bridgeport Harbor 3	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	8/1/1968
PSEG Power CT	ER03-327-000	Bridgeport Harbor 4	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	10/30/1967
PSEG New Haven LLC	ER12-1250-000	New Haven 2	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 3	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG New Haven LLC	ER12-1250-000	New Haven 4	PSEG New Haven LLC	CL&P	6/1/2012	ISO-NE	Northeast	6/1/2012
PSEG Power CT	ER03-327-000	New Haven Harbor 1	PSEG Power CT	PSEG ER&T	12/6/2002	ISO-NE	Northeast	7/1/1975
PSEG Power NY	N/A*	Bethlehem Energy Center CC	PSEG Power NY	PSEG ER&T	12/6/2002	NYISO	Northeast	7/1/2005
PSEG Solar Source LLC	N/A*	Mars Solar Garden	PSEG Solar Hackettstown LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	9/9/2009
PSEG Solar Source LLC	N/A*	JEA Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	SERC	Southeast	9/28/2010
PSEG Solar Source LLC	N/A*	Wyandot Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	4/6/2010
PSEG Solar Source LLC	N/A*	Queen Creek Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	AZ-NV-SNV	Southwest	11/14/2012
PSEG Solar Source LLC	N/A*	Milford Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Northeast	12/27/2012
PSEG Solar Source LLC	N/A	Badger Solar Farm	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ACC	West	10/15/2013
PSEG Solar Source LLC	N/A	Shasta Solar Farm	PSEG Solar California LLC	PG&E	12/16/2013	CAISO	West	3/1/2014

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSEG Solar Source LLC	N/A	Newman Solar Farm (Texas)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	El Paso Electric	Southwest	12/30/2014
PSEG Solar Source LLC	N/A	Whitcomb Solar Farm (Vermont)	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	ISO New England	Northeast	10/30/2014
PSEG Solar Source LLC	N/A	Rockfish Solar LLC, Southern Maryland	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	7/10/2015
PSEG Solar Source LLC	N/A	Columbia Solar, Pittsburg, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PG&E	West	10/21/2015
PSEG Solar Source LLC	N/A	Whitehorn Solar, Livermore, CA	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Authority	West	2/17/2016
PSEG Solar Source LLC	N/A	Meadows Solar, Martin County, NC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	6/9/2016
PSEG Solar Source LLC	ER16-1924-000	Bison Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Western Area Power Administration, Colorado-Missouri Region	West	8/1/2016
PSEG Solar Source LLC	ER16-1925-000	Pavant Solar II LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp East	West	8/1/2016
PSEG Solar Source LLC	N/A	Obsidian - Black Cap	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PacificCorp West	West	11/1/2016
PSEG Solar Source LLC	N/A	Hemlock Solar	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	N/A	Turkey Creek	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	PJM	Southeast	12/31/2016
PSEG Solar Source LLC	ER16-1926-000	San Isabel Solar LLC	PSEG Solar Source LLC	PSEG Solar Source LLC	N/A	Public Service Company of Colorado	West	8/1/2016
PSE&G (Solar 4 All)	N/A*	Trenton, 500-520 Brunswick Ave., Trenton, NJ 08638	PSE&G	PSE&G	N/A	PJM	Northeast	10/07/2010 (Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Barringer High School (NPS), 90 Parker St., Newark, NJ 07104	PSE&G	PSE&G	N/A	PJM	Northeast	09/24/2010 (Commercial Operation)
PSE&G (Solar		Park Elementary						10/20/2010

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
4 All)	N/A*	School, 120 Manchester	PSE&G	PSE&G	N/A	PJM	Northeast	(Commercial Operation)
PSE&G (Solar 4 All)	N/A*	Linden, South Wood Avenue, Linden, NJ 07036	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Yardville, Broad Street, Hamilton, NJ 08611	PSE&G	PSE&G	N/A	PJM	Northeast	12/31/2010
PSE&G (Solar 4 All)	N/A*	Silver Lake, 410 Silver Lake Avenue, Edison, NJ 08817	PSE&G	PSE&G	N/A	PJM	Northeast	11/09/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Central HQ, 472 Weston Canal Road, Franklin, NJ 08873	PSE&G	PSE&G	N/A	PJM	Northeast	11/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Edison Training, 234 Pierson Avenue, Edison, NJ 08837	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All)	N/A*	WEA Texas Bayonne, 30-100 Pulaski Street, Bayonne, NJ 07002	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2010
PSE&G (Solar 4 All)	N/A*	Matrix Building A, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/24/2011
PSE&G (Solar 4 All)	N/A*	Matrix Building B, 1000 and 1050 Amboy Ave, Perth Amboy, NJ 08861	PSE&G	PSE&G	N/A*	PJM	Northeast	1/14/2011
PSE&G (Solar 4 All)	N/A*	Camden Street School, 281 Camden Street Newark, New Jersey 07103	PSE&G	PSE&G	N/A*	PJM	Northeast	1/12/2011

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G (Solar 4 All)	N/A*	New Central High School, 246 18th Ave, Newark, NJ 07108	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2010 (Energized)
PSE&G (Solar 4 All)	N/A*	Rider University Solar Farm, Lawrenceville, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/19/2011
PSE&G (Solar 4 All)	N/A*	Mill Creek Solar Farm, Burlington Township, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	11/30/2011
PSE&G (Solar 4 All)	N/A*	PSE&G Thorofare Solar Farm, West Deptford	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	Raritan Center – Warehouse Solar, Edison, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/28/2011
PSE&G (Solar 4 All)	N/A*	NJMC – Landfill Solar, Kearny, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/30/2011
PSE&G (Solar 4 All	N/A	Matrix – Stults Rd., South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	5/31/2011
PSE&G (Solar 4 All)	N/A*	Metro Division HQ, Clifton, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	7/9/2012
PSE&G (Solar 4 All)	N/A*	Black Rock-Matrix, South Brunswick, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	3/20/2012
PSE&G (Solar 4 All)	N/A*	Food Bank Solar Farm, Hillside, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	8/16/2012
PSE&G (Solar 4 All)	N/A*	Hackensack Solar Farm, Hackensack, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2012
PSE&G (Solar 4 All)	N/A*	Moorestown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	10/14/2013
PSE&G (Solar 4 All)	N/A*	Seg 2 (Pole attached solar units)	PSE&G	PSE&G	N/A*	PJM	Northeast	7/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Kinsley Solar Sewell, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014

Appendix B

Asset Appendix: Generation Assets								
						Location		
Filing Entity and its Energy Affiliates	**Docket # where MBR authority was granted**	**Generation Name (Plant or Unit Name)**	**Owned By**	**Controlled By**	**Date Control Transferred**	**Balancing Authority Area**	**Geographic Region**	**In-service Date**
PSE&G (Solar 4 All Extension)	N/A*	Parkland Solar Bordentown, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2014
PSE&G (Solar 4 All Extension)	N/A*	L&D Solar Mt. Holly, NJ	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2015
PSE&G (Solar 4 All Extension)	N/A*	Hopewell Valley Central HS	PSE&G	PSE&G	N/A*	PJM	Northeast	12/24/2015
PSE&G (Solar 4 All Extension)	N/A*	ILR Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016
PSE&G (Solar 4 All Extension)	N/A*	Caldwell Waste Treatment Solar	PSE&G	PSE&G	N/A*	PJM	Northeast	12/22/2016
[i] PSEG Fossil has a 22.5% interest in the Conemaugh coal fired plants.								
[ii] PSEG Global has a 4% interest Conemaugh Hydroelectric plants.								
[iii] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear Plants.								
[iv] PSEG Nuclear has a 57.41% interest in the Salem Nuclear Plants.								
[v] JCP&L – Jersey Central Power & Light Company								
[vi] PSEG Fossil has a 50% interest in each of the Yards Creek facilities.								
[vii] CL&P – The Connecticut Light and Power Company.								
[viii] PSEG Power Ventures has a 100% ownership in PSEG Hackettstown LLC.								
[ix] PSEG Power Ventures has a 100% ownership interest in PSEG Solar Source LLC								
[x] All solar assets are using AC MW ratings. PSEG's previous triennial listed the DC ratings.								
[xi] PG&E -- Pacific Gas and Electric Company								
[xii] PSE&G started installations of pole units in September of 2009. As of November 30, 2016, a total of 174,630								

Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing**	**Capacity Rating: Methodology Used in K**	**End Note Number (Enter text in End Notes Sheet**
NA*	NA*	NA*	
NA*	NA*	NA*	
775.2	775.2	N	
625.6	625.6	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
60.5	60.5	N	
210.6	210.6	N	
210.6	210.6	N	
0.625	0.625	N	[i]
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
1	1	N	[ii]
1	1	N	
93.6	93.6	N	
1,290.70	1,290.70	N	
659.7	659.7	N	
242	242	N	
242	242	N	
121	121	N	
213.8	213.8	N	
213.8	213.8	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
0.625	0.625	N	
677.8	677.8	N	
677.8	677.8	N	
96.1	96.1	N	
96.1	96.1	N	

Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing**	**Capacity Rating: Methodology Used in K**	**End Note Number (Enter text in End Notes Sheet**
96.1	96.1	N	
96.1	96.1	N	
326.4	326.4	N	
326.4	326.4	N	
704	704	N	[iii]
689	689	N	
671.7	671.7	N	[iv]
671.7	671.7	N	
24	24	N	
110.8	110.8	N	
107.5	107.5	N	
107.5	107.5	N	
126.5	126.5	N	
68.5	68.5	N	[v]
68.5	68.5	N	[vi]
56.4	56.4	N	
399.5	399.5	N	
18.6	18.6	N	
60.5	60.5	N	[vii]
60.5	60.5	N	
60.5	60.5	N	
460.3	460.3	N	
893.2	893.2	N	
2	2	N	[viii]
12.6	12.6	N	[ix]
10.1	10.1	N	[x]
19	19	N	
12	12	N	
15	15	N	
1.5	1.5	N	[xi]

Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing**	**Capacity Rating: Methodology Used in K**	**End Note Number (Enter text in End Notes Sheet**
10.2	10.2	N	
2.2	2.2	N	
10.3	10.3	N	
19	19	N	
3	3	N	
20	20	N	
30	30	N	
50	50	N	
8	8	N	
5	5	N	
13.5	13.5	N	
30	30	N	
1.14	1.14	N	
0.64	0.64	N	
		N	

Capacity Rating: Nameplate (MW)	Capacity rating: Used in Filing	Capacity Rating: Methodology Used in K	End Note Number (Enter text in End Notes Sheet
0.55	0.55	N	
3	3	N	
3.7	3.7	N	
1.75	1.75	N	
0.76	0.76	N	
0.64	0.64	N	
1.5	1.5	N	
		N	
1.5	1.5	N	
1	1	N	
0.83	0.83	N	
		N	

Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing**	**Capacity Rating: Methodology Used in K**	**End Note Number (Enter text in End Notes Sheet**
0.5	0.5	N	
		N	
0.67	0.67	N	
3.5	3.5	N	
0.75	0.75	N	
2	2	N	
2.5	2.5	N	
2.5	2.5	N	
0.57	0.57	N	
2.5	2.5	N	
1	1	N	
1	1	N	
0.93	0.93	N	
38.5	38.5	N	[xii]
8.8	8.8	N	

Capacity Rating: Nameplate (MW)	**Capacity rating: Used in Filing**	**Capacity Rating: Methodology Used in K**	**End Note Number (Enter text in End Notes Sheet**
7.9	7.9	N	
10	10	N	
1	1	N	
6.6	6.6	N	
2	2	N	

panels and 38.5 MW capacity have been installe

Asset Appendix: Transmission/Natural Gas Assets
Electric Transmission Assets and/or Natural Gas Intrastate Pipelines and/or Gas St
Location

Filing Entity and its Energy Affiliates	Cite to Order Accepting OATT or order approving the transfer of transmission facilities to an RTO or ISO	Asset Name and Use	Owned By	Controlled By	Date Control Transferred	Market / Balancing Authority	Geograph
PSEG ER&T	NA	NA	NA	NA	NA	NA	N
PSEG Power CT	NA	NA	NA	NA	NA	NA	N
PSEG New Haven	NA	NA	NA	NA	NA	NA	N
PSEG Fossil	NA	NA	NA	NA	NA	NA	N
PSEG Nuclear	NA	NA	NA	NA	NA	NA	N
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	Jointly Owned by PSE&G and others	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 500 kV Lines	Owned by others	PJM	N/A*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	Owned by others	PJM	NA*	PJM	North

PSE&G	96 FERC ¶ 61,061	Combined 345 kV Lines	Jointly Owned by PSE&G and others	PJM	N/A*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 230 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 230kV Lines	Owned by Others	PJM	N/A	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 138 kV Lines	PSE&G	PJM	NA*	PJM	North
PSE&G	96 FERC ¶ 61,061	Combined 69 kV Lines	PSE&G	PJM	NA*	PJM	North

:orage Facilities

	Size	
ic Region	**Size (e.g., length and kV for electric length and diameter for pipeline, and capacity for gas storage)**	**End Note Number (Enter text in End Notes Sheet**
A	NA	NA
A	NA	NA
A	NA	NA
A	NA	NA
A	NA	NA
ıeast	Approximately 272 combined miles.	
ıeast	Approximately 151 combined miles.	
ıeast	Approximately 64 combined miles	
ıeast	Approximately 32 combined miles.	
ıeast	Approximately 20 combined miles.	

ıeast	Approximately 3.76 combined Miles
ıeast	Approximately 750 combined miles.
ıeast	Approximately 39 combined miles
ıeast	Approximately 228 combined miles.
ıeast	Approximately 235 combined miles.

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Asset Appendix: Long Term Purchased Power Agreements

Filing Entity and its Energy Affiliates	Docket No. where MBR Authority Granted	Seller Name	Amount of PPA (MW)	Market / Balancing Authority	Geographic Region	Start Date (mo/day/year)

End Date (mo/day/year)	End Note

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Document Content(s)

PSEG 2016 Triennial Transmittal FINAL.DOC.....1-27

Exhibit A - Morris Affidavit - PSEG Triennial.PDF.....28-109

Exhibit E - Letters of Concurrence - PSEG Triennial.PDF.....110-134

Appendix B - Generation Assets - PSEG Triennial.XLSX.....135-146

Appendix C - Triennial - Transmission Chart.XLSX.....147-150

Appendix D - Long Term Contracts - Triennial.XLSX.....151-152

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Associate General Regulatory Counsel

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PSEG
Services Corporation

October 4, 2017

VIA EFILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: ***PSEG Energy Resources & Trade LLC*****, Docket No. ER10-1789-005;**
Public Service Electric and Gas Company**, Docket No. ER10-1768-004;**
PSEG Power Connecticut LLC**, Docket No. ER10-1793-004;**
PSEG Fossil LLC**, Docket No. ER10-1770-004;**
PSEG Nuclear LLC**, ER10-1771-004;**
PSEG New Haven LLC**, ER12-1250-004**
***Pavant Solar II LLC,* ER16-1925-002**
***San Isabel Solar LLC,* ER16-1926-002**
***Bison Solar LLC,* ER16-1924-002**
***PSEG Energy Solutions LLC,* ER16-2725-002**

Dear Secretary Bose:

On December 28, 2016, PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG Fossil LLC, PSEG Nuclear LLC, PSEG New Haven LLC, Pavant Solar II LLC, San Isabel Solar LLC, Bison Solar LLC, and PSEG Energy Solutions LLC, ("Applicants") jointly submitted their updated market power analysis in support of their continued eligibility to engage in market-based rate transactions. This letter clarifies that, in addition to the approvals sought in the December 28, 2016 filing, Applicants (other than Public Service Electric and Gas Company and PSEG Energy Solutions LLC) ("Generator Applicants") are seeking the waivers set forth in Order No. 807, *Open Access and Priority Rights on Interconnection Customer's Interconnection Facilities*, Order No. 807, 150 FERC ¶ 61,211, Docket No. RM14-11-000 (2015).

Generator Applicants do not own or control any transmission facilities other than the interconnection facilities necessary to interconnect with the transmission grid. The generator interconnection facilities that Generator Applicants own and control are limited and discrete radial facilities that do not form an integrated transmission grid and are used solely to interconnect Generator Applicants' facilities to the grid. Generator Applicants

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affirm to the Commission that they (together with their affiliates) are eligible for priority rights and waiver under Order No. 807, *Id.* at P 165, such that Generator Applicants and their affiliates are immune from the Open Access Requirements to the extent set forth under Order No. 807, without the need for further filings or orders.

Thank you for your attention to this matter.

Respectfully submitted,

Cara J. Lewis

Cara J. Lewis

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Document Content(s)

Triennial MBR Filing Update - 807 Waiver.PDF.....1-2

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PSEG Services Corporation

October 12, 2017

VIA EFILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: ***PSEG Energy Resources & Trade LLC*****, Docket No. ER10-1789-005;**
Public Service Electric and Gas Company**, Docket No. ER10-1768-004;**
PSEG Power Connecticut LLC**, Docket No. ER10-1793-004;**
PSEG Fossil LLC**, Docket No. ER10-1770-004;**
PSEG Nuclear LLC**, ER10-1771-004;**
PSEG New Haven LLC**, ER12-1250-004**
***Pavant Solar II LLC,* ER16-1925-002**
***San Isabel Solar LLC,* ER16-1926-002**
***Bison Solar LLC,* ER16-1924-002**
***PSEG Energy Solutions LLC,* ER16-2725-002**

Dear Secretary Bose:

On December 28, 2016, PSEG Energy Resources & Trade LLC, Public Service Electric and Gas Company, PSEG Power Connecticut LLC, PSEG Fossil LLC, PSEG Nuclear LLC, PSEG New Haven LLC, Pavant Solar II LLC, San Isabel Solar LLC, Bison Solar LLC, and PSEG Energy Solutions LLC, ("Applicants") jointly submitted their updated market power analysis in support of their continued eligibility to engage in market-based rate transactions.

Applicants' application included the Report & Affidavit of Dr. John R. Morris ("Morris Affidavit"), which contained the following exhibits: PEG-2; PEG-3; PEG-4; PEG-5; PEG-6; PEG-7; PEG-8; PEG-9; PEG-10; and PEG-11. In the instant filing, Applicants are resubmitting the above-mentioned exhibits to the Morris Affidavit in Excel format as required by the Commission's regulations.

Thank you for your attention to this matter.

Respectfully submitted,

Cara J. Lewis
Cara J. Lewis

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Northeast Region Generation Owned and Controlled by PS

Owner	Plant Name	State	Owned Capacity: Winter Seasonal Capacity	Owned Capacity: Summer Seasonal Capacity
ISO - New England				
PSEG Power CT	Bridgeport Station 2	CT	148	130
PSEG Power CT	Bridgeport Station 3	CT	385	383
PSEG Power CT	Bridgeport Station 4	CT	20	15
PSEG Power CT	New Haven Harbor 1	CT	455	448
PSEG New Haven	New Haven Harbor GT2	CT	61	61
PSEG New Haven	New Haven Harbor GT3	CT	61	61
PSEG New Haven	New Haven Harbor GT4	CT	61	61
Total ISO - New England Capacity			**1,190**	**1,158**
New York ISO				
PSEG Power NY	Bethlehem Energy Center CC	NY	845	754
Total New York ISO Capacity			**845**	**754**
PJM				
PSEG Fossil	Conemaugh 1	PA	191	191
PSEG Fossil	Conemaugh 2	PA	191	191
PSEG Fossil	Conemaugh A[1]	PA	1	1
PSEG Fossil	Conemaugh B	PA	1	1
PSEG Fossil	Conemaugh C	PA	1	1
PSEG Fossil	Conemaugh D	PA	1	1
PSEG Power	Conemaugh Hydroelectric Plant 1[2]	PA	1	1
PSEG Power	Conemaugh Hydroelectric Plant 2	PA	1	1
PSEG Fossil	Keystone 1[3]	PA	194	194
PSEG Fossil	Keystone 2	PA	194	194
PSEG Fossil	Keystone 3	PA	1	1
PSEG Fossil	Keystone 4	PA	1	1
PSEG Fossil	Keystone 5	PA	1	1
PSEG Fossil	Keystone 6	PA	1	1
PSEG Solar Source LLC	Wyandot Solar Farm	OH	12	12

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Northeast Region Generation Owned and Controlled by PS

Owner	Plant Name	State	Owned Capacity: Winter Seasonal Capacity	Owned Capacity: Summer Seasonal Capacity
PJM East				
PSEG Fossil	Bergen 3[7]	NJ	21	21
PSEG Fossil	Bergen CC1	NJ	628	628
PSEG Fossil	Bergen CC2	NJ	550	555
PSEG Fossil	Burlington 8[7]	NJ	21	21
PSEG Fossil	Burlington 9[10]	NJ	184	184
PSEG Fossil	Burlington 11[7]	NJ	184	184
PSEG Fossil	Burlington 121	NJ	42	42
PSEG Fossil	Burlington 122	NJ	42	42
PSEG Fossil	Burlington 123	NJ	42	42
PSEG Fossil	Burlington 124	NJ	42	42
PSEG Fossil	Edison 1[7]	NJ	168	168
PSEG Fossil	Edison 2[7]	NJ	168	168
PSEG Fossil	Edison 3[7]	NJ	168	168
PSEG Fossil	Essex 9	NJ	81	81
PSEG Fossil	Essex 10[7]	NJ	168	168
PSEG Fossil	Essex 11[7]	NJ	168	168
PSEG Fossil	Essex 12[7]	NJ	168	168
PSEG Nuclear	Hope Creek 1	NJ	1,161	1,161
PSEG Fossil	Hudson 2	NJ	608	608
PSEG Fossil	Kearny 9[8]	NJ	21	21
PSEG Fossil	Kearny 12	NJ	175	175
PSEG Fossil	Kearny 13	NJ	0	178
PSEG Fossil	Kearny 14	NJ	0	89
PSEG Fossil	Linden 1	NJ	455	458
PSEG Fossil	Linden 2	NJ	775	778
PSEG Fossil	Linden 7	NJ	84	84
PSEG Fossil	Linden 8	NJ	84	84
PSEG Fossil	Linden GT5	NJ	86	86
PSEG Fossil	Linden GT6	NJ	86	86
PSEG Hackettstown LLC	Mars Solar Garden	NJ	2	2
PSEG Fossil	Mercer 1	NJ	316	316
PSEG Fossil	Mercer 2	NJ	316	316
PSEG Fossil	Mercer GT3[9]	NJ	115	115
PSEG Solar Source LLC	Milford Solar Farm	DE	15	15
PSEG Fossil	National Park GT1[7]	NJ	21	21
PSEG Nuclear	Salem 1[4]	NJ	674	674
PSEG Nuclear	Salem 2	NJ	665	665
PSEG Nuclear	Salem GT3	NJ	22	22
PSEG Fossil	Sewaren 1	NJ	104	104
PSEG Fossil	Sewaren 2	NJ	118	118
PSEG Fossil	Sewaren 3	NJ	107	107
PSEG Fossil	Sewaren 4	NJ	124	124
PSEG Fossil	Sewaren 6[7]	NJ	105	105
PSE&G	Solar 4 All Units	NJ	78	78
PSEG Fossil	Yards Creek 1[5]	NJ	70	70
PSEG Fossil	Yards Creek 2	NJ	70	70
PSEG Fossil	Yards Creek 3	NJ	60	60
PJM 5004/5005				
PSEG Nuclear	Peach Bottom 2[6]	PA	561	561

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Northeast Region Generation Owned and Controlled by PS

Owner	Plant Name	State	Owned Capacity: Winter Seasonal Capacity	Owned Capacity: Summer Seasonal Capacity
PSEG Nuclear	Peach Bottom 3	PA	561	561
Total PJM Capacity			**11,272**	**11,550**
Total Northeast Region Capacity			**13,307**	**13,462**

Source: PSEG.
Notes:
[1] PSEG Fossil has a 22.5% interest in the Conemaugh coal-fired units.
[2] PSEG Global has a 4% interest in the Conemaugh Hydroelectric facility.
[3] PSEG Fossil has a 22.84% ownership interest in the Keystone facility.
[4] PSEG Nuclear has a 57.41% interest in the Salem Nuclear facility.
[5] PSEG Fossil has a 50% interest in the Yards Creek facility. Yards Creek is operated by Jersey Central Power & by JCP&L in the analysis.
[6] PSEG Nuclear has a 50% interest in the Peach Bottom Nuclear facility.
[7] Unit retired on 06/01/2015
[8] Unit retired on 08/31/2014
[9] Unit retired on 07/31/2015

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EG

Controlled Capacity	
Winter Seasonal Capacity	**Summer Seasonal Capacity**
148	130
385	383
20	15
455	448
0	0
0	0
0	0
1,008	**976**
845	754
845	**754**
191	191
191	191
1	1
1	1
1	1
1	1
1	1
1	1
194	194
194	194
1	1
1	1
1	1
1	1
12	12

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EG

Controlled Capacity	
Winter Seasonal Capacity	**Summer Seasonal Capacity**
21	21
628	628
550	555
21	21
184	184
184	184
42	42
42	42
42	42
42	42
168	168
168	168
168	168
81	81
168	168
168	168
168	168
1,161	1,161
608	608
21	21
175	175
0	178
0	89
455	458
775	778
84	84
84	84
86	86
86	86
2	2
316	316
316	316
115	115
15	15
21	21
674	674
665	665
22	22
104	104
118	118
107	107
124	124
105	105
78	78
0	0
0	0
0	0
561	561

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EG

Controlled Capacity	
Winter Seasonal Capacity	**Summer Seasonal Capacity**
561	561
11,072	**11,350**
12,926	**13,080**

Light, and thus is controlled

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Northeast Region Generation Owned and Controlled by PS

Owner	Plant Name	State	Owned Capacity: Winter Seasonal Capacity	Owned Capacity: Summer Seasonal Capacity
ISO - New England				
PSEG Power CT	Bridgeport Station 2	CT	148	130
PSEG Power CT	Bridgeport Station 3	CT	385	383
PSEG Power CT	Bridgeport Station 4	CT	20	15
PSEG Power CT	New Haven Harbor 1	CT	455	448
PSEG New Haven	New Haven Harbor GT2	CT	61	61
PSEG New Haven	New Haven Harbor GT3	CT	61	61
PSEG New Haven	New Haven Harbor GT4	CT	61	61
Total ISO - New England Capacity			**1,190**	**1,158**
New York ISO				
PSEG Power NY	Bethlehem Energy Center CC	NY	845	754
Total New York ISO Capacity			**845**	**754**
PJM				
PSEG Fossil	Conemaugh 1	PA	191	191
PSEG Fossil	Conemaugh 2	PA	191	191
PSEG Fossil	Conemaugh A[1]	PA	1	1
PSEG Fossil	Conemaugh B	PA	1	1
PSEG Fossil	Conemaugh C	PA	1	1
PSEG Fossil	Conemaugh D	PA	1	1
PSEG Power	Conemaugh Hydroelectric Plant 1[2]	PA	1	1
PSEG Power	Conemaugh Hydroelectric Plant 2	PA	1	1
PSEG Fossil	Keystone 1[3]	PA	194	194
PSEG Fossil	Keystone 2	PA	194	194
PSEG Fossil	Keystone 3	PA	1	1
PSEG Fossil	Keystone 4	PA	1	1
PSEG Fossil	Keystone 5	PA	1	1
PSEG Fossil	Keystone 6	PA	1	1
PSEG Solar Source LLC	Wyandot Solar Farm	OH	12	12

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Northeast Region Generation Owned and Controlled by PS

Owner	Plant Name	State	Owned Capacity Winter Seasonal Capacity	Owned Capacity Summer Seasonal Capacity
PJM East				
PSEG Fossil	Bergen 3[7]	NJ	21	21
PSEG Fossil	Bergen CC1	NJ	628	628
PSEG Fossil	Bergen CC2	NJ	550	555
PSEG Fossil	Burlington 8[7]	NJ	21	21
PSEG Fossil	Burlington 9[10]	NJ	184	184
PSEG Fossil	Burlington 11[7]	NJ	184	184
PSEG Fossil	Burlington 121	NJ	42	42
PSEG Fossil	Burlington 122	NJ	42	42
PSEG Fossil	Burlington 123	NJ	42	42
PSEG Fossil	Burlington 124	NJ	42	42
PSEG Fossil	Edison 1[7]	NJ	168	168
PSEG Fossil	Edison 2[7]	NJ	168	168
PSEG Fossil	Edison 3[7]	NJ	168	168
PSEG Fossil	Essex 9	NJ	81	81
PSEG Fossil	Essex 10[7]	NJ	168	168
PSEG Fossil	Essex 11[7]	NJ	168	168
PSEG Fossil	Essex 12[7]	NJ	168	168
PSEG Nuclear	Hope Creek 1	NJ	1,161	1,161
PSEG Fossil	Hudson 2	NJ	608	608
PSEG Fossil	Kearny 9[8]	NJ	21	21
PSEG Fossil	Kearny 12	NJ	175	175
PSEG Fossil	Kearny 13	NJ	0	178
PSEG Fossil	Kearny 14	NJ	0	89
PSEG Fossil	Linden 1	NJ	455	458
PSEG Fossil	Linden 2	NJ	775	778
PSEG Fossil	Linden 7	NJ	84	84
PSEG Fossil	Linden 8	NJ	84	84
PSEG Fossil	Linden GT5	NJ	86	86
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PSEG Fossil	Mercer GT3[9]	NJ	115	115
PSEG Solar Source LLC	Milford Solar Farm	DE	15	15
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PSEG Nuclear	Salem 1[4]	NJ	674	674
PSEG Nuclear	Salem 2	NJ	665	665
PSEG Nuclear	Salem GT3	NJ	22	22
PSEG Fossil	Sewaren 1	NJ	104	104
PSEG Fossil	Sewaren 2	NJ	118	118
PSEG Fossil	Sewaren 3	NJ	107	107
PSEG Fossil	Sewaren 4	NJ	124	124
PSEG Fossil	Sewaren 6[7]	NJ	105	105
PSE&G	Solar 4 All Units	NJ	78	78
PSEG Fossil	Yards Creek 1[5]	NJ	70	70
PSEG Fossil	Yards Creek 2	NJ	70	70
PSEG Fossil	Yards Creek 3	NJ	60	60
PJM 5004/5005				
PSEG Nuclear	Peach Bottom 2[6]	PA	561	561

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Northeast Region Generation Owned and Controlled by PS

Owner	Plant Name	State	Owned Capacity: Winter Seasonal Capacity	Owned Capacity: Summer Seasonal Capacity
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Total Northeast Region Capacity			**13,307**	**13,462**

Source: PSEG.
Notes:
[1] PSEG Fossil has a 22.5% interest in the Conemaugh coal-fired units.
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EG

Controlled Capacity	
Winter Seasonal Capacity	**Summer Seasonal Capacity**
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455	448
0	0
0	0
0	0
1,008	**976**
845	754
845	**754**
191	191
191	191
1	1
1	1
1	1
1	1
1	1
1	1
194	194
194	194
1	1
1	1
1	1
1	1
12	12

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EG

Controlled Capacity	
Winter Seasonal Capacity	**Summer Seasonal Capacity**
21	21
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42	42
42	42
42	42
168	168
168	168
168	168
81	81
168	168
168	168
168	168
1,161	1,161
608	608
21	21
175	175
0	178
0	89
455	458
775	778
84	84
84	84
86	86
86	86
2	2
316	316
316	316
115	115
15	15
21	21
674	674
665	665
22	22
104	104
118	118
107	107
124	124
105	105
78	78
0	0
0	0
0	0
561	561

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EG

Controlled Capacity	
Winter Seasonal Capacity	**Summer Seasonal Capacity**
561	561
11,072	**11,350**
12,926	**13,080**

Light, and thus is controlled

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Scenario 1 PSEG 2016 MBR for ISONE

	PSA		WM			
			Winter		Spring	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result
ISO New England	8,715	Pass	5.4	Pass	5.2	Pass
Connecticut	3,388	Pass	11.8	Pass	11.3	Pass
Southwest Connecticut	1,701	Pass	16.4	Pass	15.7	Pass

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SA

Summer		Fall	
Share (%)	**Result**	**Share (%)**	**Result**
6.5	Pass	6.0	Pass
14.3	Pass	13.3	Pass
14.9	Pass	13.0	Pass

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **ISONE**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	852	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	16	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	190	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	30,892	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	16	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,358	Calculated
I	Study Area Reserve Requirement	2,510	Gendata
J	Amount of Line I Attributable to Seller, if any	3	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	16,073	
	Load		
L	Balancing Area Annual Peak Load	24,054	Loads
M	Average Daily Peak Native Load in Peak Month	17,708	Loads
N	Amount of Line M Attributable to Seller, if any	10	SellerLoads
O	Wholesale Load (L-M)	6,346	
P	Net Uncommitted Supply (K-O)	9,728	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,012	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	4,548	
	% of SIL for Seller's imported capacity →	0.04	
	% of SIL for Other's imported capacity →	0.96	
	SIL Value →	4548	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **CT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	843	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	102	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	7,524	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	2,948	Calculated
I	Study Area Reserve Requirement	689	Gendata
J	Amount of Line I Attributable to Seller, if any	10	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	5,674	
	Load		
L	Balancing Area Annual Peak Load	6,419	Loads
M	Average Daily Peak Native Load in Peak Month	5,054	Loads
N	Amount of Line M Attributable to Seller, if any	14	SellerLoads
O	Wholesale Load (L-M)	1,365	
P	Net Uncommitted Supply (K-O)	4,309	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	920	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	3,050
% of SIL for Seller's imported capacity →	0.03
% of SIL for Other's imported capacity →	0.97
SIL Value →	3050
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **SWCT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	400	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	98	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	2,090	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	3,102	Calculated
I	Study Area Reserve Requirement	205	Gendata
J	Amount of Line I Attributable to Seller, if any	0	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	2,985	
	Load		
L	Balancing Area Annual Peak Load	3,286	Loads
M	Average Daily Peak Native Load in Peak Month	2,500	Loads
N	Amount of Line M Attributable to Seller, if any	0	SellerLoads
O	Wholesale Load (L-M)	786	
P	Net Uncommitted Supply (K-O)	2,199	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	498	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	3,200	
	% of SIL for Seller's imported capacity →	0.03	
	% of SIL for Other's imported capacity →	0.97	
	SIL Value →	3200	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **ISONE**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)				
A	Installed Capacity (inside the study area)	860	852	843	852
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	12	16	16	16
D	Seasonal Average Planned Outages	29	87	7	79
E	Uncommitted Capacity Imports	222	188	177	188
	Capacity Deductions				
F	Average Peak Native Load in the Season	16,956	14,847	17,687	15,178
G	Amount of Line F Attributable to Seller, if any	113	102	39	5
H	Amount of Line F Attributable to Non-Affiliates, if any	16,843	14,745	17,648	15,173
I	Study Area Reserve Requirement	2,530	2,510	2,510	2,510
J	Amount of Line I Attributable to Seller, if any	16	20	10	3
K	Amount of Line I Attributable to Non-Affiliates, if any	2,514	2,490	2,500	2,507
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	32,149	30,892	29,634	30,892
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	12	16	16	16
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
O	Seasonal Average Planned Outages	1,097	3,148	229	2,881
P	Uncommitted Capacity Imports	4,326	4,360	4,371	4,360
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	16,033	14,885	13,644	14,707
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	911	815	948	935
S	Total Seasonal Uncommitted Capacity (Q+R)	16,944	15,700	14,592	15,642
T	**Applicant's Market Share (R÷S)**	5.4%	5.2%	6.5%	6.0%
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**
U	Total Imports, as filed by Seller (E+P)	4,548	4,548	4,548	4,548
V	SIL Value	4,548	4,548	4,548	4,548
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No

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Reference
SellerGendata Table2Data SellerInMarket Table2Data SellerInMarket; Table2Data SellerGendata Calculated
Loads SellerLoads F - G Gendata SellerGendata I - J
Gendata; Row A Table2Data SellerInMarket Table2Data SellerInMarket; Table2 Data Gendata; Row D Calculated

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **CT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)				
A	Installed Capacity (inside the study area)	860	852	843	852
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
D	Seasonal Average Planned Outages	29	87	7	79
E	Uncommitted Capacity Imports	106	93	93	94
	Capacity Deductions				
F	Average Peak Native Load in the Season	4,207	3,642	4,503	3,772
G	Amount of Line F Attributable to Seller, if any	113	102	39	5
H	Amount of Line F Attributable to Non-Affiliates, if any	4,093	3,540	4,464	3,766
I	Study Area Reserve Requirement	683	683	689	683
J	Amount of Line I Attributable to Seller, if any	21	22	10	3
K	Amount of Line I Attributable to Non-Affiliates, if any	662	661	679	680
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	8,048	7,786	7,524	7,786
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
O	Seasonal Average Planned Outages	275	793	58	726
P	Uncommitted Capacity Imports	2,944	2,957	2,957	2,956
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	5,963	5,749	5,279	5,570
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	802	734	881	857
S	Total Seasonal Uncommitted Capacity (Q+R)	6,765	6,482	6,160	6,427
T	**Applicant's Market Share** (R÷S)	11.8%	11.3%	14.3%	13.3%
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**
U	Total Imports, as filed by Seller (E+P)	3,050	3,050	3,050	3,050
V	SIL Value	3,050	3,050	3,050	3,050
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No

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Reference
SellerGendata Table2Data SellerInMarket Table2Data SellerInMarket; Table2Data SellerGendata Calculated
Loads SellerLoads F - G Gendata SellerGendata I - J
Gendata; Row A Table2Data SellerInMarket Table2Data SellerInMarket; Table2 Data Gendata; Row D Calculated

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **SWCT**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)				
A	Installed Capacity (inside the study area)	407	404	400	404
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
D	Seasonal Average Planned Outages	14	41	3	38
E	Uncommitted Capacity Imports	86	68	91	101
	Capacity Deductions				
F	Average Peak Native Load in the Season	2,048	1,758	2,178	1,766
G	Amount of Line F Attributable to Seller, if any	0	0	0	0
H	Amount of Line F Attributable to Non-Affiliates, if any	2,048	1,758	2,178	1,766
I	Study Area Reserve Requirement	209	206	205	206
J	Amount of Line I Attributable to Seller, if any	0	0	0	0
K	Amount of Line I Attributable to Non-Affiliates, if any	209	206	205	206
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	2,321	2,206	2,090	2,206
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
O	Seasonal Average Planned Outages	79	225	16	206
P	Uncommitted Capacity Imports	2,454	2,302	3,109	3,089
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	2,439	2,318	2,799	3,116
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	479	430	488	467
S	Total Seasonal Uncommitted Capacity (Q+R)	2,918	2,748	3,287	3,583
T	**Applicant's Market Share** (R÷S)	16.4%	15.7%	14.9%	13.0%
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**
U	Total Imports, as filed by Seller (E+P)	2,540	2,370	3,200	3,190
V	SIL Value	2,540	2,370	3,200	3,190
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No

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Reference
SellerGendata Table2Data SellerInMarket Table2Data SellerInMarket; Table2Data SellerGendata Calculated
Loads SellerLoads F - G Gendata SellerGendata I - J
Gendata; Row A Table2Data SellerInMarket Table2Data SellerInMarket; Table2 Data Gendata; Row D Calculated

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **NYISO**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	757	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	265	Table2Data
C	Long-term Firm Sales (in and outside the study area)	0	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	585	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	42,506	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,265	Calculated
I	Study Area Reserve Requirement	2,620	Gendata
J	Amount of Line I Attributable to Seller, if any	0	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	22,514	
	Load		
L	Balancing Area Annual Peak Load	31,138	Loads
M	Average Daily Peak Native Load in Peak Month	25,244	Loads
N	Amount of Line M Attributable to Seller, if any	0	SellerLoads
O	Wholesale Load (L-M)	5,894	
P	Net Uncommitted Supply (K-O)	16,620	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	1,607	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	
	Total Imports (Sum D, H) as filed by Seller →	6,850	
	% of SIL for Seller's imported capacity →	0.09	
	% of SIL for Other's imported capacity →	0.91	
	SIL Value →	6850	
	Do Total Imports exceed the SIL Value? →	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **NYISO**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)				
A	Installed Capacity (inside the study area)	870	814	757	814
A1	Remote Capacity (from outside the study area)	0	0	0	0
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0
B1	Long-Term Firm Purchases (from outside the study area)	265	265	265	265
C	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
D	Seasonal Average Planned Outages	71	115	13	92
E	Uncommitted Capacity Imports	731	600	582	640
	Capacity Deductions				
F	Average Peak Native Load in the Season	21,006	18,974	23,056	19,579
G	Amount of Line F Attributable to Seller, if any	0	0	0	0
H	Amount of Line F Attributable to Non-Affiliates, if any	21,006	18,974	23,056	19,579
I	Study Area Reserve Requirement	2,620	2,620	2,620	2,620
J	Amount of Line I Attributable to Seller, if any	0	0	0	0
K	Amount of Line I Attributable to Non-Affiliates, if any	2,620	2,620	2,620	2,620
	Non-Affiliate Capacity (owned, controlled or under LT contract)				
L	Installed Capacity (inside the study area)	40,162	41,334	42,506	41,334
L1	Remote Capacity (from outside the study area)	0	0	0	0
M	Long-Term Firm Purchases (inside the study area)	0	0	0	0
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0
O	Seasonal Average Planned Outages	3,277	5,820	726	4,652
P	Uncommitted Capacity Imports	6,904	6,924	6,268	7,055
	Supply Calculation				
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	20,162	20,843	22,372	21,538
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	1,795	1,564	1,591	1,627
S	Total Seasonal Uncommitted Capacity (Q+R)	21,958	22,407	23,963	23,166
T	**Applicant's Market Share** (R÷S)	8.2%	7.0%	6.6%	7.0%
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**
U	Total Imports, as filed by Seller (E+P)	7,635	7,524	6,850	7,695
V	SIL Value	7,635	7,524	6,850	7,695
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No

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Reference
SellerGendata Table2Data SellerInMarket Table2Data SellerInMarket; Table2Data SellerGendata Calculated
Loads SellerLoads F - G Gendata SellerGendata I - J
Gendata; Row A Table2Data SellerInMarket Table2Data SellerInMarket; Table2 Data Gendata; Row D Calculated

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Scenario 1 PSEG 2016 MBR for PJM						
	PSA		WM			
			Winter		Spring	
Destination	Margin (MW)	Result	Share (%)	Result	Share (%)	Result
PJM Interconnection	35,891	Pass	9.5	Pass	7.7	Pass
PJM East	3,572	Pass	32.7	Fail	27.0	Fail
PJM East of 5004/05	5,389	Pass	24.3	Fail	20.7	Fail
PJM East of AP South	7,602	Pass	18.5	Pass	15.5	Pass

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SA			
Summer		Fall	
Share (%)	Result	Share (%)	Result
8.3	Pass	8.3	Pass
32.9	Fail	29.7	Fail
23.7	Fail	23.1	Fail
18.8	Pass	17.0	Pass

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	9,844	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	195	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	1,943	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	152	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	175,931	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	1,943	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	195	Row B; Table2Data
H	Uncommitted Capacity Imports	7,448	Calculated
I	Study Area Reserve Requirement	8,187	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	63,588	
	Load		
L	Balancing Area Annual Peak Load	143,633	Loads
M	Average Daily Peak Native Load in Peak Month	121,600	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	22,034	
P	Net Uncommitted Supply (K-O)	41,555	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,664	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	7,600
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	7600
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	14	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	88	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	26,628	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	14	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,449	Calculated
I	Study Area Reserve Requirement	1,724	Gendata
J	Amount of Line I Attributable to Seller, if any	176	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	15,220	
	Load		
L	Balancing Area Annual Peak Load	30,240	Loads
M	Average Daily Peak Native Load in Peak Month	24,093	Loads
N	Amount of Line M Attributable to Seller, if any	2,269	SellerLoads
O	Wholesale Load (L-M)	6,148	
P	Net Uncommitted Supply (K-O)	9,072	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,500	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P)	**Pass**	
	(Fail if Line Q > Line P)		

Total Imports (Sum D, H) as filed by Seller →	6,537
% of SIL for Seller's imported capacity →	0.01
% of SIL for Other's imported capacity →	0.99
SIL Value →	6537
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	107	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	51,729	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	6,212	Calculated
I	Study Area Reserve Requirement	2,975	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	20,577	
	Load		
L	Balancing Area Annual Peak Load	52,190	Loads
M	Average Daily Peak Native Load in Peak Month	42,368	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	9,822	
P	Net Uncommitted Supply (K-O)	10,754	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,365	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	6,319
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	6319
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part I -- Pivotal Supplier Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	(MW)	Reference
	Generation		
	Seller and Affiliate Capacity (owned or controlled)		
A	Installed Capacity (from inside the study area)	7,871	SellerGendata
A1	Remote Capacity (from outside the study area)	0	Table2Data
B	Long-term Firm Purchases (from inside the study area)	0	SellerInMarket
B1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
C	Long-term Firm Sales (in and outside the study area)	28	SellerInMarket; Table2Data
D	Uncommitted Capacity Imports	85	Calculated
	Non-Affiliate Capacity (owned or controlled)		
E	Installed Capacity (from inside the study area)	75,381	Gendata; Row A
E1	Remote Capacity (from outside the study area)	0	Table2Data
F	Long-term Firm Purchases (from inside the study area)	28	SellerInMarket
F1	Long-term Firm Purchases (from outside the study area)	0	Table2Data
G	Long-term Firm Sales (in and outside the study area)	0	Row B; Table2Data
H	Uncommitted Capacity Imports	4,370	Calculated
I	Study Area Reserve Requirement	4,032	Gendata
J	Amount of Line I Attributable to Seller, if any	186	SellerGendata
K	Total uncommitted supply (A+A1+B+B1+D+E+E1+F+F1+H-C-G-I-M)	25,567	
	Load		
L	Balancing Area Annual Peak Load	70,729	Loads
M	Average Daily Peak Native Load in Peak Month	58,108	Loads
N	Amount of Line M Attributable to Seller, if any	2,398	SellerLoads
O	Wholesale Load (L-M)	12,621	
P	Net Uncommitted Supply (K-O)	12,946	
Q	Sellers's Uncommitted Capacity (A+A1+B+B1+D-C-J-N)	5,344	
	Result of Pivotal Supplier Screen (Pass if Line Q < Line P) (Fail if Line Q > Line P)	**Pass**	

Total Imports (Sum D, H) as filed by Seller →	4,455
% of SIL for Seller's imported capacity →	0.02
% of SIL for Other's imported capacity →	0.98
SIL Value →	4455
Do Total Imports exceed the SIL Value? →	No

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season: Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	11,339	10,592	9,844	10,592	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	195	195	195	195	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	1,643	1,944	1,943	1,944	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	491	1,461	225	1,374	SellerGendata
E	Uncommitted Capacity Imports	214	204	138	117	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	108,842	91,954	109,399	91,992	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	106,988	90,430	107,540	90,648	F - G
I	Study Area Reserve Requirement	7,474	6,516	7,991	6,470	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	7,335	6,385	7,817	6,352	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	181,889	178,911	175,931	178,911	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	1,643	1,944	1,943	1,944	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	195	195	195	195	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	7,868	24,681	4,028	23,215	Gendata; Row D
P	Uncommitted Capacity Imports	11,783	12,069	7,462	6,950	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	72,929	71,233	65,756	67,394	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,622	5,931	5,975	6,123	
S	Total Seasonal Uncommitted Capacity (Q+R)	80,550	77,164	71,731	73,518	
T	**Applicant's Market Share** (R÷S)	9.5%	7.7%	8.3%	8.3%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	11,997	12,273	7,600	7,067	
V	SIL Value	11,997	12,273	7,600	7,067	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJME**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	22	14	14	14	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	121	72	78	68	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	18,303	15,919	20,901	16,346	Loads
G	Amount of Line F Attributable to Seller, if any	1,749	1,434	1,764	1,268	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	16,553	14,485	19,137	15,078	F - G
I	Study Area Reserve Requirement	1,258	1,168	1,659	1,211	Gendata
J	Amount of Line I Attributable to Seller, if any	130	122	165	110	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	1,128	1,046	1,494	1,101	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	26,328	26,478	26,628	26,478	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	22	14	14	14	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	1,139	3,653	610	3,436	Gendata; Row D
P	Uncommitted Capacity Imports	7,381	8,758	6,459	7,791	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	14,911	16,065	11,860	14,667	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,230	5,954	5,826	6,199	
S	Total Seasonal Uncommitted Capacity (Q+R)	22,141	22,019	17,686	20,867	
T	**Applicant's Market Share** (R÷S)	32.7%	27.0%	32.9%	29.7%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	7,502	8,830	6,537	7,859	
V	SIL Value	7,502	8,830	6,537	7,859	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJM50**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	162	91	95	69	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	35,188	30,080	37,518	30,214	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	33,334	28,556	35,658	28,871	F - G
I	Study Area Reserve Requirement	2,450	2,184	2,889	2,189	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	2,311	2,054	2,715	2,071	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	52,220	51,975	51,729	51,975	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	2,259	7,170	1,184	6,744	Gendata; Row D
P	Uncommitted Capacity Imports	7,942	8,202	6,224	6,034	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	22,294	22,424	18,423	20,350	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,144	5,861	5,725	6,103	
S	Total Seasonal Uncommitted Capacity (Q+R)	29,438	28,286	24,148	26,453	
T	**Applicant's Market Share** (R÷S)	24.3%	20.7%	23.7%	23.1%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Fail**	**Fail**	**Fail**	**Fail**	
U	Total Imports, as filed by Seller (E+P)	8,104	8,293	6,319	6,103	
V	SIL Value	8,104	8,293	6,319	6,103	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Appendix A:
Part II -- Market Share Analysis

Applicant → **Public Service Enterprise Group Inc**
Destination Market → **PJMAP**
Data Year → **Dec 2014 — Nov 2015**

Row	Description	Season Winter (MW)	Spring (MW)	Summer (MW)	Fall (MW)	Reference
	Seller and Affiliate Capacity (owned, controlled and under LT Contract)					
A	Installed Capacity (inside the study area)	9,418	8,645	7,871	8,645	SellerGendata
A1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
B	Long-Term Firm Purchases (inside the study area)	0	0	0	0	SellerInMarket
B1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
C	Long-Term Firm Sales (in and outside the study area)	36	28	28	28	SellerInMarket; Table2Data
D	Seasonal Average Planned Outages	407	1,193	180	1,122	SellerGendata
E	Uncommitted Capacity Imports	187	115	77	81	Calculated
	Capacity Deductions					
F	Average Peak Native Load in the Season	48,658	41,074	51,437	41,155	Loads
G	Amount of Line F Attributable to Seller, if any	1,854	1,524	1,859	1,343	SellerLoads
H	Amount of Line F Attributable to Non-Affiliates, if any	46,804	39,551	49,577	39,811	F - G
I	Study Area Reserve Requirement	3,496	3,025	3,935	2,991	Gendata
J	Amount of Line I Attributable to Seller, if any	139	130	174	118	SellerGendata
K	Amount of Line I Attributable to Non-Affiliates, if any	3,358	2,895	3,762	2,873	I - J
	Non-Affiliate Capacity (owned, controlled or under LT contract)					
L	Installed Capacity (inside the study area)	77,314	76,348	75,381	76,348	Gendata; Row A
L1	Remote Capacity (from outside the study area)	0	0	0	0	Table2Data
M	Long-Term Firm Purchases (inside the study area)	36	28	28	28	SellerInMarket
M1	Long-Term Firm Purchases (from outside the study area)	0	0	0	0	Table2Data
N	Long-Term Firm Sales (in and outside the study area)	0	0	0	0	SellerInMarket; Table2 Data
O	Seasonal Average Planned Outages	3,344	10,532	1,726	9,907	Gendata; Row D
P	Uncommitted Capacity Imports	7,710	8,741	4,378	5,987	Calculated
	Supply Calculation					
Q	Total Competing Supply (L+L1+M+M1+P-H-K-N-O)	31,554	32,139	24,722	29,772	
R	Seller's Uncommitted Capacity (A+A1+B+B1+E-C-D-G-J)	7,169	5,885	5,707	6,115	
S	Total Seasonal Uncommitted Capacity (Q+R)	38,723	38,024	30,429	35,886	
T	**Applicant's Market Share** (R÷S)	18.5%	15.5%	18.8%	17.0%	
	Results (Pass if < 20% and Fail if ≥ 20%)	**Pass**	**Pass**	**Pass**	**Pass**	
U	Total Imports, as filed by Seller (E+P)	7,897	8,856	4,455	6,068	
V	SIL Value	7,897	8,856	4,455	6,068	
	Do Total Imports exceed SIL Value? (Is U <=V?)	No	No	No	No	

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Document Content(s)

PSEG Nuclear 2016 Form 580.PDF.....1-1

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email: alexander.stern@pseg.com

PSEG
Services Corporation

January 11, 2013

VIA E- FILING

Kimberly D. Bose, Secretary
Nathaniel J. Davis, Sr., Deputy Secretary
Federal Energy Regulatory Commission
888 1st Street, N.E., Room 1A
Washington, D.C. 20426

Re: Order No. 580
Docket No. RM 94-14-000

Dear Secretary Bose and Deputy Secretary Davis:

In accordance with 18 CFR § 35.33(d), attached is the financial reports furnished by our trustee, Mellon Bank, for PSEG Nuclear LLC's ("PSEG") Qualified and Non-Qualified Nuclear Decommissioning Trust Funds for the year ending December 31, 2012.

On December 31, 2012 assets in the trust funds totaled $1,505,604,227.68, included in this balance are amounts collected through FERC jurisdictional rates totaling $14,694,132.34. This total represents the contributions and earnings on the funds since its inception in 1988. During 2011, there were no contributions made to the PSEG trust funds.

If you have any questions, or would like to see the detailed information that comprise the numbers shown on the Mellon Bank statements, please contact Peter Caruso at (973) 430-5222.

Sincerely,

Alexander C, Stern

Alexander C. Stern

ACS/jb
Enclosure(s)

PSEG Nuclear LLC
FERC ASSET Allocation
As of December 31, 2012

Account Names	Percentage	Total Trust Market Values	Non-FERC Assets	FERC Assets
Q Hope Creek	33.5%	$ 441,553,084.25	$440,981,066.52	$572,017.73
Q PB 2	14.9%	$ 196,479,797.38	$194,047,436.05	$2,432,361.33
Q PB 3	15.9%	$ 209,945,931.86	$207,501,529.04	$2,444,402.82
Q Salem 1	17.0%	$ 223,468,610.35	$218,912,667.16	$4,555,943.19
Q Salem 2	18.6%	$ 245,223,576.06	$241,287,704.85	$3,935,871.21
PSEG Nuclear LLC Qual. Plans	G716275	$ 1,316,670,999.90		
Non-Q Salem 1	36.8%	$ 69,535,900.56	$69,363,037.68	$172,862.88
Non-Q Salem 2	12.0%	$ 22,651,660.58	$22,568,186.80	$83,473.78
Non-Q PB 2	26.5%	$ 50,026,995.04	$49,778,236.48	$248,758.56
Non-Q PB 3	21.0%	$ 39,597,779.64	$39,349,338.80	$248,440.84
Non-Q Hope Creek	3.8%	$ 7,120,891.96	$7,120,891.96	$ -
PSEG Nuclear LLC Non Qual. Plans	G716277	$ 188,933,227.78		
Totals		$ 1,505,604,227.68	$1,490,910,095.34	$14,694,132.34
			99.02%	0.98%

SI-SSA-0010-6042

THE BANK OF NEW YORK MELLON.

TRDPSB PSBG71627500 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

INVESTMENT DETAIL PAGE: 1

PSB G716275 31 DECEMBER 2012 M1101

PSEG NUCLEAR LLC QUAL. PLANS

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	PSE&G QUALIFIED MTU				
222,508,462.5060	HOPE CREEK QUAL	385,136,043.97	1.9818	440,981,066.52	55,845,022.55
97,911,679.0430	PEACH BOTTOM #2 Q	171,686,913.92	1.9818	194,047,436.05	22,360,522.13
104,700,291.4640	PEACH BOTTOM #3 Q	183,512,010.54	1.9818	207,501,529.04	23,989,518.50
110,458,077.8860	SALEM Q UNIT 1	195,970,112.18	1.9818	218,912,667.16	22,942,554.98
121,747,984.9000	SALEM Q UNIT 2	216,309,941.06	1.9818	241,287,704.85	24,977,763.79
2,298,819.5910	SALEM Q #1 FERC	4,834,461.98	1.9818	4,555,943.19	278,518.79-
1,985,946.1490	SALEM Q #2 FERC	4,025,695.96	1.9818	3,935,871.21	89,824.75-
1,227,311.1520	PB#2 Q FERC	2,543,635.47	1.9818	2,432,361.33	111,274.14-
1,233,386.9960	PB#3 Q FERC	2,563,315.52	1.9818	2,444,402.82	118,912.70-
288,626.4160	HOPE CREEK QUAL FERC	688,317.49	1.9818	572,017.73	116,299.76-
664,360,586.1030		1,167,270,448.09		1,316,670,999.90	149,400,551.81
TOTAL INVESTMENTS UNIT OF PARTICIPATION		1,167,270,448.09		1,316,670,999.90	149,400,551.81
TOTAL INVESTMENT		1,167,270,448.09		1,316,670,999.90	149,400,551.81

SI-SSA-0010-6043

THE BANK OF NEW YORK MELLON.

TRDPSB PSBG71627700 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

INVESTMENT DETAIL PAGE: 1

PSB G716277 31 DECEMBER 2012 M1101

PSEG NUCLEAR LLC NQ PLANS

SHARES/ PAR VALUE	SECURITY DESCRIPTION	COST	PRICE	MARKET VALUE	UNREALIZED GAIN/LOSS
INVESTMENTS UNIT OF PARTICIPATION					
	PSE&G NON-QUALIFIED MTU				
4,397,995.9250	HOPE CREEK NONQUAL	6,603,610.81	1.6191	7,120,891.96	517,281.15
30,743,968.9440	PEACH BOTTOM #2 NQ	46,794,106.27	1.6191	49,778,236.48	2,984,130.21
24,302,886.8740	PEACH BOTTOM #3 NQ	37,099,813.63	1.6191	39,349,338.80	2,249,525.17
42,839,908.0980	SALEM NQ UNIT 1	65,054,244.90	1.6191	69,363,037.68	4,308,792.78
13,938,533.8450	SALEM NQ UNIT 2	21,112,746.71	1.6191	22,568,186.80	1,455,440.09
106,763.3430	SALEM NQ #1 FERC	171,486.30	1.6191	172,862.88	1,376.58
51,554.9650	SALEM NQ #2 FERC	82,809.07	1.6191	83,473.78	664.71
153,637.9330	PB#2 NQ FERC	246,781.37	1.6191	248,758.56	1,977.19
153,441.7060	PB#3 NQ FERC	246,465.84	1.6191	248,440.84	1,975.00
116,688,691.6330		177,412,064.90		188,933,227.78	11,521,162.88
TOTAL INVESTMENTS UNIT OF PARTICIPATION		177,412,064.90		188,933,227.78	11,521,162.88
TOTAL INVESTMENT		177,412,064.90		188,933,227.78	11,521,162.88

SI-SSA-0010-6044

20130111-5084 FERC PDF (Unofficial) 1/11/2013 10:46:10 AM

FERC Non-Qualified Reports

THE BANK OF NEW YORK MELLON.

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFITS
31 DECEMBER 2012

PSB F092879
PSEG NUCLEAR HOPE CREEK QUAL
NC100

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 437,199,251.97		$ 397,965,333.67
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 58,139.27		$ 251,809.61	
UNREALIZED GAIN/LOSS-INVESTMENT	2,779,376.71		30,385,569.31	
		2,837,515.98		30,637,378.92
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		127,695.46	
MASTER TRUST ALLOCATED EXPENSES	69,817.54-		2,150,761.87-	
MASTER TRUST CHANGE IN REALIZED G/L	636,509.37		5,708,628.65	
MASTER TRUST INTEREST INCOME EARNED	548,044.75		7,088,138.05	
MASTER TRUST DIVIDEND INCOME EARNED	308,561.99		4,032,787.08	
		1,423,298.57		14,806,487.37
TRANSFERS IN:				
CASH	0.00		9,866.56	
		0.00		9,866.56
TOTAL RECEIPTS		4,260,814.55		45,453,732.85
DISBURSEMENTS:				
UBTI TAX EXPENSE	479,000.00		2,438,000.00	
		479,000.00		2,438,000.00
TOTAL DISBURSEMENTS		479,000.00		2,438,000.00
NET ASSETS - END OF PERIOD		$ 440,981,066.52		$ 440,981,066.52

SI-SSA-0010-6046

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09288202 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092882 31 DECEMBER 2012 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 192,382,525.31		$ 175,151,831.16
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 23,073.17		$ 101,191.17	
UNREALIZED GAIN/LOSS-INVESTMENT	1,223,025.13		13,370,637.09	
		1,246,098.30		13,471,828.26
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		56,198.12	
MASTER TRUST ALLOCATED EXPENSES	30,722.22-		945,026.81-	
MASTER TRUST CHANGE IN REALIZED G/L	282,597.07		2,522,091.87	
MASTER TRUST INTEREST INCOME EARNED	241,159.28		3,119,379.24	
MASTER TRUST DIVIDEND INCOME EARNED	135,778.31		1,774,791.93	
		628,812.44		6,527,434.35
TRANSFERS IN:				
CASH	0.00		4,342.28	
		0.00		4,342.28
TOTAL RECEIPTS		1,874,910.74		20,003,604.89
DISBURSEMENTS:				
UBTI TAX EXPENSE	210,000.00		1,108,000.00	
		210,000.00		1,108,000.00
TOTAL DISBURSEMENTS		210,000.00		1,108,000.00
NET ASSETS - END OF PERIOD		$ 194,047,436.05		$ 194,047,436.05

SI-SSA-0010-6047

THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09288402 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092884 31 DECEMBER 2012 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 205,720,623.16		$ 187,294,145.91
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 24,697.09		$ 108,481.62	
UNREALIZED GAIN/LOSS-INVESTMENT	1,307,822.40		14,298,957.13	
		1,332,519.49		14,407,438.75
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		60,094.20	
MASTER TRUST ALLOCATED EXPENSES	32,852.31-		1,011,923.80-	
MASTER TRUST CHANGE IN REALIZED G/L	302,166.50		2,696,659.41	
MASTER TRUST INTEREST INCOME EARNED	257,879.83		3,335,638.12	
MASTER TRUST DIVIDEND INCOME EARNED	145,192.37		1,897,833.12	
		672,386.39		6,978,301.05
TRANSFERS IN:				
CASH	0.00		4,643.33	
		0.00		4,643.33
TOTAL RECEIPTS		2,004,905.88		21,390,383.13
DISBURSEMENTS:				
UBTI TAX EXPENSE	224,000.00		1,183,000.00	
		224,000.00		1,183,000.00
TOTAL DISBURSEMENTS		224,000.00		1,183,000.00
NET ASSETS - END OF PERIOD		$ 207,501,529.04		$ 207,501,529.04

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THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09288602 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092886 31 DECEMBER 2012 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 217,031,505.42		$ 197,644,297.34
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 23,248.69		$ 104,520.20	
UNREALIZED GAIN/LOSS-INVESTMENT	1,379,743.53		15,087,478.37	
		1,402,992.22		15,191,998.57
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		63,412.07	
MASTER TRUST ALLOCATED EXPENSES	34,658.96-		1,067,868.06-	
MASTER TRUST CHANGE IN REALIZED G/L	321,590.12		2,855,710.54	
MASTER TRUST INTEREST INCOME EARNED	272,061.42		3,519,650.11	
MASTER TRUST DIVIDEND INCOME EARNED	153,176.94		2,002,566.77	
		712,169.52		7,373,471.43
TRANSFERS IN:				
CASH	0.00		4,899.82	
		0.00		4,899.82
TOTAL RECEIPTS		2,115,161.74		22,570,369.82
DISBURSEMENTS:				
UBTI TAX EXPENSE	234,000.00		1,302,000.00	
		234,000.00		1,302,000.00
TOTAL DISBURSEMENTS		234,000.00		1,302,000.00
NET ASSETS - END OF PERIOD		$ 218,912,667.16		$ 218,912,667.16

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THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09288802 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092888 31 DECEMBER 2012 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 239,220,352.69		$ 217,782,940.67
RECEIPTS:				
INVESTMENT INCOME:				
REALIZED GAIN/LOSS	$ 25,886.79		$ 108,388.71	
UNREALIZED GAIN/LOSS-INVESTMENT	1,520,766.95		16,628,707.11	
		1,546,653.74		16,737,095.82
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		69,876.76	
MASTER TRUST ALLOCATED EXPENSES	38,201.45-		1,178,410.88-	
MASTER TRUST CHANGE IN REALIZED G/L	354,197.96		3,153,338.66	
MASTER TRUST INTEREST INCOME EARNED	299,868.78		3,878,674.79	
MASTER TRUST DIVIDEND INCOME EARNED	168,833.13		2,206,789.90	
		784,698.42		8,130,269.23
TRANSFERS IN:				
CASH	0.00		5,399.13	
		0.00		5,399.13
TOTAL RECEIPTS		2,331,352.16		24,872,764.18
DISBURSEMENTS:				
UBTI TAX EXPENSE	264,000.00		1,368,000.00	
		264,000.00		1,368,000.00
TOTAL DISBURSEMENTS		264,000.00		1,368,000.00
NET ASSETS - END OF PERIOD		$ 241,287,704.85		$ 241,287,704.85

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TRDPSB PSBF09319702 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093197 31 DECEMBER 2012 NC100

PSEG NUCLEAR HOPE CREEK QUAL

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 566,490.82		$ 513,275.90
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 3,605.26		$ 148,921.91-	
		3,605.26		148,921.91-
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		165.06	
MASTER TRUST ALLOCATED EXPENSES	90.56-		185,418.78	
MASTER TRUST CHANGE IN REALIZED G/L	901.06		7,701.34	
MASTER TRUST INTEREST INCOME EARNED	710.90		9,165.66	
MASTER TRUST DIVIDEND INCOME EARNED	400.25		5,212.90	
		1,921.65		207,663.74
TOTAL RECEIPTS		5,526.91		58,741.83
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 572,017.73		$ 572,017.73

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THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09319502 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093195 31 DECEMBER 2012 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 2,408,859.55		$ 2,182,525.22
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 15,330.48		$ 5,180.15	
		15,330.48		5,180.15
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		701.82	
MASTER TRUST ALLOCATED EXPENSES	385.10-		150,011.76	
MASTER TRUST CHANGE IN REALIZED G/L	3,831.54		32,747.61	
MASTER TRUST INTEREST INCOME EARNED	3,022.90		38,974.26	
MASTER TRUST DIVIDEND INCOME EARNED	1,701.96		22,166.28	
		8,171.30		244,601.73
TRANSFERS IN:				
CASH	0.00		54.23	
		0.00		54.23
TOTAL RECEIPTS		23,501.78		249,836.11
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 2,432,361.33		$ 2,432,361.33

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THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09319602 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093196 31 DECEMBER 2012 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 2,420,784.69		$ 2,193,329.87
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 15,406.37		$ 2,933.90-	
		15,406.37		2,933.90-
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		705.32	
MASTER TRUST ALLOCATED EXPENSES	387.01-		158,894.09	
MASTER TRUST CHANGE IN REALIZED G/L	3,850.51		32,909.70	
MASTER TRUST INTEREST INCOME EARNED	3,037.87		39,167.24	
MASTER TRUST DIVIDEND INCOME EARNED	1,710.39		22,275.99	
		8,211.76		253,952.34
TRANSFERS IN:				
CASH	0.00		54.51	
		0.00		54.51
TOTAL RECEIPTS		23,618.13		251,072.95
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 2,444,402.82		$ 2,444,402.82

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THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09319302 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093193 31 DECEMBER 2012 NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 4,511,923.10		$ 4,087,986.73
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 28,714.79		$ 31,061.30-	
		28,714.79		31,061.30-
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		1,314.61	
MASTER TRUST ALLOCATED EXPENSES	721.31-		321,744.01	
MASTER TRUST CHANGE IN REALIZED G/L	7,176.68		61,337.98	
MASTER TRUST INTEREST INCOME EARNED	5,662.06		73,000.91	
MASTER TRUST DIVIDEND INCOME EARNED	3,187.87		41,518.65	
		15,305.30		498,916.16
TRANSFERS IN:				
CASH	0.00		101.60	
		0.00		101.60
TOTAL RECEIPTS		44,020.09		467,956.46
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 4,555,943.19		$ 4,555,943.19

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THE BANK OF NEW YORK MELLON.

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F093194
31 DECEMBER 2012
NC100

PSEG NUCLEAR SALEM QUAL UNIT

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 3,897,842.32		$ 3,531,604.45
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 24,806.67		$ 118,924.37	
		24,806.67		118,924.37
MASTER TRUST INVESTMENT GAIN/LOSS	0.00		1,135.69	
MASTER TRUST ALLOCATED EXPENSES	623.14-		132,195.95	
MASTER TRUST CHANGE IN REALIZED G/L	6,199.92		52,989.78	
MASTER TRUST INTEREST INCOME EARNED	4,891.44		63,065.32	
MASTER TRUST DIVIDEND INCOME EARNED	2,754.00		35,867.88	
		13,222.22		285,254.62
TRANSFERS IN:				
CASH	0.00		87.77	
		0.00		87.77
TOTAL RECEIPTS		38,028.89		404,266.76
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 3,935,871.21		$ 3,935,871.21

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THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09288502 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092885 31 DECEMBER 2012 NC100

PSEG NUCLEAR SALEM NONQUAL

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 69,203,973.10		$ 60,792,399.99
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 206,236.25-		$ 4,403,764.37-	
		206,236.25-		4,403,764.37-
MASTER TRUST INVESTMENT GAIN/LOSS	38.33		58,029.32	
MASTER TRUST ALLOCATED EXPENSES	81,564.54-		232,707.84-	
MASTER TRUST CHANGE IN REALIZED G/L	268,994.36		10,861,547.21	
MASTER TRUST INTEREST INCOME EARNED	93.97		380.09	
MASTER TRUST DIVIDEND INCOME EARNED	177,738.71		2,287,153.28	
		365,300.83		12,974,402.06
TOTAL RECEIPTS		159,064.58		8,570,637.69
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 69,363,037.68		$ 69,363,037.68

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THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09288702 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092887 31 DECEMBER 2012 NC100

PSEG NUCLEAR SALEM NONQUAL

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 22,516,433.02		$ 19,779,615.84
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 67,101.70-		$ 1,432,823.30-	
		67,101.70-		1,432,823.30-
MASTER TRUST INVESTMENT GAIN/LOSS	12.47		18,880.63	
MASTER TRUST ALLOCATED EXPENSES	26,538.11-		75,714.62-	
MASTER TRUST CHANGE IN REALIZED G/L	87,520.89		3,533,948.84	
MASTER TRUST INTEREST INCOME EARNED	30.58		123.66	
MASTER TRUST DIVIDEND INCOME EARNED	57,829.65		744,155.75	
		118,855.48		4,221,394.26
TOTAL RECEIPTS		51,753.78		2,788,570.96
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 22,568,186.80		$ 22,568,186.80

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THE BANK OF NEW YORK MELLON.

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFITS
31 DECEMBER 2012

PSB F092881
PSEG NUCLEAR PEACH BOTTOM #2
NC100

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 49,664,084.13		$ 43,627,536.57
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 148,005.02-		$ 3,160,352.14-	
		148,005.02-		3,160,352.14-
MASTER TRUST INVESTMENT GAIN/LOSS	27.51		41,644.65	
MASTER TRUST ALLOCATED EXPENSES	58,534.62-		167,002.30-	
MASTER TRUST CHANGE IN REALIZED G/L	193,043.23		7,794,766.25	
MASTER TRUST INTEREST INCOME EARNED	67.44		272.76	
MASTER TRUST DIVIDEND INCOME EARNED	127,553.81		1,641,370.69	
		262,157.37		9,311,052.05
TOTAL RECEIPTS		114,152.35		6,150,699.91
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 49,778,236.48		$ 49,778,236.48

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THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09288302 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F092883 31 DECEMBER 2012 NC100

PSEG NUCLEAR PEACH BOTTOM #3

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 39,259,102.18		$ 34,487,254.65
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 116,996.88-		$ 2,498,235.68-	
		116,996.88-		2,498,235.68-
MASTER TRUST INVESTMENT GAIN/LOSS	21.75		32,919.79	
MASTER TRUST ALLOCATED EXPENSES	46,271.21-		132,014.13-	
MASTER TRUST CHANGE IN REALIZED G/L	152,599.28		6,161,706.78	
MASTER TRUST INTEREST INCOME EARNED	53.31		215.62	
MASTER TRUST DIVIDEND INCOME EARNED	100,830.37		1,297,491.77	
		207,233.50		7,360,319.83
TOTAL RECEIPTS		90,236.62		4,862,084.15
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 39,349,338.80		$ 39,349,338.80

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THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09288002 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S

PSB F092880
31 DECEMBER 2012
NC100

PSEG NUCLEAR HOPE CREEK

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 7,104,562.20		$ 6,241,020.10
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 21,172.47-		$ 452,095.69-	
		21,172.47-		452,095.69-
MASTER TRUST INVESTMENT GAIN/LOSS	3.94		5,957.38	
MASTER TRUST ALLOCATED EXPENSES	8,373.51-		23,890.07-	
MASTER TRUST CHANGE IN REALIZED G/L	27,615.28		1,115,059.36	
MASTER TRUST INTEREST INCOME EARNED	9.65		39.01	
MASTER TRUST DIVIDEND INCOME EARNED	18,246.87		234,801.87	
		37,502.23		1,331,967.55
TOTAL RECEIPTS		16,329.76		879,871.86
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 7,120,891.96		$ 7,120,891.96

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TRDPSB PSBF09336202 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093362 31 DECEMBER 2012 NC100

PSEG NUCLEAR SALEM NON-QUAL

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 172,466.47		$ 151,503.59
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 513.97-		$ 10,974.81-	
		513.97-		10,974.81-
MASTER TRUST INVESTMENT GAIN/LOSS	0.10		144.63	
MASTER TRUST ALLOCATED EXPENSES	203.27-		579.94-	
MASTER TRUST CHANGE IN REALIZED G/L	670.37		27,068.56	
MASTER TRUST INTEREST INCOME EARNED	0.23		0.93	
MASTER TRUST DIVIDEND INCOME EARNED	442.95		5,699.92	
		910.38		32,334.10
TOTAL RECEIPTS		396.41		21,359.29
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 172,862.88		$ 172,862.88

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THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09336302 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093363 31 DECEMBER 2012 NC100

PSEG NUCLEAR SALEM NON-QUAL

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 83,282.35		$ 73,159.59
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 248.19-		$ 5,299.66-	
		248.19-		5,299.66-
MASTER TRUST INVESTMENT GAIN/LOSS	0.05		69.85	
MASTER TRUST ALLOCATED EXPENSES	98.16-		280.04-	
MASTER TRUST CHANGE IN REALIZED G/L	323.72		13,071.15	
MASTER TRUST INTEREST INCOME EARNED	0.11		0.44	
MASTER TRUST DIVIDEND INCOME EARNED	213.90		2,752.45	
		439.62		15,613.85
TOTAL RECEIPTS		191.43		10,314.19
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 83,473.78		$ 83,473.78

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THE BANK OF NEW YORK MELLON.

TRDPSB PSBF09336402 MONTHLY FINAL 011523 2012-12-31 CYCLE A 01:15:22 RUN DATE: 10-JAN-13

STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

PSB F093364 31 DECEMBER 2012 NC100

PSEG NUCLEAR PEACH BOTTOM #2

	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 248,188.10		$ 218,021.45
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 739.63-		$ 15,793.38-	
		739.63-		15,793.38-
MASTER TRUST INVESTMENT GAIN/LOSS	0.14		208.11	
MASTER TRUST ALLOCATED EXPENSES	292.52-		834.57-	
MASTER TRUST CHANGE IN REALIZED G/L	964.70		38,953.06	
MASTER TRUST INTEREST INCOME EARNED	0.34		1.41	
MASTER TRUST DIVIDEND INCOME EARNED	637.43		8,202.48	
		1,310.09		46,530.49
TOTAL RECEIPTS		570.46		30,737.11
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 248,758.56		$ 248,758.56

SI-SSA-0010-6066

THE BANK OF NEW YORK MELLON.

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STATEMENT OF CHANGE IN NET ASSETS AVAILABLE FOR BENEFIT S PAGE: 1

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	CURRENT PERIOD 01-DEC-12	CURRENT PERIOD 31-DEC-12	YEAR TO DATE 01-JAN-12	YEAR TO DATE 31-DEC-12
NET ASSETS - BEGINNING OF PERIOD		$ 247,871.11		$ 217,742.99
RECEIPTS:				
INVESTMENT INCOME:				
UNREALIZED GAIN/LOSS-INVESTMENT	$ 738.68-		$ 15,773.11-	
		738.68-		15,773.11-
MASTER TRUST INVESTMENT GAIN/LOSS	0.13		207.82	
MASTER TRUST ALLOCATED EXPENSES	292.14-		833.49-	
MASTER TRUST CHANGE IN REALIZED G/L	963.47		38,903.31	
MASTER TRUST INTEREST INCOME EARNED	0.34		1.34	
MASTER TRUST DIVIDEND INCOME EARNED	636.61		8,191.98	
		1,308.41		46,470.96
TOTAL RECEIPTS		569.73		30,697.85
DISBURSEMENTS:				
TOTAL DISBURSEMENTS		0.00		0.00
NET ASSETS - END OF PERIOD		$ 248,440.84		$ 248,440.84

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Portfolio Statements

1 JAN 14 - 31 DEC 14

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Account Name
FERC PECO

Account Number
FERCPE

Questions?
If you have any questions about this report, call your Northern Trust account administrator.

You may have the right under applicable federal banking law to receive, at no additional cost, separate notifications of securities transactions effected for your account. If you wish to receive separate notifications, please contact your relationship officer.

***Applicable for entities subject to ERISA:**
The Northern Trust Company hereby certifies that this report furnished pursuant to 29 CFR 2520.103-5(c) is a complete and accurate reflection of its records.

Gabriel A. Lorenzo Jr.
Senior Vice President

***No Data Available**

Northern Trust

Generated by Northern Trust from periodic data on 27 Feb 15

SI-SSA-0010-6069

Notifications

IRS CIRCULAR 230 NOTICE: To the extent that this message or any attachment concerns tax matters, it is not intended to be used and cannot be used by a taxpayer for the purpose of avoiding penalties that may be imposed by law. For more information about this notice, see http://www.northerntrust.com/circular230.

Please note that this report has been created using the best available data. This report may also contain information provided by third parties, derived by third parties or derived from third party data and/or data that may have been categorized or otherwise reported based upon client direction - Northern Trust assumes no responsibility for the accuracy, timeliness or completeness of any such information. If you have questions regarding third party data or direction as it relates to this report, please contact your Northern Trust relationship team.

The term "Tax Credit" refers to local market terminology for the taxation associated with an income event. It makes no representation or warranty relating to the ability of the recipient to utilise the value as a "credit", "offset" or other benefit for their own tax purposes. Investors should seek their own tax advice relating to the specific tax considerations of investments in such markets. The Tax Credit is informational only data in the context of this report.

Please note where a client may be eligible to reclaim taxes, these are calculated and accrued for as a tax recoverable on ex date. The net amount may include the accrual of withholding taxes, tax credits or both.

◆ Change in Book and Market Value

	Cost	Market value	For more information
Opening balance	1,310,658,017.72	1,641,238,529.63	
Miscellaneous Cash Receipts	2,822,583.79	2,822,583.79	See funding & disbursement summary
Sponsor Contributions	23,454,732.96	23,454,732.96	See funding & disbursement summary
Interportfolio Transfers In	373,372,927.61	373,372,927.61	See funding & disbursement summary
Security Receipts	10,625.03	21,987.20	See funding & disbursement summary
Total receipts	399,660,869.39	399,672,231.56	See funding & disbursement summary
Miscellaneous Cash Disbursements	- 2,822,583.75	- 2,822,583.75	See funding & disbursement summary
Interportfolio Transfers Out	- 373,372,927.61	- 373,372,927.61	See funding & disbursement summary
Security Deliveries	- 10,624.97	- 21,987.14	See funding & disbursement summary
Total disbursements	- 376,206,136.33	- 376,217,498.50	See funding & disbursement summary
Income received	44,514,953.67	44,514,953.67	See income & expense summary, cash activity detail
Expenses paid	- 17,898,331.24	- 17,898,331.24	See income & expense summary
Unrealized gain/loss change	0.00	39,309,373.67	See asset summary
Realized gain/loss	36,648,889.91	36,648,889.91	See realized gain/loss summary
Accrued income change	78,247.99	78,247.99	See income & expense summary
Total amortization expense	- 4,920,382.93	- 4,920,382.93	See fixed income amortization
Total OID/MKT accretion income	179,806.28	179,806.28	See fixed income amortization
Accrued expense change	- 819,588.46	- 819,588.46	See income & expense summary
Closing balance	1,391,896,346.00	1,761,786,231.58	

Change in Cash Value

	Market value	Cost	For more information
Opening balance	82,062,361.53	82,062,425.67	
Miscellaneous cash receipts	2,948,135.39	2,948,135.39	See funding & disbursement summary
Sponsor contributions	23,454,732.96	23,454,732.96	See funding & disbursement summary
Interportfolio transfers in	373,372,927.61	373,372,927.61	See funding & disbursement summary
Total receipts	399,775,795.96	399,775,795.96	See funding & disbursement summary
Miscellaneous cash disbursements	- 2,822,583.75	- 2,822,583.75	See funding & disbursement summary
Interportfolio transfers out	- 373,372,927.61	- 373,372,927.61	See funding & disbursement summary
Total disbursements	- 376,195,511.36	- 376,195,511.36	See funding & disbursement summary
Income received	44,521,722.02	44,521,722.02	See income & expense summary, cash activity detail
Expenses paid	- 17,898,331.24	- 17,898,331.24	See income & expense summary
Capital changes	10,940,183.43	10,940,183.43	See capital change detail
Foreign currency bought	3,426,000.00	3,426,000.00	See foreign exchange summary
Foreign currency sold	- 3,426,000.00	- 3,426,000.00	See foreign exchange summary
Realized gain/loss	- 27,137.39	- 27,137.39	See realized gain/loss summary
Unrealized gain/loss	- 496.38	0.00	See asset summary
Securities bought	- 872,181,012.43	- 872,181,012.43	See investment transaction summary
Securities sold	779,327,278.13	779,327,278.13	See investment transaction summary
Principal paydowns	110,647.60	110,647.60	See investment transaction summary
Closing balance	50,435,499.87	50,436,060.39	

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Translation	Total	Market value incl. accruals	%
Equities								
Common stock								
Australia - AUD	74.60	698,162.36	620,734.42	188,048.13	-110,620.19	77,427.94	698,236.96	0.040%
Austria - EUR	0.00	16,863.16	16,613.69	1,461.41	-1,211.94	249.47	16,863.16	0.001%
Belgium - EUR	0.00	140,357.95	88,149.35	58,448.13	-6,239.53	52,208.60	140,357.95	0.008%
Canada - USD	0.00	36,306.00	24,837.75	11,468.25	0.00	11,468.25	36,306.00	0.002%
China - HKD	0.00	25.08	18.84	6.22	0.02	6.24	25.08	0.000%
Denmark - DKK	0.00	138,495.22	98,046.15	47,747.75	-7,298.68	40,449.07	138,495.22	0.008%
Finland - EUR	0.00	94,844.48	55,458.95	43,071.54	-3,686.01	39,385.53	94,844.48	0.005%
France - EUR	0.00	990,629.24	764,115.87	276,691.62	-50,178.25	226,513.37	990,629.24	0.056%
Germany - DEM	0.00	66,015.49	34,444.07	48,627.01	-17,055.59	31,571.42	66,015.49	0.004%
Germany - EUR	0.00	803,093.14	576,606.97	258,848.59	-32,362.42	226,486.17	803,093.14	0.046%
Germany - GBP	0.00	3,143.00	1,473.06	1,692.08	-22.14	1,669.94	3,143.00	0.000%
Hong Kong - HKD	0.00	327,423.40	258,669.43	68,503.05	250.92	68,753.97	327,423.40	0.019%
Ireland - EUR	0.00	31,280.30	24,039.90	9,097.37	-1,856.97	7,240.40	31,280.30	0.002%
Ireland - USD	0.00	41,244.00	24,617.00	16,627.00	0.00	16,627.00	41,244.00	0.002%
Israel - ILS	0.00	51,041.24	41,188.79	12,586.47	-2,734.02	9,852.45	51,041.24	0.003%
Italy - EUR	0.00	205,594.70	171,777.93	45,012.75	-11,195.98	33,816.77	205,594.70	0.012%
Japan - JPY	1,909.30	2,146,531.72	1,616,423.25	984,619.86	-454,511.39	530,108.47	2,148,441.02	0.122%
Netherlands - EUR	0.00	301,650.01	205,094.78	111,237.04	-14,681.81	96,555.23	301,650.01	0.017%
New Zealand - NZD	0.00	11,686.07	9,013.78	3,059.14	-386.85	2,672.29	11,686.07	0.001%
Norway - NOK	0.00	60,803.40	54,389.93	16,952.41	-10,538.94	6,413.47	60,803.40	0.003%
Portugal - EUR	0.00	5,027.02	7,791.22	- 2,296.27	-467.93	- 2,764.20	5,027.02	0.000%
Singapore - SGD	410.54	140,570.35	122,312.69	24,233.48	-5,975.82	18,257.66	140,980.89	0.008%
Singapore - USD	0.00	1,380.00	1,501.16	- 121.16	0.00	- 121.16	1,380.00	0.000%
Spain - EUR	0.00	356,285.33	245,028.89	123,162.78	-11,906.34	111,256.44	356,285.33	0.020%

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Translation	Total	Market value incl. accruals	%
Equities								
Common stock								
Sweden - SEK	0.00	319,639.89	244,283.50	106,097.23	-30,740.84	75,356.39	319,639.89	0.018%
Switzerland - CHF	0.00	972,841.51	672,859.02	342,549.83	-42,567.34	299,982.49	972,841.51	0.055%
Switzerland - GBP	0.00	3,733.78	4,290.69	- 238.35	-318.56	- 556.91	3,733.78	0.000%
United Kingdom - GBP	6,145.22	2,146,790.48	1,757,588.23	425,638.18	-36,435.93	389,202.25	2,152,935.70	0.122%
United Kingdom - USD	0.00	53,102.59	20,469.33	32,633.26	0.00	32,633.26	53,102.59	0.003%
United States - USD	39,641.05	30,600,870.55	19,615,798.18	10,985,072.37	0.00	10,985,072.37	30,640,511.60	1.739%
Total common stock	**48,180.71**	**40,765,431.46**	**27,377,636.82**	**14,240,537.17**	**-852,742.53**	**13,387,794.64**	**40,813,612.17**	**2.317%**
Funds - common stock								
United States - USD	0.00	728,032,585.31	402,938,014.40	325,094,570.91	0.00	325,094,570.91	728,032,585.31	41.324%
Total funds - common stock	**0.00**	**728,032,585.31**	**402,938,014.40**	**325,094,570.91**	**0.00**	**325,094,570.91**	**728,032,585.31**	**41.324%**
Preferred stock								
Germany - EUR	0.00	61,099.88	43,454.23	20,847.40	-3,201.75	17,645.65	61,099.88	0.003%
United Kingdom - GBP	0.00	256.25	0.00	256.25	0.00	256.25	256.25	0.000%
Total preferred stock	**0.00**	**61,356.13**	**43,454.23**	**21,103.65**	**-3,201.75**	**17,901.90**	**61,356.13**	**0.003%**
Stapled securities								
Australia - AUD	1,067.20	67,382.04	58,753.28	18,278.44	-9,649.68	8,628.76	68,449.24	0.004%
Total stapled securities	**1,067.20**	**67,382.04**	**58,753.28**	**18,278.44**	**-9,649.68**	**8,628.76**	**68,449.24**	**0.004%**
Rights/warrants								
Hong Kong - HKD	0.00	419.56	0.00	419.56	0.00	419.56	419.56	0.000%

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Translation	Total	Market value incl. accruals	%
Equities								
Rights/warrants								
United States - USD	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.000%
Total rights/warrants	**0.00**	**419.56**	**0.00**	**419.56**	**0.00**	**419.56**	**419.56**	**0.000%**
Funds - equities etf								
Emerging Markets Region - USD	0.00	55,066,545.89	56,720,553.99	- 1,654,008.10	0.00	- 1,654,008.10	55,066,545.89	3.126%
Total funds - equities etf	**0.00**	**55,066,545.89**	**56,720,553.99**	**- 1,654,008.10**	**0.00**	**- 1,654,008.10**	**55,066,545.89**	**3.126%**
Total equities	**49,247.91**	**823,993,720.39**	**487,138,412.72**	**337,720,901.63**	**-865,593.96**	**336,855,307.67**	**824,042,968.30**	**46.773%**
Fixed Income								
Government bonds								
Brazil - USD	53,996.38	3,013,487.50	3,184,968.00	- 171,480.50	0.00	- 171,480.50	3,067,483.88	0.174%
Colombia - USD	19,690.17	850,225.00	771,964.06	78,260.94	0.00	78,260.94	869,915.17	0.049%
Jordan - USD	7,358.49	1,763,905.10	1,735,570.60	28,334.50	0.00	28,334.50	1,771,263.59	0.101%
Mexico - USD	45,737.32	3,119,280.00	3,200,437.31	- 81,157.31	0.00	- 81,157.31	3,165,017.32	0.180%
Panama - USD	3,961.98	502,900.00	532,814.70	- 29,914.70	0.00	- 29,914.70	506,861.98	0.029%
Peru - USD	2,385.16	418,012.50	406,120.00	11,892.50	0.00	11,892.50	420,397.66	0.024%
Philippines - USD	21,386.38	1,330,650.00	1,260,468.93	70,181.07	0.00	70,181.07	1,352,036.38	0.077%
South Africa - USD	10,548.44	475,312.50	446,625.00	28,687.50	0.00	28,687.50	485,860.94	0.028%
Turkey - USD	33,258.90	2,396,043.75	2,419,796.61	- 23,752.86	0.00	- 23,752.86	2,429,302.65	0.138%
United States - USD	119,584.24	22,717,048.22	22,569,830.92	147,217.30	0.00	147,217.30	22,836,632.46	1.296%
Total government bonds	**317,907.46**	**36,586,864.57**	**36,528,596.13**	**58,268.44**	**0.00**	**58,268.44**	**36,904,772.03**	**2.095%**
Government agencies								
KOREA, REPUBLIC OF - USD	7,136.99	1,005,848.45	1,009,216.28	- 3,367.83	0.00	- 3,367.83	1,012,985.44	0.057%
Multi-National Agencies Region - USD	33,663.48	1,787,677.17	1,584,941.41	202,735.76	0.00	202,735.76	1,821,340.65	0.103%
Total government agencies	**40,800.47**	**2,793,525.62**	**2,594,157.69**	**199,367.93**	**0.00**	**199,367.93**	**2,834,326.09**	**0.161%**

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Translation	Total	Market value incl. accruals	%
Fixed Income								
Municipal/provincial bonds								
Canada - USD	20,768.05	2,004,174.60	1,951,796.36	52,378.24	0.00	52,378.24	2,024,942.65	0.115%
United States - USD	1,436,762.45	102,543,167.54	94,116,417.79	8,426,749.75	0.00	8,426,749.75	103,979,929.99	5.902%
Total municipal/provincial bonds	**1,457,530.50**	**104,547,342.14**	**96,068,214.15**	**8,479,127.99**	**0.00**	**8,479,127.99**	**106,004,872.64**	**6.017%**
Corporate bonds								
Australia - USD	9,176.39	2,236,330.33	2,157,925.49	78,404.84	0.00	78,404.84	2,245,506.72	0.127%
Belgium - USD	32,476.62	1,958,153.51	1,871,433.76	86,719.75	0.00	86,719.75	1,990,630.13	0.113%
Canada - USD	83,110.57	10,731,831.02	10,375,925.04	355,905.98	0.00	355,905.98	10,814,941.59	0.614%
China - USD	7,358.35	1,220,482.32	1,170,160.22	50,322.10	0.00	50,322.10	1,227,840.67	0.070%
France - USD	19,910.35	2,546,021.34	2,467,889.33	78,132.01	0.00	78,132.01	2,565,931.69	0.146%
Germany - USD	4,186.02	778,373.73	779,929.80	- 1,556.07	0.00	- 1,556.07	782,559.75	0.044%
Japan - USD	19,808.89	3,233,203.81	3,233,847.63	- 643.82	0.00	- 643.82	3,253,012.70	0.185%
Luxembourg - USD	4,408.87	1,607,628.26	1,608,508.31	- 880.05	0.00	- 880.05	1,612,037.13	0.092%
Mexico - USD	26,236.89	4,496,817.44	4,282,819.71	213,997.73	0.00	213,997.73	4,523,054.33	0.257%
Netherlands - USD	64,851.77	4,998,241.80	4,823,592.47	174,649.33	0.00	174,649.33	5,063,093.57	0.287%
Netherlands Antilles - USD	3,636.94	1,036,407.02	1,018,009.54	18,397.48	0.00	18,397.48	1,040,043.96	0.059%
Norway - USD	35,985.60	2,332,439.11	2,070,753.43	261,685.68	0.00	261,685.68	2,368,424.71	0.134%
Spain - USD	9,321.24	843,001.62	713,485.95	129,515.67	0.00	129,515.67	852,322.86	0.048%
Switzerland - USD	61,418.46	4,062,952.15	3,946,520.95	116,431.20	0.00	116,431.20	4,124,370.61	0.234%
United Kingdom - USD	50,973.98	8,984,872.05	8,889,300.05	95,572.00	0.00	95,572.00	9,035,846.03	0.513%
United States - USD	3,357,846.90	339,724,801.68	323,598,862.37	16,125,939.31	0.00	16,125,939.31	343,082,648.58	19.474%
Total corporate bonds	**3,790,707.84**	**390,791,557.19**	**373,008,964.05**	**17,782,593.14**	**0.00**	**17,782,593.14**	**394,582,265.03**	**22.397%**
Funds - corporate bond								
International Region - USD	0.00	42,334,098.84	41,031,321.08	1,302,777.76	0.00	1,302,777.76	42,334,098.84	2.403%

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Translation	Total	Market value incl. accruals	%
Fixed Income								
Funds - corporate bond								
United States - USD	0.00	74.16	74.16	0.00	0.00	0.00	74.16	0.000%
Total funds - corporate bond	**0.00**	**42,334,173.00**	**41,031,395.24**	**1,302,777.76**	**0.00**	**1,302,777.76**	**42,334,173.00**	**2.403%**
Gov't-issued commercial mortgage-backed								
United States - USD	2,374.79	7,567,538.13	7,647,988.51	- 80,450.38	0.00	- 80,450.38	7,569,912.92	0.430%
Total gov't-issued commercial mortgage-backed	**2,374.79**	**7,567,538.13**	**7,647,988.51**	**- 80,450.38**	**0.00**	**- 80,450.38**	**7,569,912.92**	**0.430%**
Index linked government bonds								
United States - USD	544,382.40	141,605,193.35	140,079,595.15	1,525,598.20	0.00	1,525,598.20	142,149,575.75	8.068%
Total index linked government bonds	**544,382.40**	**141,605,193.35**	**140,079,595.15**	**1,525,598.20**	**0.00**	**1,525,598.20**	**142,149,575.75**	**8.068%**
Synthetic g.i.c.s								
United States - USD	- 694,969.97	23,909,038.00	22,127,197.98	1,781,840.02	0.00	1,781,840.02	23,214,068.03	1.318%
Total synthetic g.i.c.s	**- 694,969.97**	**23,909,038.00**	**22,127,197.98**	**1,781,840.02**	**0.00**	**1,781,840.02**	**23,214,068.03**	**1.318%**
Total fixed income	**5,458,733.49**	**750,135,232.00**	**719,086,108.90**	**31,049,123.10**	**0.00**	**31,049,123.10**	**755,593,965.49**	**42.888%**
Real Estate								
Real estate								
United States - USD	0.00	812,935.00	1,181,969.68	- 369,034.68	0.00	- 369,034.68	812,935.00	0.046%
Total real estate	**0.00**	**812,935.00**	**1,181,969.68**	**- 369,034.68**	**0.00**	**- 369,034.68**	**812,935.00**	**0.046%**
Total real estate	**0.00**	**812,935.00**	**1,181,969.68**	**- 369,034.68**	**0.00**	**- 369,034.68**	**812,935.00**	**0.046%**

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Translation	Total	Market value incl. accruals	%
Venture Capital and Partnerships								
Partnerships								
Global Region - USD	0.00	36,600,492.00	36,283,467.81	317,024.19	0.00	317,024.19	36,600,492.00	2.077%
North America Region - USD	0.00	6,831,776.00	7,125,112.00	- 293,336.00	0.00	- 293,336.00	6,831,776.00	0.388%
United States - USD	0.00	89,572,423.00	87,241,071.36	2,331,351.64	0.00	2,331,351.64	89,572,423.00	5.084%
Total partnerships	**0.00**	**133,004,691.00**	**130,649,651.17**	**2,355,039.83**	**0.00**	**2,355,039.83**	**133,004,691.00**	**7.549%**
Total venture capital and partnerships	**0.00**	**133,004,691.00**	**130,649,651.17**	**2,355,039.83**	**0.00**	**2,355,039.83**	**133,004,691.00**	**7.549%**
All Other								
Recoverable taxes								
Recoverable taxes	31,500.52	0.00	0.00	0.00	0.00	0.00	31,500.52	0.002%
Total recoverable taxes	**31,500.52**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**31,500.52**	**0.002%**
Total all other	**31,500.52**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**31,500.52**	**0.002%**
Cash and Cash Equivalents								
Short term bills and notes								
United States - USD	0.00	289,995.39	289,985.21	10.18	0.00	10.18	289,995.39	0.016%
Total short term bills and notes	**0.00**	**289,995.39**	**289,985.21**	**10.18**	**0.00**	**10.18**	**289,995.39**	**0.016%**
Funds - short term investment								
Funds - Short Term Investment	381.78	42,576,075.53	42,576,075.53	0.00	0.00	0.00	42,576,457.31	2.417%
Total funds - short term investment	**381.78**	**42,576,075.53**	**42,576,075.53**	**0.00**	**0.00**	**0.00**	**42,576,457.31**	**2.417%**

Asset Summary

Country	Accrued income/expense	Market value	Cost	Unrealized gain/loss Market	Translation	Total	Market value incl. accruals	%
Cash and Cash Equivalents								
Cash								
Cash	- 6.83	22,859.35	23,419.87	0.00	-560.52	- 560.52	22,852.52	0.001%
Total cash	**- 6.83**	**22,859.35**	**23,419.87**	**0.00**	**-560.52**	**- 560.52**	**22,852.52**	**0.001%**
Invested cash								
Invested cash	24.99	7,836,564.99	7,836,564.99	0.00	0.00	0.00	7,836,589.98	0.445%
Total invested cash	**24.99**	**7,836,564.99**	**7,836,564.99**	**0.00**	**0.00**	**0.00**	**7,836,589.98**	**0.445%**
Total cash and cash equivalents	**399.94**	**50,725,495.26**	**50,726,045.60**	**10.18**	**-560.52**	**- 550.34**	**50,725,895.20**	**2.879%**
Adjustments To Cash								
Pending trade purchases								
Pending trade purchases	0.00	- 4,277,142.38	- 4,277,142.38	0.00	0.00	0.00	-4,277,142.38	- 0.243%
Total pending trade purchases	**0.00**	**- 4,277,142.38**	**- 4,277,142.38**	**0.00**	**0.00**	**0.00**	**-4,277,142.38**	**- 0.243%**
Pending trade sales								
Pending trade sales	0.00	1,976,970.05	1,976,970.05	0.00	0.00	0.00	1,976,970.05	0.112%
Total pending trade sales	**0.00**	**1,976,970.05**	**1,976,970.05**	**0.00**	**0.00**	**0.00**	**1,976,970.05**	**0.112%**
Other payables								
Other Payables	0.00	- 125,551.60	- 125,551.60	0.00	0.00	0.00	-125,551.60	- 0.007%
Total other payables	**0.00**	**- 125,551.60**	**- 125,551.60**	**0.00**	**0.00**	**0.00**	**-125,551.60**	**- 0.007%**
Total adjustments to cash	**0.00**	**- 2,425,723.93**	**- 2,425,723.93**	**0.00**	**0.00**	**0.00**	**-2,425,723.93**	**- 0.138%**
Total Unrealized Gains						**376,172,854.42**		
Total Unrealized Losses						**- 6,282,968.84**		
Total	**5,539,881.86**	**1,756,246,349.72**	**1,386,356,464.14**	**370,756,040.06**	**-866,154.48**	**369,889,885.58**	**1,761,786,231.58**	**100.000%**

Total Cost incl. Accruals **1,391,896,346.00**

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. ER18-1314-000**
	)	**ER18-1314-001**
	)	
	)	

PROTEST OF EXELON CORPORATION

PJM Interconnection, L.L.C. ("PJM") has filed two alternative tariff revisions seeking approval under Section 205. Neither is just and reasonable. But Option B is particularly indefensible. By forbidding resources receiving compensation under state environmental programs from making offers reflecting that compensation, Option B makes the Commission's markets less efficient, procures redundant capacity, and distorts energy markets—while drawing arbitrary distinctions between favored and disfavored programs. The Commission should reject PJM's filing.

INTRODUCTION

PJM declares—as its filing's core premise—that when states choose to make payments that recognize the environmental benefits of renewable and nuclear generators, states are "distorting" price signals, and action is needed to redress the supposed distortion.[1] The effect of PJM's requested relief, under either option, will be to pad profits for fossil-fuel generators, on the backs of customers forced to pay more. Option B would prevent state-supported clean generators from clearing *at all*, replacing them with polluting units. Perversely, that will not just force customers

[1] PJM, Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market at 25-26, 45, Docket No. ER18-1314-000 (Apr. 9, 2018) ("PJM Filing"); *see also id.* at 6, 15, 20, 34, 36, 37, 38, 39.

to pay higher electricity prices, but also will inflict on customers the *additional* costs of grappling with the pollution Option B has created. In three respects, PJM's premise is wrong, and the relief it seeks is badly misguided.

First, PJM's filing ignores basic economics, and gets the nature of the "distortion" exactly backwards. Sound economics recognizes that some generators emit harmful pollutants imposing costs on society, which clean generators avoid—known as "externalities." And sound economics understands that when states tax polluting generators, or pay clean generators for their environmental value, they do not "distort" price signals. They reduce distortions and account for true economic costs and benefits. The only *distortion* comes from treating clean and polluting generators as the same when they are not. For decades, fossil-fuel generators have reaped profits without paying for the pollution they have imposed on society. They now have prevailed upon PJM that not only should they be allowed to continue their free ride, but that PJM should adopt market rules designed to *frustrate* states' modest attempts to compensate clean generators that help to avoid this harm.

Second, PJM's view is inconsistent with the Commission's market design and bedrock principles of federalism. While the "Commission's policies are fuel-neutral,"[2] the Commission has long recognized that the real world is *not*.[3] If *no one* addresses environmental externalities, the Commission's markets could never achieve their goal to provide for "the selection of the least-cost set of resources."[4] So the Commission has designed its markets to complement efforts by other authorities—state and federal—to regulate in this gap. In particular, states have long exercised authority as regulators of "facilities used for the generation of electric energy"[5] to

[2] *ISO New England Inc.*, 162 FERC ¶ 61,205, at P 26 (2018) ("CASPR Order").
[3] *Infra* at 18-22.
[4] CASPR Order at P 21.
[5] 16 U.S.C. § 824(b)(1).

regulate and tax emitting generators and to compensate clean generators for their environmental value. While PJM implies that states forfeited this authority when they chose to restructure retail markets, it cites nothing to support this claim—which is badly misguided. Under our federal system, these programs are in the heartland of states' authority. Thus, both federalism and sound economics require accommodating state efforts to address environmental externalities by allowing state-supported resources to make auction offers reflecting that support (as Option A would do). But these principles also require that those offers be allowed to influence the market price (which Option A would prevent). And in all events, these principles cannot tolerate the result that Option B would yield—forcing customers to pay more to buy capacity from resources that pollute, by preventing clean, state-supported resources from clearing.

Thus far, the Commission's actions have always accorded with the sound principles set forth above—recognizing that when generators receive payments reflecting environmental benefits or other services not captured by the Commission's markets, bids should not be mitigated, because they reflect generators' true economic costs and benefits. PJM's departure from these principles would yield results that are especially untenable because even PJM acknowledges that over the medium term, markets must evolve—one way or the other—to address "currently unvalued" environmental externalities. There is no reason to adopt efficiency-reducing "reforms" that move the markets in the *opposite* direction of what PJM admits is the "theoretical ideal market approach."[6] The Commission should thus reject PJM's filing.

Third, PJM's proposals are not consistent with the Federal Power Act's mandate "to encourage the orderly development of plentiful supplies of electricity … at reasonable prices."[7]

[6] PJM Filing at 54.
[7] *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,157, at P 30 n.39 (2016) (quoting *Pub. Utils. Comm'n of Cal. v. FERC*, 367 F.3d 925, 929 (D.C. Cir. 2004)).

That mandate is amply satisfied in PJM today. Supplies are plentiful, new gas resources continue to enter the market, and prices paid by customers are historically low. PJM hypothesizes that state environmental programs may undermine investor confidence and reduce willingness to invest. But investors have understood for well over a decade that states can, and do, regulate to affect the generation mix's environmental profile. The possibility that states would continue marching along the path they have set by *expanding* these environmental policies—via joining cap-and-trade programs, reducing emissions permits, or promoting emissions-free generation by increasing renewable targets or maintaining emissions-free nuclear facilities—is just one of many regulatory risks that sophisticated investors consider. With no evidence of any genuine problem—that supply is tightening, that investors are unwilling to invest, or that market participants are incapable of factoring in these regulatory risks as they do myriad other risks—it would not be just and reasonable to approve tariff reforms whose main consequence is to increase the prices paid by customers. Instead, the Commission should continue to narrowly apply mitigation as it traditionally has done in PJM: to new resources, not existing resources, in order to prevent the exercise of buyer-side market power. In short, the Commission should let the market work.

Finally, to the extent that the Commission does believe action is warranted, any just and reasonable capacity market reform must respect five fundamental principles:

(1) The Commission should allow the mix of resources selected by the capacity market to reflect the impact of state programs addressing environmental externalities. Under basic economics, identifying the least-cost set of resources requires accounting for environmental effects. State environmental programs thus complement the Commission's markets to produce a more efficient outcome.

(2) The Commission should approach state environmental programs in a spirit of cooperative federalism. Under the Federal Power Act's division of authority, and pursuant to their historic police powers, states have traditionally regulated the environmental effects of generation. The Commission should respect that role, accepting that state environmental programs will influence which capacity resources are in the market, what costs those capacity resources will need to recover from the market, and what the ultimate market price will be.

(3) The Commission should avoid forcing customers to overprocure capacity. If the Commission adopts market changes that do not allow state-supported resources to clear, the result will be unnecessary overprocurement: Customers will continue to support the environmentally friendly resources their states seek to encourage, and those resources will still provide capacity to the system (though without compensation). Yet customers will be forced to pay for additional capacity that appears to be needed only because the Commission has chosen to ignore the state-supported resources. That is not just or reasonable.

(4) The Commission should treat all government support in an even-handed and nondiscriminatory manner. Distinctions among forms of government support should reflect genuine differences in how the policies affect wholesale markets. Otherwise, those distinctions are arbitrary and are not just or reasonable.

(5) The Commission should avoid taking actions in capacity markets that will worsen existing price suppression in energy markets. Price suppression in energy markets is already a big problem, as PJM admits. Capacity market changes cannot be just and reasonable if they risk exacerbating these problems.

Option B (also called MOPR-Ex) satisfies none of these principles. *First*, it selects an inefficient set of resources by countermanding, rather than accommodating, state environmental policies. It would select an inefficient coal unit at the margin in place of an emissions-free nuclear plant, even though the nuclear plant is lower cost after accounting for environmental externalities.

Second, Option B does not respect the legitimacy of state regulation. Option B works from the theory that, once states decided to depend on wholesale markets for resource adequacy, they forfeited their power to encourage clean over polluting generation.[8] That view is inconsistent with the Federal Power Act ("FPA"), under which states continue to regulate electric generation facilities, even when they sell at wholesale. It is also bad policy. Organized wholesale markets exist because states have decided they are valuable. If states must forfeit core historic police powers—their authority to legislate for "the protection of the lives, limbs, health, comfort, and quiet of all persons"[9]—as the price of admission, then many states may decide that the price is too high. The Commission's policy has always been to complement, not countermand, state environmental programs.

Third, Option B would over-procure capacity and inflate costs. It would require PJM to ignore capacity provided by a state-supported nuclear resource whose mitigated capacity offer is too high to clear, and instead procure redundant capacity. That result is particularly perverse because nuclear plants are the highest-performing and most reliable capacity resources.

Fourth, Option B draws a host of arbitrary distinctions among programs that have equivalent economic effects on wholesale prices. It does so because Option B is the product of a political logroll, not a just and reasonable economic theory. Indeed, before flip-flopping, PJM was

[8] PJM Filing at 21.
[9] *Metro. Life Ins. Co. v. Massachusetts*, 471 U.S. 724, 756 (1985) (quotation marks omitted).

against Option B—telling stakeholders that it could not "recommend[]" this approach because it was "not sustainable."[10] Likewise, the Independent Market Monitor ("IMM") has long opposed many of the exemptions that Option B creates, accepting them only as part of back-room dealmaking with stakeholders that, otherwise, favored the status quo.

For example, Option B exempts certain RPS programs based on whether the state procurement process is sufficiently "competitive and non-discriminatory" to satisfy the IMM. Yet as PJM concedes, RPS programs affect wholesale market prices by inducing the entry of new resources that would be unprofitable without state support. If the goal of Option B is to prevent state policies from affecting wholesale prices, there is no basis for mitigating nuclear and offshore wind, but exempting solar and onshore wind. Option B also arbitrarily excludes from mitigation recipients of non-environmental state subsidy programs, as well as federal production tax credits and tax incentives such as the wind Production Tax Credit and solar Investment Tax Credit. These subsidies indisputably affect wholesale market prices, including by increasing how often energy prices fall below zero. Option B likewise arbitrarily excludes resources that would not be cost-competitive if forced to rely on PJM market revenues alone, but which are able to maintain operation due to guaranteed cost recovery through retail rates. PJM acknowledges that 25% of the resources in the RTO receive guaranteed cost recovery through retail rates. Thus, if the Michigan Public Service Commission decides to promote a zero-emissions policy by allowing the Donald C. Cook Nuclear Plant to recover any market losses through retail rates, no mitigation is applied. But if the Illinois Commerce Commission pursues the same policy by allowing Quad Cities to sell Zero Emission Credits to retail utilities, mitigation is applied. That distinction is indefensible.

[10] *Infra* at 42-43.

Option B also categorically exempts public power, even though doing so invites the direct exercise of buyer-side market power.

Finally, by unnecessarily procuring more capacity than is needed, Option B fails to set "price signals that guide … orderly entry and exit,"[11] resulting in price suppression in the energy markets. PJM admits this will occur. But PJM has done no study to even consider these adverse consequences.[12] That failure is yet another reason why Option B is not just or reasonable.

As explained above, Exelon does not believe that either PJM proposal is just or reasonable. Option A, however, does far less violence to the five key principles that should inform any capacity market reform. It will select the most efficient set of resources by accommodating state environmental programs, and it views such state efforts as complementary to the Commission's goals in wholesale rate-setting. It will procure the right amount of capacity, not additional unneeded capacity. It avoids some of Option B's most egregiously arbitrary distinctions. And it will not worsen energy market price suppression.

Option A could be improved, however, in two respects. First, it unjustifiably exempts from repricing any resource of less than 20 MW. Yet Option A purports to be addressing the aggregate effect of state support payments on capacity prices. Resources smaller than 20 MW are important contributors to that aggregate effect. Second, the proposed materiality screen that triggers repricing—3.5% of the reliability requirement for an LDA or 5,000 MW RTO-wide—is arbitrary. Instead, the Commission should require a screen that is connected to the supposed problem that repricing is purported to solve—the need to attract new investment to ensure reliability.

[11] CASPR Order at P 21.

[12] Indeed, the Issue Charge of the Capacity Construct/Public Policy Senior Task Force excluded consideration of energy market effects. *See* PJM, Issue Charge: Assess state public policy initiatives and the PJM capacity construct (2017), http://www.pjm.com/-/media/committees-groups/task-forces/ccppstf/postings/ccppstf-issue-charge.ashx?la=en.

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Accordingly, the Commission should require a price-based materiality screen, so that repricing would not occur when supply remains plentiful, but would be triggered in the event that PJM markets fail to elicit needed new entry. That would achieve PJM's objectives but prevent unnecessary price increases for customers.

PROTEST

I. The Commission Should Reject PJM's Filing Outright Because Its "Two Alternative[]" Approach Contravenes PJM's Tariff And Section 205.

PJM has filed "two alternative[]" proposals under Section 205, inviting "the Commission to decide" what PJM characterizes as the "federal policy question" that divides the alternatives—"accommodate" state programs (PJM's "preferred" approach), or "mitigate" them.[13] Section 205, however, is the wrong procedural vehicle for the relief PJM seeks. If PJM wishes to obtain guidance on policy questions, it should petition for a declaratory order. And if PJM wishes to confer on the Commission broad policy discretion to refashion market rules, it can attempt to carry the burden to invoke Section 206. Section 205, however, does not permit PJM to set a broad policy choice before the Commission by presenting two alternatives that are worlds apart.

To begin, PJM's Tariff plainly does not authorize PJM's approach. True, the tariff of ISO-New England contains a "jump ball" provision that allows submission of an "alternative … proposal."[14] PJM's Tariff, however, nowhere contains authorization to file alternative tariff proposals under Section 205.[15]

Section 205 also does not authorize PJM to present "alternative" tariffs asking the Commission to choose between widely divergent policies. Tellingly, the avenues that allow the Commission to exercise this type of broad discretion—petitions for declaratory orders and Section

[13] PJM Filing at 6, 17-18, 36, 42.
[14] *ISO New England Inc.*, 130 FERC ¶ 61,105, at P 51 (2010).
[15] *See* PJM Tariff § 9.2(a) (setting forth PJM's Section 205 filing rights).

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206—do not include the tight timeline that governs Section 205 filings. That is appropriate: When the Commission is exercising that type of broad discretion, deliberation is needed. By contrast, what enables the accelerated litigation that Section 205 demands is the "passive and reactive role" that Section 205 requires the Commission to play: It reviews "the proposed rate scheme" and must "accept or reject the proposal," aside from suggesting "minor" changes, as permitted by *NRG Power Marketing, LLC v. FERC*.[16] That rule protects stakeholders by focusing litigation on the precise proposal presented.[17]

PJM's approach is inconsistent with Section 205's structure. Rather than accepting the Commission's "passive" role[18]—which requires PJM to resolve, in the first instance, each "federal policy question" raised by its filing[19]—PJM asks the Commission to decide. PJM's approach, moreover, would substantially expand the Commission's power under Section 205 beyond what Congress conferred. No longer would the Commission be limited to rejecting or approving (with minor modifications) a *single* proposed tariff. Instead, PJM has offered the Commission two proposals on opposite ends of the spectrum, asking the Commission to approve either one. Given how far apart are Option A and Option B, that vastly expands the range of outcomes.

If the Commission accepts PJM's gambit here, moreover, the Commission can expect to receive many more such Section 205 filings from ISOs and RTOs in the future. Instead of proposing a single tariff revision under Section 205, which may result in a dissatisfied group of stakeholders, RTOs and ISOs can punt to the Commission the responsibility for making divisive policy choices, and require it to do so on the compressed timing required by Section 205. Indeed, PJM has not only submitted two proposed rates (Option A and Option B), but its "affirmative

[16] 862 F.3d 108, 114-15 (D.C. Cir. 2017) (internal quotation marks omitted).
[17] *Id.* at 116 (quotation marks omitted).
[18] *Id.* at 114 (quotation marks omitted).
[19] PJM Filing at 17-18.

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notice" inviting the Commission to approve Option B *without* the RPS Exemption effectively adds a third—and arguably, a fourth, as PJM further "offers the option of either (i) applying the standards set forth in Capacity Repricing to govern the treatment of renewables" under Option B, or "(ii) identifying this question for further stakeholder consideration in subsequent processes."[20] The result is that a single tariff may in reality contain dozens of permutations of proposed rates, each of which stakeholders must analyze and comment on; indeed, already public interest organizations have noted the burdens of the need "analyze and prepare detailed comments on not one but two highly complex proposals" in a short comment period.[21] That system is inconsistent not just with the notice that Section 205 is meant to provide, but also the "passive and reactive role" that the Commission must play under Section 205.[22] Instead of approving or rejecting tariffs proposed by utilities, the Commission will face a shelf full of choose-your-own-adventure tariff filings.

The Commission should not entertain PJM's attempt to twist Section 205 to create a new procedural vehicle. If PJM wants to solicit general policy guidance, or to give the Commission broad discretion to reshape market rules, a petition for a declaratory order or Section 206 filing allow PJM to seek such relief. But PJM cannot claim the benefits of these vehicles without accepting their burdens. Because Section 205 does not allow the filing PJM has made, the Commission should reject PJM's filing or, alternatively, decline to consider PJM's Option B.

[20] PJM Filing at 114. PJM's suggestion that the Commission may sever the RPS Exemption is unlawful for reasons explained below. *Infra* at 54-55.
[21] Joint Mot. for Extension of Time to File Comments of Public Interest Organizations at 1 (Apr. 9, 2018).
[22] *NRG*, 862 F.3d at 114, 116 (quotation marks omitted).

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II. The Commission Must Accommodate State Payments That Account For Environmental Externalities.

A. Accounting For Environmental Externalities Improves Efficiency And Complements The Design Objective Of PJM's Markets.

By credulously accepting fossil-fuel generators' refrain about the "distorting effect of state subsidies" to "uneconomic" resources,[23] PJM forgets what any first-year economics undergraduate knows: Markets cannot be efficient when large externalities go unaddressed, and subsidies that address externalities make markets *more* efficient, not less. This point is explained at length in the Declaration of Dr. Robert Willig, attached to this filing.[24] But in short: When fossil-fuel generators produce electricity, they create pollutants such as carbon dioxide, sulfur dioxide, nitrogen oxide, ozone, mercury, and particulate matter.[25] These pollutants are harmful to human health and the environment, but these costs generally fall on society, not the generators that produce them. Put otherwise, the costs are "externalized," and hence these pollutants create "negative externalities."[26] These externalities are, economically, a subsidy. Fossil-fuel generators produce this harm, but do not pay. Indeed, for carbon dioxide alone, estimates put this subsidy's value for fossil-fuel generators across PJM at $12.1 billion to $17.7 billion dollars *annually*.[27] Conversely, when clean generators produce electricity without creating this harmful pollution, thereby abating the pollution that would result in their absence, they benefit society. But they do

[23] PJM Filing at 6, 32.
[24] Many of the same points are explained in an April 2018 report by the Institute for Policy Integrity, also attached to this filing. *See* Institute for Policy Integrity, *Capacity Markets and Externalities: Avoiding Unnecessary and Problematic Reforms* (April 2018), http://policyintegrity.org/files/publications/Capacity_Markets_and_Externalities_Report.pdf ("*Capacity Markets and Externalities*").
[25] Willig Decl. ¶ 25; *Capacity Markets and Externalities* at 6.
[26] Willig Decl. ¶¶ 25, 30-31; *Capacity Markets and Externalities* at 6.
[27] These figures reflect 291.9 million tons of CO_2 emitted in PJM in 2017 and 426.6 million tons emitted in 2016, at a cost of $41.40 per ton. *See* Monitoring Analytics, LLC, *2017 State of the Market Report for PJM, Volume 2: Detailed Analysis*, at 361 (Mar. 2018).

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not receive compensation from the Commission-regulated markets for providing this benefit. Instead, the benefit is externalized—a positive externality.[28]

Externalities distort incentives, and so result in inefficiencies. When the fossil-fuel generator decides how much to produce, it considers only its private costs, not the full costs to society.[29] When the clean generator weighs the same decision, the same mismatch occurs in the opposite direction. The fossil-fuel generator will produce too much, and the clean generator, too little. As Dr. Willig explains, when incentives are misaligned, the outcome will not be efficient.[30]

This misalignment is fixable. Command-and-control regulation, for example, can forbid especially polluting methods. But markets are often superior. The polluting activity can be taxed to allow consideration of private costs and social costs.[31] Or clean generators can be paid for the benefits they provide to society—again, aligning private incentives with social benefits.[32]

The Commission's approach to these issues has been one of cooperative federalism—one that "fulfill[s the Commission's] statutory mandate under the FPA to ensure that … rates … are just, reasonable and not unduly discriminatory or preferential" by "respect[ing] the traditional role of states."[33] The Commission thus far has elected to make its market rules "fuel-neutral,"[34] and has not attempted itself to redress the externalities described above—for example, by incorporating a Commission-established carbon price into wholesale markets. Instead, the Commission has looked to other regulators—in particular, states—to address these externalities.[35] By statute and by history, states are well-suited to do so. The FPA expressly protects states' authority over

[28] Willig Decl. ¶ 25.
[29] *Id.* ¶¶ 30-31.
[30] *Id.* ¶ 31; *see also Capacity Markets and Externalities* at 7.
[31] Willig Decl. ¶ 32.
[32] *Id.* ¶¶ 32-37.
[33] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61274, at P 1112 (2006).
[34] CASPR Order at P 26.
[35] *Infra* at 18-22.

"facilities used for the generation of electric energy,"[36] and the Supreme Court has explained that "regulation of utilities is one of the most important of the functions traditionally associated with the police power of the states."[37] Likewise, "[l]egislation designed to free from pollution the very air that people breathe clearly falls within the exercise of even the most traditional concept of … the police power."[38]

The range of actions states have taken with respect to environmental externalities—cap-and-trade programs, environmental tax credits, RPS programs, zero-emissions credit programs, and others—have furthered the Commission's "first principles of capacity markets" set forth in the CASPR Order.[39] The Commission's markets fulfill all of their goals *better* when states are addressing environmental externalities and the Commission's markets can operate against the backdrop of such state environmental programs.[40] When private and social costs are better aligned, "competition" is more "robust," and the markets' "price signals" more accurately "guide the orderly entry and exit of capacity resources" to select the "set of resources" that is truly "least cost."[41] By contrast, if the Commission designed its market rules to insulate its markets from the effects of state environmental initiatives, yet did not itself incorporate any carbon price, that would recreate the same type of "regulatory void" that the Commission was created to address[42] and doom the Commission's markets to inefficiency. Wholesale rates designed to *prevent* consideration of environmental externalities could never be just and reasonable.

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[36] 16 U.S.C. § 824(b)(1).
[37] *Ark. Elec. Co-op. Corp. v. Ark. Pub. Serv. Comm'n*, 461 U.S. 375, 377 (1983); *see Exxon Mobil Corp. v. U.S. EPA*, 217 F.3d 1246, 1255 (9th Cir. 2000); *Nat'l Solid Wastes Mgmt. Ass'n v. Killian*, 918 F.2d 671, 676 (7th Cir. 1990), *aff'd sub nom. Gade v. Nat'l Solid Wastes Mgmt. Ass'n*, 505 U.S. 88 (1992).
[38] *Huron Portland Cement Co. v. City of Detroit*, 362 U.S. 440, 442 (1960).
[39] CASPR Order at P 21.
[40] *See ISO New England Inc.*, 158 FERC ¶ 61,138, at P 58 (2017).
[41] CASPR Order at P 21; *see* Willig Decl. ¶ 54.
[42] *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 767 (2016).

These basic principles—the economics of externalities—are what is missing from PJM's contrived picture of how state payments "[s]ignificantly and [a]dversely [a]ffect [w]holesale [m]arket [p]articipants" by unjustly "impos[ing] costs on market participants."[43] In PJM's narrow view, externalities do not exist, the "right" price is the one free of any state environmental policy, and the result of state intervention is that one market participant effectively funds subsidies to another. But in the real world, externalities are front-and-center. So, for example, PJM asserts that payments to compensate zero-emission resources for their environmental benefits might reduce capacity market revenues for a 1,000 MW coal plant by $6.75 million.[44] But PJM ignores that, from carbon dioxide alone, "the annual external damages … [from] a typical 1,000 MW coal plant … would amount to $234.3 million."[45] Intervention, by states or the Commission, is essential to address such externalities. And absent such intervention, the result is that fossil-fuel generators impose the costs of their pollution on everyone else, allowing them to bid lower than they would be able to bid if they were forced to internalize those costs.[46] Indeed, consistent with these principles, the Commission correctly rejected the argument that ISO-New England's former renewables exemption would "result in an inappropriate wealth transfer."[47]

Correcting PJM's hypotheticals shows what PJM misses.[48] As in PJM's hypothetical, suppose a system has 200 MWs of load, and three resources, each with 100 MWs of capacity. Two burn fossil fuels: A "competitive" resource needs at least $40/MW-day to meet its avoided costs, and a "marginal" resource needs $45/MW-day. The third is a "zero emission" resource, which requires $50/MW-day but avoids at least $10/MW-day in pollution costs that the other two

[43] PJM Filing at 29.
[44] *Id.*
[45] *Capacity Markets and Externalities* at 11.
[46] *Id.* at i, 7; Willig Decl. ¶ 13(c).
[47] *ISO New England Inc.*, 158 FERC ¶ 61,138, at P 58 (2017).
[48] *See generally* Willig Decl. ¶¶ 41-43.

plants emit. As shown in Figure 1, with no intervention, the Competitive and Marginal Resources clear at a clearing price of $45/MW-day, and the Zero Emission Resource does not and retires.

Figure 1: Without State Intervention

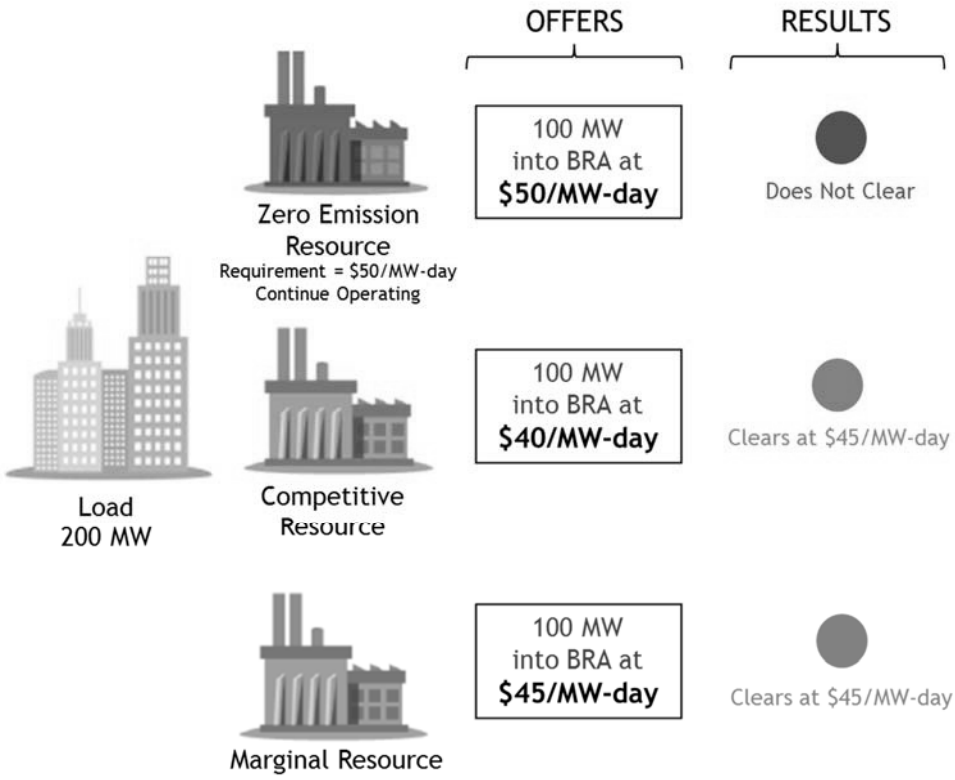
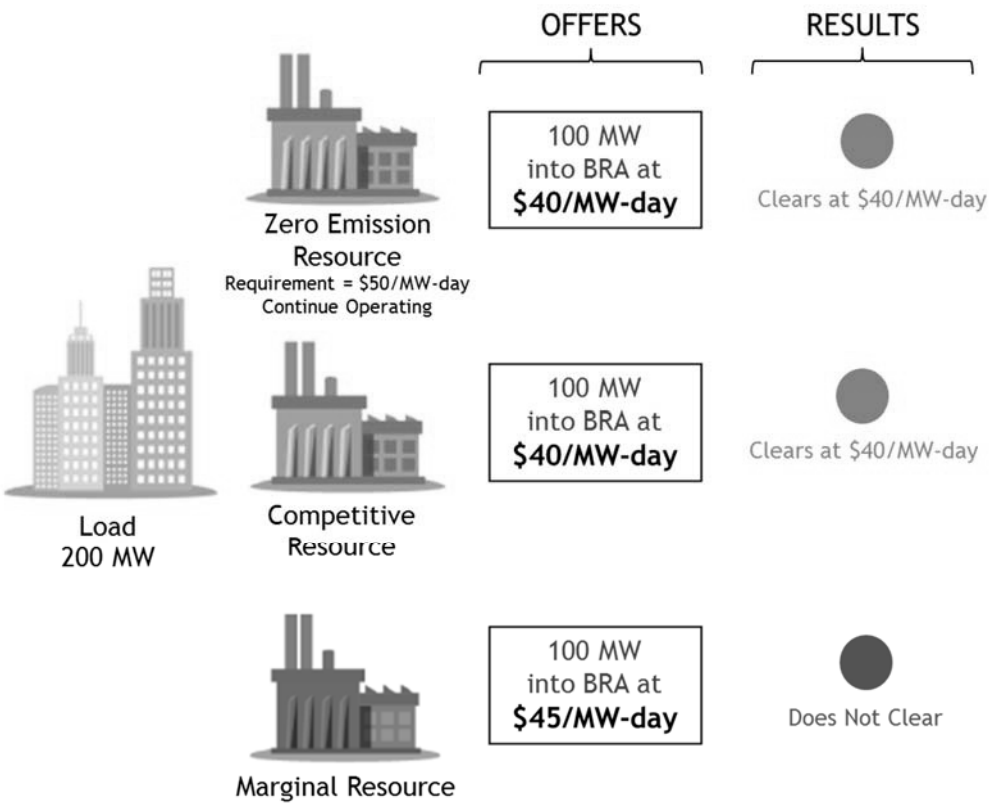


Figure 2 takes this system and adds an environmental attribute payment of $10/MW-day to the Zero Emission Resource, to compensate for the pollution avoided. With this payment, the Zero Emission Resource will bid as low as $40/MW-day, accounting for its $50/MW-day costs and the $10/MW-day attribute payment. As a result, the Competitive Resource and the Zero Emission Resource clear; the Marginal Resource does not clear.

Figure 2: With State Intervention



This result is more efficient. The first market selected the polluting Marginal Resource over the Zero Emission Resource, even though the Marginal Resource, when pollution costs are taken into account, is more costly: $45/MW-day in avoided costs, plus $10/MW-day in pollution costs. The attribute payment fixes this flaw, with the result that the market selects the two resources that are least cost all things considered.[49] To be sure, the Marginal Resource is worse off: It no longer clears. But the Marginal Resource *should not* clear an efficient market.[50] Likewise, as in PJM's hypothetical, the Competitive Resource in some sense "pays" for part of the attribute payment: It loses $5/MW-day due to the market clearing at $40/MW-day instead of $45/MW-day. But that is not unfair or inefficient: The Competitive Resource benefits from not having to pay the $10/MW-

[49] Willig Decl. ¶¶ 43, 52; *see Capacity Markets and Externalities* at 7.
[50] Willig Decl. ¶¶ 43, 52; *see Capacity Markets and Externalities* at 7.

day in pollution costs that it creates, and the price reduction only partially offsets the windfall.

The upshot is that actions to address externalities promote the efficiency of the Commission's markets. PJM's proposals cannot be just and reasonable when they are premised on ignoring that fact.

B. The Commission Has Properly Accommodated State Payments For Environmental Attributes In Its Markets.

The Commission's decisions, unlike PJM's filing, have always been consistent with the sound economic principles outlined above. The Commission has not given *all* state policies a free pass: When state policies reflect exercises of buyer-side market power and "artificially depress[] capacity prices" by supporting new entry that is truly "uneconomic," the Commission has acted.[51] But when policies address environmental externalities, the Commission has explained that these "policy objectives" are "legitimate,"[52] and it has always made sure that those policies would be accommodated. Never has it sought to *thwart* their effects. Thus, the Commission has long recognized that state command-and-control "environmental regulation … driv[es] significant changes in the mix of resources" by increasing costs of fossil-fuel generators, and "resulting in the early retirement of some coal-fired generation."[53] The Commission has not attempted to *counteract* those pro-efficiency results by rejiggering auction rules to offset the costs of regulation. Likewise, when states have exercised their authority to incentivize clean generators, the Commission has affirmed that states may "encourage renewable or other types of resources" even when doing so "allow[s] states to affect the [wholesale] price" or makes clean generation "more competitive in a cost comparison with fossil-fueled generation."[54] States are "free" to incentivize

[51] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 141 (2011).
[52] *ISO New England Inc.* 158 FERC ¶ 61,138, at P 68 (2017).
[53] *Transmission Planning & Cost Allocation*, 139 FERC ¶ 61,132, at P 5 (2012).
[54] *S. Cal. Edison Co.*, 71 FERC ¶ 61,269, 62,080 (1995).

clean generation, the Commission has explained, "even if the price signals in the regional wholesale capacity market indicate that [those] resources are [not] needed."[55]

PJM implies that, by restructuring their retail markets and joining PJM, states forfeited their right to take actions affecting "resource entry and exit."[56] If accepted, this view would condemn a broad swath of state programs, from tax credits and RPS programs to pollution controls and cap-and-trade. It would also frustrate states' attempts to comply with the Clean Air Act ("CAA"), which sets air-quality standards for many pollutants produced by fossil-fuel plants. For example, the Environmental Protection Agency recently designated 22 areas—including in several PJM states—as nonattainment for ozone.[57] On PJM's view, if states favor clean over fossil-fuel resources to meet CAA obligations, these resources' bids are subject to mitigation.[58]

PJM, however, cites no case or Commission decision that supports its view. And it is false. Restructured states retain the, like other states, authority they have exercised for centuries over "facilities used for the generation of electric energy," which the FPA expressly protects.[59] Indeed, there is "a strong presumption against finding" that the "powers traditionally exercised by states" have been superseded under the FPA.[60] In no manner did states give up their authority to regulate the environmental effects of generation by restructuring and joining PJM. To the contrary, the D.C. Circuit has held that restructured states "retain the right to forbid new entrants from

[55] Amicus Br. of United States at 33, *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288 (2016) (No. 14-614), 2016 WL 344494.
[56] PJM Filing at 21.
[57] EPA, News Release, *EPA, Working with States and Tribes, Takes Next Steps on 2015 Ozone Designations* (May 1, 2015), https://www.epa.gov/newsreleases/epa-working-states-and-tribes-takes-next-steps-2015-ozone-designations.
[58] *Cf.* EPA, *Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans* at 12-13, 20-21 (July 2012), https://www.epa.gov/sites/production/files/2016-05/documents/eeremanual_0.pdf (explaining how state policies favoring clean generation, like RPS programs, can be important elements of state and tribal implementation plans under the CAA).
[59] 16 U.S.C. § 824(b).
[60] *Niagara Mohawk Power Corp. v. Hudson River-Black River Regulating Dist.*, 673 F.3d 84, 94 (2d Cir. 2012).

providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities."[61] And proof positive that states did not, by joining PJM, give up this authority is that PJM also contains *unrestructured* states. PJM does not attempt to explain how membership in PJM can be incompatible with state actions to affect the generation mix when some PJM states exercise virtually *plenary* authority over the generation mix.

Indeed, the Commission has *ensured* that state environmental programs can affect wholesale markets—even in restructured states. For example, the Commission approved the proposal of the California Independent System Operator Corporation ("CAISO") to lower its "bid floor" in energy markets "from negative $30/MWh to negative $150/MWh."[62] It permitted "variable energy resources" to bid at such extremely low prices because they "generally receive, in addition to market revenues, production tax credits, renewable energy credits, and contractual energy payments."[63] As a result, such variable resources are allowed to submit large negative energy offers, and presumably reduce energy market revenues for other participants—because the Commission understood that the negative $150/MWh offer reflects the "opportunity cost" of not receiving significant revenues tied to clean energy production.[64] Likewise in New England, the Commission approved the deduction of revenues from REC payments in the calculation of the offer review trigger price applicable to new renewable resources,[65] and exempted 200 MW of new renewable generation from ISO-NE's MOPR[66]—until expansion of renewables mandates made

[61] C*onnecticut Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009).
[62] *California Indep. Sys. Operator Corp.*, 145 FERC ¶ 61,254, at P 34 (2013).
[63] *Id.* at P 5.
[64] *Id.* at P 34.
[65] *ISO New England Inc.*, 146 FERC ¶ 61,084, at P 32 (2014) (rejecting argument that REC revenues are out-of-market revenues, and approving reduction of ORTP for new renewable resources to account for REC revenues).
[66] *ISO New England Inc.*, 158 FERC ¶ 61,138, at P 4 (2017).

clear that *yet more* accommodation of renewable resources was necessary, which the Commission supplied in the CASPR Order.

The Commission's acceptance of state environmental programs as complementary to its markets is consistent with a more general principle: When generators receive compensation for services not captured by the Commission's markets, they properly take account of that compensation in their bids. That is why the Commission has held that resources operating pursuant to reliability services support agreements ("RSSAs") should be permitted to submit *de minimis* bids into capacity markets: Because the units "are needed for reliability and would clear a capacity market that also reflected local reliability needs, RSSA revenues received by these resources reflect the value of the services provided by these resources to customers."[67] Similarly, revenues from state environmental programs represent the "value of the [environmental] services provided by these resources."[68] The Commission should follow its precedent and reject proposed market reforms intended to insulate market prices from the effects of state environmental programs.

Even on the one occasion where the Commission did reset market prices to a higher level than would result from offers reflecting state compensation, the Commission made clear that it did so in the spirit of cooperative federalism and in recognition of states' legitimate role. In the CASPR Order, ISO-NE explained to the Commission that "New England states recently have significantly increased both their targets and their efforts to promote the development of renewable resources," and the Commission observed that ISO-NE's existing exemption from its MOPR for renewable resources "would not be able to accommodate" the region's new clean energy

[67] *Indep. Power Producers of N.Y., Inc. v. N.Y. Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,214, at P 66 (2015), *reh'g pending*.
[68] *Id.*

initiatives.[69] So ISO-NE created CASPR "to better accommodate [these] actions."[70] And the Commission approved CASPR as just and reasonable because it succeeded in this goal by "accommodat[ing] the entry of new Sponsored Policy Resources into the FCM over time" and so providing a "'better way to integrate these state policies into the competitive wholesale markets.'"[71] Exelon recognizes that some parties have argued on rehearing that CASPR's design may not be effective in achieving its goals, but the key point is that the Commission approved CASPR on the premise that it "provides a reasonable opportunity to accommodate state sponsored resources in the FCM."[72] Accepting Option B, in particular, would require the Commission to overturn this long line of precedent.

C. The ZEC Program, Which The PJM Filing Targets, Is A Legitimate And Unusually Efficient State Effort To Account For Environmental Externalities.

PJM's filing makes no secret that it targets Illinois' Zero Emission Credit ("ZEC") Program.[73] But there could not be a less justified occasion for the Commission to depart from its precedent of accommodating state environmental programs. The ZEC Program is distinctive only in that it is unusually *efficient*. It does not warrant mitigation under any defensible theory.[74]

In its purpose, the ZEC Program is similar to the RPS and renewable energy credit ("REC") programs the Commission has long accommodated and allowed to affect wholesale prices. It aims to ensure Illinois can "achieve the State's environmental objectives and [ ] reduce the adverse impact of emitted air pollutants on the health and welfare of the State's citizens."[75] Illinois

[69] CASPR Order at PP 24, 26, 101 n.185.
[70] *Id.* at P 1.
[71] *Id.* at P 6 (quoting ISO-NE Transmittal at 4).
[72] *Id.* at P 102.
[73] PJM Filing at 25-27, 45, 101.
[74] *See generally* Willig Decl. ¶¶ 47-60.
[75] Illinois SB 2814, § 1.5, 99th Gen. Assemb. (Ill. 2016), http://www.ilga.gov/legislation/99/SB/PDF/09900SB2814enr.pdf ("Ill. 2016 Energy Act").

determined that action on nuclear generation was necessary because, despite its enormous environmental benefits, nuclear energy had thus far been excluded from the state's environmental initiatives, putting plants at risk of retirement. State agencies had concluded that premature closure of nuclear plants would significantly increase greenhouse gas emissions and inflict billions of dollars in harm.[76] The legislature thus found that "Illinois must expand its commitment to zero emission energy generation and value the environmental attributes of zero emission generation that currently falls outside the scope of the existing renewable portfolio standard, including … nuclear power."[77]

Illinois employed the same mechanism that REC programs use. Under the ZEC Program, the Illinois Power Agency ("IPA"), a state agency, will procure contracts for ZECs from nuclear facilities capable of generating zero-emissions credits cost-effectively in an amount equal to 16% of electricity used in Illinois in 2014. Like a REC, a ZEC values the environmental attributes of zero-emissions generation. One ZEC reflects one megawatt-hour of zero-emission production. Of necessity, the ZEC Program selects participants and sets prices administratively: Nuclear plants are few in number, and auctions would invite anticompetitive conduct. Illinois thus charged the IPA with developing a procurement plan and selecting participating plants based on public interest factors, including 1) "minimizing carbon dioxide emissions that result from electricity consumed in Illinois," 2) minimizing sulfur dioxide, nitrogen oxide, and particulate matter emissions that adversely affect the citizens of the State," and 3) "the incremental environmental benefits resulting from the procurement, such as any existing environmental benefits that are preserved by the

[76] Ill. Commerce Comm'n et al., *Potential Nuclear Power Plant Closings in Illinois: Impacts and Market-Based Solutions* at 122 (Jan. 5, 2015), https://www.nirs.org/wp-content/uploads/neconomics/illhr1146report115.pdf (estimating the societal cost of carbon occurring during 2020-29 associated with nuclear plant closures at $2.5-$18.6 billion).
[77] Ill. 2016 Energy Act § 1.5(3).

procurements … and would cease to exist if the procurements were not held, including the preservation of zero emission facilities."[78] On January 25, 2018, the IPA announced that that the Quad Cities and Clinton plants had been selected.[79]

The ZEC Program's pricing mechanism ensures that it will be more economically efficient than other state environmental initiatives. The ZEC Program sets the value of ZEC payments based on the social cost of carbon, as reported by the United States Interagency Working Group in effect at the time of the law's promulgation, multiplied by the emissions rate of a natural gas combined-cycle plant.[80] ZEC payments can never exceed that amount. As a result, participating nuclear plants will never receive payments that exceed their environmental value. And in estimating that value, the ZEC price is conservative. First, it measures only nuclear plants' carbon benefits, ignoring their value in avoiding other harmful pollutants, such as particulate matter and mercury. Second, the ZEC price assumes that combined-cycle gas plants would replace retiring nuclear plants—but in fact, in the PJM region, the marginal resources that would likely replace nuclear plants have even higher emissions than the gas plants assumed in setting the ZEC value.[81] Moreover, two additional caps further limit the payments that ZEC plants can receive.[82]

Dr. Willig explains why the ZEC Program's unusually efficient structure cannot warrant mitigation under any defensible theory. By compensating nuclear plants for the environmental benefits they provide, the program addresses an environmental externality and brings private incentives back in line with social costs and benefits.[83] And because payments are capped at a conservative estimate of this environmental value, the ZEC Program's outcome is guaranteed to

[78] *Id.* at (d-5) Zero emission standard (1) (C).
[79] Willig Decl. ¶ 48.
[80] *Id.* ¶ 49.
[81] *Id.* ¶ 50.
[82] *Id.* ¶ 66; Ill. 2016 Energy Act at (d-5) Zero emission standard (1)(B), (C-5).
[83] Willig Decl. ¶¶ 51-54.

be efficient: The plants will rationally choose to operate only if their value to society—reflected in the market revenues for their electricity, capacity, and ancillary services, plus the ZEC payments for their environmental benefits—exceed their costs.[84] If not, the ZEC Program will not save the plants. The ZEC Program does not protect participating plants against risks that prices will fall, or their costs will increase, to levels that render these plants uneconomic even taking account of their environmental benefits. In this respect, the ZEC Program compares favorably with REC programs, which do not cap payments at the resources' environmental value, and can yield payments that are vastly in excess of any plausible estimate of this value—like the payments of $2,575/MW-day and $4,751/MW-day noted by PJM's expert, Dr. Giacomoni.[85]

The ZEC Program's carefully crafted scheme thus brings the Commission's markets closer to what perfect economic efficiency would dictate.[86] In so doing, the ZEC Program may well displace marginal fossil-fuel generators that, absent the ZEC Program, would have cleared. But that is efficient: In a market that takes into account full social costs and benefits, these plants *should not* clear, and ZEC plants should. And the generators that *do* clear still make a profit. All receive a market clearing price equal to or in excess of their offers.[87]

D. PJM Fails To Justify Why "Workably Competitive" Wholesale Markets Should Be Insulated From Pro-Efficiency State Programs That Address Environmental Externalities, Particularly Given The Many Actions That Go Unmitigated.

PJM's decision to target programs redressing environmental externalities is especially indefensible given its admission that wholesale markets are affected by "all manner of distortions that might make prices imperfectly competitive," and that "benefit … some at the expense of

[84] Willig Decl. ¶¶ 51, 62-63.
[85] Giacomoni Aff. ¶ 35; *see also* Willig Decl. ¶¶ 56, 59.
[86] Willig Decl. ¶ 54.
[87] *Id.* ¶ 52.

others."[88] PJM invokes the "Commission's 'workably competitive' standard"[89] without explaining why that standard requires action to target programs addressing environmental externalities—which, when well designed, only improve efficiency—and *not* myriad interventions that affect wholesale markets with weaker or no pro-efficiency justifications.

A good starting point for a list of subsidies that affect wholesale markets comes, ironically enough, from PJM's enumeration of the "local, state, and federal subsidies" that it "propos[es] to *exclude* … from consideration" in its definition of "Actionable Subsidies."[90]

- "[P]ayments (including payments in lieu of taxes), concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area";

- "[P]ayments, concessions, rebates, subsidies or incentives designed to incent, or participation in a program, contract or other arrangements from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality"; or

- "[F]ederal government production tax credits, investment tax credits, and similar tax advantages or incentives that are available to generators without regard to the geographic location of the generation."[91]

Some marginal gas-fired generators would not exist without subsidies from various economic development programs. Likewise, the pervasive practice of states and localities of offering subsidies "designed to incent … siting facilities in" particular locations assuredly results in development of some resources that, otherwise, would not exist *at all*. Indeed, some of these programs are enacted or expanded to spur development of *particular* plants. In Pennsylvania, for example, a coal-to-gas conversion was the "anchor tenant" for a new "Keystone Opportunity Expansion Zone"—which enabled this plant to be built by eliminating state and local taxes through

[88] PJM Filing at 15.
[89] *Id.* at 16 (quoting *PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053, at P 53 (2005)).
[90] PJM Filing at 70 (emphasis added).
[91] *Id.*; *see* proposed PJM Tariff § 1, Definitions L-M-N (Option A).

2023.[92] Indisputably, those subsidies affect who participates in PJM's auctions and the prices that result. Yet PJM ignores them. PJM's sudden and selective urgency is especially unjustified because these subsidies, unlike environmental programs, have no sound economic justification.

PJM's defense is that "these exclusions are the same as those employed … prior to" the *NRG* remand.[93] But that is no justification. The prior MOPR was solely "a mechanism that seeks to prevent the exercise of buyer-side market power," and the Commission found that the type of subsidies discussed above "do not raise price suppression concerns" reflecting "buyer-side market power."[94] PJM's present filing, however, gives mitigation a new and vastly broader purpose—to combat any "material price suppression effect," whether or not due to buyer-side market power.[95] With this expanded role, there is no justification for excluding these subsidies.

Likewise unjustified is PJM's sudden concern about state environmental programs when it continues to exclude from mitigation "vertically integrated, cooperative, and municipal utilities."[96] The regulatory structure that supports such entities is, economically, a subsidy—and a massively distorting one at that. Such entities sell energy and capacity in wholesale markets, but if their revenues are less than their costs, captive ratepayers make up the difference. That guarantee is a subsidy, insuring the utility against losses that, otherwise, it would have to bear.[97] This subsidy, moreover, affects which resources participate in wholesale markets and, hence, the prices that result—exactly what PJM's filing purports to target. Consider, for example, a high-cost coal plant. If its owner had to rely solely on market revenues, it might well retire. A vertically integrated

[92] *Sunbury Generation Lands First Tenant for Old Trail Industrial Park KOEZ*, Oil & Gas 360 (Oct. 28, 2015), https://www.oilandgas360.com/sunbury-generation-lands-first-tenant-for-old-trail-industrial-park-koez-with-announcement-of-financing-of-panda-hummel-station-power-plant/.
[93] PJM Filing at 70.
[94] *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at PP 20, 56, 66 n.47 (2013).
[95] PJM Filing at 35; *see* Willig Decl. ¶ 75.
[96] PJM Filing at 73-74.
[97] Willig Decl. ¶ 80.

utility, however, can continue running the plant, shifting losses to captive ratepayers. And because this utility can bid this high-cost coal plant into the auctions as a price taker, it will pull down clearing prices.[98] Indeed, the Commission has *acknowledged* "the potential competitive impact of" vertically integrated utilities.[99] Yet PJM has not seen fit to act in response to those impacts.

Again, PJM's selective targeting is particularly untenable because there is no sound pro-efficiency justification for exempting vertically integrated utilities. To the contrary, it has long been understood that, as a result of the implicit subsidy given to vertically integrated utilities, they have incentives to overinvest.[100] Yet PJM not only exempts this subsidy from mitigation, but it *doubles down* on the permissible distortion by authorizing vertically integrated utilities to overbuild by up to 1300 MWs—roughly the size of the Quad Cities plant targeted by PJM—without mitigation.[101] What is more, PJM's filing perversely embraces the ability of states with vertically integrated utilities to take the same actions that, when taken by other states, PJM *condemns* as "price suppression." If a nuclear power plant owned by a vertically integrated utility is not covering its full costs in the wholesale markets, a state that wishes to preserve the plant's environmental benefits can authorize the plant to recover its full costs from ratepayers. That is no mere hypothetical: To avoid the risk that it might lose the environmental benefits of nuclear plants, Minnesota is considering guaranteeing those plants cost recovery as "carbon reduction facilities."[102] A regulated PJM state, such as Michigan or Virginia, might someday choose to do

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[98] *Id.*

[99] *See, e.g.*, *Utilization of Elec. Storage for Multiple Servs. When Receiving Cost-Based Rate Recovery*, 158 FERC ¶ 61,051, at P 22 (2017) (acknowledging "the potential competitive impact of [vertically integrated utilities] on other competitors in those markets").

[100] *See generally* Averch & Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 Amer. Econ. Rev. 1052 (1962); *Conn. Dep't of Pub. Util. Control v. FERC*, 593 F.3d 30, 35 (D.C. Cir. 2010) (describing this "Averch–Johnson effect" as "familiar").

[101] PJM Filing at 28-29; Proposed PJM Tariff, Attachment DD § 5.14(h)(7)(d) (Option A & Option B).

[102] *See generally* S.F. No. 3504, 19th Sess. (Minn. Mar. 6, 2017), https://www.revisor.mn.gov/bills/text.php?number=SF3504&version=0&session_year=2018&session_number=0&format=pdf.

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the same. PJM offers no persuasive reason why out-of-market revenue derived from guaranteed retail rate recovery should be exempt from mitigation, yet revenue derived from ZECs purchased by retail utilities should be subject to mitigation. Both advance the same policy of supporting zero-emissions facilities that would otherwise retire.

Tellingly, PJM does not claim that the *effects* of vertically integrated utilities are less than the state environmental programs its filing targets. Nor could it. A *quarter* of generation in PJM's markets "is owned by traditionally regulated, vertically integrated public utilities or public power."[103] And there can be no doubt that a substantial part of this generation would be uneconomic without the implicit subsidy provided by captive ratepayers. As a conservative estimate, PJM contains 5.5 UCAP GW of small and medium coal plants under 600 MW owned by vertically integrated utilities, which almost certainly would not be economic outside the vertically integrated model.[104] That dwarfs the PJM capacity receiving payments under the Illinois ZEC Program. Instead, PJM's only justification is—again—that the Commission previously exempted vertically integrated utilities from PJM's MOPR because they "do not raise concerns of possible price suppressive intent."[105] That justification fails for the same reason already explained: The self-supply exemption may be justified so long as mitigation remains limited to addressing buyer-side market power, but the entire *premise* of PJM's filing is that mitigation should be expanded to address any "material price suppression effect."[106] Indeed, PJM elsewhere proclaims that mitigation should apply "regardless of intent."[107]

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[103] PJM Filing at 9.
[104] The underlying data for this calculation comes from PJM's resource model for the 2020/21 Base Residual Auction, http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-rpm-resource-model.ashx?la=en. The units at issue are Chesterfield 3-5, Clover 1-2, Mt. Storm 1-3, Clinch River 1-2, and Ft. Martin 1-2, and Spurlock 1-4.
[105] PJM Filing at 73-74.
[106] *Id.* at 35.
[107] *Id.* at 15 n.37 (quotation marks omitted).

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When PJM tries to explain why its "Actionable Subsidy" definition excludes federal subsidies, its filing descends into incoherence. PJM does not claim that it has excluded federal subsidies because their effects are small, or especially pro-efficiency. Nor could it. Every year, the U.S. government subsidizes *fossil-fuel generators* to the tune of $4.7 billion.[108] That massive subsidy has *no* pro-efficiency justification. The federal government's pro-environmental subsidies, such as the Production Tax Credit ("PTC") for wind, likewise are large and have significant effects: Without the PTC, wind generation would not be built, and the low wind bids that result from the PTC reduce capacity prices by 2.4% across PJM and 6.1% in the ComEd zone

Table 1: Impact Of Subsidized Wind On PJM Capacity Prices

Estimated Impact of Subsidized Renewables on PJM Capacity Prices in 2020/21 Base Residual Auction
WIND ONLY

	Cleared Renewable UCAP (MW)				2020/21	Estimated BRA Price if Wind	Price Suppression
Region	Wind	Solar	Biomass	Total	BRA Price ($/MWD)	Bid at Net CONE x B ($/MWD)	Due to Wind (%)
RTO	412	0	0	412	76.53	78.45	-2.4%
ComEd	356	0	0	356	188.12	200.30	-6.1%
MAAC	120	0	0	120	86.04	87.02	-1.1%
EMAAC	0	0	0	0	187.87	187.87	0.0%
	888	0	0	888			

Sources: Cleared renewable UCAP per PJM 2020/21 BRA results. Regional renewable shares estimate based on 2020/21 resource model. Biomass assumed to include wood, other gas, and other liquid resource categories. Price impact of renewables estimated based on PJM 2020/21 RPM Base Residual Auction sensitivity analysis.

The PTC cashes out to $815/MW-day, which vastly exceeds any plausible estimate of wind power's environmental benefits.[109]

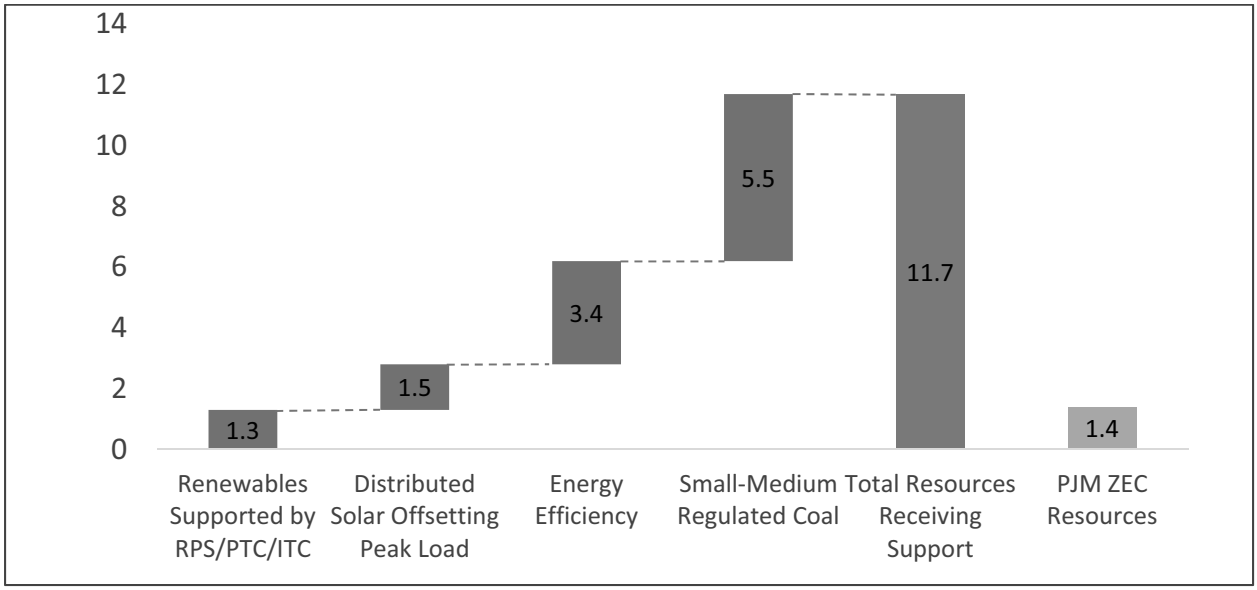
PJM can only aver that it "strains credibility to believe that the Commission's jurisdiction under the FPA would extend to countermand other acts of Congress, including … the production tax credit."[110] But the premise of PJM's Capacity Repricing proposal, at least, is that "this approach result[s] in *respecting and accommodating* state policy choices."[111] PJM cannot say with

[108] *Capacity Markets and Externalities* at 17.
[109] This number is based on the same assumptions used in the Giacomoni Affidavit—a 28% capacity factor and 15% capacity credit for wind—and the $18.2/MWh PTC applicable to new builds commencing construction in 2018.
[110] PJM Filing at 71.
[111] *Id.* at 46 (emphasis added).

a straight face that the *same action*—repricing—is respectful and accommodating when it comes to states, but "countermand[ng]" as to federal policies. And if applying Capacity Repricing (or MOPR-Ex) *were* tantamount to countermanding federal policies, PJM does not try to explain why the Commission would have *greater* authority to take that step as to state environmental policies given states' exclusive jurisdiction to regulate "facilities used for the generation of electric energy."[112] Indeed, PJM's position here would also appear to require an exemption for units receiving federally mandated cost-of-service recovery under Section 202(c) of the FPA, despite the obvious effects such contracts would have on auction results. That too would be arbitrary.

Here is the bottom line: Myriad resources have long received support via subsidy payments, as reflected in Figure 3.

Figure 3: RPM Capacity Resources Receiving Long-Standing Support (UCAP GW)



Notes: Renewables includes all RPM-cleared wind, solar, and wood biomass resources. Distributed solar is PJM forecast for 2020 per the 2017 Load Forecast. Energy efficiency includes all RPM-cleared energy-efficiency resources, virtually all of which receives rebates or other state support connected with state energy-efficiency programs. Energy Efficiency includes past energy-efficiency resources that are now incorporated into load forecast. Small-medium regulated coal includes all regulated coal units with capacity less than 600 MW.

[112] 16 U.S.C. § 824(b)(1).

This data is conservative, as it excludes many tax credits and development incentives outlined above. But conservatively estimated, the resources *already* receiving support dwarfs the capacity affected by the ZEC Program that PJM targets. PJM bears the burden to show that its proposed tariff is just and reasonable. PJM cannot make that showing when its proposals target pro-efficiency state environmental programs affecting 1.4 GW, leaving untouched myriad other interventions affecting more than ten times that amount that yield just as much "material price … effect," and many of which make the Commission's markets less efficient.

III. It Is Not Just And Reasonable To Alter Capacity Rules To Increase Capacity Prices When There Remains Significant Over-Supply And Robust New Entry.

PJM's proposals are not just and reasonable, but if a dearth of new entry jeopardized resource adequacy, they would at least be understandable. The markets, however, are working well. Prices are low (benefitting consumers), yet new entry is robust (confirming that the markets continue to attract investment). In such circumstances, it would violate the Commission's statutory mandate to raise prices via administrative action, as PJM's proposals would do.

A. The Commission Should Not Change Capacity Market Rules To Combat Low Prices At A Time Of Plentiful Supply.

The Commission's mandate under the FPA is "to encourage the orderly development of plentiful supplies of electricity … at reasonable prices."[113] Absent concrete evidence of a danger to that mandate, or of the exercise of buyer-side market power, the Commission has declined to apply mitigation.[114] Today, the wholesale markets are providing plentiful supplies at low prices.

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[113] *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,157, at 30 n.39 (2016) (quoting *Pub. Utilities Comm'n of Cal. v. FERC*, 367 F.3d 925, 929 (D.C. Cir. 2004)).

[114] *E.g.*, *ISO New England Inc.*, 158 FERC ¶ 61,138, at P 28 (2017) ("Generators have not shown that the renewables exemption will, in fact, suppress prices over time such that the capacity market is unable to perform its function of attracting and retaining sufficient capacity to maintain reliability … at a just and reasonable price."); *id.* P 58 ("[W]e are not persuaded that there is substantial evidence that FCM capacity prices will be so low as to prevent sufficient entry into the FCM to meet ISO-NE's reliability targets, on average over time. Thus, we consider Generators' assertions that the renewables exemption will result in an inappropriate wealth transfer — i.e. that Generators will be effectively paying for the cost of the renewable resources — to be a misunderstanding of the purpose of the FCM. It

And while the CASPR Order indicated that part of the Commission places weight on whether there is a "level of investor confidence" that ensures that supplies remain plentiful going forward,[115] the markets are succeeding in that respect too.

PJM's filing relies on theoretical claims about how state environmental policies make "investment … less sustainable over time."[116] Those claims should sound familiar: The Commission has heard them since Illinois and New York passed ZEC programs in 2016. The Commission was told that Illinois' legislation posed an "existential threat,"[117] and was "poised to drop onto the RPM market like an anvil onto a woeful coyote beginning with the Base Residual Auction for … 2020/2021."[118] It heard the same thing about New York's ZEC Program and the markets of the New York Independent System Operator, Inc. ("NYISO").[119]

Today, that rhetoric is testable. The coyote is alive and well. New York's ZEC Program was adopted nearly two years ago, and Illinois' is more than a year old, including spanning a cycle of PJM's Base Residual Auction. These programs have thus been understood and factored into both markets for some time. And if they were undermining resource adequacy or investor confidence, the data would show it. Yet PJM presents no evidence of any adverse market impacts. And the *real* data show the opposite. In both regions, capacity is plentiful. In PJM's most recent Base Residual Auction, 165.1 GW of unforced capacity cleared.[120] Including commitments under

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is the purpose of the FCM to attract and retain sufficient capacity to meet ISO-NE's reliability targets on average over time, at least cost to customers, given the renewable generation that will enter as a result of state programs.").

[115] CASPR Order at P 21.

[116] PJM Filing at 34.

[117] Motion to Amend, and Amendment to, Complaint and Request for Expedited Action on Amended Complaint at 2, 3, *Calpine Corp. v. PJM Interconnection, L.L.C.*, Docket No. EL16-49-000 (Jan. 9, 2017) ("Calpine Mot. to Amend"); Motion to Lodge and Request for Expedited Action on Amended Complaint at 2-3, *Calpine Corp. v. PJM Interconnection, L.L.C.*, Docket No. EL16-49-000 (Aug. 30, 2017).

[118] Calpine Mot. to Amend at 2-3.

[119] Request for Expedited Action at 13-14, *Independent Power Producers of New York, Inc. v. New York Independent System Operator, Inc.*, Docket No. EL13-62-002 (Jan. 9, 2017).

[120] *See* PJM, 2020/2021 RPM Base Residual Auction Results 1 (May 23, 2017), http://pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx.

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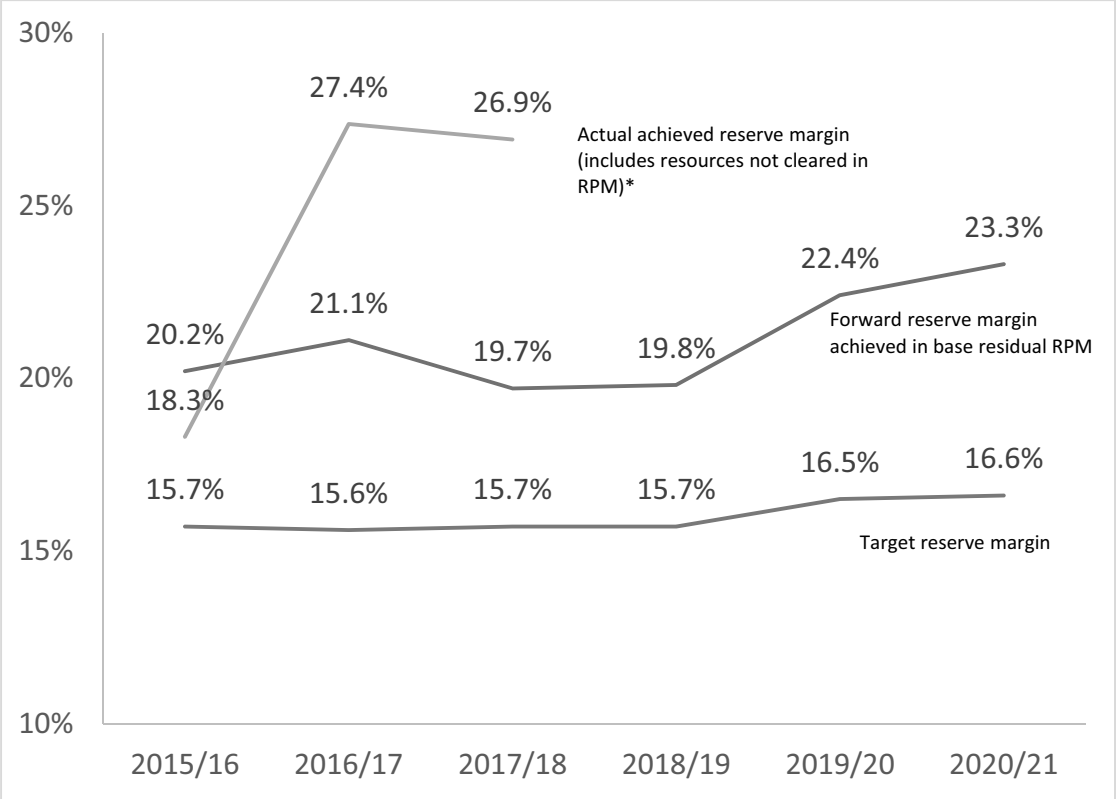
Fixed Resource Requirement plans, PJM's reserve margin is 23.3%, or 6.7% higher than the target.[121] The achieved margin, which includes resources that did not clear in the Base Residual Auction, is even higher, at 26.9% in 2017/18. That pattern is stable, as the following figure shows:

Figure 4: PJM Achieved Versus Target Reserve Margins



Note: Data are per NERC summer reliability assessments.

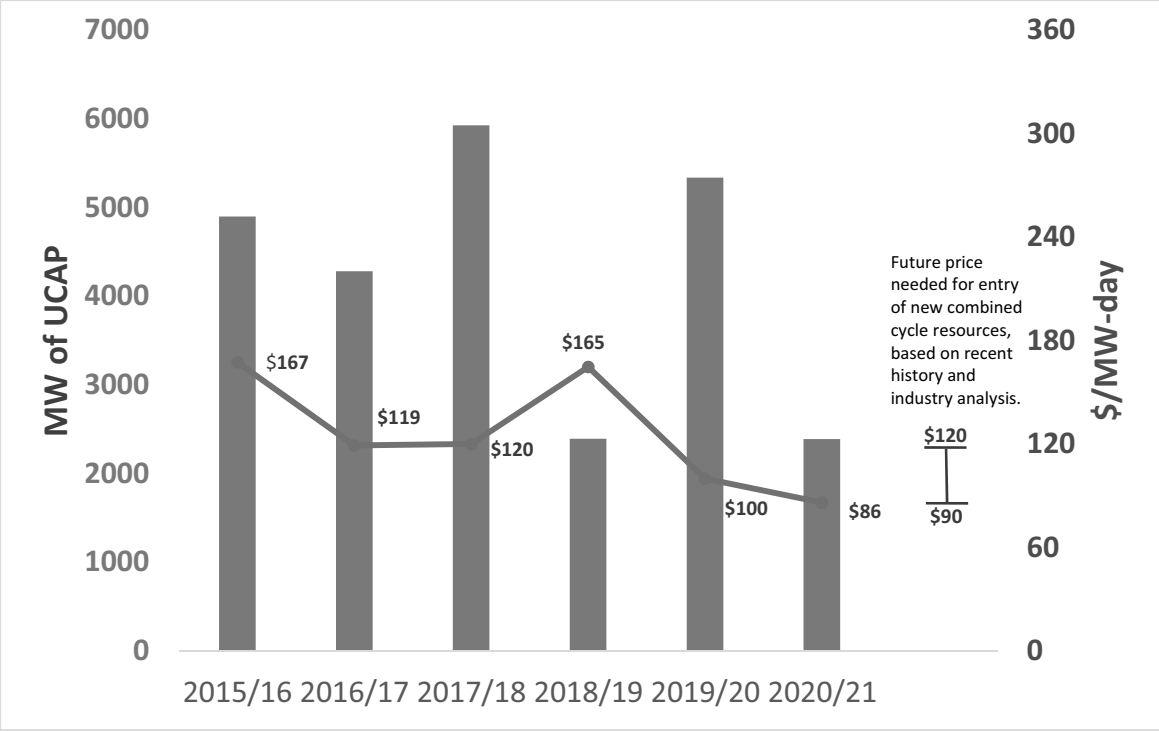
PJM contends that state environmental programs will lead investors to distrust market price signals, and they will refuse to invest. But for two decades, states have been implementing REC programs, as well as many other programs that impact wholesale market profits, including demand response and energy efficiency programs that reduce demand, net metering programs, and subsidies for storage. Sophisticated investors have always considered these types of regulatory risks. Today's risks are nothing new. Against this backdrop, it is not just and reasonable to revise

[121] *See id.*

market rules for the purpose of increasing prices without evidence that supply is tightening or investors are unwilling to invest even as prices approach or exceed Net CONE.

Even at today's low prices, moreover, new gas units are regularly entering both markets. The most recent Base Residual Auction attracted 2,350 MW of new combined-cycle gas resources, despite clearing prices between approximately 26% and 66% of PJM's Net Cost of New Entry ("Net CONE").[122] Thus, the capacity market is clearing enough new and existing resources to more than satisfy the reserve margin, at prices well below Net CONE. That has been true for years. In the last six Base Residual Auctions, at least 2 GW of new generation (often 4-5 GW) has cleared:

Figure 5: New Build Capacity Cleared And Clearing Prices In PJM Base Residual Auction, 2015-16 – 2021/21

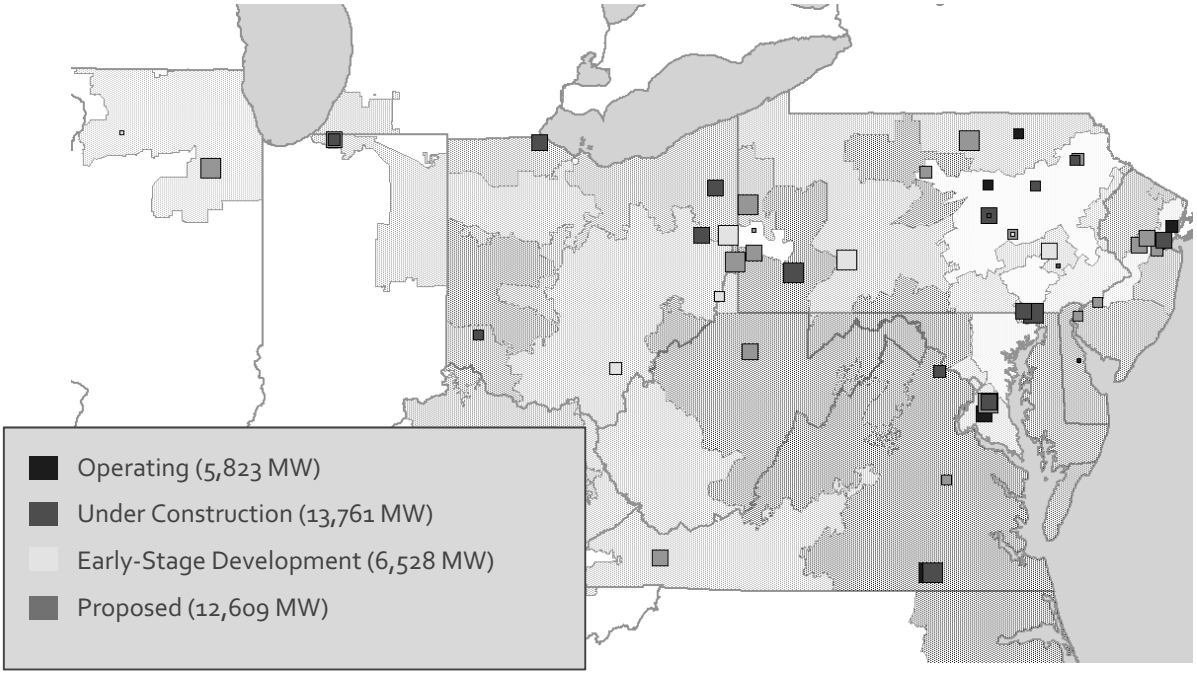


Note: Includes all RTO and MAAC capacity. New build clearing price is higher of RTO and MAAC. Excludes EMAAC new entrant capacity in years where EMAAC price separated and cleared higher than MAAC price. Does not include uprates.
Source: PJM Interconnection Base Residual Auction Reports, various years. http://www.pjm.com/markets-and-operations/rpm.aspx.

[122] *Id.* Thus, the facts refute the assertion made at the Technical Conference that new investments are not being made.

To the extent that the pace of new entry is slowing, that is because the market is responding to oversupply. Nevertheless, looking forward, there are almost 40 GW of recently entered or potential near-term entrant gas combined-cycle plants spread across PJM—25% of the market:

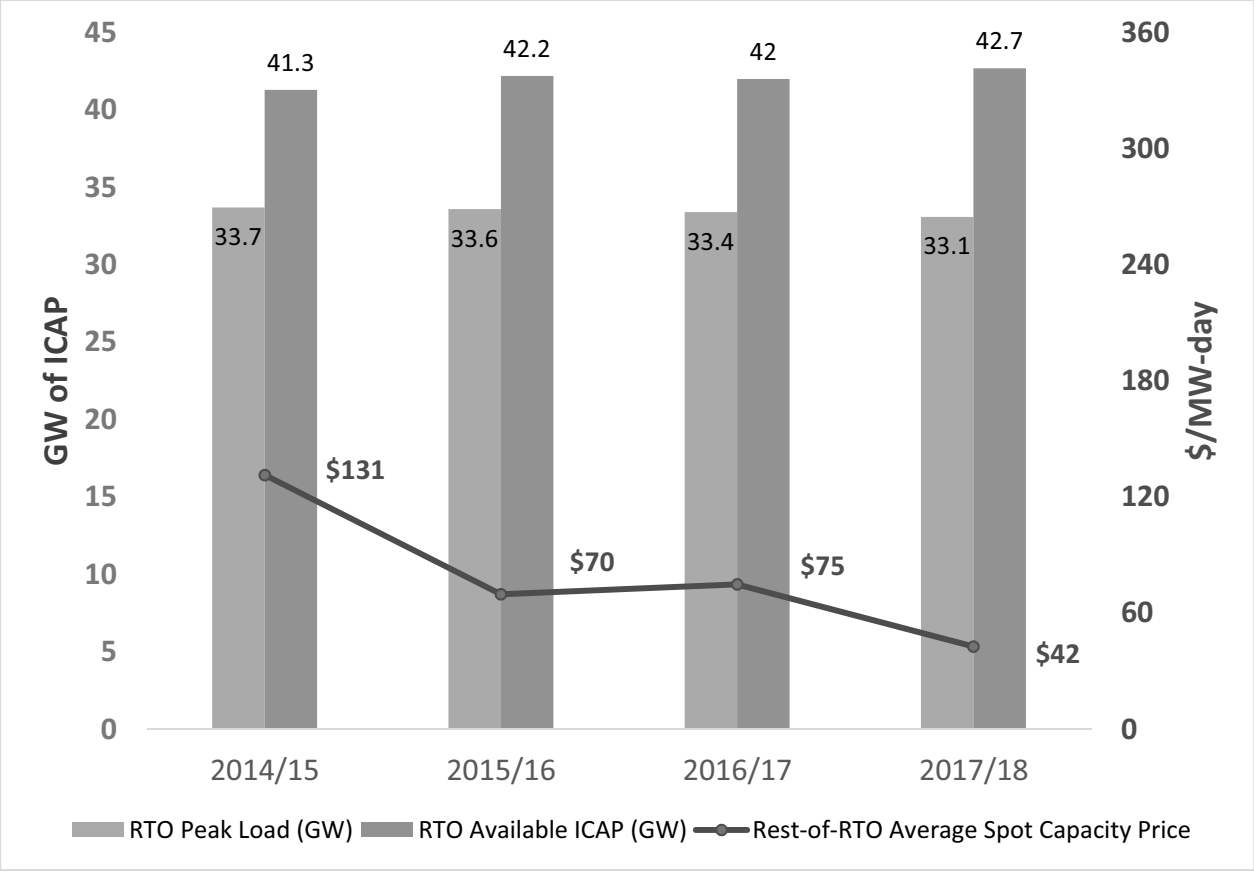
Figure 6: The 40 GW Of Recently Entered Or Potential Near-Term Entrant Gas Combined-Cycle Plants In PJM



Note: Box size denotes relative size of each unit in net summer capacity.

NYISO's story is similar. While new entry has not taken place at the same pace, reserve margins are even higher—25.6% in 2015/16, 26.0% in 2016/17, and 29.1% in 2017/18—at lower clearing prices of around $42 per MW/day. If new entry is needed, NYISO would likely see substantial new entry at modest prices. Even at current prices, New York will add two new combined-cycle gas plants, including the 1,100 MW Cricket Valley plant, over the next few years. There is no resource adequacy issue, as the following figure underscores:

Figure 7: NYISO Reserve Margins And Capacity Prices, 2014/15 – 2017/18



Source: New York ISO ICAP Market Reports, July 2014 through April 2018.

There is no reason to doubt that these trends will continue. PJM's markets are *designed* to maintain equilibrium, and safeguard resource adequacy, across a broad range of conditions. For example, if state programs reduce capacity prices, but tightening supply indicates that new entry is needed, prices will rise, and the downward sloping demand curve will ensure that the capacity price adjusts to reflect the costs of the generators that are necessary for resource adequacy.[123] In these circumstances, without any concrete evidence of a threat to reliability or investor confidence resulting from state environmental programs, it is not just or reasonable to approve tariff changes designed to increase prices for certain resources.

[123] *Capacity Markets and Externalities* at 18; *see* Willig Decl. ¶ 46.

B. The Commission Should Not Expand Capacity Market Mitigation Beyond The Purpose For Which It Was Adopted—Combatting Buyer-Side Market Power.

On the present record, it is not just and reasonable to embark on the two unprecedented expansions to buyer-side capacity market mitigation sought in PJM's filing. First, PJM's filing would expand such mitigation beyond its original purpose: avoiding buyer-side market power. Second, it would sweep in a vast universe of additional resources by mitigating existing resources.

Expansion beyond buyer-side market power. Combatting buyer-side market power is undoubtedly a legitimate concern under the FPA. Rates are "unjust and unreasonable … in violation of section 205(a) of the FPA" when they are "due to the exercise of market power."[124] The Commission narrowly crafted PJM's MOPR to address the concern that "net buyers might have an incentive to depress market clearing prices by offering … at less than a competitive level," and it found that the MOPR was "a reasonable method of assuring that net buyers do not exercise monopsony power."[125] The Commission has continued to describe the "very purpose"[126] and the "underlying objective[]" of "PJM's MOPR" as "to prevent the exercise of buyer-side market power."[127] Likewise, when the Commission has weighed modifications to PJM's MOPR, it has assessed whether those modifications are necessary to address buyer-side market power.[128]

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[124] *Portland Gen. Exch., Inc.*, 51 FERC ¶ 61,108, 61,243-44 (1990).
[125] *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at PP 103, 104 (2006).
[126] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 104 (2011).
[127] *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 20 (2013) (describing "PJM's MOPR [as] a mechanism that seeks to prevent the exercise of buyer-side market power").
[128] *See, e.g.*, *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 70 (2011) (revised threshold "reasonabl[y] … protect[s] against unreasonable exercises of market power"); *id.* at P 88 (amending rule that was "ineffective at protecting against buyer market power"); *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 25 (2013) (self-supply exemption approved because it "will operate to identify those self-supply entities lacking the incentive to exercise buyer-side market power"); *id.* at P 109 (declining to "categorially exempt self-supply" because a "blanket exemption" would allow an "unacceptable opportunity to exercise buyer market power"); *id.* at P 56 (approving competitive entry exemption because qualifying entities "do[] not raise buyer-side market power concerns"); *id.* at P 166 (limiting MOPR to gas-fired generation as the "most likely" to "be used to exercise market power").

Under this precedent, PJM's filing fails at the threshold. PJM does not allege that buyers are exercising market power, or that its proposals are designed to prevent the exercise of buyer-side market power. Instead, PJM seeks to transform mitigation rules into a roving tool to address any "material price … effect in the wholesale capacity market" from external influences outside the market. But such external influences are omnipresent and inescapable, as PJM elsewhere acknowledges.[129] And as PJM's incoherent proposals show, the project of "draw[ing] … lines between actionable and un-actionable" influences[130] is fraught. Under present conditions, it is not just and reasonable to embark on that difficult task by unmooring buyer-side mitigation from its foundations.[131]

Exelon recognizes that, in ISO-New England, the CASPR Order applied mitigation rules for a broader purpose. But the Commission stressed that its "acceptance of th[at] proposal" was "only … a finding … on the record before" it.[132] On the record *here*, PJM has failed to identify either sufficient justification for departing from the existing scope of PJM's mitigation rules, or a just and reasonable proposal to implement some broader purpose.

Expansion to existing resources. The CASPR Order only underscores the second unprecedented change sought by PJM's filing. Buyer-side mitigation has *always* been limited to new resources,[133] including in CASPR.[134] That is for good reason. If the intent is to exercise buyer-side market power by lowering prices, the best way to do it is with new resources that can

[129] PJM Filing at 15-16, 34-35.
[130] *Id.* at 15.
[131] *See* Willig Decl. ¶¶ 13(a)-(b); 23-24.
[132] CASPR Order at P 26.
[133] *PJM Interconnection, L.L.C.*, 153 FERC ¶ 61,066, at P 3 (2015) ("PJM's MOPR is designed to protect against buyer-side market power by setting a price floor, i.e., a minimum bid, and by requiring that all *new*, non-exempted resources bid at that floor" (emphasis added)); *see also, e.g.*, *id.* at P 44 (approving self-supply exemption because it adequately addresses "the price effects attributable to uneconomic *new* self-supply" (emphasis added)).
[134] CASPR Order at P 8.

be built quickly and have high capacity factors—specifically, new gas-fired plants. That is why the Commission found that PJM had properly limited its MOPR to new "gas-fired resources" as "those resources most likely to raise price suppression concerns," which the Commission determined "appropriately balanc[ed] the need for mitigation of buyer-side market power against the risk of over-mitigation."[135]

By contrast, existing resources are not a promising tool for exercising buyer-side market power, and MOPR's remedy does not fit. Existing resources already are participating in the market, and their capacity has contributed to prices the Commission has found just and reasonable. When PJM proposed extending the mitigation period to three years, the Commission rejected that request because, "given the market's demonstration of its need for the resource," there was "no reasonable basis for continuing to apply the MOPR."[136] Likewise, the mitigation remedy—resetting bids to Net CONE * B—does not fit existing resources. Their costs are largely sunk. Thus, as the Commission explained, this remedy "could lead to over-mitigation by requiring a commercially operational resource to bid at an offer floor … substantially above its going-forward costs."[137] These principles apply with particular force to nuclear resources, which have supplied capacity for decades and predate the capacity markets. Their cost of construction has already been sunk, and they have been licensed by the Nuclear Regulatory Commission ("NRC") to operate for years. The Commission should reject the notion that a nuclear unit's continued supply of capacity through the end of its NRC license somehow distorts the capacity market, and should maintain its longstanding and well-grounded limitation of buyer-side mitigation to new entrants only.

[135] *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 26 (2013).
[136] *Id.* at P 211.
[137] *Id.* at P 212; *see* Willig Decl. ¶ 13(g)(iii).

IV. MOPR-Ex Violates Each Of The Core Principles That Should Guide Commission Decisionmaking.

As explained above, Exelon does not believe that either proposal is just and reasonable. But if the Commission deems some reform warranted, it should adhere to five principles grounded in Commission precedent.

First, the Commission should allow the mix of resources selected by the capacity market to be affected by state programs that address environmental externalities. So long as the Commission keeps its policies "fuel neutral,"[138] it must accommodate actions of other regulators addressing the reality that fuels have different environmental impacts. If the Commission's markets were designed to *prevent* states from influencing the mix of resources selected in the auction, and if the Commission does not itself step into the gap and adopt a carbon price, then the Commission's markets would not fulfill their "first principles" of "facilitat[ing] robust competition" and "select[ing] … the least-cost set of resources."[139] Polluting plants would receive an implied subsidy, and the resources selected would not be the set that minimizes social costs.

Second, if the Commission decides to accept market rule changes, it should do so in the spirit of cooperative federalism and accommodate state choices as much as possible. Wherever possible, the Commission must "fulfill [its] jurisdictional responsibilities while also respecting the states' traditional role."[140]

Third, the Commission should avoid putting customers in the position of having to over-procure capacity via market rules that prevent state-supported resources from clearing. As the Commission has recognized, while the harsh medicine of the MOPR may be effective and

[138] *Id.* at P 26.
[139] CASPR Order at P 21.
[140] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1112 (2006).

appropriate to deter against exercises of buyer-side market power, that remedy is neither effective nor appropriate in response to environmental policies that states are committed to pursuing.[141] Mitigating state-supported resources only leads to the retention of unneeded capacity.

Fourth, the Commission should treat compensation from environmental programs in an even-handed and nondiscriminatory manner. Distinctions in treatment must reflect differences in how policies affect wholesale markets. Otherwise, the Commission is inappropriately sitting in judgment on state policies with no basis in the FPA. Likewise, the Commission should not distinguish between federal and state policies when effects on wholesale markets are identical.

Fifth, the Commission should avoid taking actions in capacity markets that will exacerbate existing price suppression in energy markets. There is no justification for embarking on a purported cure that may well be worse than the disease.

Option B's MOPR-Ex violates each of these principles. First, it selects the *wrong* resources by favoring inefficient polluting resources over clean resources whose costs, all things considered, are lower. Second, it treats state environmental programs as hostile to, rather than complementary of, the Commission's markets. Third, MOPR-Ex selects *too many* resources by ignoring the capacity that will be provided by state-supported resources whose mitigated bids do not allow them to clear. Fourth, even as Option B purports to aim at protecting the market from influences of state policies, it is riddled with arbitrary exceptions. Far from being fuel-neutral, it is gerrymandered to target nuclear and offshore wind. Fifth, MOPR-Ex will suppress energy market prices.

MOPR Ex's flaws are no secret to its sponsors, PJM and its IMM, which developed MOPR-Ex. Just a few months ago, PJM's management emphasized it could not "recommend[]" the "MOPR-Ex … approach to the PJM Board," having concluded that it "is not sustainable and does

[141] CASPR Order at P 45.

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not strike an appropriate balance between legitimate state interests and wholesale market integrity."[142] The IMM has long pushed for an expanded MOPR. But even the IMM understands that MOPR-Ex's distinctions are arbitrary: On April 11, 2016 the IMM filed testimony in support of an expanded MOPR, supposedly based on the IMM's own economic analysis. That proposal would have expanded the MOPR broadly—including to several categories of resources exempted from MOPR-Ex, such as qualifying facilities, public power resources that do not meet the requirements for the self-supply exemption, and state RPS programs (aside from REC payments).[143] MOPR-Ex's newfound exemptions do not stem from any *change* in the IMM's analysis. They are politics. A substantial majority of PJM stakeholders supported the status quo over the IMM's proposal[144]—until the IMM log-rolled powerful voting blocs with exemptions for public power, existing RPS programs, and qualifying facilities. Meanwhile, fossil-fuel generators needed no inducement to support a proposal that harms their cleaner competitors.

No deference should be afforded to the failed stakeholder vote on MOPR-Ex. The proposal did not receive the required supermajority support, and the economically unsound and politically motivated exemptions doled out by the IMM were essential to garnering even the modest level of support the proposal obtained.[145] Regardless, stakeholder votes cannot render a proposal just and reasonable. That determination remains with the Commission.

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[142] Letter from Andrew L. Ott, President and CEO, PJM (Jan. 16, 2018), https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180116-pjm-president-and-ceo-letter-regarding-capacity-market-repricing-proposal.ashx?la=en.

[143] Comments of the Independent Market Monitor for PJM at 8, Docket No. EL16-49-000 (Apr. 11, 2016).

[144] PJM, CCPPSTF Vote Results at 5 (Nov. 21, 2017), http://www.pjm.com/-/media/committees-groups/task-forces/ccppstf/20171121/20171121-ccppstf-vote-results.ashx.

[145] *Sw. Power Pool, Inc.*, 152 FERC ¶ 61,226, at PP 111, 116 (2015) (rejecting Section 205 filing despite "degree of deference [provided] to RTO stakeholder processes," and noting argument of PJM Market Monitor that "no deference to SPP stakeholders is appropriate in this case" given conflicts of interest among stakeholders); *see PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,139, at P 136 n.244 (2018).

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A. Option B's MOPR-Ex Would Result In An Inefficient Selection Of Resources.

PJM admits that the "theoretical ideal market approach" would account for externalities via, for example, "a carbon emissions objective embedded in the wholesale market."[146] Judged by those principles, Option A's Capacity Repricing improperly adjusts prices in its second-stage auction and treats payments under state environmental programs as subject to mitigation. But Capacity Repricing at least selects the correct resources. MOPR-Ex is far worse.[147] It artificially raises bids of clean resources receiving payments for environmental attributes—resources that, accounting for externalities, are economic.[148] So instead of clearing these economic clean resources, the market clears marginal fossil-fuel-fired resources that, when pollution costs are accounted for, are not economic.[149] In so doing, MOPR-Ex contravenes the mandate that market rules should provide "price signals that guide … orderly entry and exit" to "the selection of the least-cost set of resources."[150] Indeed, approving MOPR-Ex would require the Commission to disavow all of its precedent accommodating state environmental programs, from its CAISO order to the just-issued CASPR Order.[151] And this departure from Commission precedent would be especially harmful as to the nuclear plants MOPR-Ex targets. If MOPR-Ex forces them to retire, they are gone forever. Yet there is broad agreement that, over the medium term, markets should evolve to account for clean generation's environmental benefits.[152] There is no justification for

[146] PJM Filing at 54.
[147] *Id.* at 54-55.
[148] Willig Decl. ¶ 71.
[149] *Id.*
[150] CASPR Order at P 26.
[151] *Supra* at 18-22.
[152] *See, e.g.*, Post-Technical Conference Comments of Calpine Corp. at 4, *State Policies and Wholesale Markets*, Docket No. AD17-11-000 (June 22, 2017); Post-Technical Conference Comments of Dynegy Inc. at 4, *State Policies and Wholesale Markets*, Docket No. AD17-11-000 (June 22, 2017); Post-Technical Conference Comments of Electric Power Supply Association at 9, *State Policies and Wholesale Markets*, Docket No. AD17-11-000 (June 22, 2017); Post-Technical Conference Comments of NRG Energy, Inc. at 4, *State Policies and Wholesale Markets*, Docket No. AD17-11-000 (June 22, 2017); *see generally* Post-Technical Conference Reply Comments of Exelon Corp. at 4 & n.9, *State Policies and Wholesale Markets*, Docket No. AD17-11-000 (July 13, 2017) (citing additional comments in support).

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enacting, in the short term, rules that intentionally lead PJM's resource mix away from the direction that a broad swath of stakeholders—including several fossil-fuel generators that Exelon expects to support MOPR-Ex—believe it should head.

B. MOPR-Ex Is Inconsistent With The Accommodative And Cooperative Approach Endorsed In The CASPR Order.

MOPR-Ex also violates the prime directive of the FPA's scheme of cooperative federalism—that the Commission must, when possible, "fulfill [its] jurisdictional responsibilities while also respecting the states' traditional role."[153] MOPR-Ex is expressly "punitive" and "mitigative in nature."[154] But even if the Commission determines that action is needed to address the effects of state environmental programs on capacity prices, the Commission should take such action in the spirit of cooperative federalism—seeking to design its markets to ensure just and reasonable prices while complementing, rather than countermanding or punishing, such state programs. Indeed, the Commission has *already* approved, in CASPR, a model that addresses state programs' effects on wholesale markets in a spirit of cooperative federalism. As explained above, CASPR promised "to better accommodate" state environmental policies in wholesale markets, and the Commission approved CASPR only after it concluded that CASPR would "provide[] a reasonable opportunity to accommodate state sponsored resources."[155] With the more accommodating model of Capacity Repricing available, it is not just and reasonable to adopt an approach that goes out of its way to frustrate state policy choices.

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[153] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1112 (2006); *see Connecticut Light & Power Co. v. Fed. Power Comm'n*, 324 U.S. 515, 526 (1945) (Commission authority is "'so drawn as to be a complement to and in no sense a usurpation of State regulatory authority,'" and Commission is obligated "'to receive and consider the views of State[s]'" (quoting legislative history of FPA)); *Panhandle E. Pipe Line Co. v. Pub. Serv. Comm'n of Ind.*, 332 U.S. 507, 517 (1947) (Commission authority has "no purpose or effect to cut down state power"; rather, its "primary purpose [i]s to aid in making state regulation effective, by adding the weight of federal regulation to supplement and reinforce it").

[154] PJM Filing at 53, 96.

[155] CASPR Order at P 102.

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C. MOPR-Ex Would Over-Procure Capacity And Distort Energy Prices.

Option B is also far worse than Option A because it yields *too much* capacity. The Commission has recognized that when states are pursuing clean energy policies, they will continue to support clean generation even if market rules preclude that generation from clearing. Thus, the CASPR Order observed that such capacity "will be developed by the operation of state environmental and clean energy mandates, whether that capacity clears the [market] or not."[156] In this respect, mitigating clean generation policies differs from mitigating exercises of buyer-side market power. If a buyer's goal is to suppress capacity prices by introducing new capacity, then applying the MOPR means the anti-competitive capacity will not get built *at all*. Building that capacity would be irrational because it cannot further the buyer's price-suppressive goals.

Clean energy is different. As the Commission has recognized, states are likely to continue promoting clean generation even if it cannot clear—because even if the capacity does not clear, it still provides environmental benefits. Thus, as PJM admits, the clean generation will continue to be built and to operate.[157] That means applying the MOPR is likely to "send an incorrect signal to construct new capacity that is not needed."[158] State-supported clean generation will go forward, yet the wholesale markets—ignoring that capacity—will signal that further capacity is needed. The Commission has always acted to avoid that result, either by exempting clean generation policies from mitigation,[159] or by ensuring that any mitigation provides a pathway to accommodate clean generation policies and avoid over-procurement, as in CASPR. Capacity Repricing, despite

[156] *Id.* at P 45.
[157] PJM Filing at 56 ("In many cases, loss of capacity revenues likely will not induce retirement of the subsidized resource, and loads will be paying for more resources than it needs."); *see* Willig Decl. ¶¶ 72-73.
[158] *ISO New England Inc.*, 158 FERC ¶ 61,138, at P 9 (2017).
[159] *Id.* at P 48 (exemption "for state-subsidized resources … so that customers may avoid having to pay for duplicative capacity").

its flaws, also avoids these problems.[160] MOPR-Ex runs headlong into them. As PJM admits, MOPR-Ex is likely to "disqualify[]" clean generators "from clearing as capacity, and will clear other resources to meet capacity needs."[161] As a result, several years hence, the PJM region will have far more capacity than it needs and customers will pay more to support the excess.[162]

That excess capacity will yield a second problem: MOPR-Ex is likely to "enable[e] price suppression in the wholesale energy and ancillary service markets."[163] Because PJM's system will include both the clean generation that the capacity markets ignore, and the replacement generation that the capacity markets acknowledge, there will be "greater supply in the energy market than economic conditions … justify," which will—in turn—"suppress prices."[164]

PJM's failure to grapple with this energy market suppression is reason enough to reject MOPR-Ex. While MOPR-Ex purports to address "suppress[ed] capacity market clearing prices,"[165] PJM does not even attempt to quantify MOPR-Ex's energy market price suppression. As a result, the problem that MOPR-Ex creates may be even worse than the supposed problem that it addresses. Indeed, adopting MOPR-Ex would leave the Commission's work half unfinished: It would be guaranteeing itself the need to take up a new set of energy market issues in short order, but without any indication of how PJM will propose to *solve* the problems it has created.

Risking new and unquantified price suppression in the energy market is especially wrongheaded because energy market price suppression is *already* a big problem. As PJM explained a few months ago, "under the current market rules, inflexible units are not permitted to

[160] PJM Filing at 56 ("Capacity Repricing avoids … duplication, because it allows state-selected resources to commit as capacity….").
[161] *Id.*
[162] *Id.*
[163] *Id.* at 57.
[164] *Id.*; *see* Willig Decl. ¶ 74.
[165] PJM Filing at 17.

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set price," even when they are "needed to serve demand."[166] When that occurs, PJM's locational marginal price "does not accurately reflect the true incremental cost to serve load," and "energy and reserve prices" are "suppress[ed]."[167] PJM cannot defensibly exacerbate these problems when it admittedly has no idea whether it is creating a bigger problem than it is solving.

Price suppression in energy markets has a particularly pernicious effect on baseload resources that earn most of their revenue in the energy market. Thus, rather than creating a disincentive for additional state support programs, as MOPR-Ex's proponents suggest, it may *exacerbate* economic pressure on baseload nuclear resources, which in turn may spur additional action from states to avoid the environmental consequences of widespread nuclear retirements.

D. MOPR-Ex's Exemptions Draw Arbitrary Distinctions Among State Programs And Are Otherwise Unlawful.

Even if one accepted MOPR-Ex's incorrect premise that capacity markets should be "protected" from the influence of some state environmental policies, the proposal is indefensible as a matter of market design. It is full of discriminatory exemptions betraying that it is a political logroll, not a just and reasonable market reform. A more apt name would be "MOPR-Exemption." MOPR-Ex's exemptions are also unlawful in numerous ways.

1. The RPS Exemption Is Unduly Discriminatory And Not Just And Reasonable.

MOPR-Ex exempts from its definition of Capacity Resources with Actionable Subsidies any resources qualifying for an "RPS Exemption." The exemption "grandfathers" renewable resources procured or subject to an RFP issued before December 31, 2018, and going forward, it exempts any renewable resources procured under an RPS that is what MOPR-Ex calls

[166] PJM, *Proposed Enhancements to Energy Price Formation* at 2 (Nov. 15, 2017), http://www.pjm.com/-/media/library/reports-notices/special-reports/20171115-proposed-enhancements-to-energy-price-formation.ashx ("PJM Proposed Enhancements"); *see* Comments and Responses of PJM Interconnection, L.L.C., at 74-75, Case No. AD-18-7-000 (Mar. 9, 2018) (noting that resiliency problems may be exacerbated by suppressed energy market prices, and that "because [certain units] are not able to set clearing prices, those clearing prices are artificially low[]").
[167] PJM Proposed Enhancements at 2.

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"competitive and non-discriminatory"—which MOPR-Ex defines to *forbid* discrimination against "renewable Capacity Resources," but to *permit* discrimination "restricting imports from other states," and to *require* discrimination against "offshore wind," and "coal, natural gas, or nuclear thermal resources."[168] The intent is to "accommodate most state RPS programs," but to mitigate other state environmental policies based on disfavored technologies or procurement processes. For two reasons, this RPS Exemption is unduly discriminatory, and not just and reasonable.

First, under MOPR-Ex's rationale, the RPS Exemption is untenable. MOPR-Ex purports to target "material state subsidies" with "price suppressive effects … on … clearing prices."[169] RPS standards are exactly this.[170] Indeed, PJM *admits* as much: It concedes that the RPS Exemption is *not* based on a judgment that "renewable generation resources … do not suppress prices."[171] That concession was necessary because PJM's filing is replete with evidence that these resources *do* affect prices, and PJM's filing identifies them as "subsidies of concern."[172] PJM's expert, Dr. Anthony Giacomoni, explains that "RPS/REC programs contribute significantly to the installation of renewable resource capacity," and "bring forth more renewable resources … than would have developed absent the programs."[173] Today, RPS requirements require "4,969 MWs of 'around-the-clock' capacity … located and metered in the PJM Region," which is expected to grow to "8,000 MWs by 2025."[174] Indeed, the capacity price effects of renewables—most of which receive support under RPS programs qualifying for the RPS Exemption—are significant. As the below table shows, prices across PJM are 4.1% lower than they would be if renewables had to bid without the benefit of subsidies, and prices in the ComEd and EMAAC zones are 6.5% lower.

[168] PJM Filing at 52, 112-13 & n.291; Proposed PJM Tariff, Attachment DD § 5.14(h)(10)(b)(ii) (Option B).
[169] *Id.* at 102.
[170] Willig Decl. ¶¶ 78-79.
[171] PJM Filing at 114.
[172] *Id.* at 25.
[173] Giacomoni Aff. ¶¶ 21, 23.
[174] *Id.* ¶ 29.

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Table 2: Estimated Impact Of Subsidized Renewable Resources On PJM Capacity Prices In 2020/21 Base Residual Auction

Estimated Impact of Subsidized Renewables on PJM Capacity Prices in 2020/21 Base Residual Auction

	Cleared Renewable UCAP (MW)				2020/21	Estimated BRA Price if Renewables	Price Suppression
Region	Wind	Solar	Biomass	Total	BRA Price ($/MWD)	Bid at Net CONE x B ($/MWD)	Due to Renewables (%)
RTO	412	67	256	735	76.53	79.84	-4.1%
ComEd	356	1	22	379	188.12	201.09	-6.5%
MAAC	120	1	147	268	86.04	88.84	-3.2%
EMAAC	0	56	152	207	187.87	201.03	-6.5%
	888	125	576	1589			

Sources: Cleared renewable UCAP per PJM 2020/21 BRA results. Regional renewable shares estimate based on 2020/21 resource model. Biomass assumed to include wood, other gas, and other liquid resource categories. Price impact of renewables estimated based on PJM 2020/21 RPM Base Residual Auction sensitivity analysis.

Taking MOPR-Ex's stated purpose as its word, the RPS Exemption is untenable. When the Commission approves exemptions, it does so because the resources that qualify do not have the characteristics deemed to warrant mitigation in the first place.[175] Never has the Commission found that a class of resources has the characteristics deemed to warrant mitigation, yet exempted them anyway. But that is what MOPR-Ex does. The reason, presumably, is that some stakeholders regard the MOPR-Ex's core policy choice—that state environmental policies should be mitigated—as unacceptable when applied in a principled manner, but were willing to go along so long as a one-off exemption was made for politically popular RPS programs. Nor can the RPS Exemption be defended as an exercise in incrementalism that exempts programs *least likely* to affect price: The exemption's main trigger—whether a procurement process is "competitive and nondiscriminatory"—has nothing to do with whether a program is likely have significant effects.

While PJM justifies the RPS Exemption as reflecting "deference to [state] public policies,"[176] that deference only underscores the second reason that the RPS Exemption is

[175] For example, the Commission approved the self-supply exemption because PJM's existing MOPR "[wa]s a mechanism that seeks to prevent the exercise of buyer-side market power," and self-supply entities that qualify for the exemption lacked the ability and "the incentive to exercise buyer-side market power." *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at PP 20, 25 (2013).
[176] PJM Filing at 114.

arbitrary. MOPR-Ex's deference is unjustifiably selective. It awards an exemption *only* to the renewable/RPS model, excluding other state environmental policies regardless of whether the effects on capacity auctions are similar and even if the disfavored policies are more efficient. As Dr. Willig explains, the archetype of a well-designed environmental policy is one that limits payments to the externality being addressed. Illinois' ZEC Program follows that mandate, but there is no guarantee RPS programs will do so.[177] Yet MOPR-Ex exempts payments under RPS programs even if they are inefficiently high, while mitigating environmental programs that may be perfectly efficient. That is arbitrary and undue discrimination.

MOPR-Ex's RPS Exemption is especially egregious because it compels discrimination against non-renewable technologies that provide the same environmental benefits as renewable technologies.[178] The RPS Exemption provides that the "renewable characteristic" must be the "only screen for participation" and specifies that "renewable does not include coal, natural gas, or nuclear thermal resources."[179] So suppose that a state wishes to address the externalities of carbon emissions and recognizes that supporting nuclear power plants may be its most efficient solution—indeed, so efficient that it is concerned that other zero-emitting technologies, such as wind and solar, would not be able to compete head-to-head with nuclear in a zero-emission credit market open to all non-emitting technologies. The RPS Exemption not only would penalize the state for creating a nuclear-specific program in order to protect its support for wind and solar, but also would even penalize the state if it decided to instead impose a zero-carbon purchase obligation rather than create an RPS program. Doing so would result in the mitigation of any units receiving

[177] Willig Decl. ¶¶ 59, 82-87.
[178] *Id.* ¶ 86.
[179] Proposed PJM Tariff, Attachment DD § 5.14(h)(10)(b)(ii) (Option B). The RPS Exemption would also thus apparently require mitigation if states adopt carve-outs for particular renewable technologies, such as solar.

payments under the program, including renewable generators, because the "renewable characteristic" would not be the "only screen" for participation in the program.[180]

Similarly indefensible is the discrimination in the RPS Exemption's "grandfathering" provision.[181] That exemption purports to protect "seller expectations," and PJM defends it as a "reasonable transition" because "commitments were likely made based on RPM's longstanding practice of applying the MOPR to only gas-fired generation resources."[182] But non-renewable generators also have expectations at stake. The Quad Cities plant, for example, was procured under Illinois' ZEC Program at a time when PJM's MOPR only applied to gas-fired generation and had never applied to existing resources of *any* type. Expectations, to the extent they are a legitimate basis to exempt resources, must be respected consistently.

MOPR-Ex's selectivity violates not just sound economics, but the FPA's division of authority. As explained above, the FPA protects states' authority, as regulators of "facilities used for the generation of electric energy,"[183] to enact programs that address the environmental aspects of electricity generation, including selecting *which resources* benefit from state policies. The Commission, for its part, has some authority to tailor its market rules in light of state policies—but only to the extent that state policies "affect[] wholesale rates."[184] This principle forbids the Commission from approving market rules that attempt to micromanage the design of state policies regarding generation facilities, absent evidence of materially different effects on federal markets that result from different state policy designs.

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[180] *Id.*; *cf.* Ryan Randazzo, The Republic, *Arizona Regulator Proposes Adding Nuclear Power to Renewable-Energy Rules*, azcentral.com (Dec. 12, 2016), https://www.azcentral.com/story/money/business/energy/2016/12/12/arizona-regulator-proposes-adding-nuclear-power-renewable-energy-rules/95343412/.
[181] PJM Filing at 112.
[182] *Id.*
[183] 16 U.S.C. § 824(b)(1).
[184] *Conn. Dep't of Pub. Util. Control*, 569 F.3d at 481.

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PJM does not genuinely defend MOPR-Ex's RPS Exemption. PJM says it "targets the mitigation action to the most recent state actions."[185] Vintage, however, is not a principled distinction, especially because RPS programs today are *larger* than they have ever been and growing every year.[186] Yet no matter how large they get, they will enjoy the RPS Exemption. PJM also avers that the RPS Exemption targets "state actions … focused on … specific units."[187] But that distinction also has no basis in economics. RPS standards supporting 4,969 MWs of renewable resources from dozens or hundreds of units may have similar effects as a program supporting a single 1,400 MW nuclear plant,[188] and the nuclear program may be more efficient.[189] The nuclear program's focus on "specific units" reflects only that nuclear plants are large and discrete. It has nothing to do with anything that should matter under PJM's market rules.

2. The RPS Exemption Delegates Excessive Discretion To Make Mitigation Decisions, In Violation Of Order No. 719.

In Order No. 719, the Commission admonished RTOs to ensure that "mitigation tariff provisions [are] as non-discretionary as possible,"[190] and it has stressed that "mitigation is supposed to be nondiscretionary in nature."[191] That is especially important where, as here, the IMM makes mitigation decisions. "[T]here is an inherent conflict of interest in an MMU conducting mitigation and also opining on the state of the market, the health of which may in part reflect the results of its mitigation."[192] Only nondiscretionary criteria temper that conflict;

[185] PJM Filing at 112.
[186] Giacomoni Aff. ¶ 30.
[187] PJM Filing at 112.
[188] Giacomoni Aff. ¶¶ 25, 30.
[189] Willig Decl. ¶ 59.
[190] *Wholesale Competition in Regions with Organized Elec. Markets*, 125 FERC ¶ 61,071, at P 379 (2008) ("Order No. 719").
[191] *Wholesale Competition in Regions with Organized Elec. Markets*, 122 FERC ¶ 61,167, at P 209 (2008).
[192] Order No. 719, at P 371.

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discretion exacerbates it. Hence, the Commission has rejected a PJM proposal that would have "provid[ed] the IMM with unfettered discretion" to make mitigation decisions.[193]

The RPS Exemption violates these principles by conferring nearly unbounded discretion to determine whether an RPS program is "competitive and nondiscriminatory." While the exemption sets forth eight factors to provide a patina of objectivity, these factors merely cover for boundless discretion. For example, a program's requirements must be "fully objective and transparent."[194] Who decides what this means? The IMM, with nothing objective or transparent to limit its discretion. Likewise, the RPS exemption warns that programs must not include criteria that "could give preference to" new or existing resources, or "use indirect means" to discriminate based on vintage—with nothing to constrain the discretion in applying these vague terms.[195]

3. Under *NRG*, The RPS Exemption Cannot Be Severed, As PJM Suggests.

Rather than genuinely defend the RPS Exemption, PJM invites the Commission to sever this exemption. But under *NRG Power Marketing, LLC v. FERC*, the Commission cannot do so. *NRG* holds that the Commission can only change proposed rates under § 205 when the change is "minor."[196] Eliminating the RPS Exemption is not. PJM's filing is about what to do about "state subsidy programs" with a "material price suppression effect,"[197] and in myriad ways, RPS programs are the most significant such subsidy. They are the most widespread (existing in all PJM states except two),[198] they are the largest in megawatt terms (and perhaps also dollar terms),[199] and

[193] *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275, at P 190 (2009).
[194] *See* proposed PJM Tariff, Attachment DD § 5.14(h)(10)(b)(ii) (Option B)
[195] *Id.*
[196] 862 F.3d at 116 (quotation marks omitted).
[197] PJM Filing at 35.
[198] National Conference of State Legislatures, State Renewable Portfolio Standards and Goals, http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx (last visited May 7, 2018).
[199] Giacomoni Aff. ¶ 29.

they are the most popular. In no sense is a tariff that mitigates RPS programs only a "minor" modification to a proposal that exempts these programs.[200]

PJM suggests that even if eliminating the RPS Exemption is not a minor change, the Commission can do so because PJM has provided "affirmative notice" that it would accept this change.[201] But that is not what *NRG* held. The question *NRG* asked was "whether Section 205 allows FERC to suggest modifications that are more than 'minor.'"[202] The answer, *NRG* said, is no.[203] And *NRG* did not stop there: It underscored that a "utility's consent is relevant when FERC proposes 'minor' modifications"—and otherwise, not.[204] While *NRG* also invoked notice concerns as one reason supporting its holding,[205] it nowhere suggested that an RTO can expand the Commission's power to propose non-minor changes by providing "notice" that it will accept them.

Indeed, reading *NRG* to permit PJM's stratagem would badly undermine the stakeholder process. As *NRG* explains, for ISOs and RTOs like PJM, the stakeholder process is crucial for negotiating and vetting contentious proposals.[206] But now PJM, while purporting to propose the MOPR-Ex approach that appeared on the stakeholder ballot, effectively disavows a central plank of that approach. Never did stakeholders have the chance to vote on the Option-B-minus-RPS-Exemption approach that PJM now invites the Commission to adopt. If they had, Exelon suspects that proposal would have failed overwhelmingly—but because PJM bypassed the stakeholder process, the Commission will never know.

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[200] *NRG*, 862 F.3d at 116 (quotation marks omitted).
[201] PJM Filing at 114.
[202] *NRG*, 862 F.3d at 110.
[203] *Id.* at 115.
[204] *Id.* at 116.
[205] *Id.* at 116-17.
[206] *Id.*

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4. MOPR-Ex's Myriad Other Exceptions Are Unduly Discriminatory And Not Just And Reasonable.

Like Capacity Repricing, MOPR-Ex exempts a variety of state subsidies aimed at promoting "general industrial development" or "siting" in a particular location, and federal production tax credits and tax incentives like the PTC for wind and the Investment Tax Credit for solar.[207] MOPR-Ex also exempts vertically integrated utilities via the "Self-Supply Exemption."[208] These exemptions are arbitrary for the same reasons explained above: These subsidies affect wholesale prices in amounts that would exceed any "materiality"[209] threshold the Commission could apply.[210] Moreover, these subsidies lack the efficiency justification of environmental programs, and they are certainly less economically efficient than the ZEC Program that MOPR-Ex targets.[211] Likewise, PJM's attempt to defend these arbitrary exemptions fails for the same reasons already explained. PJM stresses that these exemptions track exemptions under PJM's existing MOPR.[212] But the justification for the existing MOPR is narrowly focused on combatting buyer-side market power. If that is the MOPR's purpose, then these exemptions might make sense. But MOPR-Ex is an expansion of the MOPR that applies the MOPR more broadly to address any "material price suppression effect,"[213] without regard to whether buyer-side market power is being exercised. These exemptions are incompatible with that broader purpose.

[207] PJM Filing at 100-01 (noting that Capacity Repricing and MOPR-Ex use the same definition of "Capacity Resource with Actionable Subsidy").
[208] *Id.* at 105-06.
[209] PJM Filing at 34.
[210] *Supra* at 26-32.
[211] Willig Decl. ¶¶ 80, 88, 90.
[212] PJM Filing at 100-01, 105-06.
[213] *Id.* at 35.

5. MOPR-Ex's "Public Entity Exemption" Is An Invitation To Buyer-Side Market Power.

PJM's Option B creates a new "Public Entity Exemption" for vertically integrated utilities that are publicly owned. The Self-Supply Exemption would normally govern these entities' ability to obtain an exemption, except that the MOPR-Ex proposal creates an exemption specific to public power. This exemption has all the discriminatory problems of the Self-Supply Exemption, plus another glaring flaw: It invites exercises of buyer-side market power.[214]

The Commission has linked approval of the self-supply exemption to strict net-short and net-long thresholds. In 2011, the Commission rejected an "across-the-board exemption from MOPR for new resources designated as self-supply" that lacked such thresholds, finding it "allow[ed] for an unacceptable opportunity to exercise buyer market power."[215] And when the Commission approved the exemption in 2013, it stressed that its approval "depend[ed] critically on" these thresholds.[216] Only these thresholds, the Commission found, adequately "limit[ed] the incentive of self-supply entities to influence market-clearing capacity prices."[217]

Under this precedent, the Public Entity Exemption is indefensible. It disposes with a quantitative net short threshold altogether, and allows an entity that serves only a few hundred MWs of load to go approximately 600 MWs long. Public power entities with the incentive to exercise buyer-side market power gain the ability to exercise it, subject to practically no mitigation whatsoever. Indeed, the Public Entity Exemption resembles nothing so much as the across-the-broad exemption that the Commission rejected in 2011. There is no legal or economic rationale

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[214] *Consol. Edison Co. of N.Y., Inc.*, 150 FERC ¶ 61,139, at P 2 (2013) ("The original purpose of buyer-side mitigation rules—and minimum offer price rules (MOPR) generally—was to address buyer-side market power, i.e., the market power exhibited by entities seeking to lower capacity market prices for the capacity they buy."); Brief of Respondent FERC at 11, *NRG Power Marketing, LLC v. FERC*, 862 F.3d 108 (D.C. Cir. 2017) (No. 15-1452), 2016 WL 5405117 ("The Minimum Offer Price Rule was designed to prevent the exercise of monopsony power ….").
[215] *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, at P 5 (2011).
[216] *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 110 (2013).
[217] *Id.*

for this exemption. It is merely a politically motivated concession to one group of stakeholders to garner support for an attack on disfavored resources. PJM defends its free pass to 600 MW of net long capacity on the theory that the existing Self-Supply Exemption sets a net long threshold of 15% of an entity's capacity obligation for entities with obligations between 500 MW and 5,000 MW—and 600 MW "is equal to 15% of 4,000."[218] But this is arbitrary: Many public entities serve far less than 5,000 MW, and 600 MW is far more than 15% of their capacity obligations:[219]

Table 3: Public Entities Serving Small Amounts Of Load

Muni/Coop	Peak Load (MW; approx.)
Central Virginia Electric Coop.	222
Allegheny Electric Coop.	735
Southern Maryland Electric Coop.	844
Northern Virginia Electric Coop.	1,028
Old Dominion Electric Coop.	2,750
East Kentucky Power Coop.	2,890

Source: U.S. Energy Information Administration, 2016 Form EIA-861 data.

On the short side, PJM points to the requirement that "over the entity's long-term planning horizon, [it] must plan on having under its control a quantity of capacity resources that is 'planned to be less than or equal to' its retail load capacity obligations."[220] But this vague standard is no substitute for the quantitative threshold on which the Commission's prior approval "depend[ed] critically."[221]

6. MOPR-Ex' Unit-Specific Exception Process Is Unlawful.

Even if the Commission could require generators to exclude from "competitive" bids the revenues they receive from environmental programs, MOPR-Ex's unit-specific exception process violates the FPA. That exception allows a generator subject to the MOPR to request "a unit-specific offer price that is consistent with the competitive, cost-based, fixed, net cost of new entry

[218] PJM Filing at 110.
[219] Willig Decl. ¶ 89.
[220] PJM Filing at 111 (quoting proposed PJM Tariff, Attachment DD § 5.14(h)(9)(a) (Option B)).
[221] *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at P 110 (2013).

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were the resource to rely solely on revenues from PJM-administered markets."[222] But if PJM's Office of Interconnection does not deem the generator's proposed price "acceptable," PJM calculates its own proxy bid.[223] The proposed tariff makes no provision for the generator to object to the proxy bid by seeking a determination from the Commission that its unit-specific offer price was just and reasonable under Section 205. That omission is arbitrary and inconsistent with the rights acknowledged as to similar issues in other sections of PJM's Tariff.[224] Depriving generators of this important right also violates Section 205. Suppliers of capacity in PJM's capacity auction are public utilities entitled to file, under Section 205, the rates they seek to charge for their capacity—manifested, in this context, in auction bids—unless the Commission determines that those rates are not just and reasonable.[225]

V. To The Extent The Commission Accepts Option A, It Should Require Certain Changes.

To the extent the Commission accepts Option A, several adjustments are warranted.

First, Option A unjustifiably exempts from repricing any resource of less than 20 MW—an exemption that, in practice, will mostly eliminate solar and wind resources from coverage. Option A's premise, however, is that RPS-supported renewable resources *in the aggregate* affect capacity prices.[226] It makes no sense to exempt renewables that happen to affect prices in small increments. Indeed, this rule is ripe for manipulation: Solar and wind power rely on small

[222] *See* proposed PJM Tariff, Attachment DD § 5.14(j)(4)(b)(i)(A)-(B) (Option B).
[223] *See* proposed PJM Tariff, Attachment DD § 5.14(j)(4)(b)(i)(C) (Option B).
[224] *See* PJM Tariff, Attachment DD, § 5.5A(A)(i)(B) (determinations concerning status as a Capacity Performance Resource); *id.* § 6.4(c) (seller offer caps); *id.* § 6.5(a)(ii)(A) (offers from Planned Generation Capacity Resources); *id.* § 6.6(e) (determinations concerning EFORd); *id.* § 6.6(g) (removal from Generation Capacity Resource status under must-offer rules).
[225] *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002); *see also Atl. City Elec. Co. v. FERC*, 329 F.3d 856 (D.C. Cir. 2003).
[226] PJM Filing at 27-28.

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individual pieces wired together at a single interconnection point and developers can configure these assemblies as desired to trigger or avoid repricing.

Second, in order to minimize the impact of repricing on customers and prevent the unnecessary imposition of costs, the Commission should create a price-based materiality screen. PJM proposes its own quantity-based materiality screen of 5,000 MW, RTO-wide, receiving an Actionable Subsidy, or 3.5% of the reliability requirement for an LDA. But these numbers are plucked from the air, unmoored from any theory of what purposes PJM's capacity auction serves or when action is needed to safeguard those purposes. Indeed, despite PJM's claim that its materiality threshold is a desirable "transition mechanism" that "provide[s] the market time to adjust to the[] new rules," PJM buries in a footnote its admission that the ComEd LDA *already* exceeds PJM's threshold, and thus the market will have *no* time to adjust.

In the stakeholder process, Exelon proposed a better materiality screen—one derived from the core purpose of PJM's capacity markets, and that would provide a genuine chance for these markets to adjust. These markets exist to ensure resource adequacy at reasonable cost.[227] So, under Exelon's proposal, repricing occurs only if there is evidence of a threat to resource adequacy due to insufficient needed new entry.

In particular, the first auction stage would run as in PJM's Option A and identify the resources that would receive capacity obligations based on bids reflecting the receipt of state payments. In the next stage, PJM would run a screening auction. It would reprice resources with "Actionable Subsidies" to the default offer cap, Net CONE * B, for the relevant locational delivery area, and then re-run the auction with those repriced bids. This repriced figure—Net CONE * B—

[227] *Cf.* CASPR Order at P 25 ("In evaluating whether, under CASPR, the FCM will continue to maintain resource adequacy at just and reasonable rates, we must assess, as an initial matter, whether the FCM can continue to attract and maintain resource investment when the system requires it, and to do so at a reasonable cost.").

is what PJM and its IMM have identified as a "competitive" bid. If the Stage 2 auction still clears below Net CONE * B for a locational delivery area, this means that "competitive" (and non-repriced) offers are sufficient to drive the clearing price. Repricing is not needed to ensure "competition" or incentivize new entry. Likewise, given the mechanics of the demand curve, a clearing price below the default offer cap implies that the cleared reserve margin exceeds the target reserve margin—so reliability is not in danger either. In these circumstances, the auction meets the Commission's "workably competitive" standard,[228] and repricing is unnecessary. The clearing price in the initial first-stage auction thus would stand.

If, however, the screening auction cleared at (or above) Net CONE * B, that would indicate that competitive bids are not sufficient to drive clearing prices. Instead, new entry is called for, and repricing would proceed as in the second stage of PJM's proposal to incentivize that new entry.

CONCLUSION

The Commission should reject PJM's filing as not just or reasonable.

[228] *PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053, at P 53 (2005).

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Dated: May 7, 2018

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 7th day of May, 2018.

/s/ *Marianne Alvarez*

_____

Marianne Alvarez
Exelon Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Calpine Corporation, Dynegy Inc., Eastern Generation, LLC, Homer City Generation, L.P., NRG Power Marketing LLC, GenOn Energy Management, LLC, Carroll County Energy LLC, C.P. Crane LLC, Essential Power, LLC, Essential Power OPP, LLC, Essential Power Rock Springs, LLC, Lakewood Cogeneration, L.P., GDF SUEZ Energy Marketing NA, Inc., Oregon Clean Energy, LLC and Panda Power Generation Infrastructure Fund, LLC,	)	Docket Nos. EL16-49-000
v.	)	
PJM Interconnection, L.L.C.	)	
PJM Interconnection, L.L.C.	)	ER18-1314-000 ER18-1314-001
PJM Interconnection, L.L.C.	)	EL18-178-000 (Consolidated)

REQUEST FOR REHEARING OF EXELON CORPORATION

Pursuant to Rule 713 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("the Commission"), 18 C.F.R. § 385.713, Exelon Corporation ("Exelon") hereby submits the following Request for Rehearing in the above-captioned dockets.

INTRODUCTION

The Commission's Order[1] finds PJM's capacity market to be unjust and unreasonable on the ground that its current minimum offer price rule ("MOPR") "does not address subsidies to

[1] *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 (2018) ("Order").

existing resources."[2] This is a problem, according to the Order, because subsidies allow for the retention of "resources that the market does not regard as economic," which leads to "suppresse[d] prices."[3] The Commission's analysis wholly ignores the economic testimony submitted by Exelon, as well as by others such as the Institute for Policy Integrity, explaining that an efficient market must account for the costs of pollution (which are a type of externality). Accordingly, polluting plants that appear "able to clear the market based on their costs alone" are only able to do so because they do not actually pay their full costs.[4] They pollute for free, and impose those costs on society. Meanwhile, state-supported non-emitting resources, such as nuclear plants, *are* economic once environmental externalities are considered. The capacity price that results from their participation in the market is not "suppressed"; it is the just and reasonable price that results from competitive bids, after accounting for the value of the environmental services these units provide to the public for which they are compensated through attribute credits. This is Economics 101, and it is arbitrary and capricious for the Commission to entirely ignore textbook economics.

Additionally, the Commission's finding that the PJM capacity market is unjust and unreasonable because "out-of-market payments … have reached a level sufficient to significantly impact … the integrity of the … price signals on which investors and consumers rely to guide the orderly entry and exit of capacity resources"[5] is conclusory and entirely fails to engage with the relevant evidence. The actual evidence from recent PJM auction is that capacity resources have considered entering the market in substantial numbers (and that there is significant excess capacity), and have exited the market in substantial numbers. The Commission fails to meaningfully engage with this data, let alone explain what evidence it relies upon for the notion

[2] Order at P 154.
[3] *Id.*
[4] *Id.*
[5] *Id.* at P 155.

that "orderly entry and exit of capacity resources" has somehow been disrupted. The Commission fails to explain why there is excess capacity and robust new entry despite state attribute payments to retain existing clean resources. And the Commission also fails to explain why retaining existing clean resources for their environmental value disrupts "orderly … exit." Such resources *should* be retained once their environmental value is accounted for.

Furthermore, the Commission's determination that prices are "suppressed"—in other words, too low to be just or reasonable—is detached from the statutory "just and reasonable" standard the Commission is supposed to apply. As the Supreme Court has explained, just and reasonable rates are those that balance consumer and investor interests "to encourage the orderly development of plentiful supplies of electricity … at reasonable prices."[6] That is exactly what PJM has today: plentiful supplies of electricity—a reserve margin that significantly exceeds the target reserve margin, and robust entry by new natural gas units—at reasonable prices. The Commission does not explain why, in light of these circumstances, it makes sense to institute market reforms designed to goose investment by increasing prices. To the extent the Commission believes that state regulation creates uncertainty for investors, regulatory uncertainty is inherent in this industry, and it has not deterred the thousands of megawatts of new natural gas-fired plants that have entered the market over the last several years.

Finally, while Exelon disagrees with the Commission's determination that the current Tariff is not just or reasonable, the Commission rightly concluded that the MOPR alone is not a just or reasonable remedy.[7] Instead, a just and reasonable revision to the market rules must provide states with some avenue to promote their environmental goals within the federal capacity

[6] *NAACP v. FPC*, 425 U.S. 662, 670 (1976).
[7] Order at PP 158-60.

construct. As Exelon will argue in comments filed in the Commission's paper hearing, a resource-specific FRR is an appropriate mechanism.

I. STATEMENT OF ISSUES AND SPECIFICATIONS OF ERROR

Pursuant to Rule 713(c)(2), 18 C.F.R. § 385.713(c)(2), Exelon provides the following statement of issues:

1. The Commission acted arbitrarily and capriciously in failing to address evidence presented by the parties that, under elementary principles of economics, efficient entry and exit as well as efficient market prices should reflect the cost of pollution or, conversely, the benefits of avoiding pollution. *See* Order at PP 150-56; *Motor Vehicles Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (an agency must "examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made."); *NorAm Gas Transmission Co. v. FERC*, 148 F.3d 1158, 1165 (D.C. Cir. 1998) (agency will be reversed when it does not "engage the arguments raised before it").

2. The Commission acted arbitrarily and capriciously in concluding that changes to market rules were needed to protect the integrity of the market, without addressing evidence that the market continues to attract plentiful supply and significant new entry. *See* Order at PP 150-56; *Motor Vehicles Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (an agency must "examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made."); *NorAm Gas Transmission Co. v. FERC*, 148 F.3d 1158, 1165 (D.C. Cir. 1998) (agency will be reversed when it does not "engage the arguments raised before it"); *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1520 (D.C. Cir. 1984) ("[S]elf-contradictory, wandering logic does not constitute an adequate explanation" of agency action).

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3. The Commission acted arbitrarily and capriciously in concluding that changes to market rules were needed to protect the integrity of the market, without substantial evidence to support its claim that resource adequacy or investor confidence were threatened by state support for clean resources. *See Pacific Gas & Elec. Co. v. FERC*, 306 F.3d 1112, 1115–16 (D.C. Cir. 2002) (FERC "must be able to demonstrate that it has made a reasoned decision based upon substantial evidence in the record").

4. The Commission's Order violates Section 206 insofar as it finds capacity markets to be too low to be just or reasonable, when supply remains plentiful and new entry robust. 16 U.S.C. § 824e; *NAACP v. FPC*, 425 U.S. 662, 670 (1976) (purpose of Federal Power Act is "to encourage the orderly development of plentiful supplies of electricity … at reasonable prices.").

II. THE ORDER FAILS TO ACCOUNT FOR ENVIRONMENTAL EXTERNALITIES—NAMELY, THE SOCIAL COST OF POLLUTION.

The Order concludes that out-of-market revenue, such as environmental attribute payments for clean generation, results in "unreasonable price distortions … regardless of the generation type or quantity of the resources support by such out-of-market support."[8] That is because, the Order states, "out-of-market support to existing resources may allow even uncompetitive resources, for whom a competitive offer would be significantly higher than zero, to submit low or zero priced offers into the capacity market."[9] The Commission's analysis is premised on the notion that an efficient market is one unaffected by state environmental attribute payments, and that a "competitive offer" is one based solely on a resource's production costs. That premise, however, ignores basic economic principles, which the Commission's Order does not even acknowledge or attempt to reconcile.

[8] Order at P 150.
[9] *Id.* at P 151.

As Exelon explained in its Protests in the consolidated dockets, supported by testimony from noted economist Dr. Robert Willig,[10] as well as a study by the Institute for Policy Integrity,[11] the field of economics has long understood that for market outcomes to be efficient, markets must account for externalities of production. Pollution is the classic externality. When fossil-fuel generators produce electricity, they create pollutants such as carbon dioxide, sulfur dioxide, nitrogen oxide, ozone, mercury, and particulate matter. These pollutants are harmful to human health and the environment, but these costs generally fall on society, not the generators that produce them. Put otherwise, the costs are "externalized," and hence electric generation creates "negative externalities." In an efficient market, the polluting generators will bear the costs of their pollution—thereby internalizing the externality. Otherwise, society will end up with more polluting generation resources than is efficient.[12] As Dr. Willig notes, this is textbook economics.[13]

The ability to pollute while generating electricity without paying the cost of pollution is, from the standpoint of economics, a subsidy.[14] Society bears a cost that should properly be treated

[10] Protest of Exelon Corp., Docket No. ER18-1314 at 12-22 (May 7, 2018) ("Exelon PJM Protest") and Declaration of Robert D. Willig at 17-29 ("Willig Decl.") (attached to Exelon PJM Protest); *see also* Protest of Exelon Corp., Docket No. EL16-49 at 19-30 (Jan. 30, 2017) ("Exelon CPV Protest") & Declaration of Robert D. Willig at 8-16 (attached to Exelon CPV Protest).

[11] Comments of Institute for Policy Integrity at New York University School of Law, Docket No. ER18-1314 (May 7, 2018) ("IPI Comments"); Sylwia Bialek & Burcin Unel, *Capacity Markets and Externalities* (attached to IPI Comments).

[12] As Commissioner Glick put it: "[T]he order ignores the fact that governmental policies that internalize the externalities associated with electricity generation are essential to reaching an efficient market outcome…. Without policies addressing these externalities, PJM's capacity market will produce a sub-optimal outcome." Order, Dissent of Commissioner Glick at 6 ("Glick Dissent").

[13] *See* Willig Decl. ¶¶ 30 n.28, 31 n.29, 34 n.32 (citing P.A. Samuelson & W.D. Nordhaus, *Economics* at 346-355 (1995); R.S. Pindyck & D.L. Rubinfeld, *Microeconomics*, 639-657 (2d ed. 1992); A.C. Pigou, *The Economics of Welfare* (4th ed. 1932); W.J. Baumol & W.E. Oates, The theory of environmental policy, Ch. 3 (2d ed. 1995)); *see* Motion for Leave to Answer and Answer of Exelon Corp. and PSEG Companies, Docket No. ER18-1314, at 2-3, 16-17 (May 22, 2018) ("Exelon PJM Answer").

[14] Exelon PJM Protest at 12.

as a cost of production. Indeed, for carbon dioxide alone, estimates put this subsidy's value for fossil-fuel generators across PJM at $12.1 billion to $17.7 billion dollars annually.[15] As Dr. Willig explains, the resulting market outcome will not be efficient. Polluting resources are able to submit bids that are far lower than their true competitive offers would be, because they do not need to account for the cost of pollution. Moreover, resources that would exit the market if forced to bear the costs of pollution—such as aging coal plants—will remain in the market.[16] In other words, the market's failure to account for the costs of pollution leads precisely to the harms that the Order purports to address: "unreasonable price distortions and cost shifts,"[17] non-competitive offers that are not "based on actual costs,"[18] the retention of "resources that [an efficient] market does not regard as economic,"[19] and "resulting price signals" that do not promote "the orderly entry and exit of capacity resources."[20]

States have chosen to address this inefficiency in two ways. Some have taxed polluting generation—by, for example, joining a cap-and-trade program like the Regional Greenhouse Gas Initiative. Others have compensated non-emitting generation for displacing polluting generation, through environmental attribute payments like Zero Emission Credits ("ZECs") and Renewable Energy Credits ("RECs"). As Dr. Willig explains, these initiatives help to ensure that private production decisions account for the cost of pollution (or the benefits of non-pollution). The result is a more efficient market outcome.[21] Yet the Order stands economics on its head by labeling the

[15] These figures reflect 291.9 million tons of CO_2 emitted in PJM in 2017 and 426.6 million tons emitted in 2016, at a cost of $41.40 per ton. *See* Monitoring Analytics, LLC, *2017 State of the Market Report for PJM, Volume 2: Detailed Analysis*, at 361 (Mar. 2018); Exelon PJM Protest at 12.
[16] Willig Decl. ¶¶ 25-46.
[17] Order at P 150.
[18] *Id.*
[19] *Id.* at P 154.
[20] *Id.* at P 156; *see* Exelon PJM Protest at 14; Willig Decl. ¶¶ 33-46.
[21] Willig Decl. ¶¶ 47-60.

resulting prices unjust and unreasonable. The Order does not acknowledge its deviation from basic economics or rely on any economic principles for its conclusion. Nor does the Order explain why market rules are unjust and unreasonable if they allow market prices to be influenced by state programs addressing the environmental externalities of production. Indeed, a market designed to be insulated from such policies—by resetting bids to offset attempts to account for those externalities—would inevitably and necessarily result in inefficient outcomes and the continued operation of resources that, after accounting for externalities, are uneconomic. Such a market design could never be just or reasonable. The Order's failure to address "an important aspect of the problem,"[22] and "to engage the arguments raised before it,"[23] is arbitrary and capricious and a failure of reasoned decisionmaking.

III. THE ORDER IS ARBITRARY AND CAPRICIOUS BECAUSE IT FAILED TO GRAPPLE WITH EVIDENCE THAT THE CAPACITY MARKET CONTINUES TO FUNCTION PROPERLY, AND CITES NO EVIDENCE TO JUSTIFY ITS FINDING TO THE CONTRARY.

The Order is also arbitrary and capricious because it finds that the PJM capacity market is unjust and unreasonable without even addressing unrebutted evidence that the market has a healthy reserve margin and continues to attract new entry and promote exit of uneconomic resources. The evidence concerning the market's performance cannot be reconciled with the Commission's assertion that "out-of-market payments by certain PJM states have reached a level sufficient to significantly impact … the integrity of the resulting price signals on which investors and consumers rely to guide the orderly entry and exit of capacity resources."[24] Indeed, the Commission's conclusion that state environmental attribute payments "will significantly affect the

[22] *State Farm,* 463 U.S. at 43.
[23] *NorAm Gas*, 148 F.3d at 1165.
[24] Order at P 156.

PJM capacity market" in a manner detrimental to that market's integrity is not supported by any evidence at all.

A. The Commission Failed to Address Evidence That the Market Has a Large Reserve Margin and Continues to Foster Orderly Entry and Exit.

As pointed out by Exelon and many others,[25] the actual data concerning the PJM capacity market's performance demonstrates that, by all measures, the market is performing well. There is no sign at all of any resource adequacy concern on the horizon. "PJM currently has far more generating capacity than it needs to reliably meet the region's electricity needs, even several years out."[26] In the most recent Base Residual Auction, PJM's reserve margin was 21.5%, which is 5.7% higher than the target reserve margin of 15.8%.[27] That is down slightly (1.8%) from the prior year's auction, showing that the market has responded to oversupply through exit, but there still remains significantly more capacity on the system than is needed for resource adequacy, as has been the case since the RPM mechanism was adopted. The current and historical reserve margins are shown in the chart below:[28]

[25] Protest at 32-37; *see* Exelon PJM Answer at 7-8; Exelon CPV Protest at 12-16; *see also* Protest of Clean Energy Advocates, Docket No. ER18-1314, at 35-42 (May 7, 2018); Protest of Clean Energy Industry Associations, Docket No. ER18-1314, at 10-14 (May 7, 2018); Protest of Joint Consumer Advocates, Docket No. ER18-1314, at 10-14 (May 7, 2018); Protest and Comments of the Maryland Public Service Commission, Docket No. ER18-1314, at 5 (May 7, 2018); Protest of the Office of the People's Counsel for the District of Columbia, Maryland Office of People's Counsel, and New Jersey Division of the Rate Counsel, Docket No. ER18-1314, at 2-3, (May 7, 2018); Comments of the Organization of PJM States, Docket No. ER18-1314, at 5-7 (May 7, 2018).

[26] Glick Dissent at 9.

[27] PJM Interconnection, L.L.C., *2021/2022 RPM Base Residual Auction Results* at 3, http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx ("2021/2022 PJM Results").

[28] *Id.* at 6; *see also* Exelon PJM Protest at 34-35.

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	Auction Results		
Delivery Year	Resource Clearing Price	Cleared UCAP (MW)	Reserve Margin
2007/2008	$ 40.80	129,409.2	19.1%
2008/2009	$ 111.92	129,597.6	17.4%
2009/2010	$ 102.04	132,231.8	17.6%
2010/2011	$ 174.29	132,190.4	16.4%
2011/2012[1]	$ 110.00	132,221.5	17.9%
2012/2013	$ 16.46	136,143.5	20.5%
2013/2014[2]	$ 27.73	152,743.3	19.7%
2014/2015[3]	$ 125.99	149,974.7	18.8%
2015/2016[4]	$ 136.00	164,561.2	19.3%
2016/2017[5]	$ 59.37	169,159.7	20.3%
2017/2018	$ 120.00	167,003.7	19.7%
2018/2019	$ 164.77	166,836.9	19.8%
2019/2020	$ 100.00	167,305.9	22.4%
2020/2021[6]	$ 76.53	165,109.2	23.3%
2021/2022	$ 140.00	163,627.3	21.5%

Moreover, despite oversupply and low prices, the capacity auction continues to attract new entry. In the Base Residual Auction for 2020/21, which occurred after the Illinois Zero Emissions Credit Program went into effect, more than 2,300 MW of new combined-cycle gas resources cleared the market.[29] In the Base Residual Auction for 2021/22, PJM attracted another 890 MW of new entry plus 508 MW of generation upgrades, for a total of more than 1,400 MW of new generation.[30] As Exelon pointed out in its comments,[31] looking forward, there are almost 40 GW of recently entered or potential near-term entrant gas combined-cycle plants spread across PJM—equivalent to 25% of the market. Over half of that capacity is an advanced state of development:

[29] PJM Interconnection, L.L.C., *2020/2021 RPM Base Residual Auction Results* at 1, https://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx.
[30] 2021/2022 PJM Results at 7.
[31] Exelon PJM Protest at 36.

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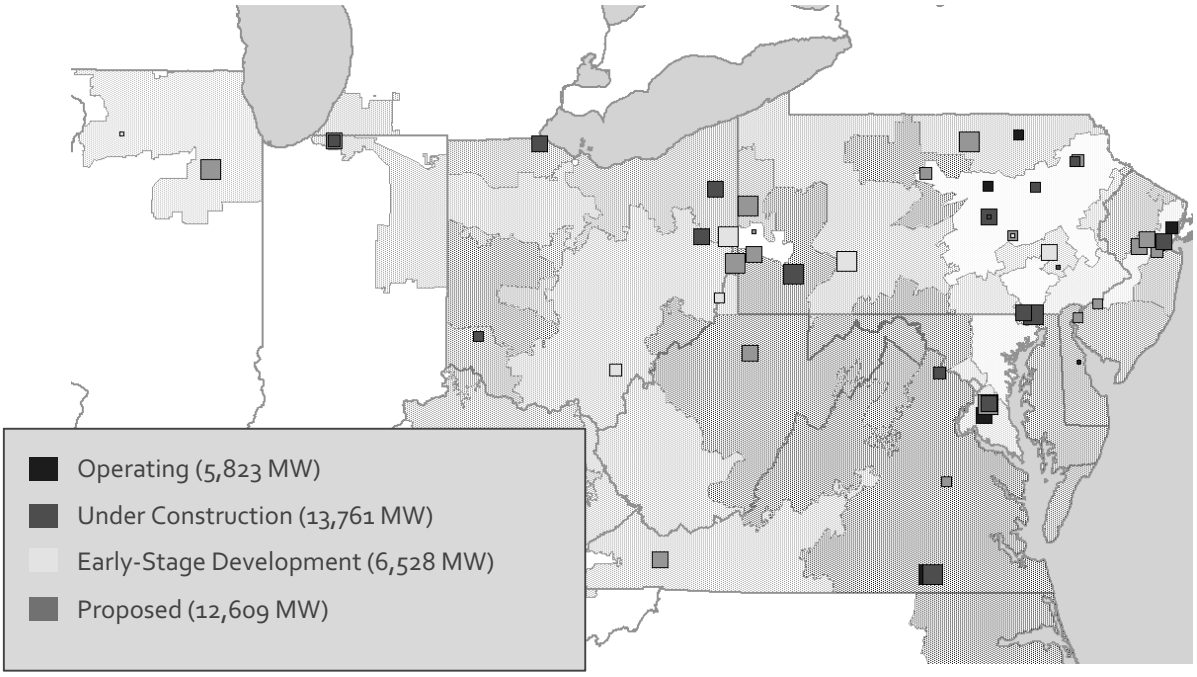
40 GW Of Recently Entered Or Potential Near-Term Entrant Gas Combined-Cycle Plants In PJM



Note: Box size denotes relative size of each unit in net summer capacity.

The Commission's Order does not even acknowledge this evidence, let alone explain how it can be reconciled with the Commission's determination that it can "no longer rely on [the current market] construct to harness competitive forces and produce just and reasonable rates."[32] That omission renders the Commission's Order arbitrary and capricious.[33]

B. The Commission's Finding That Rates Are Unjust and Unreasonable Is Unsupported by Substantial Evidence.

Instead of engaging with actual evidence concerning the market's performance, the Commission's Order instead relies on *ipse dixit* to find that the market construct is unjust and unreasonable. The Commission states that because state support is enough "to significantly affect whether a resource receiving such support chooses to remain in operation[,] [t]herefore, we find

[32] Order at P 156.
[33] *See State Farm,* 463 U.S. at 43; *NorAm Gas*, 148 F.3d at 1165.

that PJM's Tariff is unjust and unreasonable because PJM's MOPR does not address subsidies to existing resources."[34] That conclusory statement does not explain why a market construct is unjust and unreasonable simply because it allows entry and exit decisions to be significantly affected by public policy concerns. Indeed, as Exelon's Protest pointed out and as Commissioner Glick emphasizes in his dissent, subsidies are ubiquitous, and even the broad MOPR that PJM contemplates does not even begin to address all of the various subsidies that power plants enjoy. "The PJM states have adopted over 100 programs to subsidize all forms of energy sources."[35] Approximately one-fifth of PJM's capacity is subsidized through guaranteed cost recovery via retail rates.[36] And, of course, the ability of fossil fuel generators to pollute the air without paying for the cost is the largest subsidy of all.

To the extent the Commission's Order rests on the premise that it must respond to a growing trend of state subsidies—"[w]e are compelled by the evidence … to conclude that out-of-market payments by certain PJM states *have reached a level sufficient to significantly impact* the capacity market clearing prices and the integrity of the resulting price signals on which investors and consumers rely"[37]—the Commission's decision is not justified by evidence. The Commission nowhere explains what it regards as a "significant[] impact" on prices, nor does it document the evidence showing that the cumulative impact of state subsidies on capacity prices has significantly increased in recent years. The Commission also cites no evidence actually documenting any erosion in investor and consumer reliance on capacity market price signals.

[34] *Id.* at P 154.
[35] Glick Dissent at 8; Exelon PJM Protest at 26-27; Exelon PJM Answer at 17; *see also* Protest of Clean Energy Advocates, Docket No. ER18-1314, at 35-41, 90 (May 7, 2018).
[36] Glick Dissent at 8; Exelon PJM Protest at 29; Reply Comments of Exelon, Docket No. EL18-169-000, at 2-5 (June 26, 2018); Willig Decl. ¶¶ 13(h)(iii), 80.
[37] Order at P 156.

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The only actual evidence on which the Commission relies is an affidavit from a PJM economist, Dr. Anthony Giacomoni, which does not support the sweeping conclusions that the Commission has reached. The Giacomoni affidavit merely describes various state environmental attribute programs, and using the arithmetic, converts the attribute payments into $/MWh quantities.[38] Dr. Giacomoni says nothing to support the Commission's conclusion that, despite widespread subsidies for the capacity market's entire history, suddenly "out-of-market payments … have reached a level sufficient to significantly impact … the integrity of the resulting price signals."[39] Indeed, Dr. Gianconomi does not even address the integrity of the capacity market's price signals. Neither his testimony nor the Order "meaningfully link[] the existence of those programs to the claim that PJM's capacity market may not result in just and reasonable rates."[40]

The Order refers to uncertainty,[41] but in reality, as Commissioner Glick explains, "[u]ncertainty in many forms—commodity price uncertainty, demand uncertainty, and yes, policy uncertainty—pervades the electricity industry and the Commission leaves it to private companies to manage that uncertainty."[42] Exelon made the same point in its Protest.[43] Yet the Order says nothing about "why the uncertainty created by certain state policies is any different or why that difference is sufficient to render PJM's Tariff unjust and unreasonable."[44]

[38] *See* PJM Filing at Attach. F (Aff. of Dr. Anthony Giacomoni).
[39] Order at P 156.
[40] Glick Dissent at 11.
[41] Order at P 156.
[42] Glick Dissent at 11.
[43] Exelon PJM Protest at 34-35.
[44] Glick Dissent at 12.

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III. THE ORDER'S ANALYSIS IS DISCONNECTED FROM THE RELEVANT CONSIDERATIONS UNDER SECTIONS 205 AND 206.

The Commission should also rehear the Order because it fails to consider the proper criteria when assessing PJM's Tariff under Section 206. In charging the Commission to set just and reasonable rates, Congress intended for the Commission "to encourage the orderly development of plentiful supplies of electricity … at reasonable prices."[45] That mandate is amply satisfied in PJM today. As discussed above, supplies are plentiful, new gas resources continue to enter the market, and prices paid by customers are historically low. There is no resource adequacy issue on the horizon, and the Order does not claim otherwise.[46]

Under these circumstances, it is arbitrary and capricious, and contrary to the purpose of Section 206, for the Commission to mandate market reforms on the theory that prices are too low and that investors have insufficient confidence in the market.

IV. THE ORDER CORRECTLY CONCLUDES THAT A MOPR ALONE WOULD NOT BE A JUST AND REASONABLE REMEDY.

As discussed above, Exelon disagrees with the Order that the current Tariff is unjust and unreasonable. However, to the extent the Commission disagrees, it correctly concluded that imposing a MOPR alone would not be a just or reasonable remedy. The Order identifies "two aspects to our proposed replacement rate."[47] The first is an expanded MOPR with "few or no exceptions" that, as the Order puts it, "should protect PJM's capacity market from the price suppressive effects of resources receiving out-of-market support."[48] The second aspect is a method

[45] *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,157, at P 30 n.39 (2016) (quoting *Pub. Utils. Comm'n of Cal. v. FERC*, 367 F.3d 925, 929 (D.C. Cir. 2004)); *NAACP*, 425 U.S. at 670.
[46] Exelon PJM Answer at 4.
[47] Order at P 158.
[48] *Id.*

for "accommodat[ing] resources that receive out-of-market support" outside the capacity auction.[49] Specifically, the Order proposes a resource-specific FRR Alternative.[50]

A mechanism for accommodation is necessary for the tariff to be just and reasonable. First, allowing resources receiving state support to provide capacity to customers within PJM—albeit outside of the capacity auction—ensures that states will still have some mechanism for valuing and addressing the environmental externalities of production. As discussed above, the Commission should not design its markets to stand in the way of "valid policy goals,"[51] including state efforts to account for environmental externalities. The Federal Power Act assigns to states the power to regulate generation facilities and fuel type. The Commission's markets should be designed to make room for states to exercise that power. A MOPR-only remedy fails to make such room; it counteracts, rather than accommodates, valid state policy choices.

Second, a MOPR-only remedy would impose unjust and unreasonable costs on consumers by leading to the over-procurement of capacity. If state-supported resources are in fact providing capacity to the system, that capacity should be counted and compensated. It would not be just or reasonable to design market rules so as to require customers to procure a quantity of capacity through the capacity auction that ignores the existence of state-supported capacity and its actual contribution to system reliability. As the Commission recognized, "if PJM's MOPR applies to state subsidized resources with few or no exceptions, and yet the states continue to support those resources, some ratepayers may be obligated to pay for capacity both through the state programs providing out-of-market support and through the capacity market."[52] Designing market rules that

[49] *Id.* at P 160.
[50] *Id.*
[51] *Id.*
[52] *Id.* at P 159.

foreseeably lead to significant over-procurement of capacity is particularly misguided at a time when, as discussed above, the system already has a large amount of excess capacity.

Thus, to the extent the Commission affirms its finding that the current Tariff is unjust and unreasonable, it should also reaffirm that a MOPR-only remedy would not be just or reasonable, and that a just and reasonable remedy must accommodate state-supported resources by "continu[ing] to … recognize[them] as capacity on the system."[53]

V. CONCLUSION.

For the foregoing reasons, the Request for Rehearing should be granted.

Dated: July 30, 2018

Respectfully submitted,

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[53] *Id.* at P 162.

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 30th day of July, 2018.

/s/ *Marianne Alvarez*

_____

Marianne Alvarez
Exelon Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. ER18-1314-000**
	)	**ER18-1314-001**
	)	
	)	

MOTION FOR LEAVE TO ANSWER AND ANSWER OF EXELON CORP. AND THE PSEG COMPANIES

Pursuant to Rules 212 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"),[1] Exelon Corp. ("Exelon") and the PSEG Companies[2] move for leave to answer, and submit their answer, to the comments and protests filed in the above-captioned dockets.

MOTION FOR LEAVE TO ANSWER

Exelon and the PSEG Companies respectfully request that the Commission permit this Answer, and the attached Declaration of Michael M. Schnitzer ("Schnitzer Decl."), to protests and comments filed in the above-captioned dockets on May 7, 2018. The protests and comments include new evidence, including many new expert affidavits. Moreover, the protests and comments stake out novel positions—not just advocating for and against Capacity Repricing and MOPR-Ex, but suggesting modified versions of both, as well as entirely new approaches. Several protests and comments also respond to PJM's Section 205 filing by urging the Commission to act under Section 206. The Commission has allowed answers to protests where the answer provides

[1] 18 C.F.R. §§ 385.212, 385.213 (2017).
[2] The PSEG Companies include: Public Service Electric and Gas Company, PSEG Power LLC and PSEG Energy Resources & Trade LLC.

information that assists the Commission in its decision.[3] Exelon and the PSEG Companies respectfully suggest that this Answer will do so. In particular, the Schnitzer Declaration provides important new evidence concerning the Capacity Repricing proposal, in response to comments submitted by other parties.

ANSWER

The commenters clamoring for an expanded MOPR seek to exploit the Commission's commitment to markets and competition for ends that are profoundly anti-market and anti-competitive. While they purport to be purifying the Commission's markets from state intrusions, in reality they are seeking to entrench an unfair advantage they have enjoyed for decades: continuing to exploit the market's failure to value certain environmental attributes, and thereby imposing harm on society without paying for the costs. It is not a "level playing field" to treat resources that pollute as though they did not. When a coal or gas plant can underbid a wind farm, or a nuclear generator, by polluting the air we breathe, this is not a triumph of markets' power to drive efficient results. It is a market failure. When state policies attempt to internalize the pollution externality—through subsidies, taxes, or otherwise—they make markets more competitive and market outcomes more efficient.[4] This is, literally, textbook economics.[5] That is why there is broad agreement—even among advocates of MOPR-Ex—that markets should and must evolve, one way or another, to take into account environmental externalities like carbon.[6]

[3] *See, e.g.*, *Southwest Power Pool, Inc.*, 113 FERC ¶ 61,014, at P 7 (2005); *Southwest Power Pool Inc.*, 112 FERC ¶ 61,319, at P 56 (2005); *see also PJM Interconnection, L.L.C.*, 116 FERC ¶ 61,140, at P 18 (2006); *PJM Transmission Owners*, 115 FERC ¶ 61,345, at PP 10, 12 (2006).
[4] Decl. of Robert D. Willig ¶¶ 32-37 ("Willig Decl."), attached to Protest of Exelon Corp. ("Exelon Protest").
[5] *See id.* ¶¶ 30 n.28, 31 n.29, 34 n.32 (citing P.A. Samuelson & W.D. Nordhaus, *Economics* at 346-355 (1995); R.S. Pindyck & D.L. Rubinfeld, *Microeconomics*, 639-657 (2d ed. 1992); A.C. Pigou, *The Economics of Welfare* (4th ed. 1932); W.J. Baumol & W.E. Oates, The theory of environmental policy, Ch. 3 (2d ed. 1995)).
[6] Exelon Protest at 44 & n.152; *see* PJM Filing at 54-55; *infra* at 20-21.

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The Commission, of course, has decided so far that its market mechanism should be fuel-neutral. But the Commission can afford to ignore the different environmental profiles of different generation types only because *states'* policies are *not* fuel neutral. Resources thus bring with them to the Commission's fuel-neutral markets a cost structure that reflects whatever fuel-related benefits or penalties states have chosen to impose in light of state environmental priorities. The Commission's market mechanism selects the least-cost set of resources against the backdrop of those state policies. As Exelon's Protest showed, the Commission thus far has always crafted market rules to respect and accommodate state programs addressing environmental externalities.[7] Doing so adheres to the principle that the Commission must, whenever possible, "fulfill [its] jurisdictional responsibilities while also respecting the states' traditional role,"[8] consistent with the Federal Power Act's purpose to "complement," not "usurp[] … State regulatory authority."[9] For two decades, this is how the Commission's markets have operated. Thus, there is no truth to the allegation that this proceeding is a referendum on the Commission's commitment to markets.[10]

Advocates of MOPR-Ex ask the Commission to sweep away this market-based model of cooperative federalism in favor of one that countermands state environmental policies, so that the Commission's market yields the outcome that would result if the state policies did not exist. The Commission should not be fooled by these parties' rhetoric: while they cloak themselves in the language of market integrity and fairness, what these generators really want is to protect the market advantage they gain by polluting without paying. They urge PJM market rules that would neuter state policies compensating for the real benefits of cleaner fuels, and thus would strangle

[7] Exelon Protest at 18-22.
[8] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1117 (2006).
[9] *Conn. Light & Power Co. v. Fed. Power Comm'n*, 324 U.S. 515, 526 (1945).
[10] *See, e.g.*, Comments of the Independent Market Monitor for PJM at 6 ("IMM Comments"); Protest of the PJM Power Providers Group at 23 ("P3 Protest"); Protest and Comments of Electric Power Supply Association at 30-32 ("EPSA Protest").

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competition from cleaner generators that, when pollution costs are taken into account, would outcompete the polluters.

As Exelon and the PSEG Companies showed in their Protests, such action is not only inconsistent with sound economics and principles of cooperative federalism, but also is unjustified in light of current PJM market conditions. The Commission's markets are achieving what the Supreme Court has identified as "the principal purpose of" the Federal Power Act: "the orderly development of plentiful supplies of electricity … at reasonable prices."[11] Supply is plentiful, prices are low, and new entry remains significant. The commenters declaring that the markets are on the verge of collapse never address this reality, nor offer any evidence at all to support their panicked assertions that PJM is in the midst of a crisis.

For these reasons, the Commission should reject both PJM proposals. But if the Commission nevertheless determines to take some action to bring capacity prices closer to the levels that would exist without state environmental policies, the Commission should approve Capacity Repricing. Advocates of MOPR-Ex, of course, prefer MOPR-Ex, because it shields them from competition and furthers their goal of ridding the capacity markets of their non-emitting competitors. But if the Commission is compelled to act and finds Capacity Repricing, "PJM's preferred approach,"[12] to be just and reasonable (or that it can be rendered just and reasonable with an appropriate conditional acceptance), the Commission must approve it without reaching MOPR-Ex. Capacity Repricing satisfies the Commission's standard for market design—that it be "workably competitive."[13] And even if the comparison to MOPR-Ex were relevant, from a policy standpoint, Capacity Repricing is clearly superior to MOPR-Ex.

[11] *NAACP v. Fed. Power Comm'n*, 425 U.S. 662, 669-70 (1976).
[12] PJM Filing at 53.
[13] *See, e.g.*, *PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053, at P 84 (2005).

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Under MOPR-Ex: (1) The wrong resources clear (because clean resources should have the chance to out-compete polluters, after environmental harm is accounted for); (2) Too many resources clear (given the likelihood that the clean resources excluded by MOPR-Ex will continue to supply capacity without compensation from the market); and (3) Energy market price signals are corrupted (suppressed by forced overprocurement). The MOPR's proponents claim this harm is good because it "disincentiv[izes]" states.[14] But the Commission has no business trying to deter states from protecting citizens' health and welfare, and it is doubtful that the Commission could do so in any event.

Capacity Repricing avoids all these problems. The correct resources clear, after accounting for environmental harm; the right quantity of resources clears; and energy market prices are not distorted. Advocates of MOPR-Ex nevertheless argue that Capacity Repricing must be rejected because it yields a price-quantity pairing that is not on the demand curve, and because it may create opportunities for strategic bidding. But these critiques, even if true, are not fatal to Capacity Repricing, and they certainly are no reason to select MOPR-Ex in its stead. As to the price-quantity issue, this theoretical criticism has only modest practical effects. And MOPR-Ex *also* yields a price-quantity pairing that is not on the demand curve, once one accounts for the reality that states will continue support environmentally friendly resources that will effectively provide capacity to the system. Likewise, as to alleged incentives for strategic bidding, any effects "are likely to be modest and would reduce the cost of repricing to customers."[15] To the extent there is any effect, strategic bidding will tend to result in a clearing price that is still significantly higher than the status quo, but lower than the MOPR-Ex clearing price would be. In effect, Capacity Repricing strikes a middle ground. If the Commission remains concerned about bidding incentives, they can be

[14] IMM Comments at 14-15; EPSA Protest at 28-29.
[15] Schnitzer Decl. ¶ 15.

fixed. One example of a potential fix would be including an "opportunity cost" payment in the Capacity Repricing model. Such payments, by making resources indifferent between clearing and not, could virtually eliminate these bidding incentives. In a variety of contexts, the Commission has approved similar payments to align incentives with efficient behavior.

Thus, while there are good reasons to reject any mitigation of environmental payments, including Capacity Repricing, the broad criticisms of Capacity Repricing are overblown. Capacity Repricing is flawed because clean resources should be allowed to account for environmental attribute revenues and other state compensation in making capacity bids. These revenues reflect payments for separate services, and thus those resources, to cover their going forward costs, do not need to receive those amounts from the capacity market. But if the Commission disagrees, Capacity Repricing is the only proposed workable—and "workably competitive"—alternative.

I. The Comments Confirm That PJM's "Two Alternative[]" Approach Violates Section 205.

The comments underscore why Section 205 prohibits alternative filings like PJM's. Arrayed before the Commission are dozens of comments advocating for or against an unbounded universe of potential tariffs: Capacity Repricing,[16] MOPR-Ex,[17] and assorted permutations of MOPR-Ex without certain exemptions (with various commentators seeking to sever versions of the RPS Exemption, Self-Supply Exemption, Public Entity Exemption, Competitive Entry Exemption, and the carve out for federal subsidies, among others).[18] By placing this free-for-all

[16] A number of commentators show that no change is warranted, but that Capacity Repricing is vastly superior to MOPR-Ex. *See* Comments of American Electric Power Service Corp. at 1 ("American Electric Comments"); Protest of Dominion Energy Services, Inc. at 9-11 ("Dominion Comments"); Exelon Protest at 8; Comments of Nuclear Energy Institute at 1 ("NEI Comments"); Protest and Motion to Reject of the PSEG Companies at 2 ("PSEG Protest").
[17] Comments of American Petroleum Institute, J-Power USA Development Co., Ltd., and Panda Power Generation Infrastructure Fund, LLC at 7-8 ("API Comments"); EPSA Protest at 2; IMM Comments at 3.
[18] *See, e.g.*, Comments of LS Power Associates, L.P. at 18 ("LS Power Comments"); Comments of Natural Gas Supply Association at 8 ("NGSA Comments"); Protest of the NRG Companies at 25 ("NRG Protest"); P3 Protest at 20; Comments and Protest of Rockland Capital, LLC at 5 ("Rockland Comments"); Comments of Vistra Energy Corp. and Dynegy Marketing & Trade, LLC at 13 ("Vistra Comments").

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before the Commission, instead of proposing a single tariff "stating plainly the change or changes to be made,"[19] PJM's filing is inconsistent with the "passive and reactive role" that Section 205 requires the Commission to play.[20] If PJM wishes to give the Commission broad discretion to set policy, it must attempt to carry Section 206's heavy burden, or else seek a declaratory judgment. Because Section 205 does not sanction PJM's approach, the Commission must reject its filing.

II. The Comments Confirm That The Commission Should Not Hesitate To Reject Both Of PJM's Proposals And Preserve The Status Quo.

Stakeholders of every stripe have identified significant problems with both of PJM's proposals. Yet proponents of mitigation urge the Commission to press ahead anyway based on claims that the sky is falling—that state programs are "wreak[ing] havoc with PJM's markets,"[21] which are supposedly facing a "serious threat"[22] and "will collapse."[23] These are serious charges that, if true, would yield evidence for all to see. But what the comments of mitigation proponents reveal, more than anything, is that no *evidence* backs up this rhetoric. And the *actual* evidence confirms that the crisis is manufactured. As shown by Exelon, the PSEG Companies, and others, reserve margins are historically high (23.3% for the 2020-21 BRA) at prices that are historically low ($86/MW-day)—yet still, new entry continues at a significant pace (including almost 40 GW of recently entered or potential near-term entrants across PJM).[24] These high reserve margins, moreover, have been sustained despite years of claims that the capacity markets face "imminent

[19] 16 U.S.C. § 824d(d).
[20] *NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 115 (D.C. Cir. 2017).
[21] NRG Protest at 2.
[22] EPSA Protest at 34.
[23] P3 Protest at 8.
[24] Exelon Protest at 33; *see* Protest of Clean Energy Advocates at 35-42 ("Clean Energy Advocates Protest"); Protest of Clean Energy Industry Associations at 10-14 ("Clean Energy Industry Protest"); Protest of Joint Consumer Advocates at 10-14 ("Joint Consumer Protest"); Protest and Comments of the Maryland Public Service Commission at 5 ("Maryland PSC Protest"); Protest of the Office of the People's Counsel for the District of Columbia, Maryland Office of People's Counsel, and New Jersey Division of the Rate Counsel at 2-3 ("DC/MD/NJ Ratepayers Protest"); Comments of the Organization of PJM States at 5-7 ("PJM States Comments"); PSEG Protest at 11.

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and substantial," and even "existential," "threat[s]."[25] The efficacy of PJM's capacity markets, and investors' faith in them, speaks for itself.

While PJM does not need to point to a crisis to justify tariff revisions under Section 205, the absence of any on-the-ground problem means that the Commission should not hesitate to reject both of PJM's proposals. Instead, until PJM formulates a new tariff that is genuinely just and reasonable, the Commission should leave PJM's capacity market rules where they are—with the MOPR limited, as it has been, to counteracting buyer-side market power by new resources.[26] That cautious approach avoids all the problems that come from expanding mitigation. And it respects stakeholders' wishes: Of the comments filed that take a position on the merits, a substantial majority urge the Commission to reject both proposals.[27] That preference has been consistent since November 2017, when 64% of stakeholders stated that they preferred the status quo.[28]

III. Although The Capacity Repricing Proposal Is Unwarranted And Flawed, Claims That The Proposal Is Unworkable Are Incorrect.

Exelon and the PSEG Companies agree with the commenters who criticize Capacity Repricing as unwarranted and unnecessary because it needlessly raises prices for customers at a

[25] Complaint Requesting Fast Track Processing at 5, *Calpine Corp. v. PJM Interconnection, L.L.C.*, Docket No. EL16-49-000 (Mar. 21, 2016); Motion to Amend, and Amendment to, Complaint and Request for Expedited Action on Amended Complaint at 2, 3, *Calpine Corp. v. PJM Interconnection, L.L.C.*, Docket No. EL16-49-000 (Jan. 9, 2017); *see* Exelon Protest at 33.

[26] Exelon Protest at 38-40.

[27] Comments of Advanced Energy Buyers Group at 1-2; American Electric Comments at 1; Comments of American Municipal Power, Inc. at 20; Protest of American Public Power Association at 1; Clean Energy Advocates Protest at 1; Clean Energy Industry Protest at 1-2; Dominion Comments at 5; Comments and Limited Protest of Duquesne Light Company at 3 ("Duquesne Comments"); Protest and Comments of FirstEnergy Service Company & East Kentucky Power Coop., Inc. at 2-3 ("FirstEnergy Comments"); Comment of Harvard Electricity Law Initiative at 1-3 ("Harvard Electricity Law Comments"); Motion to Dismiss and Protest of Illinois Commerce Commission at 4-5; Comments of Institute for Policy Integrity at 1-2; Joint Consumer Protest at 1; Maryland PSC Protest at 2; NEI Comments at 1; Protest of the New Jersey Board of Public Utilities at 1; NRG Comments at 1; PJM States Protest Comments and Protest of Public Utilities Commission of Ohio at 2; Comments and Protest of Old Dominion Electric Cooperative at 1; P3 Protest at 3; Comments of the Pennsylvania Public Utility Commission at 16; PJM States Comments at 1-2; PSEG Protest at 1-2; Protest of Solar RTO Coalition at 1 ("Solar RTO Protest"); Protest of Southern Maryland Electric Cooperative, Inc. at 3; Comments of Talen PJM Companies at 2.

[28] PJM, CCPPSTF Vote Results at 5 (Nov. 21, 2017), http://www.pjm.com/-/media/committees-groups/task-forces/ccppstf/20171121/20171121-ccppstf-vote-results.ashx; *see* Exelon Protest at 43.

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time of oversupply with no corresponding benefit, and because it incorrectly mitigates payments recognizing the environmental value of clean generation. But to the extent the Commission disagrees and deems some departure from the status quo necessary, it is not "free to accept the better of the two approaches filed under Section 205," as the IMM incorrectly asserts.[29] PJM has identified Capacity Repricing as its "prefer[red]" approach, and thus the Commission must "assess first whether it can accept Option A, even if subject to suspension and further proceedings."[30] If the Commission determines Capacity Repricing is just and reasonable (or, with an appropriate conditional acceptance, can be *made* just and reasonable), it cannot reach MOPR-Ex. And while Capacity Repricing is unnecessary, the broader attacks on it are meritless. Capacity Repricing's auction mechanism can meet the Commission's "workably competitive" standard,[31] and can accommodate state programs while insulating capacity prices from those programs' effects.

A. The Criticisms Of Capacity Repricing's Auction Design Are Overstated And Can Be Remedied.

Several commentators note strategic bidding incentives that exist under Capacity Repricing's two-stage design—three such incentives, in particular. First, if a portfolio owner has high-cost resources that cannot hope to receive a capacity commitment at Stage 1, it might inflate the bids for those resources in the hope of contributing to higher Stage 2 clearing prices for other resources (what the Wilson Affidavit calls "clear-out-the-top").[32] Second, some "in between" resources—which might be economic at the Stage 2 clearing price, but cannot clear at Stage 1—may drop out.[33] Third, if resources would be economic at the anticipated Stage 2 clearing prices, they may have incentives to make offers below their forward costs in order to increase their

[29] IMM Comments at 3.
[30] PJM Filing at 46.
[31] *See, e.g.*, *PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053, at P 84 (2005).
[32] DC/MD/NJ Ratepayers Protest at 10; *see* EPSA Protest at 10.
[33] EPSA Protest at 11 n.46 and Affidavit of David W. DeRamus and Collin Cain ¶¶ 49-53.

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chances of receiving a capacity commitment at Stage 1 (what the Wilson Affidavit calls "race-to-the-bottom").[34] The first two incentives tend to increase prices; the third, to decrease prices.

Even if these incentives exist, they are not *per se* fatal. Indeed, as the Schnitzer Declaration explains, "[w]hile commenters' witnesses point out these strategic bidding behaviors, they do not provide any well-supported analysis of their combined net impact."[35] And careful analysis shows that the concerns about Capacity Repricing are overblown. Any incentives to "clear-out-the-top" reflect issues that are already addressed by existing market rules, such as seller offer caps and the risk of Commission enforcement penalties for manipulative bidding.[36] Likewise, the effect of "in between" resources dropping out of the market will be limited given PJM's deep well of potential new entrants.[37] Finally, as between the three incentives, the effect termed "race-to-the-bottom" likely will affect a broader range of resources, and this price-reducing effect will likely swamp the other two price-increasing effects.[38] This effect, however, is also self-limiting: If a resource were the *only* one pursuing this strategy, perhaps it might steeply reduce its bid, predicting that Stage 2 would increase the clearing price.[39] But bidders take into account others' expected behavior.[40] And here, a resource will know that other bidders are also likely to reduce their bids—and thus if the resource reduces its bid too steeply, it risks losing money even at the higher Stage 2 price.[41] This will limit incentives to reduce bids.

The upshot of these incentives will be to mitigate the price increases that would otherwise result from Capacity Repricing. For example, one witness estimates that Capacity Repricing (and

[34] DC/MD/NJ Ratepayers Protest at 9.
[35] Schnitzer Decl. ¶ 51.
[36] *Id.* ¶ 54.
[37] *Id.* ¶ 57.
[38] *Id.* ¶ 58.
[39] *Id.* ¶¶ 59, 61.
[40] *Id.* ¶ 59.
[41] *Id.*

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MOPR-Ex) would increase capacity prices by about 50% absent strategic bidding.[42] The bidding incentives, on plausible assumptions, lower this amount slightly to 39%.[43] Exelon and the PSEG Companies have shown that Capacity Repricing and MOPR-Ex both "will raise capacity market prices and costs for consumers"; the bidding incentives produced by Capacity Repricing thus somewhat limit that effect, yielding prices that are "elevated relative to the status quo, but below MOPR-Ex."[44] That is a reason to prefer it to MOPR-Ex.[45] Whatever the theoretical criticisms of Capacity Repricing's design, it cashes out as a compromise. It respects state policies by allowing state-supported clean generation to clear while still raising prices to offset this support—albeit not as much as certain fossil-fuel generators hope to achieve via MOPR-Ex.[46]

If the Commission remains concerned about Capacity Repricing's effects on bidding incentives, there are potential solutions. For example, the Schnitzer Declaration explains that resources whose offers are above the Stage 1 clearing price but below the Stage 2 clearing price could receive a "lost opportunity cost" payment equal to the difference between their offers and the Stage 2 clearing price.[47] The lower the offer, the higher the payment.

A "lost opportunity cost" payment largely could eliminate all three incentives detailed above: It could eliminate "clear-out-the-top" (artificially inflated offers would be costly, as they would reduce lost opportunity cost payments); the drop out of "in between" resources (who would receive an incentive, via the lost opportunity cost payment, to submit a bid); and the "race to the

[42] *Id.* ¶ 61.
[43] *Id.*
[44] *Id.* ¶¶ 18, 61.
[45] *Id.* ¶ 64.
[46] EPSA also contends that the effect termed "race-to-the-bottom" will cause the auction to procure too much capacity—because when the demand curve slopes down, lower offer prices will yield a larger quantity. EPSA Protest at 11. Because the demand curve is so steep, however, any such effect will be very small—on the order of 0.1% of the market, or 167 MW. Schnitzer Decl. ¶ 63.
[47] Schnitzer Decl. ¶ 67.

bottom" (as failing to clear at Stage 1 would no longer harm resources that can beat the Stage 2 price).[48] This modification could also address the concern that Stage 2 clearing prices will be set by resources with no capacity commitment at stake: A lost opportunity cost payment means that *all* resources that can beat the Stage 2 price have something at stake.[49] The size of these payments would likely be small—0.75% of total capacity payments.[50]

Nor would such payments amount to money for nothing: preparing bids is costly,[51] and PJM would be compensating generators for their expense in preparing cost-based bids that help the PJM market operate efficiently. Opportunity cost payments are already used by PJM to align bidder incentives with efficient behavior—for example, to address out-of-market dispatch for reliability reasons in energy markets, and in operating reserves markets.[52]

If the Commission concludes that a modification to Capacity Repricing is warranted, Exelon and the PSEG Companies respectfully suggest that the appropriate next step would be to reject the current filing as unjust and unreasonable, but indicate that the Commission would accept a Section 205 filing including such a modification.

B. The Broader Attacks On Capacity Repricing Are Meritless.

The broader attacks on Capacity Repricing—many pressed by fossil-fuel generators hoping to drive the Commission toward an unwarranted expansion of the MOPR—are baseless.

Clearance by state-supported resources. One supposed flaw is that clean generators receiving payments for their environmental value clear at the expense of other generators.[53] But this is Capacity Repricing's key *virtue*. As Dr. Willig's Declaration explains, this is the efficient

[48] *Id.* ¶¶ 68-72.
[49] *Id.* ¶ 68.
[50] *Id.* ¶ 73.
[51] *See* Affidavit of David W. DeRamus & Collin Cain, ¶ 50, attached to EPSA Protest.
[52] Schnitzer Decl. ¶ 74.
[53] *See, e.g.*, EPSA Protest at 9; P3 Protest at 12-13.

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result when environmental externalities are taken into account,[54] and by permitting this result, Capacity Repricing avoids the costly overprocurement and distorting energy market effects that plague MOPR-Ex (as discussed further below). In this respect, Capacity Repricing follows the CASPR Order's lead—which also permitted, through a different mechanism, state-supported clean resources to replace existing polluting resources.

Effects on other states. Next, the proponents of a broader MOPR claim Capacity Repricing "would create a significant externality" by allowing "states … to shift th[e] costs of th[eir] polices … onto other" states.[55] Not so. State policies themselves do not impose any costs on other states—for example, the funds for Illinois' ZEC Program come entirely from Illinois customers—and the whole *point* of Capacity Repricing is to set prices where they would have been without state payments that qualify as Actionable Subsidies. That does not export any costs onto other states, or alter prices received by other generators. To the contrary, states *benefit* other states when they support clean generation, because the benefits of pollution abatement are experienced by citizens of all states, not only the state paying for the pollution abatement.

EPSA also repackages similar arguments as constitutional objections, claiming that Capacity Repricing unconstitutionally "[a]llow[s] [s]tates [t]o [r]egulate [b]eyond [t]heir [b]orders" by permitting "the actions of one state to affect[] … other states."[56] The Commerce Clause prohibits states from enacting extraterritorial legislation that "directly regulates transactions which take place across state lines."[57] Never could the Commission's *federal* approval of market rules violate that restriction on state authority. And regardless, EPSA does not

[54] Willig Decl. ¶ 52; *see* Institute for Policy Integrity, *Capacity Markets and Externalities: Avoiding Unnecessary and Problematic Reforms* at 10-12 (April 2018), http://policyintegrity.org/files/publications/Capacity_Markets_and_Externalities_Report.pdf.
[55] EPSA Protest at 29.
[56] *Id.* at 21 (internal quotation marks omitted).
[57] *Edgar v. MITE Corp.*, 457 U.S. 624, 641 (1982).

point to any "direct[] regulat[ion]" of interstate commerce;[58] at most, it alleges that one state's actions may have effects elsewhere.[59] But mere extraterritorial effects do not violate the Commerce Clause: "it is inevitable that a state's law … will have extraterritorial effects," and the "Supreme Court has never suggested that the … Commerce Clause" precludes such effects.[60] Indeed, EPSA's argument proves vastly too much. Whenever states have subsidized fossil-fuel plants, they have required citizens "in other states to shoulder much of the burden"—in less efficient wholesale electricity markets, and in more polluted air.[61] On EPSA's theory, all such subsidies would be unconstitutional. The Commerce Clause has never stretched so far.

Violation of constitutional limits on ratemaking. EPSA's other constitutional objection fares no better. EPSA argues that, as to resources that offer below the Stage 2 clearing price but do not receive a capacity commitment at Stage 1, Capacity Repricing violates the Constitution (and FPA) because it does not provide these resources the "*opportunity* to recover [their] costs,"[62] invoking *FPC v. Hope Natural Gas Co.*[63] and *Bridgeport Energy, LLC*.[64] That standard, however, does not apply here. When a utility is compelled to provide service to the public, as with a traditionally regulated utility, this standard forbids "confiscatory" rates for compelled service.[65] Likewise, when a generator is compelled to remain operational for reliability, the same standard governs.[66] In PJM, however, generators are not compelled to provide capacity. To be sure, generators that have sold capacity generally have a must offer obligation into the Reliability

[58] *Id.*
[59] EPSA Protest at 21-22.
[60] *Instructional Sys., Inc. v. Computer Curriculum Corp.*, 35 F.3d 813, 825 (3d Cir. 1994); *see SPGGC, LLC v. Blumenthal*, 505 F.3d 183, 194 (2d Cir. 2007).
[61] EPSA Protest at 22-23 (quotation marks omitted).
[62] *Id.* at 21 (quoting *Bridgeport Energy, LLC*, 113 FERC ¶ 61,311, at P 29 (2005)); *see* LS Power Comments at 8-9 (same argument).
[63] 320 U.S. 591, 603 (1944)
[64] *Bridgeport Energy, LLC*, 113 FERC ¶ 61,311, at P 29 (2005).
[65] *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 310 (1989) (citing *Hope Natural Gas*, 320 U.S. at 502).
[66] *Bridgeport Energy, LLC*, 113 FERC ¶ 61,311, at P 29 (2005).

Pricing Model. But if these resources choose to retire, they can do so upon 90 days' notice (and, presumably, upon covering any outstanding capacity obligations)—regardless of reliability implications.[67] In such circumstances, the Commission has held that "there can be no question of confiscation of a resource's property."[68]

Seller-side market power. The American Petroleum Institute ("API") claims, uniquely, that state support generally, and Capacity Repricing in particular, "facilitate the exercise of *supplier*"—not buyer—"market power"[69] via three anticompetitive tactics: (1) "predatory pricing"; (2) "entry deterrence"; and (3) "economic withholding" of a portion of an owner's portfolio.[70] As best Exelon and the PSEG Companies can discern, API's argument appears to be that these tactics require that the owner have the financial wherewithal to withstand temporary losses or losses in part of its portfolio, and that subsidies and Capacity Repricing "facilitate" these tactics by giving generators more money overall. But that money could just as well come from *anywhere*—utility operations, capital markets, or tax reductions. API's argument has nothing to do with Capacity Repricing.

Price/quantity pair not on the demand curve. EPSA criticizes Capacity Repricing because it yields a result that does not fall on "RPM's sloped demand curve": Because Stage 1 determines the quantity procured, and Stage 2 determines the price, Capacity Repricing yields a "price/quantity relationship" that does not appear on the demand curve.[71] But that theoretical flaw

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[67] PJM Open Access Transmission Tariff, § 113.

[68] *Id.*; *see also N.Y. Indep. Sys. Operator, Inc.*, 124 FERC ¶ 61301, at P 58 (2008) (similar). To the extent EPSA's argument is that Capacity Repricing is unreasonable under the FPA because it does not "represent[] an appropriate balancing of consumer and investor interests," EPSA Protest at 19, Exelon and the PSEG Companies agree—but EPSA gets the imbalance backwards. For consumers, Capacity Repricing strikes the wrong balance because it raises prices with no sound justification. But for investors, it is not unfair that some polluting resources fail to clear due to states' efforts to address environmental externalities—which remains true even if these resources could have beaten the Stage 2 clearing price.

[69] Affidavit of Paul M. Sotkiewicz ¶ 6, attached to Comments of API.

[70] *Id.*

[71] EPSA Protest at 14; *see* Affidavit of David W. DeRamus and Collin Cain ¶ 38.

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is no reason to reject Capacity Repricing absent some evidence that it is *actually* unworkable. And certainly, it is no reason to select MOPR-Ex over Capacity Repricing: As the Schnitzer Declaration explains, "the same is true of MOPR-Ex," which *also* yields a "price and quantity pair [that] does not fall on the demand curve," once one accounts for the resources that will continue to receive state support and effectively provide capacity to the system, even though they are not selected in the capacity auction.[72] "Indeed, because MOPR-Ex results in *significant over-procurement*, the effective price-quantity pair that results is even further away from the demand curve than Capacity Repricing."[73]

IV. The Proposals To Expand The MOPR Are Fundamentally Flawed.

Even if the Commission determined that a change must be made and that it could not approve Capacity Repricing (or a variant), it could not approve MOPR-Ex or any of the expansions of the MOPR proposed here. Both in theory and in execution, they are fundamentally flawed.

A. The Proposals To Expand The MOPR Are Flawed In Theory.

The commentators pushing for an expanded MOPR depict competitive markets as, by definition, insulated from the effects of state policies—which, when those policies involve payments for environmental benefits, they derisively call "subsidies."[74] Thus, they proclaim that "*all* subsidies" "are bad," "evil[]," and a "problem[]."[75] But the Commission will not find a citation to any economic authority that supports that broad proposition. That is because this proposition is false—for reasons Exelon has explained. Markets are not efficient when fossil-fuel generators inflict pollution on society without paying.[76] And state policies that attempt to

[72] Schnitzer Decl. ¶ 22.
[73] *Id.* ¶ 15 (emphasis added).
[74] *See, e.g.*, API Comments at 5; EPSA Protest at 12; NGSA Comments at 1-2; P3 Protest at 3.
[75] P3 Protest at 11 & Aff. of Roy J. Shanker, attached thereto, at PP 10, 34.
[76] Willig Decl. ¶¶ 13(c)-(d), 31.

internalize this externality, whether by taxing or penalizing pollution, or by supporting clean generation that abates pollution, make markets more efficient and competitive.[77] This is Economics 101.[78]

In reality, the MOPR's proponents do not really believe that *all* state interventions must be mitigated; instead, their pious rhetoric is only meant to encourage the Commission to adopt changes that harm cleaner competitors, while leaving untouched the massive subsidies they have long reaped. Thus, P3 proposes a supposedly "Clean MOPR" that removes MOPR-Ex's enumerated exemptions and also the carve-out from the definition of "Actionable Subsidy" for "federal production and investment tax credits."[79] But tellingly, P3 does not seek to remove the exclusion for various siting- or development-based subsidies—subsidies that happen to go to gas-fired generators. Likewise, there is not a peep about the untold billions in subsidies that coal-fired generators have and continued to receive, including both direct subsidies—$4.7 billion, just on the federal side, every year[80]—and indirect support, such as Pennsylvania's sales-tax exclusion for coal.[81] And all of this is in addition to the *implicit* subsidy that fossil-fuel generators receive from the ability to pollute without paying, which Exelon showed comes to $12.1 to $17.7 billion annually.[82] There is no justification for targeting government policies for mitigation *only* when they promote clean generation and make the Commission's markets more efficient.

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[77] *Id.* ¶¶ 32-37.
[78] *See id.* ¶¶ 30 n.28, 31 n.29, 34 n.32 (citing P.A. Samuelson & W.D. Nordhaus, *Economics* at 346-355 (1995); R.S. Pindyck & D.L. Rubinfeld, *Microeconomics*, 639-657 (2d ed. 1992); A.C. Pigou, *The Economics of Welfare* (4th ed. 1932); W.J. Baumol & W.E. Oates, The theory of environmental policy, Ch. 3 (2d ed. 1995)).
[79] P3 Protest at 20 & n.50.
[80] Exelon Protest at 30; *see* Clean Energy Advocates Protest at 41 ($7.5 billion in federal subsidies to coal in 1989 alone).
[81] Clean Energy Advocates Protest at 90.
[82] Exelon Protest at 12.

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The MOPR's proponents have no adequate answer for how their approach undermines not just sound economics, but federalism principles the Commission has long respected. As explained by Exelon and others, states have long exercised their FPA-protected authority as regulators of "facilities used for the generation of electric energy,"[83] and the Commission has reaffirmed that it must, whenever possible, "fulfill [its] jurisdictional responsibilities while also respecting the states' traditional role."[84] That means that when states regulate generators to protect the air citizens breathe, the Commission should not attempt to thwart or disincentivize those policies, no matter how much rhetorical noise the policies' opponents employ.

The MOPR's proponents insist that an expanded MOPR does not seek to thwart state environmental policies. But in more candid moments, they admit the opposite—that an expanded MOPR aims to create "a disincentive" for state policymaking favoring clean generation.[85] That is consistent with PJM's statement that applying the MOPR to federal payments to wind and solar resources would, in effect, "countermand … acts of Congress."[86] But under the FPA, the Commission has no authority to establish market rules that seek to deter states from legislating to protect their citizens' health and welfare, or to countermand state actions that do so.[87]

Again and again, the MOPR's proponents labor to narrowly limit the state authority over generation that the Commission must respect. First, they put states to an all-or-nothing choice—claiming that states forfeited any ability to influence the generation mix when they joined "an organized capacity market," and that states wishing to make any "policy decision[s]" concerning generation must "pursue Fixed Resource Requirement ('FRR') treatment."[88] But as many

[83] 16 U.S.C. § 824(b)(1).
[84] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1117.
[85] EPSA Protest at 27-28 (quotation marks omitted); IMM Comments at 14.
[86] PJM Filing at 71.
[87] Exelon Protest at 18-19.
[88] P3 Protest at 21.

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commentators note, that claim mocks history: In myriad states, restructuring went hand-in-hand with RPS programs.[89] That is why the D.C. Circuit has held that restructured states "retain the right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities."[90] Likewise, states' ability to fulfill their obligations under *other* cooperative-federalism statutes, like the Clean Air Act, often *depends* on influencing the generation mix that serves them.[91] Indeed, the Commission's organized markets have earned sustainable support precisely *because* the Commission has not required, as a condition of entry, that states give up their authority to influence the generation mix. To the contrary, in myriad ways, the Commission has actively "accommodate[d]" such policies.[92]

Second, the MOPR's proponents insist that states must make the perfect the enemy of the good. The IMM, for example, avers that states can address the harm caused by carbon dioxide only if they can agree on "a carbon price."[93] But unlike the IMM, states cannot wait for "[t]he theoretical ideal market approach."[94] They want to protect citizens *today*. Thus, acting under their police powers, states can—and often must—"take reform 'one step at a time, addressing [themselves] to the phase of the problem which seems most acute."[95] States, like the Commission, are permitted to adopt market-based approaches, entirely non-market mechanisms, or something

[89] Clean Energy Advocates Protest at 47-52; Harvard Electricity Law Comments at 2-3; MD PSC Protest at 9.
[90] *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009).
[91] Exelon Protest at 19.
[92] *ISO New England Inc.*, 162 FERC ¶ 61,205, at P 101 (2018) ("CASPR Order"); *see, e.g.*, *California Indep. Sys. Operator Corp.*, 145 FERC ¶ 61,254, at P 34 (2013) (approving reduction in CAISO's bid floor in the energy market to negative $150/MWh to accommodate renewable resources); *Reform of Generator Interconnection Procedures & Agreements*, 163 FERC ¶ 61,043 (2018) (requiring changes to large generator interconnection agreements and processes to streamline the process for new resources, which are predominantly wind and solar); *Integration of Variable Energy Res.*, 139 FERC ¶ 61,246, at P 92 (2012) (adjusting rules for transmission scheduling periods to avoid imposing penalties on variable resources supported by states).
[93] IMM Comments at 10.
[94] PJM Filing at 54.
[95] *McDonald v. Bd. of Election Comm'rs of Chicago*, 394 U.S. 802, 809 (1969) (quoting *Williamson v. Lee Optical of Oklahoma, Inc.*, 348 U.S. 483, 489 (1955)).

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in-between. As Dr. Willig explains, well-designed environmental initiatives like Illinois' ZEC Program, which tie compensation to the value of the externality being abated and procure resources based on their environmental contribution, result in more efficient markets. There is no justification for thwarting those efforts simply because a carbon price would be superior.

Third, the MOPR's proponents imply that the Commission need not respect state policy choices because states may have different views about what externalities are most important to address—noting that FirstEnergy has identified, as "externalities," "fuel diversity" and "fuel security," and that resources possessing these attributes may be different from the clean generators targeted by MOPR-Ex.[96] But this concern is purely hypothetical. The *real* programs that states have enacted, and that MOPR-Ex targets, address environmental externalities like air pollution. Such environmental externalities are the easiest and clearest case. They are "the classic example found in almost every economics textbook."[97] So while the IMM disingenuously says that action may be warranted "[*i*]*f* society determines that carbon is a pollutant with a negative value"[98]—implying that carbon *might not* be a harmful pollutant—nobody *really* doubts that air pollution is a harmful externality, and that addressing it makes markets more efficient. At the May 2017 technical conference, even representatives of Calpine and NRG agreed that "carbon [is] an externality" that should be "price[d]."[99] Indeed, the federal government has *already found* that carbon is a harmful pollutant (in, for example, the EPA's "endangerment finding," which was affirmed on judicial review)[100]—and in any event, states need not wait for the federal government

[96] EPSA Protest at 30 (quotation marks omitted).
[97] Willig Decl. ¶ 30 n.28.
[98] IMM Comments at 10 (emphasis added).
[99] Transcript of Technical Conference at 331, *State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.*, Docket No. AD17-11-000 (May 2, 2017) (comments of Thad Hill); *see id.* at 320 (comments of Abe Silverman) ("[U]ltimately you know we do want to get to the point where the wholesale markets facilitate the state desires to meet the environmental externalities").
[100] *See, e.g.*, *Coal. for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 121 (D.C. Cir. 2012), *aff'd in part, rev'd in part on other grounds sub nom. Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427 (2014).

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to address threats to citizens' health and welfare. Whatever the scope of the externalities that states can permissibly address, environmental externalities are in the heartland of what states have historically addressed, and should be encouraged to address.

B. The Proposals To Expand The MOPR Are Flawed In Execution.

Apart from its conceptual flaws, MOPR-Ex is indefensible purely as a matter of auction design. The same is true of the broader variants, like "MOPR Clean." All should be rejected.

Proponents suggest that an expanded MOPR *must be* just and reasonable because PJM has a MOPR rule, which "already reflects stakeholder compromises."[101] Not so. The present MOPR is narrow in its purpose (combatting buyer-side market power), in the fuel sources it covers (gas only), and in the vintage it targets (only new generators).[102] The broader MOPRs proposed in this proceeding would twist this rule for a sweeping new purpose, and to a new universe of resources—counteracting the effects of disfavored state policies on wholesale markets, for both new and existing resources of any fuel type. PJM's MOPR was not designed for this new role, and has never been applied in this far-reaching manner. Stakeholders' agreement to, or the Commission's approval of, the narrow existing MOPR provides no support for the sea change sought here.[103]

Moreover, the comments confirm that the expanded MOPR's Swiss-cheese exceptions are incurably arbitrary. Stakeholders from all walks—generators, environmental groups, customer advocates—agree that the RPS Exemption is discriminatory: It exempts favored RPS programs for renewables, while mitigating environmental programs based on disfavored technologies (like nuclear or offshore wind), disfavored procurement processes, and even RPS programs with

[101] IMM Comments at 10; *see* API Protest at 10.
[102] Exelon Protest at 38-40.
[103] *Id.*

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technology-specific tiers.[104] It does so even though the favored and disfavored programs pursue the same purposes and have the same effects on capacity markets, and even though disfavored programs like Illinois' ZEC Program may be more economically efficient than the exempted programs, by capping payments at the value of the environmental externality being abated.[105]

Likewise, myriad commentators explain why the Self-Supply and Public Entity exemptions are indefensible under MOPR-Ex's proposed new purpose of counteracting effects of state policies on wholesale markets. Because of the implicit subsidy provided by captive ratepayers, the vertically integrated utilities that qualify for these exemptions can build or maintain generation that "may be uneconomic" and that "would not have been built" or maintained, "but for being backed by ratepayer funds."[106] The state policies favoring the vertically integrated business model may be *older* than the pro-environmental policies that have spread over the last two decades. But that does not justify differential treatment.

Contra the suggestion of some fossil-fuel generators, these problems cannot be solved by blue-penciling MOPR-Ex's enumerated exemptions. One reason—again, acknowledged by several commentators—is that *NRG Power Marketing, LLC v. FERC*[107] precludes doing so.[108] But the more important reason is that once the Commission starts down the path of applying the MOPR to some disfavored policies—even state environmental policies that promote market efficiency—there is no non-arbitrary stopping point. The comments illustrate the point. Many commenters, as noted above, explain that MOPR's enumerated RPS Exemption, Self-Supply Exemption, and Public Entity Exemption are discriminatory. But even if the Commission severed these

[104] Clean Energy Advocates Protest at 102; Duquesne Comments at 4-5; Joint Consumer Advocates Comments at 22-23; LS Power Comments at 18; NEI Comments at 9-12; NGSA Comments at 8; NRG Protest at 25; P3 Protest at 20; PSEG Protest at 9-10; Rockland Comments at 5; Solar RTO Protest at 20-22; Vistra Comments at 13.
[105] Willig Decl. ¶¶ 51, 59.
[106] NRG Protest at 19; *see* Clean Energy Advocates Protest at 82-85; P3 Protest at 18.
[107] 862 F.3d 108 (D.C. Cir. 2017).
[108] Clean Energy Advocates Protest at 65; Joint Consumer Advocates Protest at 8-9; PSEG Protest at 10.

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exemptions, that would still leave the sundry additional subsidies that PJM excludes from the definition of "Actionable Subsidy"—subsidies that "promote … general industrial development in an area," subsidies that "incent … siting facilities in [a particular] locality," and federal tax credits.[109] As many commentators show, those subsidies also affect wholesale capacity markets by supporting resources that might not otherwise be economic, and they may be less efficient than well-designed state environmental programs.[110] There is no justification for applying the MOPR to state environmental policies, but not to these distorting subsidies. P3 trumpets its support for a "Clean MOPR."[111] But as explained above, P3 only proposes eliminating the exclusion for federal subsidies to renewables, not the state and local subsidies that generally benefit gas and coal generators. Even if those exclusions were eliminated, that would still leave the various upstream subsidies fossil-fuel generators receive—for example, Pennsylvania's sales tax exemption for coal.[112] The solution to this problem is not to embark along the path proposed by MOPR-Ex.

If, however, PJM's market rules exempt *some* state policies from an expanded MOPR, then the market rules must, at the least, exempt Illinois' ZEC Program. As Exelon has established, that program is more efficient than state RPS programs—not to mention state policies favoring vertically integrated utilities—because it links the externality payment to a conservative estimate of the participating plants' environmental value.[113] Failing to exempt the ZEC Program thus would be arbitrary. The ratepayer advocates for the District of Columbia, Maryland, and New Jersey defend an RPS-specific exemption on the theory that RPS programs are "long-standing" and

[109] *See* proposed PJM Tariff § 1, Definitions L-M-N (Option B).
[110] Exelon Protest at 24-25; *see* Clean Energy Advocates Protest at 8, 54-55; Duquesne Comments at 5; FirstEnergy Protest at 19-20; NEI Protest at 10-11; PSEG Protest at 10; Solar RTO Protest at 19, 25-26.
[111] P3 Protest at 20.
[112] Clean Energy Advocate Protest at 90.
[113] Exelon Protest at 24-25.

widespread across PJM.[114] Exelon and the PSEG Companies agree that RPS programs should not be subject to the MOPR, but once the Commission begins applying the MOPR to environmental programs, neither the vintage nor the political popularity of RPS programs is a reasoned ground for exempting them.[115]

The proponents of an expanded MOPR also have no adequate answer for the gross overprocurement of capacity that it will yield. They predict—without evidence—that an expanded MOPR will deter states from supporting clean resources. There is no reason to think that is so, and every reason to think the opposite. Despite ISO-New England's limited MOPR exemption for 200 MW of renewables, for example, states issued the Multi-State Clean Energy request for proposals, which aims to procure 460 MW of new renewable resources, and Massachusetts enacted the 2016 Massachusetts Energy Diversity Act, which requires clean energy procurements in the range of 2,800 MW.[116] And in PJM, if the unsupported predictions of the MOPR's proponents prove wrong, the result will be a massive overprocurement of capacity estimated to cost customers $14-24.6 billion annually.[117] The Commission should not adopt a policy premised on speculation that states will abandon *en masse* policies in which they have invested for a decade and to which they have shown increasing commitment in recent years. In the CASPR Order, the Commission found that clean energy "will be developed by the operation of state environmental and clean

[114] DC/MD/NJ Ratepayers Protest at 22.

[115] The ratepayer advocates also aver that RPS programs are different because they are "designed to bring new resources … online," rather than to "prevent[] the retirement of … older facilities." DC/MD/NJ Ratepayers Protest at 22. This is backwards: PJM's MOPR has only ever applied to *new* resources, precisely because those resources are better vehicles for buyer-side market power. *See* Exelon Protest at 39-40. The ratepayer advocates assert that the "long lead time for new entry" provides time for the market to "anticipate[] and absorb[]" these resources. DC/MD/NJ Ratepayers Protest at 22. But to the extent this argument is meant to distinguish RPS programs from the ZEC Program, it does not. Nuclear generators have been in operation for decades, and have been part of the markets from their origin. Market prices have always accounted for their operation.

[116] CASPR Order, at P 4.

[117] Clean Energy Advocates Protest at 105 & Grogging Aff. at PP 3-4, 15; *see* Exelon Protest at 46-48.

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energy mandates, whether that capacity clears the [market] or not."[118] There is no reason to think that PJM states will act any differently.[119]

MOPR proponents say that if states do not acquiesce to the "disincentive" provided by an expanded MOPR, the overprocurement is states' fault.[120] But this ignores the FPA's jurisdictional lines. States regulate generation, while capacity requirements—how much must be procured, and what resources count toward satisfying the administratively determined obligations—rest with the Commission.[121] So if capacity is procured inefficiently—or if more capacity is procured than is needed to ensure resource adequacy, because the Commission is ignoring capacity provided by state-supported resources—that error is squarely within the Commission's domain. Moreover, proponents of the MOPR-Ex badly disrespect state authority in claiming that states can avoid overprocurement by relinquishing the ability to legislate to protect their citizens' health and welfare. Never has the Commission sought to deter states from implementing legitimate environmental policies in their domain by punishing their citizens—and those elsewhere in PJM, too—with unnecessary capacity costs. Instead, the Commission has made sure to accommodate those policies.[122]

MOPR's proponents also have no answer to the price suppression in energy markets this overprocurement will yield. PJM identified this problem in its filing.[123] Yet the MOPR's proponents barely attempt to respond. The Commission cannot approve an expanded MOPR when the problems it creates may be larger than the problems it purports to solve.[124]

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[118] CASPR Order, at P 45.
[119] *See* Willig Decl. ¶ 73.
[120] EPSA Protest at 26, 28-29.
[121] *See Conn. Dep't of Pub. Util. Control*, 569 F.3d at 481.
[122] *Supra* at 19.
[123] PJM Filing at 57.
[124] Exelon Protest at 46-48; *see* Willig Decl. ¶ 74.

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Finally, the MOPR's proponents cannot account for the CASPR Order, which made clear that the Commission's policy is to accommodate rather than countermand state initiatives. This policy is not new: more than a decade ago, the Commission likewise emphasized that it must, whenever possible, "fulfill [its] jurisdictional responsibilities while also respecting the states' traditional role."[125] MOPR proponents make much of the CASPR Order's statement that the Commission would use "the MOPR as our standard solution" "[a]bsent a showing that a different method would" be effective.[126] But that statement referred to ISO-New England's narrower MOPR applying to only new resources, and even then, only two Commissioners endorsed it. The CASPR Order's actual *holding* was that ISO-New England's proposed reforms were just and reasonable precisely because the Commission concluded that they would succeed in ISO-England's goal of reasonably "accommodat[ing] state sponsored resources … over time."[127] Moreover, Exelon and the PSEG Companies respectfully suggest that it would be unwise for the Commission to establish a rule that it will apply the MOPR unless a different "market design proposal[]" is "developed by [an RTO] and [its] stakeholders,"[128] and is "the result of extensive compromise."[129] Under that rule, stakeholders that will financially benefit from an expanded MOPR—like EPSA's fossil-fuel generators—will never compromise, knowing that a default Commission action will award them what they cannot achieve through negotiation.

[125] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1117 (2006).
[126] CASPR Order, at P 22.
[127] *Id.*, at P 102.
[128] EPSA Protest at 24 (quoting CASPR Order, at P 62,098 (LaFleur, Comm'r, concurring in part)).
[129] *Id.* (quoting CASPR Order, at 62,099 (Powelson, Comm'r, dissenting)).

C. If The Commission Finds That It Cannot Approve Either Of PJM's Proposals, It Should Not Proceed Under Section 206.

A few stakeholders urge that, if the Commission rejects both Capacity Repricing and MOPR-Ex, it should proceed under Section 206 and craft new rules itself.[130] Exelon respectfully suggests that this would be a mistake. It would require the Commission to carry the dual burdens of showing that "existing rates are 'entirely outside the zone of reasonableness,'" and that the solution crafted by the Commission is just and reasonable.[131] In turn, that would require the Commission to show, based on substantial evidence, that it is necessary for just and reasonable rates to raise prices at a time of vast oversupply, and to apply PJM's MOPR for the first time to existing resources receiving payments for their clean-energy benefits under state environmental programs. The Commission would also have to craft new rules that avoid all of the fatal flaws that parties have correctly identified in PJM's proposals, and amass a majority of Commissioners to support them. The Commission should not embark on this venture. No imminent—or even foreseeable—threat to reliability or investment has been shown, and the Commission should instead simply reject PJM's filing.

[130] *See, e.g.*, *id.* at 2; NRG Protest at 1.
[131] *NRG*, 862 F.3d at 114 n.2; *see Mkt.-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utilities*, 123 FERC ¶ 61,055, at P 24 (2008).

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CONCLUSION

The Commission should reject PJM's filing as not just or reasonable.

Dated: May 22, 2018

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 22nd day of May, 2018.

/s/ *Marianne Alvarez*

_____

Marianne Alvarez
Exelon Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. EL18-178-000**
PJM Interconnection, L.L.C.	)	**ER18-1314-000**
	)	**ER18-1314-001**
Calpine Corporation, et al.,	)	**EL16-49-000**
Complainants,	)	**(Consolidated)**
v.	)	
PJM Interconnection, L.L.C.,	)	
Respondent.	)	

MOTION FOR LEAVE TO ANSWER AND ANSWER OF EXELON CORPORATION

Pursuant to Rules 212 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("the Commission"), 18 C.F.R. §§ 385.212 and 385.213 (2014), Exelon Corporation ("Exelon") hereby moves for leave to submit this Answer to address an issue raised in reply comments that is crucial to the functioning of the resource-specific Fixed Resource Requirement ("FRR-RS") Alternative proposed by the Commission: the relative roles of the states and the Commission in the procurement of capacity. In reply comments by PJM Interconnection, L.L.C. ("PJM"), Direct Energy and NextEra Energy Resources ("Direct/NextEra"), NRG Power Marketing LLC ("NRG"), the Electric Power Supply Association ("EPSA"), and LS Power

Associates, L.P. ("LS Power"),[1] there have been suggestions that the Commission's jurisdictional responsibilities, and specifically its exclusive authority to set just and reasonable wholesale rates, limit the ability of states to utilize the proposed capacity market opt-out. This limited Answer addresses those arguments and the guidance needed from the Commission for states to implement the FRR-RS Alternative. It also addresses the Commission's intervening decision in *CXA La Paloma, LLC*, 165 FERC ¶ 61,148 (2018).

MOTION FOR LEAVE TO ANSWER

Exelon respectfully requests that the Commission permit this Answer to arguments made for the first time in reply briefs concerning the scope of states' role in capacity procurements undertaken pursuant to the FRR-RS Alternative (or in PJM's terminology, the Resource Carve-Out ("RCO")); the Commission's jurisdiction over the rates paid to resources under those procurements; the ability of suppliers to rely on market-based tariffs to make sales pursuant to state-sponsored capacity procurements; and the applicability of the Commission's affiliate rules to such transactions.[2] Certain parties have also made new arguments concerning the allocation of capacity participating in the resource-specific FRR to load. These issues are critically important to the successful design of the resource-specific FRR. The Commission has also issued a new

[1] *See* Reply Submission of PJM Interconnection, L.L.C. (Feb. 6, 2018) ("PJM Reply"); Reply Comments of Direct Energy and NextEra Energy Resources (Nov. 6, 2018) ("Direct/NextEra Reply"); Reply Brief of NRG Power Marketing LLC (Nov. 6, 2018) ("NRG Reply Br."); Reply Brief of the Electric Power Supply Ass'n (Nov. 6, 2018) ("EPSA Reply Br."); Reply Brief of LS Power Assocs., L.P. (Nov. 6, 2018) ("LS Power Reply Br.").

[2] As explained in our reply brief, the mechanics of the FRR-RS proposal endorsed by ratepayer advocates, environmental organizations, renewable advocates, and nuclear generation owners including Exelon are generally similar to the RCO proposal offered by PJM. *See* Reply Brief of Exelon Corporation (Nov. 6, 2018) at 1 n.2 ("Exelon Reply Br."); *id.* at 42-44. Differences between those two proposals are addressed in a variety of reply comments, including our own, and are not repeated here. As noted in those replies, however, there is widespread agreement that any expansion of the Minimum Offer Price Rule ("MOPR") must be paired with a workable state accommodation mechanism such as the FRR-RS or RCO.

order in *CXA La Paloma* which bears on issues in this docket. Accordingly, Exelon respectfully suggests that its Answer will assist the Commission in its decisional process as the Commission evaluates the comments it has received.[3]

ANSWER OF EXELON CORPORATION

In this docket, the need for clear guidance from the Commission is unusually significant. The FRR-RS Alternative envisioned by the Commission's Order can be a significant step forward, but it will require many states to make legislative or administrative changes authorizing the procurement of resources outside of PJM's market. Clarity is thus essential: when legislators or regulators convene to hammer out new legislation or rules, they must know the parameters within which they are operating. The Commission should avoid putting states in the position of undertaking time-intensive legislative or regulatory changes only to later find out after subsequent clarifications from the Commission that further actions are needed or, worse yet, that prior actions are exposed to unforeseen litigation risk.

Importantly, the Commission's order in this docket will lay the ground rules for clean energy policy going forward for the fourteen jurisdictions in the PJM footprint. While some parties appear to believe that this case is only about how to treat existing programs,[4] states have far greater clean energy ambition than is represented by existing laws.[5] The Commission's order must give

[3] The Commission has allowed answers to protests where the answer provides information that will assist the Commission in its decision. *See, e.g.*, *Southwest Power Pool, Inc*., 113 FERC ¶ 61,014, at P 7 (2005); *Southwest Power Pool Inc*., 112 FERC ¶ 61,319, at P 56 (2005); *see also Midwest Indep. Transmission Sys. Operator, Inc*. 116 FERC ¶ 61,140, at P 18 (2006); *PJM Transmission Owners*, 115 FERC ¶ 61,345, at PP 10, 12 (2006).

[4] For example, PJM contends that the Extended RCO proposal will not significantly increase customer costs because only three nuclear plants are likely to be removed from the supply stack. PJM Reply at 28. That ignores the reality of the climate challenge and the commitment of states to increase their clean energy ambition.

[5] In 2018, voters elected seven new governors who promoted 100 percent clean energy by 2050. If those promises result in policies, nearly one in five states will have such policies. *See, e.g.*, Jeff

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guidance not just to states that have already acted, but to those that wish to expand clean energy investments in the future. To the extent that the Commission adopts its Order's preliminary view that a MOPR is justified when states provide additional compensation to clean energy resources, thus depriving many of those resources a capacity payment, states will need to understand how they may compensate those resources for providing capacity. Answers to the following questions are needed to formulate legislation and regulations:

- **What products should be procured from FRR-RS resources?**

A state that wishes to incentivize investment in clean energy resources will need to decide how to structure its procurement of resources under the FRR-RS construct. In recognition of the state's authority under the Federal Power Act to regulate both the procurement decisions of its utilities and the generation facilities serving its citizens, the Commission should afford states flexibility to decide how to structure procurements under the FRR-RS construct. Some states may wish to procure "clean capacity"—that is, a capacity-only product—and therefore limit procurement eligibility to non-emitting resources. Other states may choose to procure capacity from zero-emitting resources and also provide a separate compensation scheme for environmental attributes through a supplemental, unbundled transaction. Still other states may seek to procure capacity bundled with environmental attributes. The Commission should allow states freedom to choose the structure that best serves the state's policy goals and administrative structures.

NRG argues that states should be forbidden from procuring capacity from FRR-RS resources and should only be permitted to procure state-jurisdictional products such as environmental attributes.[6] That approach makes no sense. FRR-RS resources will be providing

McMahon, "These Seven New Governors May Be The Biggest Election Boon For Climate And Clean Energy," *Forbes*, Nov. 13, 2018, https://bit.ly/2A9ReaW.

[6] NRG Reply Br. at 13-14.

capacity to the system and will be subject to all of the requirements of Capacity Performance resources. Given that PJM is receiving capacity from these resources and treating them as Capacity Resources for purposes of their performance obligations, FRR-RS resources must receive compensation for providing that product. The purpose of the FRR-RS, as expressed in the Commission's June 29, 2018 Order, is to allow compensation for capacity to flow outside the RPM auction through a state-directed mechanism.[7] The only rule that is consistent with this purpose is one allowing states to procure capacity from FRR-RS resources (whether by itself or bundled with attributes) and to arrange for those resources to be compensated for the capacity they provide. Moreover, NRG's rule would be incompatible with existing state procurements that the Commission has long accepted, such as New Jersey's Basic Generation Service ("BGS") procurement and Maryland's Standard Offer Service procurement, which already procure capacity bundled with other products.[8]

EPSA and Direct/NextEra, meanwhile, take the opposite position and contend that an FRR-RS resource should be compensated *only* for capacity and should not be permitted to sell that capacity bundled with environmental attributes.[9] According to them, "irrespective of how a given state subsidy may have been characterized for other purposes, that subsidy must be included in the

[7] 163 FERC ¶ 61,236, P 162 (2018) ("[T]he bifurcated capacity construct should make more transparent which capacity costs are the result of competition in the capacity market and which capacity costs are being incurred as a result of state policy decisions.") ("Order").

[8] *See, e.g.*, "Overview," bgs-auction.com ("The winners of the BGS-RSCP Auction become BGS-RSCP suppliers and are responsible for fulfilling all the requirements of a PJM Load Serving Entity (LSE) including capacity, energy, ancillary services, transmission, and any other service as may be required by PJM."), http://www.bgs-auction.com/bgs.auction.overview.asp; Maryland Standard Offer Service Model Full Requirements Service Contract at 4 (defining "full requirements" to include capacity), https://bit.ly/2OSem2I.

[9] EPSA Reply Br. at 22; Direct/NextEra Reply at 9.

deemed price for the associated capacity in an RCO/FRR Alternative transaction."[10] The Commission should reject that position as well. The Commission has long held that states have authority to create environmental attributes, which are "state-created and state-issued instruments certifying that electric energy was generated pursuant to certain requirements and standards."[11] Moreover, the Commission has permitted attributes to be bundled for sale with Commission-jurisdictional products,[12] and nothing in the Commission's rules or practices precludes a bilateral transaction for capacity bundled with attributes. There is no reason for the Commission to apply any different rule when that bilateral transaction is entered pursuant to the FRR-RS framework—particularly when the existence of the attribute payments is what triggers a resource's eligibility for the FRR-RS Alternative to begin with.

PJM, meanwhile, argues that FRR-RS resources *must* sell attributes in addition to capacity, and *cannot* be compensated for capacity alone.[13] Thus, for example, PJM argues that a state-directed payment for capacity cannot itself count as a subsidy triggering eligibility for the FRR-RS, and that eligibility for the FRR-RS should be limited to resources that already have a separately established material subsidy. That limitation also makes no sense. Attribute payments, and state capacity procurements limited to resources meeting state policy objectives, are two identical paths to the same destination. If a state wishes to recognize the value of clean generation, it can do so through attribute payments such as RECs or ZECs, either unbundled or bundled with capacity. Alternatively, the state can simply procure capacity that is clean, and value that clean capacity in

[10] EPSA Reply Br. at 22.

[11] *WSPP, Inc.*, 139 FERC ¶ 61,061 at P 21 (2012).

[12] *Id.* at P 15.

[13] PJM Reply at 13-14.

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accordance with the benefits it provides.[14] Under such a procurement, the only product procured would be capacity, but eligibility would be limited to the types of resources that can satisfy the state's public policy goals. The public policy value these resources provide to the state would be reflected in "clean capacity" prices that would likely be higher than the RPM clearing price. This higher price, in substance, reflects the incremental value to the state of the environmental attribute: additional revenues are being provided to these resources—in the form of clean capacity payments—in recognition of their public policy value. The FRR-RS mechanism should therefore be available to states pursuing either of these procurement paths. Restricting the FRR-RS mechanism to those states that first establish a material subsidy, and then separately procure capacity through the FRR-RS, would be illogical, unnecessarily complicated, and inconsistent with the Commission's stated goal of respecting state authority.

In sum, the Commission should reject the mutually incompatible rules proposed by NRG, EPSA, Direct/NextEra, and PJM that would restrict state flexibility. All of the various approaches that states might elect, and that one or another commenter seeks to forbid—payments for capacity separate from the unbundled sale of attributes; payments for capacity bundled with attributes; and payments for "clean capacity"—have the same substantive outcome: they are methods by which the state can ensure the new entry and continued operation of resources important to the state's public policy goals, without relying on RPM market revenues. The Commission should not force legislatures or state agencies to select one over the other. Instead, the Commission should afford states the maximum flexibility in deciding how to arrange payments to FRR-RS resources.

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[14] *E.g.*, Specified State Agencies and Electric Distribution Companies in Connecticut, Massachusetts, and Rhode Island, Notice of Request for Proposals from Private Developers for Clean Energy and Transmission (Nov. 12, 2015), https://cleanenergyrfpdotcom.files.wordpress.com/2015/11/clean-energy-rfp-final-111215.pdf (seeking procurement of clean energy, RECs, or clean energy bundled with RECs).

- **How should a state select the resources to be compensated under the FRR-RS framework?**

Just as states require their load-serving entities to acquire a certain number of RECs or ZECs, so too states will determine the quantity of FRR-RS resources they seek to compensate outside the RPM market. In making that determination, states will need to evaluate which resources are to be selected to receive such compensation. In light of states' broad authority to regulate their load-serving entities' procurement decisions,[15] the Commission's Order should affirm the ability of states to tailor selection procedures to the particular energy goals within the state. Some states, for example, may choose to hold competitive procurements open to certain types of technologies (for example, non-emitting resources), in which the state would receive bids and select the winning bidders either directly through a power agency or indirectly through regulated load-serving entities. In selecting winning bidders, some states may wish to base their decision on price factors alone. Other states may seek to maximize the environmental benefits they receive from the procurement—and the most cost-effective set of resources from the standpoint of the state's ultimate environmental goal may not be the same as the cheapest set of resources.[16] Still other states may adopt a "clean peak" standard or a "clean capacity" portfolio standard and allow LSEs to enter bilateral contracts with resources that satisfy state eligibility

[15] *See, e.g.*, *S. Cal. Edison Co.*, 70 FERC ¶ 61,215, 61,676 (1995) (acknowledging "that resource planning and resource decisions are the prerogative of state commissions and that states may wish to diversify their generation mix to meet environmental goals in a variety of ways," and that a "state may choose to require a utility to construct generation capacity of a preferred technology or to purchase power from the supplier of a particular type of resource").

[16] For example, under the Illinois ZEC program, the Illinois Power Agency selected resources based upon their environmental contribution to Illinois. *See* Illinois Power Agency, Zero Emission Standard Procurement Plan (Oct. 31, 2017), at 32-45, https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/Zero-Emission-Standard-Procurement-Plan-Approved.PDF.

requirements. The Commission's Order should not impose arbitrary limits on the ability of states to choose the procurement structure that best fits the state's public policy needs.

- **What rate should be paid to FRR-RS resources?**

Just as states must know how they may procure capacity under the FRR-RS, they also must know how they can compensate FRR-RS resources for that capacity. The Commission, of course, retains the final word on whether payments for capacity are just and reasonable, and its Order must provide guidance to states on how the Commission will make such a determination in the context of compensation paid under an FRR-RS arrangement. The state's involvement in procuring FRR-RS resources—and the ability of the state to decide *not* to procure FRR-RS resources if the price is too high, as well as the seller's ability to decline to participate as an FRR-RS resource if the price is too low—should give the Commission comfort that rates emerging from state-directed procurement processes remain just and reasonable, and reflect an appropriate balance between investors' interests in receiving sufficient compensation to operate and consumers' interests in not overpaying. Accordingly, as discussed further below, the Commission should affirm that market-based rate sellers may use existing authority to make FRR-RS sales, subject to EQR reporting. This approach affords leeway to states—whose citizens, after all, will be paying for the resources—without in any way ceding the Commission's jurisdiction over wholesale sales or its ultimate responsibility to ensure that all wholesale rates are just and reasonable.[17]

[17] *See California ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1013 (9th Cir. 2004) (upholding market-based rate authority premised on reporting requirements to FERC to enable FERC review for justness and reasonableness); *La. Pub. Serv. Comm'n v. FERC*, 761 F.3d 540, 552 (5th Cir. 2014) (upholding FERC's incorporation of a state commission-determined depreciation expense into the federal rate, even though the state commission's method for calculating depreciation diverged from FERC's own method, because "FERC exercised its role when it initially reviewed and accepted the … formula incorporating the state agencies' depreciation rates" as just and reasonable, and because "FERC has clarified that it will continue to exercise oversight of the state rates in a Section 206 complaint proceeding."); *La. Pub. Serv. Comm'n v. FERC*, 860 F.3d 691, 696 (D.C. Cir. 2017) ("[W]e … conclude that there has been no unlawful subdelegation because FERC has exercised,

PJM contends that under no circumstances can a state arrange for an FRR-RS resource to be compensated for its capacity at a price pegged to the RPM clearing price.[18] That limitation is irrational. States are free to compensate FRR-RS resources as they see fit, so long as the capacity price is just and reasonable. And the RPM clearing price plainly is a just and reasonable price for the capacity commitment that an FRR-RS resource would make. PJM nevertheless contends that such an arrangement would be inappropriate because the FRR-RS resource has elected not to participate in the RPM auction.[19] But an FRR-RS resource does not receive any compensation from the RPM auction. Instead, it relies on state-directed compensation paid outside the auction. If a state wishes to ensure that its citizens pay no more for capacity outside the auction than they would inside the auction, and therefore proposes that the FRR-RS resource be compensated at a rate pegged to the RPM clearing price, there is no basis for the Commission to conclude that such a rate would be unjust or unreasonable.[20]

Indeed, under the existing FRR tariff provisions, which FERC has found just and reasonable, the unconstrained RPM clearing price is the default rate that load-serving entities in a restructured state are to be charged for capacity procured by the FRR entity, absent an alternative state compensation mechanism.[21] In the context of bilateral transactions as well, the Commission

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and intends to continue to exercise, its § 206 review authority."); *Coalition for Fair & Equitable Regulation of Docks on Lake of the Ozarks v. FERC*, 297 F.3d 771, 779 (8th Cir. 2002) (rejecting subdelegation challenge to license where "FERC retains authority to require the modification of the project and its plans and specifications, to accomplish the outlined goals…. Therefore, the license represents no real delegation of power …, because FERC retains the right to require modification of … [the] program.").

[18] PJM Reply at 23.

[19] *Id.*

[20] For example, a state might adopt this approach with respect to resources that separately sell unbundled environmental attributes.

[21] *See PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,164, at P 3 (2013) (quoting PJM Reliability Assurance Agreement Sched. 8.1 § D.8: "In the absence of a state compensation mechanism, the

contemplates that contracting parties will use prices emerging from the Commission's auction markets as indices or benchmarks for transactions outside those markets.[22] Thus, Commission precedent supports the ability of states, subject to Commission review and supervision, to peg the capacity rate to be paid to FRR-RS resources to the RPM clearing price.

PJM cites two paragraphs of the Commission's Order that, it claims, hold that "subsidized resources should not be paid the same as non-subsidized Capacity Resources."[23] PJM is mischaracterizing the Commission's Order. The Order said that PJM's *repricing* proposal was not just or reasonable because subsidized resources should not receive the same capacity price as unsubsidized resources "for purposes of ratemaking *in PJM's FERC-jurisdictional wholesale capacity market*"—i.e., in the RPM auction.[24] But under the FRR-RS approach, subsidized resources do not participate in PJM's wholesale capacity market. Consistent with the Order, such resources are subject to a "different ratemaking treatment"[25]—the rate they are paid is derived from the state's procurement process, not the RPM market rules. If the state decides to pay such

applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act [FPA] proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA."); *see also* Reliability Assurance Agreement Sched. 8.1 App. (stating, with respect to the Ohio Power Company, "[f]or purposes of administering the state compensation mechanism, the wholesale rate shall be equal to the adjusted final zonal PJM RPM rate in effect for the rest of the RTO region for the current PJM delivery year").

[22] *See, e.g.*, *Price Discovery in Natural Gas and Electric Markets*, 109 FERC ¶ 61,184, at P 42 (2004) (noting that "price indices are widely used" in transactions undertaken pursuant to market-based rate authority).

[23] PJM Reply at 23 (citing Order at PP 67-68).

[24] Order at P 68.

[25] *Id.*

resources a capacity rate that is pegged to the RPM auction price, that rate is still a function of the state's procurement process, and thus is fully consistent with the Commission's Order. The Commission should expressly confirm that states are free, if they wish, to peg capacity payments made under the FRR-RS framework to RPM clearing prices.

While some states may choose to peg FRR-RS capacity payments to the RPM clearing price, other states may choose a different approach. Thus, the Commission should also make clear that the RPM price is not the *only* just and reasonable price for capacity, and that different approaches to procuring capacity from FRR-RS resources may result in different capacity rates, each of which may be just and reasonable. For example, some states may wish to procure clean capacity through an auction mechanism and pay a single clearing price to the resources that are selected. Such an approach will likely result in a capacity price that is higher than the RPM clearing price. But the state is getting a product that is different from the generic resource adequacy product sold through the RPM auction: for example, the state may be procuring zero-emitting capacity that is more valuable to the state, in light of its public policy priorities, than generic capacity.[26] Indeed, no party has responded to the extended discussion in Exelon's brief, and the briefs of other parties, regarding the existence of environmental externalities and the importance of addressing those externalities in order to promote more efficient markets.[27]

[26] *CXA La Paloma, LLC*, 165 FERC ¶ 61,148, at PP 12, 77 (2018) (rejecting argument that CAISO capacity market is unjust and unreasonable because renewable resources procured through state-administered procurements are paid four to seven times more for their capacity than resources receive through the CAISO resource adequacy construct).

[27] Initial Br. of Exelon Corp. (Oct. 2, 2018) at 13-14 ("Exelon Init. Br."); Protest of Exelon Corp., Docket No. ER18-1314 (May 7, 2018), at 12-25; Decl. of Robert D. Willig at 17-28, Ex. A to Protest of Exelon Corp., Docket No. ER18-1314 (May 7, 2018); Comments of Inst. for Policy Integrity at N.Y.U. School of Law (Oct. 2, 2018) at 6-18, 25-32; Exelon Reply Br. at 29-35.

As noted above, states also might have different preferences as to the particular products they wish to procure, with some procuring a clean capacity (capacity-only) product, and other states procuring capacity bundled with attributes. Sales might be made in some FRR-RS procurements through cost-based contracts akin to reliability must-run arrangements, subject to Commission review under Section 205. In the normal course, however, transactions under an FRR-RS procurement are more likely to be undertaken pursuant to a seller's market-based rate authorization, with the terms and conditions of transactions reported on the EQR. With respect to bundled procurements of capacity and attributes, the Commission has recognized that bundled contracts sometimes separately state a price for each of the bundled products, and sometimes do not.[28] In the event that the Commission may need to review the justness and reasonableness of market-based payments for a bundled FRR-RS procurement (such as in response to a complaint or if the Commission believes it must review affiliate transactions), the Commission should create a safe harbor in its upcoming order for a bundled price that is less than or equal to the sum of the RPM price and any explicit state valuation of the attribute. For example, some states have chosen explicitly to value the state-jurisdictional attribute as equal to the social cost of carbon abated through clean production.[29] If the bundled rate is less than the sum of the RPM price and the attribute value assigned by the state (in this example, the social cost of carbon), then the Commission should treat the bundled rate as falling within the safe harbor. Customers are paying no more for capacity than they would pay through the RPM auction, and are paying no more for attributes than the state has determined those attributes are worth to it.[30]

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[28] *WSPP, Inc.*, 139 FERC ¶ 61,061, at PP 15, 24 (2012).

[29] *See, e.g.*, 20 ILCS 3855/1-75(d-5)(1)(B)(i) (Illinois); State of N.Y., Pub. Serv. Comm'n, Order Adopting a Clean Energy Standard, Case 15-E-0302, Case 16-E-0270 (Aug. 1, 2016), at 131-35.

[30] *See Boston Edison Co.*, 55 FERC ¶ 61,382, 62,169 (1991) (recognizing, in context of affiliate transactions, that justness and reasonableness can be established by "benchmark evidence which

States may also wish to adopt price caps and other mechanisms intended to protect retail customers from paying more to FRR-RS resources than those customers can afford to pay, or paying more to FRR-RS resources than those resources are worth to the state. Such measures will of course impact the capacity price ultimately received by the FRR-RS resources. But so long as the Commission retains ultimate review authority to ensure the justness and reasonableness of the price, and the power to override or disallow any rate derived from the state-directed process, the Commission does not cede its jurisdiction—and states do not intrude on its jurisdiction—when states decide how much they are willing to direct customers to pay to FRR-RS resources.[31]

- **Through what mechanism will the Commission review the rates paid to FRR-RS resources?**

States, of course, are not public utilities and would not themselves file rates with the Commission under Section 205. Rather, FRR-RS resources, as the suppliers of capacity, will be responsible for obtaining Commission approval of the rates they will receive under the FRR-RS framework. There is no need, however, for the Commission to require individual Section 205 filings from every FRR-RS resource. As noted above, the Commission should affirm that existing market-based rate authority can be used for sales undertaken pursuant to an FRR-RS procurement, subject to the normal EQR reporting protocols so that the Commission can exercise active oversight and intervene as necessary to adjust any rates it deems unjust or unreasonable.

Several parties contend that the sale of capacity pursuant to a state-sponsored procurement cannot be made under the seller's market-based tariff.[32] According to these parties, the premise

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shows the prices, and terms and conditions of sales made by nonaffiliated sellers"); 18 C.F.R. § 2.25(c) (allowing emissions allowances to be valued based upon indexed prices).

[31] *See supra* nn. 17, 21.

[32] EPSA Reply Br. at 17-19; Direct/NextEra Reply at 11-13.

of a market-based sale is that, in a competitive market where neither the seller nor buyer have market power, one can assume that the terms of voluntary exchanges are reasonable. But under the FRR-RS, they contend, the transactions result from state regulation, not from competitive forces. However, several methods of state procurement under the FRR-RS may in fact harness competitive forces and thus satisfy the predicates for market-based rates. And regardless, the same presumption of reasonableness applied to market-based rates should likewise apply to rates resulting from state-sponsored procurements under the FRR-RS, irrespective of whether the procurements are competitive.

First, several procurement methods *directly* ensure competition, and for such procurements, sellers should continue to be able to rely on their market-based tariffs. For example, if a state conducts a clean energy procurement open to all non-emitting resources able to serve the state's load, and imposes rules such as bid caps that limit any party's ability to exercise market power, sales taking place pursuant to that procurement should be permitted under the sellers' market-based tariffs. Indeed, such a procurement is no different than the many types of state-sponsored procurements that already exist today, in respect to which sellers rely on their market-based tariff. For example, the Illinois Power Agency currently procures capacity for Ameren's non-shopping customers by holding a procurement event, receiving bids, and selecting the winners.[33] The resulting sales of capacity are made pursuant to the sellers' market-based tariffs. Similarly, several states in PJM—including New Jersey and Maryland—conduct procurement events to obtain a bundled product of energy and capacity to be supplied to non-shopping

[33] *E.g.*, Illinois Power Agency, Electricity Procurement Plan: 2018 Plan (Sept. 25, 2017) at 70 (recommending "procurement of a portion of the Ameren Illinois capacity needs for the 2017-2018 and 2018-2019 delivery years through bilateral capacity purchases obtained through the IPA competitive procurement process, with the remainder of its capacity needs procured through the MISO PRA.").

customers.[34] The resulting sales are made pursuant to sellers' market-based tariffs. Likewise, three New England states conducted a joint procurement of energy from qualifying non-emitting generators and, again, sales were made pursuant to the sellers' market-based rate authority.[35] And these are just a few examples. If the Commission were to deny the ability of sellers to rely on their market-based tariffs in making sales pursuant to state-directed FRR-RS procurements, it would call into question whether sellers in any of these other state-directed procurements have authority for their transactions.

Second, even where states do not employ a competitive procurement, the Commission would still be justified in allowing market-based rate sellers to rely on existing authorization, as long as the seller complies with EQR reporting so that the Commission can oversee the rates. Just as competitive forces prevent a supplier from exercising market power, thus justifying the Commission's ex ante approval of whatever rate emerges from the competitive process, so too under the FRR-RS framework, the state's political control prevents a supplier from exercising market power. The state acts *in parens patriae* on behalf of its citizens, and nothing requires the state to direct its load to enter into the procurement of the FRR-RS resource. The state is not captive to the resource seeking compensation under an FRR-RS framework; to the contrary, the resource is captive to the state. The state has tremendous power to ensure that its citizens pay a just and reasonable price, and the resulting transaction will be the product of a voluntary decision by the seller to sell and a political decision by a democratically accountable state government to buy. Just as the Commission has made the judgment that competitive market forces by and large will produce just and reasonable rates, so too it should make the judgment that the state's

[34] *See supra* at n.8.

[35] *See* Draft PPA, RPS Class I Renewable Draft PPA, § 3.5(l), *available at* https://cleanenergyrfp.com/documents/.

involvement in overseeing a procurement will by and large produce just and reasonable rates, justifying ex ante approval accompanied by ex post reporting.[36]

For similar reasons, and contrary to the suggestion of several parties,[37] the Commission should allow waiver of its affiliate rules for state-directed procurements of FRR-RS resources. As Exelon has already explained in its Initial Brief, and as EPSA acknowledges, the purpose of the affiliate rules is to prevent "the risk of self-dealing and other affiliate abuse that arises when a franchised utility transacts with its affiliates."[38] As the Commission explained in *Edgar*, in an affiliate transaction, "the rate may not be just and reasonable because the buyer potentially may have unduly favored the rates offered by its affiliate seller over lower rates offered by other nonaffiliate sellers."[39] That concern is absent when the load is directed by the state to enter into the transaction, and takes place only if the state chooses to go forward. In those circumstances, the franchised utility has no ability to favor its affiliates, and the generator has no ability to use its affiliate relationship with the utility in order to extract higher prices than it would otherwise be able to obtain. After all, the transaction takes place at the state's direction and following the state-sponsored procurement process, and the state has no incentive to force customers to pay any more than the minimum needed to procure the resource. Accordingly, the Commission should allow

[36] Such a judgment is particularly warranted when the state benchmarks its capacity price to the RPM clearing price—a rate that emerges from a competitive auction process and that the Commission has determined is just and reasonable. As the Commission has held in the context of affiliate transactions, a market-based benchmark can establish the justness and reasonableness of prices emerging from a non-competitive process. *Boston Edison Co.*, 55 FERC ¶ 61,382, 62,169 (1991) (holding that affiliated seller may rely on "benchmark evidence which shows the prices, and terms and conditions of sales made by nonaffiliated sellers").

[37] EPSA Reply Br. at 19-22; Direct/NextEra Reply at 14-17.

[38] EPSA Reply Br. at 20.

[39] *Boston Edison Co.*, 55 FERC ¶ 61,382, 62,167-68 (1991).

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state-directed affiliate transactions to take place under an FRR-RS framework without requiring an individual Section 205 filing.[40]

- **How should FRR-RS capacity be allocated to load-serving entities?**

The Commission must also give clear guidance concerning how FRR-RS capacity should be allocated to load-serving entities, and how much flexibility states have in assigning that capacity to load-serving entities within their jurisdiction. NRG accuses Exelon of having argued that resources that elect the FRR-RS framework should be able to decide unilaterally what load should be credited with their capacity.[41] That is not our position. While the FRR-RS resource should have the obligation to *inform* PJM which load is matched to its capacity, the *decision* as to which load should be matched is one that the relevant state should make (except, of course, in the event of a bilateral capacity contract that the state has not directed).[42] Exelon supports a default rule, consistent with the default rule currently in place for the existing FRR, that the capacity of FRR-RS resources will be allocated on a pro rata basis to load-serving entities within the state that is supporting the FRR-RS resource.[43] Contrary to the arguments made by some commenters, this approach is easy for PJM to administer using existing accounting mechanisms. Currently, PJM

[40] Even if a Section 205 filing were required, the Commission should still adopt a safe harbor under which the rate for a bundled purchase of capacity and attributes is deemed just and reasonable if it less than the sum of the RPM clearing price and the explicit state valuation of the attributes being procured. *See supra* at 13. It should also find an affiliate transaction to be just and reasonable if the capacity price is pegged to the RPM clearing price, which is the kind of "benchmark evidence which shows the prices, and terms and conditions of sales made by nonaffiliated sellers" that should dispel any concern of affiliate abuse. *Boston Edison Co.*, 55 FERC ¶ 61,382, 62,169 (1991).

[41] NRG Reply Br. at 10.

[42] *See* Exelon Init. Br. at 22 ("FRR-RS resources procured by a state in this manner would submit the state procurement order or other state directive to indicate the corresponding load to be removed.").

[43] PJM Reliability Assurance Agreement Sched. 8.1 § D.8.

collects payments from load and then makes corresponding payments to capacity resources. Under the proposed approach, PJM will credit load for any FRR-RS capacity that is allocated to it, and PJM will not make any RPM-related payment to the FRR-RS resource.

But the default would only apply to the extent that the state does not opt for a different allocation method for the capacity of FRR-RS resources. Nor should this default rule foreclose any state decision regarding how to allocate the *cost* of procuring FRR-RS resources. For example, a state could choose to place the cost on a Distribution Utility, which would then recover the cost through a non-bypassable charge.

- **Additional Matters, Including the Commission's Decision in *CXA La Paloma.***

Finally, we briefly address two other matters raised in reply briefs, as well as the Commission's intervening decision in *CXA La Paloma, LLC*.[44]

First, several parties support LS Power's proposal to cap the number of megawatts permitted to participate in the FRR-RS framework. Exelon opposes such a cap for the reasons it has already discussed—in particular, any cap would be arbitrary, particularly given an existing FRR framework which allows the withdrawal of an entire zone's load from the RPM auction.[45] LS Power's proposed cap improperly intrudes on states' authority to expand clean energy goals. And a cap on FRR-RS participation would be particularly unjustified if the Commission adopts PJM's proposed MOPR exemption for self-supply resources. The combination of a self-supply exemption plus an FRR-RS cap would effectively allow vertically integrated states an unlimited ability to support resources for state public policy reasons, while curtailing the ability of restructured states to do so. Both vertically integrated states and restructured states have the same

[44] 165 FERC ¶ 61,148 (2018).

[45] Exelon Reply Br. at 49-50.

inherent police power over generation facilities, and attribute payments are simply a mechanism by which restructured states can continue to exercise control over the generation mix consistent with the regulatory structure adopted by the state. There is no justification for the Commission to constrain states' abilities to achieve their public policy goals through attribute payments, while allowing states unfettered ability to achieve their public policy goals through retail rate recovery. If the Commission is going to apply a cap—and it should not—it would need to apply that cap consistently to both restructured states and vertically integrated ones, including self-supply.

Second, in defending its Extended RCO concept, PJM claims that repricing will not significantly increase customer costs. It justifies that conclusion by pointing to "simulations of the clearing price effects if the three nuclear plants likely to receive ZEC payments were removed from the supply stack."[46] But of course, these three plants will not be the only ones removed from the supply stack under PJM's proposal—and particularly as states expand their clean energy commitments and seek to induce significant new entry of renewables. PJM is assuming a static view of the world in order to justify the Extended RCO, despite previously having defended an expanded MOPR on the ground that states could be expected to significantly expand their support of clean resources in coming years.[47] Moreover, even assuming that only three nuclear plants will be removed from the supply stack, the price impact of the Extended RCO will still be very significant: nearly $2 billion per year based on PJM's own numbers.[48] Moreover, PJM

[46] PJM Reply at 28.

[47] Order at PP 102-03.

[48] PJM Reply at Attachment A. PJM calculates the total RTO costs for the status quo (labeled "Sim 1") at $8.78 billion per year and the Extended RCO (labeled "Sim 2") at $10.65 billion per year. Thus, the Extended RCO amounts to an incremental increase of $1.87 billion over the status quo. Note that this calculation does not include any costs associated with infra-marginal rent payments to the extent that those are ultimately borne by customers as well.

acknowledges that the bulk of that increase will be borne by customers in EMAAC. PJM thus fails in its attempt to downplay the very significant burden on customers that would result from the Extended RCO.

Finally, the Commission's intervening decision in *CXA La Paloma* only underscores that the proposed resource-specific FRR Alternative is a just and reasonable market design, and that opponents' contrary arguments are ill-conceived. In that case, the Commission rejected the very arguments that MOPR-only advocates make here: that a bifurcated capacity construct is unjust and unreasonable because it tends to lead to low prices in the residual market and thereby threatens resource adequacy over the long term; that the only just and reasonable capacity construct is a mandatory centralized capacity market; and that the Commission should not accommodate state authority to conduct capacity procurements aimed at achieving important state public policy goals.[49]

The Commission rejected each of these arguments in *CXA La Paloma*, and its reasons for doing so apply with equal force to the same arguments made by some of the same parties in this proceeding. The Commission noted that, notwithstanding the significant state role in overseeing capacity procurement, CAISO still had enough capacity "to reliably operate the grid, while respecting the role of local regulatory authorities, such as the CPUC."[50] Indeed, the Commission noted that the complainants had not provided "credible evidence that any … reliability violations are likely in the foreseeable future" and that "the current resource adequacy paradigm will ensure sufficient reserve margins through 2021."[51] In PJM, too, there is a large surplus of capacity, and

[49] *CXA La Paloma, LLC*, 165 FERC ¶ 61,148, at PP 9-10, 12, 15, 46-50.

[50] *Id.* at P 70.

[51] *Id.* at P 73.

the sloped demand curve ensures that prices in the RPM auction will rise if that surplus diminishes over time.[52]

The Commission also noted that the bifurcated capacity construct it had approved for California "respects the jurisdictional boundaries of the FPA while recognizing the states' historical role in ensuring resource adequacy."[53] That is so notwithstanding that the CPUC conducts capacity procurements limited to resources that advance the state's public policy goals and that result in capacity prices significantly higher (indeed, four to seven times higher) than those received through CAISO's residual resource adequacy program.[54] Likewise, the resource-specific FRR construct proposed in this docket respects state policy choices and should afford states significant flexibility in designing capacity procurements for resources of public policy interest. That construct is fully consistent with the Commission's final authority and responsibility to ensure that the rates charged for capacity are just and reasonable.[55]

The Commission further held in *CXA La Paloma* that the mere fact that low prices emerged from the competitive residual capacity market did not, "in and of themselves, demonstrate that a market is not just and reasonable," and it cited another recent proceeding in which it had rejected similar claims.[56] Thus, it concluded, "generalized claims about revenue insufficiency do not satisfy" the burden to show that a market design is unjust or unreasonable.[57] Similarly here, arguments that the FRR-RS construct will result in the continuation of low prices does not

[52] Exelon Reply Br. at 37.

[53] *CXA La Paloma, LLC*, 165 FERC ¶ 61,148, at P 70.

[54] *Id.* at P 12.

[55] Order at PP 159-62.

[56] *CXA La Paloma, LLC*, 165 FERC ¶ 61,148, at P 72.

[57] *Id.*

demonstrate that the FRR-RS construct is unjust or unreasonable. The Commission's Order in this docket properly focuses on ensuring that offers in the RPM auction are competitive and are unaffected by state subsidies—not on the ultimate price level emerging from that competitive process.[58]

The Commission also confirmed in *CXA La Paloma* that it had "not required a centralized capacity market as part of a just and reasonable market design," and cited several recent decisions in which it had affirmed a bifurcated capacity market that respected states' role in resource procurement—notwithstanding allegations that the residual capacity market yielded low prices.[59] Indeed, the Commission underscored that it "has not imposed a centralized capacity market in an RTO/ISO or found that it is the only just and reasonable resource adequacy construct to attract and retain sufficient capacity."[60] As to the eastern RTOs, such as PJM, the Commission noted that "the capacity markets" in those regions "originated through section 205 filings or developed through settlements."[61] They were not imposed by the Commission. Thus, the Commission should reject arguments made in this docket that a mandatory centralized capacity market is the only just and reasonable market design. To the contrary, the proposed resource-specific FRR Alternative is a just and reasonable approach, tailored to the specific needs and circumstances in the PJM region, that respects traditional state authority while ensuring political accountability for state decisions, preventing capacity over-procurement, and ensuring competitive offers in the auction market.

* * *

[58] Exelon Reply Br. at 24-29 (discussing the Commission's Order).

[59] *CXA La Paloma, LLC*, 165 FERC ¶ 61,148, at P 76.

[60] *Id.*

[61] *Id.*

In sum, the Commission should adopt the resource-specific FRR Alternative it proposed in its Order. However, its final Order must provide guidance on the questions detailed above, so that states can legislate with confidence. The Commission should afford states wide flexibility to design FRR-RS procurements and determine the compensation to be paid to FRR-RS resources, subject to ex post review by the Commission in the exercise of its authority to ensure the justness and reasonableness of wholesale rates.

Dated: November 21, 2018

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 21st day of November, 2018.

/s/ *Marianne Alvarez*

_____

Marianne Alvarez
Exelon Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. EL18-178-000**
PJM Interconnection, L.L.C.	)	**ER18-1314-000**
	)	**ER18-1314-001**
Calpine Corporation, et al.,	)	**EL16-49-000**
Complainants,	)	**(Consolidated)**
v.	)	
PJM Interconnection, L.L.C.,	)	
Respondent.	)	

INITIAL BRIEF OF EXELON CORPORATION

Pursuant to ordering paragraph (F) of the June 29, 2018 Order Rejecting Proposed Tariff Revisions, Granting In Part and Denying In Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act ("Order") and the August 22, 2018 Notice of Extension of Time issued by the Federal Energy Regulatory Commission ("Commission"),[1] Exelon Corporation ("Exelon") hereby submits the following comments addressing proposed changes to the Open Access Transmission Tariff ("Tariff") of PJM Interconnection, L.L.C. ("PJM"), discussed by the Commission in the June 29, 2018 Order Rejecting Proposed Tariff Revisions, Granting In Part and Denying In Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act ("Order").

[1] 18 C.F.R. § 385.212 (2017).

INTRODUCTION

The Commission's Order requesting comments reached two clear conclusions.[2] First, the Commission identified a need to protect "PJM's capacity market from the price suppressive effects of resources receiving out-of-market support by ensuring that such resources are not able to offer below a competitive price" in the RPM auction.[3] Accordingly, the Commission proposed an expanded minimum offer price rule (MOPR) "with few or no exceptions."[4] Second, at the same time, the Commission recognized that it is necessary to respect "states' right to pursue valid policy goals" concerning the generation mix and "mitigate or avoid the potential for double payment and over procurement."[5] Accordingly, the Commission requested comment on "a resource-specific FRR Alternative option" that would "accommodate such resources by allowing them to remain on the system, despite their inability to compete in the capacity market based on their costs, by permitting them to exit the capacity market with a commensurate amount of load and operating reserves."[6]

If properly designed, Exelon believes that this "bifurcated capacity construct"[7] will succeed in balancing the Commission's concern regarding the integrity of capacity market bidding with respecting state policy choices—while also increasing transparency for all stakeholders. This will only be the case, however, if the resource-specific FRR ("FRR-RS") mechanism is workable

[2] *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 (2018) ("Order").

[3] Order at P 158.

[4] *Id.*

[5] *Id.* at PP 159-60.

[6] *Id.* at P 160.

[7] *Id.* at PP 161-62. Exelon has sought rehearing of the Commission's findings in the Order that that the existing PJM tariff provisions are unjust and unreasonable. The comments herein as to the appropriate structure for the FRR-RS should not be construed as waiving, or in any way undermining, the positions taken in that request for rehearing. For purposes of these comments, Exelon is taking the Order as it now stands and proposing a path forward with respect to the FRR-RS as contemplated in that Order.

for the states. The Commission doubtless will receive comments from certain stakeholders urging the Commission to adopt a MOPR with few exceptions, as proposed, but to abandon the resource-specific FRR Alternative outright or adopt overly burdensome mechanics that would render the resource-specific FRR Alternative unusable by states.[8] Contrary to the position of these commenters, the Commission must do more than just pay lip service to states' legitimate energy policy interests. An overly burdensome or restrictive approach that states cannot readily use would be, in effect, the same as the "MOPR-Ex" rejected by the Commission. Such an approach would not be a just or reasonable balancing of the Commission's key concerns. It would result in a significant over-procurement of capacity, with the capacity market ignoring clean state-supported resources that are in fact on the system and contributing to system reliability.

Advocates of a MOPR-only solution (or of a MOPR combined with a resource-specific FRR that is difficult for states to use) may respond that the Commission should not be concerned with over-procurement, as states remain free to pay for the consequences of their policy choices. The Commission should not be persuaded by that glib response. States across PJM have set ambitious clean energy targets, and the quantity of state-supported resources is likely to increase significantly over the next decade.[9] If the Commission adopts a capacity market design that fails to recognize the existence of these resources—thereby forcing customers to procure redundant capacity, at significant unnecessary cost—the capacity markets will no longer be serving customers' interests. States would face the choice of (1) continuing to bear increasing and

[8] For example, the Commission should resist calls to require resources to commit to remaining an FRR-RS resource for an extended period of time or the life of the unit, or to impose burdensome and costly requirements on an FRR-RS resource that seeks to reenter the RPM auction. It also should not attempt to micro-manage or restrict the processes by which states might choose to select resources of public policy interest or the mechanisms by which states may choose to arrange for their compensation. As discussed further below, many resources of state public policy interest are owned by the affiliates of load-serving entities. The Commission should not allow parties to use the affiliate rules to challenge and undermine state-administered procurements of such resources.

[9] *See* PJM Filing at Attach. F (Aff. of Dr. Anthony Giacomoni & Attach. 1).

unnecessary costs to procure unneeded capacity from the PJM market, (2) withdrawing entirely from the PJM capacity market through the existing FRR (or from PJM altogether) in order to maintain their right to control the resource mix, or (3) effectively forfeiting their authority to make decisions in "their role as regulators of generation facilities" regarding how to satisfy their capacity needs.[10] Putting states to this choice is not a tenable policy. Doing so would disregard the cooperative federalist framework of the Federal Power Act, and it would weaken federal markets in the long run by pushing states to exit. Unless and until the Commission is ready to approve carbon pricing so that state clean energy policies are integrated into wholesale energy market prices, the Commission must at the very least adopt market rules with the flexibility to accommodate state policy initiatives.

To that end, Exelon supports a resource-specific FRR Alternative ("FRR-RS") that is workable for states seeking to exercise control over their generation mix, and that allows states the flexibility to conduct an out-of-market capacity procurement of the resources they wish to support for public policy reasons. States should have flexibility in designing such procurements and compensation, with resulting wholesale sales of capacity subject to the Commission's jurisdiction under the Federal Power Act and, if undertaken using market-based rate authority, reported to and monitored by the Commission through the supplier's EQR and subject to Commission review under Section 206. Resources receiving out-of-market revenue, or that have had their capacity procured by states pursuant to an out-of-market capacity procurement, would be removed from the capacity market along with matching load identified by the supplier in advance of the Base Residual Auction. Load would be matched according to bilateral agreements presented by the

[10] *Connecticut Dep't of Pub. Utility Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009); *Coalition for Competitive Electricity v. Zibelman*, No. 17-2654 (2d Cir. Sept. 27, 2018), slip op. at 12 ("The states are … authorized to regulate energy production … and facilities used for the generation of electric energy.").

supplier in the event that the FRR-RS resource has sold its capacity bilaterally, or as designated by the procuring state in the event that capacity is procured through a state-administered process. Although FRR-RS resources will be selling their capacity outside the RPM market, these resources would still be making capacity commitments to PJM pursuant to the FRR-RS, and accordingly they would take on all the obligations of Capacity Performance resources, thereby ensuring reliability.

Exelon shares this vision of a workable FRR-RS mechanism with a broad range of other stakeholders, who have agreed to a set of shared principles filed in this docket on October 1, 2018.[11] Exelon submits these additional comments to describe in greater detail how those principles should be implemented by the Commission and to address matters not otherwise addressed in those shared principles, such as the proper scope and application of the MOPR. Proposed tariff language implementing Exelon's combined proposal is attached as Attachment A.

Under our proposal, eligibility for the FRR-RS should be tied to the application of the MOPR: if a resource will be subject to a MOPR because it is receiving state support, then it should be able to exit the RPM market by electing the FRR-RS Alternative. And resources should be subject to the MOPR if they are receiving any out-of-market payments that, taken together, exceed a materiality threshold of one percent of the revenues the plant would expect to receive in the PJM markets. To the extent the Commission seeks to apply the MOPR to prevent units from bidding in the RPM auction below their going-forward costs, there is no economic rationale for applying the MOPR to resources receiving environmental attribute payments, but exempting resources receiving guaranteed cost recovery through retail rates, or development incentives that make it possible for a plant to have been built. Any such out-of-market revenue allows the resource

[11] Joint Brief of Consumer Advocates, NGOs, and Industry Stakeholders, Docket Nos. EL18-178, *et al*. (Oct. 1, 2018).

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receiving it to bid lower in the capacity market than it would otherwise be able to do, and the Commission's logic concerning the MOPR applies to all such sources of revenue. Thus, the Commission should reject PJM's definition of "Material Subsidy," which exempts from the MOPR resources receiving subsidies promoting general economic development or siting. For the same reason, the Commission should reject calls to exempt self-supply and vertically integrated resources from the MOPR. These units receive guaranteed cost recovery through retail rates, and thus they can offer into the capacity market as price takers freed from the need to make competitive offers. Given that the Commission's goal is to "ensure that all resources participating in the capacity market … offer competitively"[12]—by which the Commission appears to mean, without having their offers influenced by out-of-market revenue—the Commission must not allow a MOPR exception for any type of out-of-market support.

Requiring self-supply and vertically integrated resources to either accept a MOPR or elect the FRR-RS Alternative will not interfere with their traditional business models. A properly designed FRR-RS Alternative would give these entities all the flexibility they need to maintain their existing business models, and will not impair state oversight of their integrated resource planning. Indeed, allowing states that kind of resource-planning flexibility is the entire point of the FRR-RS Alternative. The FRR-RS Alternative will also provide sufficient flexibility for resources receiving development or siting incentives. To the extent a state is committed to siting a new generation facility within its boundaries, and the facility does not expect to clear the capacity market if its offer is mitigated, that facility can elect the FRR-RS, and the state can ensure the procurement of its capacity so that the full costs of supporting that resource are transparent to customers and policymakers.

[12] Order at P 162.

Finally, the Commission should express its willingness to entertain a Section 205 filing from PJM incorporating carbon pricing. A wide array of stakeholders, including some of those that have been most vocal in advocating a MOPR for state-supported resources, have acknowledged that carbon pricing is the most efficient approach to addressing the environmental externalities of emitting generation,[13] which is the primary driver underlying many of the state policies giving rise to this proceeding. Integrating a carbon price into PJM's markets would reduce or eliminate the need for states to address carbon emissions from the power sector in other ways, and would allow resources that will exit the RPM auction under the Commission's Order to reenter that market. PJM has explained how it can run its markets incorporating state-imposed carbon prices while respecting the choice of other states not to impose such a price,[14] and Exelon has similarly proposed ways PJM could allow for carbon pricing with border adjustments to ensure that the effects of carbon pricing are contained within those states adopting it. The Commission should direct PJM to conduct stakeholder discussions to evaluate options for integrating carbon pricing into its market rules.

[13] The following comments supportive of carbon pricing were filed on June 22, 2017 in *State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.*, Docket No. AD17-11-000: Comments of American Municipal Power, Inc. at 9-10; Comments of American Wind Energy Association at 5-7; Comments of Brookfield Renewable, Conservation Law Foundation, and NextEra Energy Resources, LLC at 1-2; Comments of Calpine Corp. at 3; Comments of Canadian Electricity Association at 4; Comments of Clean Energy Industries at 5-6; Comments of Connecticut at 12-13; Comments of Dominion Energy Services, Inc. at 7; Comments of Dynegy Inc. at 4; Comments of Electric Power Supply Association at 8-9; Comments of Independent Market Monitor for PJM at 10; Comments of Invenergy Wind Development LLC, Invenergy Thermal Development LLC, Invenergy Storage Development LLC, and Invenergy Solar Development LLC at 5; Comments of Independent Power Producers of New York, Inc. at 2; Comments of Massachusetts Department of Public Utilities at 6; Comments of New England States Committee on Electricity at 10; Comments of New York Power Authority at 6-7; Comments of Nuclear Energy Institute at 2; Comments of Noble Environmental Power, LLC at 3; Comments of Natural Resources Defense Council and Sustainable FERC Project at 1; Comments of NRG Energy, Inc. at 4, 13; Comments of PJM Interconnection, L.L.C. at 4-5, 10; Comments of Andrew G. Place, Vice Chairman, Pennsylvania Public Utility Commission at 2-3; Comments of PSEG Companies at 10-11; Comments of Perry D. Robinson at 2-3; Comments of Shell Energy North America (US), L.P. at 14; Comments of Solar Energy Industries Association at 1-2; Comments of Vitol Inc. at 2.

[14] PJM Interconnection, L.L.C., Advancing Zero Emissions Objectives through PJM's Energy Markets: A Review of Carbon-Pricing Frameworks (Aug. 23, 2017), https://www.pjm.com/~/media/library/reports-notices/special-reports/20170502-advancing-zero-emission-objectives-through-pjms-energy-markets.ashx.

COMMENTS

I. A Mechanism for Accommodation Is a Necessary Counterpart to an Expanded MOPR.

The Commission's Order rightly recognizes that a market reform adopting an expanded MOPR alone would be incomplete and have negative consequences. As both the courts and the Commission have held, states have a right to pursue valid policy goals.[15] The Commission therefore expressed concern that, "if PJM's MOPR applies to state subsidized resources with few or no exceptions, and yet the states continue to support those resources, some ratepayers may be obligated to pay for capacity both through the state programs providing out-of-market support and through the capacity market."[16] That outcome would result in the significant over-procurement of capacity resources—particularly as states increase their commitment to a clean energy future. Indeed, by 2025, approximately 13 GW of capacity resources (in unforced capacity terms) will be supported by state environmental mandates, such as portfolio standards, compared to about 6 GW today.[17] These figures will be even higher if states committed to clean energy decide to further increase their procurement targets between now and 2025.[18] Indeed, that is likely. Rapid decarbonization of the power sector is necessary for our society to avoid the worst impacts of climate change, and in the absence of a national policy, states are likely to ramp up their commitment to carbon-free generation.[19]

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[15] Order at PP 158-59 (citing *Connecticut DPUC*, 569 F.3d at 481); *Elec. Power Supply Ass'n v. Star*, Nos. 17-2433, 17-2445, 2018 WL 4356683, at *3 (7th Cir. Sept. 13, 2018) ("[T]he need to make adjustments in light of states' exercise of their lawful powers does not diminish the scope of those powers."); *Coalition for Competitive Electricity*, *supra*, Slip Op. at 12-22.

[16] Order at P 158.

[17] See PJM Filing at Attach. F (Aff. of Dr. Anthony Giacomoni & Attach. 1).

[18] A number of states have recently significantly increased their clean energy commitments, including California, Illinois, Maryland, Michigan, New Jersey, New York, Oregon, and a number of New England states.

[19] Decarbonization is not merely a matter of increasing the zero-emissions share of current generation resources. Even reference-case electrification scenarios envision a one-third increase in electricity consumption by 2050. To meet even modest carbon-free generation targets, states will need to support large quantities of new carbon-free

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Applying a MOPR to these resources without also allowing them some avenue like the FRR-RS to sell their capacity outside the RPM market would, in effect, pretend that these resources do not exist—even though they are actually on the system and contributing to system reliability. It would not be just and reasonable for the Commission to adopt market rules that force customers in PJM to procure redundant capacity at a significant unnecessary cost. And doing so is all the more unjustifiable in present circumstances, when the market already has a significant overhang of excess supply, such that PJM is procuring well beyond its reserve margin.[20]

It is no answer to say, as some stakeholders have contended, that it is appropriate for states to bear these unnecessary costs. According to these stakeholders, such costs are the natural consequence of the states' policy decisions. However, the Commission is correct that it is "just and reasonable to accommodate resources that receive out-of-market support" through state policies concerning the generation mix, rather than adopting rules that will foreseeably lead to "double payment and over procurement."[21] The Commission should reject these stakeholders' calls to adopt capacity market rules that willfully ignore the capacity provided by state-supported resources. That is so for four reasons.

First, the Commission should not impose costly capacity purchase obligations that are entirely unnecessary to ensure system reliability. Customers would be forced, by virtue of such rules, to pay hundreds of millions of dollars per year to procure capacity that is not actually needed

generation.*See* Nat'l Renewable Energy Laboratory, Electrification & Decarbonization: Exploring U.S. Energy Use and Greenhouse Gas Emissions in Scenarios with Widespread Electrification and Power Sector Decarbonization at 17 (July 2017), https://www.nrel.gov/docs/fy17osti/68214.pdf; Electric Power Research Inst., U.S. Nat'l Electrification Assessment at 9 (April 2018), http://mydocs.epri.com/docs/PublicMeetingMaterials/ee/000000003002013582.pdf.

[20] The 2021/2022 BRA cleared 163.6 GW of unforced capacity and a reserve margin of 21.5% (including commitments under Fixed Resource Requirement plans), or 5.7% higher than the target margin of 15.8%. That pattern is stable: the last seven auctions have cleared reserve margins above 19%. PJM, 2021/2022 RPM Base Residual Auction Results at 3, 6, http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx.

[21] Order at P 160.

for reliability. Such a market design choice would be akin to refusing to acknowledge that some load-serving entities own their own generation and self-supply capacity, and forcing those entities to buy redundant capacity in the market, a position the Commission has never taken. And for good reason: such a policy would impose costly requirements while ignoring the realities that make those requirements unnecessary, and therefore would not constitute reasoned decision-making.[22] Nor could the Commission disclaim responsibility for imposing these unnecessary costs. The Commission is responsible through the PJM Tariff for establishing capacity requirements for load-serving entities, and if its rules ignore capacity that is actually on the system serving load (regardless whether the capacity is self-supplied or supported by state clean energy programs), the unnecessary costs of procuring redundant capacity would be traceable to the Commission's market-design choice.

Second, market rules that impose unnecessary costs on customers are ultimately unsustainable. A MOPR-only approach forces states onto the horns of dilemma. In order to maintain their authority to adopt policies supporting particular resources, states would either be forced to pay increasing sums for unneeded capacity or to withdraw entirely from the PJM capacity market through the existing FRR (or from PJM altogether) and reclaim responsibility for all resource adequacy. As the Commission recognizes, "the states, should they so choose, undeniably have the power simply to reregulate—i.e., to revert to an era and regulatory model in which competition amongst utilities was not prevalent."[23] The Commission should reject the call by

[22] *See Michigan v. EPA*, 135 S. Ct. 2699, 2707-08 (2015) ("Agencies have long treated cost as a centrally relevant factor when deciding whether to regulate. Consideration of cost reflects the understanding that reasonable regulation ordinarily requires paying attention to the advantages and the disadvantages of agency decisions. It also reflects the reality that too much wasteful expenditure devoted to one problem may well mean considerably fewer resources available to deal effectively with other (perhaps more serious) problems." (internal quotation marks omitted).

[23] Order at P 163 (internal quotation marks omitted).

certain stakeholders for market rules that would force states to exit the PJM capacity market entirely in order to pursue state energy policies.

Third, to the extent that MOPR-only advocates hope that states will choose a third approach—abandoning their energy policies—and view the MOPR as a method to deter such policies, deterrence is not an appropriate basis for Commission action. This would be akin to the Commission declaring that states have no legitimate role in selecting generation resources, which is contradicted by the plain language of the Federal Power Act. The FPA expressly protects states' authority over "facilities used for the generation of electric energy,"[24] and the Supreme Court has explained that "regulation of utilities is one of the most important of the functions traditionally associated with the police power of the states."[25] Likewise, "[l]egislation designed to free from pollution the very air that people breathe clearly falls within the exercise of even the most traditional concept of . . . the police power."[26] As a letter to the Commission from a coalition of seventeen governors indicates:

> The Commission must let states retain their historical right to choose their own mix of energy generating resources and policies with minimal federal interference. The Commission must discover ways to regulate markets in ways that complement state policy preferences and objectives rather than overriding or negating them.
>
> The governors respectfully urge the Commissioners to refocus their policy decisions on reliability and efficient power markets – recognizing that utilities, consumers, and states will be making resource choices, which are fully within their authority and which has been the longstanding practice in the nation's electricity markets.[27]

[24] 16 U.S.C. § 824(b)(1).

[25] *Ark. Elec. Co-op. Corp. v. Ark. Pub. Serv. Comm'n*, 461 U.S. 375, 377 (1983); *see Exxon Mobil Corp. v. U.S. EPA*, 217 F.3d 1246, 1255 (9th Cir. 2000); *Nat'l Solid Wastes Mgmt. Ass'n v. Killian*, 918 F.2d 671, 676 (7th Cir. 1990), *aff'd sub nom. Gade v. Nat'l Solid Wastes Mgmt. Ass'n*, 505 U.S. 88 (1992).

[26] *Huron Portland Cement Co. v. City of Detroit*, 362 U.S. 440, 442 (1960)

[27] Governors' Wind & Solar Energy Coalition Letter, EL18-178 (Aug. 29, 2018).

Consistent with this precedent, the Commission has long sought to "respect the traditional role of states,"[28] and whenever the Commission has confronted policies addressing environmental externalities, the Commission has explained that these "policy objectives" are "legitimate."[29] And the courts have agreed, concluding that "the need [for the Commission] to make adjustments in light of states' exercise of their lawful powers does not diminish the scope of those powers."[30] A market design that sought to deter states from exercising the authority that Congress expressly reserved to them, by forcing states exercising that authority to bear large and unnecessary costs, would be no more respectful of the FPA's division between state and federal authority than a state program that targeted wholesale prices and tried to adjust them.[31]

Moreover, given states' long-standing authority to pursue energy policies, and their relationship to core state police powers, there is no reason to believe that states will stop supporting the resources that they believe are necessary to meet their policy goals. In the CASPR Order, the Commission found that clean energy "will be developed by the operation of state environmental and clean energy mandates, whether that capacity clears the [market] or not."[32] There is no basis for believing that PJM states will act any differently. Thus, a strategy to deter states from

[28] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 1112 (2006).

[29] *ISO New England, Inc.* 158 FERC ¶ 61,138, at P 68 (2017); Order at P 158; Brief for the United States and Federal Energy Regulatory Commission as Amici Curiae, *Village of Old Mill Creek v. Star*, No. 17-2433 (7th Cir. May 29, 2018), at 7, 10-11, 26-27.

[30] *Elec. Power Supply Ass'n v. Star*, Nos. 17-2433, 17-2445, 2018 WL 4356683, at *3 (7th Cir. Sept. 13, 2018); *Coalition for Competitive Electricity, supra*, Slip Op. at 12-22.

[31] *See FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 775 ("The above conclusion does not end our inquiry into the Commission's statutory authority; to uphold the Rule, we also must determine that it does not regulate retail electricity sales. That is because, as earlier described, § 824(b) … reserv[es] regulatory authority over retail sales (as well as intrastate wholesale sales) to the States…. FERC cannot take an action transgressing that limit no matter how direct, or dramatic, its impact on wholesale rates."); *Coalition for Competitive Electricity*, *supra*, Slip Op. at 22 ("FERC uses auctions to set wholesale prices and to promote efficiency with the background assumption that the FPA establishes a dual regulatory system between the states and federal government and that the states engage in public policies that affect the wholesale markets.").

[32] *ISO New England Inc.*, 162 FERC ¶ 61,205, at P 45 (2018).

exercising their congressionally granted authority would likely be doomed to failure in any event. More likely, such a strategy would only result in unnecessary costs on customers, and would encourage states to withdraw altogether from the federal markets.

Fourth, adopting market rules intended to stymie legitimate state action promoting environmentally friendly methods of producing electricity would entrench inefficient market outcomes, and consequently would be arbitrary and capricious.[33] Certain forms of generation produce socially harmful pollution. When emitting generators are not forced to internalize those costs—and when the value of clean production is not recognized—the result is a resource mix that produces a greater amount of pollution than is socially desirable. An efficient market should seek to align private incentives with social costs and benefits, either by making polluting resources internalize the cost of pollution (leading them to produce less than they otherwise would) or by allowing clean resources to be compensated for the benefits of clean production (leading them to produce more than they otherwise would). This is textbook economics.[34]

The Commission has chosen to remain agnostic to environmental externalities, but has sensibly been able to do so only because of states' traditional role in regulating them. Working in tandem, federal market design and state policy can drive toward a more efficient outcome—even if a Commission-imposed carbon price is the most efficient solution.[35] By contrast, a market reform intended to *deter* states from regulating environmental externalities, by adopting market

[33] To be sure, not all state subsidy programs seek to address environmental externalities. For example, development incentives and regulated retail rates ensuring cost recovery do not. But the programs discussed by the Commission as primarily motivating its decision to revamp the capacity market rules—REC and ZEC programs—are aimed toward reducing such externalities by incentivizing the emissions-free production of electricity.

[34] Decl. of Robert D. Willig at 17-28, Ex. A to Protest of Exelon Corporation, Docket No. ER18-1314 (May 7, 2018) ("Willig Decl."); Institute for Policy Integrity, *Capacity Markets and Externalities: Avoiding Unnecessary and Problematic Reforms* (April 2018), http://policyintegrity.org/files/publications/Capacity_Markets_and_Externalities_Report.pdf.

[35] Willig Decl. at 29-35.

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rules that countermand the effects of state environmental policies, would mark a dramatic change in policy and lead to irrational results. The effect would be to ensure that the market produces foreseeably inefficient outcomes. Wholesale market rules adopted in order to *prevent* an accounting of environmental externalities could never be just and reasonable.

For these reasons, the Commission's Order correctly viewed a mechanism for accommodating state policy initiatives as a necessary corollary to any expanded MOPR.

II. A Properly Designed Resource-Specific FRR Alternative Is an Appropriate Mechanism for Accommodation.

The Commission's Order sought comment on a proposed mechanism for accommodation that would "allow, on a resource-specific basis, resources receiving out-of-market support to choose to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time."[36] This approach would "allow[] resources that receive out-of-market support to remain in PJM's energy and ancillary services markets, and continue to be recognized as capacity on the system."[37] As the Commission described the FRR-RS, "[r]esources and load that take advantage of this new resource-specific FRR Alternative would not participate in the PJM capacity market."[38]

The Commission found that this approach would yield "increased transparency for investors, consumers, and policymakers."[39] According to the Commission, removing subsidized resources from the capacity market would ensure that all capacity offers in the market are "competitive," that is, unaffected by out-of-market sources of revenue; this would improve the

[36] Order at P 160.

[37] *Id.* at P 162.

[38] *Id.*

[39] *Id.*

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clarity of capacity market price signals and promote more robust competition within the market.[40] Consumers, meanwhile, would have a transparent view into "which capacity costs are the result of competition in the capacity market and which capacity costs are being incurred as a result of state policy decisions."[41] States would need to take responsibility for the full cost of maintaining a state-supported resource, and to the extent consumers regard that cost as too high, the transparency provided by the bifurcated market structure would allow policymakers to be held politically accountable.[42] Thus, "the construct will provide the information that states and all other stakeholders will need in order to make informed decisions about the degree to which they prefer to rely on the capacity market versus out-of-market mechanisms, and it will manage the results of those decisions in an orderly fashion."[43]

The Commission identified "a number of details" on which it requested comment. These include "[t]he appropriate scope of out-of-market support to be mitigated by the expanded MOPR, thereby rendering a resource eligible for the new resource-specific FRR Alternative"; how the Tariff should address the FRR-RS election "procedurally and substantively"; "[h]ow to identify the load that will be removed"; "whether part of a resource should be eligible" for the FRR-RS; "the length of time resources receiving out-of-market support who chose the [FRR-RS] must remain outside of the PJM capacity market auction"; and other implementation issues. With respect to the MOPR, the Commission requested comment on "the types of MOPR exemptions that should be included," and what minimum offer price to apply.[44]

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[40] *Id.*

[41] *Id.*

[42] *Id.*

[43] *Id.* at P 163.

[44] *Id.* at PP 164-171.

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This Part describes in detail our proposal for a workable FRR-RS Alternative, consistent with the shared principles supported by Exelon and other commenters. Proposed Tariff language is attached as Attachment A.

A. Eligibility: Resources Receiving a Material Subsidy.

1. Application of the MOPR Should Be Paired With Eligibility for the FRR-RS Alternative.

The Commission's Order contemplates that the MOPR and the FRR-RS are two sides of the coin: a resource that is subject to mitigation on account of a Material Subsidy should be eligible to elect the FRR-RS Alternative if it chooses.[45] Exelon agrees that these two concepts—the MOPR and the FRR-RS—should be connected in this manner. The point of the FRR-RS Alternative is to provide a mechanism for states to support resources for policy reasons, when application of the MOPR could leave those resources unable to clear the capacity market. Thus, the application of the MOPR should remain connected to eligibility for the FRR-RS Alternative, regardless of how a Material Subsidy is defined.

2. Material Subsidies Should Include State-Directed Capacity Procurements.

The Commission should recognize that, once an FRR-RS mechanism is in place, states may choose to support resources of public policy interest by directing the procurement of capacity from those resources. States may find a state-administered, centralized capacity procurement outside the PJM auction to be the most efficient means to assure that resources of state public policy interest will receive compensation for their capacity, and for assuring that the associated costs are allocated equitably and in a competitively neutral manner among the state's load-serving entities. The Commission's Order should make clear that a state-directed capacity procurement of

[45] *Id.* at P 165.

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this kind constitutes a Material Subsidy that would allow the resource to elect the FRR-RS and sell its capacity pursuant to the state procurement, rather than through the RPM auction.

3. The Commission Should Define Material Subsidy to Include All Types of Out-of-Market Revenue.

With respect to what types of support should constitute a Material Subsidy—thereby triggering mitigation as well as eligibility for the FRR-RS—that definition should include any form of out-of-market revenue, regardless of its purpose. Under the Commission's logic for expanding the MOPR's application, there should be "few or no exceptions,"[46] since any subsidy makes it possible for the resource receiving the subsidy to offer into the capacity market at a level below its actual going-forward costs. The Commission's goal is to ensure that all capacity market offers are "competitive," and allowing some subsidized entities to be exempt from mitigation is incompatible with that goal. When paired with an FRR-RS mechanism that is readily available for states, however, a stringent MOPR will not unduly interfere with state authority or with any existing business models. Instead, consistent with the Commission's goals, a MOPR with few or no exceptions will increase transparency, by enabling all stakeholders to have a clear view of the relative costs of the capacity market and out-of-market mechanisms.

a. Development Incentives Are Material Subsidies.

Based on its prior filing and statements during the stakeholder process, PJM's proposed definition of Material Subsidy excludes payments that promote "general industrial development in an area" or "siting" in a particular location.[47] That carve-out is arbitrary. Development and siting incentives raise the identical concerns that the Commission has identified regarding transparency and the competitiveness of offers in the capacity market. These types of incentives may induce

[46] *Id.* at P 158.

[47] *Id.* at P 165 n.294.

investments that would not otherwise have occurred—indeed, that is their entire point. For example, as Exelon has noted previously, in Pennsylvania, a coal-to-gas conversion was the "anchor tenant" for a new "Keystone Opportunity Expansion Zone," which enabled this plant to be built by eliminating state and local taxes through 2023.[48] These types of subsidies also allow generators to make offers in the capacity market that do not reflect their full going-forward costs. There is therefore no basis for carving this type of state support out of the definition of Material Subsidy.

b. The Commission Should Not Exempt Self-Supply and Vertically Integrated Resources From the MOPR.

Some stakeholders have argued that the Commission should continue to recognize MOPR exemptions for self-supply and vertically integrated resources. There is no reasoned basis for the Commission to do so. Self-supply and vertically integrated units typically offer into the capacity market as price takers, because they do not require capacity market revenues in order to cover their costs. Instead, they are guaranteed cost recovery through retail rates, and any capacity market revenues are credited as an offset against costs. Guaranteed cost recovery through retail rates frees these resources from any competitive discipline and allows them to take whatever market price is paid, because retail rate recovery "protects [them] from the potential downside of that bidding behavior."[49] In no way are these resources making "competitive offers."[50]

[48] Oil & Gas 360, Sunbury Generation Lands First Tenant for Old Trail Industrial Park KOEZ (Oct. 28, 2015), https://www.oilandgas360.com/sunbury-generation-lands-first-tenant-for-old-trail-industrial-park-koez-with-announcement-of-financing-of-panda-hummel-station-power-plant/.

[49] Order at P 153.

[50] *Id.*

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Resources with guaranteed cost recovery *today* comprise almost 20% of PJM's cleared capacity—approximately 30 GW.[51] That is nearly twice the number of gigawatts that PJM forecasts will be supported by states for environmental reasons *in 2025*, to which the Commission cites in finding that reforms to the PJM tariff are needed. To exempt from the MOPR resources that receive cost recovery through retail rates is to rip a large tear—not a mere loophole—in the fabric of the proposed market design. If the Commission includes such an exemption, it cannot achieve the objectives it has set forth in its Order, which include a capacity market in which all participants are making what the Commission regards as competitive offers, and transparency for consumers and state policymakers regarding the full cost of their regulatory choices. Indeed, it would make little sense for the Commission to mitigate resources receiving attribute payments in order to convey transparent information to states about the costs of state *re*-regulation, but exempt from the MOPR resources receiving guaranteed retail rate recovery, and thereby obscure the costs of *maintaining* state regulation.

Self-supply and vertically integrated entities have advanced two main arguments for an exemption, but neither withstands scrutiny. First, they argue that utilities that use their generation resources for self-supply have no incentive to exercise buyer-side market power. But that argument, even if factually accurate, misses the point. The Order's premise is that the MOPR in PJM should no longer be restricted to combatting buyer-side market power; instead, it should be used to ensure that offers reflect a resource's going-forward costs, "regardless of intent" (and irrespective of externalities).[52]

[51] This includes both self-supply (24.8 GW) and public power (6.2 GW), which totals 18.9% of PJM's cleared capacity. *See* Declaration of Michael M. Schnitzer ¶ 15, attached to Protest of Exelon Corporation and the PSEG Companies, Docket No. EL18-169 (June 20, 2018).

[52] Order at P 155.

Second, advocates of an exemption have argued that self-supply and vertical integration are longstanding business models. That does not provide a basis for treating them differently. For one thing, attribute payments are also longstanding: they first emerged in the late 1990s, at the same time the organized energy markets were formed, and prior to the introduction of capacity markets a decade later; and they similarly draw upon the historic power reserved to states to regulate generation facilities.[53] More fundamentally, vintage is no justification for exempting units that, under the Commission's reasoning, are making non-competitive offers.

In any event, mitigating self-supply and vertically integrated units would not disrupt their business model, because they can always elect the FRR-RS Alternative (or the existing FRR) and arrange to serve associated load outside the capacity market in exchange for payments made by retail customers. Indeed, that model more truly replicates their long-standing business model than one in which capacity supported by retail ratepayers pursuant to state mandate must nevertheless be bid into the RPM market as a price taker, with retail customers then billed for costs net of market revenues.

For these reasons, it would be arbitrary for the Commission to distinguish between existing self-supply resources and other existing resources receiving state support with respect to the MOPR and eligibility for the FRR-RS.

c. Small Units Should Not Be Exempt.

Some have proposed exempting units 20 MW or less from mitigation. The Commission should not grant that exemption for two reasons. First, because the unforced capacity value of renewable resources is typically substantially de-rated compared to nameplate capacity, this will

[53] *See generally, e.g.*, Barry Rabe, *Race to the Top: The Expanding Role of U.S. State Renewable Portfolio Standards*, 7 Sustainable Dev. L. & Pol'y 10 (2007); Br. of Amici Curiae Electricity Regulation Scholars, *Village of Old Mill Creek v. Star*, Nos. 17-2433, 17-2445 (cons.), at 10-18 (7th Cir. Nov. 3, 2017); *see also* 16 U.S.C. § 824(b)(1).

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result in many individual renewable projects of typical sizes being exempted. For example, with the typical wind capacity credit of 13%, any wind project of less than 150 MW nameplate, a very typical size for a wind farm, will be exempted. This will invite gamesmanship in the design of renewable energy projects, as well as needless litigation over whether co-located 20 MW groups of solar panels or wind turbines should be treated as a single resource or as multiple resources. Second, even if any particular 20 MW resource is viewed as having a de minimis effect on the market, the aggregate quantity of such resources is considerable, particularly given that many typical renewable projects would fall at or below this threshold. Indeed, in the 2020/21 Base Residual Auction, we estimate that there were more than 800 MW of unforced capacity offered by wind and solar facilities of 20 MW or less.[54] Allowing forty 20 MW wind farms to offer as price takers has the same effect as allowing one 800 MW nuclear unit to do so. If the Commission is not willing to allow the latter, neither should it allow the former.

B. Election of the FRR-RS Alternative and Matching of Load.

As discussed above, a resource subject to mitigation should be permitted to elect participation in the FRR-RS Alternative. Consistent with the timing for the existing FRR Alternative, a resource electing to participate in the FRR-RS should be required to make its election 120 days prior to the Base Residual Auction from which it seeks to be relieved of its must-offer obligation. A resource can make its election by certifying that it will receive a Material Subsidy in the Delivery Year—for example, from the sale of RECs or ZECs, or from the recovery of its costs through retail rates—or by demonstrating that its capacity and attributes have been procured for the Delivery Year under a state-sponsored forward procurement.

[54] This consists of 430 MW of wind and 386 MW of solar. The calculation is based on *PJM 2021/22 RPM Resource Model*, available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-rpm-resource-model.ashx?la=en.

A resource electing the FRR-RS should also be required to identify, no fewer than 120 days prior to the Base Residual Auction, what corresponding load will be removed from the auction. Some resources electing the FRR-RS Alternative may choose to sell their capacity to load-serving entities through bilateral contracts outside the auction. This might be the case, for example, with a resource receiving REC payments. Such resources would present their bilateral contracts to indicate the corresponding load to be removed. Other resources may sell their capacity through a state-administered procurement, under which the state, pursuant to state law, would assign the capacity credit to load-serving entities under its jurisdiction. FRR-RS resources procured by a state in this manner would submit the state procurement order or other state directive to indicate the corresponding load to be removed. The compensation to be received by the FRR-RS resource (whether a sum certain or a formula) should also be set forth in the documentation identifying the load to be matched to the FRR-RS resource. The FRR-RS election and documentation setting forth compensation would then be confirmed by an LSE or other relevant entity (such as a state power authority) no later than 30 days prior to the Base Residual Auction. This approach would ensure that both the election of the FRR-RS and load-matching occur prior to the Base Residual Auction, and would facilitate the Commission's goal of providing transparency to consumers and policymakers regarding the relative cost of capacity resources procured through the market and those procured outside the market as FRR-RS resources.[55]

Although the foregoing process would ensure orderly implementation of the FRR-RS mechanism in the normal course, additional time may be necessary for the first year in which the FRR-RS is available. In order to give states sufficient lead time to make any necessary legislative

[55] Any concern that the FRR-RS Alternative will be abused by states seeking to withdraw load from the capacity market in order to suppress capacity market prices can be addressed through the Commission's prohibition on market manipulation. That prohibition should be applied to manipulative uses of the FRR-RS Alternative. The Commission has the full ability and means to police and punish any such misuse.

or regulatory changes following the Commission's final order in this proceeding, Exelon suggests that for the first year in which the FRR-RS is implemented the deadlines for election and load-matching should be reduced to 45 days prior to the Base Residual Auction.

In addition, the FRR-RS mechanism must maintain the existing ability under the PJM Tariff to partially offer resources into the capacity market. Many resources are owned by more than one owner; in those cases, PJM's tariff allows each owner to submit its own capacity offer for the portion of the resource that it owns, and to submit different offers for discrete segments of the same resource. Sometimes ownership of a resource is split between entities with different business models—for example, one portion of a plant may enjoy cost recovery through retail rates, while the rest of the plant does not. And some state support payments (for example, the Illinois ZECs paid to Quad Cities) are received only by one owner in respect to the fraction of the plant it owns. Because partial resources already offer into the capacity market, partial resources are subsidized, and as a result partial resources can be subject to mitigation, it makes sense that partial resources should also be able to elect the FRR-RS Alternative, consistent with existing tariff provisions governing segmented offers.[56]

C. Compensation and Payment Mechanics.

For ease of administration, PJM should provide states the option of using PJM's existing billing and accounting mechanisms to collect FRR-RS costs from the matched load and to disburse payment to FRR-RS resources. The FRR-RS resource would indicate whether to use these billing and accounting mechanisms in its election.

[56] PJM OATT, Att. DD, Sec. 5.6.1 (a)(ii) ("The Sell Offer may take the form of offer segments with varying price-quantity pairs for varying output levels from the underlying resource, but may not take the form of an offer curve with nonzero slope").

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Compensation should be provided consistent with the documentation submitted at the time of the FRR-RS resource's election. The sale of capacity from an FRR-RS resource is of course a sale subject to the Commission's jurisdiction, so the Commission must retain regulatory oversight over the terms and conditions of that sale to ensure their justness and reasonableness. If the sale is undertaken pursuant to the seller's market-based rate authority, compensation would be reported to the Commission during the Delivery Year on the FRR-RS resource's EQR. And the Commission should make clear that it retains the power under Section 206 to deem the wholesale capacity price unjust and unreasonable, and to replace it with a just and reasonable rate.

However, the Commission should make clear in its Order that it seeks to afford substantial flexibility to states in proposing methods of compensation, subject to the Commission's regulation of the resulting wholesale sale. For example, the Commission should state in its Order that a state conducting a capacity procurement could adopt one of many different compensation mechanisms, including a cost-based metric, competitive offers arising from a request for proposals or a state-run clean energy auction, or a mechanism based on RPM clearing prices plus an attribute price based on the value of the environmental externality abated (such as the social cost of carbon). There may be other potential approaches to compensation as well. The role for states is similar to the role contemplated under the existing FRR provisions, which incorporate a state compensation mechanism, while still preserving the Commission's ultimate authority over the justness and reasonableness of any resulting wholesale rate.[57]

[57] RAA, Sched. 8.1 § D.8; *see Am. Elec. Power Serv. Corp.*, 134 FERC ¶ 61,039, PP 8-13 (2011) (deferring to state compensation mechanism).

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D. The Commission Should Provide Advance Authorization for Affiliate Transactions Arising from a State-Directed Procurement.

In restructured states, many load-serving entities are affiliated with generation companies that own or may develop resources of state public policy interest. Indeed, approximately 50 percent of the clean energy generation in PJM is owned by affiliates of load-serving entities. Thus, in order for states to be able to use the FRR-RS mechanism as an effective means for procuring resources of public policy importance, the Commission will need to address potential affiliate transactions that arise from state-directed procurements by load-serving entities subject to state jurisdiction.

To that end, the Commission should clarify that wholesale sales of capacity undertaken pursuant to a state-directed procurement shall not be subject to the Commission's affiliate transaction rules.[58] When a state legislature or regulatory commission directs an affiliate transaction pursuant to state policy mandate, the concerns underlying the Commission's affiliate rules are absent. Those rules were adopted to prevent a regulated utility from using its captive retail customers to cross-subsidize an unregulated generation affiliate.[59] The economic theory behind the policy is that, if such an affiliate transaction were permitted, the generation company may have market power over the utility's captive customers, and could use that position to extract excessive payments from them.[60]

There is no such concern when a state political body is directing the procurement of capacity in furtherance of its policy goals. In those circumstances, the transaction does not result

[58] 18 C.F.R. § 35.39(b).

[59] *Elec. Power Supply Ass'n v. FirstEnergy Solutions Corp.*, 155 FERC ¶ 61,101, P 59 (2016) (explaining that the Commission's "fundamental goal" in its affiliate rules "is to protect consumers served by franchised public utilities from inappropriately subsidizing the market-regulated or non-utility affiliates of the franchised public utility or otherwise being financially harmed as a result of affiliate transactions and activities.").

[60] *Id.*

from the generator's exploitation of the utility's captive customer base to exercise market power. Instead, the transaction results from a determination by a democratically accountable political body that the transaction is in the public interest and must occur. Any affiliate relationship between the buyer and seller is a happenstance irrelevant to the state directing the procurement, not the motivating reason for the sale, as is true in cases of affiliate abuse. If customers disagree with their elected representatives about where the public interest lies, they will make that known at the ballot box.

Subjecting transactions to the affiliate rules even when undertaken pursuant to state direction would make the FRR-RS Alternative unworkable for many states. The concept of the FRR-RS Alternative is to provide a path for states to make their own policy judgments regarding which resources are to receive state support and to allow these resources to enjoy that support without second-guessing. Applying the affiliate transaction rules to state-directed capacity procurements would allow those rules to be used to undermine the FRR-RS and, in some instances, could effectively block the states from carrying out their public policy. Nor would it be appropriate for opponents of the bifurcated market structure to undermine the FRR-RS mechanism by litigating individual affiliate transaction approvals or for the Commission to use the affiliate rules to micromanage how states carry out their procurements—for example, by approving FRR-RS transactions only when a state conducts a competitive solicitation process and selects the lowest bidder. In pursuing clean energy policies, states seek to balance cost considerations with their environmental goals. This is why the Illinois ZEC and New Jersey ZEC statutes each contemplate procurements that select resources based on their environmental contributions, subject to a cost cap.[61] In Illinois, the Illinois Power Agency implemented these environmental statutory criteria

[61] *See* 20 ILCS 3855/1-75(d-5)(1)(C) (directing IPA to select ZEC plants based on "minimizing carbon dioxide emissions that result from electricity consumed in Illinois"; "minimizing sulfur dioxide, nitrogen dioxide, and

by modeling the impact of resources participating in the procurement on state air quality and carbon emissions, and selected the resources that best satisfied these environmental criteria.[62] Reviewing procurements under this program would put the Commission in the untenable position of second-guessing the state's evaluation of such environmental criteria. The FRR-RS Alternative should enable states to pursue their own policy priorities, and the Commission's affiliate rules should not be used to stymie states' ability to support the resources that best serve the states' environmental goals, merely because they happen to be owned by generation affiliates of load-serving entities subject to the state's jurisdiction.

The Commission therefore should clarify in this proceeding that market-based rate sellers can seek waiver of their tariffs and the Commission's regulations with respect to the filing of wholesale sales undertaken pursuant to a state clean energy program. An advance authorization for affiliate transactions resulting from a state-directed procurement would not conflict with recent precedent regarding proposed affiliate transactions. In the Ohio affiliate cases, for example, the regulated utilities sought to enter power purchase agreements with their unregulated generation affiliates as part of a utility-initiated "electric security plan." While the Ohio Commission reviewed the resulting power purchase agreement for prudence, it did not direct the agreement;

particulate matter emissions that adversely affect the citizens" of Illinois; and "any existing environmental benefits that are preserved by" selection of the winning facilities); N.J. Stat. Ann. § 48:3-87.5 (directing Board of Public Utilities to select ZEC plants "based on how well the nuclear plants satisfy" environmental criteria, including "demonstrat[ing] to the satisfaction of the board that [the plant] makes a significant and material contribution to the air quality in the State by minimizing emissions that result from electricity consumed in New Jersey, … minimizes harmful emissions that adversely affect the citizens of the State, and if the nuclear power plant were to be retired, that that retirement would significantly and negatively impact New Jersey's ability to comply with State air emissions reduction requirements.").

[62] Illinois Power Agency, Public Notice of Successful Bidders and Average Prices (Jan. 25, 2018), https://www.ipa-energyrfp.com/?wpfb_dl=1450; Illinois Power Agency, Zero Emission Standard Procurement Plan (July 31, 2017) at 31-47, https://www.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/Zero-Emission-Standard-Procurement-Plan-ICC-Filing.pdf. The New Jersey Board's selection process is still being formulated.

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rather, the transaction originated with the utility, not the state.[63] The reactive role played by the Ohio Commission in those cases is quite different from the proactive role that a state legislature or commission would play in conducting or directing the capacity procurement of an FRR-RS resource. The latter involves an affirmative policy decision by the state to support a particular resource in order to promote the public interest. The Commission should respect that policy judgment, which arises from the public political process, not the private exercise of market power; and accordingly, to the extent such state-directed procurements involve affiliate transactions, the Commission should provide advance authorization under its affiliate rules. Alternatively, at the very least, the Commission should treat state involvement in the procurement of capacity by a load-serving entity from an affiliated generation company as strong evidence pointing against any affiliate abuse.

E. Capacity Performance Requirements.

A resource electing the FRR-RS Alternative makes a capacity commitment to PJM through that election. Such a resource should be subject to all of the obligations of any capacity resource, including all performance requirements, non-performance charges, and bonus payments. That will ensure that the FRR-RS Alternative will not have any adverse reliability consequences.

F. Market-Clearing Process.

Consistent with the Commission's Order, and as discussed above, "[r]esources and load that take advantage of the [FRR-RS] would not participate in the PJM capacity market, and would neither make nor receive payments from that capacity market."[64] However, with respect to the mechanics of clearing the PJM capacity auction in a manner that respects all locational constraints,

[63] *See* Ohio Rev. Code § 4928.143 (providing that "an electric distribution utility may file an application for public utilities commission approval of an electric security plan"); *Elec. Power Supply Ass'n*, 155 FERC ¶ 61,101 at P 6.

[64] Order at P 160.

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PJM may elect to include FRR-RS resources and associated load in running its market-clearing algorithm. For purposes of PJM's algorithm only, the FRR-RS resources could be treated as "self-supplied" and the matched load would remain in the demand curve. This approach would allow PJM to avoid making any adjustments to the demand curve and would automatically ensure that load procures the appropriate amount of reserves in the aggregate, and that load collectively respects all locational constraints. Consistent with the Commission's Order, however, the FRR-RS resources would not make any offers, nor sell any capacity or receive any compensation, in the capacity market. Their inclusion in the market-clearing algorithm would be solely for administrative ease on PJM's part. Thus, in the financial settlement process, FRR-RS resources will not be paid the RPM clearing price, and the load matched to FRR-RS resources will receive a credit for the amount not paid to such resources.

G. Term Length.

The Commission should not impose any minimum term for FRR-RS resources to remain the FRR-RS Alternative. It also should not impose any onerous conditions that an FRR-RS resource must meet to reenter the RPM auction. Over time, market conditions may change and make state support unnecessary. Requiring FRR-RS resources to remain outside the RPM market in such circumstances, or imposing burdensome reentry conditions that effectively consign such resources to remaining outside the RPM market, will only reduce market liquidity in the long run and harm consumers.

H. Mitigation Level.

For resources receiving Material Subsidies that choose to continue participating in the capacity market subject to the expanded MOPR, the Commission must decide on an appropriate minimum offer price. In the capacity performance proceeding, the Commission determined that

"an appropriate competitive offer includes all of the marginal and opportunity costs faced by a resource."[65] For resources with avoided cost rates of less than Net CONE multiplied by the balancing ratio B, the competitive offer price was determined to be equal to Net CONE * B, the balancing ratio.[66] This amount reflects the opportunity cost of taking on a commitment as a capacity performance resource. That is, a resource "will be willing to take on a capacity obligation as long as the amount it can earn for capacity (including both capacity auction revenues as well as net Performance Bonus Payments) exceeds the amount it could earn in Performance Bonus Payments by participating in the energy market only."[67] And the amount it could expect to earn in Performance Bonus Payments by participating in the energy market only is equal to Net CONE multiplied by the balancing ratio B.[68] Consistent with this existing approach for new resources, the Commission should set the minimum offer level for both new and existing resources subject to the MOPR at Net CONE * B, the opportunity cost of taking on a capacity commitment. This approach would be transparent and simple to administer.

The Commission should not allow unit-specific exceptions to these offer levels. The Commission's rationale for applying a MOPR to resources receiving Material Subsidies, and providing those resources with a path out of the PJM capacity market, is to ensure that offers in the capacity market reflect competitive forces. Offers based on a unit-specific exception process, however, are not based on competitive forces; they are set administratively, based on the Independent Market Monitor's own assessment of the unit's costs. That process is opaque to outsiders, and in Exelon's experience, highly subjective. Creating an avenue for resources

[65] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208, P 335 (2015), *on rehearing*, 155 FERC ¶ 61,157, at PP 174, 185 (2016).

[66] *Id.* at P 338.

[67] *Id.* at P 336.

[68] *Id.* at PP 337-38.

receiving subsidies to remain in the capacity market, but then to bid below their opportunity cost based on a unit-specific exception process, would run counter to the very reason the Commission took action in this proceeding: transparency and robust competition. Moreover, introducing such complexity for existing resources is unnecessary as long as a workable FRR-RS mechanism is available to resources that receive out-of-market revenue and do not wish to offer into the capacity market at a mitigated level. It is therefore appropriate for the Commission to now eliminate the unit-specific exception. If the Commission nevertheless were to allow unit-specific exceptions, the calculation of the offer floor under such an exception should still be required to reflect the opportunity cost of taking on a capacity commitment, which is common across all units and is equal to Net CONE times B.

III. The Proposed Resource-Specific FRR Alternative, Combined With a MOPR Applied to All Subsidized Resources Participating in the Capacity Market, Will Achieve the Commission's Goals.

The proposed FRR-RS Alternative set forth above, together with a MOPR applied to all resources participating in the capacity market but receiving out-of-market revenues, would satisfy the Commission's objectives: ensuring greater "integrity of [the capacity market's] price signals," as capacity market offers would be unaffected by out-of-market payments;[69] "avoid[ing] the potential for double payment and over procurement" of capacity;[70] and "increas[ing] transparency for investors, consumers, and policymakers."[71]

First, regarding capacity market integrity, the proposal outlined in the Commission's Order would ensure that no resource participating in the capacity market would be able to bid below its costs by virtue of receiving out-of-market revenue. The Commission's Order indicated that, in the

[69] Order at P 156

[70] *Id.* at P 160.

[71] *Id.* at P 162.

Commission's view, this is important to the integrity of the capacity market and to ensuring that (in the Commission's words) "all resources participating in the capacity market, whether or not these resources receive out-of-market support, offer competitively."[72] The rates that emerge from these offers will, in the Commission's view, be "the result of competitive market forces."[73]

Second, a workable FRR-RS Alternative would avoid the potential for double payment and capacity over-procurement by allowing states a mechanism for withdrawing load from the capacity market to be served by resources of public policy interest outside that market. This was one of the core goals of the Commission's pairing of a MOPR with limited or no exceptions with a mechanism pursuant to which states could implement payments outside of the PJM capacity market for preferred resources.

Third, the combination of these policies would result in increased transparency for all stakeholders. Investors would know that the prices emerging from the capacity market reflect competitive bidding among market participants, and they can plan entry and exit accordingly. Consumers would have visibility into "which capacity costs are the result of competition in the capacity market and which capacity costs are being incurred as a result of state policy decisions."[74] And policymakers would have "the information that states and all other stakeholders will need to make informed decisions about the degree to which they prefer to rely on the capacity market versus out-of-market mechanisms."[75] The "bifurcated approach" identified by the Commission,

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[72] *Id.*

[73] *Id.* at P 158. To be clear, while the Commission's proposed bifurcated market structure will improve competitive market outcomes considerably, such rates will not completely reflect all competitive market forces, as they ignore the negative externalities associated with pollution. A truly competitive market is one that accounts for the externalities of production. Exelon explained this point at length in its July 30, 2018 Petition for Rehearing in these consolidated dockets.

[74] *Id.* at P 162.

[75] *Id.* at P 163.

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and described in more detail above, "will manage the results of those decisions in an orderly fashion."[76]

Some commenters are likely to argue that the FRR-RS Alternative is incompatible with the Commission's conclusion that market prices have been unjustly and unreasonably suppressed by non-competitive offers. According to these commenters, removing FRR-RS resources and matching load from the capacity market will not result in any change in capacity market prices—those prices will be just as low as they were previously. Thus, these commenters will argue, the FRR-RS Alternative cannot be just or reasonable. The Commission should reject that argument for several reasons.

First, the argument assumes that states will necessarily provide out-of-market capacity payments for all subsidized resources. That assumption may not turn out to be true, in which case at least some subsidized resources will offer into the capacity market at a mitigated level—thereby tending to increase the market clearing price. Because one cannot predict exactly how states will respond to the availability of an FRR-RS Alternative, one cannot draw any definitive conclusion regarding what effect the FRR-RS Alternative will have on market prices.

Second, even accepting the dubious premise of these commenters' argument, the Commission did not—nor did it purport to—predetermine a particular price level for RPM auctions as "just and reasonable" or "unjust and unreasonable." Rather, it determined that capacity prices would be just and reasonable if they result from "competitive market forces."[77] The construct set forth in the Commission's Order, and described above, is consistent with that determination. Sellers participating in the capacity market would "not [be] able to offer below a

[76] *Id.* at PP 162-63.

[77] *Id.* at P 158.

competitive price."[78] The market price that emerges from these offers will, *ipso facto*, reflect "competitive market forces."[79] That is so regardless of what the market price is—indeed, it is so even if the market price is no different from what it is today.

Third, regardless what the new market price is, it will *not* be derived from below-cost offers by subsidized competitors. Under the FRR-RS construct, resources receiving out-of-market support are either mitigated and forced to make offers reflecting their costs, or instead exit the market altogether. They make no market offer and receive no market compensation.[80] Thus, the "price suppression" alleged by opponents of the FRR-RS is not a consequence of below-cost capacity market offers. Instead, what opponents label "price suppression" is simply the consequence of reduced capacity market demand, as a result of state policy decisions to withdraw a portion of their load from the capacity market to be served outside that market by resources of special public policy interest. Thus, the capacity market might be smaller—there may be less load for competitive resources to serve, resulting in lower prices. But "all resources participating in the capacity market" to serve that remaining load will "offer competitively."[81]

The argument that the FRR-RS Alternative must be rejected if the market price of capacity does not rise ultimately rests on the flawed assumption that the Commission can compel load to remain in the PJM market. The Commission cannot do so. As the Commission recognized, "the states, should they so choose, undeniably have the power simply to reregulate—i.e., to revert to an era and regulatory model in which 'competition among utilities was not prevalent.'"[82] Thus, for

[78] *Id.*

[79] *Id.*

[80] *Id.* at PP 160-61.

[81] *Id.* at P 162.

[82] *Id.* at P 163.

example, a state can choose, if it wishes, to have its franchised utility self-supply capacity. The result of that choice is to reduce the amount of load to be served by the capacity market. PJM has always recognized that reality by clearing self-supply resources in its auction as price-takers—effectively removing the load served by those resources from the capacity market. Or the state can withdraw its entire load from the capacity market by opting into the FRR. These steps would similarly tend to lower capacity market prices by removing load from the market. But there is nothing "artificial" or "suppressive" about the resulting price: it is the natural consequence of a state policy choice to have its load served through a mechanism other than the PJM capacity market. There is nothing preordained regarding the amount of load that procures capacity through the PJM market, versus outside that market. That is a function of choices made by other regulators, not the Commission.

The FRR-RS Alternative is simply a more modest version of what states already can do. Instead of requiring states to make an all-or-nothing choice concerning how their load is served—either all through the capacity market or all through an FRR Plan—the FRR-RS Alternative allows a state to withdraw a *portion* of its load from the capacity market, to be served outside of the market by resources that the state wishes to support for public policy reasons. Doubtless, commenters hostile to the FRR-RS Alternative would prefer for the Commission to force each state into a binary choice between either fully withdrawing all of its load from the capacity market (by electing the full FRR or by leaving PJM altogether) or requiring all of the state's load to be served by the capacity market, while subjecting state-supported resources to a MOPR. But not only is such a coercive policy unlawful (as discussed above), the Commission's FRR-RS proposal recognizes that it would be unwise—for customers, who would be foreclosed from participating in and gaining the efficiency benefits of markets if they wished to procure any portion of their capacity outside

the market, or alternatively would be forced to pay twice for capacity; for investors, who as a result might well end up serving an even smaller competitive market, at even lower prices; for states, which would be forced to either forfeit their authority over resource mix or abandon the Commission's markets altogether; and for the markets themselves, which would be increasingly unsustainable against a backdrop of increasing state commitment to clean energy.

Accordingly, the Commission has correctly pursued a more nuanced approach—one that "will not interfere with the states' ability to choose the path of re-regulation, whether via a conscious policy decision or a simple failure to take steps to prevent reregulation … on an unplanned basis," but will "provide the information that states and all other stakeholders will need in order to make informed decisions" about the wisdom of those state policies.[83]

Finally, whatever market price emerges from the intersection of supply and remaining capacity market demand will accurately reflect the value of capacity sold in that market. If a state chooses to pay higher costs to maintain or induce the entry of non-emitting resources, that choice will be rooted in a desire to distinguish between different types of capacity resources depending on their environmental profile, and to pay extra for the clean attributes of non-emitting resources. To the extent that the market price of emitting capacity sold in the Base Residual Auction turns out to be lower than some commenters may wish, that price will not be the product of below-cost bidding by resources in that market; rather, it will be the result of the fact that states have withdrawn a portion of their demand from that market to be served outside of it by non-emitting resources. The RPM price will be the competitive price for the generic capacity sold in the PJM market. And the cost of non-emitting capacity sold outside the PJM market will be transparent for customers and policymakers alike.

[83] *Id.*

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CONCLUSION

For the foregoing reasons, the Commission should adopt a Resource-Specific FRR Alternative as described herein.

Dated: October 2, 2018

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 2nd day of October, 2018.

/s/ *Marianne Alvarez*

_____

Marianne Alvarez
Exelon Corporation

Attachment A
Proposed Tariff Language

PJM OPEN ACCESS

TRANSMISSION TARIFF

1. Definitions

Unless the context otherwise specifies or requires, capitalized terms used in this PJM Tariff shall have the respective meanings assigned herein or in the Schedules hereto, or in the PJM Operating Agreement or RAA if not otherwise defined in this PJM Tariff, for all purposes of this PJM Tariff (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to sections, Schedules, Exhibits or Appendices are to sections, Schedules, Exhibits or Appendices of this Agreement. As used in this Agreement.

Definitions – A – B

Abnormal Condition:
"Abnormal Condition" shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

Acceleration Request:
"Acceleration Request" shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.4A, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 or Tariff, Attachment K-Appendix, section 1.9.4.

Actionable Subsidy:
A Material Subsidy shall be an "Actionable Subsidy" when the total amount of all Material Subsidies received by a Capacity Market Seller for a particular Capacity Resource is greater than one percent of the total revenues that such Capacity Resource would actually or reasonably anticipate receiving from markets administered by the Office of Interconnection.

Additional Day-ahead Scheduling Reserves Requirement:
"Additional Day-ahead Scheduling Reserves Requirement" shall mean the portion of the Dayahead Scheduling Reserves Requirement that is required in addition to the Base Day-ahead Scheduling Reserves Requirement to ensure adequate resources are procured to meet real-time load and operational needs, as specified in the PJM Manuals.

Affected System:
"Affected System" shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the Transmission System.

Affected System Operator:
"Affected System Operator" shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

Affiliate:
"Affiliate" shall mean any two or more entities, one of which controls the other or that are under common control. "Control" shall mean the possession, directly or indirectly, of the power to direct

the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreements:
"Agreements" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Ancillary Services:
"Ancillary Services" shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Annual Demand Resource:
"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Annual Energy Efficiency Resource:
"Annual Energy Efficiency Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Annual Resource:
"Annual Resource" shall mean a Generation Capacity Resource, an Annual Energy Efficiency Resource or an Annual Demand Resource.

Annual Resource Price Adder:
"Annual Resource Price Adder" shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

Annual Revenue Rate:
"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under Tariff, Attachment DD, section 11.

Annual Transmission Costs:
"Annual Transmission Costs" shall mean the total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in

Attachment H for each Zone until amended by the applicable Transmission Owner or modified by the Commission.

Applicable Laws and Regulations:
"Applicable Laws and Regulations" shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

Applicable Regional Entity:
"Applicable Regional Entity" shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:
"Applicable Standards" shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Applicable Technical Requirements and Standards:
"Applicable Technical Requirements and Standards" shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of an Interconnected Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual provided, however, that, with respect to any generation facilities with maximum generating capacity of 2 MW or less (synchronous) or 5 MW or less (inverter-based) for which the Interconnection Customer executes a Construction Service Agreement or Interconnection Service Agreement on or after March 19, 2005, "Applicable Technical Requirements and Standards" shall refer to the "PJM Small Generator Interconnection Applicable Technical Requirements and Standards." All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider's internet website.

Applicant:
"Applicant" shall mean an entity desiring to become a PJM Member, or to take Transmission Service that has submitted the PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:
"Application" shall mean a request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

Attachment Facilities:
"Attachment Facilities" shall mean the facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.

Attachment H:

"Attachment H" shall refer collectively to the Attachments to the PJM Tariff with the prefix "H-" that set forth, among other things, the Annual Transmission Rates for Network Integration Transmission Service in the PJM Zones.

Auction Revenue Rights:
"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:
"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Government Agency:
"Authorized Government Agency" means a regulatory body or government agency, with jurisdiction over PJM, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, State Commissions, and state and federal attorneys general.

Avoidable Cost Rate:
"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Balancing Congestion Charges:
"Balancing Congestion Charges" shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Balancing Ratio:
"Balancing Ratio" shall have the meaning provided in Tariff, Attachment DD, section 10A.

Base Capacity Demand Resource:
"Base Capacity Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Base Capacity Demand Resource Constraint:

"Base Capacity Demand Resource Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the Base Capacity Demand Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources (displacing otherwise committed generation) as interruptible from June 1 through September 30 and unavailable the rest of the Delivery Year in question and calculates the LOLE at each DR and EE level. The Base Capacity Demand Resource Constraint is the combined amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a five percent increase in the LOLE, compared to the reference value. The Base Capacity Demand Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Demand Resource Price Decrement:
"Base Capacity Demand Resource Price Decrement" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources and the clearing price for Base Capacity Resources and Capacity Performance Resources, representing the cost to procure additional Base Capacity Resources or Capacity Performance Resources out of merit order when the Base Capacity Demand Resource Constraint is binding.

Base Capacity Energy Efficiency Resource:
"Base Capacity Energy Efficiency Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Base Capacity Resource:
"Base Capacity Resource" shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(b).

Base Capacity Resource Constraint:
"Base Capacity Resource Constraint" for the PJM Region or an LDA, shall mean, for the 2018/2019 and 2019/2020 Delivery Years, the maximum Unforced Capacity amount, determined by PJM, of Base Capacity Resources, including Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources, that is consistent with the maintenance of reliability. As more fully set forth in the PJM Manuals, PJM calculates the above Base Capacity Resource Constraint for the PJM Region or an LDA, by first determining a reference annual loss of load expectation ("LOLE") assuming no Base Capacity Resources, including no Base Capacity Demand Resources or Base Capacity Energy Efficiency Resources. The calculation for the PJM Region uses the weekly load distribution from the Installed Reserve Margin study for the Delivery Year in question (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a weekly load distribution (based on the Installed Reserve Margin study and the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question. Additionally, for the PJM Region and relevant LDA calculation, the weekly capacity distributions are adjusted to reflect winter ratings.

For both the PJM Region and LDA analyses, PJM models the commitment of an amount of Base Capacity Demand Resources and Base Capacity Energy Efficiency Resources equal to the Base Capacity Demand Resource Constraint (displacing otherwise committed generation). PJM then models the commitment of varying amounts of Base Capacity Resources (displacing otherwise committed generation) as unavailable during the peak week of winter and available the rest of the Delivery Year in question and calculates the LOLE at each Base Capacity Resource level. The Base Capacity Resource Constraint is the combined amount of Base Capacity Demand Resources, Base Capacity Energy Efficiency Resources and Base Capacity Resources, stated as a percentage of the unrestricted annual peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Base Capacity Resource Constraint shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [one minus the pool-wide average EFORd] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Base Capacity Resource Price Decrement:
"Base Capacity Resource Price Decrement" shall mean, for the 2018/2019 and 2019/2020 Delivery Years, a difference between the clearing price for Base Capacity Resources and the clearing price for Capacity Performance Resources, representing the cost to procure additional Capacity Performance Resources out of merit order when the Base Capacity Resource Constraint is binding.

Base Day-ahead Scheduling Reserves Requirement:

"Base Day-ahead Scheduling Reserves Requirement" shall mean the thirty-minute reserve requirement for the PJM Region established consistent with the Applicable Standards, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

Base Load Generation Resource
"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

Base Offer Segment:
"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

Base Residual Auction:
"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self- Supply.

Batch Load Demand Resource:
"Batch Load Demand Resource" shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

Behind The Meter Generation:
"Behind The Meter Generation" shall refer to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Service:
"Black Start Service" shall mean the capability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

Breach:

"Breach" shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:
"Breaching Party" shall mean a party that is in Breach of Tariff, Part IV or Part VI and/or an agreement entered into thereunder.

Business Day:
"Business Day" shall mean a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Buy Bid:
"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

Definitions – C-D

Canadian Guaranty:
"Canadian Guaranty" shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in Canada, and meets all of the provisions of Tariff, Attachment Q.

Cancellation Costs:
"Cancellation Costs" shall mean costs and liabilities incurred in connection with: (a) cancellation of supplier and contractor written orders and agreements entered into to design, construct and install Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, and/or (b) completion of some or all of the required Attachment Facilities, Direct Assignment Facilities and/or Customer-Funded Upgrades, or specific unfinished portions and/or removal of any or all of such facilities which have been installed, to the extent required for the Transmission Provider and/or Transmission Owner(s) to perform their respective obligations under Tariff, Part IV and/or Tariff, Part VI.

Capacity:
"Capacity" shall mean the installed capacity requirement of the Reliability Assurance Agreement or similar such requirements as may be established.

Capacity Emergency Transfer Limit:
"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Emergency Transfer Objective:
"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Export Transmission Customer:
"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Tariff, Part II to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in Tariff, Attachment DD, section 6.6(g).

Capacity Import Limit:
"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Interconnection Rights:
"Capacity Interconnection Rights" shall mean the rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.

Capacity Market Buyer:
"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

Capacity Market Seller:

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

Capacity Performance Resource:
"Capacity Performance Resource" shall mean a Capacity Resource as described in Tariff, Attachment DD, section 5.5A(a).

Capacity Performance Transition Incremental Auction:
"Capacity Performance Transition Incremental Auction" shall have the meaning specified in Tariff, Attachment DD, section 5.14D.

Capacity Resource:
"Capacity Resource" shall have the meaning provided in the Reliability Assurance Agreement.

Capacity Resource Clearing Price:
"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Tariff, Attachment DD, section 5.

Capacity Storage Resource:
"Capacity Storage Resource" shall mean any hydroelectric power plant, flywheel, battery storage, or other such facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets and which participates in the Reliability Pricing Model.

Capacity Resources with Actionable Subsidies:
A Capacity Resource that meets any of the following criteria shall be deemed to be a "Capacity Resource with Actionable Subsidy":

(a) The Capacity Market Seller formally or informally, directly or indirectly, receives, or is authorized and intends to receive, an Actionable Subsidy with regard to such Capacity Resource; or

(b) The Capacity Market Seller is guaranteed recovery of the costs of its Capacity Resource from retail customers.

If an officer of the Capacity Market Seller certifies that the Capacity Resource will forgo any revenues that would be available under any known mechanism that would otherwise qualify the Capacity Resource as a Capacity Resource with an Actionable Subsidy, such mechanism will not be considered an Actionable Subsidy with respect to such Capacity Resource.

Capacity Transfer Right:
"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the

Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

Capacity Transmission Injection Rights:
"Capacity Transmission Injection Rights" shall mean the rights to schedule energy and capacity deliveries at a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Capacity Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility and/or Controllable A.C. Merchant Transmission Facilities that connects the Transmission System to another control area. Deliveries scheduled using Capacity Transmission Injection Rights have rights similar to those under Firm Point-to-Point Transmission Service or, if coupled with a generating unit external to the PJM Region that satisfies all applicable criteria specified in the PJM Manuals, similar to Capacity Interconnection Rights.

Cold/Warm/Hot Notification Time:
"Cold/Warm/Hot Notification Time" shall mean the time interval between PJM notification and the beginning of the start sequence for a generating unit that is currently in its cold/warm/hot temperature state. The start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc.

Cold/Warm/Hot Start-up Time:
For all generating units that are not combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval, measured in hours, from the beginning of the start sequence to the point after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero for a generating unit in its cold/warm/hot temperature state. For combined cycle units, "Cold/Warm/Hot Start-up Time" shall mean the time interval from the beginning of the start sequence to the point after first combustion turbine generator breaker closure in its cold/warm/hot temperature state, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For all generating units, the start sequence may include steps such as any valve operation, starting feed water pumps, startup of auxiliary equipment, etc. Other more detailed actions that could signal the beginning of the start sequence could include, but are not limited to, the operation of pumps, condensers, fans, water chemistry evaluations, checklists, valves, fuel systems, combustion turbines, starting engines or systems, maintaining stable fuel/air ratios, and other auxiliary equipment necessary for startup.

Cold Weather Alert:
"Cold Weather Alert" shall mean the notice that PJM provides to PJM Members, Transmission Owners, resource owners and operators, customers, and regulators to prepare personnel and facilities for expected extreme cold weather conditions.

Collateral:
"Collateral" shall be a cash deposit, including any interest, or letter of credit in an amount and form determined by and acceptable to PJMSettlement, provided by a Participant to PJMSettlement as security in order to participate in the PJM Markets or take Transmission Service.

Collateral Call:

"Collateral Call" shall mean a notice to a Participant that additional Collateral, or possibly early payment, is required in order to remain in, or to regain, compliance with Tariff, Attachment Q.

Commencement Date:
"Commencement Date" shall mean the date on which Interconnection Service commences in accordance with an Interconnection Service Agreement.

Committed Offer:
The "Committed Offer" shall mean 1) for pool-scheduled resources, an offer on which a resource was scheduled by the Office of the Interconnection for a particular clock hour for an Operating Day, and 2) for self-scheduled resources, either the offer on which the Market Seller has elected to schedule the resource or the applicable offer for the resource determined pursuant to Operating Agreement, Schedule 1, section 6.4, or Operating Agreement, Schedule 1, section 6.6 for a particular clock hour for an Operating Day.

Completed Application:
"Completed Application" shall mean an application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

Compliance Aggregation Area (CAA):
"Compliance Aggregation Area" or "CAA" shall mean a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, the same locational price separation in the Third Incremental Auction.

Conditional Incremental Auction:
"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

CONE Area:
"CONE Area" shall mean the areas listed in Tariff, Attachment DD, section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to Tariff, Attachment DD, section 5.10(a)(iv)(B).

Confidential Information:
"Confidential Information" shall mean any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the present or planned business of a New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, without limitation, all information relating to the producing party's technology, research and development, business affairs and pricing, and any

information supplied by any New Service Customer, Transmission Owner, or other Interconnection Party or Construction Party to another such party prior to the execution of an Interconnection Service Agreement or a Construction Service Agreement.

Congestion Price:
"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Consolidated Transmission Owners Agreement, PJM Transmission Owners Agreement or Transmission Owners Agreement:
"Consolidated Transmission Owners Agreement," "PJM Transmission Owners Agreement" or "Transmission Owners Agreement" shall mean the certain Consolidated Transmission Owners Agreement dated as of December 15, 2005, by and among the Transmission Owners and by and between the Transmission Owners and PJM Interconnection, L.L.C. on file with the Commission, as amended from time to time.

Constructing Entity:
"Constructing Entity" shall mean either the Transmission Owner or the New Services Customer, depending on which entity has the construction responsibility pursuant to Tariff, Part VI and the applicable Construction Service Agreement; this term shall also be used to refer to an Interconnection Customer with respect to the construction of the Customer Interconnection Facilities.

Construction Party:
"Construction Party" shall mean a party to a Construction Service Agreement. "Construction Parties" shall mean all of the Parties to a Construction Service Agreement.

Construction Service Agreement:
"Construction Service Agreement" shall mean either an Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

Control Area:
"Control Area" shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common automatic generation control scheme is applied in order to:

(1) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Zone:
"Control Zone" shall have the meaning given in the Operating Agreement.

Controllable A.C. Merchant Transmission Facilities:
"Controllable A.C. Merchant Transmission Facilities" shall mean transmission facilities that (1) employ technology which Transmission Provider reviews and verifies will permit control of the amount and/or direction of power flow on such facilities to such extent as to effectively enable the controllable facilities to be operated as if they were direct current transmission facilities, and (2) that are interconnected with the Transmission System pursuant to Tariff, Part IV and Tariff, Part VI.

Coordinated External Transaction:
"Coordinated External Transaction" shall mean a transaction to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Coordinated Transaction Scheduling:
"Coordinated Transaction Scheduling" or "CTS" shall mean the scheduling of Coordinated External Transactions at a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Corporate Guaranty:
"Corporate Guaranty" shall mean a legal document used by an entity to guaranty the obligations of another entity.

Cost of New Entry:
"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with Tariff, Attachment DD, section 5.

Costs:
As used in Tariff, Part IV, Tariff, Part VI and related attachments, "Costs" shall mean costs and expenses, as estimated or calculated, as applicable, including, but not limited to, capital expenditures, if applicable, and overhead, return, and the costs of financing and taxes and any Incidental Expenses.

Counterparty:

"Counterparty" shall mean PJMSettlement as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Market Participant or other entities, including the agreements and transactions with customers regarding transmission service and other transactions under the PJM Tariff and the Operating Agreement. PJMSettlement shall not be a counterparty to (i) any bilateral transactions between Members, or (ii) any Member's self-supply of energy to serve its load, or (iii) any Member's self-schedule of energy reported to the Office of the Interconnection to the extent that energy serves that Member's own load .

Credit Available for Export Transactions:
"Credit Available for Export Transactions" shall mean a designation of credit to be used for Export Transactions that is allocated by each Market Participant from its Credit Available for Virtual Transactions, and which reduces the Market Participant's Credit Available for Virtual Transactions accordingly.

Credit Available for Virtual Transactions:
"Credit Available for Virtual Transactions" shall mean the Market Participant's Working Credit Limit for Virtual Transactions calculated on its credit provided in compliance with its Peak Market Activity requirement plus available credit submitted above that amount, less any unpaid billed and unbilled amounts owed to PJMSettlement, plus any unpaid unbilled amounts owed by PJMSettlement to the Market Participant, less any applicable credit required for Minimum Participation Requirements, FTRs, RPM activity, or other credit requirement determinants as defined in Tariff, Attachment Q.

Credit Breach:
"Credit Breach" shall mean the status of a Participant that does not currently meet the requirements of Tariff, Attachment Q or other provisions of the Agreements.

Credit-Limited Offer:
"Credit-Limited Offer" shall mean a Sell Offer that is submitted by a Market Participant in an RPM Auction subject to a maximum credit requirement specified by such Market Participant.

Credit Score:
"Credit Score" shall mean a composite numerical score scaled from 0-100 as calculated by PJMSettlement that incorporates various predictors of creditworthiness.

CTS Enabled Interface:
"CTS Enabled Interface" shall mean an interface between the PJM Control Area and an adjacent Control Area at which the Office of the Interconnection has authorized the use of Coordinated Transaction Scheduling ("CTS"). The CTS Enabled Interfaces between the PJM Control Area and the New York Independent System Operator, Inc. Control Area shall be designated in the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C., Schedule A (PJM Rate Schedule FERC No. 45). The CTS Enabled Interfaces between the PJM Control Area and the Midcontinent Independent System Operator, Inc. shall be designated consistent with Attachment 3, section 2 of the Joint Operating Agreement between Midcontinent Independent System Operator, Inc. and PJM Interconnection, L.L.C.

CTS Interface Bid:
"CTS Interface Bid" shall mean a unified real-time bid to simultaneously purchase and sell energy on either side of a CTS Enabled Interface in accordance with the procedures of Operating Agreement, Schedule 1, section 1.13, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.13.

Curtailment:
"Curtailment" shall mean a reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

Curtailment Service Provider:
"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market, Ancillary Services markets, and/or Reliability Pricing Model by causing a reduction in demand.

Customer Facility:
"Customer Facility" shall mean generation facilities or Merchant Transmission Facilities interconnected with or added to the Transmission System pursuant to an Interconnection Request under Tariff, Part IV, subpart A.

Customer-Funded Upgrade:
"Customer-Funded Upgrade" shall mean any Network Upgrade, Local Upgrade, or Merchant Network Upgrade for which cost responsibility (i) is imposed on an Interconnection Customer or an Eligible Customer pursuant to Tariff, Part VI, section 217, or (ii) is voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade Request. No Network Upgrade, Local Upgrade or Merchant Network Upgrade or other transmission expansion or enhancement shall be a Customer-Funded Upgrade if and to the extent that the costs thereof are included in the rate base of a public utility on which a regulated return is earned.

Customer Interconnection Facilities:
"Customer Interconnection Facilities" shall mean all facilities and equipment owned and/or controlled, operated and maintained by Interconnection Customer on Interconnection Customer's side of the Point of Interconnection identified in the appropriate appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions, or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System.

Daily Deficiency Rate:
"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under Tariff, Attachment DD, section 7, Tariff, Attachment DD, section 8, Tariff, Attachment DD, section 9, or Tariff, Attachment DD, section 13.

Daily Unforced Capacity Obligation:

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Reliability Assurance Agreement, Schedule 8, or, as to an FRR entity, in Reliability Assurance Agreement, Schedule 8.1.

Day-ahead Congestion Price:
"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

Day-ahead Energy Market:
"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Energy Market Injection Congestion Credits:
"Day-ahead Energy Market Injection Congestion Credits" shall mean those congestion credits paid to Market Participants for supply transactions in the Day-ahead Energy Market including generation schedules, Increment Offers, Up-to Congestion Transactions, import transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Energy Market Transmission Congestion Charges:
"Day-ahead Energy Market Transmission Congestion Charges" shall be equal to the sum of Day-ahead Energy Market Withdrawal Congestion Charges minus [the sum of Day-ahead Energy Market Injection Congestion Credits plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, as applicable)].

Day-ahead Energy Market Withdrawal Congestion Charges:
"Day-ahead Energy Market Withdrawal Congestion Charges" shall mean those congestion charges collected from Market Participants for withdrawal transactions in the Day-ahead Energy Market from transactions including Demand Bids, Decrement Bids, Up-to Congestion Transactions, Export Transactions, and Day-Ahead Pseudo-Tie Transactions.

Day-ahead Loss Price:
"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

Day-ahead Prices:
"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

Day-Ahead Pseudo-Tie Transaction:

"Day-Ahead Pseudo-Tie Transaction" shall mean a transaction scheduled in the Day-ahead Energy Market to the PJM-MISO interface from a generator within the PJM balancing authority area that Pseudo-Ties into the MISO balancing authority area.

Day-ahead Scheduling Reserves:
"Day-ahead Scheduling Reserves" shall mean thirty-minute reserves as defined by the Reliability*First* Corporation and SERC.

Day-ahead Scheduling Reserves Market:
"Day-ahead Scheduling Reserves Market" shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Operating Agreement, Schedule 1, section 1.10 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.

Day-ahead Scheduling Reserves Requirement:
"Day-ahead Scheduling Reserves Requirement" shall mean the sum of Base Day-ahead Scheduling Reserves Requirement and Additional Day-ahead Scheduling Reserves Requirement.

Day-ahead Scheduling Reserves Resources:
"Day-ahead Scheduling Reserves Resources" shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

Day-ahead Settlement Interval:
"Day-ahead Settlement Interval" shall mean the interval used by settlements, which shall be every one clock hour.

Day-ahead System Energy Price:
"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

Deactivation:
"Deactivation" shall mean the retirement or mothballing of a generating unit governed by Tariff, Part V.

Deactivation Avoidable Cost Credit:
"Deactivation Avoidable Cost Credit" shall mean the credit paid to Generation Owners pursuant to Tariff, Part V, section 114.

Deactivation Avoidable Cost Rate:
"Deactivation Avoidable Cost Rate" shall mean the formula rate established pursuant to Tariff, Part V, section 115 .

Deactivation Date:

"Deactivation Date" shall mean the date a generating unit within the PJM Region is either retired or mothballed and ceases to operate.

Decrement Bid:
"Decrement Bid" shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

Default:
As used in the Interconnection Service Agreement and Construction Service Agreement, "Default" shall mean the failure of a Breaching Party to cure its Breach in accordance with the applicable provisions of an Interconnection Service Agreement or Construction Service Agreement.

Delivering Party:
"Delivering Party" shall mean the entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

Delivery Year:
"Delivery Year" shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Tariff, Attachment DD, or pursuant to an FRR Capacity Plan under Reliability Assurance Agreement, Schedule 8.1.

Demand Bid:
"Demand Bid" shall mean a bid, submitted by a Load Serving Entity in the Day-ahead Energy Market, to purchase energy at its contracted load location, for a specified timeframe and megawatt quantity, that if cleared will result in energy being scheduled at the specified location in the Day-ahead Energy Market and in the physical transfer of energy during the relevant Operating Day.

Demand Bid Limit:
"Demand Bid Limit" shall mean the largest MW volume of Demand Bids that may be submitted by a Load Serving Entity for any hour of an Operating Day, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Bid Screening:
"Demand Bid Screening" shall mean the process by which Demand Bids are reviewed against the applicable Demand Bid Limit, and rejected if they would exceed that limit, as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1B, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1B.

Demand Resource:
"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

Demand Resource Factor or DR Factor:
"Demand Resource Factor" or ("DR Factor") shall have the meaning specified in the Reliability Assurance Agreement.

Designated Agent:
"Designated Agent" shall mean any entity that performs actions or functions on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer required under the Tariff.

Designated Entity:
"Designated Entity" shall have the same meaning provided in the Operating Agreement.

Direct Assignment Facilities:
"Direct Assignment Facilities" shall mean facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Direct Load Control:
"Direct Load Control" shall mean load reduction that is controlled directly by the Curtailment Service Provider's market operations center or its agent, in response to PJM instructions.

Dispatch Rate:
"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

Dynamic Schedule:
"Dynamic Schedule" shall have the same meaning provided in the Operating Agreement.

Dynamic Transfer:
"Dynamic Transfer" shall have the same meaning provided in the Operating Agreement.

Definitions – E - F

Economic-based Enhancement or Expansion:
"Economic-based Enhancement or Expansion" shall have the same meaning provided in the Operating Agreement.

Economic Load Response Participant:
"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A, to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:
"Economic Maximum" shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:
"Economic Minimum" shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective FTR Holder:
"Effective FTR Holder" shall mean:

(i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) (iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EFORd:
"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

Electrical Distance:
"Electrical Distance" shall mean, for a Generation Capacity Resource geographically located outside the metered boundaries of the PJM Region, the measure of distance, based on impedance and in accordance with the PJM Manuals, from the Generation Capacity Resource to the PJM Region.

Eligible Customer:
"Eligible Customer" shall mean:
(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Tariff, Part VI, Eligible Customer shall mean only those Eligible Customers that have submitted a Completed Application.

Emergency Action:
"Emergency Action" shall mean any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action including, but not limited to, a Voltage Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning, or Manual Load Dump Action.

Emergency Condition:
"Emergency Condition" shall mean a condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Interconnected Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Interconnection Customer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Customer Facility or to the Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Interconnection Customer is not obligated by an Interconnection Service Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

Emergency Load Response Program:
"Emergency Load Response Program" shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Energy Efficiency Resource:
"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

Energy Market Opportunity Cost:
"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations, and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Resource:
"Energy Resource" shall mean a generating facility that is not a Capacity Resource.

Energy Settlement Area:
"Energy Settlement Area" shall mean the bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

Energy Storage Resource:
"Energy Storage Resource" shall mean flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancillary Services markets as a Market Seller.

Energy Transmission Injection Rights:
"Energy Transmission Injection Rights" shall mean the rights to schedule energy deliveries at a specified point on the Transmission System. Energy Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Deliveries scheduled using Energy Transmission Injection Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Environmental Laws:
"Environmental Laws" shall mean applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.
Environmentally-Limited Resource:

"Environmentally-Limited Resource" shall mean a resource which has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited by a governmental authority to operating only during declared PJM capacity emergencies.

Equivalent Load:
"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

Existing Generation Capacity Resource:
"Existing Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Export Credit Exposure:
"Export Credit Exposure" is determined for each Market Participant for a given Operating Day, and shall mean the sum of credit exposures for the Market Participant's Export Transactions for that Operating Day and for the preceding Operating Day.

Export Nodal Reference Price:
"Export Nodal Reference Price" at each location is the 97th percentile, shall be, the real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

Export Transaction:
"Export Transaction" shall be a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

Export Transaction Price Factor:
"Export Transaction Price Factor" for a prospective time interval shall be the greater of (i) PJM's forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction's dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

Export Transaction Screening:
"Export Transaction Screening" shall be the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

Export Transactions Net Activity:
"Export Transactions Net Activity" shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Operating Agreement, Schedule 1 and the parallel provisions of Tariff, Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

Extended Primary Reserve Requirement:
"Extended Primary Reserve Requirement" shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Summer Demand Resource:
"Extended Summer Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Extended Summer Resource Price Adder:
"Extended Summer Resource Price Adder" shall mean, for Delivery Years through May 31, 2018, an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

Extended Synchronized Reserve Requirement:
"Extended Synchronized Reserve Requirement" shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:
"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

External Resource:
"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

Facilities Study:
"Facilities Study" shall be an engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to: (1) determine the required modifications to the Transmission Provider's Transmission System necessary to implement the conclusions of the System Impact Study; and (2) complete any additional studies or analyses documented in the System Impact Study or required by PJM Manuals, and determine the required modifications to the Transmission Provider's Transmission System based on the conclusions of

such additional studies. The Facilities Study shall include the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate a New Service Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Customer Funded Upgrades necessary to accommodate the New Service Customer's New Service Request in accordance with Tariff, Part VI, section 207.

Federal Power Act:
"Federal Power Act" shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

FERC or Commission:
"FERC" or "Commission" shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

FERC Market Rules:
"FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish.

Final Incremental Auction:
"Final Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates for the 2021/2022 Delivery Year and all subsequent Delivery Years.

Final Offer:
"Final Offer" shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day.

Final RTO Unforced Capacity Obligation:
"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with RAA, Schedule 8.

Financial Close:
"Financial Close" shall mean the Capacity Market Seller has demonstrated that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. A sworn, notarized certification of an independent engineer certifying to such facts, and that the engineer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration. For resources that do not have external financing, Financial Close shall mean the project has full funding available, and that the project has been duly authorized to proceed with full construction of the material portions of the project by the appropriate governing body of

the company funding such project. A sworn, notarized certification by an officer of such company certifying to such facts, and that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration.

Financial Transmission Right:
"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:
"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(b).

Financial Transmission Right Option:
"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Firm Point-To-Point Transmission Service:
"Firm Point-To-Point Transmission Service" shall mean Transmission Service under the Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Tariff, Part II.

Firm Transmission Feasibility Study:
"Firm Transmission Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part II, section 19.3 and Tariff, Part III, section 32.3.

Firm Transmission Withdrawal Rights:
"Firm Transmission Withdrawal Rights" shall mean the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System with another control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

First Incremental Auction:
"First Incremental Auction" shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

Flexible Resource:
"Flexible Resource" shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Forecast Pool Requirement:

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

Foreign Guaranty:
"Foreign Guaranty" shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of Tariff, Attachment Q.

Form 715 Planning Criteria:
"Form 715 Planning Criteria" shall have the same meaning provided in the Operating Agreement.

FRR-RS Resource:
"FRR-RS Resource" shall mean, for the duration of such election, a Capacity Resource, or portion thereof, that has elected the FRR-RS Alternative.

FTR Credit Limit:
"FTR Credit Limit" shall mean the amount of credit established with PJMSettlement that an FTR Participant has specifically designated to be used for FTR activity in a specific customer account. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the FTR Participant may have with PJMSettlement.

FTR Credit Requirement:
"FTR Credit Requirement" shall mean the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or for which it is bidding. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems. FTR Credit Requirements are calculated and applied separately for each separate customer account.

FTR Flow Undiversified:
"FTR Flow Undiversified" shall have the meaning established in Tariff, Attachment Q, section V.G.

FTR Historical Value:
For each FTR for each month, "FTR Historical Value" shall mean the weighted average of historical values over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year.

FTR Holder:
"FTR Holder" shall mean the PJM Member that has acquired and possesses an FTR.

FTR Monthly Credit Requirement Contribution:
For each FTR, for each month, "FTR Monthly Credit Requirement Contribution" shall mean the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

FTR Net Activity:
"FTR Net Activity" shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

FTR Participant:
"FTR Participant" shall mean any Market Participant that provides or is required to provide Collateral in order to participate in PJM's FTR auctions.

FTR Portfolio Auction Value:
"FTR Portfolio Auction Value" shall mean for each customer account of a Market Participant, the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

Fuel Cost Policy:
"Fuel Cost Policy" shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller's method used to price fuel for calculation of the Market Seller's cost-based offers for a generation resource.

Full Notice to Proceed:
"Full Notice to Proceed" shall mean that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.

Definitions – L – M – N

Limited Demand Resource:
"Limited Demand Resource**"** shall have the meaning specified in the Reliability Assurance Agreement.

Limited Demand Resource Reliability Target:
"Limited Demand Resource Reliability Target**"** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016/2017 and 2017/2018 Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Limited Resource Constraint:

"Limited Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and Delivery Years, for the PJM Region or each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

Limited Resource Price Decrement:
"Limited Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

List of Approved Contractors:
"List of Approved Contractors" shall mean a list developed by each Transmission Owner and published in a PJM Manual of (a) contractors that the Transmission Owner considers to be qualified to install or construct new facilities and/or upgrades or modifications to existing facilities on the Transmission Owner's system, provided that such contractors may include, but need not be limited to, contractors that, in addition to providing construction services, also provide design and/or other construction-related services, and (b) manufacturers or vendors of major transmission-related equipment (e.g., high-voltage transformers, transmission line, circuit breakers) whose products the Transmission Owner considers acceptable for installation and use on its system.

Load Management:
"Load Management" shall mean a Demand Resource ("DR") as defined in the Reliability Assurance Agreement.

Load Management Event:
"Load Management Event" shall mean a) a single temporally contiguous dispatch of Demand Resources in a Compliance Aggregation Area during an Operating Day, or b) multiple dispatches of Demand Resources in a Compliance Aggregation Area during an Operating Day that are temporally contiguous.

Load Ratio Share:
"Load Ratio Share" shall mean the ratio of a Transmission Customer's Network Load to the Transmission Provider's total load.

Load Reduction Event:
"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

Load Serving Entity (LSE):

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

Load Shedding:
"Load Shedding" shall mean the systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Tariff, Part II or Part III.

Local Upgrades:
"Local Upgrades" shall mean modifications or additions of facilities to abate any local thermal loading, voltage, short circuit, stability or similar engineering problem caused by the interconnection and delivery of generation to the Transmission System. Local Upgrades shall include:

(i) Direct Connection Local Upgrades which are Local Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) Non-Direct Connection Local Upgrades which are parallel flow Local Upgrades that are not Direct Connection Local Upgrades.

Location:
"Location" as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

LOC Deviation:
"LOC Deviation," shall mean, for units other than wind units, the LOC Deviation shall equal the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval real-time Locational Marginal Price at the resource's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments and limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit. For wind units, the LOC Deviation shall mean the deviation of the generating unit's output equal to the lesser of the PJM forecasted output for the unit or the desired megawatt amount for the resource determined according to the point on the Final Offer curve corresponding to the Real-time Settlement Interval integrated realtime Locational Marginal Price at the resource's bus, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, minus the actual output of the unit.

Locational Deliverability Area (LDA):
"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Reliability Assurance Agreement, Schedule 10.1.

Locational Deliverability Area Reliability Requirement:
"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

Locational Price Adder:
"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

Locational Reliability Charge:
"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

Locational UCAP:
"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

Locational UCAP Seller:
"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

Long-lead Project:
"Long-lead Project" shall have the same meaning provided in the Operating Agreement.

Long-Term Firm Point-To-Point Transmission Service:
"Long-Term Firm Point-To-Point Transmission Service" shall mean firm Point-To-Point Transmission Service under Tariff, Part II with a term of one year or more.

Loss Price:
"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

M2M Flowgate:
"M2M Flowgate" shall have the meaning provided in the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Maintenance Adder:

"Maintenance Adder" shall mean an adder that may be included to account for variable operation and maintenance expenses in a Market Seller's Fuel Cost Policy. The Maintenance Adder is calculated in accordance with the applicable provisions of PJM Manual 15, and may only include expenses incurred as a result of electric production.

Manual Load Dump Action:
"Manual Load Dump Action" shall mean an Operating Instruction, as defined by NERC, from PJM to shed firm load when the PJM Region cannot provide adequate capacity to meet the PJM Region's load and tie schedules, or to alleviate critically overloaded transmission lines or other equipment.

Manual Load Dump Warning:
"Manual Load Dump Warning" shall mean a notification from PJM to warn Members of an increasingly critical condition of present operations that may require manually shedding load.

Market Monitor:
"Market Monitor**"** means the head of the Market Monitoring Unit.

Market Monitoring Unit or MMU:
"Market Monitoring Unit" or "MMU" means the independent Market Monitoring Unit defined in 18 CFR § 35.28(a)(7) and established under the PJM Market Monitoring Plan (Attachment M) to the PJM Tariff that is responsible for implementing the Market Monitoring Plan, including the Market Monitor. The Market Monitoring Unit may also be referred to as the IMM or Independent Market Monitor for PJM

Market Monitoring Unit Advisory Committee or MMU Advisory Committee:
"Market Monitoring Unit Advisory Committee" or "MMU Advisory Committee" shall mean the committee established under Tariff, Attachment M, section III.H.

Market Operations Center:
"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

Market Participant:
"Market Participant" shall mean a Market Buyer, a Market Seller, an Economic Load Response Participant, or all three, except when such term is used in Tariff, Attachment M, in which case Market Participant shall mean an entity that generates, transmits, distributes, purchases, or sells electricity, ancillary services, or any other product or service provided under the PJM Tariff or Operating Agreement within, into, out of, or through the PJM Region, but it shall not include an Authorized Government Agency that consumes energy for its own use but does not purchase or sell energy at wholesale.

Market Participant Energy Injection:

"Market Participant Energy Injection" shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Day-ahead generation schedules, realtime generation output, Increment Offers, internal bilateral transactions and import transactions, as further described in the PJM Manuals.

Market Participant Energy Withdrawal:
"Market Participant Energy Withdrawal" shall mean transactions in the Day-ahead Energy Market and Real-time Energy Market, including but not limited to Demand Bids, Decrement Bids, real-time load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), internal bilateral transactions and Export Transactions, as further described in the PJM Manuals.

Market Seller Offer Cap:
"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with Tariff, Attachment DD. section 6 and Tariff, Attachment M-Appendix, section II.E.

Market Violation:
"Market Violation" shall mean a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, as defined in 18 C.F.R. § 35.28(b)(8).

Material Modification:
"Material Modification" shall mean any modification to an Interconnection Request that has a material adverse effect on the cost or timing of Interconnection Studies related to, or any Network Upgrades or Local Upgrades needed to accommodate, any Interconnection Request with a later Queue Position.

Material Subsidy:
"Material Subsidy" shall mean:

(1) material payments, rebates, or subsidies directly or indirectly from any state or local governmental entity connected to the construction, development, production, or operation of the Capacity Resource;

(2) other material support or payments, obtained in any state-sponsored or state-mandated processes, connected to the construction, development, production, or operation of the Capacity Resource; or

(3) payments outside the RPM Auction for the procurement of capacity or energy from a Capacity Resource, obtained through a state-sponsored or state-directed procurement process.

Maximum Daily Starts:
"Maximum Daily Starts" shall mean the maximum number of times that a generating unit can be started in an Operating Day under normal operating conditions.

Maximum Emergency:
"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

Maximum Facility Output:
"Maximum Facility Output" shall mean the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer's Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study.

Maximum Generation Emergency:
"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

Maximum Generation Emergency Alert:
"Maximum Generation Emergency Alert" shall mean an alert issued by the Office of the Interconnection to notify PJM Members, Transmission Owners, resource owners and operators, customers, and regulators that a Maximum Generation Emergency may be declared, for any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market, for all or any part of such Operating Day.

Maximum Run Time:
"Maximum Run Time" shall mean the maximum number of hours a generating unit can run over the course of an Operating Day, as measured by PJM's State Estimator.

Maximum Weekly Starts:
"Maximum Weekly Starts" shall mean the maximum number of times that a generating unit can be started in one week, defined as the 168 hour period starting Monday 0001 hour, under normal operating conditions.

Member:
"Member" shall have the meaning provided in the Operating Agreement.

Merchant A.C. Transmission Facilities:

"Merchant A.C. Transmission Facility" shall mean Merchant Transmission Facilities that are alternating current (A.C.) transmission facilities, other than those that are Controllable A.C. Merchant Transmission Facilities.

Merchant D.C. Transmission Facilities:
"Merchant D.C. Transmission Facilities" shall mean direct current (D.C.) transmission facilities that are interconnected with the Transmission System pursuant to Tariff, Part IV and Part VI.

Merchant Network Upgrades:
"Merchant Network Upgrades" shall mean additions to, or modifications or replacements of, physical facilities of the Interconnected Transmission Owner that, on the date of the pertinent Transmission Interconnection Customer's Upgrade Request, are part of the Transmission System or are included in the Regional Transmission Expansion Plan.

Merchant Transmission Facilities:
"Merchant Transmission Facilities" shall mean A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include (i) any Customer Interconnection Facilities, (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003 ; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff, or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned.

Merchant Transmission Provider:
"Merchant Transmission Provider" shall mean an Interconnection Customer that (1) owns, controls, or controls the rights to use the transmission capability of, Merchant D.C. Transmission Facilities and/or Controllable A.C. Merchant Transmission Facilities that connect the Transmission System with another control area, (2) has elected to receive Transmission Injection Rights and Transmission Withdrawal Rights associated with such facility pursuant to Tariff, Part IV, section 36, and (3) makes (or will make) the transmission capability of such facilities available for use by third parties under terms and conditions approved by the Commission and stated in the Tariff, consistent with Tariff, section 38.

Metering Equipment:
"Metering Equipment" shall mean all metering equipment installed at the metering points designated in the appropriate appendix to an Interconnection Service Agreement.

Minimum Annual Resource Requirement:
"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource

Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Down Time:
For all generating units that are not combined cycle units, "Minimum Down Time" shall mean the minimum number of hours under normal operating conditions between unit shutdown and unit startup, calculated as the shortest time difference between the unit's generator breaker opening and after the unit's generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero. For combined cycle units, "Minimum Down Time" shall mean the minimum number of hours between the last generator breaker opening and after first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero.

Minimum Extended Summer Resource Requirement:
"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

Minimum Generation Emergency:
"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

Minimum Participation Requirements:
"Minimum Participation Requirements" shall mean a set of minimum training, risk management, communication and capital or collateral requirements required for Participants in the PJM Markets, as set forth herein and in the Form of Annual Certification set forth as Tariff, Attachment Q, Appendix 1. Participants transacting in FTRs in certain circumstances will be required to demonstrate additional risk management procedures and controls as further set forth in the Annual Certification found in Tariff, Attachment Q, Appendix 1.

Minimum Run Time:
For all generating units that are not combined cycle units, "Minimum Run Time" shall mean the minimum number of hours a unit must run, in real-time operations, from the time after generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator

megawatts greater than zero, to the time of generator breaker opening, as measured by PJM's State Estimator. For combined cycle units, "Minimum Run Time" shall mean the time period after the first combustion turbine generator breaker closure, which is typically indicated by telemetered or aggregated State Estimator megawatts greater than zero, and the last generator breaker opening as measured by PJM's State Estimator.

MISO:
"MISO" shall mean the Midcontinent Independent System Operator, Inc. or any successor thereto.

Multi-Driver Project:
"Multi-Driver Project" shall have the same meaning provided in the Operating Agreement.

Native Load Customers:
"Native Load Customers" shall mean the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Owner's system to meet the reliable electric needs of such customers.

NERC:
"NERC" shall mean the North American Electric Reliability Corporation or any successor thereto.

NERC Interchange Distribution Calculator:
"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

Net Benefits Test:
"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Operating Agreement, Schedule 1, section 3.3A.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 3.3A.4.

Net Cost of New Entry:
"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset.

Net Obligation:
"Net Obligation" shall mean the amount owed to PJMSettlement and PJM for purchases from the PJM Markets, Transmission Service, (under Tariff, Parts II and III , and other services pursuant to the Agreements, after applying a deduction for amounts owed to a Participant by PJMSettlement as it pertains to monthly market activity and services. Should other markets be formed such that Participants may incur future Obligations in those markets, then the aggregate amount of those Obligations will also be added to the Net Obligation.

Net Sell Position:

"Net Sell Position" shall mean the amount of Net Obligation when Net Obligation is negative.

Network Customer:
"Network Customer" shall mean an entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Tariff, Part III.

Network External Designated Transmission Service:
"Network External Designated Transmission Service" shall have the meaning set forth in Reliability Assurance Agreement, Article I.

Network Integration Transmission Service:
"Network Integration Transmission Service" shall mean the transmission service provided under Tariff, Part III.

Network Load:
"Network Load" shall mean the load that a Network Customer designates for Network Integration Transmission Service under Tariff, Part III. The Network Customer's Network Load shall include all load (including losses) served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

Network Operating Agreement:
"Network Operating Agreement" shall mean an executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Tariff, Part III.

Network Operating Committee:
"Network Operating Committee" shall mean a group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Tariff, Part III.

Network Resource:
"Network Resource" shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

Network Service User:
"Network Service User" shall mean an entity using Network Transmission Service.

Network Transmission Service:
"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Tariff, Part III, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

Network Upgrades:
"Network Upgrades" shall mean modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System. Network Upgrades shall include:

(i) **Direct Connection Network Upgrades** which are Network Upgrades that only serve the Customer Interconnection Facility and have no impact or potential impact on the Transmission System until the final tie-in is complete; and

(ii) **Non-Direct Connection Network Upgrades** which are parallel flow Network Upgrades that are not Direct Connection Network Upgrades.

Neutral Party:
"Neutral Party" shall have the meaning provided in Tariff, Part I, section 9.3(v).

New PJM Zone(s):
"New PJM Zone(s)" shall mean the Zone included in the Tariff, along with applicable Schedules and Attachments, for Commonwealth Edison Company, The Dayton Power and Light Company and the AEP East Operating Companies (Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company).

New Service Customers:
"New Service Customers" shall mean all customers that submit an Interconnection Request, a Completed Application, or an Upgrade Request that is pending in the New Services Queue.

New Service Request:
"New Service Request" shall mean an Interconnection Request, a Completed Application, or an Upgrade Request.

New Services Queue:
"New Service Queue" shall mean all Interconnection Requests, Completed Applications, and Upgrade Requests that are received within each six-month period ending on April 30 and October 31 of each year shall collectively comprise a New Services Queue.

New Services Queue Closing Date:
"New Services Queue Closing Date" shall mean each April 30 and October 31 shall be the Queue Closing Date for the New Services Queue comprised of Interconnection Requests, Completed Applications, and Upgrade Requests received during the six-month period ending on such date.

New York ISO or NYISO:

"New York ISO" or "NYISO" shall mean the New York Independent System Operator, Inc. or any successor thereto.

Nodal Reference Price:
The "Nodal Reference Price" at each location shall mean the 97th percentile price differential between day-ahead and real-time prices experienced over the corresponding two-month reference period in the prior calendar year. Reference periods will be Jan-Feb, Mar-Apr, May- Jun, Jul-Aug, Sept-Oct, Nov-Dec. For any given current-year month, the reference period months will be the set of two months in the prior calendar year that include the month corresponding to the current month. For example, July and August 2003 would each use July- August 2002 as their reference period.

No-load Cost:
"No-load Cost" shall mean the hourly cost required to create the starting point of a monotonically increasing incremental offer curve for a generating unit.

Nominal Rated Capability:
"Nominal Rated Capability" shall mean the nominal maximum rated capability in megawatts of a Transmission Interconnection Customer's Customer Facility or the nominal increase in transmission capability in megawatts of the Transmission System resulting from the interconnection or addition of a Transmission Interconnection Customer's Customer Facility, as determined in accordance with pertinent Applicable Standards and specified in the Interconnection Service Agreement.

Nominated Demand Resource Value:
"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

Nominated Energy Efficiency Value:
"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

Non-Firm Point-To-Point Transmission Service:
"Non-Firm Point-To-Point Transmission Service" shall mean Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Tariff, Part II, section 14.7. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

Non-Firm Sale:
"Non-Firm Sale" shall mean an energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

Non-Firm Transmission Withdrawal Rights:
"No-Firm Transmission Withdrawal Rights" shall mean the rights to schedule energy withdrawals from a specified point on the Transmission System. Non-Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Withdrawals scheduled using Non-Firm Transmission Withdrawal Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Non-Performance Charge:
"Non-Performance Charge" shall mean the charge applicable to Capacity Performance Resources as defined in Tariff, Attachment DD, section 10A(e).

Nonincumbent Developer:
"Nonincumbent Developer" shall have the same meaning provided in the Operating Agreement.

Non-Regulatory Opportunity Cost:
"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of Catastrophic Force Majeure; and, (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Non-Retail Behind The Meter Generation:
"Non-Retail Behind The Meter Generation" shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, or electric distribution companies to serve load.

Non-Synchronized Reserve:
"Non-Synchronized Reserve" shall mean the reserve capability of non-emergency generation resources that can be converted fully into energy within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

Non-Synchronized Reserve Event:
"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources able and assigned to provide Non-Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes to increase the energy output by the amount of assigned Non-Synchronized Reserve capability.

Non-Variable Loads:

"Non-Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Non-Zone Network Load:
"Non-Zone Network Load shall mean Network Load that is located outside of the PJM Region.

Normal Maximum Generation:
"Normal Maximum Generation" shall mean the highest output level of a generating resource under normal operating conditions.

Normal Minimum Generation:
"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

Ramping Capability:
"Ramping Capability" shall mean the sustained rate of change of generator output, in megawatts per minute.

Real-time Congestion Price:
"Real-time Congestion Price" shall mean the Congestion Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Loss Price:
"Real-time Loss Price" shall mean the Loss Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Energy Market:
"Real-time Energy Market" shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

Real-time Offer:
"Real-time Offer" shall mean a new offer or an update to a Market Seller's existing cost-based or market-based offer for a clock hour, submitted after the close of the Day-ahead Energy Market.

Real-time Prices:
"Real-time Prices" shall mean the Locational Marginal Prices resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Real-time Settlement Interval:
"Real-time Settlement Interval" shall mean the interval used by settlements, which shall be every five minutes.

Real-time System Energy Price:
"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

Reasonable Efforts:
"Reasonable Efforts" shall mean, with respect to any action required to be made, attempted, or taken by an Interconnection Party or by a Construction Party under Tariff, Part IV or Part VI, an Interconnection Service Agreement, or a Construction Service Agreement, such efforts as are timely and consistent with Good Utility Practice and with efforts that such party would undertake for the protection of its own interests.

Receiving Party:
"Receiving Party" shall mean the entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

Referral:
"Referral" shall mean a formal report of the Market Monitoring Unit to the Commission for investigation of behavior of a Market Participant, of behavior of PJM, or of a market design flaw, pursuant to Tariff, Attachment M, section IV.I.

Reference Resource:
"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology all CONE Areas, dual fuel capability, and a heat rate of 10.096 Mmbtu/ MWh.

Regional Entity:
"Regional Entity" shall have the same meaning specified in the Operating Agreement.

Regional Transmission Expansion Plan:
"Regional Transmission Expansion Plan" shall mean the plan prepared by the Office of the Interconnection pursuant to Operating Agreement, Schedule 6 for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.

Regional Transmission Group (RTG):
"Regional Transmission Group" or "RTG" shall mean a voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

Regulation:
"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to seperately increase and decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

Regulation Zone:
"Regulation Zone" shall mean any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

Relevant Electric Retail Regulatory Authority:
"Relevant Electric Retail Regulatory Authority" or "RERRA" shall mean an entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end- customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission, a State legislature, or any other such entity.

Reliability Assurance Agreement or PJM Reliability Assurance Agreement:
"Reliability Assurance Agreement" or " PJM Reliability Assurance Agreement" shall mean that certain Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, on file

with FERC as PJM Interconnection L.L.C. Rate Schedule FERC No. 44, and as amended from time to time thereafter.

Reliability Pricing Model Auction:
"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction, or, for the 2016/2017 and 2017/2018 Delivery Years, any Capacity Performance Transition Incremental Auction.

Required Transmission Enhancements:
"Regional Transmission Enhancements" shall mean enhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B ("Appendix B Agreement") designates one or more of the Transmission Owner(s) to construct and own or finance. Required Transmission Enhancements shall also include enhancements and expansions of facilities in another region or planning authority that meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities constructed pursuant to an Appendix B Agreement cost responsibility for which has been assigned at least in part to PJM pursuant to such Appendix B Agreement.

Reserved Capacity:
"Reserved Capacity" shall mean the maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Tariff, Part II. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

Reserve Penalty Factor:
"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone or Reserve Sub-zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone or Reserve Sub-zone.

Reserve Sub-zone:
"Reserve Sub-zone" shall mean any of those geographic areas wholly contained within a Reserve Zone, consisting of a combination of a portion of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Reserve Zone:
"Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more Control Zone(s), as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

Residual Auction Revenue Rights:

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability, including the return to service of existing transmission capability, that was not modeled pursuant to Operating Agreement, Schedule 1, section 7.5 and the parallel provisions of Tariff, Attachment K- Appendix, section 7.5 in compliance with Operating Agreement, Schedule 1, section 7.4.2 (h) and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2(h), and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to Operating Agreement, Schedule 1, section 7.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.2; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Tariff, Part VI; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Operating Agreement, Schedule 6 for transmission upgrades that create such rights.

Residual Metered Load:
"Residual Metered Load" shall mean all load remaining in an electric distribution company's fully metered franchise area(s) or service territory(ies) after all nodally priced load of entities serving load in such area(s) or territory(ies) has been carved out.

Resource-Specific Fixed Resource Requirement Alternative or FRR-RS Alternative:
"Resource-Specific Fixed Resource Requirement Alternative" or "FRR-RS Alternative" shall mean an alternative method by which a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource can obtain a capacity commitment for that Capacity Resource.

Resource Substitution Charge:
"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

Revenue Data for Settlements:
"Revenue Data for Settlements" shall mean energy quantities used in accounting and billing as determined pursuant to Tariff, Attachment K-Appendix and the corresponding provisions of Operating Agreement, Schedule 1.

RPM Seller Credit:
"RPM Seller Credit" shall mean an additional form of Unsecured Credit defined in Tariff, Attachment Q, section IV.

Scheduled Incremental Auctions:
"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction for Delivery Years prior to the 2021/2022 Delivery Year; and the First or Final Incremental Auction for the 2021/2022 Delivery Year and all subsequent Delivery Years.

Schedule of Work:
"Schedule of Work" shall mean that schedule attached to the Interconnection Construction Service Agreement setting forth the timing of work to be performed by the Constructing Entity pursuant to the Interconnection Construction Service Agreement, based upon the Facilities Study and

subject to modification, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Scope of Work:
"Scope of Work" shall mean that scope of the work attached as a schedule to the Interconnection Construction Service Agreement and to be performed by the Constructing Entity(ies) pursuant to the Interconnection Construction Service Agreement, provided that such Scope of Work may be modified, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

Seasonal Capacity Performance Resource:
"Seasonal Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Secondary Systems:
"Secondary Systems" shall mean control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers.

Second Incremental Auction:
"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates. A Second Incremental Auction is conducted for Delivery Years prior to the 2021/2022 Delivery Year but is not conducted for the 2021/2022 Delivery Year and all subsequent Delivery Years.

Security:
"Security" shall mean the security provided by the New Service Customer pursuant to Tariff, section 212.4 or Tariff, Part VI, section 213.4 to secure the New Service Customer's responsibility for Costs under the Interconnection Service Agreement or Upgrade Construction Service Agreement and Tariff, Part VI, section 217.

Segment:
"Segment" shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e).

Self-Supply:
"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self- Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

Sell Offer:
"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

Service Agreement:
"Service Agreement" shall mean the initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

Service Commencement Date:
"Service Commencement Date" shall mean the date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Tariff, Part II, section 15.3 or Tariff, Part III, section 29.1.

Short-Term Firm Point-To-Point Transmission Service:
"Short-Term Firm Point-To-Point Transmission Service" shall mean Firm Point-To-Point Transmission Service under Tariff, Part II with a term of less than one year.

Short-term Project:
"Short-term Project" shall have the same meaning provided in the Operating Agreement.

Short-Term Resource Procurement Target:
"Short-Term Resource Procurement Target" shall mean, for Delivery Years through May 31, 2018, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

Short-Term Resource Procurement Target Applicable Share:
"Short-Term Resource Procurement Target Applicable Share" shall mean, for Delivery Years through May 31, 2018: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

Site:

"Site" shall mean all of the real property, including but not limited to any leased real property and easements, on which the Customer Facility is situated and/or on which the Customer Interconnection Facilities are to be located.

Small Commercial Customer:
"Small Commercial Customer," as used in RAA, Schedule 6 and Tariff, Attachment DD-1, shall mean a commercial retail electric end-use customer of an electric distribution company that participates in a mass market demand response program under the jurisdiction of a RERRA and satisfies the definition of a "small commercial customer" under the terms of the applicable RERRA's program, provided that the customer has an annual peak demand no greater than 100kW.

Small Generation Resource:
"Small Generation Resource" shall mean an Interconnection Customer's device of 20 MW or less for the production and/or storage for later injection of electricity identified in an Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities. This term shall include Energy Storage Resources and/or other devices for storage for later injection of energy.

Small Inverter Facility:
"Small Inverter Facility" shall mean an Energy Resource that is a certified small inverter-based facility no larger than 10 kW.

Small Inverter ISA:
"Small Inverter ISA" shall mean an agreement among Transmission Provider, Interconnection Customer, and Interconnected Transmission Owner regarding interconnection of a Small Inverter Facility under Tariff, Part IV, section 112B.

Special Member:
"Special Member" shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:
"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

Spot Market Energy:
"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Start Additional Labor Costs:

"Start Additional Labor Costs" shall mean additional labor costs for startup required above normal station manning levels.

Start-Up Costs:
"Start-Up Costs" shall mean the unit costs to bring the boiler, turbine and generator from shutdown conditions to the point after breaker closure which is typically indicated by telemetered or aggregated state estimator megawatts greater than zero and is determined based on the cost of start fuel, total fuel-related cost, performance factor, electrical costs (station service), start maintenance adder, and additional labor cost if required above normal station manning. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

State:
"State" shall mean the District of Columbia and any State or Commonwealth of the United States.

State Commission:
"State Commission" shall mean any state regulatory agency having jurisdiction over retail electricity sales in any State in the PJM Region.

State Estimator:
"State Estimator" shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3 and the parallel provisions of Tariff, Attachment K- Appendix, section 2.3.

Station Power:
"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource or a Capacity Storage Resource; or (v) used in association with restoration or black start service.

Sub-Annual Resource Constraint:
"Sub-Annual Resource Constraint" shall mean, for the 2017/2018 Delivery Year and for FRR Capacity Plans the 2017/2018 and 2018/2019 Delivery Years, for the PJM Region or for each LDA for which the Office of the Interconnection is required under Tariff, Attachment DD, section 5.10(a) to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for the 2017/2018 Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

Sub-Annual Resource Price Decrement:

"Sub-Annual Resource Price Decrement" shall mean, for the 2017/2018 Delivery Year, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

Sub-Annual Resource Reliability Target:
"Sub-Annual Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for the 2017/2018 and 2018/2019 Delivery Years. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

Sub-meter:
"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Summer-Period Capacity Performance Resource:

"Summer-Period Capacity Performance Resource" shall have the same meaning specified in Tariff, Attachment DD, section 5.5A.

Switching and Tagging Rules:
"Switching and Tagging Rules" shall mean the switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.

Synchronized Reserve:
"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

Synchronized Reserve Event:
"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self- scheduled Synchronized Reserve capability.

Synchronized Reserve Requirement:
"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

System Condition:
"System Condition" shall mean a specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Tariff, Part II, section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Energy Price:
"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2 and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

System Impact Study:
"System Impact Study" shall mean an assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a Completed Application, an Interconnection Request or an Upgrade Request, (ii) whether any additional costs may be incurred in order to provide such transmission service or to accommodate an Interconnection Request, and (iii) with respect to an Interconnection Request, an estimated date that an Interconnection Customer's

Customer Facility can be interconnected with the Transmission System and an estimate of the Interconnection Customer's cost responsibility for the interconnection; and (iv) with respect to an Upgrade Request, the estimated cost of the requested system upgrades or expansion, or of the cost of the system upgrades or expansion, necessary to provide the requested incremental rights.

System Protection Facilities:
"System Protection Facilities" shall refer to the equipment required to protect (i) the Transmission System, other delivery systems and/or other generating systems connected to the Transmission System from faults or other electrical disturbance occurring at or on the Customer Facility, and (ii) the Customer Facility from faults or other electrical system disturbance occurring on the Transmission System or on other delivery systems and/or other generating systems to which the Transmission System is directly or indirectly connected. System Protection Facilities shall include such protective and regulating devices as are identified in the Applicable Technical Requirements and Standards or that are required by Applicable Laws and Regulations or other Applicable Standards, or as are otherwise necessary to protect personnel and equipment and to minimize deleterious effects to the Transmission System arising from the Customer Facility.

ATTACHMENT M – APPENDIX

I. CONFIDENTIALITY OF DATA AND INFORMATION

A. Party Access:

1. No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Market Monitoring Unit, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Market Monitoring Unit or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

2. Except as may be provided in this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff, the Market Monitoring Unit shall not disclose to PJM Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Market Monitoring Unit or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Market Monitoring Unit from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality.

The Market Monitoring Unit, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this section I. Nothing contained herein shall prohibit the Market Monitoring Unit from sharing with the market monitor of another Regional Transmission Organization ("RTO"), Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such market monitor has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such market monitor is bound by a tariff provision requiring that the e-Tag data be maintained as confidential, or in the absence of a tariff requirement governing confidentiality, a written agreement with the Market Monitoring Unit consistent with FERC Order No. 771, and any clarifying orders and implementing regulations.

The Market Monitoring Unit shall collect and use confidential information only in connection with its authority under this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

3. Nothing contained herein shall prevent the Market Monitoring Unit from releasing a Member's confidential data or information to a third party provided that the Member has delivered to the Market Monitoring Unit specific, written authorization for such release setting forth the data

or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Market Monitoring Unit shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Market Monitoring Unit, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

4. Reciprocal provisions to this section I hereof, delineating the confidentiality requirements of the Office of the Interconnection and PJM members, are set forth in Operating Agreement, section 18.17.

B. Required Disclosure:

1. Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of section I.C below, if the Market Monitoring Unit is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, PJM Operating Agreement, Tariff, Attachment M or this Appendix, the Market Monitoring Unit may make disclosure of such information; provided, however, that as soon as the Market Monitoring Unit learns of the disclosure requirement and prior to making disclosure, the Market Monitoring Unit shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Market Monitoring Unit shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Market Monitoring Unit shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

2. Nothing in this section I shall prohibit or otherwise limit the Market Monitoring Unit's use of information covered herein if such information was: (i) previously known to the Market Monitoring Unit without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection and/or the Market Monitoring Unit using non-confidential information; (iii) acquired by the Office of the Interconnection and/or the Market Monitoring Unit from a third party which is not, to the Office of the Interconnection's or Market Monitoring Unit's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this section I.

3. The Market Monitoring Unit shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation of the Plan or this Appendix a contractual duty of confidentiality consistent with the Plan or this Appendix. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Market Monitoring Unit shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

C. Disclosure to FERC and CFTC:

1. Notwithstanding anything in this section I to the contrary, if the FERC, the Commodity Futures Trading Commission ("CFTC") or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Market Monitoring Unit that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, the Market Monitoring Unit shall provide the requested information to the FERC, CFTC or their staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Market Monitoring Unit may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall promptly notify any affected Member(s) if the Market Monitoring Unit receives from the FERC, CFTC or their staff, written notice that the commission has decided to release publicly or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission Market Monitoring Unit.

2. The foregoing section I.C.1 shall not apply to requests for production of information under Subpart D of the FERC's Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection and/or the Market Monitoring Unit shall follow the procedures in section I.B.

D. Disclosure to Authorized Commissions:

1. Notwithstanding anything in this section I to the contrary, the Market Monitoring Unit shall disclose confidential information, otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, to an Authorized Commission under the following conditions:

(i) The Authorized Commission has provided the FERC with a properly executed Certification in the form attached to the PJM Operating Agreement as Operating Agreement, Schedule 10A. Upon receipt of the Authorized Commission's Certification, the FERC shall provide public notice of the Authorized Commission's filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission's Certification, that party may file a protest with the FERC within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a response to any such protest within seven days. Each party shall bear its own costs in connection with such a protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the FERC, the Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the FERC as set forth above in this paragraph.

(ii) Neither the Office of the Interconnection nor the Market Monitoring Unit may disclose data to an Authorized Commission during the FERC's consideration of the Certification and any filed protests. If the FERC does not act upon an Authorized Commission's Certification

within 90 days of the date of filing, the Certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this Section I. In the event that an interested party protests the Authorized Commission's Certification and the FERC approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

(iii) Any confidential information provided to an Authorized Commission pursuant to this section I shall not be further disclosed by the recipient Authorized Commission except by order of the FERC.

(iv) The Market Monitoring Unit shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.

(v) The Authorized Commission may provide confidential information obtained from the Market Monitoring Unit to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the Market Monitoring Unit and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a nondisclosure agreement in the form attached to the PJM Operating Agreement as Operating Agreement, Schedule 10 before being provided access to any such confidential information.

2. The Market Monitoring Unit may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The Market Monitoring Unit will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this section I.D.2. In any such discussions, the Market Monitoring Unit shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Market Monitoring Unit shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Market Monitoring Unit shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) Business Day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member is released to the Authorized Person; provided however, disclosure of the identity of the Affected

Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) Business Days of the initial oral disclosure.

3. As regards Information Requests:

(i) Information Requests to the Office of the Interconnection and/or Market Monitoring Unit by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Market Monitoring Unit, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Market Monitoring Unit shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) Subject to the provisions of section I.D.3(iii) below, the Market Monitoring Unit shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) Business Days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) Business Day without the express consent of the Affected Member. To the extent that the Market Monitoring Unit cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Market Monitoring Unit shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Market Monitoring Unit shall not reveal any Member's confidential information to any other Member.

(iii) Notwithstanding section I.D.3(ii), above, should the Office of the Interconnection, the Market Monitoring Unit or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) Business Days following the Market Monitoring Unit's receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection, Market Monitoring Unit, or the Affected Member may file a complaint with the FERC pursuant to Rule 206 objecting to the Information Request within ten (10) Business Days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at the FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission's

ability to protect confidential information arising since the filing of or rejection of a protest directed to the Authorized Commission's Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that "exceptional circumstances," as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or Market Monitoring Unit workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Market Monitoring Unit. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute "exceptional circumstances" as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection and/or Market Monitoring Unit shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Market Monitoring Unit shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at the FERC within ten (10) Business Days following receipt of information designated as "Confidential," challenging such designation. Any complaints filed at FERC objecting to the designation of information as "Confidential" shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit "Confidential" status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with "publicly available" not being deemed to include unauthorized disclosures of otherwise confidential data).

4. In the event of any breach of confidentiality of information disclosed pursuant to an Information Request by an Authorized Commission or Authorized Person:

(i) The Authorized Commission or Authorized Person shall promptly notify the Market Monitoring Unit, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this section I.

(ii) The Office Market Monitoring Unit shall terminate the right of such Authorized Commission to receive confidential information under this section I upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected Member; or (ii) similar good cause is shown. Any appeal of the Market Monitoring Unit's actions under this section I shall be to Commission. An Authorized Commission shall be entitled to reestablish its certification as set forth in section I.D.1 by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not act upon an Authorized Commission's recertification filing with sixty (60) days of the date of the filing, the recertification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

(iii) The Office of the Interconnection, the Market Monitoring Unit, and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from the FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Market Monitoring Unit.

(iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this section I.D.4(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in section I.D.4(ii) or I.D.4(iii)(a) above, shall be submitted to the FERC for hearing and resolution. Any dispute or conflict requesting the relief in section I.D.4(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

E. <u>Market Monitoring:</u>

1. Subject to the requirements of section E.2, the Market Monitoring Unit may release confidential information of Public Service Electric & Gas Company ("PSE&G"), Consolidated Edison Company of New York ("ConEd"), and their affiliates, and the confidential information of any Member regarding generation and/or transmission facilities located within the PSE&G Zone to the New York Independent System Operator, Inc. ("New York ISO"), the market monitoring unit of New York ISO and the New York ISO Market Advisor to the limited extent that the Office of the Interconnection or the Market Monitoring Unit determines necessary to carry out the responsibilities of PJM, New York ISO or the market monitoring units of the Office of the Interconnection and the New York ISO under FERC Opinion No. 476 (see Consolidated Edison Company v. Public Service Electric and Gas Company, et al., 108 FERC ¶ 61,120, at P 215 (2004)) to conduct joint investigations to ensure that gaming, abuse of market power, or similar activities do not take place with regard to power transfers under the contracts that are the subject of FERC Opinion No. 476.

2. The Market Monitoring Unit may release a Member's confidential information pursuant to section I.E.1 to the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor only if the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor are subject to obligations limiting the disclosure of such information that are equivalent to or greater than the limitations on disclosure specified in this Section I.E. Information received from the New York ISO, the market monitoring unit of the New York ISO, or the New York ISO Market Advisor under section I.E.1 that is designated as confidential shall be protected from disclosure in accordance with this section I.E.

II. DEVELOPMENT OF INPUTS FOR PROSPECTIVE MITIGATION

A. Offer Price Caps:

1. The Market Monitor or his designee shall advise the Office of the Interconnection whether it believes that the cost references, methods and rules included in the Cost Development Guidelines are accurate and appropriate, as specified in the PJM Manuals.

2. The Market Monitoring Unit shall review the incremental costs (defined in Operating Agreement, Schedule 1, section 6.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4.2) included in the Offer Price Cap of a generating unit in order to ensure that the Market Seller has correctly applied the Cost Development Guidelines, including its PJM-approved Fuel Cost Policy, and that the level of the Offer Price Cap is otherwise acceptable. The Market Monitoring Unit shall inform PJM if it believes a Market Seller has submitted a cost- based offer that is not compliant with these criteria and whether it recommends that PJM assess the applicable penalty therefor, pursuant to Operating Agreement, Schedule 2.

3. On or before the 21st day of each month, the Market Monitoring Unit shall calculate in accordance with the applicable criteria whether each generating unit with an offer cap calculated under Operating Agreement, Schedule 1, section 6.4.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4.2 is eligible to include an adder based on Frequently Mitigated Unit or Associated Unit status, and shall issue a written notice of the applicable adder, with a copy to the Office of the Interconnection, to the Market Seller for each unit that meets the criteria for Frequently Mitigated Unit or Associated Unit status.

4. Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by Operating Agreement, Schedule 1, section 6.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.4. Such proposals shall take effect upon Commission acceptance of the Market Monitoring Unit's filing.

5. The Market Monitoring Unit shall review all Fuel Cost Policies submitted by Market Sellers for market power concerns. The Market Monitoring Unit shall communicate its determination regarding these criteria to PJM and the Market Seller pursuant to the process further described in PJM Manual 15.

B. Minimum Generator Operating Parameters:

1. For the 2014/2015 through 2017/2018 Delivery Years, the Market Monitoring Unit shall provide to the Office of the Interconnection a table of default unit class specific parameter limits to be known as the "Parameter Limited Schedule Matrix" to be included in Operating Agreement, Schedule 1, section 6.6(c) and the parallel provisions of Tariff, Attachment K- Appendix, section 6.6(c). The Parameter Limited Schedule Matrix shall include default values on a unit-type basis as specified in Operating Agreement, Schedule 1, section 6.6(c) and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6(c). The Market Monitoring Unit shall review the Parameter Limited Schedule Matrix annually, and, in the event it determines that revision is

appropriate, shall provide a revised matrix to the Office of the Interconnection by no later than December 31 prior to the annual enrollment period.

2. The Market Monitoring Unit shall notify Market Sellers of generating units and the Office of the Interconnection no later than April 1 of its determination of market power concerns raised regarding each request for a period exception or persistent exception to a value specified in the Parameter Limited Schedule Matrix or the parameters defined in Operating Agreement, Schedule 1, section 6.6 and the parallel provisions of Tariff, Attachment K-Appendix, section 6.6 and the PJM Manuals, provided that the Market Monitoring Unit receives such request by no later than February 28.

If, prior to the scheduled termination date, a Market Seller submits a request to modify a temporary exception, the Market Monitoring Unit shall review such request using the same standard utilized to evaluate period exception and persistent exception requests, and shall provide its determination of whether the request raises market power concerns, and, if so, any modifications that would alleviate those concerns, to the Market Seller, with a copy to Office of the Interconnection, by no later than 15 Business Days from the date of the modification request.

3. When a Market Seller notifies the Market Monitoring Unit of a material change to the facts relied upon by the Market Monitoring Unit and/or the Office of the Interconnection to support a parameter limited schedule period or persistent exception, the Market Monitoring Unit shall make a determination, and provide written notification to the Office of the Interconnection and the Market Seller, of any change to its determination regarding the exemption request, based on the material change in facts, by no later than 15 Business Days after receipt of such notice.

4. The Market Monitoring Unit shall notify the Office of the Interconnection of any risk premium to which it and a Market Seller owning or operating nuclear generation resource agree or its determination if agreement is not obtained. If a Market Seller submits a risk premium for its nuclear generation resource that is inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such risk premium, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns pursuant to Tariff, Attachment M.

C. RPM Must-Offer Requirement:

1. The Market Monitoring Unit shall maintain, post on its website and provide to the Office of the Interconnection prior to each RPM Auction (updated, as necessary, on at least a quarterly basis), a list of Existing Generation Capacity Resources located in the PJM Region that are subject to the RPM must-offer requirement set forth in Tariff, Attachment DD, section 6.6.

2. The Market Monitoring Unit shall evaluate requests submitted by Capacity Market Sellers for a determination that a Generation Capacity Resource, or any portion thereof, be removed from Capacity Resource status or exempted from status as a Generation Capacity Resource subject to section II.C.1 above and inform both the Capacity Market Seller and the Office of the Interconnection of such determination in writing by no later ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR

Capacity Plan, FRR-RS Alternative, Locational UCAP transaction and/or by designation as a replacement resource under Tariff, Attachment DD.

3. The Market Monitoring Unit shall evaluate the data and documentation provided to it by a potential Capacity Market Seller to establish the EFORd to be included in a Sell Offer applicable to each resource pursuant to Tariff, Attachment DD, section 6.6(b). If a Capacity Market Seller timely submits a request for an alternative maximum level of EFORd that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, the Market Monitoring Unit shall attempt to reach agreement with the Capacity Market Seller on the alternate maximum level of the EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Market Monitoring Unit shall notify the Office of the Interconnection in writing, notifying the Capacity Market Seller by copy of the same, of any alternative maximum EFORd to which it and the Capacity Market Seller agree or its determination of the alternative maximum EFORd if agreement is not obtained.

4. The Market Monitoring Unit shall consider the documentation provided to it by a potential Capacity Market Seller pursuant to Tariff, Attachment DD, section 6.6 of Attachment DD, and determine whether a resource owned or controlled by such Capacity Market Seller meets the criteria to qualify for an exception to the RPM must-offer requirement because the resource (i) is reasonably expected to be physically unable to participate in the relevant auction; (ii) has a financially and physically firm commitment to an external sale of its capacity; or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource. The Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection of its determination by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Tariff, Part V, section 113.1, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Tariff, Part V, section 113.2 for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Tariff, Attachment DD;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order,

decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or,

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

5. If a Capacity Market Seller submits for the portion of a Generation Capacity Resource that it owns or controls, and the Office of Interconnection accepts, a Sell Offer (i) at a level of installed capacity that the Market Monitoring Unit believes is inconsistent with the level established under Tariff, Attachment DD, section 5.6.6, (ii) at a level of installed capacity inconsistent with its determination of eligibility for an exception listed in section II.C.4 above, or (iii) a maximum EFORd that the Market Monitoring Unit believes is inconsistent with the maximum level determined under section II.C.3 of this Appendix, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and/or request a determination from the Commission that would require the Generation Capacity Resource to submit a new or revised Sell Offer, notwithstanding any determination to the contrary made under Tariff, Attachment DD, section 6.6.

The Market Monitoring Unit shall also consider the documentation provided by the Capacity Market Seller pursuant to Tariff, Attachment DD, section 6.6, for generation resources for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement as set forth in Tariff, Attachment DD, section 6.6(g), to determine whether the Capacity Market Seller's failure to offer part or all of one or more generation resources into an RPM Auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction as required by Tariff, Attachment DD, section 6.6(i), and shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination by no later than two (2) Business Days after the close of the offer period for the applicable RPM Auction.

~~**D. Unit Specific Minimum Sell Offers:**~~

~~1. If a Capacity Market Seller timely submits an exception request, with all of the required documentation as specified in Tariff, Attachment DD, section 5.14(h), the Market Monitoring Unit shall review the request and documentation and shall provide in writing to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer (a) its determination whether the level of the proposed Sell Offer raises market power concerns, and (b) if so it shall calculate and provide to such Capacity Market Seller a minimum Sell offer Based on the data and documentation received.~~

~~2. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.~~

~~E.~~D. Market Seller Offer Caps:

1. Based on the data and calculations submitted by the Capacity Market Sellers for each Existing Generation Capacity Resource and the formulas specified in Tariff, Attachment DD, section 6.7(d), the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource and provide it to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days before the commencement of the offer period for the applicable RPM Auction.

2. The Market Monitoring Unit must attempt to reach agreement with the Capacity Market Seller on the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such agreement cannot be reached, then the Market Monitoring Unit shall inform the Capacity Market Seller and the Office of the Interconnection of its determination of the appropriate level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction, and the Market Monitoring Unit may pursue any action available to it under Attachment M.

3. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in Tariff, Attachment DD, section 6.4(a).

~~F.~~E. Mitigation of Offers from Planned Generation Capacity Resources:

Pursuant to Tariff, Attachment DD, section 6.5, the Market Monitoring Unit shall evaluate Sell Offers for Planned Generation Capacity Resources to determine whether market power mitigation should be applied and notify in writing each Capacity Market Seller whose Sell Offer has been determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction.

~~G.~~F. Data Submission:

Pursuant to Tariff, Attachment DD, section 6.7, the Market Monitoring Unit may request additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

~~H.~~G. Determination of Default Avoidable Cost Rates:

1. The Market Monitoring Unit shall conduct an annual review of the table of default Avoidable Cost Rates included in Tariff, Attachment DD, section 6.7(c) and calculated on the bases set forth therein, and determine whether the values included therein need to be updated. If the Market Monitoring Unit determines that the Avoidable Cost Rates need to be updated, it shall

provide to the Office of the Interconnection updated values or notice of its determination that updated values are not needed by no later than September 30th of each year.

2. The Market Monitoring Unit shall indicate in its posted reports on RPM performance the number of Generation Capacity Resources and megawatts per LDA that use the retirement default Avoidable Cost Rates.

3. If a Capacity Market Seller does not elect to use a default Avoidable Cost Rate and has timely provided to the Market Monitoring Unit its request to apply a unit-specific Avoidable Cost Rate, along with the data described in Tariff, Attachment DD, section 6.7, the Market Monitoring Unit shall calculate the Avoidable Cost Rate and provide a unit-specific value to the Capacity Market Seller for each such resource, and notify the Capacity Market Seller and the Office of the Interconnection in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction whether it agrees that the unit-specific Avoidable Cost Rate is acceptable. The Capacity Market Seller and Office of the Interconnection's deadlines relating to the submittal and acceptance of a request for a unit- specific Avoidable Cost Rate are delineated in Tariff, Attachment DD, section 6.7(d).

~~I.~~H. Determination of PJM Market Revenues:

The Market Monitoring Unit shall calculate the Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied pursuant to Tariff, Attachment DD, section 6.8(d), and notify the Capacity Market Seller and the Office of the Interconnection of its determination in writing by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction.

~~J.~~I. Determination of Opportunity Costs:

The Market Monitoring Unit shall review and verify the documentation of prices available to Existing Generation Capacity Resources in markets external to PJM and proposed for inclusion in Opportunity Costs pursuant to Tariff, Attachment DD, section 6.7(d)(ii). The Market Monitoring Unit shall notify, in writing, such Generation Capacity Resource and the Office of the Interconnection if it is dissatisfied with the documentation provided and whether it objects to the inclusion of such Opportunity Costs in a Market Seller Offer by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. If such Generation Capacity Resource submits a Market Seller Offer that includes Opportunity Costs that have not been documented and verified to the Market Monitoring Unit's satisfaction, then the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Generation Capacity Resource to remove them.

III. BLACKSTART SERVICE

A. Upon the submission by a Black Start Unit owner of a request for Black Start Service revenue requirements and changes to the Black Start Service revenue requirements for the Black Start Unit, the Black Start Unit owner and the Market Monitoring Unit shall attempt to agree to values on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. The Market Monitoring Unit shall calculate the revenue

requirement for each Black Start Unit and provide its calculation to the Office of the Interconnection by no later than May 14 of each year.

B. Pursuant to the terms of Tariff, Schedule 6A and the PJM Manuals, the Market Monitoring Unit will analyze any requested generator black start cost changes on an annual basis and shall notify the Office of the Interconnection of any costs to which it and the Black Start Unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a Black Start Unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost component, and the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Unit owner, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission.

IV. DEACTIVATION RATES

1. Upon receipt of a notice to deactivate a generating unit under Tariff, Part V from the Office of the Interconnection forwarded pursuant to Tariff, Part V, section 113.1, the Market Monitoring Unit shall analyze the effects of the proposed deactivation with regard to potential market power issues and shall notify the Office of the Interconnection and the generator owner (of, if applicable, its designated agent) within 30 days of the deactivation request if a market power issue has been identified. Such notice shall include the specific market power impact resulting from the proposed deactivation of the generating unit, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

2. The Market Monitoring Unit and the generating unit owner shall attempt to come to agreement on the level of each component included in the Deactivation Avoidable Cost Credit. In the case of cost of service filing submitted to the Commission in alternative to the Deactivation Cost Credit, the Market Monitoring Unit shall indicate to the generating unit owner in advance of filing its views regarding the proposed method or cost components of recovery. The Market Monitoring Unit shall notify the Office of the Interconnection of any costs to which it and the generating unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a generating unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and seek a determination that would require the Generating unit to include an appropriate cost component. This provision is duplicated in Tariff, Part V, section 114 and Tariff, Part V, section 119.

V. OPPORTUNITY COST CALCULATION

The Market Monitoring Unit shall review requests for opportunity cost compensation under Operating Agreement, Schedule 1, section 3.2.3(f-3) and Operating Agreement, Schedule 1, section 3.2.3B(h) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-3) and Tariff, Attachment K-Appendix, section 3.2.3B(h), discuss with the Office of the

Interconnection and individual Market Sellers the amount of compensation, and file exercise its powers to inform Commission staff of its concerns and request a determination of compensation as provided by such sections. These requirements are duplicated in Operating Agreement, Schedule 1, section 3.2.3(f-3) and Operating Agreement, Schedule 1, section 3.2.3B(h) and the paralelle provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-3) and Tariff, Attachment K-Appendix, section 3.2.3B9H).

VI. FTR FORFEITURE RULE

The Market Monitoring Unit shall calculate Transmission Congestion Credits as required under Operating Agreement, Schedule 1, section 5.2.1(b) and Tariff, Attachment K-Appendix, section 5.2.1(b), including the determination of the identity of the Effective FTR Holder and an evaluation of the overall benefits accrued by an entity or affiliated entities trading in FTRs and Virtual Transactions in the Day-ahead Energy Market, and provide such calculations to the Office of the Interconnection. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the subject activity if the amount forfeited is less than the benefit derived by the Effective FTR Holder. If the Office of the Interconnection imposes a forfeiture of the Transmission Congestion Credit in an amount that the Market Monitoring Unit disagrees with, then it may exercise its powers to inform Commission staff of its concerns and request an adjustment.

VII. FORCED OUTAGE RULE

1. The Market Monitoring Unit shall observe offers submitted in the Day-ahead Energy Market to determine whether all or part of a generating unit's capacity (MW) is designated as Maximum Emergency and (i) such offer in the Real-time Energy Market designates a smaller amount of capacity from that unit as Maximum Emergency for the same time period, and (ii) there is no physical reason to designate a larger amount of capacity as Maximum Emergency in the offer in the Day-ahead Energy Market than in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

2. If the Market Monitoring Unit observes that (i) an offer submitted in the Day-ahead Energy market designates all or part of capacity (MW) of a Generating unit as economic maximum that is less than the economic maximum designated in the offer in the Real-time Energy Market, and (ii) there is no physical reason to designate a lower economic maximum in the offer in the Day-ahead Energy Market than in the offer in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

VIII. DATA COLLECTION AND VERIFICATION

The Market Monitoring Unit shall gather and keep confidential detailed data on the procurement and usage of fuel to produce electric power transmitted in the PJM Region in order to assist the performance of its duties under Tariff, Attachment M. To achieve this objective, the Market Monitoring Unit shall maintain on its website a mechanism that allows Members to conveniently and confidentially submit such data and develop a manual in consultation with stakeholders that describes the nature of and procedure for collecting data. Members of PJM owning a Generating unit that is located in the PJM Region (including Dynamic Transfer units), or is included in a PJM

Black Start Service plan, committed as a Generation Capacity Resource for the current or future Delivery Year, or otherwise subject to a commitment to provide service to PJM, shall provide data to the Market Monitoring Unit.

ATTACHMENT DD

Reliability Pricing Model

References to section numbers in this Attachment DD refer to sections of this Attachment DD, unless otherwise specified.

1. INTRODUCTION

This Attachment sets forth the terms and conditions governing the Reliability Pricing Model for the PJM Region. In the event of a conflict between this Attachment DD and Attachment M and its Appendix with respect to the responsibilities of the Market Monitoring Unit, the provisions of Attachment M and its Appendix shall control. As more fully set forth in this Attachment and the PJM Manuals, and in conjunction with the Reliability Assurance Agreement, the Reliability Pricing Model provides:

(a) support for LSEs in satisfying Daily Unforced Capacity Obligations for future Delivery Years through Self Supply of Capacity Resources;

(b) a competitive auction mechanism to secure the forward commitment of additional Capacity Resources and Qualifying Transmission Upgrades as necessary to satisfy the portion of LSEs' Unforced Capacity Obligations not satisfied through Self-Supply, in order to ensure the reliability of the PJM Region for future Delivery Years;

(c) long-term pricing signals for the development of Capacity Resources, including demand resources and planned generation resources, to ensure the reliability of the PJM Region;

(d) recognition for the locational benefits of Capacity Resources;

(e) deficiency charges to ensure progress toward, and fulfillment of, forward commitments by demand and generation resources to satisfy capacity requirements;

(f) measures to identify and mitigate capacity market structure deficiencies; ~~and~~

(g) a means for states to procure, outside of the auction mechanism, Capacity Resources of state public policy interest; and

~~(g)~~(h) a Reliability Backstop mechanism to ensure that sufficient generation, transmission and demand response solutions will be available to preserve system reliability.

2. [Reserved for Future Use]

3. RESPONSIBILITIES OF THE OFFICE OF THE INTERCONNECTION

3.1 Support for Self-Supply and Bilateral Transactions

The Office of the Interconnection shall:

(a) support electronic tools to facilitate communication by Market Sellers and Market Buyers of information to the Office of the Interconnection concerning Self- Supply arrangements;

(b) support an electronic bulletin board providing a forum for prospective buyers and sellers to transact Capacity Resources outside the Reliability Pricing Model Auctions, including Locational UCAP transactions (including mechanisms to allow prospective Sellers with partial-year resources to explore voluntary opportunities to combine their resources such that they can be offered together for a full Delivery Year) and support electronic tools to report bilateral capacity transactions between Market Participants to the Office of the Interconnection, in accordance with procedures set forth in the PJM Manuals; and

(c) define one or more capacity trading hubs and determine and publicize values for such hubs based on the capacity prices determined for one or more Locational Deliverability Areas, in accordance with the PJM Manuals.

3.2 Administration of the Base Residual Auction and Incremental Auctions

The Office of the Interconnection shall conduct and administer the Base Residual Auction and Incremental Auctions in accordance with this Attachment, the Operating Agreement, and the Reliability Assurance Agreement. Administration of the Base Residual Auction and Incremental Auctions shall include, but not be limited to, the following:

a) Determining the qualification of entities to become Capacity Market Sellers and Capacity Market Buyers;

b) Determining PJM Region Peak Load Forecasts and Locational Deliverability Area Reliability Requirements;

c) Determining the Minimum Annual Resource Requirements and the Minimum Extended Summer Resource Requirements for the PJM Region and applicable LDAs for Delivery Years starting June 1, 2014 and ending May 31, 2017;

d) Determining Limited Resource Constraints and Sub-Annual Resource Constraints for the 2017/2018 Delivery Year;

e) Determining Base Capacity Demand Resource Constraints and Base Capacity Resource Constraints for the 2018/2019 and 2019/2020 Delivery Years;

f) Determining the need, if any, for a Conditional Incremental Auction and providing appropriate prior notice of any such auction

g) Calculating the EFORd for each Generation Capacity Resource in the PJM Region to be used in the Third Incremental Auction;

h) Receiving Buy Bids and Sell Offers, determining Locational Deliverability Requirements and Variable Resource Requirement Curves, and determining the clearing price that reflects all such inputs;

i) Conducting settlements for auction transactions, including but not limited to rendering bills to, receiving payments from, and disbursing payments to, participants in Base Residual Auctions and Incremental Auctions.

j) Maintaining such records of Sell Offers and Buy Bids, clearing price determinations, and other aspects of auction transactions, as may be appropriate to the administration of Base Residual Auctions and Incremental Auctions; and

k) Posting of selected non-confidential data used in Reliability Pricing Model Auctions to calculate clearing prices and other auction results, as appropriate to inform market participants of auction conditions.

3.3 Records and Reports

The Office of the Interconnection shall prepare and maintain such records as are required for the administration of the Base Residual Auction and Incremental Auctions. For each auction conducted, the Office of the Interconnection shall, consistent with section 18.17 of the Operating Agreement, publish the following: (i) Zonal Capacity Prices for each LDA; (ii) Capacity Resource Clearing Prices for each LDA; (iii) Locational Price Adders; (iv) the total megawatts of Unforced Capacity that cleared; and (v) such other auction data as may be appropriate to the efficient and competitive conduct of the Base Residual Auction and Incremental Auctions. Such information shall be available on the PJM internet site through the end of the Delivery Year to which such auctions apply.

3.4 Counterparty

(a) PJMSettlement shall be the Counterparty to the transactions arising from the cleared Base Residual Auctions and Incremental Auctions; provided, however, PJMSettlement shall not be a contracting party to (i) any bilateral transactions between Market Participants, or (ii) with respect to Self-Supply for which designation of Self-Supply has been reported to the Office of the Interconnection.

(b) Charges. PJMSettlement shall be the Counterparty with respect to the obligations to pay, and the payment of, charges pursuant to this Attachment DD.

4. GENERAL PROVISIONS

4.1 Capacity Market Sellers

Only Capacity Market Sellers shall be eligible to submit Sell Offers into the Base Residual Auction and Incremental Auctions. Capacity Market Sellers shall comply with the terms and conditions of all Sell Offers, as established by the Office of the Interconnection in accordance with this Attachment, Attachment M, Attachment M - Appendix and the Operating Agreement.

4.2 Capacity Market Buyers

Only Capacity Market Buyers shall be eligible to submit Buy Bids into an Incremental Auction. Capacity Market Buyers shall comply with the terms and conditions of all Buy Bids, as established by the Office of the Interconnection in accordance with this Attachment, Attachment M, Attachment M - Appendix and the Operating Agreement.

4.3 Agents

A Capacity Market Seller may participate in a Base Residual Auction or Incremental Auction through an Agent, provided that the Capacity Market Seller informs the Office of the Interconnection in advance in writing of the appointment and authority of such Agent. A Capacity Market Buyer may participate in an Incremental Auction through an Agent, provided that the Capacity Market Buyer informs the Office of the Interconnection in advance in writing of the appointment and authority of such Agent. A Capacity Market Buyer or Capacity Market Seller participating in such an auction through an Agent shall be bound by all of the acts or representations of such Agent with respect to transactions in such auction. Any written instrument establishing the authority of such Agent shall provide that any such Agent shall comply with the requirements of this Attachment and the Operating Agreement.

4.4 General Obligations of Capacity Market Buyers and Capacity Market Sellers

Each Capacity Market Buyer and Capacity Market Seller shall comply with all laws and regulations applicable to the operation of the Base Residual and Incremental Auctions and the use of these auctions shall comply with all applicable provisions of this Attachment, Attachment M, Attachment M - Appendix, the Operating Agreement, and the Reliability Assurance Agreement, and all procedures and requirements for the conduct of the Base Residual and Incremental Auctions and the PJM Region established by the Office of the Interconnection in accordance with the foregoing.

4.5 Confidentiality

The following information submitted to the Office of the Interconnection in connection with any Base Residual Auction, Incremental Auction, Reliability Backstop Auction, or Capacity Performance Transition Incremental Auction shall be deemed confidential information for purposes of Section 18.17 of the Operating Agreement, Attachment M and Attachment M - Appendix: (i) the terms and conditions of the Sell Offers and Buy Bids; and (ii) the terms and conditions of any bilateral transactions for Capacity Resources.

4.6 Bilateral Capacity Transactions

(a) Unit-Specific Internal Capacity Bilateral Transaction Transferring All Rights and Obligations ("Section 4.6(a) Bilateral").

(i) Market Participants may enter into unit-specific internal bilateral capacity contracts for the purchase and sale of title and rights to a specified amount of installed capacity from a specific generating unit or units. Such bilateral capacity contracts shall be for the transfer of rights to capacity to and from a Market Participant and shall be reported to the Office of the Interconnection in accordance with this Attachment DD and the Office of the Interconnection's rules related to its eRPM tools.

(ii) For purposes of clarity, with respect to all Section 4.6(a) Bilateral transactions, the rights to, and obligations regarding, the capacity that is the subject of the transaction shall pass to the buyer under the contract at the location of the unit and further transactions and rights and obligations associated with such capacity shall be the responsibility of the buyer under the contract. Such obligations include any charges, including penalty charges, relating to the capacity under this Attachment DD. In no event shall the purchase and sale of the rights to capacity pursuant to a Section 4.6(a) Bilateral constitute a transaction with the Office of the Interconnection or PJMSettlement or a transaction in any auction under this Attachment DD.

(iii) All payments and related charges associated with a Section 4.6(a) Bilateral shall be arranged between the parties to the transaction and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The Office of the Interconnection, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a Section 4.6(a) Bilateral reported to the Office of the Interconnection under this Attachment DD.

(iv) With respect to capacity that is the subject of a Section 4.6(a) Bilateral that has cleared an auction under this Attachment DD prior to a transfer, the buyer of the cleared capacity shall be considered in the Delivery Year the party to a transaction with PJMSettlement as Counterparty for the cleared capacity at the Capacity Resource Clearing Price published for the applicable auction.

(v) A buyer under a Section 4.6(a) Bilateral contract shall pay any penalties or charges associated with the capacity transferred under the contract. To the extent the capacity that is the subject of a Section 4.6(a) Bilateral contract has cleared an auction under this Attachment DD prior to a transfer, then the seller under the contract also shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any penalties or charges associated with the capacity and for which payment is not made to PJMSettlement by the buyer as determined by the Office of the Interconnection. All claims regarding a default of a buyer to a seller under a Section 4.6(a) Bilateral contract shall be resolved solely between the buyer and the seller.

(vi) To the extent the capacity that is the subject of the Section 4.6(a) Bilateral transaction already has cleared an auction under this Attachment DD, such bilateral capacity transactions shall be subject to the prior consent of the Office of the Interconnection and its

determination that sufficient credit is in place for the buyer with respect to the credit exposure associated with such obligations.

(b) Bilateral Capacity Transaction Transferring Title to Capacity But Not Transferring Performance Obligations ("Section 4.6(b) Bilateral").

(i) Market Participants may enter into bilateral capacity transactions for the purchase and sale of a specified megawatt quantity of capacity that has cleared an auction pursuant to this Attachment DD. The parties to a Section 4.6(b) Bilateral transaction shall identify (1) each unit from which the transferred megawatts are being sold, and (2) the auction in which the transferred megawatts cleared. Such bilateral capacity transactions shall transfer title and all rights with respect to capacity and shall be reported to the Office of the Interconnection on an annual basis prior to each Delivery Year in accordance with this Attachment DD and pursuant to the Office of the Interconnection's rules related to its eRPM tools. Reported transactions with respect to a unit will be accepted by the Office of the Interconnection only to the extent that the total of all bilateral sales from the reported unit (including Section 4.6(a) Bilaterals, Section 4.6(b) Bilaterals, and Locational UCAP bilaterals) do not exceed the unit's cleared unforced capacity.

(ii) For purposes of clarity, with respect to all Section 4.6(b) Bilateral transactions, the rights to the capacity shall pass to the buyer at the location of the unit(s) specified in the reported transaction. In no event shall the purchase and sale of the rights to capacity pursuant to a Section 4.6(b) Bilateral constitute a transaction with PJMSettlement or the Office of the Interconnection or a transaction in any auction under this Attachment DD.

(iii) With respect to a Section 4.6(b) Bilateral, the buyer of the cleared capacity shall be considered in the Delivery Year the party to a transaction with PJMSettlement as Coutnerparty for the cleared capacity at the Capacity Resource Clearing Price published for the applicable auction; provided, however, with respect to all Section 4.6(b) Bilateral transactions, such transactions do not effect a novation of the seller's obligations to make RPM capacity available to PJM pursuant to the terms and conditions originally agreed to by the seller; provided further, however, the buyer shall indemnify PJMSettlement, the LLC, and the Members for any failure by a seller under a Section 4.6(b) Bilateral to meet any resulting obligations, including the obligation to pay deficiency penalties and charges owed to PJMSettlement, associated with the capacity.

(iv) All payments and related charges associated with a Section 4.6(b) Bilateral shall be arranged between the parties to the contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The Office of the Interconnection, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a Section 4.6(b) Bilateral capacity contract reported to the Office of the Interconnection under this Attachment DD.

(v) All claims regarding a default of a buyer to a seller under a Section 4.6(b) Bilateral shall be resolved solely between the buyer and the seller.

(c) Locational UCAP Bilateral Transactions Between Capacity Sellers.

(i) Market Participants may enter into Locational UCAP bilateral transactions which shall be reported to the Office of the Interconnection in accordance with this Attachment DD and the LLC's rules related to its eRPM tools.

(ii) For purposes of clarity, with respect to all Locational UCAP bilateral transactions, the rights to the Locational UCAP that are the subject of the Locational UCAP bilateral transaction shall pass to the buyer under the Locational UCAP bilateral contract subject to the provisions of section 5.3A. In no event, shall the purchase and sale of Locational UCAP pursuant to a Locational UCAP bilateral transaction constitute a transaction with the Office of the Interconnection or PJMSettlement, or a transaction in any auction under this Attachment DD.

(iii) A Locational UCAP Seller shall have the obligation to make the capacity available to PJM in the same manner as capacity that has cleared an auction under this Attachment DD and the Locational UCAP Seller shall have all obligations for charges and penalties associated with the capacity that is the subject of the Locational UCAP bilateral contract; provided, however, the buyer shall indemnify PJMSettlement, the LLC, and the Members for any failure by a seller to meet any resulting obligations, including the obligation to pay deficiency penalties and charges owed to PJMSettlement, associated with the capacity. All claims regarding a default of a buyer to a seller under a Locational UCAP bilateral contract shall be resolved solely between the buyer and the seller.

(iv) All payments and related charges for the Locational UCAP associated with a Locational UCAP bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a Locational UCAP bilateral contract reported to the Office of the Interconnection under this Attachment DD.

(d) The bilateral transactions provided for in this section 4.6 shall be for the physical transfer of capacity to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Attachment DD and pursuant to the Office of the Interconnection's rules relating to its eRPM tools. Bilateral transactions that do not contemplate the physical transfer of capacity to and from a Market Participant are not subject to this Attachment DD and shall not be reported to and coordinated with the Office of the Interconnection.

5. CAPACITY RESOURCE COMMITMENT

5.1 Introduction

In accordance with the Reliability Assurance Agreement, each Load Serving Entity is obligated to pay a Locational Reliability Charge for each Zone in which it serves load based on the Daily Unforced Capacity Obligation of its loads in such Zone. An LSE may offset the Locational Reliability charge for a Delivery Year, in whole or in part, by: (a) Self-Supply of Capacity Resources in the Base Residual Auction or an Incremental Auction; (b) offering and clearing Capacity Resources in the Base Residual Auction or an Incremental Auction (but only to the extent of the additional resources committed to meet Unforced Capacity Obligations through such Incremental Auction); (c) receiving payments from Capacity Transfer Rights; ~~or~~ (d) offering and clearing Qualifying Transmission Upgrades in the Base Residual Auction~~.~~; or (e) matching its load to the capacity supplied by a Capacity Resource outside the RPM Auction pursuant to the FRR-RS Alternative

5.2 Nomination of Self Supplied Capacity Resources

A Capacity Market Seller, including a Load Serving Entity, may designate a Capacity Resource as Self-Supply for a Delivery year by submitting a Sell Offer for such resource in the Base Residual Auction or an Incremental Auction in accordance with the procedure and time schedule set forth in the PJM Manuals. The LSE shall indicate its intent in the Sell Offer that the Capacity Resource be deemed Self-Supply and shall indicate whether it is committing the resource regardless of clearing price or with a price bid. Any such Sell Offer shall be subject to the minimum offer price rule set forth in section 5.14(h). Upon receipt of a Self-Supply Sell Offer, the Office of the Interconnection will verify that the designated Capacity Resource is available, in accordance with Section 5.6, and, if the LSE indicated that it is committing the resource regardless of clearing price, will treat such Capacity Resource as committed in the clearing process of the Reliability Pricing Model Auction for which it was offered for such Delivery Year. To address capacity obligation quantity uncertainty associated with the Variable Resource Requirement Curve, a Load Serving Entity may submit a Sell Offer with a contingent designation of a portion of its Capacity Resources as either Self-Supply (to the extent required to meet a portion (as specified by the LSE) of the LSE's peak load forecast in each transmission zone) or as not Self-Supply (to the extent not so required) and subject to an offer price, in accordance with the PJM Manuals. PJMSettlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.

5.2A Election of FRR-RS Alternative.

A Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource with an Actionable Subsidy may elect to commit that Capacity Resource, or a segment of that Capacity Resource, outside the RPM Auction by electing the FRR-RS Alternative.

a) No less than 45 days before the conduct of the Base Residual Auction for the 2022/23 Delivery Year, and no less than 120 days before the conduct of any subsequent Base Residual Auction which the FRR-RS Alternative election is to be effective, any Member seeking to elect the FRR-RS Alternative for any Capacity Resource, or segment of a Capacity Resource pursuant to Section 5.6.1(a)(ii) of Attachment DD, shall notify the Office of the Interconnection in writing of such election. The notification shall include documentation (i) certifying that the FRR-RS Resource is a Capacity Resource with Actionable Subsidy and identifying the Actionable Subsidy; and (ii) identifying the quantity of Unforced Capacity that the FRR-RS Resource will provide pursuant to the FRR-RS Alternative.

b) The notification submitted pursuant to paragraph (a) of this Section 5.2A shall also identify the Load Serving Entity or Entities that shall receive credit toward their Daily Unforced Capacity Obligation for the Unforced Capacity provided by the FRR-RS Resource. If more than one Load Serving Entity is to receive credit, then the Member electing the FRR-RS Alternative shall specify how the FRR-RS Resource's Unforced Capacity provided pursuant to the FRR-RS Alternative shall be allocated among those Load Serving Entities.

c) Notwithstanding paragraph (b) of this Section 5.2A, if the FRR-RS Resource is procured through a state-directed procurement process, and the procuring state regulatory jurisdiction has implemented retail choice, the notification pursuant to Section 5.2A(a) of Attachment DD need not identify the particular Load Serving Entity or Entities that shall receive credit toward their Daily Unforced Capacity Obligation, but instead may identify the LDA that will provide compensation to the FRR-RS Resource. The Relevant Electric Retail Regulatory Authority shall determine how to allocate an FRR-RS Resource's capacity among the Load Serving Entities subject to its jurisdiction. No later than two months before the Delivery Year, the FRR-RS Resource shall supplement the documentation submitted pursuant to Section 5.2A(a) of Attachment to indicate the Relevant Electric Retail Regulatory Authority's allocation. Nothing in this Tariff shall preclude a Relevant Electric Retail Regulatory Authority from allocating an FRR-RS Entity's capacity among Load Serving Entities subject to its jurisdiction even if the FRR-RS Entity receives compensation from a third party, including but not limited to a non-bypassable charge assessed by an Electric Distributor (as defined in the RAA) pursuant to a Relevant Electric Retail Regulatory Authority's directive. A Load Serving Entity allocated any FRR-RS capacity by the Relevant Electric Retail Regulatory Authority, or any other aggrieved party, may, at any time, exercise its rights under Section 206 of the Federal Power Act to challenge the allocation of capacity among Load Serving Entities, and/or the compensation paid to the FRR-RS Resource for its capacity, as unjust and unreasonable.

d) No later than one month before the Base Residual Auction, the Load Serving Entity or Entities to be credited with the FRR-RS Resource's capacity pursuant to Section 5.2A(b) shall confirm the quantity of capacity to be credited toward each Load Serving Entity's

Daily Unforced Capacity Obligation, or the Relevant Electric Retail Regulatory Authority that has directed the procurement of the FRR-RS Resource's capacity pursuant to Section 5.2A(c) shall confirm the quantity of capacity to be credited toward an identified LDA. In addition, the Member electing the FRR-RS Alternative shall provide documentation setting forth the compensation the FRR-RS Resource will receive for committing its capacity pursuant to the FRR-RS Alternative. Such compensation shall additionally be reported to the Commission on the FRR-RS Resource's EQR and shall be subject to the Commission's review under Section 206 of the Federal Power Act.

e) An FRR-RS Resource receiving compensation for its capacity from an affiliated LSE or Electric Distributor with captive customers may seek waiver of the Section 205 filing requirement under the FRR-RS Resource's market-based rate tariff if the transaction is undertaken at the direction of a state procurement authority or Relevant Electric Retail Regulatory Authority. However, any aggrieved party may challenge the transaction as affiliate abuse under Section 206 of the Federal Power Act.

f) The FRR-RS Resource shall be subject to the Non-Performance Charge for Capacity Performance Resources as provided in Section 10A of Attachment DD, and all other obligations of Capacity Performance Resources, including, as applicable, requirements and milestones for Planned Generation Capacity Resources and Planned Demand Resources. An FRR-RS Resource must commit unit-specific capacity. The election of the FRR-RS Alternative may not be based on a "slice of system" or similar agreements that are not unit specific.

g) An FRR-RS Resource may terminate its election of the FRR-RS Alternative effective with the commencement of any Delivery Year following the first Delivery Year by providing written notice of such termination to the Office of the Interconnection no later than two months prior to the Base Residual Auction for such Delivery Year. Absent such termination, the election of the FRR-RS Alternative in respect to a Capacity Resource shall remain in effect so long as the Capacity Resource is a Capacity Resource with Actionable Subsidy, provided that the Member electing the FRR-RS Alternative annually update the documentation required under Section 5.2A(b) and/or 5.2A(c) of Attachment DD not later than one month before the Base Residual Auction.

h) To ensure the deliverability of any FRR-RS Resource to the Load Serving Entity or Entities that shall receive credit for the FRR-RS Resource's capacity, PJM shall treat the FRR-RS Resource as a Self-Supply Resource belonging to those Load Serving Entities or future LSEs in the relevant load zone (as indicated in the documentation required under Section 5.2A(a), (b) and (c) of Attachment DD) for purposes of its auction-clearing mechanism. However, FRR-RS Resources shall not be compensated in such auction and the Load Serving Entities credited with an FRR-RS Resource's capacity shall use the value of such foregone compensation to offset the LSE's Locational Reliability Charge for the relevant Delivery Year.

i) PJMSettlement shall be the Counterparty with respect to an FRR-RS Resource for the purpose of managing the transfer accounting associated with the crediting of Load-Serving Entities for capacity supplied by an FRR-RS Resource, and shall administer the collection and payment of amounts pursuant to the allocation method and compensation set forth in the FRR-RS Entity's documentation submitted pursuant to Sections 5.2A(b) and 5.2A(c).

5.3 Commitment of Contractually Purchased Capacity Resources

A Load Serving Entity that has purchased the right to the capacity output of a generation resource and desires to commit such right as a Capacity Resource for a Delivery Year shall be considered a Capacity Market Seller. Such an LSE must submit a Sell Offer in the Base Residual Auction for such Delivery Year, in accordance with the procedure and time schedule set forth in the PJM Manuals. In such Sell Offer, the Capacity Resource offered by the LSE may be submitted as Self-Supply or with an offer price. PJMSettlement shall not be the Counterparty with respect to a Capacity Resource designated as Self-Supply.

5.3A Locational UCAP Bilateral Transactions

A Member that has committed capacity through an RPM Auction for a Delivery Year may purchase Locational UCAP as replacement capacity from a Member with available uncommitted capacity for such Delivery Year in accordance with the terms of this section and the PJM Manuals. Locational UCAP may not be sold or purchased prior to the date that the final EFORD is established for such Delivery Year, and if designated to PJM by the Locational UCAP Seller as sold prior to the Third Incremental Auction for a Delivery Year must be confirmed by the buyer prior to such Third Incremental Auction as purchased for replacement capacity, or such transaction shall be rejected. In accordance with procedures specified in the PJM Manuals, the parties to a Locational UCAP transaction must notify PJM of such transaction, which notification must specify: i) the buyer, ii) the Locational UCAP Seller, iii) the start and end dates of the transaction (which may not be retroactive), iv) the Locational UCAP amount (no less than 0.1 megawatts), v) the demand or generation resource with available uncommitted capacity that is the basis for the sale, and vi) the Locational Delivery Area in which the resource is located. The Locational UCAP Seller shall be responsible for any charges imposed under sections 7, 8, 9, 10, 10A, 11, or 13, as applicable, for such Delivery Year, with respect to the increment of capacity sold as Locational UCAP; any other settlement of charges under the Locational UCAP transaction shall be between the parties. A purchaser of Locational UCAP may not offer such capacity into an RPM Auction.

5.4 Reliability Pricing Model Auctions

The Office of the Interconnection shall conduct the following Reliability Pricing Model Auctions:

a) Base Residual Auction.

PJM shall conduct for each Delivery Year a Base Residual Auction to secure commitments of Capacity Resources as needed to satisfy the portion of the RTO Unforced Capacity Obligation not satisfied through Self-Supply of Capacity Resources for such Delivery Year. All Self-Supply Capacity Resources must be offered in the Base Residual Auction. As set forth in section 6.6, all other Capacity Resources, and certain other existing generation resources, must be offered in the Base Residual Auction. The Base Residual Auction shall be conducted in the month of May that is three years prior to the start of such Delivery Year. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Load Serving Entities through the Locational Reliability Charge during such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and the payments, by Load Serving Entities; provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

b) Scheduled Incremental Auctions.

PJM shall conduct for each Delivery Year a First, a Second, and a Third Incremental Auction for the purposes set forth in section 2.34. The First Incremental Auction shall be conducted in the month of September that is twenty months prior to the start of the Delivery Year; the Second Incremental Auction shall be conducted in the month of July that is ten months prior to the start of the Delivery Year; and the Third Incremental Auction shall be conducted in the month of February that is three months prior to the start of the Delivery Year.

c) Adjustment through Scheduled Incremental Auctions of Capacity Previously Committed.

The Office of the Interconnection shall recalculate the PJM Region Reliability Requirement and each LDA Reliability Requirement prior to each Scheduled Incremental Auction, based on an updated peak load forecast, updated Installed Reserve Margin and an updated Capacity Emergency Transfer Objective; shall update such reliability requirements for the Third Incremental Auction to reflect any change from such recalculation; and shall update such reliability requirements for the First Incremental Auction or Second Incremental Auction only if the change is greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement. Based on such update, the Office of the Interconnection shall, under certain conditions, seek through the Scheduled Incremental Auction to secure additional commitments of capacity or release sellers from prior capacity commitments. Specifically, the Office of the Interconnection shall:

1) seek additional capacity commitments to serve the PJM Region or an LDA if the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability

requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year) is less than, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such additional capacity commitments only if such shortfall is in an amount greater than or equal to the lesser of: (i) 500 MW or (ii) one percent of the applicable prior reliability requirement;

2) seek additional capacity commitments to serve the PJM Region or an LDA if:

i) the updated PJM Region Reliability Requirement less, for Delivery Years through May 31, 2018, the PJM Region Short-Term Resource Procurement Target utilized in the most recent auction conducted for the Delivery Year, or if the LDA Reliability Requirement less, for Delivery Years through May 31, 2018, the LDA Short Term Resource Procurement Target applicable to such auction, exceeds the total capacity committed in all prior auctions in such region or area, respectively, for such Delivery Year by an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM conducts a Conditional Incremental Auction for such Delivery Year and does not obtain all additional commitments of Capacity Resources sought in such Conditional Incremental Auction, in which case, PJM shall seek in the Incremental Auction the commitments that were sought in the Conditional Incremental Auction but not obtained.

3) seek agreements to release prior capacity commitments to the PJM Region or to an LDA if:

i) the PJM Region Reliability Requirement or LDA Reliability Requirement utilized in the most recent prior auction conducted for the Delivery Year (including any reductions to such reliability requirements as a result of any Price Responsive Demand with a PRD Reservation Price equal to or lower than the clearing price in the Base Residual Auction for such Delivery Year) exceeds, respectively, the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement; provided, however, that in the First Incremental Auction or Second Incremental Auction the Office of the Interconnection shall seek such agreements only if such excess is in an amount greater than or equal to the lesser of: (A) 500 MW or (B) one percent of the applicable prior reliability requirement; or

ii) PJM obtains additional commitments of Capacity Resources in a Conditional Incremental Auction, in which case PJM shall seek release of an equal number of megawatts (comparing the total purchase amount for all LDAs and the PJM Region related to the delay in Backbone Transmission with the total sell amount for all LDAs and the PJM Region related to the delay in Backbone Transmission) of prior committed capacity that would not have been committed

had the delayed Backbone Transmission upgrade that prompted the Conditional Incremental Auction not been assumed, at the time of the Base Residual Auction, to be in service for the relevant Delivery Year; and if PJM obtains additional commitments of capacity in an incremental auction pursuant to subsection c.2.ii above, PJM shall seek in such Incremental Auction to release an equal amount of capacity (in total for all LDAs and the PJM Region related to the delay in Backbone Transmission) previously committed that would not have been committed absent the Backbone Transmission upgrade.

4) The cost of payments to Market Sellers for additional Capacity Resources cleared in such auctions, and the credits from payments from Market Sellers for the release of previously committed Capacity Resources, shall be apportioned to Load Serving Entities in the PJM Region or LDA, as applicable, through adjustments to the Locational Reliability Charge for such Delivery Year.

5) PJMSettlement shall be the Counterparty to the sales (including releases) of Capacity Resources that clear in such auctions and to the obligations to pay, and the payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

d) Commitment of Replacement Capacity through Scheduled Incremental Auctions.

Each Scheduled Incremental Auction for each Delivery Year shall allow Capacity Market Sellers that committed Capacity Resources in any prior Reliability Pricing Model Auction for such Delivery Year to submit Buy Bids for replacement Capacity Resources. Capacity Market Sellers that submit Buy Bids into an Incremental Auction must specify the type of Unforced Capacity desired, i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource. The need to purchase replacement Capacity Resources may arise for any reason, including but not limited to resource retirement, resource cancellation or construction delay, resource derating, EFORd increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences. The cost of payments to Capacity Market Sellers for Capacity Resources that clear such auction shall be paid by PJMSettlement from amounts collected by PJMSettlement from Capacity Market Buyers that purchase replacement Capacity Resources in such auction. PJMSettlement shall be the Counterparty to the sales and purchases that clear in such auction, provided, however, PJMSettlement shall not be a Counterparty to committed Self-Supply Capacity Resources.

e) Conditional Incremental Auction.

PJM shall conduct for any Delivery Year a Conditional Incremental Auction if the in service date of a Backbone Transmission Upgrade that was modeled in the Base Residual Auction is announced as delayed by the Office of the Interconnection beyond July 1 of the Delivery Year for which it was modeled and if such delay causes a reliability criteria violation. If conducted, the Conditional Incremental Auction shall be for the purpose of securing commitments of additional capacity for the PJM Region or for any LDA to address the identified reliability criteria violation. If PJM determines to conduct a Conditional Incremental Auction, PJM shall

post on its website the date and parameters for such auction (including whether such auction is for the PJM Region or for an LDA, and the type of Capacity Resources required) at least one month prior to the start of such auction. The cost of payments to Market Sellers for Capacity Resources cleared in such auction shall be collected by PJMSettlement from Load Serving Entities in the PJM Region or LDA, as applicable, through an adjustment to the Locational Reliability Charge for such Delivery Year. PJMSettlement shall be the Counterparty to the sales that clear in such auction and to the obligations to pay, and payments, by Load Serving Entities, provided, however, that PJMSettlement shall not be a Counterparty to committed Self- Supply Capacity Resources.

5.5 Eligibility for Participation in RPM Auctions

A Capacity Market Seller may submit a Sell Offer for a Capacity Resource in a Base Residual Auction, Incremental Auction, or Capacity Performance Transition Incremental Auction only if such seller owns or has the contractual authority to control the output or load reduction capability of such resource and has not transferred such authority to another entity prior to submitting such Sell Offer. Capacity Resources must satisfy the capability and deliverability requirements of Schedules 9 and 10 of the PJM Reliability Assurance Agreement, the requirements for Demand Resources or Energy Efficiency Resources in Attachment DD-1 and Schedule 6 of the Reliability Assurance Agreement, as applicable, and, for the 2018/2019 Delivery Year and subsequent Delivery Years, the criteria in section 5.5A.

5.5A Capacity Resource Types

(a) Capacity Performance Resources

Capacity Performance Resources are Capacity Resources which, to the extent such resources cleared in a Reliability Pricing Model Auction or are otherwise committed as a Capacity Resource, are obligated to deliver energy during the relevant Delivery Year as scheduled and/or dispatched by the Office of Interconnection during the Performance Assessment Hours. As further detailed in Section 10A of this Attachment, Capacity Performance Resources that fail to meet this obligation will be subject to a Non-Performance Charge, unless excused pursuant to Section 10A(d) of this Attachment. Subject to 5.5A(a)(i), the following types of Capacity Resources are eligible to submit a Sell Offer as a Capacity Performance Resource: internal or external Generation Capacity Resources; Annual Demand Resources; Capacity Storage Resources; Annual Energy Efficiency Resources; and Qualifying Transmission Upgrades. To the extent the underlying Capacity Resource is an external Generation Capacity Resource, such resource must meet, *to the extent subsection (b) or (c) of this section is applicable to offers from such resource, meet the applicable requirements of such subsection, and if neither subsection (b) or (c) is applicable, then offers from such resource must* the criteria for obtaining an exception to the Capacity Import Limit as contained in article 1 of the Reliability Assurance Agreement.

(i) Process for Support and Review of Capacity Performance Resource Offers

A. The Capacity Market Seller shall provide to the Office of the Interconnection and the Market Monitoring Unit, upon their request, all supporting data and information requested by either the Office of the Interconnection or the Market Monitoring Unit to evaluate whether the underlying Capacity Resource can meet the operational and performance requirements of Capacity Performance Resources. The Capacity Market Seller shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the request to reflect any material changes.

B. The Office of the Interconnection and the Market Monitoring Unit shall review any requested supporting data and information, and the Office of the Interconnection, considering advice and recommendation from the Market Monitoring Unit, shall reject a request for a resource to offer as a Capacity Performance Resource if the Capacity Market Seller does not demonstrate that it can reasonably be expected to meet its Capacity Performance obligations consistent with the resource's offer by the relevant Delivery Year. The Office of Interconnection shall provide its determination to reject eligibility of the resource as a Capacity Performance Resource, and notify the Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences. A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules unless and until ordered to do otherwise by FERC.

(b) Offers from External Generation Capacity Resources for the 2020/2021 Delivery Year and Subsequent Delivery Years—General Rule

For the 2020/2021 Delivery Year and any subsequent Delivery Year and for Capacity Performance Resource Sell Offers in any RPM Auction conducted for the 2018/2019 Delivery Year or 2019/2020 Delivery Year after May 9, 2017, unless excepted pursuant to subsection (c) below, a Capacity Market Seller may submit a Sell Offer for an external Generation Capacity Resource in an RPM Auction if the Capacity Market Seller demonstrates to PJM, by no later than five (5) business days prior to the commencement of the offer period for the relevant RPM Auction, that such resource meets all of the following requirements:

(i) The Capacity Market Seller has obtained a determination that the Pseudo-Tie required for its external Generation Capacity Resource is feasible, including (without limitation) that such Pseudo-Tie meets the following requirements:

(A) meets the Electrical Distance requirements established in the PJM Manuals for Pseudo-Ties;

(B) at least one generation resource that has a historic economic minimum offer lower than its historic economic maximum offer, located inside the metered boundaries of the PJM Region, has a minimum flow distribution impact at the level specified in the PJM Manuals on each eligible coordinated flowgate resulting from such Pseudo-Tie;

(C) each external entity with which PJM may be required to coordinate flowgates under an agreed congestion management process maintains a network model that produces results for such flowgates that are within two percent of the results produced by the PJM network model for such flowgates;

(D) the Capacity Market Seller has secured written acknowledgement from the external Balancing Authority Areas that such Pseudo-Tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM.

and the Capacity Market Seller has committed in writing that it will take all steps necessary to implement such Pseudo-Tie prior to the start of the relevant Delivery Year;

(ii) it has, for transmission outside PJM, obtained long-term firm point-to-point transmission service (evaluated for deliverability from the unit-specific physical location of the resource to PJM load pursuant to a study that is reviewed and approved by PJM in accordance with PJM deliverability criteria to ensure uniformity for internal and external resource deliverability requirements), with rollover rights for the term of the transmission service that is confirmed by the Balancing Authority for the Balancing Authority Area where such resource is geographically located; and, as to transmission within PJM, has obtained Network External Designated Transmission Service; and

(iii) it is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by Tariff, Attachment DD, section 6.6 to offer their capacity into RPM Auctions.

A Capacity Market Seller that satisfies the above requirements with respect to an external Generation Capacity Resource Sell Offer submitted in an RPM Auction for a Delivery Year shall be required to demonstrate satisfaction of such requirements for any Sell Offer with respect to such resource submitted in an RPM Auction for any subsequent Delivery Year, including, without limitation, demonstration that the required external transmission service continues to satisfy PJM's deliverability standards.

(c) Offers from external Generation Capacity Resources for the 2020/2021 Delivery Year and Subsequent Delivery Years—Exception.

A Capacity Market Seller of a Prior CIL Exception External Resource may continue to submit Sell Offers for such resource for any RPM Auction for any Delivery Year up to and including the 2021/2022 Delivery Year (or, solely for any such resource that is (1) owned by a Load Serving Entity and used to self-supply (under arrangements initiated before June 1, 2016, with a duration of at least ten years) such entity's PJM Region load or (2) the subject of a contract for energy or capacity or equivalent written agreement entered into on or before June 1, 2016 for a term of ten years or longer with a purchaser that is an internal PJM load customer, for any Delivery Year during the life of such resource for subparagraph (1) or for the term of the agreement under subparagraph (2)) so long as it continues to comply with all conditions on the grant of its exception to the Capacity Import Limit, subject to the following additional conditions:

(i) for any Delivery Year, beginning with the 2017/2018 Delivery Year, for which such Prior CIL Exception External Resource has cleared an RPM Auction, PJM may in its sole judgment determine that the resource is not Operationally Deliverable for such Delivery Year because it does not satisfy the requirements of subsection (b). If PJM determines a Prior CIL Exception External Resource is not Operationally Deliverable for a Delivery Year, it must notify the Capacity Market Seller of its determination by no later than October 1 immediately preceding such Delivery Year. After receiving such notice, the Capacity Market Seller may elect to:

(A) take the necessary actions to make the Prior CIL Exception External Resource Operationally Deliverable, in PJM's sole judgment, prior to the beginning of such Delivery Year, provided that PJM will, if transmission upgrades are required to make such resource Operationally Deliverable, facilitate the performance of transmission studies and otherwise cooperate with the external Transmission Provider of the system on which such upgrades are required to identify the upgrades required to meet PJM's deliverability standards;

(B) be relieved of its capacity obligation for such Delivery Year, with no entitlement to any capacity revenues based on such resource, with no requirement to seek replacement for such capacity for such Delivery Year, with no penalty for non-performance or lack of commitment for such Delivery Year, and with no further must-offer obligation that would otherwise arise solely from clearing such capacity for such Delivery Year; or

(C) procure, by purchase or otherwise, replacement in a sufficient quantity to replace the capacity that would have been provided by the Prior CIL

Exception External Resource but for PJM's determination that such resource is not Operationally Deliverable.

(ii) Such Capacity Market Seller's continued ability to offer such resource under this exception is conditioned on external Transmission Providers continuing to honor the firm status of the Capacity Market Seller's transmission service for all Delivery Years for which such seller offers such resource under the exceptions provided in this subsection (c).

(iii) A Capacity Market Seller offering and clearing a Prior CIL Exception External Resource pursuant to this subsection (c) shall be relieved of its must-offer obligation that would otherwise arise solely from clearing such capacity. Such relief of the must-offer obligation shall be for any Delivery Year after the last Delivery Year for which it is permitted to offer such resource under this subsection (c).

(d) Base Capacity Resources

For the 2018/2019 and 2019/2020 Delivery Years, following types of Capacity Resources eligible to submit a Sell Offer as a Base Capacity Resource: Generation Capacity Resources, Capacity Storage Resources, Annual Demand Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. Each resource that clears a RPM Auction as a Base Capacity Resource must provide energy output to PJM if called during Performance Assessment Hours occurring in the calendar months of June through September, including any necessary recall of such capacity and energy from service to areas outside the PJM Region. As further detailed in Section 10A of this Attachment, Base Capacity Resources that fail to meet this obligation will be subject to a Non-Performance Charge, unless excused pursuant to Section 10A(d) of this section.

(e) Seasonal Capacity Performance Resource

For the 2020/2021 Delivery Year and subsequent Delivery Years, a Seasonal Capacity Performance Resource shall mean a Summer-Period Capacity Performance Resource or Winter-Period Capacity Performance Resource, as defined below.

i) Summer-Period Capacity Performance Resource

For the 2020/2021 Delivery Year and subsequent Delivery Years, the following types of Capacity Resources are eligible to submit a Sell Offer as a Summer-Period Capacity Performance Resource: Summer Period Demand Resource, Summer-Period Energy Efficiency Resource, and Capacity Storage Resource, Intermittent Resource, or Environmentally-Limited Resource that has an average expected energy output during summer peak-hour periods consistently and measurably greater than its average expected energy output during winter peakhour periods. To the extent such resource clears an RPM Auction or is otherwise committed as a Summer-Period Capacity Performance Resource, it is obligated to deliver energy as scheduled and/or dispatched by the Office of Interconnection during Performance Assessment Hours occurring in the calendar months of June through October and the following May of the Delivery Year, and must satisfy the requirements of a Capacity Performance Resource for such period of time. As further

detailed in section 10A of this Attachment, Summer-Period Capacity Performance Resources that fail to meet this obligation will be subject to a Non-Performance Charge, unless excused pursuant to section 10A(d) of this Attachment.

ii) Winter-Period Capacity Performance Resource

For the 2020/2021 Delivery Year and subsequent Delivery Years, the following types of Capacity Resources are eligible to submit a Sell Offer as a Winter-Period Capacity Performance Resource: Capacity Storage Resource, Intermittent Resource, and Environmentally-Limited Resource that has an average expected energy output during winter peak-hour periods consistently and measurably greater than its average expected energy output during summer peak-hour periods. To the extent such resource clears an RPM Auction or is otherwise committed as a Winter-Period Capacity Performance Resource, it is obligated to deliver energy as scheduled and/or dispatched by the Office of Interconnection during Performance Assessment Hours occurring in the calendar months of November through April of the Delivery Year, and must satisfy the requirements of a Capacity Performance Resource for such period of time. As further detailed in section 10A of this Attachment, Winter-Period Capacity Performance Resources that fail to meet this obligation will be subject to a Non-Performance Charge, unless excused pursuant to section 10A(d) of this Attachment.

5.6 Sell Offers

Sell Offers shall be submitted or withdrawn via the internet site designated by the Office of the Interconnection, under the procedures and time schedule set forth in the PJM Manuals.

5.6.1 Specifications

A Sell Offer shall state quantities in increments of 0.1 megawatts and shall specify, as appropriate:

a) Identification of the Generation Capacity Resource, Demand Resource, Capacity Storage Resource or Energy Efficiency Resource on which such Sell Offer is based;

b) Minimum and maximum megawatt quantity of installed capacity that the Capacity Market Seller is willing to offer (notwithstanding such specification, the product offered shall be Unforced Capacity), or designate as Self-Supply, from a Generation Capacity Resource;

i) Price, in dollars and cents per megawatt-day, that will be accepted by the Capacity Market Seller for the megawatt quantity of Unforced Capacity offered from such Generation Capacity Resource.

ii) The Sell Offer may take the form of offer segments with varying price-quantity pairs for varying output levels from the underlying resource, but may not take the form of an offer curve with nonzero slope.

c) EFORd of each Generation Capacity Resource offered.

i) If a Capacity Market Seller is offering such resource in a Base Residual Auction, First Incremental Auction, Second Incremental Auction, or Conditional Incremental Auction occurring before the Third Incremental Auction, the Capacity Market Seller shall specify the EFORd to apply to the offer.

ii) If a Capacity Market Seller is committing the resource as Self-Supply, the Capacity Market Seller shall specify the EFORd to apply to the commitment.

iii) The EFORd applied to the Third Incremental Auction will be the final EFORd established by the Office of the Interconnection six (6) months prior to the Delivery Year, based on the actual EFORd in the PJM Region during the 12-month period ending September 30 that last precedes such Delivery Year.

d) The Nominated Demand Resource Value for each Demand Resource offered and the Nominated Energy Efficiency Value for each Energy Efficiency Resource offered. The Office of the Interconnection shall, in both cases, convert such value to an Unforced Capacity basis by multiplying such value by the DR Factor (for Delivery Years through May 31, 2018) times the Forecast Pool Requirement. Demand Resources shall specify the LDA in which the Demand Resource is located, including the location of such resource within any Zone that includes more than one LDA as identified on Schedule 10.1 of the RAA.

e) For Delivery Years through May 31, 2018, a Demand Resource with the potential to qualify as two or more of a Limited Demand Resource, Extended Summer Demand Resource or Annual Demand Resource may submit separate but coupled Sell Offers for each Demand Resource type for which it qualifies at different prices and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. For such coupled Demand Resource offers, the offer price of an Annual Demand Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Extended Summer Demand Resource offer and the offer price of a Extended Summer Demand Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Limited Demand Resource offer.

f) For a Qualifying Transmission Upgrade, the Sell Offer shall identify such upgrade, and the Office of the Interconnection shall determine and certify the increase in CETL provided by such upgrade. The Capacity Market Seller may offer the upgrade with an associated increase in CETL to an LDA in accordance with such certification, including an offer price that will be accepted by the Capacity Market Seller, stated in dollars and cents per megawatt-day as a price difference between a Capacity Resource located outside such an LDA and a Capacity Resource located inside such LDA; and the increase in CETL into such LDA to be provided by such Qualifying Transmission Upgrade, as certified by the Office of the Interconnection.

g) For the 2018/2019 and 2019/2020 Delivery Years, each Capacity Market Seller owning or controlling a resource that qualifies as both a Base Capacity Resource and a Capacity Performance Resource may submit separate but coupled Sell Offers for such resource as a Base Capacity Resource and as a Capacity Performance Resource, at different prices, and the auction clearing algorithm will select the Sell Offer that yields the least-cost solution. Submission of a coupled Base Capacity Resource Sell Offer shall be mandatory for any Capacity Performance Resource Sell Offer that exceeds a Sell Offer Price equal to the applicable Net Cost of New Entry times the Balancing Ratio as provided for in section 6.4. For such coupled Sell Offers, the offer price of a Capacity Performance Resource offer must be at least $.01 per MW-day greater than the offer price of a coupled Base Capacity Resource offer.

(h) For the 2018/2019 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, or Energy Efficiency Resources may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with their average expected output during peak-hour periods. Alternatively, for the 2018/2019 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls one or more Capacity Storage Resources, Intermittent Resources, Demand Resources, Energy Efficiency Resources, or Environmentally-Limited Resources may submit a Sell Offer which represents the aggregated Unforced Capacity value of such resources, where such Sell Offer shall be considered to be located in the smallest modeled LDA common to the aggregated resources. Such aggregated resources shall be owned by or under contract to the Capacity Market Seller, including all such resources obtained through bilateral contract and reported to the Office of the Interconnection in accordance with the Office of the Interconnection's rules related to its eRPM tools. For the 2018/2019 and 2019/2020 Delivery Years, any such offer may be submitted as Capacity Performance Resource, Base Capacity Resource, or as a coupled offer for Capacity Performance Resource and Base Capacity Resource, provided that, for any such coupled Sell Offers, the offer price of a Capacity Performance Resource offer must be at least $.01 per MW-day greater than the offer price of a

coupled Base Capacity Resource offer. For the 2020/2021 Delivery Year and subsequent Delivery Years, any such offer must be submitted as a Capacity Performance Resource.

(i) For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Summer-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Summer-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during summer peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Summer-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. For the 2020/2021 Delivery Year and subsequent Delivery Years, a Capacity Market Seller that owns or controls a resource that qualifies as a Winter-Period Capacity Performance Resource may submit a Sell Offer as a Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during peak-hour periods, and may submit a separate Sell Offer as a Winter-Period Capacity Performance Resource in a MW quantity consistent with the average expected output of such resource during winter peak-hour periods, provided the total Sell Offer MW quantity submitted as both a Capacity Performance Resource and a Winter-Period Capacity Performance Resource does not exceed the Unforced Capacity value of the resource. Each segment of a Seasonal Capacity Performance Resource Sell Offer must be submitted as a flexible Sell Offer segment with the minimum MW quantity offered set to zero.

5.6.2 Compliance with PJM Credit Policy

Capacity Market Sellers shall comply with the provisions of the PJM Credit Policy as set forth in Attachment Q to this Tariff, including the provisions specific to the Reliability Pricing Model, prior to submission of Sell Offers in any Reliability Pricing Model Auction. A Capacity Market Seller desiring to submit a Credit-Limited Offer shall specify in its Sell Offer the maximum auction credit requirement, in dollars, and the maximum amount of Unforced Capacity, in megawatts, applicable to its Sell Offer.

5.6.3 [reserved]

5.6.4 Qualifying Transmission Upgrades

A Qualifying Transmission Upgrade may not be the subject of any Sell Offer in a Base Residual Auction unless it has been approved by the Office of the Interconnection, including certification of the increase in Import Capability to be provided by such Qualifying Transmission Upgrade, no later than 45 days prior to such Base Residual Auction. No such approval shall be granted unless, at a minimum, a Facilities Study Agreement has been executed with respect to such upgrade, and such upgrade conforms to all applicable standards of the Regional Transmission Expansion Plan process.

5.6.5 Market-based Sell Offers

Subject to section 6, a Market Seller authorized by FERC to sell electric generating capacity at market-based prices, or that is not required to have such authorization, may submit Sell Offers that specify market-based prices in any Base Residual Auction or Incremental Auction.

5.6.6 Availability of Capacity Resources for Sale

(a) The Office of the Interconnection shall determine the quantity of megawatts of available installed capacity that each Capacity Market Seller must offer in any RPM Auction pursuant to Section 6.6 of Attachment DD, through verification of the availability of megawatts of installed capacity from: (i) all Generation Capacity Resources owned by or under contract to the Capacity Market Seller, including all Generation Capacity Resources obtained through bilateral contract; (ii) the results of prior Reliability Pricing Model Auctions, if any, for such Delivery Year (including consideration of any restriction imposed as a consequence of a prior failure to offer); and (iii) such other information as may be available to the Office of the Interconnection. The Office of the Interconnection shall reject Sell Offers or portions of Sell Offers for Capacity Resources in excess of the quantity of installed capacity from such Capacity Market Seller's Capacity Resource that it determines to be available for sale.

(b) The Office of the Interconnection shall determine the quantity of installed capacity available for sale in a Base Residual Auction or Incremental Auction as of the beginning of the period during which Buy Bids and Sell Offers are accepted for such auction, as applicable, in accordance with the time schedule set forth in the PJM Manuals. Removal of a resource from Capacity Resource status shall not be reflected in the determination of available installed capacity unless the associated unit-specific bilateral transaction is approved, the designation of such resource (or portion thereof) as a network resource for the external load is demonstrated to the Office of the Interconnection, or equivalent evidence of a firm external sale is provided prior to the deadline established therefor. The determination of available installed capacity shall also take into account, as they apply in proportion to the share of each resource owned or controlled by a Capacity Market Seller, any approved capacity modifications, and existing capacity commitments established in a prior RPM Auction, an FRR Capacity Plan, Locational UCAP transactions and/or replacement capacity transactions under this Attachment DD. To enable the Office of the Interconnection to make this determination, no bilateral transactions for Capacity Resources applicable to the period covered by an auction will be processed from the beginning of the period for submission of Sell Offers and Buy Bids, as appropriate, for that auction until completion of the clearing determination for such auction. Processing of such bilateral transactions will reconvene once clearing for that auction is completed. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Attachment DD.

(c) In order for a bilateral transaction for the purchase and sale of a Capacity Resource to be processed by the Office of the Interconnection, both parties to the transaction must notify the Office of the Interconnection of the transfer of the Capacity Resource from the seller to the buyer in accordance with procedures established by the Office of the Interconnection and set forth in the PJM Manuals. If a material change with respect to any of the prerequisites for the application of Section 5.6.6 to the Generation Capacity Resource occurs, the Capacity Resource Owner shall immediately notify the Market Monitoring Unit and the Office of the Interconnection.

5.7 Buy Bids

Buy Bids may be submitted in any Incremental Auction. Buy Bids shall specify, as appropriate:

a) The quantity of Unforced Capacity desired, in increments of 0.1 megawatt;

b) The maximum price, in dollars and cents per megawatt per day, that will be paid by the buyer for the megawatt quantity of Unforced Capacity desired;

c) The type of Unforced Capacity desired, i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource; and

d) The desired LDA for a replacement Capacity Resource. In the event of delay or cancellation of a Qualifying Transmission Upgrade, the Buy Bid shall specify Capacity Resources in the LDA for which such Qualifying Transmission Upgrade was to increase CETL.

5.8 Submission of Sell Offers and Buy Bids

The Office of the Interconnection shall evaluate and accept or reject Sell Offers and Buy Bids submitted by Capacity Market Sellers on the basis of the following requirements and criteria:

a) A Sell Offer or Buy Bid that fails to specify a positive megawatt quantity shall be rejected by the Office of the Interconnection.

b) A Buy Bid that fails to specify price shall be rejected by the Office of the Interconnection. A Sell Offer that fails to either designate such offer as self-scheduled or to specify an offer price shall be rejected by the Office of the Interconnection.

c) A Buy Bid that fails to designate the type of Unforced Capacity desired, i.e., an Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource, shall be rejected by the Office of the Interconnection.

d) All Sell Offers and Buy Bids must be received by the Office of the Interconnection during a specified period, as determined by the Office of the Interconnection, in accordance with the PJM Manuals. A Sell Offer or Buy Bid may be withdrawn by a notification of withdrawal received by the Office of the Interconnection at any time during the foregoing period, but may not be withdrawn after such period.

e) Sell Offers or Buy Bids shall be submitted or withdrawn via the Internet site designated by the Office of the Interconnection; provided, however, that if the Internet site cannot be accessed at any time during the period specified for the applicable auction, a Sell Offer or Buy Bid may be submitted or withdrawn by electronic mail transmitted to the e-mail address, or faxed to the fax number specified by the Office of the Interconnection.

f) Sell Offers must be based on the Capacity Market Seller's Capacity Resource position at the opening of the auction's bidding window.

g) The Office of the Interconnection shall accept a Sell Offer only up to the megawatt amount of installed capacity of Capacity Resources owned or controlled by such Capacity Market Seller that has not previously been committed for the applicable Delivery Year.

h) No Sell Offer shall be accepted from an FRR Entity unless it meets the requirements applicable to such offers under Schedule 8.1 of the Reliability Assurance Agreement.

i) The Office of the Interconnection shall have final authority to determine whether to accept or reject a Sell Offer in accordance with the terms of the Tariff and the PJM Manuals.

j) A Capacity Market Seller and Capacity Market Buyer may submit any Sell Offer or Buy Bid, respectively, that it chooses or make a decision not to offer a committed resource, provided that the Office of the Interconnection determines that: (i) the Capacity Market Seller has participated in the review process conducted by the Market Monitoring Unit (without regard to whether an agreement is obtained) if required by the Tariff; (ii) the Sell Offer is no higher, in the case of seller market power, or lower, in the case of buyer side market power, than the level to which the Capacity Market Seller has committed or agreed in the course of its participation in such

review process; and (iii) the Sell Offer or Buy Bid is compliant with the Tariff and PJM Manuals. Capacity Market Sellers and Capacity Market Buyers assume exclusive responsibility for their Sell Offers and Buy Bids, respectively, and any adverse findings at the Commission related to its Sell Offers and Buy Bids.

5.9 Time Standard

All deadlines for the submission or withdrawal of Sell Offers or Buy Bids, or for other purposes specified in this Attachment, shall be determined by the prevailing time observed in the Eastern Time zone.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (for Delivery Years through May 31, 2018, less the Short-Term Resource Procurement Target) or Locational Deliverability Area Reliability Requirement (for Delivery Year through May 31, 2018, less the Short-Term Resource Procurement Target for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;
- For the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:
    - • For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 3%) divided by (100% plus IRM%)], and for Delivery Years through May 31, 2018, minus the Short-Term Resource Procurement Target;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)], and for Delivery Years through May 31, 2018, minus the Short-Term Resource Procurement Target; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)], and for Delivery Years through May 31, 2018, minus the Short-Term Resource Procurement Target;

- For the 2018/2019 Delivery Year and subsequent Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), and (iii) a straight line connecting points (2) and (3), where:

  - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 0.2%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

  - For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 2.9%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target; and

  - For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 8.8%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target.

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), and Mid-Atlantic Region ("MAR") LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and, for Delivery Years through May 31, 2018, the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

For each such LDA, for the 2018/2019 Delivery Year and subsequent Delivery Years, the Office of the Interconnection shall (a) determine the Net Cost of New Entry for each Zone in such LDA, with such Net Cost of New Entry equal to the applicable Cost of New Entry value for such Zone minus the Net Energy and Ancillary Services Revenue Offset value for such Zone, and (b) compute the average of the Net Cost of New Entry values of all such Zones to determine the Net Cost of New Entry for such LDA; provided however, that the Net Cost of New Entry for an LDA may be greater than,

but shall be no less than, the Net Cost of New Entry determined for any other LDA in which the first LDA resides (immediately or successively) including the Net Cost of New Entry for the RTO. The Net Cost of New Entry for use in an LDA in any Incremental Auction for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years shall be the Net Cost of New Entry used for such LDA in the Base Residual Auction for such Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to (i) endorse the proposed modification, (ii) propose alternate modifications or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Incremental Auctions for the 2015/2016, 2016/2017, and 2017/2018 Delivery Years, the Cost of New Entry for the PJM Region and for each LDA shall be the respective value used in the Base Residual Auction for such Delivery Year and LDA. For the Delivery Year commencing on June 1, 2018, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for each CONE Area listed in this section as adjusted pursuant to subsection (a)(iv)(B).

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in $/MW-Year
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	132,200
BGE, PEPCO ("CONE Area 2")	130,300
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC, Dominion ("CONE Area 3")	128,900
PPL, MetEd, Penelec ("CONE Area 4")	130,300

B) Beginning with the 2019/2020 Delivery Year, the CONE for each CONE Area shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable United States Bureau of Labor Statistics ("BLS") Composite Index, in accordance with the following:

(1) The Applicable BLS Composite Index for any Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Price Index for Construction Materials and Components (weighted 50%), and the BLS Producer Price Index Turbines and Turbine Generator Sets (weighted 30%), as each such index is further specified for each CONE Area in the PJM Manuals.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable BLS Composite Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark CONE values for the 2018/2019 Delivery Year to which the Applicable BLS Composite Index shall be applied to determine the CONE for subsequent Delivery Years).

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vi)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) For the Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the Office of the Interconnection will employ for purposes of the Variable Resourcce Requirement Curves for such Delivery Years the same calculations of the sub-regional Net Energy and Ancillary Services Revenue Offsets that were used in the Base Residual Auctions for such Delivery year and sub-region. For the 2018/2019 Delivery Year and subsequent Delivery Years, the Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each Zone, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for such Zone shall be used in place of the PJM Region average hourly LMPs; (2) if such Zone was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the Zone was integrated; and (3) a posted fuel pricing point in such Zone, if available, and (if such pricing point is not available in such Zone) a fuel transmission adder appropriate to such Zone from an appropriate PJM Region pricing point shall be used for each such Zone.

vi) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to (i) endorse the proposed values, (ii) propose alternate values or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net

Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before May 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to (i) endorse the proposed methodology, (ii) propose an alternate methodology or (iii) recommend no modification, by August 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Resource Requirements and Constraints

Prior to the Base Residual Auction and each Incremental Auction for the Delivery Years starting on June 1, 2014 and ending May 31, 2017, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and Incremental Auctions for the 2017/2018 Delivery Year, the Office of the Interconnection shall establish the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and Incremental

Auctions for 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORd, the Forecast Pool Requirement, and all applicable Capacity Import Limits;

iii) For the Delivery Years through May 31, 2018, the Demand Resource Factor;

iv) The PJM Region Reliability Requirement, and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) For the Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which PJM is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year; and for the 2017/2018 Delivery Year , the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which PJM is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the 2018/2019 and 2019/2020 Delivery Years, the Office of the Interconnection shall establish the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year;

vii) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in section 5.11A;

viii) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

ix) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each

Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

~~b)~~b) In addition to the information required to be posted by subsection (a), PJM will post for a Delivery Year, at least sixty (60) days prior to conducting the Base Residual Auction for such Delivery Year (and at least thirty (30) days prior to conducting the first Base Residual Auction for which the FRR-RS Alternative is effective), the aggregate megawatt quantity of the Capacity Resources that have elected the FRR-RS Alternative for the PJM Region and for each LDA.

c) The information listed in (a) will be posted and applicable for the First, Second, Third, and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

~~c~~d) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

~~d~~e) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORd values for such Generation Capacity Resources prior to the conduct of the Third Incremental Auction for such Delivery Year.

~~e~~f) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. At such time, PJM also shall post the aggregate megawatt quantity of Capacity Resources with Actionable Subsidies.

If PJM discovers an error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth Business Day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the seventh Business Day following the initial publication of the results of the auction. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth Business Day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth

above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

5.11 A Backbone Transmission Upgrade Project Development Milestones

A Transmission Upgrade including transmission facilities at voltages of 500 kV or higher that is in an approved Regional Transmission Expansion Plan ("Backbone Transmission") shall be included in the system model for an RPM Auction only if it satisfies the project development milestones set forth in this section.

a) Base Residual Auction

Backbone Transmission shall be included in the system model used for a Base Residual Auction only if:

i) No later than 60 days before posting of the planning parameters for the Base Residual Auction, a corporate officer of the project sponsor submits a current critical path project development schedule containing intermediate milestones and showing the project in full commercial operation no later than the start of the Delivery Year corresponding to such Base Residual Auction, and must certify that such schedule is reasonably achievable based on information then known to and reasonably anticipated by the project sponsor. Such notice must identify all states in which such project is subject to the requirement to obtain a certificate of public convenience and necessity, or functional equivalent approval or licensure requirement, and must describe the nature and current status of such approval requirement;

ii) such development schedule additionally must show the scope, schedule, and current status of all other key milestones, including, at a minimum, right-of-way acquisition, engineering design, equipment procurement, construction permitting, and construction activities;

iii) applications for certificates of public convenience and necessity (or for equivalent approval) have been filed in all states applicable to such project that have such requirement.

b) Incremental Auctions

A Backbone Transmission project shall be included in the system models for Incremental Auctions only if the following requirements are satisfied no later than 60 days before each Incremental Auction, as indicated below:

i) a corporate officer submits, and certifies to, an updated project development schedule for the First Incremental Auction that shows, among other things, that 50% of the right-of-way by linear distance has been secured;

ii) a corporate officer submits, and certifies to, an updated project development schedule for the Second Incremental Auction that shows, among other things, that 75% of the right-of-way by linear distance has been secured, and that all certificates of public convenience and necessity (or equivalent approvals) have been issued by the responsible regulatory bodies;

iii) a corporate officer submits, and certifies to, an updated project development schedule for the Third Incremental Auction that shows, among other things, that 100% of the right-of-way by linear distance has been secured.

c) Audit, Removal from System Model, and Reinstatement in System Model

i) for the Backbone Transmission project to remain in the applicable system model, the Office of the Interconnection or independent third party with established expertise in such area must audit the project development schedule and affirm, no later than 30 days before each applicable auction, that the schedule is reasonable and remains on progress to full commercial operation prior to the commencement of the relevant Delivery Year. Audits may include site visits as deemed necessary by the auditor to verify progress.

ii) a Backbone Transmission project that fails to satisfy any of the requirements indicated for the Base Residual Auction shall not be included in the system model for such Base Residual Auction or any Incremental Auction for the relevant Delivery Year. A Backbone Transmission project that fails to satisfy any of the requirements indicated for an Incremental Auction shall not be included in the system model for such Incremental Auction or any subsequent Incremental Auction for the relevant Delivery Year.

iii) a Backbone Transmission project that is excluded from the system model for any RPM Auction for a Delivery Year may be included in the system model for RPM Auctions for a subsequent Delivery Year only if it demonstrates that all deficiencies have been cured and the project is on schedule for full commercial operation prior to such subsequent Delivery Year.

5.12 Conduct of RPM Auctions

The Office of the Interconnection shall employ an optimization algorithm for each Base Residual Auction and each Incremental Auction to evaluate the Sell Offers and other inputs to such auction to determine the Sell Offers that clear such auction.

a) Base Residual Auction

For each Base Residual Auction, the optimization algorithm shall consider:

- all Sell Offers submitted in such auction;
- the Variable Resource Requirement Curves for the PJM Region and each LDA;
- any constraints resulting from the Locational Deliverability Requirement and any applicable Capacity Import Limit;
- for Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a); for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a); and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a);
- For the Delivery Years through May 31, 2018, the PJM Region Reliability Requirement minus the Short-Term Resource Procurement Target;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement; and
- For the 2020/2021 Delivery Year and subsequent Delivery Years, the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region.

The optimization algorithm shall be applied to calculate the overall clearing result to minimize the cost of satisfying the reliability requirements across the PJM Region, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity, while respecting all applicable requirements and constraints, including any restrictions specified in any

Credit-Limited Offers. Where the supply curve formed by the Sell Offers submitted in an auction falls entirely below the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all such Sell Offers. Where the supply curve consists only of Sell Offers located entirely below the Variable Resource Requirement Curve and Sell Offers located entirely above the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. In determining the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, the optimization may select from among multiple possible alternative clearing results that satisfy such requirements, including, for example (without limitation by such example), accepting a lower-priced Sell Offer that intersects the Variable Resource Requirement Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the Variable Resource Requirement Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the Variable Resource Requirement Curve that corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. For the 2020/2021 Delivery Year and subsequent Delivery Years, the supply curve formed by the Sell Offers submitted within an LDA for which a separate VRR Curve is established, shall only consider the quantity of MW from Summer-Period Capacity Performance Resources that are equally matched with Winter-Period Capacity Performance Resources within the LDA, such that only the equally matched quantity of opposite-season Sell Offers are considered in satisfying the LDA's reliability requirement.

The Sell Offer price of a Qualifying Transmission Upgrade shall be treated as a capacity price differential between the LDAs specified in such Sell Offer between which CETL is increased, and the Import Capability provided by such upgrade shall clear to the extent the difference in clearing prices between such LDAs is greater than the price specified in such Sell Offer. The Capacity Resource clearing results and Capacity Resource Clearing Prices so determined shall be applicable for such Delivery Year. The Capacity Resource clearing results and Capacity Resource Clearing Prices determined for Summer-Period Capacity Performance Resources shall be applicable for the calendar months of June through October and the following May of such Delivery Year; and shall be applicable for Winter-Period Capacity Performance Resources for the calendar months of November through April of such Delivery Year.

b) Scheduled Incremental Auctions.

For purposes of a Scheduled Incremental Auction, the optimization algorithm shall consider:

- For the Delivery years through May 31, 2018, the PJM Region Reliability Requirement, less the Short-term Resource Procurement Target;
- For the 2018/2019 Delivery Year and subsequent Delivery Years, the PJM Reliability Requirement;
- Updated LDA Reliability Requirements taking into account any updated Capacity Emergency Transfer Objectives;

- The Capacity Emergency Transfer Limit used in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction;

- All applicable Capacity Import Limits;

- For the Delivery Years through May 31, 2018, for each LDA, such LDA's updated Reliability Requirement, less such LDA's Short-Term Resource Procurement Target;

- For the 2018/2019 Delivery Year and subsequent Delivery Years, for each LDA, such LDA's updated Reliability Requirement

- For Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each LDA for which PJM is required to establish a separate VRR Curve for the Base Residual Auction for the relevant Delivery Year; for the 2017/2018 Delivery Year, the Limited Resource Constraints and the Sub-annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a); and for the 2018/2019 and 2019/2020 Delivery Years, the Base Capacity Demand Resource Constraints and the Base Capacity Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by Tariff, Attachment DD, section 5.10(a);

- For the 2020/2021 Delivery Year and subsequent Delivery Years, the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region;

- A demand curve consisting of the Buy Bids submitted in such auction and, if indicated for use in such auction in accordance with the provisions below, the Updated VRR Curve Increment;

- The Sell Offers submitted in such auction; and

- The Unforced Capacity previously committed for such Delivery Year.

(i) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by Tariff, Attachment DD, section 5.4(c)(2), the Office of the Interconnection shall employ in the clearing of such auction the Updated VRR Curve Increment.

(ii) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by Tariff, Attachment DD, section 5.4(c)(1), and the conditions stated in Tariff, Attachment DD, section 5.4(c)(2) do not apply, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the

Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year plus any amount required by section 5.4(c)(2)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of Tariff, Attachment DD, sections 5.14B, 5.14C, 5.14E, and 5.5A(c)(i)(B) and RAA, Schedule 6, section L.9, minus (E) the quantity of new Unforced Capacity commitments for the 2016/2017 and 2017/2018 Delivery Years associated with the transition provisions in Tariff, Attachment DD, section 5.14D where this quantity is assumed to have been procured in the form of non-Capacity Performance Resources for purposes of this paragraph E. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, with exception for the Third Incremental Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. In seeking to sell back such quantity for the Third Incremental Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall employ in the clearing of the auction a curve represented by a straight line connecting two points with the first point located at 0 megawatts and at a price set to the lowest price point of the Updated VRR Curve Decrement and the second point located at a megawatt amount corresponding to the negative quantity defined above and at a price set to the Resource Clearing Price of the 2017/2018 Base Residual Auction.

(iii) When the possible need to seek agreements to release capacity commitments in any Scheduled Incremental Auction is indicated for the PJM Region or any LDA by Tariff, Attachment DD, section 5.4(c)(3)(i), the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (C) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year minus any capacity sell-back amount determined by PJM to be required for the PJM Region or such LDA by Tariff, Attachment DD, section 5.4(c)(3)(ii), plus (D) the reduction in Unforced Capacity commitments associated with the transition provisions of Tariff, Attachment DD, sections 5.14B, 5.14C, 5.14E, *and 5.5A(c)(i)(B)* and RAA, Schedule 6, section L.9, minus (E) the quantity of new Unforced Capacity commitments for the 2016/2017 and 2017/2018 Delivery Years associated with the transition provisions in Tariff, Attachment DD, section 5.14D where this quantity is assumed to have been procured in the

form of non-Capacity Performance Resources for purposes of this paragraph E; provided, however, that the amount sold in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade may not exceed the amounts purchased in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, with exception for the Third Incremental Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. In seeking to sell back such quantity for the Third Incremental Auction for the 2017/2018 Delivery Year, the Office of the Interconnection shall employ in the clearing of the auction a curve represented by a straight line connecting two points with the first point located at 0 megawatts and at a price set to the lowest price point of the Updated VRR Curve Decrement and the second point located at a megawatt amount corresponding to the negative quantity defined above and at a price set to the Resource Clearing Price of the 2017/2018 Base Residual Auction.

(iv) If none of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection first shall determine the total quantity of (A) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus, for the Delivery Years through May 31, 2018, the Short-Term Resource Procurement Target Applicable Share for such auction, minus (B) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. For the Delivery Years through May 31, 2018, if more than one of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection shall not seek to procure the Short-Term Resource Procurement Target Applicable Share more than once for such region or area for such auction

(v) If PJM seeks to procure additional capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years due to a triggering of the tests in subsections (i), (ii), (iii) or (iv) then the Minimum Annual Resource Requirement for such Auction will be equal to the updated Minimum Annual Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity from Annual Resources, and the Minimum Extended Summer Resource Requirement for such Auction will be equal to the updated Minimum Extended Summer Resource Requirement (based on the latest DR Reliability Targets)

minus the amount of previously committed capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years from Annual Resources and Extended Summer Demand Resources. If PJM seeks to release prior committed capacity due to a triggering of the test in subsection (iii) then PJM may not release prior committed capacity from Annual Resources or Extended Summer Demand Resources below the updated Minimum Annual Resource Requirement and updated Minimum Extended Summer Resource Requirement, respectively.

(vi) If the above tests are triggered for an LDA and for another LDA wholly located within the first LDA, the Office of the Interconnection may adjust the amount of any Sell Offer or Buy Bids otherwise required by subsections (i), (ii), or (iii) above in one LDA as appropriate to take into account any reliability impacts on the other LDA.

(vii) The optimization algorithm shall calculate the overall clearing result to minimize the cost to satisfy the Unforced Capacity Obligation of the PJM Region to account for the updated PJM Peak Load Forecast and the cost of committing replacement capacity in response to the Buy Bids submitted, while satisfying or honoring such reliability requirements and constraints, in the same manner as set forth in subsection (a) above.

(viii) Load Serving Entities may be entitled to certain credits ("Excess Commitment Credits") under certain circumstances as follows:

(A) For either or both of the Delivery Years commencing on June 1, 2010 or June 1, 2011, if the PJM Region Reliability Requirement used for purposes of the Base Residual Auction for such Delivery Year exceeds the PJM Region Reliability Requirement that is based on the last updated load forecast prior to such Delivery Year, then such excess will be allocated to Load Serving Entities as set forth below;

(B) For any Delivery Year beginning with the Delivery Year that commences June 1, 2012, the total amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Scheduled Incremental Auctions for such Delivery Year that does not clear such auctions, less the total amount that the Office of the Interconnection sought to procure pursuant to subsections (b)(i) and (b)(ii) above in the Scheduled Incremental Auctions for such Delivery Years that does not clear such auctions, will be allocated to Load Serving Entities as set forth below;

(C) the amount from (A) or (B) above for the PJM Region shall be allocated among Locational Deliverability Areas pro rata based on the reduction for each such Locational Deliverability Area in the peak load forecast from the time of the Base Residual Auction to the time of the Third Incremental Auction; provided, however, that the amount allocated to a Locational Deliverability Area may not exceed the reduction in the corresponding Reliability Requirement for such Locational Deliverability Area; and provided further that any LDA with an increase in its load forecast shall not be allocated any Excess Commitment Credits;

(D) the amount, if any, allocated to a Locational Deliverability Area shall be further allocated among Load Serving Entities in such areas that are charged a Locational Reliability Charge based on the Daily Unforced Capacity Obligation of such Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

c) Conditional Incremental Auction

For each Conditional Incremental Auction, the optimization algorithm shall consider:

- The quantity and location of capacity required to address the identified reliability concern that gave rise to the Conditional Incremental Auction;
- All applicable Capacity Import Limits;
- the same Capacity Emergency Transfer Limits that were modeled in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction; and
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity and location of capacity required to address the identified reliability violation at a Buy Bid price equal to 1.5 times Net CONE.

The optimization algorithm shall calculate the overall clearing result to minimize the cost to address the identified reliability concern, while satisfying or honoring such reliability requirements and constraints.

d) Equal-priced Sell Offers

If two or more Sell Offers submitted in any auction satisfying all applicable constraints include the same offer price, and some, but not all, of the Unforced Capacity of such Sell Offers is required to clear the auction, then the auction shall be cleared in a manner that minimizes total costs, including total make-whole payments if any such offer includes a minimum block and, to the extent consistent with the foregoing, in accordance with the following additional principles:

1) as necessary, the optimization shall clear such offers that have a flexible megawatt quantity, and the flexible portions of such offers that include a minimum block that already has cleared, where some but not all of such equal-priced flexible quantities are required to clear the auction, pro rata based on their flexible megawatt quantities; and

2) when equal-priced minimum-block offers would result in equal overall costs, including make-whole payments, and only one such offer is required to clear the auction, then the offer that was submitted earliest to the Office of the Interconnection, based on its assigned timestamp, will clear.

5.13 [Reserved]

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, Sub-Annual Resource Price Decrements, Base Capacity Demand Resource Price Decrements, and Base Capacity Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying an LDA's reliability requirement. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDAs and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest Sell Offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher level constrained LDA, where they are considered in a similar manner for compensation.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. If the Sell Offer price of a cleared Seasonal Capacity Performance Resource exceeds the applicable Capacity Resource Clearing Price, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the difference between the Sell Offer price and Capacity Resource Clearing Price in such RPM Auction. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole

Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd).

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and

(v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in sections 5.14B, 5.14C, 5.14D, 5.14E and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for

such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Generation Capacity Resources

(1) General Rule. Any Sell Offer based on a Capacity Resource with Actionable Subsidy submitted in any RPM Auction shall have an offer price no lower than the MOPR Floor Offer Price.

(2) Process for Establishing a Capacity Resource with Actionable Subsidy.

(a) By no later than one hundred twenty (120) days prior to the commencement of the offer period of any RPM Auction each Capacity Market Seller must provide for each Generation Capacity Resource, and uprate, or planned uprate, of a Generation Capacity Resource that the seller intends to offer into the RPM Auction, information needed to determine whether such Capacity Resource qualifies as a Capacity Resource with Actionable Subsidy. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate whether such Capacity Resource is a Capacity Resource with Actionable Subsidy. The Capacity Market Seller shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the Office of the Interconnection and the Market Monitoring Unit regarding any material changes in the qualifications of the Capacity Resource. The Office of Interconnection and the Market Monitoring Unit may request additional information from the Capacity Market Seller prior to the commencement of the offer period for the RPM Auction. Such Capacity Market Seller shall provide any requested information to the Office of Interconnection and Market

Monitoring Unit within five (5) business days upon receipt of the request for additional information.

(b) For each Capacity Resource, an officer of the Capacity Market Seller must certify whether or not such Capacity Resource is a Capacity Resource with Actionable Subsidy.

(c) Once a Capacity Resource is a Capacity Resource with Actionable Subsidy, the status of such Capacity Resource will remain unchanged unless and until the Capacity Market Seller provides notification of a change in such status or the Office of the Interconnection removes such status, or by Commission order. All Capacity Market Sellers shall have an ongoing obligation to provide notification of any change in status.

(4) MOPR Floor Offer Price. The MOPR Floor Offer Price for a Capacity Resource with Actionable Subsidy shall be the Net Cost of New Entry times the Balancing Ratio.

(5) Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with a Capacity Resource with Actionable Subsidy. In the event the Office of the Interconnection reasonably believes that a certification of a Capacity Resource's status contains or is based on fraudulent or material misrepresentations or omissions such that the Capacity Market Seller's Capacity Resource is a Capacity Resource with Actionable Subsidy, then:

(a) the Office of the Interconnection will provide written notice of suspected fraudulent or material misrepresentation or omission to the Capacity Market Seller no later than thirty (30) days prior to the commencement of the offer period for the RPM Auction for which the seller submitted the certification. In such event, a resource that is a Capacity Resource with Actionable Subsidy shall be subject to the Minimum Offer Price Rule. The Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection deems necessary. A Capacity Market Seller may challenge the Office of Interconnection's determination of suspected fraudulent or material misrepresentation or omission by filing a petition with FERC;

(b) if the Office of the Interconnection does not provide written notice of suspected fraudulent or material misrepresentation or omission at least thirty (30) days before the start of the relevant RPM Auction, then the Office of the Interconnection may file the certification that contains any alleged fraudulent or material misrepresentation or omission with FERC. The Office of the Interconnection shall implement any remedies ordered by FERC; and

(c) prior to applying the Minimum Offer Price Rule, the Office of the Interconnection, with advice and input of the Market Monitoring Unit, shall notify the affected Capacity Market Seller and, to the extent practicable, provide the Capacity Market Seller an opportunity to explain the alleged fraudulent or material misrepresentation or omission. Any filing to FERC under this provision shall seek fast track treatment and neither the name nor any identifying characteristics of the Capacity Market Seller or the resource shall be publicly revealed, but otherwise the filing shall be public. The Capacity Market Seller may submit a revised certification for that Capacity Resource for subsequent RPM Auctions, including RPM Auctions held during the pendency of the FERC proceeding. In the event that the Capacity Market Seller is cleared by FERC from such allegations of fraudulent or material misrepresentations or omissions then the certification shall be restored to the extent and in the

manner permitted by FERC. The remedies required by this subsection 5.14(h)(5) to be requested in any filing to FERC shall not be exclusive of any other actions, remedies, or penalties that may be pursued against the Capacity Market Seller by, including but not limited to, the Office of the Interconnection, the MMU, or others.

i) Net Cost of New Entry.

(1) For purposes of this section, the Net ~~Asset Class Costs~~Cost of New Entry shall be ~~asset-class estimates~~an estimate of competitive, cost-based nominal levelized Cost of New Entry, net of energy and ancillary service revenues. Determination of the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Section 5.10(a)(iv)(A) of this Attachment.

The gross Cost of New Entry component of Net ~~Asset Class~~ Cost of New Entry shall be, for purposes of the 2018/2019 Delivery Year and subsequent Delivery Years, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT"), and a combined cycle generator ("CC") respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (~~h)(2) below. For purposes of Incremental Auctions for the 2015/2016, 2016/2017 and 2017/2018 Delivery Years, the MOPR Floor Offer Price shall be the same as that used in the Base Residual Auction for such Delivery Year.~~i)(2) below. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (~~h)(3) below. Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) Sell Offers based on nuclear, coal or Integrated Gasification Combined Cycle facilities; or (ii) Sell Offers based on hydroelectric, wind, or solar facilities.~~i)(3) below.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4
CT $/MW-yr	132,200	130,300	128,900	130,300
CC $/MW-yr	185,700	176,000	172,600	179,400

(2) Beginning with the Delivery Year that begins on June 1, 2019, the gross Cost of New Entry component of the Net ~~Asset Class~~ Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that the Applicable BLS Composite Index used for CC plants shall be calculated from the three indices referenced in that section but weighted 25% for the wages index, 60% for the construction materials index, and 15% for the turbines index, and provided further that nothing herein shall preclude the Office of the Interconnection from filing to change the Net ~~Asset Class~~ Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

(3) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except

that the heat rate assumed for the combined cycle resource shall be 6.722 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the CC resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3198 per MW-year.

(4) Any Sell Offer that is based on:

i) a Generation Capacity Resource located in the PJM Region ~~that is submitted in an RPM Auction for a Delivery Year unless a Sell Offer based on that resource has cleared an RPM Auction for that or any prior Delivery Year, or until a Sell Offer based on that resource clears an RPM auction for that or any subsequent Delivery Year~~; or

ii) a Generation Capacity Resource located outside the PJM Region (where such Sell Offer is based solely on such resource) that requires sufficient transmission investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region, ~~unless a Sell Offer based on that resource has cleared an RPM Auction for that or any prior Delivery Year, or until a Sell offer based on that resource clears an RPM Auction for that or any subsequent Delivery Year, in any LDA for which a separate VRR Curve is established for use in the Base Residual Auction for the Delivery Year relevant to the RPM Auction in which such offer is submitted, and that is less than 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class Cost of New Entry for a combustion turbine generator as provided in subsection (h)(1) above shall be set to equal 90 percent of the applicable Net Asset Class Cost of New Entry (or set equal to 70 percent of such cost for a combustion turbine, where there is no otherwise applicable net asset class figure), unless the Capacity Market Seller obtains the prior determination from the Office of the Interconnection described in subsection (5) hereof. This provision applies to Sell Offers submitted in Incremental Auctions conducted after December 19, 2011, provided that the Net Asset Class Cost of New Entry values for any such Incremental Auctions for the 2012-13 or 2013-14 Delivery Years shall be the Net Asset Class Cost of New Entry values posted by the Office of the Interconnection for the Base Residual Auction for the 2014-15 Delivery Year.~~

~~(5) Unit-Specific Exception. A Sell Offer meeting the criteria in subsection (4) shall be permitted and shall not be re-set to the price level specified in that subsection if the Capacity Market Seller obtains a determination from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets . The following process and requirements shall apply to requests for such determinations:~~

~~i) The Capacity Market Seller may request such a determination by no later than one hundred twenty (120) days prior to the commencement of the offer period for the RPM Auction in which it seeks to submit its Sell Offer, by submitting simultaneously to the Office of the Interconnection and the Market Monitoring Unit a written request with all of the~~

required documentation as described below and in the PJM Manuals. For such purpose, the Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for the relevant RPM Auction, a preliminary estimate for the relevant Delivery Year of the minimum offer level expected to be established under subsection (4). If the minimum offer level subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the planned generation resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for an exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the Minimum Offer Price Rule exception request.

~~iii) A Sell Offer evaluated hereunder shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the minimum offer level prescribed by subsection (4), based on competitive cost advantages relative to the costs estimated for subsection (4), including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than estimated for subsection (4). Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of an exception hereunder by the Office of the Interconnection.~~

~~iv) The Market Monitoring Unit shall review the information and documentation in support of the request and shall provide its findings whether the proposed Sell Offer is acceptable, in accordance with the standards and criteria hereunder, in writing, to the Capacity Market Seller and the Office of the Interconnection by no later than ninety (90) days prior to the commencement of the offer period for such auction. The Office of the Interconnection shall also review all exception requests and documentation and shall provide in writing to the Capacity Market Seller, and the Market Monitoring Unit, its determination whether the requested Sell Offer is acceptable and if not it shall calculate and provide to such Capacity Market Seller, a minimum Sell Offer based on the data and documentation received, by no later than sixty-five (65) days prior to the commencement of the offer period for the relevant RPM Auction. If the Office of the Interconnection determines that the requested Sell Offer is acceptable, the Capacity Market Seller Shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer to which it agrees to commit by no later than sixty (60) days prior to the commencement of the offer period for the relevant RPM Auction~~

~~i~~that is less than the MOPR Floor Offer Price as defined in Attachment DD, Section 5.14(h)(4), shall be set to equal to the MOPR Floor Offer Price.

j) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly

to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(ij)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer's Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

"Export Path Import" means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (ij)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (ij)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (ij)(1) above.

5.14A [Reserved.]

5.14B Generating Unit Capability Verification Test Requirements Transition Provision for RPM Delivery Years 2014/2015, 2015/2016, and 2016/2017

A. This transition provision applies only with respect to Generation Capacity Resources with existing capacity commitments for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years that

experience reductions in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals. A Generation Capacity Resource meeting the description of the preceding sentence, and the Capacity Market Seller of such a resource, are hereafter in this section 5.14B referred to as an "Affected Resource" and an "Affected Resource Owner," respectively.

B. For each of its Affected Resources, an Affected Resource Owner is required to provide documentation to the Office of the Interconnection sufficient to show a reduction in installed capacity value as a direct result of the revised capability test procedures. Upon acceptance by the Office of the Interconnection, the Affected Resource's installed capacity value will be updated in the eRPM system to reflect the reduction, and the Affected Resource's Capacity Interconnection Rights value will be updated to reflect the reduction, effective June 1, 2014. The reduction's impact on the Affected Resource's existing capacity commitments for the 2014/2015 Delivery Year will be determined in Unforced Capacity terms, using the final EFORd value established by the Office of the Interconnection for the 2014/2015 Delivery Year as applied to the Third Incremental Auction for the 2014/2015 Delivery Year, to convert installed capacity to Unforced Capacity. The reduction's impact on the Affected Resource's existing capacity commitments for each of the 2015/2016 and 2016/2017 Delivery Years will be determined in Unforced Capacity terms, using the EFORd value from each Sell Offer in each applicable RPM Auction, applied on a pro-rata basis, to convert installed capacity to Unforced Capacity. The Unforced Capacity impact for each Delivery Year represents the Affected Resource's capacity commitment shortfall, resulting wholly and directly from the revised capability test procedures, for which the Affected Resource Owner is subject to a Capacity Resource Deficiency Charge for the Delivery Year, as described in section 8 of this Attachment DD, unless the Affected Resource Owner (i) provides replacement Unforced Capacity, as described in section 8.1 of this Attachment DD, prior to the start of the Delivery Year to resolve the Affected Resource's total capacity commitment shortfall; or (ii) requests relief from Capacity Resource Deficiency Charges that result wholly and directly from the revised capability test procedures by electing the transition mechanism described in this section 5.14B ("Transition Mechanism").

C. Under the Transition Mechanism, an Affected Resource Owner may elect to have the Unforced Capacity commitments for all of its Affected Resources reduced for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years to eliminate the capacity commitment shortfalls, across all of its Affected Resources, that result wholly and directly from the revised capability test procedures, and for which the Affected Resource Owner otherwise would be subject to Capacity Resource Deficiency Charges for the Delivery Year. In electing this option, the Affected Resource Owner relinquishes RPM Auction Credits associated with the reductions in Unforced Capacity commitments for all of its Affected Resources for the Delivery Year, and Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are adjusted accordingly. Affected Resource Owners wishing to elect the Transition Mechanism for the 2015/2016 Delivery Year must notify the Office of the Interconnection by May 30, 2014. Affected Resource Owners wishing to elect the Transition Mechanism for the 2016/2017 Delivery Year must notify the Office of the Interconnection by July 25, 2014.

D. The Office of the Interconnection will offset the total reduction (across all Affected Resources and Affected Resource Owners) in Unforced Capacity commitments associated with

the Transition Mechanism for the 2015/2016 and 2016/2017 Delivery Years by applying corresponding adjustments to the quantity of Buy Bid or Sell Offer activity in the upcoming Incremental Auctions for each of those Delivery Years, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD.

E. By electing the Transition Mechanism, an Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years, and a Locational UCAP Seller that sells Locational UCAP based on an Affected Resource owned by the Affected Resource Owner may receive relief from applicable Capacity Resource Deficiency Charges for the 2014/2015 Delivery Year, to the extent that the Affected Resource Owner demonstrates, to the satisfaction of the Office of the Interconnection, that an inability to deliver the amount of Unforced Capacity previously committed for the 2014/2015, 2015/2016, or 2016/2017 Delivery Years is due to a reduction in verified installed capacity available for sale as a direct result of revised generating unit capability verification test procedures effective with the summer 2014 capability tests, as set forth in the PJM Manuals; provided, however, that the Affected Resource Owner must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief.

5.14C Demand Response Operational Resource Flexibility Transition Provision for RPM Delivery Years 2015/2016 and 2016/2017

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2015/2016 or 2016/2017 Delivery Years (alternatively referred to in this section 5.14C as "Applicable Delivery Years" and each an "Applicable Delivery Year") that (i) cannot satisfy the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) are not excepted from the 30-minute notification requirement as described in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2015/2016 Delivery Year, or cleared in the Base Residual Auction for the 2016/2017 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14C referred to as an "Affected Demand Resource" and an "Affected Curtailment Service Provider," respectively.

B. For this section 5.14C to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information by the applicable deadline:

i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; the end-use customer name; electric distribution company's account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why

the end-use customer cannot comply with the 30-minute notification requirement or qualify for one of the exceptions to the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.

ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the 30-minute notification requirement provided in Section A.2 of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2015/2016 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2015/2016 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2015/2016 Delivery Year.

. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auctions for the 2016/2017 Delivery Year.

3. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision must not have sold or offered to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Second Incremental Auction for the 2016/2017 Delivery Year, and may not sell or offer to sell megawatts in the modeled LDA or sub-LDA where an Affected Demand Resource is located in the Third Incremental Auction for the 2016/2017 Delivery Year.

C. For the Third Incremental Auction for the 2015/2016 Delivery Year and the First, Second, and Third Incremental Auctions for the 2016/2017 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, "non-viable megawatts"), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for

an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Third Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Second Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared megawatts in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction Credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

5.14D Capacity Performance and Base Capacity Transition Provision for RPM Delivery Years 2016/2017 and 2017/2018

A. This transition provision applies only for procuring Capacity Performance Resources for the 2016/2017 and 2017/2018 Delivery Years.

B. For both the 2016/2017 and 2017/2018 Delivery Years, PJM will hold a Capacity Performance Transition Incremental Auction to procure Capacity Performance Resources.

1. For each Capacity Performance Transition Incremental Auction, the optimization algorithm shall consider:

- the target quantities of Capacity Performance Resources specified below;

- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity of Capacity Performance Resources specified for that Delivery Year. For the 2016/2017 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 60 percent of the updated Reliability Requirement for the PJM Region. For the 2017/2018 Delivery Year, the Office of the Interconnection shall submit a Buy Bid, at a price no higher than 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year, for a quantity of Capacity Performance Resources equal to 70 percent of the updated Reliability Requirement for the PJM Region.

2. For each Capacity Performance Transition Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. For the 2016/2017 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed

0.5 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year. For the 2017/2018 Delivery Year, the Capacity Resource Clearing Price for any Capacity Performance Transition Incremental Auction shall not exceed 0.6 times the Net CONE value for the PJM Region determined for the Base Residual Auction for that Delivery Year.

3. A Capacity Market Seller may offer any Capacity Resource that has not been committed in an FRR Capacity Plan, that qualifies as a Capacity Performance Resource under section 5.5A(a) and that (i) has not cleared an RPM Auction for that Delivery Year; or (ii) has cleared in an RPM Auction for that Delivery Year. A Capacity Market Seller may offer an external Generation Capacity Resource to the extent that such resource: (i) is reasonably expected, by the relevant Delivery Year, to meet all applicable requirements to be treated as equivalent to PJM Region internal generation that is not subject to NERC tagging as an interchange transaction; (ii) has long-term firm transmission service confirmed on the complete transmission path from such resource into PJM; and (iii) is, by written commitment of the Capacity Market Seller, subject to the same obligations imposed on Generation Capacity Resources located in the PJM Region by section 6.6 of Attachment DD of the PJM Tariff to offer their capacity into RPM Auctions.

4. Capacity Resources that already cleared an RPM Auction for a Delivery Year, retain the capacity obligations for that Delivery Year, and clear in a Capacity Performance Transition Incremental Auction for the same Delivery Year shall: (i) receive a payment equal to the Capacity Resource Clearing Price as established in that Capacity Performance Transition Incremental Auction; and (ii) not be eligible to receive a payment for clearing in any prior RPM Auction for that Delivery Year.

D. All Capacity Performance Resources that clear in a Capacity Performance Transition Incremental Auction will be subject to the Non-Performance Charge set forth in section 10A.

5.~~14 E~~14E Demand Response Legacy Direct Load Control Transition Provision for RPM Delivery Years 2016/2017, 2017/2018, and 2018/2019

A. This transition provision applies only to Demand Resources for which a Curtailment Service Provider has existing RPM commitments for the 2016/2017, 2017/2018, or 2018/2019 Delivery Years (alternatively referred to in this section 5.14E as "Applicable Delivery Years" and each an "Applicable Delivery Year") that (i) qualified as Legacy Direct Load Control before June 1, 2016 as described in Section G of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; (ii) cannot meet the requirements for using statistical sampling for residential non-interval metered customers as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA; and (iii) cleared in the Base Residual Auction or First Incremental Auction for the 2016/2017 Delivery Year, cleared in the Base Residual Auction for the 2017/2018 Delivery Year, or cleared in the Base Residual Auction for the 2018/2019 Delivery Year. A Demand Resource meeting these criteria and the Curtailment Service Provider of such a resource are hereafter in this section 5.14E referred to as an "Affected Demand Resource" and an "Affected Curtailment Service Provider," respectively.

B. For this section 5.14E to apply to an Affected Demand Resource, the Affected Curtailment Service Provider must notify the Office of the Interconnection in writing, with regard to the following information, by the applicable deadline:

i) For each applicable Affected Demand Resource: the number of cleared megawatts of Unforced Capacity for the Applicable Delivery Year by end-use customer site that the Affected Curtailment Service Provider cannot deliver, calculated based on the most current information available to the Affected Curtailment Service Provider; electric distribution company's account number for the end-use customer; address of end-use customer; type of Demand Resource (i.e., Limited DR, Annual DR, Extended Summer DR); the Zone or sub-Zone in which the end-use customer is located; and, a detailed description of why the endues customer cannot comply with statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA.

ii) If applicable, a detailed analysis that quantifies the amount of cleared megawatts of Unforced Capacity for the Applicable Delivery Year for prospective customer sales that could not be contracted by the Affected Curtailment Service Provider because of the statistical sampling for residential non-interval metered customers requirement as described in Section K of Attachment DD-1 of the Tariff and the parallel provision of Schedule 6 of the RAA that the Affected Curtailment Service Provider cannot deliver, by type of Demand Resource (i.e. Limited DR, Annual DR, Extended Summer DR) and by Zone and sub-Zone, as applicable. The analysis should include the amount of Unforced Capacity expected from prospective customer sales for each Applicable Delivery Year and must include supporting detail to substantiate the difference in reduced sales expectations. The Affected Curtailment Service Provider should maintain records to support its analysis.

1. For the 2016/2017 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the Second and/or Third Incremental Auction for the 2016/2017 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the Second or Third Incremental Auction for the 2016/2017 Delivery Year.

2. For the 2017/2018 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2017/2018 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2017/2018 Delivery Year.

3. For the 2018/2019 Delivery Year, the notice shall be provided by no later than seven (7) days prior to the posting by the Office of the Interconnection of planning parameters for the First, Second and/or Third Incremental Auction for the 2018/2019 Delivery Year. Such Affected Curtailment Service Provider that utilizes this transition provision may not sell or offer to sell megawatts in the matching LDA or sub-LDA where an Affected Demand Resource is located in the First, Second or Third Incremental Auctions for the 2018/2019 Delivery Year.

C. For the Second and Third Incremental Auction for the 2016/2017 Delivery Year, the First, Second, and Third Incremental Auctions for the 2017/2018 Delivery Year, and the First, Second, and Third Incremental Auctions for the 2018/2019 Delivery Year, the Office of the Interconnection shall publish aggregate information on the undeliverable megawatts declared under this transition provision (hereafter, "non-viable megawatts"), by type of Demand Resource and by Zone or sub-Zone, concurrently with its posting of planning parameters for the applicable Scheduled Incremental Auction. Non-viable megawatts for a Scheduled Incremental Auction for an Applicable Delivery Year represent those megawatts meeting the criteria of subsection A above and declared in accordance with subsection B above. Prior to each Scheduled Incremental Auction for an Applicable Delivery Year, the Office of the Interconnection shall apply adjustments equal to the declared non-viable megawatt quantity to the quantity of Buy Bid or Sell Offer activity in the upcoming Scheduled Incremental Auctions for the Applicable Delivery Year, as described in sections 5.12(b)(ii) and 5.12(b)(iii) of this Attachment DD. Prior to the Second Incremental Auction for the 2016/2017 Delivery Year, the First and Second Incremental Auction for the 2017/2018 Delivery Year, and the First and Second Incremental Auction for the 2018/2019 Delivery Year, the Office of the Interconnection shall adjust the recalculated PJM Region Reliability Requirement and recalculated LDA Reliability Requirements, as described in section 5.4(c) of this Attachment DD, by the applicable quantity of declared non-viable megawatts, and shall update the PJM Region Reliability Requirement and each LDA Reliability Requirement for such Incremental Auction only if the combined change of the applicable adjustment and applicable recalculation is greater than or equal to the lessor of (i) 500 megawatts or (ii) one percent of the prior PJM Region Reliability Requirement or one percent of the prior LDA Reliability Requirement, as applicable.

D. Prior to the start of each Applicable Delivery Year, the Office of the Interconnection shall reduce, by type of Demand Resource and by Zone or sub-Zone, the capacity commitment of each

Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year based on the non-viable megawatts declared by the Affected Curtailment Service Provider under this transition provision. If the Affected Curtailment Service Provider cleared megawatts from multiple Affected Demand Resources of the same type and Zone or sub-Zone, or cleared MWs in multiple RPM Auctions for the Applicable Delivery Year, the Office of the Interconnection shall allocate the reduction in capacity commitment by type of Demand Resource and by Zone or sub-Zone across the applicable Affected Demand Resources and relevant RPM Auctions. Such allocation shall be performed on a pro-rata basis, based on megawatts cleared by the Affected Demand Resources in the relevant RPM Auctions.

E. For each Applicable Delivery Year, an Affected Curtailment Service Provider that utilizes this transition provision for the Applicable Delivery Year relinquishes an Affected Demand Resource's RPM Auction credits for the amount of capacity commitment reduction as determined under subsection D above. Locational Reliability Charges as described in section 5.14(e) of this Attachment DD are also adjusted accordingly.

5.15 Capacity Transfer Rights

(a) To recognize the value of Import Capability and provide a partial offset to potential Locational Price Adders that may be determined for an LDA (as to any Zone that encompasses two or more LDAs, the term "LDA" as used herein shall refer to such Zone, rather than to the LDAs it encompasses), the Office of the Interconnection shall allocate Capacity Transfer Rights to each LSE serving load in such LDA pro rata based on such LSE's Daily Unforced Capacity Obligation in such LDA. The total megawatts of Capacity Transfer Rights available for allocation shall equal the megawatts of Unforced Capacity imported into such LDA determined based on the results of the Base Residual Auction and Incremental Auctions ("Capacity Imported"), less any megawatts of CETL increase into such LDA attributable to Qualifying Transmission Upgrades cleared in an RPM Auction and any Incremental Capacity Transfer Rights into such LDA allocated pursuant to section 5.16 (but not less than zero), and shall be subject to change in subsequent Delivery Years as a result of changes in the quantity of such Capacity Imported into such LDA. Each change in an LSE's Daily Unforced Capacity Obligation during a Delivery Year shall result in a corresponding change in the Capacity Transfer Rights allocated to such LSE.

(b) For LDAs in which the RPM Auctions for the Delivery Year resulted in a positive average weighted Locational Price Adder with respect to the immediate higher level LDA, the holder of the Capacity Transfer Rights in such LDA shall receive a payment during the Delivery Year equal to (i) the average weighted Locational Price Adder for such LDA determined with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year, multiplied by (ii) the megawatt quantity of the Capacity Transfer Right allocated to such LSE in such LDA.

(c) Capacity Transfer Rights shall be transferable. A purchaser of Capacity Transfer Rights from the original party allocated such rights shall receive any payments due under this section or section 5.16, provided the seller and purchaser of such rights timely notify the Office of the Interconnection of such purchase, in accordance with procedures specified in the PJM manuals.

5.16 Incremental Capacity Transfer Rights

(a) The Office of the Interconnection shall allocate Incremental Capacity Transfer Rights to a New Service Customer obligated to fund a transmission facility or upgrade through a rate or charge specific to such facility or upgrade, to the extent such upgrade or facility increases the Import Capability into a Locational Deliverability Area, with respect to any such transmission facility interconnected to or an upgrade of the Transmission System pursuant to Part IV and/or Part VI of this Tariff, including transmission facilities interconnected to or upgrades of the Transmission System pursuant to Part IV and/or Part VI prior to the effective date of this Attachment. Incremental Capacity Transfer Rights shall be available for a facility or upgrade for a Delivery Year only if the Office of the Interconnection certifies the quantity of Import Capability provided by such facility or upgrade at least 45 days prior to the Base Residual Auction for such Delivery Year. The megawatt quantity of Incremental Capacity Transfer Rights allocated to such a New Service Customer shall equal the megawatt quantity of the increase in Import Capability across a locational constraint resulting from such upgrade or facility, provided that the total Incremental Capacity Transfer Rights awarded as to an LDA (including those allocated pursuant to Schedule 12A of the Tariff) may not exceed the total Capacity Transfer Rights determined as to such LDA. A Capacity Market Seller that offers and clears a Qualifying Transmission Upgrade in the Base Residual Auction for a Delivery Year shall not receive Incremental Capacity Transfer Rights with respect to such upgrade for such Delivery Year. Terms and conditions for the allocation of Incremental Capacity Transfer Rights to New Service Customers shall be as further set forth in Part VI of this Tariff, and those for the allocation of Incremental Capacity Transfer Rights to Responsible Customers shall be as further set forth in Schedule 12A of this Tariff.

(b) For LDAs in which the RPM Auctions for such Delivery Year result in a positive average weighted Locational Price Adder with respect to the immediate higher level LDA, the holder of an Incremental Capacity Transfer Right into such LDA shall receive a payment equal to the average weighted Locational Price Adder for the LDA into which the associated facility or upgrade increased Import Capability, multiplied by the megawatt quantity of the Incremental Capacity Transfer Right allocated to such Interconnection Customer.

6. MARKET POWER MITIGATION

6.1 Applicability

The provisions of the Market Monitoring Plan (in Tariff, Attachment M and Attachment - M Appendixand this section 6) shall apply to the Reliability Pricing Model Auctions.

6.2 Process

(a) [Reserved for Future Use]

(b) In accordance with the schedule specified in the PJM Manuals, following PJM's conduct of a Base Residual Auction or Incremental Auction pursuant to Tariff, Attachment DD, section 5.12, but prior to the Office of the Interconnection's final determination of clearing prices and charges pursuant to Tariff, Attachment DD, section 5.14, the Office of the Interconnection shall: (i) apply the Market Structure Test to any LDA having a Locational Price Adder greater than zero and to the entire PJM region; (ii) apply Market Seller Offer Caps, if required under this section 6; and (iii) recompute the optimization algorithm to clear the auction with the Market Seller Offer Caps in place.

(c) Within seven days after the deadline for submission of Sell Offers in a Base Residual Auction or Incremental Auction, the Office of the Interconnection shall file with FERC a report of any determination made pursuant to Tariff, Attachment DD, section 5.14(h), Tariff, Attachment DD, section 6.5(a)(ii), or Tariff, Attachment DD, section 6.7(c) identified in such sections as subject to the procedures of this section. Such report shall list each such determination, the information considered in making each such determination, and an explanation of each such determination. Any entity that objects to any such determination may file a written objection with FERC no later than seven days after the filing of the report. Any such objection must not merely allege that the determination was in error, and must provide support for the objection, demonstrating that the determination overlooked or failed to consider relevant evidence. In the event that no objection is filed, the determination shall be final. In the event that an objection is filed, FERC shall issue any decision modifying the determination no later than 60 days after the filing of such report; otherwise, the determination shall be final. Final auction results shall reflect any decision made by FERC regarding the report.

6.3 Market Structure Test

(a) [Reserved for Future Use]

(b) Market Structure Test.

A constrained LDA or the PJM Region shall fail the Market Structure Test, and mitigation shall be applied to all jointly pivotal suppliers (including all Affiliates of such suppliers, and all third-party supply in the relevant LDA controlled by such suppliers by contract), if, as to the Sell Offers that comprise the incremental supply determined pursuant to section 6.3(c) below that are based on Generation Capacity Resources, there are not more than three jointly pivotal suppliers. The Office of the Interconnection shall apply the Market Structure Test. The Office of the

Interconnection shall confirm the results of the Market Structure Test with the Market Monitoring Unit.

(c) Determination of Incremental Supply

In applying the Market Structure Test, the Office of the Interconnection shall consider all (i) incremental supply (provided, however, that the Office of the Interconnection shall consider only such supply available from Generation Capacity Resources) available to solve the constraint applicable to a constrained LDA offered at less than or equal to 150% of the cost-based clearing price; or (ii) supply for the PJM Region, offered at less than or equal to 150% of the cost-based clearing price, provided that supply in this section includes only the lower of cost-based or market-based offers from Generation Capacity Resources. Cost-based clearing prices are the prices resulting from the RPM auction algorithm using the lower of cost-based or price-based offers for all Capacity Resources.

6.4 Market Seller Offer Caps

(a) The Market Seller Offer Cap, stated in dollars per MW/day of unforced capacity, applicable to price-quantity offers within the Base Offer Segment for an Existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW/day of unforced capacity, provided, however, that the default Market Seller Offer Cap for any Capacity Performance Resource shall be the product of (the Net Cost of New Entry applicable for the Delivery Year and Locational Deliverability Area for which such Capacity Performance Resource is offered times the average of the Balancing Ratios in the three consecutive calendar years (during the Performance Assessment Intervals in such calendar years) that precede the Base Residual Auction for such Delivery Year), however, for the Base Residual Auction for the 2021/2022 Delivery Year, the Balancing Ratio used in the determination of the default Market Seller Offer Cap shall be 78.5 percent, and provided further that the submission of a Sell Offer with an Offer Price at or below the revised Market Seller Offer Cap permitted under this proviso shall not, in and of itself, be deemed an exercise of market power in the RPM market. Notwithstanding the previous sentence, a Capacity Market Seller may seek and obtain a Market Seller Offer Cap for a Capacity Performance Resource that exceeds the revised Market Seller Offer Cap permitted under the prior sentence, if it supports and obtains approval of such alternative offer cap pursuant to the procedures and standards of subsection (b) of this section 6.4. A Capacity Market Seller may not use the Capacity Performance default Market Seller Offer Cap, and also seek to include any one or more categories of the Avoidable Cost Rate defined in Tariff, Attachment DD, section 6.8 below. The Market Seller Offer Cap for an Existing Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with Tariff, Attachment DD, section 6.7. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in Tariff, Attachment M-Appendix, section II.E.3.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must provide to the Market Monitoring Unit and the Office of the Interconnection data and

documentation required under section 6.7 below to establish the level of the Market Seller Offer Cap applicable to each resource by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the Market Seller Offer Cap proposed by the Market Monitoring Unit, and attempt to reach agreement with the Market Monitoring Unit on the level of the Market Seller Offer Cap by no later than ninety (90) days prior to the commencement of the offer period for the applicable RPM Auction. The Capacity Market Seller shall notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, whether an agreement with the Market Monitoring Unit has been reached or, if no agreement has been reached, specifying the level of Market Seller Offer Cap to which it commits by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. The Office of the Interconnection shall review the data submitted by the Capacity Market Seller, make a determination whether to accept or reject the requested unit-specific Market Seller Offer Cap, and notify the Capacity Market Seller and the Market Monitoring Unit of its determination in writing, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction. If the Market Monitoring Unit does not provide its determination to the Capacity Market Seller and the Office of the Interconnection by the specified deadline, by no later than sixty-five (65) days prior to the commencement of the offer period for the applicable RPM Auction the Office of the Interconnection will make the determination of the level of the Market Seller Offer Cap, which shall be deemed to be final. If the Capacity Market Seller does not notify the Market Monitoring Unit and the Office of the Interconnection of the Market Seller Offer Cap it desires to utilize by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction, it shall be required to utilize a Market Seller Offer Cap determined using the applicable default Avoidable Cost Rate specified in section 6.7(c) below.

(c) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the Sell Offer complies with the requirements of the Tariff.

(d) For any Third Incremental Auction for Delivery Years through the 2017/2018 Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year. For any Third Incremental Auction for the 2018/2019 or 2019/2020 Delivery Years, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Base Capacity resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year. For any Third Incremental Auction *or Final Incremental Auction, as applicable*, for the 2018/2019 Delivery Year or any subsequent Delivery Year, the Market Seller Offer Cap for an Existing Generation Capacity Resource offering as a Capacity Performance Resource shall be determined pursuant to subsection (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to the greater of the Net Cost of New Entry times the Balancing Ratio for the relevant LDA and Delivery Year or 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year.

6.5 Mitigation

The Office of the Interconnection shall apply market power mitigation measures in any Base Residual Auction or Incremental Auction for any LDA, Unconstrained LDA Group, or the PJM Region that fails the Market Structure Test.

(a) Mitigation for Generation Capacity Resources.

i) Existing Generation Capacity Resource

Mitigation will be applied on a unit-specific basis and only if the Sell Offer of Unforced Capacity from an Existing Generation Capacity Resource: (1) is greater than the Market Seller Offer Cap applicable to such resource; and (2) would, absent mitigation, increase the Capacity Resource Clearing Price in the relevant auction. If such conditions are met, such Sell Offer shall be set equal to the Market Seller Offer Cap.

ii) Planned Generation Capacity Resources

(A) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) shall be presumed to be competitive and shall not be subject to market power mitigation in any Base Residual Auction or Incremental Auction for which such resource qualifies as a Planned Generation Capacity Resource, but any such Sell Offer shall be rejected if it meets the criteria set forth in subsection (C) below, unless the Capacity Market Seller obtains approval from FERC for use of such offer prior to the close of the offer period for the applicable RPM Auction.

(B) Sell Offers based on Planned Generation Capacity Resources (including Planned External Generation Capacity Resources) shall be deemed competitive and not be subject to mitigation if: (1) collectively all such Sell Offers provide Unforced Capacity in an amount equal to or greater than two times the incremental quantity of new entry required to meet the LDA Reliability Requirement; and (2) at least two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA. Notwithstanding the foregoing, any Capacity Market Seller, together with Affiliates, whose Sell Offers based on Planned Generation Capacity Resources in that modeled LDA are pivotal, shall be subject to mitigation.

(C) Where the two conditions stated in subsection (B) above are not met, or the Sell Offer is pivotal, the Sell Offer shall be rejected if it exceeds 140 percent of: 1) the average of location-adjusted Sell Offers for Planned Generation Capacity Resources from the same asset class as such Sell Offer, submitted (and not rejected) (Asset-Class New Plant Offers) for such Delivery Year; or 2) if there are no Asset-Class New Plant Offers for such Delivery Year, the average of Asset-Class New Plant Offers for all prior Delivery Years; or 3) if there are no Asset-Class New Plant

Offers for any prior Delivery Year, the Net CONE applicable for such Delivery Year in the LDA for which such Sell Offer was submitted. For purposes of this section, asset classes shall be as stated in section 6.7(c) below as effective for such Delivery Year, and Asset-Class New Plant Offers shall be location-adjusted by the ratio between the Net CONE effective for such Delivery Year for the LDA in which the Sell Offer subject to this section was submitted and the average, weighted by installed capacity, of the Net CONEs for all LDAs in which the units underlying such Asset Class New Plant Offers are located. Following the conduct of the applicable auction and before the final determination of clearing prices, in accordance with Section 6.2(b) above, each Capacity Market Seller whose Sell Offer is so rejected shall be notified in writing by the Office of the Interconnection by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction and allowed an opportunity to submit a revised Sell Offer that does not exceed such threshold within one (1) Business Day of the Office of the Interconnection's rejection of such Sell Offer. If such revised Sell Offer is accepted by the Office of the Interconnection, the Office of the Interconnection then shall clear the auction with such revised Sell Offer in place. Pursuant to Tariff, Attachment M-Appendix, Section II.F, the Market Monitoring Unit shall notify in writing each Capacity Market Seller whose Sell Offer has been determined to be non-competitive and subject to mitigation, with a copy to the Office of the Interconnection, by no later than one (1) Business Day after the close of the offer period for the applicable RPM Auction.

(b) Mitigation for Demand Resources

The Market Seller Offer Cap shall not be applied to Sell Offers of Demand Resources or Energy Efficiency Resources.

6.6 Offer Requirement for Capacity Resources

(a) To avoid application of subsection (h) below, all of the installed capacity of all Existing Generation Capacity Resources located in the PJM Region shall be offered by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to this RPM must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, section 5.6.6. The Unforced Capacity of such resources is determined using the EFORd value that is submitted by the Capacity Market Seller in its Sell Offer, which shall not exceed the maximum EFORd for that resource as defined in section 6.6(b). If a resource should be included on the list of Existing Generation Capacity Resources subject to the RPM must-offer requirement that is maintained by the Market Monitoring Unit pursuant to Tariff, Attachment M-Appendix, section II.C.1, but is omitted therefrom whether by mistake of the Market Monitoring Unit or failure of the Capacity Market Seller that owns or controls all or part of such resource to provide information about the

resource to the Market Monitoring Unit, this shall not excuse such resource from the RPM must-offer requirement.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit and the Office of the Interconnection all data and documentation required under this section 6.6 to establish the maximum EFORd applicable to each resource in accordance with standards and procedures specified in the PJM Manuals. The maximum EFORd that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, is the greater of (i) the average EFORd for the five consecutive years ending on the September 30 that last precedes the Base Residual Auction, or (ii) the EFORd for the 12 months ending on the September 30 that last precedes the Base Residual Auction.

Notwithstanding the foregoing, a Capacity Market Seller may request an alternate maximum EFORd for Sell Offers submitted in such auctions if it has a documented, known reason that would result in an increase in its EFORd, by submitting a written request to the Market Monitoring Unit and Office of the Interconnection, along with data and documentation required to support the request for an alternate maximum EFORd, by no later one hundred twenty (120) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. The Capacity Market Seller must address any concerns identified by the Market Monitoring Unit and/or the Office of the Interconnection regarding the data and documentation provided and attempt to reach agreement with the Market Monitoring Unit on the level of the alternate maximum EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. As further described in Tariff, Attachment M-Appendix, section II.C, the Market Monitoring Unit shall notify the Capacity Market Seller and the Office of the Interconnection in writing of its determination of the requested alternate maximum EFORd by no later than ninety (90) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year. By no later than eighty (80) days prior to the commencement of the offer period for the Base Residual Auction for the applicable Delivery Year, the Capacity Market Seller shall notify the Office of the Interconnection and the Market Monitoring Unit in writing whether it agrees with the Market Monitoring Unit on the alternate maximum EFORd or, if no agreement has been reached, specifying the level of alternate maximum EFORd to which it commits. If a Capacity Market Seller fails to request an alternate maximum EFORd prior to the specified deadlines, the maximum EFORd for the applicable RPM Auction shall be deemed to be the default EFORd calculated pursuant to this section.

The maximum EFORd that may be used in a Sell Offer for a Third or Final Incremental Auction, and for Conditional Incremental Auctions held after the date on which the final EFORd used for a Delivery Year is posted, is the EFORd for the 12 months ending on the September 30 that last precedes the submission of such offers.

(c) [Reserved for Future Use]

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the maximum level of the alternate EFORd that may be used in a Sell Offer for RPM Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted,

the Office of the Interconnection shall make its own determination of the maximum level of the alternate EFORd based on the requirements of the Tariff and the PJM Manuals, per Tariff, Attachment DD, section 5.8, by no later than sixty-five (65) days prior to the commencement of the offer period for the Base Residual for the applicable Delivery Year, and shall notify the Capacity Market Seller and the Market Monitoring Unit in writing of such determination.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the EFORd complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit an EFORd that it chooses for an RPM Auction held prior to the date on which the final EFORd used for a Delivery Year is posted, provided that (i) it has participated in good faith with the process described in this section 6.6 and in Tariff, Attachment M-Appendix, section II.C, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) A Capacity Market Seller that owns or controls an existing generation resource in the PJM Region that is capable of qualifying as an Existing Generation Capacity Resource as of the date on which bidding commences for an RPM Auction may not avoid the rule in subsection (a) or be removed from Capacity Resource status by failing to qualify as a Generation Capacity Resource, or by attempting to remove a unit previously qualified as a Generation Capacity Resource from classification as a Capacity Resource for that RPM Auction. However, generation resource may qualify for an exception to the RPM must-offer requirement, as shown by appropriate documentation, if the Capacity Market Seller that owns or controls such resource demonstrates that it: (i) is reasonably expected to be physically unable to participate in the relevant Delivery Year; (ii) has a financially and physically firm commitment to an external sale of its capacity, ~~or~~ (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource, or (iv) is a Capacity Resource with Actionable Subsidy that has elected to commit its capacity through the FRR-RS Alternative pursuant to Section 5.2A of Attachment DD.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Tariff, Part V, section 113.1, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Tariff, Part V, section 113.2 for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Tariff, Attachment DD;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

In order to establish that a resource has a financially and physically firm commitment to an external sale of its capacity as set forth in (ii) above, the Capacity Market Seller must demonstrate that it has entered into a unit-specific bilateral transaction for service to load located outside the PJM Region, by a demonstration that such resource is identified on a unit-specific basis as a network resource under the transmission tariff for the control area applicable to such external load, or by an equivalent demonstration of a financially and physically firm commitment to an external sale. The Capacity Market Seller additionally shall identify the megawatt amount, export zone, and time period (in days) of the export.

A Capacity Market Seller that seeks to remove a Generation Capacity Resource from PJM Capacity Resource status and/or seeks approval for an exception to the RPM must-offer requirement, for any reason other than the reason specified in Paragraph A above, shall first submit such request in writing, along with all supporting data and documentation, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than one hundred twenty (120) days prior to the commencement of the offer period for the applicable RPM Auction.

In order to obtain an exception to the RPM must-offer requirement for the reason specified in Paragraph A above, a Capacity Market Seller shall first submit a preliminary exception request in writing, along with supporting data and documentation indicating the reasons and conditions upon which the Capacity Market Seller is relying in its analysis of whether to retire such resource, to the Market Monitoring Unit for evaluation, notifying the Office of the Interconnection by copy of the same, by no later than (a) November 1, 2013 for the Base Residual Auction for the 2017/2018 Delivery Year, (b) the September 1 that last precedes the Base Residual Auction for the 2018/2019 and subsequent Delivery Years, and (c) two hundred forty (240) days prior to the commencement of the offer period for the applicable Incremental Auction. By no later than five (5) Business Days after receipt of any such preliminary exception requests, the Office of the Interconnection will post on its website a

summary of the number of megawatts of Generation Capacity Resources for which it has received notification of preliminary exception requests, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

Thereafter, as applicable, such Capacity Market Seller shall by no later than (a) the December 1 that last precedes the Base Residual Auction for the applicable Delivery Year, or (b) one hundred twenty (120) days prior to the commencement of the offer period for the applicable Incremental Auction, either (a) notify the Office of the Interconnection and the Market Monitoring Unit in writing that it is withdrawing its preliminary exception request and explaining the changes to its analysis of whether to retire such resource that support its decision to withdraw, or (b) demonstrate that it has met the requirements specified under Paragraph A above. By no later than five (5) Business Days after receipt of such notification, the Office of the Interconnection will post on its website a revised summary of the number of megawatts of Generation Capacity Resources for which it has received requests for exceptions to the RPM must-offer requirement for the reason specified in Paragraph A above, on an aggregate basis by Zone and Locational Deliverability Area that comprises a subset of a Zone, as specified in the PJM Manuals.

A Capacity Market Seller may only remove the Generation Capacity Resource from PJM Capacity Resource status if (i) the Market Monitoring Unit has determined that the Generation Capacity Resource meets the applicable criteria set forth in Tariff, Attachment DD, sections 5.6.6 and this section 6.6 and the Office of the Interconnection agrees with this determination, or (ii) the Commission has issued an order terminating the Capacity Resource status of the resource. Nothing herein shall require a Market Seller to offer its resource into an RPM Auction prior to seeking to remove a resource from Capacity Resource status, subject to satisfaction of this section 6.6.

If the Capacity Market Seller disagrees with the Market Monitoring Unit's determination of its request to remove a resource from Capacity Resource status or its request for an exception to the RPM must-offer requirement, it must notify the Market Monitoring Unit in writing, with a copy to the Office of the Interconnection, of the same by no later than eighty (80) days prior to the commencement of the offer period for the applicable RPM Auction. After the Market Monitoring Unit has made its determination of whether a resource has satisfied the RPM must-offer requirement or meets one of the exceptions thereto and has notified the Capacity Market Seller and the Office of the Interconnection of the same pursuant to Tariff, Attachment M-Appendix, section II.C.4, the Office of the Interconnection shall approve or deny the exception request. The exception request shall be deemed to be approved by the Office of the Interconnection, consistent with the determination of the Market Monitoring Unit, unless the Office of the Interconnection notifies the Capacity Market Seller and Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences, that the exception request is denied.

If the Market Monitoring Unit does not timely notify the Capacity Market Seller and the Office of the Interconnection of its determination of the request to remove a Generation Capacity Resource from Capacity Resource status or for an exception to the RPM must-offer requirement, the Office of the Interconnection shall make the determination whether the request shall be

approved or denied, and will notify the Capacity Market Seller of its determination in writing, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences.

After the Market Monitoring Unit and the Office of the Interconnection have made their determinations of whether a resource meets the criteria to qualify for an exception to the RPM must-offer requirement, the Capacity Market Seller must notify the Market Monitoring Unit and the Office of the Interconnection whether it intends to exclude from its Sell Offer some or all of the subject capacity on the basis of an identified exception by no later than sixty-five (65) days prior to the date on which the offer period for the applicable RPM Auction commences. PJM does not make determinations of whether withholding of capacity constitutes market power. A Generation Capacity Resource that does not qualify for submission into an RPM Auction because it is not owned or controlled by the Capacity Market Seller for a full Delivery Year is not subject to the offer requirement hereunder; provided, however, that a Capacity Market Seller planning to transfer ownership or control of a Generation Capacity Resource during a Delivery Year pursuant to a sale or transfer agreement entered into after March 26, 2009 shall be required to satisfy the offer requirement hereunder for the entirety of such Delivery Year and may satisfy such requirement by providing for the assumption of this requirement by the transferee of ownership or control under such agreement.

If a Capacity Market Seller doesn't timely seek to remove a Generation Capacity Resource from Capacity Resource status or timely submit a request for an exception to the RPM must-offer requirement, the Generation Capacity Resource shall only be removed from Capacity Resource status, and may only be approved for an exception to the RPM must-offer requirement, upon the Capacity Market Seller requesting and receiving an order from FERC, prior to the close of the offer period for the applicable RPM Auction, directing the Office of the Interconnection to remove the resource from Capacity Resource status and/or granting an exception to the RPM must-offer requirement or a waiver of the RPM must-offer requirement as to such resource.

(h) Any existing generation resource located in the PJM Region that satisfies the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for the Base Residual Auction for a Delivery Year, that is not offered into such Base Residual Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All generation resources located in the PJM Region that satisfy the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for an Incremental Auction for a particular Delivery Year, but that did not satisfy such criteria as of the date that on which bidding commenced in the Base Residual Auction for that Delivery Year, that is not offered into that Incremental Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such

Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All Existing Generation Capacity Resources that are offered into a Base Residual Auction or Incremental Auction for a particular Delivery Year but do not clear in such auction, that are not offered into each subsequent Incremental Auction, and that do not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any Incremental Auctions conducted for such Delivery Year subsequent to such failure to offer; (ii) shall not receive any payments under Tariff, Attachment DD, section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

Any such Existing Generation Capacity Resources may also be subject to further action by the Market Monitoring Unit under the terms of Tariff, Attachment M and Tariff, Attachment M – Appendix.

(i) In addition to the remedies set forth in subsections (g) and (h) above, if the Market Monitoring Unit determines that one or more Capacity Market Sellers' failure to offer part or all of one or more existing generation resources, for which the Office of the Interconnection has not approved an exception to the RPM must-offer requirement, into an RPM Auction as required by this Section 6.6 would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, and the Office of the Interconnection agrees with that determination, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to participate in the relevant RPM Auction, or for other appropriate relief, and PJM will postpone clearing the auction pending FERC's decision on the matter. If the Office of the Interconnection disagrees with the Market Monitoring Unit's determination and does not apply to FERC for an order directing the Capacity Market Seller to participate in the auction or for other appropriate relief, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and to seek appropriate relief.

6.~~6 A~~6A Offer Requirement for Capacity Performance Resources

(a) For the 2018/2019 Delivery Year and subsequent Delivery Years, the installed capacity of every Generation Capacity Resource located in the PJM Region that is capable (or that reasonably can become capable) of qualifying as a Capacity Performance Resource shall be offered as a Capacity Performance Resource by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each such Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to the Capacity Performance Resource must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Tariff, Attachment DD, section 5.6.6.

(b) Determinations of EFORd and Unforced Capacity made under this section 6.6 as to a Generation Capacity Resource shall govern the offers required under this section as to the same Generation Capacity Resource.

(c) Exceptions to the requirement in subsection (a) shall be permitted only for a resource which the Capacity Market Seller demonstrates is reasonably expected to be physically incapable of satisfying the requirements of a Capacity Performance Resource. Intermittent Resources, Capacity Storage Resources, Demand Resources, and Energy Efficiency Resources shall not be required to offer as a Capacity Performance Resource, but shall not be precluded from being offered as a Capacity Performance Resource at a level that demonstrably satisfies such requirements. Exceptions shall be determined using the same timeline and procedures as specified in section 6.6.

(d) A resource not exempted or excepted under subsection (c) hereof that is capable of qualifying as a Capacity Performance Resource and does not offer into an RPM Auction as a Capacity Performance Resource shall be subject to the same restrictions on subsequent offers, and other possible remedies, as specified in section 6.6.

6.6 Data Submission

(a) Potential participants in any PJM Reliability Pricing Model Auction shall submit, together with supporting documentation for each item, to the Market Monitoring Unit and the Office of the Interconnection no later than one hundred twenty (120) days prior to the posted date for the conduct of such auction, a list of owned or controlled generation resources by PJM transmission zone for the specified Delivery Year, including the amount of gross capacity, the EFORd and the net (unforced) capacity. A potential participant intending to offer any Capacity Performance Resource at or below the default Market Seller Offer Cap described in Tariff, Attachment DD, section 6.4(a) must provide the associated offer cap and the MW to which the offer cap applies.

(b) Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or Unconstrained LDA Group that request a unit specific Avoidable Cost Rate shall, in addition, submit the following data, together with supporting documentation for each item, to the Market Monitoring Unit no later than one hundred twenty (120) days prior to the commencement of the offer period for such auction:

i. If the Capacity Market Seller intends to submit a non-zero price in its Sell Offer in any such auction, the Capacity Market Seller shall submit a calculation of the Avoidable Cost Rate and Projected PJM Market Revenues, as defined in subsection (d) below, together with detailed supporting documentation.

ii. If the Capacity Market Seller intends to submit a Sell Offer based on opportunity cost, the Capacity Market Seller shall also submit a calculation of Opportunity Cost, as defined in subsection (d), with detailed supporting documentation.

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. EL18-178-000**
PJM Interconnection, L.L.C.	)	**ER18-1314-000**
	)	**ER18-1314-001**
Calpine Corporation, et al.,	)	**EL16-49-000**
Complainants,	)	**(Consolidated)**
v.	)	
PJM Interconnection, L.L.C.,	)	
Respondent.	)	

REPLY BRIEF OF EXELON CORPORATION

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REPLY BRIEF OF EXELON CORPORATION

Pursuant to the Federal Energy Regulatory Commission's ("the Commission's") June 29, 2018 Order Rejecting Proposed Tariff Revisions, Granting In Part and Denying In Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act ("Order"),[1] Exelon Corporation ("Exelon") hereby submits the following reply brief addressing the Order's proposed changes to the Open Access Transmission Tariff ("Tariff") of PJM Interconnection, L.L.C. ("PJM").

INTRODUCTION

The comments submitted in this docket present the Commission with a stark choice. On one side is the resource-specific Fixed Resource Requirement Alternative preliminarily proposed by the Commission and supported by a wide swath of stakeholders representing a broad coalition of interests, including state regulators, consumer advocates, generators, load-serving entities, environmental organizations, and PJM itself.[2] Done correctly, this approach—whether labeled a "resource-specific FRR," an "FRR-RS," or, per PJM, a "Resource Carve-Out" or "RCO"—strikes a just and reasonable balance among equally important policy goals. It makes room for states to pursue energy policy initiatives favoring particular types of generation resources, by allowing states to provide for the procurement of their capacity outside the PJM auction market—but credits load for that capacity, thus avoiding unnecessary costs for customers. Moreover, because states

[1] 163 FERC ¶ 61,236 (2018).

[2] Joint Br. of Consumer Advocates, NGOs, and Industry Stakeholders (Oct. 1, 2018) at 3-6 & Ex. A ("Joint Stakeholders Br."); Comments of Joint Consumer Advocates (Oct. 2, 2018) at 14-15 ("Joint Consumer Comments"); Init. Argument of the N.J. Board of Pub. Utilities (Oct. 2, 2018) at 9-11, 25-26; Comments of Office of Att'y Gen. for the District of Columbia (Oct. 2, 2018) at 10; Initial Comments of FirstEnergy Solutions Corp. (Oct. 2, 2018) at 13-14 ("FirstEnergy Solutions Comments"); Comments of the PSEG Companies (Oct. 2, 2018) at 3-5; Comments of Clean Energy and Consumer Advocates (Oct. 2, 2018) at 6-30; Comments of the Am. Wind Energy Ass'n et al. (Oct. 2, 2018) at 22-27 ("AWEA Comments").

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would take on full responsibility for arranging compensation for the capacity procured outside the RPM market, the full cost of state policies will be transparent for all to see. Meanwhile, resources competing in PJM's capacity auction to serve remaining load would compete on a resource-neutral, least production-cost basis in an auction market free from subsidized bids. And, as a result, states choosing to rely exclusively on the RPM auction would not be forced to pay to support resources favored by other states.

On the other side, owners of fossil-fuel generation contend that accommodation of state policies is incompatible with a just and reasonable market design. According to them, state energy policies that advance decarbonization by supporting non-emitting generation pose a mortal threat to federal markets and must be combatted and deterred. They demand that the Commission apply a minimum offer price rule ("MOPR") to subsidized resources, *without* allowing such resources any ability to serve load outside the RPM market. Their position amounts to a mandate that, in order for a state to be part of PJM, the state must procure all of its capacity in a centralized market, with bidding rules that override state efforts to account for the environmental costs and benefits of different generation types. States that wish to recognize the reality that generators differ in their environmental profile must either exit the PJM capacity market entirely or pay twice for capacity—by procuring capacity outside the PJM market but receiving no credit from the PJM market for that capacity via reduced load requirements.[3] This approach would raise capacity bills for EMAAC customers alone by over $700 million per year—a 37 percent increase in capacity costs,

[3] The IMM's proposal—which he labels the "Sustainable Market Rule"—is essentially indistinguishable from the MOPR-only approach and would suffer from all the same flaws of overprocurement, double payment, and disrespect for state policy concerning the generation resource mix. But in one sense it is even worse: it deems a "competitive offer" to be one based on the IMM's calculation of the unit's net going forward costs, or ACR. This approach would effectively replace competition—in which suppliers decide how to offer in light of their own costs and their expectations about the market—with administrative rate-setting. The IMM, through unit-specific review, would determine what every supplier can bid. *See* Br. of the Independent Market Monitor for PJM at 15-18 (Oct. 2, 2018) ("IMM Brief").

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based on the most recent Base Residual Auction. The total RTO-wide incremental cost to consumers would exceed $900 million per year.[4] Of this, approximately $100 million annually would be attributable to over-procurement.[5]

For good reason, the Commission has already rejected such a draconian approach.[6] Rather, the Commission has acknowledged that the Federal Power Act ("FPA") establishes a cooperative federalist framework in which the Commission and state regulators each have a role to play. States should not be forced to forfeit their role—or be forced to require customers to incur significant unnecessary expense in order to exercise that role—in order to remain part of PJM.

The main argument made by opponents of the Commission's resource-specific FRR proposal is that clearing prices in the capacity market will remain "suppressed." Under the Commission's proposal, however, the MOPR will ensure that all bids to serve the load procuring capacity through the RPM auction are "competitive," thereby ensuring market integrity. The resulting price will be derived from these competitive bids; it is not "suppressed." States, meanwhile, are free to make a policy choice as to how their load should procure capacity, whether from the RPM market or instead outside that market.

Opponents' true argument is that states should not be allowed to make that policy choice, and that suppliers are entitled to serve *all* load through the RPM auction. But suppliers have no such entitlement. States always have the final word as to how their load procures capacity, and the Commission has long recognized that principle. In PJM, the existing FRR allows states to withdraw their load from the PJM auction market. This has been a feature of PJM's capacity construct since its inception, and no one questions its continued justness and reasonableness. The

[4] Declaration of Michael Schnitzer ¶ 55 (Nov. 6, 2018), attached hereto as Exhibit A ("Schnitzer Decl.").

[5] *Id.*

[6] Order at PP 158-162.

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proposed resource-specific FRR is simply a lesser version of what already exists: rather than requiring a state to withdraw either *all* of its load from the auction market or none, the resource-specific FRR permits a state to make a more tailored policy choice that will have a smaller impact on the PJM market and on customers than the withdrawal of all load. In other regions, such as MISO and CAISO, the Commission has found capacity constructs to be just and reasonable that provide similar opportunities for partial procurement—exactly what MOPR-only advocates disparage for PJM.[7]

MOPR-only advocates also assert that allowing a resource-specific FRR will create inefficiencies by substituting lower-cost generation with higher-cost, state-supported generation. These opponents ignore textbook economics in espousing an unduly constricted view of "efficiency." The state programs they seek to frustrate are designed to account for the reality that different generation resources have different environmental profiles. Emitting generation imposes costs on the rest of society that the emitting generator does not bear, and PJM's market mechanism does not value those costs. Emitting generators only *appear* more efficient because they are not internalizing the costs of their pollution. But in reality, they are not more efficient. Instead, they are heavily subsidized via their ability to pollute a common resource—the air—without paying for the costs.[8]

But even ignoring basic economics, states still are entitled under the FPA to make a policy choice to pay more for capacity in pursuit of their own environmental goals. The Commission

[7] *See, e.g., California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at PP 1117-18 (2006) (deferring to state and local regulatory authorities in California in the first instance to ensure resource adequacy); *Midcontinent Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,176, at PP 2, 61-66 (2018) (accepting MISO's version of a partial FRR mechanism).

[8] Eastern Generation departs from this perspective by calling on the Commission to direct PJM to work toward internalizing the cost of pollution into the wholesale market, a move Exelon endorses. *See* Init. Br. of Eastern Generation LLC at 6-9 (Oct. 1, 2018) ("Eastern Gen. Init. Br.").

should not pass judgment on these policy goals, penalize them, or make it more costly for states to achieve them. Instead, the Commission should accommodate those state policies, while ensuring that their costs are as transparent as possible and that states and their constituents can make informed choices. The resource-specific FRR accomplishes that. It should be approved as a necessary corollary to a broad MOPR for subsidized resources that continue to sell within the PJM capacity market.

For all of the same reasons, however, PJM's *Extended* RCO proposal should be rejected. That proposal allows states to withdraw resources and matching loads from the PJM auction, but then reprices the auction results to mimic a world in which the same amount of load must be served by a supply stack in which those resources did not exist. As a result, PJM's proposal would greatly inflate capacity prices well beyond levels that would occur in a MOPR-only world, massively increasing costs to customers: for EMAAC customers, by as much as $2.2 billion per year, and RTO-wide, by approximately $2.6 billion per year.[9] And the higher prices would reflect capacity offers by resources that are not actually needed to serve load, and would therefore "signal that the market would buy capacity from higher cost resources than actually clear the market and receive capacity commitments"[10]—the same disconnect between price and quantity that led the Commission to reject PJM's earlier repricing proposal in Docket No. ER18-1314.

PJM's repricing proposal not only is punitive to customers, but also is based on the same flawed premise as the MOPR-only approach: that the only just and reasonable price is the one that would result if *all* load were required to procure capacity through an auction construct that overrides state policies differentiating between emitting and non-emitting generation. There is no

[9] Schnitzer Decl. ¶ 76.

[10] Order at P 65.

basis for that conclusion, given that states have authority to support non-emitting generation and to decide how their load is served. The efficient price is the one that results from competitive offers to serve whatever load seeks to procure capacity through the PJM auction, after states have carved out the portion of their load that they wish to be served outside that market.[11]

To the extent the Commission nonetheless wishes to adopt some form of repricing, it still could not accept PJM's proposal. In setting the price at stage 2, PJM irrationally proposes to ignore reality by removing RCO resources from the supply curve entirely, rather than inserting RCO resources into the supply curve at "competitive" levels. PJM's proposal thus does *not* mimic the price that would result in the absence of any state support. Instead, it boosts customer costs by more than *three times* that level. At the very least, then, if the Commission were to adopt repricing, it would need to modify PJM's proposal by placing RCO resources into the stage 2 supply curve at competitive levels.[12] That is the only logical way that repricing could be implemented.

But for all the reasons already discussed, the far better approach is to adopt the framework that the Commission initially proposed: a resource-specific FRR that allows states to withdraw load from the RPM auction to be served outside it, combined with a broad MOPR applied to all subsidized resources remaining within the auction.

[11] Schnitzer Decl. ¶¶ 26-38.

[12] The Commission would also need to modify PJM's proposal to make RCO resources pay for the "lost opportunity costs" of resources that are not needed for resource adequacy, but that would have cleared if all load were forced to procure capacity through the RPM market. That allocation of costs punishes states electing the RCO by effectively forcing them to pay emitting resources every time they pay non-emitting ones, and is also inconsistent with cost-causation principles.

ARGUMENT

I. The Bifurcated Capacity Market Proposed by the Commission Is Just and Reasonable.

A. The Benefits of a Bifurcated Capacity Construct Are Essentially Undisputed.

In the Order, the Commission identified at least six important policy objectives that a resource-specific FRR Alternative would achieve. These include:

1. **Respect for legitimate state policies aimed at regulating the generation mix located in or serving a state.**[13] The FPA expressly reserves to states the authority to regulate generation facilities, notwithstanding the reality that such state regulation will inevitably affect federal wholesale markets in which those facilities sell.[14] "It is a fact of economic life that the wholesale and retail markets in electricity, as in every other known product, are not hermetically sealed from each other."[15] To preserve the cooperative federalism embedded in the FPA, the Commission's rules must accommodate the multiplicity of state policy choices, not seek to deter or override them.

2. **"[M]itigat[ing] or avoid[ing] the potential for double payment and over procurement"** by customers that would result if the federal capacity construct ignored capacity actually provided by state-supported resources.[16]

3. **"[I]ncreasing the integrity of the PJM capacity market"** by preventing suppliers participating in the RPM auction from submitting non-competitive offers.[17]

4. **"[I]ncreased transparency for investors."**[18] All capacity offers in the PJM auction would be "competitive"—that is, unaffected by out-of-market sources of revenue—and the resulting capacity price would accurately reflect the value of residual capacity procured through that market.

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[13] Order at PP 159-60.

[14] 16 U.S.C. § 824(b)(1); *Connecticut Dep't of Pub. Utility Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009); *Coalition for Competitive Electricity v. Zibelman*, 906 F.3d 41 (2d Cir. 2018) ("The states are … authorized to regulate energy production … and facilities used for the generation of electric energy.").

[15] *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 776 (2016) ("*EPSA*").

[16] Order at PP 159-60.

[17] *Id*. at PP 161-62.

[18] *Id.*

5. **"[I]ncreased transparency for … policymakers."**[19] If a state wishes to support a capacity resource outside of the PJM auction because of particular characteristics that resource possesses—for example, that it does not emit pollutants—the state will need to take onto its own books the entire cost of doing so. Thus, "the construct will provide the information that states and all other stakeholders will need in order to make informed decisions about the degree to which they prefer to rely on the capacity market versus out-of-market mechanisms, and it will manage the results of those decisions in an orderly fashion."[20]

6. **"[I]ncreased transparency for … consumers."**[21] Because a state will need to take onto its own ledger the full cost of supporting a capacity resource valued for its environmental or other attributes, consumers will see transparently "which capacity costs are the result of competition in the capacity market and which capacity costs are being incurred as a result of state policy decisions."[22] That transparency, in turn, will allow customers to hold their elected officials accountable for deciding to expand or contract state energy policy initiatives.

These benefits of a bifurcated capacity construct are essentially undisputed. Even opponents of the resource-specific FRR Alternative do not dispute that the construct would allow the Commission to regulate cooperatively with states exercising their reserved authority under the FPA; prevent the over-procurement of capacity and the unnecessary costs to customers that would result from a MOPR-only approach; ensure that offers in the PJM capacity auction are competitive; and increase transparency and political accountability regarding state policy choices.

Instead, opponents of the resource-specific FRR largely contend that the Commission should disregard the importance of these policy goals, and give greater weight to the purported need to maintain high capacity prices.[23] For example, some opponents contend that the

[19] *Id.*

[20] *Id.* at P 163.

[21] *Id.*

[22] *Id.*

[23] Exelon renews its arguments, presented in its Application for Rehearing of the Order, that there is no need for the Commission to seek to increase capacity prices at a time when supply remains abundant—

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Commission should *not* attempt to prevent consumers from double-paying for capacity.[24] They misleadingly cite a Third Circuit decision for the proposition that the Commission should have no compunction about forcing customers to pay twice for capacity, on the ground that states should be forced to shoulder the costs of their regulatory choices.[25] That is not what the Third Circuit held. Rather, it held that the FPA did not *categorically preclude* the Commission from making that decision.[26] But, like any decision within the Commission's discretion, the Commission must make such decisions in a reasoned way and consider the merits and disadvantages of the options before it. And when the Commission sets rates, among the core considerations it must consider is whether proposed rates unduly burden customers—including whether those rates impose unnecessary costs.[27] Here, imposing a MOPR without a corresponding resource-specific FRR would increase capacity costs for EMAAC customers alone by over $700 million per year—about a 37 percent increase over the most recent Base Residual Auction. Approximately $100 million

indeed, available in quantities that far exceed the target reserve margin. *See* Request for Rehearing of Exelon Corp., Docket No. ER18-1314 (July 30, 2018) at 8-14.

[24] That is, customers pay once for the capacity acquired in the capacity market to satisfy the Commission-imposed reliability requirement and again for resources that were procured outside the market, so do not "count" for purposes of satisfying the reliability requirement, but nevertheless do in reality provide capacity to the system.

[25] *E.g.*, Init. Br. of Electric Power Supply Ass'n (Oct. 2, 2018) at 10 ("EPSA Init. Br.") ("[T]here is nothing wrong with requiring states to 'pay twice' for capacity"); *id.* at 22; Init. Br. of NRG Power Marketing, LLC (Oct. 2, 2018) at 12 ("NRG Init. Br."); Init. Br. of the PJM Power Providers Group (Oct. 2, 2018) at 13 ("P3 Init. Br.") (all citing *New Jersey Bd. of Pub. Utilities v. FERC*, 744 F.3d 74, 97 (3d Cir. 2014)).

[26] *New Jersey Bd. of Pub. Utilities v. FERC*, 744 F.3d 74, 98-100 (3d Cir. 2014) (reviewing Commission's choice for reasoned decision-making under the Administrative Procedure Act).

[27] *See Michigan v. EPA*, 135 S. Ct. 2699, 2707-08 (2015) ("Agencies have long treated cost as a centrally relevant factor when deciding whether to regulate. Consideration of cost reflects the understanding that reasonable regulation ordinarily requires paying attention to the advantages and the disadvantages of agency decisions. It also reflects the reality that too much wasteful expenditure devoted to one problem may well mean considerably fewer resources available to deal effectively with other (perhaps more serious) problems." (internal quotation marks omitted)); *NAACP v. FPC*, 425 U.S. 662, 670 (1976) (holding that just and reasonable rates are those that "encourage the orderly development of plentiful supplies of electricity … at reasonable prices").

of that annual cost increase would be due to over-procurement of capacity. The total incremental cost increase to customers RTO-wide would exceed $900 million each year.[28]

Nor could the Commission disclaim responsibility for adopting a regulatory construct that ignores the capacity supplied by state-supported resources. States retain authority under the FPA over generation facilities; they have for decades exercised that authority to support particular generation resources; and a mountain of evidence proves that this support will continue and expand in the years and decades ahead.[29] When the Commission assesses whether its market rules are just and reasonable, it cannot ignore these realities. If the Commission nonetheless chooses to pretend that state-supported capacity does not exist, the consequences of that choice—including the billions of dollars in excessive and unnecessary costs—would properly fall at the Commission's feet. That is why the Commission's Order was exactly right to prioritize avoiding a market structure that would lead to capacity over-procurement and double payment, and instead to pursue a construct that would prevent needless expense by crediting consumers for *all* resources contracted to provide capacity.[30]

Some of the same opponents, misconstruing the Commission's amicus brief in *EPSA v. Star*, contend that non-preemption of state programs is accommodation enough.[31] The Commission's brief, however, merely said that preemption was unnecessary because the

[28] Schnitzer Decl. ¶ 55.

[29] *See, e.g.*, "Renewable Energy Requirements by PJM State," Attach. 1 to Aff. of Dr. Anthony Giacomoni at 2, Attach. F to PJM Interconnection L.L.C., Capacity Repricing or in the Alternative MOPR-Ex Proposal, Docket No. ER18-1314 (Apr. 9, 2018).

[30] Order at PP 159-60; *see also ISO New England, Inc.*, 162 FERC ¶ 61,205, at PP 23-24 (2018); *Indep. Power Producers of New York, Inc.*, 150 FERC ¶ 61,214, at P 66 (2015) (units needed for reliability that are compensated on an out of market basis under reliability support services agreements ("RSSA") are required to offer in at a *de minimis* level because "it is efficient for these units to clear in the NYISO capacity market, [and] [a]ny provisions imposed that would cause them not to clear would be unreasonable." (citations omitted)).

[31] EPSA Init. Br. at 11-12.

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Commission "can exercise its responsibility under the Federal Power Act to ensure just and reasonable prices in the wholesale markets subject to its jurisdiction."[32] The brief did not address *how* just and reasonable market rules should be designed in a manner consistent with the FPA's cooperative federalism.

That question, unanswered by the *Star* amicus brief, is now before the Commission. Contrary to the claims of MOPR-only advocates, Sections 205 and 206 do not require the Commission to attempt to thwart state policies, nor stamp out any effect of those policies on the Commission's markets. Otherwise, Congress's decision to divide authority between federal and state regulators would make little sense. Congress made that choice knowing that "what states do in the exercise of their powers affects interstate sales, just as what the FERC does in the exercise of its powers affects the need for and economic feasibility of plants over which the states possess authority…. [E]ach use of authorized power necessarily affects tasks that have been assigned elsewhere."[33] That interplay is an inherent part of the legislative design, and the effects of that interplay pose no barrier to the Commission's ability to set just and reasonable wholesale rates. Indeed, the Commission has never expressed such a narrow view with respect to how state policies should be reflected in markets and in fact has only suggested the opposite.[34]

The Commission's proposed resource-specific FRR appropriately embraces the FPA's cooperative federalism framework. It leaves room for states to pursue their energy policies alongside, but outside of, the federal-jurisdictional capacity auction—by withdrawing load to be

[32] Brief of the United States and the Federal Energy Regulatory Commission as Amici Curiae in Support of Defendants-Respondents and Affirmance at 20, *Elec. Power Supply Ass'n v. Star*, No. 17-2433 (7th Cir. May 29, 2018), 2018 WL 2746229, at *20.

[33] *Elec. Power Supply Ass'n v. Star*, 904 F.3d 518, 523 (7th Cir. 2018).

[34] *E.g.*, Order at P 159 (stating that Commission "do[es] not take … lightly" the concern that customers will "have[] to pay twice for capacity" or "states' right to pursue valid policy goals.").

served through a separate mechanism. Meanwhile, the resource-specific FRR preserves the capacity auction for the remainder of supply and load *not* subject to a state procurement mandate. The Commission's proposal thereby appropriately balances the relevant interests—consumers' interests in avoiding over-procurement and double payment; investors' interests in an auction market "untainted" by "non-competitive" offers; and the statute's commitment to a federalist framework in which states exercise important regulatory authority over generation.

B. The Resource-Specific FRR Is a Less Extreme, More Tailored Variation on a Construct the Commission Has Already Approved as Just and Reasonable.

1. The Resource-Specific FRR Is Consistent With Market Constructs That the Commission Has Already Found to Be Just and Reasonable.

A number of MOPR-only advocates depict the resource-specific FRR Alternative as a radical change from PJM's current market design.[35] It is not. It is a more tailored version of the existing FRR Alternative, which similarly allows load to be withdrawn from the market to be served outside it—and which has been a part of the PJM capacity construct since its inception.

In the numerous Commission orders addressing the PJM capacity market since its inception, the Commission's focus has always been on ensuring competitive offers by suppliers selling within the RPM market—not on conscripting load into the RPM market.[36] Accordingly, the Commission has emphasized the importance of an alternative outside the RPM market for states wishing to pursue their own public policies. For example, when the Commission first

[35] *E.g.*, NRG Init. Br. at 23-26.

[36] From the outset of RPM, the Commission has required that an alternative FRR mechanism be available. *See PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079, at P 103 (2006) ("We find that the use of a sloped demand curve, in a forward procurement auction, as proposed by PJM, would be a just and reasonable option for acquiring capacity as long as load can choose to avoid the auction and, instead, satisfy a fixed resource requirement through the more traditional alternative of self-supplying sufficient capacity to meet its obligations."); *see also id.* at PP 70-71, 110-11; *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 193 (2011); *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145 at P 160 (2011); *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208, at PP 202-12 (2015) (preserving FRR in the Capacity Performance reforms).

applied the MOPR to new state-sponsored resources, it noted its interest in preventing "below-cost offers into the RPM auction"—but emphasized that its bidding rules did not "encroach on a state's ability to act within its borders to ensure resource adequacy or to favor particular types of new generation."[37] That is because, as the Commission explained, PJM's tariff allowed states to remove their load from the capacity auction: "[S]tates seeking full independence in resource procurement choices can implement a form of capacity procurement that complements the RPM or can opt out of the RPM markets via the FRR alternative."[38]

To be sure, the full FRR remains an option for states seeking to support particular resources of public policy interest. But for that end, it is an overbroad and needlessly cumbersome tool for states that have imposed a procurement mandate on only a portion of their load. The withdrawal of an entire zone's load could significantly reduce the size of the RPM market, reducing the market's depth, efficiency, and scale more than is necessary to accommodate the state program. And for states that have implemented retail competition, the full FRR is more difficult to use than a resource-specific FRR.[39] In sum, it makes little sense for the Commission to force states to withdraw their *entire* load from the RPM market when the state seeks to have only a *portion* of that load procure capacity from resources of public policy interest. For example, if Illinois has carbon-reduction goals that can be met by procuring less generation than is needed to serve all of the state's load, there is no reason why Illinois should be required to withdraw all of the in-state load from the RPM market.

[37] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 142 (2011).

[38] *Id.* at P 141 n.76; *id.* at P 193 ("The FRR option is the alternative for load serving entities that wish to secure their own capacity resources outside of a competitive market, whether as directed by state-authorized integrated resource plans, or pursuant to other considerations.").

[39] Schnitzer Decl. ¶¶ 58-64.

LS Power and EPSA point out that PJM previously did not want to allow a partial FRR.[40] PJM explained to the Commission its concern that, if a partial FRR was available, a load-serving entity could use the partial FRR to obtain the long-term reliability benefits of the sloped VRR demand curve, while protecting its load from paying for the full short-term economic costs of procuring in excess of the Installed Reserve Margin ("IRM").[41] This prior concern, however, was in the context of a self-supplying *market participant* implementing a partial FRR. At issue here is whether the partial FRR should be available for a *state* exercising its sovereign authority to implement energy policies supporting particular generation facilities. Denying the states the ability to use the FRR partially would be tantamount to dictating the resources that a state is required to support. Nevertheless, if the Commission disagrees and is concerned about the interaction between reserve margins and an FRR-RS to serve partial load, we note that PJM proposes to adjust the capacity credit received by a load-serving entity matched with an FRR-RS resource to account for the *actual* reserve margin procured by PJM using the sloped VRR demand curve—and *not* simply the IRM.[42] That adjustment would avoid the problem previously identified by PJM.

NRG, meanwhile, argues that the FRR was intended for vertically integrated utilities, not for load in restructured states.[43] However, no such limitation is found in the actual language of the FRR option. Rather, as PJM explained to the Commission in defending the existing FRR, "the

[40] Init. Br. of LS Power Assocs. L.P. at 21 (Oct. 2, 2018) ("LS Power Init. Br."); EPSA Init. Br. at 27.

[41] LS Power Init. Br. at 21 & EPSA Init. Br. at 27 (citing *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, at PP 175-76).

[42] Affidavit of Adam J. Keech ¶ 8, Attach. B to Initial Submission of PJM Interconnection, L.L.C. (Oct. 2, 2018) ("Keech Aff.").

[43] NRG Init. Br. at 22.

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FRR option expressly accommodates retail choice jurisdictions."[44] The goal was to allow states a mechanism "to secure their own capacity resources outside of a competitive market, whether as directed by state-authorized integrated resource plans, *or pursuant to other considerations*."[45] The resource-specific FRR aims toward the same goal.

NRG also contends that the resource-specific FRR is more likely than the existing FRR to have price-reducing impacts on the RPM market, because it is specifically designed for resources that would not clear in the RPM market if subjected to a MOPR.[46] This argument is flawed. The existing FRR also reduces prices unless *every* FRR resource would have been infra-marginal if it had participated in RPM. The resource-specific FRR is exactly the same. Any resource that is part of an FRR plan, but would not have cleared the RPM market, has the exact same price impact as a resource that is an FRR-RS resource and that would not have cleared the RPM market. But NRG provides no reason at all to assume that *every* traditional FRR resource would have cleared the RPM market if it had been forced to bid at its avoidable costs. Vertically integrated utilities are likely to retain at least some units that are used for self-supply but that would not clear in the RPM market if subjected to a MOPR—whether to avoid imposing stranded costs on customers from an early retirement, or for other public policy reasons. For example, a number of the units contained in 2021/22 FRR capacity plans are similar to uneconomic units that have announced retirement.[47] Thus, states have used the existing FRR to retain units that would not clear in RPM. Moreover, as

[44] *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145 at P 177 (2011).

[45] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 193 (2011) (emphasis added).

[46] NRG Init. Br. at 22-23.

[47] For example, the most recent set of units designated in FRR plans for the 2021/22 auction include three gigawatts (GW) of older (1950s-60s vintage), smaller (under 400 MW per unit) coal units that closely resemble the types of units that have largely otherwise retired across PJM. Further, FRR plans include nine GW of larger (400 MW or more) coal units whose economics are uncertain. A number of units this size also have retired in PJM. *See* "Resources Designated for FRR" and "Resource Model," available at https://www.pjm.com/markets-and-operations/rpm.aspx.

noted above, nothing in the existing FRR limits its use to vertically integrated utilities. A state that wishes to promote environmental priorities, and elects the full FRR to pursue those priorities unencumbered by the MOPR, will have the same or greater effect on price as a state that invokes the resource-specific FRR to remove only as much load as necessary to match the capacity resources of state policy interest.[48]

Finally, EPSA argues that the resource-specific FRR is potentially more dangerous than the full FRR because load-serving entities could use the resource-specific FRR to engage in the exercise of buyer market power—withdrawing some load from the PJM market in order to reduce the RPM clearing price for the remainder of its load still participating in that market.[49] Yet the programs on which the Commission has focused—and which have prompted the Commission to propose reforms—are all state-sponsored environmental programs aimed at supporting non-emitting resources. To the extent that the Commission is presented in the future with an instance of anti-competitive conduct, it has the enforcement tools it needs to investigate and punish that conduct. All capacity transactions taking place under a resource-specific FRR remain subject to Commission jurisdiction as wholesale sales. The Commission will therefore have transparency into the costs being incurred and the basis for the state procurement. If it determines that parties are engaged in market manipulation or anti-competitive conduct, it has the power under Sections 205 and 206 to reject rates submitted to it, as well as other enforcement tools. Finally, to the extent any danger still exists, that is a danger shared just as much by the existing FRR. Under that existing construct, a state with multiple load-serving entities could attempt to do what EPSA describes—

[48] Schnitzer Decl. ¶¶ 59-61, 63.

[49] *See* Aff. of Paul M. Sotkiewicz, Ph.D., Attach. A to EPSA Init. Br., at ¶¶ 19-26 ("Sotkiewicz Aff."); *see also* NRG Init. Br. 16.

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but that has not prevented the Commission from affirming that the existing FRR is just and reasonable.[50]

The Commission should not lose sight of what EPSA is asking it to do by conjuring the specter of buyer-side market power: the cost of avoiding that speculative possibility will be to impose, with certainty, more than $900 million annually in unnecessary costs on customers RTO-wide—and $700 million annually on EMAAC customers alone.[51] The Commission should adopt the resource-specific FRR to avoid the concrete harm, rather than imposing concrete costs to avoid a theoretical loophole that it has other tools to address.

2. The Prediction That the Resource-Specific FRR Will Be Easier for States to Use Than the Existing FRR Is Not a Valid Ground for Opposing It.

To the extent MOPR-only advocates view the resource-specific FRR as more dangerous than the existing FRR construct because it is easier for states to use—and thus, under the resource-specific FRR, states within PJM will not be sufficiently deterred from attempting to regulate the generation mix—that rationale would violate the FPA and the Tenth Amendment. "Legislation designed to free from pollution the very air that people breathe clearly falls within the exercise of even the most traditional concept of … the police power" reserved to states under the Tenth Amendment.[52] The FPA preserves that traditional police power by expressly protecting states' authority over "facilities used for the generation of electric energy."[53] And in reliance on that

[50] Moreover, under PJM's proposed MOPR rule—which many other parties support—self-supply would be exempt from the MOPR. If that exemption is accepted, self-supply will be a much less burdensome path than the resource-specific FRR for load-serving entities seeking to "exercise buyer market power." Such entities could simply bilaterally contract for capacity and then offer that capacity into RPM as a price taker.

[51] Schnitzer Decl. ¶ 55.

[52] *Huron Portland Cement Co. v. City of Detroit*, 362 U.S. 440, 442 (1960).

[53] 16 U.S.C. § 824(b)(1).

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authority, states have restructured their retail electric industries, giving up the command-and-control regulatory authority they exercised over vertically integrated utilities, but with the expectation and understanding that they still would be able to exercise control over the generation mix serving their states through renewable energy credit programs and other mechanisms regulating procurement by load-serving entities.[54]

Thus, at RPM's inception, PJM's tariff largely exempted new state-supported resources from the MOPR, and even after that exemption was eliminated, the MOPR was never targeted specifically at state-supported resources, but instead was applied to the predominant type of new resources (gas-fired combustion turbines and combined cycle units) regardless of whether they were receiving state support. And states were still free to use financial incentives to influence the existing resource mix, including through environmental attribute payments, to encourage or delay retirements of particular types of generation resources. In many states, these programs now cover one-fifth or more of the state's electricity consumption.[55] When states permitted their utilities to join PJM, states had no reason to think that, by doing so, they would be forfeiting their authority to regulate generation facilities within their jurisdictions so as to promote their environmental goals.

MOPR-only advocates now support a bait and switch. Having attracted states into the PJM market on terms that would allow states to continue to exercise their authority over the generation mix, they now urge the Commission to adopt market rules that force states into a trilemma: states

[54] Br. of Amici Curiae Electricity Regulation Scholars, *Village of Old Mill Creek v. Star*, Nos. 17-2433, 17-2445 (cons.), at 10-18 (7th Cir. Nov. 3, 2017), available at https://statepowerproject.files.wordpress.com/2017/02/electricity-regulation-scholars-brief-webposting.pdf; *see infra* n.60 (collecting authorities establishing state authority over utility procurement).

[55] "Renewable Energy Requirements by PJM State," Attach. 1 to Aff. of Dr. Anthony Giacomoni at 2, Attach. F to PJM Interconnection L.L.C., Capacity Repricing or in the Alternative MOPR-Ex Proposal, Docket No. ER18-1314 (Apr. 9, 2018).

must leave PJM altogether or opt into the existing FRR, which (according to MOPR-only advocates) is unattractive and costly; remain in the RPM auction but forfeit their ability to regulate the generation mix; or remain in the RPM auction and incur substantial and unnecessary capacity costs in order to exercise the authority that Congress reserved to them and that lies at the core of their police powers—and on which they have relied in establishing renewable portfolio standards, zero emission credit programs, and other state programs.

However, as the Supreme Court recently reaffirmed in *NFIB v. Sebelius*, the federal government cannot induce states to rely on a cooperative federalist scheme and then leverage that reliance to coerce states into giving up control over core sovereign powers.[56] In *Sebelius*, for example, the Supreme Court held that although Congress had the power to attach conditions to Medicaid spending in order to encourage states to regulate in a manner favored by the federal government, Congress could not lure states into dependency on the Medicaid program and then use its Spending Clause power to force states to yield additional regulatory authority to the federal government.[57] Similarly here, MOPR-only advocates seek to leverage state dependence on PJM membership and then use the Commission's wholesale rate-setting powers to force states to surrender their efforts to influence the generation resource mix—a core police power that Congress expressly reserved to states and which states expected to be able to continue to exercise when they joined PJM. That violates the Federal Power Act (and its protection for states' authority over "facilities used for the generation of electric energy"), and the Tenth Amendment (which protects states' policymaking powers from federal commandeering). And while states theoretically could

[56] *Nat'l Fed'n of Indep. Bus. v. Sebelius*, 567 U.S. 519, 575-84 (2012).

[57] *See id.* at 576-77 ("The legitimacy of Congress's exercise of the spending power thus rests on whether the State voluntarily and knowingly accepts the terms of the 'contract.'" (internal quotation marks omitted)).

re-regulate, that choice would certainly be extremely costly and disruptive to an industry that provides an essential service to citizens.

Sebelius's rationale powerfully underscores why the Commission properly proposed a resource-specific FRR, and why proposals for a MOPR-only solution are pernicious. As *Sebelius* explains, political accountability vanishes when the federal government leverages state dependence on a federal regulatory construct in order to force states into regulatory changes. When that happens, "it may be state officials who will bear the brunt of public disapproval, while the federal officials who devised the regulatory program may remain insulated from the electoral ramifications of their decision."[58] Here, for example, if the Commission were to accept a MOPR-only solution, states that wished to maintain their preexisting regulatory programs concerning the generation mix would be forced to pay for redundant capacity at significant expense. Even though the Commission's regulatory scheme forced states into that bind, state decision-makers would bear the brunt of public disapproval for the consequences, and the federal government (through the Commission) would remain insulated from the electoral ramifications. To the extent states succumb and abandon their environmental initiatives to avoid the significant costs of over-procuring capacity, again it is state policymakers that would bear the political costs—even though the bind into which they are placed is the consequence of the Commission's regulatory program. That "would threaten the political accountability key to our federal system."[59]

The resource-specific FRR proposal, by contrast, places political accountability in the right place. States are free to rely on state-procured resources to provide capacity, but the resource-

[58] *Id.* at 578 (internal citations, quotation marks omitted).

[59] *Id.*

specific FRR ensures that the costs of state policy choices will be transparent. As a result, the right decisionmakers can be held accountable. The Commission's proposal is consistent with basic federalism principles that form the bedrock division of authority in the FPA.

3. The Resource-Specific FRR Is Consistent With the Commission's Exclusive Rate-Setting Authority.

To the extent opponents contend that the resource-specific FRR is inconsistent with the Commission's exclusive authority to set wholesale rates, their argument rests on a misunderstanding of the state's role in arranging for the procurement of capacity under the resource-specific FRR. States will not be setting wholesale capacity prices, nor usurping the Commission's role in determining whether capacity prices are just and reasonable. Rather, states will be establishing procurement processes for capacity, just as many PJM states (such as Illinois, New Jersey, Maryland, and others) already do for energy to be resold to non-shopping retail customers. The FPA assigns states the power to direct utility procurement and permits states to establish procurement processes subject to state supervision—including procurement rules establishing the maximum cost that it would be prudent for buyers to incur, in light of the state's authority over cost recovery from retail customers.[60]

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[60] *See Southern Cal. Edison Co.*, 70 FERC ¶ 61,215, 61,676 (1995) (acknowledging "that resource planning and resource decisions are the prerogative of state commissions and that states may wish to diversify their generation mix to meet environmental goals in a variety of ways," and that a "state may choose to require a utility to construct generation capacity of a preferred technology or to purchase power from the supplier of a particular type of resource"); *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities,* Order No. 888 (1996), at 434 n.544 (noting "state authority in such traditional areas as … utility buy-side and demand-side decisions …; authority over utility generation and resource portfolios; and authority to impose non-bypassable distribution or retail stranded cost charges." (emphasis added)); *Midwest Power Systems*, 78 FERC ¶ 61,067, 61,246 (1997) (state policy is "consistent with federal law to the extent that [it] require[s] electric utilities located in [the state] to purchase from certain types of generating facilities"); *Southern California Edison Co.*, 71 FERC ¶ 61,269, 62,080 (1995) (noting "broad powers under state law to direct the planning and resource decisions of utilities under their jurisdiction. States may, for example, order utilities to build renewable generators themselves, or deny certification of other types of facilities if state law so permits. They also, assuming state law permits, may order utilities to purchase renewable generation."); *see also Pike County Light & Power Co. v. Penn. Pub. Utility Comm'n*, 465 A.2d 735, 738 (Comm. Ct. Pa. 1983); *Appalachian Power*

Capacity suppliers, meanwhile, will decide whether or not they wish to sell their capacity pursuant to the state procurement, through the RPM auction, through a bilateral contract, or in some other way. The state will not be exercising any regulatory authority over the capacity supplier with respect to its capacity sales. Any resulting sale of capacity pursuant to the resource-specific FRR will thus fall comfortably within the seller's market-based tariff, which allows a supplier to sell at a price for which it can find a buyer. Such sales will be reported to the Commission on the seller's EQR. The Commission will thus be informed of those sales and can review them, and the Commission will have the final word regarding whether or not the price is just and reasonable. If not, the Commission has the power under Section 206 to replace the rate with a different one.[61] Similar provisions have long been part of the PJM Tariff.[62]

This framework is consistent with the FPA's division of authority and the Commission's exclusive power to set wholesale rates. For example, in *Allco Finance Ltd. v. Klee*, the Second Circuit rejected a field preemption challenge to a Connecticut procurement statute that directed wholesale purchases of energy bundled with RECs by its utilities from renewable developers chosen by the state.[63] The court reasoned that the state's procurement resulted in "the kind of traditional bilateral contracts that are subject to FERC review for justness and reasonableness," and that the request-for-proposals at issue specifically required that any resulting contract be filed

Co. v. Pub. Service Comm'n of W. Va., 812 F.2d 898, 903 (4th Cir. 1987); *Kentucky West Virginia Gas Co. v. Penn. Pub. Utility Comm'n*, 837 F.2d 600, 609 (3d Cir. 1988) (discussing state authority to regulate the prudence of utility purchases).

[61] 16 U.S.C. § 824e.

[62] *E.g.*, *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,164 (2013) (discussing and applying RAA, Sched. 8.1 § D.8, concerning the existing FRR, which incorporates a state-determined compensation mechanism, subject to review and displacement by the Commission); *Am. Elec. Power Serv. Corp.*, 134 FERC ¶ 61,039, at PP 2-3 (2011) (same); *see also* FirstEnergy Solutions Comments at 10-11.

[63] 861 F.3d 82, 99-100 (2d Cir. 2017).

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with FERC under Section 205.[64] "Because FERC has the ability to review any bilateral contracts that arise out of Connecticut's RFPs, we hold that Connecticut's 2015 RFP … is not preempted by the FPA."[65]

Nothing in *Hughes v. Talen Energy Marketing, LLC* is to the contrary. *Hughes* dealt with a contract-for-differences in which the state payment was conditioned on clearing the PJM auction. In conditioning payment on auction clearance, the state disregarded or adjusted a rate that FERC had already set—namely, the PJM auction clearing price. Thus, the Court held, "States interfere with FERC's authority by disregarding interstate wholesale rates FERC has deemed just and reasonable."[66] By contrast, a resource-specific FRR would be implemented pursuant to a Commission order contemplating a state procurement process *outside* the PJM auction, with resulting capacity contracts that would then be subject to Commission review for justness and reasonableness. Such a structure does not disregard any Commission-established rate. It respects

[64] *Id.* at 99.

[65] *Id.* at 100; *see also La. Pub. Serv. Comm'n v. FERC*, 761 F.3d 540, 552 (5th Cir. 2014) (upholding FERC's incorporation of a state commission-determined depreciation expense into the federal rate, even though the state commission's method for calculating depreciation diverged from FERC's own method, because "FERC exercised its role when it initially reviewed and accepted the … formula incorporating the state agencies' depreciation rates" as just and reasonable, and because "FERC has clarified that it will continue to exercise oversight of the state rates in a Section 206 complaint proceeding."); *La. Pub. Serv. Comm'n v. FERC*, 860 F.3d 691, 696 (D.C. Cir. 2017) ("[W]e … conclude that there has been no unlawful subdelegation because FERC has exercised, and intends to continue to exercise, its § 206 review authority."); *Coalition for Fair & Equitable Regulation of Docks on Lake of the Ozarks v. FERC*, 297 F.3d 771, 779 (8th Cir. 2002) (rejecting subdelegation challenge to license where "FERC retains authority to require the modification of the project and its plans and specifications, to accomplish the outlined goals…. Therefore, the license represents no real delegation of power …, because FERC retains the right to require modification of … [the] program."). To the extent opponents rely on U.*S. Telecom Ass'n v. FCC*, 359 F.3d 554 (D.C. Cir. 2004), that case is easily distinguished: the Court found an improper subdelegation by the FCC where the agency "lets the states make crucial decisions" reserved to the FCC by statute "with FCC oversight neither timely nor assured." *Id*. at 567. Here, the Commission's oversight is both timely and assured under Sections 205 and 206.

[66] 136 S. Ct. 1288, 1299 (2016).

the jurisdictional lines drawn in the FPA while advancing the statute's cooperative federalism framework.

C. Whether Clearing Prices Change Is Irrelevant.

The main argument of parties opposing the resource-specific FRR is that, if load is allowed to exit the RPM market along with subsidized capacity resources, applying the MOPR will not end up increasing capacity prices.[67] The Commission should not be swayed by this argument, for several reasons.

As an initial matter, the argument is speculative. It is premised on the assumption that states will continue to subsidize at the same rate even after they are required to take responsibility for the subsidized resources' capacity revenue. One goal of the resource-specific FRR is to bring additional transparency to states' policy choices, so that those choices can be better informed.[68] There is no guarantee that states will procure capacity in addition to other attributes for *every* subsidized resource; those subsidized resources whose capacity revenues are not replaced through the resource-specific FRR will participate in the RPM auction but be subject to a MOPR, resulting in increased capacity prices relative to the status quo.[69]

Second, and more fundamentally, the Commission's goal in granting the Section 206 complaint and imposing a new capacity market design should not be to guarantee a generator any particular price level. Instead, it should be to ensure that the prices that emerge from the RPM market reflect genuine competition among suppliers to serve residual RPM demand by requiring

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[67] *See, e.g.*, EPSA Init. Br. at 20-22; NRG Init. Br. at 14-15; Initial Br. of Calpine Corp. (Oct. 2, 2018), at 5-8 ("Calpine Init. Br."); Initial Br. of Carroll County Energy LLC et al. (Oct. 2, 2018) at 9-11; LS Power Init. Br. at 19-20; P3 Init. Br. at 7-8.

[68] Order at P 162.

[69] *See, e.g.*, *ISO New England Inc.*, 162 FERC ¶ 61,205, at P 73 (2018) (noting possibility that new resources will be discouraged by CASPR market design and "it is not clear that past offer behavior will reasonably predict future offer behavior under alternative market designs").

that their bids reflect the cost of supplying capacity, but not other attributes that PJM's market does not value. The Commission's Order is consistent with this goal. The Commission did not focus on prices in the abstract, but rather on the "price suppressive effects" of capacity sell offers by subsidized resources that were "below a competitive price."[70] As the Commission explained, "out-of-market support to existing resources may allow even uncompetitive resources, for whom a competitive offer would be significantly higher than zero, to submit low or zero priced offers into the capacity market."[71] The prevalence of these below-cost offers, the Commission said, had become sufficiently widespread that they had begun to "compromise the capacity market's integrity."[72] Thus, the Commission's solution was not to order an administrative increase in prices, but instead was to impose a bidding rule that would ensure that all capacity market offers were "competitive." The Commission explained, "An expanded MOPR, with few or no exceptions, should protect PJM's capacity market from the price suppressive effects of resources receiving out-of-market support by ensuring that such resources are not able to offer below a competitive price."[73] As a result, "the rates … in the capacity market [would be] the result of competitive market forces, and therefore … just and reasonable."[74] The Commission appropriately focused its Order on fixing the mechanism that polices suppliers' auction bids, not the resulting prices—in other words, the auction inputs, not the outputs.

MOPR-only advocates respond that RPM prices will still be affected by state subsidy decisions, because all else being equal, auction clearing prices will decline when demand is

[70] Order at P 158.

[71] *Id.* at P 151.

[72] *Id.* at P 150; *id.* at P 156.

[73] *Id.* at P 158.

[74] *Id.*

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removed from the auction to be satisfied outside the market by FRR-RS resources. Their position boils down to the assertion that suppliers are entitled to serve *all* load through the RPM auction.[75] But the Commission has never sought to dictate load's participation in a capacity auction as the exclusive method of capacity supply procurement. Even the name for the RPM auction—the Base *Residual* Auction—acknowledges that the auction is a default aggregate procurement after accounting for commitments undertaken outside of the auction.

From a legal and market design perspective, there is an important difference between auction clearing prices being "suppressed" by non-competitive bids submitted by auction participants, and auction clearing prices decreasing because of a reduction in demand reflecting a state's policy decision to withdraw load from the auction.[76] The Commission's core responsibility with respect to the RPM auction is to protect the integrity of the auction process, by ensuring that suppliers are making competitive offers, so that the clearing price reflects robust competition among suppliers to serve the available load. By contrast, the Commission does not have the last word on whether states rely on the auction to serve their load. That decision is up to the states.

[75] EPSA Init. Br. at 5 ("[T]he fact remains that an expanded MOPR and the FRR Alternative are fundamentally in conflict and cannot coexist, because the latter will effectively nullify the former"); Sotkiewicz Aff. ¶ 132 ("[I]t is simply not possible to accommodate [state] polices and preserve efficient and just and reasonable outcomes in the PJM capacity market."); P3 Init. Br. at 17 ("Again, the door is open for any state … that wants to go its own way. But for those who stay, playing in a regional wholesale market that does not tolerate price suppression because of the subsidization of politically selected resources, is a trade off that a state must be willing to make."); Aff. of Roy J. Shanker, Ph.D., Attach. to P3 Init. Br., ¶ 26 ("Shanker Aff.") ("While 'counting' rules related to the amount of load removed under the type of proposal suggested by the Commission can mitigate the magnitude of the suppression, *it can't be eliminated if any load is removed*." (emphasis in original)).

[76] Dr. Sotkiewicz contends that demand does not exit the market even when it procures outside the RPM auction, *see* Sotkiewicz Aff. ¶¶ 8-9, 13-14, but this is word play. Of course, load-serving entities must satisfy their obligations under the Reliability Assurance Agreement; in this sense, load cannot be withdrawn from the PJM market—unless a load-serving entity leaves PJM altogether. But, as the Commission recognized, load can satisfy its obligations to procure capacity in different ways—including through the existing FRR outside of PJM's capacity auction, or through PJM's capacity auction.

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The states' policy decision to remove their load from the auction may indirectly affect auction prices, but it does not render the auction rules unjust or unreasonable.

The existing FRR construct, which the Commission has long deemed just and reasonable, reflects the distinction between regulating supplier offers *within* the RPM auction, and regulating states' policy decisions regarding how their load-serving entities procure capacity. States can direct their load-serving entities to elect the existing FRR construct, even though such a choice, as MOPR-only advocates concede, has price effects on the RPM auction that are at least as large as a more tailored resource-specific FRR.[77] Nevertheless, in approving the FRR, the Commission saw no conflict between its mandate to "protect the integrity of PJM's wholesale capacity markets under RPM," and state authority to direct load-serving entities "to secure their own capacity resources outside of a competitive market."[78] As the Commission explained, the FRR provided "an alternative for those load serving entities that wish to bring new generation resources into the PJM capacity market without risk of being mitigated under the MOPR."[79]

Indeed, the Commission has repeatedly approved the existing FRR as just and reasonable without ever expressing any concern about its potential impact on RPM prices.[80] It has also expressly considered the argument that the existing FRR cannot be just and reasonable because of its potential price-reducing effects—but approved the FRR nonetheless.[81] The Commission has

[77] Shanker Aff. ¶ 8 (acknowledging that the existing FRR is "still price suppressive"); *id.* at ¶ 41 ("The existing FRR mechanism does admittedly raise similar price suppression concerns."); Sotkiewicz Aff. ¶¶ 60-67 (acknowledging that large price effects could result from use of the current FRR).

[78] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 193 (2011).

[79] *Id.* at P 192.

[80] *See supra* at n.36.

[81] *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, at P 203 (2011) (noting, and then going on to disregard, argument that "undue reliance on the FRR Alternative may have unintended consequences. The New Jersey Board asserts that if load serving entities and states decide that FRR is the best option, the proliferation of FRR service areas could reduce the auction clearing price and accelerate capacity retirements.").

never sought to micromanage the particular price levels that result from competitive offers to supply the remaining load procuring through the RPM auction.[82]

Likewise, in other regions, the Commission has approved capacity market constructs that recognize state authority to decide whether load should be served from supply procured within or outside the RTO/ISO capacity construct. In MISO, for example, the Commission has made clear that the capacity auction is voluntary, and that "most [utilities] will continue to obtain most—if not all—of their supplies outside the auction."[83] Over objections, the Commission has held that the resulting capacity auction prices nevertheless are just and reasonable, because they result from competition among suppliers to serve whatever demand exists in that market. And in CAISO, the Commission does not administer any centralized capacity market at all, but instead requires CAISO to impose a backstop resource adequacy procurement mechanism in the event that a state-administered resource adequacy construct fails.[84] MOPR-only advocates have no explanation for why these other constructs can be just and reasonable, yet the resource-specific FRR is not.

Moreover, even if the Commission could theoretically mandate that all PJM capacity be procured through a centralized auction construct, imposing such a mandate would not be good policy. Everyone agrees that states can ultimately direct their load-serving entities to withdraw from PJM. Because states have the last word, it behooves the Commission to adopt a capacity construct that is workable for states and that allows them to pursue their policy priorities while remaining part of the RTO.

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[82] *Id.* at P 86; *id.* at P 100 ("PJM's tariff provides this alternative method of satisfying resource requirements while preserving wholesale market prices, and states and distribution companies can make this choice based on their individual circumstances").

[83] *Midwest Independent Transmission System Operator, Inc.*, 139 FERC ¶ 61,199, at P 187 (2012).

[84] *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at PP 1117-18 (2006).

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Finally, in light of all this, there is no merit to Calpine's argument that current market prices are confiscatory.[85] Any supplier that has cleared the capacity market, and thus has a capacity commitment, submitted an offer less than or equal to the clearing price and so presumably was willing to accept that level of compensation. Suppliers that do not clear the capacity market have no capacity commitment—so nothing is being confiscated from them. Calpine's real argument is that it invested in capacity hoping that states would rely only on the RPM market to satisfy their demand. But Calpine made its investments against a backdrop in which states were free to withdraw their load to be served in other ways, especially to achieve environmental aims that many of its facilities cannot satisfy. The risk that states would do so is a risk that Calpine and other investors knowingly assumed.

D. The Resource-Specific FRR Allows States to Select Resources That Are Economic and Least-Cost Once Externalities Are Considered, and the Resulting RPM Price Is Efficient.

MOPR-only advocates also argue that the resource-specific FRR will result in the wrong set of resources being selected to provide capacity. The least-cost set of resources, they say, consists of the resources that RPM's market mechanism would select absent the state programs deemed "actionable subsidies." To the extent states procure capacity from other resources outside RPM, they contend, states create inefficiencies that raise costs to customers.[86]

To start, this argument is irrelevant because it ignores the same federalism principles set forth above and memorialized in the FPA: states retain final authority over the generation facilities that serve their people, and when they exercise this sovereign authority, they are not bound to select the resources that MOPR-only advocates—or indeed, the Commission itself—view as the

[85] Calpine Init. Br. at 11-13.

[86] *See, e.g.*, Sotkiewicz Aff. ¶¶ 15-18.

most efficient. The Commission's proper concern extends only to whether *RPM's market mechanism* selects an efficiently competitive set of resources from among the suppliers participating *in that market*.

But even judged solely by efficiency, the MOPR-only advocates are wrong. Because the RPM mechanism ignores externalities like pollution, it inefficiently selects the wrong resources and sets the wrong price. By contrast, the state environmental attribute programs, like REC and ZEC programs, that trigger eligibility for the resource-specific FRR make outcomes *more* efficient—as to both resource selection and clearing prices. They do so by moving the world closer to what virtually everyone agrees would be the economic ideal: a market that internalizes the cost of carbon pollution.

For MOPR-only advocates, externalities are the elephant in the room. Their various analyses strikingly ignore the RPM mechanism's failure to account for the cost of pollution.[87] Those are real costs that impose real harm on society, and without accounting for them, RPM cannot select the most efficient set of resources. Exelon has explained these points at length,[88] and only summarizes them here. When the fossil-fuel generators owned by MOPR-only advocates produce electricity, they create pollutants—notably, carbon dioxide.[89] These pollutants harm human health and the environment, but their costs generally fall on society, not generators that

[87] For example, NRG's witness Robert Stoddard asserts that the "true costs" of FRR-RS resources would place them in the highest part of the supply stack, but does not consider that any concept of a resource's "true costs" must account for the costs it externalizes onto society. *See* Affidavit of Robert B. Stoddard ¶ 39 (attached to NRG Init. Br.).

[88] Initial Br. of Exelon Corp. (Oct. 2, 2018) at 13-14 ("Exelon Init. Br."); Protest of Exelon Corp., Docket No. ER18-1314 (May 7, 2018), at 12-25; Decl. of Robert D. Willig at 17-28, Ex. A to Protest of Exelon Corp., Docket No. ER18-1314 (May 7, 2018) ("Willig Decl.").

[89] Willig Decl. ¶¶ 13(a), 27; *see, e.g.*, *Coal. for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 121 (D.C. Cir. 2012), *aff'd in part, rev'd in part on other grounds sub nom. Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427 (2014).

produce them—making them negative externalities.[90] Conversely, clean generators reduce emissions by displacing emitting resources but do not receive compensation for this benefit—positive externalities.[91] Externalities distort incentives, and so result in inefficiencies.[92] When the fossil-fuel generator decides how much to produce, it considers only its private costs, not the full costs to society.[93] When the clean generator weighs the same decision, the same mismatch occurs in the opposite direction. The fossil-fuel generator will produce too much, and the clean generator, too little. As Dr. Willig and Mr. Schnitzer explain, when incentives are misaligned, the outcome will not be efficient.[94] The fossil-fuel generator may continue operating when it should retire, and the clean generator may retire when it should continue operating—or the clean generator may never be constructed at all.

Indeed, the ability of fossil-fuel generators to produce electricity without paying for the social harm caused by pollution amounts to a subsidy—a massively distorting one. Society bears part of the cost of that generation, rather than the plant owners. For carbon dioxide alone, estimates put this subsidy's value for fossil-fuel generators across PJM at $12.1 billion to $17.7 billion

[90] Willig Decl. ¶¶ 27, 32.

[91] *Id.*

[92] Schnitzer Decl. ¶ 27.

[93] Willig Decl. ¶¶ 33-36.

[94] *Id.* ¶ 33; Schnitzer Decl. ¶ 27; *see* Institute for Policy Integrity, *Capacity Markets and Externalities: Avoiding Unnecessary and Problematic Reforms*, at 7 (Apr. 2018), http://policyintegrity.org/files/publications/Capacity_Markets_and_Externalities_Report.pdf; Comments of Inst. for Policy Integrity at N.Y.U. School of Law (Oct. 2, 2018) at 6-18, 25-32. Even PJM's witness, Hung-Po Chao, agrees that "a state-sponsored subsidy program to assist domestic production could, in principle, be justified as a second-best policy intervention to promote the economic welfare of the state when there is … a divergence between the marginal social cost (or value) of particular domestic production and the marginal private cost (or value) of that production"—*i.e.*, an externality. *See* Affidavit of Hung-Po Chao, Ph.D., Attach. C to Initial Submission of PJM Interconnection, L.L.C. (Oct. 2, 2018), at ¶ 5 ("Chao Aff."); *see also id.* ("[I]f a divergence is caused by a domestic state policy that is *not* tailored to address a market imperfection or externality, it is categorized as a market distortion." (emphasis added)). Yet Dr. Chao inexplicably fails to follow that analysis through in examining the PJM market and the impact of state environmental programs on efficiency. *See id.* ¶¶ 8-11.

dollars *annually*.[95] That means when fossil-fuel generators offer into wholesale markets, their offers are artificially low: they do not reflect the true costs of producing electricity using fossil fuels. As a result, these generators may clear at the expense of cleaner generators that would outcompete the polluters if environmental harm were taken into account.[96] That inefficient result—ignored by MOPR-only advocates—is what a MOPR-only approach would yield.

By contrast, the attribute payments that would trigger eligibility for the resource-specific FRR improve efficiency—selecting a more efficient set of resources, and yielding clearing prices that come closer to the efficient ideal. Most agree (as is plainly true) that a carbon price in the energy market is the economic ideal.[97] That ideal world would increase the energy-market bids of emitting resources by the costs of the carbon emissions they produce—with effects on resource selection and clearing prices, in both energy and capacity markets.[98]

- In energy markets, the clearing price would increase by the carbon cost of the marginal resource—likely an emitting natural gas or coal plant.[99] Net revenues for clean generators that clear would increase by this amount: they receive the carbon-enhanced clearing price, but because they do not emit carbon, they do not have to pay the carbon price.[100]

- Meanwhile, in capacity markets, clean generators would lower their bids: expecting higher net revenues from energy markets, they would rely less on

[95] These figures reflect 291.9 million tons of CO_2 emitted in PJM in 2017 and 426.6 million tons emitted in 2016, at a cost of $41.40 per ton. *See* Monitoring Analytics, LLC, *2017 State of the Market Report for PJM, Volume 2: Detailed Analysis*, at 361 (Mar. 2018).

[96] Schnitzer Decl. ¶ 47, 49-51.

[97] *Id.* ¶ 28; Willig Decl. ¶¶ 34-35; *see also* Exelon Init. Br. at 7 n.13 (collecting references to comments from industry participants supportive of a carbon price, including many of the advocates for a MOPR-only approach).

[98] Schnitzer Decl. ¶¶ 28-37.

[99] *Id.*

[100] *Id.*

> capacity revenues in order to continue operating.[101] Accordingly, clearing prices in capacity markets would fall.[102]

The net result would be that some emitting resources—no longer able to cover their costs from energy markets, capacity markets, and ancillary services, once forced to internalize the costs of their pollution—would be revealed as uneconomic and would retire.[103] Replacing them would be cleaner generators, correctly identified by the market as competitive once their environmental benefits are taken into account.[104] *This* is the truly efficient outcome—not the outcome that results from the current auction design that ignores externalities.[105]

State attribute payments like RECs and ZECs partially replicate this efficient outcome by providing the economic equivalent of a carbon price for the resources that participate.[106] Depending on the level at which it is set, the attribute payment either provides or partially provides the higher net revenues that these resources would receive from energy markets that correctly valued carbon.[107] And with these higher non-capacity revenues in hand, participating clean generators can reduce their competitive bids in capacity markets. So long as the attribute payments do not exceed the environmental value that zero-emissions resources provide, REC and ZEC programs are a step toward greater efficiency.[108] Resources participating in these programs will continue operating only if the value of their energy, capacity, and ancillary services, plus the value

[101] *Id.*

[102] *Id.*

[103] Willig Decl. ¶ 52.

[104] *Id.* ¶¶ 52-53.

[105] *Id.*; Schnitzer Decl. ¶¶ 26-37.

[106] Schnitzer Decl. ¶¶ 30, 32.

[107] *Id.* ¶¶ 26-37.

[108] Willig Decl. ¶¶ 59; Schnitzer Decl. ¶ 36.

of their environmental benefits—as captured in REC or ZEC payments—exceed their costs.[109] If they do not, these resources will shut down. And when some of these clean generators clear at the expense of some emitting generators, and when clearing prices in capacity markets fall, the market is moving closer to the efficient ideal that would exist with a carbon price.[110] True enough, the result does not move all the way: these programs do not cover all methods of achieving emissions reductions (such as demand-side measures); they do not distinguish among different types of emitting generators (such as natural gas and coal); and, depending on the level of the attribute payment, they may benefit clean resources less than a carbon price would.[111] But these programs are far better than continuing to ignore externalities altogether. And because the resource-specific FRR respects states' authority to enact such programs, and yields a resource mix and price similar to what would prevail if the PJM markets themselves accounted for externalities, the resource-specific FRR enhances efficiency.[112]

The fundamental flaw in a MOPR-only approach, from an efficiency perspective, is that it seeks to counteract these pro-efficiency results. Not only would the Commission's markets continue to ignore economic realities, but states that aim to decarbonize by paying generators for their environmental benefits would find their efforts frustrated—able to proceed, if at all, only in the most inefficient way imaginable. Such states will be forced to continue procuring capacity through the RPM auction from emitting resources that impose significant costs on society but do not include those costs in their market offers. Meanwhile, such states will be forced to make a double payment for capacity to the non-emitting resources that do not impose those costs on

[109] Willig Decl. ¶¶ 13(e), 53.

[110] Schnitzer Decl. ¶ 33.

[111] *Id.* ¶ 30.

[112] *Id.* ¶ 37.

society and, all things considered, are the more efficient resources. This would not be a just and reasonable result.[113]

E. Other Arguments Against the Resource-Specific FRR Are Without Merit.

Commenters make various other arguments against the resource-specific FRR, which the Commission should reject.

EPSA contends that the Commission's proposed adoption of the resource-specific FRR violates Section 206, because it exceeds the Commission's remedial powers. According to EPSA, the problem the Commission diagnosed was price suppression, but the resource-specific FRR does nothing to fix price suppression. And, EPSA says, the Commission's "discretion is not so broad as to empower the Commission to perform a nose job when it has diagnosed the ratemaking equivalent of a ruptured spleen."[114]

EPSA's argument is without merit. The Commission determined that the remedial tool it would use to ensure competitive outcomes, a broad MOPR with few or no exceptions, created its own problem that needed to be addressed in order for rates to be just and reasonable: the possibility that customers would "have[] to pay twice for capacity."[115] The Commission noted that it did "not take this concern—or the states' right to pursue valid policy goals—lightly."[116] Accordingly, it "reject[ed]" a MOPR-only approach, "even as an interim remedy."[117] It proposed a replacement

[113] Certain commentators have complained about the manner in which states select resources for attribute payments—for example, that procurements are not competitive, or that not all technologies are eligible. But unless the Commission is prepared to impose a carbon price itself, it is not for the Commission to pass judgment on how states implement these programs. Regardless of how they select participating resources, these programs are a large improvement on the status quo.

[114] EPSA Init. Br. at 29; *id.* at 27-31.

[115] Order at P 159.

[116] *Id.*

[117] *Id.* at P 149.

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rate that "modif[ied] two aspects of the PJM Tariff" that were intertwined and would avoid the problems created by applying the MOPR alone: "PJM should expand the MOPR for those resources seeking to participate in the capacity auction and implement a resource-specific FRR Alternative option, under which a resource receiving out-of-market support may remain on the system, outside of the capacity market."[118] This was well within the bounds of the Commission's authority under Section 206. The authority cited by EPSA affirms that the Commission has authority under Section 206 "to adopt a remedy proportionate to the problem being addressed."[119] Here, a MOPR-only solution would not be a suitable remedy for the reasons explained by the Commission. Instead, a resource-specific FRR is a necessary corollary to a broad MOPR, in order to avoid imposing unneeded excess costs on customers or unduly hampering states in their pursuit of legitimate policy goals pursuant to their reserved authority.[120] To use EPSA's medical analogy, the Commission's proposed solution was akin to surgically repairing a ruptured spleen while taking all necessary steps to avoid post-surgical infection. Nothing in Section 206 required the Commission to ignore and leave unresolved the deleterious consequences of imposing a MOPR-only solution.

Other commenters argue that the resource-specific FRR will impair reliability in the long term by suppressing RPM prices below the level needed for competitive entry.[121] This argument is flawed in two respects.

[118] *Id.* at P 157.

[119] *United Distribution Cos. v. FERC*, 88 F.3d 1105, 1132 (D.C. Cir. 1996).

[120] Order at PP 160-162.

[121] *E.g.*, NRG Init. Br. at 15.

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First, most fundamentally, it ignores that the market mechanism is dynamic. RPM prices are currently low in large part because of a significant amount of surplus capacity.[122] If resources exit the market, and new entry is needed, prices will rise to provide the signal to enter. Indeed, the PJM demand curve is designed so that if the amount of capacity falls below the target installed reserve margin, the market clearing price for capacity *must* rise above the cost of new entry. Opponents contend that the resource-specific FRR will undermine market participants' confidence in that market signal, since states could choose to withdraw additional demand from the auction to be served outside of it. But the risk that states will choose to withdraw their load from the capacity auction has been a feature of the capacity market since its inception, and there is no evidence to suggest that it has deterred new investment. In the fifteen Delivery Years for which the RPM auction has facilitated capacity procurement, PJM has received 50 GW of new capacity and uprates.[123] Approximately 30 GW of has entered since the Base Residual Auction for the 2015/16 Delivery Year.[124]

Second, the argument ignores the residual nature of the Base Residual Auction, in which load procures generic capacity—that is, capacity without regard to the technology or emissions characteristics of the capacity resource. But because different generation technologies impose different costs on society, states and their citizens are not actually indifferent to the type of capacity resources they procure from. They are willing to pay more for non-generic capacity—for example, zero emissions or renewable capacity—that provides environmental benefits. The Commission's

[122] Aff. of Dr. James Letzelter at 9, App. B to Initial Comments of the Md. Pub. Serv. Comm'n (Oct. 2, 2018) ("MDPSC Comments").

[123] PJM Interconnection, L.L.C., *2021/2022 RPM Base Residual Auction Results,* Table 8, available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en.

[124] *Id.* at 2.

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markets have always been neutral with respect to specific resource characteristics such as technology, vintage, and or other characteristics that do not bear on the ability of the resource to supply the product in question, and so do not allow states or customers to express their preference for particular types of generation resources by paying more for the resource adequacy provided by those resources. The resource-specific FRR is a mechanism for allowing those preferences to influence the generation mix, without interfering with the neutrality of the PJM auction to specific resource characteristics. Whatever price emerges in the residual market for generic capacity reflects the actual value of that generic capacity to customers, and by definition, any resource willing to satisfy the demand for generic capacity at the market clearing price is making a profit. If more generic capacity is needed, the price will rise.[125]

NRG contends that the resource-specific FRR will have interzonal effects—that is, a state's decision to withdraw load from the PJM auction may affect prices in other zones.[126] But those effects are not unique to the resource-specific FRR. Most state policies, including the existing FRR mechanism, have interzonal effects on capacity markets, as well as energy and ancillary services markets. When a state imposes environmental controls on its coal plants, that increases RTO-wide costs; so too when a state joins an emission cap-and-trade program. And when a state loosens environmental restrictions, or sites transmission lines or approves gas pipelines, or promotes retail demand response or energy efficiency programs, that reduces RTO-wide costs. The Commission and the courts recognize that in a cooperative federalist structure, where the federal and state spheres are not "hermetically sealed" one from the other, the policy choices made by some states may affect prices in the interstate market.[127] Consequently, in designing its market

[125] Schnitzer Decl. ¶ 32.

[126] NRG Init. Br. at 18-20.

[127] *EPSA*, 136 S. Ct. at 776.

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rules, the Commission cannot realistically attempt to insulate its own market prices from the influence of such state policies. Instead, its goal—as expressed in the Order—should be to ensure that the cost of state policies is transparent to states and customers, so that decision-makers can be held politically accountable. Thus, the problem identified in the Order is not simply that one state's subsidies affect the price paid by another state's customers. That type of cross-boundary effect is pervasive and unavoidable. Rather, the specific problem identified by the Order is that customers in the subsidizing state do not see the full cost of supporting the resource, because customers in other zones are paying a part of those costs through the capacity market.[128] As the Order concluded, the resource-specific FRR would solve that problem by requiring a state to be fully financial accountable for the capacity revenues of resources it wishes to support.[129]

The Maryland Public Service Commission ("Maryland PSC") argues that the resource-specific FRR is incompatible with REC programs, because RECs are not necessarily tied to units located in a particular state and frequently are not procured until just prior to the Delivery Year.[130] But there is no reason why the load purchasing a resource's RECs needs to be the same load matched to the resource's capacity. After all, RECs sold just prior to the Delivery Year have been unbundled from capacity. Thus, for example, a state could direct LSEs within its jurisdiction to procure capacity from a particular renewable resource, and that resource's capacity would be matched to those LSEs for purposes of the clearing the auction. But the resource would then remain free to sell its RECs as it wished, to any party, during the Delivery Year. Alternatively, a state could direct the procurement of RECs bundled with capacity in advance of the Base Residual

[128] Order at P 162 ("[T]he status quo requires consumers in some PJM states to subsidize the policy decisions of other PJM states.").

[129] *Id.* ("[T]he new resource-specific FRR Alternative … should help confine the cost of a particular state policy decision to consumers within the state that made that policy decision.").

[130] MDPSC Comments at 8-9.

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Auction. It is also plausible that new renewable resources, foreclosed from earning capacity revenue through the PJM capacity auction due to the MOPR, would increase their REC offer prices to make up for the lost capacity revenue. Either way, there is no incompatibility between the resource-specific FRR and the structure of REC programs. To the extent that the Maryland PSC is concerned that its current authorities do not permit it to direct the procurement of capacity and that it will need time to obtain new legislative authority to enact a new regulatory construct based on existing statutes,[131] Exelon is sympathetic to the need for states to have some lead time.

Accordingly, the Commission should expedite its decision and provide sufficient clarity so that states can put into place the mechanisms needed to implement the FRR-RS in time for the upcoming Base Residual Auction or delay application of its new policy until the May 2020 auction, to allow states adequate time to put into place the mechanisms needed to implement the resource-specific FRR. Under no circumstances, however, should the Commission apply an expanded MOPR before a workable structure for the resource-specific FRR is in place and states have had the opportunity to legislate or make regulatory changes in response to it. The resource-specific FRR is a necessary corollary to the expanded MOPR; the latter without the former would not be just or reasonable, even on a temporary transitional basis, for all the reasons discussed above.

Other commenters argue that the resource-specific FRR is incompatible with retail choice, presupposing a structure where specific load must be matched to a resource three years forward. Exelon's proposal (and PJM's) avoids that problem.[132] For purposes of accounting for FRR-RS resources and then clearing the Base Residual Auction, PJM will adopt the default rule that an FRR-RS resource will be matched proportionally to load in the state that has arranged for

[131] *Id.* at 13.

[132] Argument of the Ohio Pub. Utilities Comm'n (Oct. 2, 2018) at 7-9; Argument of Retail Energy Supply Ass'n (Oct. 2, 2018) at 7-8; NRG Init. Br. 31; Calpine Init. Br. at 8.

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procurement of that resource's capacity.[133] The actual allocation of capacity to load can be financially settled by PJM during the Delivery Year.[134] With respect to how states might choose to allocate capacity to load-serving entities subject to their jurisdiction, that is a policy choice that states may make (subject to Commission review). States can elect an allocation method that ensures competitive neutrality among retail suppliers—for example, by allocating capacity to all load-serving entities in the State proportional to their share of load, and recovering the cost of procurement from those load-serving entities or through a non-bypassable charge collected by the distribution utility.

Finally, NRG and Direct assert that the resource-specific FRR will create the need for Commission review of affiliate transactions.[135] Indeed, as Exelon noted in its initial brief, the Commission's final Order should address potential affiliate transactions that arise from state-directed procurements by load-serving entities subject to state jurisdiction.[136] Many load-serving entities are affiliated with generation companies that own or may develop resources of state public policy interest. Applying the affiliate rules to state-directed transactions between these entities will make the resource-specific FRR unworkable for many resources of state policy interest. Accordingly, the Commission should clarify that state-directed affiliate transactions arising from state-administered procurements of FRR-RS resources shall not be subject to the Commission's affiliate transaction rules. As Exelon's initial brief explained, the concerns driving the Commission's affiliate rules are absent when a state governmental entity directs an affiliate

[133] Attach. A to Exelon Init. Br., Proposed Tariff Language § 5.2A(h)-(i); Exelon Init. Br. 28-29; Keech Aff. ¶¶ 5-10.

[134] Keech Aff. ¶¶ 5-10.

[135] Comments of Direct Energy (Oct. 2, 2018) at 7-8; NRG Init. Br. at 28-31.

[136] Exelon Init. Br. at 25-28.

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transaction. The affiliate rules are intended to prevent a regulated utility from exploiting captive customers for the economic benefit of its unregulated generation affiliate. That concern is not presented when the transaction is directed by a state governmental entity for the state's public policy purposes.[137]

* * *

In sum, the Commission should approve a resource-specific FRR as a necessary corollary to an expanded MOPR.

II. Parties Broadly Agree Regarding the Key Elements of the Resource-Specific FRR, But the Commission Should Reject the Extended RCO Concept and the Onerous Reentry Conditions Proposed by PJM.

There is broad overlap among parties' various proposals for structuring a resource-specific FRR. In particular, the essential components of PJM's RCO proposal are consistent with the elements of the proposed FRR-RS submitted jointly by Consumer Advocates, NGOs, and Industry Stakeholders and supported by numerous other parties. Specifically:

- Any resource subject to the MOPR due to an entitlement to a material subsidy should be eligible for the resource-specific FRR.[138]

- Under the resource-specific FRR, states could arrange for the procurement of capacity outside the RPM market using their own processes. Capacity transactions outside the RPM auction would be reported to the Commission and subject to Commission review.[139]

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[137] *See id.*; *see also* Joint Consumer Comments at 24-25 (advocating "that wholesale sales from an RS-FRR resource with FERC market-based rate authority to an affiliated LSE with captive customers, if undertaken pursuant to a state-sponsored clean capacity procurement, should not be subject" to the Section 205 filing requirement for affiliate transactions under the seller's market-based tariff).

[138] *See* Order at P 165 (asking parties to identify the "appropriate scope of out-of-market support to be mitigated by the expanded MOPR, thereby rendering a resource eligible for the new resource-specific FRR Alternative"); Initial Submission of PJM Interconnection, L.L.C. (Oct. 2, 2018) at 52 ("PJM Submission"); Joint Stakeholders Br. at 7-8; Exelon Init. Br. at 16.

[139] Order at P 165 (asking, "for units that choose the resource-specific FRR Alternative and need to cover their Avoidable Cost Rate outside the capacity market, how … the Tariff [should] address that need both procedurally and substantively"); PJM Submission at 58-63; Joint Stakeholders Br. at 8-10; Exelon Init. Br. at 16-17, 21-24.

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- A load-serving entity entering a bilateral contract for capacity from an RCO/FRR-RS resource will be matched to that resource. A state that procures capacity from a resource participating in the resource-specific FRR can indicate, subject to Commission review, what load subject to its jurisdiction should be matched to the resource, and load-matching can be settled financially in the Delivery Year.[140]

- For resources with split ownership, participation in the resource-specific FRR Alternative by one owner shall not affect RPM participation by the other.[141]

- PJM's market-clearing mechanism would ensure that all locational constraints are satisfied.[142]

- Resources participating in the resource-specific FRR can be and will be subject to all Capacity Performance requirements and rules.[143]

The Commission should issue a final Order consistent with the broad agreement among stakeholders and PJM regarding these core elements of a resource-specific FRR Alternative.

In two respects, however, PJM's resource-specific FRR proposal should be rejected. The first concerns PJM's "Extended RCO" or repricing proposal. PJM presents this as an add-on to its core proposal, to the extent that the Commission continues to be concerned about price levels in the RPM market even after all bidders are submitting competitive offers.[144] In reality, this add-on would increase the capacity costs paid by customers by billions of dollars a year—and not only in states choosing to provide to support to certain types of resources, but in other states as well. The

[140] *See* Order at P 166 (asking parties to "identify the load that will be removed from the PJM capacity market auction in connection with resource owners choosing the resource-specific FRR Alternative"); PJM Submission at 58-63; Joint Stakeholders Br. at 9; Exelon Init. Br. at 16-17, 21-24.

[141] Order at P 166 (asking "how to address resources with split ownership"); PJM Submission at 55 n.4; Joint Stakeholders Br. at 11; Exelon Init. Br. at 23.

[142] Order at P 169 (requesting comment on "the best approach to ensure locational resource adequacy needs are met after removing load and resources from the capacity market under the FRR Alternative"); Joint Stakeholders Br. at 10; Exelon Init. Br. at 28-29.

[143] Order at P 169 (asking for comment on "whether the existing Capacity Performance construct for FRR resources can be applied to a resource-specific FRR Alternative"); PJM Submission at 50-51; Joint Stakeholders Br. at 10-11; Exelon Init. Br. at 28.

[144] PJM Submission at 64.

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Commission should therefore reject this aspect of PJM's proposal. Because this is a Section 206 proceeding, PJM's proposal warrants no deference or presumption in its favor. If, however, the Commission nevertheless seeks to implement some version of repricing in the residual market, the Commission cannot rationally adopt the Extended RCO as proposed. Under PJM's proposal, the stage 2 price is set as though state-supported resources did not exist at all, even though many would be selected by the market even after application of a MOPR.[145] As a result, PJM's Extended RCO would result in prices that are significantly higher even than those that would result from a MOPR. Instead, the only logical method for repricing is to insert state-supported resources into the stage 2 supply curve at levels consistent with their MOPR floor.

The second respect in which the Commission should reject PJM's proposal concerns the conditions governing the reentry of resources from the resource-specific FRR Alternative back into the RPM market. The unreasonable reentry conditions proposed by PJM would raise a resource's offer price to account for costs that have already been sunk.[146] But there is no reason why any rational resource owner would raise a bid to recover sunk costs. Thus, PJM's proposed mitigation for reentering resources is unjust and reasonable and must be rejected.

A. PJM's Extended RCO Proposal Is Not Just or Reasonable.

The Extended RCO purports to "restore the residual [capacity] market clearing price closer to the economically correct outcome."[147] But in reality it would result in an even more inflated market price than applying the MOPR alone. Indeed, Mr. Schnitzer estimates that the Extended RCO would increase capacity costs by approximately *$2.2 billion* each year for EMAAC

[145] *Id.* at 66 ("In stage two, PJM will remove from the supply stack all resources that elected the RCO option.").

[146] *Id.* at 48-50.

[147] *Id.* at 10.

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customers alone, and by approximately *$2.6 billion* annually RTO-wide—about three times as much as a MOPR alone.[148]

The Extended RCO results in such massively inflated customer costs because of a fatal design flaw: PJM proposes to set the stage 2 price—which cleared resources would be paid—by removing RCO resources from the supply curve entirely.[149] In other words, rather than resetting the bids of RCO resources to "competitive" levels at stage 2, as the MOPR purports to do, the Extended RCO simply acts as though the RCO resources do not exist. That makes no sense. There is no basis for concluding categorically that *no* state-supported resource would ever clear the capacity market, and thus omitting all such resources from the stage 2 supply curve. Indeed, PJM elsewhere acknowledges that existing renewable resources have a competitive offer level of zero, even though they receive state subsidies.[150] As a consequence of PJM's exclusion of all state-supported resources from the stage 2 supply curve, the market could potentially clear at the RPM price cap of 1.5 times Net CONE, even though the market is not actually physically under-supplied (and in fact may be substantially over-supplied). In other words, by ignoring these resources, the price of capacity will be set by the demand curve, even though the ignored resources would undoubtedly be available for a price below the demand curve, even after application of the MOPR. This outcome is particularly likely to happen in LDAs that are constrained and in which the number of non-RCO may be limited. But it could even occur RTO-wide.[151]

Moreover, the concept of repricing should be rejected because it rests on the same flawed premise advanced by opponents of the resource-specific FRR: that without repricing, RPM prices

[148] Schnitzer Decl. ¶¶ 74-76.

[149] PJM Submission at 66.

[150] *Id.* at 46.

[151] Schnitzer Decl. ¶ 76.

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will be "suppress[ed]" by state policy decisions to withdraw load from the RPM auction, and that these decisions will inefficiently "crowd[] out" some generators making "competitive" offers.[152]

As already explained above, however, RPM prices are not "suppressed" when states choose to withdraw load from the RPM auction. Instead, the price emerging from residual offers to serve the remaining RPM load is the competitive price for that market. Repricing, by contrast, would "signal that the market would buy capacity from higher cost resources than actually clear the market and receive capacity commitments."[153] This is the very same disconnect between price and quantity that led the Commission to reject PJM's earlier repricing proposal in Docket No. ER18-1314-000.

Moreover, as also explained above, resources receiving attribute payments from state environmental programs are not "uneconomic"; nor are the resources "crowded out" as a result of these state programs economic.[154] Rather, state environmental attribute programs help to identify the efficient set of capacity resources once externalities are taken into account. Resources "crowded out" by clean generators receiving attribute payments do not clear because, when pollution costs are even *partially* taken into account, they are uneconomic. As then-Chairman LaFleur stated at the May 2017 Technical Conference, "if what you are doing is re-pricing resources that a state re-priced and then you are re-pricing them back, it's neither accommodating nor will it lead to harmony."[155] This is exactly what the Extended RCO would do. It should be rejected in its entirety.

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[152] PJM Submission at 65, 71.

[153] Order at P 65.

[154] *Supra* at pp. 29-34; *see* Schnitzer Decl. ¶ 73.

[155] Technical Conference on State Policies and Wholesale Markets, Docket No. AD17-11, Tr. 565 (May 2, 2017).

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To the extent the Commission disagrees and nevertheless wishes to adopt some form of repricing, it cannot accept the Extended RCO proposal in its current form. There is no rational reason to ignore RCO resources entirely when repricing the auction at stage 2, given that PJM's own analysis acknowledges that at least some would be able to clear the capacity market regardless of whether they receive state support.[156] To mimic the RPM prices that would result if all load were served through the capacity auction and if state support did not exist, PJM must insert state-supported resources into the stage 2 supply curve at prices reflecting "competitive" offers—not ignore those resources altogether.[157]

B. PJM's Proposal Regarding Reentry of RCO Resources Punishes Customers and Is Not Just or Reasonable.

The Commission should also reject PJM's proposal regarding the conditions for an RCO resource to reenter the capacity auction. PJM suggests that RCO resources reentering the RPM market should be subject to a MOPR—even when they no longer have a subsidy—plus an adder for any capital investment undertaken while the resource was an RCO/FRR-RS resource.[158] The

[156] PJM Submission at 46.

[157] Schnitzer Decl. ¶ 77. The Commission also cannot accept PJM's proposal to make RCO resources pay for the "lost opportunity costs" of the "in between" resources that do not receive capacity commitments but which set price at stage 2. PJM Submission at 74-75. *First*, PJM's proposal piles inefficiency on top of inefficiency by forcing non-emitting resources—which properly should be *rewarded* for emissions-free generation—to transfer "lost profits" to emitting resources that are not economic once the cost of pollution is considered, and that should exit the market. Such a forced transfer distorts the resource mix, discourages the retirement of uneconomic emitting resources, increases the cost of state environmental programs, and perversely requires states to pay emitting generators every time they seek to support non-emitting generators. *See* Schnitzer Decl. ¶¶ 78-79. *Second*, PJM's rationale for its cost allocation proposal cannot withstand scrutiny. According to PJM, that allocation of costs is appropriate because the RCO resources somehow *caused* the lost opportunity costs to be incurred. PJM Submission at 74-75; Chao Aff. ¶¶ 17-19. That is wrong. In a world without subsidies, the "in between" resources would clear, and load would pay *both* their costs *and* their infra-marginal rents. Under the Extended RCO, these "in between" resources no longer earn their costs. But they still are paid their infra-marginal rents in the form of lost opportunity costs. Thus, "in between" resources receive infra-marginal rents with or without the Extended RCO, and with or without the presence of RCO resources. RCO resources do not create any *new* RPM costs. Accordingly, cost causation principles do not justify the allocation of these costs to RCO resources.

[158] PJM Submission at 48-50.

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Commission should be clear-eyed about what PJM is proposing: when a resource no longer receives state support and seeks to reenter the RPM auction, PJM seeks a provision that will *prevent* the resource from bidding its going-forward costs. PJM instead wants to raise the resource's bid to include costs that have already been sunk. If the reentering resource consequently fails to clear, and retires, the RPM auction will have selected a resource with *higher* going-forward costs.

Such a provision is inconsistent with the purpose of mitigation, which is to identify the offer level consistent with a unit's *going-forward* costs—not its sunk costs.[159] The true purpose of the reentry provision seems to be to punish customers for electing to withdraw load from the RPM market, and to penalize capital intensive units for supplying capacity as RCO resources, by making it more difficult for these resources to return to the RPM market after they no longer receive state support. Once costs are sunk, there is no justification for mitigating a capacity offer to account for them.

The Commission should instead focus on forward-looking value to the consumer. If the resource seeking to reenter the capacity auction is no longer receiving any out-of-market revenue, then the resource presumably will offer at no lower than its going-forward costs; a below-cost offer, if accepted, could leave the resource operating at a loss. There is no basis for mitigating such an offer, let alone for selecting a different resource with higher going-forward costs.[160]

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[159] *PJM Interconnection, L.L.C.*, 161 FERC ¶ 61,252, at PP 49-51 (2017) (rejecting proposal to extend MOPR from one year to three years as unjust and unreasonable because it would "prevent a developer from accurately reflecting its actual going-forward costs," and explaining that "the one-year application of the MOPR permits a resource to submit a competitive offer price reflecting its going-forward costs that do not include sunk construction costs, after it has cleared and incurred significant construction costs"); *PJM Interconnection, L.L.C.*, 153 FERC ¶ 61,066, at P 77 (2015) ("Construction costs incurred prior to subsequent BRAs are sunk costs; they are not part of its going-forward costs that will affect its future decisions because competitive offers are based on going-forward costs, not sunk costs.").

[160] Schnitzer Decl. ¶¶ 40-42.

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To the extent the Commission is nonetheless concerned about the potential for gamesmanship, where resources might elect the resource-specific FRR for a single year to make major capital investments funded by the state and then reenter the RPM auction after those costs have been sunk, that possibility could theoretically be addressed by imposing a minimum stay-out requirement, such the five-year stay-out required for the existing FRR. From the consumer's perspective, however, even this approach makes little sense. It is a truism that once costs are sunk, they can no longer be avoided. A competitive bid should not account for sunk costs, and the Commission should not artificially inflate a competitive offer to favor marginal units or new entry.

C. Other Proposed Alternatives Should Be Rejected.

Some parties seek to place certain caps on elements of the resource-specific FRR. The Commission should reject these proposals. For example, LS Power proposes to cap the total quantity of resources that can elect the resource-specific FRR to 6 GW.[161] But as discussed above, the Commission has never sought to force load to remain in the PJM auction. Accordingly, the existing FRR has no cap—it allows the withdrawal of all load and places no limitation on how many LSEs can avail themselves of the option. And other auction constructs, such as MISO, allow states to decide what amount of load should be procured through the capacity auction and what amount should be procured outside it. LS Power does not explain why a cap should be imposed if states choose to withdraw *less* than all of their load from the PJM auction, when these other provisions allowing the withdrawal of *all* load are just and reasonable. Moreover, a cap of 6 GW on resource-specific FRR capacity is likely to result in massive oversubscription, to the point that it is likely to be essentially indistinguishable from a MOPR-only approach.[162] Thus, LS Power's

[161] LS Power Init. Br. at 14-18.

[162] Schnitzer Decl. ¶¶ 65-68.

proposal has all the flaws of the MOPR-only approach—including double payment by customers—while failing to offer genuine accommodation to states.

The Illinois Attorney General proposes to cap the price that can be paid to a resource electing the resource-specific FRR.[163] But the Commission should not hamstring states' policy flexibility by dictating that they employ a cost-based procurement mechanism. States may instead wish to adopt other types of procurement mechanisms—for example, a clean capacity auction in which resources of public policy interest would compete for state procurement, and would be paid a single market clearing price; or a competitive procurement for clean capacity in which resources would submit proposals and those selected would be paid consistent with their proposals. If states wish instead to employ a cost-based procurement mechanism, consistent with the Attorney General's proposal, they can of course do so. But the Commission should not limit state flexibility at the outset.

The Illinois Attorney General also makes allegations of economic withholding.[164] Just as in previous capacity auctions in which Exelon's bids were reviewed by the market monitor and the auction results were declared competitive, in the most recent auction Exelon offered its carbon-free nuclear generation at a competitive price based on each plant's costs and risks of operation. Exelon did so in full compliance with all rules governing PJM capacity auctions. As PJM has explained, "The 2021/2022 Base Residual Auction was conducted in accordance with all Tariff-specified requirements and rules, including those rules related to the application of offer caps. The

[163] Initial Br. of the People of the State of Illinois (Oct. 2, 2018) at 14-17.

[164] *Id.* at 8.

PJM Tariff codifying these rules has been approved by FERC as just and reasonable, and as such, the results of the auction conducted according to those rules are also just and reasonable."[165]

Other parties propose different methods altogether for accommodating state policies. None of these is just and reasonable, let alone superior to the resource-specific FRR proposed by the Commission.

For example, Vistra proposes using a modified version of CASPR, the market design approved in ISO-NE.[166] That approach is not just and reasonable for the PJM market. PJM and ISO-NE face significantly different substantive challenges. The core issue in ISO-NE proceeding was state support for the entry of *new* renewable resources.[167] Thus, in New England, a system of transfer payments to induce exit of existing resources to make room for a preferred type of new resources—which would then be freed from any MOPR—might make sense. In PJM, however, the Commission is considering how best to address not only state support for new renewables, but also for *existing* resources that may continue to have going-forward costs. Thus, the transfer payments simply would occur between existing resources. Moreover, requiring such payments would thwart the policy goals that states are trying to achieve, by forcing clean resources to disgorge the state payments they receive to recognize their environmental attributes, and transfer them to polluting assets—a particularly perverse result when the environmental externalities described above are considered.

Moreover, even if the CASPR approach could work for PJM as a matter of mechanics, it does not follow that it would be the right approach for PJM. After all, in the ISO-NE proceeding,

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[165] PJM Interconnection, L.L.C., "PJM Statement on Independent Market Monitor's Analysis of 2021-2022 Base Residual Auction" (Aug. 10, 2018), https://pjm.com/-/media/about-pjm/newsroom/2018-releases/20180810-pjm-statement-on-imm-analysis-of-2021-22-capacity-auction.ashx.

[166] Comments of Vistra Energy Corp. (Oct. 2, 2018) at 13-25.

[167] *ISO New England Inc.*, 162 FERC ¶ 61,205 at PP 4-5 (2018).

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CASPR came to the Commission through a Section 205 filing, and the Commission was obligated to accept it as long as it was just and reasonable. In this proceeding under Section 206, by contrast, the Commission can select the most appropriate option for PJM. And PJM already has a robust and well-established structure for accommodating state policy interests that involves state-directed withdrawal of load: the existing FRR. ISO-NE has no similar framework. Thus, while it may have made sense in ISO-NE to adopt a CASPR structure to accommodate state policy initiatives, the better solution in PJM is to build on what already exists, rather than impose an entirely new structure on top of the existing one. Finally, the Commission, PJM members, and PJM have already spent significant time developing the resource-specific FRR option, and very specific proposals including tariff language have been developed and filed.[168] Even if the Commission believes that the CASPR solution might be a just and reasonable alternative, it can approve the resource-specific FRR in time for the next BRA while sending CASPR to the PJM stakeholder process for further development.

The Maryland PSC proposes a regional procurement of clean energy resources to be conducted by PJM.[169] While a regional approach may serve as a sound starting point, the core elements of this proposal are not clear from the Maryland PSC's filing, and the concept would need further study and development. PJM has already noted that it plans to study the Maryland PSC proposal but cannot implement it in time for the 2019 auction.[170] The Commission should allow that PJM process to unfold and need not rule on the viability of the Maryland PSC proposal

[168] *See* Shared Principles for a Resource-Specific Fixed Resource Requirement, Ex. A to Joint Stakeholders Br.; Proposed Tariff Language, Attach. A to Exelon Init. Br.; Attach. A to PJM Submission (proposing tariff language).

[169] MDPSC Comments at 9-11 & Appendix A.

[170] Letter from Andrew L. Ott to OPSI President Hon. John R. Rosales, Oct. 15, 2018, https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20181017-correspondence-opsi-20181011.ashx?la=en.

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at this stage. But in any event, the proposal could be an addition to, and not a replacement for, a resource-specific FRR. Different states may have a different view about which resource types warrant state support. For example, Maryland may wish to procure offshore wind; Illinois may wish to procure nuclear; and West Virginia may wish to procure coal plants with carbon capture and sequestration. A multi-state procurement overseen by PJM for resources with common attributes would not preclude use of the resource-specific FRR framework for resources of interest to a particular state. Limiting states only to an aggregated procurement of a single type of capacity would be inconsistent with the Commission's apparent intent in proposing the resource-specific FRR to give each state the flexibility to pursue its own policy objectives.

Finally, the Ohio Consumer Counsel argues that an FRR-RS/RCO resource should be excluded from energy and ancillary services markets.[171] FRR-RS/RCO resources will have Capacity Performance obligations in order to ensure that the resource-specific FRR has no adverse impact on reliability or resource adequacy. Consequently, participating resources not only should be eligible to participate in energy and ancillary services markets, but they *must* offer into those markets, just like any other Capacity Performance resource.

D. Exelon Supports Carbon Pricing, But Any Interim Measure Must Accommodate State Policies That Support Non-Emitting Resources.

Exelon strongly supports Eastern Gen's proposal that the Commission incorporate a carbon adder into PJM's dispatch.[172] As Exelon noted in its opening comments, a carbon adder ultimately is the best way to integrate state environmental initiatives into federal market design.[173] States have felt the need to provide out-of-market revenue to compensate the environmental attributes of

[171] Comments by Office of Ohio Consumer's Counsel (Oct. 2, 2018) at 4, 10-12 ("OCC Comments").

[172] Eastern Gen. Init. Br. at 6-9, 12-17.

[173] Exelon Init. Br. at 4, 7.

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zero emissions resources precisely because the federal markets have failed to recognize the full cost of emitting facilities and the full benefits of non-emitting ones. If the federal markets integrated state environmental policy goals by including a carbon adder, that would reduce the need for states to invoke their reserved authority over generation facilities to provide non-emitting resources with compensation outside the market.

A carbon adder enjoys the broad support of stakeholders, including the fossil fuel generators that brought the Complaint initiating this proceeding.[174] To the extent that the Commission is concerned about the interzonal effects of a carbon price—specifically, the impact on states that do not support a carbon price—the Commission can direct PJM to apply a border adjustment similar to the provisions the Commission has approved for the California ISO. PJM would add a constraint to carbon pricing zones that is akin to a reserve constraint, and would then co-optimize states' carbon constraint with the energy market.[175] That approach would integrate states' environmental goals in the wholesale markets, while respecting the reality that different states will have different policies toward carbon pricing.

The Commission has the legal authority to adopt a carbon adder. The Commission need not itself impose a carbon price or decide what price is the right price, although such action might prove expeditious. Rather, states would choose whether, and at what level, to impose a carbon price. The Commission would simply approve tariff provisions that would optimize dispatch in light of those state policy decisions—just as dispatch currently reflects myriad other state policy

[174] *See* Exelon Init. Br. at 7 n.13 (collecting comments supportive of carbon pricing filed in *State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.*, Docket No. AD17-11-000).

[175] PJM Interconnection, L.L.C., Advancing Zero Emissions Objectives through PJM's Energy Markets: A Review of Carbon-Pricing Frameworks (Aug. 23, 2017), https://www.pjm.com/~/media/library/reports-notices/special-reports/20170502-advancing-zero-emission-objectives-through-pjms-energy-markets.ashx.

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decisions. The FPA is designed to facilitate, not forbid, that kind of "interplay between state and federal regulation."[176] Moreover, the FPA gives the Commission authority to take account of environmental factors when regulating wholesale markets. Section 201(a) states that "the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest."[177] While the FPA's main purpose was certainly "to encourage the orderly development of plentiful supplies of electricity … at reasonable prices," the Supreme Court has also recognized that "there are undoubtedly other subsidiary purposes," including "conservation [and] environmental … questions."[178] Likewise, in Section 202(a), Congress authorized the Commission to establish ISOs/RTOs "[f]or the purpose of assuring an abundant supply of electric energy ... with the greatest possible economy *and with regard to the proper utilization and conservation of natural resources*."[179] And, of course, the Commission has wide discretion to consider non-cost factors—such as the integration of state environmental policies—when assessing the justness and reasonableness of rates.[180] The Commission should move expeditiously on this path.

Exelon strongly disagrees with Eastern Gen, however, that a MOPR-only solution is the best approach in the meantime.[181] The state initiatives that the resource-specific FRR is intended to accommodate help to bring the generation mix closer to the result that a carbon price would yield. Using a MOPR to cut off capacity revenue to non-emitting resources, and potentially forcing

[176] *Nw. Cent. Pipeline Corp. v. State Corp. Comm'n of Kansas*, 489 U.S. 493, 518 (1989).

[177] 16 U.S.C. § 824(a).

[178] *NAACP v. FPC*, 425 U.S. 662, 670 & n.6 (1976).

[179] 16 U.S.C. § 824a(a) (emphasis added).

[180] *Pub. Utils. Comm'n of California v. FERC*, 367 F.3d 925, 929 (D.C. Cir. 2004) (Commission "may consider non-cost factors as well as cost factors in setting rates").

[181] Eastern Gen. Init. Br. at 10-12, 17-19.

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those resources into retirement, is nonsensical as an interim measure, when the ultimate goal is to apply market rules that recognize those resources' environmental value—a value that the market currently does not compensate, but should.

To the extent the Commission is seeking a transitional mechanism to a carbon price—which it should—the resource-specific FRR is a just and reasonable transition mechanism. It will allow states to take necessary action to retain existing non-emitting generation that would clear the RPM market if environmental factors were reflected in federal market prices.

III. The Commission Should Reject Calls for a Swiss Cheese MOPR.

The Commission's Order calls for an "expanded MOPR, with few or no exceptions, [to] protect PJM's capacity market from the price suppressive effects of resources receiving out-of-market support by ensuring that such resources are not able to offer below a competitive price."[182] The Commission was correct that the expanded MOPR adopted in conjunction with a resource-specific FRR should be broad and inclusive of all resources that could make offers in the RPM auction freed from competitive discipline by virtue of their receipt of out-of-market revenues. There is no merit to the arguments of commentators who seek exemptions for self-supply resources, resources of less than 20 MW, and resources receiving REC revenue.

A. Self-Supply Resources Should Be Subject to MOPR.

PJM and several commenters urge the Commission to create an exemption for self-supply resources—principally, on the ground that vertically integrated utilities aspire to maintain a generally balanced position and thus "do not have the incentive to suppress prices in the RPM"[183]

[182] Order ¶ 158.

[183] Comments of Dominion Energy Services, Inc. (Oct. 2, 2018) at 3 ("Dominion Comments").

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or engage in "intentional price suppression."[184] But the *whole point* of the Commission's Order is that PJM's MOPR is no longer "limited to deterring the exercise of buyer-side market power"[185] and applies "even [to] resources … not built to exercise buyer-side market power."[186] Instead, the expanded MPR's goal is to "ensure that all resources participating in the capacity market … offer competitively"—meaning, in the Commission's view, without their offers influenced by out-of-market revenue—"regardless of intent."[187]

Self-supply resources controlled by vertically integrated utilities fall squarely within what the Order targets. Such resources do not "offer competitively" into the action.[188] Assured of cost recovery through retail rates, such resources typically offer into the capacity market as price takers—not based on their competitive costs. This guaranteed cost recovery frees these resources from any competitive discipline and allows them to take whatever market price is paid, "protect[ed] from the potential downside of that bidding behavior."[189] Meanwhile, the effect of these noncompetitive offers is huge—much larger than the effect of one plant's participation in the Illinois ZEC program or REC revenues for new renewable projects. Resources with guaranteed cost recovery today comprise almost 20% of PJM's cleared capacity—approximately 30 GW, or

[184] Affidavit of Dr. Kathleen Spees & Dr. Samuel A. Newell at 11 (attached to Dominion Comments) ("Spees & Newell Aff."); Dominion Comments at 10-15; Initial Br. of Pub. Serv. Comm'n of Ky. (Oct. 2, 2018) at 2-3; Initial Submission of American Public Power Association (Oct. 2, 2018), at 5-8; Evidence and Arguments of American Municipal Power, Inc. et al. (Oct. 2, 2018), at 8-27; Initial Submission of Old Dominion Electric Cooperative (Oct. 2, 2018) at 7; Initial Submission of the National Rural Electric Cooperative Association (Oct. 2, 2018) at 2; Initial Comments of E. Kentucky Power Cooperative, Inc. (Oct. 2, 2018) at 6-10; Initial Comments of Am. Electric Power Serv. Corp. (Oct. 2, 2018), at 7-8.

[185] Order at P 5.

[186] *Id.* at P 106; *see also id.* at P 158 (MOPR applies "not just [to] entities exercising buyer-side market power").

[187] *Id.* at PP 156, 162.

[188] *Id.* at P 162.

[189] *Id.*at P 153.

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nearly double the gigawatts that PJM forecasts will be supported by states for environmental reasons in 2025.[190] A self-supply exemption would not be a mere loophole, but rather would amount to the abandonment of the goals set forth in the Order—a capacity market in which all participants are making what the Commission regards as competitive offers, and transparency for consumers and state policymakers regarding the full cost of their regulatory choices.

Advocates of a self-supply exemption cannot wish away these facts with assertions that vertically integrated utilities have "minimal" effects "in the [l]ong [r]un."[191] Even if noncompetitive bids from self-supply entities suppress capacity prices in some years, these advocates say, in other years these entities are likely to be net short capacity and so increase prices.[192] These assurances are unsubstantiated, but more fundamentally they are beside the point. Regardless of whether self-supply entities are net short or net long, they still offer in their self-supply capacity at a price that is undisciplined by any competitive pressure: they know they will make up for any loss through retail rate recovery so are content to take whatever price the PJM market gives.[193] Thus, accepting the logic of the Commission's Order, a self-supply exemption would undermine the competitive integrity of the market and its transparency.

Applying the MOPR to self-supply resources is especially imperative because no significant consideration militates *against* doing so. Advocates for an exemption say an expanded MOPR "threaten[s] to undermine" the longstanding business model of vertically integrated utilities by requiring customers to "pay[] twice for capacity."[194] But there is no such threat: so long as the

[190] Exelon Init. Br. at 19 & n.51.

[191] Dominion Comments at 16.

[192] *Id.* at 17.

[193] *Id.*

[194] *Id.* at 8; Spees & Newell Aff. at 18.

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Commission ensures that the resource-specific FRR alternative is workable and usable, vertically integrated utilities can use it (or the existing FRR) to arrange to serve associated load outside the capacity market in exchange for payments made by retail customers. Customers need not pay twice. Indeed, that model more truly replicates their long-standing business model than one in which capacity supported by retail ratepayers pursuant to state mandate must nevertheless be bid into the RPM market as a price taker, with retail customers then billed for costs net of market revenues. Nor, in any event, does the long history of the vertically integrated business model justify treating it differently. Self-supply resources make offers that, under the Commission's reasoning, are noncompetitive. Their vintage does not justify an exemption.[195]

Alternatively, if the Commission approves an exemption for self-supply resources, that exemption should under no circumstances apply to their net long resources. The purported justification for the self-supply exemption is that the vertically integrated model seeks a "balance of supply and demand."[196] But that justification runs out when self-supply resources sell excess capacity. Indeed, the 1,300 MW safe harbor given to self-supply entities who are net long is the approximately the size of the PJM portion of the Illinois ZEC program. There is no rational basis for concluding that self-supply entities can be permitted to liquidate 1,300 MW of excess supply in the RPM market without any detrimental effect on the market, while at the same time concluding that the Illinois ZEC program threatens the integrity of the market by allowing 1,300 MW of

[195] Indeed, attribute payments are also longstanding: they first emerged in the late 1990s, at the same time the organized energy markets were formed, and prior to the introduction of capacity markets a decade later; and they similarly draw upon the historic power reserved to states to regulate generation facilities. *See generally, e.g.*, Barry Rabe, *Race to the Top: The Expanding Role of U.S. State Renewable Portfolio Standards*, 7 Sustainable Dev. L. & Pol'y 10 (2007); Br. of Amici Curiae Electricity Regulation Scholars, *Village of Old Mill Creek v. Star*, Nos. 17-2433, 17-2445 (cons.), at 10-18 (7th Cir. Nov. 3, 2017); *see also* 16 U.S.C. § 824(b)(1).

[196] Dominion Comments at 5.

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nuclear capacity to offer into the RPM market. Given the Order's concern with "the price suppressive effects" of resources "offer[ing] below a competitive price,"[197] the Commission cannot defensibly allow self-supply entities to liquidate their excess capacity in the market free from any competitive discipline on their bids.

B. The Commission Should Not Exempt Resources of Less Than 20 MW.

PJM proposes to exempt from the MOPR resources smaller than 20 MW of unforced capacity, claiming that the Commission has "previously accepted … different rules based on a 20 MW threshold," and that such resources are "too small, individually or collectively, to meaningfully impact price outcomes."[198] Because the unforced capacity value of renewable resources is typically substantially de-rated compared to nameplate capacity, this exemption will exclude from the MOPR many individual renewable projects of typical sizes—for example, any wind project of less than 150 MW nameplate.[199] PJM's justifications for this broad exemption are nonsensical, and the Commission should reject it.

That the Commission has "previously accepted" a 20 MW threshold—under PURPA, for "govern[ing] interconnection," or even for prior iterations of the MOPR[200]—says nothing about whether to carve this exemption from the expanded MOPR. The Order's purpose in expanding the MOPR is clear and broad—to "ensur[e] that … resources are not able to offer below a competitive price" in the PJM capacity auction, thereby "protect[ing] PJM's capacity market from the price suppressive effects" that result from such offers.[201] It is plainly false to claim that

[197] Order at P 158.

[198] PJM Submission at 15-16; *see also* Comments of Advanced Energy Economy (Oct. 2, 2018), at 18-19 ("AEE Comments"); AWEA Comments at 21-22.

[199] Exelon Init. Br. at 20-21.

[200] *Id.*

[201] Order at P 158.

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resources smaller than 20 MW will not affect clearing prices "individually *or collectively*."[202] One stone, individually, is too small to do much of anything. But collectively, they can build the pyramids or the Great Wall. So, too, with generation. PJM's witness Adam Keech finds that 931 MW of unforced capacity offered by wind and solar facilities came from facilities of 20 MW or less—an amount that will only grow as states expand their commitment to clean energy.[203] That scale is easily comparable to a nuclear plant. Indeed, PJM betrays how far it departs from the Order when it trumpets that "a 20 MW materiality threshold will not significantly impact the participation of renewables in the capacity market"—meaning that this threshold will protect most renewables from the expanded MOPR.[204] The Order's goal was not to protect favored generators from the MOPR. Quite the opposite. It was, again, to expand the MOPR in order to "protect PJM's capacity market" from "resources"—any resources—"receiving out-of-market support."[205]

PJM's 20 MW threshold is especially indefensible because it invites gamesmanship and litigation. With PJM's free pass in hand, a developer who intends to build, say, 60 MW of wind or solar will subdivide its enterprise into three 20 MW "projects." The price suppressive effects will be the same. But the MOPR's application will not be. The only way to *avoid* this irrational result will be to challenge the subdivision—that those three groups of solar panels, or wind turbines, are not *really* different resources but function as one. This will yield pointless litigation over arbitrary distinctions. Further, it creates an administrative incentive for states and others who seek zero-emission capacity to favor certain types of zero-emission resources over others (those

[202] PJM Submission at 18 (emphasis added).

[203] Keech Aff. ¶ 35.

[204] PJM Submission at 17.

[205] Order at P 158.

that can be scaled to 20 MW or less), which hampers the efficient procurement of such resources and dampens innovation.[206] The Commission should reject PJM's unsupported 20 MW threshold.

C. The Commission Should Not Exempt Resources Receiving REC Revenue.

A number of parties contend that resources receiving REC revenues should be exempt from the MOPR because RECs revenues are too unpredictable to drive capacity market bidding or entry decisions.[207] While it is true that REC revenues change over time, that does not mean they are irrelevant to investment decisions. REC programs facilitate the construction and operation of renewable generation by compensating their environmental attributes, and renewable developers (or their off-takers) take forecasted compensation into account when deciding whether to pursue a project. States require customers to spend hundreds of millions of dollars a year on the premise that these expenditures are needed in order to promote the growth of renewable generation. Either these states are wasting their money and REC programs should be ended, or these programs do indeed have their intended effect and induce renewable entry that would not otherwise occur. And if the latter, then under the Commission's view of the MOPR's purpose, the MOPR should plainly apply. Anticipated REC revenues enable new renewable resources to offer into the capacity market at levels below their cost.

Some parties also argue that there should at least be an exemption for renewable resources that sell their RECs in a competitive procurement.[208] That makes no sense. A competitive REC procurement only means that less costly renewable resources are selected over more costly ones; but the less costly resources still receive out-of-market revenue by virtue of the procurement, and thus are able to offer at a lower level in the capacity market than they otherwise would be able to

[206] Schnitzer Decl. ¶¶ 43-44.

[207] *E.g.*, AEE Comments at 11-14; AWEA Comments at 13-17.

[208] *E.g.*, AEE Comments at 22-23; AWEA Comments at 20-21.

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do. The Commission has stated that an "expanded MOPR … should protect PJM's capacity market from the price suppressive effects of resource receiving out-of-market support *by ensuring that such resources are not able to offer below a competitive price*."[209] If that is the rationale for a MOPR, then the MOPR should apply to renewable resources that participate in a competitive REC procurement just as surely as it should apply to any other resource that receives out-of-market revenue and can use that revenue to reduce its capacity market offer.[210]

D. Other Exemptions Should Be Rejected.

Some parties argue that demand response and energy efficiency resources should be exempted from the MOPR.[211] Again, there is no basis for an exception given the Commission's articulation of why it is imposing a MOPR. If resources of any kind receive state-sponsored out-of-market revenue that allows them to offer at less than the level that the Commission deems competitive, then those resources should be subject to a MOPR.

Finally, the Ohio Consumers Counsel argues that a partial FRR-RS resource should be subject to unit-specific review with respect to the portion of the unit participating in RPM.[212] Existing PJM rules concerning mitigation and the FRR already adequately address how to treat a unit with multiple owners, each of which submits its own bid for its share of the unit.[213] There is

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[209] Order at P 158 (emphasis added).

[210] AES suggests what it terms a "proportional MOPR" as well as a 15% materiality threshold. See Comments of AES Corp. (Oct. 2, 2017) at 12-19 ("AES Comments"). It is not exactly clear how the "proportional MOPR" would work—AES's example notwithstanding—and a 15 percent materiality standard is high enough to allow offers that are substantially below cost. As we have demonstrated (*see* Exelon Init. Br. 17-21)—and contrary to AES's statement that "[a]ll subsidies are not equal," AES Comments at 2—all subsidies have the same market impact and can impact the owner's offer strategy. In recognition of this, the Commission proposed a MOPR with "few or no exceptions" for good reason. Order at P 158. If it is going to adopt a MOPR at all, it should stick to that proposal.

[211] *E.g.*, AEE Comments at 20-22; MDPSC Comments at 11-12.

[212] OCC Comments at 20-22.

[213] *See* PJM Manual 18, § 5.4.4.

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no reason for the Commission to adopt different rules to govern the resource-specific FRR, or to rethink the rules that already exist. If the portion of the unit participating in the RPM market is not receiving any subsidy, it should not be subject to a MOPR—regardless whether a different portion of the unit under separate ownership receives a subsidy or is participating in the resource-specific FRR.

CONCLUSION

For the foregoing reasons, the Commission should adopt a Resource-Specific FRR Alternative.

Dated: November 6, 2018

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 6th day of November, 2018.

/s/ *Marianne Alvarez*

_____

Marianne Alvarez
Exelon Corporation

EXHIBIT A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. EL18-178-000**
PJM Interconnection, L.L.C.	)	**ER18-1314-000**
	)	**ER18-1314-001**
Calpine Corporation, et al.,	)	**EL16-49-000**
Complainants,	)	**(Consolidated)**
v.	)	
PJM Interconnection, L.L.C.,	)	
Respondent.	)	

DECLARATION OF MICHAEL M. SCHNITZER

November 6, 2018

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I. QUALIFICATIONS, ASSIGNMENT AND SUMMARY OF CONCLUSIONS

A. QUALIFICATIONS

1. My name is Michael M. Schnitzer. I am a director of The NorthBridge Group, Inc ("NorthBridge"). NorthBridge is a consulting firm that provides economic and strategic advice to the electric and natural gas industries. My business address is 30 Monument Square, Concord MA 01742.

2. In 1992, I co-founded NorthBridge. Before that, I was a Managing Director of Putnam, Hayes & Bartlett, which I joined in 1979. I have experience working with private sector clients in the electric utility, natural gas, and private power industries, as well as with public and nonprofit agencies. My electric industry work has focused on regulatory policy, finance, and market structure issues. I received an A.B. in chemistry, with honors, from Harvard University, and an M.S. in management from the Sloan School, Massachusetts Institute of Technology.

3. I have testified before the Commission on many matters and have participated in Commission technical conferences and workshops on capacity market and energy market design issues. I have also testified before the public utility commissions of Arkansas, California, Delaware, Illinois, Indiana, Louisiana, Maine, Maryland, Massachusetts, Mississippi, Missouri, New Hampshire, New Mexico, New Orleans, New York, Ohio, Pennsylvania, Rhode Island, Texas, Vermont, and Wisconsin.

B. BACKGROUND AND PURPOSE OF TESTIMONY

4. On April 9, 2018, PJM Interconnection, LLC ("PJM") filed at the Federal Energy Regulatory Commission ("FERC" or "Commission") two proposals to modify its capacity market design.[1] In its filing, PJM requested that the Commission approve its preferred capacity market repricing proposal (referred to as "Capacity Repricing" or "Option A"), or if the Commission cannot approve PJM's preferred proposal, that it approve in the alternative PJM's MOPR-Ex proposal (referred to as "Option B").

[1] PJM Interconnection, L.L.C., Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, FERC Docket No. ER18-1314-000, April 9, 2018.

5. I filed a reply declaration in response to PJM's proposal that concluded that both the Capacity Repricing and MOPR-Ex proposals produced outcomes that were less efficient than the status quo and that social surplus is maximized by allowing states to support environmentally beneficial resources via attribute payments with no further mitigation of the resources' offers in the capacity market.[2]

6. On June 29, 2018, the Commission issued an Order[3] in this proceeding rejecting both of PJM's proposed capacity market design modifications and finding the current capacity market design to be unjust and unreasonable. The Commission proposed an alternative conceptual design for the capacity market that would combine an expanded Minimum Offer Price Rule ("Expanded MOPR") with a Resource Specific Fixed Resource Requirement ("FRR-RS") alternative. The Commission requested comments on the specific design elements of both of these components to its proposal.

7. Numerous parties, including PJM, the Independent Market Monitor for PJM ("IMM") and many market participants and other stakeholders filed initial comments on or around October 2nd, 2018. In its comments, PJM advanced both a base proposal for modifications to the capacity market responsive to the Order ("Base Proposal") and an optional "Extended RCO" proposal.[4] PJM's Base Proposal combined an expansion of its Minimum Offer Price Rule ("MOPR") to cover both existing and new resources and all technology types, with a Resource Carve Out Option ("RCO") that is generally consistent with the Commission's FRR-RS concept, which allows state-supported resources to remove themselves from the capacity market along with a matched quantity of load. Because these state-supported resources do not participate in the capacity market or receive any capacity market payments, compensation for their capacity must come from outside the market. The Extended RCO includes the Base Proposal but adds an additional step whereby market clearing prices are adjusted by removing the RCO resources from the supply curve while leaving their matched load in the market. In addition to PJM's proposals, the IMM and many other parties also advanced various proposals, many of which advocated for a design that included only an expanded MOPR, without a workable FRR-RS.

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[2] Declaration of Michael M. Schnitzer, Docket Nos. ER18-1314-000 and ER18-1314-001, May 22, 2018.

[3] *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236 (2018) ("Order").

[4] Initial Submission of PJM Interconnection, October 2, 2018 ("PJM Comments").

8. Exelon Corporation filed initial comments[5] on October 2, 2018 that included a proposal ("Exelon's Proposal") to combine a MOPR with minimal exceptions with an FRR-RS option, consistent with the Commission's Order. Exelon's Proposal is similar to PJM's Base Proposal in many ways but differs in that it has proposes fewer exemptions to the MOPR, does not adjust prices as in PJM's Extended RCO, and does not apply the MOPR to former FRR-RS resources seeking to re-enter the RPM.

9. The purpose of my testimony is to evaluate the market designs proposed by PJM, Exelon, and certain other parties in this proceeding with respect to their economic efficiency, impact on consumers, and workability.

C. SUMMARY OF CONCLUSIONS

10. My conclusions are as follows:

11. The Order reached two clear conclusions. First, the Commission identified a need to remove from the PJM capacity market the impact of resources receiving out-of- market support by ensuring that such resources are not able to offer below the Commission's view of a competitive price in the RPM auction.[6] To address this concern, the Commission proposed an Expanded MOPR with few or no exceptions. Second, the Commission recognized that it is necessary to respect states' rights to pursue valid policy goals concerning the generation mix, while at the same time avoiding potential uneconomic outcomes such as resource double payment and over procurement. The FRR-RS alternative option proposed by the Commission to accompany the Expanded MOPR accomplishes this goal by allowing resources receiving out-of-market state support to elect to remove themselves from the capacity market with a commensurate amount of load and planning reserves. Any design for the PJM resource adequacy construct developed in response to the Order must adhere to the core concepts of the Order in its entirety. That is, any design must combine both an Expanded MOPR and a workable FRR-RS option. This combination will ensure that resources receiving out-of-market support are not able to offer below the

[5] Initial Brief of Exelon Corporation, Oct 2, 2018 ("Exelon Comments").

[6] As I discuss further in my Declaration, the offers from resources receiving out-of-market compensation designed to compensate for positive environmental externalities, which comprise all current and likely most future resources subject to PJM's proposal, are competitive under the current status quo to the extent that the size of the payment is set at or below the value of the positive externality produced by the resource in question. The Commission's Order, however, takes the view that offers from such resources are not competitive.

Commission's view of a competitive price in the RPM auction while at the same time accommodating state policy goals. The combined construct thus achieves the Commission's twin goals of maintaining competitive pricing in the RPM and respecting state's rights to exert control over their generation mix while providing a higher level of economic efficiency than an option that does not include a strong and workable FRR-RS.

12. Leaving aside a price on carbon, which most parties agree is the most efficient means of appropriately valuing environmental externalities, of all the proposals offered by parties in response to the Order, other than Exelon's Proposal, PJM's Base Proposal (as distinct from their "Extended RCO" proposal) is the most economically efficient, and the least-costly for consumers. While Exelon's Proposal and PJM's Base Proposal are similar in most respects, there are certain aspects of PJM's Base Proposal that make it less efficient than Exelon's, but which could easily be modified to make PJM's Base Proposal equivalent in terms of efficiency. Furthermore, unlike certain other proposals, PJM's Base Proposal adheres to both the letter and spirit of the Order. PJM's Base Proposal combines a revised and expanded MOPR with a RCO option that allows resources supported by states seeking to support specific types of generation resources in pursuit of state goals to elect to remove themselves from the capacity market, along with a matched quantity of load, and receive capacity compensation outside of the capacity market mechanism while still having their capacity counted for resource adequacy purposes. The RCO, with a fix to the resource re-entry provision, provides a workable implementation of the Commission's FRR-RS concept for states seeking to support zero-emission resources in pursuit of environmental goals to continue to do so without undue disruption or cost, consistent with the Order. Further, with a modification to the re-entry provision, this approach is the most economically-efficient because state programs that provide appropriately-priced attribute payments to environmentally-valuable resources make the market more efficient, rather than less efficient, as these resources are economic when their environmental attributes are properly valued. Forcing such units to offer into the capacity market at an artificial higher price due to the application of a strict MOPR is inefficient. Proposals which lack a reasonable FRR-RS pathway will result in those resources being inserted into the capacity market at an inefficiently high offer level and will result in inefficient outcomes both with respect to price and the portfolio of resources selected to receive a capacity obligation. PJM's Base Proposal avoids this inefficiency by providing a viable alternative pathway via the RCO for such resources to avoid capacity market participation at an inefficient

offer level and instead have their contribution to resource adequacy be recognized and compensated by their supporting state. Because of this, PJM's Base Proposal does not result in a significant degradation in economic efficiency relative to the status quo, avoids unnecessary price inflation, and results in an economically-efficient portfolio of capacity resources.

13. Exelon's Proposal is very similar to PJM's Base Proposal but differs in several respects which make it incrementally more efficient than PJM's Base Proposal. In particular, Exelon's Proposal includes more efficient, workable rules for re-entry of former FRR-RS or RCO resources into the RPM and avoids the arbitrary and unnecessary exemption of resources from the MOPR due to PJM's proposed size-based materiality threshold. These issues could be easily fixed in PJM's Base Proposal and if they are PJM's Base Proposal would have similar efficiency to Exelon's.

14. A number of parties in the proceeding have offered proposals that are very similar to PJM's original MOPR-Ex proposal in that they include an expanded MOPR, but do not include a workable RCO or similar FRR-RS mechanism. Such proposals hinder state policy goals and produce economically inefficient outcomes. They unnecessarily inflate market prices to an inefficient level by forcing resources with environmental attributes that would otherwise elect the RCO to instead offer into the capacity market at an inefficiently high "MOPR Floor" level. In the event that states continue to support these resources for policy reasons, such an approach results in over procurement and unnecessary costs borne by consumers. Conversely, if such an approach deters or causes states to abandon the support of resources chosen for environmental policy reasons, economically-valuable low or zero emission resources will exit the market, resulting in an overall loss of social surplus. Neither outcome is desirable, and both are less efficient than a policy that includes a workable pathway, such as the RCO, for state-supported resources to exit the RPM while still having their contribution to resource adequacy recognized and credited to the states that choose to support them. I estimate that the overall incremental cost to consumers in Eastern MAAC of a MOPR-only approach relative to PJM's Base Proposal would have been approximately $700 million annually (or a 37% increase in capacity costs) based on PJM's most recent RPM Base Residual Auction ("BRA") and the existing resources that are likely to be subject to MOPR in the near-term based on PJM's proposal. Further, due to the ripple effects on the larger market, customers in the broader RTO outside of Eastern MAAC would see their costs rise by over $200 million annually, resulting in a total incremental cost to consumers of over $900 million per

year. Other alternatives which have been proposed which artificially limit the FRR-RS or RCO option, such as reliance only on the existing "full" FRR mechanism in the PJM tariff, or a cap on the overall quantity of resources that may elect the RCO option, are not workable and produce inefficiencies similar to having no RCO at all.

15. PJM's Extended RCO proposal, which adds an RPM capacity re-pricing element to its Base Proposal, is economically inefficient, potentially greatly inflates prices for consumers, and impedes a states' pursuit of efficiency enhancing environmental programs by inappropriately "taxing" RCO resources with a portion of inefficient cost increases unnecessarily created by the proposal. The Extended RCO adds a "re-pricing" step after resources are selected in the RPM that removes the RCO resources from the price formation mechanism without any commensurate reduction in load, with the potential to result in prices even higher than if the RCO resources were subject to a MOPR. This re-pricing is inappropriate because the efficient price for RCO resources supported for environmental reasons is their unadjusted status quo offer price, and any approach that implicitly inflates their offers above this level – as PJM's Extended RCO proposal does -- will result in inefficient and unnecessarily inflated market prices. Further, removing the RCO resources from the supply curve entirely has the potential to inflate prices even further above the efficient level, particularly in constrained regions. I estimate that the overall incremental cost to consumers in Eastern MAAC of PJM's Extended RCO proposal would be approximately $2.2 billion annually (or roughly a 100% increase in capacity costs) based on PJM's most recent BRA and assuming about 3.7 GW of existing resources elect RCO in the near-term. Further, customers outside EMAAC would see their costs rise by over $400 million annually due to the ripple effect on the RTO supply curve, resulting in an overall incremental cost to consumers of $2.6 billion annually. Finally, the Extended RCO proposal includes a provision to pay "infra-marginal rent" payments to resources that do not clear the RPM but whose offers fall below the clearing price determined in the re-pricing step. PJM proposes to allocate the cost of these payments to the RCO resources because PJM claims that they are the cause of the need for the re-pricing step and thus the cause of the market inefficiencies that the re-pricing step corrects. This cost allocation approach is economically-backwards because the RCO resources reduce, rather than increase, market inefficiency because they partially correct for the lack of a carbon price in the current market.

16. At their core, PJM's Extended RCO proposal and the various MOPR-only proposals all ask the Commission to implicitly conclude that all retention/entry associated with state-

sponsored resources is uneconomic. The assumption of uneconomic retention/entry is the only thing that might justify either approach. That proposed implicit conclusion stands in stark contrast to the Commission's expressed intent to accommodate state interests, and to the undeniable state jurisdiction over resource planning, should it choose to assert it. It also flies in the face of the evidence offered here that the state-sponsored resources comprise, in the main, economic entry/retention when environmental attributes are taken into account. This core failing is the primary reason that both proposals produce such economically inefficient outcomes with unnecessary price inflation and violate the intent of the Commission's Order. For this reason, the Commission should reject all the proposals that fall in these categories.

II. AFTER THE EXELON PROPOSAL, PJM'S BASE PROPOSAL, WITHOUT THE "EXTENDED RCO," IS THE MOST ECONOMICALLY-EFFICIENT AND LEAST COSTLY SOLUTION THAT IS CONSISTENT WITH THE COMMISSION'S ORDER

A. PJM'S BASE PROPOSAL IS GENERALLY CONSISTENT WITH THE COMMISSION'S ORDER

17. The Commission very clearly identified in its Order its view that there is a need to remove resources receiving out-of-market support from the PJM capacity market or to apply the MOPR to their offers, and that the current construct is both unjust and unreasonable because it fails to do this. As such, the current status quo for the PJM RPM auction has been rejected by the Commission and the structure must be adjusted to account for this finding

18. The Commission's solution to this issue is very specific. It recommends the implementation of an expanded MOPR for all resources, existing and new, bidding into the PJM capacity market that receive material out-of-market state (and going-forward, potentially federal) subsidies.

19. However, the Commission also had a very clear second conclusion. The Commission found it necessary to "accommodate resources that receive out-of-market support," thereby respecting a state's right to pursue valid policy goals concerning generation mix and "mitigating or avoiding the potential for double payment and over procurement."

20. To ensure the accommodation of these resources without over procurement, the Commission proposed a FRR-RS option. Such a structure would accommodate the resources

receiving out-of-market payments by allowing them to stay on the system despite their inability to compete in the capacity market as currently designed based on their costs. In coming to this conclusion, the Commission demonstrated an understanding that there is merit in the state support programs that are at issue and that the changes that PJM will make to its capacity market should not be biased against the resources receiving these supports.

21. The Order's two recommended policies are clearly meant to work in concert. Solutions that only include one but not the other, or that implement one of the policies in a flawed or unworkable manner are not consistent with the intent and underlying economic logic of the Order. With a few fixes, PJM's Base Proposal implements each of the Commission's recommended policies in a workable and effective manner.

22. First, PJM proposes an expanded MOPR that covers both new and existing resources and all technology types. PJM's MOPR design re-sets the offers from affected resources to a technology- or resource-specific competitive proxy offer price (the "MOPR Floor Price") that excludes the impact of any out-of-market payments. Consistent with the Commission's intent, this design thus removes the impact of subsidy-affected bids from the market clearing outcome. For those resources that remain in the RPM auction under PJM's Base Proposal, all bids will reflect the full costs of these resources with no impact of identified subsidies. However, through its proposed size-based materiality threshold, PJM provides what amounts to a de-facto exemption for most existing and new renewable resources. As I will discuss later, this size exemption produces uneconomic incentives and should be eliminated.

23. Second, PJM proposes a RCO that addresses the Commission's recommendation for an FRR-RS option. The RCO provides resources receiving state environmental attribute payments with a pathway whereby they can receive compensation outside the capacity market for both their capacity and their environmental attributes.

24. As proposed by PJM, the RCO is generally workable for both the resources in question and their sponsoring states, in that it has reasonable rules for election of the RCO option, matching of load and resources, and for payment and billing of the cost of RCO resources. PJM's proposed rules for re-entry of RCO resources back into the market are not workable or efficient, but, as I discuss later, can easily be modified to eliminate these problems in a manner consistent with Exelon's Proposal.

25. The RCO is also workable and efficient from the perspective of reliability in that 1) PJM ensures that all locational constraints are respected by the market as a whole, and that the cost of any binding transfer limits is appropriately allocated among load serving entities , and 2) PJM's proposed mechanics for treatment of RCO resources within the larger market clearing algorithm ensures that loads matched to RCO resources are effectively assigned a share of responsibility for the overall realized PJM reserve margin.

B. OTHER THAN EXELON'S PROPOSAL, PJM'S BASE PROPOSAL IS THE MOST ECONOMICALLY EFFICIENT OPTION

26. As far as I am able to determine, all of the current "actionable subsidies" that would result in existing resources being targeted for MOPR treatment under PJM's proposal are forms of compensation for the positive environmental attributes associated with these resources. These take the form of Zero-Emission Credits ("ZECs") for nuclear resources, Renewable Energy Credits ("RECs") for renewable resources of various types, and in some cases long-term bundled contracts for specific renewable resources. All of these resources are distinguished by producing energy with zero or very low emissions. States value the environmental attributes of these resources, but the PJM power markets do not value environmental attributes,[7] and state-level tax or cap and trade programs would not be nearly as effective or efficient.

27. As I discuss below, if these resources elect the RCO under PJM's Base Proposal, their resulting treatment in PJM's overall market-clearing algorithm in the RPM is economically efficient and least cost for consumers and the market as a whole, once all public and private costs are considered. And, contrary to the contention of many parties in this proceeding, the resulting market prices are not "suppressed" nor are "economic" resources excluded from the market. The reason for this is that the "actionable subsidies" in question are all intended, in varying formats, to correct distortions caused by the failure of current PJM markets to price negative externalities associated with carbon emissions. By correcting this distortion, at least for the resources in question, these state programs enhance, rather than impede market efficiency, and by allowing a

[7] Two PJM states (Delaware and Maryland) plus the District of Columbia participate in the Regional Greenhouse Gas Initiative ("RGGI") that does place a price on carbon for generation located within these states. However, the RGGI carbon price, at about $5 per ton, is about 10% of the Social Cost of Carbon, and is thus far too low to accomplish a socially-optimal level of carbon reduction. Furthermore, RGGI's carbon reduction efforts, particularly in the PJM states, have been greatly limited by leakage of carbon emissions from neighboring non-RGGI states. These concerns have been a significant factor in constraining RGGI to a relatively low carbon price.

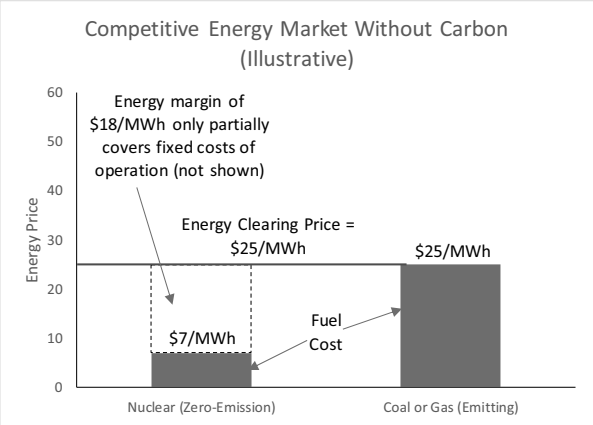
pathway for states to pursue these programs without being subject to potentially costly and inefficient MOPR treatment, the RCO thus enhances overall market efficiency relative to a MOPR-only solution.

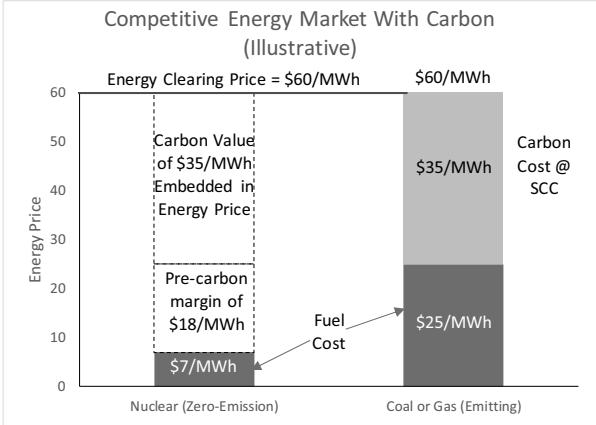
28. Many commenters[8] in this proceeding agree that the most economically efficient means of valuing carbon emissions attributes within PJM markets would be to institute a market-wide carbon price. A carbon price, assuming it is set at the economic cost it imposes on society, or the Social Cost of Carbon ("SCC"),[9] values emission attributes by aligning the public and private cost of carbon-emitting generators through the addition of a carbon charge, based on a market-wide carbon price and resource-specific emissions, to offers to sell energy into the market. Through this mechanism, emitting generators are charged for the social cost of the negative carbon pollution externality that they create when the produce energy. Because of this additional variable cost, in a competitive single-price clearing energy market such as PJM, the price of energy will rise by the amount of the carbon cost embedded in the energy offer of the marginal resource, which will generally be a carbon-emitting natural gas or coal unit under most conditions. Under a carbon price, zero-emission resources need not be paid directly for their zero-emission attribute, but rather benefit from the increase in energy price while avoiding any incremental carbon charge due to their low-emission profile. The incremental benefit per Megawatt hour of energy produced for a zero-carbon resource will generally be approximated by the carbon price multiplied by the average marginal emission rate in the market (in tons of carbon per MWh). Figure 1 below illustrates how a carbon price affects both zero-emission and emitting resources in a centralized competitive energy market such as PJM:

[8] Commenters who have agreed that a carbon price is the most efficient solution include PJM (Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, Docket No. ER18-1314-000, April 9, 2018, at 54-55), the IMM (Comments of the Independent Market Monitor for PJM, Docket No. ER18-1314-000, May 7, 2018, at 10), and Eastern Generation (Initial Brief of Eastern Generation, LLC, Oct 2, 2018). See also Initial Brief of Exelon Corp. (Oct. 2, 2018) at 7 n.13 (collecting citations to comments supportive of carbon pricing).

[9] Those states that have sought to pursue environmental policies that explicitly value emission attributes, such as the nuclear support payments in Illinois, New Jersey, and New York have chosen zero-emission attribute compensation levels that are consistent with the estimate of the Social Cost of Carbon developed by the U.S. Government as of August 2016 which is approximately $51.50 per short ton in nominal terms for the 2022/23 PJM power year (*See* U.S. Government Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, August 2016). The U.S. Government has withdrawn this estimate and is currently utilizing a lower interim estimate. However, because it has generally been adopted by the relevant states in this context the August 2016 estimate of the SCC is the most relevant yardstick for valuing and evaluating the economics of the policies in question.

Figure 1





29. As Figure 1 shows, the incremental value that accrues to a zero-emission resource under a carbon price is approximately equal to the incremental cost of carbon emissions associated with the marginal resource. In the example, the increase in the marginal cost of the emitting resource is $35 per MWh, and the incremental energy price gain for the zero-emitting nuclear resource is thus also $35 per MWh. While under a carbon pricing framework this value is achieved by pricing the negative externality of carbon emissions, in the absence of a carbon price, an identical valuation of the resource's zero-emission attribute can be achieved by providing out-of-market compensation set at the SCC times the estimated marginal emission rate for the market for each MWh of zero-emission generation output. In the example in Figure 1, this could be achieved by paying the nuclear unit an attribute payment of $35 for each MWh generated. This mode of compensation values zero-emission attributes as a positive externality associated with the avoidance of emissions driven by each MWh of zero-emission output. Thus, to the extent a resource that is uneconomic in the current market is made economic by the attribute payment, it will enter or remain in the market when it would not otherwise have done so, and overall social costs are reduced when all public and private costs are considered, including the cost of carbon emissions. In the absence of a carbon price, this is the approach taken by states seeking to achieve environmental goals.

30. The environmental attribute payment approach is not as efficient as a true carbon price because it only values the positive externality associated with zero-carbon generation, and thus does not distinguish between different types of emitting generation (e.g. between natural gas and coal) and other types of emission reductions (such as demand-side reductions) that may not be covered by the attribute payments. Relative to a baseline of doing nothing, however, such

compensation enhances efficiency and lowers costs for consumers once the public costs of carbon emissions are considered because it enables the retention and entry of economic zero-carbon resources that would not otherwise occur.

31. If a PJM-wide carbon price were implemented there is no disagreement that the capacity offer price for a zero-emission resource should include the incremental value of the zero-emission attribute, because, as discussed above, in the case of a carbon price this value is embedded in energy revenues, which all commenters agree is an in-market revenue source, and not an out-of-market subsidy. Thus, relative to the no-carbon status quo in PJM markets today, the capacity market offers of these resources would be reduced by the incremental value of the zero-carbon attribute embedded in the energy price. In the case of the nuclear resource shown in the example in Figure 1, if we assume it has a gross Avoidable Cost Rate ("ACR") of $593 per MW-day (the technology-class gross ACR PJM proposes for existing dual-unit nuclear plants), under the current market structure, its offsetting energy net revenues of $18 per MWh would reduce its offer by roughly $400 per MW-day, leading to a status quo offer of $193 per MW-day without any state support. If the energy price were to rise by $35 per MWh due to carbon it would receive additional offsetting energy revenue of about $775 per MW-day, which is more than sufficient to drive its resulting competitive capacity offer to zero. This capacity offer price is economically efficient and competitive. It follows from this that the resulting market-clearing outcome incorporating these offer prices is also economically-efficient both with respect to price and the quantity and identity of resources that are cleared.

32. Compensating zero-carbon resources via an attribute payment is economically equivalent to a carbon price from the perspective of those resources. In the case of the nuclear resource in the example in Figure 1, an attribute payment of $35 per MWh would be equivalent to a carbon price at the SCC. However, because those payments are received outside of PJM markets, they are not included in energy revenues. Economically, however, this distinction does not matter. If the attribute compensation is at or below the SCC, it enhances economic efficiency and its inclusion in the formation of a capacity offer price for the resource results in an economically-efficient offer price that is essentially equivalent to how those resources would have offered in the presence of a market-wide carbon price, and will generally result in low or zero price offers from most of the resources in question. For example, based on PJM's proposed default ACRs, the capacity offer for an existing dual-unit nuclear plant with a carbon price of $15 per ton would be

zero.[10] Just as it would be under a carbon price, the market-clearing outcome that results from such offers is economically-efficient both with respect to price and resource selection. Contrary to suggestions from various witnesses in this proceeding, this outcome does not represent "price suppression" but rather produces the correct and efficient price. The capacity price that results when zero-emission resources reflect the value of attribute payments in their offers can be viewed as the price for unbundled, environmentally-agnostic capacity whereby the offers for differentially environmentally-valuable resources are effectively adjusted downward (through inclusion of the attribute payment value in their offers) to reflect their enhanced value relative to dirtier resources. Whatever price emerges from the resulting auction represents this unbundled value of environmentally-agnostic capacity, and all resources, zero-emission or otherwise, that are able to provide it at that price or below realize a profit from the auction. To the extent that more such capacity is needed, the relatively low barriers to entry for new entrants in PJM combined with the sloped capacity demand curve ensure that the price will rise as needed to meet the need.

33. While these difficulties could be resolved by implementing a market-wide carbon price as Exelon and other commenters have urged the Commission to consider,[11] in the present market a carbon price is not a viable option for a single state acting alone. While it is feasible to implement a state-specific carbon price, its effectiveness in both reducing emissions and providing the desired price signals would be greatly hampered by emission leakage to other states that lack carbon price both within and external to the PJM footprint. The attribute payment approach, while it does not impact as broad a spectrum of emission-affecting activities as a carbon price, does not suffer from leakage issues and is thus the only realistic means by which PJM states in the current market can efficiently achieve emission reduction goals.

34. With a couple of minor exceptions, the attribute compensation that PJM states pay to zero-carbon resources is at or below the SCC. The SCC for 2022/23 is approximately $51.50 per short ton, which translates into a value of approximately $35 of avoided emission costs per MWh

[10] PJM proposes a generic technology-specific gross ACRs for existing dual-unit nuclear resources of $593 per MW-day (in ICAP terms) for the 2022/23 auction and provides an estimate of new nuclear unit energy and ancillary services revenues of $366 per MW-day, leading to a competitive offer price of $227 per MW-day for an existing nuclear resource without a carbon (gross ACR less energy and ancillary revenues). A carbon price of $15/ton translates into incremental energy value of about $10.35/MWh assuming a 0.69 tons per MWh marginal emission rate, which further translates into incremental energy revenues of $228/MW-day for a nuclear resource operating at a 92% capacity factor, which would be sufficient to drive the competitive offer price to zero.

[11] Exelon comments at 7, Initial Brief of Eastern Generation, LLC, Oct 2, 2018 at 6.

of zero-emission generation on the PJM system, assuming a marginal emission rate of 0.69 tons per MWh. The ZEC payments to nuclear resources in Illinois and New Jersey, which are calibrated explicitly based on the SCC, both fall below this level. Similarly, RECs for wind and solar in most PJM states range between $5 and $10 per MWh,[12] also well below the SCC. Even if these REC payments are added to the $9.3 per MWh[13] value from the 40% Production Tax Credit payments for which most wind resources entering the market in 2022/23 are eligible, the total payments are less than the SCC. Thus, the payments made by states for zero-emission attributes are generally economically efficient in practice because they pay at or below the economic value of the attribute to society as a whole.

35. MOPR treatment for resources receiving environmental attribute compensation, however, is clearly inefficient, because it removes the attribute payment credit against the ACR for the resource in question and re-sets its offer to a higher MOPR floor price that does not include any consideration of the value of the zero-carbon attribute. This higher offer price ignores the value of the public benefits of emission avoidance produced by the resource and is thus economically inefficient and too high. If PJM's proposed expanded MOPR were applied to these resources absent an RCO option, it risks producing a market clearing outcome with inefficient, unnecessarily high market prices and a cleared resource portfolio that excludes zero-emission resources that are economic when the value of their emission avoidance is considered.

36. The outcome whereby resources receiving environmental attribute payments reflect those payments in their offers without modification is broadly consistent with the current status quo in PJM. I have previously argued that the status quo is the most economically-efficient outcome with respect to the treatment of environmental attribute payments. While the Commission's Order finds that the status quo is not just and reasonable, it is nonetheless the case that any implementation of the Commission's order that achieves an economic outcome close or

[12] *See* Platt's Megawatt Daily, Oct 25 2018, at 10. Listing competitive REC market prices of $5.50/REC for MD Tier I, $5.75/REC for NJ Tier I, $5.00/REC for OH Tier I, and $5.75/REC for PA Tier I, along with $7.00/SREC for MD Solar RECs, $6.50/SREC for OH Solar RECs and $13.25/SREC for PA Solar RECs. New Jersey solar RECs are much higher due to market structure differences.

[13] $9.6 per MWH production tax credit for 10-years (40% of the full $24/MWh value) translates to a levelized pre-tax value of $9.3 per MWH assuming a 20% tax rate, 20-year life, and 2% inflation

identical to the status quo with respect to its treatment of resources supported for environmental reasons will be more economically-efficient than an implementation that does not.

37. The FRR-RS and for the most part, the RCO, allow resources receiving environmental attribute payments a pathway whereby they can receive compensation outside the capacity market for both their capacity and their environmental attributes and also, by removing them from the market, avoids inserting them into the capacity market at an inefficient offer level that fails to consider the value of their attributes and thus inefficiently raises market prices. Indeed, PJM's proposed mechanical implementation of the RCO for the purposes of price formation, which enters the RCO resources into the supply curve as price takers while leaving the demand curves unchanged, is very similar to how these resources would offer and markets would clear under the status quo. Many commenters have pointed out this feature of the RCO. While some commenters claim this feature makes the RCO "price suppressive" and not workable,[14] the opposite is true. Rather, to the extent that resources receiving environmental payments elect the RCO, PJM's approach treats them in the most efficient manner that is possible consistent with the Commission's Order. Any approach that results in higher prices and/or non-selection of the resources in question needlessly raises prices for consumers and potentially deprives the market of environmentally-valuable resources. Thus, of the various proposed implementations of the FRR-RS component of Commission's order, only the Exelon's Proposal and the PJM's Base Proposal with the RCO (with certain fixes discussed in the next section) avoids degradation in market efficiency relative to the status quo.

38. As I will discuss later, however, this conclusion only applies to the PJM's Base Proposal, and not the "Extended RCO" option, which the Commission should reject. The Extended RCO essentially bolts on a revised version of PJM's capacity re-pricing proposal to PJM's Base Proposal which reduces the efficiency of the RCO mechanism and needlessly raises

[14] Commenters taking this position include the IMM (*See* Brief of the Independent Market Monitor for PJM, Oct 2, 2018), PJM Power Providers Group with their witness Roy Shanker (*See* Initial Brief of PJM Power Providers Group, Oct 2, 2018), the Electric Power Supply Association and their witness Paul Sotkiewicz (*See* Initial Brief of the Electric Power Supply Association, Oct 2, 2018), LS Power and their witnesses Kurt Strunk and Willis Geffert (*See* Initial Brief of LS Power Associates, L.P., Oct 2, 2018), NRG and their witness Robert Stoddard (*See* Initial Brief of NRG Power Marketing LLC, Oct 2, 2018), and Vistra Energy and their witness Christopher Russo (*See* Comments of Vistra Energy Corp. and Dynegy Marketing and Trade, LLC, Oct 2, 2018).

costs for consumers. That said, as PJM has acknowledged, the Extended RCO is an optional addition to PJM's Base Proposal and is completely severable.

C. CERTAIN FEATURES OF PJM'S BASE PROPOSAL DETRACT FROM ITS EFFICIENCY AND/OR WORKABILITY AND SHOULD BE ADJUSTED

39. Exelon's Proposal is very similar in concept to PJM's Base Proposal in that it envisions a MOPR with very few exceptions and a workable implementation of the RS-FRR concept. Exelon's Proposal differs from PJM's in two key respects: the re-entry provisions for ex-RCO/RS-FRR resources to the RPM and the presence of a size-based materiality threshold. While PJM's Base Proposal is generally workable, its provisions with respect to these two aspects unnecessarily detract from its economic efficiency and should be rejected and replaced with the provisions contained in Exelon's Proposal.

40. First, while PJM reasonably proposes that both the MOPR and eligibility for the RCO apply for the life of the subsidy for a given resource, they further propose that in the event that a former RCO resource (that is, resources no longer receiving a state-sponsored subsidy) seeks to re-enter the RPM post-subsidy, then that resource should be subject to the MOPR on a continuing basis until it has cleared one BRA, and further that the MOPR floor price for the resource be increased by the amortized value of capital expenditures made to the resource during its time as an RCO resource. The effect of this is that these resources will have their offers adjusted to a very high MOPR floor price, despite that resource not receiving any current out-of-market payments, making it very unlikely that that resource will ever clear in the RPM. This provision renders RCO largely unworkable and appears to be entirely intended to deter re-entry of RCO resources regardless of economics, and to punish resources for electing the RCO option in the first place. This provision is thus both unnecessary and inefficient. As discussed above, the economically efficient offer price for a RCO resource during the duration of the RCO is what it would have offered under the current status quo, or at or near zero in most cases. To the extent the resource exits the RCO for any reason, this offer will continue to be the correct, economically efficient offer. Application of the MOPR needlessly inflates the offer price and makes it likely that the resource will not clear, depriving the market of an otherwise-economic resource. Further, to the extent this provision deters states from supporting economically efficient zero-emission resources in the first place, it will detract from overall market efficiency because, as discussed previously,

such state programs enhance efficiency. To the extent that the Commission decides that some form of deterrent against resources toggling between the RCO and RPM is warranted, the five year stay-out provision utilized by the existing FRR is likely a more efficient and better targeted solution than PJM's proposed approach of applying a punitive MOPR to former RCO resources.

41. A simple example illustrates the absurdity of this provision. If a carbon price at the SCC were implemented either PJM-wide or nationally, as discussed previously, there would no longer be a need for attribute payments from states to zero-carbon resources and most if not all such payments would likely be discontinued. The resources in question would now be economic based on market prices alone and would seek to re-enter the RPM with an offer price that reflected the value of carbon embedded in energy markets. This offer price would be the efficient and correct price for these resources under a carbon-pricing structure, and most, it not all would likely clear the market on that basis. Application of the MOPR with an elevated floor price to such resources is clearly highly economically inefficient and would lead to inefficiencies such as nuclear plants retiring despite being economically viable relying only on market revenues.

42. Exelon's Proposal allows former RCO resources to offer into the RPM without application of the MOPR or other modification and thus avoids the problems inherent in PJM's approach. The Commission should reject PJM's proposed approach and replace it with a re-entry provision that does not modify the offers of the former RCO resources.

43. Second, PJM proposes a "materiality threshold" for application of the MOPR that would exempt resources with capacity below 20 MW in Unforced Capacity ("UCAP") terms. This provision amounts to a de-facto exemption from MOPR treatment for a majority of existing renewables, and likely all to-be-built renewables. PJM witness Adam Keech finds that 931 MW out of 1,560 MW, or about 60%, of existing renewables fall below the materiality threshold, and that 322 MW out of 946 MW of new build renewables in the queue with a 50% or higher chance of completion, or about 35%, also fall below the materiality threshold.[15] The reason that so many renewable projects fall below the threshold is that the UCAP value awarded to wind and solar capacity is scaled down considerably from their nameplate value due to the production shape and intermittent nature of these resources. The UCAP assigned to wind is typically scaled down to

[15] Affidavit of Adam J. Keech on Behalf of PJM Interconnection L.L.C., Oct 2, 2018, at 10-12.

13% of nameplate, while solar is typically scaled down to 38%. Thus, a 150 MW wind farm, a very typical size for a PJM onshore wind facility, would be assigned a UCAP value below 20 MW and would thus fall below the materiality threshold. Looking forward, however, most types of renewables have the flexibility to scale their facility capacity to fit under the materiality threshold because a wind or solar farm is not a singular machine, but rather a aggregation of much smaller wind turbines (typically 1-3 MW nameplate each) or solar panels (typically less than 0.5 MW nameplate each) that can be aggregated in whatever numbers are desired. Thus, it is likely that in the future nearly all wind and solar facilities will scale their capacity to fall under the threshold. As Mr. Keech's analysis demonstrates, even if these resources individually are small, collectively they amount to a significant block of capacity – currently over 900 MW of UCAP and growing to over 1,200 MW, or easily comparable to a nuclear plant– and will likely continue to grow in coming years. Further, because the capacity value of wind resources (currently the largest class of renewables in PJM) are scaled down by considerably more than their average energy output (i.e. a wind resource receiving a 13% UCAP credit will typically have an annualized capacity factor of 30 to 40%), these resources also have much more significant energy market impacts than their total capacity value would suggest, particularly during off-peak periods when their energy output is highest.

44. For renewables the materiality threshold is not necessary and creates inefficient incentives. The RCO option is available to and workable for renewables that receive state payments such as RECs, SRECs, or long-term contracts. To the extent they seek to avoid MOPR treatment, they may elect this option. While exempting these resources may seem like an easier way to accomplish the same effect, it is not the same, and introduces potentially harmful and innovation-stifling incentives for states, resource owners, and equipment manufacturers. This is because states and others that seek zero-carbon resources will have a clear administrative incentive to favor certain technologies, namely land-based wind and solar, over others that cannot be easily scaled or do not receive a large de-rate to nameplate due to intermittency, such as nuclear, carbon-capture and sequestration, hydro, and potentially other pre-commercial technologies. Similarly, the threshold also creates an incentive to favor smaller projects that fit below the threshold relative to larger projects that may achieve more economies of scale. This incentive is entirely driven by administrative rules, not economics, and could result in states favoring unnecessarily favoring

higher-cost zero-carbon resources and stifling innovation in resources that do not easily fall under the materiality threshold. For this reason, PJM should eliminate the MOPR materiality threshold.

45. Exelon's Proposal does not include a size-based materiality threshold at any level and thus avoids these inefficiencies. Consistent with Exelon's approach, the Commission should reject PJM's size-based materiality threshold.

III. MOPR-ONLY PROPOSALS ARE ECONOMICALLY INEFFICIENT FOR RESOURCES THAT RECEIVE ENVIRONMENTAL PAYMENTS, COSTLY FOR CONSUMERS AND SOCIETY, AND INCONSISTENT WITH THE COMMISSION'S ORDER

A. MOPR-ONLY CREATES UNNECESSARY PRICE INFLATION AND OTHER INEFFICIENCIES

46. Certain commenters, in particular the IMM, PJM Power Providers, the Electric Power Supply Association, and LS Power, propose that the Commission reject PJM's RCO, or any other approach that implements a FRR-RS as suggested in the Commission's order, and instead simply implement an expanded MOPR targeting both new and existing resources. In addition to being inconsistent with the Commission's order, which clearly identified the need to reasonably accommodate state's resource choices, such an approach would be both economically inefficient and costly for consumers.

47. When a zero-emission resource that receives environmental payments is subjected to MOPR, as discussed previously, its offer is re-set to an alternative MOPR Floor price that is too high and not efficient because the environmental payments that resource receives are cost-effective compensation for actual valuable environmental attributes provided by the resource that are not compensated in the market today. The efficient offer for such a resource is its status quo offer, which implicitly incorporates the impact of the environmental payments. It follows that the resulting market clearing outcome after application of the MOPR produces a price that is inefficiently high, because resource's offers are re-set to an inefficiently high price, and may result in otherwise economic resources not being selected in favor of dirtier resources that are higher cost once their negative emission externalities are considered. Because of this structure, a MOPR-only approach will lead to one of two outcomes in practice, both of which are bad for consumers and the market as a whole.

48. First, if the RCO or similar workable FRR-RS option is not provided, and states are not deterred in pursuing programs seeking to preserve resources for policy reasons, a stand-alone Expanded MOPR will result in inefficient over-procurement of capacity resources. A MOPR operates by adjusting the bids of targeted resources to a higher level, seeking to undo the effect of out-of-market payments resulting from state actions. PJM would then clear the market in a single step incorporating these higher, modified bids. As a result, the resources targeted by the MOPR will likely not clear the capacity market and will instead be replaced by other resources that would not have cleared had the targeted resources' offers not been adjusted upwards. However, the targeted resources will nonetheless remain in the market if state action is not deterred – they will just be compensated through out-of-market means at the state level. The additional resources procured in their place under the MOPR will also remain in the market. This over-procurement will effectively cause the market to retain a much larger portfolio of capacity resources than is needed for resource adequacy purposes. In addition, in those cases where these state programs continue without a RCO or similar, it is very likely that customers within the states implementing these out-of-market subsidies will be forced to over-pay for capacity with no incremental benefits. PJM will fully charge these customers for their share of the RPM capacity costs, including for those capacity resources that replaced the resources targeted by the MOPR that did not clear due their upwardly adjusted bids. The customers will then also pay through out-of-market charges levied by their states for these targeted resources that did not clear the capacity auction but remain in service supported by these out-of-market subsidies. Under the RCO, this would not occur as these resources would be pulled out of the RPM auction along with an off-setting amount of state-specific load that would no longer be charged for RPM capacity but would instead pay for the capacity associated with the state-supported resource through a compensation mechanism outside of the RPM.

49. Second, to the extent that the implementation of an Expanded MOPR with no RCO does deter states from making out-of-market payments to an economically-efficient zero-emission resource, PJM would then be selecting the wrong set of resources to provide capacity and causing the inefficient exit of economic resources, when all public and private costs are considered. Under this scenario, states will either cease actions when the resources in question are targeted by the MOPR, or never engage in state programs they would otherwise have engaged in due to the threat

of MOPR treatment. In either case, total social surplus is reduced because environmentally-valuable, economically-efficient resources would exit the market due to the loss of this support.

50. In either case, by inserting the resource into the supply curve at an inefficient, too-high MOPR floor price, the MOPR will result in inefficient and unnecessarily high prices for consumers. Many commenters in this proceeding claim that the MOPR is needed to eliminate "price suppression" that occurs if these resources are not subject to MOPR treatment, and that the RCO, by allowing the resources to avoid MOPR treatment also causes price suppression. However, viewed against the efficient outcome, which is to enter these resources into the supply curve at their original pre-MOPR offer price (as in the status quo) or allow them to elect the RCO (as in PJM's Base Proposal), a MOPR-only solution causes uneconomic price inflation, not price suppression.

51. In practical terms, when viewed against the results of the recent 2021/22 auction, an expanded MOPR applicable to existing resources would cause prices to increase from the levels at which they actually cleared (with one idiosyncratic exception). Commenters, including the IMM, provide a number of examples that instead purport to show that the RCO causes price suppression. But these examples all proceed not from the status quo outcome, but rather from a hypothetical starting point where zero-emission resources are either not compensated for their attributes by states or choose to ignore that compensation when determining their offers. This is not the right starting point because it represents an inefficient hypothetical state of the world which is not consistent with the reality on the ground today in PJM.

52. The reality today in PJM is that almost all he existing resources that would be affected by an expanded MOPR in the absence of an RCO actually cleared the most recent 2021/22 RPM BRA. Specifically, essentially all renewable resources (roughly 2 GW) cleared the market, the Quad Cities plant in Illinois (which receives ZEC payments) fully cleared the market (1.35 GW), and approximately 2.7 GW of 3.4 GW of New Jersey nuclear capacity that could potentially be supported by recently-passed legislation cleared the market.[16] While the specific bids for these resources are not public, if they were all subject to MOPR, their offers would have likely increased,

[16] "PJM: Reviewing the Auction Impact on Equities," Bank of America Merrill Lynch, May 25, 2018, at 3.

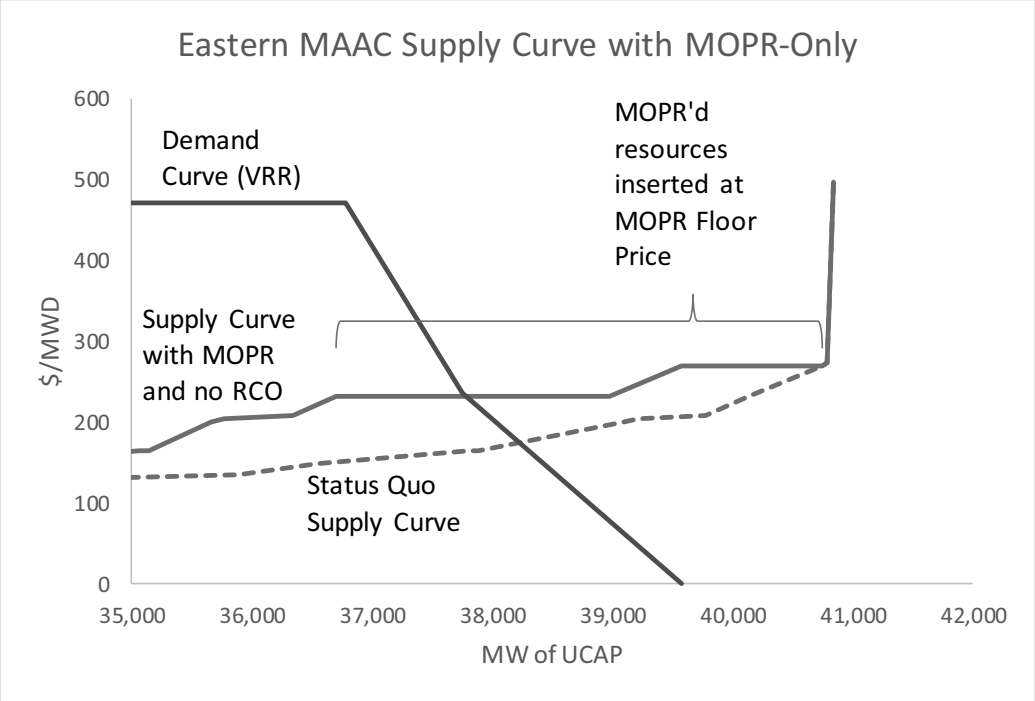
clearing prices in most cases would have been higher, and customers would have paid more for capacity.

53. Using the scenario analysis of the 2021/22 BRA provided by PJM, I have estimated the impact on market prices in Eastern MAAC and rest of RTO that would have resulted if the nuclear units identified above were removed from the supply curve and re-inserted at a higher MOPR floor price. I have not performed a similar analysis for ComEd because the IMM's scenario analysis of the 2021/22 RPM suggests that the ComEd LDA has a very flat supply curve in the marginal region with a considerable amount of uncleared capacity that would result in the application of the MOPR having little or no impact on market prices and thus minimal impact on customer costs. This does not appear to be a general result, but rather an idiosyncratic feature of the ComEd supply curve in this particular auction. For the purposes of this analysis, without knowing the final form of the MOPR or the specific costs of the plants involved I have assumed that the MOPR floor price for the nuclear plants is set to the relevant technology-specific existing resource ACR identified by PJM in its initial comments less the generic energy and ancillary services offset for new units also identified in their initial comments.[17] This estimate results in a MOPR floor price of $232 per MW-day (in UCAP terms) for dual-unit nuclear plants and $270 per MW-day for single-unit nuclear plants. While I have utilized these assumptions for the purposes of the illustrative modeling below, the actual MOPR floor prices for individual plants could be higher or lower depending on the resource-specific energy revenues estimated prior to the auction, and actual plant costs to the extent that the plant owner elects to calculate a resource-specific gross ACR for the resource. Further, if the Commission were to instead establish a MOPR Floor price at Net CONE x B, rather than at the Net ACR as proposed by PJM, the MOPR Floor prices would be similar to what I assumed - $244 per MW-day for Eastern MAAC. For the renewable resources, most of which are existing, I have conservatively assumed that the MOPR floor price is well below the clearing price in markets, consistent with PJM's suggested technology-specific MOPR floor prices. Figure 2 below shows how the MOPR changes the supply curves (estimated based on PJM's sensitivity analysis) in Eastern MAAC relative to the status quo, and the resulting impact on market clearing prices and quantities. The MOPR also has an effect on the RTO clearing price because it causes less supply to be cleared in Eastern MAAC. Because the supply cleared for LDAs is entered into the broader

[17] Initial Submission of PJM Interconnection, L.L.C., Oct 2, 2018, Table 1 and Table 3.

RTO supply curve at zero, this causes the RTO supply curve to shift inward as well (by roughly 600 MW). Based on the shape of the RTO supply curve, I estimate that this causes the RTO price to rise by about $6 per MW-day, from $140 to $146 per MW-day. This price increase would be borne broadly by customers in all unconstrained regions of the RTO.

Figure 2



54. The MOPR has two effects. First it results in different market clearing prices throughout PJM. In the Eastern MAAC region supply is constrained enough, and the amount of MOPR'd resources is significant enough, that some of the MOPR'd nuclear resources would still clear but would set price at a much higher level consistent with the MOPR floor price. This results in higher customer costs throughout Eastern MAAC paid by all consumers, regardless of the state in which they are located. In addition, I estimate that about 1,700 MW of the EMAAC nuclear capacity that cleared in the status quo would not clear due to application of the MOPR. To the extent that the lost revenue for this capacity is made up by the state to keep the capacity in the market, customers in the state in question would continue to effectively procure and pay for this capacity and would pay an incremental cost of over-procurement as a result. Further, there is an

increase in RTO capacity prices that results from the inward shift of the RTO supply curve due to the lesser amount of resources cleared in EMAAC relative to the status quo. Table 1 below summarizes the overall cost impact in customers in Eastern MAAC, relative to the status quo.

Table 1

		Capacity Price $/MWD	RPM Capacity Cost $ Millions	Reduction in State-Supported Resources Cleared MW	Over-Procurement Cost $ Millions	Total Cost to Customers $ Millions	Increase in Cost $ Millions
Status Quo	EMAAC*	173	1,847	- na -	- na -	1,847	- na -
	Rest of RTO	140	5,214	- na -	- na -	5,214	- na -
	Total		7,061	- na -	- na -	7,061	- na -
MOPR no RCO	EMAAC*	232	2,428	(1719)	104	2,532	685
	Rest of RTO	146	5,445	0	0	5,445	231
	Total		7,873	(1719)	104	7,977	916

* EMAAC includes PSEG. Status quo capacity price for EMAAC is a blend of PSEG and Rest of EMAAC prices.

55. The overall net impact is that customers in Eastern MAAC would end up paying nearly $700 million per year or 37% more under a MOPR-only structure than they do under the status quo. About $600 million of this is due to market price impacts that would be borne by all customers in Eastern MAAC and another $100 million from over-procurement costs borne by customers in the states supporting the nuclear resources in question (New Jersey in this case). Further, customers across the unconstrained portion of the RTO would in the aggregate bear about $230 million of additional costs due to the ripple effect of the EMAAC changes on broader RTO prices. In total, the incremental costs of the MOPR are approximately $920 million.

56. Alternatively, if the MOPRd resources that would not clear due to the application of the MOPR instead retired, customers would not bear the over-procurement cost, but the market would be deprived of 3.4 GW of zero-emission capacity that annually displaces about 19 million tons of carbon emissions that impose a societal cost of about $980 million per year when valued at the SCC. When added to the customer cost increase due to market price impacts, the scenario increases total costs by about $1.8 billion per year.

57. If the resources in question instead elect the RCO, the market clearing outcome would be similar to the status quo, and the unnecessary price inflation and costs associated with over-procurement and/or loss of efficient zero-emission resources would be avoided. Contrary to the

claims of MOPR-only advocates, this outcome does not represent "price suppression" but rather represents the most efficient possible outcome that complies with the Commission's order.

B. THE EXISTING FRR IS CONCEPTUALLY SIMILAR TO THE FRR-RS OR RCO, BUT IS LESS EFFICIENT FOR ACCOMMODATING STATE PROGRAMS

58. MOPR-only proponents point to the current FRR option in the PJM Tariff as an appropriate means of accommodating state programs designed to support environmentally-valuable resources.[18] Indeed, there is apparently no dispute that the existing FRR is just and reasonable and thus a viable option for states.

59. In most respects, however, if elected by the states, the existing FRR would be less efficient and produce similar or even larger impacts on prices than the RCO or FRR-RS options contained in PJM's Base Proposal and Exelon's Proposal, respectively. That is, the RCO and FRR-RS are less extreme, more efficient versions of the existing FRR.

60. To see how this is so, take the example of a state that seeks to retain two nuclear plants, but whose load far exceeds the capacity provided by those plants. Under the FRR-RS or RCO, those plants would elect the FRR-RS or RCO and just those plants would be removed from the RPM auction, while loads in the state would have an offsetting credit to their capacity obligation in the amount of the capacity of the plants. Relative to an outcome where those plants were subject to the MOPR and did not clear, market prices would be lower. Under the existing FRR, the state would be forced to induce all Load Serving Entities ("LSEs") in the state to elect the existing FRR, and then assemble an FRR resource portfolio sufficient to cover all load in the state to the PJM Installed Reserve Margin target. By removing the two nuclear plants from the auction, along with a commensurate amount of load, the existing FRR would have at least the same price impact relative to a MOPR-only outcome as the RCO or FRR-RS. However, depending on how resources are selected for the FRR portfolio, it is possible the existing FRR could have more of an impact because the additional resources supported by the state could include those that would not have cleared. To the extent that these additional resources are not economic when environmental externalities are considered, their retention via the FRR would be inefficient.

[18] *See* Initial Brief of the PJM Power Providers Group, Oct 2, 2018, at 13-18; Initial Brief of the Electric Power Supply Association, Oct 2, 2018 at 14.

61. Like the PJM Base Proposal and Exelon's Proposal, the existing FRR has no capacity re-pricing mechanism akin to PJM's Extended RCO proposal (discussed below) that seeks to somehow "fix" and inflate the resulting prices back to a "competitive" level, despite it having similar or even greater price impacts. PJM (with respect to its Extended RCO proposal), the IMM, and other proponents of MOPR-only or capacity re-pricing solutions fail to offer any credible justification as to why the existing FRR, which is less efficient and has at least the same impact on price as either the RCO or FRR-RS, can produce just and reasonable market price outcomes while the RCO or FRR-RS should be either eliminated or greatly limited (in the case of MOPR-only proponents) or subjected to a capacity repricing mechanism (in the case of PJM's Extended RCO proposal). This inconsistency suggests that calls to rely on the existing FRR instead of the FRR-RS or the RCO in PJM's Base Proposal are motivated not by a conceptual difference between the two, but rather on the practical reality that the existing FRR is more cumbersome than the FRR-RS or RCO and thus less likely to be utilized by states seeking to exercise their right to determine their generation mix. But this justification is entirely at odds with the letter and spirit of the Commission's Order, which explicitly identified the FRR-RS as a vehicle for states to do just this in the full knowledge that the existing FRR was already in place and available.

62. The reality is that the existing FRR is more cumbersome for the states in question than the FRR-RS or the RCO. And, if utilized to accommodate state programs, the FRR would introduce a number of inefficiencies that are avoided with the FRR-RS or RCO.

63. First, the existing FRR requires that LSEs (and thus, effectively entire states in the question of state programs) fully withdraw all of their load from the market, rather than just load matched to specific resources, and simultaneously withdraw a matching portfolio of resources, not just the specific resources they seek to support. Compared to the FRR-RS or RCO, this deprives the market of a large amount of depth, efficiency, and scale that it would otherwise have. Relatedly, because the existing FRR fully withdraws both load and resources from the market clearing mechanism, PJM must adopt cumbersome rules to ensure that all reliability constraints are met in the residual market. While this approach works well enough under the current market (where about 8% of load/resources utilize the FRR option) it becomes increasingly difficult if the amount of FRR where to double, or more, particularly if the FRR option were elected in a state located in or around significant transmission constraints, such as most states in the Eastern portion

of PJM. This loss of efficiency affects all PJM market participants, not just those that elect the FRR option.

64. Second, and more specific to the states that would seek to elect FRR, the FRR is more difficult and cumbersome to reconcile with retail competition in states that have it. Because the FRR requires that the state assume full responsibility for capacity procurement, rather than just for specific state-supported resources, it effectively puts the state in the position of procuring capacity for all retail providers, fully removing capacity from the portion of the retail bill subject to competition and requiring that the state develop mechanisms for delivery companies to recover the full cost of capacity from competitive retailers. While some of these issues may exist with respect to the FRR-RS or RCO, because they only cover specific resources and provides the option for PJM to continue payment and billing for these resources, the scale of the issues is much smaller.

C. A CAP ON THE TOTAL AMOUNT OF CAPACITY THAT CAN ELECT THE RCO SUFFERS FROM THE SAME PROBLEMS AS MOPR-ONLY PROPOSALS

65. LS Power and their witnesses, Strunk and Geffert, propose that the total amount of capacity able to elect the RCO be capped at 6 gigawatts, with the amount of FRR-RS or RCO capacity pro-rated across all resources that elect the FRR-RS or RCO in the event that the cap is oversubscribed.[19]

66. A cap on the amount of FRR-RS or RCO capacity suffers from the same problems as a MOPR-only proposal that I discuss above. If the cap is binding, which it most likely would be immediately at a level of 6 GW, a portion of eligible capacity would not be able to elect the FRR-RS or RCO and would thus be subject to MOPR. As I discuss above, subjecting resources with state environmental support to the MOPR results in them being inserted into the RPM supply curve at an inefficiently high price, which results in unnecessarily inflated market clearing prices and an inefficient portfolio of cleared resources. This in turn creates additional over-procurement costs for states (if they are not deterred from pursuing state programs) and/or deprives the market of efficient zero-carbon resources. This is just as true if only a fraction of the resources receiving state environmental support are subjected to the MOPR (as they would be under a FRR-RS or RCO cap) as it is under a MOPR-only structure.

[19] Initial Brief of LS Power Associates, L.P., Oct 2, 2018 at 17.

67. A cap of 6 GW on FRR-RS or RCO capacity is likely to ultimately result in massive over-subscription to the point where it is likely to be essentially indistinguishable from a MOPR-only structure in practical terms. As an initial matter, there are approximately 7 GW of existing nuclear and renewables in the market currently receiving state support of some kind, so the cap is likely to be immediately binding based on current RCO-eligible resources only. Second, while only several nuclear facilities in PJM currently receive state support, many additional nuclear facilities are uneconomic under the current market structure but would likely be economic if compensated for their zero-emission attributes, or if a carbon price were implemented, making them efficient candidates for state support. Approximately 10 GW of nuclear not receiving state support failed to clear the most recent RPM BRA and much of the merchant nuclear that cleared is economically-challenged in the current market and could fail to clear in the RPM in future years. In addition to nuclear, PJM has estimated that an incremental 4 GW of renewable capacity (in UCAP terms) will need to enter the market through 2033 to satisfy state renewable energy mandates.[20] Thus, there is on the order of 14 GW of additional potential efficient zero-emission capacity that could seek to elect the RCO in the future, on top of the 7 GW that is likely eligible today, or a total of 21 GW of potential RCO capacity. Arrayed against these totals, a RCO cap of 6 GW would only cover about 30% of RCO capacity, which is not economically distinguishable from MOPR-only in terms of its practical effect.

68. Furthermore, in addition to advocating for the FRR-RS or RCO cap, LS Power also supports a MOPR with no exemption for public power and self-supply resources from vertically-integrated regulated utilities. I estimate that these two types of capacity amount to approximately 31 GW that currently clear through the RPM.[21] If these entities are included in the MOPR, the amount of capacity sharing the cap could thus reach 52 GW, and the cap would only cover a little over 10% of RCO capacity. In addition to the inefficiencies and costs this creates for resources supported by states for environmental resources, it would render the FRR-RS or RCO non-viable as an option for self-supply and public power entities and would likely force them to elect the existing FRR option, with all the disruptions and inefficiencies that that entails. Thus, a cap on

[20] Affidavit of Dr. Anthony Giacomoni on Behalf of PJM Interconnection, L.L.C., Docket No. ER-1314-000, April 9, 2018, ¶ 29.

[21] Declaration of Michael M. Schnitzer, Docket No. EL18-169-000, June 20, 2018, at 5.

FRR-RS or RCO resources effectively renders impossible a true non-discriminatory MOPR as envisioned in the Order.

IV. PJM'S EXTENDED RCO PROPOSAL RESULTS IN ECONOMICALLY INEFFICIENT PRICES, UNNECESSARILY RAISES COSTS FOR CONSUMERS, AND INAPPROPRIATELY TRANSFERS COSTS TO CLEAN RESOURCES

69. In addition to its Base Proposal, which does not adjust the prices that result from the application of the MOPR and RCO, PJM has proposed an alternative "Extended RCO" which retains the MOPR and RCO provisions of the Base Proposal but adds a second step that adjusts the resulting clearing prices paid to the resources in the RPM. This second "repricing" step is similar to PJM's prior capacity repricing proposal but contains additional provisions that make it even less economically efficient, more costly for consumers, and more destructive to legitimate state environmental goals.

70. To accomplish re-pricing, PJM first determines what resources clear the RPM from an initial clearing of the Base Residual Auction where the supply curve includes application of the MOPR for resources with actionable subsidies that do not elect the RCO, and insertion of the RCO resources into the supply curve as price-takers for those resources that do elect the RCO, with the demand curve not otherwise adjusted. Rather than using the market clearing prices resulting from this first step, however, for price determination purposes only under the Extended RCO, PJM simply removes the RCO resources from the supply curve altogether while leaving the demand curve as-is. The prices that result from this second market clearing step are paid to the non-RCO resources that clear the first step.

71. The re-pricing step will generally result in the market price clearing above the offers of some amount of resources which do not receive a capacity obligation in the initial step. These resources have been generally referred to as the "in-between" resources. To avoid potential distorted bidding incentives, PJM proposes that these resources receive an "infra-marginal rent" payment equal to the difference between the market clearing price and their bid price. These resources would not receive a capacity obligation and would be free to exit the market. PJM proposes that the cost of the infra-marginal rent payments be allocated to the RCO resources.

72. While broadly similar in concept to PJM's original Capacity Re-Pricing proposal that the Commission found to be unjust and unreasonable, the Extended RCO has three important

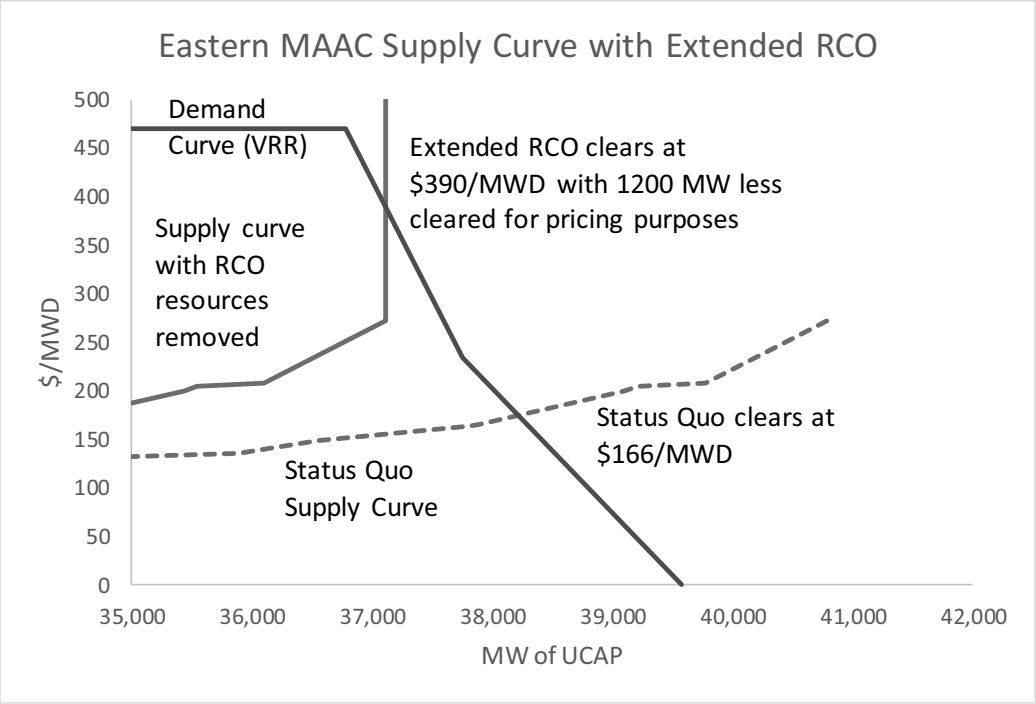
differences. First, in the original Capacity Re-Pricing proposal, all state resources that were determined to be receiving "actionable subsidies" and thus had their offers adjusted for purposes of price formation were paid the resulting market prices. Under the Extended RCO, RCO resources receive no compensation from PJM for capacity. Second, in the re-pricing step, the Capacity Re-Pricing proposal inserted resources with "actionable subsidies" into the supply curve at a competitive proxy price equal to the higher of the resource's net ACR or opportunity cost of committing as a Capacity Performance resource. The Extended RCO, on the other hand, removes RCO resources from the supply curve entirely, acting as if they do not exist even though PJM would be relying on the resources to meet reliability requirements. Third, unlike the Extended RCO, Capacity Re-Pricing did not include any infra-marginal rent payment for in-between resources. The first of these differences (non-payment of the clearing price to RCO resources) is not problematic in and of itself and is a natural consequence of the RCO structure. The total removal of RCO resources from the repricing step and the cost allocation methodology of the inframarginal rent payments, however, are deeply problematic and exacerbate the flaws already inherent in PJM's capacity repricing concept.

73. The core premise of the Extended RCO -that the prices resulting from PJM's Base Proposal are somehow wrong or inefficient -is simply incorrect. As I discuss above in my analysis of PJM's Base Proposal, with respect to resources receiving environmental support from states (which is essentially all current RCO-eligible resources), the resource offers, market clearing prices, and capacity resource selection that result from the combined application of the MOPR with appropriate election of the RCO for relevant resources are economically efficient and maximize social surplus. Any mechanism which inflates resource offers and results in different market clearing prices and/or different resource selection than PJM's Base Proposal creates inefficiencies and unnecessary costs for consumers. Relative to MOPR-only structures, to the extent that it does not deter states from supporting environmentally advantaged resources, the Extended RCO, like Capacity Repricing does result in the correct resource selection because resources receiving state environmental support may elect the RCO option and thus ensure that they receive a capacity obligation. However, because it effectively assigns an infinite offer price to RCO resources for purposes of price formation, the Extended RCO results in an inefficiently inflated set of market clearing prices which unnecessarily raise costs for consumers and send incorrect price signals to the market.

74. Even relative to the already inefficient and inflated prices produced by a MOPR-only approach or PJM's original Capacity Re-Pricing proposal, the Extended RCO stands out as producing potentially even more extreme price inflation. The reason for this is that by removing RCO resources from the supply curve entirely in the re-pricing step, PJM thus effectively sets their offers to an arbitrary infinitely high level. MOPR-only and Capacity Re-Pricing, by contrast, effectively insert the offers from RCO resources into the supply curve at a competitive proxy price, either a MOPR Floor Price based on the resources' net ACR or the higher of net ACR and the opportunity cost of committing as Capacity Performance, depending on the proposal. While these offer levels are unnecessarily inflated above the efficient level, they are nonetheless much more reasonable and lower than simply removing the offers altogether. Because of this, under the Extended RCO, the resulting supply curve for price determination purposes contracts inward by the amount of RCO resources with no offsetting change to the demand curve. Depending on the amount of RCO resources and other offers, it is possible for the market clearing prices that result to be greatly inflated and potentially even clear at the RPM price cap of 1.5 times Net CONE even if the market is not physically under-supplied. This outcome is particularly likely to occur in constrained LDAs where the amount of non-RCO offers may be limited, but it is also a possibility RTO-wide if enough resources elect the RCO. To illustrate the potential for extreme price inflation created by this provision, I have estimated how it would change the supply curves in the Eastern MAAC LDA if applied to the most recent RPM auction, assuming that all wind and solar and all nuclear resources receiving state support (a total of approximately 3.7 GW of capacity, of which about 3.0 GW cleared the market in the status quo) in this region elects the RCO and are thus removed from the supply curve used for price determination in the Extended RCO.[22] Figure 3 below shows how the supply curve, and ultimate market clearing prices would responds in EMAAC:

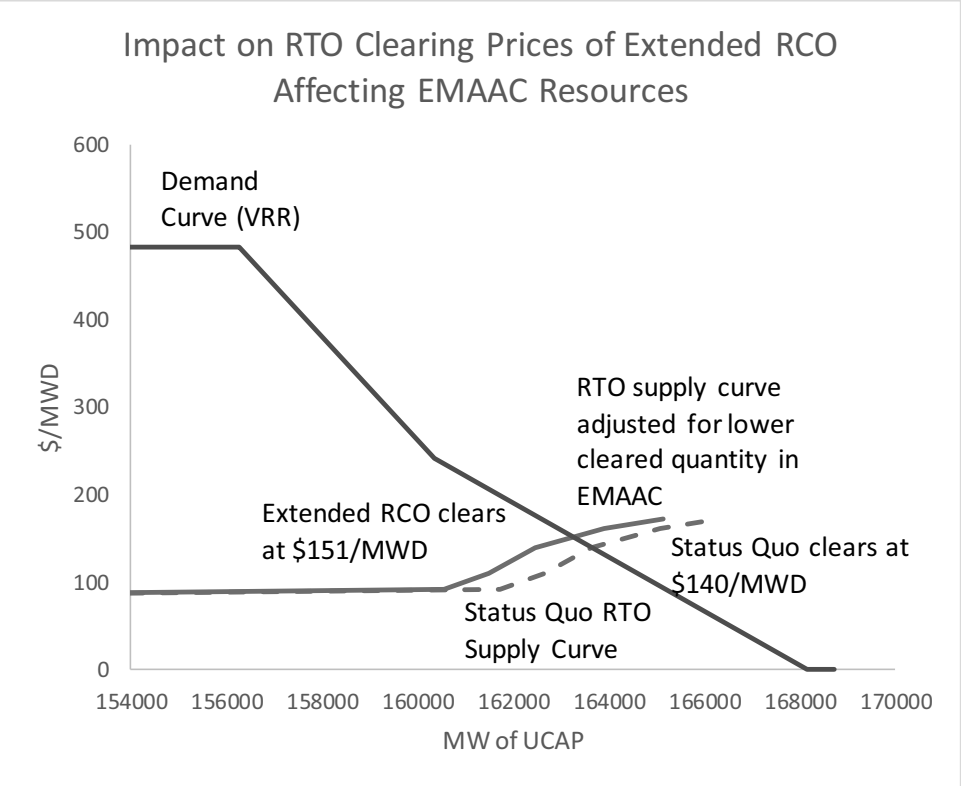
[22] Based on the amount of capacity currently receiving state support in the ComEd region and the 2021/22 supply curve, it is unclear whether the application of the Extended RCO would have significantly changed the market clearing price. If additional capacity were to receive state support in the ComEd LDA, or if a significant portion of the uncleared capacity were to retire, application of the Extended RCO would likely have a significant effect on ComEd market clearing prices.

Figure 3



75. Further, because the dramatic change in the EMAAC supply curve would reduce the total amount cleared in EMAAC for price formation purposes by about 1,200 MW, prices in the Rest of RTO would be affected because this supply would be effectively removed from the RTO supply curve. Figure 4 shows this effect:

Figure 4



76. The Extended RCO will thus drive up customer costs by greatly inflating the capacity price that all consumers in the region pay, to $390 per MW-day from the status quo EMAAC price of $166 per MW-day ($204 per MW-day in the PSEG portion of EMAAC). Further, prices in the broader RTO would also increase, albeit by a much smaller amount, which drives up costs for customers far removed from the state actually supporting the RCO resources. I estimate that based on the clearing prices shown in Figure 3 and Figure 4, relative to either the status quo or PJM Base Proposal, customers in EMAAC would pay approximately $2.1 billion per year due to higher capacity prices (which would roughly double the capacity payments of customers in EMAAC).[23] In addition, while the loads matched to RCO capacity would need to continue to compensate that

[23] Under the status quo, a total of 29.3 GW of resources cleared in EMAAC at a blended average price of $173 per MW-day ($204 per MW-day for PSEG resources and $166 per MW-day for Rest of EMAAC resources). Of these resources, I estimate that just3 GW of nuclear and renewables would be eligible to elect the RCO and would be effectively compensated at the status quo price level from states or other LSEs via the RCO mechanism, an additional 700 MW of nuclear resources that did not clear the market and would also elect the RCO. Under the extended RCO, I estimate then that 26.3 GW of resources would be cleared in the RPM (the status quo cleared resources less the 3 GW of cleared resources electing the RCO) at a price of $390 per MW-day. Incremental to the status quo, this results in additional customer costs of $2.076 billion due purely to increased prices paid to cleared resources. In the Rest of RTO, just 102 GW of resources cleared at $140 per MW-day. These resources are paid an additional $11 per MW-day due to prices rising to $151/MWD under Extended RCO, or $430 million annually.

capacity outside the RPM, under the Extended RCO proposal, the RCO resources would be allocated the costs of the infra-marginal rents paid to in-between resources. I estimate that, again based on the example shown in Figure 3, PJM would pay out $120 million per year in infra-marginal rents allocated to the RCO resources.[24] Ultimately, if these infra-marginal rents are allocated to the RCO resources, these costs would either be borne by the associated matched load, or would result in those resources existing the market. Thus, incremental to PJM's Base Proposal, the Extended RCO raises would have raised costs for EMAAC customers by about $2.1 billion per year due to inflated market prices if it were in place for the 2021/22 BRA, and further would have allocated incremental infra-marginal rent payments of about $120 million per year to consumers in the states supporting RCO resources, for a total cost to consumers in EMAAC of about $2.2 billion. In addition to this, the increased prices in the rest of RTO region would have raised costs for consumers outside of EMAAC by about $430 million, despite these customers being far removed from the RCO resources in question. Thus, the total cost to consumers in all regions of Extended RCO would have been $2.6 billion. These costs are both unnecessary and inefficient.

77. If, rather than eliminating the RCO resources from the supply stack entirely for price formation purposes, the RCO resources were re-entered into the supply stack at their MOPR Floor prices, the overall cost impact of the Extended RCO would be approximately the same as the market price impact associated with MOPR-only proposals that I calculated in the previous section, or about $800 million annually for EMAAC and Rest of RTO customers. If the value of the zero-emission attributes of RCO resources (valued at the Social Cost of Carbon) were deducted from the MOPR Floor price of the RCO resources for the purposes of the re-pricing step, which, as I discuss previously, produces the most economically-efficient offer price for these resources, the Extended RCO would not have an incremental cost (assuming all RCO resources are economic

[24] Based on the shape of the PSEG and EMAAC supply curves indicated in the RPM sensitivities provided by PJM (*See* https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-bra-scenario-analysis.ashx?la=en), I estimate that that the Extended RCO would result in 521 MW and 1,271 MW of "in-between" resources in PSEG and Rest of EMAAC respectively, with average bid prices of $207 and $213 per MW-day respectively, which results in an average infra-marginal rent payment of $178 per MW-day to a total of 1,792 MW of resources, resulting in a total payment of $117 million. I estimate that there would be an additional 800 MW of in-between resources in the Rest of RTO, but the infra-marginal rent payment to these resources would only be about $5 per MW-day, resulting in additional costs of $2 million, or $119 million total.

and clear once environmental attributes are explicitly incorporated into their offers) and would produce market prices similar to PJM's Base Proposal.

78. The aspect of PJM's Extended RCO proposal that would allocate the infra-marginal rent payments to resources electing the RCO is both economically backward and creates an inappropriate impediment to the workability of the RCO for states seeking to support clean resources. PJM claims that the reason to allocate these costs to the RCO resources is because the RCO resources cause "resource substitution" whereby they displace other resources that would have been economic had the RCO resources offered at a price level that did not incorporate they value of their state payments. These resources are conceptually the same as the in-between resources paid infra-marginal rents under the Extended RCO, and because they do not clear due to the RCO resources, PJM claims that the infra-marginal rents are a measure of inefficiency or "deadweight loss" attributable to the RCO resources, and are thus appropriately allocated to those resources.[25] This reasoning is completely backwards. As I have discussed in depth, the state payments in question that result in resources electing the RCO in the first place are intended to at least partially correct a distortion that exists in the current market, namely the fact that carbon-emitting resources are not charged for the public costs of those emissions, and thus appear cheaper, and are utilized more frequently than they would be in both energy and capacity markets than they would in the presence of a carbon price. Because of this, there is considerable deadweight loss in markets attributable to this inefficiency that primarily takes the form of economic damage from emissions from dirty resources in excess of the efficient level that would prevail if there were a price on carbon. The "resource substitution" whereby RCO resources displace non-RCO resources, thus reduces deadweight loss, or inefficiency relative to the status quo. PJM's witness Chao in fact acknowledges this. Dr. Chao notes that if a "marginal divergence" or difference between the public and private costs of a resource (such as occurs in electricity markets today due to emissions characteristics of different resources) is caused by a market imperfection or externality (as is generally accepted to be the case with the failure of markets to value carbon), then it is not considered a distortion.[26]

[25] Initial Submission of PJM Interconnection, L.L.C., Oct 2, 2018, at 72.

[26] Affidavit of Hung-Pao Chao, Ph.D. on Behalf of PJM Interconnection LLC, Oct 2, 2018, ¶ 5.

79. Thus, by allocating the infra-marginal rent payments to RCO resources receiving state support for environmental reasons, PJM is effectively imposing an additional charge on them and their sponsoring state for providing net benefits to the market as a whole. This is clearly inappropriate and creates an unnecessary and damaging impediment to states seeking to support economically-efficient zero-emission resources. To the extent that this provision deters states from pursuing these programs, such resources will either exit or never enter the market, thus creating additional deadweight losses for all market participants.

80. While the Extended RCO, with its attendant inframarginal rent payments, is unnecessary because PJM's Base Proposal reduces, rather than increases inefficiency and deadweight loss in the market, to the extent that Extended RCO is adopted, the RCO resources should be placed into the supply curve at their MOPR floor price, preferably adjusted for SCC, and the cost of infra-marginal rent payments should be allocated to the non-RCO resources that do clear the market. This repricing approach would produce lower prices and be more efficient than PJM's Extended RCO proposal.

81. At their core, PJM's Extended RCO proposal and the various MOPR-only proposals all ask the Commission to implicitly conclude that all retention/entry associated with state-sponsored resources is uneconomic. For the assumption of uneconomic retention/entry is the only thing that might justify either result. That stands in stark contrast to the Commission's intent to accommodate state interests, and to the undeniable state jurisdiction over resource adequacy, should they choose to assert it. It also flies in the face of the evidence offered here that the state-sponsored resources comprise, in the main, economic entry/retention when environmental attributes are taken into account. This core failing is the primary reason that both proposals produce such economically inefficient outcomes with unnecessary price inflation, and also clearly frustration of states' rights and violate the intent of the Commission's Order. For this reason, the Commission should reject all the proposals that fall in these categories.

82. This concludes my declaration.

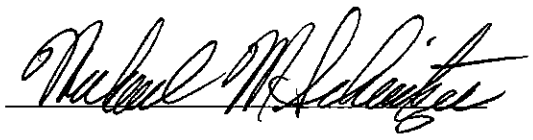
UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. EL18-178-000**
PJM Interconnection, L.L.C.	)	**ER18-1314-000** **ER18-1314-001**
Calpine Corporation, et al.,	)	**EL16-49-000**
Complainants,	)	**(Consolidated)**
v.	)	
PJM Interconnection, L.L.C.,	)	
Respondent.	)	

DECLARATION OF MICHAEL M. SCHNITZER

I, Michael M. Schnitzer, declare under penalty of perjury that the foregoing is true and correct.

Executed: November 6, 2018
Concord, Massachusetts



UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.

Docket No. AD17-11-000

PRE-TECHNICAL CONFERENCE COMMENTS OF EXELON CORPORATION

Exelon commends the Commission for opening a dialogue on how wholesale markets should evolve in light of state environmental priorities. In Exelon's view, the Commission could take one of two main approaches.

First, the Commission could continue to operate wholesale market auctions that select resources according to least-cost principles, against a backdrop of state environmental policies that address the environmental externalities of electric generation by altering the economics of generators based on their level of emissions. States have adopted a wide variety of such programs, including renewable energy credit (REC) trading programs to support state renewable portfolio standards, carbon cap-and-trade programs such as the Regional Greenhouse Gas Initiative (RGGI), and the zero-emission credit (ZEC) programs recently created by New York and Illinois, which value the environmental attributes of nuclear power. Each of these state programs addresses the environmental externalities of electric generation by penalizing pollution or promoting clean energy production. Historically, the Commission's wholesale markets have been agnostic as to environmental externalities, and states have decided for themselves how, and whether, to address them. The Commission could continue that course, while leaving open the possibility of future market reforms if there is evidence that competitive generation investment is inadequate to ensure reliability.

Second, the Commission could allow independent system operators (ISOs) or regional transmission organizations (RTOs) to file tariffs that integrate states' environmental goals into the wholesale market. ISOs and RTOs could do so in a number of different ways, ranging from a centralized procurement of environmental attributes identified by the states to the inclusion of a carbon or pollution adder in wholesale energy bids. ISOs and RTOs could also craft a combination of these two main approaches, integrating state environmental goals in part, while leaving states free to pursue different or more stringent environmental goals in the way states currently do and always have done. Section 205 of the Federal Power Act grants the Commission the authority and flexibility to accept ISO or RTO tariff revisions implementing these integrative solutions.

The Commission may not, however, undermine or interfere with states' ability to achieve their environmental goals. State environmental programs fall comfortably within the states' inherent police powers and relate to states' core sovereign interests in protecting the health and safety of their citizens.[1] If the Commission requires states to forgo their sovereign power to make their own environmental policy

[1] *Huron Portland Cement Co. v. City of Detroit*, 362 U.S. 440, 442 (1960); *Exxon Mobil Corp. v. U.S. EPA*, 217 F.3d 1246, 1255 (9th Cir. 2000); *Nat'l Solid Wastes Mgmt. Ass'n v. Killian*, 918 F.2d 671, 676 (7th Cir. 1990), *aff'd sub nom. Gade v. Nat'l Solid Wastes Mgmt. Ass'n*, 505 U.S. 88 (1992).

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as the price of admission to the federal wholesale markets, states may rethink their participation in these markets. The Commission should avoid forcing states to make such a choice.

I. The Commission's Wholesale Markets Can Continue to Coexist in Harmony With State Environmental Initiatives.

The Federal Power Act reserves for states the authority to regulate generation facilities,[2] and the Commission has already affirmed that states may support particular generation resources that advance states' legitimate policy interests, including environmental protection. The Commission has found that states "may … grant loans, subsidies[,] or tax credits to particular facilities on environmental or policy grounds,"[3] and may "encourage renewable or other types of resources … by giving direct subsidies," even when doing so "allow[s] states to affect the [wholesale] price."[4] Indeed, states are "free" to incentivize clean generation in these ways "even if the price signals in the regional wholesale capacity market indicate that [those] resources are [not] needed."[5] Responding to these precedents, states in the Eastern RTOs have adopted a variety of programs that favor clean generation, including REC/ZEC programs, carbon cap-and-trade programs, state-directed bilateral procurements, and tax and development incentives. Moreover, with respect to REC programs and other renewable subsidies, there is no natural ceiling constraining the size of these programs.[6] Particularly as storage technology improves, states can be expected to mandate that an ever-growing share of their generation fleets consists of renewable resources. New York has set its goal to have half its electricity generation come from renewable resources by 2030, and other states have likewise set aggressive goals.[7] The Commission has modified its rules to accommodate these initiatives, by exempting new renewables from minimum offer price rules that otherwise apply to new entrants and by approving increasingly negative price floors to enable sellers to realize the full value of their environmental attribute payments.[8]

Illinois and New York have recognized that existing nuclear facilities provide significant environmental value to their states by displacing carbon and air pollution that would otherwise occur if these plants retired and were replaced by fossil fuel generation. Like the environmental benefits of renewable generation, the environmental benefits of nuclear generation are not addressed by the wholesale markets; instead, states have been left to address those issues.

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[2] 16 U.S.C. § 824(b).

[3] *Cal. Pub. Utils. Comm'n*, 133 FERC ¶ 61,059, at P 31 n.62 (2010).

[4] *S. Cal. Edison Co.*, 71 FERC ¶ 61,269, 62,080 (1995).

[5] U.S. Amicus Br. at 33, *Hughes*, 136 S. Ct. 1288, 2016 WL 344494. Commission precedent is consistent with that of federal courts. *Entergy Nuclear Vt. Yankee, LLC v. Shumlin*, 733 F.3d 393, 417 (2d Cir. 2013); *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009) (states may "require retirement of existing generators, [require construction of] expensive, environmentally-friendly units, or … take any other action in their role as regulators of generation facilities," even though "those choices … affect[] the [wholesale] market clearing price").

[6] Indeed, in all of the Eastern RTOs, the amount of state-supported renewable generation and rate-regulated generation in 2025 will exceed by a significant margin the amount of ZEC-supported generation, based on current renewable targets. *See* Exhibit A.

[7] Illinois' renewable energy targets roughly double between 2017 and 2025 to 25 percent of load. *See* 20 ILCS 3855/1-75(c)(1)(B) (eff. June 1, 2017). Massachusetts has set a renewable energy target of 28.6% by 2030, Mass. Gen. Laws ch. 25A § 11F; 225 C.M.R. § 15.07. Other New England states seek to procure similar quantities. *See generally* www.dsireusa.org.

[8] *California Indep. Sys. Operator Corp.*, 145 FERC ¶ 61,254, at PP 5, 34 (2013) (approving CAISO proposal to lower its "bid floor" in the energy markets "from negative $30/MWh to negative $150/MWh" in order to permit "variable energy resources" to submit bids accounting for "production tax credits, renewable energy credits, and contractual energy payments"); *ISO New England Inc.*, 146 FERC ¶ 61,084, at P 32 (2014) (rejecting argument that REC revenues are out-of-market, and approving reduction of ORTP for new renewable resources to account for REC revenues).

The environmental problem addressed by ZEC programs is both clear and urgent. When a nuclear facility retires, it cannot feasibly be replaced by renewable generation in the time necessary to avoid a spike in emissions. Instead, it will be replaced predominantly by fossil fuel-fired plants emitting significant carbon and other air pollution. Germany's and California's recent experiences illustrate the problem. After Germany prematurely retired its nuclear fleet, it saw a massive increase in emissions despite investing in new renewable generation to such a degree that its electricity rates are now among the world's highest. In California, the closure of the San Onofre nuclear plant in early 2012 resulted in an increase in emissions that more than offset all of California's investment to date in wind, solar, and biomass generation.[9] New York similarly found that replacing its nuclear fleet would require that it triple its already-aggressive energy efficiency targets or construct "9,000 MW of onshore wind or 22,000 MW of solar," which "is virtually impossible to deploy . . . in the short-term."[10] By valuing at-risk nuclear plants' environmental benefits, ZEC programs provide a necessary bridge that allows states to decarbonize their electricity sector consistently and cost-effectively over time.

ZEC programs, like other state environmental programs including REC programs,[11] complement the efficiency of FERC's wholesale markets by addressing the environmental externalities that result from generation. Fossil-fuel generation emits pollution, a negative externality. The private cost of generating electricity using fossil fuels is therefore much lower than the social cost, and the market outcome is accordingly unlikely to be efficient. Because of this distortion, wholesale market prices create the appearance that at-risk nuclear units are not efficiently competitive, but that appearance is misleading: at-risk nuclear units are competitive once the environmental benefits they provide to society are considered. Basic economics teaches that a tax or subsidy could correct this market inefficiency by internalizing the negative or positive externalities of electricity generation.[12] Moreover, ZEC programs have been designed to harmonize with wholesale markets. The value of a ZEC is capped at the value of the environmental externality being abated, which the states have determined to be equal to the social cost of carbon. The programs thus are not intended to, and cannot, replace lost wholesale revenues if wholesale prices drop. Moreover, payments are made only to those generators whose environmental benefits would otherwise be lost. This is indistinguishable from REC programs, which likewise compensate renewable generators that would not be economic (and thus whose environmental benefits would not exist) but for revenues from selling renewable energy credits. And state environmental

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[9] Cal. Energy Commission, *California Energy Almanac*, *available at* http://www.energy.ca.gov/almanac/electricity_data/electricity_generation.html.

[10] *See* N.Y. Pub. Serv. Comm'n, Order Adopting a Clean Energy Standard at 127, Docket No. 15-E-0302 (Aug. 1, 2016).

[11] The ZEC programs are modeled on the features of REC programs that make such programs fall within state jurisdiction. As the Commission has explained, a REC "certif[ies] that electric energy was generated pursuant to certain requirements and standards." *WSPP, Inc.*, 139 FERC ¶ 61,061, at P 21 (2012). RECs are therefore "separate commodities" that "are *not* compensation for capacity and energy." *Cal. Pub. Utils. Comm'n*, 133 FERC ¶ 61,059, at P 31 n.62. The Commission has held that when RECs are sold unbundled from capacity and energy, they fall outside the Commission's jurisdiction. *WSPP*, 139 FERC ¶ 61,061 at P 24. ZEC programs follow this well-trodden path. ZECs, like RECs, certify that electricity was produced in a particular way—by a zero-emissions nuclear facility. And ZECs are sold unbundled from any wholesale sale of electricity. Under *WSPP*, that means ZECs (like RECs) fall outside the Commission's jurisdiction.

The Commission's reasoning in *WSPP* is supported by that of the Supreme Court in *Hughes v. Talen Energy Marketing, LLC*, 136 S. Ct. 1288 (2016). *Hughes* held that a state illegally "sets an interstate wholesale rate" when it expressly conditions a state payment on completion of a wholesale sale. *Hughes*, 136 S. Ct. at 1297. A program that "does not condition payment of funds on capacity clearing the auction" would not suffer the "fatal defect" that doomed the program in *Hughes*. *Id.* at 1299. Thus, "measures" to "encourage" clean generation, "including tax incentives, land grants, direct subsidies," as well as REC and ZEC programs, fall on the permissible side of the line, because they do not condition payment on "a generator's wholesale market participation." *Id.* at 1299 (quoting Br. for Resp't 40).

[12] *See* Decl. of Robert Willig, attach. to Protest of Exelon Corp., No. EL16-49-000 (Jan. 30, 2017), at 8-18 ("Willig Decl.").

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programs of this kind have contributed to resource adequacy and have not chilled merchant investment.[13]

Accordingly, FERC could simply maintain the status quo, in which wholesale markets optimize for resource adequacy against a backdrop in which states adopt their own environmental policies aimed at addressing the environmental externalities of generation.

II. The Commission Can Grant ISOs And RTOs Flexibility To Integrate State Policies And Wholesale Markets On A Regional Basis.

Alternatively, if the Commission chooses to create a pathway for states to achieve their environmental goals through wholesale markets, it should permit ISOs and RTOs the flexibility to integrate state goals in a manner that respects divergent state policy choices and regional priorities. Such an approach has the greatest potential to achieve both cost savings and stakeholder support, avoiding the litigation that has proliferated around these issues. The approach that receives the most support among economists is imposing a carbon price on emitting resources dispatched through the RTOs. The RTO would administer the carbon price on behalf of the states at a level agreed upon by the states to achieve their goals. Such an approach would internalize the environmental costs of carbon pollution and reward lower emitting resources, obviating the need for state programs to support such resources.

While it would be most efficient if an entire region participated, a multi-state RTO could also permit states to opt in or out to respect differing state policy choices. For example, an RTO could apply a border adjustment similar to the tariff provisions the Commission has already approved for the California ISO. Under this approach, the RTO would add a constraint that requires all load in carbon-pricing zones to be matched with an equal amount of generation across the RTO. Generators selected to serve the load in carbon-pricing zones would be charged for emissions; generators selected to serve the load in non-carbon pricing zones would not be charged. Effectively, such a border adjustment provision creates a new "carbon obligation" market that is analogous to a reserve constraint and is co-optimized with the energy market, as reserves are today. This solution will integrate states' environmental goals efficiently and is fair to customers in neighboring states that choose not to price carbon.[14] A border adjustment of this kind is necessary; otherwise, as RGGI has demonstrated, carbon-pricing states face difficulty achieving their environmental goals due to the "leakage" of emissions from non-carbon states, and consumers in non-participating states experience price increases due to the policies adopted by the carbon-pricing states.

We note that PJM, in its pre-technical conference comments, identifies a regional or subregional carbon price as its primary initiative. The NYISO is also studying the effects of such an approach, and the Integrating Markets and Public Policy effort in the ISO-NE region has examined the same concept. The Commission should encourage these efforts and, as described below, provide a forum for them to be cultivated. In addition, the Commission should encourage the RTOs to redouble their efforts on energy market price formation to ensure that all units that are needed to serve load are permitted to set LMP. Under current market rules, energy prices do not always reflect the true economic marginal cost of the resources operating on the system, which contributes to the economic challenges currently faced

[13] In PJM, for example, the last five Base Residual Auctions have resulted in nearly 25 GW of new gas capacity. And that is despite the fact that PJM continues to have large reserve margins—22.4% in the last Base Residual Auction, compared to a target reserve margin of 16.5%. *See* PJM Interconnection, L.L.C., *2019/2020 RPM Base Residual Auction Results* at 1, 24, http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-base-residual-auction-report.ashx.

[14] The California ISO, along with its stakeholders, is currently evaluating enhancements to its border adjustment system that would assign a carbon obligation only to the portion of external generation that incrementally serves California load relative to a no-import baseline. If successfully implemented, this enhancement is likely to further improve the efficacy of border adjustments in reducing emission leakage and enhancing the quality of the carbon price signal. It could serve as an improved template for other RTOs in developing their own border adjustment systems.

by many nuclear resources. Correcting this flaw in price formation has the potential to more appropriately value nuclear resources' contribution to reliable operations and greatly diminish the need for additional state programs to preserve existing nuclear plants' environmental attributes.

III. Mitigating Resources Receiving Support Through State Environmental Programs Is Inappropriate And Imposes Needless Costs On Consumers.

Buyer-side mitigation rules are aimed at large buyers seeking to suppress market prices by introducing new, uneconomic supply.[15] But environmental programs like ZEC programs do not fit that description. First, in ZEC and REC programs, the state is purchasing a separate environmental attribute, so ZECs and RECs are not tied to energy or capacity sales. A price-suppression mechanism would clearly condition payment on participation in the capacity market. Second, the value of a ZEC is capped at the social cost of carbon, so the ZEC program is cost-justified based solely on the state's record-based determination of its environmental benefit—unlike a price-suppression mechanism, in which the anticipated price-suppression benefits would be necessary to render the program cost-effective. ZEC facilities also still bear market risk. A price-suppression mechanism would guarantee sufficient revenues for the uneconomic supplier to remain in the capacity market. Environmental programs like ZEC programs thus are not vehicles for price suppression.[16]

Instead, to the extent clean energy resources are paid for their environmental benefits, they have lower going-forward costs and should be permitted to offer accordingly. Commission orders have long recognized as much. The Commission has approved the deduction of revenues from REC payments in the calculation of the offer-review trigger price,[17] and has approved CAISO's proposal to lower its energy "bid floor" to permit "variable energy resources" to offer at extremely low prices because they "generally receive, in addition to market revenues … renewable energy credits …."[18] The Commission thus has recognized that renewable resources receive significant compensation for their environmental attributes, but instead of mitigating them, it approved a change in the energy market offer rules to allow them to account for that compensation in their offers.

That makes sense. States could pursue these same ends in a number of ways, including emissions controls or an emissions tax. Yet the Commission would not mitigate the offers of clean resources that are exempt from emissions controls or taxes, even though those resources could underbid polluting resources because they are not so regulated. Nor should the Commission mitigate clean resources in the parallel situation when they could underbid polluting resources because they receive payments for their environmental services.

IV. Regional Technical Conferences Would Be the Appropriate Next Step.

The Commission has a critical role to play in supporting the evolution of wholesale markets to address the policy goals of the states. Exelon recommends that the Commission hold regional technical conferences to facilitate further discussion among states, RTOs, and stakeholders. At these conferences, FERC and its staff should be prepared to provide guidance regarding the Commission review process for any market rule changes developed. While it is clear that the Commission would prefer a negotiated solution, such negotiations may only be possible with such preliminary guidance from the Commission.

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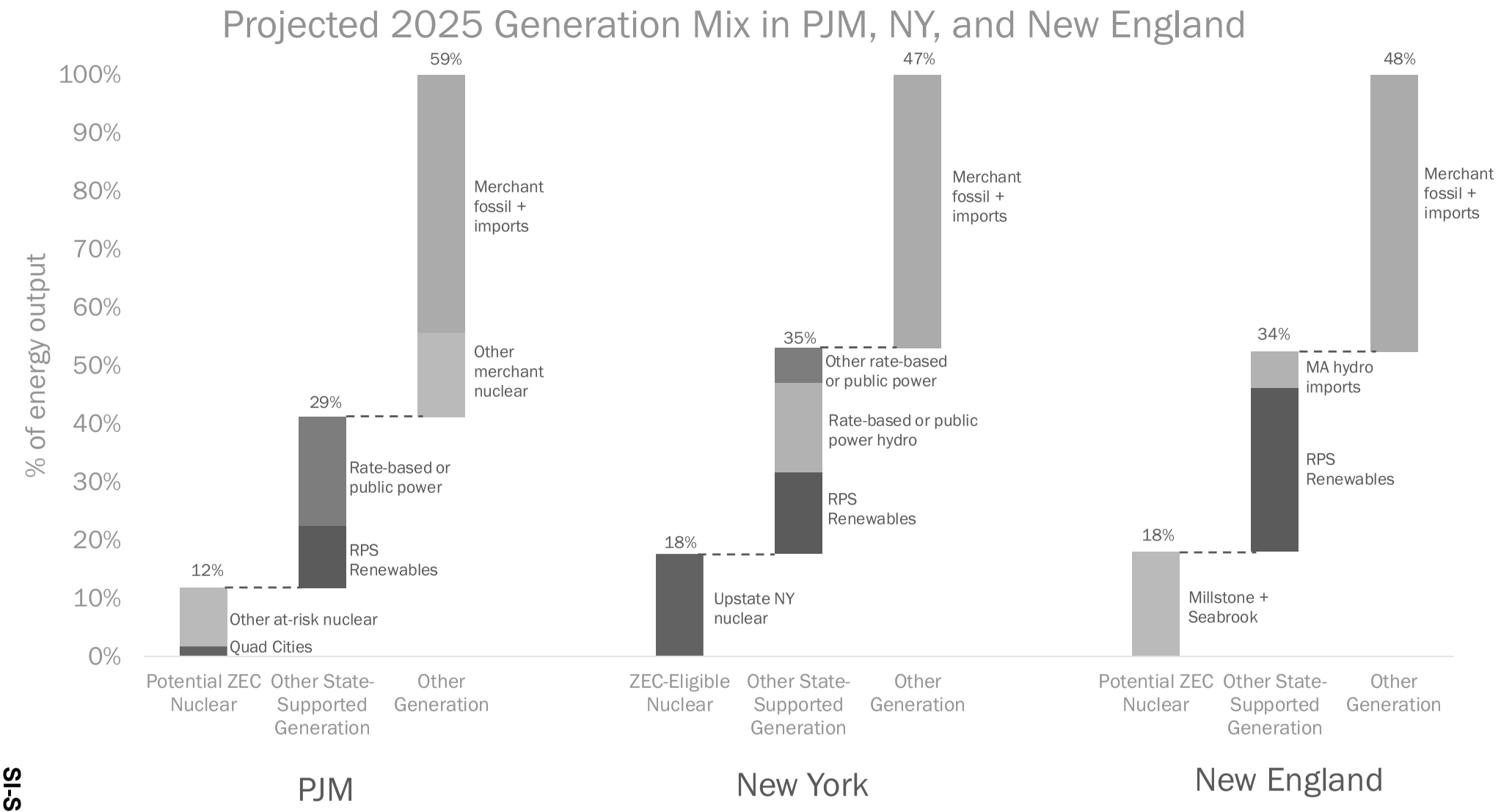
[15] *N.Y. Indep. Sys. Operator, Inc.*, 122 FERC ¶ 61,211, at P 101 (2008).
[16] *See* Willig Decl at 18-24.
[17] *See ISO New England Inc.*, 146 FERC ¶ 61,084, at P 32 (2014) (rejecting argument that REC revenues are out-of-market revenues, and approving reduction of ORTP for new renewable resources to account for REC revenues).
[18] *Cal. Indep. Sys. Operator Corp.*, 145 FERC ¶ 61,254, at PP 5, 34 (2013).

EXHIBIT A

State-supported renewables and rate-based generation will be over twice as large as potential nuclear ZEC generation by 2025



Sources: 2016 ISO-NE CELT Report; 2016 New York Gold Book; 2016 PJM Load Forecast Report; FERC Form 1 filings for investor-owned utilities in PJM and NY; Projected RPS renewables based on existing RPS legislation in various states; MA hydro imports based on 9.45 TWh clean generation procurement target specified in MA H. 4568. "At-risk nuclear" in PJM assumed to be Quad Cities, Byron, Davis-Besse, Perry, Beaver Valley, Three Mile Island, Salem, and Hope Creek.

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Exelon

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Hesser.McBride@PSEG.com

PSEG
Services Corporation

VIA ETARIFF

March 17, 2016

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: PSEG Energy Resources & Trade LLC
Docket Nos. ER15-1882-000 and ER15-1882-001
Compliance Filing Pursuant to Letter Order Issued February 24, 2016

Dear Secretary Bose:

On February 24, 2016 the Federal Energy Regulatory Commission ("FERC" or "Commission") issued a letter order[1] approving the Unilateral Offer of Settlement filed in this docket by PSEG Energy Resources & Trade LLC ("PSEG ER&T) on December 23, 2015. The Offer of Settlement resolved all pending issues arising from PSEG ER&T's submittal of its cost-based revenue requirement for providing Reactive Supply and Voltage Control from Generation or Other Sources Service ("Reactive Power") owned by PSEG Fossil LLC ("PSEG Fossil").

In compliance with the Commission's directive, PSEG ER&T hereby submits under cover of this letter in eTariff format its First Revised Rate Schedule FERC No. 3 ("Rate Schedule"), which was approved by the Commission in its February 24 order and which replaces current PSEG ER&T Rate Schedule FERC No. 3. PSEG ER&T also submits a redlined version of its Rate Schedule showing the changes being made to the as-filed version of the rate schedule. PSEG ER&T proposes that, consistent with the Commission's order approving the Offer of Settlement, the Rate Schedule become effective on January 7, 2016. To the extent necessary, PSEG ER&T respectfully request waiver of the notice requirement in Section 35.3 of the Commission' Regulations, 18 C.F.R. § 35.3 (2015), to allow the revised rate schedule to become effective on January 7, 2016.

Please contact the undersigned if there are any questions concerning this submittal.

Respectfully submitted,

By: *Hesser G. McBride, Jr.*

Hesser G. McBride, Jr.
Attorney for PSEG Energy Resources & Trade LLC

Attachments

[1] *PSEG Energy Resources & Trade LLC*, 154 FERC ¶ 61,135 (2016)

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Marked Tariff

~~PSEG ENERGY RESOUCES & TRADE LLC~~

~~RATE SCHEUDLE FERC NO. 3~~

Reactive Supply and ~~voltage~~ Voltage Control from Generation Sources Service

PSEG Energy Resources & Trade LLC ("PSEG ER&T") provides Reactive Supply and Voltage from Generation Sources Service ("Reactive Supply Service") from various generating facilities to the PJM Interconnection, LLC ("PJM") system. This Rate Schedule, which consists of seventeen separate tariff sections for each of PSEG ER&T's generating facilities, sets forth PSEG ER&T's revenue requirements for the provision of Reactive Supply Service to PJM, as contemplated by Schedule 2 of the PJM open access transmission tariff.

PSEG ER&T's total monthly revenue requirement consists of the sum of the charges for the following: (1) the Fixed Capability Revenue Requirement; and (2) the Heating Losses Component~~. Total charges~~ for ~~any 12 month period will not be less than~~each of its generating facilities. The Fixed Capability Revenue Requirement:~~-~~ the ~~sum of~~ Heating Losses Component, and the ~~annual charges specified~~ Total Revenue Requirements for each generating facility is set forth in the Rate Schedule below. This Rate Schedule and its separate sections shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

Nothing contained herein shall be construed as affecting in any way the right of PSEG ER&T to unilaterally make application to the Federal Energy Regulatory Commission for a change in rates under section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder. If PSEG ER&T seeks to change one of the revenue requirements stated herein, it will abide by relevant FERC procedures for changes in rates and notify PJM in accordance with any notice requirement in the PJM Tariff.

~~**MONTHLY REVENUE REQUIREMENT:**~~

~~**1. FIXED CAPABILITY COMPONENT**~~

~~The annual revenue requirement for the Fixed Capability Component is $25,750,450.~~

~~The monthly charge to PJM is $25,750,450 / 12 = $2,145,871~~

~~**2. HEATING LOSSES COMPONENT**~~

~~The annual revenue requirement for the Heating Losses Component is $876,337.~~

~~The monthly charge to PJM is $$876,337 / 12 = $73,028.~~

~~**3. TOTAL REVENUE REQUIREMENT**~~

~~Total Annual Revenue Requirement is $25,750,450 + $876,337 = $26,626,787~~

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~~Total Monthly Revenue Requirement is $26,626,787 / 12 = $2,218,899.~~

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BERGEN 1 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,596,977.

Total Monthly Revenue Requirement is $216,414.73.

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BERGEN 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,076,006.

Total Monthly Revenue Requirement is $173,000.46.

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LINDEN 1 & 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $7,611,923.

Total Monthly Revenue Requirement is $634,326.88

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HUDSON 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,225,284.

Total Monthly Revenue Requirement is $102,107.00.

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MERCER 1 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $282,354.

Total Monthly Revenue Requirement is $23,529.50.

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MERCER 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $855,097.

Total Monthly Revenue Requirement is $71,258.07.

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CONEMAUGH 1 & 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $436,981.

Total Monthly Revenue Requirement is $36,415.05.

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KEYSTONE 1 & 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $502,936.

Total Monthly Revenue Requirement is $41,911.37.

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SALEM 1 & 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,975,967.

Total Monthly Revenue Requirement is $164,663.88.

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HOPE CREEK 1 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $4,081,407.

Total Monthly Revenue Requirement is $340,117.28.

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PEACH BOTTOM 1 & 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $5,455,862.

Total Monthly Revenue Requirement is $454,655.17.

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SEWAREN 1 - 4 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,212,364.

Total Monthly Revenue Requirement is $101,030.37.

20160317-5036 FERC PDF (Unofficial) 3/17/2016 10:28:06 AM

BURLINGTON 12 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $916,582.

Total Monthly Revenue Requirement is $76,381.83.

20160317-5036 FERC PDF (Unofficial) 3/17/2016 10:28:06 AM

ESSEX 9 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $924,539.

Total Monthly Revenue Requirement is $77,044.95.

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KEARNY 12, 13, 14 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,589,795.

Total Monthly Revenue Requirement is $215,816.28.

20160317-5036 FERC PDF (Unofficial) 3/17/2016 10:28:06 AM

LINDEN 5, 6, 7, 8 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $986,835.

Total Monthly Revenue Requirement is $82,236.28.

20160317-5036 FERC PDF (Unofficial) 3/17/2016 10:28:06 AM

YARDS CREEK GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $269,091.

Total Monthly Revenue Requirement is $22,424.23.

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Clean Tariff

20160317-5036 FERC PDF (Unofficial) 3/17/2016 10:28:06 AM

Reactive Supply and Voltage Control from Generation Sources Service

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PSEG ER&T's total monthly revenue requirement consists of the sum of the charges for the following: (1) the Fixed Capability Revenue Requirement; and (2) the Heating Losses Component for each of its generating facilities. The Fixed Capability Revenue Requirement: the Heating Losses Component, and the Total Revenue Requirements for each generating facility is set forth in the Rate Schedule below. This Rate Schedule and its separate sections shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

Nothing contained herein shall be construed as affecting in any way the right of PSEG ER&T to unilaterally make application to the Federal Energy Regulatory Commission for a change in rates under section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder. If PSEG ER&T seeks to change one of the revenue requirements stated herein, it will abide by relevant FERC procedures for changes in rates and notify PJM in accordance with any notice requirement in the PJM Tariff.

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FERC rendition of the electronically filed tariff records in Docket No. ER15-01882-002
Filing Data:
CID: C001195
Filing Title: Filing in compliance with Feb. 24, 2016 Letter Order
Company Filing Identifier: 116
Type of Filing Code: 80
Associated Filing Identifier: 115
Tariff Title: Rate Schedule FERC No. 3 Reactive Supply And Voltage Control From Generation Sources Service
Tariff ID: 10
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Rate Schedule No. 3, Sheet 02, 1.0.0, A
Record Narative Name: Sheet 02
Tariff Record ID: 1750
Tariff Record Collation Value: 1750 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

Reactive Supply and Voltage Control from Generation Sources Service

PSEG Energy Resources & Trade LLC ("PSEG ER&T") provides Reactive Supply and Voltage from Generation Sources Service ("Reactive Supply Service") from various generating facilities to the PJM Interconnection, LLC ("PJM") system. This Rate Schedule, which consists of seventeen separate tariff sections for each of PSEG ER&T's generating facilities, sets forth PSEG ER&T's revenue requirements for the provision of Reactive Supply Service to PJM, as contemplated by Schedule 2 of the PJM open access transmission tariff.

PSEG ER&T's total monthly revenue requirement consists of the sum of the charges for the following: (1) the Fixed Capability Revenue Requirement; and (2) the Heating Losses Component for each of its generating facilities. The Fixed Capability Revenue Requirement: the Heating Losses Component, and the Total Revenue Requirements for each generating facility is set forth in the Rate Schedule below. This Rate Schedule and its separate sections shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

Nothing contained herein shall be construed as affecting in any way the right of PSEG ER&T to unilaterally make application to the Federal Energy Regulatory Commission for a change in rates under section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder. If PSEG ER&T seeks to change one of the revenue requirements stated herein, it will abide by relevant FERC procedures for changes in rates and notify PJM in accordance with any notice requirement in the PJM Tariff.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Bergen 1, Sheet 3, 1.0.0, A
Record Narative Name: Sheet 3
Tariff Record ID: 2750
Tariff Record Collation Value: 2750 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

BERGEN 1 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,596,977.

Total Monthly Revenue Requirement is $216,414.73.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Bergen 2, Sheet 4, 1.0.0, A
Record Narative Name: Sheet 4
Tariff Record ID: 3750
Tariff Record Collation Value: 3750 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

BERGEN 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,076,006.

Total Monthly Revenue Requirement is $173,000.46.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Linden 1 & 2, Sheet 5, 1.0.0, A
Record Narative Name: Sheet 5
Tariff Record ID: 4750
Tariff Record Collation Value: 4750 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

LINDEN 1 & 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $7,611,923.

Total Monthly Revenue Requirement is $634,326.88

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Hudson 2, Sheet 6, 1.0.0, A
Record Narative Name: Sheet 6
Tariff Record ID: 5750
Tariff Record Collation Value: 5750 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

HUDSON 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,225,284.

Total Monthly Revenue Requirement is $102,107.00.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Mercer 1, Sheet 7, 1.0.0, A
Record Narative Name: Sheet 7
Tariff Record ID: 6750
Tariff Record Collation Value: 6750 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

MERCER 1 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $282,354.

Total Monthly Revenue Requirement is $23,529.50.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Mercer 2, Sheet 8, 1.0.0, A
Record Narative Name: Sheet 8
Tariff Record ID: 7750
Tariff Record Collation Value: 7750 Tariff Record Parent Identifier: 0
Proposed Date: 2016-03-17
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

MERCER 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $855,097.

Total Monthly Revenue Requirement is $71,258.07.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Conemaugh 1 & 2, Sheet 9, 1.0.0, A
Record Narative Name: Sheet 9
Tariff Record ID: 8750
Tariff Record Collation Value: 8750 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

CONEMAUGH 1 & 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $436,981.

Total Monthly Revenue Requirement is $36,415.05.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Keystone 1 & 2, Sheet 10, 1.0.0, A
Record Narative Name: Sheet 10
Tariff Record ID: 9750
Tariff Record Collation Value: 9750 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

KEYSTONE 1 & 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $502,936.

Total Monthly Revenue Requirement is $41,911.37.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Salem 1 & 2, Sheet 11, 1.0.0, A
Record Narative Name: Sheet 11
Tariff Record ID: 10750
Tariff Record Collation Value: 10750 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

SALEM 1 & 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,975,967.

Total Monthly Revenue Requirement is $164,663.88.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Hope Creek 1, Sheet 12, 1.0.0, A
Record Narative Name: Sheet 12
Tariff Record ID: 11750
Tariff Record Collation Value: 11750 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

HOPE CREEK 1 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $4,081,407.

Total Monthly Revenue Requirement is $340,117.28.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Peach Bottom 1 & 2`, Sheet 13, 1.0.0, A
Record Narative Name: Sheet 13
Tariff Record ID: 19250
Tariff Record Collation Value: 19250 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

PEACH BOTTOM 1 & 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $5,455,862.

Total Monthly Revenue Requirement is $454,655.17.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Sewaren 1 - 4, Sheet 14, 1.0.0, A
Record Narative Name: Sheet 14
Tariff Record ID: 20250
Tariff Record Collation Value: 20250 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

SEWAREN 1 - 4 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,212,364.

Total Monthly Revenue Requirement is $101,030.37.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Burlington 12, Sheet 15, 1.0.0, A
Record Narative Name: Sheet 15
Tariff Record ID: 21250
Tariff Record Collation Value: 21250 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

BURLINGTON 12 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $916,582.

Total Monthly Revenue Requirement is $76,381.83.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Essex 9, Sheet 16, 1.0.0, A
Record Narative Name: Sheet 16
Tariff Record ID: 22250
Tariff Record Collation Value: 22250 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

ESSEX 9 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $924,539.

Total Monthly Revenue Requirement is $77,044.95.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Kearny 12 13 14, Sheet 17, 1.0.0, A
Record Narative Name: Sheet 17
Tariff Record ID: 23250
Tariff Record Collation Value: 23250 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

KEARNY 12, 13, 14 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,589,795.

Total Monthly Revenue Requirement is $215,816.28.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Linden 5 6 7 8, Sheet 18, 1.0.0, A
Record Narative Name: Sheet 18
Tariff Record ID: 24250
Tariff Record Collation Value: 24250 Tariff Record Parent Identifier: 0
Proposed Date: 2016-11-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

LINDEN 5, 6, 7, 8 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $986,835.

Total Monthly Revenue Requirement is $82,236.28.

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Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Yards Creek, Sheet 19, 1.0.0, A
Record Narative Name: Sheet 19
Tariff Record ID: 25250
Tariff Record Collation Value: 25250 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 500
Record Change Type: New
Record Content Type: 1
Associated Filing Identifier:

YARDS CREEK GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $269,091.

Total Monthly Revenue Requirement is $22,424.23.

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Document Content(s)

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Clean Proposed Tariff 2015-12.PDF.....22-40

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Hesser G. McBride Jr
Associate General Regulatory Counsel

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tel: 973.430.5333 fax:973.430.5983
Hesser.McBride@PSEG.com

PSEG Services Corporation

VIA ELECTRONIC FILING

April 26, 2017

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: PSEG Energy Resources & Trade, LLC
Docket No. ER17-1054-00_
Reactive Supply and Voltage Control from Generation or Other Sources – Schedule 2 PJM Tariff – Cancelation of tariff record

Dear Secretary Bose:

This filing is being made on behalf of PSEG Energy Resources & Trade ("PSEG ER&T"). PSEG ER&T provides reactive power service from various PSEG ER&T affiliated generating units pursuant to tariffs on file with the Federal Energy Regulatory Commission ("Commisssion", "FERC). As a result, PSEG ER&T receives reactive power service revenue requirements from PJM.[1]

Through conversations with FERC Staff and review of the Commission's eTariff website, we have learned that certain tariff sections PSE&G's Reactive Power Schedule that should have been cancelled by a prior filing are currently on file. The specific tariff records that should have been cancelled are identified below.

The relevant tariff sections that need to cancelled are as follows:

- 1250 Rate Schedule No. 3, Sheet 02
- 2250 Bergen 1, Sheet 3
- 3250 Bergen 2, Sheet 4

[1] On February 24, 2016, the Commission issued an order approving an offer of settlement revising PSEG ER&T's Schedule FERC No. 3 (Reactive Power Schedule) which sets forth the revenue requirement for the provision of Reactive Supply and Voltage Control from Generation Sources Service by facilities owned by PSEG Fossil LLC and PSEG Nuclear LLC. See *PSEG Energy Resources & Trade, LLC*, 154 FERC ¶ 63,008 (2016) ("Settlement Order"). On March 17, 2016, PSEG ER&T submitted tariff revisions[1] to comply with the Settlement Order. On April 14, 2016, the Commission issued an order accepting the tariff revisions submitted on March 17, 2016. See *PSEG Energy Resources & Trade, LLC*, Docket No. ER 1882-002, Order Accepting Compliance filing, April 14, 2016.

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- 4250 Linden 1 & 2, Sheet 5
- 5250 Hudson 2, Sheet 6
- 6250 Mercer 1, Sheet 7
- 7250 Mercer 2, Sheet 8
- 8250 Conemaugh 1 & 2, Sheet 9
- 9250 Keystone 1 & 2, Sheet 10
- 10250 Salem 1 & 2, Sheet 11
- 11250 Hope Creek 1, Sheet 12
- 12250 Peach Bottom 1 & 2, Sheet 13
- 13250 Sewaren 1 - 4, Sheet 14
- 14250 Burlington 12, Sheet 15
- 15250 Essex 9, Sheet 16
- 16250 Kearny 12, 13, 14, Sheet 17
- 17250 Linden 5, 6, 7, 8, Sheet 18
- 18250 Yards Creek, Sheet 19

We are hereby submitting an electronic tariff filing that cancels the above-refernced records.

Conclusion

PSEG ER&T respectfully requests that the Commission accept this filing to cancel the above-referenced tariff records.

Respectfully submitted,

Hesser G. McBride

Hesser G. McBride

CC: Jen Tribulski, PJM Interconnection L.L.C. (transmittal letter only)

FERC rendition of the electronically filed tariff records in Docket No. ER15-01882-003
Filing Data:
CID: C001195
Filing Title: Cancellation of certain tariff records in compliance with FERC Staff
Company Filing Identifier: 118
Type of Filing Code: 80
Associated Filing Identifier: 114
Tariff Title: Rate Schedule FERC No. 3 Reactive Supply And Voltage Control From Generation Sources Service
Tariff ID: 10
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Rate Schedule No. 3, Sheet 02 (Cancellation), 4.0.0, A
Record Narative Name: Sheet 02 (Cancellation)
Tariff Record ID: 1250
Tariff Record Collation Value: 4000 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

Reactive Supply and Voltage Control from Generation Sources Service

PSEG Energy Resources & Trade LLC ("PSEG ER&T") provides Reactive Supply and Voltage from Generation Sources Service ("Reactive Supply Service") from various generating facilities to the PJM Interconnection, LLC ("PJM") system. This Rate Schedule which consists of seventeen separate tariff rate sections for each of PSEG ER&T's generating facilities sets forth PSEG ER&T's revenue requirements for the provision of Reactive Supply Service to PJM, as contemplated by Schedule 2 of the PJM open access transmission tariff.

PSEG ER&T's total monthly revenue requirement consists of the sum of the charges for the following: (1) the Fixed Capability Revenue Requirement; and (2) the Heating Losses Component for each of its generating facilities. The Fixed Capability Revenue Requirement; the Heating Losses Component, and the Total Revenue Requirement for each generating facility is set forth in the Rate Schedule sections below. This Rate Schedule and its separate sections shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

Nothing contained herein shall be construed as affecting in any way the right of PSEG ER&T to unilaterally make application to the Federal Energy Regulatory Commission for a change in rates under section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder. If PSEG ER&T seeks to change one of the revenue requirements stated herein, it will abide by relevant FERC procedures for changes in rates and notify PJM in accordance with any notice requirement in the PJM Tariff.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Bergen 1 (Cancellations, Sheet 3 (Cancellation), 3.0.0, A
Record Narative Name: Sheet 3 (Cancellation)
Tariff Record ID: 2250
Tariff Record Collation Value: 5000 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

BERGEN 1 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,925,105.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $28,652.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,925,105 + $28,652 = $2,953,757.

Total Monthly Revenue Requirement is $2,953,757 / 12 = $246,146.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Bergen 2 (Cancellation), Sheet 4 (Cancellation), 3.0.0, A
Record Narative Name: Sheet 4 (Cancellation)
Tariff Record ID: 3250
Tariff Record Collation Value: 6000 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

BERGEN 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,330,193.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $31,021.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,330,193 + $31,021= $ 2,361,214.

Total Monthly Revenue Requirement is $2,361,214 / 12 = $ 196,768.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Linden 1 & 2 (Cancel), Sheet 5 (Cancellation), 3.0.0, A
Record Narative Name: Sheet 5 (Cancellation)
Tariff Record ID: 4250
Tariff Record Collation Value: 7000 Tariff Record Parent Identifier: 0
Proposed Date: 6216-11-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

LINDEN 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $8,589,078.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $68,593.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $8,589,078 + $68,593 = $8,657,672.

Total Monthly Revenue Requirement is $8,657,672 / 12 = $721,473.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Hudson 2 (Cancellation, Sheet 6 (Cancellation), 3.0.0, A
Record Narative Name: Sheet 6 (Cancellation)
Tariff Record ID: 5250
Tariff Record Collation Value: 8000 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

HUDSON 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,386,352.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $7,266.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,386,352 + $7,266 = $1,393,617.

Total Monthly Revenue Requirement is $1,393,617 / 12 = $116,135.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Mercer 1 (Cancellation), Sheet 7 (Cancellation), 3.0.0, A
Record Narative Name: Sheet 7 (Cancellation)
Tariff Record ID: 6250
Tariff Record Collation Value: 9000 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

MERCER 1 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $318,855.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $2,290.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $318,855 + $2,290 = $321,145.

Total Monthly Revenue Requirement is $321,145 / 12 = $26,762.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Mercer 2 (Cancellation, Sheet 8 (Cancellation), 3.0.0, A
Record Narative Name: Sheet 8 (Cancellation)
Tariff Record ID: 7250
Tariff Record Collation Value: 10000 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

MERCER 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $969,405.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $3,168.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $969,405 + $3,168 = $972,573.

Total Monthly Revenue Requirement is 972,573 / 12 = $81,048.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Conemaugh 1 & 2 (Cancel), Sheet 9 (Cancellation), 3.0.0, A
Record Narative Name: Sheet 9 (Cancellation)
Tariff Record ID: 8250
Tariff Record Collation Value: 11000 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

CONEMAUGH 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $482,544.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $14,470.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $482,544 + $14,470 = $497,014.

Total Monthly Revenue Requirement is $497,014 / 12 = $41,418.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Keystone 1 & 2, Sheet 10 (Cancellation), 3.0.0, A
Record Narative Name: Sheet 10 (Cancellation)
Tariff Record ID: 9250
Tariff Record Collation Value: 12000 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

KEYSTONE 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $559,507.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $12,524.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $559,507 + $12,524 = $572,031.

Total Monthly Revenue Requirement is $572,031 / 12 = $47,669.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Salem 1 & 2 (Cancel), Sheet 11 (Cancellation), 3.0.0, A
Record Narative Name: Sheet 11 (Cancellation)
Tariff Record ID: 10250
Tariff Record Collation Value: 13000 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

SALEM 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,200,674.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $46,757.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,200,674 + $46,757 = $2,247,431.

Total Monthly Revenue Requirement is $2,247,431 / 12 = $187,286.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Hope Creek 1 (Cancel), Sheet 12 (Cancellation), 3.0.0, A
Record Narative Name: Sheet 12 (Cancellation)
Tariff Record ID: 11250
Tariff Record Collation Value: 14000 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

HOPE CREEK 1 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $4,602,764.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $39,360.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $4,602,764. + $39,360 = $4,642,124.

Total Monthly Revenue Requirement is $4,642,124 / 12 = $386,844.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Peach Bottom 1 & 2 Cancel, Sheet 13 (Cancellation), 3.0.0, A
Record Narative Name: Sheet 13 (Cancellation)
Tariff Record ID: 12250
Tariff Record Collation Value: 15000 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

PEACH BOTTOM 1 & 2 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $ 6,139,449.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $65,956.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $6,139,449 + $65,956 = $6,205,405.

Total Monthly Revenue Requirement is $6,205,405 / 12 = $517,117.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Sewaren 1 - 4 (Cancel), Sheet 14 (Cancellation), 3.0.0, A
Record Narative Name: Sheet 14 (Cancellation)
Tariff Record ID: 13250
Tariff Record Collation Value: 16000 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

SEWAREN 1 - 4 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,377,492.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $1,431.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,377,492. + $1,431 = $1,378,923.

Total Monthly Revenue Requirement is $1,378,923 / 12 = $114,910.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Burlington 12 (Cancel), Sheet 15 (Cancellation), 3.0.0, A
Record Narative Name: Sheet 15 (Cancellation)
Tariff Record ID: 14250
Tariff Record Collation Value: 17000 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

BURLINGTON 12 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $ 1,041,234.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $1,271.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,041,234. + $1,271 = $1,042,505

Total Monthly Revenue Requirement is $1,042,505 / 12 = $86,875.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Kearny 12, 13, 14 Cancel, Sheet 17 (Cancellation), 3.0.0, A
Record Narative Name: Sheet 17 (Cancellation)
Tariff Record ID: 16250
Tariff Record Collation Value: 19000 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

KEARNY 12, 13, 14 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $2,940,897.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $4,692.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,940,897 + $4,692 = $2,945,589.

Total Monthly Revenue Requirement is $2,945,589 / 12 = $245,466.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Linden 5, 6, 7, 8 Cancel, Sheet 18 (Cancellation), 3.0.0, A
Record Narative Name: Sheet 18 (Cancellation)
Tariff Record ID: 17250
Tariff Record Collation Value: 20000 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

LINDEN 5, 6, 7, 8 GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $1,121,530.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $879.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,121,530 + $879 = $1,122,410.

Total Monthly Revenue Requirement is $1,122,410 / 12 = $93,534.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Yards Creek Cancellation, Sheet 19 (Cancellation), 3.0.0, A
Record Narative Name: Sheet 19 (Cancellation)
Tariff Record ID: 18250
Tariff Record Collation Value: 21000 Tariff Record Parent Identifier: 0
Proposed Date: 2016-01-07
Priority Order: 600
Record Change Type: Cancel
Record Content Type: 1
Associated Filing Identifier: 114

YARDS CREEK GENERATING FACILITY

1. FIXED CAPABILITY COMPONENT

The annual revenue requirement for the Fixed Capability Component is $302,956.

2. HEATING LOSSES COMPONENT

The annual revenue requirement for the Heating Losses Component is $3,103.

3. TOTAL REVENUE REQUIREMENT

Total Annual Revenue Requirement is $302,956 + $3,103 = $306,059.

Total Monthly Revenue Requirement is $306,059 / 12 = $25,505.

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Hesser G. McBride Jr
Associate General Regulatory Counsel

Law Department
80 Park Plaza, T5G, Newark, NJ 07102-4194
tel: 973.430.5333 fax:973.430.5983
Hesser.McBride@PSEG.com

PSEG Services Corporation

VIA ELECTRONIC FILING

May 10, 2017

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: PSEG Energy Resources & Trade, LLC
Docket No. ER15-1882-003
Reactive Supply and Voltage Control from Generation or Other Sources – Schedule 2 PJM Tariff – Cancelation of tariff record

Dear Secretary Bose:

On April 26, 2017, PSEG Energy Resources & Trade LLC ("PSEG ER&T") submitted a filing in the eTariff system in the above captioned matter (Accession No.: 20170426-5252). PSEG ER&T hereby submits for filing a withdrawal of the filing. Because of a coding error, this filing was inadvertently filed in a closed docket.

PSEG ER&T respectfully requests that the Commission withdraw the filing (Accession No.: 20170426-5252).

Respectfully submitted,

Hesser G. McBride

Hesser G. McBride

CC: Jen Tribulski, PJM Interconnection L.L.C.

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Document Content(s)

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Hesser G. McBride, Jr.
Associate General Regulatory Counsel

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PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
973-430-5333 fax: 973-430-5983
email: hesser.mcbride@pseg.com

VIA E FILING

December 23, 2015

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: PSEG Energy Resources & Trade LLC
Docket Nos. ER15-1882-000 and ER15-1882-001
Filing of Unilateral Offer of Settlement

Dear Secretary Bose:

Pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 385.602 (2015), PSEG Energy Resources & Trade LLC ("PSEG ER&T") hereby submits under cover of this letter a unilateral Offer of Settlement in this docket. The Offer of Settlement, if approved by the Commission without condition or modification (or if approved subject to one or more conditions or modifications that are acceptable to PSEG ER&T), will resolve the matter set for hearing by the Commission in its "Order Accepting and Suspending Proposed Rate Schedule and Establishing Hearing Procedures" issued August 7, 2015.[1]

The following documents are submitted herewith in support of PSEG ER&T's Offer of Settlement:

1. The Offer of Settlement;
2. Explanatory Statement;
3. Revised Tariff Sheet (in clean and redline format);
4. Draft of notice of filing of the Offer of Settlement;
5. Draft of letter order approving the Offer of Settlement; and
6. Certificate of service.

PSEG ER&T requests that this Offer of Settlement and supporting materials be promptly transmitted to the Honorable Steven A. Glazer, who is serving as Settlement Judge in this proceeding.

[1] *PSEG Energy Resources & Trade LLC*, 151 FERC ¶ 61,113 (2015).

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PSEG ER&T hereby requests a shortening of the time for filing comments and reply comments on the Offer of Settlement. Interventions and protests were due in Docket No. ER15-1882-000 on or before June 26, 2015 and in Docket No. ER15-1882-001 on or before July 1, 2015. No protests or adverse comments were filed. The undersigned also represents that it is PSEG ER&T's understanding that: (1) the Offer of Settlement is not opposed by the Commission Trial Staff, and (2) PJM Interconnection, L.L.C. ("PJM") which is the only intervenor in the docket, does not oppose the settlement. As no protests or adverse comments were filed and the Offer of Settlement is unopposed, PSEG ER&T requests that the Commission shorten the deadline for the filing of initial comments on the Offer of Settlement to ten (10) business days after the date on which the Commission issues notice of the filing of the Offer of Settlement, and that reply comments be due three (3) business days thereafter.

In accordance with Commission Rule 602(d), a copy of this submittal is being served on each participant in Docket Nos. ER15-1882-000 and ER15-1882-001. A certificate evidencing such service is provided herewith.

Please contact the undersigned if there are any questions concerning this submittal.

Respectfully submitted,

By: *Hesser G. McBride, Jr.*

Hesser G. McBride, Jr.
Attorney for PSEG Energy Resources & Trade LLC

Attachments

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

ATTACHMENT 1:

OFFER OF SETTLEMENT

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PSEG Energy Resources & Trade LLC	))	Docket Nos.	ER15-1882-000 ER15-1882-001

OFFER OF SETTLEMENT BY
PSEG ENERGY RESOURCES & TRADE LLC

Pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 385.602 (2015), PSEG Energy Resources & Trade LLC ("PSEG ER&T") hereby submits an Offer of Settlement in the above-captioned proceeding. If this Offer of Settlement is approved by the Commission without condition or modification, or if it is approved by the Commission subject to one or more conditions or modifications that are acceptable to PSEG ER&T, the Offer of Settlement will resolve the matter set for hearing by the Commission in this proceeding.

I. BACKGROUND

1.1 On June 5, 2015, PSEG ER&T tendered for filing pursuant to Section 205 of the Federal Power Act its revised Rate Schedule FERC No. 3 ("Rate Schedule"), which sets forth the cost-based revenue requirements for the provision of Reactive Supply and Voltage Control from Generation Sources Service ("Reactive Power") owned by PSEG Fossil LLC ("PSEG Fossil") and PSEG Nuclear LLC ("PSEG Nuclear") ("Reactive Power filing"). The Reactive Power filing covers all of the generating facilities currently owned by subsidiaries of PSEG Power LLC ("PSEG Power") within the PJM Interconnection, L.L.C. ("PJM") region ("the Facilities").[1] While the filing includes all of generation facilities within the PJM region owned by subsidiaries

[1] PSEG ER&T, PSEG Nuclear and PSEG Fossil are each direct subsidiaries of PSEG Power. PSEG ER&T is responsible for the administration within PJM of the assets covered by this filing and is currently recognized by PJM as the entity responsible for providing Reactive Power provided by the assets and is paid by PJM for providing such service. PSEG ER&T accordingly is the proper entity to provide this service.

of PSEG Power, the filing sets forth a proposed separate and distinct revenue requirement reflected in a separate tariff record for each "generating facility."[2]

1.2 The Commission issued the notice of PSEG ER&T's filing on June 8, 2015. The notice established a deadline of June 26, 2015 for the filing of protests and motions to intervene.

1.3 On June 10, 2015 PSEG ER&T filed an errata to correct an error in the proposed effective date and to include certain workpapers referenced in the June 5, 2015 filing.

1.4 The Commission issued the notice of PSEG ER&T's errata filing on June 10, 2015. The notice established a deadline of July 1, 2015 for the filing of protests and motions to intervene.

1.5 On June 22, 2015, PJM submitted an intervention and comments.[3]

1.6 On August 7, 2015, the Commission issued an order accepting PSEG ER&T's proposed revenue requirement, allowing it to become effective on January 7, 2016, but suspending it and establishing hearing and settlement judge procedures.[4] The Commission stated that "[w]e find that PSEG ER&T's proposed Reactive Power Schedule raises issues of material fact that cannot be resolved based on the record before us, and that are more appropriately addressed in the hearing and settlement judge procedures ordered below."[5]

1.7 On August 14, 2015, the Chief Administrative Law Judge issued an order designating the Honorable Steven A. Glazer to serve as Settlement Judge and directing the participants to explore the possibility of settlement.

---

2 The term "generating facility" refers to a specific location where a generation unit or generation units are located. In some instances, one generating unit is located at a generating facility and in others more than one generating unit is located at a generating facility.

3 *See* "Motion to Intervene and Comments of PJM Interconnection, L.L.C.," *PSEG Energy Resources & Trade LLC*, Docket No. ER15-1882-000 (June 22, 2015).

4 *See PSEG Energy Resources & Trade LLC*, 152 FERC ¶ 61,113 (2015) (the "August 7 Order").

5 *Id.*, P 10.

1.8 On August 27, 2015, Settlement Judge Glazer convened a settlement conference for the purpose of establishing a procedural schedule regarding the parties' exchange of information. PSEG ER&T and the Commission Trial Staff agreed upon a procedural schedule that the Settlement Judge adopted in an order issued on the same date.[6]

1.9 On various dates after August 27, 2015, PSEG ER&T and the Commission Trial Staff met and exchanged information in connection with settlement discussions. On October 15, 2015 and December 3, 2015, PSEG ER&T and the Commission Trial Staff participated in settlement conferences conducted by Settlement Judge Glazer.

II. OFFER OF SETTLEMENT

2.1 Pursuant to Commission Rule 602 and subject to the conditions set forth herein, and with the understanding that each term of this Offer of Settlement is in consideration and support of every other term and condition, PSEG ER&T's offers to settle the matter pending in Docket Nos. ER15-1882-000 and ER15-1882-001 on the terms set forth below. If this Offer of Settlement is approved by the Commission in its entirety or with conditions or modifications acceptable to PSEG ER&T (as provided in Section 3.1 below), the Offer would resolve the matter set for hearing by the August 7 Order.

2.2 In order to resolve the matter pending in this docket, and without prejudice to its position should the Commission reject this Offer of Settlement or approve it with conditions or modifications unacceptable to PSEG ER&T, PSEG ER&T hereby offers to reduce the aggregate reactive revenue requirement for the generation facilities set forth in the rate sheets in Rate Schedule FERC No. 3 filed in this proceeding from the aggregate amount of $38,671,025 to an aggregated amount of $34,000,000 per year. The Reactive Power revenue requirement set forth

[6] "Notice Scheduling Settlement Activities," *PSEG Energy Resources & Trade LLC*, Docket No. ER15-1882-001 (August 27, 2015).

in each rate sheet shall remain in place until the effectiveness of any subsequent PSEG ER&T's Reactive Power filing with respect to these generating facilities.

2.3 Attachment 1 to this Offer of Settlement, incorporated by reference herein, presents (in clean form) PSEG ER&T's First Revised Rate Schedule FERC No. 3, which incorporates the reduced annual revenue requirement for all rate sheets set forth in Section 2.1. PSEG ER&T's First Revised Rate Schedule FERC No. 3 specifically identifies the annual revenue requirement for each generation facility included in PSEG ER&T's Reactive Power filing in this proceeding. Thus, the First Revised Rate Schedule FERC No. 3 sets forth a separate rate for each generation facility.

2.4 In order to resolve the matter pending in this docket, and without prejudice to its position should the Commission reject this Offer of Settlement or approve it with conditions or modifications unacceptable to PSEG ER&T, PSEG ER&T hereby offers to agree to file, a Section 205 request for the Commission to modify or re-approve PSEG ER&T's rates for reactive power service for the generating facilities identified in PSEG ER&T's First Revised Rate Schedule FERC No. 3 attached hereto, to be effective no later than January 7, 2022; provided, however, that PSEG ER&T shall have the right to make a Section 205 filing to modify any or all of its Reactive Power service rates for its generating facilities at any time prior to January 7, 2022. Also, for newly constructed generation units or newly acquired units added to PSEG ER&T's generation fleet (including generators owned by any affiliate of PSEG ER&T) which have not previously supplied reactive power services to PJM, PSEG ER&T shall have the right to file under FPA Section 205 to establish an "initial" rate for each new generation unit effective as of the date of commercial operation of such unit.

2.5 If this Offer of Settlement is approved by the Commission without condition or modification, or if it is approved subject to one or more conditions or modifications acceptable to PSEG ER&T, PSEG ER&T will place First Revised Rate Schedule FERC No. 3 on file with the Commission, through the Commission's eTariff system, no later than thirty (30) days after such Commission order is issued, or on or before such other date as the Commission's order approving this Offer of Settlement may specify. PSEG ER&T's filing will request that First Revised Rate Schedule FERC No. 3 be made effective as of January 7, 2016, and will propose that PSEG ER&T's First Revised Rate Schedule FERC No. 3 supersede Original Rate Schedule FERC No. 3 in its entirety. If and to the extent PSEG ER&T has received compensation for reactive service pursuant to Original Rate Schedule FERC No. 3 that is in excess of the settlement amount, PSEG ER&T will refund the excess compensation to PJM with interest calculated in accordance with 18 C.F.R. §35.19a; provided, however, that such refund may be effectuated, with PJM's consent, through a one-time adjustment to charges payable to PJM by PSEG ER&T under the PJM Tariff.

2.6 If for any reason the Commission rejects this Offer of Settlement, or if the Commission approves the Offer of Settlement subject to one or more conditions or modifications unacceptable to PSEG ER&T, this Offer of Settlement shall be null and void, and shall be deemed to have been withdrawn by PSEG ER&T contemporaneously with the issuance of the Commission's order addressing this Offer of Settlement.

III. GENERAL PROVISIONS

3.1 Non-Severability. The provisions of this Offer of Settlement are not severable and shall not bind PSEG ER&T or any other party unless and until the Commission issues an order approving this Offer of Settlement as to all its terms and conditions without modification

or condition, unless PSEG ER&T advises the Commission within five (5) business days of the issuance of said order that any modification(s) or condition(s) imposed by such order are acceptable to PSEG ER&T.

3.2 No Admission or Precedent. PSEG ER&T's tender of this Offer of Settlement is solely for the purpose of compromising the matter set for hearing by the Commission and avoiding the costs and burdens of litigation, and is not intended to establish any principle or precedent with respect to any issue in this proceeding. Accordingly, neither this Offer of Settlement nor PSEG ER&T's performance in accordance herewith shall be deemed to constitute an admission or concession as to (i) the justness and reasonableness of any cost, charge, cost of service component, or ratemaking method, or (ii) any contention or position that was asserted, or that could have been asserted, in this docket. The Commission's approval of this Offer of Settlement shall not constitute a determination by the Commission as to the merits of any allegation or contention that was made or that could have been made in this proceeding; nor shall the Commission's approval of this Offer of Settlement be deemed to establish a "settled practice" as that term was interpreted and applied in Public Service Commission of the State of New York v. FERC, 642 F.2d 1335 (D.C. Cir. 1980).

3.3 Settlement Discussions. This Offer of Settlement results from settlement discussions conducted between PSEG ER&T and the Commission's Trial Staff. The results of those discussions were subsequently communicated to counsel for PJM. Such discussions and communication were conducted on the explicit understanding, pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602 (2015), that all offers of settlement and communications relating thereto shall be privileged and confidential, shall be without prejudice to the position of any party or participant presenting any such offer or

participating in any settlement discussions and communications, and are not to be used in any manner in connection with this proceeding, any other proceeding, or otherwise.

3.4 Effect on Statutory Rights. Other than as provided in Paragraph 2.3 above, neither PSEG ER&T's tender of this Offer of Settlement nor the Commission's approval thereof shall be construed as affecting PSEG ER&T's right to seek to amend Rate Schedule FERC No. 3 in any respect pursuant to Section 205 of the Federal Power Act and the Commission's Rules and Regulations adopted thereunder, or the right of any entity having a cognizable interest to oppose, to seek modification, to seek rejection, to seek suspension, or to seek refunds of any such amendment proposed by PSEG ER&T; or (ii) the right of any entity having a cognizable interest to petition the Commission to amend Rate Schedule FERC No. 3 under Section 206 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder, or PSEG ER&T's right to oppose any such petition.

3.5 No Effect on Commission Review Authority. Nothing in this Offer of Settlement is intended to affect the Commission's authority, pursuant to Section 205 of the Federal Power Act or otherwise, to review, accept (with or without conditions or modifications) or reject this Offer, or the legal standard applicable to the exercise of such authority.

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3.6 Interpretation. To the extent there is any inconsistency between this Offer of Settlement and the Explanatory Statement submitted in support hereof, the Offer of Settlement shall control.

Respectfully submitted,

PSEG Energy Resources & Trade LLC

By: *Hesser G. McBride, Jr.*

Hesser G. McBride, Jr.
Associate General Regulatory Counsel
PSEG Services Corporation
80 Park Plaza – T5
Newark, New Jersey 07102
(973) 430-5333
Hesser.McBride@PSEG.com

Dated: December 23, 2015
Newark, New Jersey

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ATTACHMENT 2:

EXPLANATORY STATEMENTIN SUPPORT OFOFFER OF SETTLEMENT

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PSEG Energy Resources & Trade LLC	))	Docket Nos.	ER15-1882-000 ER15-1882-001

EXPLANATORY STATEMENT IN SUPPORT OF OFFER OF SETTLEMENT

Pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 385.602 (2015), PSEG Energy Resources & Trade LLC ("PSEG ER&T") hereby submits an Explanatory Statement in support of the Offer of Settlement being filed by PSEG ER&T herewith.

I. BACKGROUND

On June 5, 2015, PSEG ER&T tendered for filing pursuant to Section 205 of the Federal Power Act its revised Rate Schedule FERC No. 3 ("Rate Schedule"), which sets forth the cost-based revenue requirements for the provision of Reactive Supply and Voltage Control from Generation Sources Service ("Reactive Power") owned by PSEG Fossil LLC ("PSEG Fossil") and PSEG Nuclear LLC ("PSEG Nuclear") ("Reactive Power filing"). The Reactive Power filing covers all of the generating facilities currently owned by subsidiaries of PSEG Power LLC ("PSEG Power") within the PJM Interconnection, L.L.C. ("PJM") region ("the Facilities").[1] While the Reactive Power filing includes all of generation facilities within the PJM region

[1] PSEG ER&T, PSEG Nuclear and PSEG Fossil are each direct subsidiaries of PSEG Power. PSEG ER&T is responsible for the administration within PJM of the assets covered by this filing and is currently recognized by PJM as the entity responsible for providing Reactive Power provided by the assets and is paid by PJM for providing such service. PSEG ER&T accordingly is the proper entity to provide this service.

owned by subsidiaries of PSEG Power, the filing sets forth a separate and distinct revenue requirement reflected in a separate tariff record for each "generating facility."[2]

The Commission issued notice of PSEG ER&T's filing on June 8, 2015. The notice established a deadline of June 26, 2015 for the filing of protests and motions to intervene.

On June 10, 2015 PSEG ER&T filed an errata to correct an error in the proposed effective date and to include certain workpapers referenced in the Reactive Power filing.

The Commission issued notice of PSEG ER&T's errata filing on June 10, 2015. The notice established a deadline of July 1, 2015 for the filing of protests and motions to intervene.

On June 22, 2015, PJM submitted an intervention and comments.[3]

On August 7, 2015, the Commission issued an order accepting PSEG ER&T's proposed revenue requirement, allowing it to become effective on January 7, 2016, but suspending it and setting it for hearing.[4] The Commission stated that "[w]e find that PSEG ER&T's proposed Reactive Power Schedule raises issues of material fact that cannot be resolved based on the record before us, and that are more appropriately addressed in the hearing and settlement judge procedures ordered below."[5]

On August 14, 2015, the Chief Administrative Law Judge issued an order designating the Honorable Steven A. Glazer to serve as Settlement Judge and directing participants to negotiate and accept or approve settlement terms.

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2 The term "generating facility" refers to a specific location where a generation unit or generation units are located. In some instances, one generating unit is located at a generating facility and in others more than one generating unit is located at a generating facility.

3 *See* "Motion to Intervene and Comments of PJM Interconnection, L.L.C.," *PSEG Energy Resources & Trade LLC*, Docket No. ER15-1882-000 (June 22, 2015).

4 *See PSEG Energy Resources & Trade LLC*, 152 FERC ¶ 61,113 (2015) (the "August 7 Order").

5 *Id.*, P 10.

On August 27, 2015, Settlement Judge Glazer convened a settlement conference for the purpose of establishing a procedural schedule. PSEG ER&T and the Commission Trial Staff submitted a proposed procedural schedule that the Settlement Judge adopted in an order issued on the same date.6

On various dates after August 27, 2015 PSEG ER&T and the Commission Trial Staff met and exchanged information in connection with settlement discussions aimed at reaching agreement on a negotiated resolution of the matter at issue in the case. And on October 15, 2015 and December 3, 2015 PSEG ER&T and the Commission Trial Staff participated in settlement conferences conducted by Settlement Judge Glazer. Those efforts resulted in an agreement in principle to resolve the matter at issue through a reduction in PSEG ER&T's requested revenue requirement.

The Offer of Settlement presents the basis for a resolution of the matter set for hearing in this docket. It is submitted by PSEG ER&T in the form of a unilateral offer of settlement, rather than a settlement agreement for reasons that are perhaps unique to this proceeding. First, Commission Trial Staff typically comments on proposed settlements rather than enters into them as a signatory. Second, PJM Interconnection, L.L.C. ("PJM"), which is the only intervenor in the docket, has advised PSEG ER&T that it will not be a signatory to the document (but also will not oppose the settlement). Accordingly, there is no participant in the docket that would be a counter-party to a settlement agreement with PSEG ER&T. In these circumstances, a unilateral offer of settlement by PSEG ER&T appears to be the correct vehicle for submitting its terms for the Commission's consideration.

6 "Notice Scheduling Settlement Activities," *PSEG Energy Resources & Trade LLC*, Docket No. ER15-1882-001 (August 27, 2015).

II. TERMS OF THE OFFER OF SETTLEMENT

A. Specific Terms

1. Subject to the other terms and conditions set forth in the Offer, PSEG ER&T will to reduce the aggregate reactive revenue requirement for the generation facilities set forth in the rate sheets in Rate Schedule FERC No. 3 filed in this proceeding from the aggregated amount of $38,671,025 to an aggregated amount of $34,000,000 per year. The Reactive Power revenue requirement set forth in each rate sheet shall remain in place until the effectiveness of any subsequent PSEG ER&T's Reactive Power filing with respect to these generating facilities. (See Section 2.1 of the Offer.) PSEG ER&T's Rate Schedule FERC No. 3 specifically identifies the annual revenue requirement for each generation facility included in PSEG ER&T's Reactive Power filing in this proceeding. Thus, each generating facility identified in Rate Schedule FERC No. 3 sets forth a separate rate for each generating facility. Attachment 1 to this Offer of Settlement, incorporated by reference herein, presents (in clean form) PSEG ER&T's First Revised Rate Schedule FERC No. 3, which incorporates the reduced annual revenue requirement for all rate sheets set forth in this Reactive Power filing.

2. In order to resolve the matter pending in this docket, and without prejudice to its position should the Commission reject this Offer of Settlement or approve it with conditions or modifications unacceptable to PSEG ER&T, PSEG ER&T hereby offers to agree to file, a Section 205 request for the Commission to modify or re-approve PSEG ER&T's rates for reactive power service for the generating facilities identified in PSEG ER&T's First Revised Rate Schedule FERC No. 3 attached hereto, to be effective no later than January 7, 2022; provided, however, that PSEG ER&T shall have the right to make a Section 205 filing to modify any or all of its Reactive Power service rates for its generating facilities at any time prior to

January 7, 2022. Also, for newly constructed generation units or newly acquired units added to PSEG ER&T's generation fleet (including generators owned by any affiliate of PSEG ER&T) which have not previously supplied reactive power services to PJM, PSEG ER&T shall have the right to file under FPA Section 205 to establish an "initial" rate for each new generation unit effective as of the date of commercial operation of such unit.

3. No later than 30 days after the Commission issues an order approving the Offer (or on or before such other date as the Commission may specify), PSEG ER&T would file a revised version of its Rate Schedule FERC No. 3 incorporating the settlement revenue requirement. (See section 2.3 of the Offer.)

4. If and to the extent PSEG ER&T has received compensation for reactive service in excess of the settlement amount, PSEG ER&T would refund the excess compensation to PJM with interest calculated in accordance with 18 C.F.R. §35.19a; provided that such refund may be effectuated through a one-time adjustment to charges otherwise payable by PSEG ER&T to PJM pursuant to the PJM Tariff.

5. Approval of the Offer without condition or modification, or with one or more conditions or modifications that are acceptable to PSEG ER&T (as provided in Section 3.1 of the Offer), would resolve the matter set for hearing in PSEG Energy Resource & Trade LLC, 151 FERC ¶ 61,113 (2015). (See Article II of the Offer.)

6. If for any reason the Commission does not approve the Offer of Settlement, or if the Offer of Settlement is approved subject to one or more conditions or modifications unacceptable to PSEG ER&T, the Offer of Settlement will then be null and void, and will be deemed to have been withdrawn by PSEG ER&T contemporaneous with the issuance of the Commission's order addressing the Offer of Settlement. (See section 2.4 of the Offer.)

B. General Terms

Sections 3.1 through 3.6 of the Offer of Settlement contain standard terms and conditions typically found in offers of settlement and settlement agreements filed with the Commission, including those pertaining to the non-severability of provisions, the absence of any precedent created by the Offer or its approval, confidentiality of settlement discussions, and preservation of parties 'Section 205 and 206 rights. The Offer also states that, in the event of any inconsistency between the Offer of Settlement and this Explanatory Statement, the Offer of Settlement controls.

III. RESPONSE TO QUESTIONS

By order dated October 15, 2003, the Chief Judge required that five questions be answered as part of every Explanatory Statement submitted in support of a proposed settlement. The questions and specific responses applicable to this Settlement are as follows:

1. What are the issues underlying the settlement and what are the major implications?

Approval of the Offer of Settlement would resolve issues relating to the justness and reasonableness of PSEG ER&T's proposed annual revenue requirement for reactive supply from its ownership interest in various generation units operating within the PJM Interconnection, LLC region. The Offer of Settlement proposes a reduction in PSEG ER&T's reactive revenue requirement without specification of any underlying cost elements or rate methodologies. Accordingly, Commission approval of the Offer of Settlement would have no major implications.

2. Whether any of the issues raise policy implications?

No. Approval of the Offer of Settlement would simply resolve the matter set by the Commission for hearing in this proceeding without specifying any particular ratemaking treatment or methodology.

3. Whether other pending cases may be affected?

No other pending cases will be affected by the proposed settlement.

4. Whether the settlement involves issues of first impression, or if there are any previous reversals on the issues involved?

There are no issues of first impression, and no previous reversals on the issues involved.

5. Whether the proceeding is subject to the just and reasonable standard or whether there is Mobile-Sierra language making it the standard, i.e., the applicable standards of review?

Section 3.5 of the Offer of Settlement states that nothing in the Offer is intended to affect the Commission's authority, pursuant to Section 205 of the Federal Power Act or otherwise, to review, accept (with or without conditions or modifications) or reject the Offer, or the legal standard applicable to the exercise of such authority. It is PSEG ER&T's understanding that, in the context of a unilateral settlement offer, any such exercise of the Commission's authority would be governed by the "just and reasonable" standard.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

IV. CONCLUSION

Approval of the Offer of Settlement would fully resolve the matter set for hearing by the August 7 Order in a fair and reasonable manner. Approval of the Offer of Settlement would allow the participants and the Commission to avoid the expense and risks of litigation, and, on that basis, approval of the Offer of Settlement is in the public interest. For these reasons, PSEG ER&T requests that, following consideration of any comments as may be filed, the Offer of Settlement be promptly certified to the Commission, and that the Commission then expeditiously approve the Offer of Settlement without condition or modification.

Respectfully submitted,

PSEG Energy Resources & Trade LLC

By: *Hesser G. McBride, Jr.*

Hesser G. McBride, Jr.
Associate General Regulatory Counsel
PSEG Services Corporation
80 Park Plaza – T5
Newark, New Jersey 07102
(973) 430-5333
Hesser.McBride@PSEG.com

Dated: December 23, 2015
Newark, New Jersey

SI-SSA-0010-6615

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

ATTACHMENT 3:

REVISED TARIFF

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

REVISED TARIFF

(CLEAN)

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

Reactive Supply and Voltage Control from Generation Sources Service

PSEG Energy Resources & Trade LLC ("PSEG ER&T") provides Reactive Supply and Voltage from Generation Sources Service ("Reactive Supply Service") from various generating facilities to the PJM Interconnection, LLC ("PJM") system. This Rate Schedule, which consists of seventeen separate tariff sections for each of PSEG ER&T's generating facilities, sets forth PSEG ER&T's revenue requirements for the provision of Reactive Supply Service to PJM, as contemplated by Schedule 2 of the PJM open access transmission tariff.

PSEG ER&T's total monthly revenue requirement consists of the sum of the charges for the following: (1) the Fixed Capability Revenue Requirement; and (2) the Heating Losses Component for each of its generating facilities. The Fixed Capability Revenue Requirement: the Heating Losses Component, and the Total Revenue Requirements for each generating facility is set forth in the Rate Schedule below. This Rate Schedule and its separate sections shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

Nothing contained herein shall be construed as affecting in any way the right of PSEG ER&T to unilaterally make application to the Federal Energy Regulatory Commission for a change in rates under section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder. If PSEG ER&T seeks to change one of the revenue requirements stated herein, it will abide by relevant FERC procedures for changes in rates and notify PJM in accordance with any notice requirement in the PJM Tariff.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

BERGEN 1 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,596,977.

Total Monthly Revenue Requirement is $216,414.73.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

BERGEN 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,076,006.

Total Monthly Revenue Requirement is $173,000.46.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

LINDEN 1 & 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $7,611,923.

Total Monthly Revenue Requirement is $634,326.88

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

HUDSON 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,225,284.

Total Monthly Revenue Requirement is $102,107.00.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

MERCER 1 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $282,354.

Total Monthly Revenue Requirement is $23,529.50.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

MERCER 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $855,097.

Total Monthly Revenue Requirement is $71,258.07.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

CONEMAUGH 1 & 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $436,981.

Total Monthly Revenue Requirement is $36,415.05.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

KEYSTONE 1 & 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $502,936.

Total Monthly Revenue Requirement is $41,911.37.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

SALEM 1 & 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,975,967.

Total Monthly Revenue Requirement is $164,663.88.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

HOPE CREEK 1 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $4,081,407.

Total Monthly Revenue Requirement is $340,117.28.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

PEACH BOTTOM 1 & 2 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $5,455,862.

Total Monthly Revenue Requirement is $454,655.17.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

SEWAREN 1 - 4 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $1,212,364.

Total Monthly Revenue Requirement is $101,030.37.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

BURLINGTON 12 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $916,582.

Total Monthly Revenue Requirement is $76,381.83.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

ESSEX 9 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $924,539.

Total Monthly Revenue Requirement is $77,044.95.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

KEARNY 12, 13, 14 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,589,795.

Total Monthly Revenue Requirement is $215,816.28.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

LINDEN 5, 6, 7, 8 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $986,835.

Total Monthly Revenue Requirement is $82,236.28.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

YARDS CREEK GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $269,091.

Total Monthly Revenue Requirement is $22,424.23.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

REVISED TARIFF

(REDLINED)

~~PSEG ENERGY RESOUCES & TRADE LLC~~

~~RATE SCHEUDLE FERC NO. 3~~

Reactive Supply and ~~voltage~~ Voltage Control from Generation Sources Service

PSEG Energy Resources & Trade LLC ("PSEG ER&T") provides Reactive Supply and Voltage from Generation Sources Service ("Reactive Supply Service") from various generating facilities to the PJM Interconnection, LLC ("PJM") system. This Rate Schedule, which consists of seventeen separate tariff sections for each of PSEG ER&T's generating facilities, sets forth PSEG ER&T's revenue requirements for the provision of Reactive Supply Service to PJM, as contemplated by Schedule 2 of the PJM open access transmission tariff.

PSEG ER&T's total monthly revenue requirement consists of the sum of the charges for the following: (1) the Fixed Capability Revenue Requirement; and (2) the Heating Losses Component~~. Total charges~~ for ~~any 12 month period will not be less than~~each of its generating facilities. The Fixed Capability Revenue Requirement:~~-~~ the ~~sum of~~ Heating Losses Component, and the ~~annual charges specified~~ Total Revenue Requirements for each generating facility is set forth in the Rate Schedule below. This Rate Schedule and its separate sections shall be effective upon the date authorized by the Federal Energy Regulatory Commission.

Nothing contained herein shall be construed as affecting in any way the right of PSEG ER&T to unilaterally make application to the Federal Energy Regulatory Commission for a change in rates under section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder. If PSEG ER&T seeks to change one of the revenue requirements stated herein, it will abide by relevant FERC procedures for changes in rates and notify PJM in accordance with any notice requirement in the PJM Tariff.

~~**MONTHLY REVENUE REQUIREMENT:**~~

~~**1. FIXED CAPABILITY COMPONENT**~~

~~The annual revenue requirement for the Fixed Capability Component is $25,750,450.~~

~~The monthly charge to PJM is $25,750,450 / 12 = $2,145,871~~

~~**2. HEATING LOSSES COMPONENT**~~

~~The annual revenue requirement for the Heating Losses Component is $876,337.~~

~~The monthly charge to PJM is $$876,337 / 12 = $73,028.~~

~~**3. TOTAL REVENUE REQUIREMENT**~~

~~Total Annual Revenue Requirement is $25,750,450 + $876,337 = $26,626,787~~

~~Total Monthly Revenue Requirement is $26,626,787 / 12 = $2,218,899.~~

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

BERGEN 1 GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $2,596,977.

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HOPE CREEK 1 GENERATING FACILITY

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BURLINGTON 12 GENERATING FACILITY

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YARDS CREEK GENERATING FACILITY

REVENUE REQUIREMENT

Total Annual Revenue Requirement is $269,091.

Total Monthly Revenue Requirement is $22,424.23.

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

ATTACHMENT 4:

DRAFT NOTICE OF FILING OF THE OFFER OF SETTLEMENT

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PSEG Energy Resources & Trade LLC	)	Docket Nos.	ER15-1882-000
	)		ER15-1882-001

NOTICE OF OFFER OF SETTLEMENT AND NOTICE OF SHORTENED COMMENT PERIOD

(Issued December __, 2015)

On December __, 2015, PSEG Energy Resources & Trade LLC filed an Offer of Settlement to resolve the matter set for hearing in the above-captioned proceeding. Included in its filing was a request to shorten the period for filing comments in response to the Offer of Settlement.

Interventions and protests were due in Docket Nos. ER15-1882-000 and ER15-1882-001 on or before July 1, 2015. No protests or adverse comments were filed. The motion to intervene and comment filed by PJM Interconnection, L.L.C. did not raise any substantive issues regarding the filing in Docket Nos. ER15-1882-000 and ER15-1882-001. As no protests or adverse comments were filed and the Settlement appears unopposed, we are shortening the date for filing initial comments to and including _____, 2016. Reply comments should be filed on or before _____, 2016.

Kimberly D. Bose,
Secretary

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

ATTACHMENT 5:

DRAFT LETTER ORDER APPROVING OFFER OF SETTLEMENT

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

_____, 2015

In Reply Refer To:
PSEG Energy Resources & Trade LLC
Docket Nos. ER15-1882-000 and ER15-1882-001

Hesser G. McBride, Jr.
Associate General Regulatory Counsel
PSEG Services Corporation
80 Park Plaza – T5
Newark, New Jersey 07102

Dear Mr. McBride:

1. On December __, 2015, you filed, in the above-referenced proceeding, a unilateral Offer of Settlement (Settlement) by PSEG Energy Resources & Trade LLC ("PSEG ER&T"). On January __, 2016, Commission Trial Staff filed comments in support of the Settlement. No other comments were filed. On January ___, 2016, the Settlement Judge certified the Settlement to the Commission as an uncontested settlement.[1]

2. The Settlement concerns PSEG ER&T's cost-based annual revenue requirement for Reactive Supply and Voltage Control from Generation Sources Service (reactive service) provided by various generation units that operation in the PJM Interconnection, LLC region and which PSEG has an ownership interest.

3. The Settlement states that "[n]othing in this [Settlement] is intended to affect the Commission's authority, pursuant to section 205 of the Federal Power Act or otherwise, to review, accept (with or without conditions or modifications) or reject this [Settlement], or the legal standard applicable to the exercise of such authority."[2]

4. The Settlement resolves all issues in this proceeding. The Settlement appears to be fair and reasonable and in the public interest, and is hereby approved. The Commission's approval of this Settlement does not constitute approval of, or precedent regarding, any principle or issue in this proceeding.

5. PSEG ER&T is directed to file tariff revisions to PSEG ER&T's reactive service

[1] PSEG Energy Resources & Trade LLC, ___ FERC ¶ _____ (2015).

[2] Settlement, § 3.5.

tariff (Rate Schedule FERC No. 3) in eTariff format,[3] within 30 days of the date of this order, to reflect the Commission's action in this order.

6. This letter order terminates Docket Nos. ER15-1882-000 and ER15-1882-001.

By direction of the Commission.

Kimberly D. Bose,
Secretary

[3] *Electronic Tariff Filings*, Order No. 714, FERC Stats. & Regs. ¶ 31,276 (2008).

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

ATTACHMENT 6:

CERTIFICATE OF SERVICE

20151223-5241 FERC PDF (Unofficial) 12/23/2015 11:43:14 AM

CERTIFICATE OF SERVICE

I hereby certify that I have, on this date, December 23, 2015 caused copies of the attached documents to be served by electronic mail on each individual included on the official service list for Docket Nos. ER15-1882-000 and ER15-1882-001 maintained by the Commission Secretary, and on the additional individuals listed below in accordance with Commission Rules 602(f) and 2010, 18 C.F.R. §§ 385.602 (F) and 385.2010 (2015):

Participants in ER15-1882-000 and ER15-1882-001

Commission Trial Staff	Kelsey Bagot	kelsey.bagot@ferc.gov

PJM Interconnection, L.L.C.

James E. Wrynn

James E. Wrynn
Paralegal

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Document Content(s)

PSEG Reative Power Settlement.PDF.....1-67